Project Management of Offshore Well Completions

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Global annual energy consumption has more than tripled during the last 50 years, mainly because of demand growth in developing countries. These countries will use more energy as their populations grow and their standards of living improve. The lack of onshore opportunities to meet the growing demand has driven E&P companies to increase the development of offshore oil and gas fields. As a result, offshore production is increasing rapidly, and output is expected to double over the next five years (below). Most of the reserves are located in deep and ultradeep water. At present, the principal deepwater fields are located in the Gulf of Mexico, offshore Brazil, West Africa, Southeast Asia and the North Atlantic margin.1

From drilling to abandonment, and even on to decommissioning, offshore wells present a myriad of technical challenges—particularly in deep water. The high productivity and inaccessibility of these wells require robust completion design, flow assurance, equipment reliability and

1 According to the US Minerals Management Service (MMS), deepwater wells are located in water depths of 1,000 ft [305 m] or greater. Ultradeepwater begins at water depths of 5,000 ft [1,520 m] or more. For more on deepwater production projects: Robertson S, Westwood R and Smith M: “Deep Water Enjoys Growth Surge,” Hart’s E&P 79, no. 5 (May 2006): 50–52.


Historical and projected oil production from onshore, shallow-water and deepwater fields. Experts estimate the proportion of offshore oil produced from deepwater fields will grow to 25% by 2015. The United States Geological Survey publication, World Petroleum Assessment, estimates that more than 300 billion bbl [48 billion m3] of oil remain to be discovered offshore. [Adapted from Robertson S: The World Offshore Oil and Gas Forecast. Canterbury, England: Douglas-Westwood Ltd. (2006).]
longevity. Economic viability requires maximizing production rates and ultimate recovery in a safe and environmentally sound manner. Deepwater drilling vessels currently command rates from US $250,000 to $750,000 per day; therefore, well completions must be installed efficiently to minimize rig time. Completion design and equipment reliability are especially critical because the cost to reenter an offshore well for workover or repair can exceed US $6 million.

In this article, we examine advanced offshore completions, from the initial planning stage through equipment manufacturing, testing and installation. First, we discuss basic completion techniques and the collaborative project-management process. Then, case histories from Trinidad and Malaysia will demonstrate the benefits of collaboration.

Introduction to Completions

A well completion is composed of tubulars, tools and equipment placed in a wellbore to convey, pump or control the production or injection of fluids. There are several ways to classify well completions. The most common criteria include the following:

- wellbore-reservoir interface (openhole or cased-hole)
- producing zones (single or multiple)
- production method (naturally flowing or artificially induced).

Openhole completions are feasible only in reservoirs with sufficient formation strength to prevent caving or sloughing. The absence of casing maximizes formation contact with the wellbore. To prevent formation solids from entering the production stream, slotted screens or perforated liners may be placed across openhole sections (above). Openhole completions minimize well-completion expenses and allow flexible treatment options if the well is deepened later.

In a cased-hole completion, casing is set through the producing reservoir and cemented into place. Fluid flow is established by perforating the casing and cement sheath, thereby opening and connecting the reservoir to the wellbore. The perforation tunnel usually extends past near-wellbore formation damage caused by drilling, exposing undamaged rock and allowing unhindered reservoir production (see “Optimal Fluid Systems for Perforating,” page 14).

In a typical single-zone completion, only one conduit or tubing string is involved, and a packer establishes hydraulic separation between the tubing string and casing or liner (next page). The packer is often considered to be the most important tool in a production string because it must provide a long-term hydraulic barrier that is compatible with reservoir fluids and the wellbore annular fluid.
Several accessories are frequently installed above and below the packer. A safety valve, typically situated toward the top of the production tubing but below the mudline, is an emergency well-flow-control device to protect personnel, the reserves and the environment against wellhead or equipment failure. Just above the packer, a sliding sleeve on the production tubing allows completion-fluid circulation through the tubing-casing annulus. Annular-fluid maintenance is necessary to preserve proper hydrostatic pressure above the packer and prevent corrosion. Landing nipples are profiled receptacles in which plugs or chokes may be landed to control fluid flow, or recording devices installed to monitor production. Slotted or ported production tubing allows hydrocarbons to enter the tubing string. A wireline entry guide ensures smooth retrieval of wireline tools back into the tubing string.

Multiple-zone completions are designed to allow production from more than one interval. There are many possible configurations that allow simultaneous production from all of the zones or selective production from certain zones. Multiple producing zones are separated for three principal reasons: government regulations often require operators to monitor production from each zone; high- and low-pressure zones are isolated to prevent crossflow; and crude oils from different zones may be chemically incompatible, forming sludges or precipitates if allowed to commingle.

Wells completed in reservoirs that can produce without assistance are typically more economical. However, in high-pressure, high-temperature (HPHT) applications, specialized engineering and equipment design are required to achieve production in a safe manner. In many cases, wells may flow naturally at first, with subsequent assistance provided by artificial lifting methods as the reservoir is depleted. These considerations are typically included as part of the initial planning process to avoid unnecessary expense and production interruption. Artificial lift completions involve gas lift techniques, or specialized electrically- or mechanically-driven submersible pumps.

3. Gas lift is an artificial lift method in which gas is injected into the production tubing to reduce the hydrostatic pressure of the fluid column, allowing the well to produce normally with its own formation pressure. For more on gas lift: Bin Jadid M, Lyngholm A, Opsal M, Vasper A and White TM: “The Pressure’s On: Innovations in Gas Lift.” Oilfield Review 18, no. 4 (Winter 2006/2007): 44–53.

^ Single-zone and multizone well completions. In the single-zone completion (left), a packer forms a seal inside the production casing that hydraulically isolates the tubing string from the region above the packer, called the “backside.” The backside contains a completion fluid with corrosion inhibitors to prevent casing corrosion. Below the packer are various devices for controlling fluid flow and allowing easy retrieval of wireline tools. The multizone completion at the center employs two packers that separate the producing zones, but the fluids from both zones are allowed to commingle during production. The multizone completion on the right employs a special dual-string packer that maintains fluid separation from each producing zone. The single-string packer isolates the lower zone and allows communication to the surface through the long tubing string. The dual-string packer isolates the upper zone from the annulus while allowing communication to the surface up the short tubing string.
At the top of all well completions is an assembly of valves, spools, pressure gauges and chokes commonly known as a tree (above). The tree prevents the release of oil and gas from the well into the environment, and directs and controls fluid flow from the well. In addition, the tree contains components that allow insertion of equipment such as wireline tools into the well. Another vital device at the wellhead during well completions is the blowout preventer (BOP)—a valve that may be closed to prevent loss of well control. Many BOPs can be actuated remotely, and are critically important to the safety of the crew, rig and wellbore.

Offshore, the tree location and design are a function of water depth and platform availability. In water depths less than about 6,000 ft [1,830 m], trees can be located atop an offshore platform or spar. These “dry trees” are advantageous because they allow wireline access to the well during production. When the seafloor depth exceeds 6,000 ft, current technology does not allow platform-based offshore installations. Therefore, a “wet tree” must be placed on the seafloor. Wet trees are typically more complex than conventional platform completions, and normally include provisions for pressure and temperature monitoring, and sophisticated hardware for automatic fluid-flow control. Because wireline access on subsea trees is costly, engineers install permanent downhole pressure, temperature and flow-monitoring equipment to anticipate or avoid problems.

Subsea trees. Vertical trees (top) are lowered onto the well after the production tubing is in place. Horizontal trees (bottom) are more compact, and can be installed before the well completion is finished. The trees are built to withstand high hydrostatic water pressure at the seafloor and the corrosive effects of seawater. (Photographs courtesy of FMC Technologies Inc.)

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Integrated offshore-well completion-team organization. Close cooperation between Schlumberger and client personnel is essential to ensure a timely flow of information, establish project-management procedures and define the project objectives for all parties. Among the issues to consider are rig scheduling to meet first-oil requirements, detailed component and completion engineering design, geographic locations of team members, and client participation in engineering design and manufacturing.

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Subsea trees may be either vertical or horizontal (above). Generally, vertical trees are installed after the production tubing has been placed in the well. Therefore, if repair is needed, the tree can be retrieved without removing the completion. Their main limitation is the difficulty of well intervention after installation. Horizontal trees, on the other hand, are designed to allow engineers to finish a completion after the tree has been installed. As a result, production tubing and other devices can be run into the well after the tree is in place. Workovers can be performed without removing the tree, reducing time and expense while improving safety. In addition, horizontal trees are more compact.
Planning and Execution of Offshore Completions

Achieving a successful offshore completion requires a closely integrated, multidisciplinary project-management team comprising personnel from the operating company, drilling and service companies, and equipment manufacturers (previous page, bottom). After the contracts are signed, at least two years are usually required for the team to analyze technical parameters and obstacles, determine the completion strategy, design and manufacture the completion equipment, perform thorough testing and finally install the completion in the well (above).


Typical offshore-completion project organization. After contracts are signed, at least two years are usually required to complete all the tasks and begin production (top). The projects are divided into nine discrete steps from initial planning to production and maintenance (bottom). Reviews are conducted after the completion of each stage, and full agreement between Schlumberger and the client is required before proceeding to the next one. Acronym definitions: BOD—basis of design; CWOP—complete well on paper; EOWR—end-of-well report; FMEA—failure modes effect analysis; HAZOP—hazard and operability study; ITT—invitation to tender; PO—purchase order; PP—project plan; Sub-Assys—subassemblies; TPS—third-party suppliers; SIT—system integration testing.

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Offshore completion design and installation involve several stages. Before proceeding from one stage to the next, all team members must approve the work that has been performed to date. From an economic standpoint, the efficiency of this process is as important as the technology.

During the planning stage, engineers evaluate the envelope of conditions within which the completion must operate. Principal parameters include geology, pressure, temperature, produced-fluid properties, anticipated production rates, flow-assurance issues and predicted well life. After completing the analysis, the team generates a robust and reliable completion design that can be installed efficiently. After design approval, procurement and manufacture of the completion components begin.

Before the equipment is shipped to the wellsite for installation, thorough system integration testing (SIT) should be performed to verify that the completion performance will meet or exceed the agreed-upon specifications, and that any unforeseen interface-compatibility issues are identified. SIT also provides a “dry run” for potential completion designs, allowing engineers to develop more efficient installation procedures, test contingency options and ultimately reduce nonproductive time.

SIT is conducted under simulated conditions equivalent to those in the actual well. To meet this testing requirement, Schlumberger opened the Cameron (Texas) Test Facility (CTF) in 2004. The ISO-9001 certified facility allows engineers to assemble the completion exactly as planned for a specific well, install the completion in an equivalent borehole and verify proper system-component performance (above right). Completion design, manufacturing and SIT are guided by failure modes effect analysis (FMEA)—a method to identify potential failure modes for a product, process or system, assess the risks associated with the failure modes, rank the issues in terms of importance, and identify and perform corrective actions to address the most serious concerns. Widely practiced in many industries, notably the automotive and aerospace sectors, FMEA enables engineers to assemble a critical items list (CIL) comprising failure modes that would have a catastrophic effect. In the context of well completions, the CIL identifies high-priority items requiring evaluation during the SIT process.

Key well-completion stakeholders witness SIT in person or remotely, and everyone must be satisfied with the total system performance. After all approvals have been secured, the well-completion hardware is shipped to the wellsite for preparation, installation and commission. The following case histories illustrate how this closely integrated project-management approach has led to success in offshore well completions.

Completing High-Rate Gas Wells in Trinidad
BP Trinidad and Tobago (BP) developed the Cannonball field in offshore Trinidad as a source for liquefied natural gas (LNG) plants. Located 22 miles [35 km] from Galeota Point, at a water depth of 231 ft [70 m], the producing sandstone known as the 33 sand is about 280 ft [85 m] thick with 185-mD permeability and 19% porosity. The reservoir temperature is 220°F [104°C] at 12,350 ft [3,764 m] total vertical depth (TVD). To meet increasing LNG demand, BP and Schlumberger collaborated on the construction and completion of three wells with 21° to 34° deviations.

Under normal circumstances, the rock strength of the producing formation, greater than 2,000 psi [13.8 MPa], would be high enough to allow a sandface completion without sand control. However, this formation was expected to be prolific and, at an anticipated production rate of 300 MMcf/d [8.5 million m³/d] per well, FMEA showed that even a small amount of sand production would cause catastrophic damage to the completion hardware and the surface equipment. Therefore, to prevent sand production, the team chose Alternate Path technology, a system of screens and shunt tubes, to place a complete and homogeneous gravel pack. They also chose high-rate water packing as the gravel-placement method.

In similar gas fields in Trinidad, BP achieved success with openhole-gravel-pack (OHGP) sandface completions with no additional production packer. This simple approach ensured minimal skin values and high flow efficiencies; therefore, the completion team chose the same strategy for three new wells. However, in light of the high production rates, BP decided that the openhole packers must be rated V0, the highest possible leak-resistance rating for a packer in ISO Standard 14310. At the time of equipment selection in 2004, Schlumberger had just released...
a 10%-in. by 6-in. QUANTUM maX gravel-pack system for HPHT conditions, a hydraulically set packer that met the V0 standard. Therefore, the team decided to incorporate it in the primary completion design (below).

In addition, the new packer had to be qualified for use with the gravel-pack system. Consequently, a successful SIT was a necessity before the OHGP system could be approved for use at the Cannonball field. Two SITs were performed between the end of 2005 and early 2006. Some problems were encountered during the first test that resulted in the use of a new wellbore-cleanout string during the second test. In addition, a FIV Formation Isolation Valve tool was included below the packer to protect the sand-control assembly from completion-fluid damage. The second test was successful, and the completion design was approved for installation in Trinidad.

On the first well, CAN-01, problems occurred when attempting to set the packer, so it was pulled out of the hole and inspected. Within 48 hours, the investigation team determined that a carbonate plug in the wash pipe prevented the packer from setting. Engineers ran a backup assembly and completed the job successfully as designed after the hole had been thoroughly cleaned.

The completion program was modified to include a more thorough cleaning of the openhole interval to prevent recurrence of the plugging problem. The team also decided to run gravel-pack logging tools, such as the RST Reservoir Saturation Tool device, to provide valuable troubleshooting data on all future gravel packs. In addition, they observed shunt-tube activation at the conclusion of the gravel-pack operation in the first well, confirming the importance of Alternate Path technology in the completion design.

On the second well, CAN-02, Alternate Path technology paid dividends with almost 50% of the gravel-pumping job completed through the shunt tubes. During drilling, a large ratheole was left below the casing. During the gravel-pack operation, a premature screenout occurred when a sand dune formed in the ratheole and collapsed after reaching critical mass. Fortunately, the shunt tubes performed as designed and the well was completed five days ahead of schedule.

The third well, CAN-03, had both problems observed in the first two wells—wash-pipe plugging and early screenout. However, with the lessons learned, best practices and a robust overall project design, CAN-03 was completed eight days ahead of schedule.

The Cannonball completion project ended below budget, with only 16.2% nonproductive time. The efficient completion of CAN-02 and CAN-03 resulted in a cost savings of US $1.25 million and US $2 million, respectively. In addition, because the V0-certified packers allowed the three wells to produce at their full potential, BP saved an additional US $800,000 by eliminating the production packer and associated joints, assembly, testing and rig time. The Cannonball gas platform began production in March 2006, and is currently producing 800 MMcf/d [22.7 million m3/d] from the three wells—the most productive in BP's offshore portfolio.

11. Skin factor is dimensionless and indicates the production efficiency of a well by comparing actual conditions with theoretical or ideal conditions. A positive skin value indicates formation damage or influences that are impairing well productivity. A negative skin value indicates enhanced productivity, typically resulting from stimulation.
Developing Resources in Offshore Malaysia

Malaysia has some of the most abundant hydrocarbon reserves in Asia. With total proven reserves of 4 billion bbl [640 million m³] of oil and 87 Tcf [2.5 trillion m³] of natural gas, the country has long been a net exporter of both commodities. However, at the present rate of consumption, Malaysia will have to begin importing oil by 2015 unless new production is brought on line. PETRONAS, the national Malaysian oil company, is responding with an ambitious program to increase production by 3% per year over the next 10 years to at least 720,000 bbl/d [114,400 m³/d] by 2010. With this goal in mind, PETRONAS accelerated exploration and discovered that most of the new oil lies in deep water.

In 2002, Murphy Oil Corporation, a PETRONAS franchisee, discovered the Kikeh field in the deepwater area of Sabah in East Malaysia. Kikeh lies 4,300 ft [1,311 m] beneath the South China Sea, and the producing sandstones are estimated to contain several million bbl of recoverable oil. The formations are slightly overpressured, with bottomhole temperatures less than 200°F [93°C], and permeabilities between 300 mD and 1,000 mD.

To develop the field, plans include drilling up to 19 subsea wells and another 20 dry-tree wells from a spar supported by a drilling-tender unit—a more efficient method that will enable Murphy Oil to begin producing oil only five years after discovery. Due to start production in 2007, Kikeh will eventually produce more than 100,000 bbl [15,900 m³] of oil per day, accounting for almost 17% of Malaysia’s 2010 production goal.

Both the subsea and spar wells include oil producers, water injectors and a gas injector. To maintain production, the water injectors will operate at a field rate of approximately 200,000 bbl [31,800 m³] per day, and the gas injector is capable of more than 100 MMcf [2.8 million m³] per day.

After more than a year of well design and development planning, PETRONAS awarded the major contracts for the Kikeh completions. The development strategy involved applying proven completion technologies whenever possible. However, several new tools and techniques were necessary to achieve Murphy’s goals: safeguarding the reservoirs during completion operations, protecting the environment, maximizing well productivity and using the most efficient and cost-effective procedures. Achieving the last goal required devising ways to minimize the number of equipment trips and days required to perform the completions.

Murphy’s Completion and Subsurface Reservoir Engineering departments performed extensive rock-strength studies before selecting the basic sandface-completion designs. Test results indicated that sand control was required across the upper two of the three principal producing sections. Murphy engineers specified expandable sand screens in cased holes for the injectors and in open holes for the producers (below).

Schlumberger and Murphy engineers also selected the PURE perforating system for clean perforations to achieve skin factors less than 2.0.12 Combining a QUANTUM maX packer, a FIV tool and tubing-conveyed eFire electronic firing head systems makes it possible to perforate the...
wells, perform reservoir analyses with injection-test programs and isolate the perforations from completion fluids—all on a single trip. For maximum reliability, the perforating system is supported by an independent pressure-activated firing system. This technique saves valuable time while offering maximum reservoir protection and exploitation.

In addition to the latest perforating and FIV technologies, the Kikeh completions include multiple-control-line ported packers set with a nonintervention tubing isolation valve (TIV) system, again offering rig-time savings while permitting full completion-integrity testing and confirmation. The TIV and FIV combination allows engineers to fully test subsea-tubing-hanger integrity and the deepwater completion-installation workstring without intervention or time-consuming surface testing.

To prevent expensive interventions, or at least minimize their magnitude, Murphy Oil must not only manage well production and injection, but also detect potential problems at an early stage. Therefore, the Kikeh completions include WellWatcher real-time reservoir and production monitoring technology involving permanent quartz gauges, and subsea and surface-tree data acquisition and transmission systems. These components are designed to operate 10 years without maintenance.

To protect the environment and Murphy Oil’s field infrastructure during completion and production operations, engineers chose TRC-II subsurface safety valves. The valves feature two separate and complete piston systems connected by individual control lines, offering redundancy and long-term reliability.13 Fouling will be prevented because the valves can be placed at depths greater than 12,000 ft [3,858 m], well below hydrate- or paraffin-deposition zones. At Kikeh, engineers installed the TRC-II valves at 5,790 ft [1,765 m] below sea level. Nevertheless, the Kikeh completions will still require chemical injections to inhibit potential scale, wax and hydrate deposition. The Dual-Check Chemical Injection Mandrel (DCIM) provides this capability.

All of the completion technologies described in this article depend on reliable equipment to install the completion hardware far below the ocean’s surface. For maximum security during these operations, Murphy decided to install a modified SenTREE 7 subsea well control system for the injectors. Subsea producers use the fully capable SenTREE 7 system with test-tree valve modules for well access and control. If difficulties are encountered during installation of subsea producer wells, the control system provides a 15-s response time to shut in the well and disconnect the landing string. As the various completion components are run into the well, the operator has direct hydraulic control of downhole valves and the completion system even before installation is complete. This flexibility not only reduces operating costs, but also offers contingency options should unforeseen situations arise.

Before the completion components were shipped to Malaysia, a thorough SIT program was conducted. The results were successful, giving Schlumberger and Murphy confidence in the completion plan. Less than one year later the first equipment began to arrive. Within six months, the first completions were installed, a major accomplishment made possible by close cooperation between the Murphy Oil drilling and completions groups and Schlumberger completions, perforating, subsea and testing personnel.

During 2006, initial well performance validated the completion architecture selected by Murphy and Schlumberger, and no major design changes have been necessary to achieve the completion objectives. Nevertheless, further collaboration and optimization have taken place to shorten field-development time and improve operations. For example, the presence of several pressure-operated TIV and FIV units requires close monitoring of all pressures applied to the well, regardless of actual pressure, to predict and prevent unexpected tool activations. This permits completion personnel to make necessary adjustments before beginning a service operation.

Kikeh’s combined spar and subsea-well approach is unique. The subsea wells allow a small spar size, reducing infrastructure costs and installation time. The dual approach also allows simultaneous spar and subsea drilling, pipeline installation and construction of other facilities. This latter development philosophy has dramatically decreased the time to market of Murphy’s product, while maximizing the efficiency of the development through shared resources and fit-for-purpose techniques. In fact, the Kikeh development will be one of the rare deepwater fields to proceed from discovery to oil production in five years.

Continued Development of Integrated Offshore Completions
The case histories presented in this article illustrate the complexity and technical challenges of today’s offshore completions, especially in deep water. Close integration between the service company and operator is critical to achieve success in a timely and economic manner. In addition, Schlumberger engineers have responded to developmental challenges by introducing a comprehensive and versatile array of completion technologies that allow operators to produce oil and gas safely and efficiently. As deepwater development continues to accelerate, lessons learned developing the fields discussed in this article will be applied to future ones, and close cooperation between all of the players will become commonplace. —EBN