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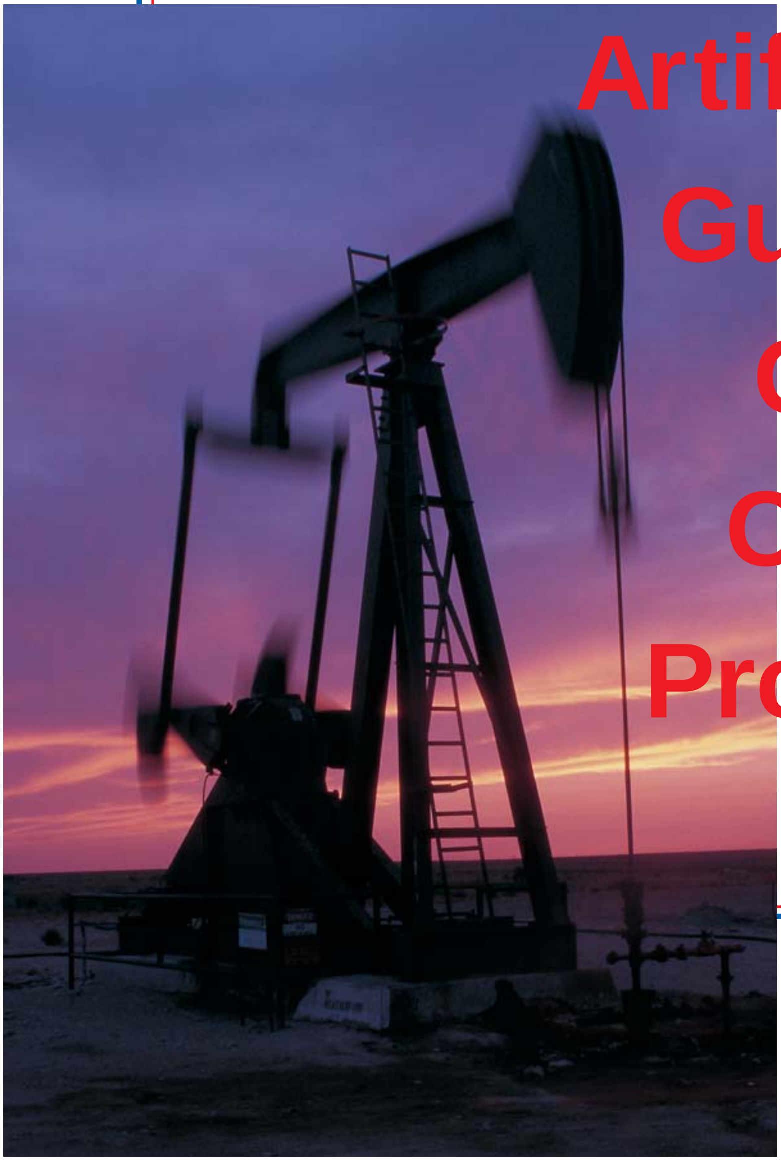
Artificial Lift Technology



Artificial Lift Guidelines Optimize Oil & Gas Production Results

‘Best Practices’ Reduce Well Problems

By Elton J. Smith
and Scott W. Long

MIDLAND, TX.–In 1996, Pioneer Natural Resources USA Inc. implemented a program to identify and implement “best practices” for its artificial lift and production operations in the Spraberry trend in the Permian Basin. With a broad goal of providing improved artificial lift guidelines to enable more efficient oil and gas production, the program has resulted in significant operational improvements and reduced equipment failures.

In 1998, two years after the program had been initiated, tubing leaks had been reduced by 61 percent, rod parts had been reduced by 35 percent, and pump repairs had been reduced by 7 percent. By 2002, failure reduction performance data showed even better results. Tubing leaks were down 85 percent (from 1.75 to 0.26 failures per well per year), rod part incidents had been cut in half (from 0.52 to 0.26 FPWPY), and pump repairs were reduced by 67 percent (from 0.46 to 0.15 FPWPY) after six years of program implementation. This was partly the result of additional failure reduction processes that had been initiated since 1998.

As these results demonstrate, a companywide best practices program can help operators continuously improve the efficiency and performance of oil and gas production, providing both operational and economic benefits.

Of the more than 3,200 producing wells that Pioneer operates in the Spraberry trend, 150 wells in the Preston Spraberry Unit (PSU) were selected in 1996 for evaluation in the best practices program. There were two unique groups of wells. The first group consisted of 87 wells that had been in operation before the program was initiated, and were equipped with used rods and used tubing in unknown condition. The remaining 63 wells were in the second group, and all had been completed in 1996-97 during the first two years of the program.. They had new rods, tubing and other lift equipment. Five of the original 150 wells–two of the “existing” wells and three of the “new” wells–are no longer producing.

FIGURE 1

Tubing Rod and Pump Failures in PSU ‘Existing’ Wells (1994-2002)

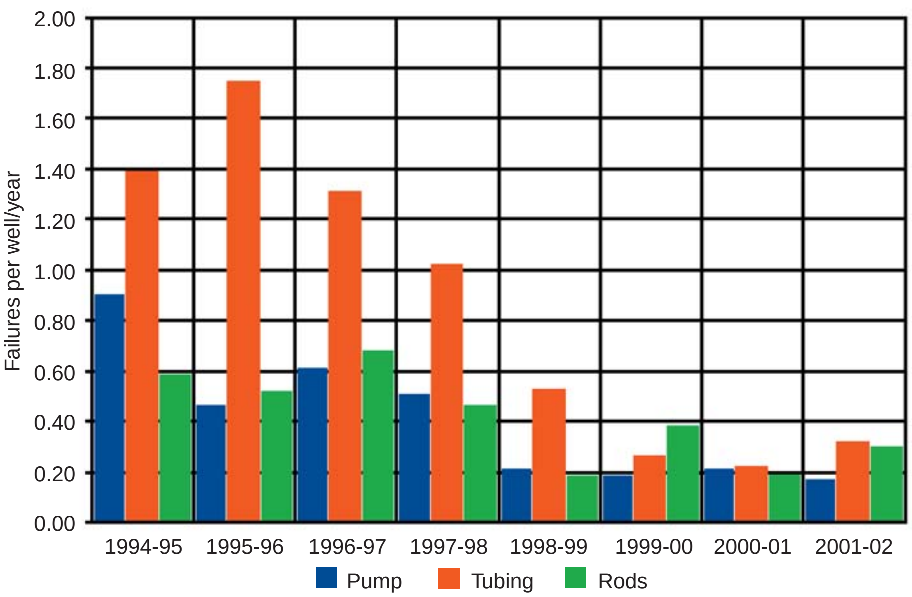
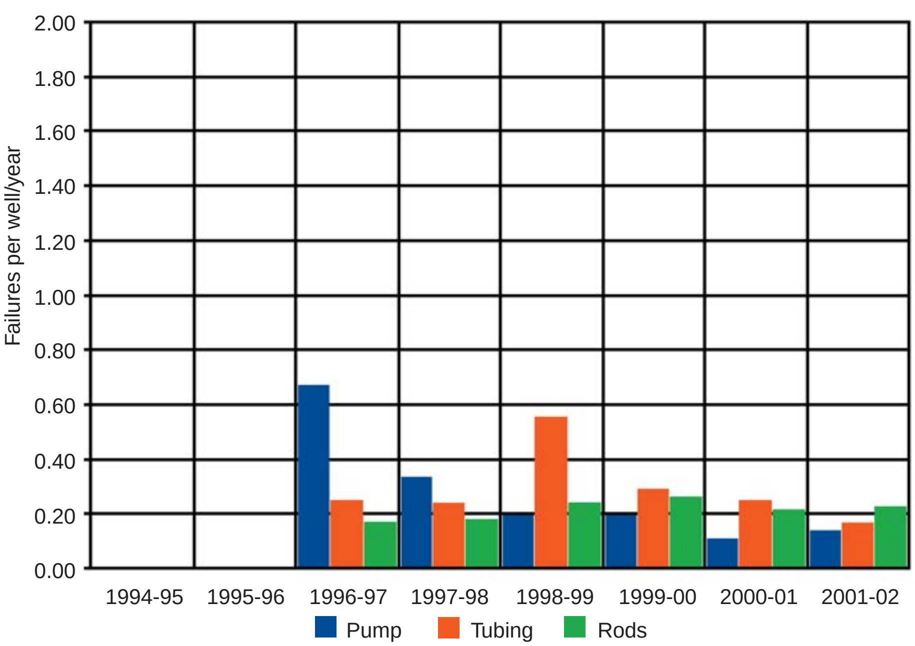


FIGURE 2

Tubing Rod and Pump Failures in PSU ‘New’ Wells (1996-2002)



Reduced Failures

Performance data shows that the best practices program reduced total failures by 72 percent in the group of existing PSU wells (Figure 1), and by 52 percent in the group of new wells (Figure 2). The second group of wells has shown the most consistent and lowest frequency of tubing leaks, rod parts and pump repairs.

The Preston Spraberry Unit is located in the southwest corner of Midland County, Tx. The Spraberry production interval is 7,000-8,700 feet. The average pump depth is 7,003 feet, and the average water cut has increased from 65 percent in 1999 to 72 percent today. Pumpjacks average seven strokes a minute with 86-inch stroke lengths. The average polished rod velocity is 1,204 inches/minute. The wells are almost evenly split between all-steel rod strings ($\frac{7}{8}$- and $\frac{3}{4}$ inch with $1\frac{1}{2}$-inch sinkerbars) and a combination of steel and fiberglass (1-inch fiberglass and $\frac{7}{8}$-inch steel with $1\frac{1}{2}$-inch sinkerbars).

An average of 882 feet of internally plastic coated (IPC) tubing is in 100 wells (the tubing in the other 45 wells has no internal coating). In 2002, the wells had an average of 400 feet of sinkerbars, compared to 375 after 1998. There was an additional 200 more feet of sinkerbars on average in wells with fiberglass rod strings than in all-steel well designs. The production tubing for all wells is $2\frac{3}{8}$ inches inside 4½ inch casing. Tubing anchor catchers are set below the seating nipples, and 90 percent of all seating nipples are located above the perforations. About 80 percent of the downhole pumps are insert type with 1¼-inch diameter plungers.

When originally implemented, the Preston Spraberry Unit best practices failure reduction program consisted of optimizing well performance, redesigning rod strings and improving run time control. Well optimization included diagnostic well analysis on existing wells and predictive analysis for future wells, and analyzing artificial lift designs to match producing rates with equipment by optimizing plunger diameter, strokes per minute, stroke length, tubing anchor tension, and downhole gas separation.

Rod string redesign included removing the bottom 450 feet of ⅞-inch guided rods, controlling downstroke buckling by installing sinkerbars, and balancing stress loading at the top of each rod taper. Sinkerbars had a profound positive effect on the performance of the tubing failure frequency. However, sinkerbars could have been used more efficiently in the wells to further improve the tubing failure frequency. In addition, well site diagnostic analyses were routinely conducted after several months of operation to evaluate initial rod string designs to improve future designs.

Pump-off controllers (POCs) were installed to manage production rates, optimize run times and monitor equipment performance. Improved control of required run times also included extensive training of all field personnel involved with wells equipped with POCs. As of August 2002, 51 of the 145 wells were equipped with POCs. This proved a very successful optimization technique that dramatically lowered the rate of tubing failures. This was especially true when combined with sinkerbars, but installing pump-off controllers was an efficient way to lower tubing failure with or without sinkerbars in problem wells.

Additional Enhancements

Additional enhancements have since been made in a number of areas, including the tubing, rod string, pump, pump-off control and chemical programs. For example, the tubing testing program evolved from hydrostatic tested on location during the first two years, to off-location electronic inspection, and finally to wellhead scanalog.

Hydrostatic testing involved locating the tubing leak, replacing 10 joints of tubing both above and tubing below the leak with new or yellow band (0-15 percent wall loss) tubing. Electronic inspection involved locating the leak, removing the bottom 100 joints of tubing and sending them to a remote yard for electronic inspection, where all tubing with greater than 30 percent wall loss (green or red band) was replaced with new or yellow band tubing. Eventually, electronic inspection was replaced with a wellhead scanalog of the bottom 100 joints.

In addition, all pulling units were instructed to shut down, if needed, and wait for replacement tubing to arrive to ensure that all replacement tubing was installed in the desired location in the new tubing string. The first electronic inspection resulted in replacing 40-50 of the bottom 100 joints, while the second and subsequent electronic inspections resulted in replacing no more than five of the bottom 100 joints.

Predictive software was used in the first two years of the program to design rod strings with sinkerbars so that 70 percent of the bottom negative stresses were isolated in the sinkerbar section. In 1999 the predictive software design process was improved by designing wells so that 100 percent of the bottom negative stresses were isolated in the sinkerbar section.

Many of the wells contained rods from numerous manufacturers that were equivalent to Norris-54 grade-D rods. The best practices program improved rod consistency by ensuring that all rods were supplied from a single manufacturer, equivalent to Norris-78 grade-D. In addition, instead of visually inspected all rods removed from T&A wells as had been the practice in the past, all rods were electronically inspected off location.

Pump program improvements cover balls and seats, pump barrels, pump plungers, mechanical sand control, shear devices, seat plug designs, and cage replacement. Since 1999, the program has required titanium carbide balls and seats with tungsten carbide metallurgy instead of balls and seats with alloy metallurgy, and on selected wells requiring solids control, the ball and seat patterns were changed to a California-style instead of a conventional pattern.

Pump barrel designs are stainless steel-chrome, except when operating in corrosive well bore fluids, when the design changes to a brass nicarb barrel. In addition, pump installations were improved by increasing the plunger-to-barrel fit to 0.006 inch, from 0.003 inch initially.

Over the last four years of the program, pump plungers design was improved by incorporating pressure-actuated plungers and ring groove-style plungers to help remove solids. Previously, all new pumps had been installed with a conventional-style plunger with Monel pins. The length of pump plungers was maintained at six feet.

In addition, a sand protection program was initiated that incorporates mechanical finned sand shields, the ⅝-inch grade-C rod subs that had been used as shear devices were replaced with on-off tools, conventional traveling valve seat plugs were replaced with compression-style seat plugs, and a program was initiated to systematically replace all traveling and standing valve cages after two years of service.

Optimization Efforts

Pioneer's operations philosophy in its Permian Basin asset area is to combine production optimization with automation to maximize shareholder value and maintain a competitive advantage. Consequently, at the same time it was implementing the best practices program for the 145 Preston Spraberry Unit wells, Pioneer also began working to optimize the performance of all

FIGURE 3

Spraberry Failure Frequency (1996-2002)

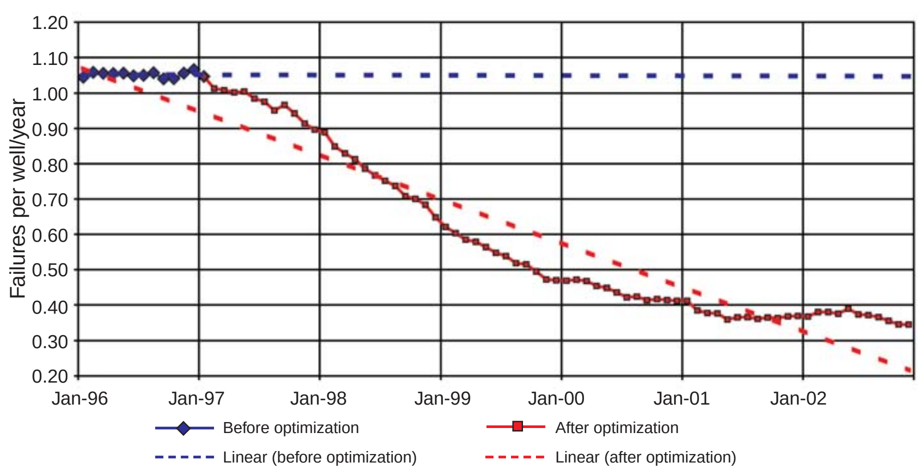


TABLE 1

Type of Failure	PSU Best Practices Project (% Reduction)	Spraberry Trend Area Optimization Project (% Reduction)
Program Results		
Tubing Leaks	85% Reduction	63% Reduction
Rod Parts	50% Reduction	55% Reduction
Pump Repairs	67% Reduction	81% Reduction
Total Failures	75% Reduction	66% Reduction

the 3,221 wells it operates in the Spraberry trend area. The result was a dramatic reduction in the frequency of well failures (Figure 3).

Comparing performance data from 1995 (one year before the optimization began) to 2002, the optimization efforts reduced tubing leaks by 63 percent, rod parts by 55 percent and pump repairs by 81 percent. In all, total failures for all Pioneer's wells in the Spraberry trend area were reduced by 66 percent (Table 1).

Pumps averaged 10 strokes/minute in 1995, with pumps running 24 hours a day. In 2002, pumps averaged 6.7 strokes/minute, with run times controlled by POCs, time clocks or percentage timers. POCs were installed on 1,079 wells, telemetry supervisory control and data acquisition was used on 689 wells, and standalone controllers were installed on 390 wells. The average pay-out for these systems was of 88 days. The benefits included reduced electrical consumption, fewer equipment failures, and a slight oil production increase. The main factors for these kind of successful fieldwide results are:

- The training that all field personnel received in overall field operations;
- The competency of the company's technical well analysis department;
- The accountability that was applied to all personnel, and the acceptability expected from all levels of management;
- Mandatory vendor support; and
- The proper application of POCs, sinkerbars and other optimization techniques, and maintaining updated databases on well failures and production.

Training is the number one tool for a successful optimization program. Without training, field personnel will not believe in optimization. It is through proper training that all employees involved in a program begin to understand that they are part of a concerted effort and realize the importance and benefit of the optimization program.

No optimization effort can succeed without a technical department that can effectively analyze every well and recommend changes to maximize efficiency from the well bore to the bank. The department must be comprised of respected technical personnel and must be supported by upper management.

Accountability among personnel elevates concern for substandard performance and leads to competition. Production plots and failure graphs are critical tools for measuring accountability by area. In addition, optimization efforts will be accepted only with the support of all levels of management. Understandably, most oil field personnel are reluctant to initiate improved operations methods, which means that management must initiate the directive. Documented improvements from past statistics will result in permanently improved operating mindsets and more efficient operations.

Finally, vendors and support companies must participate for an optimization program to succeed. Accountability for their performance results in a continual awareness of vendors' responsibility for contributing to the overall success of the program.

IPC Tubing

One aspect of the program was to compare IPC tubing with non-internally coated "bare" tubing to discern which was more effective at lowering tubing failures and which was more economical, with the ultimate objective of determining whether IPC should be a standard part of the optimization work. The cost of IPC is significantly higher than for bare tubing.

Tubing leak performance data from a sample of 62 wells from the Spraberry trend area and an additional 152 Preston Spraberry Unit wells were examined. Based on the findings, the conclusion is that while IPC can be beneficial, it should not be the first step in optimizing wells. IPC should be reserved for problem wells, where its application is most beneficial. It is a valuable tool, but it must be installed correctly and in proper amounts for its full potential to be achieved.

Polycore tubing has been installed in 20 of Pioneer's problem wells in the Spraberry trend area, and has yet to experience a tubing failure. Polycore tubing may be the closest thing to eliminating tubing failures. However, the down side of polycore tubing is the reduction of the inside diameter, which limits the size of the rods and pumps that can be installed. Polycore tubing is cheaper than IPC and it should be considered as a good alternative.

After six years of best practices in the Preston Spraberry Unit and the Spraberry trend area, the results offer strong encouragement for operators to initiate and monitor best practices programs in their field operations. For companies that already have programs in place but have not seen comparable results, the programs should be evaluated to make certain they contain appropriate procedures, such as the specific procedures used on the Spraberry wells.

Optimal results are realized when a program is initiated on newly drilled wells with new tubing, rods and sinkerbars, but the benefits of reducing tubing leaks, rod parts and pump repairs can also be substantial on older wells. ❒

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