Meeting the Subsalt Challenge

Drillers today are confident about their ability to reach reserves buried beneath thousands of feet of salt and water. Now their attention has turned to doing so economically, not through new technology, but by putting to best use what is already at hand.

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1. For more on the challenges of deepwater production: Amin A, Riding M, Shepler R, Smedstad E and Ratulowski J: "Subsea Development from Pore to Process," *Oilfield Review* 17, no. 1 (Spring 2005): 4–17.

^ Salt formations in deep water. This map shows areas with known potential subsalt exploration targets (white). The initial growth of activity in deep water has been in the so-called golden triangle of the Gulf of Mexico, Brazil and, more recently, West Africa. These established areas will continue to see the majority of deepwater capital investment, some 85% of activity over the next 5 to 10 years. However, frontier and emerging areas—most of which are at least partially subsalt—have made deepwater exploration a global phenomenon.

In the 1990s, the oil industry discovered that immense hydrocarbon reserves lay beyond continental shelves beneath thousands of feet of water. In pursuit of that prize, drilling contractors and engineers confronted technological hurdles unlike any previously experienced, as they took on an operating environment nearly as foreign to them as deep space had been to aeronautical engineers in the 1950s. In time, the effort became even more daunting with the discovery that these pay zones were covered by vast, thick sheets of salt that would challenge commonly accepted drilling and completion practices.

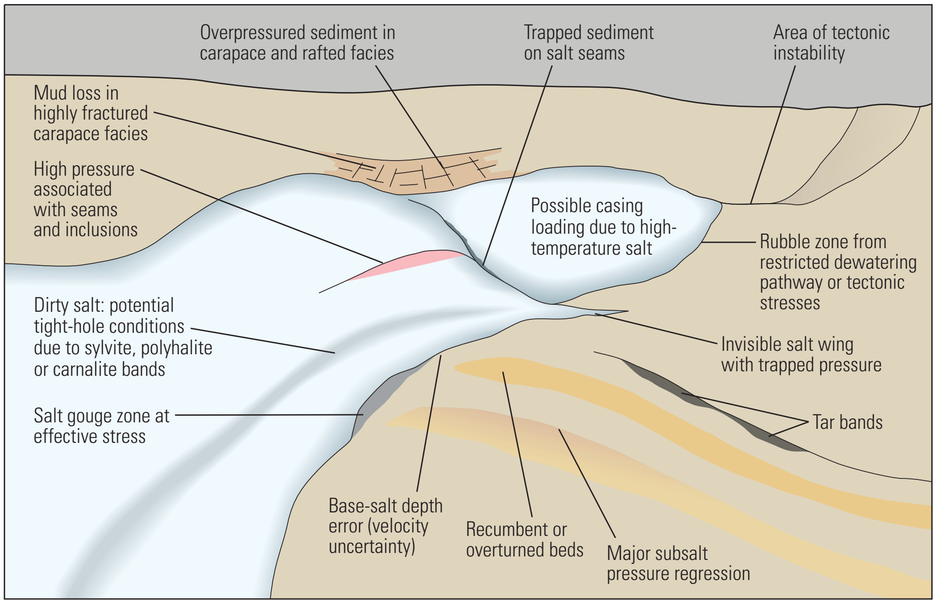
For example, in water depths beyond about 7,500 ft [2,286 m], the replacement by water of thousands of feet of overburden results in vanishingly small margins between the fracture- and pore-pressure gradients that manifest early in the drilling process. Reaching target depth under such conditions, with the technology available in the early days of ultradeepwater drilling, required setting multiple, increasingly smaller casing strings to control pore pressure while simultaneously keeping the hydrostatic pressure of the mud below that of the formation fracture gradient. The resulting well configuration often included a production string that was too narrow to accommodate desired production volumes. In other words, the industry could drill into these reserves but could not produce them at rates sufficient to justify the capital expended on the effort.

Rigs capable of handling enough pipe, riser, drilling fluids and cement to drill and complete wells in such water depths were rare. Oil industry chemistry was pushed to its limits by a requirement for drilling and completion fluids that could negotiate a thermal roller coaster as they were pumped from surface temperatures to near-freezing conditions at the seabed and then to reservoir temperatures at depth. Similarly, produced fluids had to flow from a subsurface reservoir to a wellhead bathed in the frigid waters of the seafloor and through miles of ocean-bottom flowline to production facilities that were sometimes miles away, creating unprecedented flow-assurance problems.[1]

Variable deck weight, supply chain logistics and myriad other standard offshore operating processes were all significantly altered by distance from shore and extreme water depth once operations moved beyond the world's continental shelves. In time, most of these issues were addressed through such innovations as solid expandable casing, heated flowlines, advanced chemistry and the construction of supersized drilling vessels. But for drilling engineers, one of the most daunting new facts of deepwater life was the realization that much of the prize lay beneath massive salt canopies (above).

Before the intensified interest in subsalt drilling, accepted wisdom among drilling engineers held that the best way to deal with salt intervals was to avoid them. Drilling in these formations was considered to be so fraught with risk that standard turnkey contracts—those by which contractors are paid a lump sum for drilling to an agreed depth—routinely contained a clause that converted such agreements to a standard day-rate contract if salt was encountered. Under most agreements, time calculations—used for penalty or bonus payments—were also suspended from the moment of entry into the salt until the bit exited its base and casing had been set across the formation.

The difficulties encountered while drilling these sections are a function of salt's unique characteristics. Salt sheets retain a relatively low density even after burial. Since other formations at the same depth and deeper increase in density over time as overburden is added, salt sheets tend to be less dense than the formations near and beneath them. If the overlying sediments offer little resistance to salt migration, as is often the case in the Gulf of Mexico, the salt rises. This movement generates a difficult-to-model rubble



^ Potential drilling hazards in and around salt. The opportunities for problems drilling to, through and out of salt canopies are many and derive essentially from salt's tendency to move. The industry's limited ability to image salt may lead to mistaken base-of-salt depth calculations and unexpected encounters with elevated or reduced pressure zones in and beneath the salt.

zone at the salt's base and sides (above). Because pore pressures, fracture gradients and the existence and extent of natural fractures are difficult to predict, well control is highly problematic when exiting the base of the salt (see "The Prize Beneath the Salt," *page 4*).

Penetrating salt with a wellbore also presents a unique challenge. Under sustained constant stress, salt deforms significantly as a function of time, loading conditions and its physical properties.[2] This phenomenon, known as creep, allows the salt to flow into the wellbore to replace the volume removed by the drill bit. Especially at elevated temperatures, this invasion may occur quickly enough to cause the drillpipe to stick and may eventually force the operator to abandon the well or sidetrack around it.

Another consideration for engineers is that shock and vibration levels inherent in the downhole drilling environment can become acute when drilling through salt sections. This may be attributable to poor tool selection and BHA design, inappropriate drilling-fluid design, ratty or laminated salt intervals, creeping salts, and less-than-optimal input drilling parameters such as weight on bit (WOB) or rotary speed.[3]

On the other hand, though salt is harder than most formations and therefore more difficult to drill, its unique rock characteristics also offer drillers certain advantages. For example, salts commonly have a high fracture gradient that allows longer borehole sections to be drilled between casing points. Its low permeability, in addition to providing a reliable hydrocarbon-trapping mechanism, virtually eliminates the usual well-control problems encountered when drilling more-permeable formations.[4]

To make the most of these advantages while minimizing salt's inherent drawbacks, drilling engineers have turned to a combination of existing tools. Polycrystalline diamond compact (PDC) bits, concentric under-reamers and rotary steerable systems (RSSs), originally brought together for use in extended-reach wells, have been adapted to meet the specific needs of drilling and steering through massive salt structures.

In this article, we discuss how engineers have leveraged these and other tools, seismic processing and drilling-fluid management to turn massive salt sections in deepwater plays from traditional foe to friend. We also look at how this was done while simultaneously meeting the special economic and technical demands of deepwater development. Though deepwater subsalt formations are being explored off the coasts of eastern Canada, Brazil, West Africa and elsewhere, this article primarily focuses on the Gulf of Mexico where the effort is most mature and the subsalt play has gone beyond exploration to production.

A Better Look

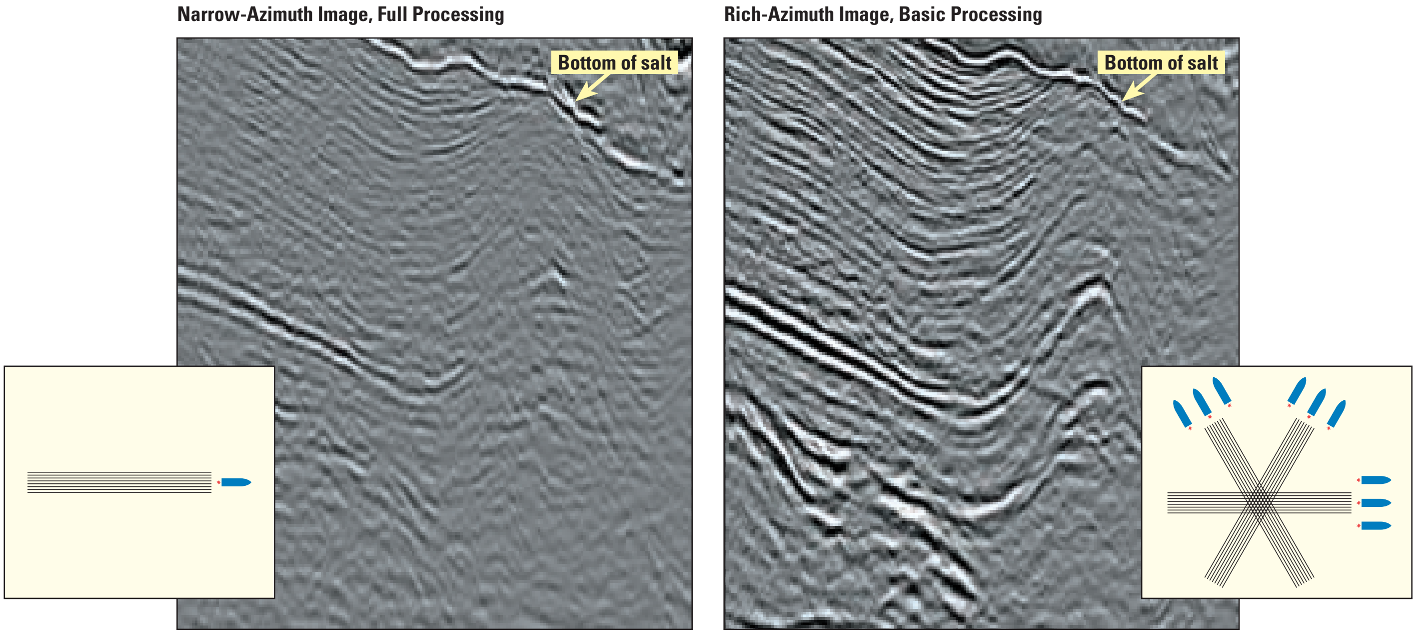
Among the most critical concerns when drilling into reservoirs that lie beneath salt are the location and angle of the wellbore exit. In the Gulf of Mexico, drilling engineers prefer to exit salt where the contact between the base of salt and underlying sediments has a low dip angle because the rubble zone tends to be more stable there than at steeply dipping flanks. When that is not possible, they strive to keep the wellbore within 30° of perpendicular to the base of salt.

Attaining these drilling targets, however, is often problematic because the base of salt can be difficult to model. Since salt may be structurally complex and seismic waves travel through it at higher velocities than in surrounding layers, surface seismic surveys have historically provided only poor images below or near it. This leaves considerable margin for error in estimating pore pressure and other properties of the subsalt formation, with potentially catastrophic results, including loss of the wellbore.

In the 1990s, 3D seismic acquisition and processing greatly improved the success rate for exploratory wells on land and in shallow waters offshore but, because of complex geology, had little impact on discovery rates in deeper water. Deepwater subsalt prospects proved particularly difficult to image using data from early 3D surveys. Furthermore, even when seismic data processing provided sufficient data for successful exploratory drilling through these formations, it often could not provide data of sufficient quality for efficient development.

In response to these and other limitations of traditional seismic survey methods, Schlumberger introduced the Q-Marine single-sensor acquisition system, which increases seismic image resolution by providing 40% greater bandwidth. Other changes to seismic survey methods aimed at increasing azimuthal coverage have also added to the industry's ability to

2. Poiate E, Costa AM and Falcao JL: "Well Design for Drilling Through Thick Evaporite Layers in Santos Basin—Brazil," paper IADC/SPE 99161, presented at the IADC/SPE Drilling Conference, Miami, Florida, USA, February 21–23, 2006.
3. Israel RR, D'Ambrosio P, Leavitt AD, Shaughnessey JM and Sanclemente J: "Challenges of Directional Drilling Through Salt in Deepwater Gulf of Mexico," paper IADC/SPE 112669, presented at the IADC/SPE Drilling Conference and Exhibition, Orlando, Florida, March 4–6, 2008.
4. Leavitt T: "BHA Design for Drilling Directional Holes in Salt in Deepwater Gulf of Mexico," presented at the 19th Deep Offshore Technology International Conference and Exhibition, Stavanger, October 10–12, 2007.
5. For more on Q-Marine, wide-azimuth and rich-azimuth surveys: Camara Alfaro J, Corcoran C, Davies K, Gonzalez Pineda F, Hampson G, Hill D, Howard M, Kapoor J, Moldoveanu N and Kragh E: "Reducing Exploration Risk," *Oilfield Review* 19, no. 1 (Spring 2007): 26–43.
6. For more on borehole seismic surveys: Blackburn J, Daniels J, Dingwall S, Hampden-Smith G, Leaney S, Le Calvez J, Nutt L, Menkiti H, Sanchez A and Schinelli M: "Borehole Seismic Surveys: Beyond the Vertical Profile," *Oilfield Review* 19, no. 3 (Autumn 2007): 20–35.



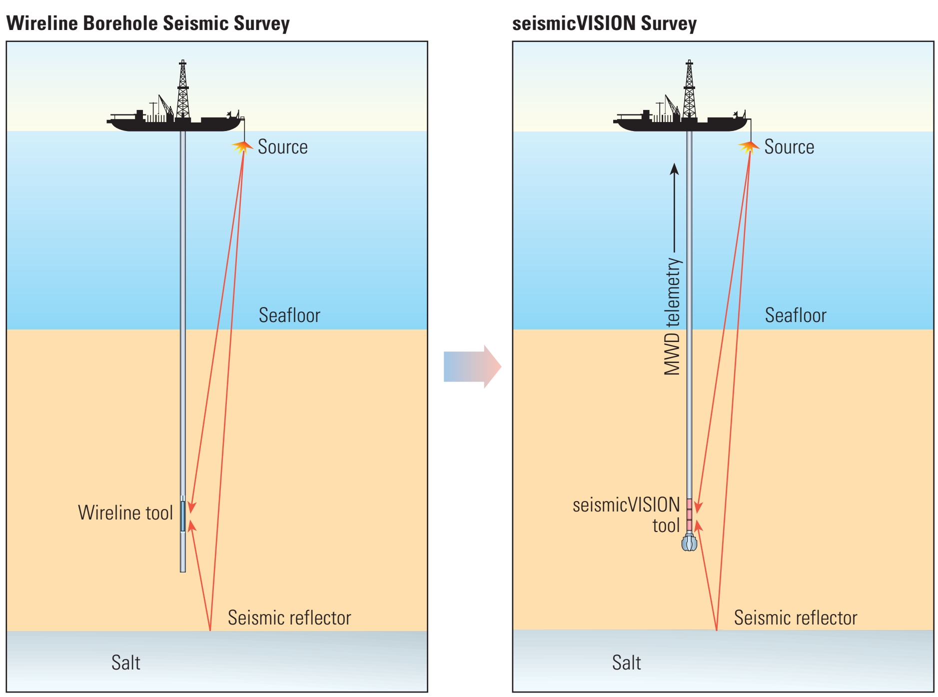
^ Enhanced views beneath the salt. The narrow-azimuth image (*left*) shows some indications of dipping layers beneath the salt, but the rich-azimuth image (*right*) illuminates subsalt layers clearly. The survey configurations for each survey are adjacent to the seismic images.

visualize subsalt formations (above).[5] In addition, a new seismic acquisition method, shooting in circles, has been effective at imaging below salt and other reflective layers and requires fewer vessels than wide-azimuth or rich-azimuth techniques (see "Shooting Seismic Surveys in Circles," *page 18*).

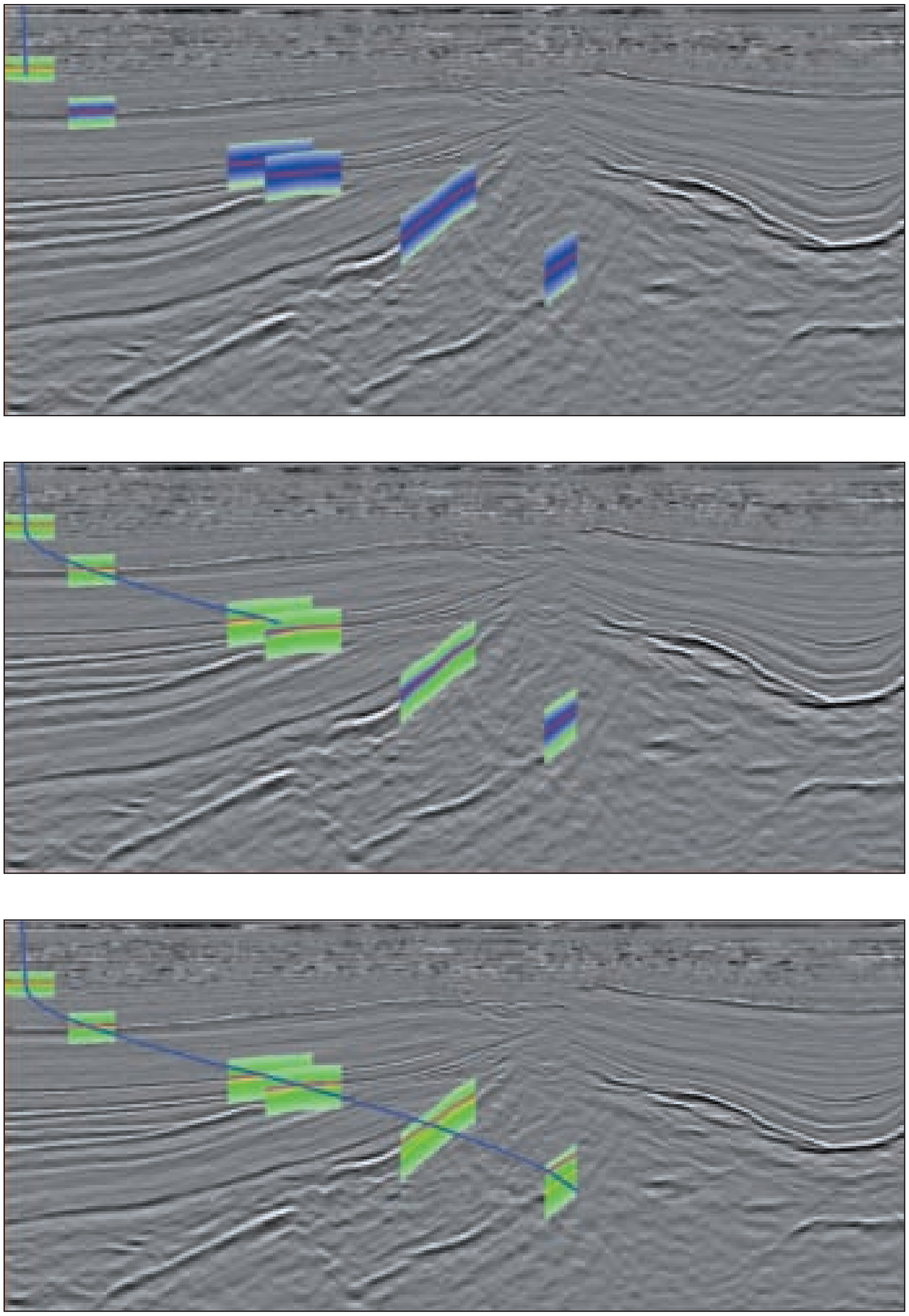
Drillers are also able to more confidently exit the salt by looking ahead of the bit. To do this they use borehole seismic procedures called walkaway vertical seismic profiles (VSPs) and seismic-while-drilling (SWD) techniques. Walkaway VSPs are conducted by moving the seismic source progressively farther from the wellhead at the surface. Receivers are clamped inside the wellbore just above the zone to be imaged—in this case near the base of salt—to provide SWD data that are used to look ahead of the bit and so better image the base of salt and its underlying formation. Amplitude variation with angle (AVA) inversion of the walkaway VSP is used to predict compressional (P-) and shear (S-) wave velocity ratios (v_p/v_s) just below the salt/formation interface. These velocities are used to predict pore pressure ahead of the bit.[6]

The walkaway VSP is then rapidly processed to provide a high-resolution image of the base of salt; it can also give details on possible sutures or inclusions in the salt. Finally, the VSP is processed to present a high-resolution image of the subsalt sediments. When the VSP is combined with surface seismic data, it is possible to attain more-comprehensive imaging of the structural and stratigraphic details in key development areas that can then be used to design well trajectories.

Familiar wireline logging technology has been adapted to LWD tools to deliver real-time time-depth and velocity information during the drilling process (below). This SWD system



^ Looking ahead of the bit. The seismicVISION sensor located in the LWD tool of the BHA (*right*) has been adapted from the wireline tool (*left*). The sensor contains a processor and memory and receives seismic energy from a conventional airgun array located either on the rig or on a source vessel. After acquisition, the seismic signals are stored and processed, and checkshot data and quality indicators are transmitted uphole in real time through a connection with a PowerPulse MWD telemetry system.



^ Refined depth prediction. Bit On Seismic software enhances visualization, communication and cooperation, updating the seismic map in real time. The map allows complex information to be presented as a wellbore placement path. Real-time seismic velocities are used to update pore-pressure predictions and predict drilling hazards. Uncertainty as to the BHA location in reference to seismic markers, represented here in blue, decreases as the well progresses toward the target.

comprises an LWD tool with seismic sensors positioned near the drill bit, a seismic source at the surface and an MWD system for real-time telemetry.[7] The time-depth data are used to position the well on the seismic map, which can be viewed at the wellsite or remotely. Real-time waveforms allow immediate processing of the VSP, enabling a true look-ahead-while-drilling capability.

Full waveforms are recorded in the tool memory for VSP processing after a bit trip. Source activation and data acquisition are conducted during drilling pauses when the downhole environment is quiet. Suitable times to acquire data are during pipe connections while drilling and tripping.

Real-time checkshot (time-depth) data are used to place the bit on the surface seismic data using a software-generated map to aid navigation, select casing points and prepare for faults, pore-pressure changes or formation variations (left).[8]

Just-in-Time Data

Despite these refinements to subsalt imaging, the science is still imperfect, and a level of risk continues to exist while drilling through and exiting the salt. As a hedge against drilling surprises or making poorly informed decisions, operators rely on data delivered in real time from the BHA to help them monitor critical drilling parameters.

MWD sensors are used to continuously update vibration, stick/slip and WOB measurements. Equivalent circulating density (ECD) measurements—critical to keeping the dynamic hydrostatic pressure of the drilling fluid from exceeding the well fracture gradient—are recorded using an annular pressure while-drilling instrument.

Although few petrophysical measurements are required while drilling salt sections, LWD data can be used to maximize drilling performance. For example, gamma ray measurements near the bit can be used to correlate changes in drilling parameters to changes in lithology associated with entering or exiting the salt or drilling through an inclusion.

Sonic compressional data can be used to improve the model by adding pore pressure measured while drilling through inclusions and in the interval below the salt, where resistivity measurements are still influenced by the salt and so may be inaccurate. Sonic shear-wave data are also important for geomechanical modeling of the salt. These models can determine the stress regimes in the salt and predict whether they vary with depth. This information is then fed back into the well-construction process for use on the next well.[9]

The most potent resource for dealing with drilling problems in salt continues to be expertise supported by quick decision making based on reliable, timely information. To that end, operators are relying on real-time drilling monitoring and on drilling support centers that use high-speed connectivity to bring together data and experts for rapid resolution of possible drilling hazards. This is partly a response to the shortage of expert personnel and the costs of the software and other tools necessary to competently drill in complex, often remote deepwater and subsalt environments.

The Toolbox

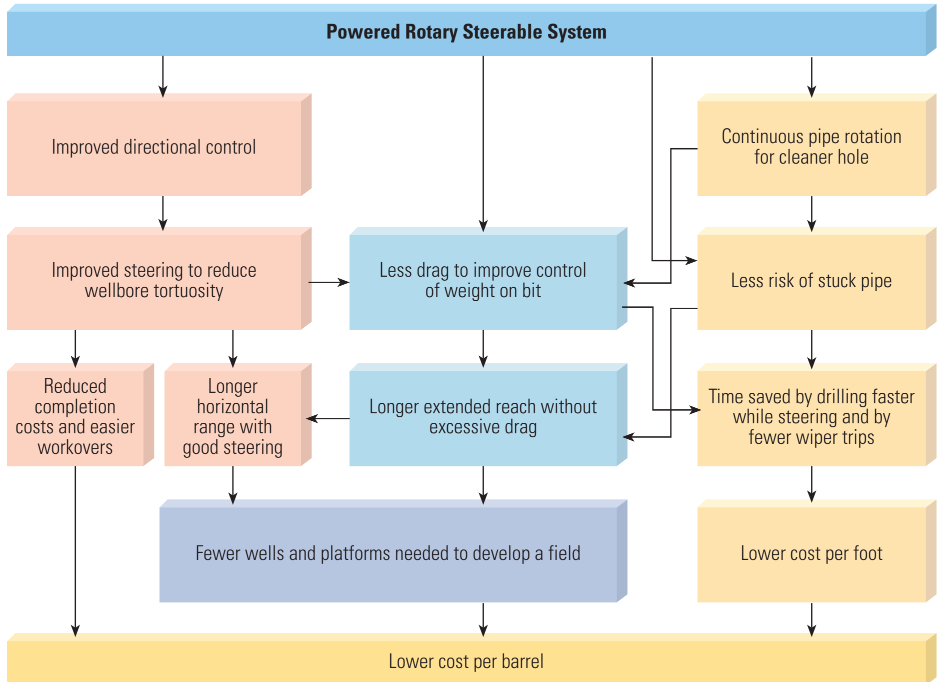
While collaboration among experts using real-time data is a powerful tool, the real measure of a project's success is in the level of its return on investment. And because the biggest subsalt prize is in ultradeep water, holding down the cost of development—often a matter of time savings—is as essential to reaching that economic goal as is use of the right technology to reaching a technical one.

A key strategy for minimizing overall field development costs is to save drilling days and capital by limiting, to the extent possible, the number of drill centers per field. To do so, it may be necessary to drill extended-reach development wells. To avoid high angles and doglegs that can cause significant problems and delays during casing and completion operations, a shallow kickoff point—that point at which the well begins to deviate from the vertical—is often necessary.

Shallow kickoffs, however, require directional drilling in the relatively large-diameter upper sections of the wellbore. This has typically been done using mud motors. But in these upper sections, mud motors tend to deliver poor rates of penetration (ROP) and highly tortuous wellbores. In response to the dilemma, drilling engineers have used a shallow kickoff with a 26-in. RSS and found that the system reduced drilling time by 63% compared with mud motors used in the same sections of nearby wells.

This success came on the heels of numerous refinements in RSS tools that are at the heart of the industry's increased success in drilling salt sections. That is because when drilling through salt, changes in well-path direction may be needed to avoid hazards indicated by real-time data. The accuracy and real-time steering capabilities of RSS tools permit drillers to steer around problems such as inclusions or tar deposits without sacrificing borehole quality.

RSS tools also are preferred to steerable motors while drilling through salt because they rotate 100% of the time while steering, which translates into improved ROP.[10] The most recent versions of RSS tools have been shown to deliver a wellbore that is rounder, more stable and less subject to creep than is possible using a drilling motor (above right).



^ RSS advantages. The engineering advantages of RSS tools quickly lead to economic ones. These benefits are magnified when applied to high-cost, high-risk deep- and ultradeepwater environments.

There are two types of RSS tools: push-the-bit and point-the-bit. The former pushes mud-actuated pads against the borehole wall. This forces the BHA and the well trajectory to move in the opposite direction. A point-the-bit system changes bit toolface angle and thus well direction by bending a flexible shaft attached to the bit.

RSS tools change direction while drilling in an almost instantaneous response to commands from the surface. Drillers also use this control capability to combat a natural build-walk tendency—a phenomenon in which the wellbore inclination increases (builds) or changes direction (walks) as the bit responds to forces imposed on it by the formation being drilled. In salt sections, build and walk directions have been known to change even within the same formation. For this reason, RSS tools are also often called upon to counter build-walk tendencies while drilling vertical sections. And, because RSS tools are always rotating, they are able to deliver better overall penetration rates than mud motors, which must change to the less efficient nonrotating sliding mode to counter salt's build-walk tendency.[11]

In some instances, high-torque, low-speed motors are recommended for use in conjunction with RSS tools. The addition of a motor creates what is referred to as a powered RSS. This system is capable of delivering increases in drilling efficiency because it allows the driller to reduce drillstring rotational speed while the motor delivers torque directly at the bit.

One recent operation in the deepwater Walker Ridge block of the Gulf of Mexico afforded Schlumberger drilling engineers an opportunity to compare the performances of two BHAs used to drill sidetrack wells below the salt formation: The No. 2 sidetrack was equipped with a push-the-bit RSS assembly and the No. 3 sidetrack with a mud motor and bicenter bit.

7. Underhill W, Esmersoy C, Hawthorn A, Hashem M, Hendrickson J and Scheibel J: "Demonstrations of Real-Time Borehole Seismic from an LWD Tool," paper SPE 71365, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, September 30–October 3, 2001.
8. A checkshot measures the seismic traveltime from the surface to a known depth in the wellbore. P-wave velocity can be measured directly by lowering a geophone to each formation of interest, sending out a source of energy from the surface and recording the resultant signal. The data can then be correlated to surface seismic data by correcting the sonic log and generating a synthetic seismogram to confirm or modify seismic interpretations. A checkshot differs from a VSP in the number and density of receiver depths recorded; geophone positions may be widely and irregularly located in the wellbore. By contrast, a VSP usually has numerous geophones positioned at closely and regularly spaced intervals.

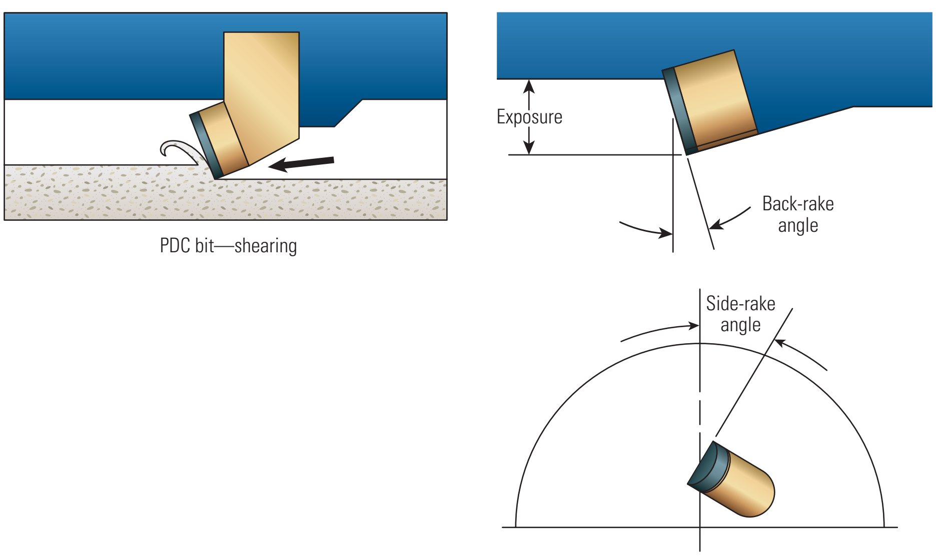
   For more on Bit On Seismic software: Breton P, Crepin S, Perrin J-C, Esmersoy C, Hawthorn A, Meehan R, Underhill W, Frignet B, Haldorsen J, Harrold T and Raikes S: "Well-Positioned Seismic Measurements," *Oilfield Review* 14, no. 1 (Spring 2002): 32–45.
9. Israel et al, reference 3.
10. By rotating 100% of the time, RSS tools better deliver WOB, which more efficiently transfers the weight of the drillstring and BHA to the bit. Other systems, such as mud motors, put much of the drillstring in tension, thus reducing downward force available.
11. For more on RSS: Copercini P, Soliman F, El Gamal M, Longstreet W, Rodd J, Sarssam M, McCourt I, Persad B and Williams M: "Powering Up to Drill Down," *Oilfield Review* 16, no. 4 (Winter 2004/2005): 4–9.

Run Statistics	PowerDrive Run	Bicenter Run
Well	Big Foot No. 2 ST01BP00	Big Foot No. 3 ST01BP00
Rig	Cajun Express	ENSCO 7500
Hole size	12 1/4 in.	12 1/4 in. x 13 1/2 in.
Bit	RSX 130 (RHC)	QDS 42 (Smith)
Date in	January 4, 2006	October 24, 2007
Date out	January 12, 2006	November 2, 2007
Total time BRT	± 8 days	± 9 days
Depth in	17,510 ft	19,125 ft
Depth out	22,197 ft	20,715 ft
Footage	4,687 ft	1,590 ft
Drill hours	74	77
ROP	63 ft/h	20 ft/h
Inclination in	0.1°	1.65°
Inclination out	31°	6.3°
Average DLS	2°/100 ft	0.29°/100 ft
Maximum DLS	3.9°/100 ft	0.57°/100 ft

^ Performance comparison. The differences in ROP and average dogleg severity (DLS) highlight the RSS advantages over a mud motor using a bicenter bit. Part of the improved time performance is a consequence of the fact that, unlike mud motors that use bent housings to build angle, it is unnecessary to pick RSS tools off bottom to directionally orient them. Also, RSS-equipped BHAs do not require bicenter bits to ensure that the borehole has sufficient casing-running clearance, which means less energy is required to drill the same section.

The mud motor and bicenter bit option was chosen because an RSS-reamer combination could not be rotated across the existing whipstock face. This choice eliminated a separate trip to pick up another BHA once the driller had exited the whipstock but still allowed an extension of the wellbore and drilling of the section in a single run.

While it took just 74 hours to drill 4,687 ft [1,429 m] of the No. 2 sidetrack, it took 77 hours to drill 1,590 ft [485 m] of the No. 3 sidetrack, translating to ROPs of 63 and 20 ft/h [19 and 6 m/h], respectively. The standard RSS was also able to achieve higher doglegs and so take the sidetrack away from the main wellbore faster (above).



^ Cutting action. PDC bits drill hard, essentially homogeneous salt sections efficiently using a shearing, lathe-like cutting action (*left*). The back-rake angle and cutter exposure (*top right*) and side-rake angle (*bottom right*) define how aggressively PDC bits contact the formation.

At the Cutting Edge

PDC bits are more suitable for drilling in the salt than milled-tooth bits. The shearing action of PDC bits makes them more efficient in cutting through salt, and they require less WOB. They are highly durable—a quality that takes advantage of the homogeneous nature of the salt so that long salt sections can be drilled in a single run before setting casing. Also, PDC bits can be designed with different degrees of aggressiveness (below left).

Proper PDC bit selection is critical. Bit type and corresponding drilling parameters are often primary sources of downhole shock, vibration and stick/slip and strongly influence a BHA's directional tendency while maximizing ROP.[12] A bit that is poorly suited to the job is likely to wear prematurely, produce poor-quality boreholes, cause tool failures and reduce ROP.

Despite extensive documentation of worldwide bit records and the proliferation of software programs and improved PDC inserts and bit designs, bit selection is usually based on local field knowledge. To address this potential shortcoming, Schlumberger and Chevron engineers assembled a bit-tracking system for the US Gulf Coast region by compiling information from drilling runs that used push-the-bit RSS tools. Bit performance metrics were based on general stability—recorded downhole shock, vibration and stick/slip—directional steering ability and the expected overall penetration rate.

Each entry was characterized by the number of blades, bit size, cutter size, specialized bit features, well profile and reamer being used. Other data included WOB and rotation rate applied to the BHA, measured depth (MD) of the bit run, formation drilled, wellbore trajectory and ROP as related to depositional environment. Each of these parameters was analyzed for significant effects on performance with regard to downhole shock and vibration and to directional steerability, which is defined as either an inability to steer the well in the desired direction or ROP problems.[13]

Among the key findings of the study were the following:

- Salt and sandstone formations had the most incidences of shock and vibration, and sandstone lithologies yielded the most steering problems.
- Vertical wells had the highest incidence of shock and vibration events.
- Significant steering problems seemed unrelated to the type of lithology drilled.
- The highest ROPs in competent formations were in wells that did not have shock and vibration and steerability problems.

- Rotary steerable systems helped reduce most problems associated with directional control.
- The appropriate choice of PDC bit characteristics and features, along with correct application of operating parameters, reduced the problems associated with shock and vibration and, in turn, delivered a higher ROP regardless of geographical area, depth and trajectory.
- The operator had to experiment to find the best combination of bit design and BHA components to reduce shock and vibration and to enable the BHA to steer the well in the desired direction.

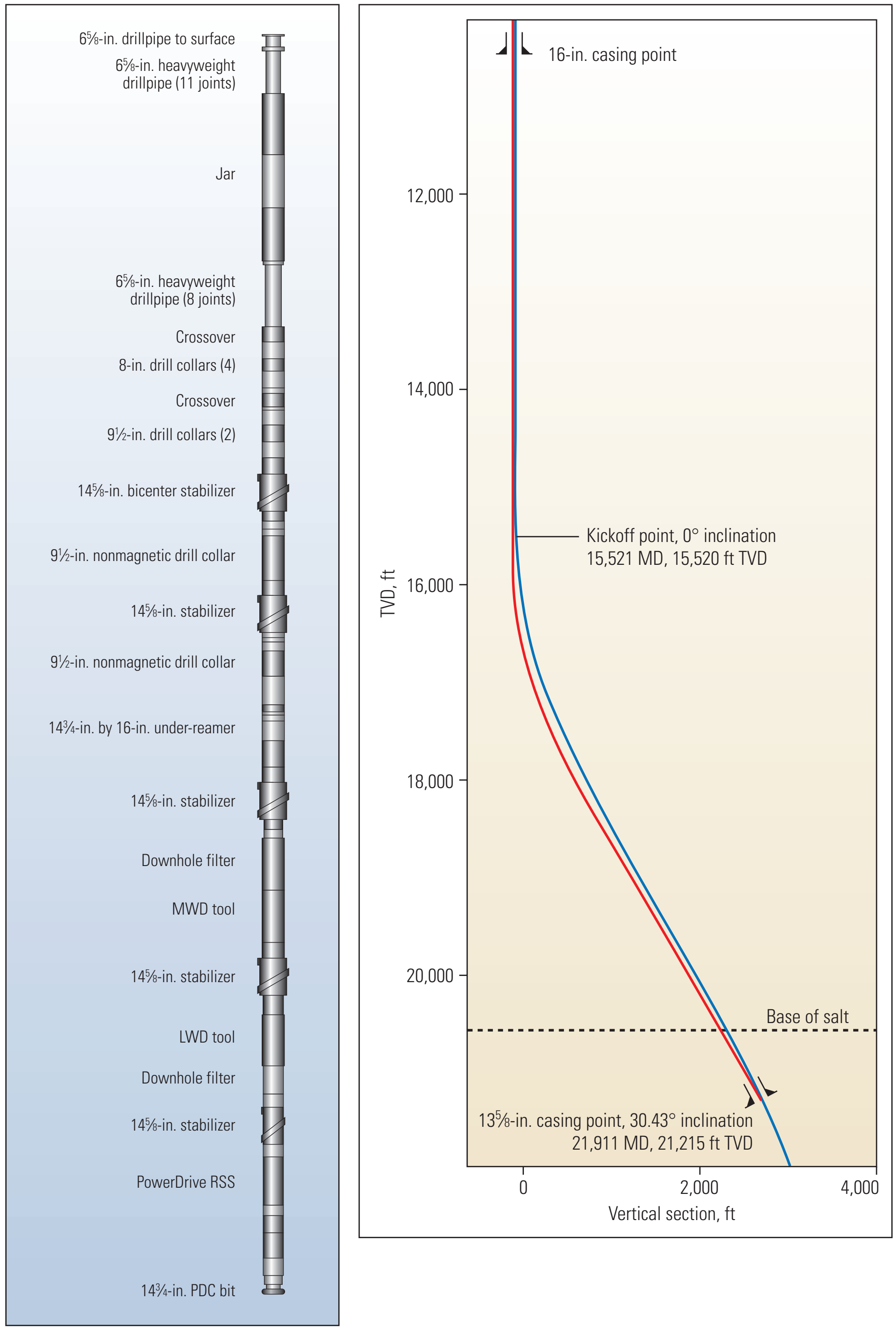
Bigger and Better Holes

The ultimate goals of every drilling program are a high-quality gauge borehole, accurate formation evaluation and rapid, uncomplicated drilling. In salt formations, added to other characteristics that define quality boreholes is a reduction in load points on the completion that would otherwise result from the salt's nonuniform transverse-loading characteristics. To achieve this in a cost-effective manner, operators use concurrent drilling and reaming techniques to enlarge the borehole as it is drilled, rather than making a separate trip for each. The most common tools for this technique—known as enlarging while drilling (EWD)—are concentric reamers, bicentered bits and eccentric reamers.

Increasing borehole size beyond the diameter of the bit delivers many advantages, including the ability to use a casing string with an outside diameter close to that of the previous string's inside diameter. While this scenario naturally creates a tight tolerance between the two casing strings, enlarging while drilling leaves a larger annulus between the casing and borehole wall. The extra space reduces surge and swab effects and cementing problems that may occur when there is too little open area between the casing being set and the wall of the openhole section.

One operator in the deepwater Gulf of Mexico planned to use the EWD technique to drill out of a 16-in. casing shoe and continue drilling vertically to the kickoff point where the well would build inclination at a rate of 1.5°/100 ft [1.5°/30 m] until the well angle reached 30°. The plan was to continue the section through the salt base to the 13⅝-in. casing point at 21,911 ft [6,678 m] MD.

Despite encountering severe shocks and vibrations while drilling the same salt section in offset wells with a powered RSS, engineers hoped to drill the section in one run. Again they used a PowerDrive RSS and a 16-in. under-reamer located 90 ft [27 m] behind a nine-bladed 14¾-in. PDC bit. As a consequence, engineers were able to finish the section in a single run and to drill it more quickly and with lower levels of shock and vibration than were experienced in the offset wells (above).



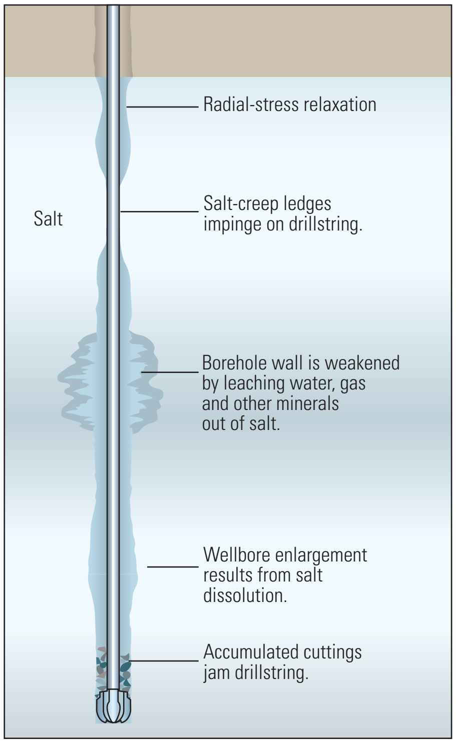
^ Purpose-built BHA. The PowerDrive RSS drilled the 14¾-in. by 16-in. salt interval (blue line) as planned in a single run (red line *right*). The BHA for this interval (*left*) was designed to avoid the severe shocks encountered in offset wells.

At the start of the run, the RSS was programmed to drill vertically and, in fact, held maximum angle to just 0.10° until the kickoff point was reached. Angle was then built to 30° using downlinked commands to steer the RSS tool, and that inclination was held until the wellbore exited the base of the salt. A flow check was then

12. Moore E, Guerrero C and Akinniranye G: "Analysis of PDC Bit Selection with Rotary Steerable Assemblies in the Gulf of Mexico," paper AADE-07-NTCE-08, presented at the 2007 AADE National Technical Conference and Exhibition, Houston, April 10–12, 2007.
13. Moore et al, reference 12.

performed, and drilling proceeded until the base of salt was confirmed on the log at 21,119 ft [6,437 m]. The well was circulated bottoms up

Potential Problems



^ Washouts. Problems associated with poor drilling-fluid selection include sections of borehole enlargement and weakened borehole walls as a result of leaching. Low mud weight may allow creep to impinge on the drillstring, while drilling fluid with unfavorable rheological properties may be unable to carry cuttings to the surface, causing the drillstring to become packed off above the bit.

and successfully drilled through the rubble zone. The section was then drilled to total depth (TD) following the planned trajectory.

Engineers drilling deepwater wells in the BC-400 field offshore Brazil recently quantified the impact of BHA and geosteering system choices on enlarging-while-drilling methods. The BHAs included LWD tools and wireline calipers to measure results and to provide a direct comparison of borehole quality attained with each system. Salt formations were drilled to ensure that each system was compared within a common drilling environment without variations attributable to formation types.[14]

The test well, in 1,745 m [5,725 ft] of water, used intermediate casing strings to isolate salt formations. After the intermediate string was set at 3,793 m [12,444 ft], three EWD combinations were used to open the 12¼-in. hole section to 14¾ in. Then, a 10¾-in. secondary intermediate casing string was set across the salt. The test comprised five drilling runs—including two with no enlarging-while-drilling assembly—that compared the following equipment types:

- conventional mud motor with a 1.15° bent housing and a PDC bit and no enlargement
- conventional BHA with a fixed-blade reamer
- conventional BHA with bicenter bit
- mud motor with 12¼-in. tricone bit, a 1° bent housing and no enlargement
- 12¼-in. x 14¾-in. concentric reamer and RSS.[15]

MWD tools recorded downhole vibrations caused by lateral shocks and stick/slip. The RSS produced a hole that was virtually free of rugosity and wellbore threading—grooves on the wellbore wall similar to those that would be left by screw threads. This BHA configuration also produced the longest run for the section with a run length of 254 m [833 ft] with an average ROP of 10 m/h [33 ft/h]. Measurements indicated low levels of stick/slip, vibrations and shocks. Additionally, hole inclination was reduced from 2 to 0.4° for the entire run.[16]

The Fluids

Just as drilling in salt requires specific BHAs, entering, drilling through and exiting the salt also place special demands on fluids selection. Because of salt washout or leaching, creep, sutures and other inclusions within the salt, and the unknowns associated with the rubble zone, drilling fluids must be designed to balance the sometimes competing interests of ROP, hole quality, wellbore stability and affordability (left).

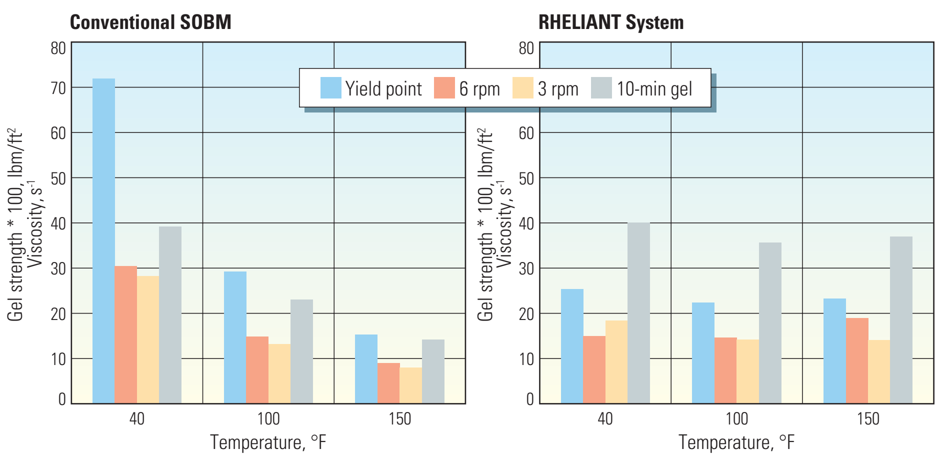
For instance, ROP increases significantly when salt formations are drilled using undersaturated brines or seawater. But their use can also lead to significant hole enlargement through salt leaching. On the other hand, using seawater offers significant cost savings while also eliminating the need for precious rig space to store weighted brines when drilling riserless into the top of the salt.

Scientists at the Schlumberger TerraTek Geomechanics Laboratory Center of Excellence in Salt Lake City, Utah, USA, investigated the potential advantages and feasibility of using seawater to enter the top of salt. To do so, they used physical laboratory modeling of salt leaching under conditions of forced convection.[17]

The laboratory test used a Reynolds number calculation to determine the dissolution characteristics of salt while flowing seawater and heavier brines at simulated field conditions.[18] Flow rates were scaled to match the Reynolds numbers associated with field flow conditions for a 24-in. borehole with a 5½-in. drillpipe, and 1,000- and 750-galUS/min [227- and 170-m^3/h] flow rates.

The analytical model was based on diffusion principles and fluid mechanics. Model inputs included initial hole diameter, drillstring diameter, BHA diameter and length, along with drilling ROP, flow rate and salt thickness. Other inputs were the temperature and initial salinity of drilling fluid, and diffusivity and salt density. With a few exceptions for specific conditions, modeled results typically matched laboratory results, usually within 10% of average diameter.

The model was applied to a well in the Gulf of Mexico where current practice is to drill a 24-in. hole riserless into the first 500 ft [152 m] of salt using seawater and gel sweeps. The final 200 ft



^ Flat rheology. Flat-rheology SOBMs, like the MI-SWACO RHELIANT system (*right*), can maintain constant gel and shear strength through a range of temperatures and pressures. This indicates that the fluid is retaining favorable drilling characteristics—including high ROP and low ECD—associated with synthetic oil-base fluids (*left*) without sacrificing the viscosity necessary for efficient borehole cleaning. Typical reported fluid properties of yield point and 10-min gel are measured in lbm/100 ft^2, and 6 rpm and 3 rpm are true centipoise viscosity (s^{-1}) as seen on a Fann viscometer dial.

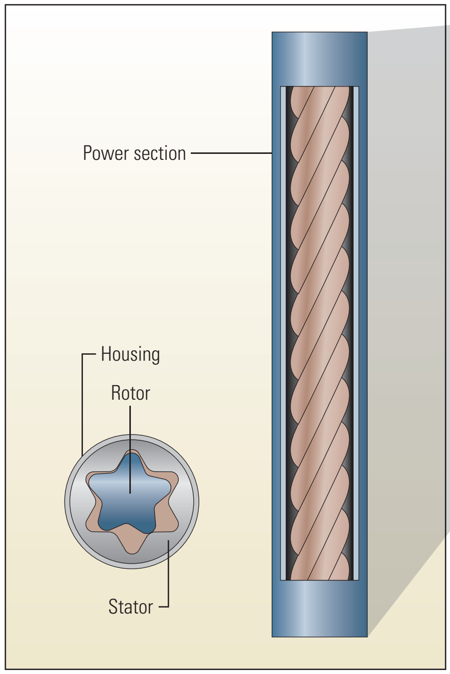
[61 m] is typically drilled with a salt-saturated mud to ensure a good cement job.

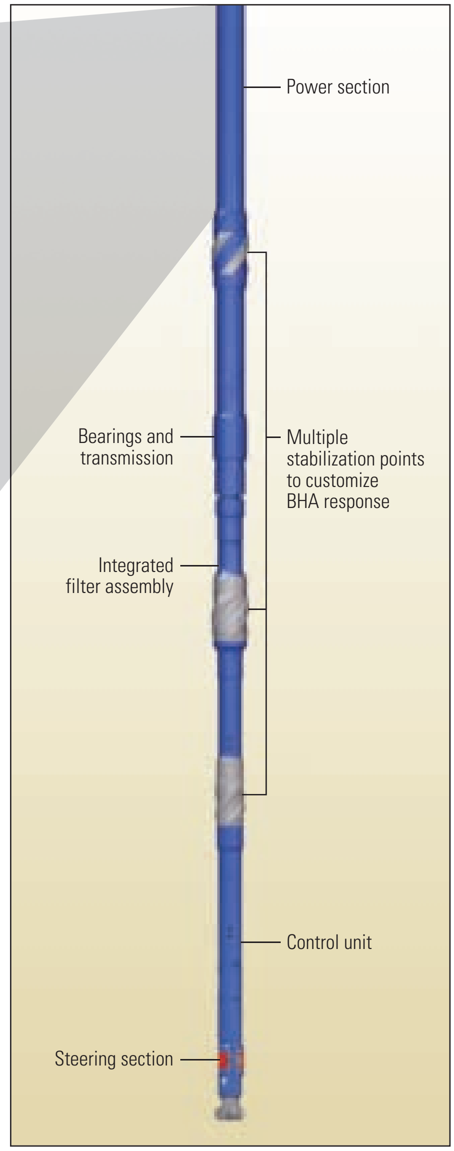
However, modeling suggested there are benefits to drilling the last 200 ft using seawater. Proposed advantages include improved ROP of 50 to 120 ft/h [15 to 37 m/h] compared to a salt-saturated mud and lower drilling-fluid costs. Predicted leaching resulted in a need to use 8% by volume more cement—the amount normally pumped to ensure cement returns to the seabed. The modelers, using 2004 rig rates, assumed savings from improved ROP and reduced fluid costs at about US $250,000 per well.[19]

Once past initial entry and during progression through the salt itself, drilling hazards may include sutures and inclusions of higher or lower pore pressure than the surrounding salt, making those sections more prone to kicks or lost circulation. Additionally, salt will creep into the wellbore if the mud's hydrostatic pressure is less than the stress developed in the salt. Early operator experiences in drilling these formations using conventional salt-saturated muds included slow penetration rates, poor hole integrity, lost returns, bit balling and packoff problems.

For relief from these difficulties, drillers turned to synthetic oil-base muds (SOBMs). Because they are more expensive than water-base fluids, operators have traditionally avoided SOBMs for drilling in areas with lost circulation potential. Additionally, although they have been shown to deliver high drilling rates and good wellbore stability, SOBMs exhibit elevated viscosity as a function of increased temperature and pressure. This may lead to higher equivalent circulating densities that can result in lost circulation. This is of particular concern in deep water where pore-pressure/fracture-gradient margins may be exceedingly narrow.

Still, the attraction of days saved in the ultradeepwater arena—both as a function of improved ROP and as a consequence of hole stability that can significantly reduce casing and cementing operations—has made SOBM the drilling fluid of choice for many operators drilling in and below the salt. For example, in 2000, after having drilled an 8,000-ft [2,438-m] salt section in its first well with a salt-saturated mud, one Gulf of Mexico operator switched to an SOBM system for the next well. The second well, which penetrated the same zones, required 78 fewer drilling days than the first well for a cost savings of about US $12 million.[20]





^ Powered RSS. Components of a powered RSS (*right*) add a power section (*above*) to the basic RSS. As drilling mud passes between the rotor and stator of the power section, the rotor attached to the bit turns. This provides the RSS with additional torque and rotational speed at the bit and so improves ROP.

SOBMs are gaining increased acceptance now that manufacturers have developed flat-rheology SOBMs to overcome these fluids' tendency toward elevated viscosity at high temperatures and pressures. The new systems are designed to maintain constant rheological parameters as temperature and pressures vary (previous page, bottom). The flat rheology allows for a higher viscosity without raising ECD and maintains cuttings-carrying capacity and barite-suspension properties.[21]

Salt-Entry Technologies

The ability of powered RSS tools to deliver torque to the bit reduces the stick/slip potential traditionally associated with large PDC bits. This feature makes the RSS option particularly well-suited for operations in the riserless section of the hole in which operators jet-in the conductor pipe. Once the borehole reaches the conductor setting point, the driller can unlatch the RSS from the casing and drill ahead while taking returns to the seafloor.

The efficiency of this practice was recently demonstrated in one deepwater Gulf of Mexico well after earlier attempts to drill the 26-in. salt section had met with mixed results, and the company was anxious to improve ROP using a powered RSS with a PDC bit (above). Previous

14. Lenamond C and da Silva CA: "Fully-Rotating Rotary Steerable and Concentric Reamers Technology Combination Eliminate Wellbore Threading in Deepwater," paper SPE/IADC 91929, presented at the SPE/IADC Drilling Conference, Amsterdam, February 23–25, 2005.

15. Lenamond and da Silva, reference 14.

16. Lenamond and da Silva, reference 14.

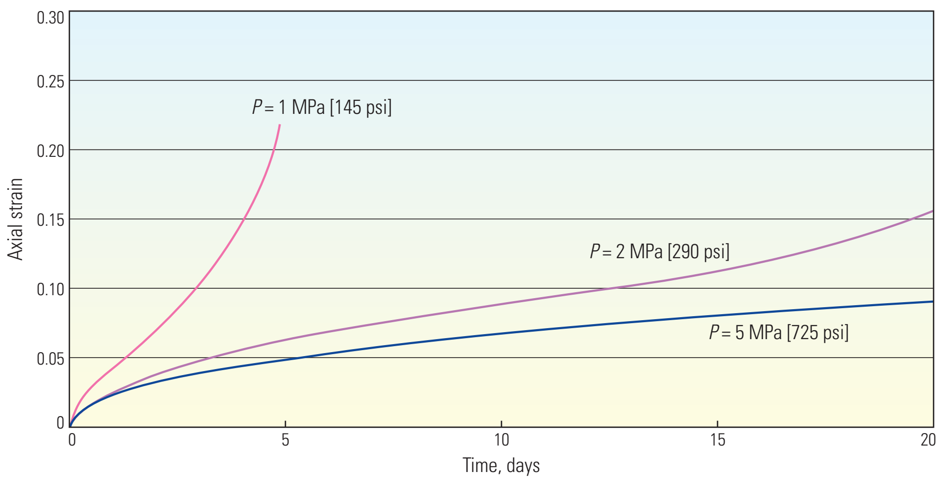
17. Willson SM, Driscoll PM, Judzis A, Black AD, Martin JW, Ehgartner BL and Hinkebein TE: "Drilling Salt Formations Offshore with Seawater Can Significantly Reduce Well Costs," paper IADC/SPE 87216, presented at the IADC/SPE Drilling Conference and Exhibition, Dallas, March 2–4, 2004.

18. Reynolds numbers (*Re*) may be expressed in oilfield units by $Re = 379 \times \rho \times Q/\mu \times D_e$, where ρ = fluid density in lbm/gal, Q = flow rate in galUS/min, μ is fluid density in cP, and D_e is effective diameter of the hole in inches. Therefore, as the effective diameter of the hole increases as a consequence of leaching, the Reynolds number decreases.

19. Willson et al, reference 17.

20. Meize RA, Young M, Hudspeth DH and Chesebro SB: "Record Performance Achieved on Gulf of Mexico Subsalt Well Drilled with Synthetic Fluid," paper IADC/SPE 59184, presented at the IADC/SPE Drilling Conference, New Orleans, February 23–25, 2000.

21. van Ort E, Lee J, Friedheim J and Toups B: "New Flat-Rheology Synthetic-Based Mud for Improved Deepwater Drilling," paper SPE 90987, presented at the SPE Annual Technical Conference and Exhibition, Houston, September 26–29, 2004.



^ Salt-creep levels. This plot illustrates the creep behavior of salt at three different levels of confining pressure (*P*). The strain-time curves for confining pressures higher than 5 MPa are identical to the one conducted at 5 MPa. Therefore, creep results obtained under a confining pressure of at least 5 MPa are expected to be appropriate for deepwater Gulf of Mexico conditions for which the mean stresses are extremely high. (Adapted from Fossum and Fredrich, reference 25.)

attempts to drill this hole section using an insert bit had met with low ROP of 15 to 20 ft/h or had been plagued by shocks and vibrations sufficient to halt drilling or cause BHA failure.

By contrast, the powered RSS delivered a consistent rate of 35 to 40 ft/h [11 to 12 m/h] and a vertical hole with a 0.17° inclination at total depth. Judged against similar wells, this 48% overall ROP increase saved the operator an estimated US $1.25 million per well.

In many instances, the top of salt cannot be reached using riserless drilling methods because salt migration may have altered stresses in the interval just above the salt, creating drilling hazards. Fractured or faulted formations are particularly common when the salt top is relatively deep. In these environments older, higher-pressured sediments have been pushed upward by the salt and subsequently fractured as the pressure bled off, creating a potential lost circulation zone. However, if the pressure is not relieved, the opposite hazard may exist and the formation just atop the salt may be overpressured, creating a zone in which a kick is likely.

In either case, the driller must proceed with caution. To gain time in which to interpret data and react to risk as the bit approaches the salt, prudent drillers reduce WOB as they encounter the first indications that they are nearing the top of salt: an increase in torque and reduced penetration rates. A gamma ray logging tool placed within 10 ft [3 m] of the bit provides useful confirmation that these drilling parameter changes correlate to the top of salt.[22]

With the top of salt thus confirmed, operators commonly maintain a cautious approach until the BHA is completely within the salt sheet—typically for 100 to 150 ft [30 to 46 m]. At this point, they can reasonably assume it is safe to drill a long section of salt without significant problems.

Drilling Through the Salt

In the Gulf of Mexico, unlike other subsalt plays around the world, drilling targets are not beneath deep, depositional, autochthonous salt. Instead they are under salt diapirs, sheets and remnant welds—evacuated salt below mobile, allochthonous salt. These deepwater salt bodies may occur as multitiered sheets that are interconnected by vertical and inclined salt feeders. Although deepwater salt sheets are not entirely understood, experience has shown them to be complex systems with a wide range of internal variations. This may be particularly true for suture zones—where the salt sheets have merged—that contain pervasive inclusions of sediments from the surrounding strata.[23]

As a consequence, within the salt, trapped pressures in rafts of fractured dolomite or in shale inclusions can cause fluid influx—a kick. Though the influx from these kicks may be relatively small, problems can arise if operators respond with standard well-control measures in environments with narrow windows between the pore-pressure and fracture gradient.[24] Raising the mud weight to kill the well, for example, can increase hydrostatic pressure to a level greater than that of the fracture gradient.

Shock and vibration imposed on the BHA may be the most difficult challenge while drilling through salt. Vibration can cause tool twist-off or failure, leading to costly fishing or other remedial operations and added trips. Unstable or overly aggressive bits, poorly matched bit-reamer combinations or ratty or creeping salts also induce shock and vibration. Drilling through heterogeneous formations may also introduce shock and vibration. When the reamer and bit are run simultaneously, often as much as 90 ft apart, it is possible that the bit will be drilling salt while the reamer is simultaneously drilling an inclusion. This could result in one component drilling faster than the other, which could cause poor weight transfer that manifests in shock and vibration levels sufficient to damage the BHA.

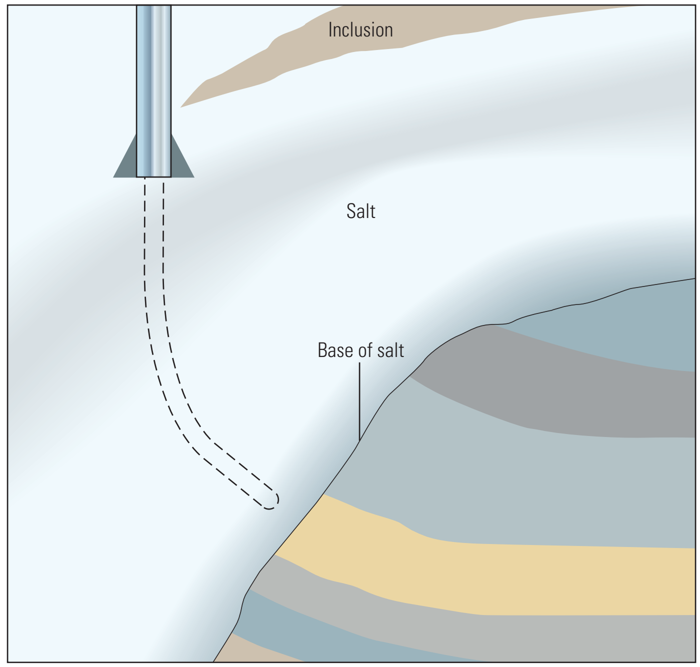
The potential hazards associated with drilling within or near massive salt sections are legion. But for many drilling and completion engineers, the most significant is the tendency of salt to creep when subjected to stress. This characteristic—essentially pseudoplastic flow caused by overburden pressures, augmented by subsurface temperatures and low permeability—accounts for the presence of salt diapirs and can cause newly drilled wellbores to close.

Salt creep involves either two or three creep stages (above left). When the confining pressures are less than 5 MPa [725 psi], strain begins at a very high rate and then decreases to a constant rate during the first stage. The second stage is marked by salt deforming at a constant rate, and in the third stage, the strain rate increases until failure occurs. When the confining pressure is more than 5 MPa, no third stage is evident.[25]

For salt formations, the in situ stress is assumed to be equal in all directions and equal to the overburden weight. The rate at which the wellbore closes because of creep increases with temperature and the differential pressure between the formation stress and the hydrostatic pressure of the mud weight. Also, calculations have shown that the closure rate is directly proportional to the wellbore radius.[26]

Other influences on creep behavior include salt thickness, mineralogy, water content and impurities. Chloride and sulfate salts containing water are the most mobile, and halite is relatively slow moving. Anhydrite and the other carbonate evaporates are essentially immobile.[27] In the Gulf of Mexico, where the salt composition is up to 96% halite, creep during the drilling process is a smaller problem than in other parts of the world and usually can be controlled with mud weight.

Still, salt creep has been responsible for casing collapse in a number of Gulf of Mexico wells. In a Green Canyon discovery well, casing collapsed as a result of catastrophic stress caused by creep nearly three months after the casing was set across a 15,000-ft [4,572-m] salt section. Recommendations for combating this problem include under-reaming the slip zone, proper drilling-fluid composition and cementing practices that improve stress distribution.[28]



^ Exiting the salt. While drillers prefer as flat a section as possible to exit the salt, that is not always an option. As demonstrated in this well plan, the alternative is to build angle within the salt itself so as to create as close to a 90° angle as possible between the wellbore and the plane of the base of salt.

Exiting the Salt

Drilling out of the base of salt is fraught with the same risks as entering it—and for the same reason: The expected stress regimes of the surrounding formations are disrupted by the migration of the salt body. Immediately beneath the salt may lie rubble zones that introduce uncertainty as to fracturing, pressure and overturned beds.[29]

Most Gulf of Mexico deepwater operators have developed company-specific procedures for exiting the salt. In general, drilling engineers seek to exit the salt at a flat or minimally angled location at the base of salt or, if that option is impractical, they attempt to keep the exit angle between the salt base and the wellbore close to 90° (above right). Once the target exit point is located and the well path established, at about 400 ft [122 m] above the expected base of salt, drillers reduce ROP to about 40 ft/h. Simultaneously, they will monitor and reach a steady state of drilling parameters of torque, WOB, bottomhole temperature, ECD, vibration and near-bit gamma ray response.

At this point, drillers may increase mud weight and add lost circulation material (LCM) to the system. Prudent drillers also often prepare an LCM pill for use in case the subsalt pore pressure is lower than that of the salt.

Once changes to drilling parameters inform the operator that the salt base has been breached, the driller pulls the bit back up into the salt and performs a flow check. While circulating cuttings above the BHA, the driller monitors pit volumes for gains or losses that indicate kicks or fluid losses in the rubble zone. The next step is to space out the drillpipe—inserting nonstandard lengths of drillpipe into the drillstring—to ensure drilling can continue beneath the salt to a depth equal to the length of a full stand of drillpipe before a connection has to be made. Drilling is then resumed in 10- to 15-ft intervals with constant monitoring of drilling conditions, and the drillstring is repeatedly pulled back into the salt to circulate cuttings above the BHA and to check pit volumes.

Once it is established that there are no high-pressure, lost circulation or hole-integrity problems, controlled drilling increments are increased to 15- to 30-ft [5- to 9-m] intervals between hole checks. This is continued until two stands or up to 300 ft [91 m] below the salt have been drilled.[30]

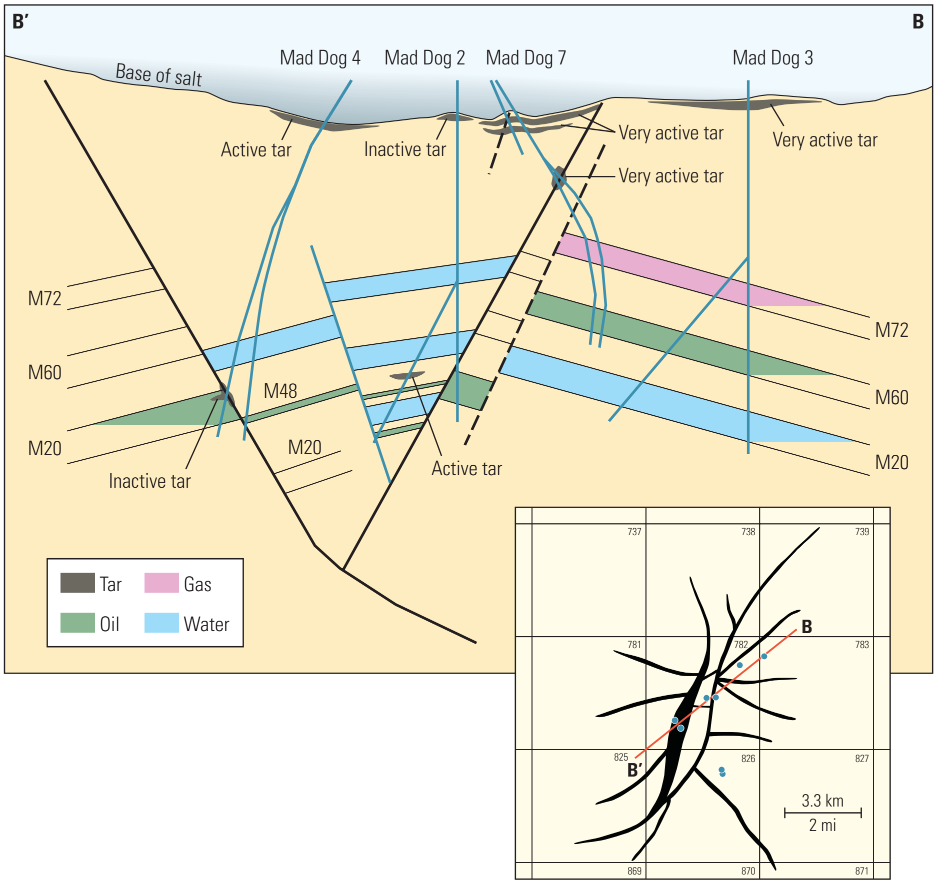
A Special Exit Challenge

Among the most vexing problems reported by operators upon exiting salt in certain deepwater areas of the Gulf of Mexico are pockets of mobile tar, or bitumen, that often occur below salt and along faults or welds. This viscous material is more than 85% asphaltene and has proved to be a significant challenge to drill through.

The problem of bitumen in deepwater subsalt drilling was initially raised by operator BP while drilling its second appraisal well in the Mad Dog field in Green Canyon Block 82. The operator reported drilling into a highly viscous

22. Israel et al, reference 3.
23. Willson SM and Fredrich JT: "Geomechanics Considerations for Through- and Near-Salt Well Design," paper SPE 95621, presented at the SPE Annual Technical Conference and Exhibition, Dallas, October 9–12, 2005.
24. Willson and Fredrich, reference 23.
25. Fossum AF and Fredrich JT: "Salt Mechanics Primer for Near-Salt and Sub-Salt Deepwater Gulf of Mexico Field Developments," SAND2002–2063, DOE Contract No. DE-AC04-94AL85000, Sandia National Laboratories, July 2002.
26. Leavitt T: "Steering for Success Beneath the Salt," *Offshore* 68 (January 1, 2008): 78–81.
27. Poiate et al, reference 2.
28. Zhang J, Standifird W and Lenamond C: "Casing Ultradeep, Ultralong Salt Sections in Deep Water: A Case Study for Failure Diagnosis and Risk Mitigation in Record-Depth Well," paper SPE 114273, presented at the SPE Annual Technical Conference and Exhibition, Denver, September 21–24, 2008.
29. Israel et al, reference 3.
30. Israel et al, reference 3.

hydrocarbon accumulation, rich in asphaltenes that were sufficiently mobile to flow into the wellbore (below).[31] The active, or mobile, bitumen occurred as discrete layers along a subsalt fault, ranging in thickness from 10 to 100 ft [3 to 30 m]. These deposits of mobile tar, found throughout the Pliocene and Miocene sections at the base of salt, have ranged from inactive to highly active.



^ Mobile tar deposits. This cross section shows the location of tar deposits in several wells of the BP Mad Dog field. The mobile tar first became evident while BP was drilling its second appraisal well in the central part of the field, where tar was observed in the Middle Miocene section from 19,720 to 19,280 ft [6,010 to 5,877 m]. Here, tar from a thin permeable sand flowed into the wellbore. (Adapted with permission from Romo et al, reference 31.)

Similarly, a layer of tar up to 100 ft thick was reported below salt and in faults at the Hess Pony discovery in Green Canyon Block 468. Tar has also been found at Chevron's Big Foot prospect and at ConocoPhillips's Spa prospect, both of which are in Walker Ridge.[32]

Such mobile tar deposits in deepwater wells are commonplace, and some intervals have proved easy to drill through. But in the Green Canyon and Walker Ridge areas and, to a lesser extent, Atwater Valley and Mississippi Canyon, large deposits found below the base of salt have been difficult to work through. The primary drilling problem associated with bitumen is difficulty keeping the borehole open. Even when underreamers are employed, the borehole is often plugged with tar when it is time to run casing.[33]

The tar zone encountered at the Big Foot prospect, for example, effectively prevented Chevron from reaching its target depth before it was forced to release its contracted rig. Although not all time lost was directly attributable to tar, its presence did prevent the original well from reaching TD. In the end, the resulting rig-schedule change caused by the delay cost an additional US $55.8 million and 127 unplanned days.[34]

Drilling problems related to tar deposits include the following:

- packoffs behind the BHA, resulting in lost circulation
- swabbing of the borehole
- shock- and vibration-induced BHA damage
- coating of logging tools
- stuck tools caused by bridging of the borehole
- casing-running problems such as sticking casing high or excessive time working casing through tar zones to depth
- excessive trips to clean tar in casing and riser
- surface handling problems.

Since tar does not appear on surface seismic data, its presence is impossible to predict. To date, the industry offers few options when it is encountered. Increased mud weight does not stop its flow into the wellbore, and though water-base drilling mud may prevent its adherence to the drillstring, it does not control it. Conventional wisdom for dealing with tar remains what it once was for all of salt: Avoid it.

31. Romo LA, Prewett H, Shaughnessy J, Lisle E, Banerjee S and Willson S: "Challenges Associated with Subsalt Tar in the Mad Dog Field," paper SPE 110493, presented at the SPE Annual Technical Conference and Exhibition, Anaheim, California, USA, November 11–14, 2007.
32. Weatherl MH: "Encountering an Unexpected Tar Formation in a Deepwater Gulf of Mexico Exploration Well," paper SPE/IADC 105619, presented at the SPE/IADC Drilling Conference, Amsterdam, February 20–22, 2007.
    Rohleder SA, Sanders WW, Williamson RN, Faul GL and Dooley LB: "Challenges of Drilling an Ultra-Deep Well in Deepwater—Spa Prospect," paper SPE/IADC 79810, presented at the SPE/IADC Drilling Conference, Amsterdam, February 19–21, 2003.
33. Willson and Fredrich, reference 23.
34. Weatherl, reference 32.
35. For more on cementing and zonal isolation: Bellabarba M, Bulte-Loyer H, Froelich B, Le Roy-Delage S, van Kuijk R, Zeroug S, Guillot D, Moroni N, Pastor S and Zanchi A: "Ensuring Zonal Isolation Beyond the Life of the Well," *Oilfield Review* 20, no. 1 (Spring 2008): 18–31.
    Abbas R, Cunningham E, Munk T, Bjelland B, Chukwueke V, Ferri A, Garrison G, Hollies D, Labat C and Moussa O: "Solutions for Long-Term Zonal Isolation," *Oilfield Review* 14, no. 3 (Autumn 2002): 16–29.
    Farmer P, Miller D, Pieprzak A, Rutledge J and Woods R: "Exploring the Subsalt," *Oilfield Review* 8, no. 1 (Spring 1996): 50–64.
36. Garzon R and Simmons B: "Deepwater Wells Drive Salt Cementing Advances," *E&P* (May 2008): 99–101.
37. Achieving turbulent flow with most cement slurries is not possible unless the slurry is very thin and the annular gap very small. Therefore, engineers often choose to place cement using laminar flow at rates of less than 8 bbl/min [1.3 m^3/min].
38. Nelson EB, Bruno D and Michaux M: "Special Cement Systems," in Nelson EB and Guillot D (eds): *Well Cementing,* 2nd ed. Sugar Land, Texas: Schlumberger (2006): 241–242.
39. Close F, McCavitt B and Smith B: "Deepwater Gulf of Mexico Development Challenges Overview," paper SPE 113011, presented at the SPE North Africa Technical Conference and Exhibition, Marrakech, Morocco, March 12–14, 2008.

Tying It Down

Once a salt formation has been drilled, casing must be run and cemented in place. As with drilling, salt creep is a significant consideration in cementing operations because it creates nonuniform loading on the casing that can ultimately lead to collapse (right). Therefore, besides providing zonal isolation and basic structural support required of any cement sheath, a cement properly designed for placement across a salt zone must also ensure that the loading that is an inevitable consequence of creep is uniform. To do so, cement must possess sufficient flexural and tensile strength to withstand the casing pressures and loadings expected over the life of the well.[35]

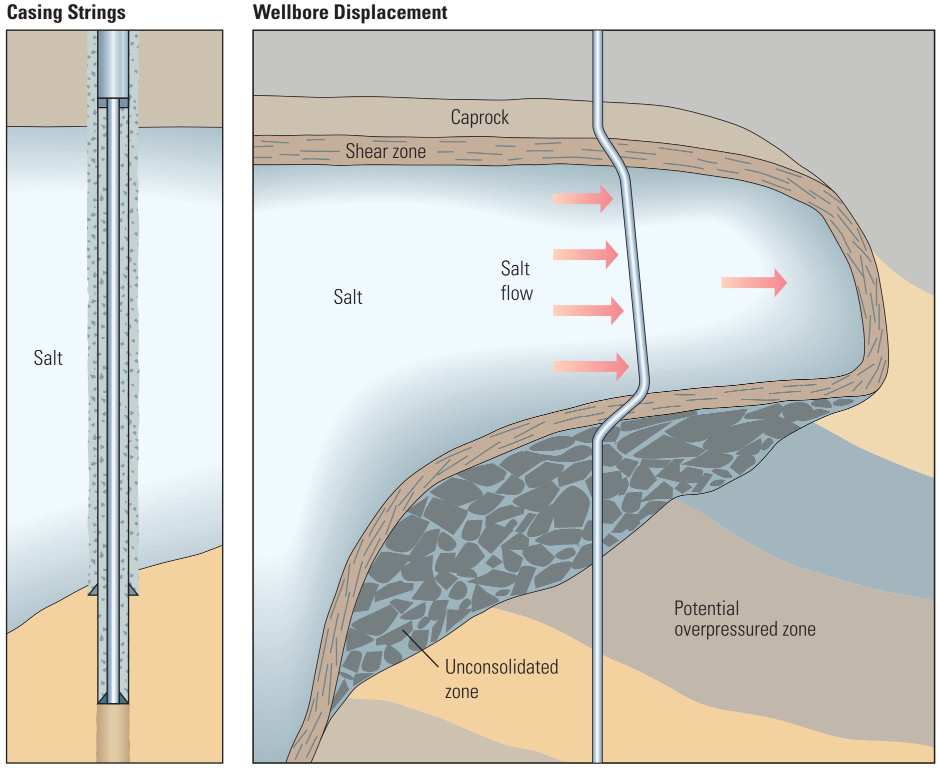
Cementing experts have traditionally used salt-saturated slurries in long salt sections, assuming they would bond better with the formation, resist chemical attack, reduce the tendency of gas migration during setting and be less likely to dissolve salt formations. However, at concentrations above about 18% by weight of water, salt retards thickening time, reduces compressive strength and promotes fluid loss and free-water development.[36]

As a consequence, the experts have turned to cement whose salt content is based on the salt formation at hand. In a salt-creep environment, it has been found that low-salinity slurries—10% or less sodium chloride [NaCl] by weight of water—develop early strength and favorable rheologies.

During operations in this environment, cement returns should be pumped—ideally in turbulent flow—to above the salt during displacement.[37] Cement bond logs should be run with the casing pressured to help identify any unusual bonding caused by creep.

Temperature is also a key factor when designing slurries for use in salt formations. High temperatures increase the dissolution rate of salt significantly and mitigate much of the delayed compressive-strength development associated with salt-rich slurries. At temperatures below about 200°F [93°C], experts recommend 10 to 18% NaCl content; at temperatures greater than 200°F, an 18 to 36% NaCl content is preferred.

Still, cement slurry design is only one factor in the success or failure of cement sheaths placed across salt formations; drilling, casing design and mud removal may have equal or greater influence on the job's final outcome. The salt itself is another variable that can substantially alter slurry properties. For example, experiments have shown that 10% contamination of a freshwater cement system can alter thickening time by 30%, increase slurry viscosity by 100% and increase fluid-loss rates by nearly 500%.[38]



^ Cementing across mobile salt. Combating the effects of nonuniform loading caused by salt creep requires that cement be returned to the top of the salt. In this case (*left*), a liner has been set inside a cemented casing in an effort to reduce radial pipe deformation. Salt movement (*right*) will continue to load the casing and may cause the tubulars to fail over time—an eventuality that can be delayed through proper cement placement practices and the use of oversized, high-strength pipe.

Potential to Match the Challenge

By the year 2015, deepwater developments are expected to account for 25% of worldwide offshore oil production, compared with about 9% in early 2008. In the Gulf or Mexico, most of these areas are in 4,000- to 10,000-ft [1,219- to 3,048-m] water depths and are covered by salt canopies ranging from 7,000 to 20,000 ft [2,100 to 6,100 m] in thickness. Overall total depths are from 25,000 to 35,000 ft [7,600 to 10,700 m].[39]

The formations beneath these massive salts hold promise of vast volumes of oil and gas production. The volumes for Tupi field in Brazil and the implications for the Lower Tertiary trend in the Gulf of Mexico, represented by success at Jack field and elsewhere, are already part of oil industry legend.

Though these and other targets have prompted considerable innovation and the industry has accomplished much to reach them, producing them efficiently in terms of recovery rates and economics remains a formidable task. The primary barrier to exploitation of the subsalt is the industry's limited ability to image the base of salt and the formations beneath it accurately. But as the demand to do so has increased, the seismic industry has responded with innovative tools and interpretive processes. It seems only a matter of time before drillers are equipped to drill through salt into the formations below with no more foreboding than they now experience passing through any other mapped transition zone.—RvF