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Gel treatment field application survey for water shut off in production wells

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GEL TREATMENT FIELD APPLICATION SURVEY FOR WATER SHUT OFF

IN PRODUCTION WELLS

by

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ABSTRACT

Enhanced oil recovery (EOR) screening criteria are considered as a guideline for candidate evaluation and determination. Not many screening criteria for gel treatment had been published. Some published gel treatment application surveys for water shut off only include limited number of oil fields and locations.

The current work aims to summarize the worldwide gel treatment applications for water shut off in production wells by creating and analyzing a dataset from a variety of sources. This study started from collecting and cleaning the gel treatment application data. All the data were from SPE field publications from 1990 to 2012 and from Petroleum Technology Transfer Council database. Only production wells gel treatment application projects were included in this study. Failed projects were detected and deleted by the proposed method. The original dataset included 56 fields and 415 wells. Upon deleting the projects with insufficient information, 33 fields and 160 wells remained. After improving the dataset quality, both graphical and statistical methods were utilized to analyze the data. Histograms and box plots were used to show the distribution of each parameter and present the range of the data. Gel type selection, injection method, pre-flush method, and post flush method were analyzed by bar charts to show the gel treatment usage conditions. For analyzing the treatment results, cross plots were constructed to compare oil wells production before and after treatments. Oil wells candidate selection criteria were discussed. To improve the success rate for future gel applications, the reasons for past failure field cases were summarized, and the treatment limitations were listed. In addition, economic analysis based on cost and payback time was also discussed.

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NOMENCLATURE

Symbol	Description
Ø	Porosity, percentage
k	Permeability, (md)
μ	Oil viscosity, (cp)
h	Formation thickness. (ft)
T	Formation temperature, (F°)
S	Saturation, fraction
P	Reservoir pressure, psi
q	Fluid flow rate, bbl
E_R	Recovery efficiency
BPM	Injection rate, barrel per day
BOPD	Barrel oil per day
BWPD	Barrel water per day
BHP	Bottom hole pressure, (psi)
GOR	Gas oil ratio, (SCF/BBL)
WOR	Water oil radio, fraction
WC	Water cut, percentage
PI	Productivity index, (bbls/day/psi)

1. INTRODUCTION

As the rate at which new reservoirs are discovered decreases, enhanced oil recovery (EOR) techniques are becoming increasingly important for mature oilfields or reservoirs that would otherwise soon be abandoned. Excessive water production due to conformance problems becomes an issue when water cut increased to an uneconomical level. Excessive water production significantly increases production costs; water production control has become an urgent task for the oil industry. Gel treatment is one of the conformance control methods acting as a plugging agent. Gel treatment controls water flooding through high permeability zones and closes off water channels near the wellbore to decrease WOR.

This study demonstrates that gel treatment has been wildly used in more than 20 counties around the word including: China, United States, Canada, Mexico, France, Brazil, Indonesia, Venezuela, and Turkey. Short payback time, high successful rate and low cost are the main advantages for this method. However, gel treatment as a chemical treatment has its own limitations. Proper candidate selection can affect the success rate. Injection volume, fluid pH, temperature and concentration should be carefully considered when using gel treatments.

The objective of this study is to summarize gel treatment applications in production oil wells. In this work, a dataset has been generated from SPE field publications from 1990 to 2012 and Petroleum Technology Transfer Council database. Data cleaning methods have been applied in the original dataset; failure application cases have been removed. Both graphical and statistical methods were utilized to analyze the data.

This thesis is organized into five sections. The first section is the overall introduction and the objective of study. The second section is a literature review and basic theories for enhanced oil recovery methods. The third section is gel treatment mechanisms. In this section, gel treatment processes have been explained in detail. The fourth section is data collection and analysis. All the parameters that affect gel treatment selection have been discussed. Data range and distribution have been observed. Treatment results have been discussed. Also in this section, oil wells candidate selection has been summarized and gel treatment application failure reasons have been listed. The last section is the overall summary and conclusion.

2. LITERATURE REVIEW

This study is a literature review of overall oil recovery mechanisms and their methods. Also gel treatment technology, injection mechanisms, application limitation, and candidate wells selection are specified. Field case applications have been discussed and criteria for gel treatment have also been reviewed.

2.1. EOR INTRODUCTION

During the oil recovery process, three major mechanisms are included: primary, secondary, and tertiary recovery. Primary recovery is the first stage of hydrocarbon production using natural energy to push oil out of the reservoir. Primary recovery includes: gas cap drive, solution gas drive, natural water drive, and gravity drainage. Unfortunately, this stage extracts only 12 to 15% of the oil within the reservoir.

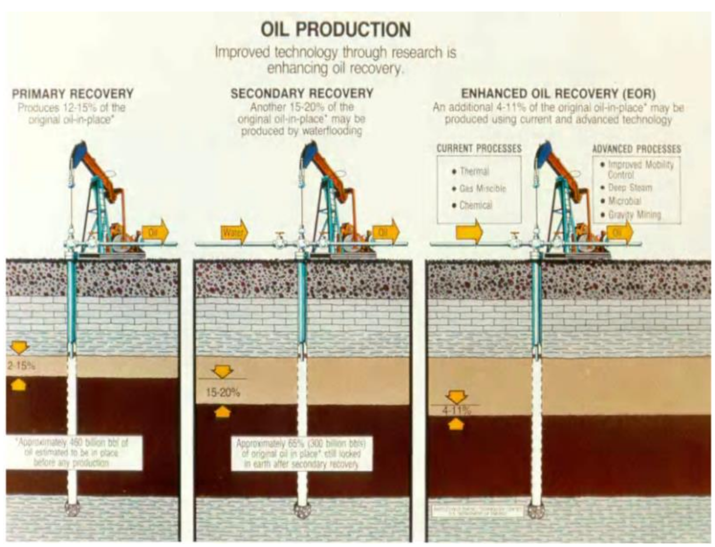


Figure 2.1. Three stages oil production (Willhite, 1998)

Secondary recovery begins with applied pressure maintenance upon exhaustion of natural energy. Water and gas injection are the two most common methods of secondary recovery. In each case, water or gas is pumped into reservoir to maintain reservoir pressure and displace the oil into the wellbore. This increases the recovery factor to 35-40% on average typically leaving more than 60% of the oil still in the reservoir. When the reservoir produces a large amount of injection fluid, the production is no longer economical.

Tertiary recovery becomes necessary to return production to an economically viable level. The tertiary recovery method is also known as an EOR method. It can be applied following secondary recovery or directly after primary recovery.

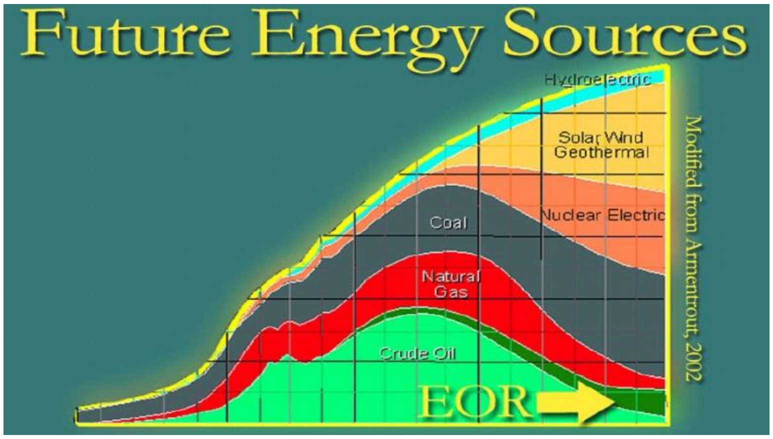


Figure 2.2. EOR potential in the world (Oil and Gas Journal,1990)

According to the EOR annual data report, a declining trend in oil discoveries leads to enhanced oil recovery technology playing a key role in meeting the energy demand. For the oil industry, only increasing recovery factors from aging oil wells will make up the shortage of the energy demand (Alvarado and Manrique 2010). EOR method helps extract oil by injecting materials which not are normally present in reservoir. The injected fluid interacts with the reservoir system to create a more favorable condition for oil displacement (Willhite 1998). EOR methods are applied for less desirable reservoirs which the natural energy is depleted and primary and secondary recovery methods are not cost effective. EOR methods are affected by the marketing of the oil price. It is considered a profitable recovery method when the oil price is high enough. According to data analysis published by the Department of Energy, the US still has 649 billion barrels of total remaining oil in the reservoirs, but only 22 billion barrels are recoverable by conventional methods. Leaving more than 90 percent of the crude oil is still available for extraction. Figure 2.3 below shows that most EOR methods are applied in sandstone reservoir based on 1507 projects around the world.

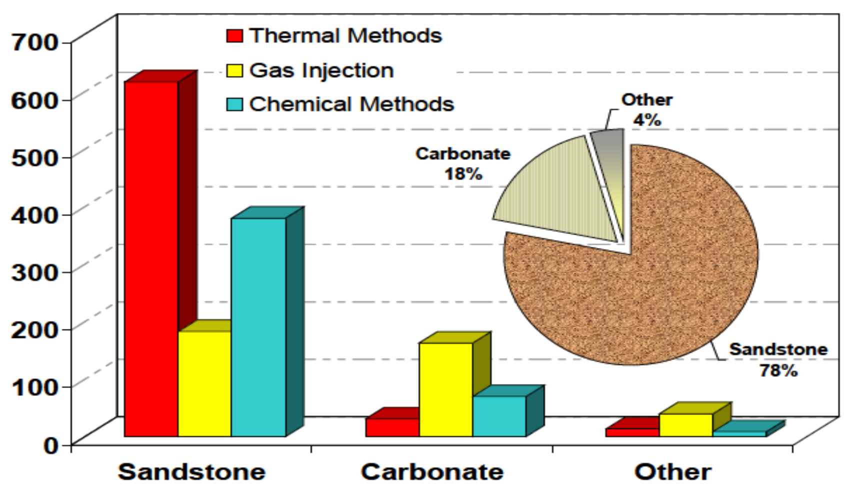


Figure 2.3. EOR application distributions (Oil and Gas Journal EOR Surveys, 2012)

EOR method can be can be classified into two groups: thermal and non-thermal methods. The non-thermal method includes chemical method and gas injection method. They are using different technology to interact with fluid system in reservoir; all the methods aim at mobilizing the remaining oil. Enhancing oil displacement and volumetric sweep efficiencies are the primary concern for the EOR objective. Oil-displacing efficiency can be improved by reducing oil viscosity, interfacial tension, and capillary force. Volumetric sweep efficiencies are affected by the mobility ratio. A lower mobility ratio can develop a more favorable fluid and rock system for oil flow. Five key reservoir issues need to be considered carefully before selecting EOR method: high residual oil, high oil viscosity, heterogeneity reservoir, reservoir fracture problems, and oil wet rock. An oil reservoir is a complex system between fluids and rock, with above reasons resulting in a low oil recovery factor. The first issue is high residual oil left in pore's media and the second is high oil viscosity. Fingering of injected fluid through oil results from an oil viscosity being higher than the viscosity of the displacing fluid. The third issue is reservoir heterogeneity. Injected water prefers to flow through high permeability zones instead of flowing through a matrix system in heterogeneity reservoir. This phenomenon will create fingering problems and water channel problems. The fourth issue is fracture problems and the fifth is oil wet rock. Many reservoirs are naturally fractured reservoirs, especially carbonate reservoirs. Plenty of channels occur in carbonate reservoirs that will decrease sweep efficiency and oil wet rock will lead to more residual oil left in reservoir. Different EOR methods have been selected based on the reservoir's specific case.

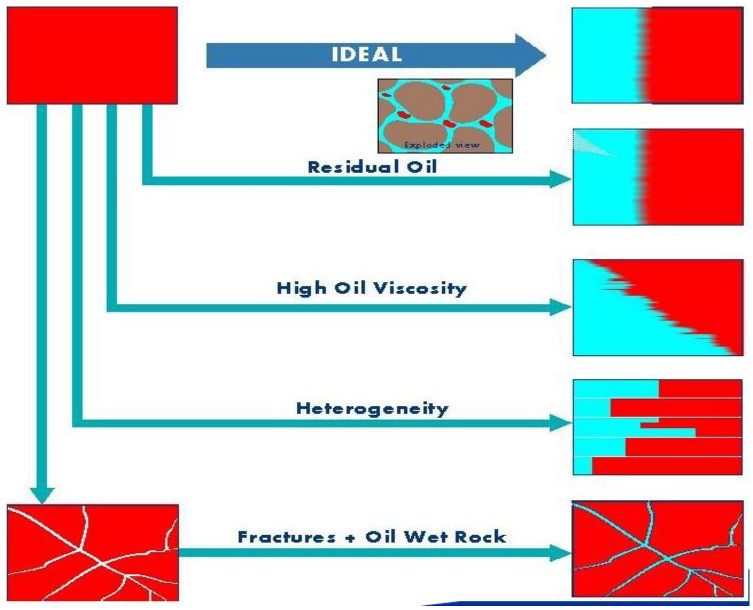


Figure 2.4. Five main reservoir issues (Willhite, 1998)

2.1.1. Thermal Method. The thermal method is a steam flooding, in-situ combustion and cyclic steam stimulation. It aims at increasing the reservoir temperature to lower the oil viscosity and improve the flow ability through reservoir to the wellbore. Thermal method has been wildly applied around the world accounting for nearly 40 percent of EOR projects in the US. Most of EOR projects are applied to reservoirs in California. Steam flooding is mostly applied when there is heavy oil, while in-situ combustion, also known as “fire flooding”, provides a combustion front which injects air or other oxygen-containing gases. Recovery factors are increased by improving oil mobility in the reservoir and this method is mostly applied in heavy oil fields with ultra-high oil viscosity. Cyclic steam simulation, also called “huff-and-puff”, injects high pressure steam into the producing well and shuts it in for multiple days allowing the steam to heat the formation.

After several weeks, the wells can resume production until a significant amount of heat is lost during the production of the fluid. Other than regular steam flooding, steam assisted gravity drainage (SAGD) has been mentioned as another important EOR thermal method to increase oil production in oil sand (EOR update review). But very few commercial industry reports have been published on SAGD, while this method remains in field testing.

2.1.2. Non-Thermal Method. Non-thermal methods include: Gas miscible recovery method and Chemical recovery methods. Gas miscible recovery methods include: miscible recovery, carbon dioxide (CO_2) flooding, cyclic carbon dioxide stimulation, nitrogen flooding, and nitrogen CO_2 flooding. Gas miscible recovery uses gas expanding to push oil to the wellbore by injecting carbon dioxide, nitrogen or natural gas. The injected gas is also dissolved into the oil, reducing viscosity and increasing mobility. CO_2 flooding is normally applied to reservoir which initial pressure has been depleted through primary production and possibly water flooding. CO_2 flooding usage has been on the rise during recent decades despite the fact that chemical treatment has been losing attention in EOR methods. CO_2 injection method is wildly used in medium and light oil production. The cyclic CO_2 stimulation, similar to cyclic steam flooding, injects CO_2 through oil wells and shuts it in for multiple days before continuing production again. Nitrogen flooding can be used for light oil recovery for deep reservoir.

Chemical methods, including polymer flooding, micellar-polymer flooding, alkaline flooding, and gel treatment, account for the remaining non-thermal methods. According to EOR field case database, polymer flooding is the most important of the mature chemical treatment methods. Large-scale of polymer flooding projects are still underway each year. For alkaline flooding, surfactants are formed when alkaline chemicals and petroleum acids reacted, which helps to loosen the oil from the rock by reducing interfacial tension and changing the rock surface wettability (Willhite, 1998). Polymer gels are used to shut off high permeability zones. Other than regular polymer gel, new polymer based gels such as Colloidal Dispersion Gels and Bright Water are currently been tested and evaluated. They are used to improve conformance problems by improving sweep efficiency.

3. GEL TREATMENT FOR CONFORMANCE CONTROL

3.1. WATER PROBLEM

An average of 210 million barrels of water accompanies 75 million barrels of oil produced daily. This ratio is even higher in the US, at 7:1, as shown in Figure 3.1. Water problem is worse in the North Sea oil field, where 222 million tons of water are produced with 4 thousand tons of oil. The economic lives of many wells are shortened because of the excessive production cost associated with water production. These expenses include lifting, handling, separation, and disposal. The unwanted water uses up the natural drive and lead to possible abandonment of the production well. Excessive water increases the risk of formation damage, produces a higher corrosion rate, and increases emulsion tendencies. It may also form a hydrate because the water and gas are not produced in a proper ratio. The excessive water produced in water drive production wells is typically a result of a coning zone within the rock or from vertical fractures which extend into bottom water drive (Portwood, 1999).

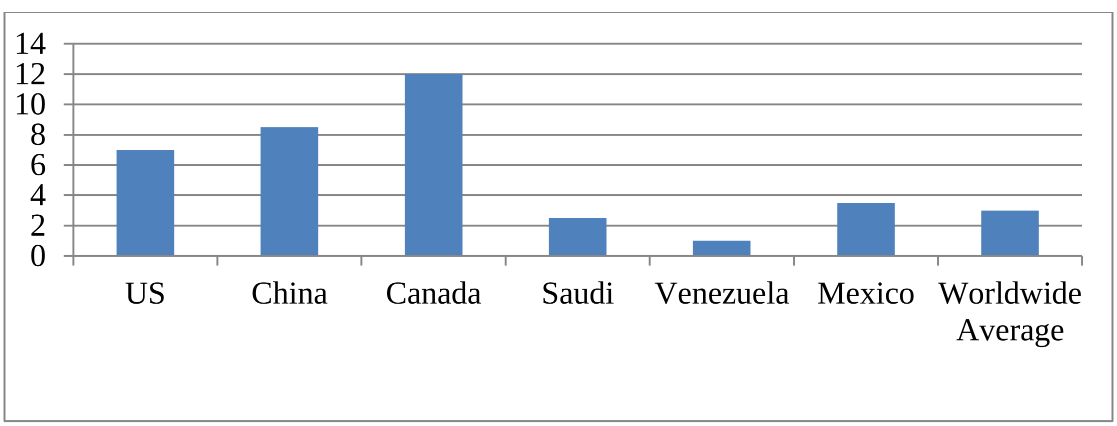


Figure 3.1. Worldwide water oil ratio distribution

One barrel of water has the same production cost as one barrel of oil. The annual cost required to dispose of the excess water is estimated to be 40 billion dollars worldwide; it is between 5 and 10 billion dollars in the US (Bailey, 2000). Reducing the amount of water produced would help in decreasing not only the chemical treatments but also the separation cost associated with the production process. It would also decrease the costs of artificial lift requirements. Water shut-off treatments can be applied to both carbonate and sandstone formations as well as fractured and matrix permeability reservoirs.

Well productivity and potential reserves have been increased by the water control method. As illustrated in Figure 3.2, the water oil ratio increases as the production increases within a mature oil well. The water control method needs to be applied when the water-to-oil ratio reaches an economical limit with high excessive water handling costs. The WOR will drop below the economic limit and continue producing oil after the production rate is reduced. Thus, the water control method extends an oil well's life.

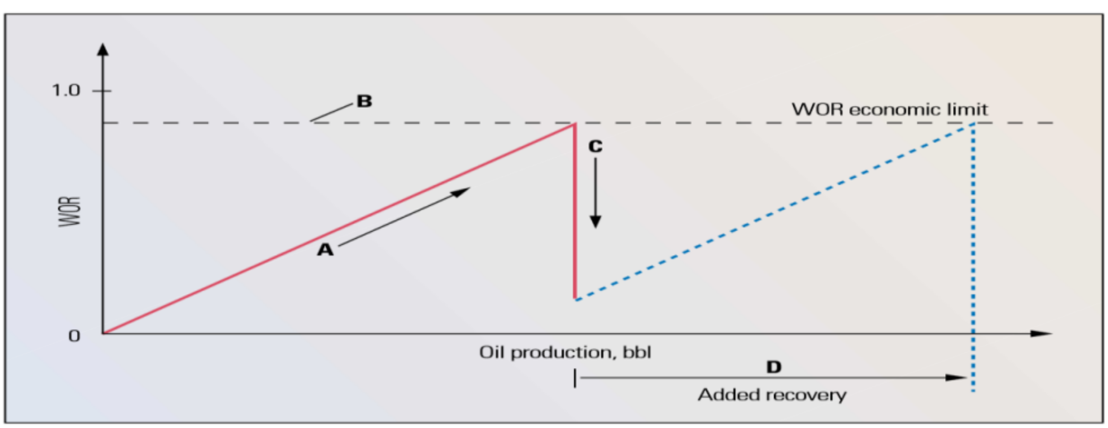


Figure 3.2. Water control method for increasing well productivity (Bailey *et al.*, Water Control)

Sweep water is good water produced by either injection wells or active aquifers that sweep the oil from the reservoir. Effective water pushes oil through the formation and toward the wellbore. It cannot be shut-off without shutting off the oil. Bad water produces an insufficient amount of oil, increasing the WOR until it is over the acceptable limit. The good and bad water concept is depicted in Figure 3.3.

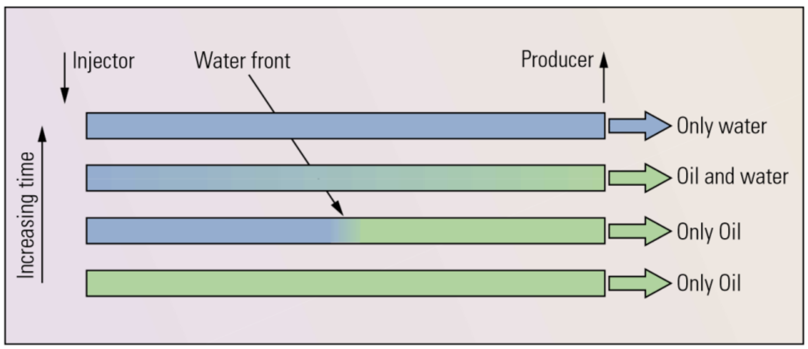


Figure 3.3. Good and bad water (Bailey *et al.*, Water Control)

3.2. WATER CONTROL PROBLEMS

Water control problems can be classified into one of two major categories: near well bore problems and reservoir related problems.

3.2.1. Near Wellbore Problem. Six near well bore problems have been listed below:

3.2.1.1 Casing leaks problem. The water that flows to the wellbore through the casing fissure arrives from either above or below the production zone. Casing leaking create an unexpected increase in the water producing rate, as demonstrated in Figure 3.4. These leaks can be classified into one of two types: casing leaks with flow restrictions and casing leaks without flow restrictions. Gel treatments offer an effective solution to casing leaks with flow restrictions. The leaks examined in this study moved through a small aperture breach (e.g. pinholes and tread leaks in the piping). The pipe fissure was less than approximately 1/8-inch; the flow conduit was less than approximately 1/16-inch (Seright, 2001). In contrast, Portland cement is a better treating method for casing leaks without flow restrictions. These leaks are created by a large aperture breach in the pipe and a large flow conduit (Seright, 2001).

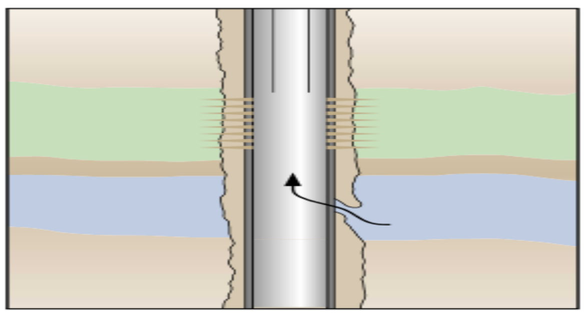


Figure 3.4. Casing leaks (Bailey *et al.*, Water Control)

3.2.1.2 Flow behind the pipe. Two situations contribute to flow behind the pipe (Figure 3.5): flow behind the pipe without flow restrictions and flow behind the pipe with flow restrictions. Cement is an effective method for flow behind the pipe without flow restrictions. A lack of primary cement behind a casing creates a large aperture, thereby producing a large flow channel. The flow conduit is approximately greater than 1/16-inch. Flow behind the pipe with flow restrictions is caused by cement shrinkage during the well's completion. A flow conduit less than 1/16-inch is formed along with small apertures (Seright, 2001).

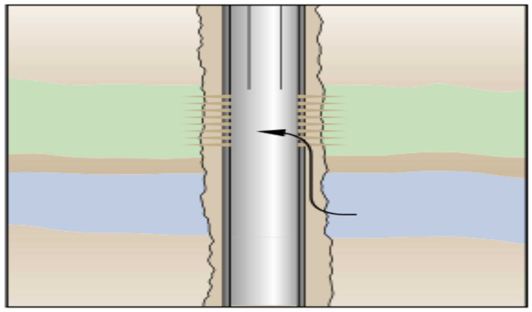


Figure 3.5. Flow behind the pipe (Bailey *et al.*, Water Control)

3.2.1.3 Barrier breakdowns. A new fracture can be formed near the wellbore by either fracture breaking through the impermeable layer or utilizing acids to dissolve the channels. The pressure difference across the impermeable layer will drive the fluid migration throughout the wellbore. This type of conformance problem can be related to the stimulation process sometimes (Reynolds, 2003).

3.2.1.4 Channels behind the casing. Bad connections between not only the formation and the cement but also the cement and the casing can create water channels behind the casing. A bad cement job, cyclic stresses, and post-stimulation treatments contribute to these issues (Jaripatke & Dalrymple, 2010). Another cause of this issue is the space behind the casing created by the sand production. Either a high strength squeeze cement in the annulus or a lower strength gel-based fluid placed in the formation can be used to stop the water channel (Bailey *et al.*, Water Control).

3.2.1.5 Inappropriate completion. Inappropriate completion can immediately create unwanted water production. This issue can also cause both coning and cresting near the wellbore. A sufficient geological survey is quite important before the completion of the project.

3.2.1.6 Scale, debris and bacterial deposits. Scale, debris, and bacterial deposits can obstruct and alter the non-hydrocarbon flow to undesired zone (Jaripatke & Dalrymple, 2010).

3.2.2 Reservoir Related Problems. Six reservoir related problems have been listed below:

3.2.2.1 Coning and cresting. Coning is a production problem that occurs either when bottom water or a gas cap gas infiltrate the perforation zone near a wellbore. This behavior reduces oil production. The interface shape for coning is different between a vertical well and a horizontal well, as depicted in Figure 3.6. The coning interface shape in a horizontal well is similar to a crest. The horizontal well will produce a smaller amount of undesired secondary fluids under comparable coning conditions. The hydrocarbon flow rate will greatly decrease after the cone breaks into the producing interval, which will also lead to a dramatic increase of water and gas rate, as illustrated in Figure 3.7. The reservoir pressure will be depleted shortly after the gas cone breaks through. This depletion may cause oil well shut-in.

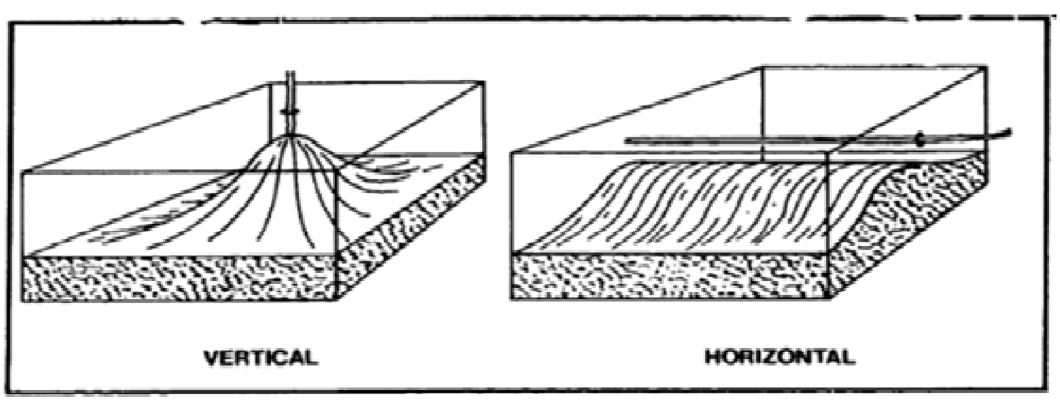


Figure 3.6. Water coning in both vertical and horizontal wells (Chaperon, 1986)

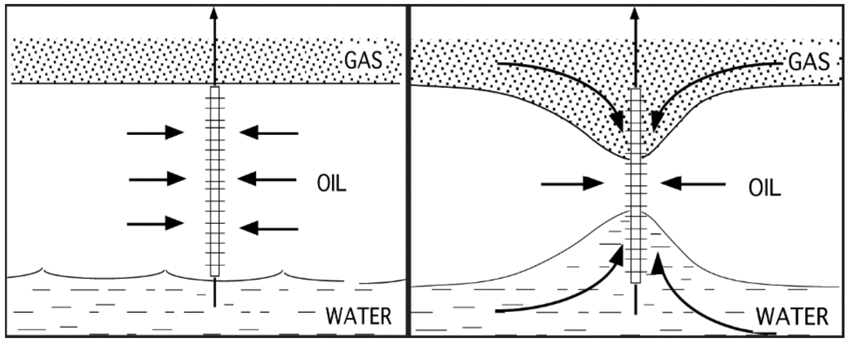


Figure 3.7. A production well both with and without coning (PetroWiki, 2013)

3.2.2.2 Watered-out layer with and without crossflow. Both the water crossflow and the pressure communication in a watered-out layer with crossflow (Figure 3.8A) occur between high permeability layers without impermeable barrier isolation. Either an injection well or an active bottom water can serve as the water source. A gel treatment should not be considered when radial crossflow occurs between adjacent water and hydrocarbon strata. A gelant will crossflow into oil producing zones, away from the wellbore. Thus they do not effectively improve the conformance problem. A conformance improvement technology (e.g. polymer flooding) should be used to improve oil viscosity (Sydansk and Romero-Zeron, 2011).

Watered-out layer without crossflow (Figure 3.8B) is a common problem. It is usually associated with multilayer production in a high-permeability zone with impermeable barriers isolation. This problem is easy to treat; either a rigid, shut-off fluid or a mechanical method can be applied in either injection wells or producing wells (Bailey *et al.*, Water Control). Coiled tubing is recommended as a placing method.

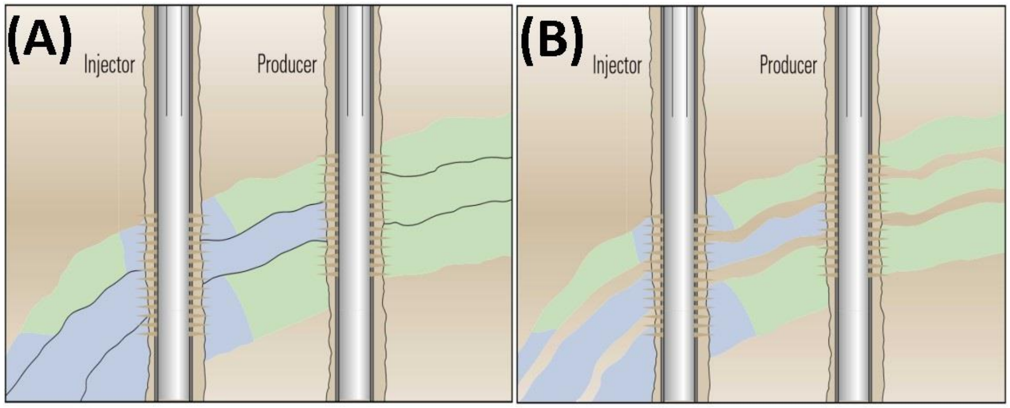


Figure 3.8. Watered-out layer (A) with and (B) without crossflow (Bailey *et al.*, Water Control)

3.2.2.3 Channeling through a high permeability zone. A high permeability zone will lead to early breakthrough. The displacing fluid will bypass lower permeability zones and flow through high permeability zones. This phenomenon leads to low sweep efficiency and a high WOR. It is most common in reservoirs with either an active water drive or a water-flooding-treated reservoir.

3.2.2.4 Fingering. Viscous fingering can cause poor sweep efficiency during the oil recovery flooding process. Viscosity will form when the oil has a higher viscosity than the displacing fluid has.

3.2.2.5 Out of zone fractures. Fracturing is one of the main causes for reservoir heterogeneity. Both hydraulic fractures and natural fractures can cause water production problems. These problems can be treated by gel placement. The following three challenges, however, must be addressed (Bailey *et al.*, Water Control):

- The gel injection volume is difficult to determine.

- Treatment may shut-off the oil producing zone. Thus, a post-flush treatment needs to be applied to maintain productivity near the wellbore.
- The flowing gel must be tolerated to resist flow-back after gel placement.

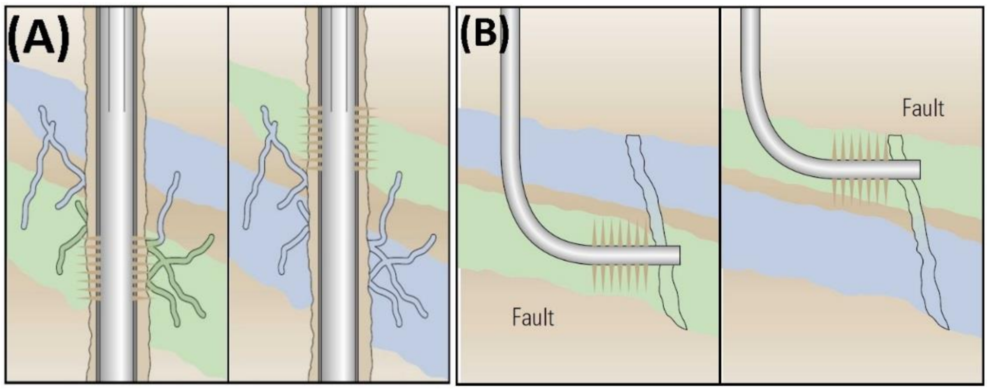


Figure 3.9. Fractures or faults from a water layer surrounding a (A) vertical well or a (B) horizontal well (Bailey *et al.*, Water Control)

3.2.2.6 Fracture between the injection and producing wells.

Injection water is easy to breakthrough. It can cause excessive water problem in production wells with naturally fractured formation between injection wells and producing wells, as shown in Figure 3.10 (Bailey *et al.*, Water Control). Gel treatments offer the best solution because they have limited penetration to matrix rock. Bullhead injection through injection well can be applied with the gel treatment (Bailey *et al.*, Water Control).

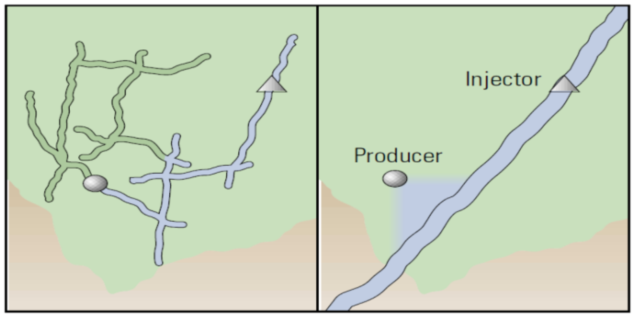


Figure 3.10. Fractures or faults between an injector and a producer (Bailey *et al.*, Water Control)

3.2.3. Excessive Water Production Problems and Treatment Categories.

Table 3.2 shows the screening criteria for conformance problem for excess water, the table was listed in increasing order of treatment difficulty. Seright, Sydansk and Lane proposed a forthright solution for each catalog. Conformance problem need to be clearly identified before effective treatment selection. Conformance problems listed in Category A are the easiest problem to solve, conventional techniques such as cement, bridge plugs and mechanical tubing patches are effective choices. Gel treatments are the most effective method for conformance problems in category B, Preformed gel are the best choice for category C. For complex conformance problem in category D, successful rate for gel treatment application is extremely low.

Table 3.1. Conformance problem for excessive water and treatment categories (Seright, 2001)

Category A: “Conventional treatment” effective case
1. Casing leaks without flow restrictions 2. Flow behind pipe without flow restrictions 3. Unfractured wells with effective barriers to crossflow

Table 3.1. Conformance problem for excessive water and treatment categories (Seright, 2001) (cont.)

Category B: Gelants treatment effective case
4. Casing leak with flow restrictions 5. Flow behind pipe with flow restrictions 6. Two dimensional coning through a hydraulic fracture from an aquifer 7. Natural fracture system leading to an aquifer
Category C: Preformed gels effective case
8. Faults or fractures crossing a deviated or horizontal well 9. Single fracture causing channeling between wells 10. Natural fracture system allowing channeling between wells
Category D: Difficult problem where gel treatment should not use
11. Three dimensional coning 12. Cusping 13. Channeling through strata with crossflow without fractures

3.3 GEL CONFORMANCE IMPROVEMENT TREATMENT

Gel treatment, acting as a plugging agent for near wellbore treatment, success rate to water shut off is around 75% (Portwood, 1999). When gel treatment has been injected into formation, it can divert fluid flow from water channels to formation matrix. Fluid prefer to flow from high permeability and low oil saturation zone, it will normally bypass low permeability zones with high oil saturation. Gel treatment can change this behavior, and to enhance oil production and improve flood sweep efficiency. Gel treatment can reduce production operation cost by lower water production rate. In the oil field, gel treatment can be applied to conformance related problems such as water or gas shutoff treatment, sweep improvement treatment, squeeze and recompletion treatments or aged wells abandonment treatment.

3.4 GEL TYPE

An appropriate gel selection is important to water shutoff treatment; it will affect treatment result directly. Gel with greater strengths can be applied in reservoir with large fractures, weaker gel will be used in reservoir with less extensively fracture or matrix with lower productivity.

3.4.1 Polymer Gels. Polymer gel treatment is the most common and effective gel treatment application in reservoir. Polymer gel can flow through fractures and also strong enough to withstand high pressure difference near wellbore. It can be placed in high permeable with high water saturation, to reduce water permeability and block the water channels. Crosslinked polymer gel can be applied to production wells with excessive water or gas flow; it can also apply to injection wells with poor injection profiles (Miller.J.M & Chan.K.S 1997). Polymer goes through crosslinking fist and then forms a solid gel with time and temperature. There have two type of crosslinker to polymer: organic crosslinker and metal ions crosslinker, the most common use for metal ions crosslinker is chrome-based crosslinker.

Metal ions crosslinkers are contain $Al3^{+}$, $Cr3^{+}$ and $Cr6^{+}$. Crosslinker with $Al3^{+}$ is hard to control or delay the crosslinking time. Chromium (III)-Carboxylate/Acrylamide-Polymer Gels is also known as CC/AP gels. CC/AP gel can be both used as water shutoff treatment and sweep improvement treatment. CC/AP is acrylamide-polymer crosslinked with chromium (III) carboxylate complex. CC/AP gel can be applied in a broad pH range, and also has a wide range of of gel strengths. CC/AP gel has wide range of controllable gelation-onset delay time, but sensitive to high temperature reservoir (Sydansk.R.D, Reservoir Conformance Improvement). The upper limit for CC/AP gel is around 300 ^{o}F (Sydansk &Southwell 2000).

The disadvantage for chrome-based crosslinkers are less remaining time during injection and sometimes tend to set up earlier than desired, particularly at temperatures above 175 ^{o}F (Uddin.S & Dolan.D.J 2003). For high reservoir temperature or oxidative degradation, Metal ions crosslinked polymers are less likely to use (Burns et al. 2008).

Organic crosslinker polymer is an environmental friendly system. It took less job to mix and pump to the field. Organic crosslinker system reacts more predictable to change of reservoir temperature, component concentration, brine type, salinity and pH values. Those characters make organic crosslinking polymer gel easier to control and to understand during the treating process (Uddin.S & Dolan.D.J 2003). Compare to chrome based polymer gel, organic crosslinkers lasts longer time than tradition polymer gel with it deep sealing properties. From the laboratory test data result, organic crosslinker can penetrate into the formation eight times as far as traditional chrome-based polymer; it can completely seal off the formation (Uddin.S & Dolan.D.J 2003).

A list of conformance problems has been tabulated, and the ones which can be solved by the polymer gel method are indicated in Table 3.2.

Table 3.2. Conformance problems suitable for polymer gels (PetroWiki, 2013)

<u>Matrix conformance problems</u>	
Without crossflow	Yes
With crossflow	Challenging—must place very deeply

Table 3.2. Conformance problems suitable for polymer gels (PetroWiki, 2013) (cont.)

Fracture conformance problems	
Simple	Depends—case-by-case basis
Network—intermediate intensity and directional trends	Yes
Network—highly intense	Often not
Hydraulic	Yes
Coning	
Water and gas via fractures	Yes
Water and gas via matrix reservoir rock	No
Behind pipe channeling	Yes, for microflow channels
Casing leaks	Yes, for microflow channels

3.4.2. Silicate Gels. Silicate gel used to be the most wildly applied inorganic conformance improvement technique years ago. But because of the low injectivity in reservoir matrix rock and reduced gel strength with increased gelation onset time, silicate gel is not been widely applied recently (Sydank.R.D, Reservoir Conformance Control).

3.4.3. Relative Permeability Modifiers (RPM). The purpose of RPM is to reduce water flow permeability while don't have meaningful changes to hydrocarbon flow. Unswept and low water saturation fracture zone are the most favorable condition for RPM application. And also RPM can be used to use to wells with water drive problem, low mobility ratio problem or layered reservoir with distinct vertical permeability barriers (Jaripatke & Dalrymple, 2010).

3.4.4. Advantages Gel Treatment over Cement Treatment. Gelents can penetrate into porous rock while cement can only seal rock surface. Cement can only seal near wellbore channels or plug normal permeability rock, sufficient injection pressure is required for significant distance by fracturing or parting the rock or sand. Cement may not sufficiently seal the channel if cement does not adhere strong enough to the rock. And also, cement cannot penetrate into narrow channels (Seright.R.S 2001). There have three advantage gels over cement listed below; two of them are summarized by Seright.R.S:

1. Gel can formed an impermeable and deeper barrier inside porous media
2. Gel can flow into narrow channels behind pipe.
3. Gel can form a non-permanent plug and can be remove easily.
4. Gel treatment is cheaper than cement because of reduced crew and rig time.

3.5 GEL TREATMENT SIZING FOR PRODUCTION WELL

Gel treatment sizing design is an unsolved problem in oil and gas industry so far. A lot of failure field cases demonstrated facts that wrong gel treatment sizing estimate is one of the main failure water shut off treatment reason. Several strategies as follows have been used to gel treatment sizing design in oil field, they are summarized from 300 producing well water shut off treatment. But comparing and considering all the methods to make final decision is always better than just relying on a single method (Potwood 1999):

1. Gel injection volume based on minimum volume. The effective way to estimate the capacity of the well is let the fluid producing for more than 24 hours in a pumped off condition, the total volume for gel treatment is the maximum daily

rate. The maximum daily rate is also refers as minimum volume. This strategy will be based on individual field, well specifics and the history data and experience. This method gel better result in natural fractured reservoir. Normally no less than minimum volume needs to be pumped, but for fractured well, 2 or 3 times the minimum gel treatment volumes need to be pumped to fill more fractures near wellbore.

2. Gel injection volume based on distance. It's difficult to predict gel treatment's penetration. One of the numerical methods of sizing a gel treatment is used radial flow calculation. According to the experience, 50 to 60 food radius of rock originating from the wellbore will be used for calculation. Another numerical method is using a minimum of 50 and up to maximum of 200 barrels of gel per perforated food. This method is productivity related, if the well has high productivity, a factor close to 200 barrels of gel per perforated food will be used; if the well has low productivity than close to 50 barrels of gel per perforated food will be applied.
3. Gel injection volume based on well response. Treating pressure is a good indicator in injection process. During the injection process, if the treating pressure starts low and increase gradually at the beginning, but then increase rapidly after barrels of gel has been pumped. That shows gel already plugged high permeability water producing zone and no more gel is required. but if no rapidly increase for treating pressure during the injection process, injection volume don't need to readjusted and keep the injection pressure below previous established maximum pressure.

4. Gel injection volume based on experience in a given field. Previous treatment field data is the most reliable source compare to methods above. Operators need to keep on tracking of gas, oil, water fluid level after gel treatment. A good before and after treatment formation profile records are good reference to evaluate treatment success, help the interpretation of result. Future treatment modification and improvement will relay on those experience (Portwood 1999).

3.6 PLACEMENT TECHNOLOGIES

Proper placement technique is one of the major determination to treatment successfully control unwanted water. A proper placement technique will plug the excessive water or gas zone with minimum invasion of gel into oil producing intervals. The selection of placement technique is based on reservoir properties and previous field experience. Weather fluid flow around the wellbore is radial or linear is a critical consideration for gel placement technique. Linear flow normally occurs in flowing situation: flow behind pipe, fractures and fracture-like features. Radial flow occurs in matrix reservoir rock without fracture. In radial flow condition, oil producing zone need to be protected during gel injection, mechanical packer need to be considered (Seright.R.S 2001). But for linear flow, it's easier to achieve with simple placement method such as bullhead injection. Four main types of placement methods are listed as below: bullhead method, mechanical packer placement method, dual injection method, isoflow placement method.

3.6.1 Bullhead Placement Technique. Bullhead placement is the simplest and most economical method compare to other three placement method. If operations need to be processed during day hours, bullhead placement takes shorter time than other methods. Treatment has been injected through casing without isolating the targeted zone. During the placement process, injection profiles need to be analyzed, multi rate analyses need to be performed to determine the entry zone which associated with different injection pressure/rate. There have three main reservoir situations are favorable for bullhead placement. First, it can be applied for wells with high permeability and saturation contrasts. Second, it can also apply to reservoir with a large pressure drop to breakdown gel damage in oil zones. Third, it could be used when wells will apply reperforating to oil zone after gel treatment (Miller.J.M & Chan.K.S 1997). The disadvantage for bullhead placement is treatment fluid may dilute in large size of casings, and also wellbore fluid can be polluted at the interface (Uddin.S & Dolan.J 2003). Compare to bullhead placement, coiled tubing can place the treatment to desired area accurately, less pollution and easier to control the process, but it takes longer time and is more expensive (Uddin *et al.*, 2003). For channel flow behind casing, coiled tubing is an efficient placement method.

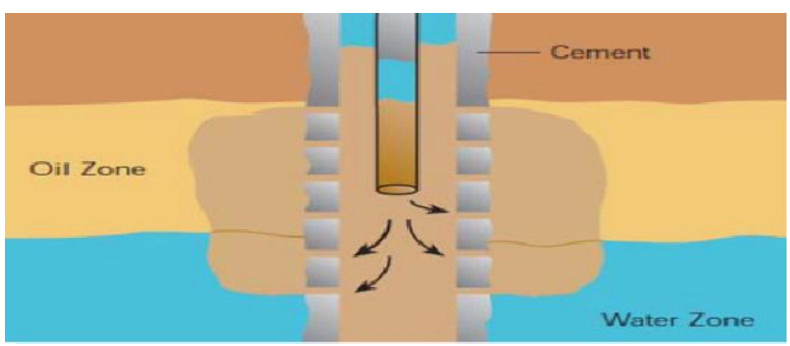


Figure 3.11. Bullhead placement technique (Jaripatke & Dalrymple, 2010)

3.6.2 Mechanical Isolation. Mechanical isolation is placement technique by using mechanical packers, selective zone packers or bridge plugs to isolate perforations or openhole area to prevent treatment fluid from sealing adjacent oil layers. Depending on the circumstances, the tool could be used as a control for injection or production when left it in the well. During the placement process, infectivity and communication aspects have to been fully tested before the determination of the packer's degree of placement control on the zone. When treating a vertical conformance problem of a radial flow well, mechanical isolation need to be used to assure that the gelant is injected exactly into the high permeability zone or low oil saturation area for near well bore gel treatment process (Seright, R.S., 2001). Mechanical isolation is an effective placement method for non-communicating layers when high permeability zone is isolated and low permeability zone is protected (Miller.J.M & Chan.K.S 1997).Compare to bullhead placement, mechanical isolation have higher successful rate. According to annual report from Alaska Prudhoe Bay, 60% success at shutting off excessive gas well by using mechanical isolation to place gelants into formation (Sanders,G.S, 1994). Other than that, 84% of the successful treatment at modifying injection profiles with mechanical isolation was applied (Roberson, J.O., 1967). Mechanical isolation method will lead to a good placement result when oil well has a good casing and cement; and don't have near wellbore fissures problem; also one or two excessive water or gas production zone have been identified. But when oil wells have channels behind pipe, this method is not always effective (Miller & Chan, 1997).

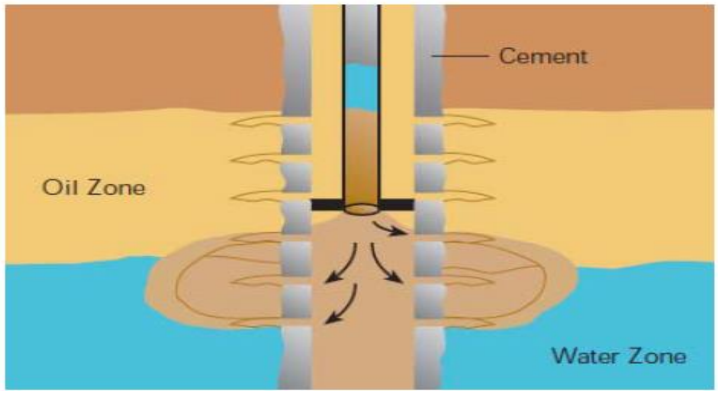


Figure 3.12. Mechanical packer placement technique (Jaripatke & Dalrymple, 2010)

3.6.3 Dual Injection. Dual injection is a placement method when gel treatment has been placed through tubing while protection fluid has been injected through the annulus into the protected oil zone. Before dual injection placement, injection profile and multirate analyses need to be completed (Jaripatke & Dalrymple 2010). During the dual injection process, packers, bridge plugs, sand plugs, chemical plugs, chemical packers, and other mechanical tools are normally used. Fluid to oil zone needs to be compatible with formation. Dual injection method can be applied to any of the flowing conditions: (Miller.J.M & Chan.K.S 1997)

a) Oil well without horizontal barriers with high vertically permeability or nearby oil zones are thin;
b) Openhole or gravel pack;
c) Communication behind the pipe

Dual injection method is not a common placement method compare to bullhead method and mechanical isolation. The success rate for this method is relatively low because of improperly sized treatment or inappropriate injection method (Miller & Chan, 1997).

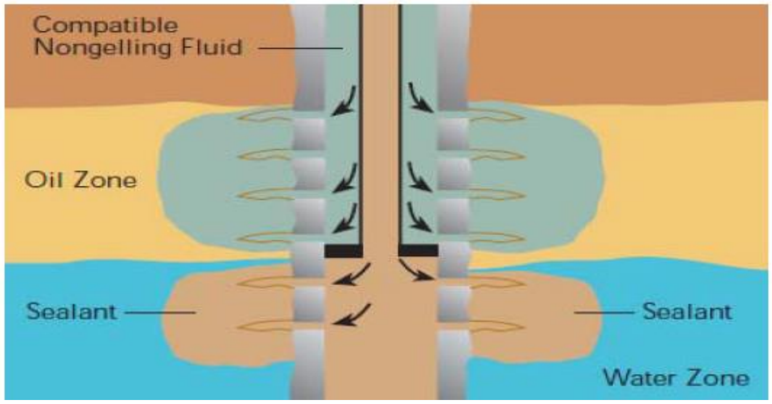


Figure 3.13. Dual-injection placement technique (Jaripatke & Dalrymple, 2010)

3.6.4 Isoflow Placement. Isoflow placement is an effective technique for crossflow wells. During the isoflow placement, the treatment has been injected into the desire zone while non-sealing fluid has been injected to protect oil zone. Non-sealing fluid contains a radioactive tracer in the annulus; a detection tool is set in tubing to help to control the annulus pump rates (Jaripatke & Dalrymple 2010). The detected tool can help to locate the interface between the annulus fluid and the sealant which is being pupped down the tubing, and the interface can be adjusted by changing the two fluid's pumping rates. Isoflow placement can get better treating result in open-hole completion when it's hard to achieve reliable zone separation (Cole & Mody, 1981)

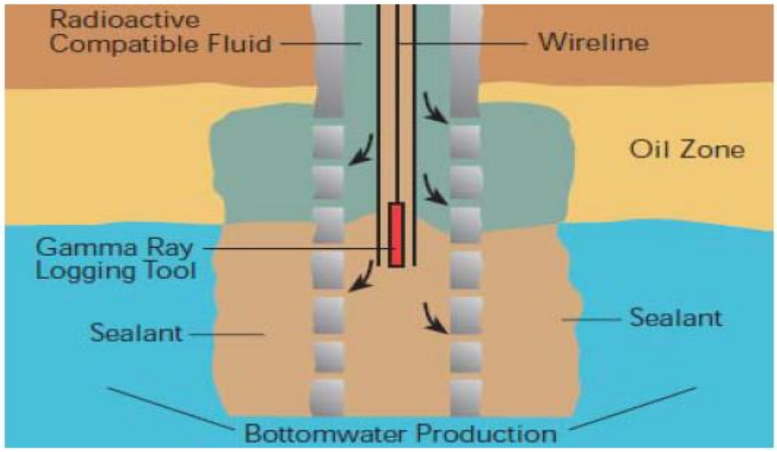


Figure 3.14. Isoflow injection placement technique (Jaripatke & Dalrymple, 2010)

3.6.5 Overview of Three Gelant Placement Methods. Table 3.3 (by Miller and Chan, 1997) lists the advantages and disadvantages among bullhead placement, mechanical isolation placement and dual-injection placement.

Table 3.3. Overview of gelant placement method (Miller & Chan, 1997)

Placement Technique	Advantage	Disadvantages
Bullhead	• Most economical method • Operational simple • Better result in Fractured formations	• Damage low pressure, low permeability zones • Hard control over fluid placement
Mechanical Isolation	• Can be used for low K_H/K_L when F_K is less than 0.01 • Can applied when K_H/K_L is larger than 100 for any F_K • Effective for non-communicating layers • Easy to control wellbore fluid	• Good casing and cement are in demand • Hard to apply in open holes • More completed workover procedure
Dual-injection	• Effective for open hole • Provide wellbore control of fluids for poor wellbore mechanical integrity or complex completions	• Hard to control treatment flow in deep formation zone and or fractures. • Difficult to operate • Only one HPZ at a time

4. DATA COLLECTION AND ANALYSIS

4.1 DATA PREPARATION

This study starts from collecting and cleaning gel treatment data. Thirty-three gel treatment application projects are from SPE publications and Petroleum Technology Transfer Council database. In some cases, the gel treatment was only a minor part of the overall IOR process, so those reports were not included in this study. The data preparation was broken down into three steps below: data collection, data cleaning and numerical analysis.

4.1.1 Data Collection. A dataset was created by collecting gel treatment field project data from the worldwide published report from year 1990 to 2012. This study indicates that the gel treatment has been used over a wide range of reservoir conditions. The review of the petroleum literature included 33 field projects which involving 160 wells. Those field projects are all applied in producing wells. 160 individual well treatments were examined; reservoir information, treating process and treatment result were collected and analyzed. This survey provides more credible EOR values since the gel treatment results were reported after projects were completed. A table is listed below to summarize the field name and location of these oil field projects included in this dataset. Oil field names and locations are included.

Table 4.1. Oil field projects included in dataset

Oil Field List
Alaska, Prudhoe Bay Field
California, Sockeye Field
Canada, Alberta Cummings Field
Canada, Pelican Lake Field

Table 4.1. Oil field projects included in dataset (cont.)

Canada, South Winter Field
Gulf Coast
Gulf Coast
India, Arabian offshore Field
India, Bombay High Field
Indonesia, North West Java Field
Kansas, Arbuckle Geneseo-Edwards Field
Kansas, Arbuckle Marcotte Field
Kansas, Arbuckle Northampton Field
Kansas, Arbuckle Trapp Field
Kansas, Arbuckle Bemis-Shutts Field
Kansas, Arbuckle Star Northwest Field
Kuwait, Wafra Ratawi Oolite Field
Mexico, Tamabra Field
Norweigian, Statfjord Field
Oman, Marmul field
Saudi Arabia, South Umm Gudair Field
Turkey, Raman Heavy oil field
United Kingdom, Heather Field
Venezuela, Motatan Field
Venezuela, North Monagas Field
Wyoming, Phosphoria Formation
Wyoming, Spring Creek Field
Wyoming, Teapot Dome Field

A map as shown in figure 4.1 was constructed to show the relative locations of the projects. The map demonstrates that gel treatment has been applied in a wide range of locations around the world. There are a total of 33 field projects, but the map only contains 28 field locations because another 5 field projects didn’t mention their locations. A large number of gel treatments have been applied in oil field in China, However, due to the limited data available in treatment processes and the insufficient reservoir information, many of the Chinese field cases were not included in this survey and were not displayed in the map.

Figure 4.1. Worldwide locations of gel treatment application

4.1.2 Data Cleaning. Data quality is essential in ensuring the quality of the analysis result. The most common problem for this field data set is the missing of data. Several field projects have incomplete parameter sets or missing information, including reservoir initial pressure, average porosity, fluid viscosity, formation thickness, oil API value and reservoir temperature. A lot of the processing detail information was not mentioned in the field report, and the treatment result data was incomplete in some treatment reports. These missing values were ignored during data analysis. And for some reservoir properties with more than 70% missing data, the numerical analysis will no longer be applicable. Table 4.3 was created for those properties with briefly explanations.

Because of the complication involved in the reservoir situation, many oil field publications didn't show specific values for the parameters. Instead, ranges of values are given in the reports. For reservoir properties such as porosity, permeability and oil ^{o}API, it is very common to have a range of values. Two main reasons may lead to those uncertain data report.

1. Because some oil reservoirs are composed of different types of formation rock. That is why some reservoir formation parameters are not a specific number. For example in Wyoming Spring Creek oil field, formation is made up of both sandstone layer and carbonate layer.

2. Formation matrix properties and fracture properties are differing significantly. That is the reason some parameters range come from.

When the values are given in a range, the upper limit of this range is chosen for our analysis. For example, “700” would be used for our data analysis when the given range is 10-700. For a value of a parameter given in the form of above or below, for example, >1000, this data is omitted from our analysis. Table 4.2 shows the data cleaning method just described.

Table 4.2. Data cleaning method

Paper No.	Oil Field Location	Original Data	Cleaned Data
56740	France	10~700	700
56740	France	>1000	Deleted

4.1.3 Numerical Analysis. After data cleaning, the numerical which includes Histogram, box plot and cross plot were applied to the cleaned dataset and used to summarize for each reservoir’s property.

Histogram

The frequency histogram shows the distribution of the parameters, and the reservoir property's range can be seen from histogram. Histogram is similar to bar chart and it shows the number of wells in each property value range. General data ranges for each reservoir properties have been observed from histograms.

Box plot

Box plot are used during numerical analysis for dataset. Minimum, maximum, median and average values for each parameter are straightforward. Also quartile of the ranked set of data tells the most popular parameter range for gel treatment.

Cross plot

Cross plots are used to describe a specialized chart that compares two related parameters from reservoir. Cross plots are mainly used for comparing treatment results. Parameters before and after gel treatment are plotted, so the treating effect can be directly analyzed by the cross plot.

Dataset is classified to three categories. The first category is reservoir properties, where basic reservoir properties or the properties affected by gel treatment have been included. The second category is the gel treating procedural data. Gel type, treating method, injection method and detail treating procedural data were recorded under this category. The last category is the result. Production data before gel treatment and after gel treatment are collected.

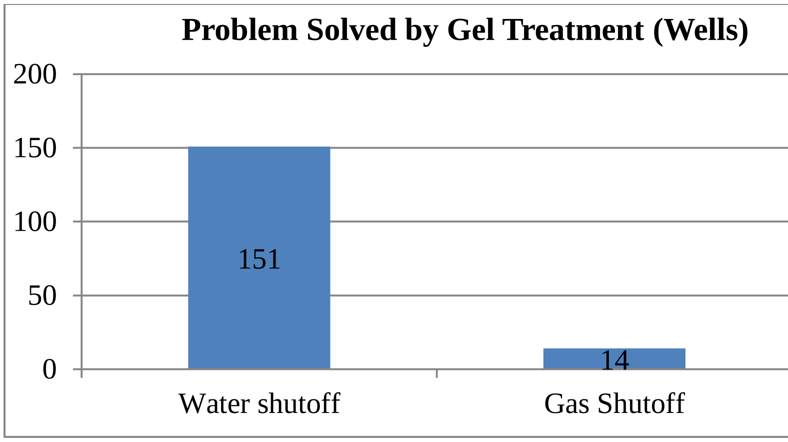
Table 4.3. Examined parameters for data analysis

Reservoir Properties	Basic information: Field name, locations, well type, fracture statues Reservoir rock properties: Initial pressure, porosity, permeability, reservoir temperature Reservoir fluid properties: Oil viscosity, formation thickness, oil ^{o}API, formation water salinity
Gel Treating Procedural Data	Gel selection: Water/gas problem, gel type, polymer molecular weight, water used for gelant preparation Treating Process: Shut in time, gelant injecting rate, treating fluid pH, injection method, gel injection volume and concentration, gel treatment process, pre-flush chemical type and volume, post flush chemical type and volume
Result	Before treatment Water cut, oil rate, water rate, gross rate After treatment: Water cut, oil rate, water rate, gross rate, successful rate, failure reason Economic concern: Payback time

4.2 RESERVOIR PROPERTIES

In reservoir properties, basic reservoir parameters are collected. Reservoir rock properties data and fluid properties data are gathered.

4.2.1 Problems Solved. Gel treatment can be applied as both water shutoff method and gas shutoff method. The bar chart below reveals that most treatment is applied for water shut off. Only a few cases are gas shutoff treatment for gas storage wells or some oil wells with gas cap.



Case	# of wells
Water Shutoff	151
Gas Shutoff	14
Total Project	165

Figure 4.2. Gel treatment solved distribution

4.2.2 Reservoir Rock Type. Figure 4.3 shows the percentage of recent gel applications in different formations in the last three decades. The pie chart shows that applications in carbonate reservoirs outnumber those in sandstone reservoirs. Lithology can have an important effect on the probability of success for gel treatment. Most vendors and operators believe that treatment success is the highest in carbonate reservoirs because of the high probability of fractures existence (Seright.R.S 1994). In carbonate reservoir, pressure is provided to drive oil from the formation flow to wellbore if water phase is linked with an aquifer in reservoir (Canbolat.S & Parlaktuna.M, 2012). That’s why excess water problem is common to carbonate reservoir.

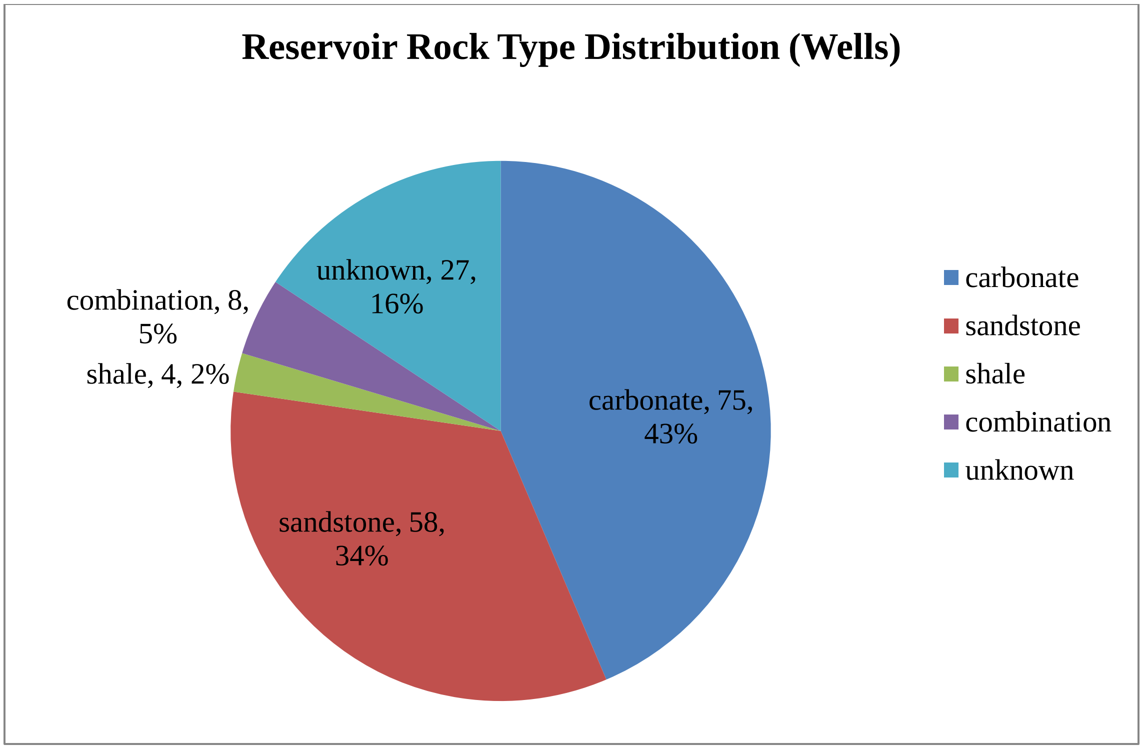
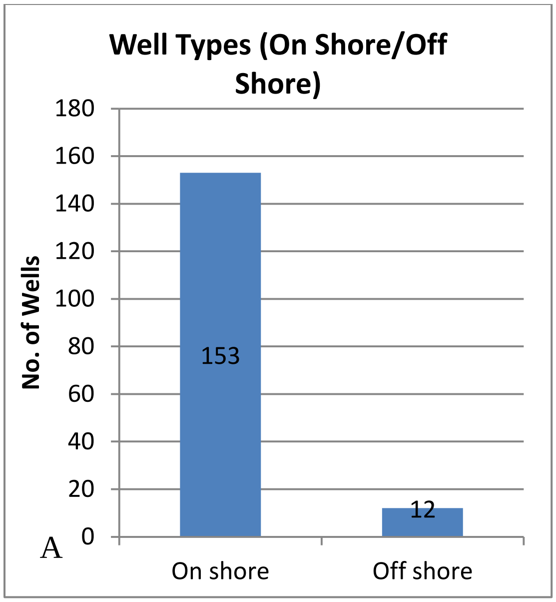
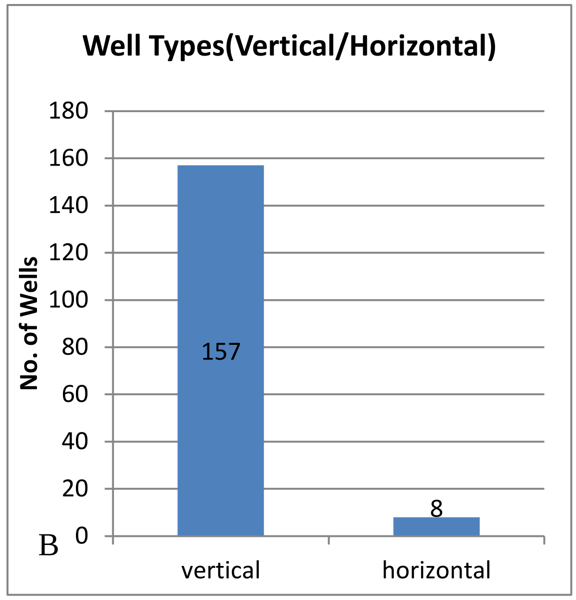


Figure 4.3. Reservoir rock type distributions

4.2.3 Oil or Gas Well Type. Gel treatments have been applied over a remarkably wide range of conditions. Gel treatment was applied to both on shore oil wells and off shore oil wells. For both vertical and horizontal oil wells, gel treatment application doesn't have the limitation for well types. Since gel treatment prefers to be used in aged oil wells, large numbers of mature on shore oil wells were treated by gel. Most gel treated oil wells are vertical wells, but successful horizontal oil well field cases indicated that gel treatment is an attractive way for horizontal wells recently.



A



B

Figure 4.4. Well types: (A) on shore/off shore and (B) vertical/horizontal

4.2.4 Reservoir Formation Fracture Status. In Figure 4.5, only 55 out of 165 wells that used gel treatment stated their formation rock fracture status, and they were all naturally fractured. The other 110 wells did not specify their formation rock fracture status.

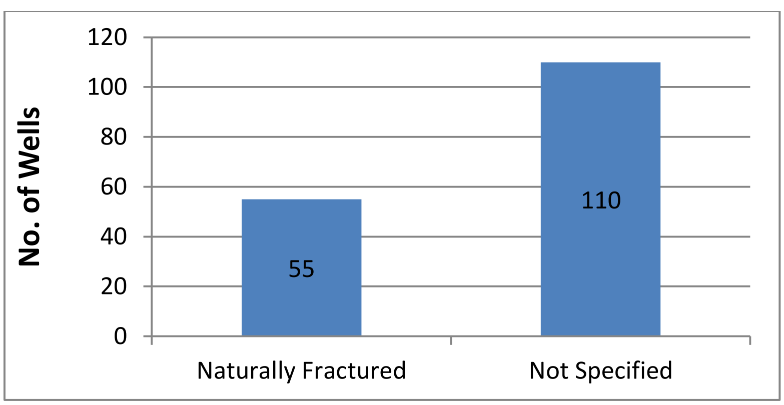


Figure 4.5. Formation rock fracture status

4.2.5 Reservoir Initial Pressure. Twenty five wells in 10 oil fields reported their reservoir initial pressure. Note that the initial pressure of different wells in one oil field is the same. The highest initial pressure in our dataset is 7642 psi of Pirital field in North Monagas area of Venezuela. The second highest initial pressure is 7500 psi of Carito field in the same area. According to the North Monagas area field report, only 1 out of 8 gel treatment applications failed. In spite of those harsh reservoir conditions, gel treatment achieved a success rate of 88% in that area. Moreover, the application in gas shutoff in Carito field had been successful for as long as three years. From Figure 4.6, one can see that gel treatment was used in a wide range of initial pressures roughly from 1000 to 8000 psi. This suggests that the initial pressure doesn't have a direct impact on gel treatment application.

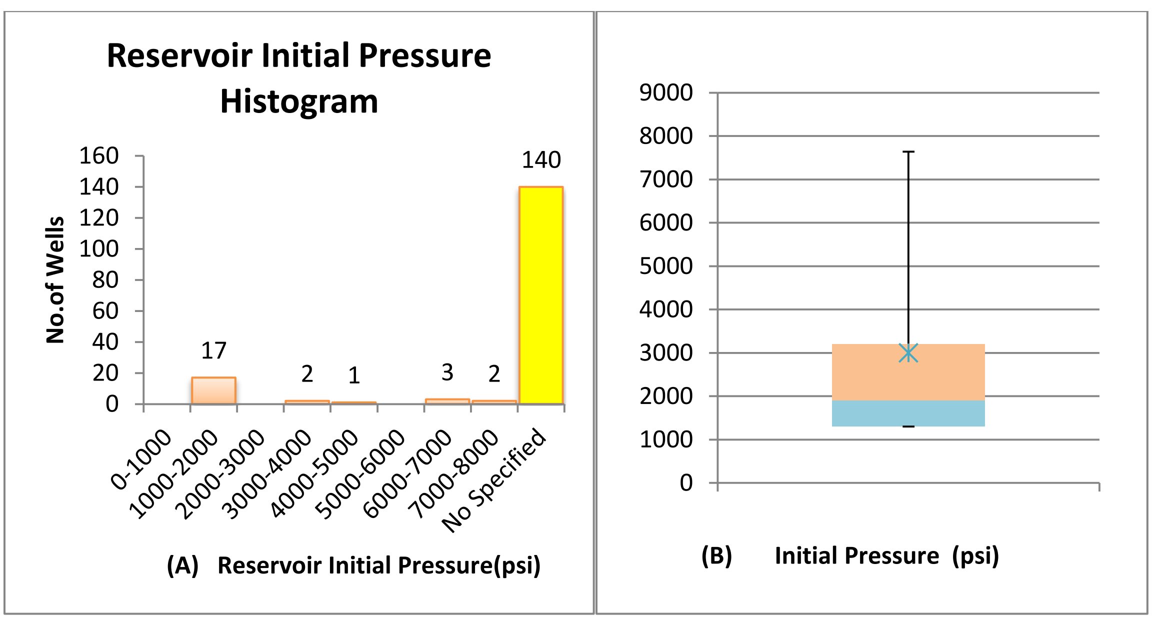


Figure 4.6. Reservoir initial pressure distributions (A) histogram and (B) box plot

4.2.6 Reservoir Average Porosity. The porosity of the oil wells varies with different formation rock types. There are also differences between matrix porosity and fracture porosity. For simplicity purposes, we used the average porosity of each oil well in our analysis. A histogram and a box plot were generated to present the distribution of the average porosity. Although only 90 wells provided their reservoir porosity information, it can be easily observed that the average porosity distribution of those 90 wells is a bell curve with most of the porosity values between 15 and 30%, as shown in Figure 4.7A. The box plot in Figure 4.7B shows the minimum of 10%, the maximum of 40%, and the average of 21.6% and the median of 20%.

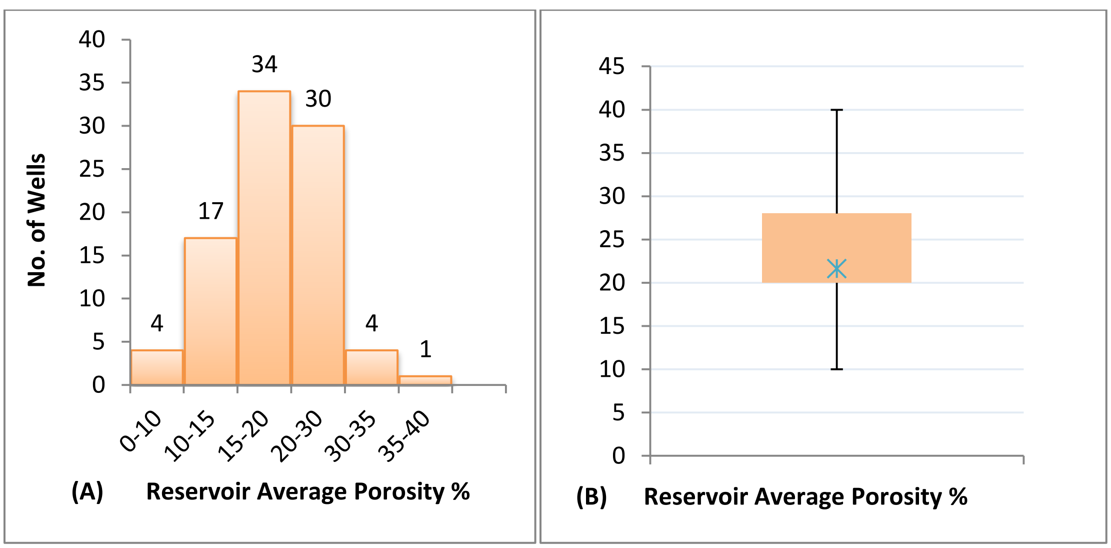


Figure 4.7. Reservoir average porosity distributions (A) histogram and (B) box plot

4.2.7 Reservoir Permeability. Out of the 165 oil wells studied, 102 wells reported their reservoir permeability values. The permeability of those 102 wells is in a normal distribution, as displayed in Figure 4.8a, and ranges from 4 md to 20,000 md, as shown in Figure 4.8b. The middle 50% of the wells have the permeability values fall between 65 and 3,000 md. The maximum permeability of 20,000 comes from the extreme case at North West Java field in Indonesia. That particular field is an offshore field with naturally fractured and vuggy limestone reservoir formation rock, which contributes to its high permeability. Yet, the gel treatment application was shown successful in this field.

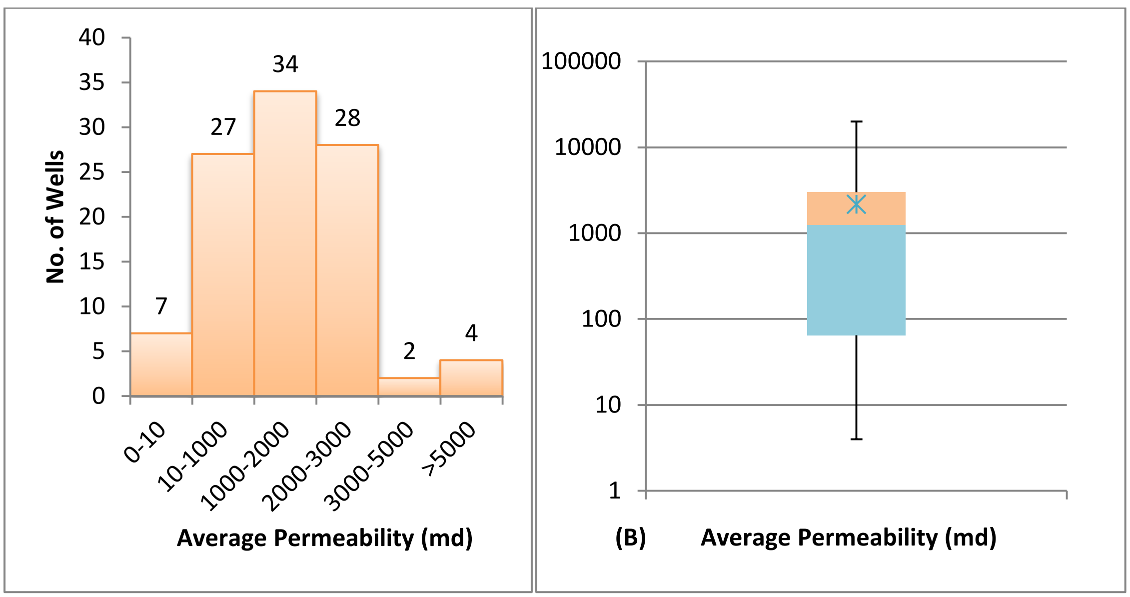


Figure 4.8. Reservoir average permeability distributions (A) histogram and (B) box plot

4.2.8 Oil Viscosity. Twenty-six wells reported the oil viscosity data. From Figure 4.9a, it can be seen that half of those wells have oil viscosity between 10 and 25 cp. Overall, gel treatments were applied successfully in the oil whose viscosity ranges from 1.5 cp and 30 cp, as shown in Figure 4.9b. Note that the viscosity data is only from a small number of wells and may not be a good representation of the entire study.

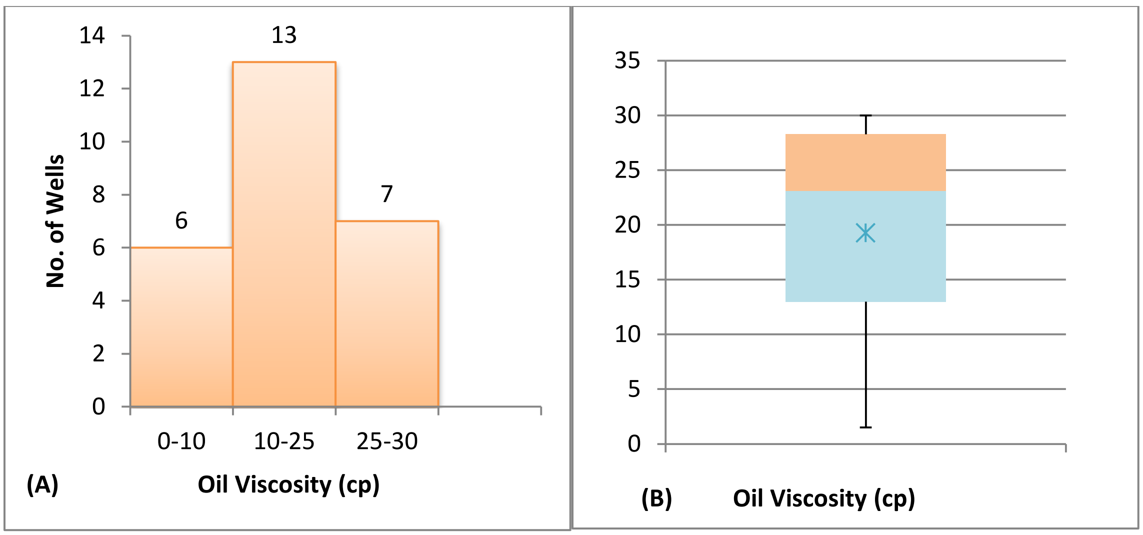


Figure 4.9. Oil viscosity distributions (A) histogram and (B) box plot

4.2.9 Oil API Gravity Distribution. Ninety-two wells revealed their oil API gravity, most of which are between 20 and 35 ^{o}API, as shown in Figure 4.10a. The minimum and maximum API gravity of this dataset can be observed in Figure 4.10b. The minimum oil API gravity of 18 ^{o}API was recorded from Raman heavy oil field in south east Turkey, and the maximum oil API gravity of 40 ^{o}API was recorded from North Monagas oil field in Venezuela. Although gel treatment had shown success in such a wide range of oil API gravity, most of the application was used in medium oil fields.

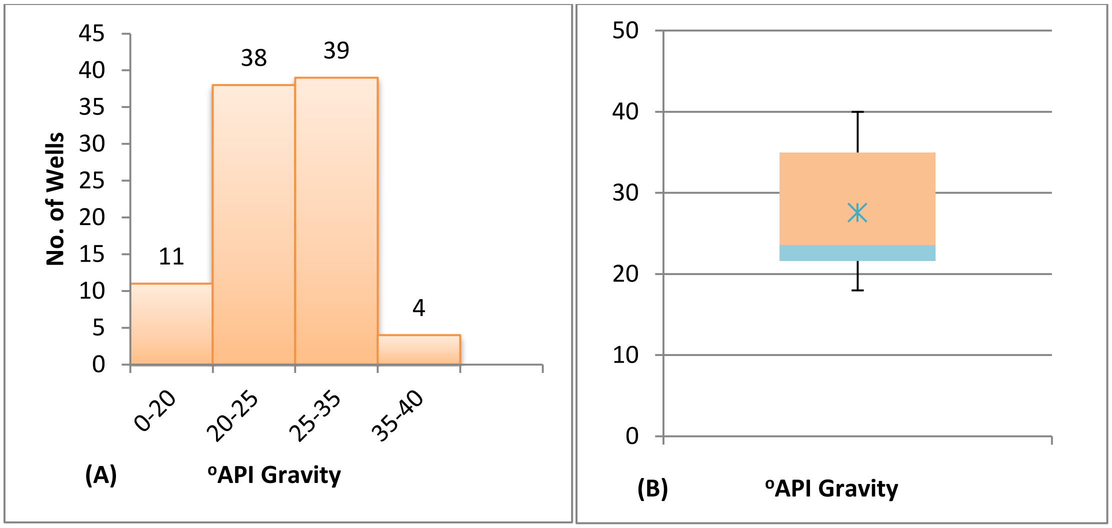


Figure 4.10. Oil API gravity distributions (A) histogram and (B) box plot

4.2.10 Formation Thickness. Fifty-six wells from 10 oil fields provided the formation thickness data. Figure 4.11a and b offer a better visualization of the formation thickness information of those wells. The minimum thickness from this dataset is 46 ft, while the maximum is 920 ft. The median is 300 ft and the average is 273 ft. The middle 50% of the formation thickness is between 100 and 300 ft.

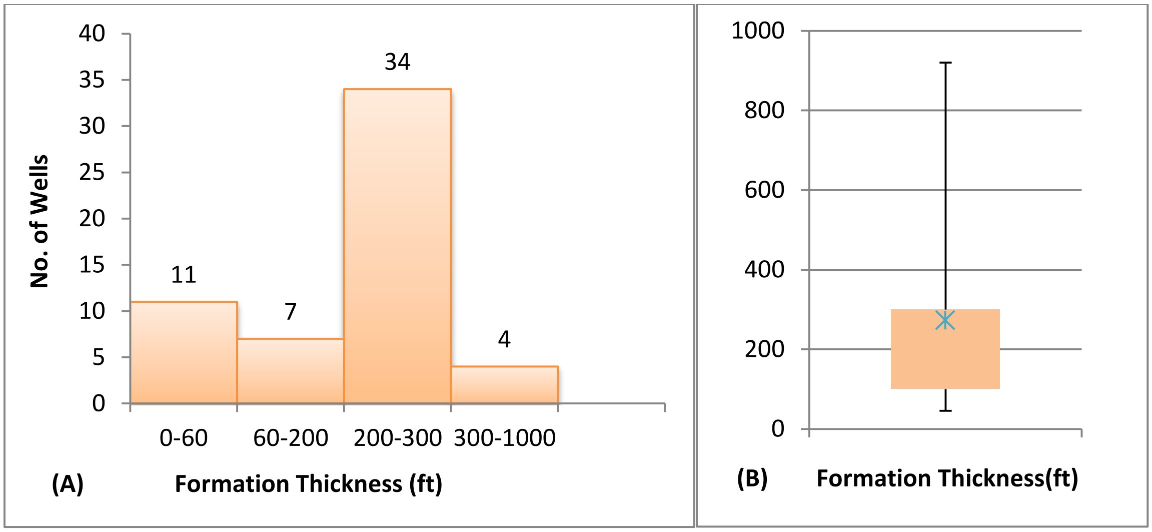


Figure 4.11. Formation thickness distributions (A) histogram and (B) box plot

4.2.11 Formation Water Salinity. Eight fields with a total of 22 wells reported the water salinity information. As shown in Figure 4.12a and b, the salinity distribution is centered on the median of 19,000 ppm. The range of salinity is huge—from 972 to 260,000 ppm, with an average of 36,142 ppm. Note that, out of the 22 wells, 10 of them are in the same oil field. Extra caution must be used when interpreting the data because the localized data sources may not represent the entire field of study.

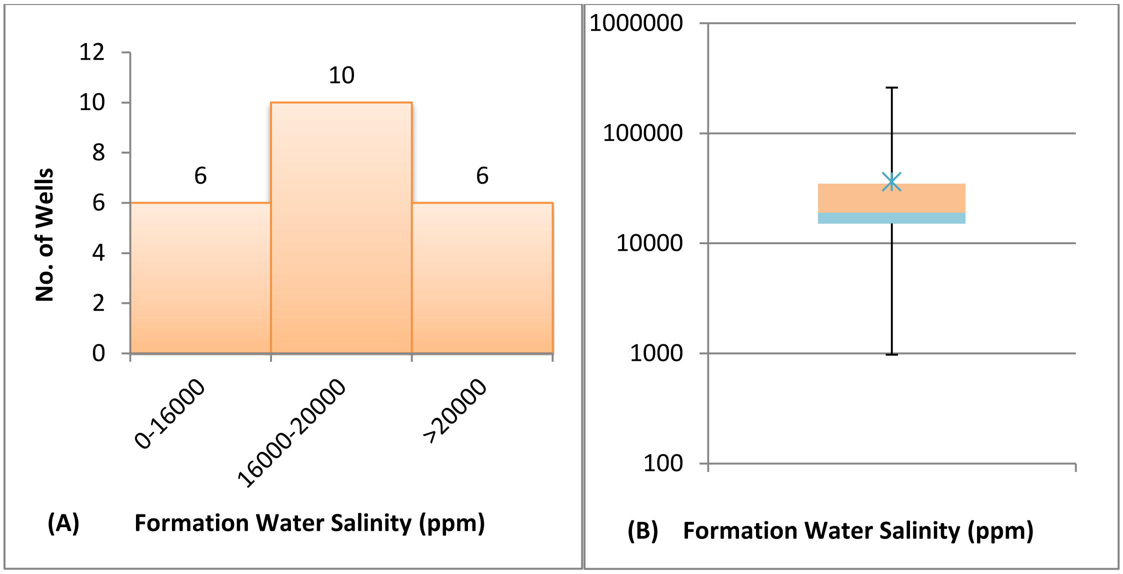


Figure 4.12. Formation water salinity distributions (A) histogram and (B) box plot

4.2.12 Reservoir Temperature. The reservoir temperature data was obtained from 96 wells. Figure 4.13a and b show the distribution of the reservoir temperatures. The minimum is 86 ^{o}F and the maximum is 300 ^{o}F. The latter extreme case was recorded in North Monagas field in Venezuela where all the reservoirs are at 280 ^{o}F and above. In that particular case, a special aqueous polymer gel with low viscosity was applied. This polymer gel was designed for high temperatures and can maintain its blocking properties over 290 ^{o}F without cool down pads injection.

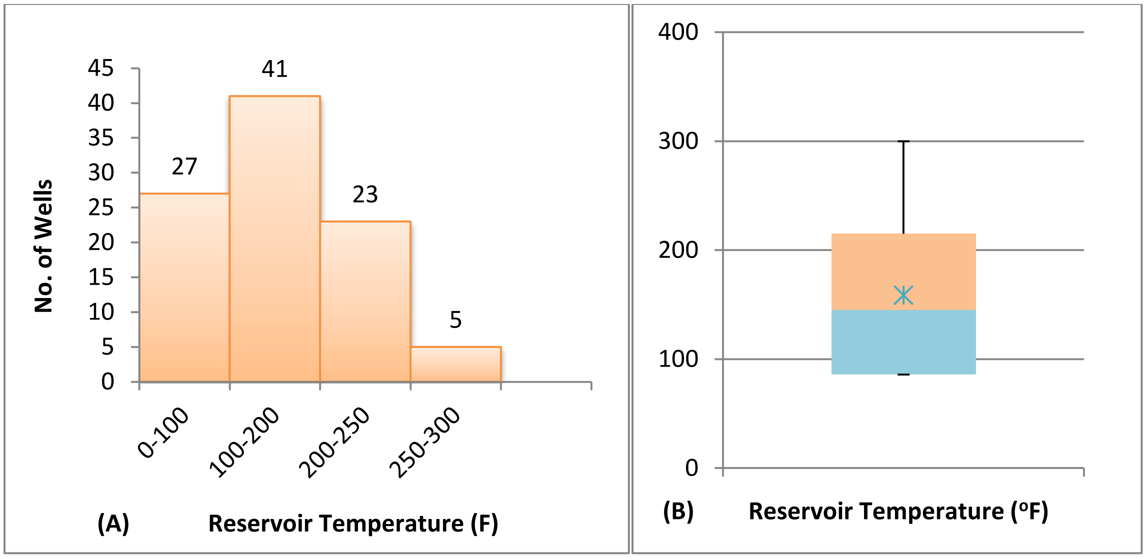


Figure 4.13. Reservoir temperature distributions (A) histogram and (B) box plot

4.3 GEL TREATMENT PROCESS

In this subsection, the gel treatment process is broken down into 10 small topics, each of which can be sorted into one of the three categories: when to use, what to use and how to use. The excessive water problem section explains when to use gel treatment. The subsequent sections discuss which method to use by explaining the following: gel type, polymer molecular weight, gelant preparation, and treatment fluid pH values. The how-to-use section describes the gel treatment procedure details which include: shut-in time, pre-flush method, injection method, injection rate, polymer injection concentration, polymer injection volume, injected polymer dry weight and post flush.

4.3.1 Excessive Water Problem. Before attempting water shutoff treatment, identification of the excessive water producing problem should be performed (Seright, 2001). Properly diagnosing water producing problems is a significant step for water shutoff treatment and will greatly increase success rate. But because of time constraints or economic limitations, inadequate diagnoses occur before water shutoff treatment, especially on marginal wells with high water cut (Seright, 2001). In addition, inadequate cement bonding near the wellbore will result water channeling following formation (Samari, 1998). From the data summary, most oil wells with poor primary cement have a water channeling problem. Classified conformance problem distributions with gel treatment are shown in figure 4.14. As shown in Figure 4.14, a large part of gel-treated oil wells suffered from fracture channeling with strong water drive. In the oil field, conformance problems are complex; most cases suffer from more than one type of conformance problem, but cases were classified by the primary conformance problem.

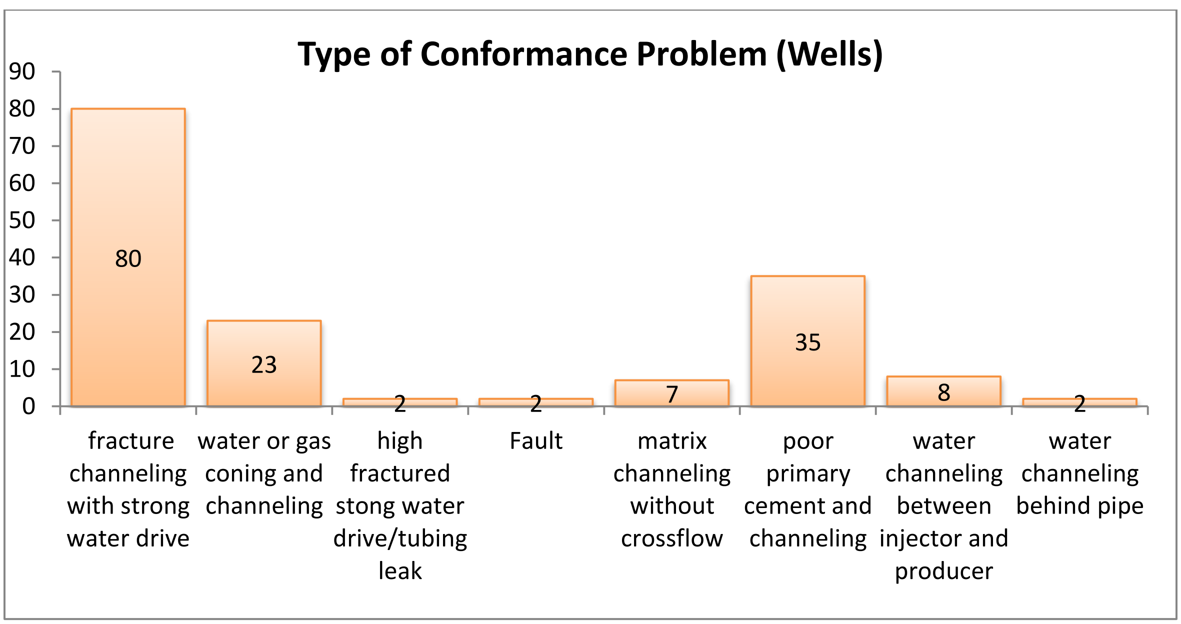


Figure 4.14. Gel treated conformance problems distributions

4.3.2 Gel Type. Table 4.15 shows gel type distribution. Inorganic crosslinked polymer gels are applied most commonly in the oil field. Beside inorganic crosslinked polymer gels, organic crosslinked polymer gels are also been widely used for water or gas shut-off. Some oil wells added components such as a CaCO3 diverter, retarder and reducing agents with gel treatment to improve the water reduction efficiency. Some oil wells pumped cement at the last step to enhance gel strengths near the wellbore, which lead to longer shutoff effectiveness. The well in Wafra Ratawi Oolite field is one of the 36 that used organic crosslinked polymer, but it actually involved two gel systems. One of the polymer gels applied temporary isolate the oil producing zone and another is to permanently damage the water producing zones.

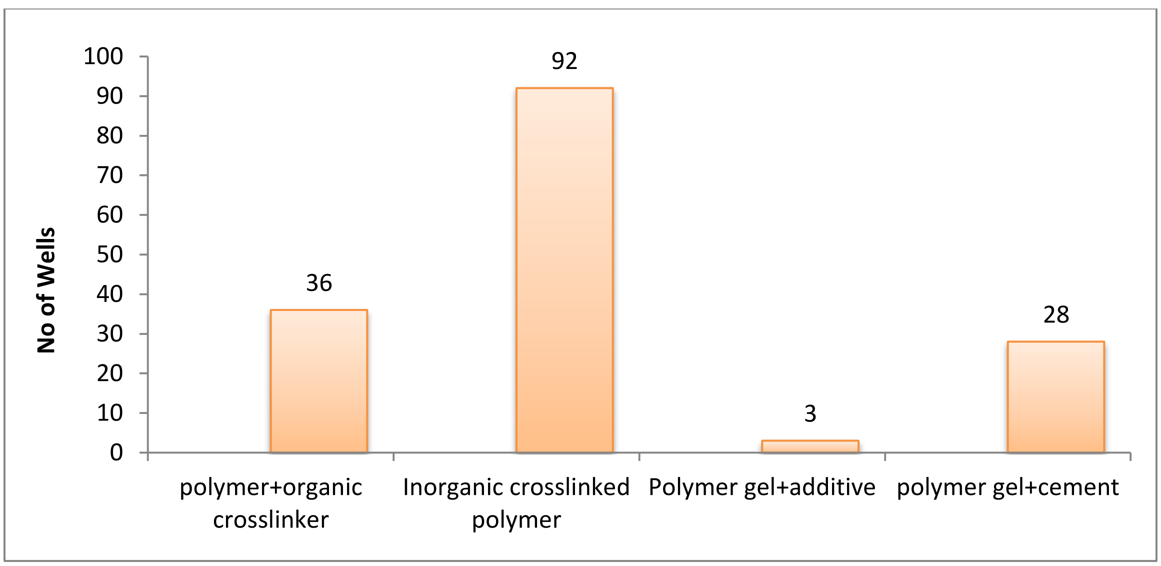


Figure 4.15. Gel types distributions

4.3.3 Gelant Preparation. Oil field operators don't give too much attention to gelant preparation, using seawater to prepare gelant solutions is the simplest and most common way, but some oil wells used deoxygenated seawater to prevent bacteria deposits. Table 4.4 summarizes the gelant preparations.

Table 4.4. Gelant preparation

Gelant Preparation	
Seawater	39
Deoxygenated Seawater	1
Freshwater	25
Not Specified	95

4.3.4 Treatment Fluid pH Values. Not many oil well reports mentioned treatment fluid pH values: only four fields recorded pH values for treatment fluid, and pH value have been listed in table 4.5. The treatment pH value is an important parameter; the proper pH controls gelation rate to ensure proper injection and that the system propagates into the reservoir. If the pH is too low, the gelation may not occur and gel treatments will lose effectiveness. If the pH is too high, gelation time will be too short and lead to an insufficient injection volume for required reduction on the water productivity (Faber & Joosten 1998).

Table 4.5. Treatment fluid pH values

Treatment Fluid pH Values			
SPE No.	Project	treatment fluid pH	problem wells
65527	Gel Water Shutoff in Fractured Horizontal Wells	6	1
39633	Water shut-off field in the Marmul field(Oman)	8	14
72118	Gas Shut off in Offshore India	10.5	2

Table 4.5. Treatment fluid pH values (cont.)

129848	Water Shut-off in A High Temperature Horizontal Gas Well	11.4	1
Not Specified			142

4.3.5 Placement Method. In Figure 4.16, the Injection method distribution indicates bullhead placement is the most attractive placement method; the dual injection placement method is rarely applied. This is likely due to the lower cost associated with the bullhead placement method. Different placement methods have an impact on treatment results, mechanical packer and dual injection placement methods achieved reliable results, placing the treatment in the desired area more accurately than bullhead placement. A special case from the Wafra Ratawi Field in Kuwait indicated a bullhead placement usage limitation in horizontal wells. Bullhead injection in this horizontal open-hole well could not be applied because damage could be done to potential future post-job producing formations at the horizontal heel side section, but bullhead placement still achieved successful results in other horizontal wells.

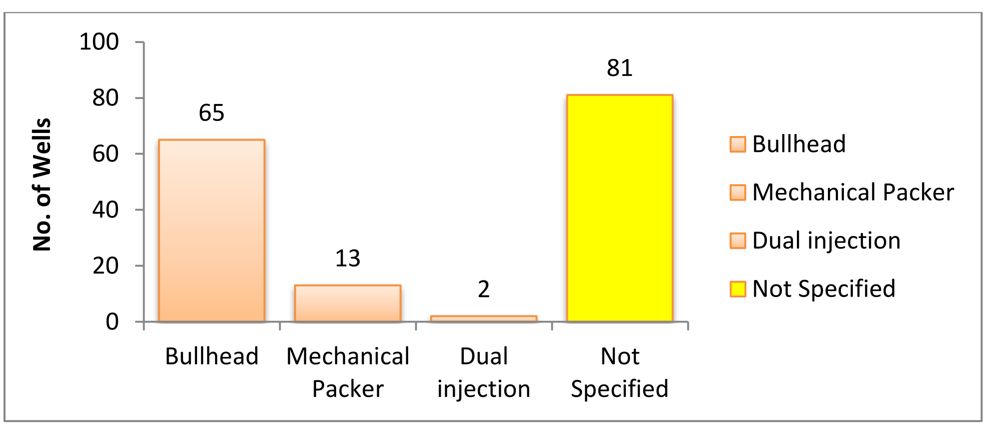


Figure 4.16. Injection methods distributions

4.3.6 Pre-Flush Treatment. Acid pre-flush treatment is injected into oil wells before gel treatment to clean the near wellbore area and establish injectivity. Figure 4.7 shows the pre-flush method distributions. Seven fields applied acid pre-flush treatment before gel injection. Some oil wells used seawater as pre-flush treatment to measure the injectivity during the injection test, and to lower the formation temperature. Besides acid and seawater, some oil wells will use low-concentration polymer injection to treat oil well before gel treatment.

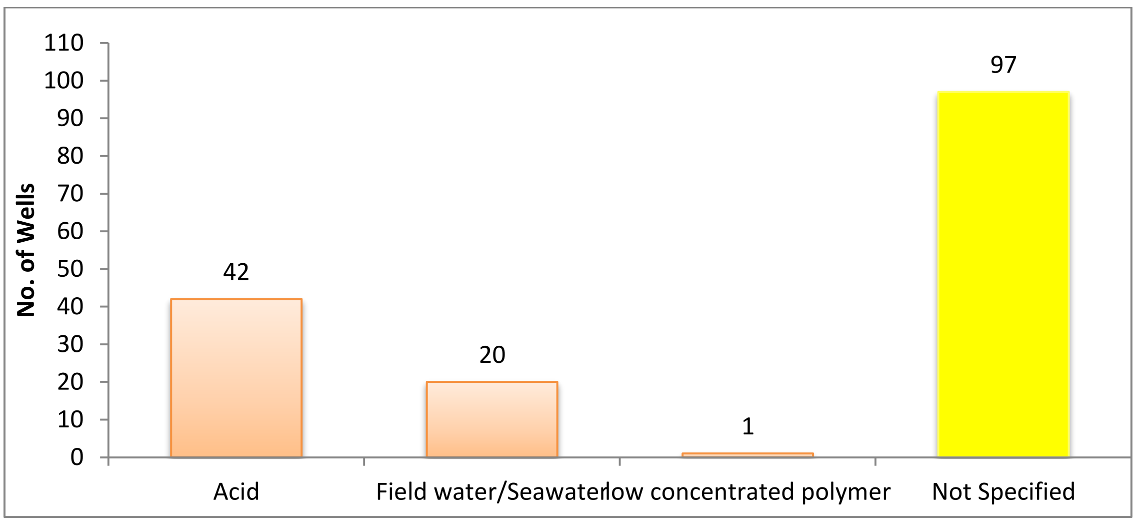


Figure 4.17. Pre-flush method distribution

4.3.7 Gel Treatment Process. For the polymer gel treatment process, the lowest concentration gel flows furthest from the wellbore to resist lower differential pressure at the beginning. In the final stage, high-concentration gel is injected to provide the strength to resist the pressure drop near the wellbore. From data analysis, most oil wells injected polymer in more than three steps with increasing concentration. Some oil wells used additives with polymer gel such as a reducing agent, retarder or silica flour. Other than that, some oil wells injected cement after gel injection to enhance the treatment effect. Table 4.6 summarize gel treatment process.

Gel+cement

Small-particle-size cement is applied after gel treatment as a combination method. These reduced-particle-size cements are different from standard cement which can penetrate to deeper section near the wellbore. In a high-permeability field, this new type of cement can even flow into matrix rock (Samari.E 1998). The cement formed a high-compressive-strength material near the wellbore for the last steps of treatment with the greatest differential pressure drop near wellbore.

Gel+Additive

Reducing agent was pumped together with gel treatment to reduce the valence of the dichromate from the pre-flush treatment (Olsen.H.E 1986). Good water shut-off results showed that the water cut decreased from 99% to 69%.

Diverter $CaCO_3$ was pumped right after gel treatment to cause precipitation to occur between the gel and $CaCl_2$ (Boreng.R 1997)' but the effect in this case is not obviously. In this case, the gel treatment got a good result with water cut reduced from 84% before to 68% after.

One of the special cases is gel treatment with retarder and silica flour applied in a high temperature horizontal gas well (Al-Muntasheri.G.A 2010). Retarder is applied with gel treatment to prevent precipitation between gelant and pre-flush fluid. In this case, silica flour is used to give extra mechanical strength to the last high-concentration gel injection stage near wellbore for isolation purposes. Silica flour was mixed with gelant before injection. In this case, water shut-off treatment got a good result with 42% water cut reduction and gas rate increase from 2.2 MMSCFD to 17 MMSCFD.

Table 4.6. Gel treatment procedure

Gel Treatment Process	field	wells
1 stage polymer gel	1	10
2 stages polymer gel	5	6
3 stages polymer gel	3	25
4 stages polymer gel	4	31
5 stages polymer gel	3	15
Polymer gel+reducing agent	1	1
Polymer gel+cement	5	17
Polymer gel +retarder+silica flour	1	1
polymer gel stage not specified	9	49

4.3.8 Post Flush. In hydraulic fracture, gel treatment could be used to shut off water channels in fractures. Fracture conductivity should not be reduced too much, since conductive paths are still needed for oil to flow into the wellbore. But gelant gravity segregation will lead to slight damage to fractures with extra water production originating from the water source. Oil or water post-flush can be used to displace gel treatment from the fracture to avoid damage to the fracture (Seright 2001).

Water

Water can be used as last stage of the treatment; some oil wells inject water after gel treatment to push gel past perforations and flow into the fractures. Water post-treatment can protect perforation and oil productivity after gel treatment (Turner.B & Zahner.B 2009). The volume of water for post flush depends on well depth.

Acid

Acid treatments as post-flush help improve productivity. Just gel treatment can reduce fluid productivity but cannot increase oil rate. Acid treatment generally failed to recover significant volumes of incremental oil when applied alone for an oil well which had produced for a long period of time (Turner.B &Zahner.B 2009). After acid post-treatment, acid penetrates new tighter fractures and rock to increase oil production. So gel treatment with acid is a combination method which is greater than either method alone. This combination method can even be applied to enhance a high cumulative production well, enabling incremental oil production for a long time (Turner.B & Zahner.B 2009). Table 4.7 below summarizes post-flush treatment applied in oil wells. Crude oil is a popular post-flush for both single usage and combination treatment.

Table 4.7. Post flush treatment

Post-Flush Treatment (Wells)		
Single treatment	Crude Oil	14
	Water/Seawater	16
	Low Concentrated Polymer	1
	15%HCl	3
	HCl +HF	4
	Not Specified	89
combination treatment	uncrosslinked polymer+crude oil	4
	Water+crude oil	29

4.3.9 Shut-in Time. Oil wells need to be shut off for couple days after polymer gel injection to allow the polymer gel to mature and set up. Figure 4.18 shows the shut-off time distribution from 2 to 16 days. The average is 7.8 days and median is7 days. Eighty three well publications reported shut time. Because of economic concerns, shut-off time for oil wells is normally less than 10 days, and those oil wells shut in for more than 10 days are all recorded from Kansas Arbuckle. Oil wells are shut off for more than 10 days in Kansas Arbuckle oil field to give the gels abundant time to reach their full maturity and maximum strength.

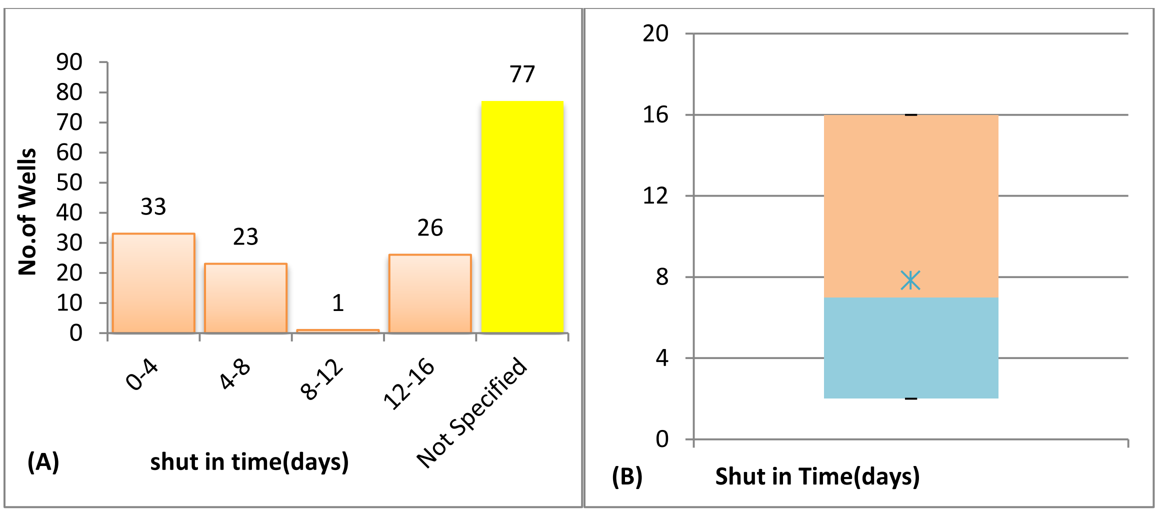


Figure 4.18. Shut-in time distributions (A) histogram, (B) box plot

4.3.10 Injection Rate. Sixty seven oil wells recorded injection rate. Figure 4.19 indicate that minimum and maximum values are 0.5 bpm and 4 bpm. The average gel injection rate is 1.26 bpm; the gel injection rate in producing well should be close to the normal production rate. Some reservoirs have a rapid pressure increase during the injection process when the injection rate is too high, that may lead to exceeding the ability of the fracture to conduct gel. A high injection rate will increase the risk of forcing gel into undesirable zones.

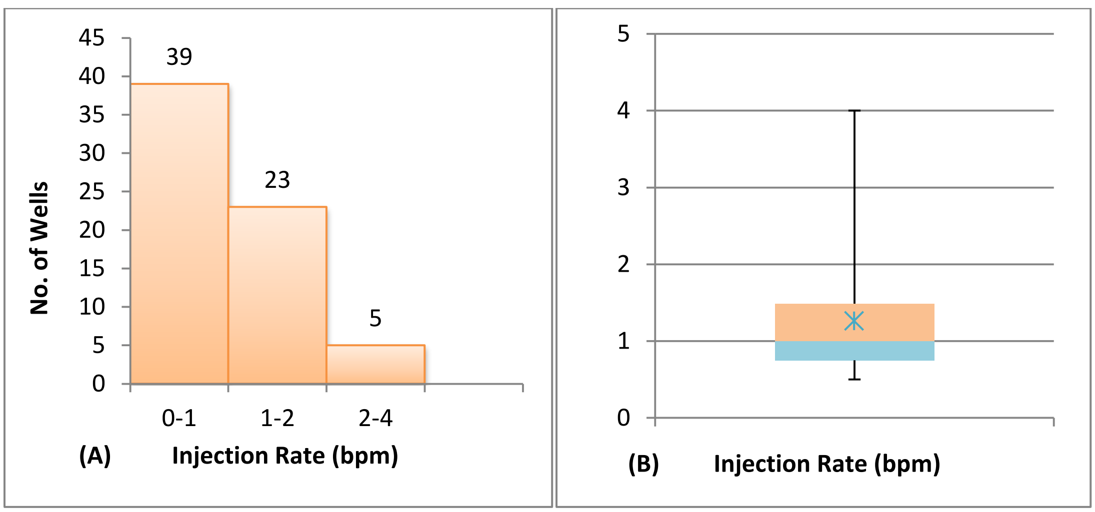


Figure 4.19. Polymer injection rate distributions (A) histogram, (B) box plot

4.3.11 Polymer Injection Calculations. Polymer is injected by steps with increasing concentration. The low-concentration polymer is injected first, and the highest concentration polymer is injected last. An average concentration has been calculated based on each step's injection volume and polymer concentration. The equation is shown below:

$$Average\ Concentration = \frac{\sum(each\ step\ polymer\ concentration \times each\ step\ polymer\ injection\ volume)}{Total\ Polymer\ injection\ Volume}$$

Figure 4.20 shows the average polymer concentration distribution based on the calculation results. Fifty eight oil wells' polymer injection average concentrations have been calculated. Figure 4.21 (a) shows a normal distribution for average concentration. Figure 4.20 (b) shows that minimum and maximum values are 2000 ppm and 7854 ppm, respectively. The mean value is 4956 ppm, and the median value is 4720 ppm. Most wells injected polymer with concentration between 4429 and 5454 ppm.

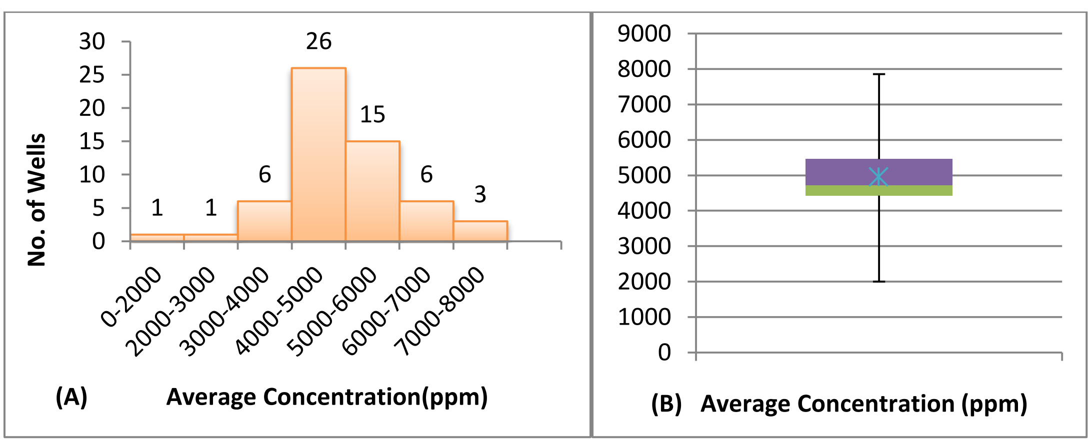


Figure 4.20. Polymer injection concentration distributions (A) histogram, (B) box plot

Figure 4.21 displays the total polymer injection volume distribution from 45 oil wells. Minimum and maximum values are 24 bbls and 12493 bbls, respectively. The average is 2547 bbls, and the median is 1515 bbls. The polymer injection volume distribution covers a broad range of values. The polymer injection volume should be tailored to the capacity of the wells and gel penetration distance. Both excess and insufficient injection volume would affect the treatment result. Well history data would be a good reference for polymer injection volume.

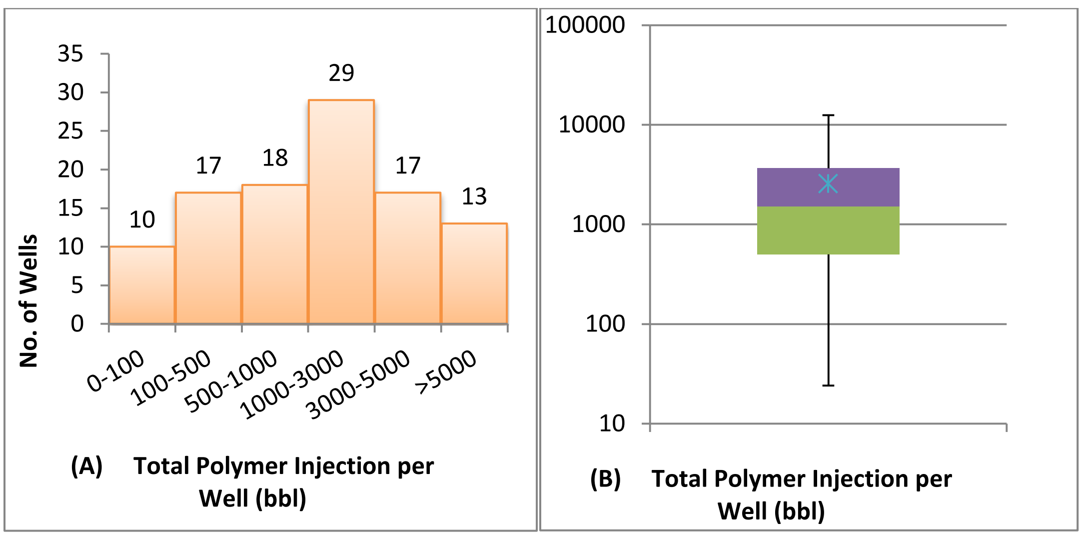


Figure 4.21. Polymer injection volume distributions (A) histogram, (B) box plot

The polymer injection dry weight was calculated from the injection volume and the polymer concentration. The basic equation used to calculate polymer weight is below:

$$Dry\ Polymer\ Weight = Polymer\ Volume \times Polymer\ concentration$$

The polymer volume here is not the total volume, but the injected volume for each step. The polymer concentration here is not the average concentration, but the polymer concentration for each step. Figure 4.22 (a) and (b) are based on 58 wells. A histogram has been generated to show a normal distribution. And a box plot shows minimum and maximum values are 350 pounds and 21854pounds, respectively. The average is 6644 pounds, and the median is 5325 pounds.

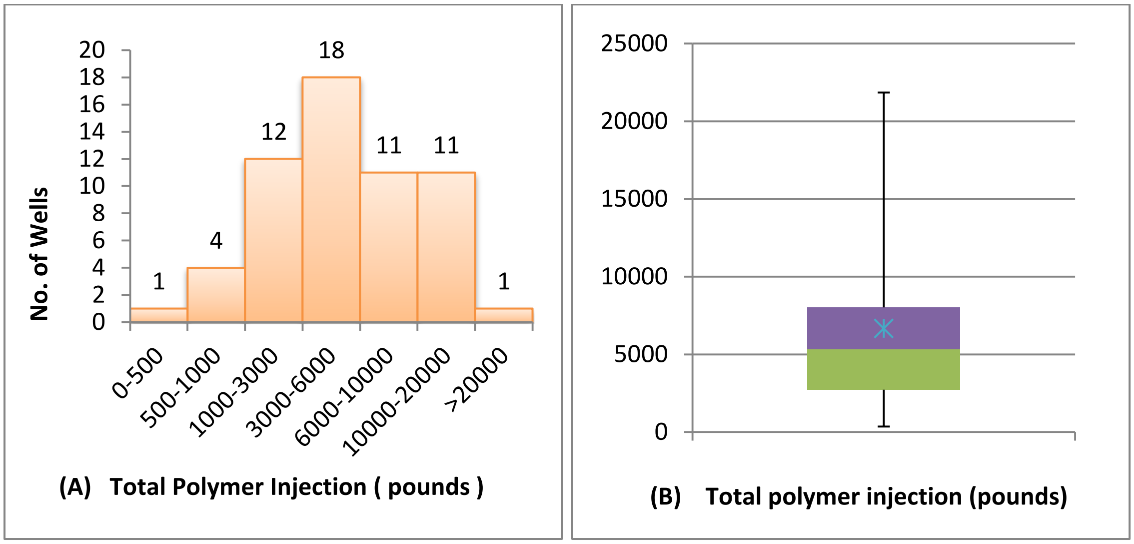


Figure 4.22. Polymer injection weight distributions (A) histogram, (B) box plot

4.4 Gel TREATMENT RESULT ANALYSIS AND DISCUSSION

The effectiveness of the gel treatment is the most conveniently evaluated by comparing the water cut before and after treatment. Such a comparison can be done simply by constructing a cross plot of water cut after gel treatment vs. water cut before gel treatment, as shown in Figure 4.23. This cross plot features a diagonal line across the graph from the bottom left to the upper right corners. The diagonal line represents the equivalent water cut before and after treatment because any point on this line corresponds to the same water cut on the x-axis and the y-axis. The data points reside above the diagonal line indicate the increase in water cut after treatment. Conversely, the data points reside below the diagonal line indicate a decrease in water cut after treatment, which means the success in the gel treatment applications. Water cut cross plot requires the water cut values both before and after treatment. Figure 4.23 includes only the cases with such a complete set of information. It can be seen that most of the data point are below the diagonal line indicating that the gel treatment was mostly successful among all the cases in our dataset.

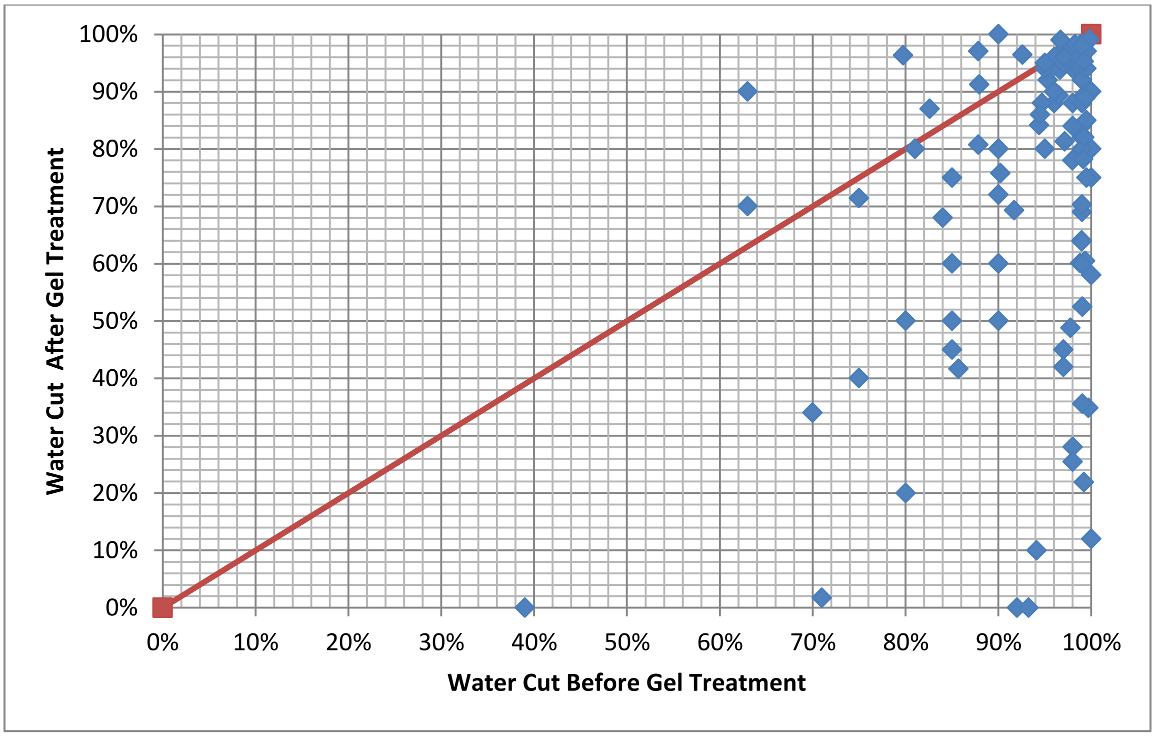


Figure 4.23. Overall water cut cross plot

The data points in Figure 4.23 above are associated with different conformance problems, such as fracture channeling with strong water drive, water coning, etc. When comparing the gel treatment effectiveness in these different situations, it is convenient to color the data points separately as shown in Figure 4.24. Here, it is clearly seen that all the fracture channeling with strong water drive cases had a decrease in water cut after the gel treatment. In contrast, oil wells with water coning problem didn't lead to totally successful outcome with gel treatments. Also for oil wells with poor primary cementing, most of the cases either maintained or increased the water cut after gel treatment. According to the water cut change observation, gel treatment applications facilitated higher successful rate for those wells with fracture channeling with strong water drive, tubing leak, fault, matrix channeling without crossflow, water channeling between injector and water channeling behind pipe. Note that the projects without specified conformance problems were not included in Figure 4.24.

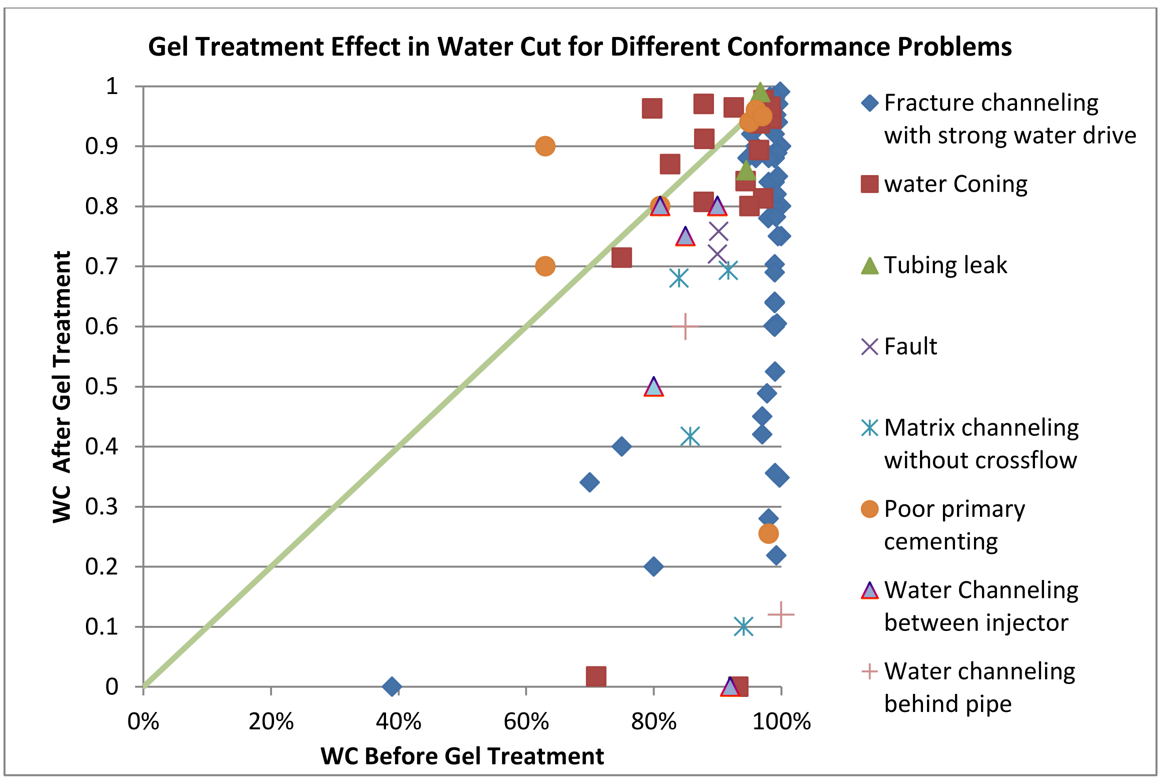


Figure 4.24. Water cut cross plot for different conformance problems

Using the same method, the water cut data points can also be colored differently to represent different placement methods used. Figure 4.25 shows that the majority of the placement methods reported was bullhead injection whose successful rate was as high as 89% with only 6 wells have increased water cut. The mechanical packer and the dual injection methods also show relatively high successful rates with the gel treatment. One of the dual injection cases even brought the water cut from 93% down to 0%. In this water cut cross plot, the projects without specified placement methods are not included.

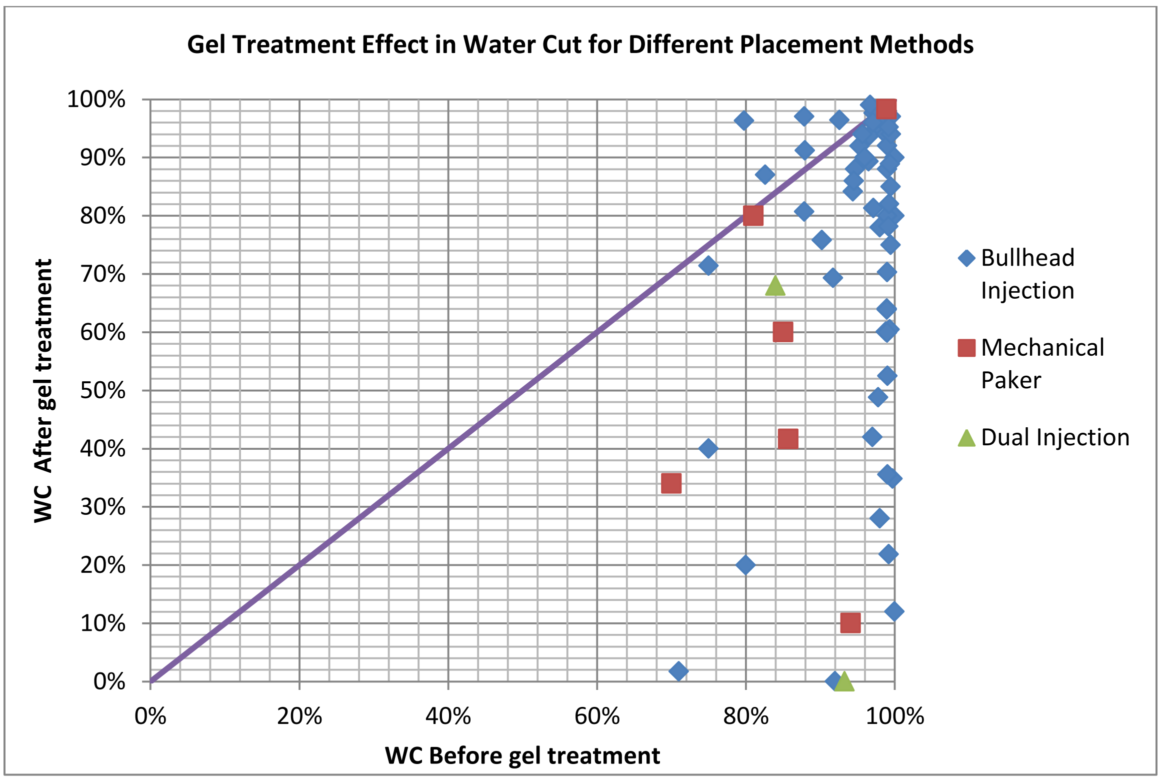


Figure 4.25. Cut cross plot for different placement methods

The types of gel can also affect the success rate of the treatment. Figure 4.26 shows the treatment results of different gel types. The inorganic crosslinked polymer gel resulted in the highest number of successful cases whereas the organic crosslinked polymer gel showed slightly less successful rate. The reason for the increased water cut in the organic crosslinked gel treatment cases could be attributed to wrong polymer sizing estimation or the damage of formation productivity due to initial mechanical failure of the pumping equipment (Zaitoun.A 1999). In addition, the polymer gel with cement and the polymer gel with additives both showed a significant decrease in water cut after treatment.

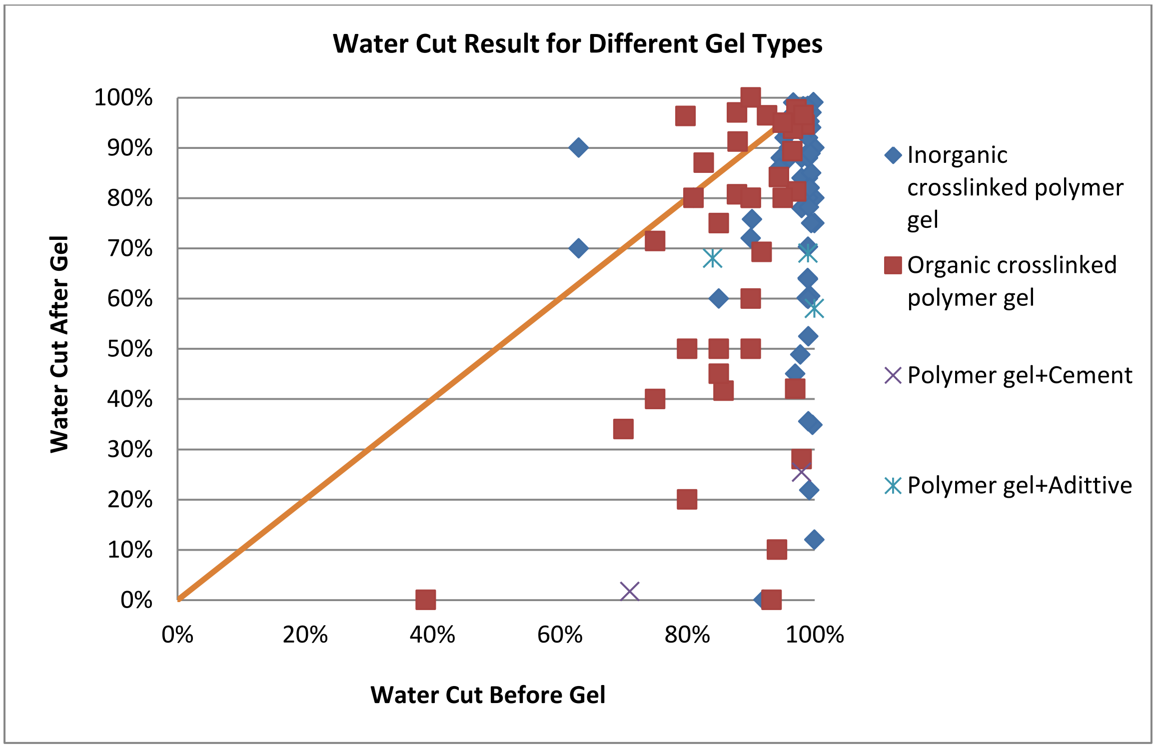


Figure 4.26. Water cut cross plot for different gel types

The change in oil rate is another factor in evaluating the success of the gel treatment. Figure 4.27 below displays the relationship between oil rate change, Δq, and the water cut before gel treatment. This plot revealed that the gel treatment was heavily applied to the wells with more than 90% water cut in attempts to solve the high water production problem. Figure 4.27 shows that most of the gel treatment results in an increase in oil rate—positive Δq. Some of the negative Δq cases were accompanied with decreased water rate and improved sweep efficiency. Those cases, however, should still be considered as a success.

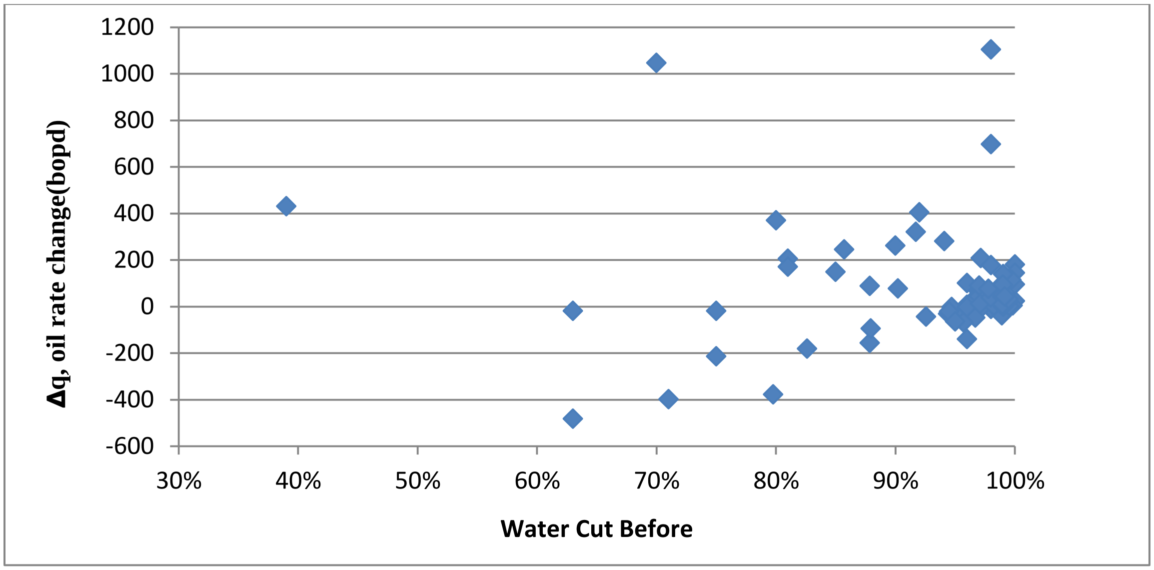


Figure 4.27. Oil rate vs. water cut cross plot

Figure 4.28 shows the cross plot between oil rate change ratio and water cut before gel treatment. And this cross plot shows the zoom-in view of the **Δ**q/q_i result between 70 and 100% water cut. Majority of the treated oil wells with more than 90% water cut. That's because of oil wells near their economic with 95%water cut or higher are considered as best candidate for oil operators (Portwood 1999).

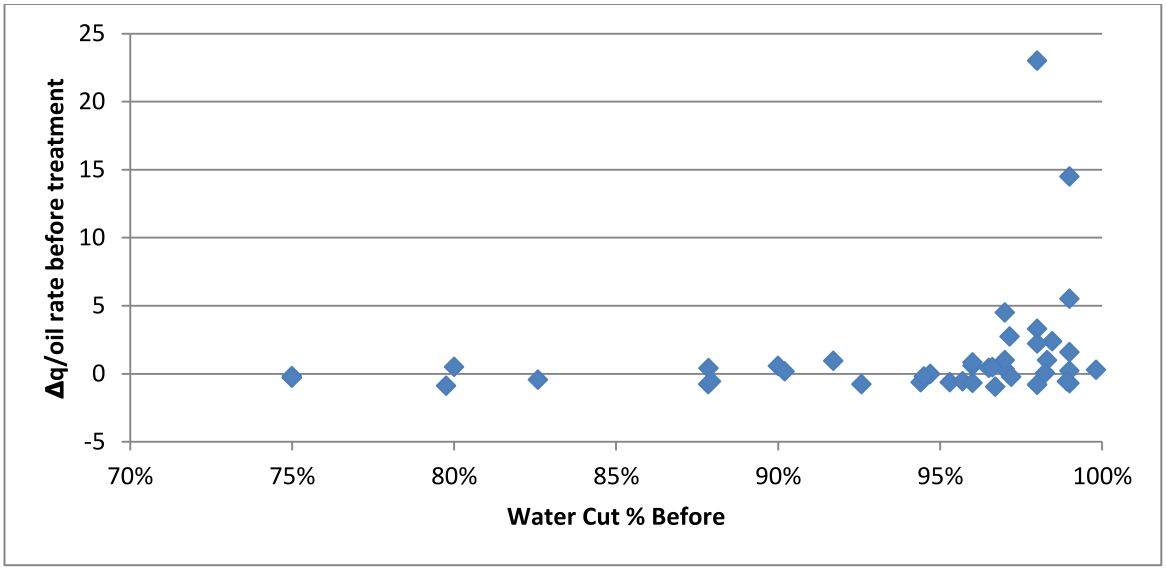


Figure 4.28. Oil rate change vs. water cut cross plot

Figure 4.29 used cumulative frequency plot to compare water oil ratio values before and after the treatments. In this plot, cumulative frequency is the percentage of the data points associated with WOR value less than or equal to that indicated on the x-axis. The distribution of WOR values at before and after gel treatment are shown in the figure below. In figure 4.30, WOR values were reduced significantly after gel treatment.

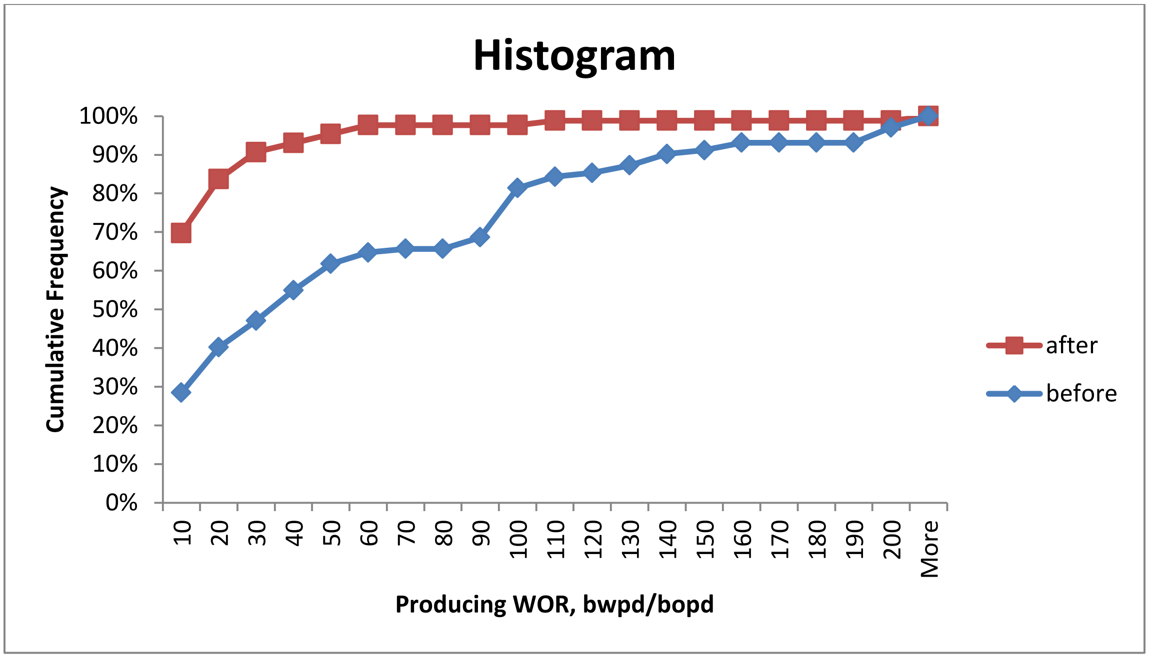


Figure 4.29. Cumulative frequency plot of producing WOR before and after gel treatment

Histogram and box plot in figure 4.30 are both used to summarize the oil rate before gel treatment and after gel treatment. Some oil wells have almost 100% water production (0% oil production) before gel treatment. Although the gel treatment improved the average oil rate only slightly, it eliminated the 0% oil rate situation.

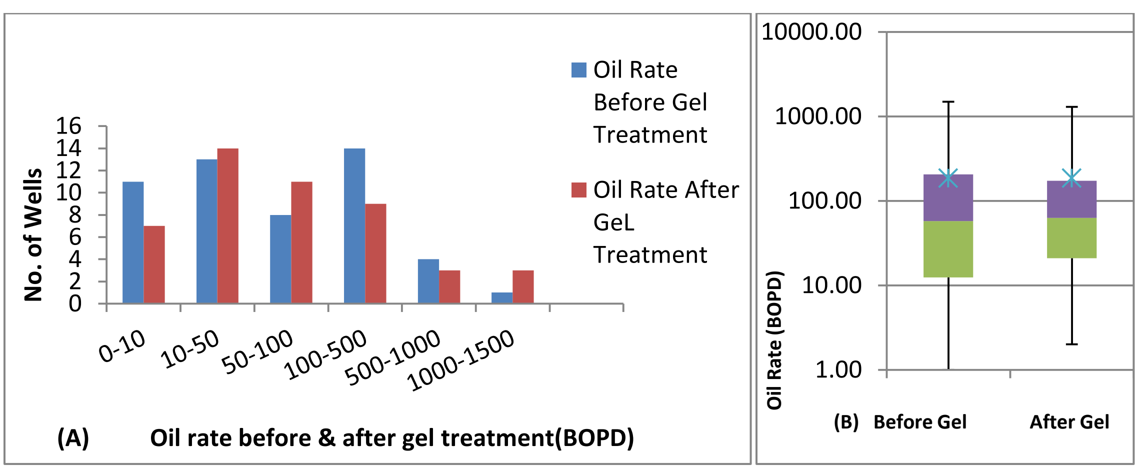


Figure 4.30. Oil rates before and after gel distributions (A) histogram, (B) box plot

Figure 4.31 represent the water rate distributions before and after gel treatments. And significant water rate decreases are shown in box plot. Histogram shows oil wells with less than 500 BWPD water rates after gel treatment increased. And the box plot shown that average water rate decreased after gel treatment.

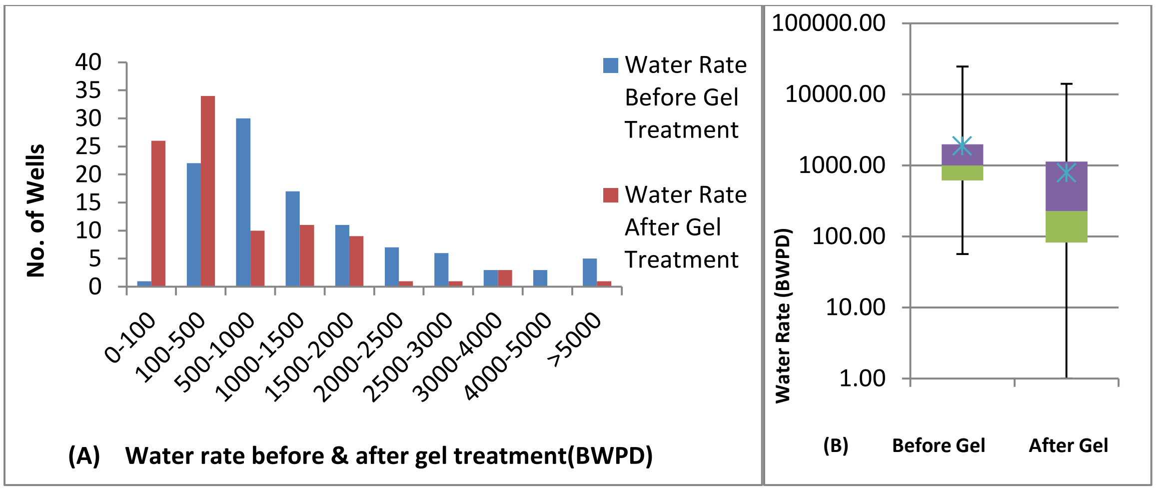


Figure 4.31. Water rates before and after gel distributions (A) histogram, (B) box plot

Figure 4.32 demonstrate the gross rate distributions before and after gel treatments. Both median and average values of the gross rate are lowered. Lower the gross rate will lower the burden to the pump and the separator which helps extending oil wells life.

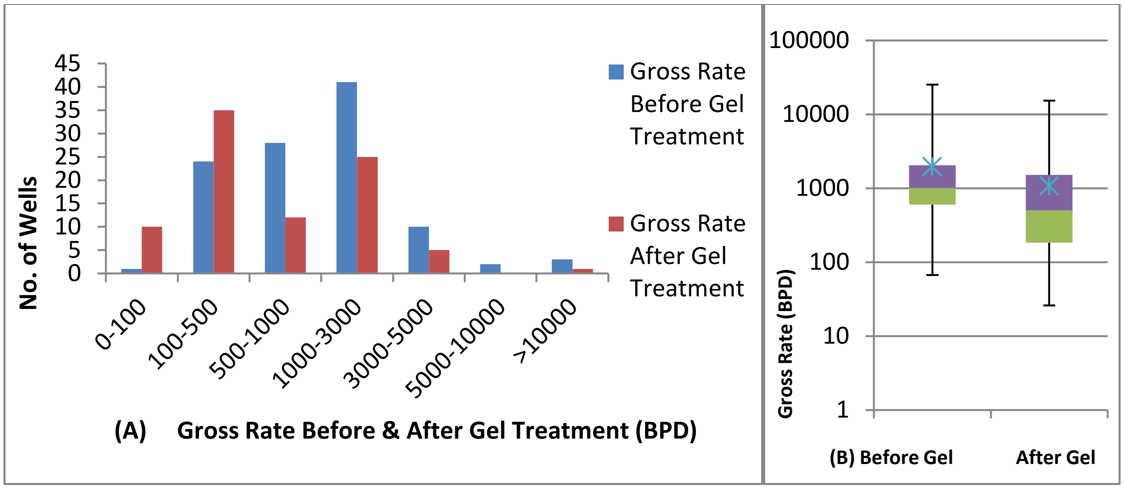


Figure 4.32. Gross rates before and after gel distributions (A) histogram, (B) box plot

Figure 4.33 summarize the water cut value before and after gel treatment. Histogram demonstrates that most oil wells have high water cut between 80% and 100%. It’s obviously that overall water cut decreased after gel treatment. Box plot shows that both median and average water cut values reduced.

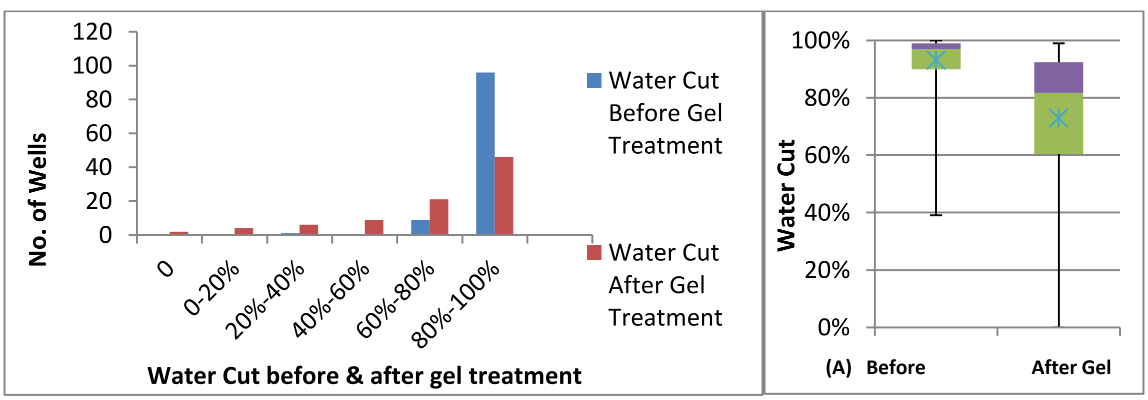


Figure 4.33. Water cut before and after gel distributions (A) histogram, (B) box plot

Figure 4.34 shows the cross plot between polymer injection and increased oil rate/initial oil rate. Figure 4.36 is the cross plot between polymer injection and decreased water rate/initial water rate. Those two figures show that most of projects applied dry polymer gel less than 10,000 pounds. Figure 4.35 indicates that a significant improvement in oil rate. The increase in oil rate in most oil wells ranged from 1to 20 times. In addition, three oil wells have dramatic oil rate increased have been circled in figure 4.35. Those three oil wells have 100% water cut and no oil rate before treatment, and gained impressive oil rates increase after treatment.

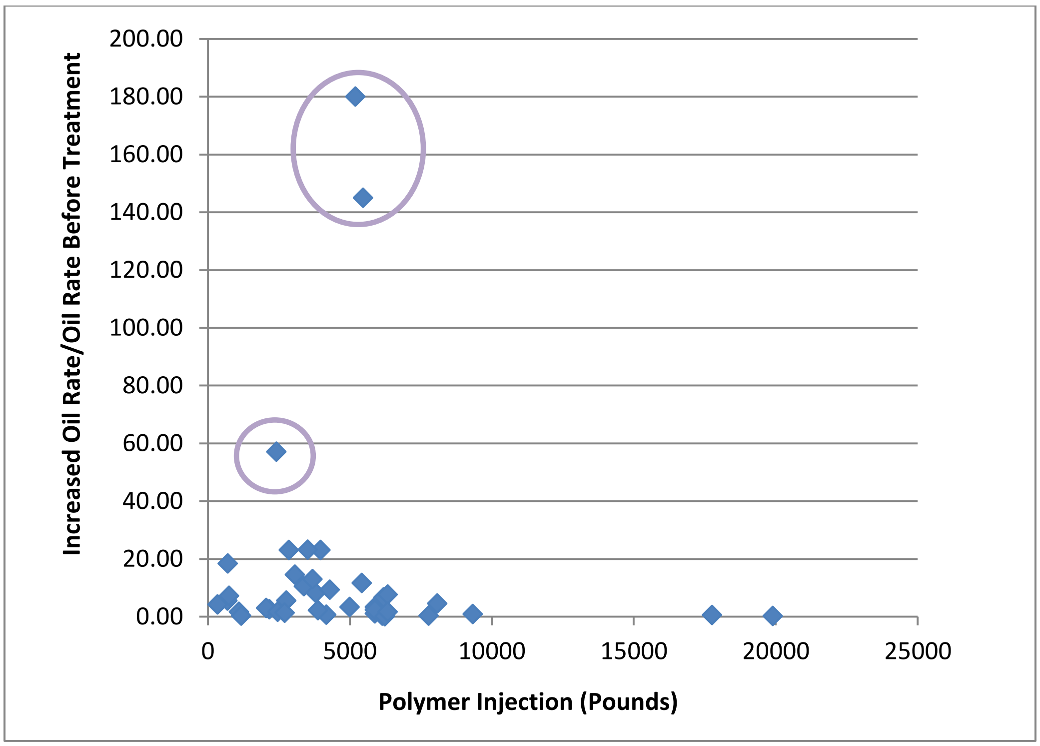


Figure 4.34. Polymer injection vs. oil rate growth

In figure 4.35 shows a good water rate reduction results. Y values close to 1 when water rates after treatment tend to 0. So this cross plot shows that most oil wells have significantly water rate decrease with most points close to 1 in Y axes. For those oil wells with extra-large size of polymer injection, figure 4.36 shows that water didn't get totally shut off; and figure 4.35 shows that oil rate didn't have apparent increase.

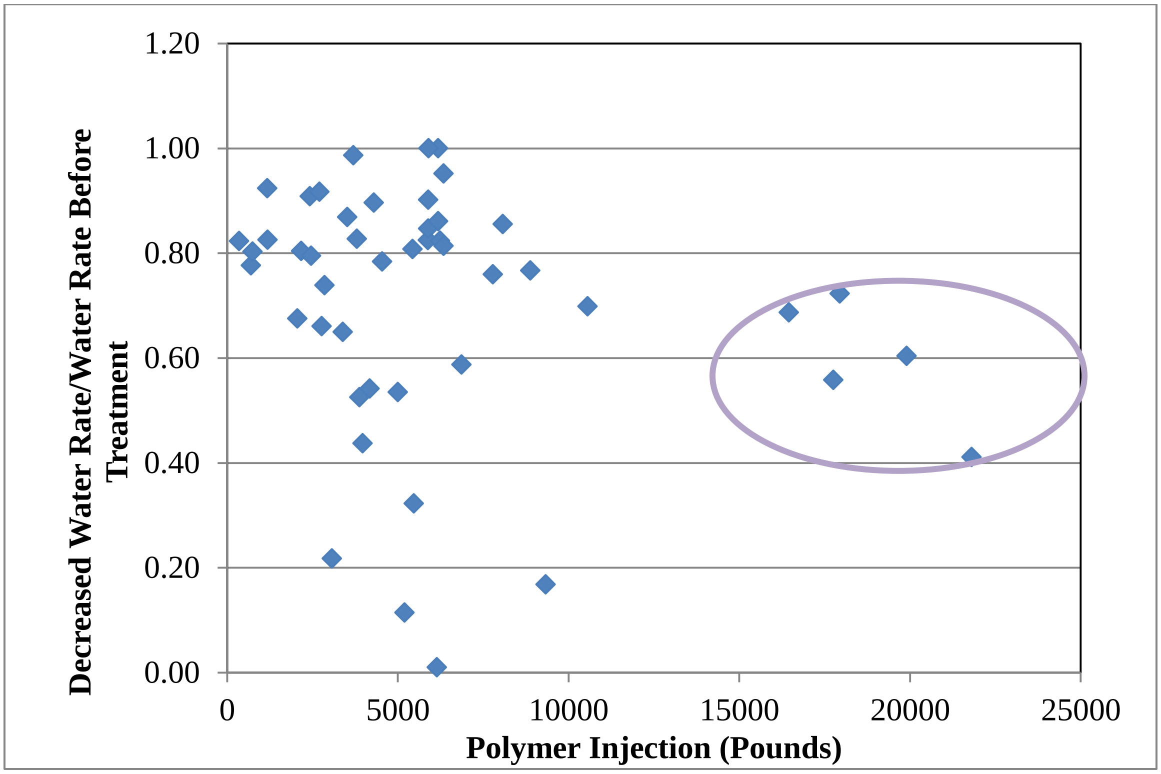


Figure 4.35. Polymer injection vs. water rate reduction

Figure 4.36 is cross plot between polymer injection volume and cumulative incremental oil production. All the data in figure 4.7 are from Kansas Arbuckle. Those data include 33 oil well cases from 6 oil fields in Kansas Arbuckle area.

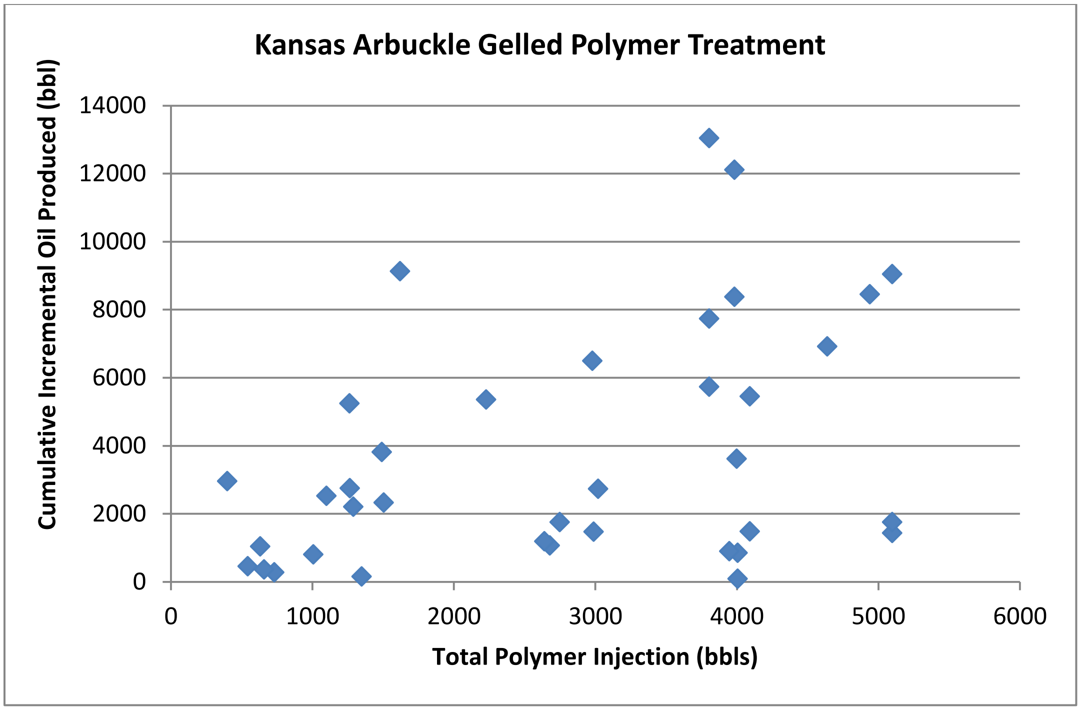


Figure 4.36. Cumulative incremental oil vs. total polymer injection in Kansas Arbuckle

Candidate selections

According to the candidate field test result, oil wells having high Productivity index values and also high fractures density distributions located on the apex of the fields were considered as good candidates. Oil wells near their economic with 95%water cut or higher are considered as best candidate because of high successful rate (Portwood 1999). Other than that, the wells completed as cased hole or shore pay zone under the open hole were also defined as good candidates for water shut off applications (Canbolate & Parlaktuna, 2012). Salinity is an indicator during oil producing process. Salinity decreasing with time can indicate that aquifer water bypassing the matrix rock and flow through the fracture (Canbolat.S &Parlaktuna.M 2012). The remaining oil in place needs to be considered during candidate wells selection. Recovery efficiency equation by Guthrie and Greenberger can be used (Arps,1956):

$$E_R = 0.2719 logK - 0.255569 S_W - 0.1355 log\mu_o - 1.53\emptyset - 0.0003488h + 0.11403$$

Table 4.8. Well Selection Criteria

Screening Criteria for Well Selection
1. High Productivity Index
2. High Water Cut
3. High fracture density distributions
4. Remaining Recoverable
5. Salinity decrease with water producing
6. Good well completion
7. The source of the excess water production is identified

Field case failure reason summaries:

Gel treatment is not a new technology; it has been exist for a number of decades. But during the early time, without modern geological and geophysics detection tool, poor understanding to water flooding process and conformance problem are the main reason for low successful rate during the old time. Five main failed reason for gel treatment during the process listed below:

1. Improper gel injection volume

If the gel injection volume is not large enough, it cannot extend far enough to block the water channels completely. Water flow will detour around and find another pathway to wellbore. After the gel treatment water production will drop for a while but will return to high production rate soon (Portwood 1999).

2. Insufficient gel strength

Misunderstanding of polymer type, fluid based crosslinked gel normally is not strong enough to hold up in high permeability zone and fractured formations. Gel blocking area will be broken down and water wills by-pass. Fluid based polymer gels can build a resistance to excess water flow in formation matrix, and this resistance result squeeze pressure in formation matrix. Since it's hard to build resistance for high permeability zone and fractures formation channels, cement injection behind the fluid based gel is highly recommended. Various gel systems have different tolerance with respect to reservoir condition, so gel type consideration is important.

3. Placing the treatment above formation parting pressure

Formations parting pressure is an important parameter during the injection process. New fracture will be formed and filled with gel when injection pressure is too large to damage the formation (Portwood 1999).

4. Block the oil zone, lose oil production

Oil production loss from high permeability zone after that zone is plugged; oil production loss from low permeability zone after that zone is invaded by gel treatment during placement process.

5. Poor pressure maintenance after gel treatment

Pelican Lake field cased showed: both oil and water rate can be strongly decreased after gel treatment because of poor pressure maintenance without active aquifer (Zaitoun.A & Kohler.N 1999).

5. SUMMARY AND CONCLUSIONS

5.1. DATA SUMMARY

Table 5.1 provides a summary of the gel treatment application from the preceding statistical analysis of the data set. This screening criteria table contains reservoir porosity, permeability, oil API gravity and reservoir temperature. The standard statistics used to describe the criteria are the mean, median, minimum and maximum values.

Table 5.1. Reservoir properties summary for gel treatment in the dataset

Statistics	Porosity %	Permeability (md)	API gravity	Reservoir Temperature
Mean	21.6	2150	27.5	158.5
Median	20	1250	23.6	145
Minimum	10	4	18	86
Maximum	40	20,000	40	300

Short payout time and low treatment cost are one of the reasons that gel treatments have been widely applied. The payout time for gel treatment varies from 30 to 180 days. According to summaries from water shut off treatment in 300 producing wells by Portwood, the cost is $0.5 to $2.00 for each barrel of incremental oil (Portwood 1999). The overall success rate is around 75%% for wells treated in a new field. However, the success rates for oil wells have been very sporadic sometimes. To improve the success rate for future gel applications, conformance problems need be adequately identified before gel treatment. Table 5.2 summarized gel treatment applications. This table provides a guideline to gel treatment process.

Table 5.2. Summary of production-well gel treatment

		No	%
Application	Water shut off	151	91
	Gas shut off	14	9
Lithology	Carbonate	75	43
	Sandstone	58	34
	Shale	4	2
	Combination	8	5
	Not specified	27	16
Well Type	On shore	153	93
	Off shore	12	7
	Vertical	157	95
	Horizontal	8	5
Fracture status	Naturally fractured	55	33
	Not specified	110	67
Conformance problem	Fracture channeling with strong water drive	80	50
	Water or gas coning and channeling	23	15
	High fractured strong water drive/tubing leak	2	1
	Fault	2	1
	Matrix channeling without crossflow	7	5
	Poor primary cement and channeling	35	22
	Water channeling between injector and producer	8	5
	Water channeling behind pipe	2	1
Gel type	Organic crosslinked polymer	36	23
	Inorganic crosslinked polymer	92	57
	Polymer+additive	3	2
	Polymer+cement	28	18

Table 5.2. Summary of production-well gel treatment (cont.)

Placement method	**Bullhead**	**65**	**41**
	Mechanical Packer	13	8
	Dual injection	2	1
	Not Specified	81	50
Pre-flush	Acid	42	26
	Field water/Seawater	20	12
	low concentrated polymer	1	1
	Not Specified	97	60
Post-flush	Crude Oil	14	9
	Water/Seawater	16	10
	Low Concentrated Polymer	1	1
	Acid	7	4
	uncrosslinked polymer+crude oil	4	2
	Water+crude oil	29	18
	Not Specified	89	56

5.2. CONCLUSION

This study summarized field application information for gel treatment in producing oil wells. The results of the treatment applications were gathered, and the application limitations were listed. Also, candidate selection criteria were tabulated and discussed for most effective scenario. To improve the success rate of gel applications, water production problems need to be clearly identified in the future. Improvements are needed in gel sizing and gel type selection.

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