Pipeline Briefing Paper #2
Last updated: September 2015

Pipeline Basics & Specifics About Natural Gas Pipelines

Introduction to Pipelines

There are over 2.6 million miles of fuel pipelines in the United States. Who regulates pipelines and under what set of regulations depends on what the pipeline carries, how much it carries, and where it goes. Pipelines are categorized into several types.

All fuel pipelines are either:

1) **Hazardous Liquid** pipelines carrying crude oil and refined fuels such as gasoline, diesel and jet fuel. They also carry highly volatile liquids, such as butane, ethane, propane, which will form vapor clouds if released to the atmosphere, and anhydrous ammonia.

or

2) **Natural Gas** pipelines carrying natural gas, the principal constituent of which is methane.

Depending on where they are in a transportation system all natural gas pipelines are either:

- **Transmission pipelines** — the large lines (typically 6-48 inches in diameter) that move gas long distances around the country, often at high pressures (typically 200 – 1500 psi); or
- **Distribution pipelines** — are a system of mains and service lines that deliver natural gas to our individual homes and businesses. They operate at a relatively low pressure; or
- **Gathering pipelines** — transporting gas away from the point of production (well pad) to another facility for further refinement or to transmission pipelines; or
- **Production Lines** — the pipes and equipment, normally near the wellhead, used to produce and prepare the gas for transport.

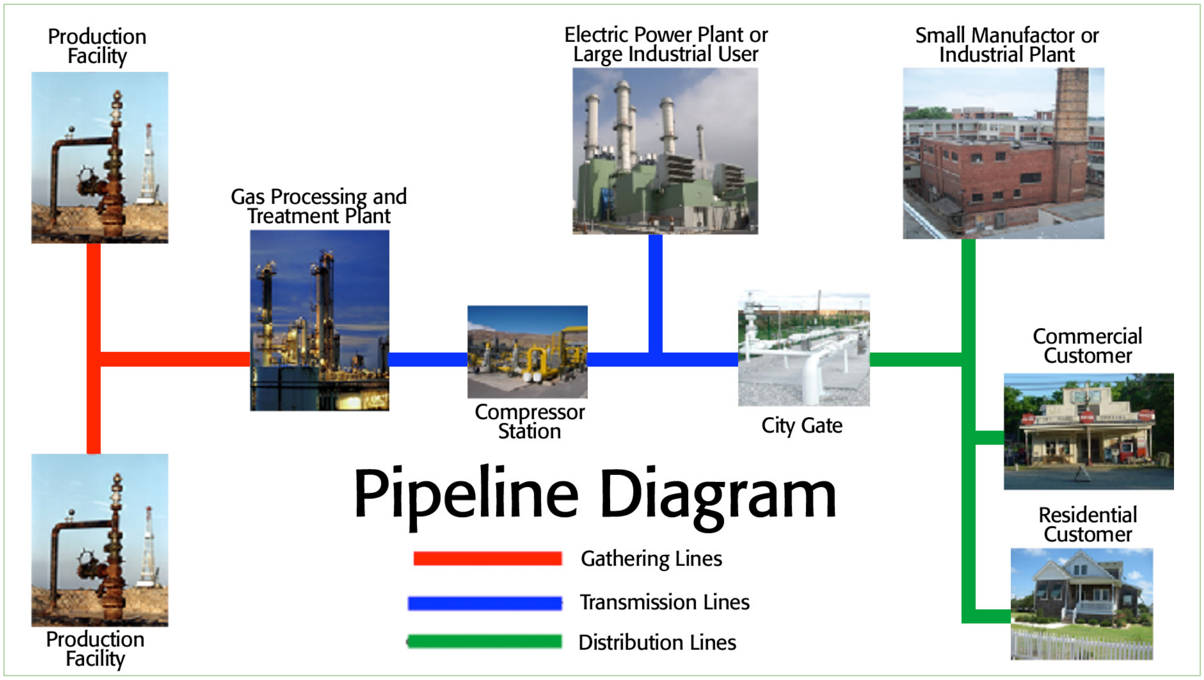
THE CURRENT U.S. PIPELINE SYSTEM

- About 200,000 miles of onshore and offshore Hazardous Liquid pipelines;
- About 320,000 miles of onshore and offshore Gas Transmission and Gathering pipelines;
- About 2,170,000 miles of Natural Gas Distribution mains and service pipelines

Finally, (and you'd think this one would be simpler) pipelines are divided for jurisdictional purposes into:

- **Interstate pipelines**
- **Intrastate pipelines**

In most cases, you can determine whether a pipeline is inter- or intra- state by finding out if it goes beyond the borders of a single state. If it leaves the state, it should be interstate; if it stays within one state, it should be intrastate. But sometimes this description is accurate, and sometimes it isn't. Some large pipelines that cross state boundaries are classified as intrastate if the pipeline ownership changes at the state line. For example, the same gas transmission pipeline designated as *interstate* in Oregon, turns into an *intra*state line when it hits California. Conversely, a transmission line that does not carry product outside one state can be considered interstate if the operator chooses to get its tariff approved by the Federal Energy Regulatory Commission (FERC), which governs tariffs on interstate transmission lines.



The gas pipeline transportation system from production to consumption

Unfortunately, even something seemingly so simple as determining whether a particular pipeline is a production or gathering line, or a gathering or transmission line, is not so simple under existing regulatory definitions, and they allow for some degree of choice by an operator in how a line is designated, and therefore how much of it is regulated as a particular type of line.

A couple other terms that are used frequently when talking about natural gas pipelines need to be defined. Unfortunately these terms are used in many different ways and standard definitions do not exist in federal regulations. They include:

Wet Gas and Dry Gas - Natural gas is a gas comprised of multiple hydrocarbons, the most prevalent being methane. The higher the methane concentration, the "drier" the gas is. Other minor components include evaporated liquids like ethane, butane and pentane, which are collectively referred to as natural gas liquids (NGLs), or condensates. The higher the percentage of NGL's, the "wetter" the gas is. There are no definitions in the federal regulations that define at what point gas is considered wet or dry.

Sour Gas – Normally this refers to natural gas that contains an appreciable quantity of hydrogen sulfide. Hydrogen sulfide is a concern because it is extremely poisonous and can cause health problems at high enough concentrations. When mixed with water it also becomes extremely acidic causing corrosion problems for pipelines.

How Natural Gas Pipelines Work

Natural gas is moved through pipelines as a result of a series of compressors creating pressure differentials – the gas flows from an area of high pressure to an area of relatively lower pressure. Compressors are powered by electric or natural gas fired engines that compress or squeeze incoming gas and push it out at a higher pressure. As one would expect compressor stations for large transmission lines are much bigger than the compressors used to move the gas through the small distribution lines to our homes. Some gathering systems do not need compressors because the pressure of the gas coming out of the wells is enough to move the gas through the gathering lines.

Natural gas is compressed in transmission pipelines to pressures typically ranging from 500 to 1400 pounds of pressure per square inch. Compressor stations on transmission pipelines are generally built every 50 to 100 miles along the length of a transmission pipeline, allowing pressure to be increased as needed to keep the gas moving. Some gas transmission pipelines are bi-directional meaning gas can be coming from both ends of the pipeline, and depending on where gas is removed and where the compressors create the pressure differential, gas may flow either direction. One example is William's Northwest Pipeline that comes past us here in Bellingham. It accepts gas from Canada to the north and from the Rocky Mountain region to the south. These bi-directional pipelines boast of greater flexibility in both supply and price to customers.

Many gas transmission pipelines are "looped," which just means there are two or more pipelines running in parallel to each other normally in the same right of way. Looping provides increased storage of gas in the system to meet demands during peak use periods.

Gas pipeline operators monitor for any problems and handle the flow of gas through the pipeline using a Supervisory Control and Data Acquisition system (SCADA). A SCADA is a pipeline computer system designed to gather information such as flow rate through the pipeline, operational status, pressure, and temperature readings. This information allows pipeline operators to know what is happening along the pipeline, and allows quicker reactions for normal operations and to equipment malfunctions and releases. Some SCADA systems also incorporate the ability to remotely operate certain equipment, including compressors and valves, allowing operators in a control center to adjust flow rates in the pipeline as well as to isolate certain sections of a pipeline.

The "city gate" is where a transmission system feeds into a lower pressure distribution system that brings natural gas directly to homes and businesses. At the city gate the pressure of the gas is reduced, and it is normally the location where odorant (typically mercaptan) is added to the gas, giving it the characteristic smell of rotten eggs so leaks can be detected. While transmission pipelines may operate at pressures over 1000 psi, distribution systems operate at much lower pressures. Some gas mains (2 to 24 inches in diameter) in a distribution system may operate up to 200 psi, but the small service lines that deliver gas to individual homes are typically well under 10 psi.

Once the gas is delivered to the local gas utility at the city gate, the gas utility's control center monitors flow rates and pressures at various points in its system. The operators must ensure that the gas reaches each customer with sufficient flow rate and pressure to fuel equipment and appliances. They also ensure that the pressure stays below the maximum pressure for each segment of the system. As gas flows through the system, regulators control the flow from higher to lower pressures. If a regulator senses that the pressure has dropped below a set point it will open accordingly to allow more gas to flow. Conversely, when pressure rises above a set point, the regulator will close to adjust. As an added safety feature, relief valves are installed on pipelines to vent gas if a line becomes over pressured and the regulators malfunction.

Construction of Natural Gas Pipelines

The construction phase of pipeline installation is a critically important time to ensure the long-term integrity of the pipeline. Below are a few of the issues dealt with during the construction phase that affect pipeline safety. Some gathering and most production lines are not required to follow these standards.

Pipeline Construction Video

This link is to a Spectra Energy video that shows what they describe as typical gas transmission pipeline construction: https://youtu.be/_gW6EU0g6ys

The content of the voiceover has a pro-industry skew, but the construction video is informative and gives a clear picture of the scale of such projects.

Materials

Most transmission and gathering pipelines are now made out of high carbon steel. Pipe sections are fabricated in steel rolling mills and inspected to assure they meet government and industry safety standards. Generally between 40 and 80 feet in length, they are designed specifically for their intended location in the pipeline. A variety of soil conditions and geographic or population characteristics of the route will dictate different requirements for pipe size, strength, and wall thickness.

Example of a problematic cross bore of a gas pipeline through a sewer line

Distribution pipelines may also be made of steel, but increasingly high strength plastic or composites are being used. Older distribution pipelines were frequently made of cast iron. Cast iron gets brittle with age, and can be susceptible to fractures when subjected to ground movement from freeze/thaw cycles or other causes. Some states require regular "frost surveys" during winter months in hopes that leaks formed from pipes cracking as a result of frost heaves are found and repaired quickly. Some plastics are also known to become brittle with age. The National Transportation Safety Board has recommended replacement of Aldyl-A type plastic pipes in distribution systems for years, yet failures in these pipes are still occurring.

Pipe Burial

Historically pipelines were installed using an open trench method, and this is still used for the majority of transmission and gathering lines. Underground techniques such as boring and horizontal directional drilling (HDD) allow pipe to be installed without digging a trench. HDD is often used where pipelines need to make river crossing as a way to greatly reduce the environmental disturbance of the river and to bury the pipeline much deeper. Boring is used extensively with distribution pipelines, especially in urban areas, for road crossings and to avoid other utilities. Both HDD and boring come with their own unique risks, for instance other utilities that are hard to locate, such as plastic or clay sewer lines, can be drilled right through (see picture). These "cross bores" often go unnoticed until the sewer lines clogs and an unsuspecting plumber or homeowner tries to clear the clog with a power snake auger. The auger may break the gas line through the pipe causing gas to leak into the sewer line and into the home where it could explode.

Federal regulations require that transmission pipelines and regulated type A gathering lines be buried at least 30 inches below the surface in rural areas and deeper (36 inches) in more populated areas. In addition, the pipeline must be buried deeper in some locations, such as at road and railroad crossings (36 inches) and crossings of navigable bodies of water (48 inches), and may be less in other locations such as when it is installed in consolidated rock (18 to 24 inches). Distribution mains must be at least 24 inches deep with some exceptions. Service lines on distribution systems must be 12 inches deep on private property, and 18 inches deep along roads and streets. The depth of burial is just for installation, and there is nothing in the federal regulations that requires this depth be maintained over time. These depth requirements went into effect in 1970, and pipelines that were installed before that time did not have to meet these requirements.

Pipe Coatings

The Enbridge pipeline that failed in Michigan in 2010 had older enamel wrap coating installed

Several different types of coatings may be used to protect the exterior of steel pipe from corrosion. The most common coatings are fusion bonded epoxy or polyethylene heat-shrink sleeves. Many coatings are now installed in the factory, but field coating application is still required in these instances in the areas where the pipes are welded together. Prior to field application, the bare pipe is thoroughly cleaned to remove any dirt, mill scale or debris. The coating is then applied and allowed to dry. After field coating and before the pipe is lowered into the trench, the entire coating of the pipe is inspected to ensure that it is free from defects. Older pipelines may be uncoated or have coal tar or enamel wrap coating. The picture here shows the older enamel wrap coating on the Enbridge pipeline that failed in Michigan in 2010.

Welding of Steel Pipelines

To carry out the welding process, the pipe sections are temporarily supported along the edge of the trench and aligned. The various pipe sections are then welded together into one continuous length, using manual, semiautomatic or automatic welding procedures. As part of the quality-assurance process, each welder must pass qualification tests to work on a particular pipeline job, and each weld procedure must be approved for use on that job in accordance with federally adopted welding standards. Welder qualification takes place before the project begins. Each welder must complete several welds using the same type of pipe as that to be used in the project; the welds are evaluated by placing the welded material in a machine and measuring the force required to pull the weld apart. It is interesting to note that a proper weld is actually stronger than the pipe itself.

Valves

The subject of pipeline valves generates substantial discussion. When it took the pipeline company in San Bruno, CA 90 minutes to drive to the valve and manually turn it off – substantially exacerbating that disaster – that led to new legislation nationally relating to automated valves on new transmission lines and a study of the idea of retrofitting certain existing lines.

On the distribution side, in 2006 Congress passed a statute requiring excess flows valves (small inexpensive valves that go on each service line to a house) to be installed on every new home built and when service lines are replaced. These "EFVs" shut off the gas to a home automatically if the line is broken by things such as excavation or a cross bore as explained earlier. PHMSA is undertaking a rulemaking in 2015 to require the installation of EFV's on multifamily dwellings and some commercial buildings.

For higher stress pipelines over 6 inches in diameter, a second level of quality-assurance ensures the quality of the ongoing welding operation. To do this, qualified technicians sample a certain number of the welds (the sample number varies based on the population near the pipeline) using radiological techniques (i.e., X-ray or ultrasonic inspection) to ensure the completed welds meet federally prescribed quality standards. The X-ray technician processes the film in a small, portable darkroom at the site. If the technician detects certain flaws, the weld is repaired or cut out, and a new weld is made. Another method of weld quality inspection employs ultrasonic technology.

Operating Pressure

Maximum allowable operating pressure (MAOP) is the maximum internal pressure at which a pipeline or pipeline segment may be continuously operated. These pressures are set at levels meant to ensure safety by requiring that the pressure does not cause undue stress on the pipeline. How this pressure is determined is defined in federal regulations and is based on a number of different factors such as the location of the pipeline, pipe wall thickness, previous pressure tests, and the pressure ratings of various components. The actual operating pressure will vary along the pipeline, depending on terrain, elevation, and distance from a compressor station. The combination of MAOP and the diameter of the pipeline determine the potential impact radius (PIR) if a pipeline should fail.

Valves and Valve Placement

A valve is a mechanical device installed in a pipeline and used to control the flow of gas. Some valves have to be operated manually by pipeline personnel, some valves can be operated remotely from a control room, and some valves are designed to operate automatically if a certain condition occurs on the pipeline. If a pipeline should fail, how quickly the valves can be closed and the distance between the valves are some of the main determinations for how much fuel is released.

Testing of Pipelines Before They Go In Service

Generally, but with certain exceptions, all regulated pipelines constructed since 1970 have to be pressure tested before they can be placed into service. The purpose of a pressure test is to eliminate any defect that might threaten the pipeline's ability to sustain its maximum allowable operating pressure plus an additional safety margin, at the time of the pressure test. A pipeline is designed to a specified strength based on its intended operating pressure. Critical defects that cannot withstand the pressure will fail. Upon detection of such failures, the defects are repaired or the affected section of the pipeline is replaced and the test resumed until the pipeline "passes".

Hydrostatic pressure testing consists of filling the pipeline with water and raising the internal pressure to a specified level above the intended operating pressure, and is the norm for testing transmission pipelines. Distribution lines are normally pressure tested with air.

Pipeline Safety Requirements During Operation

Corrosion Protection

Unprotected steel pipelines are susceptible to corrosion, and without proper corrosion protection every steel pipeline will eventually deteriorate. Corrosion can weaken the pipeline and make it unsafe. Luckily, technology has been developed to allow corrosion to be controlled in many cases to extend pipeline life if applied correctly and maintained consistently. Here are the three common methods used to control corrosion on pipelines:

- **Cathodic protection** (CP) is a system that uses direct electrical current to counteract the normal external corrosion that occurs on a metal pipeline due to soil and moisture conditions. CP is used where all or part of a pipeline is buried underground or submerged in water. On new pipelines, CP can help prevent corrosion from starting; on existing pipelines, CP can help stop existing corrosion from getting worse.

- **Pipeline coatings** and linings are principal tools for defending against corrosion by protecting the bare steel from coming in direct contact with corrosive conditions.

- **Corrosion inhibitors** are substances that can be added to the commodity running through a pipeline to decrease the rate of attack of internal corrosion on the steel, since CP cannot protect against internal corrosion. Such inhibitors are of particular use in "wet" gas pipelines.

Right-of-way Patrols

Regulations require regular patrols of pipeline right-of-ways to check for indications of leaks and ensure that no excavation activities are taking place on or near the right-of-way that may compromise pipeline safety. For transmission pipelines, these are often accomplished by aerial patrols, but federal regulations do not specify the required mode of inspection.

Leakage Surveys

Regulations also require regular leakage surveys for all types of natural gas pipelines along the pipeline routes. Personnel walk or drive the route using specialized equipment to determine if any gas is leaking and to then quantify the size of the leak. Very small leaks are a normal part of most gas pipeline systems.

Odorization

Processed natural gas is odorless, so all distribution pipelines, and some natural gas transmission and gathering lines (those mainly in highly populated areas), are required to be odorized so leaking gas is readily detectable by a person with a normal sense of smell.

Class Locations and Integrity Management

The class location of a gas transmission pipeline impacts the pressure at which the pipeline can operate, and has other impacts on how an operator must comply with the regulations. Hazardous liquid pipeline regulations do not use class locations. The class locations defined in the gas pipeline regulations consider the area within 220 yards of any given 1-mile stretch of a pipeline:

- Class 1: rural areas with ten or fewer homes/apartments;
- Class 2: an area with more than 10 but fewer than 46 homes/apartments;
- Class 3: an area with 46 or more homes/apartments, or areas of public assembly that regularly are occupied by 20 or more people; and
- Class 4: where buildings with four or more stories above ground are prevalent.

In class 1 areas the same gas pipeline can operate at a higher pressure than if that pipeline were located in a class 4 area. Class location is not the only thing that impacts the pressure – an operator can also use higher-strength or thicker steel for the pipe to achieve a higher design pressure – but class location is a very important component of the gas regulations.

—

Integrity Management refers to a set of federal rules that specify how pipeline operators must identify, prioritize, assess, evaluate, repair and validate - through comprehensive analyses - the integrity of their pipelines. Some form of integrity management applies to both transmission and distribution pipelines, although gathering lines are exempt from these requirements. Whether a gas pipeline is subject to integrity management or not, depends on whether it lies within a High Consequence Area (mainly a more populated area). Another briefing paper focuses on integrity management, so we do not go into detail here. But we bring up integrity management because of the relationship between high consequence areas (HCAs) and class locations. Though both are defined based on population, class locations and HCAs are not the same thing. Gas operators have a choice in the method they use to designate HCAs, and as a result, even some class 3 and 4 areas may not be designated as HCAs, and therefore not subject to the integrity management rules.

For further information:

Pipeline Safety Trust: http://pstrust.org/about-pipelines1/beginners/

PHMSA pipeline basics: http://primis.phmsa.dot.gov/comm/PipelineBasics.htm

Natural Gas from Wellhead to Burner Tip: http://naturalgas.org/naturalgas/