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Multiphase Pumping Meets Challenges

By Sven Olson

ALLENDALE, N.J.–Multiphase pumping technology now has more than two decades of history. From limited use in a couple of pioneering installations, it has advanced to become a very useful tool in oil and gas production.

The technology itself has gone from single pump installations with a minimum of equipment in limited sizes to installations with multiple pumps in complete modules with support equipment, automation and controls.

But the key drivers remain the same:

- Move the entire production stream from the field to central processing, commingle oil, water and gas in a single flowline, and save on operating and capital expenditures;
- Enhance reservoir-to-wellbore inflow by lowering bottom-hole pressure to accelerate production, increase total recovery, and delay well abandonment;
- Help low-pressure producing wells buck flowline pressure;
- Eliminate flaring and venting of associated gas during production and well testing, thereby lowering emissions and reducing the footprint of production equipment;
- Help mitigate hydrate formation by lowering flowing pressure in gathering lines, and reduce glycol injection costs (Heavy oils, shear-sensitive water/oil emulsions, and waxy crudes can be transferred without agitation for easier separation.);
- Lower annulus-gas pressure in single-well installations for improved inflow, and maintain tubing level for maximum pumpjack uptime and efficiency;
- Bring the total production from the seafloor to the process facility on a platform or floating production, storage and offloading facility; and
- Transport deepwater and/or production with high gas-to-oil ratio without slugging or surging.

It is not uncommon for operators to run several pumps in parallel to control both the number of pumps in operation and their individual speeds so they can adjust to the number of wells flowing to a platform or pad.

Modern Applications

Today's leading pump designs are the twin-screw pump and the helico-axial design. Electric submersible and progressive cavity pumps have limited numbers of installations, whereas the total number of twin-screw pumps installed now exceeds 500.

Pump sizes installed today are very different from before. The average horsepower per installed pump has increased substantially from a couple hundred to today's 1,000 and above. Another addition to the technology is the design of headers and controls. It is not uncommon to run several pumps in parallel, and to control both the number of pumps in operation and their individual speeds in order to adjust to the number of flowing wells on a pad or platform.

Larger installations point to increased operator confidence in multiphase pumping. Infancy mortality has been brought down and the pumps are experiencing acceptable uptime.

More and more improvements have been introduced to mechanical seals, which were always the weakest link in twin-screw pumps. A double seal arrangement is preferred now by many operators. These can be arranged with an inlet pressure sensing system or tracing that allows for higher seal-barrier fluid pressure than the inlet process flow.

The challenge is the variation of pump inlet conditions going from shut-in pressure to settle-out pressure, to full drawdown pressure. These conditions put a lot of demand on the barrier fluid system, which must react quickly to always maintain a barrier pressure higher than the inlet process.

Multiphase pumping technology has evolved from single pump installations with a minimum of equipment in limited sizes to installations such as this that feature multiple pumps in complete modules with support equipment, automation and controls.

Shale Oil Challenge

With arrival of production from tight and shale oil formations, the pump industry has taken a hard look at this new and growing market. The differences from the conventional and familiar way of oil production from vertical wells on different types of artificial lift weren't recognized initially. As a result, conventional pump technologies were installed in gathering lines in many locations.

It was learned very quickly that the life of an elastomeric liner was very short, and costly downtime and service turned out to be a problem. The gas-to-oil ratio in typical shale oil production often is higher than with conventional oil, and the increased volume of associated gas turned out to be an overwhelming challenge for many pumps.

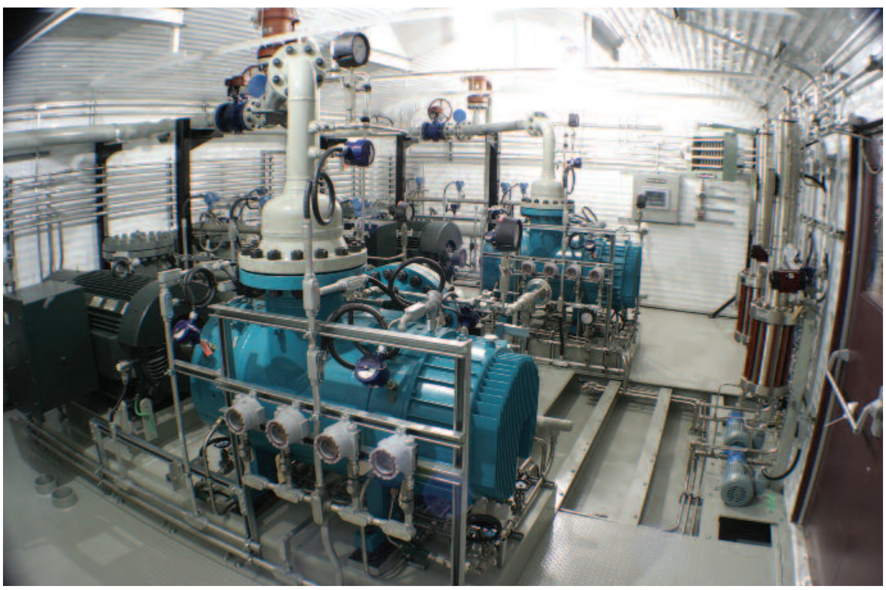
In addition to the high GOR problem, the lubricity of shale oil became a challenge. Whereas with conventional oil, viscosity is a good approximation for the lubricity of the oil, it turned out to be different with shale oil. Shale oil lubricity is very low, even at a viscosity that would not normally cause problems for a pump design with contacting rotors and stators.

A simple test of rubbing the oil between one's fingers tells a story. Shale oil is very "dry" and the friction a person will feel between his fingers is much higher than with concentration oil. Consequently, the contacting pump design has had difficulties dealing with both the high amount of associated gas and the low lubricity of the oil.

One operator reports installing protective strainers not only upstream of the pump, which is normal, but also downstream to catch rubber pieces coming off the pump stator.

When the first twin-screw multiphase pumps were introduced in shale oil production, it was to combat the types of problems encountered in the field. The twin-screw pump is a noncontacting pump design, where no moving parts such as the rotors come into contact with each other or the surrounding liner. It has excellent gas handling capabilities and can go as high as 95-97 percent GVF at pump inlet (GVF is gas void fraction at inlet temperature and pressure as a percentage of the total inlet flow).

The gas-handling feature of the pump, which is supported by a liquid knockout boot or a separator at the discharge, traps the liquid, and with the help of the pump differential pressure, circulates back the pump suction. This design feature helps the pumps retain the liquid necessary for sealing the screws and removing the compression heat. It allows operation during long gas slugs to maintain the pressure boost without interruption caused by gas locking. And, because of isothermal compression, the pump power torque remains the same, whether it is compressing gas or pumping liquids, and the heat of the compression is removed with the process fluids.



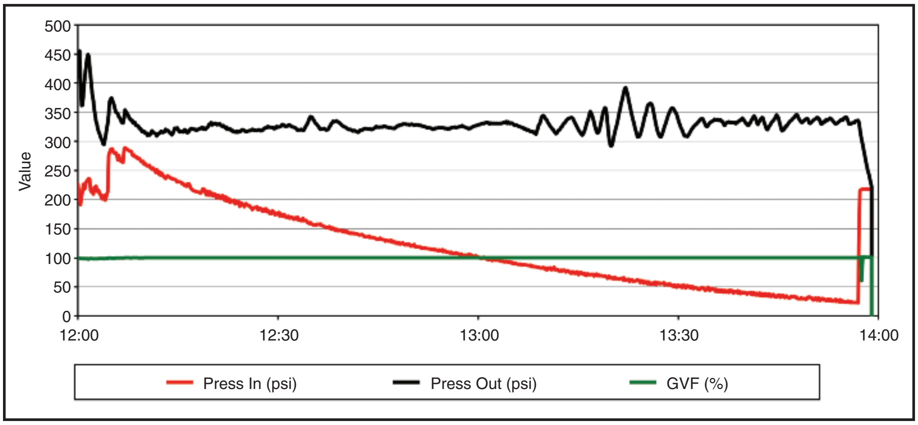
Two twin-screw pumps installed in parallel at a Canadian Bakken site operate as gathering pumps located close to a tank battery, and serve multiple satellites and wells. The gas void fraction for this installation is in the 80-90 percent range.

Twin-Screw Solutions

Because of these inherent pump-design features, multiphase twin-screw pumps have started to be introduced in shale oil

FIGURE 1

Blow-Down Cycle Curve



production during the past couple years. The results, so far, have been very promising. Not only did the previous pump problems go away, but the economics of drawing down wellhead pressure and boosting turned out very favorably.

It turns out that tight-oil or shale-oil formations react more positively to pressure drawdown than do conventional oil wells. The production gains seem to be more pronounced for shale oil. The explanation may be that shale oil, with its low viscosity, flows more easily through the formation to the producing well as it responds more positively to the low bottom-hole pressure created by the multiphase pump.

Net oil production gains between wells with multiphase pumping and without are in the 15-25 percent range, which is more than typically could be expected from a conventional oil well.

The reservoir pressure in a shale oil formation also drops off faster than does pressure in a conventional formation. Without boosting, it may be impossible to produce certain wells after a short time. Twin-screw pumps, with their high tolerance for associated gas, may be a game changer here, by extending the production life of the well.

For example, a multiphase pump was installed at a satellite site serving 10-12 pumped wells in the Canadian section of the Bakken formation. Drawdown pressures ranged from 300 psi to around 100 psi.

At another Canadian Bakken site, two twin-screw pumps were installed in parallel operation. These pumps operate as gathering pumps located close to a battery and serve multiple satellites and wells. The GVF is in the 80-90 percent range. Besides the economics of added oil production, this installation, which is connected to a gas sales system, also contributes to enhanced gas production and sales.

In yet another application, a low-cost, single-well multiphase pump was applied to casinghead, or annulus, gas. The suction of the pump was connected to the casing. Drawing down the casing gas pressure leads to increased well in-flow and 100 percent uptime for the pumpjack. To assist the pump with gas slugs, a small volume of liquid from the pumpjack was diverted to the multiphase pump, where it was commingled with the gas and sent to the export line.

Unloading Wet Gas Wells

The increasing number of wells that produce wet gas from shale or tight formations has created both opportunities and challenges. NGLs are an economic addition to gas production, and as gas demand and production grow, more NGLs are being brought to market. Cold winter weather, along with the potential for natural gas exports and new chemical facilities being planned in anticipation of abundant domestic gas supplies will continue to increase demand for natural gas.

The "new" gas is produced primarily from horizontal and deviated wellbores, where water and natural gas liquids collect, and potentially will inhibit gas flow to the wellhead. When the critical gas velocity in the production tubing drops, the gas no longer can "drag" the liquids to the surface. The result is a liquid- or water-logged well that can no longer flow the gas to the sales line. The pressure at the wellhead remains constant, but no gas is moving since the line pressure is the same or higher. The result is a shut-in well.

Conventional ways to solve this problem are to use artificial means to "lift" the liquids to the surface. The technologies range from plunger lifts to ESPs to conventional pumpjacks. Soap sticks can be launched to lower surface tension and allow gas to bubble through the liquids.

Normally, the liquids are drained to a surface blow-down tank or vessel. This requires gas either to be vented or flared to create the necessary gas flow velocity to move the liquids. The liquid volume

A portable blow-down unit can be towed to the well site by a standard 1.5-ton pickup. The pump is driven by a natural gas engine fueled by gas from the flowline. The unit is equipped with automation, controls and safeties to be completely self-supporting.

adds new problems, since the liquids have to be pumped or trucked from the field, resulting in added trucking costs and road damages.

On top of this, flaring or venting gas is uneconomical and requires permits from local and state authorities, which are more and more reluctant because of pressure from various environmental groups.

Multiphase Answer

Multiphase pumping technology has developed new and rational means to solve the liquid loading issue. Thanks to system developments and the ability of twin-screw pumps to handle well flows, whether they are 100 percent gas or 100 percent liquid, an alternative solution is a multiphase pump, which, with its support system, can unload a liquid-loaded well. The pump suction is connected to the wellhead and the discharge is connected to the export line.

As the pump starts, the well is at the shut-in pressure set by the export line with no gas flowing. The pump at this stage of the cycle is compressing the gas and is using the liquid contained in its support system to seal the screws and remove compression heat. The discharge goes directly to the export line.

As the backpressure on the wellhead drops, the gas starts flowing and the lower pressure migrates down the production tubing. Gas will start breaking out of and bubble through the liquids. The increasing gas velocity will start moving the liquids, and will accelerate continuously until it reaches critical velocity to overcome gravity and tubing resistance.

Importantly, the lower pressure also will reach the horizontal section of the well, which is holding a lot of liquids that frequently are impossible to reach with a typical plunger. Gas continues to flow at an increasing velocity because the back pressure is lowering. It will reach a point where the reservoir pressure takes over as the liquids are evacuated and the full flowing gas velocity is restored.

The multiphase pump will sense the increasing inlet pressure and low differential pressure. When no more boosting is necessary, the gas flows by natural pressure, and the blow-down cycle is completed and the pump shuts down. The well goes back to normal and the unit can move to another well.

The concept of the multiphase blow-down unit is similar to that of gas lift, where the liquid column is lightened by introducing gas, although not from a lift-gas source, but by using gas directly from the formation, which is made possible by the lower wellhead pressure created by the multiphase pump.

Figure 1 illustrates a cycle in which the pump is started at well shut-in pressure at noon, and two hours later has lowered the wellhead pressure to 50 psig. The gas is flowing freely now and the pump can be shut down.

Notable is that the pump during the whole blow-down cycle is running at 100 percent GVF at skid inlet, and the support system provides the necessary liquids.

A portable blow-down unit can be towed to the well site by a standard 1.5 ton pickup. After completing the cycle, it can be moved to another well. The pump is driven by a natural gas engine fueled by gas from the flowline, meaning no utilities are required in the field. The unit is equipped with automation, controls and safeties to be completely self-supporting.

The providers of multiphase pumps and systems are developing products continuously to meet new challenges in producing unconventional formations. Operators can benefit greatly from advances in this technology. ❒

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Sven Olson is president of Leistritz Advanced Technologies Corp. in Allendale, N.J. With headquarters in Germany, Leistritz manufactures screw pumps for the oil and gas industry. Before joining Leistritz in 1986, Olson spent most of his career with IMO in Sweden. He was involved in testing and introducing multiphase pumping technology to North America, and actively participates in applying and promoting the technology in the oil and gas industry. Olson serves as an advisory board member of the Multiphase Pump Users Roundtable sponsored by Texas A&M University. He holds a degree in process engineering and an M.B.A. from the University of Lund in Sweden.