



**MAJOR PROJECT REPORT**

ON

**Smart Water Flooding**

**UNDER THE MENTORSHIP OF**

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**SUBMITTED BY**

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**April 2015**

## **CERTIFICATE**

This is to certify that this project report titled **“Smart Water Flooding”** submitted to **University of Petroleum and Energy Studies, Dehradun** is a bonafide record of work done by **Mr. Ishan Khurana and Mr. Shashank Sanket** under my supervision from **“September, 2014” to “April, 2015”**.

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**Place:** DEHRADUN

**Date:** 27<sup>th</sup> April, 2015

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## **DECLARATION**

This is to declare that this report has been written by us. No part of the report is plagiarized from other sources. All information included from other sources has been duly acknowledged. We affirm that if of any part of the report is found to be plagiarised we shall take full responsibility for it.

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## ABSTRACT

Water flooding method to improve oil recovery is the most widely used secondary recovery technique globally. Injected water not only compensates for the voidage ratio but also aids in pressure maintenance, hence sustaining oil production. With ever increasing thirst for oil, the industry looks forward to efficient techniques of extracting the maximum resource out of the earth. When the inherent reservoir energy depletes, the most sought after technique to sustain production becomes Enhanced Oil Recovery. However, EOR techniques account for a maximum of 60% recovery beyond natural production. That too, varying from reservoir to reservoir, or layer to layer, related to its complexity.

A new technology that aims at getting production beyond the recoverable through any other previously existing conventional EOR technique is Smart Water Flooding. It involves changing the ionic concentration of injection water to such an extent that it alters the preferential wettability of reservoir rocks. Once the reservoir affinity towards water is increased, more oil can be released from rock surface, thereby reducing the irreducible oil saturation,  $S_{oi}$ .

Industry is currently focusing on changing the ionic concentration of water to be injected into the reservoir. Several mechanisms have been proposed to cause wettability alterations due to reduced salinity of injection water. Companies like BP, Chevron and Saudi Aramco are adapting this technology with the ultimate aim of getting more oil. There are several names to intricate variations of this technology as a trade mark. However, the crux lies in altering rock wettability.



## PROBLEM STATEMENT

***“TO IMPROVE OIL RECOVERY BEYOND THE MAXIMUM OBTAINABLE THROUGH CONVENTIONAL EOR TECHNIQUES, BY APPLICATION OF LOW SALINITY WATER INJECTION TO ALTER THE WETTABILITY OF THE RESERVOIR”***

## SCOPE OF STUDY

The study in this report gives a brief overview on the possible mechanisms of wettability alteration by injecting low salinity water. This also includes a study of potential recovery gains when this technology is applied to different fields of the world.

The study involves a detailed analysis of suggested mechanism of wettability alteration in the reservoir, including:

1. Osmosis
2. Fines Movement
3. Alkaline Flooding Behaviour
4. Salt-In Effect
5. Multi-Component Ion Exchange
6. pH driven

If low salinity water flooding, by some mechanism, changes the wettability from the oil wet end of the spectrum to be more mixed/ intermediate to water wet, the process will result in incremental oil recovery.

It also incorporates a brief study of the following cases of field trial of smart water flooding:

1. Endicott Field, North slope of Alaska [BP]
2. Omar Field, Syria [Al Furat, a Shell subsidiary]
3. Snorre Offshore, Upper and Lower Statfjord [Statoil]
4. Claire Ridge, Shetland [BP]

## INTRODUCTION

Smart water flooding is a new EOR technology but there is no positive evidence of field success, although the benefits are uncertain within a range of 0 to 12% OIIP. There is no absolute consensus on the mechanism that causes incremental recovery. An accurate prior prediction of the suitability of fields and the potential incremental recovery in that field is not possible, so core floods and other experimental studies are required followed by single well reactive chemical tracer tests (SWCTTs). An economic and suitable source of low salinity water must be provided economically in offshore wells from a combined nanofiltration and reverse osmosis processing plant or from a suitable shallow aquifer. Provision of a low salinity water supply in a field can act as a precursor for other water based EOR processes such as polymer flooding, alkaline/surfactant/polymer flooding and linked polymer systems (LPS) with potential for even greater incremental recoveries. It can also overcome problems such as souring and scaling. Although not yet proved, low salinity water flooding either alone or in conjunction with other EOR techniques which uses water has the ability to revolutionize offshore reservoirs on a 3 to 8 year time frame. This needs to be extensively studied and its effects verified. Prior to injection of water into the reservoir, its compatibility with the formation water must be ascertained to prevent any associated problems of reservoir or hardware damage. If discrepancy exists, an effective treatment system must be designed to alter the water quality making it a suitable fluid for injection.

## LOW SALINITY WATERFLOODING MECHANISMS

The mechanism of low salinity water flooding that give rise to incremental recovery, are not well understood although they have been demonstrated in many laboratories. Mechanisms have been divided into different types according to which flow parameter they are addressing. These mechanisms include<sup>3</sup>-

- Osmosis
- Fines Movement
- Alkaline Flooding Behaviour
- Salt-In Effect
- Multi-Component Ion Exchange
- pH driven

Osmosis and fines movement account for the porosity and permeability changes. Alkaline flooding behaviour and salt-in effect contribute to the recovery by reducing the interfacial tension. Multi-component ion exchange and pH driven mechanism contribute by wettability changes.

Except the electro and pressure-osmosis, all mechanisms involve chemical reactions at the rock-fluid interface that lead to wettability changes.

All the low salinity wettability altering mechanisms involve the formation of electric double layer at charged rock and clay surfaces, and the ion exchange capability of clays. These phenomena are briefly described-

### *Clays: Electronic Double Layer Ion Exchange Capabilities*

#### **Clay Structure**

Clays are built from layers (sheets) of  $\text{SiO}_4$  tetrahedrons and octahedrons like  $(\text{Al}_2(\text{OH})_6)_n$  or  $((\text{Fe or Mg})_3(\text{OH})_6)_n$ . They are divided into two types:

1:1 in this clay mineral consists of one octahedral sheet and one tetrahedral sheet.

2:1 in this clay mineral consists of one tetrahedral sheet between two octahedral sheets.

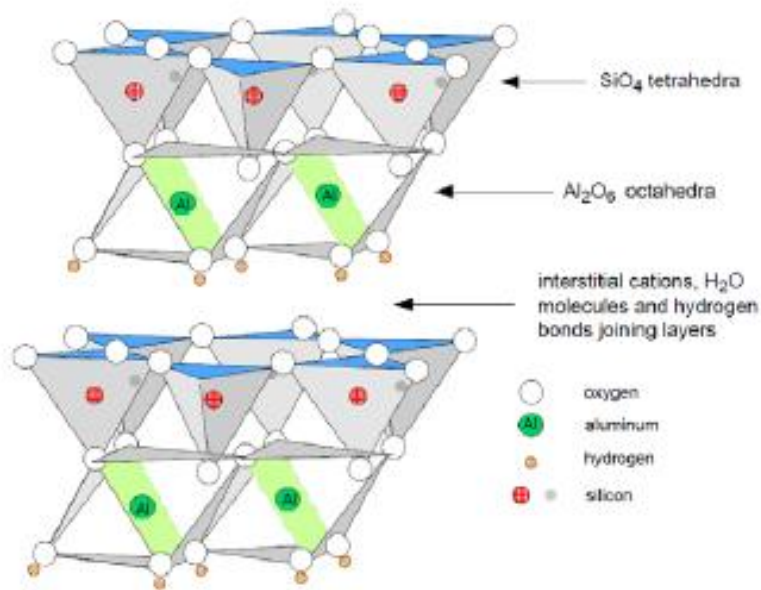


FIGURE 1: Tetrahedral – Octahedral Clay Structure (Class 1:1)

By the substitution of the cations Clays get their permanent surface charge, e.g. substitution of  $\text{Si}^{4+}$  by  $\text{Al}^{3+}$  in the tetrahedral units and substitution of  $\text{Al}^{3+}$  by for instance  $\text{Fe}^{2+}$  in the octahedral units. Usually it is found that the surface charge (zeta potential) is negative. The type and surface charge of some common clays are given in Table-

Group	Clay	Type	pHzpc	CEC meq/100g	Permanent Surface charge	
kaolin	kaolinite	1:1	4.6	3-15	no permanent charge	non-swelling
kaolin	dickite					
kaolin	halloysite					swelling
kaolin	nacrite					
smecite	montmorillonite	2:1	2.5	80-120	negative	swelling
smecite	nontronite	2:1				
smecite	saponite	2:1				
illite	illite	2:1		20-50	negative	non-swelling
chlorite	various:	2:1		10-40	positive	non-swelling
	vermiculite (trioctahedral)			100-200		swelling
	vermiculite (dioctahedral)			10-50		

TABLE 1: Clay Minerals- Type of Surface Charge

Kaolinite is a 1:1 clay with a very little fixed negative surface charge. The charge on kaolinite develops due to complexation reactions and is pH dependent. Whole kaolinite surface charge is positive below a pH threshold and above the threshold the kaolinite surface charge is negative. At the threshold, the so called pH at zero potential concentration,  $pH_{zpc}$ , the surface is neutral.

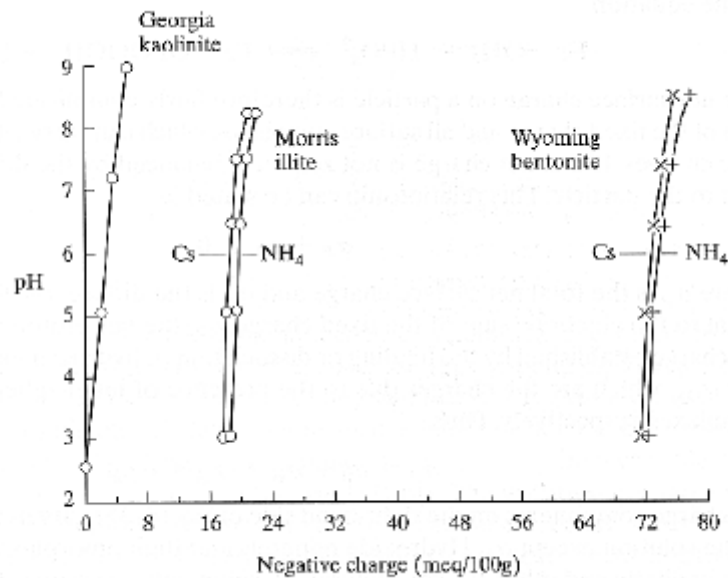


FIGURE 2: Surface charge of three clays as a function of pH

Figure shows the surface charge in meq/100g of kaolinite, illite and montmorillonite for various pH values. The charge on permanently charged clays is seen to be much bigger than the pH induced surface charge. So this means that the ion exchange capacity of the permanently charged clays is bigger and is less pH dependent than for kaolinite.

However, Kaolinite have high surface charge density as its specific surface area is considerably lower than other clays and the particle edge charge is subject to protonation/de-protonation of surface hydroxyl groups and so is highly pH sensitive.

### Double Layer Expansion

There is an attraction between the charged surfaces of a rock or the clay which attracts ions of the opposite charge present in the water phase. This leads to the formation of double layer giving rise to a zeta potential.

The thickness of the double layer is related to the concentration of ions in the water phase and the charge of the ions,  $n_e$ , by the following equation:

$$Thickness \propto \frac{1}{\sqrt{[ions]}\sqrt{n_e}}$$

This means that there is expansion of double layer in low salinity water compared to high salinity water. Expansion of the double layer can also explain the swelling of some clays in fresh water.

The above equation also implies that for the same concentration, divalent cations such as  $Ca^{2+}$  decrease the thickness of the double layer more than monovalent ions like  $Na^+$ .

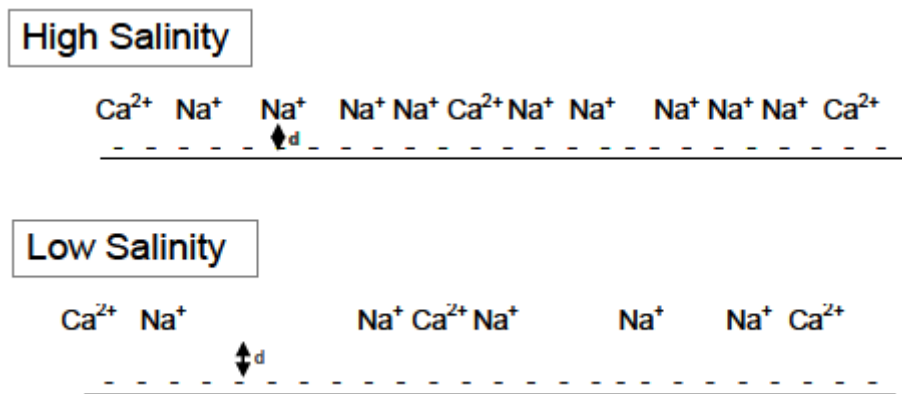
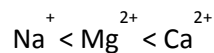


FIGURE 3: Schematic of Electrical double layer in High and Low Salinity Environments

### *Ion Exchange*

Clays have the capability of exchanging ions with the surrounding fluid. There is equilibrium between ions in the water phase and ions adsorbed to the clay surface which depends on the concentration of ions in the water phase and the tendency of a particular ion to adsorb on the surface. Equilibrium is also affected by temperature, pressure and pH.

The tendency of an ion to replace another is in this order:



This means that  $Ca^{2+}$  ions will replace both  $Mg^{2+}$  ions and two  $Na^+$  ions and  $Mg^{2+}$  will replace two  $Na^+$  ions. However, high concentrations of  $Na^+$  can reverse the process. Low salinity enhances this tendency to replace ions.

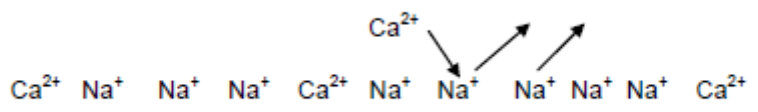


FIGURE 4: Ion Exchange

The cation exchange capacity (CEC) of various clays is given in meq/100g (milli-equivalents per 100 gram of material). Permanently charged clay like montmorillonite has a much bigger ion exchange capacity than kaolinite, with illite, that has both permanent and pH induced charge present somewhere in-between. However, the surface areas of these clays also differ and so it may not follow the same trend with the surface charge density.

### *In-Situ Osmosis*

In-situ osmosis would seem to be an intuitive explanation of the working of low salinity water flooding because this mechanism depends on the ingredients of clays present in high salinity connate water and low salinity injection water. If there is formation of tiny membranes in pore throats by clay particles then the pressure would rise on the high salinity side which would possibly force additional oil out of the pore.

This mechanism, therefore, should work regardless of the type of oil present. However, core experiments using mineral oil that is oil without polar components show no enhanced recovery with low salinity water flooding. So this explanation has now been dropped.

### *IFT Reduction*

The idea of working of low salinity water flooding by alkaline/surfactant mechanism came about because many low salinity core flooding experiments showed a rise in pH. The released oil components could undergo saponification and react like surfactants. In predicting pH values for the field using geochemical models many factors like carbon dioxide partial pressure should be taken into account.

This mechanism has been rejected because low salinity water flooding has been seen to work for oils with a low acid number and because a rise in pH is not seen in all experiments. In any of the case hydrocarbon reservoirs are generally at below neutral pH conditions and considerable buffering is provided by dissolved CO<sub>2</sub> etc. If high pH is required for low salinity water flooding to work ( up to the range 9-10) then adding alkali, as a spearhead treatment, may be necessary in order to achieve these pH values around the injected water flood front.

The oil-water surface active material that is loosened from the clay surfaces during low salinity water injection is regarded as the same that creates the wettability changes. Thus IFT reduction, and the double layer expansion, can be seen as effects that further enhance the recovery of oil.

### *Wettability Alterations*

There is always an uncertainty about the role of wettability with conflicting conclusions about the choice between water wet or intermediate wetting in improving oil recovery.

Changing the reservoir wettability from oil wet to water wet generally will improve the recovery of a water flood.



Various experiments have been carried, investigating the influence of brine salinity and wettability on oil recovery using connate brine of varying salinity and has been found that the recovery was higher with low salinity connate water than high salinity connate water, but that the salinity of the injected brine was of less importance.

One of the important conclusions from these experiments is that it is not sufficient to look at the original wettability of the rock but to be able to track changes in the wettability during flooding cycles. All the low salinity experiments that have been carried out so far demonstrate that wettability and wettability changes are products of complex rock, brine and oil interactions and the wettability changes with temperature and saturation history.

Presence of clays influences the wetting properties of a formation. Also the oil composition, with polar groups in the oil and that adsorbed onto the clays plays an important role in determining the wettability.

To explain the cause of the wettability change, two theories have been presented so far:

- MIE theory favoured by BP
- pH induced wettability change espoused by Stavanger University

These theories have given some implications on the types of clays that need to be present and the composition of the low salinity water that is required for the different clay types as well as the oil properties.

### *Multicomponent Ion Exchange (MIE) Mechanism*

The mechanism behind the incremental recovery from low salinity water flooding is that free multi-charged cations replace the double layer cations that form complexes with organic functional groups at the clay surfaces. This results both in more water wet conditions and the mobilisation of oil components. The reason for the working of this mechanism for low salinity and not for high salinity is that low salinity brine expands the electronic double layer of the clays .

The concentrations of both the  $\text{Ca}^{2+}$  and  $\text{Mg}^{2+}$  ions in the low salinity water play an important role. However, it is not clear that what concentrations need to be there to achieve incremental oil recovery. According to BP's patent application, the concentrations of both these divalent ions need to be lower than the connate water concentrations, although not zero, but these constraints have been violated in many of the low salinity water floods and have still resulted in incremental recovery. The effect of pH has to be included as ion exchange by  $\text{H}^+$  ions is important in addition to the effect of other cations, principally  $\text{Na}^+$ ,  $\text{K}^+$ ,  $\text{Ca}^{2+}$  and  $\text{Mg}^{2+}$ .

For MIE mechanism to work, clays preferably kaolinite, have to be present. Clays that swell with the fresh water and clays with a positive zeta potential like chlorite, are detrimental to the improvement of oil recovery.

In addition, connate water containing some concentration of  $\text{Ca}^{2+}$  ions has to be present for the method to work, as well as crude containing polar components.

### *pH Induced Desorption of Organic Material*

An additional recovery has been suggested by Austad, 2008 and co-workers at the University of Stavanger due to “salt-in” effect. “Salt-in” basically means that polar oil components are more soluble in water when the ionic strength of the water is low (i.e. low salinity water).

Now this idea has been changed towards a wettability alteration mechanism that, like MIE and the loosening of clay particles, results in a more water wet rock when injecting a low salinity fluid (Austad, 2010). In this mechanism the pH in the vicinity of the clay surfaces increases locally because the  $\text{Ca}^{2+}$  ions adsorbed on to the clay are substituted by  $\text{H}^+$ .

Adsorption of both base and acid oil components are very pH sensitive and the local increase in pH value leads to desorption of organic material from the clay surfaces and thus to enhanced water wettability.

This mechanism requires the presence of clays with a high cation exchange capacity, so the ranking of favourable clays follows their cation exchange capacity (CEC) ranking: montmorillonite is better than illite/mica which is better than kaolinite. As a consequence of this theory, reservoirs that contain kaolinite or chlorite have to have a certain concentration of  $\text{Ca}^{2+}$  ions in the reservoir brine for the low salinity water flooding to work, whereas there are no requirements relating to the softness if the rock contains montmorillonite or illite/mica. The crude has to contain polar components.

Generally the oilfield waters have  $\text{pH} < 7$  due to the effect of dissolved acid gases (mainly  $\text{CO}_2$ ) and oil-based (volatile fatty and naphthenic) acids. Injected water will come into contact with hydrocarbons and become carbonated and adopt a more acidic nature than the surface water before injection. The in-situ pH values applying to the reservoir and downhole conditions will be lower than those measured within surface samples due to loss of dissolved  $\text{CO}_2$ , by 0.5-1.0 units in many cases.

Generally, it appears that the effect of dissolved  $\text{CO}_2$  has not been given emphasis in core flooding methodology and in the theoretical discussion of pH effects on clays or organic polar species. It is already known that pH plays an important role in any desorption of organic components or on clay-based mechanisms. Then in the simulation of reservoir condition pH becomes more important.

Effect Type	Mechanism	Short Explanation	Contra-indications
Pressure/ permeability	Osmosis	Distributed clays separating brines with different salinities create an additional (osmotic) pressure that enhances the water drive.	Low salinity water flooding does not seem to work for mineral oil.
Pressure/ permeability	Clay particle (fines) movement	Due to the expansion of the electric double layer (and maybe also ion exchange) clay particles and other mixed-wet fines are removed from the rock surface at low salinity conditions leaving a water wet spot. The migrating fines might block narrow pore throats and cause microscopic diversion of the injected water.	Fines migration has sometimes been observed in low salinity core flooding.
IFT reduction	Alkaline flooding behaviour	pH rises during low salinity flood high enough to saponificate certain components of the oil. Thereby lowering the interfacial tension between water and oil (in a similar way to alkaline flooding).	pH increase is not seen in all experiments and is usually not as high as in alkaline flooding.
IFT reduction	“Salt-in” effect	The charged oil components on the surfaces of the clays are easier to desorb and dissolve in the water phase; “salt-in” effect. The loosened particles lower the interfacial tension between water and oil like surfactant flooding.	This potential mechanism has not been widely discussed. Austad suggested experiments to check the theory which led to the pH induced ion exchange theory
Wettability Change	Multicomponent Ion Exchange (MIE)	Due to expansion of the electric double layer and cation exchange capacity of the clay complex, bound charged organic components of the oil are substituted by $Ca^{2+}$ leading to an increase in the water wetness of the formation.	Low salinity brines without $Ca^{2+}$ and $Mg^{2+}$ ions have been seen to increase recovery
Wettability change	pH driven	The cation exchange capacity of the clays is triggered by near surface pH changes brought about by protons substituting $Ca^{2+}$ on the clay surfaces in low salinity water flooding.	No contra indications published yet.

TABLE 2: Overview of Suggested Low Salinity Water Flooding Mechanisms

## RECOVERY MECHANISMS

Not all the above mechanisms are feasible ways in which oil recovery may be improved but it could be a combination of effects that influences laboratory core tests and field trials.

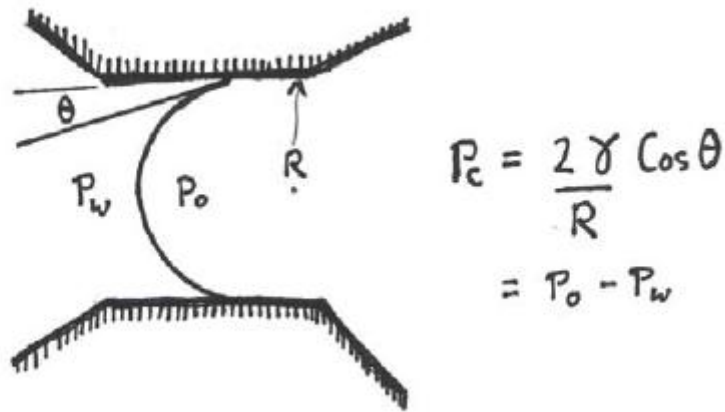


FIGURE 5: Schematic of Capillary Pressure at Curved Oil/Water Interface

Figure illustrates capillary pressure at a curved oil/water interface. This pressure is responsible for retention of oil blobs and longer oil “ganglia”. These visualisations reflect the effect of wetting (contact angle  $\theta$ ), interfacial tension ( $\gamma$ ) and pressure gradients ( $dp/dx$ ). It is easy to appreciate that any change of contact angle toward 90 degrees ( $\cos\theta=0$ , neutral wetting), lowering of interfacial tension or increase in applied pressure gradient would tend to enhance oil mobilisation and reduce trapping of oil droplets.

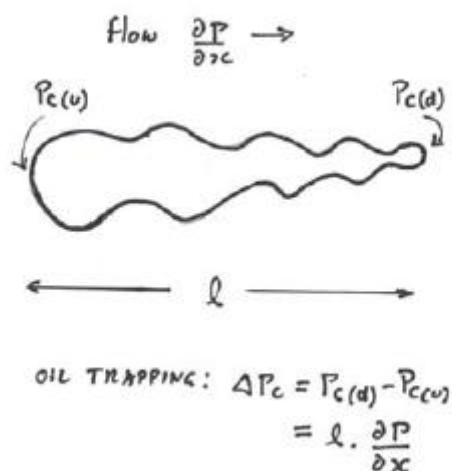


FIGURE 6: Schematic of Trapped Oil Ganglion

The length scales (influencing “l” of trapped connected oil) of pores, core samples and reservoir heterogeneities have important influences on oil trapping. It is expected from core tests to show microscopic residual oil effects, which are assumed to be effectively “linear” flow processes and are often assumed to be free of capillary end effects.

Capillary end effects are expected to be more sensitive to changes in wettability, interfacial tension and imposed pressure gradients than the microscopic residual oil which is the focus of interest in the tests. Evaluation or minimisation of, artefacts due to end effects should be seriously addressed in core test design, as well as the minimisation of random measurement errors.

Hence, there are several mechanistic advantages in low salinity water injection, while the quantification of the oil recovery benefit requires assessment more precisely. Screening on purely technical grounds may not be the only useful approach, but logistical and economic factors should also be considered.

There are significant advantages in the use of low salinity water for polymer, surfactant and alkaline EOR processes and therefore the combination of these methods with low salinity water flooding should be emphasised. Considering application economics, synergy with (sulphate reduction and desalination) water treatment technologies applied for other reasons, such as for scale control and reservoir souring prevention should be considered in the screening of candidate fields.

## SCREENING CRITERIA

Despite of the different explanations regarding working of low salinity recovery and the many parameters that apparently play a role there are some common features for each mechanism:

- Clays have to be present and distributed in the formation.
- Formation water and/or seawater (high salinity) from prior flooding has to be present.
- Salinity of the low salinity injection water have to be below some limit (TDS < 0.5% or 5000 ppm).
- The oil should contain polar components.
- The reservoir has to be oil wet or intermediate wet (or mixed wet).

In addition to these five points, according to the MIE explanation the concentration of  $\text{Ca}^{2+}$  in the injected low salinity water needs be lower than the  $\text{Ca}^{2+}$  concentration in the connate water, although this requirement is not as widely accepted as the points above.

None of these requirements is without exception but can be used as rough screening criteria to identify fields that might benefit from the method. Preferably, the process has to be laboratory tested at realistic reservoir conditions (including temperature), using the valid core, reservoir oil and brine at the appropriate composition, pH etc. for each candidate field. The required composition of the low salinity water has to be determined by trial and error method in the laboratory.

### *1. Clay*

Investigations so far indicate that the clays have to be present and distributed in the formation for low salinity additional recovery to work.

BP has found that low salinity works extremely well in the Endicott field (Seccombe, 2010), where the dominant clay is kaolinite. This is somewhat surprising as kaolinite, unlike many of the other reservoir clays, is 1:1 clay with a limited cation exchange capacity. However, this clay has a low specific surface area so the effect of CEC on surface electrical effects is much greater.

Clays that swell with fresh water and clays with a positive zeta potential are detrimental to recovery according to the MIE explanation. The supposedly detrimental effect of chlorite is perhaps seen in Zhang 2006, where Berea 60 core cannot be made to respond positively to low salinity water injection. Berea 60 has the same kaolinite content as other Berea cores but more chlorite.

There is requirement of clays with high cation exchange capacity in the clays for the pH induced cation exchange mechanism for low salinity water flood recovery so the ranking of favourable clays follow their cation exchange capacity ranking:

Montmorillonite > illite/mica > kaolinite

The swelling properties of montmorillonite can be avoided if the injected water is not totally without ions.

**Screening criterion:** Distributed clays have to be present in the formation.

## *2. Ionic Composition of the Injected Water*

There is no clear indication of how low the concentration of salt has to be in order for low salinity water flooding to work, but all experiments seem to show that the salinity has to be below some field specific threshold (around 5000 ppm), but not zero in order to avoid clay swelling.

According to BP, for the method to work the multiple cation and divalent cation concentration in the injected water has to be lower than in the formation water (Lager, 2006). The MIE theory requires  $\text{Ca}^{2+}$  ions in the injected water, implying that low salinity water injection does not work for pure NaCl solutions, or other brines not containing  $\text{Ca}^{2+}$ . However, Tang, 1999 show that incremental recovery can be obtained from low salinity water flooding regardless of the valence of the cations injected.

From the pH theory the presence of  $\text{Ca}^{2+}$  and  $\text{Mg}^{2+}$  is important when the clay is kaolinite or chlorite but does not matter for montmorillonite or illite/mica.

**Screening criteria:** None.

Trial and error studies on core flood experiments have to be carried out with the right formation, oil and reservoir brine etc. at reservoir temperature to see if an effective salinity and water composition can be found. Salinities of the order 5000 ppm should be tested as a first estimate. Following favourable core test results, field tests like log-inject-log and single well reactive chemical tracer tests (SWCTTs) are recommended before inter-well field trials are considered.

## *3. Oil Composition*

The composition of oil influences the outcome of low salinity water flooding. Polar groups have to be present in the oil for the method to work. The more these components are present, the more the oil is thought to wet the formation, so there is probably a connection between this and the wettability criteria.

**Screening criterion:** Oil must contain a fair amount of polar components, i.e. relatively high acid or base number. Crude oils in general contain such components as volatile fatty and

naphthenic acids which would be active in the desired manner. However, it may be difficult to exclude any particular crude oil from consideration.

#### *4. Wettability*

Wettability and wettability changes are products of complex rock, brine and oil interactions, temperature and saturation history. Thus applying the term wettability reflects the importance of all the parameters- oil composition, clay content and type, water composition and saturation history and perhaps these should not be put into one single simplified parameter. The mechanisms causing low salinity improved recovery are probably dependent on all the parameters that determine the wettability, so it is probably not sufficient to find a formation oil wet or mixed-wet or intermediate wet to be certain that the reservoir is susceptible to low salinity water flooding. The interaction of parameters resulting in the wettability state might turn out to be unfavourable to low salinity water flooding.

If low salinity water flooding, by some mechanism, changes the wettability from the oil wet end of the spectrum to be more mixed/intermediate to water wet, the process will result in incremental oil recovery. Nevertheless, the following screening criterion is suggested:

**Screening criterion:** Only reservoirs that are towards the oil wet and are not strongly water wet end of the wettability spectrum (i.e. intermediate, mixed or oil wet) should be considered.

#### *5. Ranking of Fields for Low Salinity EOR Potential*

There is no particular criterion for deciding low salinity water flooding to be appropriate in a particular field without doing reservoir condition core floods. However, it is necessary to rank fields on some basis in order to determine which ones to screen first.



<b>Rock/Fluid Properties</b>
Wettability (oil wet, intermediate wet, Amott Index?)
Oil/water IFT lowering (>50%)?
High salinity formation water (>5%)
High dispersed clay (kaolinite?)
High residual oil saturation (from core floods?) (>30%)
<b>Reservoir/Facilities</b>
Freshwater source (<= 5000 mg/l salts?)
Desalination feedstock water source (< 36,000 mg/l salts?)
Desalination plant practicable (space, weight etc)
High Ba, Sr, Ca in formation water (additional scale control benefits?)
Maturity of waterflood (relatively immature?)
Testing practicable (SWCTTs, confined pilot area pilot?)
Core material available (preserved?)
<b>Potential Benefit</b>
Remaining STOIIIP (large?)
Potential for other water based EOR techniques (A/S/P, LPS, Bright Water?)

TABLE 3: Possible Criteria to Rank Fields for Low Salinity Water Flooding Potential

## WATER QUALITY ENHANCEMENT

With an option of injecting the produced water or water from any other source, there lies a concern of water quality compatibility with that of formation water. Incompatible waters may lead to precipitation and other problems related to clay swelling, scaling and corrosion. This, rather than enhancing production, may deteriorate the reservoir condition to a great extent.

The first step in determining the suitability of any water for injection is to analyze water for physical, chemical and biological constituents because petroleum reservoir rocks behave like filters and are susceptible to plugging by any type of solid material which may be suspended in or precipitated from any injection fluid. The composition of formation water and mineralogy of the rocks are to be studied because formation water and rocks react with injection water and may cause injectivity problems.

Clay such as Smectite, Kaolinite is sensitive to formation water. Permeability reduction may occur due to clay swelling and clay dispersion. To overcome these problems certain water quality tests are necessary to determine such variables as the amounts and composition of solids changes with the compatibility of two waters, compatibility of injection water with reservoir rocks, degree of corrosion and bacterial population. To maintain the reservoir pressure and to enhance the oil recovery, water injection scheme is implemented. Treatment design and compatibility studies on proposed injection water are required to be carried out. The studies are divided into following parts:

- Physico-chemical characterization of effluent water
- Clay Swelling Studies ( Static & Dynamic)
- Treatment design / Coagulation flocculation studies.
- Scaling Studies.
- Corrosion Studies.

## PHYSICO-CHEMICAL CHARACTERIZATION OF DIFFERENT WATER SAMPLES

Different samples are collected and analysed. The physico-chemical parameters are determined by the following methods.

### PH

The term pH is the log of the reciprocal of the hydrogen ion concentration (Expressed in moles/liter). A simplified explanation is that the pH is a number between 0 and 14 that indicates the degree of acidity or alkalinity as shown below.

1	2	3	4	5	6	7	8	9	10	11	12	13	14
More acidic			Acidic		Neutral			Basic/Alkaline			More Alkaline		

Some of the constituents that control the pH of oil field water are dissolved solids, carbon dioxide, bicarbonate, borate, hydrogen sulfide etc.

### CHLORIDE

Chloride is present in practically all oil field waters. The concentration of chloride varies in a wide range in different waters. The chloride content is determined by the volumetric method by titrating with silver nitrate standard solution and using potassium chromate as an indicator.

### CALCIUM AND MAGNESIUM

Calcium and magnesium are considered together because they are related in water and analytical procedure is same for both. The salts of Calcium and magnesium accounts for a large % of the harden water and cause scaling problems. Calcium and Magnesium content is analysed by titrating with EDTA solution using EBT and Patton indicator.

### SULPHATE and IRON

The sulphate content is calculated by mixing the sample and Sulphaver reagent and iron by mixing sample with Ferrover reagent. The solution is then placed in spectrophotometer which directly gives its amount in ppm.



**FIGURE 7: Spectrophotometer**

### **SODIUM**

The concentration of sodium ion is calculated by using concentration of anions and other cations. The values obtained for the ions are converted to milli equivalents per litre. This is done by dividing each ion concentration in mg/l by its equivalent weight to give the meq/l of each ion present. The difference of anions and cations in meq/l is multiplied by the equivalent of sodium to give the mg/l of sodium present.

### **SALINITY**

It is calculated on the basis of amount of Chloride ion concentration.

$$\text{Salinity} = [\text{Cl}^-] \times 1.64$$

## PHYSICAL PARAMETERS

### TURBIDITY

It is measured by turbidity meter and in NTU (nephelometric turbidity units). It gives the idea about type and amount of suspended matter. The water sample is taken in a holder provided in the turbidity meter. This gives the turbidity value of given sample.



FIGURE 8: Turbidimeter

### FILTERABILITY & TSS (TOTAL SUSPENDED SOLIDS)

The volume of filtrate (in litres) collected in 30 minutes through 0.45 $\mu$  filter is called filterability. Its unit is litres/30 minutes. It is calculated using Millipore filtration assembly. 0.45 micron size filter paper is taken. It is dried for 10-15 minutes in oven and then cooled. Then the initial weight is being calculated. Then it is placed on sieve in filtration assembly and the sample water is taken in the upper part. The vacuum pump is started and is hold for 30 minutes. After 30 minutes the pump is shut down and the paper is taken out. This filter paper is again dried and cooled and final weight is being measured. The volume of filtrate is measured. This is called filterability of sample water.

The weight of suspended solids divided by total volume collected in 30 minutes is called TSS (total suspended solids). Its unit is mg/L.



FIGURE 9: Millipore Filtration Assembly

## CHLORINE DEMAND

The application of chlorine to water is an effective method of controlling micro-organisms. When chlorine is added to water, it hydrolyses to form hypochlorous and hydrochloric acid. The amount of chlorine required for control of bacteria depends upon chlorine demand of water, temperature and water pH.



FIGURE 10: Colorimeter

## DESIRED QUALITY FOR INJECTION WATER

Parameter	Unit	Desired Value
TSS	mg/L	< 2.5
Turbidity	NTU	< 0.5
Oil Content	Ppm	< 10
Filterability	l/30 mins	> 6
Dissolved Oxygen	Ppm	< 0.015
Fall in Hardness	%	< 10
Corrosion Rate	Mpy	< 1
Permeability Retention	%	> 80

TABLE 4: Desired Parameter for Injection Water

## COAGULATION AND FLOCCULATION STUDIES

All waters, especially surface waters, contain both dissolved and suspended particles. Coagulation and flocculation processes are used to separate the suspended solids portion from the water. The suspended particles vary considerably in source, composition charge, particle size, shape, and density. Correct application of coagulation and flocculation processes and selection of the coagulants depend upon understanding the interaction between these factors.

One of the forces playing a dominant role in stabilization results from the surface charge present on the particles. Most solids suspended in water possess a negative charge and, since they have the same type of surface charge, repel each other when they come close together. Coagulation and flocculation processes are used to separate the suspended solids portion from the water.

### *COAGULATION*

The first step destabilizes the particle's charges. Coagulants with charges opposite those of the suspended solids are added to the water to neutralize the negative charges on dispersed non-settable solids such as clay and color-producing organic substances. Once the charge is neutralized, the small suspended particles are capable of sticking together. A high-energy, rapid-mix is required to properly disperse the coagulant and to promote particle collisions to achieve good coagulation. Over-mixing does not affect coagulation, but insufficient mixing will leave this step incomplete. Coagulants should be added where sufficient mixing will occur. Proper contact time in the rapid-mix chamber is typically 1 to 3 minutes.

### *FLOCCULATION*

Following the step of coagulation, a second process called flocculation occurs. Flocculation is a gentle mixing stage, in this particle size increases from submicroscopic microfloc to visible suspended particles. The microflocs are brought into contact with each other through the process of slow mixing. Collisions of the microfloc particles cause them to bond to produce larger, visible flocs. High molecular weight polymers, called coagulant aids, may be added during this step to help bridge, bind, and strengthen the floc, add weight, and increase settling rate. Once the floc has reached its optimum size and strength, the water is ready for the sedimentation process. Design contact times for flocculation range from 15 or 20 minutes.





FIGURE 11: Flocculator

## FILTRATION STUDIES

Water filtration is a process for separating un-dissolved solids from water by utilizing a porous medium that retains the solids but allows the passage for water. It is critically important to know the quality and proportion of suspended solids in injection waters.

### *CERENI FILTRATION*

In Cereni method, we pass water through .45 micron filter paper under a constant pressure differential of 20 psig. It can be said that the prime reason for water quality is the presence of suspended particles. The degree and extent of damage caused by these particles depends upon its concentration, size distribution, shape and ability to bridge. Hence attempts have been made by various workers to define and correlate the water quality with solid content. Of these popular ones is the one suggested by Cereni and Davidson et al.

Injection waters must be free of all particles in suspension. It is important to know the quantity and composition of suspended solids in injection waters. This information can be obtained by filtering the water through 0.45 $\mu$ m membrane filter, determining the weight of the solids and analysing the solids by use of appropriate techniques.

Volumetric rate of flow versus cumulative volume is a common method of evaluating the membrane filter test. No direct relationship however exists between the slope and injectivity.

The slope (rate vs cumulative volume filtered) ratings show warning signals of future trouble. They are not a direct measure of the condition of the water. Slopes must be

equated with the type of chemical treatment and the amount and nature of solids. *Steeper the slope, poorer is the water quality.* The empirical number which defines water quality is called Relative plugging Index (RPI).

$$RPI = TSS - MTSN$$

Where,

$$MTSN \text{ (Millipore Test Slope Number)} = \frac{2500 \log(Qa/Qb)}{Va - Vb}$$

There are two flow stages during a rate versus cumulative volume determination:

- The initial portion of the filtration takes place at rate until the entire surface of the membrane filter is covered with suspended solids. This portion of the curve may be very short or very long depending upon the amount, the size, and the thickness of the suspended solids. This first phase may be attributed to the plugging or the filter cake formation phase.
- During the steady stage, the flow occurs through a gradual thickening of filter cake of suspended solids. The flow rate is governed by the permeability of the filter cake of suspended solids. Flow gradually decreases due to the continuous thickening and the plugging of the filter cake by deposition of solid with a consequent increase in resistance to flow.

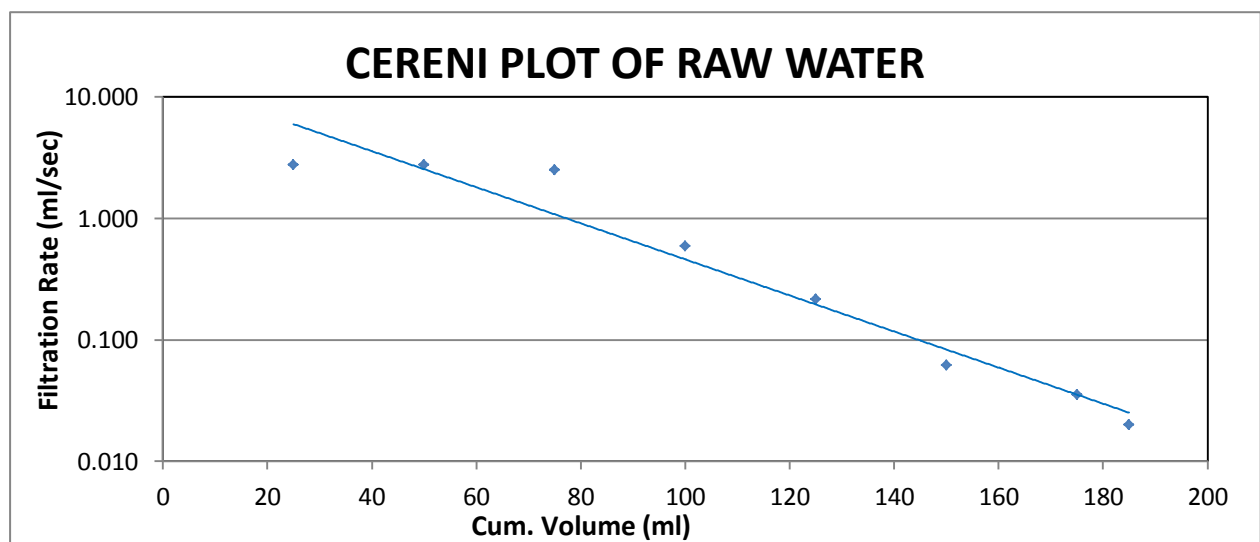


FIGURE 12: Typical Cereni Plot

## SERIES FILTRATION

Series filtration of the laboratory treated effluent water is carried out for filter size optimization and determination of the particle load in different size ranges. The effluent water is passed through a series of filters viz. coarse (80-100 micron), 8 micron, 5 micron, 3 micron, 1.2  $\mu\text{m}$  and 0.45  $\mu\text{m}$  using the filtrate of previous filtration in each successive filtration. The filtration rate vs. cumulative throughput is plotted for each filter size.

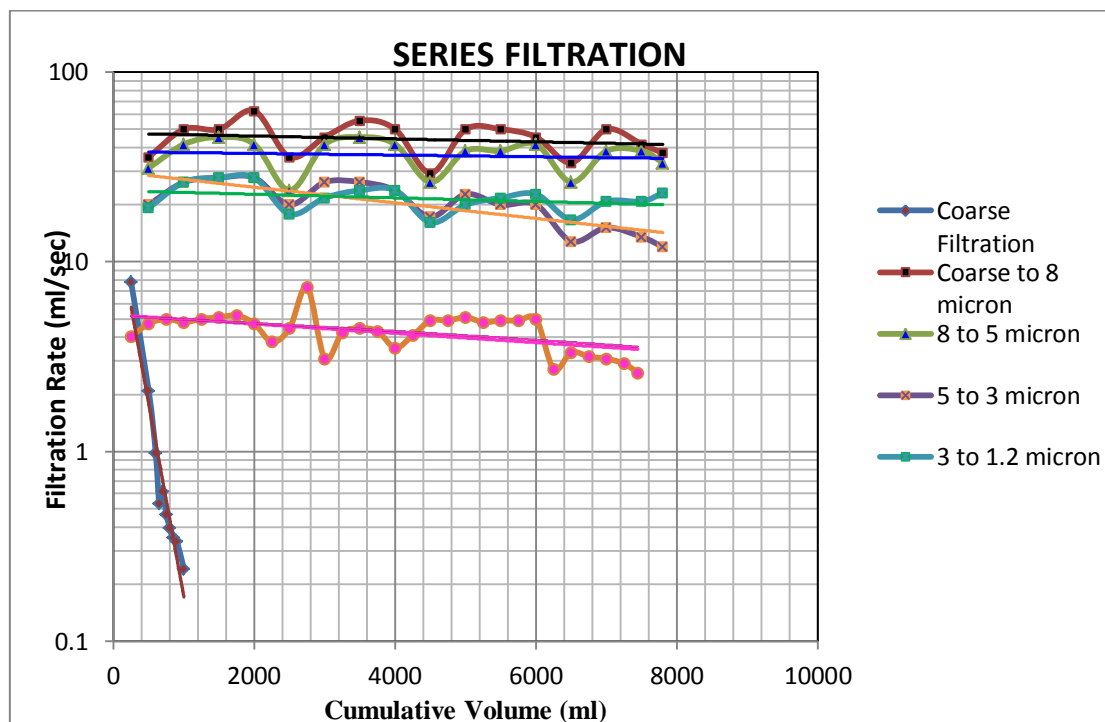


FIGURE 13: Series Filtration Plot

## SCALING STUDIES

Scale deposition is one of the most important and serious problems which water injection systems are generally engaged in. The change in pressure and temperature of the injected water in the injectors and produced fluid in producers as well as the incompatibility of the injection and formation water are the main reasons for scale formation. Two waters are called incompatible if they interact chemically and precipitate minerals when mixed.

### **Problems faced due to scaling**

- Scale limits or blocks oil and gas production by plugging the oil producing formation matrix or fractures and perforated intervals.
- It is also deposited in down-hole pumps, tubing, casing flow lines, heater treater, tanks, and other production equipment and facilities. Therefore, water formed scales are responsible for many production problems.

### **Major Causes of precipitation of any of the scales:**

- Mixing of incompatible waters.
- Reduction in pressure (calcium, barium and strontium sulfates are all more soluble under pressure).
- Evaporation of water by gas evolution or heating.
- Temperature changes.

### **Prevention of scale formation**

- Avoid mixing Incompatible Waters.
- pH Control: Lowering the pH will increase the solubility of carbonate scales (but may cause corrosion problems). This method is not widely used in the oilfield, since accurate pH control is needed.
- Water dilution
- Water softening
- Scale control chemicals (scale inhibitors).

## **Scale Inhibitors**

Scale inhibitors are chemicals which will delay, reduce or prevent scale formation when added in small amounts to normally scaling water.

### **Mechanism of Scale Inhibition:**

Most of the scale inhibitors used in the oilfield functions by one or both of the following mechanisms:

1. When scales first begin to form, very tiny crystals precipitate from the water. At this point the scale inhibitor adsorbs onto the surface of the crystals while they are still very tiny and prevents further growth. This is thought to be the primary mechanism by which most oilfield scale inhibitors work.
2. In some cases scale inhibitors prevents the precipitated scale crystals from adhering to solid surfaces such as piping or vessels.
3. The fact that most commonly used scale inhibitors function by inhibiting the growth of the scale crystals means that the inhibitor must be present in the water at the point where the crystals begin to form.

### **Procedure**

- The initial total hardness (Calcium and Magnesium ion concentration) of effluent water is determined by titrating them with 0.02 M EDTA.
- A total of 7 different samples of effluent water with different doses (concentration) of HEDP and SI are bottled. They are then placed in the oven 80°C for 96 hours.
- After 96 hours all the samples are titrated again to determine total hardness.
- The difference in the total hardness is directly proportional to scaling tendency.

## CORROSION STUDIES

Corrosion is an electrolyte process. Corrosion is defined as the deterioration of a metal by chemical or electrochemical reaction with its environment.

Equipment failures caused by corrosion in oil field water systems can nearly always be attributed to the presence of one or more of the three gases i.e. O<sub>2</sub>, H<sub>2</sub>S and CO<sub>2</sub>. Many other factors affect the rate and location of the attack. Following are some of those factors:

- Metals with different microstructure
- Scratches or abrasives
- Differential strain
- Differential oxygen concentration
- Fluid velocity
- Water salinity
- Microorganisms

The rate of corrosion can be decreased by removing corrosion causing substances from the injection water, making the surfaces corrosion resistive. Some corrosion inhibitors can also be added to the injection water to decrease the corrosion rate.

The static corrosion study is undertaken on a suitable tubular coupon at 80°C for 96hrs. Different solutions with different dose of corrosion inhibitor are used for the study. Effluent water is used for the study.

### **Procedure:**

- The static corrosion study is undertaken on 6 different steel coupons.
- Coupons are cleaned and polished.
- After preparation of coupons, their weight and dimensions are measured.
- Different solutions are prepared in the injection water with different concentrations of Oxygen scavenger (sodium sulfite) and Corrosion inhibitor (WIN).
- Before adding Corrosion Inhibitor, the prepared solutions are kept for about 30 minutes after mixing Oxygen Scavenger in them.
- Coupons are then kept hanging in the bottles using Teflon tape.
- These solutions are then kept at reservoir temperature of 88°C for 96 hours. The coupons are then taken out and weighed again.
- The difference in weight is directly related with corrosion rate which is expressed in mils per year (mpy).

## CORE FLOOD ANALYSIS FOR DYNAMIC CLAY SWELLING

The objective of this study is to determine the compatibility of core plug to various concentrations of clay stabilizer solutions. Different concentrations of clay stabilizer are used and the change in permeability of the core plug is observed. Usually the injection water can deteriorate the permeability of the formation by two major processes namely clay swelling and fine migration.

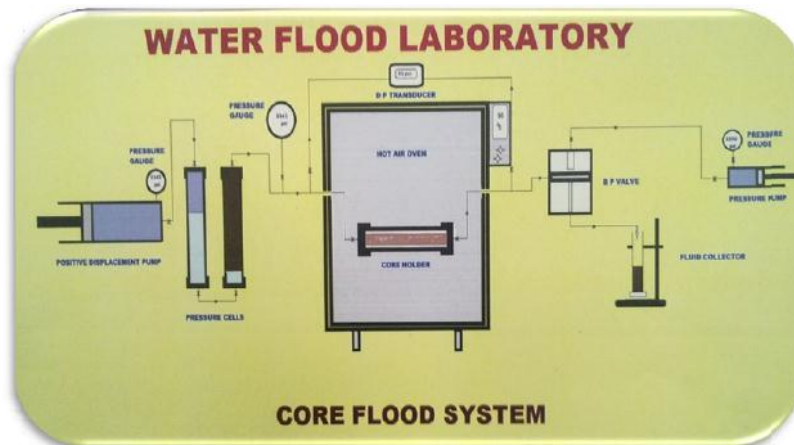


FIGURE 14: Core Flood System

### EXPERIMENTAL PROCEDURE

- 1) Preparation of Core Pack-** Horizontal plug of 3.8 cm is drilled from whole core at the core cutting machine. The extraction is carried out by soxhleting the core with a mixture of 20% Methanol and 80% Toluene. After drying at 60°C for sufficient time, the external surface of the core is coated with resins (araldite). Core pack is prepared by keeping the core plug in the central part of the core holder and then the annulus between the core plug and the core holder barrel is filled with molten Cerro metal (an alloy of tin and bismuth). After cooling off to room temperature the ends are smoothed on lathe machine. End caps and flow line connections are then made.
- 2) Determining Air Permeability-** Air permeability is measured by flowing Nitrogen gas through the pack and measuring the pressure difference and flow rate at room temperature. Permeability is determined by modified Darcy's law for gases.

$$q/A=K *(P_1^2 -P_2^2) / (2\mu LP_a)$$

Where,

$q \rightarrow$  flow rate of gas

$A \rightarrow$  Area of Core

$K \rightarrow$  Air Permeability

$P_1 \rightarrow$  Pressure at one end

$P_2 \rightarrow$  Pressure at other end

$\mu \rightarrow$  Viscosity of gas

$L \rightarrow$  Length of core

$P_a \rightarrow$  Air Pressure

**3) Determining the Pore Volume-** The core plug is evacuated through vacuum pump for attaining complete vacuum inside the core. It is saturated with 3% KCl solution. The core is kept under saturation for 24 hours. The volume of water taken up by the core pack gives the pore volume.

**4) Core Flood Experiment-** Different Clay Stabilizer solutions at various concentrations are prepared and then filtered with .45 $\mu$  filter paper. Then these solutions are used for flooding and permeability is determined. During flooding, the temperature of the oven is kept at reservoir temperature. Permeability is determined by Darcy's Law. It states that velocity of a homogeneous fluid in a porous medium is proportional to the pressure gradient and inversely proportional the fluid viscosity. For a horizontal linear system, the relationship is-

$$\frac{q}{A} = -\frac{K}{\mu} * \frac{dp}{dx}$$

Where,

$q \rightarrow$  flow rate

$A \rightarrow$  Area of Core

$K \rightarrow$  Permeability

$\mu \rightarrow$  Viscosity at given temperature

$dp \rightarrow$  pressure difference across core.

$dx \rightarrow$  length of core

Then permeability retention plot is made. The concentration of clay stabilizer which gives the maximum retention in permeability is selected as the optimum dosage for injection.



## CASE STUDY – ENDICOTT

The first comprehensive inter-well field trial of low salinity water flooding took place during 2008-9 in BP’s offshore Endicott field<sup>2</sup> on the North Slope of Alaska.

Endicott is the third largest North Slope field with estimated oil in-place of around a billion barrels. It was brought on stream in 1987 and has been produced by gas re-injection at the crest and seawater injection around the periphery. The salinity and hardness of the reservoir brine and the injected seawater are approximately equal.

<u>Species</u> (ppm)	Endicott formation water	Endicott produced water	Endicott seawater	Endicott Well 3-39A low salinity water
Barium	7	0	0	0
Bicarbonate	2,000	1,868	147	6
Calcium	320	194	402	17
Chloride	17,275	14,946	18,964	821
Iron	10	2	0	0
Magnesium	48	360	1,265	55
Potassium	110	177	386	17
Sodium	11,850.	9,190.	10,812.	468
Strontium	24	7	7	0
Sulfate	63	570	2,645	115
pH	6.5	7.0	7.7	
TDS	32,000	28,000	34,644	1,500

TABLE 5: **Endicott Water Analysis**

The original results, which prompted the trial were four single well tests with the saturation change measured using reactive chemical tracer tests (SWCTTs) undertaken in the Prudhoe Bay and Endicott fields which indicated that the incremental oil recovery from low salinity water injection was in the range 6-12% OIIP. Subsequent laboratory and simulation work, and further single well tests, both using both log-inject-log and SWCTTs to measure saturation changes was also positive.

SWCTTs indicated that the residual saturation to high salinity water flooding is 41% reducing to 27% if low salinity water is used, giving an incremental recovery of 15% OIIP ( $S_{wi}$  is 5%) which would obviously be lower when areal and vertical sweep effects are accounted for.

The field trial used a single injector–producer pair with an inter-well spacing of 1040ft (Figure 15). It was undertaken in the K3A-2 sand which has thickness 30-45 ft (isolated above and below by shales), porosity 20% and permeability 100 mD (established by pressure pulse tests). Clay content was 12% with kaolinite being the dominant clay followed by illite. Clearly by comparison with North Sea fields the residual saturation of high salinity water flooding at 41% is high and the inter-well spacing at 1040 ft is low.

The trial area was flooded using high salinity water to 95% watercut, followed by 10 months (1.6 pore volumes) of reduced salinity water injection (trucked from a gravel pit nine miles away), with a final high salinity postflush.

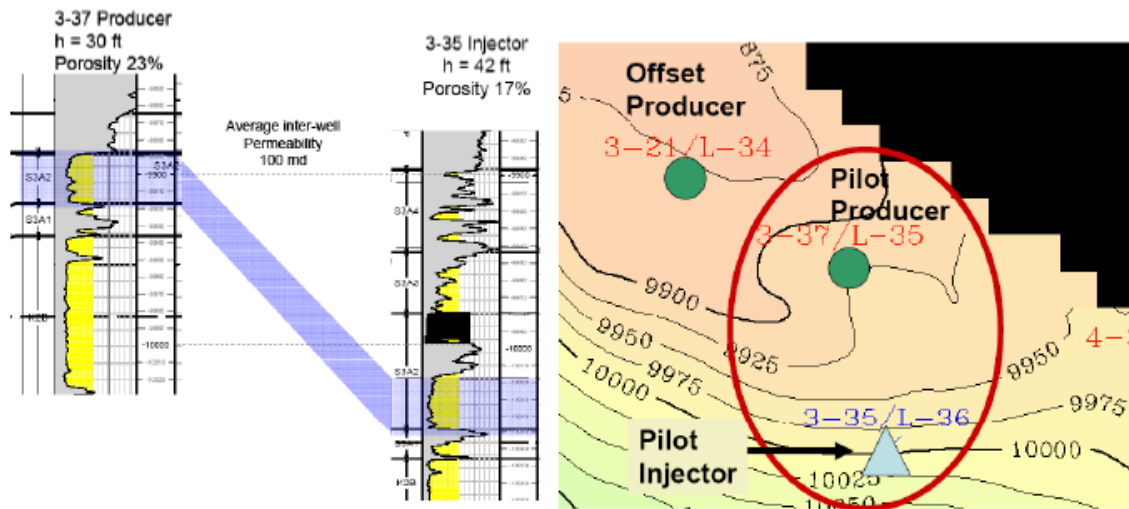


FIGURE 15: Endicott Pilot Area

After about two months an increase in oil rate and a reduction in watercut were observed with the increase in oil rate immediately followed by the arrival of reduced salinity water (Figure 16). The oil response was as predicted (from core floods and single well tests) but the drop in watercut (95 to 93%) was less than expected. Analysis of ionic content of the produced water showed that 45% of produced water was coming from outside the pilot area. Backing out production from outside the pilot area (details of how this was achieved in Secombe, 2010) it was estimated that the effective drop in watercut within the pilot area was 5.5%.

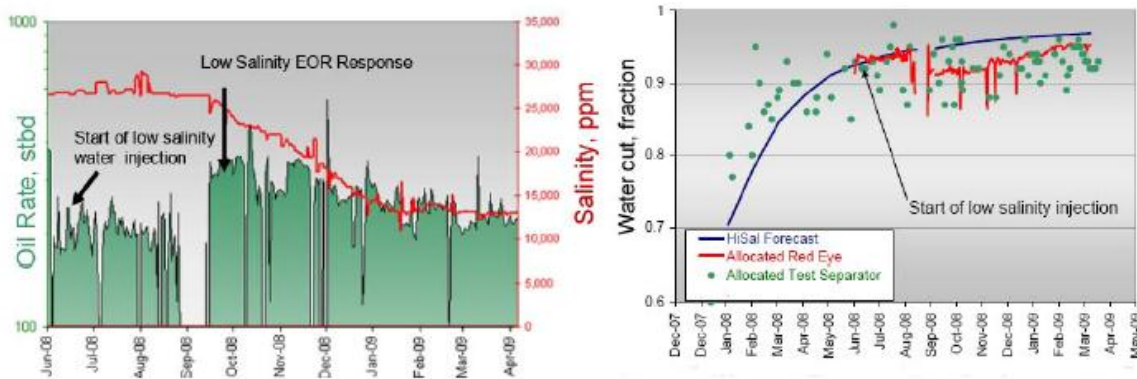


FIGURE 16: Endicott Pilot Rate and Water Cut Response

Although no iron was present in the formation or injected waters, there was a sharp increase in iron production from non-detectable amounts to 3-4 ppm corresponding to the sharp decrease in water cut (and arrival of the first low salinity tracer injected at start of reduced salinity flood). BP believes this confirms the multi-component ion exchange (MIE) theory of low salinity water flooding. They postulate that the iron coats the kaolinite binding the polar molecules in the oil to the clay but these bridges are removed by the reduced salinity water releasing polar compounds and free iron.

Analysis of the results in the pilot area by comparison with the estimated results of continuing high salinity water flooding indicate an incremental recovery of 10% OIIP by the start of the high salinity postflush.

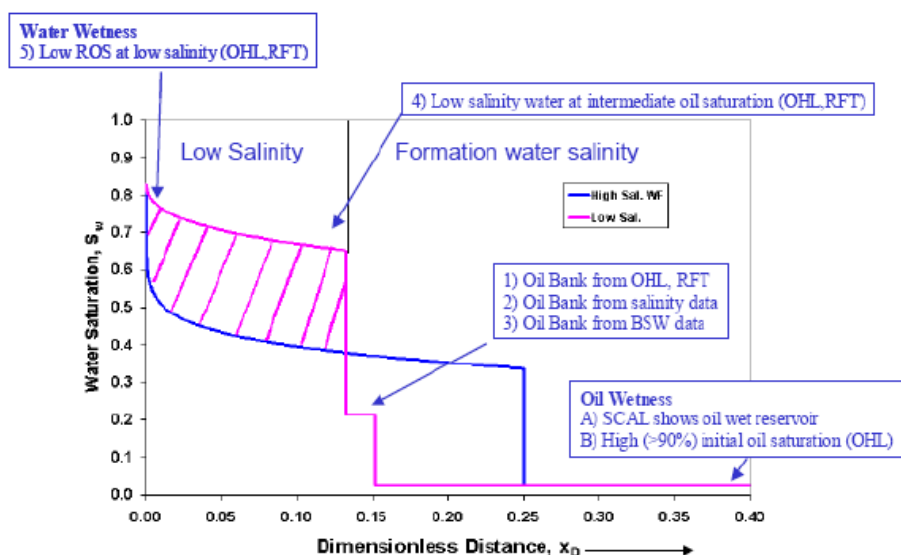
## CASE STUDY – OMAR FIELD

A detailed analysis of secondary low salinity water flooding in the Omar Field<sup>4</sup> in Syria operated by Al Furat (a Shell subsidiary) has been undertaken. This is one of the few documented proofs of the concept of low salinity water flooding on a reservoir scale.

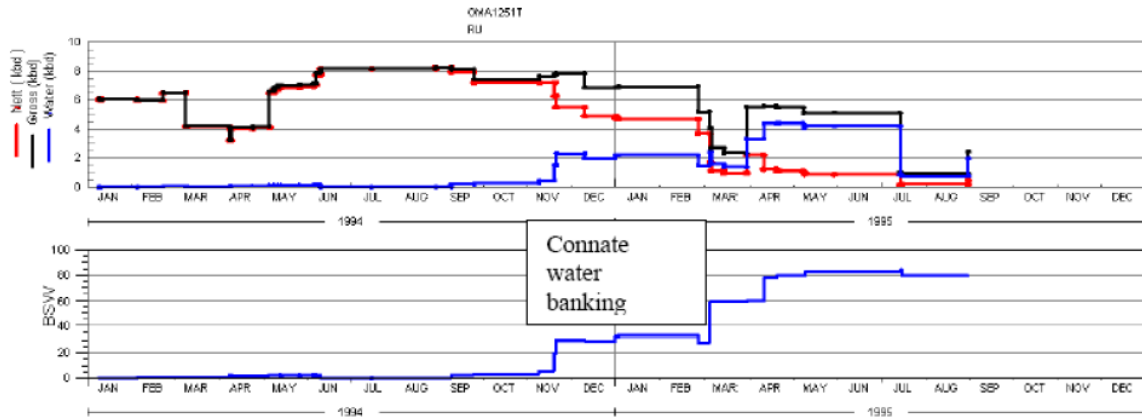
The light oil ( $\mu=0.3$  cp) field came on stream in 1989 but experienced rapid pressure loss indicating absolute lack of aquifer support. Water flooding using a river water source with salinity 500 mg/L ( $\ll 100$  mg/L bivalent ions) began in 1991. The formation water has a salinity of 90000 mg/L with a high content of bivalent ions (5000 mg/L) and the clay content is 0.5-4% of which 95-100% is kaolinite.

Special core analysis and low rate core flood measurements showed that the native state wettability in Omar was oil wet (wettability index of 1). Spontaneous imbibition experiments showed additional recovery from low salinity brine subsequent to high salinity brine correlating with kaolinite content (incremental recovery up to 24% PV). Similar laboratory results were also obtained in an analogue field where a log-inject-log test in a watered out well showed that a wettability reduction from 1 to 0.2-0.4 had occurred as a result of the low salinity water flooding.

Logs in Omar show an initial oil saturation of 95% and remaining oil saturation after low salinity water flooding of 15% (but with uncertainty in range the 10-30% as the calculation is very sensitive to the salinity used in determining the saturation from the logs). During intermediate stages of the flood, log interpretations at well OMA125 confirm the dual-step watercut development predicated by Buckley-Leverett theory (Lake, 1989), with an initial modest reduction in oil production accompanied by miscibly displaced formation water.



**FIGURE 17: Water Saturation Response from Buckley Leverett Theory for High Salinity and Low Salinity Flooding in an Oil Wet System**



**FIGURE 18: Oil and Water Production (top) and Watercut Development (bottom) for OMA125 Showing Behaviour Consistent with Buckley-Leverett Theory**

In the Al Furat (and Shell) view is that the measurements and observations at 21 wells in Omar present abundant proof of wettability alteration occurring at the reservoir scale. Analysis indicates that the change in wettability is probably from 0.8-1.0 to 0.2 which would give an expected incremental oil recovery of 17% OIIP (compared to high salinity water flooding). However, comparison of high and low salinity water flooding across Al Furat's assets indicates that a more conservative estimate would be an increase in 5-15% STOIP from low salinity water flooding in Omar.

## CASE STUDY – SNORRE OFFSHORE

A comprehensive set of experiments using Snorre core material (Upper Statfjord, Lower Statfjord), oil and formation water and flooding with various salinity and divalent cation concentrations showed negligible benefit compared to high salinity water flooding. This, even though the mineralogy was similar to other clastic systems where low salinity water flooding has shown a positive response.

Nevertheless, Statoil carried out a single well reactive tracer test (SWCTT) in 2009 after completion of the core experiments. However, this also showed no significant reduction in oil saturation.

Compared to Endicott the residual oil after water flooding in Snorre is below 25% so the wettability, or other relevant conditions, would appear to be more favourable to seawater injection than in Endicott. This obviously lowers the potential additional benefit from low salinity water flooding. The formation water salinity in Snorre is similar to Endicott, although in Endicott the divalent cations (Ca, Mg) are significantly lower.

<u>Constituent</u>	<u>Formation water</u>	<u>Synthetic sea water</u>	<u>Field pilot lowsal</u>
NaCl	30.5	23.74	0.3007
CaCl <sub>2</sub> · 2H <sub>2</sub> O	4.17	1.500	0.0234
MgCl <sub>2</sub> · 6H <sub>2</sub> O	1.35	10.70	0.0924
BaCl <sub>2</sub> · 2H <sub>2</sub> O	0.08	0.000	0.0000
SrCl <sub>2</sub> · 6H <sub>2</sub> O	0.047	0.024	0.0003
NaHCO <sub>3</sub>	0.53	0.194	0.0231
KCl	0.23	0.755	0.0211
Na <sub>2</sub> SO <sub>4</sub>	0.00	3.976	0.0344
Salinity (wt %)	3.43	3.402	0.0440
Ionic strength (mol/l)	0.631	0.691	0.0083

**TABLE 6: Water Composition for Snorre**

As for Endicott, the dominating clay in Snorre is kaolinite, varying (in the main) between 8 and 18%. From the Endicott clay content versus additional recovery correlation (Figure 2.3), this would mean an additional recovery upward of 9% OIIP, far from what is seen in the Snorre experiments.

## CASE STUDY – CLAIRE RIDGE

BP is implementing secondary low salinity water flooding in the second phase of development at the Clair field, known as Clair Ridge. 145,000 b/d of injection water will be supplied by a desalination unit fed by treated and filtered seawater. Early in field life the low salinity water would be mixed with produced water for reinjection. In later field life when the produced water rate exceeds requirements it will be disposed of via dedicated disposal wells.

Overall BP estimate that implementing low salinity water flooding in Clair Ridge will produce 7% OIIP more than conventional seawater flooding at a development cost of \$3 per barrel.

## CHEMICAL AND ENVIRONMENTAL ASPECTS

### *Offshore Production of Low Salinity Water*

For conventional water flooding project water is normally sourced from the sea. The water is filtered and deaerated, and biocide is added to reduce reservoir souring. In some cases the water is de-sulphanated to prevent the formation of sulphate scale as a result of incompatibilities between the injection and formation waters. In some cases more compatible water is sourced from nearby aquifers.

Sometimes sources of water with a composition suitable for low salinity water flooding could be found in the aquifer formations immediately around offshore installations. Alternatively, low salinity water for offshore applications could be produced by desalinating seawater. This is often done on a smaller scale offshore for potable water and to mix water based mud where fresh water is required to swell the clays.

Seawater desalination methods can be of two types

- Thermal
- Membrane based.

All the methods have been reviewed and thermal methods have been discounted principally on the physical size and weight of the plant involved, and the fact that the processes require large amounts of steam which is not easily available offshore.

On the other hand, membrane-based reverse osmosis methods are attractive for offshore use because of suitable space, weight and energy requirements. However, there are drawbacks that reverse osmosis produces almost fresh water which would swell clays. Spiking back some of the reverse osmosis reject stream or mixing the fresh water with seawater adds back sulphate which is undesirable from a reservoir souring point of view. New desalination scheme have been proposed by Shell which they have trademarked under the name "Designer Water" which involves back to back nano-filtration and reverse osmosis stages; with the former reducing the hardness of the water including removal of  $\text{SO}_4^{2-}$  and the latter reducing the salinity. The output is water with TDS <500 ppm which is lower than required (typically 1000-5000 ppm).

Such process plant could be incorporated on an offshore platform or even on a ship or floating facility (which would allow reuse). Shell see economic production of low salinity water offshore as the key to opening up the use of other water based EOR processes such as polymer flooding, Alkaline-surfactant-polymer (ASP) flooding and linked polymer systems (LPS) where the use of low salinity mixing water enables the use of smaller quantities and cheaper chemicals.



### *Costs*

There are expenditures associated with providing a source of low salinity water whether by building and operating a combined nano-filtration/reverse osmosis plant or exploring for and producing from an appropriate aquifer. The cost effectiveness will obviously depend on

- The amount and timing of the incremental recovery.
- Additional benefits would be a reduction in scaling and souring risk with a consequent reduction in the cost of chemicals.

### *Environmental Issues*

If low salinity water is sourced from a combined nano-filtration/reverse osmosis plant the high hardness and salinity reject streams and any solids, sludge's, or filter media that are by-products of the process will require to be disposed of overboard. This should not be an insuperable problem and would be dealt at the environmental impact assessment stage.

## CONCLUSION

1. Smart water flooding is an new EOR technology but there does seem to be encouraging evidence of field success. Though uncertainty exists about the benefits within a proposed range of 0 to 12% OIIP.
2. Currently, no specific mechanism can be totally accounted for, as the real reason behind increasing oil recovery through smart water flooding.
3. Prior prediction of suitability of fields and the potential incremental recovery in that field is not possible; consequentially core floods and other laboratory studies are used followed by SWCTTs.
4. An economical and suitable source of saline water must be provided in offshore applications through nanofiltration and reverse osmosis processing plant or from a suitable shallow aquifer.
5. With the encouraging trial results, smart water flooding either alone or in combination with other water based EOR techniques can be a possible revolution in offshore reservoirs on a 3 to 8 year time frame.

## RECOMMENDATIONS

1. It is recommended that the application of smart water flooding is effective only if its potential to any field is thoroughly studied. This must be undertaken methodically and consistently by appropriate laboratories using available methodology. The effectiveness of smart water flooding must be evaluated against other EOR techniques which use water.
2. The existing experimental techniques around low salinity water flooding should be developed and standardised. All relevant experiments must be carried out at reservoir conditions (including temperature, CO<sub>2</sub> partial pressure and pH) using live crude, reservoir brine and native core with original wettability conditions. Capillary end effects should be minimised and *in situ* residual oil saturation should be measured using accurate techniques like CT scanning. Flow rates and pressure gradients must to be monitored and controlled during core flood experiment. Therefore, it is recommended that uncertainties in core flood measurements must be reasonably accounted for in order to evaluate the validity of the enhanced oil recovery data.
3. Before injecting water into the reservoir, the study of its compatibility with reservoir brine is recommended. It should be ensured that the water does not cause any precipitation or other associated problems like scaling, corrosion etc. If it does, a comprehensive water treatment programme must be adopted with the aim of making the injectate fit for the purpose.
4. Lastly, smart water flooding being a new but promising technology, more investment should be made in this field by major companies and institutions. Detailed study of all aspects related to this concept is recommended and ways to improve its effectiveness must be devised.

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