

Using Downhole Displacement and Inferred Production for Verification of Measured Test Data

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Abstract

This paper describes a technique used to verify measured well test data in shallow rod pumped fields. Typically, the availability of measured well test data is constrained by test facility accuracy and the availability of the test facility for acceptable testing frequency. This technique involves the use of RPC (Rod Pumped Controller) calculated total fluid production as one source of production data for each well. A second source of production data comes from a wave equation driven diagnostic software program. This program uses load and position data gathered from each RPC to generate a downhole card from which pump displacement (production) can be calculated for all wells.

The measured well test data for each well can then be compared to the “inferred production” and the “downhole displacement” data for any observed discrepancy. “Inferred production” and “downhole displacement” make it possible for operating personnel to track daily individual well production with a high degree of accuracy without the use of actual well gauging facilities that might not be available on demand or that give questionable results.

This paper will also address methods necessary to setup RPC inferred production for reasonably accurate results, as well as necessary techniques for good displacement calculations from RPC dynamograph cards. These techniques involve the use of central site software for RPC setup and data telemetry.

Introduction

Operators of shallow well production fields often find themselves unable to obtain well test data as often or as accurately as they would prefer. This issue most often results from the sheer number of wells drilled in a restricted geographical area and not enough test facilities to adequately handle them. In many cases, this type of production also depends on steam injection as a primary production technique. Because steam is primarily a gas, varying amounts of steam must be pumped back to the surface by the downhole pump, along with the oil and water given up by each well. The presence of steam further complicates the issue of unusable well tests.

This paper describes well test data verification using RPCs and central site software currently used by several operators in shallow well fields. This technique is used in an effort to have reasonably accurate well test data as needed. Accurate well pump displacement data from the RPC can be critical to information management, decision making and in some cases, it can be used in place of the actual well tests.

Downhole Displacement

Rod pump displacement is usually calculated by the host software using a formula similar to the following:

$$\frac{\text{Downhole Displacement}}{\text{Per minute} * \text{Runtime}} = .1166 (\text{constant}) * (\text{Pump Diameter})^2 * \text{Stroke Length} * \text{Strokes}$$

The key parameter in this equation is stroke length. All the other parameters can be determined by the RPC or by the operator at the surface. The best method to determine stroke length at the pump, the basis for downhole displacement, is the wave equation solution. The wave equation solution calculates the downhole pump card from the surface dynamometer card. This calculation also determines the exact portion of the downhole stroke that is actually filling with liquid, usually called pump fillage (Figure 1).

Central site software, which is capable of automatically polling all RPC equipped wells and performing the wave equation analysis, is the best source of net pump displacement, the percent pump fillage and the daily runtime of each well. Using this information, and assuming 100% pump efficiency, downhole displacement values are calculated. Central site software can also store this information on a historical basis and trend the data. The calculated downhole displacement can be trended against the actual well test data and used to help judge the accuracy of the well test information.

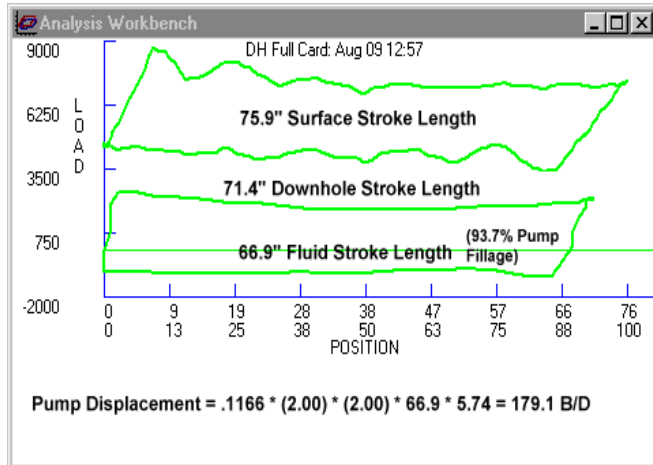


Figure 1---This graphic shows the relationship between the measured surface stroke length, the calculated downhole stroke length, and the net “fluid stroke” length based on liquid fillage of the pump. The “fluid stroke” length is the basis for “downhole displacement” or “pump displacement” calculations.

The accuracy of the calculated downhole displacement value is dependent on several factors. Because the “wave equation” solution is based on the load and position data from a surface dynamometer card, the measured “load and position” data must accurately reflect the actual load vs. position data at the polished rod of each well.

RPC Load Data. There are typically two types of load transducers used to gather data for the RPC. One is a calibrated load cell that dynamically measures polished rod load. Load cells need no initial calibration and continue to provide accurate load data for long periods unless exposed to extreme load violations. The second type of load data source is a “strain gauge” - either welded or bolted to the pumping unit walking beam. Correct installation procedures are critical whether the transducer is bolted to or welded on to the walking beam. For good downhole card shape and thus downhole stroke determination, strain gauges must be calibrated when the RPC is commissioned. “Calibration” can be defined as the procedure used to match strain gauge raw output voltage to the actual maximum and minimum loads of each well. Sources of maximum and minimum can be either a calibrated dynamometer system or a predictive design program using the industry standard “wave equation” solution. Strain gauges must also be “re-calibrated” with each change to the pumping system. It is also recommended that strain gauges be routinely “calibrated” regardless of any system change. It is important that the operator monitor each well using central site software for load transducer failure, load cable problems, load “drift” over time or changing downhole conditions that might affect downhole displacement calculations.

RPC Position Data. There are also two types of position instrumentation used to gather data for the RPC. One involves the use of a potentiometer or inclinometer. These devices provide actual polished rod position data to the RPC. Another option for position is the use of a “position or proximity switch.” This magnetic or “Hall Effect” device senses the passage of a pumping unit counterweight for the completion of each stroke of the pumping unit. The operator must accurately determine the delay between the switch closure and the actual beginning of the polished rod stroke, known as “top of stroke”. Also, he must be aware that the use of a “position switch” requires the RPC to use “simulated position” data to generate surface cards and most likely will not reflect actual well conditions. This will result in poor quality downhole cards and thus questionable downhole pump stroke / pump displacement calculations.

RPC Configuration and Operation. The RPC is the source of data for the central site software and is in control of the operation of each well. Proper commissioning procedures and on-going maintenance are important to the accuracy of the information it provides, such as the central site software calculation of the downhole card. Careful attention should be given to the RPC “pump off” set point values to ensure maximum production from a minimum amount of runtime. When “over pumping” and other conditions like

gas or steam compression are properly assessed and the RPC configured to handle them, the calculated downhole pump stroke will be more stable from day to day. If the RPC fails to measure SPM correctly, the surface and downhole cards will be “tilted” in one direction or the other – making the determination of exact downhole stroke questionable at best.

Well Configuration at the Host. The quality of the calculated downhole card is directly related to correct well data configuration. Incorrect rod information or rod taper data will distort the downhole card and make downhole stroke less useable (Figure 2). It is also important that correct damping factors or friction factors be applied to the calculated downhole card for each well.

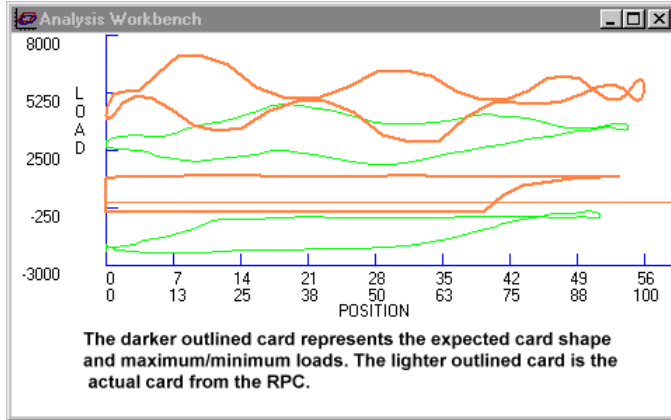


Figure 2---This graphic shows the possibility of improper calculation of “downhole displacement” due to incorrect loads from the RPC and/or well configuration problems.

RPC Based “Inferred Production” or “Fluid Stroke” Displacement

“Inferred production” or “fluid stroke” displacement is an estimate of the current daily production rate and the total daily production rate of rod pumped wells located typically in shallow, thermal reservoirs. These values are calculated from the surface dynamometer card using the estimated portion of the downhole pump stroke length that is actually moving fluid up the tubing string (Figure 3). Stated another way, this value is the portion of the downhole pump stroke that is filled with liquid. Because there is little or no rod stretch in shallow well pumping, the surface card stroke length and the downhole pump stroke length are nearly the same in most cases.

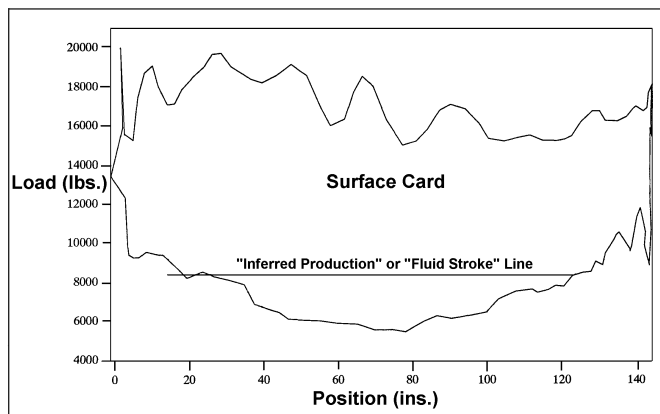


Figure 3---This graphic shows a typical shallow well surface dynamometer card with the RPC “inferred production” or “fluid stroke” line displayed.

When the pump fills completely with liquid on the upstroke (Full Card – Full Pump), the traveling valve opens at the beginning of the downstroke. The fluid load is then transferred from the rod string to the tubing string. This is easily seen as a rapid decrease in load on the surface card. When the pump fills only partially with liquid on the upstroke (Pump Off Card), the traveling valve does not open until the plunger reaches the fluid level in the pump barrel on the downstroke. Again, this is noted as a rapid decrease in load on the surface card. The distance from the bottom of the pump stroke to the point where the traveling valve opens is called the “fluid stroke”. This incomplete fillage is commonly known as “pump off” - which is often the normal operating condition of shallow wells. Under severe “pump off” conditions, this “fluid stroke” may be only a small fraction of the total pump stroke.

Manufacturers of RPCs use different methodology to estimate the “fluid stroke” value. Most involve the calculation of the average of the lowest loads as taken from the surface card downstroke. Some algorithms ignore any load “spikes” that might occur (tapping bottom, etc.) and also adjust for any “till” or unusual shape of the surface card (Figure 4-8). In addition, pumping conditions are hardly ever consistent – meaning that the “fluid stroke” may change from stroke to stroke and will almost always vary from hour to hour or day to day. Therefore, for the best accuracy, most RPCs estimate “fluid stroke” for every pump stroke. The calculation is based on the actual daily runtime of each well.

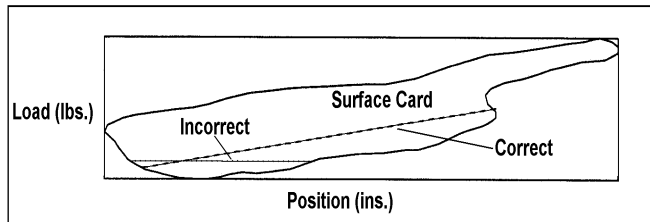


Figure 4---This graphic shows a surface card where the downstroke loads “slope”. The operator must configure the RPC to correctly identify the proper “inferred production” or “fluid stroke” line.

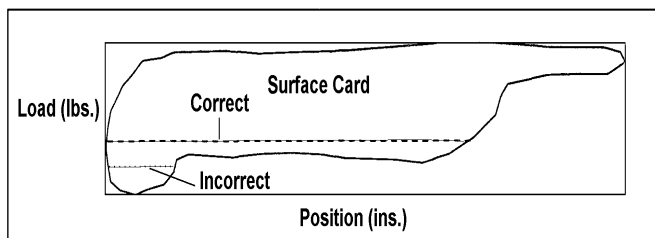


Figure 5---This graphic shows the pump “tapping bottom”. Because of much lower loads in the problem area, the “inferred production” or “fluid stroke” could be configured incorrectly.

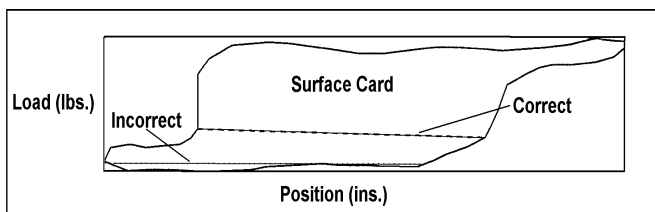


Figure 6---This graphic shows a surface card with a “toe” at the bottom of the downstroke. The operator must again correctly configure the “inferred production” or “fluid stroke” correctly.

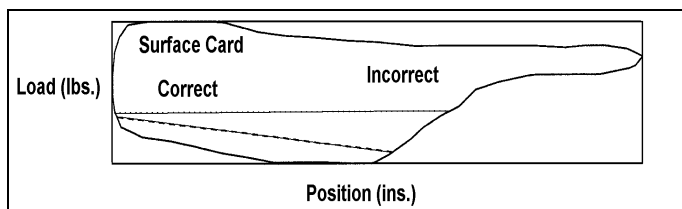


Figure 7---This graphic shows a surface card representative of gas or steam in the pump. The operator must configure the “inferred production” or “fluid stroke” to match the slightly sloping downstroke load line.

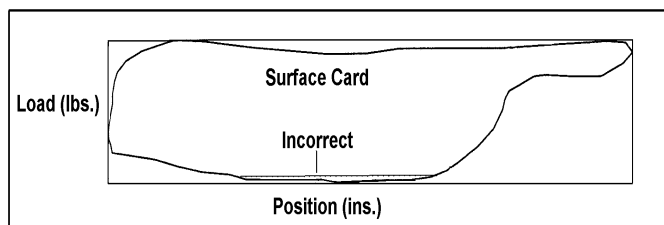


Figure 8---This graphic shows a surface card where the “inferred production” or “fluid stroke” configuration has been incorrectly selected.

RPCs allow the operator to manually determine a fixed “fluid stroke” from observation of the surface card. This fixed fluid stroke can be entered through a local interface at the RPC or “downloaded” from central site software. The operator also has the option to allow the RPC to define the “fluid stroke” internally without operator intervention. The RPC calculation of “inferred production” or “fluid stroke” can be turned “on” or “off” as needed.

The accuracy of this estimation of displacement is dependent on several factors. First, an effort should be made to make sure that each RPC has the best load and position data available, i.e. calibrated loads and good position data for the presentation of the surface card. Accuracy can depend on the type of position instrumentation used (see the section titled Downhole Pump Displacement). Second, and most important, the “inferred production” or “fluid stroke” calculations must be “fine tuned” based on a comparison of the calculated data to an accepted source of good test information - most often the test results from a well test or gauging facility. Central site software makes these tasks quick and simple (Figure 9 is an example of the interface to the RPC from a central site). “Inferred production” or “fluid stroke” results are stored by the RPC and are available through the local RPC interface or can be gathered, stored and displayed in reports or on a trend by the host software.

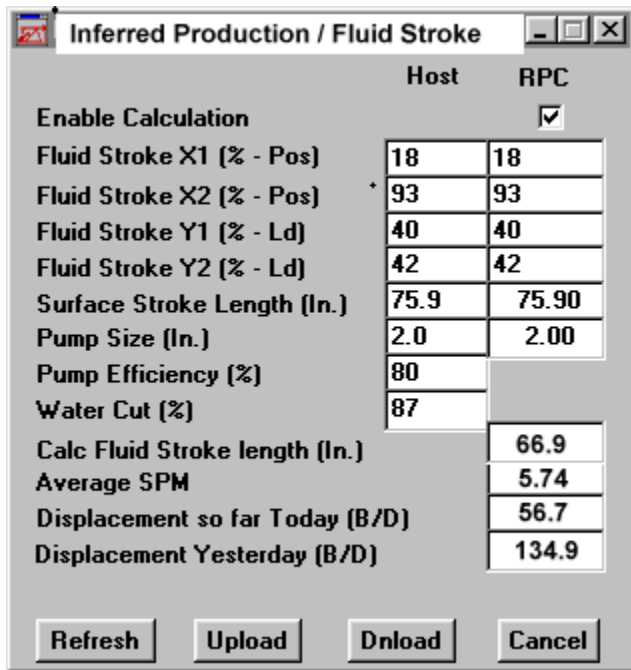


Figure 9---This graphic displays a central site software user interface panel used to configure the RPC calculation of “inferred production” or “fluid stroke” values. This panel can also be used to see the most recent result of this calculation from the RPC.

Measured Test Data

Well test information can be gathered by the central site software if a field location is equipped with either automatic or semi-automatic testing facilities equipped with PLCs or RTUs that can communicate with the software. Well test data can also be manually entered into the software – where it is stored historically and can be seen by the operator in various reports and trends.

Verification Technique

The central site software provides the tools used to gather and to store the measured test data from production facilities and the “inferred production” or “fluid stroke” displacement from each RPC. The software also automatically gathers and analyzes surface cards from each RPC to obtain and store the calculated “downhole displacement” based on net “fluid stroke” from the downhole pump card. If the well is “pumped off”, the software will use the calculated “full card” displacement factored by the actual daily runtime from each well. If the well is running 24 hours per day, the “current card” displacement factored by runtime is used. The operator is responsible for RPC load and position accuracy and well configuration for the software (see the section titled Downhole Pump Displacement). The operator is also responsible for “fine tuning” the RPC calculation of “inferred production” or “downhole displacement” to provide the most accurate information possible (see the section titled RPC Based “Inferred Production or “Fluid Stroke” Displacement).

The primary method used by the software to compare the measured test information with the “inferred production” and “downhole displacement” values is a trend called “Test Verification Data” (Figure 10). The operator can look at this trend on a daily basis and quickly determine if the “measured test data” is

verified by the other two sources of similar information. Besides the possibility of finding questionable well test data, operators can use this trend as one method to identify changes in well inflow or downhole mechanical condition.

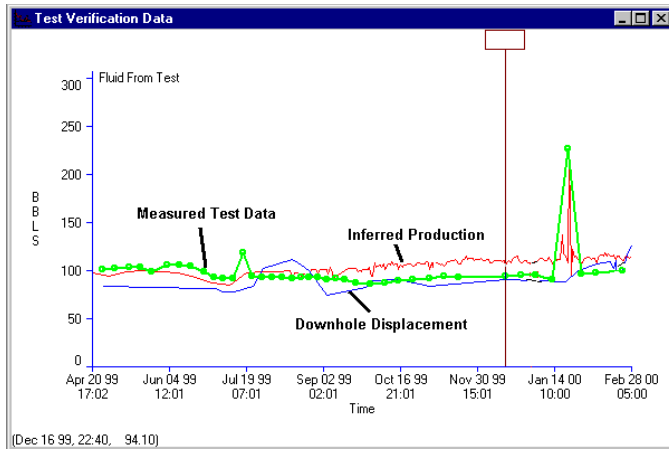


Figure 10---This graphic shows a typical "Test Verification Data" trend that is used by operators to track facility well test data in comparison to "inferred production" or "downhole displacement" provided by a wellhead RPC and "pump displacement" from a "wave equation" downhole card as calculated by the central site software.

Results

See Table 1---Data Comparison to compare "Inferred Production" (B/D) from each RPC, "Measured Well Test" (B/D), and "Calculated Downhole Displacement" (B/D) gathered at random from 36 wells in a field that produces from depths of less than 1000' to approximately 4000'. This data indicates that, with a minimum of effort in the setup of "inferred production" and in the commissioning of each RPC, the values of "Inferred Production" and "Downhole Displacement" are acceptably close to the actual well test data as measured by well testing facilities. Additionally, the values continue to track accurately over time and respond to actual changes in well inflow and the mechanical condition of each well. (Figure 11-13).

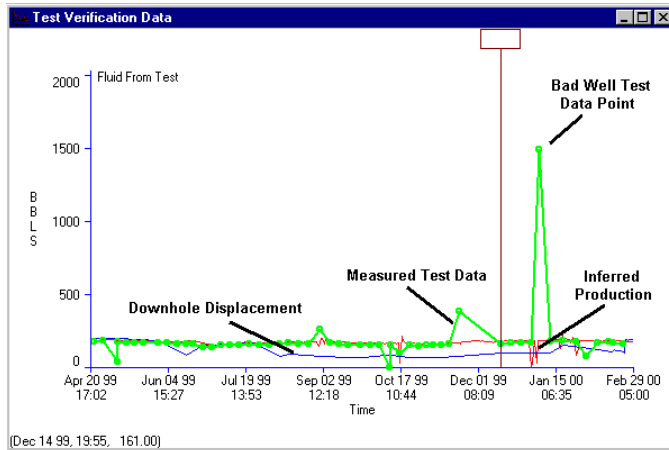


Figure 11---This graphic illustrates a typical "Test Verification Data" trend with one bad well test data point.

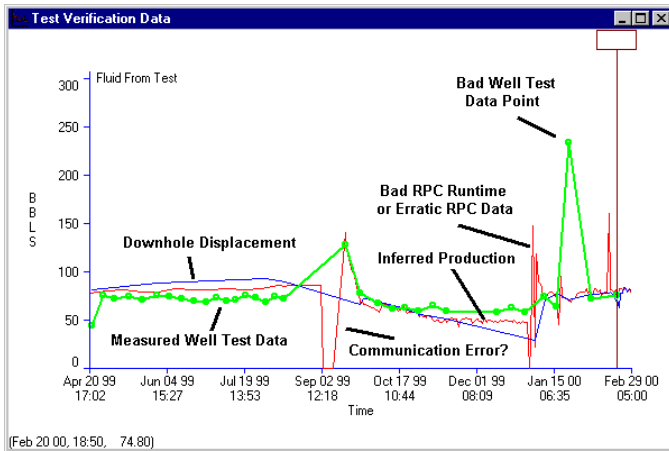


Figure 12---This graphic is another example of a “Test Verification Data” trend. The historical trend shows typical situations that may occur in the day-to-day collection of data, i.e. communication errors, erratic card information from the RPC and incorrect daily runtimes.

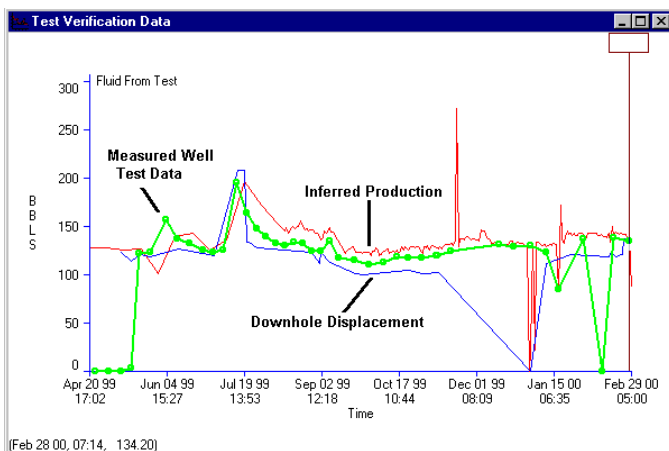


Figure 13---This graphic is another example of a typical “Test Verification Data” trend.

Several well configuration and RPC setup problems were identified and corrected during the preparation of this paper. Correct load calibration at each RPC (refer to RPC Load Data under the Downhole Displacement section) is important to both the downhole displacement and the inferred production calculation. Several wells were re-calibrated to correct maximum and minimum loads. (Figure 14-15 and 16-17).

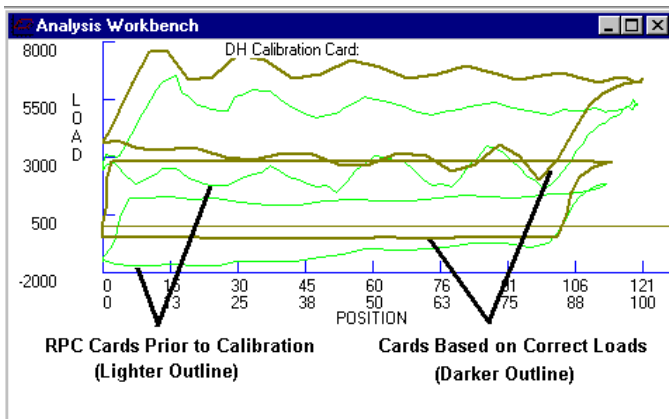


Figure 14---This graphic displays the un-calibrated card from the RPC and the card representing the correct maximum and minimum loads.

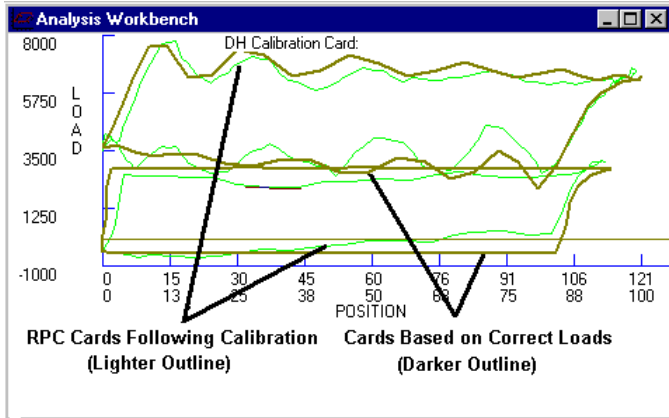


Figure 15---This graphic displays the same well as Figure 14, but following calibration of the RPC to the correct maximum and minimum loads.

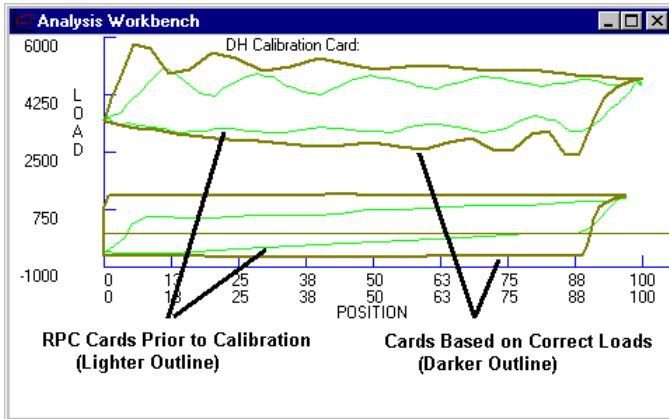


Figure 16---This graphic displays a second example of an un-calibrated card from the RPC and the card representing the correct maximum and minimum loads.

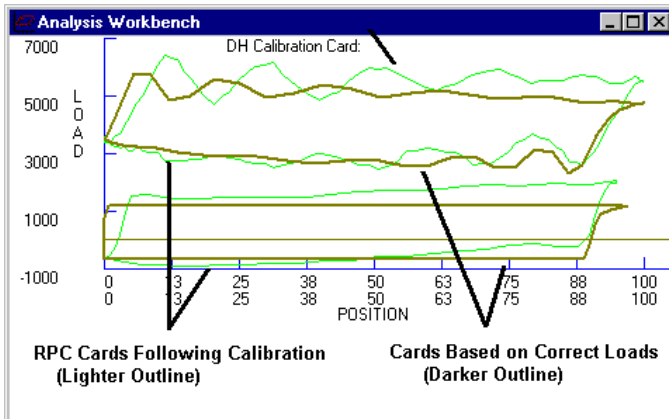


Figure 17---This graphic displays the same well as Figure 16, but following calibration of the RPC to the correct maximum and minimum loads.

Other wells were found to have been configured with an incorrect surface stroke length for purposes of calculating “inferred production”. Figure 18 shows the “Test Verification Data” trend and the result of changing the stroke length to the proper value for one of those wells. The surface stroke length was corrected from 120” to 144”. The “inferred production” value then moved from 159 B/D to 199 B/D to better match the measured well test value of 209 B/D and the calculated downhole displacement of 192 B/D. Incorrect “pump size” configuration also affected the RPC calculation of “inferred production” for some wells. Figure 19 displays the change in the RPC “inferred production” value from 213 B/D to 54 B/D when the pump size was corrected to 1.50” from 2.50”. The corrected value of 54 B/D better matches the measured well test value of 59 B/D and the calculated “downhole displacement” value of 53 B/D.

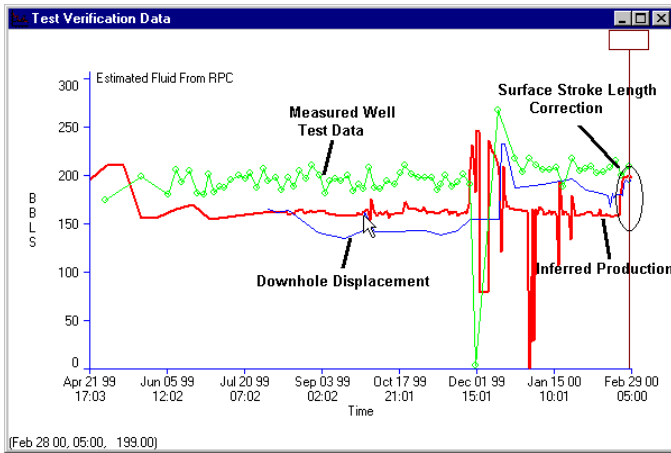


Figure 18---This graphic shows the change in the value of “inferred production” with the correction of the surface stroke length from 120” to 144”.

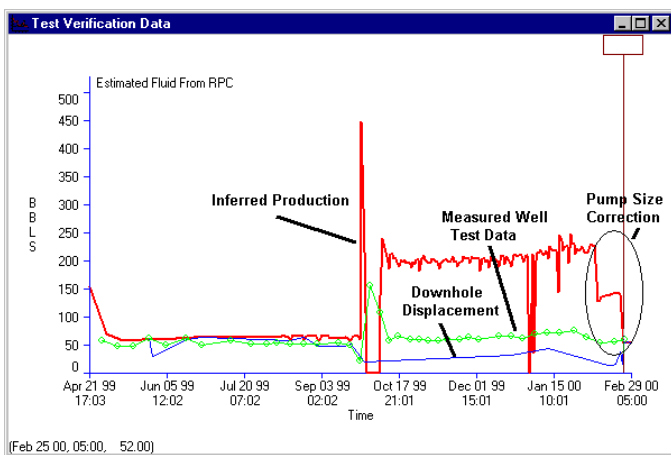


Figure 19---This graphic shows the change in the value of “inferred production” with the correction of the pump diameter from 2.50” to 1.50”.

Operators can also improve the RPC “inferred production” value by re-configuring the “fluid stroke” calculation parameters (see the section titled RPC Based “Inferred Production” or “Fluid Stroke” Displacement). Figure 20 and Figure 21 display the results of better matching the “inferred production” value to the actual measured well test data for two wells. The data from the first well (Figure 20) shows “inferred production” moving from 292 B/D to 456 B/D, which comes close to the measured well test of 448 B/D and the calculated “downhole displacement” of 459 B/D. The data from a second well (Figure 21) shows “inferred production” moving from 72 B/D to 138 B/D, which comes close to the measured well test of 136 B/D and the calculated “downhole displacement” of 141 B/D.

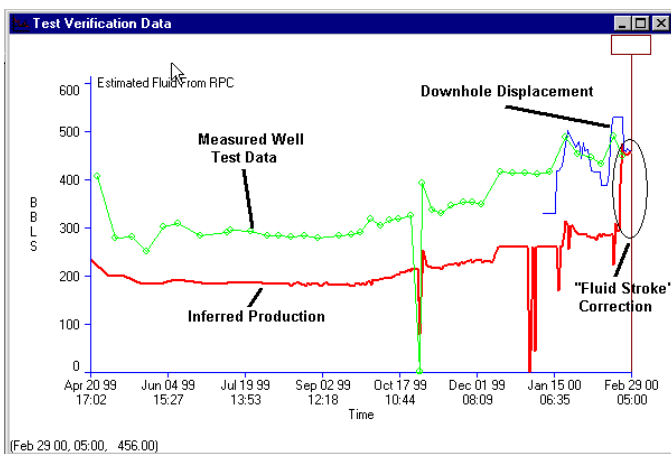


Figure 20---This graphic shows the change in the value of “inferred production” with the correction of the “fluid stroke” configuration to better match the actual measured well test value.

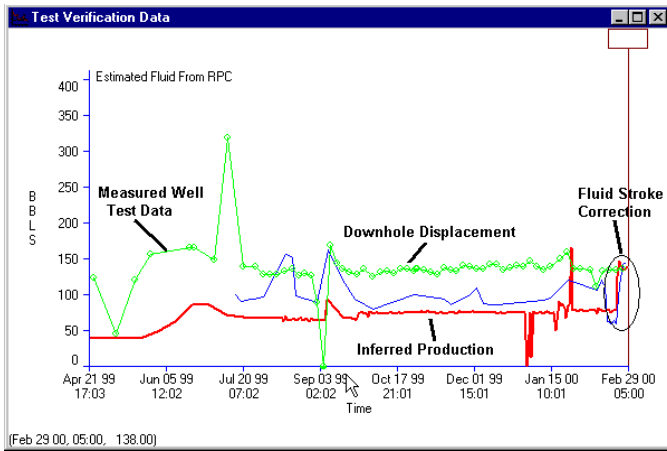


Figure 21---This graphic also shows the change in the value of “inferred production” from a second well with the correction of the “fluid stroke” configuration to better match the actual measured well test value.

One well was identified as pumping with a worn pump (Figure 22) and a calculated pump efficiency of 61%. The “Test Verification Data” trend shown for the same well in Figure 23 confirms that the measured test value (134 B/D) is less than the “inferred production” volume of 252 B/D and the “downhole displacement” value of 246 B/D.

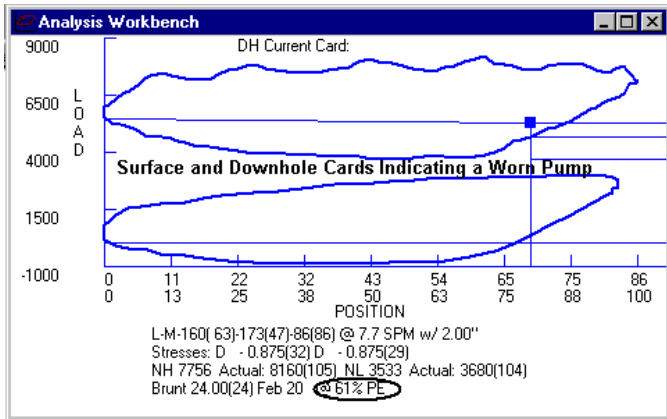


Figure 22---This graphic displays dynamometer cards that indicate a worn pump with a calculated pump efficiency of 61%.

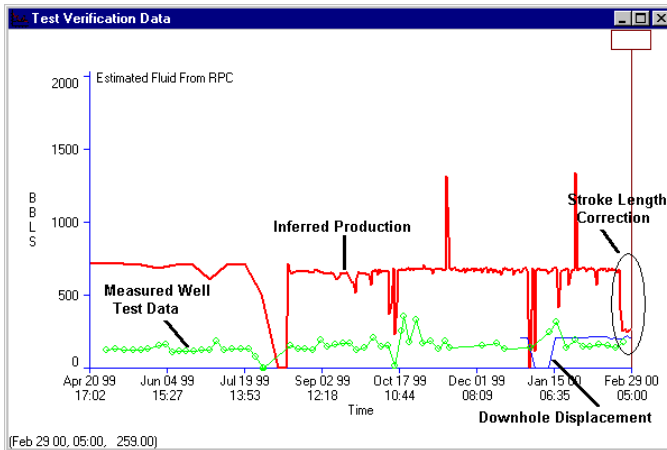


Figure 23---This graphic displays the “Test Verification Data” trend from the well identified in Figure 22 as having 61% pump efficiency. The trend confirms that the measured test data values are less than both the “inferred production” and the “downhole displacement”.

A “tilted” surface card (Figure 24) affected calculated downhole displacement results from two of the 36 wells in the sample group. “Tilted” surface cards are typically caused by improper stroke per minute measurement by the RPC.

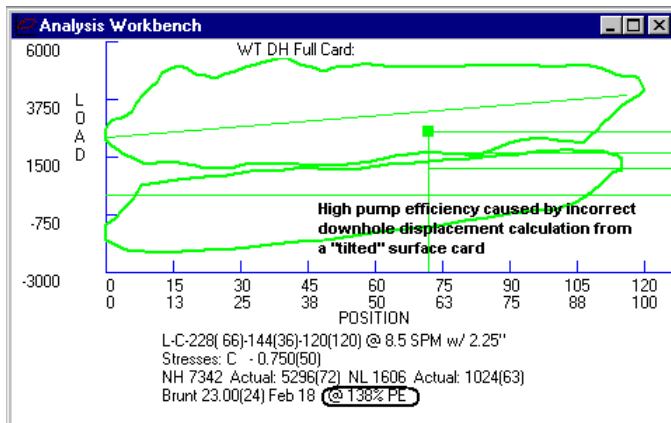


Figure 24---This graphic displays an example of a “tilted” surface card resulting in an incorrect calculation of “downhole displacement”.

The data from three of the 36 wells showed well test total fluid measurements that were noticeably higher than the totals indicated from “Inferred Production” and “Downhole Displacement”. Refer to Figure 25. Note the increase in measured well production, while “Inferred Production” and “Downhole Displacement” remain relatively unchanged. The “Test Verification Data” trend can be used in situations like this to find possible errors in fluid measurement by local well test or gauging facilities.

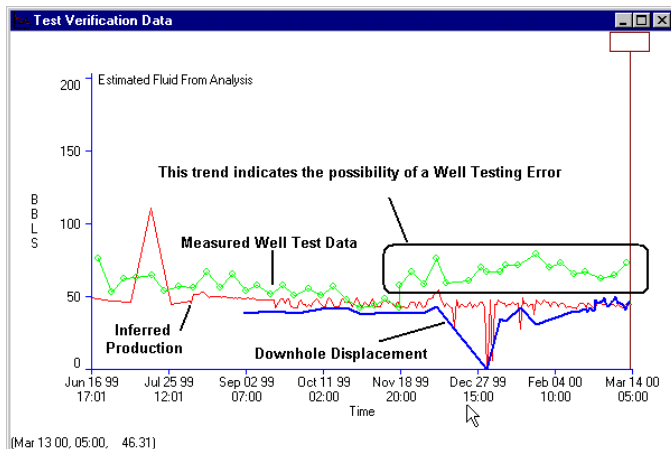


Figure 25---This graphic shows an example of the possibility of an error in fluid measurement through the local well test or gauging facilities.

Finally, the “Downhole Displacement” calculation value from wells 10, 13, and 24 was observed to be too high relative to both the measured well data and the “Inferred Production” data. This indicates that actual operating conditions for these wells have caused them to produce with a “pump efficiency” less than what might be normally expected, certainly less than 100%. Figure 26 shows the “Test Verification Data” trend for well 24. The “Downhole Displacement” value is 77.3, while the well test value is 54.9 and the “Inferred Production” value is 58.0. Figure 27 displays the same “Test Verification Data” trend after the application of a “pump efficiency” correction factor. The “Downhole Displacement” value is now 55.3, which compares well with the measured well test data and the “Inferred Production” values.

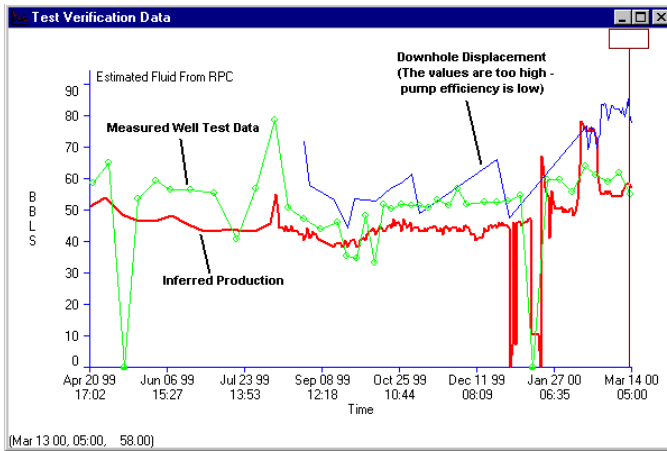


Figure 26---This graphic displays a “Test Verification Data” trend showing an example of calculated “downhole displacement” values that are too high. The operating conditions of individual wells may cause those wells to produce with pump efficiency less than what might be normally expected and certainly less than 100%.

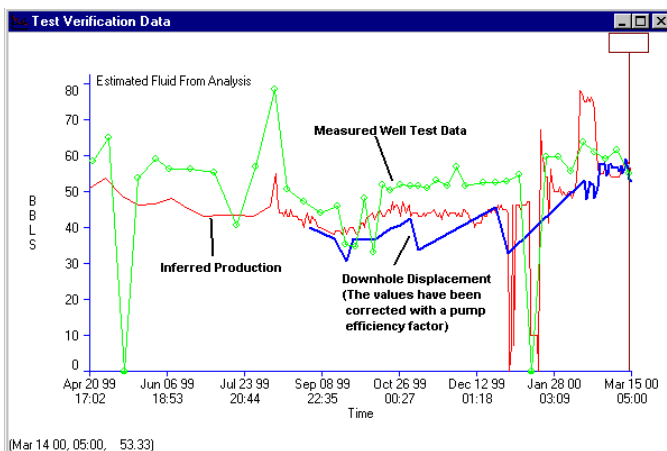


Figure 27---This graphic displays the same “Test Verification Data” trend as Figure 26, but with a “pump efficiency” factor applied to the “downhole displacement” values.

Conclusion

A comparison of the percent difference between the measured well test data and the “Inferred Production” values from each RPC from the 36 sample wells (See Table 1) reveals the following: 21 wells with a less than 5% variation, 6 wells with a difference of 5-10%, 3 wells with a difference of 10-20% and 6 wells with a variation of more than 20%. The same comparison made between the measured well test data and the calculated “Downhole Displacement” values using the downhole card from the 36 sample wells (See Table 1) reveals the following: 16 wells with a less than 5% variation, 4 wells with a difference of 5-10%, 7 wells with a difference of 10-20% and 9 wells with a variation of more than 20%.

Table 1---Data Comparison

Well	Measured Well Test (B/D)	Inferred Production (B/D – RPC)	Well Test Vs. Inf. Prod.	Cal. DH Displ. (B/D)	Well Test Vs. DH Displ.	Pump Depth	Pump Size	Comments
1	229.50	355.00	-35.4%	242.50	-5.7%	1000'	2.25" (24.0 H/D)	Bad surface card
2	364.80	361.00	1.1%	366.40	-0.4%	3400'	2.00" (21.3 H/D)	
3	236.10	242.00	-2.4%	203.50	13.8%	4000'	2.00" (24 H/D)	
4	291.90	203.00	43.8%	203.50	30.3%	3400'	2.25" (10.7 H/D)	Well Test?
5	195.80	193.00	1.5%	194.90	0.5%	3400'	2.25" (18.0 H/D)	
6	134.40	675.00	-80.1%	245.70	-82.8%	2250'	2.00" (23.5 H/D)	Worn pump
7	246.00	242.20	1.6%	248.80	-1.1%	2100'	2.00" (19.7 H/D)	
8	243.60	239.00	1.9%	183.30	24.8%	3600'	2.25" (9.9 H/D)	
9	231.00	231.00	0.0%	241.40	-4.5%	2200'	2.00" (22.2 H/D)	

Well	Measured Well Test (B/D)	Inferred Production (B/D – RPC)	Well Test Vs. Inf. Prod.	Cal. DH Displ. (B/D)	Well Test Vs. DH Displ.	Pump Depth	Pump Size	Comments
10	220.20	235.00	-6.3%	278.90	-26.7%	2300'	1.75"	(24 H/D) Pump efficiency?
11	140.60	138.00	1.9%	147.00	-4.6%	2200'	1.50"	(20.8 H/D)
12	131.00	134.00	-2.2%	141.00	-7.6%	2400'	1.75"	(11.2 H/D)
13	279.90	271.00	3.3%	298.30	-6.6%	2000'	2.00"	(22.2 H/D)
14	578.00	572.00	1.0%	471.80	18.4%	2000'	2.00"	(22.3 H/D) Poor surface card - tilted
15	143.70	155.00	-7.3%	150.80	-4.9%	2000'	2.00"	(15.5 H/D)
16	79.20	78.00	1.5%	77.30	2.4%	2100'	2.00"	(7.0 H/D)
17	306.60	295.00	3.9%	241.70	21.2%	1900'	2.00"	(22.5 H/D) Poor surface card - tilted
18	190.40	189.00	0.7%	197.70	-3.8%	2000'	2.00"	(19.5 H/D)
19	276.80	282.00	-1.8%	266.00	3.9%	2500'	2.25"	(17.3 H/D)
20	62.40	60.00	4.0%	54.60	12.5%	2200'	1.75"	(16.6 H/D)
22	148.80	148.90	-0.1%	145.10	2.5%	2300'	2.00"	(19.6 H/D)
23	229.20	220.00	4.2%	205.80	10.2%	1500'	2.00"	(16.6 H/D)
24	54.90	58.00	-5.3%	80.30	-46.3%	1250'	1.75"	(16.9 H/D) Pump efficiency?
25	264.00	381.00	-30.7%	267.10	-1.2%	1700'	1.50"	(24 H/D) Bad surface card
26	50.40	56.00	-10.0%	55.60	-10.3%	2300'	1.50"	(11.8 H/D)
27	210.10	207.00	1.5%	199.90	4.9%	2300'	1.75"	(17.1 H/D)
28	183.60	219.00	-16.2%	183.90	-0.2%	2400'	1.75"	(24 H/D)
29	170.40	180.00	-5.3%	180.50	-5.9%	2500'	1.75"	(20.7 H/D)
30	206.80	205.00	0.9%	204.20	1.3%	2200'	1.75"	(20.5 H/D)
31	195.20	219.00	-10.9%	202.60	-3.8%	2400'	2.00"	(19.0 H/D)
32	66.20	44.00	50.5%	46.30	30.1%	2000'	2.00"	(6.7 H/D) Well test?
33	452.00	452.00	0.0%	440.70	2.5%	2100'	2.25"	(24 H/D)
34	124.80	153.00	-18.4%	159.10	-27.5%	2300'	1.75"	(20.5 H/D) Well test?
35	177.00	192.00	-7.8%	145.30	17.9%	2900'	1.75"	(16.2 H/D) Pump efficiency?
36	196.80	200.00	-1.6%	172.00	12.6%	4800'	1.75"	(18.6 H/D) RPC "top of stroke"?

Six of the 36 wells were identified as having problems such as a worn pump and bad surface cards related to RPC operation or the fact that the wells were not pumping properly. The high number of wells (9) with a variation of more than 20% between the measured test data and the calculated "Downhole Displacement" can be related to the problems listed above or to the fact that the assumption of 100% pump efficiency was incorrect. It is interesting to note that 7 of these 9 wells have a pumping depth of more than 2500' to a maximum of 4800'. Typically, wells with a pump depth of more than 2500' lose pump efficiency due to slippage caused by increased hydrostatic pressure. For these wells, application of the "pump efficiency" factor described in the last paragraph under Results (Figure 26-27) would reduce this difference to less than 5%.

The technique of comparing measured well test data to the calculated downhole displacement from data provided by well site RPCs and analyzed by central site software and the inferred production value gathered from each RPC is a valid method of verifying the well test data. The technique does require operators to make a reasonable effort to validate and improve the calculated data.

Additional benefits from this technique include the recognition of changes in well inflow, changes in the condition of the mechanical portion of the lift system, and the likelihood of well test measurement errors.

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