Comparison of Multiphase Pumping Technologies for Subsea and Downhole Applications

Gong Hua, Schlumberger; **Gioia Falcone,** Texas A&M University;
Catalin Teodoriu, Clausthal University of Technology; **and Gerald L. Morrison,** Texas A&M University

Summary

The selection criteria for multiphase boosting options remain somewhat subjective and are frequently influenced by the vendors' data, which may mask potential limitations of this emerging technology. Existing literature on multiphase pumping tends to focus on a certain pump type for a specific field application, but does not provide more-generalized criteria for the selection of multiphase boosting solutions from among those available in the market. A comprehensive literature review into the working principles of the major pump types identified the intrinsic advantages and limitations of each technology for subsea and downhole applications.

The survey showed that, for subsea application, both the twin-screw pump (TSP) and the helicoaxial pump (HAP) can handle high suction gas volume fraction (GVF) with a fluid recycling system, or flow mixer. Thus, GVF is not a discriminating factor. The positive-displacement principle allows TSPs to work with very low suction pressure, but limits their operating range because of the dependency of flow rate on their relatively low speed. However, these pumps can handle highly viscous fluid. The rotodynamic concept enables the differential pressure of HAPs to self-adjust to any instantaneous change in suction GVF, and to achieve higher flow rate if sufficient suction pressure is maintained. Because HAPs usually run at higher speed, they offer a wider operating range.

For subsea application, HAPs appear to be a better option than TSPs because they offer higher operation flexibility and have a better installation track record.

For downhole applications, the electrical submersible pump (ESP) and the progressing-cavity pump (PCP) are the outstanding favorites, with the latter being preferred for lifting streams that are viscous or with high sand content. For GVF up to 70%, the rotodynamic pump (RDP) is becoming a popular solution. Although it is claimed that the downhole TSP (DTSP) can handle up to 98% GVF, it is not yet widely accepted in the field.

Introduction

Since the onset of petroleum production, typical oilfield practice has been to "degas" the well stream as close to the wellhead as practically possible to facilitate the handling of oil, water, and gas. As different phases are separated and treated individually in the very early stage, this production scheme is viewed as single-phase production. A basic requirement of this concept is that the central processing facilities or topside host be within reasonable distance to each satellite well, so the well stream can be delivered with the aid of natural reservoir pressure or by means of artificial lift. Historically, this single-phase-production scheme has technically and economically satisfied the development of most conventional oil fields, but more recently, the economic viability of this scheme has been challenged by the following factors:

- Significant petroleum accumulations in mature basins are increasingly difficult to access and there are many resources that are "stranded" in locations that do not favor traditional facilities and cannot be economically recovered unless more-cost-effective development methods are found.
- In the development of large offshore oilfields (e.g., subsea in the Gulf of Mexico, Brazil, and west Africa), local "degassing" by processing the well stream may involve high capital and operating expenditure, so connecting satellites to a remote central host is the only economic production technique available.
- The ever increasing stepout distance and water depth of offshore field developments result in significant system resistance in the production stream, which must then be boosted before phase separation for flow assurance.

Many solutions, including subsea processing, have been proposed and attempted to improve stranded-field-development economics. Boosting the untreated well effluent to a remote host or processing facility is a proven concept for multiphase production schemes, and the multiphase pump plays a key role.

The three most commonly used types of multiphase pump on the market are TSP, HAP, and PCP and they can all be installed onshore, offshore, subsea, and downhole. Obviously, the subsea and downhole multiphase-pump applications are the most technically challenging with respect to system reliability. Each type of multiphase pump has its own preferred area of application, but because the industry has yet to systematically discuss and summarize their applicability in subsea and downhole environments, the pump-type selection remains somewhat subjective and influenced by the vendors' technical data that may not reveal the limitations on each pump's application.

To compare the subsea and downhole applicability of the commonly used multiphase pumps, a comprehensive literature review was performed, primarily on the research, design, and application. The sources of literature include SPE and Offshore Technology Conference (OTC) papers from the last 25 years, oilfield magazines, operators' feedback, and pump vendors' marketing material. The comparisons of pump applicability were performed on handling varying GVF (transient flow), low-suction-pressure performance, pump capacity, and pump operating flexibility.

Benefits of Multiphase Production

Multiphase production demonstrates a number of advantages over single-phase production schemes.

Accelerating Production. Multiphase pumps can substantially reduce the flowing wellhead pressure by adding incremental head to the raw well stream to overcome the backpressure from downstream pipelines and facilities. The net effect is to directly reduce the backpressure on the producing formation.

Initiating and Stabilizing Flow in Wells That Cannot Naturally Produce to Remote Facilities. A multiphase pump can be used to initiate the well flow by lowering wellhead pressure during startup. Multiphase pumps can also dampen the slug flow to the topside host, thereby reducing process upsets.

Extending Subsea Tieback Distance. It is often impractical or uneconomic to build a host for every asset, so production from multiple satellites is gathered to a common remote host. By adding pressure to the unprocessed well effluent, the tieback distance from

This paper (SPE 146784) was accepted for presentation at the SPE Annual Technical Conference and Exhibition, Denver, 30 October–2 November 2011. Original manuscript received for review 13 July 2011. Paper peer approved 14 October 2011.

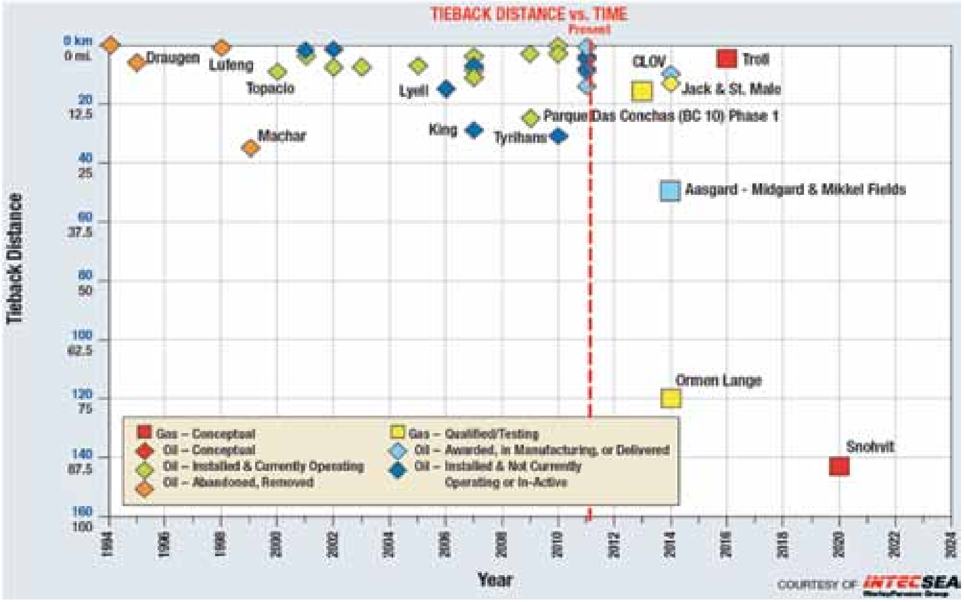

Fig. 1— Current and future subsea pump projects with tieback distance vs. year of installation. [http://www.offshore-mag.com/etc/medialib/platform-7/offshore/maps-and_posters.Par.84540.File.dat/SubseaProcessing-030311ADs.pdf (accessed 10 January 2012).]

the subsea satellite fields to the central processing facilities can be increased well beyond the current record **(Fig. 1).** Within 10 years, it is likely that tieback distance longer than 140 km will be commonplace, and will ultimately be "subsea to beach" to eliminate the offshore host completely.

Reducing Well-Intervention Costs. All subsea multiphase pumps installed to date are designed to be retrievable by a light intervention vessel. A retrievable pump and motor cartridge, including intervention tool, is typically less than 35 tons, which allows the pump and motor to be replaced by a low-cost light interventional vessel in less than 24 hours (Grimstad 2004).

Reducing Subsea-Development Costs. It is estimated that the cost of the multiphase pump is approximately 70% of conventional separation equipment (Dal Porto and Larson 1997). Because multiphase pumping normally increases a well's production rate by several thousand barrels per day, the payback time is typically a matter of months (Falcimaigne and Decarre 2008).

Environmentally Friendly. Multiphase pumping improves the possibility of zero gas flaring, in which the associated gases that were formerly flared can now be transferred to the remote processing facilities for collection and sale (Lastra and Johnson 2005). This not only generates extra revenues for the operators, but also substantially reduces the greenhouse-gas impact on the environment.

Permitting Oil and Gas Developments in Harsh Environments. Subsea multiphase pumping may eliminate the need for local processing facilities altogether. Some Arctic operators are considering using this technology to avoid the need for a topside host platform that may be surrounded by icebergs. This would minimize the risks caused by the environment, as well as alleviate public concern about the Arctic region's environmental protection.

Challenges Facing Multiphase Pumping

Pumping multiphase production streams still faces many daunting challenges yet to be overcome.

Changes in Flow Condition During Life of Asset. A specific model of pump is normally selected on the basis of the expected production, which involves assumptions of bottomhole pressure, water cut, gas fraction, and other reservoir parameters. Over time, actual production may deviate from these initial expectations, so the multiphase pump should be designed to have a wide range of operating parameters to cope with changing flow conditions. In addition to the pump design, a variable-speed drive (VSD) is commonly used to provide additional operating flexibility. Overall, the entire multiphase production system should be sized to cover the evolving operating envelope throughout the life of the asset.

GVF Variation (Transient Flow). During transient-flow situations, continuous liquid flow alternating with long gas pockets can be expected on a random basis. In extreme cases, this can be 100% liquid followed by 100% gas (i.e., GVF from 0 to 100%), which will cause sharp fluctuations in the pumped-mixture density. As a result, the pump load, and, thus, the torque of the shaft, may undergo abrupt variation that could result in serious mechanical problems in the pump. To avoid this, the fluctuation in mixture density must be dampened to an acceptable level before the mixture enters the pump inlet.

Gas-Compression Effect. A multiphase pump is essentially a hybrid of a pump and a compressor. The gases are compressed toward the discharge end. This leads to—from suction to discharge—a significant reduction in the GVF and volumetric rate, as well as an increase in the mixture density. Specifically, as the pressure increases, the gas volume decreases, so the frequency of gas molecule collision increases, which causes a rise in temperature (i.e., the work performed to compress the gas is the energy that increases the gas temperature). Normally, the pump is cooled by the fluid passing through it, but when running under high-GVF conditions, the gas-compression effect can result in a significant temperature increase that may lead to thermal expansion in the pumping elements of TSPs and HAPs. There may also be premature failure in the temperature-sensitive components such as the elastomer stator of the PCP.

Brief History of Multiphase Pumping

Historically, the petroleum industry used single-phase pumps, which, based on their physical working principles, can be divided into three distinct groups:

• Positive-displacement pumps, which physically move a finite volume of fluid from a low-pressure side to a high-pressure side.

• RDPs, which transfer kinetic energy to the fluids through a rotating impeller and then transform the kinetic energy into potential

TABLE 1—MAJOR MULTIPHASE-PUMP TYPES FOR SUBSEA APPLICATIONS

Pump Type	Twin Screw	Helicoaxial
Pumping principle	Positive displacement	RDP—Axial flow
Main supplier	1. Bornemann: mainly onshore and offshore. 2 subsea installations (2005, 2007)	1. Framo: mainly subsea, also onshore and offshore, 15 subsea installations
	2. Leistritz: mainly onshore and offshore. 1 subsea installation (2010)	2. Sulzer: onshore and offshore
	3. GE Oil & Gas: subsea	
	4. Flowserve: onshore and offshore	
Maximum GVF	100% (with external fluid recycle)[1]	100% (with buffer tank or flow mixer)[2]
Differential pressure	Up to 100 bar (1,450 psi)[1]	Up to 200 bar (2,900 psi) (GVF and suction condition dependent)[2]
Total capacity (liquid and gas)	Up to 1,200,000 BPD[1]	Up to 450,000 BPD[2]
Minimum suction pressure	Atmospheric level[1]	40 psi[2]
Mixture viscosity	Low: 0.55 cp (reported)[4]	Low: 2 cp (tested)[3]
	High: No apparent limit	High: 4,000 cp (tested)[3]
Pressure rating	5,000 psi[5]	15,000 psi[3]
Mounting orientation	Horizontal (vertical under development)	Vertical (subsea) or Horizontal (top-side)

[1] Data from Bornemann website (http://www.bornemann.com/multiphase-boosting-technology).
[2] Data from Framo brochure.
[3] Data from Framo website (http://framoeng.no/page/207/framo-multiphase-pump-hx).
[4] Data from Saadawi and Al Olama (2003).
[5] Data from Davis et al. (2009).

energy through a static diffuser; the fluids are "lifted" after acquiring this potential energy. RDPs can be subcategorized into axial-, radial-, and mixed-flow types based on the shape of the impeller.

• Hydraulic pumps, which transfer the kinetic energy from high-velocity fluid to low-pressure fluid by mixing the two, so that the resultant mixture acquires potential energy by decelerating through a diffuser nozzle.

As the need for multiphase production grew, many variants of multiphase pump were proposed on the basis of the single-phase-pump concepts. Although widely used for artificial lift, the applicability of single-phase pumps is seriously challenged when having to deal with varying GVF from the reservoir, so their testing in the field has met with varying degrees of success. The multiphase pumps being used in the industry today fall into the first two groups—positive-displacement and rotodynamic types.

Research into oil-field multiphase pumping began in the mid-1970s by French Institute of Petroleum (IFP) and Total. The early work focused on topside (onshore or on platform) application because it involves the fewest technical requirements in system integration, sealing, and footprints. In 1983, BP, Mobil, Shell, and Stothert & Pitt formed a joint venture to develop a multiphase pump using the twin-screw concept (Dolan et al. 1988). In 1985, Bornemann started to develop its twin-screw-type multiphase pumps for "live crude," and, 3 years later, the prototype topside twin-screw multiphase pump was manufactured and was operated successfully for approximately 3,500 hours in a specially constructed onshore test rig in the UK (Dolan et al. 1988). This was followed by the first commissioning of a TSP on an offshore platform in Malaysia for Shell and subsequently in the North Sea for BP.

The Poseidon HAP project, initiated by Total, Statoil, and IFP in 1984, was a milestone in applying the RDP concept in multiphase applications. The aim of this 5-year project was to develop a reliable multiphase pumping technology for subsea development of deepwater fields (Furuholt and Torp 1988). This project resulted in a prototype of the topside helicoaxial-concept multiphase pump that was installed and tested in a desert application in Tunisia, running for 4,000 hours without mechanical problems (Gié et al. 1992).

After a series of successful topside applications, the potential of multiphase pumping technology for offshore developments with deeper water and longer stepout was acknowledged in the 1990s. Consequently, multiphase pumps required marinization, which introduced a number of challenges in pump-module integration, system-unit qualification, and high-voltage electric-power transmission. The world's first subsea multiphase pump, an HAP type, was installed by Shell in 1995 and successfully boosted the well effluent from a satellite well to the host platform 6 miles (9 km) away (Grimstad 2004). Since then, 15 subsea HAPs have been installed and have accumulated more than 750,000 operating hours. The first subsea multiphase pump of the TSP type was commissioned by CNR in 2005 for a pilot project in the Lyell field in the North Sea. In 2007, BP installed two TSPs in the King field in the Gulf of Mexico in a water depth of 5,430 ft (1700 m) and with a tieback distance of 17 miles (27 km) (Davis et al. 2009).

In April 2002, the first downhole HAP was installed in an onshore well in Colombia, where it was tested to handle up to 75% free gas (Guindi et al. 2003). Another centrifugal-type downhole multiphase pump featuring a multivane impeller has also been developed and deployed, coping with up to 70% free gas. In 2003, engineers began to develop a downhole TSP that could handle up to 98% free gas; it became commercially available in 2006. The major challenge for any downhole multiphase pump is the relatively high intervention cost; hence, the performance and reliability of the pump is critical.

Comparison of Multiphase Pumps for Subsea Applications

There are only two commonly used multiphase-pump types for subsea applications (summarized in **Table 1**)—namely, TSP and HAP. Their operational characteristics are discussed in detail next.

Review of TSP Technology. The TSP was developed in 1934, primarily for viscous boosting service. In the mid-1980s, research was conducted to adapt it for oilfield-service multiphase pumping. The first multiphase TSP was field tested in 1989, followed by the first operational subsea TSP in 2005, and there are currently three TSPs deployed in subsea projects. In addition, TSPs are widely used in topside heavy-oil production. The rotation speed normally ranges from 600 to 1,800 rev/min, but they have been reliably run at 3,600 rev/min to achieve higher capacity. Depending on their size, they can produce a total volumetric flow rate (oil, water, and

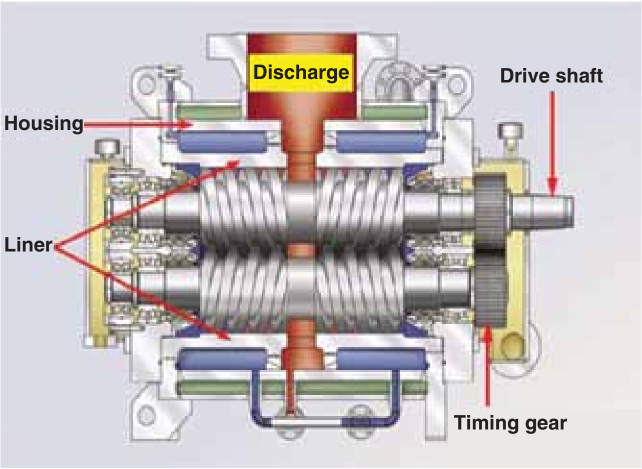

Fig. 2— Diagram of TSP internals. (Courtesy of Leistritz.)

gas) at suction conditions from 10,000 to 300,000 B/D and the differential pressure can be up to 1,450 psi.

The TSP features two parallel helical screws that mesh with each other and are driven by gears on the end of shafts. During operation, the two screws rotate in opposite directions, leading to the helical channel of one screw being periodically obstructed by the other screw. This arrangement allows one screw's flanges and another screw's shaft body, in conjunction with the liner, to form many small chambers that are filled with the pumped mixture **(Fig. 2)** and are subsequently displaced when in operation. As the two screws are rotating, these chambers progress continuously along the shafts from the suction end toward the discharge end, physically moving the mixture from a low-pressure side to a high-pressure side. In other words, the liquid and gas mixtures from the inlet are "caught" and "trapped" by the chambers, and then "squeezed" by the screw flanges and the shaft body, moving from pump inlet toward outlet.

Because of its structure and positive-displacement concept, a TSP has the following characteristics:

• Backflow: In a TSP, a minimum circumferential clearance, or gap, has to be maintained between the screws and liner to accommodate the deflection of the shaft under high-differential-pressure condition and the thermal expansion of pumping elements. These clearances allow a small amount of mixture to flow from high-pressure discharge end back to low-pressure suction end, leading to a degraded pump capacity and volumetric efficiency. Studies show that backflow is related to the differential pressure, GVF, shaft rotation speed, and fluid viscosity (Egashira et al. 1998). When the TSP is used for pure liquid, the increase of backflow is proportional to the increase of differential pressure. However, at high-GVF condition, the backflow is almost independent of differential pressure (Yamashita et al. 2001).

• Pump capacity: The capacity of a TSP is determined by the difference between the volume transferred by the screw chambers and the backflow on the suction side. The actual flow rate at suction (Q_{actual}) can be used to express pump capacity:

$$Q_{\text{actual}} = Q_{\text{theoretical}} - Q_{\text{back}}, \quad \text{(1)}$$

where Qback is the backflow rate at suction and Qtheoretical is the theoretical flow rate that is governed by the geometry of the pump and the rotation speed (Saadawi and Al Olama 2003).

$$Q_{\text{theoretical}} = A \times h \times n, \quad \text{(2)}$$

where A = net flow of the cross-sectional area of the screw, h = screw pitch, and n = screw rotation speed.

For a given application with relatively constant backflow, the TSP flow rate is solely dependent on the pump speed **(Fig. 3),** hence the TSP operating range is directly proportional to its rotation speed:

• Volumetric efficiency: The volumetric efficiency (η_{vol}) of a TSP is defined as the actual total flow rate (gas + liquid) measured at suction condition divided by the pump theoretical flow rate:

$$\eta_{\text{vol}} = \frac{Q_{\text{actual}}}{Q_{\text{theoretical}}} = \frac{Q_{\text{theoretical}} - Q_{\text{back}}}{Q_{\text{theoretical}}}. \quad \text{(3)}$$

Yamashita et al. (2001) identified that the volumetric efficiency is related to GVF, differential pressure, and shaft rotation speed. Specifically, at low-suction GVF, the pump achieves a high pump capacity, but when the differential pressure increases, the pump will lose its volumetric efficiency because of more backflow from discharge to suction. When suction GVF is high (e.g., >60%), the pump liquid capacity drops dramatically, but the loss of volumetric efficiency is less dramatic because the increased gas compression causes less backflow in the suction. Hence, TSP volumetric efficiency is highly dependent on the backflow rate, which is governed by the following factors: minimum clearance, differential pressure, GVF, liquid viscosity, liquid-recycle system, rotation speed, and screw geometry.

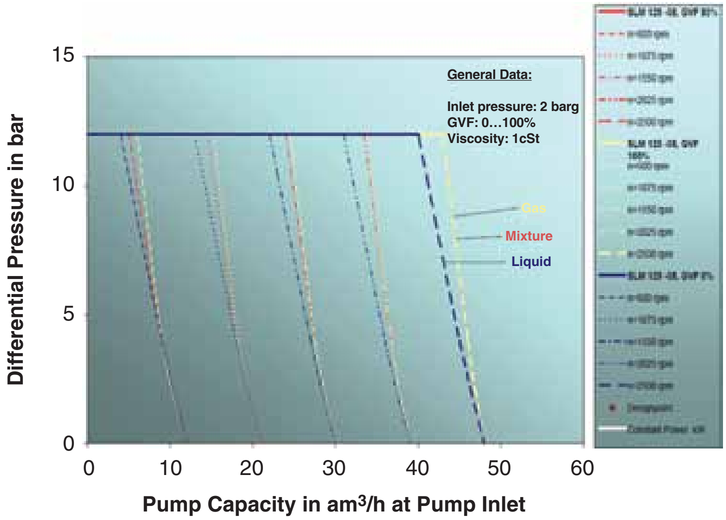

Fig. 3— Performance curves of a commercial TSP. (Courtesy of Bornemann.)

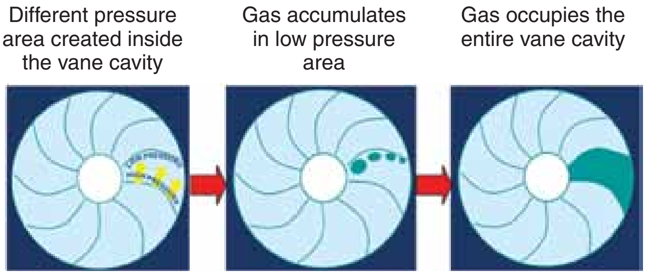

Fig. 4— Progression of gas locking in the centrifugal pump impeller. (Courtesy of Schlumberger.)

• Liquid-recycle system: An external liquid-recirculation system must be used in a TSP to provide the minimum required sealing fluids necessary to maintain the volumetric efficiency and lubricate the pump at high-GVF (>95%) conditions. Most vendors claim that their TSPs can handle mixtures up to 100% GVF, but this is based on using fluid-recirculation devices, which may or may not be factored into the efficiencies claimed by the vendors.

• Viscosity: With the positive-displacement concept, a TSP has the lowest shear rate compared with other pumps used in the petroleum industry and even though it consumes more power to pump viscous fluids, it still can maintain a much higher mechanical efficiency than an RDP. Because the clearance of a TSP is sealed by fluid, the more viscous the fluid, the more robustly the screw tolerates clearance, thus the lower the backflow. Accordingly, for a given GVF, higher-viscosity fluids enable the TSP to achieve higher volumetric efficiency, higher differential pressure, and higher capacity than do fluids with lower viscosity. These features make the twin-screw arrangement ideal for pumping viscous fluids, such as heavy-oil production, for which the technology was originally developed.

• Suction pressure: TSPs can work at a very low suction pressure as long as it is high enough to push the mixture into the first screw chamber. This is because the suction pressure does not contribute to the lift, but only affects the backflow rate through the change of differential pressure. The variation of suction pressure is often associated with varying GVF, which affects the load on the screw shafts. Compared with RDPs, TSPs often run at lower shaft rotation speed, and the screw shafts are normally made with large diameter to minimize deflection, so the impacts of torque variation on the shaft are insignificant. For this reason, a TSP does not require a buffer tank or mixer to smooth out the varying inlet liquid slugs and gas pockets, though extended gas slugs still have the potential to create mechanical damage because of low lubrication.

• Solid issue: If the pumped mixture contains sand, the close internal clearances can cause severe abrasive wear (Dorenbos et al. 2001). One solution is to select a special screw profile with an adequate hard coating and to ensure purging in the mechanical seal area. While the pump inlet housing is helpful in maintaining some fluid to seal the gaps, it can become a "sand trap" and feed the screws with a high-sand-concentration fluid. Therefore, use of TSPs in wells with high sand production should be avoided or a dedicated sand trap should be installed upstream of the pump inlet.

• The TSP can operate at very low suction pressure and is not mechanically sensitive to suction flow conditions (i.e. sharp variation in GVF or suction pressure, transient flow), though extended gas slugs will "blowdown" the pump and cause lack of lubrication. It is ideal for fluid with high viscosity, and its low rotation speed allows the use of cost-effective drivers. However, the TSP is poor at handling solids, because the housing may become a sand trap and cannot be cleaned unless dismantling occurs. It has a limited range of flow rate for a given size, which may necessitate resizing over the life of field, and it is difficult to install in series owing to process requirements for flow balancing between units.

Review of HAP Technology. The prototype multiphase HAP, which was developed during the Poseidon project—an initiative of Total, Statoil, and IFP (Arnaudeau 1988)—is sometimes called the "Poseidon pump," and it is currently licensed to three manufacturers. To date, in surface and subsea application, multiphase HAPs have been manufactured with impeller diameter ranging from 70 to 400 mm and they are normally run between 3,500 and 6,500 rev/min. They cover total flow rate (oil, water, and gas) at suction conditions ranging from 22,000 to 450,000 B/D and with differential pressures up to 2,900 psi. While it is recognized that HAPs can handle more than 90% suction GVF, the actual gas flowing through the pump can vary from 0 to 100%. In general, multiphase HAPs cover a wide range of operating parameters including low suction pressure.

The HAP is within the category of RDPs and has a pumping principle similar to that of a conventional centrifugal pump, which increases fluid kinetic energy by stacking up rotating impellers and transferring the kinetic energy into potential energy by means of static diffusers.

When a conventional centrifugal pump operates in multiphase conditions, the impeller vanes act as an efficient gas separator because the liquids are centrifuged by the rotating motion owing to their higher density whereas the gases are not, resulting in gas/liquid phase separation. On the downside, while the impeller is rotating, the pressure distribution within its vanes creates high- and low-pressure areas, resulting in gas bubbles accumulating on the low-pressure side. If the amount of gas is not limited or if this type of pressure distribution is not changed, then the vane cavities will eventually be filled with gas, and then the fluid passage is completely blocked by the gas **(Fig. 4).** This is known as "gas locking."

The HAP uses specially designed impeller/diffuser geometry **(Fig. 5),** which when combined with the profile of the hydraulic channel, minimizes the radial component of the flow, resulting in an axial flow. Consequently, the gas-separation effect caused by the rotating motion is prevented, and the homogeneity of the two-phase mixture is maintained. Some characteristics of HAPs are discussed:

• Pump head: Because RDPs transfer energy between the pump and fluid, they are normally evaluated by mechanical efficiency. Traditionally, the specific work that a centrifugal pump transfers to

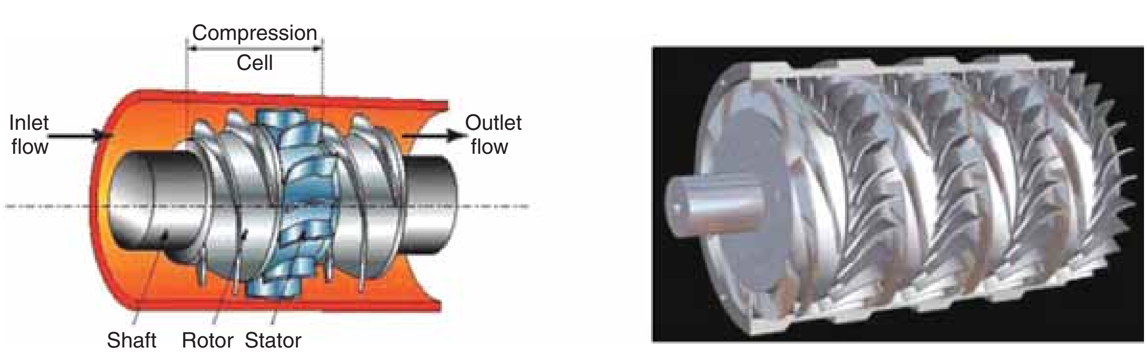

Fig. 5— HAP compression stage. (Courtesy of Framo.)

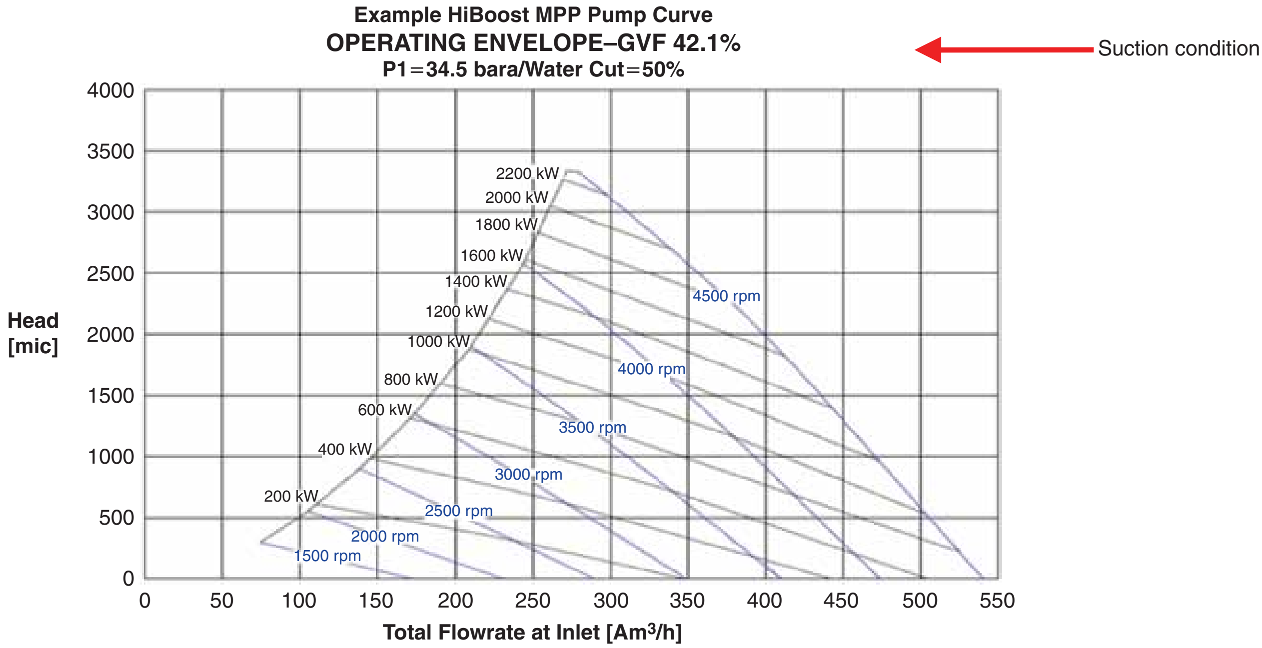

Fig. 6— HAP operating envelope. (Courtesy of Framo.)

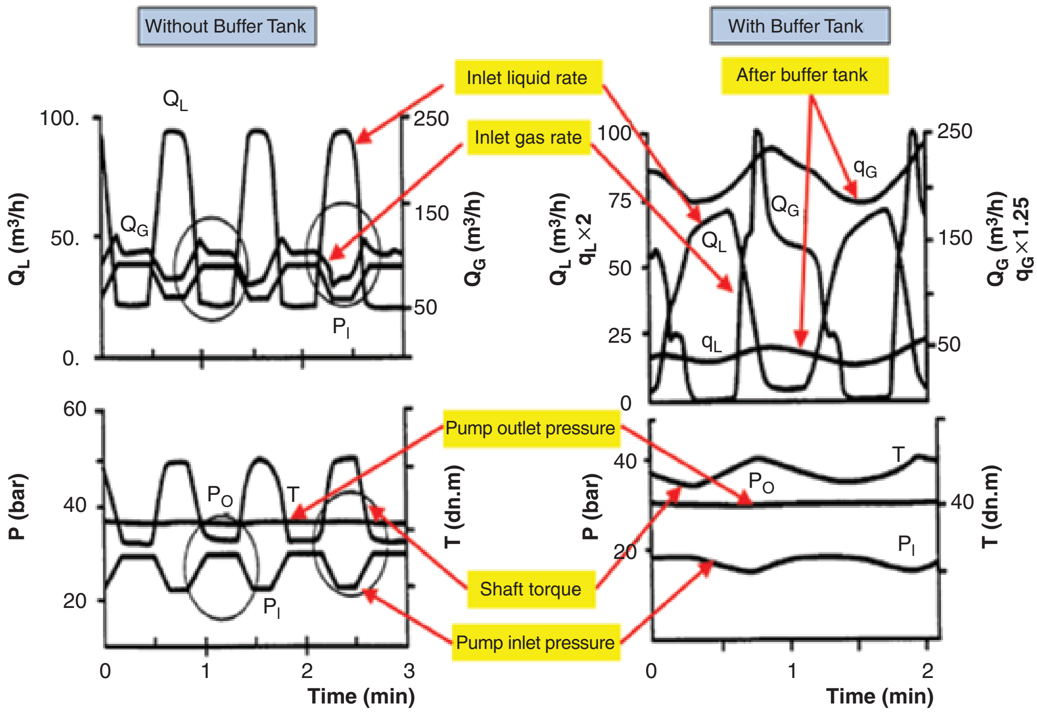

Fig. 7— Effect of buffer tank on shaft torque. (After Bratu.)

the fluid is called the "pump head" (Falcimaigne and Decarre 2008). For a centrifugal pump designed for single-phase fluid, the head is governed by the rotation speed, pump geometry, and the volumetric flow rate, but it is independent of fluid density. At multiphase-flow conditions, the suction GVF and associated suction pressure affect the performance curves. As a result, the head of an HAP is difficult to assess because it is influenced by the velocity slip between different phases, which is difficult to characterize inside the pump. For this reason, the HAP performance curves are normally made under predetermined GVF (or gas/liquid ratio) and suction pressure **(Fig. 6).** In the curves displayed in Fig. 6, the differential pressure is the difference between the discharge pressure and the available suction pressure required to boost the mixture at a stated gross volumetric (suction) flow rate. It is important to note that the HAP can achieve a wide range of flow-rate options by changing the pump speed.

- Self-adaptability to flow change: The ability of differential pressure to adapt itself to the instantaneous changes of the suction GVF is a unique feature of the HAP. The process can be summarized as

Long gas pocket encountered ➔ Suction GVF rises ➔ mixture density decreases ➔ differential pressure drops (and discharge pressure remains constant) ➔ suction pressure increases ➔ flow rate increases ➔ mixture density increases ➔ differential pressure rises.

TABLE 2—MAJOR MULTIPHASE-PUMP TYPES FOR DOWNHOLE PUMPING				
	Pump Type			
	Helico-Axial	Centrifugal	Progressing Cavity	Twin-Screw
Pumping principle	RDP—axial flow	RDP—multivane impeller	Positive displacement	Positive displacement
Main supplier	Schluberger (Poseidon)	Baker Hughes – Centrilift (MVP™)	PCM	CAN-K (ESTSP, TDTSP)
Maximum GVF	75%[1]	70%[2]	33%[3] (elastomer stator)	98%[6]
Maximum pressure	N/A	N/A	4,930 psi (2,200 m total measured depth maximum setting depth)[5]	Up to 3,500 psi[6]
Total capacity (liquid and gas)	5,000–9,000 BPD[1]	18,000 BPD[4]	Up to 6,200 BPD[5]	Up to 450,000 BPD[6]
Temperature limit	450°F[8]	410°F[9]	248°F[5]	662°F[7]

[1] Data from Poseidon datasheet (http://www.slb.com/services/artificial_lift/submersible/gas_solutions/esp_gas_handling/poseidon_gas_handling.aspx).
[2] Data from MVPdatasheet.
[3] Data inferred from PCM brochure (http://www.pcm-pump.com/oil-gas/artificial-lift-pump.html).
[4] Data read from MVP538G110 model pump curve with water as test media at 3,500 rev/min (http://www.bakerhughesdirect.com/cgi/hello.cgi/CLIFT/images/families/pumps/mvp_538_chart.pdf).
[5] Data from PCM website (http://www.pcm-pump.com/oil-gas/artificial-lift-pump.html).
[6] Data from CAN-K brochure.
[7] Data from CAN-K brochure for top drive model (TDTSP).
[8] Data inferred from Schlumberger ESP motor temperature limits.
[9] Data from Burleigh (2008).

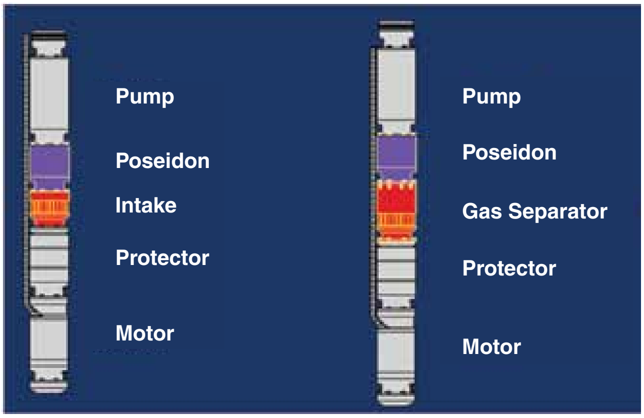

Fig. 8—Typical configuration of ESP string with helicoaxial multiphase pump. (Courtesy of Schlumberger.)

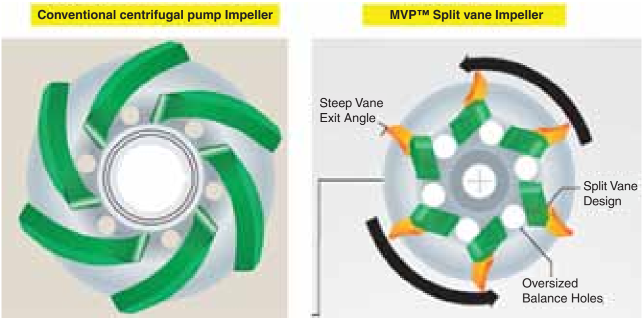

Fig. 9— Multivane-impeller design to handle multiphase flow up to GVF=70%. (Courtesy of Baker Hughes.)

In some cases, it gives the system sufficient operational flexibility that a VSD may not be required, though a VSD will typically add significant operational flexibility over the life of the asset.

• Buffer tank/mixer: When pumping in transient-flow conditions, the pump has to cope with the instantaneous transient-slug-flow conditions with random pockets of pure liquid or pure gas. The rapid change of the suction condition will cause sudden load change, which may cause mechanical problems on the pump shaft. A buffer tank is a container in which the fluid is mixed and homogenized before entering the inlet. The field-test data (Bratu 1995) demonstrate that while the sharp variations of flow condition happen in the inlet of the buffer tank, they are smoothed by the buffer tank and, as a result, the shaft torque fluctuation is minimized over time (**Fig. 7**).

• Viscosity: When pumping viscous fluids, the high velocity of the rotating impeller will cause significant energy loss in the form of dissipated heat and shear because of the increased boundary layer effects and friction between the impeller vanes and the viscous fluid. Explained another way, the impellers need much-higher-than-normal power to impart centrifugal motion to the viscous fluids. When the diffuser converts the fluid kinetic energy into potential energy, the fluid again will lose energy to heat because of the friction with the diffuser. As a result, the overall mechanical efficiency is comparatively low, making the HAP less suited to pump fluids with high viscosity.

• Sand: Unlike the TSP, the HAP has no tight internal clearances, and its geometry of free open hydraulic channels allows it to handle small particulates in the flow. Good design practice must ensure adequate velocities to prevent any sand accumulation in the pump housing or flow mixer. Optional hard face and material coating are available for abrasive-service applications.

HAPs can cope with any GVF (0 to 100%) on a continuous basis, can achieve a high pressure rise, and they are sand tolerant (i.e., no tight internal clearances). Their ability to self-adapt to flow changes enables a wide operating range, and their integrated VSD allows operational flexibility over the life of asset. Hence, they have significant track records (e.g., 15 subsea systems installed, more than 750,000 subsea operating hours) and are easily configured to series or parallel boosting. However, HAPs have low mechanical efficiency for viscous fluids and are unstable at low flow rates (but this can be offset with a fluid-recycle system). They have limited low-suction-pressure applicability in which there is low differential pressure at high GVF because of low mixture density.

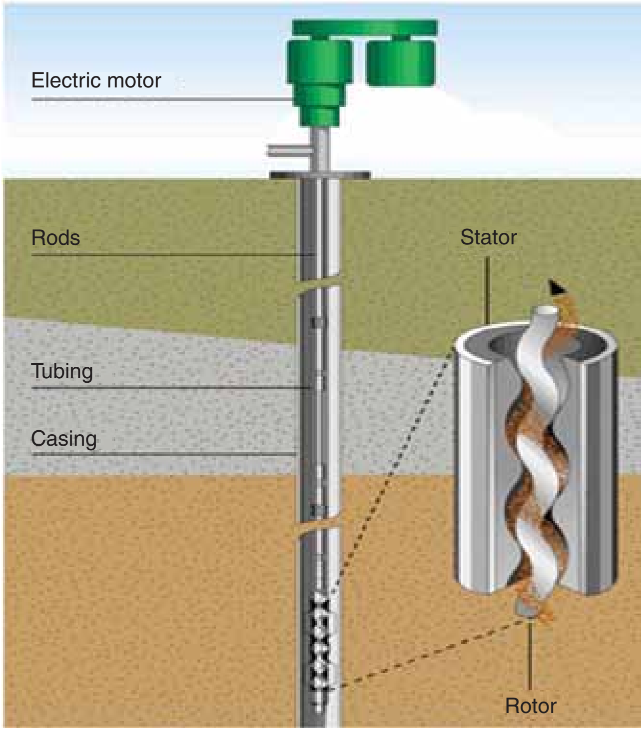

Fig. 10—Schematic of a PCP in a downhole application. [Courtesy of Schlumberger: http://www.glossary.oilfield.slb.com/DisplayImage.cfm?ID=628 (Accessed 10 January 2012).]

Comparison of Multiphase Pumps for Downhole Applications

There is more choice in multiphase pumps when considering downhole applications (summarized in **Table 2**), and the most commonly used are described in detail.

$$Q_{\text{actual}} = Q_{\text{theoretical}} - Q_{\text{back}} \quad (4)$$

$$Q_{\text{theoretical}} = A \times h \times n\eta_{\text{vol}} = \frac{Q_{\text{actual}}}{Q_{\text{theoretical}}} = \frac{Q_{\text{theoretical}} - Q_{\text{back}}}{Q_{\text{theoretical}}} \quad (5)$$

HAP. HAP use in subsea applications has been described in detail in the Review of TSP Technology subsection, but it is also used in downhole pumping, with more than 140 have been installed worldwide in oil wells with high gas content and for gas-well dewatering. Downhole HAPs have the beneficial operational characteristics of compression, mixing, and boosting. Designed to be a priming device, the downhole HAP is always connected upstream of a standard ESP that is used as the main production device; by eliminating gas separation, it allows the use of ESPs in wells in which ESPs would not have been considered before. Its gas handling is limited to 75% suction GVF, additional gas separation is required for higher GVF to handle extra gas **(Fig. 8),** and it has a limited range of size, configurations, and flow rates.

Multivane Centrifugal Pump (MVCP). Another technology to increase ESP tolerance in gassy well conditions is the MVCP, which features a split-vane impeller with enlarged balance holes **(Fig. 9).** The split-vane design alters the pressure-distribution pattern within the vanes so that gas does not accumulate in the impeller; this effectively avoids gas locking in wells with high gas content. A steep vane exit angle allows high momentum energy to be transferred to the fluid leaving the impeller, which achieves a relatively high head, and the oversized balance holes create turbulence to break up the gas bubbles, which benefits the gas handling

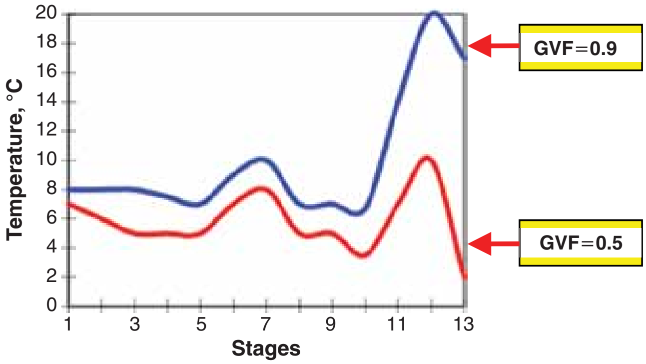

Fig. 11— Gas compression in the discharge stage causes significant temperature rise. (After Bratu.)

(Lea et al. 2003). Like the HAP type, the MVCP is normally installed upstream of a standard ESP.

Multivane centrifugal technology increases productivity and revenue from a well with high gas content by allowing free-gas production to pass through the pump to lighten the fluid column, and so reduce the power consumption. Although normally used as a charged pump in a standard ESP string, the MVCP also allows standalone configuration owing to its relatively high head per stage. However, the mixed flow impeller design allows a radial force vector, which will cause gas separation during operation, leading to a gas-handling-capacity upper limit of 70% GVF. For applications with higher GVF, additional gas-separation means must be used to reduce the gas content before the mixture enters the MVCP suction. Although gas-locking occurrence is minimized, the high gas content may degrade the downstream ESP performance.

PCP. The PCP was developed by René Moineau in 1930 and is widely used ar surface for pumping viscous mixtures. In 1979, the first downhole PCP was installed in the sand-producing heavy oil wells in Canada with topdrive configuration **(Fig. 10).** PCP technology is a proven means of downhole multiphase lifting, but the compressibility of gas phases increases the risk of "dry running" damage, so PCPs are normally used for surface or downhole submersible pumping where liquid is always present and the GVF is normally below 33%. Using PCPs for subsea boosting has never been reported.

The pumping element of a PCP consists of a flexible stator and a rigid rotor; the latter being a single external helix with a round cross section. In the PCP assembly, the rotor is suspended by the rod string and it is the only moving part during operation. The stator is a precision-molded synthetic elastomer, which is bonded to a steel tube. Because the stator is flexible, there is a compressive fit between the rotor and the stator. During operation, the rotor is driven by the surface\downhole drive and rotates within the stator. Sealed cavities with constant volume are formed between the rotor and the stator and then progress from the inlet to the outlet of the pump at a fixed rate, which is proportional to the rotor rotation speed. The total number of stages determines the maximum differential pressure drop that the pump can withstand.

Bratu (2005) pointed out that when a PCP is used in multiphase flow with high GVF, most of the differential pressure falls in the several stages close to the discharge end. As a result, when the progressing cavity approaches discharge, the gas will be compressed by the backpressure. In the last cavity (discharge end) of the pump, the gas compression reaches a maximum. Because the compressive fit between rotor and stator provides very good seal, little liquid and gas slippage happens, meaning that the liquid and gas are contained in the cavity with finite volume. According to the gas law ($PV=znRT$), the high pressure and finite volume of gas will cause temperature rise (Bratu 2005) **(Fig. 11).** Because of the temperature behavior of the elastomer, the temperature rise caused by the excessive heat may lead to premature stator failure.

The PCP is relatively inexpensive and incurs low operating cost. It is capable of extracting heavy/viscous oil and aggressive

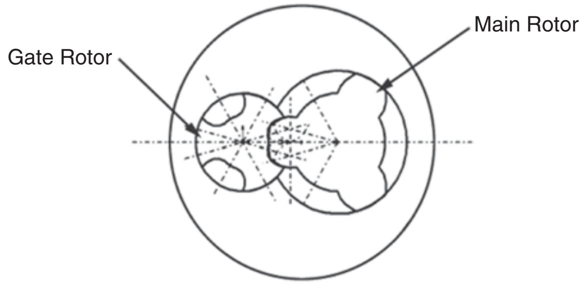

Fig. 12— Twin-screw downhole pump screw profile. (Courtesy of CAN-K.)

fluids during thermal recovery and is inherently sand tolerant. It exhibits low-shear flow characteristics because of the constant velocity through the pump and can be configured to suit application requirements (e.g., top- or bottomdrive).

Operating temperature can be a limiting factor for elastomers used in the PCP. As the rotor is turning against the stator and subjected to unbalanced mass, the rotation speed is somewhat limited, so the PCP is often used in low-flow-rate applications. It has low capacity and zero dry-running capacity, which would cause the PCP to seize up in extended gas slugs. It has limited differential pressure per section and requires high breakaway torque from zero rotational speed, especially in sandy well applications.

DTSP. Although the TSP has been installed for onshore locations, offshore platforms, and the seabed since it was commercialized, its application for downhole pumping was not commercially available until 2006. At present, the electrical submersible TSP (ESTSP) has been tested in Bohai Bay, China, with ConocoPhillips being the operator.

The internal layout of the screws is similar to that of the surface TSP, but the ESTSP features a slim and unequal screw design **(Fig. 12).** The DTSP can be selected to be submersible electric drive or topdrive. The pump unit can be connected with multiple stages, depending on the requirement of the application. For the downhole-drive system, any standard submersible motor can be used, but with a method of speed reduction from a standard two-pole motor to achieve reduced speed and breakaway. According to the vendor's data, the twin-screw downhole pump volume ranges from 150 to 56,000 B/D, with differential-pressure capacity up to 3,500 psi, and the rotation speed is up to 6,000 rev/min.

The DTSP inherits some advantages of multiphase-flow handling from the surface TSP in that it can operate at very low inlet pressures with resultant high GVF, its axial discharge arrangement allows minimum shaft deflection for high-pressure application, and it can pump viscous fluids. Downhole submergence eliminates the need for an external fluid-recycle system to maintain the lubrication and seal between screw clearances. It has no temperature-sensitive components, such as an elastomeric stator, enabling high-temperature applications. The DTSP can operate with a wide flexibility of drivers to suit application requirements, and it has low fluid shear characteristics because of the constant velocity in the pump itself.

However, the screws are not a back-to-back design, so the thrust must be handled by a dedicated thrust-bearing module. Its slim screw shaft is subject to torque variation caused by varying inlet GVF. The pump requires a high breakaway torque from zero rotational speed, especially if sand is present in the well.

Although the DTSP appears to be a promising alternative emerging technology, it is not widely accepted in the industry, so user feedback on its performance is very difficult to acquire. Although the manufacturer claims "Proprietary screw profile with rolling action almost eliminating seizing with solids," according to the limited user feedback, high sand production has caused several premature failures.

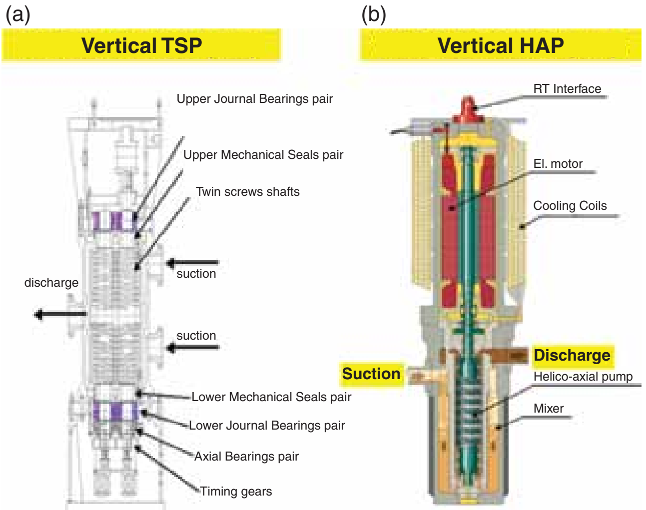

Fig. 13—TSP (a) (courtesy of GE Oil & Gas) and HAP (b) vertical configurations (courtesy of Framo).

Multiphase-Pump Selection

In this section, basic criteria for multiphase-pump selection are presented.

Selecting Multiphase Technology for Subsea Boosting. Because each type of pump has its own preferred application area, the pumps complement each other in multiphase application. For topside application, the selection of pump type is a step-by-step process based on the application requirement; the main parameters concerned include suction pressure, differential-pressure rise, liquid viscosity, and operating envelope over the life of the asset. For subsea application, however, project economics and pump reliability have understandably very high priority on multiphase-pump-type selection owing to the expensive nature of subsea operation.

The main characteristics the TSP and the HAP and their impacts on subsea application are discussed in the following. Please note that the following discussions are somewhat subjective. The backflow of the TSP is ignored for discussion purposes.

- Based on the concept of positive displacement, TSP flow rate is determined by the screw geometry and the rotation speed. HAP flow rate is determined by stage geometry, rotation speed, differential pressure, and the suction conditions. If sufficient suction pressure can be maintained (i.e., less differential pressure), HAPs would achieve higher flow rates than TSPs.
- Rotation speed plays a dominant role on the inlet flow rate for both types of pumps. This is particularly true for TSPs because their speed is the only adjustable factor to realize varying flow rate. Because HAPs normally run between 3,500 and 6,500 rev/min and TSPs run between 1,500 and 2,400 rev/min (Falcimaigne and Decarre 2008), an HAP would have more flexibility to vary the flow rate by adjusting the pump speed. Thus, they offer a wider operating range than a given model of TSP. This could be a compelling advantage of HAP over TSP for subsea deployment.
- Although working under different principles, both the TSP and the HAP can handle up to 100% GVF at suction with the aid of the fluid-recycle system or flow mixer, or buffer tank, respectively. Therefore, GVF is not a dominant factor in pump-type selection, unless the HAP cannot meet the required differential pressure at GVF.
- On the basis of positive-displacement structure, the TSP suction is practically isolated from discharge, which enables the TSP to work under very low suction pressure. TSPs can also work in series for higher-differential-pressure applications, but complicated control logic and process balancing must be in place to ensure that the upstream pump output perfectly matches the downstream pump

input. As for the HAP series configuration, no extra control process is required because the pressure generated by the upstream pump will effectively contribute to the downstream pump lift as a result of inherent flexibility in operating characteristics. However, this feature also limits HAP application at low suction pressure, in which the net lift required by the fluid may exceed the head that the pump can generate, particularly in high-GVF cases. Increasing the pump speed is a common solution to get more pump head, but only within equipment limits.

• TSPs have the unique advantage of being able to handle fluid with high viscosity, yet some HAPs can handle fluids up to 350 cp in steady state (Davis et al. 2009).

• HAPs do not have tight internal clearances, so they can tolerate higher sand production than TSPs, which can be an advantage for applications in which sand production is a major concern.

• Both types of pumps are being developed in vertical configurations **(Fig. 13),** which allows cost-effective intervention for subsea applications; however, to date, TSPs have been installed subsea only in a horizontal configuration.

• HAPs have achieved a track record of 15 subsea installations, while TSPs have been deployed in three subsea projects. Because the information on each pump's mean time between failures (MTBF) is normally difficult to acquire, this installation track record might be viewed as an indirect indicator of reliability for each type of pump in subsea applications.

In summary, for subsea boosting with low-viscosity fluid, HAP appears to be a more economic and technically viable option because the technology has accumulated significant subsea run time.

Selecting Multiphase Technology for Downhole Pumping. For downhole multiphase pumping, when GVF is less than 40%, if an ESP is used, the common practice is to add a gas separator or gas handler immediately upstream of the pump. However, when gas content exceeds 40%, either an HAP or an MVCP can be used. According to the pump vendor data, HAPs can handle slightly higher gas content than a multivane pump (i.e., 75% GVF vs. 70% GVF). This perhaps lies in their different working principle; the HAP generates axial flow, which does not cause gas separation in the mixture, and some amount of gas is even compressed back to the fluid, while the MVCP uses a conventional centrifugal-pump concept, but with higher gas tolerance. Its mixed flow stage geometry ensures a useful head generation, and the split-vane design effectively prevents gas accumulating within vanes.

PCPs are suitable for viscous fluids or low-flow-rate application. As a volumetric pump, its flow rate fully depends on the rotor speed, which is normally less than 400 rev/min. Its applicability in multiphase pumping is limited to 33% GVF, owing to the temperature-sensitive nature of the elastomer stator. A PCP with a metal stator has been proposed to allow the pump to run at high-temperature environment (Beauquin et al. 2005), but it has not yet been widely applied. Operational experience at Texas A&M University has shown that a PCP could be operated with up to 98% GVF in an air/water mixture without any fluid recirculation. The pump got hotter with increasing GVF, but was below the maximum recommended by the manufacturer at the 98% GVF.

The DTSP appears to be a promising alternative to the ESP and PCP for multiphase pumping because it can handle up to 98% GVF, which would easily meet most of the gassy-well-application requirements. However, sand production can significantly limit the applicability of the DTSP, and because it is an emerging technology, the DTSP has a very poor installation track record and has yet to gain acceptance in the industry.

Conclusions

For subsea multiphase applications, the TSP type and the HAP type are realistically the only options available.

Based on different pumping principles, equipment configurations, and installation track records, the HAP appears to be more technically and economically viable than the TSP pump for subsea application, unless for pumping fluids with high viscosity.

For downhole pumping with high gas content, RDPs are becoming accepted solutions. Their challenge is closely linked with the reliability of the entire downhole pumping system and correct application engineering for the candidate well from the start of the sizing process.

PCP applicability in the multiphase environment is generally limited by the temperature rating of the elastomer stator in association with low-GVF capability in steady-state conditions.

The DTSP is a promising alternative for multiphase pumping because it can handle fluids with higher gas content, but its solid-handling capability limits its applicability, and a statistically significant number of installations must be established before the robustness of the technology can be evaluated fully.

Acknowledgments

The authors wish to thank Ramez Guindi for sharing his invaluable experience with the downhole HAP and Peter Batho for his help with reviewing this manuscript.

References

Arnaudeau, M.P. 1988. Development Of A Two-Phase Oil Pumping System For Evacuating Subsea Production Without Processing Over A Long Distance: Poseidon Project. Paper OTC 5648 presented at the Offshore Technology Conference, Houston, 2–5 May. http://dx.doi.org/10.4043/5648-MS.

Beauquin, J.-L., Boireau, C., Lemay, L., and Seince, L. 2005. Development Status of a Metal Progressing Cavity Pump for Heavy-Oil and Hot Production Wells. Paper SPE 97796 presented at the SPE-PS-CIM/CHOA International Thermal Operations and Heavy Oil Symposium, Calgary, 1–3 November. http://dx.doi.org/10.2118/97796-MS.

Bratu, C. 1994. Rotodynamic Two-Phase Pump Performances. Paper SPE 28516 available from SPE, Richardson, Texas, USA.

Bratu, C. 1995. Two-Phase Pump Transient Behaviour. Paper SPE 30660 presented at the SPE Annual Technical Conference and Exhibition, Dallas, 22–-25 October. http://dx.doi.org/10.2118/30660-MS.

Bratu, C. 2005. Progressing Cavity Pump (PCP) Behavior in Multiphase Conditions. Paper SPE 95272 presented at the SPE Annual Technical Conference and Exhibition, Dallas, 9–12 October. http://dx.doi.org/10.2118/95272-MS.

Burleigh, L. 2009. Pushing the Limit: Taking ESP Systems to 250°C. Paper 23 presented at the 5th Middle East Artificial Lift Forum (MEALF), Manama, Bahrain, 16–18 February.

Dal Porto, D.F. and Larson, L.A. 1997. Multiphase-Pump Field Trials Demonstrate Practical Applications for the Technology. *SPE Prod & Oper* **12** (3): 159–164. SPE-36590-PA. http://dx.doi.org/10.2118/36590-PA.

Davis, B.E., Kelly, C., Kierulf, K., Eriksson, K.G., Normann, T., and Homstvedt, G. 2009. BP King—Deep Multiphase Boosting Made Possible. Paper OTC 20146 presented at the Offshore Technology Conference, Houston, 4–7 May. http://dx.doi.org/10.4043/20146-MS.

Dolan, P.J., Goodridge, R.A., and Leggate, J.S. 1988. Development of a Twin-Screw Pump for Multiphase Duties. *SPE Prod Eng* **3** (4): 629–632. SPE-15881-PA. http://dx.doi.org/10.2118/15881-PA.

Dorenbos, C., Müeller-Link, D., and Jäeschke, A. 2001. Sand Handling During Multiphase Operations With Twin-Screw Pumps. Paper SPE 69846 presented at the SPE International Thermal Operations and Heavy Oil Symposium, Porlamar, Margarita Island, Venezuela, 12–14 March. http://dx.doi.org/10.2118/69846-MS.

Egashira, K., Shoda, S., Tochikawa, T., and Furukawa, A. 1998. Backflow in Twin-Screw-Type Multiphase Pump. *SPE Prod & Oper* **13** (1): 64–69. SPE-36595-PA. http://dx.doi.org/10.2118/36595-PA.

Falcimaigne, J. and Decarre, S. 2008. Multiphase Production: Pipeline Transport, Pumping and Metering. Paris: IFP Publications, Editions Technip.

Furuholt, E.M. and Torp, T.A. 1988. With Poseidon Technology Towards Year 2000. Paper SPE 5646 presented at the Offshore Technology Conference, Houston, 2–5. http://dx.doi.org/10.4043/5646-MS.

Gié, P., Buvat, P., Bratu, C., and Durando, P. 1992. Poseidon Multiphase Pump: Field Tests Results. Paper SPE 7037 presented at the

Offshore Technology Conference, Houston, 4–7 May. http://dx.doi.org/10.4043/7037-MS.

Grimstad, H.J. 2004. Subsea Multiphase Boosting—Maturing Technology Applied for Santos Ltd's Mutineer and Exeter Field. Paper SPE 88562 presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Australia, 18–20 October. http://dx.doi.org/10.2118/88562-MS.

Guindi, R., Afanador, L., Flores, J., Aguila, H., Villamizar, J., and Beltran, A. 2003. Performance Evaluation of a New Gas Handler in an Oil Well with as much as 60% Free Gas at the Intake. Paper presented at the SPE ESP Workshop, Houston, 29 April–2 May.

Karassik, I.J., Krutzch, W.C., Fraser, W.H., and Messina, J.P. 1986. *Pump Handbook,* second edition. Columbus, Ohio, USA: McGraw-Hill.

Lastra, R. and Johnson, I. 2005. Feasibility Study on Application of Multiphase Pumping Towards Zero Gas Flaring in Nigeria. Paper SPE 98800 presented at the Nigeria Annual International Conference and Exhibition, Abuja, Nigeria, 1–3 August. http://dx.doi.org/10.2118/98800-MS.

Lea, J.F., Nickens, H.V., and Wells, M.R. 2003. Gas Well Deliquification: Solutions to Gas Well Liquid Loading Problems. Burlington, Massachusetts, USA: Gulf Drilling Guides, Gulf Professional Publishing/Elsevier.

Saadawi, H. and Al Olama, S. 2003. Application of Multiphase Pumps in a Remote Oil Field Onshore Abu Dhabi. Paper SPE 81504 presented at the Middle East Oil Show, Bahrain, 9–12 June. http://dx.doi.org/10.2118/81504-MS.

Yamashita, M., Sharma, Y., Ihara, M., and Yamada, K. 2001. Pre- Field Trial Testing of a Twin Screw Multiphase Pump. Paper SPE 68223 presented at the SPE Middle East Oil Show, Bahrain, 17–20 March. http://dx.doi.org/10.2118/68223-MS.

Gong Hua is a petroleum engineer specializing in ESP applications and is the technical project manager of artificial lift segment at Schlumberger Australia. He holds an M.Eng. degree in petroleum engineering from Texas A&M University and an MS degree in engineering physics from Tsinghua University in Beijing, China. He has worked with Schlumberger Oilfield Service in multiple roles, including as the instructor of ESP and variable speed drive (VSD) in the Middle East Learning Center in Abu Dhabi, as the field service manager of the artificial lift segment in Sudan, and as a wireline field engineer in China, onshore and offshore. His project for improving the VSD service quality was awarded the best Schlumberger general field engineer project of Middle East area in 2004. Before joining the petroleum industry, he was a research assistant in the Department of Engineering Physics at Tsinghua University, focusing on electronic design for nuclear signal detection and processing. **Gioia Falcone** has recently been awarded the Endowed Chair of Professor in Geothermal Energy at Clausthal Technical University in Germany. She is also adjunct associate professor in petroleum engineering at Texas A&M University, where she was formerly an assistant professor and then associate professor, Chevron Corporation Faculty Fellow, and faculty member of the ODASES partnership. Falcone holds a Laurea Summa Cum Laude in environmental-petroleum engineering from the University Sapienza of Rome, an MS degree in petroleum engineering from Imperial College London (with a Distinction on the final project), and a PhD degree in chemical engineering from Imperial College London. Before joining Texas A&M, she worked with Eni-Agip, Enterprise Oil UK, Shell E&P UK, and Total E&P UK, covering both offshore and onshore assignments. Falcone has served on the SPE Technical Program Committees for the SPE Annual Technical Conference and Exhibition, Latin American and Caribbean Petroleum Engineering Conference, and SPE International Conference on CO_2 Capture, Storage, and Utilization. She is a technical editor or reviewer for several peer-reviewed journals, including *SPE Projects, Facilities & Construction, SPE Journal, Journal of Canadian Petroleum Technology,* and *SPE Production & Operations.* Falcone was the recipient of the SPE Young Professional Paper Certificate at the 2008 and 2009 SPE Annual Technical Conference and Exhibition, in recognition of her paper's contributions to the technical discipline of projects, facilities, and construction. **Catalin Teodoriu** is head of the Drilling, Completion and Workover subdepartment of the Institute of Petroleum Engineering at TU Clausthal and an adjunct assistant professor in the Harold Vance Department of Petroleum Engineering at Texas A&M University. He was an assistant professor in the Harold Vance Department of Petroleum Engineering at Texas A&M University between 2006 and 2009. Teodoriu holds an equivalent MS degree from the Oil and Gas University of Ploiesti, Romania, and two PhD degrees, one from the Technical University of Clausthal and one from the Oil and Gas University of Ploiesti. He has worked as a research and development engineer for 2 years with the R&D Center of Petrom, Romania. He also worked for more than 6 years as a researcher and later as research supervisor with the Technical University of Clausthal. Teodoriu was involved in teaching graduate and undergraduate drilling, production, and completion courses. Related research activities that Teodoriu has been involved with are casing resistance under extreme loads, swelling cements for gas wells, drillstring components makeup procedures, underbalanced drilling and formation damage, evaluation of the casing fatigue and fatigue of casing connectors, and development of laboratory testing devices and facilities. His activity also includes finite element analysis and optimization of oil country tubular goods and drilling-related tools, data-acquisition systems, and integrated data possessing systems. He has published more than 100 papers, more than 12 of which are peer-reviewed and more than six are indexed by the Institute for Scientific Information. **Gerald L. Morrison** is the Nelson-Jackson professor at Texas A&M University's Department of Mechanical Engineering, where he teaches graduate and undergraduate classes in fluid mechanics, including gas dynamics and turbulence. He holds BS, MS, and PhD degrees in mechanical engineering from Oklahoma State University. Morrison's areas of professional interest are fluid mechanics and heat transfer, turbulence, acoustics, flow instabilities, flow-induced noise, turbomachinery, pumps, compressors, computerized data acquisition and analysis, and laser anemometry.