9

Maintenance

Energy is the essence of life. Every day you decide how you are going to use it by knowing what you want and what it takes to reach that goal, and by maintaining focus.
—Oprah Winfrey (1954–)

For pipeline companies, maintenance is about understanding the condition of the asset. They perform necessary inspections, correct potentially unsafe conditions before they cause failures, and repair failures after they occur. Still, even though maintenance and operations are two different functions, the same people often perform them.

Pipeline maintenance has evolved over time. It started out as "fixing components when they break," just as a driver changes a tire when it blows out. As technology improved, the industry began to appreciate the value of avoiding failures and their associated costs. Public expectations heightened. The definition of maintenance broadened to include preventive maintenance—replacing components before they break—based on the average life expectancy and visual inspections of components. Similarly, more attentive drivers change their tires when they look worn or the tread depth is below a certain level, but certainly before the tire experiences a blowout.

Nowadays, the concept of maintenance in the pipeline industry also includes predictive maintenance. This goes beyond maintenance based only on component life expectancy and elementary inspections. Maintenance plans now use sophisticated data collection and interpretation technologies to prioritize maintenance activities. Pipeline companies, just like car owners, rely on computerized analysis to determine what is happening "under the hood."

Pipeline assets can conveniently be divided into the components inside the pump stations, compressor stations, and meter stations, and those outside. Equipment inside the stations is maintained much like equipment in manufacturing plants. Other books cover the topic of maintaining plant equipment. This chapter focuses only on maintaining pipelines outside the station. It covers releases, what causes them, how to prevent them, and how to find potential problems before they become failures. It also discusses how to allocate resources to repair the most critical potential problems, and finally, how to repair problems if they occur.

What Causes Releases?

The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) tracks and reports releases from U.S. pipelines. Industry associations, specifically the Association of Oil Pipe Lines (AOPL), API, Interstate Natural Gas Association of American (INGAA), the AGA, and the American Society of Mechanical Engineers (ASME) also track and report releases. The Conservation of Clean Air and Water in Europe (CONCAWE) also periodically reports pipeline releases and their causes. Based on these consolidated reports, the leading causes of pipeline releases are:

- Equipment damage from excavators and agricultural activities
- Corrosion (external and internal) and stress corrosion cracking
- Mechanical failures from manufacturing and construction defects
- Natural hazards such as ground movement, weather, lightning, and currents
- Miscellaneous problems, including operating errors and equipment failures

Advocates of the need for enhanced pipeline safety and pipeline industry representatives sometimes disagree about which of these is "the leading cause." However, this list covers almost all the pipeline releases.

There is one special case not listed previously that deserves mention. Sometimes people try tapping into a pipeline to steal its contents, often with disastrous results. Protecting against theft is a security issue and is not dealt with in this book.

Equipment damage

Pipelines often coexist with other underground utilities, packed into the same ditch. Excavation activities of any kind pose significant risks to buried pipelines. Such activities could include utility construction or maintenance, construction of buildings, roads, railroads, parking lots, and other aboveground and underground facilities. Assuring that existing pipelines are not adversely affected by such activities requires planning and care. Work crews maintaining buried utilities or installing new facilities that are adjacent to or across pipelines sometimes inadvertently damage them. Even pipeline contractors working on the line sometimes hit and rupture or damage it.

Heavy construction equipment near the pipeline may puncture the pipeline, causing an immediate release. However, it may only gouge the line, removing metal and creating a weak spot that may fail later. Equipment scraping a pipe generates heat that can change its metallurgy, making it brittle and susceptible to cracking. Coating is easily damaged by excavation activities, leading to *corrosion hot spots,* discussed later in this chapter. Figure 9–1 shows the location of an Olympic Pipeline rupture on June 10, 1999, near Bellingham, Washington, which killed three people.

The U.S. National Transportation Safety Board (NTSB) found one of the five contributing factors to this accident was damage to the pipe by a contractor working on a water treatment plant five years prior to the rupture.[1] Figure 9–2 is a sketch from the same NTSB report showing pipeline damage.

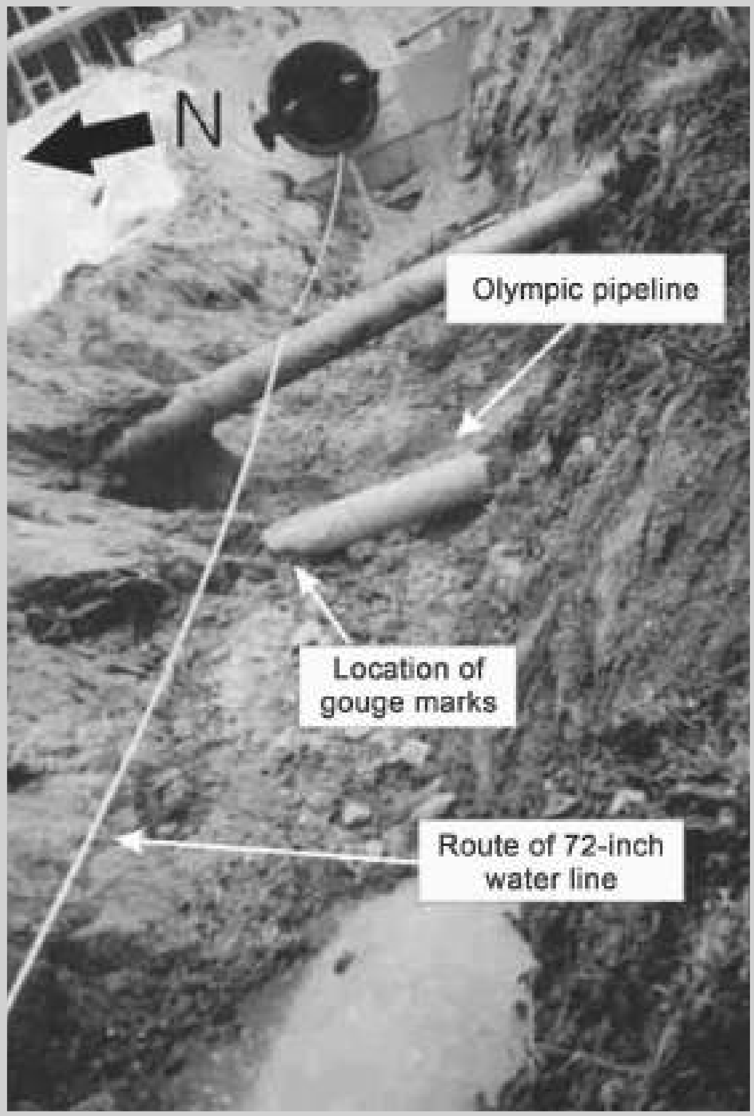

Fig. 9–1. Olympic Pipeline rupture location (Source: National `Transportation Safety Board)

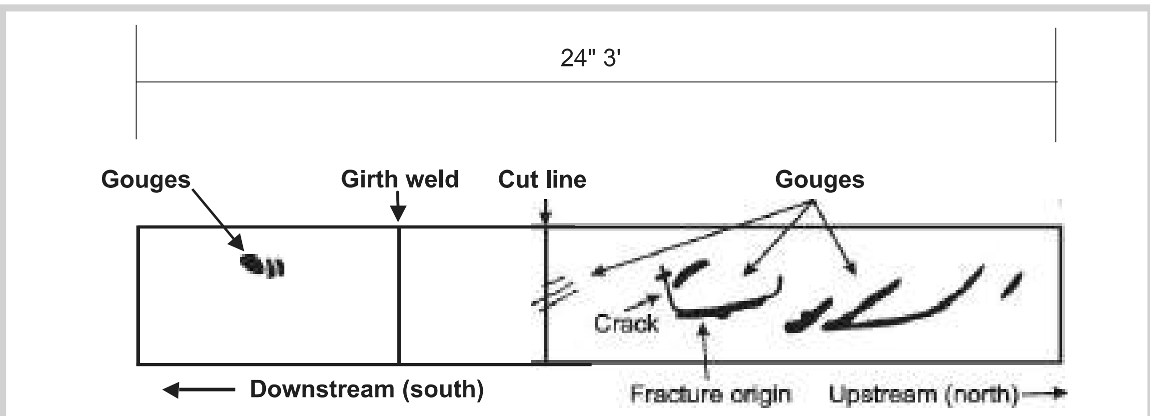

Fig. 9–2. Drawing of gouges in pipe from NTSB report. This is a top view, looking down on the pipe. Note the gouges and the fracture origin point. The cut line is where the pipe was cut following the accident. (Source: National Transportation Safety Board)

Corrosion

Almost all oil and natural gas main lines are steel. They will corrode (rust) if not protected. Properly protected, steel maintains its original properties indefinitely, but a pipeline can leak or rupture if too much metal is removed by corrosion from even a small area. There are several different types of corrosion. The type most common to pipelines is *galvanic corrosion,* which is similar to what makes flashlight batteries work. A battery supplies electric current when its zinc outer shell, the negative post of the battery (the anode), is consumed by a corrosion-like chemical reaction. The zinc metal changes to a zinc compound, and in the process, gives up electrons (electricity). The electric circuit is completed as electrons flow through the flashlight bulb and back to the positive post of the battery (the cathode).

Iron in steel accounts for 99% of the composition of pipe. Iron can be consumed in the same manner as zinc if exposed to the soil environment. Electrons flow from the pipe into the surrounding soil, migrating to other underground structures or distant parts of the same pipeline that are more positively charged. The circuit is completed by some form of electrical continuity, such as a metallic connection between the structures. The iron atoms lose electrons, becoming positively charged ions. They bond with the negatively charged molecules in the vicinity to create nonmetallic compounds that lack the strength and toughness of steel. In other words, the iron rusts, and the rust flakes off, reducing the wall thickness. The same thing can happen inside the pipe if oil and gas pipelines contain water, carbon dioxide, or other contaminants.

Corrosion of the outside and inside pipe wall is known as *external corrosion* and *internal corrosion,* respectively. Both can be influenced by microorganisms such as bacteria, fungus, and algae living on the surface of the pipe. *Microbial influence corrosion* (MIC), under certain conditions, can significantly accelerate the corrosion rate, resulting in severe pits (fig. 9–3).

Fig. 9–3. Severe microbial corrosion (Source: National Transportation Safety Board)

Mechanical failures

Mechanical defects are divided into two categories: manufacturing flaws and construction flaws.

Manufacturing flaws. Pipe materials manufactured prior to about 1970, while strong and generally serviceable, tend to be more susceptible to defects than pipe materials made in more recent times. Some pipe materials were produced with longitudinal seams made by low-frequency-current electric resistance welding (ERW). Among other materials, these have shown a propensity to failures involving the longitudinal weld seam. Pipe metallurgy, the subject of complex engineering knowledge, determines the properties of the pipe. These include the susceptibility of the pipe to brittleness and cracking, especially at cold temperatures.

Manufacturing processes, covered in chapter 11, have improved steadily over the years from the first cast-iron pipe made in Middenville, New Jersey in 1834. Improvements in pipe metallurgy and better methods for welding the longitudinal seam have all but eliminated manufacturing defects in modern pipe.

Construction flaws. There are several primary construction-related defects. These include poorly fabricated girth (circumferential) welds in the field, improper handing of the pipe during transportation and construction, and coating damage during construction. Examples of girth weld defects include mismatched alignment of the two pipe ends, incomplete penetration of the weld, lack of fusion, slag inclusion, porosity, and cracks. Improper handing and field bending of pipe sometimes causes buckles, wrinkle bends, and wall thinning.

Pipelines are coated with insulating materials to stop current flow and corrosion. Proper handling of the coated pipe during installation, or even repair, insures integrity. When damage occurs, it must be repaired to avoid concentrated current flow resulting in a corrosion hot spot.

Improper handling prior to reaching the construction site can also cause problems, as shown in figure 9–4.

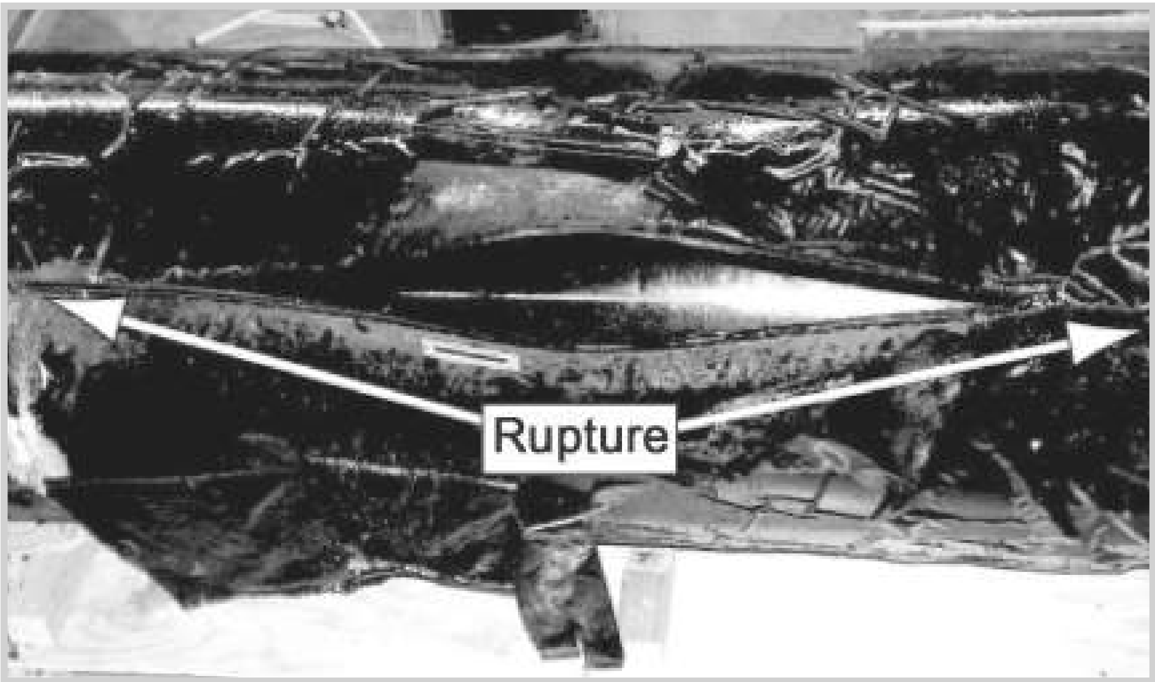

Fig. 9–4. Longitudinal seam split caused by improper loading of the pipe for transportation (Source: National Transportation Safety Board)

A fatigue crack initiated along the seam of the longitudinal weld during transit. It grew with pressure cycle stresses until the crack reached a critical size, at which time the pipe ruptured.[2] How does fatigue cracking during transportation begin? Improperly loading pipe can result in concentrations of stress that vary as the loaded railcars bounce up and down along the trip from pipe manufacturer to construction site. Bouncing flexes the pipe. By itself, this would not necessarily damage the pipe. However, if the pipe is improperly loaded, the seam weld crown (the very top of the seam weld) may inadvertently be loaded face down and bear the entire weight of the pipe. The top of the seam weld is subjected to stress as it bounces along, which can initiate a fatigue crack. The phenomenon is similar to bending a wire coat hanger back and forth until it develops a crack and fails.

Chapter 13 covers construction in more detail. Additional information regarding the evolution of manufacturing and construction techniques can be found in the report, "Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction."[3]

Natural hazards

Buried pipelines are susceptible to damage from earth movement caused by seismic activity. They are also susceptible to landslides, soil activity (shrinking, swelling, subsiding, or settling), scouring, and erosion (fig. 9–5).[4]

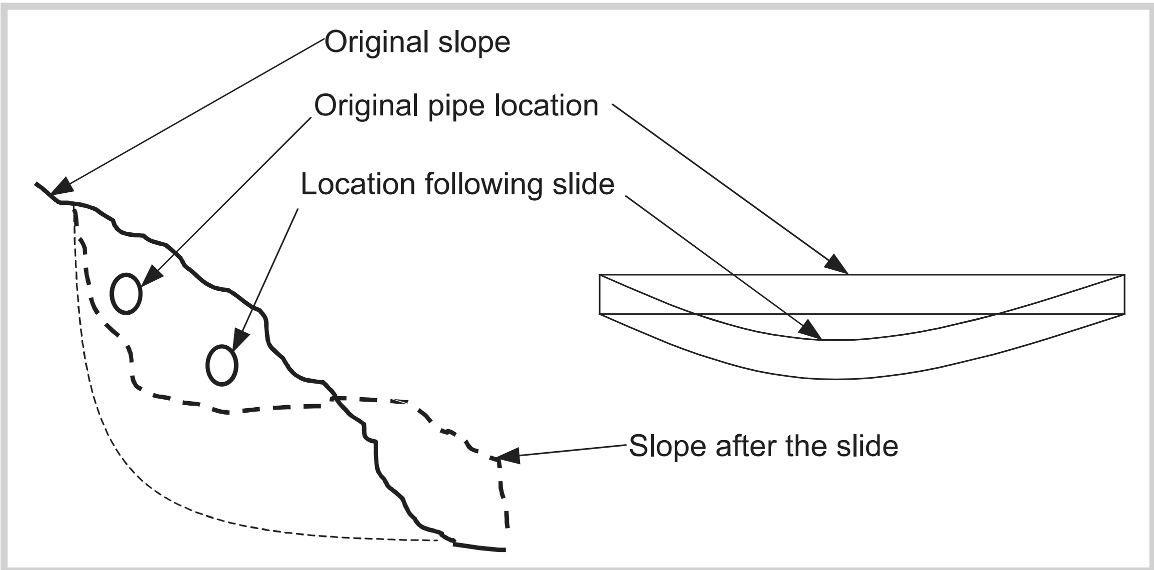

Fig. 9–5. Pipeline movements during a landslide. The force of the slide bends the pipe, causing it to stretch.

The amount of pipeline elongation is overemphasized in figure 9–5 to dramatize potential problems from land movement. Sometimes the pipeline fails during the landslide. At other times, stresses may build up and eventually rupture the pipeline, unless the pipe operator takes corrective action to relieve pipeline stresses. Sometimes the earth beneath the pipeline washes away, and the soil above the line pushes on it (fig. 9–6).

Fig. 9–6. Natural gas pipeline exposed by erosion (Courtesy Miesner, LLC)

Eventually the force may become large enough to break the line unless the pipeline operator takes corrective action.

Buried river and stream crossings and subsea pipelines are sometimes exposed by erosion. Once exposed, the flowing water presses on the pipe. Swift currents pushing against exposed pipelines increase pipeline stress and can damage and even rupture the pipeline. One of the more spectacular flooding examples occurred during October 1994 in the San Jacinto River, near Houston, Texas. Flooding ruptured 8 pipelines and undermined 29 others. The NTSB estimated more than 35,000 bbl of petroleum or petroleum products were released from the ruptured lines. Part of the spills ignited from an unknown source, causing a spectacular display of fire on the river.[5]

Sometimes riverbeds or stream bottoms wash out, exposing the pipe (fig. 9–7). When heavy rains fill a drainage ditch to overflowing, stresses can build up in the pipeline, potentially causing failures. Debris may also wash down the drainage ditch and snag on the exposed pipe, causing it to rupture.

Fig. 9–7. Natural gas pipeline exposed in a drainage ditch (Courtesy Miesner, LLC)

Lightning is another source of natural damage. Lightning is more apt to damage aboveground facilities, particularly storage tanks. At a crude oil export terminal near the Russian town of Novorossiisk, at the end of the CPC Pipeline from the Tengiz oilfield, this threat is taken seriously. They installed 16 giant lightning arrester towers as a precaution against lightning.[6] Still, there have been cases in which the lightening grounded through a hole in the coating and caused a leak in a buried line.

Damage from seismic activity along fault lines can occur when the sections of soil shear or move differentially to each other. Earthquakes sometimes temporarily liquefy the earth around pipelines, causing differential settling. Periodic and seasonal swings in rainfall can cause soil shrinking, swelling, subsiding, or settling. These can precipitate buckles and subsequent cracks in pipelines (figs. 9–8 and 9–9).

Aseismic faulting occurs when one type of soil moves more or less than a nearby soil type. This type of faulting can be observed where streets and sidewalks change elevation abruptly. Around a pipeline, it can impart extreme stress and cause failure.

Fig. 9–8. Pipeline buckle caused by differential settlement through a landfill (Source: National Transportation Safety Board)

Fig. 9–9. Crack caused by buckling (Source: National Transportation Safety Board)

Other causes of failures

Of all releases, 20% to 30% can be categorized as "miscellaneous" causes of failure. Two of the leading causes in this group are operating problems and equipment malfunction. In many cases, these two only exacerbate a previous condition, because they stress a previously weakened piece of pipe or component beyond its limits.

How to Prevent Damage

Eliminating defects and relieving excessive stresses prevent pipeline failures. This section addresses each of the causes of failure and discusses some methods to prevent them.

Equipment damage

Equipment damage is a concern of pipeline companies, owners of other types of underground utilities, legislatures, regulators, emergency response officials, and contractors. In the United States, Common Ground Alliance (CGA) is an organization comprised of members of each of the groups listed above. These members work to promote the safety of underground utilities. The following sections draw heavily on a report by CGA.[7]

Planning and design. With knowledge of the locations of pipelines, construction projects can be designed to minimize the need to dig around pipelines. This is one of the best ways to avoid pipeline accidents caused by equipment. When a project involves excavation, the designers attempt to locate all underground utilities in the area. The underground utilities should be clearly shown on project plans. Designers and utility operators should meet to plan the best ways to work around the lines. Including excavators early in the planning process sensitizes them to the requirement to dig safely.

One-call centers. One-call centers are clearing houses for excavators to learn about all underground utilities in a specific geographic area. Designers and excavators should contact the center giving them the location of their projects. (It is equally important for homeowners to call their local utilities or a one-call center before beginning a "backyard project.") The center then consults maps and databases and contacts the companies owning the underground facilities close to the excavation location. Most states in the United States have at least one such call center. Fortunately, the CGA has fostered better cooperation between various involved parties and the offices of the area's jurisdictions.

Locating and marking. If a pipeline is contacted by a one-call center, it checks its records to see how close the excavation is to its lines. If it is close enough, the pipeline company sends someone out to locate and place markers along the line. Pipeline owners also regularly clear their ROWs and mark the pipeline routes on an ongoing basis (fig. 9–10). These permanent markers (fig. 9–11) allow landowners and excavators to determine the pipeline location so they can avoid it.

Fig. 9–10. Cleared and marked ROW (Courtesy Miesner, LLC)

Fig. 9–11. Typical ROW marker (Courtesy Miesner, LLC)

Pipeline employees or contractors use their maps, line finders, and probes to locate and stake the exact location of pipelines prior to the start of excavation projects. For particularly confined excavation sites or where the location of lines is uncertain, lines are excavated manually to find the exact location prior to mechanical excavation. Hand digging costs more than mechanical excavation, but it can avoid costly accidents. Many pipeline operators require the presence of their own inspectors during any excavation work near their lines. Excavators and pipeline operators normally work together to plan their activities and allow proper inspection and monitoring.

Excavation. Prior to excavation, representatives from the excavator and pipeline operator meet to agree on the excavation plan and confirm line locations. A *tolerance zone,* equal to the width of the pipeline plus a short distance on each side, is established. (Common Ground Alliance's *Best Practices* suggests at least 18 in. on each side.) No mechanical excavation is allowed within this tolerance zone. *Spotters,* construction company employees assigned to monitor the excavation, warn the equipment operator of dangers not easily seen. Pipeline operators monitor their own contractors digging near the line as vigilantly as they monitor excavators working for others.

Maps. Accurate maps sometimes make physically locating the line during initial project design unnecessary. Supplying pipeline location coordinates directly to project designers for inclusion on the drawings makes their work easier and improves safety. Even with the most accurate maps, pipeline operators, designers, and excavators often visit the proposed construction site prior to final design approval to verify locations.

Regulations and compliance. Appropriate regulations and compliance are important factors in avoiding equipment damage. Excavation regulations tend to vary from country to country, and often within a country as the result of differing requirements within local jurisdictions. In general, regulations requiring one-call systems and establishing tough fines for excavators who do not use the centers or who damage underground utilities tend to reduce pipeline accidents.

Public education. Chapter 14 discusses the many stakeholders who ought to be knowledgeable about pipelines in order to reduce the risk of pipelines accidents. These stakeholders include landowners, residents, excavators, utility operators, legislatures, regulators, and emergency response personnel. Pipeline companies conduct education programs, informing those living and working around the line about how to protect it and how to recognize and respond to emergencies. Informed landowners are a valuable first line of defense for the pipeline operators. Beyond that, in the event an accident happens, trained emergency response personnel are essential.

Monitoring the route. Pipeline operators regularly patrol the route from the air as well as from the ground. These patrols look for excavation near the line and indications, such as stakes, markers, and vegetation clearing, that excavation is likely. At the same time, the patrols look for other signs of potential problems. These could include signs of small releases, encroachments, erosion, exposed pipe, marker condition, overgrown vegetation, earth movements, and general ROW conditions. The ROWs are normally kept clear of large vegetation to allow the aerial patrols better visibility. When aerial patrols identify a concern, pipeline employees are dispatched to investigate in more detail. Technologies are improving route monitoring, including surveillance by satellite, sonar mounted on airplanes, and fiber optic cables installed along the ROW.

Leak detection also calls for line monitoring, especially for small leaks. Large releases are normally located by leak detection systems or direct observation, since they attract attention. Small releases are difficult to detect. Oil releases cause wet spots, stains, or dead vegetation that may be spotted by aerial patrols. Natural gas, with a vapor pressure above atmospheric pressure, escapes into the surrounding air, often in small enough concentrations that it is not even ignitable. Such small leaks are difficult for aerial patrols to spot. Thus many natural gas pipelines have someone periodically walk the route with gas detection equipment looking for small leaks, particularly in sensitive areas such as those with high population concentrations.

Reporting and evaluation. The final step in reducing equipment damage is reporting and analyzing data about previous incidents. This allows pipeline companies to understand the root causes and take actions to reduce the likelihood of future damage. Collecting the information in a consistent format and providing it to one organization for analysis is the best way to learn about damage and how to avoid it. Industry associations and governmental agencies normally pick up this task. Whoever analyzes this information should include representatives from all stakeholders in a two-way communications format. Stakeholders can be educated about equipment damage and their role in preventing it. They can also offer valuable insight into improvement techniques.

Corrosion

Most pipeline corrosion is caused by current flow—electrons leaving the iron in the steel—especially in moist environments. Swamps and wet areas allow electrons to flow more easily than deserts and dry areas. Stopping the flow of electrons stops corrosion. Insulating coatings, such as coal tar enamel, and more recently, fusion-bonded epoxy, are applied to the outside pipe wall to stop current flow and can last more than 50 years. (There is more discussion of coatings in chapter 11.) They can effectively protect the pipe from current flow, but even a tiny hole in the coating (sometimes called a *holiday*) can concentrate current flow, creating an area of accelerated corrosion. That calls for care during the construction process, critical to avoiding holes in the coating.

Another alternative to stop corrosion is to reverse the flow of electrons, making them flow towards the pipe. This is called *cathodic protection* and is accomplished it two ways—by *sacrificial* or *impressed current* (fig. 9–12).

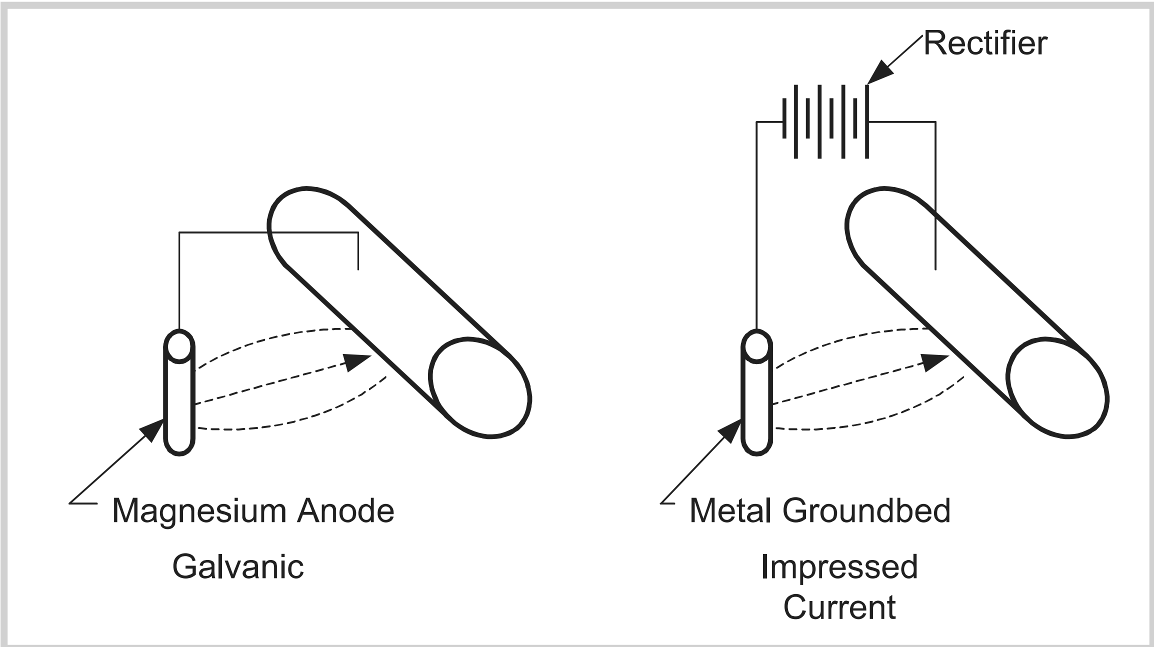

Fig. 9–12. Galvanic and impressed current cathodic protection

Sacrificial protection, the original method, involves burying a metal with a higher electrochemical potential than iron (often magnesium) in selected locations along the line. These *anodes* are connected to the line with insulated wires. Electrons flow from the sacrificial anode to the pipe (which becomes the cathode), preventing corrosion.

Impressed current involves connecting a *rectifier* (essentially a transformer that converts alternating current to direct current) to the line. The rectifier actually impresses current onto the pipeline, causing electrons to flow towards the pipe rather than away from it (something like recharging a battery). This prevents oxidation. Where do the electrons come from? As with galvanic protection, anode *groundbed*s are also buried along the line. They can be made of cast iron or other suitable material. The anodes are connected to the positive terminal of the rectifier. The negative terminal of the rectifier is connected to the pipe, completing the electrical circuit. Soil type and coating quality determine the number of rectifiers required along a particular pipeline. Rectifiers are a common sight, but probably few people can identify what they are (fig. 9–13).

Fig. 9–13. Pipeline rectifier. Note the power meter and breaker box on the pole next to the rectifier and the line markers in the background. (Courtesy Miesner, LLC)

There is one last important note regarding external corrosion and cathodic protection. Anything near a pipeline that is prone to corroding or generating electric currents must be considered by the corrosion technician or engineer. The electrical potential of power lines, other pipelines, railroad tracks, steel bridges, and the like are taken into account in the corrosion mitigation plan.

Internal corrosion normally occurs in low spots where contaminants like water tend to collect. Regular pig runs to keep the line clean and free of contaminants is one of the first defenses against internal corrosion. (Pigging is covered in more detail later in this chapter.) Inhibitors are also injected into the pipeline to prevent corrosion. Inhibitors can work by coating the internal wall of the pipe to prevent current flow or by interacting with the pipe materials to lower their electrochemical potential. They can also react with oxygen and other corrosive agents before they corrode the metal or neutralize acids that cause corrosion. Inhibitor concentrations can be tricky. In the wrong concentrations or combinations, they can actually accelerate rather than retard corrosion.

Stress corrosion cracking (SCC) is a phenomenon that may initiate on the outside surface of a pipe under stress. This can occur if the protective coating is absent or disbonded and the surface becomes exposed to certain types of soil/groundwater environments. It starts as a colony of small cracks that grow as the pipeline undergoes pressure cycles. If this growth continues unabated, it can cause the pipe to leak or rupture. Dealing with this phenomenon can be difficult and expensive, so the preferred solution is to prevent it from occurring. The best way to prevent SCC is a sound protective coating that remains tightly bonded to the pipe.

Mechanical failures

Mechanical failures are attributable primarily to either manufacturing flaws, construction-related flaws, or mishandling of the pipe during transportation. They are best minimized with robust standards and specifications, followed up by conscientious inspection and quality control. Pipe manufacturing and quality control are covered extensively in chapter 11. Construction welding is covered in chapter 13.

Natural hazards

It is important that pipeline companies recognize the potential for floods, seismic activity, landslides, and other types of soil movement, and design pipelines accordingly. This will go a long way toward preventing failures from natural hazards. Ongoing inspection is also critical to understand when corrective action is necessary. Design is covered in chapter 12, so the focus of this section is ongoing inspection.

Aerial patrols, mentioned earlier, can give early warning of impending earth movement. Trees leaning over, fresh earth scars on hillsides, newly exposed pipe, and water seeping from hillsides indicate potential problems.

Inclinometers are sometimes installed along the slope for an early warning of slope movement. Sometime exposed pipes in rivers and streams are visible during dry periods when the water is low. Strain gauges, electrical resistance or fiber optic, can also be installed on or near the pipeline to monitor pipeline stress due to earth movement. Strain gauges measure very small changes in pipe length. Increased strain indicates stress is building up in the line, which could cause a rupture.

Other causes of failure

Proper training and supervision are the best ways to prevent operational failures and the releases caused by them. The pipeline industry has traditionally employed on-the-job training, often pairing a new person with a senior person to observe and learn from them. This can be an effective means of training but should be supplemented with classroom, computer-based, and simulator work.

Finding Potential Problems before They Become Failures

Pipeline workers of the late 1800s had rudimentary tools to understand pipeline conditions, and they mostly used their eyes. (They might have observed whether the line was pulling apart or leaking.) Today, pipeline workers strive to anticipate and avoid repair problems using the ideas already mentioned, plus a variety of *destructive* and *nondestructive tests* to understand asset condition.

Destructive tests drive the material to failure by bending, pressurizing, impacting, and other forms of stress and strain, usually in a laboratory. Nondestructive tests do not damage the pipeline and are usually a better choice for operating pipelines.

Internal inspection devices

Smart pigs are pushed through pipelines just like regular pigs. The difference is that smart pigs are smart. The more appropriate name for a smart pig is *internal line inspection* (ILI) tool (fig. 9–14).

Traveling through the pipe, ILI tools look for potential problems such as metal loss, wall deformations, and cracks. They also indicate the location of extra metal, like taps or fittings welded onto the line—the purpose of which may be long since forgotten.

ILI tools employ various technologies, including deflection, magnetic flux, and ultrasonic. Each has specific applications. Some vendors combine technologies to measure several things.

Fig. 9–14. Combination MFL and caliper tool. This tool is capable of detecting both metal loss and mechanical damage. (Courtesy Baker Hughes)

Not all pipelines are suited to using pigs. From figure 9–14, it is obvious that ILI tools are rather long. Restrictions to pipeline diameter and sharp bends make traversing some lines impossible. The majority of oil lines were constructed in ways that allow ILI passage. Gas lines are more likely to contain loops for capacity expansion, sharp bends, and reduced port valves, all of which can be a problem for ILI tools.

Deflection tools. Devices using deflection technology are normally called *geometry tools*. Their purpose is to obtain information regarding the geometry or shape of the pipe wall. They are particularly useful for finding equipment- or construction-related damage. Geometry tools have sets of mechanical fingers that ride against the inside of the pipe. Pipe deformations move the finger, revealing the locations. More advanced geometry tools use electromagnetic methods to detect deformations. Most geometry tools also contain gyroscopes to provide the location of the deformation around the circumference of the pipe.

Magnetic flux tools. *Magnetic flux leakage* (MFL) tools induce a magnetic field into the pipe. Defects in the wall thickness, such as metal loss, cause disruptions in the magnetic flux field that the tools detect. Flux variations are analyzed to reveal the amount and location of wall loss due to internal and external corrosion and equipment damage. Improving technology has given rise to MFL tools with increased sensitivity—high-resolution as opposed to low-resolution tools.

Unfortunately, current versions of MFL tools are not very good at finding narrow defects. These are defects that are oriented parallel to the longitudinal axis of the pipe, such as seam cracks, stress corrosion cracking, and axial gouges. Transverse MFL tools may help in detecting these types of defects as the technology continues to improve.

Ultrasonic tools. Ultrasonic testing (UT) tools use the same technology as the ultrasound used in medical diagnosis—the ones that generate the familiar in vitro baby pictures. Ultrasonic pulses are sent into the pipe. When they encounter a boundary (the outside of the pipe wall), a portion of them bounce back. The times required for the pulse to bounce back are used to calculate wall thickness.

UT technology does have some limitations. Acquiring a signal requires a coupling fluid capable of transmitting the ultrasonic pulse from a noncontacting device into the pipe wall. (This is similar to the jelly used for medical ultrasounds.) Oil lines have sufficient lubrication to act as the couplings, but UT tools do not work as well in natural gas lines, since they are much drier. Another problem for UT is lines with internal buildup, such as crude oil lines with paraffin adhering to the inside. Buildup causes the ultrasonic pulse to travel through more than just the metal, giving false thickness indications. UT also works better with heavy wall pipe than with thinner pipe.

Technology and tool research. There are millions of miles of pipelines in the world. It is not surprising that interest in pipeline safety drives research and development aimed at improving the sensitivity and reliability of these nondestructive ILI tools. (Sensitivity refers to how well the tool detects very small anomalies or features. Reliability has to do primarily with how well the results match what actually exists on the pipeline.) To have confidence in a pipeline based on ILI tools, the operator needs to know how accurate the results are. Specifically, the operator needs to know how accurately the tool indications represent the actual characteristics (depth, size, and location) of the anomaly in the wall of the pipe. Tool data also require extensive interpretation before they can be seen as reliably representing the condition of the pipeline. Development of better interpretation techniques is ongoing.

Another important ILI development area is miniaturization of the technology to fit into smaller diameter lines. Some of the oldest lines are in the 6-in. to 12-in. diameter ranges, making the need for smaller diameter tools apparent.

Hydrostatic testing

One of the earliest pipeline analytical techniques, *hydrostatic testing,* determines if a pipeline can hold its intended operating pressure. Hydrostatic testing can be a form of destructive testing. It involves filling a line with water, pressuring it to a predetermined level, and holding it at that pressure for some period. Water, rather than oil or gas, is used because the consequences of a rupture with water in the line are much less than with oil or gas. If a piece of pipe, a valve, or some other component fails before reaching the specified test pressure, it is replaced, and the test is restarted. New pipelines are always hydrostatically tested before they are placed into service. Existing pipelines also are sometimes hydrostatically tested. This might be done to eliminate defects that may have been created or enlarged during a period of servicing or modification that could cause the pipeline to fail if left unrepaired or undiscovered.

Long-distance pipelines are normally tested in sections of 15 to 20 mi in length, depending on the configuration and elevations of the specific line. Testing in relatively short sections increases sensitivity to detecting small leaks and reduces the amount of water required (and the associated treating and disposal costs). Spheres are inserted between the oil or natural gas and water as separators (fig. 9–15).

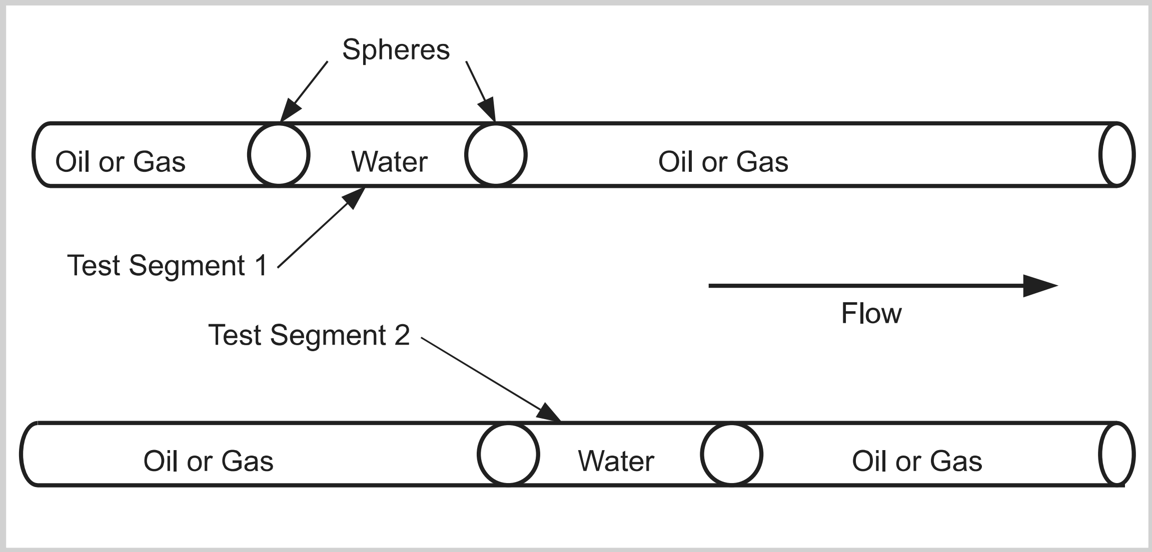

Fig. 9–15. Pigs segregating water from oil or natural gas. The oil or gas pushes the water into position for hydrostatic testing.

When one segment is finished, more oil or natural gas is put in at the origin, pushing the water along to the next segment and pushing oil or natural gas out at the destination.

Hydrostatic testing is relatively straightforward, but there are two special considerations. Chapter 8 discussed the impact of temperature on pressure. As temperature drops, so does pressure (in a closed pipe). Since pressure drop is the mechanism by which leaks are detected, it is essential to understand and minimize the pressure drop caused by decreasing temperature. During a hydrostatic test, the change in temperature must be monitored and factored into pressure drop calculations. Holding the test for 8 to 24 hours allows the temperature of the water in the pipe to equalize with the temperature of the surrounding soil, giving more dependable results.

The other special consideration is elevation change. Differences in elevation mean pressure differences. Engineers calculate the pressure due to elevation in each hydrostatic test section to ensure that test pressure at each point is high enough for a good test but not so high it stresses the pipe beyond its limits. Significant elevation changes may require short test segments to allow a high enough pressure at the highest elevation while not over pressuring the pipe at the lower elevation (fig. 9–16).

Even though hydrostatic testing is expensive and disrupts supply, it continues to be a widely used integrity assurance tool.

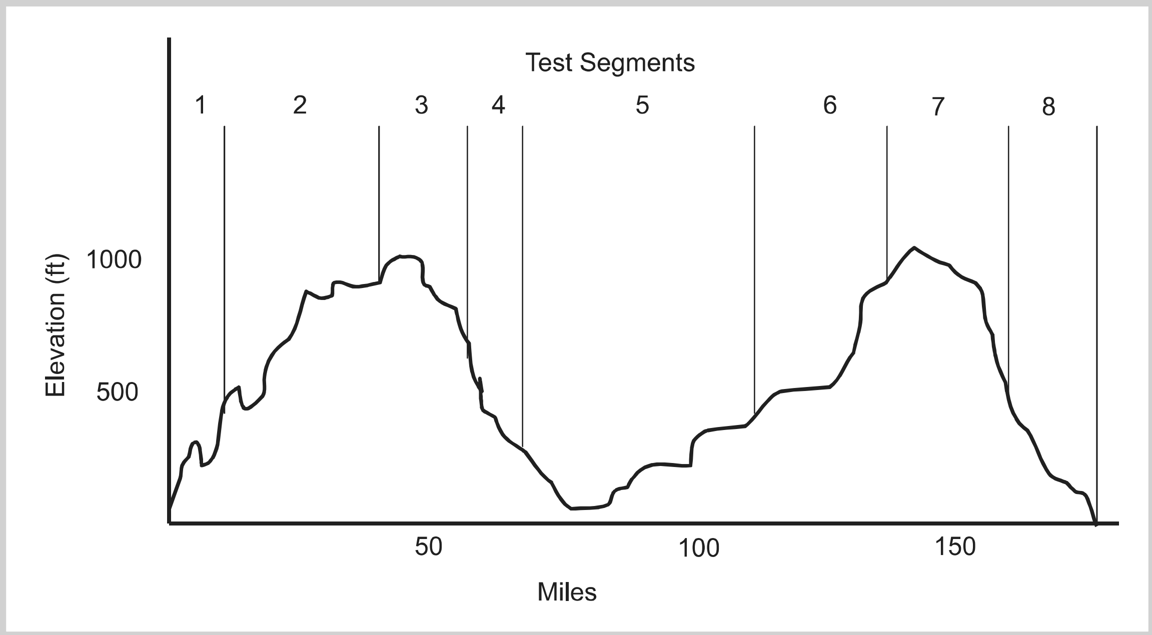

Fig. 9–16. Test segments for a pipeline. This pipeline is 175 mi long, with an elevation change along the route of 1,000 ft.

Electrical surveys

Corrosion is associated with the exchange of electrons. Knowing the electrical potential along the pipeline helps corrosion engineers and technicians to understand the condition and performance of the cathodic protection system. (This system consists of the coating, the rectifier, and the groundbed.) Cathodic test stations are used to make electrical contact with the buried pipeline from the surface to measure the difference in electrical potential between the pipe and the surrounding soil. They also have a secondary function, which is to measure current flow (fig. 9–17).

Test stations may have one or more wires connecting to the pipeline; the other end is connected to test station terminals installed about every mile along the pipeline. Normally they are located at convenient locations such as roads and fence lines (fig. 9–18).

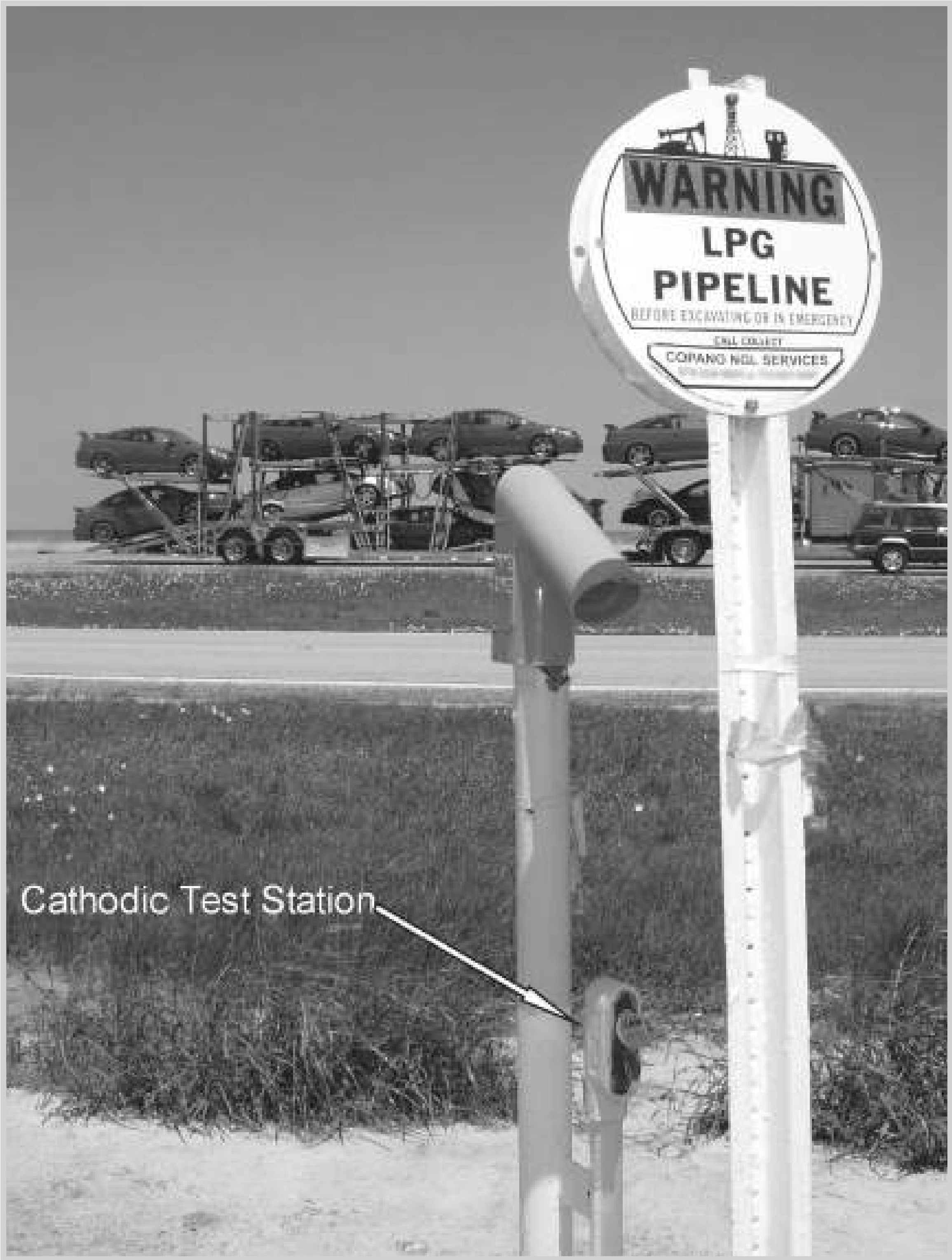

Fig. 9–17. Cathodic test lead station (Courtesy Miesner, LLC)

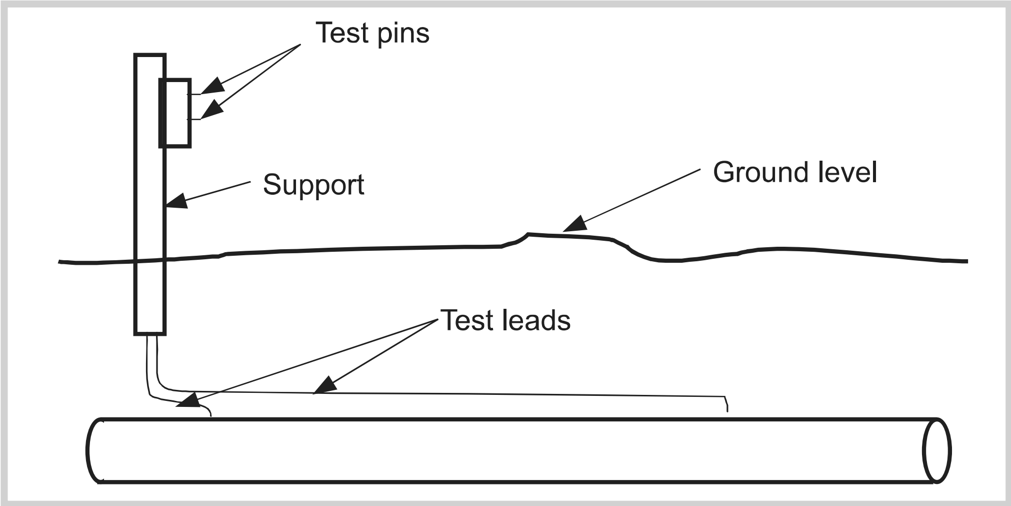

Fig. 9–18. Cathodic test lead schematic. Two wires are connected to test pins on the test station and then fastened to the pipeline a known distance apart.

Pipe-to-soil potential. To measure *pipe-to-soil potential,* technicians connect one terminal of a voltmeter to the test lead that is connected to the pipeline. The other terminal of the voltmeter is connected to a copper–copper sulfate reference electrode (half cell) that is placed in contact with the ground above the pipe. These readings (in millivolts) are compared to various benchmarks and historic readings to determine the level of cathodic polarization, or the difference in electrical potential. Then these readings along the line are plotted, allowing the technician to spot trends (fig. 9–19).

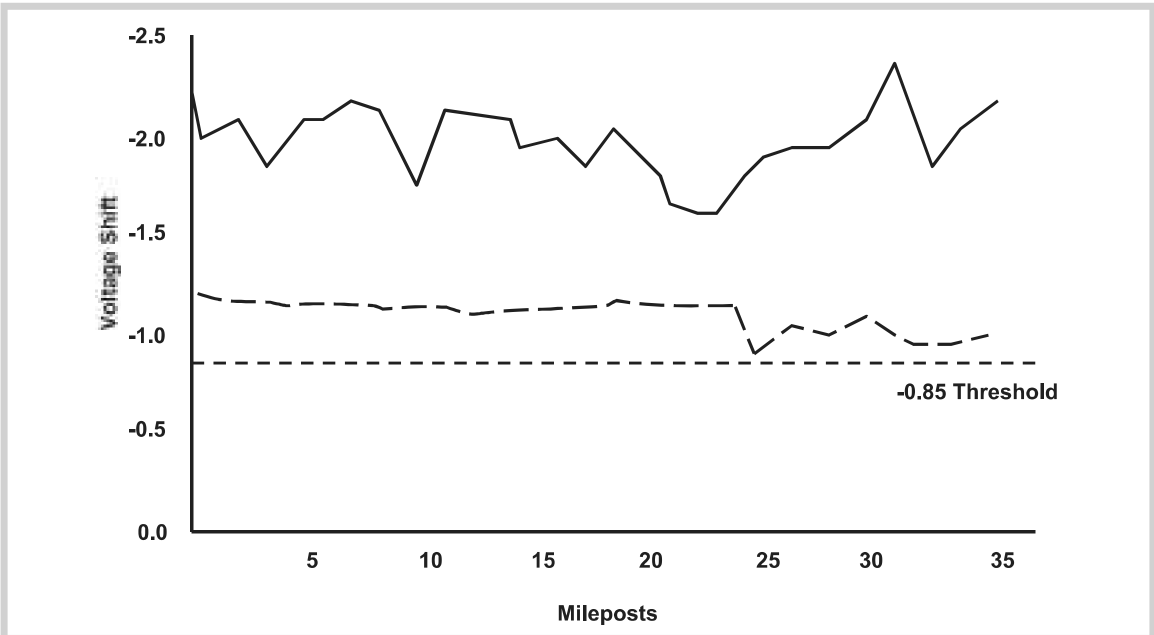

Fig. 9–19. Pipe-to-soil profile. The solid (most negative) line is the electrical potential of the pipeline with all the rectifiers turned on. The line with long dashes shows the "polarized" potential of the steel with the rectifiers turned off. The straight, short dashed line is a reference line. Generally speaking, if the two potential lines are above (more negative than) the reference line, cathodic protection of the pipeline is adequate.

Current drop. In addition to measuring pipe-to-soil potential, technicians use some test stations to measure voltage drop along the pipeline, allowing them to calculate current flow. They connect a voltmeter to test stations pins, which are fastened to wires connected to the pipeline a known distance apart. The voltmeter displays the voltage drop between those two points on the pipeline. From distance, wall thickness, and pipe diameter, resistance to current flow is known. The following electrical engineering formula comes into play:

$$\text{Voltage} = \text{Resistance} \times \text{Current}$$

Since resistance and voltage drop are known, current can be calculated. High current flow at one test lead and low current flow at the next test lead indicates a problem between the two points.

Close interval potential survey. Another current survey method, the *close interval potential survey* (CIPS), measures electrical potential with the rectifiers on and off. These measurements are taken at intervals of about 3 to 10 ft along the pipeline. Performing a CIPS requires a surveyor to physically travel along the entire section of pipeline being surveyed (fig. 9–20).

Surveyors may use a global positioning system (GPS) unit to determine the coordinates of their location. These readings are fed to the CIPS unit, making it possible to connect the CIPS readings with physical locations along the pipeline. CIPS measures the cathodic protection on the line as well as the condition of the coating

Fig. 9–20. CIS surveyor walking the pipeline (Courtesy Cathodic Technology Limited)

Voltage gradients. There are two types of voltage gradients tests: direct current voltage gradient (DCVG) and alternating current voltage gradient (ACVG). Both are used to find coating damage. For DCVG, a current pulse is created along the line, either by interrupting the rectifier or by applying a direct current (DC) pulse from an outside source. For ACVG, a current pulse is also created, but this time with low-frequency alternating current (AC). The voltage gradients in the soil are measured around the pipeline to locate coating defects. In both cases, voltage drop is measured along the line and plotted on a graph creating a gradient (with a sloping line much like hydraulic gradients).

Combined CIS and DCVG surveys. Modern electronic equipment allows measurement of CIS and DCVG values at close intervals (3 to 5 ft) simultaneously along a buried or submerged pipeline. The data from a combined CIS and DCVG survey allow the corrosion engineer to more accurately assess the level of cathodic protection on the pipeline. The engineer can also assess the effect of coating damage on the level of cathodic protection.

Pearson survey. This method, devised by J. M. Pearson, applies an AC signal to a short section of pipeline. Surveyors walk along the pipeline wearing metal cleats to provide good contact with the soil. Wires run from the metal cleats to a Pearson receiver, worn by the surveyor. A surveyor who walks over a section of the pipeline with coating damage will hear a distinctive tone in his headphones, indicating the location of the damage.

The survey methods in this section all have common goals—understanding the condition of the buried pipeline to prevent corrosion, ultimately to eliminate releases.

Direct assessment

Direct assessment (DA) is an old concept involving excavating and physically examining the pipe to determine its condition. Advances in statistical techniques make DA an alternative to ILI, especially for those pipes constructed in ways that do not allow ILI tool travel. It involves using all available data about the line to determine the most likely problem locations. These locations are excavated, and the pipe and coating are examined to determine their condition. Pipe wall thickness is measured to determine any wall loss.

The process and the science of DA continue to evolve, but generally people agree there are at least four steps in the process:

- Preassessment
  - Collecting historic data to determine what data gaps exist
  - Recommending further testing to fill the data gaps
- Indirect examination
  - Conducting additional tests to identify coating faults, anomalies, soil condition, and some types of corrosion activity
  - Analyzing soil environments and comparing them to specific models to evaluate the potential for stress corrosion cracking
  - Performing flow modeling for internal corrosion
  - Selecting sites for the next step (direct examination)
- Direct examination
  - Excavating the pipe at selected locations
  - Conducting visual and nondestructive testing to determine coating and pipe integrity
- Postassessment
  - Analyzing the data from the previous steps to establish pipe and coating integrity
  - Making repairs as needed
  - Determining the reinspection interval required to ensure integrity

The final step is critical. As lines age, they need to undergo continued inspection, testing, and maintenance to assure safe operations.

Risk and Pipeline Safety

The ultimate goal of inspecting the pipeline is to understand its condition, prevent releases, and assure safety. But what is a "safe" pipeline? Is it one without a past release? Is it one that will never have a release? How can future release potential be understood? Most people agree that it is impossible for anything to be completely safe. That leads to the topic of risk.

The typical definition of risk, and the one used in this book, is given in terms of consequences and probabilities:

$$\text{Risk} = \text{Probability} \times \text{Consequences}$$

The risk equation looks simple, and it is for one probability and one consequence. However, pipeline risk involves multiple probabilities, multiple consequences, and multiple sections of pipe. Risk is the sum of all those probabilities, and all those consequences, for each section of the pipeline. Entire books, like W. Kent Muhlbauer's *Pipeline Risk Management Manual,* deal with pipeline risk.[8] Only the basic concepts will be presented here.

Consequences

A leak from a natural gas pipeline in the farming region of Belgium may cause a crater and scare some people. When a similar leak occurs in the densely populated town of Ghislenghien, 20 mi southeast of Brussels, the consequences may be lives lost, property damage, business disruptions, and supply curtailments. Diesel leaking from a pipeline in one of the wheat fields crossing the plains of Montana is terrible, but gasoline leaking into the water source for a city is worse. Consequences depend on many factors—size, location relative to water, population density, time of day, time of year, and weather, just to mention a few.

Probabilities

Probabilities are the likelihood of something happening and are based on statistics and past occurrences. The probability of a coin landing "heads up" is 50% over repeated attempts. The 50% probability can be predicted with a small margin of error. Predicting the probability of a pipeline release is difficult. It is also difficult to predict the probability of its being a large or small release, the probability of its getting into water, or the probability of its injuring someone. There will be wide margins of error.

Framework for considering risk

In figure 9–21, the left column lists the causes of a release listed earlier. The second column has the probability of a release from the individual cause. The third column lists consequences. Finally, the fourth column has the general types of consequences.

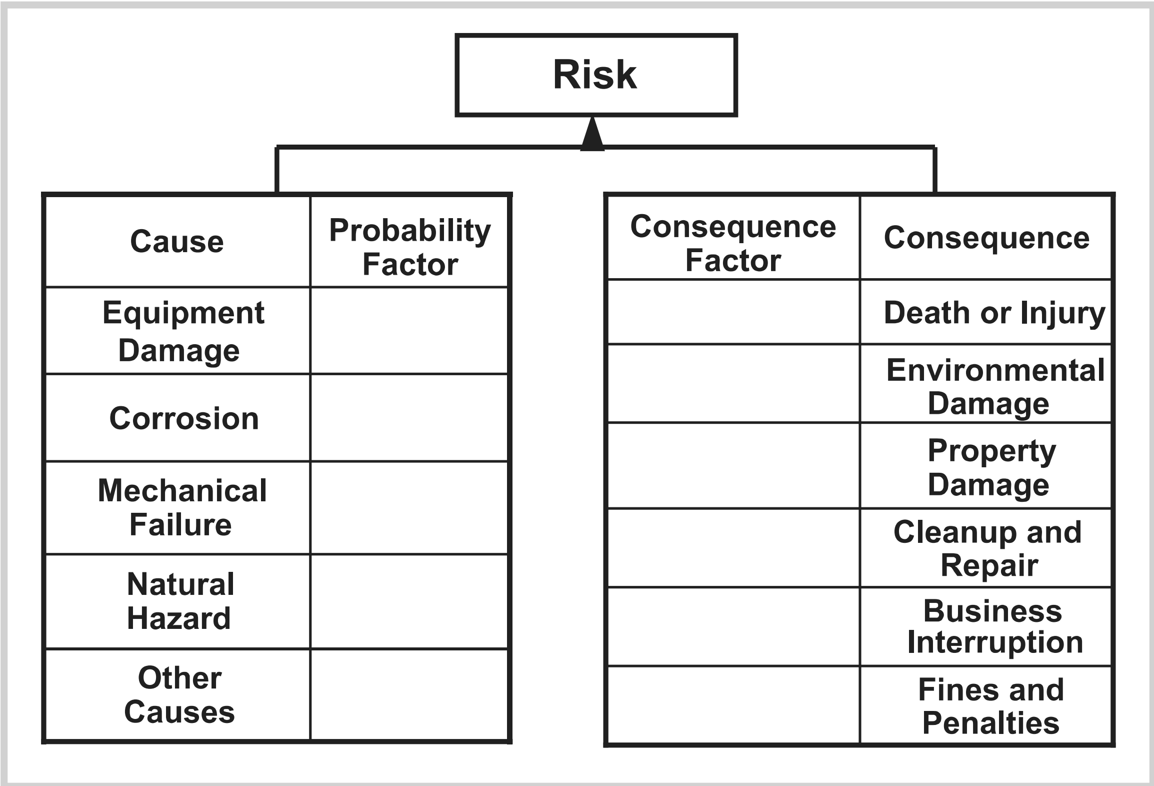

Fig. 9–21. Framework for considering risk. Note some cells are blank; filling these out is the work of integrity engineers.

These factors can be broken down even further (table 9–1). Causes, probabilities, and consequences are combined to determine the total risk for one section of the pipeline. Each section of the pipeline has its own combination of causes, probabilities, and consequences, and all sections are summed to determine total pipeline risk.

Each cell in table 9–1 requires a number. Ideally, the numerical values of probabilities and consequences would be very objective and quantifiable. Again, the challenge of accurately determining probabilities and consequences leaves a wide margin of error. While approaches vary, in general, pipeline operators use historic, quantifiable values where they can. When these numbers are not available, or are not dependable, they rely on the opinion of experts, with many years of practical experience.

The difficulty in arriving at a number for each probability and consequence gave rise to the *index method* for risk ranking. Instead of the actual probability or consequences, a relative ranking, usually between 1 and 10, is inserted into each cell, again based on all available information and the judgment of experts. Risk is calculated based on these relative rankings.

Table 9–1 Risk matrix

Probability of release from	**Probability of**	**Cost or consequences of**	**Risk**
Equipment damage	Injury or death	Injury or damage	
Equipment damage	Environmental damage	Environmental damage	
Equipment damage	Property damage	Property damage	
Equipment damage	Cleanup and repair	Cleanup and repair	
Equipment damage	Business interruptions	Business interruptions	
Equipment damage	Fines and penalties	Fines and penalties	
		Subtotal risk for equipment damage	
Corrosion	Injury or death	Injury or damage	
Corrosion	Environmental damage	Environmental damage	
Corrosion	Property damage	Property damage	
Corrosion	Cleanup and repair	Cleanup and repair	
Corrosion	Business interruptions	Business interruptions	
Corrosion	Fines and penalties	Fines and penalties	
		Subtotal risk for corrosion	
Mechanical failure	Injury or death	Injury or damage	
Mechanical failure	Environmental damage	Environmental damage	
Mechanical failure	Property damage	Property damage	
Mechanical failure	Cleanup and repair	Cleanup and repair	
Mechanical failure	Business interruptions	Business interruptions	
Mechanical failure	Fines and penalties	Fines and penalties	
		Subtotal risk for mechanical failure	
Natural hazards	Injury or death	Injury or damage	
Natural hazards	Environmental damage	Environmental damage	
Natural hazards	Property damage	Property damage	
Natural hazards	Cleanup and repair	Cleanup and repair	
Natural hazards	Business interruptions	Business interruptions	
Natural hazards	Fines and penalties	Fines and penalties	
		Subtotal risk for natural hazards	
Other causes	Injury or death	Injury or damage	
Other causes	Environmental damage	Environmental damage	
Other causes	Property damage	Property damage	
Other causes	Cleanup and repair	Cleanup and repair	
Other causes	Business interruptions	Business interruptions	
Other causes	Fines and penalties	Fines and penalties	
		Subtotal risk for other causes	
		Total risk	

As an example, the probability of equipment damage might be 10 in an area with lots of construction, and low, perhaps 1, in a national forest or park. The consequences of environmental damage in a park might be 10, and the consequences of environmental damage in an area of heavy construction 1. The risks from equipment damage in both cases are 10 (in one case, 1 × 10; in the other, 10 × 1). Quantifying risk in this manner allows pipeline operators to rank risk and spend money to mitigate the most severe risk areas.

Pipeline operators and vendors have various approaches to risk calculations. The factors can be subdivided or lumped together depending on the needs. Corrosion, for example, could be divided into external and internal, each with its own probability. The various risks for each pipeline segment for each cause are summed and then can be presented graphically (fig. 9–22).

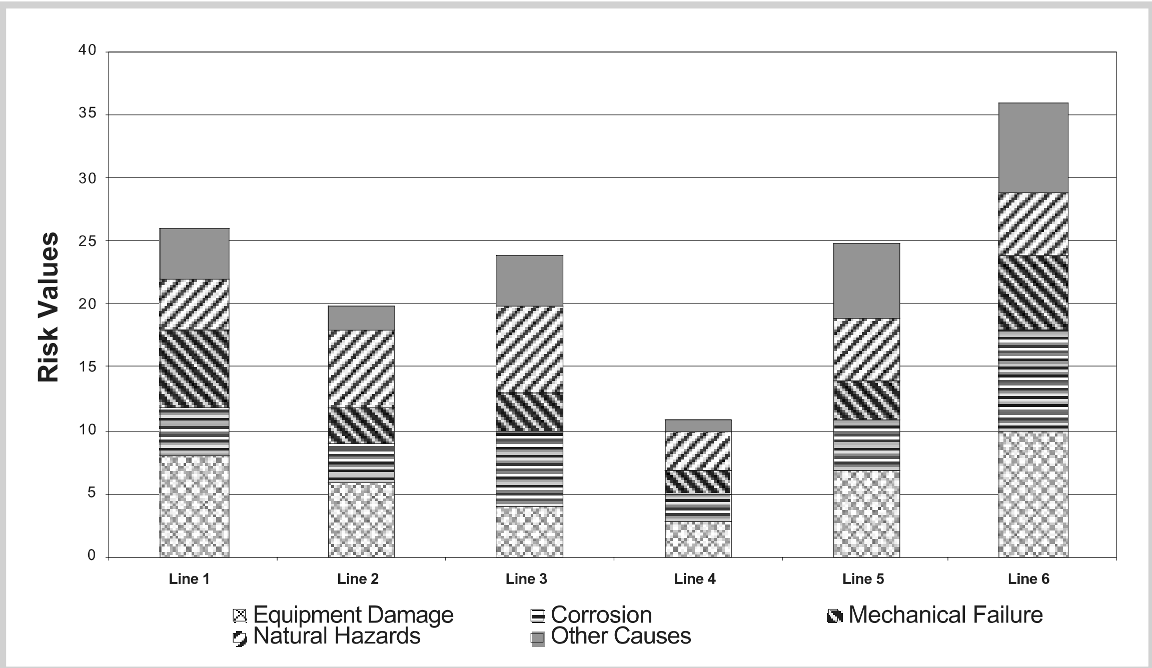

Fig. 9–22. Results by cause and segment

Each vertical bar represents the total risk of an individual pipeline, comprised of risks associated with various damage causes. Based on this graph, line 4 has the lowest risk and line 6 the most. The greatest risk for line 4 is natural hazards, and equipment damage is the highest for line 6. Tools like these help pipeline operators decide where and how to allocate their maintenance dollars.

Data

Most pipeline operators collect and store a great deal of information about their lines, including data such as:

- Original construction
  - Materials of construction
  - Construction techniques
  - Quality tests performed during construction
  - Components installed
- Operating history
  - Types and frequency of failures
  - Pressure history
  - Cathodic protection program
  - Coating and condition surveys
- Geography traversed
  - Population concentrations
  - River and stream crossings
  - Environmentally sensitive areas
  - Culturally sensitive areas
  - Elevations and soil conditions
- Inspection data
  - ILI
  - Coating surveys
  - Current surveys
  - Hydrostatic test records

This information can be used to feed risk algorithms such as those in figure 9–23.

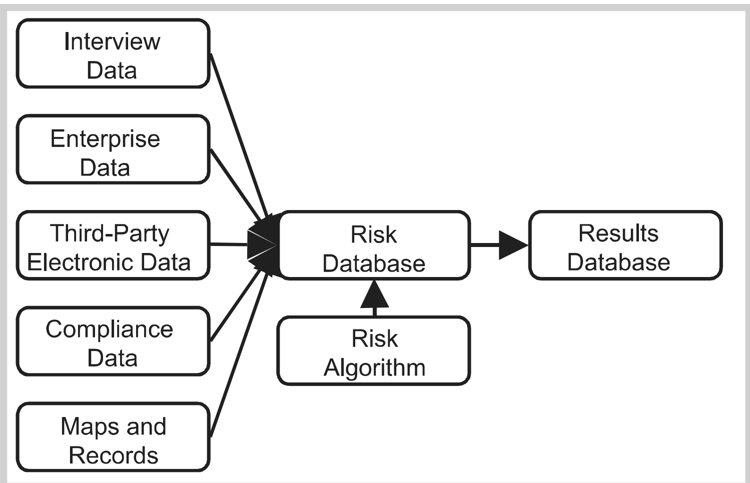

Fig. 9–23. Flow of database inputs and results for risk analysis. (Courtesy American Innovations [formerly Bass-Trigon])

Integrity Management Plan

Risk rankings, causes of pipeline damage, prevention activities, and other factors are combined into an overall plan to manage risk. Increasingly in the United States, this plan is becoming known as the Integrity Management Plan (IMP). In the United States, both industry institutions and federal regulations define IMPs. API Standard 1160 deals with integrity management for oil lines, and ANSI B31.8S covers integrity management for natural gas lines. Multiple vendors offer risk management software and plans.

The U.S. Department of Transportation's PHMSA defines an IMP as:

- *A documented set of policies, processes, and procedures that includes, at a minimum, the following elements:*
  - *a process for determining which pipeline segments could affect a high-consequence area (HCA),*
  - *a Baseline Assessment Plan,*
  - *a process for continual integrity assessment and evaluation,*
  - *an analytical process that integrates all available information about pipeline integrity and the consequences of a failure,*
  - *repair criteria to address issues identified by the integrity assessment method and data analysis (the rule provides minimum repair criteria for certain, higher risk features identified through internal inspection),*
  - *a process to identify and evaluate preventive and mitigative measures to protect HCAs,*
  - *methods to measure the integrity management program's effectiveness, and*
  - *a process for review of integrity assessment results and data analysis by a qualified individual.*[9]

Pipeline operators consider all the factors discussed in this chapter to produce a written plan and set of procedures to assure themselves, the regulators, and the public that their operations are tolerably safe. As the IMP concept becomes more pervasive in both liquid and gas pipelines, pipelines should continually get safer. Further, since it makes sense to consider the entire pipeline as a whole, IMPs may expand to include the whole notion of a risk management plan.

Repairs

People normally think of repairs when they hear "maintenance," but obviously repairs are only one aspect. Steel pipes are tough, strong, and hard to damage. However, once damaged, there are several options for repair. These include replacing the damaged section of pipe, reinforcing it from the outside, grinding it to reduce stress concentrations, or replacing metal loss by depositing weld metal. Repairing damaged coating usually involves removing the previous coating, cleaning, and applying new coating.

Replacing the pipe

One of the most obvious solutions, replacing the pipe, sounds simple but is expensive, exposes workers to hazards, and often disrupts supply. Sometimes scheduling allows shutting down the line to replace a section. In other cases, a temporary bypass can be installed to allow the defect to be remedied.

After planning the job, and ensuring that all materials and equipment have been made ready, the line is shut down, and the natural gas or oil is evacuated. The pipe is then cold cut with a mechanical cutter and lifted away from the pipeline. A new section is dropped in and welded, and the pipe is recoated and reburied, much the same as with original construction. Evacuating (draining up for oil, and blowing down for natural gas) prior to cutting the line apart can be the most time-consuming step, depending on the location of isolation valves.

Sometimes special procedures such as hot tapping and plugging are used to minimize drain up or blow down time. Hot tapping and plugging involves first welding a tee fitting onto the line without evacuating the oil or gas from the line (fig. 9–24).

Fig. 9–24. Welding a hot tap fitting onto the line (Photo by Frank Gonzales)

Next a valve and then a tapping machine are bolted to the flange on the hot tap fitting (fig. 9–25). The valve is opened and the hot tap machine extended through the valve to cut a hole into the pipe. The hot tap machine cuts the hole and withdraws the piece of pipe through the valve, and the valve is closed. Next, the hot tap machine, still holding the piece of pipe, is removed, and a plugging machine is attached in its place. The valve is reopened, and the plugging machine inserts an expandable plug that blocks any flow along the pipeline. The same procedure is performed on the other end of the section to be removed. In that way, only the oil or natural gas between the two plugs needs to be evacuated. After the replacement pipe is welded in, the plugs are removed, unstopping the line, and the line is restarted. A well-planned procedure like this may take only 24 hours or less of line shutdown.

Fig. 9–25. Lowering the tapping machine. Note the valve is already bolted to the hot tap fitting. (Photo by Frank Gonzales)

When scheduling and supply do not allow a shutdown, a bypass must be established around the replacement section, allowing the natural gas or oil to continue flowing. The hot tap machine again is called into action. For a bypass, two pairs of hot tap fittings and valves are welded to each side of the cut-out section. One plugs flow, the other connects to a bypass pipe. Once the cut-out section is welded back in, the bypass is removed. The hot tap fittings are capped and left on the line.

Reinforcing the pipe

One way to reinforce the pipe involves welding a special *split sleeve* to the pipe, sometimes called a *full encirclement split sleeve* or a reinforcing sleeve. The sleeve comes in matching halves designed for the outside diameter of the pipe. The two halves are placed snuggly on the pipe and are then welded together longitudinally (fig. 9–26). Before the sleeve is installed, any dents, gouges, or pits are filled with an epoxy material to eliminate voids.

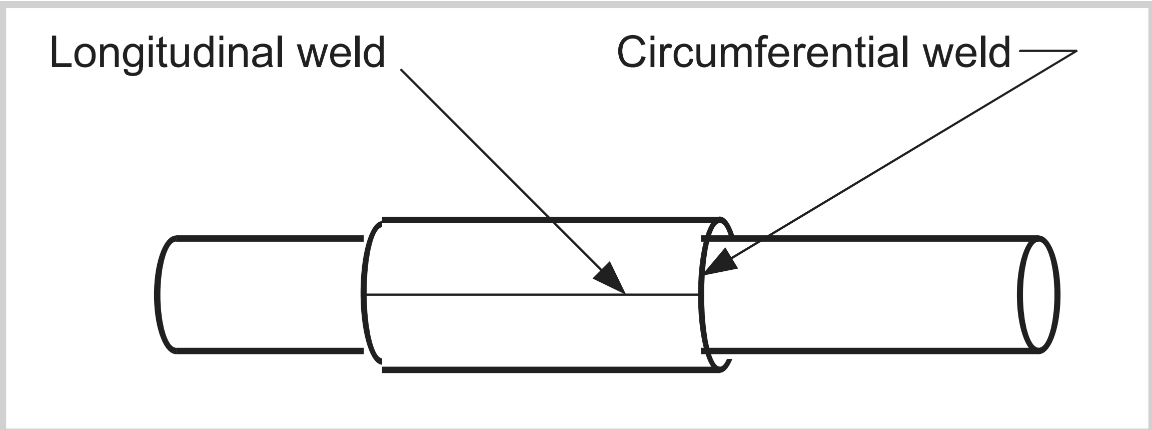

Fig. 9–26. Split sleeve installation

If the defect is leaking, the ends of a sleeve may be welded circumferentially to contain pressure. This weld is sometimes done even when no leak exists if the purpose of the sleeve is to reinforce the damaged or defective area of the pipe.

Another technique involves applying a nonmetallic reinforcing wrap around the damaged section of pipeline (fig. 9–27). Several different wrap systems exist, but each works on the same principle. The basic idea is to prevent failure of a damaged or defective pipe by keeping the defective area from bulging radially until it ruptures the pipe. These systems rely on glass or carbon fiber-reinforced polymer rather than steel to reinforce the pipe. Examples of brand names include Clockspring, Aquawrap, Strongback, Petrosleeve, Black Diamond, and Armor Plate.

Fig. 9–27. Composite wrap reinforcing the pipe (Courtesy CorroDefense, LLC)

With some of these systems, the "composite" is preformed in the factory and hauled to the field where it is coiled around the pipe and glued in place. Other systems involve wrapping the defective pipe with a fabric composed only of the reinforcing fibers. The fiber is impregnated with polymer resin in the field, and it cures to form the composite in place. Composite wrap systems are a proven way to repair many forms of pipeline damage.

Grinding to reduce stress concentrations

Small gouges or small cracks that by themselves might not be large enough to cause immediate failure of the pipe can still cause problems if left unrepaired for long periods. Any abrupt change in wall thickness creates a *stress concentration point* that can lead to crack propagation under repeated stress cycles. This is similar in effect to the bouncing rail car example earlier in this chapter. Pipelines experience stress cycles as they pack and unpack. As the pipeline cycles, stress concentration points are repeatedly stressed and unstressed, and a crack may develop, leading to a failure. Grinding is one way to repair gouges (fig. 9–28).

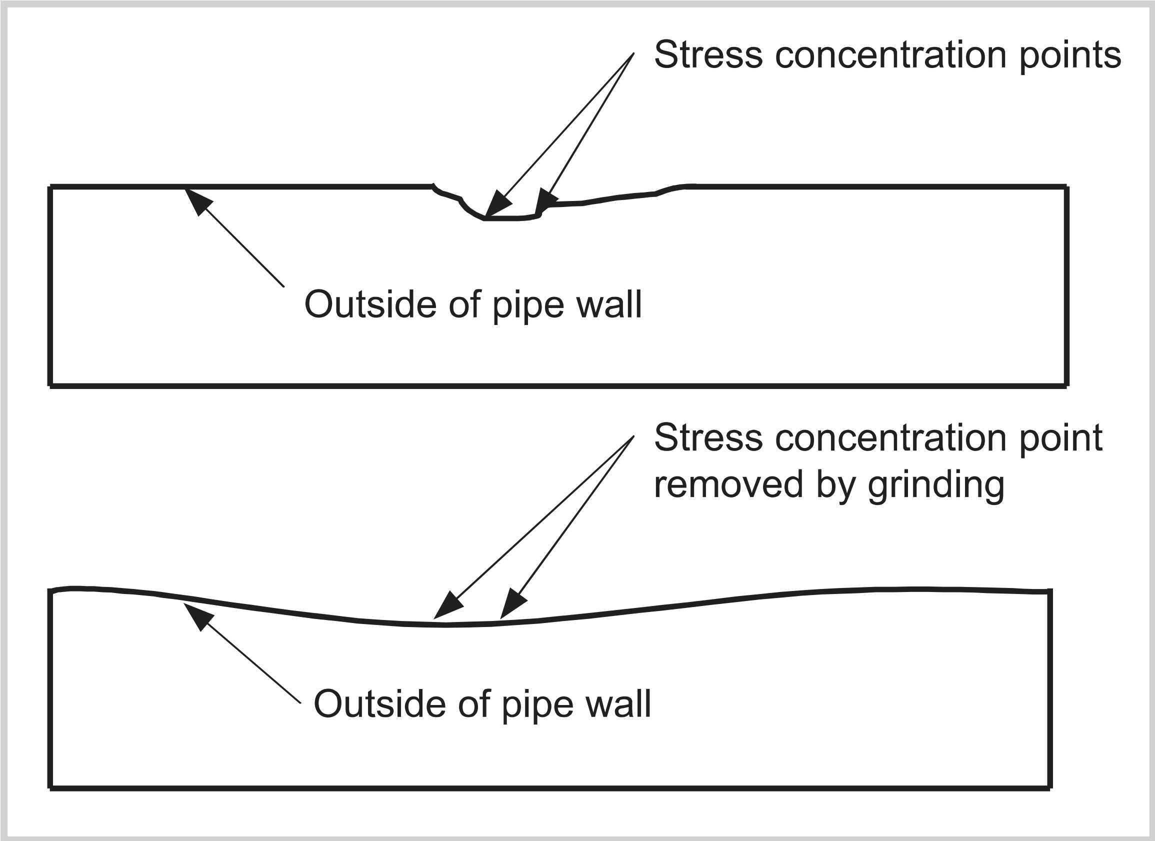

Fig. 9–28. Repairing a gouge by grinding

After grinding, stress is no longer concentrated at one point but is spread uniformly over the area. Obviously, grinding repairs are only appropriate for shallow gouges.

Deposited weld metal

Under certain conditions, areas of metal loss caused by external corrosion may be restored to full strength by depositing weld metal in the thin areas. Because of the risk of burning through the remaining wall thickness, this technique requires special procedures and specially trained welders. While this technique can result in high-quality repairs, procedures and training methods developed by experts in the technology must be used to ensure safety.

Coating repairs

As before, external pipeline coatings function as electrical insulators to stop corrosion by preventing the flow of electrons from the surface of the pipe. Damaged coating allows (and concentrates) current flow and must be repaired to limit corrosion. Repairs are accomplished by removing some of the surrounding coating, especially any that is loose or disbonded, and replacing it with new coating. Any time the coating is removed or disrupted while making a repair to a pipeline, it ought to be repaired to protect the pipe. Recoating over existing coating is difficult and can lead to further problems if air pockets remain under the coating. Water sometimes collects in these pockets, leading to even more corrosion problems.

Other Maintenance Activities

Other important maintenance activities include line lowering, ROW maintenance, cathodic measurements, maintenance pigging, and various inspections.

Line lowering

Maintaining proper *depth of cover,* the distance from the top of the pipe to the surface, is one of the best pipeline protection mechanisms. In general, the deeper the pipeline, the less likely it is to be damaged by equipment. Erosion, farming, and construction activities sometimes remove cover from the line. When this happens, the line is lowered by carefully digging along the line, removing soil from under the line, and reburying the line. Before lowering lines, pipeline operators plan the work and calculate pipeline stresses to ensure the pipe is not pushed beyond allowable limits. During lowering, the pipe must be handled carefully and lowered gently. Safe *lowering in* techniques are followed as detailed in chapter 13. Once successfully lowered, the pipe is reburied, and the ROW is restored as nearly as possible to its original condition.

ROW maintenance

Maintaining the ROW consists of keeping it clear of obstructions—trees, shrubs, and such—to facilitate patrols and clearly indicate the location of the line. When pipeline companies fall behind on ROW clearing, and then try to catch back up, they may encounter resistance from landowners. This is particularly true if they wait so long that beautiful shade trees have grown on the ROW. Keeping up with ROW-clearing activities is the best way to prevent these situations.

Proper upkeep of pipeline markers and signs is important to ensure the public knows about nearby pipelines. Pipeline operators regularly patrol the line looking for damaged or missing signs and markers.

Cathodic maintenance

Pipeline operators regularly inspect rectifiers, groundbeds, and test leads. Fortunately, cathodic test stations may function even when they need repair (fig. 9–29).

Fig. 9–29. Damaged cathodic test station (Courtesy Miesner, LLC)

Maintenance pigging

Regular running of cleaning pigs helps keep a pipeline clean and free of water, paraffin, and sediment. This reduces the likelihood of internal corrosion and undue resistance to the flow of product in the pipeline. Pigging spheres are useful for pushing out water and separating batches (fig. 9–30). Brush pigs sweep debris to the end of the line, and scraper pigs remove materials like paraffin that can build up in a crude oil pipeline.

Fig. 9–30. Spheres waiting to be launched in a natural gas pipeline (Courtesy Miesner, LLC)

Pipeline operators launch pigs from a *pig launcher* and catch them in a *pig receiver.* Pig launchers and receivers are also generically called *pig traps* or *scraper traps* (fig. 9–31). Launcher barrels are generally shorter than receivers. A bypass line is near the back of the barrel, directing the flow behind the pig, forcing it forward and out of the launcher. Receivers have longer barrels, and the bypass line is near the front. With this arrangement the pig is forced into the trap and past the bypass line. The longer barrel gives it time to decelerate before it reaches the end of the trap.

Fig. 9–31. Pig receiver. Note the "barrel" of the receiver has a larger diameter than the pipeline. Flow pushes the pig past the outlet on the bottom of the barrel, and it coasts to a stop. A valve (not shown) is closed to stop flow through the receiver, and the pig is removed by opening the closure on the end (left). (Courtesy Miesner, LLC)

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