# Chapter 2 | Drilling for Oil in Deepwater

Oil and Gas in Deepwater

How Oil and Gas Form

Offshore oil and gas reservoirs are formed from sediments deposited by rivers flowing from land into the ocean. Those sediments originate hundreds and sometimes thousands of miles away, in the mountains and broad uplands of an adjoining continent. If the sediments contain organic materials, and if geological processes later subject these sediments to intense pressure and heat, the organic materials can be transformed into liquid and gaseous hydrocarbons over the course of millions of years. The hydrocarbons may remain in the **source rock** where they originally formed, or they can be expelled from the source rock and into other, more porous rock layers. The hydrocarbons tend to migrate upward because they are lighter than other fluids in the pore spaces.

Figure 2.1. Schematic geological cross section.
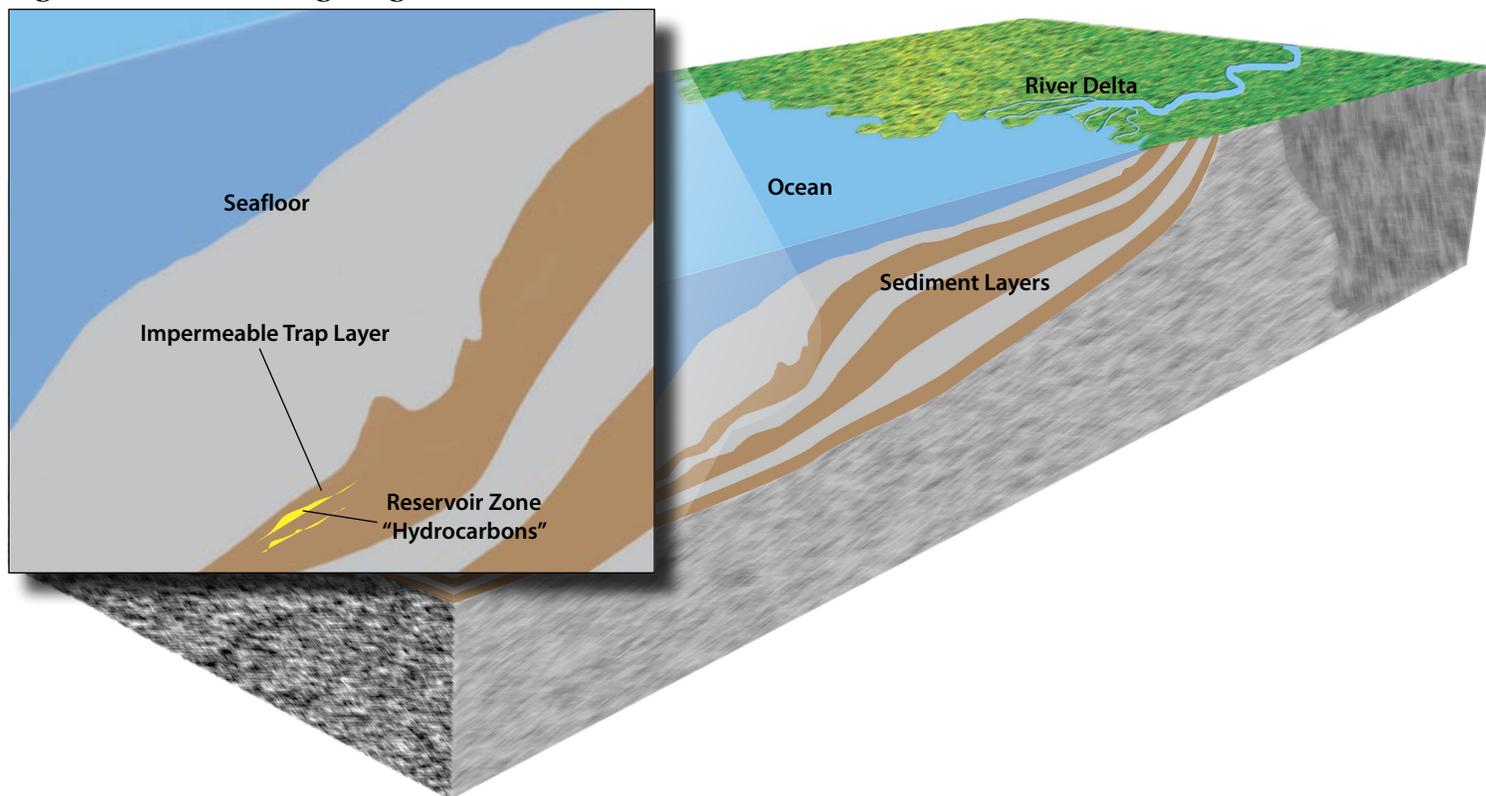
Hydrocarbons trapped beneath an impermeable layer.

If a path of porous rock layers leads to the surface, the hydrocarbons will emerge above ground in a seep or tar pit. If an impermeable **trap** layer instead blocks the way, the hydrocarbons can collect in porous rock beneath this seal (see Figure 2.1). Drilling for oil consists first of finding "reservoir zones" (or "pay zones") of trapped hydrocarbons and then drilling through the trap layers into the oil.

Porosity and Permeability. Rock layers vary according to two important measures: porosity and permeability. Porosity is the percentage of the rock that is made up of microscopic pore spaces— places where fluid can reside. Permeability is the ease with which fluid can flow through a rock and is a measure of how well the rock's pore spaces are connected.

The weight of sediments and fluids above the oil-bearing zone exert tremendous pressure on the trapped hydrocarbons. The pressure can be sufficient to force the hydrocarbons all the way to the surface once a well is drilled. Over time, the reservoir pressures can drop as hydrocarbons are extracted, and the hydrocarbons then may need to be pumped out of the well.

Deepwater Oil and Gas Reservoirs in the Gulf of Mexico

The Gulf of Mexico is a rich hydrocarbon province. The Mississippi and other coastal rivers have been eroding the North American continent and have deposited tens of thousands of feet of organic sediments in the Gulf over the past few tens of millions of years. The sedimentary section beneath the sea bed of the central Gulf of Mexico is made up primarily of sand and finer grained shale deposited slowly over time in successive layers.

The thick sedimentary section of the Gulf of Mexico has been the focus of offshore oil and gas exploration efforts since the 1930s. Over many decades, the waters of the Gulf have developed into one of the world's most prolific hydrocarbon provinces, yielding tens of billions of barrels equivalent of oil and natural gas. Today much of the submerged land in the Gulf is administered by the federal government and therefore considered part of the "outer continental shelf." (The National Commission's final report discusses the history of oil exploration in the Gulf of Mexico in Chapter 2.)

Early exploration in the Gulf of Mexico focused on what is known as "shallow water" oil deposits as opposed to "deepwater" deposits. Shallow water wells are typically drilled into sediments that lie atop the continental shelf where it extends into the ocean.

In the central Gulf of Mexico (south of Louisiana), the continental shelf slopes down gently to water depths of roughly 600 feet. At a water depth of about 600 feet, there is a marked transition from the continental shelf to continental slope. On the slope, water depth increases more quickly with distance from shore, and the sea bottom and underlying geology becomes more complex. Although there is no precise definition for the term, "deepwater" wells are typically drilled into sediments that lie on the continental slope and beyond.[*]

Deepwater wells involve markedly different conditions from shallow water wells. The water depth obviously increases, but the sea bottom and geological conditions become more complex too. The sedimentary layers in deeper water are also different. While there is generally continuous deposition of sand and shale on the shelf, deepwater sediments can be dominated by the deposition of **turbidites**. Turbidites are sediments that are deposited episodically during underwater avalanches or other discrete events. Such events can create thick layers of sand that can be very well sorted and display certain attractive reservoir properties: **high porosity**, the

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[*] Different companies and governmental organizations have adopted definitions for deepwater ranging from 600 to 1,500 feet. The Commission's report used 1,000 feet as the starting point of deepwater, a definition that is used by many in the oil and gas industry.

fraction of rock volume available for holding oil and gas, and **high permeability**, the ability of fluids to move through the rock. These properties make turbidites some of the best oil and gas reservoirs. Individual turbidite layers in the Gulf of Mexico can be many tens of feet to more than several hundred feet thick.

In addition to changes in the underlying geology, the greatly increased water depth requires different drilling approaches. In water depths greater than a few hundred feet, wells are drilled using floating rather than bottom-based rigs.

In water depths greater than about 1,000 feet, it is increasingly impractical to conduct production operations from structures that are supported by the ocean floor, and floating facilities and subsea production systems dominate.

These fundamental changes in drilling methods and reservoir geology combine to define the transition to deepwater.

The Deepwater Opportunity, Attraction, and Challenge

Because of the complexities of deepwater operations, developing a major deepwater oil field can cost enormous sums of money—far more than shallow water development. To make such developments economically viable, oil companies must identify highly productive reservoirs and then install high-productivity wells and production systems. Deepwater turbidite reservoirs are ideal targets because of their high porosity and permeability. Good shallow water wells produce at rates of a few thousand barrels of oil a day. By contrast, deepwater wells commonly produce more than 10,000 barrels per day.

In the early stages of deepwater exploration, operators were surprised by the productivity of deepwater reservoirs. For instance, when Shell developed the Auger Field in the early 1990s, the platform for collecting oil from the wells in the field was originally designed to handle about 40,000 barrels per day of production. Shell was able to increase the platform's capacity to greater than 100,000 barrels per day, despite the fact that it had drilled less than half the wells it originally planned to develop in the Auger Field.

These kinds of reservoirs, which deliver high rates of flow for long periods of time, became the standard for deepwater developments. Drilling wells into these reservoirs became a critical factor for deepwater project success because these production rates justified the high cost of deepwater development.

Favorable geology, while critical, does not alone guarantee deepwater success. It was important in early deepwater developments to establish a "learning curve" where successful engineering practices could be developed and replicated in successive field developments.

In its early Gulf of Mexico deepwater developments in the 1990s, for instance, Shell was able to cut the per barrel development cost by nearly two-thirds over time. Further optimization by Shell and other operators continued to improve the economics of deepwater operations.

As a result, with oil prices and price outlook low in the late 1990s, major oil companies moved aggressively into the deepwater Gulf of Mexico. While these operations were expensive in absolute terms, the development cost per barrel of a carefully executed deepwater project became comparable to shallow water and even small onshore developments.

Deepwater Reservoir Pressures

Another feature of deepwater Gulf of Mexico reservoirs that contributed to overall well productivity also made drilling in deepwater significantly more dangerous: The oil and gas in deepwater reservoirs was often under very high pressure.

Pressure Gradient. In oil and gas drilling, pressure is usually described in terms of a pressure gradient measured from the surface and expressed as an equivalent density of a column of fluid. A "normal" gradient is similar to that produced by a column of seawater, or 8.6 pounds per gallon (ppg). Many deepwater reservoirs, however, are at pressures exceeding 12 ppg. These pressures are not uncommon in oil and gas exploration, but they represent a challenge in that they must be managed carefully.

Managing high pressures in deepwater presents unique challenges. The oil found in deepwater Gulf of Mexico reservoirs typically contains a significant amount of dissolved natural gas. As the oil comes to the surface, the decrease in pressure allows much of this gas to come out of solution. Deepwater Gulf deposits also commonly contain "free gas," which is natural gas that exists separate from the oil, either as a gas cap in the same reservoir sand or a separate gas-bearing zone.

The pressure in a deepwater reservoir can often exceed 10,000 to 15,000 pounds per square inch (psi), several hundred to more than 1,000 times the pressure at the surface. As oil and gas come to the surface, they expand. While the expansion of the oil is moderate, the gas expands in proportion to the drop in pressure. As a result, 10 barrels (bbl) at 5,000 feet could be greater than 1,000 bbl at the surface.

For these reasons, the subsurface pressure and the expansion of fluids flowing to the surface must be carefully managed. The oil and gas industry has developed tools and techniques for doing so. The next section discusses the specific technical tools and methods used to contain and control these pressures.

Rig personnel must be especially vigilant at a deepwater well; because of the pressures involved, it is critical that they detect and address hydrocarbon influxes into the well as early as possible. If they do not stop such influxes early, the rapid expansion of hydrocarbons as they near the surface can become difficult, if not impossible, to control.

How to Drill a Deepwater Well

There are three phases to safely extracting hydrocarbons from an offshore deepwater reservoir. The first phase is drilling. During this phase, rig crews drill and reinforce a hole from the seafloor down through the trap layers and into the reservoir zone. During drilling, it is important for rig crews to prevent hydrocarbons in the reservoir from entering the hole they are drilling, which is called the **wellbore**.

The second phase is completion. During completion, rig crews open the wellbore to allow hydrocarbons to flow into it and install equipment at the wellhead that allows them to control the flow and collect the hydrocarbons.

The third phase is production. In the production phase the operator actually extracts hydrocarbons from the well.

Figure 2.2. Drilling.

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Typical onshore and offshore drilling consists of drilling mud, a drill bit, and circulating pressures to clear cuttings through the annulus to the surface.

This introduction to drilling a deepwater well focuses on the first phase—the actual drilling—and the concept of **well control**, which refers to the methods for controlling hydrocarbon flow and pressure in a well.

Drilling Overview

Offshore drilling is similar in many ways to drilling on land. Like their onshore counterparts, offshore rig crews use **drilling mud** and rotary drill bits to bore a hole into the earth (see Figure 2.2). Drillers pump the mud down through a **drill pipe** that connects with and turns the bit. The mud flows out of holes in the bit and then circulates back to the rig through the space between the drill pipe and the sides of the well (the **annulus** or **annular space**). As it flows, the mud cools the bit and carries pulverized rock (called **cuttings**) away from the bottom of the well. When the mud returns to the surface, rig equipment sieves the cuttings out and pumps the mud back down the drill string. The mud thus travels in a closed loop.

Pore Pressure and Fracture Pressure

In addition to carrying away cuttings, drilling mud also controls pressures inside the well as it is being drilled. The mud column inside a well exerts downward hydrostatic pressure that rig crews can control by varying the mud weight.

The crew monitors and adjusts the mud weight to keep the pressure exerted by the mud inside the wellbore between two important points: the pore pressure and the fracture pressure. The **pore pressure** is the pressure exerted by fluids (such as hydrocarbons) in the pore space of rock. If the pore pressure exceeds the downward hydrostatic pressure exerted by mud inside the well, the fluids in the pore spaces can flow into the well, and unprotected sections of the well can collapse.

An unwanted influx of fluid or gas into the well is called a **kick**. The **fracture pressure** is the pressure at which the geologic formation will break down or "fracture." When fracture occurs, drilling mud can flow out of the well into the formation such that mud returns are **lost** instead of circulating back to the surface.

Both pore pressure and fracture pressure vary by depth. The **pore pressure gradient** is a curve that shows how the pore pressure in the well changes by depth. The **fracture gradient** is a curve that shows how the fracture pressure in a well changes by depth (see Figure 2.3). Both gradients are typically expressed in terms of an equivalent mud weight.

MAINTAINING BALANCE
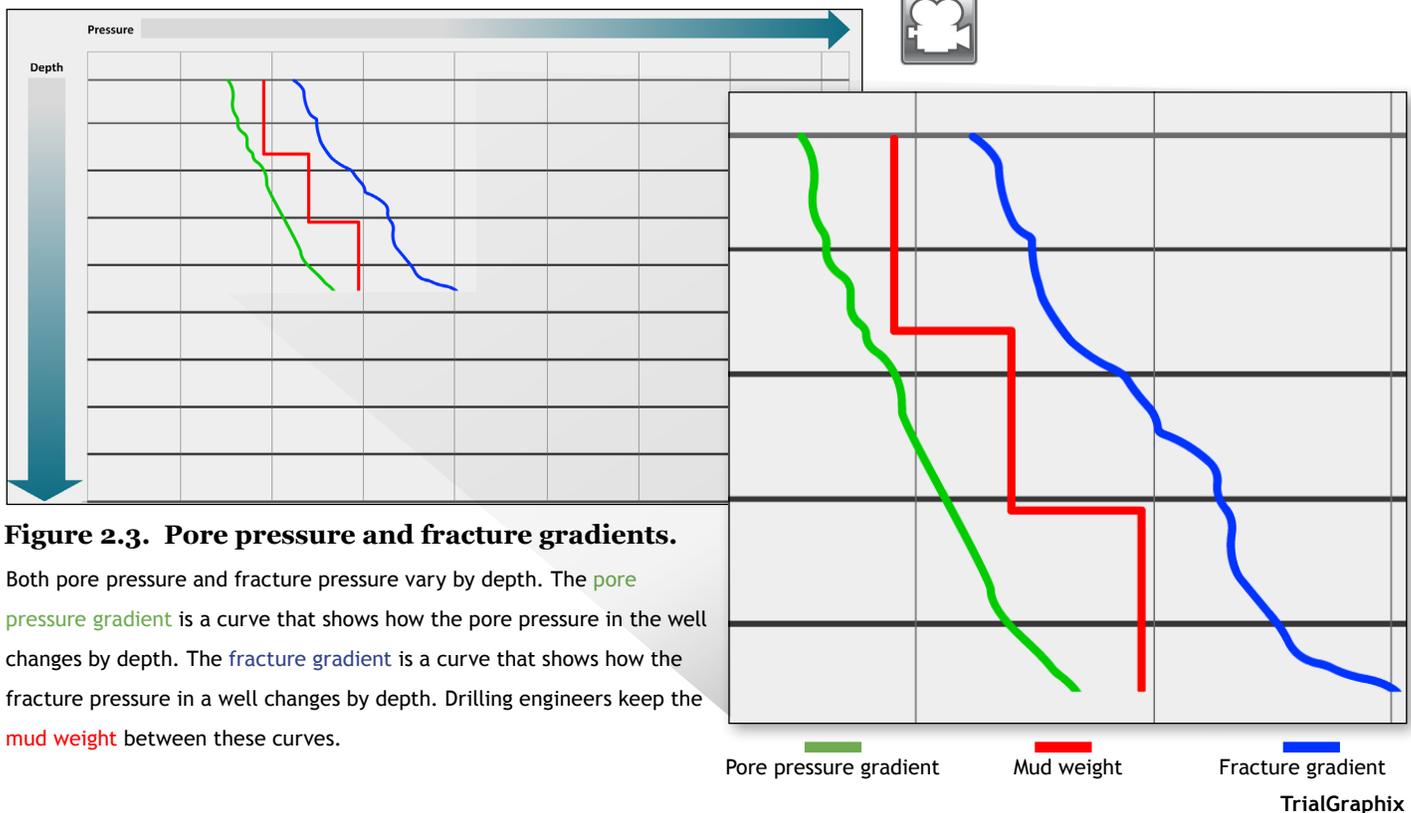
Figure 2.3. Pore pressure and fracture gradients.

Both pore pressure and fracture pressure vary by depth. The pore pressure gradient is a curve that shows how the pore pressure in the well changes by depth. The fracture gradient is a curve that shows how the fracture pressure in a well changes by depth. Drilling engineers keep the mud weight between these curves.

| Pore pressure gradient | Mud weight | Fracture gradient |

TrialGraphix

The pore pressure and fracture gradients define the boundaries of the drilling process. Drillers strive to keep the mud weight between these two curves.

LOT and FIT. There are two ways to determine a formation's fracture gradient: a **leak off test (LOT)** and a **formation integrity test (FIT)**. In a leak off test, the driller gradually increases the pressure on the formation and stops when the formation begins to give way. The driller can see this occurring by monitoring the pressure at the surface. In a formation integrity test, the driller gradually increases the pressure on the formation to a predetermined value less than the fracture pressure. This test stops before the formation actually begins to give way. In each case, the stopping point is recorded as the fracture gradient of the formation.

Achieving this goal would be simple enough if the pore pressure remained constant from the seafloor all the way down to the hydrocarbon zone. But pore pressure and fracture pressure vary. They typically increase with increasing depth but can sometimes decrease depending on the nature of the formation. As the well goes deeper, drillers typically must increase the weight of drilling fluid to balance increasing pore pressure.
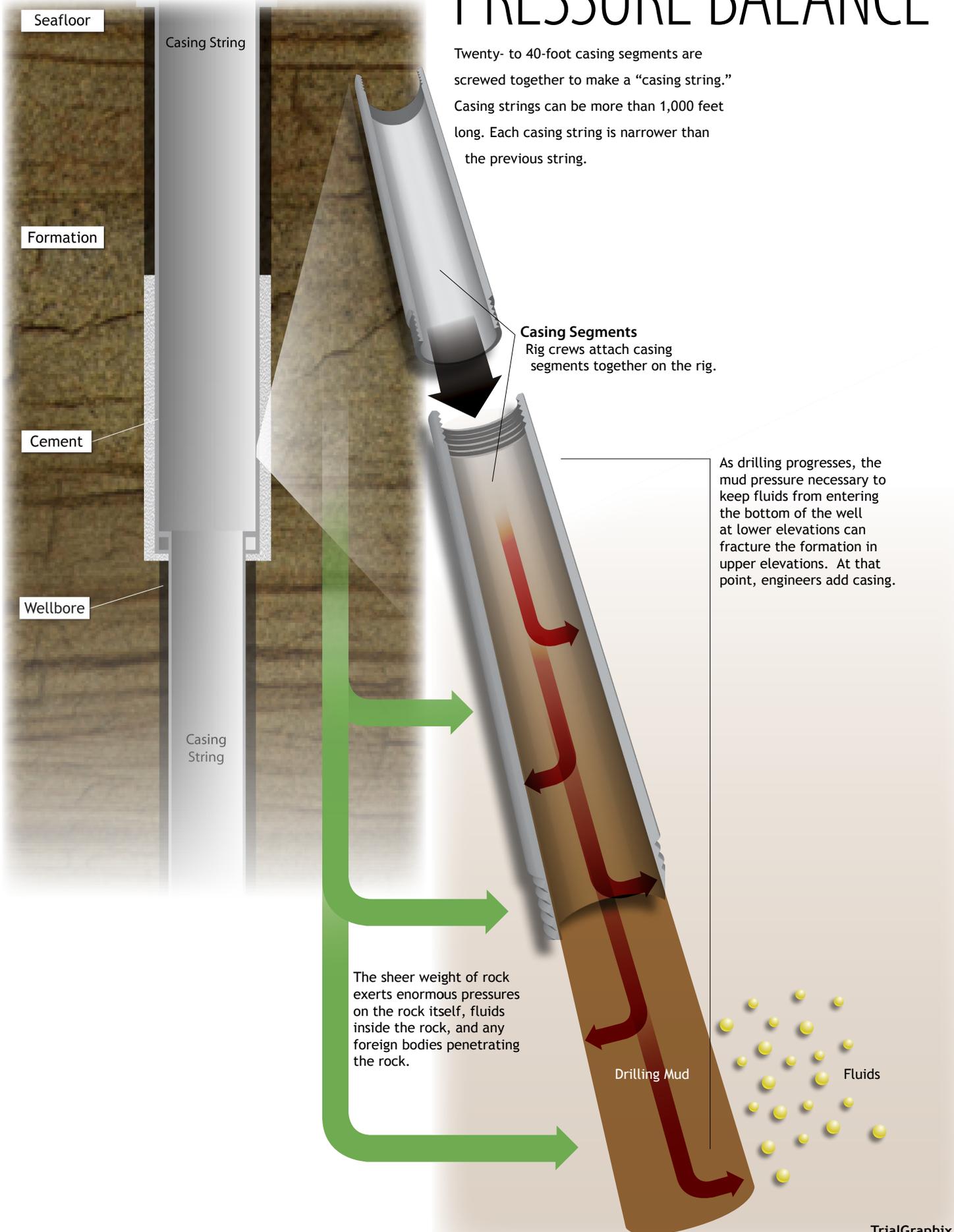
Casing and Cement

At some point as the crew drills deeper, the pore pressure in the bottom of an open hole section will exceed the fracture pressure of the formation higher up in this open hole section. When this happens, the crew can no longer rely on mud to control pore pressure. If the crew increases the mud weight, it will fracture the formation higher up. If the crew keeps drilling but does not increase the mud weight, hydrocarbons or other fluids in the deeper formation will flow into the well.

Figure 2.4. Casting strings (greatly simplified).

PRESSURE BALANCE

Twenty- to 40-foot casing segments are screwed together to make a "casing string." Casing strings can be more than 1,000 feet long. Each casing string is narrower than the previous string.

Casing Segments
Rig crews attach casing segments together on the rig.

As drilling progresses, the mud pressure necessary to keep fluids from entering the bottom of the well at lower elevations can fracture the formation in upper elevations. At that point, engineers add casing.

The sheer weight of rock exerts enormous pressures on the rock itself, fluids inside the rock, and any foreign bodies penetrating the rock.

Seafloor

Casing String

Formation

Cement

Wellbore

Casing String

Drilling Mud

Fluids

TrialGraphix

At this point, the crew stops and sets **casing**. Casing is high-strength steel pipe that comes in 20- to 40-foot sections that rig crews screw together (or "make up") on the rig to make a **casing string** (see Figure 2.4). Once placed in a well, the casing string serves at least two purposes. First, it protects more fragile sections of the hole outside the casing from the pressure of the drilling mud inside. Second, it prevents high-pressure fluids (like hydrocarbons) outside the casing from entering the well.

After a rig crew runs a casing string down a well, it must cement the casing string into place. Once it sets, the cement does two things. First, it seals the interior of the well (inside the casing) off from the formation outside the casing. Second, it anchors the casing to the rock around it, structurally reinforcing the wellbore to give it mechanical strength.
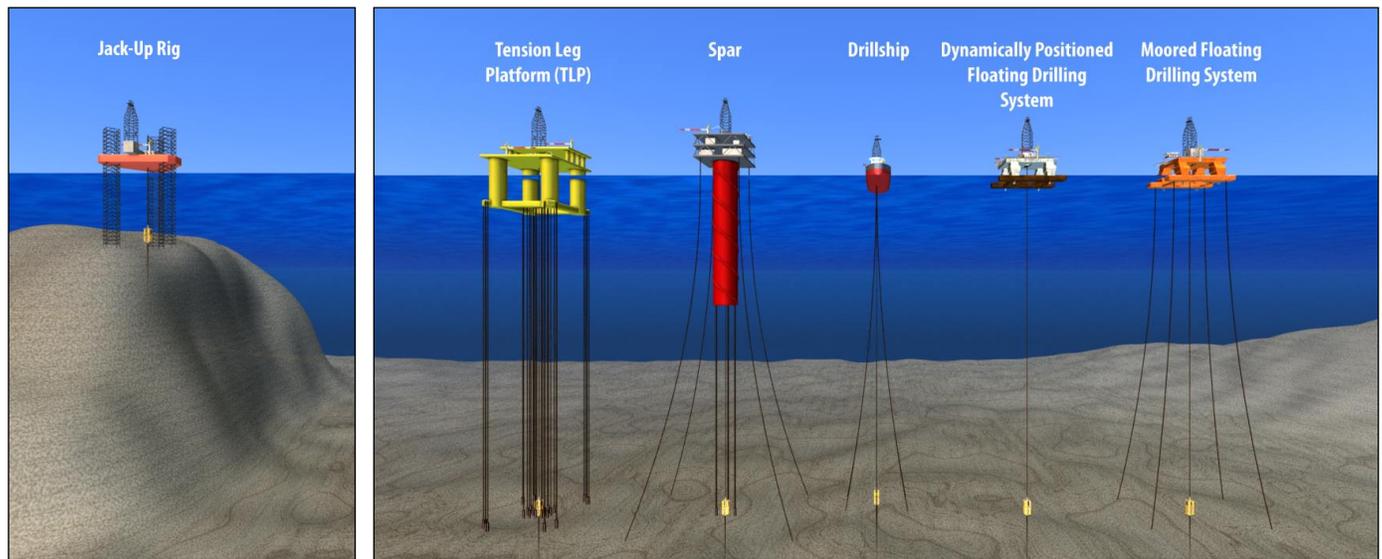
Drilling in More Detail

The Drilling Rig

Figures 2.5 and 2.6. Rig structures.

TrialGraphix

Various offshore drilling rigs.

Both offshore and onshore drill crews use drilling rigs to raise and lower drilling tools and casing down the well, pump fluids down the wellbore, and turn the drill bit. An offshore drilling rig must also provide the crew with a stable platform from which to work. There are several types of offshore drilling rigs.

A mobile offshore drilling unit (MODU) is able to move from location to location. In shallow water, rig crews can work from "jack-up" platforms that are towed onto location and then supported by mechanical legs lowered to the seafloor (see Figure 2.5). Deepwater operations require structures that float on the water's surface. Some are floating structures that are moored in place with cables attached to giant anchors. Others are drillships—vessels that carry drilling rigs and support drilling operations (see Figure 2.6).

A dynamically positioned (DP) semi-submersible like the *Deepwater Horizon* is yet another kind of rig that combines features of each of these other rig types. Once moved onto location, a DP rig

holds itself in place above a drilling location using satellite positioning technology and directional thrusters.

Spudding the Well

Drilling in deepwater starts when the rig crew "spuds" the well by lowering a first string of casing down to the seafloor. This "conductor casing" is typically 36 inches in diameter or more, and serves as part of the structural foundation for the rest of the well. Welded to the top of the conductor casing is a wellhead assembly. The wellhead assembly remains above the seafloor and serves as an anchoring point for future casing strings. The rig crew lowers the conductor casing into place using the drill string and a "running tool" that attaches the drill string to the wellhead.

The Drill String. The **drill string** is made up of "joints" of **drill pipe** that are 20 to 40 feet in length. Each joint has a threaded male end and a threaded female end that is larger than the overall pipe diameter; these **tool joints** connect one joint of drill pipe to the next. Drill pipe itself comes in different diameters (typically ranging from 5½ to 6⅝ inches in deepwater). In addition to standard drill pipe, rig crews can use drill collars or heavyweight drill pipe as well. **Drill collars** have much thicker walls than standard drill pipe. Rig crews often use drill collars to add weight to the bottom part of a drill string. Doing this helps keep the drill string from kinking or breaking and puts more weight on the bit. **Heavyweight drill pipe** is of an intermediate weight; it minimizes the stress between the drill collars at the bottom of the drill string and standard drill pipe at the top.

The sediments in the first several hundred feet below the seafloor in the Gulf of Mexico are typically unconsolidated materials that lack cohesive strength. They are little more than watery mud. Accordingly, the rig crew does not need to use drilling mud or even a rotary drill bit to create a hole for the conductor casing. The weight of the drill string and conductor casing alone can be more than enough to drive the casing down into the mud at the seafloor. The rig crew helps this process along by pumping seawater down the drill string at high pressure to "jet" away the sediments at the bottom of the conductor casing. The jetted water then carries the sediments up the inside of the conductor casing and out through ports in the wellhead into the surrounding seawater.

Figure 2.7. Early drilling phases.

Smaller Diameter Casing String
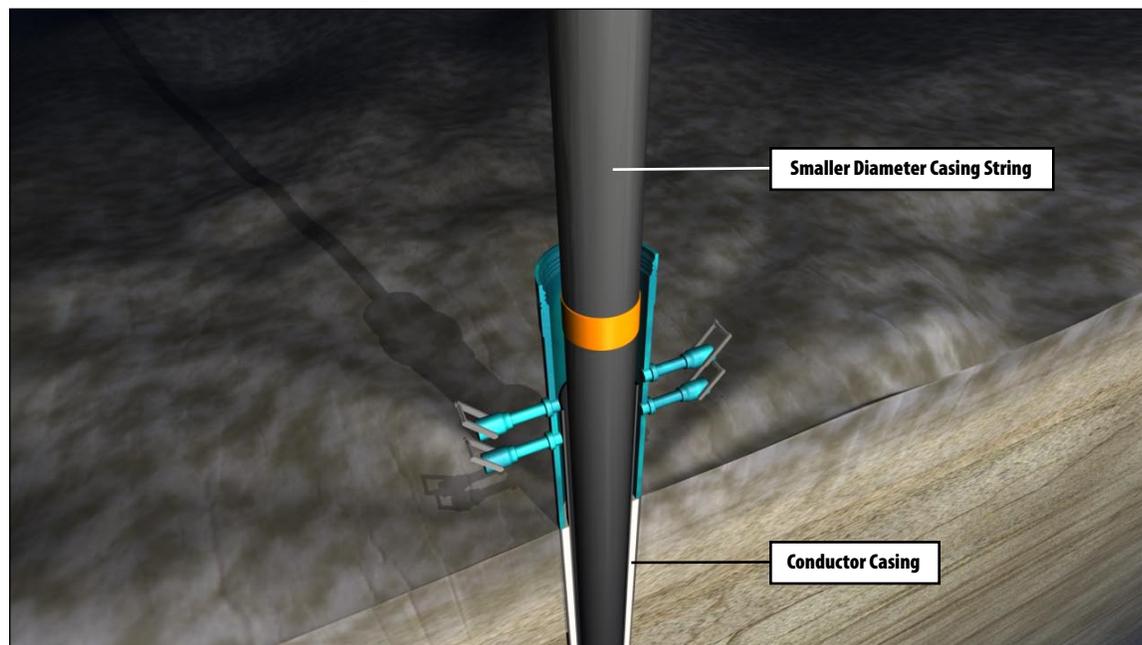
Conductor Casing

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Conductor in seafloor with early casing string attached.

Setting the Conductor Casing and Cementing Additional Early Casing Strings

Once the rig crew has jetted the conductor casing to its design depth, a second, smaller diameter casing string is installed, extending deeper into the seabed (see Figure 2.7). In a deepwater well, this second string is sometimes jetted into place, or large diameter drill bits might be used to drill the hole for it to be lowered into. If it is drilled, the hole diameter is slightly larger than the casing to leave room for the cement that secures it into place.

To cement the casing, a cementing crew pumps cement down the drill string. The cement flows down the drill string, out the bottom of the casing and back up against gravity into the annular space around the casing (between the casing and open hole). When cementing is complete, the cement fills the annular space around the casing, reinforcing the casing and creating the mechanical foundation for further drilling. This process continues as the hole is drilled using progressively smaller diameter casing and cementing each in place.

Cement Slurry. The **cement slurry** that the rig crew pumps down a well is a high-tech blend of dry Portland cement, water, and numerous dry and liquid chemical additives. Operators typically employ specialized cementing contractors to design the slurry, provide the raw materials for the slurry, and pump it into place. Cementing specialists can adjust the cement slurry composition to reflect the needs of each well. For instance, they can add "accelerators" to increase the rate at which the cement sets, or "retarders" to decrease it.

Figure 2.8. Wellhead assemblies.

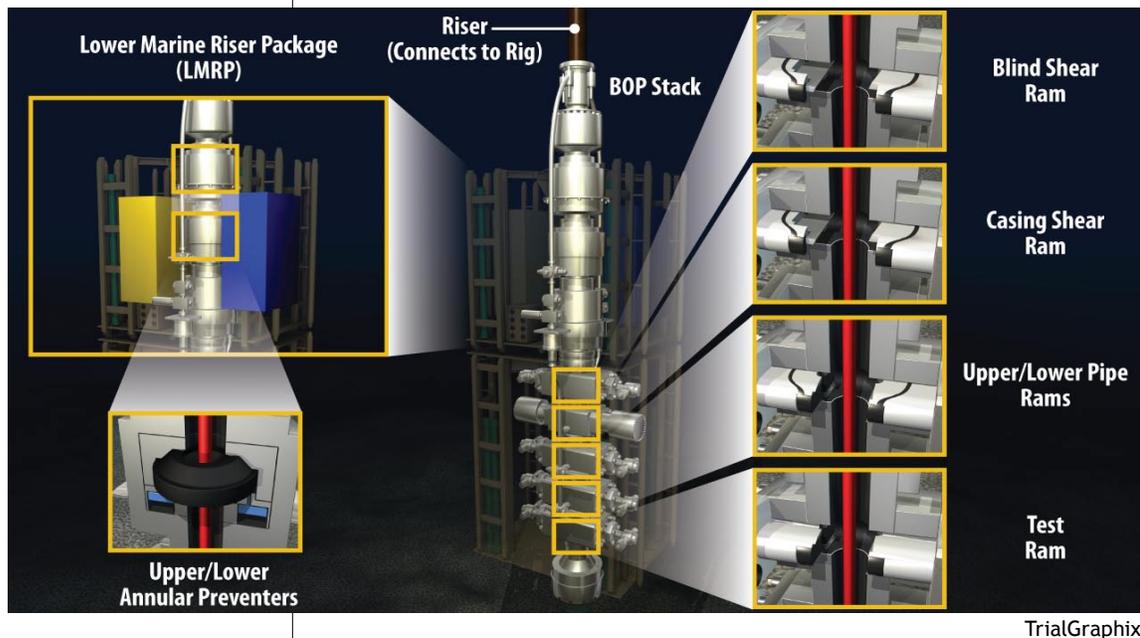Inner High-Pressure Wellhead Assembly

Outer Wellhead Assembly
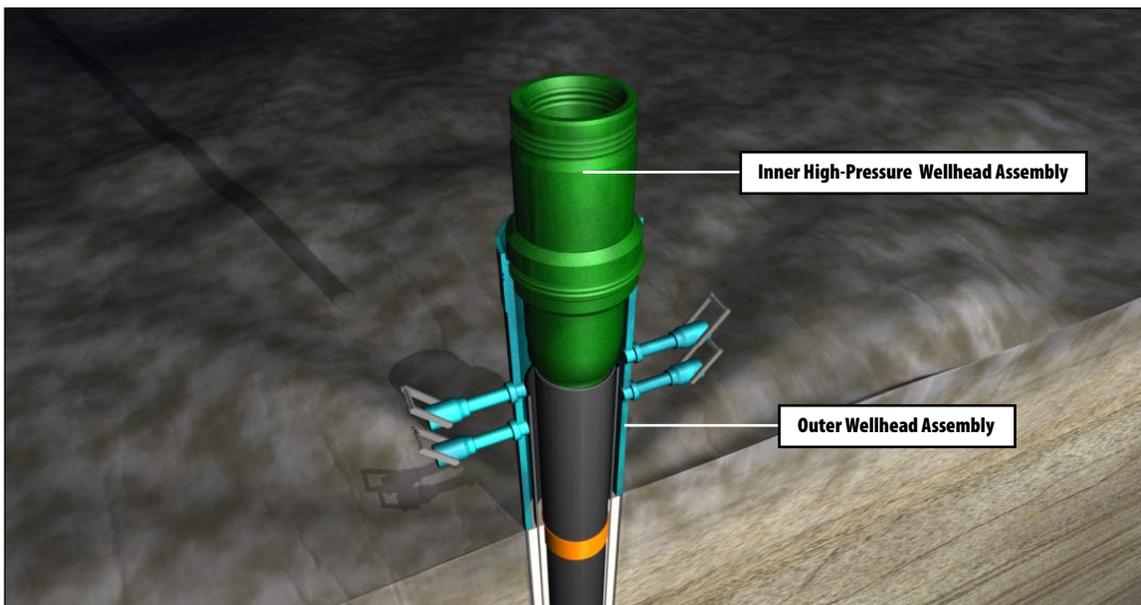
TrialGraphix

The Wellhead. A deepwater **wellhead** consists of a series of sophisticated interlocking components that are assembled together as the well is constructed. The outer portion of the wellhead is welded to the conductor casing and lowered to the bottom along with that casing. The outer wellhead accommodates multiple casing hangers that support the weight of early casing strings and seal the annular space at the top of those casing strings. Prior to lowering the BOP, drillers install an inner high-pressure wellhead assembly that is welded to a smaller diameter casing string. The high-pressure wellhead assembly interlocks with the outer wellhead assembly and includes fittings that allow the BOP to latch on to the integrated wellhead assembly. Like the outer wellhead assembly, the inner high-pressure wellhead assembly accommodates casing hangers inside it.

Lowering the Riser and BOP

When the sediments at the bottom of the well are strong enough that they can no longer be removed by jetting, the drilling crew must begin to use rotary drilling bits and may begin using drilling mud.

The term "mud" was once descriptive—early drilling fluids were simple mixtures of water and clay. Nowadays mud is a complex blend of oil- or water-based fluids and additives that serves many functions in a well. Unlike the seawater used during the jetting process, which is discharged into the surrounding sea after use, drilling mud must be recovered after it is pumped down a drill string—it is expensive ($100 per barrel or more) and can damage the surrounding ocean environment if released. Federal law generally prohibits the discharge of oil-based drilling mud into the ocean.

Figure 2.9. BOP components.

Lower Marine Riser Package (LMRP)

Riser (Connects to Rig)

BOP Stack

Upper/Lower Annular Preventers

Blind Shear Ram

Casing Shear Ram

Upper/Lower Pipe Rams

Test Ram

TrialGraphix

The Blowout Preventer. The BOP as a whole is called the "BOP stack"; it consists of a series of annular preventers and rams stacked in vertical sequence on top of one another.[†]

The term lower marine riser package (LMRP) refers to the top part of the BOP stack that contains the annular preventers and the control pods (described further in Chapter 3).

An annular preventer is a large rubber element designed to close around the drill pipe and seal off the annulus. It is like a hard rubber donut. Upon activation, the annular preventer expands and fills the space within that part of the BOP; if there is something in the annular preventer (such as pipe), the annular preventer seals around it. If no drill pipe is in the hole, the annular preventer can close off and seal the entire opening.

A pipe ram consists of two mirror-image metal blocks with semicircles cut out of the inner edges. The semicircular area is lined with a rubber seal. The pipe ram is designed to close around the drill pipe and seal off the annulus in the well below. Variable bore rams are a type of pipe ram with several concentric semicircular pieces; the concentric pieces allow the variable bore rams to seal around several different sizes of pipe.

A blind shear ram consists of two metal blocks with blades on the inner edges. It is designed to cut the drill string and seal off the annulus and the drill string in the well below. It can withstand and seal a substantial amount of pressure from below. Blind shear rams are designed to cut through drill pipe but will not cut through a tool joint (the place where two pieces of pipe are threaded together), casing hangers, or multiple pieces of pipe.

The casing shear ram is designed to cut through casing as it is being lowered into the wellbore and when there is no drill string in place. It does not seal the wellbore completely.

A test ram, if installed, sits at the bottom of the BOP stack. It is typically a pipe ram that is inverted—whereas the pipe ram is normally designed to hold pressure coming up from beneath it, the test ram is inverted and so holds pressure from above it. This allows the driller to test elements above the test ram.

In order to switch from using seawater as a drilling fluid to using drilling mud, the rig crew must add several elements to the emerging well system. The first is a **blowout preventer**, or **BOP**. The BOP is a giant assembly of valves that latches on to the wellhead. The BOP stack serves as both a drilling tool and a device for controlling wellbore pressures. The BOP stack is connected back to the rig by the **lower marine riser package** (**LMRP**) and the **riser**. The riser is a

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[†] Although not separately depicted in Figure 2.9, there are hydraulic, power, and communications lines (cables), as well as the choke, kill, and boost lines (pipes) running from the rig to the blowout preventer.

sequence of large diameter high-strength steel pipes that serves as the umbilical cord between the rig and the BOP during all remaining drilling operations. Once rig crews lower the BOP and riser system into place atop the wellhead, they perform the rest of their drilling operations through this system. The drill string, drilling tools, and all the remaining casing strings for the well go down into the well through the riser and the BOP.

Figure 2.10. Flow in a typical mud system.
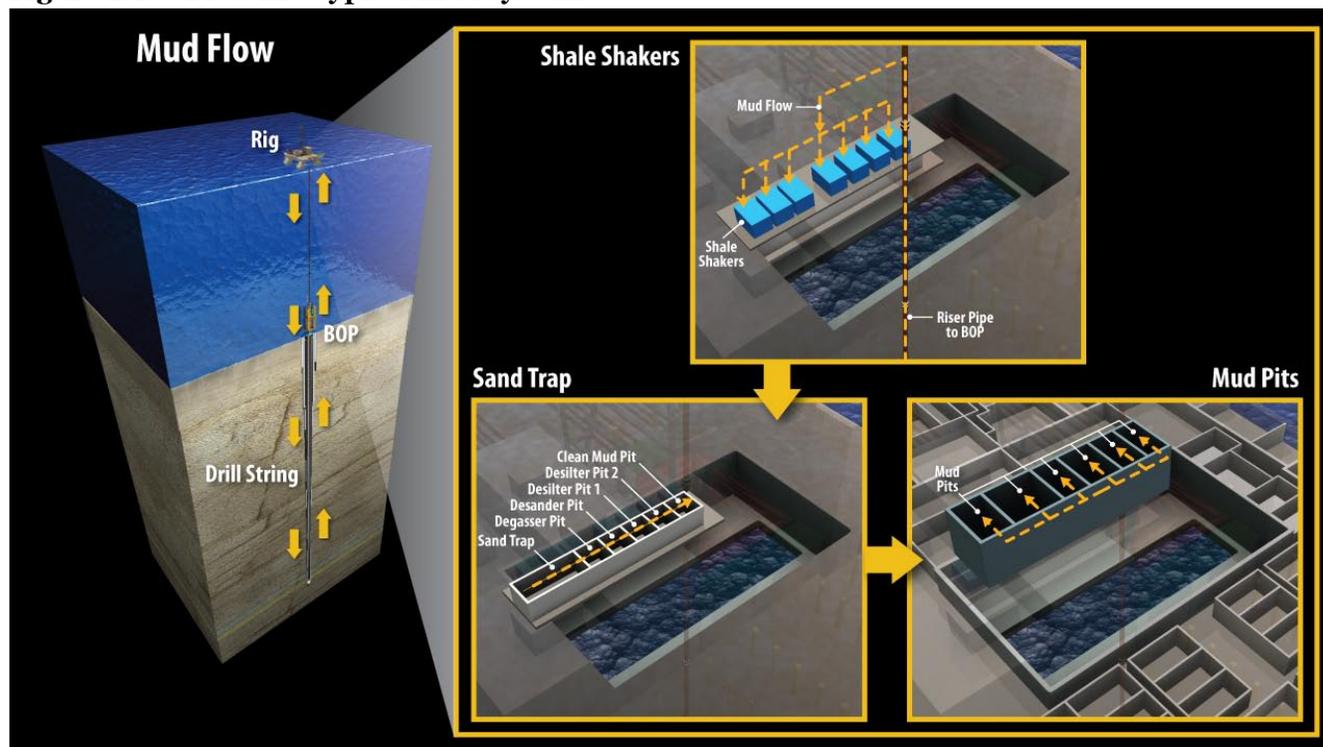
<div align="right">TrialGraphix</div>

With the riser and BOP stack in place, the drilling crew can begin using the rig's drilling mud system (see Figure 2.10). The crew circulates mud down through the drill string, into the wellbore, back up the annular space around the drill string, up through the riser, and back to the rig. Once the mud reaches the rig, it goes through a series of devices including shale shakers and sand traps to remove cuttings and suspended debris from the mud. The mud then travels to mud tanks or **pits** where the mud is stored until being pumped back down into the well again.

An operator typically contracts with **mud engineers** to prepare drilling mud and operate the mud systems, and **mudloggers** to monitor the drilling mud and other drilling parameters. Mud engineers can add additional fluids or solid materials to the circulating mud in order to change its characteristics. Most importantly, they can add weighting agents such as barite to the circulating mud to increase the pressure on the wellbore below.

Engineers typically represent the density of drilling fluids in terms of pounds per gallon (ppg). Mudloggers regularly examine the mud and cuttings for clues to the nature of the geologic formation at the well bottom, and they check the mud to see if it contains hydrocarbons.

Well Logging. Well logging refers generally to the use of instruments to learn about the characteristics of a well during or after drilling operations. The oil and gas industry has developed many different types of instruments, or "logs." For example, **pressure while drilling logs** measure the pressure inside and outside the drill bit in real time. **Electric logs** measure the electric potential and resistivity of the formation, and can identify the boundaries between formations and the fluids within them. **Gamma ray logs** measure the natural radioactivity of rock. **Sonic and ultrasonic logs** can be used to measure the porosity and lithology of a formation. **Caliper logs** measure the size of the hole that has been drilled. **Temperature logs** measure temperature gradients in a well. **Cement evaluation logs** can help identify the amount and quality of cement in the annular spacer.

Setting Subsequent Casing Strings

Figure 2.11. Casing hanger.

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Using the drilling mud system and rotary drill bits, the drilling crew drills ahead through the previously set casing strings. The rig crew extends the open hole below the existing casing strings as far as the pore pressure and fracture gradient allow and then sets subsequent smaller diameter casing strings inside the existing ones. Each new string of casing has a smaller diameter than the previous string because it must be run through the previous string. Some of these subsequent casing strings extend all the way back up to the wellhead. Others, called **liners**, attach to the bottom segment of previous casing strings. A **casing hanger** or **liner hanger** mechanically holds the casing in place (see Figure 2.11).
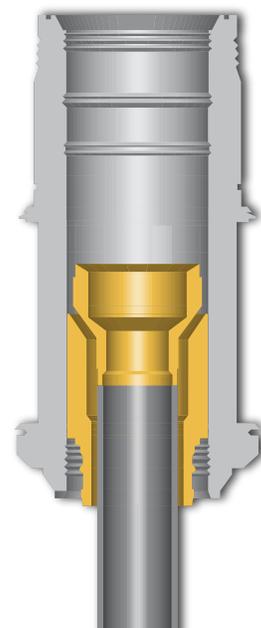
The basic method for installing a new casing string is the same whether that string will be hung from a hanger installed in the wellhead or hanger installed deeper in the well.

Figure 2.12. Wiper plugs.

TrialGraphix

Once the crew drills to a depth where a new casing string is needed, the rig crew removes the drill string from the well in a process called **tripping out**. Tripping out (or in) with the drill string is time-consuming; it typically takes a drilling crew an hour to trip in or out 1,000 feet, and tripping out of a deepwater well can be a day-long process. After tripping out, the drill crew attaches a **running tool** to the end of the drill string. The crew attaches the running tool to the casing hanger, which is in turn welded to the top of the casing. The drill crew then lowers the drill string, running tool, and casing string down the riser, through the BOP, and down into the well until the casing hanger is in position (either in the wellhead or the proper depth in the well).

Cementing Casing Strings

The process for cementing casing strings into place after installing the BOP is slightly different than cementing the early casing strings. Just as in earlier cementing steps, the rig crew pumps cement down the drill string and into place at the bottom of the well. However, because cement is typically incompatible with drilling mud, cementing crews employ two methods to keep the mud and cement separated as they flow down the well. The first involves separating the mud and cement with a water-based liquid **spacer** that is designed to be compatible with both oil-based drilling mud and water-based cement but that will prevent them from mixing. The second method involves further separating the spacer and cement with a plastic **wiper plug** that travels down the well between the spacer and the cement (see Figure 2.12).

Figure 2.13. Cementing.
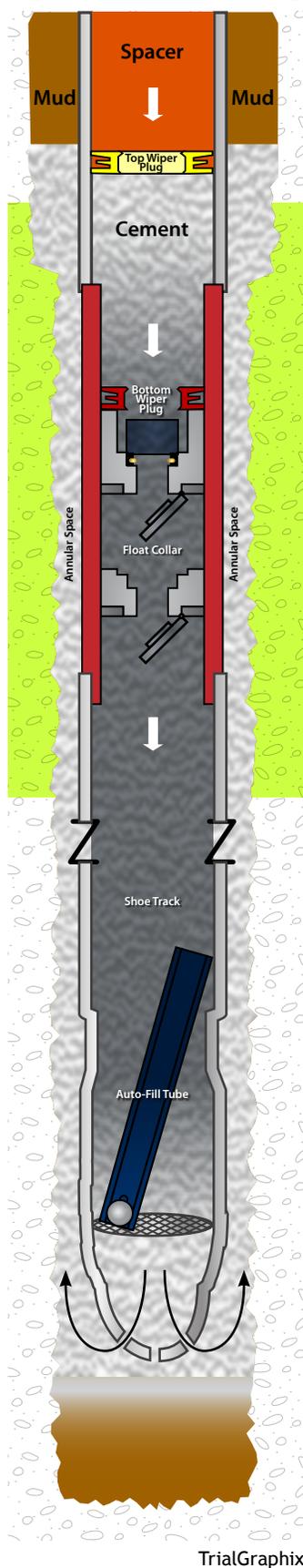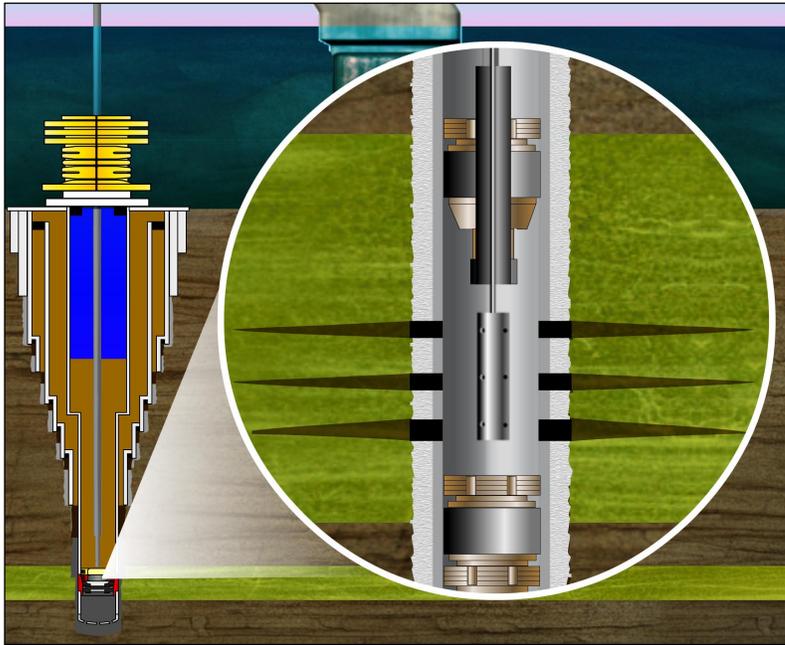

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Figure 2.13 demonstrates cementing a casing string while using mud-based drilling techniques, the cementing crew starts by pumping spacer, followed by a "bottom" wiper plug, followed by a slug of cement, a "top" wiper plug, more spacer, and then drilling mud. The spacers, wiper plugs, and cement slug travel down in sequence. When the bottom plug reaches the **float valve assembly** near the bottom of the casing string, it ruptures, allowing the cement behind it to pass through. The cement flows through the float valves and out the bottom of the casing string. It then "turns the corner" and flows up into the annular space around the casing. When all of the cement has made it through the float valves, the top plug lands on top of the bottom plug. Unlike the bottom plug, the top plug is not designed to rupture. When it lands, it blocks the flow of mud, and the resulting pressure increase signals the end of the cementing process, at which time the crew turns off the pumps. Cement should fill the annular space around the bottom of the casing string and the portion of the casing between the bottom and the float valves (called the **shoe track**). Some companies even pump cement behind the top plug to improve the effectiveness of the cement job.

Float Collar. A "float collar" is a component installed at the bottom of a casing string. It typically consists of a short length of casing fitted with one or more check valves (called float valves). The float collar both (1) stops wiper plugs from traveling farther down the casing string, and (2) prevents cement slurry from flowing back up the casing after it is pumped into the annular space around the casing. During casing installation, the float valves are typically propped open by a short "auto-fill tube." The auto-fill tube allows mud to flow upward through the float collar as the casing string is lowered. Once the casing is in place, rig personnel "convert" the float collar. By circulating mud through holes in the auto-fill tube, the rig crew creates pressure that pushes the auto-fill tube down so that it no longer props the float valves open. Once the auto-fill tube is removed, the float valves "convert" to one-way valves that allow fluid flow down the casing but prevent fluid flow upward. Though a converted float collar should prevent cement slurry from flowing upward, it is typically not considered to be a barrier to hydrocarbon flow.

After the cement slurry has set (which takes many hours), the rig crew pressure tests it to ensure that it has sealed the casing in place. They then continue the drilling process by removing the running tool, installing a smaller diameter drill bit on the end of the drill string, and lowering it back down to the bottom of the well. The crew then uses the smaller diameter drill bit to drill through the float valves and the cement in the shoe track, creating a path for drilling to continue.

Figure 2.14. Perforating the production casing.

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The Production Casing

If an operator drills a well purely to learn about the geology of an area and assess if oil or gas are present, the well is called an **exploration well**. If the operator uses the well to recover oil, it is called a **production well**. The bottomhole sections of exploration wells and production wells are different. Once an operator is finished drilling an exploration well, they typically fill the open bottomhole section with cement in a process called **plugging and abandoning**. By contrast, after drilling the final section of a production well, the operator typically installs a final string of **production casing** in the open hole section. The production casing extends past any hydrocarbon-bearing zones and down to the bottom of the well. After cementing the production casing into place, the operator can **perforate** the casing by shooting holes through it and the annular cement. This allows oil to flow into the well as shown in Figure 2.14.

Well Control

During drilling, casing, and completion operations, rig personnel must ensure that hydrocarbons do not migrate from the reservoir into the well. Well control is the process of monitoring the well and addressing any hydrocarbon influxes that are detected.

Primary Barriers—Barriers Inside the Well

To maintain well control, rig personnel must create and maintain **barriers** inside the well that will control subsurface pressure and prevent hydrocarbon flow. Some barriers are part of the well design itself while others are operational barriers that a drilling crew employs during the drilling process.

Drilling mud is a key operational barrier. As long as the column of drilling mud inside the well exerts pressure on the formation that exceeds the pore pressure, hydrocarbons should not flow out of the formation and into the well.

It is important to understand the following: If mud pressure exceeds pore pressure, the well is said to be **overbalanced**. If pore pressure exceeds mud pressure, the well is **underbalanced**, meaning that the mud pressure is no longer sufficient on its own to prevent hydrocarbon flow.

Physical components of the well also create barriers to flow. One is the casing installed in the well, along with the cement system in the bottom of the well. In a production casing string, the cement in the annular space and in the shoe track should prevent hydrocarbons in the formation from flowing up the annular space outside the production casing or up the inside of the well itself.

Rig personnel can use additional barriers inside the well to increase the redundancy of the barrier system. For instance, rig personnel can pump cement inside the final casing string of a well to create cement plugs at various depths inside the well. Rig personnel can also install

metal or plastic mechanical plugs inside the well. Some mechanical plugs are designed to be removed and retrieved later in the drilling process while others are designed to be drilled out as necessary.

Secondary Barrier—The Blowout Preventer

A BOP stack is also a potential barrier. By closing various individual **rams** in a BOP stack, rig personnel can close off the well, thereby preventing hydrocarbon flow up the well and into the riser. When a BOP ram is closed, it becomes a barrier to flow. However, the rams do not close instantaneously—they take anywhere from 40 seconds to a minute to close once activated. **Accumulators** are tanks that contain pressurized hydraulic fluid used to close the BOP. Subsea accumulators on the BOP stack are constantly charged through a conduit line from the rig.
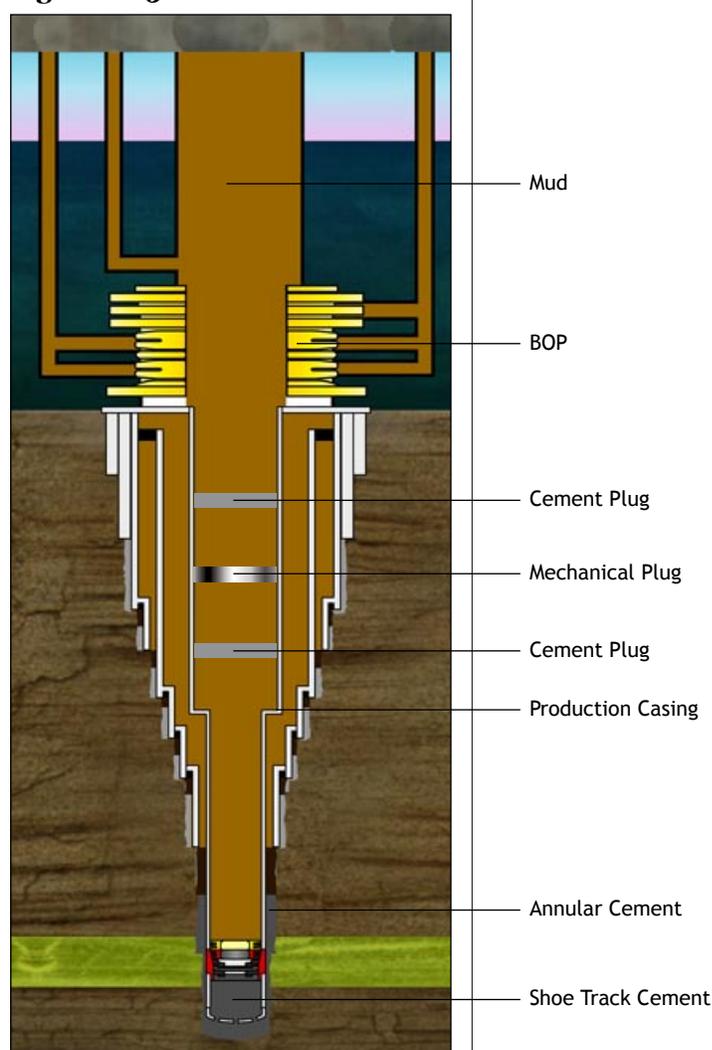
BOP rams can be activated in several ways: manually from the rig, robotically by remotely operated vehicles (ROVs), and automatically (when certain conditions are met). Each ram is activated separately.

Manual activation is generally done by the driller but also can be done by other rig personnel including the subsea engineer. BOP control panels are located on the bridge and in the drill shack. To manually activate a given BOP ram, a rig worker presses a button on the control panel corresponding to that ram. Electrical signals are sent from the control panels to subsea **control pods** on the BOP stack. The signals electrically open or close a solenoid valve, which in turn sends a pilot signal to activate the hydraulic pressure needed to operate the individual elements of a BOP stack. The control panel has a flow meter display that indicates how many gallons of hydraulic fluid are flowing into the ram, which helps the driller and subsea engineer to determine whether the ram is responding properly.
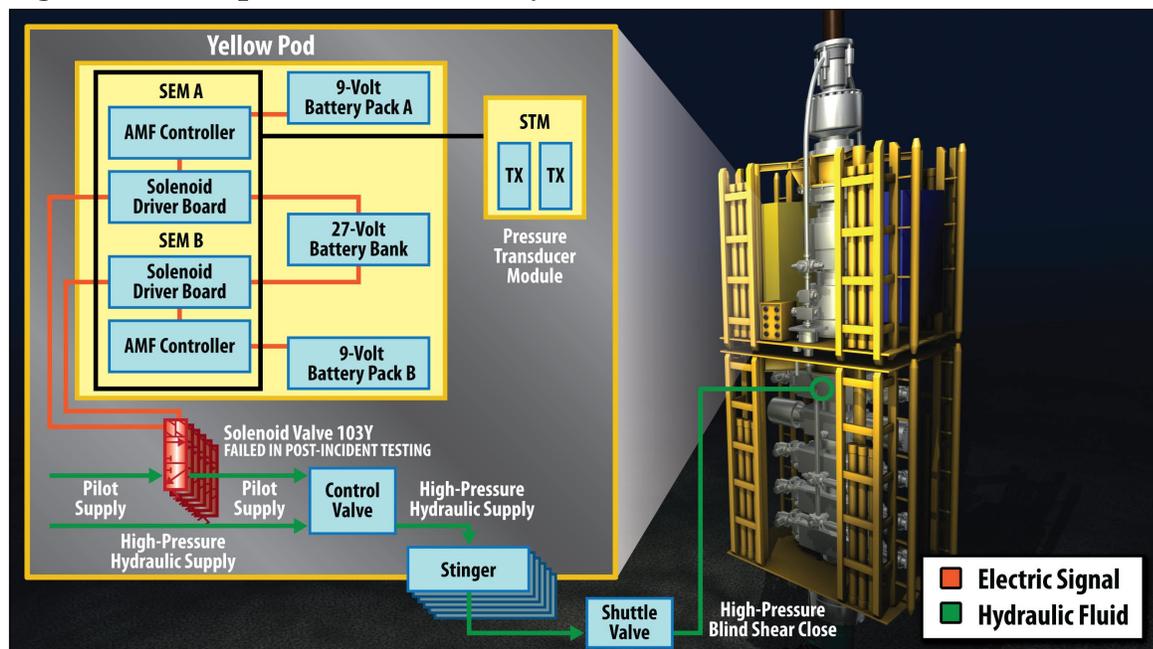
The BOP can also be activated by a mobile underwater robot (ROV) that can carry and use tools. An ROV can activate the blind shear ram through the control system or by pumping hydraulic fluid through "hot stab" ports located on the outside of the BOP stack.

Last, the BOP can be activated automatically. One automated system is the automatic mode function or **deadman** trigger. If the power, communications, and hydraulic lines running from the rig to the BOP are severed or otherwise lose functionality, circuits on the BOP stack will activate the blind shear rams to close off the well. An ROV can also create the conditions to activate the deadman by cutting power, communications, and hydraulic lines at the LMRP. Another automated system that activates the blind shear ram is the **autoshear**. A BOP system can be configured so that the autoshear activates where the rig is drifting off or driving off of its location. If the rig moves a sufficient distance, a rod between the LMRP and BOP stack is severed, and the autoshear activates. An ROV can also cut the rod between the LMRP and BOP stack to activate the autoshear system.

Figure 2.15. Barriers in a well.

- Mud
- BOP
- Cement Plug
- Mechanical Plug
- Cement Plug
- Production Casing
- Annular Cement
- Shoe Track Cement

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Figure 2.16. Simplified AMF control system schematic.

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Activating the ram systems.

Well Monitoring

If the primary hydrocarbon barriers in a well (such as the weight of drilling mud) are inadequate to contain the reservoir pressures, a kick of hydrocarbons can flow into the well. During well operations, rig personnel must always monitor the well for such kicks and respond to them quickly. Their options for responding to a kick diminish rapidly as the kick progresses.

Rig personnel (primarily the driller) watch several different indicators to identify kicks. One is the amount of fluid coming out of the well. If flow out of the well exceeds flow in or the volume of mud in the mud pits increases anomalously, that may indicate that hydrocarbons are flowing into the well. Data from sensors that measure the gas content of returning drilling mud can also warn of hydrocarbon flow. Other indicators include unexplained changes in drill pipe or other pressures, and changes in the weight, temperatures, or electrical resistivity of the drilling mud.

Once rig personnel detect a kick, they must take action to control it. The driller has a number of options for dealing with a kick depending on its size and severity. In a routine kick response scenario, the driller activates an **annular preventer** or a **pipe ram** to seal off the annular space in the well around the drill pipe. The driller then pumps heavier mud into the well. He can do this either through the drill pipe or through the **kill line**—one of three separate pipes that run from the rig to the BOP. The heavier mud is called "kill mud," designed to counteract the pore pressure of the rock formation. Because the BOP has sealed off the annular space around the drill pipe, the driller opens the **choke line** (another one of the three separate pipes running from the rig to the BOP) to allow circulating mud to return to the rig. Once the weight of the heavier drilling mud overbalances the hydrocarbon pressure and any hydrocarbons that flowed into the well have been circulated out, the driller can reopen the BOP and safely resume operations. On modern rigs, kill lines can function as choke lines, and vice versa. A third pipe, a **boost line**, connects at the bottom of the riser and can help speed circulation of fluids.

If a kick progresses beyond the point where the driller can safely shut it in with an annular preventer or pipe ram, the driller can activate the **blind shear ram**. When the two elements of the blind shear ram close against each other, they simultaneously shut in the well and sever the drill string. ⬤