

Evolving Subsea Technology Tackles Huge New Risks of Today's Projects

Joel Parshall, JPT Features Editor

As oil and gas development projects tackle some of the world's most remote locations and extreme environments, pushing out into 8,000 ft water depths or beyond and going several hundred miles offshore, innovations in subsea technology will play a vitally important role in enabling the execution of these projects and will form the basis of future, even more-ambitious plans.

Subsea technology comprises wellhead and related production infrastructure placed on the seafloor, rather than on a conventional surface platform, a spar, or a semisubmersible or other floating production facility. Subsea wells and infrastructure are tied back by flowlines, risers, and umbilicals to surface producing facilities that may be directly overhead or many miles away, possibly even onshore.

While deploying subsea technology can be very expensive, as water depths increase, conditions grow harsher, and locations become more remote, the alternative of building a larger, heavier surface facility to hold the well-

heads, pumps, separation equipment, and other infrastructure is often more expensive, sometimes prohibitively.

"There are two things that drive much of the move toward subsea," said David Morgan, Director, Subsea Processing, Cameron. "One is cost, the other is the reservoir. Typically, you must have at least one surface facility for drilling, processing, or storage. But surface facilities are a huge expense, and reservoirs sometimes are very spread out, making it hard to drill from one surface facility. That starts to drive multiple drill centers or the move to subsea development. By minimizing the size and number of surface facilities, you can save your project a lot of money."

On the one hand, when equipment is placed on a surface facility, maintenance and interventions typically are conducted from that facility, and costs are easier to project and control—compared with contracting costs for a rig or vessel to service subsea equipment. On the other hand, space is at a premium on any kind of floating facility, and the need for additional equipment (e.g., separation, water-handling, and compression facilities) as a project matures is difficult to accommodate by retrofitting late in field life. By installing the additional equipment subsea, the need for platform changes can be minimized.

"How effective we are at developing subsea technologies and evolving existing technologies is going to be an indication of how successful we are in recoverable reserves and maintaining our increasing production globally," said Neil Holder, Vice President, Sales and Marketing, Aker Solutions. "More and more companies are looking at stranded gas, offshore oil, and resources in the Arctic with long tieback distances that without subsea technology can't be accessed at all. So it becomes a facilitator."

"The challenges to subsea development posed by deep water and long distance, which we refer to as long-distance delivery management (LDDM), are to install a system that will not fail and that can be maintained," said Tom Choate, Manager, Systems Engineering, Intec Engineering, a company that works with major subsea project developers as a system technology integrator and has led a 2-year joint industry project (JIP) involving many of the major subsea operators and equipment providers. JIP participants have been assessing the state of subsea technology, defining critical needs, and recommending future directions; the project is now in planning for its second phase.

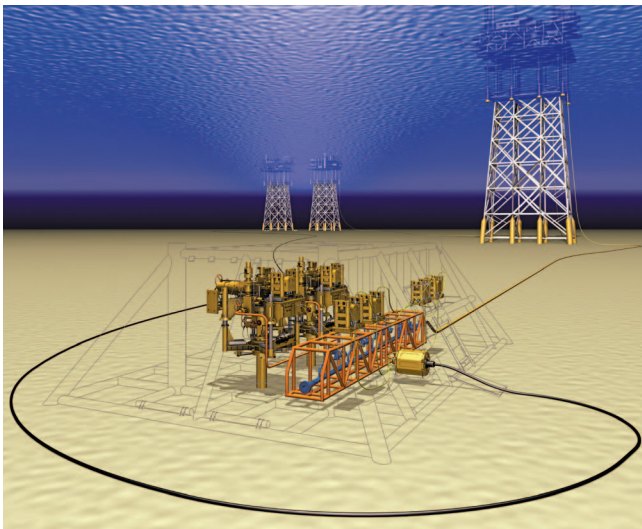


Fig. 1—Configuration of subsea production system to be installed at Total K5F field, offshore The Netherlands, including the world's first all-electric subsea Christmas trees. The project includes a three-well template/manifold, with a two-well initial installation and the option for a third. The all-electric control system is configured for a four-well application. (Image courtesy of Cameron.)

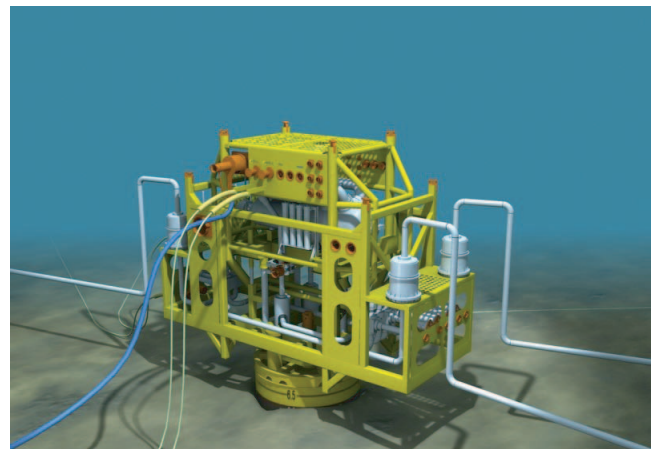
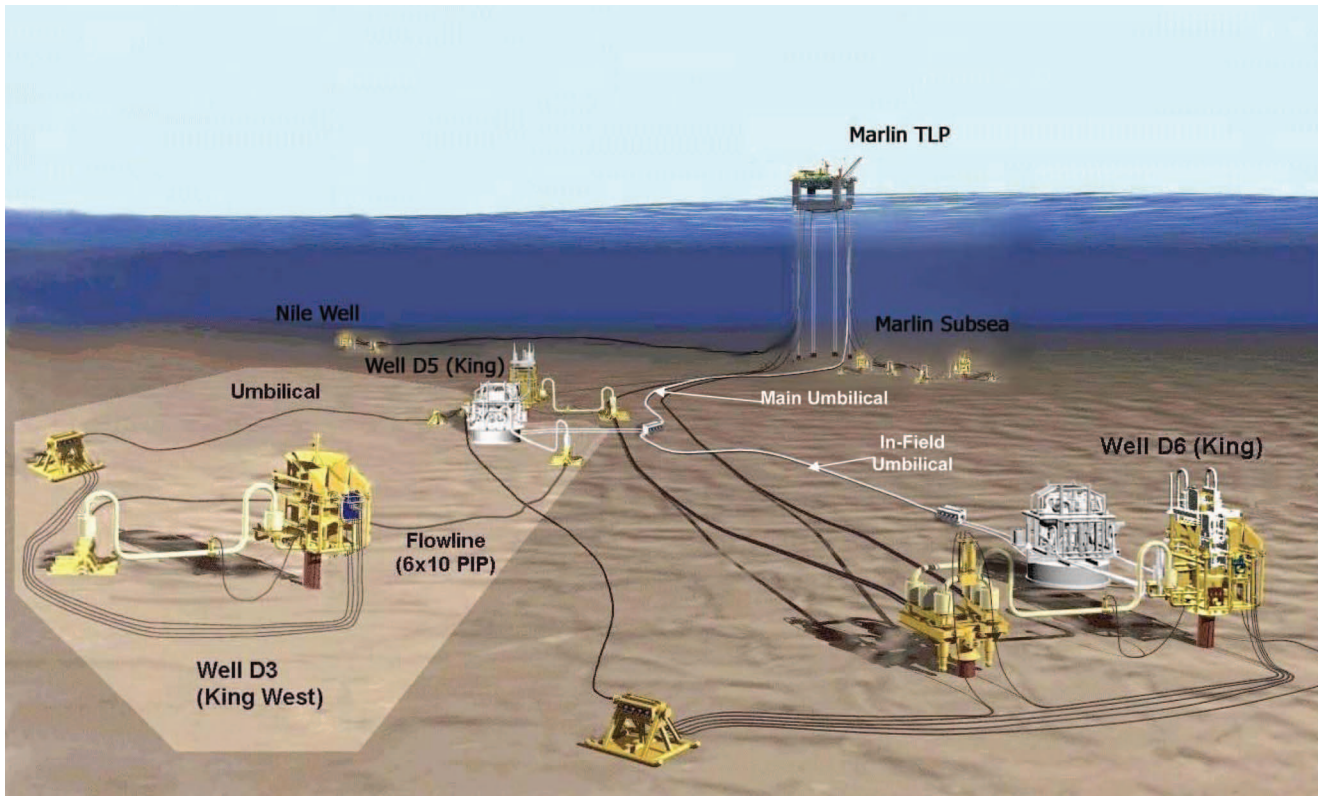


Fig. 2—(clockwise from top) Subsea configuration of the BP King field in the GOM, including addition of two multiphase boosting pumps, is shown. A pump is shown in closeup view and as it is being lowered into the water in 2007. The twin-screw, positive-displacement pumps are expected to increase the field production rate by 20% and total recovery by 7%. The pumps, in 5,600 ft of water, are the world’s deepest to date. Their tieback distance of 18 miles is the world’s longest for pumps. (Images courtesy of Aker Solutions.)

“The LDDM concept,” Choate said, “brings the various issues into a system-based engineering approach to subsea production, and the key to this is subsea processing—a term encompassing separation, pumping, and compression. In addition to that, subsea electrical power transmission and distribution are becoming increasingly important.”

“In some of the deeper waters, there is such a back-pressure from the depth of the water, that you won’t get the oil out of these formations unless you put some sort

of subsea processing with it,” said John Byeseda, Senior Principal Engineer, Subsea Processing, for Cameron’s Petreco Process Systems unit. “For some brownfield applications, where a field starts to make more and more water, for example, you would abandon the reservoir if you weren’t able to install separation technology subsea. You simply wouldn’t have room for that process equipment on the platform.”

Subsea systems “are key to sustaining oil and gas supplies,” said Roald Sirevaag, Chief Engineer, Subsea,

StatoilHydro, which has approximately 450 subsea wells that provide the company with more than half of its production. A subsea production system, consisting of wells, flowlines, umbilicals, and risers, typically will go through an evolution over the life of the field, according to Sirevaag. "The subsea system initially would consist of trees with controls and manifolds but should be configured for separation, boosting, and compression to be phased in, as applicable," he said. "We also believe it will be beneficial, in deep water, to simplify the system by making it all electric, eliminating the hydraulic part of the control system."

All-Electric Tree System

Offshore The Netherlands, Total will soon install the first all-electric subsea Christmas tree at the K5F gas field, slated to begin production later this quarter (**Fig. 1**). The all-electric system, designed and built by Cameron, comprises a manifold with two trees installed, both for production wells, and a slot for a future tree. A fourth satellite may also be added.

The system is powered by direct current (DC) and has no batteries or accumulators. Control commands can be sent in quick succession, with no lag time needed for accumulator charging. Communication with equipment and feedback on subsea conditions are virtually instantaneous. With no hydraulics, there are no fluid-handling and -disposal issues

and no leaks. Although the project is in shallow water and involves no long stepout, the achievement is particularly important because of the potential of all-electric control technology in deepwater applications.

"We have done multiple, side-by-side comparative studies of electric and electro-hydraulic systems, and in every case the all-electric system came out significantly better and more reliable," said John Burdick, Technical Manager, Subsea Electric Systems, Cameron. "Through the use of DC, the system we have designed enables very high voltage to be transmitted over very long distance by means of a coaxial cable, whereas alternating current (AC) requires a much thicker umbilical with a core of three copper cables. We employ a converter, with some patented technology, to transform the power to AC at the wellhead.

"Unlike a hydraulic system, which has to overcome high hydrostatic pressure in deep water, electric motors work just as well at 10,000 ft as they do at sea level. An all-electric system also can provide a good deal of feedback from the valves that is not normally obtainable with a hydraulic system. And over the life of a field, the cost savings from the reduced umbilical size and the elimination of hydraulic infrastructure can be very large."

At present, the only part of the production system still requiring electro-hydraulic controls is the subsurface safety valve (SSSV). Major suppliers are developing an all-electric



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control system, and a commercially available all-electric SSSV is expected by early next year, Burdick said.

Subsea Boosting Milestone

In an important subsea boosting project, BP and Aker Solutions late last year successfully completed the subsea brownfield installation of two twin-screw, positive-displacement multiphase boosting pumps at the Gulf of Mexico (GOM) King field, tied back to the Marlin tension-leg platform (TLP), in 5,600 ft of water (Fig. 2). With 1 MW each of power-consumption capacity, the pumps are expected to increase the field production rate by an average of 20% and total recovery by approximately 7%, according to BP. The two pumps are the world's deepest to date, and their 18-mile tieback distance is also a world record for pump installations.

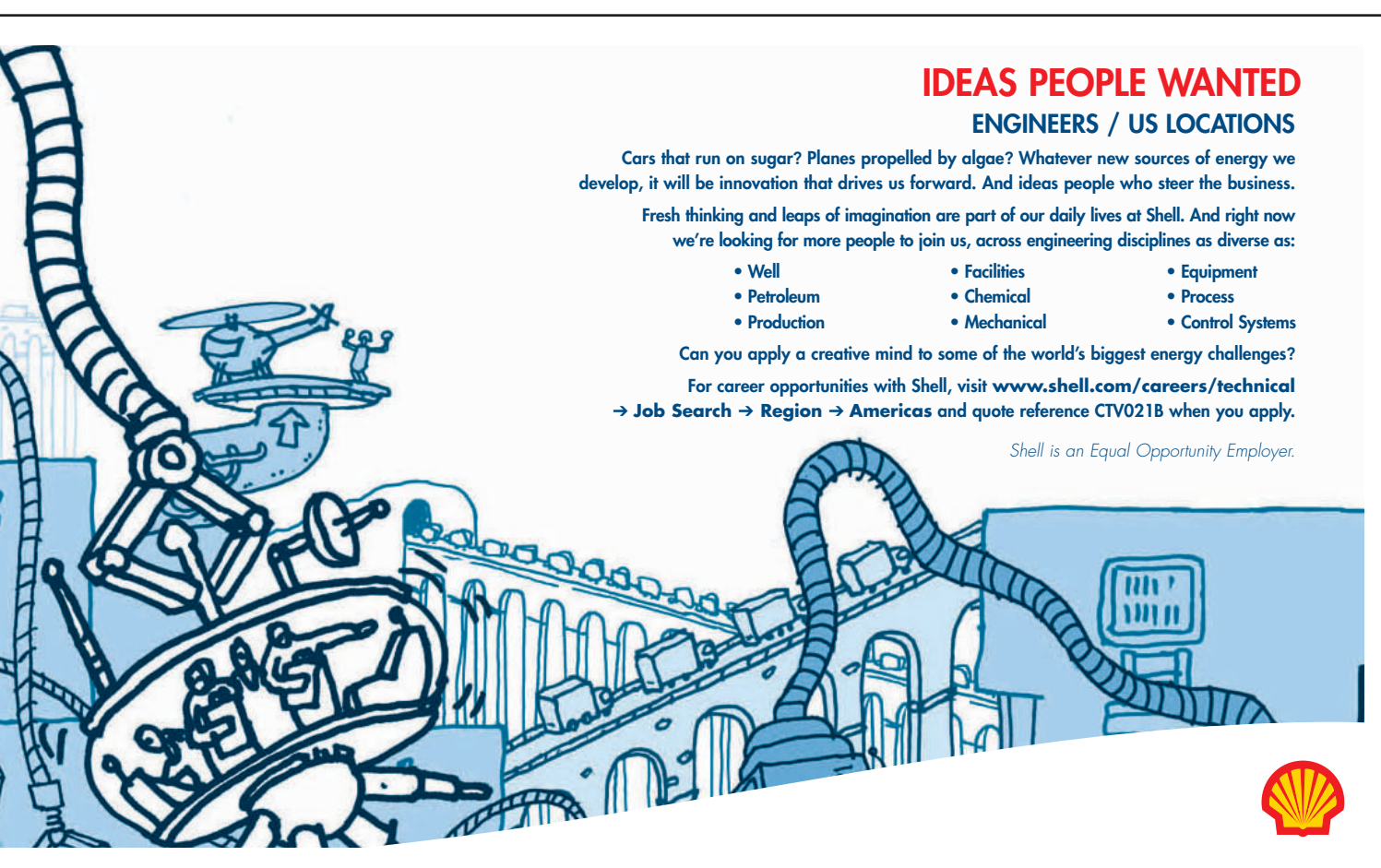
Long-distance high-voltage distribution technology enables the pumps to be controlled at different speeds by means of advanced variable-speed drives (VSDs) on the host. The umbilical linking the pumps to the Marlin TLP includes delivery lines for hydraulic fluids, chemicals, and lubricant, and it contains valve-communication fiberoptics, thus reducing total umbilical weight and cost.

"We have worked on subsea boosting/pumping systems since the late 1980s, and our first multiphase subsea pumps of this type were installed in December 2005 for Canadian

Natural Resources at the Lyell field in Scotland," Holder said. "By the time of the King project, we advanced the technology to enable a diverless installation." The pumps were installed by means of remotely operated vehicle (ROV) deployed from a service vessel. Each pump sits within a manifold and can be detached and retrieved the same way it was installed.

Facilitating the multiphase pump installations was the use of a multiple-application reinjection system. This is a technology specially designed and provided by DES, a subsidiary of Cameron. The technology comprises a universal work platform that is connected to the wellhead and enables pumping or any other process to be retrofitted without the need to break into and potentially rearrange flowlines. The work-platform installation and related flow-removal, process work, and flow reinjection, by means of the dual-annulus system applied by this technology, were performed by a light intervention rig assisted by ROV. Because water does not enter any flowlines when this technology is applied, costly downtime for flowline dewatering—along with deferral of production—was eliminated.

At the Tyrihans field in the Norwegian Sea, StatoilHydro and Aker Solutions plan to install two seafloor centrifugal pumps employing Aker's newly developed raw-seawater-injection technology for pressure support and oil-zone stabilization (Fig. 3). Together, the pumps are expected to



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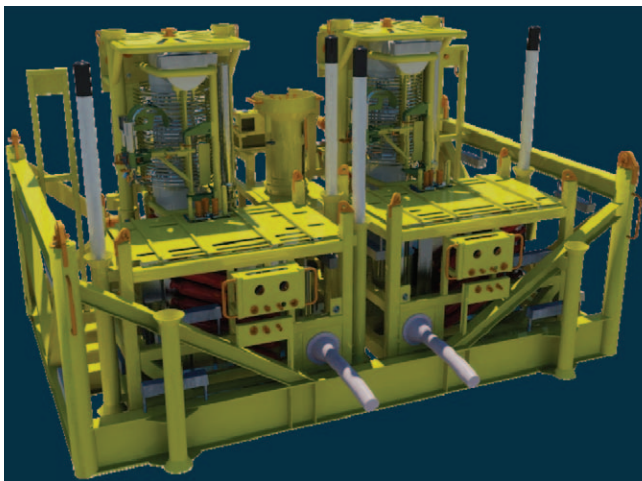


Fig. 3—A subsea raw-seawater injection system to be installed by StatoilHydro at the Tyrihans field in the Norwegian Sea is shown. Two seafloor centrifugal pumps, using newly developed raw-seawater injection technology, will be installed. The pumps, to be used for pressure support and oil-zone stabilization, are expected to boost field production by 10%. Tyrihans will be a subsea tieback to the Kristin platform, with the pump tieback distances being approximately 25 miles each. Production startup is slated for mid-2009. (Image courtesy of Aker Solutions.)

increase field production by approximately 10%, with each pump being capable of consuming up to 2.7 MW of power and generating up to 4,300 psi of injection pressure.

One of the largest projects ever on the Norwegian continental shelf, Tyrihans is being developed as a subsea tieback to the Kristin platform and is slated to begin production in mid-2009. The injection pumps will have a tieback distance of almost 25 miles, nearly 40% longer than the King field tiebacks. The power system will incorporate subsea transformers, with power up to 22 KV generated from the platform and transformed on the seafloor to a maximum 6.6 KV per pump.

“This is an evolution in power distribution, and the next step,” Holder said. “A key enabler in supplying high-voltage power to deepwater power consumers, such as in the GOM, is the use of carbon-fiber rods in the dynamic section of the umbilical, a technology we pioneered on the [Anadarko-operated] Independence Hub gas project last year. This material does not add any weight and yet has tremendous strength. This is critical because adding high-voltage power cables to an umbilical adds substantial weight, which can only be supported by extensive armoring that adds more weight, or by internally-integrated carbon fiber rods, which are neutrally buoyant and do not add weight.

“This technology, coupled with the potential for transmitting power at higher and higher voltages through the use of subsea transformers, facilitates more efficient power transmission and a robust but lighter umbilical that can be installed without weight or size constraints.”

Adding Separation

The concept of performing separation at the seabed, rather than the surface, has long been attractive and was realized

for the first time on a commercial scale at StatoilHydro’s Tordis field in the North Sea last year. The three-phase Tordis separation and boosting system, designed by FMC and installed at a seabed depth of 650 ft., performs gas/oil and oil/water separation, sand removal, reinjection, and multiphase boosting to the Gullfaks C host facility seven miles away. Gas is separated by means of an inlet cyclone and remixed later with the oil, before boosting. The temporary gas removal enables the use of a smaller separator vessel and facilitates the oil/water separation. The separated water and sand are injected into a disposal reservoir in a closed-loop system. In addition to the environmental benefits and the energy savings achieved by not having to transport the water to the host, the project is expected to improve Tordis field recovery to 55%, from 49%, because of the reduced backpressure exerted toward the producing reservoir.

Other, considerably deeper projects involving two-phase subsea separation and boosting also are under development. “Right now, what we are seeing in particular is gas/liquid separation and liquid boosting, with the gas free-flowing back to the host,” said Chris Shaw, Manager, Field Development and Technical Sales, Subsea Systems, FMC. “The [Total-operated] Pazflor project in Angola and the [Shell-operated] BC 10 and Perdido projects in Brazil and in the GOM, are three projects in which we are involved that do exactly that.”

The deepest of these projects, all three of which are slated to come on stream early next decade, is Perdido. This field will produce by artificial lift (AL) from a frontier reservoir in the Alaminos Canyon area, approximately 200 miles south of Freeport, Texas, in waters more than 8,000 ft deep. Peak production is expected to reach 130,000 BOE/D.

“This is a new play, so there is no production analog,” said G.T. Ju, Senior Staff Subsea Engineer, Subsea Projects, Shell, who has been involved with Perdido for more than 5 years. “Even after a few appraisal wells, we still had a number of uncertainties about how the reservoir would perform. In addition to the reservoir uncertainty, well counts and rig-market conditions were the two major risks that the project team had to mitigate as we were planning the Perdido development.”

Deliverability was a big concern because, unlike many deepwater GOM fields, Perdido has a low-pressure/low-temperature reservoir. To sustain production over the field life would require an AL system. A spar was viewed as the preferred producing facility because of the need for direct vertical access (DVA) to wells. However, developing the field with dry trees, as a means of controlling drilling, completion, and future intervention costs, would have required a very large spar at huge cost in order to accommodate more than 20 DVA wells with production risers. Instead, Shell innovatively designed a spar facility to be completed with wet trees on the seafloor—the industry’s first spar to do so.

The Perdido plan encompasses 22 subsea DVA wells and 11 subsea offset wells, with two large seabed manifolds that each receive the flows from half of the wells. Commingled production will flow from the manifolds to five top-tension production risers equipped with a caisson/electrical-submersible pump (ESP) system for AL (Fig. 4). All wells

can be produced through alternative riser paths, to prevent bottlenecks in case a riser is out of operation. A sixth, high-pressure drilling/completion riser will enable DVA from the spar to all wells for drilling, completion, and intervention of subsea DVA wells at any time.

The Perdido caisson/ESPs will employ gas/liquid cylindrical-cyclonic separation. Although not a new technology, this will be its first subsea application. The ESP is deployed inside a 350-ft caisson set vertically into the seabed. Flows entering the caisson will undergo gas/liquid two-phase separation. The separated gas will flow to surface under its own pressure through the production-tubing/riser annulus, while the liquid descends to the bottom of the 35-in.-diameter caisson and then is pumped to surface through the tubing (Fig. 5).

“By taking the gas out, only the liquid has to be pumped, and this makes the pumping much more efficient,” Ju said. “Removing the gas also allows heat to be retained in the liquid, which keeps its temperature high enough to prevent hydrate formation that could restrict or stop production during steady-state conditions.”

A 27/8-in. conduit inside the production tubing enables oil to be pumped down from the topside through the caisson system during well startups to ensure that the huge, 1,500-hp ESP motors do not overheat because of the initially low rate of produced liquids in the system.

Before sanctioning the project, Shell successfully pilot tested for almost a year, using a flow loop built at the company’s Gasmer research facility near Houston to replicate the Perdido

AL system. A full range of control parameters and operating conditions, including those in the caissons and ESPs, was tested, and extensive operator training was provided.

The majority of Perdido’s subsea equipment will be positioned within a 350-ft-diameter circle directly underneath the Spar, with six well-bay slots, translating into a spar with a much smaller footprint than a comparable dry-tree facility and resulting in commensurate fabrication—and installation—cost savings. Also reducing the footprint will be the industry’s first use of a surface blowout preventer (BOP) to drill and complete subsea wells, as opposed to using a much larger subsea BOP equipped with a large-diameter, multi-bore riser.

“The wet-tree DVA design we have chosen—with direct vertical access both to subsea wells and to caisson/ESP equipment—is critical to mitigating our long-term risk on Perdido,” Ju said. “Because with rotating equipment on the seafloor, the question is not *whether* it is going to fail, but rather *when and how often*?”

Boosting technology in general is likely to be critical to developing the huge recent discoveries in the deepwater GOM Lower Tertiary trend, according to FMC’s Shaw. “Simply because they are so far away from infrastructure, we are going to be looking at long tiebacks,” he said. “They are complex reservoirs, not terribly permeable, and with low gas/oil ratios. Production will be difficult. Even at 30,000-ft well depths, wells are only normally pressured. There is still 8,000 ft of water above the seabed, and the production has to travel that distance.”

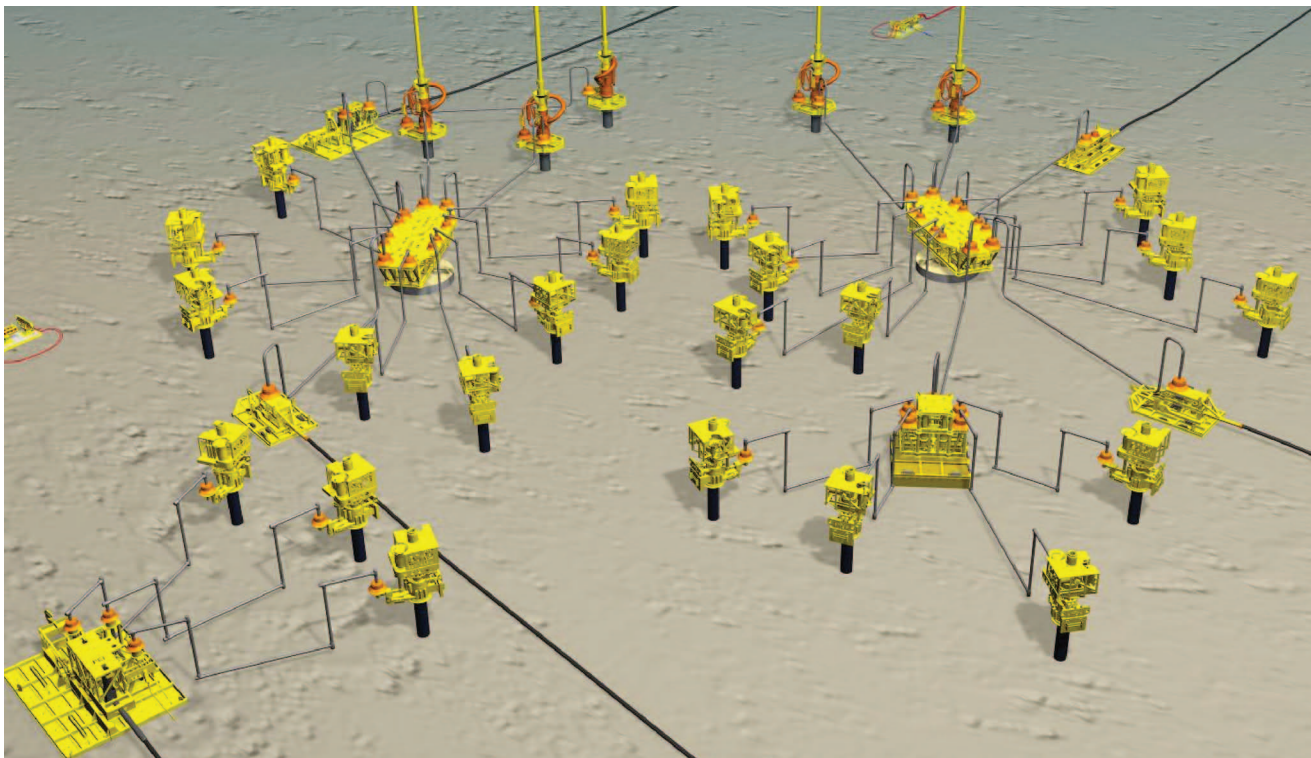


Fig. 4—Planned configuration of the Shell Perdido field in the GOM is shown. The field will be developed in waters more than 8,000 ft deep by means of a wet-tree DVA spar, the industry’s first. The flowstream will undergo GLCC separation, with gas freeflowing to the surface and liquids boosted by five caisson/ESPs, designed and built by FMC. Production is expected to begin early next decade. (Image courtesy of Shell.)

Rigless ESP Retrieval

Efficient pump retrieval for reconfiguration, maintenance, or replacement will be essential to the progress of ESP technology in deepwater projects. ESPs to be installed by Petrobras, with FMC, at the GOM Cascade and Chinook fields in 8,800 ft of water will have horizontal-caisson configurations and will be placed on the seafloor inside of cages. Retrieval and reinstallation will take place by means of a service boat deploying an ROV, with the cage and pump handled as a unit.

While seabed pumping units that serve multiple wells are an effective deepwater boosting solution, Shaw predicts that eventually, ESPs will be placed inside individual deepwater wells, as has been done on subsea wells at shallower depths. "For just a 20,000-ft well, as an example, you are looking at 9,000 psi in head pressure alone to overcome simply to reach the seabed," he said. "If you could put a typical ESP in the well, providing a drawdown of 4,000 psi, that lift might enable an extra 10% recovery of total oil in place. So the benefit would be just huge."

However, the challenge is to develop an economic means of installing and retrieving in-well pumps at great water depths. "A rigless process will be essential," Shaw said. "What is needed is further technology development that will permit use of light service vessels, and these would need to be vessels of opportunity that could be contracted on a spot basis." Wells to receive ESPs would likely benefit from being completed with in-well flow-control barriers to enable live well access effectively.

Assuming that this technology is developed—which could take 5 to 10 years—Shaw believes that plays like the Lower Tertiary eventually will employ a two-stage AL solution. As natural well flow diminishes, it will be augmented by means of seabed pumping systems. Later, this will give way to the deployment of ESPs in wells, with subsea boosting at the seabed. A different approach might be the seabed installation of subsea gas/liquid separation and liquid boosting. This would facilitate the use of gas-lift in the wells, as an alternative to ESPs.

Subsea Compression

Subsea gas compression is another process on the technology frontier, although somewhat farther in the future than the gas/liquid separation and boosting programs now under development. At the massive Ormen Lange subsea field complex in the Norwegian Sea, subsea compression is viewed as a potential solution for sustaining gas and condensate production in the face of eventual reservoir-pressure declines.

StatoilHydro, on behalf of license operator Shell, has contracted with Aker Solutions to build a full-sized pilot, 12.5-MW compressor train to undergo a 2-year test in underwater conditions. The goal is to qualify the technology for Ormen Lange by 2012. The pilot is equivalent to one of four trains planned for the complete subsea compression station, which is seen as an alternative to an offshore platform facility. The compression station, all electrically controlled, would be placed at 2,950-ft depth and tied back 77 miles to shore. All electric power distribution will be subsea; only the electricity source will be onshore. The compressor drive system (high-speed motor) is being qualified to run on monoethylene glycol—already being

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*Neil Holder
Vice President, Sales and Marketing
Aker Solutions*

used for production-system flow assurance—to avoid the need for lengthy fuel-export lines, and the motors will be cooled by process gas before compression, so no lubricant circuit is needed.

"The amount of trickle-down technology that will come out of this project for other subsea installations is vast," Holder said. "Ormen Lange is a glimpse of how things are likely to happen on the projects of the future. High voltage is taken from the shoreline; all electricity distribution, including circuit breakers, VSDs, and uninterruptible power supplies, is placed subsea; controls are all electric/fiber-optics, with no hydraulics; and the total system is simplified to minimize the need for tiebacks.

"These are the things that we as an industry start to talk about in looking at future Arctic developments or longer tiebacks, such as the massive [Gazprom-operated] Shtokman gas project more than 300 miles offshore northern Russia."

At StatoilHydro's Åsgard field in the Norwegian Sea, FMC has been awarded several qualification projects that are part of a major program, run by the operator, to develop and qualify all critical components for a subsea gas-compression system within the field. The largest of these projects are linked to the provision of subsea gas-compression control systems.

FMC's scope of supply includes the qualification of critical control-system components, including a subsea active magnetic-bearing-control system for the compressor (to be performed in cooperation with Waukesha Bearings) and a subsea antisurge actuator and valve. Also included is the addition of antisurge control features to existing FMC control systems, and the development and implementation of new sensor technologies vital to the subsea gas-compression application. A control-system test is also part of the contracted work. FMC is additionally involved in qualifying the gas-cooler and the subsea-scrubber internals, this last project through the company's CDS Engineering subsidiary in The Netherlands.

High-Integrity Pressure Protection

Subsea projects, particularly in deep water, increasingly will contend with high-pressure environments during the initial years of reservoir production. These pressure regimes can have a tremendous impact on facility design and in some cases may even make development uneconomic, without an alternative to designing the entire system to accommodate the high-pressure window. On subsea projects, furthermore, prohibition of oceanic discharges prevents the use of relief valves, which provide the final backup on topside pressure-control systems.

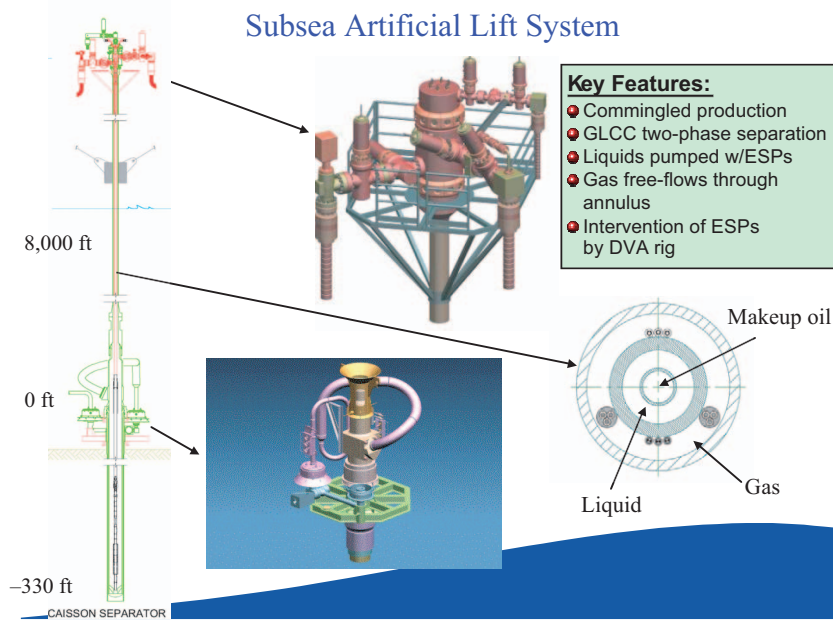


Fig. 5—A closeup view of the artificial lift system to be installed at the Shell Perdido field is shown (Image courtesy of Shell.)

A subsea solution to the pressure problem, now seeing growing use, is the high-integrity pressure-protection system (HIPPS). HIPPS units, placed on the seafloor between the pressure source and the infrastructure requiring protection, incorporate highly reliable valves in a stringently qualified, fully redundant pressure-control system, with sophisticated sensor technology oriented upstream and downstream of the unit. HIPPS technology has been used in Europe. The U.S. Minerals Management Service has yet to establish generalized permitting but will review individual applications to use HIPPS technology on a case-by-case basis.

“We can see HIPPS systems being used for several different things,” said Byeseda. “For some deepwater projects, with 15 or more pressure shut-ins, you wouldn’t want to build a 15,000- or 20,000-psi pipeline all the way to the surface. It costs too much, and when you come up the deep riser, it is too heavy. On floating production facilities, there are buoyancy issues. In other cases, HIPPS technology may be critical to the economic evaluation of [export] pipelines.”

In another type of application, Cameron is supplying a HIPPS system to Nexus Energy for the Longtom subsea project off Australia. The project, slated to come on stream later this year, entails the tie-in of a 5,000-psi field to an existing 3,000-psi pipeline. While the cost of building a separate 5,000-psi line could not be justified, installing a HIPPS system was found to be an economic means to prevent pipeline overpressure.

Cameron has qualified its HIPPS technology up to 15,000 psi and the next evolution of the system will be to develop an all-electric unit, eliminating the existing hydraulics and reducing umbilical size, Morgan said.

Other Emerging-Technology Initiatives

As tiebacks become longer and water depths greater, with lower temperatures affecting the operating environment, flow-assur-

ance issues—especially the threat of gas hydrates—become even more challenging. One technology generating increasing interest among operators is electrical heating of subsea flowlines. While there have been a few applications in the North Sea and in the GOM, so far these heating systems have been installed for use during flow startup and shutdown operations, during tail-end production, or, under some conditions, for the mitigation of hydrates when they occur. The technology has yet to be used for continuous hydrate prevention.

“It is a question of the cost of supplying the electricity and assuring reliability vs. the cost of having dual flowlines and chemical-injection programs—as well as the cost of other measures such as blowdown, various heat-circulation techniques, and perhaps even installing a local host,” said Uri Nooteboom, Vice President, Offshore Field Development, Intec Engineering. “If we could get the process right, through improvements in subsea power-distribution technology, continuous electric flowline heating could simplify system infrastructure and reduce operating costs.”

Reducing the scale of subsea systems is an objective that holds promise for greater flexibility and cost savings in field development, especially when drilling smaller targets over the life of a field. A StatoilHydro compact-system initiative called MMX—Roman numeral for 2010—is developing system configurations and interfaces that will enable a more slender well design with a smaller-diameter marine riser.

Another Statoil initiative, high-differential-pressure boosting, has the goal of increasing the subsea pump rating to 150-bar differential pressure from current levels in the range of 50.

In all, multifaceted advancements in subsea technology are enabling the oil and gas industry to take on and manage increasing levels of project risk and sustain the development of hydrocarbon resources to meet an expanding and diversifying global demand for energy.

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