PROGRESSIVE CAVITY PUMPS DELIVER HIGHEST MECHANICAL EFFICIENCY/LOWEST OPERTING COST IN MATURE PERMIAN BASIN WATERFLOOD

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ABSTRACT

Results of a field test study proved that progressive Cavity (PC) pumping systems provide greater mechanical efficiency and less electrical usage than beam and electrical submersible pumping (esp) systems in mature waterflood producing wells. These systems were evaluated in Permian Basin wells ranging from 3800 feet to 5000 feet in depth and production rates ranging from 500 barrels per day to 1000 barrel per day.

Operating facilities were used to monitor production, fluid shots were used to monitor fluid levels, and inline mechanical kw-hr meters were used to measure electrical usages before and after PC pump system installations. Mechanical efficiencies were calculated based upon this data. Production tests indicate that total well productivity was increased and an incremental oil increase was realized where PC pumping systems replaced beam lift systems previously thought to be optimum.

Increased water production due to waterflooding has necessitated lift revisions and beam pump optimization. When a beam lift system has reached maximum potential, a larger lift system becomes necessary. Esp systems provide increased lift capability, but at a much lower efficiency. The criteria used for selecting the test wells was maximized beam lift and economically marginal esp producing systems. The purpose for the field test was to determine if PC pumping systems were an economic alternative to lift these high WOR wells when compared to beam and esp systems.

A field test study was began in 1991 to evaluate mechanical and electrical efficiencies of PC pumping systems in the environment stated above. A comparative analysis to beam and esp lift systems was then performed. This paper presents the results of that analysis and confirms that PC pumping systems are the most cost effective artificial lift systems in mature Permian Basin waterlood producing wells.

INTRODUCTION

The maturing of a water flood creates constant changes which affect artificial lift design. Most often, the volume lifted must be increased while the percent of oil in the produced fluid decreases. This increase in expense and decrease in return on capital places many producing wells in a marginally economic position. The need to lift greater volumes of fluid more efficiently propagated the exploration of artificial lift alternatives that are more economically attractive.

A project was established to evaluate the performance of Progressive Cavity pumping systems as an alternative lift mechanism in high volume (500-1000 bbls. per day) beam pumped wells and low volume (800-1000 bbls. per day) esp produced wells ranging in depths of 3800 feet to 5000 feet. Producing wells from mature Permian Basin water floods were chosen for the testing. These wells produce from the Grayburg and San Andres horizons. Typical media environment was a 90% to 98% WOR, 8% to 20% H_2S content in the gas phase, 1000 ppm H_2S content in the water phase, 36 degree to 38 degree API gravity crude oil, moderate to extreme corrosivity, and moderate to extreme iron sulfide (FeS) content in the fluid. The focus was placed upon operating at or near pumped off conditions (net lift = pump setting depth).

DESCRIPTION OF PC PUMP APPLICATIONS

Rene Moineau, a French scientist, presented a doctoral thesis to the University of Paris[1] in the middle 1930s. This thesis described what Moineau termed an R.M. Capsulism. Simply stated, the Moineau principle utilizes a rotor with a single external helix which is inserted into a stator containing an internal double helix creating a series of cavities. When one member is rotated, cavities progress from one end (suction) to the other (discharge) creating a continuous flow. Positive displacement is created due to the distance between the centerline of the rotor and stator. Figure 1 illustrates the geometry of this helical gear.

Although PC pumping systems have been successfully used for shallow low gravity crude oil and water production, little testing and documentation has been done with environments and depths stated above. The first step was to become familiar with technology used in shallow heavy oil production and determine what was applicable in higher gravity crude oil, less viscous fluid, and greater net lift applications. For this reason, PRIMARY and SECONDARY operational concerns were identified.

PRIMARY OPERATIONAL CONCERNS were defined as "problems that caused catastrophic failure or were DETRIMENTAL to the use of PC Pumping systems" under conditions previously stated. They are:

- adequate pump stages to lift required volume from required depth
- elastomeric compatibilities with higher aromatics in crude oil and production chemicals, ie; corrosion inhibitor
- adequate drive head bearing performance due to increased weight/load

SECONDARY operational concerns were defined as "problems that must be addressed because of non-catastrophic failures" or "problems NOT DETRIMENTAL to the use of PC pumping systems" in the above stated environment. They are:

- tubing back-off due to friction in the pump
- tubing wear from rods and rod couplings due to increased rpm (up to 720)
- adequate pump off control
- environmental exposure, ie; stuffing box performance
- installation and pulling expense

EQUIPMENT DESIGN AND APPLICATION

The following procedure was developed for project implementation.

PHASE I
- Design a PC pumping system utilizing existing technology
- Choose candidate wells representing the majority of currently operated mature waterflood wells

PHASE II
- Install twelve (12) PC pumps and implement design changes as necessary
- Identify and remediate PRIMARY OPERATIONAL CONCERNS during the installation process

PHASE III
- Continue to identify and remediate PRIMARY OPERATIONAL CONCERNS
- Identify and remediate SECONDARY OPERATIONAL CONCERNS
- Monitor and evaluate electrical and mechanical efficiency

PHASE IV
- Optimize system operation in above stated environment over a two (2) year period to determine pump life
- Develop/evaluate effective Pump Off Control System
- Compare electrical and mechanical efficiencies to beam and esp pumping systems under like conditions

PHASE I - PC PUMPING SYSTEM DESIGN AND APPLICATION CRITERIA

Efforts were made to capitalize on all existing technology that would be applicable to mature water flood conditions. Information found in a paper titled "Optimization Of Progressive Cavity Pump Systems In The Development Of The Clearwater Heavy Oil Reservoir"[2] was very useful. A field trip to Alberta, Canada was made to visit manufacturing and field facilities and evaluate applicable technology. The pump chosen is one in which each pump stage will support 100 psi pressure. An eighteen (18) stage pump was required but it was decided that a twenty six (26) stage pump would be installed. This would allow flexibility of rotor/stator fit and compensate for elastomeric incompatibilities and the passage of solids. Pump selection was standardized using a model 200/26 stage for comparative reasons, although other models are applicable. This pump is designed to lift 1.75 barrels per day (BPD), per revolution per minute (RPM). Tubing Anchor Catchers (TAC) and modified packers were installed to allow tubing tension setting and prevent tubing back-off. Some installations were made without TACs or modified packers for evaluations. The lack of a TAC caused no problems but it is believed that tension pulled into the tubing during operation is beneficial in the prevention of tubing wear. Tubing size in all installations was 2.875 EUE 8 RD with one 8 feet long tubing sub at the discharge of the pump to allow bottom rod movement. In some installations, heavy wall tubing was used at the bottom and top of the tubing string for additional strength. One (1) inch sucker rods were used in all installations but two (2) where seven eighths (7/8) inch rods were used. Different pony rod arrangements at the bottom and top of the rod strings were used to offset harmonics of the rotating strings. This was based upon work done by the Centre For Frontier Engineering Research (C-FER), Edmonton, Alberta.

A variety of rod protection devices were evaluated. Most installations were made with poly-urethane coated couplings. Two (2) installations included four (4) rods with molded-on rod guides (3 per rod) installed at the pump discharge. Spray metal rod couplings were used in four (4) wells. Snap-on Lotus type rod guides were later applied to these strings using one per rod at the connection area after tubing failures occurred. Combination molded/snap-on type rod guides were also used which allow a molded plastic surface to spin through a snap-on poly-ethylene guide. These provide a bearing surface of plastic on plastic for the wear to occur. All installations had standard polished rods 26 feet in length to allow removal of the rotor from the stator and allow fluid bypass without the need of removing surface equipment. Vertical Electric Drive (VED) units were used to power the system. Electric motors were sized as required for volume. All motors were NEMA B. Initially, standard compression packed stuffing boxes were used which were later exchanged with oil lubricated seals. Mechanical drum type speed limiters were initially used to limit back-spin speed to within sheave limits. Some of these were later exchanged with hydraulic type limiters. In one instance, a small blow out preventer (BOP) was used below the drive head to allow stuffing box repacking without killing the well. Electronic controllers which allow programmable kill and restart features as well as constant monitoring of electrical usage were installed in all cases. These included a flow line pressure switch and flowline turbine meter which monitored rate in BPD. The controller was set to stop the motor when the rate reached one half (1/2) of designed rate for that well. Inline kilowatt hour meters were installed on five (5) wells for monitoring efficiency. Where possible, these meters were installed and monitored while the wells were being beam lifted for comparative reasons.

Figure 2 represents typical installations that were made. Modifications to this installation were made for evaluation and remediation once problems were identified. Candidate wells were chosen based upon production rate, depth, completion horizon, and problems associated with previous pumping designs. The intent was to choose wells that represent the majority of those found in South Permian Basin mature water flood fields. Large volume producers with high water to oil ratios were targeted. Candidate wells considered were those which were at or near limits of the pumping system currently producing them. The vast majority of these wells were known to have beam pump problems due to the presence of iron sulfide (FeS) in the well bore. Since H2S content is present in most wells, candidate wells chosen had H2S contents ranging from 8% to 20%

in the gas phase and 1000 ppm in the water phase. Aromatic content of the oil was approximately 8%. Corrosion inhibitors containing no aromatic were used for corrosion mitigation.

PHASE II - IDENTIFICATION, AND REMEDIATION OF PRIMARY OPERATIONAL CONCERNS

The findings in this study represent the evaluation of twelve (12) PC pump installations. Electrical and mechanical performance was evaluated in five (5) of these installations as seen in Table 1.

The 26 stage pump was adequate although net lift never exceeded 4400 feet. An attempt was made to increase production from 1000 BPD to 1200 BPD by increasing pump speed from 600 rpm to 720 rpm. Since only a small increase in volume was realized, it was determined that the pump volume begins to peak at 600 rpm, depending on net lift and rotor/stator fit.

There were no problems with the drive head and bearing due to increased weight loads. The bearings subjected to the highest loading and rpm combination were inspected and in excellent condition.

No problems were identified with aromatic incompatibilities with the high nitrile elastomer used. Oil soluble corrosion inhibitors normally used were replaced with a water soluble inhibitor to avoid potential problems. Although softening and blistering associated with aromatic attack were not experienced, five (5) stators failed to pass bench testing when pulled. Test failure was due to high torque requirements. Internal inspection revealed different degrees of surface hardening of the elastomer. The worst case of hardening was only 1/8 inch deep, but was enough to cause surface cracking and increased torque beyond allowable limits. It is suspected that H2S attack is responsible for the stator failures although other stators exposed to the same environment for even longer periods of time continue to perform without incident. It is suspected that the sulfur present in the H2S created a post curing of the elastomer. High rpm speed may have also contributed to this process. Samples of the failed elastomers are still being analyzed at the time of this writing.

PHASE III - IDENTIFICATION, AND REMEDIATION OF SECONDARY OPERATIONAL CONCERNS

A list of identified SECONDARY OPERATIONAL CONCERNS is included in Figure 3.

Tubing back-off was experienced in one installation. The tubing string had a standard TAC set just below the pump. Analysis indicated the TAC released, allowing the tension pulled into the tubing string to move the stator upwards, allowing the rotor to contact the tag bar (bottom portion of the pump used for spacing the rod string). The back off occurred instantaneously just after fluid reached the surface. Although the tubing unscrewed, the cause was a standard TAC failure. Standard TAC failures occurred in two other wells before modified packers were installed. The modification included a positive locking J setting that prevents turning of the tubing. All following TAC installations were of this type.

No appreciable tubing wear was identified where poly-urethane coated couplings and poly-urethane centralizers were used. Some debonding and breaking of the poly-urethane occurred in most wells. Other urethane blends are currently being tested. Various types of molded and field applied rod guides are also being tested as previously discussed. Tubing wear was identified in wells that had spray metal rod couplings after four (4) to six (6) months. This wear was most predominate at the bottom 100 feet with some wear at the top. The use of spray metal coated rod couplings has been discontinued. Molded rod guides such as those used in beam lifted wells experienced premature wear.

A new type of tag bar used for spacing the rotor has been developed. The new design prevents the rotor from sticking, should the rotor come in contact with it while in operation.

Some pitting of the chrome plating on the rotor has occurred, but has not been detrimental.

Correct spacing was difficult in the beginning. Failure to allow enough space for rod stretch due to loading resulted in rotor contact with the tag bar. Increased stretch allowance solved this problem.

Rods have been over torqued and, in one instance, parted due to rotor contact with the tag bar. Proper spacing has eliminated this problem.

Polished rod failure, well head movement, and stuffing box leakage have all been experienced due to improper alignment. The use of a dial indicator to assure proper well head equipment alignment with the well has eliminated these problems. Due to high rpm rotation, an oil lubricated seal has been developed to replace the compression type stuffing boxes. The seal gland is allowed to slightly move with the polished rod if required.

Originally, mechanical drum type speed limiters were used to limit rpm reverse rotation speed when the tubing fluid level equalizes with that in the annulus. These were unsuccessful and have been replaced with a newly designed hydraulic speed limiter. The new design allows the release of energy stored in the rod string and prevents reverse rotation speed.

Although some efficiency loss has been detected, in each case it has been attributed to a down hole cause which has been addressed. As shown in Table 1, the average overall system efficiency for PC pumps is 63.4%. This is 23% more efficiency than the beam pumps evaluated in this study. Also included in Table 1 are the results from an efficiency study done by Lea and Minissale[3] on wells meeting the same conditions as previously stated. Results show that PC pumps are 13% more efficient than the beam pumps and 50% more efficient than the ESP pumps previously studied. It should be noted that all system efficiencies in Table 1 were determined using the same method.

PHASE IV - PUMP OPTIMIZATION AND CONTROL

Considerable work can be done to optimize PC pump installations. Monitoring pump performance before and after installation has been very beneficial. Graphs such as the one included as Figure 4 should be maintained for future reference when the pumps are pulled. By studying graphs such as the one illustrated in Figure 5, it appears possible to design a specific rotor/stator fit to match the conditions of the well. Since PC pumping systems remain relatively constant, as opposed to cyclic, system performance is easily monitored. Since volume is proportional to rotation speed, controllers can be used to increase or decrease production rates. Use of controllers in this study has indicated possible prediction of net lift and the use of that data as a controller. Although more evaluation is necessary, there appears to be much potential in the PC pumping system. This study will be continued for one year and a conclusive evaluation will be done at that time.

CONCLUSIONS OF THIS STUDY

1. PC pumping systems are more mechanically and electrically efficient than beam and ESP pumping systems for lifting 600 BPD to 1000 BPD from 4000 to 5000 feet.

2. Although many Operational Concerns have been identified, all incidents to date appear to be economically addressable.

3. There is a need to evaluate new elastomers for use in high WOR wells where H_2S is present.

4. Further evaluation is necessary to optimize PC pumping systems in non-viscous fluid movement and capitalize on pump control potential.

ACKNOWLEDGEMENTS

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2.Lea, J.F., Anderson, P.D., Anderson, D.G.: "Optimization of Progressive Cavity Pump Systems in the Development of the Clearwater Heavy Oil Reservoir", paper 87-38-03 presented at the 1987 Petroleum Society of CIM, Calgary, June 7-12.

3.Lea, J.F., Minissale, J.D., "Efficiency of Artificial Lift Systems", paper presented at the Southwestern Petroleum Short Course, Lubbock, April 22-23.

Table 1

EFFICIENCY COMPARISON
PROGRESSIVE CAVITY, BEAM, & ESP PUMPS

	BARRELS PRODUCED OIL	WATER	TOTAL	AVG. NET LIFT	KwH PER BBL.	OVERALL SYSTEM EFF.%
PC PUMP						
JEW 82	28	903	931	2876	0.599	63
SOFO 34	72	614	588	3840	0.943	62
JEW 63	25	480	505	2850	0.727	64
SOFO 140	23	565	588	4031	0.876	61
MFU 649	40	980	1020	3930	0.892	67
				AVERAGE	0.827	63.4
BEAM						
JEW 82**	20	853	873	2303	1	35
JEW 63-A	26	502	528	3100	0.847	53
JEW 63-B	28	490	518	3370	0.819	53
SOFO 140-A	22	512	534	3350	0.938	51
SOFO 140-B	20	530	550	3350	0.898	53
				AVERAGE	0.900	49
MFU 26*	21	570		4651	1.17	54
MFU 687*	25	489		4228	1.03	55
MFU 184*	20	650		4441	1.05	57
				AVERAGE	1.08	55
ESP						
MFU 557*	33	800		4509	1.81	34
MFU 168*	110	575		4334	1.74	33
MFU 682*	25	500		4524	2.02	30
				AVERAGE	1.86	32

* From Lea, J., Minissale, J.: "Efficiency of Artificial Lift Systems", Southwestern Petroleum Shortcourse-92, 314-323
** Fiberglass Rods

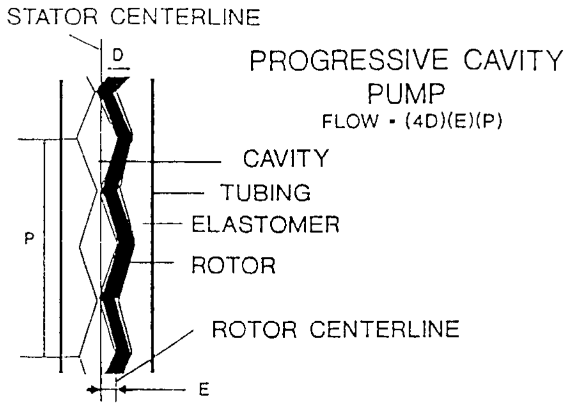

Figure 1

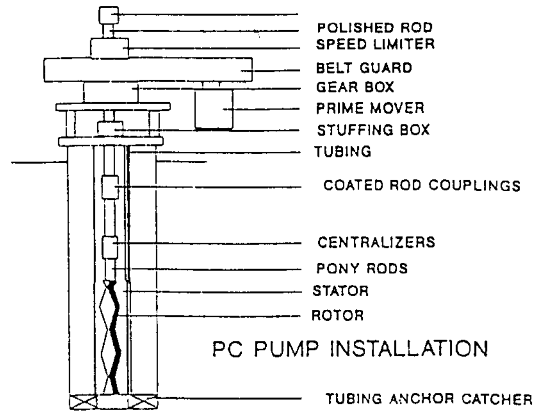

Figure 2

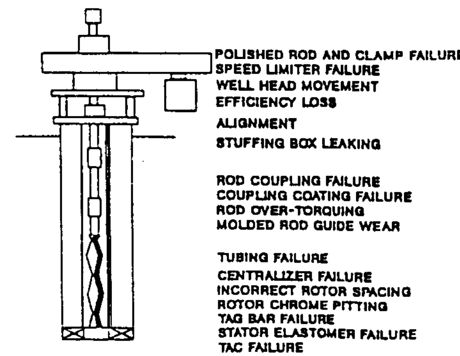

Figure 3 - Problems addressed

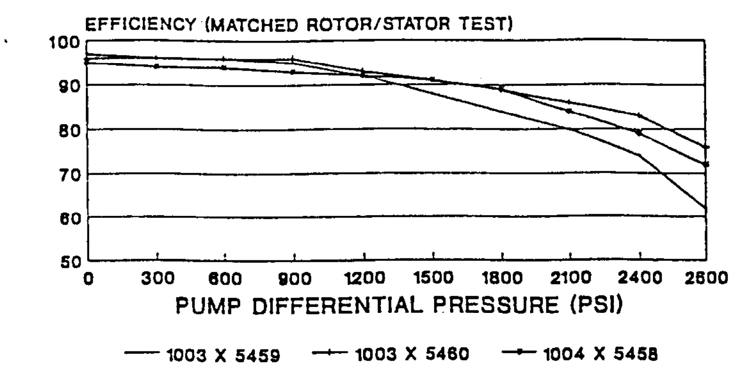

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Figure 4 - Progressive cavity pump volumetric efficiency graph bench test at 300 rpm with water

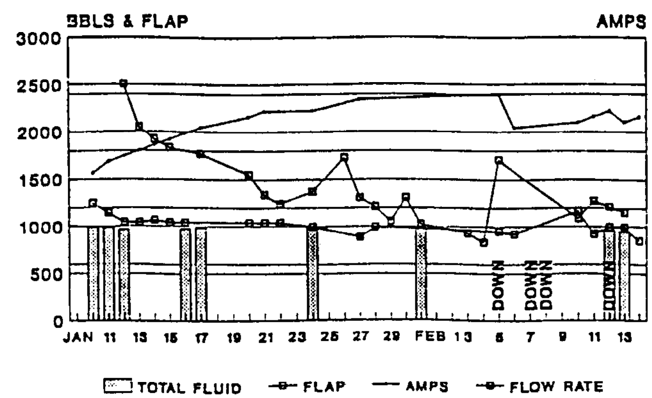

Figure 5 - Progressive cavity pump
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