

# Value of Rod Pump Control



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# Value of Rod Pump Control

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Many excellent articles and technical papers over the years have documented the economic and operating benefits achieved by installing pump off control on rod pumped wells. This paper not only examines the most common problem associated with rod pumping – displacement control, but it defines “pump off”, as well as reviews and summarizes the benefits of rod pump control already documented in past articles and technical papers. In addition, this paper provides numerous examples of case studies with microprocessor-based rod pump controllers (RPCs).

The estimates of benefits cited in this paper are based on field experience, customer dialog, and expert input. These benefits and typical improvements are based on specific case studies and should be used only as a guide to estimate the potential benefits of rod pump control in a particular situation.

## ***Introduction***

A common operating problem in a sucker rod pumping system is trying to match inflow into a well with an installed beam pumping system that has a fixed displacement. Because the amount of fluid entering a well is constantly changing as the well pumps down or is re-charged by the well’s inflow, the displacement of the installed beam pumping system almost never exactly matches the ability of the well to produce fluid. Therefore, the well is usually either “under-produced” (which means that the maximum production capacity of the well is not being produced) or “over-produced” (which means that the pumping system displacement is greater than the amount of fluid moving into the wellbore).

Both of these conditions are less than acceptable. Under-producing results in loss of revenue because oil that could be sold is not being produced. Over-producing also has quite serious consequences. For example, when the pumping system has a capacity of one gallon per stroke, but only one-half gallon flows into the well bore, fluid pound occurs when the downward moving plunger strikes the fluid in the partially filled rod pump barrel. The pump plunger instantaneously stops until the load is transferred from the rods to the tubing, causing the rods to “stack out” or go into compression. This shock loading causes damage to the sucker rods, the bottom hole pump, as well as the pumping unit. Also, if the pumping system displacement is one gallon per stroke, but has only one half gallon per stroke available to pump, the energy required to operate the pumping system is almost the same as if the system was producing one gallon per stroke.

Many methods have been used to try to match the displacement of rod pumped systems and the ability of a well to produce fluid. When using a gas engine as a pumping unit prime mover, this is possible by simply regulating the gas engine speed. Systems (Variable Speed Drives) that change electric motor speed (based on the degree of inflow detected) to regulate SPM to match the well inflow performance are currently more expensive than other available methods. This solution is, however, applicable under certain conditions: heavy crude / high sand content wells or wells that must be controlled because of other extreme downhole conditions or that cannot be shut down for long periods of time.

A common method to match capacities is to size the pumping system to have surplus capacity and then shut the unit down for some period of time (idle time) to allow fluid to build up in the wellbore. At start-up, the system pumps the fluid that accumulated in the wellbore during the idle time plus the fluid that comes in while the pumping unit is running. The pumping unit is then shut down for another period of idle time.

Two of the most widespread devices used for this type of “intermittent pumping” are the “pin type” timer and the “percent” timer. Both devices are inexpensive and easy to understand. However, the minimum cycle (run time or idle time) time available in most pin type timers is fifteen minutes. Unless the run time setting is constantly changed to meet the changing fluid inflow, the same situation exists – “over-pumping” or “under-pumping”. The fifteen-minute restriction for total run time or total idle time almost always results in over-pumping or under-pumping. A variation on the time clock is the percent timer. A percent timer operates on properly setting a percentage of each fifteen-minute period as pumping unit run time. The remainder of the fifteen-minute period is assigned as the well’s idle time. Both devices require frequent attention from the operator if they are to work in the operator’s favor at all. To find a reasonable setting, the operator must try a selected runtime setting, then check this setting against daily production or sonic fluid level and then re-adjust the setting as needed. This process is never ending!

The best solution to this “displacement versus inflow” problem is to use a RPC that automatically detects when the pumping system is beginning to run out of available fluid to pump and then shuts the well down for an adjustable “idle time” to allow the well inflow to replenish fluid in the wellbore. Ideally, this idle period should be based on specific well inflow conditions so that the production lost due to backpressure caused by the building fluid level is minimized. The rod pumped system starts pumping again after this idle period and pumps until the well starts to “pound fluid” again.

There have been many attempts to develop a basis for “rod pump control” that will do a precise job of pumping each well with maximum efficiency. Methods that have been used to detect when the well should be shut down include: a simple “flow/no flow” paddle in the flowline, shock or impact sensing devices on the polished rod or bridle carrier, motor horsepower, motor speed, etc. The most successful RPCs measure the polished rod load and position for a qualitative or quantitative dynamometer card (refer to the next section – “Understanding A Rod Pumped Well”). This gives positive real-time knowledge of what is happening in a rod pumped well. The introduction of the low cost PC computer has made it possible to combine this information with the logic necessary to diagnose and control the well completely in any situation. Bottomhole and surface equipment analysis software packages that use this load and position information make rod pump control a complete pump off control and analysis system. The addition of radio or hard wire transmission of this information to a central location for analysis and action further expands the utility of the system. It makes it possible to know the specific performance of every well at all times and to take any necessary corrective action at the earliest possible time.

The success of any pump off control method, even the sophisticated ones described above, is dependent on several factors. The most important factor is the control logic set up for each well. The selection of pump off shutdown criteria and idle times to maximize production depends on:

1. The reservoir pressure.
2. The inflow characteristics of each well.
3. The size of the casing and tubing.
4. The displacement of the installed rod pumping system.

## ***Understanding a Rod Pumped Well***

### **Surface Analysis**

Through the years, the polished rod dynamometer has been the principal tool for analyzing the operation of rod pumped wells. A dynamometer system gathers polished rod load and displacement "points" and plots the resulting "curve" - which is commonly known as the "surface dynamometer card". The shape of this card is affected by changing downhole conditions. Ideally, these conditions would be apparent from the surface card by visual interpretation. However, because of the complex behavior of the rod string and the great diversity of card shapes, visual diagnosis is not always possible. Though much information can be gained from visual interpretation of surface cards, success is directly linked to the skill and experience of the analyst – and even the most experienced analysts can be misled into an incorrect diagnosis.

### **Bottom Hole Analysis**

In the studies of surface dynamometer cards, it is understood that one of the primary things that affect the shape of the actual dynamometer card is the load condition at the bottom of the hole. Theoretical surface dynamometer cards are all based on ideal pumping conditions with full pump fillage. In "real" rod pumped wells, the pump fillage is never completely full. In addition, bottom hole conditions such as crooked hole, paraffin, scale, sand, and solids all affect the loads and the shape of the surface dynamometer card.

In an effort to find out exactly what was happening at the bottom of the hole, W. E. Gilbert and others designed a bottom hole dynagraph that measured loads and displacements at the bottom of the hole. His work was published in 1936. In 1967, Sam Gibbs received a patent on a mathematical method for simulating the sucker rod pumping system – commonly known today as the "wave equation" solution. His work and the work of others made it possible to use a surface dynamometer card as a basis for a simulated bottom hole card. In 1986, G. Albert designed an electronic bottom hole analyzer, which measured the bottom hole conditions electronically in the same manner that W. E. Gilbert had measured them mechanically. This tool confirmed that the mathematical simulation from surface dynamometer cards does indeed give accurate bottom hole loads and displacements.

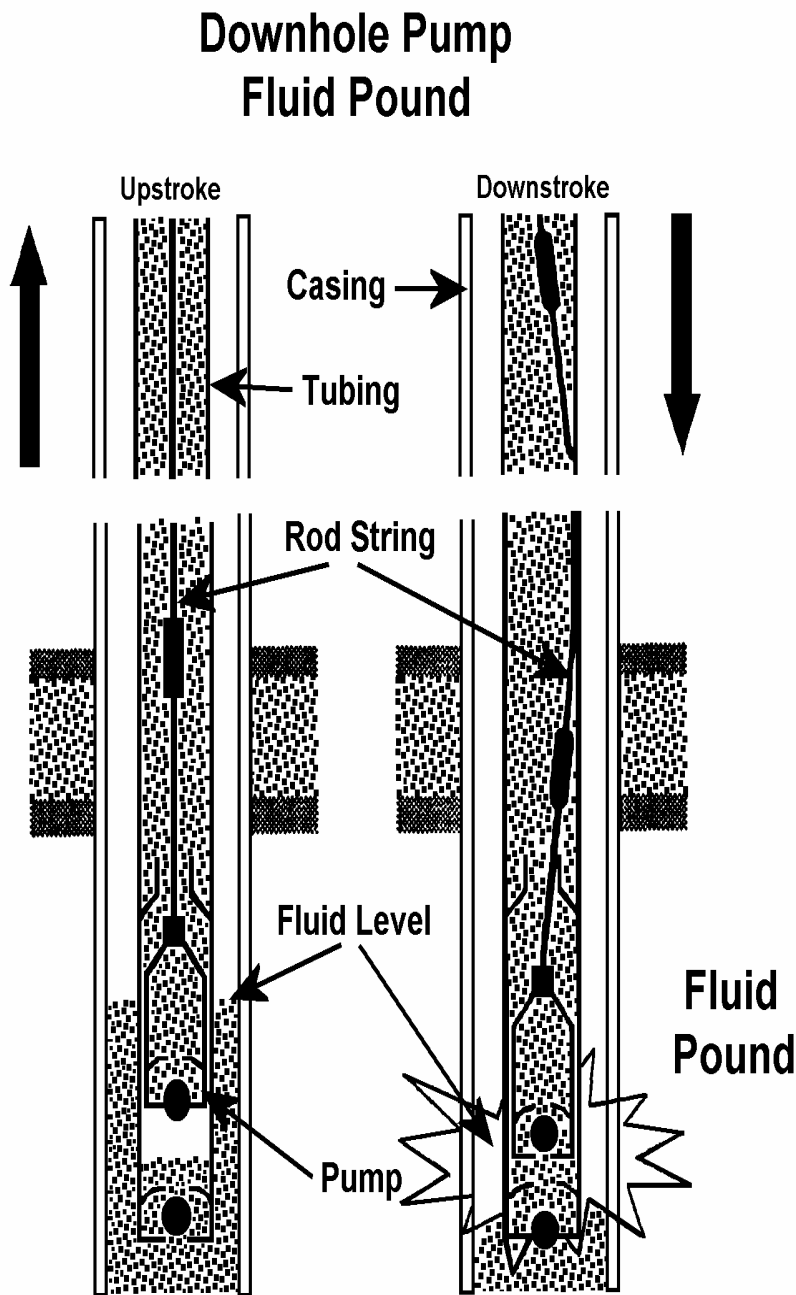
The mysterious "black magic" of the experienced dynamometer analyst was the result of a lifetime of observation and experience. Today, with a thorough understanding of the principles and aided by computer simulation, an accurate analysis of a well problem is possible in nearly every case. The calculated subsurface or downhole card removes personal judgment and experience from the diagnosis of downhole pumping conditions.

### **Predictive Programs**

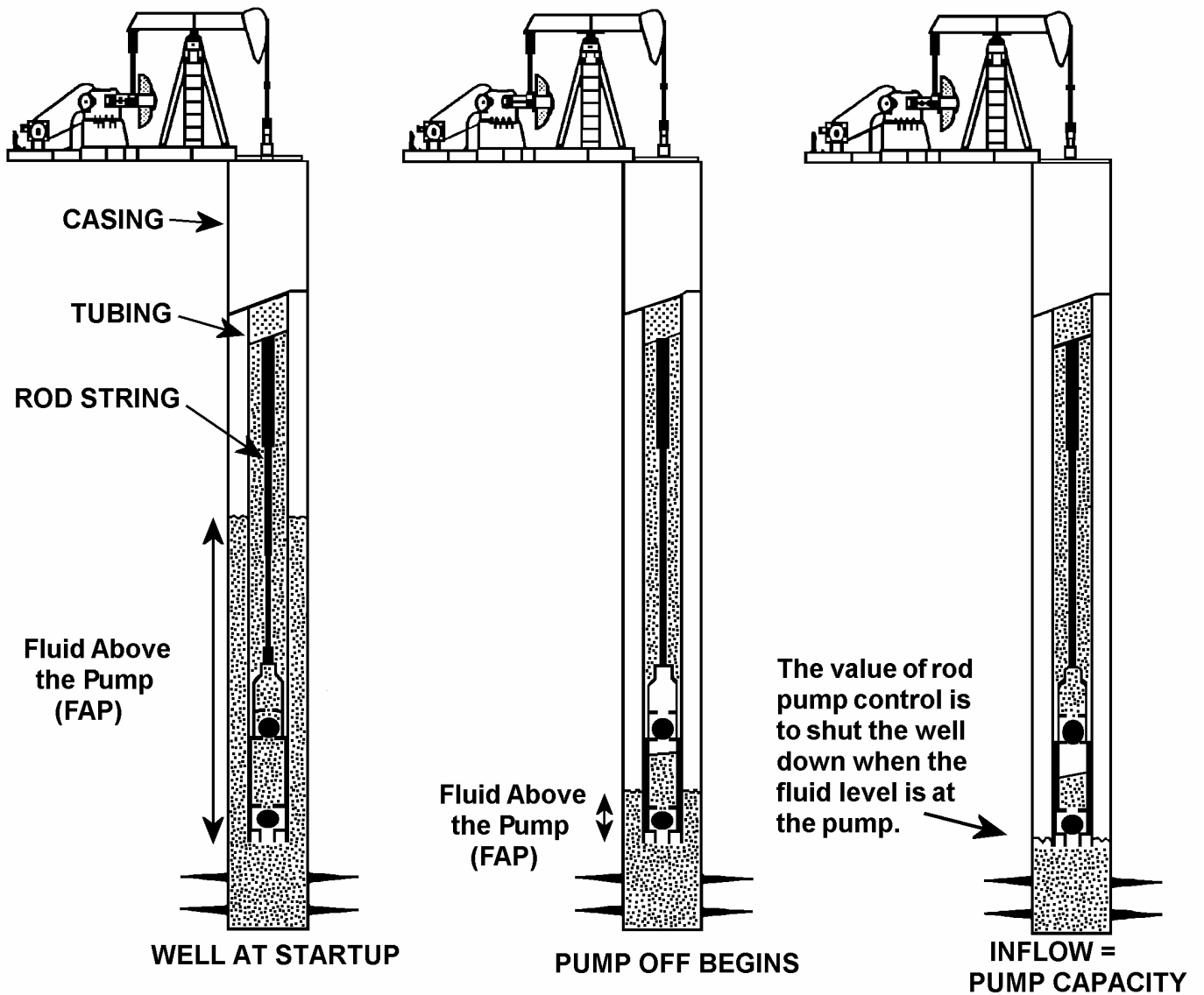
Wave equation based computer predictive programs greatly facilitate the setting up of load limits, pump off set points, idle times, and all other control parameters of a RPC. Well conditions can be simulated under a variety of normal and abnormal operating conditions. The operator can build a library of expected dynamometer cards covering most operational conditions. He then can make a much more practical analysis of problems when they occur. Unfortunately, not all wells can economically justify a "top of the line" RPC. eProduction Solutions offers a low cost solution for these low-producing wells – discussed later in this paper. In addition, some bottom hole conditions or wellbore configurations make control with an RPC impossible.

## Explanation of "Fluid Pound" or "Pump Off"

Pounding fluid can shorten the life of the rod string, as well as that of the pumping unit. When pounding fluid, the rods and the fluid in the top portion of the downstroke act as a "free falling body" at the position of the plunger. If the point of "fluid pound" is in the upper portion of the pump stroke, the plunger could hit with an impact greater than the combined rod and fluid weight. Matching pump displacement to well inflow or the use of RPCs can help to prevent fluid pound.



**Fluid Pound**, as experienced in a pumping oil well, is caused by the pump not completely filling with fluid on the upstroke. As the downstroke begins, the entire fluid and rod string load moves down through a "void" until the plunger "hits" the fluid level in the pump barrel. The traveling valve opens, suddenly transferring the load from the rod string to the tubing, causing a sharp decrease in load that, in turn, transmits a shock wave throughout the pumping system. This shock wave damages the components of the pumping system.



## Effects Of Fluid Pound

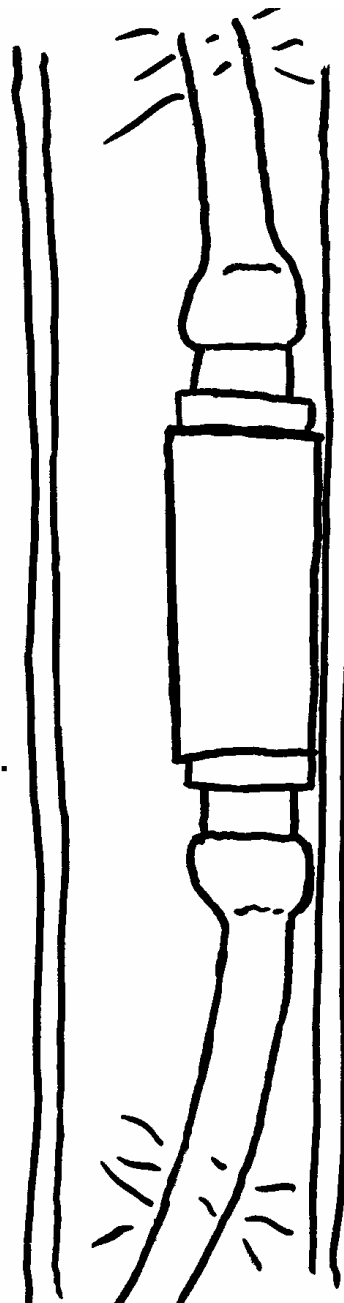
**PLUNGER STOPS  
RODS SPIRAL BEND.**

**RODS FAIL MOST  
NEAR STIFF JOINTS  
AND FAIL IN FATIGUE.**

**ROD CUT TUBING,  
WORN RODS AND  
ROD COUPLINGS  
ABOVE THE PUMP  
ADD TO THE DAMAGE.**

**BREAKS USUALLY  
OCCUR IN FIRST  
300 FEET ABOVE  
THE PUMP.**

**!! DO NOT !!  
POUND FLUID OR  
TAG BOTTOM**



### Uncontrolled Fluid Pound

- Increases energy costs.
- Increases wear and tear on downhole equipment.
- Makes it almost impossible to counterbalance the pumping unit properly.
- The counterbalance problem and the fluid pound "shock" increase gearbox wear and shorten gearbox and wrist pin bearing life.

### Fluid Pound Control Using a Rod Pump Controller

- Accelerates oil recovery

- By detecting high fluid levels that cause backpressure on the producing formation and therefore reduce fluid inflow into the wellbore.
- By the detection of worn out pumps before production loss is noticed.
- By early detection of any problem that might cause the well to stop pumping - necessary repairs can be started immediately.
- By alarming immediately when one of the above conditions occur.
  
- Saves energy
  - “Rule of thumb” – An RPC saves \$600 per polished rod horsepower per year. (This savings was verified through studies conducted by Robert Gault, a respected artificial lift engineer and teacher.)
  - Requires a reduction of only five or six polished rod horsepower for a one year payout of the rod pump control equipment.
  
- Extends the life of the downhole pump and rod string
  - Ten strokes per minute amounts to 5,250,000 strokes per year. The average life of a rod string is about 20,000,000 strokes. The average life of a downhole pump is about 5,000,000 strokes. If a well’s runtime is reduced by 25%, the rod string will last one year longer and the pump will last three months longer.
  
- Eliminates downhole problems
  - Eliminates rod failures at the pump by stopping rod "buckling" low in the rod string when the plunger is “stopped” by fluid pound.
  - Eliminates low tubing splits because fluid pound control stops tubing wear from rod buckling.
  - The elimination of about one to three low rod or tubing failures will justify the cost of installation of a RPC.

## ***Percentage Timers Vs. Rod Pump Control***

A percentage timer is a timing device used to control the operation of a pumping well. The timer can be set to turn the pumping unit “on” for part of a 15 minute interval and then turn it “off” for the remaining portion of the 15 minutes. For example, a timer can be set to run a pumping unit for five minutes and turn it off for ten minutes (to pump 33% of the time). Timers are simple, easy to use, and inexpensive. However, percentage timers are effective only if the operator can keep them adjusted correctly based on changing well conditions. If a well remains stable for a long time, a percentage timer may be sufficient to minimize fluid pound. However, a well with fluctuating production will be very difficult to control with a percentage timer. In this situation, a RPC is the only practical solution to minimize fluid pound damage, while maintaining maximum production.

A RPC turns the unit off only if it detects fluid pound or if an operator-selected load violation occurs. Therefore, it automatically adjusts the pumping rate to changing well conditions. RPCs can be thought of as "smart" percentage timers. On the contrary, percentage timers are "dumb" devices because they turn the motor on or off at the pre-set times regardless of well conditions. For example, if the well's inflow rate increases due to a waterflood response, a percentage timer will continue to pump the well at the same rate as before. This causes the fluid level to rise and may reduce production. For declining production, a percentage

timer that is not frequently adjusted will not prevent fluid pound. Therefore, system efficiency and equipment life will decrease.

## ***“Stand-alone” Rod Pump Control Systems***

Modern RPCs can operate either as a stand-alone device or as part of a centralized automation system. This is possible because modern controllers contain all logic needed to operate each rod pumped well independently. However, when RPCs are used as stand-alone devices, they must be visually inspected for alarm and electronic malfunctions on a regular basis, usually daily. It is also a good idea check to the calibration of the load and position transducers periodically with a calibrated stand-alone dynamometer system. Although stand-alone rod pump control systems cost less than supervisory centralized systems, they must be manually checked to ensure they are functioning properly. Control logic parameters, and start-up and shutdown dynamometer cards can be reviewed or changed on site with a portable analyzer, usually a laptop computer. This portable analyzer plugs into a port on the outside of the RPC enclosure.

## ***“Supervisory” Rod Pumped Control Systems***

Supervisory rod pump control systems (CAO or “Computer Assisted Operations”) represent the state-of-the-art in rod pump control application. These systems consist of a central computer that communicates with a number of wells with installed RPCs via radio, direct cable, cellular telephone or satellite telemetry. The operator of the central computer system can monitor any single well or scan several wells using a specially designed software package. The system can produce individual well performance reports that show the average runtime, present status of the well (“on”, “off”, “down”), alarms for load or run-time violations, etc. Dynamometer cards can be transferred from the individual controllers to the central computer for further analysis. A complete surface and downhole equipment analysis can be done by the host software to detect problems. In addition, RPC control parameters can be viewed or changed via the central system. Centralized systems have higher capital costs than stand-alone systems and may require significant changes in field personnel job functions. However, since central systems can detect well problems faster and more accurately than stand-alone systems, they actually help optimize manpower usage (operate by exception). Instead of manually inspecting each well, field personnel can identify problem wells and prioritize their daily work process using the host software. Software packages such as Case Services' **csBeamAnalysis** also offer other functionality such as SPC (Statistical Process Control). SPC trending makes it possible to see how each value in a trend compares with the normal or average value of data points in the particular trend. SPC trending of runtime, production, card area, maximum/minimum load comparisons, and reports of pertinent data help the user make timely operational decisions. **csBeamAnalysis** allows the user complete and easy access for adding and changing wells, as well as data entry with a “point and click” interface.

## ***Rod Pump Control Justification and Economic Benefits***

### **Justification**

RPCs can help reduce operating costs and increase production by providing production operators and well analysts with information necessary for performance analysis, problem diagnosis and equipment optimization. Early pump off controllers (then called POCs) merely sensed “pump off” and were most effective with wells that could be over-pumped. Today’s

RPCs can also be justified for wells that do not pump off because the tool enhances well surveillance and allows immediate identification of operating problems.

RPCs improve profitability in many ways. When these controllers are integrated with a computer assisted operations (CAO) system, field-operating profitability can be enhanced even further.

<b>Operating Category</b>	<b>Benefits of Rod Pump Controllers</b>	<b>Added Benefits with CAO</b>
<b>Cash flow</b>	<p>Maximizes oil recovery by matching system pumping time to well inflow capacity.</p> <p>Reduce unscheduled downtime because abnormal operating conditions (excessive fluid pound, high or low loads, etc.) can be detected and the pumping unit can be shut down before severe damage occurs.</p> <p>Reduced energy cost because wells are not pumped when the pump barrel is only partially filled with fluid.</p>	<p>Changes in inflow rate can be recognized in real time, allowing corrective action to be initiated sooner.</p> <p>Operators can readily review and adjust alarm/shut-down limits, pump-off parameters, etc. to reduce failures. Failures can be easily recognized when they do occur and corrective action can be initiated immediately.</p> <p>Operators can review and select optimum idle times and pump-off limits to maximize energy savings while assuring that production is not deferred.</p>
<b>Reduced capital investment</b>	<p>Equipment can be run closer to operating limits if it is continuously monitored and shut down when those limits are exceeded.</p> <p>Equipment will not require premature replacement because of damage caused by abnormal operating conditions.</p>	<p>Predictive beam pump design programs can be modeled with observed operating conditions to optimize equipment design and selection.</p> <p>Downhole pump cards can be run by the operator and used to optimize the setting of the pump-off control parameters to minimize fluid pound.</p>
<b>Improved surveillance</b>	<p>Operating parameters are continuously monitored to detect anomalies in beam pumping performance.</p>	<p>In addition to alerting the operator to anomalies in measured parameters at a central location, the system can monitor calculated parameters (e.g. rod stress, peak torque, pump efficiency, or unit out of balance).</p> <p>Operators can quickly focus attention on problem wells by using exception reports to screen analysis results and identify wells needing review and corrective action.</p>

		Being aware of problems as soon as they occur will permit quicker prioritization and scheduling of needed corrective action.
<b>Improved production accounting</b>	Information monitored and stored by the wellhead controller can be used to improve reporting of unscheduled downtime for production allocation purposes.	Accurate downtime is collected on each well every day. In conjunction with accurate well tests, this information can be used to highlight deferred production and help prioritize corrective action.
<b>Improved safety and environmental protection</b>	Wells can be shut down if monitoring devices that can be installed indicate unsafe conditions (e.g. high flowline pressure, stuffing box leakage, or tank level).	Wells can be stopped and started remotely. This can be tied in with critical production facility alarms to shut down wells.

RPCs with central site monitoring capabilities can improve the quality of well tests in locations that have automatic well testing by monitoring well performance during the well test.

Operators often find themselves unable to obtain well test data as often or as accurately as they would prefer, especially in shallow well production fields. This issue most often results from the sheer number of wells drilled in a restricted geographical area and not enough test facilities to adequately handle them. In many cases, this type of production also depends on steam injection as a primary production technique. Because steam is primarily a gas, varying amounts of steam must be pumped back to the surface by the downhole pump, along with the oil and water given up by each well. The presence of steam further complicates the issue of unusable well tests. Many operators use the "inferred production" capability of RPCs and, in many cases, central site software in an effort to have reasonably accurate well test data as needed. Inferred production is the ability of an RPC to estimate accurate well pump displacement from every well everyday. This data from the RPC can be critical to information management, decision making and in some cases, it can be used in place of actual well tests.

## Economic Benefits

Field-based experience with installed RPCs has allowed the documentation of the following average economic benefits:

	<b>Stand-alone RPC</b>	<b>RPC with CAO</b>
<b>Energy savings</b>	21%	22%
<b>Maintenance savings</b>	28%	35%
<b>Net operating cost savings</b>	\$50-300 /well/yr.	\$300-800 /well/yr.
<b>Production acceleration</b>	1%	2%

With this magnitude of savings, any field with beam pumping should be a candidate for effective microprocessor based RPCs and central site monitoring unless there is a very compelling reason not to do so.

### **Economic Benefits Summary:**

**Energy Savings:** Energy savings result from reducing the operating or runtime of the pumping unit and still maintaining maximum production. The amount of power savings realized is a function of how the well was being pumped prior to RPC installation.

Typically, wells are over-pumped to obtain maximum production but always at the cost of excess energy usage. The existing production methods may have been:

- A mechanical percent timer or pin-type timer.
- Twenty-four hour per day operation.
- Other operator-controlled on/off periods.

Further, the ability to set the pumping unit shut down point at the first fluid pound stroke (when the pump barrel did not completely fill) and at an operator-selected consecutive number of fluid pound strokes, ensures that the well has indeed "pumped off" before it is shut down. The well is then able to obtain maximum pump fillage before the reservoir fluid flow into the wellbore is limited by increased wellbore pressure.

"Fine-tuning" the RPC setup to specific well operating conditions so that the minimum pumping time and maximum idle time are obtained without any loss in production further enhances the amount of energy savings.

**Maintenance Savings:** Two benefits in this area result from monitoring a well with an RPC:

- The RPC is designed to detect fluid pound when "pump-off" begins and can be set by the operator to limit the amount of fluid pound allowed. This prevents wear and damage to all components in the pumping system. It should extend equipment life by limiting the detrimental effects of fluid pound. By also reducing the number of pump cycles, the life of the pumping equipment will be extended.
- The RPC also monitors maximum and minimum rod loads, load span, and card area so that if a pumping system has a component failure (i.e., a stuck pump, a "sanded up" pump, a parted rod string, a tubing leak, standing or traveling valve leakage, etc.), the RPC will shut the unit down. This prevents further damage to pumping system equipment and may also provide power savings while the unit is not producing any fluid.

**Production Acceleration:** Generally, any increase in a well's production is a result of the RPC providing immediate significant operating information to the operator so that:

- Early detection and identification of potential pumping problems allow the operator to minimize down time due to downhole problems, and thereby prevent lost production.
- The RPC automatically increases the pumping cycle "run time" to compensate for a decrease in pump efficiency (slippage) or slight tubing leaks, thus maintaining optimum production. By monitoring the daily run time on a stable well, the operator can quickly be made aware of a potential well problem when the daily run time begins

to change over time. The operator can then schedule any needed well repair by monitoring the increase or decrease in daily run times.

**Manpower Utilization:** Since an RPC can provide fault messages related to the problem it has encountered, operating personnel can easily determine corrective action as well as what type of equipment must be provided to effect needed repairs.

If CAO is available, operating personnel no longer have to drive to each well before understanding whether the well is running or if it has an operational problem.

## ***Causes of Lost Production***

- A pump that is worn badly enough to prevent pumping all of the available production, but not badly enough to alert the producer of the need to have the pump pulled and repaired.
- A tubing leak that slowly grows larger and prevents the well from producing all available production until the leak is detected.
- A well that is “off production” for several days before the problem is discovered. Then, the well is often off for several more days before it can be repaired and returned to normal production.
- Improperly set pumping cycle idle times.

## ***RPC Idle Time***

A key parameter in the set-up of any RPC is “how long to leave the pumping unit down” when pump off is detected – or “idle time”. Leave the unit down too long and production will be lost because of the increased backpressure placed on the producing formation by the rising fluid level in the casing from natural well inflow during the idle time. The amount of backpressure placed on the reservoir is a function of idle time duration. Leave the pumping unit down “not long enough” and the well will cycle (stop and start) too many times.

The correct setting of the idle time value for an RPC is a primary key to the acceptance or rejection of well control. If the controller causes the operator to lose more revenue from decreased oil production than he is saving with reduced energy and well servicing costs, he will decide that an RPC is not a good application for his wells.

For a well that is over-pumped and pumping 24 hours per day, the installation of a RPC will always result in some slight loss of production. The fluid that accumulates in the wellbore during idle time will cause some backpressure that will reduce the inflow into the wellbore. However, if the nature of the problem is understood, the lost production can be limited to a value that is economically prudent.

The primary key to setting the idle time is the inflow performance of the well. This inflow performance is a function of the properties of the well. This inflow can be predicted by using the PI (Straight Line) or the IPR (Vogel Method). An accurate understanding of the well inflow performance is extremely valuable in getting the best performance from a well controlled with an RPC.

## ***The RPC***

- Allows maximum production with reduced equipment failures.

- Allows for quick and easy downhole problem detection.
- Increases system efficiency by pumping each well only as long as necessary to produce the available fluid.
- Increases rod, pump, and tubing life by eliminating fluid pound.
- Stores start-up, shutdown, and failure surface dynamometer cards for later analysis.
- Load-based shutdown limits can be set to avoid possible major pumping unit or downhole equipment failures.
- Correct RPC idle times can insure maximum production.
- RPC idle times that are too long can decrease production.

Whether oilfield economics are good or bad, operators always look for new ways to improve production operations, reduce operating costs, and generally run a more cost effective operation. eProduction Solutions' line of RPCs provide an excellent means of reducing power costs, maintaining or perhaps slightly increasing production, and reducing maintenance costs. The RPC microprocessor can be programmed to continuously monitor for pumping system malfunctions such as rod parts, load or position sensor failures, high or low load limit violations, or load span limit violations. If the operator-set operating limits are violated, the RPC can be programmed by the operator to take one of several basic actions:

1. Turn on an alarm (fault) light only.
2. Transfer well control to an internal "software timer" (software timer uses a calculated average run time from the last six pumping cycles).
3. Transfer well control to the original pumping unit control panel (either "hand" operation or an external percent or pin type timer).
4. Turn off the pumping unit until reset by an operator.

Several basic examples of RPC-provided fault messages and possible corresponding problems are as follows:

### **Control Failure**

- HOA (Hand-Off-Automatic) switch left in hand operation or in the "off" position
- Motor panel control failure
- Pumping unit belt failure

### **Low Load Span**

- Parted rod string
- High fluid level
- Downhole pump valve failure
- Gas locked downhole pump

### **Maximum Daily Runtime**

- Tubing leak
- Downhole pump wear

### **High Load**

- Paraffin drag on the rod string or paraffin-caused high flowline pressure

- Sand or trash sticking the pump plunger on the upstroke

### **Low Load**

- Stuck pump plunger on the downstroke
- Shallow rod part

When wellsite RPCs are tied into a central monitoring and control (CAO) system, the above information is immediately available in the field office, or any other designated location on a local area network (LAN) or wide area network (WAN). Central site software shows alarms as they occur or they can be printed out as an alarm report, such as part of the morning report at the beginning of the workday. This allows only those wells with problems to be given attention.

## ***Summary of Reported Benefits***

Any number of technical papers are available that document the benefits obtained by RPCs. A summary of these papers is displayed in the table 2. This table highlights only the benefits reported. A complete reading of each paper is recommended if a full background of the operations involved is desired.

Again, it should be noted that RPCs that are part of a central monitoring and control (CAO) system can offer the additional operating benefit of continuous diagnostic data that allows quick identification of problems so that corrective action can be taken before a problem becomes critical and unnecessary downtime is accumulated.

The following are reviews of some recent RPC installations and the benefits obtained:

### **East Texas Operator**

An operator in the East Linden (Cotton Valley) field in East Texas purchased and installed RPCs, replacing time clocks, on 15 wells. These wells are 10,000 feet deep, producing 42-46<sup>o</sup> API gravity oil, with a 5 to 50% water cut. With contract pumpers and using timers set by trial-and-error, this operator saw the upside potential of using RPCs.

Before installing RPCs, well problems were identified during daily visits. Timers were used to operate the wells – set based on a single visit to each well during a 24-hour period. The trial-and-error process used to set these timers would often result in some wells pounding fluid for long periods of time. Another problem was “under-pumping” some wells where pumping time was a little as 3 hr/day. Gas “break out” during this downtime resulted in the unrecognized need to pump the wells longer to move the gas as well as all available fluid. Factor in any pump wear – also requiring additional run time – and the possibility of “under-pumping” was very real.

The installation of RPCs eliminated the guesswork and trail-and-error involved in setting time clocks for correct well control. The RPCs also automatically adjusted idle time based on buffered data in the controller from historical cycle times.

Observed benefits from the use of RPCs by this operator include reducing rod and tubing failures by 31% and electrical cost by 40% (\$50,000 per year). For wells that were maintaining a high fluid level due to incorrect timer cycles, the RPCs increased fluid production.

## Town Site Lease

An operator in Torrance, California operates a town site lease that has 41 air balanced pumping units (144" stroke) producing from approximately 3500 feet vertical depth (600 measured depth). These highly deviated wells (40° average deviation with some wells over 60°) all have rod rotators to reduce rod and tubing wear. Prior to installation of RPCs, the wells were pumped 24-hours per day. The following is a general summary of costs prior to RPC installation and after.

Cost Description	Before	After	4 Mo. Prior to Installation
Direct well pulling costs (\$/Mo.)	\$51,899	\$35,899	\$48,201
Electrical power costs (\$/Mo.)	\$46,476	\$39,797	\$41,050

The average direct well pulling costs over the 28 months prior to RPC installation was \$44,522 per month, therefore the \$23,392 per month cost after RPC installation is a 47.5% savings. If compared to the more recent 16 months operation prior to installation (average monthly cost \$50,990), it represents a 54.1% savings.

Electrical power savings show the same significant results, but at the same time the controllers were put into operation the operator entered into an "interruptible power agreement" with the power company. This agreement resulted in a 22.8% discount in monthly power costs. This reduction must be subtracted from the total power savings in order to show RPC power savings.

For the 28 months prior to installation of rod pump control, monthly power costs averaged \$42,838 as compared to \$23,897 per month after RPC installation or a 44.2% total power cost savings. Subtracting the interruptible power discount of 22.8% gives a 21.4% power cost savings due to the RPCs. If compared to the 16 months prior to the rod pump control installation, average power costs were \$45,119 per month. The reduced power cost of \$23,897 per month is a 47.0% total power cost savings, or 24.2% power cost savings due to rod pump control.

Total daily production was maintained while making these significant reductions in well pulling costs and electrical power costs. The payback for the RPCs and central monitoring and control software was less than four months.

## Long Beach Installation

Another operator in the Los Angeles area has seven wells on a town site lease in Long Beach, California. Four of the wells produce from 10,000 feet, and three from a shallower production zone. Daily average energy usage for the six months period prior to RPC installation was 1964 KWH per day. A test was initiated by installing RPCs on two key wells. The daily average energy usage decreased to 1757 KWH per day over the four-month test period. This is an energy usage decrease of 10.5%. It was then decided to install RPCs on the five remaining wells. The daily average power usage decreased to 1488 KWH per day for a total energy usage decrease of 24.2%. Production has been maintained at the same level as prior to installation of RPCs.

An example of another of the benefits that can be obtained from information provided by an RPC occurred on one of the deep wells soon after the controller had been installed. In monitoring the cycle run time (length of pumping cycle in hours, minutes, and seconds) that had been quite constant, it was evident that the cycle run time was beginning to increase significantly. A well test was obtained and production was found to be below normal. Investigation showed that the tubing went on a vacuum, indicating a tubing leak or pump problem. The pump was pulled and inspection revealed that the pump seat had begun to wash out. It was decided to run a lead seal bottom plug to seal in what was estimated to be a slightly washed seating nipple. This solved the problem and prevented a tubing job that would have cost in excess of \$10,000. This one early problem detection and resulting corrective action, provided by information easily obtained from the RPC, paid for four of the RPCs – simply by not having to do a complete tubing job. An additional benefit was the prevention of lost production.

### Test Results in West Texas

An operator in West Texas recently installed 15 RPCs for a test evaluation. At the end of the test period, the operator reported an average 16% decrease in pumping unit run time (when compared to run time on timers), and an overall decrease of 25% in pulling costs, and a 5% increase in production.

### Far East Test Producing Lower Gravity Crude

Initial results from a test conducted in the Far East using RPCs on rod pumped wells producing low gravity crude resulted in the following data:

Description	Before RPC	After RPC	Benefit
<b>Operating time hours / month</b>	240 Hours (33%)	180 Hours (25%)	25% decrease in run time
<b>Gross production</b>	102.5 B/D	399.0 B/D	289% increase in production
<b>Power consumption</b>	4843 KWH	3632 KWH	25% decrease in power usage
<b>Power consumption per BBL fluid</b>	47.25 KWH/BBL	9.10 KWH/BBL	80.7% decrease in power consumption per BBL fluid

Operating cycles prior to RPC installation were handled manually with a typical run cycle being 24 hours "on" and 48 hours "off". These operating cycles were partly due to the inaccessibility of the wells. With the RPC installed and an optimum idle time of 1-1/2 hours, the pump would then operate for 20 to 30 minutes before shutting down due to pump off. This more frequent production cycle with the RPC was much better suited to the well inflow characteristics of the well and therefore optimized production. This is an extreme comparison case, but clearly illustrates the tremendous advantages of RPCs on remote or difficult access (due to terrain or weather) wells.

## Canadian Well

An example of a serious problem avoided by RPC monitoring of a remote well in Canada occurred recently. The bolts on the Sampson Post bearing assembly loosened and before any damage was done the controller sensed abnormal loading and shut the well down. When routine well surveillance by the lease operator discovered the well down on a load fault, inspection of the pumping unit determined the cause. The problem was corrected and the unit was returned to normal operation.

## Case Studies Summary

These case studies again show that RPCs offer three basic benefits to the operator. These benefits are:

- Power Savings: An approximate 20% to 25% decrease in energy consumption is generally obtained.
- Maintenance Cost Reductions: An approximate 25% reduction is generally reported. This percentage depends heavily on the severity of the pumping conditions and the operator's efforts to minimize failures prior to RPC installation.
- Production: Data from these studies supports a possible 4% increase in production.

In addition to the three basic benefits mentioned above, RPCs should be considered especially applicable to:

- Wells in enhanced recovery programs that result in changing or cyclic well production.
- Inaccessible wells that do not receive adequate operator surveillance due to location, terrain, or weather.
- Wells with fiberglass rod strings to prevent compressive rod loading.
- Wells with severe pumping conditions such as high loads, high pumping speeds, corrosive downhole conditions, highly deviated wells, or other similar well and equipment conditions.

The table 1 below gives a summary of the more recent operating experience covered in this paper.

### Case Studies Tabular Summary

Operation	Power Savings	Maintenance/ Operating Savings	Production and Other Benefits
<b>East Texas Test</b>	40% cost savings	31% well pulling cost savings	No data
<b>Torrance, California Townsite Lease</b>	21.4 to 24.2% power cost savings	47.5 to 54.1% direct well pulling cost savings	No change
<b>Long Beach, California Townsite Lease</b>	24.2% energy usage decrease	Not established, but saved \$10,000 on one early problem detection	No change
<b>West Texas Test</b>	10.6 decrease in pumping unit run time	25% decrease in pulling costs	5% increase in production
<b>Far East</b>	25% decrease in power consumption	No data	289% increase - viscous oil production sensitive to proper cyclic timing

Table 1: Economic and Operating Benefits

### Technical Papers Tabular Summary

Technical Paper or Article	Power Savings	Maintenance/ Operating Savings	Production and Other Benefits
<b>"Successful Application Of Pump-Off Controllers" SPE Paper 6853 (1977) (1)</b>	10% to 35% reduction	10% to 35% reduction	Up to 4% production acceleration
<b>"Denver Unit Well Surveillance And Pump-Off Control System" SPE Paper 6849 (1977) (2)</b>	15% decrease in KWH/BBL	Not established	4% production acceleration
<b>"Pump-Off Controller Application For Midway-Sunset Cyclic Steam Operations" SPE Paper 9915 (1981) (3)</b>	48% decrease in power consumption	Not established	Did not increase production, but provided a more efficient method to produce available fluid

<p><b>"Shell Expands Computer Production Control" Oil &amp; Gas Journal (1981) (4)</b></p>	<p>20% to 25% decrease In electrical power</p>	<p>Data indicated there should have been substantial increase in failures due to increasing water cut. This did not occur, giving evidence that system substantially reduced maintenance</p>	<p>4% production increase</p>
<p><b>"Pump-Off Controllers Improve Sucker Rod Economics" World Oil (1982) (5)</b></p>	<p>25% average increase in the efficiency of power consumed</p>	<p>96% decrease in rod failures 83% decrease in pump changes</p>	<p>Production decrease was a field problem and not due to the RPCs. Average pump efficiency increased 41%</p>
<p><b>"Experience With Pump-Off Controllers in The Permian Basin" SPE Paper 14385 (1985) (6)</b></p>	<p>20% reduction in energy consumption</p>	<p>25% reduction in pulling expenses</p>	<p>1% to 4% increase in production</p>
<p><b>"Computerized Automation Of Oilfield Production Operations: An Extensive Five Year Study into The Costs &amp; Benefits" SPE Paper 15392 (1986) (7)</b></p>	<p>11.3% decrease in energy use per barrel of fluid lifted</p>	<p>28.6 % decrease In subsurface failures per barrel of fluid lifted</p>	<p>3.8% to 13.9% increase in production</p>
<p><b>"Analysis Indicates Benefits of Supervisory Pump-Off Control" Oil and Gas Journal July 1, 1991 (8)</b></p>	<p>Although energy efficiencies can be expected to improve, overall reduction cannot be anticipated because of possible increase in fluid production</p>	<p>14% decrease in lift equipment failures</p>	<p>3% increase in production</p>

Table 2: Economic and Operating Benefits

## ***Putting It All Together – Why “Pilot” Test RPCs? - A Case History***

Many lessons have been learned from practical application of RPCs over the past two decades concerning the best use of RPCs. Field testing obviously must be well thought out and there must be effective communication with lease operators and other key field personnel. The following discussion serves to re-enforce the results of other case histories discussed in this paper and can serve as a model for operators wishing to understand the implications of automation through the use of RPCs in their particular field situation.

# Lost Hills Field San Joaquin Valley, CA

With a large-scale waterflood project being implemented in this field, engineering efforts were focused on continuous well surveillance and timely waterflood response detection. An effective way to monitor waterflood response was to install RPCs on rod pumped wells. This method was especially effective since wells in this field could not be tested on a frequent basis. Because well tests might be obtained only once a month, the end result was the possibility that months could pass before waterflood response was measured. The installation of RPCs allowed percent runtimes to be monitored and used to identify flood response or well problems much sooner.

The studies cited previously in this paper have shown the proven benefits of using RPCs – in addition to waterflood response detection. These benefits include reduced energy consumption, reduced well failure frequency, and increased production.

## ***The Pilot***

With approximately 250 producing wells in the waterflood area, RPC installation on all pattern wells would be very expensive. The great capital investment would need to be economically justified. And, just as important, a pilot test would be a good way to develop field personnel acceptance. Concerns about automation and its implications were obstacles that had to be overcome.

The field pilot was designed to:

- Prove that RPCs would or would not work in the Lost Hills field.
- Help lease operators develop support for the further use of RPCs.
- Be small enough to limit investment risk.
- Be small enough to be easily monitored.
- Provide enough data to enable a decision about the future use of RPCs.

Nine closely spaced wells within a mile of the field office were selected for RPC installation. The pilot test was monitored for five months. It is important to note that these nine wells were monitored for two and one-half months before RPC installation and for two and one-half months after RPC installation.

Again, three operating parameters were measured during the pilot:

- Electrical usage.
- Well failures.
- Production.

## ***Well Selection Criteria***

### **Waterflood Pattern Producers**

Rod pumped wells in a waterflood pattern benefit from the installation of RPCs even more than wells outside a waterflood area because of the quick detection of waterflood response. These well types are most suited for RPCs in a waterflood:

- Wells not yet showing waterflood response, but expected to in the near future.
- Wells with changing waterflood response.

### **Wells Producing Sand**

Sand producing wells should be carefully identified and evaluated before installing RPCs. Sand settling in the rod-tubing annulus during the idle time of a normal RPC cycle may cause the pump plunger to become irreparably stuck.

### **Wells with Gas Interference**

Wells with gas interference should also be identified when RPCs are installed. Severe gas interference can cause the surface dynamometer card to be erratic and perhaps result in premature well shutdown. Possible solutions to this problem:

- Configure the RPC to continue to pump the well when gas is present in the pump to minimize the possibility of premature well shutdown.
- Lower the pump below the bottom producing perforation.
- Install a gas anchor.

### **High Failure Rate Wells**

Wells with high failure rates are generally the best candidates for RPCs because well failure reduction usually represents the largest savings associated with the benefits of RPCs. RPCs were preferentially installed on the wells with the highest historical failure rates.

### **High Producing Wells**

High productivity wells are good candidates for RPCs. These wells generate the most revenue and it is important to react quickly to well problems and limit downtime. These wells operate more efficiently when RPCs are installed.

### **Pumped Off Wells**

Wells located in a waterflood area should be over-displaced (pumped off) and therefore capable of handling waterflood response even before RPC installation. This also holds true for wells in areas of water encroachment or additional remedial potential. Several times during this pilot and field implementation, wells were found not be pumped off or to be under-displaced enough that they could not be pumped off. Time delays, additional expense, and inefficient use of manpower were the result.

## Wells on Timer

Wells operating on a pin type or percent timer are good candidates for RPCs. RPCs allow wells to automatically adjust to the dynamics of the reservoir. The well is pumped more efficiently and the RPCs adjust run time for pump wear – which a timer cannot do. Most of the increased production during the pilot test came from wells that had previously been on timer.

## Energy Rebates

Energy reduction rebates may be available from the local utility for RPC installation projects. Based on pilot results, energy rebates were typically the largest for those wells most over-pumped.

## *Well Equipment Selection*

Various methods for controlling rod pumped wells that experience pump off have been tried for many years. The most reliable method and the one that has gained the most acceptance has been the rod load versus position method. Polished rod loads can be measured in two ways, both of which are used in the Lost Hills field.

One method is to weld a beam-mounted transducer (strain gauge) to the pumping unit walking beam. The second method is to install a polished rod load cell between the bridle carrier bar and the polished rod clamp. Both methods have pros and cons.

The pros of a polished rod load cell:

- It is easier to install and remove from pumping units when compared to weld-on beam-mounted transducers.
- It does not need to be re-calibrated if the rod load changes, i.e., if the pump depth, pump size, or stroke length changes.
- It gives accurate and dynamic measurement of load.

The cons of a polished rod load cell:

- It can be easily damaged by well servicing crews.
- It is subject to damage from certain abusive well conditions, especially floating rod strings.

The pros of a beam-mounted strain gauge:

- It requires less maintenance since it is not subject to conditions such as floating rod strings.
- It is not in the way of well servicing crews because it is mounted on top of the walking beam.

The cons of a beam-mounted (welded-on) strain gauge:

- It has exacting requirements for installation. Welding requires “hot work permits”, well cellars must be emptied, and any combustible materials removed from the

immediate area. Also, manufacturer's specifications for installed location on the walking beam and welding temperature must be strictly followed.

- Removal from the walking beam is difficult.
- It must be re-calibrated each time there is a rod load change.

The rod load versus position RPC has three methods of measuring the pumping unit polished rod position: an inclinometer, angle transducer, or a position/proximity switch. However, only the inclinometer is used at Lost Hills for the following reasons:

- When the strain gauge is used to measure rod load and an inclinometer is used to measure position, the two devices can be installed as a single unit.
- The inclinometer is always easier to mount than an angle transducer or position switch – requiring only a simple magnet to mount the inclinometer to the pumping unit walking beam.
- The proximity switch only measures position at one point during a single stroke of the pumping unit.

Other factors considered were the supplier's experience, stability, and quality of service. Costs and features of the equipment were also considered, as well as the potential for the equipment to be used as a part of a remote telemetry system.

## ***Field Buy-in***

RPC projects will be much more successful if lease operators and other field operating personnel buy-in is obtained from the beginning. Skepticism about RPC usage was due to several reasons:

- Past experience with poorly designed controllers.
- The perception that RPCs would simply be "black boxes" on their wells.
- Concern that RPC implementation would result in manpower reduction.

To gain support for RPCs, several steps were taken:

- Educating personnel about RPCs and the purpose of the project.
- Training courses in the operation of RPCs were held both in the office and in the field. From the beginning, the operators were made aware that their responsibilities would now include proper RPC operation.
- Operating personnel were involved in the well selection process – both during the pilot and field installation. This promoted teamwork, responsibility, and ownership.

Obtaining field level support was the most critical step towards a successful RPC project. It should be noted that, to date, there has been no reduction in manpower. Rather, the role of a lease operator is simply changing from one of "problem-finder" to "problem-solver".

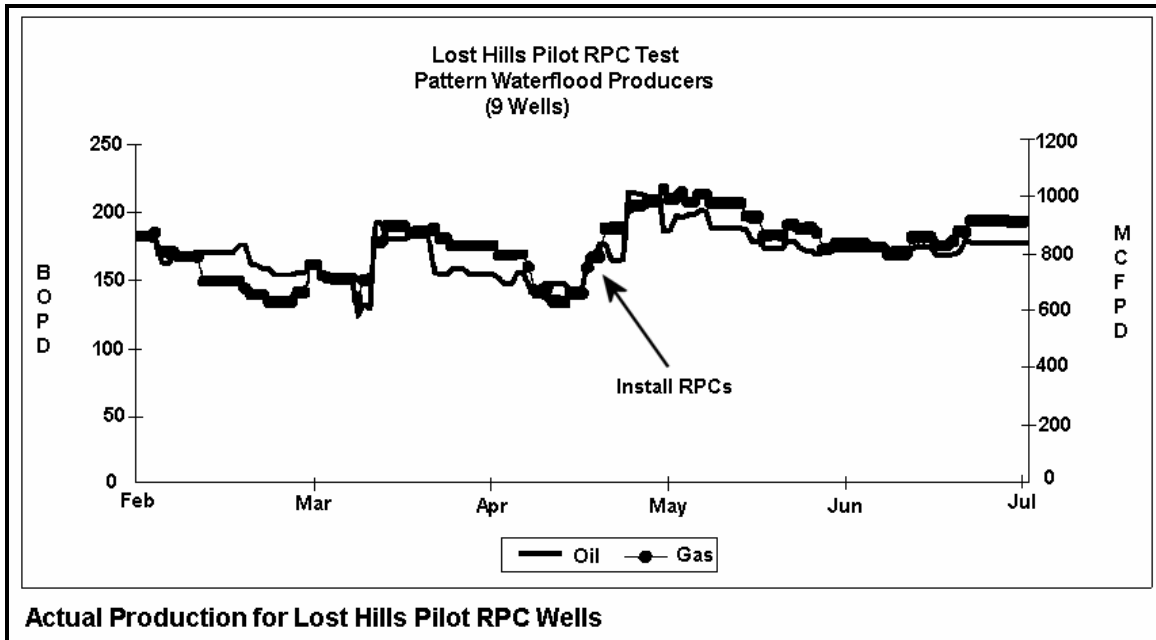
## ***Recommendations***

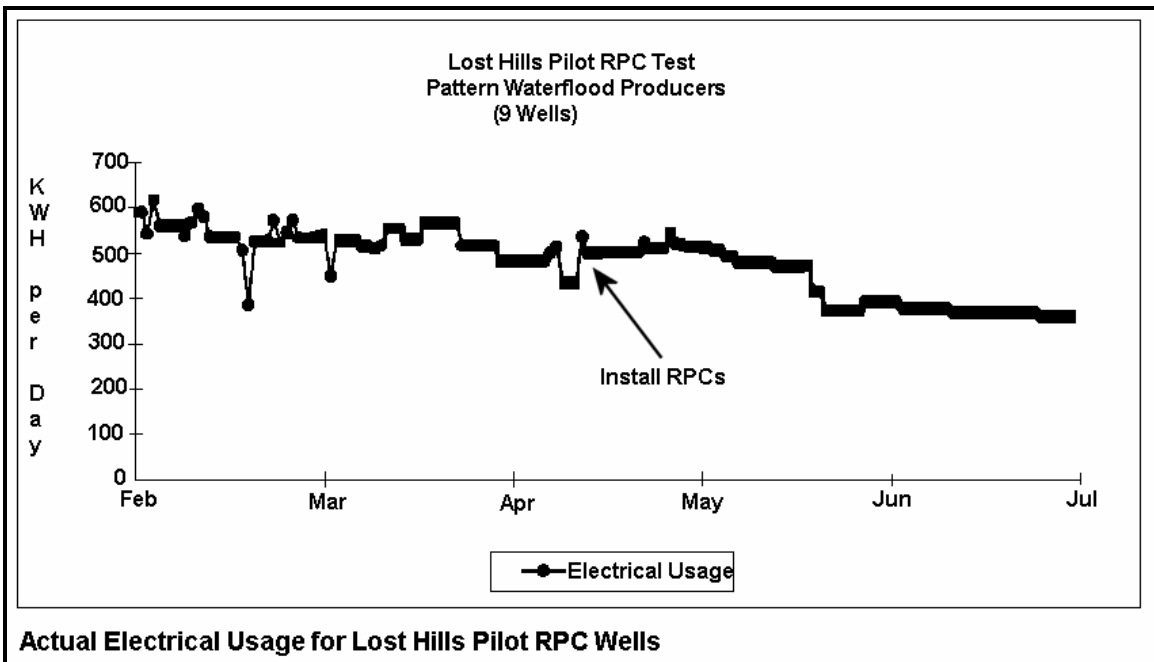
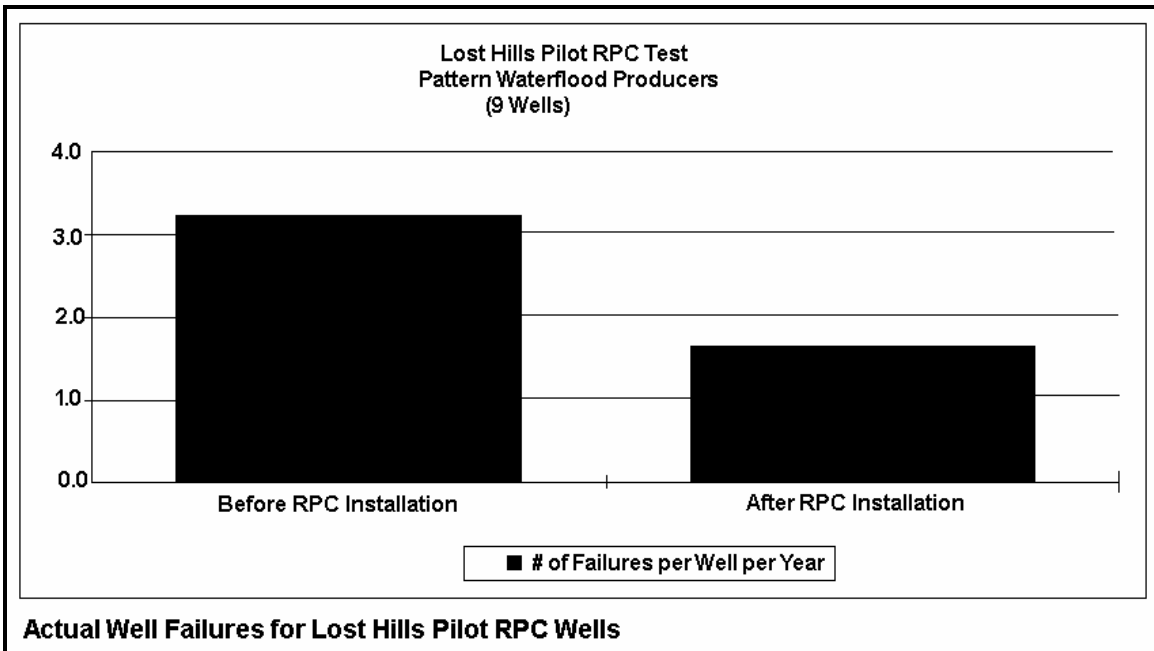
- Involve lease operators and other key operating personnel from the beginning for a successful project.
- Lease operators/responsible personnel should be trained in the use RPCs.

- Lease operators should approve of the installation of an RPC on each well.
- Selection criteria should be developed and utilized to identify the best candidate wells for RPC application.
- Both polished rod load cells and beam-mounted strain gauge work adequately to control beam pumped wells. Major consideration should be given to the use of polished rod load cells if well diagnostics is a requirement of the project.
- Inclometers are the best position device.

## Conclusions

Since previous studies have proven the benefits of rod pumped control (RPCs), the Lost Hills field felt that a large, lengthy field trial was unnecessary. Instead, a small pilot was designed and implemented to show that RPCs would economically work at Lost Hills. During the pilot and field implementation, efforts were focused on the practical and efficient use of RPCs, rather than on detailed data analysis.





# Cost Justification Worksheet

Use this worksheet to estimate the total yearly benefit available when RPCs are installed on beam pumped wells. Change the benefit percentages to be more conservative or more optimistic as the situation dictates.

## 1. Power Savings

Current Energy Cost Per Year \$

21% Decrease in Energy Consumption X       .21      

Power Savings \$

## 2. Maintenance/Operating Savings

Direct Well Pulling Cost Per Year \$

28% Decrease in Pulling Cost X       .28      

Maintenance Savings \$

## 3. Production Increase

Total Yearly Production \$

Price/BBL \$X

2% Production Increase X       .02      

Production Increase \$

TOTAL YEARLY BENEFIT (1+2+3) \$

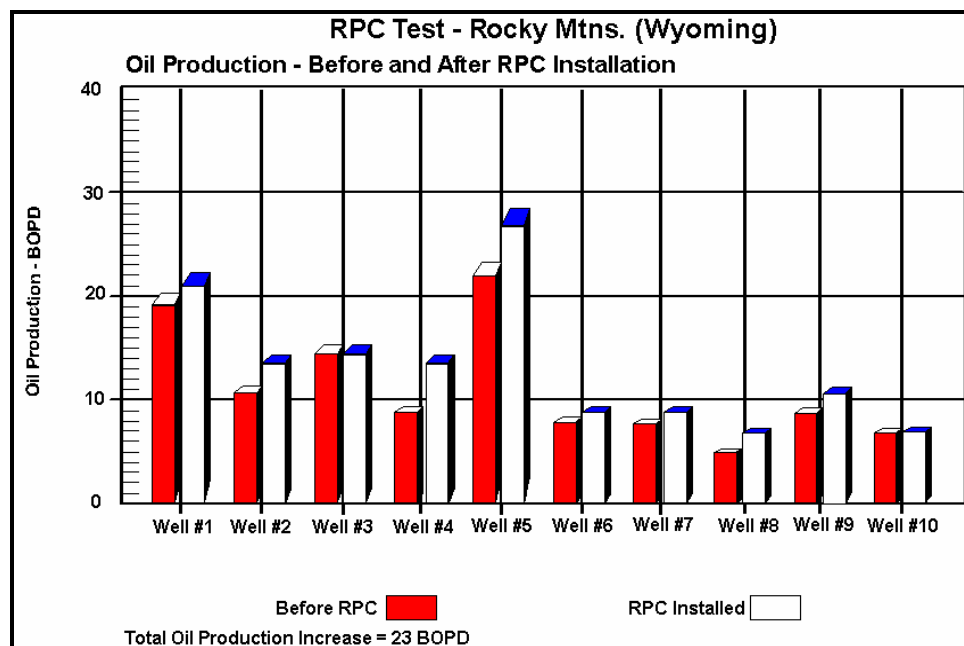
# Benefits of a Complete Rod Pump Control System

The principles discussed in this paper have been implemented in fields with as few as 20 rod pumped wells to fields with more than 3,000 wells. Rod pump control systems have been installed in primary recovery fields as well as tertiary recovery fields undergoing water, CO<sub>2</sub>, or steam flooding. These systems have been installed in new fields with no automation in place and in mature fields that have been automated for over a decade.

This discussion describes the financial benefits of implementing a comprehensive rod pump control system (well site RPCs and host diagnostic software) in the following different categories:

- Increased production.
- Reduced operating costs and well failures.
- Individual well management.
- Efficiency in field operations.
- Efficiency in computer operations and automation.

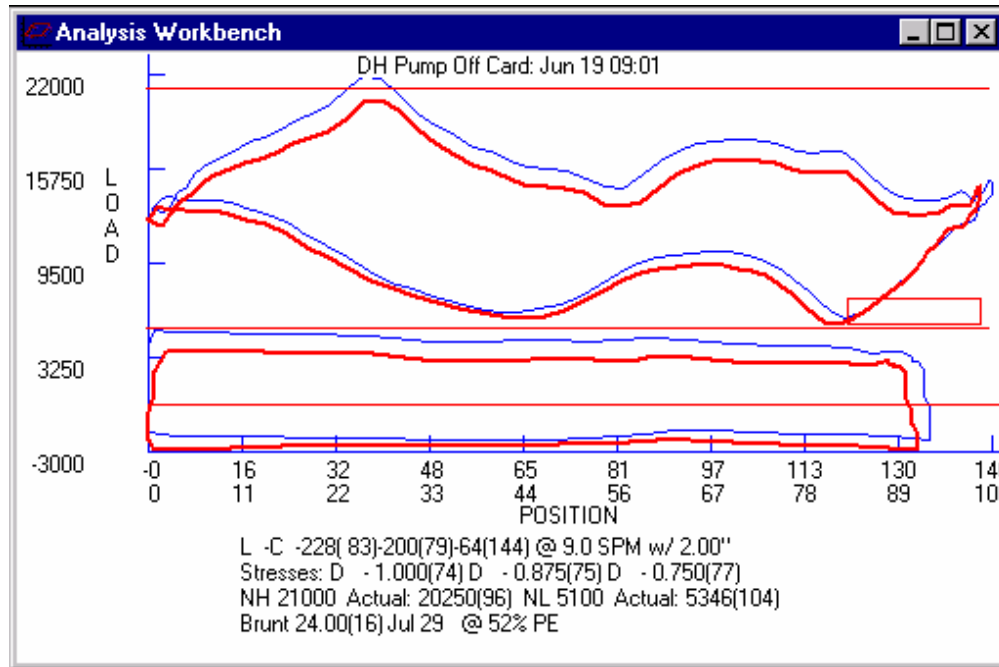
## Increased Production



## Fine-Tuning Wells As Well Behavior Changes

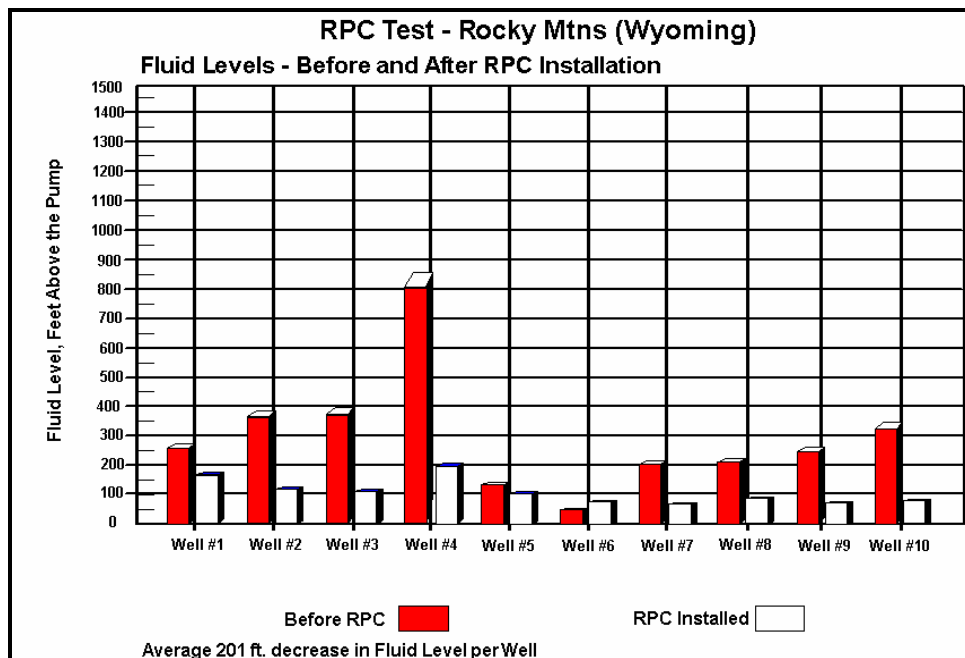
The analytical features of the diagnostic central-site software portion of a rod pump control system allow the user to make changes to the operational parameters of the wells at any time from the operating office. Changing the pump-off set point is an example of a parameter change that can be used to fine-tune production. By monitoring the performance

of the well on a daily basis, the operator can make small changes to the configuration of each wellsite RPC that can decrease the span of fluid level fluctuations.



The rod pump control system (RPCs and host software) provides both surface dynamometer cards and calculated downhole pump cards for detailed analysis.

In addition, using the various optimization tools, lower operating fluid levels are often achieved, which increases total fluid production. Assuming the same oil cut is applied to this increased fluid production, recovery of oil increases on a proportional basis.

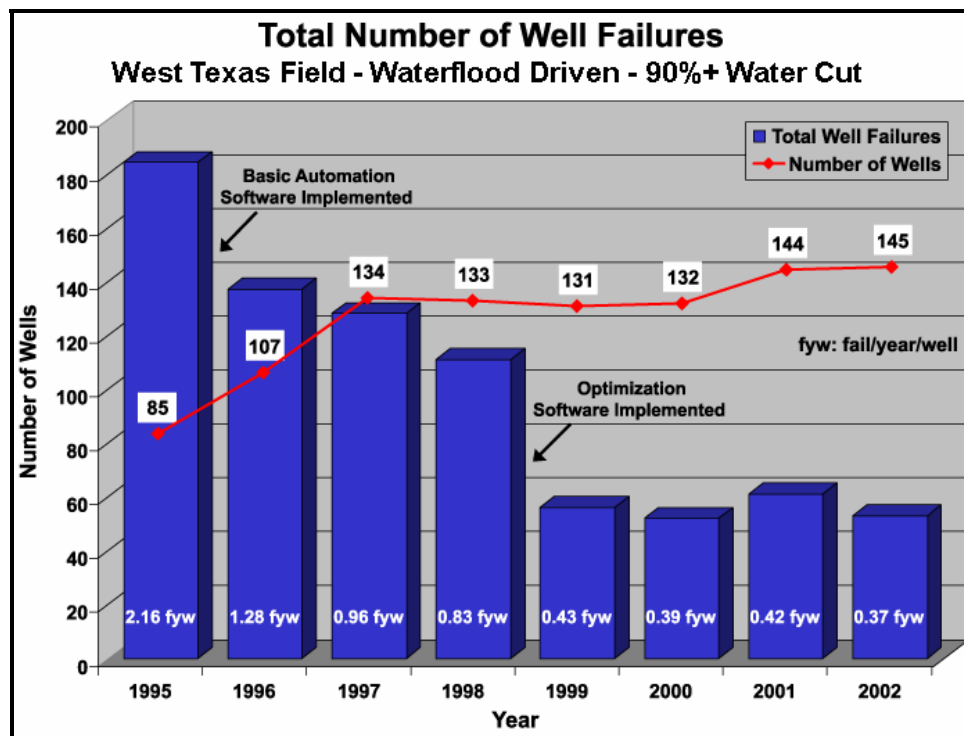


## Increased Runtime / Decreased Downtime

The concept of managing wells by “exception” promotes the ability to keep downtime to a minimum in two ways. First, when a well does go down, the operator can be notified immediately – even if the operator is off the producing property. Second, these rod pump control system tools provide indications that a pumping well may be heading toward a failure of one type or another. In the second case, the user can prevent downtime rather than react to it by correcting the factors that are leading the well into a failure condition.

## Early Detection of Production-Robbing Problems

Problems that reduce the production of a well can be seen through trends and displays of historical data as displayed by the host software used by the rod pump control system. By examining the calculated downhole card of a beam-pumped well, a user of the system can identify problems such as traveling valve and standing valve leaks, barrel / plunger fit, friction, unanchored tubing, and gas compression.



## Design Wells for Optimal Performance

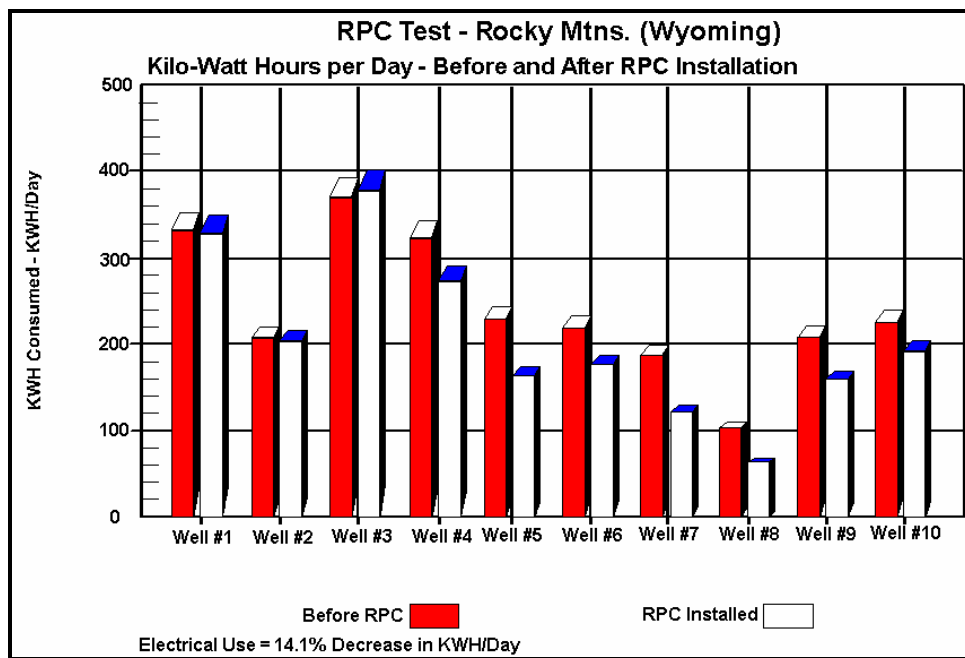
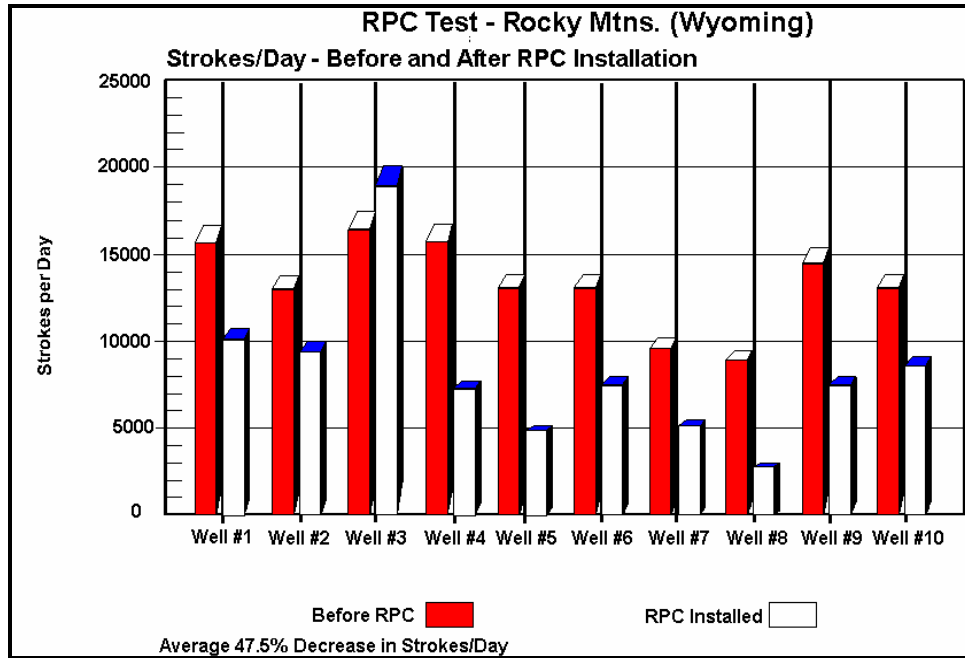
The host software also provides tools for designing and optimizing beam pump systems. By using “what-if” analysis, the user of the software can experiment with different parameters in a virtual environment before actually making changes in the field.

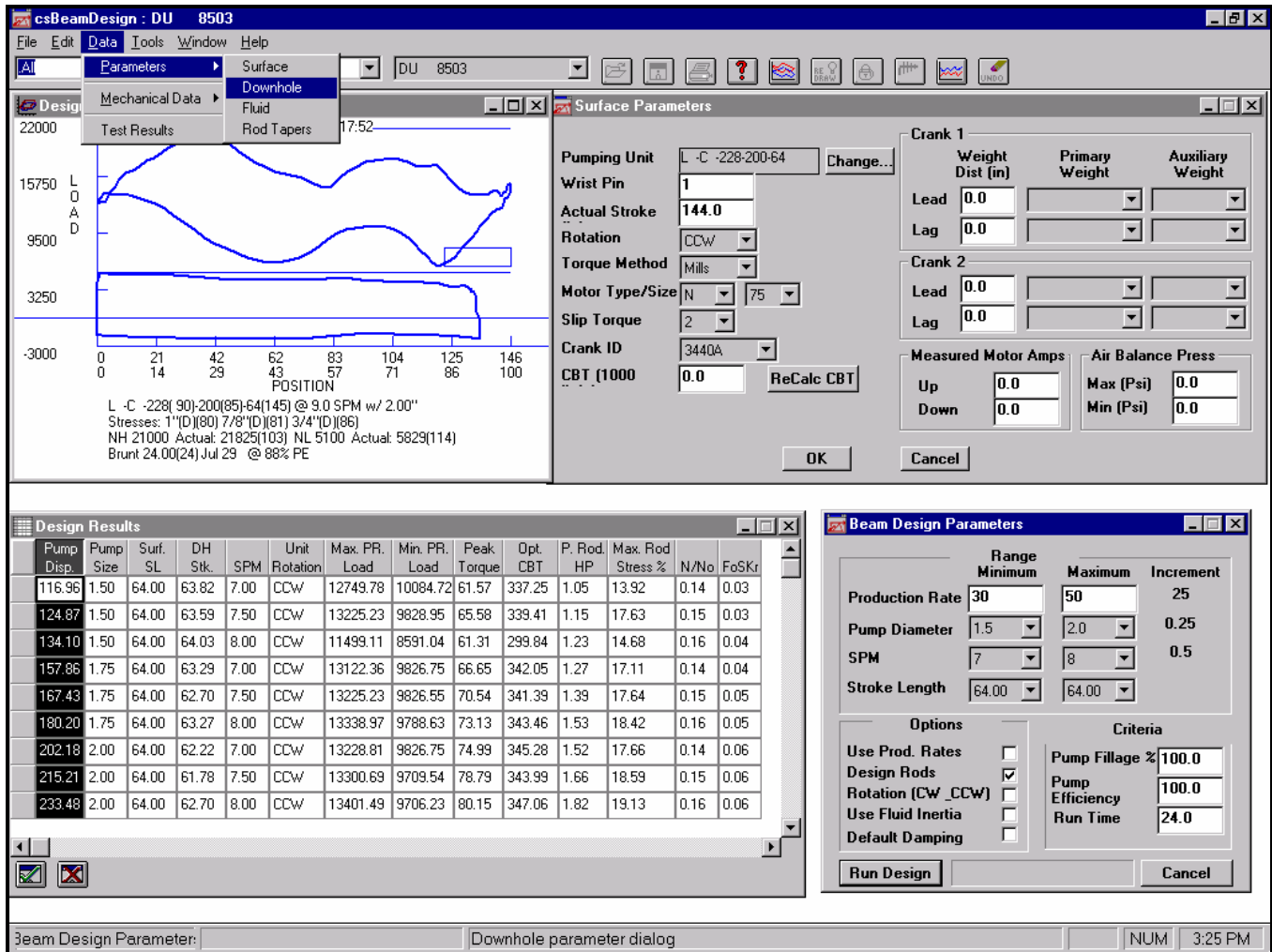
From the combination of increased runtime along with rod pumping system optimization, this type of rod pump control system typically improves production in the range of 2% to 10%, depending on the current producing conditions.

## Reduced Operating Costs & Well Failures

### Reduced Electrical Costs by Optimizing Pumping Unit and Motors

A comprehensive rod pump control system goes beyond a basic SCADA (Supervisory Control And Data Access) system's ability to merely monitor and report on the data from rod pumped wells. Analytical tools are built into the host software so a user can perform a detailed analysis on the data gathered from the wellsite RPCs without moving the data into another diagnostic product.





For beam pumping installations, the user can evaluate different pumping units and prime movers, as well as over one hundred other parameters in a virtual “what-if” scenario. Rather than actually making the expensive changes at the well, the optimization software provides the user with a way to compare various parameter changes so the user can optimize each installation for pumping unit and motor size, rod design, or displacement matched to inflow.

Additionally, the user has the ability to do “what if” analysis in designing or redesigning beam wells.

As previously stated, field experience and customer dialog has shown that the installation of a comprehensive rod pump control system (and optimizing electrical usage) will reduce total field electrical consumption in the range of 10% to 30%.

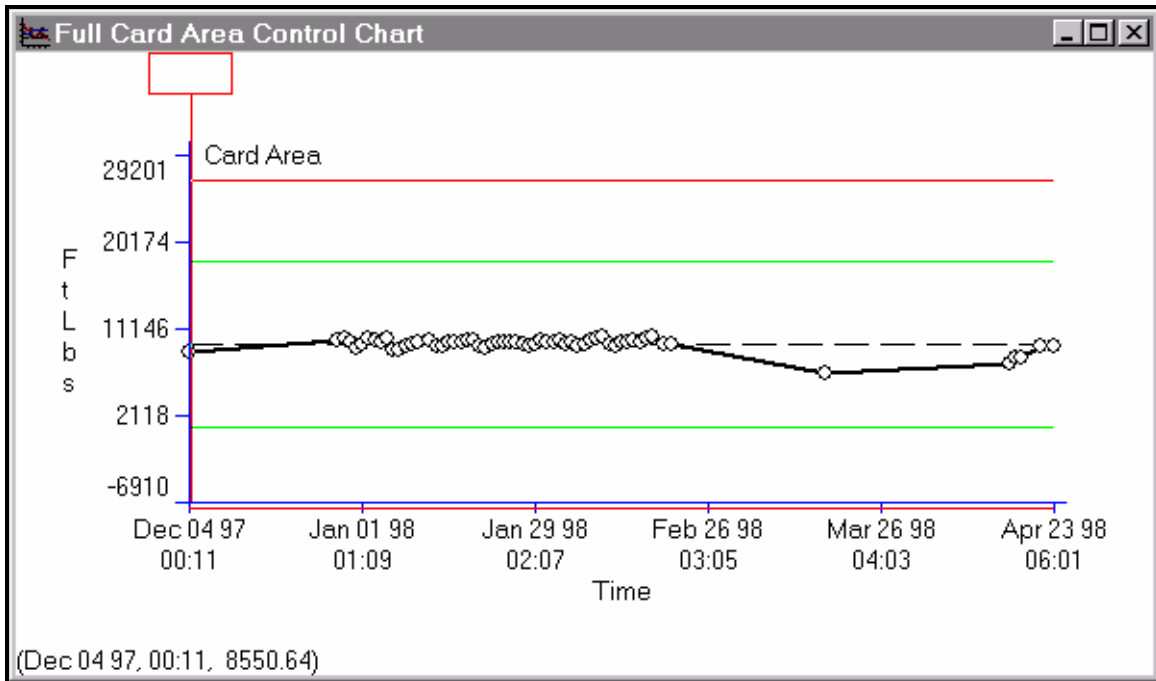
## Reduced Manual Fluid Level Determination

Downhole Performance												
Well Name	API Pumping Unit Identifier	Stroke Length	Unit SPM	G.B.T. %	Beam Load %	Pump Size	Pump Eff.	Gross Fluid	Est. Fluid	Cal. FAP	Annual Cost	
DU 2202	L C 456 305 144	144	7.4	80	56	1.500	110	221	199	633	8530	
DU 2205	A C 456 304 144	117	9.6	89	66	2.000	104	150	143	1177	12073	
DU 2206	L C 320 246 86	85	8.8	70	74	2.000	91	202	219	1300	6278	
DU 2208	L C 640 304 144	144	7.3	102	72	2.000	82	230	278	1612	15004	
DU 2214	A C 640 305 144	144	7.4	52	56	1.500	103	225	217	318	8640	
DU 2216	A C 640 305 144	143	7.3	81	72	2.000	101	243	239	68	12486	
DU 2218	L C 640 305 144	143	6.6	73	65	2.000	104	346	329	283	11509	
DU 2222	A C 640 305 144	143	8.2	71	60	2.000	88	325	368	846	12674	
DU 2226	A C 640 305 144	144	7.1	81	68	2.000	87	278	319	382	12802	
DU 2227	L C 640 305 144	143	6.4	65	61	2.000	161	219	135	835	10383	
DU 2228	A C 640 305 144	144	7.4	84	64	2.000	81	336	412	140	12970	
DU 2235	A C 640 305 144	148	10.0	73	62	2.000	72	421	582	0	0	
DU 2236	A C 456 304 144	116	7.1	86	67	2.000	93	194	207	117	9526	
DU 3102	L C 320 246 86	86	9.0	83	76	1.750	90	180	199	1385	7856	
DU 3105	L C 456 305 144	103	5.8	55	54	1.750	71	82	114	997	5678	
DU 3106	L C 228 246 86	86	7.0	78	58	1.500	78	50	63	621	4051	
DU 3108	L C 320 256 100	99	6.6	81	69	1.750	96	116	120	1092	6232	

By taking advantage of the wave equation for downhole analysis, host software portion of the rod pump control system can provide an acceptable calculation of the fluid level of a beam-pumped well based on loads from the downhole card. The time and expense of regularly shooting fluid levels can be greatly reduced. Historical trends of calculated fluid levels are also available.

## Reduced Chemical Costs by Optimizing the Chemical Treatment Plan

A comprehensive rod pump control system provides the user with card area trends. This trend is an excellent way to track any change in downhole conditions, including friction at the pump. If the trend is on an upward slant, it is an indication that friction is increasing. Experience with individual wells using this trend enables the operator to better schedule maintenance such as chemical treatments and pump changes.



The area of the surface card of each rod pumped well is displayed in a chart for easy analysis.

### Chemical Treatments Are Less Frequent but Effective

By frequently analyzing the performance of the wells and incorporating historical information provided by host software, the user has accurate information that can help in more efficiently scheduling chemical treatments.

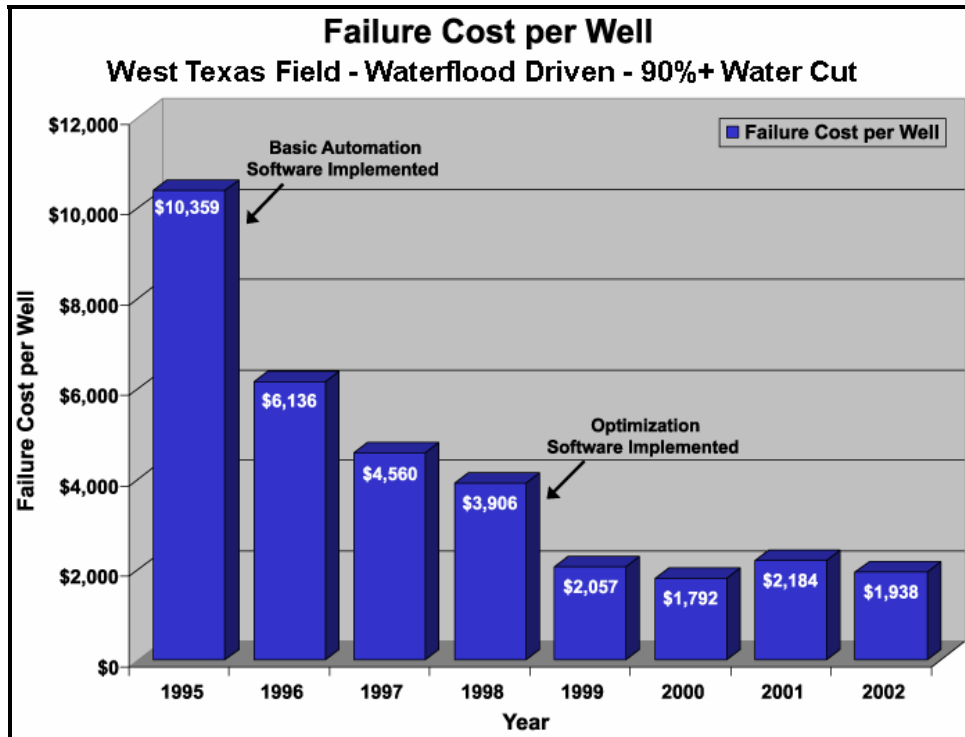
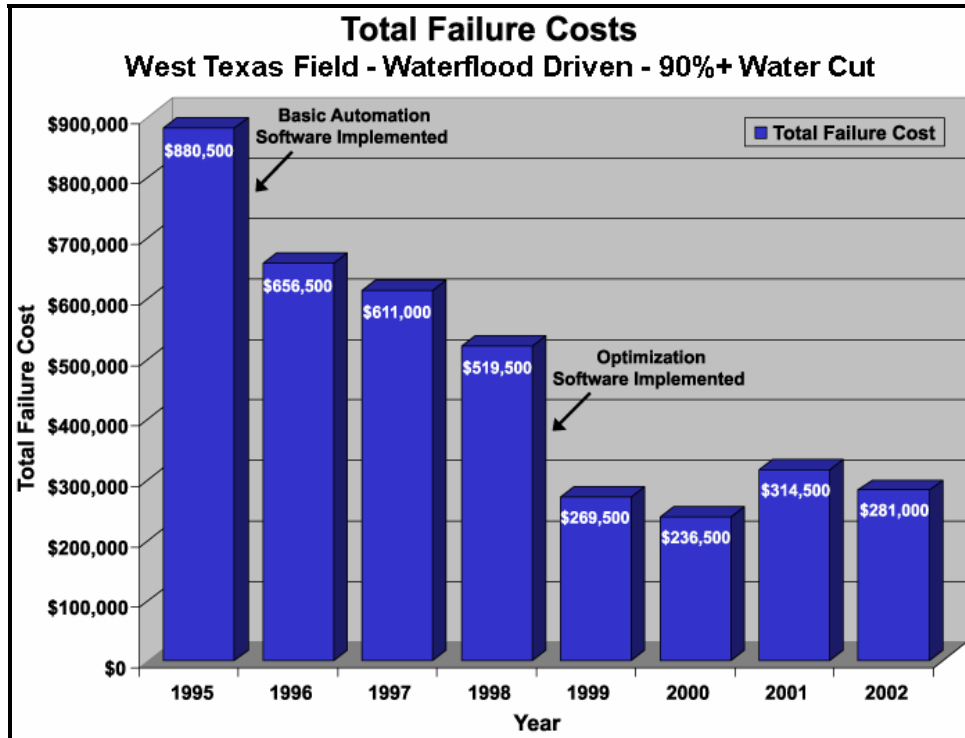
Field experience and customer dialog has shown that the installation of a comprehensive rod pump control system (and optimizing chemical usage) will reduce total field chemical consumption in the range of 10% to 30%.

### Diagnose Problems without Pulling Rods or Tubing

Through fine-tuning each RPC, the tools available in the rod pump control system allow the user to minimize rod stress and fluid pound. Another less tangible benefit is the ability to prioritize well work in the field to optimize rig usage and rig timing. The necessary information becomes immediately available from each beam pumped well to the operation office. Many problems and their causes are obvious based on the data received from each beam well. Examples include:

- Pump Wear
- Excess Friction
- Rod Overstress
- Gas Compression
- Gearbox Overload
- High Fluid Level Detection
- Tubing Anchor Slippage / Movement

Field experience and customer dialog has shown that the installation of a comprehensive rod pump control system (and correct diagnosis followed by the appropriate corrective actions) will typically reduce repair and maintenance expense by 10% to 30% per year.



# Individual Well Management Well Management by Exception

Rather than requiring an operator to examine each well's status every day, the concept of management by exception is used to provide information about anomalies through alarm and color-coded grids. The rod pump control system alerts the user to any parameter that is out of an ordinary operating range as defined by the user. This allows the user to focus on prioritizing recognized problems, rather than searching for problems that may or may not exist.

## Early Detection of Well Performance Degradation

By monitoring the daily runtimes of each beam pumped well in a field, the first indication of a change in the operating conditions of the well visually prompts the user for proactive corrective measures. Further inspection may show an increase in the area or size of the card, excessive gearbox torque, and a reduction in the rate of fluid pumped, etc. The information presented from each of those indicators provides the user with a strong start in recognizing problems at an early stage and taking appropriate measures to fix them.

## Comparison of Well Test to Theoretical Limits and Target Values

Users of a rod pump control system have the ability to use information from different parts of the production operation to evaluate the state of the beam pumped wells and related production facilities. The well test information can be compared to the calculated fluid production of each well, and this total from the wells (feeding a particular facility) can be compared to the actual metered sales from that facility.

## Notification of Wells Operating Out of Parameters Based on Artificial Lift Analysis

Beyond exception notification from RPC parameters, the rod pump control system provides notification and alarms based on the analytical calculations performed within the host software portion of the rod pump control system.

## Early Detection of Changing Wells Due To Automation

Alarms can be programmed to alert users that a beam well has begun to run too long or not long enough. The user can even be alerted after hours through call-out programs that can page or call with information about the alarm.

## Routine Management and Reporting

The rod pump control system provides historical reports and graphs that represent normal operating conditions for each rod pumped well. Since this data is a part of an overall database, it can be used for calculating accurate production data. The installation of a comprehensive rod pump control system (and operating by exception) will redirect manpower to better focus on corrective and optimization measures. This prioritizing of

operations staff time and redirection of the existing personnel to work on immediate needs is effectively equal to hiring additional staff.

Typically, effective manpower improves beyond the pre-optimization application to a point where this (effective manpower) can offset new expenses to maintain wellsite RPC equipment.

## ***Efficiency in Field Operations***

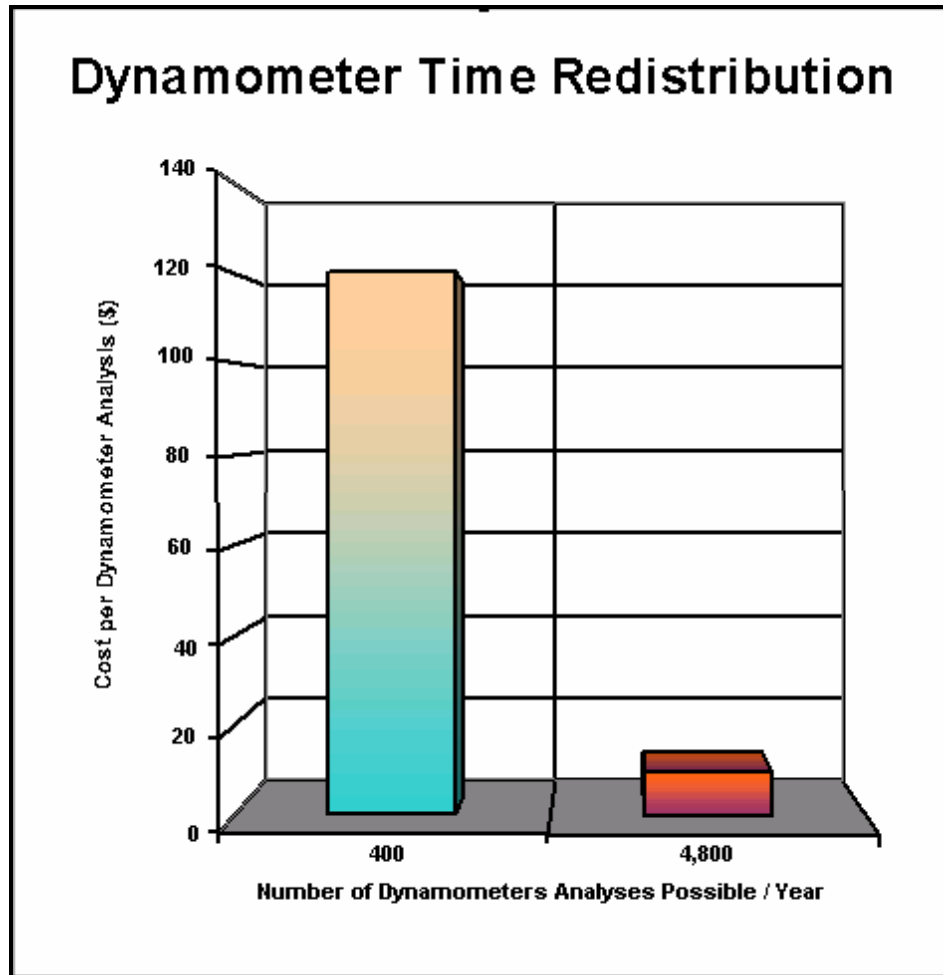
### **Reduced Windshield Time**

Data from each rod pumped well is displayed by the host software in the production office and is presented in a way that facilitates understanding the condition of a large number of wells. Companies that use a complete rod pump control system have found that they can substantially reduce the time necessary for someone to visit and personally inspect each well. Wells still need to be visited, but site visit frequency can be reduced substantially, which frees personnel for priority problem solving or other proactive activities. From past experience, site visits to each well have been reduced from daily to weekly or monthly, depending upon the operating philosophy of individual companies.

Two examples of cost reduction in “reduced windshield time” include: 1) more effective dynamometer collection and 2) more effective fluid level collection.

### **More Effective Dynamometer Collection**

Assume that a well analyst can make 400 “on site” dyno runs per year, or an average of about eight surveys per week. Assume the total cost of dynamometer collection for one year is \$48,000 or \$120 per dyno survey. Further, assume that the same well analyst can analyze 100 wells using dynamometer surveys gathered by the optimization software in one week. At 12 times faster collection pace per year or 4,800 dyno surveys, and using the same \$48,000 annual survey cost, this would equate to a per dyno cost of \$10 ( $\$48,000 / 4,800$ ). Instead of analyzing 400 wells in a year’s time, simple math dictates that 4,800 dyno surveys can be taken using the rod pump control system during the same one-year period.

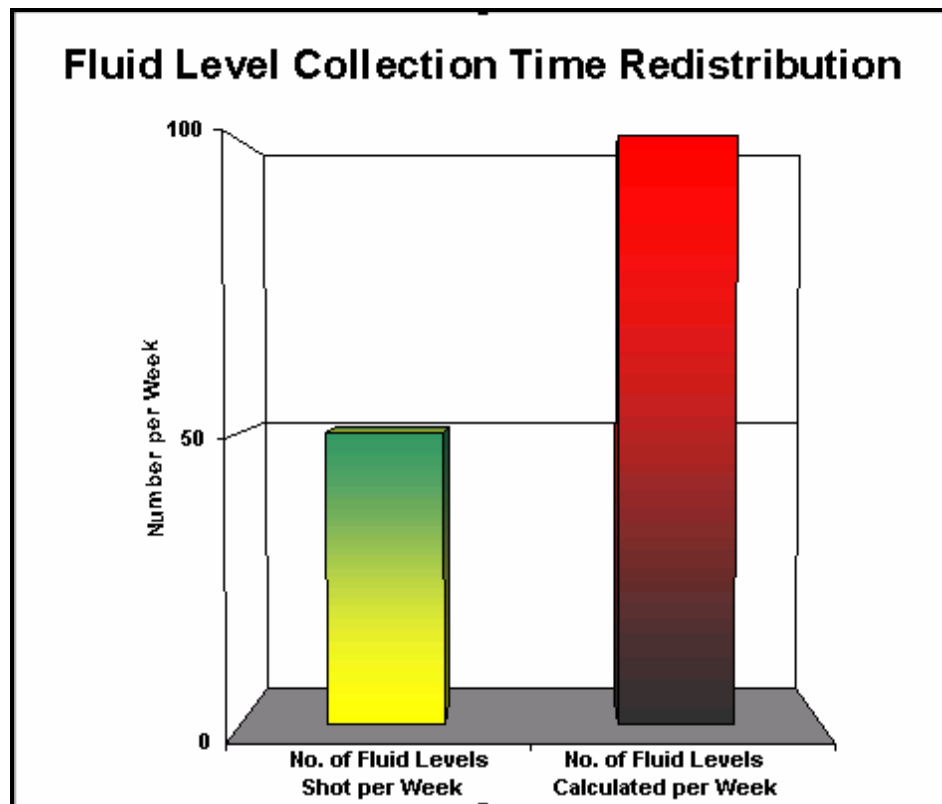


The graph depicts this example as a one-year phase-in redistribution of a well analysts' time. The real advantage of this example is time redistribution, which could then take the form of 1) more analytical time for optimizing lift equipment, 2) proactive maintenance of RPCs, and 3) attention to those remote or "low impact" wells, not previously covered by operating personnel.

Often, just the collection of well data on so-called "low impact" wells will reveal inappropriate operating practices, which can present upside opportunities, dramatically reversing the prevailing perception of remote wells or fields.

### More Effective Fluid Level Collection

Assume that a well analyst or lease operator can shoot 10 fluid levels per day and the cost is \$17.50/hour. Over one year, the total fluid levels collected would cost approximately \$33,600 or about \$14 per fluid level collected. Assume that 100 calculated fluid levels per week are collected by using calculated fluid levels gathered by the rod pump control system host software. Over a one-week period, twice as many fluid levels are collected. Therefore, the fluid level collection cost would drop to about \$7 each.



Assuming the same one-year phase-in as before, the graph depicts the relative savings or time redistribution. This redistribution of time could be better utilized for optimization of lift equipment.

## ***Alarm Notification and Management***

### **Reduce or Eliminate Answering Services**

The rod pump control system host software is integrated with current state-of-the-art call-out systems. These call-out systems take over the role provided by the answering services. An answering service typically only helps in calling people when problems are detected by automation systems. Rod pump control systems not only provide problem detection, but also provide more specific information regarding the cause of the problem, enabling field personnel to make improved decisions in case of emergencies. Using the rod pump control system, personnel can also take corrective action from their homes.

### **Reduce or Eliminate 24 Hour Duty**

An operator can be paged or called after hours because of an alarm and be given information about the problem. More than that, the operator does not need to leave his home to get detailed information about what is happening at the field. He can use the rod pump control system to connect to the field system remotely and see this information.

## ***Comprehensive Power Management System to Reduce Electrical Costs***

For almost all oil fields, electrical costs account for a substantial percentage of the operating costs. Because of the flexibility in configuration and various optimization tools, operating companies have used the following solutions to help reduce their electrical costs:

- By using the information provided by the rod pump control system, scheduled shutdown of intermittent pumping wells during peak power demand can optimize power consumption, saving considerable expense. Customized startup of rod pumped wells can aid in controlling spikes in power consumption after a power shutdown has occurred. In essence, this becomes a reverse peak shaving scheme to reduce power consumption during general peak usage.
- The host software can be used to ensure power utilization at any given time does not cross a certain threshold, thereby benefiting both the operating company and the power company.

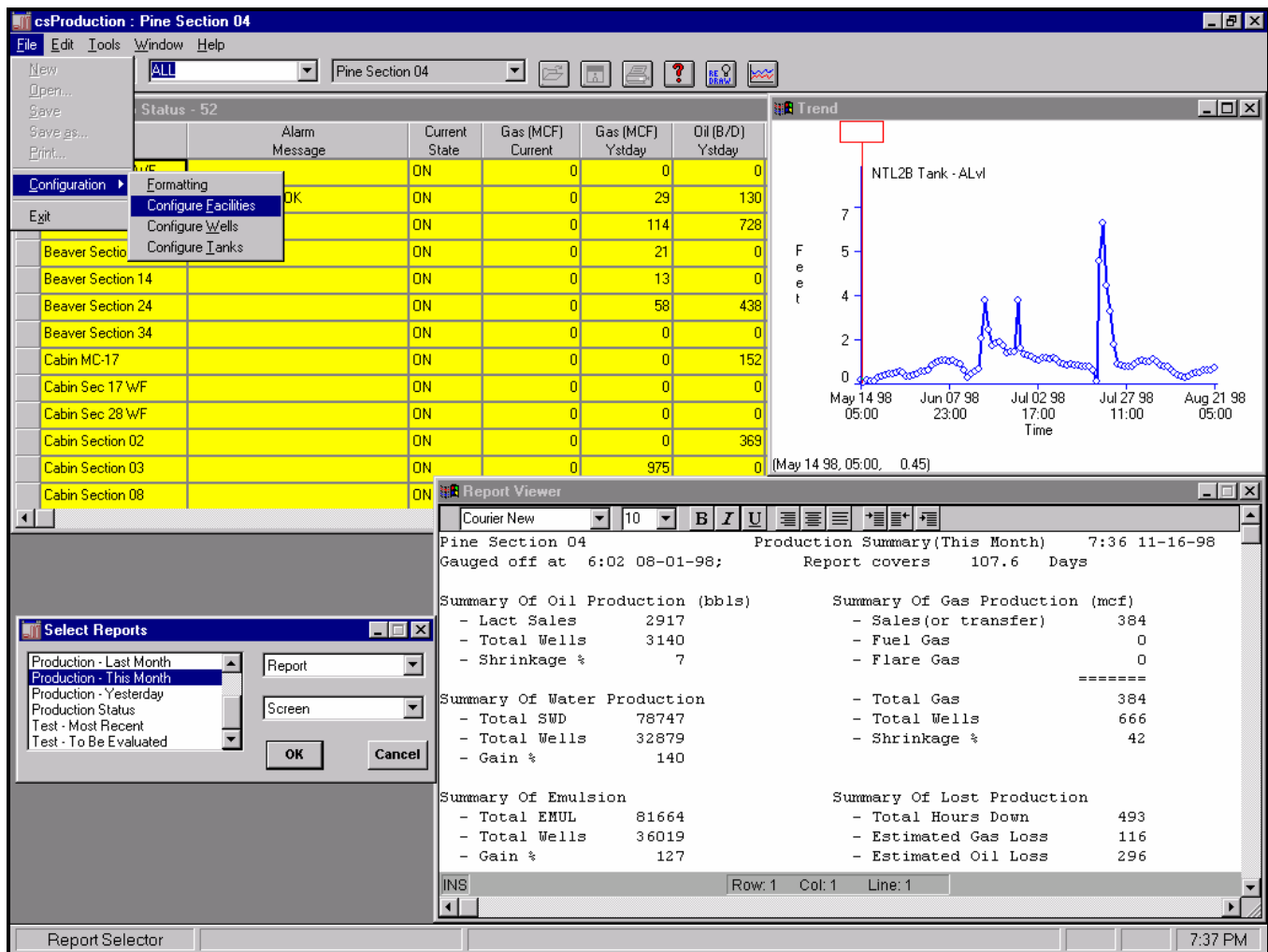
## ***Advanced Field Control Reduces Fluid Spills and Loss Prevention***

Because the rod pump control system is a part of an integrated field system, field wide control is available that is usually not present with typical SCADA systems. For example, it includes several standard control features for a rod pumped field, such as shutting down wells when tank levels are exceeded.

Because of this advanced capability, the operator has a higher level of confidence in detecting leaks or high tank levels and thus avoiding the costs associated with clean up of oil or salt water spillage. The operating company also spends less time addressing issues with landowners, land men, lawyers, and negotiators.

## ***Daily Production Reporting***

A comprehensive daily production report is provided from the rod pump control system. This report displays estimated production based on the downtime and the last known good well test of each well, shrinkage analysis by comparing the tested production to sales meter readings, and estimated lost production due to downtime of rod pumped wells.



Current information about daily, weekly, and monthly field and well production can be displayed. The production summary report can be obtained **daily** for different areas of the field or the whole field. Based upon the information presented in the production summary report, field management and personnel can better optimize their resources and prioritize which areas need attention.

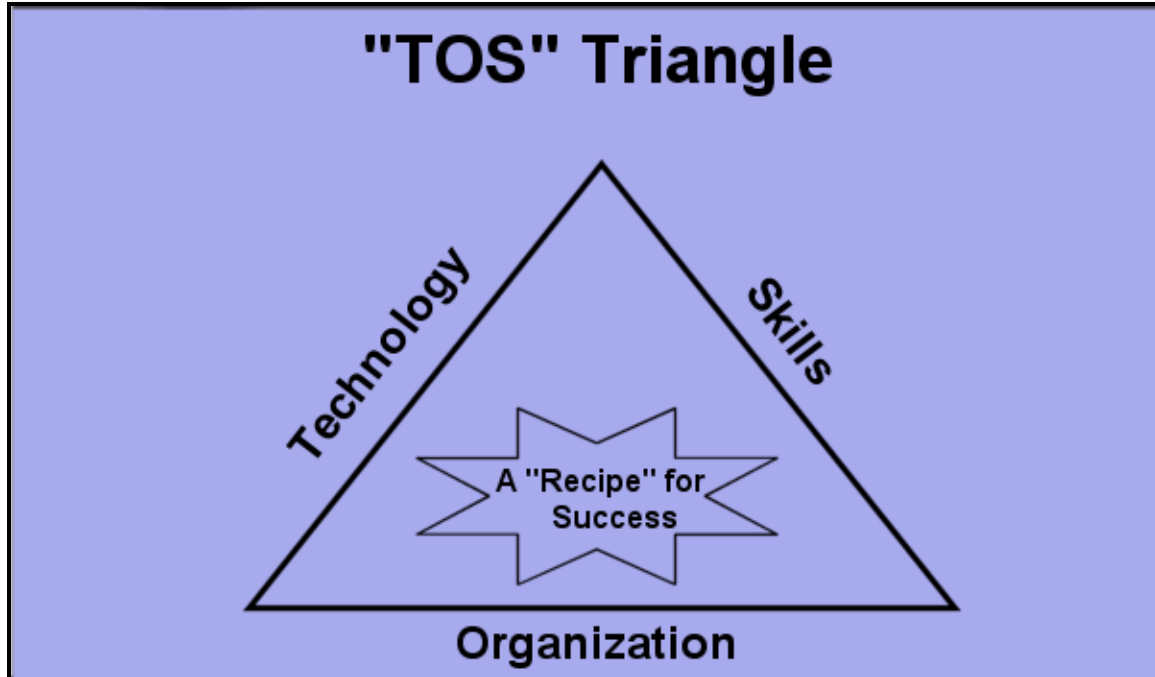
## ***Proactive Maintenance versus Reactive Maintenance***

Since the rod pump control system helps identify problems before they actually occur, field personnel can be proactive when scheduling field maintenance work. For example:

- Tubing anchors that are not holding, do not have enough tension, or that are slipping can be identified and tagged for immediate correction. Such proactive maintenance will prevent actual production losses, rod and tubing "friction" failures, and possible casing leaks.
- Daily examination of data for gearbox overloads or rod string overstress can prevent expensive failures through proactive correction and/or optimization.

## Conclusion

Implementation of a comprehensive rod pump control system will impact the entire operation of a rod pumped oil field. The following diagram shows the relationship between technology, skills, and organization:



The benefits described are always a result of the combination of changes in production operations in all three of these areas. It may involve changes in job roles and responsibility for field personnel. Note that the "foundation" of the triangle is the **Organization**.

# The eProduction Solutions Line of Rod Pump Controller Solutions

eProduction Solutions is the industry leader in providing RPCs with tens of thousands installed and operating worldwide. eP's RPCs operate a sucker rod pumping system in the most efficient way while monitoring the system for any possible problem.

## ***CAC 8800 Rod Pump Controller***

The **CAC 8800** RPC is easy to use by field operating personnel. The local wellsite display provides readily understood messages related to pumping system conditions. The keyboard allows users access to dedicated keys for important functions, e.g. "CLEAR ERRORS", etc. No computer codes, special skills, or additional equipment is needed.



The firmware is backward compatible with all previous CAC RPC models (**8500/8650/8700**) and central host software systems – providing turnkey solutions for every beam pumping field.

### **Designed for Reliable Operations**

- Conformally coated boards provide extra protection from operating conditions such as sour gas
- Wide voltage input operating range protects the RPC against field power spikes and "brown out" situations
- Protection from lightning and other transient voltage events

### **Easy to Use**

- Easily understood messages and simple to use keypad. No additional equipment needed for RPC configuration or parameter display.
- Automatic setup for many well applications.
- Operator selectable set points and action for each fault condition.
- Built-in traveling valve and standing valve check capability.
- Parameters and data protection from power loss.

## Modular Design for Upgrades

- Multiple operator interface options.
- Multiple auxiliary I/O options.
- Field communications and I/O options.
- An optional dual channel RS-232-485 serial expansion card for scanning other field devices.

## Standard Features

- Recognition of changing well inflow characteristics “on the fly” to maximize production and minimize runtime.
- Multiple control methods available for differing pumping conditions.
- Configurable load based alarms – high load, low load, low load span, and low average load. Low average load can be used in heavy oil situations where “rod float” causes low load alarm problems.
- Algorithm to handle “inoperative pump problems” caused by trashy fluids or viscous crude.
- Pump up delay timer – eliminates immediate pump off caused by incomplete pump fillage following well idle time.
- Cycle and run-time buffers for easy access to historical data.
- Card buffers – access to event cards and several cards leading up to the event .

## Unique Features

- Air Balance Control option automatically balances air balance pumping units.
- CDPD compatible.
- Peak Energy Control option can stop pumping operation during periods of peak energy demand/cost.
- Motor Restart Protection prevents motor failure when moisture condensation is present on motor windings.
- Controls virtually any pumping unit configuration, including improved geometry units, long stroke units, and two-stage pumps.
- Power fail recovery feature automatically pumps wells down when power is restored.
- Programmable I/O for unique monitoring (flowline pressure, casing pressure, stuffing box leak detector, etc.) and control applications.
- Inferred production determination for shallow wells allows measurement of total fluid production from each well. This data is stored for every pumping unit stroke, daily, and historically for 29 days.
- Automatic idle time adjustment feature allows the RPC to change the off-time between cycles as well conditions change.
- Control of two pumping systems operating in a single wellbore with one RPC.
- Stable operation in temperatures from –40°F to +185°F (-40°C to +80°C).

## ***Model 2000 Rod Pump Controller***

This controller has all the features and functionality of the **CAC 8800** RPC. This controller is meant to be a lower cost alternative to the **8800** RPC based on enclosure, user interface, and other optional features.



## ***ePIC Rod Pump Controller***

This controller was developed with all the features of the **CAC 8800** and the **Model 2000** RPCs plus a number of new functions as a part of eProduction Solutions mission to provide the best decision making opportunities for operators of rod pumped oilfields.

### **Exceptional Intelligence and Wellsite Control**

Expanded and enhanced technology found in the **ePIC** RPC:

- Wellsite alarms and system diagnostics
- Selected pumping system alarms based on host software analysis of well conditions
- Card area alarms for the detection of deep rod parts and downhole friction identification
- Wellsite valve checks and CBE determination available to host analysis systems
- Improved data storage and trending
- Enhanced data-logging function that allows any RPC register to be logged and used in application logic
- Programmable Intelligent Control Language (PICL) that provides the operator with flexibility to modify control logic to adapt to specific well conditions
- Inferred production for deep wells based on host software calculation of downhole pump stroke – without complex wellsite configuration
- Monitor only mode – provides surface dynamometer cards without regard to control setpoints or SPM range, ideal for monitoring pumping wells under Variable Speed Drive control
- Expanded alarms – host based alarms: gearbox torque, rod stress, pump efficiency, prime mover size, unit unbalance, load cell drift
- Hi-Hi, Hi, Low-Low, Low load alarms
- Simplified wellsite RPC configuration, data management, system diagnostics, and load cell calibration. Improved menu-driven interface for viewing dynamometer cards, viewing runtime information, and obtaining and storing valve check/CBE data
- Simple, three-step load cell or strain gauge calibration



## ***iBEAM Rod Pump Controller (Patent Pending)***

The addition of the **iBEAM** RPC adds a low-cost solution to eP’s family of rod pump solutions. This controller is meant to allow the benefits of eP’s RPCs to be applied to wells whose production has, in the past, not been sufficient enough to justify automated control. **iBEAM** features a simple cable-less installation, load and position technology, integrated host communications, wireless control, and low maintenance all in a completely self-contained, low cost unit. The **iBEAM** can be easily installed by attaching a built-in clamp to the pumping unit walking beam and connecting the communication module to the well-control panel. The **iBEAM** requires no cables, therefore there are no ditches to dig and more importantly, there are no cables to wear out. The RPC contains host communications, solar power supply, load and position sensors, and integrated intelligence to remotely operate rod pumped wells.

Many operators are reluctant to install RPCs on their low producing wells because of the capital, installation, and maintenance costs involved. Because of its wireless design, the controller is able to eliminate maintenance costs associated with cables to the load cell and position sensor. Additionally, the controller’s compact design provides savings resulting in a low-priced controller with high-tech capabilities. The advanced radio technology that is imbedded is used to control the well and relays operational data to a host-based software system for remote monitoring and detailed analysis. The radio also provides data to a hand held device for operators to use while visiting the wellsite.



The controller uses advanced strain gauge technology for load measurement and accelerometer technology for measuring polished rod position together as the most effective way to control rod pumped wells. The controller creates a dynamometer card that is used to identify pump-off conditions and other potential problems that can occur in a rod pumped well.

### **Filling the Need:**

Needs	iBEAM
Eliminate end device cables	No end device cables
Integrated SCADA communication	Integrated SCADA radio included
Proven technology to optimize wells	Load and position based technology
Cost effective solution	Solution cost under \$2000
Reliability	Technology currently used on 25,000 wells
Easy installation	Completely self-contained

## ***ePAC Rod Pumping System***

The **ePAC** rod pump control system goes beyond conventional variable frequency or speed drives. This solution incorporates Vector Flux Drive (VFD) technology for precision control of both speed and torque for optimizing rod pumped artificial lift systems. The ePAC has a proven track record of performance enhancements with conventional pumping units and long-stroke units such as the Rotaflex.

- Infinite speed control
- Independent up/down stroke speeds
- Reduces power consumption
- Eliminates excessive rod loads
- Provides an optional methodology that eliminates bridle separation from the polished rod
- Uses pump fillage algorithms to optimize production
- Maximum torque available from "0" to base SPM

Many conditions using conventional pumping units are particularly suited to slow SPMs. Heavy oil applications requiring steam injection, wells that produce sand, low reservoir pressure conditions, and high water cut wells are prime candidates for the **ePAC** solution. Where conventional speed controls have yielded inefficient results, the **ePAC** overcomes the problems of traditional control with variable speed and torque control.



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As the leading provider of oil and gas production automation systems, **eProduction Solutions**, based in Houston, Texas, pioneered the market for single-source automation software for producing oil and gas fields. This software is used by major oil and gas companies to run over 15,000 wells around the world.

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