Waterflood Conformance Improvement – Practical Considerations & Lessons Learned

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Abstract

Conformance improvement is commonly referred to as the action of improving the drive-fluid sweep efficiency during an oil-recovery flooding operation. This technical note highlights the authors lessons learned during the field application of one of the most widely used and quite successful conformance technologies, which is Cr(III)-carboxylate/acrylamide-polymer (CC/AP). To date, the authors have been involved in the analysis, candidate selection, design, field application and post-treatment evaluation of ±700 injection well treatments over the last 25 years. A look back to the earliest treatment designs and field applications as compared to the more recent applications, clearly shows that we have made advancements to achieve better and more consistent results. These changes have occurred gradually over time as new lessons learned are continuously applied to improve treatment strategies and results.

Keywords: Conformance, sweep efficiency, reservoir heterogeneity, flood efficiency, oil recovery factor, oil response, breakthrough, bulk gel, design considerations, channel volume, treatment slug volume, candidate screening selection, placement strategies, bulk gel polymer concentration, field application, lesson learned.

Mejoras del conformance en procesos de inyección de agua - Consideraciones prácticas y lecciones aprendidas

Resumen

El Conformance es comúnmente conocido como la acción que optimiza la eficiencia del fluido inyectado durante un proceso de recuperación mejorada de petróleo. Este trabajo técnico destaca las lecciones aprendidas por los autores, en base a su experiencia con una de las tecnologías de conformance más utilizadas y exitosas en campo, como lo es la de geles de polímero o geles obturantes, los cuales se forman al combinar cromo (III)-carboxilato, polímero (poliacrilamida) y agua (CC/AP). Hasta la fecha, los autores han participado directamente en el análisis, selección de candidatos, diseño, aplicación de campo y evaluación de resultados en más de 700 tratamientos de conformance. Una mirada retrospectiva a los primeros diseños y aplicaciones de campo, en comparación a las aplicaciones más recientes, muestra claramente que se han logrado implementar cambios o mejoras a los diseños y su aplicación en campo con la finalidad de obtener mejores resultados con este tipo de tratamientos. Estos cambios se han producido gradualmente a lo largo del tiempo a medida que las nuevas lecciones aprendidas se aplican en los nuevos tratamientos.

Palabras claves: Conformance, eficiencia de barrido, heterogeneidad del yacimiento, eficiencia de inyección, factor de recobro de petróleo, respuesta de petróleo, irrupción, geles obturantes, consideraciones del diseño, volumen del canal, criterios de selección, estrategia de colocación, concentración de polímero, aplicación de campo, lecciones aprendidas.

Introduction

If injected fluids or gases used in secondary or tertiary (EOR) recovery processes break through prematurely in one or more of the offset producers, then a conformance problem exists. In general, when implementing a conformance-improvement treatment to improve sweep efficiency and increase oil production, these treatments are most effectively applied to the injection wells.

Premature breakthrough of the injected fluid occurs, in most of the cases, through higher permeability zones within the rock matrix or through natural fractures that exist in the reservoir.

There are several chemical conformance technologies that are available to help improve flood efficiency, however, the CC/AP technology, which for the purposes of this document will be referred to as "Bulk

Gel" (BG), has been widely applied to improve and/or modify near and/or far-wellbore injection profiles with consistently successful results in the U.S and abroad. The use of BG to redistribute drive fluids can be a good strategy to improve sweep efficiency and increase oil recovery by reducing water channeling between the injectors and one or more of the offset producers in heterogeneous reservoirs.

BG technology is not a panacea, but is a process that has proven repeatedly to be effective at improving flood efficiency and oil recovery factor. The key factors to achieving the desired results are candidate selection, treatment design and field application monitoring.
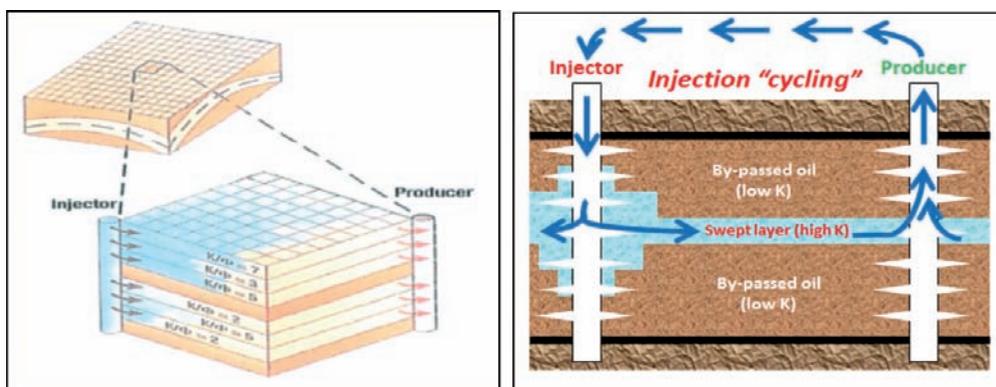
Conformance problem

A conformance problem occurs in a secondary or tertiary process when the injected drive-fluid (water or gas) prematurely breaks through in one or more of the offset producers. In reservoirs with a large variation in permeability within the oil-bearing rock, injection drive fluids (water, CO_2, chemical, etc.) will follow the path of least resistance, flowing through only that small fraction of the reservoir that contains the highest permeability. This causes the injected fluid to breakthrough prematurely at producing wells before lower permeability matrix rock and/or smaller fractures can be efficiently swept (Figure 1).

Figure 1. Pictures from: World Oil – Mature Oil & Gas Wells Downhole Remediation (left) & Flotek Ind. (right)

After these short-circuits have been established between injectors and producers, they cause the drive fluids to "cycle" through rock that has already been swept, and to by-pass those lower permeability areas that contain most of the remaining mobile oil.

Unless the injected fluids can be redistributed throughout more of the available reservoir, then the performance of these types of secondary and tertiary projects will be compromised, and significant oil reserves will be stranded when the field is abandoned.

Near-wellbore remedies like cement squeeze or mechanical segregation can help improve the injection profile, but they will do little to correct an in-depth reservoir conformance problem. These short-term solutions may change the near-wellbore injection profile, but they can also make it relatively easy for drive fluids to find their way back into the swept layers as soon as they leave the injector, which results in little change in the far-wellbore injection profile. It is also inefficient to increase the injection rate to force drive fluids into by-passed rock by building more bottom hole pressure. Although oil production may increase

because of a higher injection rate and improved distribution of the drive-fluid, the oil cut may not improve, and there is increased expense associated with handling and processing unwanted produced fluids. Finally, drilling new in-fill wells to capture "pockets" of by-passed oil may prove to be less successful if the conformance problem at the surrounding injectors is not first corrected.

Currently, there are technologies that can address conformance problems in an effective way. Most of them are polymer-based technologies that can be custom designed and injected in such a way as to penetrate deep into the high permeability zone or fractures that have already been swept by previous injection. Successful placement of the polymer solution will create resistance to the subsequent flow of drive fluids into the previously swept rock, forcing them to be redistributed into and displace oil from the by-passed smaller fractures or lower permeability rock matrix.

As of the date of this publication, the authors have treated ±700 injectors to improve conformance using BG, which is a polymer-based technology. The

methodologies and strategies used today are the result of many years of experience and lessons learned from engineered trial-and-error approaches. Although prudent engineering and laboratory work is required, there is absolutely no substitute for the experience and know-how gained from the actual field application of BG technology. It is the author's intent to share these lessons learned so that future users of BG technology can make even faster and more effective improvements in field application.

CC/AP Technology "Bulk Gel"

One of the most widely applied conformance technologies is the chromium (III)-carboxylate/acrylamide-polymer (CC/AP) gel developed by Marathon Oil Company. The CC/AP "Bulk Gel" chemistry is effective over a broad pH and temperature range and is stable in the presence of H_2S and CO_2. Extensive laboratory studies and field applications confirm that "Bulk Gels" are robust in water with high concentrations of divalent ions (Ca^{+2}, Mg^{+2}) with well documented results over a wide range of salinity. When divalent ions such as Ca and Na react with polymer carboxyl groups, anionic repulsion is decreased along the polymer molecule and viscosity is reduced; however, the addition of chromic triacetate ($CrAc_3$) as a crosslinking agent occupies the polymer carboxyl groups, forming a three-dimensional gel structure resistant to water salinity and hardness. (Figure 2).
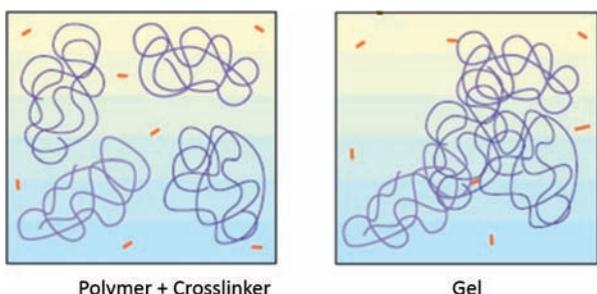

Polymer + Crosslinker   Gel

Figure 2. (Pictures from: Chemical Enhanced Recovery - SPE Training Course - Mojdeh Delshad)

Table 1. below shows the Bulk Gel technology basic Go/No Go screening criteria.

Technology	Reservoir Temperature	Water pH	Water Salinity (ppm)	Rock Type
Bulk Gel	<220°F (104°C)	6 - 8	< 300.000	Sandstone & Carbonate

The "Bulk Gel" chemistry includes a medium molecular weight dry anionic polymer that can be dissolved in field injection water. Liquid chromic triacetate ($CrAc_3$)

is added as a crosslinking agent. The gelant solution is batch-mixed and injected continuously until the treatment is completed. Gel formation occurs over a period of days to weeks as a function of reservoir temperature and concentrations of the polymer and crosslinker components. The polymer utilized to create Bulk Gels is typically a partially hydrolyzed polyacrylamide (HPAM) of 5-14 million amu (atomic mass units).

The initial Bulk Gel field trials were performed in naturally fractured sandstone and carbonate reservoirs located in the Big Horn Basin of Wyoming. Subsequently, Bulk Gels have been successfully applied for over 25 years in diverse lithology's and reservoirs worldwide and many of those cases have been documented internally and publicly by different companies/authors.

Candidate Screening Selection for Conformance Improvements

Once the existence of a conformance problem is suspected, the next step is to validate, in a practical but effective way, the quality of the wells that are possible candidates for treatment. After almost three decades of field experience with the CC/AP technology, candidate selection criteria has not changed much; however, there has been much change in the design considerations and field application strategies that have evolved over the last 25 years that are the result of field experience.

The candidate selection criteria listed below provides a fast but effective way to identify potential candidates for conformance improvement in all reservoir mineralogies and lithologies (i.e. sandstone or carbonate rock).

Low primary & secondary recovery factor and low secondary-to-primary recovery ratio: As a rule of thumb, a recovery factor (RF) less than 30% indicates that there is still a large amount of mobile oil in the reservoir that has not been swept or contacted by the injected fluid. The lower the recovery factor, the larger the mobile oil saturation that would potentially be left stranded in the reservoir when the field is abandoned. Table 2 shows an example of basic ranking based on area/pattern recovery factor. Low secondary-to-primary recovery ratio with associated high secondary water production in areas that have favorable original oil in place is also an indicator that drive-fluids are by-passing mobile oil, and sweeping through only that small fraction of the reservoir that has the best permeability.

Table 2. Conformance ranking based on recovery factor.

Injection Pattern	Cum. Oil Prod. (MM bbls)	OOIP (MM bbls)	Recovery factor (%OOIP)	Ranking for Conformance
IW#1	0,30	2,85	10,5%	1
IW#4	0,42	2,90	14,5%	2
IW#2	0,57	2,45	23,3%	3
IW#3	0,98	2,81	34,9%	possibly not a candidate

Good oil response to injection: Oil response to injection (whether the injected material is water, gas or other) followed by premature breakthrough of the injected material, is another indicator that the injectors in those areas are good candidates for conformance improvement treatment (see Figure 3). As rule of thumb, the injector pattern area should show at least some response to initial injection in order to be considered for conformance improvement treatments. If not, then an additional and detailed review of reserves and or lateral connectivity between injector and offset producers is required to confirm that reducing drive-fluid cycling will help subsequent injected drove-fluid to contact low permeability layers that have a higher mobile oil saturation.
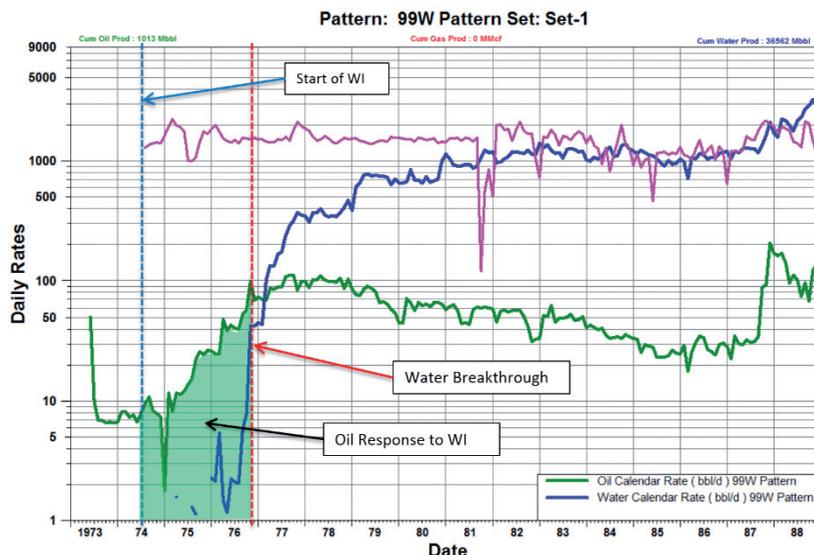

Figure 3. Basic production – injection data analysis.

Rapid water/gas breakthrough: Strong and rapid injection drive-fluid breakthrough or "channeling" is relatively easy to recognize when analyzing historical production/injection performance data such as rate versus time & WOR versus Cumulative Oil production (see Figure 4). In addition, data such as interwell tracer can also help to identify transit time of injected fluid between the injector and their offset producers, and directional permeability trends.
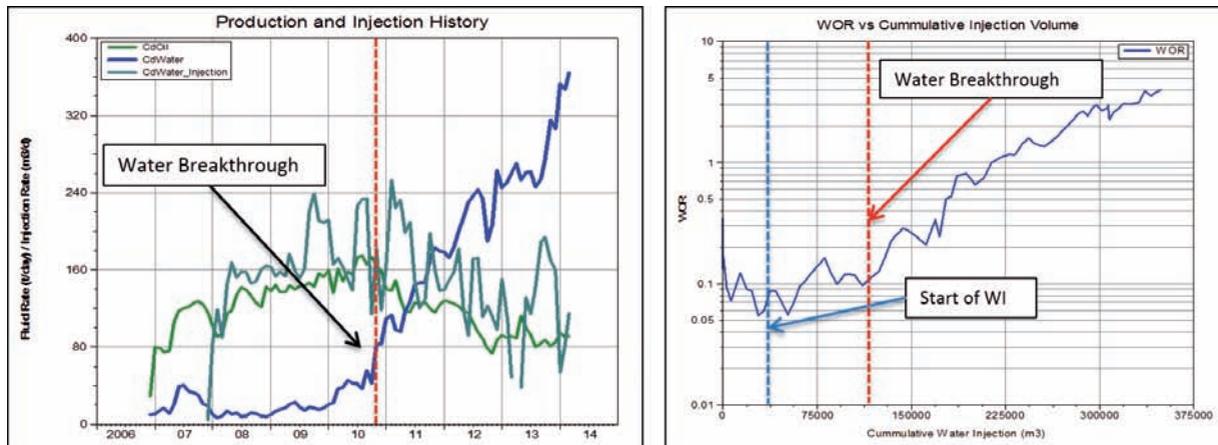

Figure 4. Injection drive-fluid breakthrough.

Reservoir heterogeneity: In general, the performance of a secondary and/or tertiary recovery process is greatly influenced by reservoir heterogeneity. It is our experience that reservoir heterogeneity is perhaps the major contributor to poor waterflood performance, which causes the injected drive fluids to breakthrough into the producing wells prematurely, and ultimately jeopardizes sweep and oil recovery. In many cases, the premature water breakthrough is also due to adverse mobility ratio (M>1). If the mobility ratio is greater than 1.0, the water is moving faster than the oil ahead of the flood front, and viscous "fingering" of oil through water will occur. Consequently, sweep efficiency is reduced in a manner similar as to what is observed when the problem is caused by reservoir heterogeneity (conformance). Therefore, care should be taken when diagnosing the cause of the premature water breakthrough issue so that it is not interpreted incorrectly. It is our experience that in most of the cases, reservoir heterogeneity is the main cause of premature water breakthrough. Even in those cases where there is an adverse mobility ratio, it is highly likely that reservoir heterogeneity is also part of the problem. If adverse mobility ratio is present, then the well may not be a candidate for a conformance treatment only, as it may also be necessary to address

the adverse mobility ratio with a longer polymer flood in order to improve waterflood efficiency.

The most common methods to characterize reservoir heterogeneity are:
a. Flow capacity distribution (K x h): evaluated from a plot of the cumulative capacity versus cumulative thickness of a reservoir having layered permeability. The capacity distribution will plot as the straight line for homogenous reservoir and a deviation from this straight line (45 degree) will be a measure of the reservoir heteropgeneity due to permeability variation.
b. Lorenz coefficient: based upon the flow capacity distribution, is a measure of the contrast in permeability from the homogenous case.
c. Dykstra-Parsons permeability variation factor (V): based on our practical experience, this is the most common method used to determine the degree of reservoir heterogeneity. Values for this coefficient range between zero for a completely homogeneous reservoir and one for a completely heterogeneous reservoir. An example plot of the estimation of reservoir heterogeneity using Dykstra-Parsons and Lorenz coefficient is shown in figure 5.
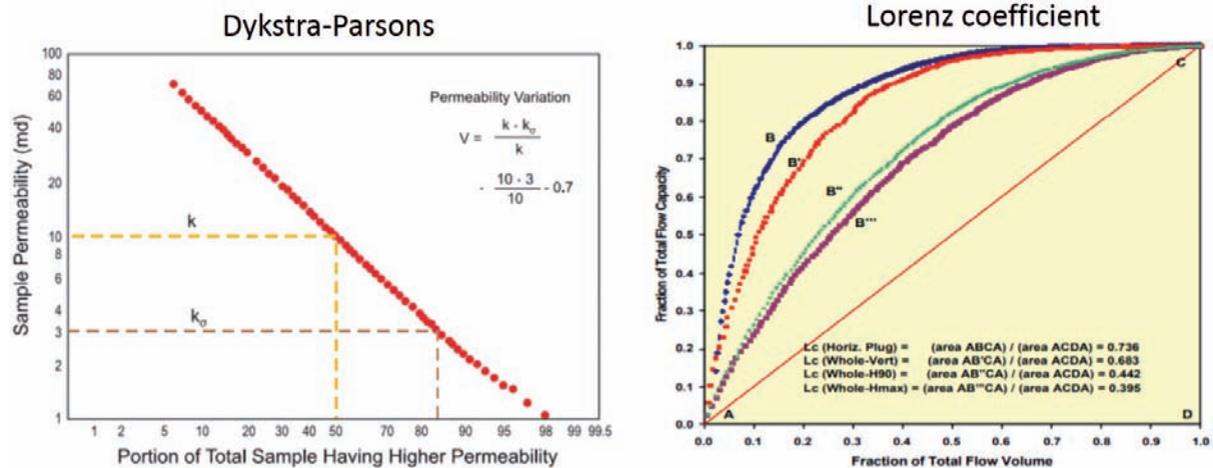

Figure 5. Dykstra-Parsons and Lorenz coefficient.

In some cases, data to estimate reservoir heterogeneity is not available (e.g. core reports). A practical way to determine heterogeneity is to obtain an injection profile log (ILT) which can show the vertical distribution of injected fluid. Interpreting ILT data in combination with production/injection performance analysis may help you to better understand just how heterogeneous the reservoir may be. It is important to consider the total perforated thickness in order to capture in more details the actual situation.

Figure 6 shows the injection profile log (ILT) for two water injection wells. At first glance, Injector #2 appears to have a regular distribution of injected water. However, when reviewing in detail and considering the total perforated interval that is being affected, it can be observed that it is injecting only into 120' out of a total of 319. In other words, 37.5% of the total perforated interval is taking water. The situation could be even worse if the same analysis is performed by sand or layer in an injector completed with more than one packer (multiple completion).
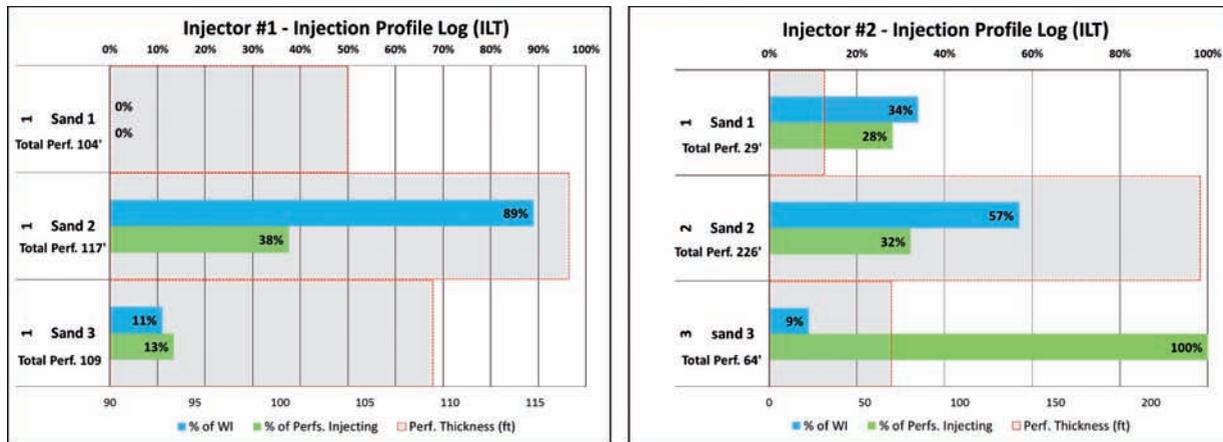
Figure 6. Injection profiles logs.

Injector-producer connectivity: It is critical to understand and confirm that most of offset producers are laterally connected with the injector. Cross sections, chemical tracers and production/injection data can be utilized to confirm reservoir connectivity. Observations from field personnel are also very important in quantifying connectivity between wells as they see, on nearly a daily basis, what impact injection changes have on surrounding producers. Vector maps can be constructed by using all of the available information, and will often times reveal if there are directional permeability trends that could be associated with natural fractures, or if trends are more radial in shape.

High injection rate & Low Pressure: High injection rate and low injection pressure is a good indicator of channeling between injector and producer wells. Continuous monitoring of injection pressure and injection rate is the simplest method of monitoring injection well performance. A plot of rate and pressure versus time can be used to identify injectors that have demonstrated decreased injection pressure with no apparent loss of injection rate. Another useful method is the Hall Plot that allows one to identify changes in injectivity trends. For example, a downward shift in the slope of the Hall Plot may correspond to the same time that water breaks through to an offset producer and would be evidence that those two wells are connected.

Injection well integrity: The candidate injection wells that have been identified for treatment should be in good mechanical condition, and their wellbores should be free of any obstruction that may prevent fluid from entering the openhole/perforated intervals. If necessary, a wellbore cleanout should be considered in order to help ensure that the bulk gel solution (gelant) will follow the path of least resistance during the application, which is

the same pathway that is the cause of the conformance problem.

Bulk Gel Treatment Goal and Design Considerations
The goal of a polymer gel treatment at an injection well is to preferentially place a polymer gel slug into the offending pathways that are providing a conduit for fluid flow between the injection wells and the offset producing wells. This process must avoid placing the polymer gel solution into the lower permeability areas of the reservoir that still contain most of the remaining mobile oil saturation. If successful, the polymer gel will create resistance to flow through the dominant flow features and prevent the continued cycling of fluids between the injectors and producers. Reducing the flow capacity of these conduits with polymer gel should create enough resistance to divert and redistribute subsequent injection into the lower permeability oil-saturated areas of the reservoir. With this in mind, the following steps needs to be considered when designing a bulk gel treatment application.

Channel volume estimation: Estimating the channel volume is the first step after selecting the candidate(s). It is one of the key steps required to understand and confirm the feasibility of the project from the technical and economic stand-point. However, in practice, estimating the channel volume can be difficult in some cases due to lack of proper data. The most common approach to estimate the channel volume is the WOR versus Cumulative Oil Production method. This approach uses historical injection data (rate & pressure) and production data (oil & water), by well, that must be available from a time that pre-dates the start of waterflood to as current time as possible. With that being said, there are a few other methods and techniques that can be used to estimate channel volume such as

secondary production performance analysis, mobile pore volume (MPV) estimation using injection profiles logs (ILT), and interwell tracer data, to name a few. For the purpose of this technical note, we will explain the WOR versus Cumulative oil production approach, which is the method most commonly used.

- WOR versus Cumulative Oil Production: This method uses the graphs of water oil ratio (WOR) vs. cumulative oil (Np) to estimate the movable pore volume (MPV) of the channel that exists between the injector and producer wells. (See figure 7). These plots can be used to reveal the volume of the conduit(s) that exist in the rock between injectors and producers, which is the same rock that is the target of a properly executed polymer gel treatment. This method of estimating the "channel" volume can be used if historical oil and water production, by well, is available from the time that water injection was first started. We then use these plots to estimate the volume of the rock that has been swept toward any given producer from the offset injectors. To estimate the swept MPV at each producer, we determine at what point the WOR curve first indicated a positive oil response, and at what point water breakthrough first occurred. The cumulative volume of oil produced between those two points is considered to be the approximate MPV of the swept rock. In order to better describe this method, please consider the following. Visualize injected water as it moves through a high permeability layer of rock that contains mobile oil. When the oil bank arrives at the producing well, the oil rate goes up and the WOR usually goes down until all of the mobile oil *within the swept zone* has been displaced to the producer. When the trailing injected water finally breaks through after displacing the mobile oil, the oil rate goes down, and the water rate and WOR go up. So, it is believed that the cumulative volume of mobile oil that was displaced and recovered between first oil response and water breakthrough is a close approximation of the volume that may need to be replaced by polymer gel.
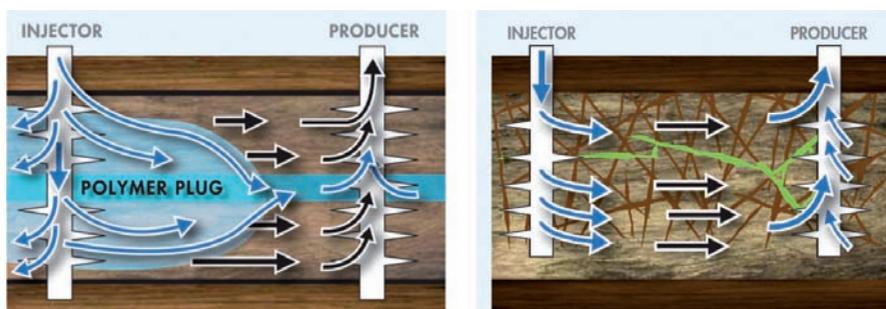
Ideally, the MPV will be estimated for each producer that offsets the pattern injector. An allocation factor should be considered if offset producers are affected by other injectors in the area. Streamlines provide an effective tool for assessing flow patterns and well allocation factors. However, if streamlines, interwell tracer data, or other methods that can provide allocation factors are not available, then the production and injection data that was used to identify communication between the injectors and producers, can also be used as a reference to allocate and understand the possible impact of offset injectors to a given producing well. In other words, if a given producing well is affected by four injectors, but only two injectors show clear communication with the producing well in question, then the estimated channel volume will be allocated between the two injectors.
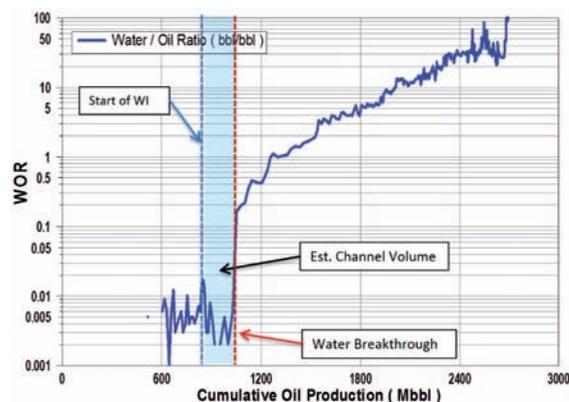

Figure 7. WOR versus Cumulative Oil Production.

Treatment slug volume: Treatment volume is based on a percentage of the estimated channel MPV using one of the methods mentioned above. As mentioned before, the goal of the treatment is to place bulk gel in the high-permeability layers (thief zones) in order to create enough resistance to divert and redistribute subsequent injection fluid into the lower permeability oil-saturated areas of the reservoir that are outside of the gel-filled and gel-treated channel or thief zone (See figure 8).

Figure 8. Redistribution of injected water after Bulk Gel.

The ideal case would be to inject a volume of gel that is equal to 100% of the total estimated channel volume. However, due to technical and or economic reasons, it is common to initially consider injecting a bulk gel volume that ranges from as low as 10% to as high as 50% of the channel MPV as starting point for conformance treatment design. In some cases, where the conformance problem is caused by open natural fractures or wormholes that directly connect the injector to the producer and result in rapid transit time, a larger volume (up to 100% of the MPV) should be considered if project economics permit. Open natural fractures and wormholes are often small volume features that can be completely filled, economically, with a correspondingly small volume

of strong bulk gel. In any case, this provides a basis for treatment design, with the understanding that the volume may need to be adjusted, "on the fly" as dictated by pressure response observed during bulk gel injection.

We believe that if we place the gel deep into the high capacity flow conduit(s), there will be less potential for future injected fluid to find another pathway around the gel at some short distance away from the injector wellbore. If the gel volume is too small, it may allow future injection to flow back into those areas of the reservoir that have already been swept. Treatment volume is critical, and it will impact project performance. (Figure 9).
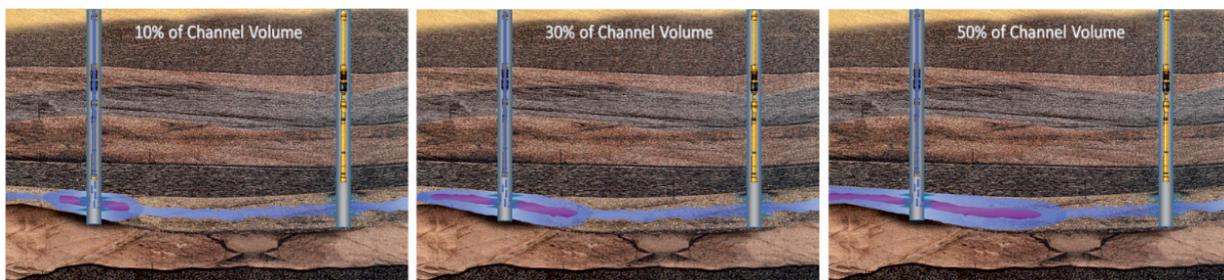

Figure 9. Importance of Bulk Gel Treatment Volume.

In general, the more bulk gel you inject, the more incremental oil you get. With that being said, the reality is that it may not be possible to inject a bulk gel volume that is equal to 100% of the MPV, even if it is affordable, because sometimes that much volume cannot be injected due to reservoir restrictions (low permeability) in combination with low margin pressure.

Bulk gel concentration/strength: The lower the polymer concentration, the weaker the gel; so, as polymer concentration is increased, the resulting gels become stronger. The strength and volume of gel solution pumped is based on reservoir/well specifics and experience. Gel formation will be sufficiently delayed so as to allow for the placement of large volumes over several days or weeks, if necessary. The resulting gels are considered to be permanent for the remaining life of the reservoir, and cannot be easily broken down and removed.

The strength of the polymer solution used during a field application will be dictated by the type of feature that it is being injected into as determined by pressure response during the job. Lower injection pressure at a constant rate will likely indicate a pipe-like channel feature, while higher injection pressure may indicate

high permeability rock matrix. The objective is to match the polymer viscosity and final gel strength to the type of feature that the gel will ultimately be occupying. The solution should exhibit a pre-gel viscosity that is high enough to block the cross-sectional area of the conduit(s) while it is being placed, but not so viscous that it limits the ability to place the desired volume. If a high enough percentage of the cross-sectional channel area of the channel is not blocked, then the feature will likely still have sufficient permeability and conductivity to "thief" most of the fluid when normal injection is resumed (see Figure 10).

Maximum treatment injection pressure: The maximum injection pressure should be determined before the treatment begins so that the margin pressure can be monitored during the treatment. This information will help to prepare and or adjust treatment design in terms of volume, polymer gel concentration and strength. In general, a greater margin of pressure allows more flexibility to make changes to the design "on the fly" during the treatment as dictated by injection pressure response.

The maximum injection pressure is usually dictated by reservoir fracture pressure. It is the fracture pressure

minus the average water injection pressure (see Table 3). If the maximum pump/plant injection pressure is lower than reservoir fracture pressure, then the maximum

pump/plant injection will be used to estimate the margin pressure. This will avoid having injectivity problems after the bulk gel treatment.
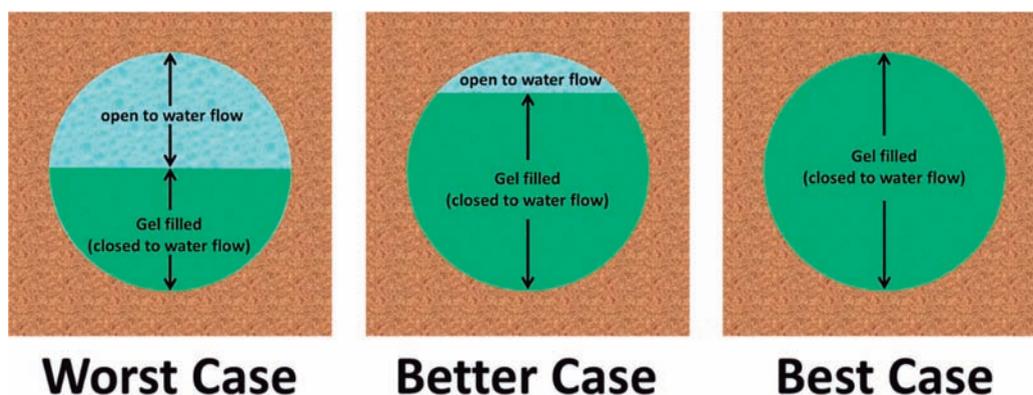

Figure 10. Importance of Bulk Gel strength.

Table 3. Margin Pressure Estimation.

	Data Input		Pressure	psi
IW #1	Frac. Grad.	0.74	$P_{Frac - Top Perf.}$	4,185
	Top. Perf.	5,656	$P_{Hydrostatic}$	2,449
	Fluid Grad.	0.433	$P_{Frac - WHP}$	1,736
	Qinj. (BPD)	2,000	WHP_{Actual}	500
	Margin Pressure (psi)			1,236

Laboratory test: Bulk gels can be formed in most types of waters. Fresh water is the best, because the polymer dissolves faster and less polymer is usually required. The most common polymer:cross-linker ratio used in the field with CC/AP "bulk gel" technology is 40:1. Even though it is known that the polymer-crosslinker ratio of 40: 1 usually works well in a wide range of water salinity and reservoir temperature, it is very

important to perform basic laboratory tests (Gel Bottle Testing) in order to ensure the quality of the bulk gel to be injected. Bulk Gel bottle testing is not a highly sophisticated technique, but it is a very cost-effective and straightforward method of obtaining the necessary information used to design and make decisions in moving forward to the field.

The objective of the gel bottle testing is to evaluate: 1) Gel Strength, 2) Gelation Rate, and 3) Gel stability at reservoir temperature. The test is performed with the water that will be used during the field application (injection brine or fresh water). The goal is to test a wide range of polymer concentrations (2.000 to 20.000 ppm) at different polymer:cross-linker ratios (e.g. 20:1, 40:1, 60:1 & 80:1) as presented in Figure 11.
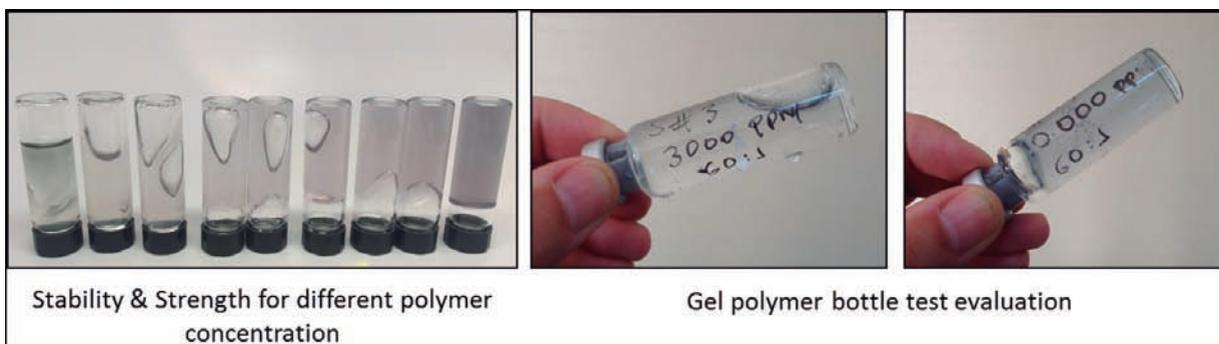

Figure 11. Bulk Gel bottle test evaluation.

This test is used to confirm the bulk gel options at different polymer and crosslinker concentrations that will be available to use during the treatment. This information is useful during the application in case

it becomes necessary to make changes to the design based on pressure response. The gel testing results help to determine the initial polymer and crosslinker concentration to be used in the design, and also provides

the range of options that are available for use during the job as dictated by changing conditions. In most cases, a good range of stable samples is obtained. However, in some cases, the range is limited, and in rare cases, results may be completely null. The results will depend on the quality of the water and the temperature of the reservoir. Figure 12 shows an example of the bulk gel strength of a few different polymer concentrations on the left, and their long-term stability on the right (good vs bad gel samples).
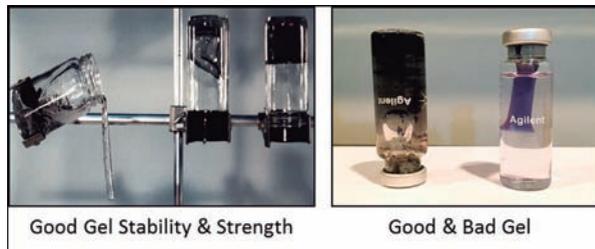

Figure 12. Bulk Gel Stability & Strength.

Gel bottle testing is easy to perform in the laboratory and can be also be done in the field during the application. It is highly recommended to take samples during the field application in each stage (2 to 3 per stage) in order to confirm actual pumped bulk gel stability, strength and gelation rate (time). The samples taken during the field application can also help to decide shut-in period time after the bulk gel treatment. For example, when the field is limited to water handling, the shut-in period time after the bulk gel treatment can be critical, where it is important to return a well to injection as soon as possible. In this case, the operator can visually evaluate the samples of the last two stages to verify the gel strength and stability after a certain period of time in order to determine if the gels have reached their maximum strength and maturity, signaling that the well can be returned to injection, or remain shut-in for a longer period of time.

Placement Strategies: Most bulk gel conformance treatments are injected through tubing, with a packer set above the top of the target perforated interval. All open perforations are exposed to the polymer gel solution with the expectation that a disproportionate amount of the gelant will enter the highest permeability channels. Depending on the type and severity of the conformance problem, different approaches can be used in order to achieve the desired results.

1. *Multiple channels (primary and secondary):* Determine if the offending gel target zones are natural features (primary) or more recent secondary features (wormholes). Both zones must be treated, with the secondary feature(s) treated first with

a smaller volume of strong gel, and the primary feature(s) treated second with a larger volume of moderately weaker gel. Treating the secondary features first will prevent premature gelant breakthrough and will also divert the subsequent gelant injection treatment towards the primary features.

2. *Dual-Tampered Gel Slug:* In reservoirs that have close spacing, where injectors and producers are directly connected to one another by features that provide for rapid transit times, then consider injecting higher polymer concentration gels first, and then taper-down the polymer concentration as pressure increases. With this approach, if polymer gel breaks through at a surrounding producer, then the gel that will reside in the near-wellbore area of the impacted producer will have enough strength to resist the high draw-down pressure to which it will be exposed and allow it to stay in place rather than being produced. It is important to immediately shut-in any producer that tests positive for polymer breakthrough during gel injection to eliminate that pressure sink and limit further gel movement in the direction of the subject producer. Polymer concentrations are increased again at the end of the treatment so that strong gels capable of resisting high energy reside in the near-wellbore area of the injector.

3. *Conventional:* Bulk gel is injected in stages of increasing polymer concentration because the lower polymer concentration gels (i.e. weaker gels) at the leading edge of the treatment will ultimately occupy rock deep in the reservoir where they will not require as much strength to resist the lower differential pressure to which they will be exposed. Beginning the job with weaker gels also enables you to test the injectivity of a solution that is more viscous than the normal injection water, and should allow you to inject a larger gel volume because pressure tends to increase slower while injecting weaker polymer solutions. As pressure builds during the job (i.e. resistance to flow), increasingly stronger gels are pumped until you reach a very strong "cap" gel. Higher polymer concentration gels (i.e. stronger gels) pumped at the end of the treatment will occupy rock nearest the injector wellbore where more strength is required to resist the higher differential pressure.

In cases where the injection well is completed with multiple mandrels, it is highly recommended to remove the existing completion and complete the well with a packer set above the top of the target perforated interval. Based on our field experience this is the best option to

achieve desired results. However, if the recommended well configuration (single completion) is not possible, due to risk assessments, cost etc., then the option to accommodate a bullhead-style polymer treatment is to inject the bulk gels only in one zone (mandrel) at the time, by blanking-off the rest of the mandrels and pulling the choke from the mandrel that will take the bulk gels. To increase the chances of success, it is important to carefully review the injection profile logs along with permeability and porosity logs (if available) in all the zones that are currently injecting thought mandrel. This will help to determine the zones that will be treated based on current percentage of perforated interval taking water in comparison with the total perforated interval in that particular zone. Low percentage of perforated interval taking water, indicates a conformance problem and bulk gels will be required to improve injection profile and contact new areas with high oil saturation.

Be aware that injecting the bulk gels in several mandrel at the same time, by blanking-off the mandrels that are currently taking little or no water, increase the risk of plugging completely one or more zones, since it is possible that not all the bulk gel can be over-displaced from the wellbore at the end of the job. For example, when pumping into two mandrels, and both mandrels take bulk gel for most of the job, but the upper mandrel is the only one taking bulk gels at the end of the job,

then it is possible that the bulk gel will only be displaced from the tubing to the upper mandrel, which means the tubing and the annular space below the upper mandrel could remain full of gel after the job is ended. Even if all of the bulk gel is displaced from the tubing, there is no guarantee that all of the bulk gel in the annular space will be displaced. If the jobs were pumped through a single string of open-ended tubing with a packer set above the top perforations, then it would be much more likely that all of the bulk gel would be displaced from the wellbore.

Field Application Schematic & Pumping Equipment:
Bulk gels are usually injected using a mobile injection plant, which contains all necessary equipment required to mix, prepare and inject the gelant based on specific treatment design. These mobile injection plants are relatively simple to operate and can be accommodated in remote locations. They can move from well to well in a short period of time and have a small footprint. This equipment is relatively inexpensive in comparison with other workover equipment and can be operated by one or two field technicians, depending on the safety requirements of the operator. A workover rig does not need to be on the well while the bulk gels are being pumped. Figure 13 provides an illustration of these mobile injection plants and schematic of the main components.
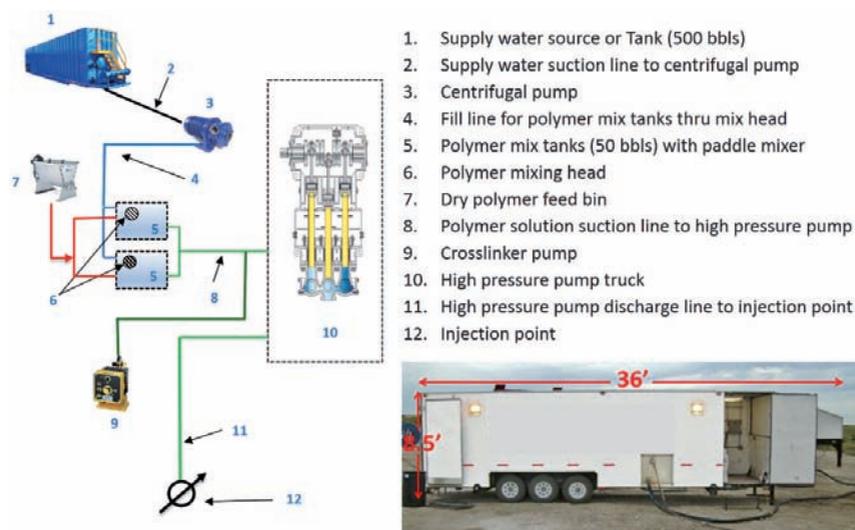

1. Supply water source or Tank (500 bbls)
2. Supply water suction line to centrifugal pump
3. Centrifugal pump
4. Fill line for polymer mix tanks thru mix head
5. Polymer mix tanks (50 bbls) with paddle mixer
6. Polymer mixing head
7. Dry polymer feed bin
8. Polymer solution suction line to high pressure pump
9. Crosslinker pump
10. High pressure pump truck
11. High pressure pump discharge line to injection point
12. Injection point

Figure 13. Field Application Schematic & Pumping Equipment.

Field Case Histories:
The results from the application of Bulk Gels in different reservoirs in the U.S and abroad confirms that this technology can be implemented successfully to improve injected fluid efficiency in order to increase oil recovery factor. The following case histories are only a samples

of the results that can be obtained when Bulk Gels are implemented correctly.

Case# 1: This case was performed in a field that was discovered in 1913. It produces from a sandstone reservoir with an average depth of 980 ft. The reservoir

temperature is 75°F with an average porosity of 21% and permeability range between 10 and >1.000 mD. Reservoir heterogeneity is high with a Dykstra-Parson permeability coefficient of 0,8.

The waterflood unit covers about 1.520 acres and has 144 MMBO OOIP with a recovery factor (primary + secondary) of less than 30%. There are about 80 injectors that support 180 producers, and the average injector-centered pattern size is 20 acres with a producer-to-injector ratio of 4:1. The average swept MPV per pattern is estimated to be 211.000 barrels. Since March 2006, a total of only 24 injection wells representing 30% of the total injectors, have been treated with an average of 13.000 barrels of Bulk Gel per well. The bulk gel treatment design has been modified or adjusted over the course of the project as determined by results and initial field experience. As of today the project has recovered about 410.000 barrels of additional oil with a projected ultimate incremental oil recovery of more than 1.7 MM barrels. Figures 14 and 15 show the pre and post treatment results using the oil rate versus time and WOR versus Cumulative Oil Production, respectively.

Figure14. Oil rate vs Time.

Figure 15. WOR vs Cum. Oil.

Case# 2: This case was performed in a field that was discovered in 1938. The field produces from a carbonate reservoir with a primary drainage area of 6.284 acres. The average depth and net pay is 3.400 ft. and 31 ft., respectively. The reservoir temperature is 104°F with an average porosity and permeability of 16.8% and 300 mD, respectively. The reservoir is stratified with a high degree of heterogeneity (V>0.75).

In 2015, two injectors were treated with an average treatment volume of 20.000 barrels of bulk gel per pattern. As of September 2017, the post treatment analysis showed an average of 28 bpd of incremental oil (see figures 16 & 17).
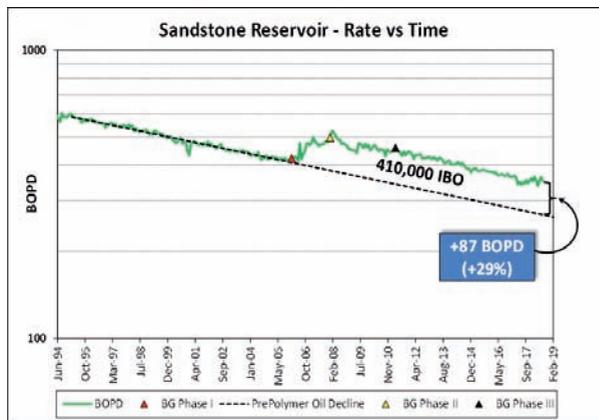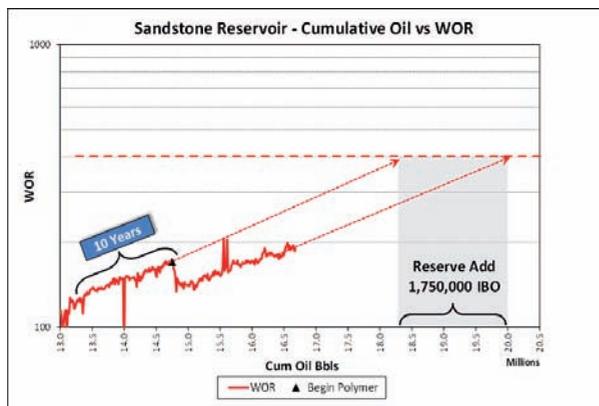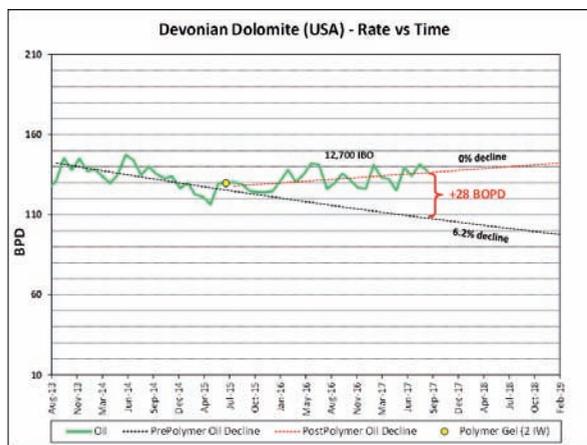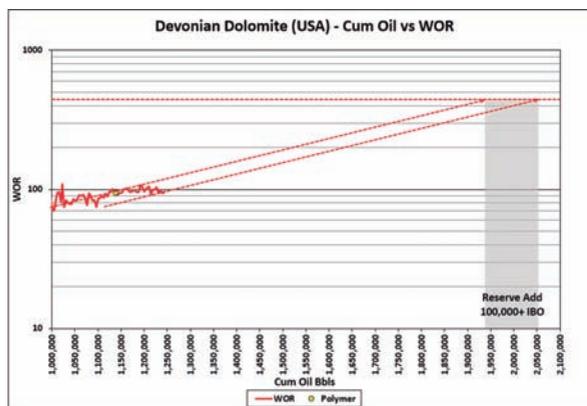

Figure 16. Oil rate vs Time.

Figure 17. WOR vs Cum. Oil.

Case# 3: This case was performed in a multilayer sandstone reservoir that was discovered in 1916. Water injection first began in the early 1970's with well spacing of 5 acres. The unit has a total area of 1.400 acres and produces from Pennsylvanian-age sands at depths ranging from about 1.000' to 3.500'. Average porosity is 25% and total net pay thickness can vary from as 50' to 250'.

The reservoir temperature is 95°F with a permeability range between 10 and 1,000 mD. The large variation in permeability is likely the primary reason why the rock has not been uniformly swept by the injected water to date.

Eight (8) injectors were treated in two phases with an average treatment volume of 8.500 barrels of bulk gel per pattern, with a range between 3.500 and 18.500 barrels. Phase I polymer gel treatments were performed in 2008 and phase II in 2015. As of May 2018, the project has recovered about 195.000 barrels of incremental oil with a projected ultimate incremental oil recovery of 795.000 barrels. This project has extended the life of the reservoir for about 11 years at a cost of $3,08 per incremental barrel of oil. Figures 18 and 19 show the pre and post treatment results using the oil rate versus time and WOR versus Cumulative Oil Production, respectively.
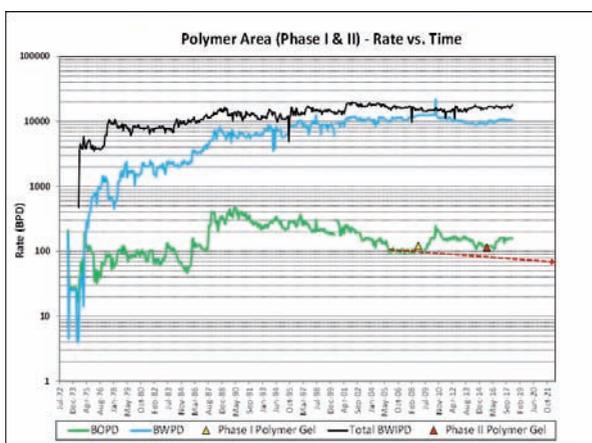

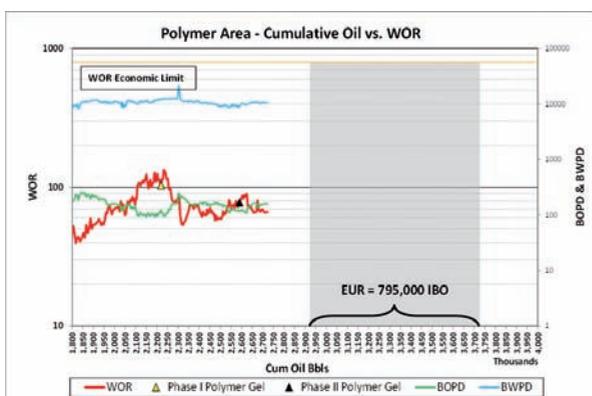
Figure 18. Oil & Water rate vs. Time.

Figure 19. WOR vs. Cum. Oil.

Summary Conclusion - Lessons Learned:

- Do not expect to have a pilot area that satisfies all of the candidate criteria.

- Just because injection pressure may be high does not automatically eliminate the well as a conformance candidate. The high pressure may be caused by:
    a. Choke/Mandrel restriction
    b. Flow capacity. The channel or thief zone is not capable of taking most of the injected fluid, even when there is a preferential channel.
    c. Near wellbore damage (skin).
- Clean the wellbore if necessary by whatever means is deemed to be appropriate for the given circumstances (e.g. remove fill, acidize, dissolve and remove parffins, etc.).
- Use the available data such an ILT and production injection data to understand and or fill the gaps when some data is not available:
    a. Reservoir heterogeneity
    b. Allocation factors
- Channel volume plays an important role in conformance treatment designs, especially when there are no permeability barriers to prevent cross-flow between swept and un-swept rock.
- The job must be accurately sized to fill a sufficiently high percentage of the total swept MPV that exists between the injectors and surrounding producers in order to prevent the subsequent drive fluids from quickly finding their way back into the offending channels at short distances from the treated wells.
- Conduct gel bottle tests before and during the bulk gel treatment and take at least two samples of each polymer gel concentration during the field application.
- Use a sample port to collect the sample during the field application.
- Use the field samples to help determine the minimum shut-in time required for the bulk gels to reach their maximum strength and maturity before returning the well to injection.
- Incremental oil is usually recovered at a cost of only a few dollars per barrel by flattening the oil decline, increasing the oil rate, and increasing the oil cut, substantially extending the economic life of the field.
- Interpreting ILT data in combination with production/injection performance analysis may help you to better understand just how heterogeneous the reservoir may be.
- Treating multiple injectors provides for critical mass, and allows results to be noticeable on the fieldwide production graph, rather than relying strictly on well tests that may or may not be accurate. Treating more injectors also provides for a larger sampling set that can be used to optimize future treatments.

- Do not expect immediate gratification. There is usually a lag-time between treatment and response. Response time will be longer (months) if well spacing is larger, and/or if un-swept (lower K) zone thickness is greater.
- Selective stimulation is complimentary to bulk gels conformance improvement treatments. High water loss intervals represent the higher permeability rock (i.e. path of least resistance) that has been swept and will subsequently be the target of the bulk gel treatment, while low/no water loss intervals represent lower permeability rock that will be the target of subsequent water injection. Low/no water loss intervals may also be indicators of near-wellbore damage that has prevented fluid entry and can be targets for selective stimulation after bulk gel has been injected into the high water-loss intervals.
- Bulk gel polymer solutions can be tagged with radioactive tracer during their placement, and the well can subsequently be logged to identify the intervals invaded by the bulk gel treatment. Those intervals that show no gel invasion, as indicated by the log, may be targets for subsequent stimulation to help water enter those un-swept zones.
- Use saltier water to improve gelant injectivity. Saline waters will significantly reduce the viscosity of and polymer solution while it is being injected but will not impact the final gel strength. If saline water is used, it is very important to determine if it is capable of being used to form gels of the desired strengths.
- Determine if the offending bulk gel target features are natural (primary) or more recent secondary (wormholes or man-made fractures). Both zones must be treated, with the secondary feature(s) treated first with a smaller volume of strong bulk gel, and the primary feature(s) treated second with a larger volume of moderately weaker gel.
- Bulk gels can be used to redistribute almost any type of flooding agent, including but not limited to water, CO_2, nitrogen, chemical flood (surfactant and/or polymer), etc.
- After the target volume and pressure have been determined and the treatment design has been prepared, then implement the job with the understanding that the polymer concentrations and injection rates used will be subject to change during the job as dictated by pressure response. It is common and quite normal to deviate from the original plan, on-the-fly, after the job has begun (i.e. let the reservoir tell you what it needs).
- In reservoirs that have close spacing, where injectors and producers are directly connected to one another by features that provide for rapid transit times, then consider injecting higher polymer concentration gels first, and then taper-down the polymer concentration as pressure increases. With this approach, if polymer gel breaks through at a surrounding producer, then the gel that will reside in the near-wellbore area of the impacted producer will have enough strength to resist the high draw-down pressure to which it will be exposed and allow it to stay in place rather than being produced. It is important to immediately shut-in any producer that tests positive for polymer breakthrough during gel injection to eliminate that pressure sink and limit further gel movement in the direction of the subject producer. Polymer concentration is increased again at the end of the treatment so that strong gels capable of resisting high energy reside in the near-wellbore area of the injector.
- Bulk gels can be used as much to prevent premature breakthrough of drive fluids as they are used to correct breakthrough problems that have already occurred.
- Success is determined by decreased WOR, increased oil rate but not necessarily by a change in the injection profile. It is common, if not the norm, for there to be little change in the near-wellbore injection profile log. This is likely due to the fact that most bulk gel treatments are over displaced from the wellbore. Consequently, injection drive fluids may continue to leave the wellbore at the same point, but will be diverted in-depth when they reach those areas inhabited by immobile gel.
- Bulk gel technology can be combined with other technology and or optimization strategy if necessary to achieve better results. For example, gel polymer can be used to redistribute injection water into new areas of the reservoir, and then that water can be augmented continuously with specialty chemicals designed to help recover residual oil in addition to mobile oil. Chemicals can also be added to improve mobility ratio and displacement efficiency of mobile oil. Bulk gel helps other injected fluids to contact more of the reservoir.
- Re-treatment can be considered and executed if necessary and will depend on:
  a. Good oil response to first Bulk Gel treatment
  b. Remaining mobile oil in the zone
- Always plan to treat at least two injectors in order to confine at least one offset producer. Treating only one injector can lead to a poor evaluation of the technology.

- There is always some risk any time injection equipment is pulled from old wells in old waterfloods, especially if the well is equipped with multiple packers and mandrels, and hasn't been pulled in a long time. However, if the injector is cycling water to surrounding producers through layers of rock that no longer contain any mobile oil (i.e. they've already been swept), then that injector is, for all practical purposes, ineffective. So the only real risk in pulling the wells is the wellbore itself, and the longer we wait to pull these old wells, the greater becomes the risk.

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