Experience Gained From 318 Injection Well KOH Clay Stabilization Treatments

Chuck Norman
Tiorco de Argentina

Abstract

Water injection in clay sensitive sandstone formations often results in decreased permeability and low injectivity. Some types of clays, including montmorillonites, swell upon contact with fresh water, plugging pore throats and reducing permeability. Migrating clays, including kaolinites and illites, reduce permeability as they become trapped in pore throat openings. KOH (potassium hydroxide) clay stabilization results from the interaction of caustic with the clay in the presence of potassium ions. The KOH-clay chemical reaction permanently alters the clay chemistry so that the clay minerals are unaffected by changes in water composition. Several field case histories, discussed in the following paragraphs, demonstrate that KOH can mitigate the effects of both swelling and migrating clays. Field results indicate that a single KOH treatment is effective over the economic life of the well.

Laboratory studies and empirical results indicate that the most important considerations for optimizing KOH treatment results are: 1) KOH concentration; 2) KOH contact time with reservoir rock; 3) maintaining a constant flow rate of the KOH solution during the treatment, and; 4) reservoir temperature.

The majority of KOH treatments have been applied in Cretaceous sandstone formations in the Powder River Basin of Wyoming. However, KOH offers the potential for injectivity improvement in other clay sensitive formations, and should be considered as an alternative to hydraulic fracturing in some areas. Finally, a simple waterflood simulation is presented in order to evaluate the economics of KOH.

Introduction

Clays are a common component in tight sandstone formations, and have the potential to adversely affect waterflood performance. The effects of clays may be subtle, causing loss in injectivity over time, or extreme, causing the formation to "lock up" soon after initiating water injection. In any case, project economics are adversely affected if optimum injection rates cannot be maintained. In addition to an overall loss in injectivity, clays tend to exacerbate heterogeneity, resulting in lower ultimate oil recovery. This happens for two reasons. First, clays have a stronger effect in tighter rock, so injectivity into the tighter rock in a formation will be lost first, resulting in a high-grading of injection into the most permeable rock. Second, as injectivity decreases over time, injection pressures are often increased to maintain rate, and parting pressure is reached sooner.

There are many technologies available for stabilizing clays, but KOH remains the only means of stabilizing clays permanently a significant distance into the formation. The KOH reacts chemically with clays, rendering them invulnerable to destabilization through swelling or migration.[1] This reaction should be distinguished from technologies that stabilize clays temporarily, such as KCl (potassium chloride), or coating clays with surfactants or polymers. While these technologies are effective, they are limited. For instance, KCl is only effective while it is in the injection water. This implies that to use it on a reservoir scale would be too expensive, because it would have to be added to the injection water continuously. Coating materials such as surfactants and polymers are effective one-time treatments, but eventually they may desorb from the clays, resulting in a need for re-treatment.

To date, a total of 318 injection wells have been treated with KOH technology in 10 different formations. The purpose of this paper is to use this experience base to provide engineering information on candidate selection and evaluation, treatment applications, post-treatment evaluation and economics. An overview of treatments that have been conducted is provided to aid in candidate selection. The information provided is intended to aid the working engineer in determining whether the process is a viable method for stabilizing clays in a given reservoir, and in estimating the economic benefits of applying the KOH process.

Candidate Selection

Table 1 is an overview of formations that have been treated with KOH, along with number of wells and general rock properties. Generally, most formations have been tight, dirty, upper Cretaceous formations. Clay contents have ranged from 2 to 20 percent by weight of total clay relative to the rock in analyzed samples. Predominant clays in treated formations have been kaolinite, illite, migrating clays, and chlorite and smectite, swelling clays.

Candidates for clay stabilization typically reveal themselves based on laboratory data or past field case histories. Both are important means of identifying candidates.

Field Case Histories. Previous waterflooding experience in the same or similar formations in an analogue field may indicate clay problems. If available, previous injection wells in the field of interest obviously are valuable analogues. In some cases, a particular formation is known to contain clays that inhibit injectivity. In others, a situation may exist where other suspected causes of lost injectivity have been ruled out systematically, with clays remaining as a potential cause. One technique of evaluating injectivity of analogue wells is through the use of a Hall plot,[2,3,4] shown in **Figure 1**. Cumulative pressure, pressure multiplied times days, is plotted against cumulative injection volume. The shape of the graph provides a “fingerprint” of injection well performance. Once the formation is filled around the injection well, the Hall plot should remain fairly straight, line A, unless specific changes are made to change the plot. A concave upward shape, line B, suggests loss of injectivity over time, while a breaking over of the curve, line C, or sudden decrease in slope, suggests formation parting. Lines B and C both bode poorly for the reservoir performance. Line B is bad for economics because less fluid injected means slower fill-up and less fluid produced. Line C suggests parting, which could lead to fluid loss out of zone or to linear flow from the wellbore and bypassing of oil-saturated rock.

The curve that indicates a potential clay problem is line B, showing injectivity loss over time. However, there are many potential causes of injectivity loss, clays being only one possiblity. Therefore, other causes must be evaluated systematically. Some potential causes of decreased injectivity beyond fill-up may include scaling or other solids buildup in the wellbore, paraffin buildup, decreased production or fill-up of offset producing wellbores, or even bringing an additional injection well on line in the vicinity of the injector of interest. If these potential possibilities have been addressed and ruled out, then clays should be investigated, particularly if the formation is a tight sandstone.

Laboratory Data. Laboratory data can be helpful, not only in detecting a clay problem, but in evaluating whether the KOH process is a potential solution to the problem. Typically, the stepwise process involves collecting cores in the field, obtaining baseline data in the laboratory, including whether injection water tends to damage the core, and finally testing whether the KOH process helps prevent damage. A general core testing procedure is provided by Sydansk.[1] However, obtaining and working with clay-filled cores is not straight-forward. Neither is testing a chemical process in a core. Finally, there is nothing simple about using laboratory data to predict field results. Given all these pitfalls, there is certainly plenty of room for mistakes and misinterpretation when testing cores; let the engineer beware. Following are some suggestions to help avoid some of the more common mistakes:

Obtaining Samples

• A non-damaging fluid, such as 3% KCl, should always be used to collect the core. Otherwise, the core could be damaged from the start.

• Be sure to collect the proper injection fluids. These fluids should be verified by analysis once they reach the lab. Do not assume a sample labeled “fresh injection water” is fresh water without verifying. This is extremely important. If an improperly collected sample is actually salt water, the injectivity results could be very favorable, as clays may not destabilize with brine, particularly formation brine. The result would be that a bad core test could suggest no problems with injectivity, then in the field severe injectivity losses could shut down the project.

Testing for Clay Problems

• Clays may reveal themselves in the lab in different types of tests, some examples of which follow. While these observations may not necessarily indicate clays, they do suggest the possibility of clays:

- *Water Sensitivity Tests,* where water movement through the core causes a decrease in injectivity.
- *Relative Perm Curves,* where relative permeability to water may be extremely low relative to oil or air permeability.
- *Petrographic Analysis (SEM),* which quantifies and defines clay types. Clay contents as low as 2 percent by weight can cause damage, depending on the type of clay.

• Establish initial saturations at extremely low flow rates with connate brine. Otherwise the core could be damaged from the start.

• Test cores over a range of permeabilities. Do not test one of the better cores, as this could provide misleading data that suggests no clay problems. Clays are more of a problem in low permeability rock than high permeability rock. At least one representative from the low, middle and high ranges of permeabilities should be tested.

• Use formation brine to get baseline injectivity and relative perm data. Tests should also be run with the intended injection water. This data will provide good relative perm data and the effect of the injection water on injectivity. A common mistake is to run tests only with injection water, then assume the resulting relative perm curves represent the entire reservoir. The problem with this is the injection water could be damaging the core from the start, again resulting in misleading data.

• Test over a wide range of linear flow rates. If all cores are tested at a low flow rate, representative of in-situ flow rates, this may not be representative of near-wellbore conditions in an injection well, where flow rates may be extremely high. It is these high flow rates that damage the rock and cause a loss in injectivity. Tests conducted at low flow rates, again, may not indicate a potential injectivity problem where one may actually exist.

Testing the KOH Process in Cores

• Use the proper chemical concentrations. KOH is effective at high concentrations, usually 15 - 30 percent by weight. It is surprising how often the actual injection concentration in the core was diluted significantly. Obviously results will not be representative if the proper chemical concentration is not used.

• Use a sufficient flow rate to flood the entire core. Originally, a minimum treatment rate of 0.1 ft/day was recommended.[1] While this rate is sufficient to treat the core without inducing treatment-related damage, more recent experience has suggested a rate less than about 1 ft/day during KOH placement may result in only a fraction of the core being contacted.

• Collect and measure both oil and water produced from the core. This is important because KOH often reduces the interfacial tension between crude oil and water sufficiently such that residual oil is mobilized. This results in higher relative permeability to water near the injection well, and additional banked oil.[5]

• Two sets of data should be collected at each permeability. First is the baseline set which shows the damaging effect of injection water on permeability. Second is a set of cores treated with KOH. Both sets should be shocked with injection brine at an extremely high flow rate, such as 100 ft/day. This is often overlooked and is very important, because injection wells typically see an extremely high flow rate as the fluid leaves the wellbore.

Examples of Laboratory Results

Figures 2, 3 and 4 show examples of laboratory core data. The purpose of these examples is to illustrate variation in results from different rock, and to illustrate some of the pitfalls in testing cores. The data was generated with restored core and in both cases the KOH concentration was 15 percent. Figure 2 is data reported previously be Sydansk,[1] showing results from core from an Oligocene age formation. This is a water-sensitive formation that contains poorly cemented authigenic kaolinite clay. Results are shown as Kf/Ki, which is a ratio of the final permeability, after exposure to fresh water, to the initial permeability, before exposure to fresh water. A ratio of 1 indicates no damage resulting from exposure of the core to fresh water, while a ratio less than one indicates damage. The baseline core, intended to show the effect of exposure to fresh results indicate that permeability reduction is less severe when KOH is applied in these particular cores.

Figure 3 is data generated in restored core from the Green River formation in the Uintah Basin of Utah. This formation is known to contain significant quantities of damaging clays, including illite, kaolinite and chlorite.[11] This data was generated to show the effect of fresh injection water on permeability. Both bars represent baseline data, in two different permeability cores. Both cores were flooded with fresh water at 1.4 ft/day. A 50 percent permeability reduction resulted in the lower perm core, and essentially no damage was indicated in the higher perm core. This suggests damage is more likely to occur in tighter rock, consistent with previous experience. However, later it was determined that the formation brine used to restore the core was contaminated with fresh water, suggesting the core was damaged from the start. Further, the cores were never shocked at a high fluid rate. Both of these factors suggest the damage due to fresh water may be under-represented based on the core test.

Figure 4 shows cores which have been treated with KOH, from the same Green River formation. In two of the tests, the KOH injection rate was decreased to 0.14 ft/day. Injectivity losses were 10 to 25 percent for the 10 and 15 md cores, respectively. These two results, taken with the two untreated cores in Figure 3, provide a somewhat weak case for clay damage, as well as for KOH as a solution. However, there are two important problems with the data. First, as mentioned before, the baseline cores had been damaged with fresh water prior to the sensitivity tests. Second, it was suspected that the reduced KOH rate may have been too low to flood the cores, resulting in fingering of the KOH through only a small portion of the core. To test this theory, a third core was run, and the flow rate during KOH was left at 1.4 ft/day, the same flow rate as the rest of the stages. This is the third core in Figure 4, which shows a permeability *increase* which is attributed to a lack of clay damage combined with mobilization of residual oil in the core. The difference between results in the first two cores and the third core illustrate the importance of maintaining a sufficient flow rate during KOH injection, so the chemical contacts the core properly, without fingering.

General Candidate Criteria. Once a clay problem has been identified based on field performance and laboratory data, additional considerations on a reservoir scale are important in determining whether the KOH process is viable from a practical and economic standpoint. One example is injection water availability. If water available for waterflooding is fresh, or significantly less saline than the formation brine, clays will probably need to be stabilized. On the other hand, if a brine similar to the formation brine is available to flood the reservoir, clay stabilization may not be necessary. Well cost is another strong consideration. If wells are particularly deep and expensive to drill, then the operator has a lot more to lose if the well is damaged from clays. Both fractured and unfractured wells have been treated. Fractures do not necessarily preclude the need for clay stabilization, as the problem of large amounts of fluid moving through a sandface still exists, and clays still cause problems. In some cases, fracturing may do more harm than good. If fracturing the formation to increase injectivity has the potential of leading to injectivity loss out of zone or directional communication to offsets, then there may be incentive to avoid fracturing and apply KOH instead of fracturing.

TREATMENT APPLICATION

Field applications of the KOH process consist of three basic steps - preflush, KOH and post-flush.[7] The purpose of the preflush is to displace divalent ions from the near wellbore region prior to KOH injection. This is important because divalents, such as magnesium and calcium, will form insoluble precipitates if contacted by KOH, plugging the well and producing the opposite of the desired effect. Following the KOH, the post-flush must be applied immediately, as fluids must be kept moving away from the injection well, so the KOH is spent out in the formation and not near the injection well. Design issues in applying a KOH treatment are concentration and sizing of the chemical stages, and field logistics, including equipment.

Concentration. The *preflush* consists of KCl, or potassium chloride, which is known to stabilize clays. Most treatments applied to date have utilized a concentration of KCl in the range of 2 - 3 percent by weight. However, in some cases, higher concentrations may be required for different formations. When a new formation is encountered, the optimum concentration should be investigated, either through laboratory testing or past field experience, possibly with drilling fluids. The KCl must be of extremely high purity. Common impurities in KCl are divalent ions, which are the very ions the preflush is intended to displace. If the preflush contains these ions, it will *displace* them and then *replace* them, so that the desired effect *will not* be achieved! The *KOH* is highly concentrated, ranging from 15 - 30 percent by weight for most applications. Reaction kinetics are temperature dependent, so at higher temperatures lower concentrations are used.

Sizing. The *KOH* slug is sized so that the concentrated solution contacts the formation an average of 10 - 20 feet from the injection well. In some cases, the concentrate may penetrate longer or shorter distances. The goal is to penetrate beyond the point where the linear velocity of fluid decreases below the critical velocity for clay destabilization. Beyond the full concentration radius, the KOH begins to dilute due to a combination of consumption and increasing fluid flux area as distance from the injection well increases. The KOH is essentially spent about 200 to 300 feet from the injection well. The clay stabilization reaction does continue to an extent beyond the radius of full concentration, until the concentration drops below a threshold that depends on specific reservoir parameters.

The *preflush* is several times the volume of the KOH volume, to ensure divalent ions are thoroughly displaced in the rock that will be exposed to KOH.

In many applications, the intended injection water is fresh water. In this case, fresh water injection can commence immediately after KOH, constituting the post-flush. However, if a brine, even a mild brine, is intended for injection, a *post-flush* consisting of fresh water should be used before brine injection. Again, this fresh water post-flush should be several times the KOH volume. In cases where it will be necessary to shut-in the injection well following the KOH treatment, even temporarily, a fresh water post-flush should be applied after the KOH and before the shut-in.

Equipment. Typically, the entire treatment, including pre-flush and post-flush is injected using specialized portable equipment tied directly into the injection well at the wellhead. Sometimes, it is possible to inject the *preflush* from a central injection plant, thus saving the operator costs. This may be possible with new field developments where none of the injection wells have been placed in service. However, for this to be practicable individual means of control must be in place for each injection well, and a high degree of teamwork is needed among operator and service company personnel. The *KOH* is typically injected directly at the injection wellhead. This is because concentrated KOH is a highly caustic, hazardous material. It must be contained within as small a surface area as possible to maintain control, and it can only be exposed to certain types of metallurgy. Injection requires specialized pumping equipment fitted with metal parts that are resistant to KOH.

Downhole Conditions. Downhole conditions and mechanical integrity must be considered prior to the treatment application. Most new injection wells do not present problems. However, in many cases an injection well has been converted from a producing well. In these cases, mechanical integrity may be suspect. KOH will wash solids and oil off the insides of tubing, causing them to plaster against the formation in the wellbore, limiting injectivity from the start. Leaky tubing or casing can result in loss of KOH. Therefore, it is imperative to success that mechanical integrity be verified and tubing and wellbores be cleaned prior to treatment application.

Stainless steel or plain carbon steel tubing will withstand the KOH application.[12] If tubing is coated with plastic, resistance to KOH should be verified.

Fracturing proppants should be examined for resistance to KOH. Porcelain coated proppants are typically resistant, even at high temperatures. However, resin coatings may break down at high temperatures.

EVALUATION OF RESULTS

The most common means of evaluating KOH treatments has been by comparing groups of wells that have been treated with KOH with groups that have not been treated. This is not straightforward. Every well has individual characteristics, with pay zones and rock quality varying, sometimes significantly, from one well to the next within a formation and even within a particular reservoir. To properly evaluate the technology based on field data, the groups of comparison wells should be as large as possible, and should consist of a minimum of three wells. In many cases, all the wells in the field are treated with KOH from the beginning of injection. While this is certainly best from the standpoint of reservoir development, it does not allow evaluations or comparisons of specific injection wells. In these types of situations one possible alternative is to rely on comparisons with other, similar formations.

Following is an example using actual field data which is intended to illustrate a recommended method for evaluating performance of injection wells that have been treated with KOH. This method was also used for the comparisons reported previously in the case history for the Triangle "U" Field.[5]

Comparing Groups of Wells. Figure 5 shows rates and pressures for a group of eight wells, four of which have been treated with KOH and four which have not been treated. All eight wells are from the same field. The point of Figure 5 is to show that, while rate and pressure plots as a function of time are necessary for tracking performance of individual wells, they are not very helpful in comparing performance of groups of wells.

Figure 6 shows Hall plots for the same group of wells. With Hall plots, it is much easier to compare injection well performance. There appear to be two general types of plots. Three wells have fairly straight Hall plots, which translates to good maintenance of injectivity. Of the three wells in this category, two have been treated with KOH. Five wells have Hall plots which concave upward, meaning injectivity is decreasing. Of these five wells, two have been treated with KOH. This suggests KOH improves injection well performance in this group of wells. However, one could also make other statements about the data that are not as favorable for KOH. For example, both the well with the best injectivity and the well with the worst injectivity have been treated with KOH. Also, of the three wells with the lowest injectivity, two have been treated with KOH. Considering these observations, it becomes clear that, while the Hall plots are helpful and useful, they don't really make a conclusive case for or against the effectiveness of KOH in this formation. Why? One potential explanation could be that KOH does not make a difference in this formation. However, before making that conclusion, it is important to remember that this data does not account in any way for the differences in zone thickness and rock quality that exist between these injection wells. Any valid comparison of injectivity must account for these differences.

In **Figure 7**, the performance of the injection wells has been normalized to account for differences in rock quality and completed intervals. This was done by dividing cumulative injection by porosity-feet, and plotting cumulative injection per porosity foot for each well against time. When differences in rock quality are accounted for in the plots, the KOH clearly appears to improve injection well performance. The two best wells in the group were treated with KOH. The two weakest wells were not. Of the top four wells in the group, three were treated with KOH. Of the weakest four, one was treated with KOH and three were untreated.

While the plot in Figure 7 allows a valid comparison of injection well performance, accounting for rock properties, it does not provide a numerical comparison of the two groups of wells. The value of a numerical comparison is that it allows the engineer to project the economic benefits of injectivity improvement as a result of permanently stabilizing clays with KOH. The benefits can be applied to wells in the field which have already been treated, or projected for planned injection wells in the same field.

The purpose of **Figure 8** is to present the data in a way that allows general numerical conclusions to be drawn about the performance of the two groups of wells. Individual well data for each group, treated and untreated, has been consolidated into two curves. There are two ways to look at the plots. First, the injection wells treated with KOH have taken about 11,000 BBLS more water per porosity-foot relative to the wells that were not treated. This is a 53 percent improvement in cumulative water injection. Second, the injection wells that have been treated reached 30,000 BBLS per porosity-foot cumulative injection eight months sooner than the untreated wells. From either of these standpoints, an economic benefit is demonstrated, because improved injection rates lead to better project economics.

PROJECT ECONOMICS (*)

The economics of KOH clay stabilization treatments can be modeled. The first step included a simulation of waterflood economics without KOH, which serves as a baseline case. Certain reservoir characteristics and economic parameters for a hypothetical waterflood are included in **Table 2**. In order to simulate the KOH treatment, only two modifications were needed: 1) Injectivity was increased over a range of 20 percent to 100 percent compared to the base case, and; 2) The estimated cost of a KOH treatment for this reservoir, $47,000, was included in first year operating costs. The economic model utilized was the Secondary Recovery Analysis Model (SRAM).[13] SRAM is a pseudo steady-state, linear flow model that assumes piston-like displacement in multiple non-communicating layers. The Dykstra-Parsons permeability variation coefficient,[14] represents a fairly heterogeneous rock, with permeability varying over three orders of magnitude. This level of permeability variation is not surprising in the type of tight, dirty sandstones that are applicable for clay stabilization technology.

Figure 9 is a graph of cumulative oil produced vs. time for the base case assumption of 300 BWIPD and a series of five incremental increases in injectivity due to KOH clay stabilization treatments. The range of 20 to 100 percent in injectivity improvement is typical of actual field results, discussed previously. **Figure 9** includes simulation results for a twelve year period. For example, base case cumulative oil production is 100,000 barrels after 60 months. This compares to 130,000 barrels if injectivity improved by 60 percent, or from 300 to 480 BWIPD. The difference, 30,000 barrels, represents an increase of 30 percent in cumulative oil production over the base case. Another way to view the curve is from the standpoint that more oil is produced sooner at higher injectivity. For instance, in the base case it takes 60 months to produce 100,000 BBLS of oil, while it only takes 30 months to produce this same volume if injectivity is improved 60 percent.

Figure 10 illustrates the same simulation results in terms of incremental net present value at a 10 percent discount rate, NPV_{10}. These increases in NPV_{10} are relative to the NPV_{10} for the base case, which is $1.2MM. For example, if injectivity is improved 60 percent, from 300 BWIPD to 480 BWIPD, the incremental NPV_{10} increases by $300,000 for the hypothetical reservoir in **Table 2**, after giving effect to the KOH treatment cost in the first year. This is an increase in NPV_{10} of 25 percent. Notice that even a fairly low injectivity increase, 10 percent, is sufficient to pay out the cost of the KOH treatment.

To use this type of information to estimate the potential effect of a level of injectivity improvement on a different formation, the data can be normalized to NPV_{10} gain as a function of injection rate increase per porosity foot, for 40-acre spacing. For instance, the modeled reservoir is 3 porosity-feet. An increase of 30 BWIPD increases NPV_{10} by $50,000. This is an increase of $50,000 NPV_{10} for every increase in injection rate of 10 BWIPD/porosity-foot. While this relationship applies to a particular reservoir and well spacing, there are significant reservoirs in this category of spacing and rock quality.

CONCLUSIONS

1. When testing cores from formations that contain clay, special care must be taken to avoid damaging the core prior to or early in the testing process.
2. When testing KOH performance in cores, linear flow rates should be maintained above 1 ft/day. Baseline and treated cores should be exposed to a shock flood with fresh water, at a linear flow rate of at least 100 ft/day, to properly demonstrate near-wellbore conditions.
3. Proper metallurgy in surface and downhole equipment, good downhole equipment integrity and clean tubulars and wellbores are of paramount importance to good results with KOH.
4. One way of evaluating performance of KOH treated wells is with normalized plots of injectivity versus time, that account for differences in rock properties. Plots for groups of wells can be averaged to allow general numerical comparisons and performance projections.
5. Computer modeling suggests an increase in injectivity due to a clay stabilization treatment of 60 percent can result in an increase in 50 percent of cumulative oil recovery over a five year time period in a heterogeneous rock with a Dykstra Parsons permeability variation of 0.7.
6. Computer modeling suggests a 60 percent increase in injectivity can increase present worth value at a 10 percent discount rate by 25 percent, or $300,000 for the modeled injection well pattern of 1200 acre-feet.
7. The computer model equates a gain of 10 BWIPD/porosity-foot to an increase in NPV_{10} of about $50,000.

**(***) : Oil prices at March, 2000.
It is important to point out that at current oil prices, the economic analysis presented in this paper would be significantly more attractive.

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Table 1 - Overview of Formations Treated With KOH

Formation	Depositional Environment	Number of Wells	Permeability md	Porosity	Clays
Shannon[2] NE Wyoming	Marine sand mid-outer shelf	116	20 - 1400 Avg - 5 - 10	16 - 34% Avg 20 - 28%	illite, smectite, chlorite, <3 - 20%
Muddy[3,4] NE Wyoming	Fluvial, deltaic, shallow marine	26	1 - 160 Avg - 40	20% Avg	kaolinite, illite, smectite, chlorite,10%
Sussex[5] NE Wyoming	Marine sand	135	2 - 80 Avg - 6 - 15	Avg - 10 - 14%	kaolinite, illite 7 - 15%
Mesaverde NE Wyoming	Fluvial deltaic, highly folded, faulted and eroded	22	1 - 70 Avg - 8 - 20	18 - 22% Avg - 16 - 20%	kaolinite, illite 4 - 20%
San Miguel SW Texas	Domal structural trap, highly faulted	1	1 - 30 Avg - 1 - 7	14 - 22% Avg - 18%	chlorite, illite, kaolinite 2 - 9%
Almy[6,7] NW Wyoming	Tertiary channel system, point bars	3	1 - 108 Avg - 21	14 - 23% Avg - 16%	chlorite kaolinite calcite
Doe Creek Alberta, Canada	-	2	1 - 1500 Avg - 160	8 - 27% Avg - 25%	Kaolinite
Teapot Central Wyoming	Marine and fluvial deltaic Sand	9	0.6 - 70 Avg - 6.6	10 - 22% Avg - 16%	illite, chlorite, kaolinite 10 - 20%
Cook NE Texas	Channel sand deposit	3	1 - 20 Avg - 6	11 - 16% Avg - 14%	kaolinite, illite
Squirrel Kansas	-	1	1 - 300 Avg - 10	17 - 24% Avg - 20%	-

Table 2
Computer Modeling Parameters

Working Interest (%)	100
Net Revenue Interest (%)	87.5
Area (Acres)	40
Average Pay Thickness (Feet)	30
Net Oil Price ($/bbl, no escalation)	15
Lifting Costs ($/month)	1,500
Cost of KOH Treatment ($, for 3 porosity-ft)	47,000
Discount Rate (%)	10
Primary Producing Rate (BOPD)	160
Primary Decline Rate (%/year)	20
Porosity (%)	10
Mobility Ratio	2
Dykstra-Parsons Permeability Coefficient[14]	0.7

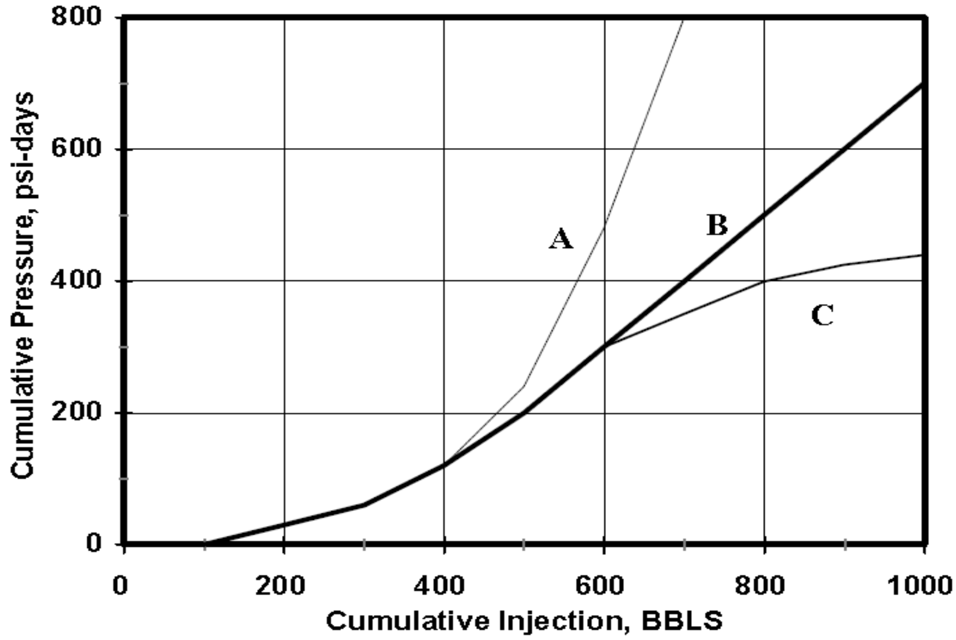

Fig. 1 - Typical Hall plot types. Line B shows continued good injectivity, while line A shows injectivity loss over time and line C suggests parting of the formation.

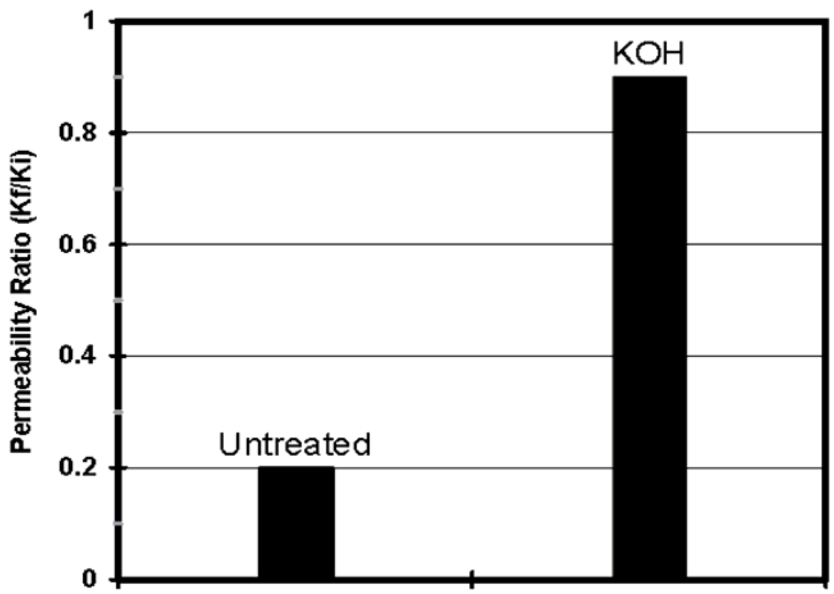

Fig. 2 - Lab data for restored Oligocene cores shows a strong water sensitivity for the untreated core, with a permeability loss of 80% compared to the core treated with KOH, which has a loss of only 10%.

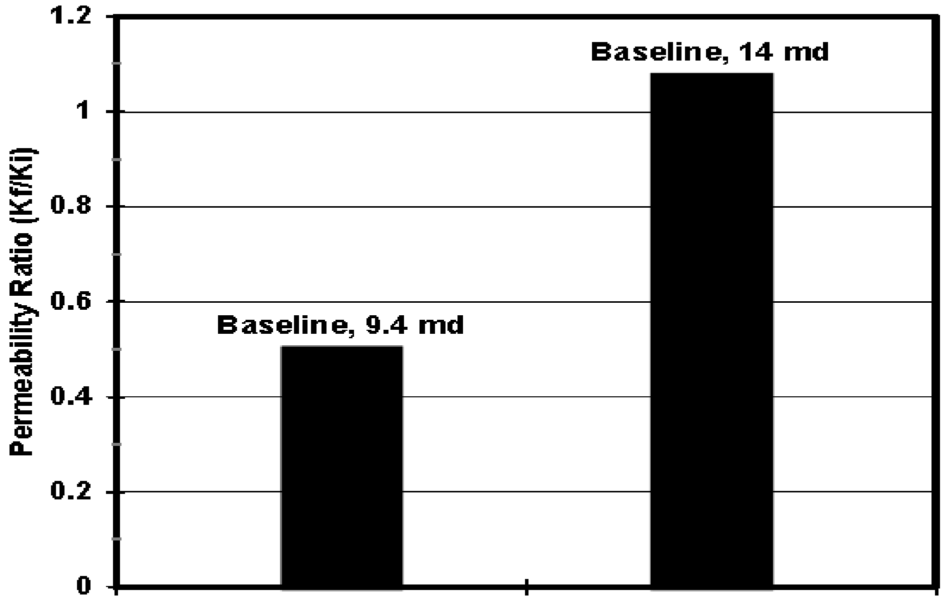

Fig. 3 - Green River cores where baseline data was generated on cores that were contaminated with fresh water. Fresh water appears to cause 50% perm reduction in the 9.4 md core and no damage in the 14 md core.

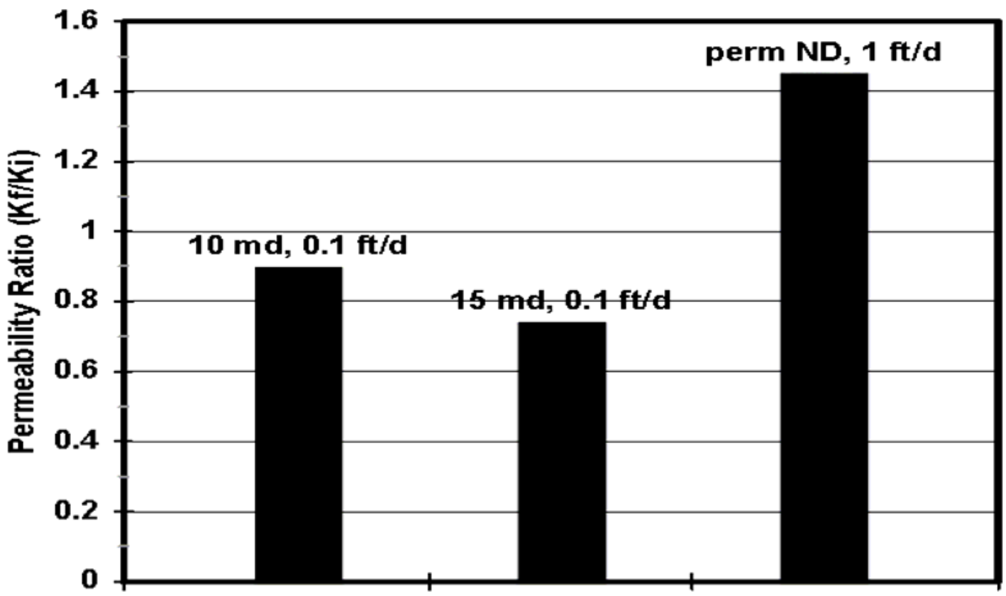

Fig. 4 - Effect of KOH treatment on Green River cores. The first two cores were treated by injecting KOH at a low flow rate, possibly resulting in limited contact with the core. In the third core, a higher flow rate was used for the KOH and the results improved.

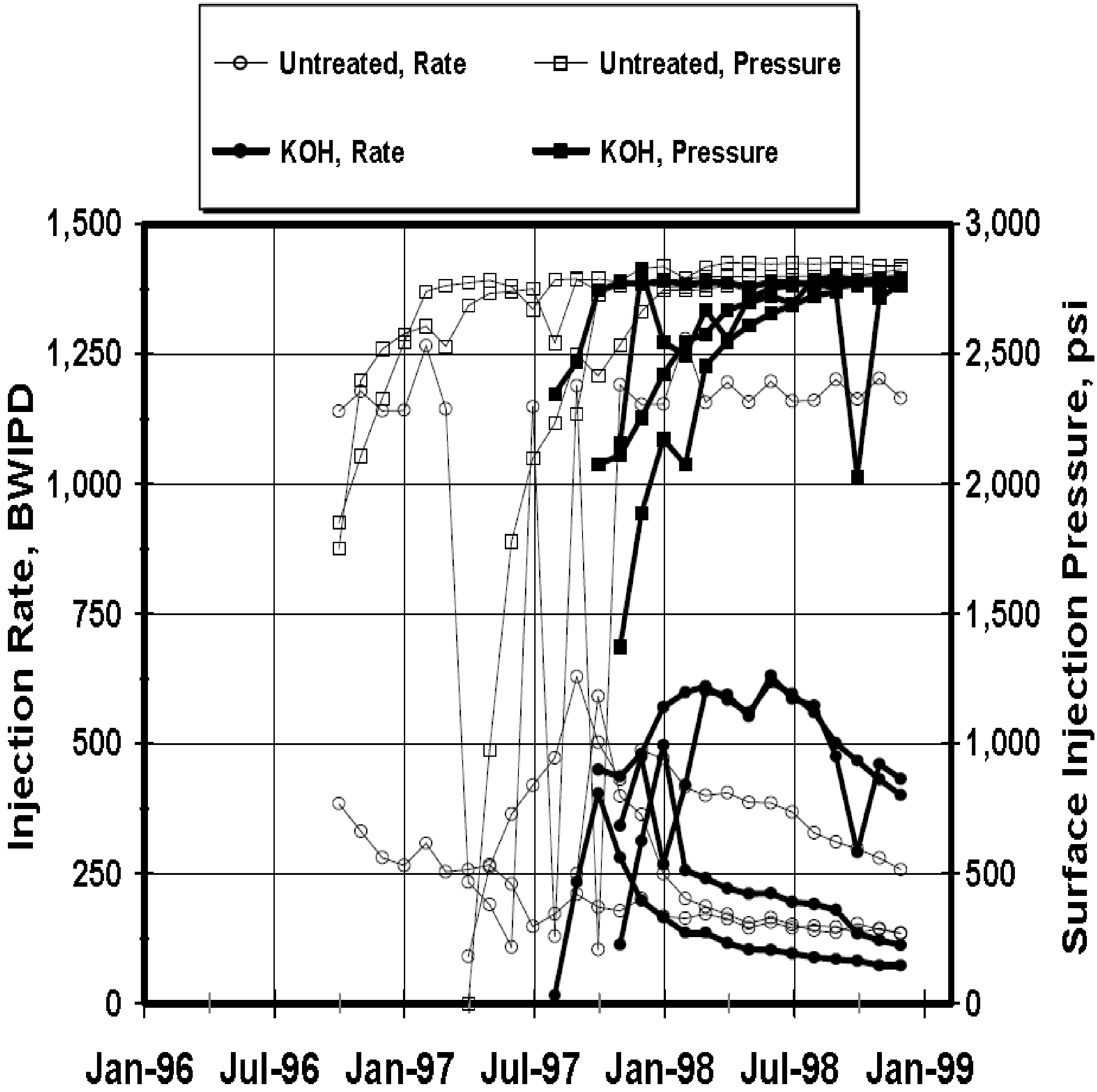

Fig. 5 - This is rate and pressure data for a group of either wells, four of which have been treated with KOH. This type of data does not lend itself to differentiating between performance of the groups of wells.

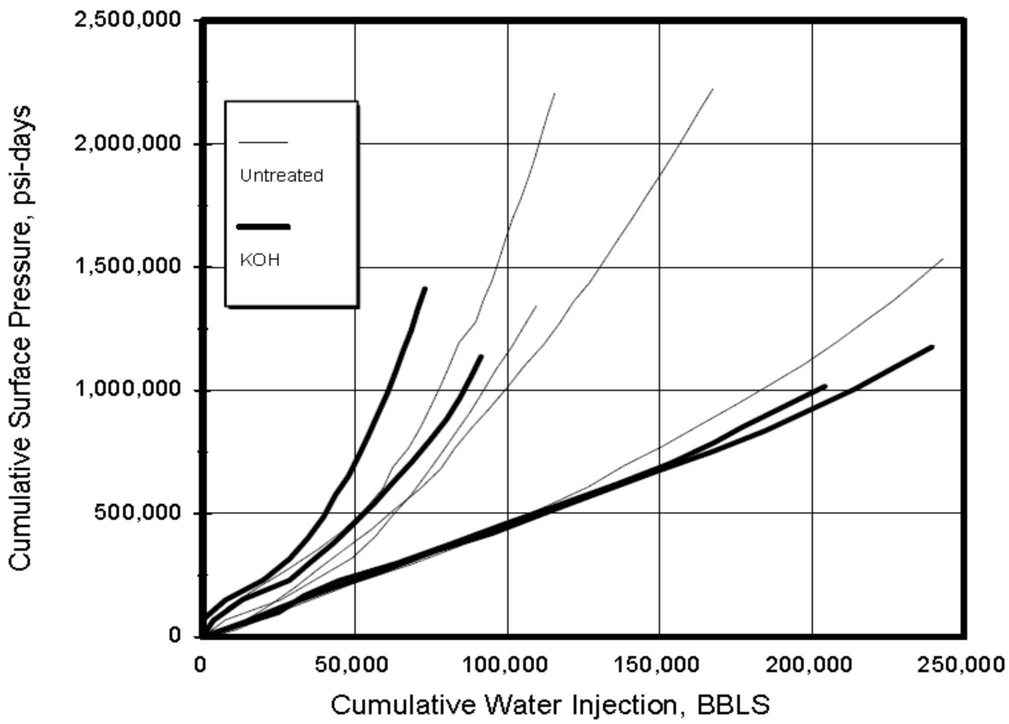

Fig. 6 - Hall plots for the same group of wells in Figure 5. It is easier to compare well performance with this type of plot, but the data still does not account for differences in rock quality.

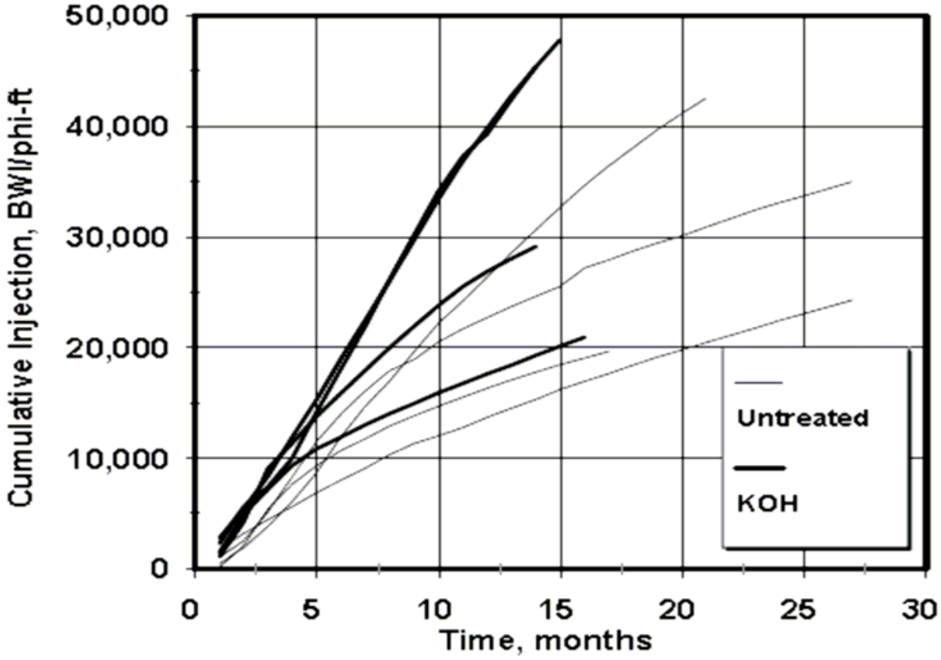

Fig. 7 - When plots of the same group of wells are normalized to account for differences in rock quality and pay interval, the wells treated with KOH show improved performance over untreated wells.

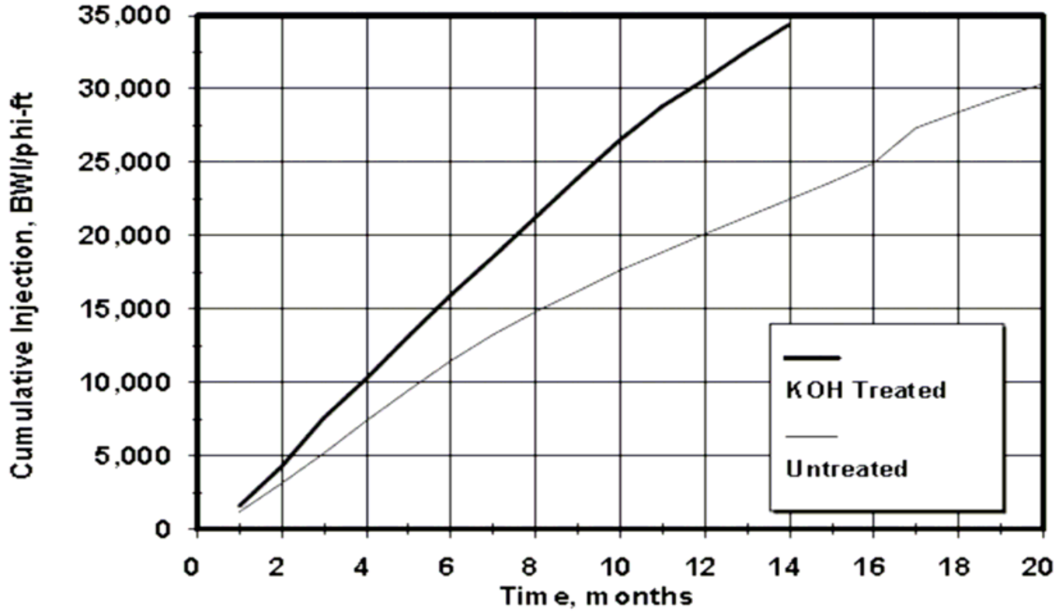

Fig. 8 - When the performance of the two groups of wells is averaged into two curves, the average difference between the two groups of wells can be quantified. At 14 months, the KOH wells have injected about 11,000 BBLS/porosity-foot, or 53% more water, than the untreated wells.

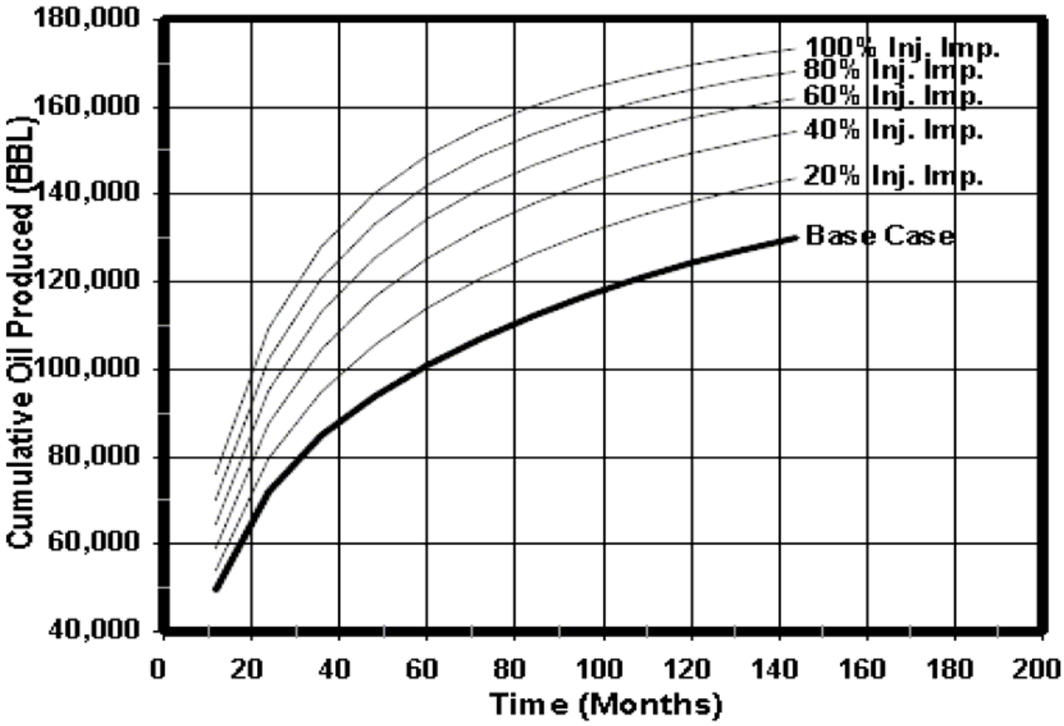

Fig. 9 - Modeled effect of improvement in injectivity due to KOH on cumulative oil recovery. Higher injectivity equates to more oil recovery in a shorter time period.

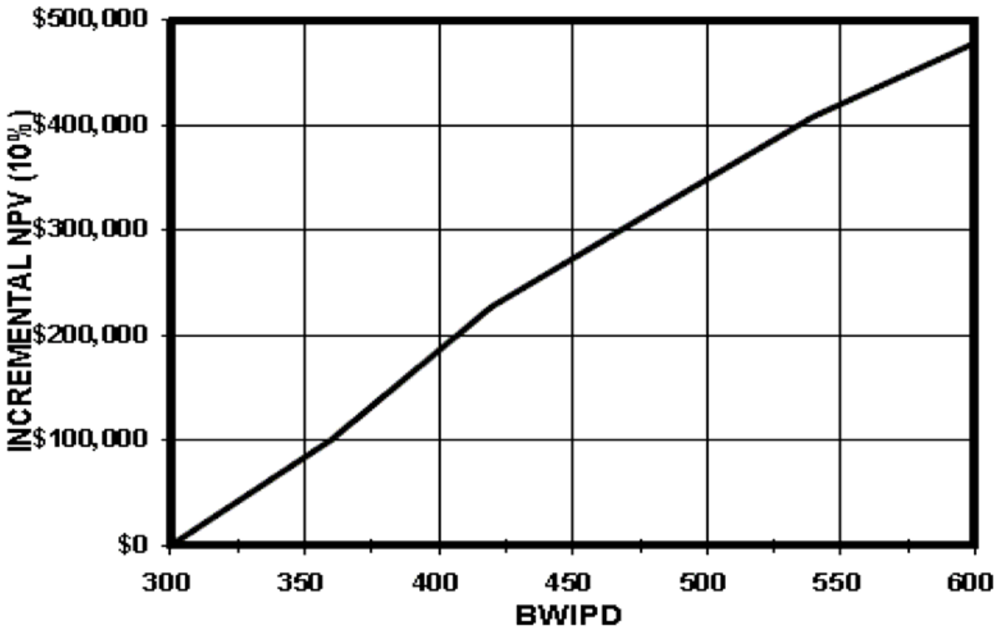

Fig. 10 - Modeled increase in net present value as injectivity increases. A 60% increase in injectivity results in an increase in NPV of $300,000.