A WEB-BASED FAILURE DIAGNOSIS AND FREQUENCY REDUCTION SYSTEM, FEATURING IMAGING OF ROD-PUMPED PRODUCING WELLS

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ABSTRACT

There are over 600,000 rod-pumped wells in North America alone and failure of this common artificial lift system substantially raises lifting costs for many operators. Among the leading causes of failure in sucker rod-pumped wells are rod parts and tubing holes or splits, caused by corrosion and/or mecahnical wear. In many cases, a minority of wells constitute the majority of repeat failures and workover cost in a field. Reliable data with regard to the root cause of tubing or sucker rod failure is critical. Obtaining tubing geometry, wall thickness and rod condition, correlated by depth, during the current well service, is critical to determine the failure root cause and prevent further failures.

A service system, VisuWell®, is presented that uses high resolution data and internet-based imaging of key well conditions to (i) enable efficient analysis and (ii) apply preventive measures before the well is returned to production. The system may be used to determine well failure root cause(s) such as corrosion, side load (as a result of deviation) or pumping mechanics, rod buckling or a combination of effects. The ultimate goal is to lower well failure frequency and thereby reduce lifting costs. Case histories involved in a total of over 1,100,000 feet of wellbore analysis are discussed.

INTRODUCTION

Significant effort has been expended in systems and techniques to optimize rod-pumped wells and lower failure frequencies. Corrosion inhibitors; variable speed drives; pump-off controllers; fluid level analysis; SCADA systems; rod-string design and predictive analysis software; tubing & rod inspections; sinker bars; rod guides; polyethylene tubing liners; rod and tubing rotators and many other innovations have all helped to drive down failure rates and thus lower lifting costs.

Operators are able to drive down failure frequencies, only to struggle with pushing further below the plateau (Figure 1). More real-time information of exactly what is happening downhole in the production conduit is required to make key decisions.

Tubing Condition

Sucker rod and tubing inspection programs have long been recognized as beneficial[1]. Significant expenditures have been incurred performing electromagnetic inspections of tubing over-the-wellhead, commonly called "tubing scans". Unfortunately, well operators' field personnel have neither the specialized knowledge of the physics involved in such inspections, nor the necessary time, to qualify the results obtained.

Newman & Jarrett in 2006[3] observed many of the shortcomings of conventional tubing scans and cautioned against relying on such data alone. Many critical factors significantly affect the results, including extreme sensitivity to pulling speed of time-based data sampling, sensor offset due to tubing surface conditions and coupling "ride", poor centralization, dependence on interpretation of analog signals and others. Fundamental signal processing and display techniques in much of this equipment have not changed in over forty years - it's still analog and depends upon operator interpretation.

Equally importantly, the condition of the tubing alone may not be indicative of a well's failure root cause. Tubing may be successively re-positioned in the well during tubing servicing and re-cycled through used tubing programs. Thus, observed wear patterns of tubing alone cannot be relied upon as a sole source for failure analysis. In general, the industry has tended to place far too much faith in such tubing scans. If the condition of the rod string could also be determined and correlated to tubing condition by depth, corroborating evidence could be obtained.

Sucker Rod Condition

Conventional magnetic flux leakage inspections of sucker rods in reclamation plants allows continued use of sucker rods that have yet to reach their ultimate fatigue life[1]. However, inspection results are commonly provided only after the well has been put back on production. The well may even fail again before the inspection report is available.

Most importantly, the valuable information as to rod body wear and coupling wear relative to well depth is lost. Anyone who has ever tried to mark sucker rods as to their position in the well when pulled and ensure this numbering is maintained throughout the reclamation process knows how difficult this is to achieve.

Tubing Deviation

Many wells drilled as “straight holes” have doglegs that pose severe problems to production staff (Figures 2 & 3). This phenomenon can be worsened by the nature of the drilling contract as deviation often occurs as the drilling rate of penetration changes through differing formations. High dogleg severity wells can be difficult to produce with sucker rod pumps and may exhibit high failure frequencies, particularly with corrosion from H_2S, CO_2 breakthrough or high water cuts[12]. In such conditions, dynamic loads can cause rapid wear-corrosion, abbreviated fatigue life and premature failure.

Formation subsidence and compaction occurs in some formations as a result of hydrocarbon production and can rapidly lead to increasingly difficult production problems due to formation shift along fault-related slip planes.

Many operators of rod-pumped fields have struggled with repeated-failure situations and undertaken costly directional surveys of producing wellbores to obtain accurate information as to inclination and azimuth. However, these surveys are expensive and low resolution. Secondly, casing deviation is not necessarily an accurate indication of tubing deviation.

Further, applying tensile load to the tubing anchor with the intent of straightening a tubing string is of questionable value. The string is subject to thermal expansion and, if the well deviates from vertical, tension may effectively be applied only to the first dogleg, potentially leaving the lower tubing zone in compression and subject to buckling.

Downhole Production Equipment & Pumping Optimization

Excellent work has been performed by others to model the effect of dynamic behavior of the rod string in deviated wellbores and the impact on rod-pumping forces[6,7,10]. Such analytical tools have lowered failure rates through predictive modeling of downhole forces[7]. However, accurate wellbore deviation data is required.

The fact that sucker rod-induced wear on the tubing string and failure of the sucker rod string due to wear constitutes a large component of total industry failures is well established[1,2,4,5,7,8,11]. The benefits of rod guides, tubing coatings/liners, sinker bars, rod/ tubing rotators and other wear-mitigation measures have long been recognized. The requirement to effectively space rod guides within the rod string is also well-documented[5,8]. Analytical tools have been presented that allow an operator to plot and monitor downhole failures[9].

Effective application of such optimization methods requires certain critical information such as fluid level and wellbore deviation. Developing wear and corrosion mitigation solutions similarly requires key condition information.

Solution Requirements

Unfortunately for the operator of rod-pumped wells, multiple techniques have not previously been integrated into a cost-effective, expert system capable of:

- Overcoming prior technology implementation shortcomings in accurately and consistently acquiring key production conduit data at the well site
- Economically measuring deviation of the tubing string (not the casing) from surface to pump, BEFORE the tubing anchor is released, so as to measure deviation exactly as encountered by the rod string
- Consolidating tubing deviation, rod condition and tubing condition into a single depth-indexed data file
- Minimal additional required rig time. Achieving close integration of the data acquisition equipment and service with the service rig and crew within existing rod and tubing operations
- Imaging a near-real time presentation of the data in a concise, quickly-understandable format to facilitate root cause failure analysis and a failure mitigation solution BEFORE the well is put back into production
- Maintaining a database of well failure history and graphically displaying failure location, coincident with other key well parameters
- Automatically calculating side loads and determining a potential solution to each well-specific case

- Display of an entire field of serviced wells with surface locations and wellbore geometry
- Providing dynamic views of problem areas in a single producing well and multiple wells in a producing unit or field for simultaneous comparison and trend evaluation
- Operating on the ubiquitous Windows PC, allow data imaging regardless of physical location

Commencing in early 2005 through 2007, an effort was undertaken, with the invaluable aid of two operators of sucker rod-pumped producing wells, to develop a mobile, web-enabled system that could deliver on these requirements and thereby help determine the root failure cause and suggest a timely mitigation solution for high cost wells.

SYSTEM DESCRIPTION

Clear goals were established early in the conceptual design phase that demanded overcoming certain existing impediments in prior uses of disparate technologies. The team felt that little groundbreaking physics would be undertaken but that a fundamentally new approach to old problems was required. The specifications included:

- Deviation profile in tubing sizes from 2⅜" to 5"
- Performing analysis of ⅝" to 1" sucker rods for pitting, cross-sectional area & diameter and of 2⅜" to 3½" tubing for pitting, wall thickness and diameter at a consistent 0.200 inch resolution throughout the well depth
- Digitizing at the raw sensor output and fully leveraging modern computer processing power, improving the signal-to-noise ratio and reducing dependence upon analog systems which require constant human interpretation
- Insensitivity to the speed of pulling tubing or rods from the well and thus generate constant resolution data, regardless of pulling speed
- Be impervious to downhole conditions by using no contact of the sensors with either the tubing or rod as they are pulled from the well
- Compensating for changing sensor-surface offset
- One foot resolution web-published data throughout the well depth
- Accommodate pulling a "wet" tubing string if necessary
- Provide a dynamic, user-friendly and easily understandable three-dimensional image of the producing wellbore with zoom capabilities on a standard Windows PC
- Provide an automated failure mitigation solution at the well site during well service and simultaneously publish it anywhere in the world
- Minimize interference with the normal well servicing and workover process and not require additional well servicing operations or equipment such as slickline or wireline units
- Be cost effective, even in lower commodity price environments

A considerable amount of technology development and engineering effort was expended to meet these requirements. For example, performing sucker rod analysis required the system to be a structural member of the rod service assembly, transferring the load of the rod elevator back into the wellhead.

The entire system consists of 4 basic sub-systems:

1) Rig Floor Sensor Package (RFSP) that houses a purpose-built microprocessor-controlled data acquisition system and replaceable sensor inserts to perform analysis of the sucker rod string and the tubing string as they are pulled from the well. All data is digitized and controlled by the RFSP microprocessor system, relative to depth, rather than time. The RFSP utilizes a tri-axial, inert gas-dampened, self-centralizing mechanism to ensure the RFSP "floats" around the rod or tubing string. (Figure 4). The RFSP housing was designed to conform to I.E.C. Standard I.P. 66 for fluid ingress so as to allow pulling of wet tubing strings (Figure 4a).

2) Deviation Profile Tool (DPT), containing an Inertial Sensor Tool Module (ISTM), with three pairs of gyroscopes and accelerometers operating in three orthogonal axes; Command, Control, Processor & memory module (CCP) and; a battery pack housed in a thermal and pressure-protective housing (Figure 5). The DPT may be operated from a standard pulling unit sand or swabbing line. A remote display of depth and speed is provided to the pulling unit operator. (Figure 6)

3) A Field Service Unit (FSU). This is a truck-mounted control room with ruggedized computer system, electronics, power supplies and conditioning, generator, air compressor and satellite communications equipment used for data processing, real-time displays and database synchronization. The FSU carries and stores the RFSP

and DPT, along with associated size-dependent accessories and provides a digital interface to the RFSP data acquisition system via real time Ethernet (Figure 7).

4) Over 700,000 lines of software code were written to accomplish the current system. This effort is perhaps the most complex element of the system, containing multiple software and firmware applications. Keeping the technology deliverable on a "standard business box" required a framework of applications to deliver complex data to the desktop. Figure 8 shows a general software data processing flow diagram

   a) By defining the necessary software into discrete applications, coding challenges that were overcome included achieving real-time data acquisition systems while performing complex classification algorithms; using standard tools such as Microsoft .NET to meet I.T. departments' security requirements and; developing optimization & mitigation rules algorithms that learnt from other rules. In some respects, parts of the software system are evolving towards "genetic algorithms", a technique used in computing to find exact or approximate solutions to optimization problems though successively reproduced generations of modified solutions.

   b) Real-time data acquisition and processing software within the microprocessor system in the RFSP to handle the high channel count digitized data on the rig floor; within the computer in the FSU to aggregate and process data with flaw classification algorithms and then pass the data to an OpenGL real-time display; allow input of well operating parameters to facilitate the development of a wear mitigation solution with an expert system; data quality management and finally; store and communicate a large volume of data to the web server portal.

   c) Database storage and processing software that resides on the web server portal. Each FSU also contains a redundant image of the web server database in case of communications failure.

   d) Web browser 3-D imaging software to interpret the web-portal data and convert it into various images, both 3-D and 2-D. This dynamic viewer provides the client user with extreme flexibility to display single wells, zoomed areas of a single well, changing view point, selected data components, through an entire field and to map cross-wellbore queries for common conditions across the entire field. (Figures 9 to 12)

FIELD OPERATION

The process of operations is generally as follows -

1. The RFSP is rigged up on the rig's standard rod table and a short pony rod through the center of the RFSP.
2. The rod string is pulled as normal, with the rod elevator landed on the RFSP, transferring the rod string weight through the RFSP and back into the wellhead (Figure 4). Velocity of the pull is limited only to a maximum of 500 feet per minute (f.p.m.).
3. Upon completion of the rod pull, the RFSP is rigged down, while the rig crew prepares the sand or swab line.
4. The DPT is assembled, made up into a standard sucker rod-rope socket x-over, stabbed into the tubing, either with or without a lubricator, as appropriate, and held stationary at surface for two minutes.
5. The DPT is run into the tubing at between 150-250 f.p.m. on the sand line to a reasonable depth slightly above the seating nipple and held on bottom for five minutes.
6. The DPT is pulled back from bottom at approximately 150 f.p.m. The pulling unit operator uses the remote display to monitor speed and depth.
7. The DPT data is removed from the tubing and the tubing anchor may then be released.
8. The RFSP is rigged up on top of the tubing slips.
9. The tubing string is pulled as normal through the RFSP. Again, velocity of the pull is limited only to a maximum of 500 feet per minute (f.p.m.).
10. The RFSP is rigged down from the tubing slips/BOP.
11. The data is synchronized back to the web server.
12. Well operator personnel then launch the VisuWell application from Internet Explorer on their local machine . This allows dynamic three-dimensional viewing of individual wells or entire producing fields. Tubing and rod

geometry and condition data, by depth in the producing well, is downloaded from a web server in a compressed data stream and then displayed in a dynamic 3-D image. Correlation of deviation, wear and failures is presented. Cross-wellbore queries allow mapping of systemic conditions within an entire field view.

ECONOMICS

Many field operations personnel find themselves pressured to focus upon the cost of the returning the well to production rather than the aggregate cost of repeated well failure over one or two years or longer. This tends to result in a focus on pulling unit hours per failure rather than reducing failures per well per year (FPWPY). In reality, if a single future failure and resultant well servicing can be prevented, the 6-8 extra hours of rig time are a wise investment.

Consolidated producing field failure frequencies of .25 – .40 FPWPY are not uncommon in North America. In a hypothetical field of perhaps 400 wells, each producing 25 BOPD, with an average cost of "tubing-out-of-the-hole" workovers of $15,000 per job, such failures cost $1.5 million to $2.4 million per year. At a 75% net revenue interest, this results in $0.55 – 0.88 per barrel of controllable lifting cost. This does not take into account the effect of deferred production and equipment replacement expenses.

To better analyze the economic effect of the additional investment to develop a mitigation solution and lower FPWPY versus the costs of current FPWPY rates, a payback, or rate of return, calculation is often performed. Operating companies may have a preferred format for these calculations. However a typical example of the type of calculation and the rate of return that can be achieved is shown in [Table 1]

RESULTS

In servicing over 200 wells and 1,100,000 feet of wellbore, VisuWell has shown itself capable of providing information and analysis on previously unidentified conditions in producing wellbores. Selected case study examples follow and are shown in the referenced figures:

Case Study 1

A Permian Basin well was completed in July 2007 in the Spraberry Trend. The TAC was set at 7,954 ft and the pump initially at 9,200 ft. By November of 2007, the well had experienced three hole-in-tubing failures for an aggregate FPWPY of over 9. All three failures had occurred between 7,700 and 8,000 feet MD. As a result of the two early failures, the operator moved the pump up to 8,042 ft, closer to the TAC. Thereafter the well failed a third time, again in the same zone. Upon performing a VisuWell analysis, it became clear that there were two distinct zones of high side load in the well, one from 6,369 ft to 6,420 ft and a second zone from 7,912 ft to 7,968 ft. (Figure 13). In order to prevent further tubing wear, the operator installed rod guides from 500 ft above the upper zone of high side load to immediately above the pump. Significant H_2S corrosion was evident in the lower zone on both the rods and tubing, leading to an improved inhibitor program. Guide wear also indicated that the side load required increased guide spacing density (Figure 14).

Case Study 2

A Permian Basin well was producing from a pump depth of 6,726 ft. A conventional tubing scan had been performed. While running back in the hole, the operator observed significant pin end wear in tubing that had been classified as "Yellow Band" per A.P.I. RP5C1 (remaining wall thickness greater than 85% of nominal). A VisuWell systematic analysis was performed that revealed 13 joints of tubing with wall thickness less than 70% of nominal ("Green Band") and 2 "Red Band" joints with wall thickness less than 50% of nominal. The joints were destructively analyzed to physically measure remaining wall thickness, corroborating the system wall thickness results within 9.9%. Much of this tubing clearly exhibited classic combination wear-corrosion in extended axial grooves, suggesting that the inhibitor batch treatment program be modified. (Figure 15)

Case Study 3

A 2,500 ft directional well in California exhibited two rod failures and a tubing failure, with average run times of 315 days. The failures had occurred at 754 ft, 1,354 ft and the hole in tubing at 2,108 ft. The system revealed that failures resulted from extreme rod body wear in two primary zones of side load over 300lbs from 630 ft to 1,227 ft and 1,330 ft to 1,885 ft. (Figure 16), that would benefit from the use of rod guides. Inclination peaked at 25.1^{o} at 1,302 ft. A rod rotator was also added as a result of the high deviation and data showing that the rod body wear was contained within an 18 ft area spanning the center of the rods (Figure 17).

Case Study 4

A Permian Basin well was producing from the Clearfork formation with the pump at 7,082 ft. The well had suffered numerous rod body failures at approximately 4,200 ft. A VisuWell analysis was undertaken in late June 2006 that identified inclination of nearly 14^{o} and side load of over 150 lbs beginning at 2,823 ft to 5,552 ft. Maximum inclination was almost 13^{o} at 3,950 ft. As a result, it was recommended that the rod string be guided from 3,000 ft to 6,025 ft.

Case Study 5

A California well, producing from the Repetto formation at 3,200 ft. had failed 9 times in approximately 52 months, for an aggregate failure frequency of over 2, substantially higher than the field average. In particular, the rod string had failed on three occasions in an interval between 1,000 and 1,600 ft. Tubing had also failed at approximately 1,600 ft. Following a VisuWell analysis, it became clear that there was inclination of greater than 8^{o} from 840 ft to 1,690 ft. The current rod string exhibited wear in two zones from 600 ft to 960 ft and from 1,600 to 1,800 ft. This wear correlated to zones of high side loads exceeding 200 lbs. It can also be seen that wear in the current tubing string was centered around the upper zone of the well above 600 ft, suggesting that the rods were stacking out in compression (Figure 18). Tubing wear is shown in Figure 19 and the failure-causing split from excessive wear in Figure 20.

CONCLUSIONS

The VisuWell system is not a panacea for rod pumped well failures. Nor is it intended to replace tubing or rod inspections performed in reclamation plants under closely controlled-environments, where additional non-destructive testing techniques can be applied to further evaluate flaws.

However, it does obtain detailed real-time data from rod-pumped well elements inherent in failure frequency analysis and mitigation. The system provides a unique methodology of helping determine the failure root cause. Dynamic imaging allows a user to quickly assess wellbore conditions and develop a solution that can prevent a repeat workover. Failure mitigation solutions have been created that have helped extend the run times for problematic wells.

It should be noted that although rod-on-tubing side load calculations provide valuable information on the possible wear points in a well, other parameters impact failure frequency and can be more injurious - particularly rod string buckling and severe corrosion. Experience however, tells us that failure root causes tend to be combinations of multiple conditions. For example, tubing failure is commonly a combination of both mechanical and chemical actions. The ability to image the entire tubing string, tubing deviation and rod string provides strong evidence that illustrates downhole problems. Data correlation provides superior information upon which to take corrective action and the system can even help determine failure root cause by confirming the absence of a condition.

By identifying failure root cause and applying a mitigation solution before the well is returned to production, a repeat failure can be avoided. The relatively small increase in well servicing cost is more than repaid in reduced future failures, associated well servicing, equipment replacement costs and increased production. Compelling rates of return and payback periods make the system a useful tool in lowering lifting costs in rod-pumped fields, especially those with systemic issues.

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Table 1

Typical well service economic analysis format

TYPICAL ECONOMIC ANALYSIS		
Date		
Well Operator		
Well name		
API Number		
Net revenue interest, %		75%
Working interest, %		100%
Net realized oil price, $/Bbl	$	78.00
Surface pumping unit		
Total well depth, ft		6,988
Pump depth, ft		6,875
Pump size		
Tubing size		3 1/2
Rod string taper I		1
Rod string taper II		7/8
Rod string taper III		3/4
Total gross daily production, Bfpd		600
Water cut, %		91%
Gross daily oil production, Bopd		54
Trailing 36 months failures, #		2
Trailing 24 months failures, #		1
Trailing 12 months failures, #		1
Implied failure frequency, FPWPY		0.67
Average workover costs	$	15,000
Workover unit rate, $/day		
Workover unit rate, $/hour	$	300
Average workover time, "tubing-out-of-the-hole", hours		
Average downtime per failure, days		6
Assumed workovers saved		1
Assumed New Failure Frequency		
Cost of wear mitigation solution	$	2,560.00
Assumed cost of capital		8%
Lost revenue per failure	$	18,954
Added workover unit cost due to VisuWell job	$	1,800
VisuWell cost	$	6,188
Mitigation solution cost	$	2,560
Incremental cost	$	10,548
Total workover cost	$	21,095
Forward 12 months Economic Impact	$	23,407
Incremental cost payback period, months		5.4
Internal Rate of Return		104%

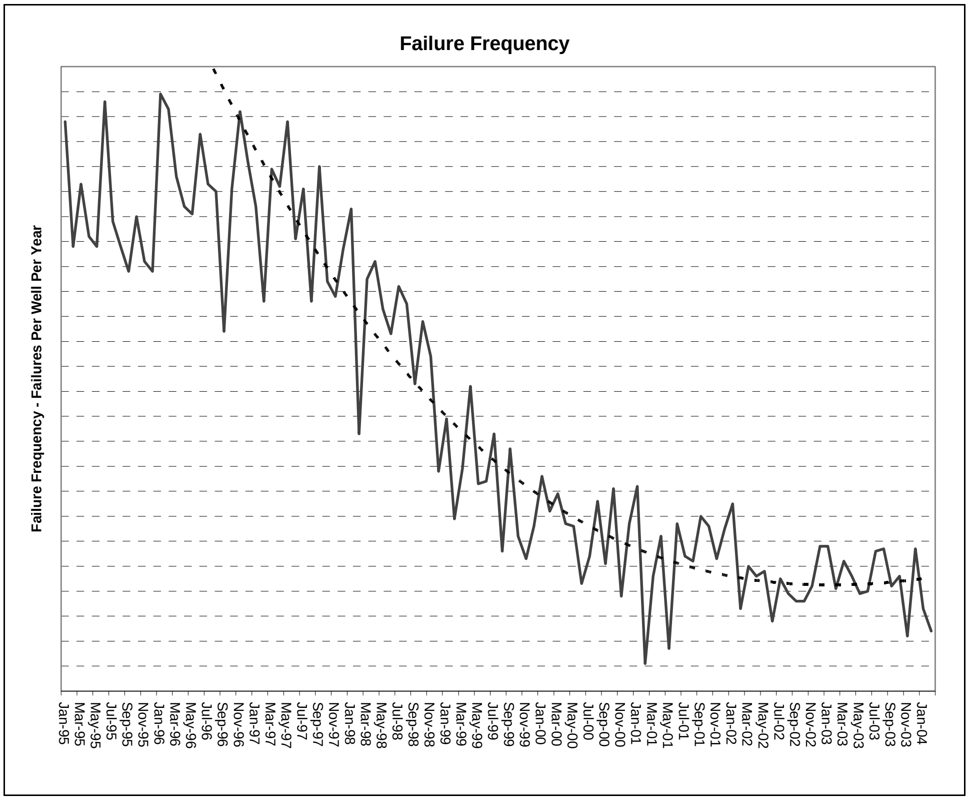

Figure 1 – Rod Pumped Well Failure History in a Large Permian Basin Field

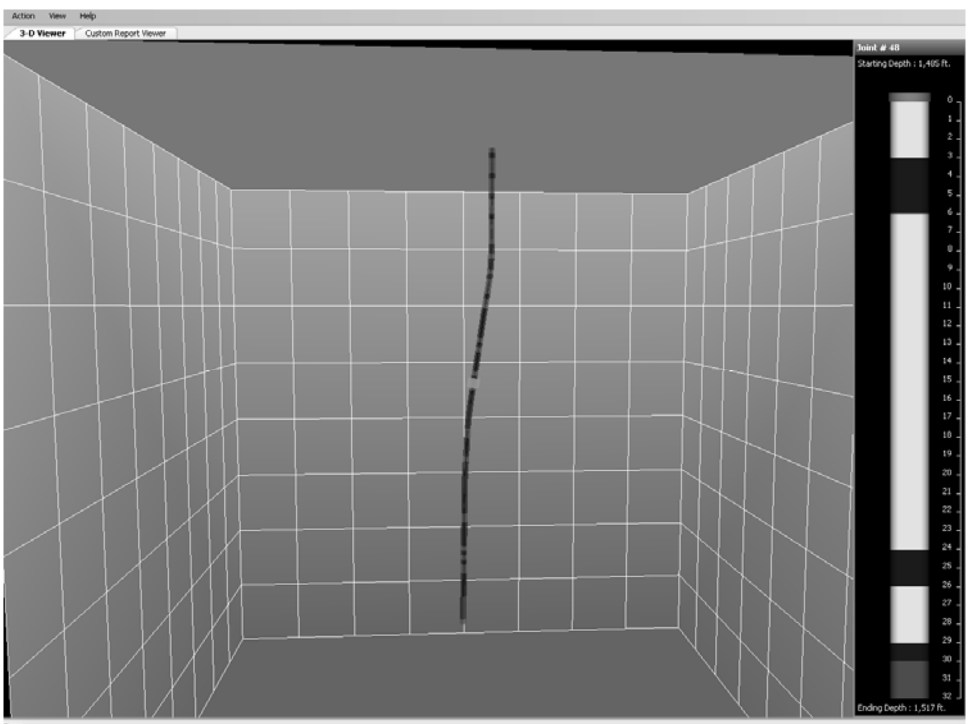

Figure 2 – Deviated Well with Worn Tubing at Top of Hole

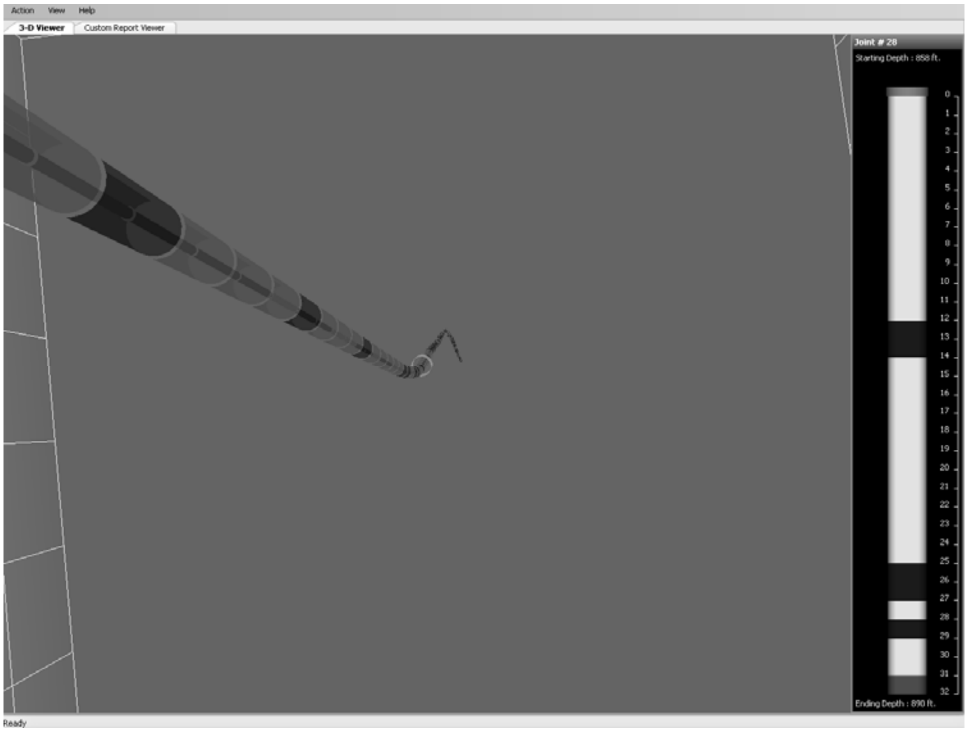

Figure 3 – Rotated View of Deviated Well

Figure 4 – RFSP Rigged Up During a Sucker Rod Analysis

Figure 4a – Tubing Analysis During a Wet String Pull

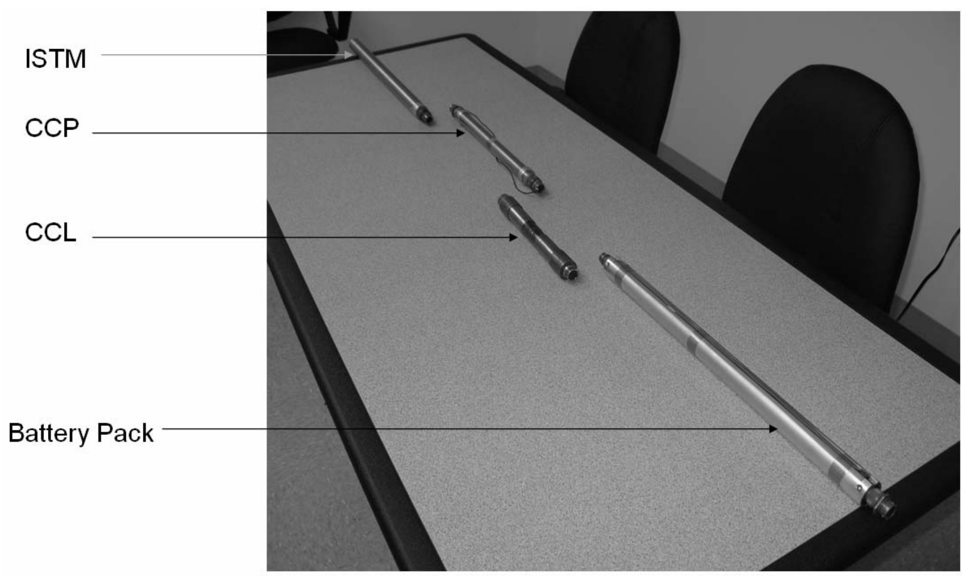

Figure 5 – Deviation Profile Tool Components

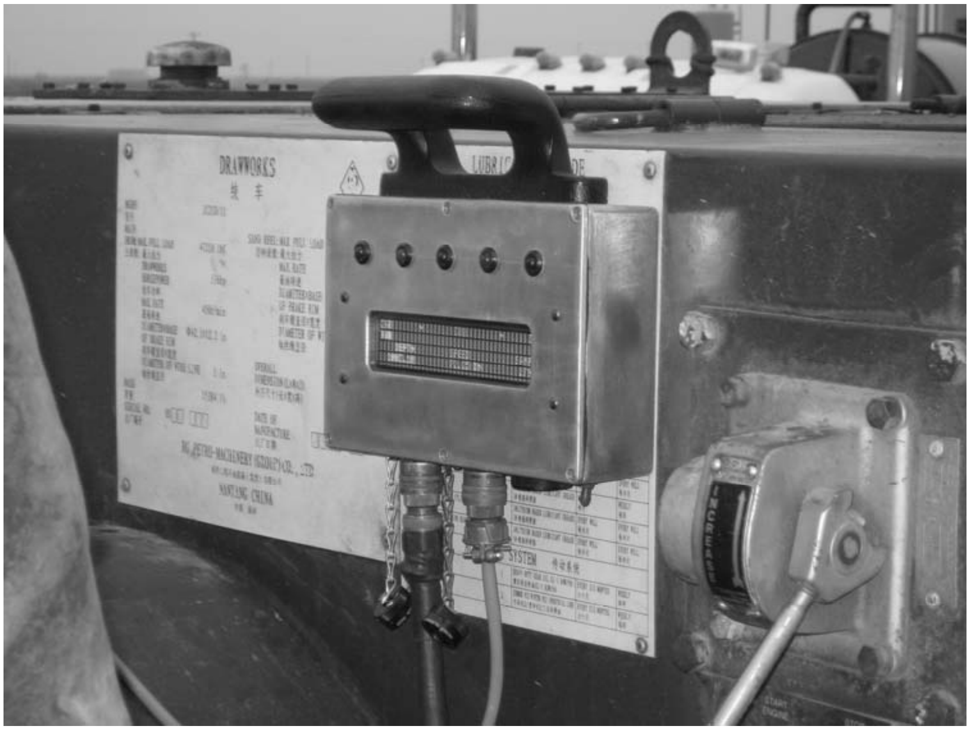

Figure 6 – Pulling Unit Operator's Remote Depth Display

Figure 7 – Field Service Unit

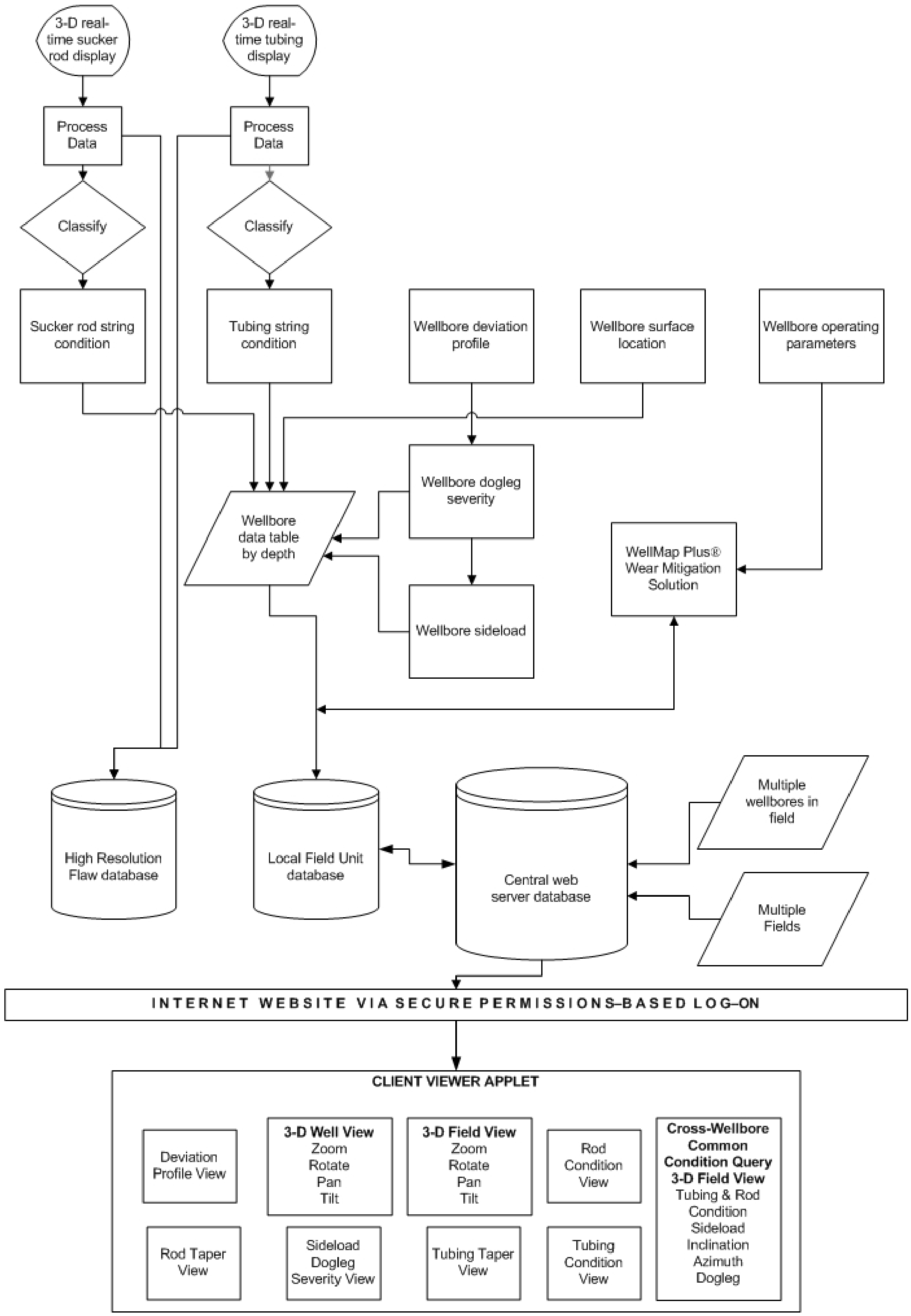

Figure 8 - Software Process Flow Block Diagram

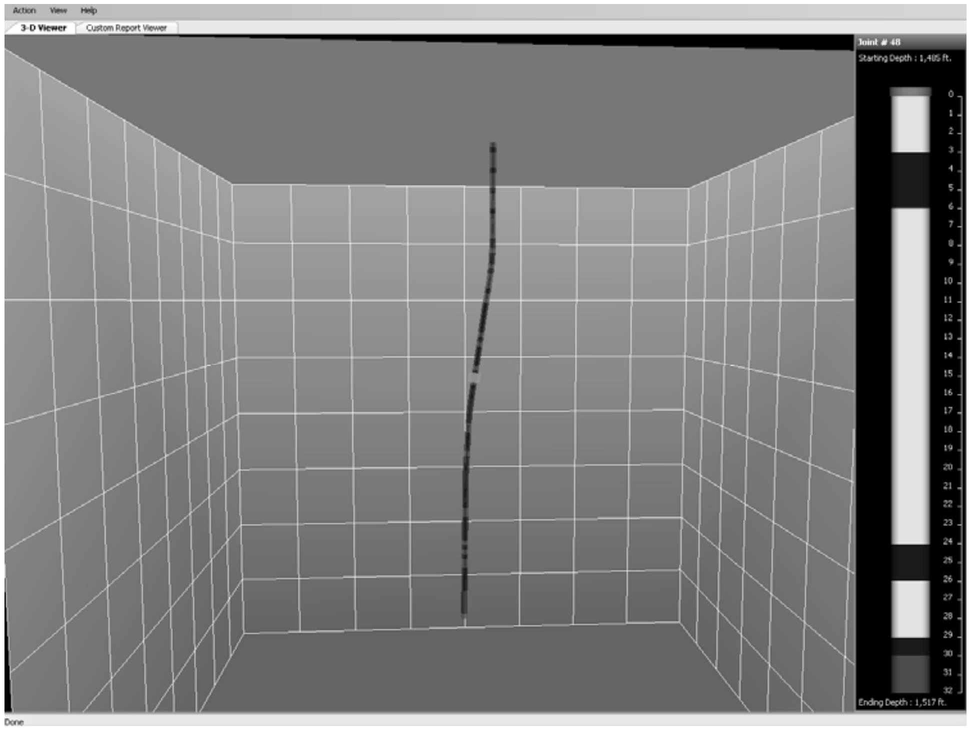

Figure 9 – Base 3-D Wellbore Image

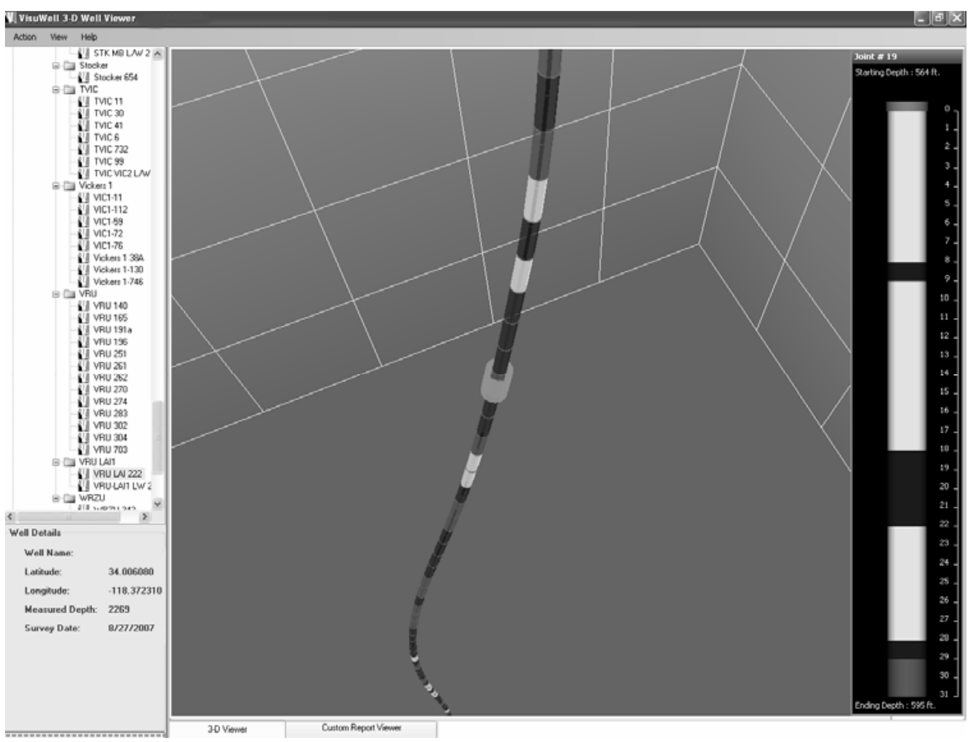

Figure 10 - Zoomed Section of Single Well Showing Deviation

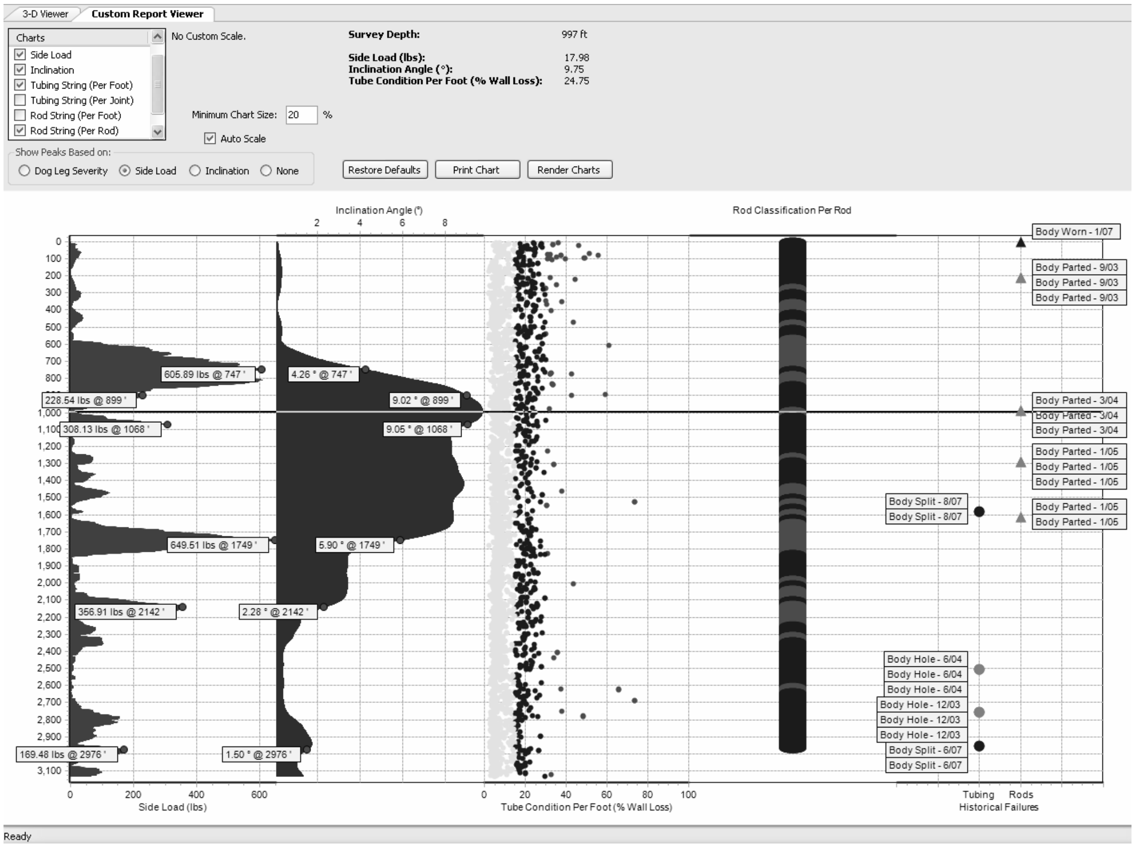

Figure 11 – Details of Wear and High Side Load Zones

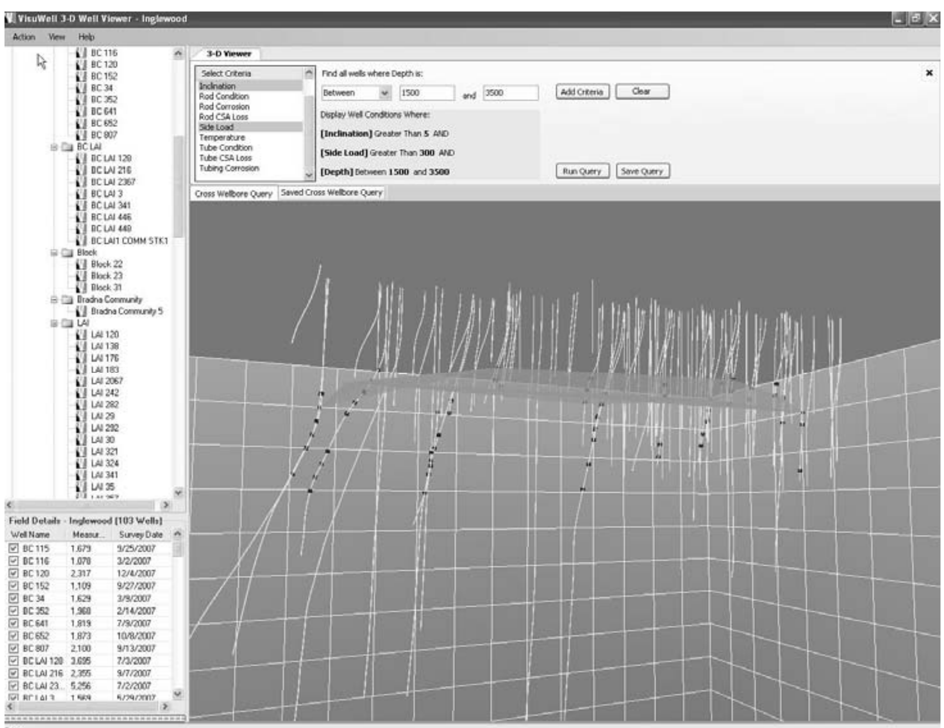

Figure 12 – Cross Wellbore Query of Entire Field

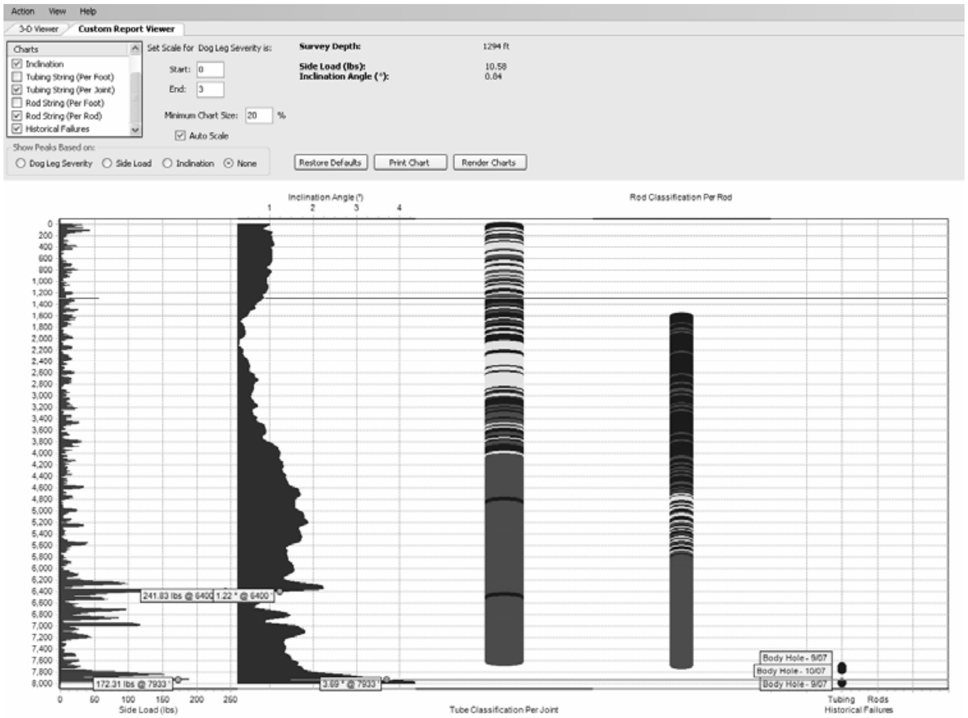

Figure 13 – Spraberry Trend Well With Failures in High Side Load Zone Above Pump

Figure 14 – Rod Corrosion Detected in Spraberry Trend Well

Note: Wear On One Lobe Of Rod Guide

Figure 15 - Typical Wear-Corrosion, Consistent with Inhibitor Wipe & Rod-On-Tubing Wear

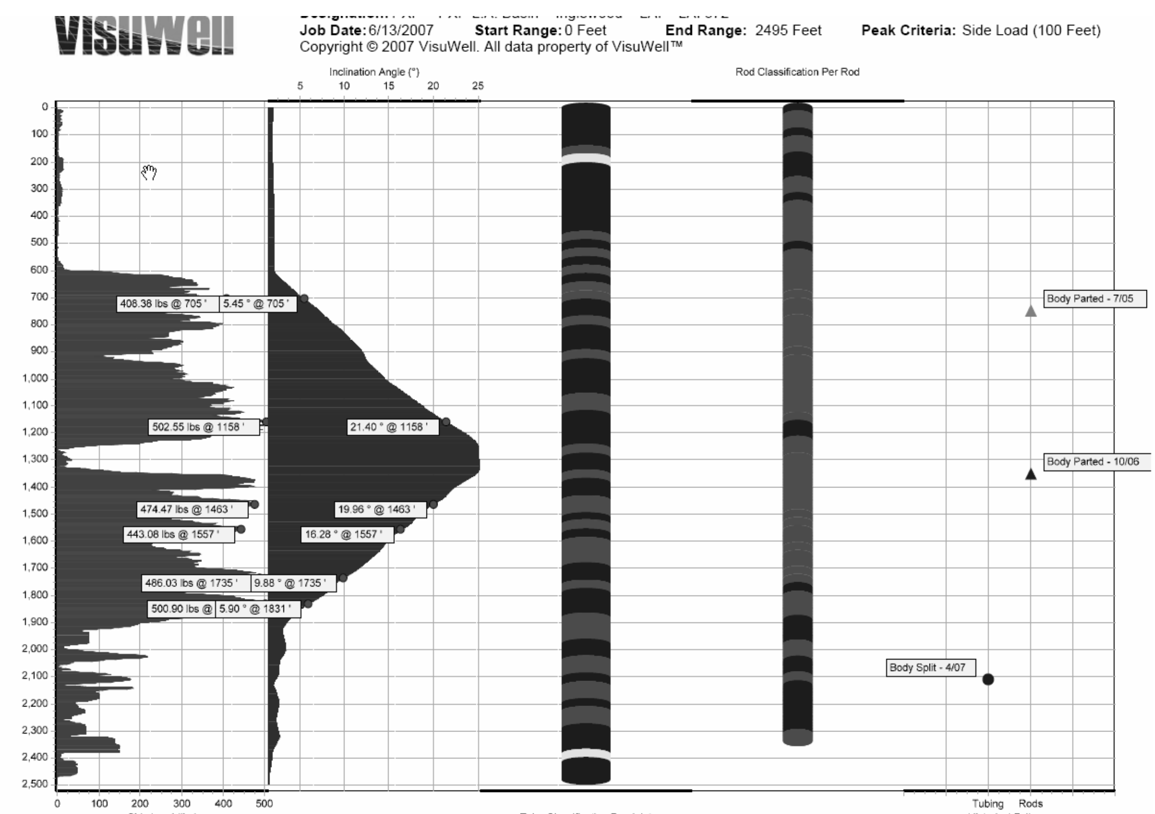

Figure 16 – Directional Well in California

Figure 17 - Sucker Rod Body Wear

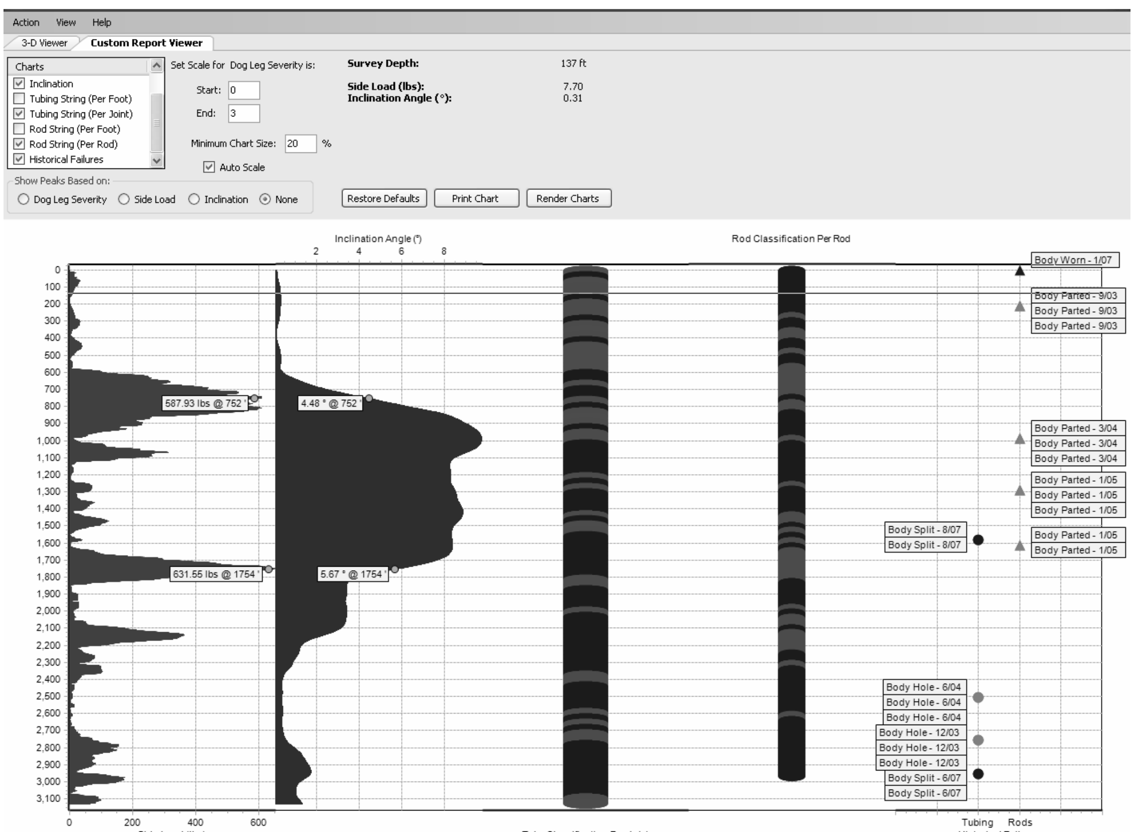

Figure 18 –Rod Wear Correlating to Zones of Higher Side Load And Tubing Wear in Upper Zone From Rod Buckling

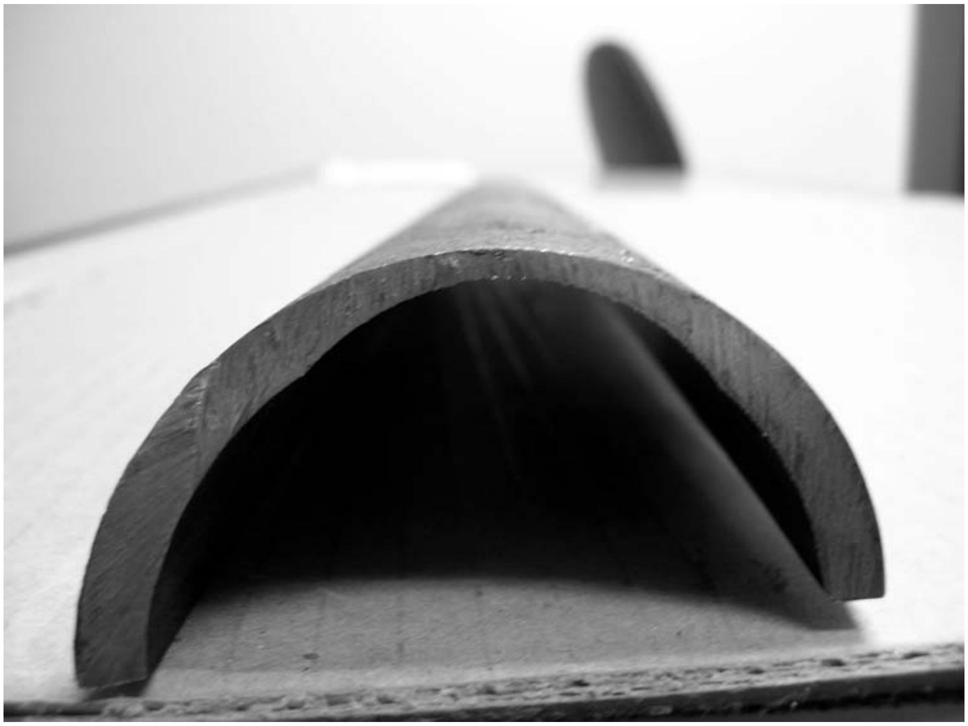

Figure 19 - Rod-on-Tubing Wear in a California Well

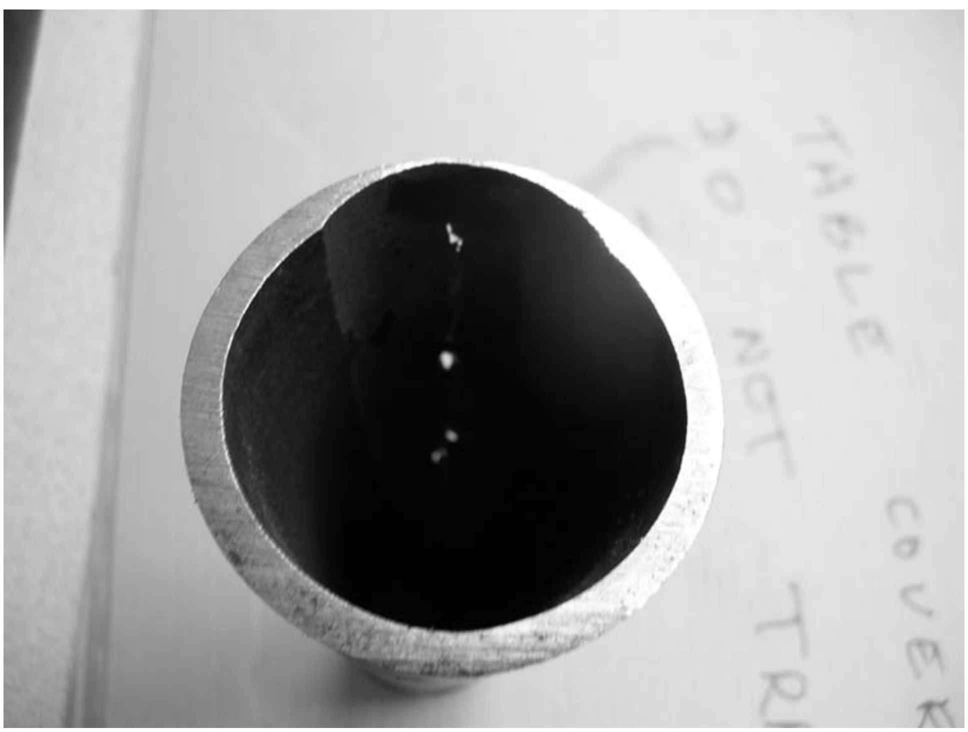

Figure 20 – Split Induced by Rod-on-Tubing Wear