The INGAA Foundation, Inc.

The Role of Pipeline Age in Pipeline Safety

PREPARED FOR THE INGAA FOUNDATION, INC.

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

The Role Of Pipeline Age In Pipeline Safety

FOREWORD BY INGAA

At the end of 2010, the members of Interstate Natural Gas Association of America (INGAA), the Washington, DC-based trade group representing the vast majority of interstate natural gas pipeline companies, defined areas in which the overall integrity of natural gas transmission pipeline systems might be improved. High-profile incidents such as the one on Pacific Gas & Electric's pipeline system in San Bruno, California, in 2010 heightened the need for such an analysis.

Members made a conscious decision to define a future path instead of simply waiting for legislation and regulation. INGAA calls its program Integrity Management Continuous Improvement (IMCI). The five IMCI initiatives undertaken to address topics related to improving evaluation of aging pipelines are:

1. Defining a path to extend integrity management principles beyond "high-consequence areas" (HCAs)[1]. IMCI commits to applying integrity management principles in a staged manner outside of HCAs. This staged approach ensures that INGAA members address the impacts of the phenomena discussed in this report in a manner that prioritizes the protection of people who live, work or congregate near pipeline systems.

2. Evaluating how threats to pipeline integrity are considered. INGAA has changed the terminology applied, and has recommended to the American Society of Mechanical Engineers (ASME) that the term "resident" be incorporated into ASME B31.8S, the engineering standards related to pipeline integrity management. The term resident better conveys that a threat 'resides' and requires diligent management. INGAA also reviewed how threats potentially interact. Examples include how external corrosion might act upon a manufacturing-related defect or how ground movement or external loads might act upon construction-related threats. INGAA has developed interim guidance for considering interactive threats and has engaged the Gas Technology Institute to examine threat interaction and provide guidance to operators. The outcome of this collective work

[1] U.S, Department of Transportion regulations CFR 192 require pipeline operators to formulate and execute integrity management plans for their pipelines that are located in "high-consequence areas" (basically, areas of high population).

will intensify evaluation of the threats described in the study and manage those threats proactively.

3. Examining how pipeline companies and in-line inspection (ILI) providers might improve how inspection tools are used to manage threats. INGAA also is investigating how to improve the analysis of data derived from ILI to address uncertainty and better integrate data.

4. Defining requirements for historical records, vintage pipeline characteristics and how in-line inspection can contribute to managing pre-regulation pipe[2].

5. Developing a road map for ILI research, development and commercialization. INGAA is engaging the research community and technology providers to improve and develop new inspection and assessment tools (platforms as well as sensors) that can reliably identify hard-to-assess threats. The phased approach employed in extending integrity management and managing pre-regulation pipe is based on anticipated improvements in ILI technology and processes that will be available in the future.

As part of its pipeline safety initiatives, INGAA also commits to implement the recommended practices of the Pipelines and Informed Planning Alliance, a joint government, industry and pipeline-safety organization initiative to encourage local officials to consider existing pipelines as they approve and plan construction of homes, businesses or community facilities.

INGAA's efforts contribute to ensuring a well-maintained and periodically assessed pipeline network that can safely transport natural gas indefinitely.

This report, commissioned by the INGAA Foundation Inc., seeks to aid INGAA's efforts by investigating the role of pipeline age in pipeline safety, so pipeline companies and contractors can take steps – if necessary – to ensure that their systems are fit for service.

[2] Pre-regulation pipe is defined as pipe installed prior to 1970 when U.S. Department of Transportation pipeline safety regulations were promulgated.

The Role of Pipeline Age in Pipeline Safety

EXECUTIVE SUMMARY

This paper demonstrates that the age of a natural gas transmission pipeline, in and of itself, is not the most important factor affecting the safety of that pipeline. This paper's review of incidents reported to the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) from 2002 through 2009 found that 85% of incidents occurred irrespective of a pipeline's age, with just 15% related in some way to the age of the pipeline.

In cases where a pipeline's fitness for service may degrade with the passage of time, pipeline operators can take action to mitigate the effects of aging. Operators can periodically assess the integrity of such pipelines. Timely repairs based on those assessments will ensure fitness for service. A well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely.

The INGAA Foundation, Inc. retained Kiefner & Associates to investigate the relationship between pipeline age and pipeline safety. The focus of the paper is natural gas transmission pipelines. Still, many of the report's findings also would apply to pipelines carrying crude oil, motor fuels and other liquid petroleum products. While the natural gas transmission pipeline industry adds new pipelines every year, the majority of natural gas pipelines in the United States were built prior to 1970. Not surprisingly, when an older pipeline fails, there is a tendency to suspect that age played a role in the failure. This can lead to the perception that such pipelines are too old to operate safely.

As part of its research, Kiefner & Associates looked at the various phenomena that can threaten the integrity of a pipeline (i.e., its ability to operate safely without rupturing). It reviewed pipeline ruptures and serious leak incidents reported to PHMSA from the period of 1992 through 2011.

The review of the reportable incidents found that during this recent 20-year period there were 2,059 pipeline ruptures or major leak incidents. The PHMSA "reportable incidents" category was chosen as the primary measure for this report because it was the largest publicly available database of pipeline incidents. From these data, one can calculate the probability of a reportable incident at any random point if an incident were equally likely at any point in the 305,000 miles of natural gas transmission pipelines in the U.S. The incident rate is approximately 0.00034 per mile per year.

The paper's authors then looked at the incidents based on the decade of construction of the pipeline involved. They found there was no time-dependent degradation of the steel itself. As has been documented in a previous study sponsored by the INGAA Foundation[3], the properties of the steels used for natural gas pipelines (including the oldest steel pipelines in service) do not change appreciably with time; that is, pipe steel does not "wear out."

Still, in connection with certain causes of failure, the report's authors found some higher correlation between age and incident frequency based on the installation period. The authors focused on incidents from 2002 through 2009 because the incident reporting criteria were consistent over that period. Incident frequency from other causes did not exhibit any correlation with age.

The data indicated that older pipelines may be more susceptible to failure if certain kinds of threats are not assessed and mitigated. Factors that contribute to those threats being a higher concern for older pipelines are fully discussed in this paper, as well as mitigation approaches that have been proven to ensure these threats do not affect the safe operation of an older pipeline. These threats include:

- External Corrosion
- Rains/Floods
- Excavation Damage
- Manufacturing Defects
- Component Defects
- Girth Welds
- Seam Welds
- Stress Corrosion Cracking

[3] Clark, E,B,, Leis, B.N., and Eiber, R.J., "Integrity Characteristics of Vintage Pipelines", Appendix C, The INGAA Foundation, Inc., 2005

KEY FINDINGS

Ultimately, the safety of a particular natural gas transmission pipeline is not necessarily related to its age because:

1. 85% of pipeline incidents reported to PHMSA from 2002-2009 occurred irrespective of the age of the pipeline, with just 15% related in some way to the age of the pipeline.
2. The properties of the steels which comprise natural gas pipelines do not change with time; that is, pipe does not "wear out."
3. The fitness of a pipeline for service does not necessarily expire at some point in time.
4. The integrity of those pipelines for which the fitness for service may degrade with the passage of time can be assessed periodically. Timely repairs - and other mitigation efforts - based on those assessments will ensure the pipeline's continued fitness for service.
5. A well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely.

PIPELINES: AN ESSENTIAL MODE OF TRANSPORTATION

This section of the report provides the reader with background on why pipelines exist, and how they are designed, constructed, operated and maintained. Underground pipelines exist in a complex network that extends to most areas within the United States. Because they are buried and out of sight, pipelines usually make news only when one of them leaks or ruptures or a planned pipeline impacts a particular area of the country. Most of the time pipelines function as intended without incident because they are fundamentally safe owing to their design and to efforts of pipeline operators to operate them in a safe manner. Pipeline failures have occurred on rare occasions. Such failures seldom lead to injuries or fatalities, but they often cause property damage. As a result, both the pipeline industry and the federal government place great emphasis on pipeline safety; that is, taking steps to design, construct, operate and maintain pipelines so that the possibility of one failing is extremely small. Pipelines in highly populated areas and many pipelines in rural areas as well are periodically assessed to find and mitigate the effects of any deterioration before it threatens the safety of the pipeline.

Their function

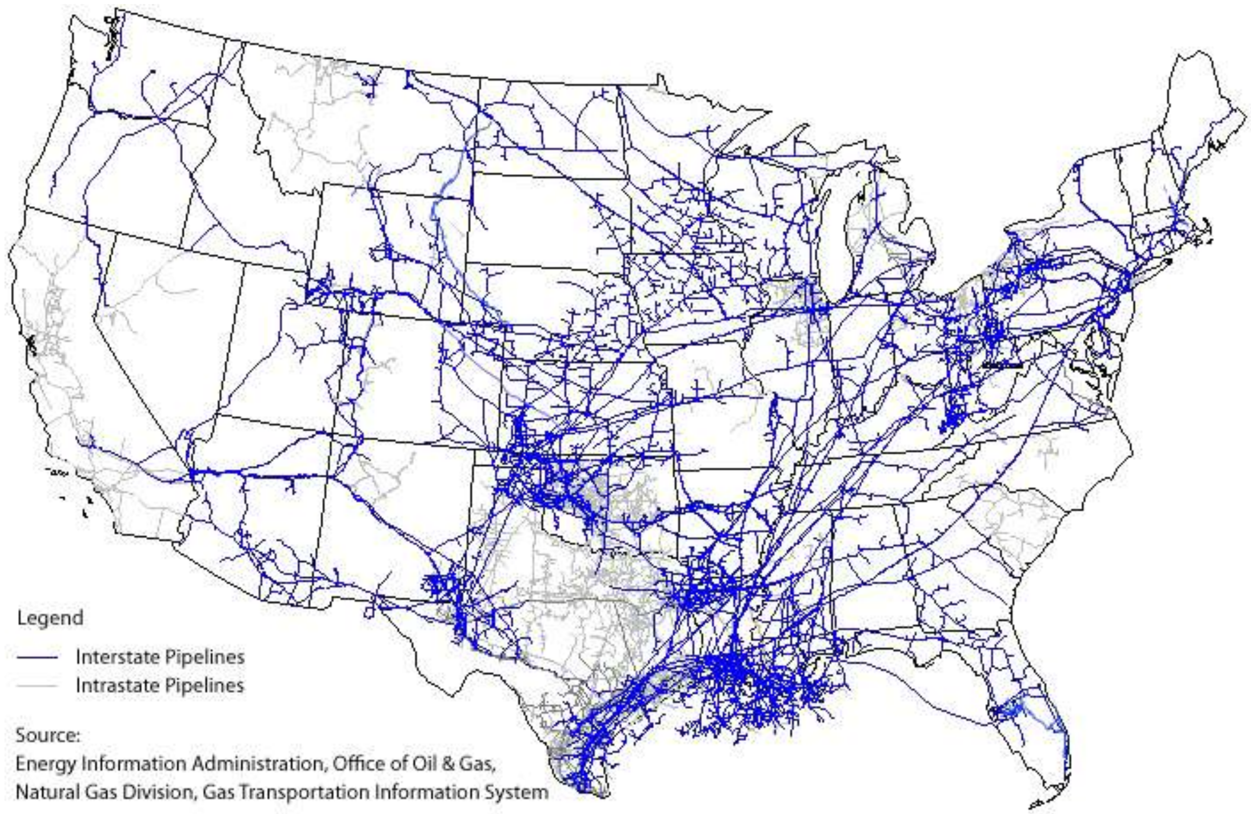
Pipelines are constructed to transport natural gas, crude oil, refined petroleum products (e.g., motor fuels, heating oil) and other fluids from sources of supply to customers or end users. The transportation of these commodities across the country is essential to our economy. Natural gas used for home heating and electric power generation, gasoline used in automobiles, diesel fuel used in trucks and buses, crude oil used to make gasoline and diesel fuel, raw materials used to make plastics and other chemicals mainly are transported by pipeline. Pipelines are both the safest and most economical means of transporting these commodities[4].

How many miles of pipelines are there?

This paper addresses a subset of these energy pipelines, namely, natural gas transmission pipelines. There are more than 305,000 miles of natural gas transmission pipelines in the United States. In general, these are pipelines that transport natural gas from sources of supply to points of interconnection with local gas distribution systems (the systems of mains and services that directly supply homes and businesses). Transmission pipelines range in size from six-inch-diameter to 48-inch-diameter and generally operate at pressure levels over 100 pounds per square inch -- well above the pressures that characterize local natural gas distribution systems. The locations of the major gas transmission pipelines are shown in Figure 1.

[4] http://phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=2c6924cc45ea4110VgnVCM1000009ed07898RCRD&vgnextchannel=f7280665b91ac010VgnVCM1000008049a8c0RCRD&vgnextfmt=print

Figure 1. Natural Gas Transmission Pipelines in the U.S.



What are the ages of pipelines?

Almost half of U.S. interstate transmission mileage was installed between 1950 and 1970. The percentage of natural gas pipeline mileage by decade installed[5] is shown in Figure 2.

The cumulative percentage by decade installed is shown in Figure 3:

- 12% of the pipeline infrastructure was installed prior to 1950,
- 37% was installed prior to 1960,
- 60% was installed prior to 1970,
- 70% was installed prior to 1980,
- 80% was installed prior to 1990, and
- 90% was installed prior to 2000.

[5] These data are taken from the 2009 Distribution, Transmission, and Liquid Annual Data published by the Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation. http://www.phmsa.dot.gov/

Figure 2. Percentage of Pipe Mileage Installed by Decade

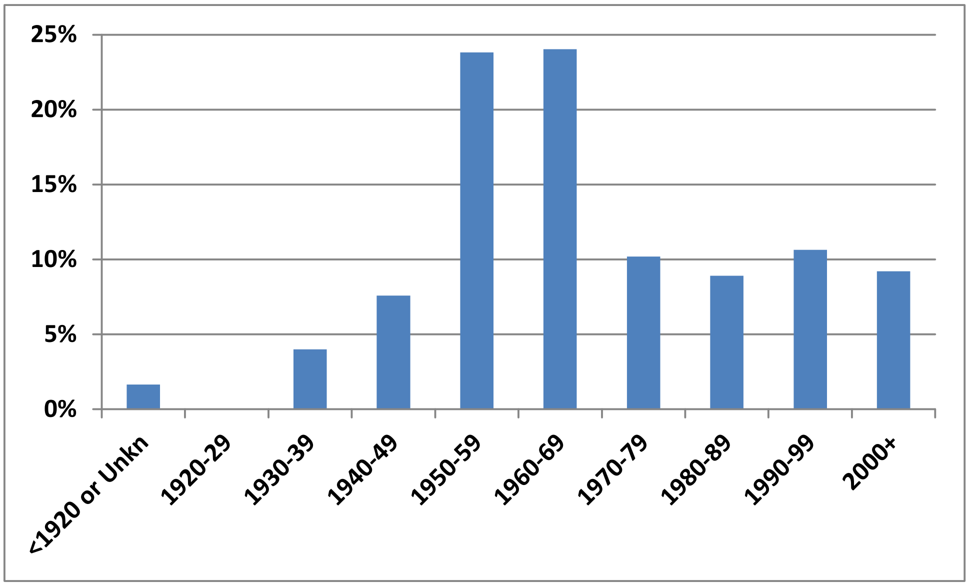
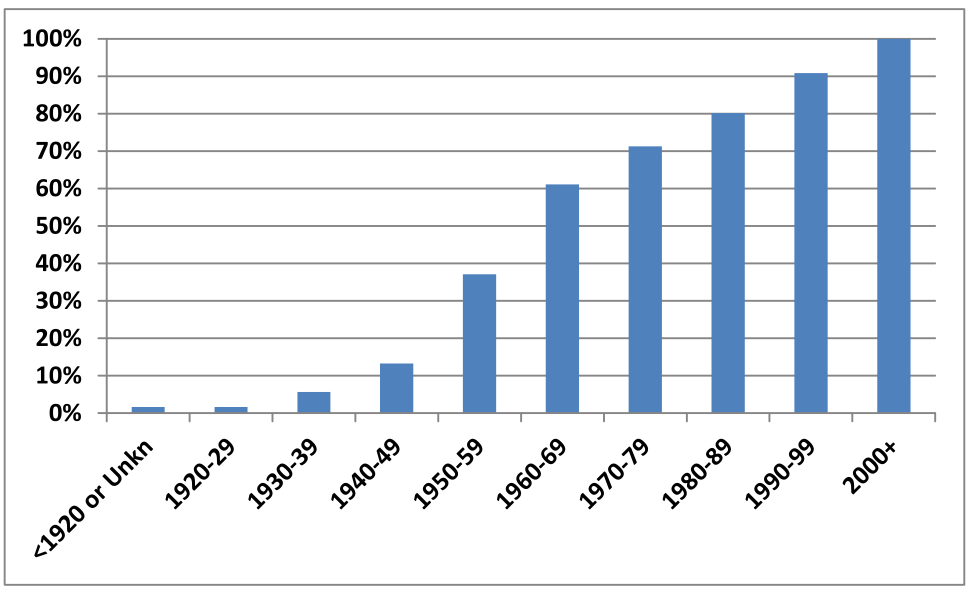


Figure 3. Cumulative Percentage of Pipe Installed by Decade



How do they work?

Natural gas is gathered from gas wells in various parts of the country. The gas is stripped of water, natural gas liquids and impurities at processing plants and injected into transmission pipeline systems. Natural gas must be pressurized to a range between 700 pounds per square inch and 1,440 pounds per square inch in order to be transported efficiently. These pressures are equivalent to 50 to 100 times atmospheric pressure and 25 to 50 times the typical pressure in a properly inflated automobile tire. The gas is propelled along by compressors located at intervals of 50 to 100 miles along the pipeline. Generally, the pressure is reduced at transfer points to local gas distribution systems (the pipe grids that serve commercial and residential customers), and the distribution pipeline operators further reduce the pressure so that gas is delivered to customers at a fraction of one pound per square inch above atmospheric pressure.

How is the pressure in the pipeline contained?

The tire, balloon and the steel pipe are very similar in the way that they contain pressure. The pressure inside a pipe exerts an outward force in the same manner that air or helium inflates a party balloon or an automobile tire. Party balloons tend to expand very noticeably because the balloon material is relatively thin, weak and easily stretched. Automobile tires, on the other hand, may change shape as they are inflated, but they expand very little because the tire body is thick enough, and strong enough to resist the inflation pressure without stretching much. Steel pipe works in a similar manner. Steel pipe can safely contain gas pressure if it has sufficient wall thickness and sufficient strength to resist the pressure. When steel pipe is pressurized, its resistance to stretching is so great that the size change is invisible to the naked eye.

Party balloons are made for fun, and it matters little if they burst. In contrast, peoples' lives depend on the soundness of automobile tires and pipelines. For that reason, automobile tires and steel pipelines are built to engineering standards which ensure that they will have more than sufficient wall thickness for a given diameter and material strength level to resist the pressure. Tires and pipelines also include a predictable and dependable margin of safety between the operating pressure and the pressure where failure would occur.

The stress in the pipe wall that resists the pressure is called the "hoop" stress because it acts in the circumferential direction. Both pipeline design standards and U.S. federal pipeline safety regulations impose distinct limits on the allowable level of hoop stress in a pipeline, discussed below.

How are pipelines designed?

Pipelines are built in response to the need to transport a certain amount of gas from a point of supply to a point of consumption. The diameter of a pipeline depends on the amount of gas that is anticipated will be transported within a certain period of time to meet demand. The designer then establishes an input pressure level that will deliver the commodity at the desired rate. Once the diameter and maximum operating pressure have been established, the designer chooses a steel pipe material with sufficient strength and wall thickness to contain the operating pressure with a sufficient margin of safety.

Natural gas pipelines are designed to operate within certain allowable hoop stress limits in accord with standards promulgated by the U.S. Department of Transportation. The actual design methods are embodied in a standard promulgated by the American Society of Mechanical Engineers (ASME)[6]. This design standard is intended to result in a finished pipeline that will safely carry the anticipated loadings (such as internal pressure, thermal stress, and external loads from soil or traffic) imposed on it during its service life with a conservative safety factor. The standard also sets forth requirements for construction, testing, inspection, operation and maintenance of the pipeline so that it can be operated in a safe manner.

What are pipelines made of?

Individual pieces of pipe that make up a pipeline are fabricated from low-carbon, low-alloy steels similar to those used to construct steel-frame buildings and steel bridges. Generically, these types of steels are classified as carbon steels or low-alloy steels to distinguish them from stainless steels, high-alloy steels or other construction metals such as aluminum. Line pipe refers to a specific type of pipe made according to a specification promulgated by the American Petroleum Institute (API)[7]. Pipe made to this standard must meet rigorous manufacturing requirements, maximum and minimum alloy-content limits, and minimum strength requirements. Each piece of pipe must be subjected to non-destructive examination using X-ray, electromagnetic or ultrasonic technology, and each must survive an internal pressure test at a level significantly in excess of its designated maximum allowable operating pressure. The pressure test establishes a safety margin for each joint of pipe.

Over many decades, improvements in steel-making and line-pipe manufacturing have enabled the use of stronger and more-reliable materials for pipeline construction. Current line pipe manufacturing processes include pipe made with double-submerged-arc-welded (DSAW) seams (either longitudinally or helically oriented), high-frequency-welded ERW seams and seamless pipe. Older-vintage (no longer manufactured) line pipe materials made with flash-welds, low-frequency ERW seams, single-submerged-arc-welded seams, or furnace-lap-welded seams are still present in some existing pipelines.

[6] B31.8-2010 Gas Transmission and Distribution Piping Systems. For a description of this design standard, please see www.asme.org/products/codes---standards/gas-transmission-and-distribution-piping-systems.

[7] "Specification for Line Pipe," ANSI/API Specification 5L/ISO 3183:2007, 44th Edition, October 1, 2007.

Federal pipeline safety regulations

The safety of natural gas transmission pipelines is regulated by the Pipeline and Hazardous Materials Safety Administration of the U.S. Department of Transportation.[8] Beginning in 1935, the American Standards Association (ASA) published standards for designing pipelines. These standards evolved over the decades as technology and processes evolved and now are embodied in ASME standards, referenced previously. Since 1970, federal pipeline safety regulations that were adapted from the ASME standards have set the minimum requirements for operators to design, construct, operate and maintain their pipelines in a safe manner. The federal standards further require each pipeline operator to have an integrity management plan for the portions of their systems that run through highly populated areas. A supplemental standard developed by ASME provides pipeline operators with additional guidance. This standard is referenced by federal standards.[9]

How are pipelines constructed, inspected and tested?

Pipelines are constructed by welding successive lengths of pipe end-to-end by means of electric-arc welding. The circumferentially oriented welds that join the lengths of pipe (i.e., the “girth” welds) are made in the field alongside the ditch that is excavated for burying the pipeline. Where changes in the horizontal or vertical alignment of the pipeline are required, curved pieces of pipe (referred to as “bends”) are inserted between straight pieces of pipe. Curved pieces of pipe can be prefabricated in special hot-bending facilities, or can be made in the field by “cold-bending” the pipe using portable hydraulic bending machines. After a number of lengths are joined in this manner, multiple bulldozers equipped with side-booms lift the pipeline in stages and lower it into the ditch. The pipeline is then covered with the soil that was removed to create the ditch.

Since the 1930s, almost all pipelines have been protected from external corrosion with a protective coating applied before installation either at a manufacturing facility or at the construction site. A pipeline may have been coated entirely in the field after it had been girth-welded by means of a line-traveling coating machine. In more recent times, the line-travel coating method has given way to applying a coating to each piece of pipe at the factory after it has been manufactured or after it has been transported to an off-site coating plant. An area at each end remains uncoated so that the pipe can be girth-welded into the pipeline. Then, after the girth welds have been inspected, coating is applied to the remaining uncoated area at each weld. In addition, as a complimentary system to coatings, cathodic protection is applied to pipelines by electrically charging it in a manner to mitigate external corrosion.

[8] Code of Federal Regulations Title 49, Part 192 Transportation of Natural and Other Gas By Pipeline: Minimum Federal Safety Standards
[9] “Managing System Integrity of Gas Pipelines”, ASME B31.8S-2010, Supplement to ASME B31.8, 2010.

After a pipeline has been buried, but before it is put into service, the pipeline is subjected to an internal pressure test to a level higher than the maximum allowable operating pressure to ensure that it is fit for service. The test determines if there are defects that would cause it to rupture at or below its maximum allowable operating pressure (MAOP). Under federal regulations in effect since 1970, the test pressure must be at least 1.1 times MAOP in areas where there are no buildings nearby the pipeline. In the vast majority of pipeline installed currently, the ratio of test pressure to MAOP is at least 1.25 in those areas. In highly populated areas, the required ratio of test pressure to MAOP is 1.5. In all cases, the test pressure of buried pipelines must be held for a minimum of eight hours to detect small leaks. Anomalies in the pipeline that survive such a test are too small to cause the pipeline to rupture while in service. The pre-service internal pressure test thus validates the "fitness for service" of the pipeline.

How are pipelines operated and maintained?

Pipelines are operated through a "control center," where trained operators dispatch natural gas according to the volume of gas demanded by the users and customers. The operators monitor internal pressures and flow rates and remotely operate compressors and valves to achieve the shipment of the required volumes of gas without allowing the internal pressure at any point in the system to exceed the MAOP. Pressure-relief devices or pressure switches and transmitters provide additional control to ensure that the MAOP is not exceeded.

Pipelines are maintained by trained maintenance personnel. Their job is to ensure that the equipment and pipe are properly functioning, and that the pipeline is protected adequately from various threats described below.

Standard inspection processes are used to validate the efficacy of these operation and maintenance practices. These processes range from validating that the protections systems are operating to confirming that the protection systems have achieved their goal. Within the past several decades, in-line inspection and direct assessment technology have augmented the standard inspection and "fitness for service" processes.

Pipeline Incidents and the Role of Pipeline Age

This section of the report describes the various phenomena that can threaten the integrity of a natural gas transmission pipeline.

What can go wrong?

If pipelines are properly designed, inspected, tested, operated and maintained as described previously, what can go wrong? Pipelines occasionally "rupture" or "leak". Occurrences of pipeline ruptures or serious leak incidents are a matter of public record[10]. The record shows that during the 20-year period from 1992 through 2011, there were 2,059 reportable incidents. Reportable incidents can range from incidents meeting a public nuisance level, to a significant incident with property damage, or to a serious incident involving injuries. From these data, one can estimate the probability of an incident at any random point if an incident were equally likely at any point in the 305,000 miles of natural gas transmission pipelines in the U.S. The rate for reportable incidents is approximately 0.00034 per mile per year if the likelihood of an incident occurring is the same everywhere.

Pipeline incidents almost invariably are caused by the presence of a weakness in the pipe or component or human error at the time of the incident. What follows is a presentation of the causes of failure incidents that can affect a pipeline. The number of incidents associated with each cause also is provided. A discussion of how pipeline operators mitigate these threats is presented later.

The rates of reportable incidents arising from each of 26 causes of pipeline failure incidents are presented below for a subset of the 20-year data discussed above. These 26 causes of incidents are the categories of reportable incidents used by PHMSA. The focus of this report is the recent PHMSA data from 2002-2009 because the incident reporting criteria were consistent over that time period[11]. During that eight-year period, there were 1,032 reportable natural gas transmission and gathering incidents. The rate of these incidents was 0.00042 per mile per year, slightly higher than the 20-year average.

The incident statistics for 2002-2009 analyzed will be restricted to those 738 incidents that occurred on onshore pipelines only because the causes of offshore incidents tend to differ significantly from those onshore.

Table 1 presents the numbers of incidents by incident-cause category[12]. Because the relationship of incident cause to the age of the pipeline is our main objective, and because not all of the

[10] The record of "reportable" incidents can be found at *http://www.phmsa.dot.gov/pipeline* under "Data, Reports, and Library" *Data & Statistics*. Under the heading "Accident/Incident Summary Statistics" and the subheading "All Reported Incidents (Gas Transmission Tab and Gas Gathering Tab)"

[11] From time to time PHMSA changes the reporting threshold or the reporting requirements. Usually, the changes result in more data being acquired. It is difficult to analyze data from two or more periods where the reporting requirements were not the same, because of confounding of effects of differences in the data from the different periods.

[12] Note that the PHMSA reportable incident database lists 25 incident cause categories. In Table 1, a twenty-sixth cause, Stress Corrosion Cracking (SCC), is added because twelve SCC incidents are separated from the External Corrosion cause category. Accordingly, the External Corrosion cause category in Table 1 shows only 83 incidents whereas in the PHMSA database 95 External Corrosion incidents are listed because they include the 12 SCC incidents. SCC is discussed separately because it requires a mitigation program that is significantly different from that applied to mitigate external corrosion.

reports gave the age of the pipeline, it was necessary to pare the number of incidents analyzed down from 738 to the 598 incidents where the age of the pipe was reported.

Table 1. Categories of Reportable Incidents on Gas Transmission and Gathering Pipelines during the Period 2002-2009

Cause Number	Category	Number of Incidents	Number of Incidents Where Age Was Reported	Percent of Total Where Age Was Known
1	External Corrosion	83	83	13.9
2	Internal Corrosion	47	46	7.7
3	Earth Movement	16	13	2.2
4	Lightning	12	8	1.3
5	Heavy Rains/Floods	27	15	2.5
6	Temperature	4	3	0.5
7	High Winds	7	5	0.8
8	Operator Excavation	24	17	2.8
9	Third Party Excavation	124	101	16.9
10	Fire/Explosion	12	9	1.5
11	Vehicle	48	39	6.5
12	Rupture of Previously Damaged Pipe	7	6	1.0
13	Vandalism	4	3	0.5
14	Body of Pipe	26	21	3.5
15	Component	19	18	3.0
16	Joint	15	12	2.0
17	Butt Welds	32	25	4.2
18	Fillet	9	6	1.0
19	Pipe Seam	18	16	2.7
20	Malfunction of Control/Relief System	55	35	5.9
21	Threads Stripped/Broken	15	14	2.3
22	Leaking Seal/ Packing	9	9	1.5
23	Incorrect Operation	23	15	2.5
24	Miscellaneous	68	48	8.0
25	Unknown*	22	20	3.3
26	Stress Corrosion Cracking	12	11	1.8
TOTAL		738	598	100

* Of the 22 incidents classified as "Unknown," 10 incidents were still under investigation at the time the reports were submitted, and for the other 12 incidents no cause was determined. No analysis of these incidents is possible because the factors that caused these incidents are not identified.

Is Pipeline Age a Factor in the Occurrence of Incidents?

Some of these causes are attributable to pipeline age because of a higher correlation between incident frequency and the period when the pipeline was installed. Our analysis focuses on the 598 accidents where usable data regarding pipeline age exists. Of these accidents, we show that 507 of them or 85% of these causes, do not exhibit any correlation with age.

At the outset, it should be noted that there is no time-dependent degradation of the steel itself. The properties of the steels that comprise natural gas pipelines (including the oldest steel pipelines in service) do not change appreciably with time; that is, the pipe steel does not "wear out." This fact was established in a previous report sponsored by the INGAA Foundation[13]. The actual level of safety associated with a given pipeline depends on how well it is defended against the various threats to its integrity that can create injurious defects in the pipe. Mitigation of threats and verification of fitness for service are necessary to keep a pipeline safe regardless of its age.

The relationships of incident causes to the age of the pipeline are shown in Table 2 (on page 17). The grouping of the incident data by decade for age was chosen because of the availability of the initial construction dates and in-service inventories of gas transmission pipelines in the PHMSA database. This decade range depicts not only the length of time that the pipeline has been in service, but provides a rough surrogate of the manufacturing methods of the pipe, the construction methods used to install the pipe and operating and maintenance practices.

To see easily where age could be a factor for a particular cause of incidents, it is useful to view these same data divided by the percentage of pipe presently installed in the pipeline system in each age group. This view normalizes the incident statistics by the amount by pipe by age in the existing infrastructure. The resulting numbers are shown in Table 3. Cells where the percentage of incidents significantly exceeds the percentage of pipe of a particular vintage (i.e. where the ratio is greater than 1.5) are highlighted because they correspond to concentrations of incidents within a particular age bracket suggesting age dependence. For the cause "External Corrosion," for example, 29% of the incidents occurred in the 12% of the pipe that was installed prior to 1950. The number "2.39" in the highlighted cell of Table 3 is simply 29% (the percentage of external corrosion incidents that occurred in pre-1950 pipe) divided by 12% (the amount of the pipeline infrastructure installed prior to 1950). The numbers in all of the cells in Table 3 were calculated in the same manner, and the highlighted cells show the vintage categories where incidents of a particular cause occurred significantly more frequently.

[13] Clark, E,B,, Leis, B.N., and Eiber, R.J., "Integrity Characteristics of Vintage Pipelines," Appendix C, The INGAA Foundation, Inc., 2005.

Table 2. Percent of Incidents by Cause that Occurred in a Pipe of a Given Vintage

Incident Cause	Incidents in the 12% of pipe presently in service that was intalled prior to 1950	Incidents in the 25% of pipe presently in service that was intalled between 1950 and 1959	Incidents in the 23% of pipe presently in service that was intalled between 1960 and 1969	Incidents in the 10% of pipe presently in service that was intalled between 1970 and 1979	Incidents in the 10% of pipe presently in service that was intalled between 1980 and 1989	Incidents in the 10% of pipe presently in service that was intalled between 1990 and 1999	Incidents in the 10% of pipe presently in service that was intalled between 2000 and 2009
External Corrosion	29%	22%	31%	11%	2%	4%	1%
Internal Corrosion	4%	20%	39%	11%	22%	4%	
Earth Movement	15%	23%	31%	15%	8%	0%	8%
Lightning	0%	25%	25%	38%	0%	0%	13%
Heavy Rains/Floods	27%	33%	0%	20%	7%	7%	7%
Temperature	0%	0%	100%	0%	0%	0%	0%
High Winds	0%	67%	0%	0%	0%	17%	17%
Op. Exc. Damage	0%	18%	35%	24%	6%	12%	6%
Third Party Exc.	20%	25%	25%	9%	8%	10%	4%
Fire/Explosion		11%	11%	11%	11%	44%	11%
Vehicle	10%	15%	23%	8%	18%	15%	10%
Rupture of Previously Damaged Pipe	33%		17%	17%		17%	17%
Vandalism	67%	0%	0%	33%	0%	0%	0%
Body of Pipe	24%	48%	14%	10%	5%	0%	
Component	22%	22%	6%	11%	11%	0%	28%
Joint	8%	17%	8%	17%	17%	8%	25%
Butt Weld	20%	24%	28%	8%	8%	4%	8%
Fillet	17%	17%	17%	17%	0%	17%	17%
Seam	6%	69%	19%	0%	0%	0%	6%
MCRE	3%	9%	6%	14%	17%	20%	31%
TSBPC	7%	7%	36%	0%	21%	0%	29%
LSPP	0%	11%	11%	11%	33%	11%	22%
Incorrect Operations	0%	20%	20%	27%	20%	0%	13%
Miscellaneous	2%	25%	17%	8%	8%	10%	29%
Unknown	25%	25%	5%	10%	5%	10%	20%
Stress Corrosion Cracking	18%	18%	64%	0%	0%	0%	0%

Table 3. Distribution of Incidents by Cause by Pipeline Age

Incident Cause	Incidents in the 12% of pipe presently in service that was intalled prior to 1950	Incidents in the 25% of pipe presently in service that was intalled between 1950 and 1959	Incidents in the 23% of pipe presently in service that was intalled between 1960 and 1969	Incidents in the 10% of pipe presently in service that was intalled between 1970 and 1979	Incidents in the 10% of pipe presently in service that was intalled between 1980 and 1989	Incidents in the 10% of pipe presently in service that was intalled between 1990 and 1999	Incidents in the 10% of pipe presently in service that was intalled between 2000 and 2009
External Corrosion	2.39	0.89	1.34	1.06	0.21	0.43	0.11
Internal Corrosion	0.36	0.78	1.70	1.09	2.17	0.43	0.00
Earth Movement	1.28	0.92	1.34	1.54	0.77	0.00	0.77
Lightning	0.00	1.00	1.09	3.75	0.00	0.00	1.25
Heavy Rains/Floods	2.23	1.33	0.00	2.00	0.67	0.67	0.67
Temperature	0.00	0.00	4.35	0.00	0.00	0.00	0.00
High Winds	0.00	2.67	0.00	0.00	0.00	1.67	1.67
Op. Exc. Damage	0.00	0.70	1.53	2.35	0.59	1.18	0.59
Third Party Exc.	1.65	0.99	1.08	0.89	0.79	0.99	0.40
Fire/Explosion	0.00	0.44	0.48	1.11	1.11	4.44	1.11
Vehicle	0.86	0.62	1.00	0.77	1.79	1.54	1.03
Rupture of Previously Damaged Pipe	2.78	0.00	0.73	1.67	0.00	1.67	1.67
Vandalism	5.56	0.00	0.00	3.33	0.00	0.00	0.00
Body of Pipe	1.98	1.90	0.62	0.95	0.48	0.00	0.00
Component	1.85	0.89	0.24	1.11	1.11	0.00	2.78
Joint	0.69	0.67	0.36	1.67	1.67	0.83	2.50
Butt Weld	1.67	0.96	1.22	0.80	0.80	0.40	0.80
Fillet	1.39	0.67	0.73	1.67	0.00	1.67	1.67
Seam	0.53	2.75	0.82	0.00	0.00	0.00	0.63
MCRE	0.24	0.34	0.25	1.43	1.71	2.00	3.14
TSBPC	0.59	0.28	1.55	0.00	2.14	0.00	2.86
LSPP	0.00	0.44	0.48	1.11	3.33	1.11	2.22
Incorrect Operations	0.00	0.80	0.87	2.67	2.00	0.00	1.33
Miscellaneous	0.18	1.00	0.73	0.83	0.83	1.04	2.92
Unknown	2.08	1.00	0.22	1.00	0.50	1.00	2.00
Stress Corrosion Cracking	1.50	0.72	2.78	0.00	0.00	0.00	0.00

As seen in Table 3, some of the highlighted cells occur in the older pipeline age brackets suggesting that age could be a factor for particular causes of incidents.

- External Corrosion incidents were concentrated in pre-1950 pipe.
- Heavy Rains/Floods incidents were concentrated in pre-1950 and 1970s pipe.
- Third Party Excavations were concentrated in pre-1950 pipe.
- Body of Pipe incidents were concentrated in pre-1950 pipe and pipe installed between 1950 and 1959.
- Component-related incidents were concentrated in pre-1950 pipe.
- Butt-weld-related incidents were concentrated in pre-1950 pipe.

It is noted that concentrations of incidents occurred in pre-1950 pipe for the causes: Previously Damaged Pipe, Vandalism, Unknown, and Miscellaneous. These concentrations can be ignored for the following reasons. In the cases involving Previously Damaged Pipe and Vandalism the numbers of incidents were too small (6 for Previously Damaged Pipe, 3 for Vandalism) to be meaningful. The same reasoning applies to the age-related concentrations of incidents cases involving Temperature (3 incidents) and High Winds (5 incidents). In the case of incidents with unknown or miscellaneous causes, there is nothing to be gained from analyzing the numbers by decade.

What accounts for the apparent tendency of the incident causes in the bullet list above to occur more often in older pipelines? Some possible reasons are discussed below.

a. External Corrosion

The likely reasons that older pipelines seem to be more susceptible to external corrosion are that some of the oldest pipelines were installed with no coating, and that the use of cathodic protection did not become common until the 1940s and 1950s. Even though many older pipelines were retrofitted with cathodic protection systems, metal loss occurring prior to the installation of cathodic protection probably established a lower baseline from which the corrosion could continue. If the corrosion continued even at a lower rate after the installation of cathodic protection, failure still would be more likely than in a pipeline that was adequately protected from its outset. Another possible contributor to the higher rate of external corrosion incidents is that some older pipelines were not designed to accommodate in-line inspection (ILI) tools. These ILI tools are now used effectively to find and repair corrosion-caused metal loss defects before they can become large enough to cause a pipeline to fail. They also provide additional guidance on where to increase cathodic protection levels or reinstall protective coating. The drop-off in external corrosion failures seen in Table 3 for newer pipe probably is the result of the advent of the use of high-technology coatings such as fusion-bonded epoxy in use since the 1970s and the application of cathodic protection early in the life of the pipeline.

b. Internal Corrosion

Two concentrations of internal corrosion incidents are seen in Table 3, neither of which suggests that internal corrosion is an age-related cause of incidents. One concentration occurred in the decade of the 1960s, and one occurred in the decade of the 1980s. Because there is no apparent reason why pipelines installed in these decades would be more susceptible to internal corrosion than pipeline installed in other decades, these concentrations are assumed to have been random occurrences and are ignored.

c. Heavy Rains/Floods

The fact that older pipelines were more susceptible to failure from heavy rains/floods than newer pipelines is probably a function of older pipelines having been in their location longer. A longer time in service increases the likelihood of removal of trench cover by scouring or undercutting of soil around the pipe due to increased water velocities caused by heavy rains or flooding. Open-cut trench crossing are used for streams and smaller bodies of water. Older pipelines were installed in trenches made in the bottoms of rivers and other water crossings and may not have been given as much cover near the banks of rivers as pipelines have received more recently. Horizontal directional drilling has been used in the construction of many water crossings since the early 1980s and is the predominant technique used in the last 10 years for rivers and large bodies of water. Operators can ensure that the pipe underwater is protected by conducting periodic surveys and observation of soil movement on banks along the water. Where there is erosion, soil and rip-rap (rock) can be added along banks and stabilized with techniques such as matting. In rivers and streams, stone and rock can be added to provide cover or the crossing can be retrenched.

It is noted that there was also a concentration of incidents in the 1970s for which there is no reason why there would be age related incidents involving heavy rains/floods. Therefore that decade has been ignored as age related.

d. Excavation Damage

Older pipelines sustained more third-party damage incidents than newer pipelines if one assumes an equal probability of excavation activities by third parties. This outcome probably is the result of older pipelines being less well-marked and buried at shallower depths than newer pipelines. Another possible contributing factor is that older pipeline materials are probably less resistant to failure than newer materials when hit by heavy excavating equipment. Interestingly, the older pipelines did not seem to be more affected by operator excavation damage than the newer pipelines, possibly due to operators applying greater diligence than third-party excavators. The above-ground portions of older pipelines did not appear to be any more susceptible to vehicle impacts than newer pipelines.

e. Pipe Body Defects

Older pipelines were more susceptible than newer pipelines to failures from pipe-body defects. Five of these failures involved wrinkle bends, an obsolete technique for bending pipe that left the pipe more vulnerable to failure than a smooth bend if there was movement. Two other incidents resulted from hard spots, which are a phenomenon associated with a particular manufacturer's pipe made in the 1950s. At least four other body-of-pipe failures were attributed to pipe mill defects or cracks that one would expect to find more readily in certain vintage manufacturing processes. Alternatively, it is possible that some of the "crack" failures resulted from small manufacturing defects having grown over a long period of time from internal pressure-cycle-induced fatigue. However, one would not expect to find failures from internal pressure-cycle-induced fatigue in a natural gas transmission pipeline unless the pipeline had never been subjected to a strength test at all, or was only tested to a small margin above the operating pressure.

f. Components

Component-related incidents (such as failures of valves, meters and other appurtenances) appeared to have taken place at a higher rate in the oldest pipelines. Twenty-two percent of the component incidents occurred in the oldest 12% of the infrastructure installed prior to 1950. The remaining component incidents were spread fairly evenly over the years of pipeline installation. The failures in the oldest systems likely were related to branch connection defects and cracks in valve bodies. Prior to 1950, fabricated fittings were more likely to have not been made according to ASME standards and some older valve bodies were made from cast iron or cast steel rather than from forged steel.

g. Butt Welds

The butt weld-related failures, involving primarily leaks at girth welds and fabrication welds, appeared to be somewhat related to the ages of the pipelines. This is probably the result of the girth welds in the older pipelines having different construction-acceptability requirements.

h. Other Defects

As seen in Table 3, incidents associated with the other causes were concentrated in pipes of particular vintages, but not the oldest vintages. In most cases, there is no explanation for this. It seems probable that many of these concentrations are random occurrences. For example, there is no conceivable reason why incidents caused by lightning, LSPP, or earth movement should be concentrated in pipe installed between 1970 and 1979, why TSBPC, and incorrect operations incidents should be concentrated in pipe installed in the time periods 1960-1969 and 1980-1989, or that the incidents caused by Operator Excavation Damage, Fire/Explosion, Vehicle, Joint, Fillet, or MCRE should be concentrated in pipelines installed in the particular decades shown in Table 3. Still, there are two causes of incidents where a concentration of incidents in pipe of a particular vintage is explainable. Those are:

- Seam incidents were concentrated in pipe installed in the period from 1950 through 1959.
- Stress Corrosion Cracking incidents were concentrated in pipe installed in the period from 1960 through 1969.

Leaks and ruptures involving seam defects were concentrated in or near the decade from 1950 through 1960. Eighty percent of these incidents occurred in pipe materials manufactured between 1949 and 1962. These incidents involved leaks and ruptures in double-submerged-arc welds, flash welds, both low- and high-frequency-welded ERW seams, and one continuous welded seam. The period of pipe making from 1949 through 1962 was characterized by a huge growth in the amount of pipe being manufactured, with new manufacturers and new processes being developed and implemented. Moreover, non-destructive testing of seams by the manufacturers was not required in the standard pipeline manufacturing requirements, API Specification 5L, until 1962.

There is some possibility that small leaks withstand initial mill and commissioning pressure testing due to high temperature oxide (mill scale) plugging the leak path; dissolution or degradation of the oxide may then eventually result in small leaks later in service. Small leaks do not necessarily constitute a failure of the pipe, although the leak may be reportable and may require a repair. The integrity threat associated with leaks is best assessed and mitigated through routine leak surveys.

The occurrences of incidents caused by stress corrosion cracking were clustered in pipelines with years of installation between 1947 and 1968. This is probably attributable to the fact the pipelines installed in that era were operated in a manner that allowed gas discharge temperatures to be as high as 180ºF. Not only did this, in some instances, lead to coating damage, it also facilitated the occurrence of a type of stress corrosion cracking that grows at higher rates with increased temperature. Once it was learned that these high discharge temperatures promoted the occurrence of this type of stress corrosion cracking, pipeline operators installed gas cooling systems at compressor stations. Pipelines installed after the gas-discharge-temperature problem was recognized appear to be much less susceptible to that particular form of stress corrosion cracking. A second factor is that conditions that promote another type of stress corrosion cracking are most prevalent with a particular coating type (plastic tape wrap) that can disbond intact from the pipe surface so as to trap moisture. In addition, the plastic tape has a high dielectric value that shields the pipe from the cathodic protection current. This type of coating for new construction was common in the 1960s and 1970s.

The number of age-related incidents for each age-related cause is shown in Table 4. The number was calculated by multiplying the total number of incidents associated with that cause (in Column 3 of Table 4) by the percentage of incidents in the time period of interest (in Column 2 of Table 4). The percentage of incidents in Column 2 of Table 4 is the percentage of incidents that were age-related. Age-related incidents also are highlighted in “red” in Table 3. It is seen that pipeline age was a factor in about 15% of incidents (91 out of 598 incidents). Conversely, 507 or 85 percent of the incidents occurred irrespective of the age of the pipeline.

Table 4. Numbers of Incidents Where Year of Installation was Known

Incident Cause (Age-related Incident Causes Highlighted)	Percent of Incidents Affecting Older Pipelines	Number Where Year of Installation Was Known	Number of Age-Related Incidents (Column 2 times Column 3)
External Corrosion	30%	83	25
Internal Corrosion		46	
Earth Movement		13	
Lightning		8	
Heavy Rains/Floods	27%	15	4
Temperature		3	
High Winds		5	
Op. Exc. Damage		17	
Third Party Exc.	20%	101	20
Fire/Explosion		9	
Vehicle		39	
Previously Damaged Pipe		6	
Vandalism		3	
Body of Pipe	71%	21	15
Component	22%	18	4
Joint		12	
Butt Weld	20%	25	5
Fillet		6	
Seam	69%	16	11
MCRE		35	
TSBPC		14	
LSPP		9	
Incorrect Operations		15	
Miscellaneous		48	
Unknown		20	
Stress Corrosion Cracking	64%	11	7
TOTAL		598	91

How Pipeline Operators Assure the Safety of their Pipelines and How They Address the Effects of Pipeline Age on Pipeline Safety

In this section of the document, the steps and actions that pipeline operators take to operate and maintain their pipelines safely are discussed.

Time-dependent degradation of pipelines

As mentioned previously, pipeline degradation may occur from external or internal corrosion-caused metal loss, from stress corrosion cracking, or from pressure-cycle-induced fatigue crack growth of material defects or construction and fabrication defects (though few, if any, fatigue failures have occurred in natural gas pipelines because of the infrequency of large pressure fluctuations in a gas pipeline). Operators must be aware of the potential of fatigue occurring and periodically evaluate applicable portions of their systems. One approach for evaluating the fatigue susceptibility appears in a 2003 GRI report.[14]

The preventive and mitigative measures employed by pipeline operators against these threats are many and are discussed below. Further, if these degradation phenomena affect a given pipeline and threaten its integrity in spite of the preventive and mitigative measures, pipeline operators can perform periodic integrity assessments and repair any defects discovered through these assessments. In fact, PHMSA regulations require that pipeline operators carry out periodic integrity assessments of their pipelines located in high-consequence areas, and most pipeline operators carry out such assessments on other parts of their pipeline systems as well.

Responses to effects of time-dependent degradation

Pipelines can tolerate some degree of deterioration without failing because of the inherent safety factors included in their design. A piece of pipe that has sustained some deterioration (from external corrosion, for example) could still be fit for service as long as the amount of metal loss does not cause the pipe to be seriously weaker at or near the operating stress level of a pipeline. If the defect were allowed to continue to grow, of course, its failure stress level would eventually degrade to the operating stress level, and a pipeline failure would result. Pipeline operators apply corrosion evaluation criteria in evaluating integrity assessment data and investigate anomalies where the amount of deterioration appears to encroach upon the accepted margin of safety against failure at the operating stress level. Whenever a time-dependent defect growth

[14] Kiefner, J. F., and Rosenfeld, M.J., "*Effects of Pressure Cycles on Gas Pipelines*", Gas Research Institute Contract No. 8749, Report No. GRI-04/0178 (September 17, 2004).

mechanism is active, maintaining fitness for service requires repeated assessment of the integrity of the pipeline at intervals that ensure that no defect grows to the size that will cause the pipeline to fail. Methods of integrity assessment used by pipeline operators include: a.) hydrostatic testing, b.) in-line inspection and c.) direct assessment. These are explained below.

a. Pressure testing

Because the primary source of stress on a pipeline is the internal pressure of gas, one way to demonstrate that a pipeline can safely carry its design stress level is to pressurize the pipeline to a satisfactory margin of stress above its MAOP. An in-service pipeline must be taken out of service to conduct pressure testing. In such a case, the natural gas is purged from the pipeline, the pipeline is filled with water, and the water is pressurized to a higher level than MAOP (e.g. 1.25 times MAOP). Defects with failure pressures below the maximum test pressure will fail. The failed sections, if any, are replaced, the water is removed and the pipeline is restored to service.

Pressure testing demonstrates a level of fitness for service depending on the ratio of test pressure to operating pressure. If such a test is done to assure the integrity of a pipeline that is subject to growing stress corrosion cracks for example, the test stress level assures that the surviving stress corrosion cracks are too small to fail at the operating stress of the pipeline at the time of the test. If the stress corrosion cracks can be expected to continue growing, the pipeline operator must anticipate that another test will be needed in the future to reconfirm that the pipeline is safe from failing at its operating stress level. Pipeline operators schedule future tests on the basis of their best understanding of how fast the stress corrosion cracks are growing, but irrespective of the growth rate itself, the higher the ratio of test pressure to operating pressure is, the longer the interval between tests can be. The same thought process applies to other crack or defect growth mechanisms, such as, external corrosion, internal corrosion or pressure-cycle-induced fatigue.

b. In-line inspection

The fitness for service of a pipeline affected by a time-dependent defect growth mechanism can be demonstrated using ILI, or running a “smart pig” through the pipeline. ILI involves inserting an instrumented device into a pipeline and causing the device to move through the pipeline with the flow of gas. Smart pigs of various types are available. Some are designed to locate and characterize corrosion-caused metal loss. Others are designed to locate and characterize dents or other geometric irregularities. Still others are designed to locate some kinds of material defects and crack-like defects. The information on each type of anomaly recorded by the device guides the pipeline operator to the location of the anomaly. In many cases, the information also provides reasonably accurate information on the sizes of the anomalies, so the pipeline operator can prioritize the examinations of anomalies by their severity. The pipeline operator can then excavate and examine the pipeline at the indicated locations to verify the nature of the anomaly. If the anomaly is determined to be potentially injurious, the operator will make a suitable repair to restore the pipeline to a safe condition.

To perform an in-line inspection, the pipeline operator choses a particular tool that is capable of locating and characterizing the size of a defect associated with a particular mode of degradation, such as external corrosion-caused metal loss. The location and sizing data are recorded for analysis after the tool run. A failure stress prediction model is applied to each recorded anomaly to predict its failure stress level based on the length and depth of the anomaly indicated by the tool data. The same model also is used to determine how large the anomaly would have to grow for it to cause a failure at the operating stress level. Using the apparent defect growth rate, the pipeline operator can determine when each anomaly must be excavated and repaired in order to maintain the integrity of the pipeline. The operator can anticipate that a future ILI tool run will be needed to revalidate the integrity of the pipeline from the standpoint of the anomalies that are not excavated and repaired. If ILI is used to assess the integrity of a pipeline located in a highly populated area, PHMSA regulations require that the inspections be run every seven years. To the extent that a particular ILI technology is capable of finding and sizing the defects accurately, ILI may be used to assess the integrity of a given pipeline that may be affected by stress corrosion cracking or fatigue as well as corrosion-caused metal loss.

The integrity of most pipelines can be assessed periodically in this manner if the pipeline is capable of accommodating the appropriate ILI tool. Data compiled by INGAA[15] show that 74% of the mileage of their members' pipelines is piggable at this time and that 89% of its members use ILI technology for assessing pipeline integrity[16].

c. Direct assessment

Another form of integrity assessment is referred to as "direct assessment" (DA). DA may be used for assessing a pipeline that is affected by external corrosion, internal corrosion or stress corrosion crackin*g*, by applying techniques and standards tailored to each of the three phenomena. DA relies on a rigorous four-step process, starting with an evaluation of the operating and maintenance history and the environment surrounding the segment to be assessed. This includes an analysis of the suitability of DA, as it is not suitable under some circumstances. Further analysis is done to define the appropriate tools to make indirect measurements, above ground, that provide indications of the pipeline's integrity. The indirect measurements are used to identify areas suspected of being affected by one of the three phenomena. Operators excavate

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[15] INGAA Members Achieve Significant Integrity Management Progress in 2011, INGAA, April 2012
[16] Progress Made with Integrity Management, INGAA, March 27, 2012

and examine locations along the pipeline that they suspect may be undergoing degradation. The severities of the defects found, if any, are noted, and repairs are made if necessary. Findings are used to assess the process and revise it if appropriate. As with pressure testing and ILI, re-assessment following DA is scheduled based on the perceived rate of defect growth. A fourth and final step in the DA process entails review and evaluation of findings and a confirmation of the planning for future assessments.

Features of some older pipelines that may expose them to increased risk of failure

Certain features of some older pipelines and pipe materials necessitate more effort on the part of pipeline operators to maintain their integrity.

Inherent problems with older line pipe steels

Prior to 1960, most line pipe was made from alloys primarily composed of carbon-manganese steels. Starting in the 1960s, manufacturers of line pipe began to switch from carbon-manganese steels to micro-alloyed steels with lower carbon contents. The micro-alloyed steels tended to be more resistant to fracturing in a brittle fashion and were more easily welded. By the 1980s, most manufacturers of line pipe had switched from open-hearth, ingot-cast steels to basic-oxygen, low-sulfur, continuous-cast materials, resulting in steels that were much less prone to have non-metallic inclusions resident in the material. The newer steels not only tended to be relatively free of injurious impurities, they also were more resistant to fracturing in the presence of a defect. As the data on pipeline age shows, 70% of the pipeline infrastructure in the U.S. is comprised of steels manufactured prior to 1980. The older pipelines need not be retired, however, if an adequate manufacturer's test or an adequate test before or during service has been performed. A test to a pressure level at least 1.25 times the maximum allowable operating pressure of a natural gas pipeline after construction generally is considered adequate for demonstrating initial pipeline integrity. Such a test ensures that any remaining manufacturing or construction defect is small enough to remain stable for hundreds of years, provided the line is not subject to unforeseen external conditions or extreme operating pressure fluctuations. Still, operators can periodically evaluate the potential impact of external loads and pressure cycling to reduce risk. External load impacts can be mitigated through matting when equipment is operating over a pipeline, lowering the line and, in some instances, replacing short sections of pipe. Meanwhile, the effects of pressure cycling can be mitigated through a change in operations, pressure-limiting devices or periodic assessment via ILI or hydrostatic tests.

Problems with older types of seam welds

Prior to 1978, several seam-manufacturing processes existed that have since become obsolete. These included furnace lap-welded seams, flash-welded seams, low-frequency-welded ERW seams and single-submerged-arc-welded seams. All of these seams were prone to contain more manufacturing defects and to have less resistance to fracturing than the seams of newer line pipe materials. The analysis of reportable incident data for the period 2002-2009 showed that 80% of the seam defect failures were clustered in pipe manufactured in the period from 1949 through 1962. After 1962, line pipe manufacturers were required to perform non-destructive inspection on all seam welds at the time of manufacturing. This does not mean that no pipe made prior to that year was inspected by manufacturers, but rather, that the practices of manufacturers and requirements of the customers prior to 1960 were not uniform. Around that time and throughout the 1960s, manufacturers abandoned seam manufacturing processes that involved furnace lap-welding, low-frequency ERW welding and flash welding. Since then, the consistency of line pipe seam welds has improved greatly. Nevertheless, the seam integrity of the older pipelines is initially assured for those pipe segments that were subjected to an adequate pressure test (e.g. test-pressure-to-operating-pressure ratio of at least 1.25) at some time in their history. Pipelines with the older longitudinal seam types require continued diligence from the standpoint of external loads and unforeseen pressure fluctuations, as discussed in the prior section.

Older bending and joining methods

Wrinkle bends result from an obsolete bending practice that left prominent transverse wrinkles in the pipe. These wrinkles are often linked to problems such as corrosion because the wrinkles were hard to coat uniformly. In addition, wrinkle bends occasionally have exhibited failures from longitudinal forces that would have little or no impact on a smooth bend. Wrinkle bends also may constitute an obstruction to running smart pigs through a pipeline. Even if they do not constitute an obstruction, it is difficult to obtain valid smart pig data from the region of the wrinkles. These bends require greater diligence in unstable soils. There have been recent advances in the use of ILI to identify anomalies associated with girth welds, and this is an area of continued technology development.

Couplings and acetylene girth welds were used to construct pipelines into the 1930s (or a bit later in some systems comprised of small-diameter pipe) when shielded-metal-arc welding became the standard method for joining pipe in the field. Pipelines with these types of joints are more prone to failure from earth movement or from heavy rains and floods than pipelines fabricated with shielded-metal-arc girth welds. These joining methods require greater diligence during excavations for routine maintenance and in locations with unstable soil

Built-in obstructions to in-line inspection tools

Many older pipelines were installed with non-full-opening valves such as plug valves. Other older pipelines were installed with circular-opening but reduced-diameter valves. Some other older gas pipelines were constructed of sections of pipe having different diameters. These features make it very difficult to accommodate smart pig inspections.

Smart pig vendors have developed tools that can traverse these “reduced-port” valves or can work in more than one pipe diameter. Also, some operators have undertaken projects to remove restrictive appurtenances such as plug valves in order to accommodate standard ILI tools.

Miter bends and closely spaced factory bends in some older pipelines prevent the passage of smart pigs. Some tools have been developed that can negotiate bends of this type. Typically, ILI tools that are capable of negotiating obstructions described here are one generation behind the most current sensing technologies, but are still effective for assessing the integrity of the pipe.

Most older pipelines were originally built without launching and receiving facilities for smart pigs. Many operators, however, have retrofitted such facilities into their older pipelines.

Low pressure or low gas flow in a pipeline may make it impossible to run a smart pig as conventional ILI tools are moved by the gas flow, and are referred to as being “gas-driven.” For pipelines where ILI tools cannot be readily accommodated, the other options for assessing integrity - hydrostatic testing or direct assessment - can be employed.

Extensive research and development work has been undertaken in the past 10 years to develop platforms to enable sensors deployed on gas-driven ILI to be deployed on robotic tools. Robotic platforms now are able to navigate through obstructions in a pipeline and provide their own propulsion system to move through the pipeline. Robotic platforms became available for commercial use at the end of the first decade in the 2000s and their numbers are increasing to address the range of diameters present in the natural gas infrastructure. In addition, for short segments that are otherwise not conducive to gas-driven ILI, tethered ILI tools exist that may be launched into a pipeline and retrieved by a cable system connected to the tool.

IS THERE A LIMIT TO THE LIFE OF A PIPELINE?

As demonstrated in the sections above, a well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely because the time-dependent degradation threats can be neutralized with timely integrity assessments followed by appropriate repair responses. This applies to old pipelines as well as to newer pipelines, provided that the pipeline operators recognize and compensate for the problems associated with the characteristics of the older pipelines. With regard to age-related threats, the safety of a well-maintained and periodically assessed pipeline is ensured regardless of age through diligent and well-planned integrity management practices.