HOW TO MAINTAIN HIGH PRODUCING EFFICIENCY IN SUCKER ROD LIFT OPERATIONS

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ABSTRACT

Throughout the world the most common method used to artificially produce wells is through the means of sucker rod lift. Low producing efficiencies caused by incomplete pump fillage is the most common operational problem experienced by these the sucker rod lifted wells. Incomplete pump fillage is the result of having a pump capacity that exceeds the production rate of the well or having poor gas separation at the pump intake and a portion of the pump capacity being lost to gas interference. More efficient operations and lower cost will result, if these wells are operated with a pump filled with liquid. To operate with a full pump requires the elimination of any gas interference in the pump and requires controlling pump run time so the pump displacement will match the inflow of liquid from the reservoir into the wellbore. Periodically the operator must monitor the wells operations to insure that the pump has no mechanical problems and efficient operations are maintained as all the available liquid is produced from the wellbore.

INTRODUCTION

Sucker rod lift systems are the most common method used to artificially produce oil wells. Inefficient energy use is one of the most common operational problems experienced from these the sucker rod lifted wells. Due to the inefficiencies of the various components of the sucker rod lift system' energy losses occur in lifting the liquid to the surface. The pump being incompletely filled with liquid is the most common reason for low producing efficiencies and usually the largest source of energy waste. More efficient operations and lower power use will result, if these wells are operated with a pump filled with liquid. The first step in this process is to eliminate any gas interference in the pump and insure that the pump has no mechanical problems; then the next step is to optimize the pump displacement to remove all the available liquid from the wellbore. To match the pump capacity to the production potential of the well some simple changes in pumping speed and stroke length can be made. Controlling the pump run time with a pump-off controller or a percentage timer can adjust the number of strokes so the pump displacement will equal the volume of liquid that flows into well bore. Operating the pumping system with a pump barrel full of liquid will result in more efficient operations and lower power use.

Wells that operate 24 hours per day and have a pump capacity in excess of the well's producing rate "pound" liquid on the down stroke. This "pounding" of the pump plunger against the liquid causes shock loading throughout the entire pumping system. The shock loading can cause rod buckling, pump wear, tubing wear, severe rod loading changes, and pumping unit vibration even to the extent that the vibration can be visually observed and heard. Changes in loading are easily measured using a dynamometer system. Sudden changes in rod loading on the downstroke also affect the pumping unit balance and motor power requirements. Longer life will be experienced by the pump, rods, tubing and pumping unit system if the plunger does not "pound" liquid near the middle of the down stroke. Operating the pumping system with a pump barrel full of liquid will result in longer equipment life.

Analyzing the performance of the pumping system requires an integrated analysis' of the prime mover, surface equipment, wellbore equipment, downhole pump, downhole gas separator, and the reservoir. One of the cost-effective advantages of an integrated analysis system is that the well data is entered only once and all of the calculations use the data to determine the complete system's performance. The analysis is based on information obtained from liquid level instruments, dynamometers, and motor power probes. Use of a portable system at the well site allows immediate analysis of any operational conditions that may be hindering the performance of both the equipment and the well. The operator using the integrated analysis method can identify the cause of any operational problem, monitor pump conditions, and optimize withdrawal rates, thereby efficiently producing the sucker rod lift well.

Performing an acoustic producing level survey, dynamometer survey, and power survey begins the process by determining the producing efficiency of lifting the liquid to the surface. The energy efficiency of lifting the liquid to the surface plus a pump dynamometer card indicating percent pump fillage provides the information necessary to optimize the operation of the sucker rod lift system. This paper discusses how to maintain a high producing efficiency in sucker rod lift operations.

ACOUSTIC FLUID LEVEL SURVEY

An acoustic fluid level survey should be conducted to determine the depth of the producing fluid level with respect to the pump intake depth. If there is fluid above the pump intake, then the well may not be produced at or near its maximum production rate. If the producing efficiency is low and the incomplete pump fillage is due to gas interference, then there will be fluid above the pump intake depth, as shown in **Fig. 1**. If the producing efficiency is low and the incomplete pump fillage is due to over-pumping the well, then the fluid level should be at or near the pump intake depth, as shown in **Fig. 2**.

Most operators desire that wells be produced at or near their maximum production rate. The maximum production rate (potential) of a well is obtained when the producing bottom hole pressure (PBHP) is low compared to the static bottom hole pressure (SBHP). If sufficient capacity equipment exists on the well, the PBHP should be maintained at a value less than 10% of the SBHP to insure maximum production. Most producing and static bottom hole pressures and analyses are obtained from surface measurements by acoustically measuring the distance to the liquid level in the well, measuring the casing pressure and calculating the bottom hole pressure[3, 4, 5].

When acquiring an acoustic fluid level measurement, the operator can perform a simple test to determine the casing gas pressure buildup rate by closing the casing valve while the sucker rod lift system continues to pump. The casing pressure buildup rate is used to determine the annular casing gas flow rate and to determine the pressure contributed from the gaseous liquid column above the pump. If the casing pressure increases with respect to time, then gas is accumulating in the casing annulus and free gas is at the pump intake and under normal operating conditions gas will be flowing up the casing annulus. Under these conditions if separation of the free gas at the pump is not effective, then any incomplete pump fillage is very likely due to gas interference.

To determine the exact conditions at the pump the results from the producing fluid level survey should be used in conjunction with a pump dynamometer card indicating percent pump fillage. By knowing:
1) If the well is being produced at its maximum production rate,
2) If the height of fluid column is above the pump intake depth,
3) If the pump is incompletely filled with liquid, and
4) If free gas is flowing up the casing annulus
Then the operator can determine if the low producing efficiency is caused by incomplete pump fillage due to gas interference or from over-pumping the well.

DYNAMOMETER DETERMINES PERCENTAGE PUMP FILLAGE

Using an integrated data acquisition system, motor power and dynamometer data can be obtained simultaneously. **A** single technician can make the dynamometer and power/current measurements in a matter of minutes. The load cell can either be of the horseshoe type, which is positioned on the polished rod between the carrier bar and the polished rod clamp, or of a special design that is easily clamped directly onto the polished rod. The current/power sensors are connected to the electrical switch box, thus the power and current input to the motor are acquired. Analysis of the downhole pump operation is performed by calculation of the pump dynamometer card from measured surface load and position data. The pump dynamometer card is a plot of the calculated loads at various positions of pump stroke and represents the load the pump applies to the bottom of the rod string. Identifying how the pump is performing and analysis of downhole problems is one of the primary uses of the pump dynamometer card.

Fig.1 shows that incomplete pump fillage is the main cause of this well's inefficiency and the shape of the pump dynamometer card gives a strong indication that gas interference due to inefficient downhole gas separation is the primary reason for the problem. The downhole dynamometer card indicating a pump fillage of 42% of the 782 BPD pump displacement coupled with a high gaseous liquid column above the pump (in **Fig. 1)** is conclusive evidence that inefficient gas separation is occurring at the pump intake. Reference 7 gives detailed information on efficient downhole gas separators. From analysis of the acoustic survey data the maximum liquid potential of the well is 428 BPD and potentially this well's oil production could be increased by 19 BPD by installing a good downhole separator. If good gas separation were to occur at the pump intake, then the pump's liquid displacement would be greater than maximum potential for liquid to flow into well bore and the pump run time would have to be controlled to operate this well in an efficient manner.

Fig. 2 shows incomplete pump fillage due to over-pumping the well. In addition to the problem of inefficient operation this well has the additional problem of fluid on the downstroke that will cause reduced equipment life. The pump dynamometer card indicates incomplete pump fillage of 26% of the 135 BPD pump displacement plus the acoustic survey showing that the fluid level is at the pump intake (in **Fig. 2)** are conclusive evidence that excellent gas separation is occurring at the pump intake and that the maximum liquid potential of the well is being produced. Since good gas separation is occurring at the pump and the pump displacement is greater than maximum potential for liquid to flows into well bore, then controlling the pump run time is required to operate this well in an efficient manner.

To ensure that the pump has no mechanical problems, both standing and traveling valve tests should be performed as part of the dynamometer survey. Correct operation of the pump valves is mandatory to achieve high efficiency. Although standing and traveling valve tests are routinely made, proper interpretation depends on the requirement that the tests are performed correctly. For this reason, a series of valve measurements should be performed in order to insure their reproducibility and validity. **Fig. 3** shows a series of two traveling valve tests followed by two standing valve tests. The plot of the acquired polished rod load data shows, that the valve tests are reproducible (thus valid and well executed) and the measured values agree with the theoretical values (thus the rod and pump data, stored in the well file, is up to date and there is little rod-tubing friction). Based on the analysis of the valve test, it is possible to conclude that the valves are operating properly and the pump has no apparent mechanical problems.

IDENTIFYING WELLS WITH LOW ENERGY EFFICIENCY

One method of identifying wells that need improvement is to determine the overall efficiency of the well's pumping system. Experience[8, 9,10,11,12] has shown that determining the overall efficiency requires only the measurement of input power to the prime mover, determination of the producing bottom hole pressure (PBHP) and accurate production test data.

Fig. 4 shows the results of a power survey obtained using power probes on the well illustrated in **Fig. 2.** Both instantaneous motor power and motor current are plotted for one complete pump stroke. Note that the motor generates power (negative power) during portions of the stroke. The unit is rod heavy since more power is required on the upstroke than on the downstroke. The operating cost is calculated on the basis of a barrel of fluid pumped and a stock tank barrel of oil produced. These values are calculated from the production rates that were entered in the well data file and based on the most recent well test. **A** complete motor power and current analysis is performed using the well data and acquired data. In this example, the overall system efficiency is a low 31.0%. Since the overall efficiency of a beam pump system should be approximately 50%, then this well is a good candidate to be studied to improve its performance.

The following Decision Table 1 can be applied to the analysis of wells where the system efficiency is less than 35%. For the well of **Fig. 2,** the fluid level is low and the pump fillage is low, therefore the potential exist for the operator to improve the efficiency of the well by controlling pump run time. The following Decision Table 2 can be applied to the analysis of wells where the system efficiency is greater that 35%. For the well in **Fig. 1,** the fluid level is high and the pump fillage is low, therefore it should be a high priority for the operator to improve the operation of the well by correcting the gas interference problems in the pump.

DECISION TABLE 1 – SYSTEM EFFICIENCY < 35%

Low Producing BHP or Low Fluid Level	Low Producing BHP or Low Fluid Level	High Producing BHP or High Fluid Level
Pump Full	Low Pump Fillage	Low Pump Fillage
Low Priority Study Surface Efficiency	*Potential to Improve Study Comb Run Time*	*High Priority Study Gas Interference*

DECISION TABLE 2 – SYSTEM EFFICIENCY > 35%

Low Producing BHP or Low Fluid Level	High Producing BHP or High Fluid Level	High Producing BHP or High Fluid Level
Pump Full	Pump Full	Low Pump Fillage
Well OK	*Potential to Improve Study Pump Capacity*	*High Priority Study Gas Interference*

The primary objective of acquiring power data is to determine the efficiency with which the pumping unit is being operated from both standpoints of energy utilization and of mechanical loading. The following techniques are available to the operator for improving the overall system efficiency:

1)Maintain high volumetric efficiency:

a)Match pumping requirements with wellbore inflow.

b)Eliminate Gas interference

c)Use Full Pump Capacity by controlling the unit with a POC or Timer

2)When System Efficiency is low, find and fix problem.

3)Verify power meter calibration.

4)Mechanically / Electrically balance pumping unit.

5)Properly size pumping unit to match well loads.

6)On severely over sized motors where average surface efficiency falls below 60%, then change out motor

The item in the above list have a direct impact on the efficiency of the sucker rod pumping system, plus the items are ranked so that at the top of the list is the most cost-effective technique to improve system efficiency, he bottom is the usually least cost-effective technique to improve system efficiency, motorntain high volumetric efficiency will be discussed in the following sections.

Low system efficiency can be an indicator of a mechanical problem at the surface or in the downhole equipment. Where a large percentage of the input power to the pumping system is being lost due to mechanical wear and friction, the operator should find and repair these problems, because the increased wear will result in premature failure of one the components in the sucker rod lift system.

Many of the electric utility power meters in the field have been installed at the well site for an extended time period, sometimes meters can be out of calibration or an incorrect meter number may be assigned to a particular well. If the results from the power survey do not agree well with the bill form the electric utility company, then the power meter can sometimes be the problem.

On a company wide basis mechanically / electrically balancing the torque loading on all the pumping unit gearboxes in a field[13, 14] has been shown to reduce power consumption by approximately 12%. Depending on how heavily loaded the prime mover is, movement of the counter weights small distances usually results in little or no improvement in the system efficiency. Well conditions change over time and the operator should periodically survey the gearbox torque loading on all of sucker rod lift systems in a field and correct the counterbalance as needed.

A popular method used to size the electric motor is to select the next motor size greater than twice the calculated polished rod horsepower, this practice tends to result in oversizing the electrical motors installed on beam pumping systems. This usually results in a NEMA D motor having abundant starting torque, while the efficiency of the motor is usually less than 80%. The normal surface efficiency of a sucker rod lift system is in the 75-80% range, with most of the loss due to motor efficiency. In general where average surface efficiency falls below 60%, then changing out the severely over-sized motor will be of economic benefit.

DOWNHOLE GAS SEPARATION

Inefficient pump operation is frequently caused by gas interference as a result of poor downhole gas separation[15, 16]. Poor downhole gas separation can be identified through the use of an acoustic liquid level instrument and a dynamometer. If the liquid level measurement indicates a high gaseous liquid column above the pump, yet the dynamometer indicates incomplete pump fillage, then there is a problem with downhole gas separation. Correcting downhole gas separation problems results in increased system efficiency, increased production, reduced runtime, lower electrical costs and reduced maintenance[17, 18].

There are many improper oilfield practices commonly used to produce wells having incomplete pump fillage due to gas interference. The following practices do not solve the problem and cause inefficient operation: Gas interference is not eliminated by tapping bottom with the pump, running the pump at excessive speed, operating the pumping unit for excessive periods of time, increasing the tubing pressure or increasing the casing pressure. Using proper downhole gas separation techniques to reduce the amount of free gas entering the sucker rod pump eliminates gas interference[19, 20,21].

The preferred method of downhole gas separation should be to set the pump intake below the fluid entry zone. If the pump intake is set above the fluid entry zone, then a gas separator should be used that has an efficient gas/liquid separation chamber with low dip tube friction loss. This type of separator should result in complete pump fillage if sufficient liquid inflow from the formation is available.

GAS SEPARATION BELOW THE FORMATION

If the seating nipple is placed at least ten feet below the bottom of the fluid entry zone, then efficient gas separation will occur in the annulus without using an extension below the seating nipple. In this case the casing acts as the outer barrel of the separator. Aperforated extension can be used. This extension would allow the operator to tag bottom to determine debris fillage without forcing debris into the seating nipple. The extension can be a perforated sub or a joint of tubing below the perforated sub. A bull plug is usually used below the bottom collar, however it would be preferred that the bottom be orange-peeled to prevent sticking in fill. A dip tube is commonly run below the bottom of the pump. A dip tube in this situation is not needed since it increases friction losses and results in less efficient gas separation. **Fig. 5** shows examples of gas separators that are commonly placed below the fluid entry interval.

If the liquid capacity of the tubing sized separator does not exceed the pump capacity, then a higher capacity separator should be used, such as shown in **Fig. 6.** In this case nothing is attached to the tubing below the seating nipple, but a dip tube is run below the pump. The dip tube should be sized such that the friction loss within the dip tube is less than 0.5 psi. The dip tube should extend at least ten feet below the bottom of the fluid entry zone. Using only a dip tube results in a greater area between the pump intake and the casing. This increases the liquid capacity. Gas bubbles rise about 6 inches per second in most low viscosity (< 10 cp.) liquids, so the liquid capacity is approximately 50 barrels per day per square inch of annular area[22, 23,24].

GAS SEPARATION ABOVE THE FORMATION

Often, well conditions may prevent placing the pump below the fluid entry zone. Conditions such as insufficient rat hole, fill problems from produced solids, liners, and undersized pumping units may require setting the pump intake above the fluid entry zone. Setting the pump above the fluid entry zone requires different design considerations for the downhole gas separators. There are several gas separator designs that are suitable in this situation.

The most commonly used gas separator is the conventional or inexpensive, yet can be efficient if properly designed and sized. A **Fig. 7.** This separator is typically built from standard oilfield tubing and perforated subs. It consists of fluid entry section such as a perforated sub, an outer barrel such as a joint of tubing with a bull plug on bottom and a dip tube on the bottom of the pump. The downward fluid velocity between the outer barrel and the dip tube should be less than 6 inches per second. Gas bubbles rise approximately six inches per second and downward velocity less than this is required to insure that the free gas will be liberated from the produced fluids. Another design consideration must be the area between the outer barrel of the separator and the casing. Gas flow velocities in excess of approximately ten feet per second will lift the liquid and mist flow will occur. The area must be sufficient to allow liquid to enter the separator by preventing mist flow.

The efficiency and capacity of a an be improved with several design modifications[19, 25]. These design modifications include using thin wall pipe, large fluid entry ports and properly sizing the dip tube. An illustration of an improved gas separator is shown in **Fig. 8.**

Thin wall pipe can be used instead of conventional oilfield tubing to manufacture the outer barrel. The outer barrel diameter should be greater than or equal to the same OD as the tubing collar. Conventional tubing generally has heavy walls and is upset at the collar connections. These conditions reduce the liquid capacity of the tubing by reducing the cross sectional area between the dip tube and the outer barrel. The use of collar–sized thin wall pipe results in a greater area between the dip tube and the outer barrel. This increases liquid capacity by reducing the downward liquid velocity in the separator.

The use of large fluid entry ports instead of a perforated sub improves the efficiency of the gas separator. When a conventional perforated sub is used, liquid and gas flow into the separator on the upstroke and gas discharges from the separator on the downstroke. This results in low efficiency since fluids have to flow in two directions through the same perforations. When large ports are used, liquid will fall into the gas separator on both the upstroke and the downstroke. The large ports result in a gravity feed of the liquid from the casing annulus to the gas separator resulting in more liquid and less gas entering the separator. Generally, four large ports are used. The area of each port is sized to be the same as the area between the dip tube and the outer barrel of the separator. The design of an improved separator should also minimize the friction loss through the dip tube. It is preferable that this friction loss be less than 0.5 psi.

CONTROLLING PUMP DISPLACEMENT

Once gas interference is eliminated, then for purposes of efficient, low cost operations the pump displacement should be controlled so that the pump capacity is equal to the inflow performance of the well. Making adjustments to four different parameters can control pump displacement:

1)Plunger size,
2)Stroke length,
3)Pumping speed

4)Daily run time.

Changing out an improperly sized pump is usually not done, primarily due to the expense of pulling the downhole equipment. The simplest method to change the pump displacement is to make changes in the surface equipment configuration, such as moving the pitman arm to a different hole on the crank to change the surface and pump stroke lengths. The next most common technique is to control pumping speed by changing out the motor sheave; the minimum size for the motor sheave is determined by the motor shaft diameter and the minimum radius a v-belt can bend. A more expensive technique of installing an additional sheave between the motor sheave and unit sheave, called a jackshaft, can result in very slow pumping speeds. In addition to matching pump capacity to the well's inflow with a jackshaft, the motor size can be significantly reduced and large savings in the power bill will be achieved when the power bill is based on the connected horsepower of the motor. The most expensive technique of controlling the motor speed is to install a variable speed drive to the motor. This option is usually avoided due to the high equipment and installation cost. One disadvantage of all methods used to slow the pumping unit speed is fluid slippage through the plunger/barrel clearance of the pump can result in severe loss in efficiency. Changing speeds and pump sizes are more difficult to justify than controlling daily run time. Daily run times can be readily changed to match the pump capacity to the production potential of the well.

OPTIMIZING PUMP RUN TIME

The run time on a pumping system should be optimized only after achieving optimal mechanical performance and downhole gas separation in the pumping system. The run time should be optimized to operate the pump periodically and still produce all available liquid from the well. So that maximum inflow occurs during both the operating time and the downtime, the bottomhole pressure in the well should be maintained at low values compared to the reservoir pressure. Several devices exist which can be used to control the run time of a pumping unit. These devices include pump off controllers[26,27,28,29], interval timers, and percentage timers.

PUMP OFF CONTROLLERS

A pump off controller monitors one or more parameters of the pumping system and shuts down the pumping unit when one of the parameters exceeds a limit set by the operator. Parameters monitored to detect pump off can include polished rod load and position, electrical usage, pumping unit speed[30] and pressures. One common use of pump off controllers is to detect incomplete pump fillage and then turn the pumping system off. The pump off controller usually starts the pumping system after a predetermined downtime. This off and on cycle is repeated throughout the day and generally reduces both operating time and operating expense without the loss of oil production.

A significant advantage of a pump off controller over a timer is that a pump off controller monitors the well's performance. With some pump off controllers, the run-time is recorded. Pump problems can be detected by monitoring the run time and observing an increased run time with no increase in production. Some pump off controllers may be used with a SCADA[31,32] systems for remote monitoring of polished rod loads and other parameters for early detection of well problems. Early detection enables timely correction of the problems while minimizing production losses. Pump off controllers are more expensive than timers and may require additional specialized personnel to monitor their operation and keep the controllers in a good working condition.

TIMERS

Timers can also be used to control run time[33]. Timers are inexpensive and simple to operate. **A** disadvantage of the timer is that the run time must be manually set. Another disadvantage of a timer is that the amount of run time will not automatically change as the pump condition or the well's performance change. An efficient way to set the run time on a timer is through the use of a modem dynamometer, which calculates a pump dynamometer card showing pump fillage. The timer should be set to approximately operate the unit a percentage of time equal to the percentage of pump fillage that is observed when the pump is operated continuously. Periodic checks should be performed with a dynamometer and liquid level instrument to adjust run time as the well conditions change.

Two types of timers are commonly used in the oilfield. These are the interval timer and the percentage timer:

a)An interval timer controls the time intervals during which the pumping unit operates. Most interval timers have a 24-hour rotating disk with fifteen minute on and off tabs. Each fifteen-minute interval during 24 hours can be selected to correspond to either run time or down time. The interval timer is commonly used in the oilfield.

b)A percentage timer controls the percent of time that the pumping unit operates during a time cycle. A typical cycle on a percentage time is fifteen minutes, so the percent run time in each fifteen-minute interval is controlled. A fifteen-minute percentage timer is the preferred timer for most oilfield use because generally its proper use results in a lower electrical power cost.

DURATION OF PUMP CYCLE DOWN TIME

Inflow performance, electric utility billing practices and equipment should be considered in determining the duration of the down time during a pump cycle.

Inflow performance relationships indicate that maximum fluid inflow from the reservoir occurs when the producing bottomhole pressure is less than 10% of the static reservoir pressure[34]. This concept should be applied to timer and pump off controller operation. The downtime duration should be short enough that the producing bottomhole pressure does not increase to a value greater than 10% of the reservoir pressure while the pumping unit is shut down. The producing bottomhole pressure can be determined using a modern acoustic liquid level instrument. A common problem in managing wells is the lack of accurate reservoir pressure information. An inexpensive acoustic static bottomhole pressure test can be used to determine reservoir pressure. In general, inflow performance relationships will indicate that shorter downtimes are preferred over longer downtimes because initial inflow into the wellbore is rapid, but slows down as the downtime becomes extended.

Shorter downtimes are also dictated in situations where multiple zones are commingled downhole. Crossflow can occur during the downtime if one zone has a significantly higher pressure than the other zone. Using shorter downtime intervals can reduce crossflow.

Electric utility billing practices influence the determination of optimal downtime. The demand charge may be a significant portion of the electric utility bill. The demand cost is based on the maximum power used during the billing interval. The power consumption is typically measured during each fifteen minute time period and the fifteen-minute interval with the greatest power consumption is used to calculate a demand charge, which is applied to the entire billing period. If the pump is not operated continuously then it can be advantageous to make the run time a percent of the fifteen-minute interval to reduce the demand cost. An example of this would be if the well conditions indicate that the optimal run time percentage is 66%, then demand cost would be reduced by 33% if the pumping system is cycled ten minutes on and five minutes off instead of two hours on and one hour off.

Equipment considerations have an effect on the selection of the downtime interval. When a motor starts a pumping unit system, electrical energy is used to start the counterweights and cranks rotating. A common belief is that electrical consumption is higher at startup than when the motor is operating continuously. This belief would indicate that longer run times might be preferable. In practice, power consumption measurements indicate that the effect on operating cost of frequently starting the electric motor is negligible. At start-up, a NEMA D motor typically operates at three times its full load power rating, however the duration of the increased power consumption typically lasts for only 0.65 seconds. The energy consumed by a 30 HP NEMA D motor during start-up is only 0.01 KWH, which costs approximately $0.005. The additional consumption charge for starting a 30 HP motor once every fifteen minutes is approximate $1.20 per month. The demand charge is also increased every time the motor is started in a fifteen-minute period. Each start-up in a fifteen-minute period typically increases demand charge by one percent. Stopping and starting the motor once every fifteen-minute period generally affects the electricity bill less than one percent compared to longer cycles.

After weighing all considerations it appears that generally a shorter onioff cycle is preferred over a longer onioff cycle. The optimum on/off timer cycle would be where the run time and down time are percentages of a fifteen-minute period. The short cycles maintain a low bottomhole pressure and can significantly reduce electric demand for wells on a single point meter.

PROCEDURE TO INSTALLAND SET TIMERS

All mechanical problems should be corrected prior to setting timers and pump off controllers. Any gas interference problems should be corrected through the use of proper gas handling techniques previously discussed. The well should then be operated continuously at normal producing conditions until the well stabilizes. A dynamometer should then be run to determine the pump fillage. Precise loads determined through the use of a quantitative calibrated load cell are not required to set the time cycle, but a qualitative load cell, such as a polished rod transducer will provide sufficient information to accurately determine pump fillage. A polished rod transducer is also easier and faster to install[35] and does not affect the pump spacing. Once the percentage of pump fillage is determined from the pump dynamometer card, then the percent run time of the timer should be set. It may be advantageous to set the percent run time at a value of five to ten percent greater than the percent of the pump fillage. Once the timer is set, then proper operation should be verified with a liquid level instrument and dynamometer. The pump dynagraphs should be measured and observed throughout the entire on/off cycle. The pump should remain full until near the end of the on cycle. If the pump is not full at the beginning of the on cycle, then there may be a mechanical or gas interference problem that should be solved prior to setting the run time.

Another method to determine the proper percentage of run time is to shut down the well for approximately 10 minutes. Then, start the pumping unit with a dynamometer monitoring the pump's performance, continuing to operate the well as long as the pump is full of liquid. As soon as the pump plunger begins to "pound" liquid because of partial pump fillage, note the run time while the pump was full. The percentage (or fraction) of time that the pumping system should operate is the run time divided by the 10-minute shutdown period plus the run time. (Run Time/(10 + Run Time)

Yet another method to set a timer is to compare the well's production from well test information to the calculated pump capacity. Divide the well's production by the predicted pump capacity. This is the fraction of time that the pump should operate, if the pump is operating efficiently with no additional run time added to cover fluid slippage between the barrel and the plunger.

Dynamometers are the most precise method for setting timers. Dynamometers should be run periodically to ensure that the pumping system is performing properly and to reset the timer as well conditions change.

TOTAL MANAGEMENT OF SUCKER ROD LIFTED WELLS

To determine the existing system efficiency and to analyze the operating conditions of the sucker rod lift system, a production technician can undertake the complete survey[2, 36] including acquisition and field processing of the acoustic, dynamometer and motor power data in about 45 minutes per well. The same measurements are used to define the well's productivity, the downhole pump performance, the downhole gas separator performance, the rod and beam unit loading, and the motor performance. The well's production rate can be maximized and the operating costs minimized with this 45-minute well analysis. The procedure to analyze the sucker rod lifted well involves the following steps:

1) Analyze the well's inflow performance to determine if additional production is available.
2) Determine the overall efficiency to identify wells that are candidates for improvement.
3) Analyze the performance of the pump.
4) Analyze the performance of the downhole gas separator.
5) Analyze mechanical loading of rods and beam pumping unit.
6) Analyze performance of prime mover.
7) Design modifications to existing system.
8) Implement changes and verify improvement.

While at the well as the collected data is analyzed, the goal for the production technician should record any recommendations to fix any problems discovered in the analysis of the collected data. These notes recording the work necessary to fix a problem are called the production technician's work plan and the notes are called recommendations. When the recommended changes to the well are completed, new data should be collected in a few weeks once the well is operating under stabilized conditions. The production technician should re-read the recommendations from the previous analysis of the well's data and notice if the well performance has changes as planned. The analysis step to evaluate the recommended changes is called the follow-up step of the analysis. Following-up on recommendations is how production technicians learn from their successes and failures; and their role changes from a data collector to a knowledgeable well analyst and problem solver with the knowledge and skill to maintain high producing efficiency in all their sucker rod lift operations.

SUMMARY

Periodically the operator must monitor the wells operations to insure that the pump has no mechanical problems and efficient operations are maintained as all the available liquid is produced from the wellbore. Operating a well with high volumetric pump efficiency will result in cost savings by reducing electric utility bills and maintenance costs[36].

Electric utility bills are based on the electrical consumption and the maximum electrical demand during the billing period. The consumption is measured in Kilowatt-hours whereas the demand is measure in Kilowatts. The fifteen-minute time interval during the biling cycle with the highest consuniption is typically used to calculate the demand cost. Consumption charges will be reduced whenever the run time is reduced, however the demand charges would only be reduced if the pumping unit never runs for a portion of every fifteen-minute interval during the billing period. If a fifteen minute percentage timer were used and the pump were to operate 40% of the fifteen-minute interval then the demand cost would be reduced by almost 40%. Both reductions in consumption and reduction in demand can usually be achieved by using a fifteen-minute percentage timer.

Cost savings would also result from the reduction in pump and pumping unit maintenance. Maintenance will be reduced because the equipment is only operating a portion of the time and not subjected to the wear and tear of continuous operation. Maintenance is also reduced because fluid pound is minimized. Pounding of the pump plunger against the liquid causes shock loading on the pumping system. The shock loading can cause rod buckling, pump wear, tubing wear, severe rod loading changes, and pumping unit vibration. Reduction of the shock loading will reduce maintenance costs.

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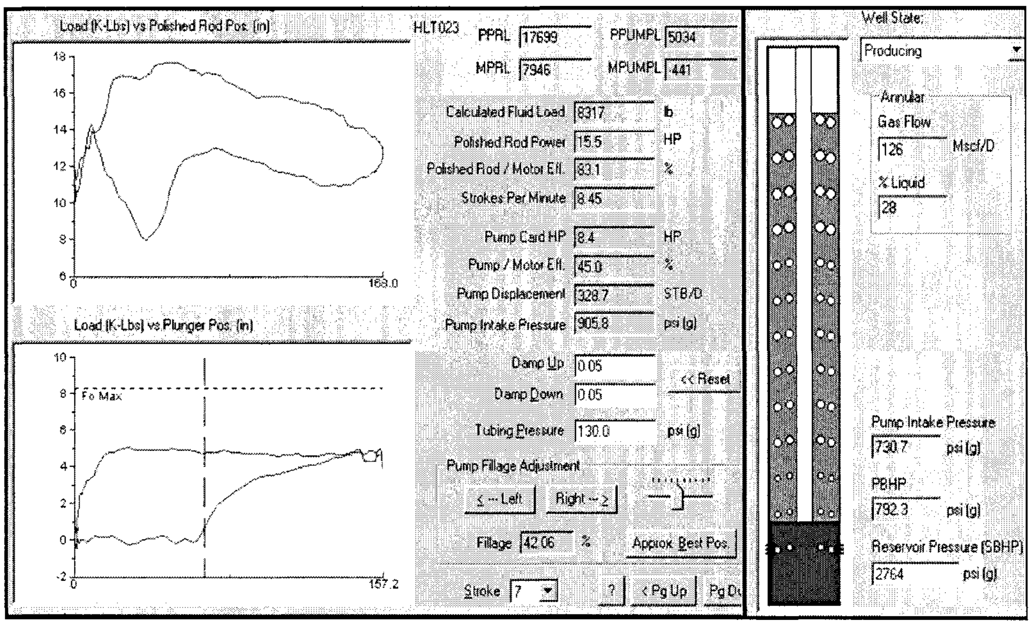

Figure 1 - Low Producing Efficiency Due to Incomplete Pump Fillage From Gas Interference

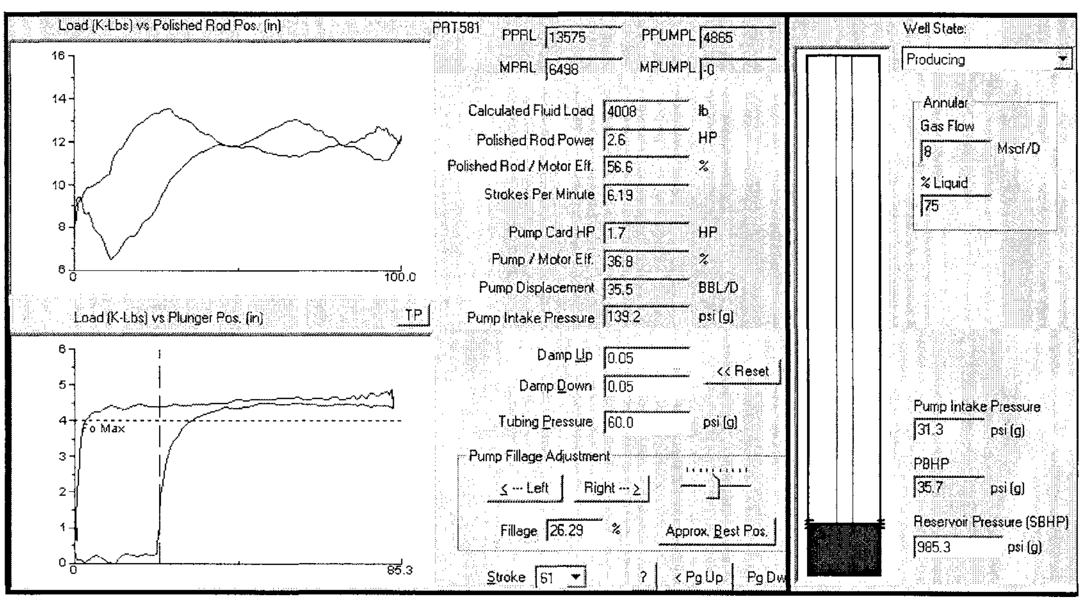

Figure 2 - Low Producing Efficiency Due to Incomplete Pump Fillage From Over-Pumping the Well

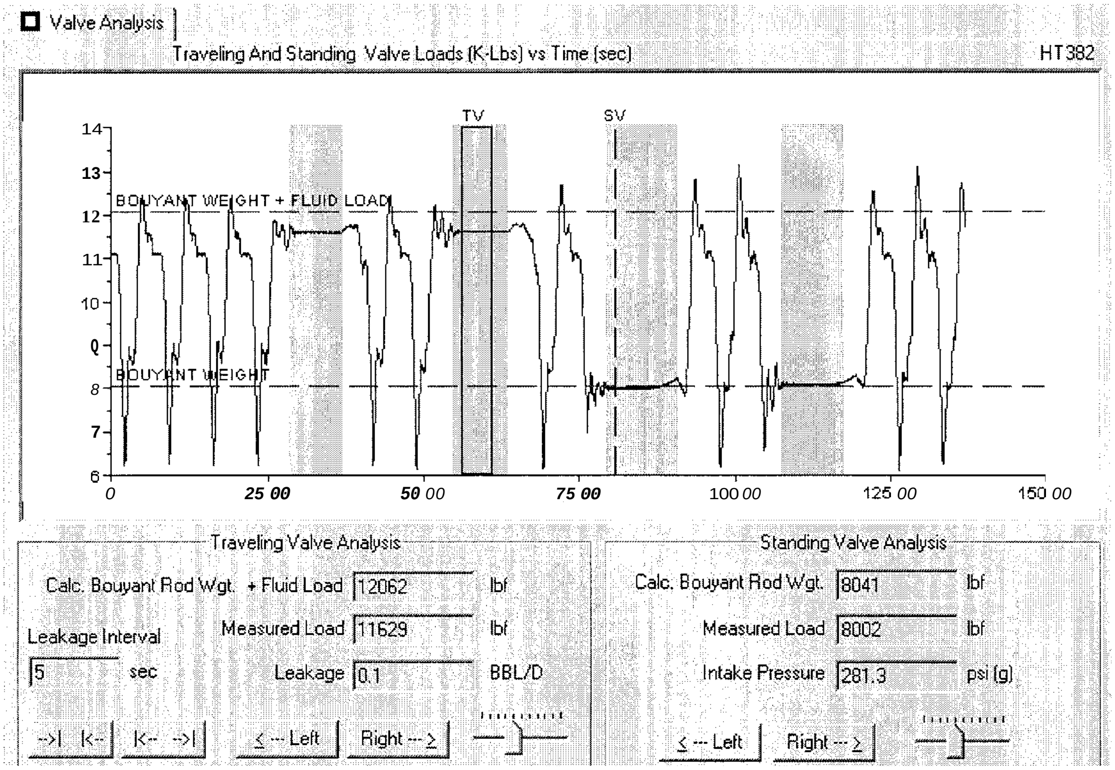

Figure 3 - Standing and Traveling Valve Tests Performed as Part of Dynamometer Survey

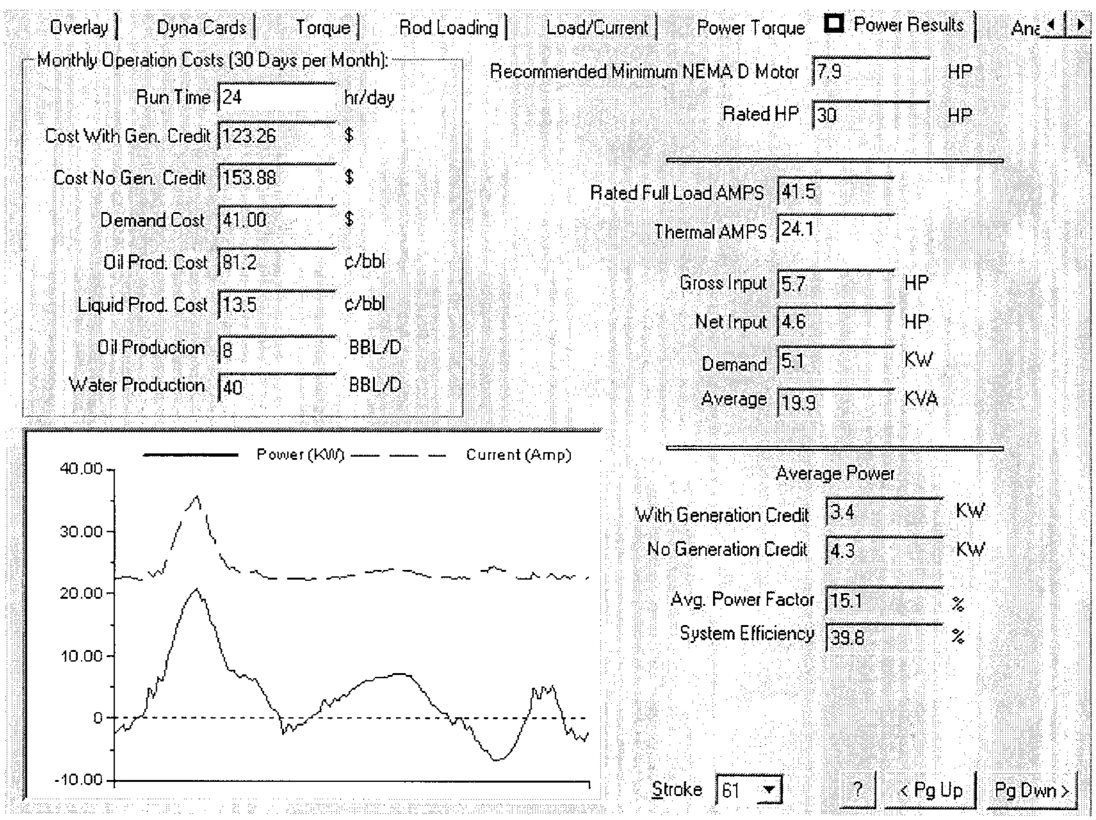

Figure 4 - Motor Power Survey

Fig. 7 – Poorboy Gas Separators

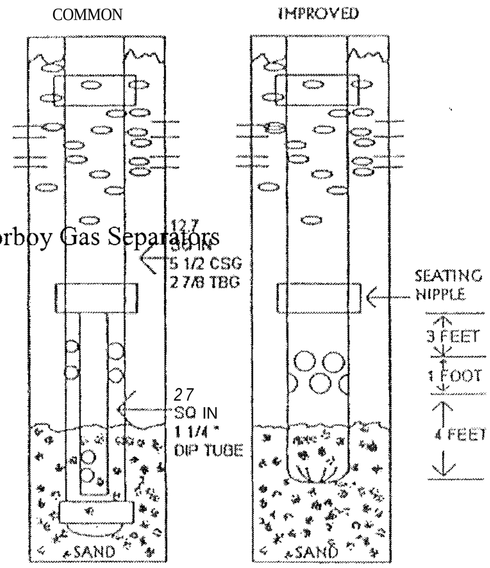

Figure 5 – Natural Gas Separators

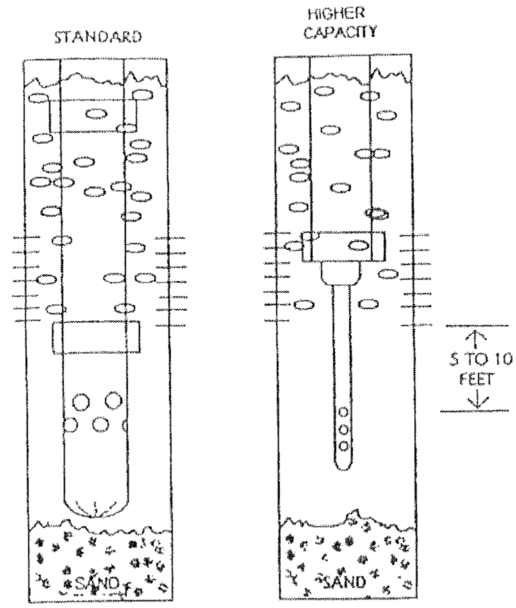

Figure 6 – Higher Capacity Natural Gas Separator

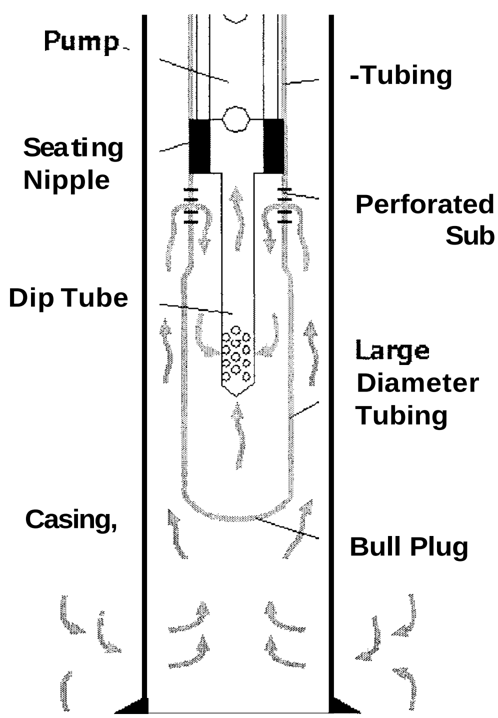

Figure 7 – Poorboy Gas Separators

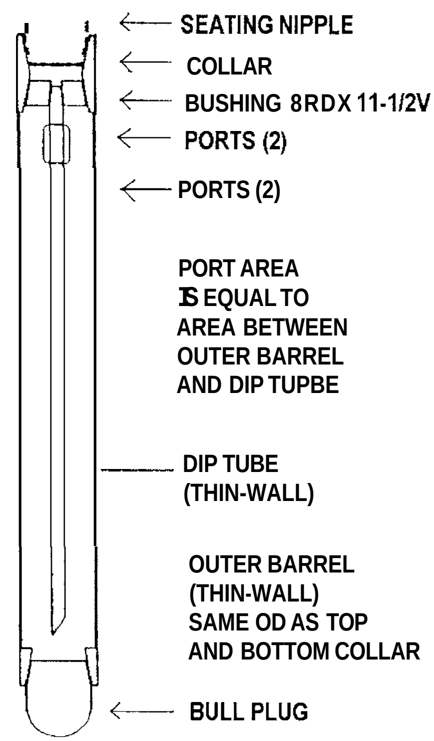

Figure 8 – Improved Gas Separators