

MAJOR PROJECT REPORT ON
“ANALYSIS OF WATER SHUT OFF
TECHNIQUES USING DIVERSE
POLYMERS”

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B.Tech Applied Petroleum Engineering- Upstream

PROJECT GUIDE

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PROJECT WORK SUBMITTED TO

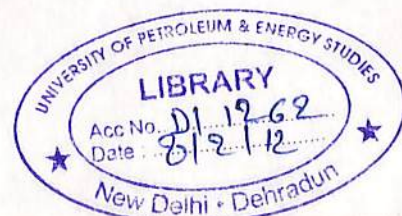
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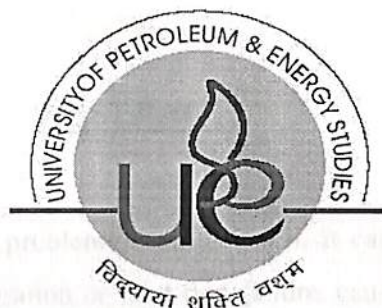
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CERTIFICATE

This is certify that **Rahul Roy (R010207043)** and **Ramil Verma (R040207043)** have successfully completed the Major Project Work for “**Analysis of Water Shut Off Techniques Using Diverse Polymers**” under the able guidance of **Mr. Arvind Chittambakkam**.

The project work is a part of the fulfillment of the Degree of Bachelor of Technology in **Applied Petroleum Engineering** to be awarded to them by the **University of Petroleum & Energy Studies, Dehradun**.

They have performed their job sincerely with commitment and integrity and their demeanor has been good.

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ABSTRACT

Water production is indication of problems in an oil well. It causes scaling related problems in susceptible wells, causes fines migration or sand face failure, causes corrosion of tubular and kills the well by hydrostatic loading. Hence, it is necessary to prevent the onset of water production for as long as possible.

The high water production in oil wells causes major economic and operational problems for several reasons. It decreases oil production, and results in large amounts of produced water that need to be disposed. It also requires increased capacity of water separation and handling facilities. Other production related problems include high corrosion rates and increased tendency for emulsion and scale formation. Therefore, there is a need to reduce water production.

Identification of the mechanism for excess water production is as important as the treatment design for combating water production. Diagnostic plots are very much helpful in this aspect. They are helpful in identifying whether the mechanism is due to coning or channelling by the trend of the WOR and WOR' curves. Though many other methods are present they provide much useful results.

Several mechanical and chemical methods are available for water shut-off treatment. However, the choice of a specific treatment depends on the source of water production, well characteristics, and cost. There are various ways to control this water production such as: mechanical, chemical and downhole separation methods. Water shut-off treatments using chemical means include injection of a gelling solution which is one of the most frequently used methods.

Most of the gels are in the form of pre-gels which enter into rock matrices, cracks and fractures. They block or reduce the water content in the produced fluid by decreasing the permeability of the water or increasing the permeability of formation to water or by increasing viscosity of water.

Detailed information on the production profile, history of water cut helps in diagnosing the well for carrying out successful water shut off or profile modification job.

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CHAPTER 1: INTRODUCTION

1.1 Project Background

Water production from oil and gas reservoirs is increasing world-wide, as more reservoirs are being mature and high water production in associated with crude oil is one of the major production difficulties for the petroleum industry, with water often comprising more than 50% of the produced fluids. In order to control water production, polymers or gels are injected into production wells to either block the flow, or to reduce water permeability much more than to oil. This report discusses both, the characteristics of reservoirs and wells which result in high WOR, as well as characteristics of gel treatments which need to be designed in order to effectively minimize the produced water from a reservoir or an oil field and also describes straightforward strategy for diagnosing and solving excess water production problems using different Polymer gel technologies with organic polymer gels with laboratory experiments at simulated reservoir conditions. Gel treatment applications have been used for production well for WOR reduction. There have been a number of cases where there was high WOR and the wells were proving uneconomical but by invocation of gel treatment strategies, well have become economical. In the area of oil field, water & gas control technological advancement is trained towards high temperature formations. However suitable technology for controlling the water production, in high temperature formations was not matured enough even a decade ago. Over the years polymer based cross linked gel technology has gained tremendous importance owing to the fact that polymer-gel water- shutoff (WSO) treatments are highly reservoir, well and problem-specific. In order to successfully apply a polymer-gel WSO treatment, the underlying problem must first be correctly identified (or deduced) and be amenable to polymer-gel WSO treatments. Then an appropriate polymer-gel system should be properly selected, sized and applied. Laboratory experiments were carried out using Sand Packs of different sizes in Core flow set up using core holders that have internal pressure taps. Sand packs with different sizes of sands have been prepared and were subjected to gel treatment and found effective in plugging the brine permeability by 80 to 85%.

The primary constituent of these chemical gel systems is partially hydrolyzed acryl amide based polymers cross linked to their active sites with cross linkers having multiple reacting sites. These polymers are specially designed to achieve quick dispersibility in water and brine without forming fish-eyes and to withstand high temperature and hostile chemical environment such as high salinity, bi- & trivalent ions (viz. Ca^{++} , Mg^{++} and Fe^{+++}) for a very long period of time.. A careful hydrolysis of the polymer is necessary to optimize its dispersibility. Too much hydrolysis may lead to instability and too less would lead to poor dispersibility in aqueous medium. Since molecular weight of the polymer governs its bulk viscosity (also to a great extent its stability) and since injectivity is dictated primarily by solution viscosity, careful consideration of molecular weight is another important factor which determines the quality of the polymer.

1.2 Aims of the Project

- To study the reasons of high water production from an oil well and their effect on the production of crude oil from the well.
- To understand the process of water shut off techniques in the oil wells.
- To study the diverse polymers used in the water shut off techniques and their effects on the net water production from the well.
- To analyze the production of the North Kadi and Jhalora Field and develop a polymer gel system for the reduction of excess water production.

1.3 Project objectives

The objective of this project is to determine the feasibility of polymer gel technology to increase the recoverable reserves from the North Kadi Field of Mehsana Asset and Jhalora field of Ahmadabad asset

Specifically, this would be accomplished by:

- Reducing water production from both Fields and the well operating cost.
- Increasing the draw down on Fields and increasing oil production and remaining recoverable reserves.
- Enabling uneconomic producers to be returned to production.

1.4 Scope of the project

- Understanding the water problems in an oil well and diagnosing the cause of the excess water production from the oil wells.
- Water cut reduction and relative permeability reduction in North Kadi field by polymer treatment.
- Developing a polymer gel system for the high water cut reduction in the oil wells of Jhalora field by laboratory experiments and core flow studies.

1.5 Project methodology

- First of all, we have gone through all water problems that are faced in an oil well which results in high production.
- We have then discussed the strategies for the control of the excess water production and the methods for the diagnosis of the causes for excess water production.
- The project then discuss methods used for the determination of the properties of polymers used and core flow analysis.
- We have then taken the case study of the North Kadi field where the water cut is very high.
- The project ends with the results and conclusions based on the case study.

1.6 Project limitations

- In this project only chemical methods for the control of high water production has been used.
- Only organic polymers have been used in this project for the gellant treatment of the oil well.
- The project fails to control the water production if it is taking place due to three-dimensional coning, cusping or channeling flow through the strata with cross flow.

SCHAPTER 2: LITERATURE REVIEW

2.1 Introduction

Today, oil companies produce an average of 3 barrels water for each barrel of oil from their depleting reservoirs. Every year more than \$40 Billion is spent dealing with unwanted water. Water handling costs are high – estimates range from 5 to 50% barrel of water. In well producing oil with an 80% water cut, the cost of handling water can be as high as \$4 per barrel of oil produced. Water is present in every oil field and is the most abundant fluid in the field. No operator wants to produce water, but When it comes to producing oil, a key issue is the distinction between Sweep, Bad (or excess), Good (or acceptable) water.

A) “Sweep Water”:

Sweep water comes from either an injection well or an active aquifer that is contributing to the sweeping of oil from the reservoir. The management of this water is a vital part of reservoir management and can be a determining factor in well productivity and the ultimate reserves.

B) “Bad” Water:

Bad water production in oil producer is a factor that reduces oil production, limits the productive life of a well & increases production cost to a greater extent.

The figure below describes that Good water needs to be produced with oil. It can not be shut off without shutting off oil. Down hole separation may be a solution. Bad water does not help production, and it depletes pressure.

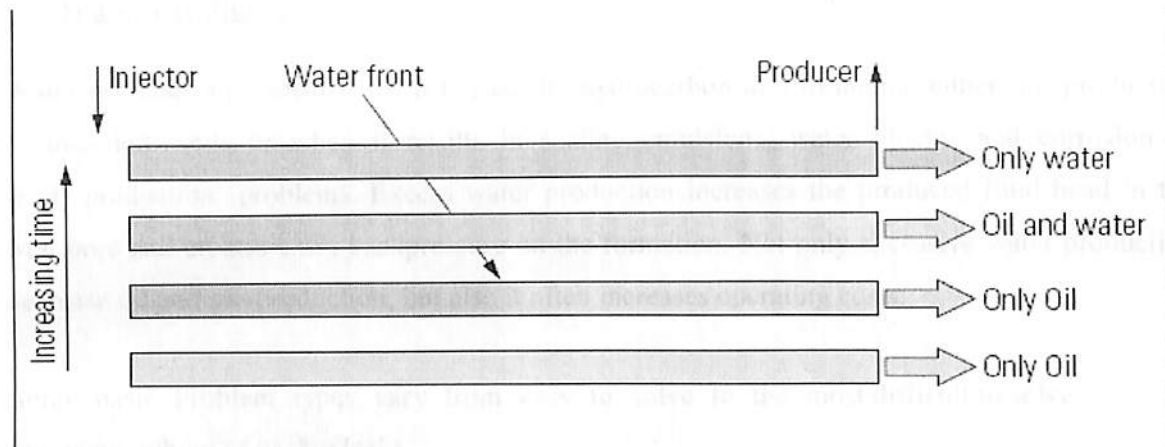


Figure 1

C) "Good" Water:

This type of water is produced into the well bore at a rate below the Water/Oil Ratio (WOR) economic limit. It is an inevitable consequence of water flow through the reservoir, and it can not be shut off without losing reserves. Good water production occurs when the flow of oil and water is commingled through the formation matrix.

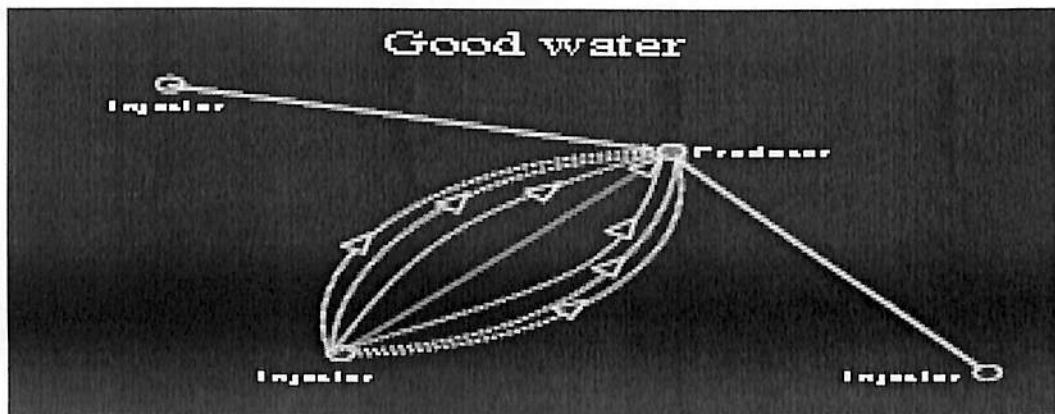


Figure 2

But our aim is to prevent production of bad water only.

2.2 Water Problems

Water becomes a problem when it bypass the hydrocarbon in a formation either in production or injection wells or when it results in scaling, emulsions, water blocks, and corrosion or sand production problems. Excess water production increases the produced fluid head in the well bore and creates extra backpressure on the formation. Not only excessive water production decrease oil and gas production, but also it often increases operating costs.

Some basic Problem types vary from easy to solve to the most difficult to solve.

- A) Casing, tubing or packer leaks
- B) Channel flow behind casing
- C) Water-out layer without cross flow
- D) Moving oil-water contact
- E) Coning or Cusping
- F) Poor areal sweep

A) Casing, tubing or Packer leaks:

Leaks through casing, tubing or packers allow water from non oil- productive zones to enter the production string.

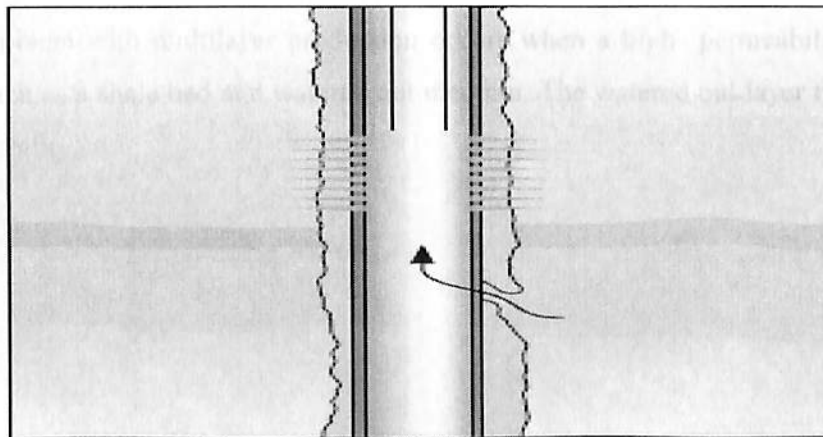


Figure 3

Basic production logs such as fluid density, temperature and spinner may be sufficient to

diagnose these problems.

B)Channel flow behind casing

These channels allow water to flow behind casing in the annulus

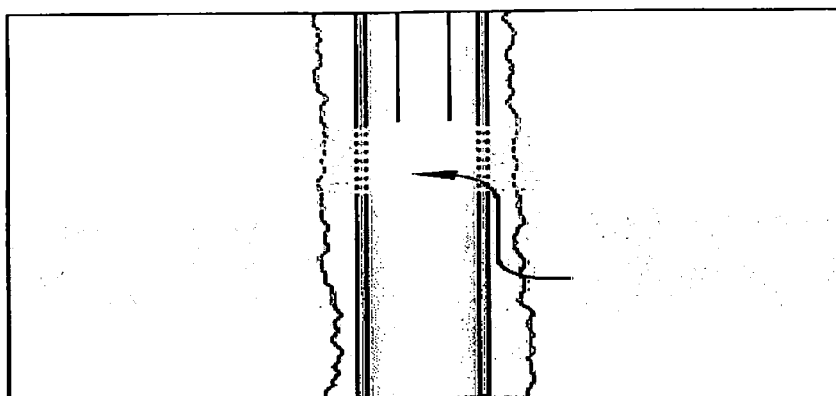


Figure 4

The main solution is the use of shutoff fluids, which may be either high-strength squeeze cement, resin-based fluids placed in the annulus or lower strength gel-based fluids placed in the formation to stop flow into the annulus.

C) Watered-out layer without cross flow:

A common problem with multilayer production occurs when a high- permeability zone with a flow barrier such as a shale bed and watered out medium. The watered out layer typically has the highest permeability.

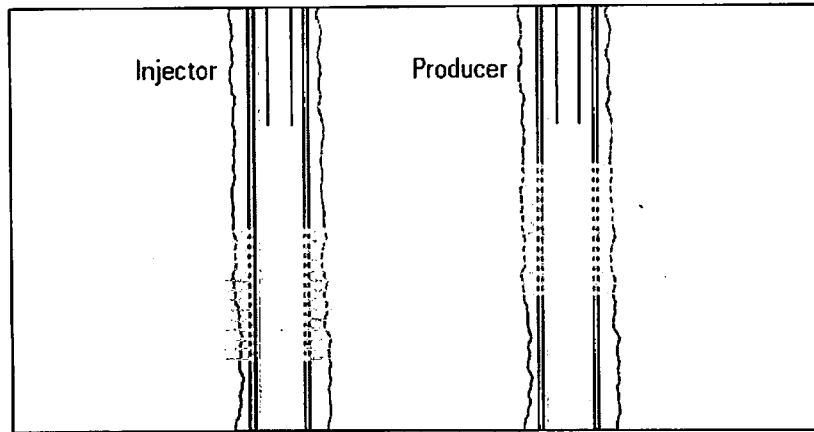


Figure 5

In the absence of reservoir cross-flow, this problem is easily solved by the application of rigid, shutoff fluids or mechanical shutoff in either the injector or producer.

D) Moving Oil-Water contact:

A uniform oil-water contact moving up into a perforated zone in a well during normal water-driven production can lead to unwanted water production. This happens wherever there is very low vertical permeability.

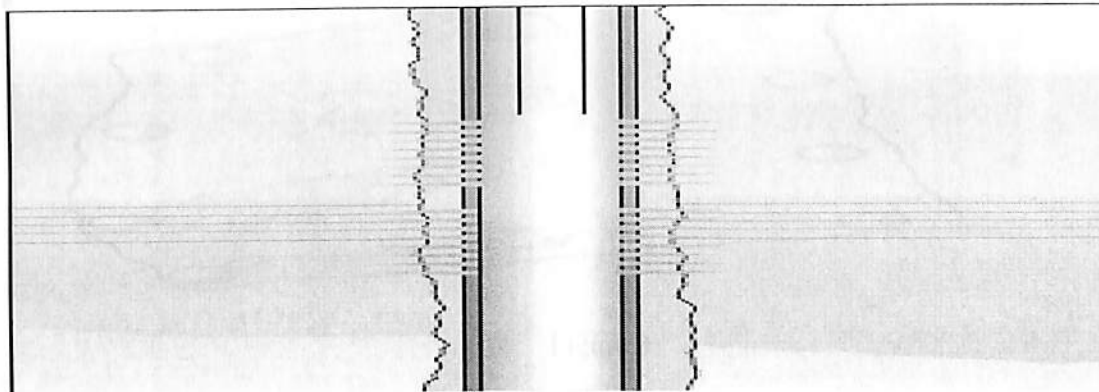


Figure 6

It is considered as subset of Coning. In a vertical well this problem can be solved easily by abandoning the well from the bottom using a mechanical system such as a cement plug or bridge plug set on wire line.

E) Coning or cusping:

Coning occurs in a vertical well when there is an OWC near perforations in a formation with a relatively high vertical permeability.

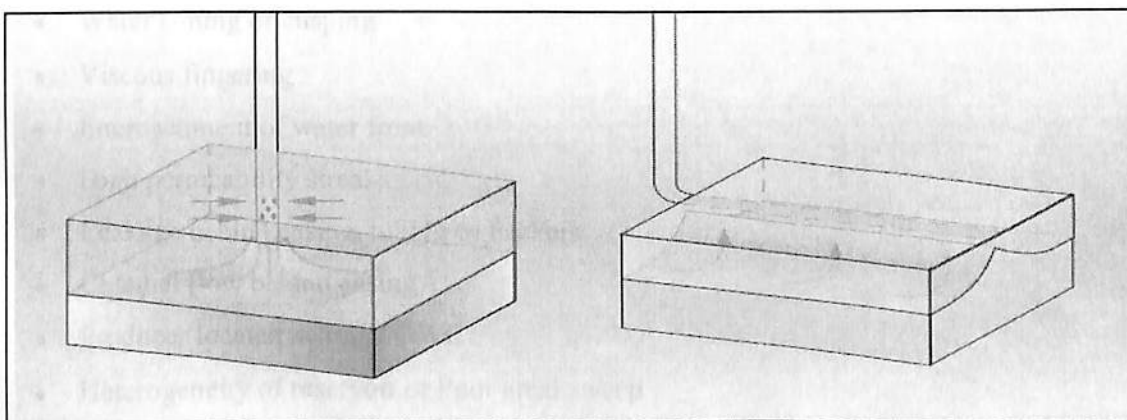


Figure 7

Place a layer of gel above the equilibrium OWC. However this will rarely stop coning & requires a large volume of gel to significantly reduce the WOR.

F) Poor areal sweep:

Edge water from an aquifer or injection during water flooding through a pay zone often leads to poor areal sweep. Alternatively, water may break through to one part of the well simply because of horizontal proximity to the water source.

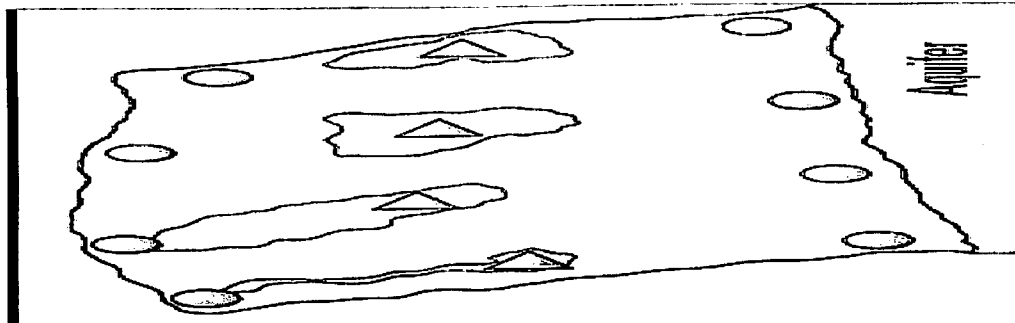


Figure 8

In either case, it may be possible to control water by near-well bore shutoff sufficiently up and down hole from the water.

Identified reasons for high Water Cut are:

- Poor cement bondage for sand wash out
- High water saturation
- Adverse mobility ratio
- Premature water break-through
- Water coning or cusping
- Viscous fingering
- Encroachment of water front
- High permeability streaks
- Leakage behind casing, tubing or Packers
- Channel flow behind casing
- Producer located near the OWC
- Heterogeneity of reservoir or Poor areal sweep
- Rapid acid jobs resulting in creation of large cavities
- Edge water/Bottom water Encroachment
- Fracture or faults between injector and producer
- Moving oil-water contact

High water production causes reduced oil or gas production, there by rendering the well uneconomical. The following points will show some light on the evils of high bad water production:

- Reduced sweep efficiencies by not effectively flooding all productive intervals-water cycling between injection and producing wells through their zones or high permeability intervals.
- Increased fluid column head caused by higher density water in the producing string. This often causes significant loss of gas production in low pressure wells which leads to early shut in.
- Increased water saturation in the formation near the well bore which reduces the relative permeability to oil or gas.
- Formation damage by mobile or hydratable clays and formation fines which are trapped near the producing well bore area.
- Scale precipitation in the well bore, perforations, and near well bore formation pores.
- Water blocking which creates increased water saturation in the near well bore formation of a producing well and reduces the relative permeability to oil.
- Creation of emulsions as crude oil and water mix upon entering the well bore or down hole pump this problem is more serious if the emulsion is injected into the formation during a work over operation.
- Hydrogen sulphide and carbon dioxide corrosion is accelerated by water production.

Sand production is often associated with increased water production rates. High water production causes reduced oil or gas production, thereby rendering the well uneconomical.

2.3 Strategy for attacking Bad water production:

The strategy advocates that the easiest problems should be attacked first and diagnosis of water production problems should begin with information already at hand. Many different materials methods can be used to attack excess water production problems.

Table 1. Water Shut-off Materials & Methods

Many different materials and methods can be used to attack excess water production problems. Generally, these methods are categorized as chemical or mechanical.

Chemical & Physical Plugging Agents	Mechanical & Well Techniques
Cement,sand,calcium carbonate	Packers, bridge plugs, patches
Gels, Resins	Well abandonment, infill drilling
Foams,emulsions,particulates,precipitates,micro-Organisms	Pattern flow control
Polymer/mobility-control floods	Horizontal Wells

Each of these methods may work very well for certain types of problems but are usually ineffective for other types of problems. Again, for effective treatment, the nature of the problem must first be correctly identified.

Table 2.0 Level of difficulty & Treatments

Category	Problem	Level of difficulty	Type of treatment
A	(1) Casing leaks without flow restrictions (medium to large holes)	Easiest	Conventional treatment
	(2) Flow behind pipe without flow restrictions (no primary cement)		
	(3) Unfractured wells (injectors or producers) with effective barriers to cross flow		
B	(4) Casing leaks with flow restrictions (pinhole leaks)	Intermediate difficulty	Gel Treatment
	(5) Flow behind pipe with flow restrictions (narrow channels)		
	(6) "Two-dimensional coning" through a hydraulic fracture from an aquifer		
	(7) Natural fracture system leading to an aquifer		
C	(8) Faults or fractures crossing a deviated or horizontal well		Pre-formed Gel
	(9) Single fracture causing channeling between wells		
	(10) Natural fracture system allowing channeling between wells		
D	(11) Three-dimensional coning	Most difficult	Gel application not recommended
	(12) Cusping		
	(13) Channeling through strata (no fractures), with cross flow		

Category A:

Casing leaks without flow restrictions (medium to large holes):

Problems involving casing leaks without flow restrictions are those where the leak is occurring through a large aperture breach in the piping (greater than roughly 1/8 in.) and a large flow conduit (greater than roughly 1/16 in.) behind the leak.

Flow behind pipe without flow restrictions (no primary cement):

Problems involving flow behind pipe without flow restrictions, is where the fluid flow is occurring through a large aperture flow conduit behind the pipe (greater than roughly 1/16 in.). This problem is often manifested by a total lack of primary cement behind the casing.

Unfractured wells (injectors or producers) with effective barriers to cross flow:

Often, when radial flow exists around a well (i.e., fractures are not important), impermeable barriers (e.g., shale or anhydrite) separate hydrocarbon-bearing strata from a zone that is responsible for excess water production.

Category B:

Casing leaks with flow restrictions (pinhole leaks):-

Problems involving casing leaks *with* flow restrictions, is where the leak is occurring through a small aperture breach (e.g., —pinhole and tread leaks) in the piping (less than roughly 1/8 in.) and a small flow conduit (less than roughly 1/16 in.) behind the leak.

Flow behind pipe with flow restrictions (narrow channels):-

Problems involving flow behind pipe *with* flow restrictions, is where the flow behind pipe is occurring through a small aperture flow conduit (less than roughly 1/16 in.).

Such problems are often exemplified by micro-annuli flow behind the pipe. This problem often results from cement shrinkage during its curing during the well's completion.

Two-dimensional coning through a hydraulic fracture from an aquifer:-

When production wells are hydraulic fractured, the fracture often unintentionally breaks into water zones, causing substantially increased water production. The case is even worse in 3-D coning where production rates are very high which leads to heightened water production rates.

Natural fracture system leading to an aquifer:-

This problem arises when a natural fracture is existent in the vicinity of the pay zone which leads to an aquifer. As contact between the well bore and the aquifer is established, more and more of bad water production is obtained from the well.

Category C:

Faults or fractures crossing a deviated or horizontal well:-

Deviated and horizontal wells are prone to intersect faults or fractures. If these faults or fractures connect to an aquifer, water production can jeopardize the well.

Fractures causing channeling between wells:-

These problems arise when channeling between two or more wells is caused due to the presence of a fracture. The channeling may be between injector-producer combinations or even between two or more producers in which case the water cut in any one of the wells will be distributed in the other linked producers also thereby causing excess water production from all the linked wells.

Category D:

Three-dimensional coning:-

When production wells are hydraulic fractured, the fracture often unintentionally breaks into water zones, causing substantially increased water production. The case is even worse in 3-D coning where production rates are very high which leads to the viscous forces overcoming the gravity forces.

Cusping:-

In cusping, like three-dimensional coning, the well is produced so rapidly that viscous forces overcome gravity forces. For cusping in particular, water from an aquifer follows an inclined zone up to the well.

Channeling through strata (no fractures), with cross flow:-

This problem is encountered when the underlying fluids permeate through a high permeability channel instead of permeating through the whole strata as a whole. This channeling simplifies the movement of unwanted fluids like bad water and results in excess production of the same.

2.4 Well diagnostics

A) Recovery Plots

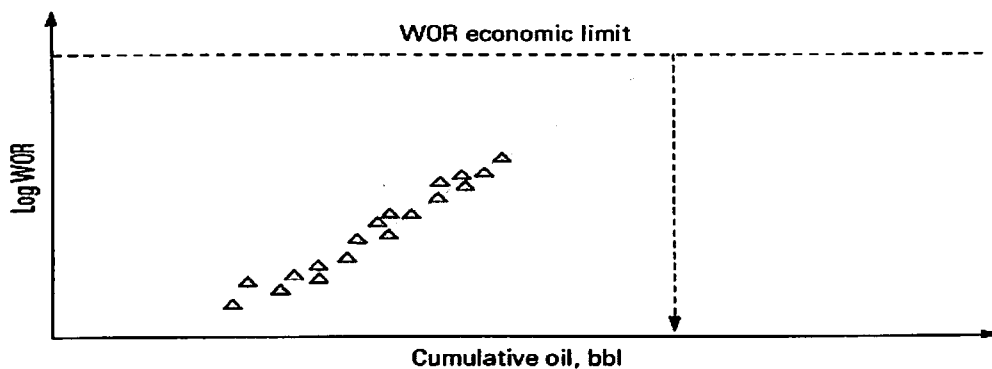


Figure 9

The Recovery plot shows the increasing trend in water/oil ratio with production. It is semi log plot of WOR against cumulative oil production. Identification of the excess water production problem should be performed before attempting a water shut-off treatment.

B) WOR Plots

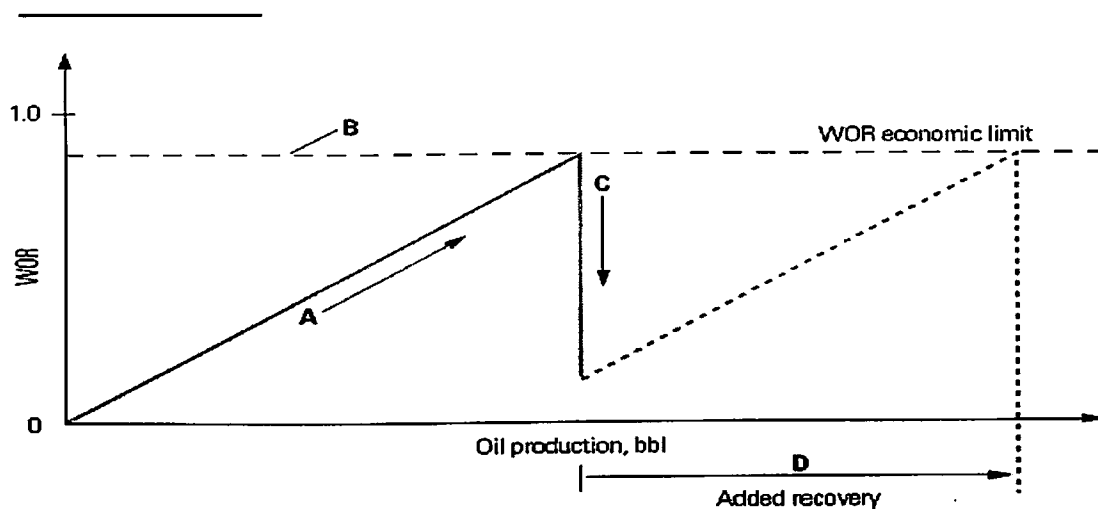


Figure 10

Plots of water/oil ratio (WOR) versus time can provide a valuable indication of when an excess water problem develops. This method was said to be capable of distinguishing whether a production well is experiencing premature water breakthrough caused by water coning or channelling through high permeability layers.

According to this method:

- Gradually increasing WOR curves with negative derivative slopes are unique for coning problems.
- Rapidly increasing WOR curves with positive derivative slopes are indicative of a channelling problem.

2.5 Water – Control Solutions:

Two primary techniques can be used to restrict water from entering the well.

(1) Mechanical blocking devices,

(2) Chemicals that shutoff the water bearing channels

Taking the case of Gels, Resins and Cement, being the most common choices for a remedial job. Today, in addition to the traditional solutions described above, there are new, innovative and cost-effective solutions for water control problems. Various technologies are also used to eliminate water problem:

- Down hole Separation & Injection
- Chemical & Mechanical Shut-off
- Surface water separation
- Production facilities

2.5.1 Mechanical Techniques

- Straddle packers
- Bridge Plugs
- Tubing Patches
- Cement
- Well bore sand plugs
- Well abandonment
- Infill drilling
- Pattern flow control
- Horizontal wells

In many near well bore problems, such as casing leaks, flow behind casing, rising bottom water and watered out layers without cross flow, mechanical or inflatable plugs are often the solution of choice.

2.5.2. Chemical Solutions

Chemical treatments require accurate fluid placement done by Coiled tubing with inflatable packers. Coiled tubing with inflatable packers can help place most treatment fluids in the target zone without risk to oil zones.

Rigid gels are highly effective for near-well bore shutoff of excess water. Unlike cement, gels can be squeezed into the target formation to give complete shutoff of that zone or to reach shale barriers. They have an operational advantage over cement treatments because they can be jetted rather than drilled out of the well bore. Typically based on cross-linked polymers, products like Mara seal and organ seal-R systems can be easily mixed and have a long working life. It is selectively placed in the water zone using coiled tubing and a packer.

Another solution is a flowing gel that can be injected into small faults or fractures, but only penetrates formations with permeability greater than 5 Darcies. Large volumes of these inexpensive fluids often successfully shutoff extensive fracture systems surrounding water flood injector or Producing wells .

2.5.3. Other Factors which are also considered:

Building further on the fact that choosing the right material to attack a given problem holds the key to success of the operation at hand, there are a number of other factors which go a long way in determining the success or failure of the job and which must always be kept in mind while the choice is made. These are:

- Cost
- Availability
- Blocking agent set times
- Permeability reduction provided to water
- Permeability reduction provided to oil or gas
- Ability to withstand high pressure gradients in porous rocks
- Ability to withstand high pressure gradients in fractures or voids
- Rheology / filtration properties
- Stability at elevated temperatures
- Environmental concerns

The Water Control Flow Chart

Table 3

Diagnosis Through	Water Source	Remedial Measures
Analysis of well log, Correlation data, Fluid & Tracer analysis	Perforation in Water Zone	Water zone isolation by cement plug/bridge plug/packer
Well log, Thermo log, Caliper, USIT, Casing Inspection	Casing Leak	Isolation by cement/bridge plug or packer & casing patch
Core analysis, drill rate, core cutting rate, tracer survey.	High Permeability Streaks	Grouts/X-Linking Polymer gels
Open hole logs, core analysis	Natural Fractures	Selective X-Linking Polymer gels/Zonal isolation
Review of simulation, hydro fracturing, squeeze & cementing data.	Induced Fracture	Selective Isolation with Sealant gel
Nodal analysis & material Balance	Rise of OWC	Squeeze 7 selective Perforation
CBL, VDL, PLT, USIT, water analysis & diagnostic plot	Channeling	Squeeze, MF cement or ringing gel
Study of production rate variation, water cut history	Coning	Controlled withdrawal/isolate top layer by pancake treatment.

2.6 Polymer Gel Water Shut-Off Treatment

2.6.1 Introduction:

This product joins several chains of PHPA and this cross linking results in the formation of gel. During crosslinking the -COOH present in PHPA polymer and -OH in the product formed above combine together resulting in the loss of a water molecule and a link is created between them through oxygen. Polymer solutions and crosslinking agents are mixed together to form a gelant solution. Gelants can flow into porous matrix rock. With time and on chemical crosslinking gelants develop 3-D structures that will not enter into, or flow through, porous rock of normal permeabilities if the gelation occurs too quickly. Gelation time determines how far a gelant can penetrate into a porous rock. Gelation time for most commercial gelants is fairly short even at moderate temperatures. There are several methods to increase gelation time. Higher molecular weight polymers that are incorporated into gel formulations used to treat reservoir high-permeability anomalies, such as fractures, require lower concentrations for 3-D gel formation.

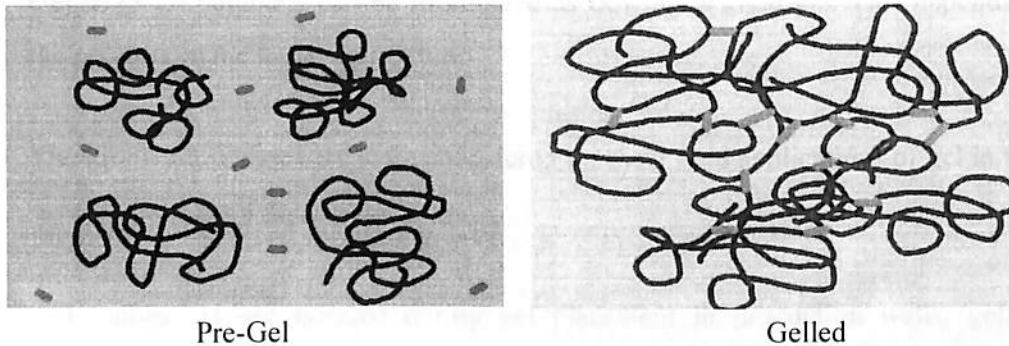


Figure 11: Gel Formation as Crosslinkers contact polymer molecules

Water soluble polymers such as polyacrylamides and polysaccharides have been used as means for improved oil recovery since 1990's. These polymers are crosslinked to form three dimensional structures. For polyacrylamide based gels, the cross-linker can be either metallic or organic. In metallic cross-linking, the carboxylate groups of the polymer chain react with multivalent cations forming ionic bonds. Chromium is the most commonly used metallic cross-linker. A major disadvantage of the chromium-based cross-linkers is their toxicity, especially those that are based on Cr^{+6} . Moreover, the ionic bonds that formed between the polymer and cross linker are unstable at high temperatures. Another concern with inorganic cross-linker is their short gelation times at

temperatures greater than 60°C. At temperatures greater than 100°C, Polyacrylamide based polymers exhibit hydrolysis and oxidative degradation of the polymer chains. Organically cross-linked gels are known to have good stability at elevated temperatures. This is attributed to the covalent bonds that form between the polymer and the organic cross-linker. These gels were reported to be stable at temperatures up to 150°C. In our study we have used the organic crosslinkers as the field being studied is a high temperature field. Also at temperatures greater than 75°C, and in the presence of multivalent cations, over cross-linking occurs, which results in expulsion of water out of the gel structure, known as Syneresis.

Examples of metallic cross-linker.

Aluminum (+3), Chromium (+3&+6), Zirconium (+3), titanium, boron etc.

Examples of organic cross-linkers.

Phenol: phenol, hydroquinone, resorcinol, phenyl acetate, salicyl alcohol, furfuryl alcohol

Aldehydes: formaldehyde, paraformaldehyde, hexamethylene tetramine (HMTA) etc.

Gelled (3-D) polymers can be formulated as flowing or rigid gel. This depends on the loading of the polymer in the make-up mixture

The following features are to be considered for most field applications of gel in production wells in order to have ideal gel placement:-

- If zones are not isolated during gel placement in production wells, gelants can penetrate significantly into all open zones, not just those with high water saturations.
- In core flood experiments in oil-wet cores, capillary effects could inhibit an aqueous gelant from entering the core. In field applications, however, the pressure drop between injection and production wells usually is so large that capillary effects will not prevent gelant penetration into oil productive zones and this can result in loss of oil productivity.
- Oil productivity loss after treatment in vertically fractured wells is expected to be less than that in unfractured wells.
- In the ideal gel placement, the fracture is plugged far from the wellbore but the fracture remains open near the well. Then water channeling can be reduced while maintaining a high productivity for the well.
- In vertical fractures that cut through multiple zones in case of horizontal wells, we might want

- to exploit gravity and density differences to place gel in lower part of the fracture, thereby reducing water influx from the lower zones while leaving the upper part of the fracture open to oil flow.
- If the distance of gelant leak off is great, the near wellbore region could be plugged and the gel treatment could do more harm than good.

Ideal microgels for water shut-off should have the following characteristics:-

- Insensitive to shear and reservoir physico-chemical conditions.
- Size controlled i.e., small enough to ensure as in depth treatment and large enough to reduce significantly water permeability.
- Soft enough to be disproportionate relative permeability modifiers.
- Strongly adsorbing onto pore surface for a long time.
- Non-toxic for the environment.

2.7 Gelation

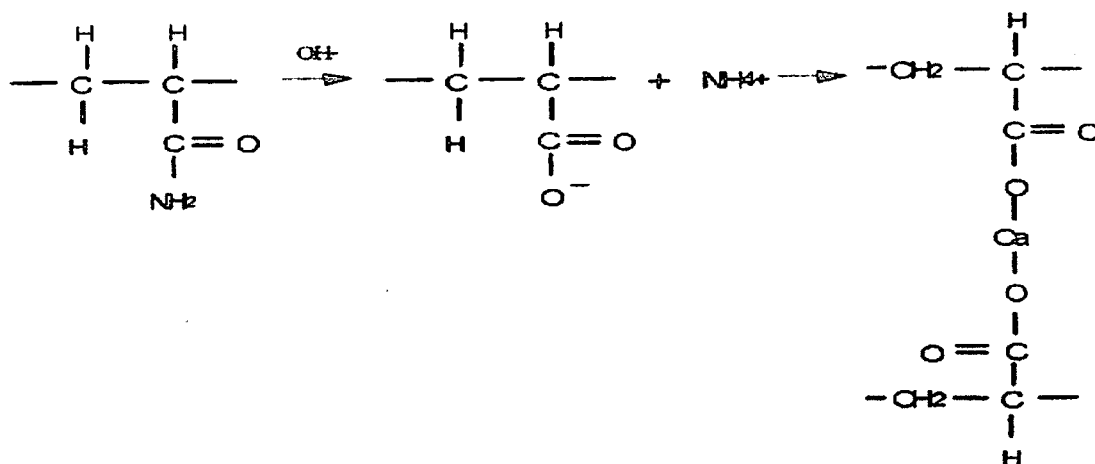
Polymer gel system starts as a flowing mixture of two components – polymer and another chemical called a cross-linker. After sometime, each cross-linker molecule, which is tiny as compared to the polymer molecule, starts attaching itself to polymer molecules chemically linking them together. The result is a three dimensional tangle of interconnected polymer molecules that ceases behaving like a fluid and can eventually constitute a rigid, immobile gel.

2.8 Polymer:

The polymer may be naturally occurring or may be manufactured synthetically. The cross-linker may be metal ions or metallic complexes that bond ionically to polymer or organic molecule that bond covalently. Polyacrylamide is a readily available polymer comprising of a carbon-carbon backbone hung with amide groups, possibly tens or thousands of them to provide molecular weight.

However, when mixed with a little alkaline solution, such as sodium hydroxide or sodium chloride or when subjected to elevated temperatures, some of the amide groups convert to carboxylate groups. Each of these carries a negative charge. The proportion of amide group that converts into carboxylate group is called the degree of hydrolysis and typically varies from 0 to 60%.

In this form the polymer is called partially hydrolyzed Polyacrylamide (PHPA) and its negatively charged carboxylate group is susceptible to ionic cross-linking.



The carboxylate group has a very high affinity for Hydroxyl group (H_3O^+) and so this gel has got a tendency to move towards the water saturation and get solidify and in turn restrict the permeability of water in the reservoir.

Partially hydrolyzed Polyacrylamide has carboxylic acid and amide groups in the proportion as per the degree to which it is hydrolyzed. Hexamine ($\text{C}_6\text{H}_{12}\text{N}_4$, mol wt: 140.19) at higher temperature and in presence of water forms formaldehyde and Ammonia. Hydroquinone ($\text{C}_6\text{H}_6\text{O}_2$, mol wt: 110.11) on reaction with formaldehyde forms.

Similar reaction takes place on the other sides thus several chains of PHPA polymer are crosslinked.

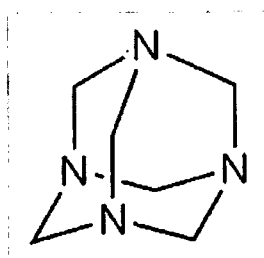
To make the gelant we are not using high concentrations of cross linkers and so there will not be any formation of phenol formaldehyde resin.

The polymer used for the present study is MAGNAFLOC - 24. It is a high molecular weight PHPA copolymer.

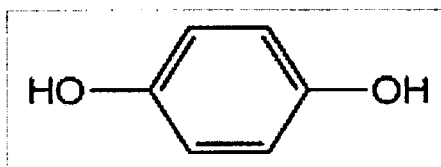
2.9 Cross-Linkers

Organic cross linkers are used to link the polymer molecules. Organic cross-linkers used in this project are of Hexamine and Hydroquinone.

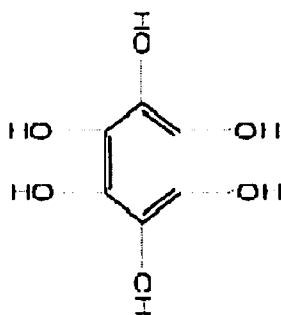
The structure of Hexamine is as shown below:



At high temperature this structure breaks into formaldehyde and NH_3 .



The reaction between Hydroquinone and formaldehyde give rise to:



2.10 Hydrolysis and precipitation of Gels

2.10.1 Implications of precipitation

If precipitation occurs before the PAM solution or gelant solution has been placed in the desired locations, it is useless. However, if it happens after the solution/gelant has been placed properly in matrix; the effect may be relatively minor. In fractures, precipitation will cause complete treatment failure.

Deep Matrix Penetration

At the pore scale, there are three main issues:

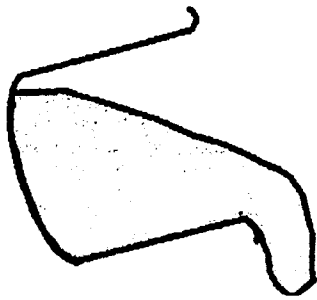
Differential Adsorptivity: Some part of both the polymer as well as cross-linker will get adsorbed onto the pore walls during injection. If the adsorptivity of the two components are different, then the volumetric ratio of polymer to cross-linker will change as the treatment invades the formation, possibly compromising control of gelling time. Addition of sodium glycolate was shown to reduce this adsorption/precipitation problem of Cr (III) cross linker in laboratory.

Polymer Elasticity: Polymers being long, complex molecules exhibit a degree of elasticity that makes how they move somewhat dependent on their surroundings. For example, the viscosity observed in a free polymer solution will not necessarily be mirrored when the same polymer is trying to squeeze through a pore throat. In general, polymer elasticity inhibits the progress of treatment fluid through porous medium.

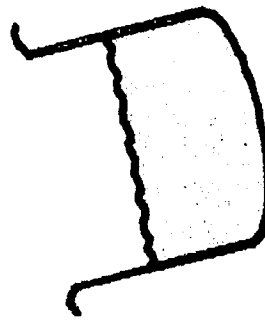
Pore Throats Blockage: Pore throats may get blocked by microclusters/ microgels containing several polymer molecules. All these issues are being researched and to an extent represent the key to leaping from laboratory evidence to certainty on what happens in the field.

2.10.2 Gelation Control at Elevated Temperature

Chemical process always speeds up with elevated temperature, and this makes gelling increasingly difficult to control. This is one of the important parameters that dictate design of a PAM gel treatment. Working time is required to place the polymer solution at desired location(s) before it gels. This is one of the key drivers in the evolution of PAM gels. These retarders can have detrimental effects on the final strength of the resulting gels.



Flowing Gel



Rigid Gel

2.10.3 Gelation Time and Factors Affecting It

The gelation time is defined as the time needed to reach a certain viscosity.

- **Effect of the Initial pH Value on the Gelation Time**

In a typical field application, the pH value of the gelling solution may change upon mixing with reservoir fluids and contacting the formation. The presence of acidic gases can also lower the pH somewhat. There is a rapid increase in the viscosity of the gelling solution at acidic pH conditions but the gel has a very short life and breaks.

At pH greater than 8, there is increase in gelation time and a stable gel is formed. The most important conclusion that can be inferred from these results is that the gelation time depends on the initial pH value of the solution. Low pH values can adversely affect the gelation process.

- **Effect of Temperature on the Gelation Time**

Temperature is a key parameter that determines the gelation time. The gelation time at reservoir temperature is needed to find out how deep the gel can be placed in the formation and how long the shut-in time should be. At room temperature, the viscosity of the gelling solution is observed to increase but no gelation occurs. As the temperature is increased the gelation occurs quickly and the gelation time decreases. This shows the endothermic nature of the gelation reactions.

Thus it is clear that the gelling solution should be pumped within a few hours following mixing on the surface. It will be difficult to pump a gelling solution that has been sitting in the mixing tank for several days.

- **Effect of polymer and cross-linker concentration on Gelation Time**

It is observed that increasing the cross-linker and polymer concentration reduces the gelation time. This is because, as the polymer concentration or the number of cross-linking sites increases, the rate of gel formation increases and hence, the gelation time decreases.

- **Effects of Mixing Water on the Gelation Time**

Gels can be prepared in the field using fresh water, aquifer water or seawater. These waters contain various ions that can impact the gelation process. Therefore it is of interest to measure the gelation time for gels prepared in various waters.

The gelation time for the gel prepared in sea water is nearly double than that for gel prepared in distilled water, as increasing the salt content of the mixing water delays the cross-linking process and increases gelation time.

At high temperatures, the ester groups thermolyze/hydrolyze into carboxylate groups, which carry negative charges. Carboxylate groups can also form upon the hydrolysis of the amide groups of the polymer in alkaline conditions. The repulsive forces between the negative charges will increase the hydrodynamic volume of the polymer chains. As a result, the cross-linking sites become more accessible to the cross-linker molecules. This explains the short gelation time that is achieved by using distilled water.

On the other hand, the concentrations of mono and divalent cations in seawater are high. The cation shields the negative charges available on the carboxylate groups and, as a result, the polymer chains collapse. Consequently, potential cross-linking sites on the polymer chain are not as

accessible to the cross-linker molecules. Thus the gelation time will be longer in this case and hence the gel will take a longer period of time to form.

If only saline water is available on the site, then the gelation time can be reduced by either increasing the concentration of the polymer or the cross-linker. However, adding too much cross-linker may cause over cross-linking and loss of gel volume with time, which is known as gel syneresis. Syneresis is not desirable, especially when the gel is placed in naturally fractured reservoirs. This is because the reduction in gel volume will generate new flow paths, which will reduce the effectiveness of the gel treatment. It is generally observed that gels prepared in saline water are physically weaker than those prepared in distilled water.

2.10.4 Problems with PAM Gels

Gel Stability

Instability in a polymer gel can result in three distinct phenomena:

- (a) Syneresis, (b) Precipitation, (c) Breakage, (d) Shear Degradation

(a) Syneresis

It means a collapse of the gel structure, generally characterized by a loss of adhesion, reduction in volume and expulsion of water. This commonly observed form of instability has been observed for all polymer systems. It does not result from chemical bond breakage. Possible causes are, excess crosslinker, polymer hydrolysis and divalent ions (Ca).

(i) Excess cross-linking

The polymer-to-gel transformation is mediated by a chemical cross-linker. As the cross-linker bonds to reactive groups on adjacent polymer chains, the effective molecular weight of the polymer increases. Above some threshold, the solution becomes a viscoelastic solid. Where too much cross-linker is present, cross-linking continues well past the point of gelation. This causes the polymer gel to contract in volume (synerese) expelling water as it does so. Depending on the composition, a syneresed gel may occupy as little as 5% of the initial solution volume.

ii) Polymer hydrolysis

At high temperature and interaction with divalent ions syneresis can happen. It can also happen from chemical modification of the polymer during ageing. The PAM based polymers used in WGSO are prone, to a greater or lesser degree, to hydrolysis at elevated temperature (DH depends on temperature). Hydrolysis converts acrylamide groups on the polymer backbone to the acrylate functionality, whose interaction with divalent cations can lead to syneresis of the polymer gel. Therefore, syneresis is a strong function of temperature and divalent ion concentration.

Implications of Syneresis

After a gel has syneresed, the final gel volume will only be a fraction of the initial gel solution volume. It has been shown that permeability of a gel-treated porous medium does increase as syneresis proceeds. However, the degree of permeability reduction in cores remains technologically useful even when 95% syneresis is observed in bulk samples. In contrast, in a fracture system, the effects of syneresis are expected to be much more important than in matrix applications.

(b) Precipitation

The amide groups present in PHPAM polymers will hydrolyze in aqueous solutions to an extent that depends on pH and temperature. The resulting, more hydrolyzed PAM may have a degree of hydrolysis sufficient to cause precipitation in the reservoir or injection water used (PAM loses solubility in water after about 40% conversion to acrylic acid). The Degree of Hydrolysis is, however, largely independent of the brine composition. For example, in brines containing large amounts of sodium chloride, but less than 20 ppm total hardness, PAMs appear to be indefinitely stable, at least at temperatures up to 400°F if no oxygen is present. It is also widely accepted that precipitation is the result of interaction between divalent cations and the carboxylate groups present within the hydrolyzed polymer. Strong site binding apparently occurs between the divalent cation and two carboxylate groups on the polymer. Whether actual precipitation occurs is, however, temperature dependent. If the temperature of a solution of PAM in water containing divalent cations is gradually raised, the solution will, in general, turn cloudy at a temperature called the "cloud point" of that system. If the temperature is raised further, precipitation follows. The cloud point temperature has less dependency on polymer molecular weight and polymer concentration.

(c) Breakage

In some cases, gel strength may develop, and then gradually decrease to a water thin solution. This involves the breaking of chemical bonds, with the resulting loss of molecular weight and structure. Probable causes are oxygen contamination, peroxide contamination, free radical generation etc. The implication of gel breakage is that after an initial short-term positive result, it gradually returns to the original flow conditions.

(d) Shear Degradation

Polymers are shear degradable. Some degradation may occur as polymer passes through a pump, in turbulent flow through pipes and tubing, through perforation tunnels and through formation pores. The result of shear degradation is that polymers are less effective in reducing water production. It is commonly recommended that the injection rate be controlled to less than 0.05 bpm per perforation, unless fractures are present. In spite of an abundance of technical literature showing the shear degradation problem in lab tests, many excellent successes have been obtained with water shut-off treatments when the injection rate was much greater than 0.05 bpm. At least in part, this apparent contradiction is explainable because shear degradation is much less severe in fractured wells, since the fractures substantially increase the area of entry into the matrix. PAM gelants are shear degradable as well. Gels made from degraded polymers may not gain the final expected strength after placement.

CHAPTER 3:

OVERVIEW OF EQUATIONS AND METHODS USED IN CASE STUDY

3.1 Introduction

In order to find out the correct polymers and cross linkers, their concentration which is needed for the effective water shut off treatments job; a core from the field is taken and its analysis is done in the laboratory. Thus on the basis of the core analysis and laboratory studies, WSO job is performed. In order to find out the change in the relative permeability and production rate of oil and water, Darcy's Law is then used. We will now discuss properties of polymers and its determination and the method of core flow studies.

3.2 Determination of Active Content

The Active content is the percentage of polymer solid content on drying. It is obtained by deducting moisture content from the sample. The procedure for determining moisture content is clearly explained.

Apparatus:

- Ventilated Oven

- Analytical Balance (0.0001 gms)

- Covered Petri-dish

- Dessicator

- Tissue paper

- Spatula

3.2.1 Procedure

Weigh about 5 gms of Polymer in a tarred glass dish (M1). Place the dish in the oven, maintained around $105 \pm 2^\circ\text{C}$ for about 2 hrs. Cool the dish in the dessicator and weigh. The sample is to be re-heated for 30 minutes, cooled and weighed again. Heat the sample again for 30 minutes in the air oven, cool and re-weigh. Continue till a variation in the mass of the polymer not more than 5 mg is obtained for 30 minutes drying time (M2).

3.2.2 Calculation

The moisture content of the formula is calculated from:

$$\text{Moisture Content, \% by mass} = (M1 - M2) * 100 / M1$$

Where M1 = Mass of polymer in grams taken for testing

M2 = Mass of polymer in grams after drying.

3.3 Determination of Insoluble Residue:

Generally polymers contain some impurities and insoluble particles. The amount of insoluble particles present in a given polymer must be determined. The procedure for determining Insoluble Residue is clearly explained.

3.3.1. Apparatus:

- 2 lts. Glass beaker
- Millipore filter holder and assembly
- 120 mesh stainless steel screen
- Dessicator
- Graduated Measuring cylinder (250 ml)
- Ventilated Oven

3.3.2. Reagents:

- Sodium Chloride
- De-mineralized /double distilled water

3.3.3. Procedure:

Place 200 ml of stock 0.5% polymer solution in 2 lts beaker, add 800 ml of 2% NaCl brine and mix with magnetic stirrer for at least 15 minutes to get 1000 ml of homogenous solution of polymer (0.1% or 1000 ppm).

Wash the mesh screen with acetone and rinse with distilled water at least four times and let it dry in an oven at $105\pm 2^{\circ}\text{C}$ for 2 hrs or till constant weight. Remove 120 mesh screen from the oven, cool it in a dessicator and weigh the screen to an accuracy of 0.0001 gm. This is Weight 1. Filter 1000 ml of 0.1% polymer solution through 120 mesh screen, using glass filter assembly under gravity. Rinse the beaker with a minimum amount of 200 ml of distilled water at least three or four 24 times to ensure that all insoluble particles from beaker are transferred into mesh screen. Wash the insoluble matter retained on screen with filtered distilled water till the filtrate is clean of chloride ions.

The insoluble matter retained on the screen is now dried in oven at $105\pm 2^{\circ}\text{C}$ till constant weight is obtained. Remove screen from oven and cool it in a dessicator. Re-weigh it to an accuracy of 0.0001 gm. This is Weight 2.

Insoluble Matter % = $(\text{Weight 2} - \text{Weight 1}) * 100 / \text{Weight of polymer in the solution}$

3.4 Determination of Brook Field Viscosity of Polymer Solution

Brook Field Viscosity is determined by using spindle 1 at 60 RPM and UL adapter (with spindle at 60 RPM). Brook Field Viscometer is extensively used under field conditions to determine viscosity. It is designed in such a way that it can be used at field conditions. The viscosity will be measured for 0.1% polymer solution in 2% NaCl brine at 40°C.

3.4.1. Apparatus

- 250 ml glass beaker
- Graduated cylinder/ pipette
- Magnetic Stirrer
- Thermometer
- Analytical Balance
- UL Adapter(open cup)
- Spindle 1
- Constant Temperature Bath
- 120 mesh SS steel screen
- pH meter & buffer standards

3.4.2. Procedure

The pH of the solution is adjusted to $8 \pm 0.05^\circ\text{C}$ by using dilute NaOH and/or HCl. Lift the lower shaft of viscometer and attach spindle nut. After attaching adapter body, place the hook on the UL spindle through eyelet of the spindle nut. Transfer 16 ml of the polymer solution to be measured into UL adapter cup. With the spindle held at an angle, slowly immerse the spindle into polymer solution. This is required to ensure no air entrapment. Attach the cup to main adapter body. Set the desired speed on the speed indicator knob. Start at the lowest and work upward. The speed must be changed while the motor is running and clutch is depressed. Immerse the cup into constant temperature bath up to main adapter and start rotation of spindle by depressing the clutch, turning on motor and releasing clutch.

Take the reading on scale by depressing clutch and turning motor off with the pointer in view. The rotation speed and readings are noted.

The same procedure is followed for the 0.2% polymer solution in 2% NaCl Brine.

Viscosity of polymer solution in cp is given by:

$$\text{Viscosity of polymer solution} = (\text{Reading Value} - 0.4) * 0.1$$

3.5 Relative Viscosity

Relative viscosity (η_r) (a synonym of "viscosity ratio") is the ratio of the viscosity of a solution (η) to the viscosity of the solvent used (η_s),

Relative Viscosity of a polymer solution is to be determined by Cannon Fenske routine Viscometer at 40°C .

3.5.1. Apparatus

1. Routine Cannon Fenske Viscometer (Size 75)
2. Pipettes of 2 and 5 ml
3. Stopwatch
4. Temperature Controlled water bath

3.5.2. Procedure

Adjust the pH of 0.1% polymer solution to 8 ± 0.05 by using dilute HCl or NaOH solution. A clean dry Cannon Fenske Viscometer which will give a minimum flow time of 200 seconds is selected.

7 ml of sample solution is pipetted out and is transferred to the viscometer. Insert the viscometer into a holder and place in constant temperature bath maintained at 40°C . With viscometer aligned vertically apply the suction and allow the sample to be filled to a level above the upper mark. The efflux time is obtained by allowing sample to flow freely and measuring time for meniscus to pass from upper mark to lower mark. Repeat the flow time measurements unless two figures fall within 1%. Take average of two readings.

Flow times of 2% NaCl brine (t_0) and polymer solution (t) are measured as described above

The ratio of the flow times of polymer solution and 2% NaCl brine gives Relative Viscosity¹

Relative Viscosity (η_r) = t/t_0

The same viscometer and stopwatch must be used to determine all the flow times of the brine and polymer solutions.

3.6 Intrinsic Viscosity

A measure of a solute's contribution to the viscosity η of a solution. It can be possible to find this quantity also named as "Inherent Viscosity", which actually is its name into the macromolecules literature. It is defined as

$$[\eta] = \lim_{\varphi \rightarrow 0} \frac{\eta - \eta_0}{\eta_0 \varphi}$$

where η_0 is the viscosity in the absence of the solute and φ is the volume fraction of the solute in the solution. As defined here, the intrinsic viscosity is a dimensionless number

Intrinsic viscosity of a polymer solution will be determined by using routine Cannon Fenske Viscometer at 30°C .

3.6.1. Apparatus:

- Routine Cannon Fenske Viscometer (Size 75)
- Pipettes of 2,5,10 and 20 ml.
- Standard Flasks (500, 100 and 50 ml)
- Thermometer
- Stop Watch
- Temperature Controlled Water Bath
- Magnetic Stirrer
- Analytical Balance
- De-mineralized/ Distilled Water
- 1M NaNO₃ solution

3.6.2. Procedure:

500 ml of 1M of NaNO₃ solution is prepared. 100 ml of 0.2% polymer solution in 1M NaNO₃ solution is prepared. The following solutions must be prepared. 0.16% solution – by diluting 40 ml of 0.2% to 50 ml in Std. flask

0.12% solution – by diluting 30 ml of 0.2% to 50 ml in Std. flask

0.08% solution – by diluting 25 ml of 0.16% to 50 ml in Std. flask

0.04% solution – by diluting 10 ml of 0.2% to 50 ml in Std. flask

Measure the Relative Viscosities of each of the samples. Calculate relative viscosity, specific viscosity and reduced viscosity.

$$\eta_r = t/t_0$$

$$\eta_{sp} = \eta_r - 1$$

$$\eta_{red} = \eta_{sp}/C$$

Where η_{red} is the reduced viscosity and C, the polymer concentration in gm/dl

3.7 .Degree of hydrolysis

Potentiometric titration method is used to determination the degree of hydrolysis of the polymer sample.

Apparatus:

- Electronic pH meter
- Magnetic stirrer with paddle
- Burette(25 ml)
- Glass beaker(100ml)
- De-mineralization/double distilled
- Conc. HCl
- Std. NaOH

3.7.1. Procedure:

Weight accurately about 0.3-0.4 gms of polymer and transfer to a clean 100 ml beaker containing 150 ml de mineralized / double distilled water. Put a 1.5l magnetic paddle in the beaker and place on the magnetic stirrer adjusting the stirrer to a low speed (40-60 rpm). Continue to stir the solution at low speed for 2-3 hours and let it stand overnight.

Insert the pH electrodes in the polymer solution, adjust the stirrer to a low speed (40-40) and allow sufficient time for stabilization. Note the pH. Bring the pH of the solution down to 3.0 with drop-wise addition of 0.1N HCl. Add Std. NaOH solution in small aliquots from a burette. Note the pH

of the solution and burette reading after each addition of alkali. The solution should be well mixed and sufficient time be given for stabilization before taking the reading.

The volume of Std. NaOH solution required to raise the pH of the polymer solution from 3.3 to 7.0 is obtained.

Degree of hydrolysis in % = vol. of NaOH, ml * Normality of NaOH * 71

10 * wt of polymer used in gms

Weight of polymer C used: 1) 0.20 gms and 2) 0.3 gms

Normality of NaOH : 1 N (6 gms in 150 ml distilled water)

3.8 Core flow Studies

In order to assess how far the polymer gel has been effective in preventing the flow of water, core flow studies can be carried out by simulating the bottom hole temperature condition. The core from the particular field of interest can be used, impregnated with the polymer gel, followed by oil flooding and later brine. The residual resistance factor to brine flow can be calculated.

Disproportionate permeability reduction occurs when the permeability to brine (formation water) after the polymer reduces by larger amount than the permeability to oil.

This often expresses in terms of **Residual Resistance Factor (Frr)** for oil and brine.

The residual resistance factor for oil (F_{rro}) is defined as

$$(F_{rro}) = k_o/k_{og}$$

Similarly, the residual resistance factor for brine (F_{rr}) is defined as

$$(F_{rrw}) = k_w/k_{wg}$$

Where k_{og} and k_{wg} are the permeability to oil and water at endpoint saturation after gel treatment, and k_o and k_w are permeability to oil and water before treatment, at interstitial water saturation water saturation and residual oil saturation, respectively. Thus, disproportionate permeability reduction occurs when $(F_{rro}) < (F_{rrw})$.

3.8.1. Equipment and Apparatus:

1. A clean core
2. Positive displacement pump
3. Air oven
4. Pressure Transducers
5. Thermometer
6. Cerro metal
7. Field oil or kerosene
8. Berea core in absence of well core
9. Pressure measuring cylinder
10. Pressure gauges with hastelloy
11. Connector
12. Heating tape

3.8.2 Core cleaning:

Prior to most laboratory measurement porosity and permeability, the original fluids must be completely removed from the core sample. This is generally accomplished through flushing, flowing, or contacting with various solvents to extract hydrocarbons, water, and brine. The various solvents used for extracting core samples can be reclaimed by well-known physical and chemical methods.

Selected solvents and their use:

SOLVENT	BOILING POINT °C	SOLUBILITY
Acetone	56.5	Oil, water, salt
cyclohexane	81.4	Oil
Ethylene chloride	83.5	Oil, limited water

Hexane	49.7-68.7	Oil
Naphtha	160	Oil
Toluene	110.6	Oil, limited water
Trichloroethylene	87	Oil, limited water
Xylene	138-144	Oil

Table 4

3.8.3 Distillation extraction method:

The Soxhlet extractor and suitable solvents should be used to dissolve and extract oil and brine. Extraction can be arranged in a manifold so that oil and water-laden solvent siphons from each extractor into the still from which fresh solvent is continuously distilled, condensed, and again come into the extractors. The cleanliness of the sample is best determined from the colour of the solvent that siphons periodically from the extractor. Extraction should be continued until the extract remains clear. Non - luminescence of extract under fluorescent light is a good criterion for determining complete extraction of the oil for a given solvent. It should be noted that the complete extraction of certain oils from core samples may require more than one solvent, and the fact that one solvent is clear after contact with the sample does not necessarily mean that oil has been

completely removed from the sample. Cleaning a core removes original fluids from the core, preparing it for further tests that do not require those fluids.

Core drying:

Conventional core sample can be dried by the methods listed below:

ROCK TYPE	METHOD	TEMPERATURE oC
Sandstone	Conventional oven	116
(low clay content)	Vacuum oven	90
Sandstone (high clay content)	Humidity oven , 40% relative humidity	63
Carbonate	Conventional oven	116
	Vacuum oven	90
Gypsum- bearing	Humidity oven, 40 % relative humidity	60
Shale or other high clay	Humidity oven, 40% relative humidity Conventional vacuum	60

Table 5

3.9 Determination of Permeability:

Permeability is a measure of the formation to transmit fluids. Unit of permeability is DARCY, named after the French scientist Henry Darcy. The permeability is measured by flowing a fluid of known viscosity μ , through a core plug of measured dimension area (A) and length (L). Measuring flow rate (Q) and pressure drop (ΔP). Darcy equation becomes:

$$K = Q\mu L / A\Delta P$$

CHAPTER 4: CASE STUDY ANALYSIS

4.1 CASE STUDY 1. Development of Polymer Gel System for Water Cut Reduction, Jhalora Field, Ahmadabad Asset, India

Jhalora GGS-I was commissioned in 1977. Around 60% of the wells connected to this GGS are on Gas Lift. With the ageing of the field the water cut being handled by the installation has increased to 85%, reducing the oil cut from the produced crude oil. Thus the production from these wells is not techno-economically feasible since this firstly reduces the oil cut and secondly this increases the load on the water handling facilities. In order to reduce the water cut, chemical treatment method has been used and a polymer gel system has been developed. For this purpose laboratory experiments have been carried out. The experiments have been performed on a core sample taken from the field using Hassler Core Holder. These experiments have been discussed below and the results have also been given.

4.1.1 Laboratory Experiments

EXPERIMENT 01

AIM: To study the gel strength and gelation time of the sample having different polymer cross linker concentrations at different temperatures.

Materials required: Distilled water, Polymer, Chromium (3+) Chloride, Formaldehyde, Urea, Isopropyl alcohol,

Equipment required:

Laboratory glassware, magnetic stirrer, PH meter, vial bottles and caps, oven,

Procedure:

Different concentration gels were made by mixing different concentration of polymer, cross linker and other chemicals in beakers with constant stirring action by the magnetic stirrer, and then they are sealed in vial bottles and put into the oven. After the specific period of time their stability is checked.

Observation: Tables are attached in the following pages.

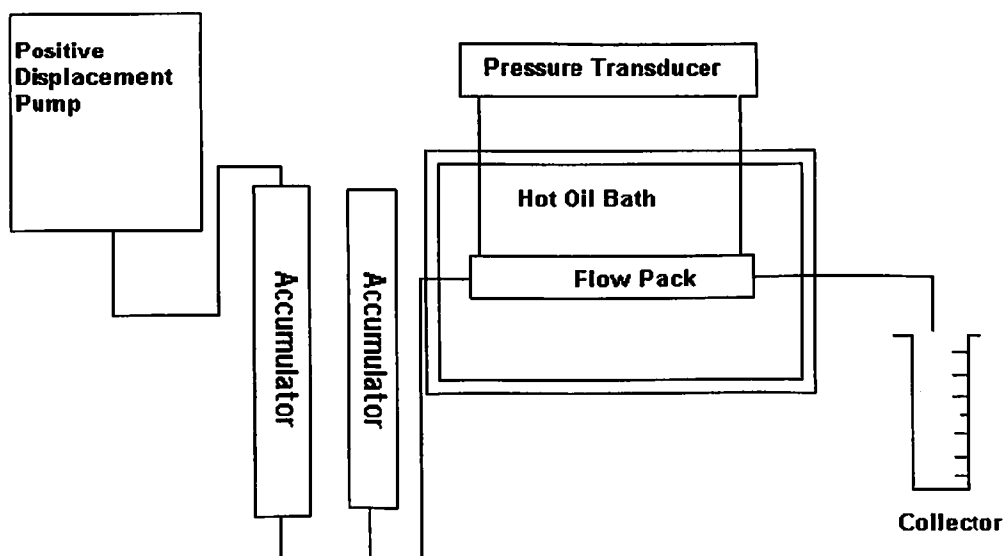
Precautions:

1. The polymer must be thoroughly and homogeneously mixed with water. Continuing agitation for 6 hours or more after mixing creates good homogeneity. If time permits the polymer solution may be prepared on the previous day and a whole night agitation will be helpful. Since these polymers are not easily biodegradable early preparation will not have any effect on gel quality.
2. Gel should be pumped through the core at a lesser flow rate as doing otherwise may lead to formation of a low permeability channel in the core.
3. Enough time should be given to the gel in the core to set before continuing with the experiment further.
4. Readings should preferably be taken at close intervals of time to ensure accuracy.

EXPERIMENT 02

Aim: Core Flow Study

Permeability reduction due to the swelling of gel was studied in a core flow setup as shown below. Results of permeability studies are given thereafter.



EQUIPMENT:

1. High precision RUSKA displacement pump
2. Accumulator manifold
3. Hassler core holder
4. Measuring cylinders
5. Funnels

Method:

1. Two core samples were prepared by using sands of grain size 20/20 and 20/40 to behave as high and low permeability zones respectively. These were then placed in the core holders.
2. 2% KCl brine was now passed through these cores at varying flow rates under a confining pressure and water bath temperature of 90 °C. Stabilized pressure readings and flow rates were recorded and average permeability as per measurement was calculated. Gel solution was prepared as per design and pumped through the cores.

The tow gel solutions prepared for core flow studies were of the following composition:

A) A-254S (3%), NaCl (5000ppm), Sodium dithionite (200ppm), Chromium acetate (1000ppm)

B) A-254S (4%), NaCl (5000 ppm), Sodium dithionite (200 ppm), Chromium acetate (2000ppm)

1. Disconnected and isolated the core holders after displacing with minimum 150 ml of gel solution each, were placed in a hot air oven at 90 °C for 24 hours.
2. Core holders were reinstalled in the setup and flow measurements were taken at three different stabilized flow rates.

- Permeability values were recalculated.
- Reduction in permeability w.r.t base permeability was also calculated.

4.1.2 THEORY:

High pressure precision RUSKA positive displacement pump, accumulator manifold, sand pack holder has been used in this study. In the core flow set up, Permeability reduction is checked by using formulated gel.

There is Four Type of flow in core holder using Core flow set up.

1. Pre- gelation Brine Flow
2. Gel Flow
3. Post gelation Brine Flow
4. Post gelation Diesel Flow

TABLE 7: Gel Flow

TABLE: Gel Flow

S.N	PUMP	Date/Time	Volume (cc)	Flow rate	Pressure
1	Pump 1	15/07/08 16:31:29	0.000000	0.000	-15
1	Pump 2	15/07/08 16:31:29	21.493792	5.000	3
2	Pump 1	15/07/08 16:31:39	0.000000	0.000	-15
2	Pump 2	15/07/08 16:31:39	22.328185	5.000	4
3	Pump 2	15/07/08 16:31:49	23.149373	5.001	3
4	Pump 2	15/07/08 16:31:59	23.983362	5.001	4
5	Pump 2	15/07/08 16:32:09	24.817354	5.001	5
6	Pump 2	15/07/08 16:32:19	25.651475	5.001	2
7	Pump 2	15/07/08 16:32:29	26.485467	5.001	3
8	Pump 2	15/07/08 16:32:39	27.319454	5.001	3
9	Pump 2	15/07/08 16:32:49	28.153580	5.000	3
10	Pump 2	15/07/08 16:32:59	28.987567	5.001	3
11	Pump 2	15/07/08	29.821559	5.001	3

		16:33:09			
12	Pump 2	15/07/08 16:33:19	30.655547	5.000	3
13	Pump 2	15/07/08 16:33:29	31.489671	5.000	4
14	Pump 2	15/07/08 16:33:39	32.323661	5.000	3
15	Pump 2	15/07/08 16:33:49	33.157650	5.000	3
16	Pump 2	15/07/08 16:34:00	33.991774	5.000	3
17	Pump 2	15/07/08 16:34:10	34.825762	5.000	3
18	Pump 2	15/07/08 16:34:20	35.659755	5.000	3
19	Pump 2	15/07/08 16:34:30	36.493875	5.000	3
20	Pump 2	15/07/08 16:34:40	37.327867	4.999	3
21	Pump 2	15/07/08 16:34:50	38.161854	5.000	3
22	Pump 2	15/07/08 16:35:00	38.995980	4.999	2
23	Pump 2	15/07/08 16:35:10	39.829967	4.999	3
24	Pump 2	15/07/08 16:35:20	40.663958	4.999	5
25	Pump 2	15/07/08 16:35:30	41.497948	5.000	2
26	Pump 2	15/07/08 16:35:40	42.332070	4.999	3
27	Pump 2	15/07/08 16:35:50	43.166062	4.999	4
28	Pump 2	15/07/08 16:36:00	44.000049	4.999	3
29	Pump 2	15/07/08 16:36:10	44.834042	4.999	3
30	Pump 2	15/07/08 16:36:20	45.668162	4.999	2
31	Pump 2	15/07/08 16:36:30	46.502154	4.999	2
32	Pump 2	15/07/08 16:36:40	47.336142	4.999	3
33	Pump 2	15/07/08 16:36:50	48.170267	4.999	3
34	Pump 2	15/07/08	49.004255	4.999	4

		16:37:00			
35	Pump 2	15/07/08 16:37:10	49.838245	4.999	3
36	Pump 2	15/07/08 16:37:20	50.672236	4.999	3
37	Pump 2	15/07/08 16:37:30	51.506358	4.999	4
38	Pump 2	15/07/08 16:37:40	52.340349	4.999	3
39	Pump 2	15/07/08 16:37:50	53.174336	4.999	3
40	Pump 2	15/07/08 16:38:00	54.008463	4.999	3
41	Pump 2	15/07/08 16:38:10	54.842449	4.999	3
42	Pump 2	15/07/08 16:38:20	55.676442	5.000	3
43	Pump 2	15/07/08 16:38:30	56.510562	5.000	3
44	Pump 2	15/07/08 16:38:40	57.344554	4.999	3
45	Pump 2	15/07/08 16:38:50	58.178543	5.000	3
46	Pump 2	15/07/08 16:39:00	59.012666	5.000	1
47	Pump 2	15/07/08 16:39:10	59.846656	5.000	3
48	Pump 2	15/07/08 16:39:20	60.680644	5.000	3
49	Pump 2	15/07/08 16:39:30	61.514637	5.000	3
50	Pump 2	15/07/08 16:39:40	62.348757	5.000	3
51	Pump 2	15/07/08 16:39:50	63.182749	5.001	3
52	Pump 2	15/07/08 16:40:00	64.016736	5.000	1
53	Pump 2	15/07/08 16:40:10	64.850728	5.001	3
54	Pump 2	15/07/08 16:40:20	65.684850	5.001	2
55	Pump 2	15/07/08 16:40:30	66.518840	5.001	3
56	Pump 2	15/07/08 16:40:40	67.352830	5.001	3

Table 8: Post Brine flow

9	Pump 2	16/07/08 13:17:13	123.586847	5.000	29	
10	Pump 2	16/07/08 13:17:23	124.420839	4.999	32	
11	Pump 2	16/07/08 13:17:34	125.254827	5.000	35	
12	Pump 2	16/07/08 13:17:43	126.088819	5.000	37	
13	Pump 2	16/07/08 13:17:53	126.922940	4.999	38	
14	Pump 2	16/07/08 13:18:03	127.756932	5.000	41	
15	Pump 2	16/07/08 13:18:13	128.590921	5.000	41	
16	Pump 2	16/07/08 13:18:24	129.425045	5.000	42	
17	Pump 2	16/07/08 13:18:34	130.259035	5.000	40	
18	Pump 2	16/07/08 13:18:44	131.093024	5.000	40	
19	Pump 2	16/07/08 13:18:54	131.927148	5.000	42	
20	Pump 2	16/07/08 13:19:04	132.761137	5.000	42	
21	Pump 2	16/07/08 13:19:14	133.595129	5.000	40	
22	Pump 2	16/07/08 13:19:24	134.429251	5.000	40	
23	Pump 2	16/07/08 13:19:34	135.263242	5.000	48	
24	Pump 2	16/07/08 13:19:44	136.097231	5.000	66	
25	Pump 2	16/07/08 13:19:54	136.931222	5.000	99	
26	Pump 2	16/07/08 13:20:04	137.765345	5.000	141	
27	Pump 2	16/07/08 13:20:14	138.599335	5.000	195	
28	Pump 2	16/07/08 13:20:24	139.433325	5.000	255	
29	Pump 2	16/07/08 13:20:34	140.267314	5.000	318	

30	Pump 2	16/07/08 13:20:44	141.101439	5.000	370	
β1	Pump 2	16/07/08 13:20:54	141.935428	5.000	400	
32	Pump 2	16/07/08 13:21:04	142.769419	5.000	373	
33	Pump 2	16/07/08 13:21:14	143.603541	5.000	233	
34	Pump 2	16/07/08 13:21:24	144.437532	5.000	139	
35	Pump 2	16/07/08 13:21:34	145.271521	5.001	96	
36	Pump 2	16/07/08 13:21:44	146.105512	5.000	78	
37	Pump 2	16/07/08 13:21:54	146.939635	5.000	67	
108	Pump 2	16/07/08 13:33:44	206.155591	4.999	70	
109	Pump 2	16/07/08 13:33:54	206.989716	5.000	70	
110	Pump 2	16/07/08 13:34:04	207.823704	4.999	69	
111	Pump 2	16/07/08 13:34:14	208.657694	5.000	71	
112	Pump 2	16/07/08 13:34:24	209.491685	4.999	70	
113	Pump 2	16/07/08 13:34:34	210.325808	5.000	69	
114	Pump 2	16/07/08 13:34:44	211.159798	5.000	70	
108	Pump 2	16/07/08 13:33:44	206.155591	4.999	70	
109	Pump 2	16/07/08 13:33:54	206.989716	5.000	70	
110	Pump 2	16/07/08 13:34:04	207.823704	4.999	69	
111	Pump 2	16/07/08 13:34:14	208.657694	5.000	71	
112	Pump 2	16/07/08 13:34:24	209.491685	4.999	70	
113	Pump 2	16/07/08 13:34:34	210.325808	5.000	69	
114	Pump 2	16/07/08 13:34:44	211.159798	5.000	70	
108	Pump 2	16/07/08 13:33:44	206.155591	4.999	70	

109	Pump 2	16/07/08 13:33:54	206.989716	5.000	70	
110	Pump 2	16/07/08 13:34:04	207.823704	4.999	69	
111	Pump 2	16/07/08 13:34:14	208.657694	5.000	71	
112	Pump 2	16/07/08 13:34:24	209.491685	4.999	70	
113	Pump 2	16/07/08 13:34:34	210.325808	5.000	69	
114	Pump 2	16/07/08 13:34:44	211.159798	5.000	70	
108	Pump 2	16/07/08 13:33:44	206.155591	4.999	70	
109	Pump 2	16/07/08 13:33:54	206.989716	5.000	70	
110	Pump 2	16/07/08 13:34:04	207.823704	4.999	69	
111	Pump 2	16/07/08 13:34:14	208.657694	5.000	71	
112	Pump 2	16/07/08 13:34:24	209.491685	4.999	70	
113	Pump 2	16/07/08 13:34:34	210.325808	5.000	69	
114	Pump 2	16/07/08 13:34:44	211.159798	5.000	70	
108	Pump 2	16/07/08 13:33:44	206.155591	4.999	70	

TABLE 9: Diesel Flow

10	Pump 2	16/07/08 12:51:22	9.210607	5.000	1
11	Pump 2	16/07/08 12:51:32	10.044598	5.000	2
12	Pump 2	16/07/08 12:51:42	10.878588	5.000	4
13	Pump 2	16/07/08 12:51:52	11.712577	4.999	6
14	Pump 2	16/07/08 12:52:02	12.546702	5.000	10
15	Pump 2	16/07/08 12:52:12	13.380690	5.000	13
16	Pump 2	16/07/08 12:52:22	14.214682	5.000	16
17	Pump 2	16/07/08 12:52:32	15.048671	4.999	24
18	Pump 2	16/07/08 12:52:42	15.882796	4.999	31
19	Pump 2	16/07/08 12:52:52	16.716785	5.000	42
20	Pump 2	16/07/08 12:53:02	17.550776	5.000	56
21	Pump 2	16/07/08 12:53:12	18.384899	4.999	74
22	Pump 2	16/07/08 12:53:22	19.218889	4.999	99
23	Pump 2	16/07/08 12:53:32	20.052880	5.000	132
24	Pump 2	16/07/08 12:53:42	20.886869	5.000	171
25	Pump 2	16/07/08 12:53:52	21.720994	5.000	222
26	Pump 2	16/07/08 12:54:02	22.554982	5.000	276
27	Pump 2	16/07/08 12:54:12	23.388974	5.000	336
28	Pump 2	16/07/08 12:54:22	24.223096	5.000	405
29	Pump 2	16/07/08 12:54:32	25.057088	5.000	471
30	Pump 2	16/07/08	25.891077	4.999	530

		12:54:42			
31	Pump 2	16/07/08 12:54:52	26.725068	5.000	509
32	Pump 2	16/07/08 12:55:02	27.559191	5.000	302
33	Pump 2	16/07/08 12:55:12	28.393181	5.000	159
34	Pump 2	16/07/08 12:55:22	29.227305	5.000	104
35	Pump 2	16/07/08 12:55:32	30.061294	5.000	78
38	Pump 2	16/07/08 12:56:02	32.563266	5.000	48
39	Pump 2	16/07/08 12:56:12	33.397388	5.000	43
40	Pump 2	16/07/08 12:56:22	34.231379	5.000	39
41	Pump 2	16/07/08 12:56:32	35.065369	5.000	39
42	Pump 2	16/07/08 12:56:42	35.899492	5.000	36
43	Pump 2	16/07/08 12:56:52	36.733482	5.000	35
44	Pump 2	16/07/08 12:57:02	37.567472	5.000	33
45	Pump 2	16/07/08 12:57:12	38.401463	5.000	33
46	Pump 2	16/07/08 12:57:22	39.235585	5.001	32
47	Pump 2	16/07/08 12:57:32	40.069577	5.000	32
48	Pump 2	16/07/08 12:57:42	40.903566	5.000	31
38	Pump 2	16/07/08 12:56:02	32.563266	5.000	48
39	Pump 2	16/07/08 12:56:12	33.397388	5.000	43
90	Pump 2	16/07/08 13:04:43	75.932751	5.000	24
91	Pump 2	16/07/08 13:04:53	76.766875	5.000	23
92	Pump 2	16/07/08 13:05:03	77.600864	5.000	24
93	Pump 2	16/07/08 13:05:13	78.434855	5.000	24

4.1.3 CALCULATION:

L=Length of core holder =31 cm R= Radius of
core=5.3 cm Area=22.07 Square cm

$$\text{Porosity} = (1 - 1.696/2.323 * 100) = 26.98\%$$

Using Darcy's Law formula, We can calculate permeability.

1. Before gel formed – Brine permeability

$$\text{Viscosity of NaCl is one and Permeability} = k = (Q * \text{Viscosity} * l / \Delta P * A) = 5/60 * 1 * 31 / 3 / 14.7 * 22 = 0.5737 \text{ Darcy} = 575.37 \text{ md}$$

2. after gel formed brine permeability = $k = 5/60 * 1 * 31 / 90 / 14.7 * 22 = 0.01917 \text{ darcy} = 19.17 \text{ md}$

3. Diesel Flow after gel Formed, Permeability = $5/60 * 45 * 31 / 22 / 14.7 * 22 = 3.5307 \text{ darcy} = 3530.7 \text{ md}$

$$\text{Damage Ratio} = (575.37 - 19.17) / (575.37) * 100 = 96.66\% \text{ Retain Ratio} = (19.17 * 100) / (575.37) = 3.33\%$$

4.2 CASE STUDY 2: Water Cut Reduction with cross linked polymer gel treatment, North Kadi Field, Mehsana Asset, India

High water cut is very acute in North Kadi field and producing sands are having a bottom water/edge water drive. Good reservoir properties, excellent aquifer support and adverse mobility ratio are jointly responsible for high water cut. The water cut is gradually increasing every year with the production of oil.

To design a proper gel formulation, experiments were carried out to find the suitability of different polymers received as per prevailing reservoir conditions of North Kadi field of Mehsana Asset.

After analyzing physical parameters, time – setting characteristics of cross – linked gel formulation were carried out at reservoir temperature. The studies were further extended to thermal stability, compatibility, solubility and return permeability studies on cores at reservoir simulated conditions.

Indigenous polymer samples were analyzed and finally two have been selected for field trial in North Kadi. These two polymer samples had shown good thermal stability and permeability reduction (around 90%) at 85°C. The formulation is compatible with reservoir matrix and good solubility of gelled mass is observed after mild acid soaking.

The gel formulation of both the polymers was implemented in four Wells code no. # W, X, Y and Z of North Kadi field of Mehsana Asset.

4.2.1 EXPERIMENTAL DETAILS

Laboratory experiments were conducted for commercially available indigenous partially hydrolyzed polyacrylamide polymer for inorganic crosslinked gel formulation. The gel system was designed by cross linking PHPA polymer with chromium (III)/ Thiourea redox system. The polymer samples were analyzed at the reservoir condition of North Kadi Field.

Extensive studies on qualitative method of gel determination, gelation kinetics and mechanism have been carried out on various polymer samples with inorganic cross-linkers at 85⁰C. The solution of solid polymer was prepared by dissolving the polymer in NaCl (0.2%) solution and kept for hydration for 24 hrs. Gelling solution consisting polymer and X-Linker were mixed appropriately, kept in oven and inspected visually. These screening experiments provided a qualitative measurement of gelation time and gel strength. Out of the all products analyzed two products namely Code-A and B meet the requisite parameters for the reservoir conditions of North Kadi wells. Physical properties of both polymers are tabulated in Table -6. Laboratory result for optimized gel formulation is summarized in Table-7.

Return permeability core flow studies were carried out to get an idea about the potential of the formulated gel systems for water production control in the actual field conditions. Berea core was taken to evaluate the behaviour of optimized gel system in reservoir conditions. After the relevant conditioning of the core, effective brine permeability is measured which later on again measured and compared after gel flooding and setting. Results are as tabulated in Table - 8.

Compatibility test of product A & B was carried out with the synthetic brine, crude oil and rock matrix of producing horizon of North Kadi wells. Lab result shows that the gel formulation is compatible with North Kadi matrix. The stiff gel formed was subjected to solubility test in 15% HCl at 85⁰C. It is observed that the set mass is soluble in acid medium after 6 hours at 85⁰C. Thermal stability of gelled mass was observed in terms of syneresis and strength for three months at 85⁰C.

4.2.1 CANDIDATE SELECTION

The selectivity of low viscous gelling system to water shut off in production wells is believed to be due to ease of penetration of the chemical into watered out zone. The polymer selection is based mostly on it's capability to adsorb on the reservoir rocks, compatibility and stability at reservoir conditions and economics. The reservoir properties, geological analysis, petrophysical properties PLT surveys and well production history are considered for useful diagnostic tools for the selection of suitable wells.

4.2.3 FIELD IMPLEMENTATION

The above studies suggest that polymer product code- A & B are suitable for WSO job in North Kadi wells of sand KS-IA. Therefore, it was proposed to implement both the polymers for WSO job on trial basis. Well selection and implementation modalities were carried out jointly with Mehsana Asset. Reservoir properties of North Kadi field are provided in Table- 9. For product-A, well no; NK-X and NK-Y and for product-B, well no; NK-W and NK-Z have been identified for the execution of WSO job.

The volume of gel system is based on the penetration of 8-10 m. Before the gel pumping, the well bore was cleaned and injectivity of well was found. The water shut-off jobs were carried out by preparing and pumping 90-100 m³ of the polymer solution treated with salt, thiourea, sodium sulphite and potassium dichromate solutions at the rate depending upon the injectivity.

Displacement with relevant crude oil was followed with required volume of the depth of the well. Individual well was kept shut-in for five days and was opened thereafter with 5-8 mm bean. Implementation details carried out are given in the Table-10.

TABLES

Table 10: Physical properties of polymer sample Identified

Sl. No.	Parameter	Product Code	
		A	B
1.	State	White, Granular	White, Granular solid
2.	Ionic Nature	Anionic	Anionic
3.	Viscosity of 1% soln. in 2% NaCl (at 511 Sec ⁻¹)	68	45
4.	Viscosity of 1% soln. w/o NaCl (at 511 Sec ⁻¹)	72	42
5.	pH of 1% Soln.	7.28	7.9

Table 11: Laboratory testing for the optimization of Gel formulations

Sl. No.	Product Code	Polymer conc. in	Inorganic X-Linker		Gel Quality	Gelation Time
			Pot. di-	Thiourea (ppm)		
1	Code-A	8000	1000	1000	VF	35
		8000	1500	1500	T	40
		10000	1000	1000	G	34
2	Code-B	8000	1000	1000	VF	38
		8000	1500	1500	SG	36
		10000	1000	1000	*	30

TG- Tonguing Gel; VF- Viscous Flow able, SG- Stiff Gel; * - Syneresis

Table 12: Return permeability core flow studies

Sl.No	Gel Solution	Parameters	Product	
			A	B
1	Polymer A&B. Polymer-10000 ppm.	Initial Permeability wrt. brine	490 md	40 md.
2	Salt - 2000 ppm. Sod. Sulphite- 200ppm	After treatment at 85°C for 48 hrs.	1 md.	1.5 md.
3	Pot. Dich.- 1500 ppm.	%reduction in K; wrt brine	99	95
4	Thiourea - 1500 ppm.	% Reduction in K; w.r.t. brine (After 1 month aging at 85°C)	98	94

Table13: Reservoir properties of North Kadi field

Oil producing Sand	KS-1, 2
Drilled	1000-1200
API	13-21Degrees
Av. Reservoir pressure	100
Reservoir temperature	75 -
Drive mechanism	Water
Average Porosity	25 –30%

Table 14: Details of WSO job implemented in wells of North Kadi Field.

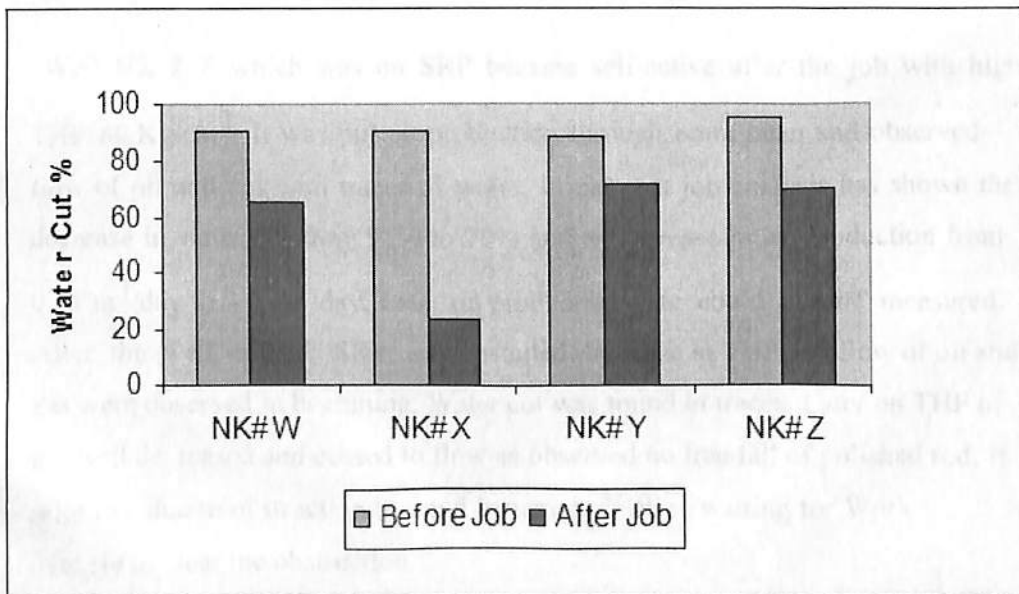
Well No.	Perforation interval	Water Cut (%) Before	Date of WS O Job.	Product Code	Gel Vol. pumped	Pumping pressure	displacement volume
NK# W	1065 – 1069 m	90	13.01.04	B	95 m ³	1300-1500 psi	3.3 m ³
NK# X	1036 – 1038 m	Ceased	16.07.03	A	100 m ³	100 psi	3.2 m ³
NK# Y	1068.5 – 1070.5m	90	06.02.04	A	95 m ³	50-250 psi	3.75 m ³ 250-500psi
NK# Z	1055– 1056m	98	04.07.03	B	100 m ³	125-250 psi	4.1 m ³ 400-450psi

Table 15: Summary Of Pre And Post Job Production Data

Well no. (Code)	Pre job data			Post job data			Additional oil gained
	QI m ³ / d	W/C %	Qo m ³ /d	QI m ³ / d	W/C %	Qo m ³ / d	
NK# W	21	90	2.1	13.5	65	4.7	100 m ³
NK# X	12	90	1.2	20	24	15.2	400 m ³
NK# Y	15	88	1.8	12	72	2.5	Initial good production no test data available.
NK# Z	15	95	0.75	10	70	3.0	Initial good production, no test data

FIGURES

Fig12 : Graph showing initial reduction in W/C after Implementation of WSO Job



CHAPTER 5: RESULTS AND DISCUSSION

For Case Study 1

1. Well NK # W becomes active on reinstallation of SRP. Production testing data shows a decrease in water cut from 90% to 55% and an increase in oil production from 2.1 m³/day to 4.7 m³/day initially. The well has produced around 100 m³ of additional oil before it's comes down to its original rate of prior to the job.
2. The post job analysis of well NK # X was very encouraging. Production testing data after the job has shown the reduction of water cut from 90% to 24% and increased in oil production from 1.2 m³/day to 15.2 m³/day initially. The well has produced around 400 m³ of additional oil after WSO job before the production rate declined after ten months, to its original rate prior to job.
3. Post job analysis of well NK# Y has shown positive indication of decrease in water cut from 88% to 72% with increase in THP. However production testing for rate measurement could not be done after the WSO job. Later on, THP of the well decreased and ceased to flow. Well is waiting for the installation of SRP.
4. Well NK # Z which was on SRP became self-active after the job with high THP 60 Kg/cm². It was put on production through 8mm bean and observed flow of oil and gas with traces of water. Initial post job analysis has shown the decrease in water cut from 95% to 70% and an increase in oil production from 0.75 m³/day to 3.0 m³/day. Later on production rate could not be measured. After the well ceased, SRP was installed. Increase in THP and flow of oil and gas were observed in beginning. Water cut was found in traces. Later on THP of the well decreased and ceased to flow as observed no free fall of polished rod. It might be due to obstruction by sand incursion. Well is waiting for Work over rig to clear the obstruction.

5. From the above job results, it appears that the gel treatment carried out in all the four wells have responded the treatment life of more than six months.

For Case Study 2

1. Polyacrylamide polymer is depending on cross linker concentration because if we increase cross linker concentration it forms very stiff gel.
2. By increasing Cross linker concentration, the time of gelation decreases with polyacrylamide.
3. But in case of Biopolymer it is reversed, using higher concentration of cross linker will lead to release of water and finally gel losses its stability.
4. The stability of gel containing 2000,3000,4000 ppm XC-polymer with Sodium sulphite & IPA was observed up to 18 days at 90°C and found stable.
5. With the use of this polymer gel, the permeability of water with respect to oil was reduced to 95 %.

CHAPTER 6: CONCLUSIONS AND RECOMMENDATIONS

1. A polymer-gel system exhibiting long term thermal stability at temperature 85°C was designed and tested under simulated reservoir conditions.
2. The gel was compatible with North Kadi reservoir matrix and could be used under the field conditions.
3. Spacer should be used to prevent the contamination of gel from work-over fluid. Any contamination will affect the gelation properties drastically.
4. Gel pumping followed by cement tail-in around the well bore will further increases the gel treatment life during the course of oil production.
5. Post job analysis of the water shut-off jobs carried out in four wells indicated that it has not adversely affected the oil production. Rather it has curtailed the water production during the test period. Out of four wells, job in two wells have shown encouraging results with additional amount of oil gained.
6. The testing results of remaining two wells have also shown the decrease in water cut and increase in THP/ oil production. Both the wells were waiting for work over rig for clearing the obstruction and for installation of SRP.
7. The field implementation of the polymer gel system had been found to be low cost as well as profitable cost effective. Techno-economics of WSO jobs were evaluated and found that the chemical cost can be paid back by the production of $30 - 35 \text{ m}^3$ of additional oil gained per well.

8. By performing the two above given tests, we were able to successfully develop polymer gel system which will work as a Tough Sealing Agent for water in the Jhalora Field.

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Appendix:

ABBREVIATIONS:

WOR - water oil ratio

OWC -oil water contact

WOC -water oil contact

PHPAM –Partially Hydrolyzed Polyacrylamide

DH -degree of hydrolysis

WGSO -water and gas shut off

IPA-Iso propyl alcohol