TOP TEN CHALLENGES IN JET LIFT PRODUCTION OPERATIONS AND THE SOLUTIONS SUCCESSFULLY IMPLEMENTED IN PRODUCING OIL WELLS IN THE SOUTH TEXAS REGION

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ABSTRACT

Jet lift systems have earned a strong reputation as an effective artificial lift method for unconventional oil well production across the most prolific hydrocarbon-producing regions in the United States of America. In prolific reservoirs such as the Permian Basin, Eagle Ford, and Bakken, operators have successfully utilized jet lift as the primary lifting method for challenging oil wells. For the last fifteen years oil and gas well operators in the Eagle Ford Basin have consistently employed jet lift as the main production technique for their wells.

Like any other artificial lift system used in unconventional oil well production, jet lift has its strengths and weaknesses. Its most notable advantage over other powered production methods is its ability to handle a wide range of flow rates, from 10 barrels of fluid per day (bfpd) up to 5,000 bfpd, using the same jet pump housing size. The “free pump” feature, which allows the operator to hydraulically retrieve and reinstall the jet pump without the need for workover or wireline, using only reverse power fluid circulation. This characteristic of jet pumps is widely recognized as critically important in the artificial lift selection matrix.

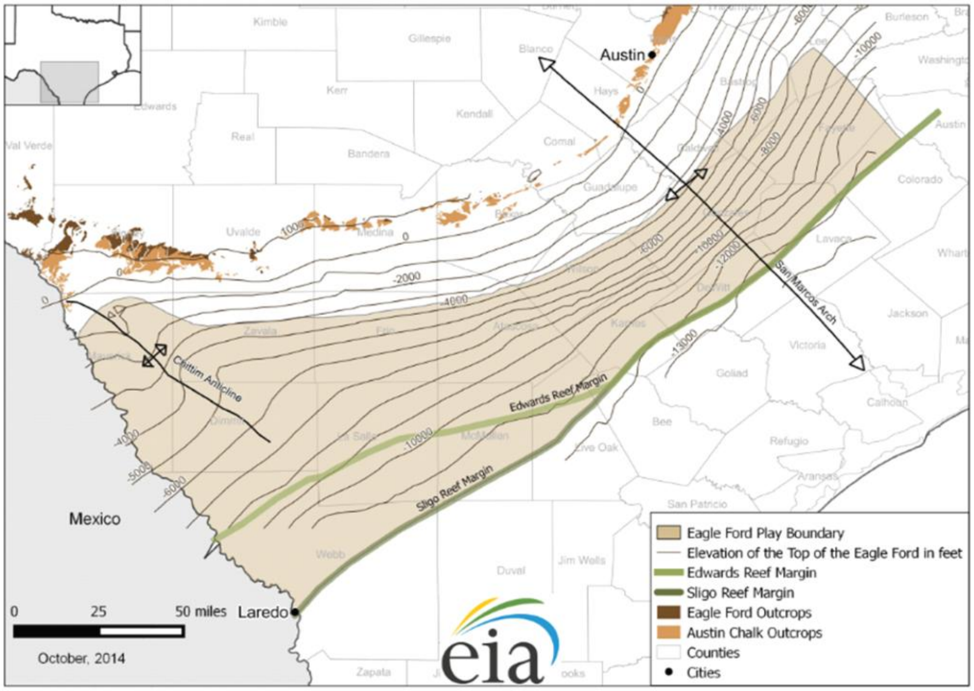
The most common considerations that need to be addressed during the implementation of jet lift systems typically include: uncertainty regarding the placement of the jet pump cavity or the optimal depth for the deviation seating point; determining the right moment to start producing the well using the jet pump after the early flowing-well production stage; identifying the most effective initial nozzle-throat combination; selecting the most cost-effective surface equipment capacity (horsepower) for the user; managing the well's transient behavior by resizing the jet pump nozzle-throat combination; preventing cavitation in the jet pump during both early and late production stages; and, finally, developing a properly designed strategy to convert from jet lift to rod lift.

This paper provides a clear discussion of the issues and challenges associated with jet lift operations, along with field-proven solutions successfully implemented in the Eagle Ford formation across approximately 150 jet-pumped wells, during a time span of 15 years.

INTRODUCTION

The Eagle Ford shale is a hydrocarbon-bearing, Late Cretaceous formation that was deposited in a marine continental shelf environment. The Eagle Ford formation consists of organic-rich calcareous-mudrock with mineralogy ranging from 40–90% carbonate minerals, 15-30% clay, and 15-20% silica. The total-organic-carbon content (TOC) ranges from 2-12%, thermal maturity (%Ro) 0.45-1.4%, API gravity 28-62 degrees, porosity 8-12%, and initial static pressure gradient 0.5-0.8+ (psi/ft). The Eagle Ford sits above the Buda Limestone and unconformably below the Austin Chalk.

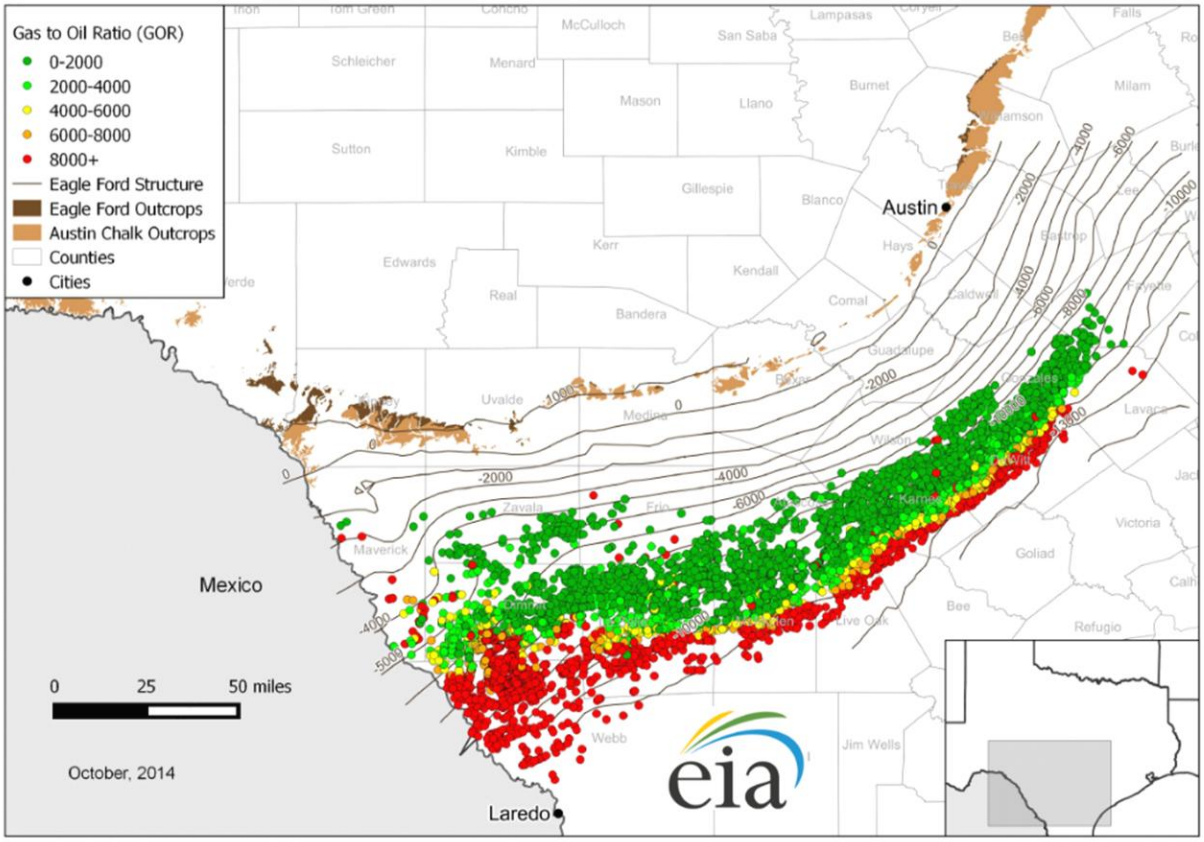
The Eagle Ford Play (Figure 1) has four major boundaries: 1) The international border with Mexico to the west, 2) a northern boundary above a minimum subsea depth of 3,650 ftTVD to intersect the top of the upper Eagle Ford formation in Frio County and counties east, and above minimum depths in Maverick and Zavala counties, ranging from 650 ftTVD to 2,900 ftTVD, 3) a southern boundary that traces the Early Cretaceous Sligo Reef Margin, and 4) a northeastern boundary where the lower Eagle Ford (the primary target for drilling and completion) thins and grades into more silica-rich units of the Pepper Shale of the East Texas Basin.



Sources: U.S. Energy Information Administration, DrillingInfo, Inc., Texas Natural Resources Information, U.S. Geological Survey, Texas Bureau of Economic Geology.

Figure 1: Eagle Ford Play, Western Gulf Province, Texas

The gas to oil ratio (GOR) distribution across the play is shown in figure 2. Because of the higher profitability of oil production when compared to gas production, most of the drilling activity is in the belt-shaped area where the wells produce hydrocarbons with lower initial GORs, which magnitudes range from 0 to 2,000 scf/STBO.



Source: U.S. Energy Information Administration and Drillinginfo Inc., September 2014.

Figure 2: Initial gas to oil ratios of Eagle Ford wells

Starting approximately from the year 2015, jet lift has been implemented as one of the main production methods in the Eagle Ford play. The jet pump ability to be installed trough high deviation angles and closer to the well’s heel, wide pump rates spectrum capability, high tolerance to sand production, easiness of pump assembly retrieval and resizing, and longevity of its tubing completion have positioned it as an effective and reliable artificial lift system that oilwell operators have widely implemented in the Eagle Ford Play to produce their wells from their early production stage all the way to depletion, at which point jet lift wells are typically converted to rod lift.

A typical jet lift system consists of five subsystems, which can be briefly described as follows:

- Power fluid unit or pump skid: It is the equipment that pressurizes the power fluid from its reservoir pressure, which is normally between 25 and 500 psig, up to the required pressures that range from 1,000 psi to 4,500 psig, depending on the application. The mechanical device that is used to accomplish this task can be a plunger pump, diaphragm pump, or a multistage centrifugal pump. The power fluid unit is typically comprised of an oilfield skid that serves as support for the power fluid unit, an electric motor or internal combustion engine, suction and discharge piping, instrumentation for pressure, flow rate, temperature, and vibration, and the variable frequency controller. Please see figure 3.

Figure 3: Power fluid unit or pump skid

- Power fluid reservoir: It is the pressurized or non-pressurized recipient where the power fluid is contained and ready to be supplied to the power fluid unit. The power fluid reservoir should provide clean and degassed liquid to the power fluid pump. The most common power fluid reservoir types in the oilfield are specialized horizontal pressurized vessels, and oilfield production storage vertical tanks. Please see figure 4 and 5.

Figure 4: Pressurized power fluid reservoir

Figure 5: Non-pressurized power fluid reservoir

- Christmas tree – retrieving manifold assembly: Similar to a slickline lubricator, it is a manifold-piping installed to the well Christmas tree. By means of piping and valves, it enables the user to reverse the power fluid injection circuit, to eject the jet pump from its cavity, and circulate it up the tubing to the surface. The lubricator also allows to safely reinsert the jet pump in the tubing string. See figure 6.

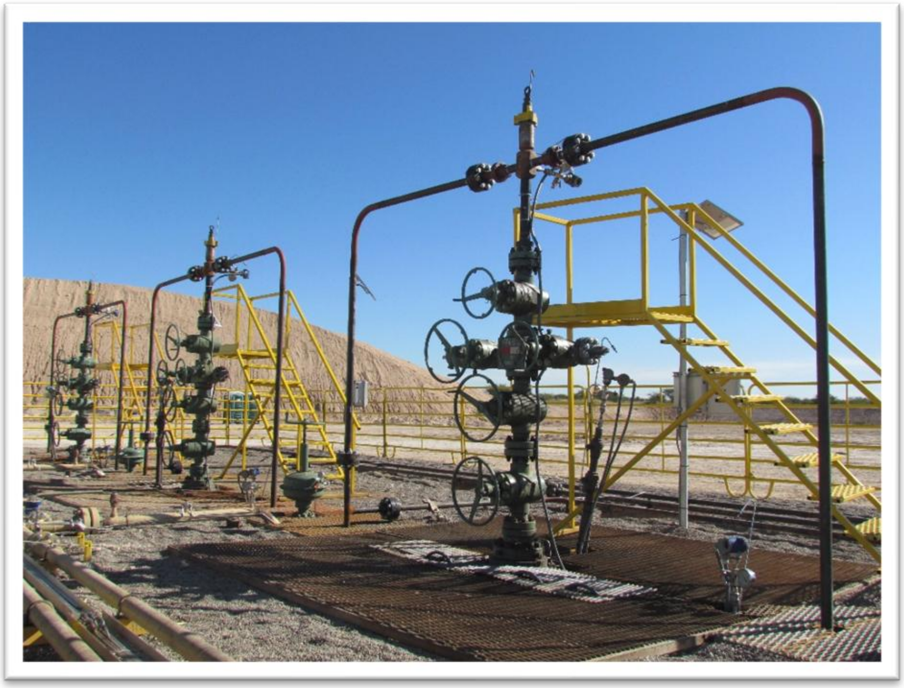


Figure 6: Christmas tree – Jet pump retrieving manifold assembly

- The Jet Pump Assembly (complete): This is the sub-equipment for which this artificial lift system takes its name. It is installed at the bottom of the well, as close as possible from the perforations' top. The jet pump is a hydrodynamic device that uses the Venturi principle to draw fluids (liquid and gas) from a formation and pump them to the surface, where the produced hydrocarbons will be treated, stored, transported and then sold. The jet pump assembly is comprised of: A bottomhole assembly or BHA, a standing valve, and the jet pump. The BHA, sometime called the jet pump cavity, is part of the tubing string and is typically installed right above an annular packer. The BHA has along its inner cavity, several seal-bore surfaces for the jet pump to seal off, and one or more "no-go" internal diameters to hold and secure the standing valve, and sometimes, the jet pump as well, depending on the jet pump mechanical design. The standing valve is a non-return valve that is located at the bottom no-go internal diameter of the BHA. The standing valve has two functions: Hold the fluids up during a system shut down and allows the hydraulic reversal of the jet pump to the surface. The jet pump itself is freely located inside the BHA and on top of the standing valve. The jet pump most important parts are the nozzle, throat, diffuser and flow crossover. Please see figure 7.

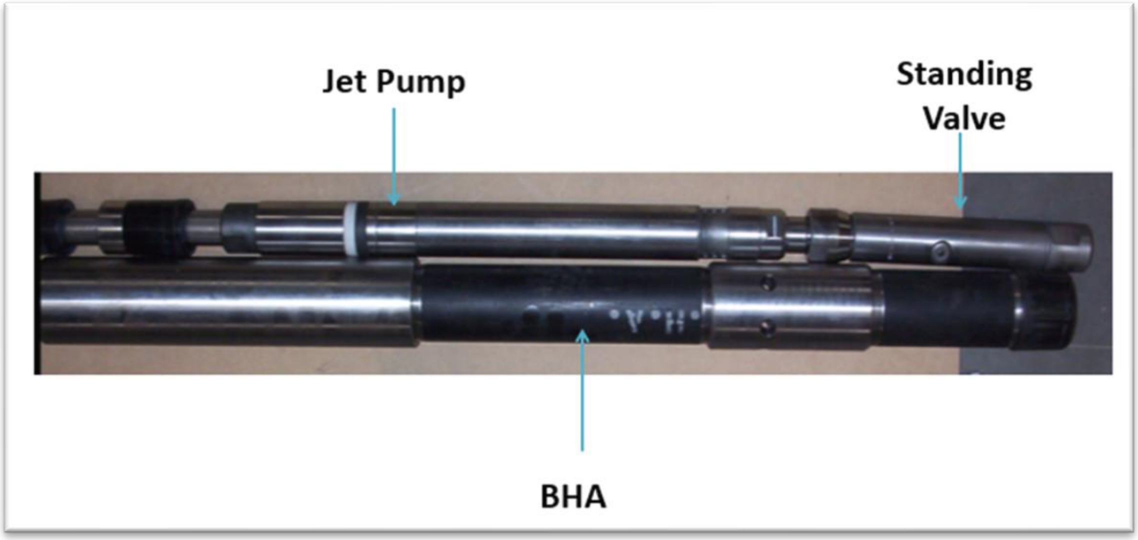


Figure 7: The Jet Pump Assembly (complete)

- The annular packer and tubulars: The packer is installed on the tubing string, above the perforations' top, and below the BHA. It must provide effective and long-lasting seal and endure the high temperatures at the bottom of the well. On standard jet pump installations, on which power fluid is pumped down the tubing, the annular packer is the sub-equipment that prevents the return fluids from flowing back into the formation. On reverse jet pump installations, where power fluid is pumped down the annulus, the packer holds the power fluid column in the annular to flow down to the perforations, so this will be flowed entirely to the jet pump nozzle. To operate a jet pump, at least two tubulars are required, the power fluid conduit, and the return commingled fluids conduit. In most cases, jet pump completions are made with a tubing string concentrically installed inside the well's production casing. Please see figure 8.

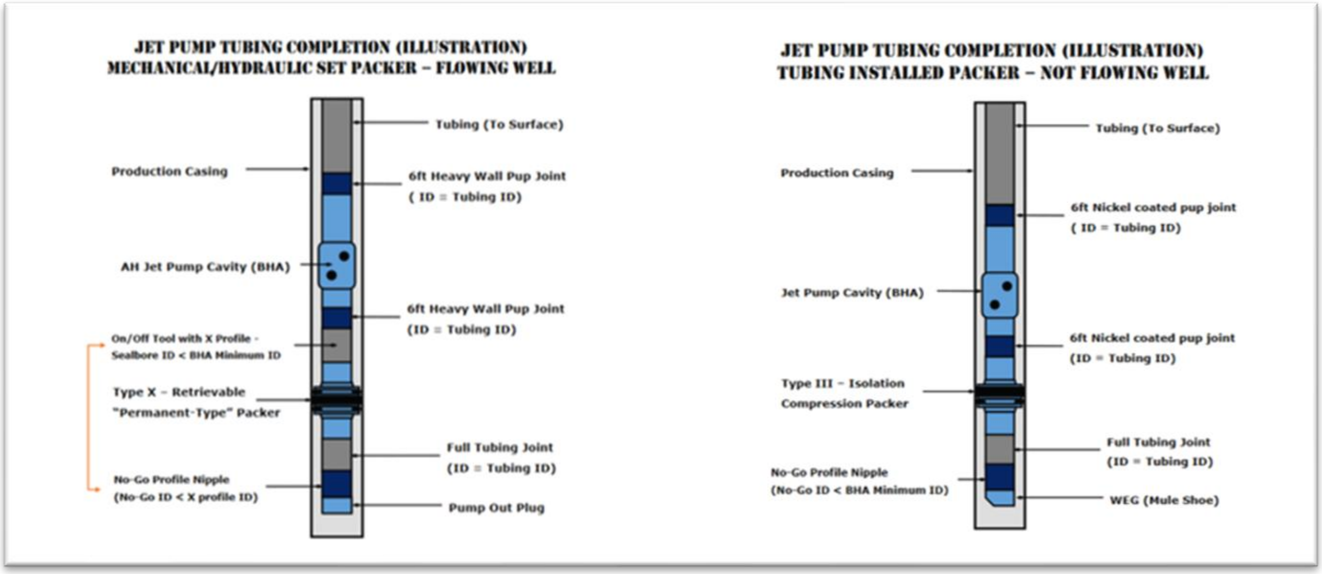


Figure 8: Typical jet pump completions (Eagle Ford)

TYPICAL JET LIFT SURFACE EQUIPMENT CONFIGURATION IN THE SOUTH TEXAS REGION

On a typical jet lift system, as the ones that are used in the South Texas Region in the United States of America, the operation is conducted as follow (refer to figure 9):

- The power fluid vessel is filled with the chosen motive fluid, which can be produced water or produced oil. In the reservoir, the power fluid must have a minimum time of residence that allows the separation of produced gas and solids. The power fluid reservoir should provide the power fluid pump with de-gassed and clean power fluid, with a net positive suction head that must be higher than that required by the power fluid pump.
- The low-pressure (typically between 25 – 500 psi), cleaned and degassed power fluid flows from the power fluid vessel, through the suction piping, to the power fluid pump. The power fluid pump increases the static pressure to the required levels, providing proper hydraulic energy to the downhole jet pump. The power fluid pump can be a multiplex pump (triplex or quintuplex), a diaphragm pump, or a multistage centrifugal pump.
- The high-pressure power fluid (typically between 1,000 and 4,500 psi) that has been energized by the power fluid pump, exits its discharge and is directed to the well's Christmas tree, through a high pressure rated pipeline. Then the power fluid is flowed

down the well through the tubing if the jet pump is of the standard flow type, or down the casing annulus if the jet pump is of the reverse flow type.

- The power fluid reaches the jet pump which is installed at the predetermined depth, which can typically be between 2,000 ft and 15,000 ft. The power fluid flows through the nozzle where high pressure fluid flow is converted to a high velocity – low pressure stream of flow, named “jet core”. At the nozzle’s tip nozzle, the local pressure is lower than the reservoir pressure, that creates the right conditions for the reservoir fluids to flow to the jet pump admission (“suction”) and then to be “dragged” by the jet core towards the mixing tube (throat). Inside the throat, the high velocity jet core mixes with the slow-moving reservoir flow, and it is on here where the velocity energy (momentum transfer) takes place inside the jet pump. Once the power fluid (jet core) and produced fluids (reservoir fluids, including oil, gas, and water) exits the mixing tube as a well-mixed-turbulent flow, it enters the diffuser where the high velocity energy (kinetic energy) is transformed back into high pressure (potential energy). At the diffusers exit, the discharge stream must have high enough pressure energy to flow back up the surface, overcoming the hydrostatic head, friction losses, and flowline pressure.
- The commingled fluid flows from the wellhead back to the power fluid vessel, where it will remain for a minimum period of time (residence time) to allow produced sand to fall onto the vessel’s bottom, and for the gas to move up to the vessel’s top. The required power fluid rate will again get flowed towards the power fluid pump, and the produced fluids are transferred to the production facilities. Please see figure 9.

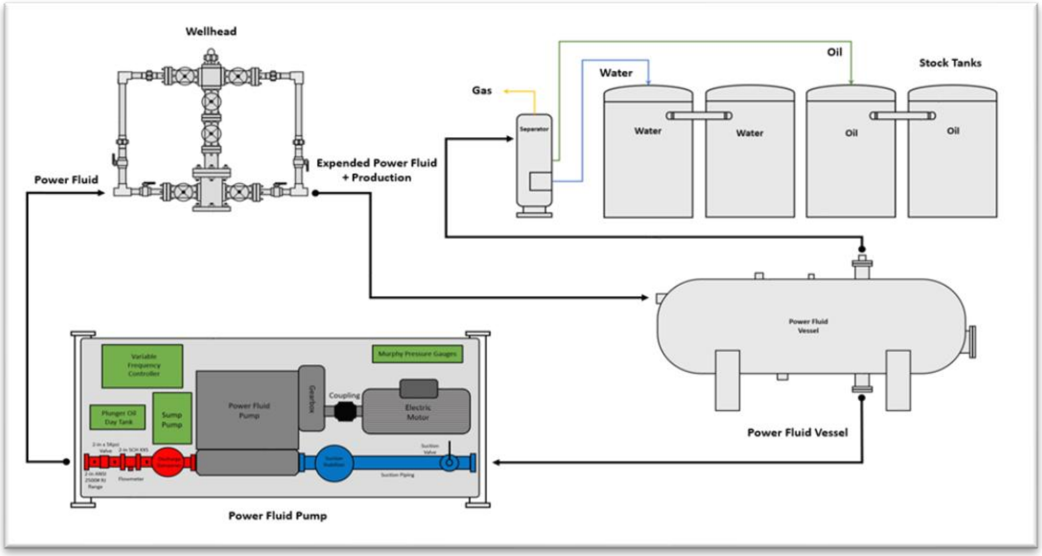
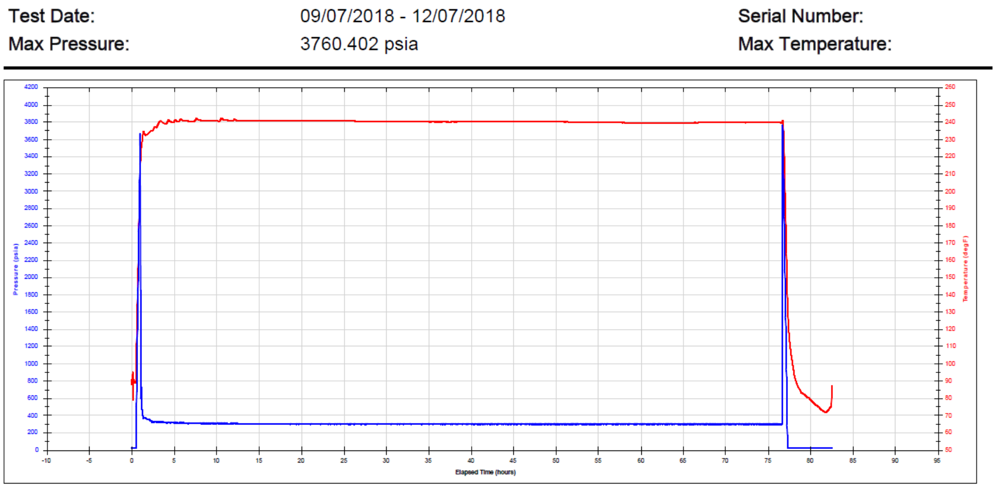


Figure 9: typical jet lift surface equipment configuration in the South Texas region

TOP TEN CHALLENGES IN JET LIFT PRODUCTION OPERATIONS AND THE SOLUTIONS SUCCESSFULLY IMPLEMENTED IN PRODUCING OIL WELLS IN THE SOUTH TEXAS REGION

1. JET PUMP BHA MOST CONVENIENT SEATING DEPTH
   From the technical standpoint, we need to clarify that the downhole jet pump can work at any deviation angle, in fact, the reverse flow jet pumps are installed upside down. Also, because of its length (around two to three feet), this can travel through very high dogleg severities (equal or less than 45 degrees per 100 ft). A BHA that has been installed at a depth between the kickoff point and 20 degrees can lead to low pump intake pressure situations during the well late production stage. A BHA installed at or beyond 65 degrees will make it very difficult for the standing valve retrieval using slickline equipment, because at such angle of deviation, the standing valve fishing tool will not travel down the tubing, it will stay static on the tubing inner surface, because a slickline cannot push the retrieving tool assembly. Based on our experience across Eagleford Basing, the most effective and convenient BHA installation depth is located at a deviation angle that ranges between 30 and 50 degrees. By placing the jet pump BHA in between this range, the following benefits are gained:
   - The most common annular packers are type III (as the AS-III) or a type X Packer (as the ASI-X). It is recommended to add an on-off tool assembly right above the packer, in case that sand settles on top of the packer's rubber element.
   - The standing valve can get retrieved with no problems, using standard slickline procedures.
   - The well productivity will be depleted to very low levels by a single artificial lift method, the jet pump. Around the Eagleford basin, numerous wells have started with jet pumps producing rates of around 3,000+ bfpd at pump intake pressure of +/- 3,500 psi; and down the road, depleted to production points of 150 bfpd at pump intake pressure of 300 psi. See figure 10.



Test Date: 09/07/2018 - 12/07/2018

Serial Number:

Max Pressure: 3760.402 psia

Max Temperature:

Figure 10: Memory gauge data from a jet pump well in the Eagleford Basin

2. PRODUCTION CAVITATION DURING THE JET LIFT STARTUP

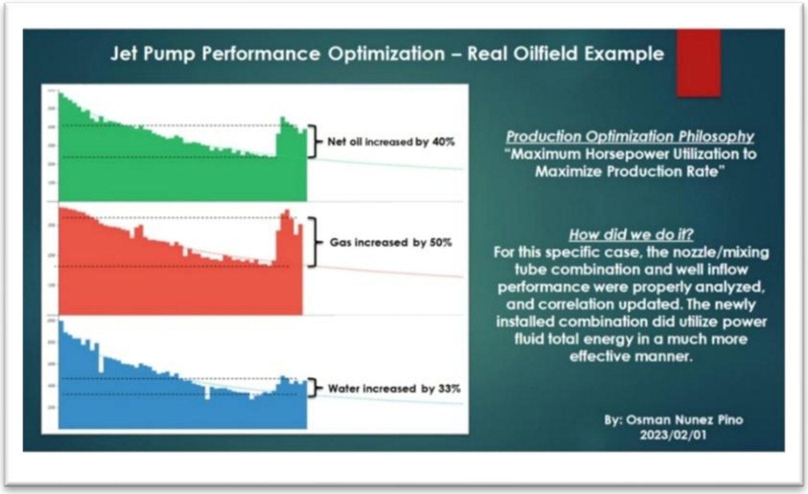
Production cavitation usually happens during the early production stage, and it basically takes place when an excessive flow rate flows through the jet pump nozzle-mixing tube annular passage. Production cavitation happens when the jet pump is induced to produce excessively high production rates, making the flow velocity reach high magnitudes, and as consequence, the creation of a low local pressure environment. When the total local pressure decreases below the corresponding fluid vapor pressure, then low pressure (voids) bubbles get formed right before or at the mixing tube curved inlet. When these bubbles contact the mixing tube inner surface, they implode and strike the mixing tube inner surface with extreme-localized force, causing a “pitting-like” damage which is distributed on the mixing tube inlet surface. See figure 11.

Figure 11: Production Cavitation Damage on a Jet Pump Mixing Tube

The production cavitation problems are prevented by selecting the right nozzle/throat combination, crafting a proper “power fluid pressure schedule”, and close operating parameters monitoring. The power fluid pressure schedule is made following the outlined steps below:

- Collect reliable production data, for at least three continuous days.
- Run a NODAL analysis on the jet pumped well or free flowing producing well if this is a brand new well, and try to establish a well IPR, as close to the reality as possible.
- Using a reputable jet pump performance calculation software, select the best nozzle/throat combination, and determine the injection pressure that will be needed to power the jet pump to produce the target total production rate (final injection pressure).
- Start up the jet lift system with an injection pressure of 65% - 70% of the final injection pressure and hold this pressure for at least 48 hours.
- Increase injection pressure by no more than 300 psi (maximum pressure incremental) every 48 hours (minimum time interval), until the final injection pressure is achieved.
- If at any time during the power fluid pressure increments, the total production rate does not increase, then reduce the injection pressure back to the previous level and rerun the jet lift calculations to find out how separated the current production point on the IPR (reservoir rate vs PIP), is from the production cavitation onset value.

3. JET LIFT PRODUCTION OPTIMIZATION: KEEPING UP WITH THE WELL TRANSIENT IPR.
In addition to selecting the most convenient and effective nozzle/throat combination, it will be necessary to make sure that the jet pump is equipped with the best combination throughout the jet pump usage in that well. We have found that many operators are not being properly supported by their jet pump vendors with a structured nozzle/throat combination optimization program. Through more than 20 years of jet pump field and application engineering experience, we found that the most effective way to keep each jet pump well within an appropriate optimization track, is by following the procedure explained below:
    - Constantly monitor the jet lift system operating parameters (power fluid pressure and rate, surface pump suction pressure and pump speed), as well as the well production data (rates of oil, water, and gas). Remote monitoring of well data has never been easier and more cost effective, there are many options that range from large SCADA network systems to smaller plug-and-play cellular based systems.
    - Using average values of each of these data parameters, from the last three to five days of consistent and homogenous operation, calculate the jet pump intake pressure (PIP).
    - Use one of the recognized and tested jet pump performance modeling software, run calculations for several nozzle and throat combinations. The objective is to find out if the current combination is the most convenient for the operation, or if there is another combination that will perform better. The most convenient or best combination is that one that will produce the highest reservoir fluids rate, using the available surface horsepower, or the combination that will produce the operator's target production rate, by using the least horsepower.
    - This nozzle/throat optimization procedure needs to be repeated every four weeks during the early production stage of the well, and every six to eight weeks during the late production stage. Please see figures 12 and 13.



Jet Pump Performance Optimization – Real Oilfield Example

Net oil increased by 40%

Gas increased by 50%

Water increased by 33%

Production Optimization Philosophy
"Maximum Horsepower Utilization to Maximize Production Rate"

How did we do it?
For this specific case, the nozzle/mixing tube combination and well inflow performance were properly analyzed, and correlation updated. The newly installed combination did utilize power fluid total energy in a much more effective manner.

By: Osman Nunez Pino
2023/02/01

Figure 12: Positive Effects of Nozzle/Throat Combination Optimization

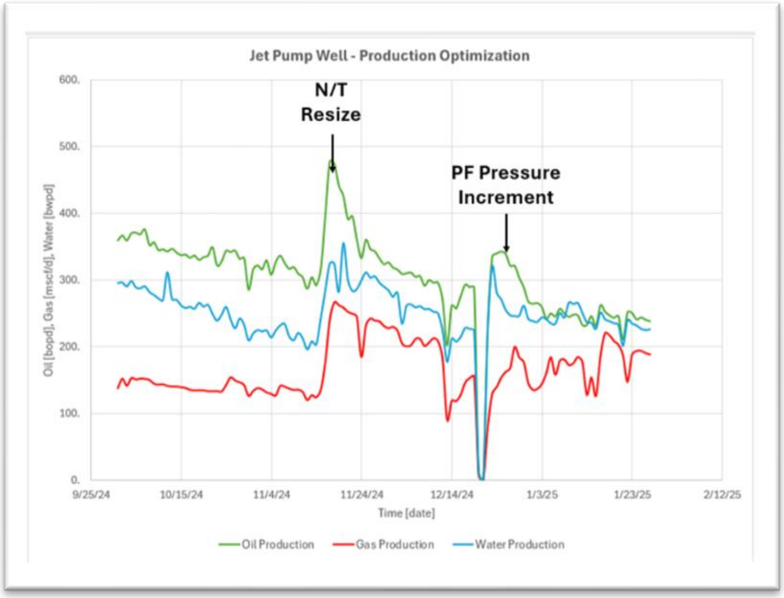


Figure 13: Positive Effects of Nozzle/Throat Combination Optimization and Power Fluid Pressure Management

4. <u>SAND-SCALE SETTLING AND SAND EROSION IN THE STANDING VALVE</u>
   The production of sand along the reservoir fluids has the potential to create several problems for the jet pump assembly, as well as with the surface equipment and facilities. It is during the early production stage where the highest sand concentration

is typically seen, causing equipment problems and failures at the below described sub-equipment of the jet lift system.

The standing valve inner flow path can get partially or totally obstructed by sand and/or scale accumulation settled inside this. This problem will not likely happen during an uninterrupted operation of the jet, but more likely right after a system shutdown, during which the sand-rich produced fluids fall back inside the standing valve. The settled material will hold the ball closed against the seat, no matter how much drawdown the jet pump makes when trying to restart the operation. See figure 14.

Figure 14: Standing Valve Plugged with Scale (Iron Sulfide) and Sand

When this problem takes place, the recommended way to solve it is the following steps:

- Hydraulically retrieve the jet pump to surface.
- Circulate power fluid, pumping it down the casing and returning it up the tubing. The reverse circulation of power fluid should continue until little to no sand is observed in the returns. The recommended rate of circulation flowrate to transport sand from the jet pump BHA up to the surface is: 2,000 bpd (at least) for 2-3/8” tubing strings, and 3,000 bpd (at least) for 2-7/8 tubing strings.

- Using standard slickline equipment, retrieve the standing valve. Disassemble the standing valve and clean it out, inspect it, replace any damaged part and reassemble.
- Using standard standing valve and jet pump procedures, drop into the tubing string these two assemblies and restart the jet lift system.

5. <u>JET PUMP FLOW CROSSOVER BODY DAMAGED BY SAND EROSION</u>

With high production rates, i.e., greater than 2,500 bfpd, the flow velocity through the crossover body suction intake passages is relatively high, so high that sand grains will indeed erode the internal passages of this jet pump part. The erosion can be of such magnitude that the jet pump intake passages can communicate with the discharge ports of the crossover, preventing the jet pump from functioning properly. When an operator expects high production rates (greater than 2,500 bfpd), the proven options to mitigate sand erosion damage to the crossover body of the jet pump are two:

- For conventional standard jet pump assemblies, apply a case-hardening heat treatment (for example, boronizing) to the crossover. The enhanced metallurgy of this part will increase the hardness of the case to around 1,500 HV.
- When even higher production rates with high sand concentrations are expected (more than 4,000 bfpd), the best option to minimize jet pump assembly damage is to install a high flow jet pump system. On the high flow jet pump assembly, the intake passages are not in the jet pump, but in the BHA. With a significantly large cross-sectional area, the BHA can accommodate larger intake ports, which translate into lower flow velocities through the passages. See figure 15.

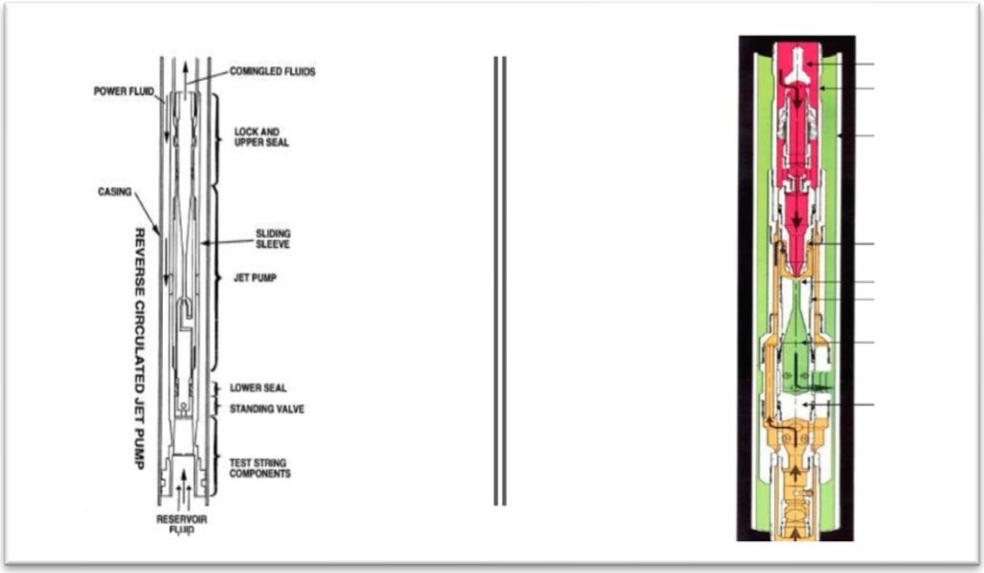


Figure 15: Conventional Standard Flow Jet Pump (left) and Standard-High Flow Jet Pump

6. <u>LOW PUMP INTAKE PRESSURE CAVITATION</u>
   Low Intake Pressure Cavitation typically happens when a jet pump is operated to produce relatively low flow rates at a very low intake pressure. In unconventional oilwell production, this scenario might take place during the late production stage, where the well deliverability is being depleted.
   When a low inflow well is produced with a jet pump, the magnitude of energy that needs to be provided to the jet pump, by means of the power fluid, is usually high. In more practical words, to produce a deep well with low intake pressures, the injection pressure and rate to power the jet pump are considerably high. That said, when the large potential energy supplied to the nozzle entrance, and the energy transformation takes place from potential to kinetic energy, that results on a jet core which means flow velocity is substantially greater than the mean flow velocity of the produced fluids entering the suction area between throat and nozzle. As previously indicated, the molecules of produced fluids are “dragged” into the throat by the power fluid jet core molecules. When high injection pressures are required for the jet pump to lift depleted wells, where both production rates and pump intake pressure are low, the difference of velocities between jet core and produced flow can be very large. Along the mixing layer, where high velocity molecules (jet core driving molecules) collide with low velocity molecules (dragged molecules), a sort of vortices or “mini-tornados” are formed. The center portion of these vortices present a total pressure, low enough to initiate the inception of bubbles. As in production cavitation, the

recently formed bubbles grow, shrink, collapse, and if located around the throat inner surface vicinity, impact and cause damage to the throat. See figure 16.

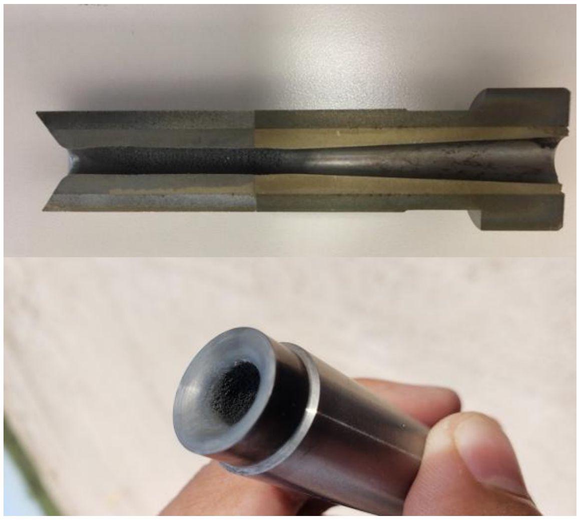
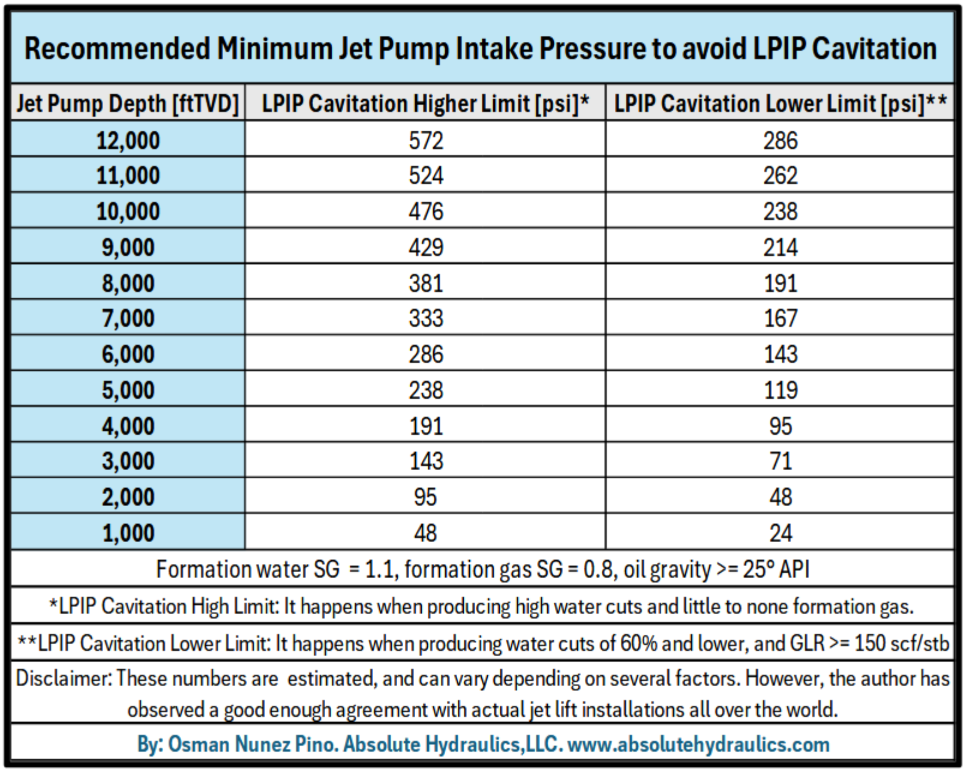


Figure 16: Jet Pump Low Intake Pressure Cavitation

The procedure that one of the authors uses to prevent or, in the worst case, mitigate LPIP cavitation damage is described below:

- Calculate the minimum required jet pump intake pressure to avoid the LPIP cavitation onset. The author has created a simplified chart as a preliminary reference to estimating the LPIP cavitation onset pressure. See figure 17.
- Make a mathematical analysis of the specific jet lift system, using a trustable jet pump software, to estimate the most effective and convenient nozzle/throat combination for the specific production operation.
- Using the jet pump software, determine the maximum injection rate that will drive the jet pump to induce a pump intake pressure that will be 10% higher than the LPIP onset pressure, calculated at the beginning of this procedure.
- Re-evaluate the jet pump performance, based on actual production and operating data. Ensure that the calculated pump intake pressure is 10% higher than the LPIP cavitation onset pressure.



Jet Pump Depth [ftTVD]	LPIP Cavitation Higher Limit [psi]*	LPIP Cavitation Lower Limit [psi]**
12,000	572	286
11,000	524	262
10,000	476	238
9,000	429	214
8,000	381	191
7,000	333	167
6,000	286	143
5,000	238	119
4,000	191	95
3,000	143	71
2,000	95	48
1,000	48	24

Recommended Minimum Jet Pump Intake Pressure to avoid LPIP Cavitation

Formation water SG = 1.1, formation gas SG = 0.8, oil gravity >= 25° API

*LPIP Cavitation High Limit: It happens when producing high water cuts and little to none formation gas.

**LPIP Cavitation Lower Limit: It happens when producing water cuts of 60% and lower, and GLR >= 150 scf/stb

Disclaimer: These numbers are estimated, and can vary depending on several factors. However, the author has observed a good enough agreement with actual jet lift installations all over the world.

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Figure 17: Minimum PIP to avoid LPIP cavitation in jet pumps

7. MULTIPHASE FLOW CHOKING AT THE JET PUMP INTAKE

During the late production stage, at relatively low jet pump intake pressures, the density of reservoir gas at the jet pump intake pressure and temperature conditions becomes low and its local volume high. At this point of the well production stage, the jet pump must process the produced oil, water, and an expanded volume of gas. On this scenario of production, the average velocity of the gas rich – multiphase flow entering the annular area between the nozzle and mixing tube is typically very high, so high that sometimes it will reach the local velocity of sound. For a specific nozzle/mixing tube combination, when the production stream compressible flow at the jet pump intake reaches its sound velocity (Mach Number = 1), it means that this is the maximum production rate that can physically be achieved. It does not matter if the power fluid injection pressure is increased to a much higher values, the jet pump won’t decrease its intake pressure any further and will not produce with a higher rate. To face and overcome this challenge, we basically must find a nozzle/throat combination that provides a larger intake area, that will allow to process equal or greater multiphase flow, at a lower average velocity, lower than the sound velocity at the jet pump intake pressure and temperature conditions. These are the steps that we follow in these cases:

- Calculate the current jet pump intake pressure.
- Based on the most current data, calculate the Mach Number (MN) of the multiphase flow at the jet pump intake.
- If the Mach Number is less than 1, then the secondary stream (production) is not choked.
- If the calculated (theoretical) Mach Number output is 1 or greater, then the secondary stream is choked. In this case, we need to calculate and find a nozzle/throat combination with a larger flow area.
- Consider that a combination with larger secondary stream flow area (i.e. lower area ratio), will also provide a reduced lifting capacity. We must make sure that the chosen combination will provide high enough discharge pressure to ensure the lifting of the commingled fluids to the surface.

8. REDUCING OPERATING EXPENSES BY USING MULTISTAGE HORIZONTAL CENTRIFUGAL PUMPS.

Multiplex plunger pumps have been the most common type of power fluid pump used on hydraulic lift operations for a very long time, since the 1930's. In most recent years, another type of positive displacement pump has joined the power fluid pump options, the diaphragm pump. Positive displacement pumps provide high energy efficiency, which is one of the main attractive characteristics to justify its wide-spread usage. They also are well known across the oil and gas industry; personnel and repair shops to assemble, maintain, and repair these pumps are abundant across the main hydrocarbon producer area of the United States of America and worldwide.

Despite the high efficiency advantage, multiplex plunger pumps have weaknesses, which are typically related to their plunger packings and valves. Depending on the pump speed, discharge pressure, sand content in the power fluid, and the concentration of aggressive chemical agents, these packings will need to be replaced frequently. Power fluid that has been poorly or not conditioned will cause faster damage to the packings and valves. On the other hand, despite not suffering from the packing problems, because they don't have, diaphragm pumps share with plunger pumps the frequent damage to its valves. From the field standpoint, damaged packings mean fluid leaks in the pump cradle and around the pump skid are negative collateral problems of plunger pump usage. Valves that are partially damaged will not provide the needed steady discharge pressure and rate. Besides that, both plunger pumps and diaphragm pumps require rigorous preventative maintenance programs. Every three to six months, the lubricants need to be changed. Altogether, this frequent preventative maintenance and packing and valve changes, and plunger lubrication oil (in plunger pumps), drive the operating cost to unwanted levels, as well as causing extended loss of production because of relatively high non-operating time. Looking for a more cost-effective power fluid pump option, several jet pump users have had a very satisfactory experience using multistage horizontal centrifugal pumps as their jet lift systems power fluid pumps. These types of pumps have been used in the oilfield starting from the 1990’s to power jet pump wells at few oilfields around the world. One of the authors of this paper worked with jet pumps powered by horizontal pumping systems on Maracaibo Lake, Venezuela, and at the North Slope of Alaska, United States of America. However, it wasn’t until the second decade of the 2000’s where these pumps started to gain more extensive usage as jet lift power fluid pumps. Nowadays, Multistage centrifugal pumps (also known as “HPS” or “H-Pumps”) are substantially more common in the oilfield to drive jet pumps. HPSs with capacities ranging from 250 HP through 600 HP (motor horsepower) are being used in the Eagleford Basin to serve as single or multiple wells power fluid pumps. See figure 18.

Figure 18: Horizontal Multistage Centrifugal Pump

The advantages of these types of pumps are:

- They are rotating-well-balanced pumps. This feature mitigates mechanical problems related to high-amplitude vibrations.
- They don’t have multiple packings that will likely get damaged in short time, but a single mechanical seal that typically stands in good condition for six to twelve months.
- HPS do not have valves that separate the low and high-pressure chambers, the fluid pressure is progressively increased through the multiple stages of the pump, from the suction to the discharge.
- The fluid pressure at these pumps discharge is steady, there is no sinusoidal pressure variations, which eliminates the vibrations through the suction and discharge pipelines that reciprocating pumps cause.
- The only sub-assembly that needs lubricant oil is the trust chamber, and it needs oil change every three to six months, with a needed volume of oil is approximately one gallon.

Not all HPS characteristics are great, there are a couple of lowlights that need to be considered:

- HPS’s energy efficiency is lower when compared to positive displacement pumps. The operating energy efficiency of a typical HPS is normally placed between 55 and 65 %. On practice, this lower efficiency means that, for the same hydraulic horsepower that a positive displacement pump delivers, an HPS requires a prime mover which output power is around 40% higher. At the end, this needed higher motor horsepower capacity translates into higher electricity costs, and a larger-more expensive motor to pay for.
- Since HPS’s have been used for relatively short time in the jet lift industry, qualified technical service personnel are not as abundant as in the reciprocating pumps case.

9. JET PUMP STUCK IN THE BHA

The combination of high pressure, high solids and scale content, and jet pump assembly not reversed out for preventative inspection and maintenance, may cause among other problems, a jet pump that gets stuck into the BHA. When this happens, the jet cannot be retrieved by reverse-circulation of power fluid (hydraulics retrieval), and in some worse cases, not even a slick-line truck can complete the mechanical retrieval job.

The authors recommend these actions:

- As a preventative measure: Hydraulically retrieve the jet pump for inspection and maintenance every 3 months. The sole action of ejecting the jet pump from the BHA will loosen and break away the deposits of solids and scale that get settled between the gap of the top section of the pump and the BHA seal bore.
- As a remedial action: Before calling out the workover unit to pull the jet pump completion out of the hole, the recommendation is to pump down the tubing 10% of the tubing volume of a 5% solution of hydrochloric acid (HCL). Once the HCL is all placed inside the tubing string, immediately start power fluid injection with the jet lift surface pump (do not let the HCL soak in the completion), just like in the system normal production operation. Keep pumping power fluid down the tubing (for standard flow jet pumps) until the HCL solution has been pumped back to the surface. Do not leave HCL in the well, it must be completely returned to the surface. It is important to mention that to carry out this procedure, one must ensure that power fluid is still free to flow through the jet pump.

10. CONVERTING THE JET LIFTED WELL TO ROD LIFTED WELL, WHEN IT IS THE RIGHT TIME?

When an oilwell has been produced using a jet lift system for a long time, to what we use to call “depletion”, the production operation costs may reach levels on which is no longer economic to continue producing with the jet. If this is the case, one must consider finding a lifting method that can yield the expected production rate, and at the same time, be more economical to operate when compared to the jet lift system. The main operating costs of a jet lift system that is producing a late production stage well are power consumption and preventative maintenance. Consequentially, the artificial lift system that would replace the jet pump must reduce the cost of consumed power to run the unit and at least match the average production rate that the jet pump is making.

The authors have participated in several conversions from jet lift to rod lift, and have learnt that the most important considerations when planning to do this transition are:

- Before taking action to physically replace the lifting method, run comprehensive rod pump calculations to verify a rod lift system will operate satisfactorily. These include pump installation depth, rod-to-tubing contact loads, pump fillage, additional downhole gas separation equipment and required horsepower.
- Based on theoretical knowledge, nearby wells data, and experience, estimate the time between failures of the rod pump system. This analysis gives an idea how many workover jobs the well will need in a period of time, and how much the cost of these well repairs will add to the lease operating expenses account.
- If this pre-conversion study suggests that the rod lift system will be technically appropriate, reduce the operating expenses and produce the required barrels of oil per day, then converting to rod lift may be the right thing to do.

For the scenario where it is more convenient to keep the jet lift for longer, until the point where this method cannot operate any longer, one of the authors of this work has created a blocks diagram as an aid to walk oil and gas operators through this production method conversion. This diagram of jet pump – to rod pump conversion was created based on the premise that the only consideration (breaking point) to converting is Low Pump Intake Cavitation (LPIP Cavitation). See figure 19.

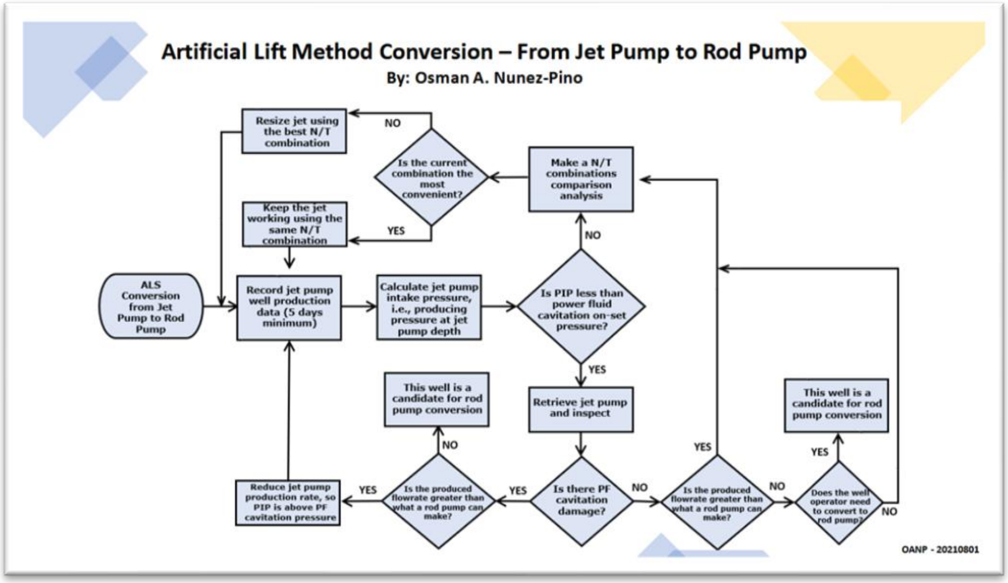

Figure 19: Jet Lift to Rod Lift Conversion Diagram (Based on LPIP Cavitation)

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