SUCKER ROD SIDE LOAD AND WEAR IN DEVIATED COALBED METHANE GAS WELLS

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ABSTRACT

ConocoPhillips presents side load vs. running time data for their longer running wells, and learning's from two "S" well repairs completed in early 2012. The load a sucker rod applies to the tubing wall is called side load. Side loads will be higher in the depth intervals of the tubing that are more deviated. The time required to wear the sucker rod or tubing to failure should be a function of side load, friction, lubricity (oil cut) and cumulative travel (stroke length time stroke per minute) . ConocoPhillips San Juan Business Unit operates rod pumps in more than 50 "S" shaped deviated wells. ConocoPhillips San Juan's "S" shaped rod pumped wells have shallow curved sections that tend to have side loads of one hundred pounds force or greater, and many have been running for several years.

INTRODUCTION

The San Juan Basin Fruitland Coal seam is 200-400ft gross thickness including sandstones, mudstones, and coals, overlying the Pictured Cliffs sandstone. It outcrops around the edge of the basin and the depth of the coal varies from the outcrop at surface down to 4200ft[1]. The Fruitland Coal has produced more than 16 Tcf of gas to date.

Rod pumps are typically used to deliquify Fruitland Coal wells because they are able to pump the high initial rates required, and achieve the lowest bottom hole pressures. This is unusual based on the prevalence of plunger lift systems for lifting water from other zones in the San Juan Basin.

ConocoPhillips began drilling "S" shaped wells to access Fruitland Coal pay that was either inaccessible from the surface due to features like Navajo Lake, or to minimize surface acreage disturbance. Deviated "S" wells were drilled from existing vertical well locations to bottom hole locations some distance away.

ConocoPhillips typically begins an "S" well by drilling directly down to a depth of 300-600ft, then turning the path away from the vertical to a slant section. The slant section is extended as far as needed to get close the target bottom hole location. The typical distance in the horizontal plane from the surface spud location to the bottom hole location is 800ft to 1200ft; but sometimes is as far as 3000ft. Next the path is curved down again, passing vertically through the Fruitland Coal. Typical true vertical depths for these wells are in the range of 2900ft to 3300ft.

Figure 1 is a typical S well trajectory. The axis title "Horizontal Distance Travelled by the Well" in this figure, and the "Cumulative Horizontal Distance Travelled" in other figures is what you would see if you rolled out the well trajectory (looking at it through the earth from the side) onto a flat surface, disregarding the azimuth changes. Figure 2 is a chart showing many of our "S" well paths.

The "S" shape is a unique challenge for sucker rod pumping. The pumping unit activates the downhole pump by dragging the sucker rods across the two curves. The rods will cycle up and down several times a minute for several years. Where steel sucker rods are dragged through the curves, there is significantly more wear than in a vertical well, if all other conditions the same.

While rod pumping and rod design processes have been around for more than half a century, designs for deviated wells have been developed more recently. Lucasiewicz[2] in 1991 concluded that the rod axial load and dogleg severity were critical factors for determining important loads. S. G. Gibbs[3] in 1992 stated the important measurements were the "weight of the rod and its curvature". While Lukasievicz and Gibbs both understood what needed to be considered, they hadn't yet used the "side load" term to characterize it. By 1997, Long and Bennett[4] measured what had been by then termed "side load" in a test apparatus. Their results showed that for the same side load, there was less tubing wall loss due to sinker bars than sucker rods.

Side load is a force that develops between the internal tubing wall and the exterior surface of the rod string due to inherent differences in flexural stiffness and variations in alignment and curvature throughout the length of the wellbore. The primary force vector of side load is perpendicular to the axis of the production string and frictional forces (parallel to the surfaces) develop as a result of the contact pressure between the rods and tubing. The friction in these wells can be influenced by the type of the fluid pumped and these wells produce water than has minimal lubricating properties as compared to crude oil. Side load is a function of both the well curvature, measured by dogleg severity in degrees per hundred feet, and axial load. Axial load is the load in the rod string in the same orientation as the rod string.

Side loading is a phenomenon that exists to some extent in all reciprocating lift system wellbores due to the virtual impossibility of drilling a perfectly straight and vertical hole. Side load results in accelerated wear of the contact surfaces as the materials dissipate the energy resulting from the frictional forces. Side load can lead to premature failure of the tubing wall and/or rod string components if not mitigated appropriately. More energy is required at the surface to overcome frictional forces due to deviation on the upstroke. The extra friction results in added operating expense due to increased pumping unit and downhole rod and tubing wear.

In “S” wells, when both the shallow and deeper curves have similar doglegs, the shallower curve will have more side load due to higher axial loads from the extra rod weight below it. You can see how the upper and lower curves have higher dogleg severity than the other intervals by looking at the upper two charts of Figure 3. The lower charts in Figure 3 show that the sucker rod and tubing contact in the upper curve of the well has a higher side load than the lower curve, despite the two curves having similar doglegs. This is because the rod string in the upper curve has a higher axial load, due primarily the longer length of rods below the upper curve.

Operators are drilling many horizontal wells that require artificial lift. We need to understand the implications of side load on wear and equipment runtimes to cost effectively plan and operate rod pumps in deviated wells.

SIDE LOAD CALCULATION

Deviation surveys were input into a rod string design program, along with installed rod system data like rod diameters, sinker bar size and length, and pump depth. A friction factor of 0.28 was used for all guided intervals, based on a previous study of field dynamometer data[5]. A computer program used the deviation surveys and pertinent wellbore data to create a report with graphical representations. The highest calculated side load value along the length of the string was recorded and used for comparison with the estimated well runtime.

Deviation Survey Extrapolation

For some wells the recorded deviation surveys were not complete and data had to be extrapolated to cover some portion of the shallowest and/or deepest ends of the wellbore. These extrapolations were only necessary in a limited number of cases, and did not encompass any significantly deviated interval. A comparison of the program output files for these cases confirmed that no significant side load occurred in the sections where data was extrapolated to complete a wellbore profile.

UNCERTAINTIES IN DATA

The data considered in this document is field data. The lack of control over variables in the field has distinct advantages and disadvantages. The advantage is it is real data from a system exposed to true operating conditions and all the real fluctuations in those conditions. The disadvantage is due to the uncertainties that arise from the fluctuations in conditions, and a lack of complete documentation of the affecting variables. This portion of the paper serves to acknowledge the some of the uncertainties and the effects they may have on the data presented.

Rod Guide Data

Specifics on the rod guides, including the manufacturer and number of guides per rod were available for a few, but not all of the wells. Records available show that several guided intervals had 5 guides per rod, and a few with as many as 10 guides per rod. Since the number of guides per rod was not known, the data is presented as side load per rod instead of the preferred side load per guide.

A few of the well records did not indicate rod guides. We assumed they had guides because the wells would have failed much earlier in their runtimes if they did not. This assumption is supported by the discovery of tubing wear failures at very low side loads in the absence of rod guides.

Pumping Speed

The pumping unit speed in strokes per minute is not always recorded or saved for historical purposes. As a result, the available data for most wells analyzed consists of a pumping speed at one or just a few points in time. A pumping unit's speed may have been obtained from annual pumping unit inspections, on-site fluid level and dynamometer records, or from rod pump controller data that has been captured and communicated to a database. We selected a speed that appeared to best represent the data available. In order to determine the importance of this uncertainty, a sensitivity analysis was completed using the known range of pumping speeds and the calculated side load across that range. The relationship between pumping speed and side load for each "S" well in this study can be seen in Figure 4. Pumping speed variations, within the known ranges, had little effect on side loads.

Adjusted Run Time

The best measure of rod and tubing runtimes would be based on pump cycles and feet of travel. To compare performance versus side load an operational time had to be calculated. Many of the wells had a significant period of time where the pumping unit was not running for various reasons. In order to provide more accurate and consistent data, an adjusted runtime was estimated for each well. This was done using historical production and decline curves. Months when the well produced significantly below the expected production or was declining due to apparent liquid loading were removed from the original runtime. Excluded time probably included some time when surface facilities issues like compressor downtime had affected production, but we may have pumped regardless. A few of the wells produced above annular critical lift for some time. We included time above critical lift because we determined that at least some of the wells were pumped during those times. The total time between start of production and the failure date for each well was "adjusted" for the various considerations above to estimate the actual operating time or the "Adjusted Run Time". Figure 5 shows the highest side load versus the Adjusted Run Time.

Rod Pump Control and Daily Runtime

Some of the wells considered in this study have rod pump control capabilities and depending on conditions may or may not have pumped 24 hours per day. A well with a controller may still have pumped 24 hours per day if the water rates were sufficient to keep the pump relatively full, or if the pump off control equipment wasn't working. Many of these wells have gas engines for which pump off control equipment has been a challenge. Wells with controllers may have pumped 24 hours a day, but they may have been turned off occasionally due to some equipment problem, or to see how long it would take the well to start liquid loading. We didn't have the data to make a good estimate of daily runtimes or cycles. Reporting runtimes between failures that are not adjusted for daily rod pump control runtimes is not unusual.

Failures Not Due to Wear

We had a few wells that established significant runtime before failing due to some reason other than wear. We kept these data points in the chart because when a well fails due to some reason other than wear, it at least establishes a lower limit on what the wear life could be. If a well fails due to coal fines after four years, you know that system wouldn't have failed due to wear for at least four years. Another benefit of including the failed well data is the value of the higher side load data points, because there are few non-failure points in this area of the plot. An example is the 463 lbf side load system that ran 4.2 years.

Effect of Coal Fines on Wear

The effect of solids on the equipment runtime in the "S" shaped wells is outside the scope of this analysis. However, the majority of rod pumped wells operated by ConocoPhillips in the San Juan Basin are completed in the Fruitland Coal formation. Production of coal fines is often seen in Fruitland Coal wells, and the coal fines along with any other produced solids may expedite a wear failure and reduce the runtime for the system. The potential increase in wear is a result of the solids being trapped between the rods and the tubing and grinding into the tubing as the rods move. The presence of produced solids may have a significant impact on the tubing wear.

RESULTS

Side Load versus Runtime

The results of the estimated runtimes and side load calculations are shown in Figure 5. Maximum Side Load in pounds force (lbf) on the y-axis and "Adjusted Run Time" on the x-axis for wells with reasonably long runtimes. Maximum side load is the highest calculated side load in the rod string, and is usually found in the upper curve. Maximum side load is sometimes found in the lower curve if the dogleg in the lower curve is significantly larger than the dogleg in the upper curve.

There are three different types of symbols on the chart. Black squares indicate systems that have failed, and represent actual runtimes. Green circles are wells without working rod pump control that are still running, and therefore are "running times", and blue diamonds represent running times for wells that have rod pump control (RPC). The distinction that the well has rod pump control is significant because these wells are more likely to have had more planned daily off time due to the on/off nature of the controller. Wells without controllers are more likely to have been pumping twenty four hours per day, every day. This distinction was made to help interpret the results in terms of real runtime.

"Adjusted Run Time" is the x-axis and is based on a review of the production chart as discussed previously. Run or running times were reduced for each month the well was declining or down. This is based on the assumption that the well was not pumping during those months. This was also done to get a better representation of the actual runtime.

The results show three wells with side loads between 180 and 200 lbf have run longer than six years. The well with the longest runtime of these three did not have active rod pump control so is more likely to have been pumped the full 8+ years indicated.

Two wells with greater than 400 lbf of side load have run more than 4 years. Two more wells with side loads greater than 300 lbf have also run more than 4 years.

Acceptable runtimes for a given operation are functions of local repair costs and processes.

Field Wear Measurements

When a rod pump system is repaired, the operator should repair each major rod pump system component (rods, tubing, and pump) in a manner that gives the total system its most cost-effective runtime. Time between failures will be dictated by the shortest-lived component. To reduce repeat tubing wear failures, ConocoPhillips San Juan discontinued pressure testing tubing to identify thin wall tubing for removal, in favor of rig floor electromagnetic inspection. Pressure testing tubing and only removing the joints that burst, did not remove enough of the red and green band tubing to prevent short runtime repeat tubing failures. The change in operating practice to rig floor electromagnetic inspection has resulted in the removal of more of the worn and corroded tubing with significant wall loss.

The rig floor inspection used is a combination of electromagnetic and gamma ray measurement devices housed in a cylinder that sits on the rig floor. We pull the tubing through the cylinder, and the resulting measurements are wired back to a truck where a technician monitors a chart of the data. The technician evaluates the measured signals, categorizes the tubing as yellow, blue, green or red band depending on maximum wall loss. The term "band" refers to the color actually painted or marked on the tubing to identify the severity of its wall loss. Yellow band tubing is less than 15% wall loss, blue band is 15-30%, green band is 30-50%, and red band is > 50% wall loss. We lay down red and green band tubing, and re-run yellow and blue band.

The rig floor inspection depends on the technician's interpretation of a little more than 30ft of data into a single wall loss value for the whole tubing joint. Operators may be troubled by the occasional blue band joint, that is almost green, being classified as a green (due to measurement or interpretation issues), and is laid down. Newman[6] in 2006 studied accuracy issues with rig floor tubing inspections. For our purposes, losing a few of the green band joints that are nearly blue is acceptable, because it results in getting rid of all of the red and green band joints.

The rig floor inspection cannot see corrosion inside the tubing at the ends of the tube, where upsets and collars change the wall thickness. The inspection system also cannot distinguish quantitatively the difference between 80% and 90% wall loss. We don't run any of that tubing back into the well, so that is not an issue.

Despite its potential shortcomings, rig floor inspections eliminate more of the high metal-loss tubing (red and green band) that reduce wear life, than hydrostatic pressure testing can.

Tubing Leak in Un-Guided Interval

We will show some results from two "S" well repairs. The first well's data is shown in the Figure 6. The well trajectory in a vertical plane is shown on the left. The dogleg severity of the well is shown in the middle, and the side load resulting from the axial load and dogleg is shown on the right. The dogleg severity for the upper and lower curves is typically between 4^o and 6^o per hundred feet. The resulting side load tops out at over 350 lbf for the upper curve, and at less than 200 lbf for the lower curve.

Figure 7 is the side load output, correlated with the wellhead tubing inspection. The tubing inspection shows maximum corrosion wall loss in the left track, and maximum rod wear wall loss in the right. The guided and unguided rod intervals are labeled on the chart. Looking at the guided rod sections in the curves, you see significantly less tubing wear. Most of the guided rod intervals tested as yellow band, having less than 15% wall loss. That indicates the rod guides are effectively reducing tubing wear.

The tubing leak that caused the well failure was found in joint 54 from surface in the unguided section (see Figure 7). There are no rod guides in this interval that has a calculated 60 lbf side load. Other significant wall loss is seen in other un-guided intervals near relatively low side loads.

Significant Tubing Wear in Sinker Bar Interval

Another "S" well was repaired in 2012. The well path, dogleg severity and side load curves are shown in Figure 8. Doglegs in the upper and lower curves are 5^o to 6^o per hundred feet. Side load in the upper curve is over 300 lbf, and the lower curve more than 100 lbf. The sinker bar interval above the lower curve is indicated on the chart. Despite its relatively low dogleg severity, less than 1^o per hundred feet, the program calculated greater than 100 lbf of side load for part of the sinker bar interval.

In Figure 9, the side load chart is correlated with the tubing inspection. This well did not have a tubing leak, but did have significant wear in the sinker bar interval resulting in red band tubing. There was also some corrosion seen by the tubing inspection, and there may have been coal fines present as suggested by the 10ft of coal fines fill cleaned out during the repair. Sinker bars are run above lower curves to keep the sucker rods above them in tension. While Long and Bennett[4] demonstrated slower tubing loss with sinker bars, this well had accelerated wear due to some combination of high side loads, solids or corrosion.

CONCLUSIONS

1. Pumping unit speed variations within the operating ranges of our wells had little effect on side load.
2. Several of our wells have achieved runtimes of greater than five years with side loads of 200 lbf or less. Two wells with greater than 400 lbf of side load have run more than 4 years. Two more wells with side loads greater than 300 lbf have also run more than 4 years.
3. Rod guides have been effective at reducing wear and extending the runtimes of production tubing and sucker rods in our deviated wells.
4. We experienced a tubing leak in an unguided interval in a slant section that had 60 lbf side load.

5. Sinker bars in the presence of solids, coal fines and corrosion in a slant section interval with more than 240 lbf side load, created significant wear.

RECOMMENDATIONS

1. Continue to track and analyze failures to better understand the effect of side load on runtimes. Use this information to help design wellbore trajectories in horizontal and deviated wells that will be rod pumped.
2. Improve data quality. The findings of this study would have been more conclusive if, for example, better runtime or even cumulative rod travel (SPM x SL x cum time) from rod pump surveillance equipment was available.
3. Encourage other operators to publish any similar field or test data to improve industry's ability to design and optimize deviated wells.

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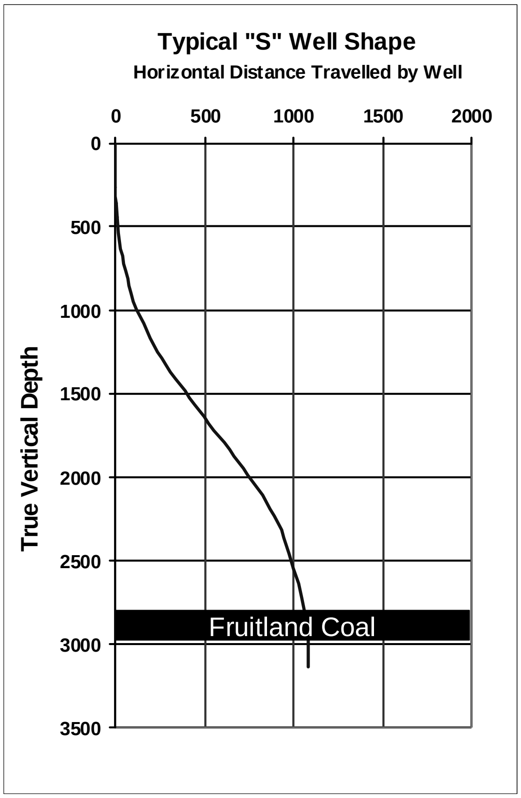


Figure 1

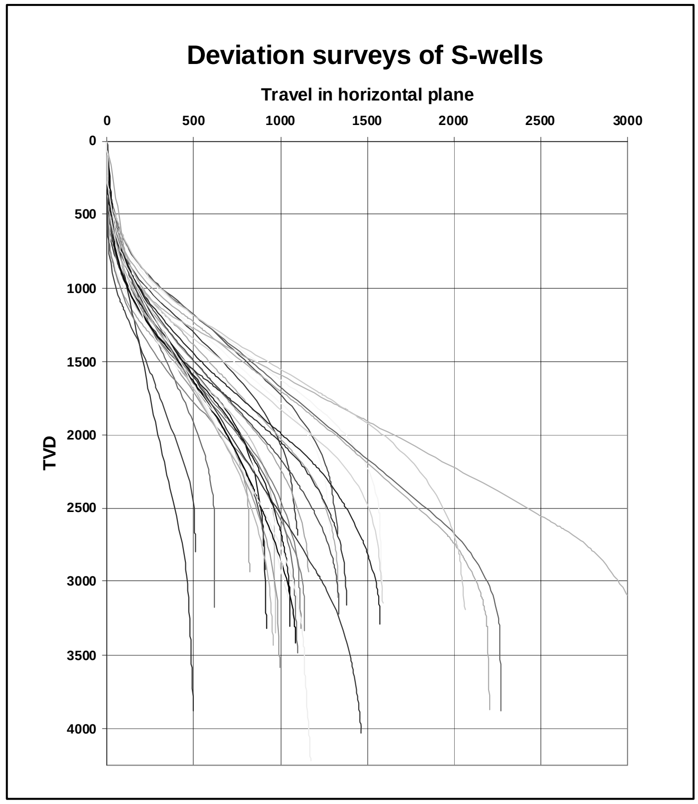
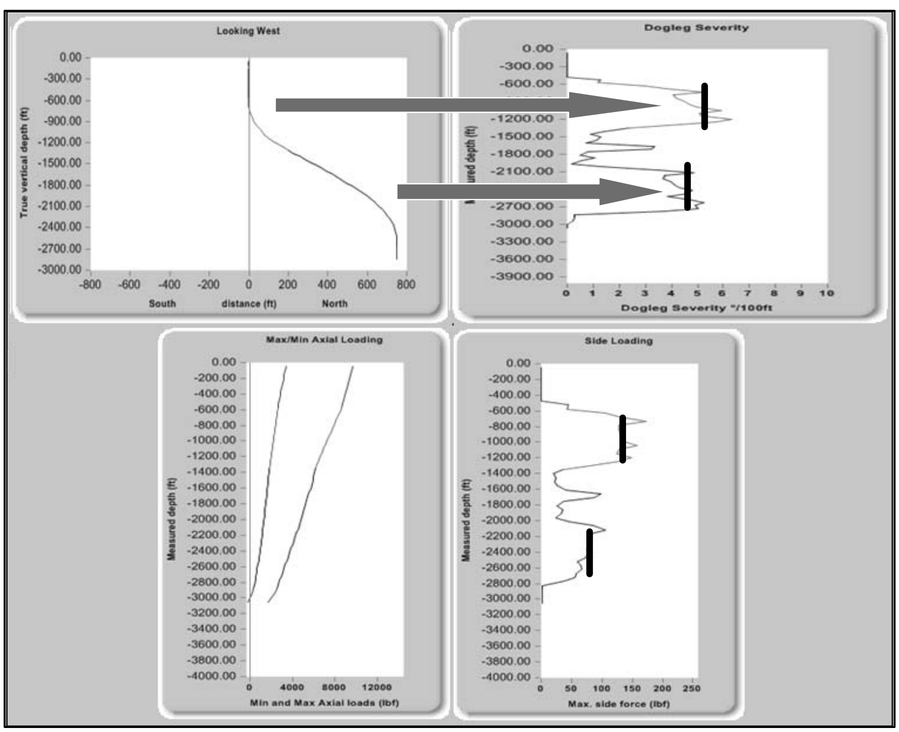


Figure 2



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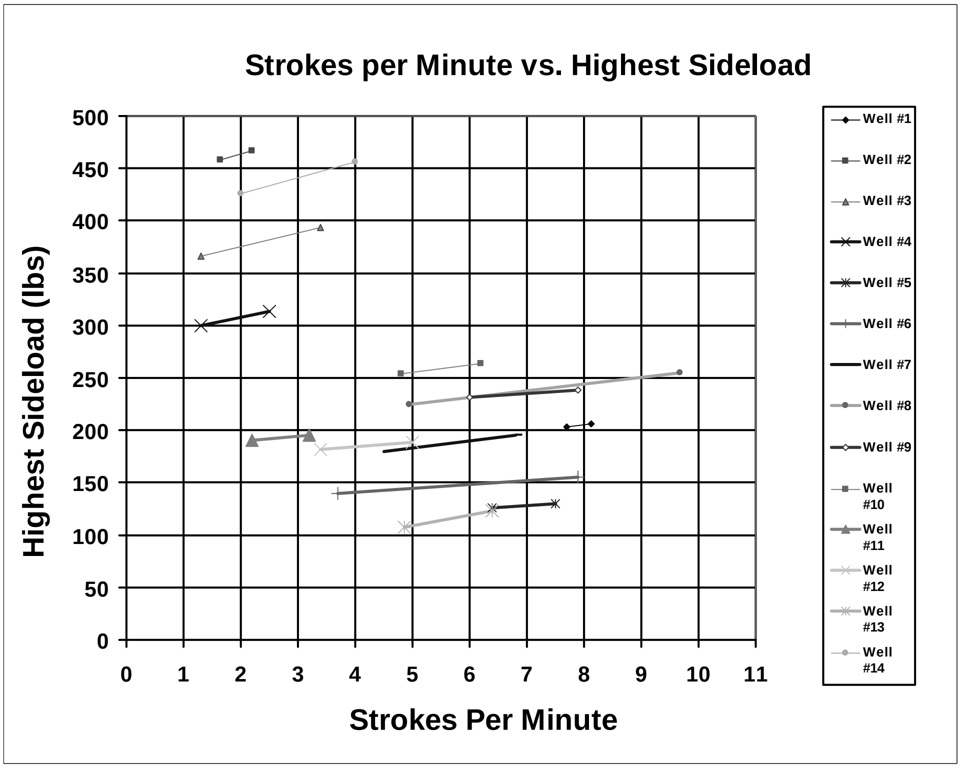

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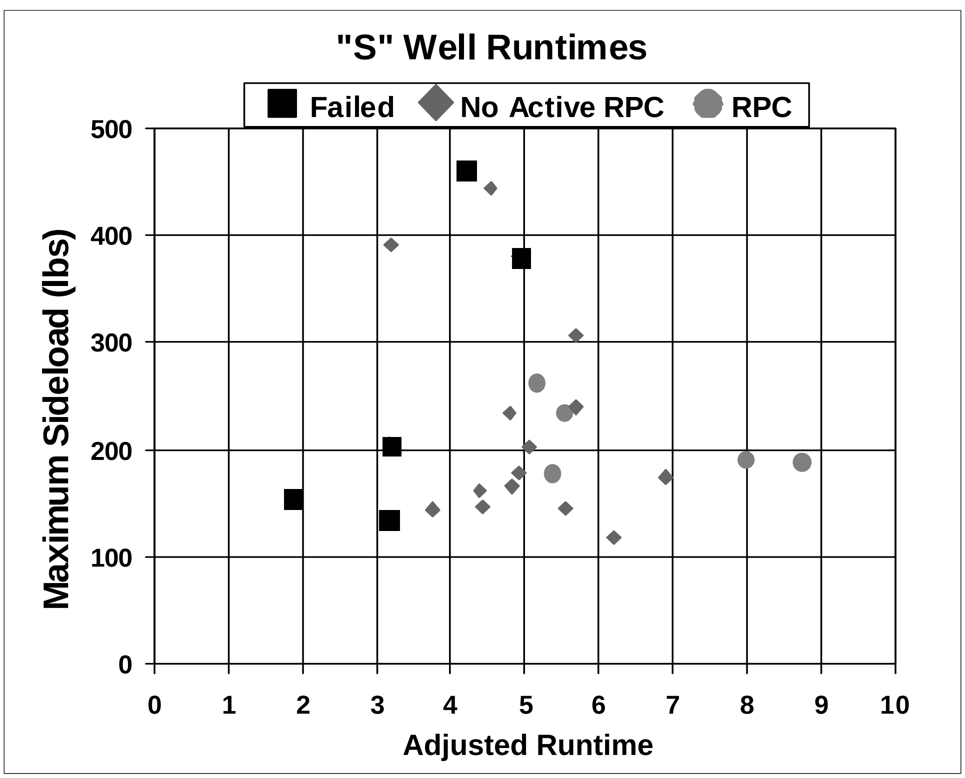

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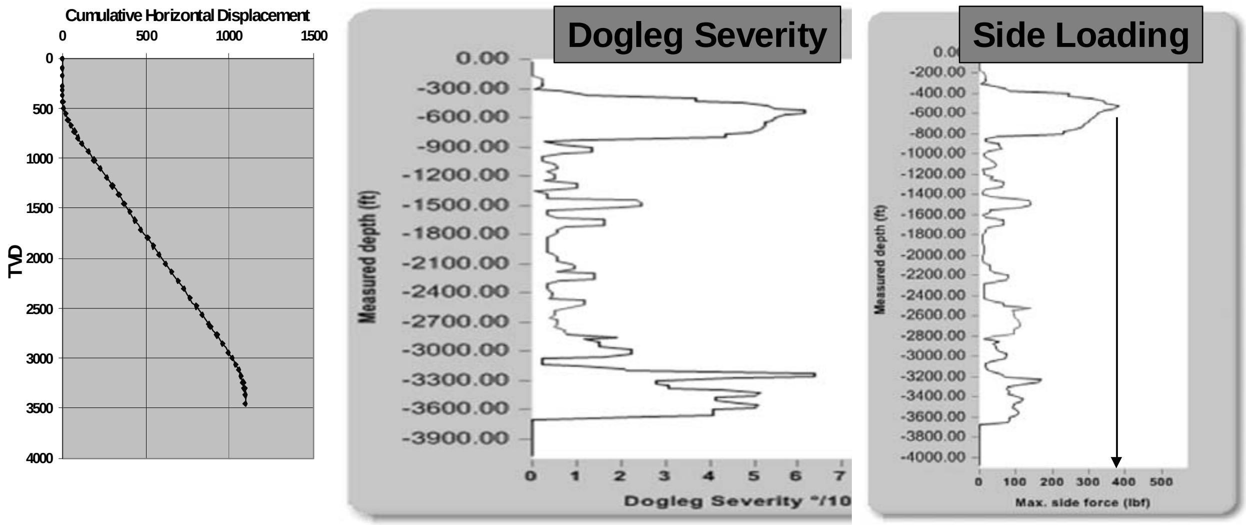

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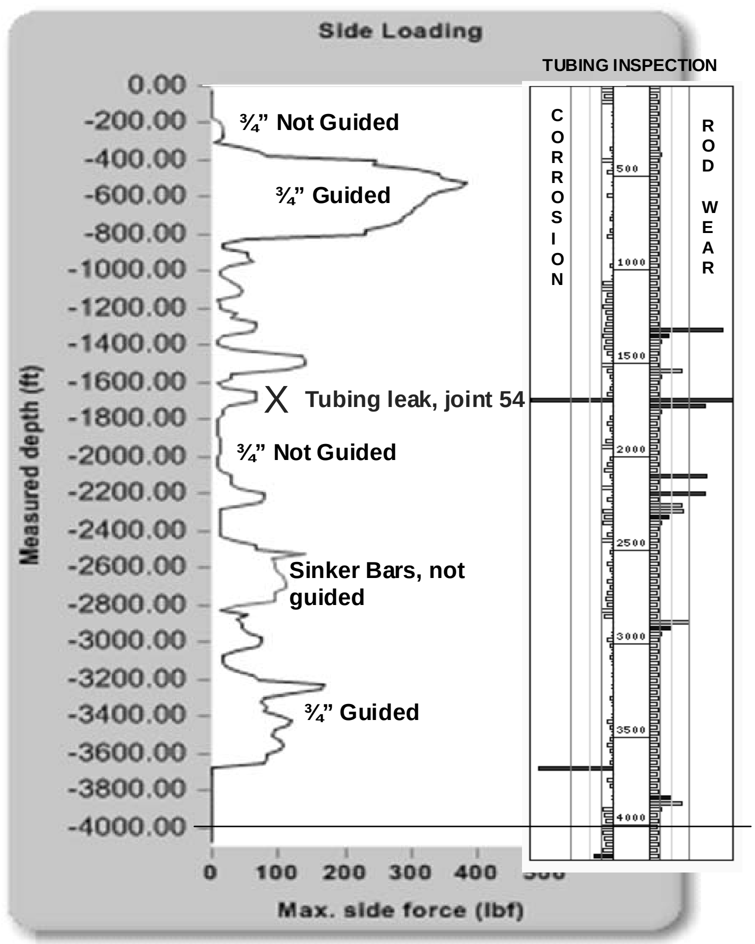

Figure 7

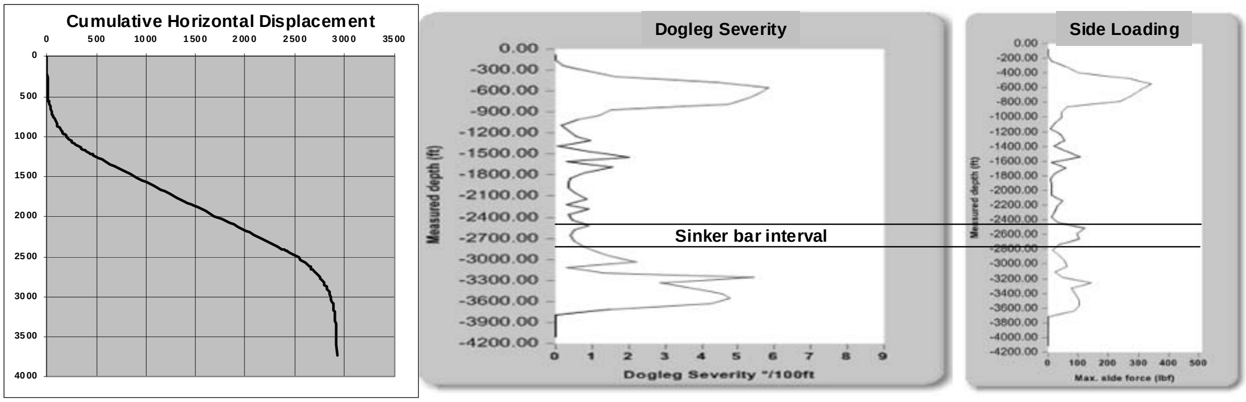

Figure 8

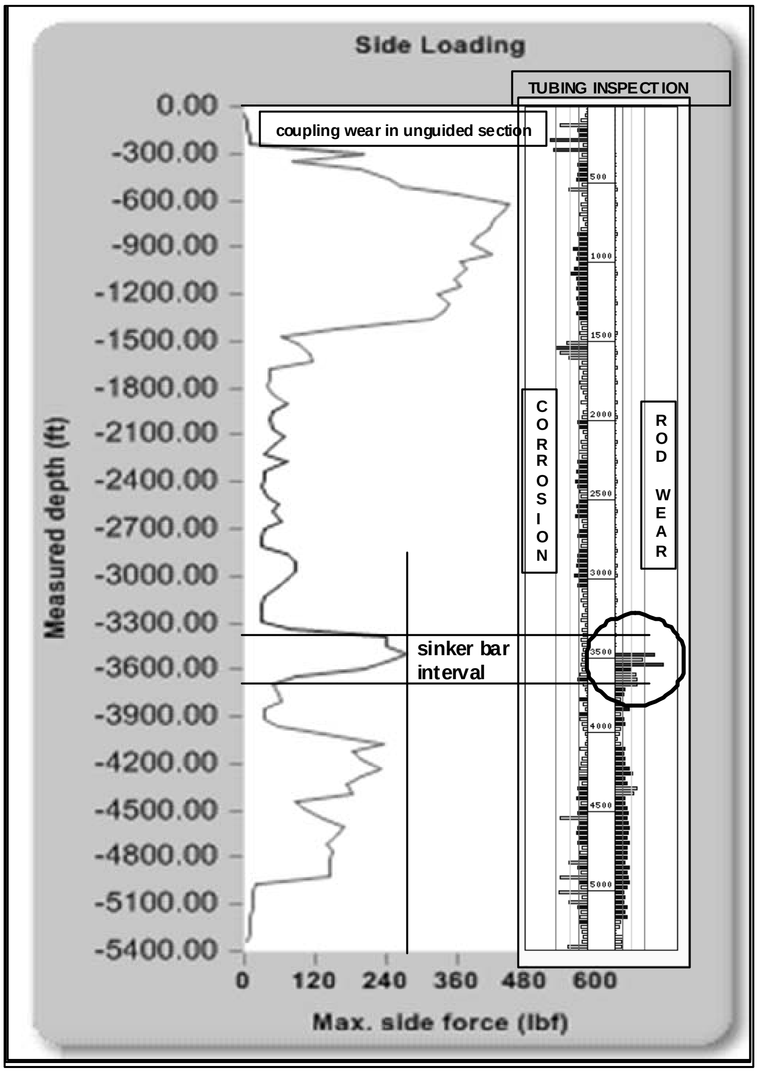

Figure 9