A SUCCESSFUL HOLISTIC ROD PUMP FAILURE REDUCTION PROGRAM

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INTRODUCTION

Oasis Petroleum's success in further reducing the failure rate (FR) of wells over the past couple of years has been the result of an analytic and holistic approach to a broad spectrum of operational and equipment change options with corresponding changes in operating philosophy. The definition of failure rate used by Oasis is number of failures per well per year. Oasis produces approximately 850 rod pumped wells in North Dakota and Montana with the majority of Bakken and Three Forks wells set in the vertical section at 8,000 to 10,000 feet. A continuing focus on failure reduction over the last couple of years has resulted in a decrease in FR from .92 in 2016 to .68 in 2018. The rate decrease was not due to one change, but a combination of ongoing changes in design, operations, training, analysis and the implementation of new technology.

Key Areas of Improvement

Even though these wells are producing from the Bakken and Three Forks, there is still a great deal of diversity among them in terms of fluid production, gas/oil ratio (GOR), salinity and temperature. The operations are split into several producing areas with production tech's responsible for individual areas and groups of wells in that area. The additional improvement in FR was the outcome of focusing on four key areas: pump off controller (POC) optimization; rod design; standard operating procedures and failure analysis.

POC OPTIMIZATION

POC optimization is thought to be the most significant contributor to FR reduction. As a result of VFD firmware upgrades in late 2016 Oasis began utilizing secondary pump fillage (SPF) as part of a focus on production optimization and failure reduction. Utilizing this feature (while also adjusting pumping speed, idle time, daily cycles, pump sizing, and matching production to pumping speed) have all been integral parts in the significant reduction in failures.

Firmware Upgrades

Implementing the SPF feature required firmware upgrades to the majority of the controllers. After installing the new firmware upgrade most wells were setup for SPF, and the decision was made to start slowing down at 80% PF, to shut down at 70% SPF, and to aim for less than ten on/off cycles per day and leave the idle time at the default of five minutes. SPF was ultimately enabled field-wide; although, the set points did vary throughout the field depending on the GOR. All of these changes were initially made without remote automation, as we wanted to determine whether they produced the desired results before making the additional investments in technology. This absence of remote automation meant that someone had to physically go to every well, look at the controller to see if the well was cycling, and then filter through POC data to determine what changes needed to be made. This laborious process required a great deal of time and effort.

Momentum of Operational Philosophy and Innovation

After the initial implementation of SPF, the fine tuning of set points resulted in the wholesale acceptance of this change in operational philosophy. The set points that received additional fine tuning were: PF, SPF, speed stroke delay (SSD), and idle time. These successful changes and the new operational philosophy combined to create traction for the installation of remote monitoring software, which greatly increased the rate of optimization. The software also reduced the time required to make changes. The operations team was able to further justify the need for speeding up the rate of operational change to

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reduce the amount of work required with personnel making manual adjustments in the field. With a sharply decreasing FR, it was easy to see that the cost savings from failure reduction would pay for the installation of remote monitoring software. The software would also decrease the time required to optimize a well at current conditions and adjust to changes throughout the life of the well.

Value of Remote Monitoring Software

Remote monitoring software has been a huge asset for the entire production team. The extreme weather conditions in North Dakota and Montana limit or prevent traveling to wells many times per year; however, wells can be monitored with remote access and optimized in any weather condition. Production techs cover large areas, and remote monitoring software has greatly reduced their driving time, enabling them to spend time on more productive activities. The analytics and diagnostic tools in the software have allowed the techs a more efficient daily routine by enabling them to quickly respond to problem wells. In addition to the analytical tools, the techs also have access to more data, since the volume of data stored in the software is much greater than what is stored in the controller. This gives greater flexibility when identifying trends for optimization. The software has also been invaluable for increasing our ability to evaluate well failures and for determining the subsequent installation design.

Long Stroke Cornering and Up/Down Stroke Speed Change

Additional features including long stroke cornering and up/down stroke speed change also appears to have contributed to the reduction in failures in specific cases. Approximately 25% of Oasis Petroleum's rod pumped wells operate with long stroke units. In efforts to manipulate plunger velocity in the critical transitions between the upstroke and downstroke, the utilization of the cornering feature was implemented and considered to be optimized at cornering speeds of approximately1.0 stroke per minute (SPM). In addition, reducing the cornering speeds to approximately 1.0 SPM greatly reduced the harmonics in the shape of the cards that long stroke units typically display (see Figures 1a and 1b). The use of the up/down stroke speed change feature is now being employed in a broader spectrum on conventional and Mark units, and this innovation should have a significant positive impact on failure reduction. The biggest impact should be seen with Mark II units since the geometry of the unit generates a faster downstroke. Initial set-points used for the up/down stroke speed change feature were set at levels greater than 30% stroke length (SL) with less than 25% speed change. This feature has also aided in reduction of intermittent tagging with wells allowing optimal pump spacing. Fine tuning SSD set-points has had a great deal of success with both optimization and failure reduction; and the operational philosophy is to allow our POC's to make an algorithmic decision to respond to pumping speed as quickly as possible by setting the SSD at one stroke. However, that is not always the case because we have found that in some instances an SSD of one causes the well to cycle too often, and it does not allow us to pump through gas. Overlaying shutdown buffer cards and utilizing real time trending, with very high sampling frequency with remote monitoring software, has considerably aided in fine tuning this feature. Lastly, in specific cases many wells have benefitted by changing the speed scaling increase/decrease default values of 5%. Some wells benefitted from a speed decrease change of 25%, which allowed the well to slow down and pump through gas without cycling.

ROD DESIGN

Another obvious key area to evaluate for improvement was rod design. Initially, most designs were calculated using the industry standard of 300 – 600 psi bottom minimum stress (BMS); however, many of our tubing scans were showing rod wear in the bottom of the string just above the seating nipple. Since this is an indication of compression, the BMS was raised to 1,000 – 1,200 psi on a number of wells for designing rod strings. With this design change our tubing scans have been showing much less rod wear in the bottom of the string. However, all of the improvement cannot be strictly attributed to increasing the BMS criteria.

Fluid Specific Gravity Impact On Design

Many wells in the Bakken produce very high specific gravity (SG) water (approximately 1.2 SG); and some of the wells have high water cuts (70% +). This condition causes the produced fluid gravity to be very high in the rod design software that Oasis utilizes (considering the program is allowed to calculate the produced fluid gravity). The program does not account for gas in the tubing. The Bakken is typical of many unconventional well environments, and it produces a high gas-to-liquid ratio (GLR) of 1,000 – 5,000 scf/BF. As a result of the high fluid gravity and high GLR, the calculated SG that the rod design software generates (approximately 1.0) is typically much higher than actual produced fluid gravity, because no gas is assumed to be produced in the tubing.

Calculated Loads
The resultant calculated loads in response to the fluid gravity values generated in the rod design software may be much higher than actual, meaning that Grade D rods can appear to be overloaded when in actuality they may not be. The method used to determine the actual produced SG was to match actual cards from remote monitoring software with predicted cards from rod design program. As a result of matching predicted cards with actual cards most of the specific gravities used in the rod design program have changed from approximately 1.0+ to .75 - .45. This change has a significant impact on rod loading and rod string design. There was an increase in the occurrence of on/off tool failures and one of the possible reasons could have been the overly aggressive bottom minimum stress created by using unrealistically high fluid specific gravities. When the gravities were changed from ~1.0 to ~.7, the bottom minimum stress calculated was sometimes higher than the intended ~1000 psi range.

Data Matches
In some cases data matches are easily obtained by adjusting the pump condition, (full pump, gas interference, etc.), anchored or unanchored tubing, and fluid specific gravity. However, in many cases the matches are much more difficult, and many more parameters, such as rod-fluid dampening and pump fillage, must also be adjusted to compensate for actual conditions in the system. Even after these variables are manipulated, a good match is not always obtained. An example of a card before matching and the change after adjusting specific gravity can be seen in Figures 2a and 2b. The purpose of this exercise was an attempt to verify fluid specific gravity. When matching cards is difficult, fluid gravity from nearby wells is used for design purposes.

Worst Case Modeling
Caution must be exercised in using the entire matched data set because this data represents the condition at one point in time. If the current conditions represent a high FL with a low water cut and the well pumps down later with a higher water cut, then there is a possibility that the rods and/or pumping unit could be overloaded. This scenario explains why most rod design programs recommend running designs at worst case conditions. For the majority of the Bakken wells, conditions generally do not change dramatically enough between rig interventions to impact the actual scenario versus the worst case scenario.

STANDARD OPERATING PROCEDURES

When a failure occurs the technician works with the production engineer to design the best rod string, pump, and bottom-hole assembly for that well. There is not one standard design that has been found to be successful and implemented throughout all the parts of the operation, but there are similarities in design and operation.

All of the trials, pilots and failure analyses have led to a number of Oasis Standard Operating Procedures (SOPs). Some of them are listed below:

- **Innovation Implementation**
  When new technology, equipment, and techniques are discovered, an evaluation is performed to determine if any of these discoveries are applicable to the operation. Innovations are frequently used in trials. All technicians and engineers have the ability to install the configuration that will be the most successful for that particular well, and that data will be tracked as a trial.

- **Communication**
  One important success factor lies in the abundance of communication between technicians and engineers. Everyone learns from one another's experience through both successes and failures.
- **Polished and Pony Rods**
  Polished rods and all pony rods are replaced at every workover.
- **Rod Break Rotation**
  Rotation of rod-breaks are required to ensure that the same rods are not broken and made up each pull resulting in a different break.
- **Rod Inspection Guidelines**
  Most of the high strength rods are not inspected due to increased handling to prevent mechanical damage that could cause a premature failure. ¾" rods are generally not inspected as a result of tracking rejection rate and inspection cost versus the cost of new rods. Oasis' experience has shown that there are typically no savings by inspecting ¾" rods. Oasis has run most every applicable rod brand and grade in North Dakota and Montana, and there has not been one brand or grade that has significantly out-performed the other. Even though no rod brand outperformed the other, one consistent finding is that high strength rods had a higher occurrence of failure many times due to micro-pitting corrosion. As a result Oasis has made an effort to avoid utilizing high strength rods if at all possible due to the corrosive environment of the Bakken.
- **Overloading Grade D Rods**
  Since the experience with high strength rods is not what is desired, Oasis has piloted a group of wells running Grade D rods 10-15% over the T/2.8 design criteria. There are several wells which have been running longer than warranty period with no body breaks to date.
- **87 Taper**
  Another rod related pilot which has been implemented is running 87 tapers, opposed to 86 tapers, in lighter loaded wells in order to stiffen the rod string. This may be especially beneficial on wells with Mark II units with inherently faster down strokes which can increase rod compression, but it is too early to evaluate the FR of 87 taper wells versus 86 tapers.
- **Rod Replacement Practices**
  The rod replacement guideline Oasis created determines whether rods should be rerun or replaced. Generally, rods are replaced at ~15M cycles if there are no previous parts. If there are previous parts, the number of cycles is reduced for every prior part. There have been a few iterations of this practice trying to replace the top X# of rods based on the part location, but there was no verifiable reduction in failures attributable to that strategy. Laying down tapers, inspecting, and replacing them based on the guidelines Oasis developed has significantly reduced rod related failures
- **Frequency of Scanning Tubing**
  Scanning tubing gives insight into the efficacy of the corrosion treatment program and can also indicate if the well is experiencing significant amounts of rod compression. The frequency of scanning tubing varies greatly throughout the field. There are areas which can run for years with no tubing-related failures, but there are also areas with higher corrosion rates and high GORs. There are also wells that "flump" frequently. These wells are scanned every pull if more than six months has elapsed since the last scan. If the scan indicates a high degree of rod wear in the bottom section, then the POC settings are evaluated for set point changes. Once the POC settings have been optimized, a significant decrease in the amount of rod wear can be frequently seen in subsequent tubing scans. These wells also make excellent candidates for 87 taper rod strings.
- **Reduction of Rod Wear and Tubing Leaks**
  In most wells a few joints of boronized tubing are run above the seating nipple to combat rod wear due to compression and gas interference. Some wells have poly-lined tubing to further reduce the leaks. Both methods have been successful, and many of the wells with poly-lined tubing are wells which "flump" frequently.
- **Tubing Rotation with Red and Yellow Band Protocol**
  Tubing rotation from top to bottom during rig pulls was sometimes difficult to track causing confusion in future scans. The historical practice of routinely rotating tubing from bottom to top to even out rod wear throughout the string has been discontinued because rod wear is less of an

issue, and the difficulty of tracking rotated tubing location became a problem. Since the color yellow denotes a structurally sound tubing wall, a recent practice has been to slightly expand the yellow band tubing protocol and classify everything else as red band. Eliminating the inspection criteria except for red or yellow has clarified the issue and prevented confusion as to whether tubing is good or bad.

- **Monitoring, Managing, and Mitigating Corrosion and Scale**
  Corrosion awareness and monitoring is a practice that has shown itself to be beneficial in many circumstances. The majority of operating areas have varying degrees of corrosion. It is a constant challenge to continually monitor and make necessary modifications to the scale and corrosion treatment program to ensure reasonable protection. One thing that has helped Oasis over the years was to fill a position that directly overlooks the chemical program.
- **Training and Supervision**
  Like most companies, Oasis performs frequent rod handling and makeup training. With wells in the Bakken, rod handling and makeup are more important due to the high loads, salinity and corrosion. Fortunately, the rod handling training program is reinforced by consistency with quality rig supervision. Adherence to standards provides the foundation for both training and supervision. Without this adherence to standards, it would be difficult to consistently reduce the FR.
- **Operator Roundtable Meetings**
  One unique and positive aspect of operating in North Dakota is participation in the operator roundtable meetings. The meetings are open to any company operating in the Bakken/Three Forks and are held twice each year for the discussion of general production, operational practices and challenges. Where possible, operators share successes and failures within their operations. When these experiences are shared, the environment nurtures mutually beneficial knowledge growth with the potential for improvements in operational proficiency for everyone.
- **Soil Settling**
  When pumping units are set on concrete bases on the ground with constant freezing and thawing, keeping the units aligned can be an on-going battle. As a consequence of these environmental challenges, polished rod failures constitute a larger-than-optimal part of total failures. All of the long stroke units are set on piers, but the majority of conventional and Mark II units are set on concrete bases which are more susceptible to settling and alignment issues. Anytime a well fails, the rig supervisor takes two 90° pictures of the polished rod hanging in the stuffing box and sends the pictures to the production technician. If the well appears to be miss-aligned, then the unit is not started until it is realigned. The same practice of alignment is used for all polished rod failures.

FAILURE ANALYSIS

Failure analysis is an important part of Oasis's FR improvement. A Monthly Failure Review Meeting provides a venue for production techs and engineers to convene to discuss the prior month's failures as well as failure performance by production area. Prior to this meeting, the engineer and tech typically meet to discuss each failure in detail. Information generally reviewed during this time are production, pump shop report, solids analysis, chemical treatment, failure history, rod design, fluid level, debris in tailpipe, remote monitoring software data, SPM, cycles, and other points of concern. Decisions are made regarding any needed changes in design, operation or the chemical program.

Continuous Improvement of Failure Data

Failure data tracking improvements have significantly assisted with the overall company FR reduction. Throughout the years, an increase in specific failure data points have been captured, providing a more in-depth look at failure trends. Once trends have been identified, process improvements, design innovations, and operational changes can take place that result in a reduction of failures for specific failure sources.

Key Data Points

Well identifiers such as well name, producing area, failure date, workover dates and workover costs are tracked. The detailed data being tracked enables two important data points to be identified:

- The correlation of failure types to specific producing areas, and
- Correlation of costs to particular failure types.

Failure specific data points are captured ranging from broad to very specific inputs. These include:
Broad Buckets:

- Job Bucket (Pump, Rod, Tubing, Casing)
- Job Type (1” Rod Section, 2” Pump, Tubing Leak, Rod Sinker Section)

Specific Buckets:

- Failed Component (Rod – Main Body, Rod – 6” Critical, Tubing – Body, Pump – Plunger, BHA – De-sander)
- Primary/Secondary Symptoms (Salt, Sand, Corrosion, Improper Makeup, Manufacturing)
- Root Cause (Improper Chemical Usage, Deviated Wellbore, Human Error, BHA Needs Improving)
- Manufacturer of failed component
- Component Grade
- Current rod taper during failure
- Rods, rod string replaced or tapers replaced
- Workover rig on location (rig that installed failed component)
- Any kind of experimental pilot design in well
- Artificial Lift Surface Unit

Data Levels
Many levels of data, ranging from broad to very specific, provide the ability to drill down into the failure trends. Since the Bakkens’ downhole environment changes dramatically as you move across the basin, capturing and analyzing the data by producing area is vital. Specific failure trends and the recommended process or operational changes that accompany these failure trends usually cannot be standardized across large areas. Each area is analyzed individually, and changes are implemented accordingly. An exception to this would be failure trends specific to component manufacturers or grade. Once a failure trend involving these inputs is realized, process changes are made. The components involved are no longer used across the company.

Response to Failure Trends
The process or operational changes that Oasis has made due to failure trends found during failure data analysis include:

- Specific polished rods
- Guided or unguided above and below on-off tools
- Moving from guided 1” for sinker tapers to K-bar
- Not using pressure actuated plungers in corrosive wells
- Changes to the chemical program in areas with chemical related failures

Process changes can also evolve based on continual data collection. An example of this would be replacing rods after a rod part. Rods were being replaced above and below the part, which then appeared to precipitate failures elsewhere in the taper. After analyzing the depths of these parts, the decision was made to replace the top 40 rods of the parted taper. After additional data was collected and analyzed, a new failure trend was realized. The parts had moved down the taper, which indicated that replacing the top 40 rods was not sufficient. Data analysis resulted in the recommendation to replace the taper as a whole when applicable, and this recommendation has significantly reduced rod related failures.

Data Quality
The quality of data is enhanced when a large enough data set is available to create meaningful trends, but high quality data is vital for failure reduction efforts. Due to the level of precise data points, each well failure input submitted by the production tech is reviewed with the production engineering analyst to validate consistency with previous inputs for similar well failures. This ensures that failures are classified correctly when specific trends are being analyzed. The production engineering analyst is the primary

owner of all well failure data and is responsible for housing, analyzing and maintaining the integrity and accuracy of the data. Once the data has been reviewed and finalized, dashboards (See Figure 3) and other interactive interfaces are created for the Production Optimization Team.

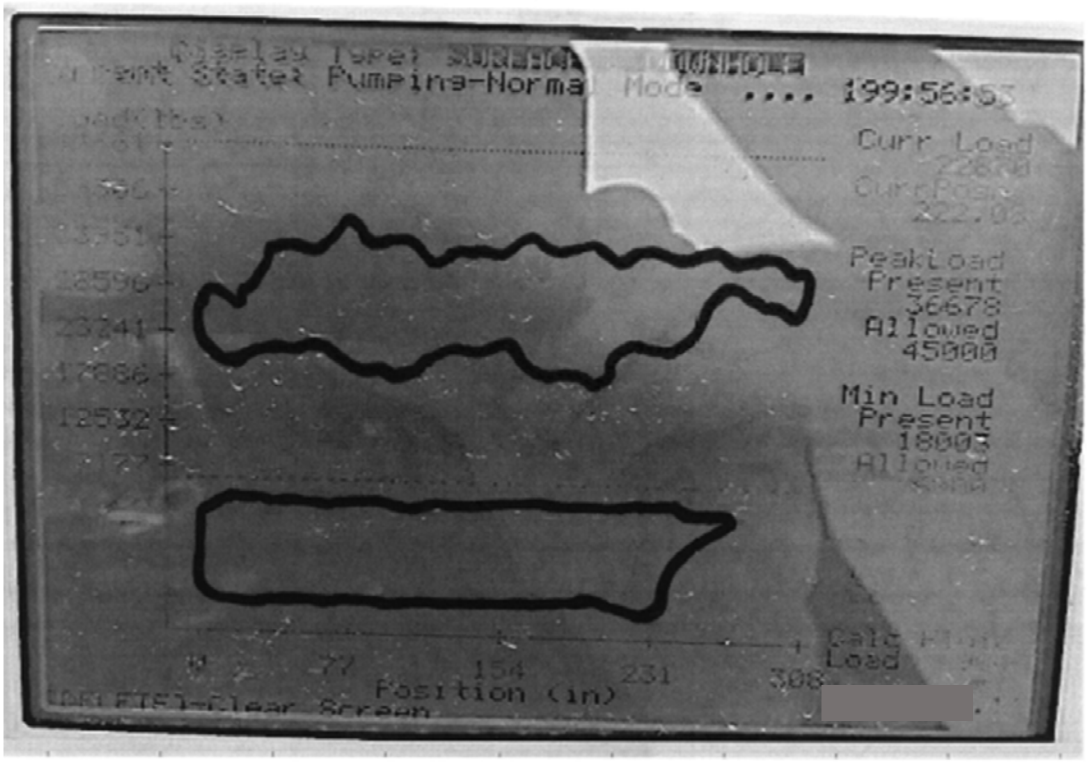
PILOTS AND TESTS

The Bakken is a very challenging environment for artificial lift, and many of the designs are pushing rods and pumping units to their maximum permissible loading. This situation makes it inherently receptive to testing new and better products and technology. There have been instances where a product was tried and failed, but it was simply viewed as a lesson learned. An important role of new trials and pilots involves the identification and tracking of wells and the performance of the wells in the trial, enabling successes and failures to be understood, documented and shared with the team. This tracking allows for sharing and expanding successful changes and of making sure mistakes are not repeated.

SUMMARY

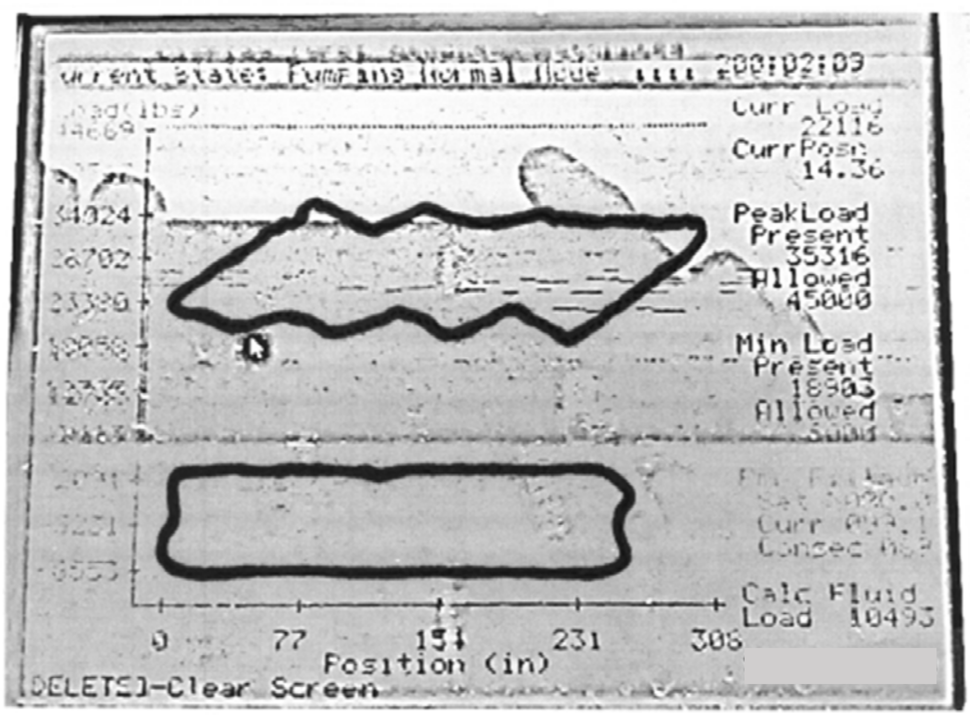
Oasis continues to make significant progress in reducing the FR of wells, and this success was not the result of one single change. The evaluation of well criteria and the implementation of changes have resulted in the installation of lift equipment which is more effective for matching operating conditions. Even though the equipment design has been a critical part of the success, the operational changes that have been made have possibly made an even greater impact than design. Since introducing remote monitoring and operational capability, wells are now able to be monitored and adjusted even more frequently than before. In conclusion, the FR reduction has been the result of a holistic and analytical approach addressing all aspects of rod pumped design and a continued advancement in operational philosophy.

FIGURE 1a



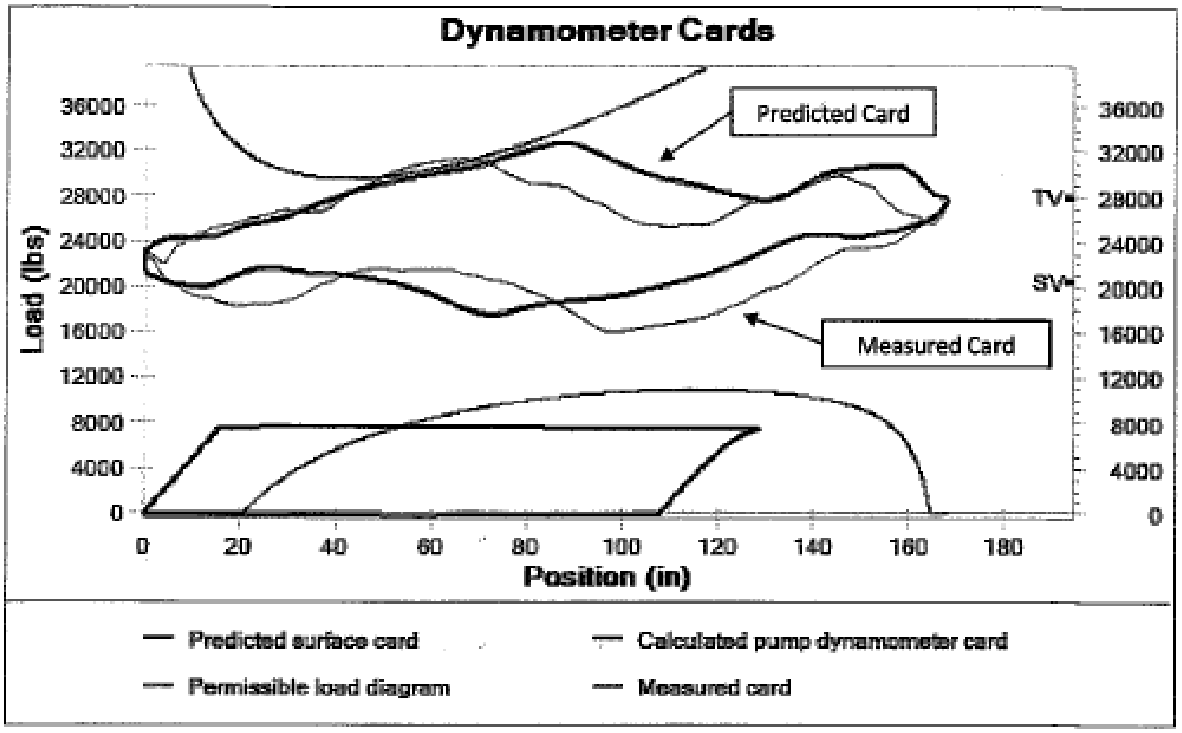
Without Cornering

FIGURE 1b



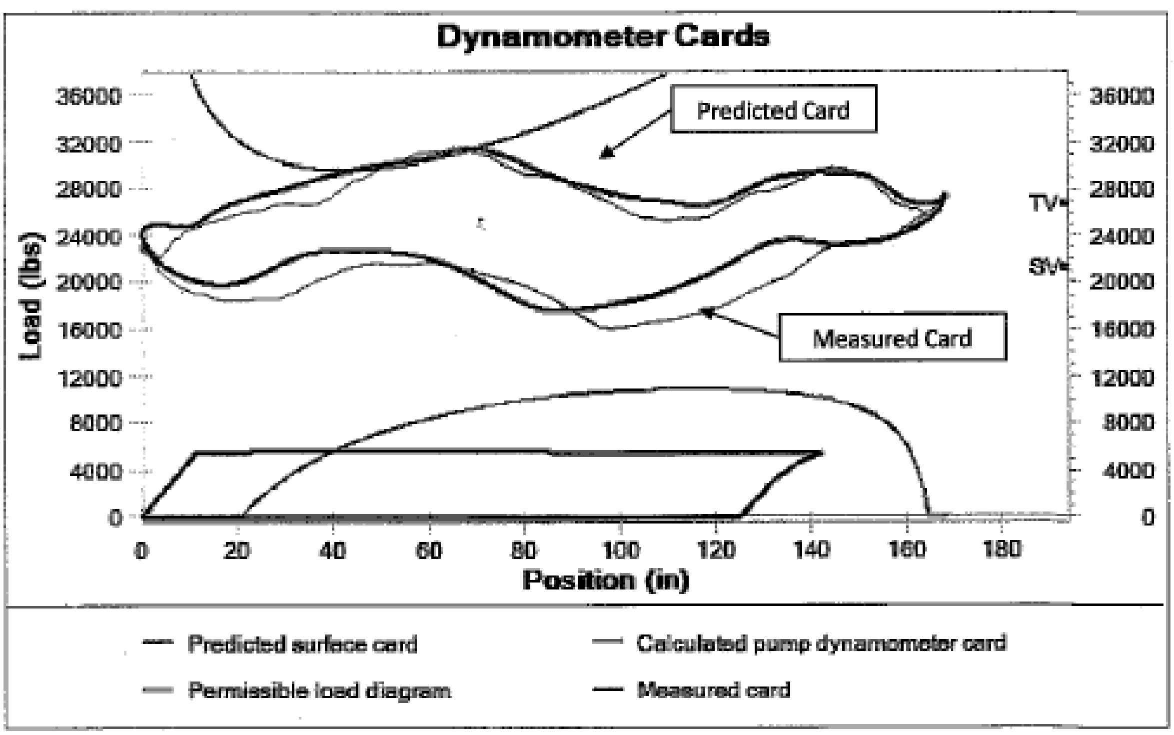
With Cornering - This is the same well a few minutes after cornering was enabled

Figure 2a



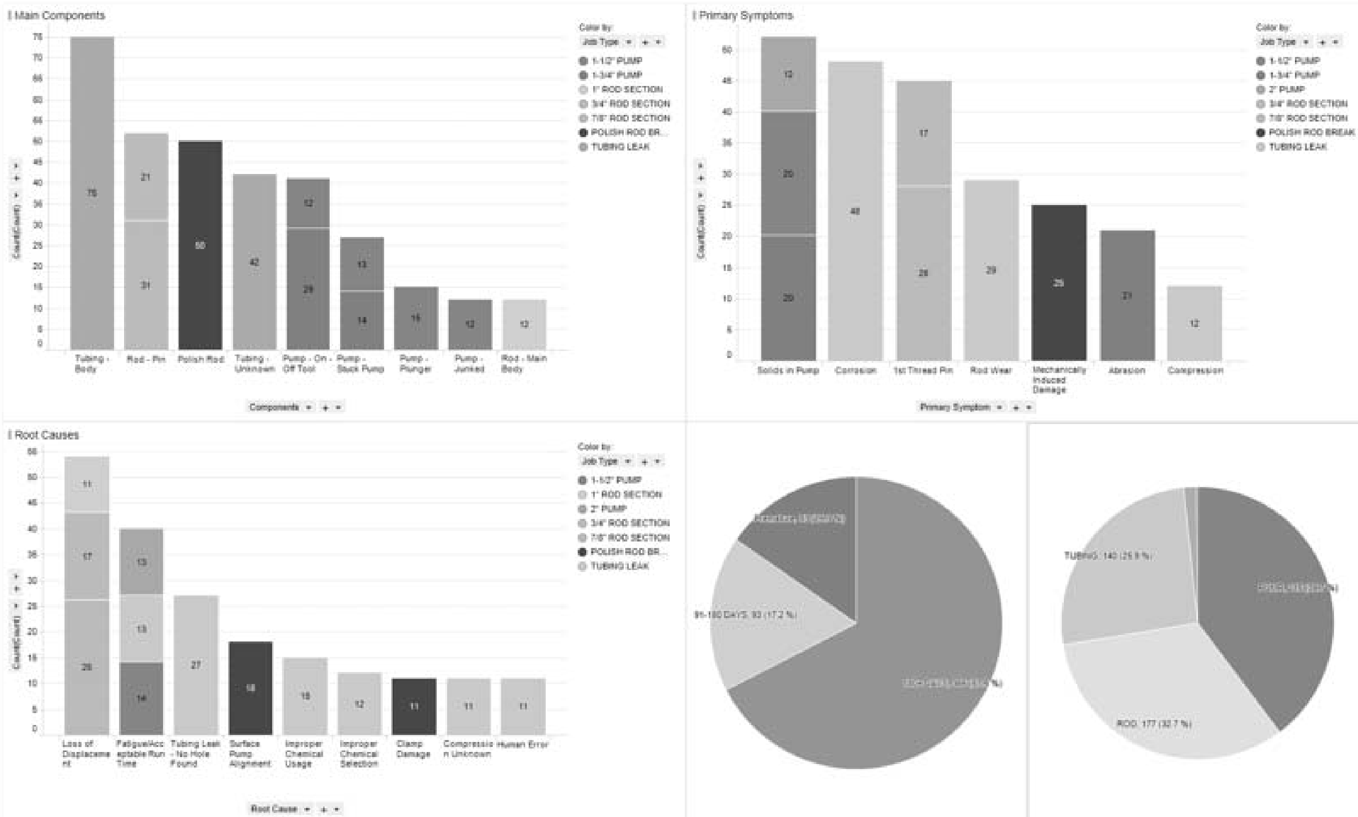
Rod Design Program Calculated Fluid Specific Gravity of 1.087

Figure 2b



Specified Fluid Specific Gravity of .80

Figure 3



Failure Data Dashboard