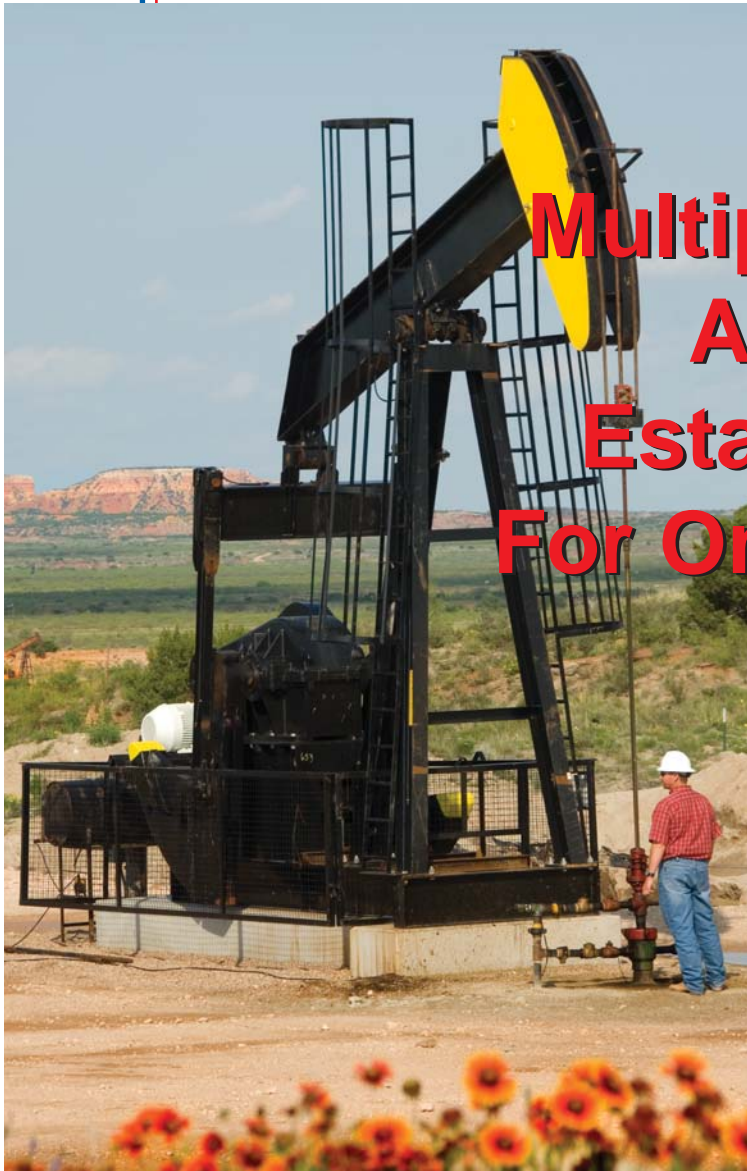


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## Artificial Lift Technology



**Multiphase Field  
Applications  
Establish Value  
For Onshore And  
Offshore  
Production**

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# Projects Proving Merits Of Multiphase

By Kari Johnson  
Special Correspondent

From regular and heavy oil production operations onshore to deepwater field developments offshore, multiphase pump and meter technology is proving its value in a growing list of real-world applications.

One example—in this case, a “brown field” topside application—is the Ship Shoal 150C platform in the Gulf of Mexico, where multiphase pumping has allowed Century Exploration, New Orleans to economically increase production rates from a shallow-water Shelf field that was among the first blocks leased at the inaugural U.S. Minerals Management Service Lease Sale 01 held in 1954. Faced with production inhibited by back pressure, the company had to find a way to reduce pressure to boost production without the expense of laying larger-diameter pipe, according to Chief Operating Officer Michael J. Willis.

Century Exploration, New Orleans acquired the Ship Shoal 150C platform in late 2000 and subsequently drilled four new wells: the Nos. C4, C5, C6 and C7 wells. The problem, Willis says, is that system pressure on the 150C platform was 220-250 psi, which placed significant back pressure on the four wells and inhibited production from a reservoir in which pressures had been depleted by a half century of drilling and development activity.

“If we could lower system pressure to approximately 50 psi, we could increase production rates, improve recoverability and reduce the burden on the gas lift production system,” says Willis. “But we realized that we would have to achieve this using equipment with a minimal footprint, because space was very limited on the platform.”

With the help of a contractor, he says Century Exploration, New Orleans selected a multiphase pump skid that would provide suction pressure of 50 psi and a discharge pressure of 300 psi. The pump selected, says Willis, was a Leistritz twin-screw design with a gas engine. To accommodate the pump skid, a deck extension was added to the platform. The total estimated cost, including the deck extension and installation, was \$1.47 million, he reports.

The pump was installed in late 2006.

“We had some initial problems related to thermal coupling that delayed ultimate production, but once the pump was fully operational, production increased by about 420 barrels of oil a day for all four wells,” Willis states.

Averaged monthly production from the wells climbed from 19,440 barrels in 2006 to 31,877 in 2007—a 40-percent increase, Willis reports. “The incremental increase over 12 months was 150,000 barrels of oil, and payout on the pump/deck extension was about four months, taking into account the ultimate investment and incremental revenues,” he remarks. “The pump is running well and we have experienced minimal downtime. After this experience at the Ship Shoal 150C platform, I would have no hesitation using multiphase technology again in a similar situation.”

## Expanding Applications

Driven by those kinds of results in real-world applications, multiphase pumping and metering installations continue to expand in step with the technology’s evolution. Handling and measuring complex mixes of water, oil and gas, multiphase technology boasts a wide range of benefits to production, capital expenses and operations, points out Michael Amburgey, a mechanical engineer at Moyno Inc. in Springfield, Oh.

The key advantage of multiphase pumps of all types is their ability to relieve back pressure, Amburgey holds. “As fields mature, bottom-hole (reservoir) pressure typically decreases and the well’s ability to lift the liquid is inhibited. Depending on the mix of liquids and gas, and the nature of the reservoir itself,

some wells cannot flow at all without artificial lift to provide flowline back pressure relief,” he says.

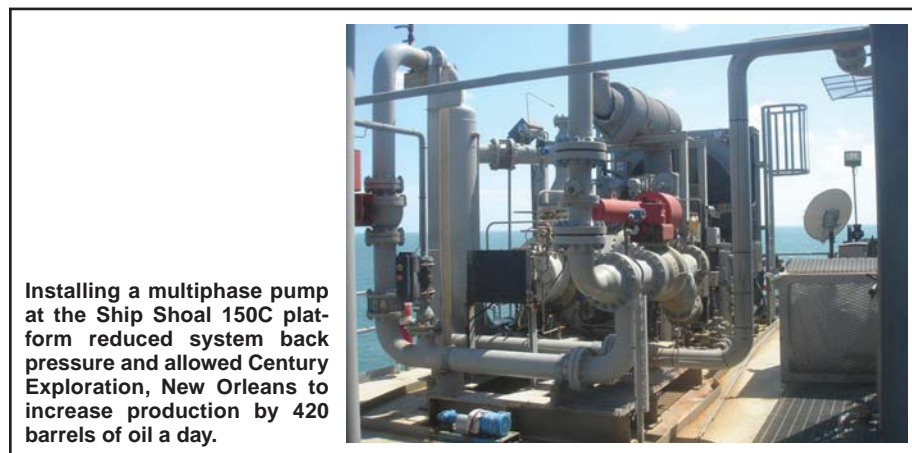
Multiphase pumps relieve the pressure on the suction side while maintaining much higher pressure on the discharge side, explains Amburgey. “Variable speed drives help enable the pumps to optimize the flow rate and inlet pressure. As a result, production rates increase and production levels can be sustained for longer periods, providing valuable flow assurance,” he comments.

Pumps can be controlled either locally or remotely, and can include various parameters to manage heat and other conditions. This control can be combined at the manifold with controls for valves, meters and other elements, manufacturers note.

Multiphase pumps first appeared in the 1990s, handling two or three phases plus entrained solid or sand loading. Various designs have emerged for moving the liquid and gas through the pump, including progressing cavity, twin screw and heli-co-axial. Products based on these designs handle high gas fractions, small to very large flow volumes, high external pressures (such as those experienced in deepwater), and can be used on per well, per manifold or in series and/or parallel configurations for additional head and flow, according to Peter Batho, North America business development manager for pumping systems at Framo Engineering.

## New Capacities, Capabilities

With demand for all sizes of multiphase pumps continuing to grow in producing regions around the globe, manufacturers



Installing a multiphase pump at the Ship Shoal 150C platform reduced system back pressure and allowed Century Exploration, New Orleans to increase production by 420 barrels of oil a day.



are expanding pumping capacities and introducing new technical capabilities, reports Tim Mabes, general manager of Bornemann Pumps.

"Pumps can already handle 400,000 barrels of liquid equivalent a day, and they will be able to handle 1 million bbl/d of combined oil, water and gas flow in the near future. These large systems will be used in fields with multiple high gas-fraction oil producers," he says. "Demand for small pumps is rising as well. There are 90,000 marginal wells in the United States alone. Many of them produce very small volumes, but a small pump that ties several marginal wells together in a single manifold can be economical."

The industry's wholesale move into gas shales and tight gas sands also may spur demand for multiphase pump technology eventually. "These plays are using horizontal drilling techniques. Long horizontal laterals are susceptible to back pressure issues that can be mitigated by multiphase pumps," Mabes goes on.

A relatively new technology is the degressive screw used in some twin screw assemblies. The degressive screw acts like a compressor, details Mabes. "As the liquid and gas move from suction to discharge, the distance between the flanges of the screws narrows, so higher gas fractions (90-96 percent) can be handled. This design provides more efficiency and dampens vibrations resulting from slugging," Mabes remarks.

Because of the central role of the pump in production, reliability is extremely important. Two factors that can threaten reliability are heat and abrasion. As pressure and gas volume change, temperature rises. Seals can fail if they overheat, so pumps are designed to use liquid for cooling and specialty heat-resistant materials, explains Sven Olson, president of Leistritz Corp. (U.S.).

"During the first hours or days of production using the multiphase pump, the gas can crowd out the liquid, risking seal failure. Special procedures or system designs help mitigate this risk. Abrasion from sand also can lead to problems, so pumps are outfitted with hardened materials," Olson says.

"Our specialization is subsea system supply, and logically, the ultradeepwater frontier is a strong focus area," states Batho. "By mid-2010, pumping systems with 15,000-psi process pressure and 10,000-foot water depth capability will be a rigorously qualified reality."

The pump assembly is one of the elements within a full system scope of supply, notes Batho. He says a Framo core philosophy is to deliver offshore and subsea boosting systems, in particular, as part of a thoroughly tested complete system. "There is enormous value in stacking, starting and boosting a multiphase mixture in a best-in-class 'wet dock' controlled testing environment," Batho comments. "No one wants last-minute surprises on the installation vessel."

Another important element of maintainability is modularity, says Michael Smith, business development manager for multiphase meters at Framo Engineering. "Subsea installations, in particular, demand that individual components can be retrieved for maintenance. This reduces the weight a repair ship must be rated to lift, and increases the likelihood that the system can be returned to service quickly through a component exchange by a smaller vessel. Both pump and meter systems are designed in this manner," Smith points out.

### Multiphase Metering

The key applications for multiphase meters are reservoir management, allocation and production management, Smith goes on. "Meters assist with reservoir management by identifying changes in flow and the mix of liquids and gas. When individual wells are tested, reservoir engineers get a better understanding of changes in the overall reservoir and adjust accordingly," he comments. "The more often individual wells are tested, the clearer it becomes how to allocate production, thus continuous measurement using multiphase meters results in the best possible allocation scenario. Analyzing trends in flow and mix can lead to a better overall production plan for the field. In addition, the integration of multiphase meters can provide monitoring and control functionality within pumping systems."

Multiphase meters can be configured to measure the flow rates of oil, gas and water from individual wells or groups of wells. The oil, gas and water fractions are typically determined by electrical impedance or gamma ray density, or a combination of the two, observes Kenneth Olsvik, senior vice president of measurement for Roxar. One new technology now measures velocities as a function of its 4-D location, intending to account for variance caused by composition, turbulence, viscosity and other effects, Olsvik adds.

Topside meter components can be switched for maintenance or when production volume changes. If production flow changes over time, elements can be replaced to expand or reduce the operating range of the meter. This is particularly useful for topside applications where the footprint on the platform cannot easily change, and also significantly reduces the cost of replacing the existing meter with a smaller or larger one.

Hardened materials are used in meters as in pumps to protect from sand. Sand detectors can be added to multiphase meters to measure the presence of sand so that preventive measures can be taken, Olsvik notes.

Meters are generally placed on the wellhead, retrievable choke bridge, jumper or manifold. For best results, Smith says multiphase flowmeters must have accurate fluid properties determined at meter conditions. "Regular sampling at the meter is the ideal if fluid properties are expected to change significantly over the life of the field, so that the meter can remain accurate in changing conditions. This is especially challenging in subsea applications, where accurate sampling means collection at depth and under pressure," Smith continues. "One technique is already in use in the North Sea and offshore West Africa with 10 operational subsea sampler units and an additional 13 on order. Additionally, several operators are working within the U.S. government-funded Research Partnership to Secure Energy for America program to identify and develop additional practical and reliable methods to retrieve a subsea sample in the deepwater Gulf of Mexico.

"The operators involved in the RPSEA program are pursuing this for the stated purpose of maintaining multiphase measurement accuracy over the life of their fields," Smith goes on. "This is not technology-specific, because all meters require some inputs, and if those inputs vary excessively, the meters need to be updated. The need for sampling is determined by the reservoir characteristics, the production methods used for that particular field and operator experience. Examples where sampling may be indicated include wells producing from various zones with differing fluids, wells with injected water of different composition from produced water that result in density or conductivity differences, and reservoirs in operating areas where there is uncertainty regarding the produced fluids composition over time because of





stratification or other issues.”

However, Olsvik says frequent resampling is not necessarily a requirement, noting that field applications have demonstrated that changing fluid properties generally do not significantly impact the accuracy of Roxar’s multiphase meters. “Our experience from more than 900 meters in use is that such properties are small over the lifetime of the reservoir, although occasionally there may be extreme cases,” he comments.

Given that 60 percent or more of all wells drilled have multiphase flow, according to Amburgey, demand for multiphase pumps and meters will increase only as the technology demonstrates its value in a range of applications.

One future growth area is high-pressure/high-temperature applications, and Smith says a new generation of meters is being engineered specifically for the demands of HP/HT wells. “As oil and gas companies continue to expand their deep- and ultradeepwater programs, HP/HT service will become a requirement. Expected pressure and temperature tolerances are 15,000 psi and 400 degrees Fahrenheit in water depths of 3,500 meters (11,500 feet),” Smith remarks. “Combined with subsea pumps, HP/HT multiphase meters will provide better understanding and production control of the reservoir than ever before.”

## Onshore Pump Applications

Multiphase pumps also are being deployed in a myriad of land-based applications. Canadian operators with heavy oil production were among the earliest adopters of multiphase pumps. In fact, Mapes points out that two Canadian independents, Imperial Oil and Canadian Natural Resources Ltd., remain the largest users of multiphase technology in North America.

Multiphase pumping is often used in conjunction with artificial lift systems such as pumpjacks and enhanced recovery operations such as cyclic steam flooding, Amburgey says. By reducing the back pressure, the pump is able to increase production. At the same time, it lessens the load on downhole pumps and surface production equipment, reducing failures and workovers, he notes.

Because multiphase pumps handle all the liquid and gas flowing from the well bore, Amburgey says there is no need for traditional wellhead separation of water and gas, helping cut down infrastructure

and capital costs. “Operating costs have also gone down through greater pump efficiency,” he adds. “For instance, Tundra Oil & Gas was able to direct flows to a central battery from multiple low-producing wells, making an otherwise uneconomical operation practical. Avoiding new surface facilities also avoids lengthy permitting processes. One company saved two years in permitting time by using a multiphase pump in place of a new separator.”

Water knockout at the wellhead is sometimes included as part of a multiphase production system, Amburgey goes on. A prime example is waterflood operations, where EnCana Corp. and other operators are using water knockout at the wellhead to reduce water handling requirements at central facilities, he notes. “A waterflood may pump out 70 percent water mixed with oil and gas. Operators do not want to pump all that water to the central facility, so they knock out some of the water at the wellhead, leaving enough to make the mix easily transportable. The water is then reinjected,” Amburgey details.

Another application is in reducing annulus gas pressure and boosting it to overcome flowline pressure, according to Olson. “Multiphase pumps can be used to draw down casing gas pressure, allowing increased inflow of production liquids. This often requires only a small pump,” he says, noting that Talisman Energy is using this strategy successfully in Canada. “No separate gas gathering system is required and no flaring is needed. These pumps also sometimes compete with compressors for dewatering wet gas. The compressor, however, requires that water is removed and dumped into a gathering

line or water tank.”

Multiphase pumps also are proving useful in avoiding hydrate formation, Olson goes on. “In many producing areas, surface flowlines can freeze in the winter. Multiphase pumps can be used to draw down the pressure below the hydrate formation pressure,” he explains. “In one application, multiphase pumping is allowing Devon Energy Corp. to produce year round and avoid the cost of additives that would be needed to dissolve hydrates.”

In some cases, economics favor deploying multiple smaller pumps rather than a single large pump. For example, Amburgey says EnCana is using four small pumps in parallel to handle flows from a 20-well pad. “In this application, multiple small pumps were more economical than one larger pump,” he holds.

Other examples of multiphase installations around the world include Aera Energy LLC in California, which according to Olson, has three pumps handling 1,000 producing wells. “These are low-volume, heavy oil wells, produced with the combination of steam flooding and multiphase pumps. This approach meant considerable facility reductions, which saves both capital and operating expenses,” he says.

In Chad, ExxonMobil has 15 pumps serving more than 120 wells in three producing fields, according to Olson. All of the production is handled by one central process facility, he says, with no flaring and no water knockout in the field.

In Algeria, Amburgey reports that multiphase pumps were used to increase flowline pressure to get oil to a central battery, with all pump data monitored from a central control office. “Gas-locked



**Aera Energy has three multiphase pumps handling 1,000 wells producing heavy oil using a combination of steam flooding and multiphase pumping at its Belridge Producing Complex in California.**



In Algeria, multiphase pumps are being used to produce gas-locked oil wells and optimize flowline pressure to get oil to a central battery, with all pump data monitored from a central control office.

oil wells are now producing, and flaring has been eliminated, increasing sales gas and reducing emissions,” he comments.

The deserts of the Middle East have been another area where Framo multiphase pumps and meter systems have been combined to provide high-rate, long-tieback boosting systems in a harsh, remote and unmanned environment, according to Batho.

## Topside Pump Applications

Multiphase pumps can bring immediate value-adding benefits to topside platform applications, where the need to lift liquid and gas to the surface from platform and satellite wells increases the likelihood of back-pressure problems, Olson notes. Extended-reach wells and subsea tiebacks only exacerbate back-pressure concerns on offshore platforms, he says. And because space is at a premium, avoiding the need for platform-based separation and compression facilities can pay big dividends.

Chevron installed its first topside offshore natural gas-driven multiphase pump in 2007 at the Main Pass 59A unmanned platform in the Gulf of Mexico. This was the first time the company had used the technology on gas-lifted wells and is the largest multiphase pump in Chevron’s fleet, according to Greg Sinclair, facilities engineer, who detailed the application at the 2009 Multiphase Pump Users Roundtable held May 7 in Houston.

The Main Pass 59A platform serves 18 wells, and production had become constrained by pipeline pressures, Sinclair explains. The platform is situated in 70 feet of water. Production had peaked at 4,000 barrels a day and was down to 2,000 barrels a day by 2007, with all wells inhibited by back pressure. “Back pressure was up to 350 psi and needed to be reduced

to 150-200 psi,” Sinclair says. “The anticipated production uplift from using a multiphase pump and future drills was enough to justify the multiphase pump.”

The relative costs and benefits of other approaches were also evaluated, including adding a larger pipeline and more topside equipment. However, Sinclair says the multiphase pump option offered an estimated 50 percent lower capital expense than either conventional alternative.

The Leistritz pump package with a Waukesha 9390 gas engine was designed for 150 psi suction pressure, 120 degree Fahrenheit suction temperature and 680 psi discharge pressure at a 95 percent gas volume fraction with daily flow rates of 8 million cubic feet of gas, 4,000 barrels of oil and 4,000 barrels of water (152,000 barrels a day equivalent). The entire package was tested onshore using water, which Sinclair says proved a critical step that identified several skid deficiencies that would have been costly to correct offshore. “Once in operation, the multiphase pump effectively lowered the back-pressure to 200 psi, resulting in a 40-per-

cent production uplift from the 18 gas-lifted wells connected to the platform,” Sinclair concludes.

Bob Heyl, senior staff engineer at Chevron, expects multiphase pumps to gain popularity in platform and subsea applications over the next decade. “A lot will depend on improvements in reliability, which is extremely important in these applications and particularly in deepwater,” he notes. “In fact, there is a movement for an API standard for high reliability.”

## Subsea Pump Applications

The first subsea system went into operation in 1994 in Norway, according to Batho. Today, Framo pumps alone have more than 800,000 subsea operating hours, with subsea multiphase pumps in action globally in more than 15 projects, he says.

As subsea fields mature, the operating economics become more and more marginal, with some offshore and deepwater fields being abandoned at as little as 25 percent recovery of the in-place reserves, says Sjur Wie, North America Customer Support Manager at Framo Engineering.

“Subsea multiphase pumps provide flow assurance to enhance project viability on these capital-intensive projects. They increase and prolong production levels to provide front-end payback and stretch late-life cash flow,” he relates. “In subsea operations, flowline back pressures frequently exceed 2,000 psi because of long flowlines and associated risers. Multiphase pumps overcome this pressure challenge to maintain high and consistent oil flow. They have been proven to attenuate multiphase transient conditions to alleviate processing issues at the topside (host) facility.”

Subsea pumps typically are delivered as part of a full system on a standardized



A multiphase pump packaged with a natural gas-fired engine lowered system back pressure and increased production by 40 percent from 18 gas-lifted wells at Chevron’s Main Pass 59A platform in the Gulf of Mexico.





footprint to minimize surprises during installation and operation. "In subsea applications, it is important to keep things simple and designed for robustness," says Wie. "Using standardized interfaces makes it far easier to adapt to changing production levels, and if necessary, change the pump type to facilitate extended production strategies."

Intervention is typically a last resort because of inherently challenging access issues with subsea equipment, Wie goes on. However, it is facilitated by a retrievable element design approach on the key components within the subsea system.

From the operator's perspective, Heyl points out that the single most important factor in expanding multiphase pumping in subsea applications is also a fundamental requirement of any other equipment installed subsea: overall reliability. What oil and gas companies want, he insists, are units that perform as designed with high run times. "As water depths increase, it becomes prohibitively expensive and time consuming to get a ship on location with a remote vehicle," Heyl comments. "It is always better to avoid downtime and the need for make a repair in the first place."

Increasingly, subsea pumps are being used in combination with other technologies for production optimization. In Norway, Batho references a subsea satellite separation project that enables subsea processed water to be reinjected in conjunction with multiphase pumping to topside. The result is extended productive field life and increased ultimate recovery, he says, noting that subsea raw water projects also have been installed to allow reservoir pressure maintenance to be provided by seabed water injection pumps. Source water is filtered and treated within the pump module, he reports.

Looking forward, one of the frontiers in subsea multiphase applications is increasingly longer step-out and tieback distances, reports Mabes. One project that is demonstrating what is achievable with multiphase pumps is the BP-operated King Field in the Gulf of Mexico, where Mabes says two subsea multiphase pumps were installed in October 2006. "The pumps are in almost 5,600 feet of water and have a tieback distance of 20 miles," he reports. "The total capacity is almost 75,000 barrels a day at a gas volume fraction of 98 percent."

Batho reports Framo is pursuing a line extension program to provide ultra-deepwater operators the necessary equip-

ment to produce some of their most promising assets. "The 10,000-foot water depth, 15,000-psi process pressure multiphase pump and meter developments will create the necessary tools for these developments. Power distribution and motor power is being similarly upgraded to confront the challenge. The largest single units are approaching three megawatts and plans are in the works for four-megawatt systems," Batho updates.

### Metering Applications

Multiphase metering has reached the point in its evolution where meters are routinely included in the design of new offshore production facilities, according to Roxar's Olsvik. "Meters provide a much better understanding of the reservoir and flow conditions. Monitoring and control can be done locally on a platform or remotely from halfway around the world," says Olsvik. "And the newest (topside) meters have removable elements to expand the operating range of a meter without changing its footprint or having to replace the entire system."

Topsides meters are used to test the manifold and individual wells. When wells have individual production lines, then each well can be individually metered, Olsvik explains. "However, if there is a single production line from the manifold to the platform, there is a single test line as well. This test line must be moved between the various wells, which is an expensive and noncontinuous process," he notes. "The challenge with delayed meas-

urement is it takes a while to know if the wells are water coning, have gas breakthrough or other problems that could jeopardize transporting the oil to the platform or shore."

In Saudi Arabia, Olsvik says one field of 250 wells has a meter connected to each well. "The result is very detailed and continuous information on every producing well and the field as a whole," he remarks. "In another Middle East application, an operator installed multiphase meters on wellhead platforms with one to nine wells. Previously, only half of producing wells were tested each month. With the new meters in place, testing more than doubled and the amount of oil lost because of testing was reduced from 12,000 to less than 50 barrels a month. The operator has successfully reversed declining production."

Subsea metering is gaining momentum, with 30 percent of all new subsea wells developed last year equipped with multiphase meters, according to Olsvik. A big incentive for included metering subsea is increased overall recovery. A 2004 study by the Norwegian Petroleum Directorate found 20 percent higher hydrocarbon recovery rates from topside versus subsea, says Olsvik. "The lack of data about individual subsea wells makes reservoir management more difficult and results in lower recovery," he says. "With more measurement in place, operators can more effectively manage the reservoir and improve recovery rates." □



Three subsea multiphase pumps installed in almost 5,600 feet of water at BP's King Field have a tieback distance of 20 miles and total capacity of nearly 75,000 barrels a day at a gas volume fraction of 98 percent.