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Energy Research and Development Division

FINAL PROJECT REPORT

Pipeline Safety and Integrity Monitoring Technologies Assessment

Gavin Newsom, Governor
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PREFACE

The California Energy Commission's Energy Research and Development Division manages the Natural Gas Research and Development program, which supports energy-related research, development, and demonstration not adequately provided by competitive and regulated markets. These natural gas research investments spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission, and distribution and transportation.

The Energy Research and Development Division conducts this public interest natural gas-related energy research by partnering with RD&D entities, including individuals, businesses, utilities and public and private research institutions. This program promotes greater natural gas reliability, lower costs, and increased safety for Californians and focuses on these areas:

- Buildings End-Use Energy Efficiency
- Industrial, Agriculture and Water Efficiency
- Renewable Energy and Advanced Generation
- Natural Gas Infrastructure Safety and Integrity
- Energy-Related Environmental Research
- Natural Gas-Related Transportation

Pipeline Safety and Integrity Monitoring Technologies Assessment is the final report for the Pipeline Safety and Integrity Monitoring Technologies Assessment project (Contract Number PIR-15-012) conducted by Gas Technology Institute. The information from this project contributes to Energy Research and Development Division's Natural Gas Research and Development program.

For more information about the Energy Research and Development Division, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

The project focused on assessing emerging and close-to-market technologies that improve the prediction of pipeline performance, monitor threats, and reduce operation costs for the natural gas pipelines in California. This project:

- Assessed the status of transmission and distribution natural gas pipeline safety and integrity management practices.
- Identified various emerging technologies through surveys, technologies searches, and industrywide metrics such as technology readiness levels.
- Determined development gaps, estimated projects benefits, and related technology transfer requirements.
- Provided California natural gas operators with a Web-based program and database to access the status and applicability of the technologies.
- Helped implement and commercialize close-to-market technologies through field demonstrations at utility sites.

The project covered a broad area of pipeline technologies and addressed the various causes of pipeline incidents. The technologies included damage prevention, pipeline inspection and monitoring of threats, integrity management, and risk assessment. The project team reviewed more than 200 referenced sources and literature reviews; obtained feedback from the technical advisory committee, including California natural gas utilities and technology developers; and obtained feedback through a stakeholder public workshop.

The research team selected several technologies for field demonstrations based on quantifiable measures for improved safety and operations efficiency; the maturity of the technology and demonstrated capabilities; and coordination with the California gas utilities to support their safety and operation requirements.

Keywords: Natural gas, transmission, distribution, pipelines, technology, assessment, safety, damage, pipe locating, threats, integrity, anomalies, risk, data management, security

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EXECUTIVE SUMMARY

Introduction

California's natural gas transmission system consists of nearly 11,000 miles of high-pressure pipelines. This system feeds more than 105,000 miles of gas distribution mains and more than 8.7 million services. Safe and secure operation of this system is an ongoing public interest requiring research into and application of new and emerging technologies to reduce pipeline threats and improve inspection, operation, and maintenance.

This research project was intended to assist regulators and operators in selecting and implementing instrumentation, devices, and systems that enhance the safety, operation, and management of the natural gas pipeline infrastructure. The project explored opportunities for new and emerging technologies with the greatest potential to prevent incidents and address related consequences.

Project Purpose

This project sought to develop a comprehensive technology assessment that identifies emerging and close-to-market technologies that could be moved to commercial availability. The Web-based technology assessment used quantifiable scales consisting of evaluating technology performance, technology readiness levels, and cost-to-market value.

The assessment also addressed the various causes of pipeline incidents. The technologies included damage prevention, threat monitoring, integrity management, and risk assessment.

Project Process

The technology search focused on helping distribution and transmission pipeline operators identify particularly problematic segments of the pipeline systems where technological solutions are needed. This identification was achieved through:

- A baseline search of pipeline incidents and significant trends in gas transmission and distribution systems in California. The investigation included incident records from the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration, National Transportation Safety Board, Common Ground Alliance, California Public Utilities Commission annual reports, and California utility data.
- An industry survey of natural gas operators and a workshop in July 2017 to connect with the technical advisory committee, professional organizations, and technology developers.
- Review of more than 200 referenced sources and search for recently completed and close-to-commercialization technologies that are two to four years to the market. The project team considered technologies developed and funded by various research organizations, including the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration, United States Department of Energy, California Energy Commission, Pipeline Research Council International, Northwest Gas

Associations, Operations Technology and Development, university research projects, and industry-developed technologies and tools.

- Development of a public database that allows stakeholders to select and assess new and emerging technologies.
- Field demonstrations of technologies selected with the California gas utilities to inform developers on applications and requirements for utility service areas.
- Identifying and quantifying the benefits of the demonstrated technologies.
- Developing a road map for future development and implementation of the technologies.

Project Results

This project created a Web-based program and provided a catalog of available technologies for the pipeline and utility operators. The Web-based program summarized each technology and applicable conditions, scope, and development status. The research team also identified emerging and close-to-market technologies and grouped them into three categories: damage detection and prevention, threats and integrity management, and risk assessment and information management. The team evaluated the selected technologies using a modified technical readiness level approach to determine readiness for commercialization. The research demonstrated several emerging and close-to-market technologies in the three categories:

- Damage detection and prevention: These technologies included devices and systems to locate pipelines during excavation and horizontal directional drilling, monitor for encroachments to pipeline rights-of-way, and detect and quantify leaks using drones.
    - The team demonstrated ORFEUS, a device that detects obstacles during horizontal directional drilling, at the Pacific Gas and Electric Company (PG&E) testing site in Livermore, California in July 2017. ORFEUS, which stands for “operational radar for every drill-string under the street” uses a ground-penetrating radar technology and was developed by a consortium of European companies. A “drill string” includes the drill pipe and bottom-hole assembly and is an important part of the rotary drilling process. Following field trials in Europe, PG&E and other gas utilities were interested in using the technology to prevent hits to underground utilities during horizontal directional drilling installations. The reported number of excavation damages due to drilling equipment in California in 2016 was 59 to energy lines and 18 to sewer lines. Horizontal directional drilling installations can also cause damage that goes undetected for extended periods.

      The field demonstration at PG&E moved the ORFEUS technology to Technical Readiness Level 8. The demonstration included evaluating the ability of the technology to detect hits in real-time under actual field conditions. Further developments are in progress to enhance sensing capabilities, improve real-time visualization of the software, and implement the system with horizontal directional drilling equipment providers. These developments are expected to continue for two years.

  - The field demonstration of meter breakaway fitting was performed in Ontario, California for SoCal Gas in January 2019. Breakaway valves were installed at gas meter risers to shut off the gas when a vehicle hits the gas meter. The device succeeded in shutting off the gas line in 75 percent of the tests when the vehicle directly hit the riser side of the meter setup.

    Reported incidents by the California Public Utilities Commission show that 33 percent of the incidents caused by natural and external forces on the gas pipeline system in California in 2015 to 2017 resulted from vehicle hits to gas meters. California gas utilities are evaluating the breakaway device for further field demonstrations and implementation in their service areas.

- Technologies for threats and integrity management: These technologies included inspection of weld failures and cracks in unpiggable pipelines (those that are difficult to inspect internally with conventional in-line tools called "smart pigs") and difficult-to-inspect pipelines; smart devices for field data capture; and failure prediction models.
  - The research team demonstrated an electromagnetic acoustic transducer (an ultrasonic testing method) for cracks and weld defects in February 2018 at the PG&E facility in San Ramon, California. The sensor successfully detected pre-set cracks in eight-inch diameter unpiggable test pipes.

    The electromagnetic acoustic transducer demonstration unit had a wireline unit connected to a computer for power supply and data management. Development is in progress to build a stand-alone unit with a own battery that is disconnected from the computer. Further development is also underway to produce a field unit in one year and validate the inspections under real operating conditions, which will move the system technical readiness level to Level 8.

    Only about 11 percent of in-line inspections are able detect cracks and seam-weld defects. The electromagnetic acoustic transducer technology increases and enhances inspections by providing the capability of detecting cracks and anomalies in small-diameter and unpiggable pipes.
  - The project team also completed a demonstration on the Spar Aboveground Coating Assessment Tool, which locates external corrosion and coating disbondment (a type of metal corrosion) on steel pipes. The demonstration occurred at Southern California Gas Company service locations in August 2018. The technology is available for locating steel pipe and the demonstration enhanced the usage of the technology by identifying coating disbondment locations in the field.

    The field demonstrations identified coating disbondments in several steel pipes. Southern California Gas Company is excavating at these locations to validate that coating disbondment existed and determine the success detection rate of the application.
- Technologies for risk assessment and information management: These technologies include those for data automation; asset tracking and traceability; visualization and

geographical information system; risk assessment; response awareness; and cyber and physical security.

The project demonstrated the LocusView geographical information system device and data system for automating the gathering, storing, and accessing material traceability data at a PG&E excavation site in September 2018. The demonstration revealed the need for further research including developing a standard business process and coordinating with steel pipes manufacturers to install traceability codes during manufacturing.

This report presents a road map of future development priorities and implementation of selected technologies. Examples of recommended technologies for further development in the coming two to four years include:

- Pipe locating and depth identification technologies, including development and enhancement of ground-penetrating radar systems in plastic and difficult-to-inspect pipes.
- Acoustic technologies for field inspection of fusion joints in plastic pipes.
- “Smart pipe” networks with integrated sensors to provide continuous real-time monitoring of stresses and leak detections.
- Quantitative risk models to rank repair needs and predict pipeline failures.
- Data management and machine learning approaches for analysis and quantification of leaks and other failure consequences.
- Training programs and situational awareness procedures for efficient and quick response to pipeline incidents and repair emergencies.

Technology Transfer and Benefits to California

The project identified technologies that provide the most benefits to California’s natural gas pipeline integrity management practices. The Web-based database began running in March 2018 and continues to provide gas operators and regulators with selections of the best technologies to address threats, site conditions, and operation requirements.

The field demonstrations enabled gas operators to interact with manufacturers to address utility-specific requirements and other research needs. The implementation of these technologies provides:

- Safety: The demonstrated technologies address approaches associated with California natural gas transmission and distribution pipeline safety for damage prevention and detection, as well as threats to pipeline integrity to detect cracks, weld seams, and coating damage.
- Cost: The technologies reduce operational down-time, improve pipeline locating and leak detection, and reduce rehabilitation costs providing overall cost savings.
- Environmental impact: New technologies related to detecting natural gas leaks reduce emissions of methane, a potent greenhouse gas, in California.

- Efficiency gains: Many new technologies provide operational efficiencies along with safety and environmental benefits. Examples include technologies with increased capabilities to inspect smaller pipes, navigate obstacles, and enhance data management and analysis.

The research team performed quantifiable estimates on the demonstrated technologies of technology benefits. These estimates were based on the baseline criterion of reducing the number of incidents and gas emissions compared to technology development and application costs. For example, the researchers estimated that improving the locating practices of plastic pipes in California would reduce the annual loss of $1,542,300 due to damages and repairs to plastic pipes. Similarly, installing meter breakaway fillings provides benefits by reducing damage from vehicular hits to residential meters. These incidents represent 33 percent of those caused by external forces and result in about 45 incidents in California annually at an annual cost of about $1,276,360, not including costs associated with fatalities and injuries.

CHAPTER 1:
Introduction

The natural gas infrastructure system is subjected to various threats that vary according to the material type, age, location, and operational characteristics of the pipeline. These threats include corrosion, excavation damage, natural forces, material and weld failures, and incorrect operation.

Project Objective

Safe and reliable operation of gas pipeline system requires applying new technologies to improve its inspection, operation, maintenance, and integrity management. The objective of this project was to perform a thorough assessment of the current status of transmission and distribution natural gas pipeline safety and integrity management technologies. The assessment evaluates the various emerging technologies that provide quantitative measures of improved performance and reduced risk from natural gas pipeline threats.

Project Approach

The technology search aimed at assisting distribution and transmission pipeline operators in the identification and rehabilitation of particularly problematic segments where there is a need to provide safer and more cost-effective solutions. This was achieved by working with the California natural gas utilities on the following deliverables:

- An industry survey of natural gas operators to identify emerging new technologies to improve the integrity and safety of their system and reduce operations costs
- An industry workshop in July 2017 to communicate with the Energy Commission, technical advisory committee, professional organizations, and technology developers
- A Web-based program and database for the selection and application of new technologies. The database is planned to be continuously updated to serve the industry beyond the completion date of the research project
- Field demonstrations of technologies selected with the California gas utilities to assist in their applications in their service areas
- Identification and quantification of the benefits of the demonstrated technologies.

The approach for the technology transfer and implementation of the demonstrated technologies consisted of the following steps:

- Review natural gas market segments in California. Identify how the selections of the technologies targeted the gas system characteristics
- Use the outcome of the industry survey and workshop to focus on utilities’ needs and application gaps

- Research and categorize the technologies to match utilities' needs and identify their development status
- Coordinate and perform field demonstrations of selected technologies and investigate their commercialization plans
- Develop a road map for future development and implementation of the technologies.

The above project approach is discussed in detail in these report chapters:

- Chapter 2: Presents the California natural gas system characteristics and current status of inspection technologies used by the natural gas utilities.
- Chapter 3: Identifies the threats on the natural gas pipeline system in California and associated research needs. The chapter also includes a survey and a summary of the workshop to identify new and currently-developed technologies. Chapters 2 and 3 cover Tasks 2 and 4 of the project agreement.
- Chapter 4: Establishes a baseline of technologies for monitoring pipeline threats, integrity management, and risk assessment. This chapter covers Task 3 of the project agreement.
- Chapter 5: Presents the web-based program and database to access, search and catalogue the technologies. This chapter addresses Task 7 of the agreement.
- Chapter 6: Includes an evaluation of the selected technologies and an assessment of the technical readiness level (TRL) approach. This chapter covers Tasks 5 and 6 of the agreement.
- Chapter 7: Field demonstrations performed on selected technologies to evaluate their field performance, effectiveness, and further development needs. This chapter addresses Tasks 8 and 9 of the agreement.
- Chapter 8: Evaluation of project benefits. This chapter investigates the development of the demonstrated technologies and their benefits in reducing pipelines operations and incidents costs. This chapter covers Tasks 10 and 11 of the agreement.
- Chapter 9: Technology transfer activities and description of the intended implementation of the technology. This chapter covers Task 12 of the agreement.

CHAPTER 2:
Characteristics of Natural Gas System in California

The application of new technologies to address natural gas pipeline threats in California requires characterizing the system and its development requirements. This chapter provides a summary of the characteristics of the California natural gas system, its integrity management program, and associated inspection technologies.

Characteristics of Gas Transmission System in California

The natural gas system in California consists of a total of 215,715 miles of pipelines. Table 1 shows the mileages of the gas pipelines in California in 2017. The natural gas system in California is about 8.5 percent of the total pipeline miles in the United States.

Table 1: Natural Gas Pipelines System in California 2017

System Type	System Detail	All States	California
Gas Distribution	Main Miles	1,295,945	106,257
Gas Distribution	Service Miles	927,062	96,932
Gas Gathering	Miles	18,382	148
Gas Transmission	Miles	300,645	12,378
Total		**2,542,034**	**215,715**

Source: https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-mileage-and-facilities

The gas transmission and gathering pipelines in California consist mainly of onshore transmission lines (98 percent) with the remaining lines being offshore and gathering lines.

Gas transmission pipes are defined in the Code of Federal Regulation 49 CFR §192.3 as pipelines, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of the specified minimum yield strength (SMYS) of the pipe; or (3) transports gas within a storage field. Table 2 lists gas transmission and gathering companies in California with total mileage larger than 10 miles as of 2017.

More than 85 percent of these transmission lines are operated by two major companies; Pacific Gas and Electric Company (PG&E) and Sempra (Southern California Gas Company [SoCal Gas] and San Diego Gas & Electric Company [SDG&E]).

A considerable portion of the transmission pipeline system runs through high population areas, with 27 percent of total California's transmission lines running in high consequence areas (HCA), about three times the national average of 6.4 percent as shown in Table 3. This high percentage underlines the importance of monitoring and preventing threats to these lines due to their high-risk consequences.

Table 2: Gas Transmission Pipeline Companies in California, 2017

Utility Name	City	High Consequence Areas Total	Total Miles
Pacific Gas & Electric Company	San Ramon	1,507	6,535
Southern California Gas Company	Los Angeles	1,138	3,448
San Diego Gas & Electric Company	San Diego	191	234
CPN Pipeline Company	Rio Vista	17	140
Sacramento Municipal Utility District	Sacramento	25	76
Standard Pacific Gas Line Inc.	San Francisco	32	55
DCOR, LLC	Ventura	0	54
California Resources Central Valley	Bakersfield	6	51
Freeport-McMoran Oil & Gas	Orcutt	0	46
Lodi Gas Storage, LLC	Acampo	1	45
Calpine Texas Pipeline LP	Rio Vista	10	42
California Gas Gathering Inc.	Rancho Cordova	0	33
Prospector Pipeline Company	Rancho Cordova	0	27
California Resources Elk Hills, LLC	Bakersfield	0	24
Thums Long Beach Company	Long Beach	0	17
California Resources Ventura Basin	Long Beach	0	15
Greka	Santa Maria	0	13
Aera Energy LLC	Bakersfield	0	13
Elysium Jennings, LLC	Bakersfield	0	11

Source: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

Table 3: Gas Transmission Miles in High Consequence Areas, 2017

	Total Miles	In HCA Areas	%
Miles [All States]	319,014	20,564	6.4%
Miles [California]	10,879	2.927	26.9%

Source: Compiled from https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

The class locations of the HCA for a pipeline segment are defined as:[1]

- Class 1 location: Offshore area or any area that has 10 or fewer buildings intended for human occupancy.

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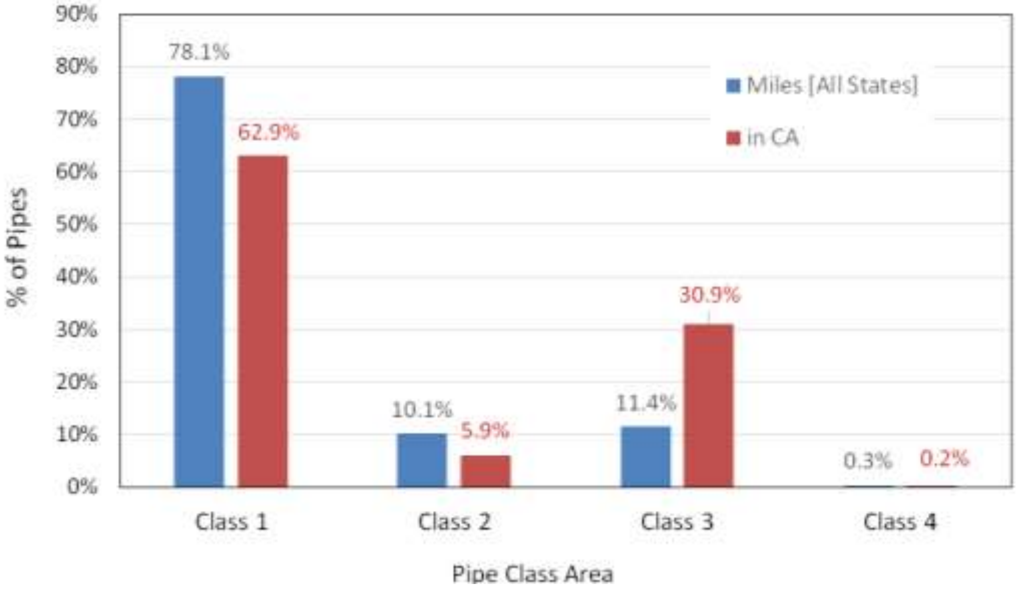
[1] 49 CFR Part 192. Transportation of Natural and Other Gas by Pipeline, Minimum Federal Safety Standards. Section O - Gas Transmission Pipeline Integrity Management. 2016

- Class 2 location: Any area that has more than 10 but fewer than 46 buildings intended for human occupancy.
- Class 3 location: Any area that has 46 or more buildings intended for human occupancy; or an area where the pipeline lies within 100 yards of a building or public area occupied by 20 or more persons for a specified duration.
- Class 4 location: An area where four or more story buildings are prevalent.

The CFR code allows for two different methods to be used towards determining locations where HCAs exist. The California Public Utilities Commission[2] restricts the use of method to pipeline segments of 12-inches or less as a more conservative approach.

Figure 1 shows the distribution of gas transmission lines per class area in California in comparison with the national average. The figure shows a relatively lower percentage of transmission pipes in Class 1 and a higher percentage in Class 3 (higher populated areas) in California.

Figure 1: Gas Transmission Lines per Class Area in California, 2015



Source: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

California's transmission lines are primarily high-pressure, large-diameter steel pipelines with protection characteristics as shown in Table 4. Most of the transmission lines in California have cathodic protection. Composite pipes are not currently used for onshore transmission lines. Accordingly, the technology assessment in this project did not give high priority for composite pipes or steel pipes without cathodic protection.

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[2] State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems. General Order No. 112-F. 2015.

Table 4: Types of Gas Transmission and Gathering Onshore Pipes, 2017

	Cathodic Protection, Bare Steel	Cathodic Protection, Coated	No Cathodic Protection, Bare Steel	No Cathodic Protection, Coated	Composite	Total
All States	4,589	289,999	697	507	10	297,429
California	14	10,850	9	23	0	10,919

Source: Compiled from https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

Characteristics of Gas Distribution System in California

The mileage of distribution lines in California is more than 8 percent of the total miles in the United States Table 5 shows the mileage and number of services of the gas distribution companies in California.

Table 5: Gas Distribution Companies in California, 2015

Name of Company	City	Miles – Main	Number of Services
Southern California Gas Company	Los Angeles	50,181	4,409,063
Pacific Gas & Electric Company	San Ramon	42,487	3,394,599
San Diego Gas & Electric Company	Los Angeles	8,057	634,313
City of Long Beach Gas Department	Long Beach	915	86,728
City of Palo Alto	Palo Alto	210	17,469
Navitas Utility Corporation	Costa Mesa	1,013	5,433
City of Coalinga	Coalinga	43	3,853
City of Susanville	Susanville	60	3,030
Alpine Natural Gas	Valley Springs	37	1,519
West Coast Gas Company Inc.	Sacramento	40	1,418
Navitas Utility Corporation	Costa Mesa	34	558
Island Energy	Vallejo	19	358
Navitas Utility Corporation	Costa Mesa	33	145
City of Victorville	Victorville	12	88
City of Vernon	Vernon	44	84

Source: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

Table 6 depicts the gas distribution lines in California that are characterized by a range of pipe materials and sizes. Plastic pipes (such as polyethylene PE, and aldyl-A pipes) constitute about 50 percent of these pipes. Multi-year pipe replacement programs by natural gas local distribution companies (LDC) have focused on replacing cast-iron pipes with PE. As a result, there were only about 60 miles of cast-iron pipes remaining in California as of 2015. Accordingly, cast-iron inspection and monitoring technologies were not included in the assessment search.

Table 6: Miles of Main Gas Distribution System in California, 2015

	Cathodic Protection Bare Steel	Cathodic Protection, Coated	No Cathodic Protection, Bare Steel	No Cathodic Protection, Coated	Plastic	Cast Iron	Other	Total
All States	11,973	472,810	39,935	15,928	706,594	28,345	1,307	1,276,913
California	211	42,417	3,591	4,568	52,394	60	0	103,242

Source: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

Pipeline Integrity Management Program

The United States Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) requires pipeline operators to implement integrity management programs for both gas transmission[3] and distribution systems.[4] These programs identify threats to the gas pipeline systems that include corrosion, excavation damage, natural forces, and material and weld failures.

A breakdown of significant pipeline incidents caused by these threats in gas transmission and distribution systems are shown in Figure 2 and Figure 3, respectively. Corrosion, incorrect operation, and equipment failures were the top three threats to transmission lines nationwide. With more than 50 percent of the distribution system being plastic pipes, corrosion damage did not result in significant incidents, while excavation damage was the top threat to these pipes.

The requirements of the integrity management program for transmission lines are provided in Subpart O of the Code of Federal Regulations 49 CFR Part 192. In this Subpart, the code assigns integrity assessment and scheduling requirements for pipelines operating at stress levels at or above 20 percent SMYS and located in HCA areas.

For the gas distribution lines, PHMSA requires operators to develop and implement a distribution integrity management program (DIMP) to identify and reduce pipeline integrity risks. The main elements of the program requirements are:

- Know the gas distribution system
- Identify threats and evaluate and rank risks
- Measure and monitor performance and evaluate effectiveness
- Periodic evaluation, improvement, and reporting.

A task group of the Gas Piping Technology Committee (GPTC) of the American Gas Association developed a guidance document to clarify the requirements of the DIMP rule.[5] Most natural gas LDCs use this guidance to apply the DIMP requirements.

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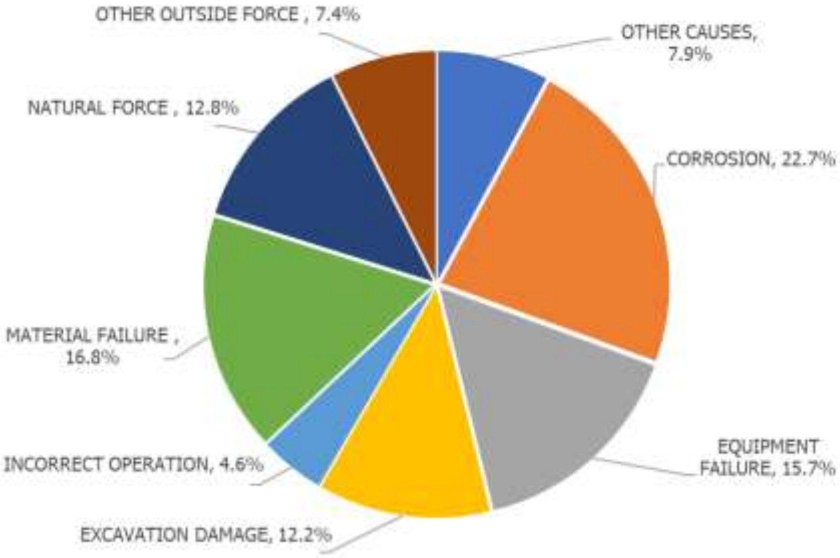
[3] 49 CFR Part 192. Transportation of Natural and Other Gas by Pipeline, Minimum Federal Safety Standards. Section O - Gas Transmission Pipeline Integrity Management. 2016.

[4] 49 CFR Part 192. Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines; Final Rule. Federal Register. Vol. 74, No. 232. December 2009.

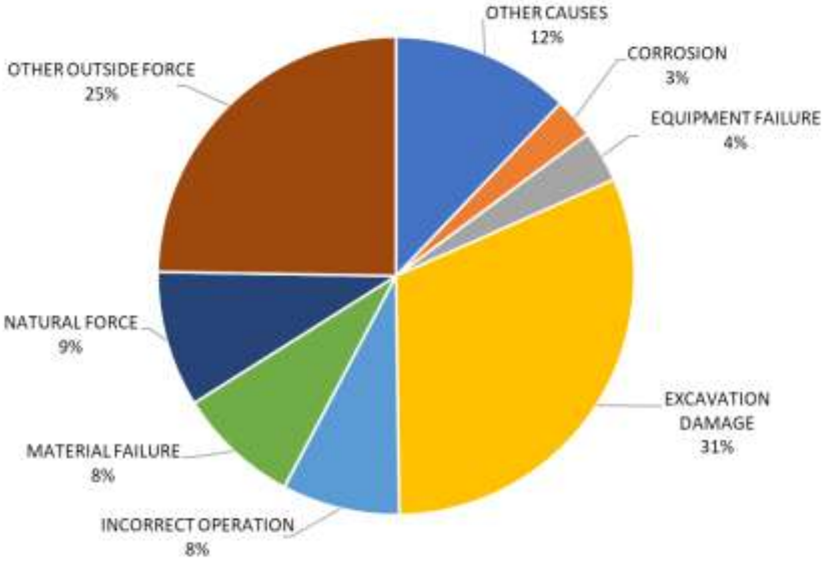
[5] GPTC Guide for Gas Transmission and Distribution Piping Systems, the Gas Piping Technology Committee, GPTC Z380.1. ANSI Technical Report No. ANSI-GPTC-Z380-TR-1. 2009.

Figure 2: Gas Transmission System Incidents by Threats, 2005-2018



Source: https://www.phmsa.dot.gov/data-and-statistics/pipeline/national-pipeline-performance-measures

Figure 3: Gas Distribution System Incidents by Threats, 2005-2018



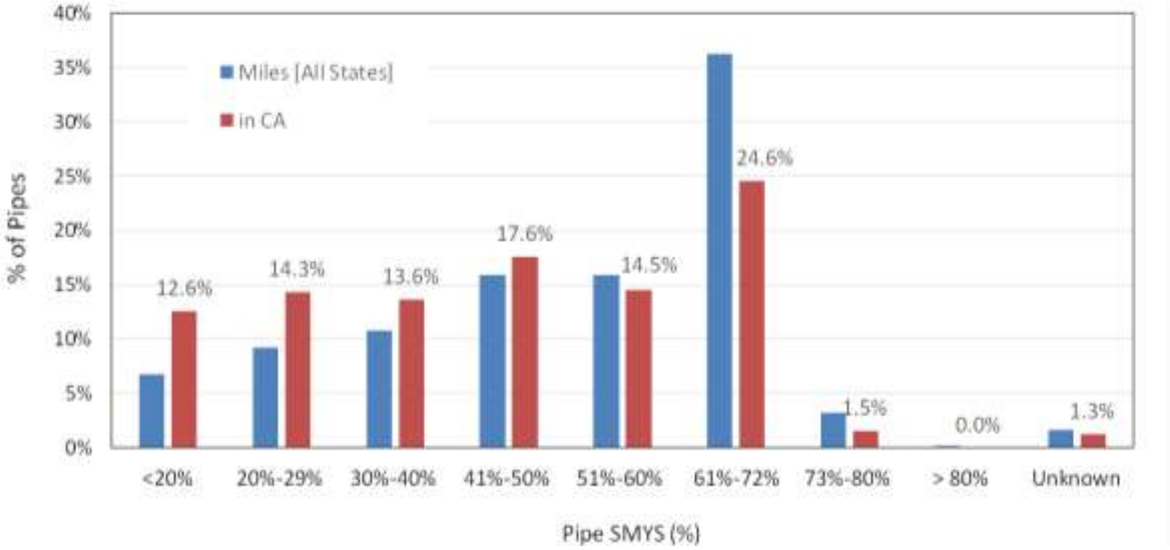
Source: https://www.phmsa.dot.gov/data-and-statistics/pipeline/national-pipeline-performance-measures

Damage Characteristics in Natural Gas Pipelines

Most transmission pipelines operate below 72 percent of the SMYS. Figure 4 shows the breakdown of transmission pipelines, nationally and in California, based on operating pressures. In California, the percentage (by mileage) of transmission lines that operate near or at 72 percent SMYS is below the national percentage (24.6 percent in California compared to 36.2 percent nationally). However, the percentage of pipes operating at and below 20 percent

SMYS is higher in California than the national average. An average of 1.3 percent of the transmission pipelines in California have unknown SMYS.

Figure 4: Transmission Pipe Operating Pressures, 2015



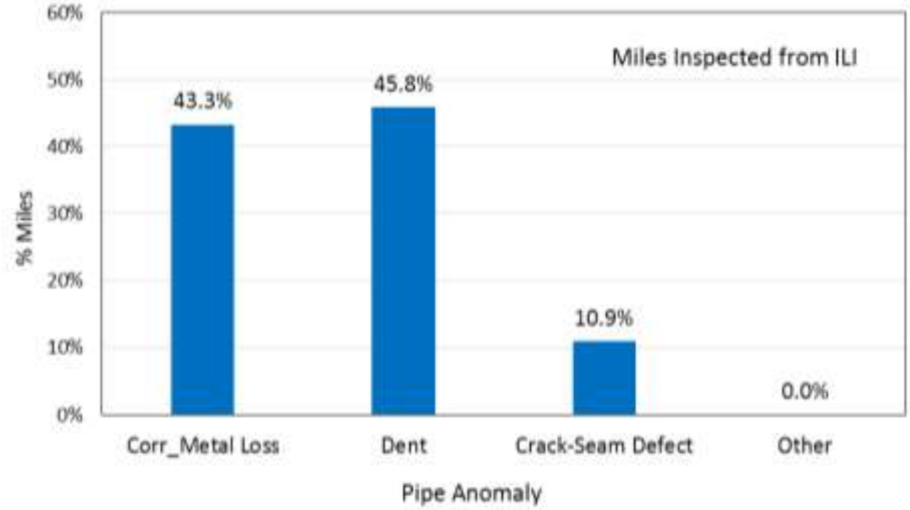
As percentage of specified minimum yield strength.

Source: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

Figure 5 shows the types of the anomalies detected by in-line inspection (ILI) in California in 2015. This type of inspection was mostly performed to detect metal loss and dents resulting from mechanical damage. A small portion of the percentage of miles inspected in California was for cracks and seam defects. As will be discussed later, several technologies for these inspections are still under development.

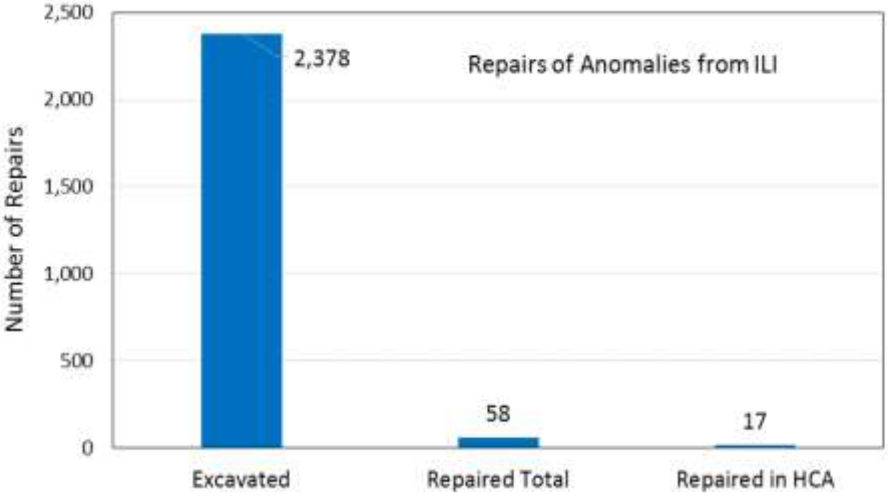
Figure 6 shows the number of excavations resulting from ILI inspections in 2015. The identified anomalies from these inspections are categorized for immediate repair, scheduled repair, or monitoring. The figure shows a small percentage of serious damages scheduled for immediate repair. Leak records and repairs are also reported annually by pipeline operators. In 2015, total leaks reported by California LDC’s were 5,882 and 63,944 for transmission and distribution lines, respectively. Figure 7 shows the number of these leaks categorized by leak cause.

Figure 5: Types of Pipe Anomalies Detected by In-Line Inspection, 2015



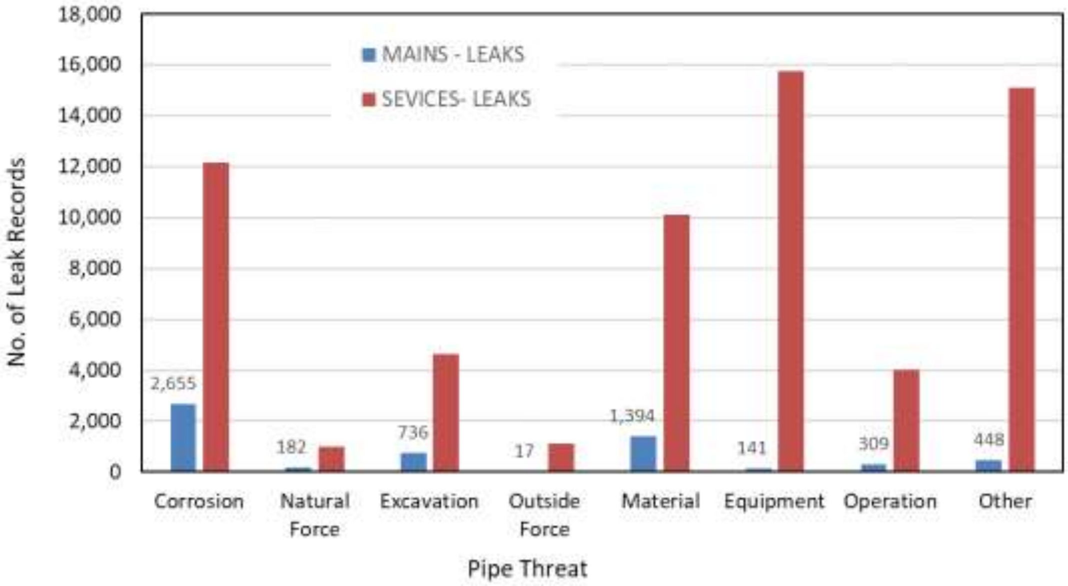
Source: Compiled from https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

Figure 6: Excavations Resulting from In-Line Inspection, 2015



Source: Compiled from https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

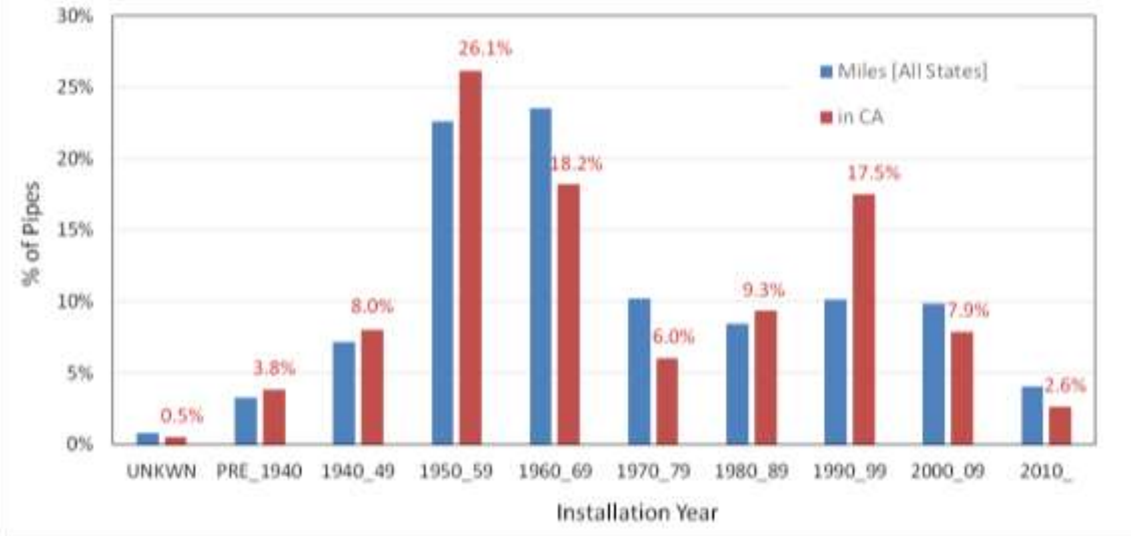
Figure 7: Reported Leaks in Mains and Services by Leak Cause, 2015



Source: Compiled from https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

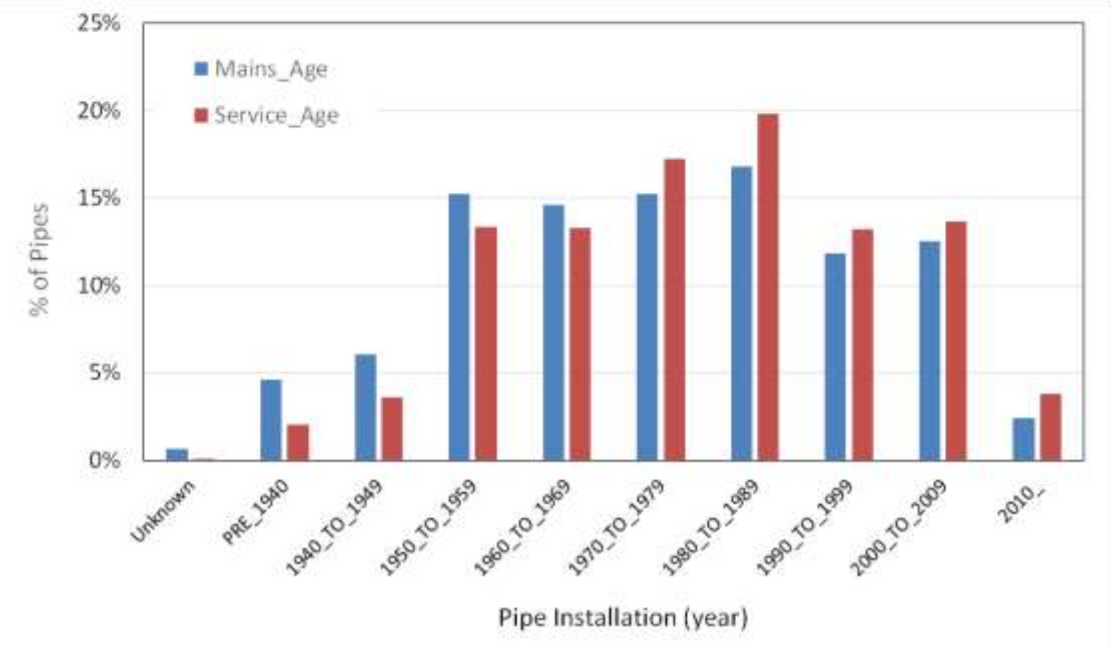
The aging of pipeline infrastructure is increasingly becoming a concern for pipeline operators and regulators, with ongoing national efforts to increase safety and reliability of the system. The installation years of transmission and distribution lines in California, in comparison to the national average, are shown in Figure 8 and Figure 9, respectively. The figures show most of transmission lines were built in the 1950s and 1960s, and the distribution lines in California are relatively newer than the national average.

Figure 8: Gas Transmission Lines by Pipe Age in California, 2015



Source: Compiled from https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

Figure 9: Distribution Mains and Services by Pipe Age in California, 2015



Source: Compiled from https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

Current Safety and Integrity Management Technologies

Gas transmission and distribution pipeline operators use a variety of technologies to ensure the safety and integrity of pipelines in accordance with the guidelines of the integrity management program. Continuous improvements of these technologies provide the opportunity to maintain and enhance the program to accommodate the characteristics of their various systems.

Internal and External Assessment

Most of current inspection methods in the integrity management program were identified in a previous report[6] and they consist of pressure tests, direct assessment, and ILI methods. Further details of these technologies are presented in Chapter 4 of the report. The main characteristics of these methods are:

- Pressure tests are the primary strength diagnostics for steel pipes as per the PHMSA integrity management program. The test involves temporarily disconnecting a section of pipeline and pressurizing it to 125 percent of the maximum operating pressure of the pipe.[7] Figure 10 shows a small number of pressure tests performed in California in comparison to all states in 2015.

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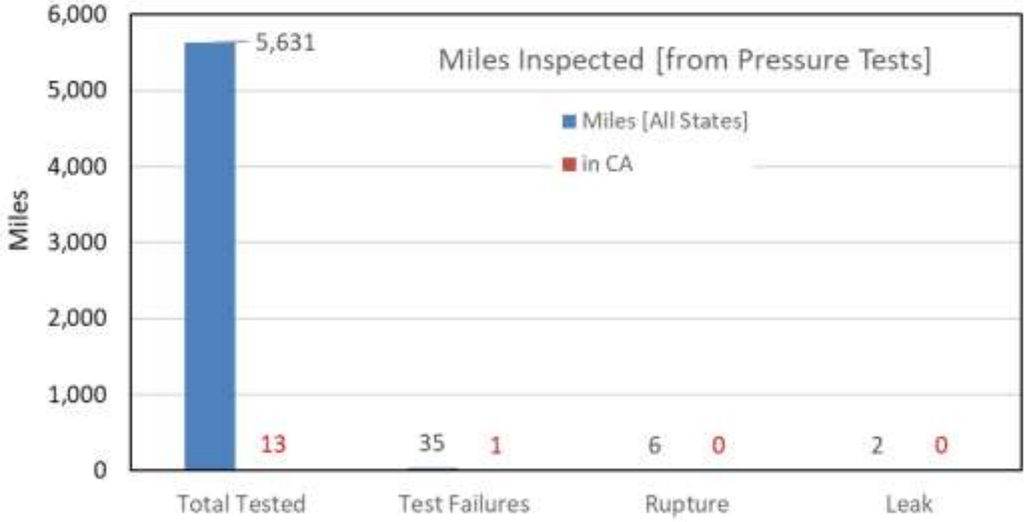
6 California Natural Gas Pipeline Assessment: Improving Safety through Enhanced Assessment and Monitoring Technology Implementation, California Energy Commission. Report CEC-500-10-050. 2013.

7 Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide, American Petroleum Institute, API Recommended Practice 1110, 2007.

Figure 10: Miles of Steel Pipes Inspected by Pressure Tests, 2015



Source: Compiled from https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

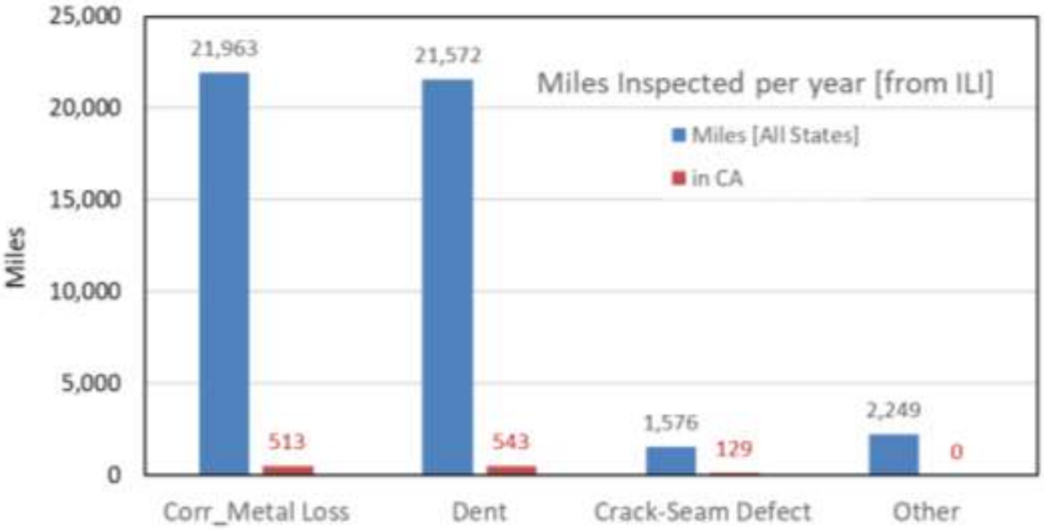
- External corrosion direct assessment (ECDA), internal corrosion direct assessment, and stress-corrosion cracking direct assessment (SCCDA) methods are used for corrosion metal loss and mechanical damage (for example gouges, dents, and cracks). These methods are commonly used in the distribution integrity management programs. Figure 11 shows the miles inspected in 2015, broken down by type of direct assessment inspection method.

Figure 11: Miles Inspected Using Direct Assessment Methods, 2015

Source: Compiled from https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

- The most common inspection method of transmission pipes is the ILI, consisting of about 80 percent of transmission inspections. Various ILI tools are used for inspection of metal loss, dents, and cracks.[8] These technologies include shear-wave, magnetic flux leakage (MFL), ultrasonic testing (UT), eddy current, and other electromagnetic based tools. Figure 12 shows the miles inspected in California in 2015 in comparison to all states.

Figure 12: Miles Inspected using In-Line Inspection Technologies, 2015



Source: Compiled from https://cms.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids

Right-of-Way Encroachment and Excavation Damage

Pipeline leak detection uses walk- and drive-through leak detectors. Remote systems use vehicular and aerial detection technologies. Data from subsequent leak surveys are analyzed and incorporated in the risk-assessment models for use in pipe repair and replacement programs.

Several types of aerial and ground-based equipment are used to patrol the pipeline right-of-way (ROW) for security and third-party excavation encroachments, and to identify leak locations.

Nondestructive Stress/Strain Testing

Pipeline stresses and strains typically result from induced stresses during pipe installation (such as in wrinkle bends) and additional soil loads resulting from ground movement (such as landslides and earthquakes). Nondestructive tests, at the time of an excavation, rely on a variety of tools such as ultrasonic testing of remaining wall thickness, magnetic particle testing for cracks, and mapping techniques to size and analyze stresses. Estimating the remaining strength of pipe relies on post-analysis calculations to determine if sufficient change has occurred.

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[8] In-Line Inspection of Pipelines, Standard Practice, NACE SP0102, 2010.

Data Collection and Communication Technologies

Data collection and communications technologies provide means to monitor the operation of the gas pipeline system. The techniques used for data collection vary widely based on the frequency of collection, accuracy and precision, and the systems used to communicate and integrate the data.

The availability of real-time data from sensors has made continuous monitoring of the gas system possible. Significant advances in global positioning system (GPS) technology in the last few years has expanded its use in daily pipeline operations by increasing efficiency, facilitating regulatory compliance, and improving the quality of field data.

The gas industry is currently investigating the deployment of large arrays of low-cost and powerful sensors for continuous evaluation of the state of a pipeline, including deformation, conditions influencing corrosion potential (for example, temperature, soil chemistry), local operational parameters and flow.

Furthermore, recent advances in the Internet-of-Things have enabled the development of powerful predictive models that can analyze the sensors' data in real time and provide a visual dashboard of the current status of the system. Such vast applications in data management and transfer on the internet makes it, on the other hand, susceptible to cyber-attacks and possible disruptions to the services, which emphasizes the need to enhanced risk modeling and security measures.

Risk-Modeling and Assessment Tools

The current approach to pipeline risk analysis is based on historical data, pipeline age, operational characteristics, and leak and corrosion records, with the objective of identifying high-risk segments for repair and replacement. This analysis commonly uses risk scales developed from system data, subject matter experts, and probability estimates to establish and rank the likelihood of failures. However, this approach does not incorporate comprehensive and rigorous evaluation of combined threats and the associated pipe material characteristics.

Additionally, risk models and assessment tools are heavily dependent on the quantity and quality of available data. Data collected and integrated from current tools and technologies are used only for trend analysis and comparing normal operations to changes in the physical and operating aspects of the pipeline system. This limitation suggests the need for a review of previous assessments and mitigative activities and investigating additional risk assessment approaches.

CHAPTER 3:
Technology Requirements and Development Needs

The California Public Utilities Commission (CPUC) regulates privately-owned natural gas utilities that operate in California. These utilities include PG&E, SoCal Gas, SDG&E, and Southwest Gas (SW Gas). Publicly owned utilities and municipal utilities (such as Long Beach Gas & Oil) are under federal jurisdiction.

The CPUC is responsible for enforcing the safety standards in the natural gas pipeline system. The agency implements programs such as risk assessment and integrity management in accordance with state and federal regulators; inspects construction, operation and maintenance activities; and amends regulations as necessary to protect public safety.

This chapter presents an overview of recent federal and state rulemakings that identify research needs and address pipeline safety requirements in response to the various recent pipeline incidents. It also presents the results of a survey of natural gas operators and a summary of the technology workshop presented at the California Energy Commission, Sacramento, California on July 7, 2017 to discuss emerging pipeline safety and integrity management technologies. The survey form is in Appendix A.

Recent Regulatory Recommendations of Pipeline Incidents

The researchers reviewed the most recent California natural gas pipeline incidents in the National Transportation Safety Board (NTSB)[9] and PHMSA pipe failure records.[10] The review provided an insight into the causes of failures and possible technology gaps contributing to these incidents. The California gas incident records reported by PHMSA and NTSB are shown in Appendices B and C, respectively.

In response to the San Bruno pipeline explosion that occurred on September 9, 2010, the NTSB issued various safety recommendations based on the incident's probable causes and to address the need to establish adequate quality assurance and quality controls in the integrity management program.[11]

The probable cause of the accident was the failure of a substandard and poorly welded pipe section. The pipe was originally installed in 1956 and the pipeline integrity management program failed to detect the defective pipe section, which was found to have visible weld seam flaws, causing the pipeline to rupture.

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[9] NTSB Accidents Records. https://www.ntsb.gov/investigations/AccidentReports/Pages/AccidentReports.aspx.

[10] PHMSA Pipe Failure Investigation Reports. http://www.phmsa.dot.gov/pipeline/library/failure-reports.

[11] Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California. NTSB/PAR-11/01, 2011.

The NTSB report addressed various requirements to enhance the quality and effectiveness of Federal and State integrity management programs. The following summary presents the recommendations that relate to the effort, discussed in this chapter, to identify technology development and implementation needs:

- Integrity management and risk programs:
    - Assess the effectiveness of performance-based safety programs. The assessment addresses the completeness and accuracy of pipeline operators' integrity management program data and the adequacy of inspection protocols.
    - Update the risk models to reflect: (a) Actual recent data on leaks, failures, and incidents; (b) Consideration of all defect and leak data for the life of each pipeline, including its construction, in risk analysis; (c) A methodology to ensure that assessment methods are selected to address all applicable integrity threats; and (d) Continuous evaluation of the effectiveness of assessing the integrity of pipeline segments.
- Data management and emergency response:
    - Provide system-specific information about the pipeline system to emergency response agencies. Develop, and incorporate into public awareness program, written performance measurements and guidelines. Establish a comprehensive emergency response procedure for responding to large-scale emergencies on transmission lines.
- Technologies for damage detection and prevention:
    - Equip the system with tools to assist in recognizing and pinpointing locations of leaks, including line breaks; such tools could include a real-time leak detection system and appropriately-spaced flow and pressure transmitters along covered transmission lines.
    - Require that automatic shutoff valves or remote-control valves in HCAs and in Class 3 and 4 locations be installed and adequately spaced.
    - Require that all gas transmission pipelines constructed before 1970 be subjected to a hydrostatic pressure test that incorporates a spike test.
    - Develop and introduce advanced ILI inspection platforms for use in gas transmission pipelines not currently accessible to existing ILI inspection platforms; including a timeline for implementation of these advanced platforms.

Recent State Actions Affecting Pipeline Safety

The CPUC publishes an annual safety report that lists gas and electric service safety incidents in accordance with Senate Bill 1409 (Hill, Statue 2014, Chapter 563) requirements.[12] Similar to

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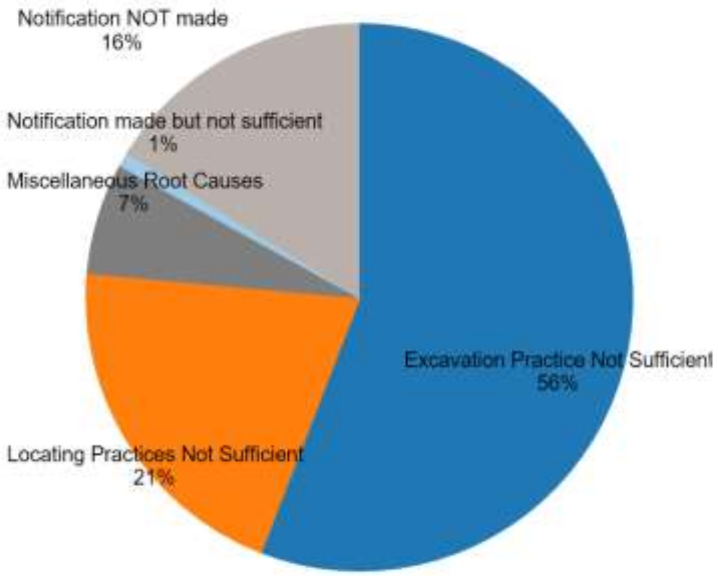
[12] Senate Bill 1409 Public Utilities Commission: safety investigations.

the PHMSA's significant incident records, the CPUC report identifies incidents resulting in casualty, hospitalization, or damage.

The CPUC report also includes other non-significant incidents that were reported by media coverage or recorded based on operator judgement. A breakdown of the CPUC reported incidents from 2015 to 2017 shows that about 43 percent of the incidents are caused by excavation damage.[13] The root cause analysis of excavation damage in Figure 13 shows that insufficient locating and excavating practices contribute to most of these incidents. Further details about incidents' records in the CPUC annual reports are presented in Appendix D.

Figure 13: Excavation Damage Root Causes in California



Source: DIRT Interactive Report, http://commongroundalliance.com/dirt-2016-interactive-report

Two recent events/regulatory actions have provided a potential for development of technologies to improve pipeline safety through various means, including operations, pipeline integrity, risk assessment and data management. These two events are: (1) Gas Safety Action Plan and (2) Aliso Canyon Well Failure.

Gas Safety Action Plan (October 2012)

The CPUC created a gas safety action plan[14] in response to the San Bruno pipeline failure. The gas safety action plan applied to regulated natural gas utilities in California and reflected the CPUC's "culture shift" from the traditional compliance model to an approach based on risk assessment and risk management.

The plan tracks the CPUC's implementation of recommendations made by the independent review panel and NTSB. The gas safety action plan goals matrix is shown in Table 7.

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[13] California Public Utilities Commission (CPUC). Annual Reports. 2015 to 2017.

[14] CPUC Gas Safety Plan. http://www.cpuc.ca.gov/General.aspx?id=2496.

Table 7: Gas Safety Plan Goals Matrix

Task	Goal: Ensuring safety of the existing gas system	Goal: Upgrading and replacing the gas system to make it safer	Goal: Making safety CPUC priority	Goal: Instilling Safety Culture in Gas Operators
1	Require testing of all grandfathered transmission pipes.	Adopt Pipeline Safety Enhancement Plans for each operator.	Base safety program on Risk Assessment, not solely compliance with rules.	Use regular management audits to benchmark and evaluate progress.
2	Require complete record searches to ensure operators know what they have.	Consider installation of automatic and remote valves and safety enhancements.	Empower staff to aggressively identify problems and pursue timely response.	Institute quarterly open house for utility field personnel to bring ideas/concerns.
3	Comprehensively inspect the physical condition of the gas system.	Consider effective emergency response plans.	Establish vigorous Whistleblower protection programs.	Establish vigorous Whistleblower protection programs.
4	Audit operators' procedures to ensure they're safe.	Direct the replacement of pipes that cannot be adequately tested.	Acquire and retain qualified inspectors; provide enhanced training and increased involvement.	Mandate periodic CEO safety certification and reporting at Gas Safety Summit.
5	Perform targeted and random field-checks of facilities.	Adopt SB 705 plans to keep focus on safety.	Adopt SB 705 plans to keep focus on safety.	Adopt SB 705 plans to keep focus on safety.
6	Develop and implement a comprehensive distribution safety plan (Aldyl-A, etc.).	Develop and implement a comprehensive distribution safety plan (Aldyl-A, etc.).	Establish internal Safety Council.	Educate operators of small gas systems.
7	Develop and implement a comprehensive transmission safety plan.	Develop and implement a comprehensive transmission safety plan.	Set rates and order programs to ensure safe operation.	Set rates and order programs to ensure safe operation.
8	Use enforcement to deter unsafe behavior by operators.	Increase oversight capability using CPUC staff with consultant support.	Increase oversight capability using CPUC staff with consultant support.	Use enforcement to deter unsafe behavior by operators.
9	Adopt new gas safety regulations where necessary	Adopt new gas safety regulations where necessary	Promote continuous improvement in work quality and transparency.	Promote continuous improvement in work quality and transparency.
10	Develop and use risk-based safety programs	Develop and use risk-based safety programs	Conduct root cause analysis of incidents.	Develop and use risk-based safety programs.

Source: CPUC Gas Safety Plan, http://www.cpuc.ca.gov/General.aspx?id=2496

The plan provides potential areas for improving the technologies to benefit pipeline safety with emphasis on the following tasks:

- Comprehensive inspection of the physical condition of the gas system, including Aldyl-A pipe
- Using risk-based safety programs; including identifying measures to improve the overall integrity of pipeline systems and reduce risk,

- Performing threat and risk analysis that integrate accurate data
- Reducing the number of gas incidents involving excavation.

Aliso Canyon Well Failure (October 2015)

As a result of the well failure at the Aliso Canyon storage field, California utilities presented changes to their monitoring procedures to better detect storage leaks. The incident resulted in California state legislators introducing Senate Bill SB 887,[15] which included additional testing requirements for gas storage wells and required the operators of all gas storage wells to begin performing mechanical integrity testing before January 2018. The requirements included the following:

- Regular leak testing
- Casing wall thickness inspection
- Pressure test of the production casing
- Any additional testing deemed necessary by the state's Division of Oil, Gas, and Geothermal Resources to demonstrate the integrity of the well

Several methodologies are currently being performed and investigated to assess the integrity of the gas wells.[16] These technologies include pressure testing, temperature and acoustic (noise) logging, and electromagnetic casing inspection for corrosion. Infrared (IR) videography monitoring of the well is also used to evaluate a visual inspection of gas flow from the wellhead.

Gas Pipeline Industry Technology Survey

A survey was performed to identify current technologies used by the pipeline companies and to solicit their research needs. The objectives of the survey were to:

- Outline natural gas operator needs and technology gaps to improve the integrity and safety of their system and reduce operations costs
- Identify emerging new technologies that address operator needs and have been used or will be considered.

The survey consisted of 10 questions that covered the company's identified threats and the technologies, devices, and tools that they currently use or would consider. The survey was sent to 25 transmission and distribution companies and 10 responses were received, including 4 from companies operating in California.

Figure 14 shows the types of surveyed pipeline companies and Figure 15 shows the technical expertise and interests of the respondents to the survey.

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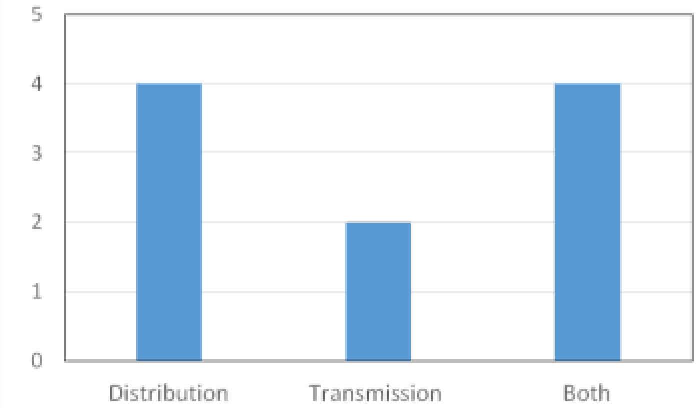
[15] California Senate Bill SB 887, Chapter 673. 2015.

[16] Arthur, J.D. Application of Well Integrity Methods for Gas Storage Well Storage. 23rd IPEC Conference. 2016.

Figure 14: Number of Companies Responding to Survey by Type



Source: Gas Technology Institute

Figure 15: Technical Expertise and Interests of Survey Respondents

Source: Gas Technology Institute

Pipeline Operators' Response

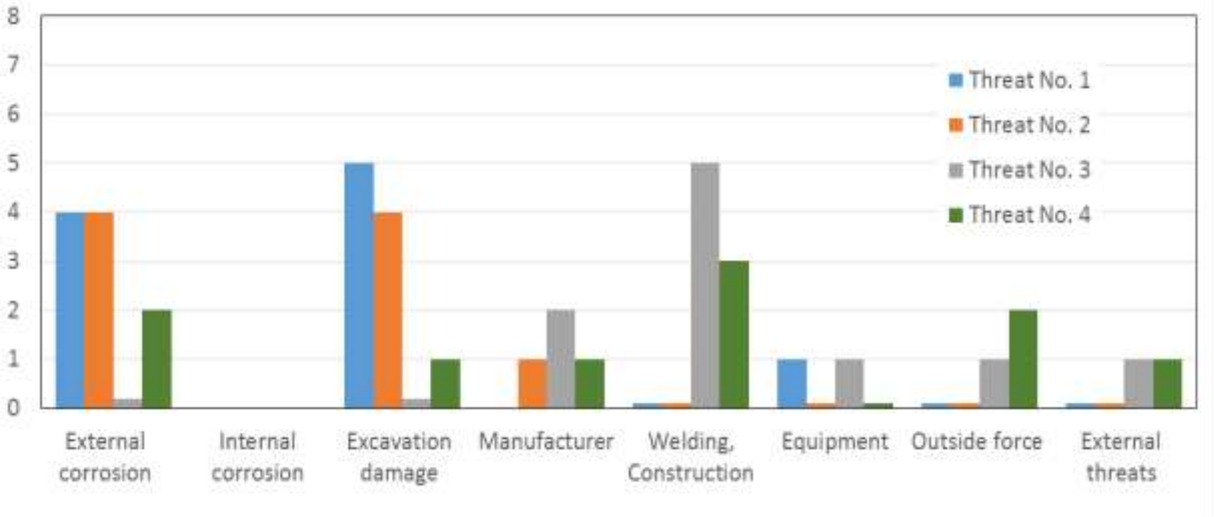
The survey questionnaire is shown in Appendix A. Survey participants were asked to rank the top four threats to their pipeline system. The results of the survey in Figure 16 show that external corrosion and excavation damage are the top two threats for these companies, followed by welding and construction damage.

The technologies that are used, or will be considered, for these threats were organized in the following four categories:

1. Pipeline monitoring and health assessment: Technologies related to pipe locating, ROW encroachments, excavation damage, welding inspection, and field tests and monitoring.
2. System integrity management: Leak detection sensors, direct assessment inspection, and risk and threat interaction.

3. System communication and control: Data management and communications systems, response awareness, and system security.
4. Asset life-cycle management: Asset tracking and traceability, visualization and geographical information system (GIS).

Figure 16: Top Four Threat Categories from Survey Results

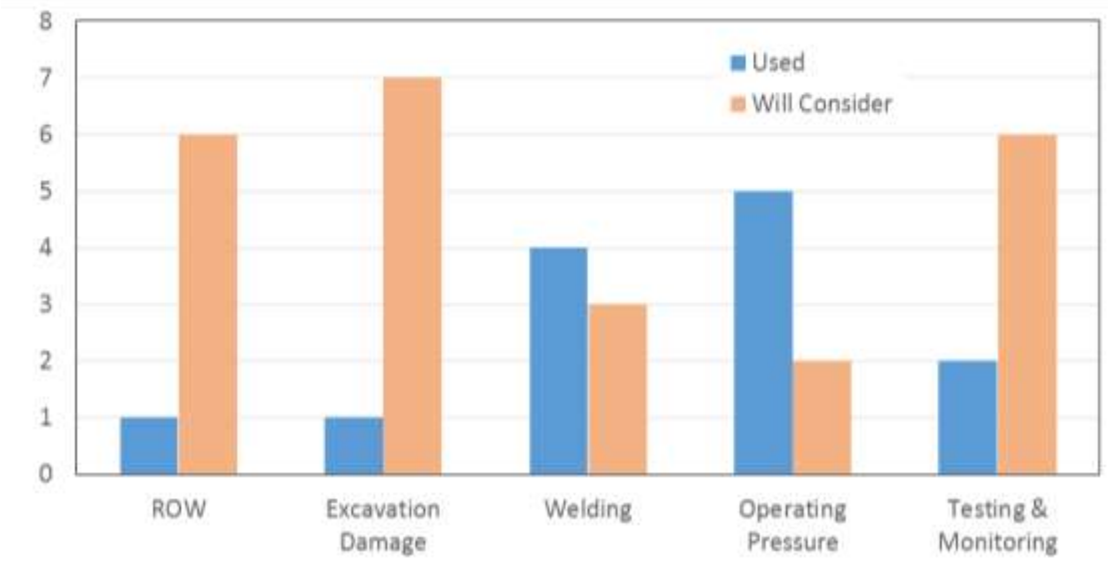


Source: Gas Technology Institute

The responses to these areas are shown in Figure 17 through Figure 20 and summarized as follows:

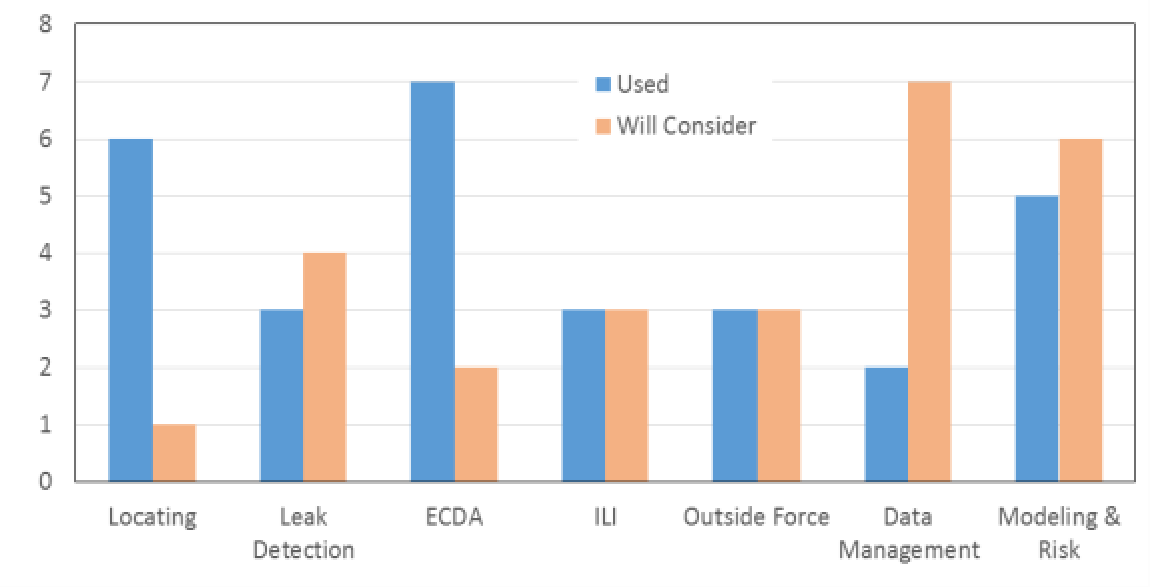
- Technologies that are currently being used:
    - Distribution companies have been using the technologies needed to address their integrity management and DIMP programs. Transmission pipeline companies use methods in their ILI program such as MFL and UT to detect wall loss and mechanical damage.
    - Distribution companies have been using various commercially available ECDA tools. The technologies used to address the companies' specific threats include enhanced pipe locating and leak detection technologies and welding inspections (Figure 17 and Figure 18). Many companies implement commercial and in-house risk assessment programs.
- Technologies that will be considered:
    - Technologies that enhance the use of ILI platforms in pipe inspection, such as welding inspection, detecting cracks, and application in unpiggable pipes.
    - System communication and control technologies that enhance risk modeling, response awareness, and asset tracking and traceability, as shown in Figure 19 and Figure 20.

Figure 17: Technologies for Monitoring and Health Assessment



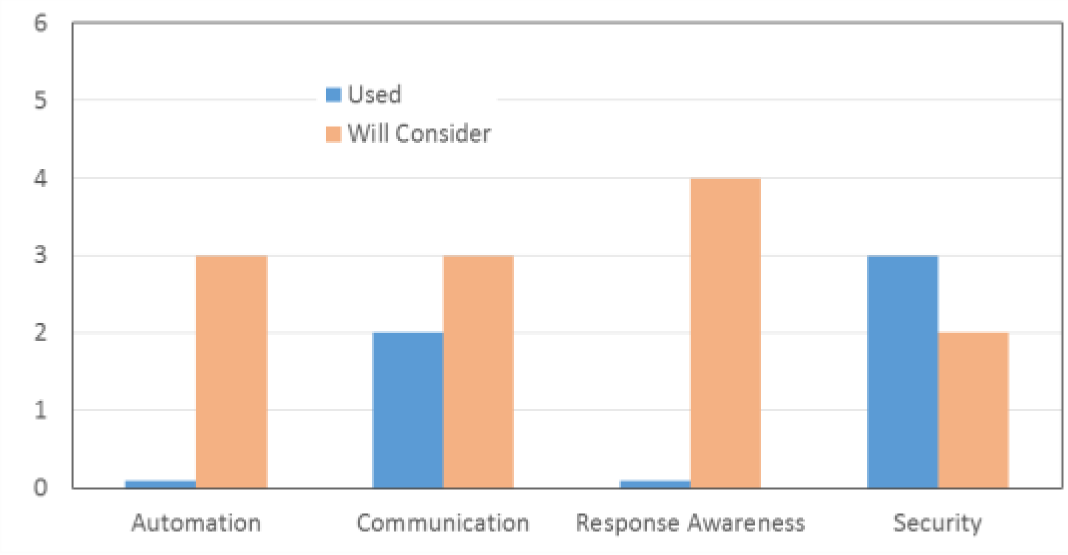
Source: Gas Technology Institute

Figure 18: Technologies for System Integrity Management



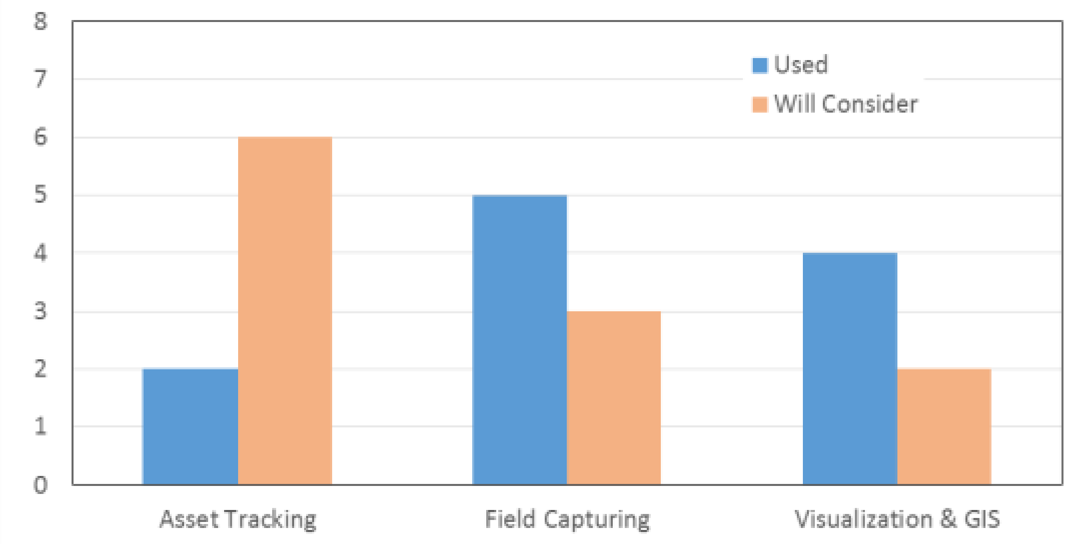
Source: Gas Technology Institute

Figure 19: Technologies for Communication and Control



Source: Gas Technology Institute

Figure 20: Technologies for Asset Life-Cycle Management



Source: Gas Technology Institute

Natural Gas Safety and Integrity Workshop

The project team held a technology review workshop during Task 4 of the project to address California's key natural gas safety issues and recommendations for future research activities. The workshop took place at the Energy Commission in July 2017 and included the CPUC, Department of Conservation Division of Oil, Gas and Geothermal Resources (DOGGR), PHMSA, the United States Department of Energy (USDOE), project technical advisory committee utilities, and technology providers and developers.[17]

The technical presentations included completed and ongoing Energy Commission research. Other key stakeholders such as PHMSA and DOGGR presented their activities and a panel discussion addressed current state of the natural gas system and the value of the ongoing and planned research. The following research needs were addressed in panel discussions:

- Natural gas research areas and their impact on energy efficiency, transportation, and energy infrastructure.
- Critical knowledge and tools to reduce risk and provide integrated risk approach.
- Incorporating SB 1371 goal to minimize leaks as a hazard.[18]
- Natural gas storage risk modeling and related Energy Commission research plans.[19]
- Implementation of USDOE's Monitor Program technologies for leak detection and quantification.
- Recent developments in ILI inspection robots, methane detectors, RFID markers, and GPE for horizontal drilling.

Summary of Development Needs

Pipeline operators use various technologies to address threats to the pipelines. An effective integrity management procedure for the pipeline system requires advanced inspection, monitoring, and risk assessment technologies to identify certain damages and provide comprehensive evaluation of pipeline threats. These threats include the following:[20]

- Time-dependent threats, such as external and internal corrosion and stress corrosion cracking.
- Stable threats, such as manufacturing-related, welding, and construction defects.
- Time independent threats, such as third-party damage, outside force, and incorrect operation procedures.

A review of system integrity status, previous incidents, and related Federal and State regulations was performed to identify development needs and address technology gaps based on previous pipeline incidents. A survey of natural gas pipeline operators was performed to identify the current technologies used by the pipeline companies and to investigate operator priorities for enhancing the integrity and safety of their systems and cost-effective operation.

Technical requirements and technology needs varied between transmission and distribution pipeline systems. These two systems differed widely in their material types, pipe sizes,

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[17] California Energy Commission. http://www.energy.ca.gov/calendar/index.php?eID=2966.

[18] Natural gas: leakage abatement. California Senate Bill No. 1371. Chapter 525. 2014.

[19] Natural Gas Storage Infrastructure Safety and Integrity Risk Modeling Research Grants. GFO-16-508 Research Grant. California Energy Commission. 2017.

[20] American Society of Mechanical Engineers, ASME B31.8S, Managing System Integrity of Gas Pipelines, 2010.

operating pressures, age, control systems, and data transfer and management capabilities. These differences resulted in a need for various requirements for their operation, inspection protocols, and environmental and risk consequences. Accordingly, technologies were categorized to address the requirements of these systems.

Technologies for Damage Detection and Failure Prevention

Technologies that focus on preventing failure include:

- Advanced ILI platforms for use in gas transmission pipelines not currently accessible to existing platforms; including advanced platforms and ILI sensors that can identify weld defects and line cracks.
- Real time monitoring of the system with devices that recognize and pinpoint the location of leaks to predict rupture and catastrophic failures. These devices include appropriately-spaced flow and pressure transmitters along the length of covered lines.
- Pipeline locating with devices that recognize and pinpoint the non-metallic pipes.
- Real time monitoring of excavation damage using devices installed in the right-of-way and remote sensing technologies.
- Damage mitigation approaches, repairs, and procedures that prevent rupture and catastrophic failures.

Threat Identification and Integrity Management

Technologies that focus on detecting defects from pipeline threats and decreasing the consequences of failure include:

- Advanced ILI platforms for use in gas transmission pipelines not currently accessible to existing platforms and ILI sensors that can identify weld defects and line cracks.
- Effective material characterization and failure prediction models; incorporating accurate operators' data and the output of adequate inspection protocols.
- Systems for emergency automatic shut off in high consequence areas.

Data and Risk Management and Emergency Response

These technologies focus on data management and information systems to accurately identify and categorize pipeline risks. These technologies include:

- Methods to improve data management and traceability records for construction, operations, and maintenance.
- Systems for emergency response, situational awareness, and automatic shut off during pipeline incidents.
- Effective failure prediction models; incorporating accurate operator data and the output of adequate inspection protocols.
- Updated risk models to include consideration of the combined threats, including adequately measuring the effectiveness of the integrity management assessment.

CHAPTER 4:
Baseline Technologies for Gas Transmission and Distribution Systems

This chapter identifies the various emerging pipeline safety and integrity management technologies. It presents recent technologies in the market and close-to-market equipment, sensors, systems and processes. Recent commercial technologies in the market are presented in Appendix E and the in-development and close-to-commercialization technologies are presented in Appendix F.

Following the research needs identified in the earlier chapters, the technologies were categorized into the three following groups:

- Damage detection and prevention
    - Pipe and facility locating
    - Excavation damage and ROW encroachments
    - Leak detection in pipeline, storage facilities, and aboveground systems
    - Damage mitigation and prevention
- Threats and integrity management
    - ECDA
    - ILI
    - Pipeline testing and monitoring
    - Remote monitoring of facilities response to natural force (earth movement, earthquakes and fire)
    - Stress analysis and smart devices
    - Pipeline repair
- Risk and information management
    - Data automation and management system
    - Asset tracking and traceability
    - Field data capturing
    - Visualization and GIS
    - Modeling and risk assessment
    - Response awareness
    - Communications protocols
    - Cyber-physical security

Technologies for Damage Detection and Prevention

Pipe Locating and Excavation Damage

Excavation damage is the leading cause of natural gas pipeline failure incidents. PHMSA incidents records in gas distribution system were shown in Figure 3. A considerable percentage of these incidents (25.4 percent in 2017) was caused by excavation damage. Pipe locating is the first line of defense against excavation damage.

Electromagnetic locators represent the standard of locating equipment in the last few decades because of their low cost, ease-of-use, and relative accuracy. These locators use a transmitter that places a signal on a target conductor and a receiver to process and communicate the signal to the user. These locators are capable of identifying the horizontal position of metallic pipes, but environmental factors often distort the received signal and may misrepresent the target's location. Soil conditions, other utility lines, broken tracer wires, and insulated joints can all contribute to an unsuccessful locate. A review of several of these existing locators in the market has been performed by the Gas Technology Institute (GTI).[21]

Recent advancements in data collection and display capabilities of acoustic and ground penetrating radar (GPR) technologies have improved their accuracy and made them easier to operate and locate non-metallic pipes. However, soil conductivity remains a limiting factor in their overall effectiveness. Table 8 shows examples of these two technologies.

Table 8: Acoustic and Ground Penetrating Radar Locating Technologies on Market

Technology	Description	Technical Advancement
Acoustic pipe locating (a)	Hand-held devices that send an acoustic signal into the ground and detect reflection from the pipe at the ground level.	The ability to locate plastic pipes at depths up to five feet. Few other current tools address plastic pipes, such as tracer wires.
GPR (b)	A GPR transmitter emits high-frequency electromagnetic waves into the ground. A receiving antenna records the reflected waves to identify underground objects.	Several GRP products exist in the market to detect both metal, and plastic utilities. Multi-frequency units are suited for clay soils, deep utilities, and small pipes.

(a) Acoustic Pipe Locator (APL), SENSIT Technologies (www.gasleaksensors.com)

(b) Sensors and Software (https://www.sensoft.ca/products/), GSSI Geophysical Systems, (http://www.geophysical.com/), GP Rover Mapping System. United States Radar Inc. (http://www.usradar.com/), Interragator EZ. Vermeer. (http://www.vermeer.co.za/images/GPR/InterragatorEZ.pdf).

Source: Gas Technology Institute

New and enhanced technologies to improve pipe locating and protect ROW have been developed in recent years. The success of these technologies depends on their capability to better detect plastic pipes and pinpoint leaks; while providing reduced costs, and increased reliability when compared to existing technologies. Research needs in locating technologies still

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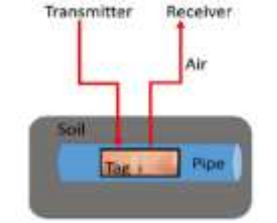
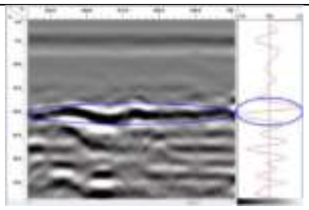
[21] Underground Facility Pinpointing, Alternative Locating Technology Assessment. Operations Technology Development. OTD Project 21291. 2015.

pertain to locating pipes during horizontal direction drilling (HDD) and the ability to locate plastic pipes.

Recent close-to-commercialization technologies include aerial and ground-based equipment to patrol pipeline ROW for security and encroachments. Table 9 shows a list of close-to-commercialization technologies in this area.

Table 9: Close-to-Commercial Technologies for Locating and Right of Way

Technology	Description	Technical Advancement	
Look Ahead Technology for HDD [(a)]	A GPR system is attached to the HDD unit for obstacle detection during drilling	The system is used to detect cross bores when the installed HDD gas lines inadvertently transects a sewer line.	
GPS Excavation Encroachment Notification [(b)]	A GPS sensor box installed in excavation equipment characterizes the excavator’s movement. It connects to the satellite system and communicates with a dashboard to notify of encroachments.	The technology enhances the real-time situational awareness of excavators and reduces the risk of third-party damage to utility infrastructure.	
Aerial Inspection of ROW [(c)]	Unmanned Aerial Systems (Drones) for the inspection of gate stations and pipelines. The drone collects high resolution imagery of gate stations and ROW.	Drones increase worker safety by providing visual access to locations that are challenging to access. Pipeline safety also increases with more frequent inspections of the ROW.	
Aerial Inspection of ROW [(c)]	Laser-Based Technology (LIDAR) Fly-by pipeline leak detection using infrared laser differentiation to scan the area and pinpoint natural gas plumes.	The device allows for pipelines in harsh, overgrown, or impassible environments to be scanned for leaks without endangering utility personnel. Relatively expensive.	
Sensors to Monitor Encroachment[(d)]	Stationary vibrating sensors near the ground at ROW. The sensors use advanced wireless technology that enables monitoring miles of range with very low power.	The system targets the most active excavation areas and reduces the risk of excavation damage. It characterizes the excavation behavior and transfers the data to a notification station.	

Technology	Description	Technical Advancement	
Embedded Passive RF Tags(e)	Low-cost, thin-film sensors using Radio-frequency (RFID) tags to automatically identify and track stored information. Passive tags collect energy from a nearby RFID reader's radio waves.	Embedded RFID tags will have the capability to locate buried plastic pipes and have other sensing functionality, such as measuring strain-stress changes in the plastic materials.	
Advancements in Locating Plastic Materials(f)	Integrate the GPR and Infrared Thermography (IRT) for buried pipe location.	Advance plastic pipe manufacturing and subsurface detection using a combination of reinforced polymers and ground sensory technologies.	
Advancements in Locating Plastic Materials(f)	Integral electronic marking systems that are energized by an aboveground transceiver, causing them to generate their own magnetic field.	Electronic markers are detectable passive devices that do not use batteries. They are used to locate plastic pipes.	

(a) ORFEUS. TT Technologies. D5.19 Demonstration completion report D5.19, 2015.

(b) GPS Excavation Encroachment Notification System. California Energy Commission. Project PIR-15-015.

(c) NYSEARCH. 2016, (http://www.nysearch.org/news-info_110216.php), LASEN. ITT (ESRI) (http://www.laseninc.com/).

(d) Monitor Encroachments on the Pipeline ROW, California Energy Commission, Project PIR-14-014.

(e) Imbedded Passive RF Tags for Pipelines. PHMSA. https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=628.

(f) Integrated GPE for Pipe Locations, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=632), Marking System for pipelines, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=654).

Source: Gas Technology Institute

Gas Leak Detection

Operator damage prevention focuses primarily on detecting leaks in the pipeline system as indicators for excavation damages, corrosion, and other various threats. Recent developments in leak detection technologies include drive-through and stationary systems, installed in perimeters around gas facilities, and aerial technologies. PHMSA has established a process for enforcing the Federal damage prevention standards[22] and to determine the adequacy of State programs. Table 10 to Table 12 present examples of aerial and stationary leak detection technologies.

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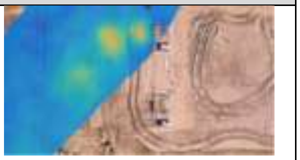
[22] 49 CFR Parts 196 and 198, PHMSA. Pipeline Safety: Pipeline Damage Prevention Programs. Final Rule. July 2015.

Table 10: Aerial Leak Detection Technologies

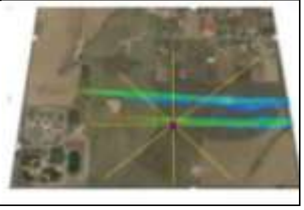
Technology	Description	Technical Advancement	
Methane Monitor Differential LIDAR(a)	Differential LiDAR (DIAL)	Scan large areas from the air, fast enough to work with fixed-wing aircraft. Commercially available	
RMLD-Sentry for Upstream Natural Gas Leak Monitoring(b)	Laser Backscatter Detection using the Remote Methane Leak Detector RMLD.	Quickly scan fixed infrastructure such as well pads, localize leak with drone search pattern, differentiate sources.	
Mobile LiDAR for Methane Leak Detection Applications(a)	Prototypes of manned aircraft and UAV versions are planned to be tested in ARPA-E Monitor program	Quickly scan fixed infrastructure such as well pads. Fixed-position sensor has been tested.	

(a) Methane Monitor Differential LIDAR , http://www.ball.com/aerospace/markets-capabilities.

(b) ARPA-E (Advanced Research Projects Agency–Energy) Monitor Program. https://arpa-e.energy.gov/?q=slick-sheet-project/methane-leak-detection-system.

Source: Gas Technology Institute

Table 11: Perimeter Leak Detection Technologies

Technology	Description	Technical Advancement	
Mid-IR Laser Spectrometer(a)	Perimeter monitoring system. Miniature, tunable mid-IR Laser Spectrometer for CH4/C2H6 Leak Detection.	In early commercialization stage. System developed under the ARPA-E Monitor program.(c)	
Methane Sensing Solutions for Oil & Gas(b)	Laser absorption spectroscopy	Low cost continuous monitoring	
Frequency comb laser spectrometer	Frequency Comb-Based Remote Methane Observation Network	Can detect gases over long distances. One fixed base system can be deployed with multiple retroreflectors to monitor in any direction.	

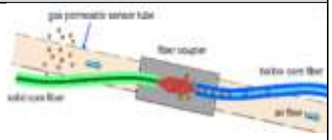
(a) Methane Monitor Differential LIDAR (http://www.ball.com/aerospace/markets-capabilities).

(b) Quanta (http://www.quanta3.com)

(c) ARPA-E Monitor Program (https://arpa-e.energy.gov/?q=slick-sheet-project/methane-leak-detection-system)

Source: Gas Technology Institute

Table 12: Stationary and Mobile Leak Detection Technologies

Technology[(a)]	Description	Technical Advancement	
Micro-structured fiber optic cable	Hollow core fiber optics permeable for infrared absorption measurements of methane concentration	Gas can be deployed with in various configurations for local monitoring or long-distance monitoring along length of pipeline.	
Low-cost TDLAS sensor	An intelligent multi-modal CH4 Measurement System (AIMS)	Networks of Internet-of-Things sensors wirelessly connected to the cloud to provide low-cost continuous monitoring of natural gas infrastructure.	
Carbon nanotube (CNT) sensors	System of Printed Hybrid Intelligent Nano-Chemical Sensors (SPHINCS).	Printed carbon nanotube sensors provide low cost, low power system.	
Laser spectroscopy	Portable measurements platform. Working on 3rd generation prototype as of mid-2017.	Ultra-Sensitive Methane Leak Detection System exploiting a novel Laser Spectroscopic Sensor. Low cost cavity-based sensor	

(a) ARPA-E Monitor Program (https://arpa-e.energy.gov/?q=slick-sheet-project/methane-leak-detection-system).

Source: Gas Technology Institute

Damage Mitigation and Prevention

PHMSA Docket 2012-0021 required the development of management systems and procedures for leak detection response by pipeline operators.[23] Operator damage response includes incident mitigation, quick shut-off to avoid the release of natural gas, and safe repair procedures. Technologies have sought to minimize the time required for system shut-offs to stop gas flow once a leak or rupture has occurred. Other technologies focus on damage mitigation, reducing the time and work effort, and increasing operator safety during pavement repair and restoration work. Examples of current technologies in the market are in Table 13. Table 14 shows a list of close-to-commercialization technologies in this area.

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23 PHMSA. Docket ID PHMSA–2012–0021. Pipeline Safety: Public Comment on Leak and Valve Studies. 2012.

Table 13: Current Damage Mitigation and Repair Technologies

Technology	Description	Technical Advancement
Flow Stopping Mainline Control Systems(a)	Inflatable stopping bags used to stop gas flow in pipes. The system monitors pressure in the stopper and the pipeline without having to make additional taps. Portable "No-Blow" gas systems for gas service abandonment, renewal, and main tapping and stopping. The device is inserted from the gas meter and runs to the service lines.	The technology is used in pipe diameters up to 18 inches and pressures up to 60 pounds per square inch, which traditionally have limited options such as large and costly mechanical valves to control gas flow. Gas meters and valves replacements can be easily and safely performed even when there is no available gas shut off between the gas main and the valve.
Inspection Camera Systems(b)	The keyhole camera is inserted into the gas line using a power drive motorized cable feeder, allowing the inspection work through small 18-inch diameter keyhole cuts in the pavement.	Inspection system is used in live gas mains to detect and assist in the repair of water ingress, locate blockage, verify installations, repairs, and resolve other issues involving 2- to 12-inch diameter gas distribution mains.
Pipe Repair and Utility Restoration(c)	Lift Assists for Pavement Breakers: A pneumatic device is attached to conventional pavement breakers and jackhammers to assist workers in lifting the jackhammer during pipe repair work.	The device reduces workers' injury and fatigue resulting from using heavy pavement breakers during pipeline repair and restoration operations.

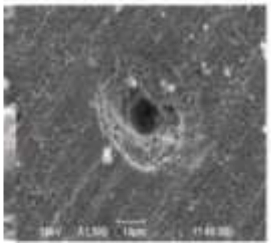
(a) Kleiss Mainline Control Systems (www.mainlinecontrolsystems.com), NO-BLO DBS System, Mueller Company (www.muellercompany.com)

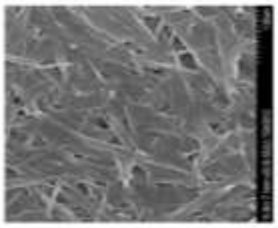
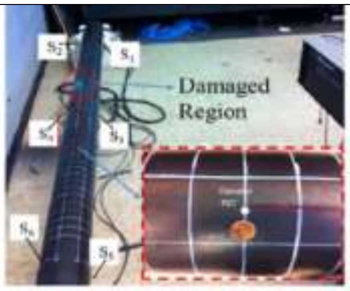
(b) PRX250K Keyhole Camera, ULC Robotics (www.ulcrobotics.com).

(c) Integrated Tool Solutions (www.integratedtoolsolutions.com).

Source: Gas Technology Institute

Table 14: Close-to-Commercial Technologies for Damage Mitigation and Repair

Technology	Description	Technical Advancement	Image
Breakaway Disconnect and Shutoff Product[a]	Breakaway disconnect and shutoff fittings are installed in meter set assemblies (MSA) and other aboveground gas systems to reduce the risk from vehicle collision or ice/snow falling from a building.	This product addresses the need to protect outdoor gas meter systems with an automatic gas shutoff when subjected to physical damage from outside forces, such as vehicular damage and extreme weather.	
Breakaway Disconnect and Shutoff Product[a]	Shutoff valve is attached to the service line. An inner and outer PE lines are attached to the valve and fitting. Gas flows in the inner system. If leak occurs, gas is released that closes the valve.	The technology enhances the detection of small flow and is compatible with Internet-of-Things to notify utilities of the status of flow.	
Valve Position Confirmation Technology[b]	Use the sound of gas flow through a valve to confirm exact position of critical valves in gas distribution systems.	Valve testing is a regular part of operations and safety program. Acoustic technology ensures that the positioning of the valve is as indicated.	
Mitigating Pipeline Corrosion[c]	Electrochemical and ultrasonic-type sensing technologies with polyurethane foam to monitor Cathodic Protection (CP) and pipe coating.	Effective CP systems are vital to pipeline integrity. Polyurethane foam sack breakers have operational advantages and allows for data monitoring of the CP and the coating.	
Mitigating Pipeline Corrosion[c]	Mitigation of Pipeline Microbiologically-Influenced Corrosion (MIC) using a Mixture of D-Amino Acids with a Biocide.	MIC corrosion amounts to 20% of all corrosion losses. D-amino acids have been found to be biocide enhancers in biofilm mitigation.	

Technology	Description	Technical Advancement	Image
Mitigating Pipeline Corrosion[d]	Produce cement-based coating by effective dispersion of nanomaterials to mitigate external corrosion of pipelines.	The engineered cement-based coating material is easy to apply and provides superior sealing and fatigue properties.	
Permanently Installed Pipeline Monitoring Systems[e]	Arrays of low-profile piezoelectric transducers for transmitting and receiving guided ultrasonic waves over the length of the pipeline. Signal processing algorithms perform damage localization.	The system is a change from periodic inspections, based on fixed time intervals, to more cost-effective permanent condition-based inspections.	
Permanently Installed Pipeline Monitoring Systems[e]	Development and testing of a resistive-based, self-sensing composite system for pipeline repairs. The material allowed for the monitoring of the composite bond using small, low-voltage electronics.	Use of composite repairs has expanded in the last two decades. Industry acceptance of composite repairs has grown since the initial products came on the market.	

(a) Disconnect/Shut-off for Meter Risers. OTD Project 5.11.s., An Intelligent Shutoff Device for Commercial and Industrial Customers. OTD Project 5.12.a, 2012.

(b) NYSEARCH, 2016 (http://www.nysearch.org/news-info_110216.php).

(c) SBIR-STTR (https://www.sbir.gov/sbirsearch/detail/691165), PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=512).

(d) PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=510).

(e) USDOT, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=507), USDOT, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=506).

Source: Gas Technology Institute

Technologies for Pipeline Threats and Integrity Management

The identification of pipeline threats and integrity management focuses on technologies for detecting existing damages on the pipeline and evaluating the pipe fitness for service. The following topics are areas for potential research and development of technologies:

- Anomaly detection and characterization
- Pipeline testing and stress analysis.

Natural gas transmission and distribution systems are subjected to multiple threats that can potentially result in various types of damages based on their material type, age, location, and operational characteristics. These threats include pipe corrosion, excavation damage, natural forces, material and weld failures, and incorrect operation.

USDOT-PHMSA requires pipeline operators to annually report repairs performed, categorized by threat type, and to implement integrity management programs for both gas transmission and distribution systems in accordance with the Code of Federal Regulations 49 CFR Part 192 Subpart O for transmission and Subpart P for distribution pipes.

In the integrity management program, hydrostatic pressure testing is the main strength diagnostic test for steel pipes under specific conditions. The test involves temporarily disconnecting a section of pipeline and pressurizing it with water.[24] Different test requirements exist for steel distribution versus transmission pipelines and hydrostatic testing can be recognized as a destructive test since failure of a pressurized pipe results in a leak or rupture of the pipe. Accordingly, there is a considerable interest in the development of non-destructive methods such as ECDA, guided wave technology (GWT), and internal inspection methods such as ILI.

ECDA is a structured process that identifies the tools and procedures for assessing external pipeline corrosion.[25] It is used in the assessment of corrosion and mechanical damage (e.g., gouges, dents, and cracks) and includes a broad range of technologies such as close interval (CIS) and AC and DC voltage gradient surveys.

GWT is a non-destructive evaluation technology that employs low frequency ultrasonic waves that propagate along the length of the pipe while guided by its boundaries.[26] GWT is an external method that is widely used to inspect and screen metallic pipelines. Details of commercially available ECDA and GWT technologies are presented in an earlier Energy Commission report.[27]

ILI, also known as "smart pigs," is an integrity assessment method that uses devices traveling through the pipe to locate and characterize metal loss and other anomalies. The effectiveness of the ILI tool depends on the condition of the specific pipeline section and how well the tool matches the requirements set by the inspection objectives. The following section provides information about current and newly-developed technologies used in ILI inspection.

In-Line Inspection of Pipelines

Several ILI methods have been developed and used for detecting and quantifying pipe wall loss and mechanical damage. They include shear-wave, MFL, UT, eddy current testing (ET), and other electromagnetic inspection tools.

Currently, the primary inspection method for detecting and measuring longitudinal cracks in liquid pipelines is shear-wave technology. These tools launch electromagnetic shear waves to

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[24] Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide, American Petroleum Institute. API Recommended Practice 1110. 2007.

[25] Pipeline External Corrosion Direct Assessments. Standard Practice. NACE SP502. 2010.

[26] Guided Wave Technology for Piping Applications. Standard Practice. NACE SP0313. 2013.

[27] California Natural Gas Pipeline Assessment: Improving Safety through Enhanced Assessment and Monitoring Technology Implementation. California Energy Commission. Report CEC-500-10-050. 2013.

estimate crack depth. MFL tools use saturated magnetic fields to analyze and interpret the flaw characteristics. Multi-modal tools such as UT with gas-coupled bulk waves are also used to measure wall thickness. However, UT requires a liquid couplant to operate, which is not feasible in gas pipelines. Eddy Current and other electromagnetic-based tools such as electromagnetic acoustic transducer (EMAT) sensors can detect internal cracks and wall loss. However, existing tools are typically used for larger pipes. Various technical and operational factors should be considered for the application of ILI tools, including:[28]

- Detection sensitivity: The minimum defect size specified for the ILI tool should be smaller than the size of the defect to be detected.
- Classification: The tools should be able to differentiate among various types of anomalies.
- Sizing accuracy: The detection algorithm should enable prioritization of the anomalies for an integrity management plan.
- Location accuracy: The tool should pinpoint the locations of the defects for excavation and repair.

None of the available ILI technologies is universally applicable to detect all the various defects of pipelines. Accordingly, pipeline operators choose multiple technologies as needed to match expected threats to their pipelines. Reviews of the available technologies in the market are resented in several publications.[29, 30] Table 15 summarizes the most common ILI technologies on the market with a description of their characteristics and detection capabilities.

To advance ILI platforms for gas distribution lines, the NTSB issued safety recommendation P-15-23 in response to the 2010 San Bruno gas line incident.[31] The recommendation requires enhancing ILI technology for implementation in pipelines that are not currently accessible by existing inspection platforms.

Electromagnetic Acoustic Transducer Technology

An EMAT tool is a type of ultrasonic transducer. It uses coils to induce alternating current in the pipe wall. Simultaneously, a permanent magnet establishes a static magnetic field in the pipe. The interaction of the electric currents and the static magnetic field generates compression waves in the pipe wall due to Lorentz forces, creating acoustic waves in the material. As a result, the technology can be used to inspect welds, coating disbondment, and cracks, including stress corrosion cracks (SCC). Unlike UT, EMAT does not require couplant to

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[28] ASME B31.8S, Managing System Integrity of Gas Pipelines. American Society of Mechanical Engineers. 2004.

[29] Bickerstaff, R., Vaughn, M., Stoker, G., Hassard, M., and Garrett, M. Review of Sensor Technologies for In-line Inspection of Natural Gas Pipelines. Sandia National Laboratories. 2002.

[30] Varma, V.K. State of the Art Natural Gas Pipe Inspection. United States Department of Energy Report. National Energy Technology Center. Natural Gas Infrastructure Reliability Industry Forum. NETL. Morgantown WV. 2002.

[31] Pipeline & Hazardous Materials. Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, NTSB. 2010. http://www.sanbruno.ca.gov/PDFs/NTSB - PipelineSanBruno992010.pdf.

transfer the acoustic wave. A schematic of the EMAT wave generation in comparison to traditional acoustic (UT) sensors with a couplant is shown in Figure 21.

Table 15: Current In-Line Inspection Technologies

Technology	Description	Detection Capabilities
Magnetic Flux Leakage (MFL)	Applies a saturating magnetic field, created by powerful magnets, into the pipe material and senses local changes in the field. The technology is the most common ILI application and it is applied at various resolutions and detection ranges. However, it requires large data management and causes long-term magnetization of pipe.	Detects mechanical damage and can effectively size metal loss to about 5% wall thickness. Good in detecting circumferential cracks but not suitable for axial cracks. This depends on the alignment of the magnetic field.
Eddy current Testing (ET)	ET is induced in coils near the surface. The current sets up magnetic fields within the wall which oppose original ones. The impedance of the coils is affected by the induced current that is distorted by the presence of flaws. The technology is non-contact with no residual effect but sensitive to distance variations. It has a relatively slow response that limits its ILI application.	Assesses wall thickness, pitting, cracks, and laminar defects.
Ultrasonic Testing (UT)	High frequency acoustic waves detect flaws and measure wall thickness. The requirement for a couplant between the transducer and the pipe surface limits its applications in gas pipes.	Ultrasonic-based technologies quantify metal loss and are best for cracks and SCC detection.
Electromagnetic Acoustic Transducer (EMAT)	Coils induce alternating current through the pipe wall. Interaction with applied magnetic fields produce charged fields (Lorentz forces) and generate acoustic waves in the material. The type and configuration of the transducer used characterize the wave propagation through the pipe wall. The technology does not require couplant and can produce shear waves for inspection in areas such as welds.	Allows for relatively high-speed screening and detects metal loss, weld inspection, plate lamination inspection and can be used to collect coating disbondment information. Transverse EMAT tools cannot detect circumferential cracking. Current commercial products are mostly for large diameter pipes.

Source: Gas Technology Institute

Some commercial EMAT tools are gaining acceptance for detecting and assessing cracks and coating disbondment. Current products are mostly mounted on piggable platforms for large diameter pipes. Figure 22 shows the EMAT detection signal of various anomaly types of in large diameter pipes. Research on the performance of large-diameter commercial EMAT sensors[32] has shown good agreement between the EMAT estimated crack depth and the actual depth with the reported criteria shown in Table 16.

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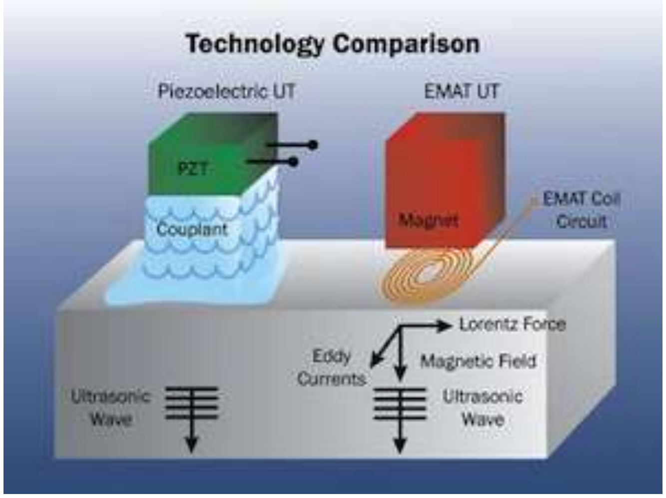
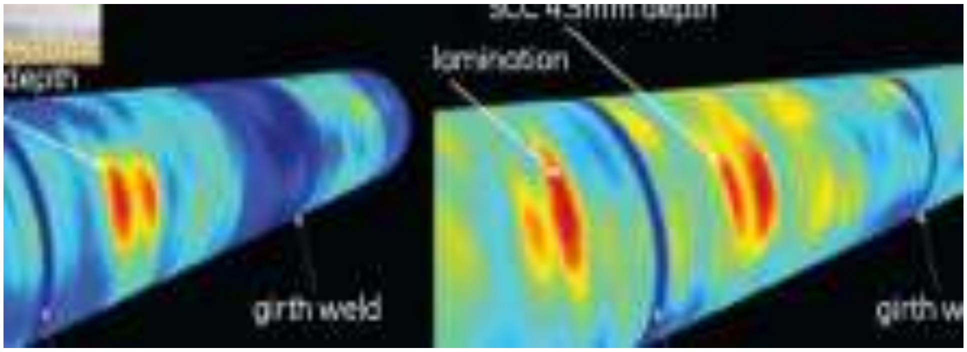
[32] Validation of Latest Generation EMAT In-Line Inspection Technology for SCC Management, 8th International Pipeline Conference (IPC2010), Calgary, Alberta, Canada, September 2010.

Figure 21: Electromagnetic Acoustic Transducer Wave Generation and Ultrasonic Testing Sensor



Source: http://www.innerspec.com/knowledge/emat-technology/

Figure 22: Anomaly Signals from Electromagnetic Acoustic Transducer Tool in Large Diameter Pipe



Source: Third-Generation EMAT Tool Enhanced for Finding SCC And Disbonded Coating in Dry Gas Pipelines. Pipeline & Gas Journal, Vol. 236 No. 6. June 2009.

Table 16: Performance Evaluation of Electromagnetic Acoustic Transducer Technology

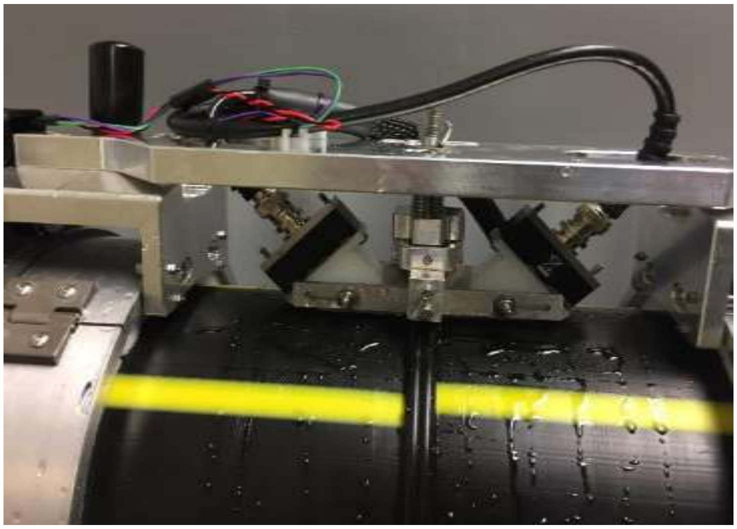
Performance Criteria	EMAT Test	Field Evaluation Results
Probability of Detection (POD)	90%	93%
Probability of Identification (POI)	66%	76%
Sizing Accuracy	80% certainty, ± 0.5mm tolerance at 95% confidence.	

Source: Internal Inspection Optimization Program: Phase 1 - R&D Roadmap, Gas Technology Institute, Report No. 21227, October 2012

Ultrasonic Technologies

UT technology uses high-frequency sound waves ranging from 2 to 20 kHz to determine flaws in the pipe material. Imperfections and inclusions in the pipe material cause sound waves to be scattered, resulting in echoes and dampening of the sound waves. Ultrasonic tools have been used for several years to detect, identify, and size pipe wall thickness, metal loss, cracks, and crack-like defects. The effectiveness of the technique varies depending on if it is applied manually or mounted on an ILI tool. Figure 23 shows a UT tool for the external inspection of butt-fusion of plastic pipes.

Figure 23: Ultrasonic Testing Tool for External Inspection of Butt-Fusion



Source: Gas Technology Institute

Because gases are relatively poor transmitters of ultrasonic waves, the application of the technology requires the use of a liquid couplant (a material that serves as a medium for the transmission of sound waves) to ensure efficient transmission of the wave from the transducer to the pipe wall.

Ultrasonic waves consist of two types: transverse waves (also known as shear waves) moving in a direction perpendicular to the direction of the wave propagation and longitudinal waves (also known as compression waves) moving in a direction parallel to the direction of the wave propagation. Several detection characteristics are associated with choosing the type of wave for testing. Transverse waves have shorter wave length, resulting in more sensitivity to smaller discontinuities and cracks. However, they do not travel a long distance or in liquids.

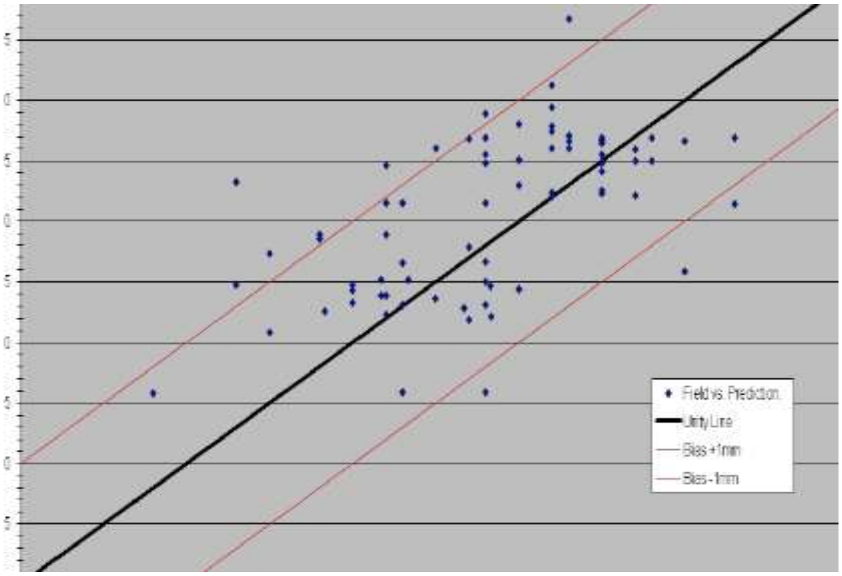
Currently there are two types of ultrasonic tools available: single transducer and phased array. Table 17 shows the performance characteristics of both types of sensors. Figure 24 shows the sizing accuracy of crack depth using the UT technologies in comparison to field measurements.

Table 17: Performance Characteristics of Ultrasonic Testing Technology

Performance Criteria	Single Transducer Ultrasonic Testing	Ultrasonic Phased Array
Probability of Detection (POD)	99-100% Crack field:76-96% Crack like: 60-69% Notch like:100% Weld Anomaly:77-100%	Crack with a length of 25 mm and a depth of 1 mm can be reliably detected with a POD of 90%
Probability of Identification (POI)	Crack field: (±0.4 mm): 78.6% (±0.5 mm): 85.7% Crack-Like Features (±0.4 mm): 33.3% (±0.5 mm): 33.3%	90%
Sizing Accuracy depth	Notch-Like Features (±0.4 mm): 100% (±0.5 mm):100% Weld Anomaly Features (±0.4 mm):0% (±0.5 mm): 0%	90%
Sizing Accuracy Length	Crack Field Features (±7.5 mm/ 7.5%): 18.2% (±10 mm/10%): 45.5% Crack-Like Features (±7.5 mm/ 7.5%): 12.5% (±10 mm/10%):12.5% Notch-Like Features (±7.5 mm/ 7.5%): 12.5% (±10 mm/10%): 25.0% Weld Anomaly Features (±7.5 mm/ 7.5%): 9.1% (±10 mm/10%):15.2%	±1mm at a 95% confidence level

Source: Internal Inspection Optimization Program - R&D Roadmap, Gas Technology Institute. Report No. 21227. 2012.

Figure 24: Predicted Depth of Cracks Using Ultrasonic Testing Measurements versus Field Depth

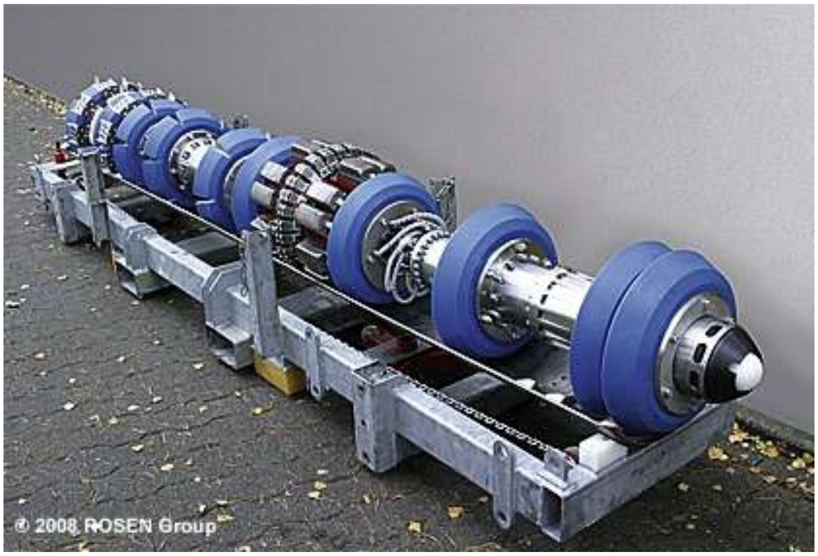


Source: Internal Inspection Optimization Program - R&D Roadmap. Gas Technology Institute. Report No. 21227. 2012.

Magnetic Flux Leakage Technology

MFL tools use powerful magnets to create a saturating magnetic field into the pipe material. The disruption or "leak" of the magnetic flux is detected by sensors located around the circumference of the tool as shown in Figure 25. The technology uses a multi-segment pigging tool with a magnetizer and sensors in one segment, and data storage components, power supply, and other sensors in additional segments.

Figure 25: Magnetic Flux Leakage and Ultrasonic Testing In-Line Inspection Tool



Source: http://www.offshore-technology.com/contractors/pipeline_inspec/rosen/rosen2.html

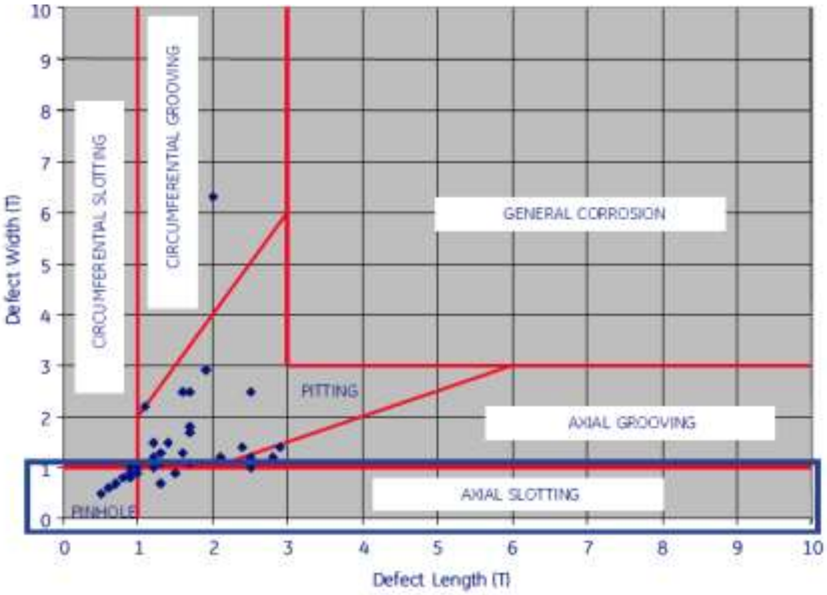
Data can be interpreted to establish the dimensions of the metal loss. Secondary sensors make it possible to discriminate between internal and external metal loss. The technology is used to detect corrosion, metal loss due to mechanical damage, and can effectively size metal loss to about 5 percent wall thickness. The technology is good in detecting circumferential cracks but not suitable for axial cracks. This depends on the alignment of the magnetic field. If aligned axially, it will detect circumferential anomalies better; if aligned circumferentially, it will better detect axial anomalies.

The technology is the most common ILI application and it is applied at various resolutions and detection ranges. However, it requires large data management and causes long term magnetization of pipe.

MFL is an indirect measurement system and models are used to translate the signals recorded by the tool into estimations of pipeline wall loss feature depth, length and width. Improvements in the application of MFL technology and in MFL data analysis have been reported such as the latest generation MFL tools. These new tools cover a wider range of defects as shown in Figure 26. Additionally, new combinations of ultrasound and MFL technologies have been developed. EMAT sensors use coils for sending and receiving ultrasound. These coils are also used to pick up the MFL signals. The availability of these simultaneous and independent measurements allows for considerable improvement regarding both defect sizing and feature discrimination.[33]

The depth sizing performance of ILI tools for dents show a tool tolerance as accurate as ± 1.5 percent outer diameter at 80 percent certainty and 95 percent confidence level, depending on ILI tool diameter. The depth sizing performance for dent with metal loss was found to be approximately ±12 percent, which is slightly higher but comparable to that for metal loss in the pipe body. However, the use of the sensors over complex shape or severe deformations can adversely affect detection and sizing performance.

Figure 26: Pipeline Operators Forum Categorization for Various Defect Types



See [Pipelines Operators Forum](https://www.pipelineoperators.org/) (https://www.pipelineoperators.org/) for more information.

Source: Internal Inspection Optimization Program - R&D Roadmap. Gas Technology Institute. Report No. 21227. 2012.

Eddy-Current Technology

This technology uses electromagnetic coils to induce eddy currents near the pipe the surface. The current sets up magnetic fields within the wall that oppose the original magnetic field. The impedance of the coils is affected by the induced current, which is distorted by the presence of flaws. The technology is used to assess wall thickness, pitting, cracks, and laminar defects.

The technology is non-contact with no residual effect but sensitive to distance variations. It has a relatively slow response that limits its ILI application and it is also commonly used in external inspection.

In-Line Inspection Platforms

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[33] Validation of Latest Generation MFL In-Line Inspection Technology Leads to Improved Detection and Sizing Specification for Pinholes, Pitting. Axial Grooving and Axial Slotting, 8th International Pipeline Conference (IPC2010). Calgary. Alberta, Canada. 2010.

Current ILI sensors require advanced platforms to carry the sensors inside the pipe and provide the power supply and other operational requirements. Additionally, inspection of small diameter unpiggable pipes require the development of advanced platforms that can be launched and retrieved in live conditions. The main requirements for these platforms include:

- Ability to accommodate diameter changes across the pipeline and directional changes such as curves and bends. The system also must be able to navigate the connections between main pipelines and laterals or distribution lines.
- Ability to provide typical ILI devices with electrical power by a cable system. This is especially needed in distribution lines where flow direction is not commonly identified.
- Ability to insert and retrieve the ILI device. This requires technical and capital investment to install launchers and receivers in distribution system.

Significant developments of ILI inspection platforms were recently carried out by the Northeast Gas Association (NYSEARCH) to address new requirements for unpiggable pipes inspection. Table 18 provides a summary of the ILI technologies based on their functionality and inspection purpose.

In response to the NTSB recommendations, a study by the America Gas Association and Interstate Natural Gas Association of America (INGAA) provided a comprehensive review of current ILI sensors and highlighted the primary requirements for their advancement:[34]

- Navigation: ILI devices need to accommodate diameter changes across the pipeline and directional changes such as curves and bends. The system also must be able to navigate the connections between main pipelines and laterals or distribution lines.
- Motive power: Typical ILI devices are transported by the flow of the natural gas in the line or externally powered by a cable system. This may present technical difficulties in distribution lines where flow direction is not commonly identified.
- Access: The ability to insert and retrieve the ILI device requires technical and capital investment to install launchers and receivers in distribution system.

Recent significant developments of ILI inspection platforms and non-destructive testing tools address most of the limitations of current ILI tools. Table 19 shows examples of close-to-commercialization technologies in this area.

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[34] Report to the NTSB on Historical and Future Development of Advanced In-Line Inspection Platforms for use in Gas Transmission Pipelines. INGAA and AGA. 2012.

Table 18: In-Line Inspection Technologies Based on Inspection Purposes

Imperfection/ Defect/ Feature	Metal Loss Tools (1)	Metal Loss Tools (2)	Metal Loss Tools (3)	Crack Detection Tools (1)	Crack Detection Tools (2)	Deformation Tools
Flat dents	Detection(E)(G)	Detection(E)(L)	Detection(E)(G)	Detection(E)(G)	Detection(E)(G)	Detection,(F) sizing
Buckles	Detection(E)(G)	Detection(E)(L)	Detection(E)(G)	Detection(E)(G)	Detection(E)(G)	Detection,(F) sizing
Wrinkles, ripples	Detection(E)(G)	Detection(E)(L)	Detection(E)(G)	Detection(E)(G)	Detection(E)(G)	Detection,(F) sizing
Ovalities	No detection	No detection	No detection	No detection	No detection	Detection,(B) sizing

Miscellaneous Components	Metal Loss Tools (1)	Metal Loss Tools (2)	Metal Loss Tools (3)	Crack Detection Tools (1)	Crack Detection Tools (2)	Deformation Tools
In-line valves and fittings	Detection	Detection	Detection	Detection	Detection	Detection
Casings (concentric)	Detection	Detection	No detection	No detection	Detection	No detection
Casings (eccentric)	Detection	Detection	No detection	No detection	Detection	No detection
Bends	Limited detection	Limited detection	Limited detection	Limited detection	Limited detection	Detection,(H) sizing(H)
Branch appurtenances/ hot taps	Detection	Detection	Detection	Detection	Detection	No detection
Close metal objects	Detection	Detection	No detection	No detection	Detection	No detection
Thermite welds	No detection	No detection	No detection	No detection	No detection	No detection
Pipeline coordinates	No detection	Detection(K)	Detection(K)	Detection(K)	Detection(K)	Detection(K)

Previous Repairs	Metal Loss Tools (1)	Metal Loss Tools (2)	Metal Loss Tools (3)	Crack Detection Tools (1)	Crack Detection Tools (2)	Deformation Tools
Type A repair sleeve	Detection	Detection	No detection	No detection	Detection	No detection
Composite sleeve	Detection(I)	Detection(I)	No detection	No detection	Detection(I)	No detection
Type B repair sleeve	Detection	Detection	Detection	Detection	Detection	No detection
Patches/half soles	Detection	Detection	Detection	Detection	Detection	No detection
Puddle welds	Limited detection	Limited detection	No detection	No detection	Limited detection	No detection

Table 18 [Continued]: Types of In-Line Inspection Technologies Based on Inspection Purposes

Miscellaneous Damage	Metal Loss Tools (1)	Metal Loss Tools (2)	Metal Loss Tools (3)	Crack Detection Tools (1)	Crack Detection Tools (2)	Deformation Tools
Laminations	Limited detection	Limited detection	Detection,sizing$^{(B)}$	Limited detection	Limited detection	No detection
Inclusions (lack of fusion)	Limited detection	Limited detection	Detection,sizing$^{(B)}$	Limited detection	Limited detection	No detection
Cold work	No detection	No detection	No detection	No detection	No detection	No detection
Hard spots	No detection	Detection$^{(J)}$	No detection	No detection	No detection	No detection
Grind marks	Limited detection$^{(A)}$	Limited detection$^{(A)}$	Detection$^{(A)(B)}$	Detection$^{(A)(B)}$	Limited detection$^{(A)(B)}$	No detection
Strain	No detection	No detection	No detection	No detection	No detection	Detection$^{(J)}$
Girth weld anomaly (voids, etc.)	Limited detection	Detection	Detection	Detection$^{(D)}$	No detection	No detection
Scabs/slivers/ blisters	Limited detection$^{(A)}$	Limited detection	Detection$^{(A)(B)}$	Detection$^{(A)(B)}$	Limited detection$^{(A)}$	Limited detection

(A) Limited by the detectable depth, length, and width of the indication.

(B) Defined by the sizing accuracy of the tool.

(C) Reduced probability of detection for tight cracks.

(D) Transducers to be rotated 90 degrees.

(E) Reduced probability of detection depending upon size and shape.

(F) Also circumferential position, if tool is equipped.

(G) Sizing not reliable.

(H) If tool is equipped for bend measurement.

(I) Composite sleeve without markers is not detectable.

(J) If tool is equipped, dependent on parameters.

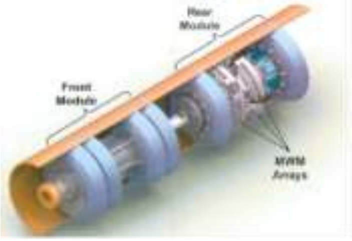
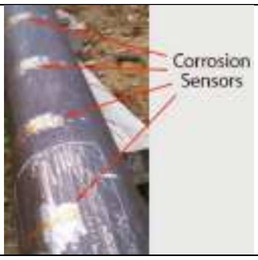
(K) If tool is equipped with mapping capabilities.

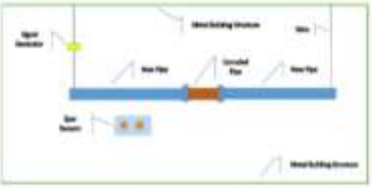
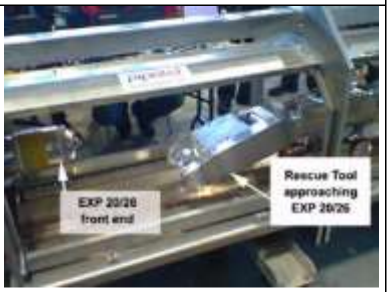
(L) Sizing is tool dependent.

(M) In-line inspection technologies that can be used only in liquid environments, that is liquids pipelines or in gas pipelines with a liquid couplant.

Source: Standard Practice, In-Line Inspection of Pipelines, NACE International, SP0102-2010

Table 19: Close-to-Commercial Technologies for Anomaly Detection and Characterization

Description	Technical Advancement	Image
In-Line EMAT Technologies[(a)] In-Line Inspection Technology to detect, locate, and measure pipeline girth welds.	The technology uses an EMAT Girth Weld scanner (GWS) module mounted on existing remotely operated diagnostic inspection system (RODIS).	
In-Line EMAT Technologies[(a)] A device that can be pulled via an umbilical through pipe and uses Electromagnetic Acoustic Transducer (EMAT) to detect and quantify longitudinal cracks.	A laboratory bench-scale unit has been completed in Phase-1. The prototype runs in 8-inch pipes with a commercial target to test 6- to 12-inch unpiggable pipes.	
Eddy-Current Based Sensors[(b)] An anisotropic magneto resistive (AMR) eddy current (EC)-based sensor for live, in-line inspection of 6- to 8-inch diameter, unpiggable natural gas pipelines.	Eddy current-based technology, developed by RMD Inc., can be integrated onto the Explorer 6 - 8 inches robotic platform.	
Eddy-Current Based Sensors[(b)] Structured Waveform Magnetic Field (SWMF) and Low-Frequency Eddy Current with Saturating Field for ERW weld crack detection, internal and external corrosion imaging, and longitudinal stress mapping.	These technologies have the potential to produce an ILI tool that provides ID, mid-wall, and outer diameter defect inspection for corrosion and cracks.	
Sensor-Based Systems[(c)] Real-time active pipeline integrity detection (RAPID) consists of a network of sensors placed on new and existing pipelines at regular intervals. The sensors are small piezoelectric sensors embedded in a thin dielectric film applied on the pipelines.	Structural health monitoring (SHM) is increasingly being evaluated by the pipeline industry as an alternative method to improve the safety, reliability, and reduce operational costs of pipeline systems	
Sensor-Based Systems[(c)] State-of-the-art corrosion sensors. While primarily applied to coated steel, these sensors can measure corrosion rates in real time on the external surfaces of pipe using a unique linear sensor array.	The sensors measure corrosion rates in real-time specifically in conditions where corrosion potential is known or suspected to exceed the norm	

Description	Technical Advancement	Image
ECDA Inspection(d) Above-Ground Detection Tool for disbondment and metal loss. Alternating current is applied to the pipe, generating magnetic fields that are affected by corrosion and disbondment. A suite of sensors moves along the pipe at specific intervals to take readings.	The Above-Ground Detection Tool (ADT) consists of a mobile platform for detecting coating disbondment, graphitization and external corrosion by measuring the pipe magnetic field signatures from above ground.	
In-Line Inspection Platforms(e) The Explorer (EXP) 20/26 Cleaning Tool consists of an array of brushes mounted on the commercial EXP robot, which is used to conduct in-line inspections of live, unpiggable natural gas pipelines.	The tool carries the debris downstream to a diverter assembly that directs the dirt-contaminated gas stream through a coalescing filtration system. This cleaning technology improves the ability to conduct inspection.	
In-Line Inspection Platforms(e) A rescue tool used with the Explorer 20/26 Unpiggable Pipeline Inspection Platform. The tool provides in-line assistance to the inspection robot in case of malfunction or problems with battery supply or wireless communication.	The technology addresses one of many challenges faced during in-line inspections with tetherless inspection platforms.	
In-Line Inspection Platforms(e) Explorer 30/36 The Explorer 30/36 tool is an addition to the line of pipeline robots, including Explorer 6/8, Explorer 10/14 and Explorer 20/26. The system is battery-powered to inspect 30 to 36-inch pipe diameters.	Unlike traditional “smart pigs” used for in-line inspection and propelled by natural gas within the pipeline, the untethered Explorer is battery-powered and controlled wirelessly. This allows it to navigate through live pipelines that are considered unpiggable.	

(a) In-Line Inspection Technology to Detect, Locate, and Measure Pipeline Girth Weld Defects - A Field Demonstration. California Energy Commission, Report CEC-500-2015-028. February 2015; EMAT Technology for Unpiggable Pipes. PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=653).

(b) Eddy Current-Based Crack Detection Sensor, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=648); Integrity Assessment Using In-Line Inspection, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=562).

(c) Real-Time Active Pipeline Integrity Detection System. California Energy Commission. Report CEC-500-2015-095, 2015; State-of-the-Art Corrosion Sensors, NYSEARCH (http://www.nysearch.org/news-info_110216.php).

(d) Above-Ground Detection Tool for Disbondment, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=500).

(e) Explorer (EXP) 20/26 Cleaning Tool, NYSEARCH (http://www.nysearch.org/news-info_110216.php); Explorer 20/26 Unpiggable Pipeline Inspection Platform, NYSEARCH (http://www.nysearch.org/news-info_110216.php); Explorer 30/36, NYSEARCH (http://www.nysearch.org/news-info-item1.php).

Source: Gas Technology Institute

Pipeline Testing and Stress Analysis

The development of technologies to evaluate residual stresses in the pipeline provides estimates of the remaining strength of damaged pipes and their fitness-for-service.

Induced stresses on pipelines typically result from pipe installation (such as in wrinkle bends) and additional soil loads caused by ground movement (such as in landslides and earthquakes). Nondestructive tests on excavated pipe sections include methods such as ultrasonic testing of remaining wall thickness, magnetic particle testing for cracks, and mapping techniques to size and analyze stresses.

Most of the technologies developed for pipeline stress analysis identify its mechanical properties such as material modulus and hardness, rank and screen the defects, and analyze the structural significance of the damage. This information is critical to evaluate fitness-for-service and to create guidelines for pipeline repair or replacement decisions.

Methods for estimating the state of stresses in the pipeline involve a variety of techniques including sensors, mapping of the pipe surface for cracks and metal loss, and data management procedures for optimum data integration into the integrity management programs. Table 20 shows examples of commercially available technologies.

Table 20: Current Stress Analysis Technologies

Technology	Description	Technical Advancement
Nondestructive Pipeline Stress Assessment(a)	The G2MT's eStress system is used in the residual stress assessment of pipeline damage. The inspection tool measures residual stresses around pipeline damage areas to determine susceptibility to failure.	The technology is coupled with advanced modeling techniques to quantitatively measure local stress and map stress around the entire area.
Hardness Tester in live transmission pipes(b)	Integrates an in-line non-destructive tool for the quantification of material properties (toughness and strength) for piggable and unpiggable natural gas pipelines. The device performs indentation tests for toughness measurements	The device is integrated onto the commercial Explorer 20/26 inspection platform. The design is scalable to other pipe sizes.
Dynamic Response Spectroscopy (DRS)(c)	An ultrasonic inspection technique for corrosion mapping through coatings and composite wraps, where existing ultrasonic techniques are ineffective. The DRS probe excites the steel pipe with a range of low ultrasonic frequencies, which pass easily through the coating/ wrap.	This technique has been designed to look through the composite repairs to measure the remaining wall thickness of the underlying metallic pipe.
Leak-Rupture Boundary Calculator(c)	The project provided a calculator for the operators to determine the leak-rupture boundary of a pipe segment based on properties such as its diameter, toughness, and yield strength. The operators can use the calculator for risk modeling and consequence analysis.	The calculator determines if the pipe segment would fail by leak instead of rupture when operated at a specific percentage of SMYS with known yield strength, toughness, diameter, and wall thickness.

(a) Nondestructive Residual Stress Assessment System, Generation 2 Materials Technology (http://www.g2mt.com/).

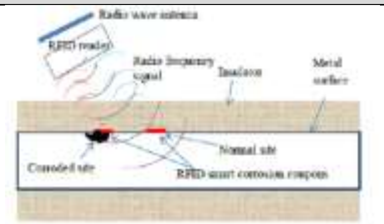
(b) Hardness Tester for Quantification of Material Properties in Live Natural Gas Transmission Pipelines (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=646).

(c) DRS corrosion Mapping, Sonomatic Inc. (http://www.sonomatic.com/advanced-inspection/applications/pipelines/).

Source: Gas Technology Institute

Table 21 shows examples of close-to-commercialization systems.

Table 21: Close-to-Commercial Technologies for Stress Analysis

Technology Description	Technical Advancement	Image
Sensor-Based Systems[(a)] Use radio frequency identification (RFID) technology. The coupons emit signals indicating the corrosion status. The passive RFID tags act like conventional corrosion coupons.	The “smart” corrosion coupons combine the advantages of RFID technology and the conventional corrosion coupon to develop a better corrosion management system.	
Sensor-Based Systems[(a)] Electromagnetic sensors to quantify strength and toughness in steel pipelines. The characterization testing provides improved reliability-based Integrity Management.	This nondestructive testing technology is linked with other inspection methods for real-time evaluation of pipeline mechanical properties.	
Sensor-Based Systems[(a)] Micro-electro-mechanical sensors (MEMS) are low-cost solution to provide real-time data for pipeline integrity. Micro-fabrication techniques are used to produce small and inexpensive sensors to measure many variables.	The sensors perform several measurements relevant to gas pipelines, such as instantaneous gas pressure, gas flow velocity, humidity inside the pipe, and vibration of the pipe.	
Laser Peening for Pipe Corrosion and Failure[(b)] Laser peening employs laser-induced shock waves to create compressive residual stress in the metal surfaces of pipelines, which significantly enhance their corrosion resistance.	The laboratory system uses Nd:YAG laser with a pulse energy of ~ 650 mJ with lens groups, a beam delivery system, a control system, and a power system to construct a compact laser peening system.	

(a) Radio Frequency Identification Smart Corrosion Coupon, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=505); Electromagnetic Sensors to Quantify Strength and Toughness, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=649); Low-Cost Sensors for Natural Gas Pipeline Monitoring and Inspection, California Energy Commission, Report CEC-500-2014-104. Jan. 2015.

(b) Laser Peening for Pipe Corrosion, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=570).

Source: Gas Technology Institute

Technologies for Pipeline Risk and Information Management

The current approach to pipeline risk analysis uses historical data, pipeline age, operational characteristics, and leak and corrosion records to identify high-risk segments for repair and replacement. This analysis commonly uses risk scales developed from system data, subject matter experts, and probability estimates to establish and rank the likelihood of failures. However, this approach does not account for combined threats or pipe material characteristics.

Furthermore, assessment technologies rely heavily on the quantity and quality of available data. Data collection and communications technologies depend on the frequency of collection, accuracy and precision, and the systems used to communicate and integrate the data. New research and development focus on the use of large arrays of low-cost and powerful sensors to provide data on deformation, conditions influencing corrosion potential such as temperature and soil chemistry, local operational parameters, and flow. The availability of real-time data from sensors has made continuous monitoring of the gas system possible.

New technologies for system risk modeling and emergency response technologies provide new focus on preventing failure through GIS systems and integrated risk analysis and they include:

- Failure prediction models; incorporating accurate operators' data and the output of adequate inspection protocols.
- Risk models, including consideration of the combined threats and adequately measuring the effectiveness of the integrity management assessment.
- Methods and procedures to improve traceability records for the pipeline system.
- Technologies that focus on decreasing the consequences of failure, including systems for emergency automatic shut off of gas meters and high-pressure lines.
- Approaches that incorporate public awareness programs and procedures for responding to emergencies.

These technologies incorporate mapping and pipeline infrastructure information in interactive formats for emergency response and communication. This information includes system maps, aerial photography, and written procedures for situational awareness and response in cases of pipeline incidents. Significant advances in GPS technology in recent years has expanded GPS use in daily pipeline operations by increasing efficiency, facilitating regulatory compliance, and improving the quality of field data.

Finally, recent advances in the Internet-of-Things have enabled the development of powerful predictive models that can analyze the sensors' data in real time and provide a visual dashboard of the current system status.

System Security

Natural gas pipeline operators are required to establish and implement protocols and procedures for managing security related threats, incidents, and responses.[35] These procedures

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[35] Pipeline Security Guidelines, Transportation Security Administration, April 2011.

address the physical threats (to pipelines and facilities and automatic shutoff valves) and cyber security threats (to supervisory control and data acquisition and remote-control systems).

The National Institute of Standards and Technology (NIST) developed a framework for reducing cyber risks through the establishment of standards, procedures, and processes. NIST released its cybersecurity framework for use across all critical infrastructure sectors.[36] In parallel, USDOE developed the Cybersecurity Capability Maturity Model (C2M2).

C2M2 provides a measurement and investment decision tool a company can use to assess their implementation status of the NIST framework.

Situation Awareness

The development of Situational Awareness systems aims at "understanding the current environment and being able to accurately anticipate future problems to enable effective actions."[37] Energy companies, and specifically electric utilities, are increasingly developing mechanisms to capture, transmit, and analyze real-time or near-real-time data to detect anomalous conditions in their grid systems and take appropriate actions to remediate them.[38]

However, there is still a need in the natural gas sector to investigate and integrate such mechanisms into risk assessment programs. Moreover, recent investigations recognize the need to integrate critical infrastructures such as electricity, natural gas, communications, water, and waste water as they become increasingly dependent on one another. The objective of these SA systems is to allow operators to share the location of control devices or system status information with other organizations. Research in this area aims at providing the following:

- Increased situational awareness related to threat identification, preparation, and restoration. This is mainly achieved through incident prediction information and data supplied to the responders and public through selective and general information.
- High-quality, reliable data for effective decision making, including live geospatial representation of the system available for analysis.
- Automated processes that significantly reduce the risk of errors.
- Quick information exchange to meet time-critical demands. This includes interactive status update display of all services in the area and coordinated planned activities.

The end result would be a system that provides the opportunity for improved resilience for all infrastructure operators through pre-disaster planning, training and mitigation efforts followed by more rapid restoration during and following a disaster.

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36 Framework for Improving Critical Infrastructure Cybersecurity. National Institute of Standards and Technology. January 2017.

37 Pacific Northwest National Laboratory (PNNL). United States Department of Energy. http://eioc.pnnl.gov/research/sitawareness.stm

38 Situational Awareness for Electrical Utilities. National Institute of Standards and Technology. NIST Special Publication 1800-7. February 2017.

Recent research projects in this area includes the development of an integrated situational assessment approach funded by the Department of Homeland Security Research[39] and promoting situational awareness through high accuracy mapping during emergencies[40] funded by the Energy Commission. The technologies presented in Table 22 and Table 23 present examples of available and close-to-commercialization technologies in this area.

Table 22: Current Risk Modeling Systems

Technology	Description	Technical Advancement
Distribution Integrity Management Risk Model(a)	The software enables gas distribution network and pipeline operations to document risk, and schedule and track inspection and compliance activities. It fits into existing GIS and enterprise management systems.	The software integrates the early version of "Uptime" software and data management system for the integrity management of gas distribution and transmission pipeline assets.
Leak-Rupture Boundary Calculator and Training Manual(b)	A calculator for the operators to determine the leak-rupture boundary of a pipe segment based on properties such as its diameter, toughness, and yield strength.	The calculator determines if the pipe segment would fail by leak instead of rupture when operated at a specific percentage of SMYS with known yield strength, toughness, diameter, and wall thickness.
Mobile GIS Solution for Traceability of Pipes(c)	Locus Map software is used in new distribution lines installations for tracking and traceability and collecting data for pipes, fittings, and joints.	The software is a mobile GIS tool creating features directly in a GIS format and allows field-collected data to be directly integrated into the enterprise GIS with minimal back-office processing. Barcode scanning and high-accuracy GPS automate data entry in the field and create high-accuracy maps.

(a) Distribution Integrity Management Risk Mode. GL Noble Denton, DNV.GL.

(b) Leak-Rupture Boundary Calculator. Operations Technology Development (OTD). Report 4.9.a. 2012.

(c) Mobile GIS Solution for Traceability. LocusView, www.locusview.com.

Source: Gas Technology Institute

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[39] Developing a Gas Situational Awareness System (GSAS) for Emergency Response. http://www.gastechnology.org/Solutions/Pages/Developing-a-GSAS-4-Emergency-Response.aspx

[40] High Accuracy Mapping for Excavation Damage Prevention and Emergency Response. California Energy Commission. Project PIR-15-014, 2016.

Table 23: Close-to-Commercial Technologies for Risk and Situation Awareness

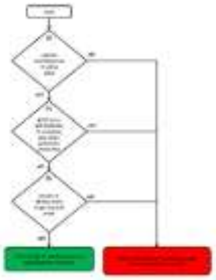
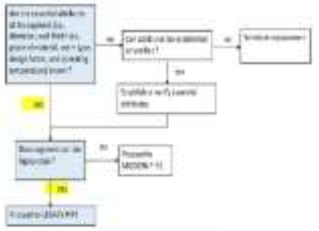
Technology	Description	Technical Advancement	Image
High Accuracy Mapping for Damage Prevention and Emergency Response	The technology reduces excavation damage and builds a situational awareness tool for operations and emergency response. The workflow supports the business processes.	The technology will enable more effective and systematic decisions. This will improve pipeline safety, reduce losses during unanticipated events, and reduce operating costs.	
Models for Complex Loadings, Operational Considerations, and Interactive Threats	Reportable accidents are evaluated to determine the types and frequencies of interacting threats. The model develops guidance for operators to identify and evaluate complex, higher-risk situations involving interactions.	An analysis to determine the interacting threats and form procedures to evaluate the significant threat interactions. The analytical tool is presented in the form of flow charts to consider mitigative responses to reduce the risk of a pipeline failure.	
Gas Situational Awareness System (GSAS) for Emergency Response	The system is used for response by more than one emergency responder. The data model is a collection of tables describing the information to be tracked. The data incorporated will be used for required reporting to all levels of regulatory authority.	Provide status information to all responders allowing them to know the extent of the event and the other infrastructure, such as roads, bridges, electric status within the impacted area.	
Risk Analysis	The risk model for Adyl-A plastic pipes is an integrated set of quantitative tools that provide an approach to reducing risk in vintage plastic pipes susceptible to slow crack growth failures. An endoscopic structured light scanning tool was developed for internal inspection of small diameter pipes.	The data generated are synthesized with available properties such as external conditions, leak records, and historic fitness-for-service evaluations. The assessment includes a probabilistic estimate of the remaining effective lifetime of vintage plastic pipe.	

Table 23 (continued): Close-to-Commercial Technologies for Risk and Situation Awareness

Technology	Description	Technical Advancement	
	Repair/Replacement Considerations for “pre-regulation” pipes provide a standardized method for operators to decide which of their pre-regulation pipelines can be maintained safely or replaced.	The guidelines address pre-regulation pipeline repair/replacement programs. “Pre-regulation” generally refers to pipelines installed prior to November 1970, when Federal safety regulations were promulgated.	

(a) High Accuracy Mapping for Damage Prevention. California Energy Commission. Project PIR-15-014. 2016.

(b) Models for Complex Loadings, Operational Considerations, and Interactive Threats, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=557).

(c) Developing a Gas Situational Awareness System (GSAS) for Emergency Response, Gas Technology Institute (http://www.gastechnology.org/Solutions/Pages/Developing-a-GSAS-4-Emergency-Response.aspx).

(d) Slow Crack Growth Evaluation of Vintage PE Pipes, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=643): Repair/replacement Considerations for “pre-regulation” pipes, PHMSA (https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=559).

Source: Gas Technology Institute

CHAPTER 5:
Web-Based Technology Database

This chapter presents a catalog of the status and applicability of the available technologies in a database and web-based program for access by the pipelines and utilities operators. The catalog consists of the following:

- A summary of each technology, its applicable conditions and scope and development status.
- A database management system to tabulate the data with key characteristics
- A web-based program for the access and search of the database.

Database Management Program

Figure 27 shows the main page of the web-based program, Pipeline Safety and Integrity Technologies Database, http://gasapps.gastechnology.org/webroot/app/techindex.

Figure 27: Web Program Main Page

Pipeline Safety and Integrity Technologies Search

A database search of natural gas pipeline safety and Integrity monitoring technologies. The database provides an assessment of recently completed and close-to-market technologies which monitor pipeline threats, improve pipeline performance, and reduce operation costs for the natural gas pipelines in California.

Background

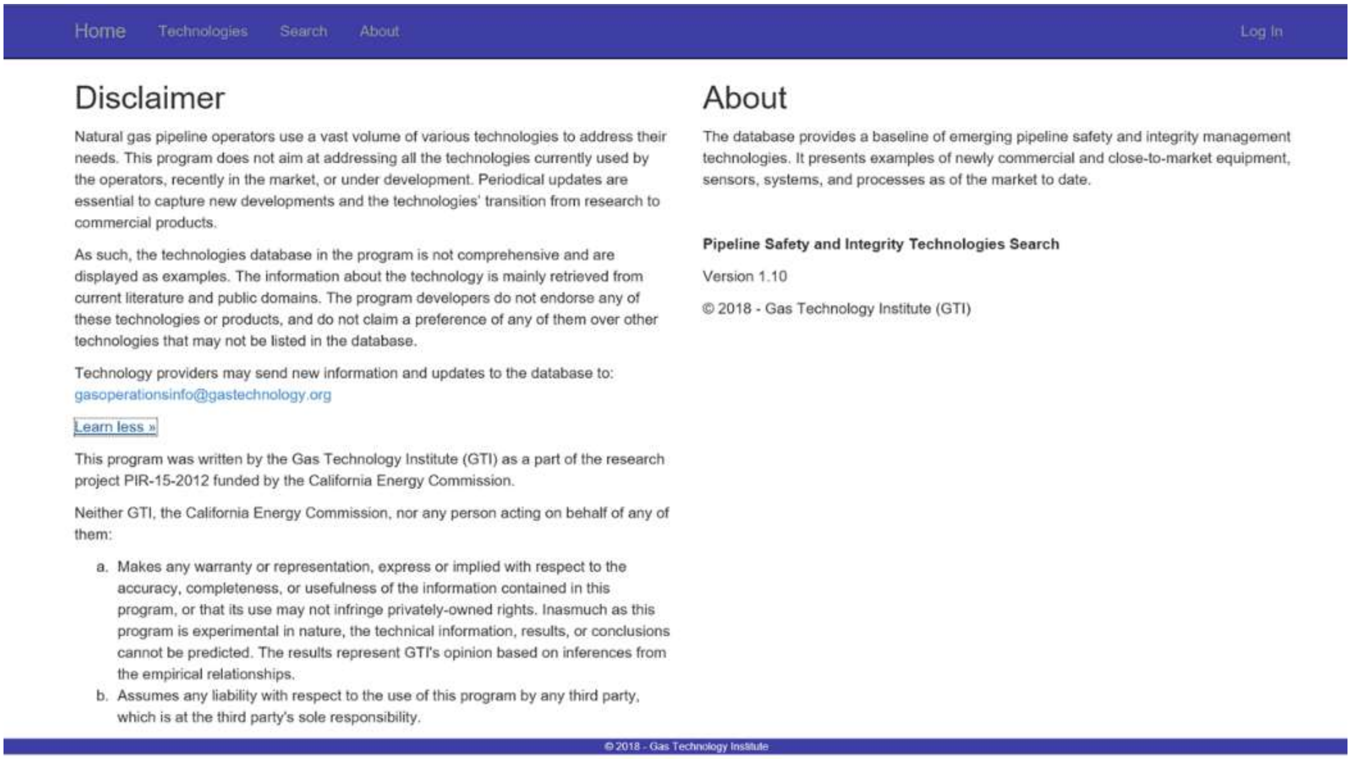
1. Damage Prevention and Mitigation:
    - Pipe locating, Leak, and Excavation Damage Detection
    - Damage Mitigation
2. Threats and Integrity Management:
    - Anomaly Detection and Characterization
    - Pipeline Testing, Analysis, and Repair
3. Pipeline Risk and Information Management:
    - Data Management and Information Systems
    - System Risk Modeling and Security

Acknowledgement

Source: Gas Technology Institute

The main page includes a project background describing the database and the main areas of the technologies in the database. These areas are based on the three main technology groups identified in Chapter 4. The top bar allows navigation between a list of the technologies, a search engine and the program disclaimer shown in Figure 28.

Figure 28: Database Disclaimer and Description



Disclaimer

Natural gas pipeline operators use a vast volume of various technologies to address their needs. This program does not aim at addressing all the technologies currently used by the operators, recently in the market, or under development. Periodical updates are essential to capture new developments and the technologies' transition from research to commercial products.

As such, the technologies database in the program is not comprehensive and are displayed as examples. The information about the technology is mainly retrieved from current literature and public domains. The program developers do not endorse any of these technologies or products, and do not claim a preference of any of them over other technologies that may not be listed in the database.

Technology providers may send new information and updates to the database to: gasoperationsinfo@gastechnology.org

This program was written by the Gas Technology Institute (GTI) as a part of the research project PIR-15-2012 funded by the California Energy Commission.

Neither GTI, the California Energy Commission, nor any person acting on behalf of any of them:

a. Makes any warranty or representation, express or implied with respect to the accuracy, completeness, or usefulness of the information contained in this program, or that its use may not infringe privately-owned rights. Inasmuch as this program is experimental in nature, the technical information, results, or conclusions cannot be predicted. The results represent GTI's opinion based on inferences from the empirical relationships.
b. Assumes any liability with respect to the use of this program by any third party, which is at the third party's sole responsibility.

About

The database provides a baseline of emerging pipeline safety and integrity management technologies. It presents examples of newly commercial and close-to-market equipment, sensors, systems, and processes as of the market to date.

Pipeline Safety and Integrity Technologies Search

Version 1.10

© 2018 - Gas Technology Institute (GTI)

© 2018 - Gas Technology Institute

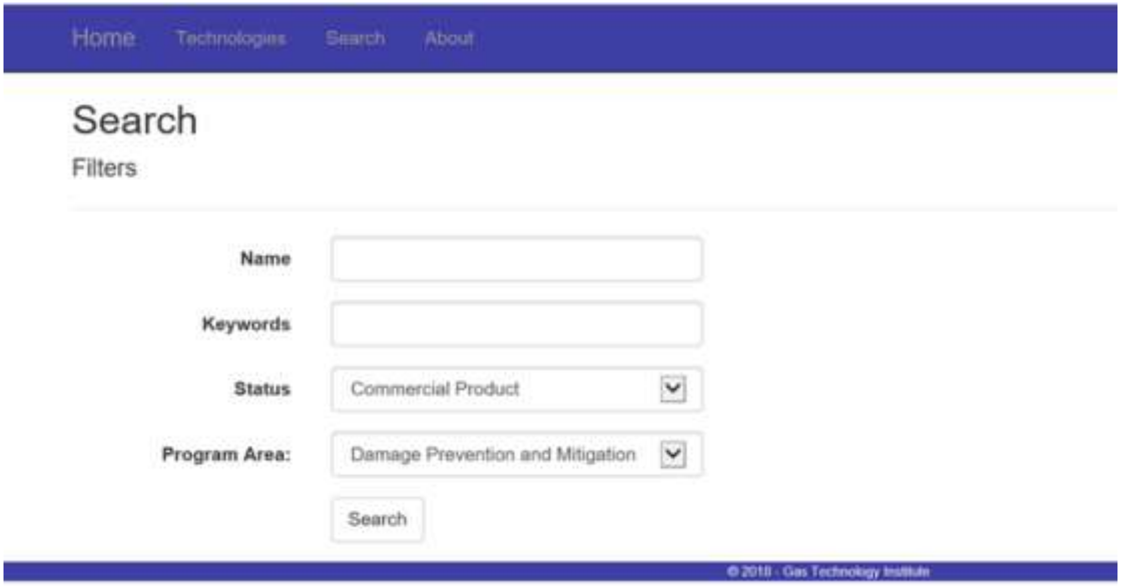
Source: Gas Technology Institute

The search engine provides search options by the name of the technology and keywords of the technologies, developers, and related applications. The "Status" option filters the search based on the following categories:

- Commercial products in the market
- Projects resulting in developed guidelines and procedures
- Technologies under development.

The list of commercial products focuses on products introduced to market in the last 2-5 years. A "Program Area" option enables further filtering of technologies based on the three program areas of Damage Prevention and Mitigation, Threats and Integrity Management, and Risk and Data Management. Figure 29 shows the search engine page.

Figure 29: Technologies Search Engine



Search

Filters

Name

Keywords

Status Commercial Product

Program Area: Damage Prevention and Mitigation

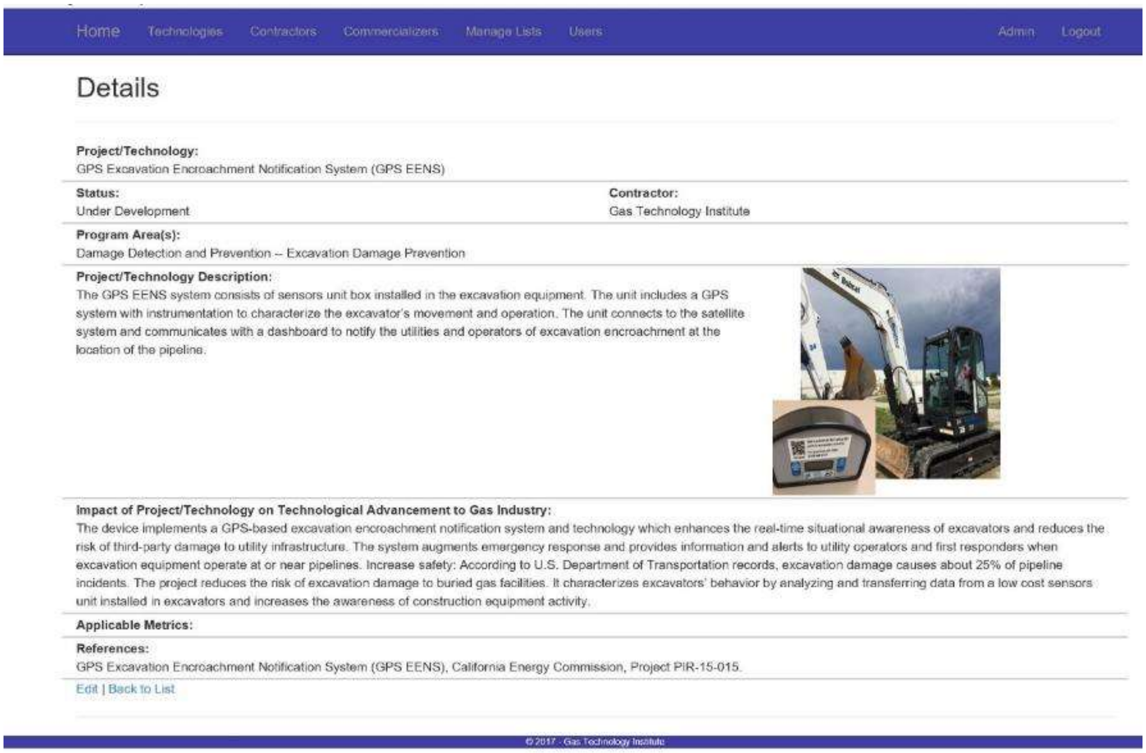
Source: Gas Technology Institute

Web-Based Database Catalog User's Manual

The selected technologies are displayed in the format shown in Figure 30. The display provides the following information:

- Project name and type of the technology
- Project status (commercial product or under-development)
- Technology developers and commercializer information for technologies already in the market
- A description of the technology and its function
- Impact of the technology on the technical advancement of the gas industry. The impact identifies the potential benefits. The Applicable metrics for identifying this impact are:
    - Increased safety
    - Reduce operations cost
    - Greater reliability
    - Environmental benefits
- A list of the references related to the specified technology

Figure 30: Database Details of Selected Technology



Details

Project/Technology:
GPS Excavation Encroachment Notification System (GPS EENS)

Status:
Under Development

Contractor:
Gas Technology Institute

Program Area(s):
Damage Detection and Prevention -- Excavation Damage Prevention

Project/Technology Description:
The GPS EENS system consists of sensors unit box installed in the excavation equipment. The unit includes a GPS system with instrumentation to characterize the excavator's movement and operation. The unit connects to the satellite system and communicates with a dashboard to notify the utilities and operators of excavation encroachment at the location of the pipeline.

Impact of Project/Technology on Technological Advancement to Gas Industry:
The device implements a GPS-based excavation encroachment notification system and technology which enhances the real-time situational awareness of excavators and reduces the risk of third-party damage to utility infrastructure. The system augments emergency response and provides information and alerts to utility operators and first responders when excavation equipment operate at or near pipelines. Increase safety: According to U.S. Department of Transportation records, excavation damage causes about 25% of pipeline incidents. The project reduces the risk of excavation damage to buried gas facilities. It characterizes excavators' behavior by analyzing and transferring data from a low cost sensors unit installed in excavators and increases the awareness of construction equipment activity.

Applicable Metrics:

References:
GPS Excavation Encroachment Notification System (GPS EENS), California Energy Commission, Project PIR-15-015.

Source: Gas Technology Institute

CHAPTER 6:
Assessment of Selected Technologies

The investigation identified various commercial and close-to-market equipment, sensors, systems, and processes that enhance the response to pipeline threats in transmission and distribution pipelines integrity management plans.

Technical requirements and technology needs vary between transmission and distribution pipeline systems. These two systems differ in terms of their material types, pipe sizes, operating pressures, age, control systems, and data transfer and management capabilities. These differences resulted in different requirements for their operation, inspection protocols, and environmental and risk consequences. Accordingly, different technologies may be developed to address the requirements of each system. In general, development needs and technology gaps fall in the following categories:

- Damage detection and failure prevention:
    - Pipeline locating with devices that recognize and pinpoint non-metallic pipes
    - Real-time monitoring of excavation damage using remote sensing technologies and devices installed in the right-of-way. These devices include appropriately-spaced flow and pressure transmitters along the length of covered lines.
    - Damage mitigation approaches, repairs, and procedures that prevent rupture and catastrophic failures.
- Threat identification and integrity management:
    - Technologies that focus on improving the detection of defects that result from mechanical damage, corrosion, welding, and manufacturing. These technologies include ILI sensors, which can identify weld defects and line cracks, and advanced ILI platforms in unpiggable pipelines.
    - Effective material characterization and failure prediction models; incorporating accurate operators' data and the output of adequate inspection protocols.
- Pipeline risk and information management:
    - These technologies focus on data management and information systems to accurately identify and categorize pipeline risks. These technologies include:
        - Methods to improve data management and traceability records for construction, operations, and maintenance.
        - Updated risk models to include consideration of the combined threats, incorporating adequate measurements of the effectiveness of the integrity management assessment.
        - Systems for emergency response, situational awareness, and automatic shut off during pipeline incidents.

This chapter provides the basis for the selection of close-to-commercialization technologies to introduce to the natural gas pipeline operators through field demonstrations at utility sites. The selection identified one to two technologies in each of the three areas above. The technologies maturity levels were investigated based on their technical concepts and demonstrated capabilities. A review of the technology maturity approach is presented in the following section.

Technology Readiness Level

Background of Technology Readiness Levels Assessment

TRL is a method of estimating technology maturity of a technology during the development process. The TRL assessment examines the technology concept, requirements, and demonstrated capabilities. Its standard form is based on a scale from 1 to 9 with 9 being the most mature technology. The use of TRLs provides consistent and uniform assessment of technical maturity across different types of technologies. Comprehensive approaches for the TRLs have been established by various organizations.

The TRL concept was originally developed by the National Aeronautics and Space Administration (NASA) and the United States Department of Defense to allow for more effective assessment of the newly developed technologies.[41] The concept used a linear scale for evaluating single components of a technology. Figure 31 shows the NASA's TRL scale.

The system is currently being used by other organizations such as USDOE and the European Association of Research and Technology Organizations (EARTO). The same 9-level scale is used by these organizations, but the definitions and descriptions used to implement the scale have been modified to meet their specific needs. Similarly, the TRL scale proposed here has been slightly modified to meet the products' commercialization needs of the natural gas industry.

USDOE has established a TRL guide to assist in developing the technology maturation plan for their funded projects.[42] Their guide presents a tailored version of the NASA model to ensure that the project satisfies its intended purpose in a safe and cost- effective manner. It uses similar scale with different descriptions of the levels to better define the various laboratory and field validation stages of the system as shown in Figure 32.

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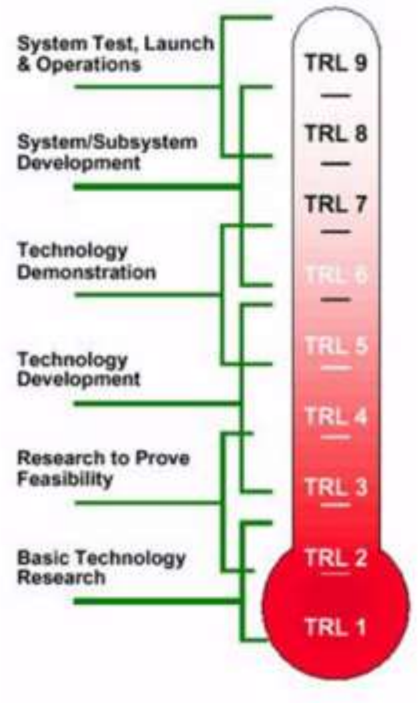
[41] Mankins, John C. Technology Readiness Levels: A White Paper. NASA. Office of Space Access and Technology. Advanced Concepts Office. 1995.

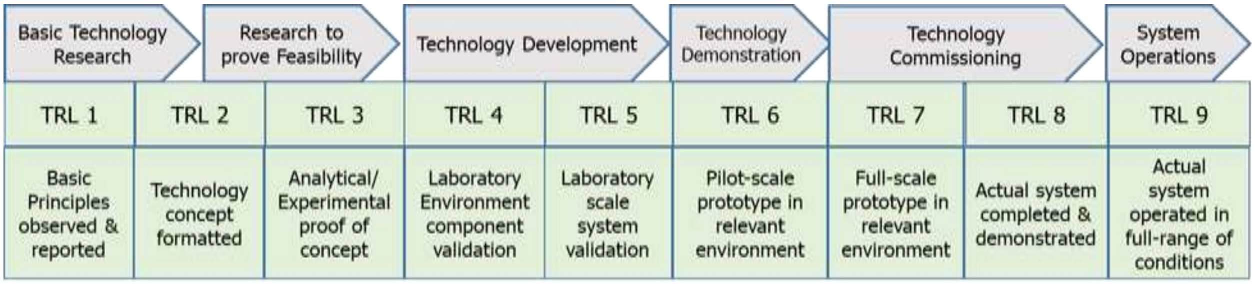
[42] Technology Readiness Assessment Guide. DOE G 413.3-4A. United States Department of Energy. 2011.

Figure 31: National Aeronautics and Space Administration Technology Readiness Levels



Source: The TRL Scale as a Research & Innovation Policy Tool. EARTO. 2014

Figure 32: United States Department of Energy Technology Readiness Level Scale



Basic Technology Research	Research to prove Feasibility		Technology Development		Technology Demonstration	Technology Commissioning		System Operations
TRL 1	TRL 2	TRL 3	TRL 4	TRL 5	TRL 6	TRL 7	TRL 8	TRL 9
Basic Principles observed & reported	Technology concept formatted	Analytical/ Experimental proof of concept	Laboratory Environment component validation	Laboratory scale system validation	Pilot-scale prototype in relevant environment	Full-scale prototype in relevant environment	Actual system completed & demonstrated	Actual system operated in full-range of conditions

Source: Technology Readiness Assessment Guide. United States Department of Energy. 2011

The USDOE TRL scale requires that a prototype design is tested in a relevant environment. The tests performed to demonstrate the operational capability of systems are shown in Table 25. The table shows that TRL 6 requires that the system components have already been integrated and that testing should be completed at an engineering or pilot scale in a similar environment to the actual application.

Although the primary purpose of using TRL is to help making decisions concerning the technology development, it should be viewed as one of several tools that are needed to manage the progress of research and development activity within an organization. Among the advantages of using the TRL system are:

- Provide a common understanding of technology status.
- Help managing the risk of financing and developing a new technology.

- Make decisions concerning technology funding.
- Make decisions about technology transitions.

Table 24: Description of United States Department of Energy Technology Readiness Levels

TRL	Definition	Description
9	Actual system operated over a full range of expected conditions.	Actual operation in its final form, under the full range of operating conditions.
8	Actual system completed and qualifies through tests and demos.	Technology has been proven to work in its final form and under expected conditions. This represents the end of system development.
7	Full-scale similar system demonstrated in a relevant environment	Prototype full-scale system, requiring demonstration of an actual system prototype in a relevant environment in the field.
6	Engineering/pilot scale similar system validation in a relevant environment.	Representative engineering scale model or prototype that is well beyond the lab scale in TRL 5, is tested in a relevant environment.
5	Laboratory scale similar system validation in a relevant environment.	Basic technology components are integrated so that the system configuration matches the final application.
4	Component or system validation in a laboratory environment.	Basic components are integrated to demonstrate they work together. Examples include integration of an “ad-hoc” hardware in a laboratory and testing with a range of simulants.
3	Analytical and experimental critical function proof of concept.	Active research and development is initiated. This included analytical and laboratory scale studies to validate the separate elements of the technology. Examples include components not yet integrated together.
2	Technology concept and application formulated.	Invention begins, once basic principals have been observed. Examples are technologies still limited to analytical studies.
1	Basic principles observed and reported.	Scientific research begins to be translated into applied research and development. Examples may include paper studies of a technology’s basic development.

Source: Technology Readiness Assessment Guide. United States Department of Energy. 2011

Some of the characteristics of TRLs that limit their implementation in the technology assessment include:[43]

- Readiness does not necessarily fit with appropriateness or technology maturity. A mature product may possess a greater or lesser degree of readiness for use in a particular system context than one of lower maturity.
- Numerous factors must be considered, including the relevance of the products’ operational environment to the system at hand, as well as the product-system architectural mismatch.

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[43] The TRL Scale as a Research & Innovation Policy Tool. European Association of Research and Technology Organizations (EARTO). 2014.

Table 25: United States Department of Energy Testing Recommendations for Technology Readiness Levels

Level	Scale of Testing	Testing Fidelity	Testing Environment
9	Full-scale matching final application	Identical configuration to final application	Full-range of actual operating conditions
8	Full-scale matching final application	Identical configuration to final application	Operations, limited range of actual operating conditions
7	Full-scale matching final application	Similar configuration in almost all aspects to final	Limited range of relevant conditions.
6	Engineering/pilot scale < full-scale	Similar configuration in almost all aspects to final	Limited range of relevant conditions.
5	Lab-scale testing	Similar configuration in almost all aspects to final	Limited range of relevant conditions.
4	Lab-scale testing	Pieces or components of final	Simulated range of operating conditions
3	Lab-scale testing	Pieces or components of final	Simulated range of operating conditions
2		Analytical/paper	
1		Paper study	

Source: Technology Readiness Assessment Guide. United States Department of Energy. 2011

Another limitation of existing TRL rating systems is that they do not assess the status of product commercialization. Systems may reach a development maturity in a full range of operating conditions, but this does not guarantee their translation to the market as a commercial product. Many factors affect a product availability in the market, including cost, ease of use, and the presence of competing technologies in the market. Accordingly, the identification of a commercial path of a technology in the final TRL levels was added to the TRL assessment of the technologies used in the natural gas industry.

To overcome this TRL limitation we defined a modified TRL scale for the natural gas industry based on the USDOE example, as shown in Table 26. The table presents slight additions to levels 8 and 9, including an assessment of technology commercialization potential and financial projections in level 8, and a technology transfer plan to market in Level 9.

Table 27 provides a detailed checklist of technology characteristics associated with each TRL scale level. This table was used to determine the TRL levels of the pipeline safety and integrity management technologies assessed in this report

Table 26: Technology Readiness Levels Implemented in Technologies Assessment

Level	Description
1	Beginning of a project. It is basic technology research that has begun to be translated into applied research and development.
2	A transition from basic technology research to research to prove feasibility. The new technology concept or application is formulated. Practical applications are invented.
3	Research to prove feasibility. Active research and development is initiated. The work moves beyond the paper phase to experimental work that verifies that the concept works. This includes analytical and laboratory scale studies to validate the separate elements of the technology.
4	Bridging from scientific research to engineering. It is the first step in determining whether the individual components will work together as a system. Components and/or the system is validated in a laboratory environment.
5	Further bridges from scientific research to engineering. It covers laboratory-scale similar system testing and evaluation in a relevant environment. The major difference between TRL 4 and 5 is the increase in the fidelity of the system and the environment to the actual application.
6	Complete the bridge from scientific research to engineering. It begins true engineering development of the technology as an operational system. Engineering or pilot-scale testing is performed to validate a similar (prototypical) system in a relevant environment.
7	First step in system commissioning. This is a major step up from TRL 6. It includes a full-scale, similar (prototypical) system demonstrated in a relevant environment.
8	Completes the system commissioning. In almost all cases, TRL 8 represents the end of true system development. An actual system is operated over the full range of expected mission conditions. A path to the market has been identified.
9	System operations. An actual system is operated over the full range of field conditions. It is also the point in the technology development where a manufacturer or commercializing partner has been identified, and license or technology transfer agreements have been finalized.

Source: Gas Technology Institute

Table 27: Technology Readiness Level Scale for Natural Gas Industry

Relative Level of Technology Development	Level	Definition	Description
Basic Technology Research	**1**	Basic principles observed and reported	Lowest level of technology readiness. • Scientific research has begun to be translated into R&D. Possible examples include: ○ Paper studies of a technology's basic properties, or ○ Experimental work that consists mainly of observation of the physical world. • Supporting information includes references that identify the principles that underlie the technology: ○ Published research, or ○ Other references
Basic Technology Research/ Research to Prove Feasibility	**2**	Technology concept and/or application formulated	Practical applications have been invented. • Ideas have been moved from pure to applied research • Application may be speculative. There may be no proof or detailed analysis to support the assumptions. • Examples remain as in TRL 1 • Supporting information: ○ Outlines the application being considered, and Provides analysis to support the concept. Incudes publications, or other references.
Research to Prove Feasibility	**3**	Analytical and experimental critical function and/or characteristic proof of concept	Active R&D is initiated. The work has moved beyond the paper phase to experimental work that verifies that concept works as expected on simulants or variables. • Studies to physically validate the analytical predictions of separate elements of the technology. ○ Analytical studies, and ○ Laboratory-scale studies • Components are not yet integrated or representative tested. • Supporting information: ○ Results of laboratory tests performed to measure parameters of interest, and ○ Comparison to analytical predictions for critical subsystems. • Components of the technology are validated, • But there is no attempt to integrate the components into a complete system. • Modeling and simulation may be used to complement physical experiments.

Table 27 (continued): Technology Readiness Level Scale for Natural Gas Industry

Relative Level of Technology Development	Level	Definition	Description
Technology Development [bridging from scientific research to engineering]	**4**	Component and/or system validation in laboratory environment	First step in determining whether the individual components will work together as a system. • The laboratory system with a mix of on-hand equipment and special purpose components that might require special handling to function. The basic technological components are integrated to establish that the pieces will work together. • Relatively “low fidelity” compared with target system. • Examples: ○ Integration of ad hoc hardware in a laboratory, ○ Testing with a range of simulants • Supporting information: ○ Results of the integrated experiments, and ○ Estimates of how the experimental components and experimental test results differ from the expected system performance goals.
Technology Development [bridging from scientific research to engineering]	**5**	Laboratory-scale, similar system validation in relevant environment	The major difference between TRL 4 and 5 is the increase in the fidelity of the system and environment to the actual application. • The system tested is almost prototypical. • The basic technological components are integrated so that the system configuration is similar to (matches) the final application in almost all respects. • Example: ○ Testing a high-fidelity, laboratory scale system in a simulated environment. • Supporting information: ○ Results from the laboratory scale testing, ○ Analysis of the differences between the laboratory and eventual operating system/environment, and ○ Analysis of what the experimental results mean for the eventual operating system/environment.
Technology Development [bridging from scientific research to engineering]	**6**	Engineering/pilot-scale, similar (prototypical) system validation in relevant environment	Begins true engineering development of the technology as an operational system. • Step up from laboratory scale to engineering scale ○ Determination of scaling factors that will enable design of the operating system. • Engineering-scale models or prototypes are tested in a relevant environment. (This represents a major step up in a technology’s demonstrated readiness.) ○ Example: Testing an engineering scale prototypical system with a range of simulants. • Supporting information: ○ Results from the engineering scale testing, and ○ Analysis of the differences between the engineering scale and the laboratory scale used in TRL 5 ○ Analysis of what the experimental results mean for the eventual operating system/environment.

Table 27 (continued): Technology Readiness Level Scale for Natural Gas Industry

Relative Level of Technology Development	TRL Level	Definition	Description
Technology Development	**6**	Engineering/pilot-scale, similar (prototypical) system validation in relevant environment	• The prototype is capable of performing all the functions that are required of the operational system. • The operating environment for the testing closely represents an actual operating environment.
System Commissioning	**7**	Full-scale, similar (prototypical) system demonstrated in relevant environment	A major step up from TRL 6, requiring: • Demonstration of an actual system prototype in a relevant environment. • Testing to cover system limits in the full range of applicable variables (e.g., pressures, range of pipe diameters, distances or lengths, applicable materials, weather). • Example: ○ Testing full-scale prototype in field with range of variables. • Supporting information: ○ Results from full-scale testing, ○ Analysis of the differences between this test environment and that used in TRL 6, and ○ Analysis of what the experimental results mean for the eventual operating system/environment. • Final design is virtually complete.
System Commissioning	**8**	Actual system completed and qualified through test and demonstration.	Represents the end of true system development. • The technology has been proven to work: ○ In its final form, and ○ Under expected conditions. • Example: ○ Developmental testing and evaluation of the system in actual field conditions. • Supporting information: ○ Operational procedures that are virtually complete. • A review has been completed to ensure that the path to the market has been identified • The financial projections are reviewed to ensure that they are commensurate with the project.
System Operations	**9**	Actual system operated over the full range of expected mission conditions.	• The technology is: ○ In its final form, and ○ Has operated under the full range of operating mission conditions. • Example: ○ Using actual system with full range of conditions in actual field conditions. • Path to commercialization defined. ○ Manufacturer or commercializing partner identified. ○ License/technology transfer agreements have been finalized.

Source: Gas Technology Institute

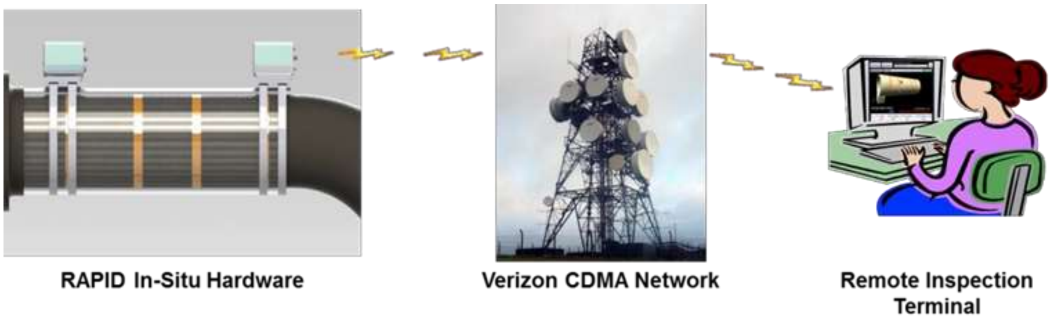
Application of the Technology Readiness Level Assessment to Real-Time Active Pipeline Integrity Detection Development

The real-time active pipeline integrity detection (RAPID) system is a non-destructive inspection system for gas pipeline safety monitoring of steel or plastic pipe with minimal labor involvement.[44] The system is based on an acoustic ultrasonic detection technology used in the aerospace industry for structural health monitoring (SHM) and detecting and monitoring damage to aircraft structures. The project was funded by the Energy Commission and conducted by Acellent Technologies, Inc.

The system is intended to detect and size areas of a pipeline at risk from mechanical damage and degradation due to corrosion and environmental factors such as moisture, temperature, and ground movement. This capability would provide an early indication of physical damage and enable monitoring of the progression of the damage. The early warning provided by a pipeline health monitoring system would then be used to identify remedial strategies before damage leads to a catastrophic failure. Currently, there is no reliable, built-in nondestructive method for determining if damage is sufficient to affect operational safety without excavating the pipeline at great cost.

The RAPID system layout is shown in Figure 33 and it consists of a series of sensors that are directly attached to a pipeline. The sensors communicate through a wire with a field-mounted unit which in turn communicates through the internet with a remote inspection terminal in a distant office.

Figure 33: Layout of Real-Time Active Pipeline Integrity Detection System



Source: *Real-Time Active Pipeline Integrity Detection System for Gas Pipeline Safety Monitoring*. California Energy Commission. Publication number: CEC-500-2015-095. 2015.

The network of sensors is placed on new or existing pipelines at regular intervals. The sensors are small piezoelectric sensors/actuators embedded in a thin dielectric film that is applied to the pipelines. The sensors monitor and evaluate the vibrations caused by the flow of gas and the hardware wirelessly transmits the data to computers for monitoring and analysis. The system was designed to provide a detection sensitivity of 95 percent probability of detection.

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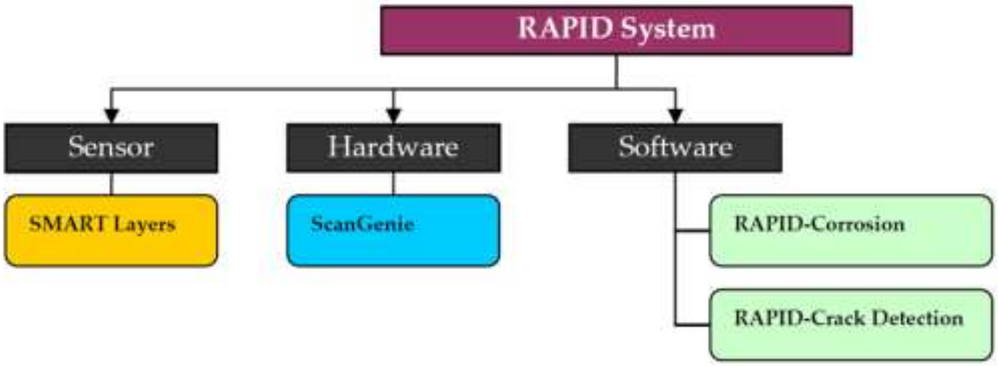
[44] *Real-Time Active Pipeline Integrity Detection System for Gas Pipeline Safety Monitoring*. California Energy Commission. Publication number: CEC-500-2015-095. 2015.

A network of up to 32 sensors is used in a single monitored section. The RAPID hardware periodically scans the pipeline using ultrasonic guided Lamb-wave signals and sends this data to a central data management and analysis center.

The software allows data to be retrieved by command (user initiated) or automatically (system initiated). The software detects damage areas and determines the size of corrosion area and crack depth. Figure 34 illustrates the functionality of the RAPID system.

Figure 34: Layout of Real-Time Active Pipeline Integrity Detection System Data Management



Source: California Energy Commission. Publication number: CEC-500-2015-095. 2015.

The application of the TRL check list shown above in Table 27 shows that the system has completed the “basic technology research” and “proof of feasibility” requirements of TRL levels 1 to 3. It has also satisfied the “technology development” from scientific research to engineering design in TRL levels 4 to 6 as follows:

- TRL 4: Components have been validated in a laboratory environment and have been shown to be able to work together as a system.
- TRL 5: Laboratory-scale components have been assembled in a prototype. Basic technological components were integrated so that the system configuration was similar to the final application.
- TRL 6: Engineering-scale testing has been completed in a real-world environment. The system was demonstrated at the PG&E test site under typical testing conditions.

Table 28 shows the check list assessment of the technology in TRL levels 7 to 9. The check mark **X** in the boxes indicate that the activity has been completed. An evaluation of the system from the final report of the funded project shows that:

- The system has been demonstrated in a pilot scale test at PG&E test site. A damage map has been generated on a large diameter steel pipe under representative testing condition.
- The system has been tested on aboveground piping, with further verification needed in belowground environment over a longer period. The final report stated that the developer would like to investigate the applicability and demonstrate the feasibility of the system in underground pipelines.

Table 28: Technology Readiness Level Assessment of Real-Time Active Pipeline Integrity Detection System

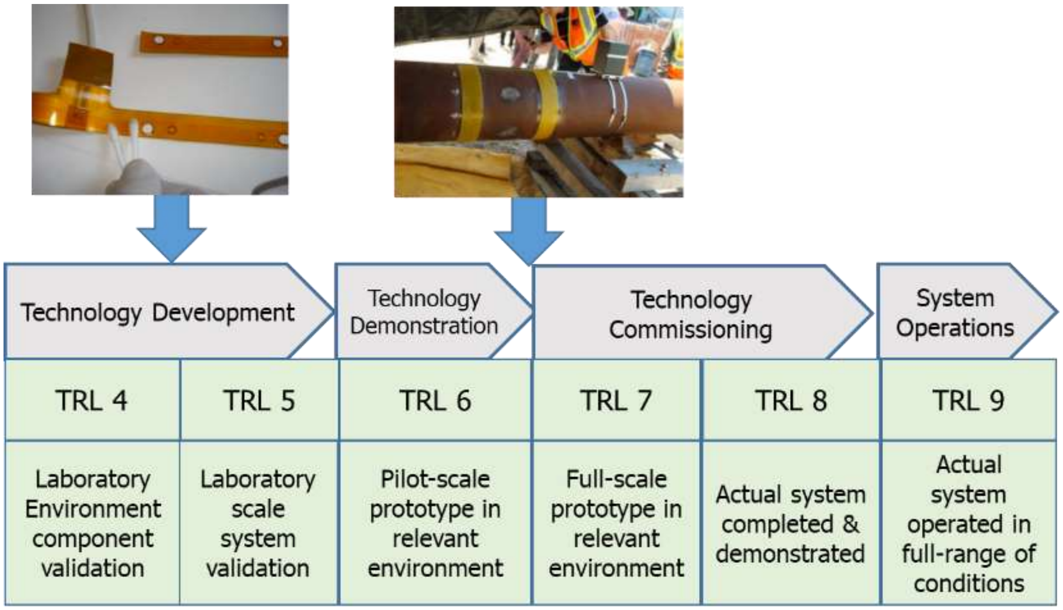
Relative Level of Technology Development	Level	Definition	Description
System Commissioning	**7**	Full-scale, similar (prototypical) system demonstrated in relevant environment	A major step up from TRL 6, requiring: • Demonstration of an actual system prototype in a relevant environment. • Testing to cover system limits in the full range of applicable variables (e.g., pressures, range of pipe diameters, distances or lengths, applicable materials, weather). • Example: ○ Testing full-scale prototype in the field with a range of variables. • Supporting information: ○ Results from full-scale testing ○ Analysis of the differences between this test environment and that used in TRL 6 ○ Analysis of what the experimental results mean for the eventual operating system/environment • Final design is virtually complete.
System Commissioning	**8**	Actual system completed and qualified through test and demonstration.	Represents the end of true system development. • The technology has been proven to work: ○ In its final form, and ○ Under expected conditions. • Example: ○ Developmental testing and evaluation of the system in actual field conditions. • Supporting information: ○ Operational procedures that are virtually complete. • A review has been completed to ensure that the path to the market has been identified • The financial projections are reviewed to ensure that they are commensurate with the project.
System Operations	**TRL 9**	Actual system operated over the full range of expected mission conditions.	• The technology is: ○ In its final form, and ○ Has operated under the full range of operating mission conditions. • Example: ○ Using the actual system with the full range of conditions in actual field conditions. • Path to commercialization defined. ○ A manufacturer or commercializing partner has been identified. ○ License/technology transfer agreements have been finalized.

Source: Gas Technology Institute

- The system has not been tested under a full range of applicable variables.
- Validation of system application to the full range of pipe sizes, material, and coating types found in transmission and distribution systems has not been performed.
- The system used a local monitoring unit with further development plans for remote communications.

The status of the system after the completion of the project final report is at TRL 6, with some activities started toward TRL 7. The Final Report indicated that many spills and explosions could potentially be avoided with the implementation of the system, but the system has only been tested aboveground and in a small representative setup of existing piping network. Figure 35 shows a graphical representation of the system TRL status.

Figure 35: Representation of System Development in Technology Readiness Level Chart



Source: Gas Technology Institute

Application of the Technology Readiness Level Assessment to Excavation Encroachment System

The global positioning excavation encroachment notification system (GPS EEN) consisted of a GPS unit, cellular connectivity, and motion sensors assembled in one device and installed on excavators to provide utility operators with real-time accurate locations and operational status of excavating equipment.[45] A dashboard interface provided the utilities with the excavator's status and location in relation to their pipeline facilities. The excavation warning system was developed using a cloud-based computing platform and a machine learning and characterization algorithms.

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[45] Global Positioning System Excavation Encroachment Notification System Implementation, California Energy Commission, Publication number: CEC-500-2018-014. 2018.

The project built and deployed 150 devices for installation at the PG&E and SoCal gas service territories. The deployment was coordinated with stakeholders to provide actionable information with the primary goal of preventing unintentional dig-ins to the gas system. The main components of the GPS EEN system include:

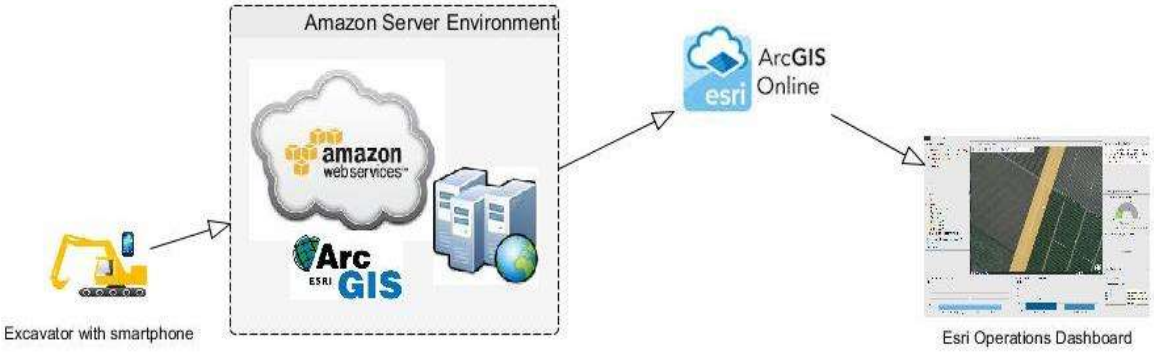
- A black-box device containing Global Navigation Satellite (GNSS) sensors for positioning, nine degree of freedom (9DoF) sensor to provide orientation, accelerometer and gyroscope data for movement, and a cellular modem to transmit data in real- time. The device also contains an audible alarm to warn an operator of the presence of a gas main and LED lights for visual warnings (Figure 36).

Figure 36: Geographical Information System Excavation Encroachment Notification Device

Source: Gas Technology Institute

- An Amazon Web-based System (AWS) Computing platform comprised of a combination of Environmental Systems Research Institute (Esri) products, including their Operations Dashboard and Geo-Event Processor, and a machine learning and characterization algorithm to determine the status of excavators and backhoes in the field (Figure 37).

Figure 37: Geographical Information System Excavation Encroachment Notification Communication Platform



Source: Gas Technology Institute

The black-box devices were installed on a host of varying equipment including backhoes, excavators, and agricultural equipment (Figure 38). The devices were built to provide continuous monitoring, be easy to install and operate, and be resistant to weather conditions. Once the devices are installed on the field equipment, they send location and activity as the equipment moves in a set of monitoring zones around underground gas lines. The motion sensors update the status constantly and provide discrete information about the physical movement of the field equipment in the X, Y and Z axes for the gyroscope, orientation and accelerometer. This data is used to understand the physical movement of the field equipment while the GPS device provides spatial location information.

Figure 38: Installation of Device on Excavation Equipment

Source: Gas Technology Institute

To provide alerts and warnings to the field operator and stakeholders, the GPS EEN system used utility GIS data that contain spatial information about the transmission lines. The GIS data, in conjunction with the location of the equipment in the field, provide a means for analyzing the proximity of the equipment to the gas system in real-time, signaling to the operator using audible and visual alarms that a gas main is near. Two-way communication between the black box device and the computing platform allows the operator to confirm and silence alarms.

The tests at the utility sites evaluated the system in actual field conditions, characterized the excavation activities, and allowed for calibrating the algorithm to significantly reduce the occurrence of false-positive alarms.

The deployment of about 150 devices on excavation and agricultural equipment in utilities service territories showed that the warning algorithm was 80 percent effective in characterizing digging activity and will continue to improve as more training data are collected.

Applying the TRL check list shows that the system has completed the “basic technology research” and “proof of feasibility” requirements of TRL 1 to 3. It has also satisfied the “technology development” from scientific research to engineering design in TRL levels 4 to 6. Table 29 shows the development checklist for TRL 7 to 9. An **X** in the table indicates that the activity has been completed. The system has recently completed TRL 9 with identifying and signing a commercializing partner in November 2018.

Table 29: Check list of Geographical Information System Excavation Encroachment Notification Technology in Technology Readiness Levels 7 to 9

Relative Level of Technology Development	Technology Readiness Level	Definition	Description
System Commissioning	**7**	Full-scale, similar (prototypical) system demonstrated in relevant environment	A major step up from TRL 6, requiring: • **X** Demonstration of an actual system prototype in a relevant environment. • **X** Testing to cover system limits in the full range of applicable variables (e.g., pressures, range of pipe diameters, distances or lengths, applicable materials, weather). • **X** Example: ○ **X** Testing full-scale prototype in the field with a range of variables. • **X** Supporting information: ○ **X** Results from full-scale testing, ○ **X** Analysis of the differences between this test environment and that used in TRL 6 ○ **X** Analysis of what the experimental results mean for the eventual operating system/environment. • **X** Final design is virtually complete.
System Commissioning	**8**	Actual system completed and qualified through test and demonstration.	Represents the end of true system development: • The technology has been proven to work: ○ In its final form, and ○ **X** Under expected conditions. • **X** Example: ○ **X** Developmental testing and evaluation of the system in actual field conditions. • Supporting information: ○ Operational procedures that are virtually complete. • **X** A review has been completed to ensure that the path to the market has been identified • **X** The financial projections are reviewed to ensure that they are commensurate with the project.

Relative Level of Technology Development	Technology Readiness Level	Definition	Description

System Operations	**9**	Actual system operated over the full range of expected mission conditions.	- The technology is:
			  ○ In its final form, and
			  ○ Has operated under the full range of operating mission conditions.
			- Example:
			  ○ Using the actual system with the full range of conditions in actual field conditions.
			- X Path to commercialization defined.
			  ○ X A manufacturer or commercializing partner has been identified.
			  ○ X License/technology transfer agreements have been finalized.

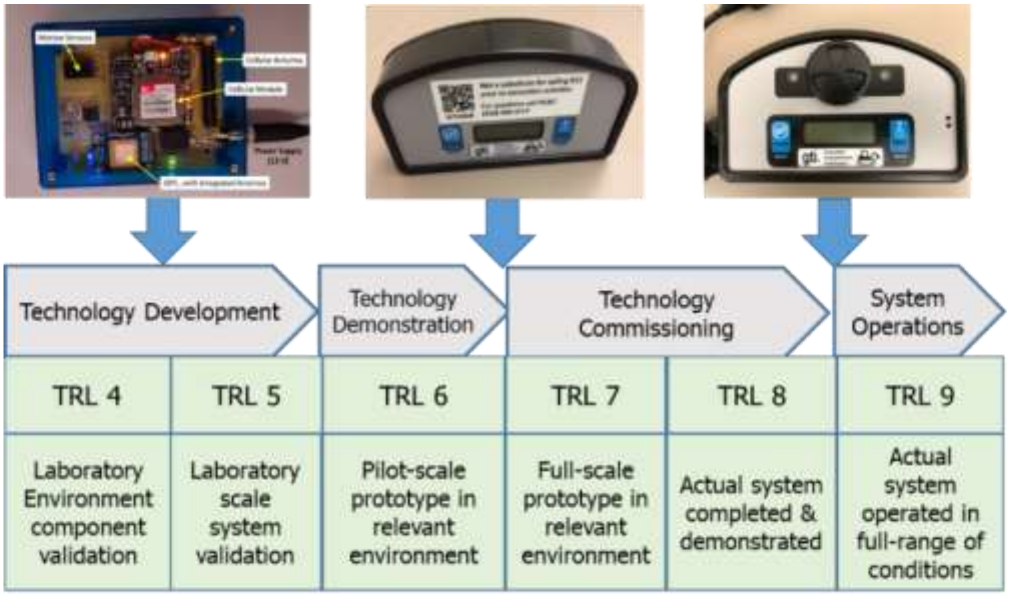
Source: Gas Technology Institute

The evaluation of the system from the final report of the project shows that:

- The system has been demonstrated in pilot scale tests at PG&E test sites. The complete functionality of data collection, transfer, and analysis have been demonstrated.
- The system has been tested on various equipment over an extended period.
- The system has been tested under a full range of applicable variables and locations.
- The system was integrated with the utilities GIS pipeline systems.

The system development has completed the requirements of TRL 9. It has been proven to work in its final form. Figure 39 shows a graphical representation of the system development with respect to the TRL levels.

Figure 39: Representation of System Development in Technology Readiness Level Chart



Source: Gas Technology Institute

Technology Selections for Field Demonstrations

The selection of technologies for field demonstrations at utility sites in California was based on the following criteria:

- Natural gas industry needs of technologies with quantifiable measures for improved safety and integrity of the California pipeline system.
- Federal and State recommendations following current trends of pipeline incident records from PHMSA, NTSB, and CPUC data.
- Technology status based on their technical concept, demonstrated capabilities, and commercial potential; with emphasize on technologies that are 1 to 3 years to market and with maturity levels of 7 and 8 in the TRL scale.
- Coordination with the California gas utilities to support their safety objectives and operation plans.

The selection included technologies in each of the following categories identified in the previous chapters:

- Technologies for damage detection and failure prevention:
    - Real-time monitoring of excavation damage during HDD.
    - Damage mitigation of aboveground gas meters against natural forces.
- Threat identification and integrity management:
    - ILI inspection sensor for cracks and weld defects in small unpiggable pipes.
    - External assessment tool for pipe corrosion and coating disbondment..
- Pipeline risk and information management:
    - Automated material traceability and data management for steel pipes.

The follow sections present the details of the above technologies selected for the field demonstrations.

Cross-Bores during Horizontal Directional Drilling

Cross-bore incidents occur during HDD installations when a gas line hits a crossing sewer line. These damages can go undetected for extended periods and are typically found when repair of the sewer lateral shows the gas line inside the line. Several pipeline incidents caused by cross-bore damage have been reported by NTSB.[46, 47]

To address cross-bores threats, the NTSB has issued safety recommendations requiring:[48]

- Complete inspection of those locations along the construction route where gas mains and sewer laterals may be in proximity to one another and correct any deficiencies.

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[46] Pipeline Explosion and Fire, Kenosha, WI. National Transportation Safety Board. P-76-83.

[47] Pipeline Rupture and Fire, Indianapolis, IN. National Transportation Safety Board. PAB-99-02.

[48] National Transportation Safety Board. Safety Recommendations P-76-83 through P-76- 86. 1976.

- Revised construction standards requiring underground facilities be located accurately before construction and providing protection for these facilities near boring operations.

More recently, the NTSB Safety Recommendation P-99-1 has required that natural gas operators" damage prevention programs include actions to protect their facilities when directional drilling operations are conducted in proximity to those facilities.[49]

Several agencies have addressed these recommendations and provided guidelines for reducing the risk of HDD installations. These guidelines include educating the public, operators, developers, and plumbing associations of their roles in getting sewer lines marked and incorporating technologies to detect sewer lines during the HDD operations.[50, 51]

The selected technology for field demonstration is the operational radar for every drill-string under the street or "ORFEUS" system, a GPR for real-time obstacle detection during the HDD operation.[52] The demonstrated technology addresses the safety of the infrastructure during HDD operations and it was evaluated in coordination with PG&E in a field trial at their test site.

Table 30 shows the check list assessment of the technology TRL level. Further details of the technology and field demonstration are presented in Chapter 7 of the report.

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49 National Transportations Safety Board Safety Recommendation P-99-1. 1999.

50 Natural Gas Pipelines and Unmarked Sewer Lines, American Gas Association. 2010.

51 GPTC Guide for Gas Transmission and Distribution Piping Systems. Appendix G-192-6. Subsurface Damage Prevention Guidelines for Directional Drilling and Other Trenchless Technologies. 2003.

52 Operational Radar For Every drill string Under the Street (ORFEUS). Demonstration completion report. Grant agreement no: 308356. Sept. 2015.

Table 30: Technology Readiness Levels Assessment of ORFEUS Technology

Relative Level of Technology Development	Technology Readiness Level	Definition	Description
System Commissioning	**7**	Full-scale, similar (prototypical) system demonstrated in relevant environment	A major step up from TRL 6, requiring: • X Demonstration of an actual system prototype in a relevant environment. • X Testing to cover system limits in the full range of applicable variables (e.g., pressures, range of pipe diameters, distances or lengths, applicable materials, weather). • X Example: ○ X Testing full-scale prototype in the field with a range of variables. • X Supporting information: • X Results from full-scale testing, ○ X Analysis of the differences between this test environment and that used in TRL 6, and ○ X Analysis of what the experimental results mean for the eventual operating system/ • X Final design is virtually complete.
System Commissioning	**8**	Actual system completed and qualified through test and demonstration.	Represents the end of true system development. • The technology has been proven to work: ○ In its final form, and ○ X Under expected conditions. • X Example: ○ X Developmental testing and evaluation of the system in actual field conditions. • Supporting information: ○ Operational procedures that are virtually. • X A review has been completed to ensure that the to the market has been identified • X The financial projections are reviewed to ensure they are commensurate with the project.
System Operations	**9**	Actual system operated over the full range of expected mission conditions.	• The technology is: ○ In its final form, and ○ Has operated under the full range of operating mission conditions. • Example: ○ Using the actual system with the full range of conditions in actual field conditions. • X Path to commercialization defined. ○ X A manufacturer or commercializing partner has been identified. ○ X License/technology transfer agreements have been finalized.

ORFEUS = operational radar for every drill-string under the street

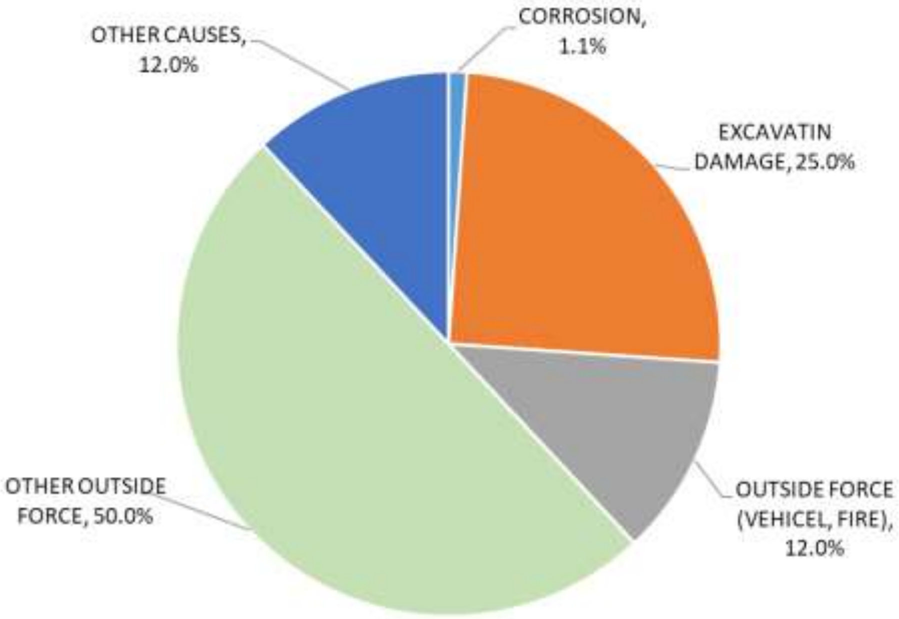
Source: Gas Technology Institute

Meter Breakaway Fitting for Outside Force

The USDOT PHMSA records show that the second primary cause of significant incidents in gas distribution systems is "outside force damage" (Figure 40). Distribution integrity management programs require utilities to identify and minimize these threats. One of the most common outside-force threats to aboveground piping is vehicular damage to meter sets.

To mitigate damages resulting from vehicular hits, the OPW breakaway valve was developed to connect to the meter riser and shuts-off the gas line if a car accidently hits the meter, thus eliminating gas leak and possible fire hazards.

Figure 40: Gas Distributing Significant Incident Causes in California, 2010-2017



Source: http://www.phmsa.dot.gov/pipeline/library/data-stats

The OPW breakaway valve has been demonstrated and tested in the lab to evaluate its performance under various testing conditions, including its location with respect to the ground level, pipe riser size, and meter set type.[53] A field demonstration of the valve under realistic testing conditions was recently coordinated and performed with SoCal Gas. Table 31 shows the TRL Check List for the assessment of the breakaway technology.

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[53] Breakaway Disconnect/Shut-off for Meter Risers – Phase 3. Operations Technology Development. Report 5.11.s. 2018.

Table 31: Technology Readiness Level Assessment of Meter Breakaway Valve Technology

Relative Level of Technology Development	Technology Readiness Level	Definition	Description
	8	Actual system completed and qualified through test and demonstration.	• X The technology has been proven to work: ○ X In its final form, and ○ X Under expected conditions. • X Example: ○ X Developmental testing and evaluation of the system in actual field conditions. • X Supporting information: ○ X Operational procedures that are virtually complete. • X A review has been completed to ensure that the path to the market has been identified • X The financial projections are reviewed to ensure that they are commensurate with the project.
System Operations	**9**	Actual system operated over the full range of expected mission conditions.	• The technology is: ○ X In its final form, and ○ Has operated under the full range of operating mission conditions. • X Example: ○ X Using the actual system in actual field conditions. • X Path to commercialization defined. ○ X A manufacturer or commercializing partner has been identified. ○ X License/technology transfer agreements have been finalized.

Source: Gas Technology Institute

Electromagnetic Acoustic Sensor for Small-Diameter Unpiggable Pipes

One of the main technologies needs in the area of pipeline inspection and integrity is the development of advanced ILI devices and platforms; including ILI sensors that can identify weld defects and line cracks. These needs focus on gas pipelines not currently accessible to existing platforms. Currently, ILI inspection of transmission lines in California shows:

- Only about 11 percent of the transmission miles inspected using ILI systems in California had systems to inspect cracks and weld seams (Figure 12).
- About 37 percent of the transmission miles in California have diameters less or equal to 12 inches. Internal inspections of these lines require devices and platforms capable of inspecting these small diameters and unpiggable pipes.

In an effort to advance the use of ILI platforms for gas distribution lines, the NTSB issued safety recommendation P-15-23 in response to the 2010 San Bruno gas line incident.[54] The

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[54] Pipeline & Hazardous Materials. Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, NTSB. 2010. http://www.sanbruno.ca.gov/PDFs/NTSB - PipelineSanBruno992010.pdf.

recommendation requires enhancing ILI technology for implementation in pipelines that are not currently accessible by existing inspection platforms.

The EMAT sensor is a device that can be pulled by an umbilical cord through a small-diameter, unpiggable gas pipeline for detecting and quantifying internal and external cracks and weld defects.

A device prototype was recently completed and tested at the PG&E testing facility. The tests were performed on 8-inch diameter pipes under simulated field cracks in the facility. Work is currently in progress to produce a field prototype for mounting on an inspection platform. The technology has completed TRL level 6 and Table 32 shows the TRL assessment of the technology. Details of the EMAT demonstration are presented in Chapter 7 of the report.

Table 32: Technology Readiness Levels Assessment of Electromagnetic Acoustic Transducer Technology

Relative Level of Technology Development	Technology Readiness Level	Definition	Description
System Commissioning	**7**	Full-scale, similar (prototypical) system demonstrated in relevant environment	A major step up from TRL 6, requiring: • X Demonstration of an actual system prototype in a relevant environment. • X Testing to cover system limits in the full range of applicable variables (e.g., pressures, range of pipe diameters, distances or lengths, applicable materials, weather). • Example: ○ Testing full-scale prototype in the field with a range of variables. • X Supporting information: ○ X Results from full-scale testing, ○ X Analysis of the differences between this test environment and that used in TRL 6, and ○ X Analysis of what the experimental results mean for the eventual operating system/environment. • Final design is virtually complete.
System Commissioning	**8**	Actual system completed and qualified through test and demonstration.	Represents the end of true system development. • The technology has been proven to work: ○ In its final form, and ○ X Under expected conditions. • Example: ○ Developmental testing and evaluation of the system in actual field conditions. • Supporting information: ○ Operational procedures that are virtually complete. • X A review has been completed to ensure that the path to the market has been identified. • The financial projections are reviewed to ensure that they are commensurate with the project.

Relative Level of Technology Development	Technology Readiness Level	Definition	Description
System Operations	**9**	Actual system operated over the full range of expected mission conditions.	• The technology is: ○ In its final form, and ○ Has operated under the full range of operating mission conditions. • Example: ○ Using the actual system with the full range of conditions in actual field conditions. • Path to commercialization defined. ○ **X** A manufacturer or commercializing partner has been identified. ○ License/technology transfer agreements have been finalized.

Source: Gas Technology Institute

Aboveground Coating Assessment Tool

The utility industry needs tools to perform aboveground assessments of underground metallic pipes. Excavation is expensive and has potential risks. ECDA techniques that provide insight prior to excavation help in evaluating significant mileage of pipelines without the need for random excavations or optimizing utility resources.

The Spar 300 system is used to perform aboveground evaluation of the pipeline coating condition. The technology can increase system knowledge of coated steel pipes without the need for excavation. In addition to providing assessment data, the method also generates Global Navigation Satellite System (GNSS) referenced maps of the facility surveyed.

The ability to capture and pinpoint the anomalies on utility maps in a single procedure would streamline the capture of integrity management data. A field demonstration of the Spar system was performed to evaluate its use and its integrated GPS capability with new data analysis routine for identifying corrosions and coating disbondment.

The new modifications of the technology extend the applicability of the device and requires demonstrations at utility sites under various field conditions. Table 33 shows the TRL assessment of the technology.

Table 33: Technology Readiness Level Assessment of Spar Technology

Relative Level of Technology Development	Technology Readiness Level	Definition	Description
	8	Actual system completed and qualified through test and demonstration.	• X The technology has been proven to work: ○ X In its final form, and ○ X Under expected conditions. • X Example: ○ X Developmental testing and evaluation of the system in actual field conditions. • X Supporting information: ○ X Operational procedures that are virtually complete. • X A review has been completed to ensure that the path to the market has been identified • X The financial projections are reviewed to ensure that they are commensurate with the project.
System Operations	**9**	Actual system operated over the full range of expected mission conditions.	• The technology is: ○ X In its final form, and ○ Has operated under the full range of operating mission conditions. • Example: ○ Using the actual system with the full range of conditions in actual field conditions. • X Path to commercialization defined. ○ X A manufacturer or commercializing partner has been identified. ○ X License/technology transfer agreements have been finalized.

Source: Gas Technology Institute

Automated Material Traceability of Steel Pipes

The USDOT PHMSA requires operators of gas distribution pipelines to develop and implement a DIMP program to identify and reduce their pipelines integrity risks.[55] The main elements of the program include:

- Know the gas distribution system and identify threats.
- Evaluate and rank risks and identify and implement measures to address the risks.
- Measure and monitor performance and evaluate effectiveness.

Likewise, the CPUC gas safety plan goal matrix shown in Table 7 identifies the need for testing all grandfathered transmission pipes. It also requires developing and utilizing risk-based safety programs for these systems. The characteristics of these pipes, their installation history, and manufacturers data are all necessary parameters that need to be identified in a reliable and automated traceability system.

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55 49 CFR Part 192, Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines, Final Rule. Federal Register, Vol. 74. No. 232. 2009.

Risk analysis and integrity management programs rely on high-quality data for analysis to support threat identification, risk ranking, selection of mitigation techniques, and other related decision making. Material traceability data, including mechanical and chemical properties, is the foundation of a complete asset record to support risk and integrity analysis.

Current techniques for capturing critical material traceability properties involve legacy processes requiring manual data entry, which can lead to missing or incomplete records. The field demonstration of the traceability system was coordinated with the developer “LocusView” to automate data entry and transfer to eliminate opportunities for errors. Further, it uses techniques that are open and non-proprietary and could be incorporated into a published industry standard. Table 34 shows the TRL assessment of the technology.

Table 34: Technology Readiness Level Assessment of Steel Pipe Traceability System

Relative Level of Technology Development	Technology Readiness Level	Definition	Description
	8	Actual system completed and qualified through test and demonstration.	• The technology has been proven to work: ○ X In its final form, and ○ Under expected conditions. • X Example: ○ X Developmental testing and evaluation of the system in actual field conditions. • Supporting information: ○ Operational procedures that are virtually complete. • X A review has been completed to ensure that the path to the market has been identified • X The financial projections are reviewed to ensure that they are commensurate with the project.
System Operations	**9**	Actual system operated over the full range of expected mission conditions.	• The technology is: ○ X In its final form, and ○ Has operated under the full range of operating mission conditions. • Example: ○ Using the actual system with the full range of conditions in actual field conditions. • X Path to commercialization defined. ○ X A manufacturer or commercializing partner has been identified. ○ X License/technology transfer agreements have been finalized.

Source: Gas Technology Institute

CHAPTER 7: Technologies Demonstrations

The selected technologies for field demonstrations included each of the major categories identified in the previous chapters. These categories, discussed in detail below, are:

- Technologies for damage detection and failure prevention:
    - ORFEUS system for real-time obstacles detection during HDD. The demonstration was performed at PG&E's Livermore, California test site.
    - Damage mitigation of gas meters against outside forces and vehicle hits. The demonstration was performed with SoCal Gas in Ontario, California.
- Threat identification and integrity management:
    - EMAT sensor for cracks and weld defects in small unpiggable pipes. The demonstration was performed at the PG&E test facility in San Ramon, California.
    - External assessment tool for pipe corrosion and coating disbondment. The demonstration was performed at several SoCal service areas in Santa Monica, California.
- Pipeline risk and information management:
    - Automated material traceability and data management for steel pipes. The demonstration was performed at a PG&E excavated pipeline location in Concord, California.

ORFEUS Demonstration at Pacific Gas and Electric Company Test Site, Livermore, California

HDD is an efficient method of installing belowground utility lines in urban environments (Figure 41). The method avoids the costs of open trenching installation that requires traffic management, transport of backfill material, re-instatement of road surface, and significant noise and disruption to businesses and the public. However, its use in dense urban areas is constrained due to the risk of damaging existing infrastructure, which has increased significantly with urban growth.

Currently, there are limited approaches to successfully detect underground obstacles during the drilling process. These include surface inspections and exploration digs along the construction route where gas mains and sewer laterals may exist. Consequently, safe installation of new utilities in urban environment is still largely performed by using open-cut methods.

Utility installation using open cuts have their own excavation damage risks due to incomplete or inaccurate maps of buried utilities and poor excavation practices, and they commonly cause significant disruption to businesses and the public. The associated consequences of open excavations commonly result in increased risk of incidents and economic loss.

Figure 41: Horizontal Directional Drilling Machine at Pacific Gas and Electric Company Test Site

Source: Gas Technology Institute

Cross-Bores during Horizontal Directional Drilling

The continuous growth of drilling operations in pipeline installations has raised the need to reduce the risk of hitting sewer lines. Sewer laterals may intersect the routes of new gas lines and occasional hits during gas lines installations have been documented (Figure 42).

There is currently no practical approach for locating sewer laterals in the vicinity of the gas lines and determining their depth in all types of soils. Gas utilities and HDD installers use various methods to detect sewer pipes before drilling and inspect them after HDD installation to identify hits. These methods include pot-holing along the HDD path, advanced utility locating, and camera inspection. However, standard drilling technologies are still “blind” with respect to the underground environment.

ORFEUS Technology

ORFEUS was developed for utility installation companies using HDD. The system consists of a GPR mounted inside the HDD drill head (Figure 43). It provides a real-time communication and display system that alerts the drill operator when underground obstacles are identified. The operator can then change the drilling path to avoid striking them.

Figure 42: Polyethylene Gas Lines Penetrating Sewer Pipes

Source: Cross Bore Safety Association, http://www.crossboresafety.org

Figure 43: ORFEUS System Components

ORFEUS = operational radar for every drill-string under the street.

Source: ORFEUS system demonstration at PG&E Training Facility. Technical Report. 2017

The technology was developed through a collaborative research project with financial support from a consortium of natural gas and industries in Europe.[56] The system was developed in two phases. Phase-2 included 11 companies participating in its development and had several main modifications; including a rugged standalone unit, integrated one antenna, eliminated system battery, used a cable in the drill rod, used a high frequency GPR of 1.5 MHz, and introduced a real-time software for the display.

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56 Operational Radar For Every drill string Under the Street (ORFEUS). Demonstration Completion Report. Grant Agreement No: 308356. Sept. 2015.

Table 35 shows the performance characteristics of Phase-2 prototype.[57] The prototype was tested in 4 field trials in Europe and the system was evaluated in the field demonstration at the PG&E test site at Livermore, California in April 2017.

Table 35: Performance Measures of ORFEUS System

Variable	Range
Detection Distance	(50 cm - 100 cm) not in clay soil
Minimum detectable object size	10 mm
Resolution	300 mm
Axial and radial distance accuracy	10% of the range
Positive Target detection percentage	>95%
False target generation percentage	< 1%

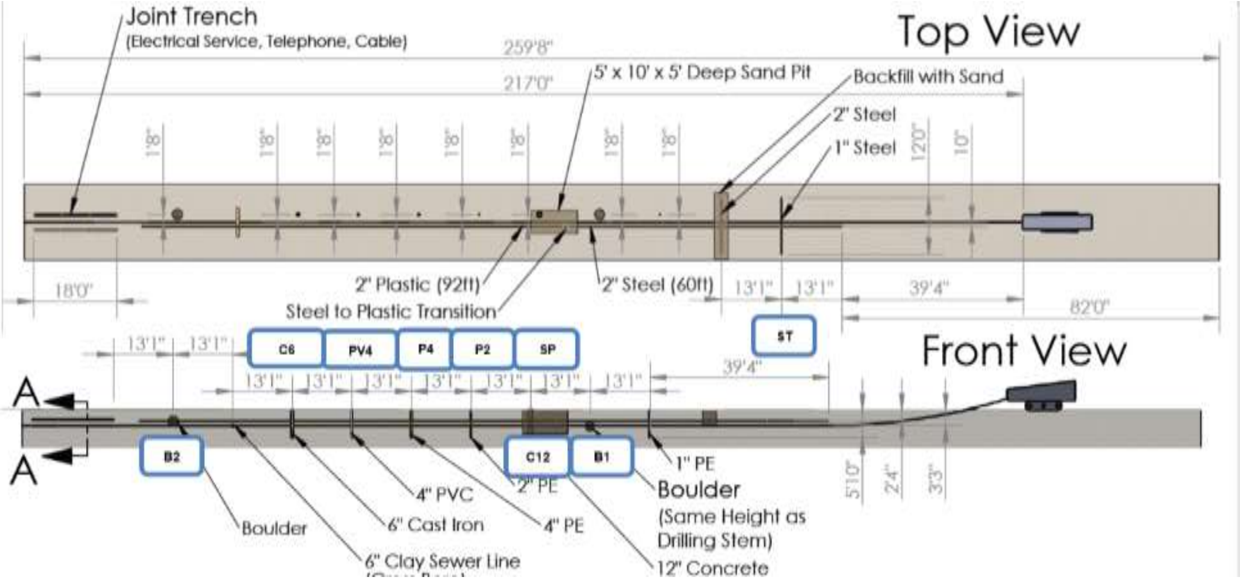
ORFEUS = operational radar for every drill-string under the street.

Source: ORFEUS System. Demonstration completion report

Field Demonstration

Figure 44 shows a layout of the test site and the various types of pipes installed in the path of the HDD drill head. The site consisted of silty-clay soil mixed with gravels. Sand pits and large boulders were buried at specific locations along the path as shown in the figure.

Figure 44: Top and Side Views of Site Layout



Source: ORFEUS system demonstration at PG&E Training Facility. Technical Report. 2017

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[57] ORFEUS System Demonstration at PG&E Training Facility. Technical Report. IDS GeoRadar. Oct. 2017.

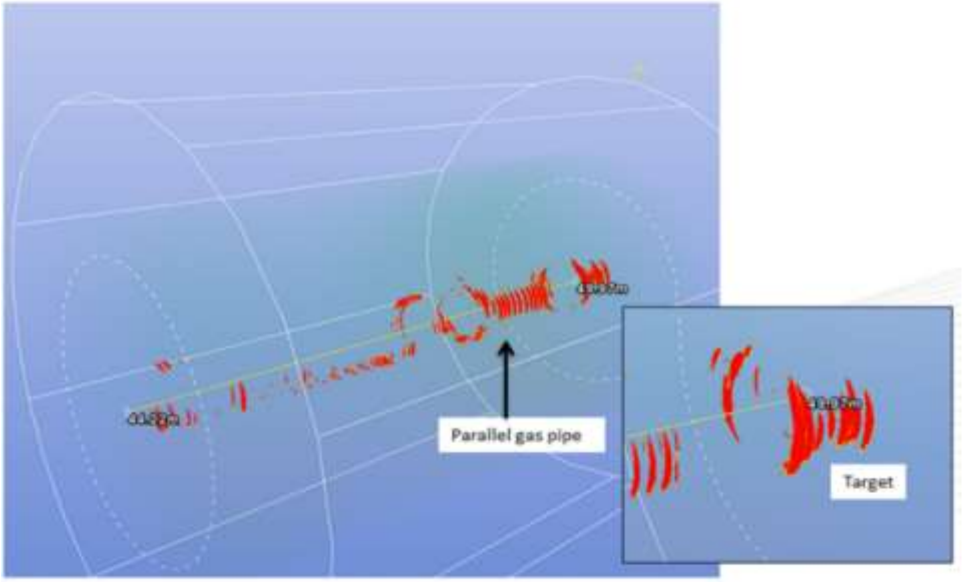
Several sections of pipe samples were installed vertically and horizontally across the expected drilling path. These pipes included non-conductive clay and plastic pipes and metallic pipes. These pipes had sizes from 1-inch to 6-inch diameters. Additionally, a longitudinal pipe was placed at about 1 foot parallel to the drill path at depth of 3 feet. Figure 45 shows a view of the site.

Figure 45: Installed Pipes and Drill Path at Test Site

Source: Gas Technology Institute

The results of the field demonstration at PG&E confirmed the performance of the prototype. The system was found capable of detecting belowground objects in the proximity of the drilling head as shown in Figure 46, up to a distance of about 1.6 feet ahead and aside of the head.

Figure 46: ORFEUS Field Trial Result Showing Targets in Real-Time Three Dimensional Display

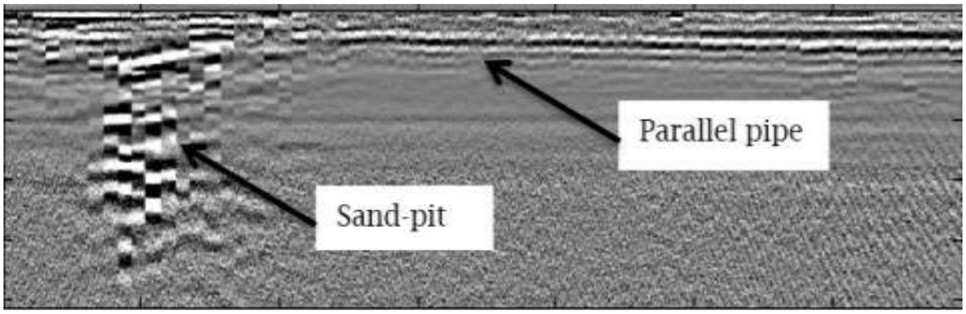


ORFEUS = operational radar for every drill-string under the street.

Source: ORFEUS system demonstration at PG&E Training Facility. Technical Report. 2017

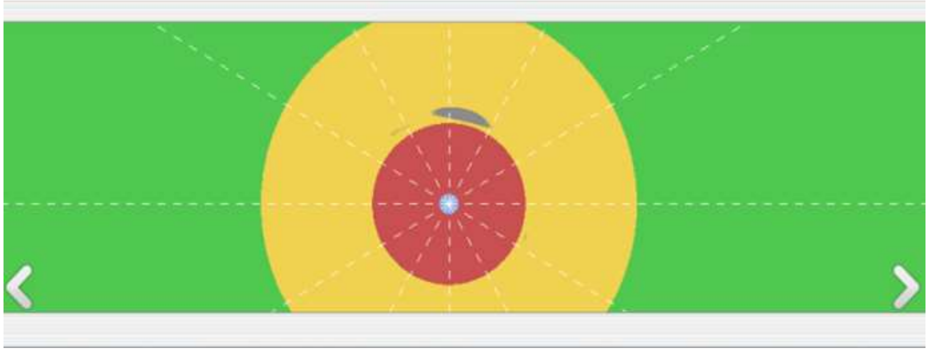
The change in soil condition as the drill head moved from the native soil to the sand pit is shown in the fixed-angle radargram in Figure 47. As the drill head moves from the sand pit, the parallel pipe was detected as a straight line. As the bore head moved in the forward direction, the parallel pipe was also represented in the 3-D view of the software. A real-time tracking algorithm correlated subsequent detections and display them (in grey) as shown in Figure 48.

Figure 47: Radar Image of Sand Pit and Parallel Pipe



Source: ORFEUS system demonstration at PG&E Training Facility. Technical Report. 2017

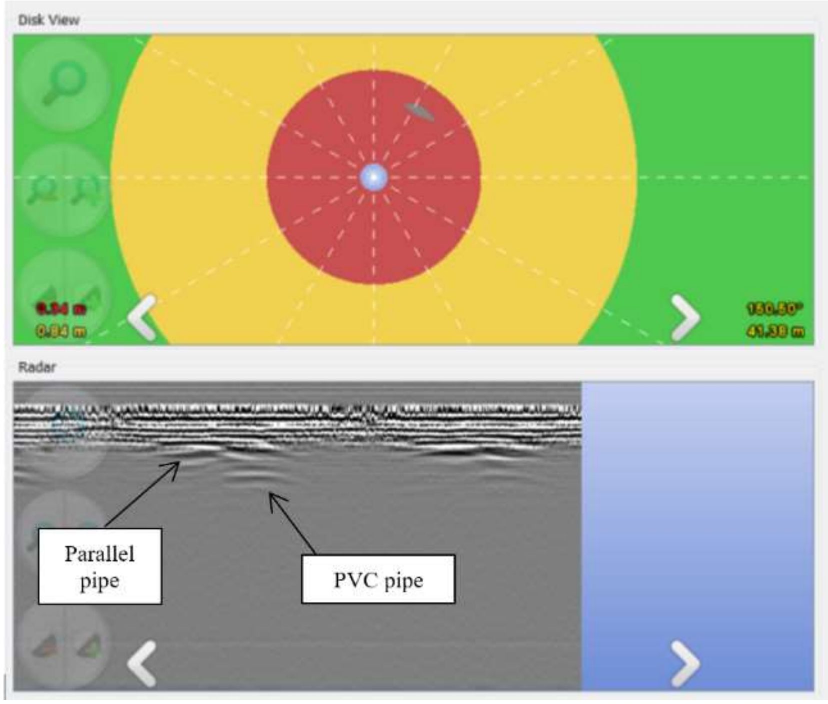
Figure 48: Two Dimensional View of Parallel Pipe Detection



Source: ORFEUS system demonstration at PG&E Training Facility. Technical Report. 2017

In Figure 49, the radar view shows the 4-inch diameter polyvinyl chloride pipe. The figure also shows the parallel pipe that is about 8 inches from the drill head. The plastic pipe can be identified as a second hyperbola in the radar view.

Figure 49: Two Dimensional View of 4-inch Polyvinyl Chloride Pipe



Source: ORFEUS system demonstration at PG&E Training Facility. Technical Report. 2017

Real-Time Monitoring and Reliability of Data Reporting

The software display of the GPR results in Figure 50 shows that:

- The hardware (i.e., radar, communication, tilt sensor) identified the cross objects in the field
- The drilling mud (bentonite) associated with the HDD operation had no effect
- The real-time data display identified the positions of the detected targets.

Further developments of the technology should improve the real-time visualization of the software (for example, synthetic results after target detection) and the generation of warning alarms when a risk of strike is detected.

Figure 50: Software Display of ORFEUS During Field Demo

ORFEUS = operational radar for every drill-string under the street

Source: Gas Technology Institute, PG&E Field demonstration

Ease of Training and Implementation

The current prototype is available for the HDD installation and testing of pipelines under various site and testing conditions. HDD installers and service providers are participants of the technology development. This will provide a smooth transition of the technology to implementation.

The prototype provides automatic detection and correlation of the locations of the HDD head and underground obstacles. The operation of the software and detection during drilling requires trained personnel and it is anticipated that the service will be contracted and provided through specialized installers.

Breakaway Disconnect and Shut-off for Meter Risers

The breakaway fitting device is designed to minimize the threat of an incident when a meter set or other aboveground distribution piping is impacted by an outside force. Common outside force includes vehicular and other motorized equipment impacts and also falling snow and ice from building roofs.

The breakaway device has two length sizes of 4-inch and 6-inch with a reduced diameter at the middle to force the breakage at this location. A spring-loaded mechanism inside the valve is activated when breakage occurs, resulting in shutting off the gas flow (Figure 51).

Figure 51: OPW Breakaway Fitting and Cross Section

Source: Breakaway Disconnect/Shut-off for Meter Risers. Operations Technology Development. Report 5.11.s. 2018

The breakaway device manufacturer (OPW) has worked with GTI to perform laboratory testing of the device in 2017 under controlled testing conditions and has moved forward with the commercialization of the device. The laboratory tests have shown that approximately 50 percent of the tests had a successful breakaway and gas shut off. Using schedule 80 pipe risers, instead of the thinner schedule 40 risers, resulted in higher success rates of 82 percent. Additionally, a higher breakaway rate occurred when the meter was impacted from the regulator side as shown in Figure 52.

Figure 52: Impact from Regulator Side in Laboratory Tests

Source: Breakaway Disconnect/Shut-off for Meter Risers. Operations Technology Development. Report 5.11.s. 2018

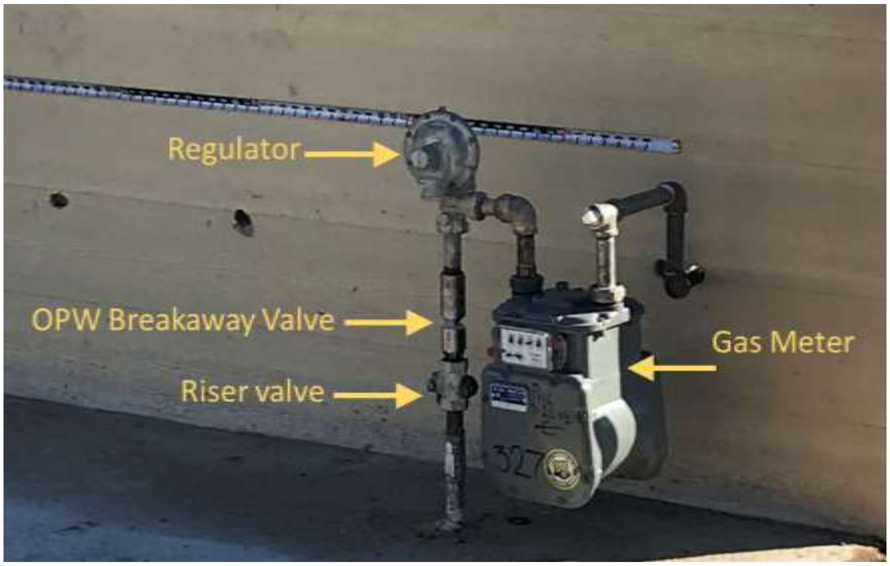
Field Demonstration

The goal of the field tests was to evaluate the breakaway valve's functionality when installed in a realistic environment. The tests were performed by a subcontractor in California (Exponents Inc.) in coordination with GTI and SoCal Gas.

The subcontractor's test setup included testing nine residential gas meter set assemblies (MSA) according to the standard specifications provided by SoCal Gas. The MSA's were built adjacent to wall mock-ups to represent the serviced building. The walls were firmly secured to the ground and were finished with exterior siding.

The breakaway valves were installed between the riser valve and the regulator as shown in Figure 53. Upstream of the riser, a quick-connect fitting was used to provide compressed air at pressure of 60 psi commonly used in the gas distribution system.

Figure 53: Gas Meter Assembly with Breakaway Valve

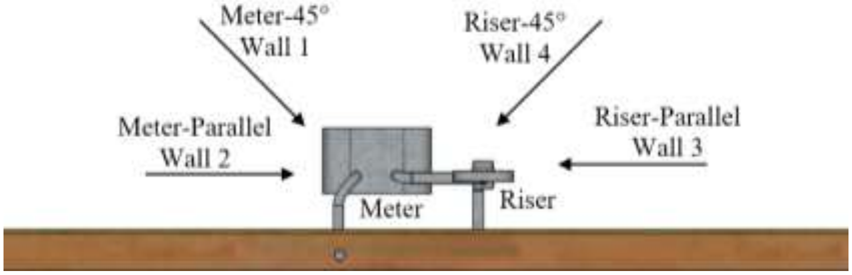


Source: Gas Technology Institute, field demonstration

The first round of four tests were performed with the MSA's installed in compacted soil base. The second round included five tests performed with the MSA's installed in concrete base. Both types of bases are commonly encountered in the gas distribution system. The second round of tests consisted of four tests identical to the first round plus one control test without the breakaway valve.

The tests were set to simulate vehicular impacts from both sides of the gas meter. The impacts were applied in directions parallel to the wall and at angle 45 degrees from the wall. Figure 54 shows the directions of the vehicular impacts in the four tests in each set and Figure 55 shows a view of the MSA setup in the field. A passenger car was driven at a "parking lot" speed of 5 mph and hit the gas meters at the assigned directions. Figure 56 shows a vehicular hit to the gas meter at a direction of 45 degrees.

Figure 54: Directions of Vehicular Hits of Meter Set Assemblies in Tests



Source: Breakaway Disconnect/Shut-off for Meter Risers. Operations Technology Development. Report 5.11.s. 2018

Figure 55: View of Test Setup of Vehicular Impact Tests

Source: Gas Technology Institute, field demonstration

Figure 56: Vehicular Hit to Gas Meter Assembly During Field Test

Source: Gas Technology Institute, field demonstration

Discussion of Field Results

The results showed that out of the eight tests with valves, the breakaway valve performed as expected and stopped gas flow in five tests (Figure 57); indicating a gas stoppage ratio of 62.5 percent. The results of the field tests are shown in Table 36.

Figure 57: Breakage of the Riser at the Location of the Breakaway valve

Source: Gas Technology Institute, field demonstration

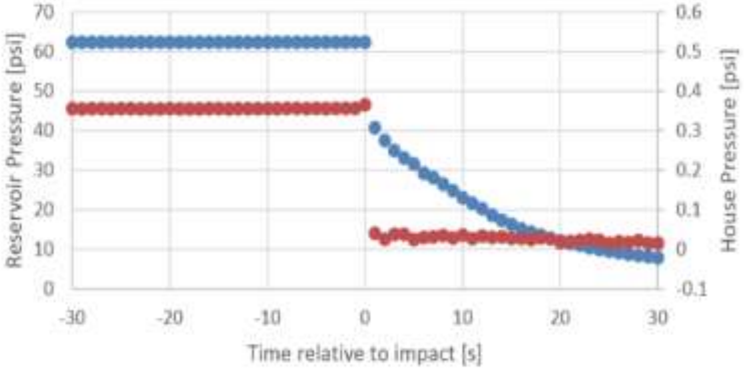
Table 36: Results of Field Tests on the Breakaway Meter Valve

Date – Wall Number	Impact Direction	Valve Length	Qualitative Outcome
Control	Riser parallel	N/A	System failed between regulator and piping to meter.
Soil – 1	Meter – 45 degrees	6 inches	Breakaway valve partially severed and stopped flow.
Soil – 2	Meter – parallel	4 inches	Breakaway valve severed, but valve did not fully stop flow. Leaked through breakaway valve.
Soil – 3	Riser – parallel	6 inches	Breakaway did not function and system failed downstream of meter.
Soil – 4	Riser – 45 degrees	6 inches	Breakaway valve severed and stopped flow.
Concrete – 1	Meter – 45 degrees	4 inches	Breakaway did not function and system failed downstream of meter.
Concrete – 2	Meter – parallel	6 inches	Breakaway valve severed and stopped flow.
Concrete – 3	Riser – parallel	6 inches	Breakaway valve severed and stopped flow.
Concrete – 4	Riser – 45 degrees	4 inches	Breakaway valve severed and stopped flow.

Source: Breakaway Disconnect/Shut-off for Meter Risers. Operations Technology Development. Report 5.11.s. 2018

In one of the three tests that did not pass, the breakaway valve broke as expected, however it did not fully stop the flow and a small audible leak was observed. In the other two tests, the vehicle hit the MSA at the meter side and the valve did not break. The pressure data from a failed test (shown as a pressure drop in the line) and a successful test are shown in Figure 58.

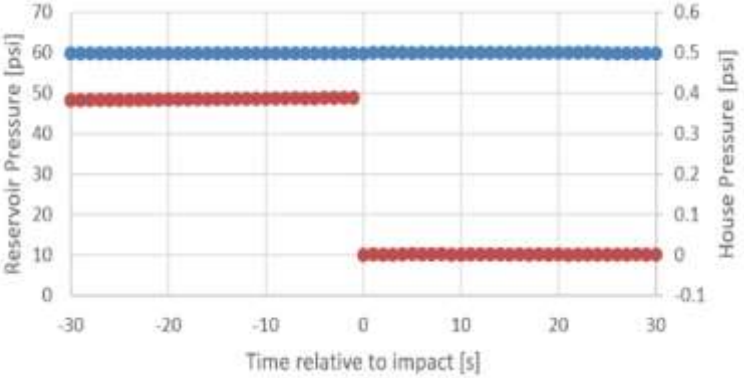
Figure 58: Pressure Measurements in System During Tests



(a) Failed test (pressure drop in reservoir, indicating leak).

● Reservoir Pressure

● Meter assembly Pressure



(b) Successful shut-off test (no drop-in reservoir pressure indicating no gas leak).

Source: *Breakaway Disconnect/Shut-off for Meter Risers. Operations Technology Development*. Report 5.11.s. 2018

Electromagnetic Acoustic Transducer Demonstration at Pacific Gas and Electric Company, San Ramon, California

The EMAT device can be pulled by an umbilical through a small-diameter (8-inch), unpiggable gas pipeline and uses a sensor to detect and quantify pipe cracks and seam weld defects.

The development of the technology was funded by USDOT-PHMSA, pipeline companies through operations technology development (OTD), and Quest Integrated, Inc. (Qi2). In Phase 1 of the development,[58] a laboratory bench-scale unit was built and tested. Phase 2 prototype (shown in Figure 59) was completed in 2017 and demonstrated at the PG&E Test facility in 2018.[59] Currently, work is in progress in Phase 3 to build a field prototype with integrated data collection and power supply.

The manufacturer of the EMAT sensor (Qi2) uses circumferential guided wave technology to detect and quantify pipe defects in a small-diameter, unpiggable gas pipeline. Key results from Phase 1 included:

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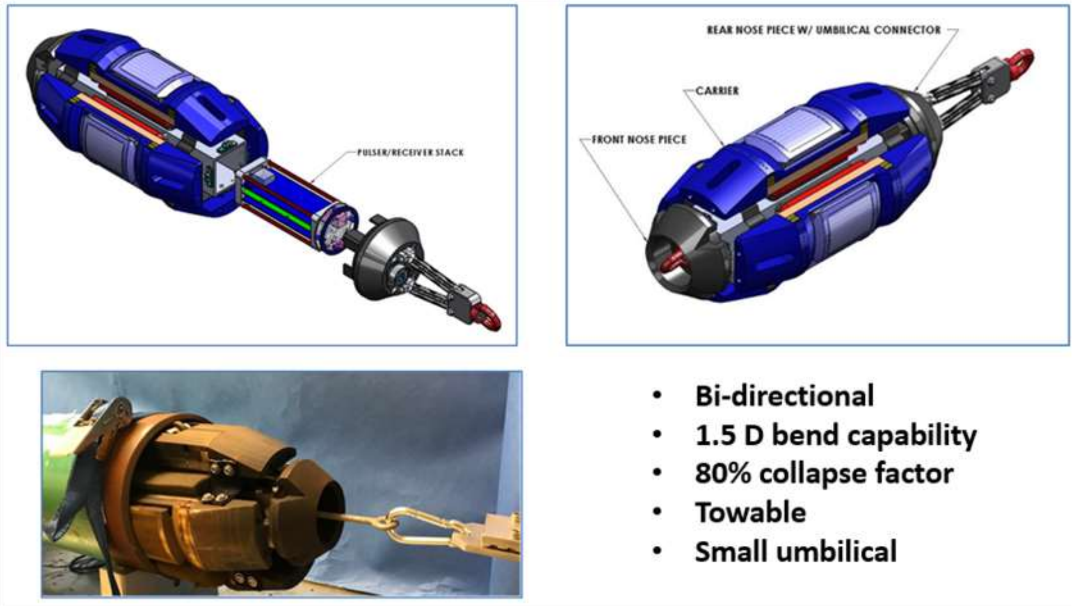
[58] *EMAT Sensor for Small Diameter and Unpiggable Pipes; Prototype and Testing. Phase 1.* PHMSA Report DTPH56-13-T-00007. 2015.

[59] *EMAT Sensor for Small Diameter and Unpiggable Pipes; Prototype and Testing. Phase 2.* 2018.

- A bench-scale prototype was successfully built that demonstrated 0.5 mm flaw depth sensitivity, focused on 0.25”-0.5” wall thickness, and accommodated 1.5D bends.
- The initial prototype runs on 8” pipe, with a commercial target to test 6-inch to 12-inch unpiggable pipe.

Figure 59: Electromagnetic Acoustic Transducer Prototype



Source: Gas Technology Institute

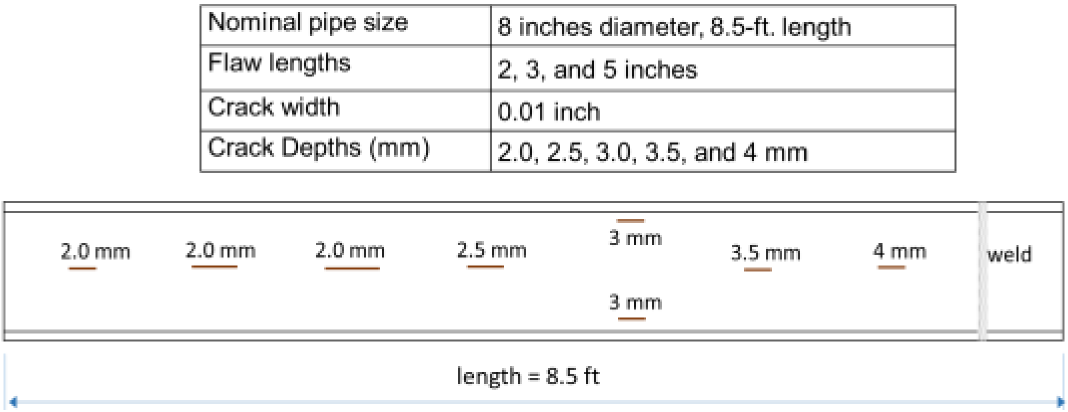
Traditionally, EMAT signals are launched circumferentially or at an angle, but this is not scalable to small sizes. The new system in Phase 2 uses unidirectional transmitter (TX) that can be steered clockwise or counterclockwise so that signals are essentially launched bi-directionally. The system also uses medical ultrasound technology to decompose the signal received (RX) into transmission and reflection (forward and backward propagating waves). The ratio of decomposed signal strengths (relative strengths of the clockwise and counterclockwise signals) indicates the presence of a flaw.

Demonstration Planning

The primary focus of the demonstration was to evaluate the device ability to detect axially-oriented flaws under the common field conditions. Axial flaws generate larger hoop stresses as compared to similar size defects in the radial direction (which generate axial stresses). The Phase 1 study indicated that more than 95 percent of crack failures are caused by axially-oriented defects that are perpendicular to the maximum hoop stress.

For demonstration at the PG&E’s facility, 8-inch diameter, 8.5-ft long steel pipes were prepared with axial cracks as shown in Figure 60. Table 37 shows the testing parameters of the pipe samples. The pipes were wrapped with a plastic cover and the flaws were not displayed for a blind test.

Figure 60: Flaw Characteristics and Geometry of Pipe Sample



Nominal pipe size	8 inches diameter, 8.5-ft. length
Flaw lengths	2, 3, and 5 inches
Crack width	0.01 inch
Crack Depths (mm)	2.0, 2.5, 3.0, 3.5, and 4 mm

Source: Gas Technology Institute

Table 37: Test Variables of Pipe Samples

Variable	Range
Pipeline diameter range	8 inches
Typical wall thickness	0.375 inches
Crack typical length	Typically, 2 inches
Crack depth	Typically, 0.5 to 5 mm
Crack width and orientation	Axial, 0.006 inches

Source: Gas Technology Institute

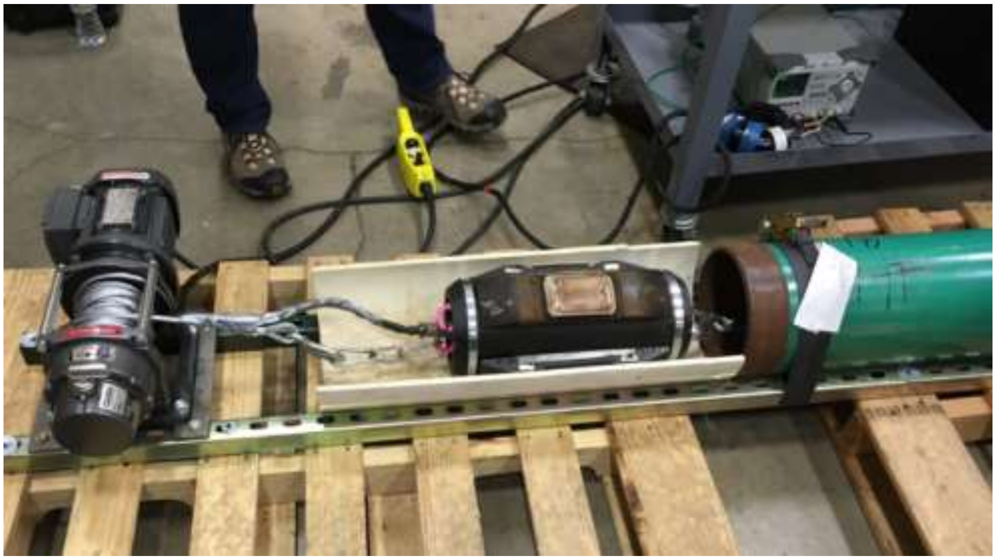
Field Demonstration

The field demonstration was performed in February 2018 at the PG&E facility in San Ramon, CA. The device was pulled thought the test pipes using a winch system as shown in Figure 61. The analytical software provided a real-time display of the defects on a large screen.

The test was performed using Phase 2 prototype that addressed signal congestion issues and mode purity of Phase 1 device. Phase 2 uses a bi-directional system that provides additional mode control to eliminate or “mask” reflection of the transmitted signal. Using this method, Qi2 reported a 10x improvement in signal levels on test samples.

The pipe test set up is shown in Figure 62. An 8-inch steel pipe (American Petroleum Institute 5L Grade X-42, 8.625-inch outer diameter, 0.322-inch wall thickness) was used for the demonstration. Half of the pipe was FBE-coated steel (green) and the other half was uncoated steel (black). The FBE-coated section contained simulated internal flaws (cracks/notches made using EDM). The uncoated section contained simulated flaws on the outside of the pipe and was covered in black plastic to conceal the location of the flaws for purposes of the demonstration. The EMAT sensor uses different algorithms for coated and uncoated pipe.

Figure 61: Electromagnetic Acoustic Transducer Device at Pacific Gas and Electric Company Demonstration



Source: Gas Technology Institute

Figure 62: Test Pipe and Data Display in Pacific Gas and Electric Company Test

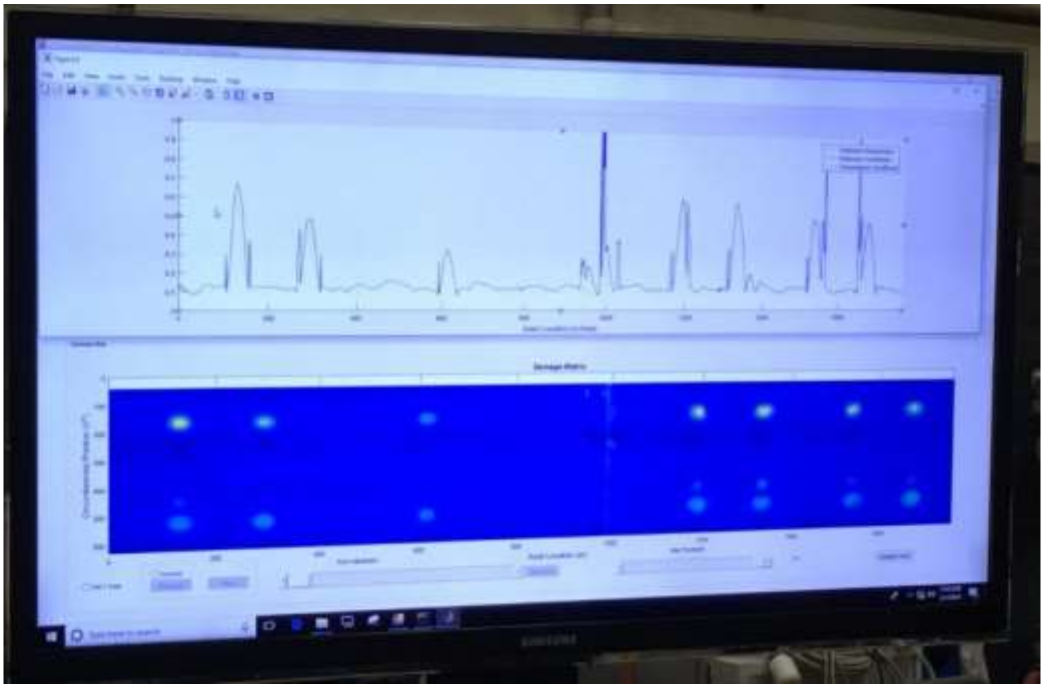
Source: Gas Technology Institute

Real-Time Monitoring and Reliability of Data Reporting

Figure 63 shows the B-scan data of the sensor during the test. The horizontal axis on top and bottom graphs corresponds to the tool location index (axial location) as the tool traverses along the length of pipe. The vertical line near the center of both graphs corresponds to the weld seam joining the FBE and bare sections of the test pipe.

The top graph (Cartesian) in the figure shows the reflection and transmission coefficients. The peaks along the curve represent flaws along the length of the pipe.

Figure 63: B-Scan Data from Test Pipe



Source: Gas Technology Institute

The bottom graph of the figure (blue damage matrix) shows the location of flaws. Each flaw (a longitudinal crack) is indicated by a yellow spot and flaw sizing occurs at these locations. In the sample pipe, all of the flaws were located on the same circumferential location along the length of the pipe, so the yellow spots “line up” in the graph.

The results in the figure shows that the EMAT sensor could successfully locate the simulated longitudinal cracks in terms of circumferential location and axial location. The algorithm does not distinguish between internal and external flaws. The algorithm could rank the sizes of the flaw with uncertainties regarding the actual applied depth of measurements.

The results of the demonstration are consistent with past peer reviews and performance described in project status reports. The bi-directional system introduced in the EMAT sensor provides higher sensitivity and better results than existing unidirectional methods. The sensor will need further development and validation under real operating conditions to demonstrate reliability and accuracy, and to provide more detailed information on flaw sizing and characteristics.

Further Development Status

Phase 2 of the EMAT sensor successfully located and sized the simulated longitudinal cracks. Phase 3 of the device development has recently started to build a stand-alone field unit and to further develop and validate the inspections under real operating conditions.

Currently, the wireline unit is connected to a computer. Ultimately, the computer will be disconnected, with a wireline battery installed to expand the sensor range (distance) and migrate the tool. Electronics pose a challenge as they are a function of the wireline.

The technology has potential to enhance safety by detecting cracks and anomalies in the pipe so that proactive measures can be taken to repair or replace the pipe. In a separate project on a parallel path, Qi2 is in the process of developing a robot-driven corrosion tool, with a small sensor footprint that has a higher probability of finding pits. Qi2 anticipates having a “field ready” EMAT sensor in approximately 18 months.

Aboveground Coating Assessment Tool, SoCal Gas

The utility industry needs improved and more efficient tools to perform routine aboveground ECDA assessment of underground metallic pipes. Excavation is expensive and has potential risks. New technique that provides insight prior to excavation helps optimize utility resources.

The Spar 300 system consists of multiple magnetometers for pipe locating (Figure 64). it integrates GPS location and timekeeping, and it accordingly references true location of the pipe rather than one generated by a separate mark-out operation.

In addition to locating, the system was demonstrated to assess pipe coating in order to increase system knowledge without the need for excavation. In addition to providing assessment data, the method also generates Global Navigation Satellite System (GNSS) referenced maps of the facility surveyed. The ability to capture both by executing a single procedure would streamline the captured integrity management data.

The Spar 300 Technology

The Spar system consists of a pair of 3-axis magnetometers separated by a known baseline.[60] This allows the location of a pipe to be triangulated by measuring the radiated field of the pipe when excited with a signal current. The curvature of the field measured by the two sensors allows the system to infer the location of the current source. Multiple Spars can be linked wirelessly when longer baselines are needed to triangulate deeper pipes.

In this application, two Spars are carried by two operators at a fixed distance and they are linked to determine the pipe signal phase shift between their relative locations as shown in Figure 65. These locations are provided by GPS that can be augmented with Real Time Kinematic (RTK) correction for improved accuracy. The frequency of the pipe excitation current is pre-determined to a high precision and shared by the components of the system.

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[60] Underground Utility 3-D Survey. Spar 300 Product Brief. Optimal Ranging, Inc. 2015.

Figure 64: Spar 300 Magnetometer with Global Positioning System Antenna

Source: Optimal Ranging Inc. Spar 300 Product Brief

While previous work on the device[61] has focused mainly on the locating functionality of the tool, the objective of the field demonstration was to evaluate its ability to detect coating disbondment. The data will be compared with the results of future excavations by SoCal gas. This effort would refine the analysis used for pipe and coating assessments.

Figure 65: Operation of 2 Spar Units for Pipe Locating and Inspection

Source: Gas Technology Institute

Field Demonstration

The field demonstrations were performed July 9-10, 2018 at several SoCal Gas pipeline locations. SoCal Gas had identified seven sites for the field survey with the Spar system. The pipeline sections were identified for possible coating disbondment and are scheduled for future excavations to identify and repair the coating. The survey was identified as pre-evaluation of

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[61] Above-Ground Detection Tools Including Disbondment and Metal Loss for all Metals Including Cast-Iron Graphitization. United States DOT PHMSA Agreement No. DTPH56-13-T-000011. 2016.

the locations before the excavation occurs. The following section presents results from the surveys at two of the seven sites in the demonstration.

The first test site was located at the intersection of Santa Monica and Upson roads in Carpinteria, California. The site runs a high-pressure gas line at the right of way. The survey was performed along two sections of the pipeline. Section 1 ran along Upson Drive and section 2 continued along Santa Monica Road. Figure 66 to Figure 68 show the Spar survey and measurements along the roadway in Section 1. The lower readings (in mA) in Figure 69 are indications of possible coating disbondment.

Results of Section 2 are shown in Figure 70 and Figure 71. The results provide indications of the potential flaws.

Figure 66: Location of Test Site No. 1

Source: Gas Technology Institute

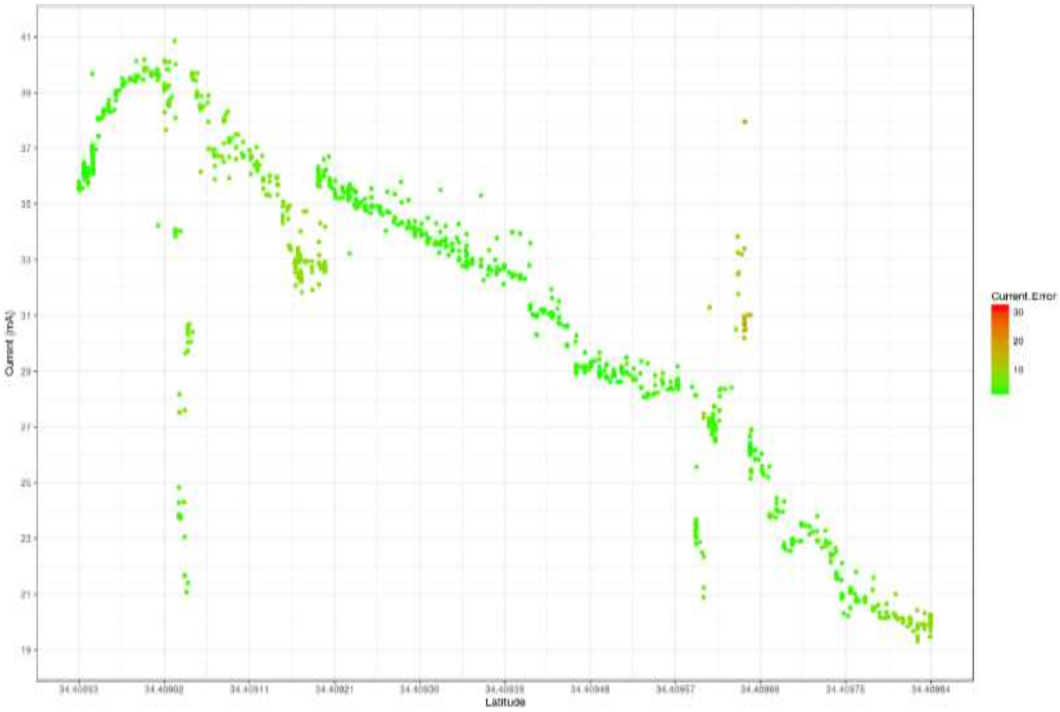
Figure 67: Spar Survey of Belowground Gas Line

Source: Gas Technology Institute

Figure 68: Mapping of Location of Pipe Segment in Section 1

Source: Gas Technology Institute

Figure 69: Plot of Measurement of Device in Section 1



Source: Gas Technology Institute

Figure 70: Mapping of Location of Pipe Segment in Section 2

Source: Gas Technology Institute

Figure 71: Plot of Measurement of Device in Section 2

Source: Gas Technology Institute

Further Development Status

The implementation of the device to identify coating disbondment, in addition to pipe locating, was demonstrated in the field tests. Further work is planned by the utility in 2019 to dig and inspect the pipes at the identified locations. Further tests in various field conditions may also need to be performed to enhance system accuracy. Further calibration of the software tools may also be performed based on the new field data after utility excavations and validation.

Automated Material Traceability, Pacific Gas and Electric Company Pilot Demonstration

Current techniques for capturing critical material traceability properties involve legacy processes that require manual data entry and can lead to missing or incomplete records. The process demonstrated in this project automated data entry and transfer to eliminate opportunities for errors. Furthermore, the approach used open and non-proprietary systems that could be implemented for steel pipes.

Traceability for steel pipes is more challenging than for plastic pipes as it requires detailed data on the chemical and mechanical properties. This data is typically supplied to operators through a complex “Material Test Report’. Also, steel assets can be composed of materials from multiple different manufacturers, further complicating the ability to accurately record traceability data.

To address these challenges, the demonstrated system allowed steel asset manufacturers to submit material traceability data to a central repository that creates a unique ID to facilitate traceability. The desired end-state includes a business process where the manufacturer uploads material traceability data, receives a unique ID, and applies a barcode with the unique ID to the asset. The operator would then scan the barcode during construction and retrieve the material traceability data from the central repository for storage in a GIS or other system of record.

The objective of the demonstration was to support the implementation of this process to improve risk assessment and integrity management programs by automating data gathering, storage, and material traceability.

Field Demonstration

The demonstration was coordinated with the system developer “LocusView” and was performed on September 20, 2018 at the PG&E job site in Concord, California. It included the following tasks:

- Requesting steel pipe mills to deliver material traceability data (mechanical and chemical properties) in a standardized, electronic format
- Requesting steel pipe mills to use a standardized barcode and/or RFID tag to label the pipe with a unique identifier that links back to the material traceability data
- Field demonstration of using the barcode/RFID tag to capture material traceability data as part of the construction documentation record (as-built record)
- Demonstration of automatically transferring the material traceability data into the enterprise system of record (GIS) without manual data entry.

The site was excavated at a steel main connected to a service line as shown in Figure 72.

Figure 72: Attachment of Barcodes at Main and Service Lines

Source: Gas Technology Institute

PG&E operators attached sample barcodes to the pipe and fittings at the job site. In actual operation, the manufacturer would be required to apply barcode labels during the manufacturing process. The barcode structure for the steel pipes is shown in Table 38 in comparison to the standard American Society for Testing and Materials (ASTM) code for plastic pipes.

Table 38: Barcode Structure for Plastic and Steel Pipes

	ASTM F2897 – Plastic	New Steel Material Traceability Code
Asset Type	Tapping tee	Valve
Asset Subtype	EF by stab outlet	Ball
Material Type	PE2406	Steel
Size	2-inch	24-inch
Manufacturer	Perfection	Mueller
Manufacture Date	July 1, 2018	July 1, 2018
Unique ID	123456 (lot code specific to each manufacturer	80658 (unique ID assigned by new material traceability system that links back to full material traceability data)

Source: Gas Technology Institute

Barcodes were scanned as shown in Figure 73 to capture the unique ID information in the GIS database, and precise coordinates were captured using a handheld mobile GPS unit. Supporting information such as weld traceability data was also captured during the demonstration. The process of accessing mapped assets, with the unique ID stored as an attribute, in a Web GIS application was demonstrated.

Figure 73: Scanning Barcodes at Job Site

Source: Gas Technology Institute

The operator down loads the traceability records with the unique IDs in the web-page at the site. The form is shown in Figure 74 and the web system provides the following:

- Web interface to search for records using the unique ID.
- Web interface to download the COC and related manufacturers data.
- Records of the material test report (MTR) as the authoritative material traceability documentation for steel pipe and certification of compliance (COC) as the authoritative material traceability document for steel valves and links to multiple MTRs for sub-components.

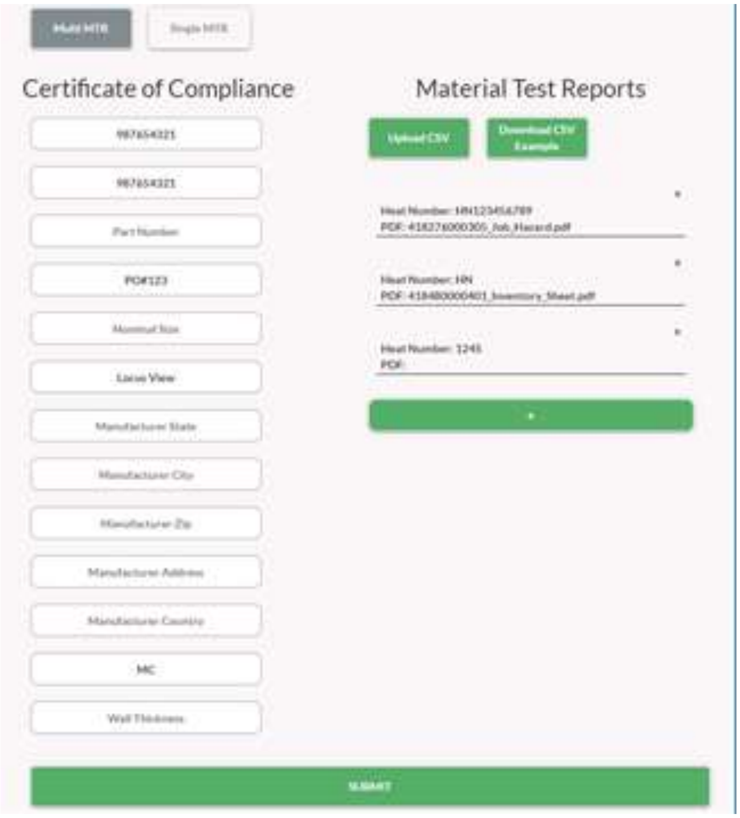
Further Development Status

Risk models and integrity management programs rely on high quality analytical data to support threat identification, risk ranking, and selection of mitigation techniques. Material traceability data, including mechanical and chemical properties, is the foundation of a complete asset record to support risk and integrity analysis. The field demonstration has shown the applicability of the procedure. Further development needs for a fully implemented application would require the following:

- Involvement of steel pipes manufacturers to apply codes during the manufacturing process.
- Development of a business process to upload and retrieve the data sets.

- Standard format for the manufacturer’s ID and other assets properties; possibly in an ASTM standard similar to ASTM F2897 for plastic pipes.
- Field demonstrations for the procedure implementation under various testing conditions.

Figure 74: Material Traceability Record with Unique Identification



Certificate of Compliance

987654321

987654321

Part Number

PO#123

Nominal Size

Lucas View

Manufacturer State

Manufacturer City

Manufacturer Zip

Manufacturer Address

Manufacturer Country

MC

Wall Thickness

Material Test Reports

Heat Number: HN123456789
PDF: 418276000305_Job_Hazard.pdf

Heat Number: HN
PDF: 418480000401_Inventory_Sheet.pdf

Heat Number: 1245
PDF:

Source: Gas Technology Institute

CHAPTER 8: Evaluation of Project Benefits

The project identified the technologies that provide the most benefits to California's natural gas pipeline integrity management practices. The web-based database of available and close-to-commercialization technologies provides operators with a reference for selecting the best technologies to use for their specific threats, site parameters, and operation conditions.

Several technologies were selected for field demonstrations based on: (a) Quantifiable measures for improved safety and operations efficiency, (b) technical concept and demonstrated capabilities, (c) Technology Readiness Level (TRL) with emphasis on technologies that are 1 to 3 years to the market, and (d) Coordination with the California gas utilities to support their safety and operation requirements.

How the Project Outcome Benefits California Ratepayers

The field demonstrations enabled operators to interact with manufacturers to address utility-specific requirements and produce successful implementations. Through providing these resources to pipeline operators, the safety of the natural gas infrastructure in California can be maintained efficiently.

The implementation of the new technologies provides the following benefits:

- Safety: The demonstrated technologies addressed the main areas associated with California natural gas transmission and distribution pipeline safety, specifically:
    - Damage prevention and detection, with a field demonstration of cross-bore detection during HDD.
    - Threats to pipeline integrity, with field demonstrations of the EMAT for detecting cracks and weld seams, and aboveground coating assessment tool for external inspection of corrosion and coating disbondment of pipelines.
- Cost: Cost savings are recognized from technologies that result in reduced operation time, improved pipeline locating and leak detection processes, reduced risks of damage, and lower rehabilitation costs. Examples of such technologies are listed in the Baseline Technology Review section of the report and may be retrieved from the web-based database. Examples of these technologies include:
    - Composite wrap repair integrity assessment.
    - Smart sensors network for pipeline monitoring.
    - Use of acoustic sensors for plastic pipe locating.
    - Automated pipe encroachment warning systems.
- Environmental impact: New technologies related to the detection of natural gas leaks will quantify methane emissions estimates from pipelines and other natural gas

facilities in California. Examples of these technologies are the 11 new and close-to-commercialization remote sensing technologies developed in the Monitor projects of the USDOE Advanced Research Projects Agency–Energy (ARPA-E) program.[62]

- Efficiency: Many of the new technologies provide operation efficiency gains along with safety and environmental benefits. Examples of these technologies include:
    - ILI inspection technologies with increased capabilities of inspecting smaller pipes, navigating obstacles, and increased sensor capabilities provide higher efficiency in pipeline inspection, data capture, and management. These new technologies address NTSB Safety Recommendation P-15-24 to develop and implement a strategy for increasing the use of ILI tools.[63]
    - Field demonstration of remote data collection and management provide an automated process of gathering, storing, and accessing material traceability data. This application addresses NTSB Safety Recommendation P-15-23 to collect data that supports the development of probabilistic risk assessment models.

Quantitative Estimates of Technology Benefits

The main benefit of implementing the research technologies is increasing pipeline safety and reducing significant pipeline incidents in California. A baseline estimate of these incidents is shown in the 20-year trend of significant incidents in transmission lines in California in Figure 75. Significant incidents are identified as those including any of the following conditions:

- Fatality or injury requiring in-patient hospitalization.
- $50,000 or more in total costs, measured in 1984 dollars.
- Highly volatile liquid releases and natural gas.
- Liquid and gas releases resulting in an unintentional fire or explosion.

Estimates of the costs associated with significant incidents in California are shown in Table 39 and Table 40. The tables show the consequences of these incidents for the period from 2005 to 2018 for transmission and distribution lines, respectively. Annual average costs of $45,591,750 in transmission lines incidents and $4,727,670 in distribution lines incidents were estimated in California from this data.

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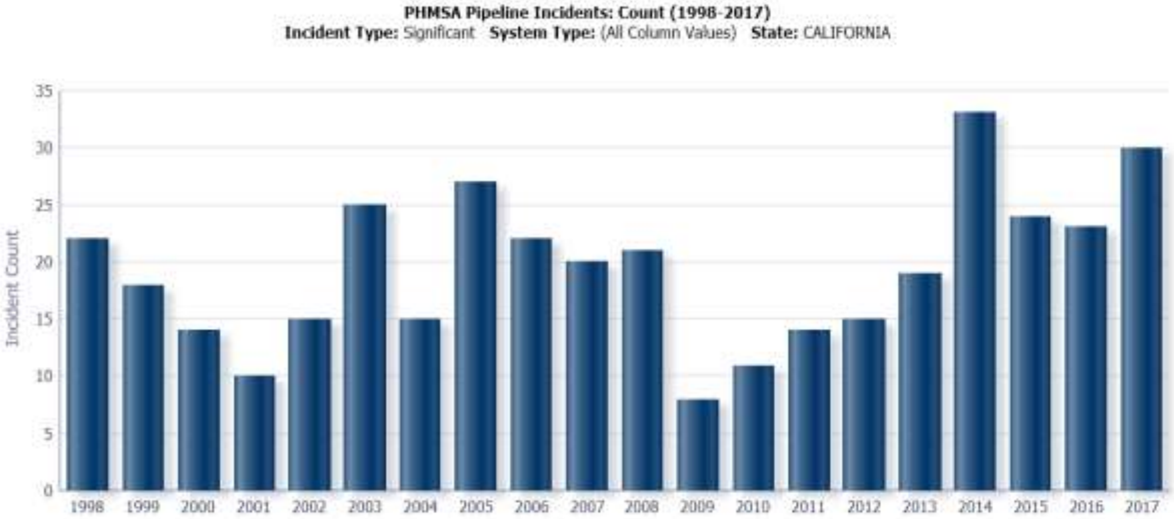
[62] Methane Observation Networks with Innovative Technology to Obtain Reductions – Monitor. USDOE ARPA-E, 2015. https://arpa-e.energy.gov/?q=arpa-e-programs/monitor.

[63] National Transportation Safety Board. Safety Recommendation P-15-23 and P-15-24. February 2015.

Figure 75: 20-Year Trend of All Pipeline Incidents in California



Source: PHMSA (https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-20-year-trends).

Table 39: Significant Incident Consequences in Gas Transmission Lines 2005-2018

Calendar Year	Public Fatalities	Public Injuries	Total Cost	Public Cost	Industry Cost
2005	0	0	$3,449,000	$0	$3,449,000
2006	0	0	$878,000	$0	$878,000
2007	0	0	$797,500	$0	$797,500
2009	0	0	$1,660,000	$300,000	$1,360,000
2010	8	51	$558,898,512	$50,000,000	$508,898,512
2011	0	0	$3,608,000	$0	$3,608,000
2012	0	0	$2,487,553	$31,450	$2,456,103
2013	0	0	$2,324,207	$300,000	$2,024,207
2014	0	0	$10,045,368	$0	$10,045,368
2015	2	15	$9,438,626	$1,000,000	$8,438,626
2016	0	0	$1,990,328	$0	$1,990,328
2017	0	0	$3,992,161	$275,500	$3,716,661
2018	0	0	$6,123,529	$1,571,913	$4,551,616

System type: as transmission; state: California

Source: PHMSA, (https://primis.phmsa.dot.gov/comm/StatePages/California.htm).

Table 40: Significant Incident Consequences in Gas Distribution Lines 2005-2018

Calendar Year	Public Fatalities	Public Injuries	Industry Injuries	Total Cost	Public Cost	Industry Cost
2005	0	1	0	$1,630,100	$1194000	$436,100
2006	0	1	0	$1,191,020	$1188000	$3,020
2007	0	0	5	$978,650	$850000	$128,650
2008	1	3	2	$829,060	$800000	$29,060
2009	0	0	0	$1,248,000	$750000	$498,000
2010	0	0	0	$396,100	$100000	$296,100
2011	0	0	0	$810,001	$600000	$210,001
2012	3	1	0	$1,476,945	$1110000	$366,945
2013	0	0	0	$3,058,737	$1676000	$1,382,737
2014	2	1	0	$18,350,294	$520000	$17,830,294
2015	0	2	0	$871,652	$250000	$621,652
2016	0	1	0	$2,073,224	$390000	$1,683,224
2017	0	2	0	$26,277,534	$3279696	$22,997,838
2018	0	2	3	$6,897,076	$250126	$6,646,950

System type: Gas distribution; state: California

Source: PHMSA. https://primis.phmsa.dot.gov/comm/StatePages/California.htm

The incidents costs and consequent environmental impact caused by the release of natural gas were used to estimate the benefits of using the technologies. This procedure is applied in the following example of the quantitative benefits of technologies for plastic pipes locating.

Plastic Pipe Locating Technologies

Excavation damage is the primary threat to gas distribution pipelines. Incident records reported by CPUC show that about 43 percent of incidents are caused by excavation damage.[64] The root cause analysis of excavation damage in shown in Figure 76. The figure shows that insufficient locating practices contribute to about 21 percent of these incidents.

Several existing electromagnetic technologies can locate metallic pipes. However, development of locating devices that recognize and pinpoint non-metallic pipes is an identified research need. Current locating practice for non-metallic pipes includes installation of tracer wires above the plastic pipes that can be located using traditional metallic locators. Several new technologies for locating plastic pipes are presented in Chapter 4. These technologies include acoustic pipe locators and GPR.

The number of excavation damage incidents in plastic pipes and consequent leaks in California are shown in Table 41. The table shows a total sum of 5,651 incidents in 2016.

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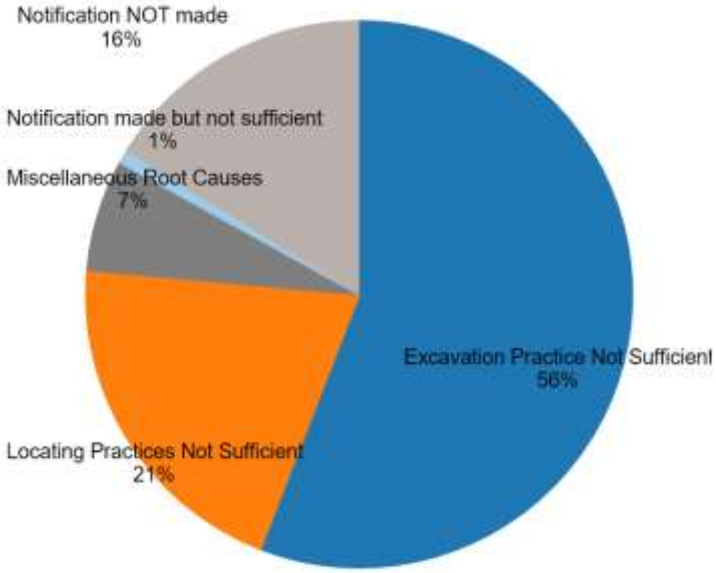
[64] California Public Utilities Commission (CPUC). Annual Reports. 2015 to 2017.

Figure 76: Excavation Damage Root Causes



Source: DIRT Interactive Report, http://commongroundalliance.com/dirt-2016-interactive-report

Table 41: Number of Excavation Damages and Leaks in Plastic Pipes in California, 2016

Operator Name	Total Leaks Excavation Mains	Total Leaks Excavation Services	Excavation Damages
Kamps Propane	0	0	9
City of Victorville	0	0	0
City of Susanville	0	3	3
Island Energy	0	0	0
Alpine Natural Gas	0	4	4
Ferrellgas	0	0	0
City of Coalinga	0	0	0
West Coast Gas Company Inc.	0	0	0
City of Long Beach Gas Department	0	30	48
City of Vernon	0	0	0
Navitas Utility Corporation	27	8	35
San Diego Gas & Electric Company	54	313	405
Southern California Gas Company	402	2,750	3,300
Pacific Gas & Electric Company	239	1,438	1,806
Navitas Utility Corporation	0	0	0
City of Palo Alto	1	34	35
Southern California Edison Company	0	0	6
Torrance Pipeline Company	0	0	0
Total	723	4,580	5,651

Source: Compiled from https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-annual-data

Quantitative Benefits of Plastic Pipe Locating Technologies

Quantitative estimates of the benefit of improving locating practices of plastic pipes in California include:

- About 5,650 hits were reported on plastic mains and services in California in 2016.
- About 21 percent of excavation damages to plastic mains and services resulted from inaccurate and insufficient locating practices.
- Applying this data shows that inaccurate locating of plastic pipes resulted in 1,186 hits on plastic lines in the distribution system in California in 2016.
- With an estimated average cost of about $750/repair for mains (in 2002 estimate),[65] the cost of poor plastic pipe locating resulted in about $889,500 of repairs in 2016.
- The cost of significant incidents in plastic pipes in California is shown in Table 42. A total of about $652,800 in property cost and 1,030 standard cubic feet (SCF) of gas release have resulted from plastic pipes excavation damage in 2016.
- The above estimates resulted in a total annual loss of $1,542,300 of damages and repairs to plastic pipes. This estimate does not include other consequences such as system shut off, fatalities, and injuries.

The estimates in Table 42 may be compared against the cost of improving current excavation practices and using new technologies for locating non-metallic pipes. These practices and technologies include:

- Improving practices of installing tracer wires.
- Installing RFID sensors on pipes for location and identification.
- Enhancing the development and commercialization of acoustic sensors, GPS and other locating technologies.
- Improving utility GIS data, inventory records, and traceability procedures.
- Enforcing notification before digging and improve utility excavation practices around underground facilities.

Further detailed cost-benefit analysis was performed on the technologies selected for field demonstrations since these demonstrations provided further knowledge of the technology scope, limitations, reliability, performance, and projected costs of implementation. Several other parameters were considered for the selected close-to-commercialization technologies, including:

- Real-time monitoring and reliability of data reporting.
- Ease of training and implementation.
- Estimated costs associated with development and commercialization.
- Benefits in comparison with existing technologies that can perform similar functions.

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[65] Gas Distribution Industry Survey of Costs of Installation, Maintenance and Repair, and Operations. Gas Technology Institute. Report GRI-02/0183. 2002.

Table 42: Consequences of Significant Incidents in Plastic Pipes in California

Year	County	Gas Released (scf)	Fatality	Injuries	Ignition	Explosion	System	Property Cost ($)	Cause
2016	Los Angeles	701	0	0	Yes	No	Main	90,946	Excavation damage
2016	Merced	1,500	0	0	No	No	Service	216,602	Equipment failure
2016	Sacramento	330.16	0	0	No	No	Main	561,860	Excavation damage
2016	Alameda	0	0	0	Yes	Yes	Meter/ Regulator	155,000	Other outside force damage
2016	Ventura	0	0	1	No	No	Main	0	Other outside force damage
2015	Sacramento	427.53	0	0	No	No	Main	51,838	Excavation damage
2015	Los Angeles	3,185	0	0	No	No	Main	56,194	Excavation damage
2015	Sacramento	293	0	0	No	No	Main	164,860	Excavation damage
2014	Santa Clara	1,228	0	0	No	No	Main	109,640	Excavation damage
2014	Contra Costa	3.59	0	0	No	No	Main	70,021	Excavation damage
2014	Santa Clara	67.5	0	0	No	No	Main	67,567	Excavation damage
2014	Monterey		0	0	No	Yes	Main	302,000	Incorrect operation
2013	El Dorado		0	0	Yes	No	Service	56,000	Excavation damage
2013		10.9	0	0	No	No	Main	3,775	Excavation damage
2013	Orange	11	0	0	Yes	No	Service Riser	50,866	Other outside force damage
2013	Santa Clara	820	0	0	No	No	Main	55,000	Excavation damage
2013	Alameda		0	0	Yes	No	Service	102,200	Excavation damage
2012	Orange	162	0	0	Yes	No	Service	72,000	Material failure of pipe or weld
2012	San Bernardino	1	0	0	No	No	Main	76,006	Other outside force damage
2012	Riverside	1	0	0	No	No	Main	70,506	Other outside force damage
2012	San Francisco		0	1	Yes	Yes	Service	1,000,000	Other outside force damage
2012	Monterey		0	0	Yes	No	Meter/ Regulator	152,000	Other outside force damage
2012	Los Angeles	19	0	0	No	No	Service	151,415	Other outside force damage
2011	Santa Clara	120	0	0	Yes	No	Main	612	Material failure of pipe or weld
2011	Nevada	158	0	0	No	No	Service	89,876	Material failure of pipe or weld
2010	Placer		0	0	No	No	Main	293,600	Material failure of pipe or weld
Total		**9,039**						**4,631,792**	

Source: https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files

Cross-Bore Detection Technology

Specific excavation damage incidents are associated with HDD in urban environments. These cross-bore incidents occur during HDD installation of a gas line which involves hitting a crossing sewer line and can go undetected for extended periods of time. When the gas line clogs the sewer line, sewer cleaning operation often causes damage to the gas line, resulting in gas leaks into the sewer system.

ORFEUS is a GPR for real-time obstacle detection during the HDD operation. The technology was developed through a collaborative research project with financial support from a consortium of natural gas and industries in Europe.[66]

The technology was evaluated in a field trial at the PG&E test site at Livermore, California in April 2017. Details of the demonstration setup and results were presented in Chapter 7.

Quantitative Benefits of Cross-Bore Detection Technology

The demonstrated technology addressed safety of the infrastructure system against reported cross-bore incidents during HDD operations. Gas utilities do not typically identify cross-bores as a separate category in excavation damage incidents reported to PHMSA. However, examples of the NTSB-reported incidents in Table 43 show the severity of potential damages from cross-bores.

Table 43: National Transportation Safety Board Record of Cross Bore Incident

NTSB Record	Incident	Property Damage Consequences	Probable Cause
P-76-83	Pipeline Explosion and fire, Kenosha, WI	2 fatalities, 4 injuries, and 3 destroyed homes	HHD installation of gas main broke a sewer lateral. Later cleaning of sewer line resulted in damage to gas line.
PAB-99-02	Pipeline Rupture and fire, Indianapolis, IN	$2 million Property damage	Directional drilling operations carried out in the proximity of existing underground facility.

Source: National Transportation Safety Board. Incident Reports.

More recently, the NTSB Safety Recommendation P-99-1 in 1999 has required that natural gas operators" damage prevention programs include actions to protect their facilities when directional drilling operations are conducted in proximity to those facilities.

Other state's recommendations address cross-bore threats during HDD operations. The Minnesota Office of Pipeline Safety (MNOPS) has reported 155 instances in Minnesota where gas pipelines were inadvertently installed through privately owned sewer service laterals due to trenchless construction techniques.[67] The majority of these "cross bores" were found by plumbers while cleaning sewer service lines. Since 2000, six gas lines have been punctured by sewer cleaning contractors. On three occasions, the gas ignited, resulting in significant injuries and property damage.

The Common Ground Alliance is an association consisting of 1,700 organizations and members of the underground utility industry. The alliance promotes best practices for the reduction of excavation damage and publishes annual Damage Information Reporting Tool (DIRT). Table 44 of the DIRT statistical excavation damage in California in 2016 shows 59 damages to energy

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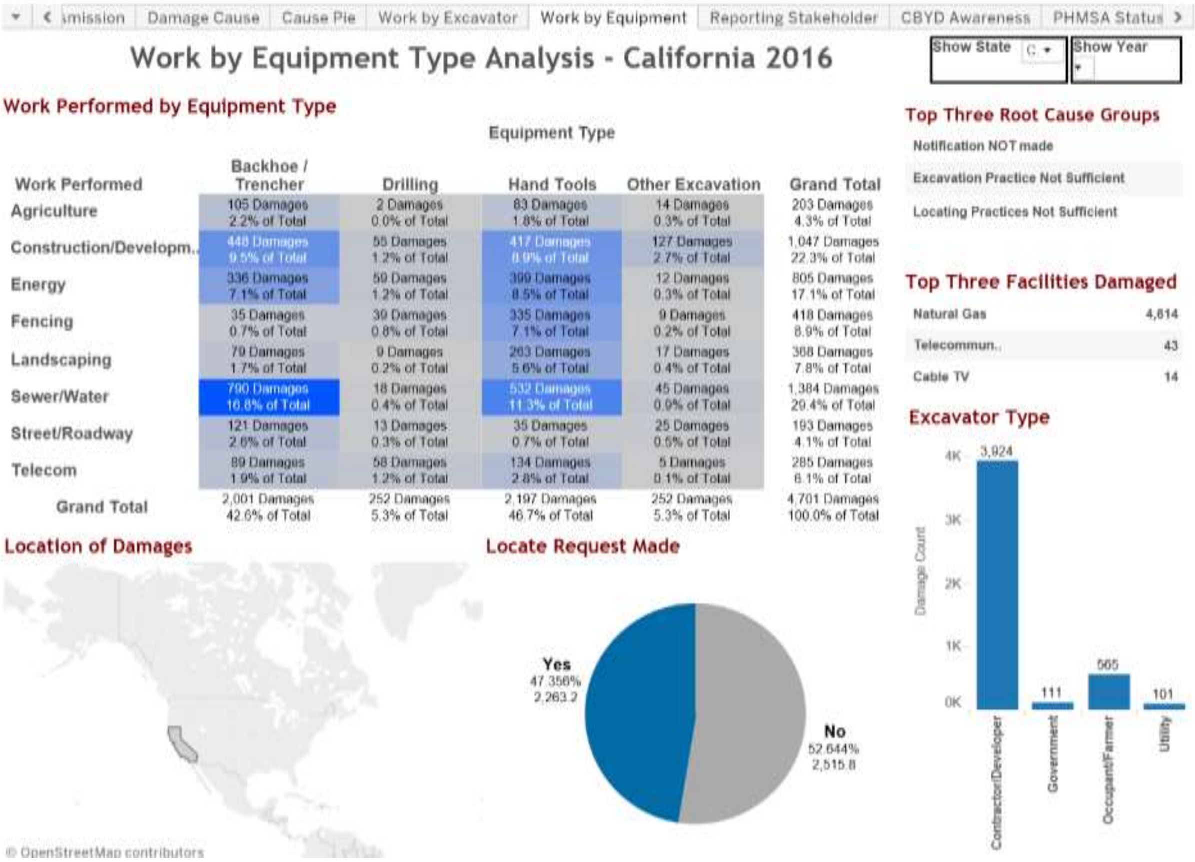
[66] *Operational Radar For Every drill string Under the Street (ORFEUS)*. Demonstration completion report. Grant agreement no: 308356. Sept. 2015.

[67] Minnesota Department of Public Safety. Alert Notice. May 10. 2010.

lines and 18 damages to sewer lines due to drilling equipment. The data, however, does not specify the details of the drilling equipment and consequences of these damages.

Table 44: Excavation Damage by Drilling in California, 2016



Work by Equipment Type Analysis - California 2016

Work Performed by Equipment Type

	Equipment Type				
Work Performed	Backhoe / Trencher	Drilling	Hand Tools	Other Excavation	Grand Total
Agriculture	105 Damages 2.2% of Total	2 Damages 0.0% of Total	83 Damages 1.8% of Total	14 Damages 0.3% of Total	203 Damages 4.3% of Total
Construction/Developm..	448 Damages 9.5% of Total	55 Damages 1.2% of Total	417 Damages 8.9% of Total	127 Damages 2.7% of Total	1,047 Damages 22.3% of Total
Energy	336 Damages 7.1% of Total	59 Damages 1.2% of Total	399 Damages 8.5% of Total	12 Damages 0.3% of Total	805 Damages 17.1% of Total
Fencing	35 Damages 0.7% of Total	39 Damages 0.8% of Total	335 Damages 7.1% of Total	9 Damages 0.2% of Total	418 Damages 8.9% of Total
Landscaping	79 Damages 1.7% of Total	9 Damages 0.2% of Total	263 Damages 5.6% of Total	17 Damages 0.4% of Total	368 Damages 7.8% of Total
Sewer/Water	790 Damages 16.8% of Total	18 Damages 0.4% of Total	532 Damages 11.3% of Total	45 Damages 0.9% of Total	1,384 Damages 29.4% of Total
Street/Roadway	121 Damages 2.6% of Total	13 Damages 0.3% of Total	35 Damages 0.7% of Total	25 Damages 0.5% of Total	193 Damages 4.1% of Total
Telecom	89 Damages 1.9% of Total	58 Damages 1.2% of Total	134 Damages 2.8% of Total	5 Damages 0.1% of Total	285 Damages 6.1% of Total
Grand Total	2,001 Damages 42.6% of Total	252 Damages 5.3% of Total	2,197 Damages 46.7% of Total	252 Damages 5.3% of Total	4,701 Damages 100.0% of Total

Top Three Root Cause Groups

Notification NOT made

Excavation Practice Not Sufficient

Locating Practices Not Sufficient

Top Three Facilities Damaged

Natural Gas	4,814
Telecommun..	43
Cable TV	14

Location of Damages

Locate Request Made

Excavator Type

Source: DIRT Interactive Report. http://commongroundalliance.com/dirt-2016-interactive-report

Estimated Cost of the Demonstrated Technology

The current status of the ORFUES technology development is at the TRL 8 level. This level is characterized by the system prototype being completed and demonstrated in the field. Findings from the demonstration were:

- The technology has been proven to work in its final form, and under expected field conditions.
- Data management and supporting information are complete.
- Operational procedures are virtually complete.

Table 45 shows the development phases and associated funds of the prototypes. The development is currently in the process of developing a commercial unit with the following steps for implementation and commercialization:

- Review user interface and simplify the use of the system.

- Update data review module for target locations in 3-D and output of detected targets into a database.
- Further rugged design of critical components
- Minimize number of components to allow easy integration into standard drilling rigs
- Increase the operational drilling length (communication)
- Operational testing under further anticipated site conditions.

Table 45: Development Phases of ORFEUS Technology

Phase	Development	Duration	Funding Agencies	Funding ($)
Phase-1	Development of the GPR system and prototype	Nov 2006 - April 2010	European Consortium (9 organizations)	6 million€ (about 7 million US$)
Phase-2	Field prototype A - 4 demos in Europe & 1 Demo at PG&E	Oct 2012 - Sept 2015	European Consortium (11 organizations)	3.5 million€ (about 4.1 million US$)
Phase 3	Field Prototype B, commercial unit	2018 - Current [expected 2 years]	OTD, PHMSA and industry matching fund	about 3 million US$

ORFEUS = operational radar for every drill-string under the street

Source: Gas Technology Institute, Field demonstration reports

Comparison with Existing Technologies

Although the development costs of GPR technologies such as ORFEUS are relatively high, they avoid the costs of open trenching installation that requires traffic management, transport of hard-core material, re-instatement of road surface, and significantly reduce noise and disruption to businesses and the public.

Alternative options of the detection of unmarked sewer lines include the following:[68]

- Use "one-call" center for pipe locating as well as identifying and marking the locations of buried assets before any infrastructure is added or altered in an area.
- Expose all underground utilities that are perpendicular or parallel to the bore path and verify the depth of the facilities.
- Consider excavating test holes at all crossing locations.
- Use a sewer camera or listening device where sewer lines are not physically exposed.

The above recommendations may reduce some of the risks for hitting laterals when they are detected. However, the use of a technology that provides real-time detection capabilities eliminates the risks of hitting undetected obstacles. Moreover, post-construction detection

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[68] American Gas Association White Paper. *Natural Gas Pipelines and Unmarked Sewer Lines – A Damage Prevention Partnership*. April 2010.

systems such as cameras and other mechanical systems only show hits after they occur and fail to detect all damage that may have occurred to sewer lines.

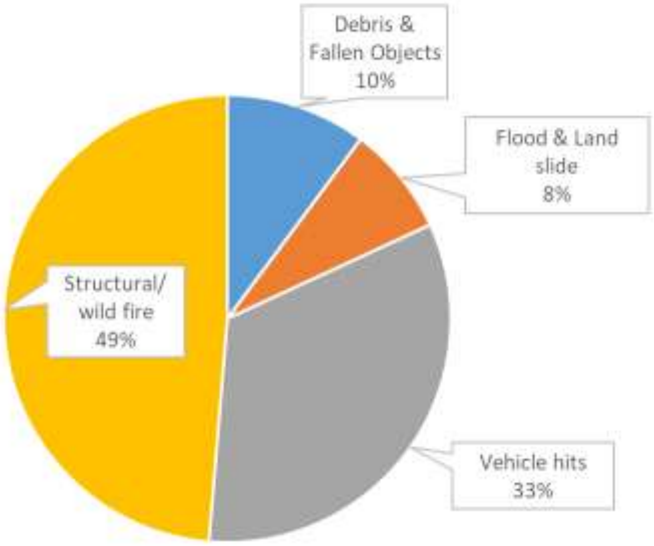
A review by the city of Palo Alto, CA on cross-bores in their sewer system shows that about 10,791 sewer laterals (60 percent of their 18,028 laterals) were inspected and nearly half of the attempted inspections were not completed because of adverse conditions in sewer lines.[69]

Breakaway Disconnect and Shut-off for Meter Risers

Incident records reported by the CPUC from 2015 to 2017 showed 865 incidents. These incidents were reported according to a set criterion that included consequences of casualty, hospitalization, damage, media coverage, and service interruption. Some of these reported incidents were listed in multiple years, depending on the durations of their investigations. Details of CPUC records during this period are shown in Appendix D.

Incidents resulting from natural and external forces in California were about 31 percent of the reported incidents. A significant number of these accidents were due to vehicular hits to aboveground gas meters. Figure 77 shows that 33 percent of the incidents caused by natural and external forces on the gas pipeline system in California resulted from vehicular hits. The above figures show estimated 88 vehicular hits in California during the 2015 to 2017 reporting period.

Figure 77: Reported Damages in California by Natural and External Forces, 2015-2017



Source: Compiled from California Public Utilities Commission, Annual Reports, 2015 to 2017

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[69] Utilities Department: Cross Bore Inspection Contract Audit. City of Palo Alto Office of the City Auditor. June 2017.

Estimated Cost of Demonstrated Technology

The demonstrated technology addressed safety of the infrastructure system against the reported incidents of hitting gas meters. Consequences of these incidents are not typically identified in a separate category in PHMSA reports.

The current status of the breakaway disconnect technology development is at TRL 9 level. With the completion of field demonstrations of the technology, the costs of implementing the technology consist mainly of the cost of the breakaway valves and labor and related retrofit costs for the installation of the valves at the locations of high risks of vehicular hits of gas meters.

Electromagnetic Acoustic Transducer Technology

EMAT technology is an acoustic (UT) sensor that uses magnets combined with an alternating current to induce ultrasonic waves in pipe material. The EMAT addresses the regulatory requirements to find and characterize cracks in welds and pipe walls as a part of the integrity management of natural gas transmission and distribution pipelines.[70,71] The use of EMAT technology in the internal inspection of gas pipelines addresses the following needs:

- Inspection of unpiggable pipes. There is a continued need for the development of technologies to improve access into the pipe interior for axial inspection in these pipes. Low flow, small diameters, bends, valves, and other reduced diameter constraints are the greatest barriers in the inspection of unpiggable pipes that the new EMAT technology is developed to overcome. The currently developed technology inspects small-diameter (8 inch) pipes, with future development plans to inspect smaller sizes.
- Detection and characterization of micro-anomalies such as planar defects, surface cracks, lack of fusion in welds, fatigue cracks, and general wall loss.
- The developed technology provides a viable alternative to acoustic sensors (UT) in the inspection of gas pipelines since it does not require a liquid couplant for contact with the inside pipe wall.

Quantitative Benefits of Demonstrated Technology

Most commonly ILI are performed to detect corrosion metal loss and dents resulting from mechanical damage. Figure 78 shows the types of the anomalies detected by ILI in California in 2015. A small portion of ILI (about 11 percent) is currently performed for cracks and seam-weld defects.

The integration of EMAT technology in an ILI platform to inspect small-diameter unpiggable pipes is expected to find and characterize crack defects in these pipes. A review of USDOT PHMSA serious incident records of gas transmission lines in California from 2010 to 2016

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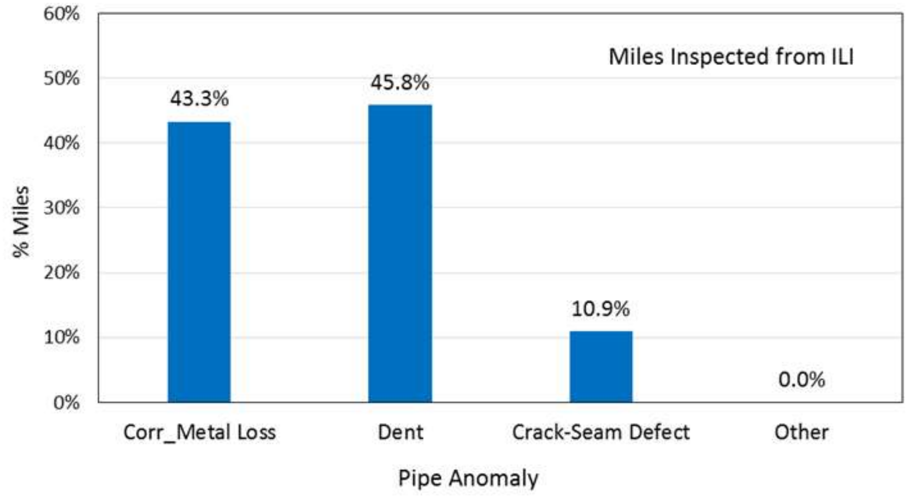
[70] 49 CFR Part 192, Subpart O - Gas Transmission Pipelines Integrity Management, August 2018.

[71] 49 CFR Part 192, Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines, Final Rule, Federal Register, Vol. 74, No. 232, December 2009.

shows that threats detectable by ILI caused 32 out of 49 incidents in this period as shown in Table 46. The threats detected by ILI are identified as:

- Construction and fabrication related defects
- Environmental-related cracking
- Excavation damage and previous damage due to excavation activities
- External corrosion

Figure 78: Breakdown of Types of Pipe Anomalies Detected by In-Line Inspection



Source: Compiled from USDOT, PHMSA, Pipeline Natural Gas Incidents, 6-year Data [from 2010 - 2016]

Table 46 also shows the volume of unintentional gas release in thousand cubic ft (Mcf) and costs of these incidents in California. The PHMSA incident records in transmission lines in California from 2010 to 2016 are shown in Appendix B.

Table 46: Costs of incidents Detectable by In-Line Inspection in California [2010-2016]

Cause Detail	Number of Incidents	Unintentional Release of Gas	Fatality	Injury	Cost of Gas Released ($)	Total Cost ($)
All incidents in California	49	832,909	10	64	3,043,622	586,204,128
Incidents with threats detectable by in-line inspection	32	562,737	2	13	1,826,294	14,466,566
Incidents with threats detectable by in-line inspection (pipes less than 12-inch diameter)	17	303,601	0	0	844,944	4,791,731

Source: Compiled from USDOT, PHMSA, https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files [2010-2016]

Since the developed EMAT technology addresses small diameter pipes, the benefit of using the technology is specific to the incidents in pipes with diameters smaller than 12 inches. A total number of 17 incidents in the table occurred in these pipe sizes, which could have been addressed with the implementation of this technology. These incidents resulted in the release of about 303,600 Mcf of natural gas and had a total cost of $4,791,730.

The estimates in Table 46 are conservative since other ILI technologies are used in the inspection of several threats other than cracks and seam welds, such as metal loss and other mechanical damages. NTSB records of incidents related to cracks and crack-like damage in weld seams are shown in Table 47. The table shows high costs and significant gas and liquid releases from pipeline rupture incidents caused by this type of damage.

Table 47: Consequences of Crack-Related Significant Pipeline Incidents

NTSB Record	Incident	Gas/Liquid Release	Cost	Probable Cause
PAR-12-01	Pipeline rupture and release, Marshall, MI	843,444 gal crude oil	$767 million	Corrosion fatigue cracks that grew from crack and corrosion defects under disbanded polyethylene tape coating
PAR-11-01	Natural gas transmission pipeline rupture and fire, San Bruno, CA	47.6 million scf	Fire destroyed 38 homes, damaged 70, fatalities 8	Inadequate quality assurance and quality control in 1956 during line relocation that allowed installation of a substandard and poorly welded pipe section with visible seam weld flaw
PAR-09-01	Rupture of hazardousliquid pipeline with release and ignition of propane, Carmichael, MS	430,626 gal	Fire destroyed 4 homes, fatalities 2, injuries 7	Failure of weld that caused pipe to fracture along longitudinal seam weld
PAR-04-01	Rupture of Enbridge pipeline and release of crude oil, near Cohasset, MN	251,860 gal of crude oil	$5.6 million	Inadequate loading of pipe for transportation allowed fatigue crack to initiate along seam of longitudinal weld during transit
PAR-01-03	Pipe failure and leak, Greenville, TX	564,000 gal	$18 million	Corrosion fatigue cracking that initiated at edge of longitudinal seam weld at likely pre-existing weld defect
PAB-01-01	Liquid petroleum pipeline rupture, Knoxville, TN	53,550 gal	$7 million	Pipe rupture initiated by environment-induced cracking in area of pipe coating failure

Source: National Transportation Safety Board. Incident Reports.

Real-Time Monitoring and Reliability of Data Reporting

The output of pipe scanning during the test demonstration at the PG&E facility was shown in Figure 63. The top graph in the figure shows the reflection and transmission coefficients with the peaks representing flaws along the length of the pipe. The bottom graph shows the locations of the flaws. Further developments are ongoing in the current phase to produce simplified versions for the operators to identify and characterize flaws.

Ease of Training and Implementation

The current prototype provides automatic detection and characterization of the crack flaws in pipes manufactured with controlled cracks for calibration. The test results have shown that the EMAT sensor successfully located the simulated longitudinal cracks in terms of circumferential location and axial location.

Operation of the software and crack-detection tool requires trained personnel. The device developer (Qi2) has developed various ILI tools used in the inspection of liquid and gas pipelines and it is likely that the technology will be moved to a service provider to integrate the device in an inspection platform.

Estimated Cost of Demonstrated Technology

The current development of the EMAT technology by Qi2 is in Phase 3 of the work program shown in Table 48.

Table 48: Development Phases of Electromagnetic Acoustic Transducer Technology

Phase	Development	Technology Readiness Level	Duration	Funding Agencies	Funding
Phase 1	Bench unit for proof of concept	3 to 5	2014-2016	OTD-PHMSA-developer Matching fund	$480,000
Phase 2	Field prototype A, demos at developer (Quest), PG&E, and platform provider	5 to 6	2016-2018	OTD-PHMSA-Developer Matching fund	$1,183,775
Phase 3	Field prototype B, integrated unit with controlled field tests	6 to 8	2018-Current (expected 2 years)	OTD-PHMSA-Developer Matching fund	$974,413
Phase 4	Commercial units, field tests under various conditions	8 to 9	1 year	TBA	Estimated $900,000

Source: Gas Technology Institute

The technology development in Phase 3 is at the TRL 7 level with a system prototype being completed and demonstrated in the lab under simulated field conditions. At this level, the demonstration has shown that:

- The technology has been proven to work under expected field conditions
- Data management and supporting information are complete

- Operational procedures and mounting to a field unit platform are under development.

The development of an integrated field unit is currently in process and expected to complete by the end of 2018. Further field tests of the integrated unit are planned in a commercial platform.

Comparison with Existing Technologies

Several pipeline inspection technologies have been developed and used in traditional ILI for detecting and quantifying wall loss of large diameter pipes; and with limited effectiveness in sizing small longitudinal cracks. These technologies include shear-wave, MFL, UT, eddy current, and other electromagnetic based tools:

- Currently the primary inspection method for detecting and measuring longitudinal cracks in pipelines are shear-wave tools. These tools use angled transducers to launch shear waves that bounce between the inner and outer walls. Disruptions in both amplitude and timing are used to estimate crack depth. These tools require a liquid couplant to operate, which does not work in gas pipelines. Batching can be used to provide a liquid "plug" with the tool immersed in liquid; resulting in a more complex and less desirable approach.
- MFL tools saturate the pipe wall with a magnetic field. Material loss in the wall causes the magnetic field to leak outside the wall. Magnetic field detectors positioned near the wall sense the leaking flux which is analyzed to interpret flaw characteristics. Traditional MFL tools have difficulty finding axially-oriented cracks due to the axial magnetizer orientation. Circumferential and spiral tools have been developed to provide a more orthogonal relationship between the crack direction and the magnetic field. However, small volume-loss measurements make these cracks difficult to detect.
- Multi-modal tools such as UT tools with gas-coupled bulk waves are also used to measure wall thickness. These technologies do not require a couplant material but are currently focused on quantifying the wall loss and do not measure cracks.
- Eddy Current and other electromagnetic-based tools are able to detect internal cracks; however, they are more sensitive to cracks that initiate at mid-wall or from the outside wall of the pipe; causing the measurements of the crack depths using these tools to be problematic.
- EMAT sensors are used in crawlers to detect cracks and wall loss. However, current ones are used for larger pipes.
- There are a number of Guided-Wave tools used in the inspection of large diameter gas pipelines. These tools are not yet available for the smaller diameters.

In addition to sensor limitations, there are few inspection platforms that will work with unpiggable pipelines in the natural gas industry. Recent platform advancements include Pipetel's Explorer and Pipeline Crawler technology. Explorer, an untethered platform, is commercially available for various diameters with remote field eddy current (RFEC) and MFL sensors. Pipeline Crawler, a tethered platform with a range expected to increase to up to three miles. There are advantages and limitations of tethered and untethered platforms and the industry needs both options to allow the selection of the most appropriate method for a specific pipe segment.[72] Some of these platforms can be used with EMAT technology.

Recent advances in EMAT technology are promising for crack detection including stress corrosion cracks and longitudinal, long seam welds. Vendors such as General Electric and Rosen provide EMAT inspection tools, but these are currently limited to traditional ILI platforms and are not suitable for smaller diameter or unpiggable lines.

Corrosion and Coating Damage Inspection

The assessment of internal and external corrosion and mechanical damage (e.g., gouges, dents, and cracks) includes a broad range of technologies such as ECDA tools (for example, close interval and AC and DC voltage gradient surveys), pressure tests, and ILI tools. Examples of existing and new technologies for ECDA inspection are listed in Chapter 6.

The Spar 300 system for the ECDA inspection of steel pipes and coating was developed by Optimal Ranging Inc. (ORI). It was originally evaluated under the sponsorship of PHMSA as an effective tool for locating and mapping buried steel pipes. The post-processing of the data collected during surveys has also been able to locate breaks in coatings and attached appurtenances. The tool has indicated potential for detecting corrosion and disbonded coatings.

Quantitative Benefits of Demonstrated Technology

The NTSB records of incidents caused by corrosion damage are shown in Table 49.

Table 49: Consequences of Corrosion-Related Significant Pipeline Incidents

NTSB Record	Incident	Property Damage, Losses	Probable Cause
PAR-14-01	Pipeline rupture and fire, Sissonville, WV	Destroyed 3 houses, injuries 0, damaged several houses	External corrosion of the pipe wall due to deteriorated coting and ineffective cathodic protection
PAB-13-01	Pipeline rupture and gas release, Palm City, FL	Gas release 36 million scf, damage $606,360	Environmentally assisted cracking under a disbanded polyethylene coating that remained undetected
PAR-03-01	Natural gas pipeline rupture and fire, Carlsbad, NM	Fatalities 12, destroyed 2 bridges, damages $998,296	Significant reduction in pipe wall thickness due to severe internal corrosion
PAR-81-04	Pipeline rupture and fire, Long Beach, CA	Destroyed 1 house, damaged 11 houses, injuries 5	Overpressure of the pipeline and rupture at location thinned by internal corrosion

Source: National Transportation Safety Board. Incident Reports.

These records show significant damages of the gas pipeline system nationwide. As per PHMSA records, about 562,737 scf (standard cubic feet) of gas release and costs of $1,826,297 were

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[72] Internal Inspection Optimization Program: Phase 1 - R&D Roadmap. Gas Technology Institute. Project Number 21227. December 2012.

caused by incidents related to pipe corrosion, excavation damages, and material defects. About 33 percent of these incidents were caused by corrosion, resulting in an estimated 187,580 scf of gas release and $608,765 of costs in transmission lines in California from 2010 to 2016.

Records of significant incidents in the distribution pipeline system in California from 2010 to 2016 are shown in Table 50. These records show that corrosion failures in the distribution system resulted in costs of $326,500.

Table 50: Consequences of Distribution Line Incidents in California, 2010-2016

Cause	Incidents	Gas Release (mcf)	Fatality	Injury	Ignition	Explosion	Total Cost
Corrosion failure	1	365	0	0	0	0	$326,500
Equipment failure	1	1,500	0	0	0	0	$216,602
Excavation damage	24	33,598	8	6	5	0	$4,569,386
Incorrect operation	2	100	0	0	1	1	$357,000
Material, weld failure	5	1,312	3	1	2	1	$1,121,076
Natural force	60	7,702	9	11	55	8	$23,206,581
Other	1	210	0	0	0	0	$86,260
Total	94	44,787					$29,833,405

Source: Compiled from USDOT, PHMSA, https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files

Comparison with Existing Technologies

USDOT-PHMSA requires pipeline operators to annually report repairs performed, categorized by threat type, and to implement integrity management programs for both gas transmission and distribution systems. In these programs, hydrostatic pressure testing is the main strength diagnostic test for steel pipes under specific conditions. The test involves temporarily disconnecting a section of pipeline and pressurizing it with water. Hydrostatic testing can be recognized as a destructive test since failure of a pressurized pipe results in a leak or rupture of the pipe. Accordingly, there is a considerable interest in the implementation of non-destructive methods such as ECDA, GWT, ILI and internal inspection methods.

The effectiveness of the ILI tool depends on the condition of the specific pipeline section, its size, and the availability of a launching platform. These limitations restrict the ILI use in distribution systems. ECDA is a structured process that identifies the tools and procedures for assessing external pipeline corrosion. GWT is a non-destructive evaluation technology that employs low frequency ultrasonic waves that propagate along the length of the pipe while guided by its boundaries.

CHAPTER 9:
Technology Transfer Activities

The project focused on enhancing the efforts for the modernization of natural gas infrastructure. The technologies search aimed at assisting distribution and transmission pipeline operators in the identification and rehabilitation of particularly problematic segments where there is a need to provide safer and more cost-effective solutions. This was achieved by engaging California natural gas utilities in the following activities:

- An industry survey of natural gas operators to identify emerging new technologies to improve the integrity and safety of their system and reduce operations costs.
- An industry workshop in July 2017 to communicate with the Energy Commission, technical advisory committee, professional organizations, and technology developers.
- A Web-based program and database for the selection and application of new technologies. The database is planned to be continuously updated by GTI to serve the industry beyond the completion date of the research project.
- Field demonstrations of technologies selected with the California gas utilities to assist in their applications in their service areas.
- Identification and quantification of the benefits of the demonstrated technologies.

The approach for the technology transfer and implementation of the demonstrated technologies consisted of the following steps:

- Review natural gas market segments in California. Identify how the selected technologies target gas system characteristics.
- Use the outcome of the industry survey and workshop to focus on utilities needs and applications gaps.
- Research and categorize the technologies to match utilities' needs and identify their development status.
- Coordinate and perform field demonstrations of selected technologies and investigate their commercialization plans.
- Develop a road map for future development and implementation of the technologies.

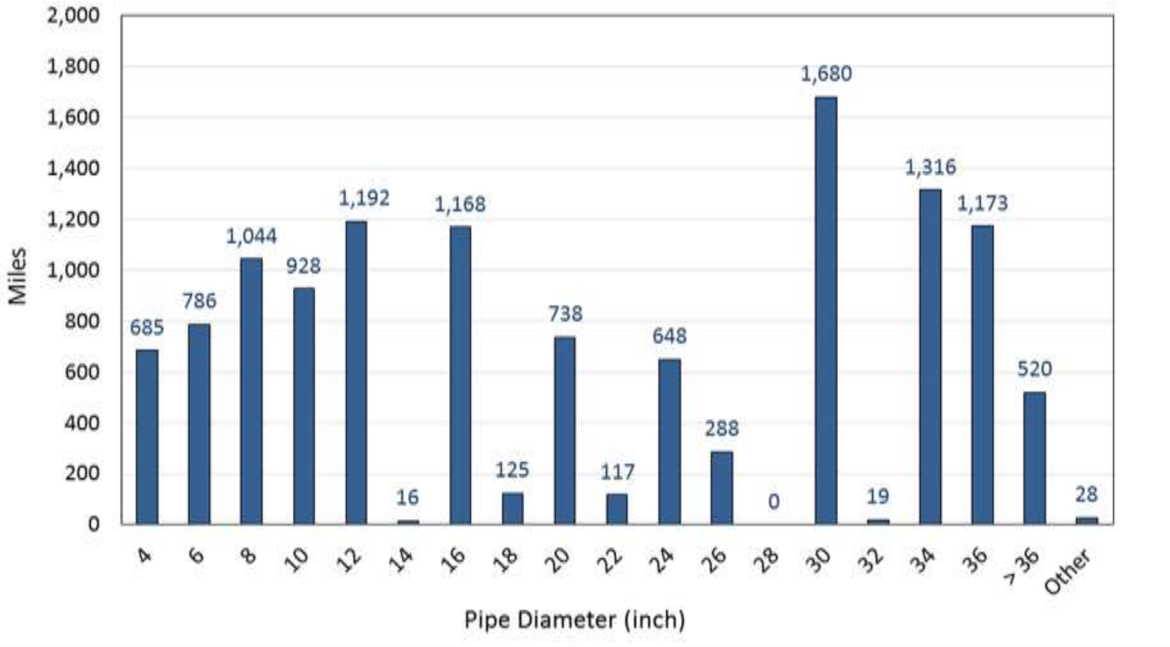
This chapter provides details about these steps.

Characteristics of Market Segments in California

Transmission and Distribution Pipeline Sizes

Gas transmission pipes are defined in the Code of Federal Regulation 49 CFR §192.3 as pipelines, other than a gathering line, that: (1) transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field. Figure 79 shows the distribution of onshore transmission pipe sizes in California.

Figure 79: Pipe Sizes in Onshore Gas Transmission Lines



Source: USDOT, PHMSA. https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-annual-data

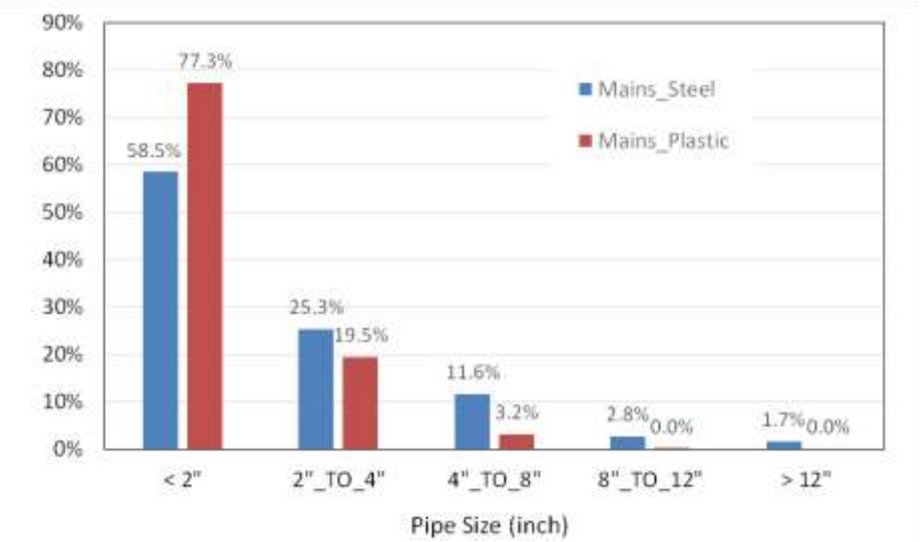
Twenty percent of the pipe sizes are 8-inch diameter or smaller. These data identify the following characteristics for technology selection:

- Inspection and damage detection of pipelines in populated high consequence (HCA) areas.
- Internal inspection of unpiggable and small diameter (8-inch and smaller) pipes.
- Low incidents of corrosion anomalies in the mostly cathodic-protected lines.
- No present need for technologies to evaluate and inspect composite pipes.

Figure 80 shows the sizes of the steel and plastic lines in gas mains in California. The majority of the gas distribution system consists of small diameter pipes of 2 to 4 inches. These characteristics of the gas distribution system identify the following for technologies' needs:

- Technologies for locating small diameter plastic pipes and preventing excavation damage.
- Research to inspect plastic pipe joints and butt-fusion.
- Corrosion monitoring and ECDA inspection of the coating disbondment.
- Data management and traceability records of plastic and steel pipelines.
- No need for technologies to evaluate and inspect cast iron pipes.

Figure 80: Pipe Sizes of Gas Mains in California



Source: Source: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-annual-data

Research Areas for Technology Implementation

Chapter 3 presented pipeline threats and the current status of inspection and integrity management in California. The chapter also summarized the results of an industry survey of California natural gas operators to identify research needs and emerging new technologies.

The project team reviewed more than 180 reference sources (listed in the References and Appendices sections of this report) and researched more than 150 recently-completed and close-to-commercialization technologies. The close-to-commercialization search focused on technologies that are one to three years to market. The search considered technologies developed and funded by various research organizations, including:

- Pipeline and Hazardous Material Safety Administration (PHMSA)
- USDOE National Energy Technology Laboratory and ARPA-E
- Department of Homeland Security
- California Energy Commission
- Pipeline Research Council International
- Northwest Gas Associations, NYSEARCH
- Operations Technology and Development
- University research projects
- Industry-developed devices and tools.

The technologies fall into the three main categories shown in Figure 81.

Figure 81: Technologies Categories and Research Areas

Source: Gas Technology Institute

Technologies for Damage Detection and Prevention

This category includes locating pipelines and underground facilities, identifying excavation damage and encroachments to the ROW, leak detection, and damage mitigation.

These technologies included the development of several devices and tools identified in Chapter 3. Examples are:

- Systems to locate pipelines during excavation and HDD.
- Remote monitoring for encroachments to pipeline ROW.
- Remote sensors using drones and fly over systems to detect and quantify leaks from underground pipes, well-head casings, and storage facilities.

The selection of technologies for possible implementation and transfer in this area resulted in two field demonstrations:

- Obstacle detection during HDD. The developed device (ORFEUS) is mounted on the drilling heard of the HDD unit and used GPR technology for obstacle detection. The demonstration was performed at PG&E testing site at Livermore, California in July 2017.
- Meter breakaway fitting. The device is a breakaway valve designed by OPW installed at the riser below the gas meters to shut off the gas when a damage due to vehicular hit occurs. The field demonstration was performed in January 2019 with SoCal Gas in Ontario, California.

Technologies for Threats and Integrity Management

This category includes detecting existing defects (such as corrosion metal loss, cracks, and dents) utilizing several devices in ECDA, internal inspection, pipeline testing and monitoring, and stress analysis techniques. Examples of these technologies include:

- Inspection of weld failures, and cracks; and enhance the output of adequate inspection protocols.
- Inspection of unpiggable and difficult-to-inspect pipes.

- Field data capture and control systems using smart devices.
- Effective failure prediction models, incorporating accurate operators' data.

The selection of technologies for possible implementation and transfer in this category has resulted in the following two field demonstrations:

- EMAT sensor for small-diameter, unpiggable gas pipeline for detecting and quantifying cracks and weld defects. The field demonstration was performed in February 2018 at the PG&E facility in San Ramon, California.
- Aboveground ECDA system for the assessment of steel pipes and coating disbondment. The device was tested at SoCal Gas sites in August 2018.

Technologies for Risk Assessment and Information Management

This category covers various technologies for data automation, asset tracking and traceability, visualization and GIS, risk assessment, response awareness, and cyber and physical security. Examples of these technologies include:

- Data collection and communications technologies.
- Risk models with integrated combined threats.
- Methods and procedures to improve asset tracking and traceability records.
- Technologies for decreasing the consequences of failure, including systems for emergency automatic shut off and flow control valves.
- Approaches that incorporate public awareness programs and procedures for emergency response.
- Systems to provide education and awareness to operators and the public.
- Cybersecurity of gas operation systems.

The following technology was selected in a field demo for possible implementation and transfer in this category:

- GIS device and data system for automating the process of gathering, storing, and accessing material traceability data. This system was demonstrated with PG&E in September 2018.

Technologies Commercialization Status

The ORFEUS device was demonstrated at PG&E test site and has an estimated TRL level of 8. The development of the ORFEUS technology started in 2006, and the research team continues to develop the equipment towards implementation and commercialization of the device in the HDD system. The technology is currently about two years from its commercialization. Chapter 8 estimated the remaining effort and costs to bring it to market.

The development of the breakaway disconnect valve was completed by the developer (OPW). The product is currently being evaluated by several natural gas utilities for installation at their service areas. Several field demonstrations of the technology may be performed for its implementation.

The development of the current EMAT device started in 2013 and consisted of 3 phases to develop a field-ready unit for evaluation under various conditions. A commercial unit is estimated in 2-3 years. Estimated development costs for the commercialization of this device were shown in Chapter 8.

The Spar device is currently available for steel pipe locating. Further field tests are needed for evaluating its use in detecting coating disbondment. Further work is planned by SoCal Gas to validate the inspections by the device at their sites.

The automated material traceability system is currently presented and evaluated by LocusView to establish a standard business process for its implementation. The process includes further coordination with pipe manufacturers and field demonstrations under various conditions.

Technology Knowledge Transfer

In addition to the workshop and field demonstrations listed at the California utility sites, papers were published and presented at a professional conference to share technical background and implementation data on two of the demonstrated technologies, namely:

- *Advanced EMAT Crack Tool for Unpiggable Pipelines*, Proceedings of the 12th International Pipeline Conference, Calgary, CA September 2018.
- *Reducing Excavation Damage in the Natural Gas Industry using Real-Time GIS and Sensors*, Proceedings of the 12th International Pipeline Conference, Calgary, CA September 2018.

Development of Roadmap

A recommended roadmap for technology implementation provides a general framework independent of the type of the technology. It consists of two-phases; with both phases administered concurrently. Such an approach is recommended to maximize the potential benefits of an implementation program and meet the goal of deploying technologies within a 2- to 4-year timeframe.

Phase 1 - Using Commercial and Close-to-Commercialization Technologies

Use of emerging technologies in this phase will provide a quick pathway to optimize the value of new technologies and the performance of the natural gas system. The projects tasks in this phase may include:

- Coordinate between commercializers and developers of new technologies and natural gas utilities for implementation in the gas industry.
- Perform field demonstrations at utility sites to evaluate the technologies under various operating conditions typically encountered by the utilities in their service areas.
- Address the barriers for the deployment of these technologies by the utilities.

- Perform cost-benefit analysis and study the impact of the technology implementation on program safety and reliability objectives.

Projects in this phase are at the 8 and 9 TRL levels and represent the first priority to address quick development and implementation needs. Funded projects in this phase require the coordination and involvement of developers, commercializers, and utilities.

The demonstrated technologies in this project provided examples of the developments in this phase based on market needs and benefits. Table 51 summarizes the current status of these technologies and remaining development and implementation needs.

Table 51: Demonstrated Technologies Status and Development Needs

Technology	Utility Demonstration Location	Completed Technology Readiness Level	Technology Status and Future Developments
ORFEUS, Real-time obstacles detection during HDD drilling	PG&E Test Site, Livermore, CA.	7	• Technology proven to work in field tests under controlled conditions. Provided automatic detection of pre-set obstacles. • Future work is enhancing development of software and visualization of the output. • Path to commercialization is defined. Commercial partners are involved in the development.
Meter Breakaway Fitting for Outside Force	SoCal Gas, at Subcontractor’s site, Ontario, CA.	8	• Demo helped identifying the success rate and parameters affecting the device performance. • Commercializer exists. Future work for utilities is evaluating the system in their service areas and recommending modifications for its implementation.
EMAT Sensor for Small-Diameter Unpiggable Pipes	PG&E, San Ramon, CA.	6	• Prototype proven to work under controlled testing conditions. • Currently developing field unit. Next step is testing under various field conditions. • Path to commercialization is defined.
Spar Aboveground Coating Assessment Tool	SoCal Gas service areas, Santa Monica, CA.	8	• Field demo identified locations of coating disbondment. Further validations by utilities in in progress. • Commercializer exists. • Further tests to evaluate full range of field conditions.
Automated Material Traceability of Steel Pipes	PG&E excavated site, Concord, CA	7	• Demo under one field conditions. Further tests to evaluate under full range of operating conditions. • Commercializer exists. Requires involvement of steel assets producers. • Needs standardized data format, possibly though an ASTM standard.

Source: Gas Technology Institute

Phase 2 – Support and Development of Emerging Technologies

This phase supports a wide variety of emerging technologies presented in Chapter 3 of this report. Further developments of these technologies would result in improved communications and monitoring capabilities along with a strategy to integrate their use in routine operations and inspections by the utilities. Projects tasks in this phase may include:

- Moving technologies from full-scale laboratory tests to higher TRL levels with prototypes used in field tests.
- Coordinate with developers to address specific utility needs.
- Work with the developers to engage in commercialization efforts.
- Identify the impact of implementing the technology.
- Conduct workshops for technology transfer.

Projects in this phase are anticipated to be at the 6 and 7 TRL levels with the following development requirements:

- Development of complete full-scale model and prototype with implementation in existing utilities systems.
- Field demonstration of the model and prototype in relevant environment.

Examples of technologies that fall in Phase 2 category include the following:

- Pipe locating and depth identification technologies, including development and enhancement of GPR systems in plastic and difficult-to-inspect pipes.
- Inspection of fusion joints in plastic pipes. These technologies include acoustic technologies for field inspection of the joints.
- Smart pipe networks with integrated sensors to provide continuous real-time monitoring of stresses and leak detections.
- Quantitative risk models for ranking the repair needs and prediction of pipeline failures.
- Data management and machine learning approaches for analysis of leaks and failure consequences.
- Training programs and situational awareness procedures for efficient and quick response to pipeline incidents and repair emergencies.

A summary of research areas and technologies for implementation in the road map is shown in Table 52. The table is an update of an earlier project for the Energy Commission on safety assessment of Transmission pipes.[73] The table shows selected technologies for the short-term Phase 1 implementation and the technologies above the TRL levels 6 that require 2 to 4 years of implementation and fit in Phase 2 activities of the roadmap.

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[73] California Natural Gas Pipeline Assessment: Improving Safety through Enhanced Assessment and Monitoring Technology Implementation. California Energy Commission. Report CEC-500-10-050. 2013.

Table 52: Status of Technologies in Implementation Road Map

Program Category	Technology Area	Projects 2016	2017	2018	2019	2020
a) Damage Detection and Prevention						
	Pipe and Facility Locating	🟩 Acoustic (APL), Metallic Joint Locators (MJL)	🟩	🟩		
		🟦 ORFEUS GPR Technology for HDD	🟦	🟦	🟦	🟦
		🟧 Plastic Pipe Locating (UT, RFID)	🟧	🟧	🟧	
	Right-of-Way (ROW) Encroachments		🟩 EEN Technology	🟩		
			🟩 High Accuracy Mapping	🟩		
		🟧 Stationary Sensors to Monitor Encroachment	🟧	🟧	🟧	
	Excavation Damage and Leak Detection	🟩 ARPA.E-Supported Leak Detection Technologies	🟩	🟩		
		🟩 PMD and RMLD Methane Detectors	🟩	🟩		
		🟦 Aerial Surveillance - LIDAR & Satellite-Based deployment	🟦	🟦	🟦	🟦
			🟦 Acoustic and Fiber Optic Sensors	🟦	🟦	🟦
	Damage Mitigation and Prevention		🟦 Integrity of Repairs: Composite material	🟦	🟦	🟦
		🟦 Breakaway Meter Disconnect	🟦	🟦	🟦	
			🟦 Leak Detection: Well-heads and storage facilities	🟦	🟦	🟦
b) Threats and Integrity Management						
	External Direct Assessment (ECDA)	🟦 Coating Disbondment (SPAR)	🟦	🟦	🟦	
		🟦 Guided-Wave Testing: Needs further field evaluation	🟦	🟦	🟦	
		🟦 Field Inspection of Welds and Joints	🟦	🟦	🟦	
	Internal Inspection (ILI)	🟩 MFL & Eddy current sensors	🟩			
		🟦 EMAT Sensors for Corrosion & Crack Detection	🟦	🟦	🟦	🟦
		🟩 Explorer Platform	🟩			
		🟩 Non-Piggable Platforms (TIGER)	🟩			
	Pipeline Testing and Monitoring		🟧 PE Butt-Fusion Inspection	🟧	🟧	🟧
			🟧 Stress Corrosion Cracking (SCC)	🟧	🟧	🟧
	Field Monitoring and Smart Devices	🟧 In-situ Sensors: For cathodic protection & pipe stresses	🟧	🟧	🟧	🟧
	Stress Analysis and Smart Devices		🟧 Smart-Pipe Network Sensors	🟧	🟧	🟧
c) Risk and Information Management						
	Data Automation and Management		🟧 Quantitative Models: For interactive threats	🟧	🟧	🟧
	Asset Tracking and Traceability	🟩 Traceability Standard for Plastic Pipes	🟩	🟩		
			🟦 Asset Tracking of Steel Pipes	🟦	🟦	
	Visualization and GIS	🟦 High Accuracy Mapping for Damage Prevention	🟦	🟦	🟦	
	Modeling and Risk Assessment		🟧 Quantitative & Bayesian Risk Models	🟧	🟧	🟧
			🟦 Interactive threats	🟦	🟦	
			🟦 Risk Assessment of LNG and Storage Facilities	🟦	🟦	🟦
	Risk Assessment of Natural force			🟦 Earth Movement and Earthquakes	🟦	🟦
	Response Awareness	🟦 Utility Situational Awareness System	🟦	🟦	🟦	
	Communications Protocols		🟧 RFID pipe communication systems	🟧	🟧	
	Cyber-Physical Security	🟦 Cybersecurity Collaborative Program	🟦	🟦	🟦	🟦
	[TRL 8-9] Developed/Commercially Available		🟩			
	[TRL >6] Developed, not commercialized		🟦			
	[TRL <6] Benchmark prototypes		🟧			

Source: Gas Technology Institute

LIST OF ACRONYMS

Term	**Definition**
AGA	American Gas Association
ARPA-E	Advanced Research Projects Agency - Energy
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
CFR	Code of Federal Regulations
CPUC	California Public Utilities Commission
DIMP	Distribution integrity management program
DOGGR	California Department of Conservation Division of Oil, Gas and Geothermal Resources
ECDA	External corrosion direct assessment
EEN	Excavation encroachment notification
EMAT	Electromagnetic acoustic transducer
ET	Eddy current testing
GIS	Geographical information system
GPR	Ground penetrating radar
GPS	Global positioning system
GPTC	Gas Piping Technology Committee (American Gas Association)
GTI	Gas Technology Institute
GWT	Guided wave technology
HDD	Horizontal directional drilling
ILI	In-line inspection
INGAA	Interstate Natural Gas Association of America
LDC	Local distribution company
LIDAR	Laser-based detection and ranging technology
MFL	Magnetic flux leakage technology
MIC	Microbiologically-influenced corrosion

Term	**Definition**
MSA	Meter set assemblies
NACE	National Association of Corrosion Engineers
NASA	National Aeronautics and Space Administration
NDT	Non-Destructive Testing
NIST	National Institute of Standards and Technology
NTSB	National Transportation Safety Board
NYSEARCH	Northeast Gas Association, Research Committee
ORFEUS	Operational radar for every drill-string under the street
OTD	Operations technology development
PG&E	Pacific Gas and Electric Company
PHMSA	Pipeline and Hazardous Materials Safety Administration
psig	Pounds per square inch
Qi2	Quest Integrated, Inc.
RAPID	Real-time active pipeline integrity detection system
RFID	Radio-frequency identification
ROW	Right-of-way
SCC	Stress corrosion cracks
SMYS	Specified minimum yield strength
SoCal Gas	Southern California Gas Company
SwRI	Southwest Research Institute
TRL	Technology readiness level
USDOE	United States Department of Energy
USDOT	United States Department of Transportation
UT	Ultrasonic testing

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Appendices

Appendices A through F listed below are available in *Pipeline Safety and Integrity Monitoring Technologies Assessment,* Appendices, CEC-500-2019-XXX-APP-A-F.

- Appendix A: Industry Survey Form
- Appendix B: Pipeline and Hazardous Materials Safety Administration Gas Incident Records in California [2010 – 2016]
- Appendix C: National Transportation Safety Board Gas Accident Records in California
- Appendix: Incident Records, California Public Utility Commission Safety Reports
- Appendix: Examples of Recent Commercial Pipeline Technologies
- Appendix: Examples of Close-to-Commercialization Pipelines Technologies