LONG TERM SCALE INHIBITION USING A SOLID INHIBITOR APPLIED DURING HYDRAULIC STIMULATION IN THE PERMIAN BASIN WOLFBERRY

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ABSTRACT

Long term scale inhibition and economic enhancement is a desired outcome for oil and gas operators. Scale is only considered a problem in this industry when it precipitates somewhere undesirable, such as providing the restriction of flow of profitable minerals such as crude oil and natural gas. Scale issues can result in deferred production, failure costs, wellbore remediation costs, and non-productive wellbore intervention periods. Primarily, inorganic scale begins to precipitate because of the mixing of incompatible waters, pressure changes, temperature changes, pH changes, or a combination of these. The completion phase of a well involves hydraulic fracturing, which involves the implementation of a mixture of water and specially engineered chemicals pumped at high pressures and rates to achieve a fracture into a low permeable formation. Due to these mix waters, pressure fluctuations, and temperature variations from the fracturing operation, liquid scale inhibition chemicals are typically pumped 'on the fly' throughout the fracturing treatment. Typically, these chemicals deplete within months after the fracturing operation and the need for continuous intervention from a chemical service company is then required to inhibit any scale potential while the well produces.

The following study examines various wolfberry solid scale inhibitor applications in order to validate solid scale inhibitor uses. This project evaluates two fields and compares results. This study demonstrates the methodology and selection process of solid scale inhibitors as well as the effectiveness of the solid scale inhibition, longevity, and the economic impact.

INTRODUCTION

Scale Inhibitor – General Information

Scale can be defined as inorganic substances formed from a supersaturated aqueous solution that deposit as a non-flowing accumulation. Typically, operators primarily treat for scale with liquid chemical inhibitors. Usually these applications consist of a squeeze, batch, and/or continuous treatment depending on the severity of the scale. A squeeze treatment consists of a scale inhibitor chemical being 'squeezed' or pushed into the formation into the theorized affected zones. A batch treatment consists of an allotted amount of scale inhibitor being injected at calculated intervals. A continuous treatment is a slow 'drip' of chemical injected at a steady stream. Typically, a squeeze treatment is the most effective of the three treatments described due to the ability to adsorb into the formation and allow penetration into the affected zones. This in return provides some adsorption to the formation providing some near wellbore protection as well as tubular protection. The other treatments never penetrate the formation and only mitigate the wellbore tubular. Scale squeezes remain active in the well between 3 months to 12 moths depending on how precise the treatments are. Typically, operators request the lowest economical amounts of chemical to be applied or required but can result with ineffective and shorter lived treatment; thus, rendering the service company to continuously follow up with treatments at a higher frequency.

In order to determine the effectiveness of a scale inhibitor treatment, monitoring of some fashion must be maintained. Usually, water samples are taken from the wellhead post-treatment at intervals established by the Service Company or operator to test for active chemical within the produced water. The reported values for scale inhibitor tests are commonly termed 'residuals', or 'active component' of the chemical. The residuals must maintain a certain threshold level defined as the minimum effective concentration (MEC) required to be effective against scale deposition. The MEC is usually determine by sampling produced water from an existing older well and running a series of tests that will demonstrate the lowest concentration that can be effective to mitigate scaling tendencies. However, with a continuous or batch treatment residuals are irrelevant because that the well undergoes intermittent treatments. Residuals are best to collect when squeeze applications are utilized to form a trend and determine longevity of inhibition.

Scale Inhibitor – Hydraulic Fracturing Applications

Hydraulic fracturing in the oil and gas industry is the primary completion treatment to remove skin damage and optimize productivity of a well. Hydraulic fracturing involves the mixture of water and specially engineered chemicals pumped at high pressures and rates to achieve a fracture into a low permeable formation. Due to the high mixed water volumes and pressure changes mentioned about hydraulic fracturing one can assume that scale is of high risk in this environment. The given assumption leads to the fact that scale inhibitor is generally pumped during hydraulic fracturing treatments. Usually, a liquid inhibitor is run 'on the fly' during the fracturing job at recommended intervals that consist of either inhibitor loaded within the acid, in a lumped 'pill' ahead (pre-pad) or behind (flush) the fracturing job, or distributed evenly in all water based liquids pumped throughout the fracturing job. The basis of the treatment is similar to a squeeze treatment methodology and the scale inhibitor is pushed into the formation as far as the fracture propagates. Depending on the adsorption capability and volume of the chemical the scale inhibitor experientially lasts from 3 to 6 plus months. Eventually the well will have to be re-treated over the lifetime the well produces, as the inhibitor flows back and concentration depletes.

Various liquid scale inhibitors exist in the marketplace today for hydraulic fracturing uses. Scale inhibitors exist in various chemistries that can offer inhibition for a range of scales including carbonate, sulphate, and even barium type scales. As scale inhibitors can be affected by water quality and environmental factors to which they are introduced, inhibitor chemistries have evolved to inhibit scale in multiple environments, for example in an environment with high iron. Analytical technology has progressed in having the ability to identify which scale inhibitors are more tolerant or more apt to inhibit particular scale threats and work best in the production environments. Though traditionally scale inhibitors are liquid, recent technology has allowed for more solid inhibitors with various chemistries to enter the market. Several types of solid inhibitors that are currently available for hydraulic fracturing include: dehydrated inhibitor powders, encapsulated solid inhibitors, infused solid inhibitors, crystalized scale inhibitors and impregnated solid inhibitors. The focus of this paper is to highlight the benefits of impregnated slow release solid inhibitor applications.

Slow release solid scale inhibitor applications have the key performance indication of achieving a longer life of scale inhibition. The impregnated solid granular scale inhibitor was chosen to be used for the treatments of this study for the application and practicality of its use. This impregnated solid scale inhibitor can be described as a solid granular structure that consists of an inhibitor adsorbed onto an inert solid substrate. This solid inhibitor is applied during a fracturing operation within the proppant slurry. A typical hydraulic fracturing job uses proppant material, mostly common sand that is pushed into the formation along with the water and specially engineered chemicals in order to propagate or keep the fracture open. The propagation of the fracture serves as the pathway for profitable minerals such as oil and natural gas to flow through. The value of this solid inhibitor is to mitigate any near wellbore scale issues as well as inhibit scale issues in any well tubulars and provide longevity of inhibition. Recall, typical liquid scale inhibitors last months while the solid inhibitor in use at the time of the field studies and inscription of this paper, has lasted upwards of over a year with few other wells into the second year of production without any secondary intervention. The longevity of the level of active inhibitor over time and the prolonged longevity of the application are substantial. Figure 1 demonstrates the conventional residual effects after a typical fracturing operation over a period of time. Typically the solid inhibitor residual has a slow desorption rate providing slow dissolving capability. The liquid, in comparison, depletes over time in which the curvature of the residual depletion for the liquid is a higher gradient towards full depletion. The placement and value of the solid inhibitor saves chemical waste over time based on residual depletion.

BACKGROUND

The amount of solid inhibitor of applied is limited primarily by economics, compatibility with fracturing fluids, and the conductivity of fracture propppant bedding. A chemical mass balance equation is used to configure the amount of solid inhibitor required based on water production with a theoretical return on time and return concentration, or residual. A water analysis of a similar offset well is a good initiation point to consider the type of solid inhibitor to choose from, pending the scaling tendency of the field or the water quality coming from production of a similar formation.

Previous compatibility testing of the fracturing fluids with the solid inhibitor assured the proper use on these applications and the typical fracturing treatment utilized. Previous lab testing has also provided that the loadings indicating that the amounts of the solid inhibitor should not exceed 4% by total weight of sand or loss of conductivity could occur. The solid scale inhibitor chemical is to be injected in the slurry portion of the fracturing operation which consists of a sand mixed aqueous solution. With this in mind, the solid inhibitor is actually specially engineered and formulated for this case to be delayed in solubility.

The monitoring phase commences after treatment when the well is put on production. The solid inhibitor in this discussion is a conventional phosphonate chemistry that is easily monitored by phosphate residual testing. The typical accepted manner is to keep monitoring periodically until the well reaches the MEC (minimum effective concentration) for two testing periods in a row and then turned over to treat via conventional production upstream methods such as squeeze, batch, or continuous treatments depending on severity of scale issues and operational agreements. In theory, when the residuals fall below the MEC; the well should be re-treated using the conventional upstream methods but the fluctuation anomaly of multiple producing zones shutting on and off requires the secondary endorsement.

FIELD TRIALS

Both longevity of solid inhibitor and liquid inhibitor are analysed in one field application (Wolfberry Field 1). The other field application resulted in a residual case study (Wolfberry Field 2). Loadings in Field 1 were based off a pound per thousand gallons of volume of fracturing fluid (ppt). Initially, the loadings were 2 ppt and changed over time to 4 ppt to determine the affects. Field 2 loadings were based on an average of ~100 to 150 pounds per stage used. Due to the variability of loadings and measures of proppant used along with a variable number of stages per well, the amounts of applied solid inhibitor vary. The loadings were kept within the reasonable <4% by weight of sand limits to ensure conductivity would not be affected. The granular size of the solid inhibitor mostly exhibits 20/40 particle sieve size; therefore, it was recommended on these fracturing jobs that the solid inhibitor be placed within the 20/40 sand stages, but is still suitable to run among similar sand proppants such as 30/50, 40/70, & 16/30 mesh proppants. The solid inhibitor is applied via the hopper on the blender unit in the fracturing job in order to ensure an even spread of chemical throughout the sand stages. The distribution can be calculated and configured a set point to run throughout the job for ease of programming and application for the fracturing crew.

RECCOMENDATION METHODS

At first, the process underwent various water testing and analyses to confirm the selection of solid inhibitor chemistry used. The scaling tendency modelling verified that calcite was the main issue in the area by evaluating the produced water mixed with the fracturing water source (Figure 2). The best solid scale inhibitor to use was then chosen based off the predicted scale analysis on top of tube block testing completed. The tube blocking test analysed a range of solid inhibitors for the operation based on the water scaling models and the tendency of the water itself put under pressure and heat resembling the multiple zone vertical wolfberry formations. The testing determined the most effective scale inhibitor as well as the MEC (Figure 3). The best scale inhibitor overall, between liquid and solid selections, was a solid inhibitor we shall term, for the purpose of this paper, as SS3. It is important to recognize that all demonstrated scale inhibitors in Figure 3 are affective and will inhibit scale threats in the given scenario. The recommendation is made on the basis of which scale inhibitor provided the lowest MEC. Economics and key performance indicators can play a role in scale inhibitor selection, but inhibitor effectiveness and potential extended inhibition longevity should be weighed into the decision pending scale severity in the field. The MEC is configured to be close to a theoretical 2.5 ppm concentration, meaning when residuals reached less than 2.5 ppm that the effectiveness of the chemical is reaching a point that it will soon be ineffective at scale prevention. In order to obtain accuracy, a second residual should be analysed to confirm the chemical is reaching depletion due to the possibility of multiple water zones shutting on and off at variant frequencies during production.

Considerations are now taken to fitting the solid inhibitor within the fracturing design and compatibility. The dominant fluid type in the fracturing operation performed in this area are 12-15 pound cross-linked borate systems. Compatibility is tested in the lab to assure the solid inhibitor would remain passive to the fracturing fluid and cause no instability. The lab concluded that the inhibitor loading would not affect the fluid system (Figure 4). The particle size distribution and crush resistance of the solid inhibitor particles mostly resemble the 20/40 proppant being used in the fracturing operation; therefore, the inhibitor is to be applied on stages where 20/40 proppant is configured at an initial 2 ppt loading. Previous research and papers concluded that the same impregnated solid inhibitors can reach upwards of 6000+ psi crush ratings with up to a 2% loading by weight of sand (SPE 159701). Therefore, the loading is assured that the 2% rating is not exceeded in order to prevent embedment or fines migration issues within the fracture. It is important to denote and understand crush ratings or maximum loadings on any solid inhibitors used in order to assure fracturing permeability is maintained and to prevent fines migration issues.

FIELD ONE RESULTS (ECTOR COUNTY, TX)

Over the course of the field treatments, residual monitoring took place. Field treatments accounted for 111 treated well's data sets within Field 1 from 2009-2013. A measure of longevity is established in this study when the wells are squeezed after the fracturing operation took place. At times the squeeze is deemed necessary by the operator and at times is due to the residual being close to its depletion limit, hence the variability in data per time. Certain wells in the study were treated by secondary means invalidating a residual based study and the longevity or time used is providing the scale of measure for the study in Field 1. The average chemical life before a secondary squeeze is concluded to be 9 months with an average amount of 2000 pounds of solid inhibitor placed within each fracture for the field (Figure 5). The maximum life spiked at 23 months for the Field 1 study (Figure 5).

To serve as a longevity comparison 18 wells in the field were fractured using liquid scale inhibitors (Figure 6). The longest lasting liquid inhibitor monitored lasted roughly 6.5 months (Figure 6). The overall average life span of the liquid inhibitor comparison lasted about 1.5 months (Figure 6). This demonstrates the shorter longevity of a liquid scale inhibitor and the requirement for a premature secondary squeeze than if using a solid scale inhibitor.

Throughout the field trial a loading increase occurred to oversee any possible enhancements. A 4 ppt loading was established to test in comparison to the original 2 ppt loading. The effect of increase in solid inhibitor placement was demonstrated between two wells in the same field within the same vicinity to obtain best results for the study. Well A (4 ppt) had a higher cum. oil production than Well B (2 ppt) over the course of 12 months (Figure 7). It can be inferred that a higher loading provided significant production benefits. The benefits are potentially associated with less work over being completed or added benefit to the reduction of near wellbore or fractured formation associated scale issues. The oil production is analysed using the cumulative oil production of both Well A & Well B. The initial production of well B was greater until the 3rd month mark when Well A overtook the rest of the production increase for the remainder of the year. Well B was squeezed at 11 months; therefore, production was only trended to a full year in this study in order to remain within a reasonable analysis boundary.

Overall, a full production analysis was concluded for the field treatments versus alternative participant treatments. The field treatments analysed are only solid inhibitor treatments versus alternative treatments for the field. The alternative treatments are unknown and could be liquid and/or solid application or a combination thereof. All the jobs were assumed and categorized by similar treatments and applied within similar lithology for the producing formations in the wolfberry Field 1. It can be seen that field treatments using solid inhibitors produced better oil production benefits providing a 7% enhancement in production throughout the field (Figure 8). Although, there is much variability to the data and possibilities of additional enhancement treatments performed it is assumed that solid inhibitor placement is a major cause of the field's production enhancement. A total of 261 wells were studied in this field with 111 wells as "solid inhibitor treated" and 150 wells as 'alternatively' wells.

An average cost analysis based on initial investments and longevity is demonstrated in Figure 9. Liquid scale inhibitor treatments on average lasted approximately 1.5 months. With this knowledge it can be implied a secondary treatment be implemented after the 1.5 months. The average cost estimates provided for secondary treatments based on estimated longevity are charted in Figure 9. The maximum longevity of a solid inhibitor treatment is plotted to demonstrate the benefit of longevity and associated cost. The dashed lines represent the point in time where the initial solid scale inhibitor investment is paid. The data represented is for chemical treatment costs and does not account for any deferred production, equipment costs, and/or work over rig costs that would be accounted for in secondary squeeze type treatments.

FIELD TWO RESULTS (MIDLAND COUNTY, TX)

Field 2 represents a field in Midland County with 64 treated wells with the solid scale inibitor of focus. The key peformance indicators established on this specific field study are to validate how long residuals on average are lasting into the production phase. Figures 10, 11, 12, & 13 represent the study completed in Field 2. Figure 10 is a conglomeration of residuals plotted together for all 64 wells. In order to simplify the process Figure 11 demonstrates the average of the residuals of all 64 wells. Figure 12 represents the minimum residuals of the subject wells and the maximum of these residuals are represented in Figure 13. The basis of providing the maximum and minimum is to demonstrate the best and worst case scenarios of active residuals in the field. All figures demonstrate that residuals are present in significant amounts and extend into the 24 month period of the study demonstrating a concise 2 year scale inhibition life by the use of solid scale inhibitor treatments. Data for field 2 has been monitored and collected from the years 2011-2014.

CONCLUSIONS

It can be noted that solid scale inhibitors not only influence longevity but can also yield production benefits. The ultimate goal is to defer wellbore intervention associated with scale issues and the solid scale inhibitor demonstrates the capability to provide, annual if not multiannual, protection from associated scale threats. By utilizing modern conveniences, including technology and technical analysis, an optimum scale treatment is possible via application within hydraulic fracturing. In this case the solid inhibitor outperformed a liquid inhibitor, provided long term inhibition, and even yielded oil production enhancement benefits.

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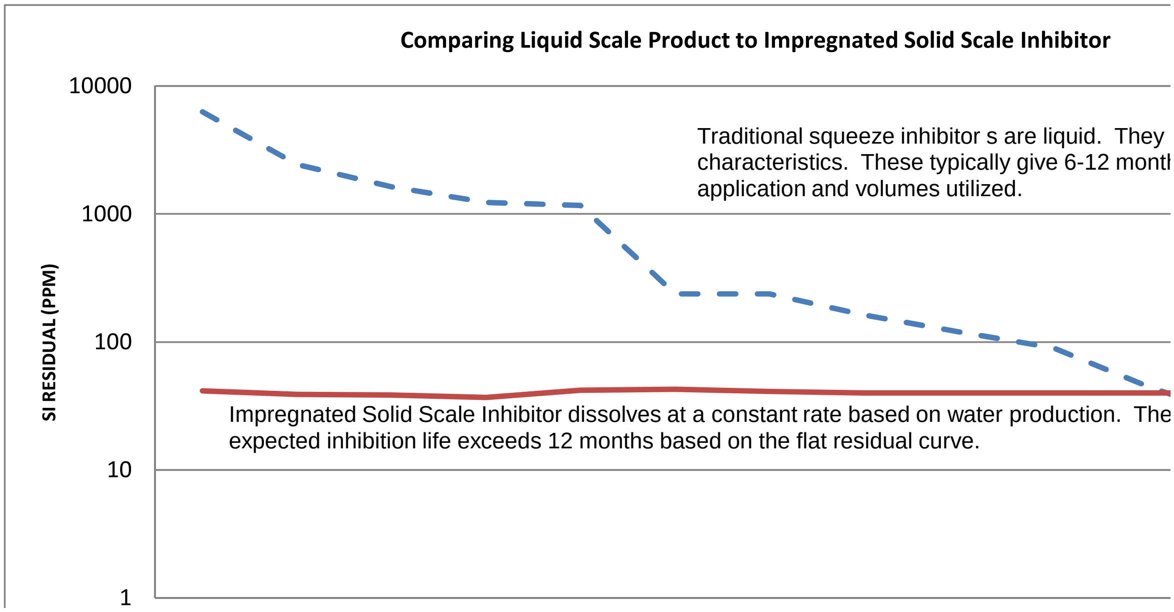

Figure 1 - Comparing Liquid Scale Product to Impregnated Solid Scale Inhibitor

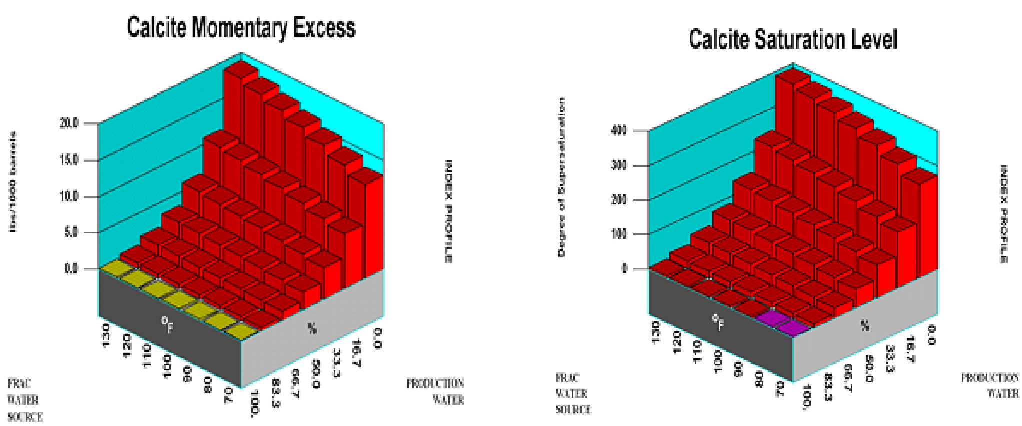

Figure 2 - Predicted Scale Field Saturation Level & Momentary Excess (Field 1)

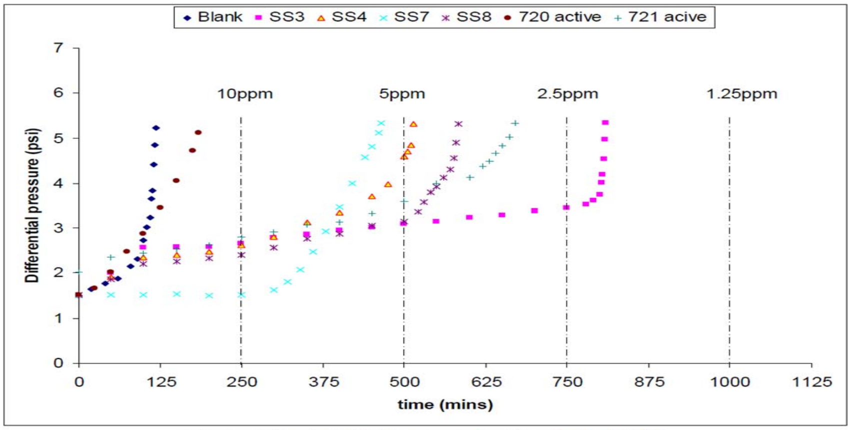

Figure 1 Scale inhibition test at pH = 7.45, 146°F

Figure 3 - Tube Blocking Test Presenting Effective Inhibitors & MEC

Method: Heat Cup/ Fann35			Spring/Bob Configuration: R1/B2 Readings @: 100 RPMs
S S 3	0 ppt	2 ppt	
	0 ppt		
	0 ppt		
5 Min	55	50	
15 Min	45	45	
30 Min	46	42	
45 Min	44	43	Base Gel Viscosity: 12.5 cp @ 511/sec
60 Min	45	45	Base Gel pH: 7.54 @ Temperature (F): 70
90/120 Min	45/45	45/45	Hydration Time of 3 min
180 Min	41	41	
Xl pH	10.21	10.21	
Breaker Type: None			

Figure 4 - Fracturing Fluid Compatibility Test with Solid Scale Inhibitor Present

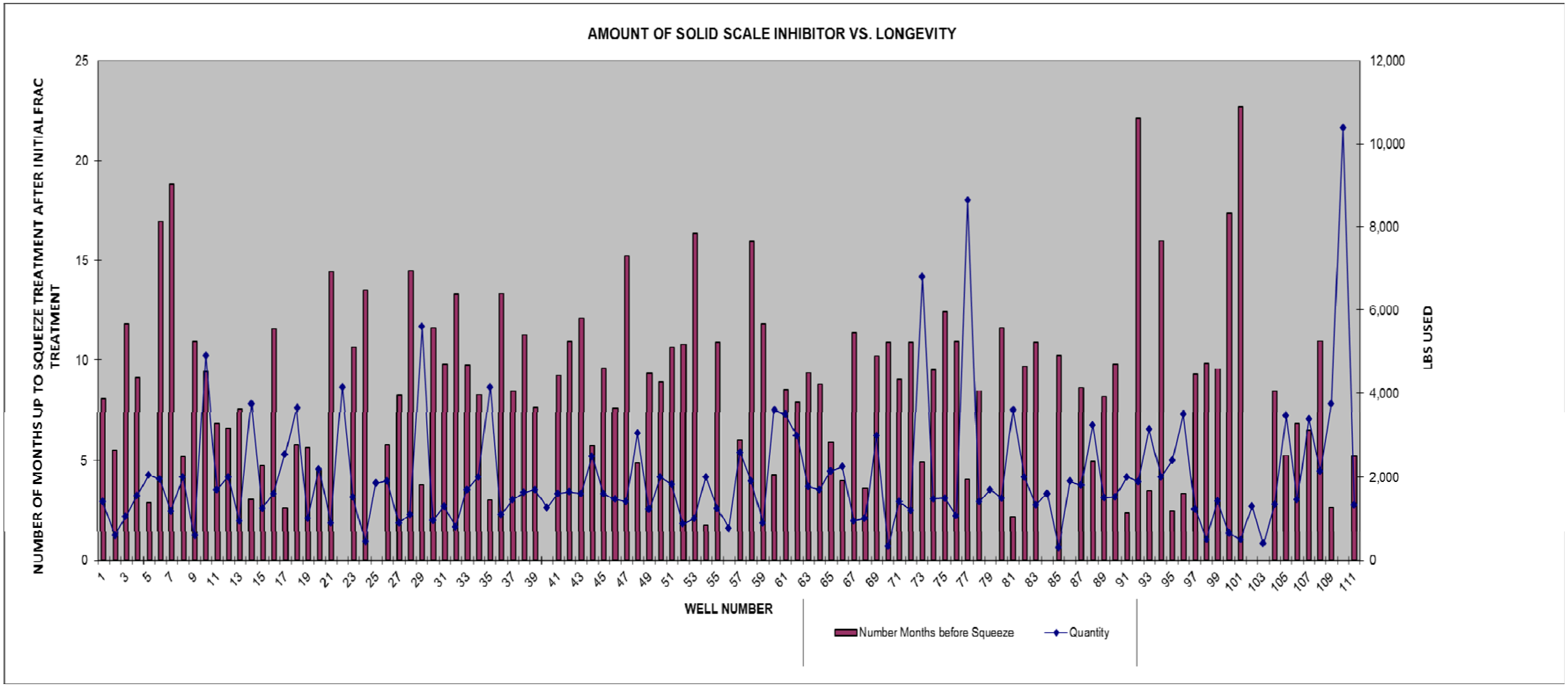

Figure 5 - Solid Inhibitor Longevity Chart

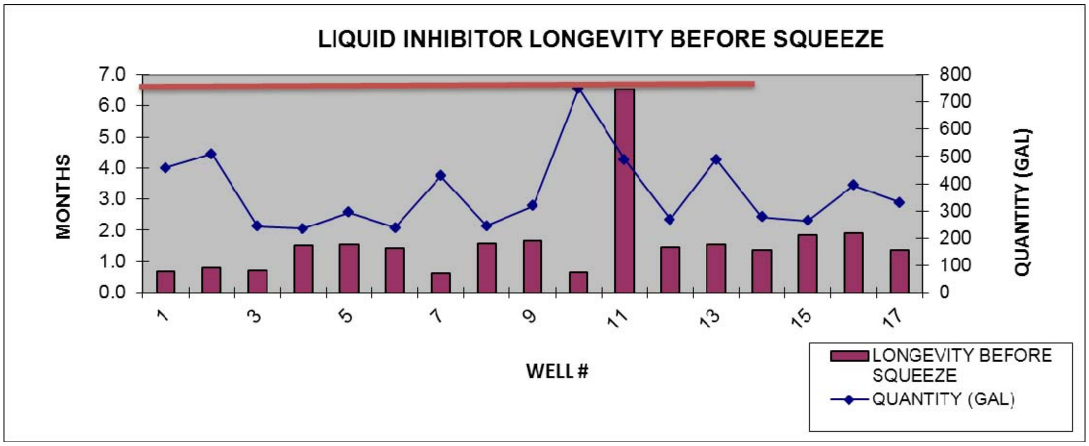

Figure 6 - Liquid Inhibitor Longevity Chart

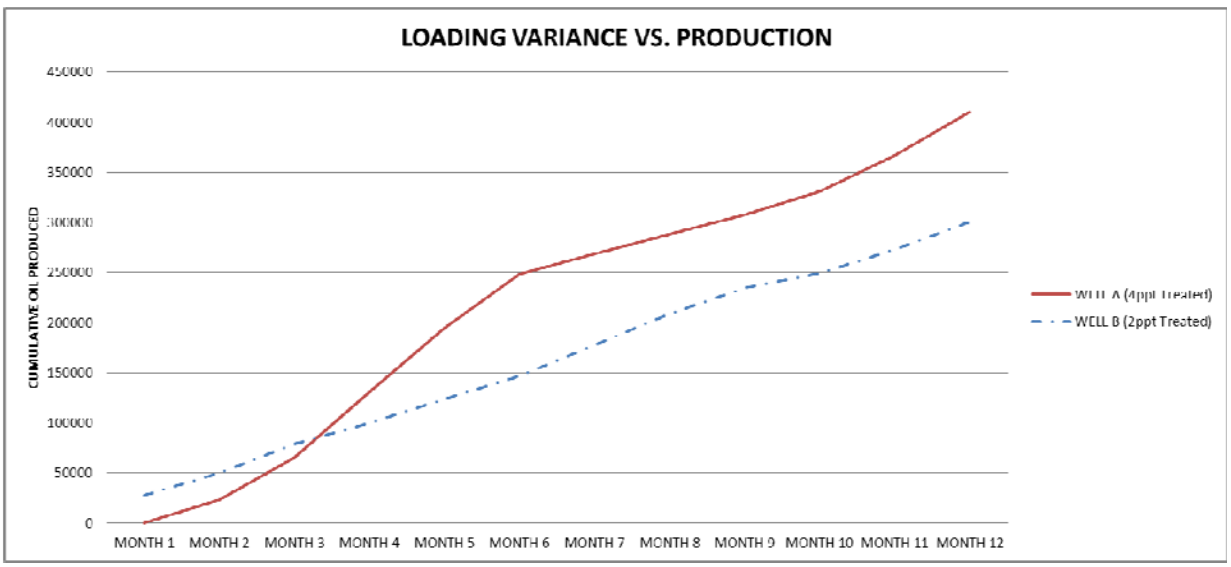

Figure 7 - 4 ppt Solid Inhibitor Loading vs. 2 ppt Solid Inhibitor Loading: Cumulative Production

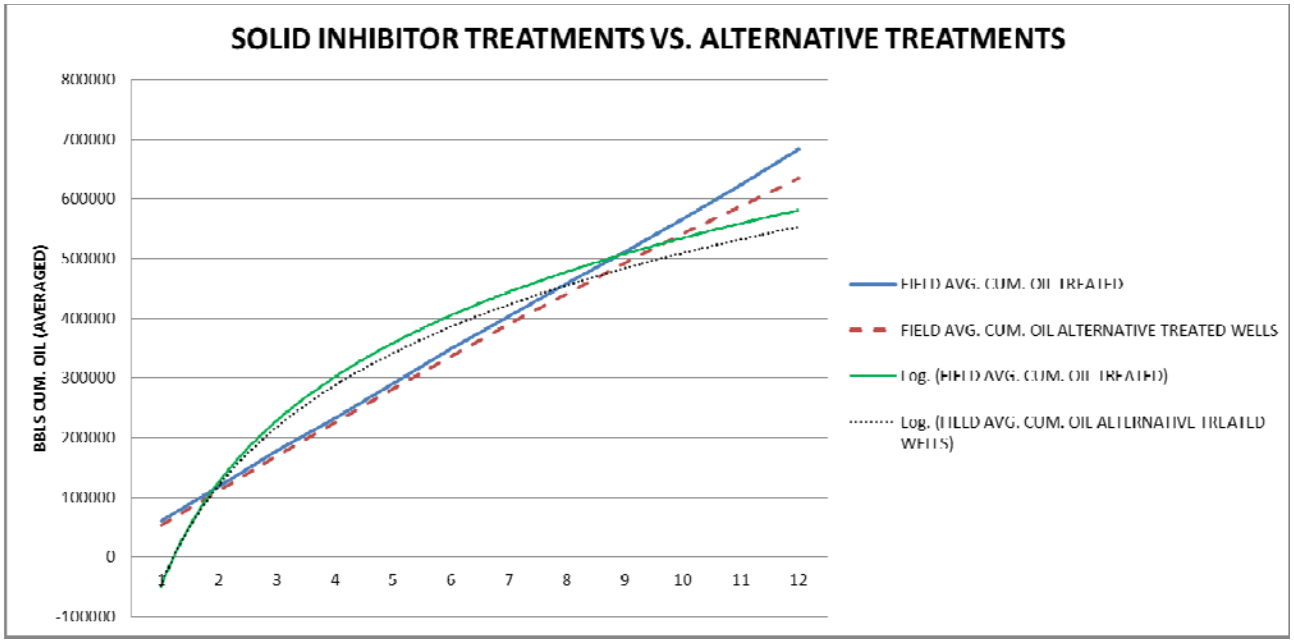

Figure 8 – Impregnated Solid Scale Inhibitor Treatments vs. Alternative Treatments: Averaged Cumulative Oil Field Production

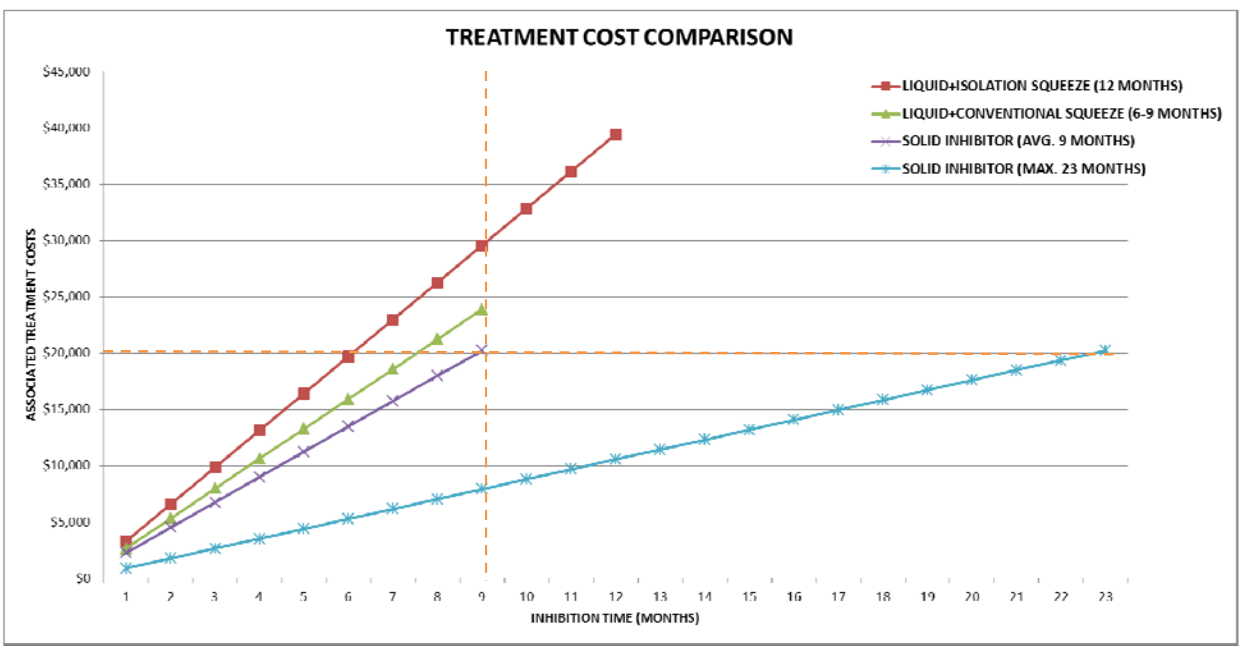

Figure 9 – Treatment Cost Comparisons

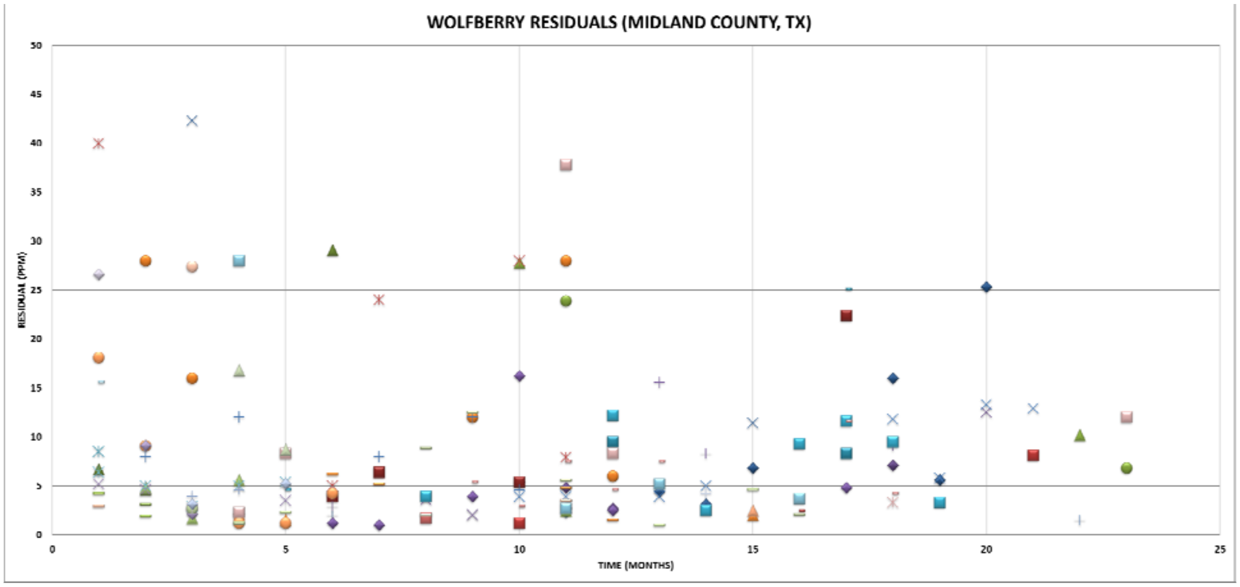

Figure 10 – Field 2 Residual Data: 64 Treated Wells

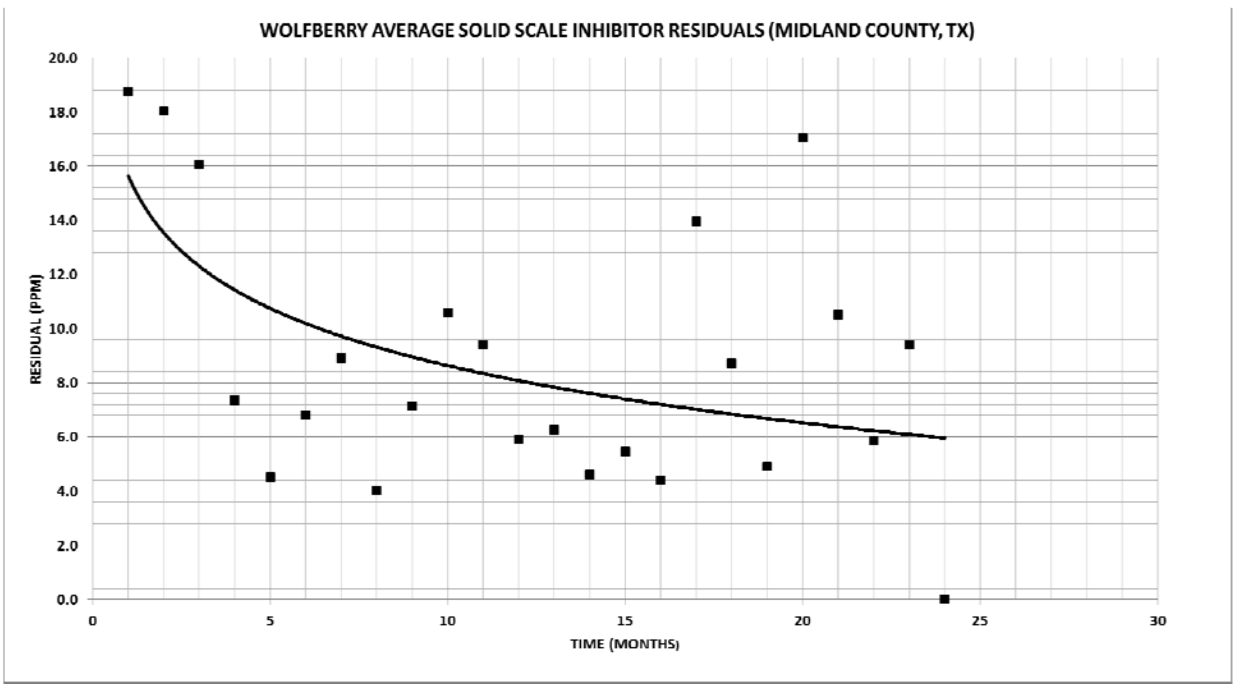

Figure 11 – Average Residual Data: 64 Treated Wells

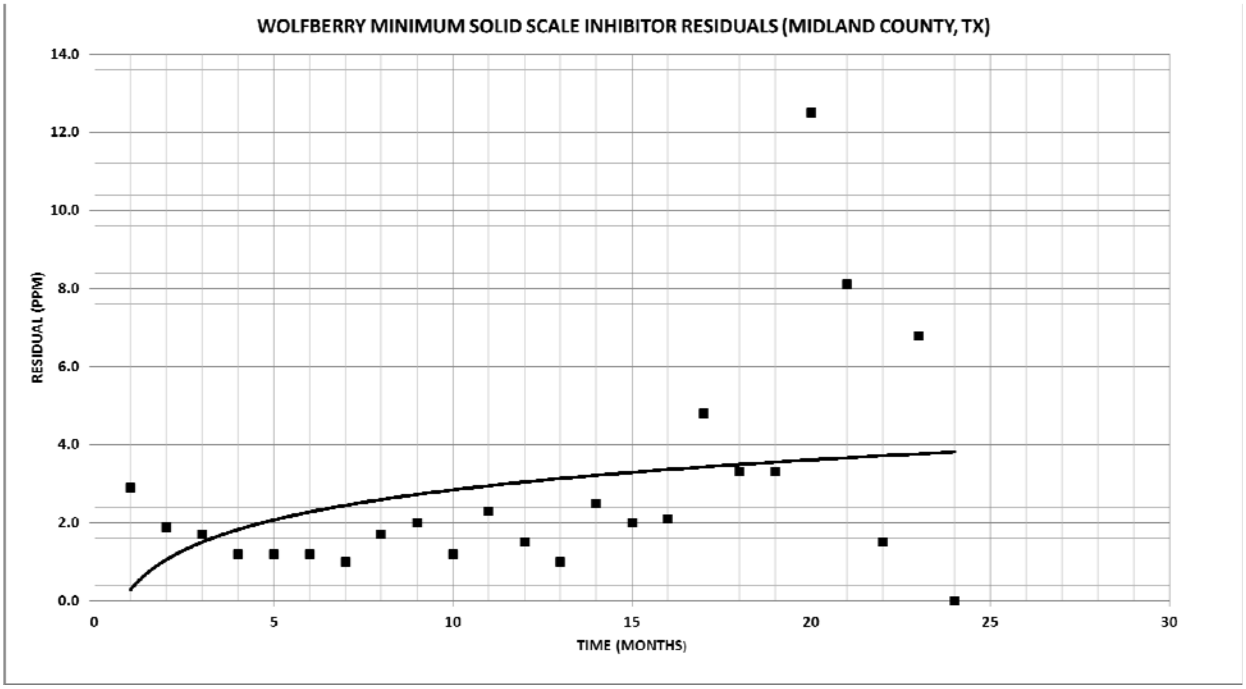

Figure 12 – Minimum Residual Data: 64 Treated Wells

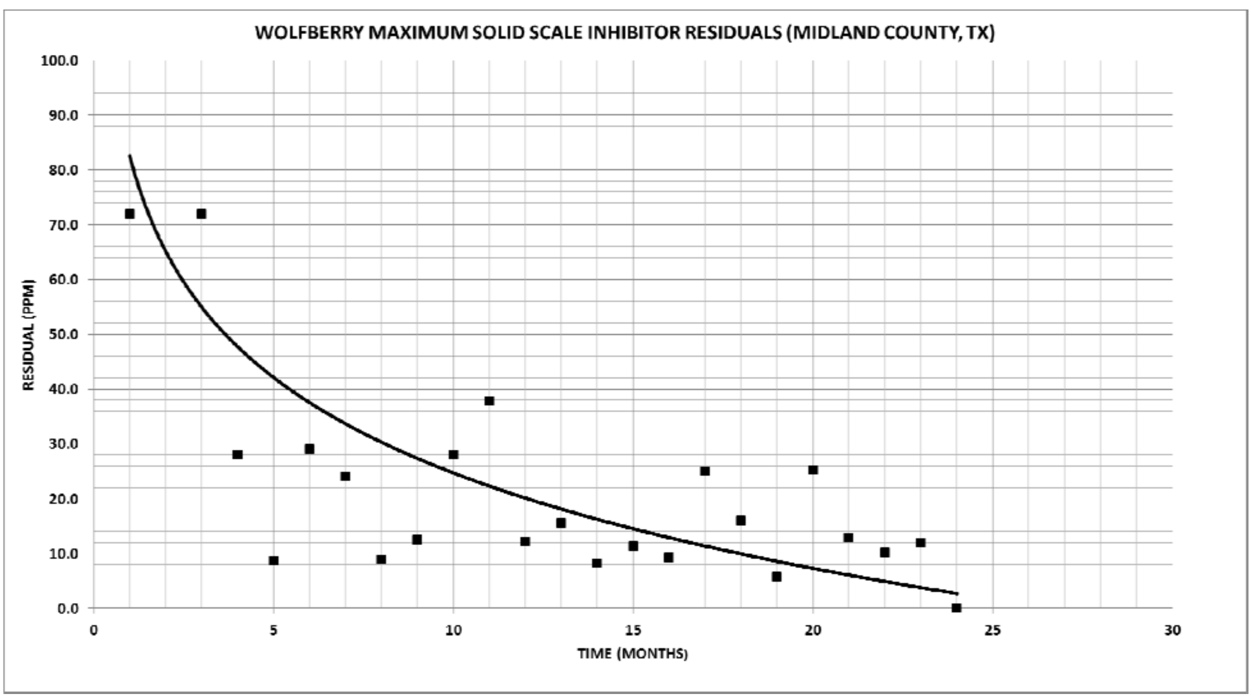

Figure 13 – Maximum Residual Data: 64 Treated Wells