

Overview of the Design, Construction, and Operation of Interstate Liquid Petroleum Pipelines

Environmental Science Division

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Overview of the Design, Construction, and Operation of Interstate Liquid Petroleum Pipelines

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NOTATION

The following is a list of the acronyms, initialisms, and abbreviations (including units of measure) used in this document. Acronyms and abbreviations used only in tables and figures are defined in the respective tables and figures.

ACRONYMS, INITIALISMS, AND ABBREVIATIONS

AASHTO	American Association of State Highway and Transportation Officials
AC	alternating current
ACEC	areas of critical environmental concern
ALA	American Lifelines Alliance
ANSI	American National Standards Institute
AOPL	Association of Oil Pipe Lines
API	American Petroleum Institute
AREA	American Railway Engineering Association
AREMA	American Railway Engineering Maintenance-of-Way Association
ASCF	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
AWS	American Welding Society
BTEX	benzene, toluene, ethylbenzene, and xylene
CDPD	Cellular Digital Packet Data
CFR	<i>Code of Federal Regulations</i>
CPS	cathodic protection system
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EIA	Energy Information Administration (DOE)
EPA	U.S. Environmental Protection Agency
FEMA	Federal Energy Management Agency
FERC	Federal Energy Regulatory Commission
GPS	global positioning system
HDD	horizontal directional drilling
IAPMO	International Association of Plumbing and Mechanical Officials
IEEE	Institute of Electrical and Electronic Engineers, Inc.

LNG	liquefied natural gas
LPG	liquefied petroleum gas
MAOP	maximum allowable operating pressure
MFL	magnetic flux leakage
MOP	maximum operating pressure
MTU	master terminal unit
NACE	National Association of Corrosion Engineers
NDT	nondestructive testing
NORM	naturally occurring radioactive materials
OPS	Office of Pipeline Safety (DOT)
OSHA	Occupational Safety and Health Administration
RCRA	Resource Conservation and Recovery Act
ROW(s)	right(s)-of-way
RP	Recommended Practice
RTU	remote thermal unit
SCADA	supervisory control and data acquisition
TAPS	Trans-Alaska Pipeline System
UHF	ultrahigh frequency
VHF	very high frequency

UNITS OF MEASURE

cSt	centistoke
°F	degree(s) Fahrenheit
lb	pound(s)
ppm	part(s) per million
psi	pound(s) per square inch
psia	pound(s) per square inch absolute
psig	pound(s) per square inch gauge

1 INTRODUCTION

1.1 U.S. PIPELINE NETWORK

The U.S. liquid petroleum pipeline industry is large, diverse, and vital to the nation's economy. Comprised of approximately 200,000 miles of pipe in all fifty states, liquid petroleum pipelines carried more than 40 million barrels per day, or 4 trillion barrel-miles, of crude oil and refined products during 2001. That represents about 17% of all freight transported in the United States, yet the cost of doing so amounted to only 2% of the nation's freight bill. Approximately 66% of domestic petroleum transport (by ton-mile) occurs by pipeline, with marine movements accounting for 28% and rail and truck transport making up the balance. In 2004, the movement of crude petroleum by domestic federally regulated pipelines amounted to 599.6 billion ton-miles, while that of petroleum products amounted to 315.9 billion ton-miles (AOPL 2006). As an illustration of the low cost of pipeline transportation, the cost to move a barrel of gasoline from Houston, Texas, to New York Harbor is only 3¢ per gallon, which is a small fraction of the cost of gasoline to consumers.

Pipelines may be small or large, up to 48 inches in diameter. Nearly all of the mainline pipe is buried, but other pipeline components such as pump stations are above ground. Some lines are as short as a mile, while others may extend 1,000 miles or more. Some are very simple, connecting a single source to a single destination, while others are very complex, having many sources, destinations, and interconnections. Many pipelines cross one or more state boundaries (interstate), while some are located within a single state (intrastate), and still others operate on the Outer Continental Shelf and may or may not extend into one or more states. U.S. pipelines are located in coastal plains, deserts, Arctic tundra, mountains, and more than a mile beneath the water's surface of the Gulf of Mexico (Rabinow 2004; AOPL 2006).

The network of crude oil pipelines in the United States is extensive. There are approximately 55,000 miles of crude oil trunk lines (usually 8 to 24 inches in diameter) in the United States that connect regional markets. The United States also has an estimated 30,000 to 40,000 miles of small gathering lines (usually 2 to 6 inches in diameter) located primarily in Texas, Oklahoma, Louisiana, and Wyoming, with small systems in a number of other oil producing states. These small lines gather the oil from many wells, both onshore and offshore, and connect to larger trunk lines measuring 8 to 24 inches in diameter.

There are approximately 95,000 miles of refined products pipelines nationwide. Refined products pipelines are found in almost every state in the United States, with the exception of some New England states. These refined product pipelines vary in size from relatively small, 8- to 12-inch-diameter lines, to up to 42 inches in diameter.

The overview of pipeline design, installation, and operation provided in the following sections is only a cursory treatment. Readers interested in more detailed discussions are invited to consult the myriad engineering publications available that provide such details. The two primary publications on which the following discussions are based are: *Oil and Gas Pipeline Fundamentals* (Kennedy 1993) and the *Pipeline Rules of Thumb Handbook* (McAllister 2002).

Both are recommended references for additional reading for those requiring additional details. Websites maintained by various pipeline operators also can provide much useful information, as well as links to other sources of information. In particular, the website maintained by the U.S. Department of Energy's Energy Information Administration (EIA) (<http://www.eia.doe.gov>) is recommended. An excellent bibliography on pipeline standards and practices, including special considerations for pipelines in Arctic climates, has been published jointly by librarians for the Alyeska Pipeline Service Company (operators of the Trans-Alaska Pipeline System [TAPS]) and the Geophysical Institute/International Arctic Research Center, both located in Fairbanks (Barboza and Trebelhorn 2001), available electronically at <http://www.gi.alaska.edu/services/library/pipeline.html#codes>. The Association of Oil Pipe Lines (AOPL) and the American Petroleum Institute (API) jointly provide an overview covering the life cycle of design, construction, operations, maintenance, economic regulation, and deactivation of liquid pipelines (AOPL/API 2007).

1.2 FLUIDS HANDLED

The products carried in liquid pipelines include a wide range of materials. Crude oil systems gather production from onshore and offshore fields, while transmission lines transport crude to terminals, interconnection points, and refineries. The crude oil may be of domestic origin or imported. Refined petroleum product, including gasoline, aviation fuels, kerosene, diesel fuel, heating oil, and various fuel oils, are sizable portions of the pipelines business, whether produced in domestic refineries or imported to coastal terminals. Other materials include petrochemical feedstocks (also known as secondary feedstocks) such as benzene, styrene, propylene, and aromatics such as xylene, toluene, and cumene that are delivered by pipeline from refineries to petrochemical production plants or to other refineries. Also carried by pipeline are liquefied petroleum fuels such as liquefied natural gas (LNG) (albeit over relatively short distances), liquefied petroleum gas (LPG) and propane, all of which are gases at standard temperature and pressure but easily liquefied with the application of pressure.¹ Still other materials transported by pipelines include carbon dioxide and anhydrous ammonia, both transported as liquids under their own pressure.² In recent years, long-distance pipelines have been constructed to carry distillate fractions from the distillation of crude oils from refineries to production facilities for crude feedstocks such as bitumen recovered from tar sands and heavy oils. Such feedstocks are too viscous to be transported by pipeline. However, the distillate fractions are used to dilute these feedstocks, with the resulting mixture being suitable for delivery back to the refinery by pipeline for further processing. Also in recent years, long-distance pipelines have been constructed to carry "produced water"³ from oil and gas fields to refineries and other industrial facilities that use copious amounts of water, but are located in arid areas or areas where water availability is limited. Hydrogen is also delivered by pipeline, albeit over relatively short distances, typically connecting hydrogen production facilities with refineries and other industries that use hydrogen as a starting material in their processes. Table 1.2-1

¹ However, the majority of natural gas transported by pipeline over long distances is transported as a gas.

² Carbon dioxide is also transported by pipeline as a gas.

³ As used here, produced water includes water recovered at the well head or crude oil and/or natural gas production wells.

TABLE 1.2-1 Characteristics of Liquid Hydrocarbons

Type 1(a): liquefied gases (liquefied petroleum gas, ethylene, propylene)

- Highly volatile
- Gas at ambient conditions; maintained at high pressures

Type 1(b): very light grade oils (gasoline)

- Highly volatile
- Evaporates quickly, often completely within 1 to 2 days

Type 2: light grade oils (jet fuels, diesel, No. 2 fuel oil, light crude)

- Moderately volatile
- Will leave residue (up to one-third of spill amount) after a few days
- Moderately soluble, especially distilled products

Type 3: medium grade oils (most crude oils)

- About one-third will evaporate within 24 hours
- Typical water-soluble fraction 10–100 ppm
- May penetrate substrate and persist
- May pose significant cleanup-related impacts

Type 4: heavy grade oil (heavy crudes, No. 6 fuel oil, bunker C)

- Heavy oils with little or no evaporation
- Water-soluble fraction typically less than 10 ppm
- Heavy surface contamination likely
- Highly persistent; long-term contamination possible
- Weathers very slowly; may form tar balls
- May sink in water, depending on product density
- May pose significant cleanup-related impacts
- Low acute toxicity relative to other oil types

Type 5 low API fuel grade oils (heavy industrial fuel oils)

- Neutrally buoyant or may sink
 - Weathers slowly; sunken oil has little potential for evaporation
 - May accumulate on bottom under calm conditions and smother subtidal resources
 - Sunken oil may be resuspended during storms, providing a chronic source of shoreline oiling
 - Highly variable and often blended with oils
 - Blends may be unstable, and the oil may separate when spilled
 - Low acute toxicity relative to other oil types
-

provides an overview of the physical characteristics of the more common liquid hydrocarbons transported via pipeline. Typically, more than one product is transported through the same interstate pipeline. In those instances, the line pipe meets the most rigorous product-specific standards among all of the materials being transported. Increased numbers of products carried on a pipeline increase the support facilities, such as tankage, required to receive and segregate the different products.

1.3 TYPES OF LINE PIPE

Steel pipe is used in most pipelines transporting hydrocarbons. It is manufactured according to the specifications of the American Petroleum Institute (API 1994, 2000), the American Society of Mechanical Engineers (ASME), the American National Standards Institute (ANSI), and the American Society of Testing Materials (ASTM).

Various grades of line pipe are specified, based on yield strength.⁴ Grade A line pipe has a minimum yield strength of 30,000 pounds per square inch (psi), with Grade B having a minimum yield strength of 35,000 psi. Other grade categories may indicate special fabrication methods. For example, Grade X42 indicates a pipe made of steel with a 42,000 psi minimum yield strength; X60 pipe has a minimum yield strength of 60,000 psi, etc. Newer pipe grades X70 and X80⁵ are available, but are typically used in offshore or high-pressure gas pipelines for large-diameter or high-pressure applications.⁶ Additional information on line pipe grades can be obtained from the EUROPIPE and U.S. Steel Tubular Products websites http://www.europipe.de/www/download/EP_TP47_02en.pdf and <http://www.usstubular.com/products/seamslp.htm>, respectively. A more detailed discussion of pipe fabrication can be found in Kennedy (1993).

Line pipe is manufactured as either seamless or welded. These designations refer to how each length, or joint, of pipe is manufactured, not how the joints are connected in the field to form a continuous pipeline. Seamless steel pipe is made without a longitudinal weld by hot-working lengths of steel to produce pipe of the desired size and properties. Welded pipe is made using several manufacturing processes. The two types of pipe differ both by the number of longitudinal weld seams in the pipe and the type of welding equipment used. Welded pipe is the most common pipe used in petroleum pipeline service.

The individual lengths of pipe are normally joined by welding sections of pipe together (20 or more feet in length). Pipe made of materials other than steel, including fiberglass, various plastics, and cement asbestos, has been used for special applications involving corrosive liquids, such as saltwater disposal or the transport of highly corrosive crude oils.

Most pipe used in the United States is manufactured as seamless, or longitudinally welded, pipe. However, other parts of the world use spiral-welded pipe, which has a spiral weld along its length.

⁴ Yield strength is the amount of tensile force that must be applied to cause a permanent deformation (elongation) in a test sample. The force is typically expressed in units of pounds per square inch.

⁵ X80 line pipe is for large-diameter high-strength pipelines. See http://www.europipe.de/www/download/EP_TP47_02en.pdf. (Accessed July 12, 2006.)

⁶ See “General Description of Seamless Standard and Line Pipe Grades” at <http://www.usstubular.com/products/seamslp.htm>. (Accessed July 14, 2006.)

1.4 SYSTEM COMPONENTS

1.4.1 Tankage

Most pipeline systems have the ability to temporarily store and/or receive shipped product on each end of the pipeline, to facilitate product movements and, in some cases, to accommodate product blending. The size and nature of the storage depend on the business of the pipeline and the product(s) it carries. API and ASME standards have been promulgated to address the design and construction of these facilities.⁷ In addition, each facility needs to have waste handling and environmental control capabilities. Again, the nature and capacity of the storage depend on the business of the pipeline and the product(s) it carries. Since many pipelines originate or terminate at coastal facilities to enable marine movements, dock facilities are also often included in a comprehensive definition of a pipeline system.

Along with meeting all of the tankage requirements mentioned above, most facilities have the ability to handle pipeline waste materials and/or interface materials when the pipeline handles multiple products. Transmix, which is the mixture of two hydrocarbons shipped together, must be segregated and either downgraded to an appropriate specification or reprocessed. Crude oil delivered through pipelines also often contains small amounts of produced water.⁸ If the crude is at a storage field, this is collected and trucked to wastewater treatment. As a first step in the refining process, refineries will process crude oils in a “desalter” to remove all water. Waters recovered in the desalter are typically combined with other refinery wastewaters and treated in on-site facilities before being used (recycled) or to meet the requirements and pollutant limitations of discharge permits.

Nearly all pipeline terminal facilities have pumps, pig launching/recovery facilities (see Section 2.1.13), and the capability of handling pipeline sludge that can accumulate on pipeline walls and is removed during pigging activities. All pipeline terminals need to handle the drainage of lubricants and pipeline products, sampling dump stations, contaminated condensates, etc. Terminals are also required to develop spill prevention, control, and countermeasure plans for responses to accidental releases of products. Some materials recovered in responses to accidental releases, as well as waste materials generated through routine pipeline and terminal

⁷ Over 51 API standards have been promulgated relating to storage tanks, dealing with such topics as design criteria, cathodic protection, and operational procedures. A catalogue of all storage tank-related API standards, as well as all other API publications, is available at the API website: <http://www.api.org/Publications>. (Accessed January 11, 2007.) API standards can be purchased electronically from a number of vendors. See, for example: http://global.ihs.com/search_res.cfm?currency_code=USD&customer_id=2125452C2E0A&shopping_cart_id=2825285B244A403C415B5D58250A&rid=Z56&mid=Z56&country_code=US&lang_code=ENGL&input_doc_title=storage%20tanks&org_code=API. (Accessed January 11, 2007.)

⁸ However, when the produced water recovered at the production well contains naturally occurring radioactive material (NORM), additional controls are typically employed to exclude this water from the pipeline to the greatest extent possible so as to prevent NORM contamination of the pipeline and its associated components. Produced water containing NORM is typically reintroduced into the oil-bearing formation through injection wells.

operation, qualify as hazardous waste under federal or state environmental laws,⁹ so terminals typically also include facilities to temporarily store such materials before transport to permitted treatment and disposal facilities. A number of facilities have on-site waste water treatment facilities, which is more cost effective. Depending on the amount of production water that is allowed to be introduced into the pipeline and the source, pipelines that carry certain crude oils, as well as the terminals and refineries that receive them, may also generate waste from pigging operations or tank and equipment cleaning operations that contain naturally occurring radioactive materials (NORM). Such wastes require segregation and treatment or disposal in specially permitted facilities.

The primary shipping and receiving terminals are adjacent to, but not necessarily within pipeline rights-of-way (ROWs) or designated energy corridors. However, interconnecting pipelines and surge or pressure-relief tanks or breakout tanks are integral to interstate pipeline transport and can be expected to be located close to, if not within, the pipeline's ROW or within the designated energy corridor. Also, at changes in elevation, small tanks that serve as pressure stabilizing elements of overall pipeline operations will also be located close to the pipeline.

In accordance with federal or state environmental regulations and to provide for safe operation, typical design and operational considerations that have been incorporated into industry standards are reflected at facilities where storage is occurring. Adherence to relevant standards results in features such as tank dikes, enclosed drainage systems, double seals on floating roof tanks, leak detection, corrosion monitoring and protection, requirements for periodic inspection and monitoring programs, procedures for purging tank vapor spaces and vapor recovery/treatment, and specification of minimum corrosion allowances. All storage locations with capacities above prescribed volumes are also required to develop and periodically exercise emergency response plans for accidental releases of stored product. Some of the API standards and recommended procedures described above address these requirements. Although storage could occur in both aboveground and underground tanks, aboveground tanks generally predominate. Various tank designs are employed, some specifically suited for particular products or conditions. These include cone roof tanks, open-top floating roof tanks, covered floating roof tanks, spherical tanks (typically used for gases stored at high pressure), or bullet-style tanks (typically used to store gases at high pressures, often in a liquefied state).

1.4.2 Piping Types

1.4.2.1 Flowlines

Flowlines are used as part of a crude gathering system in production areas to move produced oil from individual wells to a central point in the field for treating and storage. Flowlines are generally small-diameter pipelines operating at relatively low pressure. Typical in the United States flowlines are between 2 and 4 inches in diameters. The size required varies

⁹ This is especially true of pipelines that transport secondary feedstocks containing listed chemicals or distillate products that demonstrate flammability characteristics specified in hazardous waste regulations.

according to the capacity of the well being served, the length of the line, and the pressure available at the producing well to force the oil through the line. Some wells are not pressurized and require pumping to collection systems. Flowlines typically operate at pressures below 100 psi.

Flowlines are normally made of steel, although various types of plastic have been used in a limited number of applications. Pipelines used for oil flowlines typically operate at low pressures, and therefore could be made of materials other than steel. Flowline pipe wall thicknesses of 0.216 inch for a 3-inch-diameter pipe are not uncommon, corresponding to a weight of 7.58 lb/lineal foot for a 3-inch-diameter pipe (Kennedy 1993).

1.4.2.2 Crude Trunk Lines

Crude is moved from central storage facilities over long-distance trunk lines to refineries or other storage facilities. Crude trunk lines operate at higher pressures than flowlines and could vary in size from 6 inches in diameter to as large as 4 feet, as in the TAPS in Alaska.¹⁰

1.4.2.3 Product Pipelines

Pipelines carrying products that are liquid at ambient temperatures and pressures do not have to operate at excessive pressures in order to maintain the product in a liquid state. However, liquids that vaporize at ambient temperatures must be shipped at higher pressures. For instance, ethane pipelines can operate at pressures up to 1,440 psi. Product pipelines usually are 12 to 24 inches in diameter, but can be as large as 40 inches in the case of the Colonial Pipeline, which carries gasoline and distillate from the Gulf Coast to northeast markets.

Product pipelines are unique, since they are typically used to transport a variety of petroleum distillate products concurrently in a batch-wise manner. The petroleum products jointly carried in the same pipeline are always chemically compatible with each other, but may differ in physical properties such as density. Some intermixing occurs at the interface of two products sequentially introduced into the pipeline. Operating methods allow for minimizing the interface between products. Regardless of how the commodities are separated while in the pipeline, any mixtures of two commodities are segregated from the rest of the flow at terminals and handled by downgrading (i.e., marketing them as product mixtures of lower quality than the original individual products) or by recovering and refractionating each mixture into the two original petroleum products. In some instances, a sphere or a specially designed pig can be inserted between batches to reduce the amount of mixing.

¹⁰ The TAPS is currently the largest operational crude oil pipeline in the United States. More typically, 42-inch-diameter pipe is the maximum size used, since it is the maximum size that is currently manufactured within the United States. Pipe used in TAPS was manufactured in Japan.

1.4.3 Pumping Stations

As with storage tanks, pump stations require an infrastructure of their own. They require waste handling, such as nearby sewer facilities or holding facilities for transfer in batches to an off-site waste-handling facility.¹¹ Also, the handling and injection of additives, such as for viscosity reduction, often occurs at pump stations. Pumps are typically driven by electric motors; however, engines operating on a variety of fuels (but typically obtained from sources other than the pipeline itself) can also be used to drive the pumps. Depending on location, power may be an issue. In the event of power failures or other significant upset conditions, pump stations are typically equipped with sufficient emergency power generation to support monitoring and control systems to accomplish an immediate safe shutdown.¹²

1.4.4 Metering Stations

Although primarily utilized to measure the volume, quality, and consistency of product for billing purposes and delivery receipts, storage tank monitoring and product metering can be used with line pressure monitors to verify that pipeline integrity has not been compromised. Any discrepancy could indicate some sort of system leak. Typically there is some “shrinkage” in volume when products are transferred from pipeline to tanks to pipeline. Systems and processes are in place to determine when the shrinkage observed is outside expected values.

1.4.5 Valve Manifolds

Valves are installed at strategic locations along the mainline pipe to control flows and pressures within the pipe and to isolate pipe segments in the event of upset or emergency conditions. Regardless of design, all valves require regular monitoring and maintenance. Along with pump seals that require continuous leak detection and repair, valve manifolds must be closely monitored and periodically overhauled based on schedules established by the manufacturer (preventative maintenance), reduced performance, and/or observed deterioration and wear.

1.4.6 Piping Manifolds

Depending on the facility, the presence of piping manifolds can result in a very significant and complex operation at either the origin or destination of a pipeline. Since many interstate pipelines have blending facilities on one end or the other, the manifolds in which such

¹¹ For small-scale operations, wastes generated at pump stations are temporarily stored and then removed by vacuum tanker to off-site treatment or disposal facilities.

¹² Shutting down a pipeline is a complex operation. Pumps must be shut down and valves closed in a specific sequence to prevent overpressurization of some segments of the pipeline. Check valves that would prevent product within the pipeline from reversing flow and running downhill when pumps are stopped must also be closed in a specific sequence.

blending is accomplished can be elaborate and have much more piping than what would normally be required for simple movements from one location to another. Such blending facilities may also be present within a pipeline ROW in a centralized corridor.

1.4.7 Pigging Stations

Pipeline operators may incorporate the use of pigs, depending on the nature and quality (purity) of the materials being transported. Pigs can be designed to clean accumulated sludge and debris off the inside walls of a pipe, or to monitor the pipe for conditions such as corrosion (known as “smart pigs”). Pigs are introduced at launching facilities located along the mainline pipe ROW, often in conjunction with a pump station. The pig’s outer diameter is the same as, or slightly larger than the internal diameter of the pipe, so that a portion of the pig is compressed when placed inside. In most instances, the pig itself has no power source to propel it along the pipe, but instead is carried along the pipe by the flow of the liquid in the pipe. Obviously, pigs must be removed before reaching the next pump station. Such pig recovery stations are typically immediately upstream of the next downstream pump station. Depending on the product and the age of the pipeline, cleaning and monitoring pigs are routinely introduced into and recovered from the pipeline without any interruption of pipeline operations. Data recorded by smart pigs are typically integrated with the data from the pipeline’s supervisory control and data acquisition (SCADA) system (see below) and are used to control inspection, maintenance, and repair activities. See Section 2.1.13 for an additional discussion of the various types and applications of pigs.

1.4.8 Supervisory Control and Data Acquisition (SCADA) Systems

Pipelines are monitored and operated using sophisticated SCADA systems. SCADA systems regulate pressure and flow by monitoring and controlling pump operation and the positions of valves. SCADA systems also perform a variety of additional functions including alarm processing, leak detection, hydraulic analysis, pump station monitoring, throughput analysis, and other functions deemed critical to the safe operation of the pipeline. Section 2.1.15.1 provides an expanded discussion on how SCADA systems are used to monitor and control the operations of a pipeline.

1.4.9 Telecommunication Towers

SCADA systems, regardless of their degree of sophistication, are only as good as the communication system that transmits data and commands throughout the pipeline system. A communication system includes equipment, such as telecommunication towers, and cabling to provide voice and/or data communications to the various facilities along the pipeline as well as to the SCADA system components. Real-time data communications are necessary between the control center, the various pump stations, storage/distribution terminals, delivery facilities, and mainline block valve sites.

Real-time operational data communications can be supported through a combination of the following approaches: telephone company circuits, satellite terminals, microwave, point-to-point radio pairs, and fiber optic cable. Often, pipeline systems employ redundant communication links to ensure that critical data are communicated in the event of a failure in one of the systems.

1.4.10 Mass Flow Meters

There are two types of flow meters used in liquid pipeline systems. The first type is referred to as a volumetric flow meter. In the oil industry, the majority of transfers and sales are measured in volumetric units such as barrels or gallons, so this type of meter is usually applied. In other instances such as for petrochemicals, flow rates are measured in units of pounds by a mass meter. With both types of flow meters, the accuracy of the measurements is periodically checked by a “meter prover.” This process is conducted to insure the accuracy of the measured flow quantities. Flow meters are commonly used where custody transfers or sales are involved. Flow meters also offer the pipeline operator the opportunity to monitor for any leaks by performing volume or mass balance checks around specified sections of the pipeline network. These balance checks would typically be performed via the SCADA computer system.

1.4.11 Valves

Valve types and locations comprise an important facet of liquid pipeline design and operation. Valves located in the mainline must be compatible with pigging equipment. Valve location is a critical design issue to insure that discrete portions of the line can be isolated in the event of a line leak or when maintenance is required.¹³ Check valves that would prevent backflows of product down grades in the event of loss of power to pipeline pumps are also essential to prevent overpressurization of pipe segments at the base of grade changes.

1.4.12 Corrosion Control Systems

Corrosion control of pipeline systems primarily composed of steel and other metals is critical to system integrity. Buried metallic objects will corrode (chemically oxidize) through participation in electrochemical reactions if not adequately protected. Corrosion control is accomplished through a variety of means. In most instances, paints and protective coatings are applied followed by wrapping and taping sections of mainline pipe prior to burial to isolate the metallic pipe and prevent its participation in electrochemical reactions. In addition, cathodic protection is provided through the use of an impressed current or sacrificial anodes to counteract

¹³ In some instances, valve placement is dictated by environmental factors. For example, mainline valves for TAPS are spaced such that no more than a prescribed amount of product would exist in the segment of pipe between any two valves or a valve and a pump station. Thus, valve spacing limits the amount of product that can be released to the environment in the event of catastrophic failure (relying on the SCADA system to identify the failure as a precipitous drop in system pressure and to automatically shut valves to isolate the apparent problem).

those electrochemical reactions. Various polyethylene- or epoxy-based paints, some also including asphalt and/or coal tar, are used for buried pipe and valves.

Cathodic protection involves either the use of an impressed current or sacrificial (or galvanic) anodes. For impressed-current systems, anodes are buried in the soil proximate to the section of buried pipe being protected. A current is applied to the anodes equivalent to the current that would result from the electrochemical oxidation of the pipe. This current is allowed to flow through the soil to the pipe which then completes the circuit. This impressed current counterbalances the flow of electrons from the pipe to the soil that would otherwise have resulted from the pipe's oxidation, thereby canceling that reaction.. Impressed-current systems can be monitored from the ground as a demonstration of their continued proper performance. Unless malfunctions occur, impressed-current system components that are buried with the pipe will typically not need replacement for 20 to 25 years, and many last over the lifetime of the pipe. SCADA systems can be configured to monitor the performance of impressed-current systems. Alternatively, individuals using monitoring devices can check their performance (i.e., measure the voltage being applied to the pipe) at ground-level monitoring points installed along the length of the pipeline.

An alternative to impressed-current systems is the use of galvanic electrodes. Electrodes composed of magnesium or zinc, both of which corrode more easily than the iron in the pipe, are electrically bonded to and buried along side of the pipe. Current is allowed to naturally flow from the pipe to the ground; however, it is the zinc or magnesium in the electrodes that loses electrons in the process. Thus, the electrodes are "sacrificed" to protect the iron pipe. Galvanic electrodes must be replaced periodically. Site-specific conditions of soil moisture and electrical conductivity determine the proper anode replacement intervals. Typically, such site-specific conditions are determined using a test electrode placed in virtually the identical electrochemical environment, but not connected in any way to the pipeline and easily recoverable, so that the extent of its degradation can be observed and replacement intervals established for the electrodes attached to the pipe, and excavations to expose those electrodes for replacement can be done only as necessary.

2 PIPELINE DESIGN

2.1 FACTORS INFLUENCING PIPELINE DESIGN

2.1.1 General Pipeline Design Considerations

The major steps in pipeline system design involve establishment of critical pipeline performance objectives and critical engineering design parameters such as:

- Required throughput (volume per unit time for most petroleum products; pounds per unit time for petrochemical feedstocks);
-
- Origin and destination points;
-
- Product properties such as viscosity and specific gravity;
-
- Topography of pipeline route;
-
- Maximum allowable operating pressure (MAOP); and
-
- Hydraulic calculations to determine:
 -
 - Pipeline diameter, wall thickness, and required yield strengths;
 -
 - Number of, and distance between, pump stations; and
 -
- Pump station horsepower required.¹⁴

2.1.2 Safety

Safety in pipeline design and construction is achieved by the proper design and application of the appropriate codes and system hardware components, as detailed above. Design codes as set forth in U.S. Department of Transportation's (DOT's) Office of Pipeline Safety (OPS) regulations provide appropriate safety factors and quality control issues during construction. Metering stations and SCADA systems provide continuous monitoring oversight of pipeline operations. Training of pipeline operating and maintenance personnel is also a key ingredient in the ongoing efforts to insure system integrity and safety. Safe operations result from developing and strictly adhering to standard procedures and providing the workforce with

¹⁴ As a practical matter, equipment selection and operating parameters are determined based on such factors as the density of the commodity to be transported, the desired throughput, delivery schedules committed to by the pipeline operator, and overall costs associated with ROW acquisition and construction and operating costs of sample components.

adequate training, safety devices, and appropriate personal protective equipment. Standard operating procedures typically are developed with reference to government and standard industry practices, as well as corporate safety policies, experience, philosophy, and business practices. Regulations promulgated by the Occupational Safety and Health Administration (OSHA) and by counterpart agencies at the state level specify the procedures and controls required to ensure workplace safety, including, in some instances, the performance of process safety analyses and the development of very specific procedures for activities thought to represent potentially significant hazards to workers and the public.

2.1.3 Industry Codes and Standards

The ASME has a long history of developing standards for use in the oil and gas pipeline industry. The scope of the first draft of the ASME Code for Pressure Piping, which was approved by the American Standards Association in 1935, included the design, manufacture, installation, and testing of oil and gas pipelines (ASME B31.4). As the needs of the industry evolved over the years, rules for new construction have been enhanced, and rules for operation, inspection, corrosion control, and maintenance have been added. In addition to ASME, several other organizations, including the API and the National Association of Corrosion Engineers (now known as NACE International), also develop standards used by the pipeline industry.¹⁵

The industry adheres to the following summary of standards:¹⁶

- Tank operation and construction (15 standards maintained by a committee operated by API)
- Underground storage caverns (2 API standards)
- Manufacture of line pipe (4 API standards)
- Cathodic protection against corrosion (8 NACE standards and guides)
- Welding (15 American Welding Society [AWS] and 1 API standards)
- Pipeline awareness (2 API standards)

¹⁵ ASME codes can be purchased for electronic download from the ASME website at http://store.asme.org/category.asp?catalog_name=Codes+and+Standards&category_name=&Page=1&cookie%5Ftest=1. (Accessed December 6, 2006.)

A catalogue of all API publications, including national consensus standards, is available for download at <http://www.api.org/Publications/>. (Accessed December 6, 2006). Ordering information for standards may also be found there.

NACE International standards can be purchased for electronic download at <http://www.nace.org/nacestore/dept.asp?Cat%5FID=2905>. (Accessed December 6, 2006.)

¹⁶ Association of Oil Pipelines – Regulations and Standards. Available at <https://www.piersystem.com/external/index.cfm?cid=888&fuseaction=EXTERNAL.docview&documentID=57733>. (Accessed February 2, 2007.)

- Pipeline integrity (API Recommended Practice 1129, “Assurance of Hazardous Liquid Pipeline System Integrity”)
- Pipeline wall thickness (API Standard B31.G)

The following is a list of some of the primary standards governing pipeline design, manufacturing, construction, and operation:

- API standards (including standards issued jointly by ANSI):
 - “Pipeline Maintenance Welding Practices,” 3rd edition, API Recommended Practice (RP) 1107
 - “Specification for Pipeline Valves (Gate, Plug, and Check Valves),” 21st edition, API 6D1, June 1998 Supplement 2
 - “Welding of Pipelines and Related Facilities,” ANSI/API Std. 1104, September 1999
 - “Specification for Line Pipe,” API 5L, March 2004
 - “Specification for Line Pipe,” API 5L Errata 1, January 2005
 - “Steel Pipelines Crossing Railroads and Highways,” API 1102 (1993)
 - “Marking Liquid Petroleum Pipeline Facilities,” 3rd edition, API 1109, July 2003
 - “Developing a Pipeline Supervisory Control Center,” API 1113, February 2000
 - “Movement of In-Service Pipelines,” ANSI/API 1117, August 1996
 - “Computational Pipeline Monitoring for Liquids Pipelines,” API 1130, November 2002
 - “Pipeline Variable Uncertainties and Their Effects on Leak Detectability,” API 1149, November 1993
 - “Evaluation Methodology for Software-Based Leak Detection Systems,” API 1155, February 1996
 - “Hydrostatic Test Water Treatment and Disposal,” API 1157, October 1998

- “Managing System Integrity for Hazardous Liquid Pipelines,” API 1160, November 2001
- “In-Line Inspection Systems Qualification Standard,” 1st edition, API 1163, August 2005
- “Pressure Testing of Liquid Petroleum Pipelines,” ANSI/API RP 1110, March 1997
- “Repairing Crude Oil, Liquid Petroleum Gas, and Product Pipelines,” 3rd edition, API RP 2200, May 1994
- “Steel Pipelines Crossing Railroads and Highways,” API RP 1102, January 1993
- ASTM standards¹⁷
- ASME standards¹⁸
 - “Boiler and Pressure Vessel Code,” 2004 (triennial updates)
 - “Gas Transmission and Distribution Piping Systems,” ASME B31.8, 1999
 - “Refrigeration Piping,” ASME B31.5 and Addenda B31.5A, 1994
 - “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids,” ASME B31.4, 1998
 - “Power Piping,” ASME B31.1, 1998; Addenda B31.1A, 1999; Addenda B31.1B, 2000
 - “Process Piping,” ASME B31.1, 1999; Addenda B31.3A, 1999
 - “Slurry Transportation Piping Systems,” ASME B31.11, 1989; Addenda B31.11A, 1991
 - “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids,” ASME B31.4, 2002
 - “Gas Transmission and Distribution Systems,” ASME 31.8, 2003

¹⁷ Numerous ASTM standards apply. ASTM standards can be purchased for electronic download at the ASTM website: <http://webstore.ansi.org/ansidocstore/astm.asp>. (Accessed December 5, 2006.)

¹⁸ ASME standards are available for electronic purchase at http://store.asme.org/category.asp?catalog_name=Codes+and+Standards&category_name=&Page=1. (Accessed December 6, 2006.)

- *Annual Book of ASTM Standards*, Volume 6: Paints, Related Coatings, and Aromatics; Section 6.02: Paint – Products & Applications; Protective Coatings; Pipeline Coatings
- Institute of Electrical and Electronics Engineers, Inc. (IEEE), National Electrical Safety Code, 2007¹⁹
- International Association of Plumbing and Mechanical Officials (IAPMO), Uniform Plumbing Code, 2003 (an American National Standards Institute national consensus standard)²⁰
- International Conference of Building Officials, Uniform Building Codes (13 codes in all), 2007²¹
- International Conference on Building Officials, Uniform Fire Code, 2006 edition²²
- National Fire Protection Association, *National Electrical Code Handbook*, 2005 edition²³

A December 2001 report for the API's Pipeline Committee contains an interesting discussion on the evolution of pipeline technologies and standards, covering milestones from the first United States cast iron pipe in 1834 to the publication of API Standard 1160 in November 2001 (Kiefner 2001).

2.1.4 Pipeline Coating

Corrosion-resistant coatings are applied to the exteriors of most pipes to inhibit corrosion. These may be applied at the manufacturing plant or a pipe coating plant located separately. However, coatings are also sometimes applied at the construction site. Even for precoated pipe, field dressings of joints and connections are also performed at the construction site just prior to burial. For particularly corrosive products (including some crude oils with high total acid numbers), pipes are also sometimes coated on the inside for corrosion resistance. In addition to the resistance to corrosion they provide, some interior coatings are also designed to reduce

¹⁹ IEEE standards are available for electronic download at <http://standards.ieee.org/nesc/>. (Accessed December 6, 2006.)

²⁰ The IAPMO Uniform Plumbing Code is available for electronic purchase at <http://www.nfpa.org/catalog/product.asp?pid=res10703&src=catalog&cookie%5Ftest=1>. (Accessed December 6, 2006.)

²¹ Uniform Building Codes, published by the International Conference of Building Officials, are available for electronic purchase at http://www.techstreet.com/cgi-bin/browsePublisher?publisher=ICBO&orderBy=doc_no. (Accessed December 5, 2006.)

²² The Uniform Fire Code is available for electronic purchase at <http://www.nfpa.org/aboutthecodes/AboutTheCodes.asp?DocNum=1>. (Accessed December 6, 2006.)

²³ The *National Electric Code Handbook* is available for electronic purchase at http://www.nfpa.org/catalog/product.asp?pid=70HB05&order_src=A291. (Accessed December 6, 2006.)

frictional losses between the product and the interior walls of the pipe, thereby reducing the total amount of energy required to move the materials along the pipeline.²⁴ Protective wrappings, followed by the application of tape to the edges of the spirally applied overlapping wrapping, are often installed on the exterior of the pipe to further assist in corrosion control, but also to primarily protect the pipe from mechanical damage at installation. Wraps and tape often are impregnated with tar or other asphalt-based materials and heated in place once applied, to ensure uniform coverage. Once cured, the exterior coatings are chemically stable and environmentally inert, resisting degradation by soil moisture and bacteria, yet remaining sufficiently flexible that they continue to provide a protective coating on the pipe throughout a wide temperature range. Likewise, wrapping materials and tape are stable and inert (including toward the material being transported in the pipeline) and do not pose a potential for adverse environmental impacts. Figure 2.1-1 illustrates installation of an exterior pipe tape wrap prior to the pipe's installation in its trench. Other coatings, such as thin-film epoxy and extruded polymers are also used as alternative to wraps and asphaltic coatings.

Depending on local soil conditions, material of uniform size is sometimes imported to the construction site to form a bed on which the pipe is placed. The same material may also be installed around the sides and top of the pipe before the trench is filled with indigenous soils. Such bedding material serves two principal functions: protection of the pipe from mechanical



FIGURE 2.1-1 Coating Newly Installed Pipe for Corrosion Control (Source: Photo courtesy of Corrosion Control Products Co. Reproduced with permission.)

²⁴ Even with noncorrosive commodities, interior coatings are sometimes applied for the reduction of frictional losses they provide. Such interior coatings may also be used in conjunction with chemical additives that are sometimes added to especially viscous petroleum commodities such as crude oils with API gravities of 10 or less to reduce frictional losses.

damage during installation and trench filling, and stabilization of the pipe in the event of seismic shifts or frost heaves. Sands and gravels are typical bedding materials and are tamped in lifts of 12 to 18 inches per lift to ensure adequate compaction and avoid future subsidence. Bedding materials also assist in draining accumulated water from the vicinity of the pipe.

All newly coated pipe used to transport hazardous liquids must be electrically inspected prior to backfilling to check for faults not observable by visual examination. Material faults such as microcracks demonstrate a characteristic response to applied current when the detector is operated in accordance with the manufacturer's instructions and at the voltage level appropriate for the electrical characteristics of the coating system being tested.

2.1.5 Sizing

The dimensions of a pipeline — both the sizes and capacities of the various components — as well as the conditions under which the pipeline system operates dictate the system's capacity. Larger diameter pipes allow for higher mass flows of materials, provided other components of the pipeline system, primarily pumps and pressure management devices, are properly sized and positioned. In general, the longer the segment of mainline pipe between pump stations, the greater the drop in line pressure. However, grade changes and the viscosity of the materials being transported can also have major influences on line pressures. API Standard 5L provides dimensions, weights, and test pressures for plain-end line pipe in sizes up to 80 inches in diameter. Several weights are available in each line pipe diameter. The weight of the pipe in lb/ft, in turn, varies as the wall thickness for a given outside diameter. For instance, API Spec 5L lists 24 different weights in the 16-inch-diameter size (five weights are special weights), ranging from 31.75 lb/foot to 196.91 lb/foot. The corresponding wall thickness ranges from 0.188 inch to 1.250 inches. As the wall thickness increases for a given outside diameter, the inside diameter of the pipe decreases from 15.624 inches for the lightest weight pipe to 13.500 inches for line pipe weighing 196.91 lb/foot. Greater wall thicknesses are selected for high-pressure applications or when the pipe segment might be subjected to unusual external forces such as seismic activities and landslides.²⁵ Also, in hard-to-reach places, such as beneath transportation routes and at river crossings or difficult-to-access environmentally sensitive areas, overbuilding in size or quality is sometimes chosen to accommodate future expansion requirements.

2.1.6 Pressure

Operating pressure of a pipeline is determined by the design flow rate vapor pressure of the liquid, the distance the material has to be transferred, and the size of line that carries the liquid. Pipe operating pressure and pump capabilities and cost typically drive decisions on line

²⁵ Landslides would not necessarily directly impact buried pipe unless the slide action itself were to expose the pipe, making it subject to forces from additional landslide materials. However, even when the pipe is not exposed, landslides may cause substantial amounts of material to end up on the ground above the buried pipe, where the extra weight could crush or deform the buried pipe.

size, the number of pump stations, and the like. Grades notwithstanding, line pressure follows a sawtooth curve between pump stations. The maximum and minimum line pressure that can be tolerated, together with the physical properties of the materials noted earlier, dictate the spacing of the pump stations and the motive horsepower of the pumps.

2.1.7 Product Qualities

As noted earlier, critical physical properties of the materials being transported dictate the design and operating parameters of the pipeline. Specific gravity, compressibility, temperature, viscosity, pour point, and vapor pressure of the material are the primary considerations. These and other engineering design parameters are discussed in the following sections in terms of their influence on pipeline design.

2.1.7.1 Specific Gravity/Density

The density of a liquid is its weight per unit volume. Density is usually denoted as pounds of material per cubic foot. The specific gravity of a liquid is typically denoted as the density of a liquid divided by the density of water at a standard temperature (commonly 60°F). By definition, the specific gravity of water is 1.00. Typical specific gravities for the distilled petroleum products gasoline, turbine fuel, and diesel fuel are 0.73, 0.81, and 0.84, respectively.²⁶

2.1.7.2 Compressibility

Many gases that are routinely transported by pipeline are highly compressible, some turning into liquids as applied pressure is increased. The compressibility of such materials is obviously critical to pipeline design and throughput capacity. On the other hand, crude oils and most petroleum distillate products that are transported by pipeline are only slightly compressible. Thus, application of pressure has little effect on the material's density or the volume it occupies at a given temperature; consequently, compressibility is of only minor importance in liquid product pipeline design. Liquids at a given temperature occupy the same volume regardless of pressure as long as the pressure being applied is always above the liquid's vapor pressure at that temperature.

²⁶ The density of petroleum products is more commonly expressed as API gravity, a measurement convention independently established by the American Petroleum Institute for expressing the relative density of petroleum liquids to water; the greater the API gravity, the less dense the material. API gravities are close to, but not equivalent to specific gravities measured in the Baumé scale, the more conventional method of representing the density of a liquid; $\text{API gravity} = (141.5/\text{specific gravity at } 60^\circ\text{F}) - 131.5$; thus, a petroleum liquid with an API gravity of 10.0 at 60°F has a specific gravity of 1.0 (same as water). Petroleum liquids with API gravities greater than 10 have densities less than water and will float; those with API gravities less than 10 will sink; the API gravity scale is calibrated such that most petroleum liquids (crude oils as well as distillate fuels) will have API gravities between 10 and 70 API gravity degrees.

2.1.7.3 Temperature

Pipeline capacity is affected by temperature both directly and indirectly. In general, as liquids are compressed — for example, as they pass through a pump — they will experience slight temperature increases. Most liquids will increase in volume as the temperature increases, provided the pressure remains constant. Thus, the operating temperature of a pipeline will affect its throughput capacity. Lowering temperatures can also affect throughput capacity, as well as overall system efficiency. In general, as the temperature of a liquid is lowered, its viscosity increases, creating more frictional drag along the inner pipe walls, requiring greater amounts of energy to be expended for a given throughput volume. Very viscous materials such as crude oils exhibit the greatest sensitivity to the operating temperatures of their pipelines. However, in the case of crude oils, the impacts are not only from increases to viscosity, but also due to the solidification of some chemical fractions present in the oils. For example, crude oils with high amounts of paraffin will begin to solidify as their temperature is lowered, and they will become impossible to efficiently transport via a pipeline at some point.

2.1.7.4 Viscosity

From the perspective of the pipeline design engineer, viscosity is best understood as the material's resistance to flow. It is measured in centistokes. One centistoke (cSt) is equivalent to 1.08×10^{-5} square feet per second. Resistance to flow increases as the centistoke value (and viscosity) increases. Overcoming viscosity requires energy that must be accounted for in pump design, since the viscosity determines the total amount of energy the pump must provide to put, or keep, the liquid in motion at the desired flow rate. Viscosity affects not only pump selection, but also pump station spacing. Typical viscosities for gasoline, turbine, and diesel fuels are 0.64, 7.9, and 5 to 6 cSt, respectively.

As the material's viscosity increases, so does its frictional drag against the inner walls of the pipe. To overcome this, drag-reducing agents are added to some materials (especially some crude oils). Such drag-reducing agents are large molecular weight (mostly synthetic) polymers that will not react with the commodity or interfere with its ultimate function. They are typically introduced at pump stations in very small concentrations and easily recovered once the commodity reaches its final destination. However, often, no efforts are made to separate and remove these agents. Drag reduction can also be accomplished by mixing the viscous commodity with diluents. Common diluents include materials recovered from crude oil fractionation such as raw naphtha. Diluents are used to mix with viscous crude feedstocks such as bitumen recovered from tar sands and other very heavy crude fractions to allow their transport by pipeline from production areas to refineries.

2.1.7.5 Pour Point

The pour point of a liquid is the temperature at which it ceases to pour. The pour point for oil can be determined under protocols set forth in the ASTM Standard D-97. In general, crude

oils have high pour points. As with viscosity, pour points are very much a function of chemical composition for complex mixtures such as crude oils and some distillate products, with pour point temperatures being influenced by the precipitation (or solidification) of certain components, such as paraffins.

Once temperatures of materials fall below their respective pour points, conventional pipeline design and operation will no longer be effective; however, some options still exist for keeping the pipeline functional. These include:

- Heating the materials and/or insulating the pipe to keep the materials above their pour point temperature until they reach their destination.
- Introduce lightweight hydrocarbons that are miscible with the material, thereby diluting the material and lowering both its effective viscosity and pour point temperature.
- Introduce water that will preferentially move to the inner walls of the pipe, serving to reduce the effective coefficient of drag exhibited by the viscous petroleum product.
- Mix water with the petroleum material to form an emulsion that will exhibit an effective lower viscosity and pour point temperature.
- Modify the chemical composition before introducing the material into the pipeline, removing those components that will be first to precipitate as the temperature is lowered. (This tactic is effective for crude oils, but is virtually unavailable when moving distillate products that must conform to a specific chemical composition.)

Waxy crude can be pumped below its pour point; more pumping energy is required, but there is no sudden change in fluid characteristics at the pour point as far as pumping requirements are concerned. However, if pumping is stopped, more energy will be required to put the crude in motion again than was required to keep it flowing. When flow is stopped, wax crystals form, causing the crude to gel in the pipeline. If gelling occurs, the crude behaves as if it had a much higher effective viscosity; consequently it may take as much as five to ten times the energy to reestablish design flows in the pipeline than it did to support stable continuous operation when the crude's temperature was above its pour point.

For some products such as diesel fuels that still contain some waxy components (i.e., saturated, long-chain hydrocarbons), "gelling" may also occur as temperatures are lowered; however, such gelling problems are commonplace in storage tanks and vehicle fuel tanks where the fuel sits motionless for long period of time, but rarely materialize in pipelines where the materials are virtually in constant motion and where their passage through pumps typically imparts some amount of heat. Nevertheless, precipitation or gelling of products contained in pipelines can cause significant operational difficulties and may also result in environmental

impacts if pipeline ruptures occur during attempts to restart the flow, when a pressure well above design limits could result.

2.1.7.6 Vapor Pressure

The vapor pressure of a liquid represents the liquid's tendency to evaporate into its gaseous phase with temperature. Virtually all liquids exhibit a vapor pressure, which typically increases with temperature. The vapor pressure of water increases steadily with temperature increases, reaching its maximum of one atmosphere pressure (760 mm Hg, or 14.7 psi absolute [psia]) at the boiling point (212°F).

Vapor pressures of petroleum liquids are determined using a standardized testing procedure and are represented as the Reid vapor pressure. Reid vapor pressures are critical to liquid petroleum pipeline design, since the pipeline must maintain pressures greater than the Reid vapor pressure of the material in order to keep the material in a liquid state. Blended (or “boutique”) vehicle fuels, required over some periods of the year for air pollution control purposes in some parts of the country, have unique chemical compositions and unique Reid vapor pressures (as mixtures). Consequently, pipelines handling such fuels must constantly monitor their vapor pressure and adjust operating conditions accordingly. Pipelines carrying liquids with high vapor pressures can be designed to operate under a variety of flow regimes. Single-phase flow regimes intend for the entire amount of the material in the pipeline to be in the liquid state. Operators of single-phase liquid pipelines attempt to control pressure and flow to maintain a “full face” of liquids in the pipeline, minimizing the amount of volatilization that is allowed to occur. This maximizes system efficiency and also the longevity of system components. Failure to maintain a full face of liquids in a single-phase liquid pipeline can result in increased risks of fires and explosions. Single-phase liquid pipelines are the most common designs for petroleum liquids. However, pipelines can also be designed as two-phase systems in which both vapor and liquid phases of the material are expected to be present. The variation of flow regimes in such two-phase systems can range from bubbles of vapor distributed in liquid to droplets of liquid suspended in vapor. Typical vapor pressures for gasoline, turbine fuel, and diesel fuel are 15, 2, and 2 psia, respectively.

2.1.7.7 Reynolds Number

The Reynolds number, named after Osborne Reynolds, the scientist who first proposed its usefulness in studying fluid dynamics, is a dimensionless number that represents the ratio of the inertial force to the viscous force — that is, the ratio of the force moving a fluid to the force that attempts to resist that movement. In a pipeline, the inertial force is related to the fluid's velocity, which is a function of the force applied to it by the pumps. The viscous force is a product of the inherent viscosity of the fluid as well as the frictional drag created by interaction of the fluid with the interior surface of the pipeline. A low value for a Reynolds number (<2100) suggests that the fluid will be moved evenly, so-called laminar flow. Higher Reynolds numbers indicate that forces applied to a fluid are much greater than the forces resisting its movement; consequently its movement will be violent and turbulent. The Reynolds number representing the transition zone

between laminar and turbulent flows is called the critical Reynolds number (R_{crit}), which is typically assigned a value of 2320. The Reynolds number depends on the force applied by pumps, the material's viscosity at operating temperature, and the physical size and cross-sectional shape of the pipe through which the material is moving. Most pipeline designers select these components to establish operating conditions near R_{crit} while still delivering the desired throughput.²⁷

2.1.7.8 Darcy Friction Factor

Named after the French engineer Henry Darcy, the Darcy friction factor is a dimensionless number that represents the linear relationship between the mean velocity of a moving fluid and the pressure gradient. The Darcy friction factor is critical in determining the necessary force capabilities of pumps as well as the spacing between pump stations to create the desired flow (and thus throughput) of a liquids pipeline.

2.1.8 Other Design Considerations

2.1.8.1 Thermal Stresses

Except where local conditions prevent it, petroleum pipelines are typically buried. Burial depths vary with geographic location, but are typically designed to ensure that the entirety of the pipe is below the local frost line. At such depths, the ambient soil temperatures are relative constant with season, although some minor variations can occur. Despite predictably stable temperature environments, pipeline design also accounts for thermal stresses, both expansions and contractions for the pipe and other components. Expansion joints are employed, and, in some instances, trenches are made extra-wide to allow for lateral movements of the pipe with temperature. Thermal expansion joints, or loops, are also critical in locations where conditions require the pipe to be above ground, for example, at some river crossings.

Thermal stress on pipeline components can also come from internal forces. The vapors of certain volatile hydrocarbon fuels will cause supercooling of the remaining liquids, if allowed to escape from the pipeline system at significant rates. Such supercooling can result in thermal cracking of pipes and pump housings.

²⁷ Laminar flow represents a condition of greatest overall efficiency, while turbulent flow introduces vibration and generally accelerates the wear on system components and increases the potential for system failure. Laminar flow is thus the preferred operating condition. However, economic performance requirements necessitate that pipelines be operated at a rate that induces turbulent flows for most commodities. Design and operational accommodations including the use of drag-reducing agents are utilized to mitigate the negative effects while still preserving the necessary economic margins.

2.1.8.2 Soil and Load Design Considerations

During the design and site preparation phases, soil samples are taken at many points throughout to determine mechanical and thermal stability, corrosivity, and electrical conductance. Soils and subsurface materials are also evaluated for their ability to support the weight of the pipeline support facilities at sensitive areas, such as river crossings. Soil properties such as seepage, slope stability, tensile strength, and soil structure are determined. Industry standards published by the American Society of Civil Engineers (ASCE) outline the necessary site characterization studies (ASCE 2001). In addition to engineering considerations, site characterizations regarding the presence of threatened or endangered plant species and soil organisms may also need to be conducted.

2.1.8.3 Vertical External Load

Under most conditions, the internal pressures imposed on the pipe by moving fluids far exceed the static pressures on the pipe from the weight of backfill and soil material above it. Consequently, vertical external loading is not typically a matter of serious concern to pipeline designers. However, there are some circumstances where vertical loading becomes critical, including when pipelines pass beneath rivers, railroads, or highways (also see the discussion below on dynamic vertical loads) or in areas with high snowfall or landslide potential.

2.1.8.4 Surface Live Loads

In addition to supporting dead loads imposed by earth cover, buried pipes may also be exposed to superimposed concentrated or distributed live loads. Large concentrated loads, such as those caused by truck-wheel loads, railway cars, and locomotive loads, are of most practical interest.

Depending on the requirements of the design specification, the live-load effect may be based on American Association of State Highway and Transportation Officials (AASHTO) HS-20 (AASHTO 1998) truck loads or American Railway Engineering Association (AREA) Cooper E-80 railroad loads (AREMA 2006), as indicated in Table 2.1-1. The values of the live-load pressure, P_p , are given in psi and include an impact factor $F = 1.5$ to account for bumps and irregularities in the travel surface. Other important impact factors are listed in Table 2.1-2. Note that live loads depend on the depth of cover over the pipe and become negligible for HS-20 loads when the earth cover exceeds 8 feet, and for E-80 loads when the cover exceeds 30 feet. Casings can also be used to enhance the protection of the pipe.

Other impacts of loads on pipelines can be deforming the pipe (ovalizing), through-wall bending, crushing side walls, and ring buckling. Because ovalizing the pipe will affect the Reynolds number, the pipeline throughput capacity would also be impacted by such deformations, and the deformed pipeline itself would be subject to accelerated wear and an

TABLE 2.1-1 Live Loads

Live Load Transferred to Pipe (lb/square inch)			Live Load Transferred to Pipe (lb/ square inch)		
Height of Cover (ft)	Highway H20 ^a	Railway E80 ^b	Height of Cover (ft)	Highway H20 ^a	Railway E80 ^b
1	12.5	– ^c	14	d	4.17
2	5.56	26.39	16	d	3.47
3	4.17	23.61	18	d	2.78
4	2.78	18.40	20	d	2.08
5	1.74	16.67	22	d	1.91
6	1.39	15.63	24	d	1.74
7	1.22	12.15	26	d	1.39
8	0.69	11.11	28	d	1.04
10	d	7.64	30	d	0.69
12	d	5.56	35	d	d

- a Simulates a 20-ton truck traffic load, with impact.
b Simulates an 80,000 lb/foot railway load, with impact.
c Dash corresponding to Railway E-80, and 1-foot height of cover is nonapplicable.
d Negligible influence of live load on buried pipeline.

**TABLE 2.1-2 Impact Factors
for Highways and Railroads
Versus Depth of Cover**

Installation Surface Condition		
Depth of Cover (feet)	Highways	Railroads
0 to 1	1.50	1.00
1 to 2	1.35	1.00
2 to 3	1.15	1.00
Over 3	1.00	1.00

Note: Data available from AREMA

increased potential for failure. Where buried pipe is subjected to large variations in cyclical surface loads, as in the case of pipe crossing under railroad tracks or highways, federal, state, or local regulations usually specify a minimum burial depth.²⁸ These typically vary from 3 to 6 feet, depending on the type of crossing, the type of excavation (rock or normal excavation), the pipe diameter, and the consequence of failure. For example, API RP 1102, “Steel Pipeline Crossing Railroads and Highways,” specifies a minimum depth of cover of 6 feet under railroad tracks and 4 feet under highway surfaces.

If the pipe is buried with less than 2 feet of cover, the continual flexing of the pipe may cause a breakup of the road surface. If the pipe is mortar-lined or coated, the deflection limit due to the cyclic live load should be limited to an amplitude of 1%.

2.1.8.5 Buoyancy

Burying pipelines beneath the natural water table creates unique problems and challenges. During periods of saturation of the aquifer, pipeline segments may become buoyant, even when filled with product. This results in a net upward force on the pipeline segment that could be sufficient to compromise the pipe’s integrity. When such conditions are anticipated, special construction techniques need to be employed. Anchoring devices or concrete coatings over the corrosion coatings are installed to help the pipe resist the buoyant force. Mechanisms to reduce the hydraulic pressure of the groundwater in the local area of the pipeline can also be successfully applied.

2.1.8.6 Movements at Pipe Bends

When unusual internal or external forces are applied to the pipe, it is most likely to respond to such forces by moving at the apex of sidebends, sagbends, and overbends. Forces that can cause pipe movement can include a net outward force generated by internal pressure, thermal expansions or contractions of the pipe due to temperature extremes, hydraulic pressures from groundwater, or seismic activity in the vicinity of the pipe. Natural resistances to such forces include the axial stiffness of the pipe itself, the bearing and shear resistance of backfill and overburden materials, and the extent to which those materials were compacted during construction.

2.1.8.7 Mine Subsidence

Areas where extensive longwall mining of coal or other resources has occurred represent an increased potential for surface subsidence if mine reclamation activities were inadequate or not performed. Although such mining can occur to depths greater than 1,000 feet, collapse of a mined cavity can affect all overlying strata, causing bending and sagging of each and ultimately forming a subsidence basin at the surface. Typically, the area covered by such subsidence basins

²⁸ See, for example, DOT OPS regulations in Title 49, Part 195, of the *Code of Federal Regulations* (CFR).

is substantially larger than the collapsed mine cavity that caused it. The vertical displacement is greatest at the center of a subsidence basin, but is typically less than the original height of the collapsed cavity. Vertical displacement as well as tilting and shearing forces throughout the basin are of greatest concern for surface structures that lie within the basin's footprint. Forces on buried linear features within the basin's footprint are unique. The bending moments of the sagging overburden strata result in horizontal forces that behave as tensile forces on the outer portions of the basin and compressive forces closer to the center of the basin. Depending on its exact location within the basin, a buried pipeline can be subjected to both forces. The strengths of these forces may be sufficient to buckle pipe or tear pipe connections apart.

2.1.8.8 Effects of Nearby Blasting

Blasting in the vicinity of a pipeline typically occurs as a result of mining or nearby construction activities. While normally an issue for existing pipelines, blasting effects may be considered for new designs if future land-use plans are known to include the construction of an adjacent pipeline or the development of mined areas. Pipeline stresses generated by nearby blasting can vary greatly, depending on local variations in site conditions, the degree to which the blast is confined, delays between multi-shot blasts, and the type of explosive used. Expressions for peak radial ground velocity (of the resulting pressure wave) and peak pipe stress are based on characterizing the blasting configuration as corresponding to either point or parallel-line sources.

2.1.8.9 Fluid Transients

Rapid changes in the flow rates of liquid or two-phase piping systems can cause pressure transients that generate pressure pulses and transient forces in the piping system. The magnitudes of these pressure pulses and force transients are often difficult to predict and quantify. As a result of water hammer, an unbalanced impulsive force called a "thrust" load is applied successively along each straight segment of a buried pipe. This causes a pressure imbalance between consecutive bends. Such hammering actions, if sufficiently strong and continued over long periods of time, can compromise the pipe's integrity or introduce fatigue stress cracks.

2.1.8.10 In-Service Relocation

It is commonplace to relocate short pipeline segments without taking the pipeline out of service. The process involves careful excavation of the pipe, raising it out of its original trench, and placing it into a prepared parallel trench. Obviously, the new path for the pipeline must be located generally adjacent and proximate to the original path for this relocation to occur without the need of adding new pipe segments. Causes for such relocations include accommodating a new highway or rail crossing, performing over-the-ditch coating renovation, inspecting or repairing pipe submerged in shallow water, or avoiding encroachment. Even though the physical displacements of the pipe are minimal, the newly positioned pipe will be subjected to new longitudinal stresses during its move and thereafter.

2.1.8.11 Earthquakes and Landslides

Landslides involve the mass movement of native surface and subsurface materials in the uppermost portions of the soil mantle at a moderate to rapid rate (generally greater than 1 feet/year). Landslides that are characterized as catastrophic in their impacts typically involve mass movements that are many orders of magnitude more rapid. However, landslides can also involve slow creep of materials over a relatively long period of time to a point where adverse impacts result. In most instances, the movement is downslope as a result of gravitational forces, often aided by water. Landslides are initiated by a variety of forces and events, both natural (e.g., earthquakes, seismic activity, excessive saturation of surface and subsurface soils, and volcanism) and anthropogenic (e.g., nearby use of explosives, surface disturbances on steep slopes brought about by construction activities without appropriate mitigation, clear-cutting of vegetative cover, improper use of herbicides, improper management and release of precipitation). Potential earthquake and landslide impacts to buried pipelines include transitory strains caused by differential ground displacement and permanent ground displacement from surface faulting, lateral spread displacement, soil mass displacement, and settlement from compaction or liquefaction.²⁹

2.1.8.12 Scour at Stream Crossings and Suspended Rock Crossings

Pipelines buried beneath or adjacent to rivers can be compromised over time by the erosive force of the moving water. Scouring can occur that would displace the cover materials and expose the pipe, subjecting it to additional lateral forces and possibly even causing sufficient displacement to break the pipe.

High velocities of water in rocky areas or watercourses with steep banks have the highest scouring potential. Areas prone to flooding can also experience excessive water flow velocities during those periods that can also result in scouring action. The typical response to traversing rivers or drainage ways with high scouring potential is to bury the pipe at greater depths or to suspend the pipe above these areas. In addition, major river crossings are required to be inspected every 5 years for indications of scour and/or exposed pipe.

2.1.9 Leak Detection³⁰

Beginning on July 6, 1999, under Title 49, Part 195, of the *Code of Federal Regulations* (49 CFR Part 195), DOT's OPS required all controllers of hazardous liquids pipelines engaged in

²⁹ A common consequence of earthquakes or other events involved in severe ground shaking is liquefaction of surface materials. Typically liquefaction occurs in soils where the pore space between soil particles is saturated with free water. The shaking of the ground causes the water in the pore spaces to exert such force on the soil particles that they begin acting independently of one another, resulting in the entire mass of soil taking on the properties of a liquid capable of rapid movement and displacement.

³⁰ Alaska Department of Environmental Conservation, *Technical Review of Leak Detection Technologies – Volume 1: Crude Oil Transmission Pipelines*. Available at <http://www.dec.state.ak.us/spar/ipp/docs/ldetect1.pdf>. (Accessed July 5, 2006.)

pipeline leak detection to conform their programs to the objectives contained in the API document API 1130, "Computational Pipeline Monitoring."

Methods used to detect product leaks along a pipeline can be divided into two categories, externally based (direct) or internally based (inferential). Externally based methods detect leaking product outside the pipeline, and include traditional procedures such as ROW inspection by line patrols, as well as technologies like hydrocarbon sensing via fiber optic or dielectric cables. Internally based methods, also known as computational pipeline monitoring, use instruments to monitor internal pipeline parameters (i.e., pressure, flow, temperature, etc.), which are inputs for inferring a product release by manual or electronic computation (API 1995a).

The method of leak detection selected for a pipeline depends on a variety of factors including pipeline characteristics, product characteristics, instrumentation and communications capabilities, and economics (Muhlbauer 1996). Pipeline systems vary widely in their physical characteristics and operational functions, and no one external or internal method is universally applicable or possesses all of the features and functionality required for perfect leak detection performance. Small leaks on large pipelines are very difficult to detect through these automated and measurement methods.

However, the chosen system should include as many of the following desirable leak detection utilities as possible (API 1995a):

- Possesses accurate product-release alarming,
- Possesses high sensitivity to product release,
- Allows for timely detection of product release,
- Offers efficient field and control center support,
- Requires minimum software configuration and tuning,
- Requires minimum impact from communication outages,
- Accommodates complex operating conditions,
- Is available during transients,
- Is configurable to a complex pipeline network,
- Performs accurate imbalance calculations on flow meters,
- Is redundant,
- Possesses dynamic alarm thresholds,

- Possesses dynamic line pack constant,
- Accommodates product blending,
- Accounts for heat transfer,
- Provides the pipeline system's real-time pressure profile,
- Accommodates slack-line and multiphase flow conditions,
- Accommodates all types of liquids,
- Identifies leak location,
- Identifies leak rate,
- Accommodates product measurement and inventory compensation for various corrections (i.e., temperature, pressure, and density), and
- Accounts for effects of drag-reducing agent.

An overview and evaluation of some of the various commercially available systems for use in liquid pipeline leak detection is available from the Alaska Department of Environmental Conservation website.³¹

2.1.10 Overpressure Protection

A pipeline operator typically conducts a surge analysis to ensure that the surge pressure does not exceed 110% of the maximum operating pressure (MOP). The pressure-relief system must be designed and operated at or below the MOP except under surge conditions. In a blocked line, thermal expansion is a concern, especially if the line is above ground.

2.1.11 Valve Spacing and Rapid Shutdown

The spacings of valves and other devices capable of isolating any given segment of a pipeline are driven by two principal concerns: (1) maintaining the design operating conditions of the pipeline with respect to throughput and flexibility and (2) facilitate maintenance or repairs without undue disruption to pipeline operation and rapid shutdown of pipeline operations during upset or abnormal conditions. Valve spacing and placement along the mainline are often selected with the intention of limiting the maximum amount of material in jeopardy of release during upset conditions or to isolate areas of critical environmental concern to the greatest extent

³¹ <http://www.dec.state.ak.us/spar/ipp/docs/ldetect1.pdf>. Follow the link to "Leak Detection Technology Evaluation." (Accessed December 7, 2006.)

possible. Valves designed to prevent the backward flow of product in the event of a pump failure (check valves) will also be installed in critical locations. Valves may also be required on either side of an exceptionally sensitive environmental area traversed by the pipeline. Finally, valves will be installed to facilitate the introduction and recovery of pigs for pipeline cleaning and monitoring. They also are required to be installed at river crossings over 100 feet wide. The design of these must comply with regulations and industry best practices.

2.1.12 Pumps and Pumping Stations

Desired material throughput values as well as circumstantial factors along the pipeline route are considered in designing and locating pump stations. Desired operating pressures and grade changes dictate individual pump sizes and acceptable pressure drops (i.e., the minimum line pressure that can be tolerated) along the mainline; grade changes also dictate the placements of the pump stations. Pump stations are often fully automated, but can also be designed to be manned and to include ancillary functions such as serving as pig launching or recovery facilities or serving as the base from which inspections of mainline pipe are conducted. Because there are a multitude of ways in which the desired operating conditions can be obtained and sustained, the outfitting and location of pump stations are also often influenced by economics, typically representing a compromise between few large-capacity pump stations and a greater number of smaller-capacity stations. The overall length of the pipeline (to its terminal destination) and the flexibility needed to add or remove materials along the course of the pipeline also dictate pump station placement.

At a minimum, pump stations include pumps (components that actually contact the fluids in the pipeline and provide kinetic energy) and prime movers (power sources that provide power, typically some form of mechanical energy) to the pumps. To facilitate maintenance and to prevent disruptions of pipeline operation as a result of equipment failure, most pump stations use several pumps arranged in parallel fashion. Typically, all but one of the pumps is capable of producing the desired operating pressures and throughputs, so some pump is constantly off-line and in standby. Pump stations also represent locations where ownership or custody of the material is transferred. For the sake of accountability, such pump stations are also equipped with flow monitoring devices. Pump stations typically also have colocated facilities that support pipeline operation or facilitate shutdowns or maintenance on pipeline segments. Thus, breakout tanks for temporary storage of materials or for use in managing line pressures and controlling product surges are also present at pump stations. Finally, pump stations are, in some instances, colocated with terminal or breakout tankage facilities.

Although certain pump designs are preferred for certain applications, all pumps require regular maintenance and are subject to failure from a variety of factors. Pump maintenance, therefore, is critical to continued safe performance of pipeline systems.

2.1.12.1 Pump Designs

Pumps of various designs are used in crude oil and petroleum product pipelines. Selection of pump design is based on desired efficiency as well as the physical properties of the materials being moved, especially viscosity and specific gravity. The pump's head pressure, or the pressure differential it can attain, is critical for selecting pumps that are capable of moving fluids over elevation changes.

Two fundamental pump designs are in common use: centrifugal pumps and positive displacement pumps. Centrifugal pumps are preferred for moving large volumes of material at moderate pressure, while positive displacement pumps are selected for moving small volumes of material at higher line pressures. Centrifugal pumps consist of two main components: the impeller and the volute. The impeller, the only rotating component of the pump, converts the energy it receives from the force that causes its rotation into kinetic energy in the fluid being pumped, while the volute converts the kinetic energy of the fluid into pressure. Positive displacement pumps can be of various designs; however, two designs predominate in pipeline applications: reciprocating and rotating pumps. Rotating pumps are often the pump design of choice for viscous fluids such as crude oils. Unlike a centrifugal pump where power demands rise sharply with increasing fluid viscosity, the performance of rotating pumps is generally unaffected by variations in either fluid viscosity or line pressure.

2.1.12.2 Driver Selection

The component that actually provides power to the pump is referred to as the prime mover. A wide variety of primer movers are in use, including electric motors, gas turbines, and diesel internal combustion engines. In recent years, most long-distance transmission pipelines have begun using electric motors or gas turbines. Virtually any prime-mover pump design combination is possible, with decisions resting primarily on the physical properties of the fluids being pumped, the desired throughputs, operating pressures, and transport speeds for the pipeline and for logistical needs such as meeting operating parameters, availability of power or fuel for the prime mover, and compatibility with SCADA systems in use and the sensors they rely on. Initial costs and maintenance demands can also influence selection. In terms of initial costs, electric motors are far less expensive than any other option. Operating costs (measured as \$/brake horsepower/year) are generally uniform across all options; however, overall efficiencies of electric motors are substantially better than other options. When maintenance costs are considered, times between major overhauls of prime movers vary, with electric motors and industrial turbines expected to require the fewest overhauls over time (Kennedy 1993).³²

³² Cost data are from 1981 and may not be relevant any longer, since technologies for all of the prime movers have advanced; however, the relative costs between prime movers are expected to be generally unchanged.

2.1.13 Pigging Devices and Pig Launching/Receiving Facilities

Pipeline pigs come in a wide variety of sizes and designs. Pigs are inserted into the pipeline while it is operational and are carried along by the fluid being pumped. Because they are solid devices constructed of various materials including metal, plastics, and rubber derivatives, pigs must be removed before reaching the next pump. Typically, pig traps, launchers, and recovery facilities are colocated with pump stations. Pigs are designed to perform a wide array of functions. Their basic purpose is threefold: (1) provide a way to clean debris and scale from the inside of the pipe, (2) inspect or monitor the condition of the pipe, (3) or act as a plug or seal to separate products in multi-product commercial pipelines or to isolate a segment for repair without depressurizing the remainder of the pipeline. Pigs designed to clean the pipe can use mechanical means (often called scraper pigs) or chemicals. Pigs that monitor the condition of the pipe are categorized as in-line inspection tools. Monitoring pigs, also sometimes called “instrument pigs” or “smart pigs,” can perform a wide variety of functions. Geometry pigs check for deformation of the pipe (which can greatly influence throughput efficiencies, but can also be an early indicator of significant problems that could compromise pipeline integrity). Pipeline curvature, temperature and pressure profiles, bend measurements, corrosion detection, crack detection, leak detection, and product sampling represent some of the other major functions performed by smart pigs. Magnetic flux leakage and ultrasonic technologies are employed for some of these inspections. Another type of pig recently developed is the gel pig. As the name implies, gel pigs consist of a series of gelled liquids that are introduced for a variety of purposes, including serving as a separator between products in a multi-product pipeline, collecting debris (especially after initial construction or repairs that involved opening the pipeline, and dewatering the pipeline. Figure 2.1-2 provides examples of the various types of pigs in use today, while Figure 2.1-3 depicts the typical configuration of a pig launching/recovery facility.

2.1.14 Distribution Terminals

Marketing and distribution terminals temporarily store products removed from the pipeline. There also may be loading racks and transfer operations. In most instances, terminals are proximate to, but not necessarily within the pipeline ROW, even if the terminal is owned and operated by the pipeline operator.

2.1.15 Measurement and Flow Control

2.1.15.1 SCADA

A typical SCADA system collects data from, and supervises control of, third-party programmable logic controllers at each of the pipeline’s pumping stations, mainline valves, and other areas where monitoring of critical conditions takes place. Along the entire length of the pipeline, block valves are remotely monitored and controlled using advanced real-time SCADA processors designed to support complex remote applications. The communications for the system



FJR and JRN Cleaning Pigs



PitBoss™ Cleaning Pigs



SG-2 and LG-2 Gauging Pigs

IH10703

**FIGURE 2.1-2 Examples of the Types of Pigs in Use Today
(Source: Photos courtesy of T.D. Williamson, Inc.
Reproduced with permission.)**

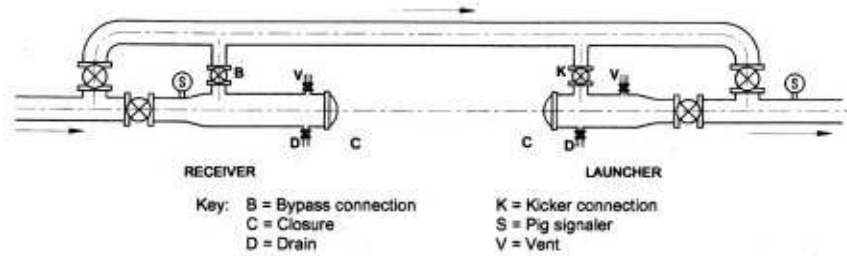


FIGURE 2.1-3 Pig Launcher/Receiver (Source: Image courtesy of the Piggings Products and Services Association. Reproduced with permission.)

is typically over the Ethernet and fiber optic lines as the backbone, backed up by public switched telephone networks.

SCADA system designs vary widely, but there are elements common to all. Operational data for liquid pipelines must be gathered from locations that are distributed widely across large geographical areas. Measurement transducers are polled frequently. To efficiently perform basic functions, data must be accessible by operations personnel located in the field and at a central pipeline control center. Operations are monitored and controlled using SCADA systems that provide thousands of data signals to pipeline controllers and operators. Some data are provided at intervals of a few seconds, other data are provided at intervals of a few minutes, and still others on an hourly or daily basis. As data are updated, the superseded older data are normally stored for a period of time to support system audits, identify trends (both good and bad), and establish a historical operating record.

SCADA systems are configured with a variety of instrumentation. Electrical signals from measurement devices are typically converted to engineering units in computers, referred to as remote terminal units (RTUs), which are located at measurement sites. Communication links are provided by radio, cell phone, private microwave, leased line, or satellite. Polling frequencies can be predetermined or on-demand.

Data from a given area of operations are often concentrated in computers at field offices, which are distributed throughout the pipeline system. SCADA software running on these field computers provides operational data and control to local operations personnel. Central computers located at a company's pipeline control center, in turn, poll field computers. SCADA software runs on the central computers to provide pipeline controllers with displays of operational data and remote control capabilities.

With so much data available at such high frequency, the effectiveness of the SCADA system hinges on appropriate data presentation, analysis, and alarming. A variety of data presentations are used to transform basic data into information. Trends, schematics, and other graphics are used to convey large amounts of data, which vary over time, in a concise and informative format. Often operational data is superimposed on facility and pipeline schematics, permitting presentation of the data in an operational context. Alarms are used to indicate that operating conditions are approaching or have exceeded prescribed tolerances. Attention can then

be focused on problem diagnosis and appropriate actions. In addition to data collection and display, SCADA systems also often include data validation programs that seek to validate each piece of data before using it to support a calculation or represent a condition. Frequent and, in some cases, continuous data validation has been shown to greatly increase the sensitivity of the system while reducing incidents of false alarms.

SCADA systems at remote control centers provide operators with complete operational information about the pipeline system in one location. Typical information includes:

- *Pipeline mimic/displays.* The complete pipeline can be mimicked to provide the operator with instantaneous visual feedback on the status of any portion of the pipeline, including pumps, valves, tanks, etc. These visual schematics include overviews of the entire pipeline system or systems and drill-down screens that take the viewer to an individual location or piece of equipment.
- *Pump, compressor, and other equipment status.* Equipment operation can be displayed with status (on/off) and other critical parameters associated with a piece of equipment such as flow, discharge pressure, vibration, case temperature, etc.
- *Valve status.* Valve information can be displayed with valve positions (open/throttle/closed) depicted.
- *Alarms and alerts.* Alarms and other operational indications are immediately available for operator response where complete system status is known and, in many cases, can be displayed. These can alert the controller to an unusual or abnormal operating situation or remind the controller about upcoming operating changes that need to be initiated. Often, system configurations allow the operator to intervene to validate the alarm or to take the necessary corrective actions. When operator intervention does not occur within a prescribed time frame, the system will automatically initiate actions that have been predetermined as being appropriate, given the circumstances.
- *Analytical tools.* Trending history and other analytical tools and graphical aids are available to assist personnel in their decision making under routine, abnormal, and emergency conditions.

The SCADA system is the central feature of a remote control center. Because the flow of product in the pipeline is typically a 24-hour-a-day, 7-day-a-week operation, the remote control centers are staffed continuously in order to monitor and maintain this round-the-clock operation. Due to the data being transmitted from potentially many miles away, the operator oftentimes must respond to the alarm and direct a corresponding response from the remote control center based on the information depicted on the display provided by the SCADA system; however, in other cases, decisions are made in conjunction with personnel located in the field at the affected location(s).

2.1.15.2 Telecommunication Towers

In all SCADA systems, the master terminal unit (MTU) and RTUs communicate through a defined network of some type. The early systems utilized wired communications, either private hard-wired systems owned by the operator (usually practical only for short distances) or the public switched phone network. Today there are still many systems using public phone systems, encompassing both wire and fiber optics technology. These facilities allow remote monitoring of the pipeline and communication with valves, compressors, and personnel during operation.

Most new systems, and many retrofits, are using some form of wireless communications. Many pipelines own their own microwave infrastructure, including dedicated towers and radio frequencies licensed by the Federal Communications Commission. There are also systems using frequencies in the very high frequency (VHF) and ultrahigh frequency (UHF) ranges. These operators may own the communication towers or lease space on towers from other communication system operators. Many newer systems make use of low-power radio transmissions, such as spread-spectrum technology, to avoid the licensing requirements. Satellite communications are also used for long-distance and rugged-terrain communications.

SCADA systems can also operate on cell phone technology, such as the Cellular Digital Packet Data. This requires no dedicated lines or other infrastructure, such as an antenna tower. Some SCADA systems operate directly through the Internet, thus eliminating certain maintenance concerns for the operator, but also simultaneously introducing cyber security concerns.

2.1.16 Risk of Natural Hazards and Human Threats

Natural and man-made hazards, such as shaking from earthquakes, flooding, and even human chemical, biological, or nuclear attacks can cause harm to pipeline components, such as pump stations, pipelines segments, and storage tanks, etc. Information in the following paragraphs was adapted from guidance published by the American Lifelines Alliance (ALA) and the Federal Emergency Management Agency (FEMA) (ALA and FEMA 2005). Table 2.1-3 provides a summary of the degree of vulnerability of each type of pipeline component to damage or disruption by these natural or man-made disasters.

2.2 COLOCATION ISSUES IN CORRIDORS

Colocation of energy transmission systems within designated energy ROWs may result in some interference between the systems or other hazards that would not exist except for the physical proximity of the two transmission systems. The paragraphs below identify some of the possible unique consequences of colocation of such systems within an energy ROW.

2.2.1 Fire Hazards

The proximity of pipelines carrying volatile materials raises the potential of a fire in one transmission system causing heating, stress, and/or rupture in another one. The normal distance between buried pipelines will probably prevent significant transfer of heat underground. However, care should be taken at locations where the pipelines exit the ground, such as at pump and compressor stations and road/river crossings, to ensure adequate separation of lines and facilities or additional insulation and fire protection.

In the event of a fire in a petroleum pipeline, overhead electricity transmission lines could be damaged if adequate distance is not maintained.

2.2.2 Coincident Construction

Coincident construction of two separate energy transmission systems within a designated corridor raises some potential problems if the construction activities are not well coordinated and well scheduled. Because of the proximity of two major construction activities, workers on one construction project may be exposed to hazards of the other. Logistics become quite complicated with both construction activities vying for the same transportation services and the same equipment laydown areas and using the same access roads to approach their respective construction sites with manpower and heavy equipment. On the other hand, with construction activities closely coordinated, impacts could be lessened, since opportunities are created for multiple uses of access roads, laydown areas, and other support systems that may be common to both construction processes.

2.2.3 Electrical Interference

The question of the impact of the collocation of metallic pipelines and high-voltage transmission lines can be framed by three broad concepts: (a) influence, (b) coupling, and (c) susceptibility. Other issues that add to the overall impact are identified and discussed below. *Influence* can be thought of as the sum total of the magnetic induction and ground-return currents. *Coupling* can be thought of as the “distance” between the source of the magnetic induction (power line) and the objects being affected (pipelines). *Susceptibility* relates to the vulnerability of the induction element (i.e., the metallic pipeline) to induced and ground-return currents.

Collocation may mean that the pipelines are located on an electric utility ROW directly underneath the power lines, usually buried in earth. This is the worse case for the coupling of magnetic induction currents, since the separation between the power line and the pipeline is very small. Thus, the full effect of the magnetic induction from the power line into the pipeline takes place.

TABLE 2.1-3 Degree of Component Vulnerability to Damage or Disruption from Natural Hazards and Human Threats

Hazards	Degree of Vulnerability									
	Transmission Pipelines	Pump Stations	Compressor Stations	Processing Facilities	Storage Tanks	Control Systems	Maintenance and Operations Buildings and Equipment	Pressure Regulating/Metering Stations	Distribution Pipelines	Service Lines or Connectors
Natural Hazards										
Earthquake shaking	L	M	M	M	H	M	H	L	L	M
Earthquake permanent ground deformation (fault rupture, liquefaction, landslide and settlement)	H	–	–	–	L	–	–	L	H (Buried)	M
Ground movements (landslide, frost heave, settlement)	H	–	–	–	L	–	–	L	H (Buried)	M
Flooding (riverine, storm surge, tsunami and seiche)	L	H	H	H	M	H	H	H	L	M
Wind (hurricane, tornado)	L (Aerial)	–	–	–	–	L	L	–	–	–
Icing	L	–	–	–	–	–	–	–	L	–
Collateral hazard: blast or fire	M	H	H	H	H	M	L	L	L	M
Collateral hazard: dam inundation	L	H	H	H	M	H	H	H	L	M
Collateral hazard: nearby collapse	–	L	L	L	–	L	L	L	M	L
Human Threats										
Physical attack (biological, chemical, radiological and blast)	M	M	M	M	–	M	M	–	M	–
Cyber attack	–	L	L	L	–	H	L	–	L	–

Note: Degrees of Vulnerability: H-High, M-Moderate, L-Low, and – (dash) for not applicable. Comments such as (Buried) or (Aerial) apply to location of the component listed as the column heading.

Alternating current (AC) induction will be reduced for power lines that parallel pipelines but are located to the right or left of the pipelines, rather than directly above. For example, the magnitude of the induced currents and voltages will be reduced by a factor that is inversely proportional to the distance from the centerline. As the separation between the power line and the pipeline increases, radically smaller values of current and voltage will be induced. In many cases, especially under ideal conditions, the induced currents and voltages would be minimal beyond 300 to 500 feet.

Each of the three broad concepts of influence, coupling, and susceptibility is highly variable for every situation, and each power-line and pipeline scenario must be considered separately. The system design, materials, and construction methods can themselves go a long way toward minimizing overall susceptibility of pipeline systems to magnetic induction and damage due to electrolysis and lightning.

The pipeline industry has devoted considerable attention to the potential problem of interferences presented by nearby electricity transmission systems. The mechanisms of electromagnetic interferences between power systems and nearby buried pipelines have been generally placed in one of three categories: inductive coupling, conductive coupling, and capacitive coupling (Li and Dawalibi 2006). Computer models have been developed to approximate the contributions of each type of interference on pipelines existing within various ROW scenarios and to predict the effectiveness of mitigative techniques (Dawalibi et al. 2006; Christoforidis et al. 2001; Borts et al. 2006). During normal operating conditions of the electricity transmission system, only inductive voltages are imparted to the pipeline as a result of the magnetic field around the electric current conductors. Interferences increase with decreasing physical separation and the angle between the power conductors and the pipeline, with the greatest interference levels being observed when the pipeline is parallel to and directly below the conductors. Interference also increases with increasing soil resistivity and with the increasing magnitude and frequency of the electric power being transmitted. The effects of abnormal conditions in the electrical system such as faults have also been investigated (Christoforidis et al. 2005). Faulted conditions can impart conductive interference to the pipeline. The magnitude of this conductive interference is influenced by such factors as soil resistivity, the electrical transmission line's grounding system, and the separation distance between the ground fault and the pipeline. During faults, both inductive and conductive interferences are present, placing in jeopardy both the pipeline and the pipeline workers in the vicinity.

Research sponsored by the Ductile Iron Pipeline Research Association has further established the factors that can influence the three coupling mechanisms of capacitance, conductance, and induction (Bonds 1999). The severity of the effect that overhead power lines can have on buried pipelines depends on a number of factors, including primarily the electrically continuous length of pipeline that is parallel to the overhead line, the strength and nature (e.g., number of phases) of the electric power, soil resistivity, the continuity of the corrosion control coating or other wrapping on the pipe, and how well the pipe is otherwise (electrically) insulated from the ground. Bare pipe that is in continuous contact with the ground is effectively at the same electrical potential as the neutral ground wires of the overhead lines, so there is little if any potential for current to flow between the two systems. Ironically, improvements in pipeline coatings applied for the purpose of corrosion control can be counterproductive with respect to

interferences from electricity transmission systems, effectively isolating the iron pipe from the ground and allowing considerable amounts of induced voltage to build up in the pipe.

Construction techniques can also greatly influence the extent of interference between power lines and buried pipelines. Pipeline segments are typically 20 feet long and connected to adjacent segments by rubber gaskets, effectively isolating each pipe segment and making the entire pipeline electrically discontinuous. As noted above, installation mechanisms that involve tightly wrapping the pipe and/or applying a continuous corrosion control coating can make the pipe more susceptible to interferences from induced currents of nearby power lines, since those techniques can prevent the pipeline from remaining at the same electrical potential as the ground (and as the neutral wire of the electricity transmission system). To overcome this problem, ductile pipe manufacturers recommend a loose wrapping of polyethylene that still provides sufficient path to ground to keep the pipe and the neutral ground wires of adjacent power lines at the same potential. Some mitigative techniques have been shown to not only reduce induced AC voltages effectively and economically, but to simultaneously provide cathodic protection for the pipeline (Southey et al. 1994).

As noted earlier, the precise alignment of the electric field with respect to pipeline orientation is critical to the severity of the potential interference. PC-based software is available that allows for calculation of both steady-state and fault-induced voltages on pipelines paralleling high-voltage overhead AC power lines.³³

Experience has shown that collocation of electricity transmission lines and buried metallic pipelines creates additional monitoring, testing, and/or preemptive actions by the pipeline operator, especially after certain events have occurred. The following conditions and potential problems are unique to colocated pipelines:

- *Phase fault currents.* Fault currents dumped to ground will naturally follow a path of least resistance involving the soil and the metallic pipeline. There can be many different scenarios depending on the resistance of the pipeline and the resistance of the surrounding soil.
- *Lightning strike currents.* Instantaneous lightning currents can be very high, in excess of hundreds of thousands of amperes. As a result, these currents can stress the electrical system such that breakdown and flashover occur at weak points, resulting in damage. If the damage is not repaired, there will be continued deterioration and ultimately system failure. An explosive effect may be associated with a direct lightning strike, which can cause significant damage not only to the electric system, but also to nearby buried pipelines. Thorough inspections of affected areas of the electricity transmission system, as well as nearby pipeline segments, are warranted after lightning strikes have occurred.

³³ See, for example, <http://www.prci.com/publications/L51835.htm>. (Accessed December 12, 2006.)

- *AC-induced corrosion.* AC-induced corrosion may result in significant metal loss and a significant threat to the integrity of the pipeline.
- *Impacts on pipeline cathodic protection systems.* Some pipelines are protected by an impressed-current cathodic protection system (CPS). A CPS is intended to minimize the loss of metal in the pipeline due to electrolysis. Because the currents applied in a CPS are typically quite low (in the milliamp range), nearby electromagnetic fields from electricity transmission lines can disrupt proper CPS operation. Interferences from nearby electricity transmission lines can be compounded where multiple pipelines exist, each with its own CPS. Increased monitoring of CPS function is warranted for pipeline segments in close proximity to electricity transmission systems.
- *Compromised insulating coatings and pipeline joints.* There may be damage to the pipeline insulating coating as a result of induced voltage. This can happen at underground sections of pipeline, as a consequence of the application of an excessive voltage stress across the pipeline coating. Likewise, insulating joints used to electrically isolate aboveground pipeline segments from those belowground, or to electrically isolate separate CPSs serving adjacent pipeline segments, can also be compromised by induced voltage.
- *Electrical shorts between carriers.* Many times, there can be electrical shorts between the CPSs of adjacent pipelines. When two independent CPSs exist, special field techniques are required to monitor for such shorts.
- *Polarized pipe.* Metal pipelines in proximity to electricity transmission lines may become electrically polarized, requiring special techniques to reveal the electrical potential differences between the pipe and the soil with which it is in contact; this is a critical consideration in designing and implementing an appropriate CPS for the pipeline.
- *Review, testing, and documentation of electrostatic or capacitive interference.* When electromagnetic interference is possible, studies are warranted to ensure the safety of personnel and other pipeline assets and that a CPS is not adversely affected.
- *Review, testing, and documentation of resistive or ohmic interference.* When lightning strikes a transmission structure, or when there is a phase-ground fault, it is important to measure and document the severity of the ohmic interference that has resulted and to verify that adverse impacts to nearby pipelines have not occurred.
- *Review, testing, and documentation of electromagnetic or inductive interference.* Phase imbalances in nearby electricity transmission lines can result in inductive interferences in metallic pipelines that are close to and

parallel with the transmission lines. Special investigations of adverse impacts to pipelines are warranted in the aftermath of such phase imbalance events.

- *Review, testing, and documentation of contact voltages.* Contact voltages may cause AC current to flow to ground through a person touching the line. Therefore, to ensure worker safety, measurements to identify the existence of such conditions must be routinely made and mitigative actions taken, when necessary.

3 PIPELINE CONSTRUCTION

Designing and constructing a pipeline is a major undertaking, requiring a wide variety of engineering and construction skills. While it is conceivable that a large pipeline operator would have the internal resources (both trained and experienced manpower and equipment) to undertake all phases of pipeline construction, it is more likely that virtually all of the major phases of construction will be contracted out to companies possessing the necessary expertise and capacities to complete the task. While that guarantees the critical requirements of pipeline construction will be met, it also introduces the need to control logistics to ensure that all contractor activities are coordinated and not mutually exclusive of one another.

Construction can take place within a relatively narrow ROW because pipeline construction equipment is distributed along the pipeline route in a type of “moving assembly line” in which only one major item of construction equipment is normally needed at any one point along the line. The distance along the pipeline over which this equipment is deployed is relatively short, typically less than a mile, but there may be several sets of construction equipment operational along the pipeline route at any given time. These complete sets of equipment — for ditching, welding, coating, lowering in, and backfilling — are called spreads. A single pipeline may be built using several spreads, reducing the overall construction period, but also increasing the amount of people and secondary resources required to support them. A very large pipeline project may even be divided into two or more segments, and different construction contractors may be used to install each segment. Various construction activities may also occur simultaneously on a number of segments. Each of these contractors may field several spreads to build a segment.

The actual installation of the pipeline includes these major steps:

1. Clearing the ROW as needed.
2. Ditching.
3. Stringing pipe joints along the ROW.
4. Welding the pipe joints together.
5. Applying a coating and wrapping the exterior of the pipe (except for the portions of the pipe at each end, which is sometimes coated before being delivered to the job site).
6. Lowering the pipeline into the ditch.
7. Backfilling the ditch.
8. Testing the line for leaks.

9. Cleanup and drying the pipeline after testing to prepare it for operation.
10. Reclaiming impacted environmental areas.

Brief discussions of each of these major steps are provided in the following paragraphs. Images representative of each topic are also provided to augment the discussion. However, many more images and engineering schematics are available than are provided below. The reader is invited to consult the following Internet websites, which provide additional imagery relating to pipeline siting and construction: http://www.uspipeline.com/html/photo_gallery.html and <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10595201>.

3.1 SCHEDULING

Summer to fall months offer the best times for construction in mountains, due to lower water tables and expected better weather.³⁴ Working around the clock may become more important for areas at higher elevations. For pipelines installed in lowland areas or areas that are perpetually wet, major construction may need to occur in the winter months when frozen ground allows access by heavy construction equipment with minimal damage. Likewise, pipelines crossing agricultural lands may need to be installed in the winter months to not disrupt agricultural activities. However, subfreezing conditions may preempt the application and proper curing of certain corrosion control coatings that, by necessity, must be field-applied.

3.2 PRECONSTRUCTION ACTIVITIES

3.2.1 Survey and Mapping

Numerous surveying and mapping operations are essential not only for pipeline construction, but to support various engineering decisions, including calculations of desired flow capacity of the completed system, foundation designs, pump sizing, and pump station spacing along the route. Surveying will also identify unique circumstantial factors that must be accommodated during construction (e.g., sensitive environmental areas, archeological or cultural resources) and possible interferences to construction and/or operation (e.g., nearby utilities, buried or otherwise). While many types of surveys are dictated by regulation, others are also routinely conducted as a matter of prudent industry practice. Various types of surveys are possible, each satisfying a specific purpose or need. The types of surveys typically associated with long-distance, land-based pipeline installation and operation are itemized below (Ricketts 2003).

³⁴ However, under certain conditions (e.g., perpetually wet areas), construction may best be conducted in winter months when the ground is frozen, allowing better and safer access to the ROW than might exist when the ground is not frozen. Construction during winter months may also be less disruptive to adjacent agricultural activities.

- *Geodetic surveying* takes into account curvature of the Earth. Applicable for large areas, long lines, and used to precisely locate basic reference points used for controlling other surveys.
- *Land, boundary, and cadastral surveys* are usually closed surveys that establish property lines and corners. Cadastral surveys are typically conducted only for public lands.
- *Topographic surveys* provide the location of natural and artificial features and the elevations used in mapmaking. Information on elevation (more precisely, elevation changes) is critical to the design and location of pump stations.
- *Route surveys* typically connect control or reference points by the most direct routes possible, given field conditions. Route surveys may need to be amended in those instances when the most direct route encounters obstacles or features to be avoided (e.g., severe grade changes, environmentally sensitive areas, etc.). Nevertheless, route surveys are conducted to establish the most direct paths between control points, which are then amended based on field conditions.
- *Construction surveys* are conducted during the construction phase to ensure design specifications are met.
- *As-built surveys* are conducted after construction has been completed as a way to verify that design specifications were met or to capture the changes to original design specifications that were required to be made to adjust to field conditions.
- *Hydrographic surveys* are required for all water crossings of pipelines to determine the shoreline and depths of the water bodies being crossed.
- *Satellite surveying* provides positioning data and imagery captured by satellites. Doppler and global positioning data are used as standard practice in remote regions and on subdivided lands where other ground-based reference points may not exist.
- *Global positioning system (GPS)* data are collected simultaneously by as many as 24 or a minimum of six high-altitude navigational satellites positioned in three orbital planes to precisely locate a point on the surface of the Earth.
- *Inertial surveying systems* are installed on helicopters or ground vehicles to acquire coordinate data that are then used to control precision of geodetic and cadastral surveys.

- *Photogrammetric data acquisition* derives from aerial photographs, unique terrestrial data, or other sensors that can be used to support any of the surveys described above.

3.2.2 Staging Areas

In addition to laydown areas along the ROW, on a large project, centralized pipeline staging areas may be located in nearby cities with rail offloading capability where pipe can be collected and prepositioned. These areas could be 15 to 30 acres in size. In addition, another 10- to 30-acre area may be required for use as a construction support yard that will serve as an assembly point for construction crews to meet prior to proceeding onto the ROW and for offices, storage trailers, and fuel tanks. See the additional discussion in Section 3.3.1 below.

3.2.3 Soil and Geology Studies

Soil deposits can be divided into six geologic groups: aeolian, alluvial, colluvial, glacial, marine, and residual. The Unified Soil Classification System classifies all soils as coarse, fine-grained, or predominantly organic. Physical properties of relevance include water content, degree of saturation, porosity (the volume of space between soil particles), and void ratio (volume of pore space to the total volume of soil). Index parameters for soils include the liquid limit, the plastic limit, the shrinkage limit, shear strength (the amount of force required to separate soil particles), deformability (changes of shape in response to external forces), and the relative density. Measuring and understanding these and other physical parameters of soil will allow design engineers to anticipate how the soil will behave under certain conditions, especially how it will react to external stresses. Arctic conditions present additional, unique challenges. For example, the presence of permafrost (free water in the pore spaces of uppermost layers of soil remaining frozen throughout the year) markedly changes the character and behavior of soils and must be accommodated by specialized construction and operation techniques. Of particular concern is the potential for latent heat of the commodity being transported to be transmitted to the permafrost, thus destabilizing pipeline installation. In areas of variable permafrost (i.e., permafrost that may occasionally melt and refreeze), pipelines are often installed above ground, along with special construction of support members to prevent heat transfer to the soil. Rock is commonly characterized by its type, degree of alteration (weathering), and continuity of the core from core samples. Rock quality indices include fracture frequency and rock-quality designation. Other considerations are floodplains, active earthquake areas, and hurricane and tornado risks.

3.3 CONSTRUCTION

Standard pipeline construction is composed of specific activities including survey and staking of the ROW; clearing and grading; trenching; pipe stringing, bending, welding, and lowering-in; backfilling; hydrostatic testing; and cleanup. In addition to standard pipeline construction methods, the pipeline construction contractor would use special construction

techniques where warranted by site-specific conditions. Rugged terrain, waterbodies, wetlands, paved roads, highways, and railroads all dictate special construction techniques.

Pipeline ROWs can vary in their cross-sectional details as they accommodate unique circumstantial factors or features. A comprehensive treatment of the various design variations that are required to address every conceivable circumstance is beyond the scope of this document. However, interested readers can consult the following Federal Energy Regulatory Commission (FERC) website for a more exhaustive display of ROW cross sections: <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10595201>.³⁵ Selected images from that website which exemplify the most typical situations encountered are reproduced below.

The typical ROW, as depicted in Figure 3.3-1, includes area for topsoil segregation, which is done in some situations.³⁶ Overburden soils are stockpiled to one side as the pipeline trench is dug. This typically requires an area ranging from 15 to 35 feet aligned parallel to the pipeline. Additional areas may be required to segregate topsoils. The other side of the pipeline

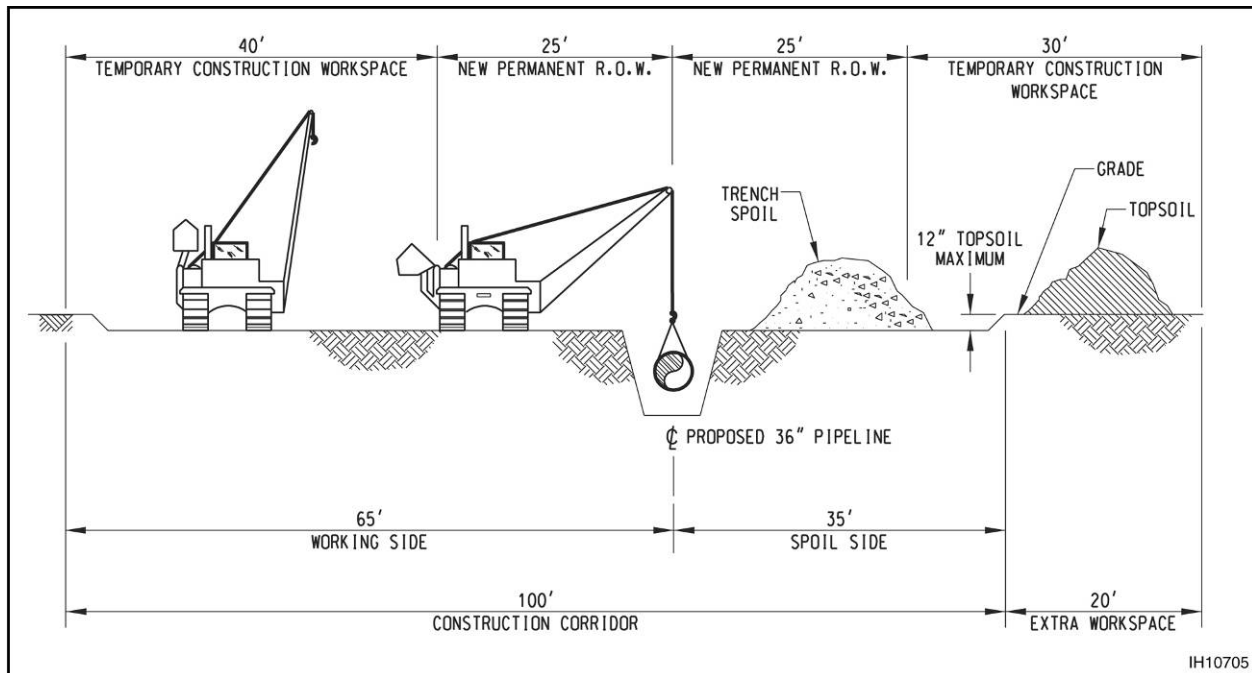


FIGURE 3.3-1 Typical ROW with Topsoil Segregation (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)

³⁵ This website provides access to Appendix D of the Final Environmental Impact Statement (FEIS) for the Golden Pass LNG Terminal and Pipeline Project issued by FERC in 2005. The entire FEIS is available electronically at <http://www.ferc.gov/industries/lng/enviro/eis/06-03-05-eis.asp>. (Accessed January 4, 2007.)

³⁶ In virtually all instances, the natural native soil horizon will be reestablished after pipeline installation is complete, and the disturbed area will be revegetated using indigenous plant species or species approved by the landowner. However trees and woody plants whose roots could compromise pipe integrity would not be replanted in the vicinity of the pipe.

trench is used for equipment access and work. This typically requires 25 to 30 feet, but can include additional workspace or staging areas. This construction area is wider at stream and river crossings to accommodate the additional construction requirements.

Figure 3.3-2 shows a typical ROW with an adjacent pipeline in place. In this example, the full 25-foot ROW boundary on each side of each pipeline is maintained and should be sufficient for two pipelines, since construction can take place to either side. However, if multiple pipelines are running in parallel and transmission systems of other types are present, such as power lines, issues of construction and maintenance repairs require further consideration. Section 2.1.8.2 provides further information on load and penetration risks.

In addition to the ROW shown in the above figures, additional laydown areas, typically 250 feet \times 450 feet (variable with individual project requirements and terrain) are adjacent to the ROW at intervals corresponding to the spreads being worked.

The ROW must be maintained free of trees and brush that could pose a fire hazard or obstruct visual identification of leaks. Trees and other woody plants also need to be eliminated from the ROW to prevent their roots from challenging the integrity of the pipeline by intrusion. Figure 3.3-3 below shows typical permanent ROW maintenance in forested areas.

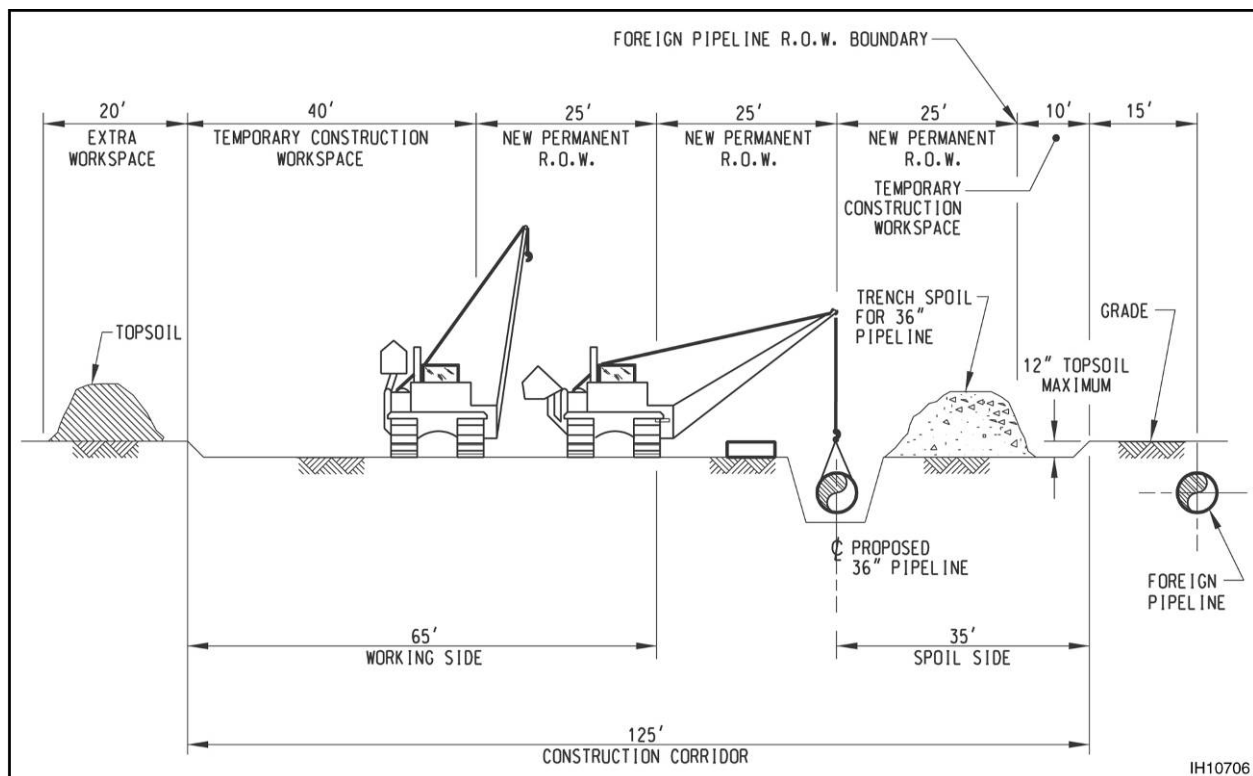


FIGURE 3.3-2 Typical ROW with Adjacent Pipeline (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)

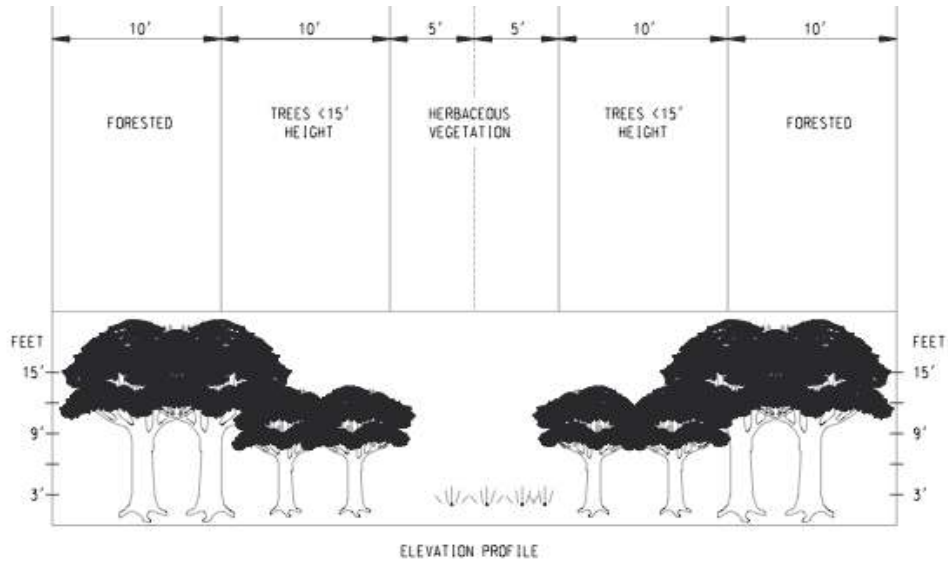


FIGURE 3.3-3 Typical ROW Maintenance in Forested Areas
 (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)

3.3.1 Movement and Staging of Pipeline Components and Construction Equipment

Pipe segments are normally delivered from their point of manufacture by rail to a rail off-loading yard conveniently located to the construction ROW (see Figure 3.3-4). From there, pipe segments are loaded onto flatbed trucks and taken to a material laydown yard that is temporarily maintained in an area close to the construction site (see Figure 3.3-5). Numerous laydown yards may be constructed to support individual pipe construction spreads. A truck typically carries a maximum of 20 pipe segments at a time; however, this varies by pipeline diameter, wall thickness, weight, and pipe stacking method. Trucks will make round-trips all day between rail off-loading areas and material laydown areas until all of the materials assigned to the laydown areas have been delivered. In areas with less road infrastructure, consolidation of crews and materials going to different spreads using the same public access roads is more likely, thereby potentially magnifying the impact. In addition to the laydown areas adjacent to the ROW, off-site staging areas used to collect equipment and workers could occupy several acres, but the amount of space would be highly dependent on the size and terrain of the project. Although their primary purpose is temporary storage of pipeline materials, laydown yards are also sometimes used for “double joining” two pipe segments before their delivery to the ROW. Laydown and staging areas could be in use from 3 to 12 weeks.

3.3.2 Clearing and Grading

The survey crew will carefully survey and stake the construction ROW to ensure that only the preapproved construction workspace is cleared. The clearing and grading crew leads the construction spread. This crew is responsible for removing trees, boulders, and debris from the



FIGURE 3.3-4 Pipe Segments Arriving at Rail Off-loading Area (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)



FIGURE 3.3-5 Pipe Segments in a Material Laydown Area (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

construction ROW and preparing a level working surface for the heavy construction equipment that follows. Depending on existing soil conditions, this may require bringing in additional materials such as stone and sand to create a temporary work road adjacent to the pipeline.

The clearing and grading crew is also responsible for installation of silt fences along the edges of streams and wetlands as necessary to prevent erosion of disturbed soil. Trees inside the ROW are cut down, roots are excavated; and timber is stacked along the side of the ROW for later removal. Brush is commonly shredded or burned.³⁷ The amount of clearing required varies widely. Sometimes only one pass down the ROW with a bulldozer is required. Where the route passes through rough or forested terrain, however, clearing operations can be much more extensive. The purpose is to make it possible to move construction equipment along the ROW as needed. The clearing and grading crew is also responsible for clearing and grading ROW access roads. As with the ROW, access roads from public roadways may also need to incorporate measures such as silt fences and stone or paved transitions, as shown in Figure 3.3-6. Construction access roads are removed and reclaimed after the construction phase; however, some will remain in place throughout the operating life of the pipeline for access to the ROW by maintenance and inspection personnel.

In virtually all circumstances, topsoils and subsoils are separately stockpiled adjacent to the trench. In most instances, the subsoil can be used to backfill the trench once appropriate bedding materials have been placed at the bottom of the trench and the pipe has been installed. An exception to this general procedure occurs when the subsoils contain rocks of varying sizes that could damage the pipe if they were used as backfill or when the subsoils are composed of heavy clays that would retain water in the vicinity of the pipe, thereby promoting accelerated corrosion. In those instances, appropriate backfill materials are brought to the site from the nearest practical source, and the original soils are disposed of elsewhere, typically under the auspices of a soil disposal permit or approved soil management plan.

3.3.3 Stringing Pipe Joints along the ROW

Normally, pipe segments are delivered to staging areas closest to the point along the mainline where they will be installed and then subsequently deployed along the ROW. This guarantees that each joint needs only to be moved over to the ditch when it is ready to be welded into the pipeline. Not only does this save cost and time, it also lessens the potential for damage to the pipe before installation. Figure 3.3-7 shows pipe segments being deployed along the ROW in preparation for welding and installation into the trench (not yet constructed in this photograph). In some rugged locations, pipe segments must be staged on the ROW with helicopters (see Figure 3.3-8). In those circumstances where longer lengths of pipe can be easily moved into place, pipe is brought to the job site in sections consisting of two single joints of pipe (typically, having an overall length of up to 40 feet). This “double-jointing” saves welding time on the job site, which often must be done under less desirable conditions than exist in a fabrication yard.

³⁷ Open burning of landscape waste will usually require a special permit issued by the local environmental regulatory authority.

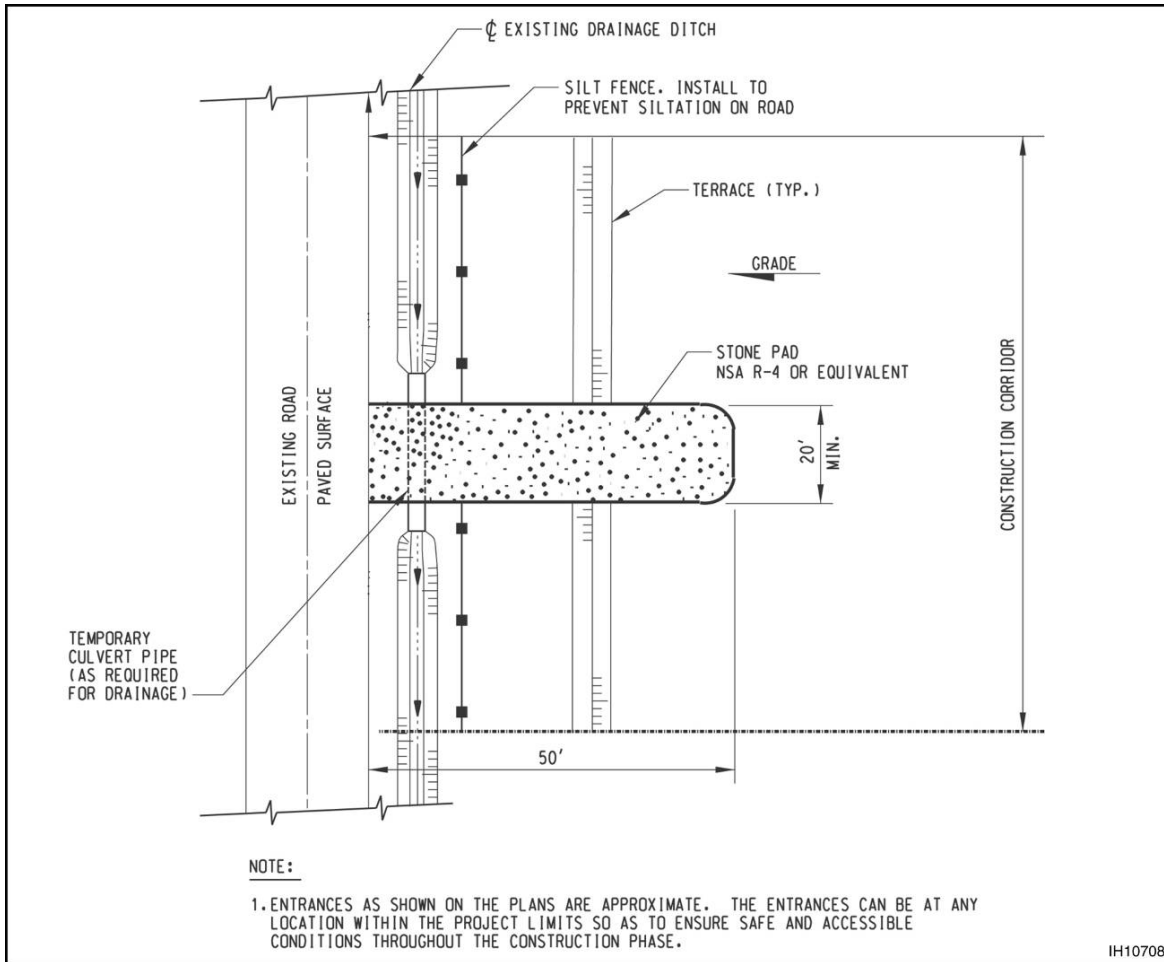


FIGURE 3.3-6 Sample Road Entrance to a Pipeline ROW (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)



FIGURE 3.3-7 Stringing Pipe along the ROW (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)



FIGURE 3.3-8 Delivering Pipe Segments to the Construction Site in Rugged Terrain May Require Special Equipment (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

3.3.4 Ditching (Excavation and Filling)

The ditch, or trench, in which the pipeline will be installed is usually made to one side of the center of the ROW rather than in the center, to provide adequate room for construction equipment and operations alongside the pipe as well as room for future installations. Ditching in relatively soft soil is done by a machine with a large wheel on which cutting teeth are mounted. The wheel rotates continuously as the machine moves along the pipeline route, and excavated material is continuously deposited alongside the ditch. In loose rock or hard soil, it may be necessary to use other equipment for trenching — for example, a backhoe or clamshell bucket. Blasting or special rock-cutting equipment may be required when the ditch must pass through solid rock.

The depth of the ditch is based on minimum cover specifications or the distance from the top of the buried pipe to the ground surface. For the same minimum cover requirements, a larger-diameter pipe requires a deeper ditch. The minimum cover varies according to requirements of

regulatory agencies, standard industry practice guidance, the type of area through which the pipeline passes, and features along the pipeline route. A minimum of 3 feet of cover is typical, but it may be less in open, unpopulated areas and more when the pipe passes under roads, rivers, and highway borrow ditches. Minimum cover for river crossings (the distance between the top of the river bed and the top of the pipeline) is set at 4 feet; however, additional cover may be necessary where scouring of river bed materials by moving water is possible. Most river crossings are directionally bored.

The width of the pipeline ditch varies according to the size of the pipeline. Typically, this width ranges from 14 to 28 inches for intermediate pipeline diameters. Figure 3.3-9 shows a typical ditching operation.

3.3.5 Pipe Bedding Material

Bedding material must be clean sand or soil and must not contain stones having a maximum dimension larger than 0.5 inch. Material must be placed to a minimum depth of 6 inches under the pipe and 6 inches over the top of the pipe. The remaining backfill must not contain rock larger than 6 inches. Organic material and wood are not permitted for bedding and backfill since they will deteriorate over time, allowing for subsidence and subsequent shifting and possible pipe damage.



FIGURE 3.3-9 Pipeline Ditching (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

3.3.6 Welding

Welding procedures and metallurgy should comply with the service of the system. Engineering standards published by the American Petroleum Institute dictate what welding techniques should be used (API 1991, 1999).

With the ditch made and the pipe delivered, welding can begin. The pipe joints are placed over the ditch for welding. As welding proceeds, a section of pipeline steadily increasing in length is in place above or alongside the ditch. Under some circumstances, pipe segments are lowered into their trench before being welded together. Pipeline welding is done with electric welding equipment, both manual and automatic. Welding machines are typically mounted on small trucks or pickups. The machines may also be mounted on tracked vehicles. A number of welders — each with a welding machine — work on each pipeline spread. Since a number of weld passes (a “bead” of weld material around the circumference of the pipe) must be made at each joint, a typical procedure is to have one welder make the initial passes at each joint. Other welders follow behind the lead welder, building up the weld metal at the joint by making additional weld passes until the appropriate number of passes have been deposited. The number of weld passes required depends on the wall thickness of the pipe and its physical characteristics, and is specified in the construction plans. The initial weld pass is one of the most critical aspects of pipeline construction and is carefully controlled and monitored.

It is important that the two ends of pipe to be welded are properly aligned so the weld will be uniform around the circumference of the pipe. Line-up clamps are used for this purpose at each joint before welding begins. After all passes have been made, the alignment clamps can be moved to the next welding station. Figure 3.3-10 shows typical welding operations, which, depending on individual circumstances, can occur either before or after the pipe is placed in its trench.

3.3.6.1 Welding Processes

The sources of heat for welding include electric arc, electric resistance, flame, laser, and electron beam. Most processes used in field pipeline welding employ a filler metal, do not involve the application of pressure, and depend on an electric arc as the heat source. Types of welding include:

- *Shielded metal arc welding.* The heat for this process is provided by an electric arc that melts a consumable electrode, with some of the metal being welded. When the weld metal cools, it hardens to form the weld.



FIGURE 3.3-10 Welding Pipe (Source: Photos courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

- *Submerged arc welding.* In this process, heat is supplied by an electric arc, and a consumable electrode is used. A granular flux composed of silicates and other elements is deposited on the weld joint. The arc melts some of the flux and is submerged in the liquid slag that is produced by this melting. The electrode in this method is wire that is fed continuously to the weld joint. The high currents used in this technique allow the weld to penetrate deeper below the surface of the pipe wall than is possible with other welding processes.

- *Gas-metal arc welding.* This process also uses the heat from an electric arc. The arc is covered by an inert gas, such as argon or helium. The insert-gas shielded metal arc process uses a consumable, continuous electrode.
- *Gas-tungsten arc welding.* An inert gas shield is required when welding with tungsten electrodes using the gas-tungsten arc welding process.
- *Electron beam welding.* Used primarily for offshore pipelines.

3.3.6.2 Welding Inspection

A key part of pipeline welding is inspection. For most projects, welders must be qualified by testing on the size and type of pipe to be used on the job. After the welds on the pipeline are made, however, they must be thoroughly examined to insure the safety of the pipeline. The most common inspection method relies on radiographic, or X-ray, examination of completed welds. Construction plans specify what type of inspection will be required and what portion of welds must be examined by each method. For instance, it might be specified that where the pipeline traverses open areas, 10% of the welds must be X-rayed, however, where the pipeline passes under railroads, highways, or rivers, all welds must be examined using radiography. In the X-ray inspection process, film wrapped around the circumference of the pipe over the weld is exposed to radiation. When the film is developed, bubbles, cracks, slag inclusions, and other defects are visible. It is desirable to make this inspection and find any defective welds before the pipe is buried because defective welds must be removed and new welds made.

Welding Inspection Requirements. Pipeline welding must follow written welding procedures outlined in 49 CFR Part 195, Subpart D. These procedures are qualified under the ASME Boiler and Pressure Vessel Code and API standards. Certain steels require separate qualification of welding procedures. Each welding procedure must be recorded in detail during the qualifying tests and the record retained for the life of the pipeline.

Nondestructive Testing (NDT). Nondestructive testing is the branch of engineering concerned with all methods of detecting and evaluating flaws in materials. Flaws can affect the serviceability of the material or structure, so NDT is important in guaranteeing safe operation as well as in quality control and assessing plant life. The flaws may be cracks or inclusions in welds and castings or variations in structural properties that can lead to loss of strength or failure in service.

Nondestructive testing is used for in-service inspection and for condition monitoring of the operating plant. It is also used for measurement of components and spacings and for the measurement of physical properties such as hardness and internal stress.

The essential feature of NDT is that the test process produces no deleterious effects on the material or structure under test. The subject of NDT has no clearly defined boundaries; it

ranges from simple techniques, such as visual examination of surfaces, through the well-established methods of radiography, ultrasonic testing, and magnetic particle crack detection, to new and very specialized methods such as the measurement of Barkhausen noise³⁸ and positron annihilation.

3.3.7 Pipe Bending

As welding proceeds along the pipeline, a slight change in direction or a significant change in elevation may require a bend in the pipeline. Many such bends are made by a bending machine on the job site that bends a joint of pipe to the required curvature (see Figure 3.3-11). Even large-diameter pipe can be accommodated in today's modern bending machines, but it may also be necessary to make some bends in a shop on a special machine. Depending on the diameter and the wall thickness of the pipe, slight changes in elevation may be accommodated by flexing the pipe without the bending machine. Very small changes in direction may sometimes be made by letting the pipe lie to one side of the ditch. But changes in direction or elevation without bending must be small, especially when large-diameter, heavy-wall pipe is being used.

3.3.8 Pipe Coating

If not precoated at the coating mill, the pipe exterior is coated and wrapped after welding is complete. Coating and wrapping are done using special machines that move along the pipeline ROW. Coal tar enamel is the most common pipeline coating; others include thin-film powdered epoxy and extruded polyethylene. Asphalt enamel and asphalt mastic are also used as pipe



FIGURE 3.3-11 Pipe Bending Machine

³⁸ Named after the German physicist, Heinrich Georg Barkhausen who first discovered the phenomenon, Barkhausen noise is the audible signal delivered by ferromagnetic materials as they realign their magnetic domains in response to externally applied alternating magnetic fields. Material testing methodologies utilizing the Barkhausen noise phenomenon (Barkhausen Noise Analysis or Micromagnetic Analysis) study the microstructures of materials and are capable of identifying the presence of stresses (e.g., in a pipe segment) and discontinuities (e.g., in a weld) that could indicate an increased potential for future structural failures.

coating materials. Tape is then wrapped over this coating to provide additional protection to the pipe and to protect the corrosion coating, especially through rocky areas that might damage the pipe coating.

In some cases, coating and wrapping are yard-applied to the pipe before the pipe is delivered to the job site (see Figure 3.3-12). When this is done, a short distance at each end of the pipe joint is left bare to permit welding. Then those areas are coated and wrapped over the ditch after welding is complete.

3.3.9 Lowering the Pipeline into the Ditch

When the welding and coating are complete, the pipe is suspended over the ditch by sideboom tractors, which are crawler tractors with a special hoisting frame attached to one side. Then the pipeline is gradually lowered to the bottom of the ditch (“lowering in”) (see Figure 3.3-13). In rocky soil or solid rock, it is sometimes necessary to put a bed of fine soil in the bottom of the ditch before lowering the pipeline. The fine fill material protects the pipe coating from damage.

3.3.10 Backfilling the Ditch

With new pipelines, or when conducting a maintenance activity for existing pipelines, backfilling and bedding must be provided in a manner that will offer firm support for the pipeline and not damage either the pipe or the pipe coating by the type of backfill material used or subsequent surface activities.

If the backfill material contains rocks or hard lumps that could damage the coating, care must be taken to protect the pipe and pipe coating from damage by such means as the use of mechanical shield material; backfilling procedures must not cause a distortion of the pipe cross section that would be detrimental to the operation of the piping and the passage of cleaning or internal inspection devices. Typical backfilling operations are shown in Figure 3.3-14.



FIGURE 3.3-12 Applying Coating to Pipeline



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FIGURE 3.3-13 Lowering Pipe into Trench
(Source: Photos courtesy of U.S. Pipeline, Inc.
Reproduced with permission.)

3.3.11 Hydrostatic Testing

All newly installed pipelines, including pipe segments that have been replaced in existing pipelines, undergo hydrostatic testing before being put into service. Hydrostatic testing involves isolating that portion of the pipeline undergoing testing, filling it with water, and then pressurizing the line to a specified pressure to check for leaks. U.S. federal safety regulations for pipelines require that pipelines used to transport hazardous or highly volatile liquids be tested at a pressure equal to 125% of the maximum allowable operating pressure (MAOP) for at least four continuous hours and for an additional four continuous hours at a pressure equal to 110% or more of the MAOP, if the line cannot also be visually inspected for leakage during the test. A batching pig driven ahead of the water is used to remove any air and forms an efficient seal to isolate that portion undergoing testing. Without a pig in downhill portions of the line, the water will run down underneath the air, trapping pockets at the highest points within the pipe. Long pipelines will normally be tested in sections; short pipelines may be tested as single units.



FIGURE 3.3-14 Backfilling Pipeline (Source: Photos courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

Temporary connections for filling and draining the pipeline are used, and a pump is used to “pressure up” the line. Once the specified pressure is attained, the pump is shut off and the “static” leak test commences. A leak is indicated if the pressure falls over the period of the test.

Once hydrostatic testing is completed, the water is removed and typically delivered to a wastewater treatment facility (e.g., a publicly owned sewage treatment works) for treatment. While the majority of the water will be removed simply by draining the water at appropriate locations along the segment undergoing a test, some water will still remain and will contaminate the subsequent product unless it is removed. Typically a pig is used that is designed specifically to capture water and deliver it to a point where it can be removed. This dewatering pig serves a dual purpose, removing water and also removing construction debris that may still remain in the pipeline and could be very damaging to downstream pumps, if not removed. Often, the pig is propelled along the pipeline by the products the pipeline was designed to carry, and once the pig

and the water it has captured have been removed, the pipeline is considered to be fully operational.

The water removal process described above is usually sufficient for crude oil and petroleum products. However, for some petrochemical feedstocks that would react adversely with water, additional steps are taken to remove the last vestiges of water before the product is introduced. Super-dry air, methanol, or inert gases such as nitrogen are typically used to flush the pipeline and capture any last remaining amounts of water.

3.3.12 Final Grading and Reclamation

Once backfill has been placed and properly compacted, the original topsoil is returned to its original location and final grading and contouring are performed. Depending on the vegetation reclamation plan that has been approved, reclamation of the disturbed area above the pipeline can begin at this time. Also at this time, as all construction work is completed for each spread, construction equipment is removed and the construction ROW is reclaimed. However, depending on access constraints, the construction road may remain in place until adjacent spreads are completed, if it provides the only access to those spreads. Figures 3.3-15 and 3.3-16 show final contouring of a pipeline ROW and a reclaimed ROW, respectively.



FIGURE 3.3-15 Final Contouring of Pipeline ROW
(Source: Photo courtesy of FERC)



FIGURE 3.3-16 Revegetated Pipeline ROW
(Source: Photo courtesy of FERC)

3.3.13 Special Conditions

3.3.13.1 Road, Railroad, and Waterbody Crossings

Even small pipeline projects often involve crossing roadways and streams; a long-distance pipeline may cross scores of each. A variety of techniques are used for crossing these obstacles, depending on the length of the crossing, the size of the stream or roadway, applicable regulations, and, where federal lands are involved, the extant policies of the federal land owner.

Road and Railroad Crossings. Crossing roadways or railroads can be done by either trenching or boring. When trenching, the roadway must be closed to traffic for some period of time. The road itself must be removed in that portion that overlays the pipeline and reinstalled after pipeline installation is complete. Because of the obvious disruptions to traffic flow that will result, this method is often not permitted for busy thoroughfares, and instead a trenching technique that will allow the road to remain in service would be used. Similarly, an analogous approach to crossing a railroad would require that a section of the railroad directly above the pipeline path be removed and reinstalled after pipe installation is complete. Again, trenching alternatives are available if disruption of rail service cannot be tolerated.

Virtually identical design considerations are made for road and railroad crossings. Of primary importance is a calculation of the maximum dynamic loading on the pipe from traffic or trains. This dictates the depth of cover between the road or railroad and the pipe and whether additional design features are added to disperse the load to a sufficient degree so as to not deform the pipe. A schematic of a typical trenched road crossing is shown in Figure 3.3-17.

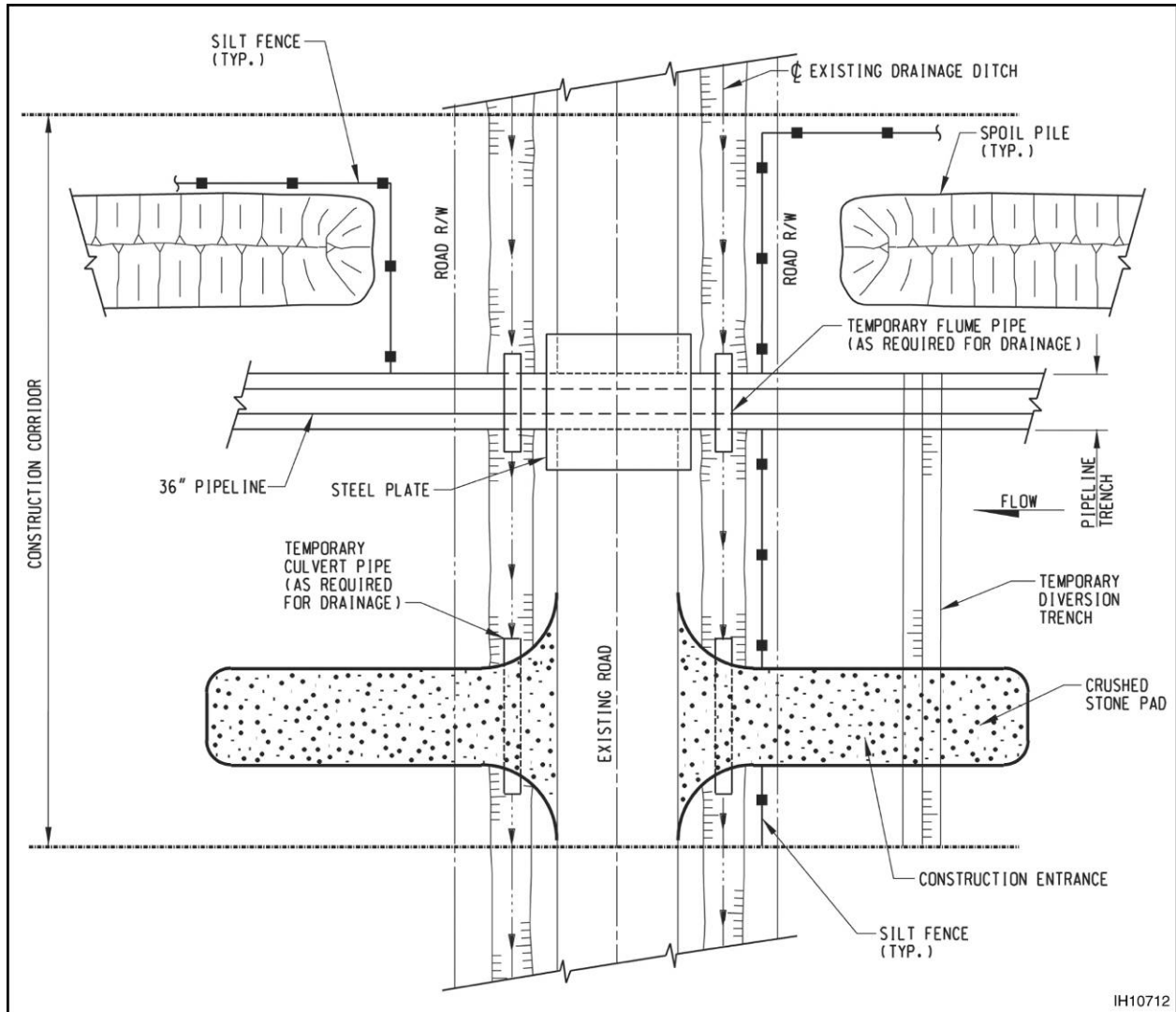


FIGURE 3.3-17 Trenched Road Crossing (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)

Boring is done with a horizontal boring machine that drills a hole under the roadway or railroad without disturbing the road surface or the trackbed. A casing pipe is normally installed in the bored hole, then the pipeline is placed inside the conductor. Spacers are used to center the pipeline within the conductor. This sleeve arrangement is effective not only in reducing the load on the pipe but also in reducing corrosion in the segment of the pipe underlying the roadway. The American Petroleum Institute document API RP 1102 provides guidance for pipelines running under roads. Generally, 4 feet of cover is adequate for pipelines 12 inches and smaller. Larger pipelines may require additional protection by way of more cover, pipe sleeves, or concrete slabs positioned above the pipe to disperse the dynamic loading from traffic and prevent deformation of the pipe. Figure 3.3-18 provides an example of a bored pipeline road crossing.

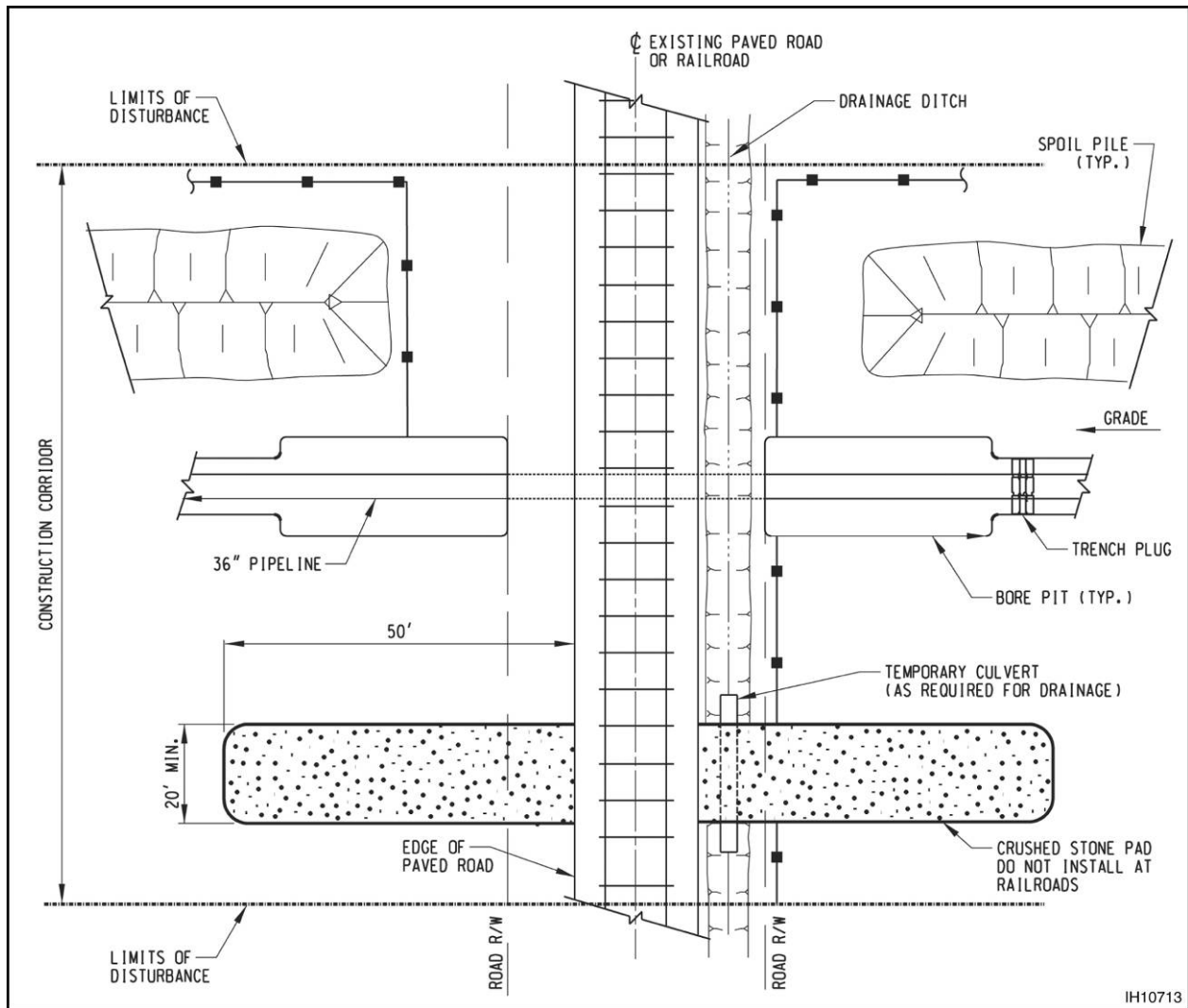


FIGURE 3.3-18 Bored Road/Railroad Crossing (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)

Waterbody Crossings. Strategies for crossing waterbodies depend on a number of site-specific factors, most importantly, the size and nature of the waterbody itself and the existing ecosystems. A schematic of a typical waterbody crossing is shown in Figure 3.3-19.

Stream and river crossings can be made in a variety of ways. The first is the open-cut wet (in-stream) method. A backhoe or dragline can be used in minor stream crossings to make a ditch for the pipe to rest in. This technique does not use any method to divert the stream. The pipe is installed and backfilled while the river/stream continues to run through the site. The ditch is then backfilled, and the pipe may be fitted with concrete weights to hold it in place against the stream currents and movement of stream bed sediments. The benefits are low cost and a quick completion time, making this the method of choice when existing regulations or policies do not require other techniques. Disadvantages include potentially significant pollutant and sediment runoff, greatly increased total suspended sediment concentrations downstream, changes in

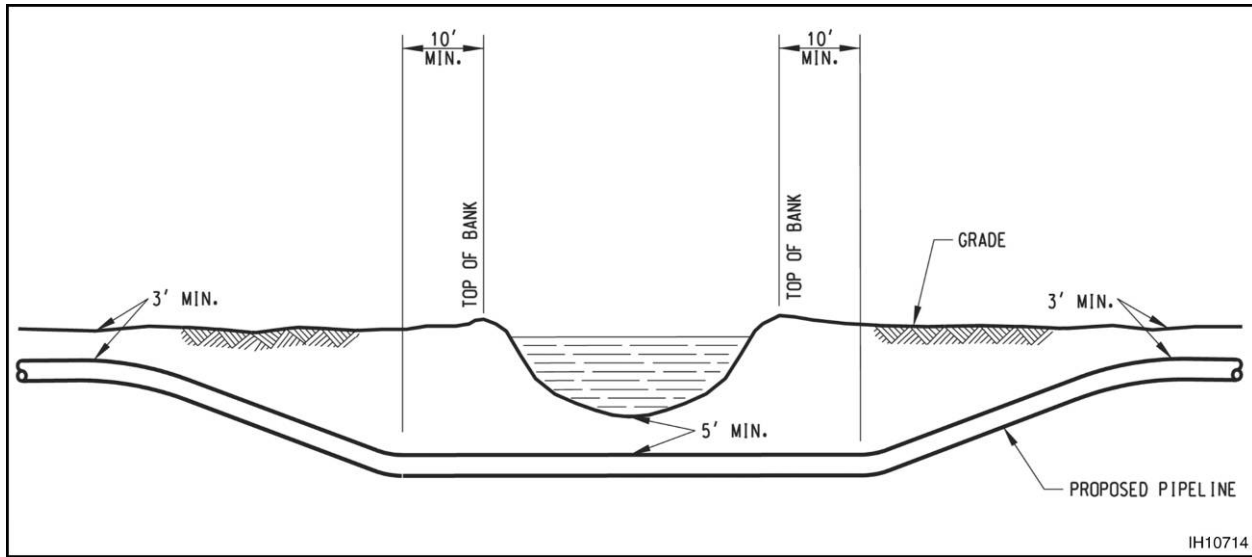


FIGURE 3.3-19 Typical Waterbody Crossing (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)

channel morphology, and impacts to aquatic ecosystems. These problems can be mitigated only by a quick completion time.

An alternative method of waterbody crossings is called the open-cut dry (isolated) method. Here the stream is isolated and diverted around the pipeline crossing. Then the trench is excavated, the pipe is installed and backfilled, and then water diversion structures are removed and the stream is allowed to restabilize over the buried pipe. It is best-suited for narrow streams and rivers with flows less than 141 cubic feet per second. The two main methods of isolated crossings are the dam-and-pump method (see Figure 3.3-20) and the flume method (see Figure 3.3-21). In the dam-and-pump method, the stream is dammed and water is transferred across the construction site by means of a temporary hose or pipe and pump.

In the flume method, the stream is dammed and a culvert is installed. Isolated crossing methods usually have less sediment yield than a wet crossing, but are often more expensive and more time consuming.

Additionally, the installation and removal of the dam can cause high releases of sediment. Other problems may arise from leakage around/underneath the dam, dam failures, flume failures, insufficient sump storage, insufficient pump capacity, and inadequate maintenance.

For larger bodies of water, horizontal directional drilling (HDD) may be used. It offers several advantages, including no disruption of traffic on the waterway and minimum environmental impact. The process proceeds in three basic steps. First, a pilot hole is drilled. Secondly, the pilot hole is enlarged to a diameter larger than the diameter of pipe to be installed. A slurry composed of bentonite clay is typically used to lubricate the drill and bring cuttings out of the hole. A similar slurry is also often pumped into the enlarged hole to prevent it from

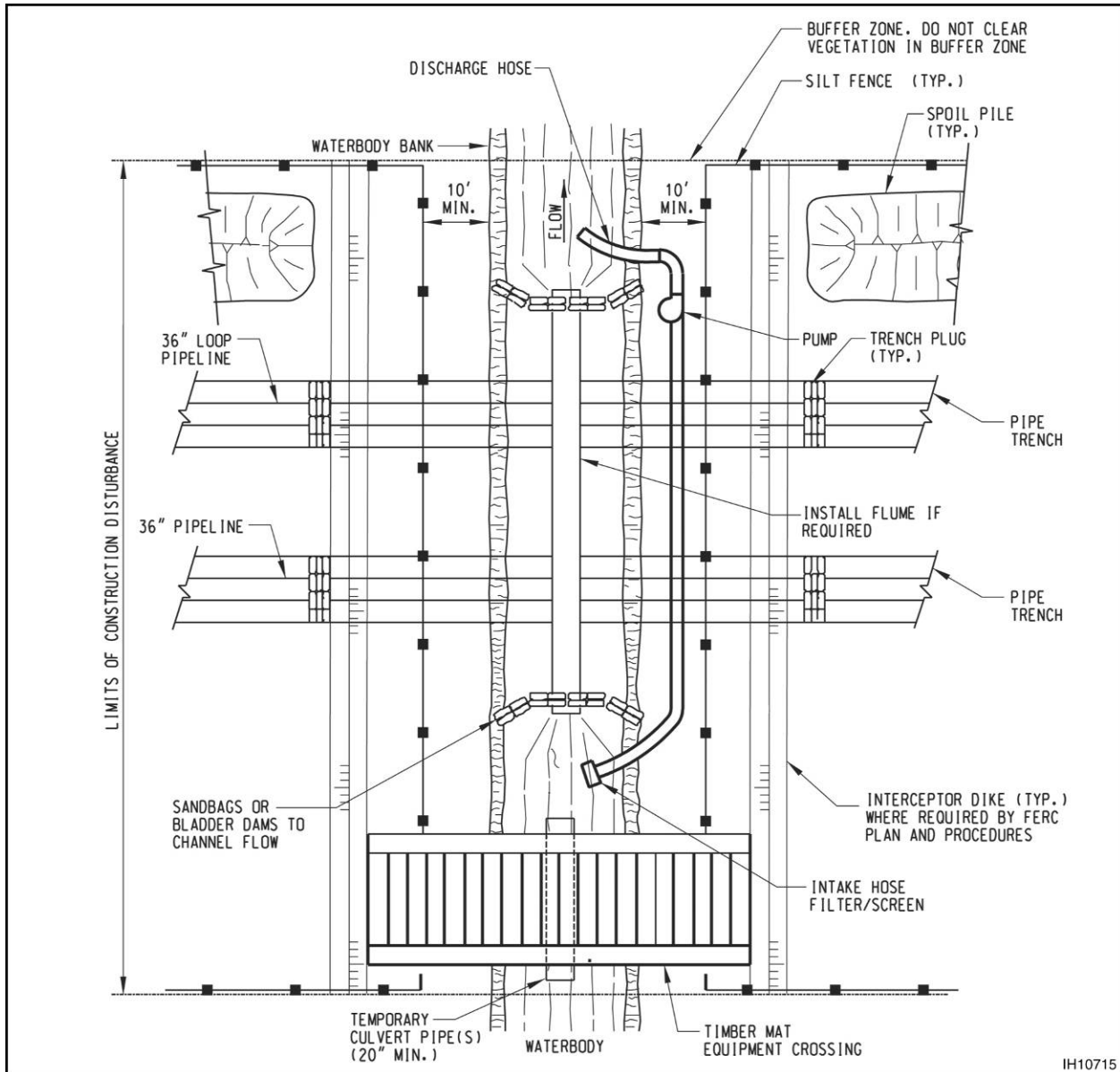


FIGURE 3.3-20 Dam-and-Pump River Crossing with Two Pipelines (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)

collapsing before the pipe can be installed. Finally, the prefabricated pipe segment is pulled into the hole, using the same drill rig that bored the initial and enlarged holes. This sequence of steps is depicted in Figure 3.3-22.

Heavy equipment is required on both sides of the waterbody crossing for HDD. The drilling rig spread requires a minimum 100-foot wide by 150-foot long area on each bank. The drilling operation requires large volumes of water for mixing the drilling slurry, often but not necessarily withdrawn from the waterbody being crossed. The length of workspace should be sufficient to permit fabricating the product pipeline into one string. The width should be what

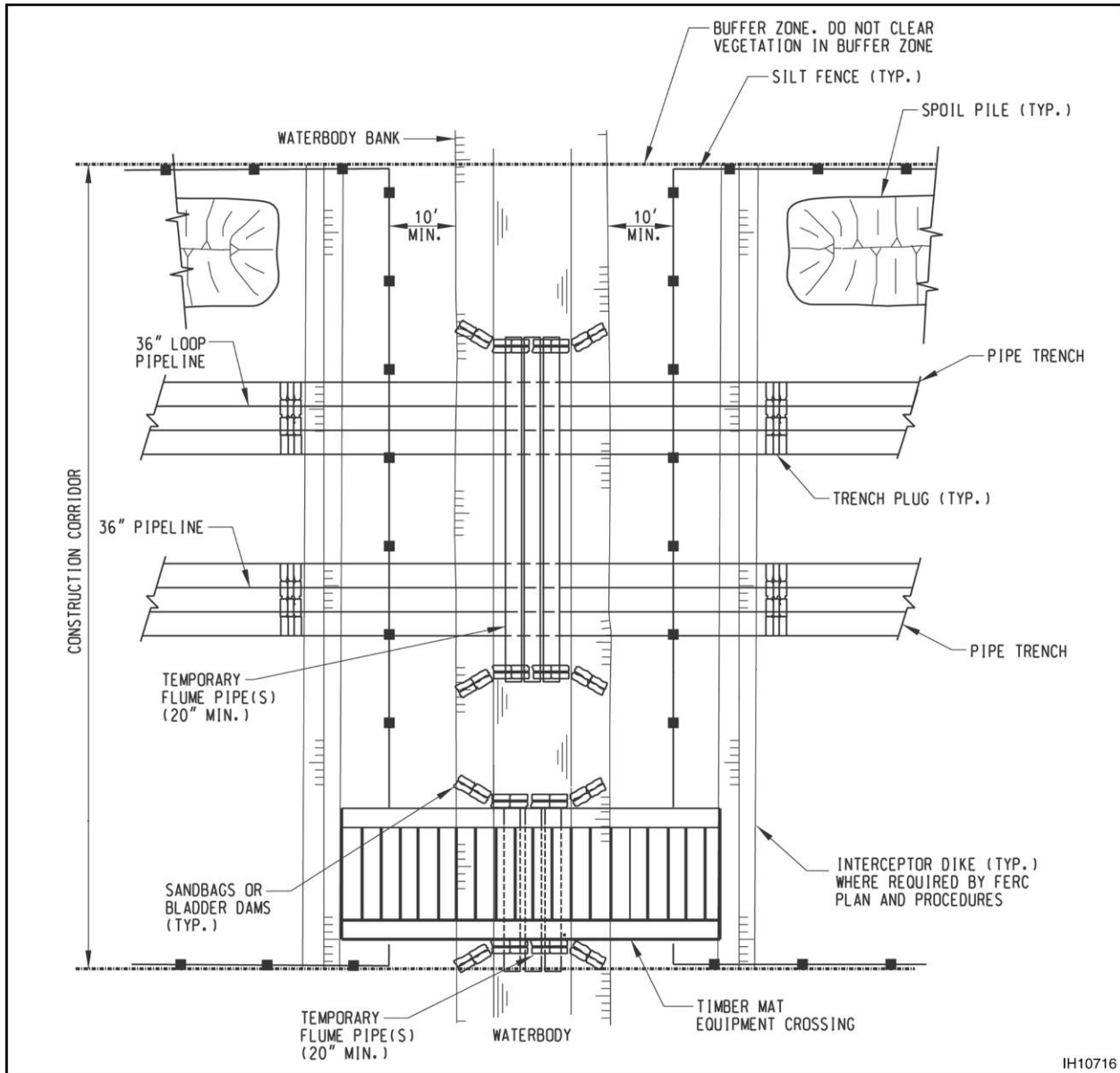


FIGURE 3.3-21 Flume Water Crossing with Two Pipelines (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)

is necessary for normal pipeline construction, although a workspace of 100-foot wide by 150-foot long will also be required at the exit point, assuring that the pipe can be installed in one uninterrupted operation during the pullback. The recommended minimum cover depth is 20 feet for the lowest section of the crossing.

Slurry pits are constructed in the construction zone to support boring operations. Slurries recovered from the hole are delivered to these pits where they can be recycled. At the completion of drilling, the slurries are removed for use at another drilling operation or used elsewhere in the pipeline construction project to be mixed with native soils to enhance slope stability or increase

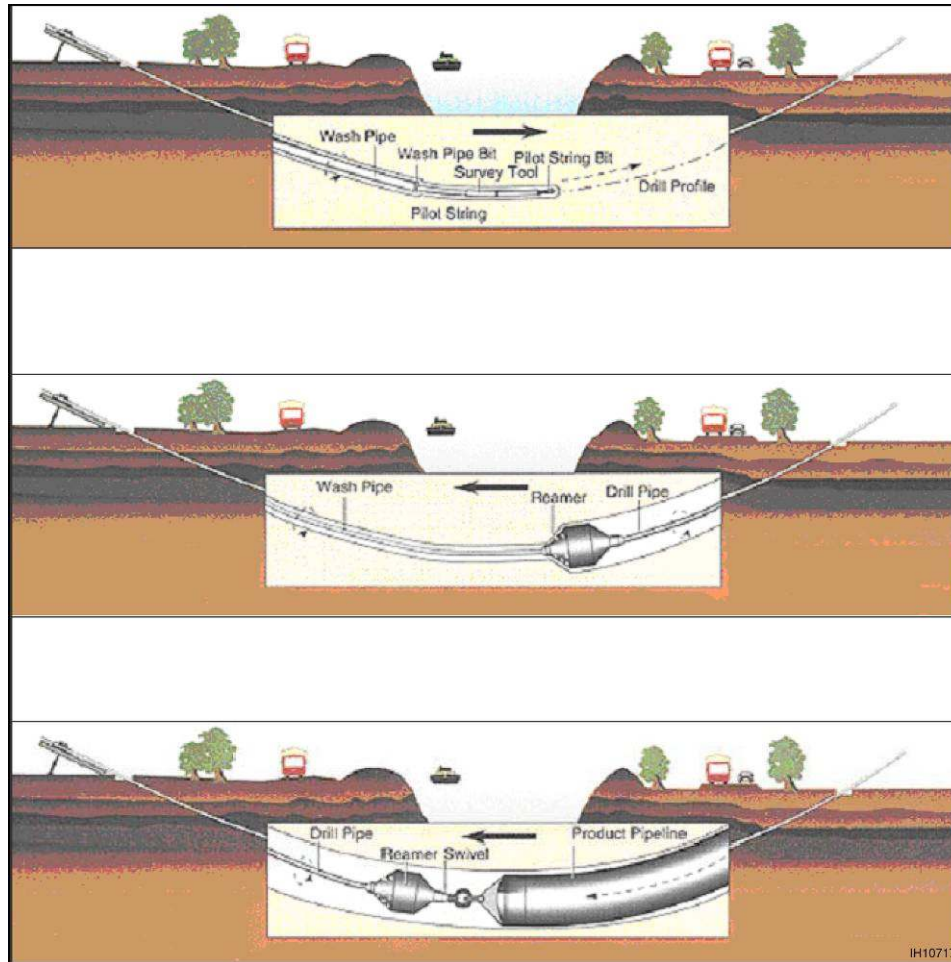


FIGURE 3.3-22 Typical Directional Drilling under Waterway
 (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)

water retention properties, where warranted. Otherwise, slurries are disposed of as nonhazardous wastes.

Not all streams are crossed by installing the pipeline beneath the stream. Some pipelines are installed on “pipeline bridges,” steel structures built to suspend the pipeline above the stream. Use of this method depends on a number of factors, including the presence of traffic on the waterway.

In addition, new pipeline construction may cross existing pipelines in service (see Figure 3.3-23).

Instances in which anchoring is required include river crossings where currents can cause pipe movement or scour beneath the pipe installed on top of the river bed, a dry wash subject to

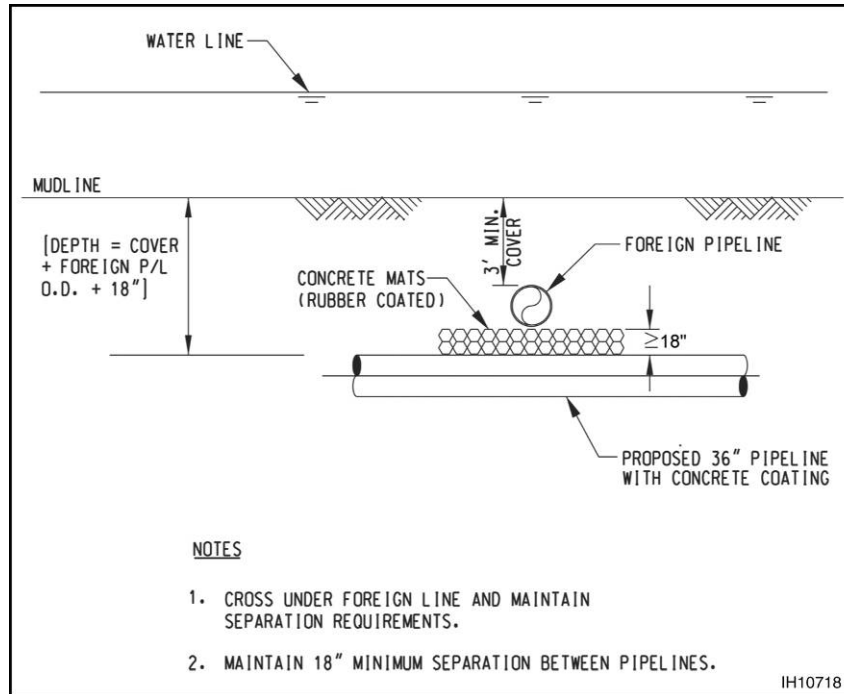


FIGURE 3.3-23 Waterbody Crossing Containing a Second Pipeline (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)

temporary flooding or extraordinarily fast stream flows after heavy rains, or where certain types of backfill are used.

3.3.13.2 Crossing Wetlands

Crossing wetlands, if required and allowed by law, creates unique construction challenges. Figure 3.3-24 depicts a typical saturated wetland crossing with topsoil segregation.

Construction equipment working in wetlands would be limited to that essential for clearing the ROW, excavating the trench, fabricating and installing the pipeline, backfilling the trench, and restoring the ROW. In areas where there is no reasonable access to the ROW except through wetlands, nonessential equipment would be allowed to travel through wetlands only if the ground was firm enough or had been stabilized to avoid rutting. Otherwise, nonessential equipment would be allowed to travel through wetlands only once.

Clearing vegetation in wetlands would be limited to trees and shrubs, which would be cut flush with the surface of the ground and removed from the wetland. To avoid excessive disruption of wetland soils and the native seeds and rootstocks within the wetland soils, stump removal, grading, topsoil segregation, and excavation would be limited to the area immediately over the trench line. A limited amount of stump removal and grading could be conducted in other areas if dictated by safety-related concerns.

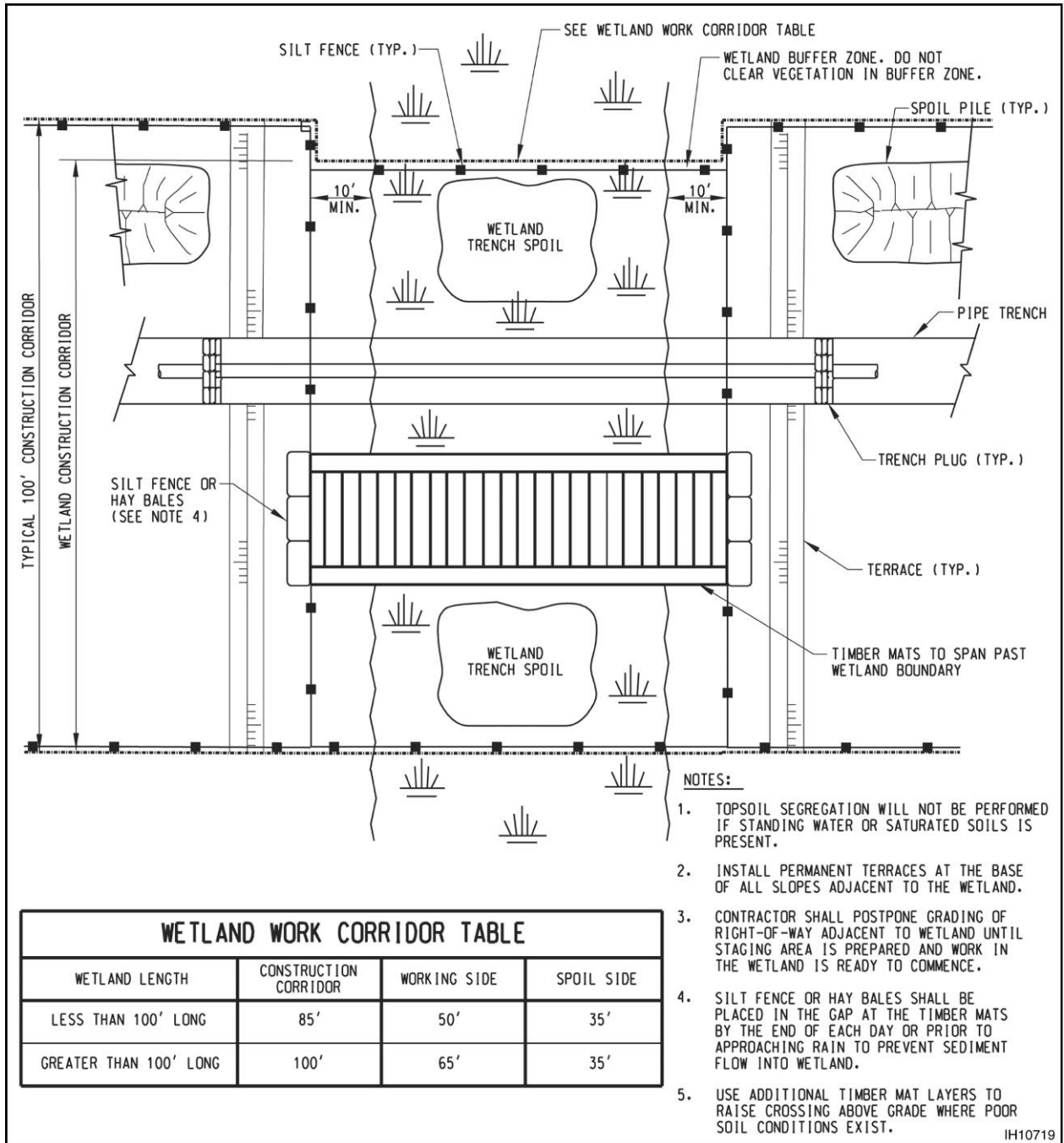


FIGURE 3.3-24 Saturated Wetland Crossing (Source: Modified from FERC Golden Pass LNG Terminal and Pipeline Project image)

During clearing, sediment barriers such as silt fences and staked certified weed-free straw bales would be installed and maintained adjacent to wetlands and within additional temporary workspace areas as necessary to minimize the potential for sediment runoff. Sediment barriers also would be installed across the full width of the construction ROW at the base of slopes adjacent to wetland boundaries. Silt fences and/or certified weed-free straw bales installed across the working side of the ROW would be removed during the day when vehicle traffic was present and would be replaced each night. Alternatively, drivable berms could be installed and maintained across the ROW in lieu of silt fences or certified weed-free straw bales. Sediment barriers also would be installed within wetlands along the edge of the ROW, where necessary, to minimize the potential for sediment to run off the construction ROW and into wetland areas located outside the work area.

The method of pipeline construction used in wetlands would depend largely on the stability of the soils at the time of construction. If wetland soils are not excessively saturated at the time of construction and can support construction equipment on equipment mats, timber riprap, or certified weed-free straw mats, construction would occur in a manner similar to conventional upland cross-country construction techniques. In unsaturated wetlands, topsoil from the trench line would be stripped and stored separately from subsoil. Topsoil segregation generally would not be possible in saturated soils.

Where wetland soils were saturated and/or inundated, the pipeline could be installed using the push-pull technique. The push-pull technique involves stringing and welding the pipeline outside of the wetland and excavating and backfilling the trench using a backhoe supported by equipment mats or timber riprap. The prefabricated pipeline would be installed in the wetland by equipping it with buoys and pushing or pulling it across the water-filled trench. After the pipeline was floated into place, the floats would be removed and the pipeline would sink into place. Most pipe installed in saturated wetlands would be encased in concrete or equipped with set-on weights to provide negative buoyancy (see Figure 3.3-25).

Because little or no grading would occur in wetlands, restoration of contours would be accomplished during backfilling. Prior to backfilling, trench breakers would be installed where necessary to prevent the subsurface drainage of water from wetlands. Where topsoil has been segregated from subsoil, the subsoil would be backfilled first, followed by the topsoil. Topsoil would be replaced to the original ground level, leaving no crown over the trench line. In some areas where wetlands overlie rocky soils, the pipe would be padded with rock-free soil or sand before backfilling with native bedrock and soil. Equipment mats, timber riprap, gravel fill, geotextile fabric, and/or certified weed-free straw mats would be removed from wetlands following backfilling.

Where wetlands are located at the base of slopes, permanent slope breakers would be constructed across the ROW in upland areas adjacent to the wetland boundary. Temporary sediment barriers would be installed where necessary until revegetation of adjacent upland areas was successful. Once revegetation was successful, sediment barriers would be removed from the ROW and disposed of properly. In wetlands where no standing water was present, the construction ROW would be seeded in accordance with the recommendations of local soil conservation authorities. Lime, mulch, and fertilizer would not be used in wetlands.



FIGURE 3.3-25 Concrete-Coated Pipe in a Wetland (Source: Photo courtesy of U.S. Pipeline, Inc. Reproduced with permission.)

3.3.13.3 Elevated Areas and Rugged Topography

There may be multiple areas that would require additional workspace areas due to exceptionally rugged or steep terrain. Additional grading may be required in areas where the proposed pipeline route would cross steep slopes. Steep slopes often need to be graded down to a more gentle slope to accommodate pipe-bending limitations and the limits of pump capabilities to move product over a grade change. In such areas, the slopes would be cut away and, after the pipeline was installed, reconstructed to their original contours during final contouring and before restoration of surface vegetation.

In areas where the proposed pipeline route crosses laterally along the side of a slope, cut-and-fill grading may be required to obtain a safe, flat, work terrace. Generally, on steep side-slopes, soil from the high side of the ROW would be excavated and moved to the low side of the ROW to create a safe and level work terrace. Under these circumstances, the topsoil would be stripped from the entire width of the ROW. After the pipeline is installed, the soil from the low side of the ROW would be returned to the high side, topsoil replaced, and the slope's original contours would be restored.

In steep terrain, temporary sediment barriers such as silt fences and certified weed-free straw bales would be installed during clearing to prevent the movement of disturbed soil off the ROW. Temporary slope breakers consisting of mounded and compacted soil would be installed across the ROW during grading, and permanent slope breakers would be installed during

cleanup. Following construction, seed would be applied to steep slopes and the ROW mulched with certified weed-free hay or nonbrittle straw or covered with erosion-control fabric. Plants with noninvasive root systems and indigenous to the area or approved by the federal land steward's vegetation management plan would be planted for long-term erosion control. Sediment barriers would be maintained across the ROW until permanent vegetation is established.

When rock or rocky formations are encountered, tractor-mounted mechanical rippers or rock trenchers would be used for fracturing the rock prior to excavation. In areas where mechanical equipment could not break up or loosen the bedrock, blasting would be required. Whenever possible, excavated rock would be used to backfill the trench to the top of the existing bedrock profile; however, crushing the rock to a uniform size may be necessary to prevent damage to the pipe during placement and to ensure proper backfilling density and minimize the potential for future subsidence.

3.3.13.4 Valves

Valves are installed at various locations along the mainline for various operational controls and to isolate segments of the pipeline for maintenance or replacement or to limit the amount of product in jeopardy of spilling in the event of a pipeline break. Typically, valves are installed at either side of sensitive or potentially problematic segments such as waterbody crossings. Such check valves can serve to quickly and efficiently isolate those segments of the pipeline in the event a problem should occur. Such isolation limits the scale of the adverse consequences that could occur in the event of a pipeline rupture in those segments. Check valves are placed at each significant change in grade to prevent backflow of product in the event of a failure of the upstream pumps. Bypasses may need to be installed around mainline valves or damaged pipeline segments to facilitate maintenance, repair, or replacement without shutting down operation of the pipeline. Bypasses typically consist of the requisite length of substitute pipe, each end of which is attached to a manually operated valve and two "hot taps" (devices that cut into the pipeline and divert the flow from the mainline pipe segment to be isolated to the bypass pipe). Once the bypass is positioned, the bypass valves are opened and the hot taps are operated to tap into the existing pipe. Such bypasses are typically removed (and the hot taps repaired) once the task is completed. See Section 4.10 for additional discussions regarding repairs of operational pipelines.

3.3.13.5 Pump Stations and Terminals

Pumps that provide the operating capability of a pipeline are located within pump stations. The location and number of pump stations, as well as the size and power of the pumps, are dictated by a number of factors, including topography along the ROW (elevation changes), the specific gravity and viscosity of the commodity, and the desired throughput. Liquids exiting a pump station will be at their highest pressure. Pressure will fall with distance from the pump station due to grade changes (if any) and frictional losses. To be effective, the pipeline's operating pressure must be maintained at or above the design discharge pressure at the pipeline's final destination. With the discharge pressure setting the lower pressure limit and the burst

pressure of the pipe and other components setting the maximum pressure, calculations can determine the number and location of pump stations required, as well as the size and power of the pumps at each of these stations.

Typical pump station configurations involve at least three pumps connected to the pipeline in parallel. Two of the three pumps operate while the third remains available, if needed, or in the event of a failure of one of the operating pumps. Such a configuration also allows pumps to be taken off-line for maintenance or replacement without affecting the operating status of the pipeline.

While housing the pumps and their prime movers remains the primary function, other activities such as pig launching and recovery also are typically colocated at pump stations. Also, many pump stations have the ability to introduce commodities into the pipeline or to remove them and direct them to storage tanks located on-site. Such actions are typically further supported by the capability to meter volumetric flow, especially when such transfers into or out of the pipeline system represent a change in custody or ownership of the commodity. Storage or “breakout” tanks are used to support maintenance or replacement activities where draining pipeline segments is required and are also an essential part of emergency-response actions to limit the amount of commodity in jeopardy of release or to relieve pressure on damaged pipeline segments. Maintenance shops and parts warehouses are also often colocated at pump stations.

Depending on the array of planned activities, pump station footprints can vary in size from a few acres to as many as 50 acres or more. Pump stations can be fully automated or manned, either continuously or during one or more shifts. Even for manned stations, however, all actions that could be taken at a pump station that affect operational conditions in the pipeline (e.g., shutting down or starting a pump) can also be controlled remotely from the pipeline control center.

Figure 3.3-26 is an artist’s representation of Pump Station No. 1, the start of the Trans-Alaska Pipeline System (TAPS) at the North Slope, Alaska. Gathering pipelines from various production areas on the North Slope deliver a mixture of gas, water, and crude oil from wellheads to a central gathering facility where the gaseous and aqueous fractions are removed and the crude oil is metered and introduced into the TAPS for its journey to the Valdez Marine Terminal, 802 miles south on Prince William Sound. The TAPS terminus is the breakout station at the Valdez Marine Terminal where crude oil is recovered from the pipeline and sent to various storage tanks to await load-out to oceangoing tankers for delivery to refineries in the contiguous United States and elsewhere.

The terminus of a pipeline is typically located within or adjacent to a petroleum bulk terminal. The pipeline ends at a breakout station where terminal personnel can perform final metering and distribute products to various storage tanks, redirect them to a different pipeline, or load them directly to truck transports or vessels for additional transport to points of use. The terminal may or may not be owned and operated by the same company that owns and operates the pipeline. A typical pipeline breakout station is shown in Figure 3.3-27.

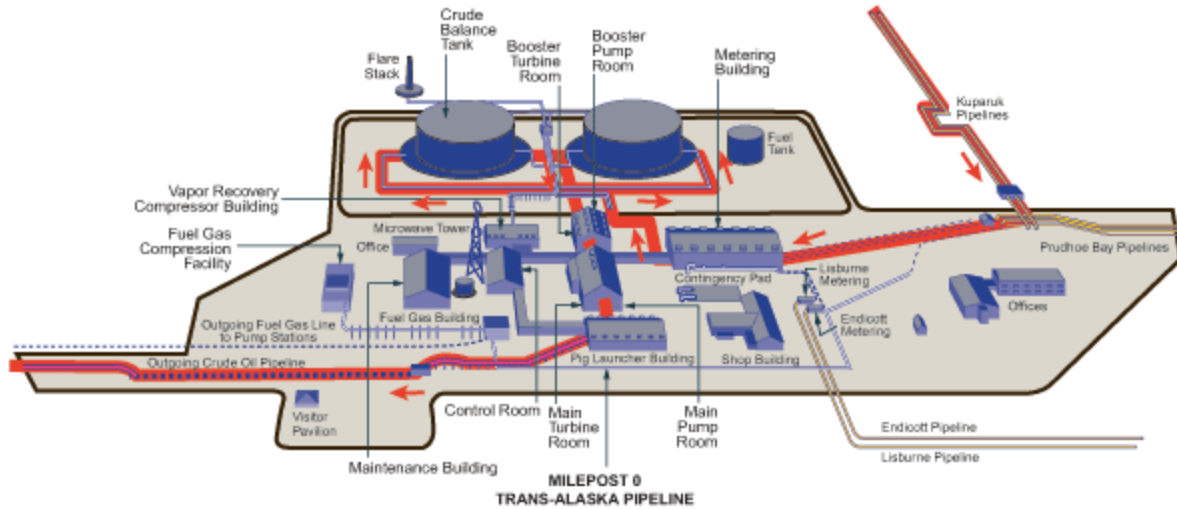


FIGURE 3.3-26 Crude Oil Pipeline Pump Station (Source: TAPS Final Environmental Impact Statement)



FIGURE 3.3-27 Typical Pipeline Breakout Station (Terminus) at a Petroleum Terminal (Source: V. Yarborough, Argonne staff)

4 PIPELINE OPERATIONS

4.1 INSPECTIONS AND MARKERS

The activities discussed below represent standard industry practices. Depending on the individual pipeline operator, company policies may result in more restrictive requirements for each of the actions. In some instances, regulation or lease stipulation specify how such activities will be conducted.

4.1.1 Inspections during Excavation

Whenever a pipe is exposed for any reason, the operator typically examines the pipe for evidence of mechanical damage or external corrosion, including the coating. Mechanical damage must be evaluated and repaired as necessary, in accordance with company repair procedures. Coating damage should be repaired prior to reburying the pipeline. If the operator finds active corrosion, general corrosion, or corrosion that has caused a leak, the operator should investigate further to determine the extent of corrosion. The pipeline should be inspected prior to and during backfilling of the exposed section.

4.1.2 ROW Inspections

ROW inspections occur with regularity. Depending on lease stipulations and other factors, frequencies can be as high as weekly. Inspections can involve individuals walking the ROW and also aerial surveillance. Flyover inspections are the most common and most efficient method for routine surveillance, but are not appropriate for many required inspection tasks.

Unique opportunities exist for surveillance and inspection activities for multiple pipelines or other energy transmission systems on adjacent ROWs. Although no system operator would be willing to entirely relinquish inspection activities to another system operator, there are many surveillance activities that are common to all types of energy systems that might be adjacent to one another, creating the possibility for a more integrated approach to routine inspections. Agreements between system operators and the federal land manager to combine routine surveillance activities can reduce environmental impacts that would result from independently conducted inspections and could potentially increase operating efficiencies for all of the system operators within the ROW. Similarly, integration of passive surveillance systems can potentially save costs and increase overall observational frequencies for all of the energy systems present. Regardless of the opportunities for combining efforts and the resources of system operators for common tasks, system operators remain individually responsible for the integrity of their systems and consequently will retain certain surveillance tasks for themselves.

4.1.3 Pipeline Markers and Aboveground Facilities

Proper pipeline markers should be placed where hazardous liquid pipelines and any associated facilities are exposed. All hazardous liquid pipelines attached to bridges or otherwise spanning an area should have pipeline markers that are visible and readable at both ends of the suspended pipeline.

4.1.4 Change in Operating Rate

Each pipeline system is designed to a maximum operating rate, or throughput, expressed as volumetric flow of the carried commodity over time. This operating rate equates to a maximum operating pressure. The design maximum operating pressure, in turn, is the product of numerous engineering parameters and limits, the most critical of which from a safety perspective are the suite of minimum yield stress pressures, pressures above which pipeline components can break or burst. Burst pressures are calculated initially for pipe segments and other components and recalculated periodically over time, based on information obtained from various monitoring and inspection activities, especially those that determine the extent of external and internal corrosion, either of which can have a dramatic influence over the component's burst or yield pressure. Regulations published by the DOT OPS in 49 CFR Part 195 require pipelines to calculate yield strengths and operate at a maximum percentage of that design minimum yield stress pressure, thus providing adequate safety margins against the minimum burst pressures of each pipeline component.³⁹ Oversight by OPS inspectors, including their review of monitoring and inspection data or in response to a system failure that is related to pressure, can result in an order for the pipeline to be operated at a reduced operating pressure (expressed typically as a new lower maximum operating rate) until observed or indicated deficiencies are further investigated and resolved.

4.2 PIPELINE REPAIRS

In most instances, pipeline repairs are accomplished expeditiously to ensure minimal disruption to pipeline operations. Unless otherwise specified by applicable regulation or lease stipulation, pipeline repairs are typically made in accordance with ASME standard B31.4, 2002, "Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids."⁴⁰ ASME B31.4 requirements and specifications extend to design, materials, construction, assembly, inspection, and testing of piping transporting crude oil, condensate, natural gasoline, natural gas liquids, liquefied petroleum gas (LPG), carbon dioxide, liquid alcohol, liquid anhydrous ammonia, and liquid petroleum products including petrochemical feedstocks and secondary refinery feedstocks. Pipeline components addressed in this standard include pipe, flanges, bolts, gaskets, valves, relief devices, fittings, and the pressure-containing portions of other support components.

³⁹ The required tests and the formulae for calculating minimum yield strength and the consequent maximum operating pressure of a liquid pipeline carrying hazardous materials are contained in 49 CFR 196.106.

⁴⁰ This and other ASME standards can be purchased through the ASME website at http://catalog.asme.org/Codes/PrintBook/B314_2006_Pipeline.cfm.

Additionally, this standard extends to marine pipelines and piping at tank farms, pump stations, terminals, pressure-reducing stations, and metering stations and all aspects of pipeline operation related to safety and protection of the general public, operating company personnel, environment, property, and the piping systems themselves.

4.2.1 Moving and Lowering Hazardous Liquid Pipelines

Prior to moving or lowering any hazardous liquid pipeline, hazardous liquid pipeline companies typically prepare a study to determine whether the proposed action will cause an unsafe condition. The study must include pipe stress calculations based on API RP 1117, "Movement of In-Service Pipelines."

4.2.2 Remedial Action for Corrosion Deficiencies

Companies must initiate remedial action as necessary to correct deficiencies observed during corrosion monitoring. Industry standards for allowable advancements of internal and external corrosion establish the action levels for such remedial activities. Remedial action may involve replacing the sacrificial anodes of a corrosion control system, a relatively minor construction activity compared to wholesale replacement of compromised pipe involving long-term shutdown of operations and major construction efforts equivalent to initial installation. To limit operational downtime, temporary bypass segments isolating the damaged segments may also be installed. See additional discussions on corrosion control in Section 4.7.

4.3 PIGGING ACTIVITIES

A variety of inspection techniques and technologies are used to monitor pipeline condition and integrity. The most important goal of pipeline inspection is usually to assess corrosion-caused metal loss. But inspection also provides information on dents and other damage that may eventually cause failure and leaks. Pigs that perform a variety of functions are essential to pipeline internal inspections.

Equipment is required to introduce the pig into the pipeline and to retrieve the pig at the end of the segment being pigged. A launcher is required at the upstream end of the section, and a receiver is required at the downstream end. The distance between these pig "traps" depends on the service, location of pump or compressor stations, operating procedures, and the material used in the pig. For obvious reasons, any launched pig must be retrieved from the mainline pipe before the pipe reaches the next pump station. Often, launching and recovery facilities are colocated at pump stations.

4.4 CHEMICAL ADDITIVES

Drag-reducing agents or other chemicals to improve the flow characteristics of the pipeline are always present and something to consider in any analysis of pipeline systems. Furthermore, dependent on the product, there may be other chemicals that affect the properties of the fluids in transmission systems, such as the static reducer added to diesels. For high-viscosity crude oils (i.e., low API gravity numbers), a diluent is often added to enhance the pumpability of the crude and reduce the frictional drag on the inside pipeline walls, thereby reducing the amount of energy needed to pump the crude. Such diluents are typically low-viscosity petroleum refining fractions such as raw naphtha.

4.5 PIPELINE SECURITY

Third-party damage and ROW encroachments are the biggest threats to pipeline safety. Pipeline operators use a combination of techniques to monitor pipeline ROWs. Aerial surveillance and satellite imaging combined with interpretive software that can survey and detect things such as heat, color, size, and shape, which can alert operators to potential encroachment concerns. Fiber optic broadband capabilities along ROWs typically are used to assist in this effort. Many pipeline operators are also enlisting the support of adjacent landowners in establishing programs for reporting observed suspicious activities along the ROWs.

4.6 WASTE MANAGEMENT

The Resource Conservation and Recovery Act (RCRA) plays a key role in determining environmental standards for the management of solid and hazardous wastes. Under RCRA, a solid waste is any material discarded or intended to be discarded; it may be solid, semisolid, liquid, or contain gases. A solid waste is a hazardous waste if it is one of more than 400 materials listed as a hazardous waste or it exhibits one or more of the characteristics of hazardous waste defined in federal or state regulations, such as ignitability, corrosivity, reactivity, or toxicity. For pipelines, benzene is an important hazardous material, as it is a component in crude oil and in many petroleum distillate fuels and secondary feedstocks that are routinely delivered by pipeline. In sufficient quantities, its presence can cause any spilled products to meet the regulatory definition of hazardous waste.

Another important aspect of RCRA is the mixture rule, 40 CFR 261.3(a)(2)(iii and iv). Mixing any listed hazardous waste with a nonhazardous waste renders the entire mixture hazardous.⁴¹ Water can pose disposal problems for pipeline operators. Water used in hydrostatic testing of repaired pipelines that carried crude oil or petroleum products can become contaminated with hydrocarbons that require it to be managed as hazardous waste. Certain

⁴¹ The mixture rule will always be in effect when “listed” hazardous wastes are involved. However, if mixing a “characteristic” hazardous waste with a nonhazardous waste results in a mixture that no longer exhibits the characteristic, the mixture is not considered a hazardous waste. However, undertaking such purposeful mixing of waste streams to avoid the application of hazardous waste regulatory controls is prohibited.

constituents in crude oil or petroleum distillates are also listed as hazardous waste (e.g., benzene), and some of these constituents also have relatively high solubility in water. Consequently, condensates removed from pipelines carrying such commodities may need to be managed as hazardous wastes. Likewise, sludge and other materials removed from such pipeline systems during routine cleaning or repairs may also qualify as hazardous waste and must routinely undergo hazardous waste determinations against the standards and specifications contained in federal or state regulations before management and disposal options are selected.

The Clean Water Act influences pipeline construction, especially through its requirements for permits for activities in wetlands and stormwater management (particularly during the construction and decommissioning phases). Stormwater controls must be established before construction begins and must be maintained until reclamation has progressed sufficiently to stabilize disturbed areas. Similar controls may need to be reinstated before major repair, replacement, or upgrading activities are conducted.

Another important environmental consideration in pipeline construction and operation is impact to air quality. Substances of concern to pipeline operators include carbon dioxide, hydrogen sulfide, and mercaptan, a sulfur-containing hydrocarbon⁴² that is introduced into natural gas systems as an odorant. Pipeline operators must also be concerned about sources of nitrous oxide, carbon monoxide, and emissions from pump engines. “Fugitive” emissions of benzene from seals on pumps, valves, meters, and storage tanks must also be controlled.

4.7 CATHODIC CORROSION PROTECTION

Underground corrosion of steel pipelines can result from the flow of electrical current between areas of different electric potential. The area of higher potential (the anode) will be corroded, and the area of lower potential (the cathode) will not be subject to corrosion. In the case of a buried pipeline, the soil can act as an electrolyte, facilitating the transfer of electrons from a metallic object such as a buried pipe (the anode in this electrochemical engine) and the ground. Areas of different electrical potential exist throughout the trace of a pipeline, with the magnitudes of such electrical potential differences depending on soil types and myriad other local conditions.

In a cathodic protection system, anodes made of materials that are more conducive to electrical current delivery than the steel of the pipeline are electrically bonded to the pipe and installed along the pipeline route, resulting in the subsequent flow of electrical current from the anodes to the ground. As electrons flow from these anodes, the anodes deteriorate, earning them the common name of “sacrificial anodes” since they are being sacrificed and allowed to corrode instead of the pipe. The pipeline becomes the cathode of the system, and its corrosion is prevented as long as some anode material remains. Keifner and Vieth (1990) established that the

⁴² The most commonly used odorant is methyl mercaptan. Details on its chemical and physical properties can be obtained at the following website: [http://www.praxair.com/praxair.nsf/d63afe71c771b0d785256519006c5ea1/bd40c55346b4930f85256e5f007e8c2a/\\$FILE/MethylMercaptan-Canada.pdf](http://www.praxair.com/praxair.nsf/d63afe71c771b0d785256519006c5ea1/bd40c55346b4930f85256e5f007e8c2a/$FILE/MethylMercaptan-Canada.pdf).

magnitude of the corrosion currents for a given potential difference between two electrodes (cathode and anode) depends on several factors:

- *Soil resistivity*. This is determined by temperature, moisture content, and the concentration of ionized salts present. Generally, corrosion is high in low-resistivity soils and can be low in very high resistivity soils.
- *Chemical constituents of the soil*. Corrosion can be low in very high resistivity soils.
- *Separation between anode and cathode*. Corrosion is more likely to occur when the anode and cathode are close together.
- *Anode and cathode polarization*. Protective films formed at the anode and cathode affect corrosion intensity.
- *Relative surface areas of cathode and anode*. For a given magnitude of corrosion current, the depth of corrosion on the anode will be inversely proportional to anode area.

Since power requirements for cathodic protection systems are relatively low, the application fits the capabilities of solar energy systems.

4.8 LEAK DETECTION

In addition to inspecting the pipeline route visually on the ground or by means of light aircraft, advanced methods are now employed to detect smaller leaks and others more rapidly. The minimum size leak that can be detected depends on a number of factors:

- Type of fluid in the pipe.
- Accuracy of the metering system and the accuracy of temperature and pressure transmitters.
- Line size.
- Wall thickness.
- Length of line.
- Steady-state or transient condition of the pipeline.

- Analytical equipment.
- Experience of the personnel involved.

Metering accuracy plays a key role in leak detection because one important way to detect leaks is by direct observation of the pressure drop and volume loss, based on comparing the flow into a segment of pipeline and the flow out of the segment. This approach can be effective with relatively simple instrumentation, but can also be used with more complex leak detection models. Instrumented pigs have been used to monitor a pipeline for leaks.

4.9 INTEGRITY ASSESSMENTS

Routine evaluation of the physical condition of an oil pipeline is critical for ensuring pipeline safety. The AOPL and the API have jointly published an overview of pipeline integrity programs in effect for liquid pipeline systems (AOPL/API 2006). Their overview is summarized below. Pipeline integrity can be determined through direct assessment methods, hydrostatic testing, and by the use of internal inspection tools. Using direct assessment methods, oil pipeline operators can determine the integrity of an oil pipeline through visual and physical (internal and external) observations. Internal inspections of oil pipelines involve the use of smart pigs. Hydrostatic testing involves pressuring the pipe to a level equal to or above its normal operating pressure. Oil pipeline operators generally use a combination of direct assessments, internal inspection tools, and/or hydrostatic tests for ensuring the safe and reliable operation.

Direct assessment methods include various types of cathodic protection surveys, such as close interval surveys (to ensure that the pipe is not corroding) and physically uncovering selected segments of the pipeline and examining the external coating as well as the steel pipe. A detailed examination of the internal and external condition of the pipe also can be accomplished when sections of pipe are inspected or removed for any reason, such as pipeline relocation, installation of taps, installation of test leads, etc. The pipeline ROW may be assessed by ground and aerial surveillance to look for any discoloration of plants and grasses as well as to observe unusual activity in the area of the pipeline (for potential outside force damage).

Smart pigs are routinely used by the oil pipeline industry to detect loss of metal and in some cases deformations in the pipeline. Inserted into the pipeline and propelled by the flowing liquid, smart pigs record physical data about the pipeline's integrity (e.g., location of reduced pipe wall thickness, dents, etc.) as they move through the pipeline. Evaluation of smart pig data allows the pipeline operator to make integrity decisions about the pipeline and to find and mitigate potential problem areas before they become a problem.

Since their development in the 1960s, smart pigs have undergone several generations of technological advancements. As smart pig technology has evolved, oil pipeline operators have required the use of specialized smart pigs. Specialized smart pigs have evolved into three types: metal-loss tools, crack-detection tools, and geometry tools.

4.9.1 Metal-Loss Tools (Corrosion Tools)

A number of smart pigs have been developed to inspect for metal loss. The magnetic flux leakage (MFL) smart pig induces a magnetic field in the pipe and monitors for anomalies in the magnetic field that are later interpreted as potential metal losses due to corrosion. High-resolution MFL smart pigs can not only locate potential corrosion, but can also collect data to allow for a determination of whether the corrosion is advancing from the inside or outside of the pipe. Industry standards have been developed for use of the collected data to perform calculations of such characteristics as the depth of corrosion pitting, but typically, corrosion must have advanced to a depth of at least 20% of the pipe wall thickness before smart pigs can detect it. However, smart pigs are not reliable for identifying flaws in the pipe that are oriented along the pipe's long axis, such as stress corrosion cracking, selective seam corrosion, and axial gouges.

The ultrasonic smart pig, also called the UT tool, measures pipe wall thickness by using ultrasonic technology. The UT tool transmits an ultrasonic pulse into the pipe wall and directly measures its thickness. However, the inside surface of the pipe must be relatively clean for the tool to be effective; consequently it is not typically used for crude oil or heavy oil pipelines where paraffins or other debris can accumulate on interior pipe walls. Further, its overall effectiveness decreases with decreasing wall thicknesses.

4.9.2 Crack-Detection Tools

A variety of smart pigs are now available with instrumentation that can identify cracks in pipe walls. One such tool uses ultrasonic sound, interpreting the reflection of that sound back to the instrument as a crack. However, because the ultrasonic signal would not travel effectively in a gaseous pipeline, this tool is effective only for use in liquid pipelines.

Another smart pig, known as the transverse magnetic flux leakage pig, is similar in operation to the magnetic flux smart pig discussed above; however, the magnetic field it creates is oriented along the long axis of the pipe, making this tool especially sensitive to longitudinal seams cracks and longitudinal seam corrosion. Nevertheless, small cracks may not be detected, and while the tool can detect the presence of a larger crack, it cannot determine its severity. Consequently, visual inspections of suspect areas typically follow the use of this pig.

Smart pigs are now under development that simultaneously send ultrasonic in two directions along the pipeline to locate and size longitudinally oriented crack and manufacturing defects.

4.9.3 Geometry Tools

As discussed above, the "roundness" of a pipe is critical to the overall performance and delivery capacity of the pipeline system. Thus, pipe deformations must be identified and corrected. Various smart pigs have been developed for that purpose. They are designed to

identify external dents or damage to the pipe from external forces that have caused a change in overall pipe geometry. Two basic types of geometry pigs are in service, caliper pigs and pipe deformation pigs, and both operate on the same principles. Caliper pigs can use either mechanical arms or electromagnetic signals to identify the exact locations of the interior pipe wall. Data collected as the pig moves along the pipe can then be interpreted as dents or deformations in the pipe. Pipe deformation smart pigs are similar in function to caliper pigs, but incorporate a gyroscope for locating anomalies along the pipe's circumference more precisely.

4.9.4 Mapping Tools

Smart pigs equipped with global positioning system (GPS) capabilities are also in service. With this feature, identified anomalies or suspect areas can be precisely located for directed repair and maintenance.

4.10 PIPELINE REPAIR TECHNIQUES

Leaks in the pipeline demand immediate attention. Repairs to mainline pipe can be accomplished in a variety of ways, from replacement of an entire segment to replacement of a small section within which the leak has occurred, to application of a patch to the existing pipe. None of these repair strategies can be selected until a thorough investigation is completed to fully understand the nature and causal factors of the leak. In addition to replacement of damaged pipe, repairs could also involve reburial or rerouting of the pipe to prevent reoccurrence of the damage.

Although some repairs require an entire shutdown of the pipeline, many might involve only very temporary interruption of operations to isolate and bypass the damaged area, with the majority of the repairs occurring while the pipeline remains operational. Typically, plugs are inserted to temporarily isolate the damaged area so that isolating valves and a bypass could be installed. A variety of plugging pigs are available expressly for this purpose. Once the bypass components are in place, "hot tap" machines already attached to the newly installed bypass valves will tap the pipeline to allow product to flow through the bypass, isolating the damaged mainline pipe. With the damaged section drained of fluid and the pressure relieved, the damaged section can be removed and the repair made. Equipment is available to perform this type of operation on pipe sizes up to 48 in. in diameter. Hot taps can be made into pipelines operating at pressures up to 1,400 psi and temperatures from -20°F to 700°F . Plugging can be done at pressures to 1,200 psi and temperatures from -20°F to 650°F . Once the repair is completed, the bypass valves can be closed and the product flow returned to the newly repair segment of the pipeline. Bypass components may be left in place or removed. If removal is called for, the hot taps initially made to create the bypass must be patched, or, alternatively, the bypass valves can be left in place as a means of sealing the hot taps.

5 DECOMMISSION AND DEMOLITION

Decommissioning is the process of taking equipment out of service when it has reached the end of its useful life. From an operational perspective, that point is reached when maintenance and replacement costs for older equipment begin to outweigh the value obtained from continued operation. Advancements in technology can also signify the point in a system's lifetime when decommissioning is warranted. Alternatively, decommissioning may be appropriate due to a change in demand for the commodity being transported or when the locations being served by the pipeline no longer align with locations of high demand for the commodity or when more economical alternative supply paths have been established. Finally, decommissioning may be specifically directed by lease or permit stipulation.

The economic lifetime of a pipeline (the time necessary for depreciation of the initial investment) is typically around 50 years; however, with a sufficient commitment to maintenance and upgrading, pipeline systems can remain functional for much longer periods of time. Unless it is incompatible with future land uses planned for the ROW, industry practice is to leave a mainline pipe in the pipeline trench located in the ROW.⁴³ This prevents the additional ecosystem disturbances that would result during removal of the pipe and other buried components. Removal costs also encourage abandonment in place.

Typical abandonment-in-place processes include:

- Removing any cathodic protection from the pipeline.
- Physically disconnecting the pipeline from any operating facilities.
- Removing the product from the line.
- Cleaning the line by flushing it with fresh water, air, or inert gas.
- Capping the pipe at all open ends by welding on steel caps.
- Hardening foam is injected at certain locations along the pipe to prevent water and contamination migration through the pipeline.

Any unnecessary surface facilities associated with the abandoned pipe are typically also removed. Land owners may also require removal of all belowground elements that exist within 3 to 4 ft of the surface so as not to encumber reestablishment of vegetative cover or impede surface land uses such as agricultural uses.

⁴³ Because cost of removal may be as great as initial installation costs and the value recovered from recycling mainline pipe is not likely to cover removal costs, most mainline pipe is abandoned in place; however, valves, special fittings, and all aboveground features (e.g., pump stations and all of the equipment therein) are removed and recycled. DOT's OPS maintains statistics regarding the lengths of interstate pipelines abandoned in place. See: http://ops.dot.gov/library/abandoned/abandon_pipelines_orig.htm.

Decommissioning plans are very site-specific and may not call for the same techniques throughout the entire pipeline system. As suggested above, there can be circumstances in which removal of buried pipe or removal of pipe from beneath a waterbody can cause more disruption to ecosystems (including the disruption caused by constructing the necessary access roads for the heavy equipment needed for pipe removal) than abandoning those segments in place. In those instances, the decision may be to purge and clean the pipe of product, remediate any accidentally released products, and abandon the pipe and associated infrastructure in place. Typically, pipe corrosion control systems are also abandoned, allowing the pipe to corrode as circumstances would dictate. Eventually, this might lead to surface subsidence when the pipe corrodes to the point that the empty pipe can no longer support the weight of the overburden. In those instances, abandonment may also include filling the pipe segment to the greatest extent possible with inert material such as sand.

6 EMERGENCIES AND OFF-NORMAL EVENTS

Once pipelines are operational, monitoring the pipeline's flow parameters, instituting operational procedures and controls, and performing periodic maintenance (especially, for example, in conformance with the principles of Reliability-Centered Maintenance)⁴⁴ are all typically used to reduce the potential for accidental releases of commodities. Notwithstanding such efforts, mechanical system failures and human error can still occur, some of which may result in accidental releases of pipeline commodities. Consequently, all pipeline operators are required to develop written procedures within an emergency plan that must address all credible off-normal events. Each such credible event must be evaluated for its short- and long-term impacts and the appropriate response actions developed accordingly.

Evaluations of off-normal events, including credible spill scenarios, consider relevant circumstantial factors (e.g., ecosystems potentially impacted); potential natural, mechanical, or human causal factors (e.g. earthquakes, equipment failure, human error); the expected frequencies of such events; and the potential magnitude and severity of the events in terms of the amounts and types of commodities released, to determine the short-term and long-term impacts of a release and to devise the appropriate response actions to mitigate those impacts without increasing the risk to facility response personnel or the public from inappropriate response actions. For example, releases of flammable liquids with high vapor pressures in lowland areas require a determination of the potential for formation of explosive vapor atmospheres before response actions involving internal combustion engines or spark-producing equipment could commence. Review of pipeline design features, such as distance from the release to the nearest upstream and downstream valves, would determine the maximum potential volume of product that would be in jeopardy of release. Such estimates, together with circumstantial factors such as environmental features and distance to areas of critical environmental concern (ACEC) or sensitive ecosystems, provide a basis for both the urgency and the necessary scale of the response action.

For the purposes of impact analysis, there is no difference whether a leak or rupture occurs along the pipeline or at a pump station. The impact from a continuous low-volume leak in the pipeline would be similar to that from drips or spills at the pump station. Likewise, the impact from a pipeline rupture would be similar to that from a large release due to an equipment failure at a pump station. In all instances, the impacts depend on the environmental setting and the quantity and nature of the leaks. However, it is important to note that pipeline control centers routinely monitor pressures along the system as their primary leak detection capability. Pipeline ruptures will result in significant pressure drops, and operators observing such pressure drops would immediately recognize the possibility of a rupture and began shutting operations down and isolating the segments where pressure drops first occurred. Automated systems are typically

⁴⁴ Reliability-Centered Maintenance is a process for systematically and scientifically establishing appropriate maintenance actions, schedules, and priorities for mechanical systems and other physical assets. When applied to operations involving hazardous materials, the nature, scope, and priority of the maintenance actions are based on an understanding of the nature and extent of adverse consequences to workers, the public, and the environment that would result from component or system failure.

designed to do the same if the operator does not act within a certain time frame after the initial pressure drop alarm is initiated. However, small-volume leaks may not necessarily result in pressure drops to which the system's pressure monitors would respond; therefore, such small leaks can go undetected at the pipeline control center and may remain undetected until pipeline ground or aerial surveillance crews discover the leak by visual observation.

Accidental releases of various commodities routinely conveyed by pipeline result in substantially different impacts and dictate fundamentally different response actions. In general, crude oil, due primarily to its viscosity, would be less mobile in the environment than less viscous refined products. However, toxic constituents in crude oil such as benzene can find their way to groundwater or surface water. Such toxic constituents are also present in many refined products. Some, such as the BTEX fraction of gasoline⁴⁵ are composed of polar organic molecules with relatively high solubility in water, thus increasing their potential environmental mobility from the spill site. Each of these highly flammable components also has a relatively high vapor pressure under standard conditions and broad explosive ranges of their vapors in air, increasing the potential for their volatilization from the surface of a spilled fluid and the subsequent formation of vapor and air mixtures having explosive properties. Obviously, such properties must be considered in the development of appropriate spill response actions to prevent the response itself from exacerbating the impact of the initial spill. In addition to contributing to gasoline's viscosity, specific gravity, and solubility, benzene and xylene can increase the permeability of clay over time. These chemicals can cause clay shrinkage and cracking, thereby increasing the chances of fracturing clay soils in the upper horizons and providing pathways for gasoline to move more rapidly to subsurface aquifers than might otherwise occur (EPA 2000).

⁴⁵ The BTEX fraction is composed of benzene, toluene, ethylbenzene, and the three isomers of xylene.

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