Applying Subsea Fluid-Processing Technologies for Deepwater Operations

Xingru Wu, University of Oklahoma; **Feyidamilola Babatola,** Linde Process Plants; **Lei Jiang,** Rhombus Energy Solutions; **Brandon T. Tolbert,** University of Oklahoma; and **Junrong Liu,** China University of Petroleum (East China)

Summary

Subsea processing is an evolving technology in response to ultradeepwater hydrocarbon development and has the potential to become one of the most attractive methods in the oil industry to economically unlock hydrocarbon resources. The objective of this paper is to examine the features of subsea fluid-processing technologies and capabilities, and compare the advantages and disadvantages of different facility types. The advantage of subsea processing systems is that they allow fluids to be boosted from longer tieback distances. Constraints associated with subsea processing systems include operation efficiency, produced-water- and sand-handling capabilities, and the system's ability to handle hydrates/scale. In this paper, we reviewed the application of subsea systems in 12 deepwater fields and discussed the significance of each. Furthermore, future subsea-technology development and anticipated challenges are outlined in this paper. The significance of this study is to summarize the lessons learned from current available uses so that future decisions regarding the application of these subsea processing technologies can be made appropriately and efficiently.

Introduction

Subsea processing is an evolving technology in response to ultradeepwater hydrocarbon development and has the potential to unlock a significant amount of hydrocarbon resources. The application of subsea processing technologies in deepwater hydrocarbon plays has the following advantages:

1. Enhances environmental and safety performance
2. Reduces the space and weight of the host platform
3. Allows for fields to be managed remotely
4. Increases total hydrocarbon recovery over the field life and accelerates production
5. Allows hydrocarbons to be produced from deeper and more-hostile environments that were not feasible previously

Therefore, subsea processing systems with industrial standards are becoming more favorable in the development of offshore hydrocarbon plays and are replacing traditional systems.

Subsea processing comprises all the activities involved in fluid conditioning and pressure boosting of wellstream fluids and water injection at the seabed. The major equipment of such a subsea processing system includes pump, separator, power-distribution system, and compressor installed on the seafloor. For oil systems, subsea processing provides pressure boosting, processing, and bulk-water separation. For subsea injection-water treatment, the process may include raw-water filtration, produced-water desanding and/or deoiling, and pressurizing processed seawater. For gas systems, subsea processing includes gas compression and gas dewpoint control/dehydration. In a subsea processing system, the wellstream fluid flows through a subsea processing unit, where sand and entrained solids are removed. This is followed by the separation of the gas and liquid components in the hydrocarbon stream at the existing temperature and pressure. The gas stream is then compressed, and the liquid stream is pumped to a processing facility onshore. If it is necessary, the liquid stream can be further separated into oil and water, and the gas can be reinjected into the reservoir or wellstream to recover more liquid oil. Chemical conditioning and active heating may be applied subsea before the processed fluids are pumped to the receiving facility (Abili et al. 2012).

In this paper, we discuss the components of a subsea processing system with emphasis on pumps and separation equipment. Additionally, we will investigate offshore assets that currently apply subsea processing technologies to extract hydrocarbons to identify challenges facing the industry and opportunities for the future development of subsea fluid-conditioning technologies.

Subsea Pumping

Since the middle of the 1990s, more than 60 subsea pumps have been deployed, with increasing power and water depth (Marjohan 2014). A subsea pump differs from a standard topside pump in that it requires protection from the hydrostatic column. Hence, the pump housing and the electrical motor have to be encapsulated in a common pressure-containing vessel, which includes the following elements: pressure housing, pump cartridge, electrical-motor cartridge, high-voltage penetrators, and a barrier-fluid system.

Subsea pumps add mechanical energy to the produced fluid to overcome pressure losses in the pipelines (Magi et al. 2012); therefore, subsea pumping systems are often used to improve oil recovery, increase production rate, and extend lifetime of fields (Eriksson and Antonakopoulos 2014; Marjohan 2014). The installation of a subsea pump can lower the backpressure on the reservoir and increase the hydraulic head for boosting the boarding pressure at the processing facility. Reducing the backpressure in the bottom of a well leads to an increase in drawdown, resulting in a higher production rate from the reservoir. Additionally, increasing the boarding pressure gives the operator more tolerance to handle production issues such as well slugging. **Fig. 1** shows a typical subsea pumping system used in deepwater operations.

When selecting a subsea pump, it is important to consider the amount of gas in the produced fluid. If low gas rate is expected with the produced fluid, then a single-phase pump is an adequate solution; otherwise, a multiphase pump or a premotor separator is required. Traditional engineering practice is to separate the fluids into the gas and liquid streams as soon as they reach the surface. However, this is not always practical for the following reasons:

- The resources are located in remote areas that do not favor traditional separation facilities. Local degassing of the wellstream would be extremely expensive operationally, so the satellite wells have to be connected to a remote central host to achieve an economic production.
- In some instances, boosting is required before phase separation because of large step-out distances and extreme water depths.

The issues listed in the preceding can be mitigated by use of a multiphase pump to boost the untreated production stream to a remote host or processing facility. A few of the subsea pumping systems

Original SPE manuscript received for review 30 July 2015. Revised manuscript received for review 8 April 2016. Paper (SPE 181749) peer approved 12 April 2016.

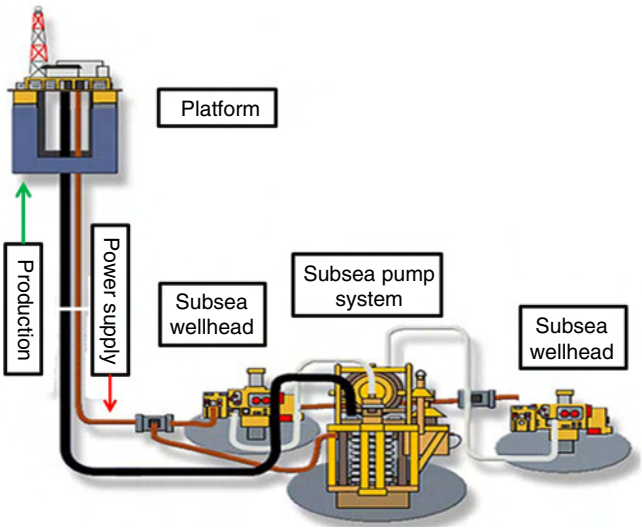


Fig. 1—Subsea pumping-system network for deepwater development (after Curtiss-Wright Flow Control Company 2012).

currently applied in the development of offshore fields are described in the following subsections.

Electrical-Submersible-Pump (ESP)/Caisson System. In this system, an ESP is installed in a dummy well or caisson on the seafloor. The caisson may be used as a gas/liquid separator to accommodate high-gas/oil-ratio (GOR) oils. The ESP/cassion system can be configured in the following ways:

- At a riser base as a slug catcher
- Subsea with gas/liquid separation at a moderate water depth
- With an ESP only in a marine riser in deep water without separation

With gas/liquid separation, this system can handle any GOR and can achieve low suction pressures without being limited by the high gas volume fraction at the pump suction that occurs at low suction pressure. In addition, it can achieve a high boosting capability suitable for any water depth. The disadvantages of this system include the need for an adequate power source to drive the electrical motor housed in the ESP and high pulling costs associated with workovers (Bass 2006).

Helico-Axial Multiphase Pump (HAP). The HAP is a dynamic pump capable of handling high gas volumes. As suction pressure drops, gas volume fraction increases and liquid volumetric efficiency declines accordingly, limiting the practical achievable suction pressure and, therefore, ultimate recovery. Because this is a seafloor system, larger motors are practical, and intervention is simpler and costs relatively less compared with an ESP/caisson system. Consequently, both capital expenditures and operating expenditures are lower compared with an ESP/caisson system for larger applications. In short, this pumping technology features simple mechanical design, compact size, tolerance of solids, and high efficiency in high gas volume fraction, and it is easy to deliver as a whole package, which sets the HAP as the established industry leader in subsea pumping deployment (Marjohan 2014).

Twin-Screw Pump (TSP). The TSP is a positive-displacement pump capable of boosting heavy oils efficiently. Although the pump can operate with very high gas volume fraction, as suction pressure drops, gas volume fraction increases and volumetric efficiency declines. This limits the practical achievable suction pressure and, therefore, ultimate recovery.

Subsea Separation

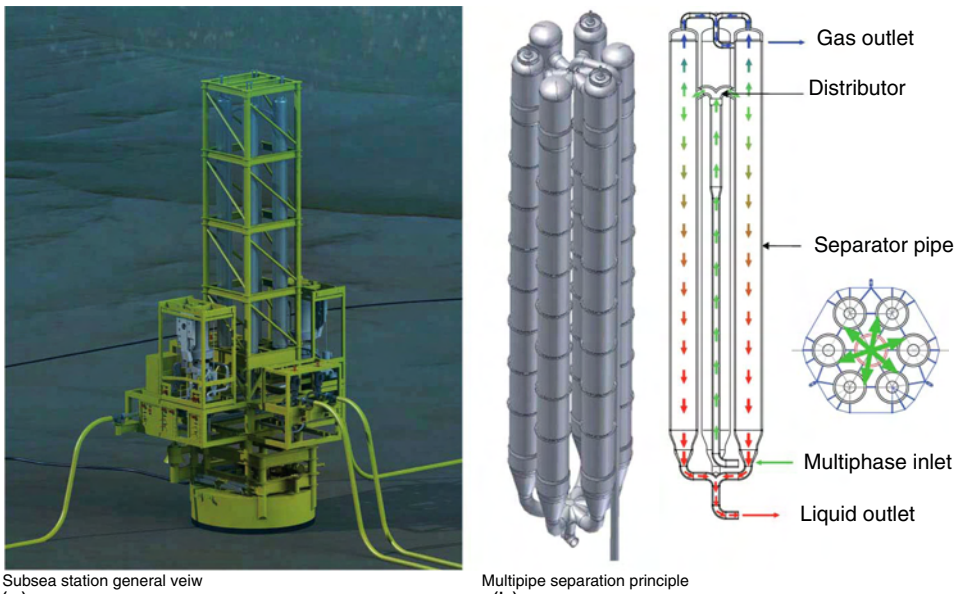
Subsea separation allows for longer tieback distances and improvements in flow assurance and slug-handling capabilities. The current state-of-the-art subsea-separation projects use large, gravity-based separators: horizontal for oil/water separation and vertical for gas/liquid separation.

An ongoing challenge of offshore operations is the proper disposal of produced water as a result of strict offshore disposal standards established by government regulatory authorities. In an offshore environment, the produced water is either injected back into the formation or disposed of into the ocean. Gas/liquid-separation systems are normally used in conjunction with the subsea pumps to increase the energy-efficiency factor (Haheim and Gaillard 2009). Various subsea-separation designs are currently available for both two-phase and three-phase separation (Chiesa and Eriksen 2000), and separation techniques and technologies are discussed in the following subsections.

Gas/Liquid Separation. Gas/liquid separation is used to separate the liquid phase from the gas phase at low pressures. Separating the gas phase from the liquid phase reduces the risk of hydrate formation in the pipeline, thus reducing potential downtime and ensuring smooth operation. Separation systems used in offshore applications have various designs (Jahnsen and Storvik 2011; Khoi Vu et al. 2009). A few are discussed in detail in the following:

- Vertical gravity gas/liquid separation: This separation process uses gravity differences to achieve the separation of phases. Vertical gas/liquid separation systems include a perforated plate and/or demisting cyclones that increase separation efficiency by promoting an even flow distribution across a large surface area.
- Multipipe gas/liquid separation: This separation process distributes the incoming wellstream into several parallel pipe sections, as shown in **Fig. 2.** By forcing the wellstream to flow through a larger cross-sectional area, the velocity of the fluid is reduced. This makes it possible for liquid entrained in the gas phase to be separated by gravity and fall to the gas/liquid interface. Each separator pipe is designed similarly to a conventional gravity separator, and specific inlet arrangements have been developed to enhance separation efficiency. The separated liquid and gas phases are then commingled in two single outlets at the bottom and at the top of the pipe bundle, respectively. The entire separation system and the associated piping network provide a continuous flow path with a self-draining design to prevent the accumulation of solid particles. The separator is configured to be integrated into a single subsea station that includes a pump and the production manifold (Di Silvestro et al. 2011).
- Inline gas/liquid separation: This separation process achieves separation by cyclonic flow. Fluid enters a swirl element, where a centrifugal force is imposed on the fluid. The centrifugal force causes the lower-density droplets (entrained gas) to move toward the low-pressure central core and the higher-density droplets (liquid phase) to be thrown against the wall of the separator vessel. The liquid and gas then proceed to their separate outlets. For gas/liquid separation, three applications of inline gas/liquid separation technology are currently available:
  1. A degasser for removing gas from liquid-dominated streams
  2. A deliquidizer for removing residual liquid from gas-dominated streams
  3. A phase splitter for bulk separation of gas and liquid

Initially, the phase splitter separates 1 to 5% of the dispersed phase from the continuous phase. Then, the deliquidizer and degasser are able to separate 80 to 99.5% of the dispersed phase from the continuous phase. Performance depends on the droplet size of the dispersed phase and on the physical and interfacial properties of the liquid and gas (Olsen 2005). Advantages of inline-separation tech-



Subsea station general veiw
(a)

Multipipe separation principle
(b)

Fig. 2—(a) Subsea station and (b) multipipe gas/liquid-separator principle (http://www.saipem.com/static/documents/BAT_Multipipe.pdf 2014).

nology include low operating costs, no moving parts, compact design, and the ability to be retrofitted to pipe segments.

- FMC Technologies CDS-Gasunie™ gas/liquid separation: This separation process is based on compact scrubber design. It includes a cyclonic scrubber with internal swirl blades (spiral vane) to promote gas/liquid separation, a conical plate to prevent foaming, and an antiswirl blade to prevent vortexing in the bottom section of the vessel. Further, the separator design includes a large volume in the lower portion of the vessel to handle slugs.
- Caisson gas/liquid separation: This separation system includes an ESP and a tall separator, both installed in a dummy well. The tall, narrow separator serves as a surge volume to accommodate slugs and encapsulates the ESP. Disadvantages of an ESP/caisson unit include high capital and intervention costs and the inability to handle large amounts of foaming crude oil.

Liquid/Liquid Separation (Two-Phase Separation). Liquid/liquid separation is used to separate water from the oil phase. Separation systems that perform liquid/liquid separation include semicompact gravity separators, inline bulk deoilers, hydrocyclones, and multipipe separators (Jahnsen and Storvik 2011). These separation systems are discussed in more detail in the following:

- Semicompact gravity liquid/liquid separation: The semicompact gravity liquid/liquid separator is one part of the subsea separation boosting and injection (SSBI) unit. Oil, gas, and water are routed to the inlet of the separator where the gas is separated from the liquid phases in the inlet cyclone. The unit can be retrofitted with a sand-removal system that routes the sand batchwise to a desander vessel in instances where there is significant sand production.
- Inline bulk liquid/liquid separation: In this system, separation of oil and water is achieved by inducing swirling flow on the fluid with the use of a swirl element. The centrifugal force enables separation of the two phases, oil and water, with different densities. An example of an inline bulk liquid/liquid separation system is shown by Bjorkhaug et al. (2011). The benefits of bulk inline separation include low weight and small footprint, ease of retrofit to pipelines, low cost, and reduced safety-system requirements.

Subsea Injection

Subsea water injection can eliminate the need for risers and flowlines to carry produced water to the surface. An example of a subsea-injection system is shown in **Fig. 3. Table 1** highlights the differences between conventional water-injection and subsea water-injection designs. Here, the conventional water injection refers to water injection from the platform or onshore facilities, and subsea water injection is water processing and injection occurring through subsea equipment that is usually installed on the seafloor. For deepwater applications, conventional water-injection designs are less energy efficient because the produced water must be pumped to the surface.

Field Applications of Multiphase-Pumping and Subsea-Separation Systems

In this paper, 12 offshore assets and their subsea processing technologies were investigated. **Table 2** includes the types of subsea technologies applied to each field. **Fig. 4** shows the locations of the fields. The 12 assets were chosen to illustrate subsea fluid processing for the following reasons:

1. Geographically different: Four geographic areas were identified, including the Gulf of Mexico, the North Sea, South America, and West Africa. Different geographic locations may have different logistical problems and environmental requirements, in additional to different subsurface properties.
2. Different applications of subsea-fluid conditioning: We demonstrate applications of different designs of fluid separation, fluid boosting, and water injection.
3. Different water depths: The listed technologies are used in water depth that varies from 250 m to more than 2000 m.

Application 1: Marlim Field, Brazil—Three-Phase Separation With Water Reinjection and Multiphase Boosting. The Marlim field is a system of oil accumulations in the Campos basin located off the coast of Brazil (Oliveira 2008). The field covers an area of 381 km^2 (94,100 acres), and the reservoir is characterized by unconsolidated sandstones with an average porosity of 30%, mean permeability of 2000 md, and oil gravity of 17 to 21 °API. Installing a subsea water and reinjection system in the Marlim field presented many challenges: There was no available disposal reservoir in the production-field area, a subsea separator needed to be installed at

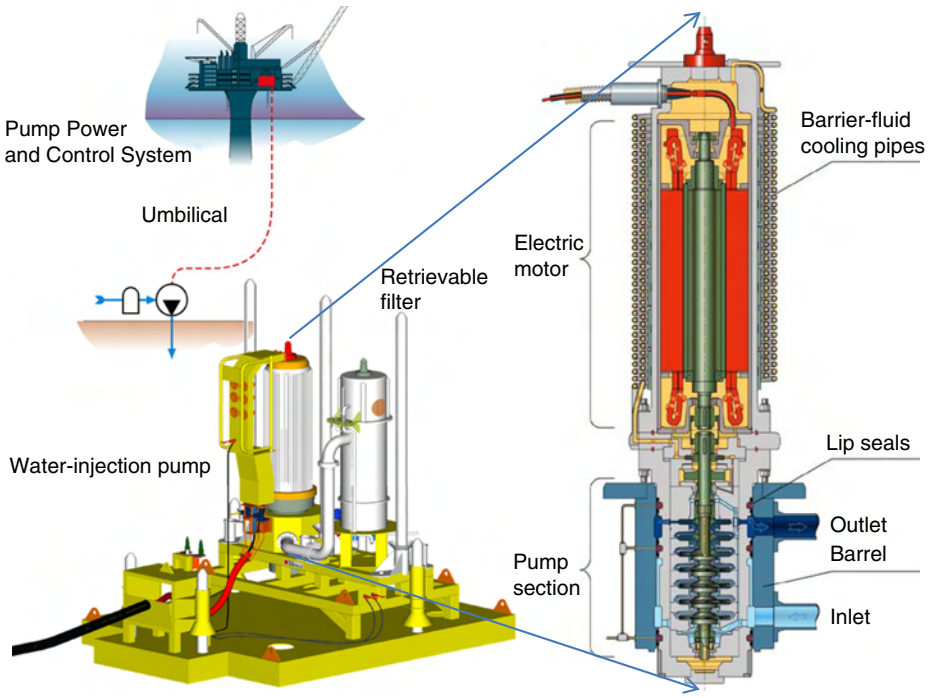


Fig. 3—Diagram of platform-controlled subsea water-injection pump (Vagen 2008; Framo Engineering 2003; modeled after Framo Engineering 2000).

an extreme depth of 870 m below sea level, and the field produced a significant amount of sand.

To manage such challenges, a combination of various types of subsea and separation technologies was used. The subsea-separation system included a harp gas/liquid separator, oil/water pipe separator systems, and two sets of deoiling hydrocyclones. Further, a long, horizontal, large-aspect-ratio pipe separator was used to remove sand from the production stream (Moraes et al. 2012; Orlowski et al. 2012).

Application 2: Marimbá Field, Brazil—Vertical Annular Separation and Pumping System (VASPS). The Marimbá field is located in the Campos basin southwest of the Marlim field. This is where the first VASPS was deployed. The system allowed high-capacity integrated separation and pumping equipment to be installed within a 30- to 36-in. conductor pipe in a dummy well. An illustration of the VASPS unit is shown by Do Vale et al. (2002).

The VASPS works by initially separating the gas and liquid phases at the mudline. Once the streams are separated, the gas flows naturally to the production unit and the liquid is pumped through a separate flowline. Because separation takes place in a compact environment in VASPSs, gas blowby and liquid carryover should be avoided in the design stage. Gas blowby occurs when the gas phase escapes with the liquid phase. This can be detrimental to pumps downstream of the separation vessel. Gas entrained in liquid can lead to cavitation, which permanently damages pump internals. Liquid blowby occurs when the liquid phase escapes with the gas phase. This can cause liquid slugs, scale, and hydrates to form in the gas pipeline (Figueiredo et al. 2006).

Application 3: Parque das Conchas (BC-10), Brazil—Caisson Gas/Liquid Separator With ESP. The Shell BC-10 Block is located 120 km (75 miles) southeast of the coastal city of Vitoria (Orlowski et al. 2012). The reservoir pressure is low, and the oil gravity ranges between 17 and 42 °API. Therefore, waterflooding was considered for pressure maintenance and enhanced-oil-recovery purposes (Stingl and Paardekam 2010). The significant breakthroughs in this project include the first full-field development using subsea separation and boosting; the first use of lazy-wave steel catenary risers hung off on a turret-moored floating production, storage, and offloading (FPSO) system; first use of multicircuit high-voltage electrohydraulic-control umbilicals in a single cross section; and the first use of surface blowout preventers to perform well completions. Extensive full-scale onshore testing was conducted before the implementation of the design to optimize the system (Stingl and Paardekam 2010).

The Shell BC-10 project includes a caisson gas/liquid separation unit with an ESP. The 100-m-long caisson unit acts as a cylindrical cyclonic gas/liquid separator. The ESP housed inside the caisson is powered by a 1,500-hp (1.1-MW) motor. The production from eight wells commingles as it enters through an angled tangential inlet spool at the top end of the caisson unit. The liquid and gas separate as the flow stream travels downward 100 m in a spiral pattern. Further separation occurs as liquid is thrown by centrifugal force to the wall of the separator. The liquid then flows

Water-injection parameters	Conventional design	Subsea water design
Oxygen-control requirements	Deaeration < 10 ppb	No deaeration required
Filtration	5–20 μm	Up to 50 μm
Pump requirements	Two parallel pumps	One pump per well
Monitoring	Intensive	Remote-operating-vehicle retrievable problems

Table 1—Differences between conventional water-injection design and subsea water-injection design for raw-water injection.

Operator, Year	Field Name	Location	Project Drivers	Technology Used	Technology Type	Technology Supplier	Water Depth (m)
Petrobras, 2011	Marlim	Eastern Brazil	Increased water production	Inline	Subsea separator	FMC	400–1800
Petrobras, 2001	Marimbá	Eastern Brazil	Flow assurance	VASPS	Gas/liquid separator and ESP	Cameron	400
Shell, 2009	BC-10	Eastern Brazil	Low reservoir pressure/heavy oil	Caisson	Caisson/artificial nonseparated	FMC/CDS	1500–2000
Total, 2011	Pazflor	West Africa	Hydrate formation risk/low reservoir pressure	Vertical separator	Gas/liquid separation with seabed boosting	FMC/CDS	600–1200
Hess, 2013	Ceiba	West Africa	Increase production rate	Multiphase HAP	Full-field development	Framo	2200
Shell, 2010	Perdido	Gulf of Mexico	Low reservoir pressure/heavy oil	Caisson	Gas/liquid caisson separators with ESP	FMC/CDS	2450
Statoil, 2001	Troll C	North Sea	Increasing water production	Horizontal SUBSIS	Horizontal SUBSIS	GE/Framo	340
Statoil, 2007	Tordis	North Sea	Increasing water production	Horizontal SSBI	Separation, boosting, water injection	FMC/CDS	200
Santos, 2006	Mutineer/ Exeter	NW Australia	High water cut	Multiphase HAP	Two single multiphase-pump systems	Framo	140–160
BP, 2009	King	Gulf of Mexico	Low reservoir pressure	Multiphase booster pumps	Two multiphase TAPs	Aker Solutions	1500–1650
Petrobas, 2013	Albacora	Campos Basin	Extend production life of the field	SRWI	SRWI pump	Framo	250–1100
Statoil, 2009	Tyrihan	Norwegian Sea	Improved oil recovery	SRWI	Two SRWI pumps	Aker Solutions	285

Table 2—Comparison of subsea pumping and separation technologies used in the reviewed projects.

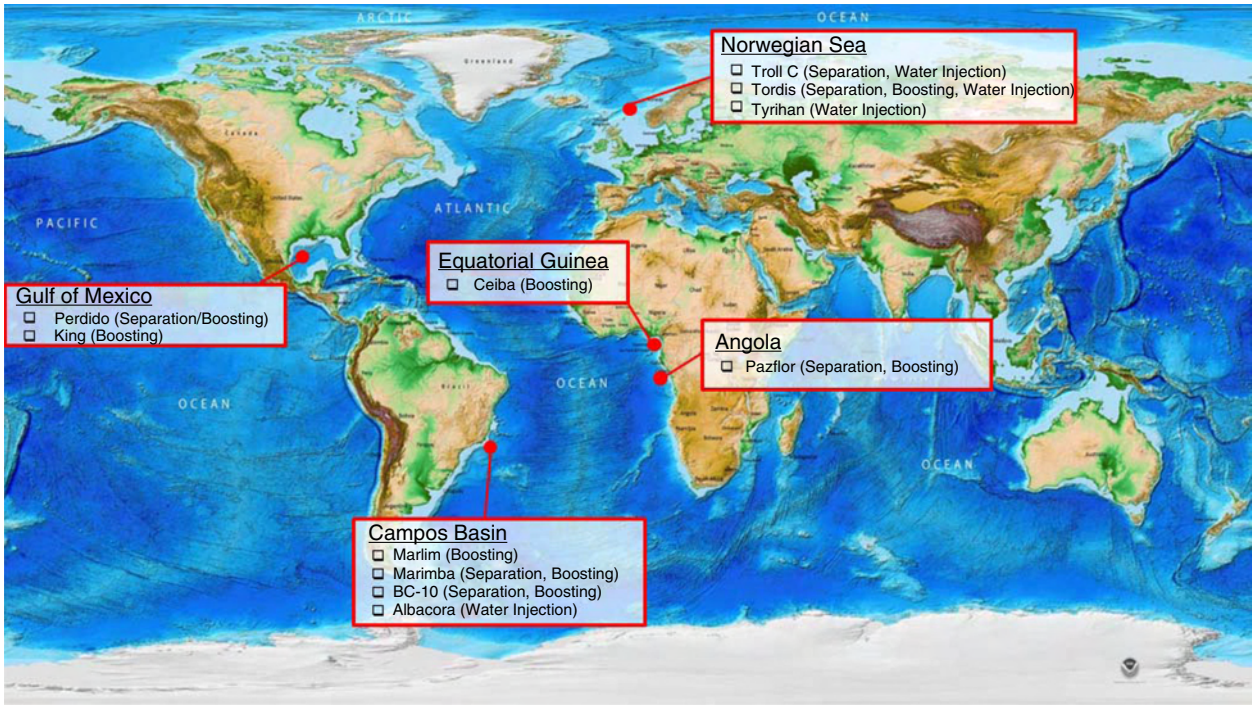


Fig. 4—Locations of the reviewed fields that use subsea separation and/or pumping technologies.

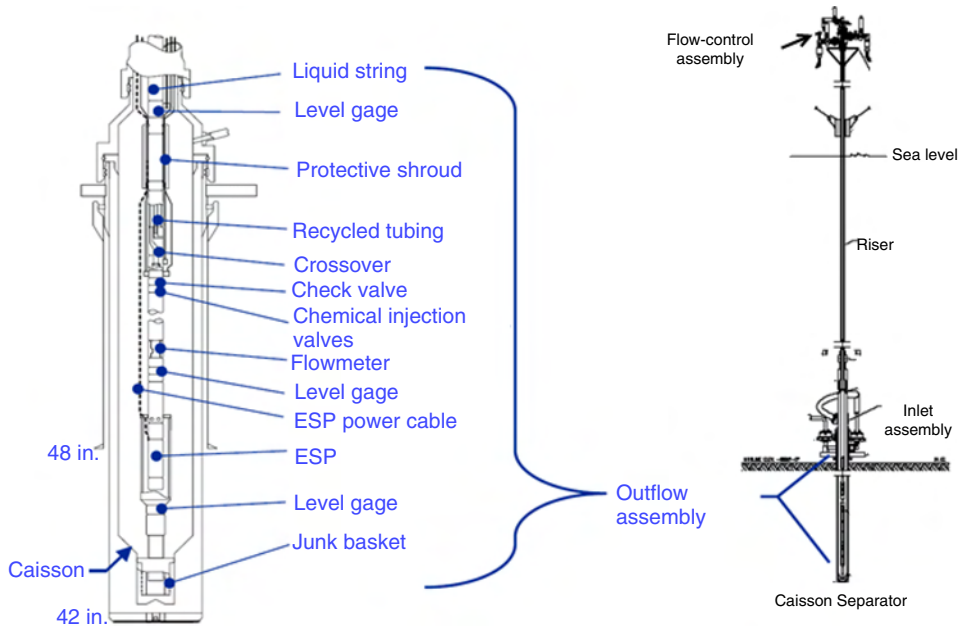


Fig. 5—Caisson separator/riser and boosting system used in Perdido regional development (after Ju et al. 2010).

down to the caisson pump, where it is boosted back upward to the FPSO by the 1,500-hp ESP. This system allows for the efficient boosting of a single-phase fluid, effectively reducing the flowing tubinghead pressure by 2,000 psi in this case. Separation of the gas and liquid by means of the separator also reduces the risk of hydrate formation and slugging. The gas collects in the caisson annulus and flows naturally back to the FPSO through a dedicated gas riser. The multiphase production from the two Argonauta B west wells is commingled subsea at the Artificial Lift Manifold #2. Because this crude has a much lower GOR, separation is not required and the multiphased liquids are boosted straight through 1,500-hp ESPs back to the FPSO. The caissons are housed in modular artificial-lift manifolds (Stingl and Paardekam 2010).

Application 4: Pazflor Field, West Africa—Vertical Gas/Liquid Separators. The Pazflor field is located 150 km (93 miles) off the coast of Angola and 40 km (25 miles) northeast of Dalia. The gas/liquid separator has a capacity of 110,000 B/D of oil and 35 MMscf/D of gas. The system includes two hybrid booster pumps. Development shows that subsea gas/liquid separation and pumping is the key technology enabling production of this heavy oil.

The Pazflor project uses vertical separator vessels to separate gas from the liquid in the production stream. These separator vessels are 9 m tall and 3.5 m in diameter. The function of the separators is to prevent the production fluid from forming hydrates. By preventing the fluid from entering the hydrate-formation region, the separators reduce the need for dual flowlines between the producing field and the host, thereby reducing the total cost of developing the field (Lim and Gruehagen 2009).

Hybrid booster pumps are used to reduce backpressure on the flowlines, therefore increasing total recovery from the field. Multiphase pumps are not applicable in this case because the pressure-differential requirement would not be met. Further, the total power consumption would increase significantly with the addition of multiphase pumps.

Application 5: Ceiba Field, West Africa—Helicoaxial Multiphase Boosting. The Ceiba field is located 35 km (22 miles) off the coast of Equatorial Guinea and 241 km (150 miles) south of Malabo. The subsea system in this field includes helicon-axial multiphase booster pumps. In 2002, two pump modules were installed in the field to increase the production rate from multiple production wells. The two 1-MW electrically driven multiphase pumps were integrated into booster stations positioned between the tree and the manifold. The electrical power was supplied through an umbilical to each station. These two pumps boost the production fluid 7 km back to an FPSO vessel that is located 29 km from the shore. The addition of the two pumps increased total oil production from the field and accelerated the oil-recovery process. Because of the success of the project, three additional pumps have been installed in the field at different locations. The addition of the three pumps helped to boost production from five additional wells (Olsen 2005).

Application 6: Perdido Regional Development, Gulf of Mexico—Caisson Gas/Liquid Separator With ESP. The Perdido field is located at Alaminos Canyon Block 857, approximately 220 miles (354 kilometers) from Galveston, Texas, USA, in the Gulf of Mexico. Perdido includes a spar-based processing hub located at a depth of 7,874 ft below sea level. A caisson separator and boosting system, shown in **Fig. 5,** was installed because of the low reservoir pressure and viscous-oil production. The system allows the separated gas to flow through the annulus of the top tension riser. In addition, a vertical caisson installed below the seafloor is used to house the ESP and the gas/liquid separator. The functionalities of the Perdido caisson separator and boosting system are discussed in the following (Lim and Gruehagen 2009):

- Multiphase flow from the Perdido subsea wells enters the piping mounted on the flow base and proceeds into the inlet block assembly.
- Multiphase flow is introduced to the vertical caisson separator (VCS) by use of a specially designed inlet.
- Separation of multiphase inlet flow into liquid and gas components occurs partially in the inlet block piping, and final separation occurs inside the VCS.
- Gas liberated from the multiphase stream rises naturally through the annulus created between the outer diameter of the ESP tubing and the inner diameter of the VCS/environmental riser.
- The ESP suspended from the spar host facility pumps liquids and associated solids from the caisson separator to surface through a tubing string from which the ESP is suspended.

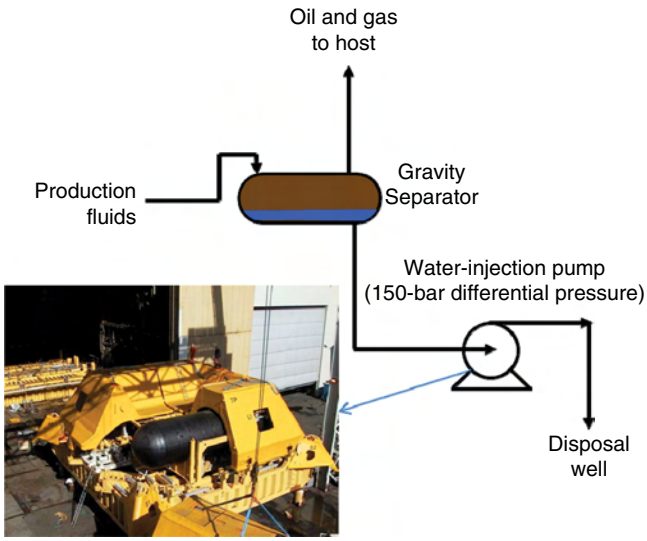


Fig. 6—SUBSIS of Troll C subsea project.

- The ESP string, inlet block assembly, and VCS may be retrieved sequentially from permanently installed foundation tubulars.

Application 7: Troll C Pilot, North Sea—Gravity Separation. The Troll C field is located 100 km west of Bergen, Norway. In January 1996, ABB launched the world's first subsea separation and injection system (SUBSIS) in this field (Knott 1997). The system was designed to handle 38,000 B/D of water and 25,000 B/D of oil. The SUBSIS consists of two subsystems—gravity separation and water injection. Gravity separation takes place in a large pressure vessel that is 10 m long and 3 m in diameter. In principle, the separator is similar to the first stage of a traditional topside process train, but specially designed so that it can function on the seabed. The pressure vessel contains specially designed internals to enhance the separation process. After separation, the oil, gas, and water are routed to specific output devices for further transport and boosting. New and innovative inlet and outlet arrangements have been developed for SUBSIS, as shown in **Fig. 6.** These new designs have replaced stacks of coalescer plates, which are normally used in a separator to enhance the formation of oil and water droplets. The novel inlet device, called the semicyclone, prevents small droplets from being formed by gradually reducing the momentum of the gas/liquid mixture. The gas is preseparated and exits at the top. The oil and water mixture is fed into the separator below the liquid surface into the water phase. The exit velocity of the liquid is very low, thus preventing undesired mixing. Special systems for collecting and disposing of the produced sand have also been developed.

Application 8: Tordis Fields, North Sea—Liquid/Liquid Separation (SSBI). The Tordis asset located in the Norwegian North Sea consists of four subsea fields that are all produced through a single platform. The Tordis fields include an SSBI system. The subsea unit consists of a semicompact, gravity-based separator. The separator removes gas in a cyclonic inlet. The Tordis separator vessel is 17 m long and 2.1 m in diameter. With a design capacity of 100,000 B/D for water and 50,000 B/D for oil, the retention time is minimized to 3 minutes. To avoid risk of clogging or damage, the vessel was equipped with performance-enhancing separator internals. The separator was equipped with a sand-removal system designed to handle 1,100 lbm/D of sand. The sand is disposed of into an injection well along with the water. The pumps and high-voltage power system applied to the Tordis fields consist of two variable-speed-drive (VSD) pumps, a multiphase pump, and a water-injection pump located at the topside of the Gulfaks C platform. The system has proved to be reliable in the Troll field and Tordis fields. It continues to have various applications for offshore water-injection and -boosting systems.

Application 9: Mutineer/Exeter Field, Northwestern Australia—ESP and Helico-Axial Multiphase Boosting. The Mutineer and Exeter fields are located 150 km north of Dampier along the northwest coast of Australia. Production from the two fields is tied back to an FPSO vessel (Olsen 2005). The reservoir is supported by an aquifer, and water production is expected to increase beyond a water cut of 90% (Claiborne et al. 2002). Mutineer/Exeter's peak output was 100,000 B/D early in the second quarter of 2005.

These fields use a combined subsea boosting system. Each well was installed with two ESPs. The ESPs operate in series with a single multiphase pump located on the seafloor. The multiphase pump is a conventional electric-drive HAP. It was installed in a free-standing support structure, which also contains the manifold, pump bypass line, isolation valves, and individual multiphase flowmeters for the well connections. Each well is tied directly into the multiphase-pump module into a single manifold structure. A bypass line was added next to the pump to minimize downtime if the pump experienced mechanical complications. Further, the design allows for future wells to be easily integrated into the production manifold containing the pump (Claiborne et al. 2002). This system greatly improved the production life of this field by maintaining a high production rate as the reservoir was depleted, therefore maximizing economic potential.

Application 10: King Field, Gulf of Mexico—Multiphase Boosting. The King oil field operated by BP is located in the Gulf of Mexico 100 miles off the coast of Louisiana**.** The field consists of three producing wells tied back to the Marlin tension-leg platform 17 miles away. As the field produced and reservoir pressure declined, the operator identified subsea boosting as a favorable opportunity to maintain production and extend field life. Two multiphase TSPs were proposed to tie back to the Marlin tension-leg platform, as shown by Davis et al. (2009), with an expectation of increasing total recovery from the field by 7%. Some of the innovations and breakthroughs from the project are described in the following:

- The first project of its kind in the Gulf of Mexico to include subsea boosting technology
- Developed a multiple-application reinjection choke-insert system, which enabled quick hook up to the flowline system, resulting in risk reduction and cost savings
- Established a pump-control and -monitoring system that used fiber-optic technology
- Developed a barrier-fluid system that could handle greater depths
- Successfully designed a pumping system at record depths

Application 11: Albacora Field, Campos Basin, Brazil—Subsea Raw-Water Injection (SRWI). The Albacora field is located in the Campos basin 100 km off the coast of Brazil and consists of two producing platforms (P-25 and P-31). After primary depletion, an SRWI system was proposed to increase oil recovery (Buk Jr. et al. 2013). To minimize the injection of solid particles into the reservoir, the water-intake system was placed at a depth of 100 m above the seabed. To reduce the risk of reservoir souring caused by H_2S-generating microbes, the continuous injection of nitrate salt into the injected seawater stream was proposed. The injection started in October 2012 with no significant negative impacts on reservoir souring or injectivity decline. In conclusion, the SRWI system has increased total oil recovery and provided significant economic benefits to the Albacora field.

Application 12: Tyrihans Field, Norwegian Sea—SRWI. The Tyrihan field is located on the Norwegian continental shelf. The Tyrihan reservoir is divided into two separate accumulations, Tyrihan North and Tyrihan South. Tyrihan North is a gas/condensate

reservoir with a thin underlying oil column. Tyrihan South is an oil reservoir with an overlying gas cap as described by Grynning et al. (2009). Among the early concepts of planned development was to use gas injection in combination with water injection to provide pressure support to both reservoirs. Reservoir simulation showed that injecting water at the saddle point between both reservoirs would increase total production from the field by 10%. Engineering concerns regarding the injection of raw seawater include the potential of scales forming because of the incompatibility between formation water and seawater, the injectivity requirement of 88,000 B/D with economic limits, and minimizing the intervention costs associated with the pumping units.

Simulations revealed that the probability of formation-water breakthrough to the producers was very low. Thus, scale problems were not expected to affect field development. To fulfill the required injection rate of 88,000 B/D to the reservoir, it was proposed to install two 2.7-MW, VSD centrifugal pumps in parallel. A parallel-pump configuration was a more-reliable option because if one pump were to fail, injectivity could still proceed with the other functional pump. Additionally, by including two pumps, a wider range of injectivity rates could be achieved if it was later discovered that more or less seawater needed to be injected to optimize production. To increase the reliability and lifetime of the subsea pumping unit, a barrier-fluid system was added to the pump design. A barrier-fluid system prevents seawater, solids, and pumped liquids from intruding into the housing unit containing the electrical motor. This task is accomplished with the use of a pressure/volume regulator (PVR), which creates an overpressure environment so that leakage will always occur from the electrical motor toward the pumped fluid. By ensuring that a constant differential pressure is held across the mechanical seals by the PVR, the life expectancy of the mechanical components within the electrical motor is increased dramatically. Given the solutions to the problems mentioned in the preceding and the economic attractiveness of the project, the SRWI system was selected and applied to the Tyrihans field.

Challenges and Opportunities for Subsea Processing Technologies

From review of the applications shown in Table 2, we identified the following challenges facing subsea processing and fluid conditioning.

1. Gas-compression effect on multiphase boosting: Compression causes the fluid temperature to rise and the density to increase. A significant temperature increase leads to thermal expansion of elements in multiphase pumps. This can result in premature failure of the mechanical components inside the pump.
2. Efficiency of water/oil separation and disposal: The operating efficiency of the separation of multiple phases and the subsea disposal of separated water constrain the applications. Current applications, such as SSBI in the Tordis field, have partially mitigated this problem by injecting the produced water into a well or by pumping the water into the nearby environment. However, water pumped into the environment must constantly be monitored to meet the disposal requirements enforced by regulatory authorities.
3. Solids handling: The presence of solids may damage pump internals or clog separation equipment. This challenge was shown in the Marlim field application in designing subsea separation. Future designs will need to consider efficient methods to handle solids in the production system.
4. High pressure and high temperature: During production, the fluid pressure and temperature could exceed the temperature and pressure rating of the current equipment in use. This calls for stronger materials, and new well commissioning and operating strategies.
5. Environmental regulations: An example is demonstrated in Application 1. If regulatory authorities impose stricter water-disposal requirements, field operators and technology suppliers will face a significant challenge.
6. Challenges from transient flow and flow assurance: Transient flow rate and induced slugging may cause pumps to operate outside of their safe operating ranges, resulting in downthrust damage or cavitation. Consequently, the pump life will be reduced dramatically. To avoid this, slugs must be dampened to an acceptable level before the mixture enters the pump inlet (Hua et al. 2012). As shown in Application 5, the successful management of flow assurance is critical for deepwater-project delivery. Increasing the complexity in the subsea infrastructure increases the difficulty level in managing flow assurance. More-rigorous flow-assurance contingency and mitigation plans should be developed.
7. Challenges from increasing water depth and long distance: As the reservoir is depleted, the wellhead pressure decreases, which causes the differential pressure between the ambient environment and the subsea processing equipment, such as pumps and separators, to increase. Large differential pressure may cause facility-integrity issues and operation concerns. Long-distance controls and communication are critical factors for effectively controlling and monitoring subsea processing systems. As the stepout distance and system complexity increase, communication and control methods will have to be modified. The challenges from long distance and increasing water depth are also related to the challenges of reliable subsea high-voltage-power delivery and distribution (Lai et al. 2014), as shown in Application 3.
8. New subsea technology comes with a cost: Subsea operations are much more expensive than onshore/shallow-water counterpart operations. Application 10 is one of many examples presenting the cost-effectiveness challenge. If the cost of applying new technology is not economically justified under the given circumstance, it will not be used.

Given the preceding challenges in subsea-fluid processing, we forecast technology developments of subsea fluid-conditioning processes in the following areas:

1. Future subsea pumping technology will likely include multiphase pumping systems, ESPs, and HAPs. They will dominate the majority of the market for subsea processing equipment.
2. High-differential multiphase pumps will be required to handle fluids at large stepout distances. Current subsea multiphase-pump designs demonstrate a maximum pressure differential of 45 bar (Cerqueira et al. 2013). This pressure differential will need to increase (possibly up to 150 bar) to provide effective pressure boosting of maturing fields (Albuquerque et al. 2013).
3. Development of subsea surveillance technology will be a critical factor for handling the challenges in subsea processing. Real-time surveillance of pressure, temperature, flow logistics, and flow rate are critical to diagnose problems associated with subsea processing equipment. The latest sensing and fiber-optic technologies show tremendous promise to be able to acquire the data necessary to troubleshoot potential problems and enhance operation efficiency.
4. As stepout distance and water depth increase, the need for compact and more-efficient separation equipment will be required. In addition, *API RP 17N, Recommended Practice for Subsea Production System Reliability and Technical Risk Management* (API 2009) and *API RP 17Q, Subsea Equipment Qualification-Standardization Process for Documentation* (API 2010) will be strict requirements for future system designs.
5. Separation technology will likely need to rely on advanced concepts such as high gravitational-force separation, electrostatic forces, and multiple low-diameter units.

Conclusion

The application of subsea technology has made the recovery of hydrocarbons from some of the world's most remote locations possible. Current technologies have not only significantly improved recovery

from these fields, but have done so economically. Boosting technologies, such as HAPs and TSPs, have made it possible to produce from offshore fields at great depths. Further, they are able to transport produced fluids to a common host facility at the surface and improve flow assurance. Subsea-separation technology has greatly improved the subsea boosting processes. In addition, it has provided a feasible solution for offshore fields that experience increasing water production and constrained topside facilities. It has been shown that offshore fields that use both systems are able to produce much more efficiently for longer periods of time at much lower costs.

Nevertheless, subsea processing technologies have not achieved their maximum potential. Traditional challenges, such as gas volume fraction, solids handling, and water/oil separation, can be improved. Future challenges include increasing stepout distances and increasing water depths. More-complex subsea processing systems are expected in the near future to address these challenges. The industry will continue to invest in subsea processing technologies to sustain growth of the offshore industry. The success of future subsea processing designs will likely depend on surveillance technologies and advancements in material science. All things considered, subsea processing systems have come a long way and will continue to have a significant role in the development of current and newly discovered fields.

References

Abili, N., Udofot, O., and Kara, F. 2012. Subsea Processing: A Holistic Approach to Marginal Field Developments. Presented at the Offshore Technology Conference, Houston, 30 April–3 May. OTC-22860-MS. http://dx.doi.org/10.4043/22860-MS.

Albuquerque, F. A., Vianna, F. L., Alves, R. P. et al. 2013. Subsea Processing Systems: Future Vision. Presented at the Offshore Technology Conference, Houston, 6–9 May. OTC-24161-MS. http://dx.doi.org/10.4043/24161-MS.

API RP 17N, Recommended Practice for Subsea Production System Reliability and Technical Risk Management. 2009. Washington, D.C.: American Petroleum Institute.

API RP 17Q, Subsea Equipment Qualification-Standardization Process for Documentation. 2010. Washington D.C.: American Petroleum Institute.

Bass, R. M. 2006. Subsea Processing and Boosting—Technical Challenges and Opportunities. Presented at the Offshore Technology Conference, Houston, 1–4 May. OTC-18261-MS. http://dx.doi.org/10.4043/18261-MS.

Bjorkhaug, M., Johannesen, B., and Eidsmo, G. S. 2011. Flow Induced Inline Separation (FIIS) De-Watering Tests at the Gullfaks Field. Presented at the SPE Annual Technical Conference and Exhibition, Denver, 30 October–2 November. SPE-146688-MS. http://dx.doi.org/10.2118/146688-MS.

Buk, L. Jr., Costa, O. C., de Siqueira, A. G. et al. 2013. Albacora Subsea Raw Water Injection Systems. Presented at the Offshore Technology Conference, Houston, 6–9 May. OTC-24167-MS. http://dx.doi.org/10.4043/24167-MS.

Cerqueira, M., Kuchpil, C. J. D. C., Silva, L. C. T. et al. 2013. Subsea High Boost Multiphase Pump System Development and Applications. Presented at OTC Brasil, Rio de Janeiro, Brazil, 29–31 October. OTC-24428-MS. http://dx.doi.org/10.4043/24428-MS.

Chiesa, G. and Eriksen, R. 2000. Subsea Processing - The Solution to Cost Efficient Deepwater Field Developments. Presented at the Offshore Technology Conference, Houston, 1–4 May. OTC-11892-MS. http://dx.doi.org/10.4043/11892-MS.

Claiborne, E. B. Jr., Malone, B. P., and Marshall, J. C. 2002. Ceiba Completion Optimization: A Fast-Track Approach to Success. Presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, 29 September–2 October. SPE-77434-MS. http://dx.doi.org/10.2118/77434-MS.

Curtiss-Wright Flow Control Company. 2012. Subsea Pumping Technologies. http://emd.cwfc.com/products/spokes/03a_subseaPumps.htm.

Davis, B. E., Kelly, C., Kierulf, K. et al. 2009. BP King - Deep Multiphase Boosting Made Possible. Presented at the Offshore Technology Conference, Houston, 4–7 May. OTC-20146-MS. http://dx.doi.org/10.4043/20146-MS.

Di Silvestro, R., Abrand, S., Shaiek, S. et al. 2011. A Novel Gas/Liquid Separator To Enhance Production of Deepwater Marginal Fields. Presented at the Offshore Technology Conference, Houston, 2–5 May. OTC-21394-MS. http://dx.doi.org/10.4043/21394-MS.

Do Vale, O. R., Garcia, J. E., and Villa, M. 2002. VASPS Installation and Operation at Campos Basin. Presented at the Offshore Technology Conference, Houston, 6–9 May. OTC-14003-MS. http://dx.doi.org/10.4043/14003-MS.

Eriksson, K. and Antonakopoulos, K. 2014. Subsea Processing Systems: Optimising the Maintenance, Maximising the Production. Presented at the Offshore Technology Conference–Asia, Kuala Lumpur, Malaysia, 25–28 March. OTC-24688-MS. http://dx.doi.org/10.4043/24688-MS.

Framo Engineering. 2000. Framo Subsea Multiphase Pumps. Brochure, Bergen, Norway: Framo Engineering AS.

Framo Engineering. 2003. Subsea Pumping—Drivers, Possibilities, and Challenges. Technology for the Next Generation Subsea System. Presented at the SPE Applied Technology Workshop, Oslo, Norway, 11 February.

Figueiredo, M. W., Kuchpil, C., and Caetano, E. F. 2006. Application of Subsea Processing and Boosting in Campos Basin. Presented at the Offshore Technology Conference, Houston, 1–4 May. OTC-18198-MS. http://dx.doi.org/10.4043/18198-MS.

Grynning, A., Larsen, S. V., and Skaale, I. 2009. Tyrihans Subsea Raw Seawater Injection System. Presented at the Offshore Technology Conference, Houston, 4–7 May. OTC-20078-MS. http://dx.doi.org/10.4043/20078-MS,

Haheim, S. and Gaillard, X. 2009. A Simplified Subsea Separation and Pumping System. Presented at the SPE Annual Technical Conference and Exhibition, New Orleans, 4–7 October. SPE-124560-MS. http://dx.doi.org/10.2118/124560-MS.

Hua, G., Falcone, G., Teodoriu, C. et al. 2012. Comparison of Multiphase Pumping Technologies for Subsea and Downhole Applications. *Oil and Gas Facilities* **1** (1): 36–46. SPE-146784-PA. http://dx.doi.org/10.2118/146784-PA.

Jahnsen, O. F. and Storvik, M. 2011. Subsea Processing and Boosting in a Global Perspective. Presented at the Offshore Mediterranean Conference and Exhibition, Ravenna, Italy, 23–25 March. OMC-2011-143.

Ju, G. T., Littell, H. S., Cook, T. B. et al. 2010. Perdido Development: Subsea and Flowline Systems. Presented at the Offshore Technology Conference, Houston, 3–6 May. OTC-20882-MS. http://dx.doi.org/10.4043/20882-MS.

Khoi Vu, V., Fantoft, R., Shaw, C. K. et al. 2009. Comparison of Subsea Separation Systems. Presented at the Offshore Technology Conference, Houston, 4–7 May. OTC-20080-MS. http://dx.doi.org/10.4043/20080-MS.

Knott, D. 1997. Worlds First Subsea Separation and Injection Plant Destined for Troll C. *Oil and Gas Journal* **95** (34).

Lai, R., Zhang, D., Dong, D. et al. 2014. A Modular Subsea Direct-Current Electrical-Power System. *Oil and Gas Facilities* **3** (6): 64–79. SPE-171564-PA. http://dx.doi.org/10.2118/171564-PA.

Lim, D. and Gruehagen, H. 2009. Subsea Separation and Boosting—An Overview of Ongoing Projects. Presented at the Asia Pacific Oil and Gas Conference & Exhibition, Jakarta, Indonesia, 4–6 August. SPE-123159-MS. http://dx.doi.org/10.2118/123159-MS.

Magi, S., Gassert, M., Russo, G. et al. 2012. Subsea Gas-Liquid Separation: Case Studies and Technology Benefits. Presented at the Offshore Technology Conference, Houston, 30 April–3 May. OTC-23478-MS. http://dx.doi.org/10.4043/23478-MS.

Marjohan, R. 2014. How To Increase Recovery of Hydrocarbons Utilizing Subsea Processing Technology. Presented at the Offshore Technology Conference–Asia, Kuala Lumpur, Malaysia, 25–28 March. OTC-24934-MS. http://dx.doi.org/10.4043/24934-MS.

Moraes, C. A. C., da Silva, F. S., Marins, L. P. M. et al. 2012. Marlim 3 Phase Subsea Separation System: Subsea Process Design and Technology Qualification Program. Presented at the Offshore Technology Conference, Houston, 30 April–3 May. OTC-23417-MS. http://dx.doi.org/10.4043/23417-MS.

Oliveira, R. M. 2008. The Marlim Field: Incorporating 4D Seismic in Reservoir-Management Decisions. *J Pet Technol* **60** (4): 52–110. SPE-109336-JPT. http://dx.doi.org/10.2118/109336-JPT.

Olsen, A. B. 2005. Multiphase Boosting - A Cost Effective and Proven Artificial Lift Method. Presented at the Offshore Mediterranean Conference and Exhibition, Ravenna, Italy, 16–18 March. OMC-2005-088.

Orlowski, R., Euphemio, M. L. L., Euphemio, M. L. et al. 2012. Marlim 3 Phase Subsea Separation System – Challenges and Solutions for the Subsea Separation Station To Cope With Process Requirements. Presented at the Offshore Technology Conference, Houston, 30 April–3 May. OTC-23552-MS. http://dx.doi.org/10.4043/23552-MS.

Stingl, K. H. and Paardekam, A. H. M. 2010. Parque Das Conchas (BC-10) - An Ultra-Deepwater Heavy Oil Development Offshore Brazil. Presented at the Offshore Technology Conference, Houston, 3–6 May. OTC-20537-MS. http://dx.doi.org/10.4043/20537-MS.

Vagen, N. J. 2008. First World Wide Subsea Raw Seawater Injection System in Operation on CNR's Columba E Field, Slide 3. Framo Engineering. http://www.possibility.no/utc2008/ps/G3%20Nils%20Vagen.pdf.

Xingru Wu is an associate professor at the University of Oklahoma. Previously, he worked for BP and CNOOC as a reservoir/petroleum engineer. Wu's research interests include reservoir engineering, numerical modeling and simulation, enhanced oil recovery, and multiphase flow in pipes. He holds a PhD degree in petroleum engineering from the University of Texas at Austin.

Feyidamilola Babatola is a project engineer at Linde Process Plants. She has been in this position for 2 years. Babatola holds an MS degree in petroleum engineering from the University of Oklahoma.

Lei Jiang is a power electronics engineer at Rhombus Energy Solutions. He has been in this position for 2 years. Jiang holds an MS degree in electrical engineering from the University of Oklahoma.

Brandon T. Tolbert is a graduate student at the University of Oklahoma. His research interests include hydrocarbon phase behavior in unconventional resources and enhanced oil recovery. Tolbert holds a BS degree in petroleum engineering from the University of Oklahoma. He is a member of SPE.

Junrong Liu is an associate professor at the China University of Petroleum (East China). He has been with the university for more than 15 years. Liu's current interests include deepwater oil and gas production, smart wells, online rate estimation, production alarms, and reservoir simulation. He has authored or coauthored more than 20 technical papers and holds eight patents in China. Liu holds a PhD degree in oil- and gasfield development engineering from the China University of Petroleum (East China).