Solving Deepwater Well-Construction Problems

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AIT (Array Induction Imager Tool), CDR (Compensated Dual Resistivity), DeepCRETE, INFORM (Integrated Forward Modeling), ISONIC (IDEAL sonic-while-drilling tool), MDT (Modular Formation Dynamics Tester), PERFORM (Performance Through Risk Management) and RFT (Repeat Formation Tester) are marks of Schlumberger.
Deepwater wells are key to the oil industry’s future. Constructing wells in water depths measured in miles and kilometers requires new solutions and challenges the industry to perform at its best.

Huge volumes of the world’s future oil reserves lie in deep waters at the very limit of our current reach, and just beyond. By all indications, tomorrow we will be drilling even deeper. The rapid advances in deepwater exploration and production (E&P) methods over the past five years ensure that as soon as one deepwater record is broken, another surpasses it.

Operators are drawn to the arena of deepwater exploration by the promise of extensive reserves and high production rates that justify the extra expense and risk. Some deepwater fields weigh in above the 2 billion-barrel [320 million-m³] mark, and a single well can produce 50,000 barrels per day [8000 m³/d]. At the end of 1998, the 28 fields producing from water depths of 500 m [1640 ft] or deeper delivered 935,000 B/D [150,000 m³]. Most of these fields are in the Gulf of Mexico and offshore Brazil, but even more deepwater discoveries have been made or are expected offshore West Africa, in the Far East and on the North Atlantic margin (near right).

Analysts report that worldwide, an additional 43.5 billion bbl [6.9 billion m³] have been discovered in water deeper than 500 m, with the potential for an additional 86.5 billion bbl [13.7 billion m³] (far right). Only about half of the deepwater acreage expected to hold hydrocarbons has been explored. Some estimates suggest that 90% of the world’s undiscovered offshore hydrocarbon reserves hide in water depths greater than 1000 m [3280 ft].

There are multiple definitions of “deep” water, which vary depending on the activity being considered. Generally, for well construction, 1500 ft, or 500 m, is considered deep. Deeper than that, the technology requirements change but solutions are available. And deeper than 7000 ft, or about 2000 m, is ultradeep water. Solutions, if available, are tailored to each project. Government and regulatory agencies may adopt other definitions for deep, such as beyond the break between continental shelf and continental slope, and confer royalty or taxation relief on fields that qualify.

Scientific drilling by groups such as the internationally funded Ocean Drilling Program and its predecessor, the Deep Sea Drilling Project, has achieved the astounding water depth of 7044 m [23,111 ft]. However, research holes like this one are drilled without many of the economic and operational constraints imposed on the offshore E&P industry.

The current water depth record in drilling for hydrocarbons is held by a Petrobras well in 9111 ft [2780 m] of water offshore Brazil. The record was broken four times in 1999, as the depth increased from 7718 to 9111 ft [2353 to 2780 m]—as many times as in the five preceding years, when it progressed from 6592 to 7712 ft [2009 to 2351 m].

The greatest challenges in constructing wells in deep water are related somewhat to the great depths, but also to the conditions encountered in each deepwater oil province. In the deepest waters, drilling can be accomplished only from dynamically positioned semisubmersible rigs or drillships. Conventionally moored drilling rigs have drilled as deep as 6023 ft [1836 m] in the Gulf of Mexico. Conditions offshore West Africa can be substantially different from those encountered in the Gulf of Mexico, where the presence of subsea currents makes drilling-riser management more critical. More powerful and larger rigs are required to maintain station under...
high currents and to carry the extra mud volume and marine riser needed to construct the well. In addition, the extreme water depth may also significantly impact rig downtime. For example, if a rig's subsea blowout preventer (BOP) malfunctions, it can take three days just to retrieve it to surface for repair.

The primary challenge facing deepwater well construction is to drill a stable hole. In young sedimentary basins with rapid rates of deposition, such as the Gulf of Mexico and parts of offshore Brazil and West Africa, sediments can become undercompacted during burial. Pore pressures can be high and fracture gradients low compared with those in land wells at the same depth, and the window between pore-pressure and fracture gradient can be narrow. Safe well-design and control practice requires advance knowledge of pore-pressure and fracture gradient. Drilling a hydraulically stable hole can be achieved only by keeping drilling mud weight within the margin between fracture and pore-pressure gradient. In some projects, so many strings of casing are needed to control shallow unconsolidated sediments as well as deeper pressure-transition zones that the reservoir cannot be reached. Or, if it is reached, the diameter of tubing that will fit through the final casing is so small as to render the project uneconomical because of restricted flow rates.

In areas such as the Gulf of Mexico, shallow flow hazards make well construction difficult. These zones below the seabed are capable of flowing water and, when encountered by a drill bit, cause severe borehole stability problems. Water-flow zones also impede logging and reentry in open hole and the setting of cement behind casing.

In the deepest waters, today's wells are completed with wellheads and production trees on the seafloor that connect to flowlines for transporting hydrocarbons to surface. The surface structures may be floating production, storage and offloading (FPSO) vessels or nearby host platforms. Controlling live subsea wells for testing, completion and intervention requires specially designed, reliable equipment. Fluids often must flow through miles of lines and sometimes rely on submersible pumps or other artificial-lift devices downhole. The wells may be made more productive by implanting permanent monitoring and flow-control devices downhole.

Keeping fluids flowing at the highest possible rates requires not only adequate tubing size, but also attention to conditions that can lead to other flow blockages. At the high pressures and low temperatures that deepwater wells encounter near the seabed, solid, ice-like compounds called gas hydrates can form from mixtures of water and natural gas. These solids can block flow in tubulars, and depressurize explosively when brought to surface. They have been responsible for offshore drilling catastrophes in the past. Hydrates can also form naturally at and below the seabed, creating a drilling hazard if penetrated. Other solids such as paraffins must also be prevented from blocking flowlines.

To ensure cost-effective, safe and efficient operations in deep waters, the industry must develop solutions to these and many other problems. In some cases, the solution will be a new tool or completely new technique; in others, an innovative application of existing technology will provide the answer. In this article, we describe some of the newly proven methods and promising directions that will permit the continued expansion of E&P activities into deeper waters.

Deepwater Excellence

The kinds of advances required to break the barriers imposed by the great oceans are not of the sort that can be achieved single-handedly, by an individual or even by a single company. Oil companies, service companies, drilling contractors, academic institutions, government groups and equipment manufacturers are all working toward solutions. Some oil companies are setting up their own specialized global deepwater drilling groups to overcome drilling at the deepwater asset level. Many operators and contractors are participating

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^Deepwater Center of Excellence organization. The center works to identify technology gaps, prioritize needs and facilitate the development of solutions to deepwater problems. Four technical domains link with other elements of the Schlumberger organization to transfer knowledge.
in industry consortia, initiatives and joint industry projects to identify technology gaps and pool their knowledge and resources. Examples of these are the Deepstar consortium led by Texaco in the US, PROCAP by Petrobras in Brazil, the Atlantic Margin Joint Industry Group (AMJIG) in the UK and the Norwegian Deepwater Programme.

To address the demand for current and future deepwater technical solutions, Schlumberger has formed the Deepwater Center of Excellence, a solutions center led by experts in Houston, Texas, USA. The center’s mission is to achieve a global cooperative effort with the industry, focused on identifying and developing cost-effective, best-in-class solutions to meet deepwater challenges.

The Deepwater Center of Excellence has defined specific methods for meeting these objectives. First, the organization must recognize existing successful deepwater applications within all the company’s groups, prioritize needs for new technology and propose technical solutions to the engineering centers and clients. Second, internal and external networks have to be established to transfer knowledge and learning. Experts in the Deepwater Center of Excellence manage and foster the development of solutions in one of four specific technical domains—well construction, completion systems, production and intervention, and geology and geophysics (previous page). These are aligned with critical well processes and with current oil-company structures. Finally, the center also acts as the Schlumberger representative in deepwater-related joint industry projects to help put the acquired knowledge into practice.

Several joint industry projects (JIPs) have been formed in attempts to overcome a wide range of deepwater E&P obstacles. Some projects have been established to investigate ways to reduce costs or operate with less impact on the environment, while others are designed to enable activities in deeper water—without them, industry will not develop the reserves found in ultradeep water.


**Drilling Joint Industry Projects**

One such JIP is a project to design a new method for drilling and constructing deepwater wells with a minimum number casing strings so that deep geological objectives can be reached with a hole size that allows hydrocarbons to be produced at high flow rates. In the Gulf of Mexico and basins offshore West Africa, high depositional rates cause sediments to accumulate rapidly and reach considerable depths without compacting, or giving up their pore water. In these weak, unconsolidated formations, pore pressures are high and formation fluids must be kept at bay by heavy drilling mud. However, fracture pressures are low; the great distance from the rig to the formation creates an unbearably heavy column of mud in the drillstring and riser, and the weight of the mud fractures the formation unless casing is set. Several casing strings are set in these upper portions of the well, reducing the number of contingency strings left available for deeper difficulties, such as lost-circulation zones, overpressured formations and other well-control incidents. A deepwater well in this kind of formation might cost more than $50 million and still not reach its objective.

In 1996, 22 companies joined a JIP aimed at removing the effect of water depth from deepwater well planning and drilling. The group determined that the most viable solution involved reducing the weight of the mud on the formation by changing the way mud returns to surface (above). The Subsea Mudlift Drilling JIP, now made up of representatives from Conoco, Chevron, Texaco, BP Amoco, Diamond Offshore, Global Marine, Schlumberger and Hydril, is developing this technology and remains on track to deliver it to the industry in 2002.
In conventional drilling, the mud column extends from the rig to the bottom of the well, forming a single mud-pressure gradient. The effect of lowering the load in the riser is to replace the single pressure gradient with a dual-gradient system: a hydrostatic pressure gradient acts from the rig to the seabed, sometimes called the mudline; a new, higher, mud-pressure gradient acts from the mudline to the bottom of the hole. In the dual-gradient system, the pore-, fracture- and mud-pressure gradients become referenced to the mudline instead of to the rig.

The decrease in wellbore mud pressure can save as many as four casing strings in the well design. The dual-gradient technology allows any well, regardless of water depth, to reach its reservoir target with a 12-1/4-in. hole size. The large-bore wells made possible by subsea mudlift drilling will be able to run 7-in. tubing to the mudline, letting many wells achieve their highest flow-rate potential. Alternatively, this larger hole size will allow for horizontals or multilaterals necessary to optimize reservoir drainage. As a consequence, fewer wells will need to be drilled to adequately drain a reservoir, resulting in considerable reduction of field development capital expenditure and greater ultimate recovery. The lower mud pressure also results in fewer well kicks and lost-circulation problems.

The JIP estimates these benefits can lead to savings of $5 million to $15 million per well.

There are several ways to reduce the weight of the mud in the drilling riser. The Subsea Mudlift Drilling JIP is developing a system with two main components. First, a subsea rotating diverter isolates the fluid in the riser from the wellbore and diverts the return drilling fluid from the base of the riser to the second key component, a mudlift pump. The mudlift pump directs the mud back up to the rig in a flowline isolated from the riser and keeps the hydrostatic pressure of the mud in the return line from being transmitted back to the wellbore.

The system design and preliminary field testing will take place in the year 2000 and early 2001, and full-scale deepwater tests will follow. The commercial system will be built in 2001 and tested in 2002, opening the way for drilling in hundreds of deepwater leases.

9. For selected references on pore-pressure estimation:

   Pennebaker ES: “Seismic Data Indicate Depth, Magnitude of Abnormal Pressures,” World Oil 166, no. 7 (June 1968): 73-78.
Other JIPs are looking into solving the same problem in different ways. Since 1996, Shell E&P has been funding and developing a subsea pumping system that accomplishes dual-gradient drilling with existing technology where possible. Several companies, including FMC Kongsberg, Centrilift, Dril-Quip and Robicon have participated in the project, which involves subsea separation of larger cuttings so that electrical submersible pumps can be used to return mud to surface. Cuttings are left on the seafloor.

Predicting Pressures

In typical sedimentary basins, formations compact as they are buried. Pore fluids are expelled, sediments compact to form consolidated rocks, and pore pressure increases hydrostatically with depth. In basins with high rates of deposition, such as the Gulf of Mexico, excess fluids can be trapped in low-permeability sediments as they continue to be buried. These formations become undercompacted and develop overpressure, or pore pressure greater than hydrostatic. In overpressured zones, the rock porosity, or some log measurement sensitive to porosity, such as sonic traveltime or resistivity, deviates from the normal compaction trend. These overpressured zones can be hazardous during drilling. They can cause kicks if they are not detected and require additional casing strings to keep the mud weight within the window between pore pressure and fracture gradient.

Accurate knowledge of pore pressures is a key requirement for safe and economic deepwater well construction. Before drilling, pore pressure can be estimated from other properties, such as local seismic velocities, drilling experience, mud weights, and sonic and resistivity measurements in nearby wells. The worth of the pore-pressure prediction depends on the quality of the input data, suitability of the method used to compute pore pressure and on calibration with measured pressures. Although not routinely done, the pore-pressure model can be enhanced by updating it with local calibration data from drilling observations, while-drilling logs and look-ahead vertical seismic profiles using either surface sources or the drill bit as a source.

Fewer casing strings and greater bottomhole completion diameter using the dual-gradient method. The lower number of casing strings in dual-gradient deepwater drilling (right) compared with conventional drilling (left) saves money and results in larger diameter tubing at bottom for greater productivity.
This approach was the key to success in a recent deepwater Gulf of Mexico three-well drilling project for EEX Corporation. The first well was spudded using a preliminary pore-pressure prediction that required updating during the drilling process. The prediction was updated and calibrated with kick information.

In the second well, the new pore-pressure prediction technique was applied. Sonic and resistivity logs, mud weights and drilling experience in an offset well helped create the preliminary pore-pressure model. The new well was predicted to encounter the same geology as the offset well but would not approach the salt that the offset well encountered near 6500 ft [1980 m] until much deeper.

A normal compaction trend appears in the offset-well sonic logging data down to about 8000 ft [2440 m], where a zone of higher than normal pressure is penetrated (below). The pore pressure predicted from the sonic data can be calibrated by actual pressures measured during the drilling process—a kick occurred at 5000 ft [1520 m] where pore pressure surpassed drilling mud weight. After that, drilling proceeded overbalanced, with mud that was heavier than necessary. A similar pore-pressure prediction was made from resistivity data.

A danger in applying these pore-pressure predictions in regions of active salt tectonism is that the measurements made at the offset-well location may not be representative of the geology traversed by the new well, especially deeper, in salt-prone sections. The only information type common to the two sites is interval velocity derived from processing the surface seismic line that ties the two wells. Seismic interval velocities produce a much lower resolution pore-pressure prediction, but still serve to define both a normal compaction trend and a predicted pressure trend to support the predictions from other measurements.

The seismic interval velocities over the new well location, combined with the log-derived predictions from the offset well, help construct the final predrill pore-pressure prediction (next page, top). The seismic-derived pore pressures indicate a narrowing safe mud-weight window with depth—less than 2 lbm/gal [0.24 g/cm³] at the target depth of 20,000 ft [6100 m].

In all three wells, the pore pressures obtained using the Schlumberger calibration method accurately predicted the pore pressures encountered in the well. Each well was drilled with the services of a Schlumberger PERFORM (Performance Through Risk Management) engineer, who monitored the drilling process with while-drilling measurements and helped update the well plan.11

Refining Predrill Pressure Predictions

As the previous example shows, offset-well data can produce a high-resolution pore-pressure prediction. However, the prediction may not hold in the vicinity of the new well. Adding the pore-pressure information from seismic interval velocities provides areal coverage, but interval velocities have several drawbacks. They are not of high enough resolution to produce pore-pressure predictions adequate for well-planning purposes. They also are not physical traveltime velocities, but rather are derived from stacking velocities—by-products of seismic data processing that happen to have the units of distance divided by time. They can correspond to actual seismic velocities.
when the subsurface comprises flat homogeneous layers. However, each velocity value represents an average over the spatial extent of the seismic source and receivers used—often up to 8 km [5 miles] in deep water. And interval velocities are not representative of true subsurface velocities in the cases of dipping layers, lateral variations in velocity or pressure, or changes in layer thickness, exactly the circumstances in which one would not be able to rely on offset-well log data and would hope to use seismic data for pore-pressure prediction.

Schlumberger geophysicists have devised a way to extract physically meaningful velocities from 3D seismic data to derive an enhanced-resolution predrill pore-pressure prediction. The technique, called tomographic inversion, incorporates an automated process that uses all the traveltime patterns in the recorded seismic data to produce a laterally varying velocity model and so an improved pore-pressure prediction (below).

![Normal compaction trend](image)

**Conventional Pore-Pressure Prediction**

**Tomography-Based Pore-Pressure Prediction**

A conventional pore-pressure prediction based on stacking velocities (left) compared with one based on tomographic inversion (right). The initial prediction has lower resolution, a lower range of pore pressures and is laterally smoothed. The refined prediction shows detail that corresponds to subsurface geology accurately.


The method has been tested on a deepwater well project for EEX in the Gulf of Mexico. An existing 2D marine seismic survey was reprocessed using tomographic inversion to generate a refined velocity model for transformation to pore pressure (left). The resulting velocity model has sufficient detail to derive an accurate pore-pressure prediction away from the offset well to the south. A drilling trajectory between the two salt bodies imaged in the seismic line could encounter a predicted low-velocity zone, which may indicate the presence of overpressure. The spatial extent of this anomaly is not well-defined by the stacking-velocity image. However, the improved resolution in the tomography-based velocities allows a more reliable predrill pore-pressure estimate to be made (next page, top).

Interval Velocities from Stacking

Interval Velocities from Tomography

^Velocity models over existing wells and proposed well location. Interval velocities derived from stacking velocities (top) do not appear to correspond to the geological interpretation of the seismic line. The interpretation is drawn in fine lines on the image. The refined velocity model constructed using tomographic inversion (bottom) corresponds to subsurface salt features interpreted in seismic section and contains enough detail to produce an accurate pore-pressure prediction.

Overpressure predictions

^Pore pressures predicted in the vicinity of the proposed well location and the low-velocity zone indicated in the seismic velocity model. The prediction shows an increase in pressure at about 7600 ft (2320 m).
The proposed well location is in the vicinity of the low-velocity zone, and the pore-pressure prediction shows a corresponding jump in pressure at about 7600 ft [2320 m] (previous page, right). The predicted pore pressures are in good agreement with the actual mud weights subsequently used to drill the well.

**Deepwater Drilling Solutions**

A variety of other problems can hinder the well-construction process in deep water. The following examples illustrate some of the latest solutions.

**Wellbore stability**— Cooling of the drilling fluid in the riser can cause higher mud viscosity, increased gel strength and high frictional pressure losses. These factors increase the likelihood of lost-circulation problems, and drilling engineers must take appropriate steps to avoid exceeding formation fracture pressures. Real-time measurement of annular pressure while drilling helps monitor the equivalent circulating density (ECD) of mud to allow drillers to keep within the narrow stability window found in many deepwater holes. Equivalent circulating density is the effective mud weight at a given depth created by the combined hydrostatic and dynamic pressures.

Real-time monitoring of annular pressure while drilling helped during construction of a deepwater well in the Gulf of Mexico (below).\(^\text{13}\) Mud weight was just below the pore pressure predicted from seismic interval velocities when a kick occurred in Zone A. Mud weight was increased to control the well and 13\%-in. casing was set. The next two hole sections were drilled without incident, then another kick was taken in Zone B, so 9\%-in. casing was set to permit another increase in mud weight. The heavier mud exceeded overburden pressure and some lost circulation was experienced in Zone C, but drilling continued successfully thereafter.

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Water-flow zones—Since 1987, operators have reported hazardous water flows in 60 Gulf of Mexico lease blocks involving 45 oil and gas fields. These abnormally pressured formations are usually sands caught in quickly slumping and rotating fault blocks or in reworked channels sealed by impermeable clay. Water flows have been reported between 800 and 5500 ft [244 to 1680 m] depth below the seafloor. A flow may contain gas and may develop solid gas hydrates in and near seabed equipment. Uncontrolled water flow can lead to formation cave-in, and if influx is severe enough, the well can be lost. Washouts can undermine the large casing, or conductor pipe, that is the main support structure for the well.

The industry spends an average of $1.6 million per deepwater well for the prevention or correction of problems associated with shallow flows. A combination of techniques is used to combat the problem, including acquiring measurements while drilling, setting extra casing, drilling pilot holes, using a riser and pumping special cements. The while-drilling measurements—by far the least expensive of the steps—are designed to identify water-flow zones as soon as they are encountered.

Operators have started to use real-time annular pressure measurements to detect water-flow zones. An example comes from deepwater Gulf of Mexico, where a water-flow zone was identified on gamma ray, resistivity and annular pressure while drilling logs (right). The jump in equivalent circulating density indicated possible influx of solids. Visual confirmation of water flow was confirmed by remotely operated video at the seafloor. Mud weight was increased to control the flow, and drilling continued. Similar flow zones were detected within the next few hundred meters. All the water-flow zones were safely contained. Early warning of water influx provided by the real-time measurements made it possible to keep on drilling to the planned depth.

Deepwater cementing—Water flows also present problems during cementing operations. Water influx can keep cement from solidifying, jeopardizing the integrity of the well. A deepwater consortium including Schlumberger and several oil companies sought to formulate a cement for deepwater wells that would be able to hold up against water flows but also be light enough not to fracture weak formations. The key was to find a cement with a short transition time—the period when it changes from a liquid to a solid—to minimize the interval during which its strength is too low to hold back water flow.

A foamed deepwater right-angle set (RAS) slurry was the solution. The deepwater RAS has the requisite short transition time and early compressive strength and thus prevents any water flow from penetrating the cement bond. As a foam, the cement density can be modified with nitrogen injection during mixing to create a slurry that is light enough to avoid fracturing weak deepwater formations.

The deepwater RAS cement has helped stop water flow and provided successful cement jobs in more than 50 deepwater wells, even at record-breaking depths. This includes cementing the conductor and surface strings for the Chevron Atwater 18 #1 well in 7718 ft [2352 m] of water in the Gulf of Mexico.

Foamed cement requires a nitrogen supply, specialized equipment for injecting it, and a cementing team trained in its use—all of which may be challenging to coordinate on a deepwater rig.
An alternative to foamed cement, DeepCRETE technology, has been developed for such deepwater wells. DeepCRETE cement strengthens quickly even at temperatures as low as 4°C [39°F], reducing waiting-on-cement times.13

Operators offshore Angola, Africa report significant savings with DeepCRETE cement for well construction in deepwater areas, where the low-temperature environment causes long setting times and ordinary cements suffer from losses due to the low fracture gradient. In one case, using a conventional cement in a well with a bottomhole circulating temperature of 12°C [54°F], the 15.8-lbm/gal [1.89-g/cm³] slurry exceeded the fracture gradient at the seabed. It took 68 hours to achieve the first 500-psi [3.4-MPa] setting. In the second case, with DeepCRETE cement, a 12.5-lbm/gal [1.5-g/cm³] slurry set in 11 hours with no evidence of cement loss to fracturing (right). The 57-hour reduction in rig time translated to savings of $475,000.

Reservoir evaluation—Difficulties in deepwater well construction manifest themselves again later as challenges in formation evaluation. Low fracture gradients and water-flow zones cause washouts and inadequate cementing, leading in turn to adverse hole conditions for logging. Logging-while-drilling (LWD) measurements help obtain formation-evaluation information before hole conditions deteriorate. This technique has been successful in the rapidly growing market offshore Angola, where deepwater production is projected to reach 1.38 million B/D [219,000 m³/d] by the year 2005 (right).14 In a well drilled in 1200-m [3940-ft]...
deep water offshore Angola, CDR Compensated Dual Resistivity tool measurements were made to determine casing and coring points (left). After drilling several hundred meters into the reservoir with oil-base mud (OBM), substantial mud losses were incurred. These were believed to originate at the bottom of the hole. Wireline AIT Array Induction Imager Tool measurements run seven days later, after mud losses totaled 300 m³, showed a completely different log response between about X050 and X130 m compared with the earlier CDR results. Increased values of wireline resistivity indicated the shale section had been altered and possibly fractured by the OBM.

Similar cases often have been documented in the past, but less common with OBM is the reversal observed in the order of the AIT curves. Here, the deeper reading AIT resistivities exhibit higher values than the near-reading ones. To understand these results, Schlumberger engineers modeled the formation, fracture and measurements using INFORM forward modeling software. Different fracture openings and relative angles of intersection with the borehole were tested to find the conditions under which the observed reversal of the AIT curves would occur (next page, top). The INFORM modeling showed that a fracture dipping at 75° can reproduce the order of the AIT readings.

Constructing Productive Wells
Achieving optimal hydrocarbon production from deepwater wells requires special attention to flow assurance. Assuring flow is a multidisciplinary effort, covering issues from asphaltene deposition and hydrate formation to hydrocarbon flow properties and flowline reliability. Any potential problem that could hinder flow from the reservoir to the production export vessel or pipeline falls under the heading of flow assurance.

Offshore Brazil and elsewhere, deepwater development layouts have been constrained by reservoir pressures. Reservoir pressure controlled the distance that could be tolerated between well and platform without critical flow loss. Pressure decline could be combated by water injection, or backpressure could be reduced by gas lift. However, gas-lift efficiency suffers in wells with the long horizontal tie-backs typical of subsea completions. Sustaining oil production from these deepwater subsea wells requires new solutions to increase flow rates, simplify production facility layouts, decrease the number of platforms and
reduce investments and operating costs. Several solutions are being investigated, including downhole boosting, subsea multiphase pumps and subsea separation.

Downhole pumps—In 1992, the Petrobras PROCAP program initiated a project to develop these boosting technologies. The downhole boosting method was the first to reach the field in deepwater offshore Brazil, in the form of the electrical submersible pump.\(^{19}\) Petrobras already had significant experience with electrical submersible pumps on fixed towers in shallower water and in dry completions onshore. In one offshore development from eight fixed towers in the area comprising the Carapeba, Pargo and Vermelho oil fields of the Campos basin, 132 wells produce with these pumps (right).


For use of electrical submersible pumps to be feasible in the deepest water, the pumps would need to assure flow through extended tie-backs to surface facilities. It was important to test the viability of the method in shallow water before investing in the development of a deepwater system. Six other companies cooperated in the development and installation of the system: Reda and Lasalle (both now part of Schlumberger), Tronic, Pirelli, Cameron and Sade-Vigesa. A Reda pump was installed in subsea well RJS-221, powered from the Carapeba 1 fixed tower 1640 ft [500 m] away. From there, with only the energy from the pump, production flowed to the Pargo 1 platform 8.4 miles [13 km] away. The pump was put into operation in October 1994 and functioned for 34 months before a failure occurred.
The installation in RJS-221 demonstrated excellent longevity compared with dry-completion installations, and proved the method for subsea use. This encouraged Petrobras to develop the technology further for deep water. The deepwater test site, well RJS-477, in the East Albacora oil reservoir is in 3632-ft [1107-m] deep water. In June 1998, as a result of the pump installation, RJS-477 began to produce to Albacora field Platform P-25, moored 4 miles [6.4 km] away in 1886 ft [575 m] of water (above). The power system has been developed for a range of 15 miles [24 km], which will allow, for example, Campos basin wells within the 3775-ft [1150-m] water-depth mark to produce to high-capacity facilities moored or fixed in shallower water.

The electrical submersible pump is the key to the success of the new method. High intervention costs in deep water mean that equipment reliability and longevity are crucial. Integration of the completion system with electrical submersible pump equipment is fundamental, and should be addressed in the planning stages of deepwater wells. Both of the wells involved in the test, RJS-221 and the deepwater RJS-477, were drilled to test new reservoirs before electrical submersible pumps were considered for these subsea wells and so were not designed to accommodate a submersible pump. Restrictions in the liner and casing size in RJS-477 presented challenges to the design of the pump system.

For the deepwater electrical submersible pump installation, new equipment was developed for the extreme water depth and long-distance power transmission. This included the Reda pump; Pirelli subsea power cables; Tronic subsea power connectors; subsea power transformer and long-distance power transmission by Siemens; and the deepwater horizontal production tree by Cameron.

This deepwater prototype has so far completed two years of run-life with no failures. Petrobras considers the system to be proven to its design limits.

Subsea boosting—Statoil, BP Amoco, ExxonMobil and Petrobras have investigated the possibility of deploying subsea multiphase boosting pumps as an alternative to subsurface downhole pumping. This option becomes attractive when the production from a large number of wells can be commingled subsea and boosted from a production manifold or when the flowing pressure in the reservoir drops below the bubblepoint. Deploying multiphase pumps on the seafloor, closer to the reservoir than if deployed at the sea surface, permits the efficient addition of pressure head to the flow and allows for a high-power system.

The equipment was first deployed in December 1997 in the Lufeng field operated by Statoil in the South China Sea (below). Five multiphase boosting pumps manufactured by Framo Engineering were installed in 330 m [1082 ft] of water.
Deepwater Wave

Along with increases in recovery percentages in existing fields, deep water is one of the industry’s main hopes for balancing supply and demand from the year 2005 onward. To realize this hope, technological solutions and project management methods must result in performance levels that will allow deepwater projects to compete economically with other sources of oil and gas. The industry is making measurable progress in this direction. In the 1980s producing a barrel of oil from a well in 200 m [656 ft] of water cost between $13 and $15 for an average field. Now technological advances have reduced that figure to $5 to $7.21

The way forward into deeper water will come from many directions. Beyond some depth, all production will be from subsea developments. Advances in subsea flowlines, production trees, electrical power distribution systems, fluid separation and reinjection technology and multiphase metering and pumping will be necessary to derive economical production from the 10,000-ft [about 3000-m] water depths that soon will be explored. These advances will allow the subsea industry to move an increasing amount of activity to the seabed.

Application of these solutions to developments in deeper water will eventually allow for more cost-effective tie-backs than are currently achievable.

Subsea separation—Several companies are investigating concepts in subsea fluid separation. Separating fluids subsea will avoid lifting large volumes of water all the way to surface for processing and disposal. This can reduce lifting costs and allow economies in topside water processing and handling capacities. The savings may extend the economic life of deepwater projects and reduce development risks.

Deepwater and other offshore wells that undergo well testing produce fluids that need to be transported or otherwise disposed of, raising environmental and operational safety concerns. Schlumberger is participating in a joint industry project with BP Amoco, Conoco and Norsk Hydro to examine the feasibility of well testing without producing hydrocarbons to the surface. The project will investigate technology to circulate fluids through a downhole testing system. The system will acquire pressure and flow-rate data downhole rather than at the surface without having to flare hydrocarbon fluids or transport collected liquids for remote disposal. The result will be improved operational safety and reduced environmental impact.

The industry recognizes that deep waters hold a key to its future survival and success. Diverse new technologies have brought exploration in deep and ultradeep water within the grasp of oil companies. As we go further and deeper, we are sure to find new challenges and opportunities. —LS

20. Reda has installed 100% of the world’s subsea electrical submersible pumps.