Subsea Processing Technology

New Subsea Development Options Boost Reservoir Recovery

By Chris Shaw and Janardhan Davalath

HOUSTON–Operators can significantly improve offshore hydrocarbon recovery from both "green field" and "brown field" reservoirs by installing subsea processing systems. Recently announced and already installed systems designed for the Gulf of Mexico, offshore West Africa, offshore Brazil and the North Sea employ a wide range of separation concepts, technologies and sizes. Gravity-based systems have been used along with enhanced gravity, semicompact separation techniques.

However, as the industry ventures into deeper waters and higher-pressure environments, there is a need to further develop more advanced and reliable separation technologies that can provide enhanced performance with compact designs and lower costs.

Subsea processing is one of the most attractive and effective technologies being utilized by operators. It is at the forefront of their efforts to increase reservoir recovery.

Treating the production flow at the seabed provides many opportunities to achieve more effective exploitation of oil reservoirs around the world. Subsea separation and boosting allows marginal reservoirs to be developed economically, and in some cases, can eliminate the need for surface host facilities. This is important as the industry must turn to reservoirs that are not easily accessible in order to maintain energy supply.

The focus is now on addressing the challenge of how to cost-effectively produce oil and gas from offshore fields located in deeper waters and more remote areas.

Subsea Pumping

The traditional way of improving asset value using subsea processing has been through installing a multiphase pump close to the well. Subsea multiphase pumping is an effective means to improve the economics by reducing backpressure on the reservoir, which increases well flow rates and total recoverable reserves. However, it has been limited to applications in shallower water with shorter tieback distances. This is primarily because of the limitations in the pumping technology itself.

To date, multiphase pump projects have been limited to 700 psi (50 bar) of drawdown. Deepwater or long tiebacks require much higher pressures. A rule of thumb to understand how much duty a pump might need in order to garner the maximum benefit uses the water depth in feet multiplied by a typical multiphase gradient (0.3 psi/foot) plus the tieback distance in miles, multiplied by a typical multiphase pipeline frictional loss (50 psi/mile). If production fluids contain produced water, then the multiphase gradient may be significantly higher (up to 0.4 psi/foot).

This equates to an approximate pump duty with the assumption that the pump suction pressure equals the fluid boarding pressure. Typical values around 500 psi can be assumed. Note, however, that a suction pressure of 500 psi could easily result in a free gas volume (GVF) above 85 percent for many typical oils–an inefficient operation point. The actual GVF is affected by the production gas-to-oil ratio, which itself is a function of any gas cap production and the oil's bubble point. Most likely, the design point would be increased to a suction pressure around 1,000-1,500 psi in order to bring free gas levels down to acceptable levels.

Advances in multiphase pumping using helicon-axial stages in a balanced piston configuration show that a theoretical maximum lift to 2,500 psi (170 bar) and 65 percent free gas is possible. Single-phase pumping facilitated by subsea gas/liquid separation will, in many cases, achieve the required drawdown (a drawdown not attainable solely by using multiphase subsea pumping). Recent work with single-phase pumps has shown that 4,000 psi (275 bar) is possible with low-viscosity (<1 centipoise) liquids. It is possible that even this limit could be exceeded once subsea motor technology catches up with the pumping capabilities.

Subsea Separation

While the development of pumping technology allows for a sufficient high pressure differential over the pump for many deepwater applications, the gas/liquid separation enables even more energy-efficient boosting because of the higher hydraulic efficiency of single-phase pumping. Furthermore, subsea gas/liquid separation and liquid pumping is also a valuable tool to develop a field more economically because of the resulting flow assurance improvements.

As noted, subsea separation contributes to reduced wellhead pressure and facilitates faster oil and gas production from the reservoir (especially when combined with liquid boosting). However, some host facilities have production bottlenecks that need to be addressed. Increasing oil production rates generally results in increased production of water and gas as well. Limitations in existing water and gas processing on the host facility could limit the potential for full utilization of a subsea processing project.

The subsea processing system on Total's landmark deepwater Pazflor project offshore Angola includes seafloor gas/liquid separation utilizing vertical vessels to separate gas from liquid in the production stream. Each separator vessel is about nine meters tall and 3.5 meters in diameter.

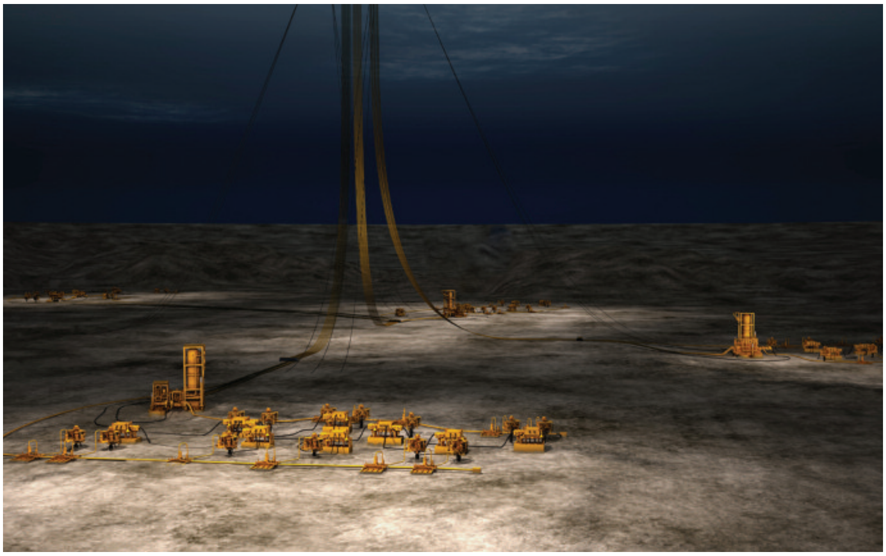
Using a high-pressure subsea pump may enable the operator to route production to a higher-pressure separator, thereby avoiding limitations of a low-pressure compressor or produced water bottleneck. Similarly, gas separated subsea can be routed to a higher-pressure separator (gas frictional pressure drop and gradient are both a fraction of the pressure drop in the liquid flowline/riser.)

A host facility with limited water processing facilities could benefit from a subsea processing system that separates the produced water. This helps the fluid gradient and reduces the friction drop in the multiphase pipeline, enabling increased production. Today's state-of-the-art subsea separation projects use large, gravity-based separators–horizontal for oil/water separation and vertical for gas/liquid separation. The operating principle is adapted from traditional topside processes.

Although efforts have been made to reduce the size and weight of the separator vessels, they are still rather bulky and heavy, which drives cost and installation challenges. In fact, the size of separation equipment manufactured to date has not been a function of performance needs, but rather is based on the heavy lift crane capacity available in the geographic location where they are to be installed.

A significant challenge to subsea produced water separation lies in the disposal of the separated water. Statoil's Troll C Pilot and Tordis projects both injected the water into a high-quality, underpressured and relatively shallow disposal zone. But an equivalent aquifer is not always available, meaning alternate solutions are needed to enable reinjecting water into the reservoir in a safe manner.

Another option for produced water disposal is to pump the water into the local environment. While not specifically prohibited, the regulatory authorities will likely ask that, at a minimum, the current overboard discharge oil-in-water targets of 20-40 milligrams per liter are met. It will be a significant challenge to process the water to reliably meet these targets, including under process upset and transient



The Pazflor development consists of 49 subsea wells and three gas/liquid separation systems connected by subsea production, injection lines and risers to a spread-moored floating production, storage and offloading system. The topside controls are designed to accommodate another 21 wells and a fourth subsea separation unit, including subsea pumps, control system and umbilicals.

conditions. Reliable monitoring and surveillance to ensure that this target is met is another challenge. Offshore platforms usually process water through hydrocyclones and/or flotation cells, as well as through degassers operated at atmospheric pressures. The long-term goal for a subsea solution will require equivalent building blocks that achieve similar process functionality as those used today in surface processing facilities.

Oil/Water Separation

The Tordis project uses a semi-compact, gravity-based separator concept that has been specially developed for subsea applications. The semi-compact design removes gas in a cyclonic inlet such that the main settling portion of the separator operates flooded. The Tordis semi-compact separator vessel is 17 meters long, with a diameter of 2.1 meters. With a design capacity of 100,000 barrels of water and 50,000 barrels of oil a day, it offers a total liquid retention time down to three minutes. While there was no strict quality requirement for the hydrocarbon stream, the produced water stream was designed to meet maximum 1,000 parts per million oil-in-water.

Interestingly, the actual operating performance as measured by remotely operated vehicle sampling exceeded this target by a factor of two. That is, the water contained an average of 500 ppm residual oil. The Tordis separator was successfully operated in the field to demonstrate the separation performance, which exceeded the operator's performance expectations.

To avoid risk of clogging or damage, the vessel was qualified with a minimum of performance-enhancing separator internals. The separator is equipped with a sand handling system and solutions qualified for sand slurry transportation and gravity-based sand separation. The sand is disposed into an injection well along with the water. The sand handling system was qualified for continuous operation with 1,100 pounds of sand a day.

Gas/Liquid Separation

Even though gas/liquid separation eases operational challenges and increases the efficiency of the subsea processing system, there is substantial potential in improving the design for new applications. Current systems have been deliberately limited in efficiency as the pumps are designed to handle a fairly high gas fraction. This gives a special requirement to the pumps that can be used, since they need to be gas tolerant. More efficient separation would enable simpler and more effective pumping. The design philosophy is a conservative one. Instead of designing the separator to produce two clean streams, the separator system is designed to ensure that the gas stream is always high quality, while the liquid stream is designed to accommodate up to 15 percent free gas.

Total's Pazflor project utilizes vertical separator vessels to separate gas from liquid in the production stream. These separator vessels have a height of about nine meters, with a diameter of 3.5 meters.

Another issue is that the gravity separator for subsea use and possibly also designed for high pressure needs a large-diameter vessel with thick walls. Such pressure vessels have manufacturing limitations as well as challenges for offshore installation because of their large size and weight. Consequently, further development of the separation technology is a key component for future projects.

Gas/liquid separation is a key enabler of flow assurance. Issues related to flow instabilities, such as slugging, can be designed out of the system. This allows the size of the primary separator on the host to be reduced and mitigates associated vibration of the multiphase risers and pipe work. Another benefit is improved hydrate management. Having a gas line to the surface allows venting of the system (multiphase and liquid lines) to very low pressure–to a pressure at which hydrates cannot exist, for example. Hydrates do not form in the liquid line since the oil has already undergone a low-pressure flash in the separator, thereby removing methane and ethane to insignificant levels.

In many cases, the gas line and liquid line can have very similar internal diameters. This allows the system to accommodate round-trip pigging through the gas line, returning through the liquid line.

Another important benefit of having a gas/liquid separator is that subsea wells can be readily unloaded. Venting the separator provides very low backpressure on the well and can be used for restarting wells that have loaded after a shutdown. Another benefit is that gas lift in the production wells can be accomplished with lower gas supply pressure, requiring a fraction of the lift gas volume versus conventional gas lift methods. Gas lift improves the recovery from reservoirs located at significant depths from the mud line, while the separator improves the system efficiency for applications with long stepout distances and/or in deepwater environments.

Sand Handling Challenges

An important challenge when processing fluids at the seabed is how to handle the sand. Sand may cause degradation of pumps as a result of wear or clogging of separation equipment. Another challenge is determining where to route the sand from a subsea separation system once it has been separated from the well stream. Problems associated with sand always will be one of the main concerns to address when selecting and designing a subsea separation system. At present, a number of uncertainties around sand handling plague equipment design and selection.

One example is the uncertainty regarding the actual sand production rate, and how the sand production rate can be estimated in the basis of design. Optimal modeling tools to quantify sand production are not available, often resulting in a very conservative assumption of the quantity of sand a subsea processing system must handle. This can result in a more costly and complex processing system. This makes it is difficult to develop an operational procedure that protects the system from high sand production rates.

Another example is uncertainty regarding how sand will impact the long-term performance of the processing equipment, such as pumps and separators. This is a fundamental design parameter for a subsea separation system.

In addition, no ideal flow streams exist to route the separated sand that is being processed in the subsea station. Especially in applications with water separation and reinjection, it would be beneficial if the sand always could be reinjected with the water. This is a simple process which also removes a problem for the topside facility. However, reservoir experts disagree on the feasibility of how much sand could be reinjected in a given reservoir or disposal zone. Better knowledge in this area is necessary to develop optimal subsea separation systems.

A final example is uncertainty regarding how sand can be transported in pipes downstream in the separation process. For a subsea separator where water has been removed from the oil and gas stream, there may not be sufficient liquid to enable sand transportation in a long pipeline to the topside facility–especially at turndown rates in late-life scenarios. Therefore, a better understanding of sand behavior in multiphase flow in pipes is essential when designing such a sand handling system.

Based on these challenges, it is obvious that sand handling is an important factor to consider when designing a subsea separation system. This topic will continue to receive considerable focus as the industry seeks more advanced separation equipment for new subsea processing applications.

Increasing Stepout Distances

As offset distances increase, a number of technical and cost challenges also will increase. Some of the key issues related to offset distance and potential mitigation options are flow assurance, long-distance controls and communications, and long-distance subsea high-voltage transmission and power delivery. Many of the mitigating solutions to overcome these challenges are either already field proven or under development.

As offset distance increases beyond 30 miles, an important technical challenge is flow management in hydrocarbon export flowlines and risers. The combination of hydrate management, wax deposition and the cost of dual flowlines for round-trip pigging becomes very expensive. Potential mitigation options include improved oil polishing to achieve a very low basic sediment and water content, direct electrically-heated flowlines, pipe-in-pipe flowlines with special insulation gels, exothermic chemical reactions, tube tracing under wet insulation, and other solutions.

Industry research also is beginning to investigate "cold flow" techniques, especially for cost-effective hydrate management without insulation or heat. Mitigation of wax buildup is often achieved through regular pigging operations. Single-pipeline operations with subsea pigging have been tested.

With respect to long-distance controls and communications, communication signals on low-voltage power are available for up to 50 miles offset. The signal on fiber is available for up to 160 miles. Both technologies are field proven. The industry is headed toward all-electric subsea systems to perform all actuation functions, which eliminates the need for hydraulics, reduces the number of tubes (therefore the cost of umbilicals), and improves the overall reliability and availability of the system.

Finally, in regard to long-distance, high-voltage subsea transmission and power delivery, most subsea processing and boosting projects use surface or onshore variable speed drives with a dedicated power triad in the umbilical for each power consumer (subsea electric motor). For projects in the 10-50 mile region, high-voltage power will be transmitted at high voltage (~120 kilovolts) and step-down transformers on the seabed will convert the power to the required voltage.

For very long offset distances and multiple motors, the cost of the power umbilical becomes prohibitive and makes it uneconomical to develop the field. These projects will consider the use of subsea variable speed drives combined with a subsea step-down transformer and subsea switch gears. An alternative might be using a floating mini tension leg platform or spar for dry topsides location of high-voltage switchgear, transformers and variable speed drives located directly above the pumps.

Existing subsea separation solutions have many applications and provide several benefits that are being harvested today. A subsea separation solution will, in many cases, enhance the flow and production profile, while most importantly, increasing total recovery from an offshore reservoir. These solutions can prolong the life of existing fields, greatly enhancing the returns for fields that otherwise may be deemed uneconomical. ❐

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