Monitoring of Damage in Gas Storage Wells

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1 Executive Summary

1.1 Background

The underground gas storage (UGS) industry uses over 400 reservoirs and 15,000 wells to store and withdraw natural gas and is thus a significant contributor to gas supply in the United States[1]. Previous work suggests that many gas storage wells show a loss of deliverability each year due to numerous damage mechanisms[2]. It is estimated that tens of millions of dollars are spent each year to recover or replace this lost deliverability[3]. These expenditures include both drilling new wells and stimulating/remediating existing wells.

Prior GRI studies (GRI-93/0001 and GRI-98/0197) have been aimed at reviewing completion and deliverability enhancement techniques used in the storage industry, identifying specific damage mechanisms present in storage reservoirs, and establishing procedures for damage mechanism identification.

To date, there has not been a comprehensive, quantitative assessment of the effectiveness and longevity of the various stimulation treatments employed in the UGS industry. The primary aim of this study is to addresses this specific question. In addition, this study also establishes techniques to conduct cost-benefit analyses on deliverability enhancement treatments, quantitatively determine the impact of operational changes on deliverability, and conduct comprehensive damage surveillance less expensively and therefore more frequently.

1.2 Objectives

There are five major objectives of this new study:

1) Monitor the long-term performance of treated natural gas storage wells and document treatment results (i.e., the effectiveness and longevity of the treatments);

2) Develop tools to perform cost/benefit analyses and optimize treatment selection for damaged storage wells;

3) Develop tools to monitor the long-term performance of natural gas storage fields to determine the effects of changing operating conditions on deliverability;

4) Develop and field test novel surveillance techniques to evaluate damage in natural gas storage wells more frequently and less expensively than traditional methods;

5) Develop guidelines and recommendations for future gas storage R&D.

1.3 Summaries

1.3.1 Objective 1: Monitor Treated Storage Wells & Document Treatment Results

1.3.1.1 Introduction

In prior GRI studies, similar issues to those addressed in our study have been examined to a very limited extent. Specifically, in a prior GRI investigation by Mauer et. al., (GRI-93/0001) Mauer conducted a broad survey of operators to determine deliverability decline rates, the types of deliverability enhancement treatments being employed in the UGS industry, and the successfulness of these techniques. All of this work was based solely on the qualitative opinions/estimates of the operators polled. No quantitative, well-specific data was collected to verify these estimates.

The primary aim of our Objective 1 is to perform a comprehensive, quantitative assessment of the effectiveness and longevity of the various stimulation treatments employed in the UGS industry. In the process of achieving this objective, we also gained considerable insight into two related areas important to UGS operators – post-stimulation cleanup effects and post stimulation deliverability decline rates.

This study represents the most comprehensive quantitative assessment to date of stimulation treatments employed, cleanup times experienced, and post-stimulation decline rates observed in the Underground Gas Storage Industry. The study involved 7 operators and 23 reservoirs. Data was collected, input, and reviewed for 381 stimulations in 365 wells. Deliverability data was input for 159 stimulations in 155 wells with sufficient data for inclusion in the study.

1.3.1.2 Conclusions

A methodology was developed to quantify a storage well's deliverability over time using standard backpressure test data. This methodology involves determination of the well's deliverability indicator, DI, (defined as the deliverability potential at a specified delta-pressure squared value that is representative of actual operating conditions) before and after a stimulation treatment.

By examining the changes in the DI versus time before and after a stimulation treatment in a specific well, various aspects of the stimulations' success/failure can be quantified, including the effectiveness of the treatment (change in deliverability levels before and after stimulation), the longevity of treatment (duration of deliverability improvements), the resulting incremental potential volume (PV) of storage gas available over the life of the stimulation, the cleanup time required to achieve peak rates, and the post-stimulation decline rates. Various UGS operators supplied the backpressure data used in these calculations and analyses.

The UGS industry relies on a small number of stimulation types to maintain deliverability. Based on the sample population of the study, the gas storage industry employs approximately 1 dozen different stimulation techniques. Overall, 4 stimulation techniques are used over 75% of the time.

It appears that operators most frequently employ the remedial treatments that their internal studies show to most effectively increase the post-stimulation deliverability. However, as observed in a previous GRI study[4], this does not necessarily represent the optimal approach, as it fails to consider the longevity of the treatment. Consequently, the concept of incremental potential volume (PV) was developed as part of this study in an effort to characterize both treatment effectiveness and longevity in one value.

A review of the PV values over a 7-1/2 yr time fame (PV75) suggest that operators do a very good job of selecting treatments that both increase the deliverability and have significant longevity in carbonate reservoirs. In sandstones, operators are less successful at selecting treatments that both increase the deliverability and have significant longevity.

There is an opportunity to accelerate the benefits of many stimulation treatments by eliminating or reducing cleanup effects. Cleanup effects were observed in about ½ of all stimulations and, on average, defer the full benefits of the stimulation treatment by over one year.

Evidence suggests that remediation treatments currently employed in the UGS industry successfully reduce or remove damage, but often do not remove the underlying cause of that damage. This is supported by the observation that the post-stimulation DI values decline at an average rate of 17% per year in about ½ of the stimulation treatments studied. It is evident that damage continues to be re-deposited in most wells.

Although there was sufficient data to examine the impact of several parameters on stimulation results for numerous treatment types, there is considerable opportunity for improvement. Currently, many operators record only the most basic of stimulation details, (e.g., total volumes), but rarely keep track of such items as fluid additives, treatment rates and pressures, perforation gun sizes and types, charge types and sizes, etc. Simply recording such details for future treatments will allow determination of the extent that such items impact the success of stimulation treatments.

Our study results for the stimulation effectiveness show the following.

Acidizing is more effective and lasts longer in carbonates than sandstones. In carbonates increasing HCl acid concentration from 15% to 28% HCl resulted in higher effectiveness, but much lower longevity. In sandstones, however, increasing the acid concentration from 7.5% to 15% HCl resulted in higher effectiveness and higher longevity. Examination of the PV75 values suggests that increasing acid concentration in carbonates significantly decreases the 7-1/2 year potential volume, but increasing acid concentration from 7.5% to 15% in sandstones slightly increased the 7-1/2 year potential volume. A review of post-decline rates indicates that in all cases except the 15% acid in carbonates (which has a small post-stimulation decline rate) the post-stimulation decline rates are in excess of 20%.

When acidizing in sandstones, the effectiveness increases with decreasing acid volume for small acid volumes (<750 Bbls), and increases with decreasing porosity. Aslo, in wells with low pre-stimulation rates (<15 MMscf/D) in sandstone reservoirs, the effectiveness increases modestly with decreasing pre-stimulation rate.

When acidizing in carbonates, the effectiveness does not appear to be imparted by acid volume, but increases with decreasing thickness. Also, for wells with high pre-stimulation rates (>10 MMscf/D) in carbonate reservoirs, the effectiveness increases with decreasing pre-stimulation rate.

Although fracturing is more effective in sandstones, it lasts longer in carbonates. A comparison of the 7-1/2 year potential volume suggests that fracturing is more successful in carbonates than sandstones, largely due to a much higher post-stimulation decline rate in sandstone reservoirs. The data also suggest that more proppant and less total fluid volume *may* yield better results when fracturing sandstones.

For re-fracturing treatments, foam re-fracturing are slightly more effective than delta re-fracturing, but the benefits of delta fracturing last longer than those of foam fracturing. PV75 values indicate that, considering both effectiveness and longevity together, Delta fracs lead to more successful fractures in sandstone wells. As was found with (initial) fracturing, more proppant is generally better. However, unlike (initial) fracturing, increased total fluid volumes lead to better re-fracs.

Very limited perforating data suggests that treatment effectiveness increases with decreasing reservoir thickness and that six or eight shots per foot *may* outperform 4 shots per foot. Little more can be said regarding perforating treatments, since little detailed data is available for perforating treatments.

For the combination acidizing, hydroblasting, and perforating treatments, higher acid volumes, higher shot densities larger number of perforations, and larger perforation diameters improve treatment results.

The combination acidizing and perforating treatments are more effective in cased hole completions, but do not last as long as in open hole completions. Examination of the average PV75 values indicates a large negative value for cased hole completion, and a small positive value in open hole complations, largely due to a much higher post-stimulation decline rate in the cased hole completions.

In sandstones, the combination acidizing and perforating treatments using an HCl-HF acid system are slightly more effective than HCl acid systems and last significantly longer. Examination of 7-1/2 year potential volume data indicates a positive value for the HCl-HF system, but a negative value for the HCl system. Also, the effectiveness increases with increasing acid volume, but the longevity decreases with increasing acid volume. Examination of 7-1/2 year potential volume data indicates that PV75 values decrease with increasing acid volume. The effectiveness, longevity, and PV75 values all decrease with increasing perforation interval length and total number of perforations.

In carbonates, there is considerably less information available for analysis, but it appears that effectiveness, longevity, and PV75 values all decrease with increased perforation interval length.

1.3.1.3 Recommendations

Evidence derived from this study suggests that remediation treatments currently employed in UGS industry treat the symptoms of damage, but often do not remove the underlying cause of that damage. Therefore, we recommend that future R&D work in the UGS industry include efforts aimed at increasing our understanding of the process of damage formation and preventative remedies.

To evaluate the effectiveness of any future deliverability maintenance efforts, an appropriate methodology for tracking DI levels before and after preventative measures or remedial treatments must be available, and the data necessary for effective deployment of this methodology must exist. In this study, we present a new method to collect these data both frequently and cost-effectively. Therefore, we recommend UGS operators continue to collect the necessary deliverability and stimulation data, and that GTI maintain/update the database with newly collected data as it becomes available from member companies to periodically update the results of this study.

The paucity of detailed stimulation data available to determine the impact of specific stimulation process parameters on the success of stimulations has prevented GTI and operators from reaping the maximum possible benefits from this study. Therefore, we recommend that individual UGS place increased emphasis on recording three types of data critical to effective deliverability maintenance:

- Detailed stimulation information should be recorded when treating wells in the future. The specific types of information we recommend be collected are summarized by the tables included in the study database.
- At a minimum, backpressure test data should be collected once or twice annually to track the deliverability history for individual storage wells (multi-rate pressure transient testing would be much better).
- Detailed information related to operational changes needs to be tracked by operators, and made available to storage engineers for analysis.

There is an opportunity to accelerate the deliverability improvements realized by currently employed stimulation treatments by reducing or eliminating the cleanup time required. Therefore, we recommend that future R&D work address cleanup related issues. Several areas should be explored, including 1) reducing the fluid used in killing, working over, and stimulating wells, and 2) evaluating alternate stimulation fluids and/or additives that minimize the time required for removal of water from the well.

Finally, this study suggests that there is a relatively small number of stimulation techniques typically employed by the UGS industry. While we would like to believe this is because the UGS industry has identified the most effective remedial techniques what work, the prevalence of cleanup effects and post-stimulation declines in DI values suggests this conclusion is incorrect. Therefore, we recommend that future R&D work include some facet aimed at exploring new deliverablity enhancement techniques. Potential new techniques should require minimum fluids and/or ensure effective removal of required fluids to minimize impacts related to cleanup. New techniques should also be designed with the goal of preventing the reoccurrence of damage over time.

1.3.2 Objective 2: Perform Cost Benefit Analysis

1.3.2.1 Introduction

Originally, our second objective was to calculate and compare some cost-benefit benchmarking parameter (e.g., amount of increase in the DI per stimulation dollar spent to achieve this deliverability increase) to identify the most cost-effective stimulation treatment. To accomplish this, it is necessary to assign some discrete value to the incremental deliverability and/or incremental working gas volumes derived from stimulation. During the study, it became quite evident that the value of such increases to individual operators was widely divergent. Consequently, it was decided that a "generic" tool would be developed that allows individual operators to supply input values/parameters specific to their operations.

1.3.2.2 Conclusions

All of the tools necessary to accomplish this objective have been developed and tested using Microsoft EXCEL™. Input screens have been developed that allow individual operators to input general project data, cost data, and estimates of the deliverability increase expected from a specific treatment (which can be estimated using the results presented in this report, or be calculated using internal company data).

Using the input data supplied by the operator, cash flow streams are generated and several "traditional" economic indicators are calculated, including undiscounted profit, present value profit, rate of return, and discounted PI ratio. In addition, several other economic indicators and benchmarks typically used within the gas storage industry are also calculated, including percent increase in deliverability per dollar spent, cost per incremental Mscf/D of deliverability, and others.

1.3.2.3 Recommendations

Given that the value of deliverability increases to individual operators is widely divergent, the cost of the same stimulation type may fluctuate from among different operators. This occurs due to differing field characteristics, well completions, proximity to service companies, etc. Thus, potential exploitation of additional deliverability varies among operators due to physical and market constraints. We believe that development a generic tool for cost/benefit analysis is prudent. Therefore, we recommend that the tools developed in this study be made available to all UGS operators so they can optimize their remediation dollars by performing cost benefit analyses.

1.3.3 Objective 3: Develop Methodology to Determine Effects of Operating Conditions on Deliverability Potential

1.3.3.1 Introduction

Mauer reports that almost 40% of the operators interviewed as part of a previous GRI study attributed deliverability decline to operational activities[5]. Several other causes of deliverability decline are cited in this report, but not quantified. Clearly, the industry believes that day to day operations impact the deliverabiltiy potential of storage fields.

We are not aware of any previous studies that establish either a qualitative or quantitative relationship between changes in operations and changes in deliverability potential. The goal of this objective was to establish a methodology to quantitatively link changes in deliverability to changes in operations.

1.3.3.2 Conclusions

There are two types of data available to evaluate damage as it relates to changes in operating conditions: 1) periodic backpressure data, and 2) electronic flow measurement (EFM) data. Quantifying the changes in deliverability due to operational changes in individual wells using manually collected backpressure data employs the same methodology developed to meet the first objective of this study. The DI values before and after implementing the operational change are used to determine effectiveness and longevity of the change.

When using EFM data collected at high frequencies (e.g., hourly data), the logistics of filtering and manipulating such large amounts of data become unwieldy. Therefore, a methodology has been successfully developed to process these large amounts of data in order to relate changes in deliverability potential to operational changes.

This methodology has been demonstrated to qualitatively relate changes in deliverability to operational changes. Unfortunately, lack of sufficient, and/or sufficiently detailed operational histories hindered efforts to quantify changes in deliverability resulting from operational changes.

1.3.3.3 Recommendations

Operational changes undoubtedly affect deliverability. Therefore, it would be prudent to continue GTI's efforts to quantitatively relate changes in deliverabilty to changes in operations. We recommend that GTI identify operators planning operational changes in the near future, and establish a cooperative effort to collect the data necessary to evaluate these changes using tools developed in this study.

1.3.4 Objective 4: Novel Surveillance Technique

1.3.4.1 Introduction

Traditionally, damage surveillance techniques in the UGS industry consist of running backpressure tests in wells every 1-5 years and comparing DI values to infer if damage has occurred since the previous test. In the most ideal cases, operators may run the preferred multi-rate pressure transient tests on select wells on a more frequent basis.

Backpressure testing requires the operator to collect surface pressure information while flowing the well at 3 or 4 different rates. It is an inexpensive procedure. However, backpressure testing alone provides only an indication of the deliverability potential at a given point in time. It cannot provide reliable estimates of Mechanical skin damage over time, nor can you reliably quantify the non-darcy flow coefficient (D) from such testing. Multi-rate pressure transient testing typically involves downhole gauges and require data collection at much more frequent intervals. Flowing the well at 3 or 4 rates is also required, but the added requirements of frequent data collection and bottom-hole pressure measurement makes this type of test much more expensive.

These types of surveillance programs, at best, identify the change in damage levels over a 1-5 year timeframe. The path of damage development between tests separated by 1-5 years is completely unknown. Consequently, it is impossible to determine if and how much the injection operations, withdrawal operations, and/or reversal operations (changing from injection to withdrawal or vice-versa) contribute to the development of skin damage.

Determining the specific type(s) of operations that induce damage would be extremely beneficial, as efforts to identify the specific source of damage would be much more focused if this was known. However, measurement of mechanical skin damage numerous times within a single injection or withdrawal cycle is virtually never done. This is primarily due to the expense of running tests that will yield mechanical skin values.

The fourth objective of the study was to develop and field test novel surveillance techniques to overcome this limitation. Specifically, we wanted to develop a technique to evaluate damage in natural gas storage wells much more frequently and much less expensively than traditional methods.

1.3.4.2 Conclusions

Three novel surveillance techniques were identified for review, which we will refer to as 1) The Lou Glen method, 2) the Minute-Rise Deconvolution method, and (3) the Sawyer-Brown method.

The Lou Glenn method uses daily EFM data to make daily estimates of skin damage, and was developed at Sandia National Laboratory. Mr. Glenn *et al.*, developed a method to provide daily estimates of shut-in pressure and flow resistance due to skin effects in natural gas storage wells.[6]

The Lou Glenn method is somewhat limited in its application, as it requires continuous wellhead measurement. Moreover, the process requires a number of assumptions that would likely be violated in typical gas storage reservoirs. Therefore no further development of this process was pursued.

The minute-rise deconvolution method uses calculated afterflow rates estimated from shut-in surface pressure data to correct early time shut-in pressures for wellbore storage effects. Thus, pressure data collected during short shut-in periods are analyzable as a pressure transient test.

The minute-rise deconvolution method was tested using simulated data with favorable results, suggesting that the underlying theory is valid. Although analyses of the first two datasets from wells gave reasonably accurate results, we were unable to consistently achieve satisfactory results using additional well data. Although the authors believe this method may prove viable with additional study, no additional work was conducted on this method due to the limited resources available to conduct further investigation and the success of our third analysis method.

The Sawyer-Brown Method represents a unique application of a method developed by Jones[7]. This method requires one comprehensive, multi-rate, pressure transient test analysis be performed, and enables the operator to estimate mechanical skin from subsequently run deliverability tests.

The Sawyer-Brown method gives reasonably consistent results over a wide range of reservoir permeabilities. A comparison of the mechanical skin values calculated using this method with the mechanical skin values determined from multi-rate pressure transient tests showed excellent agreement.

A simple Microsoft EXCEL™ spreadsheet was developed to allow storage operators to easily implement this new surveillance technique.

1.3.4.3 Recommendations

We recommend UGS operators consider the Sawyer-Brown method as part of a comprehensive deliverability monitoring program. Widespread implementation of this new technique should be considered in an effort to identify the path of damage development, which may provide considerable insight into the source of damage in storage wells.

We recommend additional work be performed on the minute rise deconvolution technique. Although successful demonstration of this technique proved to be beyond the financial scope of this project, we believe the method bears further consideration. The primary advantage of successful implementation of the minute rise deconvolution technique over the Sawyer-Brown method would be that multi-rate testing would be economically feasible, making it possible to directly measure the non-darcy flow coefficient. Implementation of the minute rise deconvolution method in this study treated the wellbore as a homogeneous tank. Development of a more sophisticated mathematical model would likely improve the model, and should be considered.

1.3.5 Objective 5: Develop R&D Guidelines for Gas Storage Industry

1.3.5.1 Introduction

The fifth objective of this study was to provide the UGS industry with guidelines for future R&D efforts. These guidelines are based on numerous broad observations made during the course of this study.

1.3.5.2 Conclusions

Several facts related to future UGS R&D issues became apparent as this study progressed. First, it appears that we do not fully understand the underlying causes of damage and the process of damage formation. Second, there are significant improvement opportunities associated with collection of additional and additionally detailed data related to field operation and well stimulation Third, we seem to employ a somewhat limited arsenal of deliverability enhancement tools. Fourth, a significant number of the remediation techniques currently employed are not optimal, as evidenced by the presence of cleanup effects and significant decline rates in post-stimulation DI values. Fifth, the tools developed and conclusions arrived at in this study warrant continuation to further improve our understanding of how to optimally remediate wells and operate storage fields.

These five observations shape our perspective of future R&D work in the UGS industy.

1.3.5.3 Recommendations

Future R&D efforts need to be heavily focused on increasing the industry's understanding of the underlying causes of damage and the process of damage formation. Preventing damage may be more cost-effective than removing it.

We also believe that there are significant opportunities associated with collection of additional and additionally detailed data related to storage field operation and well stimulation. One specific area of R&D might include advances in wellhead electronic flow measurement, including development of less expensive hardware and software, development of hardware that is less intrusive and more easily retrofitted to existing wellhead facilities, and hardware that can handle multi-phase flow (especially 2-phase gas-water flow), and injection/withdrawal scenarios over large rate variations.

We believe it would be prudent to pursue R&D efforts aimed at exploring additional means of stimulation and remediation. The options may be limited because the industry has identified the techniques that work. However, the fact that cleanup effects are frequently observed and post-stimulation declines in DI values have not been eliminated, suggesting that this conclusion is probably incorrect.

It would be prudent to continue GTI's efforts to quantitatively relate changes in deliverabilty to changes in operations. The methodology developed to accomplish this has been demonstrated to qualitatively relate changes in deliverability to operational changes. We simply need to collect sufficiently detailed operational histories to quantitatively tie operational changes to deliverability changes. Therefore, we recommend that GTI identify operators planning operational changes in the near future, and establish a cooperative effort to collect the data necessary to evaluate these changes using tools developed in this study.

We recommend additional work be performed on the minute rise deconvolution technique. The primary advantage of successful implementation of the minute rise deconvolution technique over the Sawyer-Brown method would be that multi-rate testing would be economically feasible, making it possible to directly measure the non-darcy flow coefficient. Implementation of the minute rise deconvolution method in this study treated the wellbore as a homogeneous tank. Development of a more sophisticated mathematical model would likely improve the model, and should be considered.

2 Summaries

2.1 Objective 1: Monitor Treated Storage Wells & Document Treatment Results

2.1.1 Background

2.1.1.1 Previous Work

Previous work suggests that many gas storage wells show a loss of deliverability each year due to numerous damage mechanisms. It is estimated that tens of millions of dollars are spent each year to recover or replace this lost deliverability. These expenditures include both drilling new wells and stimulating/remediating existing wells.

To date, there has not been a comprehensive, quantitative assessment of the effectiveness and longevity of the various stimulation treatments employed in the UGS industry. In a prior GRI study by Mauer et. al., (GRI-93/0001) Mauer conducted a broad survey of operators to determine deliverability decline rates, the types of deliverability enhancement treatments being employed in the UGS industry, and the successfulness of these techniques. The approach taken was to conduct interviews with UGS operators to determine which deliverability enhancement methods were being used, estimate the cost and effectiveness of each method and perform a cost-benefit analysis to determine the optimum treatment options.

It is very important to note that deliverability enhancement data used in the Mauer study was very qualitative in nature and subjectively based on operators' experience. Operators' were admittedly concerned about their ability to accurately assess the effectiveness of deliverability enhancement techniques[8]. Information derived from this study suggests that this was a very valid concern.

This is evidenced by the fact that average deliverability increases predicted in the Mauer study for fracturing and acidizing treatments were 2 and 14 times lower, respectively, than averages calculated in this study (comparisons for other treatments were not possible due to differences in categorization of treatment types). Overall, deliverability increases for all treatment categories estimated by Mauer ranged from 10% (blowing and washing) to 175% (fracturing), with all but fracturing being lower than 50%. Deliverability increases for all treatment categories estimated in this study ranged from 15% (unknown) to 550% (combination acid/hydroblast/perforate), with all but the unknown stimulation types being over 50%.

In retrospect, the need to quantitatively assess the successfulness of various stimulation treatments currently employed by the UGS industry using hard data is quite obvious.

The primary aim of our Objective 1 is to perform a comprehensive, quantitative assessment of the effectiveness and longevity of the various stimulation treatments employed in the UGS industry. In the process of achieving this objective, we also gained considerable insight into two related areas important to UGS operators – post-stimulation cleanup effects and post stimulation deliverability decline rates.

Achievement of our first objective has resulted in the most comprehensive quantitative assessment to date of stimulation treatments employed, cleanup times experienced, and post-stimulation decline rates observed in the Underground Gas Storage Industry. The study involved 7 operators and 23 reservoirs. Data was collected, input, and reviewed for 381 stimulations in 365 wells. Deliverability data was input for 159 stimulations in 155 wells with sufficient data for inclusion in the study.

2.1.1.2 Methodology

To accomplish our objective, we developed a methodology to quantify a storage well's deliverability over time using standard backpressure test data. This methodology requires determination of the well's deliverability indicator, DI, (defined as the deliverability potential at a specified delta-pressure squared value that is representative of actual operating conditions) at least once before stimulation treatments and several times after a stimulation treatment. This was accomplished by using backpressure curves and/or the associated equations supplied by the operators to determine the DI at an appropriate pressure squared value appropriate for the field.

By examining the changes in the DI versus time before and after a stimulation treatment in a specific well, various aspects of the stimulations' success/failure can be quantified. Specifically, the methodology developed in this study was employed to quantify four specific values. These values are graphically presented in **Figure 2-1** below.

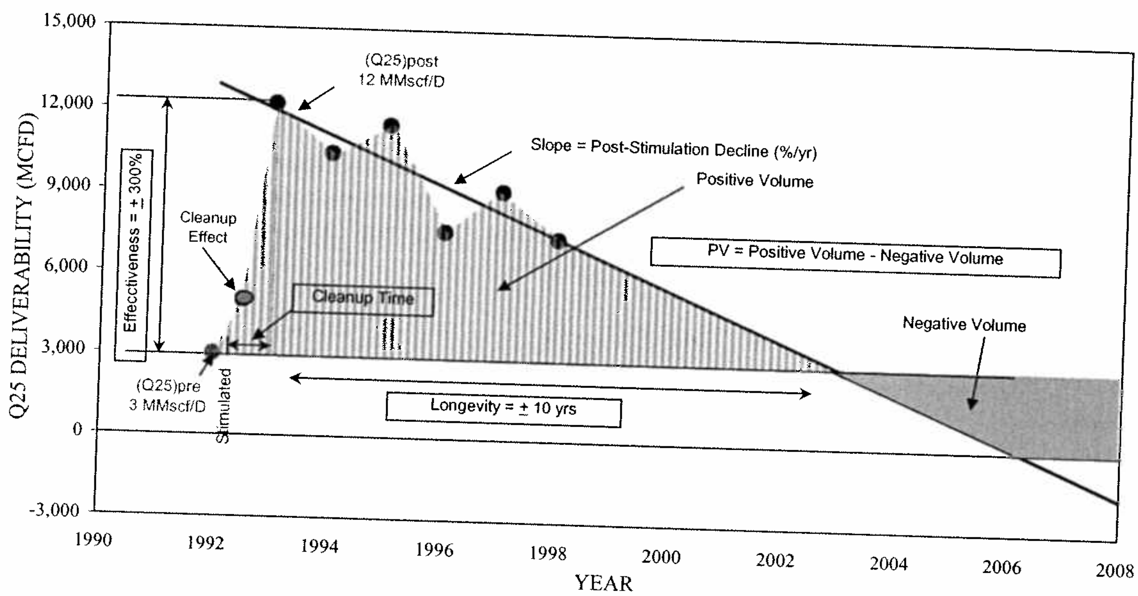


Figure 2-1: Graphical Summary of Calculation Methodology

The *effectiveness* of the treatment represents a quantitative indication of the increase in deliverability levels as a result of stimulating the well. It is the percentage increase in the pre-stimulation DI value measured after cleanup effects are over (if any cleanup effects are experienced).

The *longevity* of the stimulation treatment represents the length of time the DI indicator remains above pre-stimulation levels. This parameter is determined by calculating the post-stimulation decline rate, and extrapolating this decline to determine how long it takes for the DI value to return to the pre-stimulation level. The decline is assumed to be linear with time.

In an effort to simultaneously consider the amount of deliverability improvement as well as the duration of that improvement, we defined the concept of incremental *potential volume* (PV). The incremental *potential volume* (PV) represents the incremental volume of gas available as a result of increased deliverability potential over the life of the stimulation. This value is calculated by integrating the delta-DI vs time curve, beginning at the stimulation date for a specified duration. If the DI value drops below the pre-stimulation DI value during the specified duration (i.e., if the longevity is less than the duration specified), then negative volumes are calculated and used in the integration. In this way, any damaging effects of the stimulation can be properly accounted for.

The *cleanup time* represents the time required to realize the maximum benefits of the treatment. In many cases, it will take several months for the post-stimulation DI value to reach its maximum after the well is treated. This value represents the amount of time the full benefits of a treatment are deferred.

The *post-stimulation decline* rate is the rate at which the DI deteriorates after treatment of the well. This value is calculated by performing a linear regression analysis on post-stimulation DI values, and represents the simple annual decline rate in the wells deliverability potential.

Operators supplied all deliverability and stimulation data used in our analyses. The form of the deliverability data varied considerably, with some operators supplying hard copies of backpressure curves and others supplying more comprehensive databases that included raw data, backpressure curves, backpressure equation parameters, calculated DI values, and historical plots of DI versus time. Stimulation data also varied considerably, from a concise description of the stimulation (e.g., "October 1998 - acidized well ") to daily workover reports that included in-depth stimulation details.

Quality control measures were enforced on both the deliverability and stimulation data. Wells with insufficient or extremely erratic DI histories were excluded, as were wells with backpressure data that clearly violated theoretical limits (e.g., if the backpressure equation exponent, n, was less than 0.5 and/or greater than 1.0). Wells with insufficient, conflicting, or ambiguous stimulation data were also excluded.

A plot of the DI history was then constructed with the stimulation date indicated on the plot. The DI values immediately after the stimulation were scrutinized to determine if there was a cleanup period. If so, the date of the first post-stimulation DI value free of cleanup effects was noted and was input into the database. This point was considered the first "valid" post-stimulation DI value.

A Microsoft ACCESS™ Database was designed to store the study data, perform the necessary calculations, and store the results. Numerous queries were developed to retrieve and summarize study results. The database was specifically designed to allow GTI and/or operators to input new data and update study results. Additionally, since database calculations have been automated, any GTI member company can use the database to conduct independent studies in their own field(s).

2.1.2 Conclusions

2.1.2.1 Scope of study

This study represents the most comprehensive quantitative assessment to date of stimulation treatments employed, cleanup times experienced, and post-stimulation decline rates observed in the Underground Gas Storage Industry. The study involved 7 operators and 23 reservoirs. Data was collected, input, and reviewed for 381 stimulations in 365 wells. Deliverability data was input into the database for 159 stimulations in 155 wells that had sufficient data for inclusion in the study. Individual reservoir properties of UGS reservoirs span a range of values. There was sufficient data to calculate 150 values of effectiveness, 77 values of cleanup time, 88 values of longevity, 95 values of post-stimulation decline, 88 values of potential volume.

As shown in **Figure 2-2**, for every property for which values are widely reported to AGA, over 2/3 of the range is represented in the study population (permeability and maximum deliverability are frequently not reported to AGA)

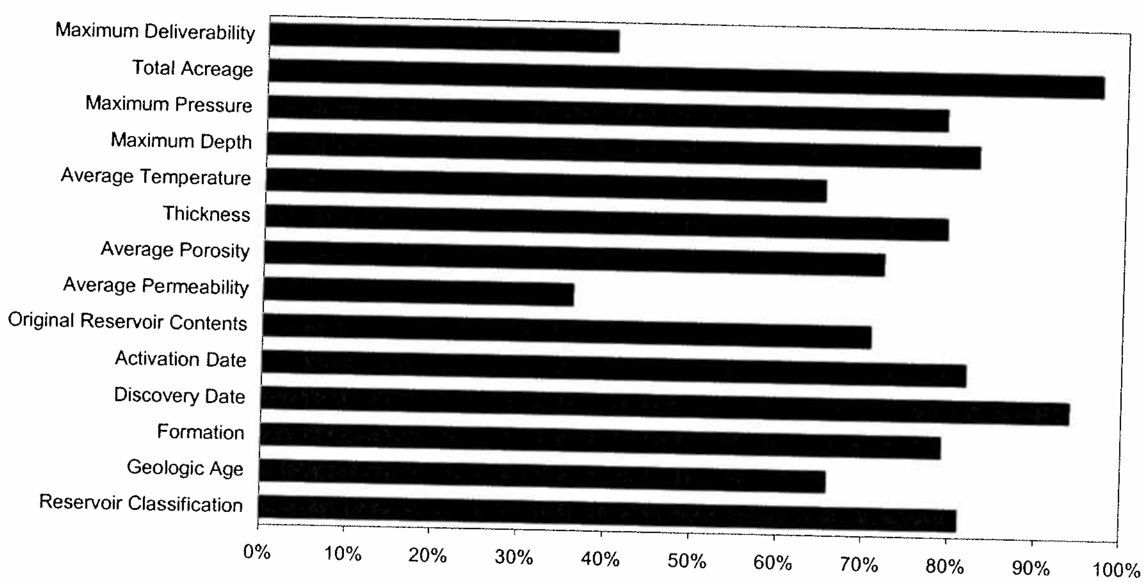


Figure 2-2: Percentage of UGS Fields Represented in Study by Field Parameter

Although additional data was available for one specific operator, not all of it was included to avoid inappropriately skewing results in favor of a single operator. The distribution of stimulation frequencies was not significantly affected by these exclusions.

2.1.2.2 Frequencies of Stimulation Types

The UGS industry relies a small number of stimulation types to maintain deliverability. Based on the sample population of the study, the gas storage industry employs approximately 1 dozen different stimulation techniques (**Figure 2-3**). Overall, 4 stimulation techniques are used over 75% of the time: acidizing, fracturing, combination acid & hydroblast & perforate , and re-fracturing.

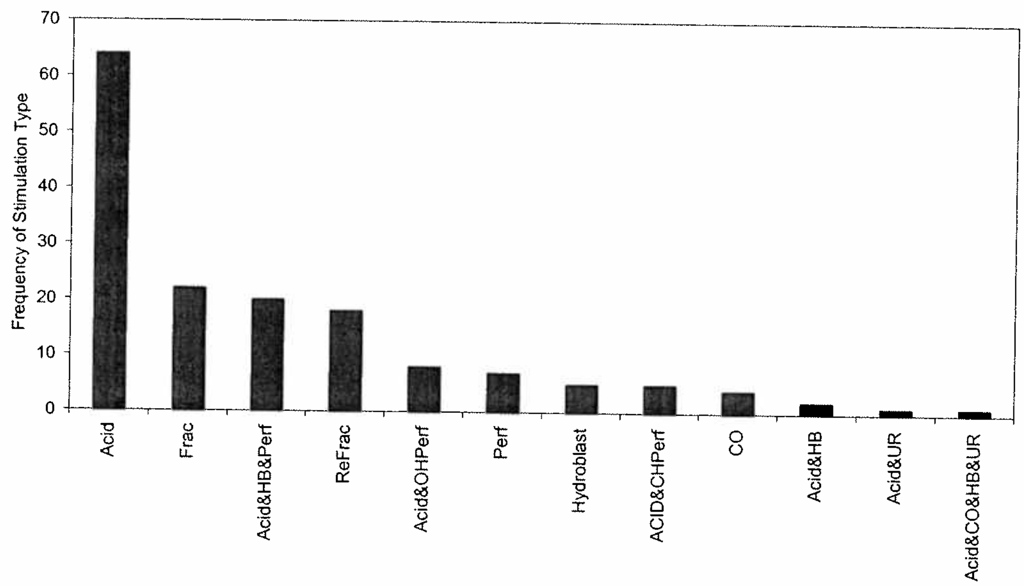


Figure 2-3: Frequency of Stimulation Types

In carbonates, acidizing is implemented over 70% of the time, and fracturing is used over 15% of the time. In sandstones, a combination acidizing, hydroblasting, perforating is used 22% of the time, refracturing is implemented 20% of the time, and acidizing is performed 18% of the time (**Figure 2-4**).

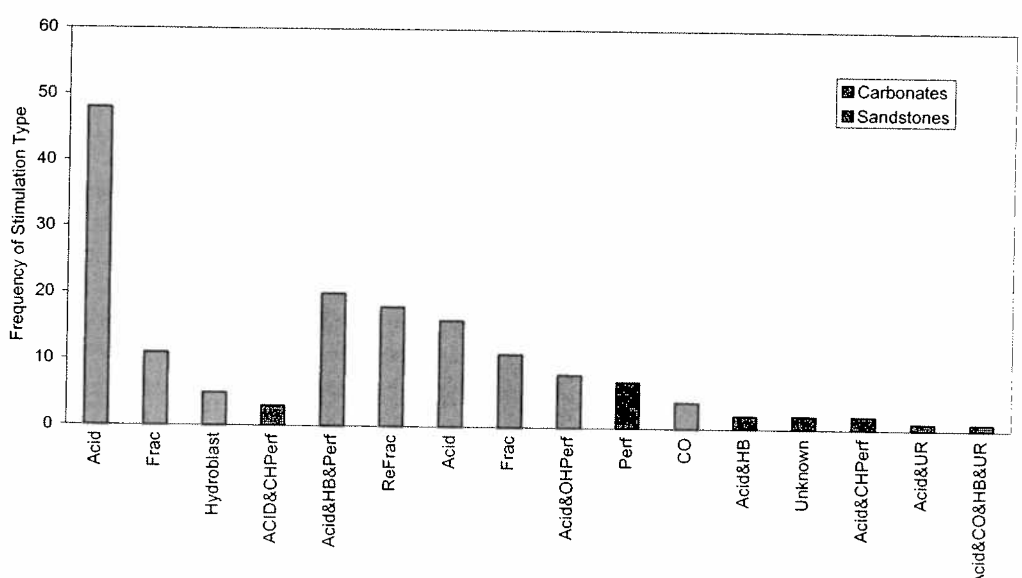


Figure 2-4: Frequency of Stimulation Type By Lithology

Treatment effectiveness may be the driving force in treatment selection. This is suggested by the fact that more effective treatments are generally employed more frequently in both carbonates and sandstones (**Figure 2-5** and **Figure 2-6**). Although longer lasting treatments are generally employed more frequently in carbonates (**Figure 2-7**), they are not necessarily employed more frequently in sandstones (**Figure 2-8**).

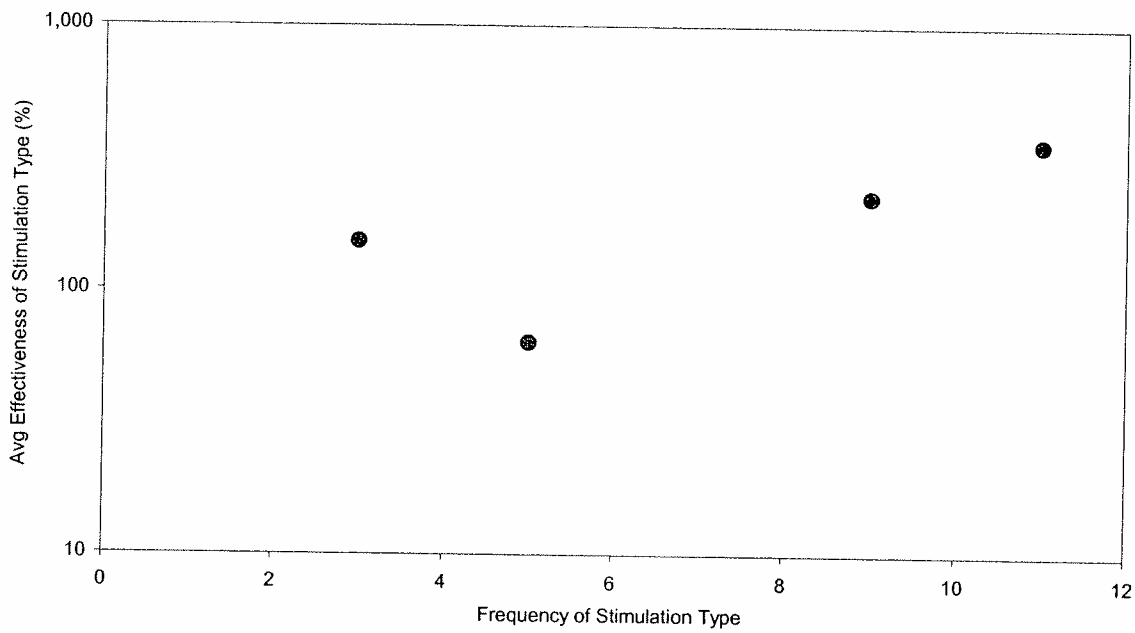


Figure 2-5: Frequency of Stimulation vs Average Effectiveness of Stimulation Type in Carbonates

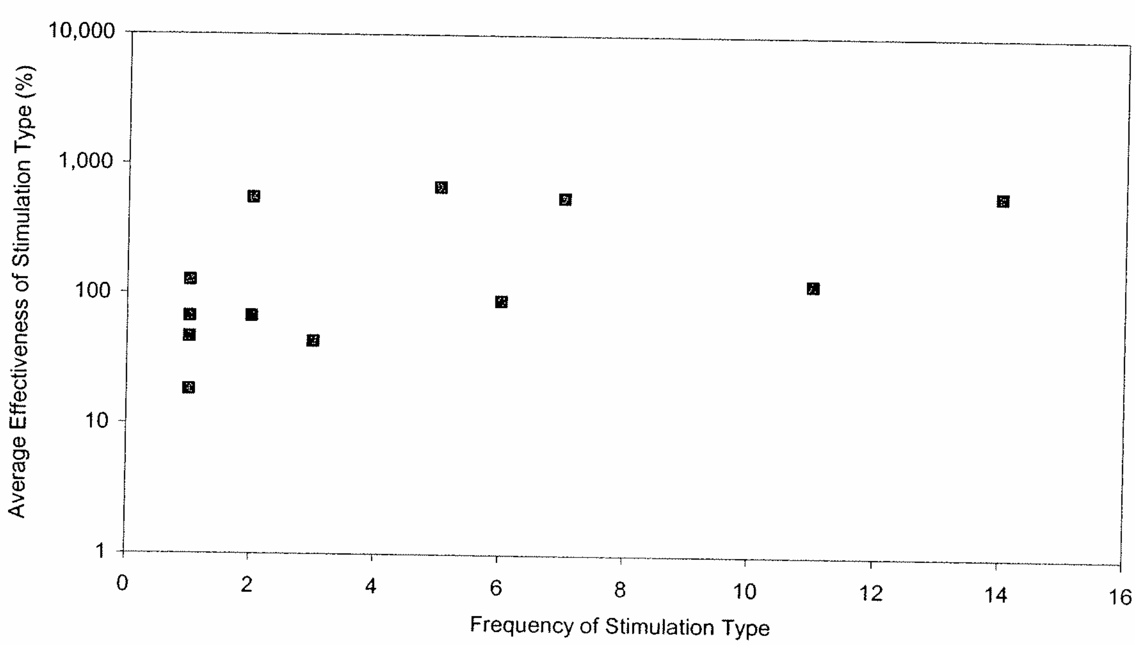


Figure 2-6: Frequency of Stimulation vs Average Effectiveness of Stimulation Type in Sandstones

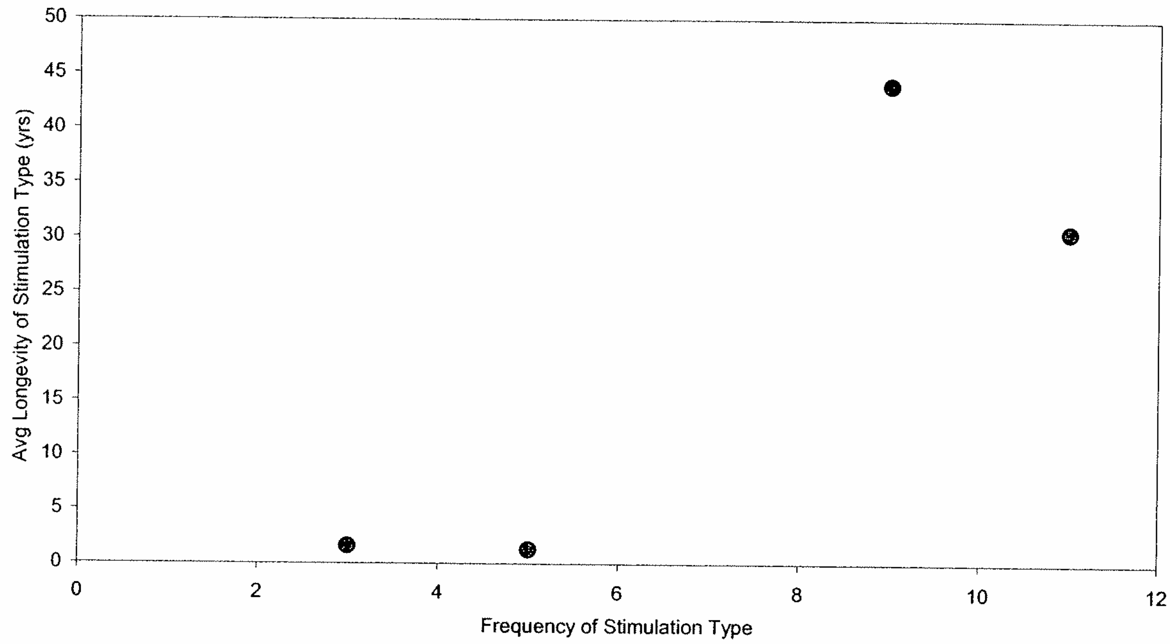


Figure 2-7: : Frequency of Stimulation vs Average Longevity of Stimulation Type in Carbonates

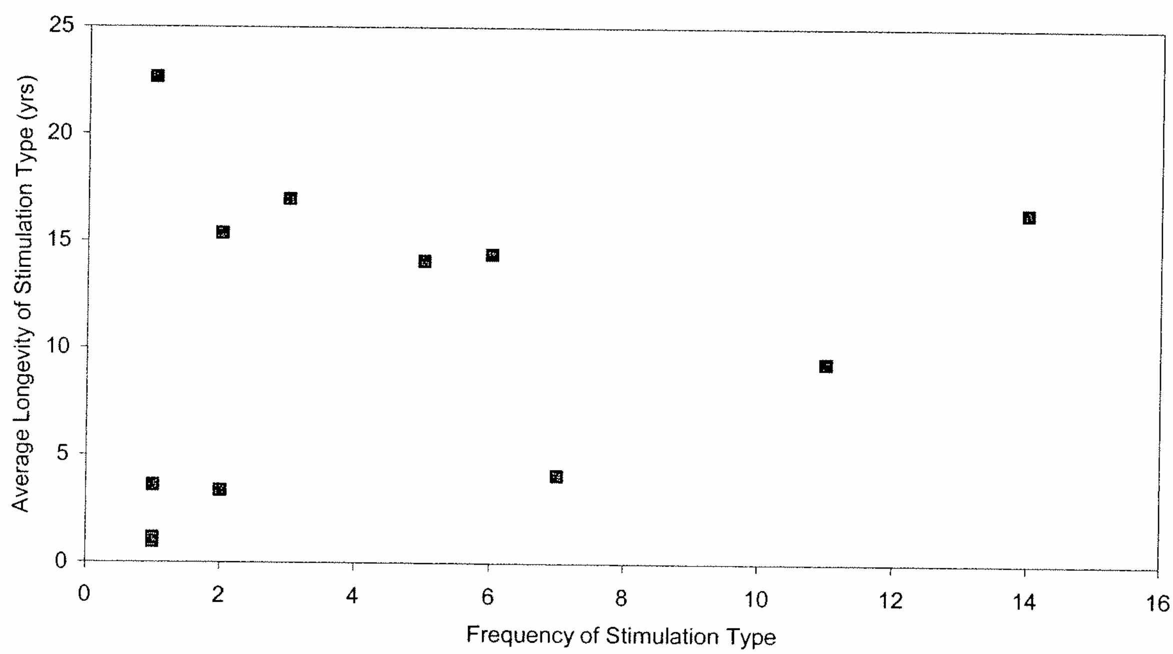


Figure 2-8: : Frequency of Stimulation vs Average Longevity of Stimulation Type in Sandstones

To better determine if the best treatments are the ones most often employed, we used the Potential Value (PV) concept discussed in Section 2.1.1.2, which simultaneously considers the amount of deliverability improvement and the duration of that improvement. Plots of frequency versus the PV realized within a 7-1/2 year timeframe (PV75) were generated for both carbonates and sandstones (**Figure 2-9** and **Figure 2-10**).

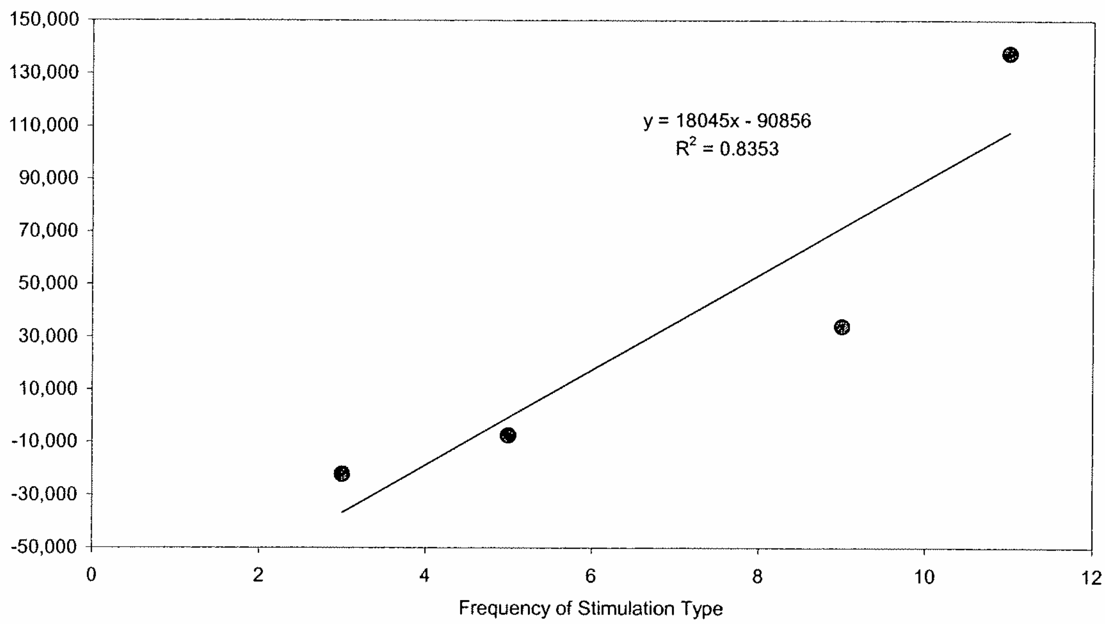


Figure 2-9: Frequency of Stimulation vs 7-1/2 Yr Potential Volume of Stimulation Type in Carbonates

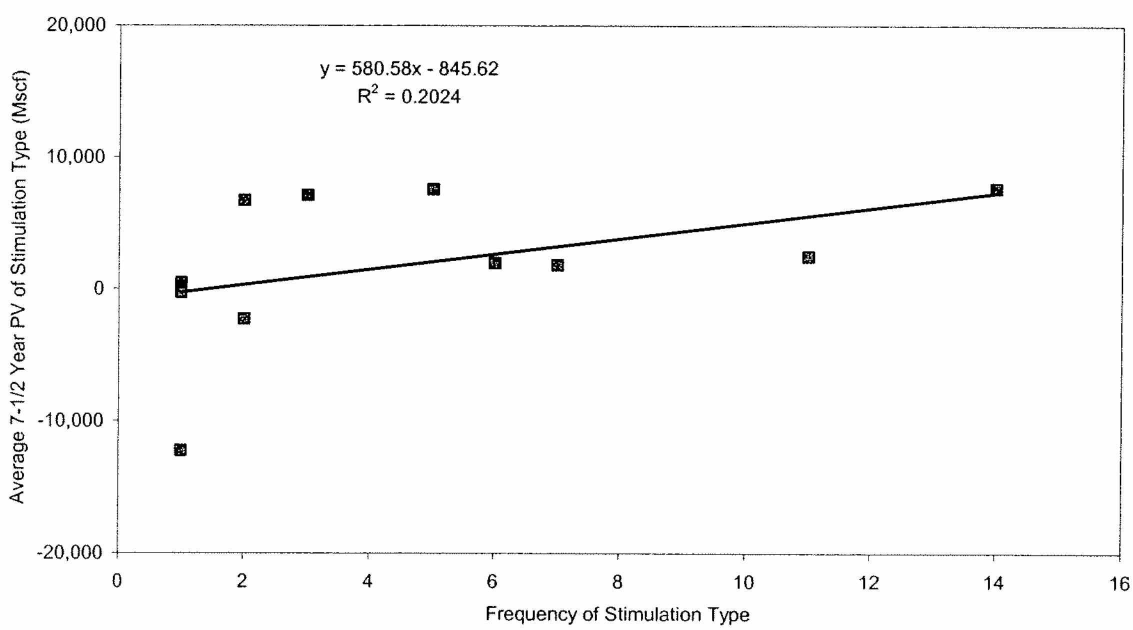


Figure 2-10 Frequency of Stimulation vs 7-1/2 Yr Potential Volume of Stimulation Type in Sandstones

These plots suggest that **operators do a good job of selecting treatments that increase *both* the deliverability and longevity in carbonate reservoirs. In sandstones, operators are less successful at selecting treatments that increase *both* the deliverability and longevity.**

One possible explanation for these phenomena may lie in the quality of correlation between effectiveness and PV75 values. As shown in **Figure 2-11** and **Figure 2-12** below, the effectiveness and PV75 correlate nicely for the available carbonate data, but poorly for the sandstone data. Therefore, if operators use effectiveness to select treatment types, they will be more successful in selecting successful treatments in carbonates than sandstones.

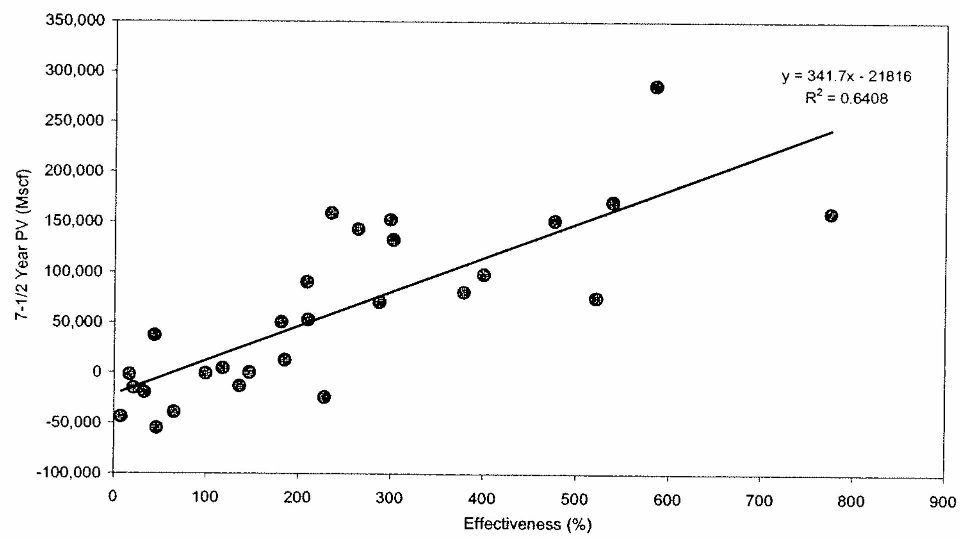


Figure 2-11: Correlation of Effectiveness vs 7-1/2 Yr Potential Volume for Carbonates

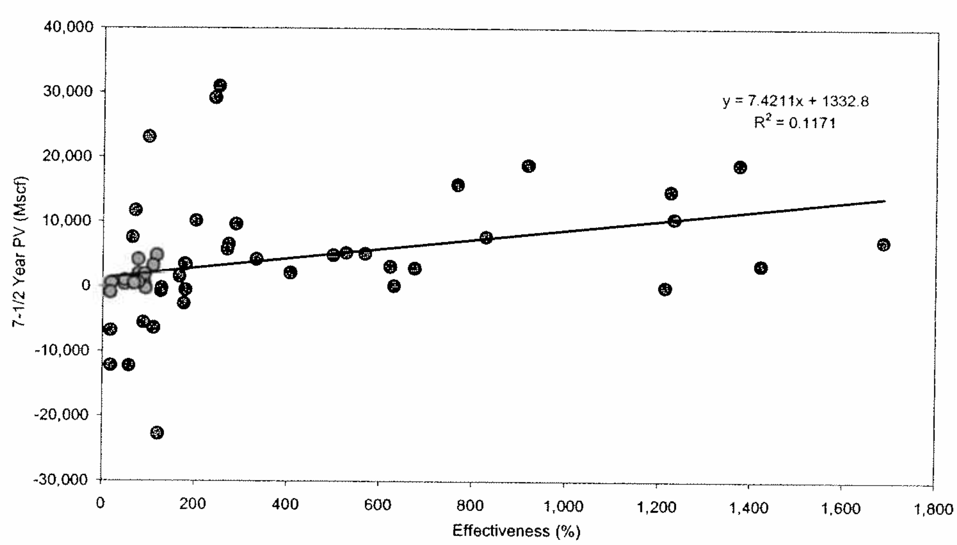


Figure 2-12: Correlation of Effectiveness vs 7-1/2 Yr Potential Volume for Sandstones

2.1.2.3 Ranking Success Using Effectiveness, Longevity, and PV75 Values

Three methods for ranking the successfulness of well treatments were used. The minimum, maximum, and average effectiveness, longevity, and PV75 values were estimated for all stimulation types, and the results were grouped by lithology. It should be noted that results for sample size of 3 or less need to be viewed with considerable caution, as small sample sizes may not provide representative results.

Figure 2-13 below shows the distribution of stimulation frequencies sorted by lithology. This plot is presented again for ease of comparison, as the subsequent plots in this section will all be presented in the same order.

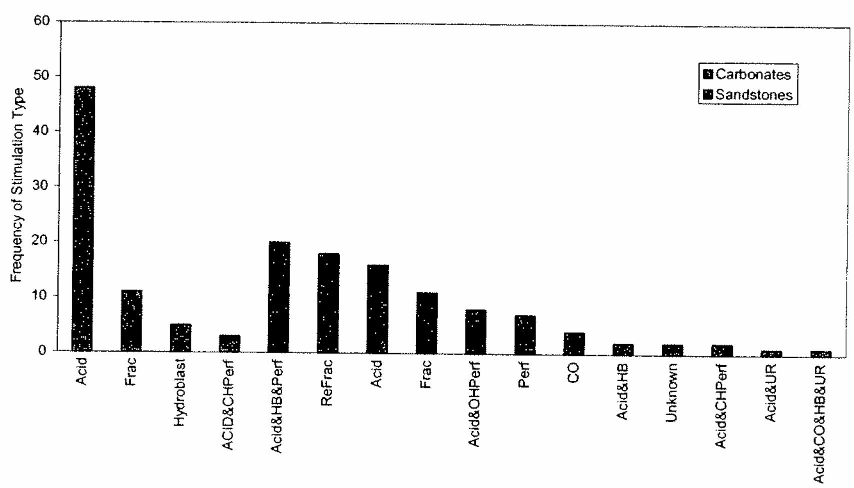


Figure 2-13: Frequency of Stimulation Type By Lithology

Figure 2-14 below shows the average effectiveness for the various stimulation types sorted by lithology. This plots suggests that the most frequently implemented treatments, in very general terms, tend to be the most successful.

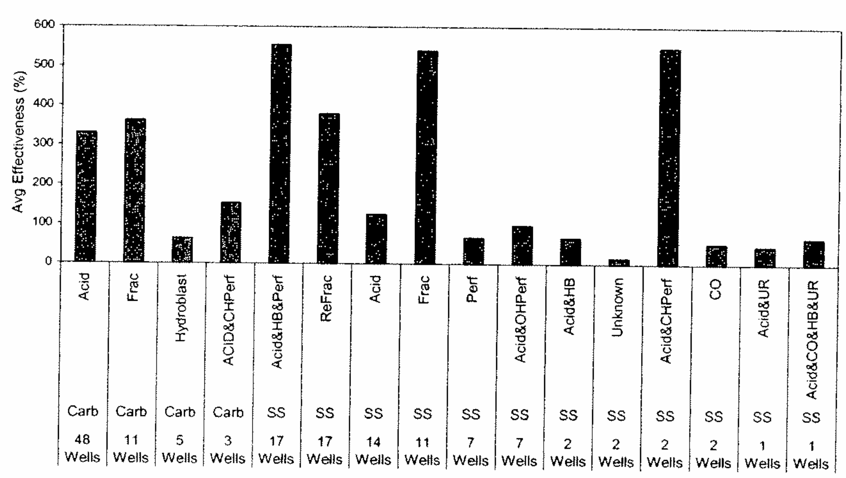


Figure 2-14: Average Effectiveness of Stimulation Types by Lithology

In an effort to determine the variation in treatment success, we also plotted the minimum, maximum, and average values of effectiveness for all treatment types having a sample size of 3 or more (**Figure 2-15**). As the datasets grow to statistically significant populations (assuming GTI periodically updates these study results), the actual *distributions* of effectiveness for each stimulation type would be available, which would be valuable information for a comprehensive risk analysis of treatment types.

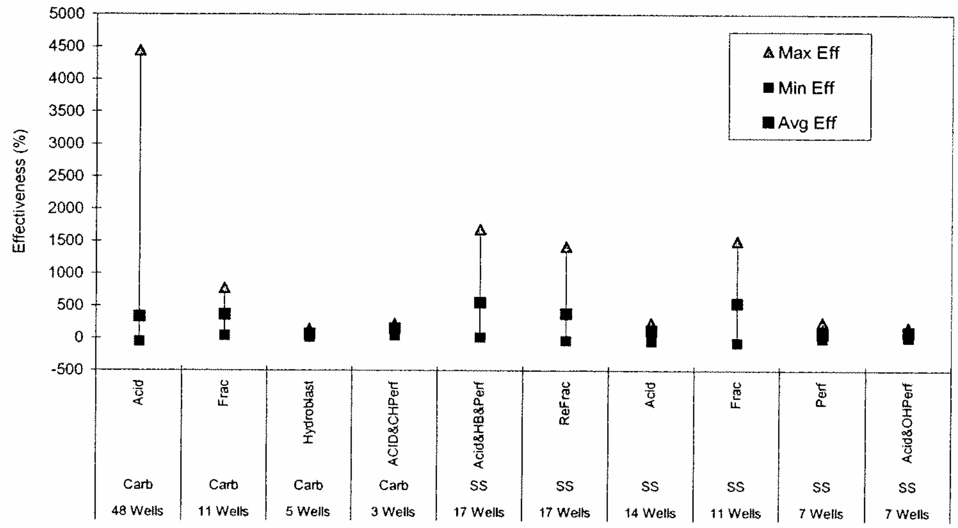


Figure 2-15: Min, Max, & Avg Effectiveness For All Treatment Types With Sample Size of 3 or More

Figure 2-16 below shows the average longevity for the various stimulation types sorted by lithology. This plot suggests that, in general, the treatments with the highest longevity are most frequently employed in carbonates, but not in sandstones.

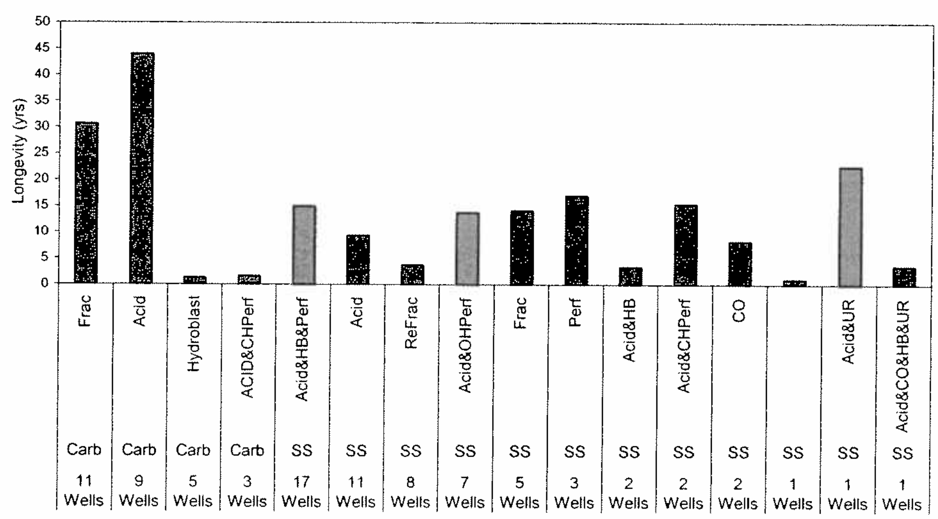


Figure 2-16: Longevity of Stimulation Types Sorted by Lithology

Minimum, maximum, and average longevity values were also calculated and plotted for each treatment, sorted by lithology (**Figure 2-17**).

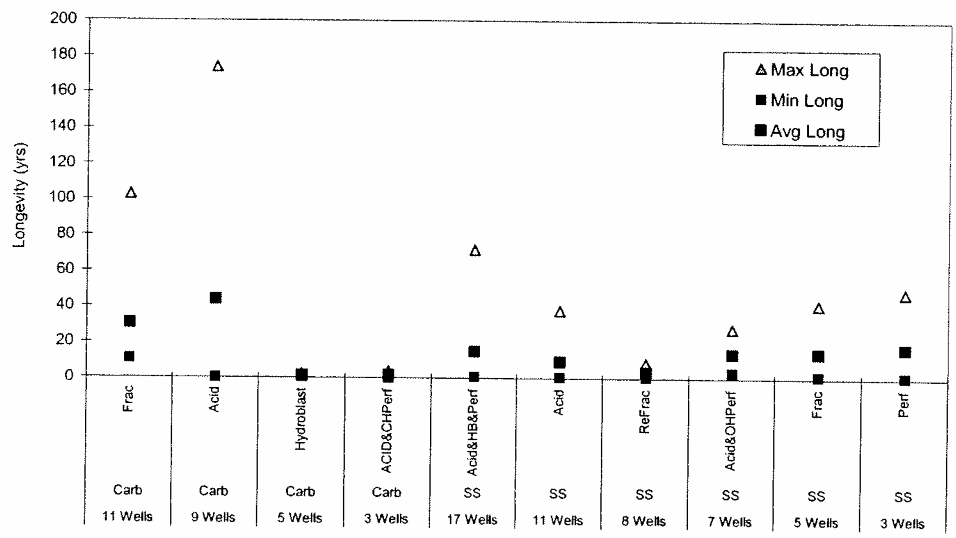


Figure 2-17: Min, Max, and Avg Longevity Values For Each Treatment Sorted by Lithology

Figure 2-18 below shows the average PV75 for the various stimulation types sorted by lithology. This plots suggests that operators do a good job of selecting treatments that increase the 7-1/2 year potential volume in carbonate reservoirs. In sandstones, operators are less successful at selecting treatments that increase the 7-1/2 year potential volume. Although some might suggests that there are cases where doing nothing is better (negative PV75 values), this conclusion may not be correct, as it implicitly assumes the DI value was not declining prior to stimulation.

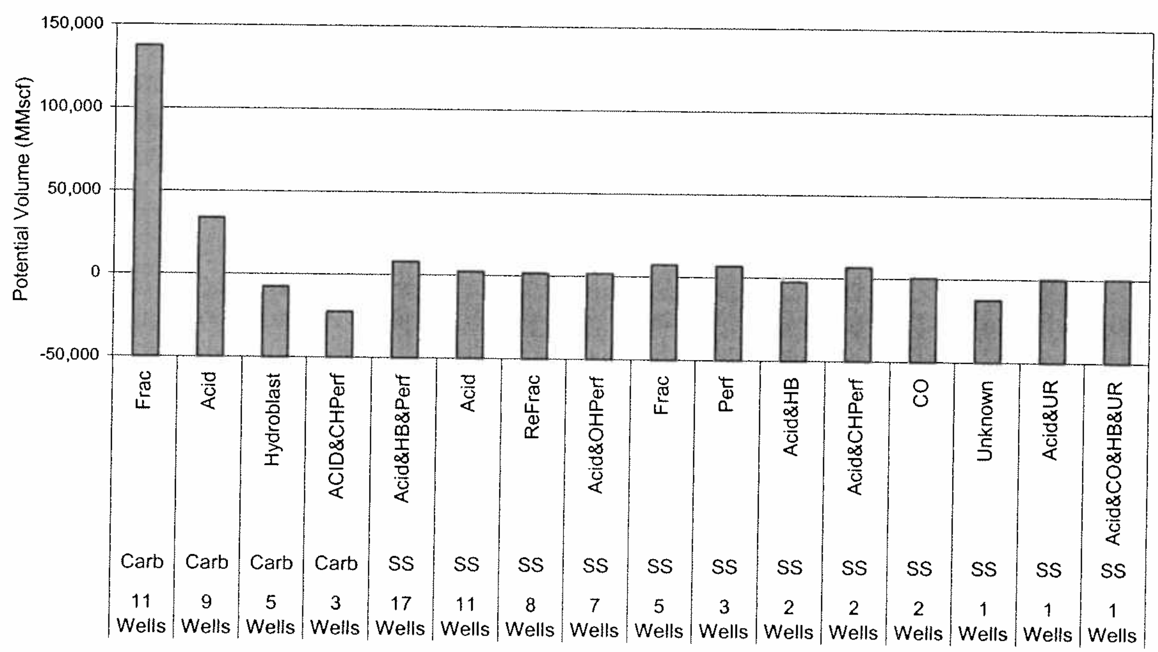


Figure 2-18: Average 7-1/2 Yr Potential Volume For Stimulation Types Sorted by Lithology

Minimum, maximum, and average PV75 values were also calculated and plotted for each treatment type and sorted by lithology (**Figure 2-19**).

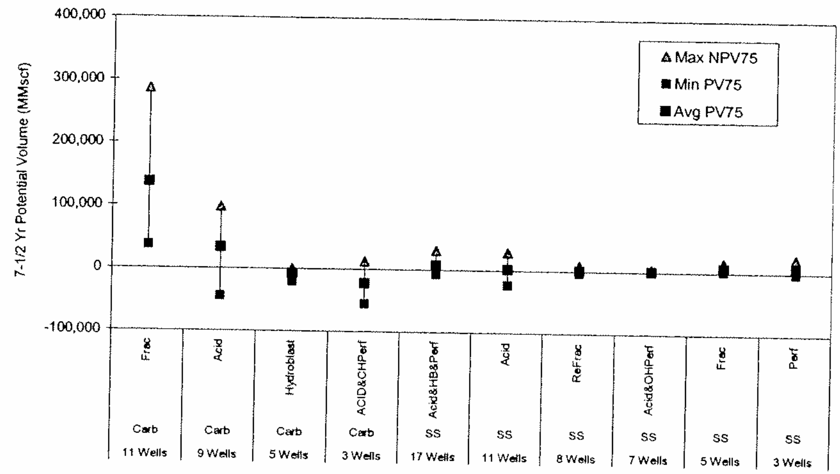


Figure 2-19: Min, Max, & Avg 7-1/2 Yr Potential Volume Values For Treatment Types by Lithology

2.1.2.4 Cleanup Time Analysis

Cleanup effects are observed after about ½ of all stimulations, and defer the full benefits of the stimulation treatment by over one year on average. Overall, cleanup effects were observed in 48% of all stimulations, and lasted an average of 16 months. Cleanup effects were observed less frequently in carbonates, and were shorter in duration than in sandstones. In carbonates, cleanup effects were observed in 31% of all stimulations, and lasted an average of 13 months. In sandstones cleanup effects were observed in 61% of all sandstone stimulations and lasted an average of 17 months.

Figure 2-20 below shows the frequency of treatments that evidence cleanup effects for each treatment type with a population of 2 or more, sorted by lithology. It should be noted that these numbers represent the minimum frequency, as many factors may result our inability to identify these effects, such as limited and infrequent test data.

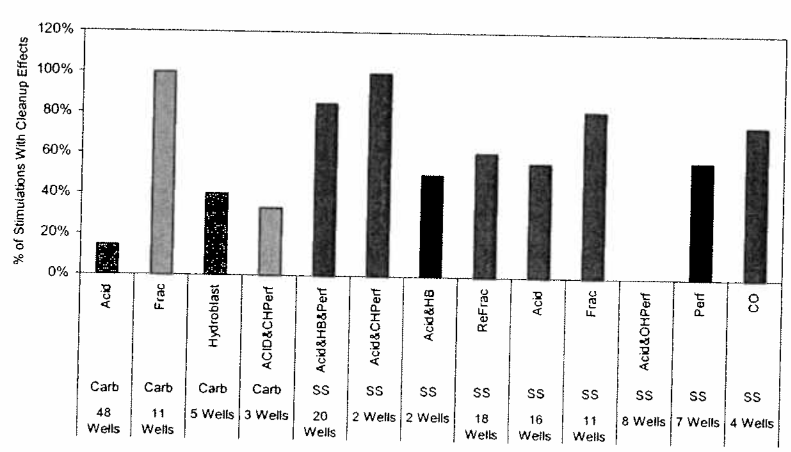


Figure 2-20: Percent of Stimulations Experiencing Clean-Up Effects

Figure 2-21 below shows the length of time required to clean up the well and achieve the maximum benefit for each treatment type having a sample population of 2 or more, sorted by lithology.

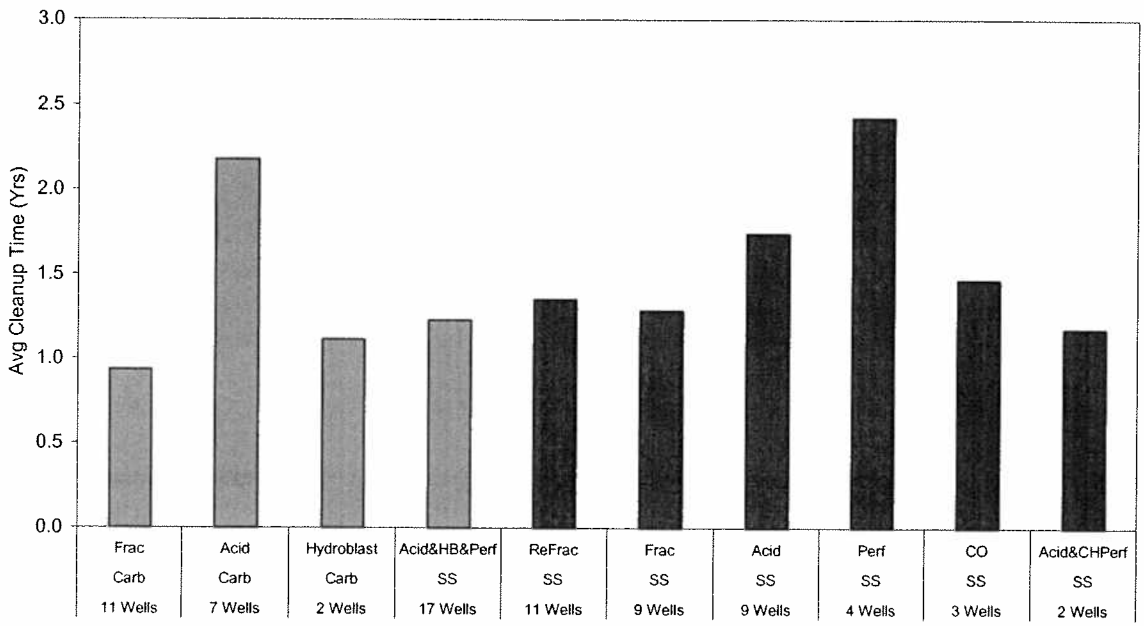


Figure 2-21: Avg Cleanup Times for Stimulations, Sorted by Lithology

Minimum, maximum, and average cleanup times were also calculated and plotted for each treatment with a sample population greater than 2, sorted by lithology (**Figure 2-22**).

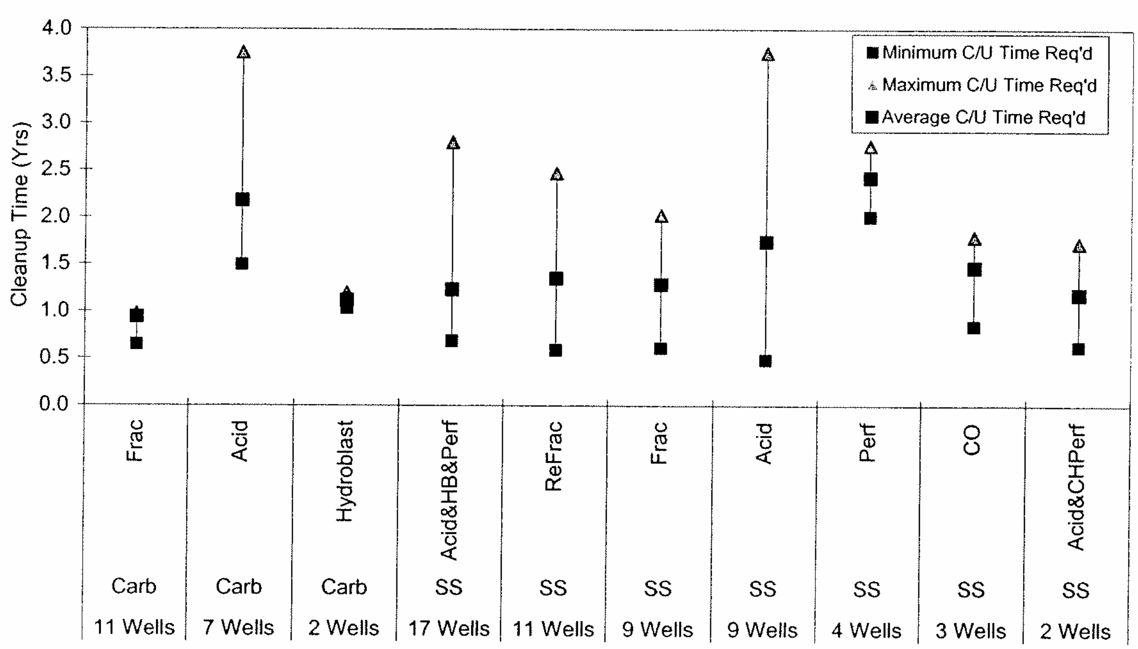


Figure 2-22: Range of Cleanup Times for Stimulations, Sorted by Lithology

2.1.2.5 Analysis of Post-Stimulation DI Decline

Currently employed stimulation techniques effectively reduce or remove damage, but often do not remove the underlying cause of that damage. Overall, post-stimulation DI values decline in at least 50% of all stimulations, with the weighted average post-stimulation decline rate for all stimulations at about 18%. In carbonates, post-stimulation DI values decline in at least 43% of stimulations, with the weighted average post-stimulation decline rate at about 20%. In sandstones, post-stimulation DI values decline at least 59% of stimulations, with the weighted average post-stimulation decline rate at about 17%

Figure 2-23 below shows the average post-stimulation decline rate for each treatment type having a sample population of 2 or more, sorted by lithology.

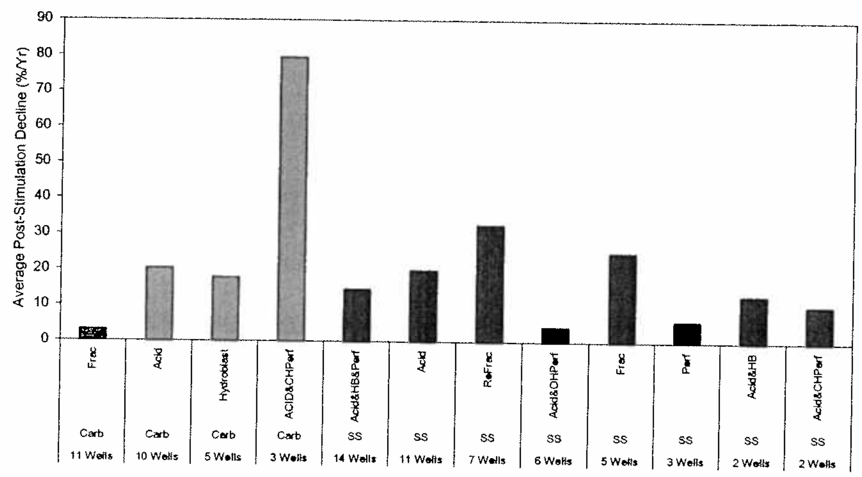


Figure 2-23: Avg Post-Stimulation Decline Rate By Treatment, Sorted by Lithology.

Figure 2-24 below shows the minimum, maximum, and average post-stimulation decline rate for each treatment type having a sample population of 2 or more, sorted by lithology.

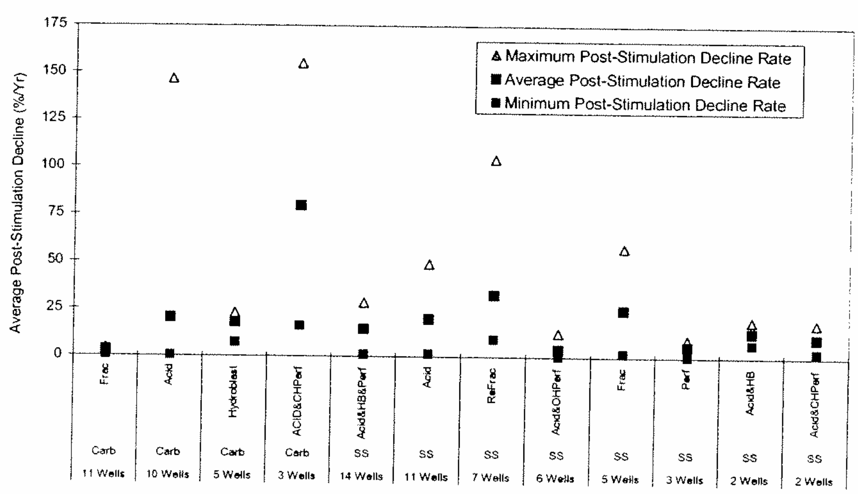


Figure 2-24: Range of Post-Stimulation Decline Rate By Treatment, Sorted by Lithology

2.1.2.6 Impact of Process and Reservoir Parameters on Success of Stimulations

Although there was sufficient data to examine the impact of several parameters on stimulation results for numerous treatment types, there is considerable opportunity for improvement. There was sufficient data to examine the impact of some process parameters on stimulation results for acidizing, fracturing, re-fracturing, perforating, combination acidizing, hydroblasting, and perforating treatment, and combination acidizing and perforating treatment. There was sufficient data to examine the impact of lithology, bottom-hole temperature, conversion date, stimulation date, thickness, porosity, and/or pre-stimulation deliverability rates on some stimulation results for several stimulation types.

It appears that operators record only the most basic of stimulation details, (e.g., total volumes), but rarely keep track of such items as fluid additives, treatment rates and pressures, perforation gun sizes and types, charge types and sizes, etc. This information is necessary to determine the extent that such items impact the success of stimulation treatments.

2.1.2.6.1 Acidizing Treatments

Examination of acidizing data suggests that acidizing is more effective and lasts longer in carbonates than sandstones, resulting in higher potential volumes in carbonates than sandstones (**Figure 2-25**, **Figure 2-26**, and **Figure 2-27**). In this case, the difference in potential volumes is not due to a significant difference in the post-stimulation decline rates, as these are similar for both lithologies (**Figure 2-28**).

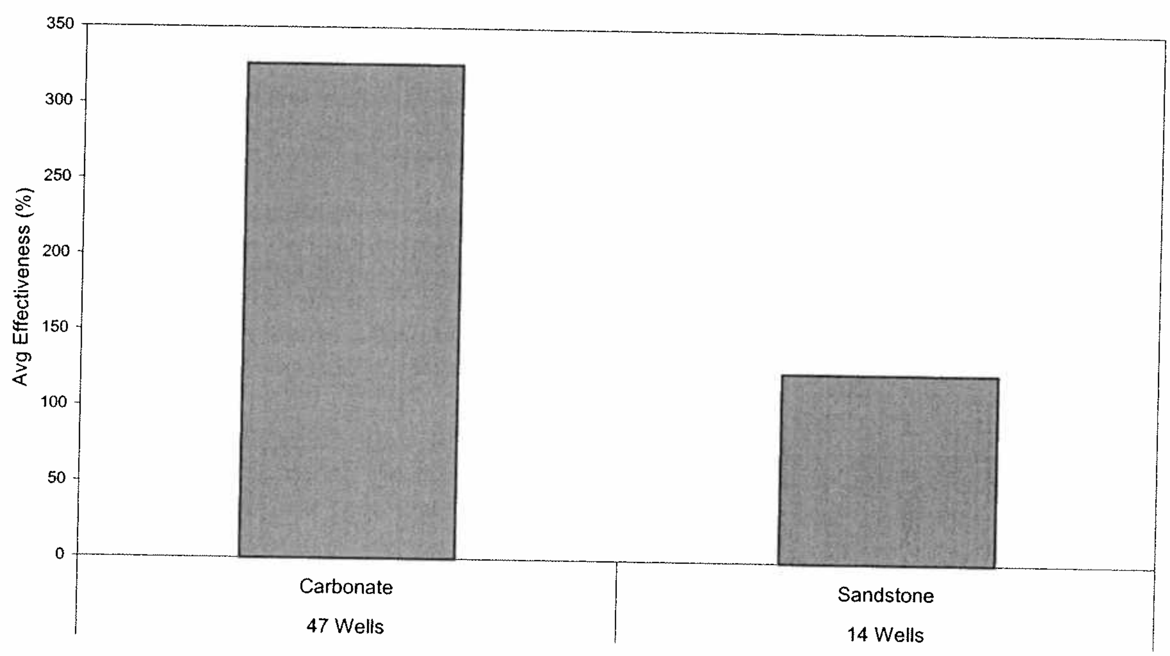


Figure 2-25: Impact of Lithology on Effectiveness of Acidizing

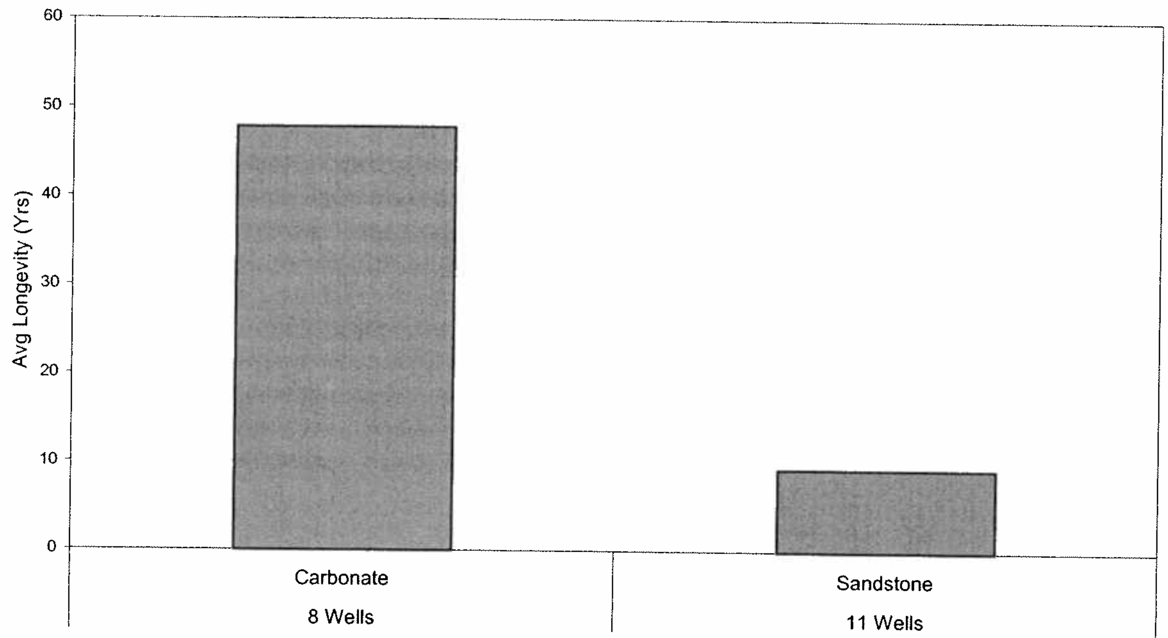


Figure 2-26: Impact of Lithology on Longevity of Acidizing

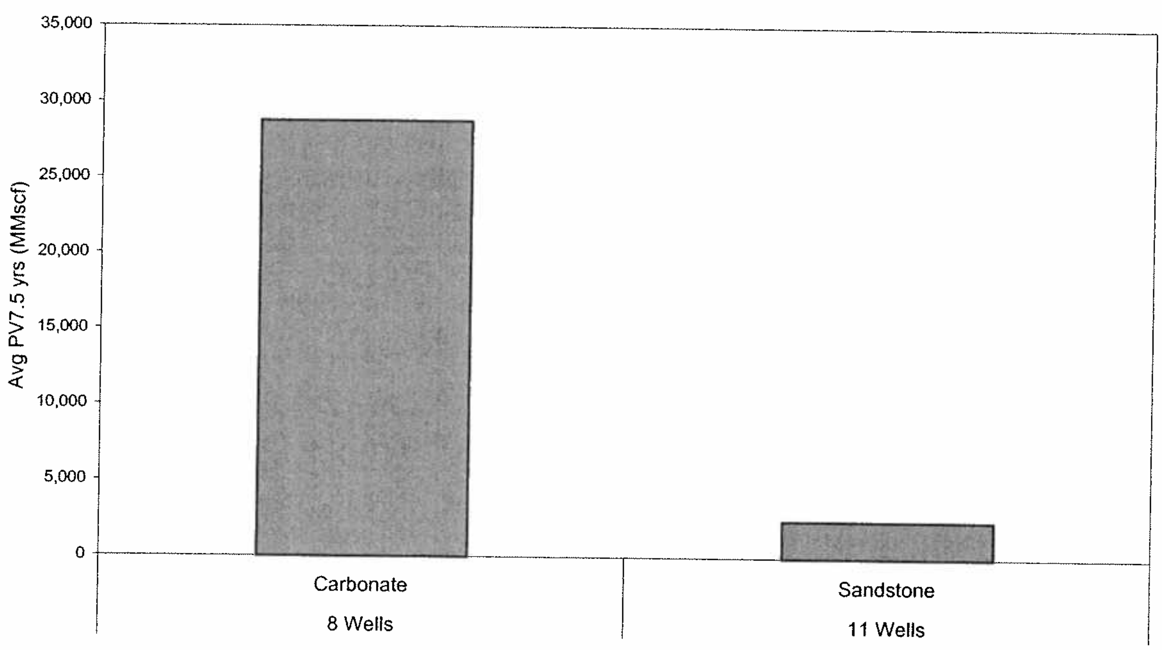


Figure 2-27: Impact of Lithology on 7-1/2 Year Potential Volume for Acidizing

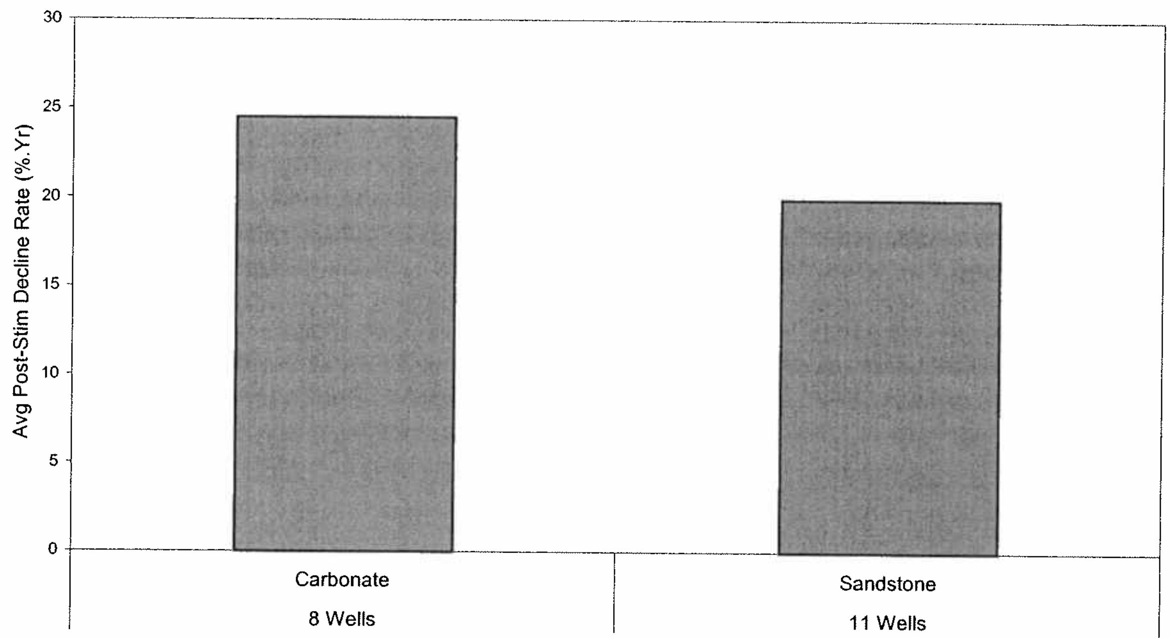


Figure 2-28: Impact of Lithology on Post-Stimulation Decline Rate for Acidizing

The range of these parameters is shown in **Figure 2-29 through Figure 2-32**.

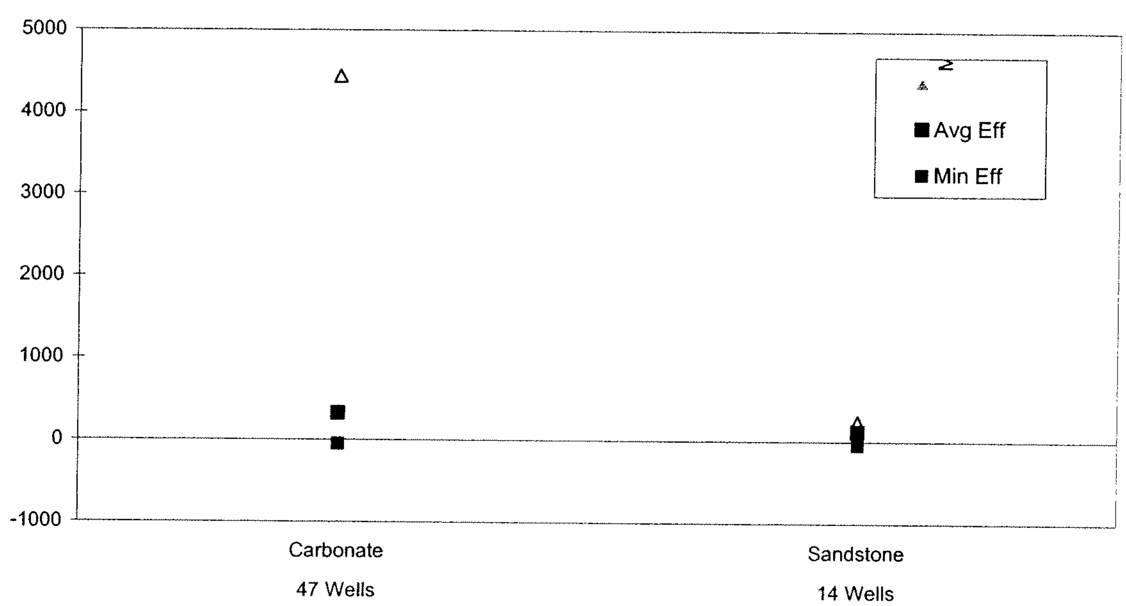


Figure 2-29: Range of Effectiveness for Acidizing by Lithology

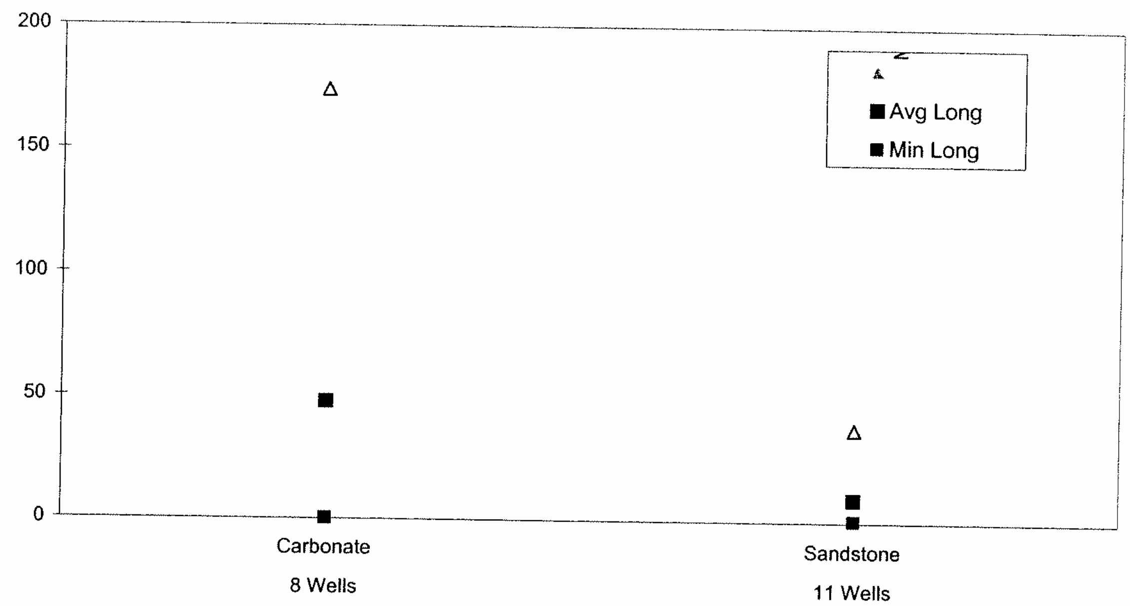


Figure 2-30: : Range of Longevity for Acidizing by Lithology

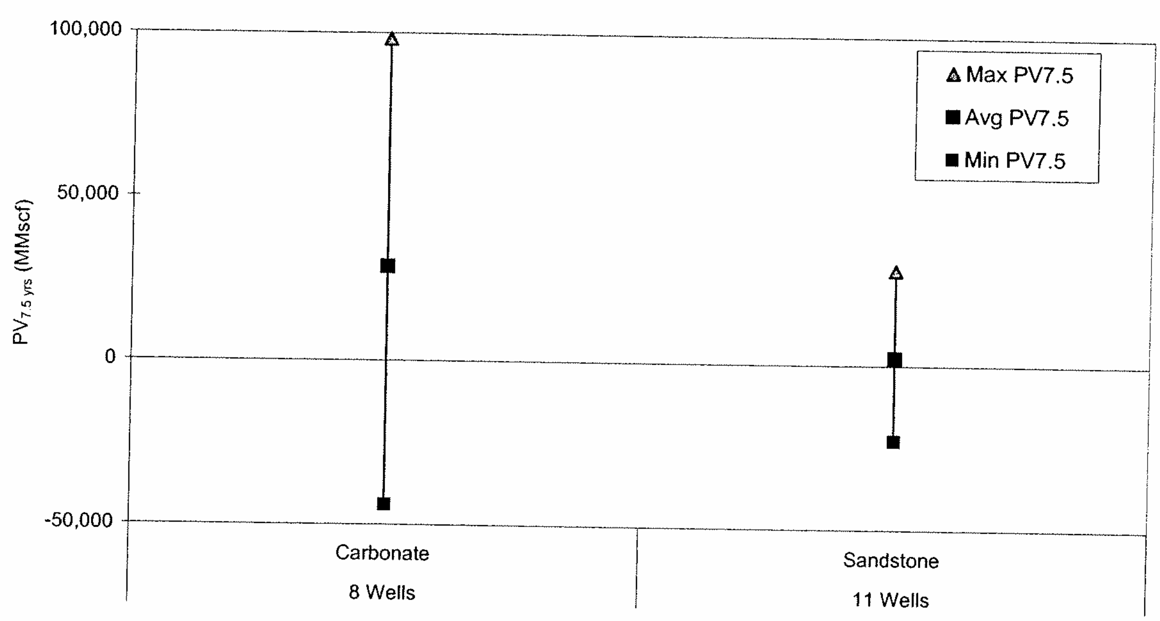


Figure 2-31: Range of 7-1/2 Year Potential Volume for Acidizing by Lithology

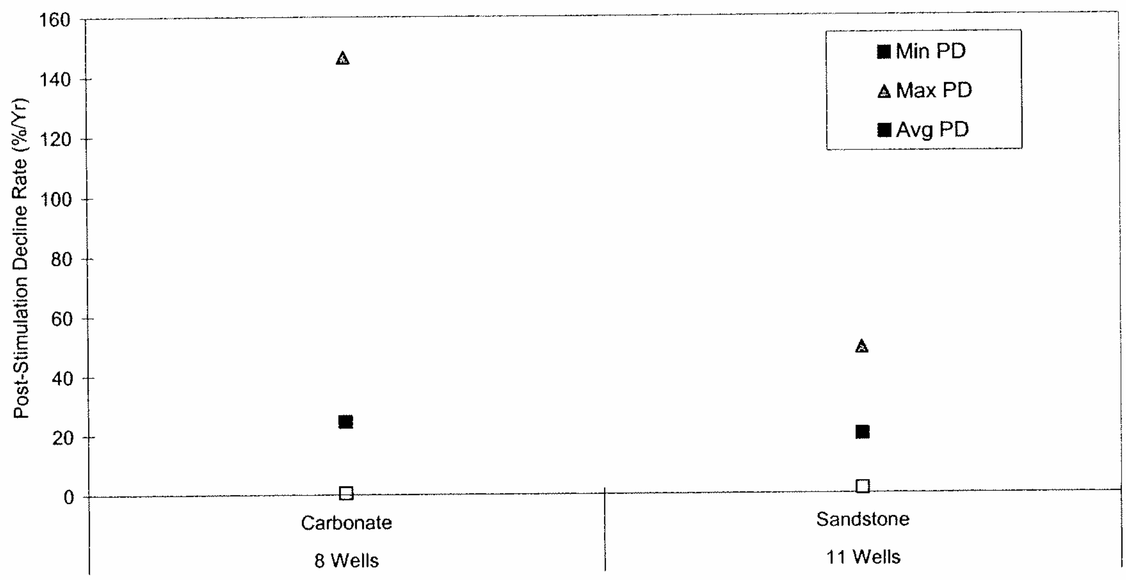


Figure 2-32: Range of Post-Stimulation Decline Rates for Acidizing by Lithology

In carbonates increasing HCl acid concentration from 15% to 28% resulted in higher effectiveness. but much lower longevity (**Figure 2-33**). However, in sandstones, increasing the acid concentration from 7.5% to 15% HCl resulted in higher effectiveness and higher longevity (**Figure 2-34**).

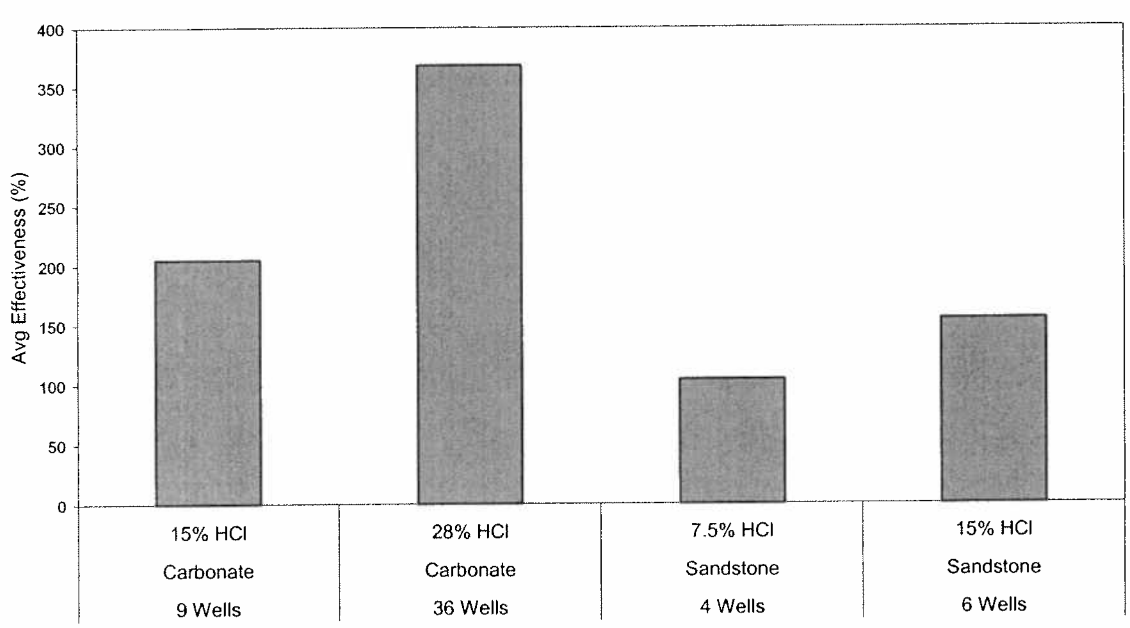


Figure 2-33: Comparison of Effectiveness For Different Acid Concentrations

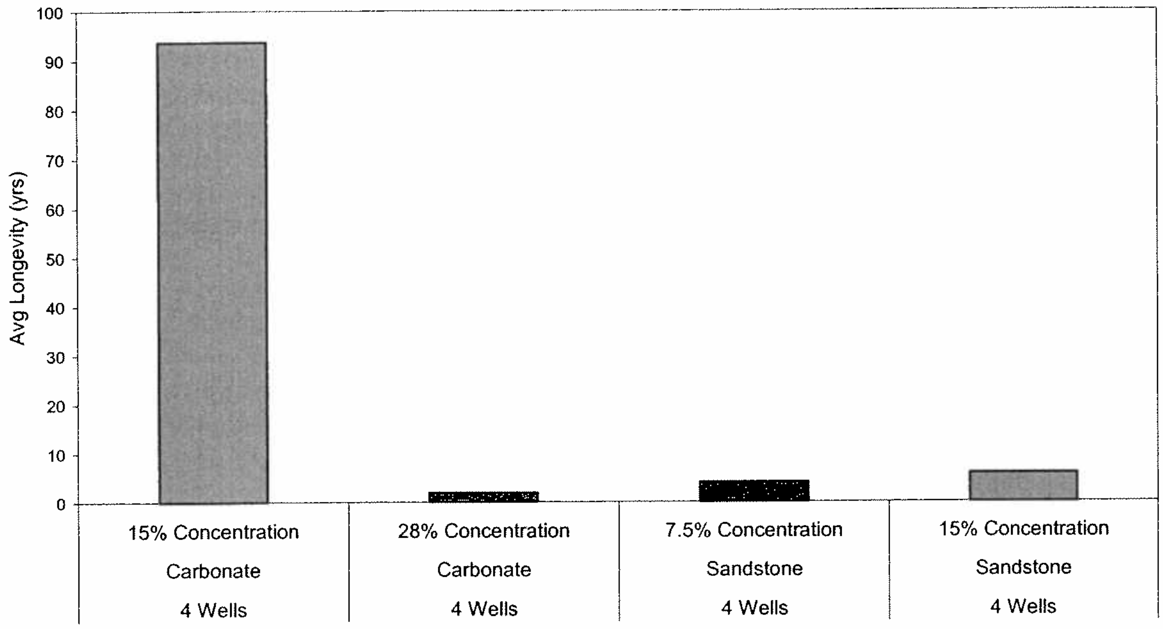


Figure 2-34: Comparison of Longevity For Different Acid Concentrations

This is a good example of the potential difficulties encountered when trying to determine the best course of action when effectiveness and longevity vary inversely as a function of changing treatment parameters. Examination of the PV75 values suggests that increasing acid concentration in carbonates would significantly decrease the performance of the well when viewed over a 7-1/2 year timeframe. (**Figure 2-35**).

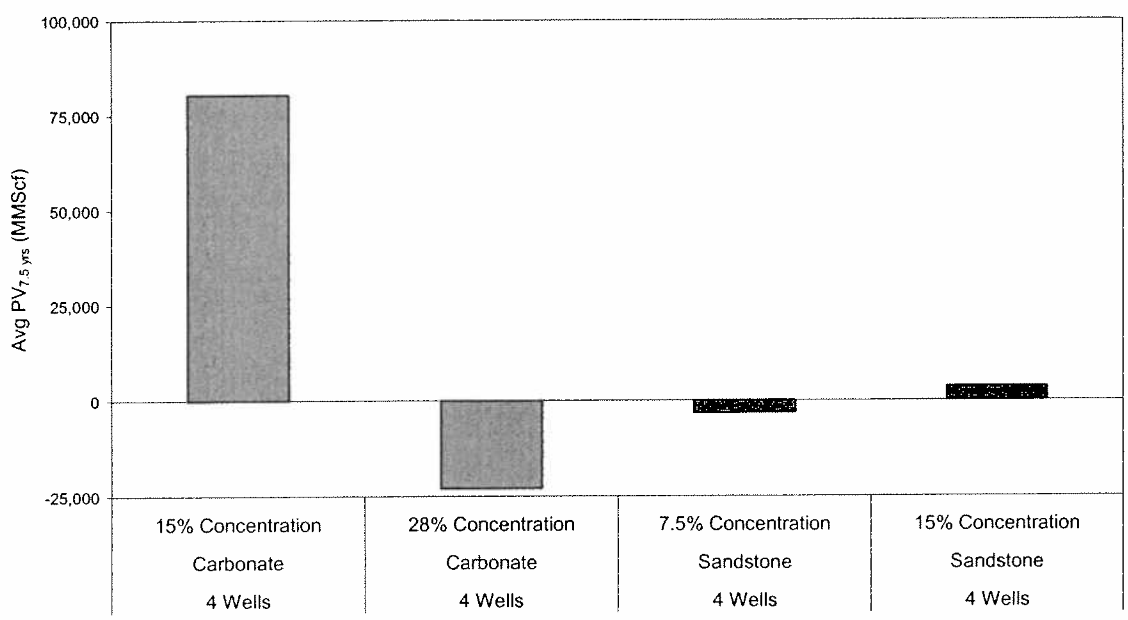


Figure 2-35: : Comparison of 7-1/2 Year Potential Volume For Different Acid Concentrations

A review of the post-stimulation decline rates reveals that the lower concentration acid in a carbonate reservoir is the only case in which there is not a high post-stimulation decline rate **(Figure 2-36)**.

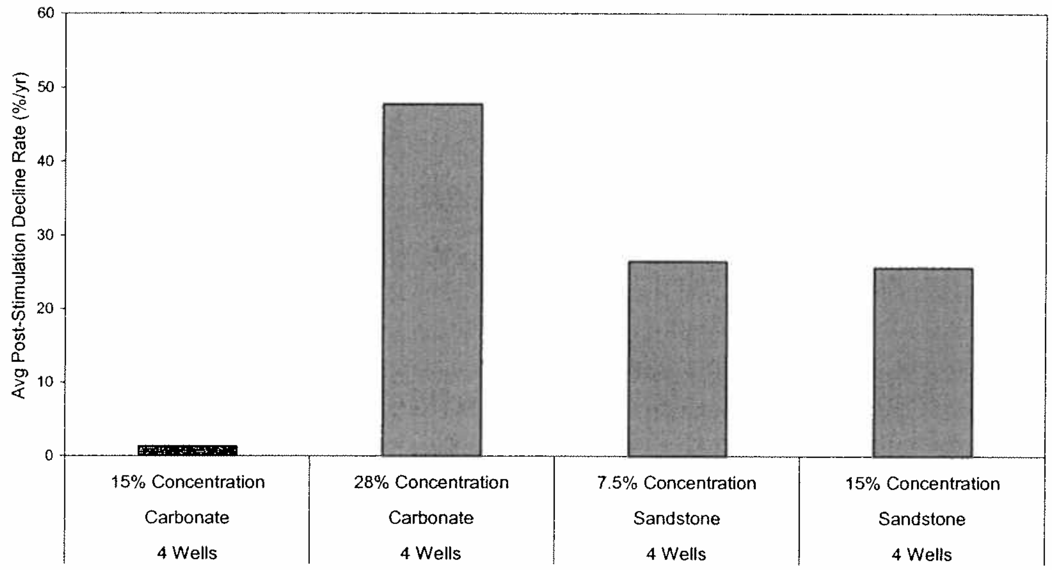


Figure 2-36: Comparison of Post-Stimulation Decline Rate For Different Acid Concentrations

Looking at the carbonate and sandstone data together, it would appear that there is a decreasing trend in the maximum achievable effectiveness with increasing acid volume, for acid volumes less than 750 bbls **(Figure 2-37)**. Although the trend of decreasing effectiveness with increasing acid volumes is fairly evident in the sandstone data over this range of acid volume, the trend is much less defined for carbonates.

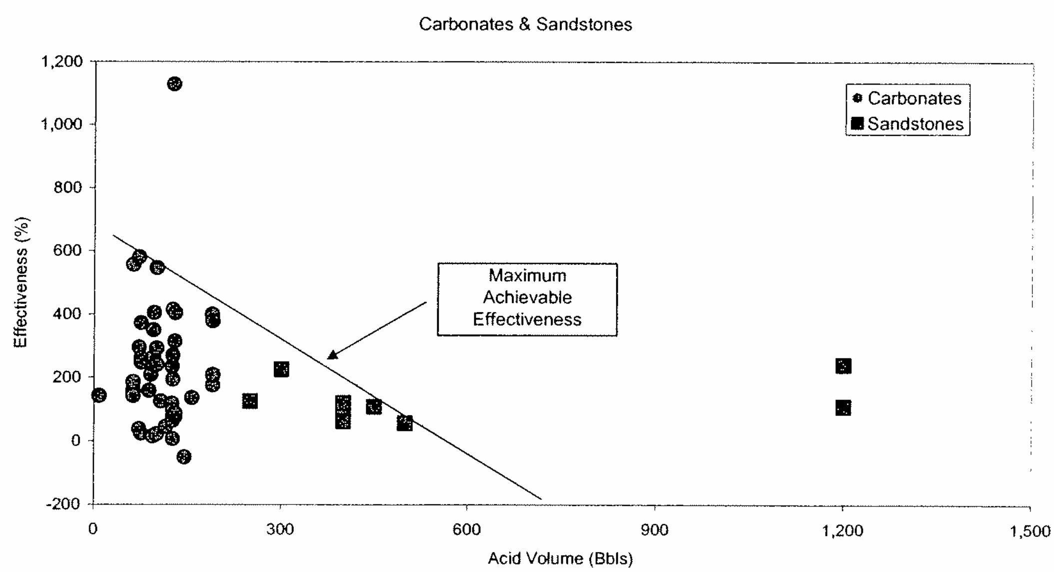


Figure 2-37: Effectiveness as a Function of Acid Volumes for Sandstones and Carbonates

The overall trend in these data are a bit more evident on a semi-log plot, as shown in **Figure 2-38**.

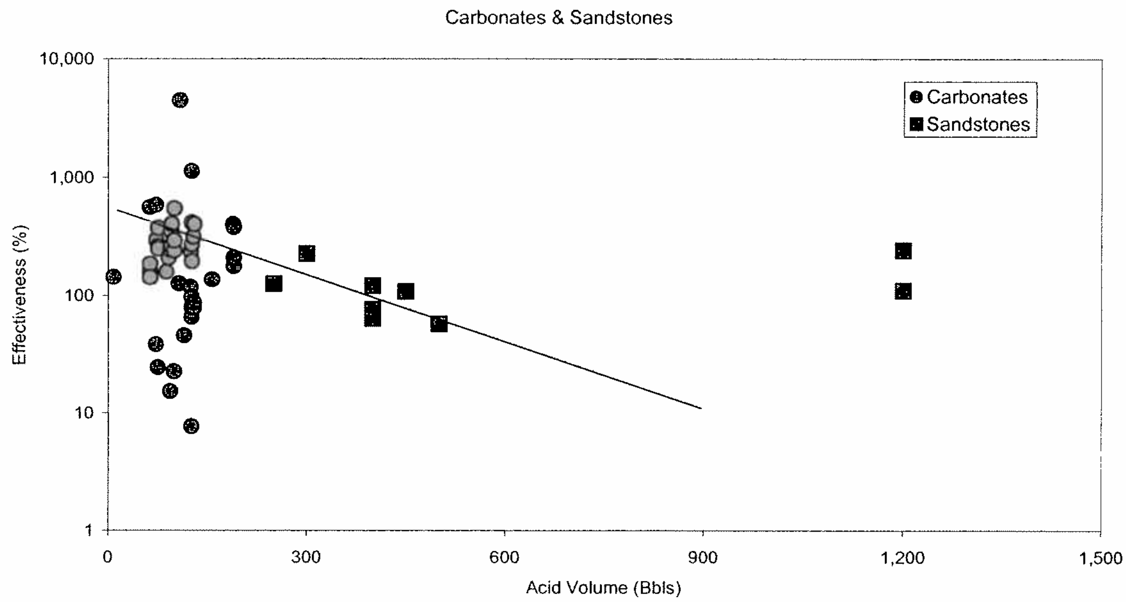


Figure 2-38: Semi-Log Plot of Effectiveness as a Function of Acid Volume for Sandstones Carbonates

There was sufficient reservoir data to evaluate the impacts of porosity on acidizing in both carbonates and sandstones. There is also sufficient data to assess the impact of thickness and pre-stimulation rate on acidizing in Carbonates. The impact of porosity on the effectiveness of acidizing is shown in **Figure2-39**, and indicated that the effectiveness increases with decreasing porosity.

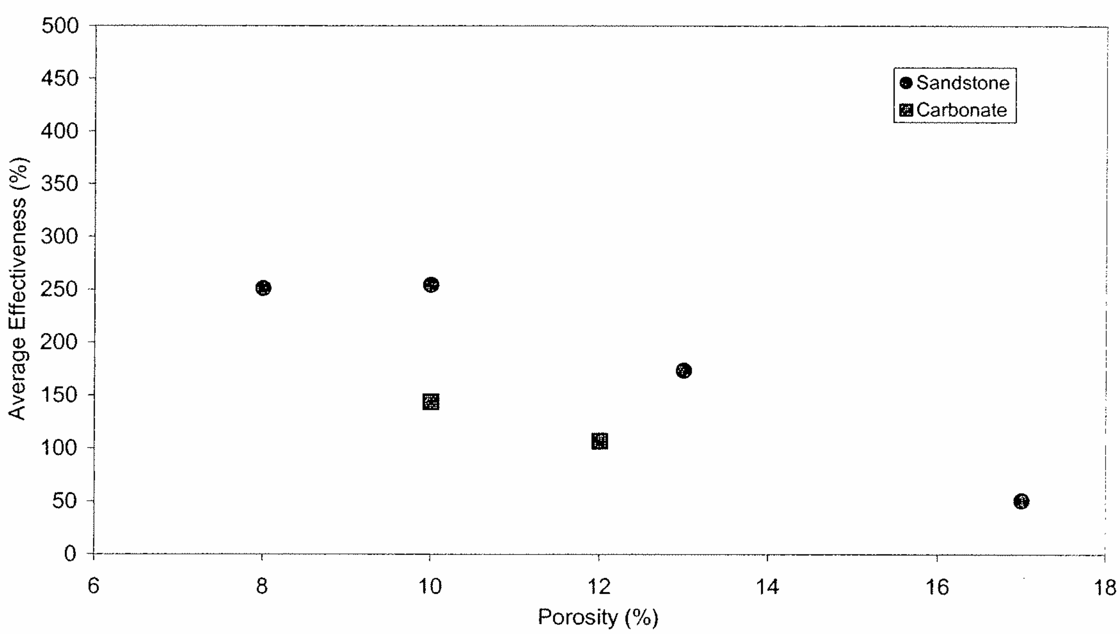


Figure 2-39: Impact of Porosity on Effectiveness of Acidizing

There is insufficient longevity, potential volume, and post-stimulation decline data to assess the impact of porosity on these benchmarks when acidizing.

In general, the effectiveness increases with decreasing thickness in carbonates (**Figure 2-40**). There is insufficient data to comment on the effects of thickness on longevity and PV75.

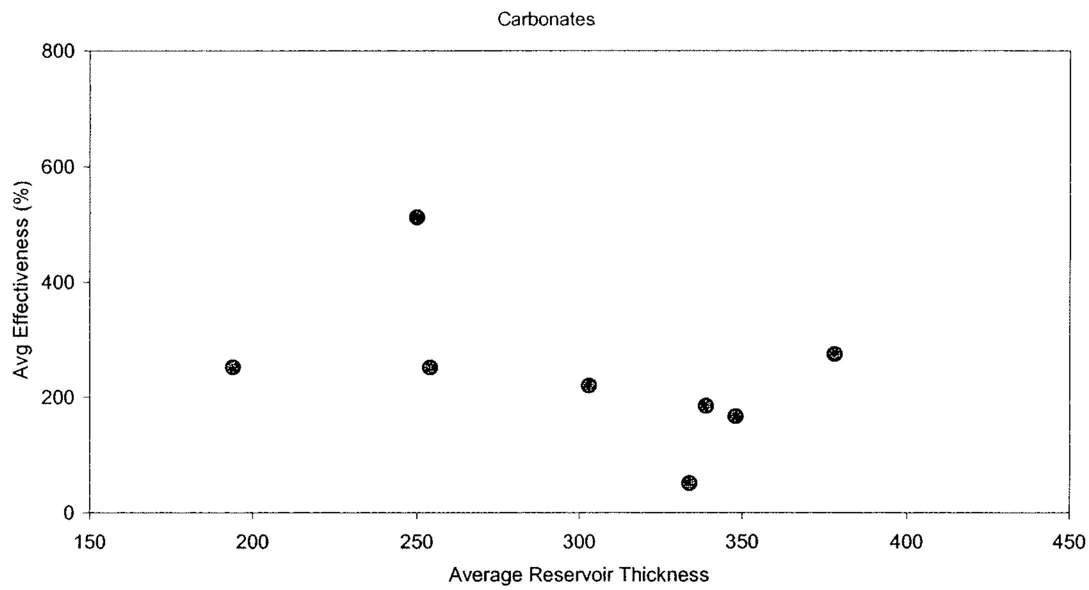


Figure 2-40: Impact of Thickness on Effectiveness of Acidizing in Carbonates

The effectiveness versus pre-stimulation rate in carbonate reservoirs is shown in **Figure 2-41** for the entire range of pre-stimulation rates.

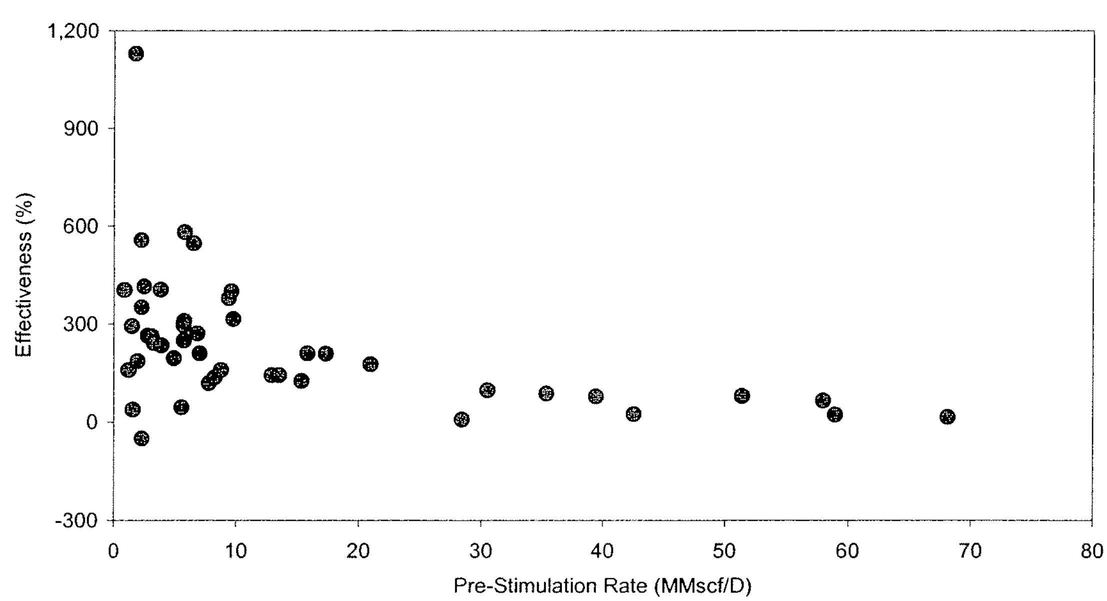


Figure 2-41: Impact of Pre-Stimulation Rate on Effectiveness of Acidizing in Carbonates

Zooming in on the lower pre-stimulation flow rates (≤ 10 MMSCF/D), this plot suggests that there is no discernable relationship between pre-stimulation rate and effectiveness in carbonates for lower pre-stimulation rates, (**Figure 2-42**).

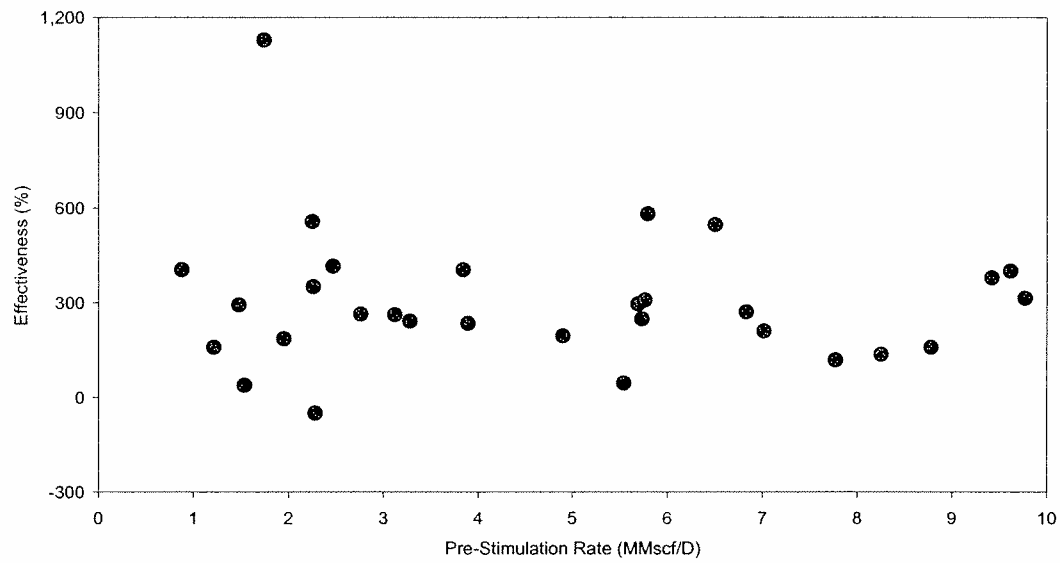


Figure 2-42: Impact of Pre-Stimulation Rate on Effectiveness of Acidizing in Carbonates for Low Rates

Zooming in on the higher pre-stimulation flow rates (≥ 10 MMSCF/D), this plot suggests that effectiveness increases with decreasing pre-stimulation rate for wells with high (≥ 10 MMScf/D) pre-stimulation rates (**Figure 2-43**).

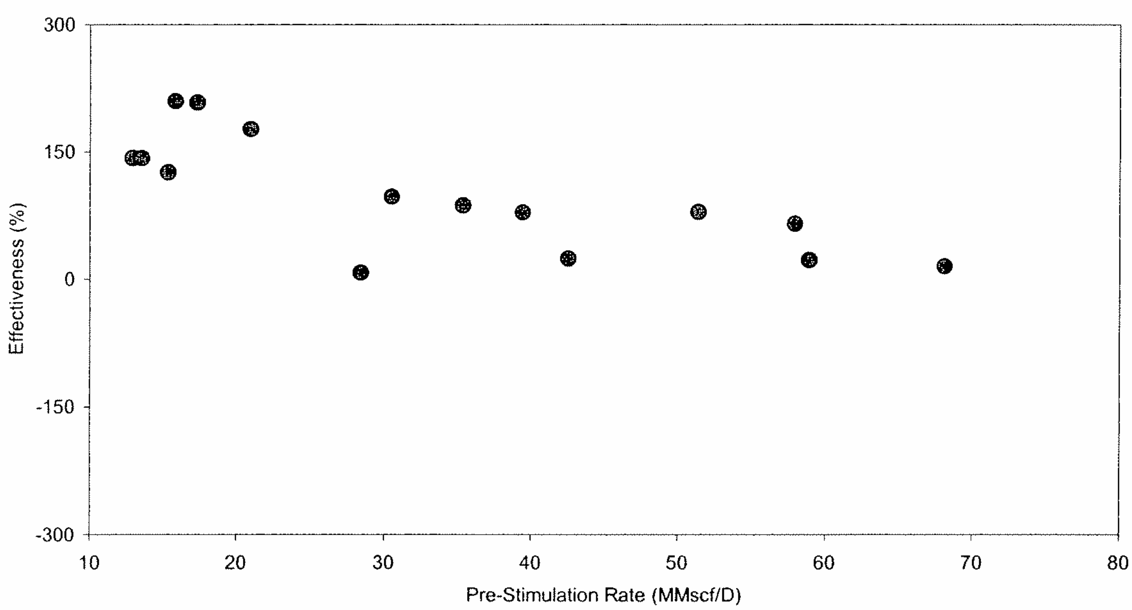


Figure 2-43: Impact of Pre-Stimulation Rate on Effectiveness of Acidizing in Carbonates for High Rates

There are similar relationships between pre-stimulation rate and effectiveness in sandstones, as shown in **Figure 2-44.** However, in sandstones, the trend of increasing effectiveness with decreasing pre-stimulation rate is evident at lower rates (<10 MMSCF). There is no discernable relationship between the pre-stimulation rate and longevity, post-stimulation decline rate, or $PV_{7.5\ yrs}$ for either sandstones or carbonates.

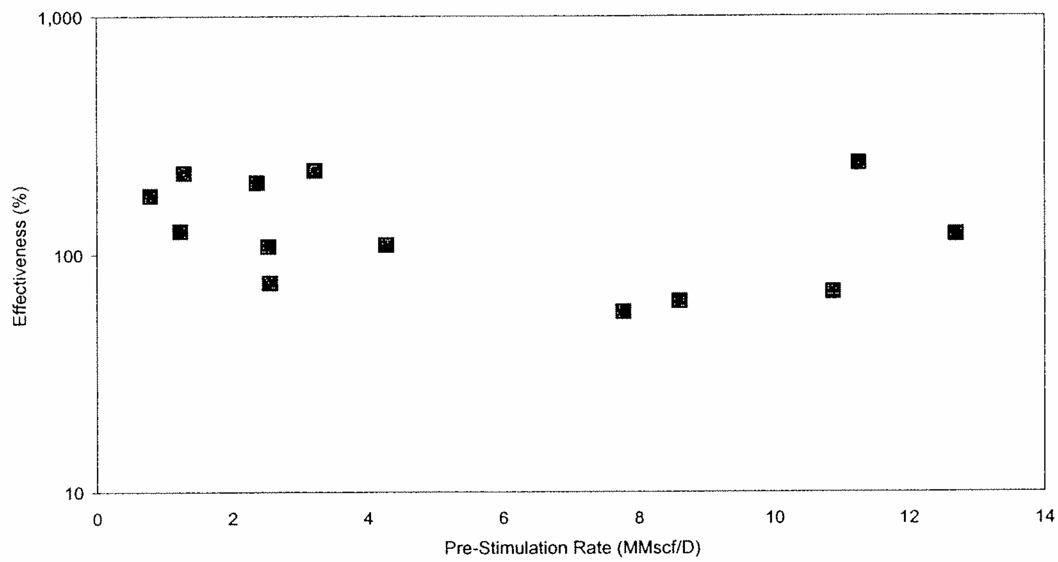


Figure 2-44: Impact of Pre-Stimulation Rate on Effectiveness of Acidizing in Sandstones

2.1.2.6.2 Fracture Treatments

Examination of fracturing treatment data suggests that although fracturing is more effective in sandstones (**Figure 2-45**), it lasts longer in carbonates (**Figure 2-46**).

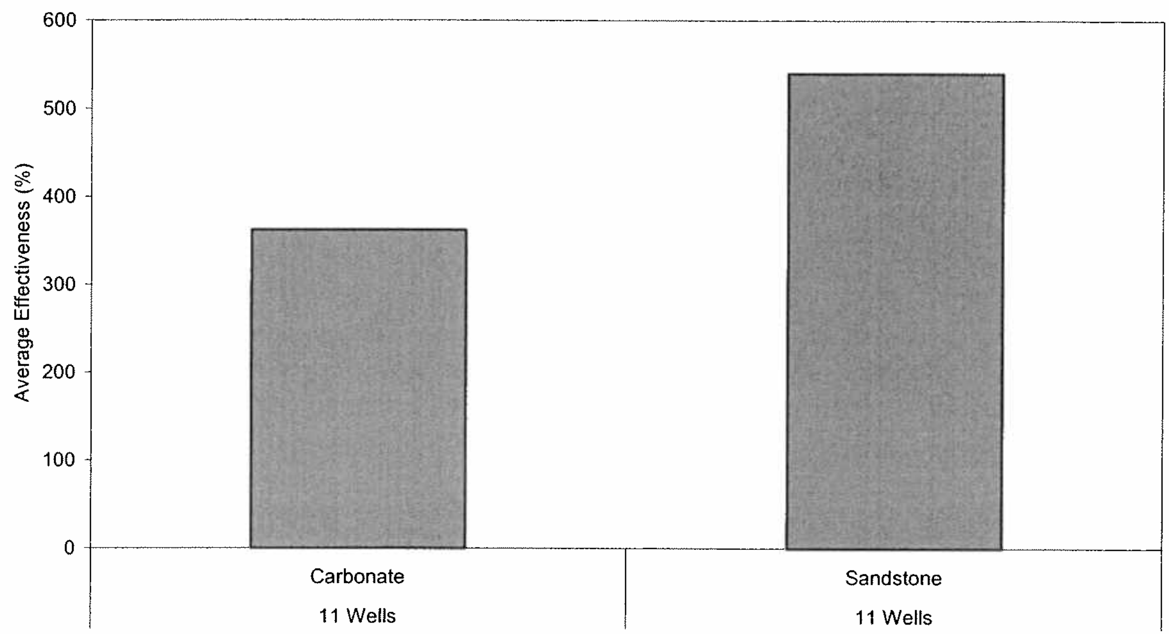


Figure 2-45: Impact of Lithology on Effectiveness of Fracturing

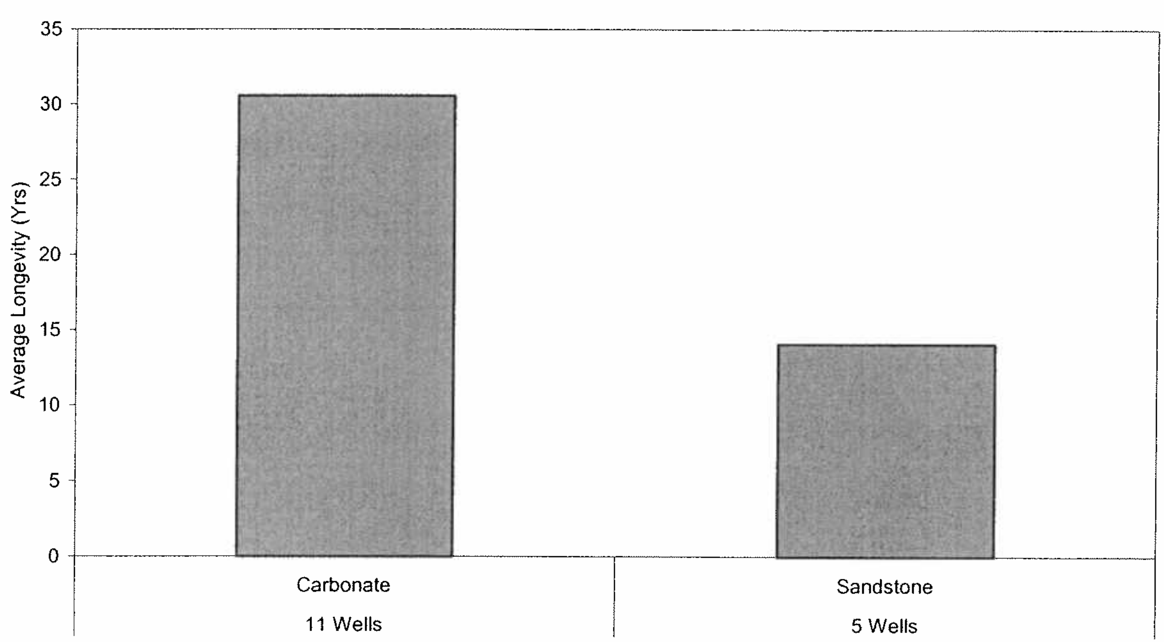


Figure 2-46: Impact of Lithology on Longevity of Fracturing

Using the PV75 concept to consider these two aspects simultaneously, it is clear that fracturing is more successful in Carbonates (**Figure 2-47**).

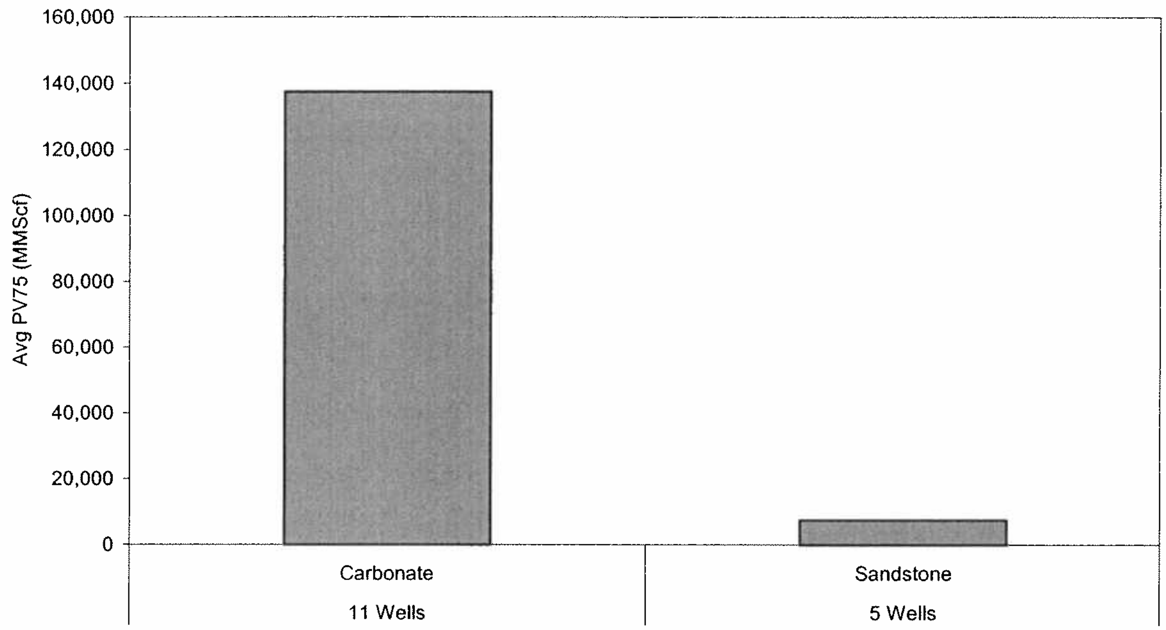


Figure 2-47: Impact of Lithology on 7-1/2 Year Potential Volume of Fracturing

Looking at the post-stimulation decline data suggests that the difference in the 7-12 year potential volume are largely due to the higher post-stimulation declines seen in sandstones (**Figure 2-48**).

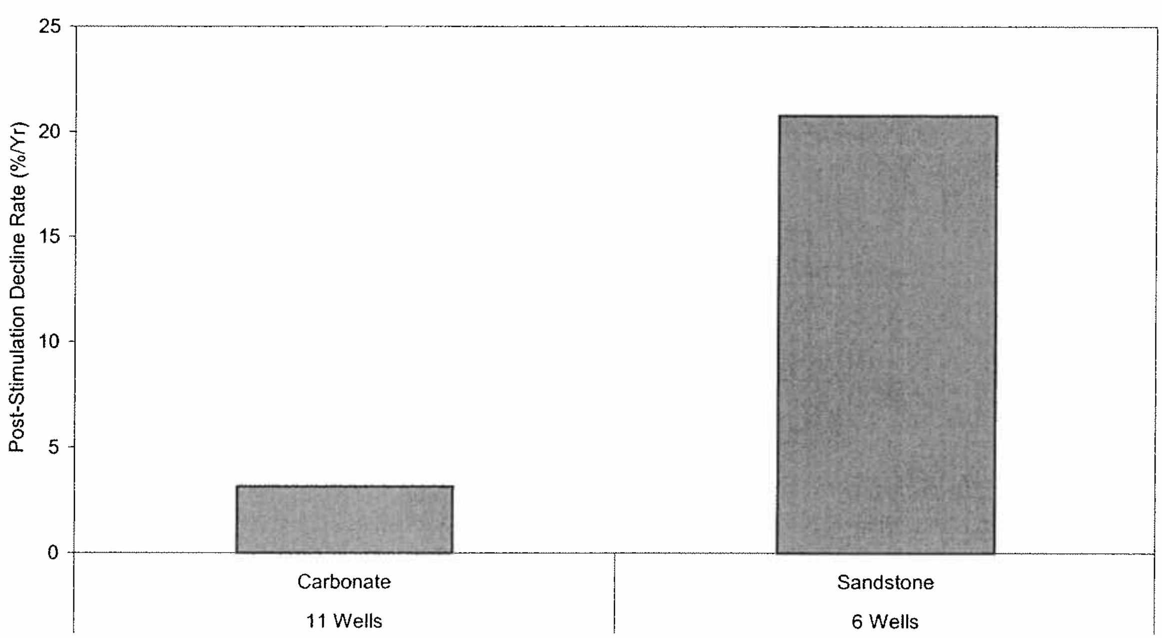


Figure 2-48: Impact of Lithology on Post-Stimulation Decline Rate of Fracturing

Figure 2-49 through Figure 2-52 show the ranges of effectiveness, longevity, PV75, and post-stimulation decline rates in fracturing treatments.

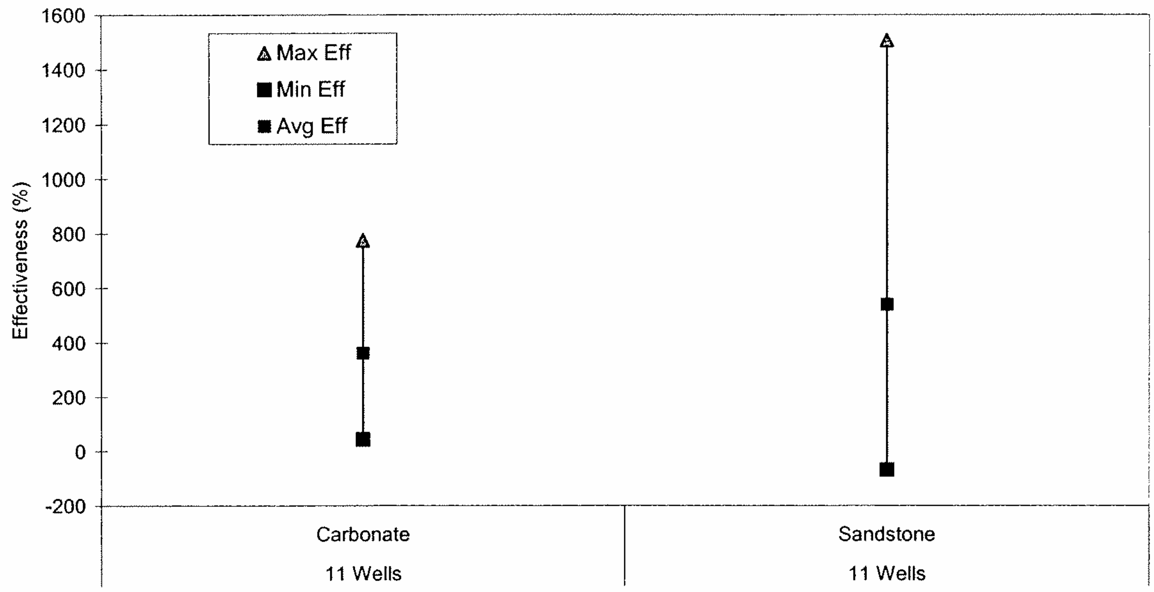


Figure 2-49: Range of Effectiveness in Fracturing

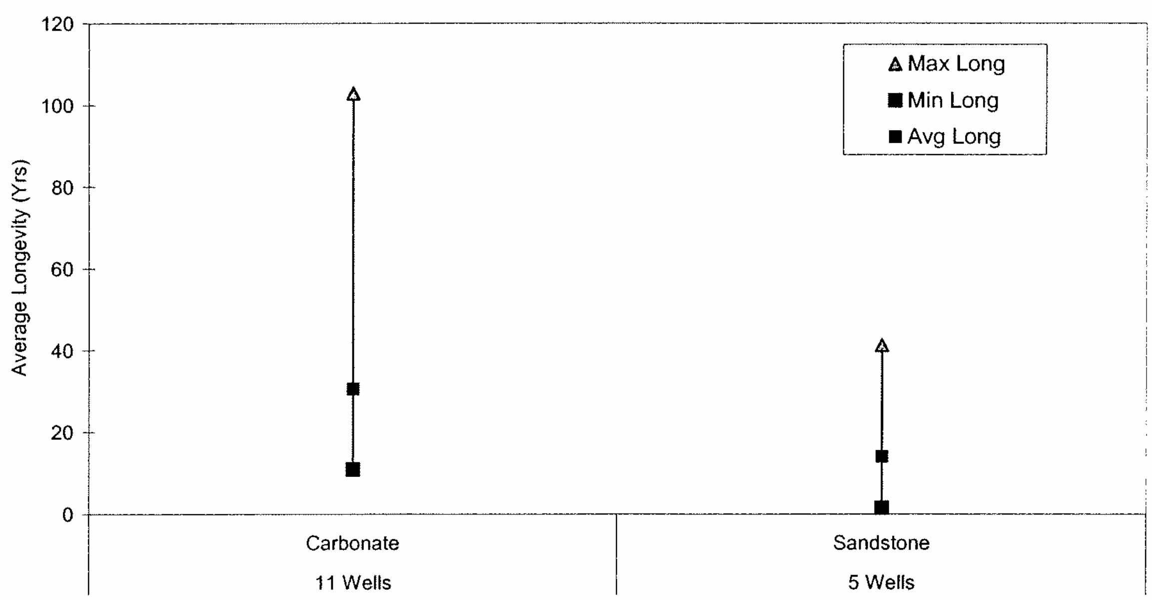


Figure 2-50: Range of Longevity in Fracturing

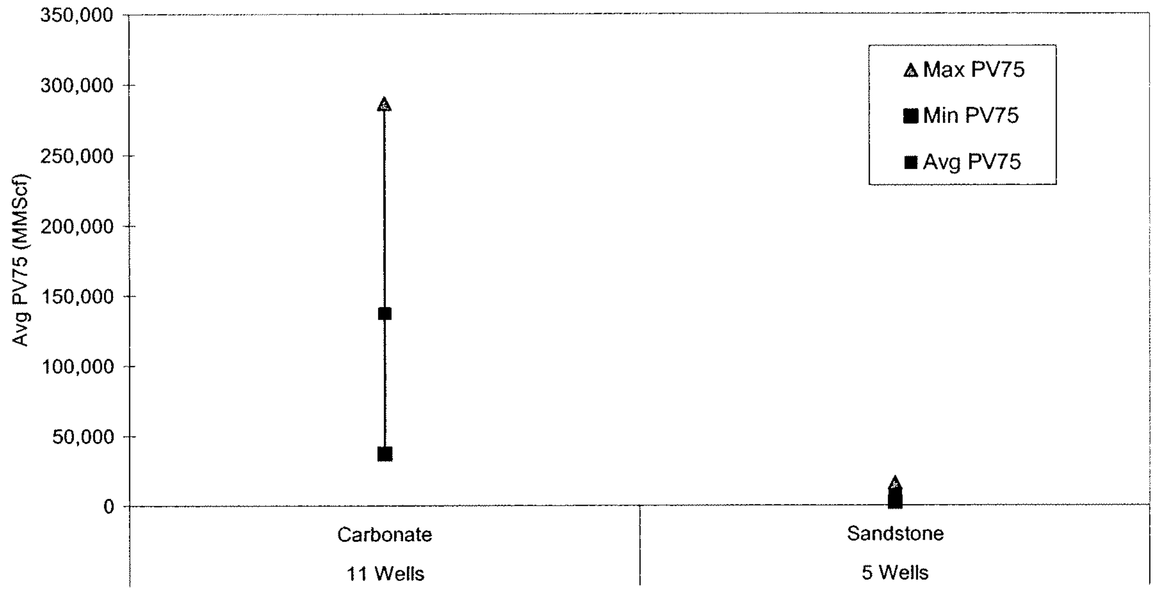


Figure 2-51: Range of 7-1/2 Year Potential Volume in Fracturing

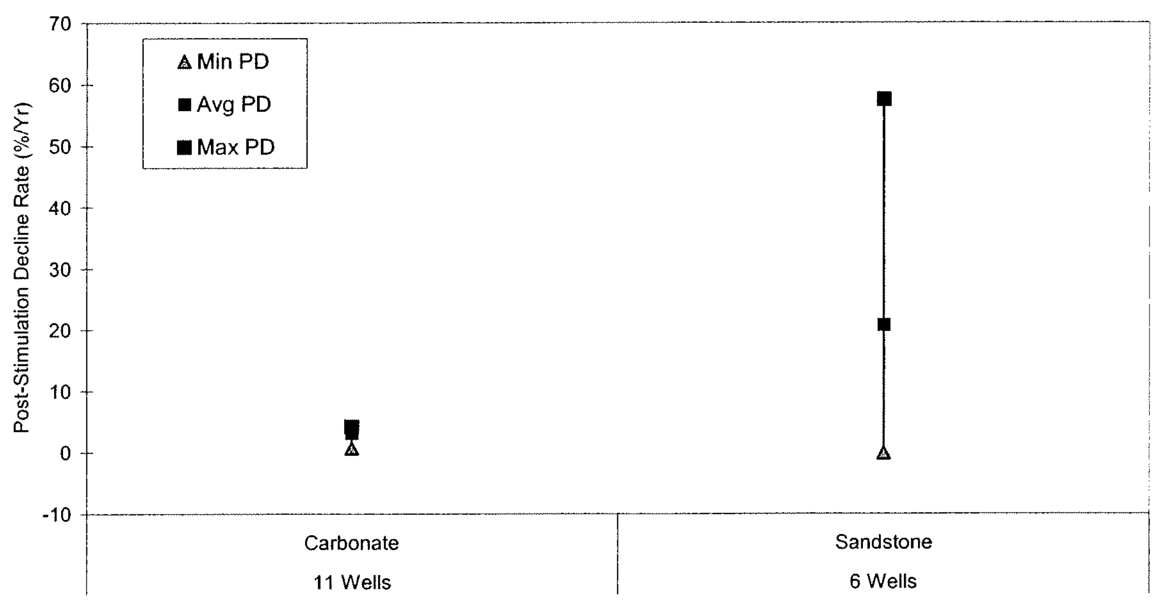


Figure 2-52: Range of Post-Stimulation Decline Rate in Fracturing

Insufficient data is available for fracturing in carbonate reservoirs to draw any statistically significant conclusions regarding the impact of process parameters (e.g., fluid volumes, acid concentrations, etc.) on fracturing success.

For sandstones, the data suggest that, generally, more proppant may result in more effective fracturing (**Figure 2-53**). There is insufficient data to determine if any correlations between proppant volume and longevity and/or effectiveness exist.

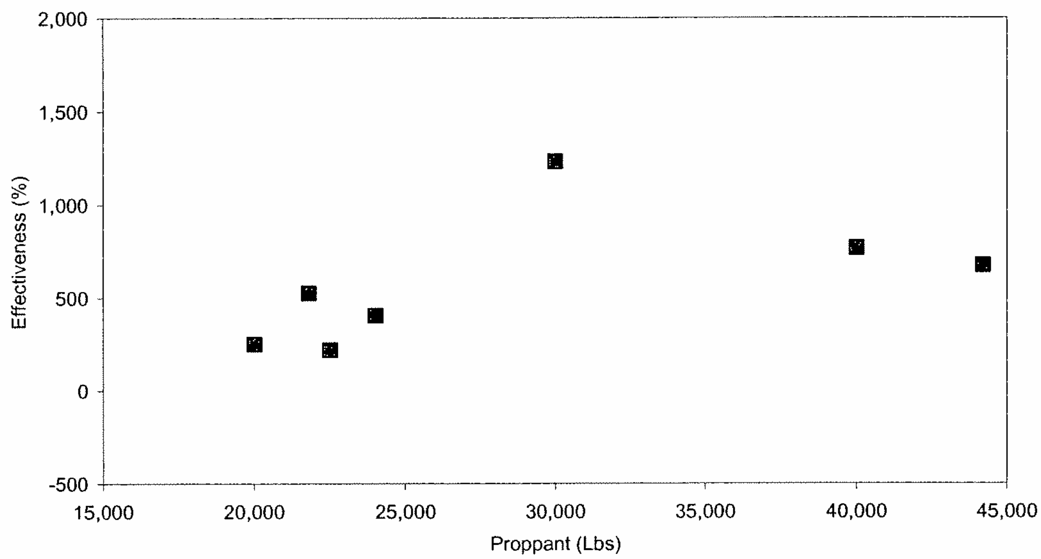


Figure 2-53: Impact of Proppant Volume on Effectiveness of Fracturing

For sandstones, the limited amount of available data suggests that, generally, less total fluid volume may results in more effective fracturing (**Figure 2-54**). There is insufficient data to determine if any correlations between total fluid volume and longevity or effectiveness exist.

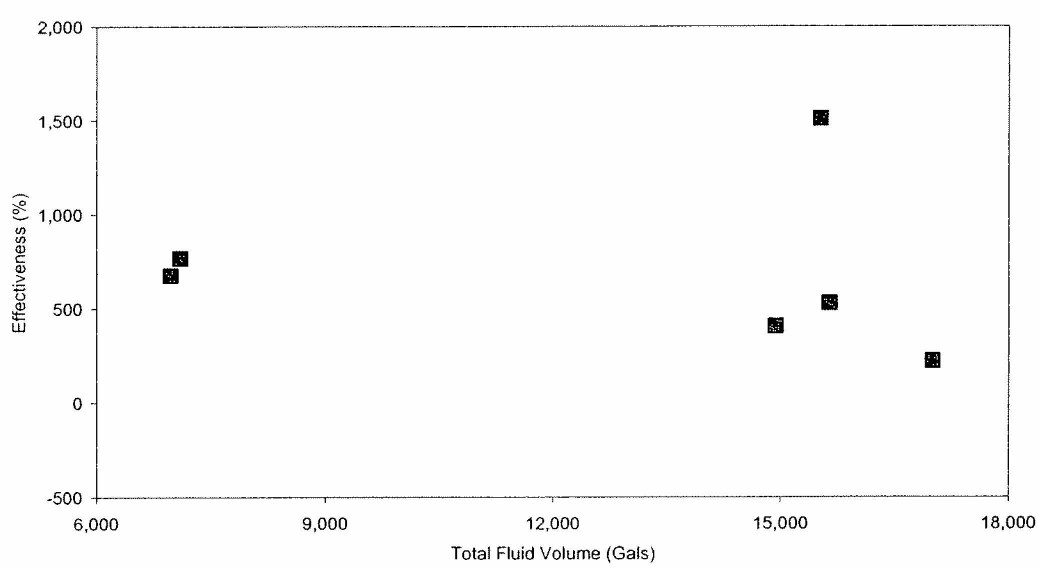


Figure 2-54: Impact of Total Fluiid Volume on Effectiveness of Fracturing

2.1.2.6.3 Re-Fracture Treatments

Examination of re-fracturing treatment data suggests that foam re-fracturing may be slightly more effective than delta re-fracturing (**Figure 2-55**), but the benefits of delta fracturing last longer than those of foam fracturing (**Figure 2-56**).

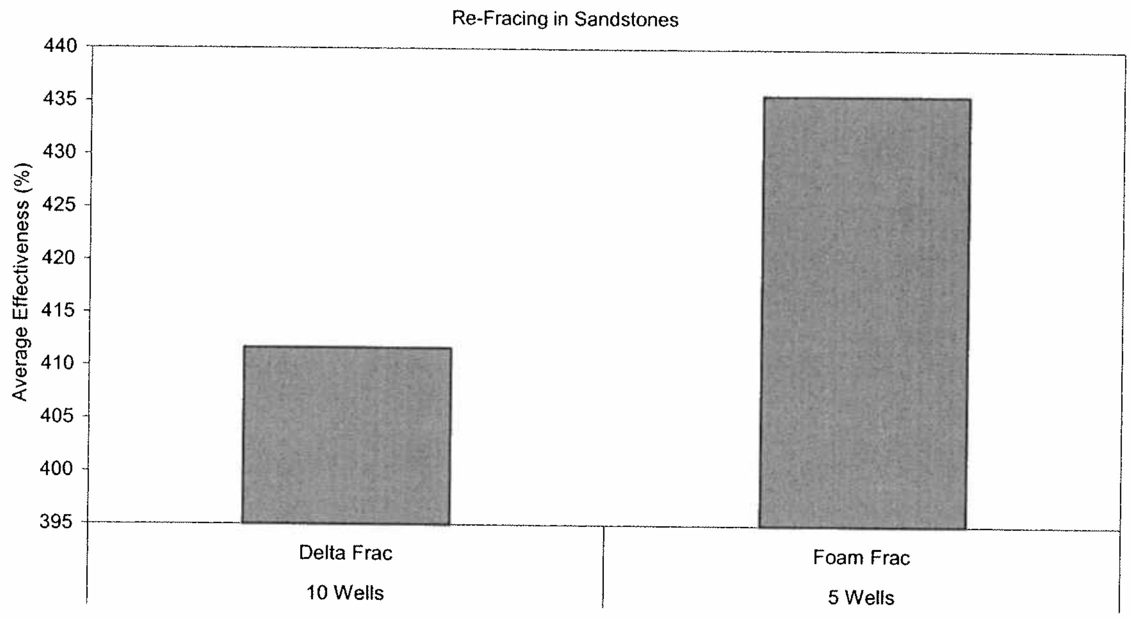


Figure 2-55: Effectiveness of Foam Frac vs Delta Frac

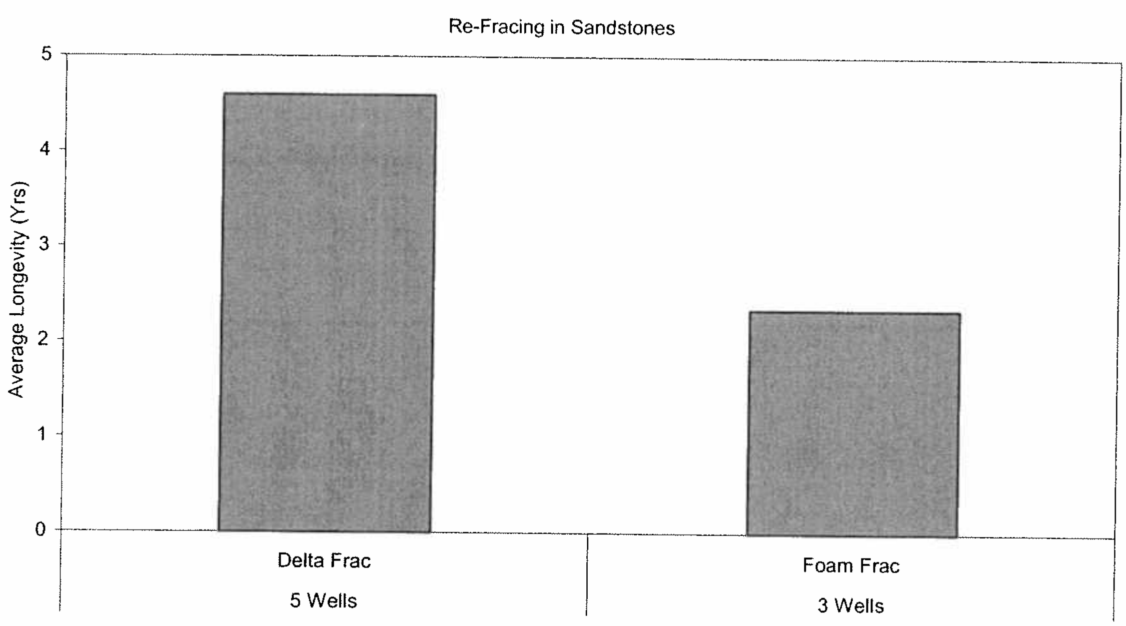


Figure 2-56: : Longevity of Foam Frac vs Delta Frac

Using the PV75 concept, it is clear that, considering these two facts simultaneously, re-fracturing is more successful in carbonates (**Figure 2-57**). As we have seen in other cases, the post-stimulation decline rates have a significant impact on the 7-1/2 year potential volume values (**Figure 2-58**).

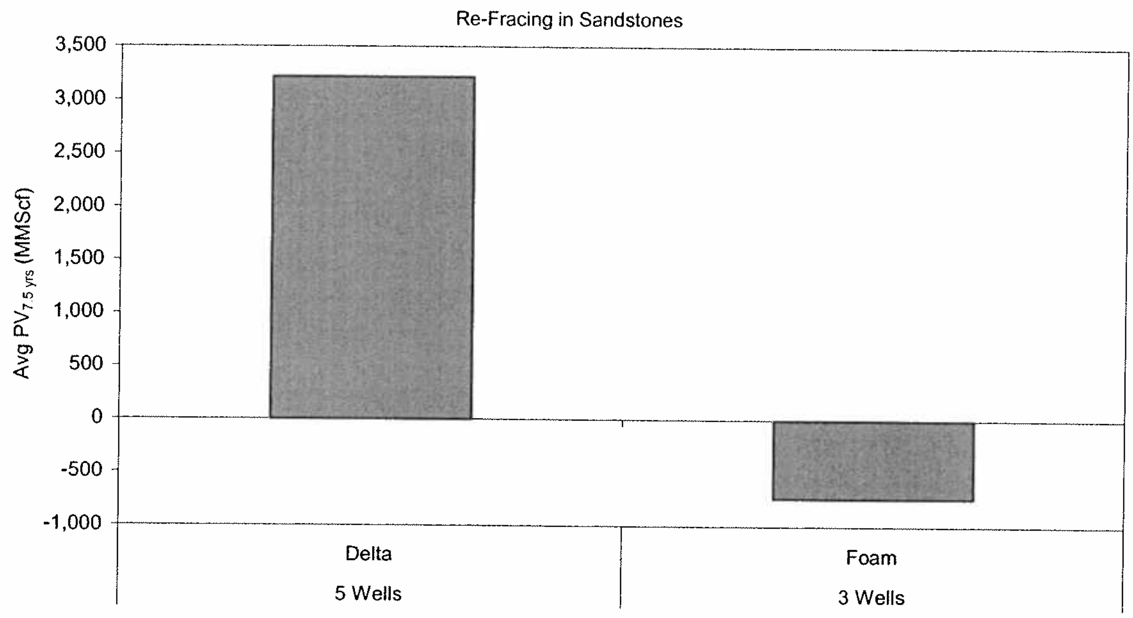


Figure 2-57: 7-1/2 Year Potential Volume of Foam Frac vs Delta Frac

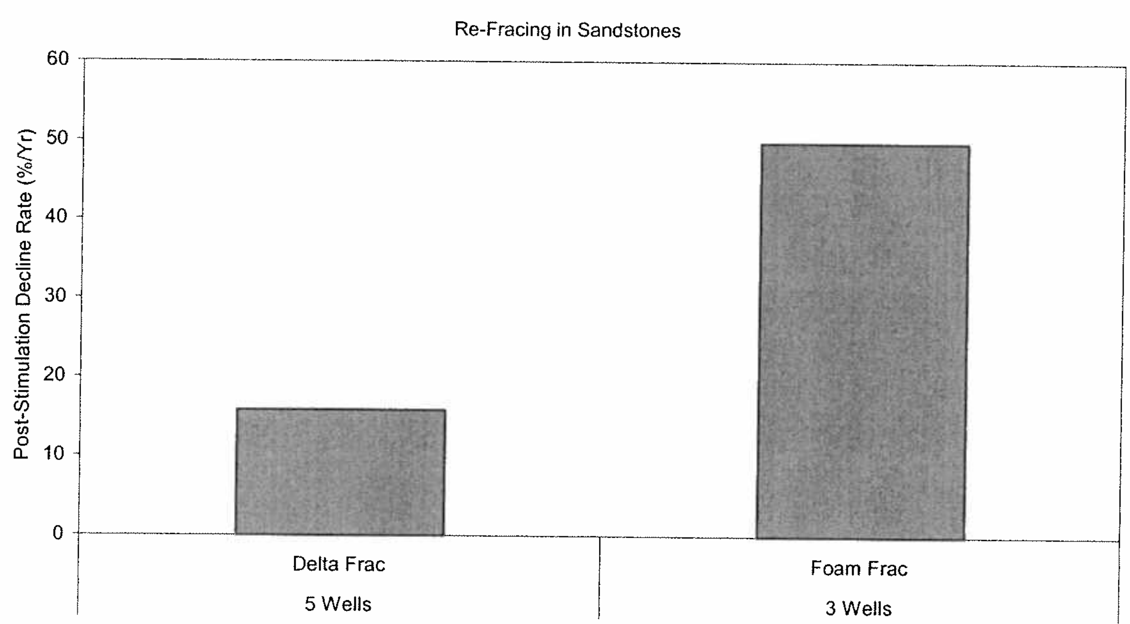


Figure 2-58 Post-Stimulation Decline Rate of Foam Frac vs Delta Frac

Figure 2-59, **Figure 2-60, Figure 2-61,** and **Figure 2-62** below show the range of values for effectiveness, longevity, PV75, and post-stimulation decline rates for two types of re-fracturing treatments.

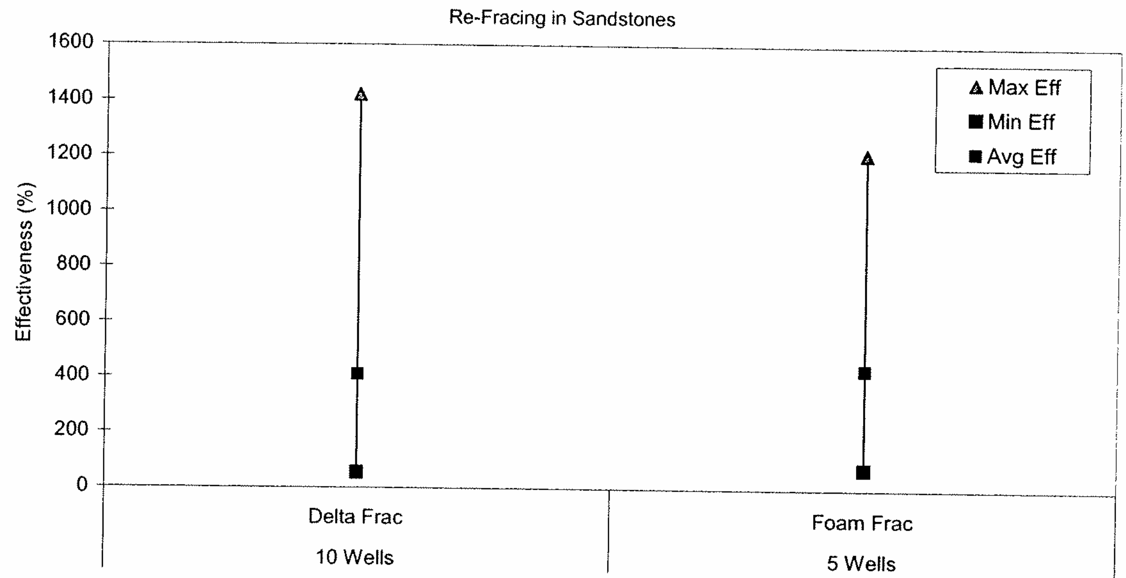


Figure 2-59: Range of Values of Effectiveness for Foam Frac and Delta Frac

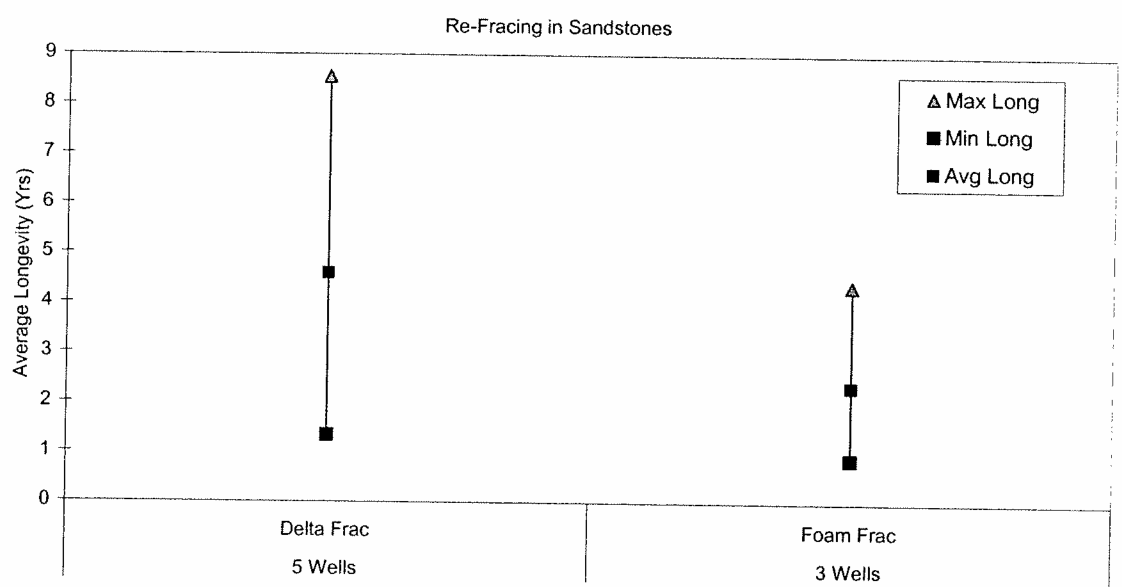


Figure 2-60: Range in Values of Longevity for Foam Frac and Delta Frac

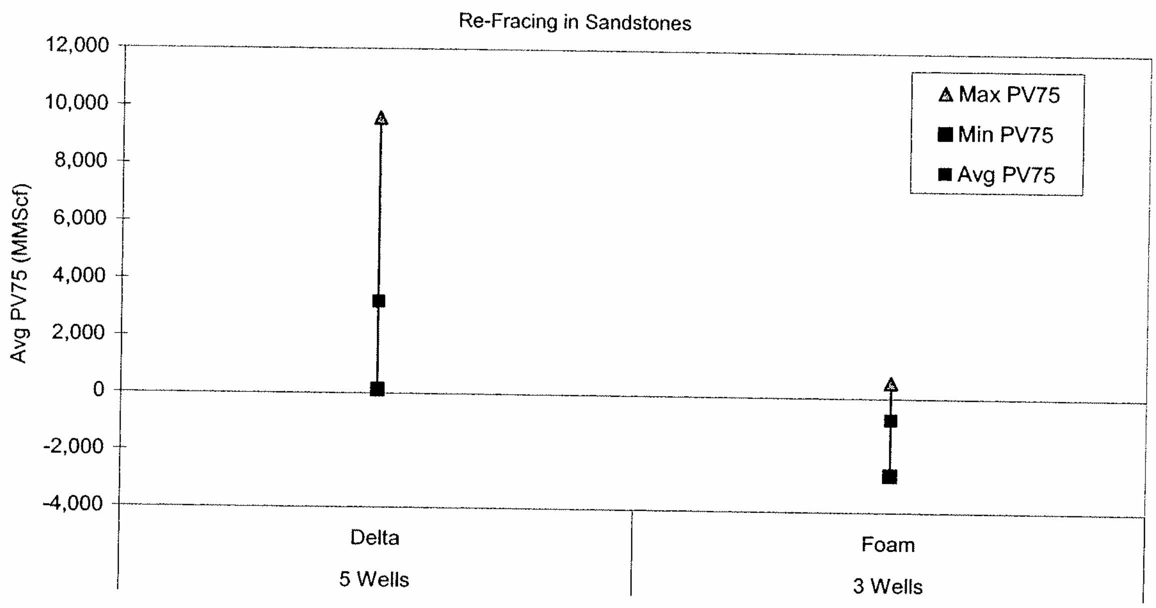


Figure 2-61: Range in Values of 7-1/2 Year Potential Volume for Foam Frac and Delta Frac

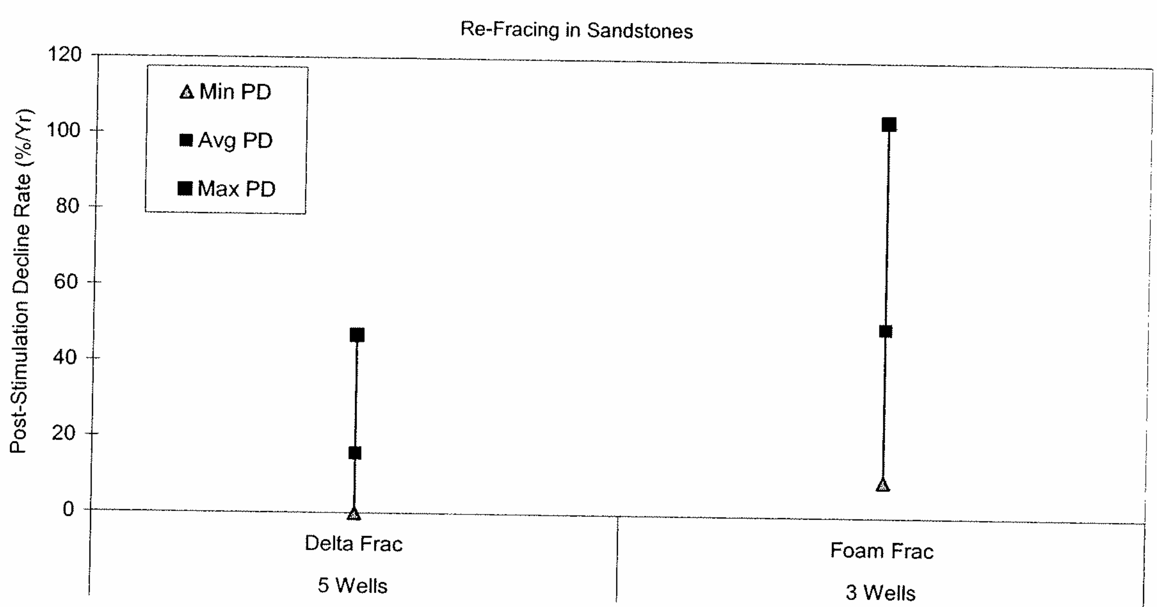


Figure 2-62: Range in Values of Post-Stimulation Decline Rates for Foam Frac and Delta Frac

Effectiveness, longevity, and 7-1/2 year potential volume as a function of proppant volume are shown for re-fracture treatments in **Figure 2-63, Figure 2-64,** and **Figure 2-65.** Although one might expect to see improved performance with additional proppant volume, such a trend is very subtle (at best) in these data.

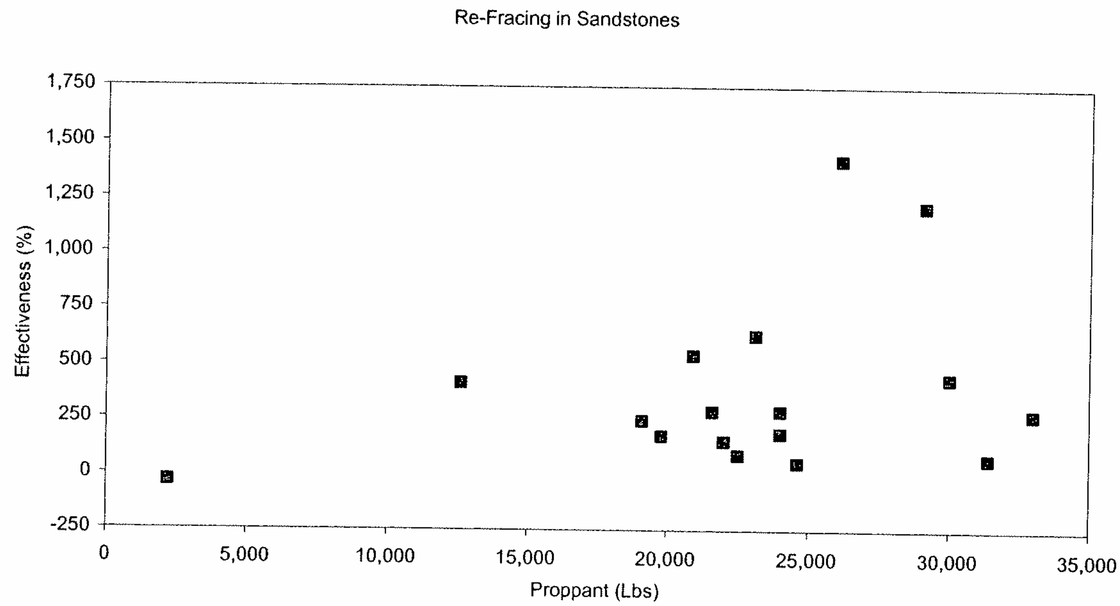


Figure 2-63: Effectiveness of Re-Fracturing vs Total Proppant Volume

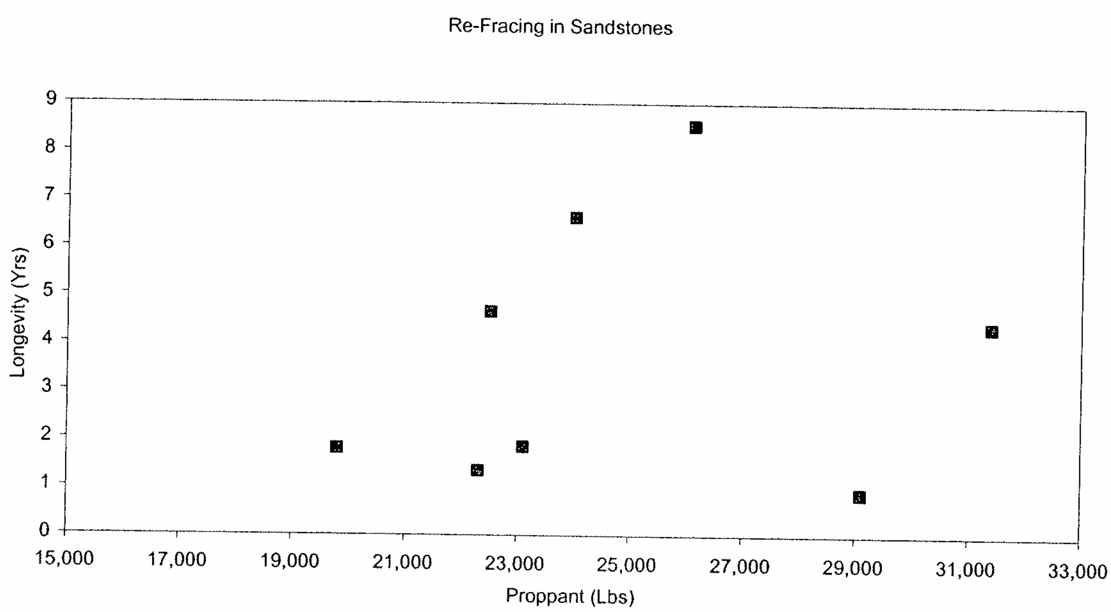


Figure 2-64: Longevity of Re-Fracturing vs Total Proppant Volume

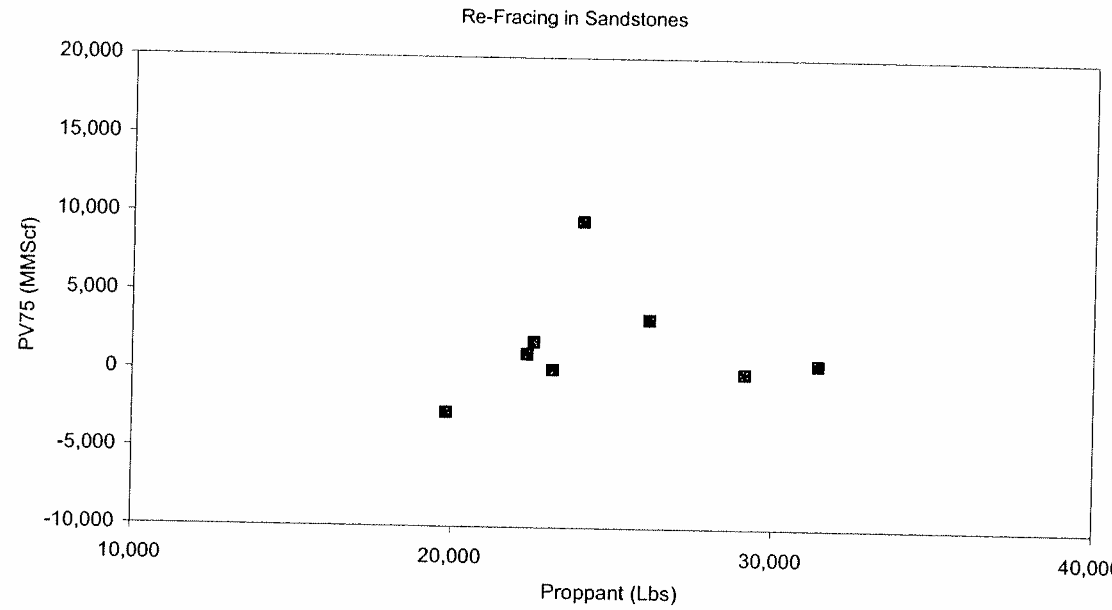


Figure 2-65: 7-1/2 Year Potential Volume of Re-Fracturing vs Total Proppant Volume

Effectiveness, longevity, and 7-1/2 year potential volume as a function of total treatment volume are shown for re-fracture treatments in **Figure 2-66, Figure 2-67,** and **Figure 2-68.** These data suggest that higher total treatment volumes *may* lead to more successful re-fracturing treatments. As was the case with the proppant data for re-fracturing treatments, the trend are somewhat subtle in these data, and additional data needs to be collected to verify these results.

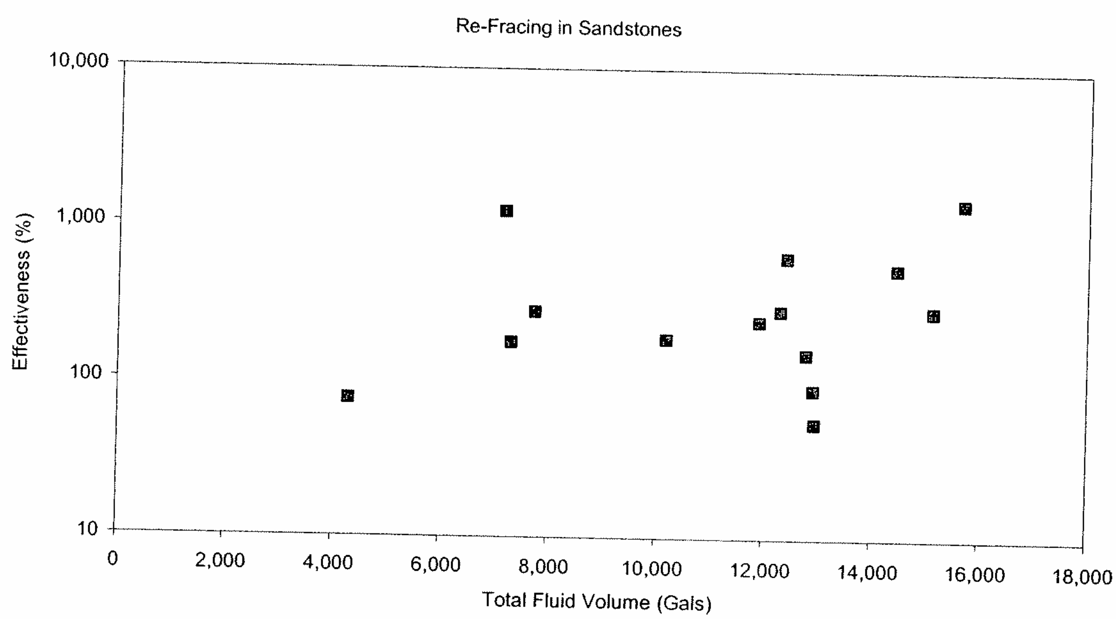


Figure 2-66: Effectiveness of Re-Fracturing vs Total Treatment Volume

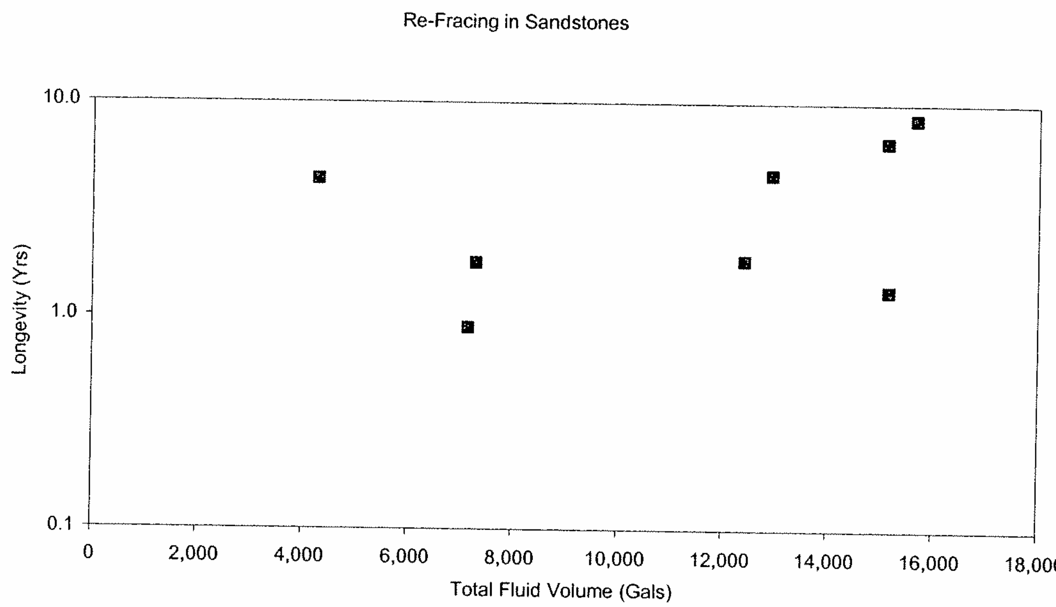


Figure 2-67: Longevity of Re-Fracturing vs Total Proppant Volume

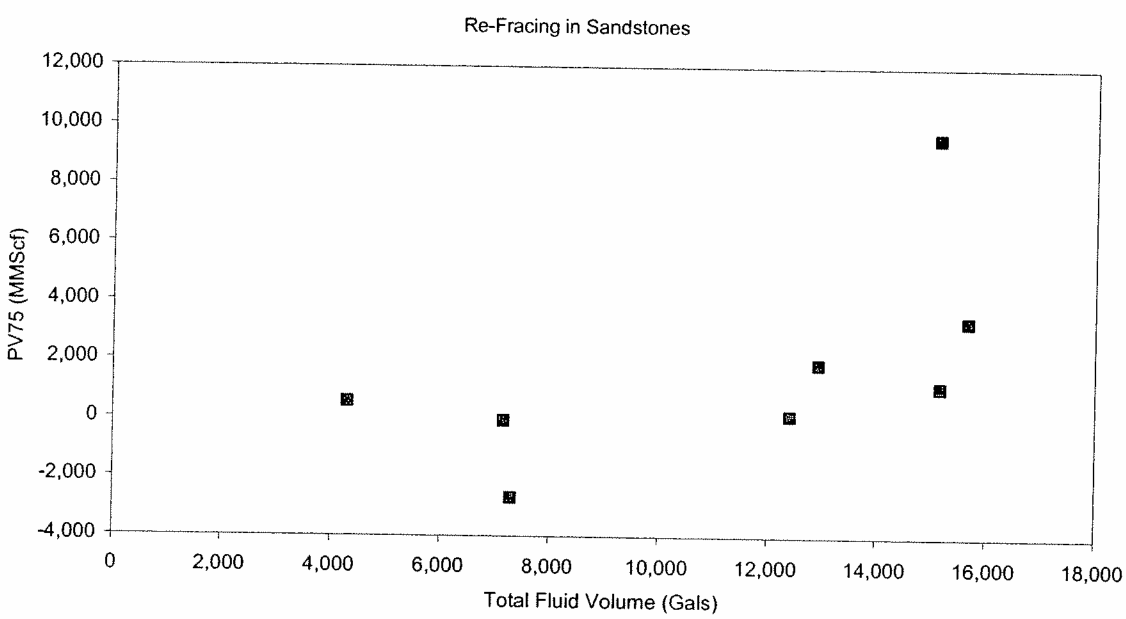


Figure 2-68: 7-1/2 Year Potential Volume of Re-Fracturing vs Total Treatment Volume

2.1.2.6.4 Perforating Treatments

The paucity of data severely limited meaningful conclusions for perforating treatments. Examination of perforating data suggests that, in sandstones, thinner reservoirs are more effectively perforated (**Figure 2-69**).

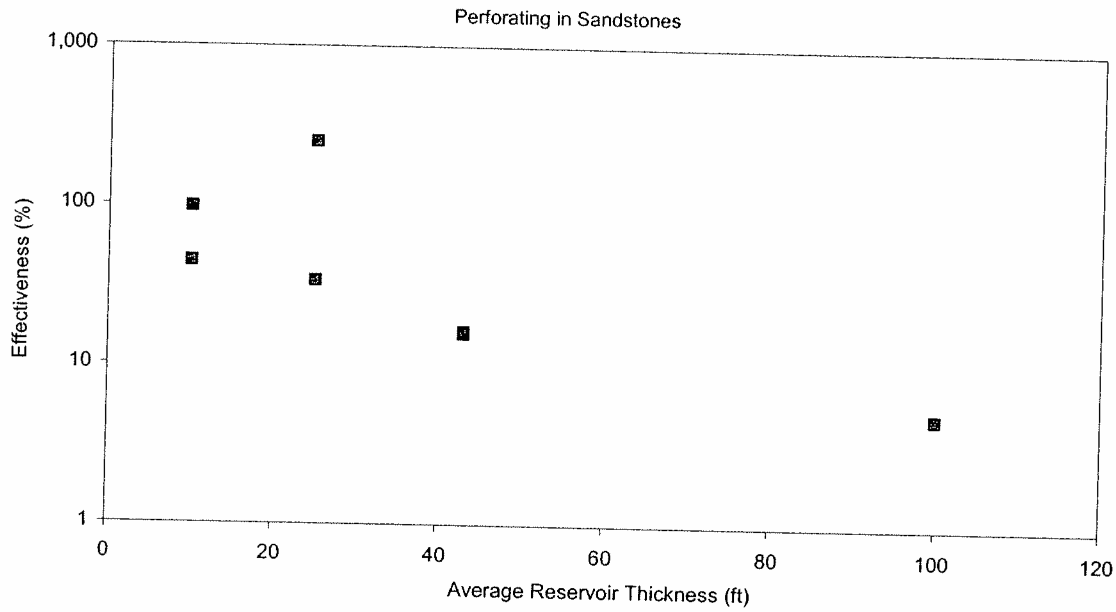


Figure 2-69: Effectiveness of Perforating Treatment in Sandstones vs Average Reservoir Thickness

Examination of extremely limited shot density data suggests that six or eight shots per foot *may* out-performs four shots per foot in sandstone reservoirs (**Figure 2-69**).

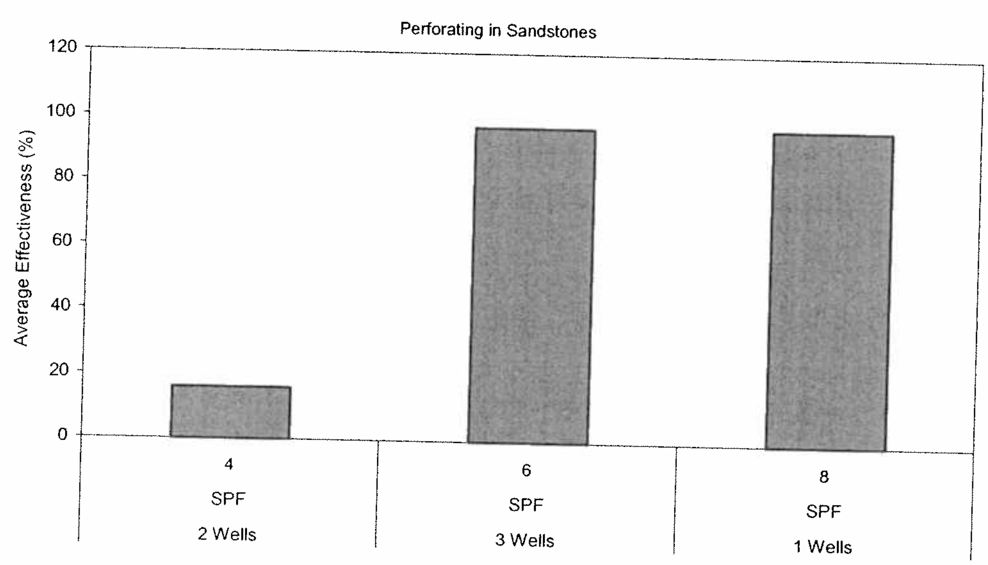


Figure 2-70: Effectiveness of Perforating Treatment in Sandstones vs Shots-Per-Foot

Lack of detailed stimulation data made it impossible to determine the impact of variables on perforating success, which suggests that little detailed data is recorded during perforating treatments.

2.1.2.6.5 Combination Acidizing, Hydroblasting, and Perforating Treatments in Sandstones

As shown in **Figure 2-71**, **Figure 2-72**, and **Figure 2-73** examination of data for the combination acidizing, hydroblasting, and perforating treatments suggests that both longevity, effectiveness and 7-1/2 year potential volume increase somewhat with acid volume.

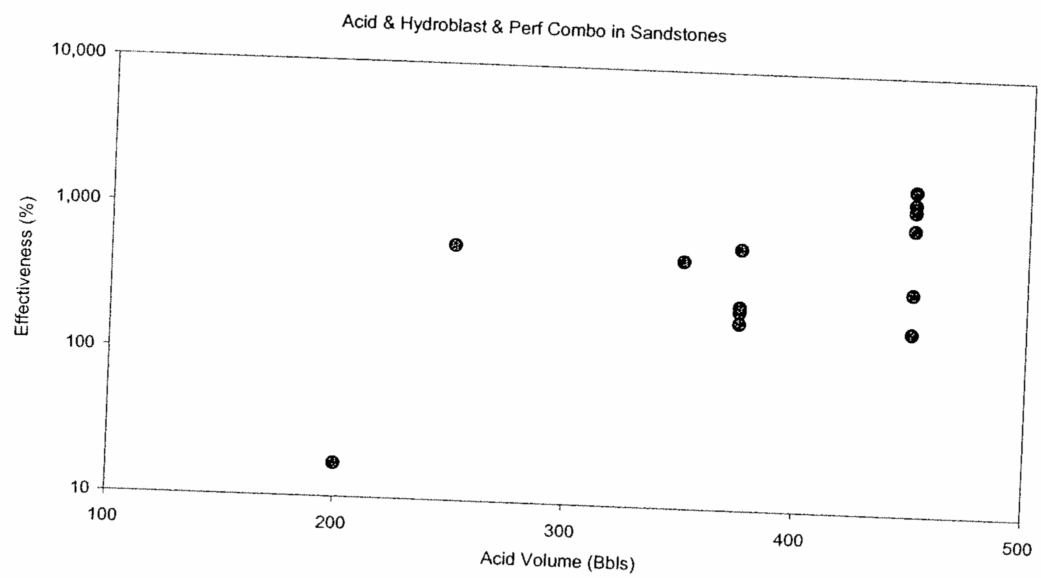


Figure 2-71: Effectiveness vs Acid Volume for Combination Acid & Hydroblast, & Perforate Treatment

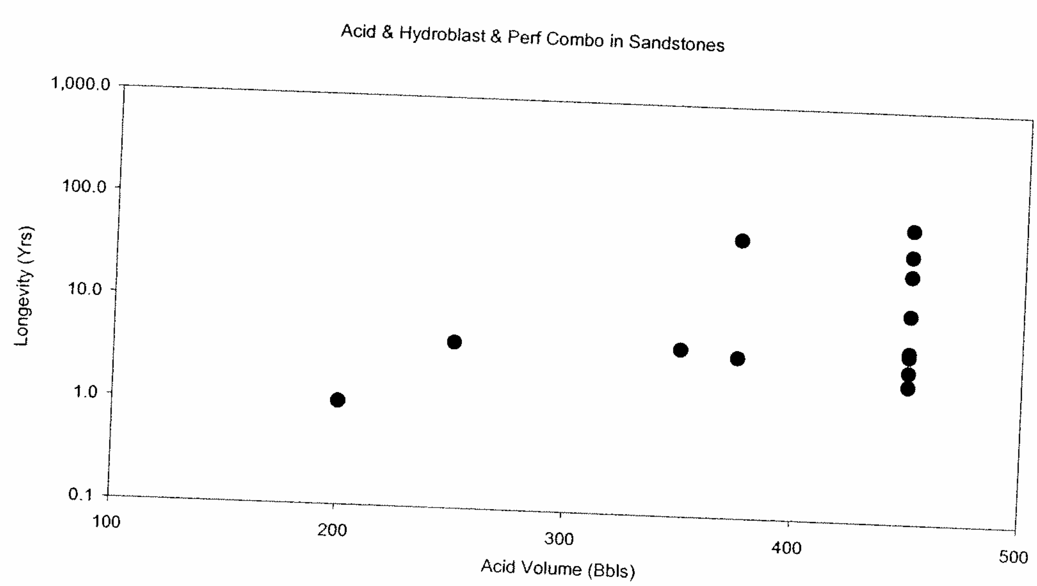


Figure 2-72: Longevity vs Acid Volume for Combination Acid & Hydroblast, & Perforate Treatment

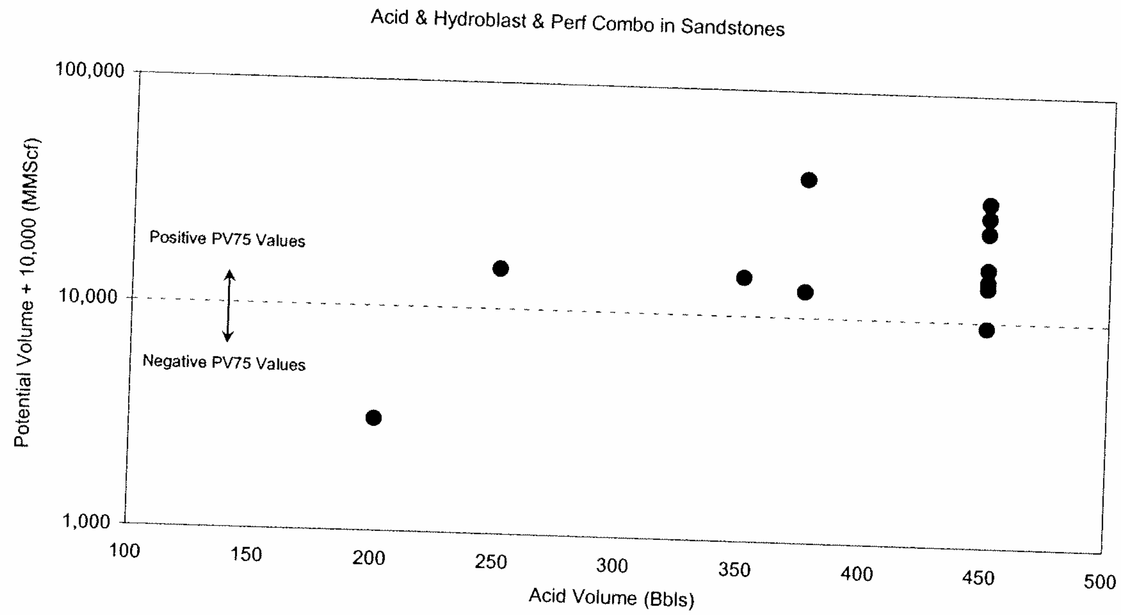


Figure 2-73: 7-1/2 Yr PV vs Acid Volume for Combination Acid & Hydroblast, & Perforate Treatment

The data also suggests that effectiveness, longevity, and PV75 increase with increased shot density (**Figure 2-74**, **Figure 2-75**, and **Figure 2-76**).

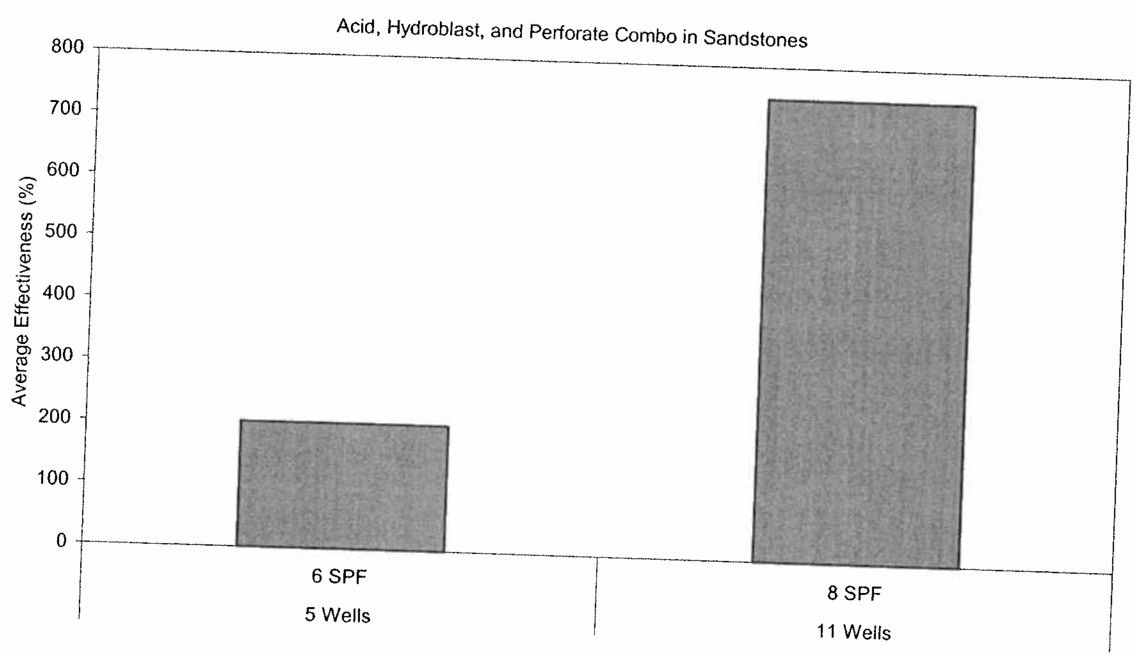


Figure 2-74: Effectiveness vs Shot Density for Combination Acid & Hydroblast, & Perforate Treatment

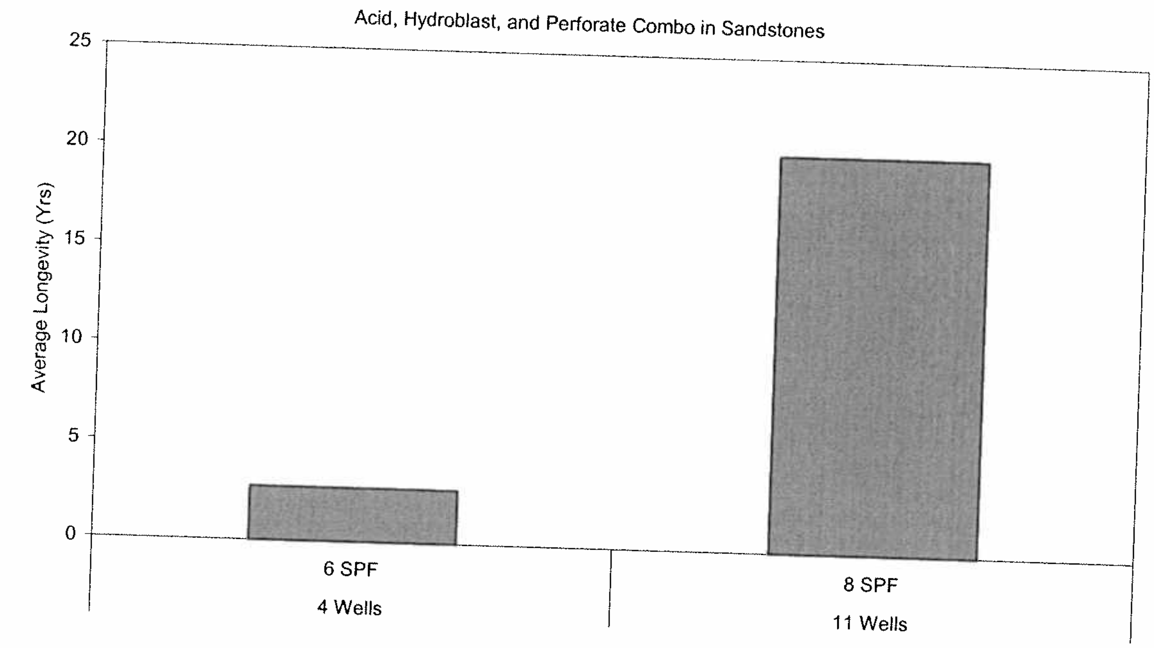


Figure 2-75: Longevity vs Shot Density for Combination Acid & Hydroblast, & Perforate Treatment

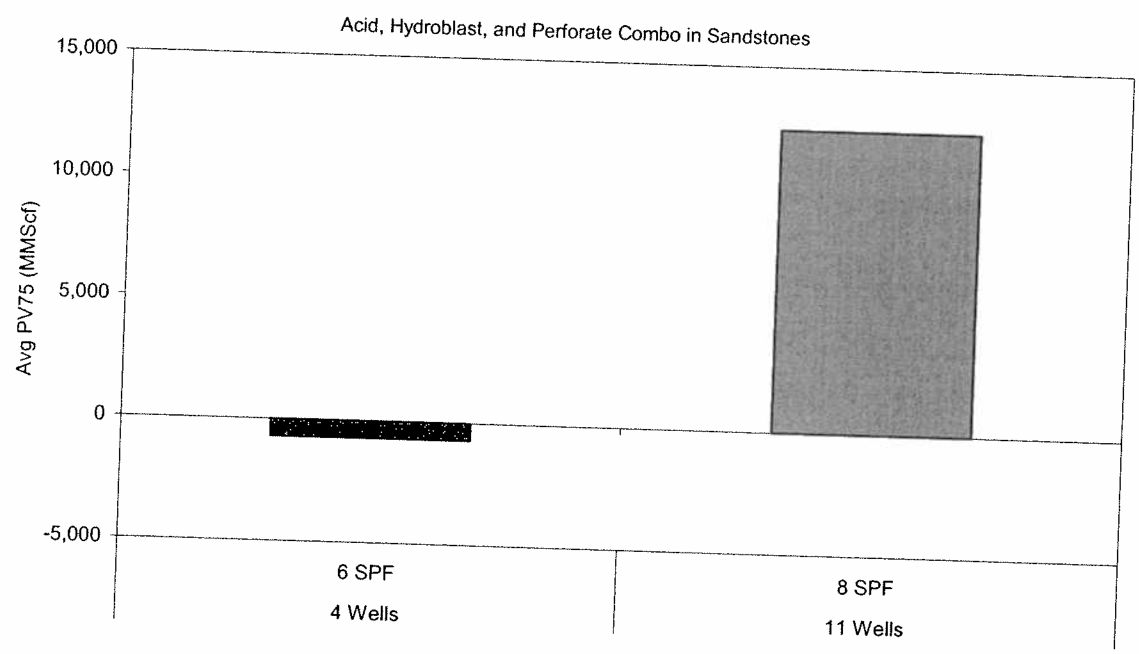


Figure 2-76: 7-1/2 Yr PV vs Shot Density for Combination Acid & Hydroblast, & Perforate Treatment

Figure 2-77, **Figure 2-78**, and **Figure 2-79** below show the range of values for effectiveness, longevity, and PV75 for various shot densities.

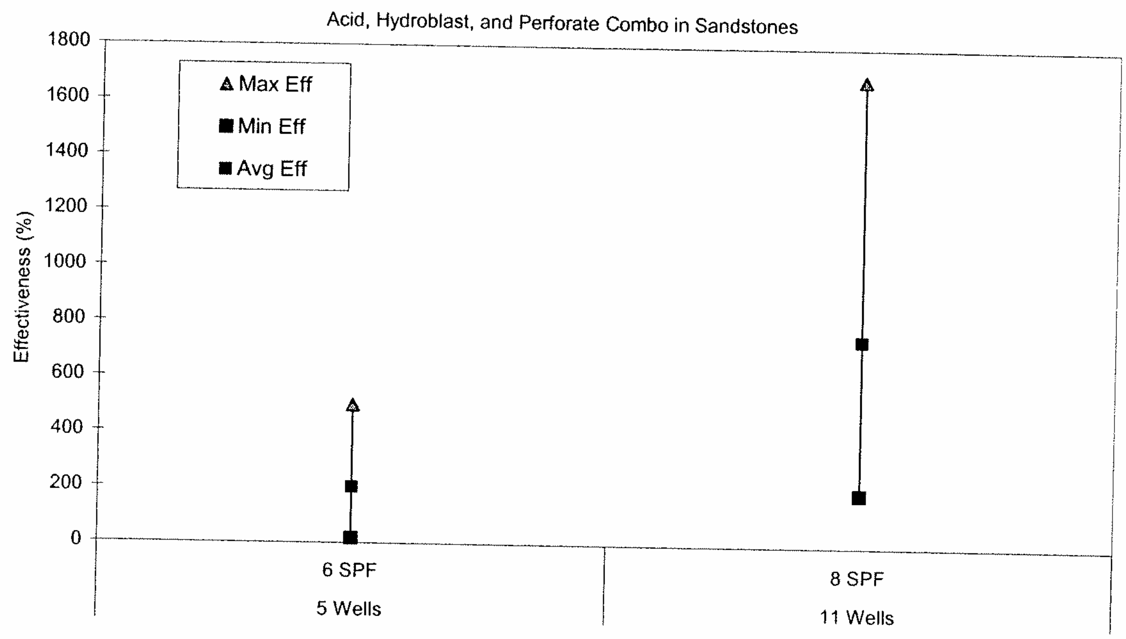


Figure 2-77 : Effectiveness Range vs Shot Density for Combination Acid, Hydroblast & Perf Treatment

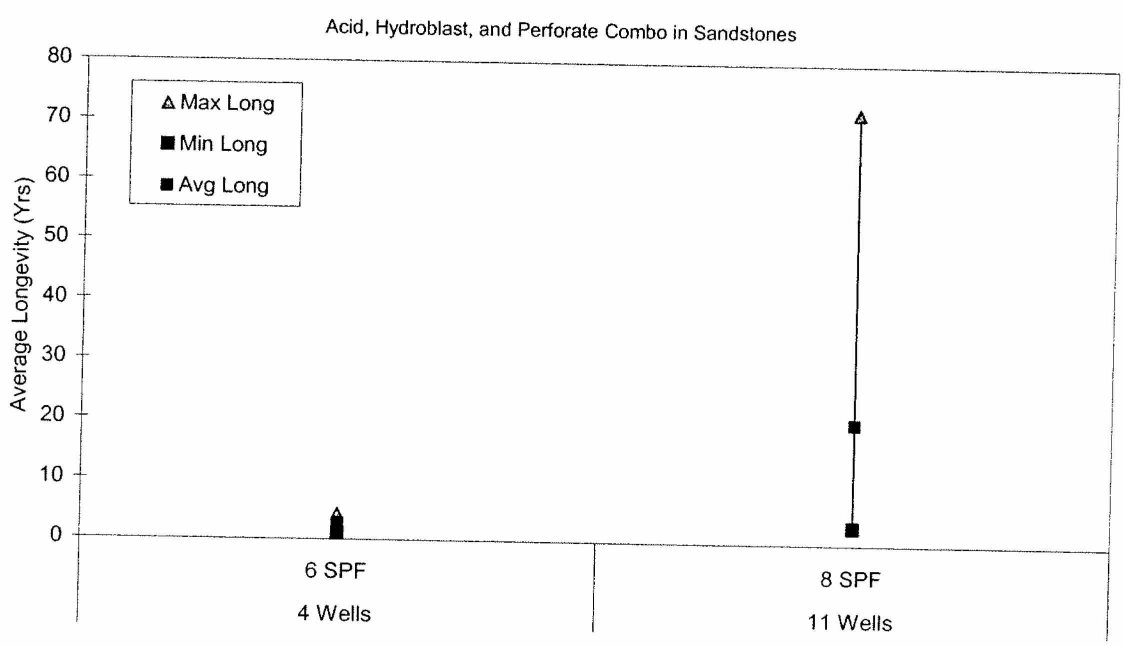


Figure 2-78: Longevity Range vs Shot Density for Combination Acid, Hydroblast, & Perf Treatment

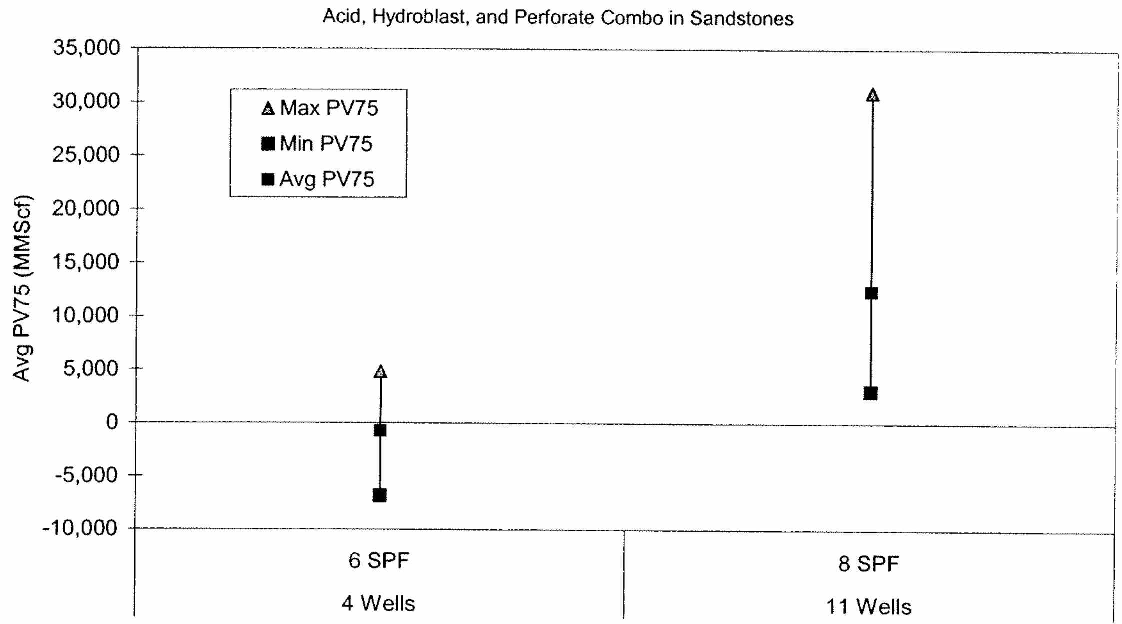


Figure 2-79: 7-1/2 Yr PV Range vs Shot Density for Combination Acid, Hydroblast, & Perf Treatment

Although the impact of the total number of perforations on effectiveness and longevity is somewhat subtle, (**Figure 2-80** and **Figure 2-81**), a plot of total number of perforations vs PV75 more clearly indicates that more perforations are better (**Figure 2-82**).

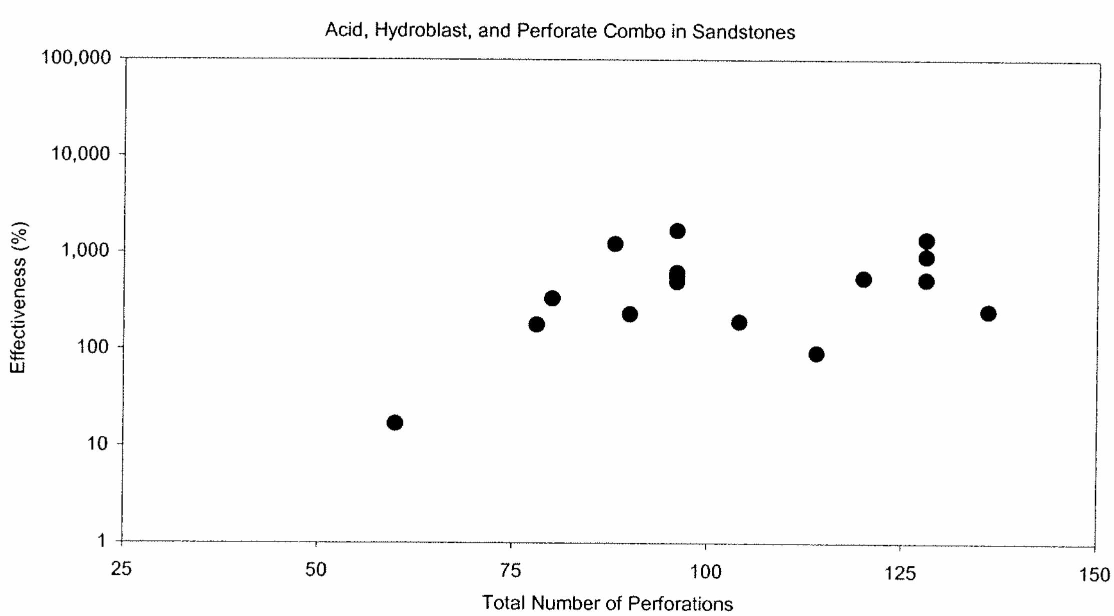


Figure 2-80: Effectiveness vs # Shots for Combination Acid & Hydroblast, & Perforate Treatment

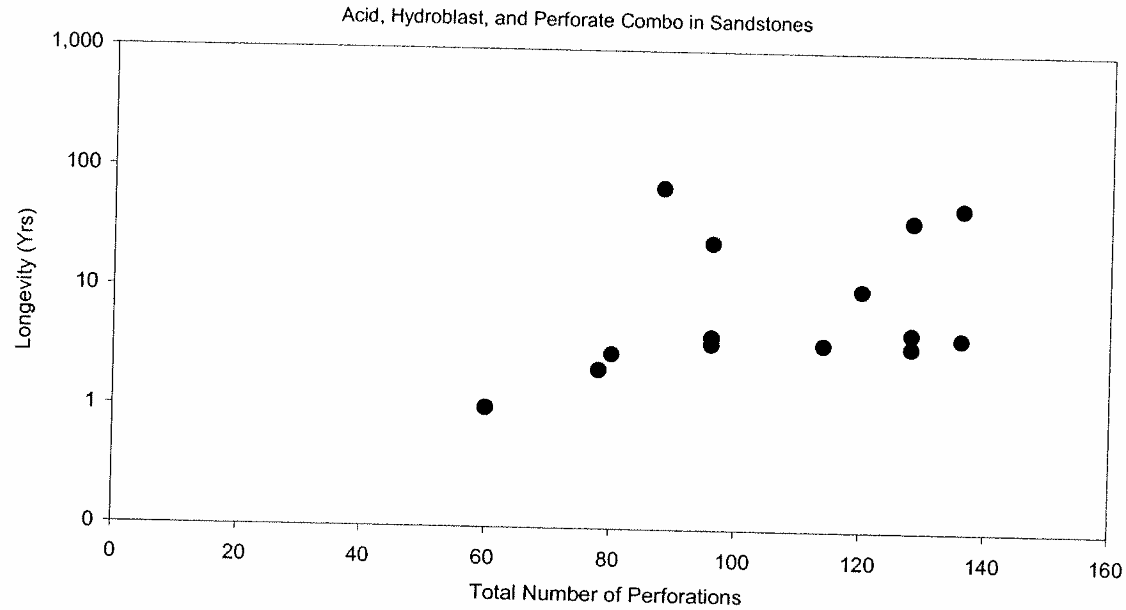


Figure 2-81: Longevity vs # Shots for Combination Acid & Hydroblast, & Perforate Treatment

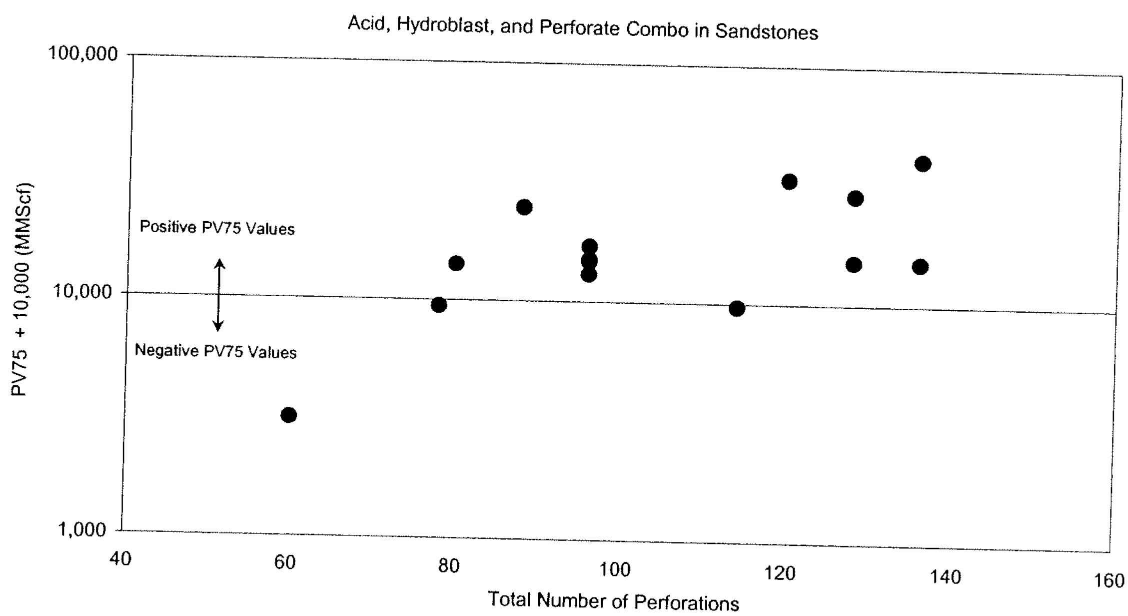


Figure 2-82: 7-1/2 Yr PV vs # Shots for Combination Acid & Hydroblast, & Perforate Treatment

Although it is virtually impossible to discern using only effectiveness and longevity plots alone (**Figure 2-83** and **Figure 2-84**), examination of the average 7-1/2 year potential volume plot (**Figure 2-85**) suggests that increased perforation diameter *may* improve treatment results.

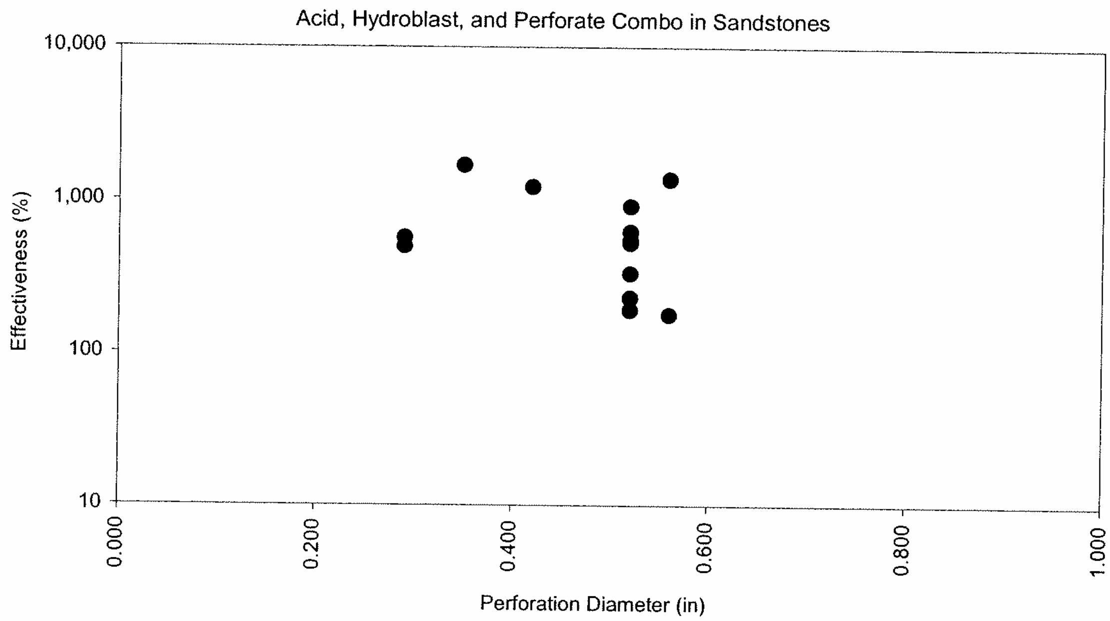


Figure 2-83: Effectiveness vs Perf Diameter for Combination Acid, Hydroblast, & Perforate Treatment

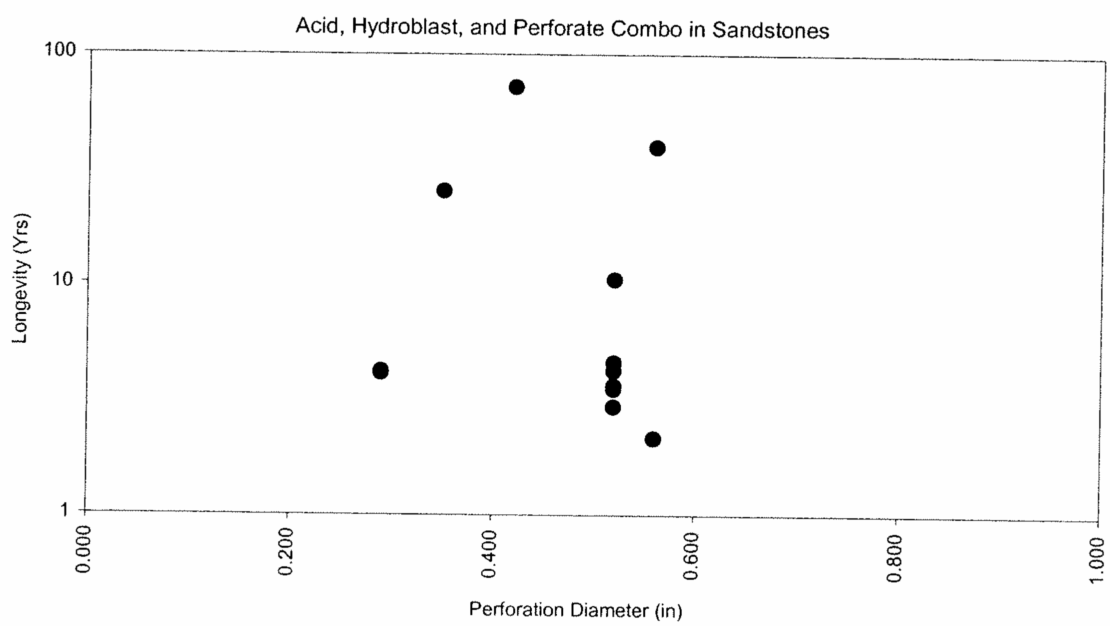


Figure 2-84: Longevity vs Perf Diameter for Combination Acid, Hydroblast, & Perforate Treatment

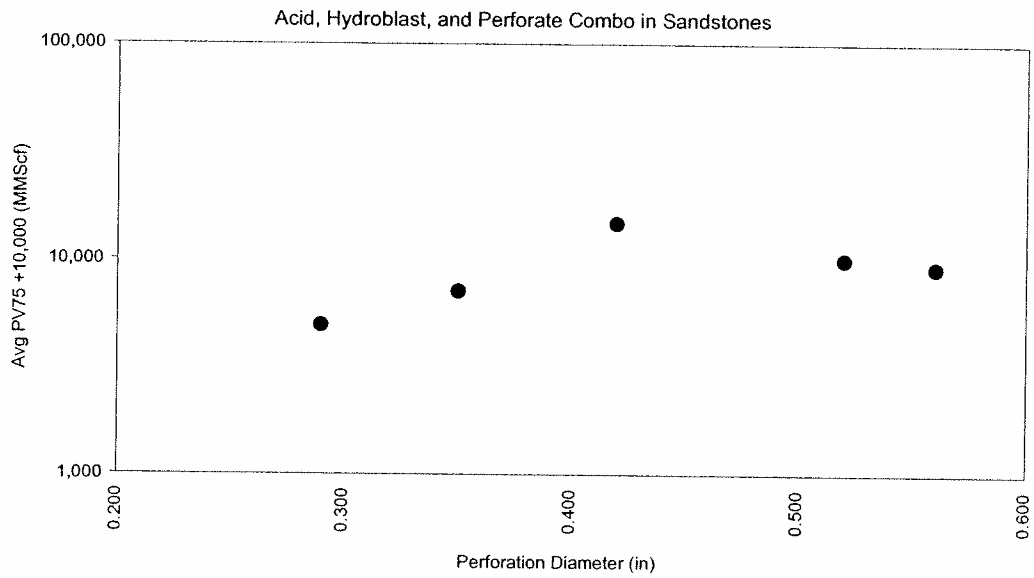


Figure 2-85: 7-1/2 Yr PV vs Perf Diameter for Combination Acid, Hydroblast, & Perforate Treatment

It should be noted that operators often report the details of acidizing data ambiguously. Hence, conclusions drawn from this data must be viewed with some caution.

2.1.2.6.6 Combination Acidizing and Perforating Treatments

Examination of data for the combination acidizing and perforating treatments suggests that HCl-HF acid systems are slightly more effective than HCl acid systems and last longer (**Figure 2-86** and **Figure 2-87**).

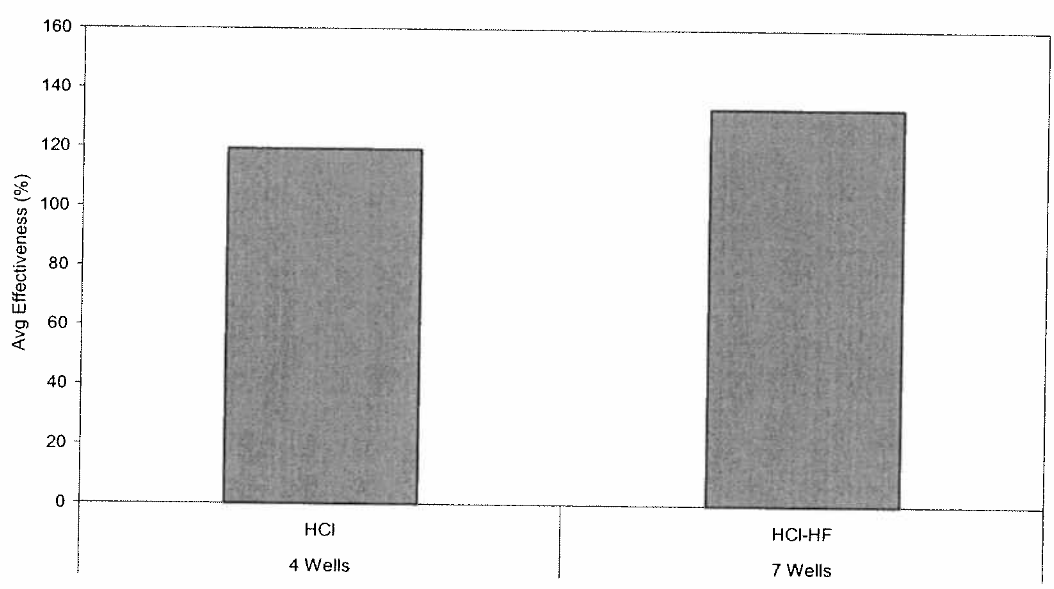


Figure 2-86: Effectiveness vs Acid Type for Combination Acidize & Perforate Treatment

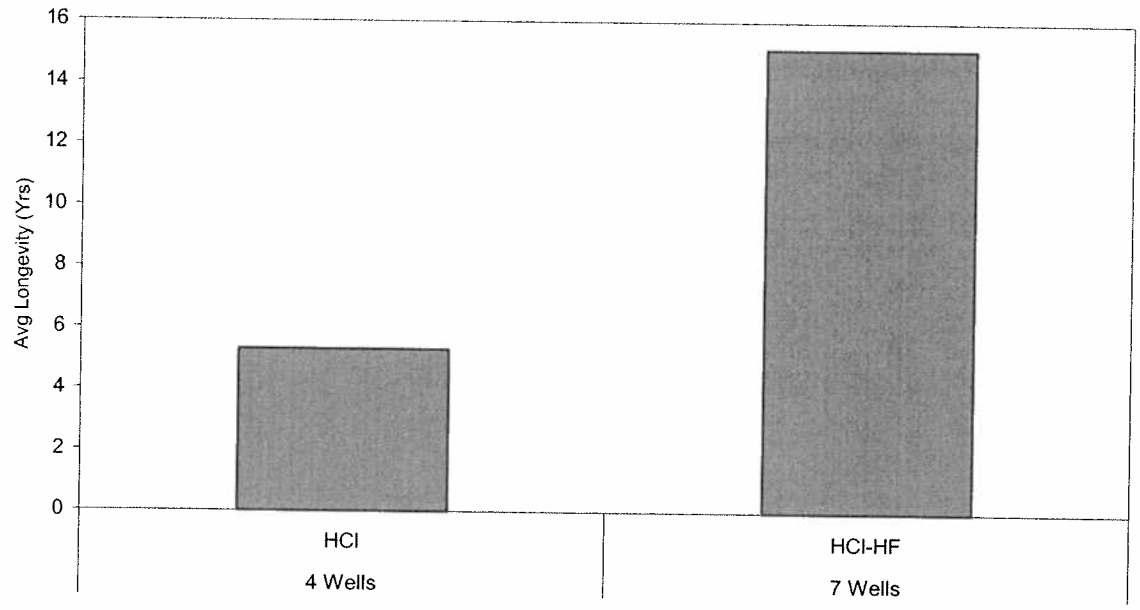


Figure 2-87: Longevity vs Acid Type for Combination Acidize & Perforate Treatment

A comparison of the average PV75 values indicates that HCl-HF system performs significantly better than the HCl system, when the overall performance improvement is viewed over a 7-1/2 year timeframe.

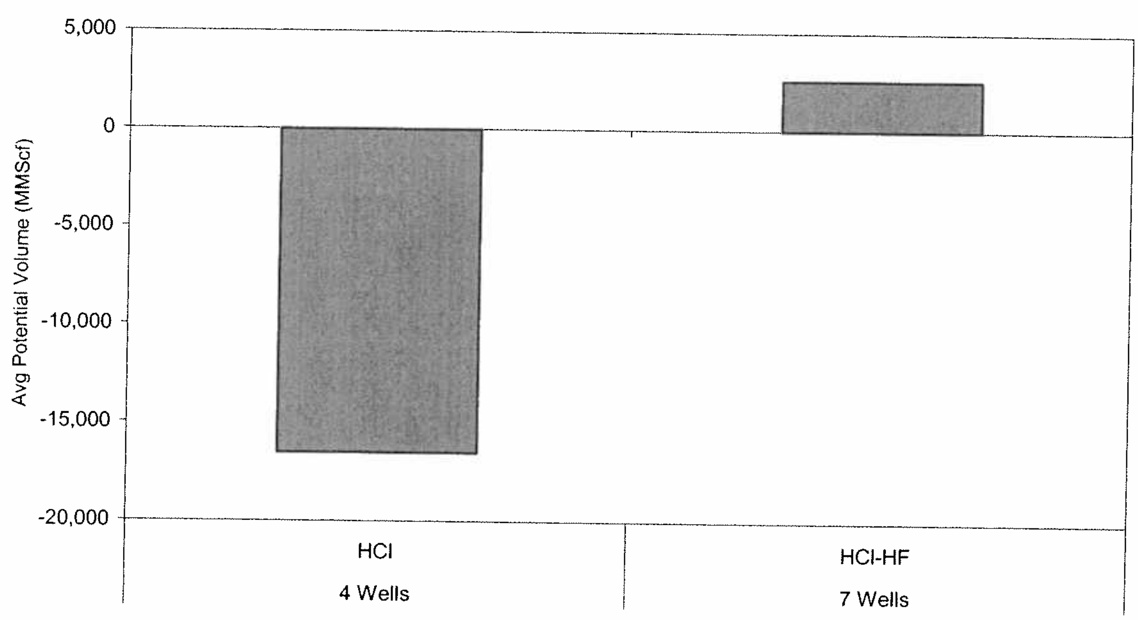


Figure 2-88: 7-1/2 Yr Potential Volume vs Acid Type for Combination Acidize & Perforate Treatment

Although the paucity of data in carbonate reservoirs limits our ability to draw many conclusions, we can make some statements about which parameters impact the success of combination acidizing and perforating treatments. **Figure 2-89**, and **Figure 2-90** below show that the effectiveness increases and the longevity decreases with increasing acid volume. Examination of the 7-1/2 year potential volume data suggests that, considering effectiveness and longevity together, success of the treatment decreases with increasing acid volume (**Figure 2-91**).

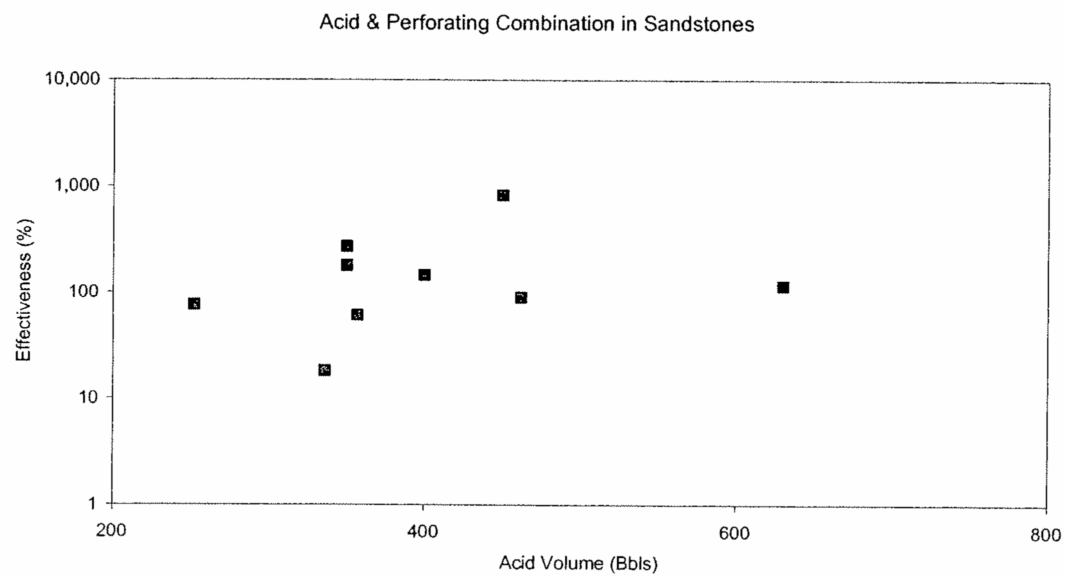


Figure 2-89: Effectiveness vs Acid Volume for Combination Acidize & Perforate Treatment in Sandstones

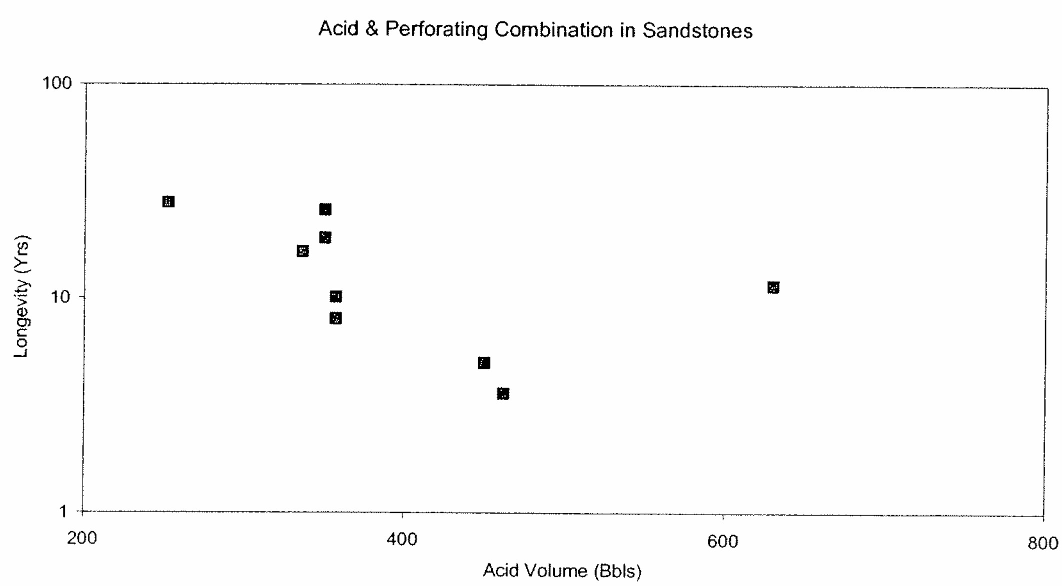


Figure 2-90: Longevity vs Acid Volume for Combination Acidize & Perforate Treatment in Sandstones

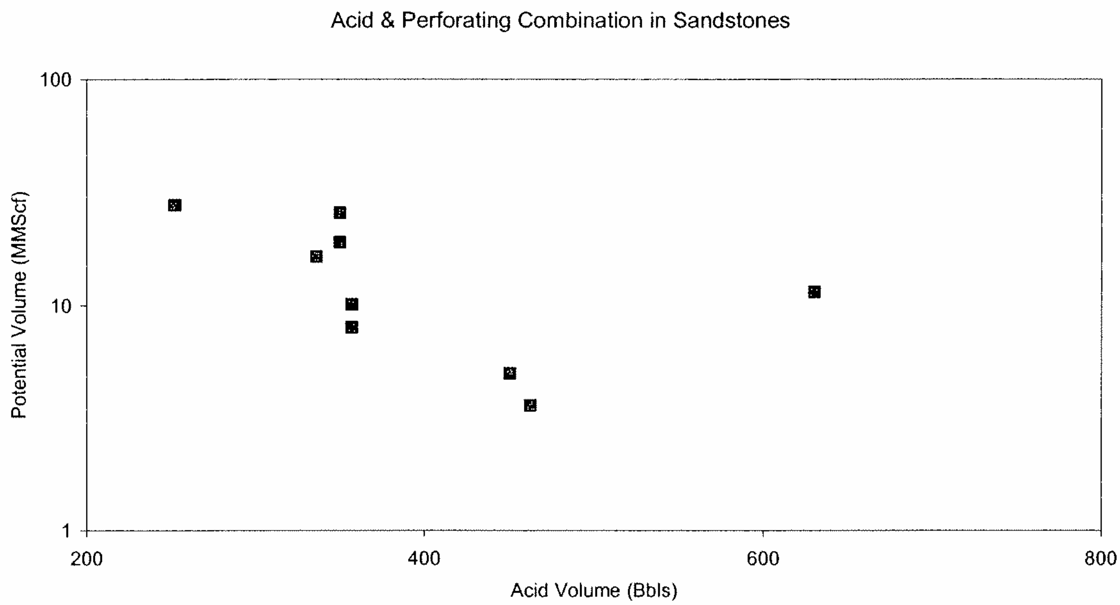


Figure 2-91: 7-1/2 Yr PV vs Acid Volume for Combination Acidize & Perforate Treatment in Sandstones

Examination of data for the combination acidizing and perforating treatments also suggests that, in sandstones, smaller perforation intervals generally result in higher effectiveness **Figure 2-92.** The relationship between the length of perforating interval and longevity is much less well-defined, but similar (**Figure 2-93**).

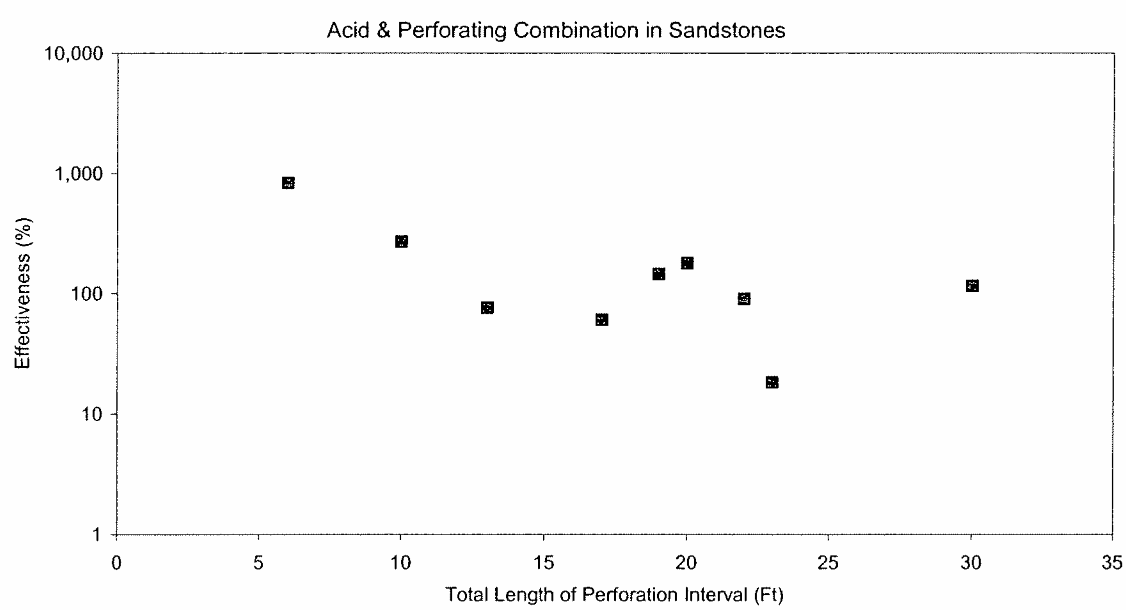


Figure 2-92: Effectiveness vs Gross Length of Perforation Interval for Combination Acidize & Perforate Treatment in Sandstones

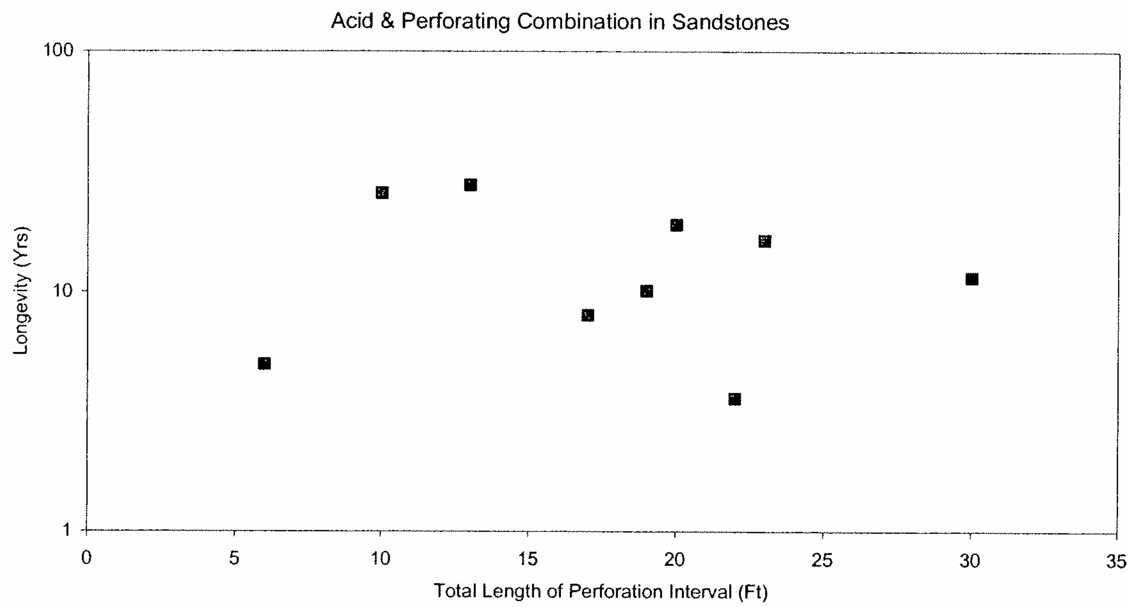


Figure 2-93: Longevity vs Gross Length of Perforation Interval for Combination Acidize & Perforate Treatment in Sandstones

Looking at the PV75 trends for sandstones suggests that smaller perforation intervals result in more successful treatments (**Figure 2-94**), if both effectiveness and longevity are considered over a 7-1/2 yr timeframe.

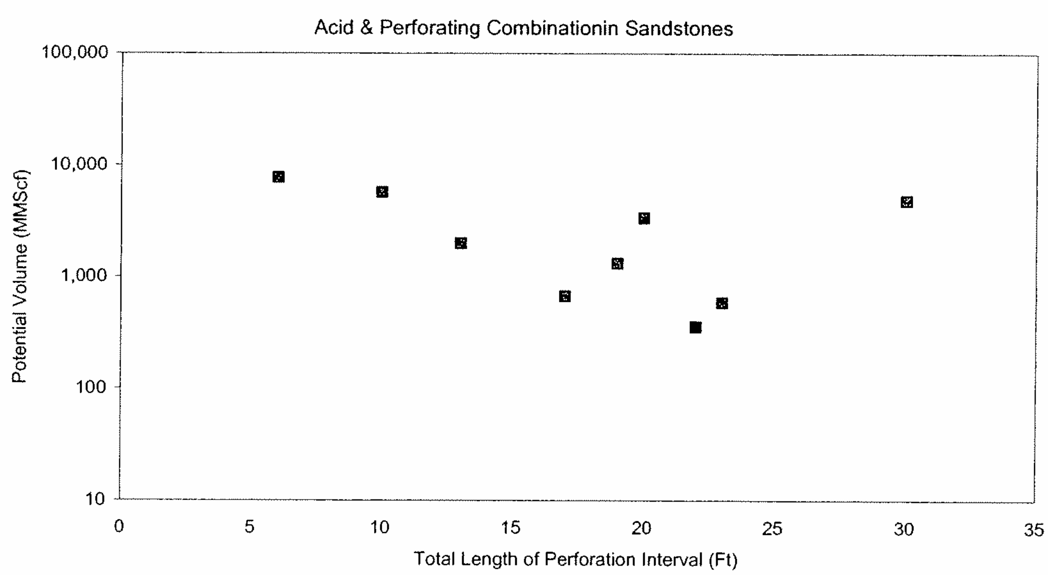


Figure 2-94: 7-1/2 Yr PV vs Gross Length of Perforation Interval for Combination Acidize & Perforate Treatment in Sandstones

Examination of the impact of the total number of perforations on treatment success in sandstones indicates that the effectiveness, longevity, and 7-1/2 year potential volume values all decrease as the total number of perforations increases (**Figure 2-95, Figure 2-96** and **Figure 2-97**).

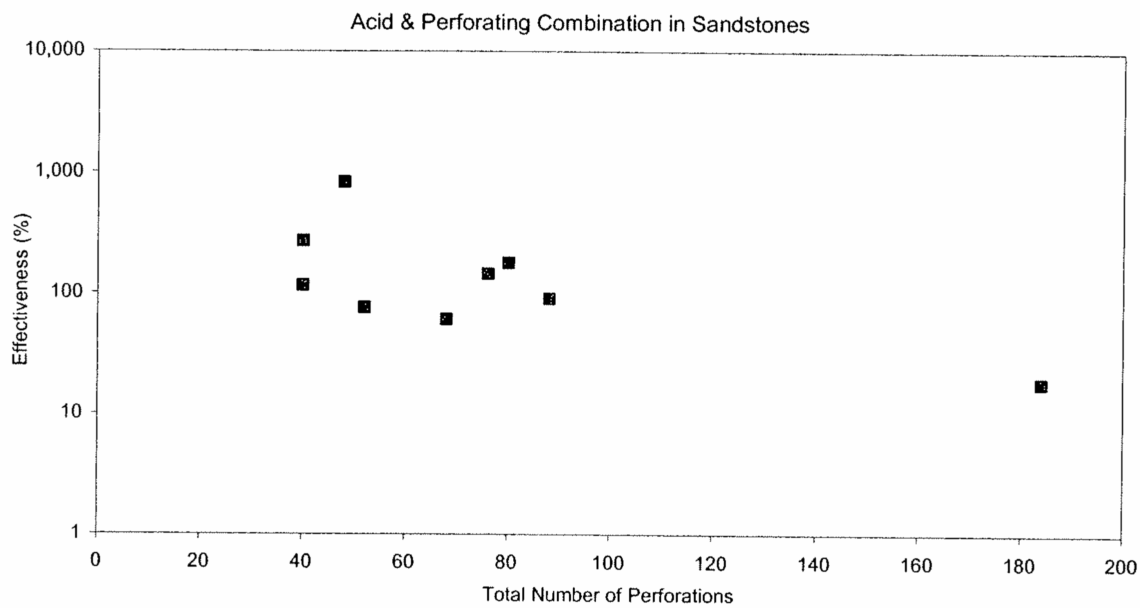


Figure 2-95: Effectiveness vs # of Perforations for Combination Acidizing & Perforating in Sandstones

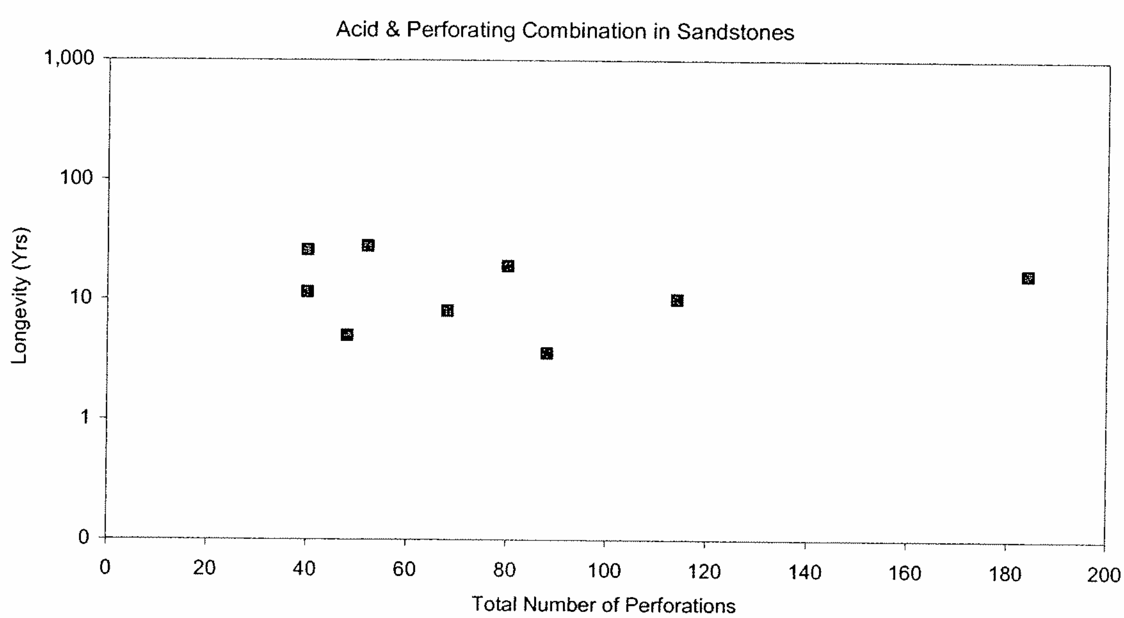


Figure 2-96: Longevity vs # of Perforations for Combination Acidizing & Perforating in Sandstones

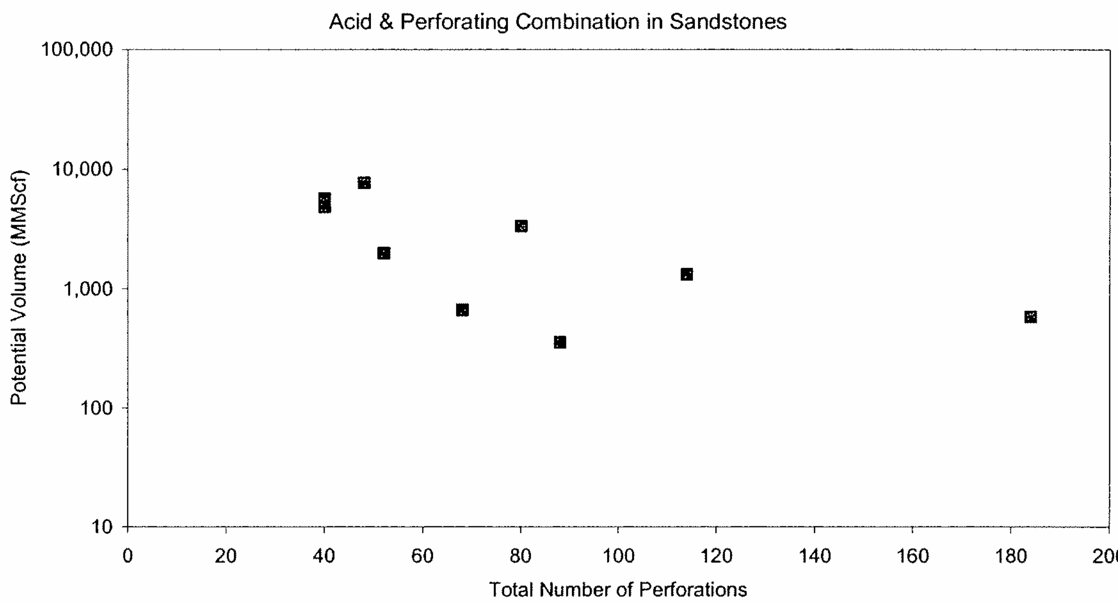


Figure 2-97: 7-1/2 Yr PV vs # of Perforations for Combination Acidizing & Perforating in Sandstones

Examination of the very limited data for the combination acidizing and perforating treatments in carbonates shows similar relationships as those seen in sandstones (**Figure 2-98**, **Figure 2-99,** and **Figure 2-100**).

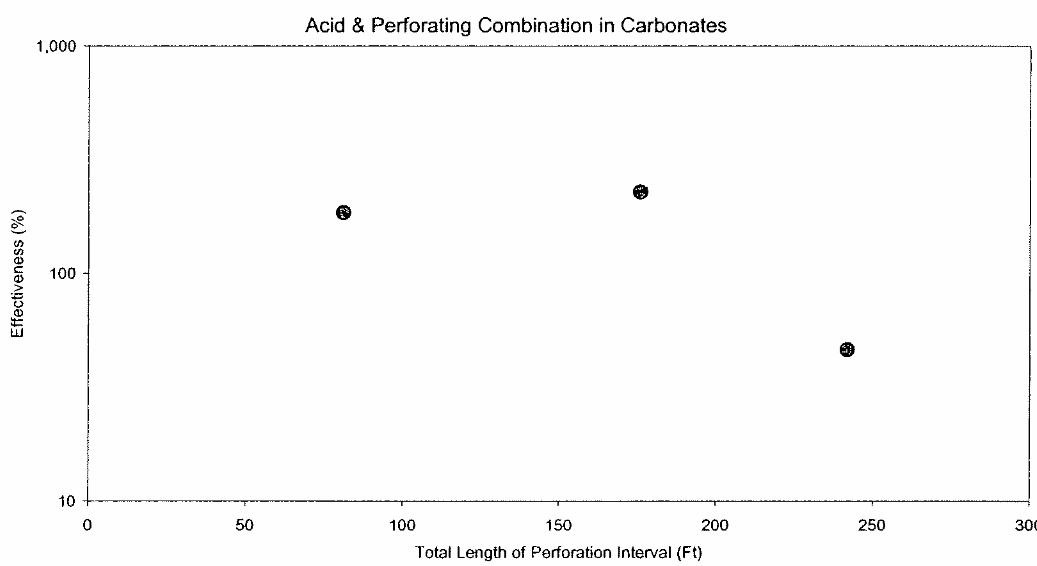


Figure 2-98: Effectiveness vs Gross Length of Perforation Interval for Combination Acidize & Perforate Treatment in Carbonates

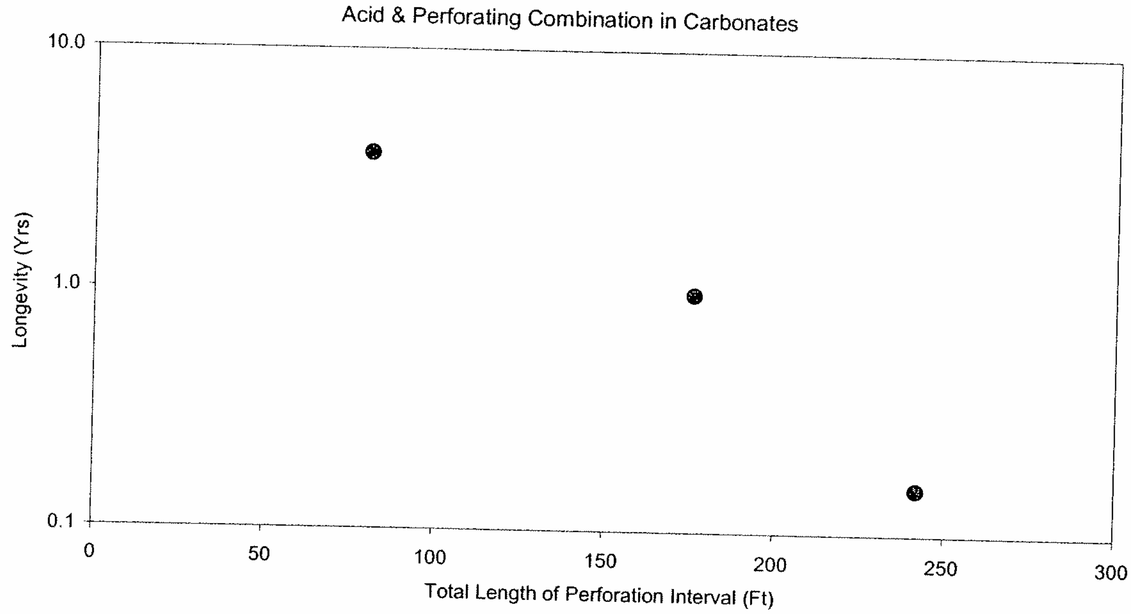


Figure 2-99: Longevity vs Gross Length of Perforation Interval for Combination Acidize & Perforate Treatment in Carbonates

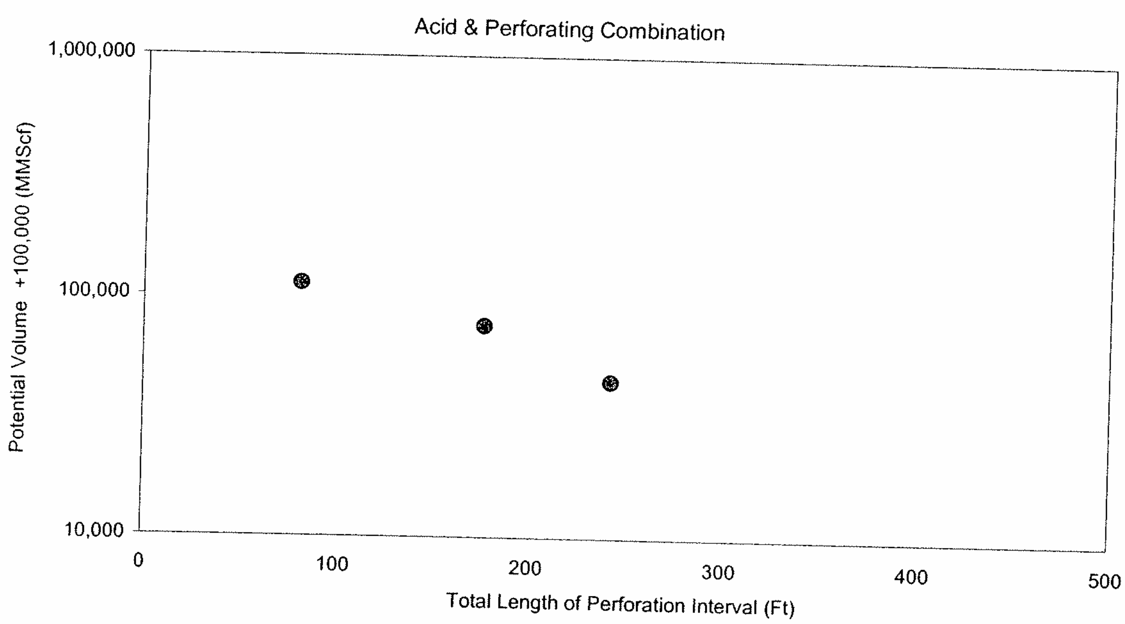


Figure 2-100: 7-1/2 Yr PV vs Gross Length of Perforation Interval for Combination Acidize & Perforate Treatment in Carbonates

The type of completion (open-hole or cased-hole) significantly impacts the success of the combination acidizing and perforating treatment. Although this treatment is more effective in cased-hole wells (**Figure 2-101**), it lasts significantly longer in open-hole wells (**Figure 2-102**).

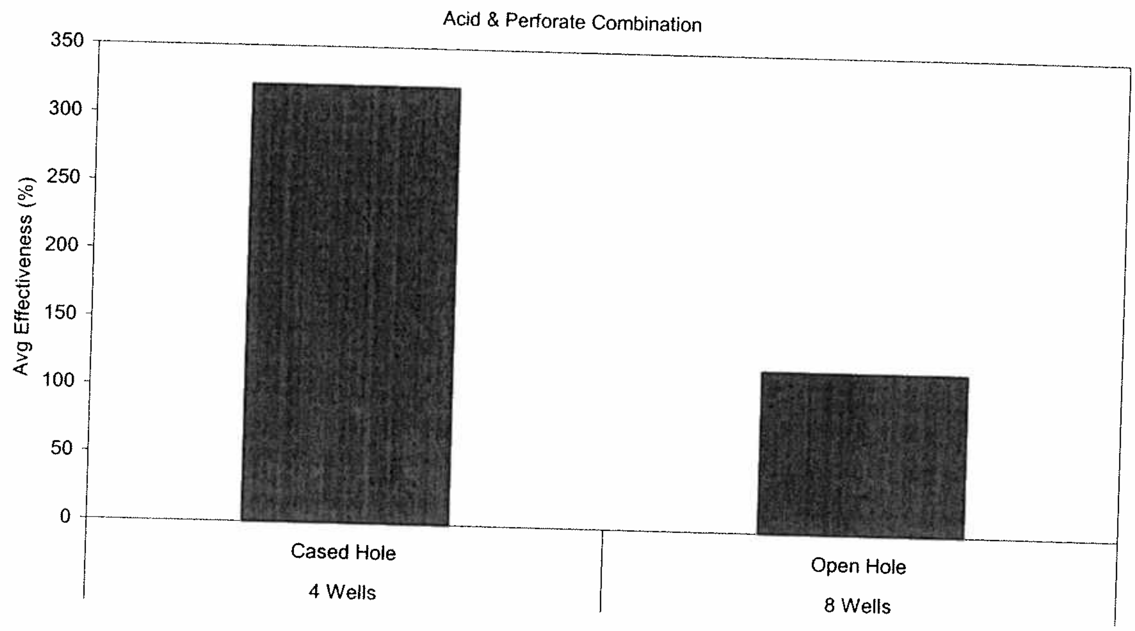


Figure 2-101: Average Effectiveness vs Completion Type for Combination Acid & Perforate Treatment

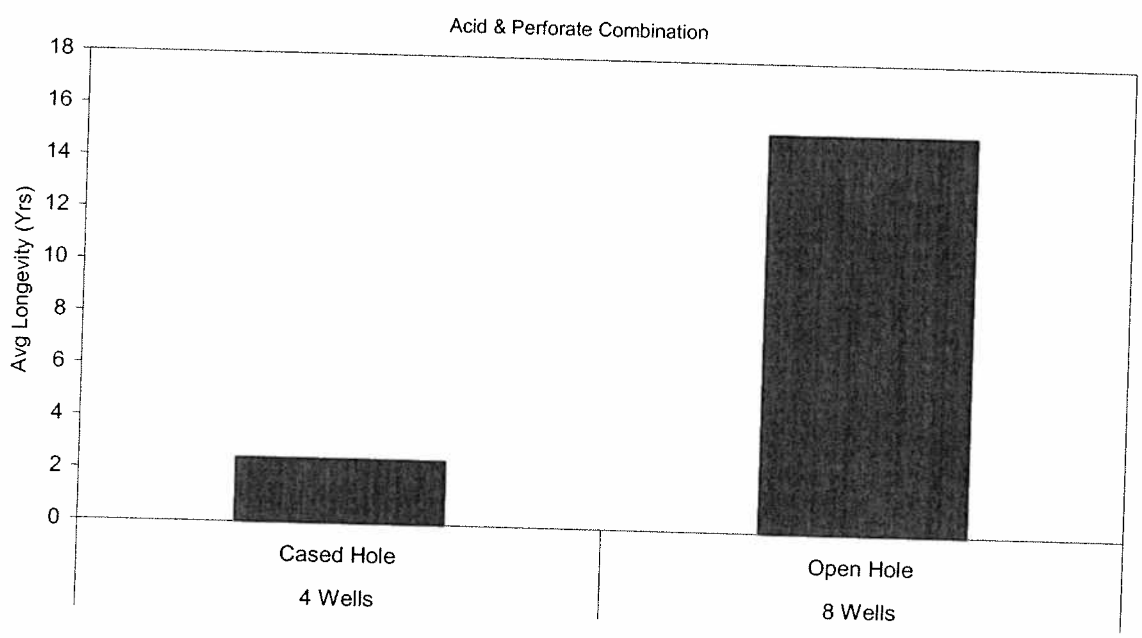


Figure 2-102: Average Longevity vs Completion Type for Combination Acid & Perforate Treatment

Examination of the average 7-1/2 year potential volume values indicates a positive value is in open-hole wells, but a large negative value in cased-hole wells (**Figure 2-103**). This is primarily due to the very large post-stimulation decline values observed in cased-hole wells, compared to rather small decline rates observed in open-hole wells (**Figure 2-104**).

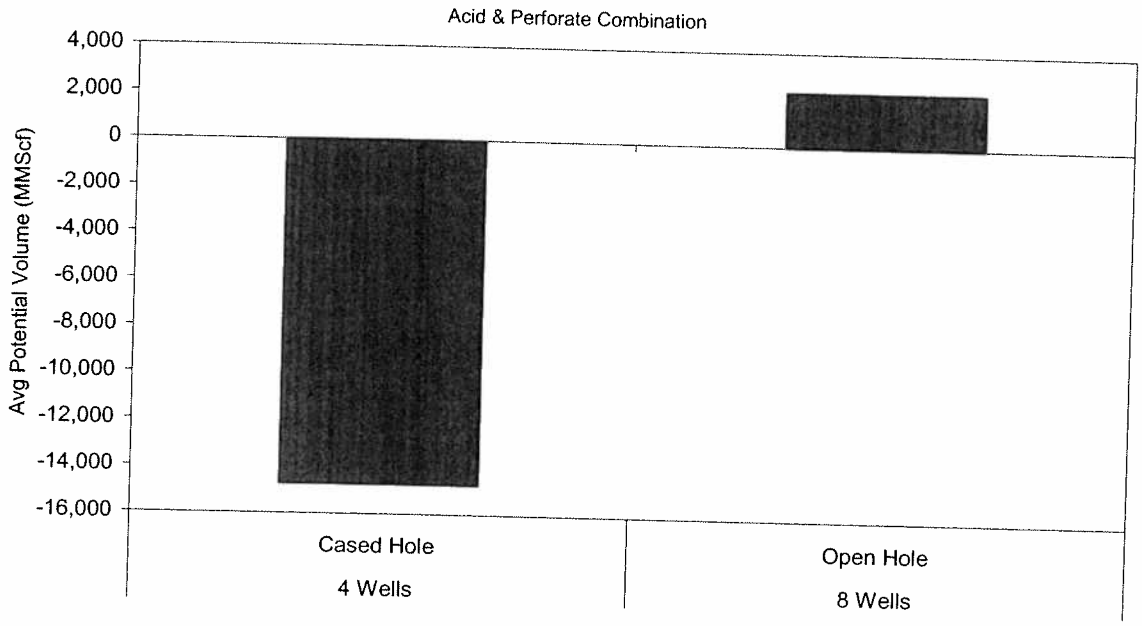


Figure 2-103: Average7-1/2 Yr PV vs Completion Type for Combination Acid & Perforate Treatment

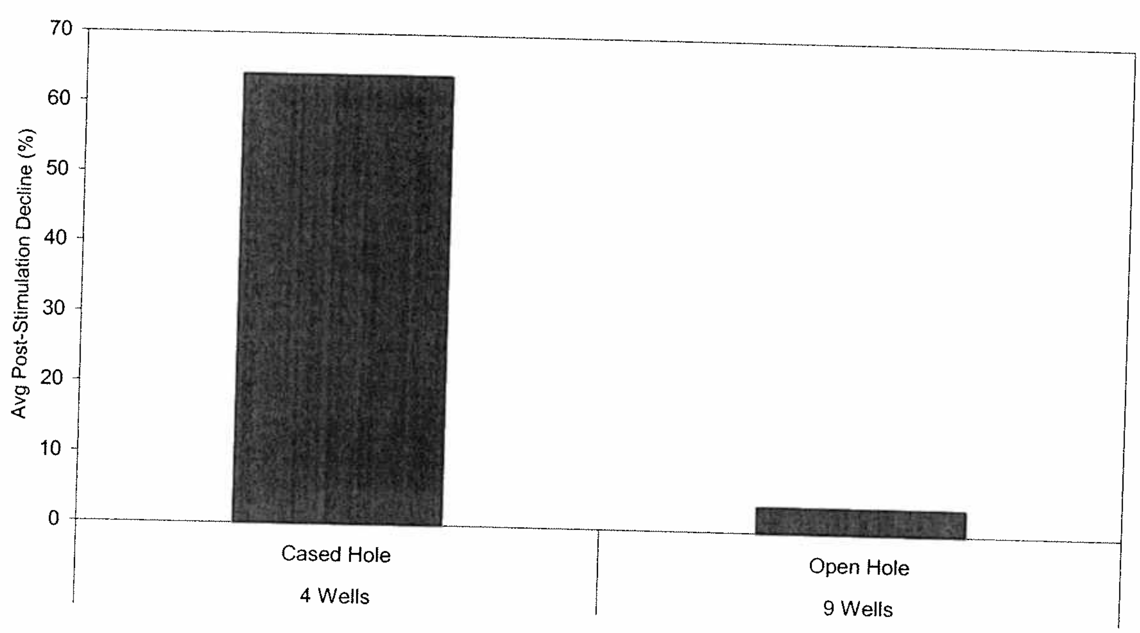


Figure 2-104: Average Post-Stimulation Decline Rate vs Completion Type for Combination Acid & Perforate Treatment

2.1.3 Recommendations

2.1.3.1 Increase our understanding of damage formation processes.

There is clearly an opportunity to reduce the expenses incurred by UGS operators for deliverability maintenance by increasing our understanding of the *process* of damage formation, and implementing effective preventative measures or designing remediation treatments that also prevent damage from re-occurring.

Evidence derived from this study suggests that remediation treatments currently employed in UGS industry treat the symptoms of damage, but do not always remove the underlying cause of that damage. This is supported by the observation that the post-stimulation DI values decline in about ½ of the stimulation treatments studied. If stimulation treatments eliminated the root cause of formation damage, we should not see any appreciable decline in the DI levels after stimulation.

Therefore, we recommend that future R&D work in the UGS industry include efforts aimed at increasing our understanding of the process of damage formation. Preventative measures and/or stimulation treatments that prevent re-occurrence of damage cannot be designed without an increased understanding of how the damage forms in the first place.

2.1.3.2 Update the database and study results as additional data becomes available.

To evaluate the effectiveness of any future deliverability maintenance efforts, an appropriate methodology for tracking DI levels before and after preventative measures or remedial treatments must be available, and the data necessary for effective deployment of this methodology must exist. The methodology developed in this study has been demonstrated to be an effective tool for comparing/contrasting the successfulness of various stimulation treatments, and exploring the relationships between reservoir and process parameters and stimulation success. However, the volume of data available for this study is somewhat limited. This is especially true considering the large amount of money UGS operators invested in deliverability maintenance treatments.

Therefore, we recommend GTI maintain/update the database with new deliverability and stimulation data as it becomes available from member companies, and periodically update the results of this study periodically. This should require minimal effort, as the database tools were specifically designed to allow GTI and individual operators to update the raw data and study results as additional data becomes available. We also recommend that individual operators use this newly developed tool to evaluate the preventative/remedial treatments specifically used in their storage fields.

2.1.3.3 Place increased emphasis on recording critical data.

The paucity of detailed stimulation data available to determine the impact of specific stimulation process parameters on the success of stimulations has prevented GTI and operators from reaping the maximum possible benefits from this study. Lack of operational data also limited opportunities to assess the impact of operational changes on deliverability in this study.

Therefore, we recommend that individual UGS place increased emphasis on recording three types of data critical to effective deliverability maintenance. First, detailed stimulation information should be recorded when treating wells in the future. Second, a regular backpressure testing program (at a minimum – multi-rate pressure transient testing would be much better) should be implemented to supply an adequate deliverability history for individual storage wells. Third, detailed information related to operational changes needs to be tracked by operators, and made available to storage engineers for analysis.

2.1.3.4 Reduce/Eliminate Cleanup Times

There is an opportunity to accelerate the deliverability improvements realized by currently employed stimulation treatments by reducing or eliminating the cleanup time required. This is evidenced by the widespread occurrence and significant negative impact of cleanup effects on USG wells. Cleanup times of 1-1/2 years are not unusual, and represent a significant delay in attaining the full benefits of remediation treatments.

Therefore, we recommend that future R&D work address cleanup related issues. Several areas should be explored, including alternate stimulation fluids and/or additives that minimize the time required for removal of water from the well..

2.1.3.5 Evaluate Alternate Stimulation Techniques

Finally, this study suggests that there is a relatively small number of stimulation techniques typically employed by the UGS industry. The number may be limited because the industry has identified the techniques what work. However, cleanup effects are frequently observed and post-stimulation declines in DI values have not been eliminated, suggesting that this conclusion is probably incorrect.

Therefore, we recommend that future R&D work include some facet aimed at exploring new deliverablity enhancement techniques. Potential new techniques should require minimum fluids and/or ensure effective removal of required fluids to minimize impacts related to cleanup. New techniques should also be designed with the goal of preventing the reoccurrence of damage over time.

Implementing the above recommendations will improve the UGS industry's understanding of damage formation *processes,* and ensure that the data and analysis methodologies are available to properly assess damage prevention and/or remediation efforts. It will also provide opportunities for development and analysis of new techniques and practices for deliverability maintenance.

2.1.4 Discussion of Results

2.1.4.1 Data Availability and Quality

Original plans for the study called for the use of downhole, multi-rate, pressure transient testing (MRPTT) data to quantify both mechanical skin damage and non-darcy skin damage over time. However, due to the extremely limited amount of MRPTT data, and the general reluctance of UGS operators to invest in collecting this type of data in the future, it was determined that backpressure data would suffice. Consequently, rather than explicitly monitoring damage levels over time, we monitored deliverability levels over time and inferred that damage was the cause of changes in deliverability levels.

The quantity and quality of deliverability information varied somewhat from operator to operator, ranging from complete raw data sets, calculation documentation, and the calculated deliverability indicator, to a table of calculated results only. Although we did not attempt to reconstruct operators' results from raw data (if provided), we did implement some basic quality control measures, such as using tests run at similar times in the storage cycle, making reasonably sure no water problems existed at the time of the test, and using only backpressure equation parameters that fell within expected ranges (e.g., $0.5 < n < 1.0$).

The quantity and quality of stimulation information varied quite widely. In some cases, nothing more than the general type of treatment was available. In some of cases, very detailed records of stimulation details were available (such as treatment volumes, additives, pump pressures and rates, perf gun size, type and orientation, etc.), but this was the rare exception. In the vast majority of cases, only the most general of information was recorded, such as gallons of acid, shorts per foot, etc. In numerous cases, conflicting or ambiguous stimulation and completion data could not be reconciled, and the stimulation was not included in the study.

There was additional data available for inclusion in the study. However, virtually all of this additional data was from a single operator. The GTI steering committee decided not to include the data to avoid inappropriately skewing the results in the direction of one particular operator. The distribution of stimulation frequencies was not significantly affected by these exclusions. The first and second most frequently implemented deliverability enhancement techniques would have been reversed if all data were included. However the resulting distribution would have been somewhat misleading, since the particular operator's very extensive use of fracturing is somewhat unique.

2.1.4.2 Calculations

The *effectiveness* of a given deliverability enhancement treatment represents a quantitative indication of the increase in deliverability level as a result of treating the well. It is defined as the percentage increase in the pre-stimulation DI value measured after cleanup effects are over (if any cleanup effects are experienced).

Although we believe this definition reasonably reflects an important, objective aspect of treatment success, it could potentially be skewed by operational practices. For example, consider the hypothetical case of two identical wells, reservoirs, damage systems, and treatments in fields managed by two different operators. If operator #1 addresses deliverability decline problems when well deliverability drops 20%, and operator #2 waits until there is virtually no deliverability left in a well before addressing the problem, the calculated effectiveness will be higher for operator #2 than operator #1 – despite the fact that the wells, reservoirs, damage types and treatment types were identical.

This study implicitly assumes that operators address deliverability issues at approximately the same point, and therefore represents a valid analysis.

The *longevity* of the stimulation treatment represents the length of time the DI indicator remains above pre-stimulation levels. This parameter is determined by calculating the post-stimulation decline rate, and extrapolating this decline to determine how long it takes for the DI value to return to the pre-stimulation level. The decline is assumed to be linear with time.

In many cases, there was limited post-treatment data available from which we calculated the post-stimulation decline and treatment longevity. Early in the study, a minimum of 3 post-treatment points was established as a reasonable minimum. However, as the study progressed, it became obvious that most wells did not have at least 3 post-treatment tests. In an effort to determine if 2 post-treatment points was sufficient, we compared the longevity determined using just 2 points with the longevity calculated using 5 or more points (**Figure 2-105**). The results suggest that there is reasonably good agreement between these two calculated values. Therefore we reduced the minimum required number of post-stimulation points to two.

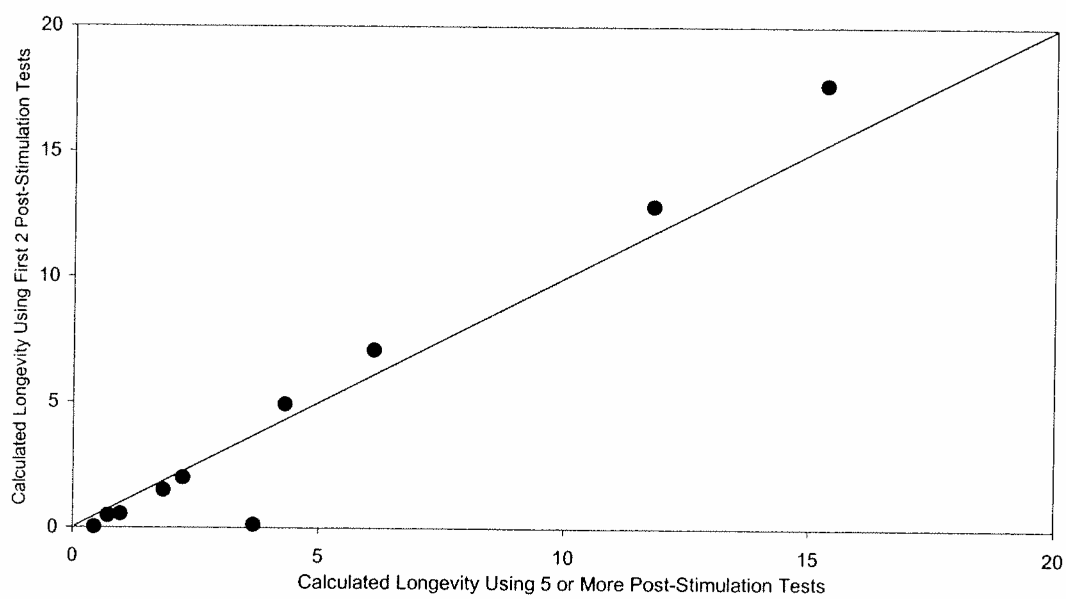


Figure 2-105: Comparison of Longevity Values alculated using 2 points and 5 points

In an effort to simultaneously consider the amount of deliverability improvement as well as the duration of that improvement, we defined the concept of incremental *potential volume* (PV). The incremental *potential volume* (PV) represents the incremental volume of gas available as a result of increased deliverability potential over the life of the stimulation.

This value is calculated by integrating the delta-DI vs time curve, beginning at the stimulation date for a specified duration. If the DI value drops below the pre-stimulation DI value during the specified duration (i.e., if the longevity is less than the duration specified), then negative volumes are calculated and used in the integration. In this way, any damaging effects of the stimulation can be properly accounted for. If the DI value declines to a value of 0.0, the integration is halted regardless of the time. The calculation is shown graphically in **Figure 2-106** below.

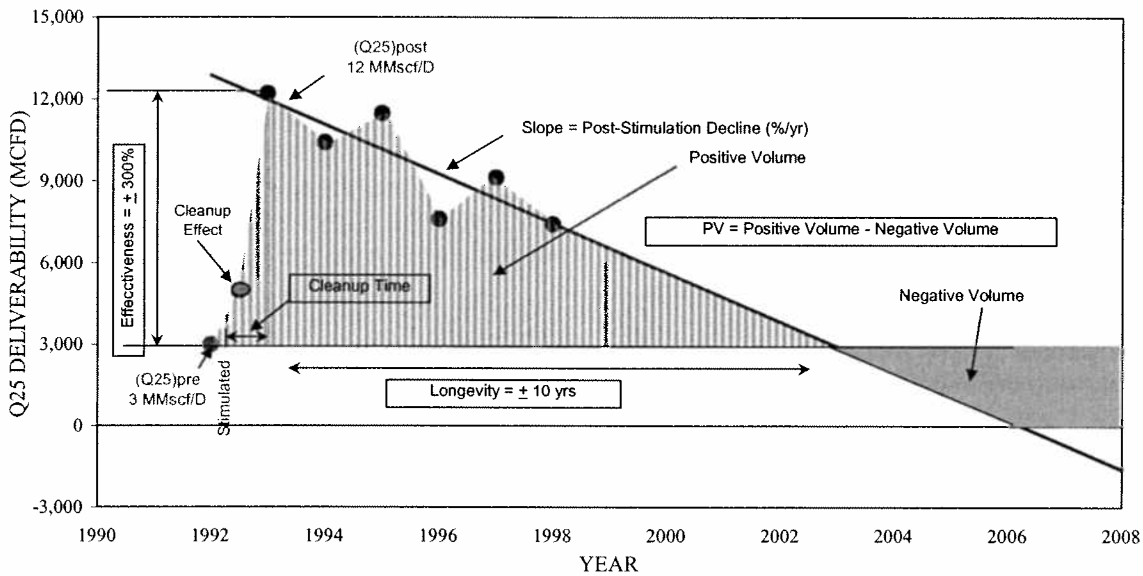


Figure 2-106: Graphical Summary of Calculation Methodology

In the database application developed for this study, the PV is calculated and stored for three different time intervals, 15 years, 10 years, and 7-1/2 years. The example shown in Figure __ above is for a 15-year time interval. The calculation process is the same for any time interval, with the exception that the interval over which integration occurs is different. All comparisons and plots included in this study were constructed using the PV calculated over a 7-1/2 year timeframe, as this shorter interval was considered to be the most appropriate for the rapidly changing UGS industry

The *cleanup time* represents the time required to realize the maximum benefits of the treatment. In many cases, it will take several months for the post-stimulation DI value to reach its maximum level after the well is treated. This value represents the amount of time the full benefits of a treatment are deferred.

Several aspects of data quality impact cleanup time calculations. Perhaps the most important is post-treatment data frequency. For cases where post-treatment data is available at frequent intervals (e.g., a well equipped with electronic wellhead flow measurement), changes in the DI will be identified sooner that where the data is much less frequent (e.g., 6-month testing intervals). A practical upper limit of 3 years was considered a reasonable maximum cleanup time. We attributed further increases in DI values after 3 years to something other than the well cleaning up.

The *post-stimulation decline* rate is the rate at which the DI deteriorates after treatment of the well. This value is calculated by performing a linear regression analysis on post-stimulation DI values, and represents the simple annual decline rate in the wells deliverability potential. As additional data is collected, the assumption of linear decline with time can be examined.

2.1.4.3 Impact of Process and Reservoir Parameters on Treatment success

2.1.4.3.1 Acidizing

Of all treatment types, acidizing lacked the most in terms of treatment detail and data quality. In many cases, even the details available were ambiguous and conflicting. In the vast majority of cases, the only data available was total volume and acid type. It was frequently difficult to determine if recorded volumes were total (i.e., included pickle, pre-flush and post-flush volumes) or primary stage volumes. Additive data was rare, and treatment pressure and treatment rate was non-existent.

The impact of lithology and concentration on treatment success involved a large number of samples, and therefore should be considered statistically significant. Although acid volume did not significantly impact treatment success, the sample sizes were limited. Additional volume data needs to be collected to identify potential relationships between acid volumes and treatment success.

Insufficient data was available to assess the impact of treatment volumes, treatment rates, or additives on acidizing success. We recommend collecting additional data and performing these analyses in the future.

When evaluating the impact of reservoir parameters on treatment success, it is important to understand that the value of the reservoir parameter represents the field average - it is not expressive of the property at the specific well location. This is true for all treatment types. This approximation is necessary because well-specific reservoir parameters are not available for the vast majority of UGS wells. Consequently, there are usually fewer unique values of a particular reservoir property available for analysis.

For example, suppose 20 acid jobs were performed in 3 reservoirs of differing porosities. If unique volumes were recorded for all 20 jobs, we would have 20 different sample points available to assess the impact of acid volume on acidizing success. However, we would only have 3 unique porosity values to assess the impact of porosity on acidizing success. This phenomenon occurs for every stimulation type, regardless of the reservoir property being assessed.

2.1.4.3.2 Fracturing

The impact of lithology, proppant volume, and total fluid volume on treatment success involved a numerous samples, and therefore should be considered statistically significant.

Insufficient data was available to assess the impact of treatment pressures, treatment rates, pad volumes, proppant size, ISIP, or additives on acidizing success. We recommend collecting additional data and performing these analyses in the future.

2.1.4.3.3 Re-Fracturing

The impact of lithology, proppant volume, and total fluid volume on treatment success involved a numerous samples, and therefore should be considered statistically significant.

Insufficient data was available to assess the impact of treatment pressures, treatment rates, pad volumes, proppant size, ISIP, or additives on acidizing success. We recommend collecting additional data and performing these analyses in the future.

2.1.4.3.4 Perforating

Our ability to assess the impacts of process and reservoir parameters was extremely limited due to the very small sample size (there was only a total of 7 perforation treatments available for study) and the limited details reported for these jobs. A shot per foot assessment was presented earlier. However since the 8 SPF "average" was for a single well, these results may be somewhat tenuous.

It should be obvious that additional information related to perforating treatments needs to be collected to more completely assess the impact of process and reservoir paramenters.

2.1.4.3.5 Combination Acid & HB & Perf

There were plenty combination Acid & HB & Perf treatments in the study sample. Unfortunately, several of the process parameters were the same in many of the jobs. For example, in the plot of Acid Volume vs Efficiency shown in **Figure2-107** below, it is apparent that most of the jobs performed included either375 Bbls or 450 Bbls of acid. Thus, the number of *unique* dependent variables is somewhat limited. Nonetheless, a general trend is evident, and at least general conclusions are valid.

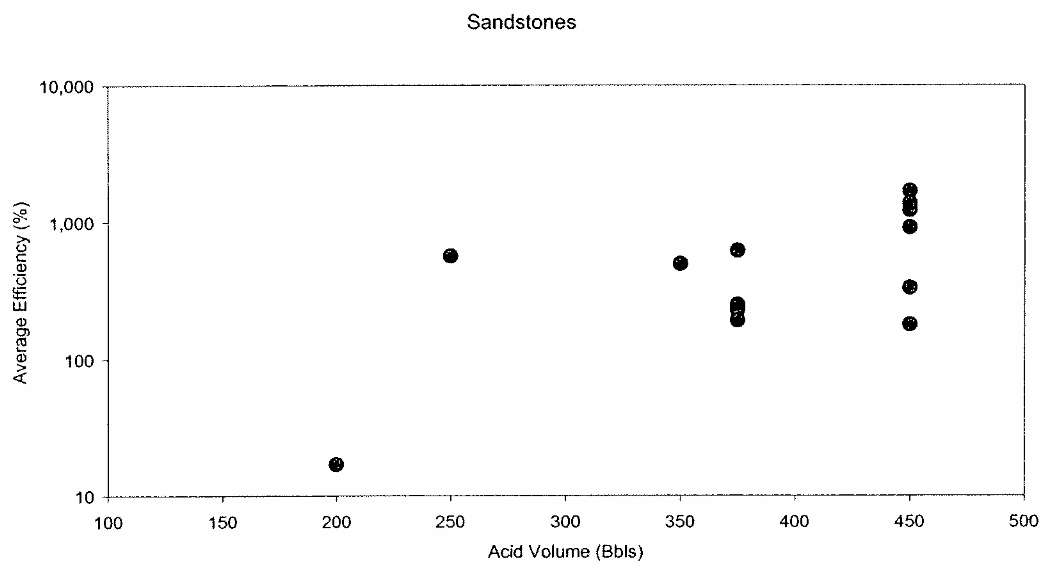


Figure 2-107: Efficiency vs Acid Volume for Combination Acidize, Hydroblast, & Perforate Treatment

It should be noted that all of the data for this combination treatment is from two different sandstone reservoirs managed by the same operator.

2.1.4.3.6 Combination Acid & Perforating

Sample sizes for combination Acid and Perforating were reasonable good for the majority of analyses performed. Perhaps the one exception is the analysis of perforation interval length in carbonate reservoirs. Although we only had 3 jobs available for study, the trends in all indicators were the same, suggesting that, indeed, smaller perforation intervals are more successfully treated than larger intervals.

2.1.4.4 Database Structure/Use

The database application used in this study was developed using Microsoft ACCESS™, and has evolved considerably since the start of the project as objectives have been clarified and/or revised. Although the final version of the database may not be the most efficient possible, it is certainly adequate for the volume of data anticipated (even assuming the most optimistic increases in future data collection).

The database was specifically designed to be user-friendly enough to allow GTI member companies to maintain and update the data and results. Nonetheless, it was made clear from the inception of the project that our objective in this task was *not* software development. Hence, some of the "bells and whistles" which might make the application more attractive have not been implemented. It does have a simple, but very intuitive and user-friendly interface, with most database activities being accessible from a main switchboard.

There are several tables to handle general types of data expected in a storage operation, including:

Master Table	Very general operator and well data
Flow Data Table	Historical deliverability indicator data
Key Dates Table	Dates of key activities (e.g., stimulation date)
Reservoir Stats Table	Reservoir properties of the storage fields (from Mauer)
Stimulation Master Table	Very general stimulation data (e.g., stimulation type)
Stimulation Details Tables	Detailed stimulation details (there are several of these tables)
AGA Database Information	Table from AGA database with field information
Analysis Results	Contains results of our analyses for all wells included in study

Data input and editing is accomplished using a variety of input forms and is controlled using the master input form shown in **Figure 2-108** below.

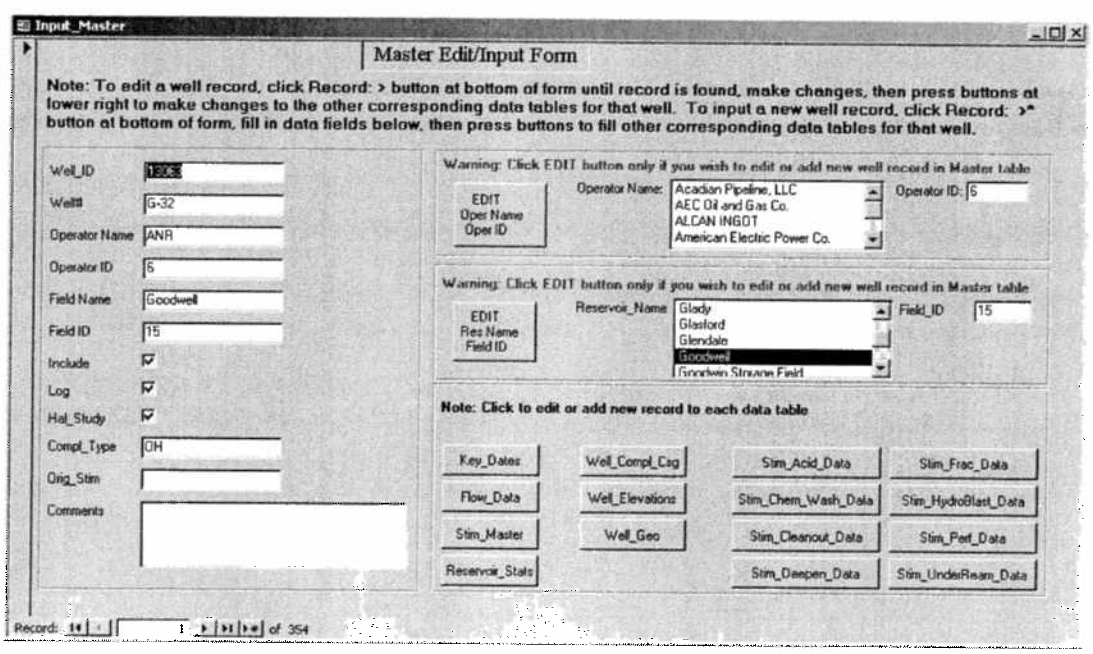


Figure 2-108: Data Input Screen For Study Database

2.2 Objective 2: Perform Cost Benefit Analysis

2.2.1 Background

The second objective of the study was to perform a cost/benefit analysis to determine the optimum stimulation treatments for damaged storage wells. Originally, the scope of this objective included calculating and comparing cost-benefit benchmarking parameter (e.g., amount of increase in the DI per stimulation dollar spent to achieve this deliverability increase) to determine the most cost-effective stimulation treatments. To accomplish this, it is necessary to assign some discrete value to the incremental deliverability and/or incremental working gas volumes derived from stimulation.

During the study, however, it became quite evident that the value of such increases to individual operators was widely divergent. Moreover, many operators were reluctant to share the "value" their company attributed to incremental deliverability with their peers (an understandable position, given the growing competitiveness within the storage industry). In addition, all of the additional deliverability available as a result of well treatment(s) may not be marketable due to demand ceilings, transportation limitations, surface facility constraints, etc.

Consequently, it was decided that a "generic" tool would be developed that allows individual operators to supply input values and parameters specific to their operations, and calculates a variety of economic benchmarking parameters.

2.2.2 Conclusions

A "generic" tool was developed that allows individual operators to supply input values and parameters specific to their operations, and calculates a variety of economic benchmarking parameters. This tool has been developed and tested using Microsoft EXCEL™. There are three basic components of the tool; input data, cash flow schedules, and benchmark calculations.

Figure 2-109 below shows example input screens, which allow individual operators to input general project data, cost data, the level of incremental deliverability utilization, and the value of incremental deliverability. Specific information pertaining to the benefit of a particular stimulation type (e.g., longevity, effectiveness, etc.) can be estimated using the results presented in this report, or they can be calculated for the specific operator and field under consideration using internal company data and the database tools developed as part of this study.

Component	Units	Input	Comments
Operator	-	Operator X	
Field	-	Field Y	
Project Name	-	Acidize Well Z	
Project Start Year	-	2002	
Project Life	Yrs	10	
Days/Yr Incremental Deliverability Utilized	Days	10	
Discount Rate	Percent	10%	

Component	Units	Input	Comments
Stimulation Type	-	Acid Wash	15% HCl w/additives
Stimulation Cost	$	$ 12,000	CTU used
Percent Capital	Percent	10%	
Percent Expense	Percent	90%	
Depreciation Schedule	-	User	
Income Tax Rate	Percent	40%	

Component	Units	Input	Comments
Stimulation Type	-	Acid Wash	Recommended by Schlumberger
Pre-Stimulation Rate	Mscf/D	3,000	From BPT Results
Effectiveness	Percent	90%	From GRI Study Results
Longevity	Yrs	10	From GRI Study Results
Post-Stimulation Decline Rate	Percent	10%	Assume Linear Decline in Deliverability

Figure 2-109: Example Input Screen for Cost Benefit Analysis Tool

Using the input data supplied by the operator, before federal income tax (BFIT) and after federal income tax (AFIT) cash flow streams are generated, as well as the net revenue stream (**Figure 2-110**). Plots of incremental deliverability, incremental revenue, and incremental cost (taxes, expenses, and depreciation) streams are also plotted for the user.

Project Year	Calender Year	Incremental Daily Deliverability (Mscf/D)	Incremental Total Revenue (M$)	Expenses (M$)	Depreciation (M$)	BFIT Incr Net Revenue (M$)	Taxes (M$)	AFIT Incr Net Revenue (M$)	Cum NPV Net Revenue (M$)
0			$ (12)						
1	2002	2,700	$ 27.000	$ 10.800	0.120	16.080	6.432	9.648	$8.77
2	2003	2,430	$ 24.300	$ -	0.120	24.180	9.672	14.508	$20.76
3	2004	2,187	$ 21.870	$ -	0.120	21.750	8.700	13.050	$30.57
4	2005	1,968	$ 19.683	$ -	0.120	19.563	7.825	11.738	$38.58
5	2006	1,771	$ 17.715	$ -	0.120	17.595	7.038	10.557	$45.14
6	2007	1,594	$ 15.943	$ -	0.120	15.823	6.329	9.494	$50.50
7	2008	1,435	$ 14.349	$ -	0.120	14.229	5.692	8.537	$54.88
8	2009	1,291	$ 12.914	$ -	0.120	12.794	5.118	7.676	$58.46
9	2010	1,162	$ 11.623	$ -	0.120	11.503	4.601	6.902	$61.39
10	2011	1,046	$ 10.460	$ -	0.120	10.340	4.136	6.204	$63.78
		175,857	$ 175.857	$ 10.800	$ 1.200	$ 163.857	$ 65.543	$ 98.314	

Figure 2-110: Example screen of Cash Flow Streams From Cost Benefit Tool

Several other economic indicators and benchmarks typically used within the gas storage industry are also calculated, including percent increase in deliverability per dollar spent, cost per incremental Mscf/D of deliverability, and others. An example output screen summarizing this information is shown in **Figure 2-111** below.

Calculations

Indicator	Description	Result	Units
Undisc Profit	Undisc (Revenues - Expenses)	$86.31	M$
PV Profit	PV of Net Rev @ Proj Disc Rate	$63.78	M$
IRR	Internal Rate of Return	215%	Percent
Disc'd P/I Ratio	Disc Profit/Investment Ratio	5.3	Dim'less
% Deliv Incr per M$	% Initial Incr Mscfd / Stim Cost	7.5%	% per M$
Cost per Init Incr Mscfd	Stim Cost / Init Incr MscfD	$ 0.0044	M$/Mscfd
Init Deliv Incr per $	Initial Incr Mscfd / Stim Cost	225	Mscfd/M$
$/(Cum Incr Mscfd)	Stim Cost / Cum Incr MscfD	$ 0.0001	$/Mscfd
(Init Incr Mscfd)/$	Cum Incr Mscfd / Stim Cost	$ 14,655	Mscfd/$

Figure 2-111: Example Output Screen Summarizing Economic Benchmarks

2.2.3 Recommendations

Given that the value of deliverability increases to individual operators is widely divergent, the cost of the same stimulation type may fluctuate from among different operators due to differing field characteristics, and potential for exploitation of additional deliverability varies among operators due to physical and market constraints, we believe that development a generic tool for cost/benefit analysis is a prudent step.

Therefore, we recommend that the tools developed in this study be made available to storage operators.

2.2.4 Discussion of Results

For the purpose of comparing remediation alternatives, the calculated benchmarks would prove beneficial and allow optimization of the remediation selection process when capital is limited. However, due to the very complex nature of the regulatory environment in the UGS industry, the values represented by these indicators may or may not reflect the actual value of the incremental deliverability to the UGS operator.

In the calculation process, we have attempted to account for some of the variables among operators. For example, the operator is asked to estimate and input the number of days the incremental deliverability will be exploited. The incremental revenue streams used for economic calculations reflect this utilization limitation.

2.3 Objective 3: Develop Methodology to Determine Effects of Operating Conditions on Deliverability Potential

2.3.1 Background

In prior studies, almost 40% of UGS operators interviewed attributed deliverability decline directly to operational activities[9], and several other causes indirectly related to operational activities were cited as potential causes of deliverability decline but not quantified. Clearly, the industry believes that day-to-day operational activities impact the deliverabiltiy potential of UGS fields. However, we are not aware of any previous studies that establish either a qualitative or quantitative relationship between changes in operations and changes in deliverability potential.

The goal of this objective was to establish a methodology to quantitatively link changes in deliverability to changes in operations. The methodology developed involves essentially the same principles and processes used to evaluate stimulation treatments. Specifically, the key parameter monitored was the deliverability indicator (DI). As defined above, the DI represents the potential deliverability available from a well or field at a specified delta-pressure squared value that is representative of routine storage operations.

Data required to implement the newly developed tool include the flow rate, the concurrent flowing pressure, and the measured (via keywell) or estimated (via inventory vs pressure correlations) average reservoir pressure. Output typically consists of a graph of the DI vs time, however, alternative presentations may include static or animated bubble maps and/or static or animated color fill grid maps. The latter options require third party software capable of generating bubble maps and color fill grid maps from a set of date vs DI arrays for numerous wells within a single UGS field.

For virtually every storage operator, difficulties in establishing an accurate, quantitative history of the DI before and after operational changes are caused by one of three things: too little flow data, too much flow data, or imprecise flow data.

For operators without electronic flow measurement at the wellhead or field level, the paucity of backpressure test data made it impossible to confidently quantify DI levels before and after operational changes. Very little can be done in this case, except to develop new techniques that allow operators to collect and analyze deliverability data less expensively and therefore more frequently (see discussion below on objective 4).

For operators with hourly electronic flow measurement at the wellhead or the field level, the amount of data available for analysis is often overwhelming. Therefore, some automated methodology was required to both filter and analyze the huge volume of raw flow data for such fields. These methodologies and tools were developed using Microsoft ACCESS™ and tested in several fields. In general, the procedure involved the following steps:

1. Define a discrete time window (e.g., 1 week), within which we would expect enough variation in flow rates to generate a backpressure plot.

2. Using flow and pressure data within each time window, perform a regression analysis to calculate the "C" and "n" backpressure constants, the DI for the well/field during the time window, and the match quality (described by the regression coefficient, r^2).

3. Filter the historical DI results to exclude "unreliable" DI values (i.e., DI values associated with low r^2 values).

4. Plot DI vs time using only DI values associated with high r^2 values.
5. Identify DI values/trends before and after implementation of operational changes to quantify the impact of these changes on deliverability

In addition to quantifying DI levels before and after operational changes, the only additional data required is detailed historical information related to when and where the specific operational change under investigation occurred. Example output using hourly EFM data is shown in **Figure 2-112** below.

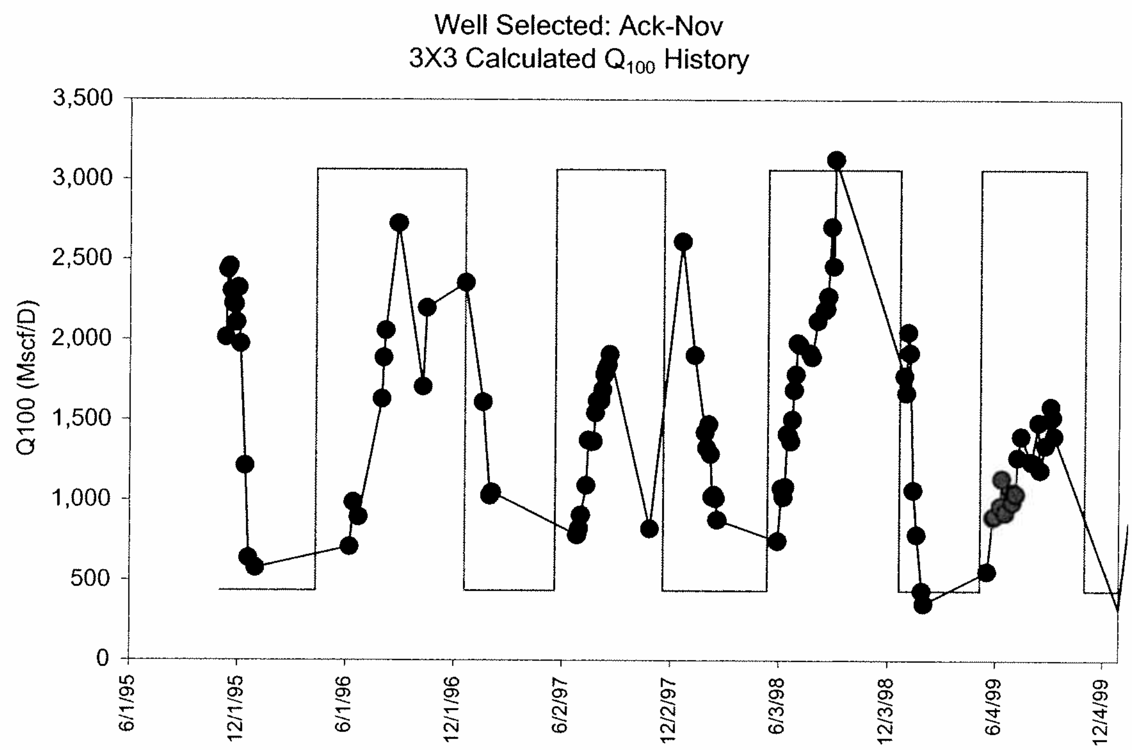


Figure 2-112: Example Output - DI History For Well With Hourly EFM Data Available

For operators with electronic flow measurement that record only average daily values, the lack of precision inherent in the data can make assessment of the DI tenuous. Typically, very little can be done in these fields. However, in the case of true base load field (i.e., the field is turned on at the beginning of the withdrawal season and steady rates are continuously maintained throughout the entire withdrawal season), it is much more likely that meaningful results may be obtained using the same techniques employed for hourly EFM data.

An example of output using daily EFM data is shown in **Figure 2-113** below. To generate this plot, we used a 28-day time window, and slid the time window 7 days to calculate individual points on the plot. As is obvious from this plot, we can effectively identify long-term trends in the DI, but we are not able to generate a plot with sufficient data frequency to identify DI trends within an individual injection or withdrawal season.

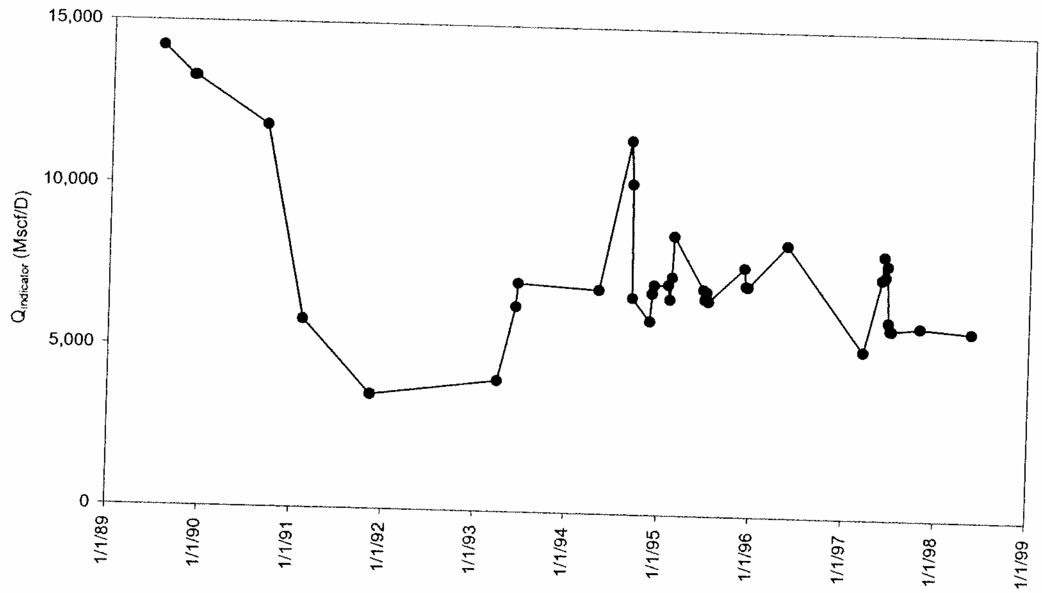


Figure 2-113: Example Output - DI History For Well With Daily EFM Data Available

For each data point shown in figure _ above, we can examine the backpressure curve generated by the database and used to calculate the individual Q100 value. An example of this detailed backpressure data is shown in **Figure 2-114** below, and suggests that the raw data was of reasonable quality for the specific point considered.

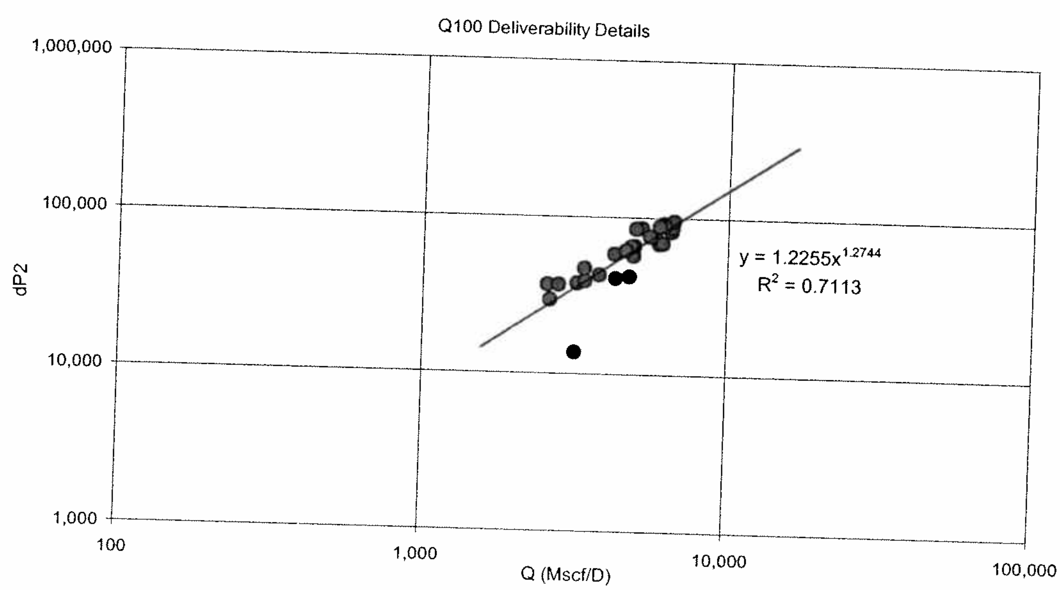


Figure 2-114: Example of Detailed Backpressure Data Used to Calculate Individual DI Values

2.3.2 Conclusions

Five UGS operators offered deliverability data for 9 fields to study the impact of operations on deliverability potential. Data types included hourly wellhead EFM data, daily wellhead EFM Data, daily station EFM data, and periodic wellhead backpressure test data.

Numerous operational changes were available for review, including imposition of maximum drawdown limits to minimize water production problems, implementation of regular pigging operations, installation of drips siphon strings, and tanks to minimize and/or improve handle water production and handling, and changes in biocides, compressor oils, and corrosion inhibitors.

Over half of the study candidates were eliminated due to lack of detailed information related to the timing, location, and extent of the operational changes implemented. In three of the candidate fields, significant gaps in the raw data around the time of implementation of operational changes made evaluation impossible (**Figure 2-115, Figure 2-116,** and **Figure 2-117**). In one field, concurrent changes in several operational parameters made it impossible to properly assess the impacts of the individual changes.

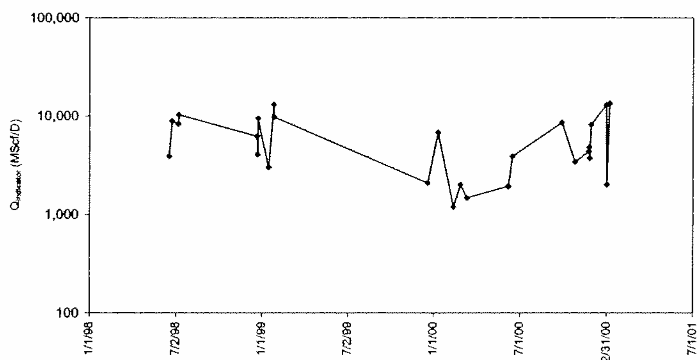


Figure 2-115: Example Data For Objective #3 Showing Gaps

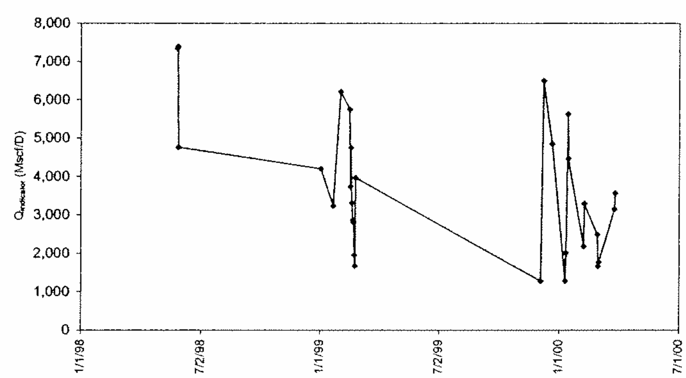


Figure 2-116: Example Data For Objective #3 Showing Gaps

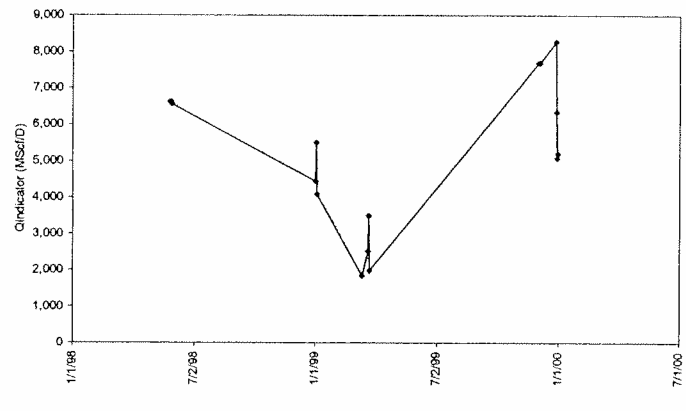
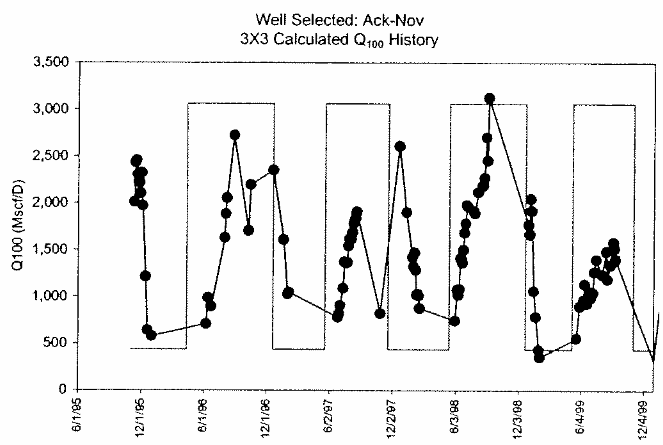


Figure 2-117: Example Data For Objective #3 Showing Gaps

Notwithstanding the above problems, we nonetheless successfully demonstrated that changes in wellhead deliverability within an individual injection and/or withdrawal cycle could be clearly identified using the newly developed tool. An example of wellhead deliverability being affected by operational parameters is shown in **Figure 2-118** below.



In this particular case, the deliverability of a well on the periphery of the field declines late in the withdrawal season because of water influx into the wellbore. This influx is, in part, caused by excessive drawdown in the wellbore late in withdrawal season. The operator recognized the cause, and imposed maximum drawdown limitations in peripheral wells, which reportedly helped to maintain the well's deliverability late in the withdrawal season.

For one study well in the fields discussed above, several backpressure tests were run spanning the same timeframe within which we processed wellhead EFM data from the well. This provided an opportunity to assess how closely the measured DI values from the well agreed with the DI calculated using our newly developed data processing tool. The results are shown in Figure _ below, and indicate that there is good agreement between DI values determined from testing and the DI values calculated with the newly developed tool.

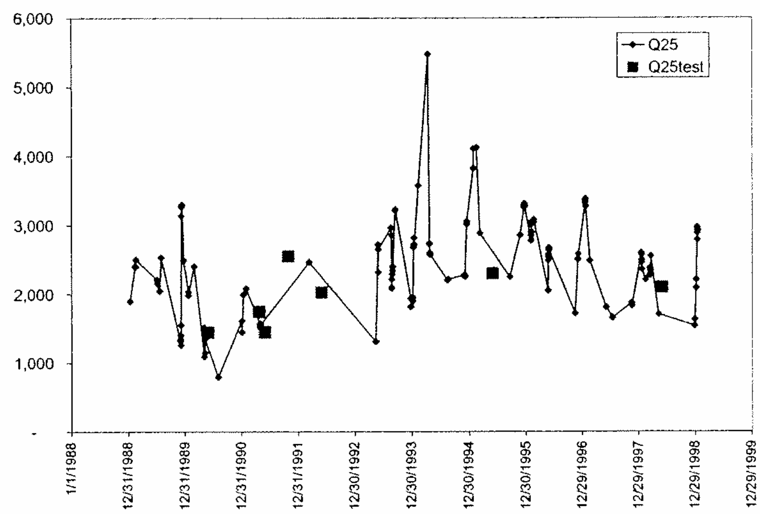


Figure 2-118: Output Showing Agreement between Calculated DI values DI values From Testing

Clearly, the theory and methodology is sound. Nonetheless sufficient, as well as sufficiently detailed, flow data and operational information (time, location, type, and magnitude of operational change) is required to implement the new methodology. Based on the results of this study, it appears that this type of information is rarely available.

2.3.3 Recommendations

Although lack of sufficient, and/or sufficiently detailed operational histories have hindered efforts to quantitatively tie operational changes to deliverability changes, the methodology developed has been demonstrated to qualitatively relate changes in deliverability to operational changes. Since operational changes undoubtedly affect deliverability, it would be prudent to continue GTI's efforts to quantitatively relate changes in deliverabilty to changes in operations.

Therefore, we recommend that GTI identify operators planning operational changes in the near future, and establish a cooperative effort to collect the data necessary to evaluate these changes using tools developed in this study.

2.3.4 Discussion of Results

For successful implementation of the methodologies developed in this study, it is necessary to consider the key issues discussed below

Given the measurement technologies currently employed in most storage fields, we cannot quantify the impact of operational changes on deliverability unless each change is chronologically and spatially isolated. If several operational changes occur at a given location over a short period of time, it will likely be impossible to determine the impact of each specific operational change. Similarly, if several different operational changes occur near the same location, it will be difficult to quantify the impact of each change. In short, we must be able to back out the effects of individual changes whenever several changes overlap in time and/or space.

The frequency of data collection necessary to quantify changes in deliverability depends on the type of field (peaking field versus a base load field), and the daily/seasonal operations of the field. When using EFM data, there must be sufficient variation in rates and pressures within the specified time window to construct a backpressure curve that accurately represents the well's capabilities during that time. Conversely, if using manually collected backpressure data, it is important to collect the data under similar conditions (e.g., when there is no fluid in the well) each time.

Any water in the wellbore will complicate the analysis considerably. Either the water level must be known for each test time to correct measured pressures, or bottom hole pressures must be collected.

In short, our ability to assess the impacts of any changes in field operations is directly impacted by the amount, type, and accuracy of the operational data collected.

2.4 Objective 4: Develop Novel Surveillance Technique

2.4.1 Background

In the early 1990's Mauer reported that the basis of most operators' remediation programs was historical performance and/or engineering judgment[10]. Mauer also reported that only 4 companies interviewed as part of his study had established a long-term deliverability improvement programs, only one company conducted deliverability tests annually, most conducted deliverability tests on an "as needed" basis due to budget constraints, and 13 companies indicated that they needed some method to evaluate the need for deliverability enhancement[11].

Currently, damage surveillance techniques in the UGS industry typically consist of running surface backpressure tests in wells every 1-5 years and comparing DI values to infer if damage has occurred since the previous test. In the most ideal cases, operators may run the preferred multi-rate pressure transient tests using downhole gauges in select wells on a more frequent basis.

Backpressure testing requires the operator to collect surface pressure information while flowing the well at 3 or 4 different rates. It is an inexpensive procedure. However, backpressure testing alone only provides an indication of the deliverability potential at a given point in time. It cannot provide reliable estimates of mechanical skin damage over time, nor can you reliably quantify the non-darcy flow coefficient (D) from such testing. Multi-rate pressure transient testing typically involves downhole gauges and require data collection at much more frequent intervals. Flowing the well at 3 or 4 rates is also required. The added requirements of multiple rates, frequent data collection and bottom-hole pressure measurement makes this type of test much more expensive than surface backpressure testing.

The surveillance programs typically employed by most UGS operators today, at best, identify the change in damage levels over a 1-5 year timeframe. The path of damage development between tests separated by 1-5 years is completely unknown. Consequently, it is impossible to determine if and how much the injection operations, withdrawal operations, and/or reversal operations (changing from injection to withdrawal or vice-versa) contribute to the development of skin damage.

This problem is shown graphically in **Figure 2-119** below, which shows three hypothetical examples of damage levels over time. The magenta points show the measured skin factor at time zero and 36 months, and represents the type of data collected by a fairly aggressive UGS operator (most would only measure DI values over a similar interval). The red and black points/curves represent what the skin factor versus time plot might look like if the skin factor were estimated much more frequently.

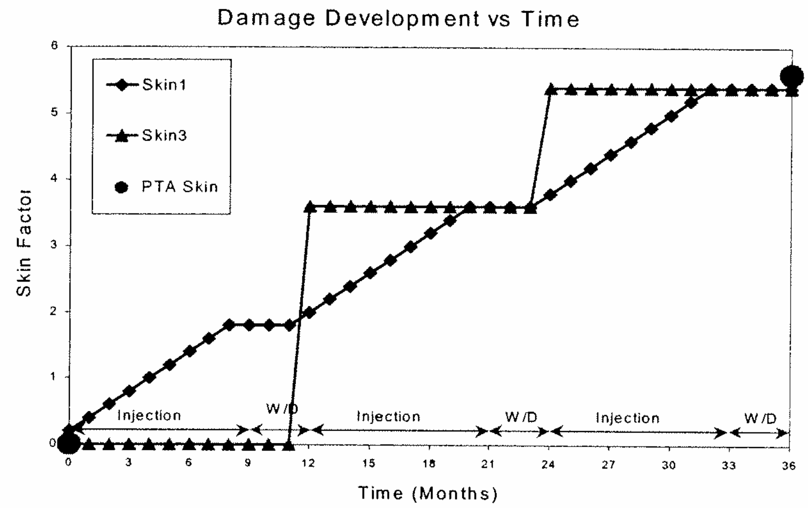


Figure 2-119: Plot Showing Three Possible Damage Development Scenarios

The black curve (labeled "Skin #1") indicates that damage increases uniformly during injection operations by remain stable during withdrawal operations. Such a profile would suggest that the mechanisms causing damage are injection related, and that withdrawal operations do not significantly increase the damage level in the well. The red curve (labeled "Skin #2") indicates that damage remains stable during both injection and withdrawal operations, but rise in a stepwise fashion when the field goes from withdrawal to injection operations. Such a profile would suggest that the mechanisms causing damage are related to "conversion" operations (i.e., the process of switching from withdrawal to injection activities).

Clearly, determining the specific type(s) of operations that induce damage would be very beneficial, since efforts to identify the specific source of damage could be much more focused if the operational cause is known. However, measurement of mechanical skin damage numerous times within a single injection or withdrawal cycle is virtually never done. This is primarily due to the expense of running tests that will yield mechanical skin values.

It should be noted that the precision necessary to identify the general path of damage formation over time is relatively low. We anticipated the precision levels required of any newly developed methods to be on the order of 10-15%. **Figure 2-120** below shows one of the hypothetical skin vs time paths presented earlier (**Figure 2-119**), with a random 10% error introduced. Obviously, the general shape is easily identifiable and would yield essentially the same conclusion concerning the timing of damage development.

The fourth objective of the study was to develop and field test novel surveillance techniques to evaluate damage in natural gas storage wells more frequently and less expensively than traditional methods. Three novel surveillance techniques were identified for review, which we will refer to as 1) The Lou Glen method, 2) the Minute-Rise De-Convolution method, and (3) the Sawyer-Brown method.

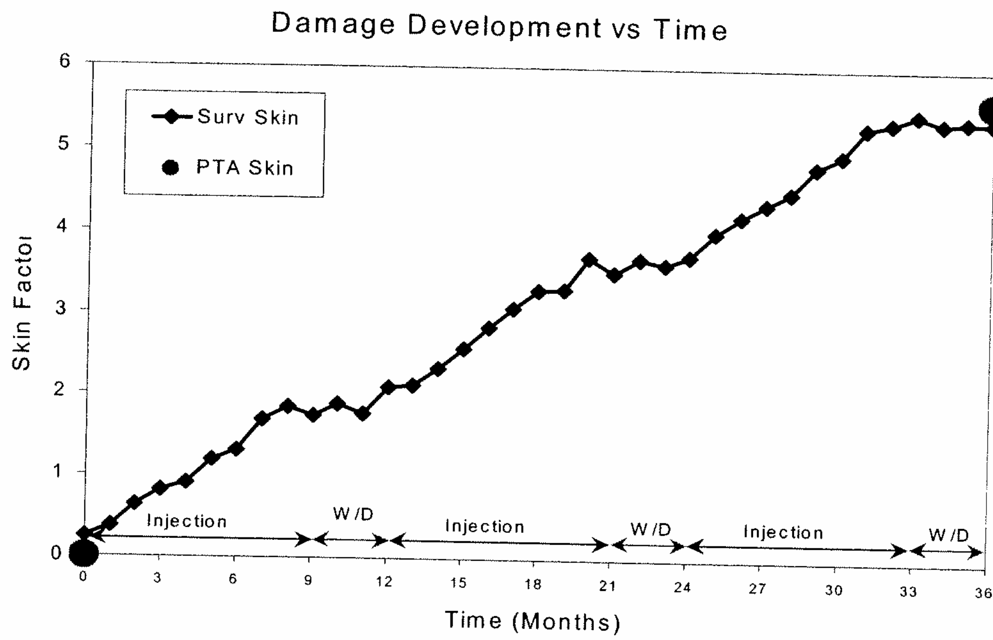


Figure 2-120: Plot Showing Three Possible Damage Development Scenarios With Random 10% Error

2.4.2 Conclusions

2.4.2.1 Lou Glenn Method

The Lou Glenn method uses daily EFM data to make daily estimates of skin damage, and was developed at Sandia National Laboratory[12]. This method uses daily wellhead pressure and flow data from the previous 30-90 days and an adaptive filter to estimate shut-in pressures and skin effects. The primary advantage of this analysis method is that it does not require any "testing" program - only analysis of routine field performance data. Hence, it is not necessary to interrupt normal field operations to assess skin damage in individual wells. **Figure 2-121** shows an example of the type of output available using this method.

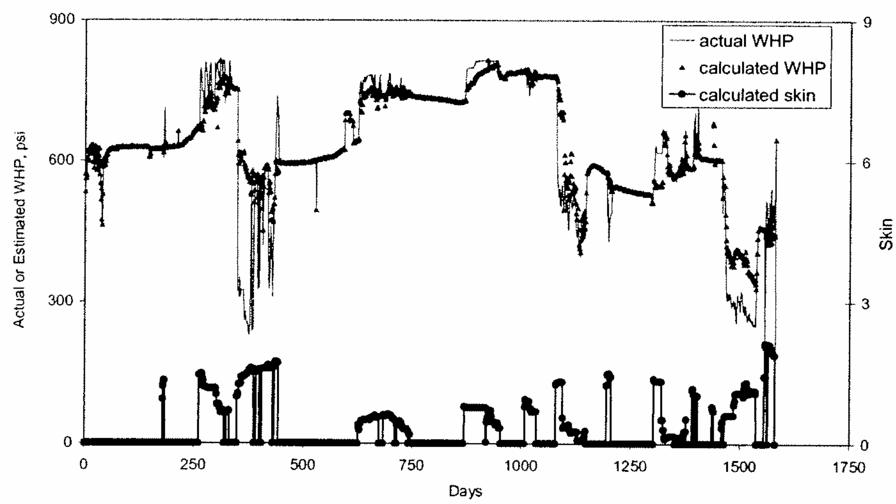


Figure 2-121: Example Output From Lou Glenn Method Using Hourly EFM Data

Several assumptions inherent in the process cause concern, however. Currently, the method requires the assumption that Darcy flow occurs in the reservoir/well. As evidenced by the recent GRI/Halliburton study[13], this assumption is violated in many gas storage wells. Although the report asserts that the process can be adapted to non-Darcy flow, no details are provided on how this is accomplished. It is further assumed that reservoir properties are independent of time. Such an assumption is not appropriate for aquifer gas storage facilities. Finally, the process assumes steady state flow, which may not be applicable in some of the lower permeability and/or low-pressured gas storage reservoirs.

There are also several other limitations associated with this analysis method. One significant drawback is that daily wellhead pressures and rates are not available for many operators. Although the technology for continuous surveillance is becoming more common, it will likely be some time before it is widespread. Also, it is not possible to separate Darcy skin and reservoir effects using the current analysis method.

After considering 1) the relatively limited application of the process (i.e., only useful for those with continuous wellhead measurement), 2) the limitations inherent in the current analysis process, and 3) the number of assumptions that could be violated in typical gas storage reservoirs, we felt that further development of this process is not warranted.

2.4.2.2 Minute Rise De-Convolution (MRD) Method

2.4.2.2.1 Background

The Minute Rise De-Convolution method is a novel combination of two existing technologies. The first, and very old, technology is a method used by turn-of-the-century gas production operators in the Appalachian Basin to estimate production rates. Essentially, this methodology treats the wellbore as a tank, and estimates the flow rate into the "tank" by calculating the influx of gas over a discrete time interval using the real gas law.

In practice, the flowing pressure is recorded, the well is shut in, and the shut-in pressure after one minute is recorded. Using the real gas law, the rate of gas influx into the wellbore over the one-minute interval is determined and converted to a daily gas rate. It should be obvious that some level of imprecision is inherent in this technology, but keep in mind that we expect that an accuracy of 10-15% will be sufficient, as discussed above.

The second existing technology, de-convolution, was developed somewhat more recently, and is used in the field of pressure transient testing (PTT) to correct test data distorted by wellbore storage effects[14]. Simply stated, if we know the downhole flow rate history immediately after a well is shut-in for a buildup test, we can enter this flowrate history into most commercial PTT software packages, and the software will correct the shut-in pressure array for these afterflow effects.

The Minute Rise De-Convolution method uses afterflow rates estimated via minute-rise theory using shut-in surface pressure data to correct early time shut-in pressures for wellbore storage effects. Thus, pressure data collected during short shut-in periods are analyzable as a pressure transient test.

2.4.2.2.2 Theoretical Development of the Minute Rise De-Convolution Surveillance Method

The theoretical basis of the MRD method uses a very simple concept developed by Appalachian gas production operators many years ago – the minute rise test. Simply stated, the minute rise test uses the real gas law to estimate the flowrate in a well.

The real gas law may be written as follows:

$$PV = z\,n\,R\,T \tag{11}$$

To determine the amount of gas that enters a fixed wellbore volume (V_{WB}) due to an increase in pressure over a time interval ($t_1 - t_0$), we can rewrite **Eq. 11** as follows:

$$n_1 - n_0 = \left(\frac{P_1}{z_1} - \frac{P_0}{z_0}\right)\left(\frac{V_{WB}}{RT}\right) \tag{12}$$

Traditional derivations of the minute rise equation assume that $z_0 = z_1 = 1.0$ and $(t_1 - t_0) = 1$ minute. Making these same assumptions, and converting the influx to a daily rate at an assumed average wellbore temperature of 70 degrees F, **Eq. 12** can be reduced to the following:

$$q = 0.09607 * V_{WB} * (P_1 - P_0) \tag{13}$$

Implementation of **Eq. 13** by Appalachian Basin producers requires an operator to record the flowing well pressure, shut the well in for 1 minute, and record the pressure at 1 minute. Estimating the wellbore volume from a wellbore schematic and plugging this volume and the recorded pressures unto **Eq. 13**, an estimate of the flowrate of the well is obtained.

Eq. 13 can be modified to accommodate any arbitrary time interval of interest. Therefore, we can use this method to estimate the afterflow rates into the wellbore immediately after shut-in using the shut-in pressure history during this time. Using these estimated afterflow rates, early time shut-in pressures that are normally unusable for pressure transient test analysis due to wellbore storage effects can be corrected for wellbore storage effects. The result is that analyzable pressure transient test data may be obtained from very brief shut-in periods.

2.4.2.2.3 Testing of Minute Rise De-Convolution Theory Using Simulated Data

The MRD Method was tested with simulated data to validate the underlying theory using reservoir properties typical of the gas storage industry. Well performance was simulated using a reservoir with a shut-in pressure of 1000 psi, 20 feet of net pay, 20 md permeability, and no skin damage. The well was flowed for 24 hours at 1 MMscf/D and shut in.

Using the calculated wellbore volume, simulated shut-in pressures, and minute rise theory, the afterflow rates were calculated and compared to the afterflow rates from the simulator. **Figure 2-122** shows a comparison of the simulated versus calculated afterflow rates, and indicates excellent agreement between the two.

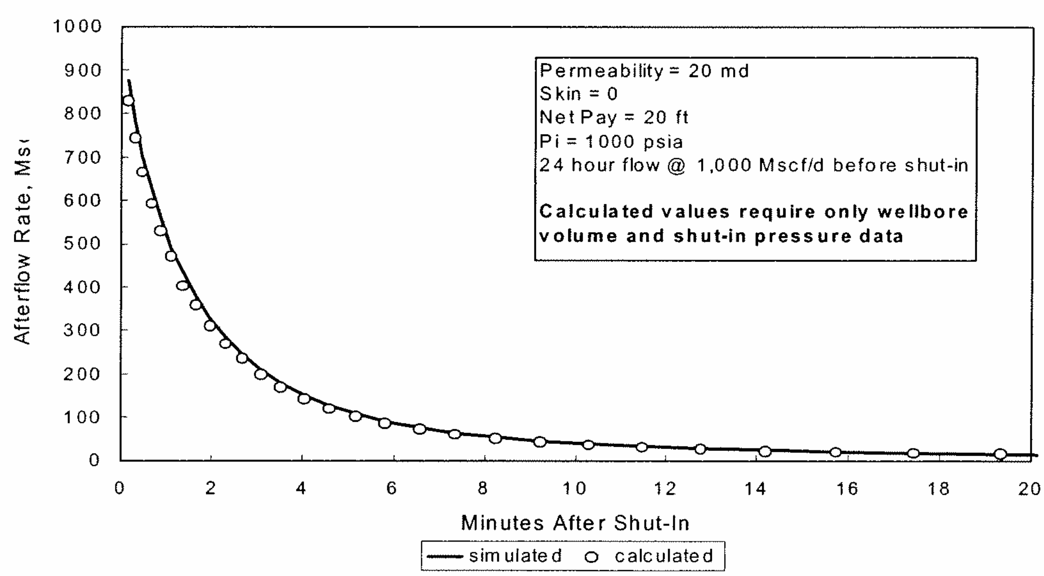


Figure 2-122: Plot of Simulated vs Calculated Afterflow rates Showing excellent agreement

Using pressure transient test analysis software, the calculated afterflow rates were used to correct early-time shut-in pressures for wellbore storage effects. **Figure 2-123** shows the results of pressure transient test analysis using the deconvolved pressure data, and indicates very good agreement between the calculated reservoir properties and the assumed reservoir properties. If an exact match were obtained, the late time test data would fall exactly on the late time model data.

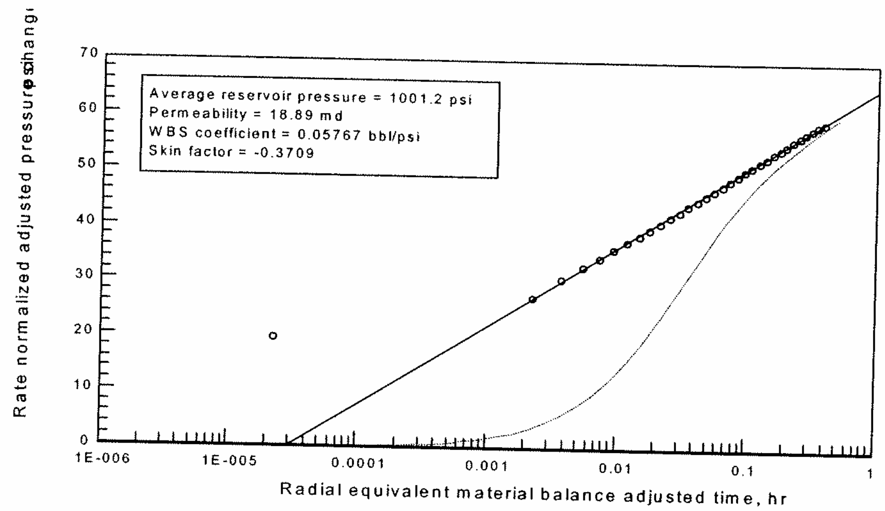


Figure 2-123: Test #1 - Results of Pressure Transient Test Analysis Using Deconvolved Pressure Data

2.4.2.2.4 Field Testing of Minute Rise De-Convolution Theory

Several field data sets have been analyzed with limited success. Testing consisted of analyzing the full pressure transient test datasets from a given well, then analyzing only the first 10-15 minutes of the dataset using the MRD Method, and comparing the results.

Figure 2-124 shows analysis of a pressure transient test using the entire dataset. **Figure 2-125** shows analysis of the same pressure transient test using only the first 10 minutes of data using the MRD method. In this example, analysis of only 10 minutes of shut-in data using the MRD method produced similar results.

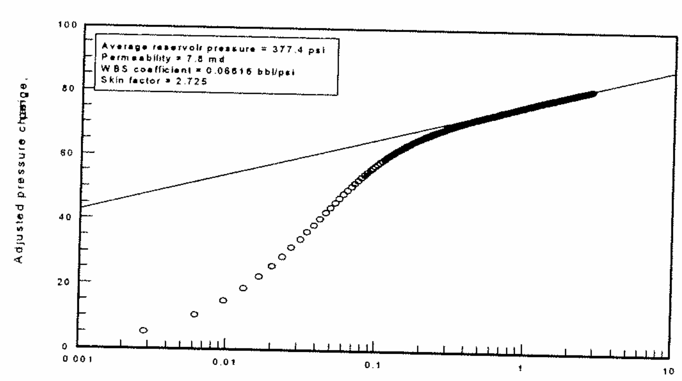


Figure 2-124: Test #1 - Pressure Transient Test Using Entire Deconvolved Dataset

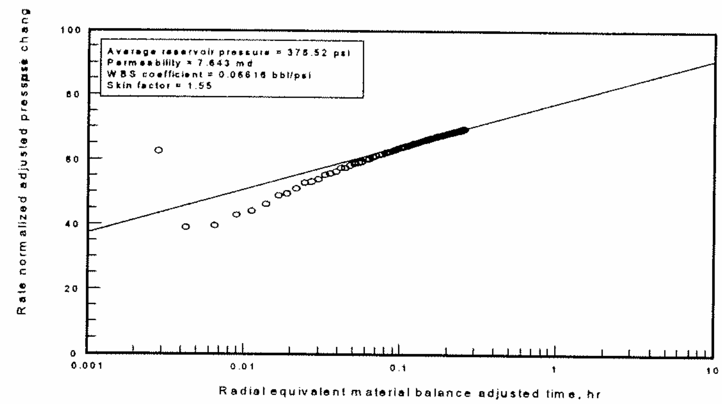


Figure 2-125: Test #1 - Pressure Transient Test Using First 10 Minute of Deconvolved Dataset

Figure 2-127 shows analysis of the pressure transient test from a different well using the entire dataset. **Figure 2-128** shows analysis of the same pressure transient test using only the first 10 minutes of data using the MRD method. In this example, analysis of only 10 minutes of shut-in data is nearly impossible.

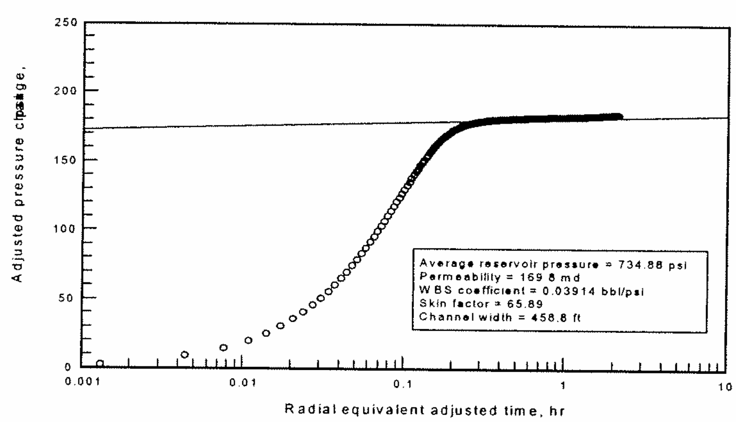


Figure 2-126: Test #2 - Pressure Transient Test Using Entire Deconvolved Dataset

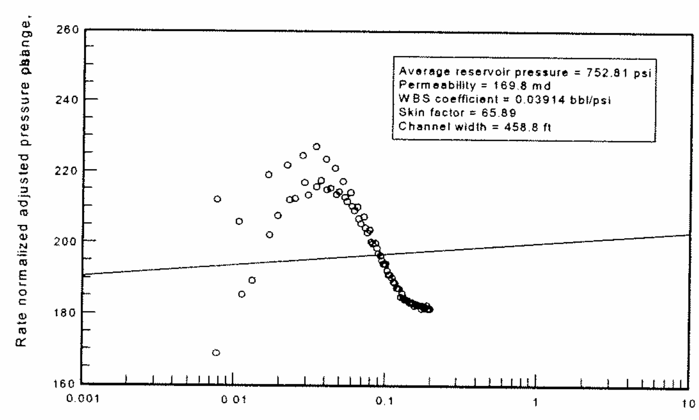


Figure 2-127: Test #2 - Pressure Transient Test Using First 10 Minute of Deconvolved Dataset

Several causes for the lack of success with field tests are possible. The development of the equation to estimate the flow rate using minute rise theory assumed z-factors were approximately 1.0, which may not be a valid assumption at higher pressures. Estimates of wellbore volumes may be near error in the event of hydraulic fractures, vugs, voids and fill in the well. The "tank" model represented by the wellbore may be too coarse. Perhaps it should be divided into sub-volumes and the influx into each sub-volume calculated and integrated. More work is required to determine why the practical application of the MRD Method falls short.

Since some operators do not have measurement facilities at every well, we also attempted to eliminate the need for any rate measurement at the wellhead, by back-extrapolation of early time afterflow rates calculated from the shut-in pressures. Unfortunately, pressures typically decline exponentially with time immediately after shut-in, making back-extrapolation very difficult.

Although we believe this method may prove viable with additional study, no additional work was conducted on this method due to the limited resources available to conduct further investigation.

2.4.2.3 Sawyer-Brown Method

2.4.2.3.1 Theoretical Development

The Sawyer-Brown Method represents a unique application of a method developed by Jones[15]. This method requires one comprehensive, multi-rate, pressure transient test analysis be performed, and enables the operator to estimate mechanical skin from subsequently run deliverability tests.

The pseudo-steady-state radial gas flow equation may be written as:

$$P_R^2 - P_{wf}^2 = Aq[b_o + s_m + Dq] \qquad (1)$$

where:

$$A = \frac{1.422 \times 10^6 \mu_g zT}{k_g h} \qquad (2)$$

and

$$b_o = \ln\left(\frac{r_e}{r_w}\right) - 3/4 \qquad (3)$$

Eq. 1 may be expressed in quadratic form as the Jones Equation.[1]

$$P_R^2 - P_{wf}^2 = a \cdot q^2 + b \cdot q \qquad (4)$$

where:

$$a = A \cdot D \qquad (5)$$

and

$$b = A \cdot (b_o + s_m) \qquad (6)$$

Eq. 4 is routinely used in deliverability test analysis. Note that A and b_o are constants by their definitions given in **Eqs. 2** and **3**. Using **Eq. 5** in **Eq. 1** and solving for mechanical skin, s_m, gives

$$s_m = \frac{1}{A}\frac{\Delta p^2}{q} - Dq - b_o \tag{7}$$

Let us assume that, at time zero, we conduct a multi-rate deliverability test and collect the transient drawdown and buildup data using a bottomhole pressure gauge. From the pressure transient data at the different rates, we can determine both the mechanical skin, s_m and the non-Darcy factor, D. Also, by plotting $\Delta p^2/q$ vs q, we can obtain the Jones parameters "a" and "b" in **Eq. 4.** Then using the Jones parameters in **Eqs. 5** and **6**, we can calculate A and b_o for use in **Eq. 7**.

Over time, the mechanical skin (s_m) and/or non-Darcy factor (D) may change. We shall show that, by judicious use of **Eqs. 5** through **7**, both s_m and D may be accurately determined throughout the life of the well using only subsequent deliverability test data.

Assume that at some time later in the life of the well, a second deliverability test is conducted and analyzed, giving substantially different values of "a" and "b". The new non-Darcy factor and mechanical skin may be calculated as follows:

Step 1: Use the new value of "a" in **Eq. 5** to calculate the new D, *i.e.,*

$$D = \frac{a}{A} \tag{8}$$

Step 2: Use the new value of "D" in **Eq. 7** to calculate a new mechanical skin for each rate used in the deliverability test. Also, a single value of mechanical skin may be obtained by using the new "b" value in **Eq. 6**. In either case, the new total skin at each rate is given by

$$s_T = s_m + Dq \tag{9}$$

As an alternative method, we may use **Eq. 7** to first solve for the new total skin at each rate, *i.e.,*

$$s_T = \frac{\Delta p^2}{Aq} - b_o \tag{10}$$

Then we can graphically determine both the new D and the new s_m by plotting s_T versus q. Using this graphical method to determine a new total skin from just a single point test represents a significant development.

In the results presented in this paper, we shall show that both the algebraic method (**Eqs. 5** to **9**), and the graphical method give reasonable estimates for total and mechanical skin.

2.4.2.3.2 Field Test of the Sawyer-Brown Surveillance Method

The following example will illustrate and verify the method described above. The test well is a gas storage well in a sandstone reservoir in the eastern U.S. The well was initially tested in June 1996.

A three-point modified isochronal test was conducted with a bottomhole pressure gauge installed. Pressure transient test analysis (PTTA) of the pressure buildup data gave a D value of 2.85 and a mechanical skin of –1.45 as shown in **Figure 2-128**. Analysis of the isochronal test data by plotting $\Delta p^2/q$ vs q (**Eq. 4**) gave values of a = 39,180 and b = 47,345 as illustrated in **Figure 2-129**. **Eq. 5** was then used to determine the constant "A" and **Eq. 6** was used to determine the constant "b_o".

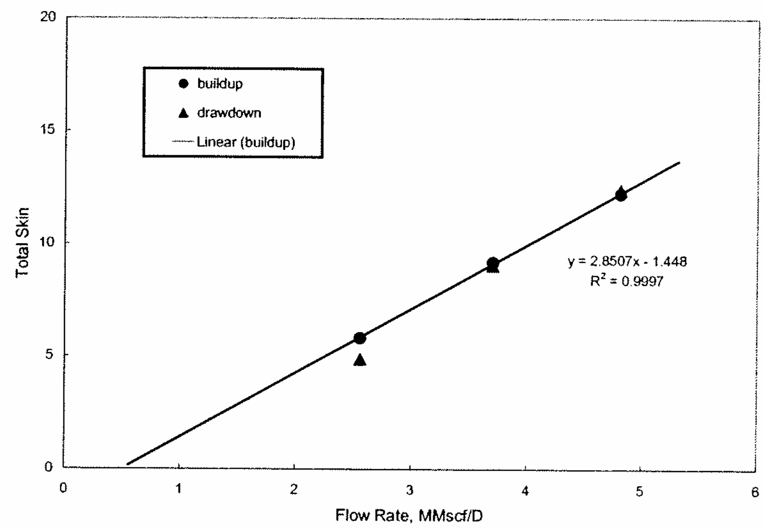


Figure 2-128: Determination of D-Factor From Pressure Transient Tests

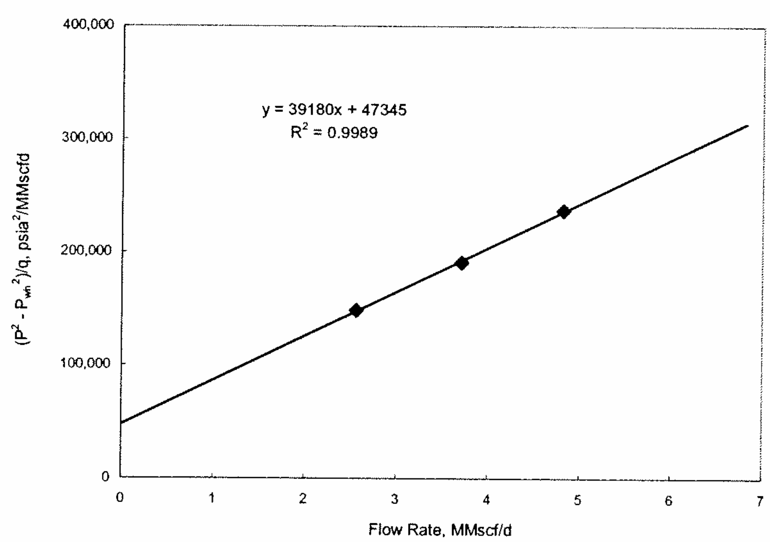


Figure 2-129: Determination of Constants "a" and "b" Using Jones Method

The well was stimulated in June 1997 and a deliverability test was conducted two days later. Subsequent deliverability tests were also conducted in September 1997 and May 1998. In each instance, a 3-point modified isochronal test was conducted. Implementation of this method used bottomhole pressures calculated from measured surface pressures, and each test was analyzed to determine "a" and "b" in **Eq. 4**.

Table 1 gives the deliverability test data for the initial test and the three subsequent tests. **Eqs. 5** and **6** were used to determine new values of D and s_m for each test. **Figure 2-130, Figure 2-131,** and **Figure 2-132** show graphs of $\Delta p^2/q$ vs q for the three subsequent deliverability tests. The slopes were determined using all three points on the plots, and the "b" values were determined by shifting this slope to pass through the stabilized flow point.

Test	Time (hours)	Bottomhole Pressure (psia)	Production Rate (MMscf/D)
#1 June 1996	0	1,875	0
	1	1,771	2.558
	2	1,874	0
	3	1,675	3.704
	4	1,871	0
	8	1,541	4.814
#2 June 1997	0	1,519	0
	1	991	2.010
	2	1,516	0
	3	1,363	0.997
	4	1,519	0
	8	1,217	1.585
#3 September 1997	0	2,216	0
	1	2,151	2.800
	2	2,213	0
	3	1,683	8.676
	4	2,206	0
	7	1,976	5.633
#4 May 1998	0	1,787	0
	1	1,636	3.286
	2	1,783	0
	3	1,541	4.402
	4	1,780	0
	7	1,402	5.738

Table 1: Summary of Deliverability Test Data for Initial Test and Three Subsequent Tests

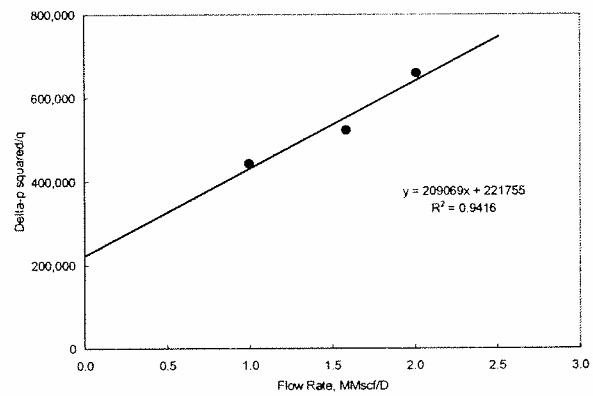


Figure 2-130: Jones Plot for Test #2

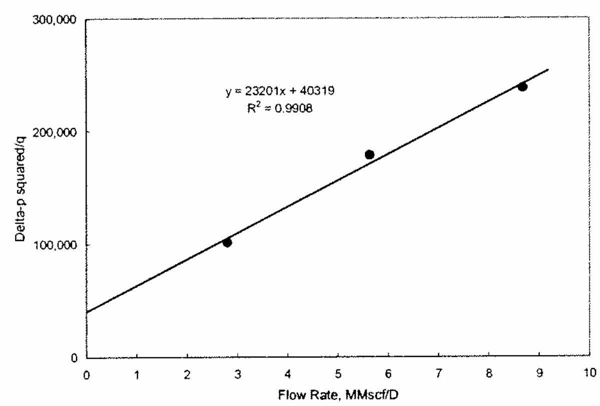


Figure 2-131: Jones Plot for Test #3

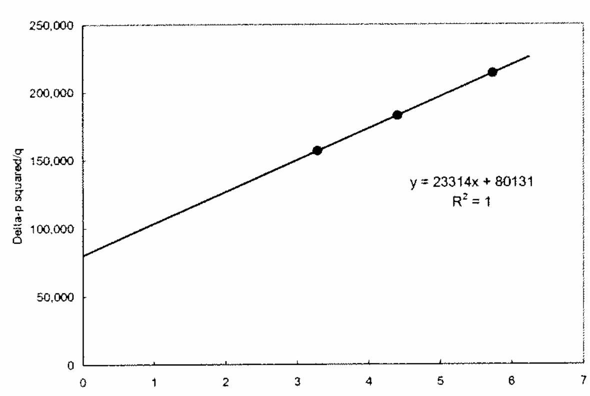


Figure 2-132: Jones Plot for Test #4

In order to validate our method, bottomhole pressure gauges were used during the three subsequent deliverability tests (i.e., Tests #2, Test #3, and Test #4). PTTA was used to obtain "measured" values of total skin for each of the three pressure buildup tests for each deliverability test. From the total skins and rates, values of D and s_m were obtained for each test. **Table 2** shows a comparison of the mechanical skin and non-Darcy factor, obtained from PTTA and from the deliverability test data using **Eqs. 5** and **6**. The agreement is reasonable for all three subsequent deliverability tests.

	Pressure Transient Analysis		Deliverability (Test) Analysis	
Date	D (MMscf/D^{-1})	s_m (dimensionless)	D (MMscf/D^{-1})	s_m (dimensionless)
June 1996	2.85	-1.45	-	-
June 1997	17.5	13.4	15.2	8.96
September 1997	1.89	-4.05	1.69	-1.47
May 1998	1.66	1.15	1.70	0.87

Table 2: Comparison of Mechanical Skin and Don-Darcy Skin Obtained from Pressure Transient Test Data and Deliverability Test Data Using Eqs. 5 and 6

Figure 2-133 shows the measured (PTTA) skin values and the deliverability test skin values in **Table 2**. We also calculated a total skin for each rate of each test using **Eq. 7** and **Eq. 9**. **Figure 2-134** and **Table 3** give a comparison of measured versus calculated total skin for each rate of all three deliverability tests.

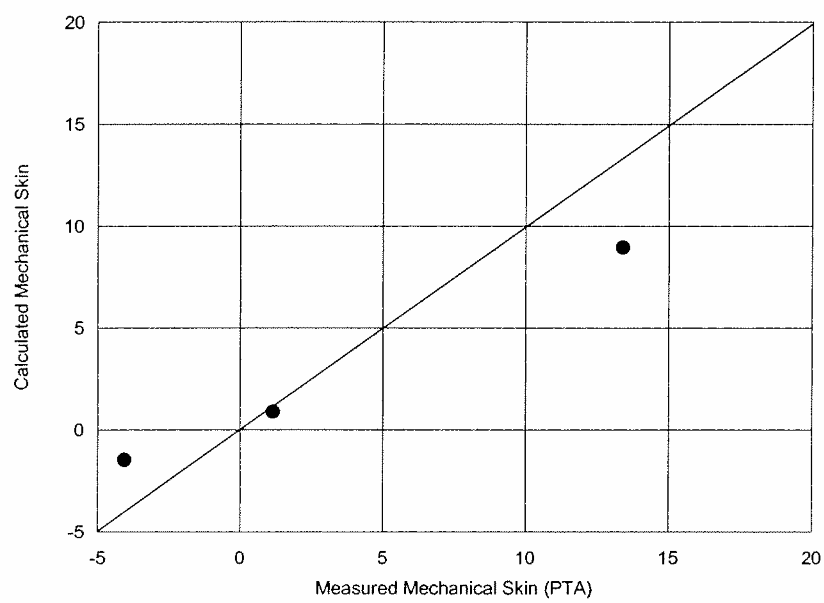


Figure 2-133: Plot of Measured (PTTA) Skin Values and Skin Values From Deliverability Test in Table 2

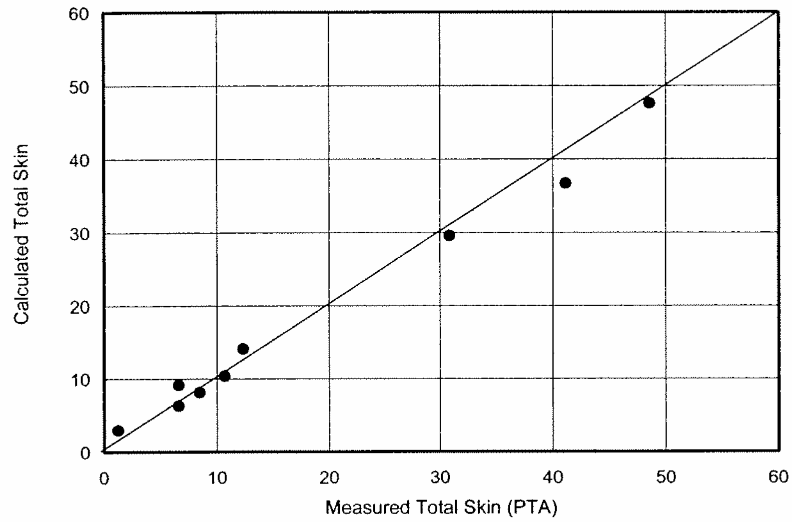


Figure 2-134: Comparison of Measured vs Calculated Total Skin for Each Rate in All Deliverability Tests.

Date	Flow Rate (MMscf/D)	Estimated Total Skin (Eq. 7)	Measured Total Skin (PTA)
June 1997	2.010	47.6	48.6
	0.997	29.5	30.8
	1.585	36.7	41.1
September 1997	2.800	3.0	1.2
	8.676	14.1	12.3
	5.633	9.2	6.6
May 1988	3.286	6.3	6.6
	4.402	8.2	8.5
	5.738	10.4	10.7

Table 3: Comparison of Measured vs Calculated Total Skin for Each Rate in All Deliverability Tests.

Instead of using **Eqs. 5** to **7** to determine new values of s_m and D, we may use **Eq. 10** to obtain the new total skin for each rate and then graphically determine s_m and D. The results of the graphical method are summarized in **Figure 2-135**. The analyses are shown in **Figure 2-136, Figure 2-137,** and **Figure 2-138**.

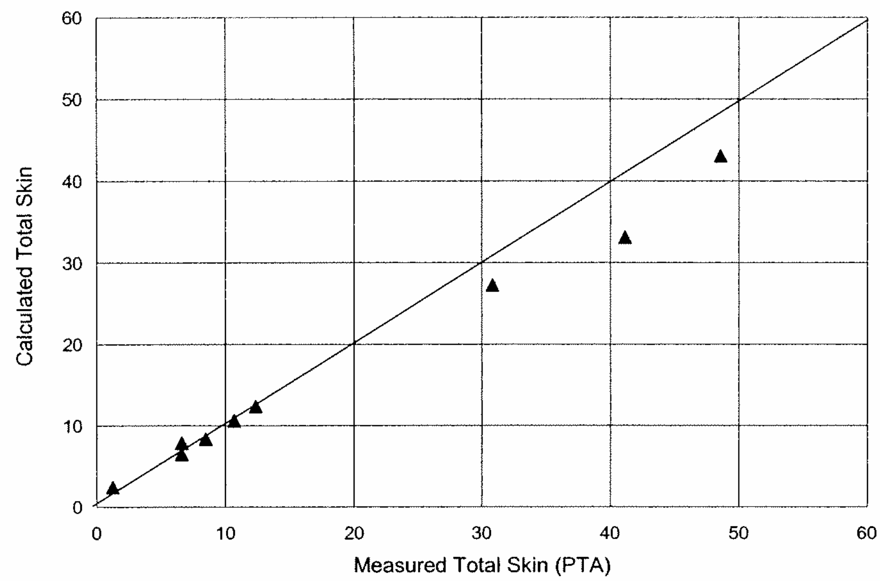


Figure 2-135: Comparison of Skin Determined From Pressure Transient Tests and Graphical Method

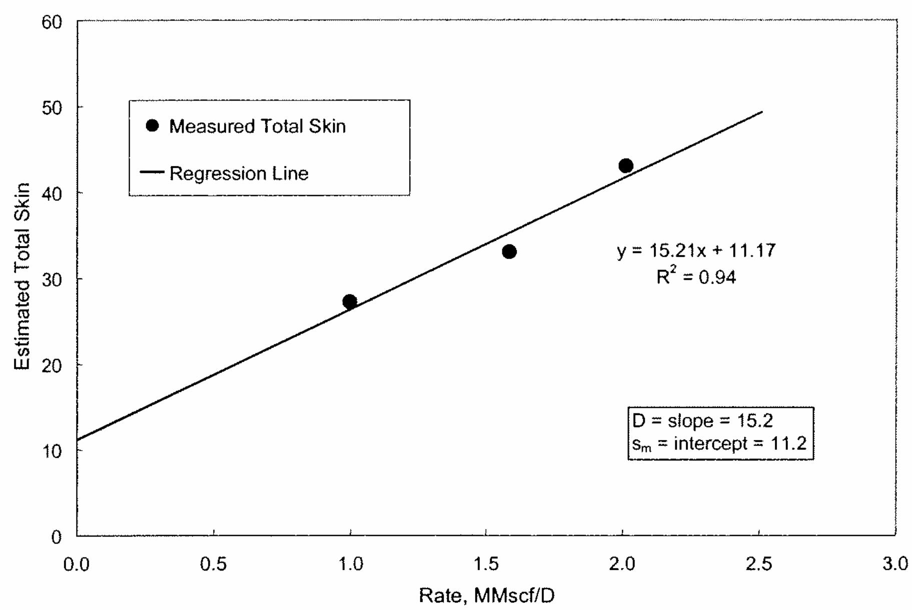


Figure 2-136Calculation of Total Skin and D-Factor From Pressure Transient Test Data for Test #2

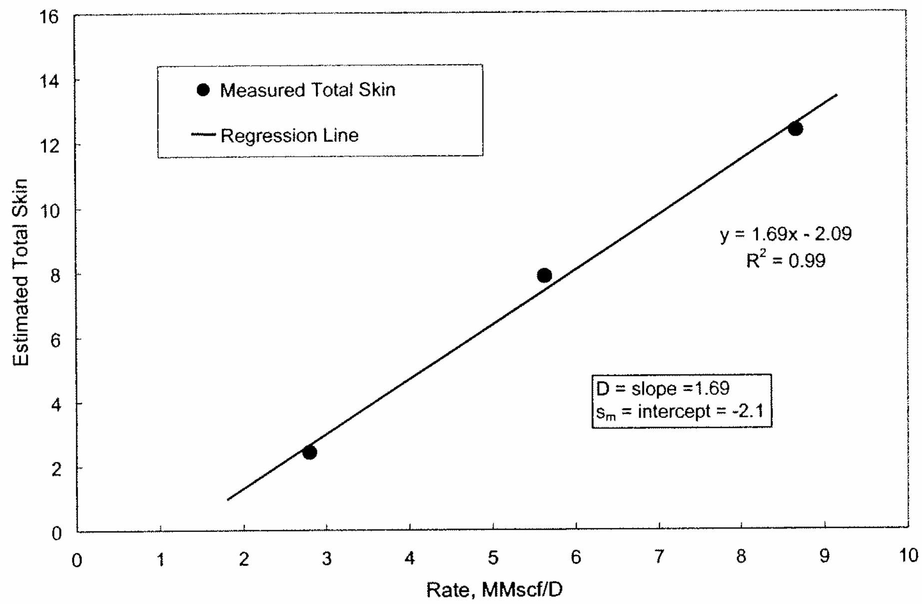


Figure 2-137: Calculation of Total Skin and D-Factor From Pressure Transient Test Data for Test #3

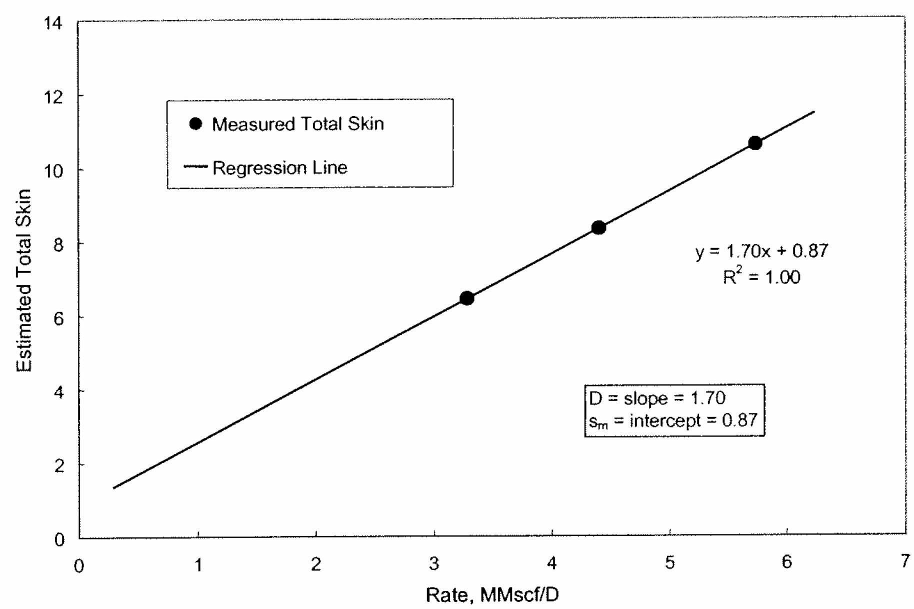


Figure 2-138: Calculation of Total Skin and D-Factor From Pressure Transient Test Data for Test #4

2.4.3 Recommendations

We recommend UGS operators consider the Sawyer-Brown method as part of a comprehensive deliverability monitoring program. The Sawyer-Brown method has been successfully tested in a several wells and fields having a range of reservoir properties. Damage levels in gas storage wells can now be monitored much more frequently at minimal costs. Widespread implementation of this new technique should be considered in an effort to identify the path of damage development, which may provide considerable insight into the source of damage in storage wells.

We recommend additional work be performed on the minute rise deconvolution technique. Although successful demonstration of this technique proved to be beyond the financial scope of this project, we believe the method bears further consideration. The primary advantage of successful implementation of the minute rise deconvolution technique over the Sawyer-Brown method would be that multi-rate testing would be economically feasible, making it possible to directly measure the non-darcy flow coefficient. Implementation of the minute rise deconvolution method in this study treated the wellbore as a homogeneous tank. Development of a more sophisticated mathematical model would likely improve the model, and should be considered.

2.4.4 Discussion of Results

A few practical considerations should be kept in mind when using the SB Method. First, Eq. 2 indicates that A is a function of $\mu_g zT$. Therefore, if test conditions change significantly from test to test, it may be necessary to update the value of $\mu_g zT$. This can be accomplished using standard industry correlations.

In addition, **Eq. 3** indicates that b_0 is a function of r_e. In gas storage operations, the status of offset wells may change from test to test, which can have an impact on the value of r_e. This can occur if the entire field is shut-in for one test, but offset wells are flowing during another test. A reasonable approximation of the new r_e should be determined from the well distribution in the field. Note that only a reasonable approximation is required, since the r_e term is within a log function.

Finally, since the SB Method is based on the pseudo-steady-state radial gas flow equation, it is necessary that the system can be reasonably approximated by a radial system and that pseudo-steady state flow is achieved during the test.

In summary, the Sawyer-Brown Method allows estimation of total skin, mechanical skin, and non-darcy factor from deliverability test data over the life of a gas storage well. Only an initial PTTA using bottomhole pressures is required. This method is simple and may easily be programmed into a spreadsheet. Both the algebraic and graphical procedures for implementing the Sawyer-Brown Methods give essentially identical results, however the graphical method has the advantage that only one Jones analysis is necessary. Consequently, damage levels in gas storage wells can now be monitored much more frequently at minimal costs. Implementation of this new technique should be employed to identify the path of damage development, which may provide considerable insight into the source of damage in storage wells.

2.5 Objective 5: Develop R&D Guidelines for Gas Storage Industry

2.5.1 Background

The fifth objective of the study was to develop guidelines and recommendations for future gas storage R&D.

2.5.2 Conclusions

Several key facts related to future UGS R&D issues became apparent as this study progressed, and are discussed below.

First, it appears that we do not fully understand the underlying causes of damage. Specifically we lack a clear understanding of the *process* of damage formation. The fact that post-stimulation DI values decline in about 50% of the remediation treatments studied is strong evidence of our lack of understanding. Clearly, we often treat the symptoms of damage rather than the underlying causes of it.

Second, detailed treatment data is usually not readily available to storage engineers. This was evidenced by the paucity of detailed treatment data available in this study. Detailed treatment data is essential to determine the impact of individual treatment parameters on the success of stimulations, and lack of such data prevents GTI and the UGS industry in general from reaping the maximum possible benefits from this study. The lack of availability of operational data also limited opportunities to assess the impact of operational changes on deliverability in this study. It is not clear whether the lack of detailed treatment data is due to its non-existence, or simply due to the effort required to retrieve it. Obviously, since the solution to this problem will differ significantly depending on its cause, it is important to clearly identify the underlying cause.

Third, the UGS industry employs a very limited arsenal of deliverability enhancement tools. Based on the study data, the UGS industry uses only 4 different stimulation treatments over 75% of the time. The limited number of techniques used to restore deliverability in UGS wells was also noted in a study by Mauer nearly a decade ago[16], in which it was estimated that only 3 techniques were used about 75% of the time. The prevalence of cleanup effects and significant post-stimulation decline rates suggest that the small number of techniques employed is not the result of successfully identifying the treatments that work. It is evident that little improvement has occurred in this area during the last decade.

Fourth, cleanup effects and significant decline rates in post-stimulation DI values are common after remedial treatments. Delays in achieving the maximum increase in deliverablity after treatment, and the deterioration of that deliverability over time, represent significant losses in deliverability available for marketing, and hence represent significant lost revenue. Improving our understanding of these issues could reduce their prevalence, making UGS operations more efficient and profitable.

Fifth, several tools developed as part of this study that warrant continued use to further improve our understanding of how to optimally remediate wells and operate storage fields. Specifically, the database tools developed for this study should be periodically updated in order to update study results, the tools developed to quantify the impact of operations on deliverability should be employed to study the effects of changing operations, the Sawyer-Brown surveillance technique should be implemented in an effort to determine the path of damage development over time, and the minute-rise deconvolution surveillance technique should be evaluated for further development.

2.5.3 Recommendations

2.5.3.1 Increased Understanding of the Damage Formation *Process*

A significant emphasis of future UGS R&D efforts should to be focused on increasing the industry's understanding of the underlying causes of damage. In particular, the industry needs to significantly increase their understanding of the *process* of damage formation. This will involve four general steps.

First, the industry needs to develop a process to identify the *primary* damage mechanism(s) causing deliverability declines and quantitatively estimate its impact on deliverability. This will ensure that subsequent R&D efforts are focused on the mechanisms responsible for the majority of damage.

Many of the recent R&D efforts in the storage industry have focused on identifying the specific damage mechanisms present in storage wells/reservoirs, and development of tools and methodologies necessary to identify them. These efforts were by no means inappropriate, as this is a necessary first step. However, none of these previous efforts involved quantifying the extent that each individual damage mechanism contributes to deliverability declines. In order to maximize the efficiency of future R&D dollars spent on damage remediation, it is necessary to know which *specific* mechanism is responsible for most of the deliverability reduction.

Second, it is likely that some basic research will be necessary to develop appropriate chemical and thermodynamic models useful for field applications. This may involve the development and/or deployment of hardware capable of real time, down hole measurements of pressure, temperature, and chemical composition. This will require going beyond the simplistic static models typically employed in the industry today, and develop *dynamic* chemical, thermodynamic, and reservoir models.

It is critical that these models enable UGS operators to understand the underlying process of damage formation. Only after gaining such understanding can the operators modify daily field operations to minimize/eliminate damage formation by interrupting the underlying process.

Third, these dynamic models should be tested in the lab before deployment in the field. Specifically, lab studies should be conducted to determine theoretical models best suited for predicting the tendency and rate of specific types of damage formation.

Finally, the models developed in the lab should be verified via field tests, and deployed for general use in the UGS industry. Follow-up testing is recommended to verify the effectiveness of using the models to prevent/reduce damage formation in the field.

2.5.3.2 Improved Data Collection and Management

We believe there are very significant opportunities associated with the collection and management of additional, and additionally detailed, data related to storage field operation and well stimulation.

A large number of wells were excluded from this study due to unavailable, insufficient and/or ambiguous stimulation and/or deliverability information. It is very likely that much of the detailed data required for inclusion in the study does indeed exist somewhere within the company, but cannot be located by the storage engineers with a reasonable level of time and effort. In some cases, the flurry of acquisition activity in the UGS industry has made the simple task of locating field and well data a daunting task. Considering the significant personnel reductions that have recently occurred within the UGS industry, this is not completely surprising. Whatever the cause, it is obvious that the areas of data and knowledge management represent significant opportunities within the UGS industry.

Therefore, any R&D efforts that would make measurement, collection, transfer, storage, retrieval, and/or processing of this data easier or more cost effective should be considered. These opportunities might include implementation of existing hardware, software, and/or operating practices that improve these tasks, or the development of new hardware, new software, and/or new operating practices that improve these tasks. The overarching objective of this R&D should be to improve the integration of engineering, operations, and marketing data, optimization of data transfer, storage, retrieval, and processing, and availability of all data and analysis results to field, engineering, and marketing personnel.

One general R&D area might include advances in wellhead electronic flow measurement. Specifically, development of less expensive measurement hardware and software, development of measurement hardware that is less intrusive and more easily retrofitted to existing wellhead facilities, and measurement hardware that can handle multi-phase flow (especially 2-phase gas-water flow) would prove beneficial.

Development of less expensive hardware for gas measurement could be accomplished by relaxing the accuracy required of the equipment. It is not atypical of UGS operators to employ the talents within their gas measurement departments when designing wellhead EFM equipment. Although these professionals are usually well-qualified and very experienced in the design of custody transfer gas measurement facilities, few have any reservoir engineering experience or pressure transient test analysis expertise. Consequently, the level of accuracy required for wellhead EFM equipment used to monitor damage and optimize remediation programs are often assumed to be the same as custody transfer facilities. The result is that many wellhead EFM systems have been overdesigned, and therefore are more expensive than necessary.

Guidelines should be developed to determine the level of accuracy required of wellhead EFM equipment, based on the type and objectives of surveillance programs. A much lower level of accuracy is required if an operator has determined that monitoring of DI over time is an adequate surveillance method. Conversely, if an operator has determined that the only appropriate surveillance program for his particular field requires frequently running multi-rate pressure transient tests a much higher level of accuracy may be required. The two scenarios require different systems, with very different costs.

Design of wellhead EFM equipment that is less intrusive and more easily retrofitted to existing wellhead facilities would greatly expand the potential for installation of wellhead EFM equipment in existing storage fields. Many existing storage fields never had measurement facilities available at the wellhead, and many others had wellhead measurement facilities removed over the years. Consequently, retrofitting the wellhead with meter runs (the most widely used traditional gas measurement type of facility) can be very costly due to the required labor and equipment involved as well as the considerable expenses often necessary to ensure compliance with prevailing safety regulations.

Less intrusive wellhead measurement equipment currently exists, such as the Annubar™ measurement system. The appropriateness of such existing equipment should be evaluated for storage applications.

The availability of reasonably prices wellhead measurement EFM facilities capable of handling two-phase gas water flow should also be explored. Two different types of systems may be required. One system is likely appropriate for the "dry" gas field that produces a relatively small amount fluid late in the withdrawal season. A different system would likely be appropriate for aquifer storage wells, which produce larger amounts of fluids ealier in the withdrawal cycle.

2.5.3.3 Increased Number of Remediation Options

The UGS industry employs a somewhat limited number of deliverability maintenance and enhancement tools. We believe it would be prudent to pursue R&D efforts aimed at exploring additional means of stimulation and remediation.

Where the damage is due to mechanical skin, new methods to remove or bypass the near wellbore damage should be explored. Due to the low costs and operational simplicity associated with perforating, we think it would be prudent to explore opportunities to improve perforating technology specifically designed to bypass the near wellbore damage. Such technology would require relatively shallow penetration and large holes, and should be applicable in both cased-hole and open-hole completions.

Other mechanical damage removal opportunities?????

For non-darcy damage, where the damage is due to non-darcy flow in the reservoir and/or completion, new remediation treatments should address the issue of insufficient area available for flow, which is usually the underlying cause of non-darcy flow.

Underreamers capable of creating an 8 ft diameter hole size through casing have been developed and tested in several producing formations. Because UGS reservoirs tend to be in harder rock than the formations in which this technology is routinely deployed, operators are somewhat reluctant to try the technology, in the belief that such a tool could not possibly cut such hard formations. R&D to determine the applicability of this type of tool should be conducted. If it is determined that the current technology is inadequate due to the tools inability to cut hard rock formations typical of storage reservoirs, R&D efforts should be pursued to develop a tool that can effectively cut hard rock. This type of tool would not only reduce/eliminate non-darcy damage in a well, but it would also reduce the mechanical damage as well.

Drilling multi-lateral horizontal wellbores from an existing vertical wellbore using water-jet technology requiring minimal use of fluids is also a developing technology that has been demonstrated to work in production wells, but not yet been tested in storage wells. One of the primary drawbacks to this technology is the inability to accurately control the location of the horizontal legs jetted. Operators' fear the "horizontal" leg could wander upward and penetrate the reservoir's caprock, thus jeopardizing the reservoir seal.

In some storage reservoirs, such as a thick carbonate reef reservoir, this concern may be eliminated if the total length of the jetted horizontal is kept shorter than the distance to the caprock. For other reservoirs, such as thinly bedded sandstone reservoirs, this may be a legitimate issue. Technology does currently exist to control the location of the horizontal, but is cost-prohibitive. R&D efforts aimed at lowering the costs associated with controlling the location of the horizontal may also be prudent.

As is the case for mechanical damage (due to the low costs and operational simplicity associated with perforating), we think it would be prudent to explore opportunities to improve perforating technology specifically designed to reduce non-darcy damage. Current systems analysis software is somewhat limited in its ability to model the reduction in non-darcy damage in open hole. This software limitation is likely due to a lack of theoretical models appropriate for such predictions. Thus, R&D efforts aimed at developing theoretical models capable of estimating the reduction in non-darcy damage as a result of perforating in open-hole would be beneficial.

2.5.3.4 Decreased Cleanup Times

The opportunity to accelerate the deliverability improvements realized by currently employed stimulation treatments by reducing or eliminating the cleanup time should be studied.

Future R&D work should explore the use of alternate stimulation fluids and/or additives that minimize the time required for removal of water from the well. For example, use of alcohol-based acids should be explored to promote more rapid cleanup of acid stimulation fluids. Also, any technology that would reduce the amount of fluid involved in killing, working over, and/or stimulating a storage well should be considered. New methods of fluid flowback and/or retrievel after a remediation treatment would also prove beneficial in reducing cleanup times.

2.5.3.5 Continue/Expand Current Damage Monitoring Efforts

The numerous tools developed as part of this study that warrant continued use to further improve our understanding of how to optimally remediate wells and operate storage fields. Including the database utilities developed to monitor damage, determine the imnpact of operations on deliverablity, and the EXCEL™ tools developed to conduct surveillance frequently enough to establish the general path of damage development over time.

The database utility developed to quantify the benefits of the various remediation treatments should be periodically updated with additional deliverability and stimulation data. The results of the study should also be updated periodically using the additional data provided. Periodic updates of effectiveness, longevity, PV75, cleanup time, and post-stimulation decline rates should be made. Comparisons with previously calculated values should be made to determine if the industry is improving its ability to effectively remediate storage well deliverability.

The database utility developed to quantify the impact of operations on deliverability has been tested and demonstrated to effectively identify and quantify changes in deliverability over time. Therefore, this utility should be deployed wherever and whenever storage operators (especially those equipped to collect hourly and/or daily EFM data) are planning on making operational changes. As demonstrated in this study, it is crucial that details related to the timing, location, and type of operational change be recorded for proper analysis.

The Sawyer-Brown surveillance technique should be deployed to operators and used to determine the general path of damage development over time, in an effort to determine which storage operation(s) are primarily responsible the formation of damage.

In addition, the minute-rise deconvolution surveillance technique should be evaluated for further development. Although successful demonstration of this technique proved to be beyond the financial scope of this project, we believe the method bears further consideration. The primary advantage of successful implementation of the minute rise deconvolution technique over the Sawyer-Brown method would be that multi-rate testing would be economically feasible, making it possible to directly measure the non-darcy flow coefficient.

Implementation of the minute rise deconvolution method in this study treated the wellbore as a homogeneous tank. Development of a more sophisticated mathematical model would likely improve the model, and should be considered. In addition, back-extrapolation techniques to estimate the flowrate in the well immediately prior to shutting in the well should be explored. Successful development of such a back-extrapolation technique would allow operators of dry gas wells without any conventional wellhead flow measurement facilities to implement the MRD surveillance method.

Nomenclature

a = Coefficient in Jones Equation

A = Constant

b = Coefficient in Jones Equation

b_0 = Constant

D = Turbulence Coefficient (1/MMscf)

h = Formation thickness, ft.

k = Permeability, md

n = Moles

P = Pressure, psi

P_R = Reservoir Pressure, psi

P_{wf} = Flowing Pressure, psi

q = Gas flow rate, MMscf/D

r_e = Radius of drainage, ft

r_w = Radius of wellbore, ft

R = Real Gas Constant,

s_m = Mechanical Skin, dimensionless

s_T = Total Skin, dimensionless

V = Volume, ft^3

V_{WB} = Volume, ft^3

z = Gas Compressibility Factor

μ = Gas Viscosity, cp

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[2] "Investigation of Storage Well Damage Mechanisms, Final Report (April 1995-August 1997)," V.J. Yeager, M.E. Blauch, and F.R. Behenna, Gas Research Institute, 1997

[3] "State-of-Technology Assessment and Evaluation of Gas Storage Well Productivity Enhancement Techniques", Mauer Engineering In. and T. Joyce Associates, Inc., Gas Research Institute, 1993 .

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[6] "Skin Estimation of Wells Using Only Wellhead Flow and Pressure Measurements", L.A. Glenn, F.U. Dowla, and R.R. Leach, Jr., Lawerence Livermore National Laboratory, 1996.

[7] Jones Reference

[8] "State-of-Technology Assessment and Evaluation of Gas Storage Well Productivity Enhancement Techniques," pg 48, Mauer Engineering In. and T. Joyce Associates, Inc., Gas Research Institute, 1993.

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[13] "Investigation of Storage Well Damage Mechanisms, Final Report (April 1995-August 1997)," V.J. Yeager, M.E. Blauch, and F.R. Behenna, Gas Research Institute, 1997

[14] Deconvolution references here (multiple?)

[15] Jones Reference

[16] "State-of-Technology Assessment and Evaluation of Gas Storage Well Productivity Enhancement Techniques," pp vii, 51, Mauer Engineering In. and T. Joyce Associates, Inc., Gas Research Institute, 1993