Pipeline to Market

The success of every prospect depends as much on an operator’s ability to move oil and gas to market as it does on getting the product out of the ground. In many regions, pipelines offer the most economical and dependable means of transporting hydrocarbons from wellhead to refinery. Pipeline companies go to great lengths to safely install and operate their transmission systems.

In response to maturing production in established onshore and shallow-water basins, many E&P companies are extending their quest for reserves toward deeper offshore prospects. Drilling and completion confirm prospect viability, then set the stage for platform construction and placement. Even after the wells are tied in to the platform, the job is far from finished.

Some method of transporting the product to market must be put in place. In developed areas supported by an established infrastructure, this often calls for installation of a few kilometers of export line to tie a platform to an existing pipeline. In frontier areas, operators must either lay extensive pipeline systems over several kilometers, or rely on ships—typically shuttle tankers from a floating production, storage and offloading (FPSO) vessel—to move the product to a receiving terminal. From there, it is usually piped to a refinery. Until a means of transport is available, hard-won reserves are simply stranded, and operators must leave those reserves in the ground.

Pipeline companies strive to keep pace with E&P companies as they move deeper offshore. To do so, the pipeline industry must design and install pipeline systems that can push high-temperature, high-pressure fluids uphill over long distances in a deep, dark, high-pressure, low-temperature environment.

Even in the face of such challenges, the pipeline industry continues to break records. In 2000, a 64-km [40-mi] pipeline laid to service the Hoover-Diana project in the Gulf of Mexico, reached water depths of 1,450 m [4,800 ft]. By 2005, the Blue Stream project had installed 386 km [240 mi] of twin pipelines in depths of 2,150 m [7,050 ft] in the Black Sea. In 2008, 206 km [128 mi] of pipeline at the Perdido Norte project was laid between the Alaminos Canyon and East Breaks areas of the Gulf of Mexico, in record depths ranging from 1,067 m to 2,530 m [3,500 ft to 8,300 ft]. The Galsi pipeline, slated for construction in 2011, will stretch beneath the Mediterranean Ocean from Algeria to Sardinia, and is expected to set a new depth record of 2,824 m [9,265 ft]. Distance records are also being set. Between 2004 and 2007, the Langeled gas pipeline was laid between Norway and England; at 1,173 km [729 mi], it is the world’s longest subsea pipeline.

Whether it sets a record or not, each pipeline has unique characteristics. Product chemistry largely dictates metallurgy, while pipeline length and depth gradients dictate operating pressures and flow rates, both of which in turn influence pipeline diameter and wall thickness. These design considerations have a direct bearing on operation and maintenance practices. This article provides a broad overview of offshore pipeline construction, operations and monitoring activities.
Design Considerations

Pipeline systems consist of all the pipe, valves, pumps, meters and facilities through which production streams are transported. These systems can be divided into distinct segments (above). Infield lines are relatively small-diameter pipelines (less than 16 in.) consisting of flowlines, gathering lines and risers, which run between the wellhead and the production platform or FPSO. The infield lines transport a raw, unrefined well stream, usually consisting of a multiphase mixture of gas, oil and water from oil wells; or the lines transport gas, natural gas liquids and water from gas wells. Export pipelines, also called trunklines or transmission or sales lines, generally consist of larger diameter pipelines (ranging from 16 in. to 44 in.) for transporting processed fluids to shore from one or more fields. The processed stream, having undergone separation and initial treatment aboard a production platform or FPSO, usually consists of oil with minor amounts of water, or of gas and condensate. These pipelines typically tie in to onshore pipelines that transmit the fluids to refineries located farther inland.

Pipelines are built in accordance with stringent codes and standards. Design requirements for subsea pipelines must account for a variety of factors, including projected length, water depth and temperature, the composition and flow rate of fluids carried by the pipeline as well as the topography on which the pipeline will be laid. These factors will ultimately impact the pipeline costs, manufacturing processes, pipe-lay techniques and operating strategies.

Pipelines are designed to withstand the internal pressures generated by a specified rate of flow. However, in deep waters, internal pressure concerns are secondary to the need for pipelines to withstand external collapse pressures imposed by water depth—especially during the installation phase when no fluids are being pumped through the pipeline. Resistance to hydrostatic collapse is governed by the ovality and the compressive strength afforded by the pipe’s metallurgy and wall thickness. Thus, while internal pressure dictates pipe thickness in conventional settings, hydrostatic pressure is the dominant influence on thickness in deepwater pipelines.

While burst and collapse pressures are prime drivers, pipeline design must also consider other factors. A study of Gulf of Mexico pipelines showed that the single most significant cause of damage to pipelines is corrosion. The composition and temperature of fluids transmitted through a pipe can affect its susceptibility to internal corrosion, thus metallurgy becomes a significant design consideration—not only for strength but for offsetting the threat of corrosion. Infield lines transport unprocessed fluids; these fluids may contain hydrocarbons mixed with a corrosive blend of water, carbon dioxide, chlorides or hydrogen sulfide [H₂S], often at elevated temperatures. And conditions generally change over time as reservoir depletion alters the fluid mixture.

The pipeline industry has developed a variety of approaches to mitigate corrosion problems. Some pipeline designs increase pipe wall thickness to compensate for the expected loss of metal caused by corrosion. Others use corrosion-resistant alloys (CRAs). These alloys combine metals such as stainless steel, chrome, nickel, iron, copper, cobalt, molybdenum, tungsten or titanium. CRAs resist corrosion more effectively than carbon-steel pipe, and are chosen based on their resistance to specific produced fluid properties. Although resistant to corrosion, CRAs may not have the tensile and compressive strength of carbon-steel pipe.

CRA cladding can be used to line the inside of the pipe. In such cases, the carbon-steel outer pipe withstands the internal and external pressure, while the alloy cladding provides corrosion protection. CRA selection must also take into consideration the strength, toughness and weldability of the alloy.
In combination with corrosion-resistant metallurgy, chemical inhibition is often employed to mitigate corrosion: This technique introduces chemical additives into the production stream to reduce the fluid’s corrosiveness. Pipelines are susceptible to external corrosion—for subsea pipelines, the primary culprit is seawater, an efficient electrolyte that promotes aqueous corrosion. All metals and alloys in this environment are subject to corrosion, depending on their individual electrical potential and the pH of the seawater. The electrochemical reaction that causes corrosion can be mitigated to an extent by cathodic protection. However, with increasing depth, water temperature falls, decreasing conductivity, hence decreasing the effectiveness of anodes intended to protect the pipeline. In addition, design specifications must preclude biochemical reactions. Sulfate-reducing bacteria in marine silts generate H2S, which can attack pipelines; other organisms, such as limpets or barnacles, can rasp or bore into unprotected metals. To ward off the ravages of the subsea environment and extend the life of pipelines, fusion-bonded epoxy (FBE) or other external coatings may be employed in conjunction with cathodic protection. Pipeline design must also thwart fatigue—progressive, localized damage caused by cyclic loading of the pipe. One form of cyclic loading can be caused by vortex-induced vibrations (VIVs) as water currents flow above and below unsupported pipeline spans. These freespans result as the pipeline crosses dips and valleys in the seabed terrain or as water currents scour and erode the seabed beneath unburied pipelines. VIV suppression devices, such as helical fin strakes and fairings, can be used to protect freespans from hazards created by ocean currents.

Thermally induced stress is another problem. The flow of hot crude oil through a pipeline can result in metal expansion, which may cause the pipeline to shift position. In a straight line between two fixed and immobile points, such movement could result in catastrophic failure in the pipeline system. However, engineers can compensate for expansion and contraction by planning a gently meandering pipeline that permits lateral movement along the line; this configuration can even dampen the effects of movement caused by earthquakes and mudslides.

**Pipe Manufacture**

The pipe used for building pipelines is known as line pipe. Most line pipe is made of carbon steel; often specific alloys are chosen to attain crucial mechanical and metallurgical properties, and stainless steel may be used on occasion. The mechanical property requirements for pipeline steel are very stringent, demanding high strength, ductility, toughness, corrosion resistance and weldability in a single grade of steel. Line pipe design properties are achieved by carefully regulating alloy chemistry and thermo-mechanical processing during production. Quality control is monitored throughout the production process, from the steel mill to the pipe yard.

Line pipe specifications often call for specialized processes, from the casting of steel slabs to the subsequent rolling of the plates into strips that are shaped into the pipe. Much of the process is computer controlled, then checked by a comprehensive array of nondestructive tests, including ultrasonic, magnetic particle, and X-ray evaluations of thickness and welds.

Line pipe is either seamless or seam welded. Seamless pipe can be manufactured up to about 16 in. OD. The seam-welded variety is commonly manufactured in sizes ranging from 16 in. to 64 in. OD.

Most seamless pipe starts as cast ingots or billets that are heated in a rotary hearth furnace, then pierced by a center punch. The pierced ingot goes to a pierce rolling mill where it is lengthened as its diameter and wall thickness are reduced. A mandrel is inserted in the annulus of the hollow ingot to hold and shape the ingot as it passes through a series of rollers and then is passed to a specialized mill to achieve exact pipe shape, thickness and diameter.
Seam-welded pipes start with coils of steel, which are split into widths that conform to the requisite pipe diameter. They are then rolled and pressed to form plates of specific size and thickness. The plates are cold formed to create a tubular shape whose seam is welded shut to create the pipe.

Finished pipes are subjected to hydrostatic testing, followed by a variety of mechanical tests that measure hardness, tensile strength and other properties. To protect against corrosion, the line pipe may be coated with a layer of epoxy. Each pipe is then individually numbered and issued a certificate that documents its metallurgy, physical properties and manufacturing history.

**Pipeline Routing**

Subsea pipeline routing must account for local geography and the attendant vagaries of meteorologic and geologic hazards presented by hurricanes, tsunamis, subsea earthquakes, mudslides, strong currents and erosion. Pipeline routing has a direct bearing on the cost and feasibility of any production project. The route is ultimately a compromise that considers:

- the need for minimizing the length of the pipeline while reducing the need for presweeping of rock or debris that could damage the pipeline
- minimizing the need for trenching, burying and freespan remediation
- avoiding pipeline crossings.¹

Pipeline route selection involves far more than simply running a straight line between two points. Route design must consider the topography and stability of the sediments on which the pipeline is to be laid, its impact on benthic communities, the effects of shipping, fishing, drilling and construction activities and the presence of existing pipelines that may cross the path of the proposed pipeline.² Furthermore, routes may be influenced by uneven or rugged seafloor topography, which increase the potential for freespans and failure from VIV or bending stress (above right). Uneven terrain also contributes to severe terrain-induced pressure fluctuations as hydrocarbons are pumped up and down steep slopes.³

Long before a potential route is surveyed, a preliminary desktop survey is carried out. The desktop evaluation maps geopolitical boundaries, existing pipelines, offshore structures, environmentally sensitive areas, archeological sites, restricted areas and known geologic or oceanic hazards that may lie between the pipeline’s proposed starting point and its landfall. It lays out prescribed seabed coring intervals, and indicates where bottom conditions or routing requirements call for additional sediment samples. This preliminary assessment is instrumental in developing a proposed pipeline route, identifying areas that require more-detailed evaluations and determining how the subsequent preinstallation survey will be conducted. Thus, for example, when a desktop assessment identifies a known ordnance dumping zone near the pipeline route, it would call for a visual survey to be conducted using a remotely operated vehicle (ROV).

Next, a seafloor survey contractor conducts a preinstallation survey and maps the locations of any shallow hazards, seafloor obstructions, archeological evidence and benthic communities along the proposed route. The preinstallation survey covers a wide swath, which includes an offset on either side of the proposed pipeline path to cover areas that pipe-lay barge anchors might disturb. This swath also creates a margin for fine-tuning the proposed route without need for resurveying each adjustment. In deep water, the standard swath is about 760 m [2,500 ft] wide.

The surveys assess geologic and man-made features on the seafloor and in the shallow subsurface. Seafloor geologic hazards include boulders, fault scarps, gas vents, reefs and unstable slopes; subsurface geologic hazards include gas-charged sediments, abnormal pressure zones and buried channels. Man-made obstructions include pipelines, wellheads, shipwrecks, ordnance, communication cables, wellheads and debris from previous oil and gas activities.

Surveys play an important role in protecting the marine environment. They are useful in identifying high-density accumulations of deepwater benthic inhabitants such as chemosynthetic communities, corals and hardbottom communities. Chemosynthetic communities, in particular, are unlike most other life on Earth. They utilize chemical energy from hydrocarbons and create colonies of unusually high biomass compared with the surrounding sea bottom.⁴ These communities are thought to be closely linked with geologic faults, natural hydrocarbon seeps and hydrocarbon-charged sediments.

---

¹. Cathodic protection is a technique used to minimize the rate of corrosion of a pipeline or other metal structure. This technique does not eliminate corrosion; rather, it transfers corrosion from the protected structure to sacrificial anodes (plates or metal bars) that can be replaced. Cathodic protection relies on the electrochemical nature of corrosion, whereby electrical current is discharged through sacrificial anodes that corrode instead of the pipeline.


⁴. Benthic communities consist of organisms that live near or on the bottom of a body of water.


For their protection, bottom-dwelling communities generally require buffer zones of several hundred feet. Benthic dwellers can be adversely affected by pipe laying and attendant anchor-handling activities. Beyond the actual impacts of pipeline touchdown, anchors and associated ground tackle, there is also potential harm caused by disturbance and resuspension of sediment resulting from these activities. Survey results can be helpful in planning buffer zones. Government approval of pipeline permits is conditioned largely on what a seafloor survey reveals. Surveys scrutinize the seafloor using a variety of instruments prescribed by government regulation. Survey instrumentation is keyed to a differential GPS navigation system to ensure positioning integration of the various data. Generally this instrumentation includes, at a minimum:
- magnetometer to determine the presence of pipelines and other ferromagnetic objects
- side-scan sonar to record continuous images that permit detection and evaluation of seafloor objects and features within the survey area
- shallow-penetration subbottom profiler to determine the character of near-surface geologic features within the upper 15 m (50 ft) of sediment
- high-frequency single- and multibeam swath echosounders for continuous water depth measurements, with multibeam backscatter data providing seabed textural information.

Follow-on investigations often involve underwater cameras, video, coring or additional geophysical survey lines.

Should any of these instruments indicate the presence of shipwreck debris or concentrations of man-made objects such as bottles, ceramics or piles of ballast rock, the discovery will prompt an imposition of a buffer zone and cessation of further operations to prevent the site from being disturbed. Archeological discoveries require immediate notification of government authorities who will assess the site for its potential historical significance. Thus, surveys, by providing a means of detecting geohazards, benthic communities and archeological sites, allow pipeline operators to make adjustments along the proposed route to preclude damage of both the environment and the pipeline.

**Pipeline Fabrication and Construction**

The pipeline industry’s migration from shallow to deep water is exemplified by changes in vessel design and capabilities. Just as drilling rigs have evolved to handle greater water depths, pipe-lay vessels have followed a similar progression, from shallow-water lay barges to deep-draft ships and semisubmersibles.

Lay barges have long been employed for pipeline installation in relatively shallow waters of the Continental Shelf. Early barges were conventionally moored and relied on multiple anchors—often 12 or more, depending on the size of the vessel (above left). As the pipestring was paid out over the stern, the vessel moved forward by reeling in anchor chain at the bow while easing it out over the stern. Once all the anchor chain was paid out, an anchor-handling vessel reset the anchors before the pipe-lay vessel advanced. Long anchor chains, however, decrease station-keeping precision, thus the depth in which con-
tionally moored lay barges can be used is limited to around 1,000 ft [305 m]. 12

Deep waters call for pipe-lay ships or semi-submersibles that employ dynamic positioning for station keeping. These vessels use multiple thrusters—propellers that swivel azimuthally to create opposing thrusts—to maintain their desired position. The dynamic positioning systems are usually driven by a computer system linked to a satellite-based geographic positioning system. Dynamic positioning requires significantly more fuel than conventional mooring, but increases the efficiency of the pipe-lay operation. 15

Pipeline design—particularly diameter, thickness and metallurgy—dictates the maximum tension, compression and bending stresses that a pipe can sustain during installation. Likewise, to avoid stress limits that could cause the pipe to buckle during installation, the choice of installation technique is crucial. The selection is largely governed by water depth; the most common are the S-lay, J-lay, pipe-reel and tow-in techniques.

The S-lay technique—so designated because the pipeline assumes an elongated S-shaped profile as it is lowered from the vessel to the seafloor—was originally developed for relatively shallow waters. An S-lay vessel is distinguished by a long stinger, a truss-like structure, which is equipped with rollers and a tensioner (previous page, bottom). The stinger is mounted off the stern to support the pipe as it leaves the vessel. On an S-lay vessel, individual joints of line pipe are laid out horizontally, welded together, X-rayed or ultrasonically inspected and coated with FBE as the pipeline is built on deck.

Stinger configuration affects the bending stresses that occur as the pipe is lowered to the seafloor. The pipe departs the stinger at the liftoff point, and contacts the seabed tangentially at the touchdown point (above right). The pipe experiences the greatest stresses at the overbend, where the pipe leaves the vessel, and in the sagbend, which extends upward from the pipeline touchdown point on the seafloor. The curvature of the overbend is controlled by the rollers on the stinger; sagbend curvature is controlled by the tensioner and vessel positioning. 14

The S-lay method has evolved for operations in ultradeep waters through modifications of the stinger and tensioner system. 15 Deep waters require a steep liftoff angle to accommodate the overbend segment, which can be achieved by a longer and more curved stinger. To date, this method has been used in waters as deep as 8,960 ft [2,731 m], and on such projects, the stinger length can easily exceed 450 ft [137 m]. 13

The J-lay method was developed for laying pipe in deep waters. J-lay vessels are distinguished by a near-vertical fabrication tower (below). Lengths of pipe are positioned at the uppermost station of the tower, where they are vertically joined together at automated welding stations. The pipe is then lowered to an ultrasonic inspection station and a field coating station before it passes through the moonpool and into the water. 15 On some vessels, a short stinger extends beneath the hull to support the pipe string, which takes on a J-shaped profile as it contacts the seabed. This profile puts less bending stress on the pipe string in deep waters. However, the J-lay method becomes impractical for shallower waters, where depths of less than 200 to 500 ft [61 to 152 m] limit the shape of the

---

16. Flowlines from Cheyenne Field, set in 8,960 ft [2,731 m] of water, were laid to the Independence Hub platform at Mission Canyon Block 920 in the Gulf of Mexico.
17. A moonpool is an opening in the vessel hull designed to permit the passage of equipment between the deck and sea. A moonpool may be found on reel-lay vessels and on certain J-lay vessels.
Spoolbase. The Technip spoolbase near Mobile, Alabama, USA, is capable of handling and welding pipe up to 18 in. OD for reel lay. The fabrication building houses two independent welding lines with alignment, welding, nondestructive examination and field joint coating stations. Technip’s Deep Blue pipe-lay vessel, docked at the end of the queue (upper left), is reeling aboard pipe. The vessel (insert), is 677.5 ft [206.5 m] long, and is equipped with twin reels, 131 ft [40 m] in diameter, each capable of carrying 2,800 t of rigid pipeline ranging from 4 in. to 18 in. OD. Flexible pipeline can be carried below deck. (Graphics courtesy of Technip USA Inc.)

Pipe angle and impose severe bending stresses on the pipe.

Pipeline installation is also carried out by reel ship. At an onshore spoolbase, long sections of rigid steel pipeline, each about 1 km [0.62 mi] long, are welded together (above). The welds are inspected and coated with a resilient protective coating of flexible epoxy or polyethylene, then the pipe is spooled aboard a vessel-mounted reel. After reeling the pipe on board, the ship departs for the pipe-laying area.

There, the pipe is fed off the reel, straightened and anchored to the seabed. In deep waters, the pipe may need to be tensioned to minimize sag that would otherwise develop as the pipe is lowered from the surface to the seabed. If the sag bend becomes too severe, the pipe will buckle.

The ship then steams at about one knot [1.85 km/h, or 1.15 mi/h], depending on weather conditions, as it slowly reels out the pipe. When all pipe has been led off the reel, a bull-plug is welded in place to seal the end of the pipe, then it is lowered to the seabed. A buoy is attached to mark the end of the pipe. The ship then proceeds to port to replenish the reel or to take on a new, fully loaded reel. Upon returning offshore, the end of the previous pipeline is retrieved from the seafloor, welded to the new line, and the process is repeated.20

A fourth approach, called the tow-in method, is used typically for insulated pipe-in-pipe or bundled pipe assemblies. This method first calls for welding, inspection, joint coating and anode installation at an onshore fabrication facility. The assembled pipe is then placed in the water and submerged. Buoyancy tanks and chain weights are usually attached to achieve neutral buoyancy. Seagoing tugboats or offshore support vessels then tow the pipe along a tightly controlled route that has been surveyed to identify potential seafloor hazards.

The main advantages of the tow-in method are that it permits complex or specialized fabrication techniques to be carried out in controlled conditions at facilities ashore. However, the length of the pipeline is also constrained by the space limitations of the fabrication facility.21 This method is especially suitable for bundled pipelines, where several pipe sections or umbilicals are tied together and shrouded within a carrier pipe. However, the tow-in method carries increased risk that the pipeline could be damaged through contact with a submerged obstruction.

A combination of techniques may be employed over the course of the pipeline installation, particularly if water depths change drastically along the proposed route. Perhaps the most challenging problem arises when an offshore pipeline makes landfall and must be installed in the often treacherous zone between land and sea.

To address the issue, a cofferdam can be extended from the beach for hundreds of feet, into near-shore waters. A dredge deepens the seaward approach to enable a pipe-lay vessel to reach the cofferdam. The cofferdam provides a stable framework in which a concrete conduit can be buried well below the depth of the existing beach floor.

This approach was used to land the Langeled pipeline at Easington, on the east coast of England (next page). The 44-in. gas line approaches shore in a pre-excavated offshore trench, dredged some 12 mi [20 km] from shore, starting in water 120 ft [37 m] deep. As required in shallow waters, to prevent anchor, trawl and dropped-object damage, the 6.5-ft [2-m] deep trench was backfilled to bury the pipeline. For the shore crossing, a temporary causeway had to be constructed during low tides using land-based heavy construction equipment. This causeway provided access through the intertidal zone for construction of a 787-ft [240-m] long sheet-piled cofferdam, built alongside the causeway. Starting at a tie-in pit located inland from the high-water mark, the cofferdam extended from the beach 200 ft [60 m] beyond the low-tide level.20

An unstable cliff face stood between the beach and a gas terminal. A tunnel-boring machine created a 1,247-ft [380-m] long concrete tunnel that provided a conduit through the cliff to permit access between the gas terminal, tie-in point and cofferdam. The tunnel and cofferdam were completed in advance of the lay barge arrival. A 500-t winch was then used to pull the pipeline from the lay barge into the tie-in pit, and the pipe was tied in 43 ft [13 m] below the low-tide level. Pipe welds were inspected and coated as the offshore pipeline was tied in to the onshore line. Once the tunnel and pipeline were safely buried, the causeway and cofferdam were removed and the site was restored to its natural state, providing no visible evidence of landfall for a pipeline that carries nearly 20% of the UK’s demand for natural gas.

Operations and Maintenance

Deepwater pipelines operate in low water temperatures under high hydrostatic pressures. Despite this hostile setting, the life span of most pipelines is 20 to 40 years, in part because corrosion management strategies and attentive pipeline monitoring are helping to increase their longevity.
A chief concern for deepwater pipeline engineers is the formation of solid compounds, such as asphaltenes, hydrates and wax. Under certain conditions, these compounds can increase fluid viscosity and restrict flow within pipelines. Pressure, temperature, fluid composition, pipe surface, flow regime, and shear can affect the deposition of waxes and asphaltenes. To precisely understand how these individual parameters affect deposition inside pipelines, Schlumberger engineers have developed a testing cell.

The RealView live solids test cell measures oil deposition in turbulent flow, with temperature control from 4°C to 150°C [39°F to 302°F] and pressure adaptability to 103 MPa [15,000 psi]. This deposition cell is suitable for testing sour, H₂S-entrained fluids. In closed batch mode, the cell requires a sample volume of only 150 ml [9.15 in.³] per test run, but can accept up to one liter [61 in.³] for flow-through testing. The RealView test cell consists of a cylindrical vessel with an axially centered heat source. The outer wall of the vessel is stationary, and the inner wall, or spindle, rotates to create either a turbulent or laminar flow regime in the annular space.

Controls on this live solids deposition cell enable precise and independent regulation of pressure, temperature, differential temperature and spindle speed. The deposits are collected and then quantified using high-temperature gas chromatography for wax deposit analysis. Simulated distillation, a technique that uses gas chromatography to simulate the distillation process in the laboratory, is employed for asphaltene deposit analysis. Deposit mass is then used to calculate a deposition rate. RealView live solids deposition studies can help operators evaluate the effects of chemical additives on deposits under representative conditions. The RealView experimental data can also be used in commercial software such as PIPESIM production system analysis software to build wax- and asphaltene-deposition simulations. Armed with these results, operators can fine-tune flow rates in their pipeline system, determine how frequently remedial procedures need to be conducted and select the optimal chemical treatment and dosage.

19. As of 2007, the maximum length of towed-in pipeline was 7 km [4.35 mi]. Kyriakides and Corona, reference 7.
Some pipelines require insulation or heating to meet proper thermodynamic conditions. Many pipelines rely on chemical injections of inhibitors or solvents, such as ethylene glycol, tri-ethylene glycol or methanol. Operators also routinely resort to a mechanical approach to remove buildups from their pipelines.

Pipeline inspection gauges, or pigs, are plunger-like devices that clean the inner walls of the pipeline. Pigs are available in various sizes, shapes and materials, ranging from metal pipe scrapers and flexible brushes to plastic foam spheres. Most have an outside diameter nearly equal to the inside diameter of the pipe to ensure a fairly tight fit. Some pigs are equipped with sensors (above). These “smart pigs” are even capable of detecting internal corrosion or locating leaks in pipelines.22

A pig is forced through the pipeline by exerting pressure on a gas or liquid to the back, or upstream end, of the pig. As the pig travels downstream, it scrapes the inside of the pipe and sweeps any accumulated buildup or liquids ahead of it. These are collected, along with the pig, at the end of a segment of pipe known as a pig trap. Routine pigging operations remove deposits in the pipe as a normal part of production operations. The frequency of pigging varies with flow rates, operating temperatures and nature of the produced fluid, and may be carried out on weekly, monthly or less frequent intervals.

Monitoring at the Speed of Light
Operators monitor the integrity of pipelines to ensure their continued performance, protect the environment and prevent product loss. There are two approaches to monitoring pipelines. Periodic inspection and surveying use mobile units such as pigs, ROVs or autonomous underwater vehicles (AUVs). Continuous monitoring involves permanently installed leak detection sensors.

A variety of sensor technologies has been adapted for subsea pipeline monitoring.23 These include the following:

- Capacitive sensors measure changes in the dielectric constant of the medium surrounding the sensor. The capacitor is formed by two concentric, insulated capacitor plates. The sensor’s capacitance is directly proportional to the dielectric constant of the medium between the capacitor plates. Because the dielectric constants of seawater and hydrocarbons differ, direct contact with hydrocarbons will register as a change in measured capacitance.
- Fluorescence detectors use a light source to excite molecules in the target material to a higher energy level. When those molecules relax to a lower state, light is emitted at a different wavelength, which is measured by a fluorescence detector.
- Mass balance methods monitor the pressure drop between two or more pressure sensors installed in the pipeline.
- Methane sniffers rely on the diffusion of dissolved methane through a membrane and into a sensor chamber, where the dissolved methane changes the electrical resistance, which generates a signal from the detector. A variation on this method uses optical nondispersive infrared spectrometry. Using this method, the methane concentration is measured as the degree of absorption of infrared light at a certain wavelength, in which the intensity of infrared light at the detector is a measure of the methane concentration.
- Passive acoustic sensors use hydrophones to measure the pressure of a sound wave generated by a rupture or leak as it is transmitted through a structure or water. By using more than two sensors to measure the arrival time of sound, it is possible to triangulate on the origin of the sound.
- Sonar detectors emit pulses of sound that are reflected by impedance changes between different media. The impedance depends on sound velocity, density, salinity and temperature of the medium. Fluids of different density, such as water and hydrocarbons, will have different acoustic impedance.
- Video cameras enable visual surveillance of the subsea system.

Ideally, a monitoring system would continuously detect and locate conditions that might forewarn operators of potential troubles anywhere along the pipeline, then combine and interpret the outputs of multiple measurements in a meaningful, prioritized display. These capabilities have been incorporated into fiber-optic monitoring systems that are being installed in offshore and onshore pipelines worldwide.

Optical-fiber sensors have an established track record of reliability, and distributed temperature sensors (DTS) have been in use since the mid-1980s. This type of sensor uses the optical fiber itself as both the sensing element and the data highway back to the controller. These sensors are based on optical time domain reflectometry (OTDR), a proven technique long used in the telecommunications industry. DTS systems are able to make precise temperature measurements every few meters along the optical fiber for distances up to 100 km [62 mi]. More localized measurements use a technology known as fiber Bragg gratings, which performs highly precise...
measurements of parameters such as strain and temperature using optical gratings inscribed in the core of the optical fiber.

The Integriti Platinum fully integrated pipeline monitoring system uses fiber-optic technology to help pipeline operators monitor conditions along the length of the pipeline. Continuous temperature, strain and vibration measurements enable the detection of a wide range of events that may threaten a pipeline’s integrity. This fiber-optic system uses variations on the DTS theme: Distributed strain temperature sensors (DSTSs) have been developed for monitoring strain; distributed vibration sensors (DVSs) measure vibrations or acoustic signals along the optical fiber. The Integriti Platinum system can measure temperature variations of 2°C [3.6°F] across 100 km of pipeline and measure strain with a resolution of 40 microstrain at 10-m [33-ft] intervals. The integrated sensors can detect and locate small pipeline leaks that are below the threshold of traditional leak detection systems based on pipeline flow rate—typical gas leak response time is just 30 s. The system can be used for a number of monitoring applications.

Onshore pipeline operators have used the DVS capability to detect the approach of heavy equipment, thus warning of digging and construction activity taking place near their pipeline. The vibration sensors are sensitive enough to detect human foot traffic. Offshore or onshore gas leaks may initially be detected by DVS, which identifies the characteristic noise of escaping high-pressure gas and issues an alert. This event can be followed by DTS or DSTS detection of localized Joule-Thomson cooling. Fluid leaks and flow assurance problems are detected by the temperature anomalies sensed by DTS or DSTS. Ground movement or pipeline strains affect optical-fiber strain and can be detected by fiber Bragg gratings or DSTS.

DTS technology is being used by Total in the Dalia field, offshore Angola (above right). One of the challenges for Total in developing this deepwater field was to maintain the flow of produced fluids in the integrated production bundle (IPB) risers. The temperature of the relatively viscous oil (21 to 23 degrees API) is 45°C to 50°C [113°F to 122°F] when it leaves the reservoir. After reaching the seabed, where the water temperature is only 4°C [39°F], the fluid is piped 1,650 m [5,413 ft] to the FPSO facility through the IPB risers. The double-ended optical system interrogates the fiber from both ends of the loop. This method provides more precise temperature measurements than single-ended systems. Accurate, real-time readings are recorded at 1-m [3.3-ft] intervals along the length of the riser bundle. In the unlikely event of fiber breakage, each portion of fiber will continue to function as a single-ended system, which provides some redundancy until a new replacement fiber can be pumped down. A customized graphical user interface displays the normal operating temperatures of the production pipe and the gas lift tubing, and alarms indicate the location of any temperature deviation. As well as helping to avoid blockages, the fiber-optic system facilitates efficient management of the electrical heating system.

A different type of temperature challenge awaited Statoil at Gullfaks field in the North Sea, where production from satellite wells is connected to platforms by long subsea flowlines. To avoid blockages, the lines are heated above the critical temperature for wax and hydrate deposition. However, operating at higher-than-necessary temperature is inefficient and wastes energy. As conditions vary along the flowline, knowledge of the temperature at every point along the production bundle is invaluable for flow assurance and minimizing energy consumption.

A condition monitoring system allowed Statoil to observe temperatures in the bundles so they could be efficiently operated just above the critical temperature. The first system was installed in a 14-km [8.7 mi] flowline bundle comprising two flowlines, three hot-water heating lines, and a small-diameter conduit, all in an insulated sleeve. After the flowline bundle was installed and connected to the Gullfaks C platform, Schlumberger operators pumped a continuous fiber-optic temperature sensor down the conduit. This technology has helped to optimize operation of the heating system and reduce the amounts of wax and hydrate inhibitors required. The system helps minimize disruptive pigging operations to clear blockages, and when temperature anomalies resulting from extreme flow and pressure changes at restrictions in the flowline are detected, the system data can help optimize the pigging operations required to clear any blockages, thus saving money and reducing downtime.

These monitoring systems make up just a fraction of the highly evolved and specialized technologies required to install and operate a subsea oil and gas transmission system. Far from being dumb iron or brute, insensitive conduits, each subsea pipeline is, by necessity, formed of specialized metallurgy, fabricated with great care, laid with utmost attention to subsea pressure and stress, and attentively monitored. —MV