# FIELD PERFORMANCE OF INTERNALLY PLASTIC COATED TUBING IN ROD PUMPED WELLS

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In the beginning of this project the primary goal was to compare IPC and Bare tubing and discern which was more effective in lowering tubing failures and which was more economical. In this project, a sample of 62 wells was examined from the Sprabeny area as well as an additional 152 wells from the Preston Spraberry Unit "Best Practices" program.

All wells were evaluated from January of 1996 to July of 2002. The question in concern was if IPC should be part of the optimizing process. During the research for the answer to this question it became evident that more conclusions could be drawn from the information gathered than was originally expected. Not only was the IPC question to be answered but the effects of other optimization techniques were seen as well. In this report, one will see the final decision on the effectiveness of IPC as well as the parameters needed for it to be effective. One will also see the benefits of Sinkerbars and Pump off Controllers (POC). (Refer to Table #1)

As indicated in the chart, the wells with IPC had a higher average of tubing failures than the wells with bare tubing. However, this number can be very deceiving because it does not show the wells that started with bare tubing and then had IPC installed. Two groups have been sorted out of the Spraberry wells that started with bare and then went to IPC. The first group consists of wells that were not problem wells and did not need IPC. The second group consists of wells that were having tubing failure problems and were good candidates for IPC. (Refer to Table #2)

In the non-problem wells, IPC actually increased the FPWPY. However, in problem wells, the IPC had a positive effect. The difference in the FPWPY could be attributed to the variation in pump friction between Bare and IPC tubing as well as the amount of IPC tubing installed in the wells.

The location of tubing failures is also alarming because the IPC seems to push up tubing failures further up in the tubing string. This is confirmed by various scanalog reports as well as tracking where the tubing failures have occurred. (Refer to Graph #1)

As seen in the scanalog report I Graph #1, the IPC is working in preventing failures in the area that it's installed. However the wear appears to be moving up the tubing string and causing failures higher in the tubing. This scanalog report is an accurate sample of the trend that is being seen in wells with IPC. (Refer to Table #3 and Table #4)

As evident in the charts, a large percentage of the failures have been occurring above the IPC. Once again this can be attributed to not installing enough IPC to cover all the side loads or to the difference in pump friction. (Refer to Graph #2)

As seen in the graph #2, the pump friction differs between the IPC and the bare tubing. At 6.5 SPM or less, the IPC has a lower pump friction than bare tubing. However, when the SPM is increased above 6.5 the bare tubing has lower pump friction. As a whole, the IPC pump friction increases 4 times than that of Bare Tubing for every increase of 200 inches per minute or 1.25 SPM.

Initially, the IPC looks to be ineffective in lowering tubing failures as well as not being cost effective. With IPC's current applications this is true. However, IPC does work when installed properly.

## PARAMETERS AND PROCEDURES FOR IPC

When IPC is installed, it lowers tubing failures in the area that it's installed. However, the predominant problem with IPC is that there is not enough installed to cover the side loadings. There are two ways to solve this problem.

1. Install enough Sinkerbars to bring the side loading down into the IPC.
   a. Recommended is enough to cover all side loading using 500 psi pump friction
2. Install enoughjoints of IPC to cover the entire side loading.
   a. For this study 50 joints of IPC covered side loading in 25% of the wells, 60 joints covered 50% and 75 joints covered all side loading in 90% of the wells.

When installing IPC, the following steps should be taken before the actual installation.

1. Have a scanalog taken and determine where the wear is occurring in the tubing.
2. Expect additional friction, apply it to the design and install enough Sinkerbars to bring the wear down into the bottom joints of tubing.
3. Ensure that enough IPC will be installed to cover the side loading area depending on all pumping parameters.

## HOW TO MAKE IPC COST EFFECTIVE

IPC cost is significantly more expensive than bare in 2.375” tubing. If IPC is not installed correctly or is ineffective, then the money used on IPC is wasted. Thus, it is very important to have parameters set for when IPC should and should not be used.

1. Do not use IPC on non-problem wells.
2. Do not install IPC in small amounts.
   a. Common practice has been to start out with 20 joints of IPC. This proved wasteful and had no effect or negative affect on the FPWPY.
3. Use IPC as last step in optimization.

## OTHER FINDINGS

There are many other ways to optimize wells before going the expense of using IPC. During the course of this project, other optimization methods, such as the installation of POCs and Sinkerbars were looked at and evaluated with the IPC.

***In the researched wells of the Spraberry Other, all Sinkerbars were installed after the installation of IPC. However, not all IPC wells had Sinkerbars installed. This explains the variance in the total FPWPY for IPC and the FPWPY for IPC in the table #5.** (Refer to Table #5)

As apparent in the chart, the Sinkerbars had a profound positive effect on the performance of the tubing failure frequency. However, the Sinkerbars application could have been used more efficiently and thus further improved the tubing failure frequency.

The POC is another very successful optimization technique that has been able to lower the tubing failures. When the POCs were combined with Sinkerbars, the average FPWPY was decreased to less than .30.

*In the researched wells of the Spraberry Other, the POCs were either installed before or after the Sinkerbars. The order they appear in the chart is the order they were installed.
(Refer to Table #6 and Table #7)

The installation of the POC in each scenario dramatically decreased the FPWPY. The POC proves to be a very efficient way to lower the FPWPY with or without Sinkerbars in problem wells.

## ALTERNATIVES TO IPC

Polycore tubing has had an impressive debut in the oilfield. It has been installed into 20 of Pioneer’s problem wells in the Spraberry area and has yet to have a tubing failure. Polycore tubing may be the closest thing to eliminating tubing failures. However, the downside of Polycore tubing is the reduction of the ID. This 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 to IPC.

## CONCLUSIONS

While IPC can be beneficial to wells, it should not be the first step taken in optimizing wells. IPC is a valuable tool in the oilfield but its application should be reserved for problem wells only. The potential for IPC can be seen in its usage in some wells. But in order for its full potential to be achieved it must be installed correctly and in proper amounts as stated.

Table 1

| Location of Well | Bare FPWPY | IPC FPWPY |
|---|---|---|
| PSU | .53 | .50 |
| Spraberry Other | .53 | .72 |
| Average | .53 | .61 |

Table 2

| Type of Well | FPWPY Bare | FPWPY IPC |
|---|---|---|
| Wells that needed IPC | .67 | .4 |
| Wells that did not need IPC | .176 | .259 |

Table 3

| Spraberry Tubing Failure Locations | Percent of Failures |
|---|---|
| Failures Abo e C | 43 % |
| Failures In IPC | 51 % |
| ailures in Sinkerb Are | [illegible] % |

Table 4

| PSU Tubing Failure Locations | Percent of Failures |
|---|---|
| Failures Above IPC | 55 % |
| Failures In IPC | 36 % |
| Failures In Sinkerbar Area | 9 % |

Table 5

| | FPWPY With IPC | FPYPW With IPC and Sinkerbar |
|---|---|---|
| Spraberry Other Wells | 1.11 | .49 |

Table 6

| | FPWPY IPC | FPWPY Sinkerbar | FPWPY POC |
|---|---|---|---|
| Spraberry Other Wells | 1.25 | **.63** | .29 |

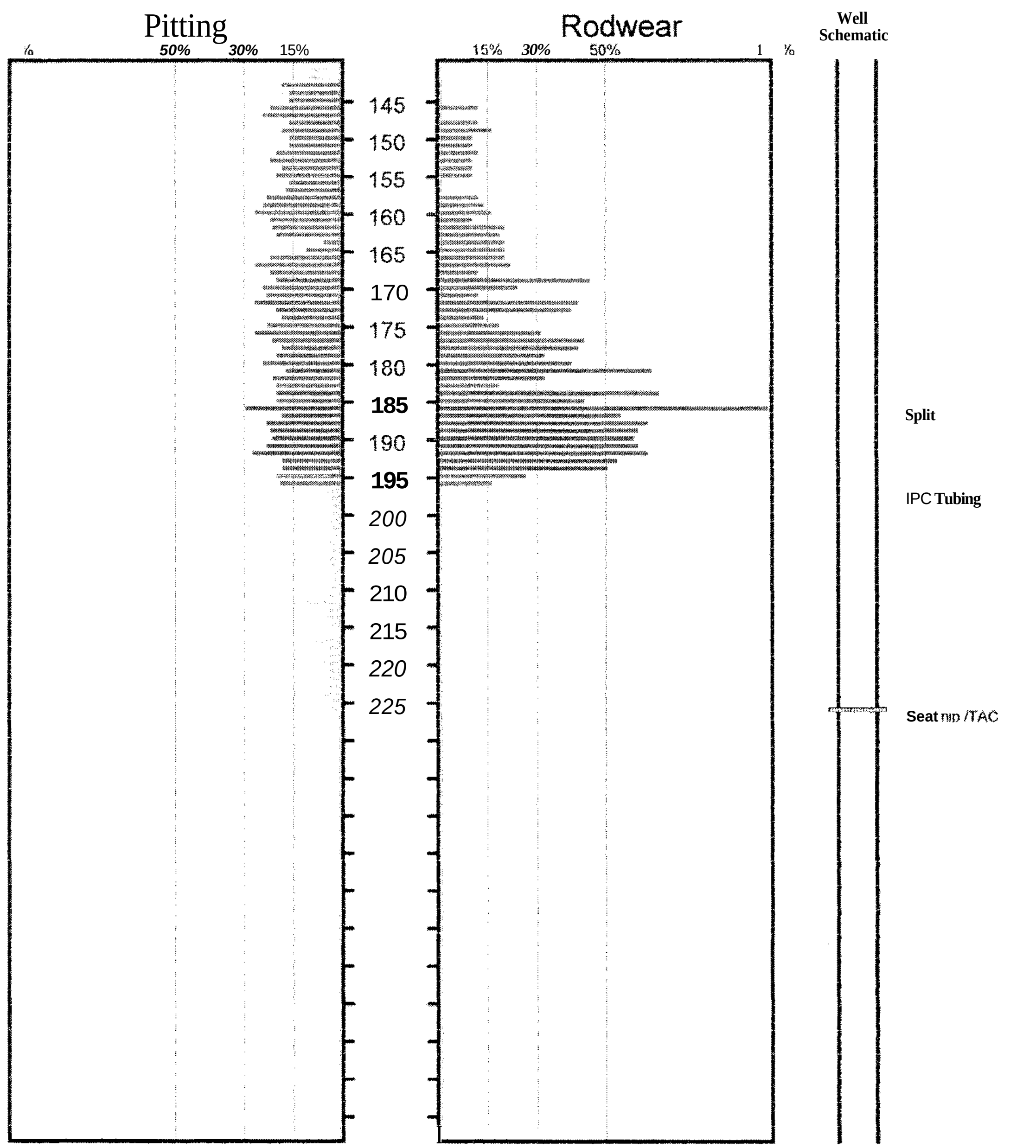
Table 7

| | FPWPY IPC | FPWPY POC | FPWPY Sinkerbar |
|---|---|---|---|
| Spraberry Other Wells | 1.06 | 35 | .26 |

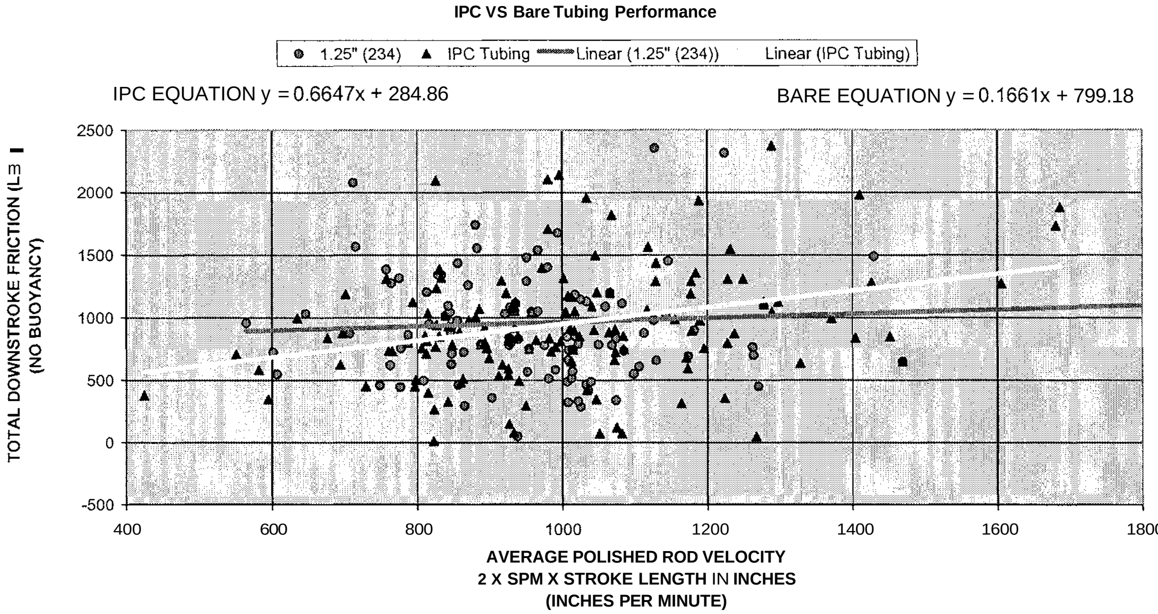
**Wellhead Scanalog**
**Well Profile**

| Customer: | Well Name: | Work Order: |
|---|---|---|
| Pioneer | SSU #167A | 2-2744 |

| Size: | Weight: | Grade: | Connections: | Date: |
|---|---|---|---|---|
| 2 3/8" | 4.70# | J-55 | 8RD EUE | 4/18/2001 |




Graph 1


IPC VS Bare Tubing Performance
1.25" (234)
IPC Tubing
Linear (1.25" (234))
Linear (IPC Tubing)
IPC EQUATION y = 0.6647x + 284.86
BARE EQUATION y = 0.1661x + 799.18
TOTAL DOWNSTROKE FRICTION (LB)
(NO BUOYANCY)
2500
2000
1500
1000
500
0
-500
400
600
800
1000
1200
1400
1600
1800
AVERAGE POLISHED ROD VELOCITY
2 X SPM X STROKE LENGTH IN INCHES
(INCHES PER MINUTE)

Graph 2