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Pioneer Natural Resources 10 Year “Best Practices” Program

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Pioneer Natural Resources 10 year “Best Practices” program

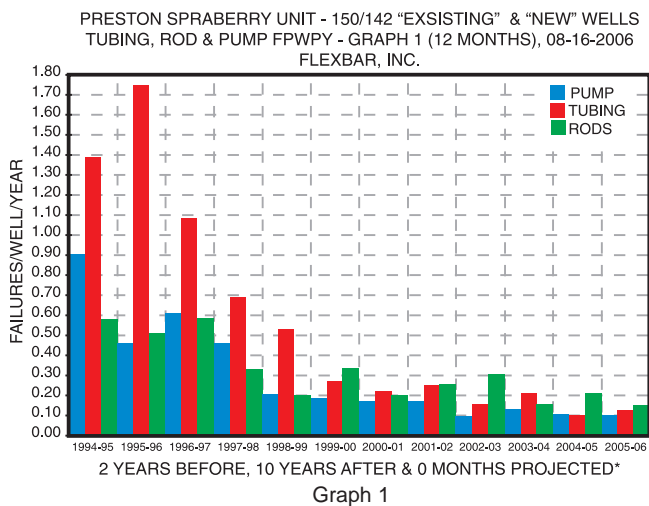
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August 17, 2006, marked the 10th anniversary for the Pioneer Natural Resources Preston Spraberry Unit (PSU) “Best Practices” Failure Reduction Program. This program was initiated during the third quarter of 1996, when Pioneer Natural Resources (then Parker & Parsley) realized that they were experiencing high downhole failure rates in the Preston Spraberry Unit.

This 10-year partnership between Pioneer Natural Resources, Flexbar Inc., Norris Rods, Tommy White Supply and Kel-Tech has resulted in a significant reduction in downhole failures and a huge savings in operational costs for Pioneer Natural Resources.

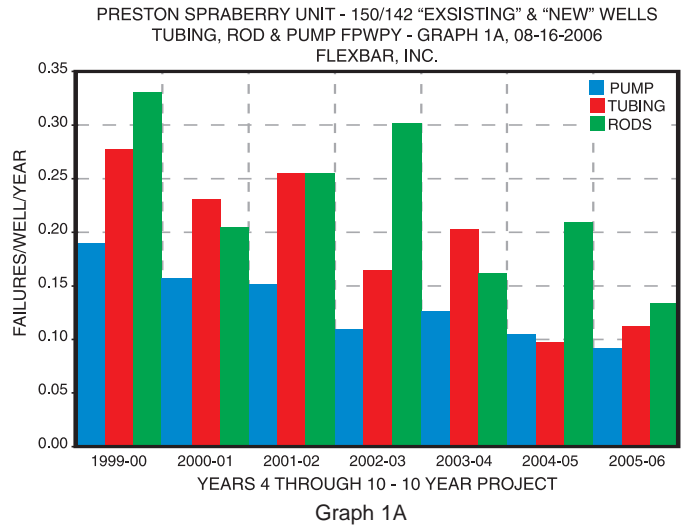
The 10-year Performance (failures per well per year – FPWPY) for this 150 well, PSU “Best Practices” program is displayed in **Graph 1** and is listed below:

Tubing Leaks	94% Reduction
Rod Failures	75% Reduction
Pump Failures	80% Reduction
Total Failures	88% Reduction



The 10-year performance for this PSU “Best Practices” 150 well project utilizing 2006 failure costs of \$16,000 per tubing leak; \$9,000 per rod failure; and \$8,000 per pump failure is estimated at \$17.9 million savings in downhole failures. This is an average savings in downhole failures of \$1.8 million per year.

While 71 percent of the reduction in total failures occurred during the first four years of this program, there was still a 58 percent reduction in total failures during years 4 through 10. Refer to **Graph 1A**.



How the program started

Starting in the third quarter of 1996, several existing producing wells in the Preston Spraberry Unit were identified as high failure rate wells. The ranking process for these high failure rate wells started with those wells with the highest failure rate and ended after a total of 87 existing wells were selected for this program. These 87 existing wells became the first group of wells selected to initiate this Best Practices Program.

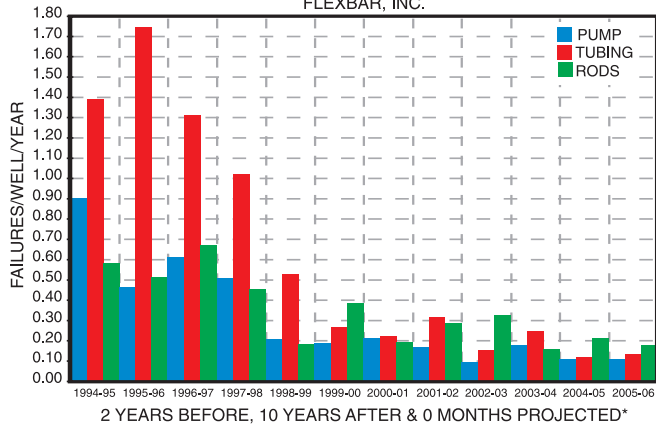
The performance benchmark was established for these 87 existing wells by calculating the failure rate for the 12 months prior to initiating this Best Practices Program. The unit of measurement utilized to establish this benchmark was failures per well per year (FPWPY). This performance benchmark for these 87 existing wells is listed below by failure and total failures:

Tubing Leaks	152	1.75 FPWPY
Rod Failures	45	0.52 FPWPY
Pump Failures	40	0.46 FPWPY
Total Failures	237	2.73 FPWPY

An analysis of the two years prior to the initiation of this Best Practices Program indicated that the frequency of tubing leaks for these 87 existing wells was increasing and quickly approaching two tubing leaks per well per year (FPWPY). The frequency of total failures was also very high — close to three failures per well per year (FPWPY) with no indication of a reduction in total failures in the future.

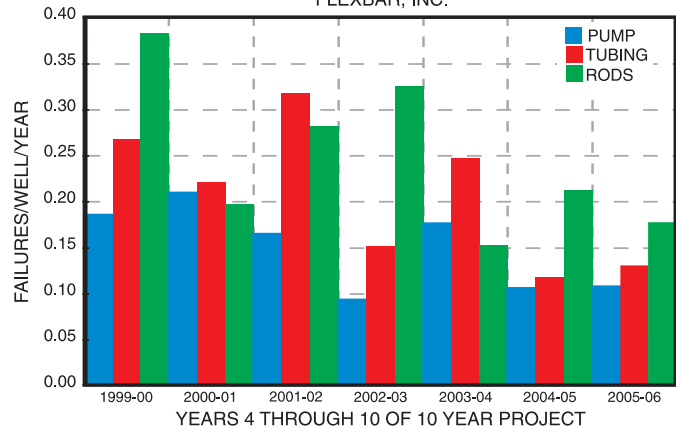
The number of tubing leaks for the following year was projected at 174 tubing leaks using a failure

PRESTON SPRABERRY UNIT - 87/85 "EXISTING" WELLS
TUBING, ROD & PUMP FPWPY - GRAPH 2 (12 MONTHS), 08-16-2006
FLEXBAR, INC.



Graph 2

PRESTON SPRABERRY UNIT - 87/85 "EXISTING" WELLS
TUBING, ROD & PUMP FPWPY - GRAPH 2A, 08-16-2006
FLEXBAR, INC.



Graph 2A

frequency of 2 tubing leaks per well year. The total cost of repairing these 174 tubing leaks was estimated at \$957,000 based on a cost of \$5,500 (1996 dollars) per tubing leak.

The decision was made to formalize a "Best Practices" program utilizing these 87 existing wells because tubing leak failures were the highest frequency failure and the most expensive failure to repair. Each of these 87 existing wells was operating with artificial lift equipment installed or replaced since initial completion of these wells.

What is a Best Practices Program?

The "Best Practices" program that was initiated utilizing these 87 existing wells was developed to ultimately reduce downhole failures. The best general definition of this "Best Practices" program involved the following steps:

1. Optimize individual well artificial lift performance
2. Monitor and record all downhole failures
3. Challenge continuous improvement at all levels
4. Involve well technicians, rod, pump, chemical and sinkerbar suppliers in program
5. Receive support from Pioneer management

This "Best Practices" failure reduction program more specifically, involved the following;

1. Complete an individual well diagnostic analysis
2. Individual well optimization using predictive software and / or dynamometer analysis
3. Re-evaluation of rod string designs for balanced loading at each taper
4. Installation of sinkerbars to reduce buckling during the downstroke
6. Installation of pump-off controllers
7. Re-evaluation of each downhole failure following each failure

Success of the original 87 existing wells

The initial success of these original 87 existing wells led to the decision to include an additional 63 newly drilled wells to this "Best Practices" program. Each of these newly drilled wells were wells operating

with artificial lift equipment in new condition, installed during initial completion of these wells. This fact proved to be very important to future failure reduction performance.

The addition of these 63 newly drilled wells increased the total well count for this "Best Practices" program to 150 wells. The decision was made to not add additional wells to this program and to monitor the performance of these 150 wells to determine the success of this "Best Practices" failure reduction program.

The original 87 existing wells

The 10 year failure reduction performance (FPWPY) of the 87 existing wells is displayed in **Graph 2** and is listed below:

	<u>95-96</u>	<u>05-06</u>	
Tubing Leaks	1.75	0.13	93% Reduction
Rod Failures	0.52	0.18	65% Reduction
<u>Pump Failures</u>	<u>0.46</u>	<u>0.11</u>	<u>76% Reduction</u>
Total Failures	2.73	0.42	85 % Reduction

While the majority (69%) of the reduction in total failures for these 87 existing wells occurred during the first four years of this program, there was still a significant reduction (50%) in total failures during years 4 through 10. Refer to **Graph 2A**.

The 63 newly drilled wells

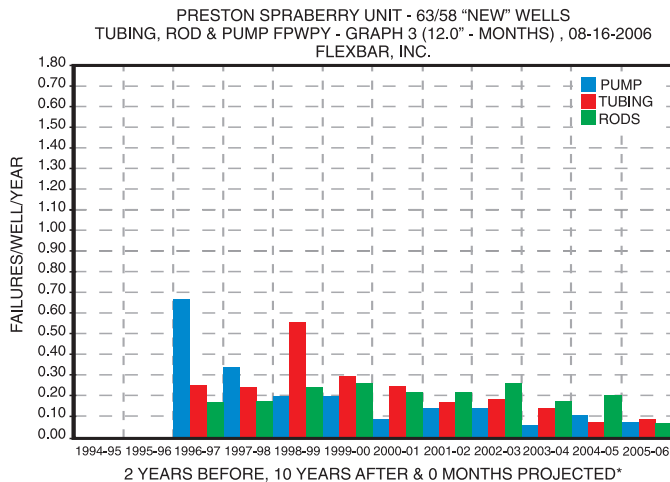
The 10-year failure reduction performance (FPWPY) of the 63 newly drilled wells is displayed in **Graph 3** and is listed below:

	<u>96-97</u>	<u>05-06</u>	
Tubing Leaks	0.25	0.09	64% Reduction
Rod Failures	0.17	0.07	59% Reduction
<u>Pump Failures</u>	<u>0.67</u>	<u>0.07</u>	<u>90% Reduction</u>
Total Failures	1.09	0.23	79% Reduction

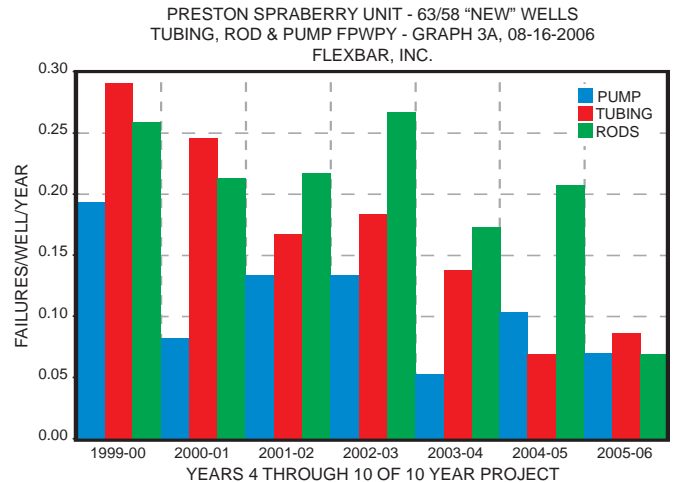
It is interesting to note that for these 63 newly drilled wells 70 % of the reduction in total failures occurred during the years 4 through 10. During the first four years, there was a 31% reduction in total failures. Refer to **Graph 3A**.

Total program performance

The 10 year failure reduction performance (FPWPY) for this 150 well, PSU "Best Practices" program



Graph 3



Graph 3A

involving the 87 existing wells and the 63 newly drilled wells is listed below:

	<u>95-96</u>	<u>05-06</u>	
Tubing Leaks	1.75	0.11	94% Reduction
Rod Failures	0.52	0.13	75% Reduction
<u>Pump Failures</u>	<u>0.46</u>	<u>0.09</u>	<u>80% Reduction</u>
Total Failures	2.72	0.33	88% Reduction

The 10 year performance for this PSU "Best Practices" 150 well project utilizing 2006 failure costs of \$16,000 per tubing Leak, \$ 9,000 per rod failure and \$ 8,000 per pump failure is estimated at \$17.9 million savings in downhole failures. This is an average savings in downhole failures of \$1.8 Million per year.

The Benefits of a Best Practices Program

The greatest benefit of this "Best Practices" Program was a \$17.9 Million savings in downhole failures during the first 10 years of this failure reduction program. Please note that these savings was calculated using 2006 failure costs.

Additional benefits of a "Best Practices" Program are that you can monitor and document performance by the following:

1. Total project
2. Existing wells & new wells
3. Downhole failure & failure cost; (tubing leak, rod failure or pump failure)

You can also market your project performance to the following:

1. The operating company management and field personnel
2. All supporting vendors
3. The oil and gas industry

The 6% - 8% premium

Two salesmen were attending the Northern Southern Communications Annual Sales Meeting. These salesmen were long time friends and had joined Northern Southern Communication the same month many years ago. One salesman asked the other "How do you sell the same communication equipment I do at a 6% to 8% premium and beat me every year in sales?" The other salesman responded "That 6%-8% premium isn't for our communication equipment; it's for me, my relationships with my clients and the extra service I provide to my clients."

A "Best Practices" program can provide that 6% - 8% premium to your client. A "Best Practices" program will represent you, help establish your relationships and provide that extra service you provide to your clients that no one else can or will provide. 🧢



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