IMPROVED DESIGN FOR SLOW LONG STROKE PUMPING UNITS

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ABSTRACT

The theoretical efficiencies of slow, long pump strokes have been discussed for over 40 years, and at least ten companies have attempted to market some form of slow, long stroke pumping unit, being either mechanical, hydraulic, pneumatic, or a combination of these. These units have generally been unsuccessful due to rather complicated designs which often incorporated short life components or required considerably more maintenance than did beam type pumping units.

Unique engineering and simplicity are the reasons for the success of this 100% mechanical slow, long stroke pumping unit. This unit will allow the operator to move a downhole pump through a slow, long stroke of 24 feet, resulting in better pump fillage, less fluid pounding, and more effective high volume or deep well production where rod stretch inefficiencies have formerly been greatly multiplied. By reducing rod stretch and requiring fewer pump cycles per barrel, this unit reduces downhole wear on pumps, sucker rods, and tubing, thus reducing downtime and increases life span of individual components.

This slow, long stroke pumping unit features short torque arm drive element, hence smaller gear reducer, fewer reversals, near constant polished rod velocity, shock absorbing load belt, and direct counterweight connection. The unit's unique design avoids inefficient power demand peaks and allows the use of smaller prime movers. Results of studies comparing NEMA D motors in conventional units and slow, long stroke units will be shown. Studies comparing NEMA D and NEMA B motors operating a slow, long stroke unit are also included.

This paper will discuss how higher surface equipment efficiencies and higher overall pumping efficiencies are obtained from this slow, long stroke pumping unit. This unique pumping unit extends the limits of sucker rod pumping to volumes and depths previously not possible with traditional sucker rod pumping.

INTRODUCTION

The advantages of slow, long stroke pumping units include fewer sucker rod and tubing problems, increased subsurface pump life, more effective and consistent draw down, less gas locking problems and higher overall pumping efficiency.

DISCUSSION

FEWER SUCKER ROD AND TUBING PROBLEMS

High pumping speed (SPM) is one of the enemies of sucker rod life. Sucker rods are subject to dynamic loads, causing stretch and compression with each stroke. On the upstroke, the artificial lift equipment must lift the full column of fluid, and, accelerating from a dead stop, boost the fluid towards the surface. Then on the down stroke the fluid load is transferred to the tubing string, allowing the sucker rods to recoil. There is stretching and compressing of the rod string, imposing cyclic stress throughout the pumping system, several times a minute. There are limits of upper and lower tension extremes that can be safely and repeatedly applied to a sucker rod and most rod manufacturers recommend using the API approved Modified Goodman Diagram as the guideline for sucker rod string design and application. A majority of well pumping applications listed in the API RP11L show that lower rod stresses result from slow, long strokes, but have higher torque requirements and use more horsepower.[1] Some slow, long stroke units have reduced the higher torque and horsepower requirements and still cause lower stresses on sucker rod strings.

Sucker rods are among the most carefully engineered equipment used in artificial lift, yet are the largest single maintenance expense in a rod pump system. Sucker rod manufacturers calculate the life of a sucker rod string based on rod stress, stress range, and number of cycles. One cycle equals one complete up and down motion of the pump plunger. Assuming that proper design, selection, operation, care and handling of a sucker rod string are correct, the sucker rod is still subjected to cyclic stresses. The fatigue endurance limit for steel can be defined as that maximum stress level at which it will operate without failure in complete reversals of loading from tension to compression for a minimum of ten million cycles.[2] One peculiar property of steel is that if a polished specimen will withstand ten million cycles under any given cyclic stress, under noncorrosive conditions, it will have an infinite life.[3] Even though laboratory conditions and oil well environments are greatly different, sucker rod manufacturers have tried to develop a sucker rod to withstand ten million cycles to first expected failure. A pumping unit, running ten strokes per minute, will exceed ten million strokes in approximately twenty-three months. However, a long stroke unit, running five strokes per minute will take over forty-six months to reach ten million cycles. Thus by increasing stroke length 100% and reducing cycles 50%, the number of months to reach ten million cycles is increased 100%. Since production is a function of pump plunger size, stroke length and strokes per minute, it is possible to reduce the number of cycles and still maintain production by increasing the stroke length. Thus, a slow, long stroke pumping unit will reduce rod failures.

Oil well tubing may seem stiff and rigid, but considering its length to diameter ratio, it becomes very flexible when installed in an oil well. Sucker rods are placed inside the tubing with a pump on one end. During a pumping cycle the fluid load is supported by the tubing on the downstroke and by the sucker rods on the upstroke. An unanchored tubing string will stretch and recoil as the fluid load is applied and removed. The sucker rods are stretching as the tubing is recoiling and the tubing is stretching as the rods are recoiling. This changing of load on every pump cycle will magnify the damage caused by rod-on-tubing wear. The resulting wear of the rods on the tubing is concentrated in an area roughly equal to the stroke length at each place the sucker rod string comes in contact with the tubing string. The shape of the sucker rod end-fitting with the coupling attached acts like a rod centralizer, therefore most rod-on-tubing wear happens where the sucker rods are joined with a coupling. By increasing the stroke length and reducing the number of cycles, production can be maintained while reducing the damaging effects of rod-on-tubing wear. The wearing surface area of the tubing affected by the metal to metal contact of the sucker rod end-fitting and coupling is increased while the frequency of the contact at a given area is decreased, resulting in fewer tubing splits and longer tubing life. Even when the bottom end of the tubing is anchored to the casing, the damaging effect of the rod string wear is greatly reduced by the slow, long pumping stroke.

INCREASED SUBSURFACE PUMP LIFE

Subsurface pumps are equipment used to force fluids to the surface. On the upstroke, fluids are lifted or forced to the surface and at the same time fluids are entering the pump barrel through the standing valve. Pressure required to fill the pump barrel is supplied by the well and is commonly referred to as the pump intake pressure. On the downstroke, fluids trapped in the pump barrel pass through the traveling valve and another cycle is started. The pump barrel is usually some type of metal and most of the time the pump plunger is metal. Metal-to-metal plunger to barrel fits are typically .003 to .004 inch, but this depends on bottom hole temperature, well depth, plunger diameter, plunger length and fluid characteristics. Plunger length requirement also depends on the fit, well depth and fluid viscosity. During the pumping cycle, the plunger and the barrel are in contact and after some number of cycles the barrel and plunger become so badly worn that the pump can no longer effectively force fluid to the surface and has to be repaired or replaced. A longer surface stroke and fewer pumping cycles per barrel of produced fluid can reduce the severity of the metal-to-metal wear and the number of pump repairs.

MORE EFFECTIVE DRAWDOWN

The following definition is copied from page 2 of the API RP11L bulletin entitled Recommended Practice for Design Calculations for Sucker Rod Pumping Systems (Conventional Units), Fourth Edition, June 1, 1988.

Note: k_r = Spring Constant of the total string and represents the load in pounds required to stretch the total rod string one inch. Sk_r then, = Pounds of load necessary to stretch the total rod string an amount equal to the polished rod stroke. [4]

A given FLUID LOAD (F_o) in pounds divided by the STROKE LENGTH (S) times the SPRING CONSTANT (k_r) equals the ratio of the stiffness of the rod string to the size of the pump plunger diameter. F_o/Sk_r produces a number that tells what percent of the length of the polished rod (surface stroke) has to move before the pump plunger moves on the upstroke. Example: If $F_o/Sk_r = 0.285$, the polished rod must move 28.5% of the stroke length before the downhole pump begins to move on the upstroke. Simply stated, all things being equal, if the stroke length is increased, this percentage will be smaller and the system will produce more fluid per foot of polished rod travel.

The increase in net pump plunger travel with respect to polished rod travel results from the fact that fewer long strokes are required for a given subsurface pump displacement. Since the rod and tubing strings are subject to stretch and compression with each stroke, the cumulative displacement loss to stretch and compression is directly proportional to the number of strokes.

When an artificial lift system fails, there is a time delay until the system is repaired and producing fluid again. When production is interrupted the fluid level in a well will rise until the hydrostatic pressure in the well bore equals the formation pressure at the perforations. As the fluid level rises, the inflow from the formation decreases. When production is re-established, and the fluid level is pumped down, the fluid flow from the formation increases. The amount of fluid NOT produced during the downtime, is lost production. Since slow, long stroke pumping units increase downhole pump life and reduce rod and tubing failures, there will be less downtime due to less workover time, thus increasing net production, thereby providing more effective and consistent drawdown.

FEWER GAS LOCKING PROBLEMS

Many wells produce gas along with the liquids. The presence of free gas within the pump barrel can interfere with the efficiency of the pump, reducing the amount of fluid produced. On the upstroke the fluid above the traveling valve is forced into the tubing and at the same time pressure under the plunger is reduced. Fluid from the well bore enters the barrel through the standing valve. There is a pressure drop across the standing valve and as the fluid enters the pump, entrained gas may break out of solution, preventing complete liquid fillage of the pump. A problem occurs when the pump barrel is filled with a mixture of fluid and free gas. On the downstroke the pump plunger must compress the gas until the pressure above and below the traveling valve are equalized to allow the traveling valve to open and force the trapped fluid into the tubing. This action also generates gas pound, a shock wave similar to that produced by fluid pound. In extreme cases of gas interference, gas completely fills the barrel of the pump and the free gas below the plunger is compressed, but resulting pressure below the plunger is not enough to unseat the traveling valve. On the upstroke the gas expands and prevents the standing valve from opening and the pump is gas locked. Gas lock will be broken if the pump intake pressure is greater than the pressure under the plunger. Long stroke pumping units raise the plunger through the pump and creates a large area for the gas to expand and it is unlikely that the pump intake pressure will not be greater. A long stroke pumping unit provides a much higher pump compression ratio, thus yielding a higher volumetric efficiency.

HIGHER OVERALL PUMPING EFFICIENCIES

The ability to generate a given subsurface pump displacement with a reduced number of pumping cycles is the key to the higher total system efficiency obtained with long stroke pumping.[3] The slower stroke allows better pump fillage and pump efficiencies. Also, dynamic loading and load reversals are reduced when compared to faster pumping, thus extending sucker rod and pump life. Prime mover loading is less cyclic which improves prime mover efficiency and allows the use of smaller prime movers.[6] With fewer rod and tubing failures and longer pump life, well servicing expenses are greatly reduced and net lifting costs are reduced. Reducing stress on production components ultimately results in fewer workovers, reduced production downtime, increased life spans of individual components and increased production.

HISTORY

With all these advantages from slow, long stroke pumping units, why has it taken so long for the industry to accept the concept and begin using these special units?

The benefits of the slow, long stroke pumping units were well received, and the desire to take advantage of these benefits was there, but the users really did not want to change from the familiar pumping unit design. It would be more acceptable if it were possible to make a long stroke pumping unit without changing the overall design. To make a long stroke conventional unit, it was necessary to increase the size of the samson post, the crank arms, the walking beam, etc. A conventional long stroke unit necessarily needs to be a huge, strong, massive unit and is very expensive to manufacture. The first "long stroke" units had relatively short strokes by today's standards. When the crank arms were extended to give longer pumping strokes, the torque arm applied more torque requiring larger gear reducers. Some of the early attempts for long stroke units were the air balanced unit and the Lufkin Mark unit. Both are Class III lever system units, but they still had gear reducers, crank arms, pitman arms, walking beams, horse heads, etc., and were accepted by the oil operators. The early attempts to make an unconventional long stroke unit were not well received by the users, because they looked different and acted different. Oil operators had some legitimate questions including, "Will it work?" "How long will it work?" "Will it operate trouble free?" "Are parts available?" "Is service available?" "What about routine maintenance?" "How many are working now and how long have they been working?" It was difficult to convince oil operators and field superintendents to authorize large capital expenditures for untried long stroke units. Then, after numerous long stroke pumping unit designs failed, the operators became even more reluctant to try new ideas in pumping units.

SPECIFIC ADVANTAGES PROVIDED BY THE ROTAFLEX UNIT

Short Torque Arm - Smaller Gear Reducer

The API gear reducer on the Rotaflex 900 series unit is attached to a 36 inch diameter sprocket. The maximum torque arm is 18 inches. This unique design allows the 900 series Rotaflex with an API 320 gear reducer to handle production requirements that compete with API 912 or 1280 units.

Increased Sucker Rod and Tubing Life

Constant rod velocity is another reason for longer sucker rod string life. There are two 36 inch diameter sprockets inside the tower of the Rotaflex 900 series unit. The drive sprocket is on the slow speed output shaft of the gear reducer and the idler sprocket is 24 feet above it. See Fig. 1. The large endless roller chain that connects the two sprockets is attached to the polished rod through the TRANSVERSING MECHANISM, the weight box, load belt and wire rope bridle. As the chain rotates around the sprockets the weight box is raised and lowered, transferring this same motion to the polished rod. At the top of the polished rod stroke the weight box is at the bottom of the tower. See Fig. 2. As the chain revolves around the drive sprocket, the weight box is lifted, which allows the polished rod to fall. At the bottom of the polished rod stroke, the weight box is at the top of the tower. The acceleration of the polished rod occurs in a 90 degree turn of the 36 inch sprocket or about 28 inches of chain movement which moves the polished rod 18 inches. The velocity of the polished rod remains nearly constant during the rest of the stroke. Deceleration also occurs in a 90 degree turn of the 36 inch diameter sprocket. The peak polished rod velocity of a Rotaflex pumping unit is 1.07 times the average velocity. At 4 strokes per minute, the acceleration from zero to peak velocity is .684 seconds. Deceleration is at the same rate and the average velocity is 192 feet per minute. Thus, for 49.056 seconds of each minute the polished rod velocity is nearly constant and deceleration and acceleration occurs only 10.944 seconds each minute at 4 strokes per minute.

On a conventional pumping unit the slow speed gear makes one complete revolution for each complete cycle of the polished rod. The polished rod is accelerating nearly 50% of the stroke and decelerating nearly 50% of the stroke and experiences a constant velocity less than 2% of the stroke. The peak polished rod velocity of a conventional unit is 1.57 times the average velocity. A conventional pumping unit with 100" stroke running 11.52 strokes per minute accelerates from zero to peak velocity of 301.6 feet per minute in 1.302 seconds, decelerates at the same rate to develop an average polished rod velocity of 192 feet per minute.

Surface card shape is affected by polished rod motion. The Rotaflex unit generates a surface card that is nearly rectangular in shape. The conventional unit has slow reversals with maximum velocities occurring near mid-upstroke and near mid-downstroke, similar to simple harmonic motion. The Rotaflex has fast reversals with near constant upstroke and downstroke velocity similar to saw-tooth motion.[7] Fig. 3 shows polished rod motion of the Rotaflex unit compared to a conventional C640-365-168.

Theoretically, a perfect surface dynamometer trace is a parallelogram, as shown in Fig. 4 where load on the polished rod is recorded on the vertical axis and polished rod movement is recorded on the horizontal axis. This theoretical dynamometer trace reflects 100% efficiency in every component of the pumping system. Point A is the beginning of the upstroke. The traveling valve closes and the load on the rod string increases instantaneously from A to B as the fluid load is picked up. From B to C, the load on the rod string is constant. Point C is the end of the upstroke and the beginning of the downstroke. The standing valve closes, the traveling valve opens and the fluid load on the rod string is transferred to the tubing. The dynamometer trace shows the load on the rod string drops instantaneously from C to D, where it remains constant through the downstroke back to A. Steel sucker rods appear to be rigid but they stretch when a load is applied and recoil when the load is removed. There is a time lag between movement of the polished rod and corresponding movement of the downhole pump plunger and because of this elasticity in the rod string the dynamometer trace will appear to be like the drawing in Fig. 5. Other forces that affect the shape of the dynamometer include downhole friction, pump action, vibration of the rod string and dynamic effects. Fig. 6 is an actual dynamometer trace measured from a conventional C640-365-168 pumping unit on a 3,110 foot well, 10.28 strokes per minute, 2.25" pump plunger, displacing 1,025 barrels of fluid per day. The dynamometer trace shown in Fig. 7 is an actual dynamometer trace from a 24 foot long stroke Rotaflex pumping unit on a 2,821 foot well, 3.3 strokes per minute, 3.25" pump plunger, displacing 1,154 barrels of fluid per day.

100% Mechanical

The Rotaflex unit is the first successful 100% mechanical slow, long stroke pumping unit. The Rotaflex unit is designed with an API double reduction gear reducer to provide the slow speed/high torque requirements to operate the polished rod. The power is transferred mechanically from the gear box to the load belt via a sprocket and industrial roller chain that changes the rotary motion of the gear reducer to articulating linear motion for operating the polished rod. It is very important to note that there is no need for the unit to slow down or stop to change direction of the polished rod. The prime mover and the gear reducer continue in the same direction with virtually no change in speed. Because simplicity can be overlooked, it should be explained that one of the most important benefits from the unique design of the Rotaflex unit is the counterweight system attaches directly to the polished rod through the load belt, a standard wire rope bridle and carriage bar, utilizing standard API approved polished rod clamps. The method used to properly counterbalance a Rotaflex unit uses the applied counterweight 100% of the time, thus efficiently counterbalancing the near constant well load. This direct connection of the counterbalance load to the well load ideally meets the requirements of the dynamometer card through the complete stroke and also reduces the average net torque.

The lubrication system is a relatively simple "dip and drip" operation with no moving parts and will properly lubricate at any speed. Since the gear reducer's slow speed output ratio is 5.62 rpm to one complete pump stroke, there is no danger of improper gear reducer lubrication due to slow speeds. The braking system is a spring loaded power brake with an oversized disk. All bearings are standard size, high quality anti-friction type. The unit is assembled and operated at the factory and is shipped to the customer in one piece. It can be ready to pump in 3 to 4 hours.

The load belt is manufactured in the United States and has been used in mining and oil industries for over 15 years. It is constructed of synthetic fibers encased within a solid block of premium high performance PVC and urethane elastomers. Polyester fibers were chosen for high modulus, resistance to water and mildew, and exceptional resistance to most chemicals, acids and petroleum based oils. The PVK 1200 belt performs well over a wide temperature range from 212° F to -30° F and below. Empirical data shows the load belt to work efficiently in temperatures reaching -60° F. If the belt should become damaged it can be replaced in the field in just a few hours. It has a safe working load capacity of 1200 pounds per inch width (50,400 pounds for the Rotaflex 900 unit).

The load belt also acts as a shock absorber. Since FORCE = MASS X ACCELERATION the peak polished rod load occurs when the mass is elevated with maximum acceleration.[8] In a rod pumping system the acceleration of the mass (sucker rods and fluid) is greatest as the plunger starts the upstroke. This generated force causes the greatest stress on the rod string and can be measured on a dynamometer trace. The modulus of elasticity for the PVK 1200 load belt is 88,000 pounds per square inch (psi), and using the formula ELONGATION = APPLIED LOAD X BELT LENGTH divided by AREA X YOUNG'S MODULUS, the load belt will stretch 3.47 inches when an additional load of 15,000 pounds is applied. Young's modulus for steel sucker rods is calculated to be 30,500,000 psi, a much stiffer member than the load belt. The load belt will absorb the shock load of applied stress and gradually transmit the stress to the sucker rod string, thus reducing the peak stress. At the beginning of the downstroke the load belt also slightly increases the minimum load at the time the fluid load is transferred to the standing valve. The resulting stress range is reduced and sucker rod life should be increased.

Smaller Prime Mover

The formula for surface equipment efficiency is POLISHED ROD HORSEPOWER divided by MOTOR INPUT HORSEPOWER.[9] Empirical data shows the unique design of the Rotaflex pumping unit to have surface equipment efficiencies ranging as high as 81.2%, and overall system efficiencies as high as 61.2%. The formula for overall equipment efficiency is PUMP OUTPUT HORSEPOWER divided by MOTOR INPUT HORSEPOWER.[10] The Rotaflex unit delivers more horsepower to the polished rod and the downhole pump. Thus, horsepower requirements for the Rotaflex unit are reduced. The Rotaflex units extends the reliability of sucker rod pumping to production capabilities that heretofore required electric submersible pumps. Electric submersible pumps require more kilovolt amps (KVA) and more expensive electrical service and controls. Smaller primer movers allow less expensive electrical service to the well site.

Runs in Either Direction

The Rotaflex unit is designed to operate as efficiently running clockwise as counter-clockwise. The manufacturer recommends changing the direction of the prime mover annually to retard wear patterns on the sprockets and chain.

Safety

The Rotaflex unit is one of the safest pumping units ever designed and operated. There are no exposed moving parts other than the polished rod and load belt. There are no rotating or reciprocating crank arms with massive weights. The prime mover output shaft and the drive belts are protected with a metal guard. The high speed input shaft and the slow speed output shaft of the gear reducer are both protected with all metal guards. There is no reason for personnel to work above ground level while preparing the pumping unit and well for downhole service. If service is required above ground the unit has an approved ladder, with O.S.H.A approved safety shroud. There are guarded platforms at both work locations (mid-tower door and crown) above ground level.

Service work is easy and straightforward and field personnel require little special training for operating and servicing the Rotaflex unit.

FIELD TEST RESULTS

ROTAFLEX pumping units have been in operation since 1986 and the present design, using the patented TRANSVERSING MECHANISM, has been operating continuously since 1987. Over the years, numerous rod pumping analyses have been performed on Rotaflex pumping units at various depths and various production volumes. A compendium of four rod pumping analyses[11] is shown in Fig. 8 comparing a conventional C640-365-168 pumping unit with a Rotaflex unit on the same well, NEMA D and NEMA B motors on the same well with the Rotaflex pumping unit, and a NEMA D motor with an ultra high slip motor with the Rotaflex unit.

The most efficient system is the Rotaflex unit powered by a heavily loaded 40 horsepower NEMA B motor. When compared to the conventional beam unit powered by a heavily loaded NEMA D multiple rated 75/52.5/39/30 HP motor connected in the 52.5 horsepower rating, the Rotaflex reduced energy cost per barrel of pump displacement per 1000 feet of net lift by 25.3%. Referring to the table in Fig. 8, overall system efficiency is 40.8% with the conventional unit and 55.2% with the Rotaflex unit.

The 40 horsepower NEMA B motor is more efficient than the NEMA D multiple rated 50/35/26/20 HP motor connected in the 35 horsepower rating on the Rotaflex unit. System efficiency is 55.2% compared to 53.0% and lifting cost decreased from 0.871 to 0.836 cents per barrel per 1000 feet or 4% with the NEMA B motor.

The Rotaflex installation involved a 3.25 inch pump compared to the 2.25 inch pump for the conventional unit. As a result, the fluid load increased about 4,230 pounds with the 3.25 inch pump (conditions with NEMA D motor), yet the peak polished rod load increased only 1,129 pounds with the Rotaflex.

The Rotaflex requires a smaller prime mover. In Fig. 8, a 35 HP NEMA D motor with the Rotaflex is creating 1,152 BPD of pump displacement. With virtually the same pumping conditions a 52.5 HP NEMA D motor is required on the conventional unit to create 1,025 BPD of pump displacement.

The ultra high slip motor did not improve the performance of the Rotaflex unit, but the power factor improved from 82.2% with the NEMA B motor to 88.8% with the ultra high slip motor.

Power losses along the rod string from rod/tubing friction, fluid friction and acceleration effects are less with the Rotaflex unit and NEMA D motor. Losses are reduced from 13.44 HP to 8.32 HP. This reduction is a result of the larger bore pump which requires less sucker rod travel for a given amount of pump displacement. With less rod travel, these losses are diminished. A rough proportionality exists between polished rod travel and rod string losses. Another effect is the difference in sucker rod sizes. The conventional unit was producing with 1 inch and 7/8 inch rods. This rod string design was replaced with a 7/8 inch and 3/4 inch rod design when the Rotaflex unit was installed.

CONCLUSIONS

Increased sucker rod string life and increased subsurface pump life result from slow, long stroke pumping units. Decreased tubing and sucker rod coupling wear result from the increase in wearing surface area and decrease in number of pumping cycles. The unique design of the Rotaflex pumping unit reduces torque requirements and allows smaller gear reducers. Less cyclic loading of the prime mover and improved overall system efficiencies allows the slow, long stroke pumping unit to operate with smaller motors. Energy consumption per barrel of fluid, per foot lifted is greatly reduced. Overall, the ability to generate a given subsurface pump displacement with a reduced number of pumping cycles is the key to the high total system efficiency obtained with long stroke pumping. The Rotaflex unit is safer to operate and service than conventional pumping units. This unique pumping unit extends the limits of sucker rod pumping to volumes and depths previously not possible with traditional sucker rod pumping.

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Fred Morrow, Nabla Corporation
Joe Chastain, Chastain Artificial Lift Schools
Spencer Duke, Duke Artificial Lift Schools

The authors wish to express appreciation to the management of Highland Pump Company and Sargent-Rotaflex, Division of Highland Pump Company for providing the opportunity, cooperation, assistance and permission to present this material. Additional thanks to the authors' business associates who contributed suggestions or data included in this presentation.

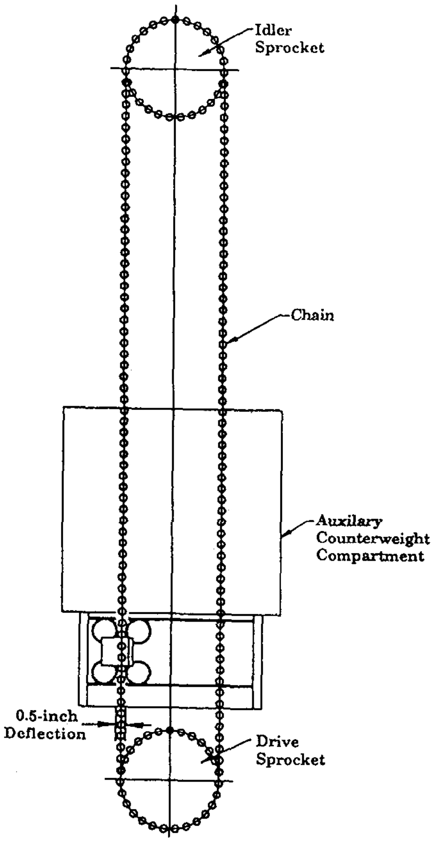
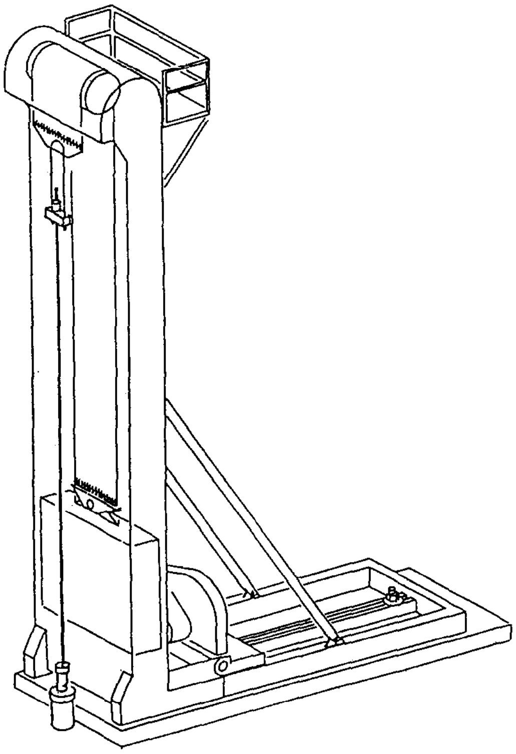


Figure 1



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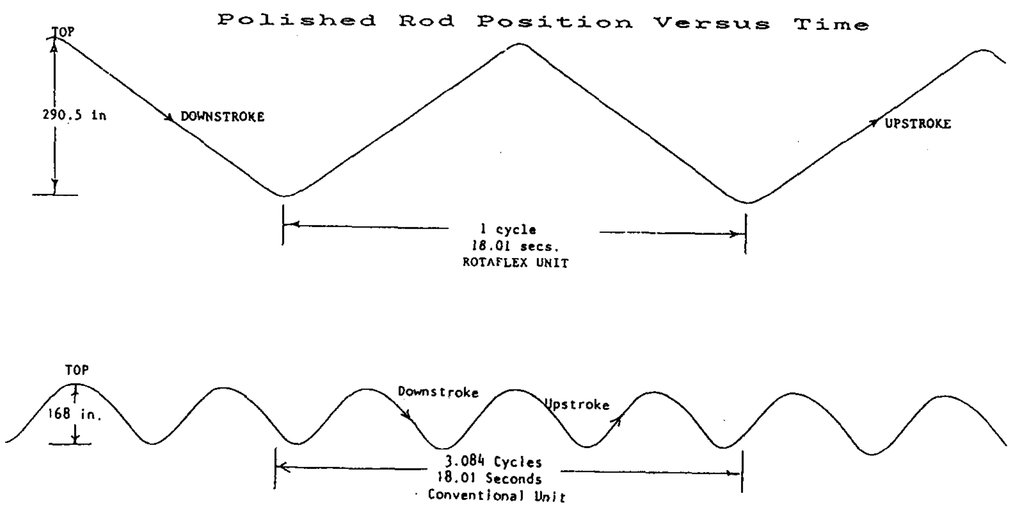

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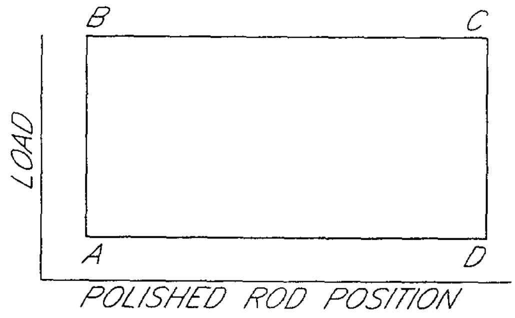

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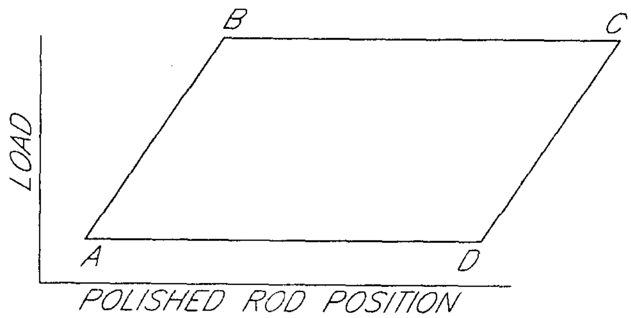

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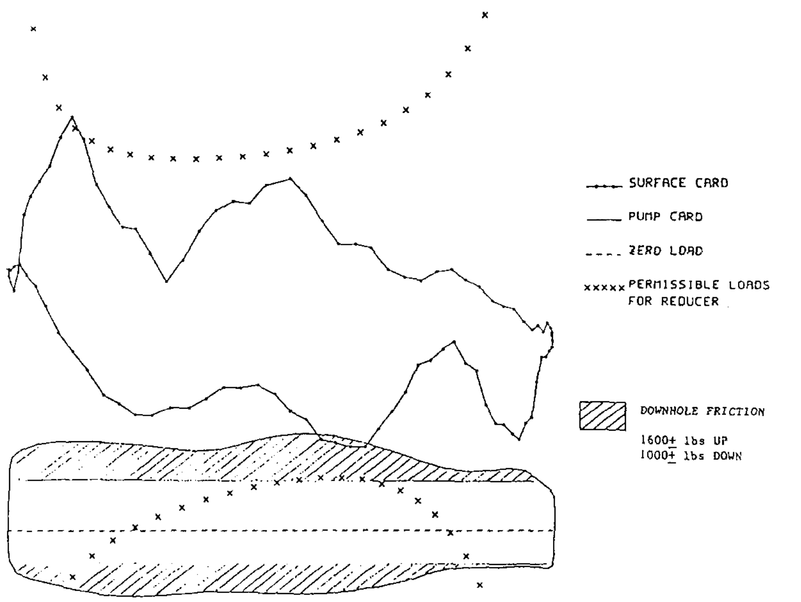

Figure 6

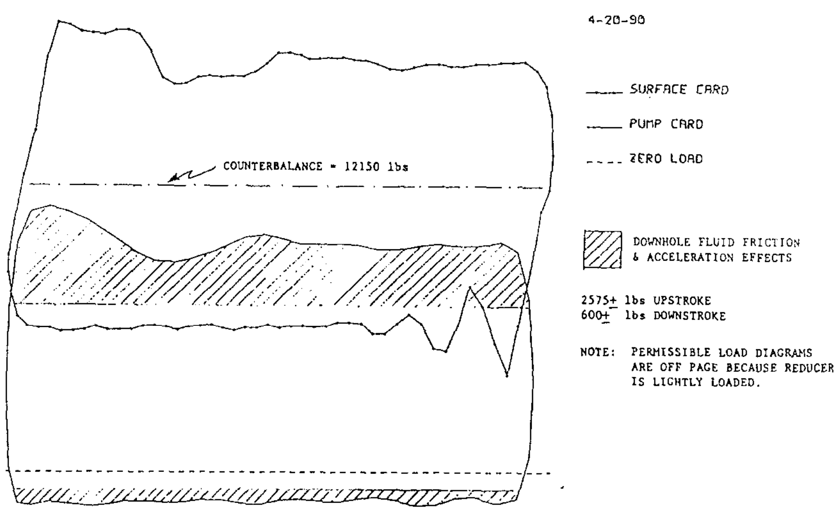

Figure 7

	Conventional Unit w/"D" Motor	Rotaflex w/"D" Motor	Rotaflex w/"UHS" Motor	Rotaflex w/"B" Motor
Pump Depth, feet	3110	3110	3110	2821
Unit Stroke, inches	168.0	290.5	290.5	290.5
Pump Size, inches	2.25	3.25	3.25	3.25
Pumping Speed, SPM	10.28	3.33	3.40	3.29
Peak Torque, in-lbs				
Existing	653600	139800	144700	160700
In-balance	614700	133500	137900	159200
Max. PR Load, lbs	18216	19345	19543	21305
Min. PR Load, lbs	3643	4178	3940	3168
Load Range, lbs	14573	15167	15603	18137
Polished Rod Power, HP	29.5	27.0	27.6	34.2
Static Fluid Load, lbs	3660	7890	7700	10050
*Rod Loading, %:				
Upper	110.2	112.4	114.6	129.6
Lower	110.9	124.1	126.8	150.9
Gross Pump Stroke, inches	169.0	281.4	281.5	279.0
Gross Pump Displ., BPD	1025.5	1154.0	1178.7	1133.7
Test, BFPD	941	1021	1021	975
Pump Intake Pressure, psi	460	480	500	110
Flow Line Pressure	50	90	90	105
Tubing Gradient	.428	.431	.43	.431
Effective Lift, ft	2152	2204	2155	2810
Motor Rating, HP	52.5	35.0	30.8	40
Motor Input Power, HP	39.41	35.25	41.69	42.36
Power Factor, %	29.4	26.3	31.1	31.6
Input to Motor (True KW)	66	41	42	48
**True Pump Power, HP	16.06	18.68	18.59	23.40
Motor Rating, amps	66	46	46.5	49
Electrical CLF	1.13	1.02	1.01	1.03
KVA	38.8	32.6	35.0	38.4
Losses Along Rods, HP	13.44	8.32	9.01	10.8
Losses in Surface Equip., HP	9.90	8.30	14.10	8.2
Surface Equip. Eff., %	74.9	76.6	66.2	80.7
Overall System Eff., %	40.8	53.0	44.6	55.2
***Lifting Cost, cents/bbl/1000 ft.	1.119	0.871	1.053	0.836

* Based on API Goodman Diagram with a service factor of 0.9 (mild corrosion).

** Pump leakage not considered.

*** Based on pump displacement (without crude shrinkage) and 3.5 cents per kwh.

Figure 8