Subsea Solutions

All wells are not created equal. Subsea wells, which spring from the ocean floor yet never see the light of day, have a life-style all their own. Constructing these wells and keeping them flowing and productive require heroic efforts that are now paying off.

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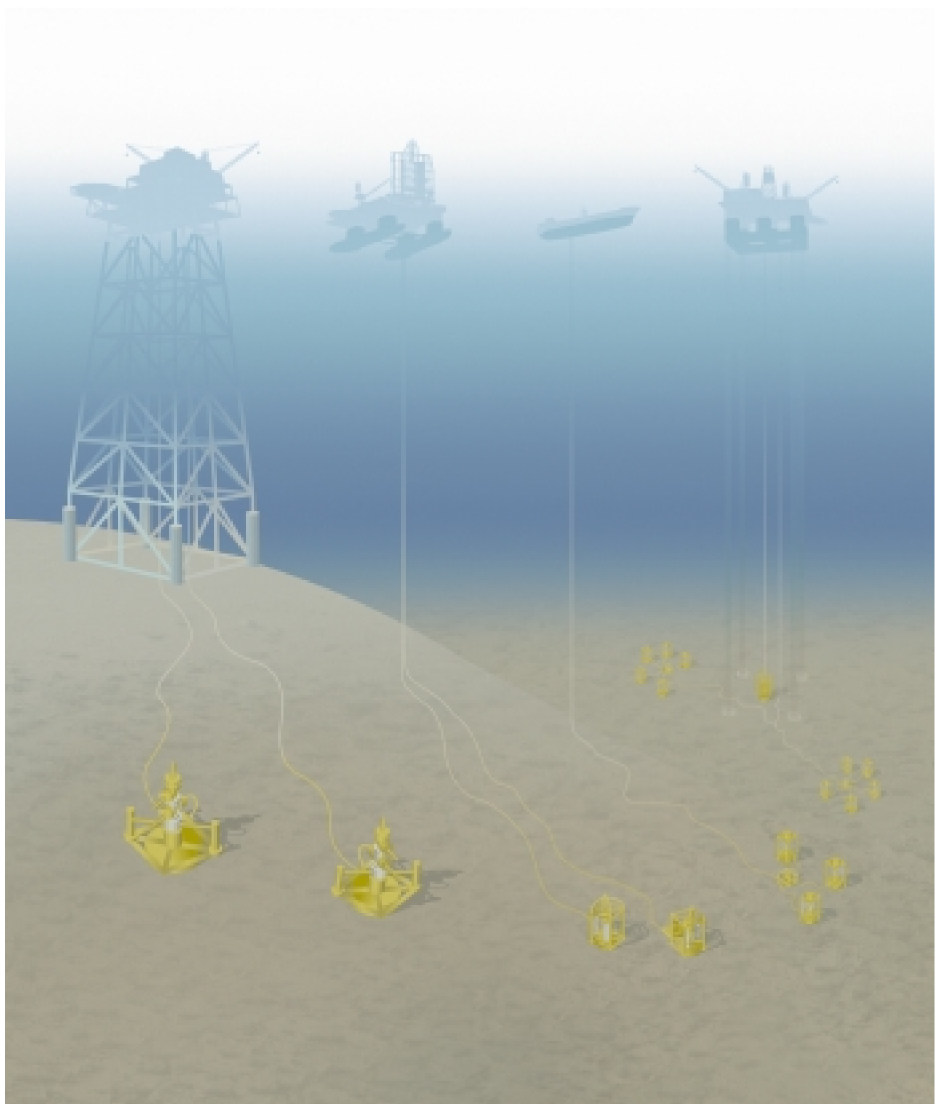

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1. Brandt W, Dang AS, Magne E, Crowley D, Houston K, Rennie A, Hodder M, Stringer R, Juiniti R, Ohara S, Rushton S: "Deepening the Search for Offshore Hydrocarbons," *Oilfield Review* 10, no. 1 (Spring 1998): 2-21.

The mysteries and challenges of the world under the sea have long enticed adventurers and explorers. For thousands of years, people have speculated on the existence of underwater civilizations and dreamed of discovering lost cities or developing ways to live and work under the sea.

Underwater cities remain a fantastic vision, but some aspects of everyday industry do transpire at the bottom of the sea: early communications cables crossed the ocean bottoms; research devices monitor properties of the earth and sea; and military surveillance equipment tracks suspicious activity—all as extensions of processes that also take place on land.

Similarly, the oil and gas industry has extended its early exploration and production operations with land-based rigs, wellheads and pipelines to tap the richness of the volume of earth covered by ocean. This evolution from land to sea has occurred over the past century, starting in 1897 with the first derrick placed atop a wharf on the California (USA) coast (right).[1] Seagoing drilling equipment followed, with offshore platforms, semisubmersible and jackup drilling rigs, and dynamically positioned drillships. From one point on a fixed platform or floating rig, wells could be drilled in multiple directions to reach more of the reservoir.

As offshore technologies advanced to conquer increasingly hostile and challenging environments, offshore drilling moved forward in two major directions: First, and predictably, wells were drilled at greater water depths every year, until the current water-depth record was achieved—6077 ft [1852 m] for a producing well in the Roncador field, offshore Brazil.[2] Drilling for exploratory purposes, without actually producing, has been accomplished at the record depth of 9050 ft [2777 m] for Petrobras offshore Brazil. Other Gulf of Mexico leases awaiting exploration reach water depths of more than 10,000 ft [3050 m].

Offshore drilling

1897 Derrick placed atop wharf 250 ft [76 m] from shore

1911 First drilling platform

1925 First artificial island for drilling

1932 First well drilled from independent platform

1953 First mobile submersible rigs

1956 Drill to 600-ft [183-m] water depth

1966 First jackup

Deepwater

1970 Guideline drilling in 1497-ft [456-m] water depth

1971 First dynamically positioned oil drillship

1987 Water depth drilling record of 7520 ft [2292 m]

1994 Water depth oil production record of 3370 ft [1027 m]

1996 Water depth oil production record of 5607 ft [1709 m]

2000 Water depth drilling record of 9050 ft [2777 m]

Subsea

1961 First subsea Christmas tree

1973 First multiwell subsea template

1991 Record subsea tieback to 30 miles [48 km]

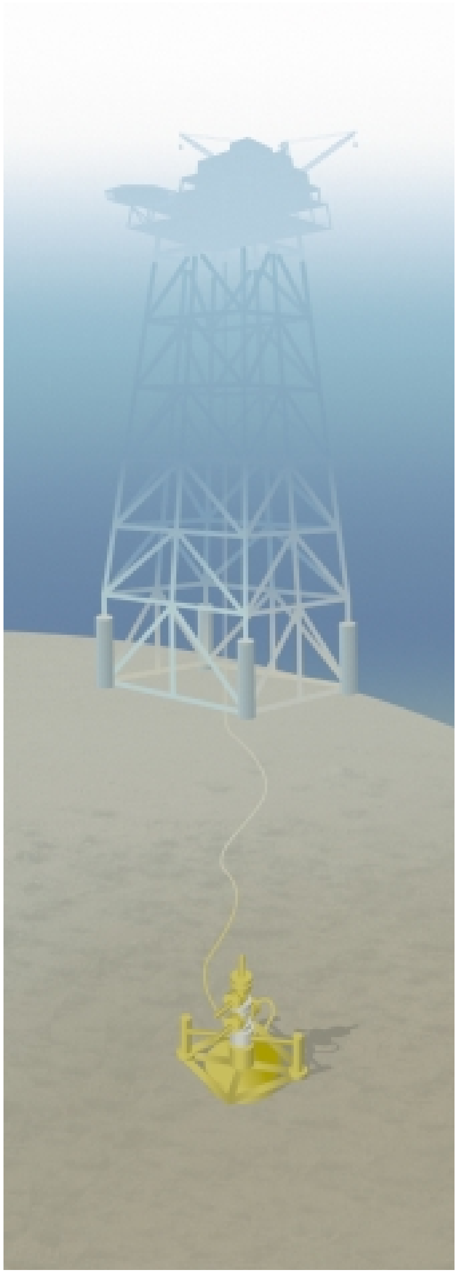
1992 First horizontal tree

1996 Record tieback to 68 miles [109 km]

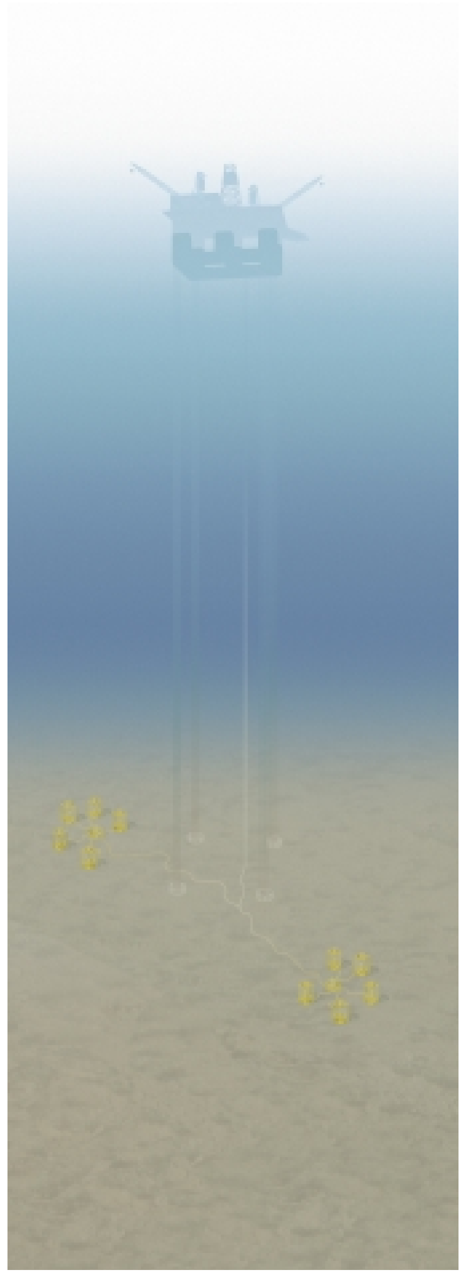
1997 1000 subsea wells completed

^ A time line of offshore operations.

2. Bradbury J: "Brazilian Boost," *Deepwater Technology, Supplement to Petroleum Engineer International* 72, no. 5 (May 1999): 17, 19, 21.
Deepwater has different working definitions. One definition of deep is 2000 ft in hostile environments, 3000 ft [1100 m] otherwise. Another is deep for more than 400 m [1312 ft] and ultradeep at more than 1500 m [4922 ft].



^ A subsea production tree, with flowline connecting to a surface facility.



^ Multiple trees. A group of five subsea production trees is linked to a manifold, where flow is collected at a single station before continuing to surface. A second group of five subsea water-injection wells is in the background.

In a second direction, well-completion equipment has entered the water. Wellheads on the seafloor, in what is called a subsea completion, connect to flowlines that transport oil and gas to the surface (above left). With multiple points of access, more of the reservoir can be reached than through extended-reach wells, so the reservoir volume can be exploited more thoroughly. In addition, field development costs can be greatly reduced through use of a common central facility.

The earliest subsea wells were completed from semisubmersible drilling rigs with the help of divers who directed the equipment into place and opened the valves. Today, subsea completions can be too deep for divers, so the production equipment is monitored and manipulated by remotely operated vehicles (ROVs). The simple wellhead and pipeline arrangement has expanded to encompass multiple wellheads connected to a manifold by flowlines, then to a floating production system, neighboring platform or shore-based facility (above right). Groups of manifolds connected to central subsea hubs maximize areal coverage of the reservoir. The tieback distance between the subsea completion and its platform connection has increased from a few hundred feet or meters to a record 68 miles [109 km], held by the Mensa field in the Gulf of Mexico.[3]

More and more of the operations originally performed at surface are moving to the seafloor. Today's subsea technology covers a wide range of equipment and activities: guidewires for lowering equipment to the seafloor; Christmas, or production, trees; blowout preventers (BOPs); intervention and test trees; manifolds; templates; ROVs; flowlines; risers; control systems; electrical power distribution systems; fluid pumping and metering; and water separation and reinjection. One futuristic vision even depicts a seafloor drilling rig.[4]

The first subsea production tree was installed in 1961 in a Shell well in the Gulf of Mexico.[5] Within 36 years, 1000 wells had been completed subsea. Industry champions predict that completing the next 1000 will take only another five years, and that expansion will continue at around 10% per year for the next 20 years.

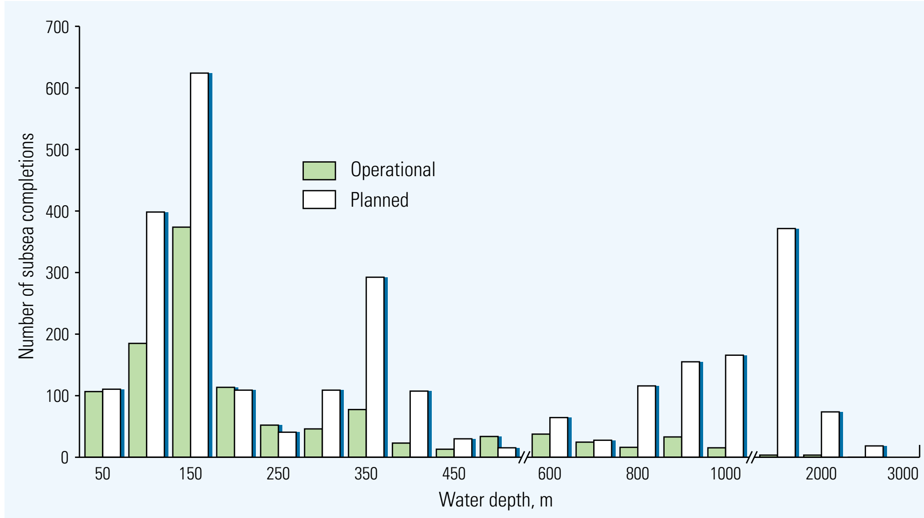
In some areas, such as the Gulf of Mexico and offshore Brazil, expansion will require pushing the frontiers of depth-limited technology. Only two wells in the world have been completed subsea at greater than a 5000-ft [1524-m] water depth. Increases in the number of subsea completions are projected for all depths, but the most striking will be for the ultradeep (above).[6]

In other areas, the North Sea in particular, growth is evident in the increasing number of subsea completions per project. Norsk Hydro is planning to develop the Troll field with more than 100 subsea wells tied back to a floating production system.

The subsea environment poses a set of technological challenges unlike anything that the surface can present, and more than can be covered here. This article reviews the task of completing a subsea well and explains the workings of the equipment that controls access to the well through every stage of its existence, from exploration, appraisal and completion to intervention and abandonment.

3. Sasanow S: "Mensa Calls for a Meeting of the Minds," *Offshore Engineer* 24, no. 7 (July 1997): 20-21.
4. Thomas M and Hayes D: "Delving Deeper," *Deepwater Technology, Supplement to Petroleum Engineer International* 72, no. 5 (May 1999): 32-33, 35-37, 39.
5. Greenberg J: "Global Subsea Well Production Will Double By Year 2002," *Offshore* 57, no. 12 (December 1997): 58, 60, 80.

   A Christmas tree is the assembly of casing and tubing heads, valves and chokes that control flow out of a well.
6. Thomas M: "Subsea the Key," *Deepwater Technology, Supplement to Petroleum Engineer International* 72, no. 5 (May 1999): 46, 47, 49, 50, 53.



^ Number of subsea wells, both operational and planned by 2003, by water depth.

Why Subsea?

Describing the full process behind choosing one deepwater development strategy over another is also beyond the scope of this article, but a brief overview will help set the background. As in the planning of any asset development, the decision-making process attempts to maximize asset value and minimize costs without compromising safety and reliability. The cost analysis focuses on capital expenditures and operating expenses, and also includes risk, or the potential costs of unforeseen events.

The conditions driving these costs are numerous and interrelated, and include all the reservoir-related factors usually considered in land-based development decisions, plus those arising from the complexities of the offshore environment. An abbreviated list includes existing infrastructure, water depth, weather and currents, seabed conditions, cost of construction and decommissioning of permanent structures, time to first production, equipment reliability, well accessibility for future monitoring or intervention, and flow assurance—the ability to keep fluids flowing in the lines.

Certain of these conditions pose awesome challenges for any offshore development, and present strong arguments for subsea completion instead of or combined with other options such as semisubmersibles, tension-leg platforms, dry-tree units, and floating production, storage and offloading systems (FPSOs). Distance from infrastructure is a key determinant in opting for a subsea completion. Wells drilled close enough to existing production platforms can be completed subsea and tied back to the platform. The tieback distance is constrained by flow continuity, seafloor stability and currents. With some fixed-platform capital expenditures measured in billions of dollars, maximizing reservoir access through additional subsea wells can increase production while keeping capital and operating costs down.

Wells whose produced fluids will be handled by an FPSO vessel are also natural candidates for subsea completions, and not only because of reduced time to production. Often these are wells in locations where water depth and weather make more permanent structures impractical or uneconomical. Other options in these environments are either the dry-tree unit, sometimes called a spar, which is a buoyant vertical cylinder, or the tension-leg platform—a floating structure held in place by vertical, tensioned tendons connected to the seafloor by pile-secured templates. Both the dry-tree unit and the tension-leg platform support platform facilities and are anchored to the seafloor. The latter techniques have been applied without subsea completions at depths reaching about 4500 ft [1372 m], but deeper than that the solution has called for a subsea completion in conjunction with the floating systems.

Schlumberger has designed a series of trees for subsea operations, testing, completion and intervention. Combinations of inside and outside tool diameters, pressure and temperature ratings and control systems are designed to suit a variety of subsea completion and well-testing applications as well as water-depth and wellbore conditions.

At the water depths in question, running hydrocarbons through flowlines, valves and pipelines is not an effortless task. The low temperatures and high pressures can cause precipitation of solids that reduce or completely block flow. Precipitation of asphaltenes and paraffins is a problem for some reservoir compositions, usually requiring intervention at some stage of well life. Scale deposits can also impede flow, and need to be prevented or removed.[7] The formation of solid gas hydrates can cause blockages in tubulars and flowlines, especially when a water-gas mixture cools while flowing through a long tieback. Prevention techniques include heating the pipes, separating the gas and water before flowing, and injecting hydrate-formation inhibitors.[8] Corrosion is another foe of flow continuity, and can occur when seawater comes in contact with electrically charged pipes.

Access to the well for any tests, intervention, workover or additional data acquisition is a key consideration. Traditionally, operators have selected platform-style solutions when the development requires postcompletion well access. Platforms house Christmas trees and well-control equipment on the surface, giving easier access to introduce tools and modify well operations. To perform these functions on subsea wells requires a vessel or rig, and sometimes a marine riser—a large tube that connects the subsea well to the vessel and contains the drillpipe, drilling fluid and rising borehole fluids—and planning for their availability when the time comes.

All of this adds up to significant cost. In many cases, the subsea production tree must be removed. Reconnecting to many subsea wells to perform workovers and recompletions can also require a specially designed intervention system to control the well and allow other tools to pass through it down to the level of the reservoir. The development of the completion test tree is now enhancing the accessibility of subsea wells, allowing reliable well control for any imaginable intervention. A full discussion follows in later sections of this article.

Equipment reliability is a major concern for any subsea installation. Once equipment is attached to the seafloor, it is expected to remain there for the life of the well. Some operators remain unconvinced about the suitability and reliability of subsea systems in ultradeepwater developments. However, more and more operators are gaining confidence in subsea practice as contractors provide innovative and tested solutions.

Equipment

Much of the specialized equipment for subsea installations is designed, manufactured, positioned and connected by engineering, construction and manufacturing companies. ABB Vetco Gray, FMC, Cameron, Kvaerner, Oceaneering, Brown & Root/Rockwater, McDermott, Framo and Coflexip Stena are among the companies that supply most of the BOPs, wellheads, templates, production trees, production control systems, tubing hangers, flowlines, umbilicals, ROVs, multiphase meters and pumps, separators and power generators. The largest structures, such as manifolds, can weigh 75 tons or more, and can be constructed and transported in modular form and assembled at the seafloor location.

In addition, oilfield service companies and other groups provide special tools and services for the subsea environment. Baker Hughes, Halliburton, Expro, Schlumberger and others have developed solutions to crucial wellbore-related problems.

One of the key concerns in constructing and operating a subsea well is maintaining well control at all times. Drilling, completion and subsequent servicing of subsea wells are typically performed from one of two types of vessel: a floating system that is tethered or anchored to the seafloor; or one that maintains location over the well with a dynamic positioning system. In both cases, it is critical that the vessel remain in the proper position, or "on station." The position can be described as the area inside two concentric circles centered over the well location on the seafloor. The inner circle represents the limit of the preferred zone, and the outer circle represents the maximum acceptable limit before damage occurs. The vessel activates thrusters to propel the vessel back to the desired location if currents or other conditions such as weather have caused it to move off station, all while continuing the drilling, testing, completion or well intervention.

However, under extreme conditions, the dynamic positioning system may be unable to remain on station or a situation may arise that could endanger the vessel. System problems could include the failure of the thruster system or loss of some anchoring lines, causing the vessel to drift off station. Other situations could include severe weather or collisions with icebergs or other vessels. Under such conditions, the dynamically positioned vessel would drive off station.

All these cases would require disconnecting the landing string and riser from the well. Once the decision to disconnect from the well is made, industry best practices for operation in deep water with dynamically positioned vessels require that the complete process be achieved within 40 to 60 seconds, depending on the conditions and systems used. However, prior to disconnecting from the well and in a separate process that itself takes 10 to 15 seconds, all flow from the well must be controlled and no hydrocarbons must enter the sea. Both ends of the disconnected conduit must be sealed. And once the hazard clears and operation becomes safe again, connection to the well can be reestablished to resume the operation.

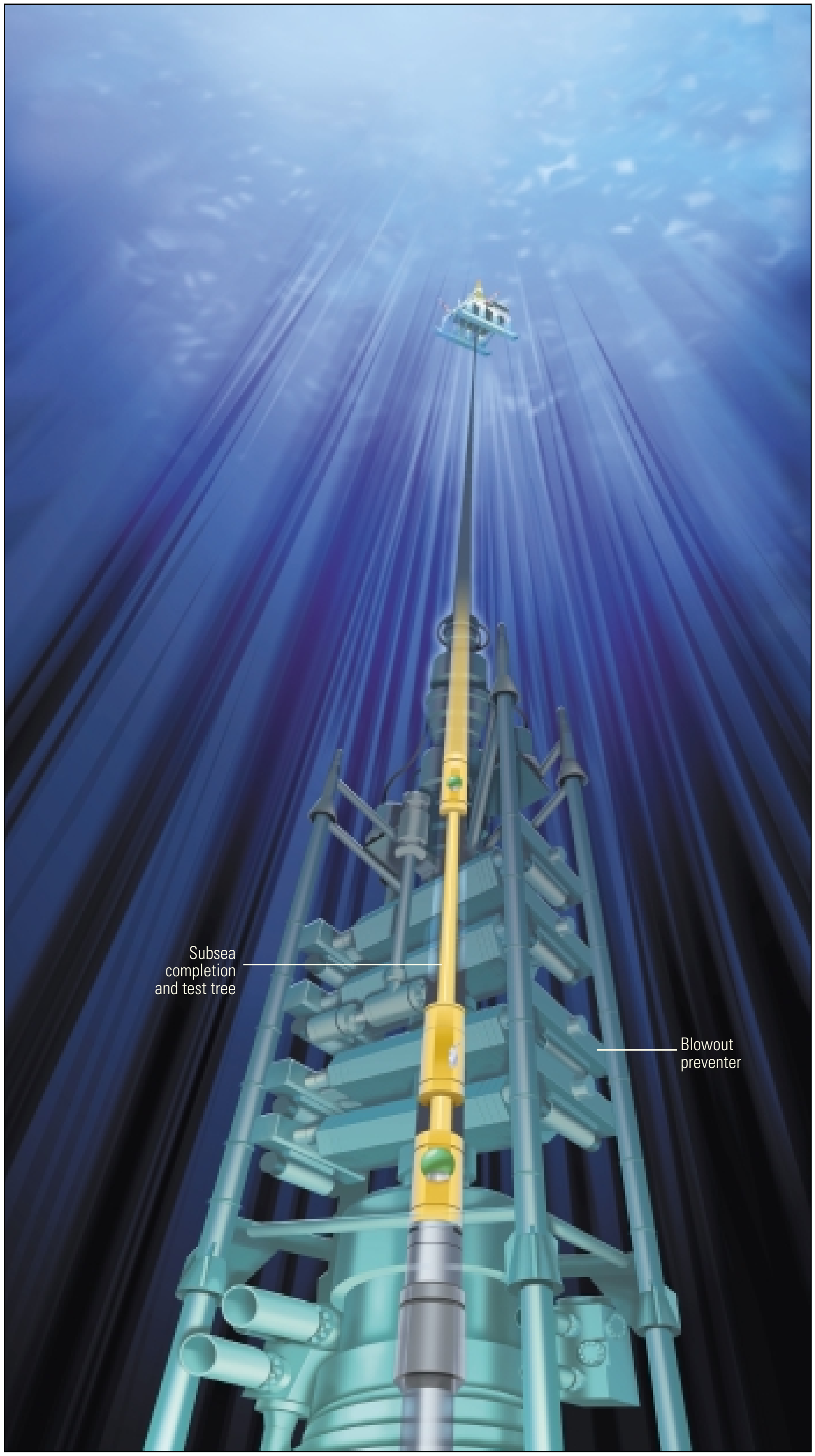
The tools that have been developed by Schlumberger and other companies to perform these tasks are called subsea completion and test trees. They are not permanently fixed to the seafloor as are the production trees, but are deployed inside the marine riser by a landing string when needed, run through the BOP stack, connected to the production tree tubing hanger and then retrieved (right). The tools combine two main features: the control-system portion of the tool transmits information between the surface and the tool and facilitates the activation of the valves and latches. The valves and latches perform the connection, flow control, disconnection and reconnection with the seafloor tree.

Schlumberger has designed a series of trees for subsea operations, testing, completion and intervention. Combinations of inside and outside tool diameters, pressure and temperature ratings and control systems are designed to suit a variety of subsea completion and well-testing applications as well as water-depth and wellbore conditions. For well testing, the smaller diameter SenTREE3 system is used. The SenTREE3 tool has a 3-in. inside diameter and ratings of 15,000 psi [103.4 MPa], and 350°F [177°C]. For completion and intervention, the SenTREE7 system is designed with a 7⅜-in. internal diameter and has 10,000 psi [68.9 MPa] and 325°F [163°C] ratings capable of operating in water depths up to 10,000 ft. A chemical-injection line allows additives to be introduced to the well to prevent corrosion or hydrate formation.

Each tool's control system is engineered according to the operator's requirements. The time available for disconnection depends on each vessel's dynamic positioning system capabilities, water depth, expected currents and wave heights, and a hazardous operations analysis. The SenTREE tools are designed to unlatch under full tension and at an angle greater than can be physically achieved in the BOP stack, to ensure that controlled unlatching is possible in all conditions. In water depths to 2000 ft [610 m], under mild conditions and from a tethered or moored vessel, the time can be up to 120 seconds. The time is longer because the vessel is anchored and does not rely on dynamic positioning to stay in place. In these cases, the control system usually has a direct hydraulic design. The signal to disconnect is sent through hydraulic lines to solenoid valves in the tool's control system that hydraulically activate the tool valves. Due to the behavior of the fluid and the control lines, the time required for the shutoff signal to travel to the subsea tool increases with depth. One method for minimizing this additional time in water depths up to 4000 ft [1219 m] is to enhance the system through use of pressure accumulators in the subsea hydraulics.

7. Crabtree M, Eslinger D, Fletcher P, Miller M, Johnson A and King G: "Fighting Scale—Removal and Prevention," *Oilfield Review* 11, no. 3 (Autumn 1999): 31-45.

8. For more on gas-hydrate inhibition: Brandt et al, reference 1: 11-12.



^ A subsea completion and test tree and subsea blowout preventer (BOP) configuration. The completion and test tree fits inside the BOP to control a live well.

At greater water depths, or in operations from a dynamically positioned vessel, disconnection must be achieved in 15 seconds or less. A hydraulic system alone, over the distance involved, functions too slowly for this, but the combination of an electrical and hydraulic system allows a fast electrical signal to activate the hydraulically controlled disconnection and flow shutoff. These systems are known as electrohydraulic. For the SenTREE3 system, the surface system sends a direct electric signal on an electrical cable to the three solenoid valves of the downhole control system. These valves control the three functions of the SenTREE3 tool, which are to close shutoff valves, vent pressure and unlatch.

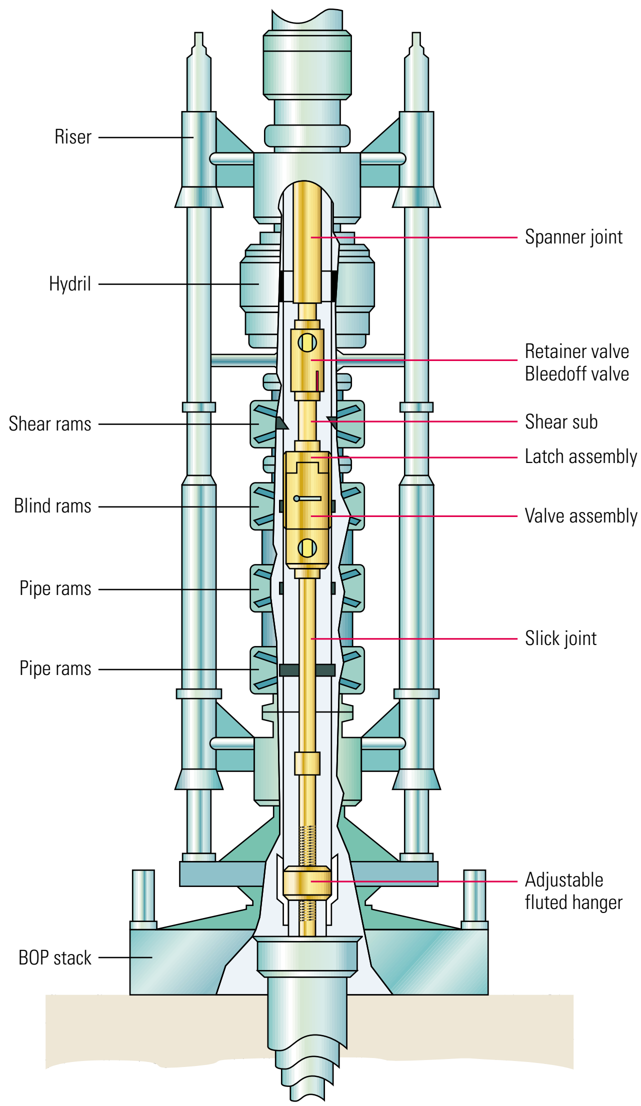
The SenTREE7 multiplex control system, on the other hand, performs 24 functions. These include opening and closing four valves, latching and unlatching two tools, locking and unlocking the tubing hanger, injecting chemicals and monitoring temperature and pressure (right and below). The system is too complicated to operate by direct electrical signal, so a multiplexed signal is sent down a logging cable, then interpreted by a subsea electronics module in the control system, which in turn activates the tool functions. In addition, the electrical system telemeters feedback on the pressure, temperature, status of the valves, and other parameters as required, providing two-way communication between tool and surface. The Schlumberger multiplexed control system is the fastest proven method available.

The shutoff system comprises a ball valve, flapper valves and a latch. A tubing-hanger running tool (THRT) completes the system. A slick joint separates the various valves and latches to match the spacing of the rams of any subsea BOP

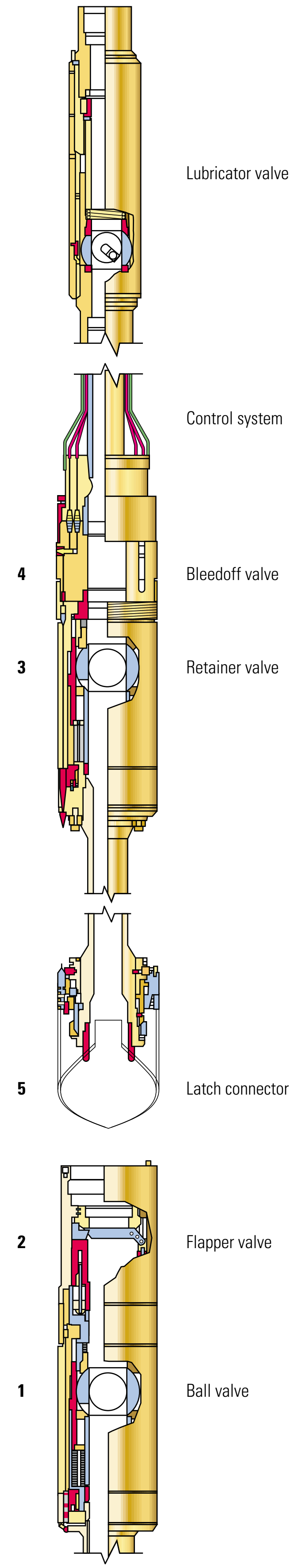
^ Inside the SenTREE7 system. The electronics module (*above*) interprets multiplexed signals sent from the surface to control tool functions. Hydraulic lines (*left*) transmit the signals to the tool's valves and latches.

configuration so the rams can close in the case of a blowout (below). The valves are specified to hold pressures exerted from inside or outside the system. To ensure fluid isolation, the valves operate in order: first, the ball then lower flapper valves shut off fluid rising from the well; second, the retainer valve above the latch closes to contain fluids in the pipe leading to the surface; third, the small amount of fluid trapped between the two valves is bled off into the marine riser; finally the latch disconnects the upper section, which can be pulled clear of the BOP stack. If the riser is going to be disconnected at the same time, the BOP blind rams are then closed and the drilling riser is disconnected. The vessel then can move off location leaving the well under control. The design of a subsea completion and test tree centers on the ability to perform a controlled disconnection—an event that both operator and service company hope will never happen, but must have the capability to manage should it occur.

The design and manufacturing process for completion and test trees is quite different from that of other oilfield service tools. Other oilfield service tools, such as wireline or logging-while-drilling tools, are typically designed by service companies to be used hundreds of times in many wells and to suit a wide variety of conditions. Subsea completion and test trees consist of standard modules, but must be adapted to suit project specifications driven by BOP dimensions, shear capability and tubing-hanger system dimensions, all according to a tightly timed development and delivery contract.



SenTREE3 tool



SenTREE7 tool

> SenTREE series of subsea test and completion tools. The SenTREE3 (*left*) and SenTREE7 (*right*) tools have similar design, with valves and latches to shut off fluid flow and disconnect from the well in a controlled operation. The SenTREE3 tool (yellow) is displayed inside a BOP stack (green). The components of the SenTREE7 system are labeled in order of their activation in the event of a disconnection.

^ A tool as big as the team. The SenTREE engineering team at the Schlumberger Reservoir Completions center in Rosharon, Texas, USA accentuates the large scale of the SenTREE7 tool.

Multiple vendors participate in building different components of a subsea installation, and each component must fit and work with others on schedule. Delays in tool availability mean delays in production. The tools themselves are physically colossal (above). Even the largest wireline tools fit inside. The substantial dimensions and weight of this equipment require special handling equipment and cranes for moving and manipulation. Tool operation, handling and maintenance are usually carried out by locations that also handle well-testing equipment.

Each completion and test tree must be adapted to fit a specific subsea production tree and BOP combination, of which it seems no two are alike.

The first production trees were mainly "dual-bore" type trees, with a production bore and separate annulus bore passing vertically through the tree and with valves oriented vertically. There were also a number of concentric-bore tree designs in which the annulus could not be accessed.[9] Both the dual-bore with separate bores and the concentric-bore trees are sometimes called vertical trees by some manufacturers.

A disadvantage of this type of tree is that it is installed on top of the tubing hanger, so that if the tubing must be pulled for a workover, the production tree—often a 30-ton item—must be removed. In some cases, this may also involve the removal of umbilicals or even pipeline connections.

In 1992 a different style of production tree, the horizontal tree, was introduced. In the horizontal tree, the production and annulus bores divert out the sides of the tree and the valves are oriented horizontally. These are sometimes called side-valve or spool trees. Since the tubing is landed inside a horizontal tree, the tubing can be accessed or pulled without moving the tree, making intervention much easier. Each type of production tree has a different arrangement with the BOP, wellhead and tubing hanger, and so requires its own completion and test tree.

The unique design and the union of electrical and hydraulic methods in the control system make the Schlumberger SenTREE7 subsea completion and test tree highly versatile and adaptable to the needs of the project at hand (next page). The subsea completion and test tree is custom-engineered to fit inside a BOP with any ram spacing and to interface with any tubing-hanger running tool.

< Certificates from Det Norske Veritas issued when modules pass their factory acceptance test, and Gary Rytlewski, subsea chief engineer at the Schlumberger Reservoir Completions center.

9. Richborg MA and Winter KA: "Subsea Trees and Wellheads: The Basics," *Offshore* 58, no. 12 (December 1998): 49, 51, 53, 55, 57.

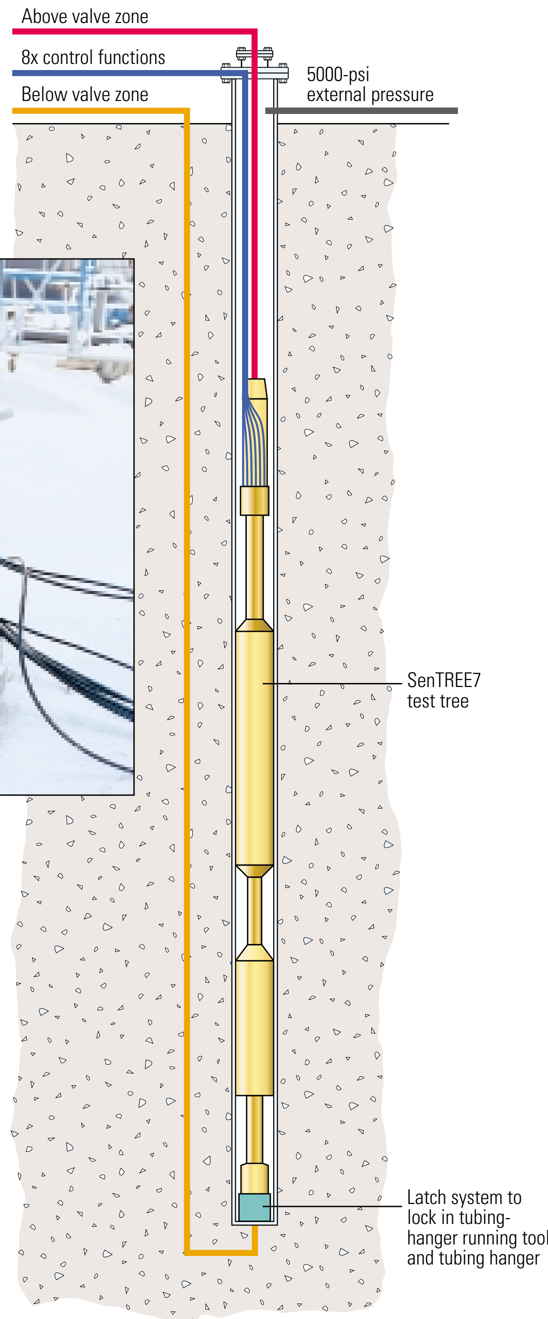
^Engineers assembling a SenTREE7 tool for testing at the Schlumberger Reservoir Completions center.

Tool Reliability

The primary consideration in selecting a subsea completion and test tree is reliability. Schlumberger ensures reliability of completion and test trees through meticulous, systematic testing. Every component of every tool undergoes tests with multiple levels of scrutiny.

The first formal test is the factory acceptance test (FAT), in which individual modules are tested in-house. The test is conducted in the presence of a representative from Det Norske Veritas who witnesses the test and reviews the calculation package that shows how that module was designed to work (previous page, bottom).

However, calculations alone do not prove that a tool will function under the extreme conditions of the subsea environment. Operators need more than numerical computations when the safety of personnel, equipment and the environment is at stake. The cost of deploying a substandard subsea tool at current rig day rates—a day or more to run the tool to depth, a few hours to discover it is malfunctioning, and another day or two to bring it back to surface—can reach the million-dollar mark, not counting any repairs. Reliability of other types of equipment can be proved in laboratory pressure vessels, but testing a subsea completion tree in a pressure vessel is not an easy task. For



^ Massive in-ground high-pressure laboratory for proving subsea tool reliability, with ground-level wellhead (*insert*). Conditions can be created to match those expected for any subsea installation down to 10,000-ft water depth.

this purpose, the Schlumberger Reservoir Completions group designed and constructed an oversized high-pressure test facility (above).

The hyperbaric test facility at Rosharon, Texas, USA was constructed by excavating a 35-ft [11-m] deep pit and creating a 19-in. [48-cm] inner-diameter hole to hold an entire completion tree at conditions equivalent to those at 10,000-ft water depth. Here, any subsea pressure scenario can be created to match conditions expected for any job and prove that the tool will function properly.

Qualification tests ensure that modules comply with specific industry standards of function and performance, such as those established by the American Petroleum Institute (API). For example, any number of API standards specify that a module must perform at a given temperature, pressure and flow rate, with various fluids, for a given length of time. These tests are conducted by the Southwest Research Institute in San Antonio, Texas, according to industry benchmarks that other subsea equipment must also meet.

Another test that requires third-party involvement is the system integration test (SIT) at which all components from all vendors are assembled in a simulation of a real subsea operation. The client is usually present to witness the integrated test. Typical equipment and services present at the SIT are the subsea production tree, manifold, flexible and hard flowlines, umbilical control, SenTREE7 subsea completion test tree and control system, tubing-hanger running tool, tubing hanger, slickline unit, dummy ROV, cranes and all the expected field personnel. In some cases, the connectors for permanent monitoring systems and the associated test equipment are also part of the SIT. Any interface between the SenTREE7 tool or tubing-hanger running tool and an intelligent or advanced completion would be incorporated in the SIT, thus helping eliminate potential costly offshore interface problems. This approach ensures that the equipment will work together properly in the field.

The following sections include field examples that demonstrate the roles completion and test trees play in the different phases of well life, from exploration and completion to intervention and abandonment.

Well Testing

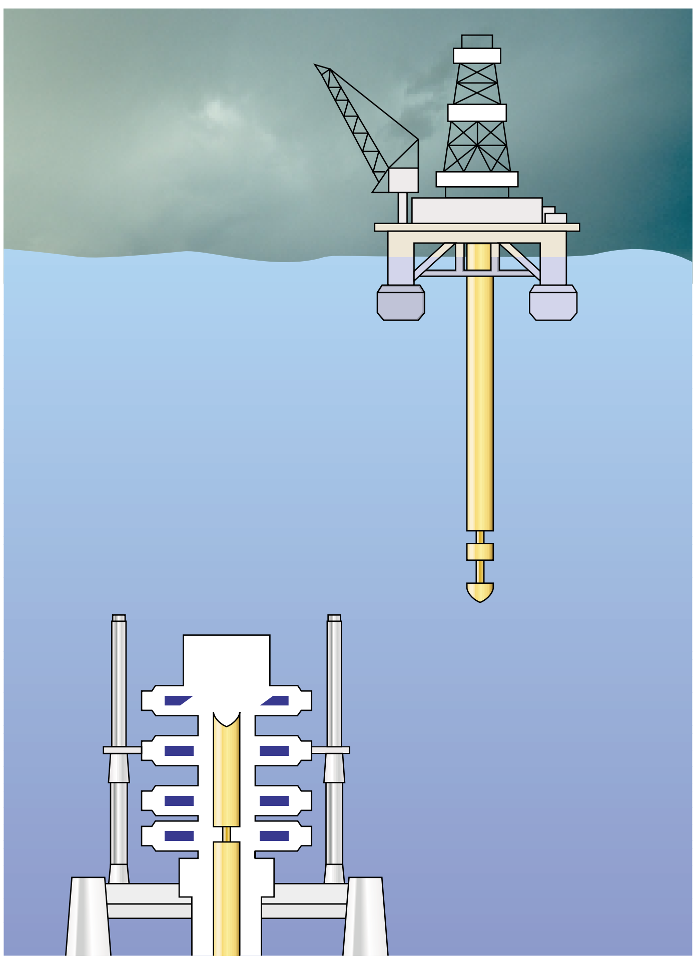
In the exploration stage of a well, after a potential pay zone is discovered, a well test is conducted to evaluate the production and flow capabilities of the well. To test a subsea well, a drillstem test (DST) string is run through the BOP. A typical DST string consists of perforating guns, gauges, a gauge carrier with surface readout capabilities, a retrievable packer and a test-valve tool. This is connected by tubing up to the seabed, then to a retrievable well-control test tree set in the BOP to ensure that disconnection, if required, is done in a controlled way. Reservoir fluids flow past the DST gauges at the reservoir level where pressure and temperature are detected, then flow through the tubing and test tree, and finally to the surface.

In 1974, when Flopetrol-Johnston Schlumberger introduced the first subsea test called the E-Z Tree tool, testing operations from a floating vessel were made possible with the required level of safety. Since then, the technology has evolved and other companies have developed related tools. Halliburton and Expro now offer similar test trees and services, and Schlumberger has developed the SenTREE3 test tree.

In one subsea testing job for Chevron, the controlled disconnect ability of the SenTREE3 system was confirmed under severe weather conditions. The North Sea well was at a water depth of 380 ft [116 m]. The SenTREE3 tool was equipped with a hydraulic control system. The heavy-oil test was conducted with an electric submersible pump and a drillstem test tool. Weather conditions deteriorated until the average heave reached 15 ft [4.6 m]. At this time, the operator decided to halt the test and unlatch. The shutoff valves were activated and the tool was unlatched and drawn up (below left). The riser was disconnected and the vessel moved off.

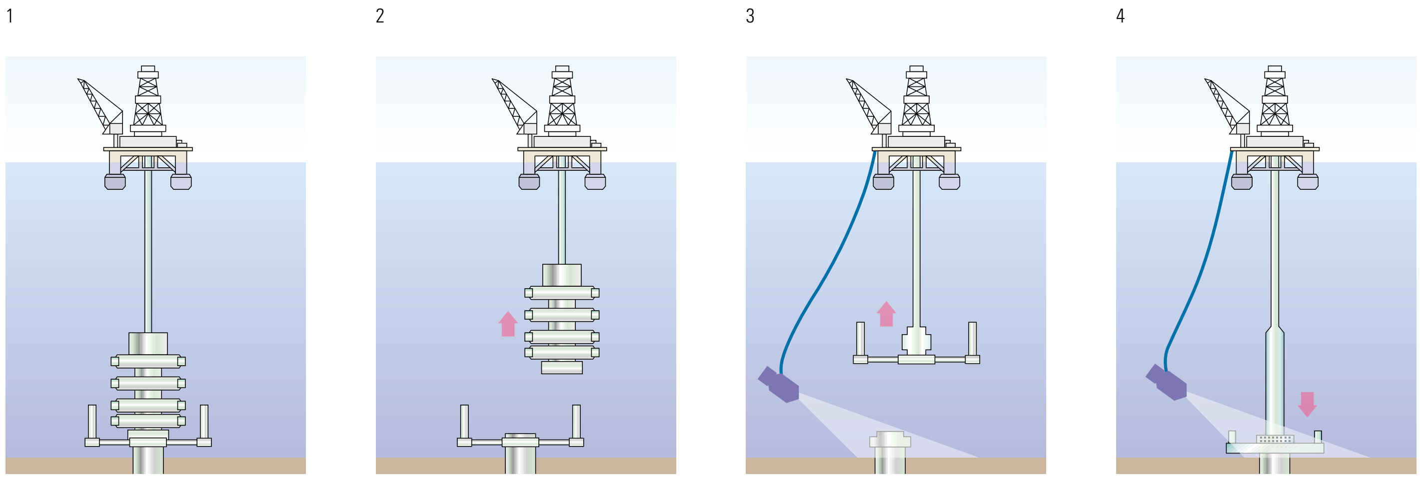
By the time the weather calmed down, the well test was cut short and the primary objective was then to relatch and retrieve the drillstem test tool. The reconnection was performed successfully and the DST was recovered to surface.

Another example of subsea testing success comes from the Barden field in the Norwegian North Sea operated by a consortium consisting of Norsk Hydro, BP, Shell, Statoil and Saga Petroleum. Early in 1998, the operators decided to evaluate the new discovery with the SenTREE3 tool and were the first in the world to use the Schlumberger electrohydraulic control module (below). The dynamically positioned *Ocean Alliance* maintained position in the 857-m [2812-ft] deep rough waters. With this combination of potentially rough seas and moderate depth, the ability to disconnect quickly is even

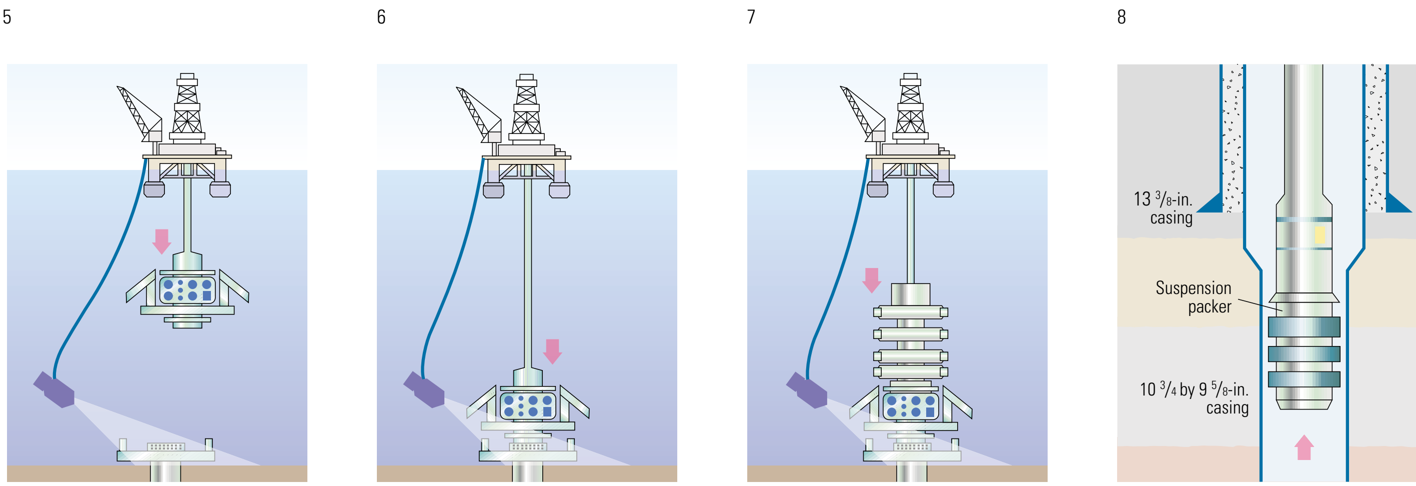


^ Emergency disconnect of SenTREE3 system during a well test for Chevron. The hydraulic control system unlatched the subsea test tree when weather conditions became hazardous, and successfully reconnected to retrieve the test tree and drillstem test tool once the weather moderated.

^ The SenTREE3 tool with electrohydraulic control used for testing the Barden field in the Norwegian North Sea.



^ Subsea completion sequence. 1. Complete drilling and install the suspension packer. 2. Retrieve the drilling riser and BOP stack, move rig off. 3. Retrieve drilling guidebase with ROV assistance. 4. Run the production flow base and latch on 30-in. wellhead housing.



5. Run subsea horizontal tree. 6. Land the tree, lock connector, test seals and function valves with ROV. Establish guidewires and release tree-running tool. 7. Run BOP stack onto horizontal tree, lock connector, run BOP test tool and test, function-test tree. 8. Retrieve suspension packer, remove wearbushing from tree, make up SenTREE7 system, rack back.

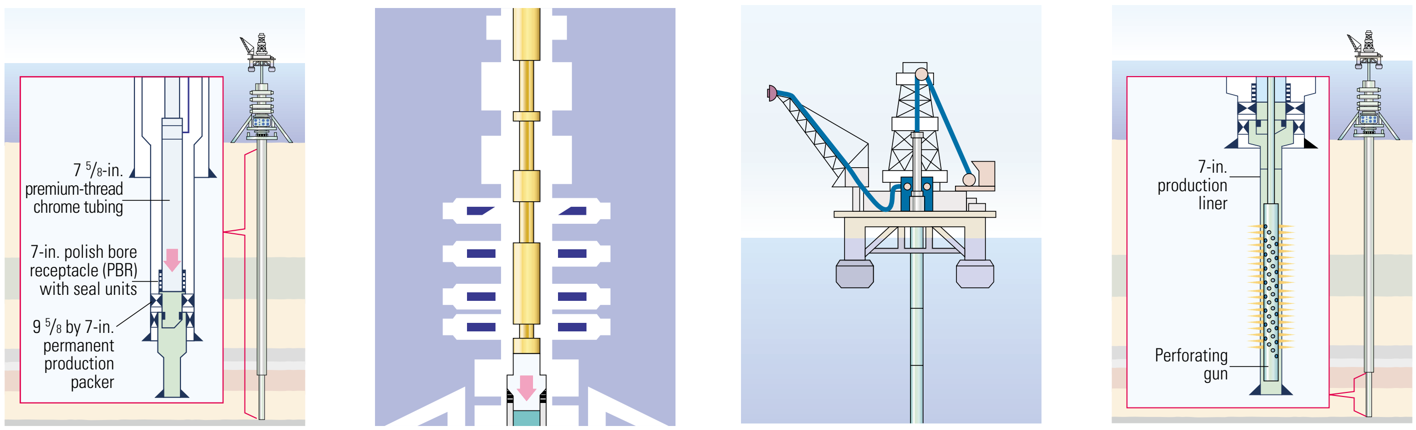
more critical than in deeper water, because the angle of the riser relative to vertical changes more quickly as the vessel moves off station, and the maximum feasible unlatch angle is reached sooner.

Fortunately, the weather remained temperate throughout the full seven days of the well test. A pressure and temperature sub inside the SenTREE3 tool monitored flowing conditions to assist in the prevention of hydrates. Reservoir fluids flowed through the IRIS Intelligent Remote Implementation System test string. The produced liquid hydrocarbons were flared with the new EverGreen burner that generates no smoke or solid fallout.

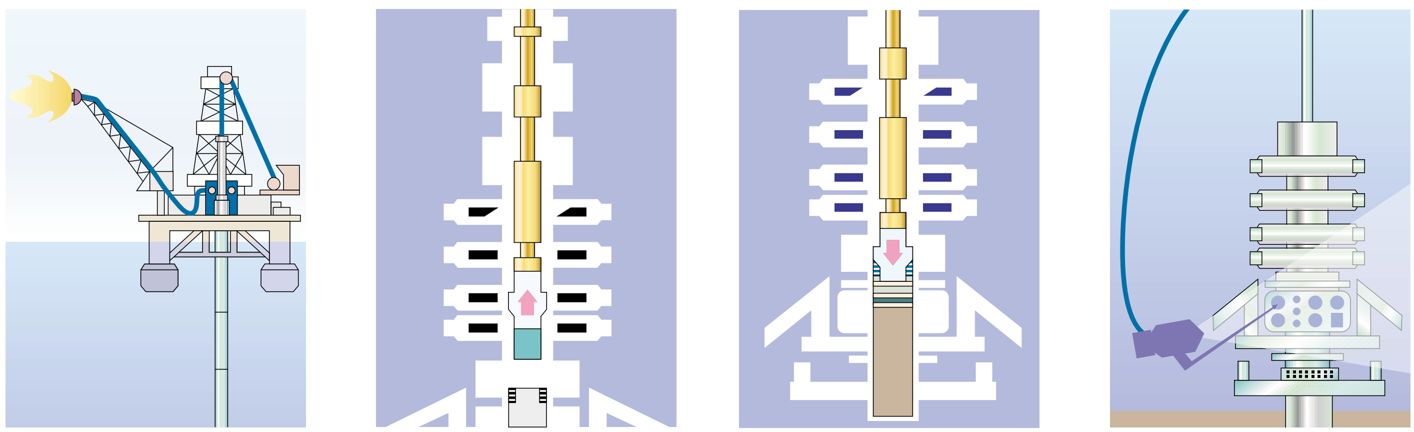
In the three years since its introduction, this new subsea testing technology has spread to other exploration provinces. Two other well tests have been conducted with the SenTREE3 tool plus electrohydraulic control system—one offshore Brazil, the other offshore Nigeria. Almost 300 other jobs have been run offshore Brazil, West Africa, Australia, Indonesia and in the Gulf of Mexico with the SenTREE3 test tree and the hydraulic or enhanced hydraulic control systems.

Completion

The operations described so far pertain to subsea exploration and appraisal wells with temporary completions: after testing, the packer, test string and tubing are pulled and the BOP is left in control of the hole for either abandonment or sidetrack operations. Installing a permanent completion, or string of production tubing, is performed in the development phase when production wells are drilled and completed or when an existing well is recompleted. The basic process of completing a subsea well with a horizontal production tree can be described as a series of five steps, with a number of subtasks within the five broad categories:



9. Run completion string, make up tubing-hanger running tool (THRT) and SenTREE7 system on tubing hanger, run landing string with umbilical, make up surface control head to landing string. 10. Land hanger in production tree and test seals. Rig up wireline and retrieve straddle sleeve. Run seat protectors. Circulate tubing to potable water for drawdown. Set wireline plug, test string and set packer. 11. Rig up production test package. Rig up electric wireline and lubricator. 12. Run guns, correlate and perforate well.



13. Carry out production test, acid stimulation and multirate test. 14. Unlatch THRT and retrieve landing string and SenTREE7 tool. Rig down production test package and flowhead. 15. Run internal tree cap. 16. ROV closes tree valves. Retrieve THRT and landing string.

(continued on page 16)

Well suspension—Suspend flow from the well with kill fluid; run plugs to shut off flow; retrieve the riser and BOP.

Production tree installation—Install the horizontal tree; rerun the drilling BOP; recover plugs and temporary suspension string.

Completion—Change to completion fluid; condition the well prior to running completion; run the completion with production equipment and the subsea completion and test tool.

Installation and intervention—Close rams; land off and test hanger; set and test packer; underbalance the well; perforate; clean up flow; pull out the landing string.

Isolation and production preparation—Run and set hanger plug; open rams; unlatch tubing-hanger running tool (THRT); pull THRT out of hole with landing string. Run internal tree cap; run and set internal tree cap plug.[10] Unlatch THRT from internal tree cap; recover landing string; recover BOP and riser.

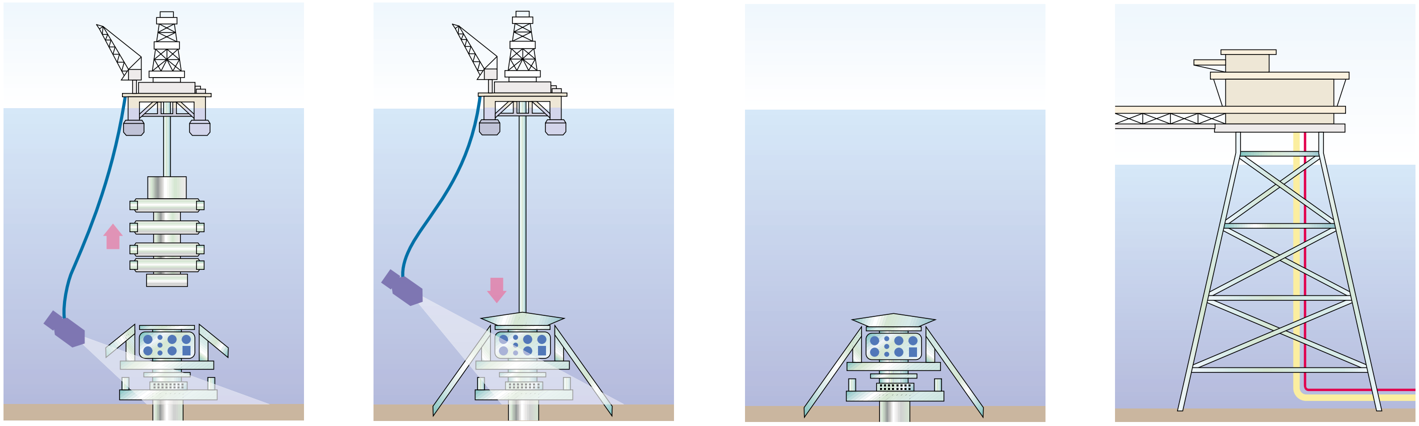
Two oilfield service companies, Expro and Schlumberger, offer tools and services for completing large-bore, horizontal-tree subsea wells. ABB Vetco Gray, an engineering company that already supplies tubing hangers, is actively developing capability to offer completion services also. As service providers gain experience with and compile success stories about subsea completions with horizontal trees, operators will learn about the advantages the newer trees offer in terms of ease of completion and intervention.

Late in 1999, Shell in Sarawak, Malaysia realized considerable savings by advancing quickly from exploration to production using an “off-the-shelf” horizontal subsea tree—the company’s first horizontal tree. Using the SenTREE7 completion tree, they successfully completed the subsea well 12 days ahead of schedule without a minute of downtime. Schlumberger became active in the earliest planning stages of the project. This early involvement ensured that the project would proceed as smoothly as possible.

The completion proceeded in a series of steps beginning with the termination of drilling and continuing through landing the production tree, running the completion string with the SenTREE7 tool, and tying into a well-test package (previous page, above and next page, top).

10. A tree cap is a cover that seals the vertical conduits in a subsea production tree.

17 18 19 20

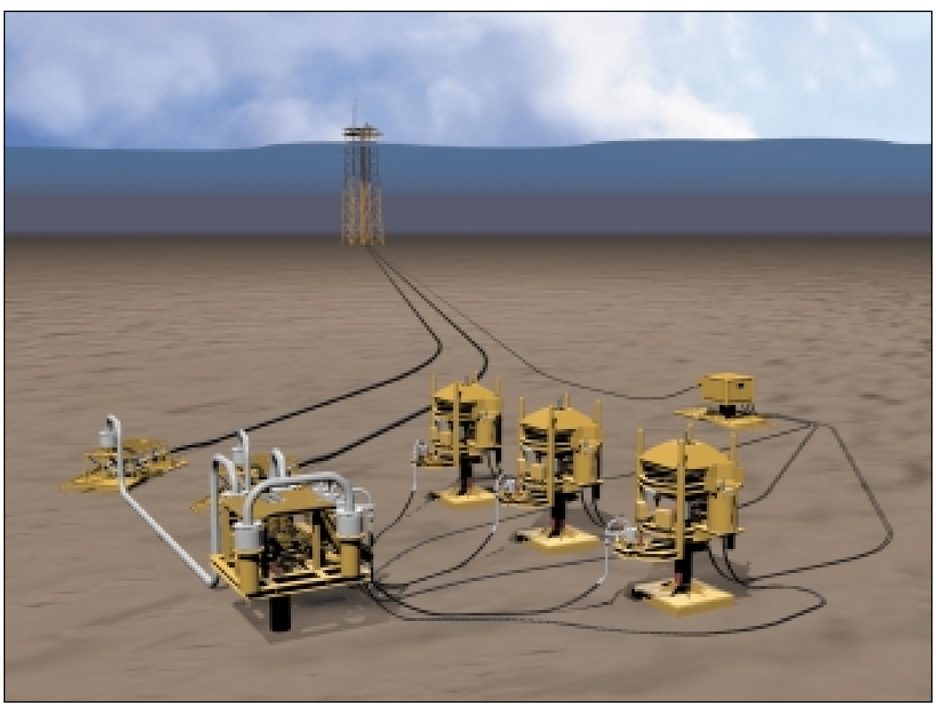


^ Subsea completion sequence (continued). 17. Retrieve BOP stack, retrieve guidewires. 18. Install debris cap, deploy telescopic legs. 19. Suspend well. 20. Tie in to pipeline for production.

By mid-1999 Texaco had set a record for deepwater subsea completions in their Gulf of Mexico Gemini field (below). The enhanced direct hydraulic SenTREE7 subsea completion tree assisted in the completion process of three subsea wells in 3400 ft [1037 m] of water, at the time a worldwide industry record for this type of subsea completion system. The enhanced direct hydraulic SenTREE7 system helped run the 5-in. completion string along with a Cameron tubing hanger on 7-in., 32-lbm/ft [14.5-kg/m] landing string. The completions were performed from the *Diamond Offshore Ocean Star*, an anchored vessel, and the enhanced hydraulic control system provided the requisite 120-sec response time to control the well and disconnect the landing string if required.

After the completions, surface well tests were performed from the anchored vessel. The first well was flowed back to the *Diamond Offshore Ocean Star* for a total of 65 hours, with a final gas rate of 80 MMscf/D [2.2 million m^3/d], condensate at 1500 bbl/day [238 m^3/d] and water at 200 bbl/day [32 m^3/d]. Methyl alcohol was continually injected at the SenTREE7 chemical-injection line to prevent formation of hydrates during the flowback period. The SenTREE7 tool was also used to facilitate the installation of the internal tree cap. Schlumberger also provided surface well test equipment and services and sand-detection equipment during well cleanup. All services, including SenTREE7 operation, were performed with 100% uptime.

Since then the water-depth record has been broken, again by the SenTREE7 tool, in another Gulf of Mexico field. Late in 1999, a Schlumberger completion and test tree operated from an anchored vessel as before, but this time in water depths of 4650 ft [1417 m]. The record was set during completion of a five-well development using a tool system similar to the one deployed in the Gemini field: the enhanced direct control system assured a 120-sec response time.



^ Gemini field subsea development. Three Texaco subsea wells in the Gulf of Mexico were completed using the SenTREE7 system from an anchored vessel.

Completions of this nature have been performed on wells in Africa, the Gulf of Mexico and the UK, and more are being planned for the year 2000. After the exceptional experience in the Gemini field, Texaco has selected Schlumberger for completions services in 15 subsea wells in its North Sea Captain field. And more multiwell contract arrangements have been made with major oil companies operating in the Gulf of Mexico.

In particular, BP Amoco has signed a three-year multiwell contract with Schlumberger for subsea completions services in its Gulf of Mexico fields. Two of these reach water depths of 7000 ft [2134 m]. These wells will be completed from *Enterprise*, a dynamically positioned drillship, and so will require the multiplexed deepwater control system that provides a 15-second controlled disconnect. The entire multiplex system has already completed a rigorous qualification test and met stringent BP Amoco requirements, including the 15-second disconnect time. BP Amoco purchased a surface well-test package that was installed on the *Enterprise* for use as a well test and early production facility.[11]

11. For more on early production systems: Baustad T, Courtin G, Davies T, Kenison R, Turnbull J, Gray B, Jalali Y, Remondet J-C, Hjelmsmark L, Oldfield T, Romano C, Saier R and Rannestad G: "Cutting Risk, Boosting Cash Flow and Developing Marginal Fields," *Oilfield Review* 8, no. 4 (Winter 1996): 18-31.

12. McGinnis E: "Coiled Tubing Performance Underlies Advances in Intervention Vessels," *Offshore* 58, no. 2 (February 1998): 46-47, 72.

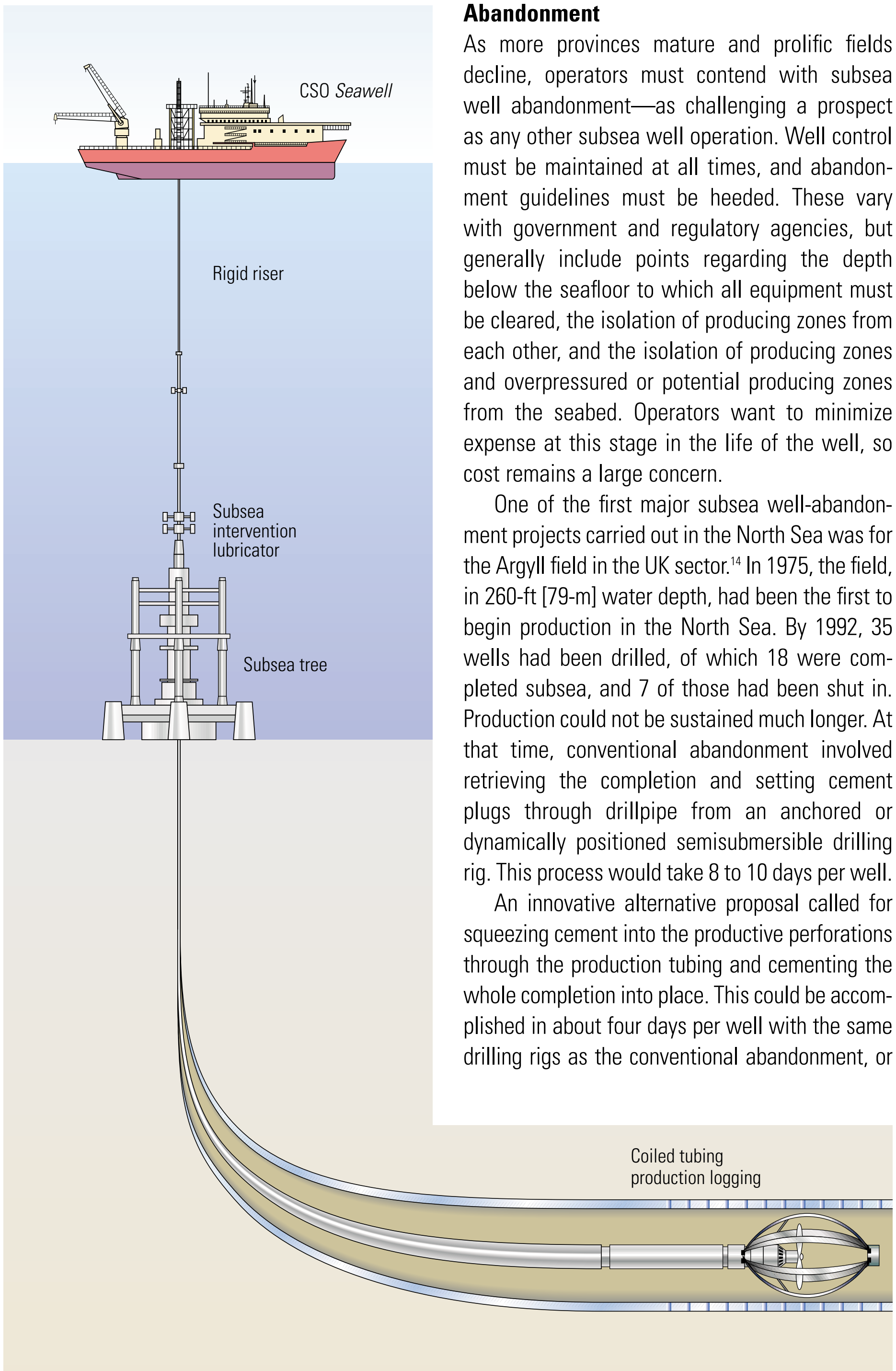
Intervention

Most wells require some kind of intervention during their life span. Interventions—installing or servicing subsurface surface-control valves, changing gas-lift valves, production logging, pulling failed tubing, removing scale or paraffins, perforating new sections, squeezing cement into perforations to shut off water flow—all can extend the productive life of a well. Some companies claim that more than half their production comes from subsea wells, and they will not tolerate reduced production that can be ameliorated through intervention.[12]

Intervention can be and has been accomplished with a drilling rig and marine riser, but returning to a subsea well using this approach is an expensive proposition. This has led the industry to seek more cost-effective methods for subsea intervention.

Subsea well intervention services of Schlumberger, together with Coflexip Stena Offshore (CSO), have devised a cost-effective alternative for light well intervention—intervention that can be run through tubing. Coflexip Stena Offshore built the specially designed dynamically positioned monohull vessels, CSO *Seawell* and CSO *Wellservicer*. The Schlumberger well intervention group developed the subsea intervention lubricator (SIL). The SIL is designed to be deployed and operated from a suitably equipped dynamically positioned vessel and permits wireline or coiled tubing access to live subsea wells without the requirement of a conventional BOP stack and marine riser. Wireline techniques have limited application in the hundreds of subsea wells that are highly deviated or horizontal. An intervention system must be able to convey tools and fluids in high-angle wells. Coiled tubing often offers these capabilities.

At the end of 1997, the world's first such coiled tubing intervention was carried out from the CSO *Seawell* on the Gannet field for Shell in the North Sea. Representatives from the Schlumberger well intervention services group, Dowell, Coflexip Stena Offshore and Shell Subsea Well Engineering and Underwater Engineering together assessed the risks associated with the development of the system. A custom-built lifting and shipping frame was installed on the CSO *Seawell* to keep the riser in tension and deploy the coiled tubing. The system was tested first on a suspended wellhead and successfully performed a series of operations: routine disconnect and reconnect; swivel check; coiled tubing run in hole; logging and circulating; emergency disconnect with 1100 psi [7587 KPa] in riser; and rigging down. On the live Gannet well, a coiled tubing-conveyed production logging test was conducted over four days with no nonproductive time (below).



^ Light intervention services on subsea wells from a dynamically positioned monohull vessel using the subsea intervention lubricator. Cost-effective subsea intervention, in the form of coiled tubing-conveyed production logging, was performed in the Gannet field, North Sea.

Since the SIL was developed in 1985, more than 1166 operational days have been registered and more than 275 subsea wells have been entered using the lubricator from the CSO *Seawell*.[13] Key factors in the success of the approach have been efficiency and cost-effectiveness of operations. Compared with operations from a mobile drilling unit, cost savings can range from 40 to 60%.

Abandonment

As more provinces mature and prolific fields decline, operators must contend with subsea well abandonment—as challenging a prospect as any other subsea well operation. Well control must be maintained at all times, and abandonment guidelines must be heeded. These vary with government and regulatory agencies, but generally include points regarding the depth below the seafloor to which all equipment must be cleared, the isolation of producing zones from each other, and the isolation of producing zones and overpressured or potential producing zones from the seabed. Operators want to minimize expense at this stage in the life of the well, so cost remains a large concern.

One of the first major subsea well-abandonment projects carried out in the North Sea was for the Argyll field in the UK sector.[14] In 1975, the field, in 260-ft [79-m] water depth, had been the first to begin production in the North Sea. By 1992, 35 wells had been drilled, of which 18 were completed subsea, and 7 of those had been shut in. Production could not be sustained much longer. At that time, conventional abandonment involved retrieving the completion and setting cement plugs through drillpipe from an anchored or dynamically positioned semisubmersible drilling rig. This process would take 8 to 10 days per well.

An innovative alternative proposal called for squeezing cement into the productive perforations through the production tubing and cementing the whole completion into place. This could be accomplished in about four days per well with the same drilling rigs as the conventional abandonment, or more cost effectively from a dynamically positioned dive-support vessel—a vessel not specially equipped for drilling. The two key factors in favor of the new approach with a dive-support vessel were reduced cost of implementation of the streamlined task and lower risk due to the shortened program with minimal hardware recovery.

The abandonment plan maximized efficiency by executing the operation in two parts—first all wells would be plugged, then all subsea production trees and wellheads would be recovered. This optimized equipment rental costs and made it possible for the crew to improve the process by repeating and learning one type of operation.

The job was performed by the Coflexip Stena Offshore Ltd. CSO *Seawell* using the subsea intervention lubricator. During the plugging phase of the plan, the SIL maintained control of and provided access to each well to carry kill-weight fluid to the open perforations, perforate the tubing, circulate cement, pressure test the plugs, circulate test dye, perforate casing and cut the tubing with explosives. In the second phase, the subsea production tree and tubing hanger were recovered, casing strings were cut explosively at least 12 ft [4 m] below the seabed and the wellhead and casing stumps retrieved. The optimized operation took 47 days instead of the 81 planned.

To date, 142 subsea production and suspended wells encompassing 8 complete production-field abandonments have been carried out in the UK continental shelf using the CSO *Seawell* and the SIL.

For deepwater subsea wells, abandonment is more involved. Late in 1999, EEX Corporation began decommissioning its Cooper field in the Garden Banks area of the Gulf of Mexico—the first such project performed at a water depth greater than 2100 ft [640 m] from a dynamically positioned vessel.[15] Schlumberger and several other contractors worked with Cal Dive Inc. through the complex operation that included removal of a one-of-a-kind freestanding production riser, 12-point mooring system, floating production unit and all the subsea equipment. Schlumberger provided subsea project management expertise along with coiled tubing, pumping, slickline, testing and wireline services.

The first step in decommissioning the field was to kill the seven subsea wells. Once this was accomplished, the riser, flowlines, production trees and export pipelines were all cleaned and flushed. The mooring lines, chains and anchors were moved off-site, and the seven wells were plugged and abandoned using a combination of wireline and specially designed coiled tubing unit. Because the entire abandonment operation was conducted from the *Uncle John,* a dynamically positioned semisubmersible, the system also used an emergency disconnect package. After the wells were plugged, the subsea trees and remote templates were retrieved. The flowlines and export lines were then filled with treated salt water and sealed. These lines, along with the main template, were left in place on the seabed in such a way that, if required, they could be used to support future regional development.

As more provinces mature and prolific fields decline, operators must contend with subsea well abandonment—as challenging a prospect as any other subsea well operation. Well control must be maintained at all times, and abandonment guidelines must be heeded.

What Next for Subsea?

Many companies already are experienced with subsea solutions and others are just beginning to become familiar with the advantages and limitations. All agree that although the industry has achieved measurable advances since the first subsea well almost 40 years ago, more work has to be done before subsea technology can be applied everywhere it is needed.

Nearly all of the current limitations are related to the extreme depths and operating conditions encountered by subsea wells. One broad category of work to be done concerns metallurgy. Embrittlement of metals at subsea temperatures and pressures causes failures in equipment. Going deeper may require completely new types of materials.

Another area of investigation addresses risers, moorings and umbilicals. Groups are looking into assessing induced vibrations on drilling risers and the possibility of developing polyester moorings.

One of the ways the industry is looking for innovation is through consortia, initiatives and joint efforts. One of these, DeepStar, is a group of Gulf of Mexico participants from 22 oil companies and 40 vendors and contractors.[16] The oil companies have specified areas in which new deepwater solutions must be found. First on their list is flow assurance. Paraffins and hydrates are the main causes of flow blockage in long tiebacks. If ways could be found to combat their deposition, longer tiebacks could be possible and economic thresholds could be lowered, allowing development of reserves that are currently marginal.

Several companies are working on solutions to these problems. Some are proposing and trying methods that attempt to unclog flowlines with coiled tubing-conveyed tools. Others are testing the feasibility of heating pipe to control paraffin and hydrate formation. In addition, the DeepStar organization has begun construction of a field-scale test facility in Wyoming, USA. The 5-mile [8-km] flow loop will be used to validate hydrate-prediction software and multiphase flow simulators, test new hydrate inhibitors, observe the initiation of hydrate plugs, evaluate sensors and understand paraffin deposition. Much more work is needed to ensure that subsea wells and long tiebacks can sustain flow.

Elsewhere, other initiatives have been undertaken. PROCAP2000 in Brazil supports the advancement of technologies that enable production from waters to 2000 m [6562 ft] depth. Since its inception in 1986, many of the group's targets have been reached, but several subsea projects concentrating on subsea multiphase flow metering, separation and pumping are continuing.

The Norwegian Deepwater Programme was formed in 1995 by the deepwater license participants on the Norwegian shelf, including Esso, BP Amoco, Norsk Hydro, Shell, Saga and Statoil. The goal was to find cost-effective solutions to deepwater challenges and included acquiring weather and current data, constructing a regional model of the seabed and shallow sediments, determining design and operational requirements, and addressing problems related to flowlines, umbilicals and multiphase flow.[17]

These joint efforts have been established not with just subsea technology in mind, but to uncover solutions for exploration and production in deep water in general. However, many operators are choosing subsea as their long-term deepwater development concept. By some estimates, 20% of the global capital investments in offshore field developments are in subsea facilities and completions.[18] This percentage is likely to rise, especially as subsea equipment continues to prove reliable, flow-assurance problems are solved and operators gain confidence in subsea practice. —LS

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16. Silverman S and Bru JG: "Taking the Initiative," *Deepwater Technology, Supplement to Petroleum Engineer International* 72, no. 5 (May 1999): 54-56.
17. Silverman and Bru, reference 16.
18. Thomas, reference 6.