Report to the National Transportation Safety Board on Historical and Future Development of Advanced In-Line Inspection Platforms for Use in Gas Transmission Pipelines

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INGAA
Interstate Natural Gas
Association of America

AGA
American Gas Association

Contents

Executive Summary

The Interstate Natural Gas Association of America (INGAA) and the American Gas Association (AGA) have prepared this document to respond to the National Transportation Safety Board's Recommendation P-11-32 in their report on the Pacific Gas and Electric Pipeline Rupture and Fire in San Bruno, California. The recommendation reads as follows:

> *"Report to the National Transportation Safety Board on your progress to develop and introduce advanced in-line inspection platforms for use in gas transmission pipelines not currently accessible to existing in-line inspection platforms, including a timeline for implementation of these advanced platforms."* (P-11-32)

In the United States, there are 2.4 million miles of natural gas pipelines that serve more than 71 million residential, commercial and industrial customers. For the operators of these natural gas pipelines, no issues are more important than those concerning safe, reliable pipelines and ensuring public confidence in those systems. INGAA and AGA, the organizations representing the vast majority of these pipeline systems, agree that in-line inspections are a vital tool in their arsenal of pipeline safety strategies, management systems and devices.

Pipeline safety has improved consistently over the decades through the application, continuous refinement and evolution of consensus standards, technology, law and regulation. Yet no natural gas pipeline incident is acceptable, and INGAA, AGA and their members recognize that more can be done to improve the safety of natural gas transmission pipelines and ensure public confidence in the safety of our pipeline infrastructure.

Getting it right is imperative because pipelines are so vital to our nation's energy supply and economy. The U.S. natural gas pipeline network is a highly integrated transmission and distribution system that allows natural gas to flow to and from nearly any location in the lower 48 states and Canada. The pipeline system will continue to be expanded and reconfigured in coming years and decades to allow access to new supply sources, including production from shale gas and other unconventional sources, and to permit delivery to growing markets, including the rapidly expanding gas-fired power generation sector. The investment needed to modify the existing pipeline infrastructure to adapt to these changes in supply and demand regions will create American jobs, generate state, federal and local tax revenue, and add to economic output.

Assessing the fitness for service of transmission pipelines can be challenging. The vast majority of the natural gas pipeline infrastructure is below ground and not amenable to direct external visual inspection unless excavated. Pipeline companies apply a broad range of measures to ensure the fitness of their pipelines for service. Pipeline operators have used design, construction, operations and maintenance practices that were a part of consensus standards since the mid-1930s and these practices have been enhanced and improved continually.

Integrity management is best described as a continuous improvement process to manage the threats that might impede safe operation of natural gas transmission systems. In-line inspection (ILI) is one form of assessment within integrity management. In-line inspections are conducted using "smart pigs," devices inserted into a pipeline that travel through the line to collects various forms of data using electronics and sensors to inspect the condition of the pipeline. When a pipeline is capable of being inspected by ILI (a "pig"), it is considered piggable. Piggability generally requires three main parts: navigation, or the ability of the pig to transverse the pipeline segment unimpeded; motive power, or a system and adequate pressure to propel the pig through the pipeline; and access, or the ability to insert the pig into the pipeline and to retrieve it.

The use of ILI has revolutionized pipeline inspections as part of integrity management programs, and pig technology has improved and expanded over the past 47 years. The earliest ILI tools to be used in natural gas transmission pipelines were first developed in 1965, using magnetic flux leakage (MFL) technology and focusing on metal loss due to corrosion. These prototype pigs could inspect less than 30 miles—much less than the 60 to 80 miles typically traversed today—and inspected only the bottom quarter of the pipeline, which was believed to be the location of the majority of corrosion. By 1970, new pigs extended the sensor arrangement to create a full circumference 360-degree tool, but limitations of the data recording systems restricted good data collection to slow speeds. While ideas abounded, technical problems, ranging from a lack of a liquid couplant for signal transmission on natural gas pipelines to poor signal-to-noise ratios, thwarted widespread development and use.

The renaissance of MFL ILI tools occurred in the 1980s. The accuracy of these ILI tools improved such that anomalies could be identified by placing the depth of the metal loss into three gross categories: less than 30 percent, 30 to 60 percent, and greater than 60 percent wall thickness.

Commercial ILI tools and technology improvements greatly accelerated into the 1990s and 2000s. Accuracy of detecting and sizing metal loss anomalies improved as new and more sensors were added to pigs, allowing higher resolution imaging. Breakthroughs were introduced in pig mobility, including suspension systems that allowed pigs to track accurately in a pipeline even as it bent and curved, and new ways to propel the pig through the pipeline. In addition, sensors were miniaturized allowing pigs to fit through smaller lines and speed controls were added, allowing pigs to more accurately assess pipelines that were constructed in areas with changing elevations. New technology also created dual-diameter pigs, allowing more lines to be inspected.

At the same time, information technology expanded, allowing robust computer-based analysis of the raw data. In the early days, magnetic sensors essentially taped data as it flowed through the pipeline. Now, terabytes of digital data are sent nearly instantaneously to powerful computers for detailed analysis. Pre-analysis algorithms help characterize metal loss defect depth, enabling the use of five gross categories instead of the early three.

During these same decades, new and different types of pig sensors using new technology were introduced, expanding the types of threats that could be detected and finding new and different ways to detect those assessed by standard MFL technology. New technology introduced ultrasonic compression wave pigs, which assessed metal loss to identify internal and external corrosion, and ultra-sheer-wave technology pigs, which utilized crack detection technology to identify stress corrosion cracking, longitudinal cracks and internal and external corrosion. Locational technology was integrated with the other sensor technology, improving accuracy.

Also introduced were transverse flux pigs, which assess metal loss and use crack detection technology to seek large longitudinal cracks and internal and external corrosion, and deformation or geometry pigs, which assess deformation of pipeline cross sections to determine if the pipeline has suffered excavation, outside-force or construction damage.

In the 2000s, combination sensors were introduced on commercial pigs. Sensors using different technologies, with different capabilities, can now be sent simultaneously through the pipeline, giving engineers a more robust view of the pipeline and a greater ability to detect and characterize anomalies.

Despite the technological developments, pigs cannot detect all problems within pipelines. Pigs cannot find very small, thin cracks, particularly those that run longitudinal along a pipeline.

Current major research initiatives are focused on closing these gaps and improving technology to address some of these limitations. Finding small cracks is the focus of much research, as is improving the algorithms to interpret the data. In addition, researchers are working to research data on external natural forces, like soil shifting and subsidence, to incorporate into computer models to detect more accurately potential areas of concerns.

AGA's member companies have recognized the common need to address local distribution company (LDC)-owned transmission mains that are unpiggable. They have invested considerable resources through the research consortiums NYSEARCH and Operational Technology Development (OTD) to develop, test and commercialize robotic platforms for inspection of these lines. The robotic platforms have made many previously "unpiggable" transmission pipelines piggable. While still new to the market, the robotic platforms are a step-change in how operators address unpiggable lines. Additional work is underway to create additional pipeline sizes and consequently the amount of pipe that can be assessed.

INGAA's member companies have long-term commitments to pipeline safety, and have laid out a number of new benchmarks related to integrity management programs that they intend to achieve in coming years. ILI tools are an integral part of that strategy and are key components in implementing these three particular commitments:

- INGAA pipelines will apply integrity management principles (IMPs) on pipelines that cover approximately 90 percent of the population living along INGAA members' pipelines by December 31, 2012.
- INGAA pipelines will consistently apply comprehensive IMPs to pipeline covering 90 percent of the population living along members' pipelines by 2020.
- INGAA pipelines will apply IMPs to pipelines covering all of the population living along members' pipelines by 2030.

While technology development has been proceeding within ILI companies, in order to reach aggressive INGAA goals, cooperative research consortiums and individual pipeline operators are expediting technology development and deployment. INGAA and its member are committed to ensuring that the technology and physical facilities are in place and intend to implement a plan to identify solutions to technology shortfalls in the summer of 2012.

INGAA, AGA, their members and research partners are committed to ensuring the safety and reliability of the nation's natural gas pipeline infrastructure. Significant efforts have been expended and progress has been made in many areas, including ILI improvements. When first developed, ILI technologies had extremely limited capability. Today, advanced ILI technology can identify a number of anomalies within the pipeline, assess miles of pipe in one run, adapt to changing diameters and overcome obstacles within the line. Robotic platforms have the ability to crawl significant distances through the line, retreat to assess further, navigate through valves and assess lines that previously were considered unpiggable. While more needs to be done, we should not lose sight of the progress made. Our goal is simple: Keep pipelines as safe as possible to serve our customers and deliver the nation's energy. Getting it right is imperative. The natural gas industry and its partners are committed to this goal.

Introduction

In September 2011, the National Transportation Safety Board, as part of its report on the Pacific Gas and Electric pipeline rupture and fire in San Bruno CA, highlighted in-line pipeline inspection as an important tool to promote transmission pipelines safety and public confidence in this vital infrastructure system.

The Interstate Natural Gas Association of America (INGAA) and the American Gas Association (AGA) have prepared this document in responding to the National Transportation Safety Board's Recommendation P-11-32. The recommendation reads as follows:

> *"Report to the National Transportation Safety Board on your progress to develop and introduce advanced in-line inspection platforms for use in gas transmission pipelines not currently accessible to existing in-line inspection platforms, including a timeline for implementation of these advanced platforms."* (P-11-32)

INGAA represents approximately two-thirds of the pipelines and over 65 percent of the mileage comprising the U.S. natural gas transmission pipeline system. INGAA's 27 members operate approximately 200,000 miles of interstate transmission pipelines, deliver one-quarter of the nation's energy and serve as an indispensable link between natural gas producers and consumers.

AGA represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 71 million residential, commercial and industrial natural gas customers in the U.S., of which 92 percent — more than 65 million customers — receive their gas from AGA members. AGA members operate approximately 50,000 miles of gas transmission pipelines.

According to the U.S. Energy Information Administration, the U.S. natural gas pipeline grid comprises about 305,000 miles of interstate and intrastate transmission pipelines (approximately 82 percent which are operated by INGAA or AGA members) and more than 11,000 delivery points, 5,000 receipt points and 1,400 interconnection points that provide for transfer of natural gas throughout the U.S. The natural gas transported by these transmission pipelines heats homes and businesses and is used to produce steel, glass, paper, clothing, and as a an essential raw material for many common products, like plastics, fertilizers, dyes, paints and medicines. Natural gas also fuels power plants and is used in homes to run stoves, furnaces, water heaters, clothes dryers and other household products. All told, natural gas meets almost one quarter of the U.S. energy needs.

Because natural gas is so important to the nation's economy, ensuring that pipelines are safe, reliable and fit for service is our number one priority.

This document contains eight sections addressing Inline Inspection (ILI) technology and its application in natural gas transmission pipeline systems, including this introduction.

They are:

Overview of Natural Gas Transmission Pipelines and Challenges of Integrity Management This section describes the important role of natural gas transmission pipelines in providing the energy needs of the United States and the challenges of maintaining the fitness for service while maintaining reliability of the infrastructure.

Overview of Integrity Management and the Role of Integrity Assessments – This section provides a brief overview of integrity management and places assessments in context of the larger set of processes and practices that are used to manage pipeline integrity.

Configuration of Natural Gas Transmission Pipeline Assets; Ability to Utilize ILI Devices – This section provides an overview of how transmission systems are configured and the challenges this configuration may create for ILI.

Development of ILI Inspection Platforms and Expansion of Piggable Pipeline Segments – This section provides a high-level history of ILI development and assessment technology and describes the expansion of the use of the technology.

Recent Integrity Management Accomplishments of the Use of ILI Technologies – This section explains how ILI technology has been incorporated into the management of integrity by natural gas transmission pipeline operators.

Development of ILI and Other Assessment Technology – This section highlights how the development of ILI inspection technology in the past has been a combination of investment by ILI vendors, collaborative research conducted through individual pipe operators, Joint Industry Projects, PHMSA and Cooperative Research Organizations

Current State of Technology and Projected Timeframes for Enhancement of Existing Technology and Development of New Technologies – This section highlights the accomplishments that have been achieved in advancing ILI technologies and includes a table depicting the current state of technology, projected timeframes for enhancement of existing ILI technology and development of new technologies based on predicted technological breakthroughs and present investment strategies.

Future ILI R&D Focus, Development and Coordination– This section outlines the areas of future development and provides a table showing timeframes for development.

Overview of Natural Gas Transmission Pipelines and Challenges of Integrity Management

There are several challenges that a natural gas operator must overcome to assure that an operating pipeline is reliable and fit for service.

Constant delivery of critical natural gas to customers

Natural gas transmission pipelines are a critical component (see Figure 1) of the natural gas delivery system that provides approximately 25 percent of the energy for the U.S. The natural gas delivery value chain can be described as a "just in time" delivery system to over 71 million residential, commercial and industrial customers.

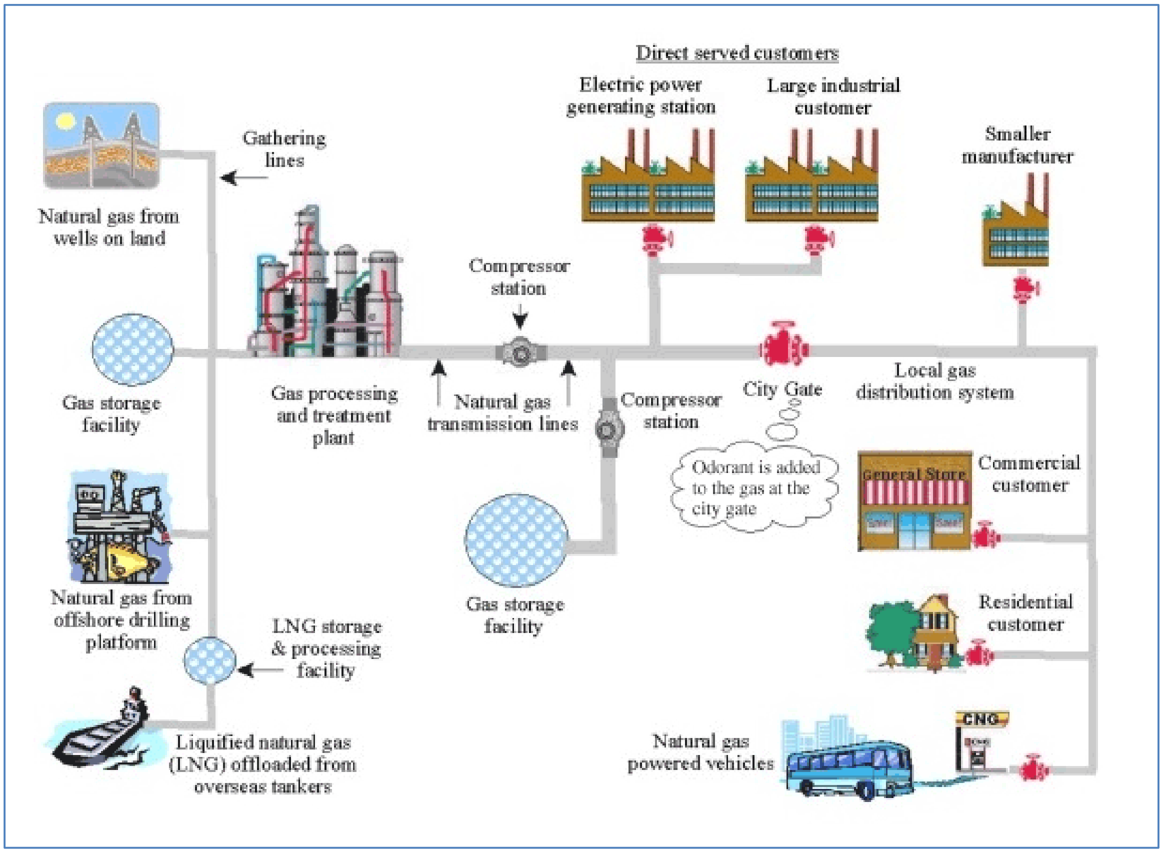

Figure 1 - Depiction of natural gas value chain (source; PHMSA web site)

Customers rely on the natural gas delivery system to be constantly in operation. While U.S. natural gas usage tends to peak in the winter months when heating demand is the highest, the increasing use of natural gas to generate electric power and as a feedstock to industrial customers limits the opportunities to take pipelines down for long-term maintenance and inspection at any point during the year. Natural gas delivery has a strong reputation for reliability, even during extreme events. Appendix A contains more information on the role of natural gas in the U.S.

Limitations of access to natural gas transmission pipelines for inspection

The bulk of the natural gas infrastructure is below ground and is not amenable to direct external visual inspection, unless excavated. Pipelines are installed two to three feet below ground depending on the soil type and pipeline diameter. Pipelines in agricultural areas with deep tilling or special circumstances may be buried even deeper.

As shown in Figure 2, the transmission infrastructure is geographically dispersed (unlike distinct plant locations) and is subject to many different types of topography and geologic environments.

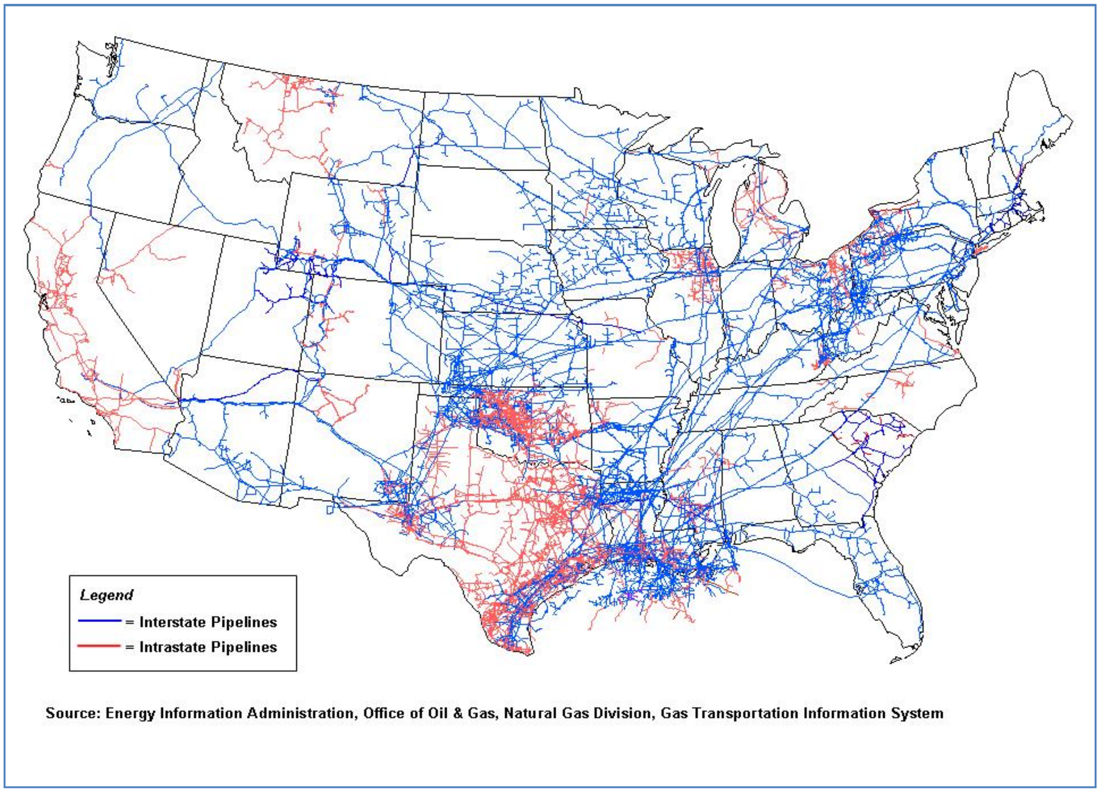

Figure 2 - Depiction of Natural Gas Transmission Pipeline Infrastructure

Since pipelines deliver energy to populated areas, the pipeline and the operation and maintenance activities of the pipeline have to coexist with the public along the right-of-way (ROW).

Technology has Enabled Improved Fitness for Service Assessments

Despite these hurdles, integrity management technology has evolved over the decades to better ensure that the pipelines are fit for service. These technological advances are best documented in research compendiums[1] and the constant updates of engineering consensus standards.[2]

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[1] GRI-00/0192 **GRI Guide for Locating and Using Pipeline Industry Research**, JF Kiefner, Kiefner and Associates, Worthington, OH

Overview of Integrity Management and the Role of Integrity Assessments

Integrity management is best described as a continuous improvement process to manage threats to a natural gas transmission pipeline and to demonstrate the fitness of service for continued safe operation of the system. This overview is provided to show the breadth and depth of integrity management and the role that Inline Inspection (ILI) assessments serve within the process. While the role is critical, it is one step among many to ensure system integrity. Original engineering consensus standards (e.g. American Society of Mechanical Engineers (ASME) B31.8) and the Department of Transportation's Pipeline and Hazardous Safety Administration (PHMSA) pipeline safety regulations (i.e. 49 CFR Part 192) that incorporate those standards have been used for many decades to design, construct, operate and maintain natural gas transmission pipelines. These standards and regulations were based on integrity management principles,[3] but were configured as prescriptive requirements or recommendations. Individual practices and technologies adopted by pipeline operators and shared among the natural gas industry have been added to these standards and regulations.

The formalization and continuous improvement component of this integrity management process for natural gas transmission pipelines began with the introduction of ASME B31.8S,[4] "Managing System Integrity of Gas Pipelines," the engineering consensus standard created through the American National Standards Institute (ANSI) international consensus standard development process in 2001. This standard defines and describes the processes for managing integrity and references individual and specific standards that provide the details of how to develop and implement an effective integrity management program utilizing proven industry practices. The standard also contains a compendium of the research and describes research used as the basis for the standards. This standard was incorporated by PHMSA in the pipeline integrity management regulations for gas transmission pipelines located in areas of high consequence.

Integrity management steps

The ASME B31.8S standard outlines six steps for managing pipeline integrity:

1. Gather and integrate available data and information related to the pipeline;
2. Identify the pipeline's susceptibility to specific threats (threat categories as defined by the standard);
3. Prioritize segments based on the risk posed by the threats through a comprehensive risk assessment;
4. Use one or more of the assessment tools, like ILI, to assess the integrity of the pipeline;
5. Evaluate the results of assessments through further integration of data and where warranted scheduling future work on the system;

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[2] API 1163 - IN-LINE INSPECTION SYSTEMS QUALIFICATION STANDARD; ASNT ILI-PQ - In-Line Inspection Personnel Qualification and Certification Standard; NACE SP0102-Standard Practice: In-Line Inspection of Pipelines

[3] GRI-00/0193 Natural Gas Transmission Pipelines: Pipeline Integrity - Prevention, Detection, & Mitigation Practices, HSB, Selig, B.; Clark, E.; Hereth, M. Hartford Steam Boiler Inspection & Insurance Co., Hartford, CT

[4] ASME B31.8S Managing System Integrity of Gas Pipelines - 2010 three Park Ave New York, NY 10016-5990

6. Select and apply preventive and mitigation measures based on the findings of the assessments and excavations.

This fourth step—use of assessment tools, and specifically ILIs—are the subject of NTSB's request to INGAA and AGA.

The first step in managing integrity is gathering and integrating available data and information related to the integrity of the pipeline. ASME B31.8S prescribes a minimum set of data and information to review and evaluate. It also provides expert guidance. Many operators supplement what is prescribed in ASME B31.8S with site-specific data for their systems. This step of gathering and integrating data provides a growing database to support evaluation and decision making in the steps that follow.

The second step is a process to identify the susceptibility of the pipeline to each of the threats (threat categories as defined by the standard) along a pipeline system. Pipeline threats generally are categorized as follows in Subpart O, §192.917 (additional information on each type of threat can be found in Appendix B: "Management of Threats to Integrity and Fitness for Service for Natural Gas Transmission Pipelines"):

1. Time-dependent
2. Time-independent
3. Resident (Static or Stable[5])

ASME B31.8S requires consideration of interactive threats, i.e., threats acting in conjunction with one another. Recent incident experience has underscored the importance of considering interactive threats.

Pipeline systems generally are viewed in terms of discrete segments, and the third step in integrity management is to prioritize these segments based on the risk (defined as probability times consequence) posed by the threats when viewed collectively as part of risk assessment. Risk assessment is a process that supports evaluation and decision making in the steps described below.

The fourth step is an integrity assessment using one or more of the assessment tools, such as ILI, the subject of this paper. The term assessment was coined in the early 2000s to differentiate that term from the term inspections, which were traditionally associated with ongoing, planned maintenance activities that operators conducted once a pipeline was installed. The particular assessments defined by ASME B31.8S are ILI, pressure testing and direct assessment. Each assessment has benefits and drawbacks. For example, direct assessment can identify areas where corrosion has occurred or is likely to occur but cannot identify material defects unless corrosion is associated with the defect. ILI can detect if corrosion has occurred but cannot identify areas where corrosion is likely to occur. Regulations in 49 CFR 192 Subpart O provide for the use of alternate assessment technology through an application process that entails DOT review and

[5] Initial versions of ASME B31.8S referred to a category of "stable" threats, meaning they were stable unless acted upon. This led to confusion as the "unless acted upon" was often omitted in discussions. The term "resident" has been adopted to better convey the nature of this threat category.

approval. For intrastate transmission pipelines, the application also must be approved by the state pipeline safety agency.

Assessment results determine which anomalies warrant action and within what timeframe -- either on an immediate (more urgent) or scheduled basis (over a longer time horizon).

In the case of time dependent threats, which deteriorate over time (e.g. corrosion), anomalies are analyzed to determine the success of operational and maintenance practices. The anomalies that fail criteria based solely on the data from the inspection become actionable anomalies. These are then categorized to determine when examination and evaluation is required. The actionable corrosion anomalies are then examined by experts and evaluated against long-established engineering acceptance criteria such as ASME B31G, Modified B31G or RSTRENG to estimate the pipeline's ability to operate safely. Based on these criteria, the anomalies are determined to be a non-critical imperfection or defect may require remediation in order to provide a conservative safety factor.

Anomalies warranting a response based on the evaluation of assessment results require an excavation. Once an excavation is made, the operator applies the same engineering criteria described above with direct measurements and predicts whether the pipe will be safe until it gets assessed again or if it requires repair or replacement.

Excavations findings are reincorporated into the process to improve and update databases in the data gathering and integration step. The process then begins again with improved information to review threats and reanalyze risk. In addition, where anomalies have been found, the operator reviews and evaluates integrated data by threat and defines prevention activities or tools to ensure that the cause of the anomalies are mitigated or managed within the timeline of the next integrity reassessment effort.

Pipeline companies apply a broad range of measures to ensure the fitness of their pipelines for service. Pipeline operators have used design, construction, operations and maintenance practices that were a part of consensus standards since the mid-1930s and these practices have been enhanced and improved. In the early 2000s, operators, government officials from PHMSA and selected states, technology providers and subject matter experts collaborated in developing improvements to the long-applied measures.

Practices that have been applied and improved through the years are shown in Table 4. The most important practices are those related to prevention of threats (consequences are a factor of encroachment around a pipeline and there are very few mitigation choices for the pipeline operator). Assessment verifies that the operating and maintenance activities are performing as expected. Table 1 identifies the threats to the integrity of the pipeline and contrasts these threats with the primary causes of the threat and prevention and mitigation practices related to the threat.

Table 1 - Prevention, mitigation and assessment practices of natural gas pipelines

<table>
<tr><th rowspan="2"></th><th colspan="3">Time-Dependent Threats
The threat level accelerates over time</th><th colspan="3">Resident Threats
The threat is inherent but does not grow over time</th><th colspan="3">Time Independent Threats
The threat exists outside of the continuum of time</th></tr>
<tr><th>External Corrosion</th><th>Internal Corrosion</th><th>Stress Corrosions Cracking</th><th>Manufacturing Related</th><th>Construction/ Fabrication Related</th><th>Equipment Related</th><th>Excavation Damage</th><th>Incorrect Operations</th><th>Weather & Outside Forces</th></tr>
<tr><td>Primary CAUSES</td><td>Poor coating and inadequate cathodic protection</td><td>Gas quality</td><td>Discharge Temperature</td><td>Long-Seam Defects, Pipe Defects</td><td>Girth Weld, Coupled Welds, Wrinkle Bends, Branch Connections</td><td>Gaskets, Relief Valves/ Regulators</td><td>1^{st}, 2^{nd} and 3^{rd} party</td><td>Human error, inadequate training, failure to follow procedures</td><td>Weather-related events, ground movement</td></tr>
<tr><td rowspan="2">Primary PREVENTION

PRACTICES</td><td>Cathodic protection</td><td>Gas quality monitoring</td><td>Cathodic protection</td><td>Pipe specification</td><td>Construction practices</td><td>Preventative maintenance</td><td>Excavation observation and patrolling</td><td>Operating procedures</td><td rowspan="2">Continuous Surveillance</td></tr>
<tr><td>Close interval survey</td><td>Site-specific plans</td><td>Field inspections</td><td>Inspection during manufacturing</td><td>Inspection during construction</td><td>Inspection during maintenance</td><td>One Call System</td><td>Training & Development</td></tr>
<tr><td rowspan="4">MITIGATION PRACTICES

INCLUDING ASSESSMENT TECHNOLOGY</td><td rowspan="2">In-line Inspection</td><td>Operational pigging</td><td rowspan="2">Pressure Testing</td><td>Mill Pressure Testing</td><td>Pressure Testing</td><td>Patrolling</td><td>Locating & Marking</td><td>Operator Qualification</td><td>Emergency Preparedness</td></tr>
<tr><td>In-Line Inspection</td><td>Pressure Testing</td><td>Patrolling</td><td>Monitoring Pressure & External Loads</td><td>Excavation Monitoring</td><td>Audits</td><td>Slope Monitoring & Stabilization</td></tr>
<tr><td>Direct Assessment</td><td>Direct Assessment</td><td>Direct Assessment</td><td>Monitoring Pressure & External Loads</td><td>Monitoring Pressure & External Loads</td><td></td><td>Public Awareness</td><td></td><td></td></tr>
<tr><td>Pressure Test</td><td>Pressure Test</td><td>In-line Inspection</td><td></td><td>In-line Inspection</td><td></td><td></td><td></td><td></td></tr>
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Assessment Capabilities of ILI Devices

ILI allows operators to find anomalies on the pipeline system, and then apply integrity management practices to determine which anomalies warrant response and under what timeframe. Some anomies require an immediate response. Others—typically ones that are based on time-dependent threats—can be scheduled over a longer time horizon. Anomaly response generally requires excavations, direct examination, and often repairs or replacements. ILI and other assessment tools are important because they allow the operator to pinpoint potential problem areas before undertaking a more extensive excavation, which can disrupt natural gas flow.

ILI is particularly useful as an early detection tool for anomalies. ILI is not going to stop a rupture if a pipeline suffers a direct hit by a backhoe. However, it can find a gouge—that could grow and eventually cause a leak or rupture—left on the pipeline by a backhoe. The technology is useful particularly in determining if a condition is getting worse, but that requires time and multiple ILI runs. ILI might find a small anomaly just as an MRI or CT scan might detect a small benign tumor in a human. Like the doctor who asks a patient to return to be re-scanned to determine if the tumor has grown before pursuing a more aggressive treatment, a pipeline operator will monitor the system and rerun ILI to see if the anomaly has grown or worsened before excavating the pipeline.

A pipeline that can be inspected using an ILI device is considered “piggable”. Piggability generally requires three main parts: navigation, or the ability of the pig to transverse the pipeline segment unimpeded; motive power, or a system and adequate pressure to propel the pig through the pipeline; and access, or the ability to insert the pig into the pipeline and to retrieve it.

Table 2 lists the different assessment methods that are used for particular pipeline threats. As the technology of a particular assessment tool and its integrated decision support system improves, it provides additional capabilities to the integrity management assessment. The abilities of the assessment tools can be classified into several capabilities:

Detection – This is the broad category of the assessment tool to be effective in managing a particular anomaly

> ***Identification*** – The assessment tool has the capability to delineate a particular type of anomaly from another type of anomaly
>
> ***Characterization*** – The assessment tool has the ability to size (e.g. depth and length) and quantify the type of anomaly at the time of the assessment.
>
> ***Prediction*** - The assessment tool provides the ability to predict continued safe operation for a period of time if additional growth of anomalies could occur.

Table 2 - High level listing of assessment tools for each threat category

Threat Assessed	Assessment Tool	Extent of Detection
Internal and External Corrosion	MFL ILI	Identification, characterization and prediction of metal loss
Internal and External Corrosion	Ultrasonic, Compression Wave ILI	Identification, characterization and prediction of metal loss
Internal and External Corrosion	Remote Field Eddy Current (RFEC)	Identification, characterization and prediction of metal loss
Internal and External Corrosion, SCC, Longitudinal Crack	Ultrasonic, Shear Wave ILI	Identification, characterization and prediction of metal loss Crack identification
Internal and External Corrosion, Large Longitudinal Crack	Transverse Flux ILI	Identification, characterization and prediction of metal loss Crack identification
Excavation Damage, Outside Force Damage, Construction	Deformation or Geometry ILI, MFL ILI	Identification, characterization of the deformation of pipe cross section
Manufacturing & Construction Anomalies, External Corrosion, Internal Corrosion, SCC, Mechanical Damage, Cracks	Pressure Testing	Strength test only identifies and only characterizes anomalies that will fail up to the test pressure. Some predictive capability on time dependent anomalies
External Corrosion, Excavation/Mechanical Damage	ECDA	Indirect assessment, direct examination, evaluation will identify active anomaly with some prediction
Internal Corrosion	ICDA	Classification of susceptible locations, direct examination and evaluation will identify anomalies
SCC	SCCDA	Classification of susceptible locations, direct examination, and evaluation will identify anomalies

Configuration of Natural Gas Transmission Pipeline Assets – Ability to Utilize ILI Devices

The configurations of the natural gas transmission systems in the U.S. are described in this section to provide perspective on the challenges posed in utilizing ILI devices (i.e. making systems piggable). The definition of piggable has varied over time as technology has advanced but has traditionally been determined by three primary components.

- **Navigation** The ability of the ILI device to physically move through the pipeline without encountering damage to the ILI device while allowing the device to assess the particular anomalies. This can be a challenge because ILI devices need to be able to accommodate diameter changes across a pipeline section and geographical shifts, including elevation and directional changes, such as curves and bends. The pig also must be able to navigate interconnections between mainline pipelines or between mainline pipelines and laterals or distribution pipelines. It is highly desirable to utilize an ILI device while the pipe still contains natural gas. State-of-the-art pigs cannot negotiate certain features (such as 90-degree mitered bends and plug valves). Recently, new robotic devices developed for this purpose are able to negotiate such features.
- **Motive Power** The ability to traverse the piping system. A typical ILI device is transported by the flow of the natural gas in the pipeline system or externally powered by a cable system. Recently, some self-powered ILI devices have been developed and are being utilized.
- **Access** The ability to insert and retrieve the ILI device in the piping system. These insertion and retrieval systems typically are described as launchers and receivers. These devices can be permanent or temporary facilities. The ability to utilize an ILI device in a pipe segment allows more flexibility in the use of ILI tools for assessments but traditionally requires significantly more capital expenditure and inconvenience to landowners living along the pipelines. A few new ILI and robotic devices do not require the traditional launchers and receivers that are permanent fixtures in the pipeline system. Instead, these new ILI devices can use temporary launchers and receivers that can be removed after use leaving behind conventional fittings.

Operators of pipeline systems that were designed and constructed before ILI devices now desire to make portions of their systems piggable. In order to accomplish this goal, most operators need to retrofit appurtenances (e.g. launchers and receivers) or replace sections of pipe unable to accommodate an ILI device, particularly in pipeline segments located in High Consequence Areas (HCAs). Many of the sensor systems utilized in the integrity management process are sensitive to the proximity of the sensor to the pipeline wall. These sensors require a tracking system that complies with geometric features, such as different pipe diameters and reduced cross sections through block valves in the pipeline segment. While advances in ILI technology have created devices that can now be used in pipelines that contain diameter changes or obstacles (such as block valves), large portions of these legacy pipeline systems require retrofitting before ILI tools can fit in these pipeline sections. Sensor placement design on newer ILI devices is improving the sensitivity and quality of the results when encountering geometric eccentricities.

ILI devices must traverse pipeline sections to collect data and must have to have a motive system to move the device. Propelling the pig through the pipeline at a speed to allow accurate assessments also can pose a challenge. Large elevations changes, such as mountains and hills, can present difficulties for pigs. ILI tools are extremely heavy because they contain magnets, batteries and other equipment to provide guidance and continually record data. When pigs travel through areas of large elevation changes, their speed can approach the lower tolerance limit of the sensor design on steep inclines and the upper limit of speed on steep declines, impeding collection of accurate data. Even with pig-speed-control technology, some pipeline segments simply do not have enough operating pressure and pipeline gas flow to run the pig effectively. Small, low-pressure pipelines are nearly impossible to inspect using pigs propelled by natural gas flow.

In cases where gas movement is too low to provide consistent motive, such as many transmission pipelines that are integrated with distribution lines, alternative-driving technologies such as cable pulling and self-powered devices are being used (e.g. battery powered electric motors). Certain sensor technologies can be extremely sensitive to speed and acceleration of the ILI device. This sensitivity requires improvements in the motive technology to provide movement within acceptable tolerances.

ILI runs (depending on the technology) can be accommodated during normal operations, restricted operations or only during periods when the pipeline is out of service. With multiple sensors used for assessments, either independently or mounted on a combination of ILI platforms, decreased operating flexibility exists during the inspection run.

To accommodate traditional ILI devices, an operator must have the ability insert the pig into the pipeline and then retrieve it after the inspection is completed. Pig launching and receiving facilities – either permanent or temporary – are necessary. This requires a significant investment and a long time horizon in order to maintain service to customers. Because pipeline segments need to be out of service for about two to three weeks during the normal installation of a pig launching and receiving facility, launchers and receivers are typically installed only during the lower demand periods so as not to disrupt customers. Only a limited number these major projects can be undertaken at any one time before outages impact service reliability and markets. As a result, pig launching and receiving facility projects need to be carefully planned and staged. In addition, adequate time must be allotted for receiving required permits, particularly in environmentally sensitive areas, and for acquiring necessary rights-of-way.

The ability to insert the ILI device into the pipeline system is heavily dependent on the pigs design. In the design of the ILI tools, the motive force (e.g. cup design, electric motors), sensor design (device length to accommodate sensor technology), data storage (e.g. disk drives) and power (sensing system and data) must all be considered. As ILI technology changes, the entry and exit design requirements for the pipeline system also may change.

Approximately 70 percent of natural gas transmission pipelines were built before ILI devices were recognized as a viable inspection technology for natural gas transmission pipelines. Many of these systems contain normal design elements that act as ILI obstacles, such as valves, diameter restrictions, tight bends and restricted access.

Industry and government have collaborated to develop robotic tools capable of inspecting unpiggable pipelines. These robotic devices allow ILI without the need for the traditional launchers and receivers and without the need to shut down the pipeline. Such tools have entered the market and are a true game changer. Additional robotic tools will be introduced over the next year or two.

Pipeline System Configurations

Natural gas transmission pipelines transport gas from production areas to market areas, where end users consume gas for fuel or as a raw material. There are four basic configurations of these piping systems as shown in Table 3:

Table 3 - Transmission pipeline configurations

Configuration Type	Characteristics	ILI Accessibility
Trunkline (Long haul)	• Hundreds to thousands of miles in length • Single diameter pipe or pipe with few diameter changes • Few interconnections • High pressure and flow	• High
Grid Systems	• Network of pipes interconnecting large customer delivery points in urban areas to long-haul systems • Multiple pipe diameters • More interconnection points near end-use customers • Lower operating pressures and flows	• Moderate
Reticulated Systems	• Multiple branches in production and end-use areas connected by long-haul segments. • Characteristics of grid systems in the production and end-use portions of the network and long-haul in the middle	• Moderate
Transmission Systems Intermingled with Distribution Systems	• Many interconnects between transmission and distribution pipeline • Multiple changing diameters of pipe in single pipeline segments; • Small pipeline diameters less than ILI tool capabilities; • Short segments between interconnections with distribution piping; • Low pressures and flow rates insufficient to move the ILI devices; • Many block valves of various sizes and types with reduced ports that restrict the ILI; • Bottom-out" fittings that present obstacles to ILI tool passage • Miter bends, • Complex curves with two or more adjacent bends (elbows); • Tight radius elbows; Vertical rising segments; and • Land use restrictions for installing launchers and receivers.	• Low

For more information on the impact of pipeline configuration on integrity management practices see Appendix C – Pipeline Configuration and Integrity Management.

Development of ILI Platforms and Expansion of Pipeline Segments that are Piggable

A company named Tuboscope developed in 1965 the earliest ILI tools used in natural gas transmission pipelines. These early tools detected material loss (corrosion) in steel pipelines, based on magnetic flux leakage (MFL) technology using large electrical coil sensors, simple electro-magnets and analog signals recorded on onboard magnetic tape drives. These prototype devices could only inspect short distances (e.g. under 30 miles), much less than the 60 to 80 miles typically traversed today between compressor stations. The first tools only inspected on the bottom quarter of the pipeline, which was believed to be the location of the majority of potential corrosion issues.

In 1970, T.D. Williamson developed the first ILI device that continuously identified the internal geometry of a pipeline. The next generation of ILI tools extended the sensor arrangement to create a full circumference 360-degree tool. Using simple pre-computer or analogue systems to record magnetic field amplitudes, these systems allowed the identification of large metal loss anomalies. Because of the limitations of the data recording systems, data collection was restricted to low speeds.

The ability of ultrasonic transducer technology to measure wall thickness was recognized on liquid pipelines in the 1970s, but the lack of a liquid couplant for signal transmission on natural gas pipeline eliminated its applicability.

Research on the use of electromagnetic acoustic transducers (EMAT) technology began on pipelines in the early 1970s to help in detecting stress corrosion cracking. Early attempts to use EMAT on ILI tools were unsuccessful because of poor signal to noise ratios. As a result, the technology was deferred.

The renaissance of MFL ILI tools occurred in the early 1980s. The accuracy of these ILI tools improved such that anomalies identified were able to be classified by placing the depth of the metal loss into three gross categories: less than 30 percent; 30 to 60 percent; and greater than 60 percent wall thickness.

Simple dual-diameter ILI platforms that could traverse multiple diameters (one or two sizes in difference) were being redeveloped in the late 1990s. The Gas Research Institute (GRI), an industry research consortium, sponsored trials of a dual-diameter pig in 1999 to demonstrate that tools feasibility and effectiveness. Some of those designs were adopted and many ILI tools today have a capability to reduce in size down to 75 percent of the base inspection diameter. There are even a few tools that can reduce in size to almost 60 percent (i.e. from 36 inches down to 24 inches).

In the early 1990s there were five major ILI MFL providers. Today there are over 30.

Ultrasonic tools for detecting cracks and crack-like features became available in the mid-1990s for liquid pipeline. Their application in gas systems, however, was limited because the technology requires a liquid couplant for the sensors to work.

MFL technology improved in the 1990s along with improved computer-based pre-analysis algorithms to characterize metal loss defect depth. This enabled the use of five wall-thickness categories instead of the early three. These algorithms help qualified analysts to prescreen hundreds of thousands of indications.

High-resolution MFL technology emerged in the late 1990s. These tools used a larger number of sensors. This greater density of sensors allowed testers to improve strength calculations. Improved accuracy, combined with the additional data acquired through multiple ILI runs spaced over a decade, allowed for the more accurate prediction of re-inspection intervals. These predictions were based on performance monitoring rather than prescriptive schedules or estimated corrosion rates.

In the early 2000s, members of NYSEARCH, a voluntary R & D organization representing many major distribution companies throughout the U.S., identified the unpiggable characteristics that companies needed to address to improve the piggability of their transmission lines, as described above in Section 5. Their research program emphasized:

- Developing innovative platforms for delivery of sensing technologies to difficult-to-inspect areas and
- Improving the sensitivity and range of sensing systems to identify and characterize features.

A range of tools, focusing initially on two sizes and with project names known as Explorer (smaller diameter) and Tigre (larger diameter) were successfully developed. The Explorer product line recently became commercially available through PipeTel Technologies Inc. and represents a collaborative success for NYSEARCH and their partners, OTD and PHMSA. The robotic platform and state-of-the-art RFEC and MFL sensors are working successfully for smaller diameter pipe (Explorer 6/8 and Explorer 10/14) in traversing many features such as tees, back to back bends, miters and vertical segments. Later this year, the larger diameter versions (Explorer 20/26) with MFL sensing will be commercially released and will also negotiate plug valves and the other obstacles. These successes have fostered interest in new robotic developments within the ILI community.

The positive progress in ILI development encouraged transmission pipelines—primarily trunkline—operators to invest in expensive capital modifications to their systems to remove legacy impediments in order to accommodate ILI tools. Modern ILI tools are more flexible, advanced and economical than the previously used integrity testing tool, the hydrostatic pressure test, and may overcome historical impediments.

In 2000 and in the following decade, the modification and adaption of pipelines systems to accommodate ILI tools accelerated because of the adoption of ASME B31.8S and the codification of the Transmission Pipeline Integrity Management Program by PHMSA.

The following time line summarizes the development of ILI technology and advancements in system piggability (Table 4). Continued and proven successes using the self-powered tools meant that the number of miles that are considered unpiggable pipelines continues to decrease.

Table 4 - Historical development of ILI technology

Est. Year	Developing ILI Technology to Meet Needs	Free Swimming ILI Tools	Unpiggable Reductions
1965	-First use	Limited detection width, only on the bottom quarter	Multiple obstructions limit use
1970's	-First geometry pig -Limited two diameter capability -Simple speed control 5 to 50'/s -Heavier wall possible < 5/8" -First mapping pig	-Weak electromagnets -Slow data acquisition -Tape storage improves -Passes reduce bore valves	-Removes first of multiple diameter obstructions
1980's	-Cable & tethered pull through MFL for short distances -Corrosion buckets <30%, 30 to 50, > 50% -3,000 psi possible -1st mapping tool (GPS) -1.5 D bends possible -Small diameter 3" to 8" MFL -UT (liquid filled wheels) for SCC	-Limited distances possible -Simple wall loss estimates -Improved canister designs -Inertial estimate strains -Tight bends overcome -Improved compact power and storage designs -Limited crack detection	-Removes some power, friction concerns -Class 3 thick wall possible -Removes some navigation bend barriers -River crossings to 1 mile -Smaller diameter lines possible
1990's	-Low pressure, low flow tools -first UT pig in liquid lines -36" collapsible MFL tool -Transverse MFL available for better resolution -Hall effect triaxial MFL for better wall loss resolution	-Improved friction reduction designs -GRI sponsored tool passes through reduced port valves -Transverse MFL helps size in axial wall loss orientation -Stronger rare earth magnets	-Some low pressure, low flow lines now possible, -Larger diameter ratio changes possible -Smaller magnets and sensors for small lines
2000's	-Depth levels can now be sorted into six buckets < 20%,20-30, 30-40, 40-50, 50-60, >60% -Better estimate of defect length -UT in water slug helps look for big cracks in gas lines -High resolution diameter deformation -Combining transverse-spiral-helical & axial MFL or transverse and axial MFL in same tool train for better data interpretation -Begin using dual magnetization for detecting and sizing mechanical damage by MFL (remote field) -Robotic tool passes demos with TV and eddy current for small diameters	-Better wall loss resolution & failure pressure calculations -Crack detection becomes possible in liquid lines -Use of liquid UT tool in gas lines, but operational difficulties are immense -Crack detection in gas lines improving -Caliper tools graduate to deformation tools -Dual magnetization sees damage in knee of B-H curve -Combining tools reduces runs and improves data integration for POD & POI	-Smaller diameter bends in pipe 4" to 8" now possible -Use MFL + other sensors proven on free swimming ILI tools -Robotics overcome dual flow and low flow hindrances -High compliance overcomes large weld root peaks and other sensor lift off errors -Self-powered tool allows simple entry and exit for inspections -Shorter tool designs
2010's	EMAT (no liquid UT) demos for SCC Tractor tools developed for a range of larger pipe diameters	-Improving crack detection in gas lines Self-powered body carries a range of sensors	-Robotic tractors enter inspect and return; no longer need traditional launchers/receivers or line shutdown More sizes & in-place charging needed; Small diameter tools using MFL have battery design challenges; new self-powered robotic tools for small diameters use RFEC sensor instead of MFL to reduce drag and eliminate battery design issues

Table 5 shows the ILI and competing options that can be used to assess a particular threat. The column headings correspond to the range of threats while the row headings correspond to the various inspections associated with the different integrity assessment methodologies. The green blocks indicate the existence of commercially available assessment technologies. The yellow blocks indicate limited applicability or restrictions that need to be considered in applying the ILI technology. The red blocks indicate technology gaps. The ultimate technology goal is to have a number of green blocks for each threat to allow for flexibility, as needed, recognizing that there are benefits to focusing on particular technology gaps (e.g. applicability, probability, technology challenge). Table 5 is intended to be a "living document" that will change with technology advances. Some of the R&D developments will be described later in this paper.

It should also be noted that the industry is devoting significant resources to exploring other methods of remote inspection, damage prevention, defining risk and addressing challenging segments, such as cased pipelines. More information on that topic can be found later in this report.

Table 5 - Current status of commercially available ILI technology

Classification	Surface Corrosion				Internal and Material Anomalies plus Features							Pipe Deformation			
Specific Threat	General External Corrosion	Axial External Corrosion	Internal Corrosion	Stress Corrosion Cracking	Mfg Related Defects	Hard Spots	Surface Breaking Axial Cracking	Surface Breaking Circumferential Cracking	Pipe Long Seam	Pipe Girth Weld	Wrinkle Bends	Dents, Wrinkles, Buckels, & Ripples	Excavation Damage	Scratch/ Gouges	Earth Movement (Strain)
High Resolution Axial MFL	Green	Yellow	Green	Red	Yellow	Yellow	Red	Red	Red	Yellow	Yellow	Yellow	Yellow	Yellow	Red
Transverse MFL	Green	Green	Green	Red	Yellow	Red	Red	Red	Yellow	Red	Red	Yellow	Yellow	Yellow	Red
EMAT	Red	Red	Red	Yellow	Yellow	Red	Yellow	Red	Yellow	Red	Red	Red	Yellow	Yellow	Red
Geometry Tool - Disks to +/- > 1% d/D	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Green	Green	Green	Red	Red
Deformation Tool - to +/- 0.5% d/D High Resolution	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Green	Green	Green	Red	Yellow
Direct Assessment	Yellow	Yellow	Yellow	Yellow	Red	Red	Red	Red	Red	Red	Red	Red	Yellow	Yellow	Red
Pressure Test	Green	Green	Green	Yellow	Green	Green	Yellow	Yellow	Green	Yellow	Yellow	Green	Green	Green	Red
Pressure Spike Test	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Red
Inertial Navigation	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Yellow	Red	Red	Red	Green
Direct Examination (includes NDE for threats)	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green	Green

Red	Not appropriate or never used
Yellow	Has applicability, provides an ancillary benefit or specific restrictions need to be considered
Green	Is always appropriate

Notes

This matrix is to help those less familiar with the range of integrity assessment technologies, ILI tools, and their capabilities.
Technology improvements may allow color changes in the future.
Direct Assessment requires following all the NACE Standard requirements of EC, IC, or SCC.
Axial & Circumferential Cracking represents surface breaking and partially open cracks unlike tight fatigue.

Current Status of Piggable Transmission Pipeline Segments

INGAA and AGA members have invested heavily to increase the number of miles that are piggable. Based on a survey of its members, 64 percent of INGAA member's mileage is piggable and will be inspected by the end of 2012. This expanded piggable mileage provides coverage for approximately 90 percent of the population near the pipeline systems. A similar survey of AGA's members indicated that approximately 25 percent of its members' transmission systems were piggable but this number may dramatically change given the recent advances in robotic platforms. The primary difference between the INGAA and AGA member systems is that the AGA member systems are closer to the end-user market so many of their transmission pipe segments have significant physical impediments. Also, many of the transmission lines operated by AGA's members are single source lines (the only source of natural gas to customers and communities). Single source pipelines cannot be shut down without disrupting customer supply. In some cases, portable gas can be brought in to temporarily supply gas to customer. In other cases, a new pipeline must be built that can continue the supply while the other line is taken out of service for testing.

Figure 3 depicts the technology that was used in IM assessments. As previously noted, most transmission operators prefer to use ILI to assess a line when the pipeline can accommodate the ILI tool because of its ability to cover large distances.

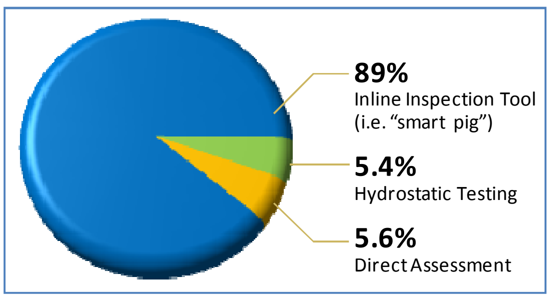

Figure 3 - Type of assessment technology utilized (INGAA 2011 survey; 146,000 miles)

Recent Integrity Management Accomplishments of the Use of ILI Technology

The following figures depict how ILI technology has been incorporated into the management of integrity by natural gas transmission pipeline operators.

INGAA 2011 Integrity Management Results Survey

PHMSA has been collecting performance data for HCAs since 2004, and INGAA has augmented that data with a voluntary reporting program within the INGAA membership. INGAA produced a report[6] of a survey in 2011 that documented the integrity management performance from 2004 to 2010. The reporting mileage in the INGAA voluntary reporting systems (146,000 miles) represents a wide cross section of different pipeline configurations and ownership and should be indicative of the INGAA membership's 185,000 miles of onshore natural gas transmission pipelines.

Figure 4 depicts the amount of pipeline mileage that has been baseline assessed since 2004 utilizing one of the preferred technologies in the PHMSA Integrity Management Program (IMP); ILI, pressure test, and direct assessment. As seen on this chart, a significant amount of the mileage assessed is outside (shown in blue) of the areas mandated (shown in red) by the PHMSA IM program. ILI technology enables long stretches of pipeline mileage to be assessed from one insertion and retrieval system if there are no physical impediments.

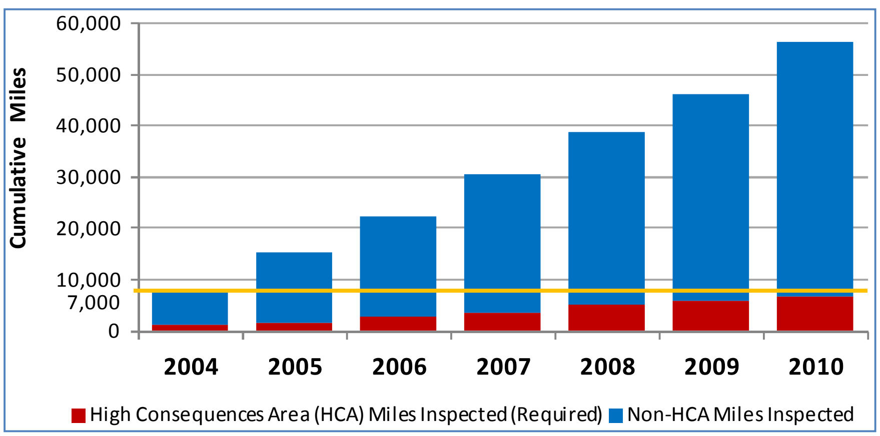

Figure 4 - Total cumulative miles baseline assessed utilizing IM inspections
(INGAA 2011 survey; 146,000 miles reporting)

Table 6 depicts the amount of piping assessed in the 2011 INGAA survey, the anomalies that were identified and characterized as needing remedial action (repairs), and the amount of pipe what was replaced as part of that repair activity. It is important to note that the performance of the transmission pipelines outside of HCAs is not markedly different than the performance inside of HCAs.

[6] Safety & Integrity Activities for Gas Transmission Pipelines; Sept. 2011; INGAA IMCI Team 1

The first part of the table breaks up the inspection activity by baseline and reassessment. The baseline activity reflects the first standardized[7] IM inspection of the pipeline segments assessed since construction (although there may have been many other assessments or repairs before this under traditional O&M activities), utilizing PHMSA IMP criteria within HCAs and integrity management principles outside of HCAs. The reassessment activity is a subsequent standardized IM inspection that occurs at a scheduled period after the baseline inspection. After 2012, the end of the baseline period, most of the IM inspection results will be reported in the reassessment portion of the survey. The chart also includes a "Non-IMP" column, which identifies the assessments that were conducted as part of IMP assessments or independent of the IMP process.

The second part of the table depicts the repair activity of those pipeline segments. Operation and maintenance practices are designed to prevent time-dependent and time-independent anomalies from occurring, but not all preventative processes are perfect. The first line depicts baseline repair activity, utilizing conservative fitness for service criteria, and reflects the change of the pipeline segment condition since the pipeline installation (i.e. if no previous ILI assessments and repairs have been conducted in the past). The second line depicts the repairs that are needed on pipeline segments that have operated for a short period of time that has occurred from the baseline assessment to the subsequent reassessment. While some repairs have increased because of ILI technology sensitivity improvements and tighter acceptance criteria, the reduction in repairs per mile is indicating the success of the improving integrity management programs in maintaining continued fitness for service. One of the key advantages of ILI and Direct Assessment technology is that they are much more of a predictive fitness for service technology than pressure tests, which are a pass-fail type of fitness for service test.

The third part of the table tries to illustrate the size of the repairs that are occurring as part of the IM program. This number illustrates (both baseline and replacement) that the amount of pipe replaced as part of the program is a very small proportion of what has been assessed. This focused replacement of pipe is a positive attribute of all three types of integrity assessment technologies.

[7] Integrity management inspections have been performed in the past, using practices defined individually by operators as use of the technology predated consensus standards for their application.

Table 6 - Baseline and reassessment inspections, repairs and replacements (INGAA 2011)

	HCAs	Non-HCAs	Non-IMP*	TOTAL	Comments
Miles Inspected					* 2010 only
Baseline	6,661	49,416	2,525	**58,602**	Since 2004
Reassessment	2,465	9,424	1,993	**13,882**	Since 2007
TOTAL Inspected	**9,126**	**58,840**	**4,518**	**72,484**	40% of all reporting pipe was inspected at least once 2004-2010
Repairs Made					
Baseline	932	8,874	860	**10,666**	Since 2004
Reassessment	73	1,795	61	**1,929**	Since 2007
TOTAL Repairs	**1,005**	**10,669**	**921**	**12,595**	Averaging 17 repairs every 100 miles inspected
Feet Replaced					
Baseline	31,653	226,966	21,097	**279,716**	Since 2004
Reassessment	108	2,486	1,703	**4,297**	Since 2007
TOTAL Replaced	**31,761**	**229,452**	**22,800**	**284,013**	53.8 miles of pipe have been replaced

Table 7 depicts the categories of anomalies that were remediated utilizing assessment technologies. The diversity of the issues addressed before operational leak or failure demonstrates the success of the IM programs.

Table 7 - Categorization of anomalies remediated during assessments (INGAA 2011)

	Baseline		Reassessment		
Anomaly Type	**HCA**	**Non-HCA**	**HCA**	**Non-HCA**	**Total Repairs**
Metal loss FPR <= 1.1	7	125	0	66	198
Metal Loss FPR <= 1.39 or other adjusted scheduled FPR	19	637	10	327	993
Metal Loss FPR > 1.39	637	192	7	174	1,010
Topside Dent w/Metal Loss, Crack/Stress Riser	19	43	5	24	91
Topside Dent>6%	1	5	0	0	6
Topside Dent >2% (NPS<12)	5	12	1	0	18
Bottom-side Dent >6%	2	6	1	0	9
Bottom-side Dent >2%	3	19	0	25	47
Bottom-side Dent w/Metal Loss, Crack, Stress Riser	15	21	5	4	45
Dents on Girth Welds/Long Seams	19	60	4	6	89
Stress Corrosion Cracking	5	21	0	5	31
Manufacturing - Pipe or Pipe Seam	6	23	0	4	33
Construction-Wrinkle Bends, Buckles, Girth Weld, Fabrication Weld	5	13	6	5	29
Mechanical Damage - Immediate, previously Damaged, Vandalism	1	27	4	11	43
Pipe Movement Due to Weather/Outside	0	0	0	0	0
Other	3	32	12	13	60
No Anomaly	2	0	0	0	2
Total	**749**	**1,236**	**56**	**664**	**2,702**

AGA 2011 Integrity Management Results Survey

A survey was conducted in 2011 of the AGA membership to better understand the success of the transmission pipeline integrity program. Table 8 depicts results in a similar format to the INGAA survey results, but the survey only covered the activity during 2010.

The survey results represent over 50 percent of the transmission mileage operated by AGA's membership. While this does not include all of AGA members that operate transmission pipelines, the sample size is substantial and diverse and should reflect a reasonably good snapshot of IM performance of the local distribution companies that operate transmission pipelines.

The first part of the table depicts the amount of miles that were inspected for the baseline part of the PHMSA integrity management program (pipe within HCAs), the number of repairs that were conducted within that mileage and the amount of pipe that was repaired. The second grouping of three rows is a tally of the same type of results above but of the piping outside of HCAs.

Table 8 - Results of AGA 2011 Transmission IM Survey – Mileage Assessed

AGA TRANSMISSION MILES –IMP-Baseline 2010	HCA	Non-HCA
Total Miles Reporting	28,761	
Total Miles of Pipeline Inspected this period due to IMP	553	1,485
Total Number of repairs due to IMP	184	1,079
Total feet of pipe replaced this period due to IMP	7,569	59,757

Table 9 depicts the type of inspection technology that was utilized by the local distribution companies to conduct IMP inspections. As in the INGAA membership, the use of ILI technology predominates at the inspection tool of choice, but the quantity of mileage inspected by direct assessment is substantially higher than the interstate pipelines. As described earlier in this paper, this result is predictable due to the more complex piping configurations located within urban and suburb areas of the LDC markets.

Table 9 - Results of AGA 2011 Transmission IM Survey - Inpection Type

AGA-Table II- 2 – IMP Baseline 2010	Miles	**%**
Miles Assessed due to IMP – ILI	1,143	56
Miles Assessed due to IMP – Hydro	162	8
Miles Assessed due to IMP – DA	730	36
Total	2,035	100%

Development of ILI and Other Assessment Technology

The development of ILI inspection technology in the past has been a combination of investment by inline inspection vendors, collaborative research conducted through individual pipe operators, Joint Industry Projects, PHMSA and Cooperative Research Organizations.

Inline Inspection vendors

As was mentioned earlier in the report, there are over 30 ILI vendors that develop technology under competitive conditions. Many evolutionary developments of ILI technology have been developed to respond to industry demand. The growing supplier base has provided a competitive source of inspection equipment for the pipeline operators, but it has limited the rate of return on investments in the ILI technology for the vendors. Revolutionary research is costly, and the bulk of the risk is in the bringing the technology to commercialization.

Individual Natural Gas Transmission Pipeline Operators

Individual pipeline operators have in many cases provided the impetus of evolutionary and revolutionary ILI development. These companies have combined financial and human resources with the inspection vendors and provided access for testing out new technology.

- Original concept and development of magnetic flux leakage technology for natural gas transmission pipelines
- Sponsoring and funding the development of dual diameter pigs
- Sponsoring and development of the elastic wave pig

Joint Industry Projects (JIP)

In some cases, individual pipeline operators have joined together and have banded together with inspection vendors to come up with solutions.

A recent example was the use of ILI technology to examine the deformation of pipe after construction. No specific criteria had been developed to judge the acceptability of the pipe (i.e. fitness for service). This particular group worked together to define acceptable post constructional dimensional guidelines found by ILI devices that reflected conservative strain loads on the installed pipe.

PHMSA

Since 2002, PHMSA has been allocated funding for research. Some of that funding has been used for the development and application of ILI technologies as well as new robotic inspection devices, including the analysis and application of the results. The program design and results are depicted on the PHMSA web site.[8]

Cooperative Research and Development (R&D)

Natural gas transmission pipelines traditionally have been supported by the following cooperative R&D organizations:

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[8] Research and Development; http://primis.phmsa.dot.gov/rd/

1. Gas Research Institute (GRI) - This organization ceased operations in 2006 and its assets (physical and human) transferred to the not-for-profit R&D organization Gas Technology Institute (GTI)[9].
2. Operations Technology Development (OTD)[10] - - OTD is a not-for-profit corporation led by its 23 members who serve over 26 million natural gas customers in the United States and Canada and pool their collaborative funding and resources to address current and future industry needs.
3. NYSEARCH[11] - A voluntary R & D sub-organization of the Northeast Gas Association (501c6 organization) currently serving (19) member companies from North America. [Note: Membership is not limited to any geographic region.] NYSEARCH works collaboratively with PHMSA, other R&D organizations and a large part of its focus is product development and technology transfer.
4. Pipeline Research Council International (PRCI) [12] – PRCI is a not-for-profit membership organization that implements R&D for the energy pipeline transmission industry, including 36 of the world's leading pipeline operating companies.
5. PHMSA – In the past, PHMSA has conducted cooperative research and co-funded research with the pipeline industry. Recent policy decisions within the Department of Transportation have precluded cooperative research with other research groups. Recent legislation has reinforced the need for cooperative research.

The following table (Table 10) shows how PHMSA has invested their R&D funds and the contributions industry has made in each area. In-line Inspection is included in the Pipeline Assessment and Leak Detection Category.

Table 10 - PHMSA R&D Classifications

Program Category	**PHMSA**	**Industry**	**Total**	**Percent**
Pipeline Assessment and Leak Detection	$ 45.47M	$62.74M	$108.21M	54.50
Improved Design, Construction and Materials	$ 39.93M	$ 51.90M	$91.83M	26.25
Defect Characterization and Mitigation	$ 10.92M	$ 14.67M	$ 25.59M	12.55
Damage Prevention	$ 4.09M	$ 3.87M	$ 7.96M	4.00

Typically, PHMSA hosts strategic planning sessions about every other year to help focus its R&D program. The last forum[13] occurred in June 2009. Another forum is scheduled for summer 2012.
Figure 5 shows the funding from all sources for energy pipeline R&D over the last 15 years. The chart depicts the expenditure drop-off of R&D expenditures as a result of the demise of GRI in the early part of the decade. Since then the investment has grown from $20 million to roughly $30 million per year. GRI was funded through a surcharge on gas deliveries as is part of NYSEARCH. PHMSA is funded by an annual appropriation that originates in part from a user fee mileage charge collected from pipeline companies. The others are funded through annual subscriptions.

[9] GTI website http://www.gastechnology.org/

[10] OTD website http://www.otd-co.org

[11] NYSEARCH website http://nysearch.org/

[12] PRCI Website http://www.prci.org/

[13] PHMSA 2009 R&D Forum http://primis.phmsa.dot.gov/rd/mtg_062409.htm

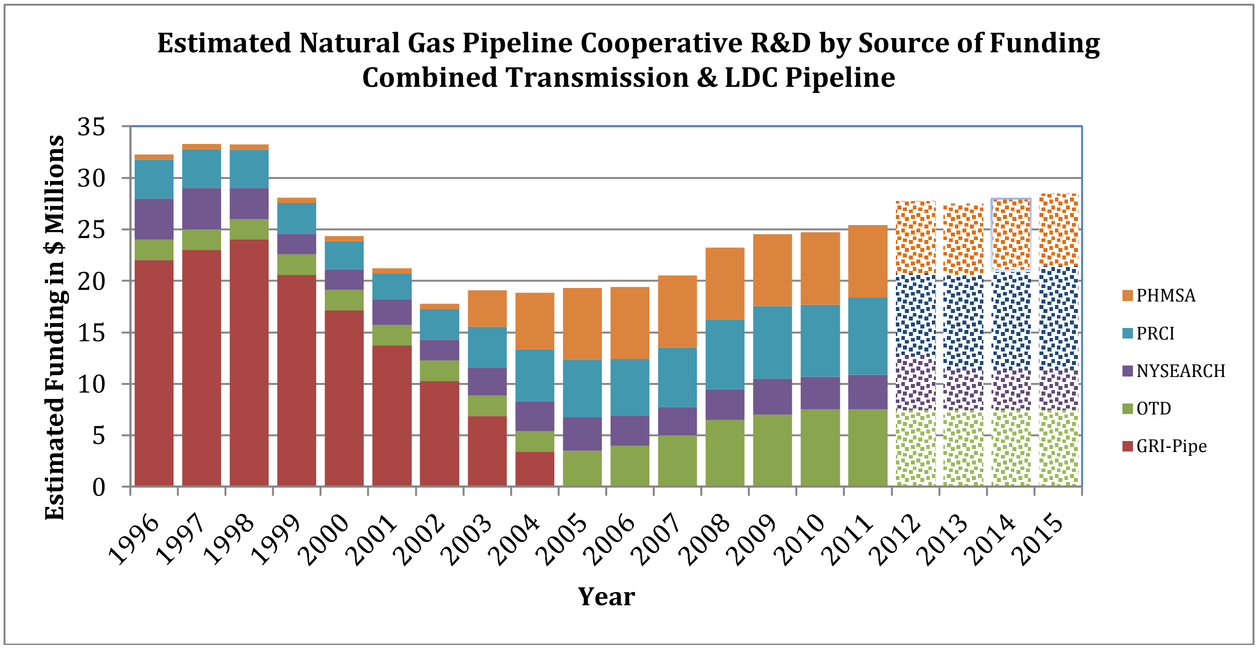

Figure 5 - Cooperative Pipeline R&D Expenditures

These collaborative R&D organizations have supported R&D for a wide range of industry needs and gaps. While this graph reflects the total R&D expenditures of these cooperative groups, integrity management has been a key subject of cooperative R&D, ILI development and the accompanying analysis programs represent a significant percentage of those expenditures.

However, the expenditures shown in Figure 5 do not depict the internal R&D expenditures by the ILI inspection vendors and the more importantly; the commercialization expenditures to bring those technologies to market. The results of that work can be demonstrated by the existence of fully commercial technology and developing prototypes as shown in Table 11.

Also not shown in Figure 5 are the large development costs borne by individual pipeline companies who have agreed to run various prototype ILI tools in their pipelines by working with the pig manufacturers to verify and validate these innovative technologies. These RD&D projects are typically in the order of several million dollars each. The funds are associated with excavating multiple pipeline locations to best characterize and correlate the field observations with the ILI sensor analyses. These pipeline operators generally hire a third party to provide independent analysis and write up the outcomes and provide recommendations for communication to other pipeline operators, inspection vendors and regulators.

Finally, the human and financial resources needed to communicate the technology development to pipeline operators and regulators are not reflected. Inherently technology is not accepted unless there are extensive efforts to illustrate and verify the results. For example one repair technology took over 8 years of extensive efforts to finally be incorporated into the U.S. pipeline safety regulations.

Appendix D – Cooperative R&D Project Summaries provides a summary of the recent R&D projects that have been conducted by these cooperative research programs and shows the extent and diversity of these programs.

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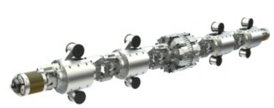
Current State of Technology and Projected Timeframes for Enhancement of Existing Technology and Development of New Technologies

As mentioned previously, significant efforts have been expended to advance ILI technologies. These efforts have resulted in many accomplishments and the recognition that more work is still needed.

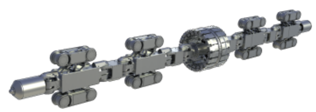
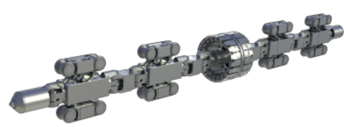
Table 11 depicts the accomplishments that have been achieved in advancing ILI technologies. The table depicts the current state of technology, projected timeframes for enhancement of existing ILI technology and development of new technologies based on predicted technological breakthroughs and present investment strategies. The table describes the different tools, diameters, sensor types and key features; the stage of commercialization; 1st generation applications and usability; 2nd generation applications and usability and other information.

Table 11: Combined Platform Sensors to Address Advancing ILI

Combined Platforms/Sensors to Address Advancing ILI
Detection & identification performance as well as sizing accuracy vary with tool type, feature type, and tool generation

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
EXPLORER 6/8 **Sensor: Remote Field Eddy Current** **Key Feature: Can inspect unpiggable lines**	Now Commercial – since 12/10 	1st gen detects metal loss & visual anomalies; not mechanical damage, ovality & crack detection; Range limited to 2 miles	2nd gen to add mechanical damage and ovality sensors, available late 2012 3rd generation to add sensors to detect cracks; available 2013; 4th gen to upgrade sensor to characterize cracks	2nd gen expanded range to 5 miles+; not yet unlimited range; keyhole communication antennas needed; 3rd gen range unlimited and crack detection added; available 2013
EXPLORER 10/14 **Sensor: MFL** **Key Feature: Can inspect unpiggable lines**	Commercial – 2nd Qtr 2012 	1st gen detects metal loss & visual anomalies; not mechanical damage, ovality & crack detection; Range limited to 2 miles	2nd gen to detect mechanical damage and ovality; available late 2012, 3rd generation to detect cracks; available 2013; 4th gen to characterize cracks	2nd gen expanded range; 3rd gen range unlimited; available 2013

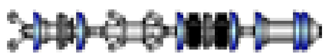
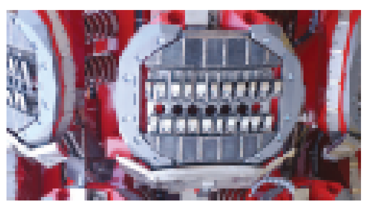
Combined Platforms/Sensors to Address Advancing ILI (cont.)

Name of Tool, Diameters, Sensor Type, and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
EXPLORER 20/26 **Sensor: MFL** **Key Feature: Can inspect unpiggable lines**	Commercial – late 2012 	1st gen detects metal loss, visual anomalies, mechanical damage & ovality: does not detect cracks; Range limited to 5 miles	2nd gen to add sensors to detect cracks; available end of 2013; 4th gen to upgrade sensor to characterize cracks	2nd gen expanded range to 5 miles+; 3rd gen range unlimited range and crack characterization added; available 2013
EXPLORER 30/36 **Sensor: MFL** **Key Feature: Can inspect unpiggable lines**	Commercial – mid-2013 	1st gen detects metal loss, visual anomalies; ovality; cracks (TBD); range limited to 5 miles	2nd gen to characterize cracks; late 2013/early 2014	Unlimited range; available 2013/2014

Combined Platforms/Sensors to Address Advancing ILI (cont.)

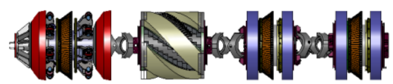
Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
EXPLORER 16 **Sensor: MFL** **Key Feature: Can inspect unpiggable lines**	Pre-commercial; commercial date TBD	1st gen detects metal loss,visual anomalies, mechanical damage & ovality, cracks; range TBD	2nd gen to characterize cracks and improve range	Limitations TBD
EXPLORER 28 **Sensor: MFL** **Key Feature: Can inspect unpiggable lines**	Pre-commercial; commercial date TBD	1st gen detects metal loss,visual anomalies, mechanical damage & ovality, cracks; range TBD	2nd gen to characterize cracks and improve range	Limitations TBD

Combined Platforms/Sensors to Address Advancing ILI (cont.)

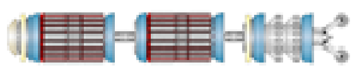
Name of Tool, Diameters, Sensor Type and Key Feature	***Stage of Commercialization***	***1st generation applications/ usability***	***2nd generation or other***	***2nd generation applications/ usability***
Axial high resolution MFL on standard pig, 3-56"; ***Sensor: One or two-axis axial MFL sensor*** ***Key Feature: Inspection for metal loss features***	*Commercially available for many years; standard inspection tool for pipeline integrity management*  	*Detecting wall loss/metal loss, pitting corrosion, and girth weld features* *Corrosion growth assessment*	*Validate capabilities for detecting and identifying features in girth welds.* *Improve ID/OD discrimination with secondary sensor*	*Improved discrimination of secondary features in dents* *Improved detection of long, longitudinal corrosion* *Pinholes and axial grooving*
Circumferential MFL on standard pig, 6"-56" ***Sensor: One or two-axis circumferential MFL*** ***Key Feature:*** ***Long seam features, and narrow axial flaws such as gouges, notches, fissures and channels***	*Commercially available* 	*The 1st use of these tools was for narrow axial corrosion. Crack-like features must be open for detection. Better detection on ID than OD.* *Detecting and discriminating plain dents and dents with corrosion and/or planar and seam weld features* 	*Field validation of capabilities for detecting flaws in long seams* *Improved sensor and data processing for quantification of corrosion and cracking feature sizes*	*Better resolution of interacting features, including long narrow corrosion and cracks in dents*

Combined Platforms/Sensors to Address Advancing ILI (cont.)

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
Tri-axial MFL; 6” to 48“ **Sensor: Tri-axial MFL** **Key Feature:** **Inspection for metal loss features**	Commercially available since 1995. Recently, more vendors supplying this configurations 	Improved sizing accuracy of depth, length and width of corrosion anomalies over single axis MFL Corrosion growth assessment	Assessment of dents with gouges and metal loss	Mechanical damage
Cathodic Protection Current Measurement Tool (CPCM) **Sensor: High Resolution Voltmeter** **Key Feature:** ability to provide high quality CP data without right of way access on piggable pipelines.	Commercially available - 6” through 36” Includes calipers	Monitor and record CP current through electric potential longitudinal gradient measurements at the inner pipe wall	Further development of the technology for application in natural gas systems; improvements with contacts to pipe wall	TBD

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
Multiple Data Set Tools **MFL, Dual Field MFL Helical (Spiral) MFL, Deformation Internal/External Discrimination XYZ** **Key Feature: Long seam features, and narrow axial features Improved detection for mechanical damage, metal loss, and crack like features**	 Commercially available in 8", 10", 12", 16" 24" available 2nd qtr, 20" 4th qtr 2012 Additional sizes TBD	Detection of external and internal corrosion, wall loss, dents and dents with metal loss, residual stresses in pipe wall, metallurgical changes near damaged area, dents with gouges, hard spots; HAZ, weld and pipe body crack like features, long seam evaluation, axially oriented features, channeling, grooving, XYZ	Validate improved capabilities for detecting and identifying features in girth welds. Application of small diameter tools, inclusion of an EMATS module	Re-inspection of previously inspected lines for shallow re-rounded dents, mechanical damage, deformation strain calculation, long seam features, axially oriented metal loss features Identification/ discrimination of pipe joint vintage Enhanced baseline survey for new construction

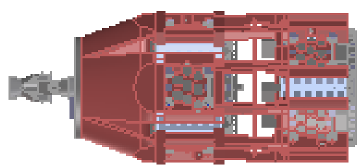
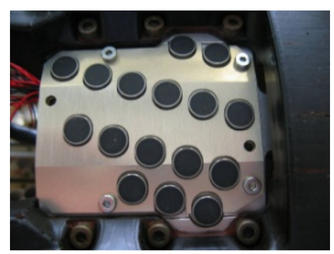
Combined Platforms/Sensors to Address Advancing ILI (cont.)

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
Combo Tools – 6” to 48”; deformation and metal loss; metal loss and cracking **Sensor: Multi high resolution** **Key Feature: Provides data on multiple conditions & features**	Currently available Caliper/MFL/inertial MFL/UT MFL/Eddy Current 	Detection of external and internal corrosion, wall loss, dents and dents with metal loss, weld flaws and cracks and other narrow features in pipe body	Application of small diameter tools for unpiggable applications and	Facility integrity applications 
Dual-Field MFL **Sensor: MFL; High and Low Magnetic fields** **Key Feature: Improved detection for both metal loss and mechanical damage**	Currently available in 30” diameter tool 	Detects metal loss, residual stresses in pipe wall, metallurgical changes near damaged area, dents with gouges/metal loss, XYZ, and hard spots	TBD; likely to be offered in range of sizes (24” and 36” initially)	Re-inspection of previously inspected lines for shallow re-rounded dents

Combined Platforms/Sensors to Address Advancing ILI (cont.)

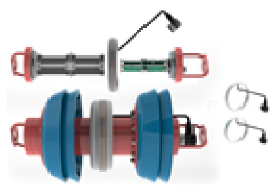
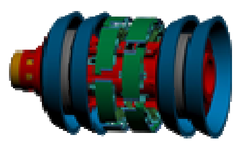
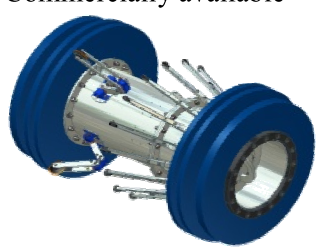
Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
Multi-Diameter ILI – 6”-8”,10”-12”, 14”-16” ,32”/42” and 14”/18 **Sensor: High resolution MFL and Caliper** **Key Feature: inspection of unpiggable, mutli-diameter lines**	Currently available	Used for inspecting lines with multiple diameters 	Further expansion of tool sizes to accommodate wider range of difficult to inspect lines	Development of smaller diameter tools for Facility integrity applications
Bi-Directional Tools, Tethered Tools **Sensor: MFL** **Key Feature: inspection of pipelines with only one entry and exit point**	Commercially available 	Able to use with launch valves; tool can be run with only limited pre-inspection cleaning , inspection capabilities up to several miles		

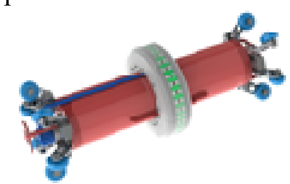
Combined Platforms/Sensors to Address Advancing ILI (cont.)

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
Oblique MFL on standard pig, 6”-24” **Sensor: Axial MFL and a magnetic field at about 45 degrees** **Key Feature: Corrosion sizing and crack detection**	Emerging technology becoming commercially available .	Improved assessment of corrosion defect sizes. Crack detection.	Assessment of dents with gouges and metal loss	Mechanical damage
Ultrasonic wall thickness Detection Tools, 6-56” **Sensor: Ultrasonics** **Key Feature: detects and characterizes metal loss for liquids pipelines**	Commercially available and used routinely in liquid lines; compression wave ultrasonic method like a common ultrasonic thickness meter 	Detects metal loss. Unlike MFL, it can determine “River Bottom” for advanced assessment method such as RSTREGTH 	Improve capabilities for short deep pits such as those caused by MIC 	Faster data recording speed for improved resolution

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
EMAT, 16-48” **Sensor: EMAT** **Key Feature: crack and SCC features for pipes**	Commercially available Work continuing on validation as an accepted ILI tool Improved implementations of EMAT technology emerging. EMATs are extremely configurable sensors that can be designed for many defect types and inspection approaches	Detecting axial crack-like indications such as SCC, seam weld / girth weld cracks, cracks in pipe body, SCC, and laminations; also provides indications of features in long seams and coating disbondment	Better visualization of crack features (hook cracks) in welds and coating disbondment. Improve depth and length sizing	Improved distance of tool runs and hours of operation
Ultrasonic Crack Detection Tools, 6-56” **Sensor: Ultrasonics** **Key Feature: detects and characterizes cracks in girth welds and seam welds for liquids pipelines**	Commercially available and used routinely in liquids pipelines; Includes shear wave, compression wave 	Detects fatigue cracks, SCC, cracks, laminations Used for inspection for cracks in pipe wall and flaws and imperfections in welds (long seam)	Improve capabilities for circumferential cracks, better crack sizing capabilities	

Combined Platforms/Sensors to Address Advancing ILI (cont.)

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
Integrated Cleaning and Inspection Tool for standard pigs, various diameters **Sensor: Low resolution sensor** **Key Feature: Data Collection as part of routine maintenance**	Availability TBD; prototype tools are 16" diameter  	Combine low resolution sensors on commercially available pipeline cleaning pigs. Provides more frequent, lower resolution data for evaluating changes and trends in pipeline monitoring data as an indication of potential threats to pipeline integrity. The inspection system will be a bolt on design, suitable for gas and multiphase pipelines, be able to travel and inspect at high speeds and allow immediate data analysis. Low cost, low maintenance, and can be deployed on a regular basis (as determined by operating system needs)	Add increased capabilities – higher res sensors, identify smaller features. Increase power performance for greater range. Work on high temp pipe +100°C	Longitudinal seam weld inspection
Caliper Technology Sensor: Caliper arms and EM **Key Features: Ground movement and deformation**	Commercially available 	Measures dents, wrinkles, buckles, ovality, and strain-in-dent analysis due to slope instability, frost heave, subsidence, temperature/pressure variations, flooding, upheaval, or new construction impact.		TBD

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
EMIT for Multiple Platforms, 10 and 16” **Sensor: EMIT** **Key Feature: Can inspect lines with debris and residue build up due to sensor offset from pie wall** **Fatigue crack testing in dry gas**	Availability TBD (target date is 4Q 2013); prototype technology is 10” and 16” diameter platform 	Detection of flaws and imperfections in girth welds, with emphasis on fatigue cracks	Complete Phase 2 development and conduct full field validation study of the Electromagnetic Impedance Technology (EMIT) sensor. Increase range of applications and longer distances for tool runs.	Multiple diameters as directed by industry. High Pressure & High Temperature pipelines. Long seam dry gas pipeline inspection.
Tethered MFL on Pipecrawler, 10-12” **Sensor: MFL** **Key Feature: Can inspect unpiggable lines**	Commercial production prototype available now. 	10-12” delivery platform, for most sensors, tethered, live gas, commercializer has jobs off shore and seeking natural gas applications. MFL is first sensor as well as visual. 3000 ft, 700 psi. Could go to 3 miles, 8-42”, UT, and GW. Handles unpiggable pipeline bends and diameter changes.	Expand diameters and sensors based on market demand.	

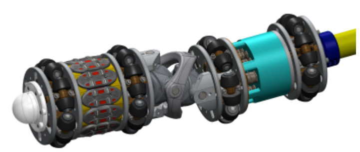
Combined Platforms/Sensors to Address Advancing ILI (cont.)

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
Tethered MFL, 4 and 12" **Sensor: MFL** **Key Feature: Practical for shorter distances**	4" is available as a service. 	1st Generation in use now. Use to inspect shorter segments of 1000 ft or less in either direction of entry fitting. 65 psig. Includes color camera. Limited to 5-7 degree bends and no intrusions into the pipe.	12" metal loss/corrosion (MFL) in live system. Able to negotiate limited 5-7 degree bends and minor diameter changes. Potential commercializer involved.	Other diameters including 10", visual inspection, improve distance to 1500 ft and unpiggable limitations to negotiate bends and diameter changes. Pressures over 65 psig.
RSD, Platform TBD, sizes TBD **Sensor: X-Ray Backscatter by Radiography** **Key Feature: Detects flaws in both plastic and metal pipelines**	**Availability** TBD	X-Ray Backscatter by Radiography with Selective Detection (RSD) for Plastic and Metallic Pipelines- Sensor validated for internal and external wall loss detection including detailed cracks, gouges and flaws	Sensor and platform developed for market needed diameters, TBD	

Combined Platforms/Sensors to Address Advancing ILI (cont.)

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
Acoustic Resonance Technology **Sensor: ART** **Key Feature: Internal corrosion Inspection**	Available now and can be used to inspect unpiggable pipelines, offshore pipelines 	Developed for internal and external corrosion inspection and shrink sleeves at girth welds for offshore systems.	Expand to platforms other than cleaning tools; test in onshore pipelines for internal inspection	Use ART tool for crack inspection
BEM Circumferential Tool, 6-8" **Sensor: Broadband electromagnetic (BEM) measures wall thickness** **Key Feature: Coating does not have to be removed**	Commercially available now. Both an external and ILI version. Low speed inspection 	BEM tool measuring wall thickness is commercially available. Requires access to surface of the pipe. In a keyhole, circumferential sensors can validate an initial ILI or DA before a major excavation. Can be used on unpiggable pipelines. Live inspection if used externally.	Needs additional validation with field testing and faster data collection.	Improved platform to move sensors internally along pipeline.

Combined Platforms/Sensors to Address Advancing ILI (cont.)

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ usability*
Tethered Guided Wave In Line Inspection Tool Sensor: Guided Wave **Key Feature: ILI version of Guided Wave. Bi- directional - reduces dig costs with better coverage**	Pre-commercial; commercial date TBD 10inch sensor head (with optional camera) designed and manufactured but not yet assembled or tested 	Bi-directional. Deployed by push/pull coil tubing type arrangement. Suitable for HCA and shorter sections of pipe and platform risers Limited to 3D bends. Pressure TBD	Expand too sizes Combined with new other technologies to size surface flaws & cracks. Increase pressure rating	Sizes to cover all diameters as required. Can be integrated with crawlers for long range excursions. Couple with electromagnetics for additional capabilities
Guided Wave, 6-36" Sensor: GW **Key Feature: Improved detection capabilities over other sensors**	Available now from a variety of commercializers. Range- cased pipe 100 – 300'; buried pipe/no casing – 30 – 70'	Current use is as a screening tool and for sizing larger corrosion/wall loss flaws; small, narrow flaws are challenging, Requires access to surface of pipe.	Improved sizing models for all defect sizes and shapes. Advances in detection of small changes with monitoring over time.	Maybe applied for specific types of pipes/conditions and coating types where signal attenuation is least affected

Combined Platforms/Sensors to Address Advancing ILI (cont.)

Name of Tool, Diameters, Sensor Type and Key Feature	*Stage of Commercialization*	*1st generation applications/ usability*	*2nd generation or other*	*2nd generation applications/ Usability*
Profile Electromagnetic Wave Guide Technology, 6-30” **Sensor: GW** **Key Feature: Improved detection capabilities**	Available now from distributors. Includes monitoring of wax fill of cased pipe systems. Range – 100’ +	Requires access to surface of pipe.		
TransKor Magnetic Tomography **Sensor: Magnetic Tomography** **Key Feature: Above ground inspection**		Not an ILI but inspects from the surface without need to make contact to pipe. Limitations if previously pigged; or in presence of strong magnetic fields.		

Future ILI R&D Focus, Development and Coordination

The development of ILI R&D is comprised of two components, the technical focus of the programs and administration of the effort. Both of these efforts need to be present and coordinated.

Technology Focus of Future ILI R&D

The majority of the R&D investments have been directed at strengthening the inspection related technologies and to provide ways to prevent and mitigate the time dependent threats. As a result, the range and capabilities of ILI tools have improved greatly. Pigs can now find many smaller imperfections and can better discriminate and assess a priority for different kinds of integrity related damage such as corrosion or gouges inside dents. This R&D has also enabled ILI tools to profit from the continued miniaturization of electronics, rare earth magnets, lower power requirements, and high-density data storage.

While ILI tools are much better at finding volumetric wall loss some threats such as pinholes, cracks, and tight narrow selective seam corrosion still remain very difficult to find in natural gas pipelines. Liquid pipelines have more ILI tools available than natural gas pipelines because they already contain the liquid couplant needed for ultrasonic sensor tools which can detect and size cracks and other tight defects. New Electromagnetic Transducer (EMAT) based ILI tools have shown great promise for identifying small cracks and one large pipeline operator is working with an ILI vendor to improve the EMAT capability to characterize stress corrosion cracking (SCC).

The natural gas pipeline industry, along with its research partners, are directing efforts to improving the identification, characterization and analysis of the anomalies and features identified in Table 5 which reflected the current state of ILI technology. The industry and its partners are also focused on expanding the size ranges and functionality of the robotic inspection platforms, including additional sensing (e.g., mechanical damage, ovality), in-line charging for unlimited inspection ranges, and cleaning. In general, the goal is to take the red and yellow boxes in Table 5 and make more of the boxes "turn green" through R&D and commercialization. While there will be a role for research and development, further demonstration of technologies (shown as yellow turning to green) will depend largely on operators and vendors committing to use the technology in segments scheduled for assessment in future years.

The pipeline industry has been focusing on the development of new ILI tools and analysis systems that provide accurate estimates of:

- crack features in pipe walls and welds,
- dents/deformations,
- corrosion profiles and especially pits/grooves in localized damage, and
- material and metallurgical properties of the pipe (e.g., laminations and hard spots, grade, etc.).
- strain caused by outside loads including ground movement
- metallurgical features of the pipe (e.g., laminations and hard spots, etc.).

Table 11 depicts the current state of technology, projected timeframes for enhancement of existing ILI technology and development of new technologies based on predicted technological breakthroughs and present investment strategies.

Future ILI R&D Development

Future ILI development will be accomplished in multiple venues, but it will be more effective if development is coordinated. Cooperative research consortiums provide coordination among pipeline operators and inspection vendors and those efforts are documented in Figure 5.

Emerging Coordination of Pipeline R&D Industry Efforts

It is anticipated that it will take the coordinated effort of INGAA, AGA and APGA membership to accomplish the goals of the organizations.

INGAA organized a Board Pipeline Safety Task Group in November 2010 to address how the interstate natural gas transmission pipeline industry could improve safety performance. AGA's Board has created a Board Safety Committee in 2006 focused on these same goals.

ILI Technology Summit

INGAA held an ILI Summit on December 6, 2011 to bring together operators, ILI providers and research program managers to define how to better define assessment needs and accelerate further development of ILI. The objectives were to ensure that ILI providers and research program managers recognize the significant investment that has been made in making systems piggable and the desire by operators to broaden and deepen the application of ILI, to meet the commitment made by INGAA and AGA's Boards to improve pipeline safety, address recommendations made by the NTSB and anticipate the requirements of recent Pipeline Safety legislation and forthcoming regulations.

There was discussion on how to augment and combine various ILI sensor technologies so that ILI technology can be utilized as an alternative to hydrostatic pressure testing. For example, an ILI inspection would be used to identify not only the defects that would fail, but also provide information on defects that would survive a pressure test. There were also discussions at the ILI Summit about longer term use of ILI to augment present pipeline records and the attribute data critical to validating the maximum allowable operating pressure (MAOP) serving as another check on records.

During the ILI Summit, discussions were held regarding current capabilities in identifying features in the pipe long seam weld that would indicate a situation similar to that in many of the short pups on the PG&E line in San Bruno. The intent is to utilize and develop ILI tools that can identify and characterize gross loss of weld material, incomplete penetration. Subject matter experts developed example models showing families of defects that would fail a hydrostatic pressure test and challenged the ILI providers to respond with tool capability that would surpass that of the hydrostatic pressure test. Similar discussions were held regarding girth welds. While there were no definitive conclusions at the summit, the intent was to raise this potential application for additional thought, evaluation and development.

INGAA Board R&D Initiative

Subsequent to that ILI summit, these particular ILI R&D goals have been elevated to priority items by the INGAA Board Task Groups. These needs and the R&D roadmap to accomplish the goals is the focal point of the INGAA Board Research Initiative, which is presently under development at this time.

PHMSA R&D Initiative

In addition to the work of the industry, PHMSA typically hosts strategic planning sessions every other year to help focus their R&D program. The next forum is scheduled for this summer and it is anticipated that ILI technology will be a major focus.

Conclusion

INGAA, AGA, their members and research partners are committed to ensuring the safety and reliability of the nation's natural gas pipeline infrastructure. Significant efforts have been expended and progress has been made in many areas, including ILI improvements. When first developed, ILI technologies had extremely limited capability. Today, advanced ILI technology can identify a number of anomalies within the pipeline, assess miles of pipe in one run, adapt to changing diameters and overcome obstacles within the line. Robotic platforms have the ability to crawl through the line, retreat to assess further, navigate through valves and assess lines that previously were considered unpiggable. While more needs to be done, we should not lose sight of the progress made. Our goal is simple: Keep pipelines as safe as possible to serve our customers and deliver the nation's energy. Getting it right is imperative. The natural gas industry and its partners are committed to this goal.

Appendix A – The Role of Natural Gas in the United States

As shown in Figure 6, the Energy Information Administration within the Department of Energy (EIA-DOE) depicts natural gas as a key component of the energy picture for the United States currently and in the future.

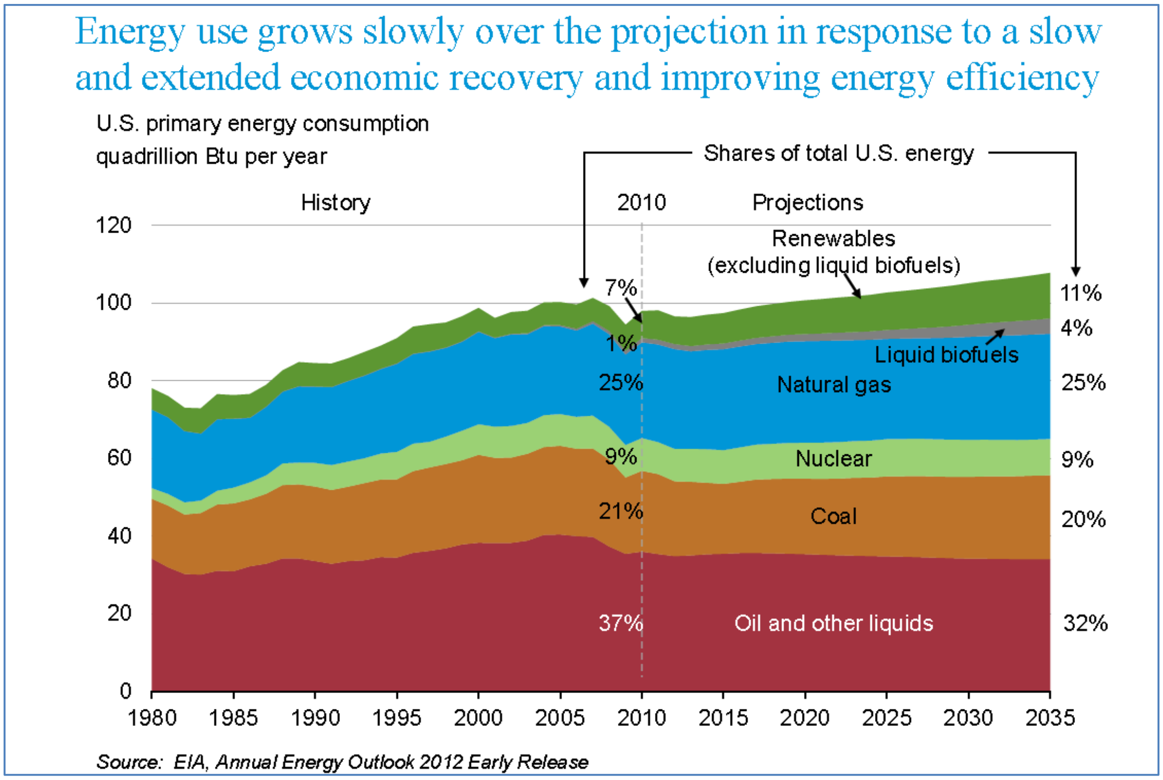


Figure 6 - Sources of Energy in United States

As shown in Figure 7 natural gas is a very important energy source for residential, commercial, industrial and electric generation customers and is critical for the economic viability of the United States.

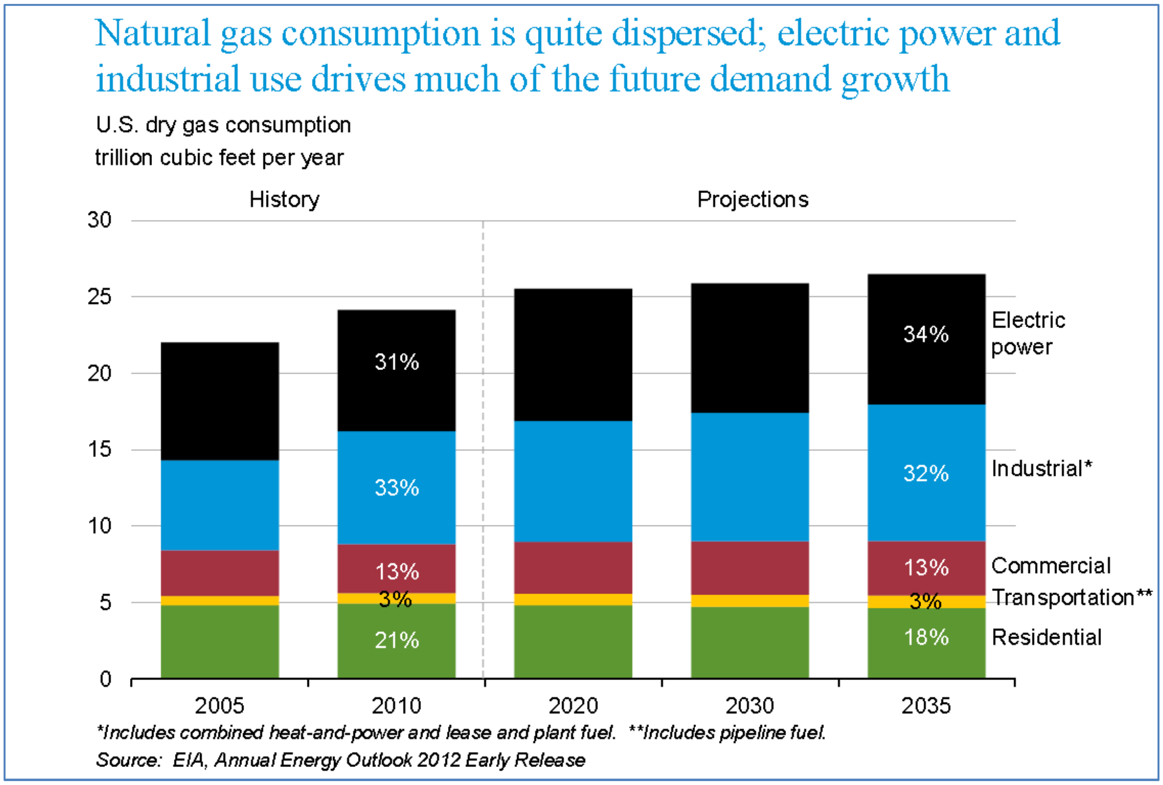


Figure 7 - Utilization of Natural Gas within United States

The amount of energy utilized by these customer groups varies by geography, time of day, weather conditions and economic activity. To meet these changing needs, the delivery system must operate 24 hours a day seven days a week. Natural gas delivery is extremely reliable, even in extraordinary events. Natural gas delivery is a continuous process, requiring innovative operating and maintenance practices and presenting unique engineering challenges for integrity assessment.

Appendix B - Management of Threats to Integrity and Fitness for Service of Natural Gas Transmission Pipelines

As described in the previous section, an operator must evaluate the full range of threats to pipeline integrity as identified in ASME B31.8S. The threats to pipeline integrity are generally categorized as follows:

1. Time Dependent Threats,
2. Time Independent Threats,
3. Resident Threats
4. Interactive Threats (various combinations of threats from the three categories above).

Time Dependent Threats on Natural Gas Transmission Pipelines

Time-dependent threats are ones that, if left unchecked, grow over time. They include internal and external corrosion as well as environmentally induced corrosion, such as stress corrosion cracking (SCC). These threats are progressive over time but vary in frequency and growth depending on the design, operation and surrounding environment. These threats are addressed by periodic integrity assessments, such as ILI, pressure testing and direct assessment.

Time Independent Threats on Natural Gas Transmission Pipelines

Time independent threats are threats related to outside force, operator error and excavation/ mechanical damage. These threats are very unpredictable and sporadic. Typical cases of outside force or excavation damage are caused by specific events and are managed by observation and prevention practices. Excavation damage, a leading cause of serious incidents, is typically the most serious of the threats because of the likely presence of the excavation personnel near the pipe when the event occurs. Excavation damage events, whether first, second or third party, are best managed through effective one call programs, prevention processes, procedures and work practices, training and qualification, management of change and audits. For example, excavation damage is most effectively managed through a complex set of interrelated prevention mechanisms such as facility identification and location, one-call systems, excavation damage prevention education, and appropriate excavation practices. Periodic assessment processes such as Direct Assessment, pressure testing, and ILI technology are effective in discovering prior damage. Threats that survive the initial time independent event are prone to time dependent deterioration. Periodic assessments with ILI or pressure testing can be used to detect those potentially latent damages. Direct Assessment is effective in detecting prior excavation damage if coating damage occurs where the pipe was damaged.

Resident Threats on Natural Gas Transmission Pipelines

Resident threats, presently referred to in ASME B31.8 documents as stable unless acted upon, include all manufacturing and construction imperfections that survived prior mill tests and post-construction pressure tests before the pipeline was commissioned into service. Some small, benign imperfections are typically present in pipe materials and fabrications that are resident or reside in the pipe body or welds as a result of design, manufacturing and construction. Engineering judgment at the time of construction identifies the level of acceptable resident anomalies (i.e. design, manufacturing and construction tolerances).

A review of the operating pressure history for natural gas transmission pipelines indicates that stress cycles (caused by internal pressure variations) are minimal in both magnitude and frequency. Therefore, the pipe segments that have had a post construction pressure test will not be susceptible to cyclic fatigue failure. Consequently, the manufacturing defect threat is considered stable and will remain stable and benign unless activated by a change in operations or the surrounding environment beyond the original engineering design. Various engineering tolerance controls (mechanical, chemical and structural) have been the mainstay of integrity verification for decades. As technology has improved, the understanding of pipeline integrity has improved and, subsequently, engineering tolerances have become more sophisticated. The use of strength tests (which measures the ability of the pipe to hold internal pressure), both in the manufacturing process and post-construction stages have been utilized throughout the development of the natural gas transmission system. ILI technology has the capability to identify resident anomalies that previously passed legacy acceptance determinations.

Interactive Threats on Natural Gas Transmission Pipelines

In addition to the threats identified in ASME B31.8S and Subpart O, there is also the requirement to address the phenomenon of interactive threats. These threats are the interaction of two or more of the previously mentioned threats that increase the probability of failure to a level that is greater than the individual threats acting alone on the pipeline system. These interactions are very difficult to predict since the manifestations of these two threats can happen at a lower threshold than the independent threats. For example, external corrosion affecting a low-frequency ERW seam can result in a type of corrosion referred to as grooving corrosion or selective seam corrosion, which can exhibit higher growth rates than external corrosion outside the seam. The external corrosion and defective pipe are ‘interacting’ when the potential selective seam corrosion exists, and they are not interacting when the potential selective seam corrosion does not exist. The interaction of external corrosion with a low-frequency ERW seam is best managed by monitoring for signs of coating flaws or corrosion near the seam through the use of Direct Assessment or ILI, the interaction of outside forces on resident manufacturing anomalies are best managed by monitoring the pipeline’s operations and surrounding environment to detect if there are actions, such as a large horizontal soil displacement, that exceed what was expected during the operation of the pipelines. But, these changes in the environment are generally sporadic and in some cases difficult to detect. Unlike time dependent threats, this sporadic nature makes periodic assessments much less effective as an integrity management. ILI technology can be used in areas where the operations or environment around the pipe has been found or is suspected to have moved. For example, deformation of pipe can be detected by ILI caliper devices, and increased stress can be detected by some of the ILI geospatial devices.

Appendix C – Pipeline Configuration and Integrity Management.

Natural gas transmission pipelines transport gas from production areas to market areas, where end users consume gas for fuel or as a raw material. There are four basic configurations of these piping system, they are:

1. Trunkline (Long Haul) Systems
2. Grid Systems
3. Reticulated Systems, and
4. Transmission Systems Intermingled With Distribution Systems

Trunkline Systems

A typical long haul, trunkline system is shown in the Figure 8 below:

Figure 8 - Typical Trunkline

Pipelines transporting gas to markets at great distance, hundreds and even thousands of miles, from production areas to other parts of the country are referred to as long haul or trunkline systems. The earliest systems were constructed in the 1920s and line capacity has been added in every decade because production has increased in existing areas, production has developed in new areas and markets for both industrial and residential have increased. Colorado Interstate Gas' first pipeline, for example, was built in 1928 and was a single 24-inch diameter line from the Panhandle of Texas to Pueblo, CO to bring gas to steel mills. Similarly, Panhandle Eastern Pipeline's first line built the same year brought gas from the Panhandle of Texas to Detroit, MI for industrial purposes.

These trunkline systems typically were constructed of single diameter pipe; however, some designs used multiple diameters recognizing that pressure of the gas being transported is reduced as gas moves away from a compressor station. Also, since natural gas is compressible, there is a miniscule efficiency penalty for pipeline equipment not being the same internal diameter as the main pipeline (equipment shortage or significant cost advantage). These multi-diameter lines were designed and constructed before internal inspection tools were conceived. These systems, unless modified, require an ILI tool that can traverse multiple internal diameters.

As these trunkline systems traverse the countryside they can receive additional gas (receipts) and deliver gas (deliveries) to a pipeline system. There is a connection at each of these points, typically a tee, where the connection is perpendicular to the line. As pipelines approach an end use market, the systems resemble a tree with a large trunk (mainline) that splits off to smaller branches (laterals). The size of the branch or connection is dependent upon the anticipated gas volume delivered; the larger the volume, the larger diameter. Receipts are similar, with a small volume producer or small pool of producers introducing gas through a smaller diameter pipeline (i.e. two to eight inches in diameter). These tee connections can be made where the base of the tees is close to the same diameter as the cross of the tee where the ILI device is traversing. The ILI device or the pipe can be damaged as parts of the ILI device might try to divert into the opening of the tee as the ILI device passes by. These tees have to be replaced with tees that have guards to keep the pig in the main pipeline. There are still large portions of the natural gas transmission system that require this type of retrofit before ILI tools can be successfully run.

Trunkline pipelines were routed through areas of large elevation change, such as mountains and hills. In areas with mountains and hills, and even subtle changes in terrain, bends are installed in the pipeline to match the topography. ILI tools are extremely heavy due to magnets, batteries, and other equipment used to provide guidance and continually record data. As these tools travel through areas of large elevation changes, their speed can approach the lower tolerance limit of the sensor design on steep inclines and the upper limit of speed on steep declines, thus impeding collection of accurate data. This necessitated the development of speed control. Even with speed control, there are pipeline segments that do not have enough operating pressure and pipeline gas flow to push an ILI effectively.

In many cases when obstructions were encountered during construction or there were diversions in the route of these trunklines, bends in the pipe were often made during the construction without the benefit of a mandrel. This causes the internal diameter to become ovalized in the area of the bend, effectively reducing the diameter in portions of the bend. Bends with a great degree of ovalization or a greater degree of bending can preclude passage of an internal inspection tool. Newer sensors are segmented and the joints have been made shorter and more flexible in order to accommodate these restrictions. Some sensor types on the joint, however, may not be able to traverse these tight bends and still effectively collect information.

An ILI device has to pass through block values along the pipeline. Block valves are spaced evenly along the system to enable isolation of a segment of pipe to conduct maintenance work or in the event of an emergency. While today it is standard to construct pipelines with valves that have a full opening port (same diameter as the pipeline), this was not always the case. Operators with legacy valve systems are making portions of systems piggable. Operators have retrofitted non-full opening valves or reduced port valves with full opening valves, particularly at segments containing HCAs. There are still large portions of trunkline systems that would require this type of retrofit before traditional ILI tools could be run.

Finally, under the original pipeline designs, there was no need to insert devices like pigs into the pipeline. The requirement to introduce the ILI device into the operating pipeline required the installation of launchers (on ramps) and receivers (off ramps). The ability to place permanent launchers is a function of how many of these devices are needed because of the limits itemized above, space availability and public acceptance.

Grid Pipeline Systems

A depiction of natural gas grid systems is shown below in Figure 9:

Figure 9 - Typical Grid System

In addition to the difficulties that may be found in transmission trunklines, there are other issues with grid systems. Transmission pipeline systems near market and gas production areas tend to have more branches due to multiple lateral lines. In parts of the country where metropolitan areas have grown, multiple connections to other transmission lines or storage systems and uncoordinated incremental expansion to the system have occurred. Pipeline diameters tend to change in these grid systems. Pressure may be reduced from hundreds of pounds in the trunkline systems to a few hundred pounds or less in a grid system. The grid system reduces the pressure further until it is suitable to provide gas into a distribution system. These types of pipelines systems initially were built to supply gas to industrial and residential customers that originally used coal gas as an energy source.

As grid systems evolved, additions were added over the decades to access new supplies and feed new markets, resulting in pipeline segments with multiple diameter changes that do not readily accommodate passage of ILI devices. Even with the advances that have occurred in ILI technology, grid systems can be a challenge or impossible for ILI tools. This can be due to the multiple diameter changes in the lines, the number of block valves and the flow within a pipeline may not great enough to provide sufficient motive power for the ILI device. While some cable systems have been designed to move these devices, care must be taken to be sure the pipe is not damaged by the cabling system. Sharp pipeline bends, particularly those made through a process known as mitering, in which multiple pieces are welded together, often cannot be traversed effectively by typical ILI tools.

Reticulated Pipeline Systems

Another type of transmission system is the reticulated system, which often includes branches in the production area, branches in the end user area and multiple lines traversing long distances of several hundred miles. El Paso Natural Gas is such a system. El Paso connects to a few large production areas and multiple lines feed market areas. It has some characteristics of a grid system in the production and marketing ends of the system and characteristics of a trunkline in the piping between those locations.

A typical reticulated system is shown in the Figure 10 below:

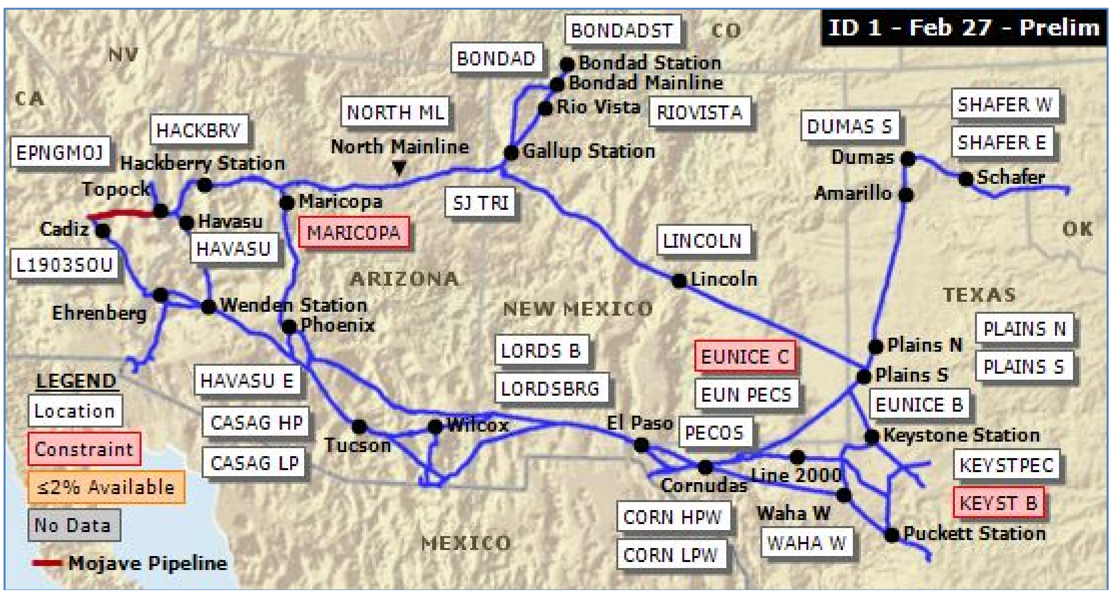


Figure 10 - Typical Reticulated Pipeline System

Transmission Systems Intermingled With Distribution Systems

Transmission systems intermingled with distribution systems typically are operated by local distribution companies within a given market area. These systems contain many lines, including crossovers that connect to distribution centers and direct sales customers. These systems tend to be complex, include high population densities and typically operate at lower pressures and pipe stress levels (percent of specified minimum yield stress or SMYS) than trunkline systems.

These systems have proven difficult to assess by ILI tools, for a number of reasons, including:

- many interconnects between transmission and distribution pipeline;
- multiple changing diameters of pipe in single pipeline segments;
- small pipeline diameters less than ILI tool capabilities;
- short segments between interconnections with distribution piping;
- low pressures and flow rates insufficient to move the ILI devices;
- many block valves of various sizes and types with reduced ports that restrict the ILI;
- bottom-out" fittings that present obstacles to ILI tool passage
- miter bends,
- complex curves with two or more adjacent bends (elbows);
- tight radius elbows;
- vertical rising segments; and
- land use restrictions for installing launchers and receivers.

Additionally, as the pipeline being inspected approaches the end customer, fewer opportunities exist to maintain natural gas service through alternative gas routing and there are more challenges to providing adequate gas flow rates and/or pressures to move the ILI tool during the inspection process.

In these complex situations with widespread obstructions, alternative technologies have been developed to assess for the most common cause of pipeline leaks, namely corrosion. Direct Assessment (DA), which combines a number of proven corrosion assessment technologies, was developed approximately 15 years ago to provide a basis to assess certain time-dependent and time-independent integrity threats (e.g. the performance of the corrosion protection systems and excavation damage). DA is a structured process to integrate multiple indirect measurements on the pipeline. With excavation and direct examination of the pipeline surface, it can be used to confirm the indirect measurements. The process is an effective tool that identifies areas where corrosion has occurred or is likely to occur. It is also an effective tool to identify excavation damage to pipelines where coating damage has occurred.

As operators gained experience using this DA integrity assessment methodology during the first decade of the Transmission Integrity Management Program, the industry recognized the need for alternative assessment tools and technologies to improve the capabilities to assess for other suspected threats. Advances in technology have resulted in several robotic platforms that have the ability to transverse pipelines that were previously considered "unpiggable." These and similar ILI technologies have been identified as promising technologies to meet these challenges that operators of transmission lines intermingled with distribution systems face, especially the challenge in overcoming limitations associated with insufficient operating pressures or flow rates to propel the ILI inspection tool down the pipeline.

Appendix D – Recent Business and Government R&D Projects Related to Inline Inspection Technology

Estimated total investment = $20,575,000 about 50:50 funded over the last 10 years

Prime Sponsor	Contract Number	MMS PHMSA Proposal Key #	Technology Title	R&D Key Word	Short Summary
PHMSA	DTRS56-03-T-0002	115	Assessment & Validation of TFI-Identified Anomalies Criteria for Repair and Available Repair Methods	ILI Improving Resolution	The objectives of this project are to (1) compile and evaluate the unique properties of early generation pipeline weld seams, (2) compile a catalog of defect types, and (3) develop methods for evaluating seam weld defects to determine whether pipeline integrity has been compromised.
PHMSA	DTPH56-05-T-0001	176	Understanding Magnetic Flux Leakage (MFL) Signals from Mechanical Damage in Pipelines	ILI Improving Resolution	Provide for understanding, identification and characterization of MFL signals arising from the geometric and residual stress components to enhance the reliability of employing MFL tools for mechanical damage detection
PHMSA	DTPH56-10-T-000011	356	Integrated Internal Inspection and Cleaning Tool Technology for Pipelines	ILI Alternative	The main objective is to develop an integrated and scalable cleaning and inspection tool that measures, records, and provides analysis of a range of parameters during conventional pipeline cleaning runs. Data collected will be used in trending and prioritization for indications of changing environments to improve integrity management through earlier response to integrity threats. The project represents step change in how the industry manages its integrity inspection program (Note: Project was terminated by PHMA and is now overseen by PRCI)
PHMSA	DTRS56-04-T-0001	141	Nonlinear Harmonic-based Mechanical Damage Severity Criteria for Delayed Failures in Pipelines	ILI Improving Resolution	The objective of this proposed research is to derive fatigue life related defect severity criteria for pressurized pipelines containing gouged dents using the nonlinear harmonic (NLH) method for detecting surface strain anomalies left in the pipe after gouging

PHMSA	DTPH56-08-T-000004	232	Improving Magnetic Flux Leakage In-Line Inspection Corrosion Sizing Using Phased Array Guided Ultrasonic Waves	ILI Improving Resolution	The goal of this development is to improve corrosion anomaly depth sizing of magnetic flux leakage (MFL) tools by adding phased array Guided-Wave Ultrasonic (GWUT) inspection technology. This addresses Research Area 3 as defined in the solicitation.
PHMSA	DTPH56-08-T-000009	236	Adaptation of MWM-Array and MFL Technology for Enhanced Detection/Characterization of Damage from Inside Pipelines	ILI Sensors for Wall Loss	JENTEK will adapt MWM-Array technology and use JENTEK multivariate inverse methods to deliver hybrid MWM-Array/MFL methods for ILI applications. For detection/sizing of internal/external corrosion, mechanical damage and SCC, with matching funds from Chevron, we will develop solutions for conventional pigs and platforms for unpiggable lines. We will also address concerns for pipelines with internal liners and coatings. Pigging platform providers will also provide matching funds
PHMSA	DTRS56-02-T-0002	107	Mechanical Damage Inspection Using MFL Technology	ILI sensors Mechanical Damage	a simplified multiple magnetization tool will be designed, a magnetizer and sensor will be developed, and ultimately the researches will collect and analyze pull rig and flow loop data
PHMSA	DTRS56-02-T-0003	108	Feasibility of In-Line Stress Measurement by Continuous Barkhausen Method	ILI sensors Mechanical Damage	This project will demonstrate the use of modified MFL ILI tools to inspect mechanical damage, cracks, wrinkles and corrosion
PHMSA	DTR57-06-C-10004	185	In-Line Nondestructive Inspection of Mechanical Defects in Pipelines with Shear Horizontal Wave EMAT	ILI Sensors Mechanical Damage	Intelligent Automation, Inc. (IAI) and Oak Ridge National Lab (ORNL) is developing a novel and integrated approach to inspect mechanical damages in the pipelines with or without coatings. that combines the state-of-the-art Shear Horizontal (SH) wave EMAT technique, through detailed numerical modeling and instrumentation data collection, with advanced signal processing and pattern classification techniques, to detect and characterize the mechanical dents in the underground pipeline transportation infrastructures

PHMSA	DTRT57-09-C-10046	292	Development of in-field pipeline inspection tool: Digital Imaging of Pipeline Mechanical Damage and Residual Stress	ILI Sensors Mechanical Damage	JENTEK will develop enhanced high resolution eddy current array imaging for characterization of mechanical damage in pipelines. JENTEK has conducted preliminary investigations that indicate that liftoff (proximity) maps can be used to develop 3-D quantitative representations of mechanical damage caused surface topology. These will provide an opportunity for automated analysis of both size and shape of damage and a permanent digital record that can be compared to future measurements.
PHMSA	DTRS56-02-T-0001	104	Application of Remote-Field Eddy Current Testing to Inspection of Unpiggable Pipelines	ILI sensors wall loss	to determine if an ILI using RFEC testing is adequate to inspect currently unpiggable pipelines
PHMSA	DTRS57-04-C-10053	157	Innovative Safety and Reliability Technologies for Pipeline System Integrity and Management	ILI Sensors wall loss	Intelligent Automation, Incorporated proposes a novel and integrated approach to inspect the metal loss in the pipelines. It combines the state-of-the-art Shear Horizontal (SH) wave EMAT technique, with our record-proven advanced signal processing and pattern classification technique, to detect and characterize the metal loss problem
PHMSA	DTRS56-05-T-0002	160	Design, Construction and testing of a segmented MFL sensor for use in the inspection of unpiggable pipelines	ILI Sensors wall loss	Develop a segmented Magnetic Flux Leakage (MFL) sensor and respective module for integration in a robotic platform TIGRE;
PHMSA	DTRS56-04-T-0008	148	Stage 2 Phased Array Wheel Probe for In-Line Inspection	ILI Sensors wall loss & SCC	Build a smaller wheel probe that can be utilized as-built for In-Line Inspections
PHMSA	DTRS56-02-T-0004	110	Baseline Study of Alternative In-Line Inspection Vehicles	ILI tool design	The purpose of this research is to conduct a baseline study of alternative ILI vehicles that might be able to negotiate unpiggable pipelines. The researchers will: (1) document the status of unpiggable pipelines and mitigation options, (2) document designs of ILI devices being used in other industries, (3) identify options to inspect

					transmission and distribution lines, (4) document current ILI systems in the U.S. and abroad, and (5) summarize internal tool capability in other related industries (nuclear, water, plant production
PHMSA	DTPH56-06-T-0009	191	Enhancing Direct Assessment with Remote Inspection through Coatings and Buried Regions	In-the-ditch Defect Sizing	Full body inspection of tar coated pipelines for corrosion damage with a minimum of excavation. The other is the measurement of residual stress and plastic strain
PHMSA	DTRT57-09-C-10044	291	Low-Cost, Full-Field, Surface Profiling Tool for Mechanical Damage Evaluation	In-the-ditch Defect Sizing	In this project, Intelligent Optical Systems will determine the feasibility of implementing a novel surface-profiling tool for mechanical damage evaluation based on the real-time processing of a single digital image. This inexpensive, full-field approach provides the full shape of the damaged region with high accuracy, and overcomes current limitations in the assessment process. In Phase I, Intelligent Optical Systems will develop detailed proof of principles of the proposed technology, determine precision as a function of lighting and environmental conditions, and determine preliminary software and hardware designs.
NETL-DOE	DE-FC26-01NT41155	na	Design, Construction, and Field Demonstration of EXPLORER: A Long-Range, Untethered Live Gas Pipeline Inspection Robot System	Robotic ILI	field demonstrate EXPLORER – a modular, remotely controlled, self-powered, long range, untethered robot system
NETL-DOE	DE-FC26-04NT42264	na	Explorer II – Wireless Self-powered Visual and NDE Robotic Inspection System for Live Gas Pipelines	Robotic ILI	The Explorer II will have an integrated inspection sensor (to be developed under a separate project) to provide enhanced in-situ, live and real-time assessments of the status of gas infrastructures
GRI	GRI-8715-7		Design, Construction and Demonstration of a Robotic Platform for the Inspection of Unpiggable Pipelines	Robotic ILI	PRCI High Impact Program supported Explorer II which was chosen
OTD	4.e		Inspection Sensor and Platform for Unpiggable Pipelines	Robotic ILI	Design, test, demonstrate and commercialize the sensors and platforms for the Explorer II and Tiger robotic inspection tools

MMS		487	An Assessment of Magnetization Effects on Hydrogen Cracking for Thick Walled Pipelines	ILI Hydrogen Cracking	Phase I of the research was completed in December 2005. From this effort, researchers at the Colorado School of Mines (CSM) believe they have identified a technically defendable testing procedure to determine steel grade susceptibility to hydrogen effects based on the use of three different and complimenting analysis methods including eddy current analysis, magnetic Barkhausen noise analysis, and electromagnetic acoustic transducer analysis. Research and efforts to substantiate the validity of the test procedures have produce results to characterize the phenomenon and its significance.
MMS		522	Methodologies for Measuring and Monitoring Hydrogen for Safety in Advanced High Strength Linepipe Steel Applications	ILI Hydrogen Cracking	This project is an extension of research completed by the Colorado School of Mines in December 2005 on the assessment of magnetism effects on hydrogen cracking for thick walled pipelines (see Project No. 487). That project found that under laboratory conditions, high-strength steel was susceptible to corrosion and hydrogen cracking at hydrogen saturation levels under magnetism. This project (No. 522) is planned to develop field testing equipment that can determine a pipeline's susceptibility to hydrogen cracking depending on the level of hydrogen content
PHMSA	DTRS56-03-T-0002	115	Assessment & Validation of TFI-Identified Anomalies Criteria for Repair and Available Repair Methods	ILI Improving Resolution	The objectives of this project are to (1) compile and evaluate the unique properties of early generation pipeline weld seams, (2) compile a catalog of defect types, and (3) develop methods for evaluating seam weld defects to determine whether pipeline integrity has been compromised.
NGA	M2004 - 1		NoPig Inspection Technology	ILI alternative	Develop a remote above-ground inspection technology with possible application to pipeline integrity testing for qualifying metal loss anomalies.

GRI	GRI-8715-3	141	NonLinear Harmonic Based Mechanical Damage Severity for Delayed Failures in Pipelines	ILI Improving Resolution	PRCI High Impact Program may find cracks has PHMSA 141 cofunding
GRI	GRI-8682		Mechanical Damage Effects on MFL Signals- Modeling and Experimental Studies	ILI Improving Resolution	moving toward acceptable signal criteria to identify mechanical damage but not yet classify the magnitude f the damage
GRI	GRI-8728		Control of Horizontal Beam Width with Phased Array Transducers	ILI Improving Resolution	needed for improved detection and sizing
PRCI	PR-320-05304		Understanding MFL Signals from Mechanical Damage (MD-1-3)	ILI Improving Resolution	see MD-1-3
PRCI	PR-301-03151		Inspection Interval Assessment	ILI Improving Resolution for Intervals	
PRCI	PR-306-04306		Inspection Intervals Using Artificial Intelligence	ILI Improving Resolution for Intervals	
NETL-DOE	FWP05FE03	na	Multi-Purpose Sensor for Detecting Pipeline Defects	ILI Sensors for Wall Loss	The Los Alamos National Laboratory (LANL) has been developing acoustic sensor techniques for pipeline structural integrity monitoring. The LANL sensors included both acoustic and optical measurement techniques (for this test only) as orthogonal sensor systems for added robustness. The focus is now to concentrate on a single acoustic sensor, and integrate it with an autonomous robotic platform under development by independently funded DOE/NETL projects.
NETL-DOE	DE-FC26-04NT42266	na	Delivery Reliability for Natural Gas - Inspection Technologies	ILI Sensors for Wall Loss	This inspection tool will consist of an advanced sensor, based on eddy current technology, capable of detecting pipeline defects and a semi-autonomous robotic platform
NETL-DOE	DE-FC26-03NT41881	na	Innovative Sensors for Pipeline Crawlers to Assess Pipeline Defects and Conditions	ILI Sensors for Wall Loss	Develop electromagnetic sensors (based on eddy current technology) that can be integrated with a robotic platform (crawler) to conduct internal natural gas pipeline inspections

OTD	4.b		Reduce Inspection Costs Through Remote Field Eddy Current of Unpiggable Lines	ILI Sensors for Wall Loss	Develop a collapsible RFEC sensor for the Explorer II robot system
OTD	4.10.a		MFL Inspection for Live Four-Inch Steel Gas Lines	MFL ILI Small Diameter	Demonstrate an MFL inspection system for live 4-diameter gas line inspection for applications such as cased crossings.
PRCI	PR-003-03155		Innovative Electromagnetic Sensors for Pipeline Crawlers	ILI Sensors for Wall Loss	
NGA	M2003 - 9		Explorer II - Metal Loss Modual	ILI Sensors for Wall Loss	Concentrate on the preliminary design of the system and the selection of the sensor
PRCI	PR-004-04312		DELIVERY RELIABILITY FOR NATURAL GAS – INSPECTION TECHNOLOGIES (Remote Field Eddy Current)	ILI Sensors for Wall Loss	Final report due, no more DOE funding
PHMSA	DTRS56-02-T-0002	107	Mechanical Damage Inspection Using MFL Technology	ILI sensors Mechanical Damage	Simplified multiple magnetization tool will be designed, a magnetizer and sensor will be developed, and ultimately the researches will collect and analyze pull rig and flow loop data
PHMSA	DTRS56-02-T-0003	108	Feasibility of In-Line Stress Measurement by Continuous Barkhausen Method	ILI sensors Mechanical Damage	This project will demonstrate the use of modified MFL ILI tools to inspect mechanical damage, cracks, wrinkles and corrosion
PHMSA	DTR57-06-C-10004	185	In-Line Nondestructive Inspection of Mechanical Defects in Pipelines with Shear Horizontal Wave EMAT	ILI Sensors Mechanical Damage	Intelligent Automation, Inc. (IAI) and Oak Ridge National Lab (ORNL) is developing a novel and integrated approach to inspect mechanical damages in the pipelines with or without coatings. that combines the state-of-the-art Shear Horizontal (SH) wave EMAT technique, through detailed numerical modeling and instrumentation data collection, with advanced signal processing and pattern classification techniques, to detect and characterize the mechanical dents in the underground pipeline transportation infrastructures
PRCI	MD-1-1	203	Dual Field MFL Inspection Technology to Detect Mechanical Damage	ILI Sensors Mechanical Damage	
PRCI	MD-1-2	204	Performance Characteristics of Current ILI Technologies for Mechanical Damage Detection	ILI Sensors Mechanical Damage	

NETL-DOE	FEAB210	na	Pipeline Flaw Detection Using Shear EMAT and Wavelet Analysis	ILI Sensors Mechanical Damage	Develop an Electromagnetic Acoustic Transducer (EMAT) sensor, capable of detecting SCC, circumferential and axial flaws, and corrosion in the wall of a 30-inch natural gas pipeline.
PHMSA	DTRS56-02-T-0004	110	Baseline Study of Alternative In-Line Inspection Vehicles	ILI Sensors wall loss	Research is to conduct a baseline study of alternative ILI vehicles that might be able to negotiate unpiggable pipelines
PHMSA	DTRS57-04-C-10053	157	Innovative Safety and Reliability Technologies for Pipeline System Integrity and Management	ILI Sensors wall loss	Intelligent Automation, Incorporated proposes a novel and integrated approach to inspect the metal loss in the pipelines. It combines the state-of-the-art Shear Horizontal (SH) wave EMAT technique, with our record-proven advanced signal processing and pattern classification technique, to detect and characterize the metal loss problem
PRCI	SCC-3-7	PRCI 2008 (ongoing)	Evaluation of Reliability of EMAT Tools - Operator Experience	ILI sensor SCC and cracks	Evaluate the reliability of EMAT ILI tools to locate, identify and characterize SCC in gas pipelines. Ealuation will be based on data obtained from the results of field trials conducted by pipeline companies. ILI tool runs and excavation data included.
PRCI	EC-4-1	PRCI 2007	Determine ILI Tool Performance Characteristics	ILI Improving Resolution	Collect and analyze information reported from in-line inspection of pipelines and measured in the ditch to establish values and performance metrics of specific MFL systems
PRCI	EC-4-2	PRCI 2010	ILI Tool Error Calibration Based on In-the-Ditch Measurements with Related Uncertainty	ILI Improving Resolution	ILI Tool Error Calibration Based on In-the-Ditch Measurements with Related Uncertainty
PRCI	EC-4-3	PRCI 2010	Improved Pipeline Reliability by Using In-Ditch Verification Data to Measure ILI Uncertainty and Applying Correction Factors	ILI Improving Resolution	Improved Pipeline Reliability by Using In-Ditch Verification Data to Measure ILI Uncertainty and Applying Correction Factors
PRCI	EC-4-4	PRCI 2010	Capabilities and Limitations of ILI Tools Dedicated to Checking CP Currents from In-line Measurement of Longitudinal Electrical Potential Gradients	ILI Improving Resolution	Capabilities and Limitations of ILI Tools Dedicated to Checking CP Currents from In-line Measurement of Longitudinal Electrical Potential Gradients