DOWNHOLE SUCKER ROD SENSOR

John MacKay, Paolo Santos, Stian Slotterøy, and Keith Fangmeier
Well Innovation AS

INTRODUCTION

In the past 10 years, drilling methods have drastically reduced the time it takes to drill wells. This is especially true in today's unconventional shale market where 20,000ft wells are being drilled in less than 14 days. This increase in drilling rates, along with increasing depths and deviations, has presented many challenges for the conventional rod lift system. These rod lift systems were designed to last for ten years, but we are seeing failures increases within the first few months of installation which results in substantial increases in workover frequency. More failures result in a significant increase in operational costs, in addition to lost or deferred production. Until now there has been no way to troubleshoot these failures beyond conventional surface measurement and downhole prediction methods. This leaves the operator and the service company to pursue an expensive trial and error troubleshooting process. Below we will review the field test results from a downhole sensor package that has been developed (patent pending) to solve these issues by measuring the downhole forces causing the failures. These sensors when placed in strategic locations throughout the rodstring measure the downhole force, with the magnitude of detail required to identify and troubleshoot downhole problems that result in rod, tubing, or pump failures. This enables the operator and/or service company to implement a systematic approach to troubleshooting. An additional benefit to the operator is the ability to verify the cost-effectiveness of new and existing technologies (rod guides, friction-reducing materials, etc) on a smaller scale before implementing across the field.

The results from the field tests will be covered in detail in the case study section below, but downhole data have demonstrated the effect of guided rods and discovered problems with tubing movement and asynchronous movement in the rod – problems not captured by the predicted Dynacards from the same tests. Measures for these problems have also been implemented, and ongoing testing suggests steady production pumping at lower speeds, which is believed to prolong the MTBF.

SUCKER ROD SENSOR AND CAPABILITIES

The downhole sucker sensor i.e., tool, can be positioned anywhere in the rodstring. It collects measured data for:

- Pressure
- Temperature
- Torque
- Tension and compression
- Velocity and position from 3 axis accelerometers

Figure 1 Tool Overview. These measurements are used to calculate downhole values for average specific gravity, pump-fillage and pump intake pressure to better understand what is happening in today's complicated boreholes and to feedback into the rodstring design model. Using these measurements, a downhole analysis of the well is completed including recommendations for improvements which are then implemented, re-measured, and further optimized. As part of this, a "measured" Dynacard is generated to compare to the conventional wave equation Dynacard. The measured card shows details about the well due to the high resolution measured data and the placement of the sensors down hole. Also, new troubleshooting methods are made available by analyzing the downhole data. In this paper, we will look at a case study that covers three successive runs in a well that has a history of tubing failures. *Table 1 – Run Information.* We will examine how the problem area was identified as well as look at what was done to maximize the mean time between failures (MTBF) while optimizing production. But first, we will introduce some of the dashboards designed to organize the data for analysis.

For ease of review, we provide an overall summary of the primary sensor measurements presented with either 1 minute or 5-minute aggregate data. This enables a snapshot of the well data during the time the tools were installed and provides a quality check of the data. *Figure 2 – Dashboard for Logging Period.* In the software, you can drill down into the data by highlighting a time of interest and plot the high-resolution data during that time. *Figure 3 Summary Plot Drill Down.* The user can then select any of the individual sensor plots and continue to drill down further. *Figure 4 – Summary Plot Pressure Data.*

The data for each tool is presented in either single or combination plots versus time depending upon a predefined grouping. In the example we have combined the following:

- Pressure & Temperature
- Load & Torque
- Displacement
- X, Y, Z acceleration etc

This is done for each of the tools in the string. *Figure 5 - Tool Dashboard.* The plots are then analyzed looking for anomalies or trends for each sensor or combination of sensors. Here again, we can drill down and look for further detail in the data such as SPM reversals, excessive radial or longitudinal motion on the accelerometers etc.

In addition to the standard load and position Dynacards, we added plots for velocity and pressure against the position. These plots are used to demonstrate how the velocity and pressure are varying during the stroke and in trouble-shooting the system movement. Figure 6 – Dynacard Dashboard.

Plotting the rod pressure on the different depths of the pumping cycle gives a characteristic dynamic signature that depends on several parameters of the well and pumping operation. One of the main benefits is to help detect the opening and closing of the traveling valve.

A typical pumping cycle shows the following pressure vs position behavior: On the downstroke, the pressure gradually decreases until the traveling valve opens creating a surge in pressure due to incoming fluid from the filled pump (when internal pump pressure > hydrostatic pressure). Continuing on the downstroke the pressure starts to decrease until reaching the bottom of the stroke.On the upstroke, the behavior of the pressure differs depending on well conditions (influenced by the amount of gas). Towards the end of the upstroke, the pressure normally increases (i.e. due to fluid compression, discharge restriction). *Figure 7 – Pressure Dynacard.*

Plotting the velocity vs position provides information about the movement profile of the rod/pump within a cycle. It allows you to see if the velocity pattern matches or is deviated from the programmed/desired velocity behavior at the surface controller (POC). It is possible to identify pump overspeed occurring at certain travel points as well as pump stops, an indicator of sticking.

In more serious situations, the visualization of overspeed and several near-stops, is a sign of out-of-synch rod sections, namely a mismatch between the surface pumping unit and the resulting pump movement. In these cases, the rod/pump could be significantly overstressed. This type of issue can happen due to the oscillatory nature of the rod movement.

In a normal pumping situation, the Velocity "Dynacard" allows you to identify and check the "cornering" effect configured in the controller at the stroke ends. Combined with the Pressure plot (and even standard Tension Dynacard) this Velocity "Dynacard" helps to detect/confirm key points and events on the pumping cycle, like standing valve opening/closing, gas interference etc. *Figure 8 – Velocity Dynacard.*

This information is captured in the final job report with a recommendation for improvements/changes on the subsequent run. In the subsequent run, the recommended changes are monitored by placing another set of tools in the same positions as the previous set and re-running the well tests. *Note: Dashboards can be fine-tuned and adapted based upon individual client preferences.

CASE STUDY

The case study was performed on a Bakken well in the North Dakota field. Similar to many of the Bakken wells, it has a vertical section of approximately 10,000 ft in-depth, where the pump is set in 2 7/8-inch tubing. The surface unit is a Liberty Rotoflex, Model R-320-500-306 (long-stroke unit) with a Lufkin WM 2.0 controller. The rodstring consists of a tapered string with a combination of 1 inch, 7/8- inch, 3/4-inch, and 1.5-inch (no guides) sinker bars on bottom. *Note that the sinker bars were replaced with 1-inch guided rods for runs #2 & #3.

Run #1 (February 27th – March 25th, 2020) The baseline run; no changes were made to the rod string other than adding the tools and replacing any worn or damaged components as per the Operator's standard maintenance and troubleshooting practices. The baseline run records the downhole information so that the problem area/s can be identified prior to implementing a change and the lessons learned can be applied to similar wells throughout the field at a later date. The tool/s records the effects of the rod movement that resulted in the failure/s. Then, based on the analysis, recommendations are made to eliminate or extend the time between failure, and the tools are rerun to verify the results. The depth placement of each sensor is chosen based on the well history, which in the case study showed multiple tubing failures over the past few years, all in approximately the same area of the well.

The first tool was positioned as close to the downhole pump as possible in order to record the movement of the string, measure the pump discharge pressure and well temperature. This is the standard bottom tool placement recommended for most wells. Since this was the first run of the commercial tool we ran a second tool immediately above to ensure the measurements were repeating. The second tool ran continuously (consecutive 12hr periods) to determine if any critical well information was missed by the other tools which were recording five-hour periods of data per day. After a review of the 24-hour tool data, it was decided that the benefit of recording 5 hours per day for a longer number of days outweighed the rationale behind recording 24 hours per day. *Note here. The assumption for this well is that failures are caused by the repetition of movement and not a single event, so recording data continuously is not critical to catch the catastrophic event. The repeatability between tools was very good, in subsequent tests the practice of doubling up tools to confirm the measurements was discontinued. *See Figure 9 – Measurement Comparison Between Runs.*

The middle tool was placed near the top of the area in the well where the tubing splits had occurred. From the well history, we saw that the tubing failures occur between joints 308 and 318, so we put the middle tool towards the top or at joint 309. This was about 370 feet above the pump. Note: The middle tool was intended to be 1 joint higher but there was a mistake of 1 sucker rod in the upper rodstring tally (above all tools) that was caught when pulling the rods at the end of run 1. (All tool depths were corrected by +25 feet on run 1). This did not influence the results as the failed tubing joint was below the middle tool.

The top tool was placed in an area of the well where there had not been any issues reported so that it would be representative of the upper part of the rod string. In this case, it was 3270 feet above the pump. This depth configuration was kept for runs #1, #2, and #3. Note: At the time of writing run #3 has failed with a suspected pump issue. Although disappointing, this is the longest run that this well has had in the past three years where the failure was not a tubing leak. The plan is to workover the well, pull and scan tubing, re-run the tools and continue the test.

On the baseline run (#1), the bottom 350 feet consisted of 1.5-inch sinker bars (no guides) connected to 3/4-inch rods (no guides). On run #2, the 1.5-inch sinker bars were replaced with 950 feet of 1 inch (8 guides per rod) rod connected to 350 feet of a 3/4-inch (6 guides per rod) rod. Tubing was not pulled, so anchor depth remained unchanged. Prior to the third run, the tubing was pulled and inspected. The bottom 4800ft of tubing was replaced with lined tubing (2-7/8" EUE TK-15XT). The rod string was the same as the previous run. *Table 2 – Summary of Run #3 with Tool Depths for Each Run.*

On the first day of recording data, a series of speed tests were conducted by varying the surface SPM from 1 – 3.5 SPM in 5-minute intervals and the resulting rubbing/sticking effects were recorded and analyzed for each tool. One of the first observations was the increase in noise on the 3 axis accelerometers on the tools closest to the pump when surface SPM increased above 2 SPM. This increase in noise did not appear on the middle tool (360 feet above the pump) or the top tool (3270 feet above the pump) and this was the first indication of how critical the SPM is linked to wear in this well. *Figure 10 – SPM and Position Overlays*, shows the link to increasing SPM and how the position of the lower tools is affected as the SPM increase above 2.0 SPM. Further testing and possible hardware could reduce this effect, but for now the recommended speed to maximize this well's MTBF is less than 2 SPM. *Figure 11 – Wear indication Normalized on Top Tool*.

Below are some of the observations from Run #1 followed by the recommendations.

- Radial accelerometers show lateral/wear movement between rods and tubing.
- Rubbing/sticking occurs at surface stroke speeds greater than 2 SPM and appears as lateral movement on the bottom 2 tools. No impact on the lateral movement of the middle and upper tools.
- Pump tagging occurred at the higher SPM (2.5 SPM) and appears as lateral movement on the bottom three tools. It has little to no impact on the upper tool.
- The Top tool shows lateral movement when the surface unit is running at 2.2 SPM and this decreases over time. It is suspected that the decrease is due to wear.
- Measured Dynacards show 20 – 30 inches of tubing movement.

Shocks from the bottom of the string are being dampened by the rods rubbing against the tubing. To minimize and/or avoid wear it is recommended to:

- Maintain maximin speed below 1.9 SPM.
    - Will extend MTBF.
    - Maintain steady production.
- Investigate if there is wear on the tubing or the sucker rods at the upper tool (7178 +/- 50ft).
- Review Tubing Anchor Catcher (TAC) setting procedure. Set with minimum tension of 30K Lbs.
- Investigate running lined or coated tubing to protect lower rods and tubing from rubbing and causing wear.

Run #1 was pulled on March 25th to analyze the data collected. The changes made prior to Run #2 were based on cooperation between the operator and the service provider. The main goal was to implement a change to the rod string that would minimize tubing wear without pulling tubing, thereby extending the mean time between failures (MTBF). Run #2 was deployed on March 27th, 2020, and retrieved on Jan 25th, 2021, unfortunately, the well failed on July 16th, 2020, due to a tubing leak. (Average SPM during this time was 2.2)

The only change made between these two runs was to replace the bottom 1.5" Sinker bars with a combination of 1 inch and 3/4-inch guided rods covering the bottom and the middle tools but ending at 1950 feet below the top tool. The rodstring for Runs #2 and #3 were identical and details can be found in *Table 2 – Summary of Run #3 with Tool Depths for Each Run.*

A closer look at the loads for Run #1 and #2 shows the effects of the guided rods in reducing the friction against the tubing. The bottom and middle tools are showing dynamic loads of 1500 lbs less *on run #2 when compared with run #1. The top tools, where there are no guides on either run are only 600 lbs less. Keep in mind that 300 lbs are due to run #2 being 300 lbs lighter than run #1. See Figure 9 – Measurement Comparison Between Runs.*

Run #2 was pulled on January 25th, 2021 and Run #3 was deployed on Jan 30st, 2021. Running the combination of 1 inch and 3/4-inch guided rods reduced the side-to-side motion and improved the movement of the rodstring on all axes. This is clearly seen on the three-axis accelerometer's measurements when comparing the results from runs #1 and #2. Note here that the guided rods section ended between the middle and upper tools (1315 feet above pump) and there is still side to side motion on the upper tool. This is an area that we will continue to monitor. *Figure 12 – Comparison of the effects of Running Guides.*

The tubing was scanned while being pulled and the condensed results are shown in *Figure 13 – Tubing Scan Run #2.* The upper section of the tubing, where the top tool is located showed minimal rod wear. As expected, most of the rod wear was found in the lower 20 joints of tubing and the tubing split was located at tubing joint 314, between the bottom and middle tools.

Run #2 was the first time that we looked carefully at the strokes per minute (SPM) calculated at each downhole tool. When reviewing the results, we saw that the top and middle tools mirrored the motion of the surface long stroke unit., The bottom tool showed the downstroke moving at a faster rate than the upstroke, but the average was the same. This separation between Up and Downstroke was an unexpected result and revealed that the rodstring was not in sync close to the pump. *Figure 14 – Run #2, Bottom of Rodstring Out of Sync.* We then went back and looked at Run #1 to see if a similar effect could be seen without the guides on the rods. For Run #1, the surface controller had been set up with downstroke enabled. This was mirrored in the motion of the top and middle tools, although the middle tool was displaying erratic behavior on the half stroke when compared to the top tool. This erratic behavior was further amplified when we plotted the results of the bottom tool which showed several areas where the half-strokes were reversing compared to the settings of the surface controller. This further reinforced the finding of Run #2 but the lower section of the rodstring was even further out of sync in Run #1. *Figure 15 – Run #1, Rodstring out of Sync.*

The next step was to compare the predicted Dynacards to the measured (downhole) Dynacards to verify if these findings are being captured in the cards. We located an area in the data where the SPM was running at 2.2 SPM, then reduced below 1.9 SPM and then picked back up to 2.2. We plotted the Dynacards for all three tools through this transition range and clearly saw the effects of the string misalignment on the upper and lower tools. When the system is running at 2.2 SPM, the three tool (measured) Dynacard plots looked very different but as the surface system slows down below 1.9 SPM all three cards' shapes align. *Figure 16 – Measured Dynacards Plots.* We then plotted the predicted cards for the same day but could not see any significant differences. *Figure 17 – Predicted Dynacard Plots.* To emphasize the significance, we plotted the predicted and measured dynacards side by side for the above case where the SPM is 2.2 and less than 1.9 SPM to show the difference. *Figure 18 – Predicted vs Measured Dynacards.*

Observations from Runs 1 & 2.

- Predicted tubing leak estimated to be between Middle (10,092 feet) and Bottom Tool (10,447 feet).
- Guided rod section reduces side loading and improves overall rod movement (in the guided section).
- Upper tool (no guides) continues to experience side loading which could lead to failure/s in the upper tubing/rod section near and around the top tool.

- Running at speeds of 2.2 SPM results in a higher down-speed than up-speed at the bottom tool causing string alignment issues which leads to an increase in failures and reduces production optimization.
- Running at speeds below 1.9 SPM minimizes wear on the lower tubing and optimizes the pump movement.

Recommendations from Runs #1 & #2.

- Maintain maximum speed below 1.9 SPM.
    - Will extend MTBF.
    - Maintain steady production.
- Investigate if there is increasing wear on the tubing or the sucker rods at the upper tool (7178 +/- 50 feet)
- Plan to set Tubing Anchor Catcher (TAC) with minimum tension of 30K lbs on Run #3.
- Plan is to run lined or coated tubing on Run #3.
- Investigate surface SPM rates vs measured Surface Production in order to maximize MTBF while optimizing production.

Run #3 was deployed on Jan 30st, 2021, within a couple of days of pulling Run #2. The main change was to replace the bottom 150 joints of tubing with 2-7/8" EUE TK-15XT (internal plastic coating) tubing to minimize wear. *Table 3 – Tubing String Run #3*. The three downhole sensors were replaced, and no changes were made to the rodstring. *Table 2 – Rodstring Summary for Run #2 and #3, Sensor Depths Runs #1, #2, #3.* During this run it was agreed to measure the surface production while monitoring the surface SPM to maximize the MTBF and optimize the production. Unfortunately, as mentioned earlier the well failed during the Production Testing, after 4.5 months, of a suspected pump failure. At this point we had about 1 month left of the Production Plan and are going to continue once the pump has been replaced. *Table 4 – Production Plan.*

Note: In the following production data analysis, we will focus on the liquid production measured at surface ignoring the gas which was being produced through the pump and up the annulus.

A Review of the production data recovered to date when compared to SPM is presented in *Figure 19 – Liquid Production Data.* We have captured the surface production, oil and water from all three runs and displayed them with their average SPM values (shaded grey background). The liquid production at the beginning of Run #3 is higher than the previous two runs for the first two months but the SPM is also higher (2.5, 2.9 & 2.4 SPM) and when we look at the individual percentages for oil and water it appears that the well was probably not under stable conditions (Well had been shut-in for six months). Keep in mind that these higher SPMs have led to faster tubing wear and are to be avoided. It is interesting to note that with the increased anchor setting force and the reduced SPM of 1.9, we are producing roughly the same volume of oil as we saw in Run #1 and Run #2 at 2.2 SPM.

The controlled Production – SPM testing began on March 31, 2021, with an SPM set to 1.7 and the testing sequence was followed as per the previously mentioned production plan. *Table 4 – Production Plan.* Again here we see with the reduced SPM of 1.9, we are producing roughly the same percentage of oil as we saw in Run #1 and Run #2 at 2.2 SPM. *Table 20 -. Production Data Percentages.*

Summary:

The plan going forward is to workover the well this summer and continue monitoring performance.

- Pull and scan tubing, replace if needed.
- Pull and inspect rods, replace if needed.
- Pull, inspect, and replace pump.
- Replace downhole tools.
- Continue Controlled Production – SPM testing.
- Return tools from Run #3 for data downloading, analysis and servicing.

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Table 1 – Run Information

Run #	Date	Tool #	Duration	Frequency	Depths
1	Feb 27 - Mar 25, 2020	SN04 (PCB1006437)	5 hrs	Daily	7178
		SN03 ((PCB1006438)	5 hrs	Daily	10084
		SN02 (PCB1006439)	24 hrs	Daily	10440
		SN01 (PCB1006440)	5 hrs	Daily	10444
2	Mar 27 - Jan 25, 2021	SN07 (PCB1006452)	2 hrs	3rd Day	7186
		SN06 (PCB1006436)	2 hrs	3rd Day	10092
		SN05 (PCB1006446)	2 hrs	3rd Day	10447
3	Jan 30, 2021	SN09 (PCB01006443)	5 hrs	3rd Day	7178
		SN04 (PCB01006437)	5 hrs	3rd Day	10084
		SN03 (PCB01006438)	5 hrs	3rd Day	10439

Table 2 – Rodstring Summary for Run #2 and #3, Sensor Depths Runs #1, #2, #3

Rod string	Size (inch)	Weight (lbs/ft)	Length (ft)	QTY	Total Weight (lbs)	Total Length (ft)	String Weight (lbs)	Run #3 Depth (ft)	Run #2 Depth (ft)	Run #1 Depth Corrected (ft)	# of Guide per rod
Polished Rod	1 1/2	6	40	1	240	40	240.0	40			
1" - 8' Pony Subs	1	2.9	8		0	0	240.0	40			
1" - 6' Pony Subs	1	2.9	6	1	17.4	6	257.4	46			
1" - 2' Pony Subs	1	2.9	2	1	5.8	2	263.2	48			
1" full length (25') rods	1	2.9	25	141	10222.5	3525	10485.7	3573			
7/8" full length (25') rods	7/8	2.2	25	144	7920	3600	18405.7	7173			
Meerkat SN0 (PCB)	1 5/8	5.74	5.37	1	30.8	5.4	18436.5	7178	7186	7178	
3/4" full length (25') rods	3/4	1.63	25	78	3178.5	1950	21615.0	9128			
3/4" full length (25') rods (6 guides/rod)	3/4	1.63	25	14	570.5	350	22190.2	9478			6
1" full length (25') rods (8 guides/rod)	1	2.9	25	24	1740	600	23935.6	10078			8
Meerkat SN0 (PCB)	1 5/8	5.74	5.37	1	30.8	5.4	23966.4	10084	10092	10084	
1" full length (25') rods (8 guides/rod)	1	2.9	25	14	1015	350	24986.7	10434			8
Meerkat SN0 (PCB)	1 5/8	5.74	5.37	1	30.8	5.4	25017.5	10439	10447	10444	
PATCO / Top of Pump	1	1.63	4	1	6.52	4	25024.0	10443			3
2" insert pump	2	8	36	1	288	36	25312.0	10479			

Red: Tool Depths.

Table 3 – Tubing String Run #3

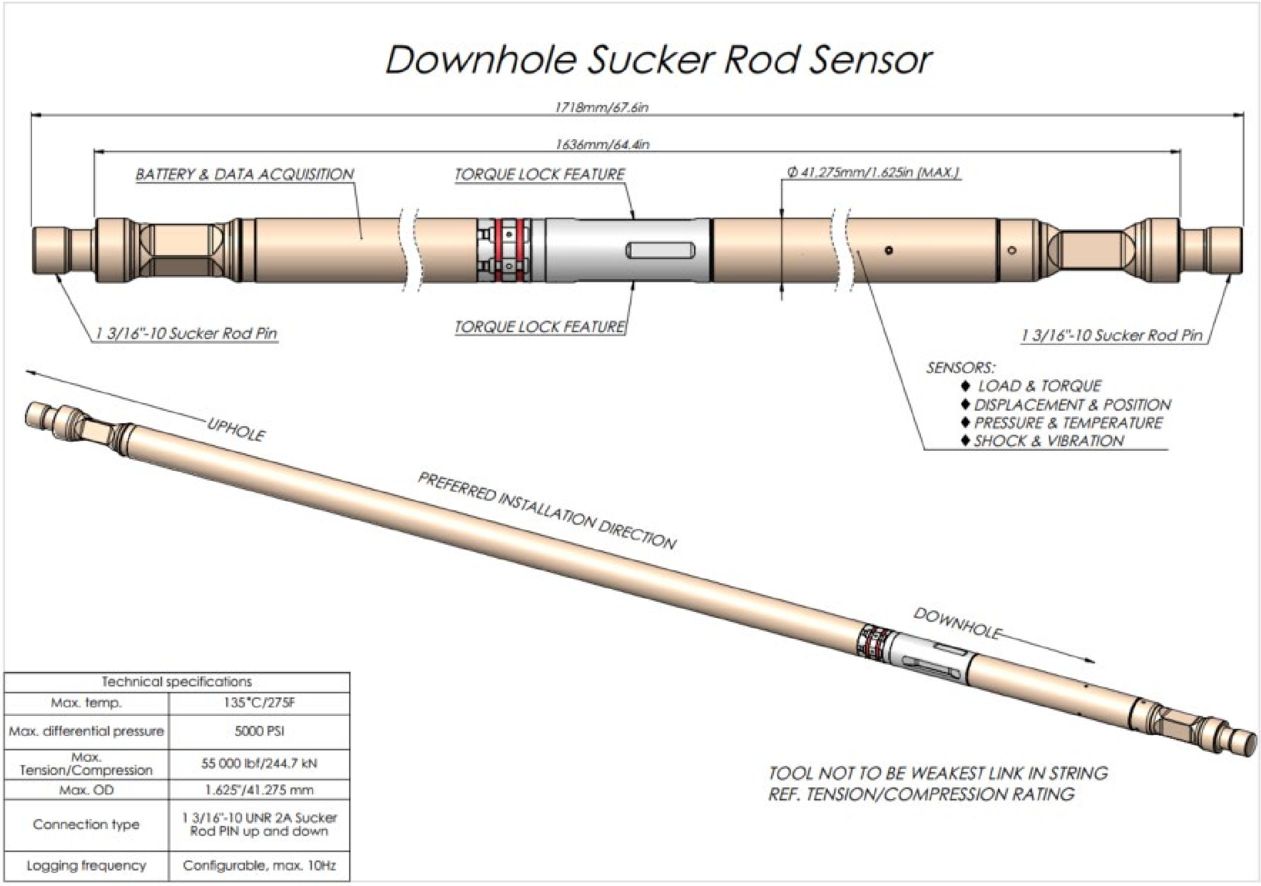
Tubing & BHA *=NEW 6/28/19					PBTD	KB	30
Joints	**Description**	**ID**	**OD**	**Length**	**Set @**	**Formation:**	3 FORKS
167	2-7/8" EUE 6.5# L-80, bottom 111, new	2.441	2.875	5,535	5571		
150	2-7/8" EUE TK-15XT Tubing	2.307	2.875	4,807	10379		
1	2-7/8" EUE L80 Pup Jt	2.441	2.875	2	10381		
4	2-7/8" EUE Enduralloy	2.441	2.875	127	10509	74" FOR 32K	
1	SSMSN w/ 1-1/4" x 31' Dip tube	1.750	3.125		10510	TENSION ON TAC	
1	2-7/8" EUE L80 Perf Sub (Elite)	2.441	2.875	4	10514		
1	7" 60K Shear TAC (Elite)	2.500	5.500	2	10517		
1	2-7/8" EUE L80 Perf Sub	2.441	2.875	4	10521		
1	5" Desander Blank (Elite)	5.000	N/A	22	10543		
1	2-7/8" EUE L80 Pup Jt	2.441	2.875	4	10547		
1	XO, 2-7/8" EUE x 4-1/2" LTC, PxP	2.441	4.500		10547	LT @	10,685
1	4-1/2" LTC Casing	4.000	4.500	44	10591	KOP @	10,706
1	No/Go Collar	4.500	5.750		10592	EOT @	10,592.87
1	Bull Plug	4	4.5		10592	92' above LT	

Table 4 – Production Plan

Start Date	End Date	SPM	Cornering	Downstroke Slowdown	Comments
Mar 18, 2021	Mar 31, 2021	2.4	Yes		Perform Speed changes 3.1.3 plan
Mar 31, 2021	Apr 15, 2021	1.7	Yes		
Apr 15, 2021	Apr 29, 2021	1.7	Yes	No	MAX SPM = 2.0
Apr 29, 2021	May 05, 2021	1.7	No	No	Fixed SPM = 1.7
May 05, 2021	May 20, 2021	1.8	Yes	No	2 week, Perform Speed changes 3.1.3 plan (Problem with drive May 9 -12/21)
May 20, 2021	May 27, 2021	1.8	Yes	Yes	1 week
May 27, 2021	Jun 03, 2021	1.9	Yes	No	1 week
Jun 03, 2021	Jun 10, 2021	1.9	Yes	Yes	1 week
Jun 10, 2021	Jun 17, 2021	2.0	Yes	No	1 Week. Well down Jun 17/21 - pump failed. Last full day of production data Jun 11/21
~~Jun 17, 2021~~	~~Jun 24, 2021~~	~~2.0~~	~~Yes~~	~~Yes~~	~~1 Week~~
~~Jun 24, 2021~~	~~Jul 01, 2021~~	~~2.1~~	~~Yes~~	~~No~~	~~1 week~~
~~Jul 01, 2021~~	~~Jul 08 2021~~	~~2.1~~	~~Yes~~	~~Yes~~	~~1 week, Perform Speed changes 3.1.3 plan~~
~~Jul 08 2021~~	~~Jul 19 2021~~	~~2.4~~	~~Yes~~	~~Yes~~	~~11 Days, extended till Monday in order to verify rate. Check for Production change~~
~~Jul 19 2021~~		~~1.9~~	~~Yes~~	~~Yes~~	~~End Test Period~~

Red: Failure Date, testing suspended.

Figure 1 Tool Overview



Technical specifications	
Max. temp.	135°C/275F
Max. differential pressure	5000 PSI
Max. Tension/Compression	55 000 lbf/244.7 kN
Max. OD	1.625"/41.275 mm
Connection type	1 3/16"-10 UNR 2A Sucker Rod PIN up and down
Logging frequency	Configurable, max. 10Hz

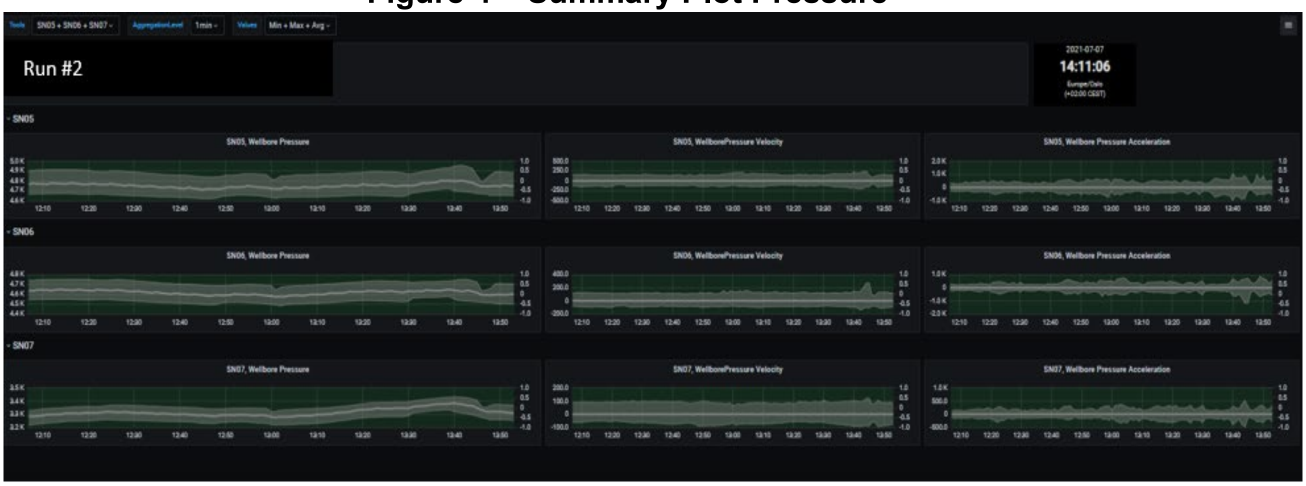
Figure 2 - Dashboard for Logging Period

Each set of graphs contains the main tool measurement on the far left with their first and second integrations going from left to right. The graphs from top to bottom are Position, Tension, String Torque, Wellbore Pressure, Wellbore Temperature.

Figure 3 – Summary Plot Drill Down

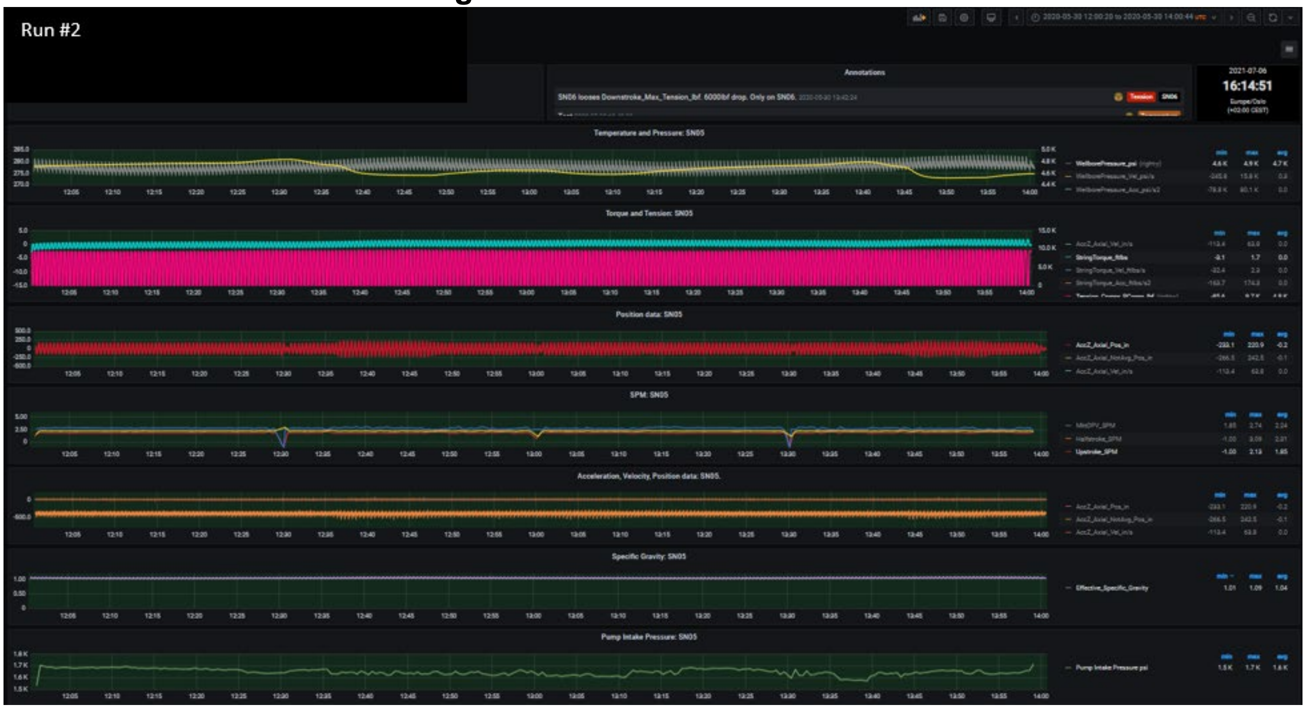
Data is plotted for the period of time that the data is collected per interval.

Figure 4 – Summary Plot Pressure



Drill down into each sensor and look at intervals down to the stroke level.

Figure 5 – Tool Dashboard

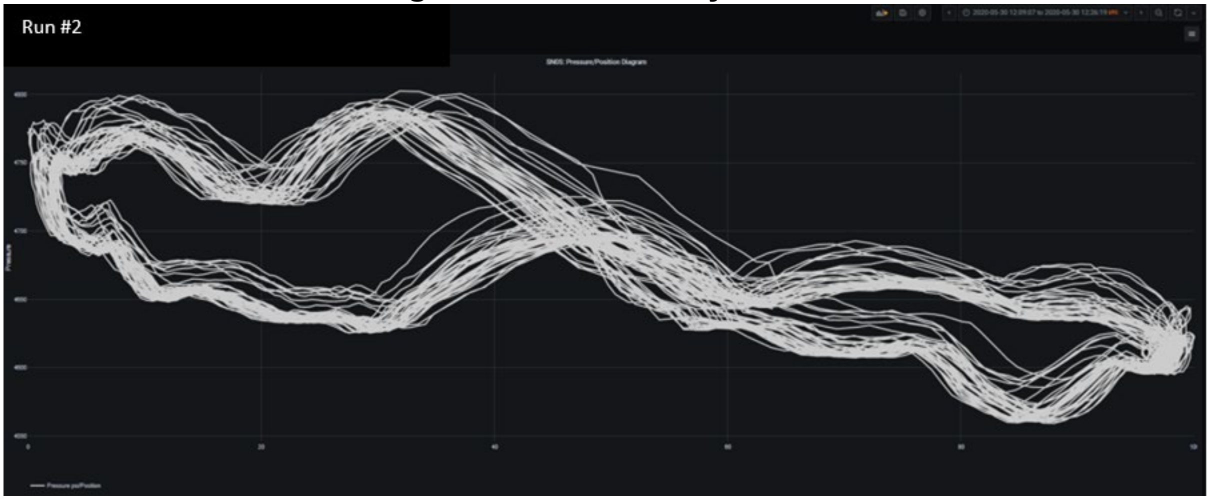


Customizable dashboard for one tool.

Figure 6 – Dynacard Dashboard

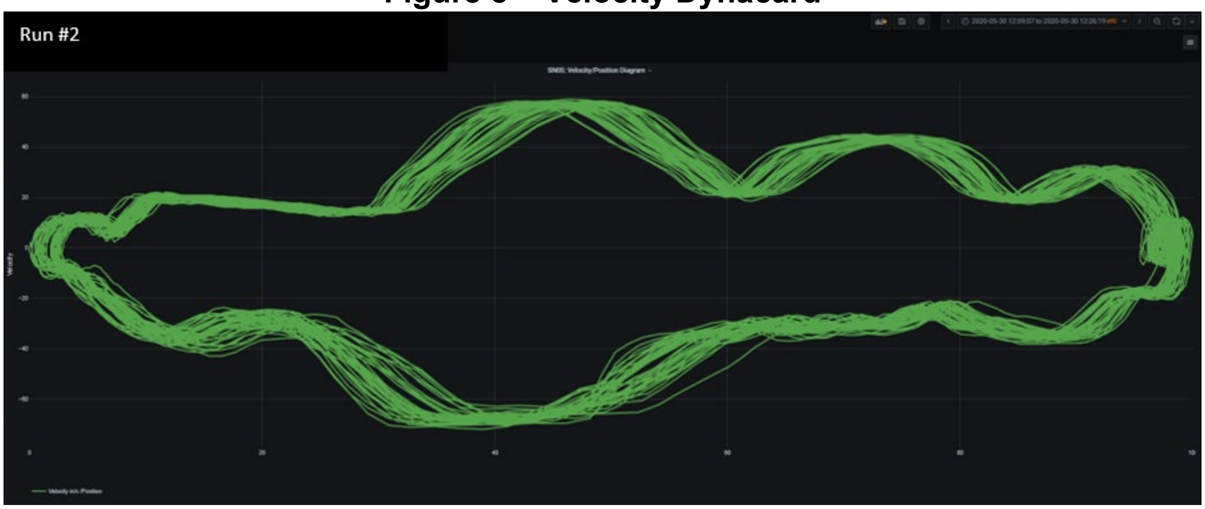
Top graph is position and load data, second graph is the tools' stroke/minute data. Middle plots show the tool's measured Dynacard on the left, followed by the velocity and pressure dyna plots. Bottom set of data contains the accelerometer's 3 axis data during the selected time period.

Figure 7 – Pressure Dynacard



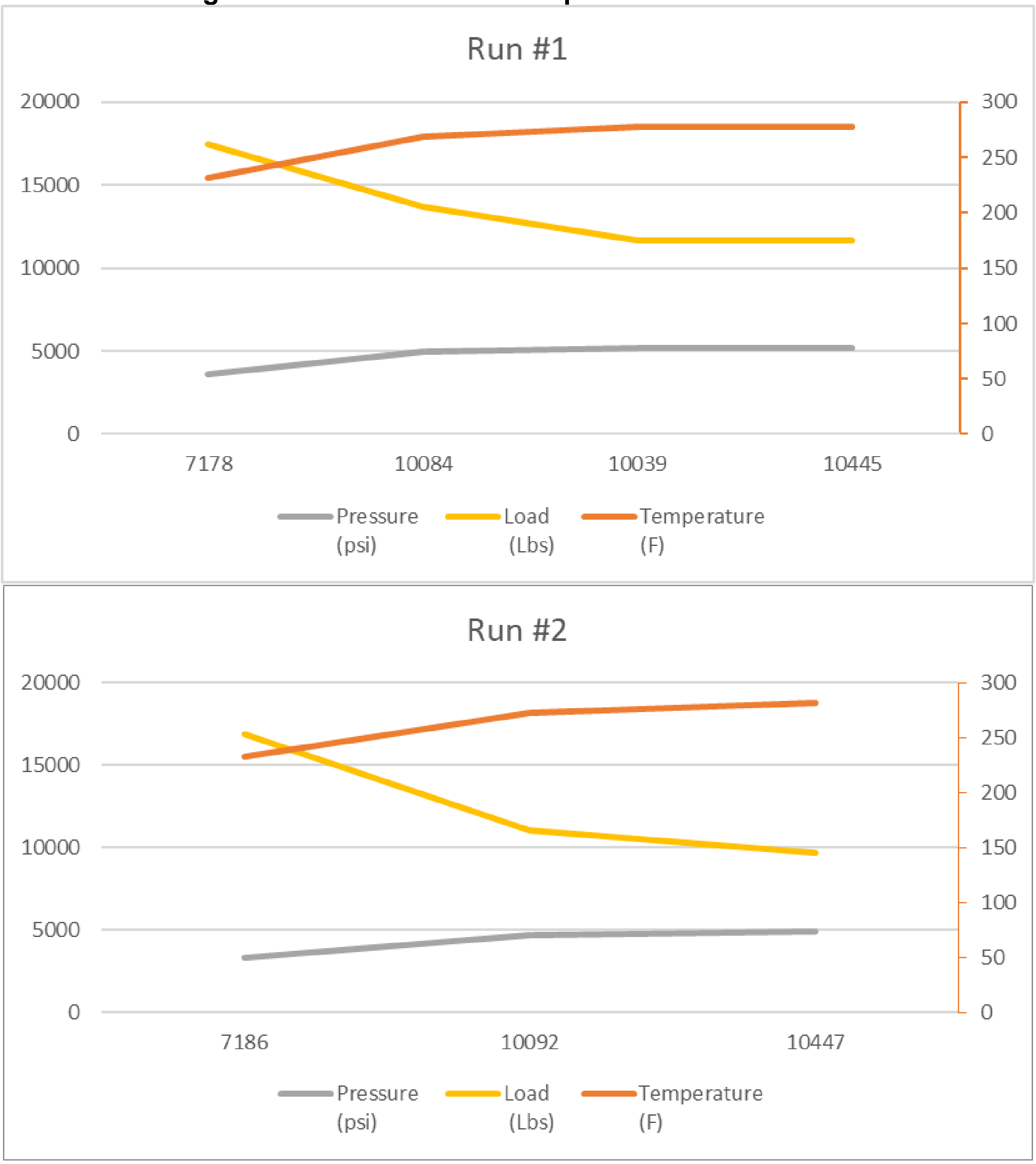
One of the main benefits is to help detect the opening and closing of the traveling valve.

Figure 8 – Velocity Dynacard



Velocity "Dynacard" allows you to identify and check the "cornering".

Figure 9 – Measurement Comparison between Runs



Dynamic Loads: Pressure and temperatures are consistent between runs but the loads for Run #2 are 1500lbs less over the guided section of rods even though the rodstring is only 300 lbs lighter.

Figure 10 – SPM and Position Overlay for each Tool

Legend: Bottom Tool 1: Orange, Bottom Tool 2: Blue, Middle Tool 3: Pink, Top Tool 4: Purple

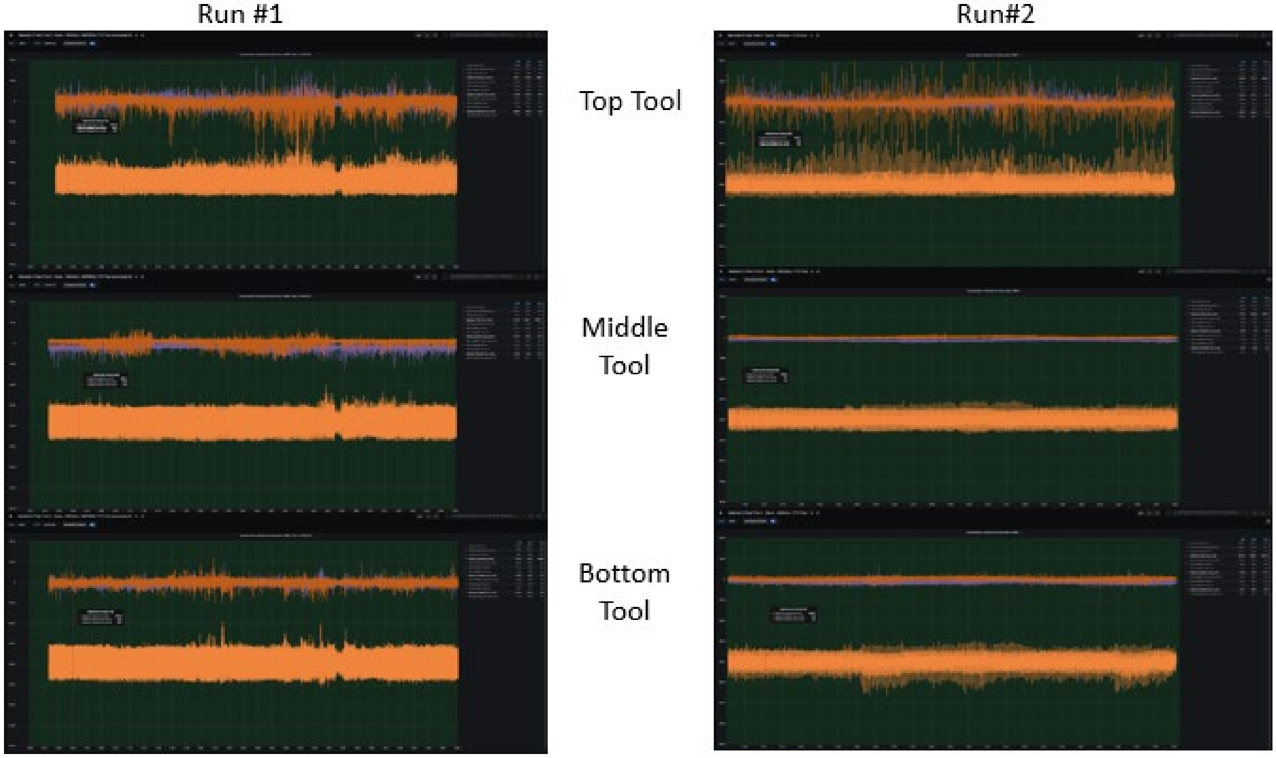
The Middle and Top tools, 3 & 4 do not vary with changes in SPM. The Bottom two tools, 1 & 2 change due to increased friction/rubbing as the SPM increases above 2 SPM.

Figure 11 – Wear indication Normalized on Top Tool

SPM of 2 SPM and greater results in higher Friction on Tools SN01 & SN02

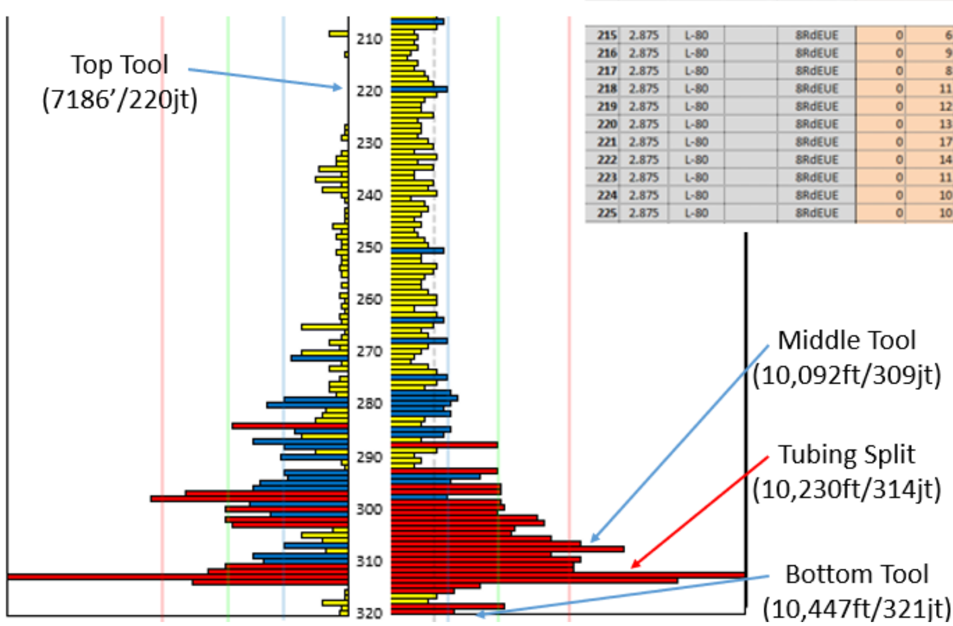
Legend: Bottom Tool 1: Yellow, Bottom Tool 2: Green, Middle Tool 3: Blue

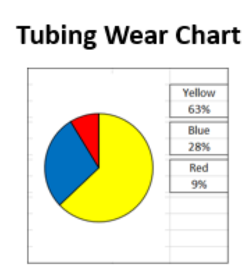
Figure 12 – Comparison of the Effects of Running Guides



Left set of graphs from Run #1, no guides on rods. Right set of graphs from Run #2, guides run with rods from bottom and end above Middle tool. Note that the graphs on the right are much smoother on all axis due to running guides but there is still side loading on the upper tool.

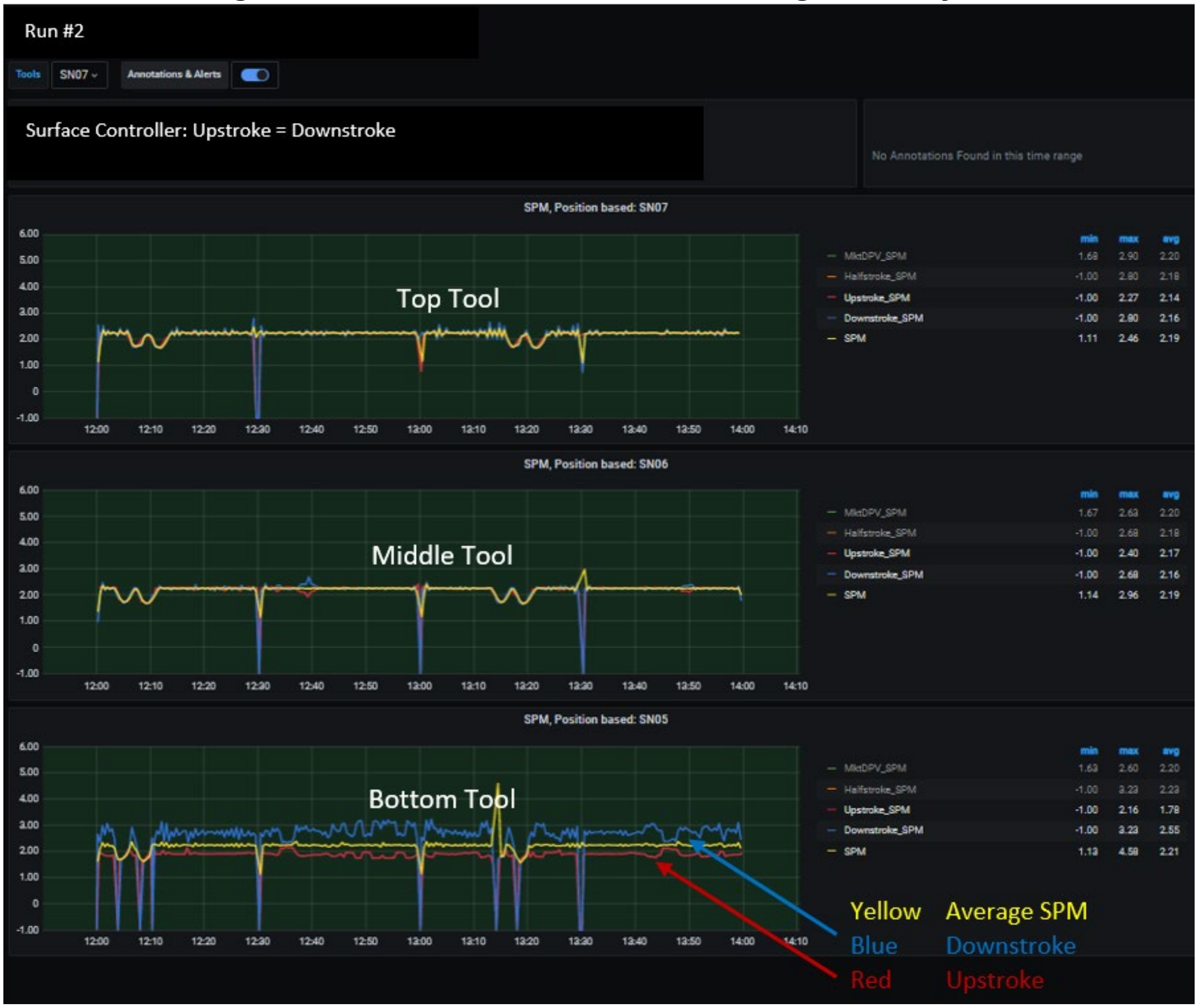
Figure 13 – Tubing Scan Run #2





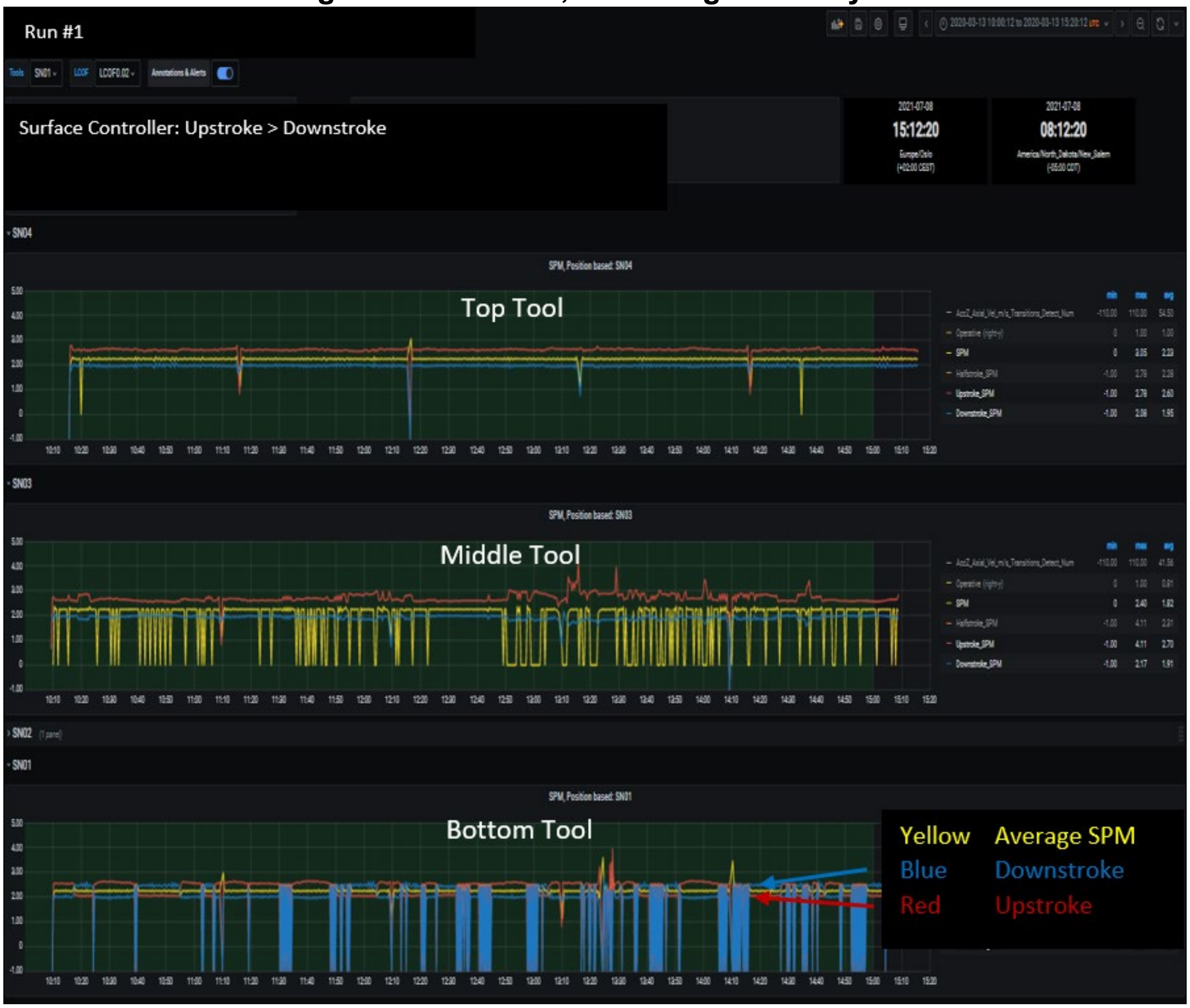
Operator Job Report Page					%	%	Default		(Color Override
Jt#	Size	Grade	Coating	Coupling	Flaw	Wall	Downgrade	Downgrade Override	Color
215	2.875	L-80		8RdEUE	0	6	Used Tubing		Y
216	2.875	L-80		8RdEUE	0	9	Used Tubing		Y
217	2.875	L-80		8RdEUE	0	8	Used Tubing		Y
218	2.875	L-80		8RdEUE	0	11	Used Tubing		Y
219	2.875	L-80		8RdEUE	0	12	Used Tubing		Y
220	2.875	L-80		8RdEUE	0	13	Rodwear		Y
221	2.875	L-80		8RdEUE	0	17	Rodwear		B
222	2.875	L-80		8RdEUE	0	14	Rodwear		Y
223	2.875	L-80		8RdEUE	0	11	Used Tubing		Y
224	2.875	L-80		8RdEUE	0	10	Used Tubing		Y
225	2.875	L-80		8RdEUE	0	10	Used Tubing		Y

Figure 14 – Run #2 – Bottom of Rodstring Out of Sync



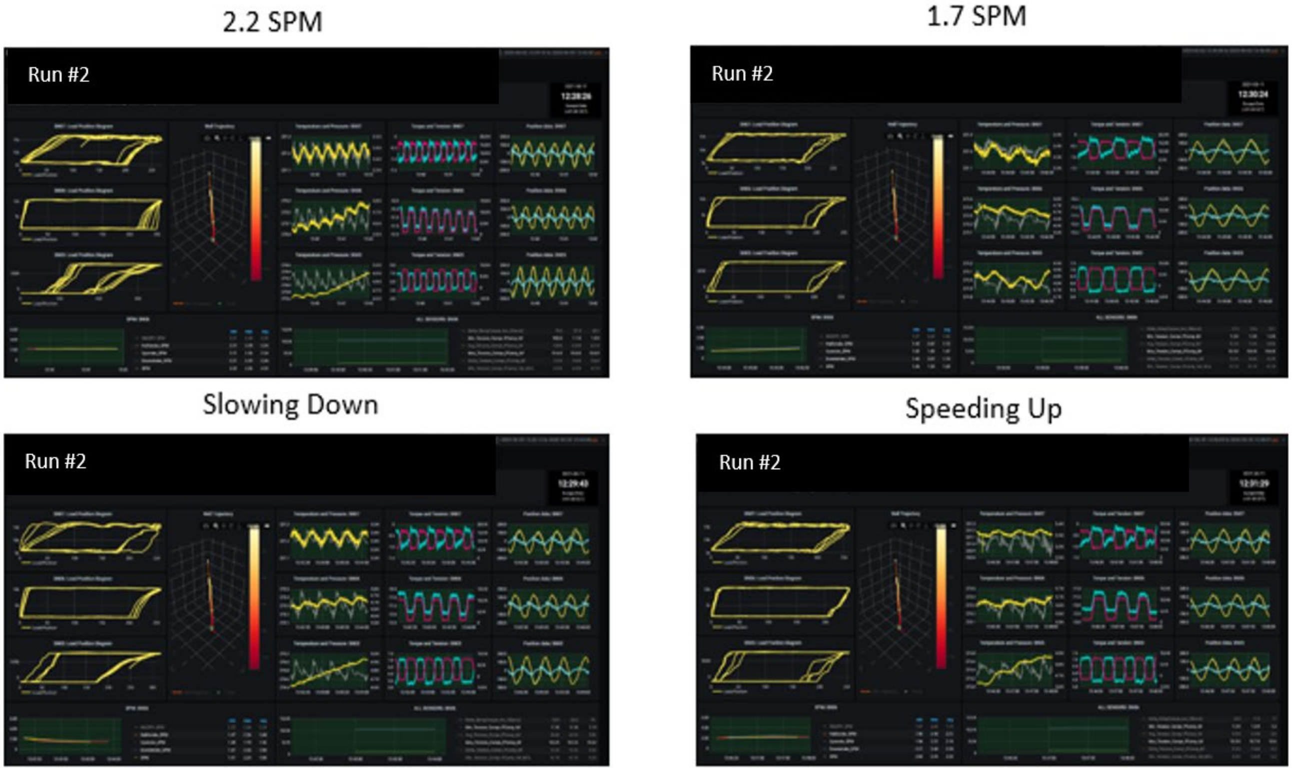
The Top and Middle tool are reflecting the surface controller set-up i.e. Upstroke = Downstroke. Notice that the Bottom tool is out of sync and the downstroke is faster than the upstroke due to rubbing.

Figure 15 – Run #1, Rodstring Out of Sync



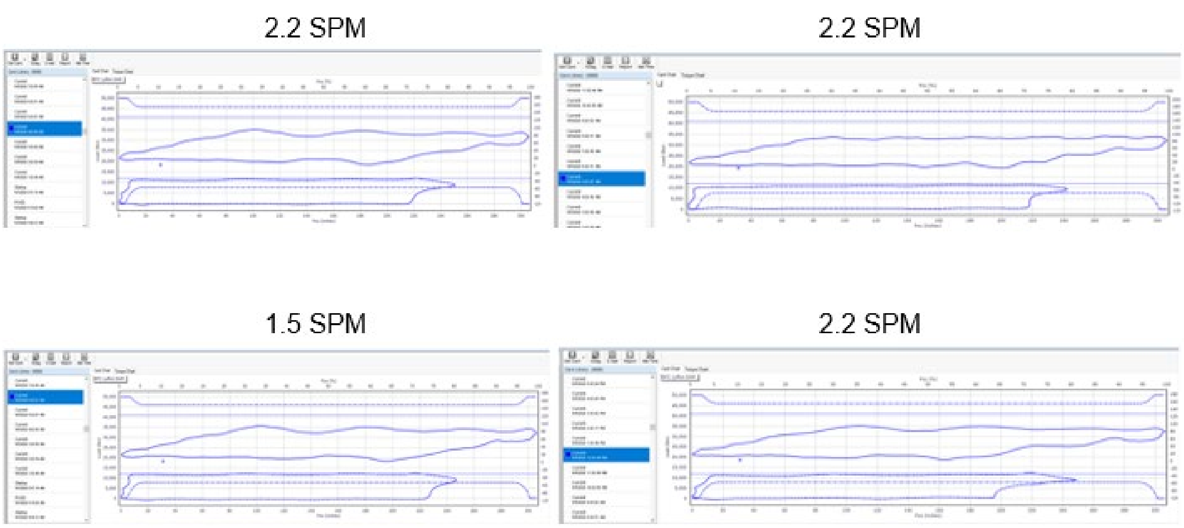
The Top and Middle tool are reflecting the surface controller set-up i.e. Upstroke > Downstroke. Notice that the Middle tool is erratic compared to Run #2 (Guided) and the bottom tool is reversing i.e. Downstroke is sometimes faster than upstroke. Keep in mind that the surface controller is set-up so that the Upstroke is faster than the Downstroke.

Figure 16 – Measured Dynacards Plots



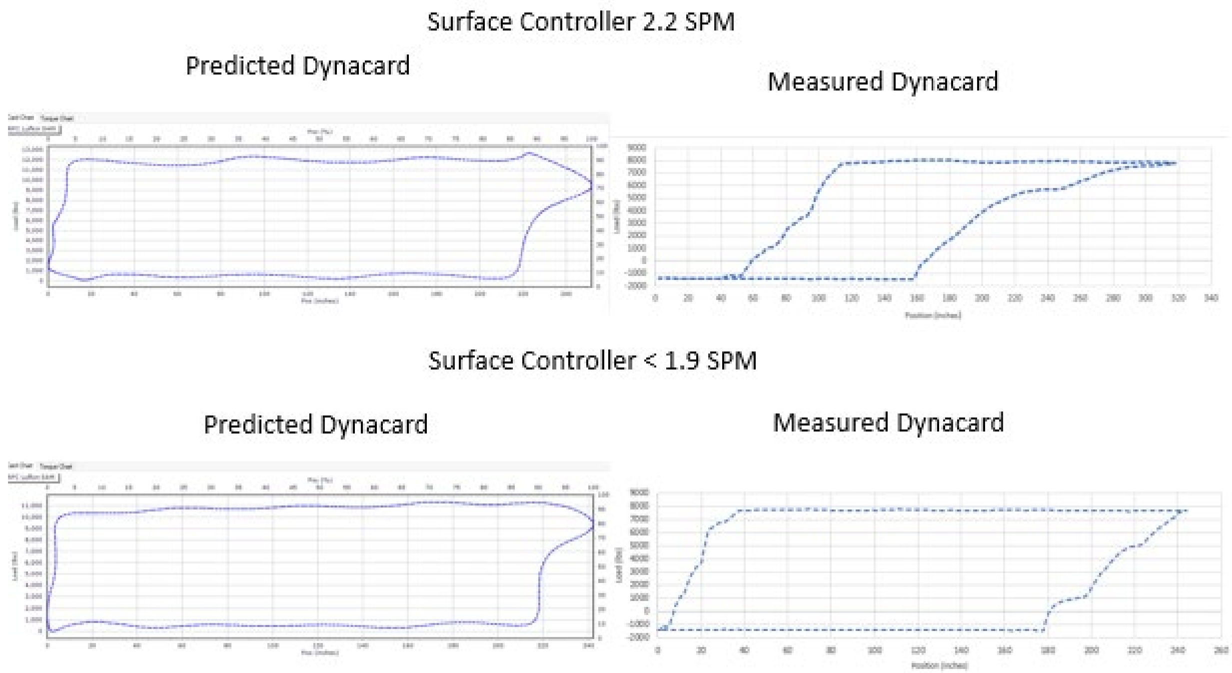
Run #2, from Top Left system running at 2.2 SPM. Top and middle cards out of sync. Bottom Left, as the system slows down the shape of the top and bottom cards start to align. Upper right plot, the system is running at 1.7 SPM, all three cards are aligned. Bottom right, system is speeding up, cards show system beginning to have alignment issues.

Figure 17 – Predicted Dynacard Plots



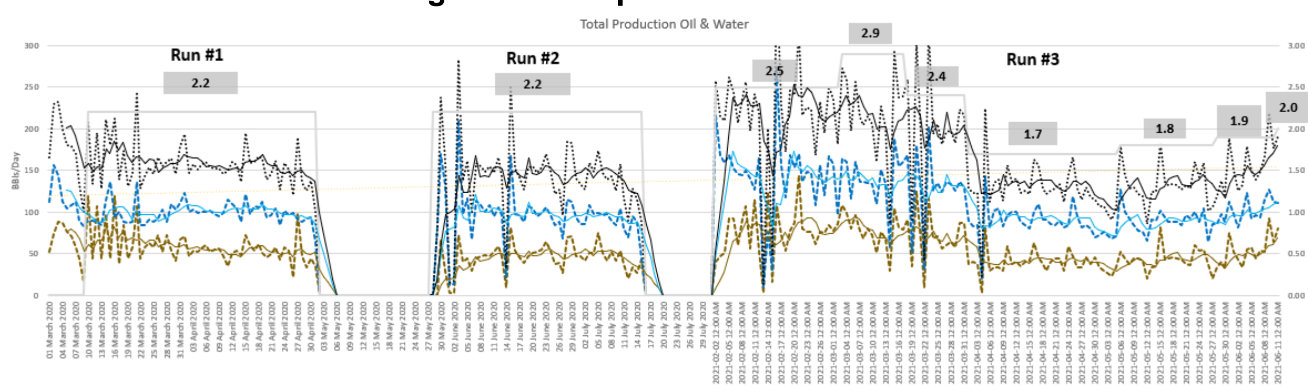
Predicted cards do not show string alignment issues with SPM changes.

Figure 18 – Predicted vs Measured Dynacards



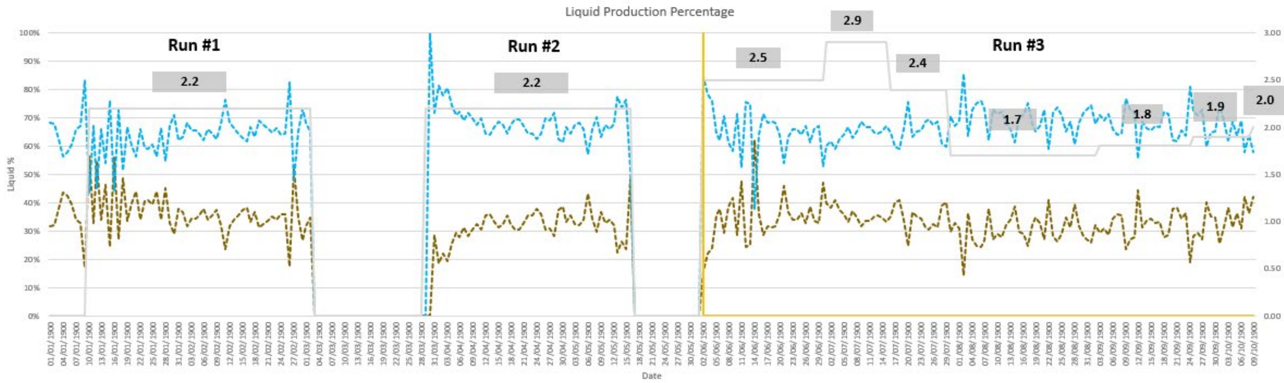
Predicted cards on left-hand-side do not show a difference when the SPM decreases from 2.2 SPM in the upper left, to 1.5 SPM in the lower left. But when looking at the subtle speed reduction for the Measured cards (2.2 to 1.9 SPM) on the right, we see a significant difference. At Speeds of 2.2 SPM the measured card is seeing the effects of the increase in rod/tubing rubbing, which has led to several tubing leaks in the past few years.

Figure 19 – Liquid Production



Total Liquid Production is Black, Blue is Water and Brown is Oil. Solid lines are 5 Day Moving Averages.

Figure 20 – Liquid Production Percentages



Percentage Liquid Production, Blue is Water and Brown is Oil.