MAXIMIZING PROFITS WITH HYDRAULICALLY OPERATED RECIPROCATING PUMPS

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ABSTRACT

Maintaining low operating costs is a critical aspect of field operations. This is a sizable challenge when producing deep, high volume, high water cut wells in a mature oil field. Profits from such wells are usually marginal and heavily dependent on oil prices due to somewhat fixed operating costs. West Texas is home to many wells that meet these criteria. Most are produced with hydraulic jet pump systems or, more commonly, submersible pump systems. Both systems are reliable and each offers advantages. Both systems are also renowned for high electrical consumption; an attribute not welcomed in today's efficiency-focused environment.

Hydraulically operated reciprocating pump systems have been used in the oil field since the mid 1930's. Despite lower daily operating costs this system is not as common due to shorter pump run life and high equipment surveillance demands. One manufacturer made major modifications to the pump improving the pump's overall performance and significantly increased the volume capacity. This type of pump offers several advantages and is extremely competitive with other high volume lift systems.

This paper summarizes the results of seven hydraulically operated reciprocating installations in the Mobil operated Russell field. The systems are installed in wells producing from 250 bfpd to 1650 bfpd from depths as great as 10,700 feet. Current data indicates that 20 to 40 percent less horsepower is consumed compared to other systems. Consequently, profit from each barrel of oil produced increases. The pump also operates at lower producing bottom hole pressures compared to jet pump systems resulting in higher production rates. The advantages and disadvantages of the reciprocating pump are presented.

INTRODUCTION

Background

The Russell (Devonian) Field is located in Gaines County, Texas approximately 15 miles northwest of Seminole, Texas. Mobil Exploration and Producing U.S., Inc. (MEPUS) operates the field. The field was developed in the mid-1950s. There are currently 16 active producing wells with production of 496 bopd, 90 mcfpd and 14,200 bwpd. The Devonian formation is found at a depth of 10,700 ft. and has a strong bottom water drive. A typical producer has water cuts greater than 90% and produces at least 500 bfpd.

Various artificial lift methods have been used over the life of the field to produce the Devonian wells. Hydraulic lift was the primary choice in the early life of the field. Central oil power systems served the entire field with one central power station. Fixed type casing reciprocating pumps were used down hole and proved to be reliable when oil cuts were still fairly high. High maintenance costs and environmental concerns mandated the consideration of other lift systems. In most cases, stand-alone 150 hp hydraulic systems (unidraulics) with down hole jet pumps replaced the central hydraulic power system. Most of these were installed in the early 1980s and proved to be very effective. Electrical submersible pumps were also installed in some wells in the early 1990s.

Increasing profits from the field is challenging especially when production is on a steady decline and operating and maintenance costs remain relatively unchanged. In the past, the focus was on reducing the cost to operate the well. These costs included chemical, down hole well work and surface equipment repair. Although good results were realized by focusing on these costs, the type of lift system was not evaluated for change.

DISCUSSION

Equipment Performance Evaluation

MEPUS personnel were interested in a lift system that optimized profits from each well. The ideal lift system would increase production for a minimal investment and be fairly low cost to operate and maintain. The evaluation would consist of analyzing the systems in place and making changes as deemed cost effective. Hydraulic jet pump and submersible pump systems were already in use producing high volume wells. A beam pump is used to produce the only low volume well in the field. Beam pump systems were not given further consideration because of the desired volumes (1000 bfpd). The analysis would entail evaluating the total system cost and not just one aspect of the lift system.

Hydraulic jet pump lift systems produced fifty percent of the wells. Overall, jet pumps systems proved to be relatively inexpensive to operate. Pump run life averaged anywhere from 18 to 24 months. However, system efficiencies as low as 14% were measured on some wells with 25 to 35% being more common. Upsizing the hydraulic jet pump systems was evaluated to increase production. This analysis indicated that higher draw downs were achievable only by the installation of larger surface equipment. With the low efficiencies associated with the jet pump, it was decided not to pursue this alternative.

Submersible pumps usually accomplished drawing the well down to approximately 500 psi producing bottom hole pressure. Wells produced at this bottom hole pressure usually experienced a 2 to 3% increase in oil cut. This is attributed to the formation having 7 distinct zones that produce simultaneously only at low producing bottom hole pressures. Although effective in drawing down the wells, submersible pump systems have high initial investment costs, high electrical consumption and high sub-surface maintenance costs making them less attractive. Problems had also been encountered in running 4-1/2 inch O.D. equipment in 5-1/2 inch casing.

Another system evaluated was the hydraulic reciprocating pump. None of the wells were equipped with this system; however, it had been used in the past with mixed results. Reciprocating pumps, like jet pumps, are operated by surface pump units. However, they will typically have higher system efficiencies. The pump is capable of reaching lower producing bottom hole pressures consequently increasing production rates. Computer simulation designs indicated that the cost to operate these units would be approximately 1/3 less than jet pump systems. Previous experience indicated that these models were accurate. The drawback to this system is that clean power fluid is an absolute must. When used previously, the reciprocating pump experienced short run times. The primary reason for the short pump life was 1) failure to use clean power fluid; and 2) pumping off the well. Nonetheless, these were factors that could be corrected and controlled.

In order to reach the desired production volumes, large bore pumps (3") would be needed. This size pump had never been installed in North America before, but had been operated successfully in South American oil fields. Pump run life exceeding 18 months had been reported. MEPUS personnel discussed the opportunities provided by the system. It was decided to test two wells with the larger pump and evaluate the results at the end of a six month period.

Equipment Installation and Design

A team consisting of a lease operator, production technician, repairman, production engineer, pump manufacturer engineer and chemical engineer reviewed the project's objectives. Past reciprocating pump failures and successes were evaluated. The group also reviewed the operational and design practices required to operate the system successfully. Topics discussed were 1) practices that assured clean power fluid; 2) testing techniques to eliminate pumping off the well; and 3) the utilization of a chemical with anti-corrosive properties as well as lubricating properties that would lubricate the moving parts of the pump engine. The group felt that if these practices could be administered successfully the pump run life could be extended to an acceptable level.

Unidraulics typically use the fluid produced from the well and reinject it as power fluid. The Devonian formation water contains high concentrations of total dissolved solids including iron. The iron content is high enough to cause problems for the engine section of the down hole pump and shorten the run life. The unidraulic's surface unit is equipped with a vortex designed to separate solids from the water. If designed and operated correctly, the vortex is capable of cleaning produced water sufficiently to reinject. The team decided to use this device as the sole method to clean the water. Special attention was given to the proper sizing of the vortex and the proper setting of the differential pressure across the unit. Sight glasses were also placed directly beneath the vortex to visibly check the power fluid as it circulates.

Since a packer is set down hole on all hydraulic systems, there are no means to measure the producing bottom hole pressure. Therefore, it is critical to have an accurate productivity index for each well prior to installing the reciprocating pump. In order to avoid pumped off conditions, the team developed a process to check the pump efficiency after each test. If a drastic drop in efficiency was observed, the strokes per minute (spm) were reduced and matched to the test. The pump efficiency will drop slowly and not drastically as observed during pumped off conditions. This technique was effective and it helped eliminate problems associated with pump off conditions. The process followed to speed up the unit is similar. The unit was sped up gradually (2 spm maximum per day). The pump efficiency was then measured by testing the well.

All wells installed with the reciprocating pump had water cuts in excess of 90%. Since both the pump and the motor have several moving parts, lubrication is critical to extend the pump life. All hydraulic systems in the field are treated continuously with corrosion inhibiting chemical designed to coat the metal it contacts. The recommended chemical was a water soluble, anti-corrosion chemical with a strong surfactant package. The chemical was extremely effective in reducing pump wear and in preventing corrosion of the pump, tubing and casing.

CASE STUDIES

A comment or explanation should be made concerning the installations that are described herein. To prevent casing damage, it was prohibited to apply pressures greater than 750 psig on the casing. Therefore, retrievable down hole pumps were not circulated out of the wellbore. When a down hole pump required changing, a pulling unit was rigged up and the pump was fished with a sand line. The exchange unit was circulated in the well as a free type unit.

As previously mentioned, the high volume wells required 3" bore pumps. In order to run this size pump, the 3" units were installed "bottled up" in the bottom hole assemblies, locked in place, and lowered on 2-3/8" or 2-7/8" tubing as fixed type pumps. 2-3/8" circulating valves were utilized above the units for the purpose of flushing the tubing strings prior to start up.

The Oilmaster 3" 220 unit was selected for this application for two reasons. The proposed criteria required a pump that was capable of displacing up to 2000 bpd at 75 to 80 percent of rated speed. The large bore pump was the only pump on the market capable of this task. Secondly, as previously stated, the reported success of this unit in South American operations made the pump ideal for Russell field wells. The fact that the tubing would have to be pulled to service "bottled up" pumps was not a concern. Experience showed that rig time was about the same for pulling tubing conveyed pumps and sand line retrievable pumps. Rig time for these units is about half of submersible pump installations.

H&J Unit 1D #22

This was the first well to receive the reciprocating pump. The pump depth is 10,766 ft and the unit that was installed was a 2" 220 unit in 2-3/8" tubing. Exhibit 1 of the attachments gives the results before and after. As indicated, the surface unit was changed from a 150 hp to a 100 hp unit. There was also a 32% reduction in daily electrical cost.

H&J Unit 1D #19

This was the second well to be converted. A submersible pump was replaced with a 2-1/2" 220 unit set at 10,694 ft. Exhibit 2 gives results before and after. Actual production declined slightly but there was a significant reduction in electrical cost.

H&J Section 451 #14

This was the first 3" 220 unit that was installed in the program. The pump was set at 10,810 ft using 2-7/8" tubing. Exhibit 3 shows the results and indicates a marked increase in the production rate along with a decrease in electrical cost.

H&J Section 451 #9

This was the second 3" 220 unit that was installed and set at 10,690 ft on 2-7/8" tubing. Exhibit 4 shows the results. This unit also gave a good increase in production and decreased electrical cost.

Exhibit 5 summarizes the reduction in the daily electrical cost realized from this program. Results from two additional wells, H&J Section 451 #5 and H&J Unit 1D #42, are also shown. Both of these wells have 3" 220 units installed and both replaced submersible pump systems.

After approximately 18 months of operation, the average run time varies from 74 days on the 2" and 2-1/2" units up to 162 days on the 3" units. Repair costs are $1400 per repair and $2853 per repair, respectively. The overall average for these units is 120 day runs with an average repair cost of $1950.

These figures include failures due to external sources not related to the pump. For example, the H&J Unit 1D #22 experienced failures related to corrosion caused by a nearby cathodic protection system. However, even when these failures are included in the calculations, the hydraulic reciprocating pump system is still 24% less expensive to operate and maintain than a submersible pump system over a 2 year period. This figure is based on historical data for all submersible systems in the Russell (Devonian) field which had an average 18 month run time.

CONCLUSIONS

The objective of the program was to find a method to reduce the overall cost of artificially lifting the deep wells in this field. The performance data indicates that this was accomplished with the reciprocating type hydraulic production unit. The overall system efficiency was improved considerably and the daily operating cost was reduced substantially. The success or failure of this operation can be attributed to the following actions:

1) Close monitoring of the surface power fluid cleaning system to insure that it is performing properly.

2) When using water as a power fluid, as in this application, it is imperative that a chemical with good anti-corrosion properties along with lubricating properties be used to provide protection to the production unit.

3) Accurate well tests taken periodically to prevent the down hole production unit from operating in a pumped off condition for extended periods of time. This will prolong the life of the unit.

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H&J Unit ID #22

	BEFORE	AFTER
TEST	* 25 bopd + 225 bwpd	* 53 bopd + 383 bwpd
EQUIPMENT	* National J165 unid	* National J100 unid
PUMP SIZE	* 9X jet	* 30" x 1.60" x 1.50"
SURFACE PRESSURE	* 4000 psig	* 3600 psig
SYSTEM EFFICIENCY	* 14%	* 42%
PRODUCING BHP	* 1080 psig	* 300 psig
WATER CUT	* 90%	* 88%
ELECTRIC COST/DAY	* $79.65	* $54.47
$/BO	* $3.19	* $1.03
$/BF	* $0.32	* $0.12

Exhibit 1

H&J Unit ID # 19

	BEFORE	AFTER
TEST	* 60 bopd + 675 bwpd	* 55 bopd + 569 bwpd
EQUIPMENT	* SUB/140 HP	* National J100 unid
PUMP SIZE	* 465 stage	* 48" x 2" x 1.75"
SURFACE PRESSURE	* NA	* 3400 psig
SYSTEM EFFICIENCY	* 43%	* 51%
PRODUCING BHP	* 300 psig	* 375 psig
WATER CUT	* 92%	* 91%
ELECTRIC COST/DAY	* $113.35	* $62.48
$/BO	* $1.89	* $1.14
$/BF	* $0.15	* $0.10

Exhibit 2

H&J 451 #14

	BEFORE	AFTER
TEST	* 40 bopd + 916 bwpd	* 103 bopd + 1538 bwpd
EQUIPMENT	* National J165 unid	* National J100 unid
PUMP SIZE	* 9A jet	* 54" x 2.44" x 2.36"
SURFACE PRESSURE	* 4000 psig	* 3400 psig
SYSTEM EFFICIENCY	* 14%	* 42%
PRODUCING BHP	* 1080 psig	* 300 psig
WATER CUT	* 90%	* 88%
ELECTRIC COST/DAY	* $79.65	* $54.47
$/BO	* $3.19	* $1.03
$/BF	* $0.32	* $0.12

Exhibit 3

H&J 451 #9

	BEFORE	**AFTER**
TEST	* 32 bopd + 846 bwpd	* 55 bopd + 1075 bwpd
EQUIPMENT	* National J165 unid	* National J165 unid
PUMP SIZE	* 9A jet	* 54" x 2.44" x 2.36"
SURFACE PRESSURE	* 4000 psig	* 3150 psig
SYSTEM EFFICIENCY	* 37%	* 69%
PRODUCING BHP	* 1825 psig	* 975 psig
WATER CUT	* 96%	* 95%
ELECTRIC COST/DAY	* $111.19	* $73.87
$/BO	* $3.47	* $1.34
$/BF	* $0.13	* $0.07

Exhibit 4

220 Pump Program
Mobil Russell Field

WELL	PREVIOUS EQUIPMENT	POWER COST ($/DAY) BEFORE	AFTER
1D #22 2" UNIT	JET PUMP	$ 80	$54
1D #19 2-1/2" UNIT	ESP	$113	$62
1D #42 3" UNIT	ESP	$ 94	$51
451 #5 3" UNIT	ESP	$150	$61
451 #9 3" UNIT	JET PUMP	$111	$74
451 #14 3" UNIT	JET PUMP	$ 97	$76

Exhibit 5