MULTIPHASE PUMPING TODAY

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ABSTRACT

Multiphase Pumping has been gradually expanding its niche as a tool for coaxing additional production from wells. In the past it was seen as a discipline for saving capital costs, such as saving on additional subsea lines, or, in the case of Venezuela, reducing the surface treatment equipment needed to gather and move heavy, gassy crude. Today it has become a specialty tool that can lower back pressure of wells that otherwise have difficulty in producing into established production systems, or it can be used in conjunction with other down hole methods to optimize gas lift, jet pumping, and even augment the performance of PCP or ESPs. Confidence has grown among the users as they have learned how to apply this equipment effectively.

This paper defines common terms used when sizing and applying multiphase equipment, and briefly describes the types of pumps available today, including the new reciprocating types of pumps that have met with recent successes. Some of the new techniques and applications are described along with considerations to keep in mind when installing such systems.

INTRODUCTION

In May 2002, there were reported over 350 multiphase pumps (not including surface progressive cavity installations) in the world and growing at an average rate of approximately 50/year. (MPUR Survey, 2002). The grand bulk of these are found on land sites and some on platforms. There are also a few trial subsea units now being installed or tested. The major reason for their use is to reduce back pressure on wells and/or to reduce the capital expenditures required.

With proliferation has come a growth in familiarity by the users, new innovative applications, improvements, and, improved economics. This technology is now coming of age and more companies are willing to include it in the design of their systems and put it on trials.

MULTIPHASE JARGON AND SIZING

The term "boosting" is often used to describe the process of increasing pressure in a mixed flow stream by both pumping and compression — which is what takes place simultaneously in a multiphase booster ("pump"). (Since most suppliers have their roots as pump suppliers for liquid systems, the term pump is commonly used.) Likewise, the "pump rate" is often referred to in liquid terms (GPM or BPD or cubic meters/day) even though the majority of the flow rate is gas. At times the term BPDe is noted to indicate that equivalent barrels of gas are included in the stated rate.

The pumps are rated in terms of the flow rates <u>at inlet conditions.</u> Compressors are rated in SCFPD - which is the gas volumetric rate at 60° F and 14.7 psia. For the multiphase pump this gas portion of the flow must be converted to reflect its volume at the actual conditions at the inlet, and then converted again into common flow rate equivalent units (eg: BPD_{gas}), then added to the liquid's rate. This can be done using the formula given below. (Note: isothermal conditions can be assumed (due to the presence of heat absorbing liquids), and because most inlet pressures are low, the compressibility deviation factor Z_{inlet}/Z is taken to be 1.0):

$$\textbf{1. "Pumped" } BPDe_{inlet} = SCFPD/5.615 \times [14.7/(p_{inlet}+14.7)] \times [(t_{inlet}+460)/520] + BPD_{liquids}$$

(p in psig and t in deg. F)

Remembering to use absolute pressures (P = psia) and temperatures (T = deg.R) this formula reduces to:

$$\textbf{1a. } BPDe = 0.005035\ SCFPD \times (P/T)_{inlet} + BPD_{liquids}$$

Finally, multiphase flows can be characterized by their average "GVF" or Gas Volume Fraction, usually expressed as a percentage. It is equal to BPD_{gas} / BPDe. Note: This is not the same as the GOR or GLR, nor is it the commonly used 6:1 factor when working on profitability analyses. The 6:1 factor is a rule of thumb used to relate financial revenues of gas and oil, and is not related to the volumetric relationships present in a pressurized well stream.

TYPES OF PUMPS

The types available today fall into two main categories: Dynamic and Positive Displacement. The dynamic types are either the rotodynamic (helico-axial) or multi-stage centrifugal. (ESP Type). The positive displacement types are either rotary (twin screw types or progressive cavity), the recently introduced linear displacement pumps (duplex piston or plunger) or (new) diaphram pumps.

MULTIPHASE PUMP TYPES

POSITIVE DISPLACEMENT

- **LINEAR DISPLACEMENT**
  - MASS TRANSFER PUMP
  - RAMPUMP™ MULTIPHASE BOOSTER PUMP
- **ROTATING**
  - TWIN SCREW
  - PROGRESSIVE CAVITY
- **OTHER**
  - DIAPHRAM

DYNAMIC

- ROTODYNAMIC (See Fig. 1)
- MULTI-STAGE CENTRIFUGAL

The rotodynamic pumps (Fig. 1) are based on the Poseidon technology developed at the IFP in France. These are dynamic pumps and induce pressure into the flow stream using a helical screw in combination with a specially designed turbine section. The pumps are particularly efficient at high flow rates (above 100,000 BPD) and operate best with flow streams that are somewhat homogenized, so that the pump does not see dramatic swings in densities as might be found in flows with pronounced liquid or gas slugs. If such flows occur, their effect should be diminished by using upstream vessels that help to mix the slugs of gas and liquids so that a feed mixture into the pump can be maintained within the desired parameters. These pumps also prefer gadliquid mixtures that are 85% or less.

The new multistage centrifugal pumps have been able to increase their tolerance for handling gas to 30% GVF and sometimes more, depending on the type of crude. These also prefer to handle gas/liquid mixtures that are somewhat homogeneous and are not suitable (at this point) for high GVF flows or flow with extended gas slugging.

The twin screw type of pump (Fig. 3) is the historical “workhorse” of the heavy oil multiphase pumps. These pumps handle flows from as high as 500,000 BPD down to 1000 BPD. They employ double axes that each have opposing flights of screws. The screws intermesh with the opposite set of screws and as rotation occurs, the trapped volume in the screws advances toward the discharge port. They offer very smooth, continuous flow. The pitch angle of the screw induces a trans-axial force however, as the pressure differential increases, so does the axial deflection. It is important that the high RPM metal surfaces do not touch as these pressures increase, so the designers also include a proprietary clearance between the two mating screws and between the screws and the sleeves that surround them. This clearance results in slip flow, which is a reverse flow back towards the inlet, and is unavoidable, causing a certain inefficiency that is influenced by viscosity and by pressure differential. Screw design is also a factor—the stiffer the screw and its method of mounting, the less deflection it will experience, hence for a stiffened design the clearances can be reduced and slip flow hopefully reduced accordingly.

The twin screw pumps can be sensitive to sand erosion under conditions where the liquids are low viscosity. Generally with high viscosity liquids the sand and silt is carried along and “cushioned” within the liquid from eroding the screw surfaces, but if the viscosity is changed by heat or by a change in the water cut, sand erosion may quickly appear, causing rapid increase in the slip flow in the pump.

Both the helico-axial and twin screw pumps seal their shafts using mechanical seals. These seals may be single mechanical or double mechanical seals. The double mechanical seal offers the most protection, and also uses a separate fluid as coolant and seal flush to help reduce friction and heat build up — which is the main enemy of this type of seal. These also offer a double barrier between the pump chamber and the environment in the event of a seal failure. They are much more expensive, however, and add complexity to the operation. Single mechanical seals are much less expensive, and can use fluid trapped from the process flow stream itself — however, any sand in this fluid can also destroy the seal, so a good filtration or conditioning system is needed to insure seal life. Since each twin screw pump has four mechanical seal systems, maintaining an evenly distributed, quality seal flush and/or double seal systems is of high importance.

The horizontal double acting piston mass transfer pump (National Oilfield) (Fig. 4) uses a motor and gear box similar to that found on a beam pump. However, instead of connecting to the walking beam and horse head, the rotating cam is connected to two horizontal piston rods which each push and pull a piston through a sleeved cylinder. At either end is a fluid receiver assembly that contains the check valves and which collect liquids from the flow stream. As the fluids enter, the liquids fill up the chamber, pushing the gas upward and out through the check valves (similar in action to the downhole rod pump). The piston then reverses for its intake stroke.

It is a mechanically simple system designed for oilfield maintenance. Sand can eventually erode the piston seals and the sleeve, both which are replaceable. It is important that sufficient liquids remain in the system to fill the fluid ends or the gas entering in will not be expelled, and will re-expand and can sharply reduce the intake volume, gas locking the pump. Accordingly, the compression ratio as well as the gas fraction in the incoming flow must be dealt with to avoid gas locking and high rod loads for this system. This system is capable of up to 110,000 BPD and 1400 psi differential.

The vertical plunger pump (Weatherford's patented RamPump™ multiphase booster pumping system) (Fig. 5) moves multiphase fluids by displacement and employs large diameter, long stroke, hydraulically actuated plungers. Standard systems are capable of up to 160,000 BPD and up to 2000 psig differential. Special models can operate at up to 5000 psig discharge without vapor locking. This unit is hydraulically controlled, allowing infinite rate change within its pumping range. The unit employs a new type of packing that can be replenished by injection while continuing to operate, and which includes a secondary backup seal. It can manage sandy flow streams and can operate at very high gas fractions continuously, as it does not depend on liquids for efficiency control or for seal lubrication.

Progressing cavity pumps (PCP's) (Fig. 6) continue to demonstrate their capability to move heavy, sandy oil that may contain appreciable gas. These are generally adapted to low delta p (est.at 350 psig or less), and up to 30,000 BPD. They may be applied in series to increase the overall delta p if required. If the flow regime is prone to develop long gas slugs, it may be necessary to provide liquid from time to time to maintain lubricity between the metal rotor and the rubber stator to reduce friction and heat buildup, and to extend stator life.

<u>Pump Characteristic Curves</u>: Specific curves are not generally published for multiphase pumps since the pressure levels, compressibility of the fluids, gas fractions, and thermodynamics can result in a broad range of results. Generally what is available from suppliers is a "pump curve" that represents the pump performance over a given range of pressure differentials for the application the client has in mind. Individual suppliers should be consulted since factors such as gas fraction changes, flashing, etc. can influence the results. This is also true for power estimates. As a way of arriving at an initial, first order estimate, the equation for liquid pump horsepower is used:

$$\mathbf{HP = Q \times Delta\ p / (1714 \times Eff.)}$$

Where Eff. is dependent on the pump type and the compression ratio and can range from 0.6 to 0.85. Usually a value of 0.75 can be used until the pump supplier is contacted and given the anticipated application conditions.

Compression ratio is as important for multiphase pumps as it is for compressors and must be taken into account. The presence of liquids in the flow stream generally help the multiphase pump control heat by taking the heat out with the liquids, which usually means the pump can operate at higher compression ratios than can a compressor. However, this can depend greatly on the type of pump (since some require liquid trapping and must recirculate the liquids to operate in high gas fractions and so are more sensitive to heat production). It also depends on the discharge pressure, as this will affect heat production in the seal system. There are efficiency limits as well; if the incoming flow is mostly gas at low pressure, the mass flow rate is small relative to the volumetric flow rate, and after undergoing a high compression ratio, the volumetric output from the pump will be small. Slip flow and/or gas re-expansion in the pump chambers will also increase, decreasing pump efficiency. For compression ratios of eight or more it is recommended that series compression (staging) be considered:

WET COMPRESSION

Wet compression is a generic term which might be loosely defined as boosting pressure of a gas stream that contains more liquid than is generally tolerated by conventional reciprocating compressors. For twin screw pumps and for PC pumps the definition is a little more critical, and generally means a flow stream with an average gas volume of 95% to approximately 90%. If the gas volume is less than 90% it tends to be called a multiphase flow stream. Above 95% there may not be enough liquids available for the rotating types of multiphase pumps and some method of storing up liquids and providing for liquids re-circulation must be on site to maintain continuous operations. The Mass Flow Pumps are less sensitive to the liquids issue, and RamPumps can run directly in flows that are 99%+ gas.

Using multiphase pumps as wet compressors can save money and space, and can be used to maintain flow line pressures and temperatures above cloud points and above hydrate formation levels. This can be one of the driving factors when applying subsea multiphase pumps. It can also help move production under cold weather conditions.

PUMP BACK UP

What will happen when a pump is off-line? Because of the liquid and gas phases present in multiphase flows, this can become both a temporary storage and a venting/flaring issue. However, in most cases the GVF is over 80% of the flow, and if the booster site plan includes using multiple pumps in parallel, total or even partial shut down can be avoided altogether in favor of allowing the inlet pressure to rise, forcing the flow to adapt to the pumping volume that remains on line. (Note: This is **not** an option with purely liquid flow systems!).

Example:

a. Three multiphase pumps are boosting 10,000 BPD liquids plus 5 Mmscf of gas at 110ºF from 80 psig to 500 psig. If one of the three is out of service, what inlet pressure is expected if the other two pumps can increase their pump rate by 20%?

Use Formula 1a and solve for pressure at new volumetric rate: P = V1/V2

V1 = 5000000 x .00504 (TIP) = 151,680 bpde (gas rate at inlet)
V2 = (151,180 + 10,000)/3 x1.2 x 2 = 129343 bpde, which includes 119343 bpd of gas
V1/V2 = 1.27, P2 = (80 + 14.7) x 1.27 = 120 psia, or 105.5 psig.

One alternative would be to order the pumps with 20% excess capacity and sufficient power to be able to maintain the back pressure less than 110 psig during the outage of one pump, without shutting down production. Another variation is to calculate the desired excess pump capacity given the maximum pressure rise that can be tolerated. (Note that since the capacity of one pump is still greater than the liquid flow rate in this example, even two pumps could be off line without shutting down the third pump.)

SUCTION AND DISCHARGE PIPING

While some pumps may have NPSH requirements (in the event the pump is handling a liquid slug), keep in mind that when dealing with high GVF multiphase flows, it is difficult to develop cavitation, so in many installations this is not the critical problem it would be with a conventional pump. Even so, if the pressure drop is too high coming into the inlet manifold, any gas flowing will expand before actually entering the pump and some gas may flash out of the liquids, all of which will reduce the mass pumping rate accordingly (the "real" inlet pressure is the pressure inside the pump inlet), so it is still important to use hydraulically efficient inlet manifolds and geometry.

The suction and discharge manifolds should also have isolation valves with a bypass line connecting the two through a check valve. This will allow isolation of the system for maintenance. Except for the RamPump, pumps will need a recirculation line with an overpressure relief that is programmed to open when the valves close, and to remain open for a period after to avoid pressure shocks to the system. (The RamPump does this internally within its hydraulic circuit).

If the inlet line can develop long-period slugging, the pump will be handling a gassy liquid slug for a while and will then will operate like a wet compressor when the gas slug arrives. The rotary type multiphase pumps are designed to handle long liquid slugs; however, excessively long gas slugs can pose a serious problems for certain types of multiphase pumps that require liquids to cool mechanical seals, to lubricate stators, or to seal against slip flow. Providing for adequate trapping, storage, filtration, and cooling for recirculating liquids can become critical for such pumps.

Keep in mind that field operating habits can also cause long period variations in gas fraction just as much as slugging can. For example, in one gasicondensate field the average liquid rate was 500 BPD in a flow of 3.2 Mmcfpd of gas — but in actuality, most of the liquids arrived during the first three days of the week after the pumpers returned to work, and then the liquids tapered off to near zero for the last 3 days of the week. That left the multiphase pump virtually without liquids until the following Monday.

NEW METHODS

WELL STIMULATION (WEATHERFORD PATENT PENDING)

If a multiphase pump is available that can provide a high differential pressure while pumping a multiphase fluid it can be used for well stimulation (Fig. 8). In situations where a well has died, or is loaded up, and if a gas source is available from other nearby wells, the wet gas can be tapped off and taken into the inlet of the multiphase pump and compressed to injection pressures. This discharge is then run through a high pressure scrubber to eliminate excess liquids, and injected into the well to be stimulated. Excess gas can be taken off to a sales line, or returned with the liquids and flowed to the processing station in the main flowline.

As the well responds, it is produced into the inlet of the RamPump. The gas is again recovered and recycled while the amount of "borrowed gas" is reduced. The RamPump continues to pull down the back pressure until the stimulated well is stabilized. If this pressure is high enough to produce the well into the gathering system, the RamPump can be moved to another site; if not, it can remain to continue to assist in producing the well.

Similarly, this same method can be adapted to drilling, well clean out, and other situations where recapture of the produced fluids can result in less environmental impact and increased income.

DUAL BOOSTER™ SYSTEM (DBS) (US PATENT 6,164,308)

For those situations wherein the volume of the gas flow is very high, with a corresponding low volume of liquids, it may be economic to consider using the DBS. This is where a small multiphase pump is installed in parallel with a compressor or bank of compressors to boost the pressure of the flow, rather than resort to multiple, large multiphase pumps, or use a tank battery with vapor recovery, additional pipelines, etc.

The rationale is as follows:

1. The efficiency of the compressor is roughly *85* - 88%, while the multiphase pumps can be between *35% - 75%*.
2. Since over 90 % of the flow is gas, this efficiency difference can make a significant reduction in overall installed power if a compressor is used to compress most of the gas.
3. It is relatively easy with a small vessel to divide out the incoming volumes of free gas in the flow stream, leaving a small residual flow of liquids and entrained gas and solids to flow to a small multiphase pump.
4. The cost will be *30%* to *50%* less than using multiple, large multiphase pumps.
5. The end result at the discharge is the same — ie; a multiphase flow boosted to the desired discharge pressure using a sealed system - no tanks and no vapor recovery required.
6. Maintenance will be about the same, since most large installations of this type will use natural gas powered engines to drive the equipment, and the engine is 80 - 90% of the maintenance effort.

In 1999, Weatherford conducted a year long pilot program to determine the practical features of dual boosting. It turned out to be remarkably simple to do since no special controls were required. The program commenced with a standard reciprocating compressor in parallel with a twin screw pump, which was later replaced by a small RamPump when sand production from the wells eroded the twin screw pump. This DBS concept was later successfully repeated offshore by another operator (Sommer - MPUR 2002).

DOWNHOLE

While it is technically feasible to place some types of multiphase pumps downhole, such applications have not yet proven practical mainly due to problems related to solids, erosion, and seal maintenance. What has become more and more evident to users is the synergy of using surface mounted multiphase pumps **in series** with conventional artificial lift techniques in order to increase productivity and to reduce downhole maintenance requirements. Reducing the surface back pressure can have many beneficial effects such as cutting back on the amount of gas compression needed to maintain gas lift, reducing the wear and tear on a PC pump so that the intervention costs can be cut in half, and reducing the down hole power required to do the job. It is now feasible and practical to evaluate the complete downhole/surface system you are using to move your product from the reservoir to the sales line.

SUMMARY

Multiphase pumps are demonstrating they are a reliable, economic means of handling many different production scenarios, from heavy crude to gassy well streams. Facilities engineers should become familiar with how to use these pumps and systems, and the new jargon that describes their applications. Many different types of multiphase pumps are available today, and can be hand picked to suit a wide variety of applications. New advances in sealing systems have extended the pressure and temperature ranges of this equipment, and new designs have increased reliability, simplicity of control, as well as the efficiency of the operation.

REFERENCES

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