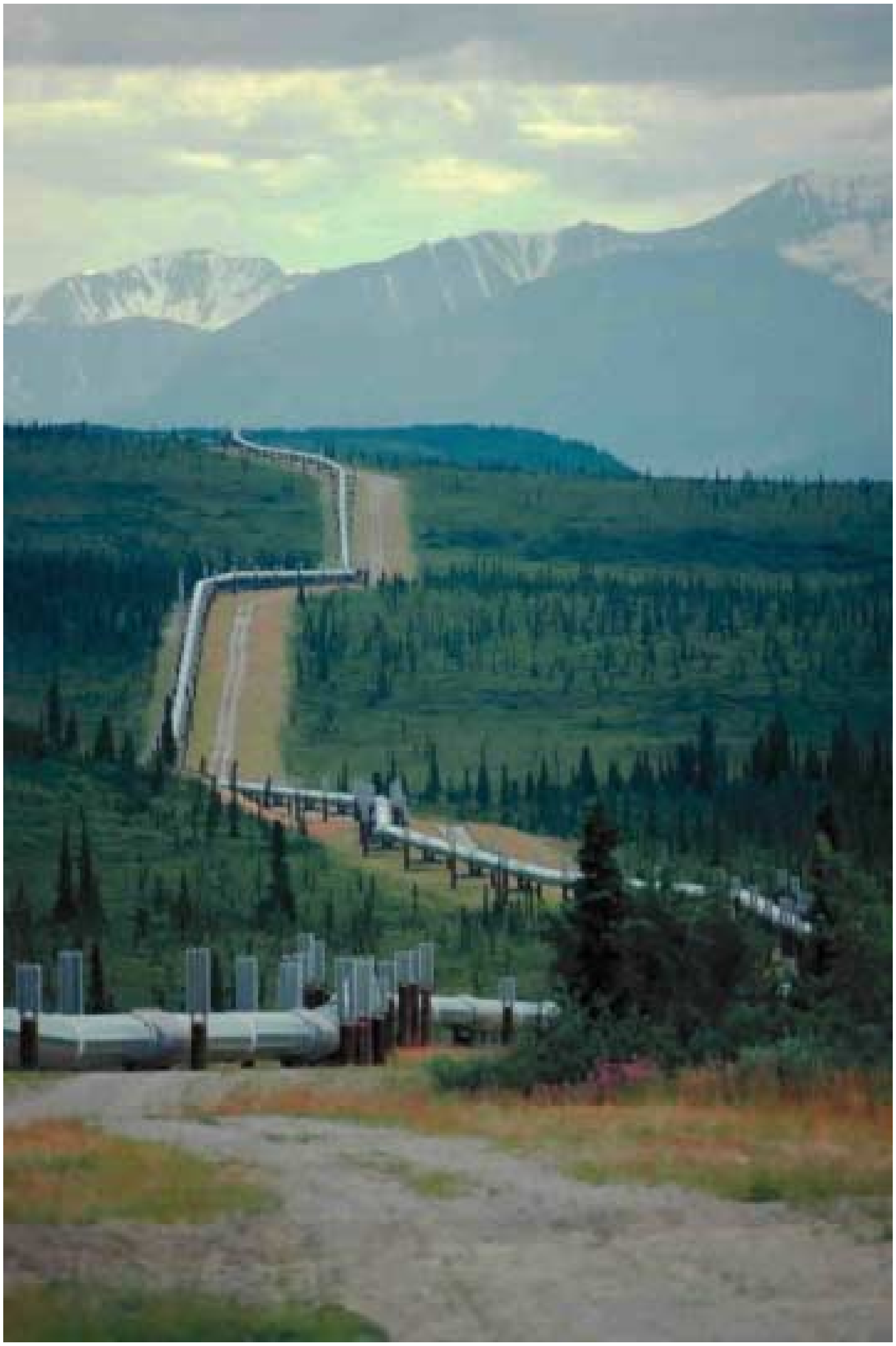
APPENDIX E

GAS AND LIQUID TRANSMISSION PIPELINES



Pipeline failure

Disbonded coating

Transgranular stress-corrosion cracking

Pipeline excavation

Coating repair

Intergranular stress-corrosion cracking

Alaskan Pipeline

GAS AND LIQUID TRANSMISSION PIPELINES

NEIL G. THOMPSON, PH.D.[1]

SUMMARY AND ANALYSIS OF RESULTS

Corrosion Control and Prevention

The corrosion-related cost to the transmission pipeline industry is approximately $5.4 to $8.6 billion annually. This can be divided into the cost of failures, capital, and operations and maintenance (O&M) at 10, 38, and 52 percent, respectively. Although data management, system quantification through the use of global positioning surveys, remote monitoring, and electronic equipment developments have provided significant improvement in several areas of pipeline corrosion maintenance, there have been few basic changes in the approach to the management of corrosion on pipelines until recently. These changes have been in the development of risk assessment strategies and pipeline integrity management programs.

In the past few years, a number of high-profile pipeline failures (both liquid and natural gas) have refocused concern on pipeline safety. Public safety concerns have provided the driving force for new regulations governing pipeline operations. The most significant of these, from a cost point of view, is the requirement for pipeline inspections. In-line inspection (i.e., "smart pigging") is the one most often discussed. The ability of this technique to find corrosion flaws larger than a certain size (10 percent of pipe wall thickness) makes it extremely valuable for locating flaws before they become critical and cause pipeline failure (either leaks or rupture). The major concern is that a "find it and fix it" mentality is pursued at the expense of corrosion prevention strategies. Both approaches are required to optimize the cost benefit of corrosion management programs. Operators may be tempted to adopt a "find it and fix it" attitude due to the significant cost of pipeline inspection, which is estimated to be as high as $35 billion over the next 5 to 7 years. If operators cut conventional corrosion O&M costs while pursuing pipeline inspection, corrosion prevention will suffer. Without a best practices corrosion prevention strategy, corrosion will continue and the cost of repairing a deteriorating pipeline will continue to escalate. Thus, a "find it and fix it" strategy utilizing in-line inspection at the expense of corrosion prevention may save money in the short term, but will greatly increase capital expenditures for pipeline replacement and major rehabilitation in the long-term.

Opportunities for Improvement and Barriers to Progress

Developing an optimum approach that includes both inspection and corrosion prevention strategies is critical to the future safety and the cost-effective operation of transmission pipelines. The overall goal of the pipeline industry must be to preserve the pipeline as an asset ($541 billion replacement cost). Corrosion consumes the asset, which cannot be recovered; this makes corrosion prevention a critical part of any strategy. Realizing that corrosion prevention will never be 100 percent effective, an inspection strategy ("find it and fix it"), in addition to the corrosion prevention strategy, is required for those pipelines that have a higher probability of corrosion. Significant savings are possible by optimizing the inspection and corrosion prevention strategies. In order to achieve such optimization, improved prediction models for both internal corrosion and external corrosion need to be developed. Inspection strategies should include all three currently available methodologies (in-line inspection, hydrostatic testing, and direct assessment), depending on the pipeline conditions.

[1] CC Technologies Laboratories, Inc., Dublin, Ohio.

Regulatory pressures can both be an effective driving force and a barrier to cost-effective engineering practices. The regulations should permit operators to implement integrity management programs that permit incorporation of developments, while allowing the use of any and all strategies available to the operator. Another barrier to the development of cost-effective programs is the increased costs associated with inspection strategies. There will be significant pressure to downplay existing corrosion prevention strategies in order to fund the new federally mandated inspection regulations. The current corrosion prevention strategies must be maintained while the inspection strategies are implemented. The corrosion prevention and inspection approaches must eventually be combined into a comprehensive cost-effective integrity management program.

Recommendations and Implementation Strategy

Corrosion prediction models need to be developed in order to more accurately determine inspection intervals and to prioritize the most effective corrosion prevention strategies. Development of new and improved inspection techniques is required to expand the capabilities of in-line inspection of flaws that cannot be currently detected and to improve resolution for existing tools.

Summary of Issues

Increase consciousness of corrosion costs and potential savings.	Impact of regulations can be to increase corrosion control costs by 50 percent to 100 percent over the next 5 to 7 years. Strategies utilizing best engineering practices can produce significant savings.
Change perception that nothing can be done about corrosion.	Corrosion prevention practices are well defined and generally known in the pipeline sector.
Advance design practices for better corrosion management.	Corrosion prevention design practices for pipelines are generally well understood. Computer models for cathodic protection design of complex systems are recently becoming available.
Change technical practices to realize corrosion cost-savings.	Technical practices will have to change based on new regulations involving increased pipeline inspection. Incorporating these inspection methods into the current corrosion prevention practices in a cost-effective manner will be critical to operators.
Change policies and management practices to realize corrosion cost-savings.	The key for management will be to incorporate inspection strategies into current corrosion prevention strategies while continuing to improve corrosion prevention.
Advance life prediction and performance assessment methods.	Life-prediction modeling for internal and external corrosion is critical to cost-effective pipeline integrity management. These models are not always available and are, in general, specific to individual pipeline conditions. Corrosion growth and life-prediction models are required for establishing inspection frequency and prioritizing corrosion prevention maintenance.
Advance technology (research, development, and implementation).	Technology advancements needed include improved inspection techniques (better reliability, resolution, crack detection).
Improve education and training for corrosion control.	New federal regulations require training of corrosion technicians. NACE International (National Association of Corrosion Engineers) has recently updated and is now providing courses and certification especially for cathodic protection technicians.

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF FIGURES (continued)

LIST OF TABLES

SECTOR DESCRIPTION

The "Gas and Liquid Transmission Pipelines" sector is a part of the oil and gas industry. This sector includes 217,000 km (135,000 mi) of hazardous liquid transmission pipelines, 34,000 km (21,000 mi) of crude oil gathering pipelines, 483,000 km (300,000 mi) of natural gas transmission pipelines, and 45,000 km (28,000 mi) of natural gas gathering pipelines.[1-3] Figure 1 summarizes the transmission pipeline sector. The boxes in gray indicate the type of pipelines addressed in this sector. Included in this sector are the above-described pipelines and the associated equipment and facilities (valve and metering stations and compressor/pump stations). In the United States, there are approximately 60 major natural gas transmission pipeline operators and 150 major hazardous liquid pipeline operators (1998 data).[4]

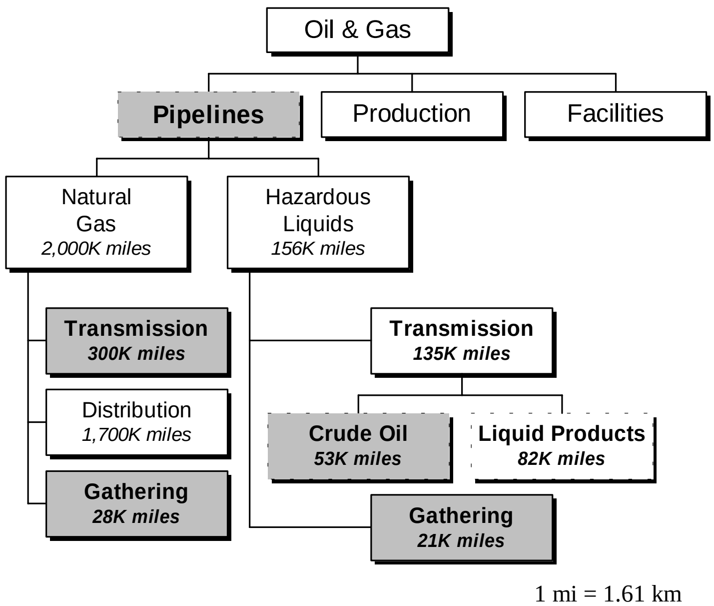


Figure 1. Chart describing transmission pipeline sector.

Figure 2 illustrates the different components of a natural gas production, transmission, storage, and distribution system. The components include production wells, gathering lines within the production fields, processing plants, transmission pipelines, compressor stations (periodically along the transmission pipelines), storage wells and associated gathering pipelines, metering stations and city gate at distribution centers, distribution piping, and meters at distribution sites (residential or industrial). Hazardous liquid systems include production wells and gathering lines for crude oil production, processing plants, transmission pipelines, pump stations, valve and metering stations, and aboveground storage facilities.

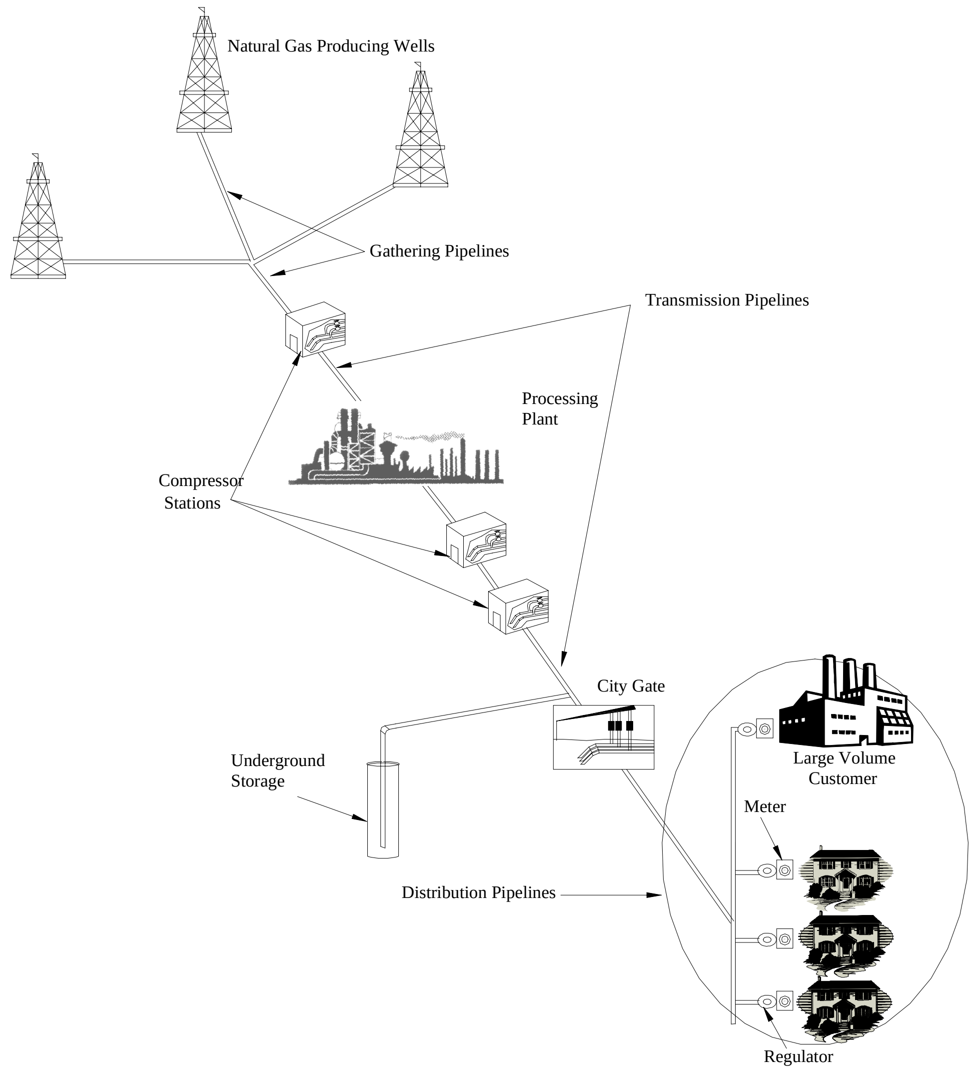


Figure 2. Components of a natural gas production, transmission, and distribution system.

Background

Underground pipelines transport large quantities of a product from the source to the marketplace. The first oil pipeline, which measured at 175 km (109 mi) in length and 152 mm (6 in) in diameter, was laid from Bradford to Allentown, Pennsylvania in 1879. Since the late 1920s, virtually all oil and gas pipelines have been made of welded steel. Although the first cross-country pipeline was laid in 1930 that connected some major cities, it was not until World War II that large-scale pipelines were laid connecting different regions of the country. In the 1960s, larger diameter pipelines ranging from 813 to 914 mm (32 to 36 in) were built. Even a 1,016-mm- (40-in-) diameter pipeline was constructed connecting Louisiana to Illinois. Discovery of oil on Alaska's North Slope resulted in the construction of the country's largest pipeline, the Trans-Alaska Pipeline System (TAPS), with a 1,219-mm- (48-in-) diameter and 1,287-km- (800-mi-) length.

Throughout this section, distinctions are made between natural gas and hazardous liquid pipelines. Although the basic design and purpose of the natural gas and liquid transmission pipeline systems are similar, there are differences in the conveyance systems and in the maintenance systems. The following brief discussion highlights some of the specific conditions for these systems.

Liquid Pipelines

Crude oil must undergo refining before it can be used as product. Once oil is pumped from the ground, it travels through pipelines to tank batteries. A typical tank battery contains a separator to separate oil, gas, and water. After the crude oil is separated, the crude oil is kept in storage tanks, where the oil is then moved through large-diameter, long-distance trunk lines to refineries, other storage tanks, tanker ships, or railcar. The pressure in the trunk lines is initiated and maintained by pumps to overcome friction, changes in elevation, or other pressure-decreasing factors. Drag reducing agents (DRAs) are also used to improve throughput by decreasing the effects of friction. Pump stations are located at the beginning of the line and are spaced along the pipeline at regular intervals to adequately propel the oil along. In 1998, there were 80 companies operating crude oil pipelines in the United States.(4)

Once oil is refined, product pipelines transport the product to a storage and distribution terminal. The products include gasoline, jet fuel, diesel fuel, ammonia, and other liquids. Other product pipelines transport liquified petroleum gases (LPG) and liquified natural gas (LNG) and highly volatile liquids (HVL) such as butane and propane.

Breakout tanks are aboveground tanks used to relieve surges in a liquid pipeline system, or to receive and store liquid transported by a pipeline prior to continued transportation by the pipeline.

Natural Gas Pipelines

The purpose of natural gas gathering and transmission pipelines is similar to that of crude oil gathering and crude oil trunk lines; however, the operating conditions and equipment are quite different. For example, gas transmission pipelines use compressors instead of pumps to force the gas through the pipe. The transmission lines connect to the distribution systems through the “city gate” valve and the metering station, which delivers the natural gas to the consumers via small-diameter, low-pressure lines. Natural gas is often treated in scrubbers or filters to ensure that it is dry prior to distribution.

In addition to the vast mileage of underground piping spanning the United States, a multitude of other facilities were required for the interstate transport of liquids and gases. The major facilities of interest in this study are pump and compressor stations, valve stations, and metering devices. For instance, gathering lines connect individual gas wells to field gas treatment facilities and processing facilities, or to branches of a larger gathering system. The natural gas is processed at the treatment facility to remove water; sulfur; and acid gases, hydrogen sulfide, and carbon dioxide. From the field processing facilities, the dried and cleaned gas enters the transmission pipeline. Each of these components has corrosion-related costs associated with them. The majority of the discussion in this section is directed toward the pipeline system.

CORROSION OF UNDERGROUND PIPELINES

Types of Corrosion

General Corrosion

Corrosion of the pipe wall can occur either internally or externally. Internal corrosion occurs when corrosive liquids or condensates are transported through the pipelines. Depending on the nature of the corrosive liquid and the transport velocity, different forms of corrosion may occur, including uniform corrosion, pitting/crevice corrosion, and erosion-corrosion. Figure 3 shows an example of internal corrosion that occurred in a crude oil pipeline due to high levels of saltwater and carbon dioxide (CO_2).

Figure 3. Internal corrosion of a crude oil pipeline.

There are several different modes of external corrosion identified on buried pipelines. The primary mode of corrosion is a macro-cell form of localized corrosion due to the heterogeneous nature of soils, local damage of the external coatings (holidays), and/or the disbondment of external coatings. Figure 4 shows typical external corrosion on a buried pipeline. The 25-mm- (1-in-) grid pattern was placed on the pipe surface to permit sizing of the corrosion and nondestructive evaluation (NDE) wall thickness measurements.

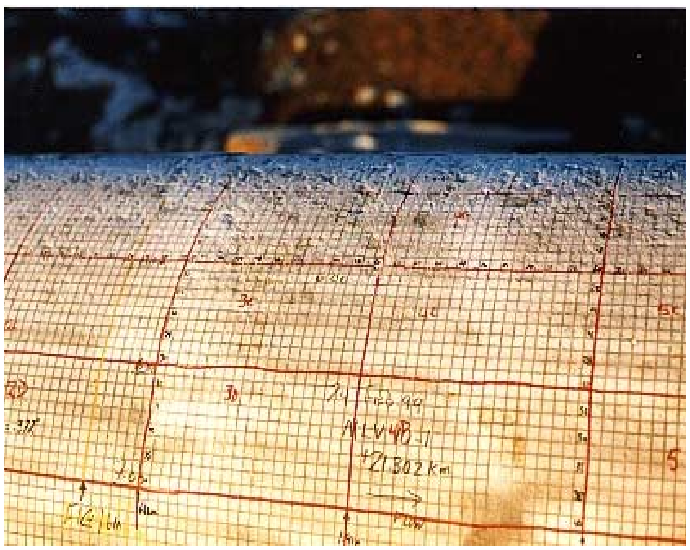


Figure 4. External corrosion on a buried pipeline.

Stray Current Corrosion

Corrosion can be accelerated through ground currents from dc sources. Electrified railroads, mining operations, and other similar industries that utilize large amounts of dc current sometimes allow a significant portion of current to use a ground path return to their power sources. These currents often utilize metallic structures (pipelines) in close proximity as a part of the return path. This “stray” current can be picked up by the pipeline and discharged back into the soil at some distance down the pipeline close to the current return. Current pick-up on the pipe is the same process as cathodic protection, which tends to mitigate corrosion. The process of current discharge off the pipe and through the soil of a dc current accelerates corrosion of the pipe wall at the discharge point. This type of corrosion is called stray current corrosion (see figure 5).

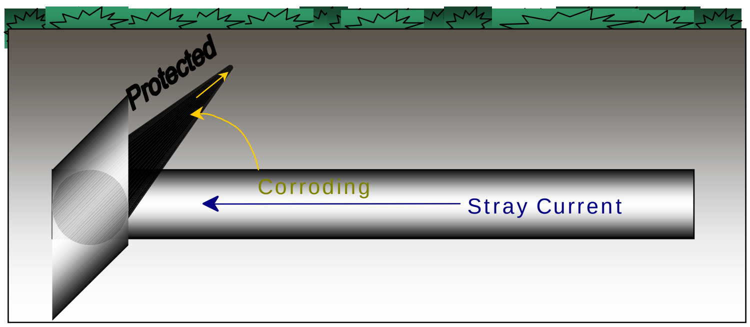


Figure 5. Schematic of stray current corrosion.

Microbiologically Influenced Corrosion (MIC)

Microbiologically influenced corrosion (MIC) is defined as corrosion that is influenced by the presence and activities of microorganisms, including bacteria and fungi. It has been estimated that 20 to 30 percent of all corrosion on pipelines is MIC-related. MIC can affect either the external or the internal surfaces of a pipeline. Microorganisms located at the metal surface do not directly attack the metal or cause a unique form of corrosion. The byproducts from the organisms promote several forms of corrosion, including pitting, crevice corrosion, and under-deposit corrosion. Typically, the products of a growing microbiological colony accelerate the corrosion process by either: (1) interacting with the corrosion products to prevent natural film-forming characteristics of the corrosion products that would inhibit further corrosion, or (2) providing an additional reduction reaction that accelerates the corrosion process.

A variety of bacteria have been implicated in exacerbating corrosion of underground pipelines and these fall into the broad classifications of aerobic and anaerobic bacteria. Obligate aerobic bacteria can only survive in the presence of oxygen, while obligate anaerobic bacteria can only survive in its absence. A third classification is facultative aerobic bacteria that prefer aerobic conditions, but can live under anaerobic conditions. Common obligate anaerobic bacteria implicated in corrosion include sulfate reducing bacteria (SRB) and metal-reducing bacteria. Common obligate aerobic bacteria include metal-oxidizing bacteria, while acid-producing bacteria are facultative aerobes. The most aggressive attacks generally take place in the presence of microbial communities that contain a variety of types of bacteria. In these communities, the bacteria act cooperatively to produce conditions favorable to the growth of each species. For example, obligate anaerobic bacteria can thrive in aerobic environments when they are present beneath biofilms/deposits in which aerobic bacteria consume the oxygen. In the case of underground pipelines, the most aggressive attack has been associated with acid-producing bacteria in such bacterial communities (see figure 6).

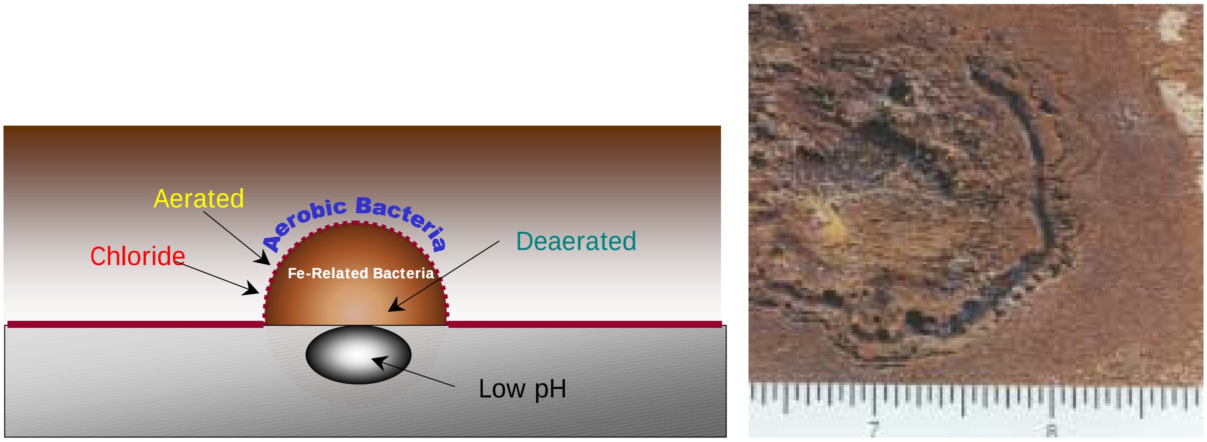


Figure 6. Iron-related bacteria reacting with chloride ions to create locally acidic environment.

Stress Corrosion Cracking

A particularly detrimental form of pipeline corrosion is known as stress corrosion cracking (SCC). SCC is defined as the brittle fracture of a normally ductile metal by the conjoint action of a specific corrosive environment and a tensile stress. On underground pipelines, SCC affects only the external surface of the pipe, which is exposed to soil/groundwater at locations where the coating is disbonded. The primary component of the tensile stress on an underground pipeline is in the hoop direction and results from the operating pressure. Residual stresses from fabrication, installation, and damage in service contribute to the total stress. Individual cracks initiate in the longitudinal direction on the outside surface of the pipe. The cracks typically occur in colonies that may contain hundreds or thousands of individual cracks. Over time, the cracks in the colonies interlink and may cause leaks or ruptures once a critical-size flaw is achieved. Figure 7 shows an SCC hydrostatic test failure on a high-pressure gas pipeline (see later section on hydrostatic testing).

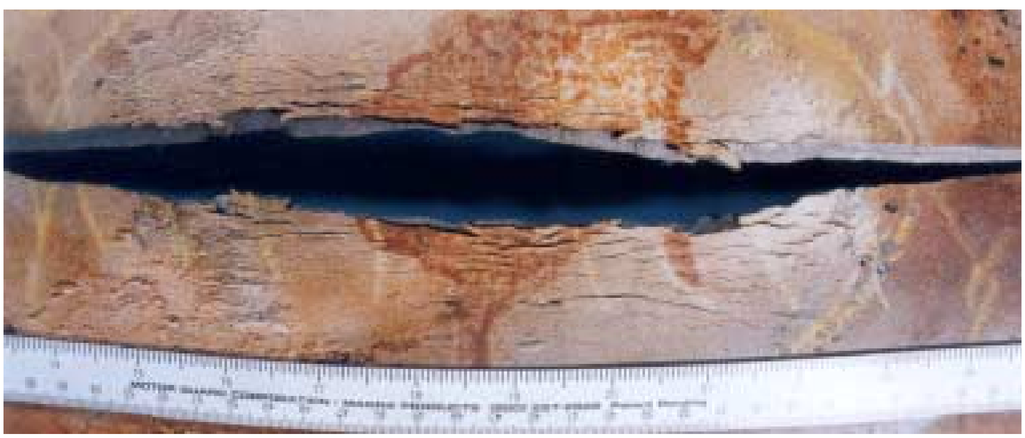


Figure 7. SCC colony found on a large-diameter, high-pressure transmission gas pipeline.

The two basic types of SCC on underground pipelines that have been identified are classical or "high pH" cracking (pH 9 to 10), which propagates intergranularly, and "near-neutral pH" cracking, which propagates transgranularly. Each form of SCC initiates and propagates under unique environmental conditions. Near-neutral pH SCC (< pH 8) is most commonly found on pipelines with polyethylene tape coatings that shield the cathodic protection current.[(5)] The environment that develops beneath the tape coating and causes this form of cracking is dilute carbonic acid. Carbon dioxide from the decay of organic material in the soil dissolves in the electrolyte beneath the disbonded coating to form the carbonic acid solution. High-pH SCC is most commonly found on pipelines with asphalt or coal tar coatings. The high-pH environment is a concentrated carbonate bicarbonate solution that develops as a result of the presence of carbon dioxide in the groundwater and the cathodic protection system.

Mitigation of Corrosion

External Corrosion

Corrosion is an electrochemical phenomenon and, therefore, can be controlled by altering the electrochemical condition of the corroding interface. For external wall surfaces, altering the electrochemical nature of the corroding surface is relatively simple and is done by altering the voltage field around the pipe. By applying a negative potential and making the pipe a cathode, the rate of corrosion (oxidation) is reduced (corrosion is mitigated) and the reduction process is accelerated. This means of mitigating corrosion is known as cathodic protection (CP).

CP is achieved in practice by one of two primary types of CP systems, including sacrificial anode (galvanic anode) CP and impressed-current CP. Sacrificial anode CP utilizes an anode material that is electronegative to the pipe steel. When connected to the pipe, the pipe becomes the cathode in the circuit and corrosion is mitigated. Typical sacrificial anode materials for underground pipelines are zinc and magnesium.

Impressed-current CP utilizes an outside power supply (rectifier) to control the voltage between the pipe and an anode (cast iron, graphite, platinum clad, mixed metal oxide, etc.) in such a manner that the pipe becomes the cathode in the circuit and corrosion is mitigated.

CP is most often used in conjunction with a coating. There are always flaws in the coating due to application inconsistencies, construction damage, or the combination of natural aging and soil stresses. If left unprotected, corrosion will occur at these coating flaws (holidays). Often the rate of attack through the wall is much higher at the holiday than the general attack of a bare steel surface. The use of a coating greatly reduces the total amount of current required to achieve protection of the pipeline system; therefore, CP and external coatings are utilized together wherever possible.

CP can be used to mitigate all types of corrosion previously discussed (general, stray current, MIC, and SCC). Sometimes it is difficult to determine the level of CP necessary to mitigate the different corrosion mechanisms and to identify which type of corrosion is present. Stress corrosion cracking presents additional problems. First, the high-pH form of SCC is only found on pipelines protected with CP. The products that result from cathodic reactions occurring on the pipe surface during CP in conjunction with soil chemistry produce the environment necessary for high-pH SCC. Since high-pH SCC only propagates in a very limited potential range, maintaining the potential of the pipe surface outside of this range by proper CP control will prevent growth of the high-pH SCC cracks. In addition, it has been established that proper CP control can inhibit the growth of near-neutral SCC cracks.

Internal Corrosion

Internal corrosion is also an electrochemical process; however, CP is not a viable option for mitigating internal corrosion in a pipeline. One of the first defense systems against corrosion for transmission pipelines is to ensure that the product being transported is free of moisture. Dry, deaerated natural gas and moisture-free oil and petroleum products are not corrosive. For corrosion to occur, there must be moisture, CO_2, oxygen, or some other reduction reactant, such as one produced by microbes. Operators typically control moisture, oxygen, and CO_2 contents of the transported product, but these constituents can enter the pipeline through compressor or pump stations, metering stations, storage facilities, or other means. Gathering lines in production fields have a much more significant problem with internal corrosion than the typical transmission pipeline.

One option available for mitigating internal corrosion is chemical treatment of the product being transported. Chemical inhibitors for mitigating corrosion and biocides to prevent microbiological activity are used. Both of these methods can be effective in either natural gas or liquid pipelines. The cost of either the inhibitor or biocide the treatment is significant. Recall that large volumes of products are continuously flowing through the pipeline. To mitigate corrosion through chemical treatment requires continuous injection or regular batching of the inhibitor or biocide.

Inspection of Pipelines

Electrical Surveys

Electrical surveys have been performed to evaluate the level of CP ever since the application of CP to pipelines in the 1940s. These surveys consist of measuring the potential (pipe-to-soil potential) of the pipe surface with respect to a reference electrode [typically copper/copper sulfate electrode (CSE)]. These measurements can be performed at permanent test station locations (test point surveys) or they can be performed continuously with a 1- to 2-m (3- to 6-ft) spacing along the entire length of the pipeline (close interval surveys). Pipe-to-soil potential surveys can be performed with the CP system energized (on-potentials) or with the CP system interrupted (off-potentials). There has been much discussion over the past 10 to 20 years as to the most appropriate survey methodology. While each method has its benefits, it is commonly accepted that the IR-voltage (voltage drop due to current, I, through a resistance, R) correction made by the off-potential measurement is most closely related to the corrosion condition of the pipeline. Figure 8 shows a schematic of a pipe-to-soil potential measurement.

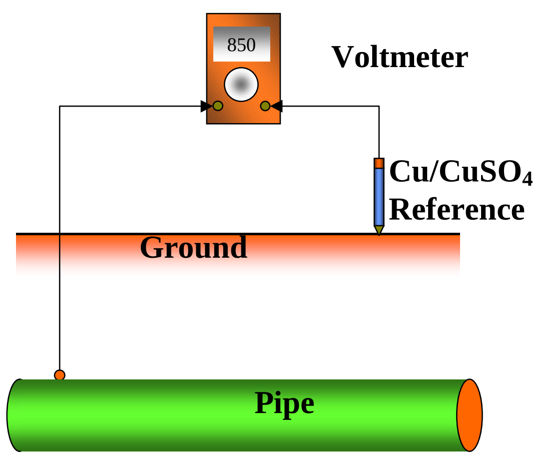


Figure 8. Schematic of pipe-to-soil potential measurement.

The basic pipe-to-soil potential measurement techniques are applied to establish whether one or more of the recommended CP criteria are met. Criteria for establishing the effectiveness of a CP system to mitigate corrosion are outlined in the NACE International Recommended Practice RP0169-96, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" and have been adopted, in part, in U.S. Department of Transportation (DOT) regulations CFR 49, Parts 192 and 195. In general, if one or more of the recommended criteria are met, the CP system is assumed to be applying a sufficient cathodic current to mitigate corrosion.

There are many survey techniques directed at detecting coating damage or establishing overall coating quality. Other surveys characterize stray current conditions, locate shorts, monitor current flow in the pipe, and establish proper rectifier operation. Over the years, the aforementioned electrical surveys have been the primary means for establishing the proper operation of a CP system, troubleshooting problem areas, establishing the necessary level of CP, and identifying areas for remedial measures.

Certain pipeline conditions make conventional electrical survey techniques difficult to interpret. These include areas of stray or telluric currents, congested areas where multiple pipelines and other utilities share rights-of-way, and pipelines with non-interruptible sacrificial CP systems. In these areas, either significant care must be taken to interpret conventional surveys or other methods of monitoring must be utilized. One such technology is the use of coupon test stations. The coupon test stations permit accurate potential measurements for a test specimen (coupon) that simulates a holiday on the pipe surface.

Direct Inspection (Digs)

Inspection digs (bell-hole inspections) are a means of verifying the condition of the coating and the pipe. The process of inspection digs includes uncovering and visually inspecting a section of the pipe (see figure 9). Nondestructive evaluation (NDE) techniques can be used to determine wall loss. Visual findings can be correlated to various electrical survey findings. Often, a dig program is used to verify the effectiveness of other techniques in establishing the condition of the pipe (i.e., electrical inspection and in-line inspection).

Figure 9. Inspection dig and pipeline repair.

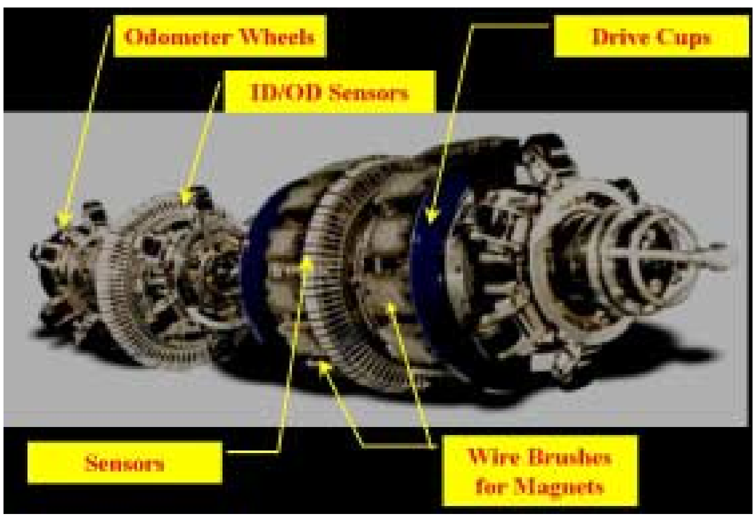
In-Line Inspection (Smart Pigs)

In-line inspection (ILI) tools, also referred to as smart or intelligent pigs, are devices that are propelled by the product in the pipeline and are used to detect and characterize metal loss caused by corrosion. There are two primary types of ILI tools: magnetic flux leakage (MFL) tools and ultrasonic tools (UT). The more advanced ILI tools (high-resolution tools) are capable of discriminating between internal and external corrosion.

MFL tools measure the change in magnetic flux lines produced by the defect and produces a signal that can be correlated to the length and depth of a defect. In recent years, the magnetics, data storage, and signal interpretation have improved, resulting in improved mapping of the flaw and a decrease in the number of unnecessary excavations. The high-resolution MFL tool is typically capable of readily detecting corrosion pits with a diameter greater than three times the wall thickness. Once detected, these tools can typically size the depth of the corrosion within ±10 percent of the wall thickness with an 80 percent level of confidence. The MFL tool can be used to inspect either liquid products pipelines or natural gas pipelines.

UT tools utilize large arrays of ultrasonic transducers to send and receive soundwaves that travel through the wall thickness, permitting a detailed mapping of the pipe wall. UT tools can indicate whether the wall loss is internal or external. The typical resolution of a UT tool is ±10 percent of the pipe wall thickness with an 80 percent level of confidence. UT tools are typically used in products pipelines (e.g., crude oil, gasoline, etc.) since the product in the pipeline is used as the required couplant for the ultrasonic sensors. This tool can be used to inspect natural gas pipelines, but requires introducing a liquid (i.e., water) into the pipeline for transporting the ILI tool through the line.

Figure 10 shows a typical MFL tool. The wire brushes in the front of the tool are used to transfer the magnetic field from the tool to the pipe wall. The ring of sensors between the wire brushes are used to measure the flux leakage produced by defects in the pipe. The drive cups are the mechanism that is used to propel the tool by the product in the pipeline. The odometer wheels monitor the distance traveled in the line and are used to determine the location of the defects identified. The trailing set of inside diameter/outside diameter sensors (ID/OD sensors) is used to discriminate between internal and external wall loss.



Photograph: Courtesy of PII, Houston, TX.

Figure 10. MFL tool for pigging a pipeline.

ILI tools are 3.0 to 5.5 m (10 to 18 ft) in length. The ILI tools must be capable of readily passing through the pipeline and the sensors must be able to produce good contact (MFL tool) or stand-off from the pipe wall (UT tool). For these reasons, pipelines with large buckles, large dents, tight-radius bends, or valves that do not open fully can provide difficulty in conducting an inspection and, in some cases, will cause limitations that make the lines not "piggable". The tool will simply not fit through the pipeline. In addition, pipelines to be inspected by ILI tools must be fitted with launchers and retrievers.

Hydrostatic Testing

The purpose of hydrostatic testing is to cause failure at existing "near critical" flaws during controlled hydrostatic testing as opposed to the flaw growing to critical size and failing during operation. Hydrostatic testing involves pressurizing the pipeline with water to a pressure that exceeds the maximum allowable operating pressure

(MAOP) for the pipeline. The concept is relatively simple. If there is a flaw that is near critical size at or below MAOP, that flaw will cause a pipeline failure when pressurized above the MAOP. In most cases, the pipeline must be tested to at least 125 percent MAOP to provide an adequate margin between the test pressure and the operating pressure.

An essential factor is to establish a proper hydrostatic test frequency. If hydrostatic testing is used as the primary defense against pipeline failure, the frequency must be equal to the time required for a flaw to grow from a size that just passes the hydrostatic test (125 percent MAOP) to a size that is critical at operating pressure. Hydrostatic testing is also used to commission a pipeline for initial service and as a criterion for qualifying a pipeline for return to service.

AREAS OF MAJOR CORROSION IMPACT

Areas of major economic impact associated with the corrosion of pipeline systems include capital cost related to corrosion control, general maintenance for corrosion control, replacement/repair costs, and costs associated with corrosion-related failures. The costs of each of these areas are discussed below. Corrosion plays a major role in decision-making concerning pipeline systems in both direct and indirect ways. Although the direct costs (costs to the owner or operator) regarding the impact of corrosion on pipelines are difficult to determine with accuracy, they are relatively easy to understand. On the other hand, indirect costs (costs to third parties) associated with corrosion of pipelines are more difficult to understand and are even more difficult to assign a value. The following are examples of indirect costs:

- Costs associated with damages to the environment or disruption to the public due to release of products (costs not directly paid by the operator as part of clean-up).
- Public relations costs for dealing directly with the public are increasing. Public opinion runs high against new pipelines in “their backyard.” The public is becoming concerned about aging pipelines, primarily due to a lack of information and a few recent high-visibility failures. This public attitude makes it difficult to obtain new rights-of-way and these are at a much higher cost than in the past. In addition, the negative public attitude will probably force decisions on the pipeline operators that are not necessarily the most optimal and cost-effective.
- Legal costs associated with a failure have become staggering when the failure has resulted in injury or death ($280 million in a case involving one fatality). These costs include defending against negligence on the part of the operator, criminal defense for officers in the company, and punitive damages awarded to the estate of the deceased or injured. Indirect costs would be the lost productivity of staff and public costs associated with the judicial process.
- Lost revenue for the producers arising from not being able to ship their product while the section of pipeline is out of service due to rupture.
- Lost revenue or increased costs to the end users for disruption of service or higher costs for alternative sources of fuels.

Capital Cost

<u>Current Investment in Capital</u>

For all natural gas pipeline companies, the total gas plant investment as of 1998 was $63.1 billion. “Gas plant” refers to the physical facilities used to move natural gas, such as compressors, metering stations, and pipelines. From this investment, a total revenue of $13.6 billion was generated. For liquid pipeline companies, the investment in carrier property was $30.2 billion. The total revenue for liquid pipeline companies was $6.9 billion. Therefore, the total capital investment for the transmission pipeline industry was $93.3 billion as of 1998.

Growth Requirements for Capital

It is anticipated that by the year 2010, the growth in the natural gas market will require a $32.2 billion to $34.4 billion investment in new pipelines and storage infrastructures.[6] This is in addition to the current annual capital investment for the pipeline industry. A significant portion of this growth comes from power generation and industrial sectors. This growth will be required because of federal Environmental Protection Agency (EPA) regulations to reduce atmospheric pollutants. The reduction in pollution will be achieved primarily by using natural gas, which is a significantly cleaner fuel for power utilities and plants than that currently used.

In addition to $93.3 billion invested in hazardous liquid and natural gas pipeline companies as of 1998, transmission pipeline companies spent $6.4 billion in capital improvements in 1998, of which approximately 75 percent was associated with the pipeline system ($4.8 billion).[4,7] Adding this $4.8 billion to the expected increase in capital due to an increase in the natural gas market of $3.3 billion ($32.2 billion to $34.4 billion divided by 10 years) gives an annual capital requirement of $8.1 billion.

Cost of Corrosion in Pipeline Construction

The average cost of new construction (onshore pipelines) for North American gas pipeline projects in 1998 and 1999 was $746,000 per km ($1.2 million per mi).[4,7] For 1998, there were approximately 2,576 km (1,600 mi) of pipeline constructed in the United States. These costs are broken down into the following categories: materials (line pipe, pipe coating, and cathodic protection), labor, miscellaneous (surveying, engineering, supervision, contingencies, telecommunications equipment, allowances for funds used during construction, overheads, and regulatory filling fees), and ROW (costs for obtaining right-of-way and allowing for damages). Table 1 shows costs for each category for 1998 and 1999 construction for natural gas onshore pipeline projects.

Table 1. Summary of construction costs for 1998 and 1999 onshore pipeline projects (natural gas pipelines).

	COST PER MILE		
	1998 Construction*	**1999 Construction**	**Average 1998 & 1999**
	($ x thousand)	**($ x thousand)**	**($ x thousand)**
Material	488	276	382
Labor	500	468	484
Miscellaneous	219	283	251
ROW and Damages	35	76	56
TOTAL	**$1,242**	**$1,103**	**$1,173**

*Estimated materials and labor cost for land projects based on total projects.

Cost of Pipeline Coating and CP

The cost of corrosion, in terms of materials, is incorporated in the $237,400 per km ($382,000 per mi) materials cost, i.e., pipeline coating, cathodic protection (CP), etc. The cost of coating is estimated at 7 percent to 10 percent of the material cost of the pipe, or $17,000 to $24,000 per km ($27,000 to $38,000 per mi).[8] The cost of an average CP system for new construction is approximately $12,000 for 24 km (15 mi) of pipeline, or $500 per km

($800 per mi).[9] The coating and CP costs discussed above are inclusive of the cost of materials and cost of labor associated with application/installation.

Cost of Corrosion Allowance

Although, a safety factor is built into the design calculations, corrosion allowance has not been specifically made a part of the design calculations. In addition, pipe wall thickness in high-risk areas is increased still further to provide an overall increased level of safety from integrity threats. Although corrosion is accounted for in the typical design safety factor for pipe wall thickness, without that safety factor, a corrosion allowance would be required. Therefore, in this study, it is estimated that the cost of the corrosion allowance for the pipe wall thickness accounts for 5 percent to 10 percent of the material cost, or $12,000 to $24,000 per km ($19,000 to $38,000 per mi).[10]

Cost of Specifications/Designs

It is estimated that the CP and coating specifications, design, and associated purchasing accounts for 2 percent to 5 percent of the miscellaneous costs or $3,000 to $7,760 per km ($5,000 to $12,500 per mi).

Total Cost of Corrosion for Construction

A total cost of corrosion can be estimated for new pipeline construction of $32,500 to $55,500 per km ($51,800 to $89,300 per mi) of pipeline, or 4.4 percent to 7.6 percent (average of 6 percent) of the total cost of pipeline construction. This breaks down into:

- $17,000 to $24,000 per km for pipeline coating.
- $500 per km for CP system.
- $12,000 to $24,000 per km for corrosion allowance.
- $3,000 to $7,000 per km for specifications/designs.

<u>Replacement Cost of Pipeline Infrastructure</u>

With the cost of new pipeline construction at $694,100 per km ($1,117,000 per mi) [total cost minus right of way (ROW) cost] and 778,900 km (484,000 mi) of the needed transmission pipelines, the cost of replacement of the transmission pipeline infrastructure is $541 billion. This is compared to the total book asset value of $93.1 billion for pipeline operations.

<u>Portion of Capital Cost Due to Corrosion</u>

Annual Cost of Capital for Pipeline Replacement

It is assumed that 25 percent of the new capital costs of $8.1 billion is for replacement of aging pipeline. Furthermore, it is assumed that all of the replacement is related to corrosion. Therefore, the annual capital cost due to corrosion for replacement of pipeline infrastructure is $2.02 billion.

Annual Cost of "Non-Replacement" New Capital

The "non-replacement" new capital expenditure is $6.08 billion ($8.1 billion minus $2.02 billion). Assuming that the average percentage of construction costs attributed to corrosion (4.4 to 7.6 percent) can be applied to capital costs, the capital expenditure related to the cost of corrosion is $268 million to $462 million (4.4 to 7.6 percent of $6.08 billion).

Depreciation of Existing Capital

Assuming that the capital cost of corrosion for total pipeline system assets ($93.3 billion) is the same as the cost of corrosion for construction, there is $4.1 billion to $7.1 billion (4.4 to 7.6 percent of $93.3 billion) in corrosion-associated existing capital. Amortizing these costs at an annual rate of 5 percent gives an annual cost of corrosion for existing capital of $205 million to $355 million.

Total Capital Costs

The total cost of corrosion for capital items is estimated at $2.50 billion to $2.84 billion ($2.02 billion for replacement capital, $0.27 billion to $0.46 billion for new capital, and $0.21 billion to $0.36 billion for depreciation of existing capital.

Operations and Maintenance (Corrosion Control)

Significant maintenance costs for pipeline operation are associated with corrosion control and integrity management. The driving forces for the expenditure of maintenance dollars are to preserve the asset of the pipeline, which is equal to $93.3 billion in book value and $541 billion in replacement value, and to ensure safe operation without failures that jeopardize public safety, result in loss product and throughput, and cause property and environmental damage, which is estimated at $470 million to $875 million per year (see "Corrosion-Related Failures").

External Corrosion

A recent survey of major pipeline companies indicated that the primary cause of loss of corrosion protection was due to coating deterioration (30 percent) and inadequate CP current (20 percent).[11] Other contributing causes included shorts or contacts (12 percent) and stray current (7 percent). The majority of general maintenance is associated with monitoring and repairing these problems. Integrity management concerns are focused on condition assessment, mitigation of corrosion, life assessment, and risk modeling.

External Corrosion Coatings

The use of protective coatings (in conjunction with CP) is the most widely used form of corrosion protection in the pipeline sector. Since the 1950s, several coating systems have been utilized, including fusion-bonded epoxy, extruded polyethylene, coal tar enamel, liquid epoxy, tape, polyurethane, mastic, and wax. Pipelines with each of these coating systems remain in service today. The most widely specified coating used on new pipelines is fusion-bonded epoxy. New multi-layered coatings are now on the market.

Coatings have been specified for all new pipeline construction since the 1960s. As previously stated, the average cost of coating pipe for new construction is estimated at $24,000 per km ($38,000 per mi). If this cost is applied to the total length of existing transmission pipe [778,900 km (484,000 mi)], the total coating corrosion prevention investment in the pipeline industry can be estimated at $18.4 billion in replacement costs.

With nearly 30 percent of the operational pipeline corrosion problems being attributed to coating deterioration, a large portion of the corrosion control budget is expended on monitoring, identifying, and repairing coating anomalies. In addition, extreme coating deterioration can significantly impact the ability to cathodically protect the pipeline from corrosion in terms of cost-effectiveness. To extend the operating life of a pipeline, an emerging method of pipeline corrosion control is pipeline coating rehabilitation (re-coating the pipeline).

Cathodic Protection

Cathodic protection is the required method of corrosion control on buried pipelines (CFR 49, Parts 192 and 195). The two forms of CP utilized are impressed-current and sacrificial anode systems. Both forms of protection represent technologies that have been used by the industry for many years and operating personnel are familiar with their installation and operation (NACE Recommended Standard RP0169-96).

Impressed-current CP systems represent the vast majority of CP systems for transmission pipelines. Impressed-current systems can be readily adjusted to compensate for changes in the amount of current required to adequately protect the structure; however, they may also contribute to the interference of other structures in the vicinity. Depending upon soil, pipe coating properties, and pipe size, impressed-current CP systems can be used to protect long lengths of pipe. However, impressed-current CP systems require more expensive installation and equipment, increased monthly monitoring, and greater power consumption charges than that of sacrificial anode systems. It is estimated that there are between 48,000 and 97,000 CP rectifiers in operation today [778,900 km (484,000 mi) of pipe with rectifiers every 8 to 16 km (5 to 10 mi)].[12] With an average installation cost of $12,000 per rectifier/groundbed, the total pipeline investment in impressed-current CP systems is between $0.6 billion and $1.2 billion. It is estimated that the annual investment by pipeline companies in impressed-current CP systems is $40 million (new installations and replacement of existing systems).

Sacrificial anode CP systems are used extensively to protect gas distribution pipelines, but are applied more as a remedial measure for problem areas on transmission pipelines. Sacrificial anodes are relatively inexpensive, do not require an external power supply, and require no regular monitoring of the anode (rectifiers for impressed-current systems require bimonthly monitoring to ensure proper operation). Due to their low driving voltages, however, sacrificial anodes are not applicable in all environments and do not have the power to protect long lengths of pipeline. Sacrificial anodes are often used to compliment impressed-current CP systems by providing protection to local areas where additional protection is required due to inadequate coating quality. It is estimated that $30 million of sacrificial anode material (zinc and magnesium) are purchased by the pipeline industry each year.[13] If it is assumed that 30 percent of the sales are for transmission pipelines, the annual cost is $9 million. The majority of the remaining $21 million goes to distribution pipelines.

Internal Corrosion

Internal pipeline corrosion is mitigated through various measures, including dewatering, inhibition, cleaning (pigging), and internal pipeline coatings. Dewatering consists of removal of the corrosive fluids prior to their introduction into the pipeline. Dewatering components are typically located at pipeline compressor and pump stations. In other cases, specific low points are selected along the pipeline right-of-way for the installation of “drips” that allow the corrosive fluids to be collected and periodically removed from the line to prevent corrosion of the pipe downstream from the site.

Inhibition consists of the addition of corrosion-inhibiting chemicals to the gas or product stream. These chemicals act in a variety of ways to mitigate the corrosion to an acceptable rate. Costs associated with corrosion-inhibition programs vary widely and are dependent upon the corrosiveness of the environment. In addition to the costs associated with introducing the chemicals to the system, most corrosion-inhibitor programs have general maintenance costs associated with the monitoring of the inhibitor additions and the determination of inhibitor effectiveness.

Another means of mitigating internal corrosion of pipelines is the periodic cleaning of the line. This is accomplished through a process called “pigging” (cleaning and scraping pigs). Pigging involves inserting one of a variety of different “pigs” into the line and propelling it through the line with gas or another product. As the pig passes through the line, it pushes and/or scrapes fluids, waxes, and debris from the line. These cleaning operations can also make use of various cleaning media, including solvents, biocides, acids, and detergents to aid in cleaning effectiveness. Corrosion is reduced by the elimination of the corrosive environment from the line. Costs associated with the pipe pigging process include the cost of preparing the line for pigging (installation of pig launchers and receivers, removal of appurtenances that could cause the pig to become lodged, etc.), possible reduced throughputs during the pigging operations, cost of pigs, solvents, etc., and the cost of the disposal of the material removed from the pipe.

Rehabilitation of internally corroded pipelines is somewhat more difficult to manage than external corrosion issues. Internal corrosion often requires cutting out and replacing the affected sections of the pipeline. Other methods of internal rehabilitation include pulled liners and epoxy flood coating. Cost estimates for these options can vary greatly and are predominantly dependent upon the extent of cleaning required to prepare the internal surface for coating.

Cost of Operations and Maintenance (Corrosion Control)

The most effective way to account for all of the related operating and maintenance costs associated with corrosion is to examine the total operating and maintenance budgets for representative companies. Table 2 shows the annual estimated cost for operations and maintenance associated with corrosion and corrosion control of three pipeline transmission companies. These costs typically include the costs associated with annual test point CP surveys, close interval surveys, monthly rectifier readings, CP maintenance and upgrades (including materials), pipe inspection at excavations, casing and insulator inspection, record-keeping, training, and aboveground maintenance coating operations. If the average corrosion operation and maintenance cost of $4,400 per km ($7,100 per mi) of pipe is representative of most operating pipeline companies, the total transmission pipeline industry cost can be estimated at $3.4 billion ($4,400 x 778,900 km of pipe). With a range of costs equal to $3,000 to $6,200 per km ($5,000 to $10,000 per mi), the range of annual operation and maintenance costs associated with corrosion is $2.42 billion to $4.84 billion.

Table 2. Estimated costs for operations and maintenance associated with corrosion and corrosion control.

COMPANY IDENTIFICATION	MILES OF PIPE (mi x thousand)	TOTAL O&M COSTS ($ x million)	O&M PER MILE	O&M COSTS DUE TO CORROSION	CORROSION COSTS PER MILE
A	11,000	$358.9	$32,627	15%	$4,894
B	10,000	$707	$70,700	15%	$10,605
C	5,000	$192	$38,400	15%	$5,760
				AVERAGE COST PER MILE	$7,086

1 mi = 1.61 km

Replacement/Rehabilitation

Introduction

Decisions for pipeline replacement versus pipeline rehabilitation are often difficult, with several important considerations. Rehabilitation includes repairing existing flaws in the pipeline and recoating the pipeline. In order to make the most effective decisions on replacement versus rehabilitation of a pipeline or segment of pipe, it is important to understand the extent of the corrosion existing on the line and the coating condition of the pipeline. For example, excessive cutouts and replacements rapidly increase the cost of coating rehabilitation. In addition, hidden costs must be taken into account, including such items as shorter coating service lives of *in situ* coatings. The following three specific conditions make replacement/rehabilitation necessary: (1) severe corrosion damage of a pipeline not properly cathodically protected, (2) severe coating deterioration leading to increased CP requirements, and (3) stress corrosion cracking along a large area of pipeline.

Corrosion

Pipeline integrity management programs are used by pipeline operators to determine the locations in which corrosion defects pose a threat to safe operation. Repairs at these locations can vary from the installation of a reinforcing sleeve to the implementation of a large-scale pipe rehabilitation or replacement program. For localized corrosion flaws, the repair process can include composite sleeves, full-encirclement steel sleeves, or replacement of a pipe segment. For local flaws, decisions regarding the repair process can typically be handled by company procedures and criteria. For large-scale corrosion and/or coating deterioration issues, the replacement/rehabilitation decision must consider both operational and economic factors.

In-line inspections (ILI) are widely used to generate a profile of defects found in a pipeline. The high-resolution UT and MFL ILI tools available today can determine the geometry and the orientation of corrosion defects. These inspections can be used to determine the number and the location of near-critical flaws that should be immediately examined (dig program to verify flaw and to repair). With appropriate corrosion growth models, predictions can be made on future dig/repair and/or reinspection requirements for the ILI inspected line. If the density of the corrosion defects is high or the potential exists for continued increase in dig/repair frequency, the affected pipe section may be a candidate for repair or replacement.

Aging Coating

Another concern related to corrosion assessment is the cost of maintaining the required level of CP. The effectiveness of the CP system can be verified using corrosion surveys. An increased number of coating defects require an increased amount of CP current. This is accomplished by increasing the current output of the impressed-current rectifiers, installing impressed-current rectifiers at more locations along the pipeline, or installing additional sacrificial anodes. Coating defects can be identified by conventional potential surveys or by specific coating defect surveys and verified by direct visual inspection (dig program). Under certain circumstances, coatings fail in a manner that makes assessment of the corrosion condition of the pipe through conventional surveying methods difficult. Aging coating and the associated increase in coating defects can make the continuous need for CP upgrading uneconomical.

Stress Corrosion Cracking

The presence of extensive stress corrosion cracking (SCC) may qualify a pipeline for replacement or rehabilitation. Because SCC is dependent on unique environmental conditions, a large-scale recoating program may protect against these environmental conditions and permit continued operation of the line. Based on the severity and density of the stress corrosion cracks, however, pipe replacement may be the most economical option.

Considerations

Replacement/rehabilitation decisions involve several considerations. These considerations include terrain conditions, expected or required life, excess capacity and throughput requirements, internal versus external corrosion, etc. A comprehensive list of considerations for pipeline rehabilitation is given in table 3.[14] Only a few of these are discussed in detail below.

Table 3. Considerations for pipeline rehabilitation.

PIPE	ANOMALIES	BURIAL	OPERATING	LABOR	MATERIAL	EQUIPMENT
Size	Position	Depth	Interruptability	Contractor versus Internal	Pipe	Digging Equipment
Span	Size	Location	Ability to Lower Pressure	Bidding versus Time & Materials	Coating(s)	Non-Digging Equipment
Grade	Quantity	Soil Conditions	Cathodic Protection	Employee Skill Level	Sleeves	Specialty Items
Wall Thickness	Profile	Drainage Conditions	Welding Issues	Job Limitations	Fittings	Transportation
Operating Pressure	Concentration	Season	Regulations	Availability	Cathodic Protection	
Availability	Wall Loss	Other Facilities	Company Standards	Location	Specialty Repair Items	
Company Specifications	Cause	Environmental Issues		Union Requirements	Site Restoration	
		Legal Issues		Benefits	Availability	

The location of the pipeline is critical to repair considerations. For example, a pipe in swampy clay would exclude recoating as a repair option. Alternatively, the prairies are conducive to recoating, with firm footing for the equipment and good accessibility.

If the expected life of a section of pipeline is relatively short, the operator must decide whether recoating and repair would extend the life of the pipe section to match the rest of the pipeline. If not, recoating is not an economically sound solution. Replacing the pipe may then be the best solution.

Several alternatives may be considered beyond replacement or rehabilitation, including abandonment of the pipe section with a bypass loop, increasing the frequency of ILI, increasing the CP level, and de-rating the pipe. Increasing the frequency of ILI enables greater accuracy in determining the point of failure for existing defects. De-rating the pipe may extend the life of the pipe, provided that throughput requirements are met. The throughput issue is strictly a function of an operator's contracts to ship products and to ensure that they are able to continue to provide service in some capacity. For either the replacement or repair option, it is generally necessary to have a looped system and allow for pressure restrictions or interruptible service to facilitate repairs.

Internal corrosion problems are not as easily addressed as external corrosion problems. The application of an internal coating or lining to ensure mitigation of active corrosion sites inside a pipe is possible. For internal coating repair, the pipeline will have to be completely out of service. This is not always required for external recoating.

Replacement/Rehabilitation Case Studies

TransCanada Transmission Pipeline (TCPL) 1996 Trial Program

A trial program was launched by TCPL in 1996 to investigate the feasibility of large-scale mainline recoating. The program was initiated after field measurements indicated substantial deterioration of the coating on TCPL's older pipelines. The project involved the rehabilitation of 1.6 km (1 mi) of an 864-mm- (34-in-) diameter pipeline. The cost of rehabilitation was $804,000. This cost was estimated to be approximately 60 percent of the cost of replacing the pipe.(15)

TCPL 1998 Mainline Recoating Program

With the success of the 1996 trial project, an annual mainline recoating program was established. [16] Table 4 presents a summary of the costs for the TCPL mainline rehabilitation program. Each project used liquid epoxy that was applied by spraying onto the pipe. As a cost example, the cost of rehabilitation in 1998 was $10.6 million for 26.2 km (16.3 mi) of 864-mm- (34-in-) diameter pipe [$404,000 per km ($650,000 per mi)]. Replacing this section with new pipe would have cost approximately $17.2 million [$656,000 per km ($1.06 million per mi)]. Recoating saved 38 percent over the cost of new pipe.

In 1998, the mainline recoating program eliminated the need for an estimated 28 digs. With an average estimated dig and repair cost of $50,000, the program produced a cost-savings of $1.4 million. In addition, rehabilitation was credited for reducing the overall maintenance cost of future pigging, hydrostatic testing, corrosion monitoring, and SCC investigations (not included in the cost calculations).

Table 4. Economic summary of TCPL's mainline recoating program.

YEAR	LENGTH RECOATED (mi)	PIPE DIAMETER (in)	TOTAL COST* ($ x thousand)	COST (per mi)
1996	1	34	804	$804,000
1997	9	34	5,829	$647,667
1998	16.3	34	10,586	$649,448
1999	19.3	42	16,415	$850,518

*The amounts in this table are in U.S. dollars; the conversion rate used was: U.S. $ = 0.67 x CAN$
1 in = 25.4 mm, 1 mi = 1.61 km

1994 - 1997 Replacement/Rehabilitation Studies in the United Arab Emirates (UAE)

Abu Dhabi National Oil Company of U.A.E. conducted a detailed comparison of the cost of rehabilitating an existing 610-mm- (24-in-) diameter oil pipeline and converting it to condensate service versus replacing it with a new 457-mm- (18-in-) diameter condensate line.[17] The analysis quantified the hidden costs of using older pipelines, primarily due to higher leakage risk, extra inspections, and higher maintenance costs. These costs were somewhat offset by lower pump costs for the larger diameter rehabilitated pipeline. Taking this into account, the rehabilitated pipeline was only 59 percent of the cost of the new pipeline. If the savings in pump costs were not counted, the cost of the rehabilitated pipeline was estimated to be 81 percent of the new pipeline costs; therefore, operational cost adjustments are critical to the analysis.

In a second project, the costs associated with installing a new 914-mm- (36-in-) diameter pipeline versus rehabilitation of two existing main oil lines were compared. It is important to note that operational costs over a 30-year service life were included. The cost of rehabilitation of the two existing pipelines was 76 percent of the cost of replacement with one large-diameter pipeline; however, it was decided to construct a new pipeline for the following reasons:

- The risks of rehabilitating in-service pipelines require either complete shutdown of the pipeline or the use of hot taps and stopples. This measure creates numerous dead-leg branches with higher leakage risks.
- More than 700 clamps and sleeves could not be reliably inspected by ILI tools. There is a high risk of leaks from these old clamps and sleeves.

- Rehabilitation of the old pipelines would have taken a long time due to terrain.
- Environmental conditions (wind, dust, humidity) would have compromised coating application.
- Installation of a new, larger diameter main oil line yielded greater operational flexibility.

East Coast (U.S.) Oil Pipeline

A major pipeline company estimated that rehabilitation costs generally are 40 percent to 80 percent of the cost of a new pipeline, depending on terrain, location, old/new coating type, length of pipe to be rehabilitated, and pipe diameter. The cost for rehabilitation was given as $577,000 to $1,650,000 per km ($924,000 to $2,640,000 per mi).(18) These rehabilitation costs do not account for repair of pipeline defects.

Transcontinental Gas Pipe Line Corp. (Transco USA)

Transco USA has had a recoating program since the early 1970s. For a 610-mm- (24-in-) diameter pipeline, a field-applied double-wrap polyethylene tape coating system was utilized. Although the cost-savings of rehabilitation were not available, the cost of recoating was estimated to be 15 percent of the rehabilitation project.(19) The recoating costs were $98,000 per km ($158,000 per mi), giving a total rehabilitation cost of $0.652 million per km ($1.05 million per mi).

Cost of Replacement Versus Rehabilitation

As discussed previously, several considerations can affect the economics of replacement versus rehabilitation. As pointed out by multiple sources, the number of repairs made to the pipeline can make the difference between the cost-effectiveness of rehabilitation versus the cost-effectiveness of replacement. In addition, operational costs, projected life, throughput requirements, and projected leak risks all play a role in the final decision. It is clear that the unique conditions of each pipeline must be considered individually. Rehabilitation of existing pipelines can be 60 percent of replacement costs, resulting in a significant cost-savings for rehabilitation versus replacement.

Corrosion-Related Failures

Introduction

If corrosion is permitted to continue unabated, the integrity of a pipeline will eventually be compromised. In other words, the pipeline will fail. Depending on the flaw size, the pipeline material properties, and the pipeline pressure, failure refers to either a leak or a rupture.

Typically, rupture of a high-pressure natural gas pipeline results in the sufficient release of stored energy (compressed gas) that the pipeline is blown out of the ground. A leak results when a flaw penetrates the pipe wall, but is not of sufficient size to cause a rupture. Typically, leaks on natural gas pipelines are detected by either periodic inspections or third party reporting and are repaired without significant incident; however, leaks can result in problems that are more substantial if they are not detected promptly. Natural gas leaks, for instance, can fill enclosed or confined spaces and, if an ignition source is present, explosions and/or fires can result, causing substantial property damage and possible injuries or deaths. For natural gas leaks or ruptures, the immediate environmental impact is minimal.

A liquid (non-compressible) pipeline has less stored energy than a natural gas pipeline; therefore, a rupture does not immediately result in a major explosion. However, once leaked out into the environment, a major explosion can occur upon ignition of an explosive liquid product. For a hazardous liquid product pipeline, the environmental impact can be as significant as the risk of an explosion. The risk of an oil leak from the TransAlaskan pipeline, for example, has continued to be the primary driver for the aggressive corrosion prevention and inspection program maintained by the operator. Of major concern is the risk of product leakage into surface waters, thereby, contaminating water supplies.

The costs associated with corrosion-induced pipeline failures can be divided into the following seven categories: (1) loss of product, (2) property damage, (3) personal injury or death, (4) clean-up of product (hazardous liquid pipelines), (5) pipeline repair and back-to-service program, (6) legal, and (7) loss in throughput. To prevent failures, an aggressive maintenance and integrity program is necessary.

Pipeline Safety

In a recent report by the U.S. General Accounting Office entitled *Pipeline Safety*, the history of pipeline safety is reviewed.(2) Compared to other forms of transportation, pipelines are inherently safer; however, pipeline accidents can have serious consequences. For example, in June 1999, a pipeline rupture in Bellingham, WA, spilled approximately 946,000 L (250,000 gal) of gasoline into a creek. When the gasoline ignited, three people were killed, eight more were injured, several buildings were damaged, and the banks of the creek were destroyed along a 2.4-km (1.5-mi) section. In July 2000, a natural gas pipeline ruptured in Carlsbad, NM. When the gas ignited, 12 people were killed.

Figures 11 through 15 give statistics on major pipeline accidents and injuries between 1989 and 1998.(2) A “major” accident (the term “incident” is typically used for natural gas pipelines and the term “accident” is typically used for hazardous liquid pipelines; “accident” will be used in this discussion) is defined as one that results in a fatality, injury, or $50,000 or more in property damage. Accidents are reported to the Office of Pipeline Safety (OPS). Property damage includes all costs of the failure (i.e., lost product, repair costs, and third party damage). Other accidents that are required to be reported to OPS, but are not defined here as “major,” include events that require emergency shutdown of a liquefied natural gas facility and any event concerning a hazardous liquid pipeline that results in an explosion or fire, or the release of 50 or more barrels of hazardous liquid (or carbon dioxide), or the escape into the atmosphere of more than five barrels per day of highly volatile liquids. Over the past 10 years, a larger number of accidents have occurred on distribution natural gas pipelines than for either natural gas transmission pipelines or hazardous liquid pipelines (see figure 11). Distribution piping, however, has the lowest average number of accidents per 16,000 km (10,000 mi) of pipe, and hazardous liquid pipelines have the highest average number of accidents (see figure 12).

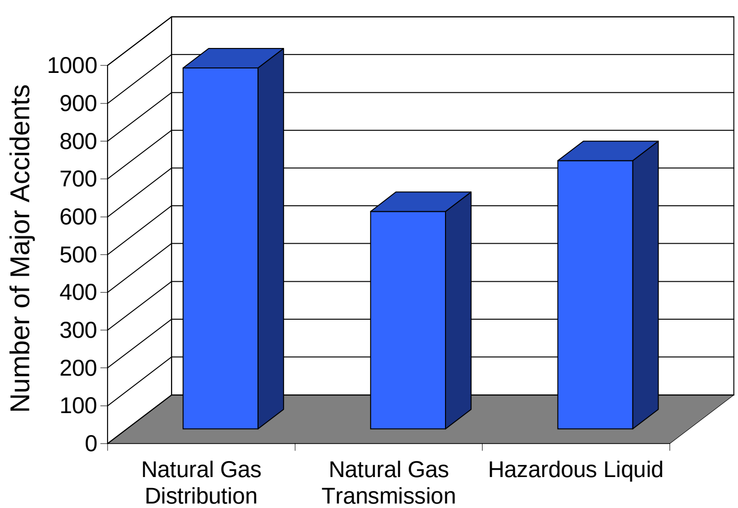


Figure 11. Number of major accidents between 1989 and 1998 for each major pipeline category.

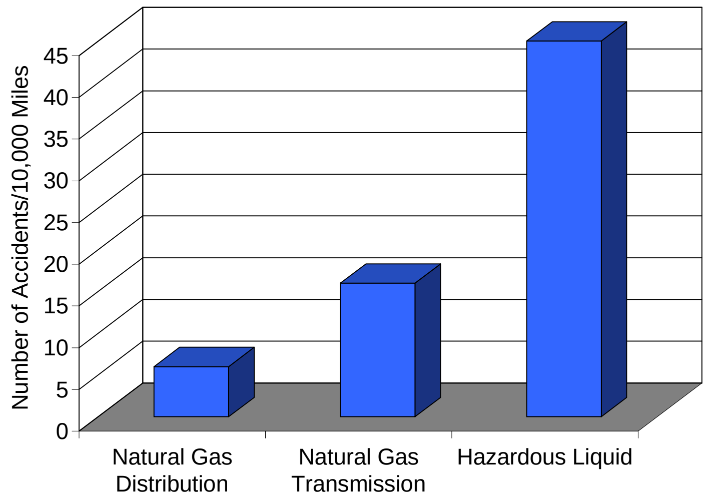


Figure 12. Average number of major accidents per 16,000 km (10,000 mi) of pipeline between 1989 and 1998 for each major pipeline category.

Natural gas distribution pipelines accounted for 77 percent and 72 percent of all of the fatalities and injuries, respectively, between 1989 and 1998 (see figures 13 and 14). Figure 15 shows the amount in dollars associated with property damage from these accidents between 1989 and 1998. Approximately 50 percent of the property damage was caused by accidents on hazardous liquid pipelines. For the accidents reported to OPS, 1.53 million barrels of hazardous liquids were spilled into the environment. In addition to the accidents reported to OPS, the Environmental Protection Agency (EPA) estimated that 16,000 spills of fewer than 50 barrels occurred between 1989 and 1998 (1,600 annually) for oil pipelines in which the spill could cause pollution of navigable waters.

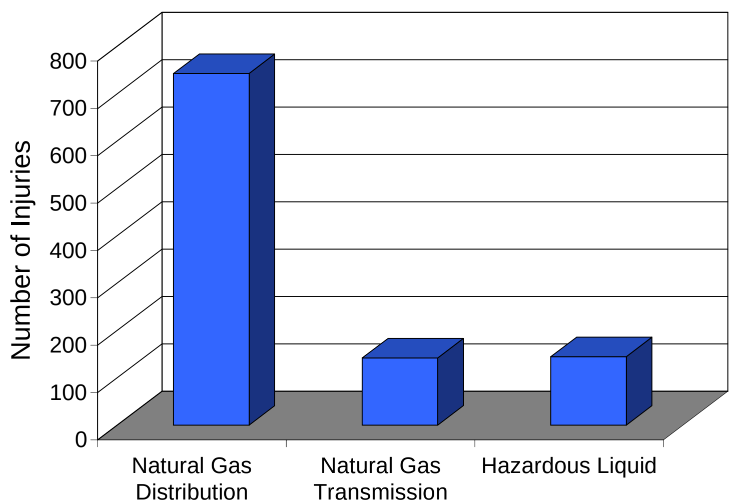


Figure 13. Number of injuries between 1989 and 1998 due to major accidents for each major pipeline category.

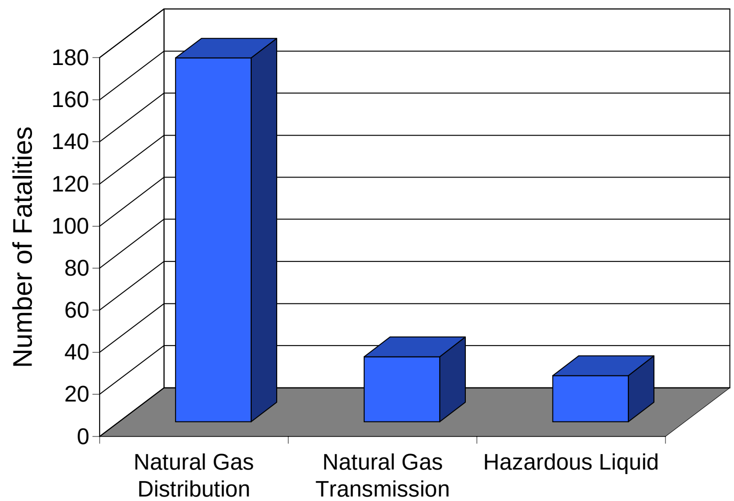


Figure 14. Number of fatalities between 1989 and 1998 due to major accidents for each major pipeline category.

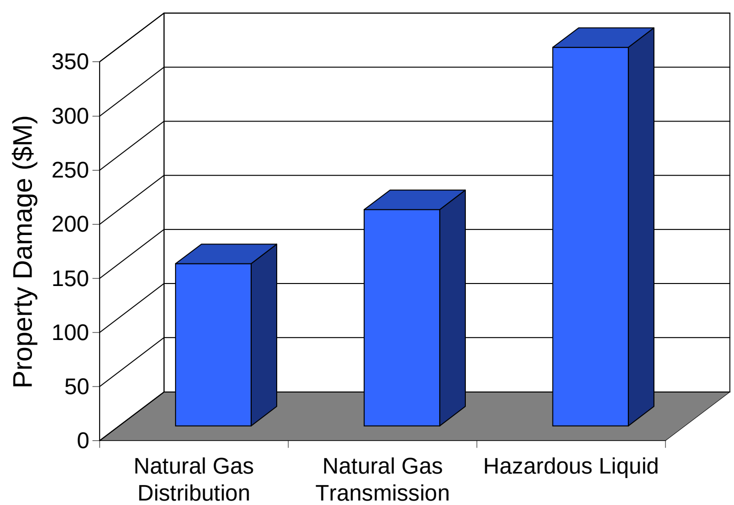


Figure 15. Property damage between 1989 and 1998 due to major accidents for each major pipeline category.

<u>Cost of Corrosion Failures</u>

For this study, it is important to examine the accidents caused by corrosion. For reporting purposes, a distinction is typically made between external and internal corrosion. In addition, it is likely that corrosion contributed to some of the accidents listed as “other.” In fact, a review of the detailed reports indicates that corrosion is described in the report for only a small percentage of the accidents reported as “other” cause. For this review, only those accidents listed as caused by corrosion are included below.

Corrosion-Related Failures

Table 5 provides a summary of the major accidents reported to the U.S. Department of Transportation by the operators for the 6-year period between 1994 and 1999.[20] The data show that for transmission pipeline systems (both hazardous liquid and natural gas), approximately 25 percent of all reported accidents were due to corrosion (see table 5). Of the hazardous liquid pipeline accidents caused by corrosion, 65 percent were due to external corrosion and 34 percent were due to internal corrosion. For natural gas transmission pipeline accidents, conversely, 36 percent were caused by external corrosion and 63 percent were caused by internal corrosion. For natural gas distribution pipeline accidents (see Appendix J of this report), only approximately 4 percent of the total accidents were caused by corrosion, and the majority of those were caused by external corrosion.

Table 5. Summary of corrosion-related accident reports on hazardous liquid, natural gas transmission, and natural gas distribution pipelines from 1994 to 1999.

	HAZARDOUS LIQUID TRANSMISSION	**NATURAL GAS TRANSMISSION**	**NATURAL GAS DISTRIBUTION**
Total Accidents Due to Corrosion Accidents (1994–1999)	271	114	26
Total Accidents (1994–1999)	1,116	448	708
Percent of Total Accidents Due to Corrosion	24.3%	25.4%	3.7%
Percent of Corrosion Accidents Due to External Corrosion	64.9%	36.0%	84.6%
Percent of Corrosion Accidents Due to Internal Corrosion	33.6%	63.2%	3.8%
Percent of Corrosion Accidents Cause Not Specified	1.5%	0.9%	11.5%

In a summary report for incidents between 1985 and 1994, corrosion accounted for 28.5 percent of pipeline incidents on natural gas transmission and gathering pipelines.[(21)] In a summary report for incidents between 1986 and 1996, corrosion accounted for 25.1 percent of pipeline incidents on hazardous liquid pipelines.[(22)] These values correspond very well to the statistics for 1994 to 1999 presented in table 5.

Recall that the accidents reported in table 5 are for major accidents that resulted in injury, fatality, or more than $50,000 in property damage. In addition to the reportable accidents, an average of 8,000 corrosion leaks per year are repaired on natural gas transmission pipelines[(23)] and 1,600 spills per year are repaired and cleaned up for liquid product pipelines.

Property Damage

Table 6 summarizes the property damage due to the reported accidents for the three pipeline categories. The reported property damage includes all direct costs of the accident (lost gas, repair, etc.). For hazardous liquid and natural gas transmission pipelines, the percentage of the total damages due to corrosion were 19 percent and 15 percent, respectively. Combining table 5 and table 6 gives an average property damage due to corrosion for hazardous liquid pipelines of $192,300 per accident and for natural gas transmission of $169,500 per accident (incident).

Table 6. Summary of property damage due to corrosion-related accidents on hazardous liquid, natural gas transmission, and natural gas distribution pipelines from 1994 to 1999.

	HAZARDOUS LIQUID TRANSMISSION	NATURAL GAS TRANSMISSION	NATURAL GAS DISTRIBUTION
Total Property Damage Due to Corrosion Accidents (1994–1999) ($ x thousand)	$52,115	$19,326	$4,923
Total Property Damage Due to All Accidents (1994-1999) ($ x thousand)	$279,270	$127,727	$137,925
Percent of Total Property Damage Due to Corrosion Accidents	18.7%	15.1%	3.6%
Percent of Property Damage From Corrosion Accidents Due to External Corrosion	56.0%	42.2%	84.8%
Percent of Property Damage From Corrosion Accidents Due to Internal Corrosion	40.1%	57.8%	1.4%
Percent of Property Damage From Corrosion Accidents Cause Not Specified	3.9%	0.0%	13.8%

Loss of Throughput

The cost to the pipeline operator, producer, and refinery/user of loss of throughput is not included in the property damage. Making the following assumptions permits a cost for loss of throughput to be estimated:

- 5,520 kPag (800 psig) for either liquid or natural gas.
- Liquid pipeline:
  406-mm- (16-in-) diameter pipeline.
  128,000 barrels per day throughput.[24]
- Natural gas pipeline:
  610-mm- (24-in-) diameter pipeline.
  8 million m^3 [287 million ft^3 (Mcf)] per day throughput.[24]

Furthermore, it is assumed that for the major accidents reported, the average time to return to service is 1 to 2 days. For those accidents involving injuries, fatalities, or major environmental damage, the loss of throughput could be weeks or months and could require major integrity inspection of the entire pipeline; for other pipelines, which have parallel or looped lines, the loss of throughput may be minimal. For liquid lines, the estimated loss of throughput is 128,000 to 256,000 barrels. The cost of loss of throughput to the pipeline operator, producer, and refinery/user is assumed to be 50 percent of the cost of the product or $9 per barrel [it is estimated that the average cost of the product (oil and refined product) in 1998 was $18 per barrel of product];[25] therefore, the average cost of loss of throughput for a hazardous liquid transmission pipeline accident is between $1.15 million and $2.30 million.

A similar analysis for natural gas pipelines gives a loss of product of between 8 million and 16 million m^3 (287 Mcf and 574 Mcf). At a cost of $71.50 per thousand m^3 ($2 per thousand ft^3)[26] and the assumption that the cost of loss of throughput is 50 percent of the product cost, the average cost of loss of throughput for a natural gas transmission pipeline incident is between $287,000 and $574,000.

Fatalities and Injuries

Tables 7 and 8 summarize the fatalities and the injuries caused by pipeline accidents, respectively. In the 6 years between 1994 and 1999, two fatalities from hazardous liquid transmission pipelines occurred. The four fatalities caused by corrosion-related accidents occurred on natural gas distribution pipelines. Only five injuries occurred on transmission pipelines (liquid and natural gas) as compared to 16 injuries on natural gas distribution pipelines.

Table 7. Summary of fatalities due to corrosion-related accidents on hazardous liquid, natural gas transmission, and natural gas distribution pipelines from 1994 to 1999.

	HAZARDOUS LIQUID TRANSMISSION	**NATURAL GAS TRANSMISSION**	**NATURAL GAS DISTRIBUTION**
Total Fatalities Due to Corrosion Accidents (1994-1999)	2*	0	4
Total Fatalities (1994-1999)	15	7	130

*Two fatalities from a 1996 liquid pipeline failure not reported in reference.

Table 8. Summary of injuries due to corrosion-related accidents on hazardous liquid, natural gas transmission, and natural gas distribution pipelines from 1994 to 1999.

	HAZARDOUS LIQUID TRANSMISSION	**NATURAL GAS TRANSMISSION**	**NATURAL GAS DISTRIBUTION**
Total Injuries Due to Corrosion Accidents (1994-1999)	2	3	16
Total Injuries (1994-1999)	62	61	460

During the period from 1985 to 1994, the corrosion-related accidents on natural gas transmission pipelines resulted in 5 fatalities and 10 injuries.[21] All five fatalities occurred in one accident in 1985. From 1986 through 1999, there were no fatalities from corrosion-related accidents on natural gas transmission pipelines; however, in 2000, a single accident, caused by internal corrosion, resulted in 12 fatalities. From 1986 to 1996, corrosion-related accidents on hazardous liquid pipelines resulted in three fatalities and three injuries.[22] Therefore, on average, it is estimated that there is approximately one fatality and one injury per year on transmission pipelines.

Summary of Costs Due to Corrosion Failures

A summary of the average annual cost for natural gas (NG) and hazardous liquid (HL) transmission pipeline accidents is given in table 9. The fatality, injury, and "added legal" costs are all estimates based on discussions with industry experts. For these costs, high and low estimates are provided. The cost of hazardous liquid spills or natural gas leaks varies depending on the severity of the leak and the repair method selected.[14] Table 10 provides a range of costs for repair options. For estimating the cost of non-reportable leaks and spills, the pipe replacement costs are not utilized since this would place the accident in a reportable category (greater than $50,000). In addition, there is a clean-up cost associated with the hazardous liquid spills. Because of the range for these estimates, the total annual cost of corrosion-related accidents (including non-reportable leaks and spills) ranges from $471 million to $875 million.

Table 9. Summary of annual cost for corrosion-related transmission pipeline failures.

	DESCRIPTION	LOW ESTIMATE ($ x thousand)	HIGH ESTIMATE ($ x thousand)
Fatalities	One fatality per year (NG and HL combined) @ $1,000,000 to $4,000,000 per occurrence	1,000	4,000
Injuries	One injury per year (NG and HL combined) @ $500,000 to $1,000,000 per occurrence	500	1,000
Added Legal	Legal issues and liability (civil and punitive) @ $100,000,000 to $200,000,000 per fatality and injury (2)	200,000	400,000
Property Damage – HL	45 HL accidents/year @ $192,300 per occurrence	8,654	8,654
Property Damage – NG	19 NG accidents/year @ $169,500 per occurrence	3,220	3,220
Loss of Throughput – HL	45 HL accidents/year @ $1.15 million to $2.3 million per occurrence	51,750	103,500
Loss of Throughput – NG	19 NG accidents/year @ $287,000 to $574,000 per occurrence	5,453	10,906
Non-Reportable HL Spills	1,600 oil spills/year (HL) of less than 50 barrels @ $25,000 to $40,000 per occurrence	40,000	64,000
Non-Reportable NG Leaks	8,000 leaks/year (NG) @ $20,000 to $35,000 per occurrence	160,000	280,000
TOTAL ANNUAL COST OF CORROSION-RELATED PIPELINE FAILURES		**$470,577**	**$875,280**

NG – Natural Gas; HL – Hazardous Liquid.

Table 10. Cost comparison of composite sleeve, full-encirclement steel sleeve, and pipe replacement repair techniques.

	COMPOSITE SLEEVE	STEEL SLEEVE	10-FT PIPE REPLACEMENT
Material Cost	$1,000	$1,600	$500
Labor Cost	$11,000	$16,500	$30,000
Gas Loss*	$0	$0	$19,000
Other Expenses**	$7,000	$7,000	$20,000
TOTAL REPAIR COST	**$19,000**	**$25,100**	**$69,500**

*Gas loss calculated from 16-km section at 5,520 kPag (10-mi section at 800 psig).
**Surveys, permits, inspection services, ROW-related expenses, etc.

Total Cost of Corrosion

The total cost of corrosion is determined by the cost of capital, operations and maintenance (O&M), and the cost of failures (non-related O&M costs). The pipeline rehabilitation and replacement costs are included in the capital costs. The costs presented in table 11 summarize these costs for typical pipeline operations in the 1990s. The total costs are estimated to be $5.40 billion to $8.56 billion annually. Figure 16 gives the percentage breakdown of the total cost of corrosion for the transmission pipeline sector. Operation and maintenance costs are 52 percent of the total costs associated with corrosion.

Table 11. Summary of the total cost of corrosion in the transmission pipeline sector.

	LOW ESTIMATE	**HIGH ESTIMATE**	**AVERAGE**	
	($ x million)	**($ x million)**	**($ x million)**	**(percent)**
Cost of Capital	2,500	2,840	2,670	38
Operations and Maintenance (O&M)	2,420	4,840	3,630	52
Cost of Failures (Non-Related O&M)*	471	875	673	10
TOTAL COST DUE TO CORROSION	**$5,391**	**$8,555**	**$6,973**	**100%**

*Non-Related O&M costs include indirect costs associated with fatalities, injuries, loss of throughput, and legal expenses (see table 9).

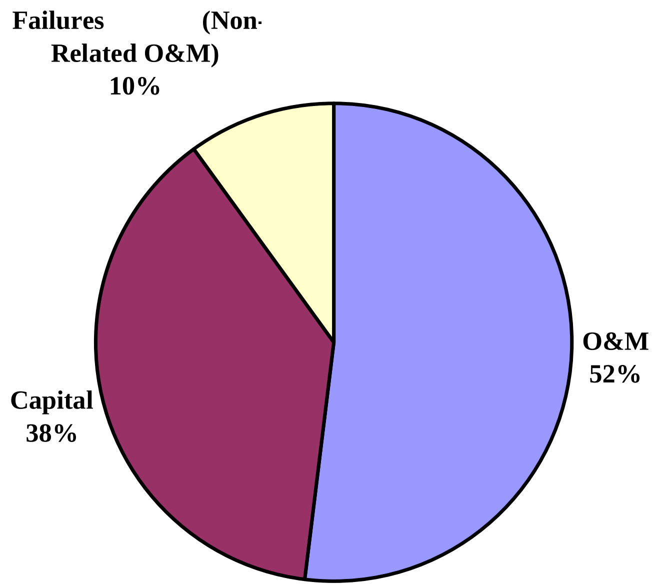


Figure 16. Percentage breakdown of the total cost of corrosion for the transmission pipeline sector.

CORROSION MANAGEMENT

Impact of Federal Regulations

In the future, pipeline operators may be faced with tough challenges due to the aging pipeline infrastructure and the new federal regulations that promote pipeline safety. The key to corrosion management will be to optimize the operational and maintenance costs in the face of a growing demand for pipeline safety. Two areas that will affect pipeline operational costs are pipeline personnel qualification programs and enhanced pipeline inspection programs. In the following paragraphs, the economic impact of these regulations is discussed. The costs associated with these programs are, for the most part, added to the existing programs that the pipeline operator has in place prior to 2000. The costs of these programs can be significant and optimization of the corrosion control program will be critical.

Personnel Qualifications

Table 11 above shows corrosion-related operation and maintenance costs. These costs are expected to change in the upcoming years as new federal regulations are enacted. One such regulation requires specific qualifications for pipeline personnel. While all pipeline operators utilize some form of a corrosion control program, a recent survey indicated that only 30 percent of those surveyed have personnel completely dedicated to corrosion control activities, and only slightly more than half require their corrosion technicians to be certified.[11]

The new regulations require pipeline operators to develop and maintain a written qualification program for individuals performing corrosion-related tasks. The intent of the regulation is to ensure a qualified work force and to reduce the probability and consequences of corrosion-related incidents. It is estimated that the qualification program set-up will cost $210 million, transitional evaluations and qualification assessments will cost $140 million, subsequent evaluations and qualification assessments will cost $87.5 million, and there will be annual costs of $32.4 million. Assuming that there are approximately 175,000 covered pipeline employees, it can be estimated that the initial cost of a qualification program will be $437 million or approximately $2,500 per employee and a very conservative annual cost of only $185 per employee.[27]

Integrity Management

With the aging of North America's pipeline systems and with changing regulations, many operators have implemented integrity management programs involving a combination of monitoring, assessment, mitigation, and life extension, coupled with a risk assessment model. A pipeline integrity management program specifies some or all of the following: an overall CP monitoring and inspection program, intervals and locations for in-line inspection, intervals and locations for hydrostatic testing, intervals and locations for a direct assessment program, safe operating conditions, repair criteria, and prioritization for inspection, re-coating, or repair. Future regulations will probably provide specific requirements for integrity inspections, including required time intervals and permitted methodologies. These integrity inspection programs will be coupled with overall risk management programs to maintain safe operation of the pipeline, provide for public safety, and protect the environment.

The integrity inspection methods that will probably be permitted include in-line inspection (ILI), hydrostatic testing, and direct assessment (see previous discussion in "Inspection of Pipelines"). The primary strengths and weaknesses of the assessment methods are summarized in table 12.

Table 12. Assessment methods summarized.

METHOD	STRENGTH	WEAKNESS
In-Line Inspection	Measures and maps remaining wall thickness.	Single run does not identify active corrosion and the accuracy of multiple run predictions is uncertain. Resolution of tools varies.
Hydrostatic Testing	Causes a controlled hydrostatic rupture of near-critical flaws.	Does not identify the presence or severity of flaws other than critical axial flaws that fail at the pressure tested.
Direct Assessment	Identifies areas of high probability of active corrosion.	Verifies accuracy through dig program, does not provide 100% direct assessment of pipeline.

In the following sections, the costs associated with each inspection methodology are examined. For comparison purposes, it will be assumed that 100 percent of the transmission pipeline system will be inspected by each method. In this manner, a direct comparison of the costs for each method and the overall impact of inspecting all pipelines can be made.

In-Line Inspection Economics and Reliability

The ILI method is the most widely accepted method of inspection of pipelines due to its ability to measure wall thickness with near 100 percent coverage of the pipe inspected. If gathering lines are omitted for the purposes of this discussion, there are approximately 217,000 km (135,000 mi) of liquid pipelines and approximately 483,000 km (300,000 mi) of natural gas pipelines [total of 700,000 km (435,000 mi) of high-pressure transmission pipelines]. Industry discussion has focused on the possibility of ILI for all high-pressure transmission pipelines in the United States. Present regulations are focused on pipelines in "high-consequence areas" (HCAs). The definition of high-consequence pipelines has not yet been agreed upon; however, in general, they would include areas where the consequences of failures are significant because of a high-population density or a great environmental impact. This could include as much as 60 percent of the pipeline system or 420,000 km (261,000 mi) of pipeline.(28)

It has been estimated that 85 percent of the liquid transmission pipelines can be readily inspected using ILI techniques. For natural gas transmission pipelines, only 30 percent can be readily inspected by ILI; another 25 percent can be converted for ILI; 43 percent would be difficult to convert for ILI, and 2 percent cannot be inspected by ILI. It is estimated that so far only 30 percent of the pipelines in the United States have been inspected by ILI.(29)

Pipeline Preparation for ILI

The cost to prepare a pipeline for inspection can vary greatly depending on the condition, the age, the location, etc. of the pipeline. Modifications and preparations for existing pipelines to permit ILI include the following:

- ILI tool launchers and receivers must be added to the pipeline. The costs of modifying a pipeline for a launcher/receiver combination can range from $80,000 to $100,000.(30)
- Caliper tools are run to identify restrictions and bend the radius of the pipe prior to the ILI tool to ensure that the pipeline is free from defects that could cause the ILI tool to be stuck or damaged. The cost of running the caliper tool is $620 to $810 per km ($1,000 to $1,300 per mi).(31)
- Clearing bends or other restrictions (i.e., reduced opening in valves) requires digging out the pipeline and replacing the problem valve or pipe section. It is estimated that replacement of an obstruction, including the cost of loss of throughput, can range from $50,000 to $250,000 (with the high cost being the replacement of a valve).(32)
- Cleaning the pipeline is required prior to ILI with either magnetic flux leakage (MFL) or ultrasonic testing (UT); however, the UT tool requires a cleaner pipe. The cost of mechanical cleaning (scraper tools) was estimated at $270 per km ($430 per mi). Chemical cleaning is significantly more expensive at $2,220 per km ($3,570 per mi) for the same line.(33) On average, it is assumed that the cost for cleaning natural gas pipelines is $310 per km ($500 per mi) (very little chemical cleaning is required). For liquid pipelines, it is assumed that 35 percent are chemically cleaned and 65 percent are mechanically cleaned (approximate split between crude oil and refined product pipelines), giving an average cleaning cost of $1,550 per km ($2,500 per mi).

The following provides a minimum cost of preparing a pipeline for ILI. The cost of the caliper tool is $620 to $810 per km ($1,000 to $1,300 per mi). Typically, launchers and receivers are required for every 160 km (100 mi) of pipeline, giving an average cost of $500 to $620 per km ($800 to $1,000 per mi). Clearing of restrictions will vary greatly; however, assuming a minimum of one obstruction per 16 km (10 mi) of pipeline gives a cost of $3,100 to $15,500 per km ($5,000 to $25,000 per mi). The overall estimated minimum cost for preparing a pipeline for ILI ranges from $4,200 to $16,900 per km ($6,800 to $27,300 per mi) of pipeline.

A natural gas company estimated the cost of converting their system to ILI to be $300 million for 16,100 km (10,000 mi) of pipeline, or $18,600 per km ($30,000 per mi).[29] This value is reasonable based on the costs provided above for preparing launchers and receivers, clearing bends, etc. In fact, the cost per km for preparing a pipeline with multiple bends and obstructions per mile of pipeline can potentially be much greater than the $18,600 per km ($30,000 per mi).

Cost of ILI

The cost of performing ILI includes the cost of cleaning (see above) plus the cost of the ILI. The cost for ILI ranges from $1,250 to $1,850 per km ($2,000 to $3,000 per mi) for the MFL and $1,250 to $2,500 per km ($2,000 to $4,000 per mi) for UT.[34] Taking an average for the two methods gives a cost for ILI between $1,250 and $2,150 ($2,000 and $3,500 per mi).

This does not include the inter-company cost of manpower and labor for planning, bid and selection of contractor, overseeing, and reporting. It is estimated that 20 person-days are required for this, giving an overall cost of $10,000 for a typical ILI run of 160 km (100 mi) or $62 per km ($100 per mi).[35]

For ILI, the pipeline typically has minimal downtime such that the loss of throughput is negligible for liquid lines, i.e., the velocity of liquid flow [2.5 to 3.1 km per hour (4 to 5 mi per hour)] is the same as the ILI tool. For natural gas pipelines, the estimated flow though a 610-mm- (24-in-) diameter pipeline at 5,520 kPag (800 psig) is 8.75 km per hour (14 mi per hour). The lower velocities during the ILI operation [3.1 km per hour (5 mi per hour)] decreases the throughput by the difference in the velocities. If the velocity is decreased by 64 percent, then the throughput is decreased by 64 percent. In our “typical” pipeline, the normal throughput is 340,000 m^3 per hour (12 million ft^3 per hour).[24] A 64 percent loss corresponds to a loss of 217,500 m^3 (7.68 Mcf) per hour. At a speed of 3.1 km per hour (5 mi per hour) and a loss of throughput of 217,500 m^3 (7.68 Mcf) per hour, the loss of throughput corresponds to an average of 43,000 m^3 (1.54 Mcf) per mile of pipe inspected. Due to prior planning, the indirect cost of loss of throughput (pipeline operator, producer, and user) is estimated to be 20 percent to 40 percent of the cost of the product. At $71.50 per thousand m^3 ($2 per thousand ft^3) the loss of throughput is estimated to be $375 to $750 per km ($600 to $1,200 per mi) of natural gas transmission pipeline inspected.

Table 13 summarizes the ILI cost for inspection of all transmission pipelines. The cost of ILI for natural gas versus hazardous liquid pipelines is different primarily due to the different costs for cleaning and loss of throughput. The range of costs for ILI of natural gas pipelines is $2,000 to $3,300 per km ($3,200 to $5,300 per mi). The range of costs for ILI of hazardous liquid pipelines is $2,850 to $3,800 per km ($4,600 to $6,100 per mi).

Table 13. Summary of ILI costs for inspection of transmission pipelines.

PIPELINE	**COST OF ILI FOR NATURAL GAS PIPELINES**		**COST OF ILI FOR LIQUID PIPELINES**		**TOTAL COST FOR ALL PIPELINES**	
	Low Estimate ($ per mi)	**High Estimate ($ per mi)**	**Low Estimate ($ per mi)**	**High Estimate ($ per mi)**	**Low Estimate ($ x million)**	**High Estimate ($ x million)**
Cleaning	500	500	2,500	2,500	488	488
Inspection	2,000	3,500	2,000	3,500	870	1,522
Operator Oversight	100	100	100	100	44	44
Loss of Throughput	600	1,200	0	0	180	360
TOTALS	**$3,200**	**$5,300**	**$4,600**	**$6,100**	**$1,582**	**$2,414**

1 mi – 1.61 km

Note: Assumes 483,000 km (300,000 mi) and 217,000 km (135,000 mi) of natural gas and hazardous liquid transmission pipelines, respectively.

Cost of ILI for All Pipelines

The analysis assumes the following:

- ILI cost for natural gas pipelines is $2,000 to $3,300 per km ($3,200 to $5,300 per mi).
- ILI cost for hazardous liquid pipelines is $2,850 to $3,800 per km ($4,600 to $6,100 per mi).
- Preparation of “readily inspected” pipelines is $4,200 to $16,900 per km ($6,800 to $27,300 per mi).
- Preparation for “possible to convert” pipelines is $15,500 to $46,600 per km ($25,000 to $75,000 per mi).
- Preparation for “difficult to convert” pipelines is $46,600 to $155,000 per km ($75,000 to $250,000 per mi).[36]
- 30 percent of both natural gas and liquid pipelines have been inspected by ILI.

Table 14 gives the estimate for the cost of preparing all pipelines for ILI. It was assumed that 30 percent of each natural gas and liquid pipeline system has been previously inspected and that the remaining pipes fall into the categories given above (and in table 14). For example, 30 percent of the total miles of liquid pipelines were previously inspected, of the remaining 70 percent, 85 percent is “readily inspected,” 7 percent is “possible to convert,” 7 percent is “difficult to convert,” and 1 percent “cannot be inspected” by ILI. Summing the natural gas and liquid pipelines gives a total cost for preparing all pipelines for ILI of $9.72 billion to $32.58 billion.

Table 14. Summary of ILI costs for preparation.

PIPELINE	Cost of Preparation For ILI		Natural Gas Pipelines	Liquid Pipelines	Cost of Preparation for ILI for Natural Gas Pipelines		Cost of Preparation for ILI for Liquid Pipelines	
	Low Estimate	High Estimate			Low Estimate	High Estimate	Low Estimate	High Estimate
	($ per mi)	($ per mi)	(mi)	(mi)	($ x million)	($ x million)	($ x million)	($ x million)
Previously Inspected	0	0	90,000	40,500	0	0	0	0
Readily Inspected	6,800	27,300	63,000	80,325	428	1,720	546	2,193
Possible to Convert	25,000	75,000	52,500	6,615	1,312	3,938	165	496
Difficult to Convert	75,000	250,000	90,300	6,615	6,772	22,575	496	1,654
Cannot Be Inspected	0	0	4,200	945	0	0	0	0
Totals			**300,000**	**135,000**	**$8,512**	**$28,233**	**$1,207**	**$4,343**

1 mi = 1.61 km

The total cost for performing the inspection for all transmission pipelines by ILI is estimated in table 13 to be $1.58 billion to $2.41 billion. Therefore, the first-time cost of ILI for all pipelines is $11.3 billion to $35.0 billion (cost of preparation plus the cost of inspection). Afterwards, the cost for subsequent ILI is $1.58 billion to $2.4 billion. Typical inspection times are 5 to 7 years. Therefore, the annual cost for the first 5 to 7 years is $1.61 billion ($11.3 billion divided by 7 years) to $7.00 billion ($35.0 billion divided by 5 years); subsequent years would be $226 million ($1.58 billion divided by 7 years) to $482 million ($2.41 billion divided by 5 years).

Reliability of ILI

The reliability of ILI tools can be evaluated through three performance characteristics: detection, discrimination, and sizing. The first measure is the ability of the tool to detect an anomaly. In the case of MFL tools, it is the ability to detect a magnetic anomaly in the pipe. Once an anomaly is detected, the ability to discriminate between different types of defects is critical. For example, UT tools are capable of detecting mid-wall laminations, which are not typically a concern. However, it is important to be able to discriminate between mid-wall laminations and corrosion-caused metal loss that could pose a potential integrity concern. Lastly, once an area of corrosion has been detected and classified, the data are used to determine the severity of the corrosion, namely, the depth of the wall loss and the axial and circumferential extent.

The high-resolution ILI tools are readily capable of detecting and discriminating corrosion. Typically, the ability to detect corrosion anomalies with a diameter less than three times the wall thickness is more difficult. Once the corrosion exceeds these dimensions, the ILI tools are more capable of detecting and sizing corrosion anomalies. Typically, ILI tools (both MFL and UT) are capable of sizing corrosion within ±10 percent of the pipe wall thickness with an 80 percent level of confidence.

Hydrostatic Testing Economics and Reliability

A strength of hydrostatic testing is that if a near critical axial flaw exists in the pipeline, it will fail during hydrostatic testing; however, hydrostatic testing provides no information on the condition of the pipeline other than for those flaws that fail during the test and it provides minimal levels of increased safety for most circumferentially oriented flaws. If corrosion rates or stress corrosion cracking (SCC) propagation rates are known, minimum times between hydrostatic tests can be calculated to have a high confidence that no service failures will occur prior to the next retest. Certain types of cracks cannot be detected with confidence by present ILI technology, leaving hydrostatic testing as the only reliable inspection method to ensure integrity when such cracks are known to exist. In addition, upon initial start-up or as part of a return-to-service program, hydrostatic testing may be required. In the following analysis, and as a comparison to ILI and direct assessment, it is assumed that all transmission pipelines will be hydrostatically tested.

Pipeline Preparation for Hydrostatic Testing

There is some preparation required to hydrostatically test a pipeline. This typically involves isolating a section of the pipeline to be tested. A typical hydrostatic test segment is 32 to 64 km (20 to 40 mi). It is assumed that the cost to prepare a pipeline is $50,000 to $100,000 per segment. This gives a preparation cost range of $775 to $3,100 per km ($1,250 to $5,000 per mi).[37]

Cost of Hydrostatic Testing

The cost of hydrostatic testing is divided into two categories: (1) the actual cost of testing and (2) the loss of throughput. It is estimated that the cost of hydrostatic testing is $1,240 per km ($2,000 per mi).[38] These costs include water handling and all testing costs.

The loss of throughput for hydrostatic testing is much more than that for ILI. A typical hydrostatic test takes 6 to 10 days to retest a 160-km (100-mi) section from the time the line is taken out of service until it isplaced back into service. This assumes multiple crews to keep downtime to a minimum. Making the following assumptions permits a cost of loss of throughput to be estimated (these are the same assumptions made for the analyses of pipeline failures and ILI costs):

- 5,520 kPag (800 psig) for either liquid or natural gas.

- Liquid pipeline:
  406-mm- (16-in-) diameter pipeline.
  128,000 barrels per day of throughput.[24]
- Natural gas pipeline:
  610-mm- (24-in-) diameter pipeline.
  8 million m^3 (287 Mcf) per day of throughput.[24]

Six to ten days of loss of throughput are equivalent to 48 million to 80 million m^3 (1,722 to 2,870 Mcf) for the natural gas pipeline and 768,000 to 1,280,000 barrels for the hazardous liquid pipeline. Making the assumption that the indirect cost in loss of throughput to the pipeline operator, producer, and refinery/user is 20 percent to 40 percent of the cost of the product $71.50 per thousand m^3 ($2 per thousand ft^3) for natural gas and $18 per barrel for the liquid product, the range of cost for loss of throughput is $689,000 to $2,296,000 for 160 km (100 mi) of natural gas pipeline and $2,765,000 to $9,216,000 for 160 km (100 mi) of hazardous liquid pipeline. This is $4,300 to $14,300 per km ($6,890 to $22,960 per mi) for natural gas pipelines and $17,200 to $57,300 per km ($27,650 to $92,160 per mi) for hazardous liquid pipelines.

Table 15 summarizes the costs for hydrostatic testing. The cost of the loss of throughput is by far the largest cost associated with hydrostatic testing. The total cost for hydrostatic testing of all pipelines would be between $7.21 billion and $22.37 billion for the first time. Because the preparation costs are relatively small, the cost of subsequent testing is only marginally less at $6.67 billion to $20.20 billion. It is obvious that operators that utilize hydrostatic testing on a regular basis must have other parallel pipelines or the pipelines are looped to reduce the cost of loss of throughput.

Table 15. Summary of hydrostatic testing costs.

ACTIVITY	COST OF HYDROSTATIC TESTING FOR NATURAL GAS PIPELINES		COST OF HYDROSTATIC TESTING FOR LIQUID PIPELINES		TOTAL COST FOR ALL PIPELINES	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
	($ per mi)	($ per mi)	($ per mi)	($ per mi)	($ x million)	($ x million)
Preparation	1,250	5,000	1,250	5,000	544	2,175
Inspection	2,000	2,000	2,000	2,000	870	870
Loss of Throughput	6,890	22,960	27,650	92,160	5,800	19,330
TOTALS					**$7,214**	**$22,375**

Note: Assumes 483,000 km (300,000 mi) and 217,000 km (135,000 mi) of natural gas and hazardous liquid transmission pipelines, respectively. 1 mi = 1.61 km

Reliability of Hydrostatic Testing

Hydrostatic testing is 100 percent reliable at removing all axially orientated flaws that are critical at or below a stress level corresponding to the pre-selected hydrostatic re-test pressure. Hydrostatic re-testing, however, has limited capabilities for removing circumferentially orientated flaws and short deep axial flaws that would be expected to leak rather than rupture in service.

Direct Assessment Economics and Reliability

"Direct assessment" is a systematic combination of existing proven monitoring methods with risk modeling to ensure pipeline integrity. A company that does minimum preventive monitoring may require an extensive exploratory dig program to assess whether or not the pipeline meets integrity standards, while a company with a regular monitoring program (close interval surveys, etc.) may require a smaller exploratory dig program to ensure integrity. Direct assessment is applicable to both external and internal corrosion and mechanical damage.

Pipeline Preparation for Direct Assessment

There is no pipeline preparation required for direct assessment. The methods employed are, for the most part, conventional methods employed by pipeline operators.

Cost of Direct Assessment

There is typically no product interruption; however, a lowering of pressure is typical during the exploratory dig. Therefore, there is loss of product depending on the pressures specified by company procedures.

The cost of direct assessment is dependent on the standard in-house practices of the individual operator. The following assumptions are made:

- $620 per km ($1,000 per mi) for detailed monitoring and diagnostic testing.
- Exploratory digs every 3.2 to 8 km (2 to 5 mi) at $5,000 to $10,000 per dig.

It is estimated that the cost of direct assessment is $1,250 to $3,100 per km ($2,000 to $6,000 per mi) of pipeline. This gives a total cost for direct assessment of all transmission pipelines of $0.87 billion to $2.61 billion.[39]

The cost of loss of throughput is due to the lowering of pressure during a direct assessment dig. It is assumed that the pressure is lowered to 50 percent of normal operating pressure. This lowering is for 12 hours in the day during the dig. It is further assumed that on any given line, two dig crews would be working and four digs per day could be accomplished (eight digs per day total). Assuming one dig per 3.2 to 8 km (2 to 5 mi), a 12-hour day would allow the inspection of 26 to 64 km (16 to 40 mi) of pipeline. For the natural gas pipeline scenario used throughout this analysis, reducing the pressure by 50 percent would reduce the throughput by 50 percent, giving a reduction in throughput of 168,000 m^3 (6 Mcf) per hour. A 12-hour workday would give a total reduction in throughput of 2 million m^3 (72 Mcf) of natural gas. Assuming the cost of loss of throughput is 20 percent to 40 percent of the $71.50 per thousand m^3 ($2 per thousand f^3) cost of the product and assessment of 26 to 64 km (16 to 40 mi) in a 12-hour day gives a range of cost for loss of throughput of $450 to $2,250 per km ($720 to $3,600 per mi) of pipeline for direct assessment. Multiplying by the 483,000 km (300,000 mi) of natural gas transmission pipelines gives a cost of loss of throughput of $216 million to $1.08 billion to assess all natural gas pipelines using direct assessment.

For hazardous liquid pipelines, the throughput is not as significant a function of operating pressure as for natural gas pipelines. In addition, the risks are not as great to the personnel performing the dig; therefore, although a pressure reduction may be required, the loss of throughput is assumed to be minimal.

Table 16 summarizes the costs for direct assessment of pipelines. The largest portion of the costs is the inspection, with a significant cost of loss of throughput for natural gas pipelines. The total cost for direct assessment of all pipelines is between $1.09 billion and $3.69 billion.

Table 16. Summary of direct assessment costs.

ACTIVITY	COST OF DIRECT ASSESSMENT FOR NATURAL GAS PIPELINES		COST OF DIRECT ASSESSMENT FOR LIQUID PIPELINES		TOTAL COST FOR ALL PIPELINES	
	Low Estimate ($ per mi)	High Estimate ($ per mi)	Low Estimate ($ per mi)	High Estimate ($ per mi)	Low Estimate ($ x million)	High Estimate ($ x million)
Preparation	0	0	0	0	0	0
Inspection	2,000	6,000	2,000	6,000	870	2,610
Loss of Throughput	720	3,600	0	0	216	1,080
TOTALS					**$1,086**	**$3,690**

1 mi = 1.61 km

Reliability of Direct Assessment

Variations of direct assessment technologies have been applied and tested through validation digs and have produced reliable results with a 70 to 80 percent positive predictive capability.

Comparison of Inspection Costs

Table 17 shows a comparison of inspection costs. The costs are compared by showing the total cost for inspecting all pipelines by each inspection method. By this comparison, the impact of the different inspection methods is readily apparent. The costs vary greatly depending on several factors. The costs of preparing the pipelines are extremely large for ILI, while the costs of performing hydrostatic testing are much greater than the other inspection methods because of the significant cost of loss of throughput. Direct assessment has no preparation costs; however, in general, the costs of inspection are comparable to the cost of ILI. The larger range of direct assessment costs is due primarily to the range in the number of digs required for direct assessment. The most cost-effective program, however, probably includes a combination of ILI, hydrostatic testing, and direct assessment.

Table 17. Comparison of costs for inspection methodologies.

INSPECTION METHOD	TOTAL COST OF PREPARING ALL PIPELINES		TOTAL COST OF INSPECTING ALL PIPELINES	
	Low Estimate ($ x billion)	High Estimate ($ x billion)	Low Estimate ($ x billion)	High Estimate ($ x billion)
ILI	9.72	32.57	1.58	2.41
Hydrostatic Testing	0.54	2.17	6.67	20.20
Direct Assessment	0	0	1.09	3.69

The number of miles of pipeline inspected by ILI, hydrostatic testing, or direct assessment on a regular basis is small, probably less than 20 percent of all pipelines.[40] In the future, the cost of inspection will significantly add to the present cost of operation and maintenance for pipeline operators. It is expected that little cost reduction in their current operating practices will result. In fact, identifying problem areas that are currently not known would initially be expected to increase the costs of repair; however, eventual savings will result from fewer leaks and fewer spills, the cost of which would continue to increase if not prevented by proper corrosion mitigation. In the long-term, preservation of an asset that has an estimated replacement cost of $541 billion is a major benefit.

CHANGES FROM 1975 TO 2000

Changes from 1975 to 2000 are minor in comparison with the changes that are anticipated for the future, as described above. Although there were many technical advances that took place in the last quarter of the 20th century, the basic corrosion control programs remained unchanged. The implementation of risk assessment programs and integrity management programs coupled with the continued aging of the pipeline infrastructure make the next 25 years very different from the previous 25 years. In addition, the deregulation of pipeline companies over the past 5 years significantly affected the free-market competitive nature of a company's operation. All of these factors will have a strong effect on pipeline operation in the future.

CASE STUDIES

Case Study 1. Integrity Maintenance on TAPS

Introduction

The Trans-Alaskan Pipeline System (TAPS) is one of the most critical pipelines in North America. It delivers approximately 1.35 million barrels per day (1998) of hot [50 °C (120 °F)] crude oil 1,290 km (800 mi) across Alaska, from the Prudhoe Bay production fields to the oil terminal at Valdez. In addition, environmental issues are of paramount concern. For both of these reasons, a single leak in this pipeline is considered to be unacceptable.

Background

The 1,219 mm- (48-in-) diameter pipeline was constructed between 1974 and 1977.[41] Of the 1,290 km (800 mi) that the pipeline stretches across Alaska, 680 km (420 mi) is above ground and 610 km (380 mi) is buried. The aboveground portion is coated and thermally insulated with only minor corrosion concerns. The buried portion is coated and cathodic protection (CP) is applied. The original sacrificial CP system consisted of continuous zinc ribbon buried in the bottom of the pipe ditch on both sides of the pipe. The pipe was originally coated with a fusion-bonded epoxy (FBE). Coating adhesion problems were encountered early in the construction phase and the FBE was overwrapped with polyethylene tape and elastomeric heat shrink tape.

At peak production in 1988, TAPS delivered 2.1 million barrels per day (bbl/day), nearly 25 percent of the U.S. domestic oil supply. Currently, an essential factor in integrity planning is that production at Prudhoe Bay is declining, which impacts the cost benefit of corrosion mitigation upgrades. An additional aspect of the TAPS system is that 75 percent of the pipeline crosses regions of permafrost, making engineering solutions more difficult and making costs significantly higher than for typical pipeline systems.

Historically, an in-line inspection program has been performed in conjunction with potential survey techniques to monitor the effectiveness of the CP system. In-line inspection utilizing the most sophisticated tools available has been performed almost every year since start-up. The in-line inspection identifies areas of probable corrosion by measuring loss in pipe wall thickness. Electrochemical potential measurement techniques (pipe-to-soil potential test station measurements and long-line surveys) typically provide an accurate measurement of the effectiveness of the CP system in mitigating corrosion.

In the early 1990s, Alaska became concerned with whether the existing CP system was mitigating corrosion and whether conventional over-the-line pipe-to-soil potential survey methods were adequately assessing the effectiveness of the CP system. The consequence was that it was concluded that the CP system may not be effective in mitigating corrosion; therefore, the operator is left with the in-line inspection program to identify areas of significant wall loss and to repair the identified areas prior to failure. The long-term problem with this approach is that if corrosion continues, the effort of repairing the pipe would become economically overwhelming as the number of critical corrosion sites increased. With this, a cooperative program was established that included Alyeska (the TAPS operator), the state of Alaska representatives, and the Federal Bureau of Land Management. The task was to identify technical and cost-effective means of improving the corrosion mitigation system of TAPS.

Overall System Integrity Program

There are five strategic elements to the system integrity approach for TAPS: (1) pipeline system design, (2) CP monitoring and maintenance, (3) integrity monitoring and repair, (4) supplemental CP, and (5) corrosion data management.

Pipeline System Design

Pipeline system design consists of a wall thickness design and a CP system design. The pipeline wall thickness was designed in accordance with ASME B31.4 standards and U.S. DOT regulation 49 CFR 195. The pipeline wall thickness design provides at least 10 percent nominal wall thickness (nwt) corrosion allowance. Operation at pressures below maximum allowable operating pressure (MAOP) can create additional corrosion tolerance. Furthermore, engineering calculations and experience show that a corrosion failure is unlikely if the corrosion depth is less than 50 percent nwt.

The CP system design consisted of the FBE primary coating overwrapped with polyethylene tape and twin zinc galvanic anode ribbons placed in the bottom of the ditch to provide protection to holidays (damaged areas) in the coating. This CP system design is critical because it establishes limitations on alternative remedial methods for enhancing the effectiveness of cathodic protection.

CP Monitoring and Maintenance

CP monitoring consists of: (1) monitoring 1,100 permanent test stations on the TAPS, (2) close interval pipe-to-soil surveys used to monitor between the test stations, and (3) 400 coupon test stations used for monitoring interference and IR-drop free pipe-to-soil potentials.

General CP system maintenance consists of placing remedial magnesium anodes in areas of low protection in accordance with NACE RP0169 and 49 CFR 195. Approximately 50 percent of the buried pipeline has remedial anodes [more than 450,000 kg (1 million lb)], and 3.2 to 8.0 km (2.0 to 5.0 mi) of remedial anodes are placed each year.

Integrity Monitoring and Repair

In-line inspections (monitoring pigs) are run annually compared to many other pipelines that run in-line inspections every 5 to 7 years. First-generation ILI tools were used prior to 1989 and were only capable of locating relatively severe corrosion (i.e., wall loss greater than 30 to 50 percent of the pipe wall thickness). More advanced, high-resolution ILI tools were used beginning in 1989 and have provided a more realistic representation of the status of corrosion on the pipeline. Curvature and deformation pigs are also used to indicate high stress areas where possible settlement has occurred.

Field inspection requires digging up the pipe for visual and ultrasonic inspection of the surface. Repair methodologies following inspections include the following: cleaning and recoating, sleeving, large-scale refurbishment, and pipe replacement.

Supplemental CP

Supplemental cathodic protection to be added to the TAPS system was mandated through the cooperative program based on a Tariff Settlement between the State of Alaska and the TAPS owners. The supplemental CP program provided protection beyond the original CP design. The original CP maintenance program was completely driven by meeting regulatory requirements. The trend of increasing the number of inspection digs required, based on pig reports, indicated that the practice of installing magnesium anodes at "low potential" areas was not effective in mitigating corrosion on the TAPS.

The primary concept of the supplemental CP program was that by supplying properly designed CP systems based on impressed-current CP, corrosion would be effectively mitigated and the number of inspection digs required would decrease over time. The supplemental CP project selection was based on economic advantages. Each supplemental CP project had to provide a net economic advantage based on the cost of the supplemental CP, the maintenance of the system, and the savings incurred by eliminating inspection digs.

Corrosion Data Management

The corrosion data management (CDM) system contains information relevant to corrosion and corrosion control, including the pipeline design and hydraulic data, in-line inspection monitoring data, CP monitoring data, and field investigation data. The CDM system also has built-in engineering calculations to support the decision process.

Life Cycle of the TAPS

The supplemental CP program is designed to minimize the life-cycle cost of corrosion on the TAPS. The life cycle for TAPS can be defined by the intersection of the revenue curve and the cost of the maintenance curve (see figure 13). One particular issue regarding TAPS is that its throughput is declining; therefore, the revenue generated by TAPS is declining. Figure 17 shows two scenarios, one for a "high" projected maintenance cost and one for a "low" projected maintenance cost. At present, approximately 10 percent of the maintenance cost is spent on corrosion-related items. The primary differences between the two scenarios is in the cost due to corrosion (dig programs, repairs, etc.) and in the projections of the life cycle for TAPS, which differs by 10 years. This indicates that optimizing corrosion-related practices can have a major impact on the life cycle of the TAPS.

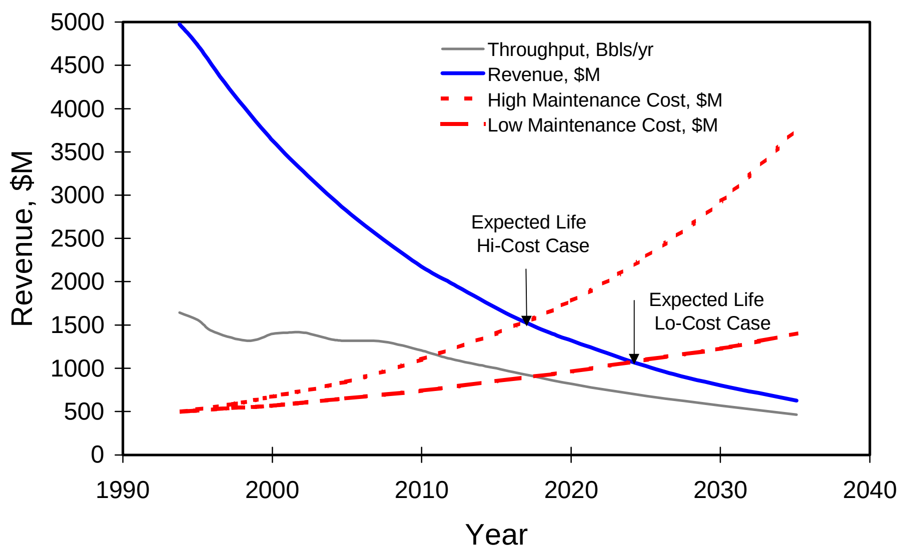


Figure 17. Hypothetical revenue versus cost for two maintenance scenarios on the TAPS.

Case Study 2. Integrity Management Program Development

Background

A gas transmission company experienced numerous corrosion-related pipeline failures.[42] From 1961 to 1997, 24 service failures were experienced (0.67 per year). An extensive pipeline integrity management program was developed in 1986. The program, which has been evolving ever since its inception, incorporates the following practices:

1. In-line inspection and excavation program (intelligent pigging).
2. Hydrostatic re-testing program.
3. Discrete investigative dig program (bell-hole inspection).
4. Soils modeling to predict likelihood for corrosion-related failures.
5. Remaining life assessments.
6. Cathodic protection monitoring, upgrading, and effectiveness testing.
7. Large-scale coating reconditioning program.

In 1998, a review was undertaken to assess the cost-effectiveness of the 13-year old pipeline integrity management program. This case study presents the results of that review.

Failures Prevented by an Integrity Management Program

Data were compiled to total the hydrostatic test failures, service failures, and in-line inspection indications ("pig indications" or "pig calls") during the 1986-1998 preventive maintenance program. The key indicator to be examined was the number of service failures prevented by the pipeline integrity management program. Each flaw associated with either a hydrostatic test failure or a direct inspection dig program that had a predicted burst pressure less than or equal to 100 percent of the specified minimum yield stress (SMYS) was analyzed to predict the expected life had that feature not been removed from the pipeline. Each of these flaws became a failure prevented by the integrity management program at a projected time based on the predicted life.

The life prediction was based on the flaw growing from its current size, as determined by an in-line inspection tool or a hydrostatic test, to a size that would have a burst pressure equal to 100 percent of the maximum allowable operating pressure (MAOP). The burst pressures were calculated using CorLAS™. Flaw growth rates, based on research by CC Technologies Laboratories, Inc. and field data, indicated an upper-bound growth rate of 0.3 mm per year for a corrosion flaw and 0.6 mm per year for an SCC flaw. By adding the remaining life as calculated above to the date of the last in-line inspection or hydrostatic re-test, the projected failure date, assuming no action had been taken, was established for each flaw.

Based on these data, the number of prevented failures can be plotted for each year, starting at the beginning of the program (1986). Figure 18 shows the prevented failures by year for three program sessions using data for 1986-1996, 1986-1997, and 1986-1998. In general, it is shown that the integrity management program implemented by the gas transmission company prevented a significant number of in-service failures. In addition, each additional year's data from 1996 to 1998 indicates an increasing number of failures prevented.

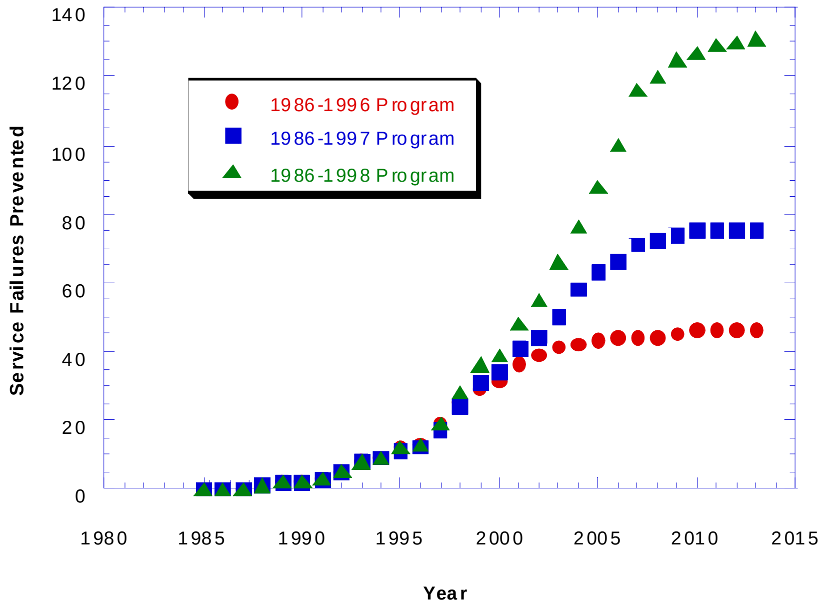


Figure 18. Number of failures prevented by the integrity management program (IMP).

Cost of Integrity Management Program

Figure 19 shows the cumulative failures and the cumulative costs of the integrity management program. The actual failures are plotted assuming zero future in-service failures, which is the technical objective of the integrity management program. The number of failures with no integrity management program is shown for comparison (based on figure 18 and actual in-service failures). Also plotted in figure 19 is the cumulative cost of the integrity management program since its initiation in 1986.

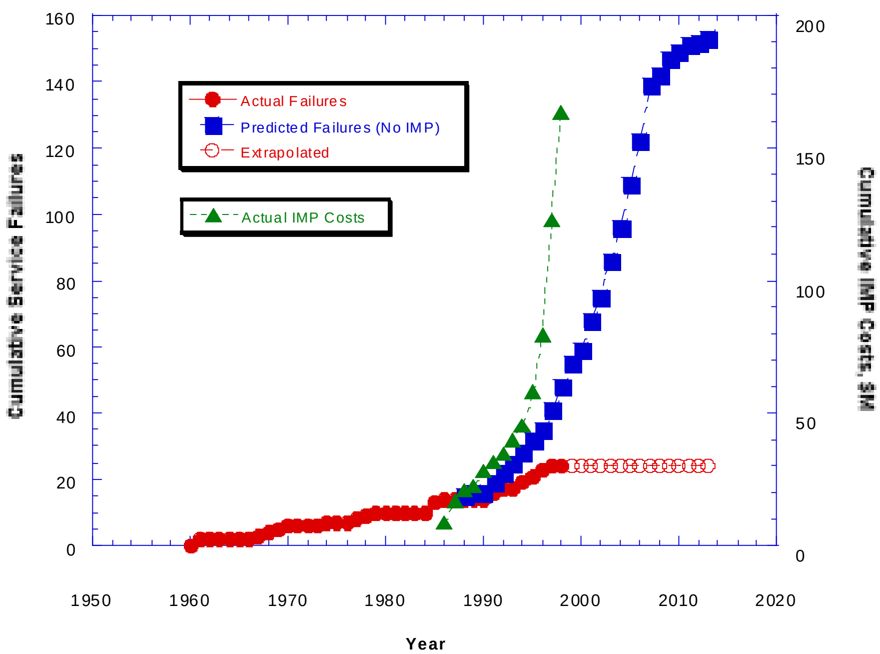


Figure 19. Cumulative in-service failures compared to cumulative costs of the integrity management program (IMP).

There are several benefits of an integrity management program, including prevented failures, continued operation at desired pressure (pressure reduction is a threat if integrity is not maintained), preservation of the pipeline asset, etc. Since inception, it is estimated that the integrity management program has prevented 125 failures (see figure 19). This alone is significant enough to justify the program.

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