URTeC: 2515

# An Examination of the Effects of Surface Data Acquisition Methods on Well Performance Evaluations and Completion Optimization

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## Abstract

It is a common practice in the development of unconventional wells to change completions designs in an effort to determine which design works best in each area. Quite often a Rate Transient Analysis ("RTA") of the flowback / early production data is used to evaluate how well performance is affected by changes in the completion design. Many analysts faced with performing RTA struggle to have confidence in the analysis results due to poor quality production data. This paper shows how different surface data acquisition methods effect the evaluation of well performance using common RTA techniques. Additionally, this paper will recommend preferred methods of data acquisition and demonstrate how these methods produce less ambiguous results.

Examples of early production data are shown that were acquired from a variety of common sources found in production operations. Practical measurement QA/QC methods are used to evaluate data quality, and RTA is used to demonstrate the effect data quality has on the well performance evaluations. Comparisons of results will be used to illustrate the impact that good and poor quality data can have on evaluating the relative difference in well performance due to changes in completion designs.

Superior data quality should be a top priority if a well's performance and/or completion design needs to be evaluated quickly and accurately with RTA of the early production period. Some data acquisition methods shown in this paper are not adequate for collecting the quality of data needed to produce reliable analysis results. Frequently, the changes from one completion design to the next are relatively small. With poor quality data, it can be impossible to quantify the effect of these changes. Examples presented in this paper show how poor data quality can be misleading when it comes to well performance evaluations. Examples of data acquisition from some of the best quality sources illustrate how straight-lines used on specialized diagnostic plots can match the data very closely. This gives the analyst much more confidence in the magnitude of the difference in well performance due to changes in the completion design.

Iterative completion optimization can be a waste of time and money if the difference in a well's performance due to changes in the completion design cannot be evaluated quickly and accurately. If those responsible for unconventional well performance optimization are going to continue to rely on the insights provided by RTA, it seems only logical that the data going into the analysis needs to be of the highest quality possible.

Reservoir and production engineers need high quality data to evaluate a well's performance so that they can provide feedback to the completions engineers on which changes in the completion design have the largest impact on well performance. None of this can be done properly if the production team does not receive the best quality data available. It is essential that the production team has the right people and equipment in place to consistently collect high quality data. This often seems to be an overlooked component of the overall value chain.

## Introduction

During the first 5-30 days of initial production--the period often described as "flowback"--valuable data can be gathered that offers the first glimpse into dynamic completion and reservoir responses. After reviewing hundreds of these data sets from every major basin in the United States, we have found that a significant portion have specific types of measurement errors that directly impact the interpretation of well performance. This is particularly concerning because this data is being used to evaluate draw down strategies, to assess well performance, and to determine the benefit of changes to completion designs that can have significant financial impacts.

As noted by Anderson (2006), the application of production data analysis methods, without consideration for data quality issues, can lead to misinterpretation of the reservoir characteristic. Clarkson (2019), discusses a 4-step workflow for quantitative RTA of flowback and early time well production data for wells completed in unconventional reservoirs. Step one of the work flow is "Assessing Data Viability." The importance of this statement cannot be stressed enough. In order to properly assess well performance with confidence, the first step must be to ensure consistent high quality data. All efforts should be made to use the best measurement methods possible and to continuously assess production data quality.

The first half of this paper will describe our preferred dashboard and workflow for identifying surface measurement errors. We discuss the most common rate and pressure measurement methods we encounter during the initial production period and summarize what we have seen in terms of data quality from the different measurement methods. Case Study 1 will demonstrate how the plots in the dashboard are used to identify a common surface measurement error.

The second half of this paper focuses on the effect surface measurements can have on well performance assessment with three case studies. Case Study 2 demonstrates how different measurement methods used on a single well effect the performance diagnostic. Case Study 3 demonstrates how our recommended measurement methods result in data quality that allows the choke schedule to be optimized in real time based on changes in the well's performance as observed on the performance diagnostic plot in between choke changes. Case Study 4 shows how our recommended surface measurement methods reduce ambiguities in assessing final well performance and in identifying the optimum completion design.

## Initial Production Data Diagnostics

Generally, we find poor quality production data arises from two different sources. The first, and by far the most common, is low quality surface measurements. Some examples of this are the wrong density used for gas rate measurement calculations, oil being counted as water, meters being out of calibration, etc. The second is from the reservoir and/or completion. Examples of this are liquid loading in the vertical section and water influx from offset well stimulation. When assessing the quality of initial production data, the analyst must determine if what they are seeing in the data is caused by the reservoir, completion, or surface measurements. If the source of the poor quality data is from surface measurements, it can usually be corrected quickly and easily.

Nobakht (2009) and llk (2010) discussed some causes of poor quality production data. They showed how certain diagnostic plots can be used for quality assessment and how poor quality data can affect well performance evaluations. Ghanbari (2013), Xu (2015), and Jones (2017) focused more on how production ratios could be used to identify completion and reservoir conditions that can affect production data. We will add to the work of these previous authors and demonstrate how production ratio trends can be a valuable tool for identifying surface rate measurement errors commonly seen during the initial production period, and how those errors affect well performance evaluations.

Below, in Figure, 1 is the dashboard we find most useful for measurement diagnostics and quality assessment of initial production data. In the top left is the production history plot. At a minimum, this plot should include the hourly wellhead pressure ("WHP"), bottomhole pressure ("BHP"), choke size, oil rate per hour ("BOPH"), water rate per hour ("BWPH"), and gas rate per hour ("MCFH"). Rates and pressures should change when the choke is changed. When the choke is increased, BHP should decrease and each rate should increase (and vice-versa if the well is choked back).

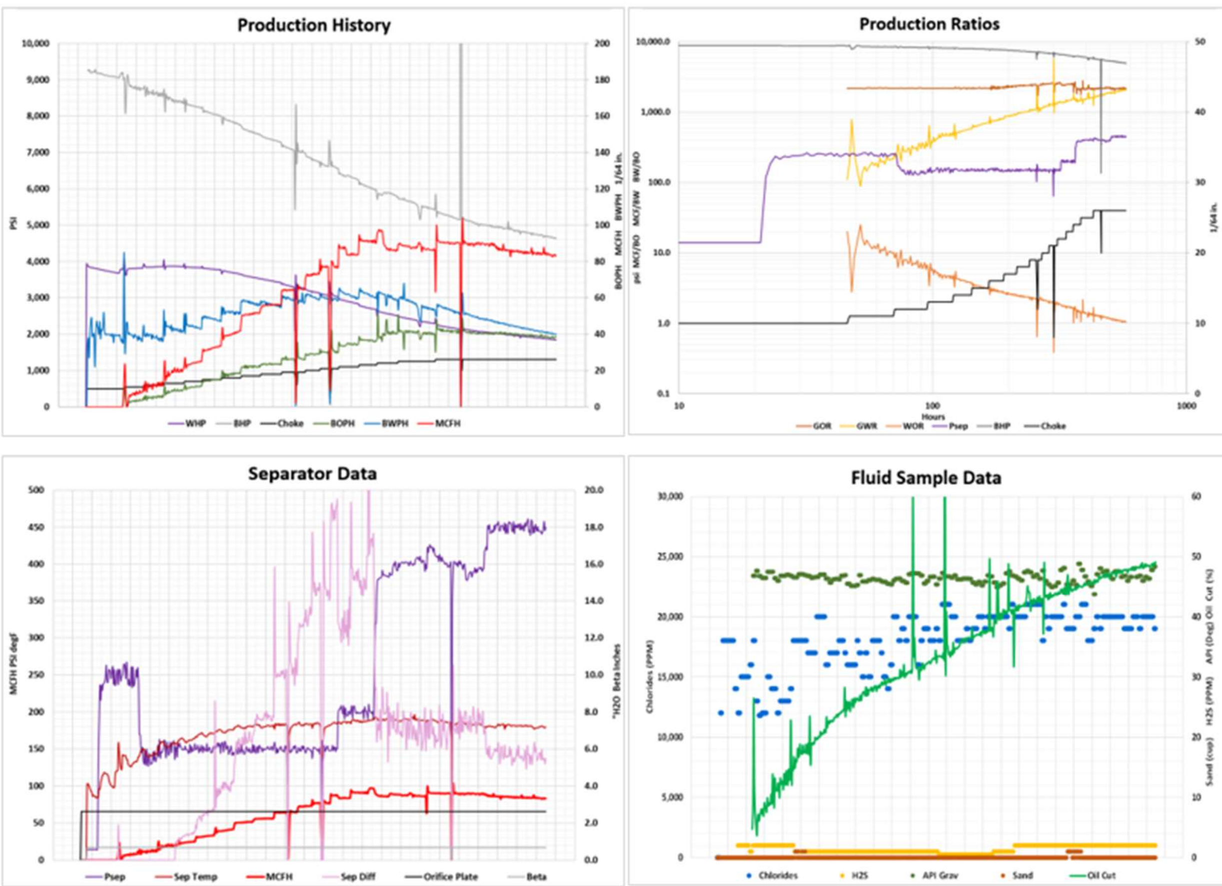


Figure 1 - Preferred dashboard for measurement diagnostics of initial production data

In the bottom left of Figure 1, we see the separator data plot which is used to identify changes in measurement conditions that may affect the gas rate measurement. In this example, we show the separator data plot for a separator that is using an orifice plate for gas rate measurement because this is the most commonly (but not the only) encountered method of gas rate measurement. When an orifice plate is used for gas rate measurement, this plot should include separator temperature, separator static pressure, differential across the orifice plate, orifice plate size, and recorded gas rate. In the bottom right of Figure 1, we see the fluid sample data which is used to identify changes in fluid composition that may affect the fluid measurements or indicate some changes in the reservoir fluid composition. This plot should include chlorides and H2S in parts per million, API oil gravity, cumulative sand and rate, and oil cut. In the top right of Figure 1, we see the production ratios plot. This is, in our opinion, the most valuable plot for identifying rate measurement errors in initial production data. This plot should include the gas-oil ratio ("GOR"), gas-water ratio ("GWR"), water-oil ratio ("WOR"), separator static pressure ("Psep"), bottomhole pressure ("BHP"), and choke size. We prefer to view this plot in log-log coordinates with delta time on the x-axis so that changes in the trends can be easily seen.

Figure 2 shows an example of the most common trends seen during the initial production period of an oil well flowing at a bottomhole pressure above the saturation pressure.

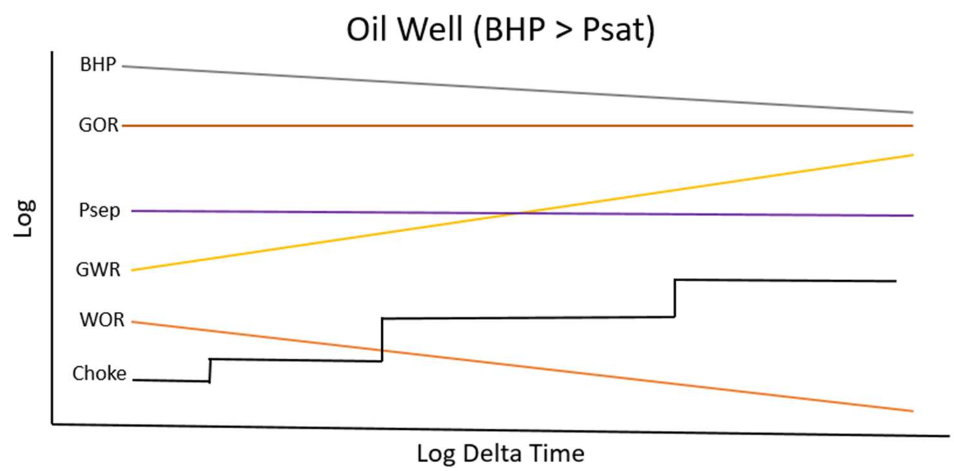


Figure 2 - Expected trends in production ratios for the initial production of an oil well flowing above saturation pressure

All of the production ratios and pressure trends in this plot should be smooth. Any changes in these trends that happen relatively quickly could be rate measurement errors, and changes in trends that happen gradually are usually due to the reservoir response. The list below details the expected response of each trend.

- **GOR** should be nearly constant when an oil well is flowing at bottomhole pressures higher than the saturation pressure. Under this condition, hydrocarbons are entering the wellbore as a single liquid phase. Deviations from a nearly constant trend can be caused by the bottomhole pressure dropping below the saturation pressure, and by changes in separator back pressure. It is important to plot BHP and Psep on the production ratios plot. Viewing these trends simultaneously allows the analyst to determine if deviations in GOR are due to the saturation pressure, changes in separator back pressure, or measurement errors.
- **BHP** should be smooth and decreasing if the choke sizes are being increased or held constant. BHP will increase if the choke sizes are decreased.
- **Psep** should be nearly constant. There are many times when the separator back pressure cannot be kept constant, but every effort should be made to reduce the amount and magnitude of separator pressure changes. Changes in separator back pressure can change the gas and oil rates which will affect calculated BHP and the well performance assessments. This tends to be more pronounced with volatile oils and condensates.
- **GWR** should be gradually increasing and may level off to become nearly constant towards the end of the initial production period.

- **WOR** should be gradually decreasing and may level off to become nearly constant towards the end of the initial production period.

The slope of the WOR and GWR trends can be indicative of the formation wettability and sensitivity to water. The slopes in the WOR and GWR trends we have observed can range from nearly zero (Bakken) to relatively steep (Woodford). Below, in Figure 3, is a field example of the initial production ratios for a well in the Permian showing the trends we would expect to see when no significant measurement errors exist.

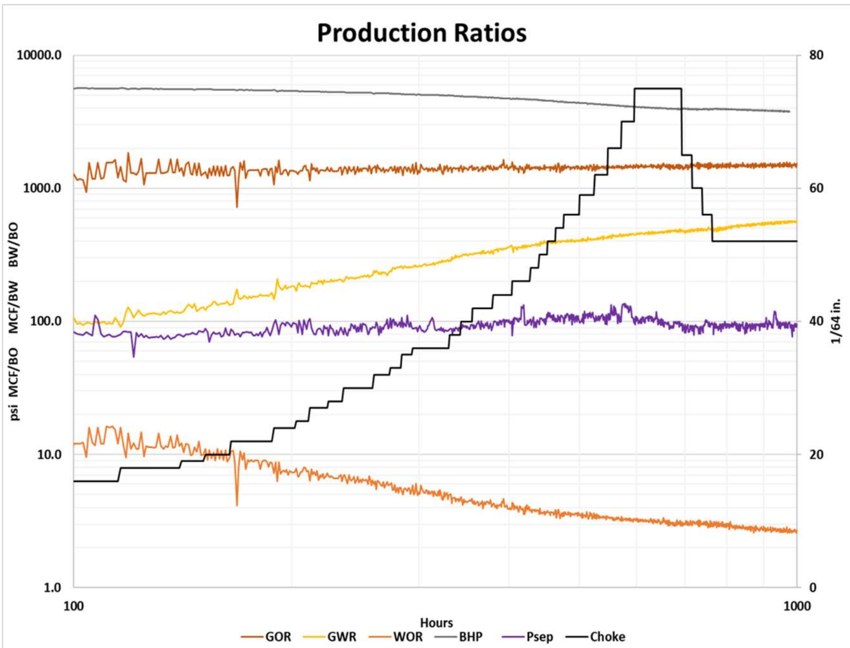


Figure 3 – Field example of expected production ratio trends for an oil well flowing at BHP>Psat

Measurement errors will manifest themselves on the production ratios plot as deviations from the expected trends of the production ratios. Usually, when a change is seen on two production ratio trends, the common phase between them is the phase with the error. Below, in Figure 4, is an example of the change in the expected trend for a well with a gas rate measurement error.

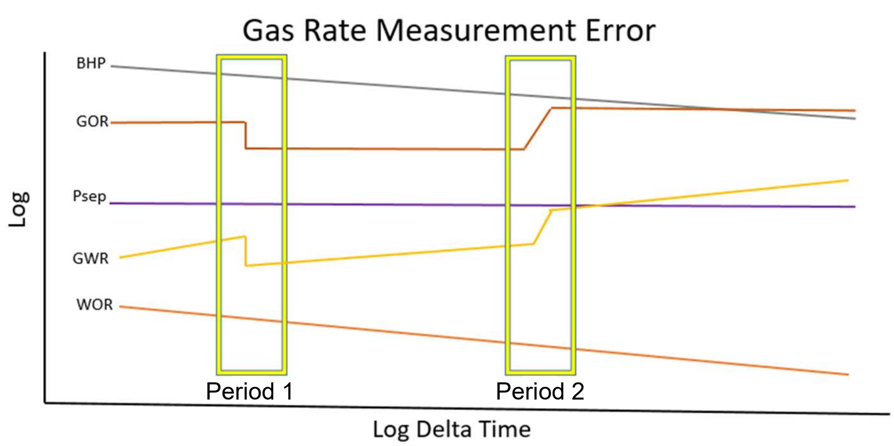


Figure 4- Production ratio trends indicating gas rate measurement error

During Period 1, there is a quick change in GOR and GWR, and at Period 2 there is a more gradual change. These changes should prompt the analyst to investigate possible measurement errors. In both cases, the common phase between the two production ratio trends where the change is seen is the gas phase indicating that there is a possible gas rate measurement error. It is important to note that the change in trend does not necessarily mean the measurement error started at that point. It could be that the measurement error was corrected at that point, and all of the data previous to that point is not correct. Below, in Figure 5, is a field example of a well with a gas rate measurement error similar to Period 1 in Figure 4.

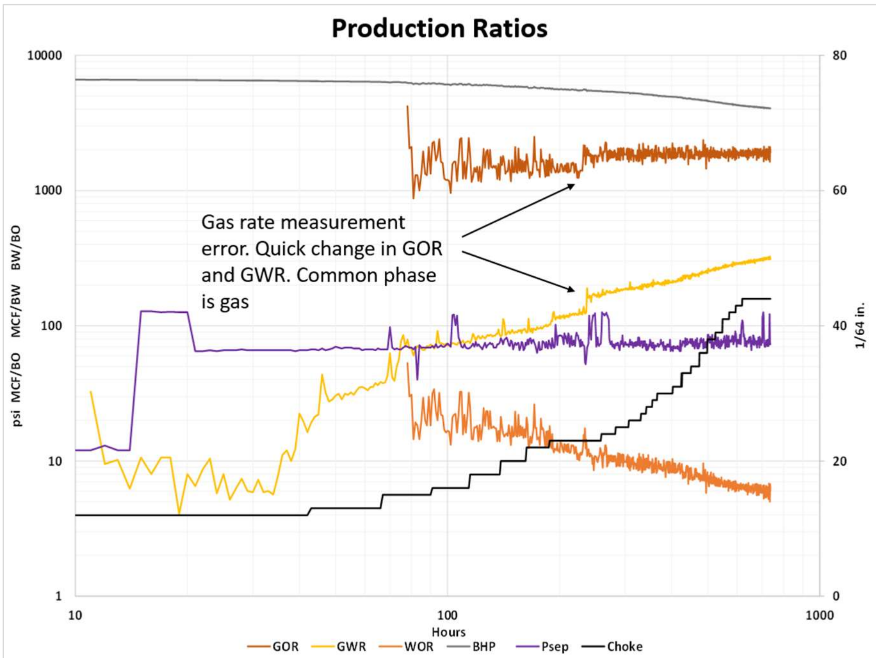


Figure 5 – Field example of production ratio trends indicating gas rate measurement error

For brevity, we only show a couple of examples demonstrating how production ratios are used for surface rate measurement diagnostics. Tompkins (2020), provides a much more detailed summary of how production ratios can be used for surface measurement diagnostics.

**Measurement Methods**

There are a variety of methods for measuring rates and pressures during the initial production of unconventional wells. The most common methods are discussed here, along with our general observations about the quality of data that comes from each, and an example showing the production history of a well that used different measurement methods throughout the initial production period.

**Tank Straps (liquid rates)** – All that is required for this type of measurement is a tank to hold produced liquids, a tape measure or dip stick, and a chemical indicator to measure the height of the liquid in the tank. The liquid rate is calculated from the difference in the height of the liquid from one hour to the next. This is a very easy method of estimating liquid rates and almost entirely inadequate for getting the data quality needed for RTA. In practice, we have observed this method of measurement to be the least accurate of all the methods discussed.

**Tank Level Sensors (liquid rates)** – Non-contact (pulse) radar and guided wave radar are the two most common tank level sensors typically used for measuring liquid rates during initial production. Like tank straps, the liquid rate is calculated from the difference in liquid height from one hour to the next. Non-contact radar sensors transmit microwaves from the top of the tank to the surface of the liquid. Guided wave radars transmit microwaves down a probe that is submerged in the liquid. Guided wave radars have been observed to be much better for measuring liquid levels because they can detect an interface more accurately and are not as sensitive to surface conditions (i.e. emulsions, foam). We have not found pulse radar level sensors to consistently provide adequate data when these conditions exist but we have found that guided wave radar level sensors provide very good quality data when properly calibrated.

**Turbine Meters (liquid rates)** – These meters have a small impellor in them that spins when fluid moves past it. The fluid rate is calculated from the rotational speed of the turbine. When functioning correctly and properly calibrated, these meters can provide adequate data quality for RTA. However, we have seen very large variations in data quality from this type of meter. Turbine meters can be fairly accurate when they are calibrated correctly and conditions do not change. This is most often the case when turbine meters are part of permanent facilities, and the well is past the initial production phase. When the turbine meters are part of temporary equipment, they are often either not calibrated correctly, not functioning correctly, and/or not operated correctly.

**Electromagnetic Meters (water rate)** – These meters measure the water rate from the magnetic field that is generated by the water flowing through a pipe. The data quality from this type of meter tends to be fairly good when the meter is calibrated and operated correctly. It is more common to see these as part of permanent facilities than temporary rental equipment.

**Coriolis Meters (gas and liquid rates)** – This type of meter measures the change in oscillation frequency created by the inertia of the mass moving through them. When properly operated and calibrated, these meters are the best option for collecting initial rate data. We have consistently seen very accurate high quality data coming from this type of meter.

**Orifice Plate (gas rate)** – This type of meter measures gas rate from the differential pressure created as gas passes through an orifice. There is a very wide range of data quality that comes from this type of meter. The most common issues associated with this meter type are caused by operator error. We have encountered a significant number of cases where the operator on location does not know how to properly operate the meter. Orifice plates may be installed backwards, the wrong size orifice plate selected, valves not completely opened or closed, gas calculation inputs not entered correctly, and incorrect meter run sizes are all examples of issues we have found using differential pressure for gas rate measurement. When these meters are properly sized, calibrated, and operated, we have found this type of meter provides good quality data.

**Analogue Gauges (WHP)** – These are mechanical gauges that usually use a Bourdon tube to sense pressure which is attached to a needle that points to a number on a scale corresponding to the pressure. These have lower accuracy than digital gauges and we find field operators tend to record the same pressure for hours, or even days, at a time even though pressure is actually changing. The data quality from these gauges is poor and not adequate to evaluate well performance from initial production data.

**Digital Gauges (WHP / BHP)** – There are a variety of digital gauges for both WHP and BHP. These gauges usually have a piezo electric material like quartz in them that is very sensitive to changes in pressure and temperature. The data quality from these is usually high. Bottomhole pressure gauges are preferred because they provide the most accurate BHP. To determine the BHP from WHP gauges, correlations combining flow rates, temperatures and fluid properties need to be used. These correlations make the calculated BHP particularly sensitive to the WHP and flow rate data being used. Diagnostic tests utilizing WHP gauges need to have the best WHP and surface rate measurements available to determine the most accurate calculated BHP. The error between bottomhole pressure gauge data and calculated bottomhole pressure increases with surface rate and pressure measurement errors.

Figure 6 is an example of the production history from a well that used different rate measurement methods during the initial production period. Digital WHP gauges were used for the entire testing period. At the beginning the well is flowing to open top tanks (which is common) and the oil and water rates are measured using tank straps. The water and oil rate data during this period is clearly very 'noisy'. After this period, the well is flowed through an automated testing system with Coriolis meters measuring liquid rates and a gas conditioning orifice plate for gas rate measurement. This is the highest quality data observed during the initial production period. Once the well was cleaned up, it was flowed through permanent facilities with turbine meters measuring the liquid rates and an orifice plate for gas rate measurement. Again, it is very clear to see that the oil and gas rates are very noisy when flowing through permanent facilities compared to when the well was flowing through the automated testing system.

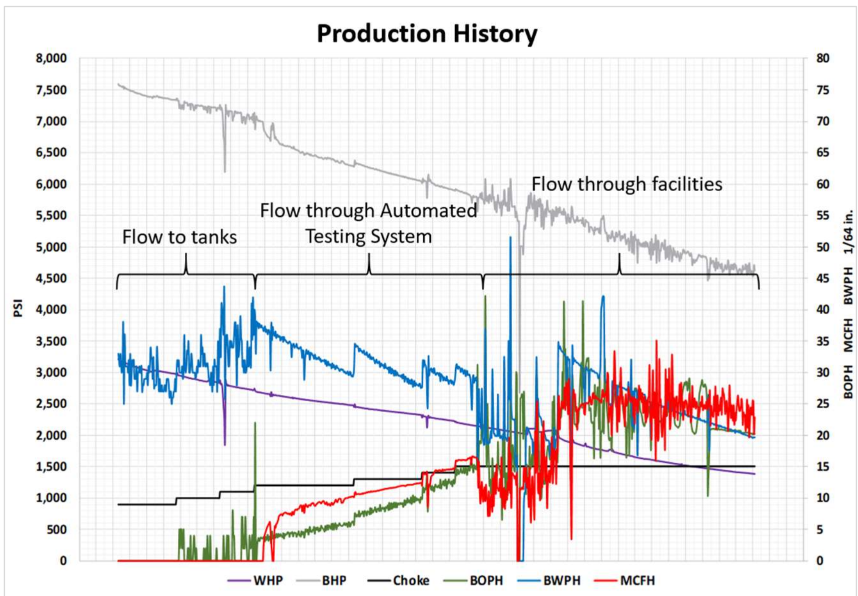


Figure 6 – Field example showing multiple measurement methods used during initial production period

The production ratios plot for the well in Figure 6 is shown in Figure 7. The data is trending as expected, but there is a clear change in data quality. Early on, while the well was flowing to tanks, the gas rate was not recorded so the ratios relative to gas do not show up during this period. However, the WOR is very noisy at the start of the test reflecting the very low measurement quality coming from tanks straps. After this period, when the well is flowed through the automated testing system, the data is very smooth and trending as expected until the well is flowed through permanent facilities. Once the well is flowed through permanent facilities, the data becomes very noisy again. This was due to gas rate and oil rate measurement errors caused by both the gas rate calculation from the orifice plate, and the oil rate calculation from the turbine meter. Eventually (not seen in this data set) the facility measurements were corrected by using the automated testing system as a reference.

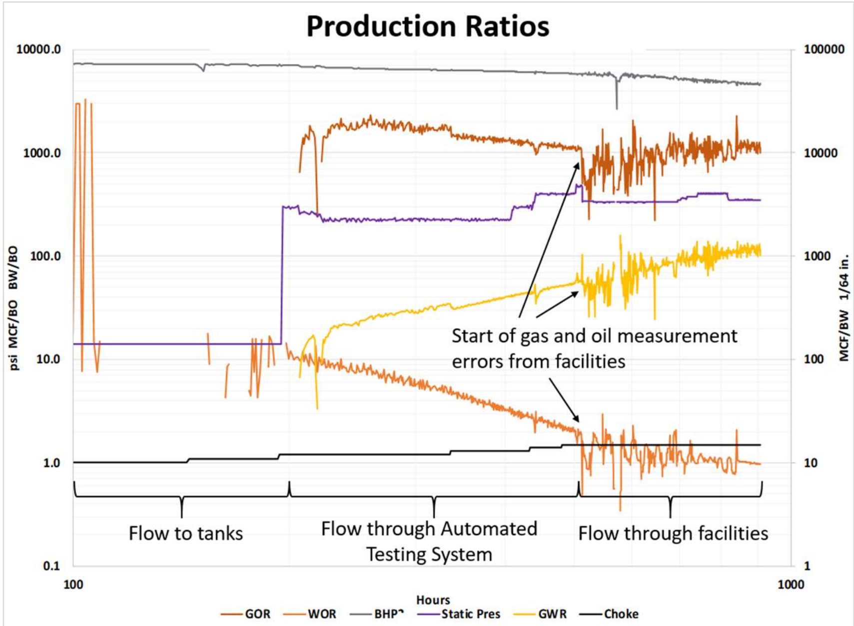


Figure 7 - Field example showing quality of multiple measurement methods during initial production period

Below, in Table 1, is a summary of the common measurement methods used on initial production data, color coded to indicate the quality of data that comes from each method. Measurement methods with a green box produce good data quality. Measurement methods with a yellow box can produce good data quality when properly calibrated, and when operated correctly by trained personnel under the right conditions. Measurement methods with a red box do not produce sufficient data quality for well performance assessments using initial production data

| | Tank Straps | Pulse Radar | Guided Wave Radar | Turbine | Electro Mag. | Coriolis | Orifice Plate | Analogue Gauge | Digital Gauge |
|---|---|---|---|---|---|---|---|---|---|
| Oil | | | | | N/A | | N/A | N/A | N/A |
| Gas | N/A | N/A | N/A | N/A | N/A | | | N/A | N/A |
| Water | | | | | | | N/A | N/A | N/A |
| Pressure | N/A | N/A | N/A | N/A | N/A | N/A | N/A | | |

Table 1 – Summary of common measurement methods color coded to indicate data quality

In addition to the measurement error associated with each type of measurement method, we have found additional sources of surface measurement error that can compound the errors from measurement methods. We briefly cover the most common additional sources of measurement error below.

**Separation Efficiency** – The accuracy of all these measurement devices discussed above are dependent on the performance of the fluid separation system used when the fluid is separated for measurement. If there is poor fluid separation, there can be carry-over from one phase into the measurements of a different phase (Mohan 2008). An example would be carry-over of water into the oil leg causing the oil measurement to look artificially high, and the water measurement artificially low. We have seen numerous examples of carry-over into each of the 3 phases causing measurement errors. Common causes of poor fluid separation include undersized separators, emulsions, foam, separator operator error, and the use of separators without (or with limited) internal devices to improve phase separation (Akpan 2013). We have found that implementing an automated sensing and control system within the separator will reduce the potential for operator error and improve measurement accuracy.

**Oil Shrinkage** –Tanks straps and tank level sensors used for oil rate measurement quite often show a different rate measurement than what would be seen on a Coriolis meter or turbine meter. When the oil is sitting in the tanks, gas flashes off and the oil shrinks. The recorded oil rate is then less than what actually has come out of the well. We have observed 15-20% differences between tank straps / tank level sensors vs. Coriolis meters. Performance diagnostic analysis should use oil rate measurements that reflect the volume coming out of the reservoir.

**Timing of Measurements** - For all of the rate and pressure measurement methods discussed above, there can be further errors induced due to the timing of when the measurement is physically taken. This error creates a substantial amount of noise in the data. For example, if a well is flowing water at 60 bbl./hr. and the well test operator takes the reading 5 minutes early, the reading will be 55 bbl./hr., and if the operator takes the next reading right on the hour, the reading will be 65 bbl./hr. This is a +/- 5 bbl./hr. (8%) error on top of the error inherent in each measurement method.

## Case Study 1 – Measurement Error Identification

This case study is used as an example of how the plots recommended in the dashboard are used for identification of a gas rate measurement error. The measurement devices used on this well were digital WHP gauges, guided wave radar tank level sensors for the oil rate, an electro-magnetic meter for the water rate, and an orifice plate for the gas rate. Surface measurements were used to calculate the BHP.

The initial production history in Figure 8 shows a spot where the BHP suddenly decreases over 200 psi when the choke was changed. At the same time the BHP decreases, the gas rate appears to increase substantially more than the oil rate. The analyst needs to rule out a surface rate measurement error in order to properly evaluate if this change in BHP is caused by the reservoir or completion.

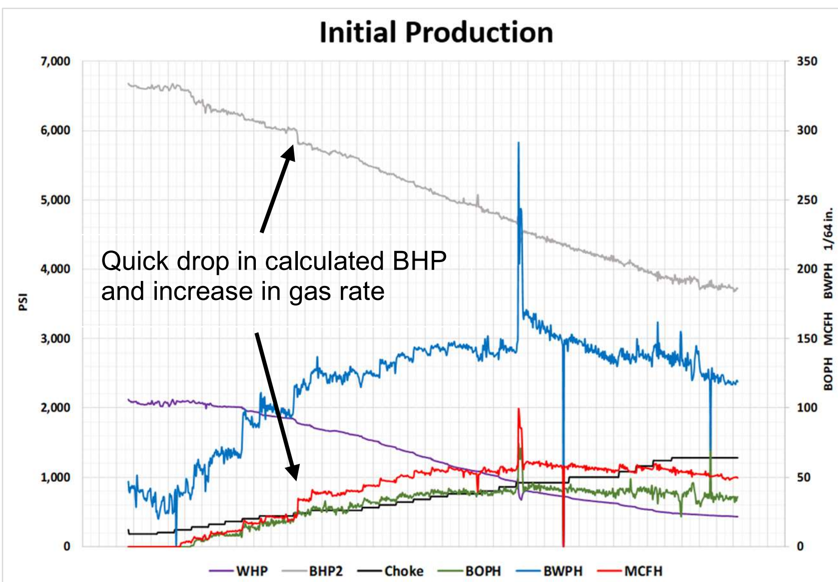


Figure 8 – Field example of a well with possible gas rate measurement error

Inspection of the production ratios plot in Figure 9 shows some general noise just before there is a quick increase in GOR and GWR at the same time. The common phase between these two trend lines is the gas phase indicating a possible gas rate measurement error.

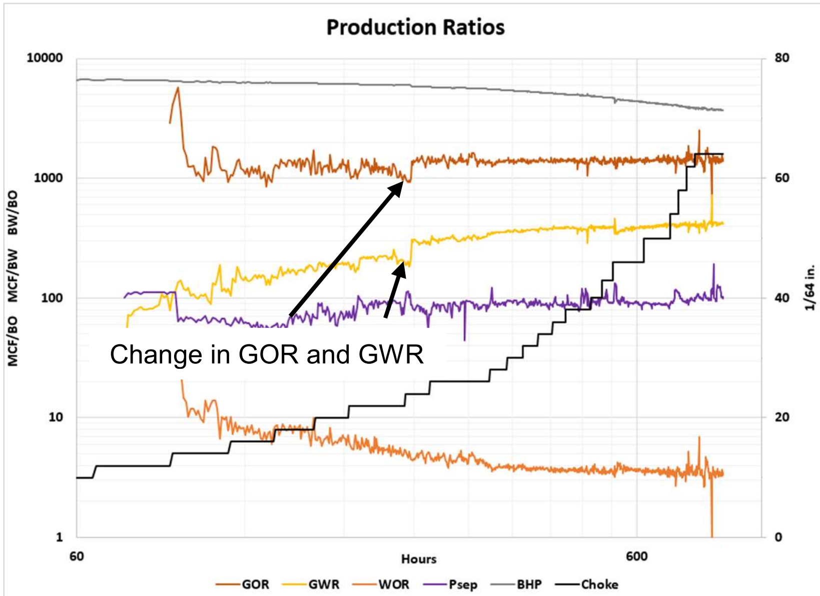


Figure 9 – Field example of production ratio trends indicating gas rate measurement error

Once again, it is important to note that the indication of a measurement error does not mean the error occurred at that time. The change in trends might indicate the error has been corrected, as is the case with this well.

Indication of a gas rate measurement error should prompt the analyst to check the separator data plot to see if any of the measurement parameters have changed. Figure 10 shows the separator data plot.

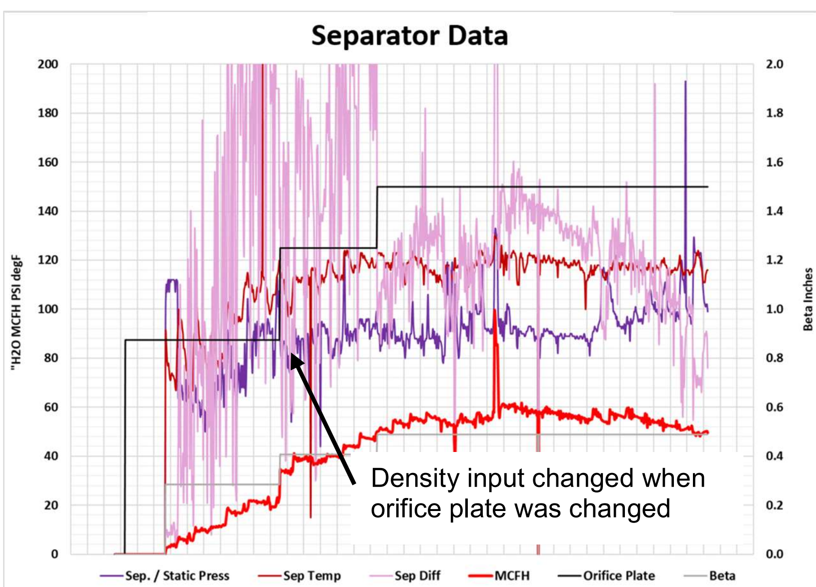


Figure 10 – Separator data plot indicating correlation between gas rate measurement error and changes in measurement parameters

The separator data plot shows that at the same time the gas rate increased, the orifice plate was changed. The gas density used for the gas rate calculation was also changed during this time because the production team received an updated gas analysis. This caused the change in the gas rate that is seen on the production history, and the change in GOR and GWR on the production ratios. Identifying and correcting a gas rate measurement error is important because the calculated BHP can be particularly sensitive to the gas rate. Errors induced in the BHP by incorrect gas rates will affect the interpretation of well performance.

## Well Performance Assessment

The most common technique for interpreting well performance from initial production data utilizes straight-line analysis methods of specialized diagnostic plots. There are two workflows that can be used with straight-line analysis methods to assess well performance. The first workflow, demonstrated by Anderson (2010), can be used to determine well performance by matching a straight-line to the general trend of specialized plots (usually a specialized linear flow diagnostic plot). Clarkson (2019) significantly added to these methods to incorporate many more factors affecting well performance.

The second workflow, demonstrated by Crafton (1998), can be used to optimize draw down by matching straight-lines to successive trends of individual transients induced by changes in rates and pressure. These transients are often caused by changes in choke size, ESP frequency, and jet pump or gas lift injection rates. This workflow is used to determine the magnitude of change in performance from one transient to the next. The magnitude of change is used to determine if performance has increased or decreased in order to optimize the draw down during the initial production period (Deen 2015, Tompkins 2016).

The primary problem that arises when trying to use either workflow using low quality data is picking the correct straight-line trend of the data.

## Case Study 2: Data Quality Effect On Well Performance Assessment

Figure 11 shows the linear flow diagnostic plot for the well shown in Figures 6 and 7. This plot is commonly used to determine the linear flow parameter $A\sqrt{k}$, which is inversely proportional to the slope of the line matched to the data. The shallower the slope, the higher the $A\sqrt{k}$, and the better the well performance (Wattenbarger 1998). From this parameter, an analyst can infer how well performance is changing when the draw down is changed, how effective the completion is, and how the well will perform relative to other wells.

At the start of the initial production period, the well is flowing to tanks and the liquids are being measured with tanks straps. During this period of time, there is no apparent change in the slope of the data (matched with the red straight-line) when the choke is changed, which implies there is no change in well performance. Once the well is flowed through the automated testing system, there is a change in slope of the data. There are very clear new trends in the data that start each time the choke is changed, and those are matched with green lines. We will demonstrate in Case Study 3 that when low quality data is matched with the red line, it is not indicative of the reservoir / completion response. Additionally, we will show that transient identification for draw down optimization is not possible with low quality data.

At the end of the initial production period, when the well was flowed through permanent production facilities, the choke was held constant. We would expect to see a reservoir response at this time that is not being influenced by choke changes. Also, the well is cleaned up enough at this point to assess the completion effectiveness. However, the data is very noisy and creates a cloud of data which makes it difficult to see where a straight-line trend would fit the data best. The two black straight-lines matched to the data during this period outline what could be considered the limits of where straight-line matches can reasonably be made. A straight-line matched to the data anywhere inside these limits would look like a sufficient match. We will show in Case Study 4 how poor quality data like this leads to ambiguous performance assessments when used for completion optimization. However, when high quality data is used there is a high degree of confidence is determining the optimum completion design.

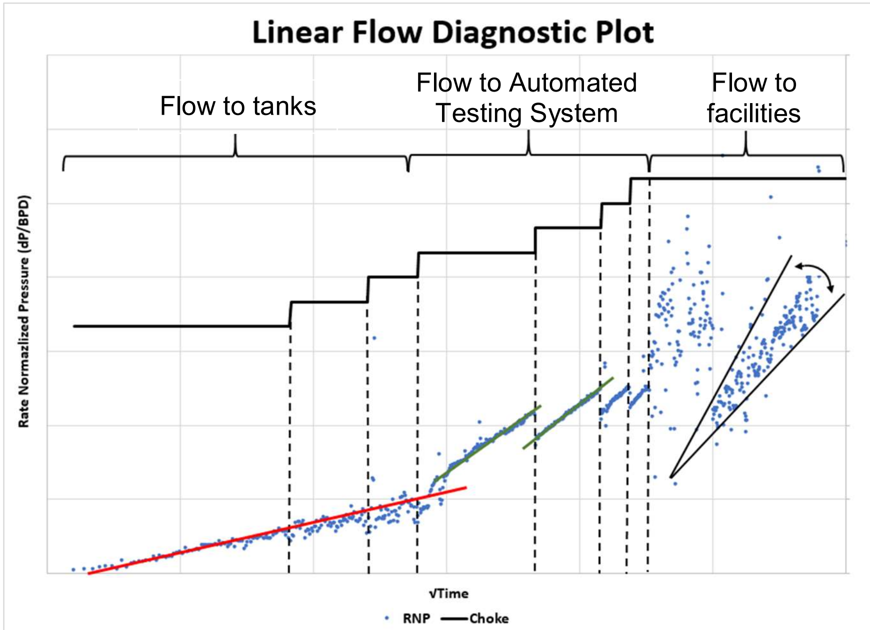


Figure 11 - Linear flow diagnostic plot showing the effect of different measurement methods on well performance assessment

**Case Study 3: Data Quality Effects On Draw Down Optimization**

Figure 12 shows the initial production histories of two wells that are landed close to each other. Well A is flowing through temporary flowback equipment with low quality measurement. Liquid rates were measured with turbine meters and gas rate was measured with an orifice plate. The data generally looks noisier than well B. Well B is flowing through a fully automated testing system with very high measurement quality. Coriolis meters were used for liquid rate measurements and a gas conditioning orifice plate was used for gas rate measurement. Both wells are using digital pressure gauges for WHP.

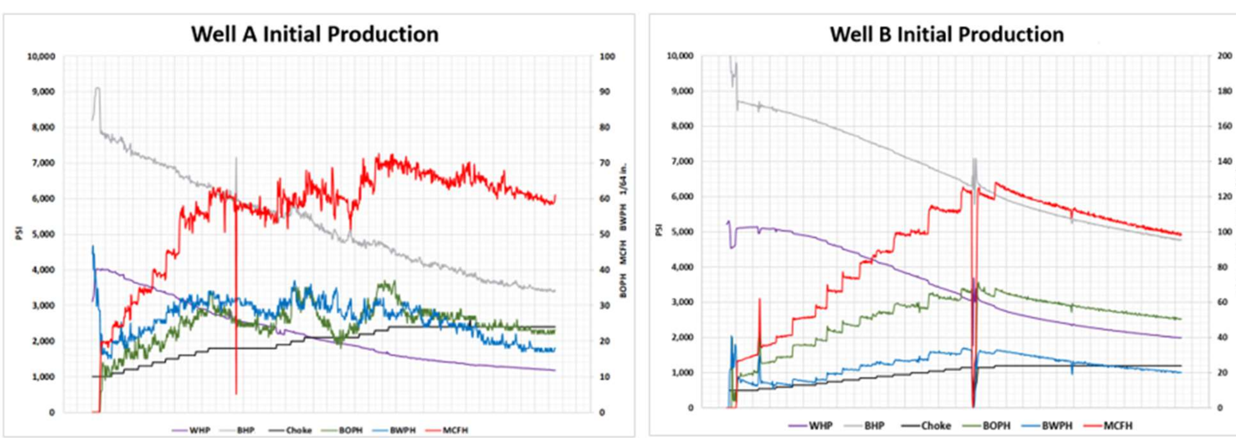


Figure 12 – Initial production examples. Well A data is noisy with indication of measurement errors. Well B data is smooth and accurate

The production ratio plot in Figure 13 for Well A should have smooth trend lines like the ones seen in the production ratio plot for Well B. However, there is a significant amount of noise in the production ratio trends and a clear indication of an oil rate measurement error where the GOR and WOR increase with no corresponding change in the GWR trend.

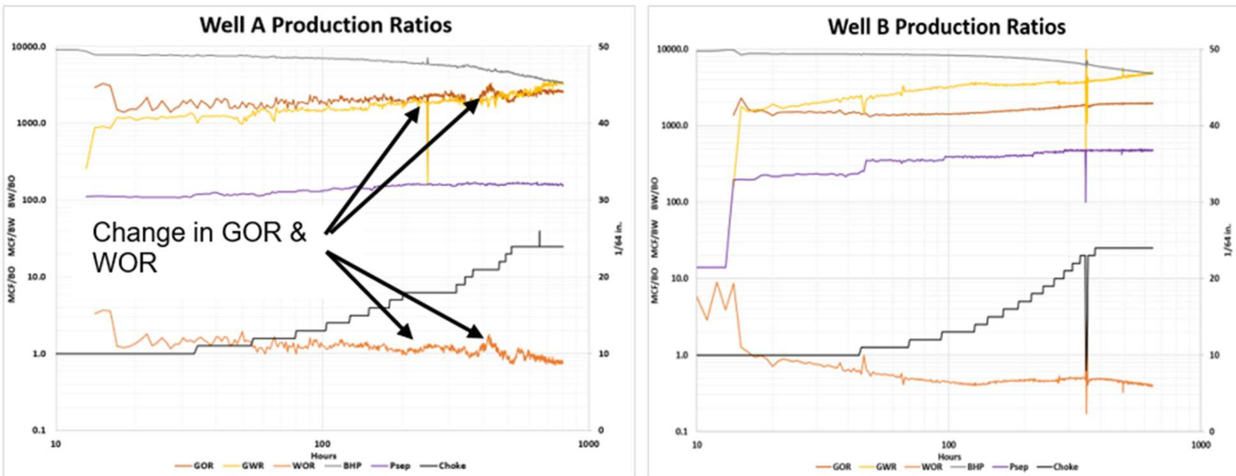


Figure 13- Production ratio comparison. Well A indicating oil rate measurement errors. Well B trends not indicating any measurement errors

Often analysts will match a straight-line from the start of the initial production period to the general trend of the data like the red line seen on the Well A and B linear flow diagnostic plots in Figure 14. However, quite often with initial production data, the slope of this straight-line trend is **NOT** caused by the reservoir or completion but instead is caused by the frequency of choke changes. Without high quality data, it is nearly impossible to discern the actual reservoir response due to measurement errors.

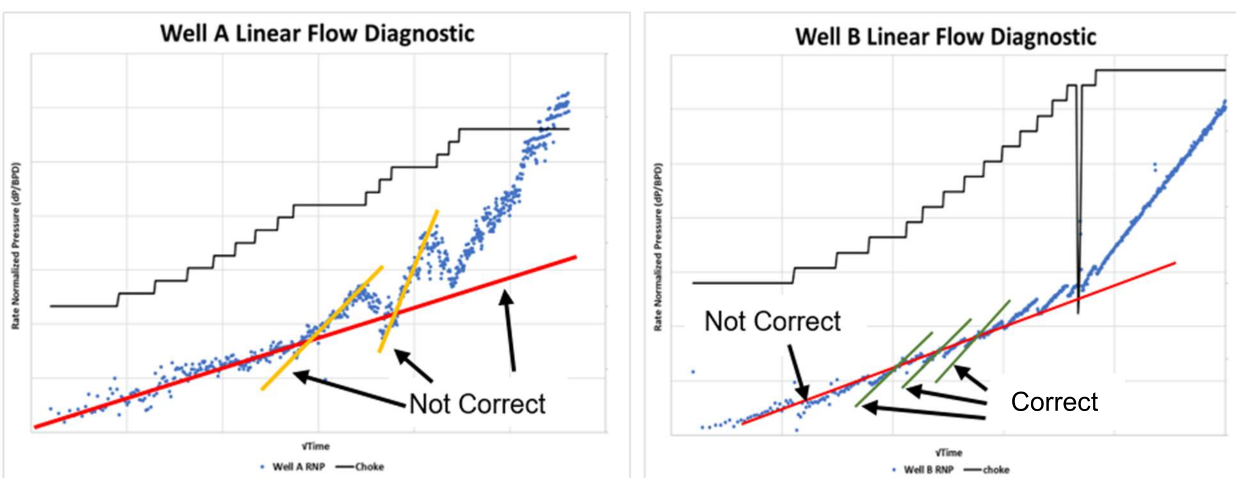


Figure 14 – Well A performance evaluation with poor quality data and Well B performance evaluation with high quality data

When changes in well performance are being evaluated during the initial production period to optimize the draw down strategy, the analyst must be able to see the relative change in slope of the straight-line matched to the data in between successive changes in rates and pressure (in this case caused by increasing the choke).

Increases in the slope of the general trend indicated by the yellow straight-line matched to the data between choke changes on the Well A linear flow diagnostic plot were interpreted as a decrease in well performance. When the performance appeared to be decreasing, the choke was not changed for a few days to see if a lower draw down would improve the performance. This increased the total time it took to get the well opened. However, these changes in slope directly correlate to the periods where oil rate measurement errors were identified on the production ratios plot. In this case the changes in slope are due to oil rate measurement errors, and not caused by changes in well performance. This well could have been opened faster and possibly to a higher choke if the changes in well performance due to choke changes could have been clearly identified.

Figure 15 shows an expanded portion of the Well B linear flow diagnostic plot. This plot shows a red straight-line matched to the general trend of all the data, and green straight-lines with steeper slopes matched to the data in between each choke change. The slope of the green straight-lines from the transients in between each choke change is a function of the reservoir and completion. The slope of the general trend matched with the red line on Well A and Well B is primarily a function of the frequency of choke changes, and has very little to do with the actual well performance. When a straight-line is matched to the general trend of the data, it gives the impression that the A√k parameter, and well performance, is significantly higher than it actually is. It also makes it seem like performance does not change much, if at all, from one choke setting to the next.

It is only possible to see the relative changes in well performance from one choke to the next when data quality is very good, like that seen on Well B. When the data is poor quality, like that seen on Well A, it is nearly impossible to see the reservoir response and changes in performance from choke changes.

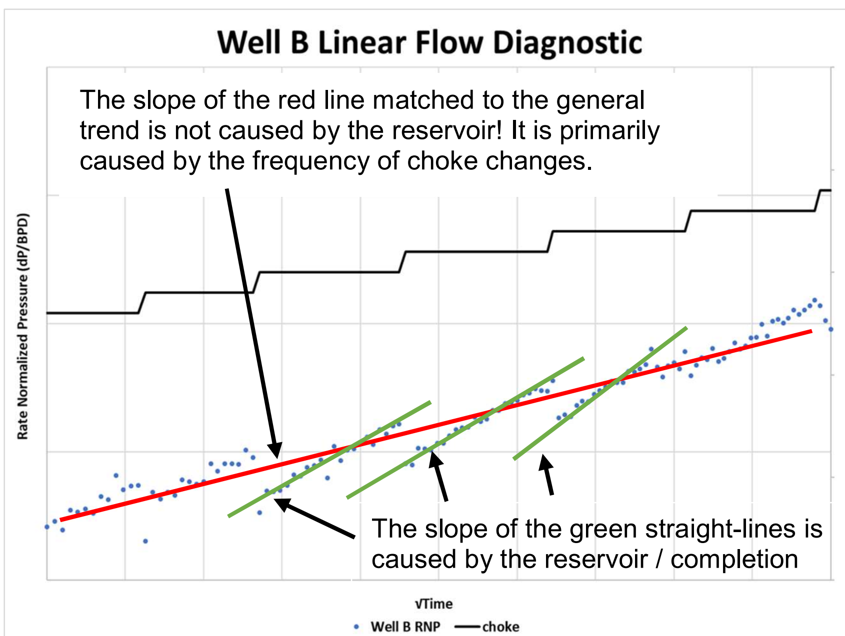


Figure 15 – Expanded Linear Flow Diagnostic using high quality data showing correct interpretation of reservoir / completion response

**Case Study 4: Data Quality Effects On Completion Optimization**

Straight-line analysis methods for assessing completion effectiveness should be applied to the data at the end of the initial production period, when the choke is not being changed frequently and the well has cleaned up. However, even when a period can be identified that is not being influenced by choke changes, the noise in the data can lead to ambiguity in where the straight-line matches the data best.

Quite often, completion designs are optimized with small iterations. It is common to see changes of 20% or less to stage length, cluster length, proppant per cluster, and water per cluster. Well C and D in Figure 16 were completed close to each other with similar lateral lengths, and a few changes to the completion design. The wells were flowed through temporary flowback equipment with low quality measurements for the initial production period. Turbine meters were used for liquid rate measurements, and an orifice plate was used for the gas rate measurement. There are large changes in the rates seen on the production history plots that do not correlate to choke changes, and there is no corresponding change in WHP. At the same time there are large fluctuations in the calculated BHP trend which leads to ambiguity in the performance diagnostic. This is the first indication of possible measurement errors.

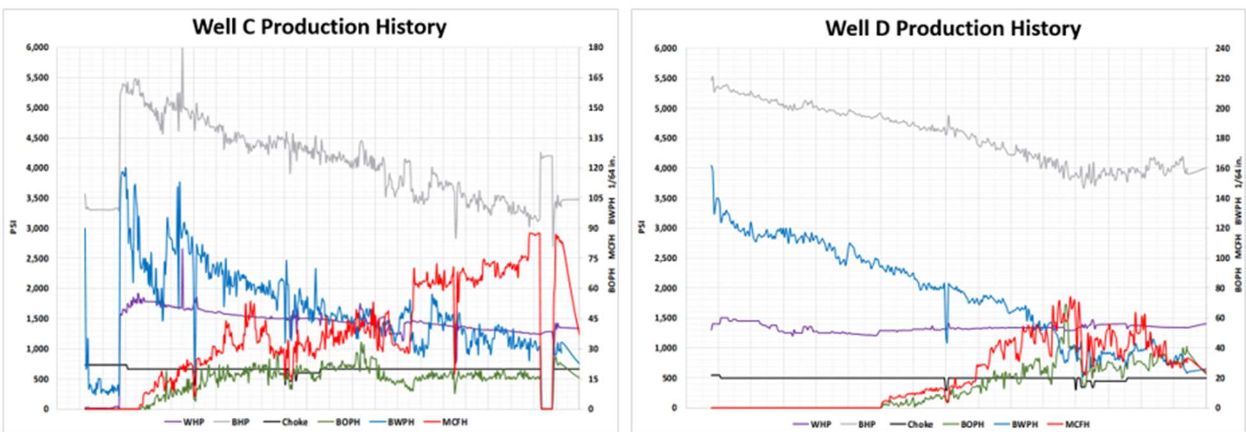


Figure 16 - Very noisy, low quality production data on both Well C and D

Referring to the production ratio plots in Figure 17, the GWR and WOR appear to diverge as expected on both wells. However, the data is clearly very noisy due to rate measurement errors occurring throughout the initial production period. A large abrupt change in GOR and GWR on Well C indicates a significant gas rate measurement error, which is likely due to an inaccurate gas rate calculation in the flow meter. A large abrupt change in GOR and WOR on Well D indicates a significant oil rate measurement error. All of these errors cause the calculated BHP to be very noisy which makes the performance diagnostic almost impossible to interpret accurately.

Two questions often arise from an interpretation of initial production data:

i) How is the draw down strategy (choke schedule) affecting well performance?

ii) Which completion design is the best?

The first question (i) cannot be answered for Well C and Well D. As seen in Figure 18 the data quality is too low on either well to see how the performance changed from one choke to the next. There are no clear changes in the trends of the data that correlate to when the choke was changed. To complicate things further, there are small changes in the slope (indicated by the red lines) of the general trend of the data on the Well C linear flow diagnostic plot that could be confused with decreases in well performance.

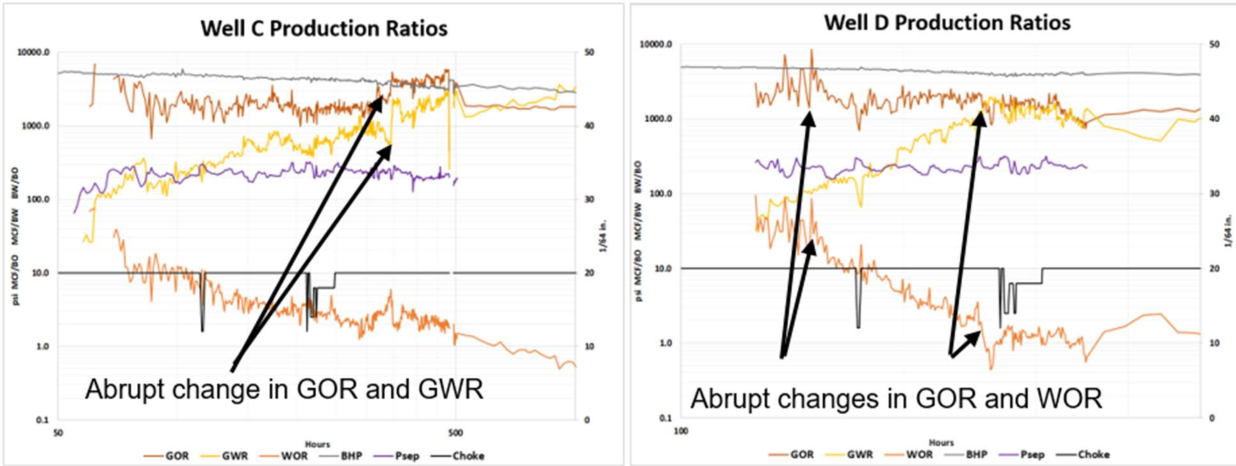


Figure 17 - Production ratios for Well C and D indicating significant measurement errors

However, in this case these are just artifacts of the measurement errors seen throughout the test, and correlate to the periods on the production ratios plot where rate measurement errors can be identified. For the second question (ii), two straight-line matches have been made on the data for each well marking the range of possible straight-line matches. A straight-line match could be made anywhere in between these two lines and it would look like it sufficiently matched the data. There is a 58% difference between the A√k parameter derived from the slope of the two straight-lines on Well C, and 46% difference between A√k parameters on Well D. This significant difference between possible A√k parameters makes it very challenging to determine which completion design is the best.

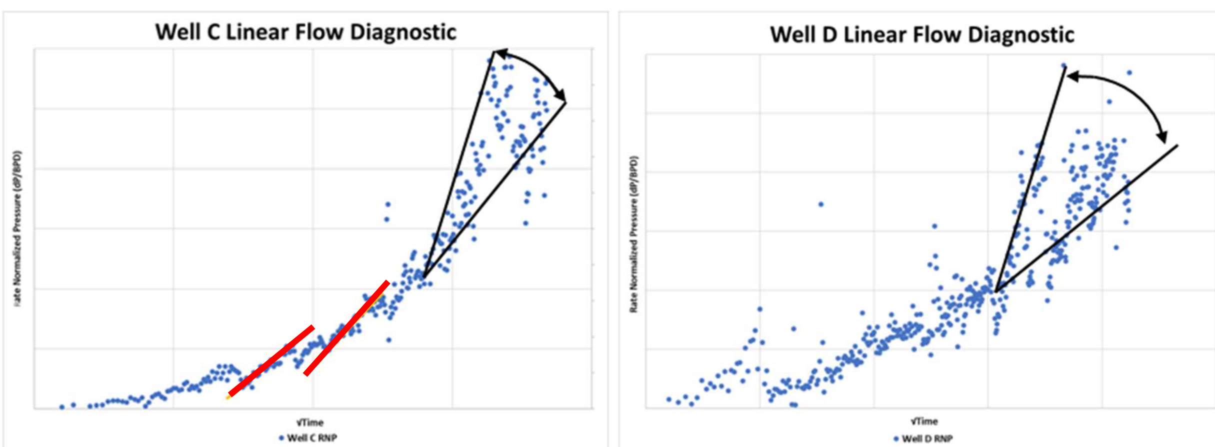


Figure 18 - Linear flow diagnostic for Well C and D showing the range of possible straight-line matches

Well D had clusters spaced further apart with more water and proppant per cluster than Well C. Table 2 shows a summary of the relative difference in Well D's major completion design parameters compared to Well C. Table 2 also shows the relative difference in A√k for straight-lines matched in the middle of the ranges of possible straight-line matches on Well C and D (A√k Mid) and the relative difference in A√k of straight-lines matched to the data to produce the smallest relative difference (A√k Smallest). However, in order to make the smallest relative difference the straight-lines have to be matched to the extremes of the range of possible A√k parameters which is unrealistic.

| Major Completion Design Parameters | % Rel. Diff |
|---|---|
| Cluster Length | 21% |
| Stage Length | 21% |
| Proppant / Cluster | 14% |
| Water / Cluster | 22% |
| A√k Mid | -72% |
| A√k Smallest | -12% |

Table 2 – Summary of the relative difference in Well D major completion design parameters and A√k relative to Well C

It appears as though Well D performance is either much less (72%) than Well C, or only slightly less (12%). This is a very common completion optimization problem faced by analysts. Well D has almost the same amount of water and proppant per foot as Well C, but Well D has a longer stage and cluster length which means this well used fewer perf charges, fewer plugs, and fewer wireline runs to set plugs and perforate. Well D likely costs less to complete, but also performs either slightly worse or much worse than the more expensive Well C completion. If Well D's performance is only slightly worse, it may be the more economical well, which could lead to a conclusion to switch future wells to the Well D completion design. However, it is also possible that Well D performed much worse than Well C, thus justifying the extra completion cost of Well C. What is the correct answer? There is no way to determine that with this data because the data quality is not good enough to have confidence in the analysis results. When the data quality is very good, the difference in completion designs is clear to see, and completion optimization decisions are much easier to make.

Well B (discussed previously in Case Study 3) and Well E in Figure 19 were completed close to each other, with similar lateral lengths, and are flowing through a fully automated testing system with high quality measurements. Coriolis meters were used for the liquid rate measurements, a gas conditioning orifice plate was used for the gas rate measurement, and a digital gauge was used for wellhead pressure measurement. The data visibly has significantly less noise then Wells C and D in Figure 16.

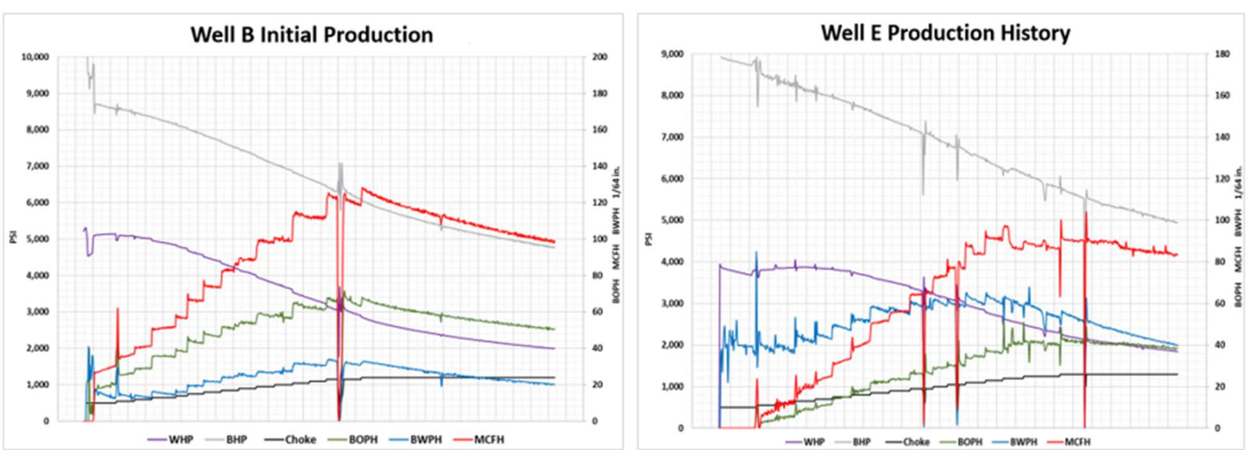


Figure 19 – Well B and E production histories with high quality data coming from fully automated testing system

The trends in the production ratios seen in Figure 20 are smooth and are trending as expected, with no indication of significant measurement errors or noise.

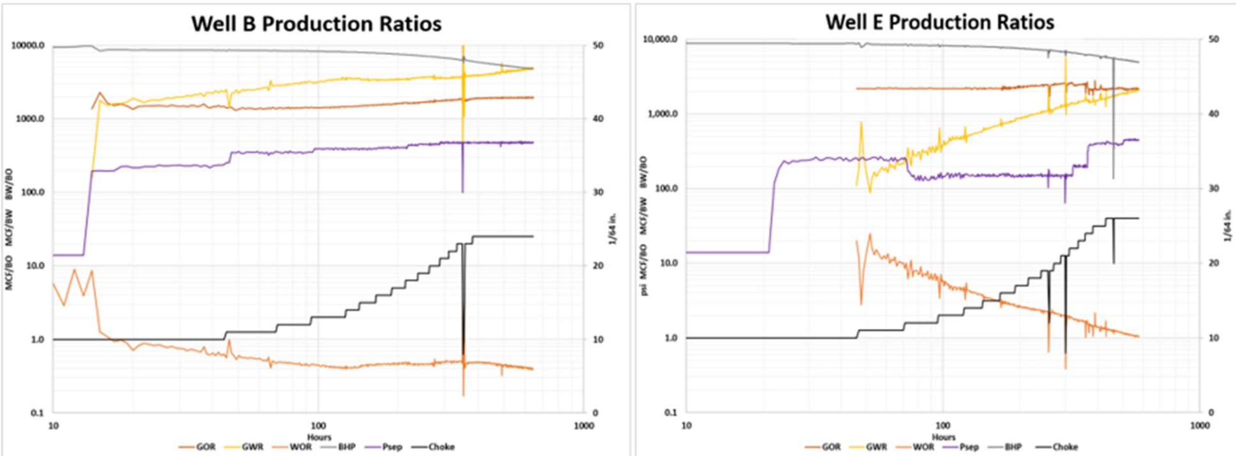


Figure 20 - Well B and E production ratios showing smooth trends and no indication of significant measurement errors or noise

Referring to the linear flow diagnostic for Well B and E in Figure 21, the reservoir response can clearly be seen in between each choke change. The draw down strategy used on both these wells was effectively optimized for the highest well performance. Additionally, the straight-line match to the data at the end of the initial production period of Well B and Well E fits directly on the data. There is no uncertainty in the model match like there was with the Well C and D matches. There is only one possible difference in A√k, not a range of possibilities like there was with Well C and D. Table 3 shows a summary of the relative differences in Well E major completion design parameters relative to Well B.

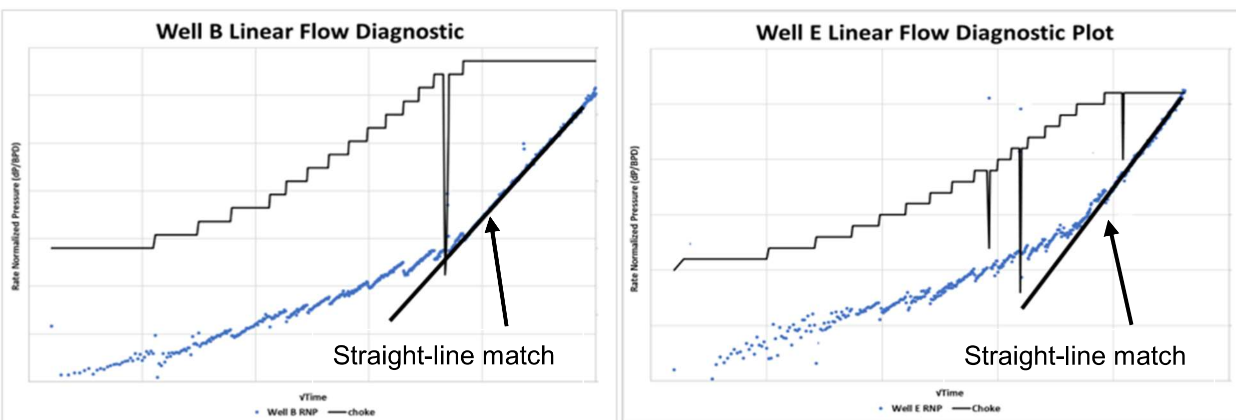


Figure 21 - Linear flow diagnostic for Well B and E showing precise straight-line match

Well E had a shorter length between clusters, the stage length was shorter, and the proppant and water volume per cluster was lower. However, the water and proppant per foot was higher than Well B. Well E required more total water and proppant, more plugs, and more perforations and therefore cost more to complete. A straight-line match on the linear flow diagnostic plot for each well determined the A√k parameter on Well E was 19% lower than Well B. There is a high degree of confidence in the model match due to the data quality. It is far easier in this case to say with confidence that the Well B completion design is not only more effective, but also more economical.

| **Major Completion Design Parameters** | **% Rel. Diff** |
|---|---|
| Cluster Length | -15% |
| Stage Length | -16% |
| Proppant / Cluster | -8% |
| Proppant / ft. | 9% |
| Water / Cluster | -10% |
| Water / ft. | 6% |
| $A\sqrt{k}$ | -19% |

Table 3 - Summary of the relative difference in Well E major completion design parameters and $A\sqrt{k}$ relative to Well B

## Conclusions

The examples presented here were from several different basins in the United States. Poor initial production data quality does not just occur in a single region. It is seen everywhere and is more the norm than the exception.

We have encountered many draw down strategies that are not maximizing well performance, and many completion design iterations that are not evaluated accurately using RTA straight-line analysis methods applied to initial production data.

The initial production period can yield very insightful results for draw down management and shorten timelines for completion design optimization using RTA when the right methods are used to collect surface data accurately. The following are a few general recommendations:

1. If the data is too noisy to clearly see the rates and pressure change when the choke is changed, the data quality is likely too poor to use confidently for an analysis of the initial production data.
2. To reduce the error in well performance assessments caused by variable oil shrinkage rates when oil rate measurements are taken from tanks, a Coriolis meter operating at separator pressure is recommended for measuring oil rates.
3. To eliminate the error created by the time hourly readings are taken, an automated testing system is recommended that records readings at the exact same time from all the measurement devices. Operator error is often the largest source of noise and ambiguity in well performance evaluations.
4. Surface measurement QA/QC should always be performed during the initial production period to ensure consistent high quality data is used in the well performance assessments.
5. To ensure the highest degree of measurement accuracy, it is recommended to utilize a separator that includes internal hardware that provides a higher degree of liquid / liquid and liquid / gas separation.

Throughout this paper we have used linear flow diagnostic plots for performance assessments. This is so the reader is presented with the most commonly encountered well performance diagnostic plot. However, we do not always find these specialized plots to be appropriate for assessing well performance for draw down optimization of initial production. We hope to elaborate on this topic further in a future paper.

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