SPE 158715

A Methodology for Reducing Bias in the Design & Evaluation of Hydraulic Fractures

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This paper was prepared for presentation at the SPE Asia Pacific Oil and Gas Conference and Exhibition held in Perth, Australia, 22–24 October 2012.

Abstract

The purpose of this paper is to present a framework to reduce bias in the design and evaluation of hydraulic fractures. When we mention "bias", we are referring to human nature. If someone knows what the answer is supposed to be (what someone else wants, or to provide a consensus), they are much more likely to provide that answer - even if it is not correct. In addition to frac design (and re-design after pre-frac tests), this process will be extended to the process of post-frac evaluation and the analysis of the frac flowback and other well tests. The process consists of three parts, to be done in isolation from each other. The first is the actual frac design. This includes the gathering of the geo-physical and reservoir property information, the creation of the geo-mechanical model, the selection of equipment, and the execution design to meet the operator's objectives. It also includes any re-design required based on DFIT/minifrac analysis, performed prior to the frac. The second part is the review of the fracture operation, often called the Frac Replay. This is where the actual field data (rates, pressures, concentrations, etc.) and geo-mechanical model are used to simulate the pad and proppant placement and concentration in the fractured interval. The final part is analysis of the frac flowback, as well as any subsequent well tests. If designed and executed properly, the flowback/well test data can provide an independent validation of the effective fracture length, fracture efficiency and drainage radius/volume.

The reason for performing these three parts in isolation is that it utilizes service companies, consultants and in-house experts to the operator's advantage. If they are not performed independently, the answers are highly susceptible to a forced consensus, especially if the party doing the design or performing the frac job wants to demonstrate the effectiveness of their work. If the results of all three independent parts point to the same conclusions, the operator has more confidence in the outcome. If not, the differences can be examined, with an eye to improving future designs and executions.

Introduction

Needless to say, hydraulically fracturing (frac'ing) a well is a complex and often serpentine operation. Multiple service companies and suppliers are involved. Multiple companies and multiple people, often with multiple responsibilities are required. The environment can be fast-paced and high-stress (everyone has something to do on the current job and usually a job to rush to next). Quite often, the equipment and materials on hand don't match the frac design and there's no time to wait. In addition, it is not unusual that the frac engineers/crew have not been told by the operator to save the frac replay data…so, it just disappears with the frac crew. Too often the attitude of "if all the proppant got pumped, it's a good frac job" holds.

Another serious problem is quite frankly the operating company's fault. If a well performs as expected, does anyone pay attention to the frac job? If a well is a disappointment, does the scrutiny extend beyond saying "it was just a poor frac job"? Doesn't a great frac job in a bad location still result in a sub-par well? Couldn't both good and bad frac jobs be better? Does drilling and frac'ing a well in a location that's already being efficiently drained really improve the bottom line? Wouldn't it be nice to at least store the frac replay information (whether you intend to use it or not) to help optimize future frac's in the same formation? Does the bonus structure for managers and/or service companies help or impede the process? Does selling the most expensive proppant and gel really improve the job?

This is primarily a philosophical article (of course, there will be some technical information too). It is intended to get more people involved in taking ownership of the end result, not just their portion of the project. As mentioned in the abstract, the primary purpose of the paper is to shed some light on the places in the process of frac'ing a well that bias is introduced. As a generic and non-finger-pointing example (and absolutely no evidence of such that we're willing to disclose), imagine that the frac company knows that they've screwed up, but knows that the operator doesn't pay attention to anything other than production rates. Do they have any incentive to hold on to the frac replay data? After all, a bad frac in a good spot still results in a good well. Are there ways to validate predicted outcomes? Is it possible that an operator acting like they're paying attention to detail will improve the results? At a bare minimum, the authors hope that this paper will encourage operators to insist on receiving the frac replay data from the frac company and ensure that the data has been received before the frac crew leaves the location…and possibly budget a few dollars for internal and/or external review.

Pre-Design Data Requirements

Frac design requires both reservoir and geo-mechanical data. Mud logs are a basic source of geo-physical modeling. They may not be perfect, but they at least give a general idea of lithology. Starting with the mud logs, a basic rock type layer-cake can be assembled and then properties required for frac design can be coupled to the lithology. From here, there is a wide assortment of data choices from analogs to anecdotal evidence. Cross-sections of pay zones can be estimated from the mud logs and core data can be tested for formation rock properties.

Realistically, mud logs are helpful but not enough to build a reliable geo-mechanical model. More detailed well logs are needed. Rock properties such as Poisson's Ratio, Young's Modulus, stresses, etc., are critical pieces of needed information but have limited sources of availability. In addition to the standard gamma ray, resistivity, lithodensity and neutron density tools, acoustic logs can measure shear and compressibility wave travel times. These acoustic (or sonic) logs then allow for many estimates of not only rock types but also the vital rock properties needed for fracture modeling and simulation. However, this is not an inexpensive endeavor. Many operators do not run sonic logs due to cost, but when compared to the cost of a botched frac job, is it really isn't that much of a completion expenditure? It is much better to have additional data to fine tune a frac design before laying out the additional cost of a frac spread only to find out that the design wasn't properly set to the formation and reservoir characteristics.

Standard well logs, drilling reports, and completion reports can be used to determine most of the reservoir characteristics. Some of these characteristics are as basic as porosity, pressure, and temperature. Others, such as compressibility, viscosity, and permeability are a little more challenging. Are there analog wells nearby to estimate these? Were there core samples tested for rock properties? Were any fluid samples taken? Did the well flow enough for reliable pressure transient testing to determine permeability? Have you performed any frac diagnostic testing to find out what is missing?

Either through well logging or even some minor pressure transient testing much of the needed data to create the initial design for a frac treatment can be accumulated with just a little preparation.

Frac Design & Simulation

In today's unconventional reservoir market, hydraulic fracturing is a requirement not only to increase productivity, but also to make reserves recoverable. If fracturing is required, then what exactly is a properly designed frac treatment? How do we, not as an industry, but as an individual operator of a well know that a frac was "good"? The answer is relatively simple. The money spent on a frac treatment has to maximize the return on investment in the total well cost. How do we know that the frac treatment maximized our return? As long as we have done our homework to meet data requirements, designed a treatment to meet our objectives, executed that design, followed up with an independent evaluation of the frac treatment to ensure our initial objectives were met, AND used that information to refine our design for future use, then we can say with confidence that the treatment was "good". Of course, if the well performs as expected or better than expected, then that provides an extra dose of confidence but that doesn't necessarily mean that you did everything right. Sometimes, wells perform as well or better than expected, regardless of our many failed attempts to "improve" them.

When planning a frac treatment, the operator must determine what the objectives and expectations of the treatment are. Is this treatment to improve productivity, to improve recoverable reserves, or both? Is this treatment required just to get the well to flow? Set definitive goals early on, and remember them. Many operators today just use a simple treatment recipe over and over. When asked why that recipe is used, the answer is usually "because that's what worked last time" or "that's what worked for the neighboring operator". Not many people have asked the neighboring operator what their goal was when that recipe was developed. Let's face it, not many people have asked themselves what the real objective is each time a frac was designed, other than to say "make the well flow".

Once the objectives are set, a realistic look should be taken at the resources available and the limitations surrounding them. Some of these limitations are simple. What is the wellbore configuration? Small tubulars restrict pump rate. Low burst rated tubulars limit maximum pumping pressures which may prevent an effective stimulation treatment. Wells may need multiple stages of treatments. If the well has multiple pay zones, is it possible to stimulate via single staged limited entry methods or separate stages? What if there are not any available pumps? This could be infrastructure related, or simply scheduling conflicts. Is there a long lead time for materials? Is there any proppant available in your area? Is the available proppant the correct type for your design? How do you know it will or will not fulfill your design criteria? Have you performed a fracture simulation with realistic parameters and restrictions? Is that what you really want? Does the design achieve your objectives, or just encourage you to spend more money on customized proppant and additives? Have you considered all of your options?

If all goes as planned, you should now have objectives set. You have contacted service companies and vendors for materials and equipment. You have even done your homework with all of the logs/core tests and have started a frac design. This is when the design gets complicated and potentially confusing. Some of the most important inputs into the frac design are still guesses. How do you determine the actual minimum horizontal stresses? After all of this hard work, you are still guessing at inputs. This stress must be obtained from the well through a minifrac. A minifrac can also provide many other pieces of information if analyzed ahead of the main frac treatment.

Before the minifrac can take place, a frac treatment simulation can be performed. If even the best inputs are only guesses, at least there is something to work with before starting to outlay money in the field. The best inputs available are then used to perform one or more simulation runs. If the design performs as intended then it must be determined if the design acts as intended because everything is correct or is it because the inputs were biased to give the intended output. The only way to really determine this is to collect and use real field data.

Minifracs

Minifracs can consist of several to a few types of tests. Step rate tests can determine an upper bound of closure pressure as well as a fracture extension pressure. Step down tests can help determine near wellbore frictions. Minifracs can give closure times and pressures, net pressures, fluid efficiencies, perforation frictions, frac geometry models, leakoff coefficients, formation permeability, and reservoir pressure. All of these items are required inputs into a frac design simulator, and all of these are merely guesses unless a minifrac is actually performed.

One of the most useful types of minifrac is also one of the simplest. A diagnostic fracture injection test (DFIT) is just a small volume of fluid pumped into the formation at a sufficient rate to create a fracture and then the falloff is monitored and analyzed. Horner analysis, regression techniques, and G function pressure decline analysis are all used together to provide the inputs required for frac simulation. G function decline also allows for determination of pressure dependent leakoff while accounting for mass conservation and fracture compliance. When this type of test can be performed with a minimal amount of fluid, it also results in a minimal test time because the fluid can leak-off completely in a shorter amount of time.

The biggest advantage of a minifrac is that the majority of answers provided are done without knowledge of the fracture geometry or a specific model. The net pressure of a minifrac can be history matched to calculate leakoff coefficients and permeability. Finally, a fracture efficiency can then be determined. Now all of those guesses that were required inputs into the fracture design simulator can have real inputs that are specific to the well and zone of interest.

Frac Re-Design

Starting with the basic frac design only got us so far. Then, a minifrac was performed in order to determine where inputs needed correction or refinement. Now that inputs such as closure stress, leakoff coefficients, permeability, etc. have been refined, what happens to the design? Does it still meet the original objectives? Does it need a complete overhaul because the original parameters were too out of line? Is it really worth pumping the frac job if the proppant is going to be crushed by the formation? These are the hard questions that have to be asked and then answered truthfully. Many times the minifrac is performed just before the main stimulation treatment. At that time, it may be too late to re-design the job in a major way. Unfortunately, many times the only re-design of the main treatment job is to adjust the pad size to account for a formerly over- or underestimated leakoff coefficient. This may or may not be enough to really impact the overall return on investment of the well, and can lead operators to question the benefit of running pre-frac diagnostics in the first place.

If a minifrac is planned early enough before the main frac spread arrives, then the original design can be completely re-worked if necessary. Not only can the pad be adjusted, but the entire treatment can be refined to match the now known reservoir characteristics.

Frac Execution/Monitoring

When the frac spread arrives, do you get what you are expecting? Do you have a checklist? If there are gels or chemicals in your frac design, are they compatible with your water on location? Did the frac company bring the correct chemicals? Does the frac company perform better if there is a higher level of scrutiny by the company representative on location?

As a company representative on location, it is your responsibility to ensure the frac is pumped to meet the design objectives. It is also your responsibility to gather the job data for QA/QC reasons. As you sit in the monitoring station during the frac job, it is imperative that you make sure all data is being recorded. There are monitors and screens throughout the treatment station with every data stream imaginable. Remember that if it is displayed, then it should be recorded. However, the data may not be recorded unless specified. At the beginning of the job, ensure that either you have a data stream into your laptop and recorded in real time or that the data is being recorded and will be transferred to you upon completion of the job. This data stream (rates, pressures, proppant concentrations, chemical additive amounts, etc.) will be used for the frac replay analysis. If it is not acquired on site, the chances of recovering the data file from the frac company are very slim. Most frac companies will use today's frac data files as a shortcut to setup tomorrow's frac data files, thereby copying over any of the previous job files. Even though it is usually company policy to copy the data daily onto a flash drive for safe keeping, the files are named in nondescript ways and become very difficult to find after the frac spread leaves location.

Frac Replay Analysis

Frac replay analysis is one of the most critical, yet underused steps in designing a frac program for an area. Usually, whatever happened during a frac treatment is noted anecdotally by the company representative and relayed back to the frac design engineers. Sometimes it is not entirely accurate but based on the assumptions of those in the field. However if the frac data has been recorded, then it is easy to import into the frac design simulator and perform a frac replay. The simulation run can then pressure matched to the replayed data. Now, hopefully everything that happened during the actual treatment can be accounted for in the simulation runs. The data can also be evaluated to ensure that the original expectations of the frac design were met or not. If they were not met, then an alternate plan of action for future frac designs can be tested with the fine-tuned frac model. In a worst case scenario, problems can be identified and corrected for future designs. In a best case scenario, then all expectations would have been met and there would not be any room for improvement. Reality says that there is always room for improvement, though, but at what cost? Will an improved frac design maximize the return on investment in the well? Or is the existing frac design, while not the best it could be, good enough for a proper investment return.

Frac Flowback Analysis

Another way to determine the effectiveness of a frac job (qualitatively and/or quantitatively) is to gather and analyze pressure, rate and temperature data during the frac flowback and/or initial production from the well. A frac flowback can include:

1) The flowback of the frac fluids and associated fluids/solids
2) The continued flow of the well after hydrocarbons to surface
3) Multiple rates during 1 and/or 2
4) The build-up/shut-in of the well afterwards
5) The initial production of the well to sales (long-term test to evaluate drainage volume)

The analysis can be a straightforward process for single-zone, single-stage fracs or for multiple fracs where the individual zones are in hydraulic communication with each other. When the data is of adequate quality, the potential results of the analysis include:

1) Fracture Permeability and/or Conductivity
2) Matrix Perm
3) Effective Fracture half-length (global for multiple fracs)
4) Effective Frac-dominated Volume
5) Is there a change in the continuous fluid in the frac/matrix system (i.e. is the pad creating a water block)?
6) Observed Drainage Volume (long-term flow)

The more zones and the more fracs contributing in a given flowback complicate the interpretation. In addition, horizontal wells are usually more challenging to analyze than vertical wells and wells with fracture complexity are more difficult to evaluate than bi-wing fracs. In some cases, one zone or stage will dominate the flow (usually not a good sign). In other cases, even with multiple contributing sections, the well will, for one reason or another, still “test” like a single section. This allows for global values to be determined. In other cases, the use of tracers and/or PLT (production logging test) runs can allow individual zones to be isolated and evaluated. Before looking at the frac replay or design simulation runs, the best practice is for the interpreter to estimate the number of zones contributing, net TVT (true vertical thickness), and for horizontal wells -- the well length “L”, from the logs and build-up response.

Unfortunately, in some cases, no matter how good the data quality is, some flowback data just can't be analyzed. This is no excuse to not bother getting the data in the first place. Given that quality automated sensors can be acquired for a relatively low purchase price to monitor all relevant inputs, data gathering costs are negligible compared to the overall operation. Even if the initial evaluation is inconclusive, the frac flowback data can prove useful, even if it is just as a comparison of early production vs. later production well performance. Fortunately (or unfortunately, if it's your well), the worse the frac job, the easier it is to analyze.

To avoid biasing the result, it is highly recommended that the individual or group (or group of groups) analyzing the frac flowback or extended production data should not be provided the frac design simulation or the frac replay results. Much as being provided the subsurface map of the reservoir can bias a conventional well test interpretation, being given the "correct" frac geometry and conductivity can bias the result of the frac flowback evaluation. An attempt should be made to analyze the data independently first. If the results are different from the frac replay, it means something!

Another concern with frac flowback data is that in a lot of cases, due to operational issues or well architecture, the data cannot be analyzed completely independently. If the well cannot be tested long enough to determine the matrix perm (the tighter the matrix and the bigger the frac, the longer it takes), one fallback is to use the permeability determined in the DFIT or minifrac. Another method is to use porosity/permeability correlations from the log data, perm from sidewall cores and full cores, and perm values from offset wells to determine the matrix perm. These methods aren't always reliable, but they do provide a means of remaining unbiased by the frac design simulation and frac replay evaluation. In short, the dilemma an operator faces in performing a frac flowback test for sufficient time to acquire data for a meaningful evaluation is the value of the information vs. the cost (time value of money). There is no magic bullet. Unless a command decision is riding on the results of the flowback, gather all the data possible without delaying other critical operations. If the data gathered was not of sufficient quality to perform the analysis during the frac flowback, gather the data when the well is placed on extended production. And by all means, if the evaluation of an individual zone or fractured interval is critical, it needs to be isolated and tested separately.

While it is beyond the scope of this paper to discuss the analysis of frac flowbacks in full detail, the authors would like to present some guidance on the subject. After quality checking the rate and pressure data (no point in analyzing bad data), the measured pressures need to be corrected to mid-completion depth pressure. A proper conversion to BHP requires the consideration of heat transfer from the well to the environment, as well as a PVT model of the produced hydrocarbons and water-based fluids. This being said, for low perm formations, this is not as critical as it is for moderate and high-perm formations. If the focus of the interpretation is the matrix rock, correlations may be used; however, if the focus is the fracture itself, variable density caused by thermal effects and phase interactions have to be considered. In addition, even with low permeability formations, estimated bottomhole pressures should be still be used to calculate fluid property inputs such as viscosity, total system compressibility (Ct) and formation volume factor (Bo, Bg, Bw) that are inputs into the well test analysis equations.

Once the BHPs have been measured or calculated, the next part of the process is to make all of the diagnostic plots for analysis. These include:

1) Cartesian plot of BHP and Rates
2) Semi-log plots of individual build-ups and drawdowns
3) Derivative plots of " "
4) Linear Plot: Square-root of delta time plots of " "
5) Bi-linear Plot: ¼-root of delta time plots of " "

For both vertical and horizontal wells, regardless of the number of stages, before embarking on an independent evaluation (without knowing the results of the frac replay or the desired result from the operator/service company/party doing the frac design), the party performing the analysis should consider: What is the expected order of information? For vertical wells, the order of response for an ideal case should be:

1) The Frac-Dominated Portion of the well/reservoir
2) The Frac-Matrix Interaction
3) The Matrix-Dominated Portion of the well/reservoir
4) Boundary Effects

For Horizontal Frac'd wells, the order of response should be:

1) The Frac-Dominated portion of the well/reservoir

2) The Interaction of the Vertical-ish component of the well/reservoir and the frac (1st radial-ish flow period)
3) The Linear Flow portion of #2 interacting with the horizontal section open to flow in the well
4) The transition from #3 to the second radial flow period (#5)
5) Second Radial Flow Period
6) Boundary Effects

Based on what is expected, the analysis can then be performed on a basis of whether that occurs…or whether something different happens. If something different happens, the differences can then be explored based on:

1) What is the displacing fluid vs. the produced fluid?
2) What is the relationship between the displaced fluid and the displacing fluid?
3) Are you sure you have 1 & 2 right?
4) Are there indications that the frac didn't go into its target?

Basically, it all comes down to geometry, relative mobility and thermodynamics. Playing with dual-porosity, dual-permeability and multi-layered models may create a match of the pressure data, but it may not provide correct results. All a good pressure match proves is that the folks coding the software used for the evaluation work were clever enough to include a model that happened to match the data…but, it doesn't mean anything unless you can compare it to the expected results. As mentioned earlier, not all frac flowbacks (and/or subsequent build-ups) can be analyzed. This doesn't mean you shouldn't try to analyze it, or just avoid gathering the data in the first place. If it works, the analysis will help to provide an independent evaluation of the frac job. If it doesn't work, you were hopefully gathering the data anyway for other reasons, so there's nothing to lose. The bottom line is that gathering the data is cheap; analyzing the data is cheap…but, if it works, the analysis will help you improve future frac jobs (which are not cheap).

It should also be stressed that the lower the matrix perm, the longer it will take to transition to matrix-dominated flow. If the matrix perm is below 0.01 md, this transition may never occur – at least in a classic diffusive sense (okay for the frac, but often not so good for determining the properties of the matrix). This makes it quite difficult to operationally justify months-long build-ups & the delayed production it implies. Thus, it is often necessary to analyze the long-term production data, especially since there is no way to guarantee that the data can be analyzed until the test is performed. For most frac'd wells, three to 6 months production on a constant choke setting will usually provide enough information to both evaluate the frac and the well's drainage area/volume. While this data may not be able to fully diagnose the fracture properties, it does give a baseline evaluation of the effectiveness of the overall completion, which can be compared with future well performance.

Case Study – Frac Diagnostics Tests, Frac Flowback (PBU) and Frac Replay Analysis

Frac Diagnostics and Replay Analysis

After a fracture treatment on a vertical, multi-stage well, the stimulation job data was provided to the authors for an independent analysis and review. Other data provided ranged from well schematics to mud logs, acoustic logs, and the planned treatment design. The initial scope consisted of sorting through as much data as possible to ensure the best resulting analysis. After sorting through the data, a geo-mechanical model of the rock layers and their properties was built. This geo-mechanical model was then tuned using minifrac data provided. Next, the actual frac treatment data was replayed using this model to confirm the properties. If needed, additional simulations were to be performed to further refine the model. This refined model was then used to review the stimulation job accomplishments and help develop a better plan for future stimulation treatments.

After many attempts at log interpretation, the acoustic logs did not seem to correlate to the rest of the data. In the essence of time savings, it was decided that mud logs would be the most reliable data set to determine stratigraphic layers for the basis of the geo-mechanical model. (Figure 1)

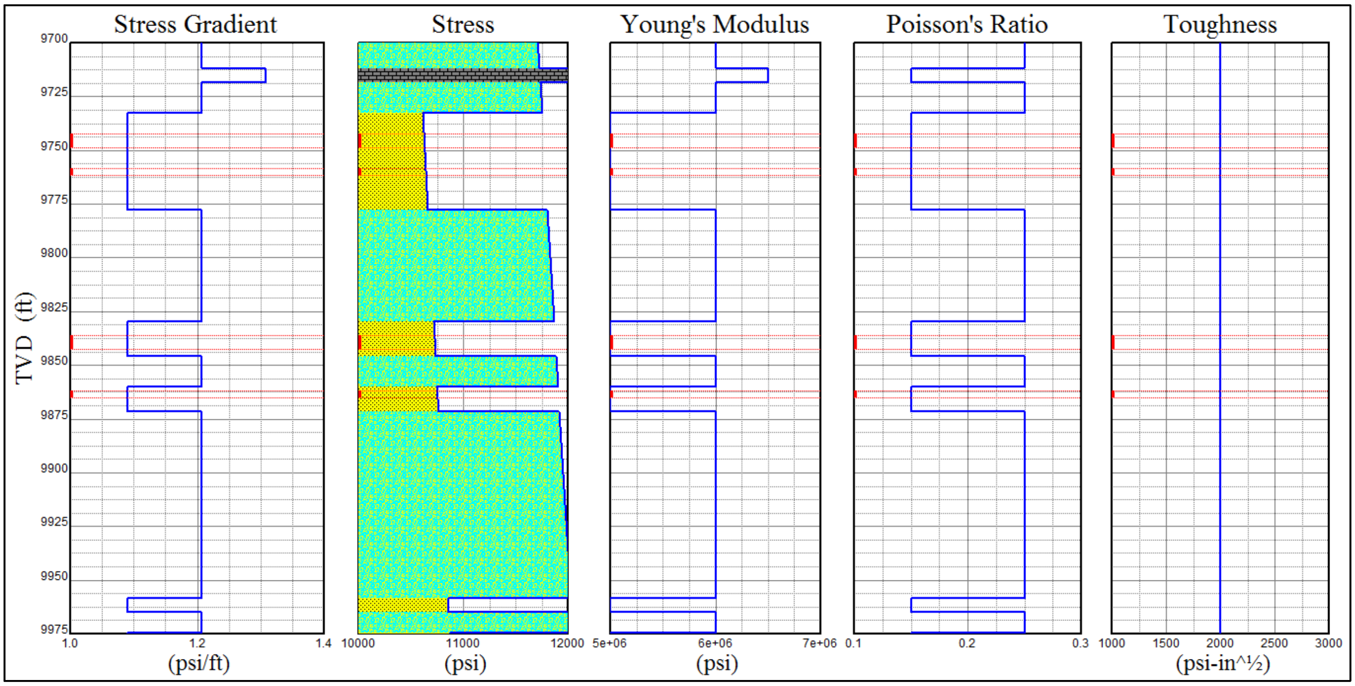

Figure 1 – Geo-mechanical Model from Mud Log Only

Just using basic mud log properties, a simulation of the treatment was performed. This data was used to history match the actual treatment data for comparison purposes. If the geo-mechanical model was exactly correct, then the simulated data would overlay the actual data. It did not in this case. The shut-in pressures were much too high and the pumping pressures varied more and more with time. (Figure 2)

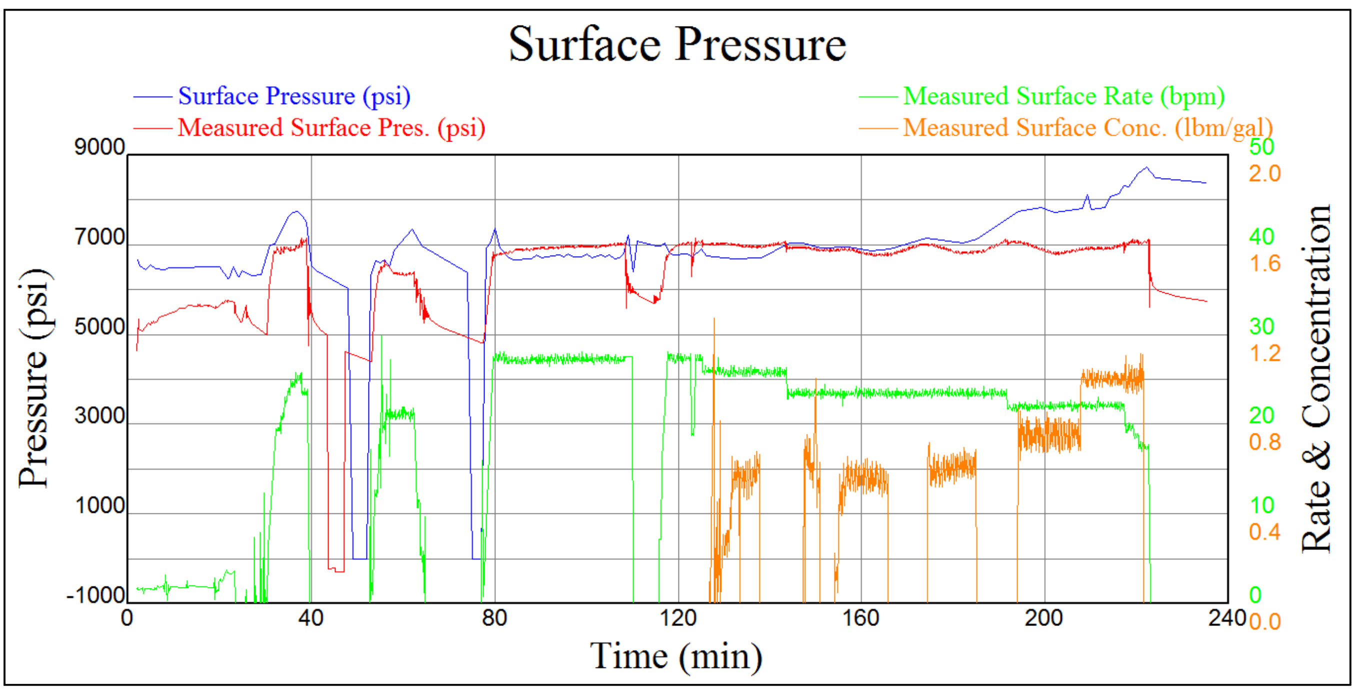

Figure 2 - History Match from Mud Log Only

After the basic geo-mechanical model was built from the mud logs, the minifrac data was analyzed. A step rate test (Figure 3) was used to determine the frac extension pressure of 5,897 psi at the surface and 10,144 psi at mid-point perforation (MPP) depth. A step down test (Figure 4) was also analyzed to determine if there were any specific near wellbore losses, i.e. unopened perforations. In this case, only half of the perforations were open, although the majority of the pressure losses were due to near wellbore tortuosity. A Horner plot (Figure 5) was used to estimate reservoir pressure at 5,201 psi surface and 9,448 MPP depth.

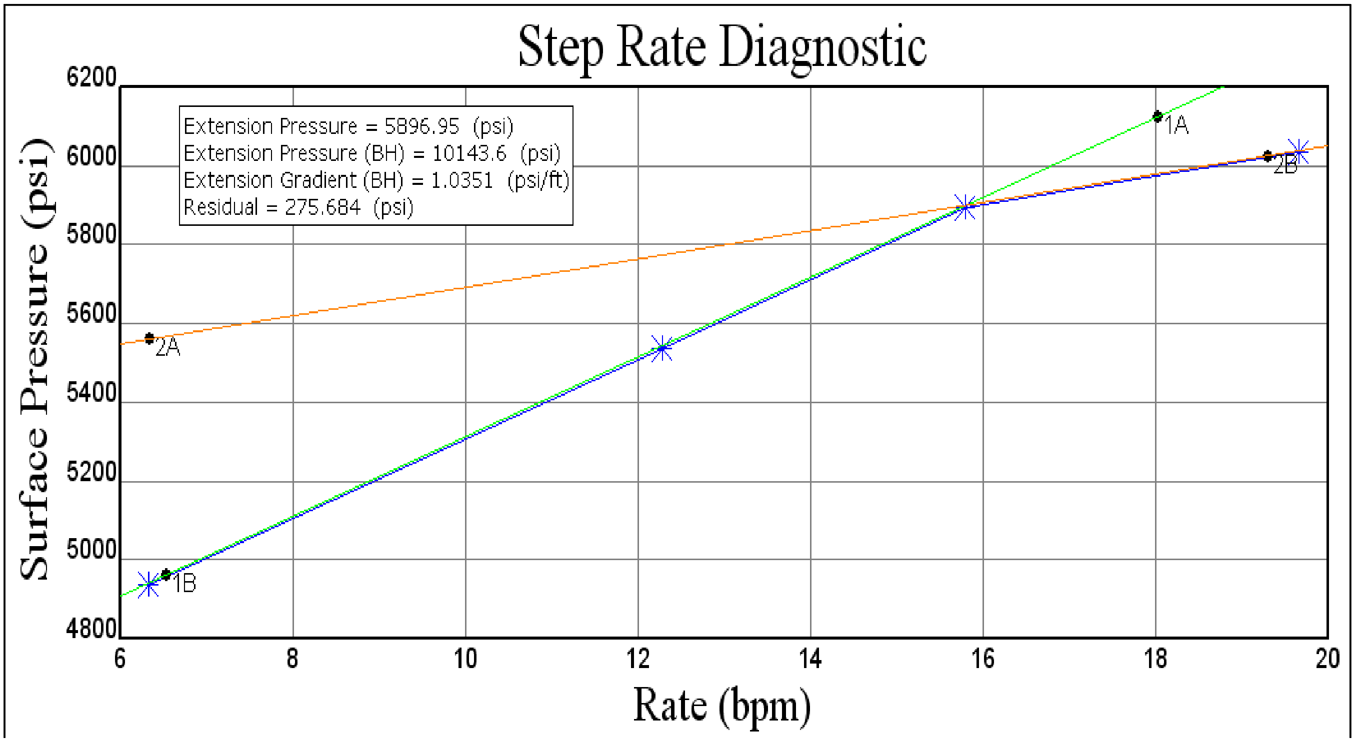

Figure 3 - Minifrac Step Rate

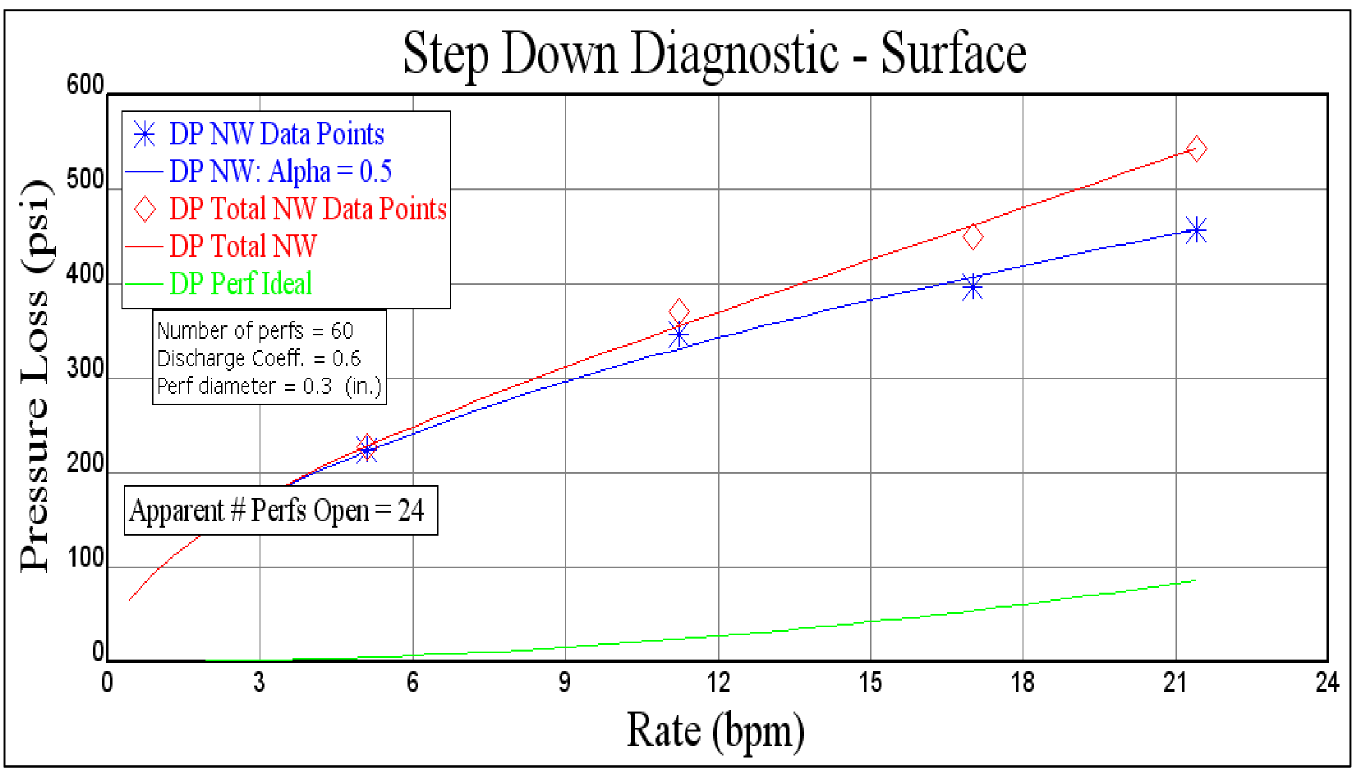

Figure 4 - Minifrac Step Down

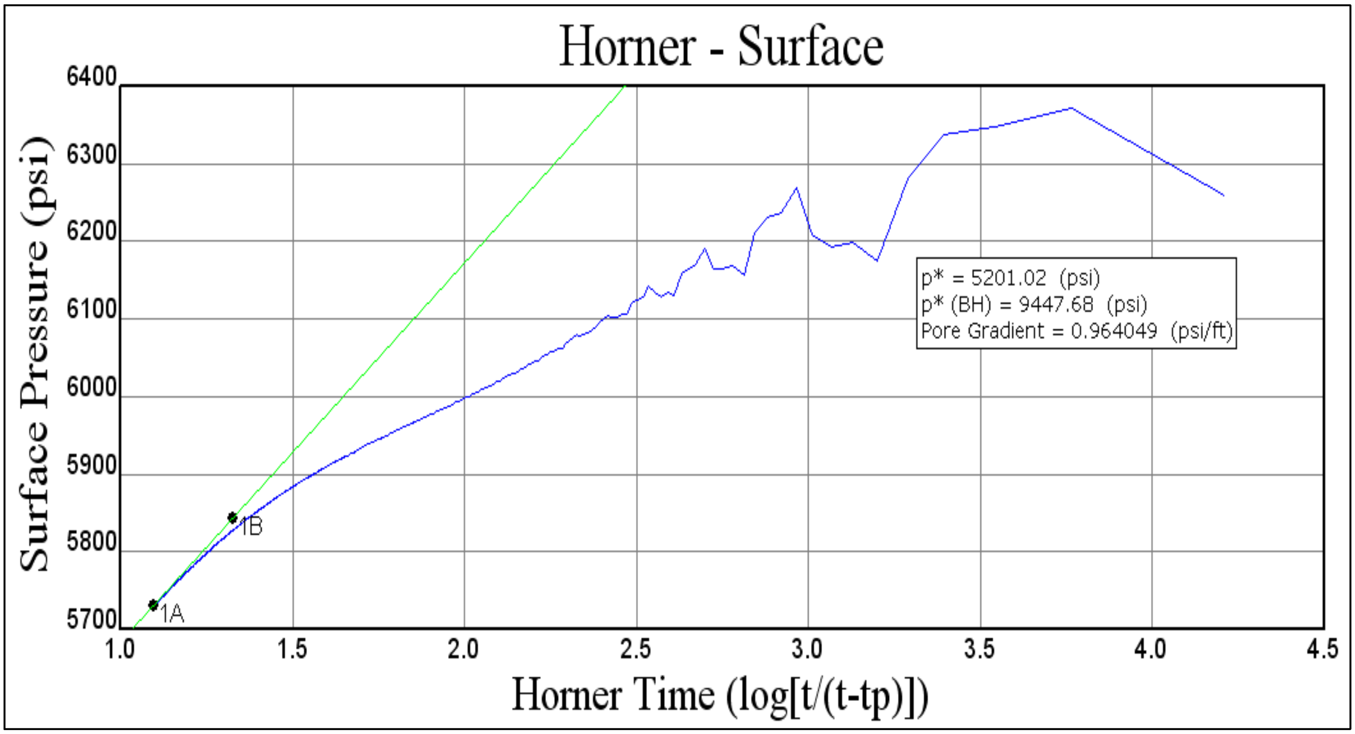

Figure 5 - Minifrac Horner Plot

Regression analysis (Figure 6) was used to determine closure time and stress gradients while After Closure analysis (Figure 7) provided another technique to fine tune the reservoir properties, including an estimation of 28 md permeability. It must be understood that this value of permeability is not always representative of the reservoir as a whole. It is only representative of the least stressed area that accepted this small volume of fluid. In fact, it is usually much more desirable to pump these small volume style tests in isolated perforated targets to get a more representative permeability of the targeted zone.

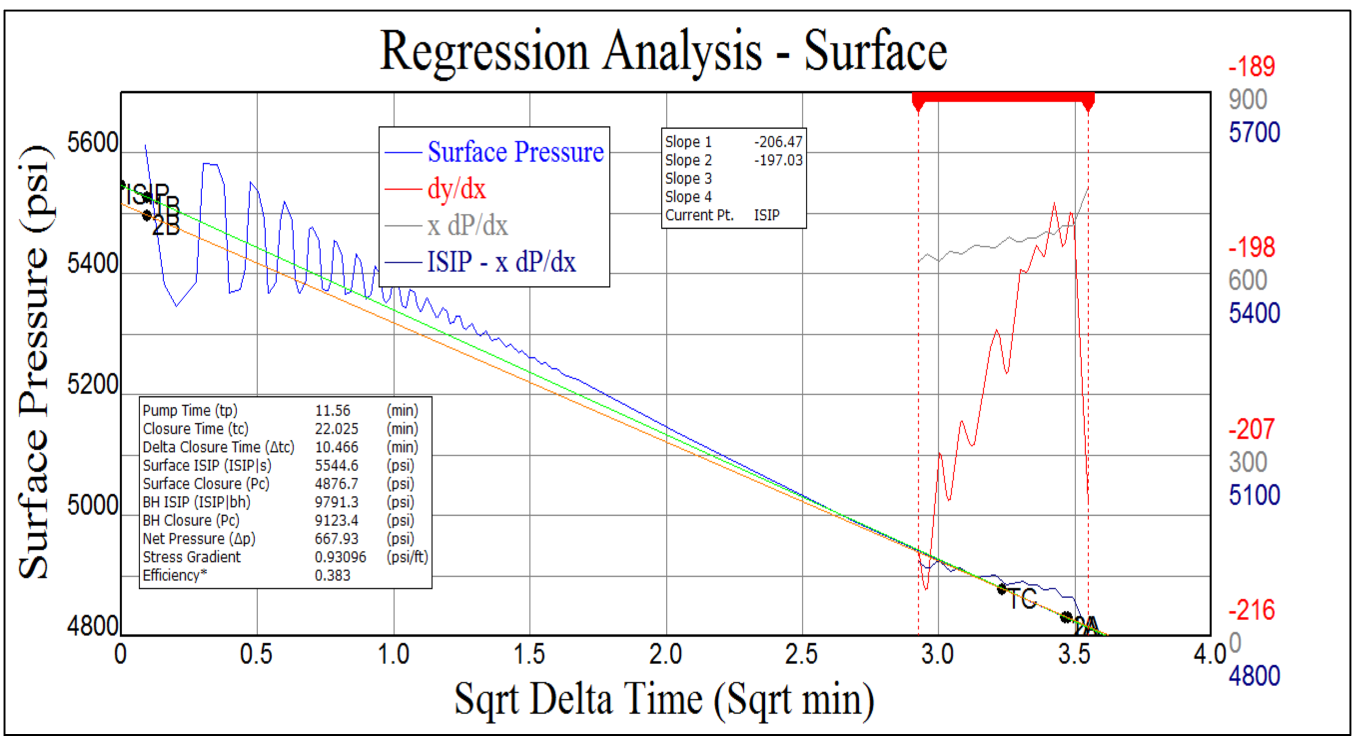

Figure 6 - Minifrac Regression Analysis

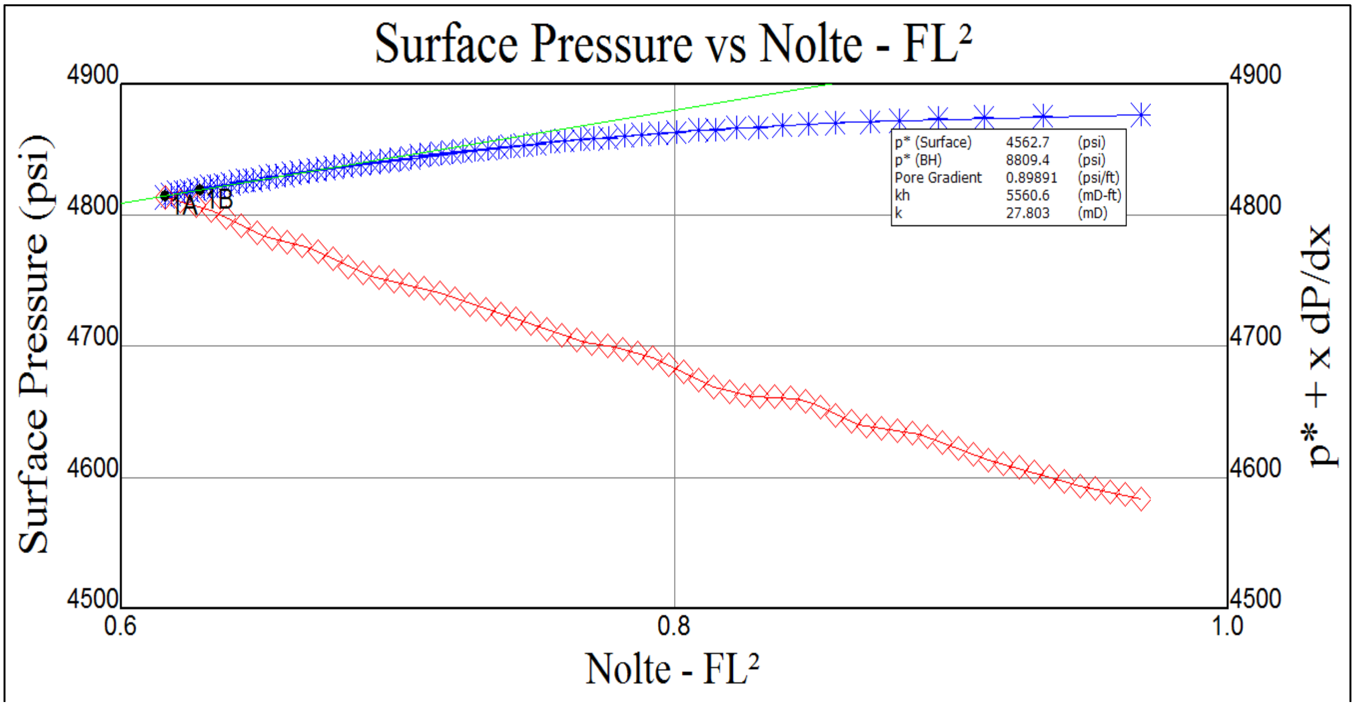

Figure 7 - Minifrac After Closure

At this point, it was time to better incorporate as much data as possible. A significant amount of time was spent correlating the acoustic rock property logs. Usually this would not have been such a large task, however something happened in the log file that was lost over email translation which resulted in considerable human interaction to regain its functionality. Finally, the acoustic log data was imported to create a new geomechanical model. (Figure 8) This model utilized all available data.

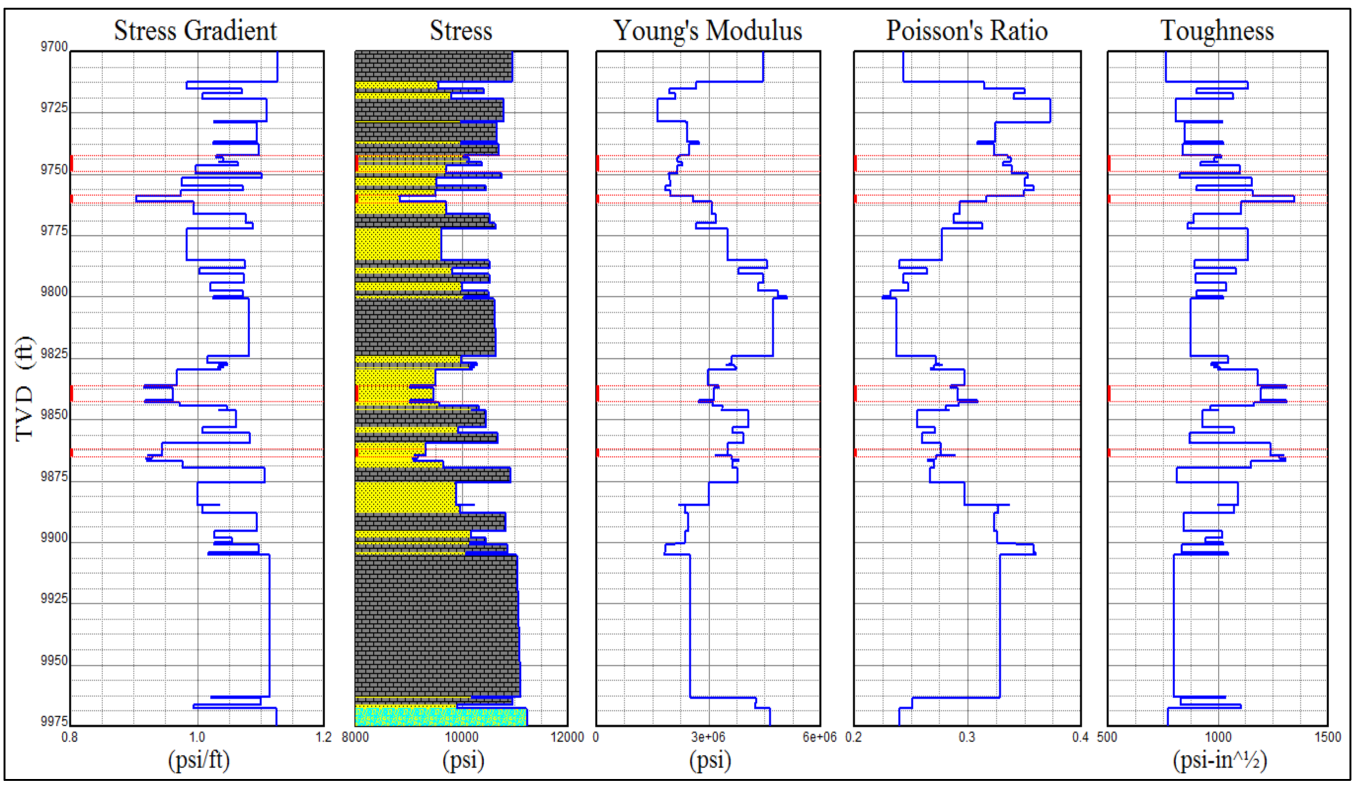

Figure 8 - Geomechanical Model using Acoustic Logs

A final simulation was run and matched to the actual measured data. (Figure 9) Judging by the improvements in the history matching of the job and the overlay of the simulated data to the actual measured data, the confidence in the final fracture characteristics (Figure 10 and Figure 11) also grew significantly.

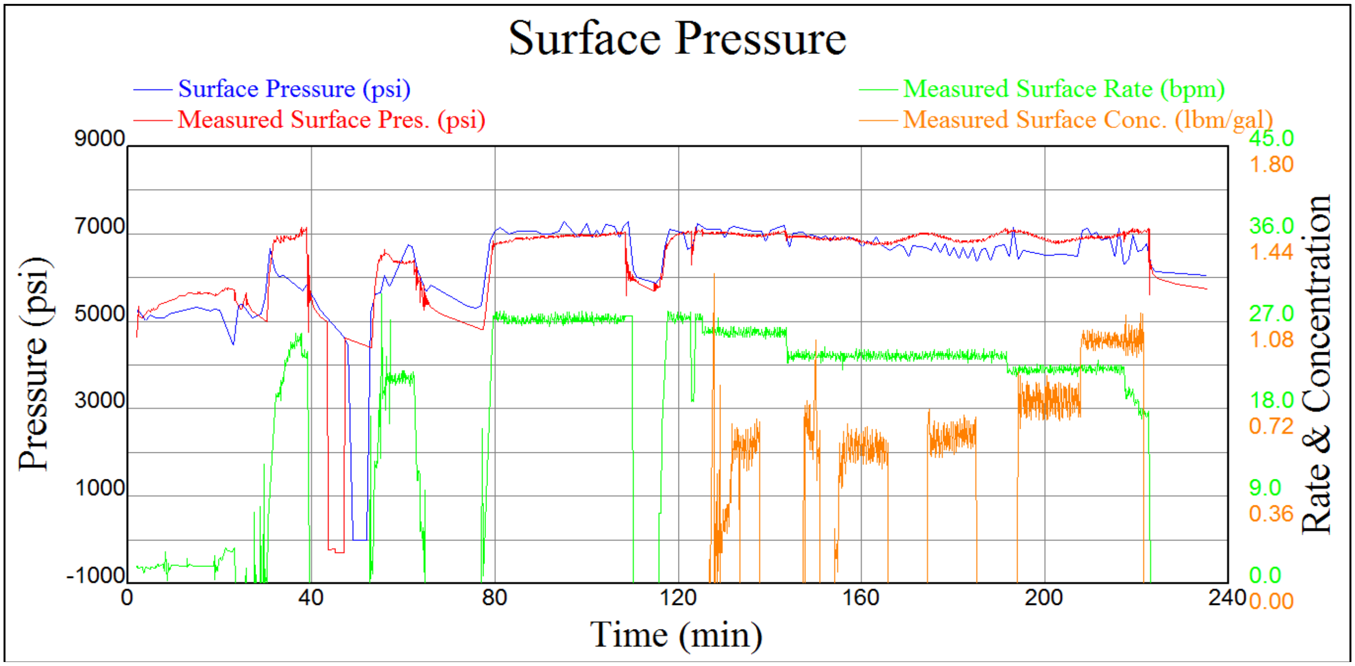

Figure 9 - History Match Using Acoustic Log Data

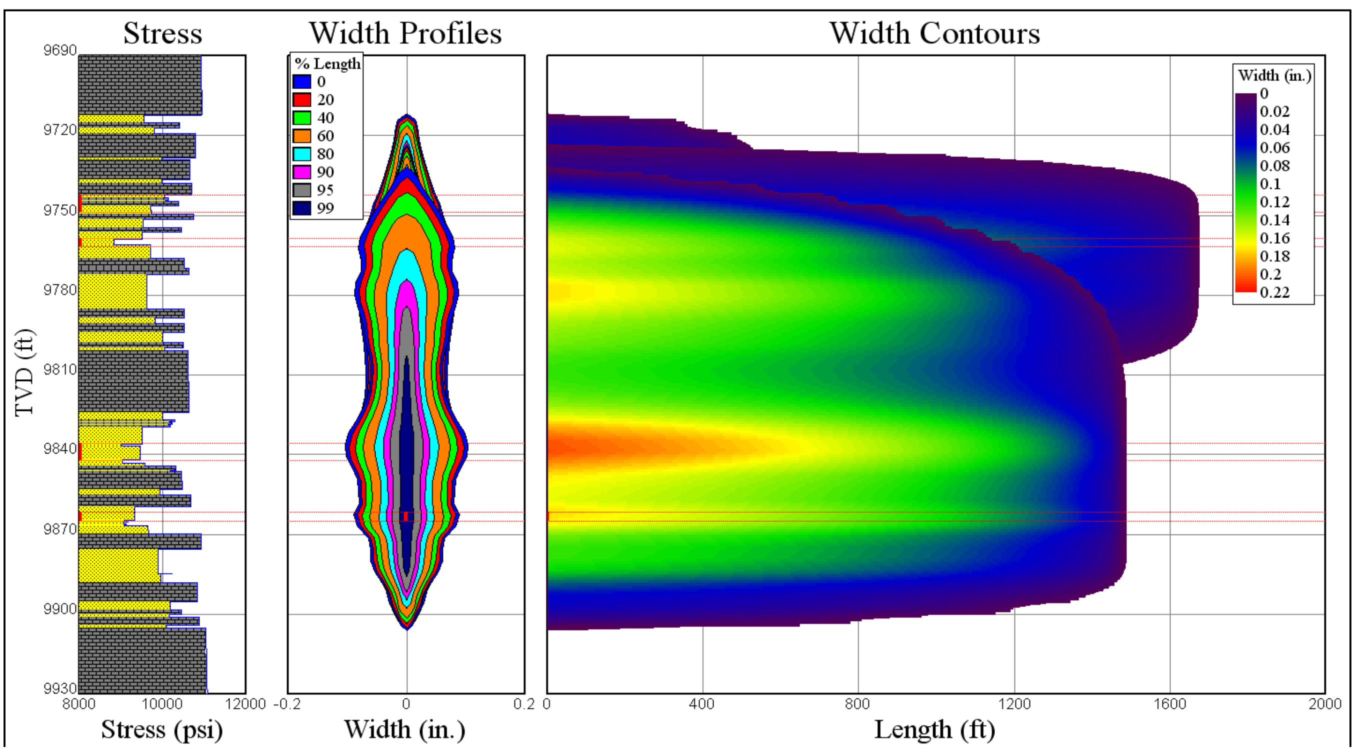

Figure 10 – Pad Placement & Frac Width Derived from Frac Replay

Figure 10 indicates that the pad/conveying fluid succeeded in breaking down the rock across from the perforated intervals and in connecting all of the zones together, albeit with a quite narrow fracture. It also shows that the pad extended out between 1500-1650 feet from the well bore. There were some issues with fluid efficiency, but the fracture initiation (once it overcame the near well pressure drop) was successful.

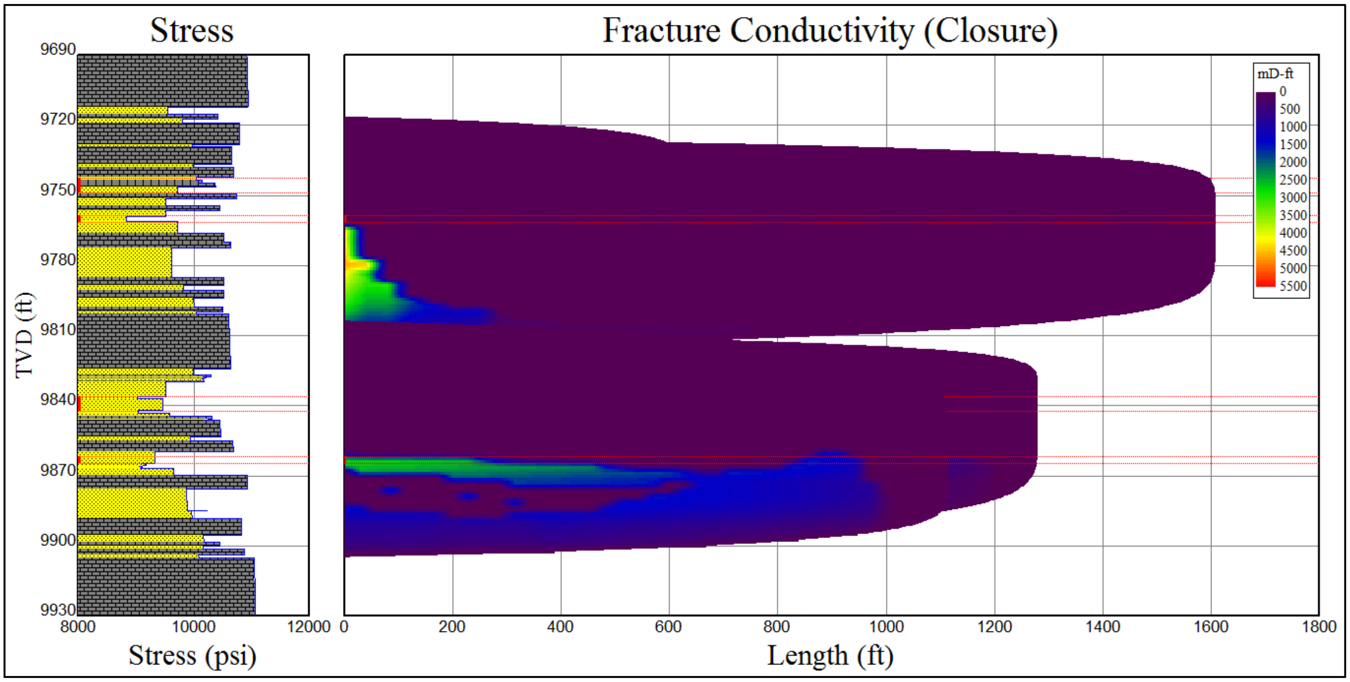

Figure 11 – Proppant Placement from Frac Replay

Figure 11 indicates that while the pad extended over 1400 feet from the well bore (purple shaded section), the proppant placement was quite poor. In the top two perforated intervals, the proppant settled out of the zones below the shale break at 9775' and barely extended out 150 feet. For the lower two perforated sections, proppant was placed in the zones, but very little fracture conductivity was created past 400 feet away from the well.

This treatment suffered from compound issues. Insufficient wellbore capacity caused higher than anticipated friction pressures. Treating pressure limitations caused a lower than designed treating rate because of the higher friction pressures. This lower rate did not create enough fracture width. Less than half of the original perforations were open initially but there was not enough proppant moved to erode and open more perforations. Leakoff overtook the volume input near the well bore and caused premature wellbore screen-outs. All of these problems resulted in a very narrow fracture with poor proppant placement that closed very quickly upon pump shut down. This very early closure time can be seen on a plot of the pressure fall off after the main frac treatment as shown in Figure 12.

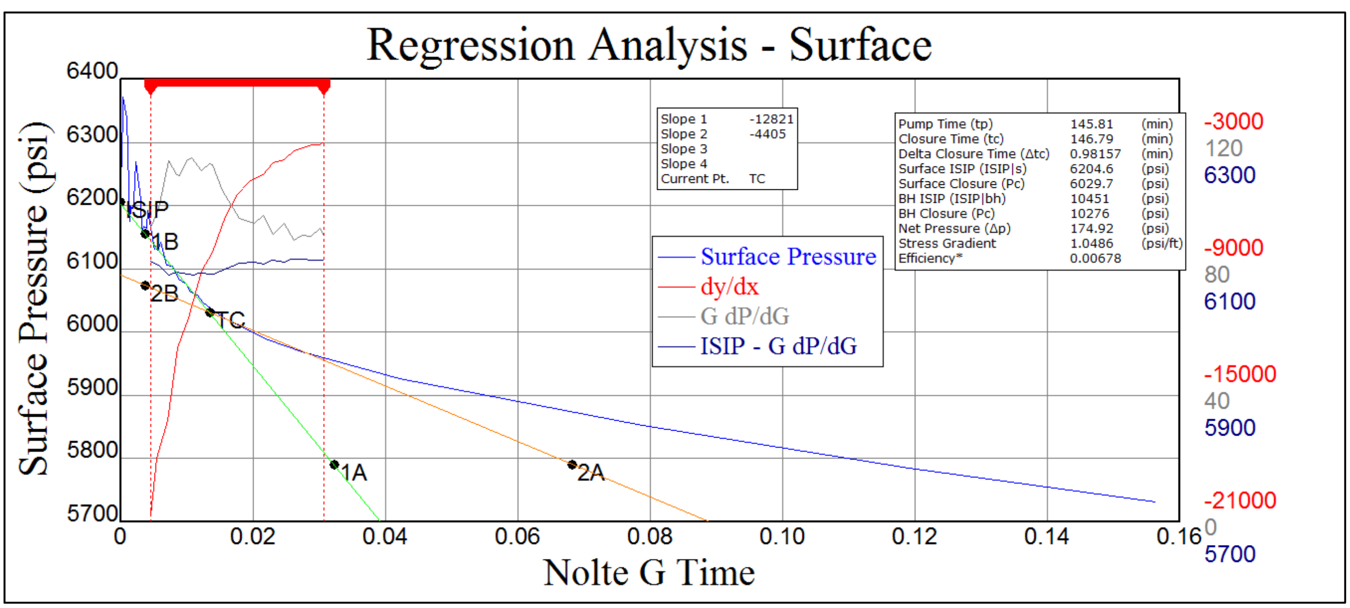

Figure 12 – Main Frac Treatment Shut In Showing Early Closure

Frac Flowback (PBU) Analysis

For this well, the frac flowback itself was not very useful, as only surface gauges were used and the well bore experienced significant slugging & loading problems. However, the build-up following the flow period was of sufficient quality to analyze both the fracture and the matrix. Figure 13 shows the Cartesian plot of WHP and Calculated BHP.

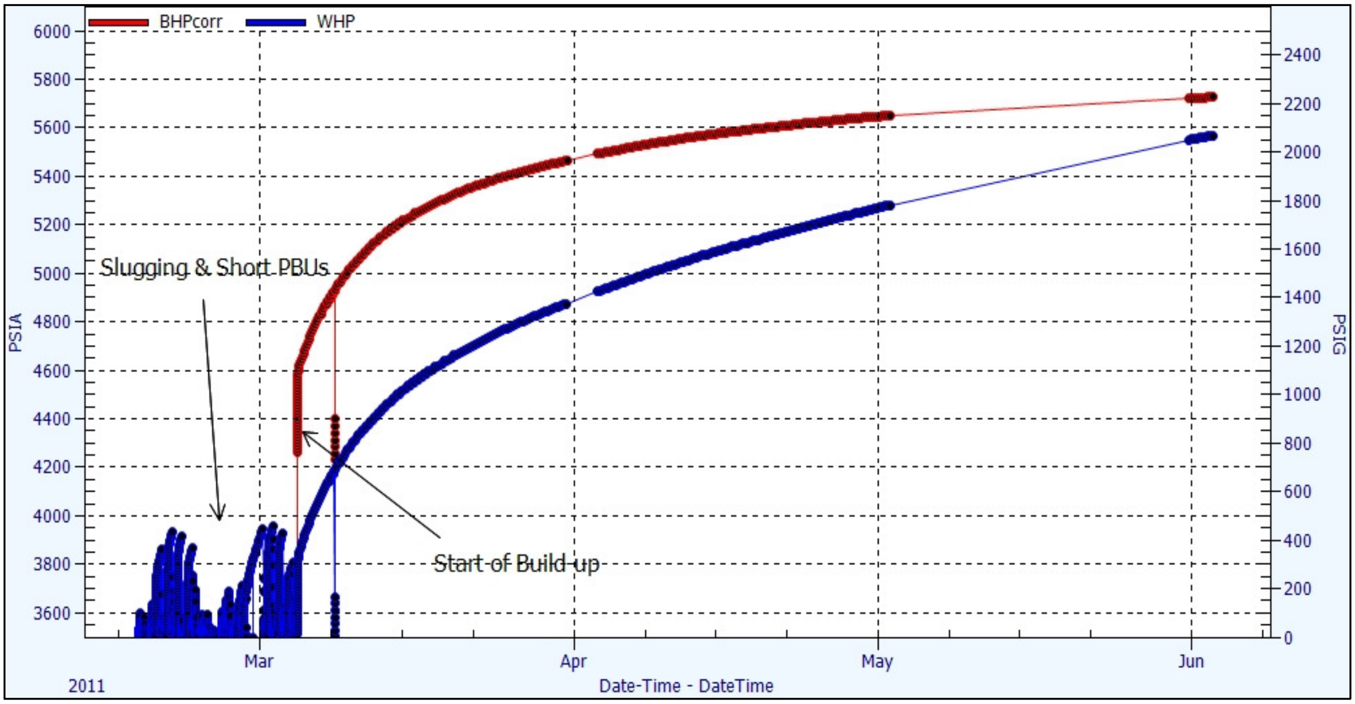

Figure 13 - Build Up Wellhead and Calculated Bottomhole Pressures

Figure 14 and Figure 15 show the Bi-linear flow and Linear Flow plots respectively.

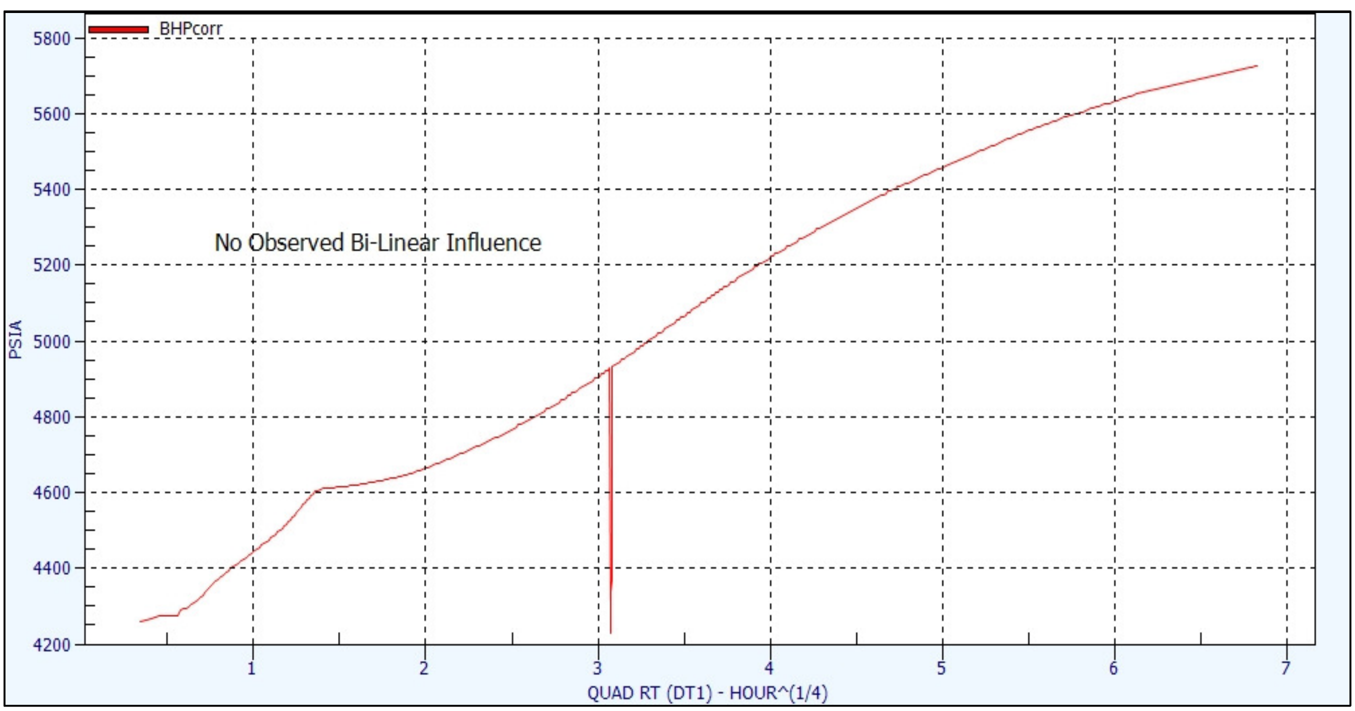

Figure 14 - Bi-Linear Flow Diagnostic Plot

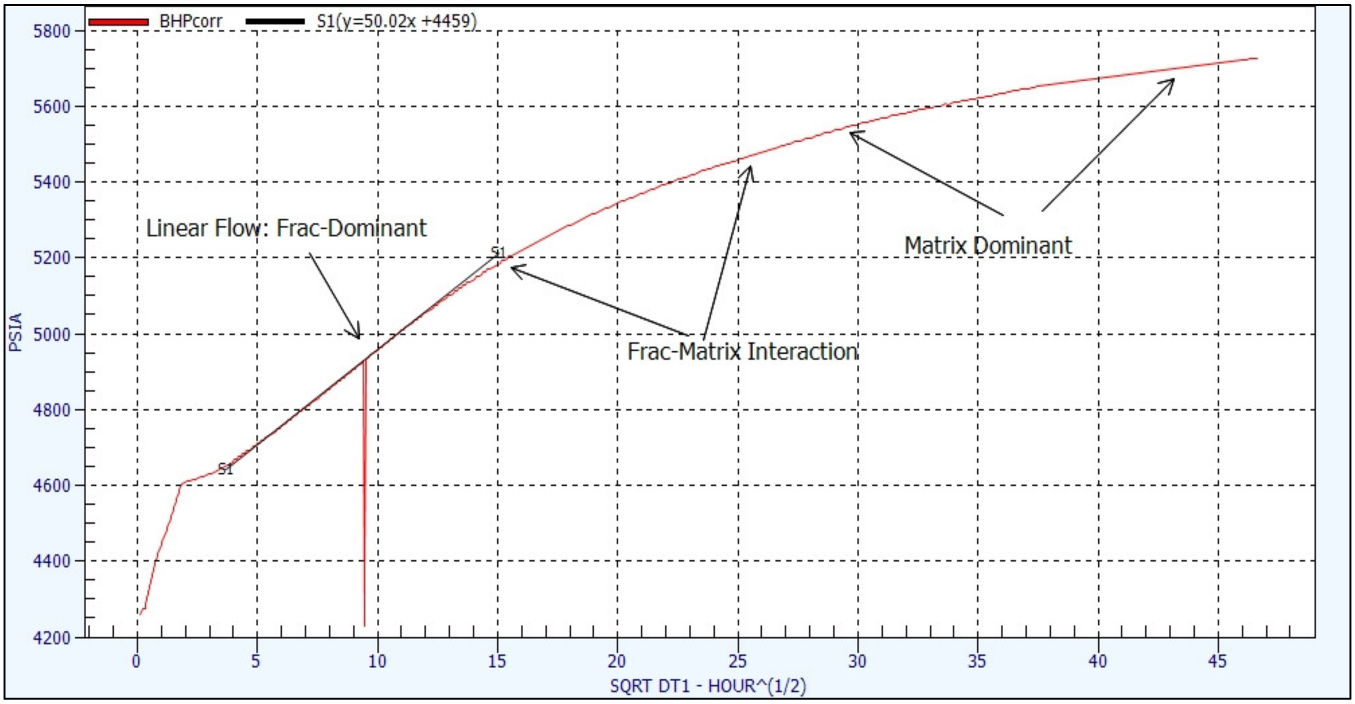

Figure 15 - Linear Flow Diagnostic Plot

No bi-linear flow was observed, so the fracture was most likely a bi-wing geometry (standard). By around 12 hours Delta Time, the well began to behave in a linear fashion, indicating Frac-Dominant flow. It then proceeded through the frac-matrix interaction period to matrix-dominant flow.

Figure 16 and Figure 17 show the Horner and MDH (Semi-log) Plots.

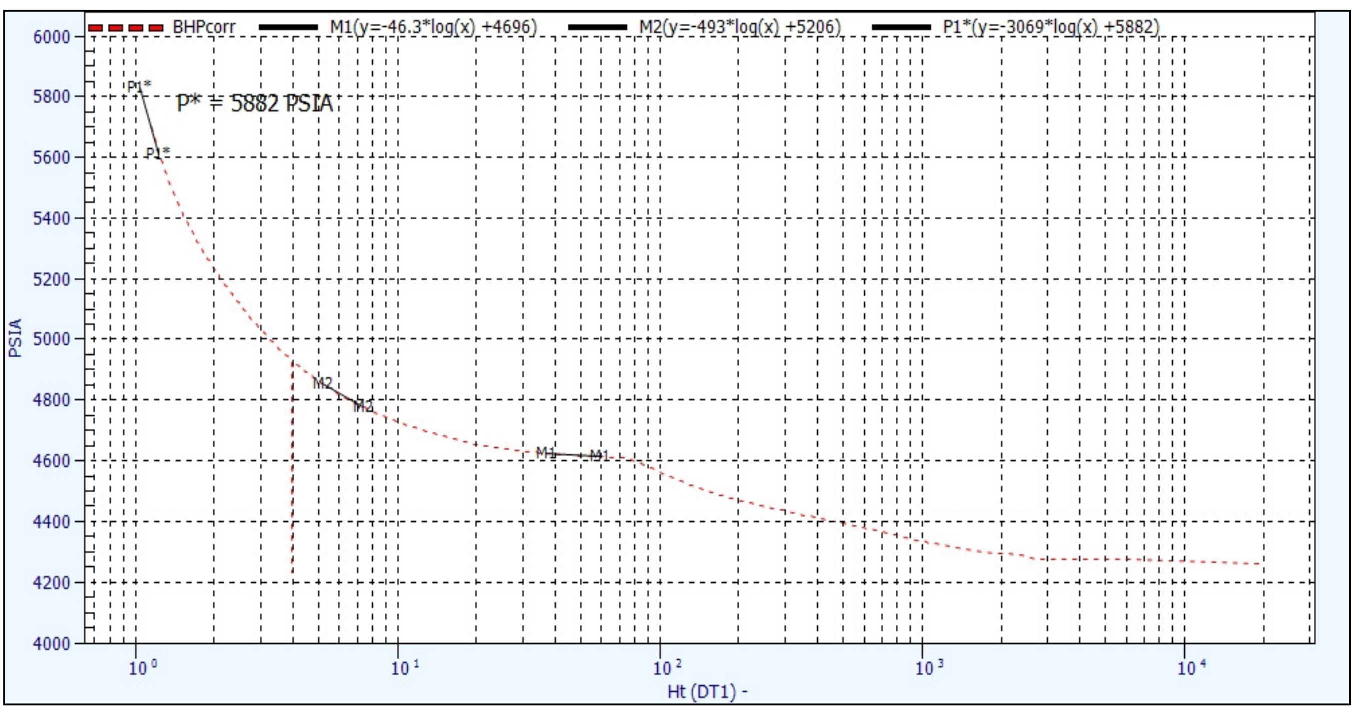

Figure 16 - Horner Plot

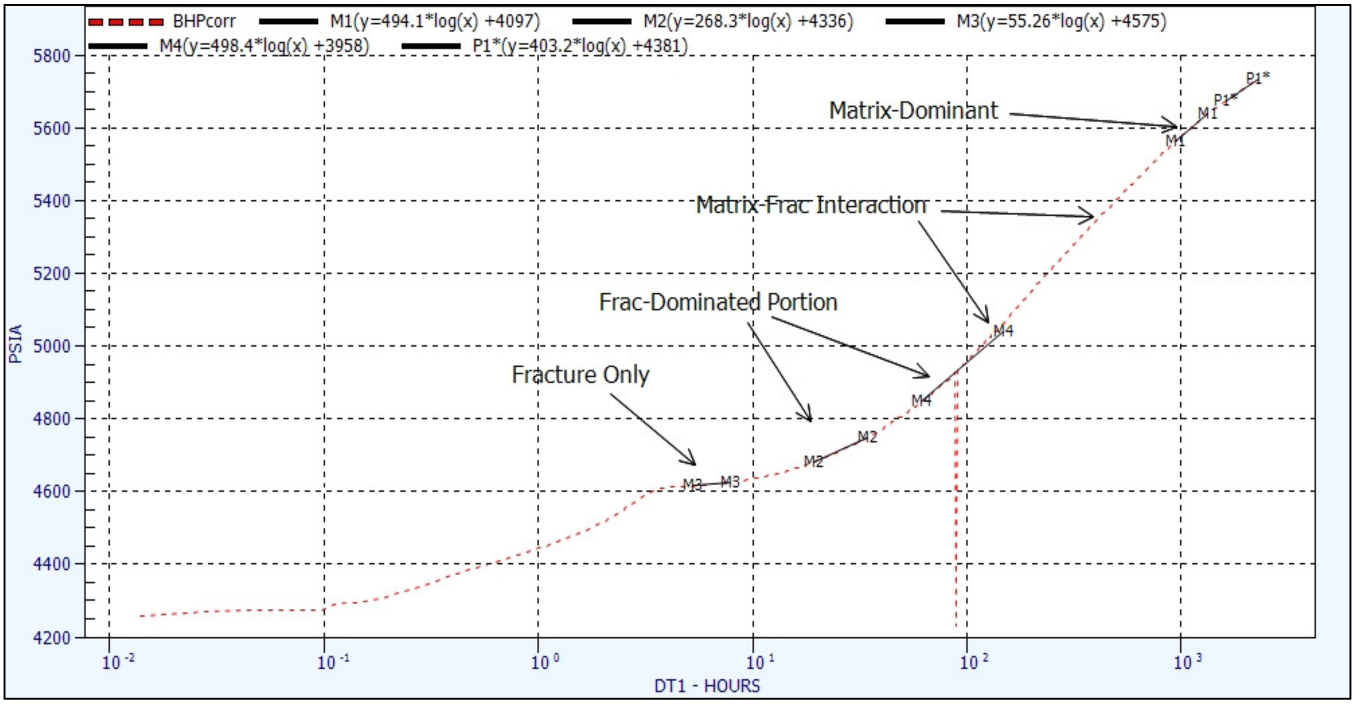

Figure 17 - MDH (Semi-Log) Plot

The Horner Plot indicates that the reservoir pressure is 5882 psia, although it could be higher, due to uncertain production time. The Semi-log (MDH) plot shows all of the features required to evaluate both the fracture itself and the matrix, as noted above in the plot. Figure 18 shows the derivative plot.

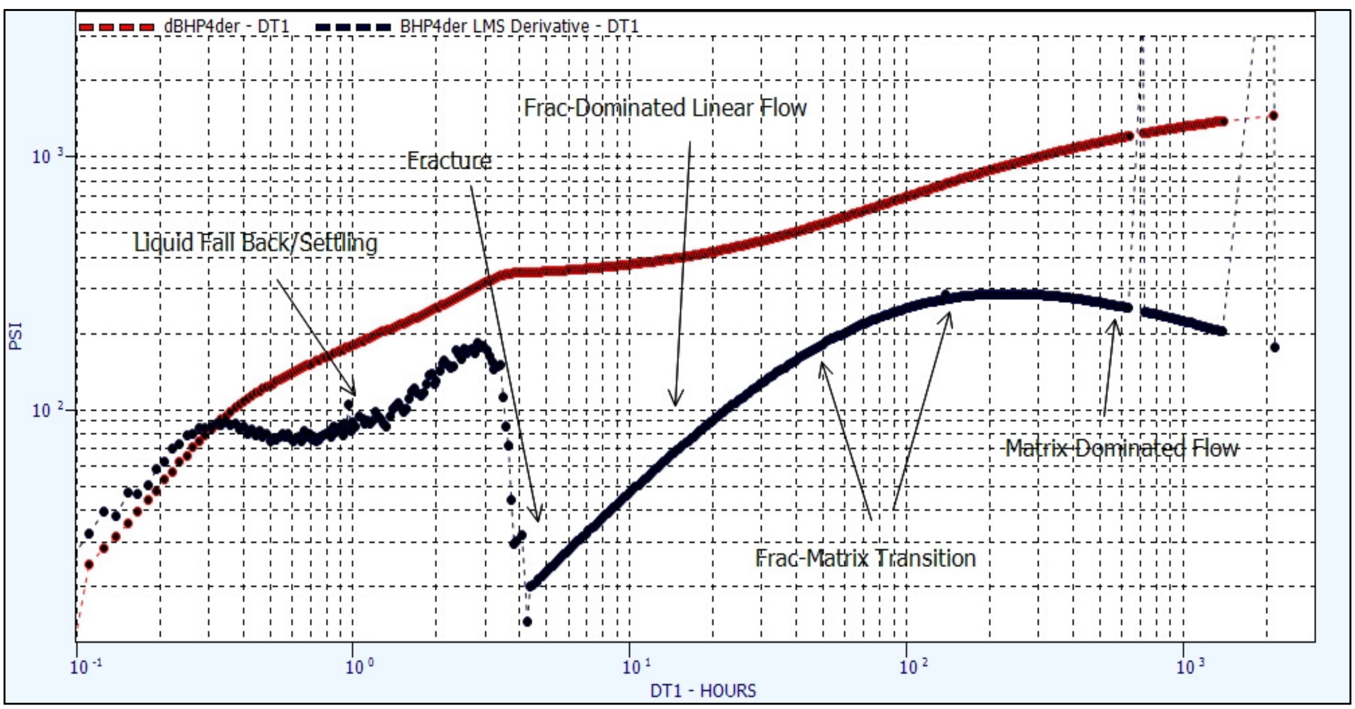

Figure 18 - Derivative Plot

The derivative plot shows liquid fallback up to about 0.3 hours delta time, followed by the signature of the fracture itself, followed by linear flow (1/2 slope on derivative). Then, like the Semi-log plot, it shows the transition from frac to matrix, followed by matrix-dominated flow.

Before the analysis could be performed, it was necessary to sort out what was the reservoir fluid and what was the displacing fluid. The well was producing frac fluids, with some formation gas. However, the gas volumes were sufficiently small to warrant using the frac fluid as the both the reservoir fluid and the displacing fluid.

The analysis indicated that the fracture extended out approximately 250 feet into the formation, and only had an effective permeability of 1.8 millidarcies (not good). The matrix rock had an ever lower perm – 0.20 millidarcies (200 micro-darcies). The frac-dominated volume was 390,000 Reservoir Barrels (RB) and the observed reservoir volume (including the frac) was 2.46 MM RB, corresponding to a potentially recoverable volume of 1.13 MM RB (1.88 Bcfe if gas-bearing). Furthermore, the long transition between the small fracture and the matrix-dominated flow, demonstrated the presence of a large water block, greatly impeding the ability of the well to produce gas.

Case Study: Putting it all together

While close in their overall conclusions (large pad injected, little proppant placed in the zones, poor fracture conductivity/permeability), there are some differences in the values derived from the frac replay and the frac flowback analysis. By examining the differences between the frac replay and the frac flowback build-up, it is possible to generate a consistent account of what happened. The well test analysis (WTA) assumed a net TVT pay thickness of 50 feet. However, the frac replay indicates that the effective net TVT pay is really about 12.5 feet. By adjusting this parameter in the WTA, the effective permeability of the frac-dominated region is 7.2 md, corresponding to a frac half-length of 500 feet. The comparison also sheds some light on the "tailing" shown in the derivative plot (Figure 17). While it was assumed that the response was caused by the prior rate periods, it could also mean that the well is in communication with more pay away from the primary fracture interval. Making the adjustments above, the frac-dominated volume decreased to 177,000 RB, the observed reservoir volume decreased to 1.23 MM RB and the potentially recoverable volume decreased to 0.56 MM RB (0.94 Bcfe if gas-bearing). Whatever the case on the net pay, the interconnected volume was not substantial enough to consider the fracture operation a commercial success.

The frac replay analysis (Figure 10 and 11) indicated that the frac fluid broke down the rock at the perforated intervals. While the pad extended over 1400 feet from the well bore, the proppant placement was quite poor. In the top two perforated intervals, the proppant settled out of the zones while the lower two perforated sections had almost no fracture conductivity more than 400 feet away from the well. The replay analysis also indicated why the treatment screened out. Treating pressure limitations caused a lower than designed treating rate to be used which resulted in a very narrow fracture with poor proppant placement. Leakoff overtook the treatment in the near wellbore region and ultimately caused the screenout.

Overall, the results from the frac replay and the frac flowback build-up were consistent on the outcome, with the exception of the formation permeability. Since the frac permeability was derived from a small volume minifrac placed over all of the targeted zones, it can be assumed that this perm is representative of a small, least-stressed area with what turned out to be very good reservoir characteristics. It is not representative of all of the targeted zones. The flowback analysis, however, considered all of the zones after being treated by the main frac treatment. It showed that the well produced as if it had a much lower effective perm than indicated in the fracture analysis. Fortunately, this difference did not change the overall conclusions regarding the fracture operation.

Conclusions

It should be emphasized that for this case study, the authors did the individual Well Test analysis and Frac Replay analysis in isolation, to avoid biasing the result. In this case, the results were similar for both post-frac analysis methods. If both parties had been provided the expected answer beforehand, there is a good chance the results would have been even more alike. Far too often, the party performing the frac replay analysis has already generated the frac design and/or executed the frac job themselves. This makes it much too easy to give the customer/operator whatever answer is expected, especially if the operator is blissfully unaware of the shenanigans going on in the background because they don't bother to look.

The recommended work process to reduce bias in frac design and evaluation separates Frac Design/Minifrac Diagnostics, Frac Replay Analysis and Frac Flowback Analysis. Completely unbiased, independent analysts should be utilized as much as possible to answer questions that come from a complex array of frac operations.

<u>Frac Design</u> includes log analysis, the design of the program & simulation thereof, and the frac re-design after the fracture diagnostic tests/mini-fracs. Logging provides the data required to build the initial geo-mechanical model used to run multiple simulations on a range of both geo-mechanical and reservoir property measurements or assumptions. Based on the results, the initial design may be finalized. However, this design should not be set in stone and less expensive options should be explored, not just ones that include more proppant and more additives.

Without actually testing the reservoir, there is not a guaranteed way to determine what pressure will fracture the rock and how long the fluid will maintain the fracture width in order to fill the fracture with proppant. Minifrac diagnostics acquire many of the necessary inputs required for designing a full size hydraulic fracture treatment. Step rate tests can determine an upper bound of closure pressure as well as a fracture extension pressure. Step down tests can help determine near wellbore frictional losses. Minifracs can give closure times and pressures, net pressures, fluid efficiencies, perforation frictions, frac geometry models, leakoff coefficients, formation permeability, and reservoir pressure. Horner analysis, regression techniques, and G function pressure decline analysis are all used together to provide inputs required for frac simulation. The net pressure of a minifrac can be history matched to calculate leakoff coefficients and permeability.

Frac Flowback Analysis can provide an independent determination of frac half-length, frac-dominated permeability-thickness, matrix perm, mobility differences in the formation, the frac-dominated volume and the overall observed volume. However, it doesn't always work. Fortunately, acquiring the pressure, rate and temperature data is very inexpensive, and often times these measurements are being done for other purposes like production monitoring and reservoir surveillance.

Frac Replay Analysis provides the ability to determine real formation response under the stress of a frac operation and the resulting frac geometry in relation to the reservoir. Knowing the rock parameters, stress profiles, and fracture geometry is not a one-time need unless the field is only large enough for one well. Every well that is to be placed in any given field should be used as a learning opportunity to improve the next well. If the operator continues to bias each set of frac data inputs, the field will never be optimized to its fullest potential. Each frac will actually suffer from the previous well's outputs instead of improve. The only way to remain honest to the well data is to analyze it independently of outside influence. The replay data will not only allow for fracture geometry determination and proppant placement, but unbiased replay analysis gets you data to utilize on your next well in the field.

Hydraulic fracture treatment designs inherently require more information than operators usually provide to the designers. Allowing for more information to be available to the designers to be input into a frac design increases the possibility of an improved ultimate frac outcome. Frac flowback analysis is valuable in providing an independent evaluation of the fracture system under producing conditions. The frac replay analysis is instrumental in diagnosing the cause-effect of operational hydraulic fracturing events. By performing these tasks independently, an operator can greatly reduce the bias present in the fracture design, execution and evaluation processes.

Acknowledgments

The authors wish to thank the Society of Petroleum Engineers for publication of this paper. The authors especially wish to thank Meyers & Associates, Inc. for the use of their hydraulic fracturing software and support. Mr. Newman wants to thank the management of ARC Pressure Data, Inc. for their understanding of the time involved in writing a paper of this magnitude. We also wish to thank Ric and Kat Flores for their input.