PennWell

Offshore®

TECHNICAL DIGEST

Advances in Subsea Recovery

Subsea processing technologies enable offshore fields to reach their full potential

Subsea processing systems have been in existence for years. Today, they are a proven solution for accelerating production and increasing recovery from hard-to-access offshore reserves.

FMC Technologies is leading the way with the development and supply of subsea processing technologies, such as: separation, boosting and compression.

With 20 subsea boosting systems and six subsea separation systems installed or awarded to date, FMC Technologies has become the most experienced integrator of subsea processing systems in the industry.

ORIGINALLY PUBLISHED APRIL 2012

Subsea processing technologies are coming of age

Qualification tests support reliability, fitness of design

by **ROB PERRY,** FMC Technologies

SUBSEA PROCESSING CONSISTS of a range of technologies for separation, pumping, and compression that enable production from offshore wells without the need for surface facilities. Seabed processing systems have become increasingly accepted by operators as a solution to accelerate reserves, maximize production, and reduce costs. Today, more than 20 subsea boosting systems and six subsea separation systems have been installed or awarded throughout the world, demonstrating these systems can reliably deliver the value promised. Given the growing number of greenfield and brownfield applications, some analysts anticipate the number of subsea processing systems installed globally could double by 2020.

The value promise

For low energy reservoirs or reservoirs with poor rock or fluid properties, multiphase boosting or the combination of gas/liquid separation and liquid boosting have enabled recovery of otherwise stranded oil. Separating gas from liquids offers the benefits of mature multi-phase boosting options, but allows even lower wellhead pressures. A very low wellhead pressure enables gas lift in the well, while having a separate gas line allows high efficiency pumping, minimizes flow assurance risks, and increases tieback distances. These applications can enable field developments by increasing recovery of reserves and accelerating production to improve field development economics. Examples of low energy field applications include Statoil's Tordis (yielding an increase of over 3% or 19 MMbbl of original oil in place) and Shell's Perdido and Parque das Conchas (BC-10).

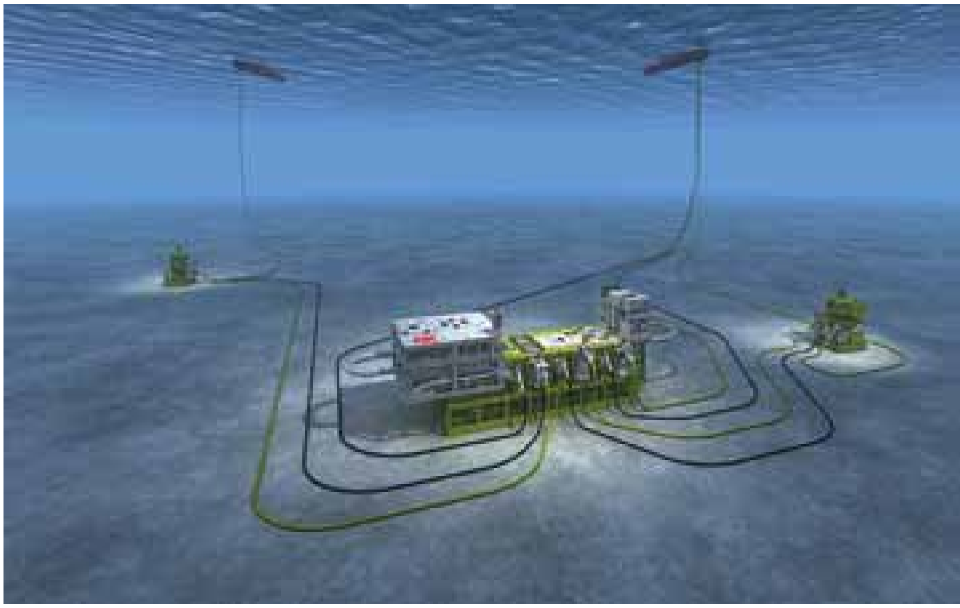
Tordis is the world's first full-scale, commercial subsea separation, boosting and injection system.

Later life reservoirs with high water cut that produce into constrained topsides facilities benefit from subsea water separation and boosting. More oil can be produced through facilities otherwise choked by water as backpressure on the reservoir is reduced to increase production. Examples of such field applications include Statoil's Tordis where separated water was injected into a disposal well. Despite initial challenges with the injection well, the Tordis separator system functions as designed with availability approaching 100%. Most recently in Brazil's Campos basin, Petrobras' Marlim subsea processing system was installed to enable the separated water stream to be further cleaned to allow reinjection into the producing reservoir. This can increase pressure support and sweep to extend Marlim's productive life and to maximize ultimate oil recovery.

In even later field life, subsea processing can allow for an entire topside facility to be decommissioned and the processed fluids to be tied back to a new, more distant, host. This type of application reduces costs and increases both overall facility integrity and recoverable reserves.

An example of this approach is Petrobras' Congro and Corvina project which is currently being executed in Brazil. Subsea processing will enhance Petrobras' revenues and return on investment by extending the life of these mature fields and increasing ultimate oil recovery. In cases when there are limitations on the host availability due to lease terms or facility integrity, or when operating costs rise, subsea processing can accelerate production and increase recovery beyond the existing natural production levels.

Overcoming adoption challenges



Marlim is the first use of subsea oil and water separation in deepwater. It is the first system to separate heavy oil and water, and the first to reinject water into a subsea reservoir to boost production.

Critical factors in the adoption of any new oilfield technology are availability and reliability when it comes to delivering the promised financial value. A number of complex subsea separation projects have been commissioned fault free and have demonstrated an availability exceeding that of conventional topside projects. This can only be achieved using a disciplined, multi-faceted approach based on reliability engineering in design, extensive qualification testing, and strategies to minimize risk.

Perhaps the most critical element is employing a disciplined reliability strategy throughout the design phase. Using techniques such as Reliability, Availability and Maintainability (RAM) analysis, and Failure Mode Effect and Criticality Analysis (FMECA) provide vital insight to inform front-end engineering and detailed system design. While the RAM analysis is typically used to predict system performance and provide a basis for system optimization, the FMECA identifies relevant subsystems and failure modes. Although these methods are useful to model and predict failures, the reliability strategy also should ensure the system includes appropriate data capture, storage, and management to bring operations data into a formal, lessons-learned program. Both operators and subsea system vendors can benefit from the analysis of field data as lessons learned can be applied to improve availability and performance of subsea processing systems.

Another important element of subsea processing is qualification testing. An extensive qualification program can help evaluate the functional, environmental, and reliability performance of the system.

A detailed risk-based program will help determine if the technology can perform within the pre-set requirements, and in accordance to the design models established. Before installation, extensive qualification testing on several process systems, including Tordis and Marlim, was performed. This testing was valuable for the operability of these systems in their various subsea environments. Similar testing will also be performed on Petrobras' Congro and Corvina project.

To reduce the risk of working with new technologies, FMC worked with most operators on qualification programs to test and evaluate technology well in advance of the upcoming projects.

Coupled with a disciplined reliability strategy and extensive qualification testing, several other information-based methods reduce the risk of implementing subsea processing. An integrity management program that incorporates monitoring, testing, and inspection can capture data for risk analysis. This information can be used for integrity monitoring. For example, wall thickness estimations can be deduced from pressure measurements, compositions, and velocity. Another use for the software is monitoring component health where specific sensors and algorithms can be used to estimate time to failure of a component with single-mode failure. Decision support software can be used to process data, model forward behavior, and train personnel on the recommended operation of equipment.

In evaluating any technology, whether proven or new, investment rewards and risks must be carefully calculated. Subsea processing systems now are reliable solutions deployed in a range of applications in both brownfield and greenfield developments. Today, a number of methods and techniques are in use to ensure availability of subsea processing systems meet or exceed operator expectations. As subsea processing technologies continue to prove their value, their use will continue to grow. In the future, full subsea processing could be possible, thereby eliminating the need for surface facilities.

ROB PERRY, FMC Technologies


FMC Technologies
Maximize recovery.
Not some day. Now.
The low-hanging fruit is long gone. Every day it's more of a challenge to increase oil and gas recovery and production from aging, under-producing fields and complex new ones: arctic and ultradeep subsea fields; tight sands, shale and thermal oil sands; HP/HT, long distance, deepwater complex pre-salt or lower tertiary formations. Whatever the need, we have the technology – rigorously proven in the world's toughest situations – to raise your recovery factor and production to unprecedented heights. Not some day. Now.
www.MaximizeRecovery.com
We put you first.
And keep you ahead.
www.fmctechnologies.com
Copyright © FMC Technologies, Inc. All Rights Reserved.

ORIGINALLY PUBLISHED MAY 2010

Subsea boosting and processing developments

by **IOANNA KARRA** and **ROGER KNIGHT**, Infield Systems Ltd.

THE LONG-TERM DRIVERS of the subsea market are well known. The relentless depletion of onshore and shallow water fields has compelled oil companies to focus on deepwater areas where a combination of floating and subsea production units is used to extract hydrocarbons. In recent years, this trend has been reinforced by operators favoring technological over political risk, with oil companies preferring to leverage their technological capability in deeper water play than to engage in places such as Iran and Venezuela that have an unpredictable business environment for investors.

Enhanced oil recovery technologies are also being further pursued with techniques such as subsea tiebacks, subsea boosting, subsea processing, and well intervention being increasingly used by operators. Subsea trees have higher costs and lower potential recovery rates compared to dry trees. Therefore, any efficiency gained from treating by-products on the seabed instead of the platform or from minimizing the likelihood of hydrate formation in pipelines can lead to increased recovery rates and hence profit maximization for operators.

This analysis provides an overview of subsea boosting and processing developments. Specifically, we will discuss the key parameters for the adoption of these technologies; the areas where they are expected to be primarily used; the oil and service companies that are involved in pilot and actual projects for these technologies; the risks that these techniques face due to the economic downturn; and, finally, the industry's innate conservatism and the lack of required complementary technologies being introduced.

Subsea processing consists of a range of technologies to allow production from offshore wells without needing surface production facilities. It consists of treating produced fluids upstream of surface facilities on or below the seabed, including seabed and downhole oil/gas/water separation, downhole and seabed multi-phase pumping, gas compression, and flow assurance. The most important benefits from using these technologies include production boosting, improved oil and gas recovery, increased Net Present Value (NPV), reduced surface production facility costs, and the lower likelihood of gas hydrate formation in flowlines.

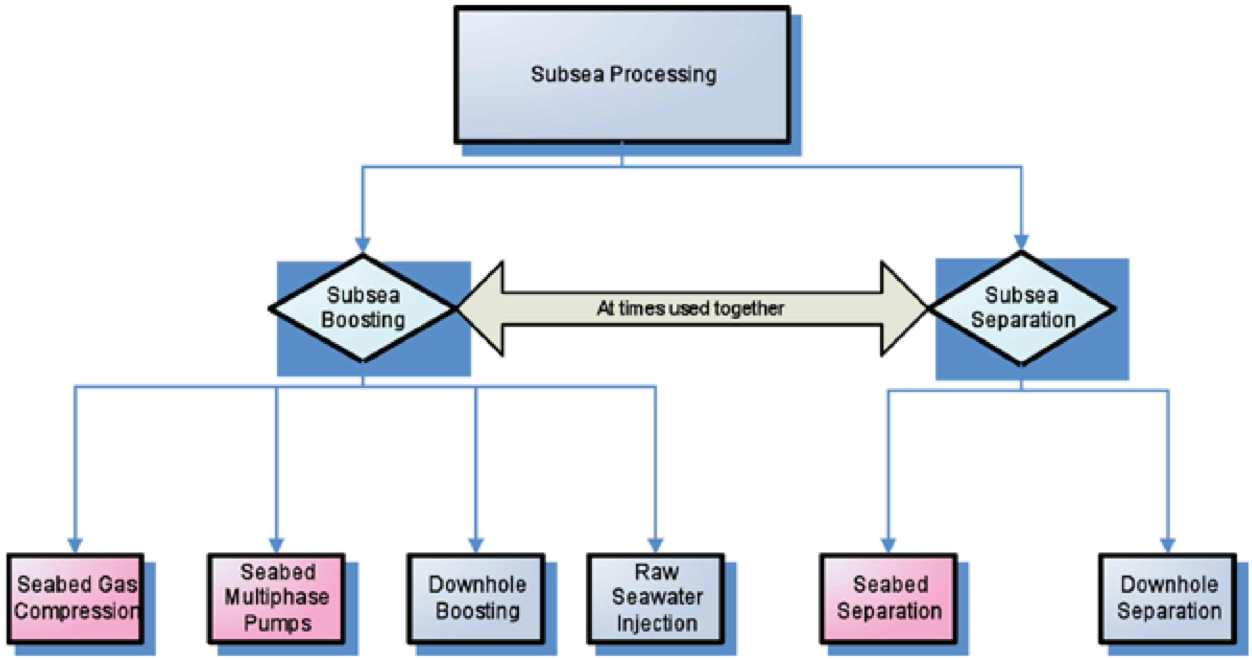
There are, however, a number of issues that have kept subsea boosting and processing from being used more widely. The most important issue is the reliability of subsea units. They must be able to operate for long periods of time without any intervention. In addition, the consequences from a subsea processing system failure are more severe than those from a topside unit because when a unit fails, an intervention vessel or a drilling rig needs to be deployed to repair or service the unit. This downtime leads to foregone revenue from stalled production and increased costs from securing an intervention vessel or drilling rig.

The two technologies discussed in detail in this analysis are seabed separation and seabed boosting. The latter technology includes seabed multi-phase booster pumps and seabed gas compression.

Seabed separation

Seabed separation involves separating the oil, gas, and water directly at the seabed instead of on a topside facility. This technology is used in mature fields where water production increasingly exceeds oil production and where it becomes economically unviable for operators to continue with the recovery of the field's reserves. The technology can be used also in green fields that have high gas to oil ratios and which face the risk of blocked pipelines because of hydrate formation. Existing and upcoming seabed separation projects show this technology often is combined with seabed boosting. Examples include Statoil's Tordis, Total's Pazflor, and Shell's Perdido Host and BC-10.

Increased water depths and a number of fields tied back to a hub are common key parameters specifying either oil/water or liquids/gas separation. Other parameters are product specific. For oil and water separation in mature fields, key factors include the level of the field's water production and the existence of heavy oil. For liquids and gas separation in green fields, high gas volume fraction, increased distance from the host, and low reservoir pressure and temperature are



Perceived interaction between different subsea processing technologies.

considered important parameters because the transport of wet gas over 10s of kilometers can lead to hydrate formation and, hence, pipe blockage.

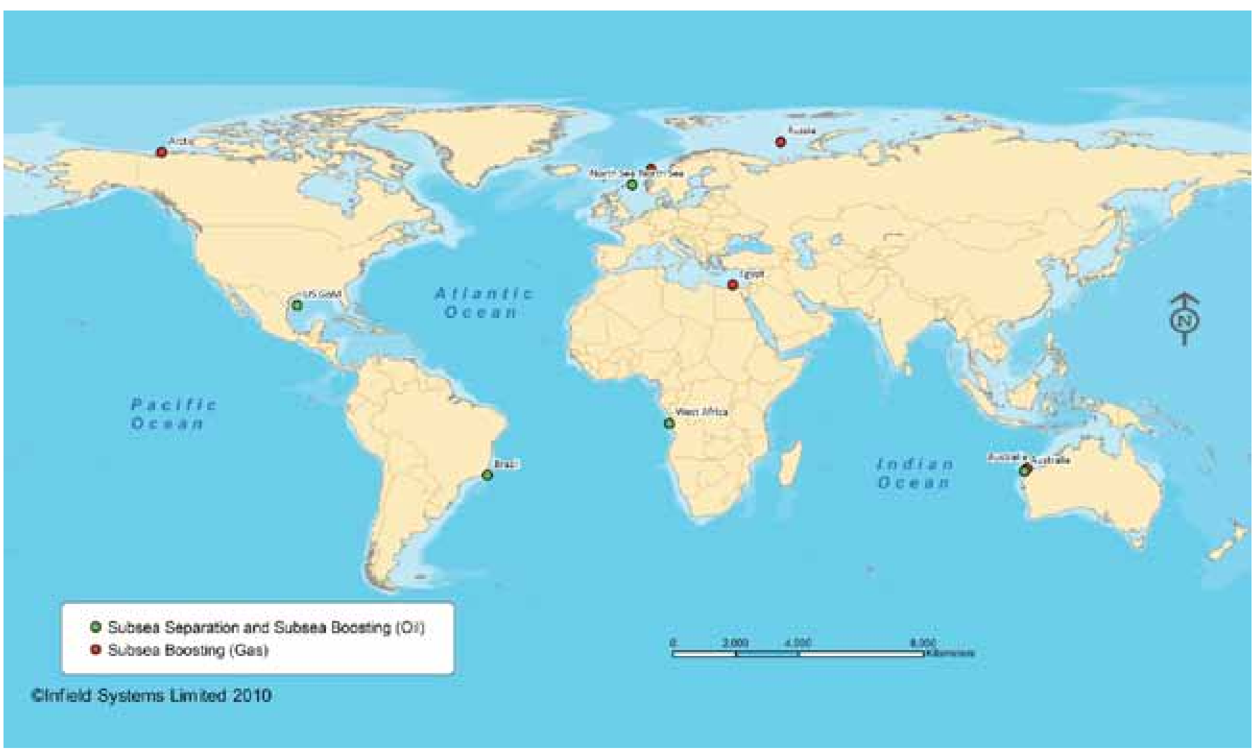
The first seabed separation unit was installed in Statoil's Troll Olje field in 2000, with Tordis, also a Statoil field, being the second field in the world operating a subsea separation unit since October 2007. The driver behind these installations is StatoilHydro's improved oil recovery (IOR) strategy.

Unlike the Troll subsea separation project (which is, at best, a quasi-commercial project), the new Tordis station – provided by FMC through its subsidiary CDS – is absolutely central to the commercial viability of the whole field. This is because its increasing water outflow was restricting production because pipelines and surface facilities do not have the capacity to transport and handle the extra water being produced in increasing amounts by the well stream.

Meanwhile, Shell recently installed seabed separation units in two of its green field projects, BC-10 in Brazil and Great White in the US Gulf of Mexico. FMC supplied six subsea separation modules for these projects. At the Perdido Host Regional Development production from the first three fields – Great White, Tobago, and Silvertip – will tieback to a central separation and boosting cluster directly beneath the Perdido Host spar. The fields' key characteristics are their low reservoir pressure, temperature, and great water depth, each of which adds to hydrate potential.

Other upcoming seabed processing projects include gas and liquids separation at Total's Pazflor field off Angola, and oil and water separation at Petrobras' Marlim field in Brazil, Statoil's Fram East project in Norway, and BP's Foinaven field in the UK. The Pazflor project includes three seabed separation units by FMC to be installed in 2011 and expected to reduce significantly the risk of hydrate formation. FMC also will supply Petrobras with a seabed separation unit in 2011 for its Marlim field. To date proposed projects for Fram East and Foinaven have not been awarded.

Infield Systems expects seabed separation units will be used mostly in Brazil's Campos and Espirito Santos basins, in the Lower Tertiary Trend region in the US GoM, in the Northwest European continental shelf (NWECS), and finally in deepwater West Africa.



Areas where subsea boosting and processing are expected to be used in the future.

In fact, West Africa could be one of the key regions for subsea processing because of its already extensive deepwater production, significant oil reserves, and, most importantly, the geographical distribution of fields, whereby multiple discoveries are gradually being tied-back to one central processing facility.

Meanwhile, Infield Systems views the mature NWECS region as a good opportunity for subsea processing technology. Statoil's extensive exposure to Norwegian waters is an important factor for the implementation and future proof of the viability of this technology. That operator has made a strategic decision to increase oil recovery rates from its fields, and subsea processing will be the primary tool to achieve this goal.

In addition, Brazil is an ideal candidate for subsea separation due to the fact that its Campos basin fields hold significant amounts of heavy oil which are more difficult and expensive to extract and process than lighter crude oil. Finally, in the GoM, our attention is drawn to new projects in the Lower Tertiary trend that have both low-temperature and low-pressure reservoirs combined with ultra deepwater.

Seabed boosting

Seabed boosting is at times deployed to ensure the flow of fluids from fields at the required rate after natural reservoir pressure declines. It includes seabed multi-phase and downhole boosting, raw seawater injection, and gas compression. Our analysis focuses on seabed multi-phase pumps and gas compressors. The former is a more "field proven" type of subsea technology compared to seabed separation and gas compression, and they were first installed in 1994 at Eni's Prezioso field. This project was only used as a testing subsea experience for the multi-phase twin-screw pump developed by GE Oil & Gas in the 1980s; it does, however, underline the industry's historical involvement with this technology.

Key parameters that lead operators to use seabed booster pumps include the existence of heavy oil, the increased distance from the host, increased water depth, low reservoir pressure, and a greater number of fields tied back to the host. Several key characteristics are similar for both seabed separation and boosting, and this explains their simultaneous use in some cases.

Seabed multi-phase pumps are separated into two main categories: positive displacement and rotodynamic. From the former category, twin-screw pumps developed by Aker Solutions and GEOG VetcoGray are the most widely used. In terms of rotodynamic pumps, Framo's helico-axial and Centrilift's centrifugal are most widespread.

Multi-phase twin-screw technology is field proven onshore and on production topsides and has also been tested at the seabed: with BP's King project in 2007 being the first commercial implementation. This technology is often used when pumping conditions contain high gas volume fractions and varying inlet conditions. Possible liquid leakage and the limited ability to handle a significant amount of solids represent some of the issues that this technology currently faces.

The helico-axial pump was developed by the Poseidon Group (French Institute of Oil, Total, and Statoil) and manufactured by Framo and Sulzer. Helico-axial pumps are more prone to stresses associated with slugging. However, installation of a buffer tank upstream of the pump is generally sufficient to dampen slugging, so that this no longer poses a problem.

Another technology that has established itself recently in multi-phase production is the electrical submersible pump (ESP) used on the seabed instead of downhole. Seabed and downhole ESPs are manufactured mainly by Baker Hughes-Centrilift and Schlumberger-Reda.

This technology is being used in two Shell projects – Perdido Host and Brazil BC-10 – and three Petrobras projects – Jubarte, Golfinho, and Cascade/Chinook. These pumps are used normally when the pumped fluid is mainly liquid. We predict that ESP type and helico-axial pumps will represent the largest market for subsea processing equipment.

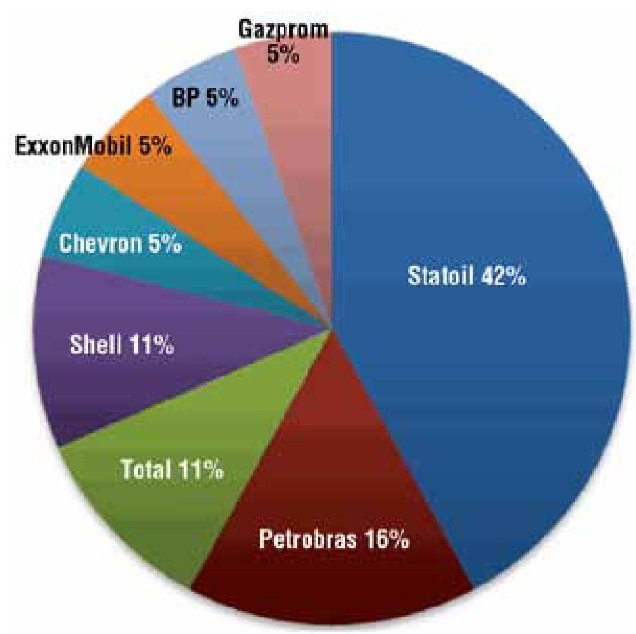
The most important region for subsea pumps is offshore West Africa where eight subsea helico-axial pumps are installed since 2000. The North Sea region and offshore plays in the US GoM and Brazil are also important for use of subsea pumps.

Finally, seabed gas compression involves gas compression at the seabed level instead of gas compression on a topside facility. Key factors driving the implementation of subsea gas compression technology are the discovery of distant offshore gas fields, increased water depths, long step-outs from the host facility, harsh environmental conditions, and low reservoir pressure and temperature. Compared to subsea separation and booster pumps, however, this technology is still embryonic. Infield believe that this is because operators still question the reliability of the system since controlling and monitoring subsea gas compression units over long distances is not as proven a technology as topside gas compression. For instance, power supply to the postulated system on the Ormen Lange field would have to travel by a series of cables over 120 km (75 mi) from the shore to the field.

At present there are no seabed gas compression projects. However, Aker Solutions' pilot program for Statoil's Ormen Lange field is under development. In its later stages, from about 2015, Ormen Lange will require offshore compression to boost gas back to shore to maintain desired production levels as the reservoir's natural pressure declines.

The field is in an area of the North Sea where environmental conditions challenge offshore hydrocarbons projects. In the short- to medium-term, other proposed seabed gas compression projects include Statoil's Norwegian Midgard, Gullfaks South, and Troll Olje fields. From 2018 onwards, we could see seabed gas compressors at Chevron and ExxonMobil's Gorgon project offshore northwest Australia and at Statoil's Snohvit and Gazprom's Shtokman fields.

On Gullfaks South, Framo is expected to use its newly developed seabed wet gas compression technology as part of a two-year development contract the company has signed with Statoil. Framo's technique is different from more established subsea gas compressors



Operators' involvement in future subsea boosting and processing projects.

and its units are expected to be able to handle an increasing amount of heavier crude oil grades.

Infield views that over the longer term the North Sea and Arctic regions are most likely to use seabed gas compression, in addition to, Russia, Australia, and Egypt.

Operators' involvement

Several oil companies are involved heavily in different subsea technologies, with Statoil and Petrobras the most proactive globally in terms of both pilot/actual projects and qualification programs. This is because these companies are partly state-owned and as such have access to capital to finance new and potentially high-risk technologies as part of national efforts to boost supply to domestic markets.

Other than NOCs, Shell, Total, BP, and Woodside are leaders in subsea processing and boosting. Profitability is key for these firms so the investment rewards and risks associated with new, unproven technologies must involve carefully calculated decision making: somewhat different to national oil companies that are sometimes used by the state as instruments of national energy policy objectives to boost domestic production. Several IOCs, however, have field portfolios that could benefit from such technologies.

Infield predicts that as major operators experiment with subsea processing and boosting technologies – and with time prove their viability (and reliability) – we also will see independent oil companies following suit where field conditions are suitable.

Manufacturers' involvement

Framo, Aker Solutions, GEOG VetcoGray, and FMC are most highly involved in the manufacturing of subsea processing and boosting equipment.

In terms of seabed multi-phase pumps, Framo, GEOG VetcoGray, and Aker Solutions are relatively well matched in product design and quality, despite the fact that these firms use different technologies. Our view on manufacturers' involvement takes into consideration both pilot and actual projects and qualification programs such as Demo 2000, OG21, and Deep Star. It will be interesting to see how Centrilift's recent multi-phase centrifugal booster pump will compete with Framo, Aker Solutions, and GEOG VetcoGray's established technologies.

On the seabed separation front, FMC has won the majority of projects. Operators seem initially to prefer to use topside proven separation technology at the seabed – FMC uses CDS' gravity separator – instead of newly qualified technologies such as those launched by Aker Solutions, GEOG VetcoGray, and Framo. Infield expects the new generation of subsea separation projects will demand more technologically sophisticated methods than those currently in operation.

Conclusion

The number of existing and proposed subsea boosting and processing projects has increased over the last few years. The majority of these units were awarded prior to the recent decline in offshore activity caused by the global economic downturn, pressures on the supply chain, and oil price volatility. Therefore, as a result of the timing of the contracts, several projects have gone ahead despite these conditions. Most operators involved in these technologies are either partly nationalized companies such as Petrobras and Statoil, or oil majors such as Shell and Total. Although several of these oil companies aim for additional cost savings in the short term, we believe there will be a continued effort to push these techniques to improve oil and gas recovery, boost production, reduce the platform's operating cost, and reduce the likelihood of gas hydrate formation in the pipelines.

Subsea processing and boosting technologies are a long-term objective for oil companies that face short-term fluctuations in R&D investment. If these technologies become proven winners that increase NPV they may become the preferred development solution.

The success of upcoming projects is vital to the longevity of the deepwater oil and gas industry. The competition between manufacturers for different technologies, such as the helico-axial and the seabed ESP, is expected to increase. The subsea boosting and processing market is experiencing its first "experimental" stage after which ISL anticipate that these technologies will be used more widely.

IOANNA KARRA and **ROGER KNIGHT**, Infield Systems Ltd.

ORIGINALLY PUBLISHED FEBRUARY 2011

Online monitoring enhances flow assurance

Statoil deploys new system to overcome unique challenges of Vega field

by **MARIT LARSEN,** FMC Technologies

NEW OIL AND gas field developments are getting more advanced and often include subsea installations, satellite wells, or subsea-to-beach solutions. Long multiphase lines, tie-ins, subsea-to-beach, and subsea production and processing can pose different operational challenges. One of the most critical challenges is to ensure efficient flow of the produced oil and gas.

The Flow Assurance System (FAS) is designed to monitor subsea equipment and well production to give operators necessary information about production content. Subsea hardware now can be equipped with lots of sensors, meters, and advanced instrumentation to provide continuous information about flow conditions. However, there is limited or no instrumentation along the flowline to give needed flow condition data. Thus, operators are forced to rely on multiphase models as virtual measurements.

Flow assurance challenges also increase as the flowline length and water depth increase. Other critical situations also can arise, such as equipment failure, wearing down of the choke, and leakage or blockage of pipelines.

An adverse situation, such as a flow rate issue or equipment malfunction, can cost the operator time and money and may become an environmental hazard. If changes in normal conditions are detected early, unplanned shut-downs of wells may be avoided.

To help operators address flow assurance challenges, FMC developed its FAS system, Flow Manager. The first installation of the online metering included in this system was in 1995. Today, the system meters some 470 oil and gas wells worldwide.

As the complexity of the field development increases, online systems require extended functionality. Statoil's Vega field in the North Sea is one successful FAS example. Statoil uses FAS to manage the unique flow assurance problems presented at Vega field.

Unique challenges

Vega is a gas condensate field near Norway's west coast. It will be developed as a tie-in to the Gjøa platform with a 167,322-ft (51 km) flowline. The field development covers three reservoirs and is split between two licenses. The subsea layout is an in-line daisy-chain with a four-slot template for each reservoir. Each reservoir will be produced by two wells for a total of six wells in the field. One multiphase meter will be installed on each well and on each template manifold. Statoil's production strategy for Vega is based on reservoir depletion.

Because of the subsea conditions, several operational and flow assurance challenges have been defined by Statoil. These challenges include high reservoir pressure, low temperature during start-up and shut-down, the possibility of hydrate or wax formation, the liquid accumulation effect on ramp-up time, and the need to operate within safe pressure and temperature margins. Unexpected situations also occur such as failing or reduced performance of the subsea sensors and multiphase flow meters, leakage in the production line and the MEG injection monitoring and control system, or blockage of the production line.

Schematic of the subsea installation at Vega.

Different modes

The main objectives of the Vega FAS are to produce safely and to minimize the shut down/restart periods. In order for the FAS to satisfy the different needs of field production, four different modes were developed.

The "Real Time" mode runs in parallel with the real process. It reads sensor values and control parameters from the process control system and automatically adapts the FAS models to the real process. Using the FAS in the Real Time mode, the user has a continuously updated metering, monitoring, and surveillance system.

The "Look Ahead" mode of FAS runs in parallel with the Real Time system and continuously simulates the predicted process behavior for a defined time horizon. It always begins with the current process conditions, and simulates what will happen if the process runs without change. This allows the user to look into the future to get an early warning in time to make any necessary corrective actions.

The "What If" simulator may be used to train, analyze, or plan. The purpose of this mode is to run scenarios and analyze the consequences of changing system set points prior to modifications. It also can analyze flow assurance situations that have occurred or are suspected. This mode can improve operational procedures and regularity, such as start-up and ramp-up procedures. The "What If" operating mode is connected to the actual process only indirectly, so it can read the current state in Real Time and use that data as an initial condition for the simulation.

"Look Back" mode provides advanced FAS users with a flexible tuning system to adjust the multiphase models in Vega FAS against the Vega field production data. This mode is available in the Web interface.

Subsea template being installed from crane vessel Thialf. Photo: AndreOsmundsen/Statoil.

Functionalities for Vega's challenges

Different Flow Manager systems were used when developing the Vega FAS, which is a customized application that addresses the specific needs of the Vega field operation.

Three subsea templates tieback to Gjøj platform.

The Virtual Flow Metering System measures individual well production rates as a redundancy to the multiphase meters at each wellhead. This virtual metering system does not depend on single sensors or the multiphase meters, so it serves as an accurate back-up to the physical meters. It also calculates pressure and temperatures along the flow path, including downhole and reservoir pressures.

The Pipeline Management System monitors the flowline. To counter the long flowline and dynamic behavior associated with Vega, the dynamic multiphase flow simulator OLGA was integrated. This dynamic model enables functionality such as the MEG injection monitoring and control, pig tracking, calculation of liquid accumulation, prediction of flow instabilities, and other transient effects.

To achieve optimal ramp-up of wells, manifolds, and pipelines, the Production Choke Control System was included in the Vega FAS. This system recommends flow set points for the production chokes based on operator-defined production targets and constraints. The production strategy contains well-priority, planned gas production, swing wells, and maximum choke openings.

An early indication of potential break-downs of sensors and equipment is crucial to planning maintenance. As such, the Condition Performance Monitoring System monitors the real-time status of subsea sensors, multiphase meters, production chokes, and other flow-related process equipment.

To guard against wax build-up and hydrate formation, and for an early indication of leakage and blockage, FMC added the Wax Condition Monitoring, the Hydrate Condition Monitoring, and the Leakage and Blockage Monitoring systems to the Vega FAS.

User interface

The Vega FAS includes an organized Web-based graphical user interface. This tool includes feature such as process pages that illustrate the field lay-out from the wells through the flowline and into the topside facilities. Output about the flowing conditions such as flow rates, pressures, temperatures, liquid content, and control parameters for the equipment are shown in various positions. Available measurements are integrated into the pages.

Other examples include special advice pages configured to show hydrate, wax, pig, and performance monitoring. Typical FAS users are in multiple locations. The control room operator is usually at the Gjøa platform and the production engineer or flow assurance specialist works primarily onshore in the Statoil offices. The Web interface has different access levels to meet the different users' needs. The Vega FAS's accessible Web interface gives different users within the Statoil organization a common tool that can improve communication and provide a common understanding about Vega's production status.

Enhanced decision making

Great effort has been put into the flow assurance advisors and the performance monitoring of the subsea production system. Improved measurements and improved field management give increased production. However, it is not the measurements themselves that lead to increased and safe production; it is the interpretation of these measurements. Because of this, a main objective of the Vega FAS is to contribute numbers as well as to provide a better understanding of flow assurance issues as a support for correct decisions. Through the Vega FAS, operators, production engineers, and flow assurance specialists have a tool to monitor the production process, plan for various scenarios, and to give early warnings in time to implement contingency plans.

MARIT LARSEN, FMC Technologies

ORIGINALLY PUBLISHED MARCH 2011

Pazflor development relies on subsea separation system handling four reservoirs

by **ELDON BALL,** Senior Editor Technology & Economics

THE PAZFLOR FIELD offshore Angola boasts a number of firsts. Foremost among them is that it is the first-ever project anywhere to deploy a development plan based on gas/liquid separation at the mudline spanning several reservoirs.

This technological innovation is what will make it possible to produce the heavy, viscous oil contained in three of the four reservoirs in this gigantic development in the Angolan deep offshore.

Pazflor, operated by French oil company Total, lies 150 km (93 mi) off Luanda in water depths ranging from 600 to 1,200 m (1,968-3,937 ft) and has estimated proved and probable reserves of 590 MMbbl. The

The Pazflor FPSO is the largest in the world at 325 m (1,066 ft) long, 62 m (203 ft) wide and a weight of more than 120,000 metric tons.

field will gradually ramp up to its full production capacity of 220,000 b/d over the coming months.

“Pazflor’s start-up, several weeks ahead of schedule and within budget, is a remarkable achievement of the teams involved,” said Yves-Louis Darricarrère, president of exploration and production at Total. “The support and trust of Sonangol, our concession holder and partner, also made an invaluable contribution to our efficiency.”

Pazflor comprises a vast subsea gathering network, the most complex ever built in Angola, including 180 km (111.8 mi) of lines tying in 49 subsea wells and 10,000 metric tons of subsea equipment and the giant Pazflor FPSO.

Held in position by 16 subsea mooring connectors, the FPSO is the largest in the world at 325 m (1,066 ft) long, 62 m (203 ft) wide and a weight of more than 120,000 metric tons. It can store up to 1.9 MMbbl of oil that is then exported to tankers via an offloading buoy. The associated gas is re-injected into the reservoir, but could also be exported to the Angola LNG plant once the latter becomes operational.

The Pazflor FPSO was constructed in South Korea by Daewoo Shipbuilding and Marine Engineering (DSME), which was contracted to provide the engineering, procurement, and construction for the FPSO vessel’s moorings, hull, and topsides. In turn, Daewoo awarded KBR the contract to provide topsides engineering, procurement, and interface design services for the FPSO.

The FPSO has a topside weight of 35,494 metric tons. It is designed with a processing capacity of 200,000 b/d of oil and 150 MMcf/d of gas. Facilities are planned for a 20-year design life, and quarters are provided for 220 operation and maintenance personnel. It began the 10,000-nautical-mile (19,000 km; 12,000 mi) journey to Angola in January, towed by three Fairmount Marine tugs, and was moored and installed on arrival.

A key technical challenge was producing two very different grades of oil from four separate reservoirs. Producing the heavy, viscous oil from the three Miocene reservoirs, which account for two-thirds of the reserves, and the related flow assurance constraints, represented a major challenge. The gas has to be separated from the liquids on the seabed so that the viscous liquids can then be pumped to the surface. The design and installation of subsea gas/liquid separation units and pumps are a world first on this scale. The pumps were purpose designed and tested for Pazflor.

Pazflor's first discovery – the Perpetua reservoir – came in 2000. Acacia and Zinia were discovered in 2002, followed by Hortensia in 2003. Pazflor encompasses all four reservoirs and covers an area of over 600 sq km (231 sq mi).

Acacia contains light, good quality oil, similar to that of Girassol. The Perpetua, Zinia, and Hortensia reservoirs contain heavier, more viscous oil, making them more difficult to produce. Total decided to combine the production of these two very different oils, in keeping with its ongoing aim of optimizing the production of deep offshore resources. The choice called for two different subsea production systems tied into a single FPSO.

For the three Miocene reservoirs containing heavy oil, the gas is separated from the oil and water on the seabed. Once separated, the oil and water are forced to the surface using pumps designed for Pazflor, also installed on the seabed. The lighter gas rises naturally to the FPSO. The subsea modules are critical to production and are designed to operate for a 20-year period.

FMC Technologies supplied the three subsea separation systems. FMC also supplied the field's 49 subsea trees (25 production, 22 water-injection and two gas-injection trees) and 49 wellhead systems. In addition, the company provided three four-slot production manifold systems, a production control and umbilical distribution system, gas export and flowline connection systems, ROV tooling, and local support for installation and start-up activities.

Total awarded a $1.1-billion contract for subsea work to a consortium led by Technip and including Acergy. Technip was responsible for engineering, procurement, fabrication, and installation of more than 80 km (50 mi) of production and water injection rigid flowlines, flexible risers, and integrated production bundle risers, plus engineering, procurement, and fabrication of 60 km (37 mi) of umbilicals. Installation was by Technip's vessels Deep Blue and Deep Pioneer.

Acergy was responsible for engineering, procurement, fabrication, and installation of 55 km (34 mi) of water injection, gas injection, and gas export lines, umbilicals, and 20 rigid jumpers.

Pazflor by the numbers

- 150 km (93 mi) offshore, comprises four reservoirs covering 600 sq km (231 sq mi)
- 600 to 1,200 m water depth
- FPSO is 325 m (1,066 ft) long, 62 m (203 ft) wide
- Living quarters for 140 people
- Production plateau of 220,000 b/d
- Two subsea production systems encompass 49 wells (25 producers, 22 water injectors and two gas injectors) and three subsea separation units connected to six pumps
- 180 km (111.8 mi) of pipeline
- 60 km (37 mi) of umbilicals

ELDON BALL is Senior Editor Technology & Economics

FMC Technologies

Company Description:

FMC Technologies, Inc. (NYSE:FTI) is a leading global provider of technology solutions for the energy industry. Named by FORTUNE® Magazine as the World's Most Admired Oil and Gas Equipment, Service Company in 2012, the Company has approximately 16,100 employees and operates 27 production facilities in 16 countries. FMC Technologies designs, manufactures and services technologically sophisticated systems and products such as subsea production and processing systems, surface wellhead systems, high pressure fluid control equipment, measurement solutions, and marine loading systems for the oil and gas industry.

www.fmctechnologies.com

SUBSEA RECOVERY LINKS:

- Greenfield solutions
- Enabling technologies
- Technology implementation
- Subsea processing projects