6 YEARS OF BEST PRACTICES BY PIONEER NATURAL RESOURCES IN THE PRESTON SPRABERRY UNIT AND THE SPRABERRY TREND AREA

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ABSTRACT

This paper is an update of a Southwestern Petroleum Short Course paper presented in 1999. This paper presents an additional 4 years of performance data from this ongoing "Best Practices" Program.

In the 1999 paper, failure reduction performance (FPWPY) after 2 years was as follows;

Tubing Leaks	Reduced 61 %	(1.75 to 0.69)
Rod Parts	Reduced 35 %	(0.52 to 0.34)
Pump Repairs	Reduced 7 %	(0.46 to 0.43)

In this paper, failure reduction performance (FPWPY) performance after 6 years is as follows;

Tubing Leaks	Reduced 85 %	(1.75 to 0.26)
Rod Parts	Reduced 50 %	(0.52 to 0.26)
Pump Repairs	Reduced 67 %	(0.46 to 0.15)

Additional failure reduction processes have been initiated since the original 1999 paper presented at the 46th Annual Southwestern Petroleum Short Course. This paper shows the results of implementing a company wide "Best Practices" program and demonstrates the benefits from an ongoing performance database able to project and evaluate future failure reduction performance.

SCOPE

The Petroleum Industry has adopted the term "Best Practices" to describe an efficient method of producing oil and gas. How you define this "method" is very subjective and is continually changing with the acceptance of improved and proven rod pumping knowledge. In the 1999 paper the term "Best Practices" was described using the phrase "Work in Progress".

After 6 years, the term "Best Practices" is best described as … "Continuous Improvement".

SUMMARY OF RESULTS

A total of 150 producing wells from the Preston Spraberry Unit were originally selected for evaluation in this "Best Practices" program. These 150 producing wells contained two unique groups of wells.

One group consisted of 87 wells in operation prior to the initiation of the "Best Practices" program. These wells were called "Existing" wells because they operated with used rods and used tubing in unknown condition.

The remaining 63 wells was the second group of newly completed wells operating with new lift equipment. These wells were called "New" wells because they operated with new rods and new tubing in new condition

After 6 years of this "Best Practices" program, the original well count of 150 wells has reduced to 145 wells due to *5* wells receiving T&A or P&A status.

PERFORMANCE OF 145 "EXISTING" AND "NEW" WELLS (REFER TO GRAPH 1)

	FPWPY and FPWPY (%) Change		
Type of Failure	1 Year Before	After 6 Years	
Tubing Leaks	1.75	0.26	(85 % Reduction)
Rod Parts	0.52	0.26	(50 % Reduction)
Pump Repairs	0.46	0.15	(67 % Reduction)
Total Failures	2.73	0.67	(75 % Reduction)

PERFORMANCE OF 85 "EXISTING" WELLS (REFER TO GRAPH 2)

	FPWPY and FPWPY % Change		
Type of Failure	1 Year Before	6 Years After	
Tubing Leaks	1.75	0.32	(82 % Reduction)
Rod Parts	0.52	0.28	(46 % Reduction)
Pump Repairs	0.46	0.16	(65 % Reduction)
Total Failures	2.73	0.76	(72 % Reduction)

PERFORMANCE OF 60 "NEW" WELLS (REFER TO GRAPH 3)

	FPWPY and FPWPY (%) Change		
Type of Failure	1 Year After*	6 Years After	
Tubing Leaks	0.25	0.17	(32 % Reduction)
Rod Parts	0.17	0.22	(29 % Increase)
Pump Repairs	0.67	0.13	(81 % Reduction)
Total Failures	1.09	0.52	(52 % Reduction)

This group of wells has shown the most consistent and lowest frequency of tubing leaks, rod parts and pump repairs. *These 60 "New" wells were completed during the first 2 years of the "Best Practices" program.

HISTORY

The Preston Spraberry Unit is located in the southwest corner of Midland County, approximately 25 miles southwest of Midland, Texas. The Spraberry production interval is 7,000 – 8,700 feet. Producing information from the 1999 paper and after 6 years is as follows;

	After 2 Years	After 6 years
The average pump depth	6,850 feet	7,003 feet
Average water cut	65 %	72 %
Average strokes per minute	8.0 spm	7.0 spm
Average stroke lengths	86 inch	86 inch
Average Polished Rod Velocity	1,376 ipm	1,204 ipm
Total Number of Wells in Program	150	145
Number of Fiberglass – Steel designs	70	70
Number of all Steel designs	80	75
Wells with IPC Tubing	26 (17 %)	100 (69 %)
Wells with Plain (Non-Internally Coated) Tubing	124 (83 %)	45 (31 %)
Average Footage of IPC Tubing	847 feet	882 feet
Average Footage of Sinkerbars	375 feet	400 feet
Average Footage of Sinkerbars with Fiberglass	475 feet	500 feet
Average Footage of Sinkerbars with Steel	300 feet	300 feet

Production tubing is 2-3/8" inside 4-1/2" casing.
Tubing anchor catchers are set below the seating nipples.
90 % of all seating nipples were located above the perforations.
Steel Rodstring Designs are 7/8" steel - 314" steel - 1.5" Sinkerbars
Fiberglass Rodstring Designs are 1" fiberglass - 718" steel - 1.5 Sinkerbars
80% of downhole pumps were insert type with 1.25" diameter plungers.

1999 "BEST PRACTICES PROGRAM

The 1999 paper presented a "Best Practices" program in the Preston Spraberry Unit located in West Texas. The 1999 "Best Practices" program consisted of well optimizations, re-designing of rodstring designs and improved control of run times.

WELL OPTIMIZATIONS

1. Diagnostic well analysis on existing wells and predictive analysis for future wells.
2. Analyze artificial lift designs to match current or future producing rates with current or future equipment by optimizing the following;
   - Plunger Diameter
   - Strokes Per Minute
   - Stroke Length
   - Tubing Anchor Tension
   - Downhole Gas Separation

RE-DESIGNING OF RODSTRINGS

1. Remove of bottom 450' of 7/8" guided rods.
2. Control downstroke buckling with installation of sinkerbars.
3. Balance Stress Loading at the top of each rod taper.
4. Well-site diagnostic analyses after several months of operation to evaluate initial rodstring designs for improvement of future designs.

IMPROVED CONTROL OF RUN TIMES

1. Install pump-off controllers to manage production rates, optimize run times, and monitor equipment performance
2. Extensive training of all field personnel.

In 1999 it was stated that recognition of and continued development of successful "Best Practices" program will provide the Oil and Gas Industry with improved artificial lift guidelines. Implementation of these guidelines will allow for a more efficient use of all valuable resources to efficiently produce oil and gas.

ENHANCEMENTS TO 1999 "BEST PRACTICES' PROGRAM

The 1999 "Best Practices" failure reduction program involving well optimizations, re-designing of rod string designs and improved control of run times has continued throughout the last 4 years of operation. There have been enhancements to this "Best Practices" failure reduction program. These enhancements have occurred in the following program areas.

Tubing Program
Rod Program
Pump Program
Pump-Off Controller Program
Chemical Program

PSU "BEST PRACTICES' - TUBING PROGRAM IMPROVEMENTS

Hydrostatic Testing

During the first 2 years of this "Best Practices" program tubing was hydrostatically tested. The testing process involved the following;

1. Locating the tubing leak
2. Replacing 10 joints of tubing above and 10 joints of tubing below the leak with new / yellow band (0-15% wall loss) tubing.
3. This hydrostatic testing was accomplished on location.

Electronic Inspection and Well-Site Scanalog

During the last 4 years of this "Best Practices" program the tubing testing program was improved by changing to electronic inspection of tubing. The testing process involved the following;

1. Locating the tubing leak.
2. Removing the bottom 100 joints of tubing.
3. Electronically inspecting the bottom 100 joints of tubing in a remote yard.

4. All inspected tubing identified as red band (>50% wall loss) or green band (30-50% wall loss) is removed from the string and replaced with new / yellow band (0-15% wall loss) tubing.
5. All removed blue band and yellow band tubing is used in other wells.

This off location electronic inspection of tubing was later replaced with a wellhead scanalog of the bottom 100 joints of tubing. In addition, all pulling units were instructed to shut down, if needed and wait on arrival of replacement tubing. This insured that all replacement tubing was installed in the desired location in the new tubing string.

1. The first electronic inspection resulted in replacing 40-50 joints of the bottom 100 joints.
2. The second and subsequent electronic inspection resulted in replacing a no more than 5 joints of the bottom 100 joints.

PSU "BEST PRACTICES – ROD PROGRAM IMPROVEMENTS

Improved Rodsting Designs from Predictive Software

During the first 2 years of this "Best Practices" program, predictive software was used to design rodstrings with Sinkerbars so that 70% of the bottom negative stresses were isolated in the Sinkerbar section.

During the last 4 years of this "Best Practices" program, this design process using predictive software was improved by designing so that 100% of the bottom negative stresses were isolated in the Sinkerbar section.

Improved Consistency of Rods in Rodstrings

During the first 2 years of this "Best Practices" program, it was discovered that many of the rodstrings contained rods from numerous manufacturers. These rods were found to be equivalent to a Norris-54 grade-D rod.

During the last 4 years of this "Best Practices" program, all rods are supplied from a single manufacturer. These rods are equivalent to a Norris-78 grade-D rod.

Inspection of Rods from T&A Wells

During the first 2 years of this "Best Practices" program, all rods removed from T&A wells were visually inspected off location.

During the last 4 years of this "Best Practices" program, this process was improved so that rods removed from T&A wells are electronically inspected off location.

PSU "BEST PRACTICES" – PUMP PROGRAM IMPROVEMENTS

Metallurgy of Balls and Seats

During the first 2 years of this "Best Practices" program, all balls and seats were alloy metallurgy

During the last 4 years of this "Best Practices" program, balls were changed to titanium carbide metallurgy and seats were changed to tungsten carbide metallurgy.

Ball and Seat Pattern Designs

During the first 2 years of this "Best Practices" program, all ball and seat patterns were a conventional pattern.
During the last 4 years of this "Best Practices" program, the ball and seat patterns were changed to a California style pattern on selected wells requiring solids control.

Pump Barrel Designs

During the first 2 years of this "Best Practices" program, all pump barrels were stainless steel – chrome barrels.

During the last 4 years of this "Best Practices" program, pump barrel designs maintained the stainless steel – chrome design. When operating in corrosive wellbore fluids, the design changed to a brass nicarb barrel.

Plunger to Barrel Fit

During the first 2 years of this "Best Practices" program, all new pumps were installed with a 0.003" plunger to barrel fit. .

During the last 4 years of this "Best Practices" program, this program was improved by increasing the plunger to barrel fit to 0.006" fit.

Pump Plungers Designs

During the first 2 years of this "Best Practices" program, all new pumps were installed with a conventional style plunger with Monel pins.

During the last 4 years of this "Best Practices" program, this program was improved by incorporating pressure actuated (P.A.) plungers and ring groove style plungers to help remove solids.

During the first 2 years and last 4 years the length of pump plungers has been maintained at 6 feet.

Mechanical Sand Protection

During the first 2 years of this "Best Practices" program, there was no sand protection associated to downhole pumps.

During the last 4 years of this "Best Practices" program, a sand protection program was initiated incorporating Finned Sand Shields.

Shear Devices

During the first 2 years of this "Best Practices" program, 5/8" grade-C rod subs were used as shear devices.

During the last 4 years of this "Best Practices" program, these 5/8" grade-C subs were replaced with on-off tools.

Seat Plug Designs

During the first 2 years of this "Best Practices" program, conventional traveling valve seat plugs were used in wells in this program.

During the last 4 years of this "Best Practices" program, these conventional seat plugs were replaced with compression style seat plugs.

Cage Replacement Programs

During the first 2 years of this "Best Practices" program, there was no cage replacement program.

During the last 4 years of this "Best Practices" program, a cage replacement program was initiated where all traveling and standing valve cages are replaced after 2 years of service.

PSU "BEST PRACTICES" – PUMP OFF CONTROLLER PROGRAM IMPROVEMENTS

During the first 2 years of this "Best Practices" program, 48 of the 150 wells were installed with pump off controllers.

During the last 4 years of this "Best Practices" program, 51 of 145 wells were installed with pump off controllers.

RESULTS OF A COMPANY WIDE "BEST PRACTICES' PROGRAM

The previous results were from 145 wells tracked for six years in a "Best Practices" program in the Preston Spraberry Unit. Pioneer Natural Resources operates 3,218 wells in the Spraberry Trend Area. At the time optimization efforts were initiated on wells in the "Best Practices" program, every well in the Spraberry Trend Area was also identified for optimization. Results for these wells for same time period as the "Best Practices" program are as follows;
(Refer to Graphs 4, 5 and 6)

		FPWPY and FPWPY (%) Change			
Type of Failure	1 Year Before	After 2 Years		After 6 Years	
Tubing Leaks	0.43	0.45	(5 % Increase)	0.16	(63 % Reduction)
Rod Parts	0.31	0.23	(26 % Reduction)	0.14	(55 % Reduction)
Pump Repairs	0.32	0.24	(25 % Reduction)	0.06	(81 % Reduction)
Total Failures	1.06	0.92	(13 % Reduction)	0.36	(66 % Reduction)

These successful field wide results occurred because of the following;

1. Training of all field personnel in overall oilfield operations
2. A competent technical well analysis department
3. Accountability applied to all personnel
4. Acceptability expected from all levels of management
5. Mandatory Vendor support

Training of all field personnel in overall oilfield operations

Training is the number one tool for a successful optimization program. Without training, field personnel will not believe in optimization. Once trained, all involved feel they are part of an effort and begin to realize the importance and benefit of the optimization program.

A competent technical well analysis department

No optimization effort will be successful without a technical department that will analyze every well and recommend changes to maximize efficiency from the wellbore to the bank. This department must be comprised of respected technical personnel and must be supported by upper management.

ACCOUNTABILITY APPLIED TO ALL PERSONNEL

Accountability elevates concern for substandard performance and leads to competition Production plots and failure graphs are critical tools for a measuring accountability by area.

Acceptability expected from all levels of management

Optimization efforts will be accepted only with the support of all levels of management. Few oilfield personnel will readily initiate improved operations methods. Management must initiate the directive. Documented improvements from past statistics will result in permanently improved operating mindsets and more efficient operations.

Mandatory Vendor support

Vendors and support companies must participate for an optimization program to succeed. Accountability for their performance results in a conscience of responsibility for contributions to the success of the program.

CONCLUSIONS

A successful "Best Practices" program was initiated on the Preston Spraberry Unit involving 150 producing wells on August 17, 1996. A similar program was initiated in the Spraberry Trend Area involving 3,218 producing wells in 1996. Performance for both projects during this 6 year period, ending on August 17,2002;

	PSU "Best Practices" Project	Spraberry Trend Project
Tubing Leaks	85 % Reduction	63 % Reduction
Rod Parts	50 % Reduction	55 % Reduction
Pump Repairs	67 % Reduction	81 % Reduction
Total Failures	75 % Reduction	66% Reduction

In the 1999 "Best Practices" paper, the conclusions were stated as follow;

If your company has yet to initiate a "Best Practices" program, the results of this paper strongly suggest that such a program be initiated and monitored, so your company can realize similar reductions in tubing leaks, rod parts and pump repairs.

If your company has a "Best Practices" program in operation that has not been able to realize comparable reductions in tubing leaks, rod parts and pump repairs as presented in this paper, evaluate your current "Best Practices" program. If your program does not involve procedures presented in the "Best Practices" program described in this paper, consider adopting those specific procedures.

Best results from a "Best Practices" program will be realized when that program can be initiated on newly drilled wells with new tubing, new rods and new Sinkerbars.

After 6 years of Best Practices in the Preston Spraberry Unit and the Spraberry Trend Area, these conclusions are still correct and justified by the recorded reductions of tubing leaks, rod parts and pump repairs presented in this paper.

CONTRIBUTORS

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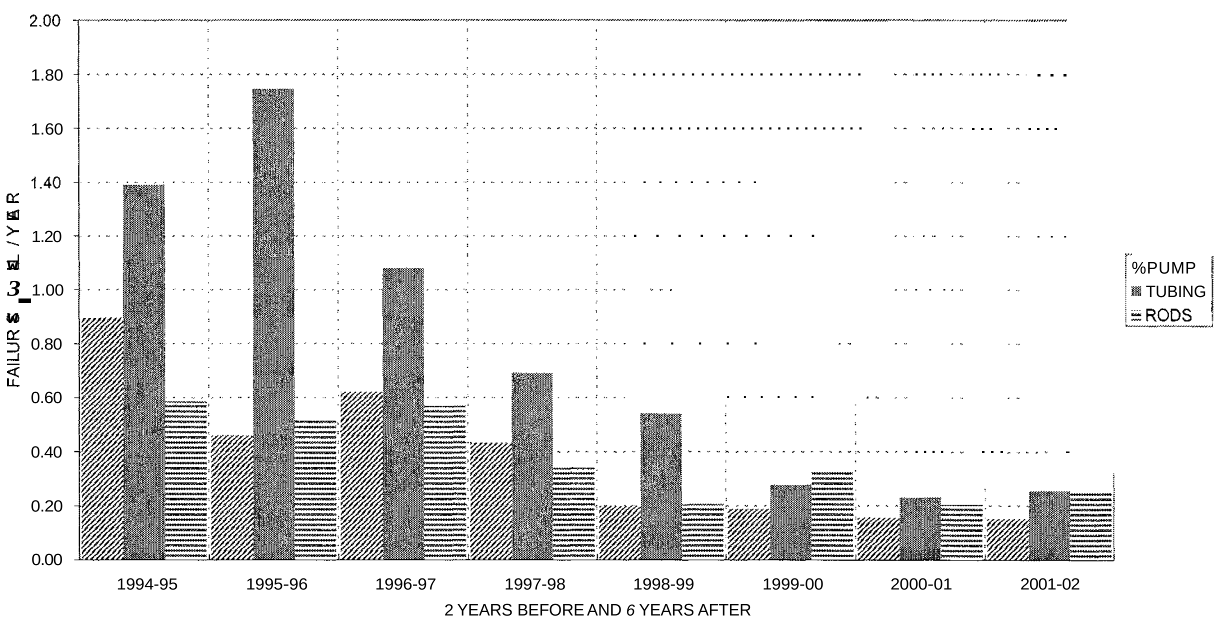
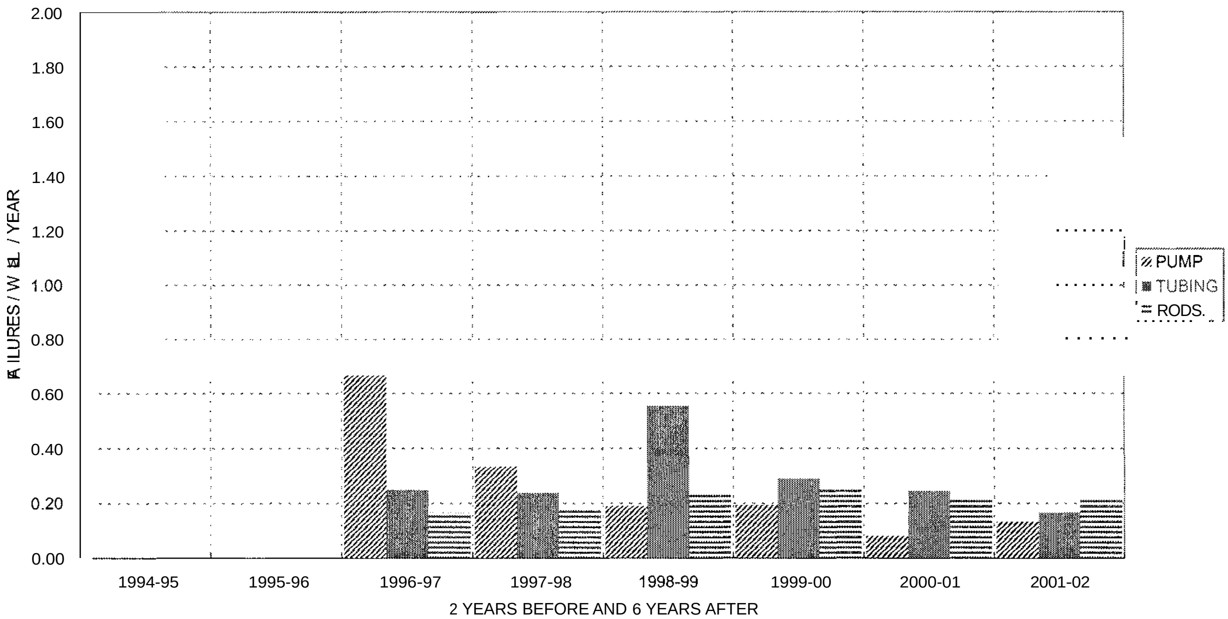
Flexbar, Inc.

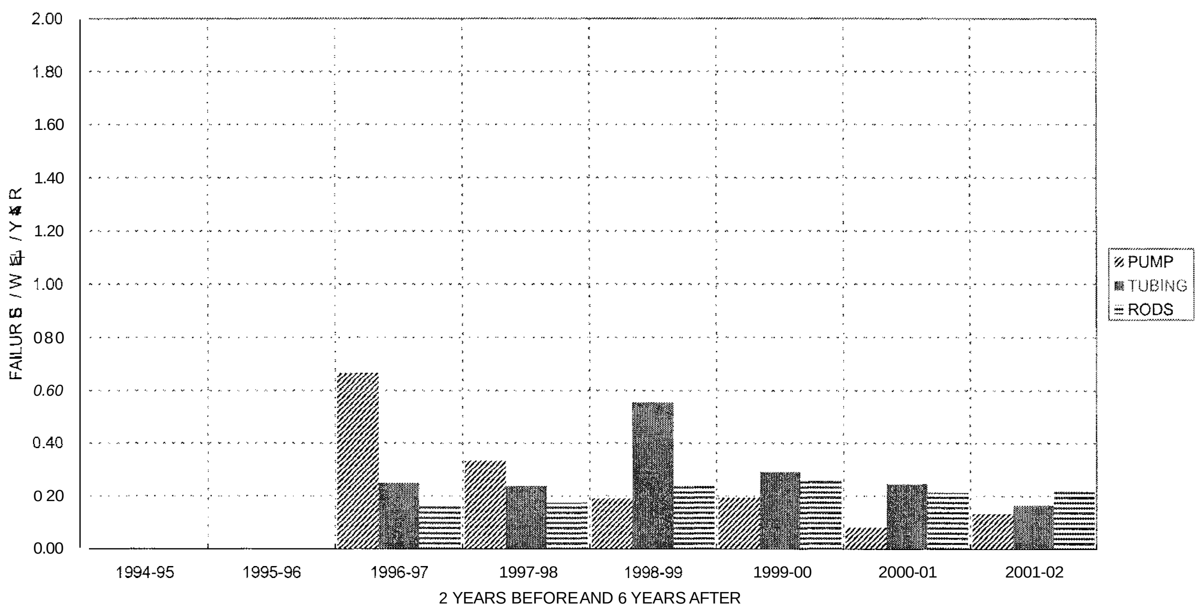
PRESTON SPRABERRY UNIT - 150 / 145 "EXISTING & " NEW WELLS
TUBING, ROD & PUMP FPWPY - GRAPH 1
FLEXBAR, INC.

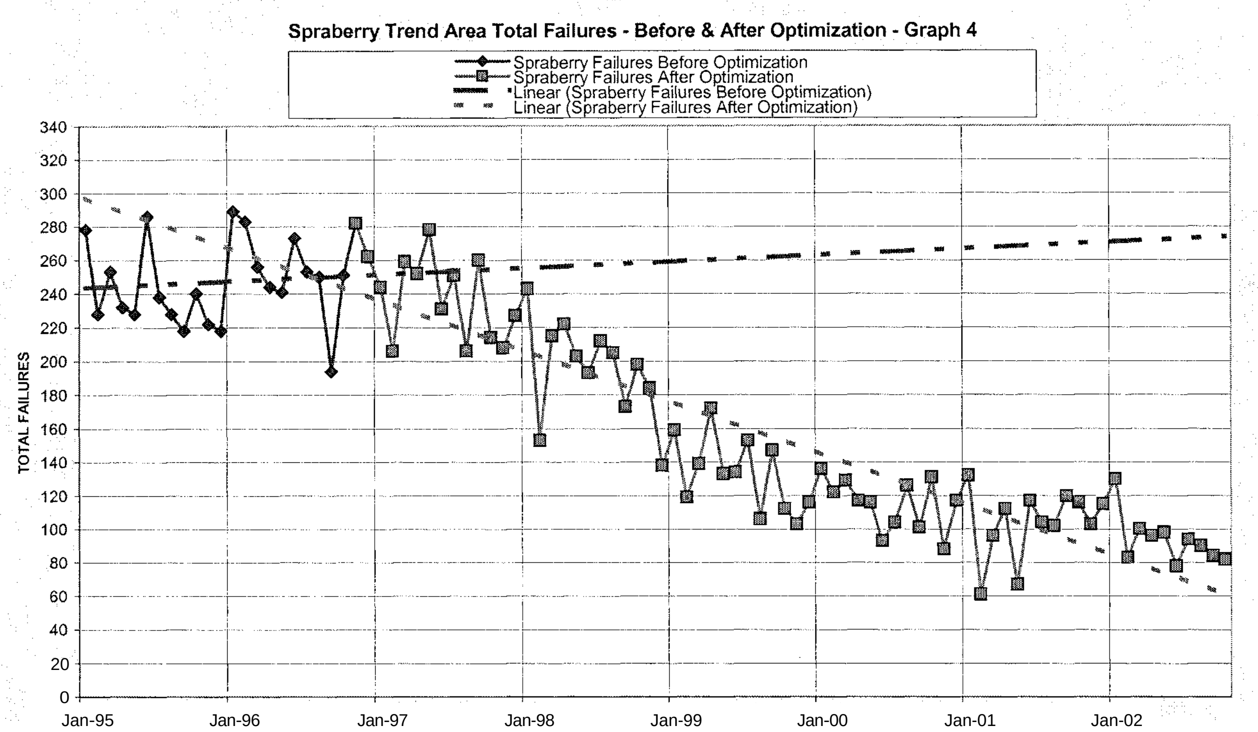


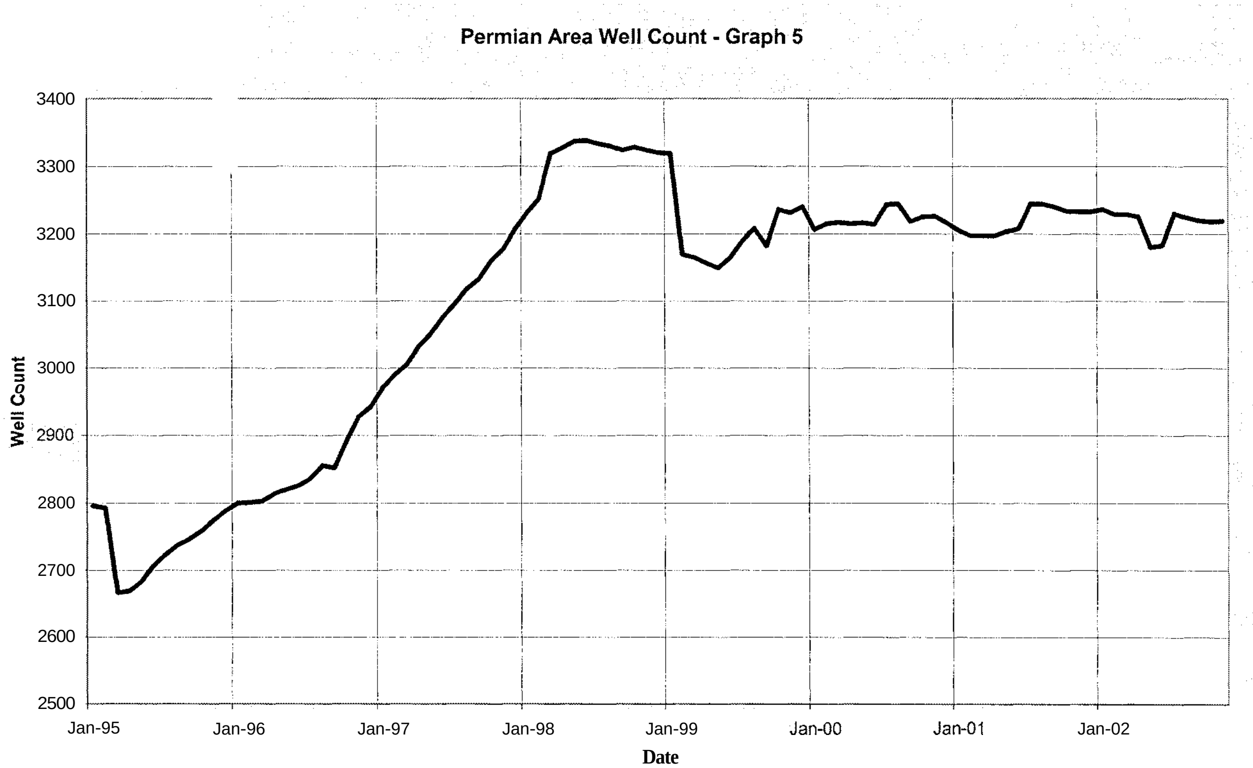
PRESTON SPRABERRY UNIT - 63 / 60 "NEW" WELLS
TUBING, ROD & PUMP FPWPY - GRAPH 3
FLEXBAR, INC.

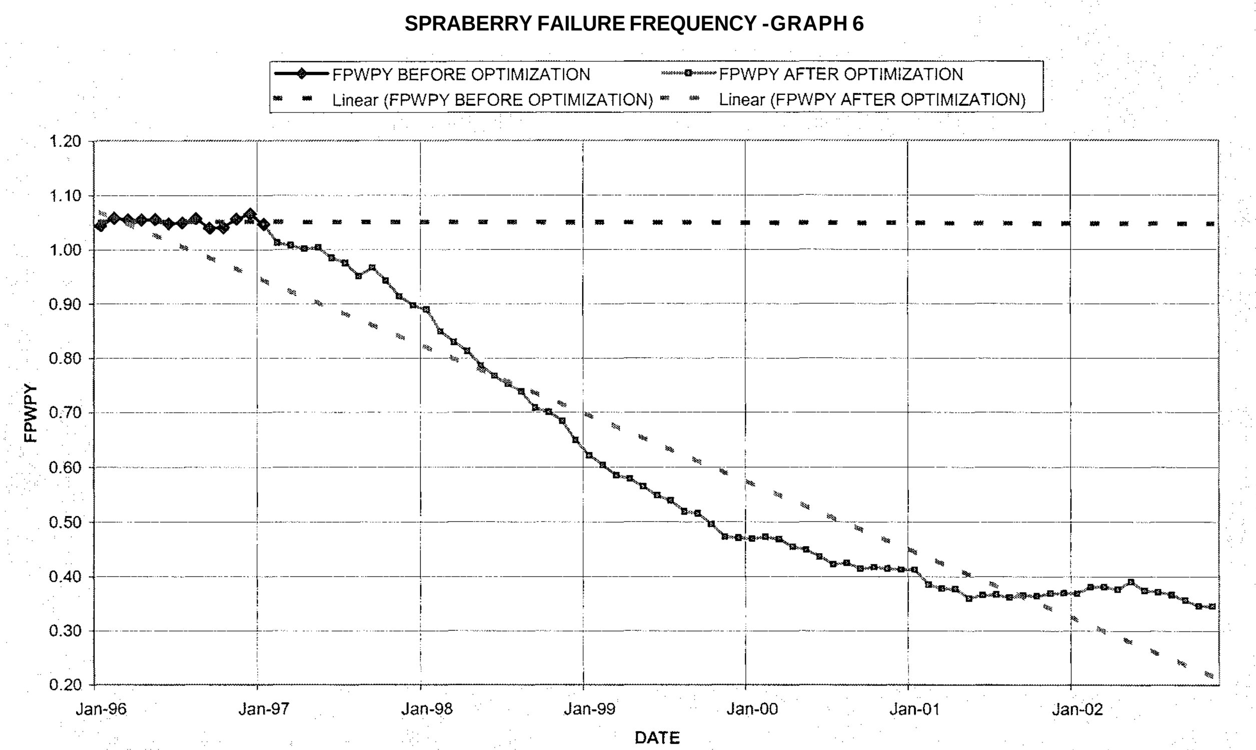


PRESTON SPRABERRY UNIT - 63 / 60 "NEW WELLS
TUBING, ROD & PUMP FPWPY - GRAPH 3
FLEXBAR. INC.




Spraberry Trend Area Total Failures - Before & After Optimization - Graph 4
Spraberry Failures Before Optimization
Spraberry Failures After Optimization
Linear (Spraberry Failures Before Optimization)
Linear (Spraberry Failures After Optimization)
TOTAL FAILURES
340
320
300
280
260
240
220
200
180
160
140
120
100
80
60
40
20
0
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00
Jan-01
Jan-02


Permian Area Well Count - Graph 5
Well Count
3400
3300
3200
3100
3000
2900
2800
2700
2600
2500
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00
Jan-01
Jan-02
Date


SPRABERRY FAILURE FREQUENCY - GRAPH 6
FPWPY BEFORE OPTIMIZATION
FPWPY AFTER OPTIMIZATION
Linear (FPWPY BEFORE OPTIMIZATION)
Linear (FPWPY AFTER OPTIMIZATION)
FPWPY
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00
Jan-01
Jan-02
DATE