A Plan for Success in Deep Water

Deepwater oil and gas are conventional resources in an unconventional setting; operations are notable mainly for their high risk and high reward. Because of the scope and complexity of projects beyond the continental shelves, the difference between success and failure often hinges on good planning.

In 2001, while constructing its massive deepwater Mars tension-leg platform, Shell concluded the plans for the facility required major adjustments. The changes were needed to take advantage of just-introduced advances in well completion technology that would boost production beyond the original design parameter of a maximum 1,750 m³/d [11,000 bbl/d] of oil per well. Fortunately, because the Mars team comprised experts from many project disciplines, it was aware of overall project parameters, and Shell was able to implement the necessary changes in the construction yard before the giant floating platform sailed off.

This Shell experience clearly demonstrates the case for planning practices that consider the development as a whole—from subsurface modeling to completion strategies to first oil and beyond. By considering every aspect of development at the planning stage, operators are more likely to find they still have viable options before or during deployment and operational phases. Such flexibility may become critical as new information about a reservoir, the available

---

Adwait Chawathe
Umut Ozdogan
Chevron Corporation
Houston, Texas, USA

Karen Sullivan Glaser
Houston, Texas

Younes Jalali
Beijing, China

Mark Riding
Gatwick, England

Copyright © 2009 Schlumberger.

For help in preparation of this article, thanks to Robert Clyde, Debra Grooms, Scott Scheid and Drew Wharton, Houston; Nils A. Solvik, Framo Engineering, Bergen, Norway; Merrick Walford, Pau, France; and Jeremy Walker, Rosharon, Texas.


---

Iterative processes. Project plans are fine-tuned constantly as a field is developed. Beginning with a 3D reservoir model, drilling experts select drilling locations, target zones and trajectories. Model updates take place as wireline and LWD measurements are acquired, enabling changes that reflect the most recent information. This process repeats throughout the development drilling program.
technology or any number of related parameters becomes apparent during project commissioning, drilling, completion or production. The penalty for inefficient or incomplete planning could be an inability to change designs or accept compromises in critical elements such as well location, completion type, well size or field configuration once work has begun. The result could be a less-than-optimal development, which almost always translates to negative outcomes such as reduced ultimate recovery, lower productivity rates and significantly higher capital and operating costs.

Adoption of proper deepwater project planning practices will probably require more cultural change than technological innovation. This is because the upstream industry traditionally treats the various operations that make up field development as separate tasks performed in series by experts working independently. More importantly, oil industry operators, contractors and service companies have a long history of working from out-of-date plans or those too general to be of much use. This mode of operation forced them to deal with individual problems in a reactionary mode rather than planning in advance for potential problems and possible solutions. In deep water, where stakes are high and the time between concept and first oil can be as much as a decade, segregation of responsibility and use of static plans that cannot be adjusted to respond to changing circumstances are no longer options. It is, therefore, essential that experts of all disciplines take a longer, more integrated view.

For example, it is usually desirable to begin a drilling program by considering the type of completion required to best exploit the reservoir. While this reservoir-driven approach is common, the ultimate goal of a thought-out plan is the profitability of the overall project. This being the case, the well's productivity becomes only one factor in the selection of completion type. Other considerations include cost-sensitive factors and the risks associated with overall project expense, interventions, well longevity, sand production and flow assurance.

In recent years, many drilling and completion engineers have made progress toward a more integrated approach. But deepwater project planning requires extension of that practice beyond well construction to connect the entire enterprise—from early exploration to final production—while using each step in between to refine the process.

Therefore, a typical deepwater project plan not only includes each of the following elements, but also considers their influence on each other:
- subsurface reservoir model
- drainage strategy and bottomhole locations
- field development plan
- well design engineering and technology
- intervention methodology
- pipeline and platform design and installation.

From a practical standpoint, planning begins at the exploratory stage. Once the reservoir has been characterized through seismic data interpretation, petrophysical information about the target formation is gathered during the drilling process using such tools as wireline logs, LWD operations and dynamic testing (previous page). The resulting combination of data about
Deepwater drilling units. The complex, dynamically positioned units capable of drilling in extreme water depths are relatively rare. The cost to build and outfit them has been reported to be as high as US $750 million, and despite a recent spate of new construction, demand outstrips supply. The investment needed to drill in water depths greater than 1,800 m [6,000 ft] is reflected in the unit lease rate—often US $1 million per day. (Photograph courtesy of Transocean Ltd.)

The reservoir matrix, fluid properties and producibility serves as a basis for the many decisions that will be made about the field throughout its life.

One such technical decision is well trajectory within a reservoir. Since efficient reservoir drainage—using as few wells as possible to access and produce the maximum volume of oil and gas at the most advantageous rate—is key to profitability in deepwater project planning, well angle and reach are decided early in the process. However, in a holistic approach these calculations must include more than maximum reservoir exposure—the most common driver for the use of extended-reach wells. Completion designs for these deepwater wells must also consider the optimal flow rate for the long term, which requires a balance between maximizing ultimate recovery through prudent production practices and maximizing immediate returns through high flow rates.

These decisions both drive and are driven by available drilling technologies and their associated completion configurations. Operators may choose to develop their fields through a few extended-reach wells, numerous vertical wells, multilateral wells, intelligent wells or some combination of these and other scenarios. Throughout exploration, assessment and development drilling, virtually all development parameters—such as well location, completion type and flow rates—may be altered as the reservoir model is refined by information gathered from new wells.

Real-time data and the actions taken in response to confirmation of, or changes to, assumptions about a reservoir are used throughout the life of the field. Improved knowledge about rock stresses, for instance, impacts such vital details as perforation density and phasing and choice of sand control system. Updated models of porosity, permeability and fluid characteristics do not just shape the drilling and completion program, they are also fundamental inputs to key decisions about flow assurance and facility design. Modeling fluid parameters over the life of a deepwater project is itself a far more complex undertaking than for onshore or shallow-water fields. In deep water, economics dictate that multiple reservoirs—often with different and changing characteristics—share facilities, pipelines and other infrastructure.

Because of the complexity-driven risk and large reserves potential involved, deepwater developments are economically more sensitive than most other E&P endeavors. According to an analysis of Gulf of Mexico lease data conducted by the US Minerals Management Service, both risk and reward rise significantly with increased water depth. Given that relationship, it is clear that operations planned in waters deeper than 3,050 m [10,000 ft] have increased the stakes to such a level that even seemingly minor missteps may conspire to quickly overwhelm project economics.

Current extreme costs in the deepwater play are rooted in two major outlays: the costs of facilities, pipelines and other infrastructure and high rental rates—dayrates—that contractors must charge to make a reasonable return on their investment in rigs. For a rig capable of operating in ultradeep water, that investment is about US $500 million in construction costs alone (above left). As a consequence, the spread rate—dayrate plus all other required equipment and services for any given operation—for such a drilling vessel is approximately US $1 million per day, or nearly US $42,000 per hour. In deep water, well construction typically accounts for about 50 to 60% of the total lifting costs, split evenly between drilling and completion. A field infrastructure often requires capital expenditures of more than US $1 billion.

3. Perforation density is the number of holes per linear foot of borehole, reported as shots per foot (spf). Perforation phasing refers to the angle at which the perforations are offset from the toolstring axis. Thus, in a 30° phasing, each perforation is separated by 30°.
6. Lifting cost is the operator’s total financial outlay for bringing oil and gas to the surface and is generally calculated in US dollars per barrel of oil equivalent.
While these absolute costs are significant, well construction costs typically include 24 to 27% nonproductive time (NPT)—a time loss that is aggravated by working in reactive mode. Subsea architecture and installation of production facilities routinely incur 30 to 35% NPT. It is clear, given the investments involved, that these percentages represent a significant amount of money and underscore why minimizing NPT is a key goal of operators.

This article looks at the many obvious and not-so-obvious parameters considered in deepwater project planning. In some instances, the project is the entire venture from seismic survey to abandonment. In others, the project is more specific—testing, cementing or some other major component of a larger operation. Deepwater case histories from the Gulf of Mexico, West Africa and the North Sea demonstrate why and how deepwater operators and service providers must take a long-term integrated view in this challenging environment.

From the Bottom Up
Reservoir drainage strategy essentially drives deepwater projects. Engineers must have a thorough understanding of the reservoir before they can optimize well locations and make informed decisions about wellbore size, sand control, artificial lift, perforation and all other facets of a drilling, completion and production program. They must also make decisions as to wellhead type, pipeline and manifold configuration and the type of host platform to be used.

As with all modeling systems, a wrong first step in deepwater project planning endangers all decisions that follow. In the case of deepwater field developments, the earliest planning steps occur at the seismic-to-reservoir simulation stage.

Good reservoir simulators have been available for more than 20 years, but for much of that time, preparing input and analyzing the results of reservoir simulation were difficult tasks. A lack of integration between pre- and post-processing tools and the need for many manual, time-consuming data transfers and data-formatting steps frequently caused operators to avoid what was often cumbersome simulation work even while making critical business decisions about their developments.

Today’s software overcomes this hurdle to best practices by clarifying the intersections of seismic data and reservoir modeling. Geoscientists now interpret and quantify reservoir properties using processes that integrate seismic data with all available petrophysical data through inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling. An important prerequisite to this process is the conditioning of both seismic and reservoir data for inversion and reservoir modeling.
Taking the proper angle. Seismic gathers that are flat out only to an angle of 30° (left) are of poorer quality than the ones made after data optimization, which makes the gathers flat out to an angle of 54° (right). Optimization resulted in a good density determination.

The solution was to calculate density through an amplitude variation with offset (AVO) process. To determine the percent gas in a reservoir, a geoscientist must first model the densities of both the rock and fluids. Doing so requires the ability to see the variation in the far angles of the seismic gathers. This information in turn allows interpreters to perform a three-term AVO inversion calculation that includes density. The outputs of the three-term inversion process are relative acoustic impedance, shear impedance and density volumes.

The lithology and fluid types, using properties derived from log measurements in nearby wells, along with varying percentages of gas are modeled to see the effects on the seismic AVO signature. The workflow process then compares the modeling results with the inverted seismic volumes—acoustic impedance, shear impedance, density volumes and Poisson’s ratio—and the results are the basis for generating lithofacies and fluid saturation prediction volumes. Using these probability volumes, with statistical uncertainties, geoscientists can give better predictions of reservoir quality and distribution.

These calculations require data to a fairly high-angle range in the seismic gathers. In this instance, the Schlumberger team was able to extend the usable seismic angle from 30 to 54°, enabling accurate density determinations (above). Calibration of the seismically derived reservoir properties of porosity and hydrocarbon saturation with measurements from an existing wellbore validated the seismic facies predictions.

Once seismic data have been used to characterize the reservoir, reservoir modeling integrates geophysics, geology and reservoir engineering to build one earth model. Reservoir engineers use this model to predict drainage patterns and design injection strategies. Drilling and production engineers use it to plan well trajectories.

The latest versions of these tools, such as Petrel seismic-to-simulation software, enable seismic- and geomechanics-centered disciplines to build shared earth models, rendering a more accurate subsurface picture than that created by one of them working independently. Changes in the seismic interpretation or geological model easily cascade through to the reservoir simulation model and back. The workflows upon which these software packages are constructed are increasing the role of seismic data in understanding dynamic reservoirs.

Surface Work
The better the understanding of the target reservoir, the less potential there is for surprises such as noncommercial volumes of hydrocarbons, flow assurance issues, early water breakthrough, sand production and changes to fluid makeup. Similarly, a well-planned overall field development strategy—completion configurations, well locations, processing facility types and sizes, and intervention decisions—is key to efficient ultimate oil and gas recovery.

This is because the consequences of poor planning are often not felt until near the end of the field’s projected life span. Significant revenue is lost when fields are abandoned prematurely because the costs of remediation or operating expenses are greater than the value of the remaining reserves.

Avoiding these risks requires bypassing the pitfalls created by strict separation of engineering disciplines. Traditionally, reservoir engineers have focused on well count, well placement and recovery mechanisms; production
and completion engineers on well design; and facilities engineers on the subsea layout, facility size and topsides design.

These seemingly disparate groups must instead be convinced to perform their tasks independently yet understand the connection imposed by production and therefore the economics of the project. In turn, these economics are dependent on the physical limitations of the overall system. To function properly, each discipline must be aware of how it impacts the work of others; each member or team involved in a development must work from a common forecasting system.

One such system that comprises dynamically linked models of the field’s subsystems—reservoir, well and facility—is called an integrated production model or integrated asset model (IAM). 10

During development planning stages and before operations are undertaken, asset teams use these integrated models to analyze the interaction of proposed subsystems within a project. IAMs represent a break with traditional field development practices that are more likely to be centered on capital expenditure and focused on implementing modifications that drive down costs. A common pitfall of the traditional approach is a failure to properly quantify the effects of changes on system deliverability that in turn may ultimately lead to suboptimal designs.

In contrast, an IAM uses a reservoir simulation model to calculate fluid movement and pressure distribution. Then, at the subsurface coupling point—the well locations in the reservoir model—these factors are put into the well model, which establishes conditions at the sandface. The sandface condition is used as a boundary to compute the fluid rates or pressures at the surface coupling point—the wellhead—where the well model is linked to the surface facility. 11

The interaction of well–surface boundary conditions makes it possible to calculate the backpressure of the production system for each well. This is then conveyed back through the system to the reservoir. The process iterates to balance the full network. The result is stabilized solutions for fluid flow from the reservoirs into the well and from the well into the surface system and then to sales points. In this way, the IAM technique considers the response of the surface system in fluid-flow calculations. 12

Chevron engineers used integrated production management as a forecasting tool to couple models of the subsurface with a surface network via a wellbore model at their deepwater Gulf of Mexico Jack field. A steady-state model calculated temperature and pressure changes within the wellbore. The surface–network model included the subsea and surface elements such as manifolds, seafloor pumps, wellheads, risers, flowlines and separators. The surface and subsurface models were linked at a bottomhole node. 13

The Chevron model was constructed using a five-step workflow (above). Those steps included:

- defining the problem in terms of objectives, time frames, givens, assumptions and deliverables
- modeling
- quality-checking of reservoir-to-separator model input data against available data under static conditions
- linking the surface and subsurface models
- quality-checking the full system for the entire prediction period under dynamic conditions.

Once the workflow steps were completed, the integrated project model determined that seafloor boosting, coupled with downhole artificial lift, would best exploit reservoir deliverability. A

second study using experimental design then allowed the Chevron team to identify the key parameters of the artificial lift system. The operator considered time of installation, seafloor boosting inlet pressure, ESP horsepower and setting depth. The company concluded that the ESP horsepower was the most significant design parameter across various recovery mechanisms.

The operator then switched from an integrated to a modular approach—using the wellbore model alone—that would support design of the Jack field water-injection facility and calculate the recovery trade-offs for various topsides pressures and injection rates. Topsides pressures were converted into bottomhole pressures (BHPs) using the wellbore model. From the resulting recovery contouring study the team concluded that maximum recovery would require a range of BHPs and injection rates. A BHP of 21,000 psi [144.7 MPa] was infeasible because the proposed high injection rates and topsides pressure requirements limited available pressure. Modeling, on the other hand, showed that lowering the injection rates would not result in significant production loss given the field recovery response. Further developments to the integrated model were used to optimize the number of flowlines, number of seafloor boosting pumps and platform location.

**Driven to Succeed**

Deposited on a seafloor of steep slopes, gullies and canyons, hydrocarbon-bearing formations found in shallow water. So it follows that project plans are driven by considerations specific to deep water. Because they are submersed in near-freezing water, subsea flowlines, mudline wellheads and manifolds pose flow assurance concerns. As a consequence, subsea surveillance instrumentation is installed throughout critical points along the well-to-surface flow path. The surveillance data are fed into fluid models that enable engineers to take preemptive steps to prevent hydrate or paraffin blockages (next page).

Because of the ability of hydrate, paraffin and asphaltine deposition to impact project economics, flow assurance is a primary consideration in many deepwater project plans. For example, given the wide separation of the five fields and comparatively small reserves base that make up BP’s Western Area Development (WAD) in Angola’s deepwater Block 18, project planners paid special attention to flow assurance issues and system deliverability.

At the planning stage, engineers applied a numerical method coupled with engineering software to calculate multiphase thermal-hydraulic behavior in an IAM. The goal was to avoid potential flow disruptions caused by the solidification of gas hydrates in the flowlines traversing the cold seafloor.

In performing the thermal analyses of the subsea systems at the WAD, the operator considered conventional wet insulation, pipe-in-pipe systems and flexible pipelines to determine the time required for the coldest location in the production flowline system to fall to temperatures at which hydrates form. Known as cooldown time, this parameter indicates how long the operator has before hydrate-prevention measures must be taken following an unplanned shut-in.

Analysts also used IAM to perform deliverability calculations for numerous field architectures and to investigate the effects of tubing and pipeline sizes, looping pipelines and subsea multiphase boosting. Their findings enabled BP to combine representative production profiles with capital and operating expense models to derive a full economic evaluation and screening of the company’s options.

**Evolution or Revolution**

Industry response to the unique challenges of deep water has done more than spawn procedural changes; it has also generated a nearly overwhelming burst of innovative drilling and production hardware in a relatively short period of time. As demonstrated by the Shell Mars platform experience, this onslaught of new technology has at times threatened to outpace engineers’ efforts to keep abreast of it.

When coupled with the economic requirement that deepwater fields be developed with as few wells as possible, this flood of new tools and procedures has made it particularly difficult for completion engineers to be certain of delivering optimal solutions throughout the project. The effort to use the most-effective equipment is also thwarted by the time elapsing between project commissioning and well completion installation—often more than five years—during which tool design and availability may change radically.

To deal with these issues, experts have designed modeling techniques to facilitate quantitative analysis of wellbore-reservoir interactions. These methods allow engineers to plan individual wells based on surface and subsurface characteristics as well as the current state of technology. All this is done while taking into account the constraints and characteristics imposed on and by the associated disciplines of geology, drilling, reservoir evaluation and production operations.

One such method treats well design in much the same way the processing industry handles engineering-design problems. Process plants are designed with feed and effluent flow streams, using a flow diagram to capture the process. This diagram then becomes the basis for detailed design, component specifications and other considerations.

Using this method, engineers divide the well design into conceptual and detail phases with iterations between the two. The conceptual design phase includes simple diagrams that highlight the impact of critical surface and subsurface attributes on well architecture. These attributes are examined by the interdisciplinary team so that alternatives may be considered for the key components of well design—well trajectory, formation completion and wellbore components.

Choice of well trajectory is a function of local geology, reservoir properties and drilling capabilities. Formation completion refers to the interface between the wellbore and the reservoir; its configuration is determined by such factors as rock lithology, mechanical properties, grain-size distribution and operational constraints in the process.

Wellbore components are important elements in the architecture of all wells. But they are especially critical in deep water, where modification after the fact can be costly and technically challenging and where conventional technologies are sometimes insufficient. One way to choose the appropriate technology for a particular completion is to sort available hardware options into four categories by function—packers, valves, pumps and sensors—and then use simple block diagrams to discern the optimal type of each.
Prevention not remediation. Flow assurance strategies are an integral part of production operations in deep water. Surveillance instrumentation such as multiphase meters, distributed temperature sensors, pressure and temperature gauges, an SMC subsea surveillance system and ESP monitors installed in the flow path (bottom) delivers data in real or near-real time. This data stream feeds predictive fluid-property models for solids deposition, corrosion, rheology and thermodynamics. The planning team uses these models to create process models that include facilities, flowline and wellbore simulators. Over time, continuous monitoring of changing parameters closes the loop and includes fluids data, flow models and real-time measurements (top). This loop drives the optimization of mitigation strategies and should be included in the production system design as early as possible. In this way, overtreating by a chemicals-delivery system set to worst-case scenarios can be minimized. Monitoring and modeling also provide the information for decisions on the most appropriate proactive, preventive treatments or remedial techniques—thermal, chemical or mechanical—to be put into place to prevent plugging and other impediments to flow, thus avoiding expensive rig-based interventions.
Well completion technology. In complex deepwater developments, where most wells are subsea completions, each well is a critical contributor to overall production. In the simplified decision tree shown, basic geological and reservoir attributes are used to determine, generally, the appropriate wellbore angle—low to vertical or high to horizontal. Knowledge of necessary wellbore deviation severity is subject to secondary parameters of formation permeability and fluid mobility.

Planning for the Unexpected
As subsea wellheads increasingly become the completion design of choice in deep water, operators strive to contain costs by minimizing interventions. The high cost and technical uncertainty associated with entering wellheads located on the ocean floor beneath thousands of feet of water were, in fact, early motivations for developing intelligent completions in the 1990s. Although remote downhole monitoring and operations, along with more-robust completions, have done much to reduce their frequency, rig-based deepwater well interventions are unlikely to be eliminated entirely (next page).

The selection process begins with an evaluation of basic geological and reservoir attributes that constrain options for wellbore trajectories (above). Similar exercises can be used to decide the advisability and type of subsea wellbore configurations such as multilateral completions, stimulations, sand control and artificial lift.

The resulting conceptual well design can be used for more detailed analysis that is then added to a project workflow. This workflow considers a quantitative assessment of well performance, preliminary economic analysis and detailed design.

The links between intervention, production and costs have been demonstrated clearly and often. Frequent, immediate remedial action to repair failed components yields higher production rates but increases operating expense. A policy of fewer or delayed maintenance operations is less costly but results in lower production volumes and revenues.

The challenge then is to develop a plan that strikes a balance of the two options, which is commonly done by dividing interventions into immediate, performance-based or campaign (numerous interventions performed within a field in sequence) repair strategies. To make such a policy workable through the life of the project requires including proactive maintenance during the front-end engineering and design (FEED) stage, rather than relegating it the traditional “as needed” role.

Norske Shell used a modified version of the three-repair strategy to help mitigate intervention costs at its Ormen Lange project—Norway’s first deepwater subsea development 120 km [74 mi] northwest of Kristiansund. During the FEED stage planners instituted a simulation approach for estimating future intervention, maintenance and repair costs of various strategies. Risk expenditures included the direct cost of the intervention to repair a specific component plus the lost revenue incurred as a result of the failure. This method allowed the operator to assess the impact of different intervention strategies throughout the life of the project.

The overall result of this type of modeling is to direct intervention, maintenance and repair efforts toward areas where they yield the highest value. It also focuses attention on critical equipment packages within the project that contribute the most to risk expenditures—the sum of the revenue lost to producing well failures and the cost of intervention. This information may be used to improve designs, increase equipment reliability and initiate smarter, less-expensive ways to fix failed units and thus reduce risk expenditures.

Finally, such a strategy often allows the operator to continually update forecasting information within the model as the project progresses into the operational phase. In the case of Ormen Lange, for example, the model was initially built on rough estimates of the

---

As the project moved forward, the Norske Shell team continually refined the model to assist in equipment configuration and to predict performance, which is used in economic evaluations.

The Big Picture

More than any previous shift in its environment, operating in deep water has forced the upstream industry to change how it conducts business. This cultural shift is due to the outsized rewards and risks attached to deepwater operations, but perhaps even more so it is the consequence of the unprecedented length of time between the decision to exploit a prospect and first oil. It is impossible to predict oil and gas prices or the state of the global economy over such a time span. Operators must make critical investment decisions without the benefit of traditional economic fundamentals that come with more immediate returns on investment.

Similarly, while a great deal of progress has been made in the past decade, the deep-water environment still holds technological challenges for the industry. Just as operators once purchased leases in water depths greater than 2,300 m (7,500 ft) knowing they could not economically produce them, today they are asking service companies and drilling contractors to customize tools to extend depth, pressure and temperature barriers to 3,050 m and beyond.

For example, Schlumberger engineers were recently asked to develop a perforating system specifically for Chevron’s Jack field test well. The solution required re-engineering existing tools based on casing size and the unique bottomhole pressure conditions expected in this ultradeepwater well. In the end Schlumberger delivered a unique combination of tools that together operated as a 172-MPa (25,000-psi) perforating system.

Such requests will continue to be made as operators bring their ultradeepwater prospects beyond the exploratory stage to testing and development. But it is important to consider that it took nine months for Schlumberger to develop, qualify, quality-test and deliver the necessary system working from a similar tool developed for Chevron’s deepwater Gulf of Mexico Tahiti field. Given the task, nine months was a remarkably short time in which to deliver. But it clearly demonstrates the necessity of maintaining a broad view if costly delays caused by technological shortcomings are to be avoided in the complex and unforgiving deepwater operating environment.

Such foresight demands a culture of planning that simultaneously encompasses a long-term vision of integrated tasks and short-term detail-oriented designs. —RvF