A SUCCESSFUL DEEP SUCKER ROD PUMPING APPLICATION

Tommy E. Taylor
Fasken Oil and Ranch Interests

ABSTRACT
A 12,500' hydraulic jet pumped well, located in Andrews County, Texas, was converted to a rod pumping system in order to reduce lifting costs and maximize profit. A rod pumping simulation program (wave equation) was used to quantify possible ranges of equipment loading, rod loading, plunger over-travel, and ultimately, production in the stock tank. The sucker rod pumping system design includes the use of fiberglass rods, a downhole separator located above a permanent packer and a tapered tubing string. The design criteria, installation procedure and actual system performance are presented.

INTRODUCTION
Barbara Fasken's Fee "C" No.1 is a one well lease located approximately 12 miles east of Andrews, Texas. This well was drilled to 12,585' in 1954 and completed as a flowing oil well in the Magutex (Devonian) field(see Figure No.1 for Wellbore Schematic).

The well ceased to flow naturally in 1967 and a sucker rod pumping system was installed at that time. The original pumping system included a 1.25" insert pump set at 8500', an API 76 rod string design, and a 320 pumping unit. The well was rod pumped for 22 months. During that time period, the well was pulled seven times; once to add a 4000' segment of tail pipe, twice for pump repairs, and four times for rod failures. Each failure in the rod string was either a broken coupling, or a broken pin.

A hydraulic reciprocating pump was installed in 1969 to increase production to a top allowable of 130 B.O.P.D. This method of artificial lift was used until 1986. From 1980 though 1986 the reciprocating pump was being surfaced and repaired frequently because of iron sulfide buildup in the engine end of the pump. Two production casing leaks across the Grayburg interval (5000') had been squeezed prior to this time. The iron sulfide may have originated from this source.

A jet pump was installed in 1986 in order to eliminate pump plugging problems. However, the operating cost with the jet pumping system were considerably higher than with the reciprocating pump. The main reason for the increased costs was the additional power oil required to operate the jet pump. Increased power oil equates to increased electrical power costs.

The jet pumping system achieved the desired production rate of 50 B.O.P.D. and 10 B.W.P.D , but as the well began to pump-off, the jet pump began cavitating.

A sucker rod pumping system was designed to pump this well from 12,500'. This system was installed in 1988, and has been in operation for approximately 4.5 years without a single failure.

Operating costs were reduced from \$7500/mo. to \$1350/mo. and oil production was increased from 38 B.O.P.D to 55 B.O.P.D. The decrease in operating expenses lowered the economic limit for this property and the estimated recoverable reserves were increased from 75,000 BBLS. to 265,000 BBLS.

OVERALL PUMPING EFFICIENCY

Comparing overall pumping efficiencies of two different artificial lift systems will indicate which system is more efficient in lifting a given amount of fluid from a given depth[1]. Overall efficiency from measured data is the ratio of the useful pumping system output, H_o divided by the input to the motor times 100. The pumping efficiency at the pump discharge for the sucker rod pumping system is calculated as follows:

Overall Efficiency = (H_o / Input Hp) x 100

where,

Input Hp = kilowatts / 0.746 = 24 kw / 0.746 = 32 Hp

P_s = Surface Pressure = 30 psi

P_d = Discharge pressure = P_s+$Grad_t$(Depth) = 30psi+(.37 x 12,500')

P_d = 4655 psi

P_{ip} = Pump intake pressure

P_{ip} = 100 psi

H_o = (Q,bpd)x(P_d-P_{ip})/58,800 = (70 bpd)x(4655psi - 100psi)/58,800

H_o = 5.4 Hp

Overall $Efficiency_{rod}$ = (5.4 Hp / 32 Hp) x 100 = 16.9%

The overall efficiency of pumping this well with a jet pumping system is calculated as follow:

Input Hp = kilowatts / 0.746 = 84 kw / 0.746 = 113 Hp

P_s = Surface Pressure = 30 psi

P_d = Discharge pressure = P_s+$Grad_t$(Depth) = 30psi+(.37 x 12,500')

P_d = 4655 psi

P_{ip} = Pump intake pressure

P_{ip} = 100 psi

H_o = (Q,bpd)x(P_d-P_{ip})/58,800 = (70 bpd)x(4655psi - 100psi)/58,800

H_o = 5.4 Hp

Overall $Efficiency_{hydraulic}$ = (5.4 Hp / 113 Hp) x 100 = 4.8%

Comparing the pumping efficiency of each system in this particular application indicates that rod pumping this well is three and one-half times more efficient than jet pumping.

DESIGN CONSIDERATIONS

The sucker rod pumping system was designed by using a commercially available rod pumping simulation program[2] (wave equation). Most of the input data for the predictive program are known quantities such as pumping unit linkages, sucker rod properties, pump size, tubing depth, etc. Other quantities such as downhole friction, pump intake pressure, and pump fillage have to be estimated. Some of the important input data, predicted results and actual measured data are presented in Tables 1 and 2.

Sucker Rod Design

The basic criteria of a sucker rod design must be the rod stresses and the fatigue endurance of the rod string[3]. A 50%-1.25" fiberglass, 50%-7/8" and 3/4" steel rod string design was chosen early in the design phase. Fiberglass rods were selected for this application because they are lightweight and have sufficient tensile strength to handle the required rod loading. Fiberglass rods are also more elastic than steel rods, and therefore provide significant overtravel of the pump plunger.

This design provided a light weight rod string that overtraveled the pump plunger, and the rod loadings fell below 100% loading range (service factor=1.0). Initially, an API 86 rod taper was selected(1", 7/8", and 3/4" taper). However, increasing the fiberglass rod diameter from 1" to 1.25" decreased the fiberglass rod loading from 66% to below 53%, and the pump plunger travel increased from 156" to 196" at pumped-off conditions.

This is important because a decrease in fiberglass rod loading increases the expected cycles to first failure (see Figures 3,4, and 5). Figure 3 (API Goodman Diagram) and Figure 4 (Stress Range Diagram) are used in the predictive program to calculate rod loadings for each size of rod. Figure 5 is used to estimate cycles to first failure for the fiberglass rods. Note the siginificant increase in cycles to first failure below fiberglass rod loadings of 85%.

Friction

Several predictive runs were made varying individual "critical" input parameters. This was done to insure that if any given actual load was higher than estimated, the pumping system would still perform under acceptable equipment loading and pump the desired amount of fluid.

The input downhole friction is one quantity that has to be estimated. This is one of the "critical" parameters. A severely deviated wellbore could prevent the well from being successfully rod pumped. A deviation survey performed on this well indicated that no severe deviation existed. The maximum hole deviation recorded was less than 3 degrees. Under normal hole deviation a "rule of thumb" of 10% times the well depth was used to estimate the downhole friction (0.10 X 12,500' = 1250 lbs. or approximately 1300 lbs.).

A predictive run at twice this value was also performed. The predictive analysis indicated the well could be rod pumped at this higher downhole friction value and the equipment would not be overloaded.

Gas Anchor Design

A permanent packer was installed above the perforations creating an artificial sump to separate the produced liquids from the produced gas. This was done because pumping below the perforations was not feasible because the PBTD was only 9 feet below the bottom perforation.

Figure No.2 shows the downhole separator arranged in a parallel packer configuration. One drawback to using this type separator is the possibility of solids, scale, etc. settling around the top of the packer making it difficult to release the seal divider when retrieving the tubing. Also, fishing operations could be difficult if attempting to retrieve tubing in the section where the 1" tubing is banded to the 2.375" tubing. However, this design is a very effective gas separato because of the relatively low downward velocity of the liquids[4]. Thi allows the gas to breakout of the liquid and rise up the tubing-casi annulus. The packer configuration also provides a tubing anchoring device.

The arrangement of this gas anchor device began with a 4' sect of seal dividers placed on a latch sub, followed by a 2-3/8" X 4' internally plastic coated sub. Next, a downhole separator sub was installed onto the 4' sub and then 3 jts. of 1" and 2-3/8" tubing screwed into the separator sub. The 3 jts. of tubing were joined together with stainless steel bands. It was necessary to use 2-3/ tubing next to the 1" tubing so that the assembly would have encu clearance to fit into the 5-1/2", 23.00 lb/ft casing.

Since the equipment below the banded tubing would be submerc stagnant fluid, it was coated with nickel plating prior to the installation.

Tubing Design

The existing 2-7/8" N-80 EUE tubing was used in the rod p design. The inner diameter of the tubing was large enough to accommodate the 1.25" rods and provided sufficient burst resis for the hydrostatic pressure of the fluid column. The tubing provided the strength to pull the tubing if the fiberglass rods parted and could not be fished.

This is commonly called a stripping job. The tubing is pulled out of the well until the top of the rod fish is found. At this point the rods can be pulled on to unseat the pump, and the rods and pump can be pulled from the tubing.

The load on the tubing during a stripping job would be the highest when the tubing was pulled out of the tubing head slips. The force on the tubing string is calculated as follows:

$$P_{max} = \text{tbg. wt.} + \text{buoyant rod wt.} + \text{fluid wt.} + \text{anchor tension}$$

$$P_{max} = (6.5 \text{ lb/ft} \times 12{,}500') + 15{,}800 \text{ lbs.} + 23{,}100 \text{ lbs.} + 12{,}000 \text{lbs.}$$

$$P_{max} = 132{,}150 \text{ lbs.}$$

This is a worst case estimate of the load on the top joint of tubing if the rods had to be stripped out of the well. The joint yield strength for this tubing is 144,960 lbs.

Shear Tool Design

Fiberglass rods cannot be torqued over 100 ft-lbs. without damage occurring in the fibers in the rod body. If a situation occurred such that the insert pump became stuck in the tubing or seating nipple, a means of releasing the rod string would be necessary.

An all steel rod string could be backed-off and pulled out of the well before the tubing was pulled to retrieve the pump. This is not a releasing technique that can be used with fiberglass rods.

A shearing device is placed below the fiberglass rods so that the rods could be pulled from the tubing without using torque. The shearing value of the tool needs to be set so that the maximum short term load on the top fiberglass rod, and the yield strength of the steel rods are not exceeded. The shear tool must be large enough to handle the pump loading.

A 26,000 lb. shear tool was selected for this application.

Pump Design

An 1.0625" heavy wall insert pump was selected to pump the well. The insert pump can be changed without pulling the tubing string and the heavy wall pump provided sufficient strength for the anticipated hydrostatic pressure of the fluid column.

Since the pump joint was 2-3/8" tubing, only two heavy wall insert pump barrels are available to fit inside the pump joint; an 1.0625" pump and a 1.25" pump. The 1.0625" pump was selected because its pump load would be less than the 1.25" pump and a lower pump load with fiberglass rods means more pump overtravel.

The pump barrel length was calculated considering the plunger length, maximum stroke length of the pumping unit, and maximum pump plunger overtravel. Maximum plunger overtravel will occur when the pump load is the lowest. This would be at start up when the fluid level in the casing is the highest. A 36' pump barrel was selected.

A mechanical hold down was selected to seat the pump. This type of hold down device is easier to release than a cup type hold down.

The pump specifications and material usage are presented in Table 5.

INSTALLATION

The installation procedure followed the American Petroleum Institute's "Recommended Practices for Care and Handling of Sucker Rods" (API RP11BR)[5]. Included in this publication are two topics that are considered important to the success of this installation; Corrosion Control by Chemical Treatment, and Sucker Rod Joint Makeup Utilizing Circumferential Displacement.

The corrosion control process for this installation began with lubricating the sucker rod pins with a corrosion inhibitor during the makeup process. Sucker rod couplings and pin ends become invaded with well fluids when the rods are run into the well[6]. The hydrostatic pressure of the fluid column forces well liquids into the threaded portion of the rods. If the well fluids are corrosive they will degrade the unprotected portion of the rod string.

After the rod string was run, the well was batch treated with corrosion inhibitor. When rods and/or tubing are pulled from a well they are subjected to atmospheric corrosion. Treating the rods and tubing with corrosion inhibitor before or after a pulling job will reduced the effects of this type of corrosion.

A corrosion maintenance program is also being followed where the well is batch treated with 2 gallons of corrosion inhibitor every 2 weeks. A coupon tests indicated metal losses of less than 0.5 mpy is occurring and the maintenance program has not been altered since the installation.

The API's guide on circumferential displacement was followed for making up the sucker rods. Power tongs were used to achieve the torque required for each size of rod couplings. It is noted that the rod couplings were made up slowly so that the rods were not over-torqued and the tongs were rechecked for calibration every 25 rods. It is also noted that the displacement guide differs when making up new Grade "D" rods verse used Grade "D" rods.

On site supervision of the installation procedure and close adherence to API's recommendations for handling sucker rods is considered key to the long term success of this rod pumping installation.

A pump-off controller was also installed and calibrated to insure that the well shuts down at pump-off. Allowing a pump plunger to pound fluid when using fiberglass rods will result in an end fitting pull out or body failure. Currently the well is pumping at 55% run time.

ECONOMIC IMPACT

The operating expenses on this lease decreased from $7500/mo. to $1350/mo. The cost to perform this installation was $100,000. Payout on this expense occurred in 1.4 years based on only decreased operation costs.

The reduced operating expense also significantly reduced the economic limit of the property from 450 B.O.P.M to 64 B.O.P.M. This lower economic limit represents an additional 190,000 bbls. of recoverable reserves. Figure 6 shows the oil production and economic limit for this well.

CONCLUSIONS

Based on the experience gained by pumping the Fee "C" No.1, the following conclusions are made:

- Commercial computer programs are available that can accurately predict sucker rod pumping performance in a deep well.
- Fiberglass sucker rods can significantly overtravel a pump plunger in a deep well.
- Conservative design and proper installation of a rod pumping system can minimize operating expenses and ultimately increase recoverable reserves in a rod pumped well.

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5. "API Recommended Practices for Care and Handling of Sucker Rods", API RP11BR, Eighth Edition, Washington, D.C.

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Table 1

INPUT			
Pumping unit description		C640-305-168	
Motor type		Reliance High Slip 4500	
Pump depth		12,500'	
Pump diameter		1.0625"	
Pump intake pressure		150 psi	
Tubing gradient		0.37 psi/ft	
Downhole friction		1300 lbs	
Pumping speed		8 SPM	
Stroke length		168"	
Pump fillage		100%	
Tubing anchor		at pump	
Rod string design			
Diameter [in.]	1.250	0.875	0.750
Length [ft.]	6,188	2,725	3,500
Taper [%]	50	22	28
Modulus [MMpsi]	7.2	30.5	30.5

Table 2

OUTPUT		PREDICTED	MEASURED
Polished Rod Horsepower		28.4	28.6
Pumping unit loading			
Gearbox loading		87%	105%
Structure loading		80%	83%
Rod loading	1.250"	53%	54%
	0.875"	63%	73%
	0.750"	64%	79%
Net pump stroke [in.]		214	222
Displacement [bpd]		238	248

Table 3

Pump Specifications:
2" x 1-1/16" x 16' x 28' x 32' x 36' RHBM
Steel Crome plated barrel
6' Spraymetal plunger with -0.002 tolerance fit to barrel
Double valving with Alloy balls and Carbide seats
Stainless steel valve cages

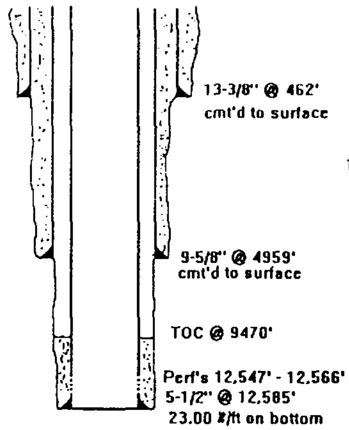

Figure 1

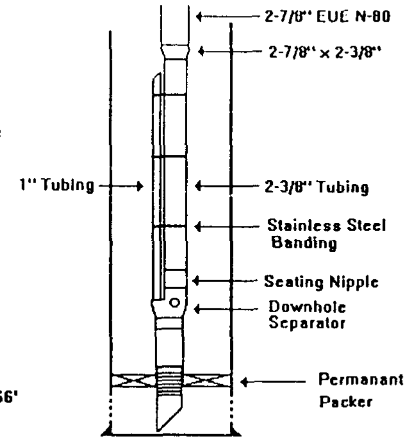

Figure 2

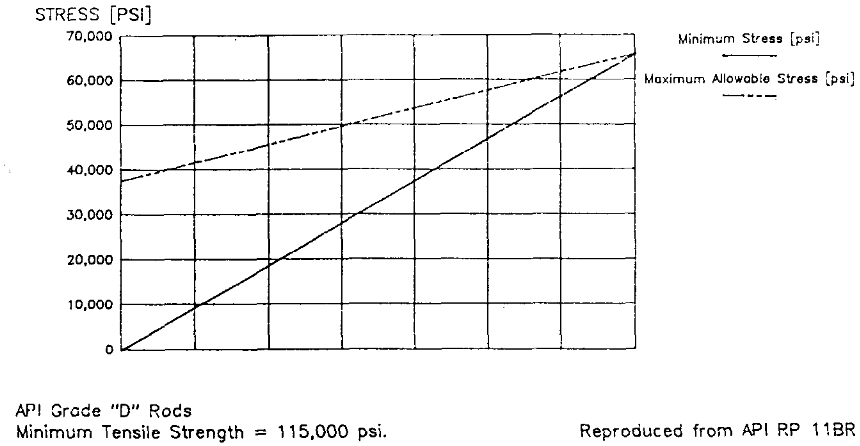

Figure 3 - Goodman diagram

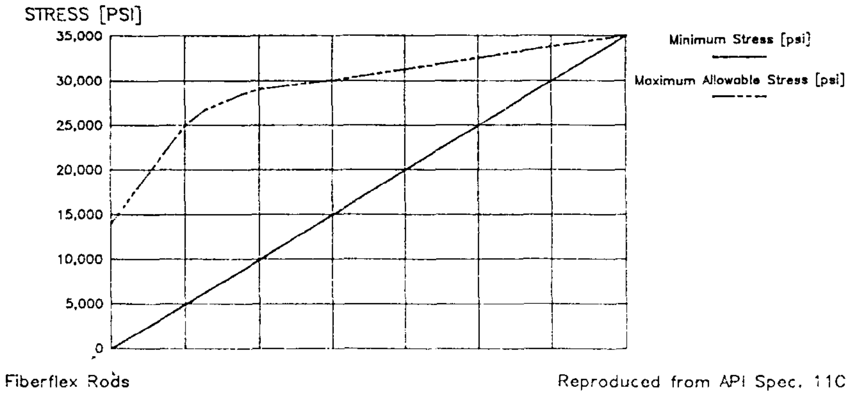

Figure 4 - Stress range diagram

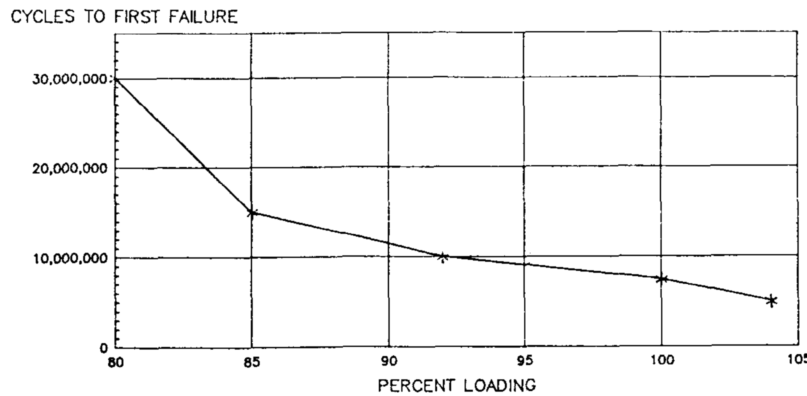

Figure 5 - Cycles to first failure vs. rod loading Fiberflex rods

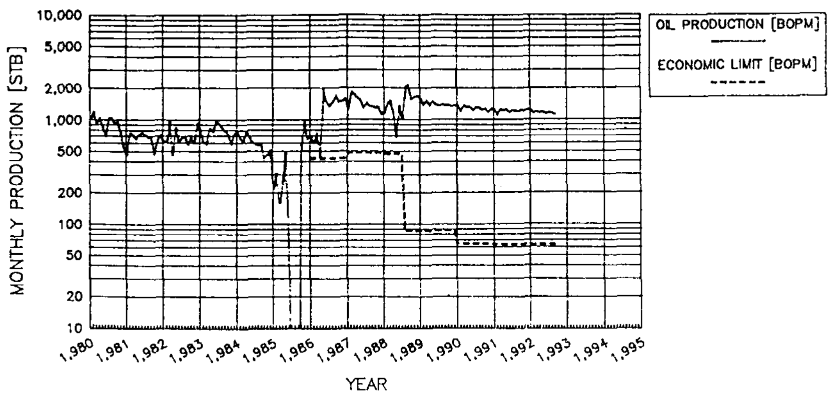

Figure 6 - Barbara Fasken Fee "C" Lease