12

Engineering and Design

If a man takes no thought about what is distant,
he will find sorrow at hand.
—Confucius (551–479 B.C.)

The pipeline planners have developed a plan with preliminary routes and volumes. After uncountable iterations, they have received approval from executive management. The new pipeline project has been announced with great fanfare, and the preliminary design document is handed off to the design group for detailed engineering. Probably the design group was involved in preliminary design and is not totally shocked by what they read.

The preliminary design document includes the line's intended use (natural gas, crude oil, refined products, or chemicals), its approximate route, and its intended volumes. It has the primary receipt and delivery points, and probably has suggested operating pressures, line diameters, and wall thicknesses. Pumping or compression needs, and ideas about booster station spacing, storage needs, metering, instrumentation, and control may also be included. Every company, and sometimes every project, varies, with larger projects usually more fully developed than smaller ones. Now the design engineers have to turn the preliminary plan into a practical pipeline scheme, with all the information the constructors will need to build it.

Safety Considerations

Any chapter on pipeline design has to start by discussing safety—the overriding design theme. Beginning with the early Pennsylvania and Baku pipeline booms and extending right up to the present, pipeline companies have always been concerned with safety. When they learned how to design safer pipelines, they shared this knowledge with others, largely through industry associations. Numerous standards and best practices resulted. Pipeline designers depend on these codes and standards, as well as the education and practical knowledge of other pipeline companies. This knowledge helps them minimize the chance of failures once the pipeline is built. In addition to the standards, each country and sometimes local governments have pipeline safety regulations to insure safe pipeline design, construction, and operation. Safety considerations are woven throughout this chapter and throughout most of the book.

Route Selection

If there were only one origin and one destination, with nothing in between, and cooperative landowners, route selection would be easy. One could draw a straight line between the two points and be done. In reality, pipeline designers normally work with multiple receipt and delivery points, all located along something that hardly looks like a straight line. Sometimes it makes sense to divert the line through a major consumption center. At other times *spur lines,* smaller diameter lines extending to a location remote from the main line, make sense.

Pipeline designers balance many factors as they search for the safest, economic, and environmentally and politically friendly route that can be permitted and constructed. Many of the items are external to the engineering aspects of the new line:

- Existing utility corridors
- Population centers and populated areas
- Future development plans and land use planning
- Major crossings
  - Road
  - Railroad
  - River
  - Stream

- Environmentally sensitive areas (wetlands, threatened and endangered species, environmental cleanup areas)
- Sensitive areas (archeological, paleontological, and cultural)
- Abrupt elevation changes or steep slopes
- Earthquake and fault zones (landslide- or flood-prone areas)
- Government lands
- Politically sensitive areas

Taking into account all these factors, pipeline designers choose several potential routes for development and then send people to the field to research possibilities. Inevitably, final route selection requires time-consuming iterations. Changes are made to the route to accommodate discoveries made, even as construction progresses.

Line Size, Wall Thickness, and Looping

Line size, wall thickness, and looping are all about meeting market needs at the lowest cost. These items are so interrelated that they take a good share of the iterative process.

Engineering aspects of friction loss

Pushing fluids through a pipe requires pressure to get the molecules moving and pressures to overcome the friction between the fluid and the pipe walls. This subject has fascinated a cadre of engineers and physicists for a long time. Formulas have been developed to describe how fluids behave and what the pressure requirements are.

Friction loss equations. Frenchmen Gaspard de Prony and Henry Darcy, and the German Julius Weisbach, studied this subject in the late 18th and early 19th centuries. They are generally credited with developing the equations on which modern pipeline designers base their pressure loss equations. Prony developed (and Darcy and Weisbach refined) the equations that finally became:

$$h = f \times \frac{L}{D} \times \frac{V^2}{g}$$

where

h is pressure loss due to friction,
f is a friction factor,
L is pipe length,
D is pipe internal diameter, and
g is acceleration due to gravity.

In the previous equation, f is a dimensionless number, but all the others in the equation have dimensions—feet, inches, feet per second, and so on. However, when everything on the right side is laid out, canceled, and consolidated, the result is feet. This means that the pressure loss due to friction (h) is measured in feet of head.

The previous equation, called the *Darcy-Weisbach* equation, forms the basis for numerous other equations developed by engineers to determine pressure loss in specific applications. They all have the same underlying factors but use different dimensions and unique friction factors for their particular application.

In this equation, viscosity, density, and internal pipe roughness do not appear. However, friction loss depends on these factors. One might wonder how the equation accounts for all three. The answer is that f, the friction factor, takes care of it all. (Engineers, and even professors, just as easily refer to f as the *fudge factor,* since the calculation of friction includes so many parameters.)

Friction factor. Early pressure loss experiments used water at room temperature. The density and viscosity did not vary much, so the change in f was mainly a function of pipeline roughness. Prony, Darcy, and Weisbach each conducted experiments in which they knew, or could measure, all the other factors in the equation, including pressure loss. They conducted repeated experiments at different flow rates, pipe diameters, and lengths, then calculated f and plotted the results. Equations like the previous one, which are based on experiments, are called *empirical equations,* and pipeline designers use many of them that have endured over time.

Reynolds number. In 1883, Osborn Reynolds proposed a number he self-promotingly called the *Reynolds number.* It characterized whether a fluid was in laminar, fully turbulent, or transitional flow, based on density, viscosity, and velocity. The Reynolds number can be calculated several ways, but one popular version is:

$$Re = \frac{v_s \times L}{v}$$

where

Re is the Reynolds number,
L is length,
v_s is fluid velocity, and
v is kinematic fluid viscosity.

At first, it may appear that this equation for the Reynolds number does not consider density, but kinematic fluid viscosity is equal to dynamic fluid viscosity divided by density.

From empirical observation, Reynolds numbers below 2,000 indicate laminar pipeline flow. Internal roughness is mild, and the molecules move down the pipe in an orderly fashion, hardly bouncing off the walls. The friction factor, f, is calculated as:

$$f = \frac{K}{Re}$$

where

f is the friction factor,
K is a conversion factor, depending on the dimensions, and
Re is the Reynolds number.

Reynolds numbers higher than 4,000 indicate that the flow is turbulent, so between 2,000 and 4,000 the flow is transitional—partly laminar and partly turbulent. This makes the friction loss between these two numbers hard to calculate. To compensate, designers calculate friction loss assuming both laminar and turbulent flow and take a number somewhere in between.

Moody diagram. Pipeline construction experienced a boom in the early to middle part of the 20th century, and so did research into fluid mechanics. Inevitably, the relationship between f and the Reynolds number was reduced to a chart. Professor Lewis F. Moody at Princeton developed it as the Moody diagram around 1944 (fig. 12–1). His work was based, again, on water and showed f for pipes of varying internal roughness.

By the time Moody developed his diagram, almost all oil and natural gas main lines had been constructed of steel of fairly uniform properties, including internal roughness. Pipeline engineers proceeded to construct diagrams, based on Moody's, where they related the Reynolds number to the friction factor for their own fluids and pipelines.

Nowadays, with the widespread use of computers, and well-developed programs, engineers seldom perform loss calculations manually. They input the required variables and let the computers calculate pressure losses.

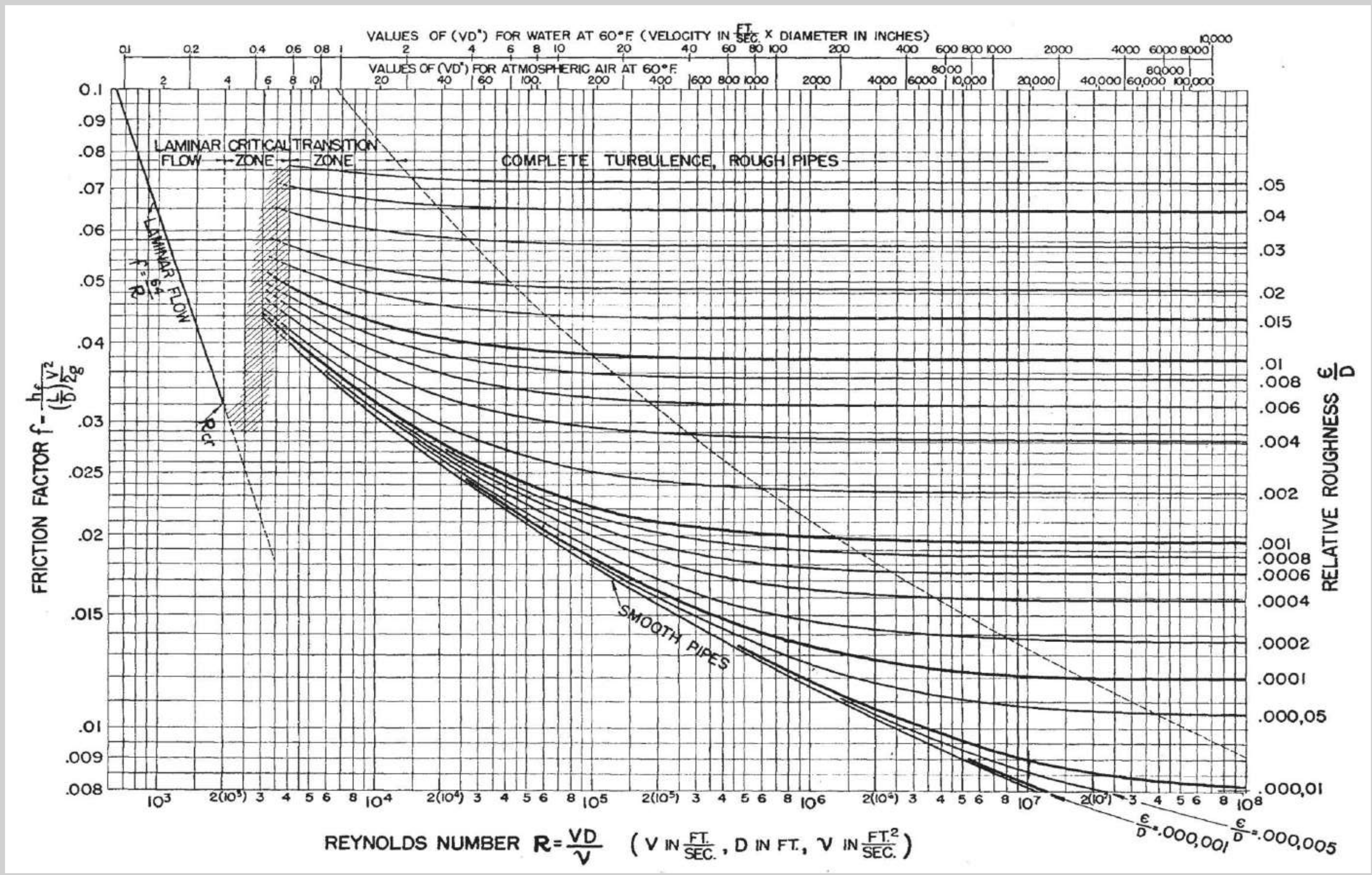

Fig. 12–1. Moody diagram (Courtesy ASME)

Systems Curves

Pipeline engineers use pressure loss, combined with elevation changes, to produce *systems curves,* graphical representations of pressure required at various flow rates for a given pipeline (fig. 12–2). To use a systems curve, one starts with a flow rate on the horizontal axis and draws a vertical line. When the vertical line intersects the systems curve, one draws a horizontal line to the left until it intersects the vertical axis. This is the pressure required to achieve the desired flow rate over the entire length of the pipeline. Systems curves are valuable tools when selecting pumps or compressors (as shown later in this chapter).

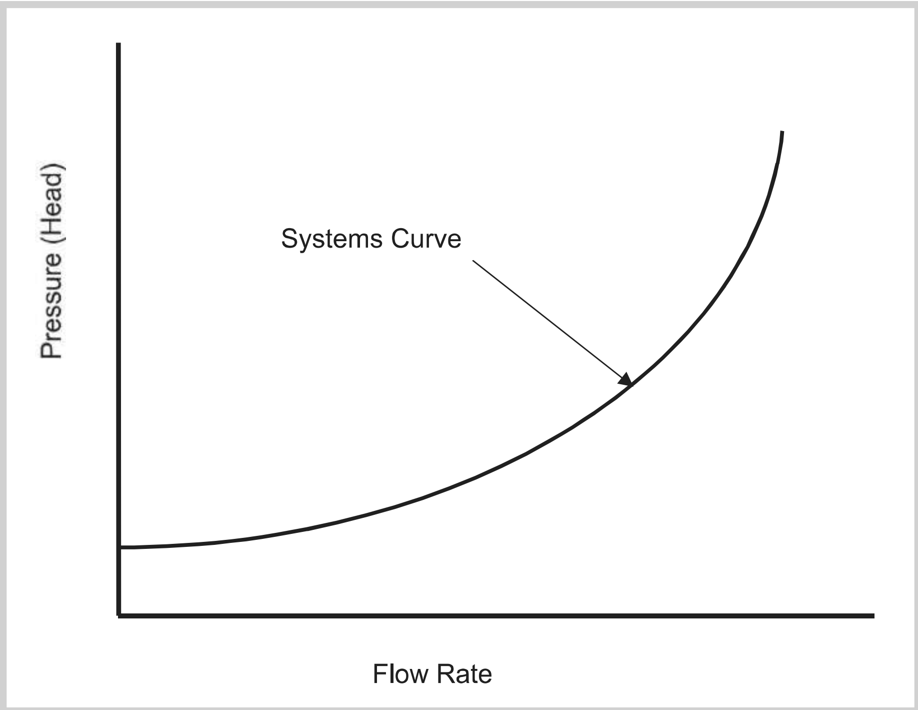

Fig. 12–2. Systems curve

In some ways, total pressure loss calculations are more difficult for natural gas than for oil. For a given fluid, velocity and density are the same along the length of a given oil pipeline. Oil pipeline designers determine friction loss per mile, multiply it by total miles, and get total friction loss. However, in natural gas pipelines, velocity and density vary. Velocity increases and density decreases as natural gas travels along, losing pressure to friction and expanding. Natural gas pipeline designers used to calculate the pressure loss in the first mile and in the last mile and average them, and then multiply by the total miles to get the total pressure loss. Now they use computer models.

In other ways, oil pipeline systems curves are more difficult. The diesel systems curve differs from the gasoline systems curve. Diesel and gasoline have different densities and viscosities, so they have different pressure losses per mile. Oil pipeline designers used to deal with this by assuming a weighted average of the product or crude oil batches in the line, producing composite systems curves.

Now systems curves are done on computers, and the primary value of the graphical curves is as an illustrative tool. Both oil and natural gas pipeline designers calculate pressure required for various different diameters, balancing cost and performance as they determine optimum diameter and wall thickness of the line.

Fittings, Flanges, and Valves

Systems curves are fine for straight pipe, but what about fittings, flanges, and valves? The manufacturers of these items typically provide *equivalent lengths* or K factors for the various types and sizes. When pipeline designers use equivalent lengths to determine pressure loss through valves and fittings, they add together all the equivalent lengths for each and multiply by the pressure loss per mile. K factors are individual pressure losses across a fitting or valve. To use them, a designer adds together these pressure losses and the pressure loss of the straight pipe. In some cases, both factors have to be added separately.

Wall Thickness and Grade of Pipe

With total pressure required in order to move various amounts of oil or natural gas in hand, pipeline designers have to determine the optimum pipe size and grade. They calculate the *hoop stress,* the force produced in the pipe wall by the fluid pressure inside the pipe pushing against the pipe wall. To do so, they use *Barlow's formula*:

$$S = \frac{2t}{D} \times P$$

where

S is hoop stress,
t is wall thickness,
D is pipe outside diameter, and
P is internal pressure.

Barlow's formula figures in an important computational, albeit convoluted, procedure. Pressure inside the pipe pushes perpendicularly against the wall all around its circumference, trying to push it apart. Steel molecules making up the pipe desperately cling to each other circumferentially, trying to hold it together. Figure 12–3 shows one slice of that pipe.

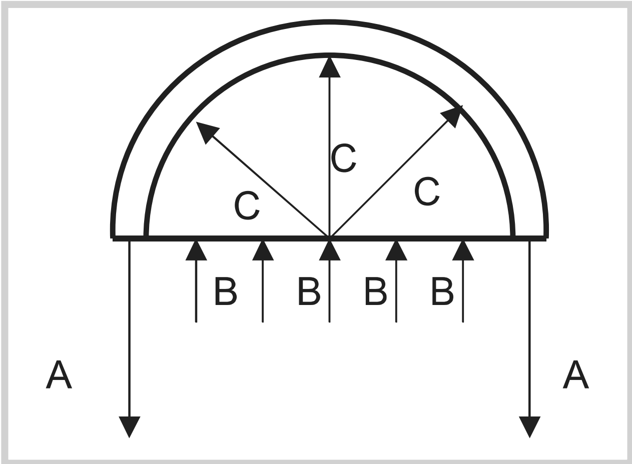

Fig. 12–3. Free-body diagram of pipe under pressure. A *represents the counterforce to* B*, holding the pipe together.* B *represents the component of* C *trying to push the wall apart.* C *represents the force on the pipe wall.*

The arrows labeled C represent the forces pushing out uniformly on the pipe. At a given pressure inside the pipe, each molecule of oil or natural gas pushes against every other molecule and against the pipe wall, all around the pipe. The bigger the diameter of the pipe, the more area over which the pressure is applied, and the bigger the force on the pipe. The offsetting force holding the pipe together is a function of the strength of the steel and the thickness of the pipe.

Pipeline designers choose pipe diameter, wall thickness, and steel to safely contain the expected pressures on the line. The MAOP of the pipe is calculated with a rearrangement of Barlow's formula:

$$\text{MAOP} = \frac{2t}{D} \times \text{SMYS} \times \text{SF}$$

where

MAOP is maximum hoop stress,
t is wall thickness,
D is pipe outside diameter,
SMYS is specified minimum yield of the steel, and
SF is a safety factor as established by standards or regulations.

As an example, the MAOP of a 30-inch piece of X-52 pipe, 0.25 in. thick, assuming a safety factor of 0.72, is:

$$(2 \times 0.25 \text{ in.}/30 \text{ in.}) \times 52{,}000 \text{ psi} \times 0.72 = 624 \text{ psi}$$

If the wall thickness is increased to 0.375 in., the MAOP goes up to 936 psi. If the diameter is decreased to 28 in., the MAOP increases further to 1,002 psi. Of course, the maximum amount flowing through the 28-in. line at its MAOP is less than the amount flowing through a 30-in. line at its MAOP. Engineers work iteratively to get the wall thickness, diameter, and grade of steel that gives the best (least costly) combination to handle the planned volumes.

Looping

Constructing two parallel lines, known as *looping,* is sometimes done during original construction to accommodate higher flow rates. More often lines are looped following original construction to increase capacity (fig. 12–4).

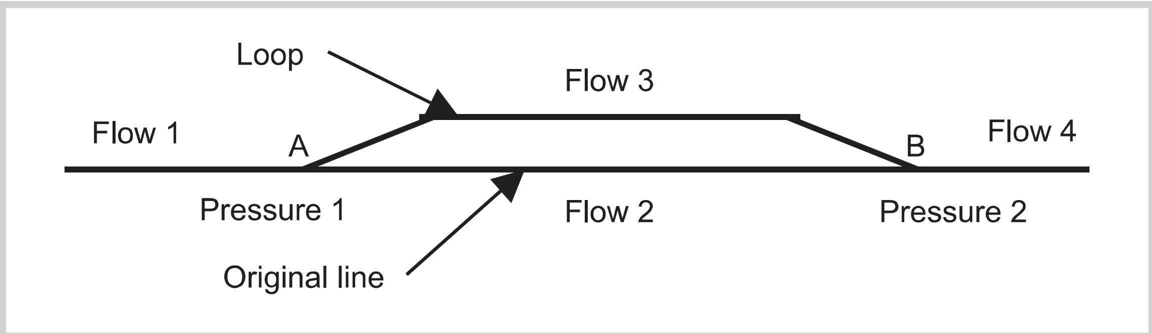

Fig. 12–4. Looping diagram

Figure 12–4 demonstrates why loops work well for natural gas pipelines but are not often used for oil pipelines. In this case, the loop starts at point A. The pressures at point A are equal in both the original line and the loop, and where the loop and original line come back together at point B. Since the loop is slightly longer than the original line, it has slightly more friction loss and consequently slightly less flow. The molecules entering the loop at point A do not exactly catch up with those traveling the original line when they come back together at point B. In a natural gas line, that is no concern. One molecule is the same as the next, more or less. However, in an oil pipeline, if the interface in the loop does not match at point B, contamination occurs. That may not be critically bad in a crude oil line, since the crude oil is processed before it goes to the ultimate customer. But contaminating a batch of refined products lines can be expensive if it requires reprocessing.

Pressure and flow calculations for loops work just like those for other lines. The pressure and flow rates are calculated separately in each of the lines, with the pressure in each line starting out the same at point A. They have to also be the same in both lines at point B.

Pump, Compressor, and Prime Mover Selection

On natural gas pipelines, PD compressors are more prevalent than centrifugal compressors. The reverse is true for oil lines. Centrifugal compressors, by their nature, offer increased reliability and take up less space than PD compressors, and are gradually taking over the natural gas compressor market. Still, many reciprocating compressors remain faithfully operating, as they have for years.

Pump selection

PD pumps push the same amount of oil regardless of pressure requirements. Centrifugal pumps move varying amounts, depending on the pressures. Superimposing a pump curve on a systems curve establishes an *operating point,* the pressure and flow rate at which a system runs (fig. 12–5).

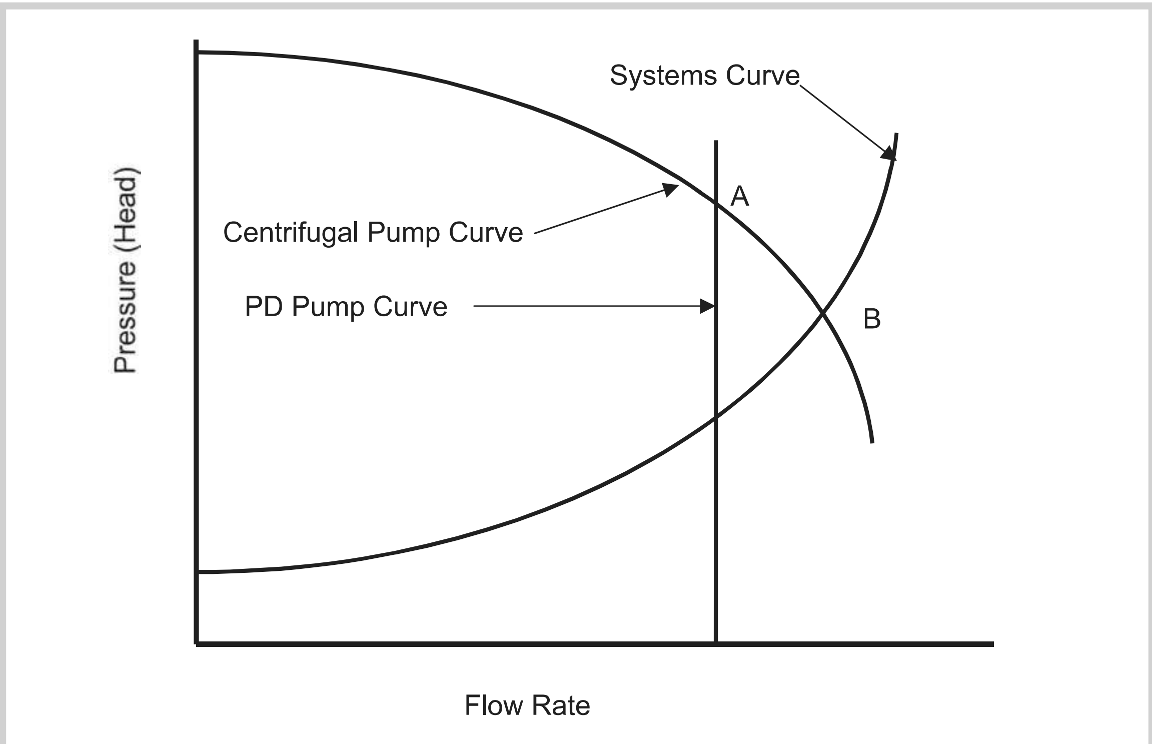

Fig. 12–5. Pump curve drawn on the systems curve. The operating point for the PD pump is A, and for the centrifugal pump, B.

Why does the pipeline operate at the operating point? It is because it is the point at which the force exerted by the pumps or compressors, the pressure added or subtracted by elevation changes, and the total friction loss are all equal and offsetting. In other words, it is the point of system dynamic equilibrium.

Until recently pipeline engineers laboriously placed pump curves over systems curves to select the best match. Today, the tedious parts of this set of calculations are done by hydraulic simulation computer programs. Still, the curves help visualize how pumps and systems interact.

Most pump stations are outfitted with two or three pumps, giving operators flexibility to vary pressures and rates. Centrifugal pumps are usually installed in series. The discharge of one feeds the suction of the next (fig. 12–6). Both pumps discharge at the same flow rate. The first pump receives the oil and raises the pressure before handing off the oil to the second one to add more pressure. The flow rates are the same, but the pressure increases are additive. Just like pumps, pump stations have representative curves. They are developed from adding together the individual pump curves (fig. 12–7).

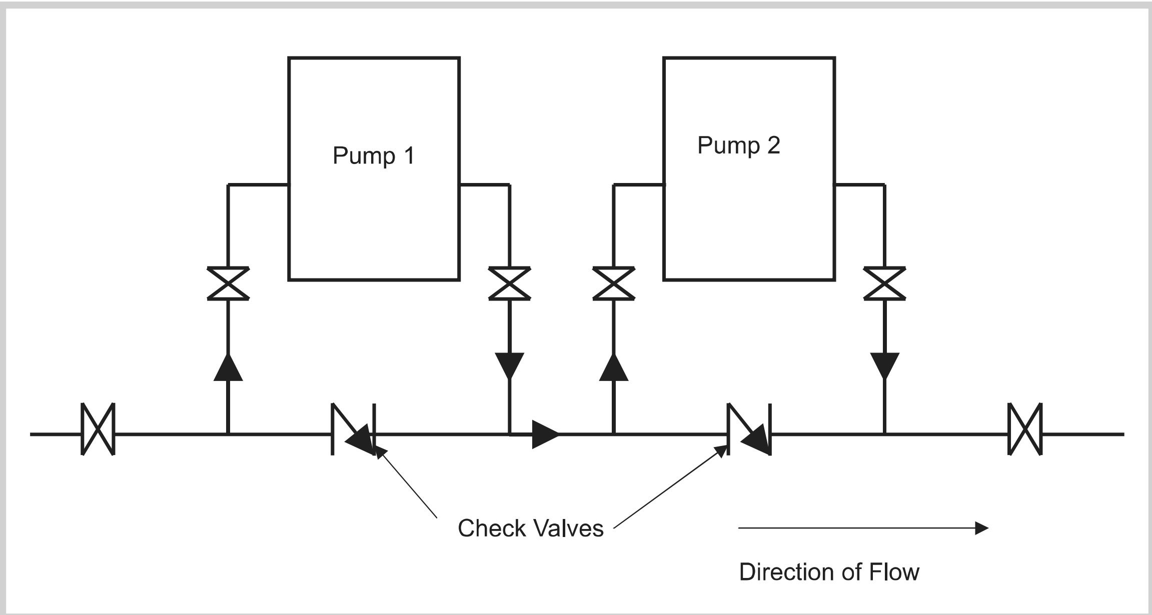

Fig. 12–6. Two centrifugal pumps installed in series. The check valves close when the pumps are operating, preventing the pumps from merely circulating product.

Where PD pumps are used, they are normally installed in parallel. PD pumps have a common suction line and discharge into a main line. Unlike pumps in series, each molecule is boosted only once (fig. 12–8). In contrast to centrifugal pumps, PD pumps installed in parallel can pump at different rates, but they discharge at the same pressure into a common discharge line.

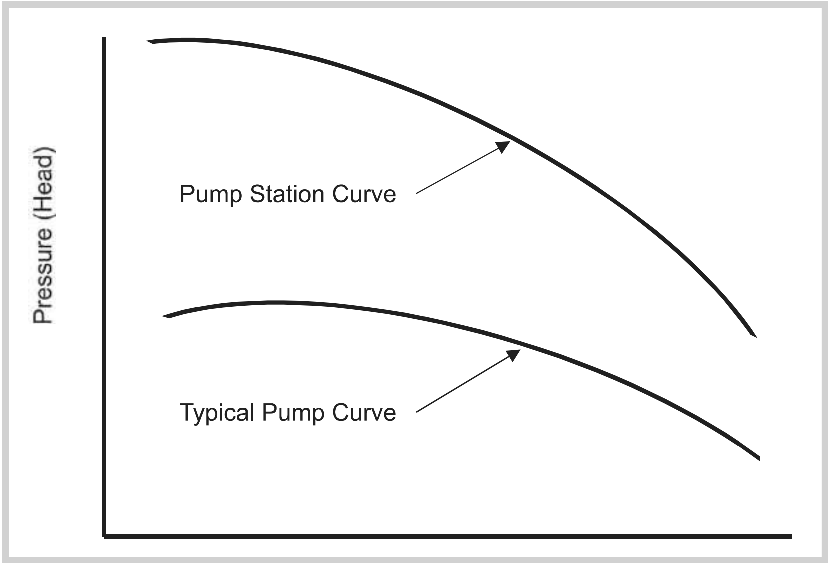

Fig. 12–7. Pump station curve. The curves for two pumps, each having a typical curve, are added together.

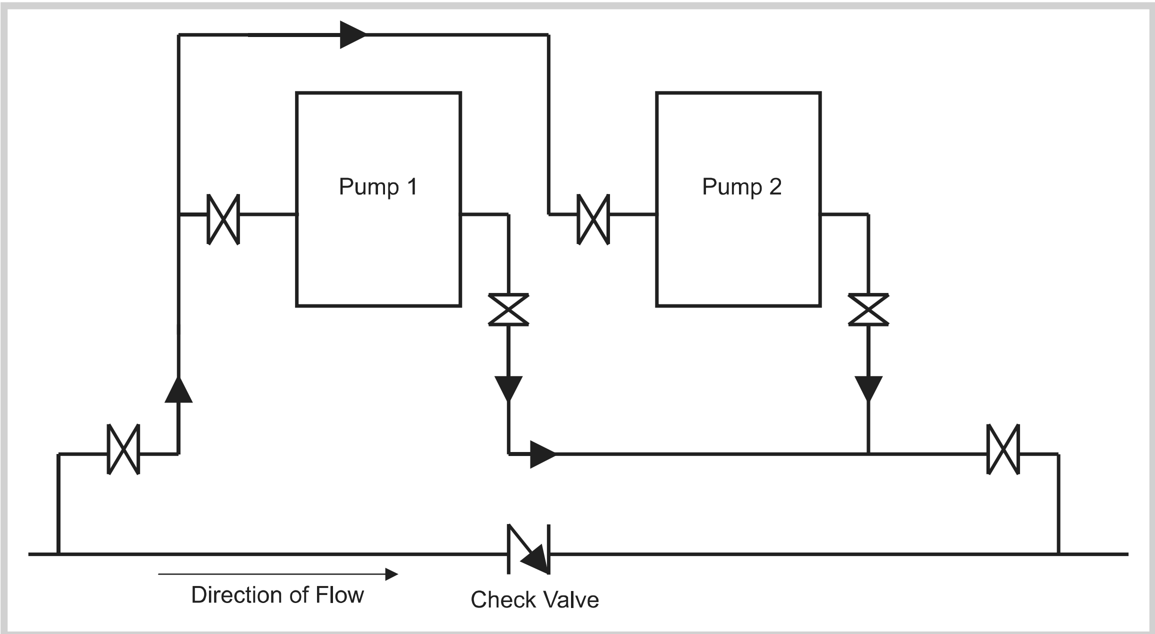

Fig. 12–8. Two PD pumps installed in parallel. The pumps have a common suction and discharge line.

The amount of pressure needed at the pump's inlet to keep the oil above its vapor pressure is the *net positive suction head* (NPSH) required. When NPSH available is less than NPSH required, vapor bubbles form as oil enters the pump impeller's eye. As the bubbles travel through the impeller and enter the volute, pressure builds and they collapse, releasing energy and causing cavitation. That can damage the pump. Different pump designs have their own required NPSH. Proper sizing and construction of the suction piping to the pump are important to prevent the excess pressure loss that can result in insufficient available NPSH.

Frequently, origination stations provide one or more small, single-stage booster pumps prior to the mainline pumps. These booster pumps have low NPSH requirements and boost the pressure into the mainline pumps to prevent cavitation.

Compressor selection

Each stroke of a PD compressor displaces the same volume. This is similar to PD pumps, with one important difference. One piston stroke displaces more natural gas molecules if the gas in the cylinder is at 1,000 psi than if it is at 100 psi. The volume may be the same, but the number of gas molecules (the weight of the gas) pushed out by PD compressors depends on the density of the natural gas in the cylinder. Unlike the line that is vertical on the PD pump curve in figure 12–5, PD compressor curves vary depending on the system pressure.

Natural gas pipelines have systems curves just like oil pipelines. Like them, the operating point is where the compressor curve (actually the compressor station aggregate compressor curve) intersects the system curve.

Compressor stations employ multiple compressors, sometimes even mixing centrifugal compressors with PD compressors. Sometimes compressors are installed in series, and sometimes they are installed in parallel. This depends on *compression ratios* (discharge pressure divided by suction pressure) and system needs. Compressors are generally operated in series to achieve additional pressure (fig. 12–9). Compressors operated in parallel into the same discharge piping (and necessarily at the same discharge pressures) have additive flow rates (fig. 12–10).

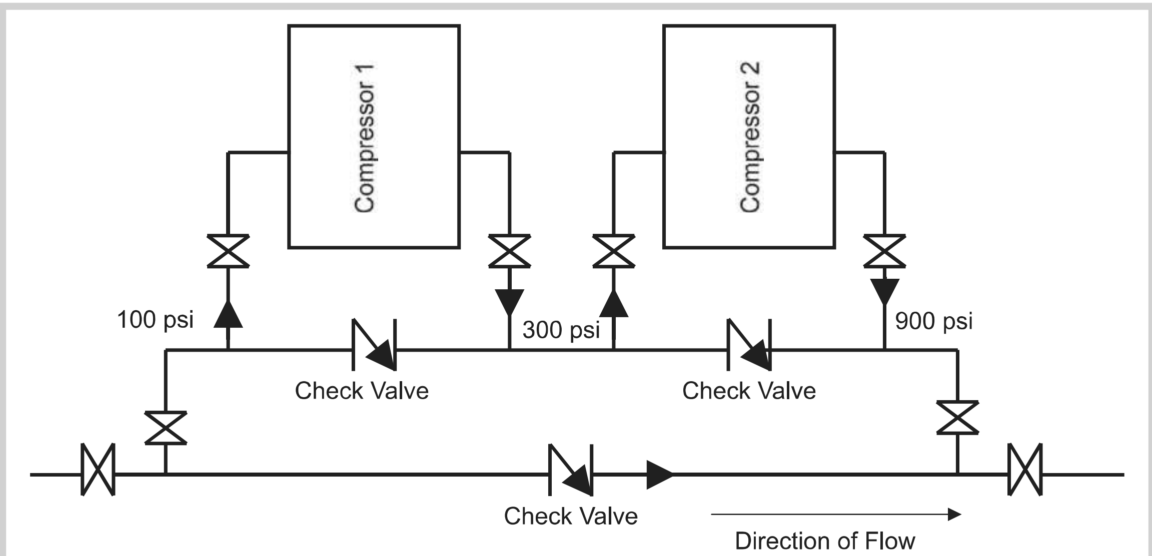

Fig. 12–9. Two compressors installed in series. Each compressor has a compression ratio of 3, raising pressure from the station inlet to the station outlet from 100 psi to 900 psi.

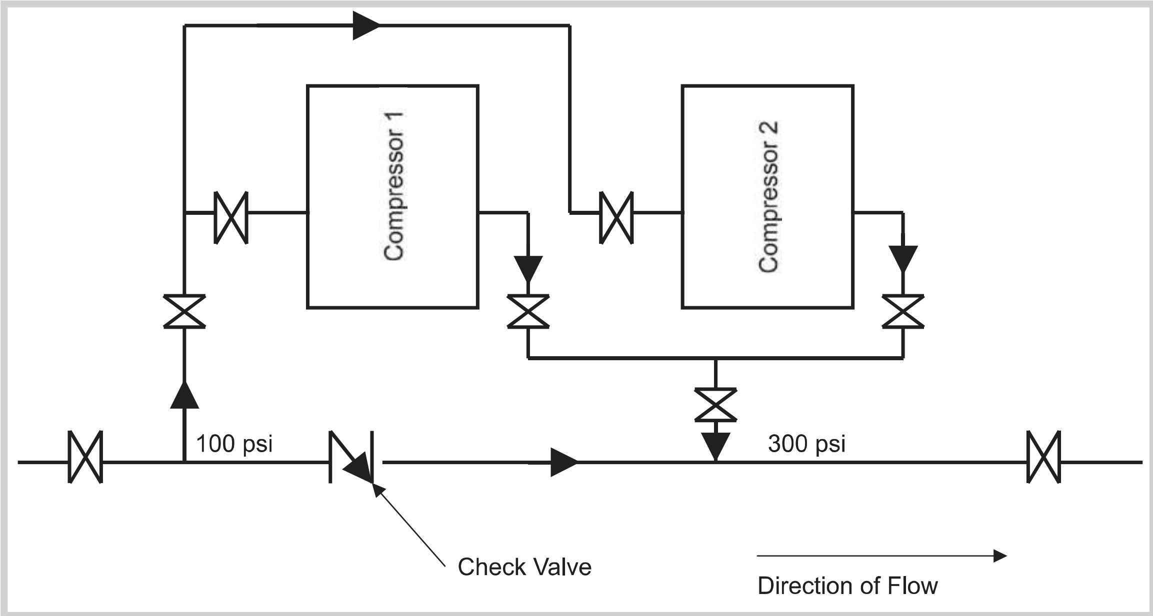

Fig. 12–10. Two compressors installed in parallel. Each compressor has a compression ratio of 3, each taking gas in at 100 psi and compressing it to 300 psi.

Prime mover selection

No one seems to know where the name *prime mover* originated. The most popular and obvious answer seems to be they are the first, or primary, source of mechanical power that drives the pumps or compressors to create pressure. Whatever the reason, the prime movers (electric motors, gas engines, or turbines) that are used to power natural gas and oil pipelines are familiar to most. As designers develop the optimum prime mover, they consider several factors:

- Compressor or pump type
- Power (primarily electrical or natural gas)
  - Source
  - Availability
  - Cost
  - Reliability
- Emissions permits and limitations
- Noise limitations

The reciprocating nature of engines coupled with ready availability of natural gas as fuel made engines (either integral or separable) ideal candidates to drive PD compressors for natural gas pipelines. This combination has been the de facto standard for natural gas pipelines for years, but centrifugal compressors are gaining popularity. Centrifugal compressors operate at higher speeds (3,000 to 12,000 rpm) than PD compressors (200 to 1,200 rpm) and call for high-speed turbines or electrical motors. The latter have fewer moving parts than engines and generally require less maintenance. As emissions and noise concerns grow, electrical motors are replacing both engines and turbines.

Early oil pipelines had steam-driven engines, but later switched to liquid fuel engines, and gradually to electric motors where electricity was readily available. Where electricity has not been accessible, engines or turbines are still used.

Flow and Pressure Control

Pipeline designers normally place several pumps or compressors in each station, giving controllers flexibility to run all, none, or any combination to achieve the required level of pressure and flow control. Beyond unit selection, there are several other ways to achieve flow and pressure control. Speed control, achieved with VSDs, is used for both PD and centrifugal pumps and compressors, and it works essentially the same for natural gas and liquids. VSDs change the speed between the prime mover and the pump or compressor, changing their curves to match the desired flow on the systems curve (fig. 12–11).

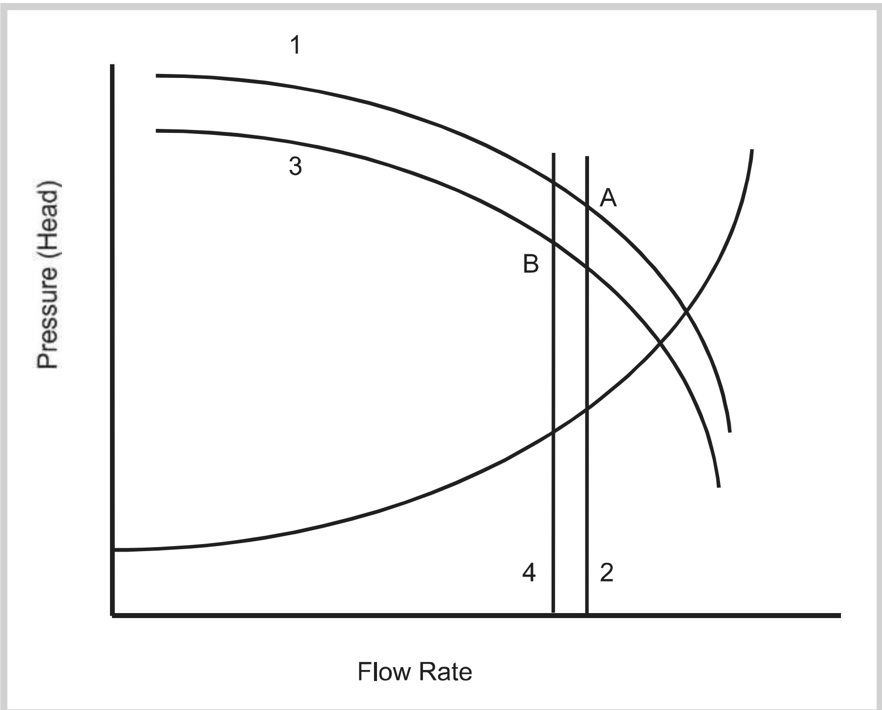

Fig. 12–11. Speed control used to move the operating point from A to B. Curves 1 and 2 are for a centrifugal and PD pump, respectively, prior to reducing their speed. Curves 3 and 4 are for the same pumps after reducing their speed.

Bypass control is also sometimes used to control PD pumps and compressors, simply recirculating some of the fluid from the discharge pipe back to the suction pipe. As mentioned previously, a pressure control valve installed in the recirculation line allows more or less flow. Recirculating more fluid gives lower pressure and flow into the pipeline, and vice versa. Recirculation is also used to control natural gas centrifugal compressors but not oil centrifugal pumps, as discussed later. Beyond speed control and recirculation, natural gas and oil controls are quite different.

Natural gas

Unit selection, speed control, bypass control, and pockets are the four ways used to control natural gas PD compressors. Pockets, discussed briefly in chapter 11, change the compressor curve by increasing or decreasing the volume of the cylinder, but leave the volume displaced with each stroke constant. Opening pockets provides less compression with each stroke, while closing them provides more.

Centrifugal compressors, in addition to using speed control, can use bypass control as well as *throttle valves* and *inlet guide vanes* (IGVs). Throttle valves are control valves installed in the compressor suction piping. They close or open, creating more or less fluid friction, allowing more or less natural gas into the compressor. IGVs are movable vanes installed inside the compressor suction piping. Moving the vanes makes the natural gas strike the impeller at different angles, changing the head characteristics of the compressor and consequently its curve. IGVs tend to be more efficient than throttle valves, since throttle valves turn pressure energy into heat by generating friction. IGVs simply change flow patterns, causing the compressor to produce more or less head.

Oil

PD pumps on oil pipelines have speed control and bypass control, just as those on natural gas pipelines. Centrifugal pumps use speed control but not bypass control. Unlike natural gas pipelines, they use control valves to change the discharge pressure, but they do not recirculate. Rather than changing the pump curve, the discharge control valves change the systems curve by creating friction loss. Discharge control valves move the systems curve to match the desired operating point on the pump curve (fig. 12–12).

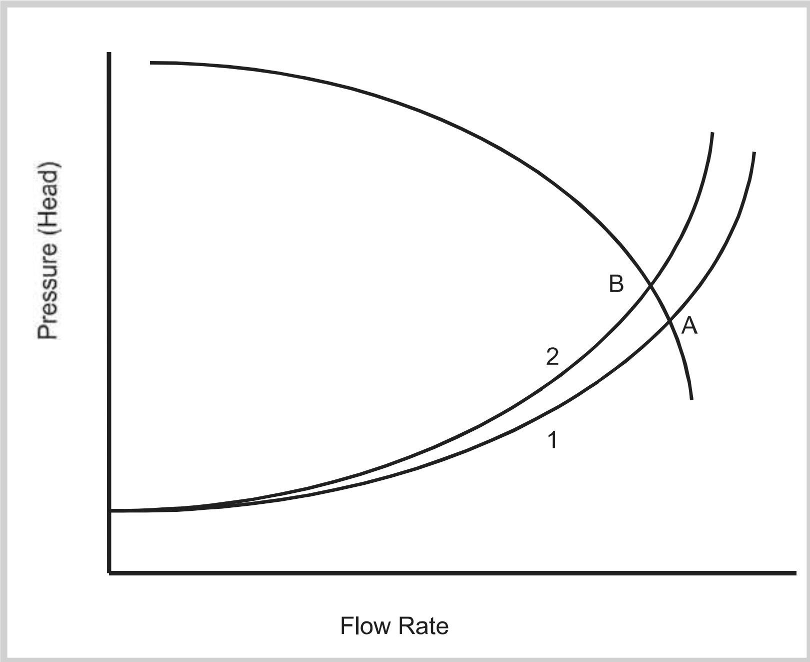

Fig. 12–12. Discharge control valve used to move the operating point from A to B. Curve 1 is the system curve with the control valve open. Curve 2 is the system curve with the control valve partially closed, moving the operating point from A to B. The distance between the curves is the amount of friction loss caused by the control valve.

There is a good reason that oil pipelines do not use recirculation to control centrifugal pumps. Each successive impeller and each successive centrifugal pump adds pressure. Relieving some of the discharge pressure back to the suction side of the pump causes the suction pressure to rise and the discharge pressure to rise. That means more recirculation, with the suction pressure rising, and so on, until the pump shuts down due to too much pressure. Compressible natural gas does not present the same spiraling problem.

Number of Stations

As a first pass to determine the number of stations, pipeline designers divide the total pressure required by MAOP. For example, one could consider a 250-mi-long, 24-in. line, with an MAOP of 1,500 psi, that requires 5,000 psi to move the desired amount. It would need about four pump stations (5,000/1,500 = 3.33). With this preliminary indication, pipeline designers decide if three or four is the best number. Perhaps it would make sense to increase wall thickness or pipe grade to increase the MAOP above 1,667 psi, thereby requiring only three stations (5,000/3 = 1,667). The capital and operating costs saved by eliminating one station may be more than the extra cost for stronger pipe. The converse could also be true, and the designers may elect to reduce wall thickness or pipe grade and build four stations.

The economic trade-off between diameter, wall thickness, pipe grade, and pump and compressor sizes typically drives station spacing to around one station every 40 to 60 mi. Economic operating pressures can cover a wide range, depending on the system. Normally though, they are between 500 psi and 2,500 psi, with most near the middle of the range.

Station Location

Pipeline designers normally try to locate intermediate (booster) pump or compressor stations near *hydraulic center points,* the points where each station on the line discharges at the same pressure. That allows pipeline designers to use identical pumps or compressors for each station, simplifying design and reducing costs. The number of stations determines the number of hydraulic center points.

All that sounds simple enough for a line with constant diameter and no elevation change, moving only one fluid. It gets more complicated when everything changes along the way, particularly for oil lines. Finding the hydraulic center for oil lines is more difficult and more important than for natural gas. Many oil pipelines operate as batch systems, moving varying grades of refined products or crude oil sequentially down the line. Hydraulic gradients and systems curves change depending on the particular assortment of refined products or crude oils in the line. For the hydraulic center, pipeline designers do the best they can, considering the array of fluids likely to move on the line.

The example introduced in chapter 4 (figure 4–14), included in figure 12–13, demonstrates how oil pipeline designers use hydraulic gradient to determine station locations. Suppose the pipe company decided to add a pump station to increase the capacity of this line. Where should they build it? The answer, based on diesel fuel, is somewhere between point A and point B.

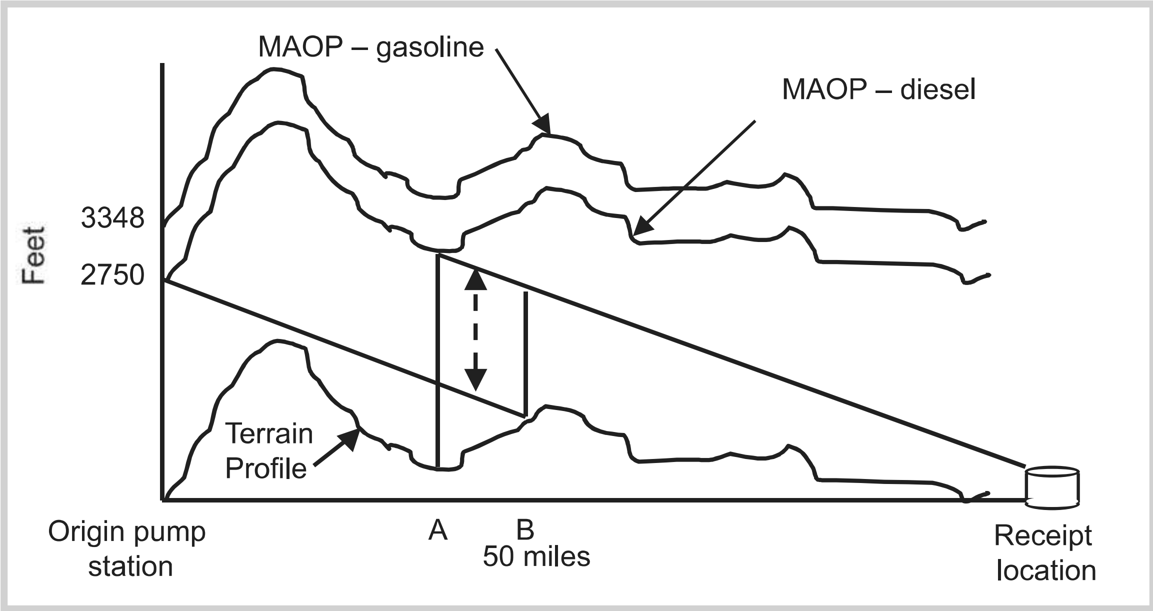

Fig. 12–13. Diesel hydraulic gradient after adding a pump station. The new station only needs to add the amount of head shown by the dashed line.

The hydraulic center point is theoretically unique for one flow rate and one fluid type. Change either, and the hydraulic center point changes as well. Locating hydraulic center points is tricky, and there is no perfect solution for batched oil pipelines. In figure 12–13, the pressure required at the origination station to pump diesel oil over the hill at the desired rate is more pressure than is needed anywhere else along the line. Consequently some might say there is not a hydraulic center point. This is different from the case of gasoline in figure 12–14. With gasoline at the given flow rate, there is a clear hydraulic center point where building an intermediate station results in discharge pressures identical to that at the origination station.

The pump station can be built anywhere between A and B and meet diesel pumping needs. Locating it at B best meets gasoline needs.

Establishing the locations of natural gas compressor stations has many of the same challenges as locating oil pump stations, but with several interesting differences. Line profiles are not as important for natural gas. "Pulling the line apart" causes contamination and interferes with leak detection in an oil line. Natural gas lines operate in a gaseous state, with flow rates varying along the line all the time.

Since natural gas pipelines normally have more receipt and delivery points than oil lines, natural gas pipeline designers pay attention to pipeline pressures near these points. A receiving pipeline may place compressors or compressor stations downstream of receipt locations to enable the delivering pipeline to get the gas into their line. A delivering pipeline may place them upstream of delivery locations to allow enough pressure to deliver.

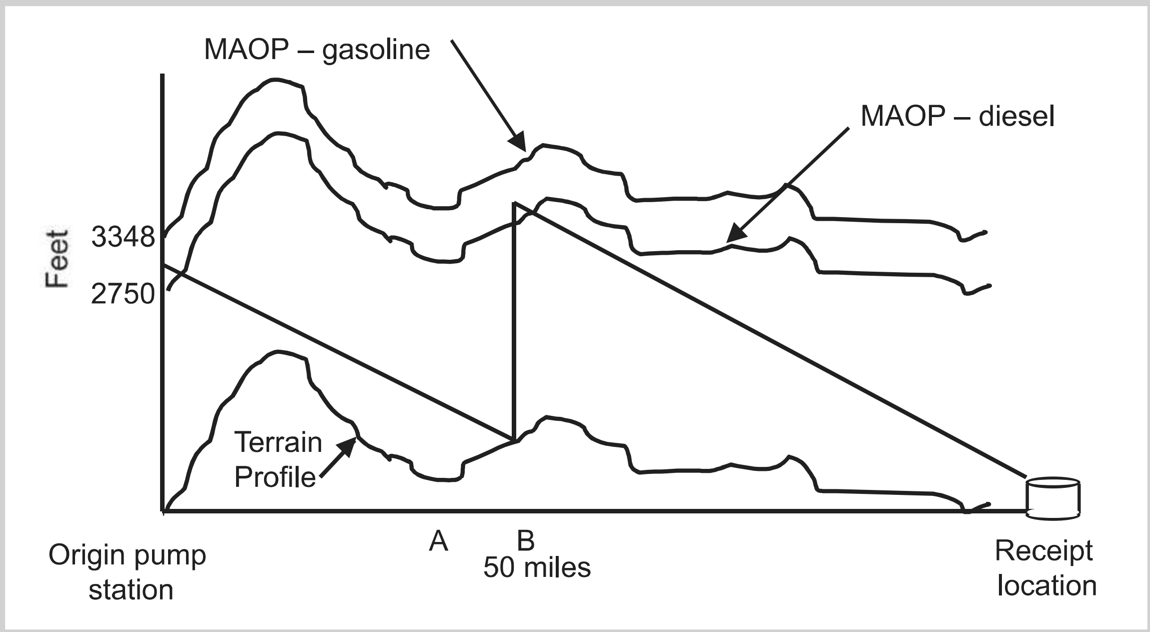

Fig. 12–14. Gasoline hydraulic gradient after adding a pump station. When pumping only gasoline, the line's hydraulic center point is at point B.

Storage

Oil is normally stored in aboveground fabricated steel storage tanks. Natural gas storage options include caverns (either washed salt dome or mined), depleted oil or gas reservoirs, aquifers, and aboveground steel storage.

Location of oil storage

Receipt and delivery points dictate the location of oil *tank farms,* groups of tanks located together. For example, one could consider refined products pipelines sequentially pumping batches of gasoline, diesel fuel, and jet fuel up the line. Along the way they may deliver into intermediate storage, used as staging areas for delivery to other pipelines. Alternatively, they might deliver into *refined products terminals,* sometimes called *bulk plants,* where gasoline and diesel fuel are stored for truck hauls to customers or gasoline stations.

Number and size of oil tanks

Each intermediate storage location or petroleum products terminal must have enough tanks of sufficient size to segregate the various product and grades. Each of these tanks (or combinations of tanks) must be sufficiently large to store the market demand of their product as other grades pass by on the pipeline. The basic elements of the tank sizing formula are:

$$\text{Tank size} = (\text{Average daily demand} \times \text{Cycle time}) + \text{Safety stock} + \text{Tank bottoms} + \text{Safe fill allowance}$$

where

Tank size is the optimum size of tank,
Average daily demand is the annual demand divided by 365,
Cycle time is the time in days between batches of the particular product,
Safety stock is the extra product kept on hand to avoid running out between deliveries or running over during delivery,
Tank bottoms is the product inaccessible in the bottom of the tank, and
Safe fill allowance is the safety factor allowed to keep from overfilling the tank.

Figure 12–15 shows the structure.

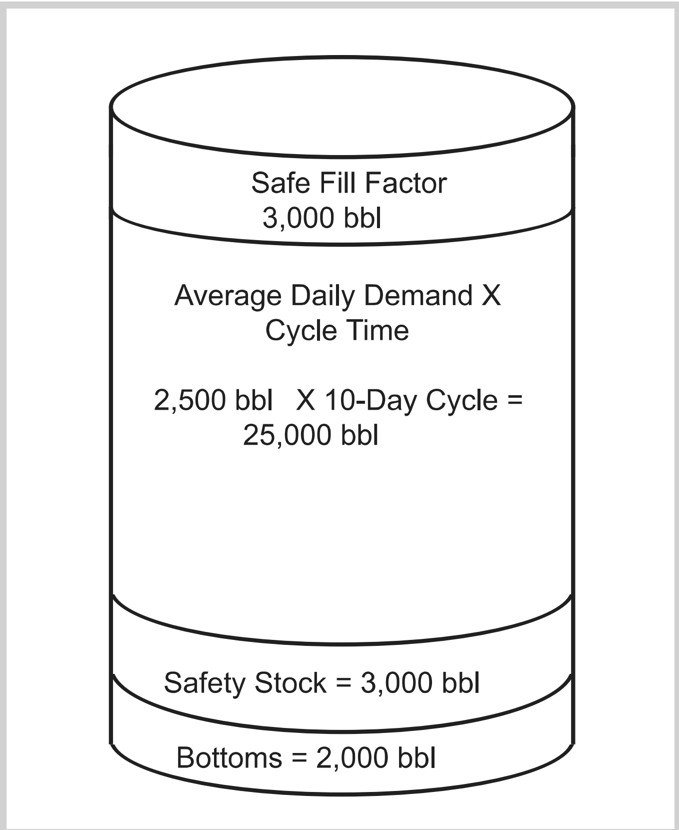

Fig. 12–15. Typical components of tank sizing. The indicated size of this tank is 30,000 bbl.

This formula seems straightforward enough, but gasoline demand is typically higher in the summer, and demand for heating fuel is higher in the winter. Thus average daily demand may also need to be multiplied by a seasonality factor. Another complicating factor concerns truck loadings. Typically more trucks load during the week than on weekends. When cycle times are 10 days, another factor, to account for the fact that two weekends occur between some deliveries into the tank and only one weekend between others, may be added.

Crude oil tank sizing, both on the receipt and delivery ends, uses the same concepts, adapting them to individual situations.

Sometimes for purely commercial reasons, pipeline companies and others build storage, and lease space to companies that attempt to buy at lower prices and sell at higher prices, keeping the commodity in storage as pricing changes.

Location of natural gas storage

Natural gas can be stored under pressure in depleted natural gas or oil reservoirs, in aquifers (water-bearing rock formations), in salt domes, or in mined caverns. If aboveground steel storage tanks are used, storage vessels are pressurized or partly pressurized and partly refrigerated to contain the gas.

Of course, depleted oil and gas reservoirs cannot be moved, and geology dictates the location of aquifers and salt deposits. Natural gas designers are therefore more constrained when it comes to storage locations. They use what is available, or build new aboveground or underground storage where geology and public opinion allow. They also build pipelines as needed to connect the storage to natural gas transmission pipelines.

One other important source of storage is the line pack on the pipeline itself. The compressibility of natural gas allows putting more into the line than is withdrawn, as long as MAOP is not exceeded. Line pack serves as important short-term storage.

Natural gas storage management

Natural gas demand varies seasonally with demand, particularly home-heating demand that is higher in the winter heating season. It fluctuates daily, and even during the day, as more natural gas is used during daylight hours when people are active and less at night as much of the population sleeps. At the same time, natural gas production capacity swings during the year (sometimes due to well maintenance) and during the day, but not with the same pattern as demand. Producers, pipeline companies, and suppliers use storage, to the extent it is available, to balance all these factors. In many natural gas pipeline systems in the world, production has to be throttled back in the summer to avoid overflowing storage capacities.

Operating storage

Pipeline companies use operating storage to balance short-term demand swings. Even in winter, they pull natural gas from storage during the day and replace it at night. In the summer, the same is true, because higher temperatures mean more air conditioners run, consuming electricity produced by natural gas–fired generation stations. During any day of the year, natural gas may be placed into storage at night. It may then be withdrawn early the next morning as people wake up and head to the shower, firing up their hot water heaters. They probably also turn up the heat in the winter, and as the sun comes up in the summer, the air conditioner kicks on.

Gas stored on the U.S. Gulf Coast takes about four days to a week to reach the U.S. Northeast. Pipeline companies would like to have storage close to the point of consumption, allowing them to respond quickly to demand changes. However, most depleted gas and oil storage fields are not located near major consumption centers. This leaves pipeline companies searching for aquifers or geologies suitable for caverns. Alternatively, it forces them to consider expensive aboveground storage or large-diameter lines to meet customer needs.

Seasonal storage

Determining the amount of seasonal storage seems straightforward. One could take the production and demand profiles and calculate how much storage is needed to balance the two. But who is responsible for seasonal storage? Sometimes pipeline companies own seasonal storage, even though they do not need it for operating reasons. Other times local distribution companies, natural gas producers, natural gas storage companies, or even trading companies own the seasonal storage. Of course, any type of storage can be used for operating as well as seasonal storage.

Station Design and Layout

In general, pipeline stations function as compressor or pump stations (origination as well as intermediate), delivery stations, storage stations (tank farms or storage fields), or interconnecting stations. They can also function as a combination of these. There are probably as many station designs as there are station designers. Accordingly, this section covers the general aspects of station design and layout, but not all the specifics.

Compressor and pump stations

These stations add pressure to the pipeline, either at the origin or along the way. One or more pipelines enter the station, and one or more exit the station. An origination station is the first pipeline station on the line. Several pipes may enter the station from natural gas or crude oil production fields, import facilities, gas plants, refineries, tank farms, storage fields, or other pipelines. Just prior to entering the station, each of these lines usually has a *station block valve,* normally a gate or ball valve used to isolate the station from the line if needed.

The line may or may not connect to a scraper receiver, used to trap pigs and keep them from entering the station. In addition, natural gas compressor stations may have scrubbers to remove liquids that have dropped out of the stream. Removing these liquids near the station entry point protects station equipment, such as compressors. Sometimes the lines have incoming meters at the station, allowing the natural gas or oil to be measured before it gets to the station.

Incoming lines may feed one or more *manifolds.* These are collections of valves, pipes, and fittings designed to commingle and feed the various streams into the compressors or pumps in an orderly fashion (fig. 12–16).

Typical station layouts include meters located where natural gas or oil moves from the incoming manifold to the compressors or pumps. *Strainers,* mesh baskets like large kitchen strainers only much larger and robust, are often installed as a precaution. These remove any rust, scale, and debris from the stream before it enters the meters, pumps, or compressors. The stream exits pumps or compressors and is discharged into the main line. Oil pipelines may have control valves between the pumps and main line, and most origination stations have launchers for inserting scrapers into the pipeline. Outgoing station block valves provide isolation on the discharge side of the station.

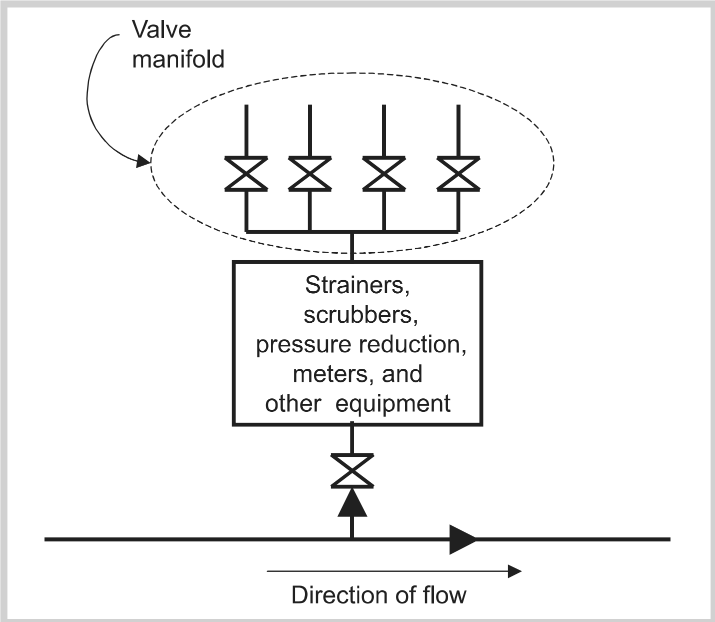

Fig. 12–16. Refined products pipeline manifold. Manifolds direct flow to specific tanks, pumps, compressors, or other equipment.

Booster stations are laid out much like origination stations, but they usually have only one or perhaps two lines entering and leaving. A booster station is normally installed on a station loop to allow it to be isolated from the main line with block valves (fig. 12–17). Like natural gas origination stations, booster stations may have scrubbers to remove liquids that have condensed out of the stream. Typically, booster stations do not have meters, since oil or natural gas does not enter or leave the stream at the station.

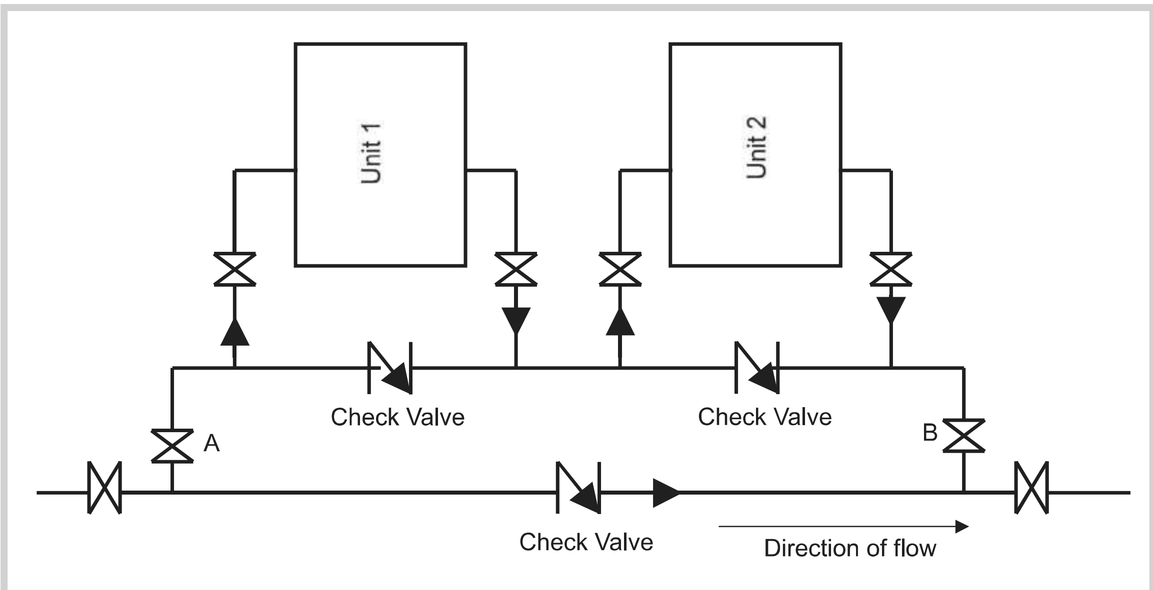

Fig. 12–17. Station loop. Closing valves A and B isolates the station from the main line to enable maintenance work.

Delivery stations

Delivery stations reduce pipeline pressures down to a level acceptable to a receiving party and measure the oil or natural gas. A typical delivery station consists of a station block valve, possibly a scrubber and a strainer, a pressure control valve, meters, and a delivery manifold.

Storage fields and tank farms

Storage fields and tank farms receive oil or natural gas, store it, and redeliver it, sometimes back to the same pipeline, sometimes to another. The equipment and its layout are essentially the same as that of receipt and origination stations, but with some additional considerations.

Storage fields. Unfortunately, not all the natural gas stored in abandoned oil or gas formations can be easily withdrawn. In actual practice, as much as 50% stays in the formation as *cushion gas* to maintain the integrity of the formation. Withdrawing too much of the natural gas in the reservoir may cause the pores of the structure, where the gas resides, to collapse, blocking the flow and reducing the useable storage space.

Salt dome caverns also require careful design and management. They have been washed out of salt formations by pumping fresh water down a shaft, dissolving the salt. Salt dome storage may be operated as either wet or dry systems. Wet systems pump brine (water saturated with salt) in or out of the dome to maintain pressure and dome integrity. If the salt concentration of the brine drops too low, additional salt dissolves from the dome walls, potentially weakening the structure. In addition, enough pressure needs to be maintained in the salt dome to keep it from collapsing. Pressure is maintained by pumping in brine and compressing the gas. Designers lay out pumps, instrumentation, and controls to keep pressures, flow rates, and brine concentrations at the correct levels to meet demand while maintaining storage field integrity. Dry systems depend on the vapor pressure of the natural gas to move it out of the cavern. As with wet systems, dry systems must maintain adequate pressure to sustain cavern integrity.

Tank farms. If natural gas inadvertently escapes, it goes into the atmosphere. If oil leaks, it can pollute surface and groundwater. Tank farm designers include earthen dikes around the tanks to contain oil if it leaks from the tank (fig. 12–18). Dikes are sized to include enough volume to hold the entire tank contents in case of complete tank failure.

Fig. 12–18. Tank dikes. These dikes contain spills, keeping them from spreading and enabling quick cleanup. (Courtesy Explorer Pipeline Company)

The pressure head inside storage tanks pushes oil out of the tank and to the pumps. The friction loss in the line and the pressure head loss or gain due to elevation differences between the tank and station pump can reduce the pressure head. As a consequence, there may not be enough NPSH available to the mainline pumps. Designers compensate by including *tank boosters,* relatively small (usually single-stage) pumps, at a tank. Alternatively, they may include one or more *yard boosters,* with connections to several tanks.

Ancillary station equipment

Most people think of piping, compressors, and pumps when they think of stations. However, there is a great deal of other ancillary and support equipment:

- Incoming electrical power and transformers
- Instruments and control equipment (discussed in chapter 8)
- Air compressors for purging and starting main compressors, and in some cases, for instruments and valve actuators
- Hydraulic pumps and motors to supply hydraulic power valve actuators

Additional Design Considerations

Designers deal with two final design considerations: crossings and block valve placement.

Crossings

Pipelines are long assets. They intersect many physical barriers—roads, railroad tracks, rivers, streams, and other pipelines, as well as residential communities and businesses. During route selection, pipeline designers attempt to minimize the number of crossings required in the final route. Invariably it is not practical or possible to go around some barriers, so plans are made to pass over or under those that cannot be avoided.

The most popular approach is a buried crossing, and pipeline designers decide whether to bury the pipe by trenching across the feature or boring under it. Trenching is usually cheaper and faster but is not always popular with the landowner.

Obstructing traffic or interfering with rivers or streams causes problems. During early attempts to bore under obstructions, the front of the drill bit sometimes was deflected from the intended route when it encountered hard dirt or a rock. This caused it to exit in unintended locations. Advances in boring with horizontal directional drilling (HDD), based on technology learned in the oil patch, has significantly improved boring reliability. This has facilitated longer and more accurate drilling.

Early in pipelining history, it seemed a good idea to place buried road and railroad crossings inside carrier pipes called casing (fig. 12–19). This practice intuitively makes sense. If the pipeline leaked under the road, it could be pulled out and replaced. Vent pipes were usually added to the casing so that vapors could escape through them to indicate a leak.

However, ideas that seem to make sense do not always work out. The two pipes, one inside the other, had to be electrically insulated from each other to prevent galvanic corrosion. Insulating spacers were developed to fill this need. Unfortunately, getting the spacers installed correctly was difficult, and corrosion problems still occurred. In addition, the vent pipes allowed airflow to the underground pipe, and humidity in the air condensed against the ground temperature pipe, speeding up corrosion.

Now, rather than cased crossings, pipeline designers normally specify installing thicker wall pipe in crossings. Concrete protective coating is typically installed to protect the cathodic coating as the pipe is pulled through bored crossings.

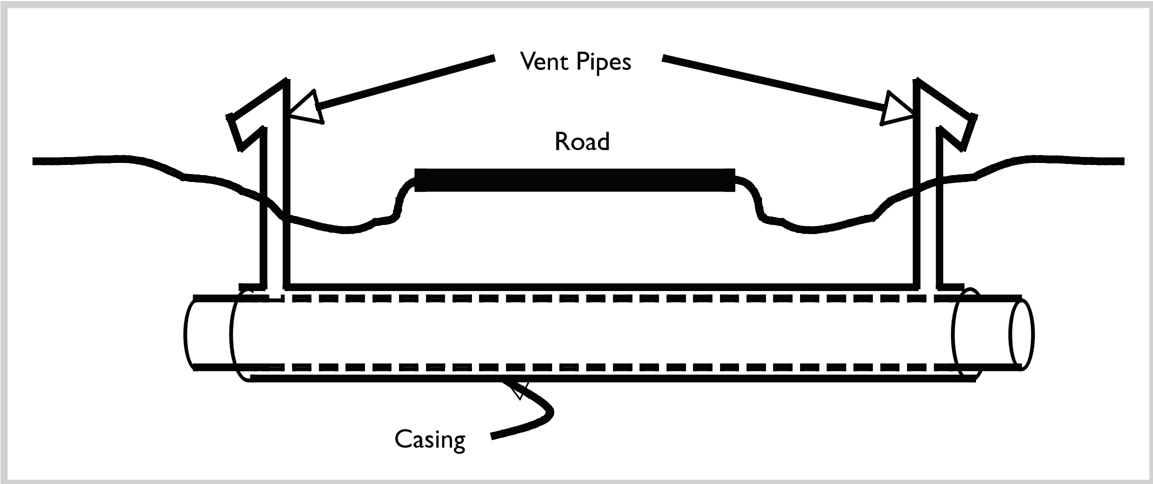

Fig. 12–19. Cased crossing. Vent pipes connected to the casing come above the surface.

Block valves

Block valves are installed along the pipeline to segment the line. They are useful during maintenance when a section of the line needs to be isolated from the rest of the line. They can also shut off sections of the line in the event of a leak. Designers look at the route profile, water, crossings, population, and other factors as they decide the number of block valves and their placement.

Conclusion

Experienced pipeliners reading this chapter will say, "It is a lot more involved than that!" They are right. This chapter simply introduces the topic of pipeline design. There are volumes of standards and recommended practices containing excruciating details. These cover all aspects of pipeline design, and detailed texts exist for those who would like to learn more.