Project Report
On

"Fluid-Fluid & Rock-Fluid Compatibility studies for Injection Water in Hydrocarbon Reservoirs and Bacteriological Analysis & Biocide Dose Optimization of Water Sample"

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Institute of Reservoir Studies
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Chandkheda, Ahmedabad

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CERTIFICATE

This is to certify that **Mr. Rijurekh Halder,** student of Petroleum Engineering from IIT (ISM), Dhanbad has successfully completed his summer training on "**Fluid-Fluid & Rock-Fluid Compatibility studies for Injection Water in Hydrocarbon Reservoirs and Bacteriological Analysis & Biocide Dose Optimization of Water Sample**" at Institute of Reservoir Studies (IRS), ONGC, Ahmedabad, Gujarat from 19th June 2023 to 14th July, 2023.

The training was supervised under **Shri Giridhar Gopal, DGM (Reservoir) and Shri Vivek Raj Srivastava, Manager (Reservoir)**. Throughout the training tenure, he was found to be sincere and hard working.
We wish all the best in his career.

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UNDERTAKING

I, **Rijurekh Halder**, **3rd** year student of **Petroleum Engineering** from **IIT (ISM), Dhanbad,** doing **Summer Training** at IRS ONGC, Ahmedabad from **19th June 2023** to **14th July 2023** on the topic **"Fluid-Fluid & Rock-Fluid Compatibility studies for Injection Water in Hydrocarbon Reservoirs and Bacteriological Analysis & Biocide Dose Optimization of Water Sample".**

We undertake the following

- That we shall not disclose any confidential information (proprietary information) received from the ONGC to any other person, company, organization, and firm; as we know that confidential information cannot be sold, exchanged, published or disclosed to anybody by any way including photocopies or reproduced materials etc. without prior written consent of ONGC.
- That we shall keep confidentiality to the highest extent in order to avoid the disclosure or use of the information received during internship.
- That we will not publish/use data provided by ONGC anywhere in India or outside India
- That if we are proved to be guilty for the disclosure of the confidential or proprietary information, ONGC has the sole discretion the right for the reimbursement of damages borne due to the disclosure.

Rijurekh Halder

(Signature of Student)

Date: 14th July 2023

Place: Ahmedabad

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TABLE OF CONTENTS

Sr. No.	Topic	Page No.
1	About IRS	6
2	Introduction	7
3	Physicochemical Characterization of Injection water	8
4	Filtration Studies	12
5	Scaling Studies	16
6	Corrosion Studies	24
7	Ion Exchange Chromatography	27
8	Rock Fluid Compatibility	31
9	Microbial Enhance Oil recovery (MEOR)	37
10	Lab Visits	47
11	Conclusion	50
12	References	51

About IRS

The Institute of Reservoir Studies (IRS) was founded in 1978 as a single source and multi-service reservoir engineering agency with the objective to:

- Maximize hydrocarbon recovery at minimum cost
- Provide holistic reservoir description
- Maximize the value of proven reserves with improved and enhanced recovery techniques
- Enhance the skills and knowledge for better reservoir management.

Since its inception, IRS has contributed effectively in the development of new concepts and innovative techniques besides adopting state–of–art technological advancements as part of its concern. All investment decisions of ONGC regarding Hydrocarbon exploitation are based on the recommendation given by the IRS.

Introduction

Water that is injected into porous formations for water-flood or disposal purposes can be sourced from a number of locations. The source of the water, its temperature and pressure path during production and injection operations, compatibility issues between blended waters, and possible seasonal variations in the water quality are all issues which may affect the overall quality of the injected water from a damage/impaired injectivity perspective. Injection water from various fields is taken into consideration by measuring its physicochemical properties like pH, turbidity and ionic composition. Before measuring all of these properties the water needs to be filtered by using filter paper of various sizes. So after filtration and evaluation of injection water, the analysis steps to preventing likely happening problems like scaling and flocculation. The samples are kept under reservoir conditions dozed enough to prevent/lessen the problems.

Thus, after filtration, measuring properties and dozing water with chemicals to prevent the likely problems.

The next step of the study is checking Rock- Fluid Compatibility by doing core flooding. Core is a miniature representation of the reservoir itself. It is initially formation water saturated and later again flooded with formation water, which is then displaced by oil and oil is again displaced by formation water and after that injection water is injected in the core sample for estimation of Recovery factor i.e., improved.

This can be used to study permeability retention, imbibition or estimation of residual oil saturation. In this case, residual oil is evaluated. This project deals with various procedures being used to make water apt for injection in oil fields. Besides, it also includes reasons for scaling, coagulation and type of chemicals used in oil industry to prevent it. It also includes few core flooding experiments.

Physicochemical characterization of injection water

Aim of the project:

This project deals with various procedures being used to make water suitable for injection in oil fields. Besides, it also includes reasons for scaling, corrosion and type of chemicals used in oil industry to prevent it. This study also includes optimizing the doze of scaling and corrosion inhibitors and to determine the compatibility of injection water with the formation

Injection Water Quality

Injection water quality is a key factor to successful water flooding. For this purpose, we need to analyze water's physical, chemical and biological properties and perform treatment design to make it compatible with formation water and reservoir rocks. Incompatible water can cause problems like plugging of pores due to suspended solids present, scales and corrosion products, which ultimately reduces the production performance of field. Therefore, it is very important to design suitable injection water.

Treatment design and compatibility studies on water from different sources are required to be carried out for each water injection scheme. The studies are divided into following parts:

Physico-chemical characterization of injection water sample involves determination of ionic composition and study of physical parameters viz. turbidity, filterability, pH, chlorine demand, TDS and TSS. The ionic composition of the given water sample and the procedure followed to carry out the tests are described below:

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.

Figure : **pH meter**

Iron and Sulphate: The Iron and Sulphate content was calculated by mixing the sample with Ferro-ver and Sulpha-ver reagent respectively. The solution was then placed in spectrophotometer which directly gives its concentration in ppm.

Figure: Spectrophotometer

Turbidity: It is measured in NTU (Nephelometric Turbidity Units). The water sample is taken in a holder provided in the turbidimeter. This gives the turbidity value of given sample. For injection water this value should be less than 0.5 NTU. Effluent water has a high turbidity value.

Figure: Turbidity meter

Filterability & TSS (total suspended solids): The volume of filtrate (in liters) collected in 30 minutes through 0.45µ filter is called filterability. Its unit is liters/30 minutes. It is calculated using Millipore filtration assembly.

Table: Ideal characteristics of injection water

pH	6.5-8.5
Turbidity	<5.0
Filterability	>5 liter/30 minutes
Total Suspended Solids	< 5.0 ppm
Oil Content	< 10 ppm
Corrosion Rate	< 1 mpy
Scaling Tendency (as % reduction in total hardness)	< 10 %
Dissolved Oxygen	< 0.02 ppm
Permeability Retention	> 80 %
GAB	10^3 to 10^4 counts/ml
SRB	Nil

PHYSICOCHEMICAL TESTS DATA PERFORMED IN LAB

Physicochemical Analysis of a sample of a field was performed in lab whose results are as follows:

Table: Physicochemical analysis of samples of field A

S.NO	Sample	Turbidity (NTU)	Iron	pH	Oil Content (ml)
1	A	155	0.04	8.9	10.3
2	B	7.42	0.17	9.02	0
3	C	475	0.25	8.94	0
4	D	71	0.13	8.96	0
5	E	50	0.08	9.05	0
6	F	67.3	0.28	8.98	0
7	G	26.2	0.13	8.91	0
8	H	65.2	Nil	8.95	0

CONCLUSION:

- As pH of the sample should lie between 6.5 to 8.5, so samples are not good.
- The turbidity of samples should be less than (<=5) as these samples show very high turbidity than permissible limit so they need treatment.
- Iron content is in permissible limit for most of samples.
- So, treatment of water is necessary with respect to their ionic concentration.

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 quantity and proportion of suspended solids in injection waters

➢ Cerini Filtration

This is the first step done to check the quality of water. And then if water needs further treatment, coagulation-flocculation is then done.

In Cerini method, we pass water through a 0.45 microns filter paper under a constantdifferential pressure of 20 psig. This is done to determine the filterability of the treated water. Higher filterability means good water quality. It can be said that the prime reason for poor water quality is the presence of suspended particles. The degree and extent of damage caused by these solid particles depends upon its concentration, size distribution, shape and ability to bridge.

WATER QUALITY RATING GUIDE	
RPI	General Quality Rating
<3	Excellent
3 to 10	Good to fair
10 to 15	Questionable
>15	Poor

As a rule of thumb, if filtration rate is more than 6 liter/30 minutes under a differential pressure of 20 psig through0.45 µm filter paper, water quality is considered as good. A water having turbidity in range of 0.2-0.5 NTU, solid content less than 2.5mg/liter and Cereni slope less than 0.3ml/sec/liter is considered as right type of water for injection.

Fig.: Millipore Filtration assembly

EXPERIMENTS FOR CERENI ON A FIELD SAMPLE

Field A sample

Table : Cereni plots of field sample

S.NO	Sample	Initial Wt.(g)	Final Wt.(g)	Filterability (ml)	Filtration Rate (ml/s)	TSS (mg/l)
1	A	0.0826	0.1431	339	0.188333333	178.4660767
2	B	0.0829	0.0921	334	0.185555556	27.54491018
3	C	0.0827	0.0984	388	0.215555556	40.46391753
4	D	0.083	0.096	203	0.112777778	64.03940887
5	E	0.0834	0.098	243	0.135	60.08230453
6	F	0.0831	0.0971	218	0.121111111	64.22018349
7	G	0.0833	0.0908	281	0.156111111	26.69039146
8	H	0.0831	0.0916	210	0.116666667	40.47619048

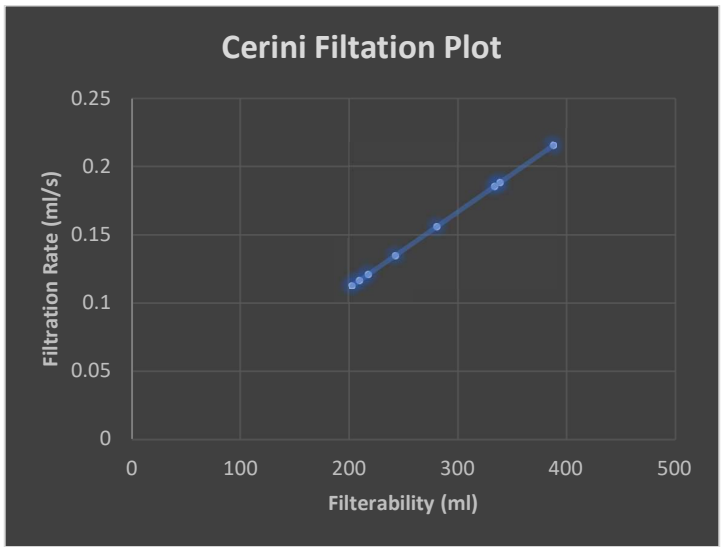


Figure: Cerini Filtration Plot

TSS Calculation:

Sample A:

Filterability = 0.339 liters/30 minutes
Initial weight of filter paper = 82.60 mg
Final weight of filter paper = 143.10 mg
TSS = (Weight of solids /Filtered volume) =178.466 mg/l

Sample B:

Filterability = 0.334 liters/30 minutes
Initial weight of filter paper = 82.90 mg
Final weight of filter paper = 92.10 mg
TSS = (Weight of solids /Filtered volume) =27.545 mg/l

Sample C:

Filterability = 0.388 liters/30 minutes
Initial weight of filter paper = 82.70 mg
Final weight of filter paper = 98.40 mg
TSS = (Weight of solids /Filtered volume) =40.464 mg/l

Sample D:

Filterability = 0.203 liters/30 minutes
Initial weight of filter paper = 83.00 mg
Final weight of filter paper = 96.00 mg
TSS = (Weight of solids /Filtered volume) =64.039 mg/l

Sample E:

Filterability = 0.243 liters/30 minutes
Initial weight of filter paper = 83.40 mg
Final weight of filter paper = 98.00 mg
TSS = (Weight of solids /Filtered volume) =60.082 mg/l

Sample F:

Filterability = 0.218 liters/30 minutes
Initial weight of filter paper = 83.10 mg
Final weight of filter paper = 97.10 mg
TSS = (Weight of solids /Filtered volume) =64.220 mg/l

Sample G:

Filterability = 0.281 liters/30 minutes
Initial weight of filter paper = 83.30 mg
Final weight of filter paper = 90.80 mg
TSS = (Weight of solids /Filtered volume) =26.690 mg/l

Sample H:

Filterability = 0.210 liters/30 minutes
Initial weight of filter paper = 83.10 mg
Final weight of filter paper = 91.60 mg
TSS = (Weight of solids /Filtered volume) =40.476 mg/l

Conclusion:

The filterability of samples is (<0.35) liters per 30 minutes which is low. Total suspended solids of samples are very high (>25ppm). So, Water Quality is bad and therefore more treatment is required for these water samples.

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.
- It reduces the diameter of the tubes and thus increases the frictional losses, which causes high pumping costs.
- It creates variation in temperature and pressure distribution and ultimately causedamage to the pipeline

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.
- Changes in pH.

Common Oil Field Scales

- Calcium sulphate (anhydrite, gypsum),
- Calcium carbonate, Magnesium carbonate,
- Barium sulphate (barite)
- Strontium sulphate (celestite)
- Other less common scales have also been reported such as iron oxides, iron sulphides and iron carbonate.

Calcium Sulphate Scale

Calcium sulphate scale poses a unique problem for the salts under consideration because Calcium sulphate exists in several crystalline forms. These include gypsum ($CaSO_4.2H_2O$) and anhydrite ($CaSO_4$).

Gypsum, the most common scale occurs at relatively low temperature. At higher temperature (Above 100 ºC), the stable phase predicted is anhydrite (CaSO4). However, hemihydrates has been known to form at 100 to 121 ºC, especially in non- turbulent systems and in high ionic strength brines.

Calcium sulphate scale formation is less dependent on temperature, but is typically formed because of a decrease in pressure or an increase in the relative concentrations of calcium or sulphate. CaSO4 solubility is fairly independent on pH and hence, can readily precipitate in acidic environment.

Calcium Carbonate Scale

Deposition of CaCO3 scale results from precipitation of calcium carbonate as per the

following equation:

$$Ca^{+2} + CO_3^{2-} \rightarrow CaCO3$$

In many oilfields, the deposition of calcium carbonate scale on surface and subsurface production equipment creates an operation problem. The formation water in which the carbonate-scale-forming components are initially dissolved becomes supersaturated with calcium carbonate because of the drop in pressure during production. The continuous flow of a supersaturated solution through the production equipment results in the growth of a dense layer of calcium-carbonate crystals Carbonate scale formation occurs when connate water or aquifer water passes through the bubble point and carbon dioxide is evolved. As carbon dioxide is evolved, the solubility with respect to carbonate declines rapidly and forms a precipitate with divalent ions, such as iron, and more commonly calcium, as outlined in the following equation.

$$Ca(HCO_3)_2 \Leftrightarrow CaCO_3 + CO_2 + H_2O$$

Calcium Carbonate Scaling Calculations

Calcium Carbonate Saturation Index

It is common to express the degree of supersaturation, and hence the likelihood of precipitation of CaCO3 from a solution in terms of the saturation index, which is defined as follows:

$$Saturation\ Index = \log_{10}\left[\frac{IP}{K_c}\right]$$

Stiff and Davis Method

Stiff and Davis empirically extended the Langelier method to apply to oilfield brines. Their equation is as follows:

SI	=	pH	−	pHs
Stability Index		Actual pH of Water		pH at which water would be saturated with $CaCO_3$

$$pHs = K + pCa + pAlk$$

Therefore:

$$SI = pH - K - pCa - pAlk$$

Where:

SI = Stability Index. If SI is negative, the water is undersaturated with $CaCO_3$ and scale formation is unlikely. If SI is positive, scale is likely to form.

pH = Actual pH of the water

K = A constant which is a function of salinity, composition and water temperature. Values of K are obtained from a graphical correlation with ionic strength and the temperature of the water.

$$pCa = \log \frac{1}{Moles\ Ca^{++}/Liter}$$

$$pAlk\ M = \log \frac{1}{Equivalents\ M\ Alkalinity/Liter}$$

$$M\ Alkalinity = Total\ Alkalinity = CO_3^{=} + HCO_3^{-}, \quad mg/L$$

In order to calculate SI we must know the temperature, pH and the $HCO3^-$ and $CO3^{-2}$ concentrations. In addition, a complete water analysis is necessary to enable calculation of the

The ionic strength is:

$$\mu = \frac{1}{2}\left(C_1Z_1^2 + C_2Z_2^2 + C_3Z_3^2 + \ldots + C_nZ_n^2\right)$$

Where:

C = Concentration of the ion in moles/liter.

Z = Valence of the ion

ionic strength. It is essential that values of pH, $HCO3^-$ and $CO3^{-2}$ be measured in the field immediately after sampling, since these parameters change very quickly once the sample is removed from a pressurized system. Valid calculations cannot be made from laboratory analyses.

Unfortunately, even field measurements of pH values will not suffice when attempting to apply this method to downhole conditions in producing or injection wells. The pH must be calculated.

Equations are given in the following section which enable estimation of pH values at elevated pressures and temperatures.

Values of K as a function of ionic strength are calculated from the Solubility graph. These curves are based on experimental data measured over the following range:

- Molar Ionic Strength: 0-3.6
- Temperature: 32,86 and 122°F (0, 30 and 50°C]
- Pressure: atmosphere [101.3 kPa)

All curves outside of this data range were extrapolated.

Interpretation of Stiff & Davis Index

Case	Conclusion
SI is negative	The water is undersaturated with $CaCO_3$. Scale formation is unlikely.
SI is positive	The water is supersaturated with $CaCO_3$. Scale formation is indicated.
SI = 0	The water is saturated with $CaCO_3$.

Conclusion:

In a general context, when the solubility index (SI) is greater than 0, it indicates a higher likelihood of CaCO3 precipitation. To mitigate this scaling effect, it is recommended to add a scaling inhibitor. The values of Stiff & Davis (K), p_{Ca}, and p_{Alk} are obtained from a graph for each sample, and the SI is calculated using the formula: $SI = pH - (K + p_{Alk} + p_{Ca})$.

Calcium Sulphate Scaling Calculations

Traditional Approach to Sulfate Scale Solubilities

Solubility values for CaSO4, BaSO4, or SrSO4,, can be calculated using the following equation

$$Solubility\,(meq/L) = 1000\left[\sqrt{X^2 + 4K_c} - X\right]$$

For a divalent ion such as Ca^{++}, Ba^{++} or Sr^{++}:

$$S(equivalents/L) = \sqrt{X^2 + 4K_c} - X$$

Or:

$$S(meq/L) = 1000\left[\sqrt{X^2 + 4K_c} - X\right]$$

providing values of conditional solubility product, K, are knows for each compound:

The "actual concentration of Ca50, in solution is equal to the smaller of the Ca++ or SO4= concentrations (expressed in meq/liter) in the water of interest, since the smaller concentration controls the amount of calcium sulphate which can be formed.

The calculated calcium sulphate solubility, S (meq/liter), is compared with the actual

Interpretation of Sulfate Scale Calculations

Case	Conclusion
S = Actual	The water is saturated with $CaSO_4$.
S > Actual	The water is undersaturated with $CaSO_4$. Scale is unlikely.
S < Actual	The water is supersaturated with $CaSO_4$. Scale is likely.

concentration to determine if scale formation is likely.

Calcium Sulphate (Gypsum) Solubility Calculations

The data measured by Skillman McDonald and Suff has bees widely used to estimate the solubility of gym in oilfield brines. They measured len product comes in simulated oilfield brines over the following range:

- Temperature: 50, 95, 122 and 175°F (10, 35, 50 and 50°C]
- Ionic Strength 0-60 mol/l.
- Pressure: atmosphere [101.3 kPa]

Their data are presented in the graph.

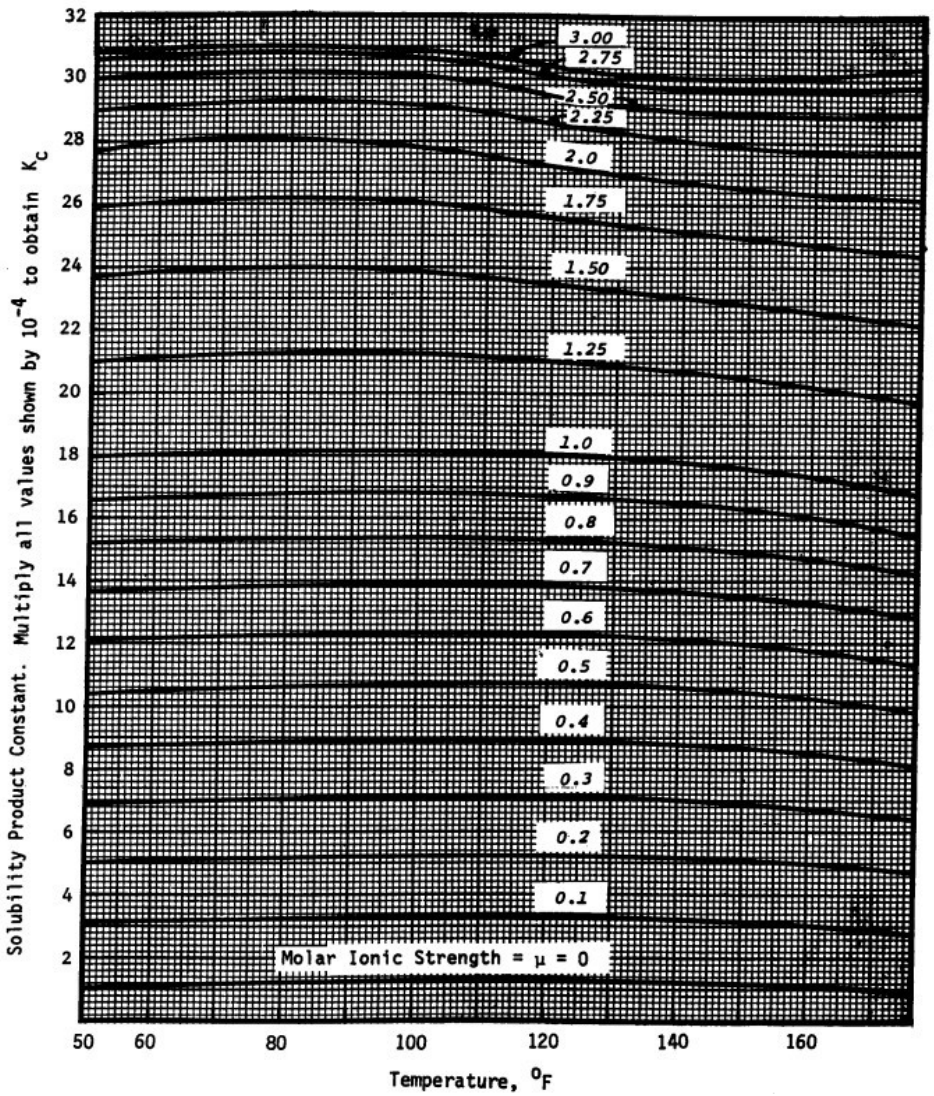
The following procedure is recommended to assess the possibility of gypsum precipitation from a given brine:

1. Calculate the molar ionic strength using the Equation given below.

$$\mu(Moles/L) = 10^{-5}(2.2\times Na^{+} + 5.0\times Ca^{++} + 8.2\times Mg^{++} + 1.5\times Ba^{++} + 2.3\times Sr^{++} + 1.4\times Cl^{-} + 2.1\times SO_4^{=} + 0.8\times HCO_3^{-})$$

2. Obtain the appropriate value of K, for the temperature of interest from the graph given below.

Calcium Sulfate (Gypsum) Conditional Solubility Product Constants



3. Calculate the solubility of gypsum in meq/liter by solving Equation given below.

$$S(meq/L) = 1000\left[\sqrt{X^2 + 4K_c} - X\right]$$

4. Calculate the "actual concentration" of gypsum in the water, which is equal to the smaller of the Ca++ or SO4= concentrations expressed in moq/liter
5. Compare the calculated solubility with the actual concentration to determine if precipitation of gypsum is likely.

Conclusion:

In general, when the solubility of a substance exceeds its actual concentration, it is unlikely that a scale will form.

Scaling Experiment

Procedure:

- The initial total hardness (Calcium and Magnesium ion concentration) of Injection water and Formation water was determined by titrating them with 0.02 M EDTA.
- In set 1, total 7 samples with different injection water to formation water ratio were prepared and then placed in the oven at 80°C for 96 hours.
- In set 2, total 7 different samples with same injection water to formation water ratio determined from the above step (20:80) with different dosing concentration of HEDP-the scaling inhibitor and SI. They were then placed in the oven 80°C for 96 hours.
- After 96 hours all the samples were to be titrated again to determine total hardness.
- The difference in the total hardness is directly proportional to scaling tendency.

CONCLUSION:

After analyzing different proportions of Injection water and Formation water, it was observed that the highest reduction in hardness, indicating the maximum scaling tendency, occurred when the Formation Water and Injection Water were mixed in a 4:1 ratio. Following optimization of the dosage, it was determined that a concentration of 10 ppm of HEDP was effective in inhibiting scale formation, as it resulted in almost zero reduction in hardness.

CORROSION STUDIES

The common material of construction in oil and gas production is carbon or low-alloy steel, so the primary aim is steel inhibition. Despite the developments in corrosion resistant alloys over the past few decades, carbon steel still constitutes an estimated 99% of the material used in the oil industry. It is usually the most cost-effective option, being a factor of 3 to 5 times cheaper than stainless steels. Yet its corrosion resistance is poor in aggressive environments, and the cost savings can only be realized by adding a corrosion inhibitor to the environment or applying a protective coating to the steel.

A large number of corrosion inhibitors have been developed and used for application to various systems depending on the medium treated, the type of surface that is susceptible to corrosion, the type of corrosion encountered, and the conditions to which the medium is exposed. Expedience of the application of any corrosion inhibitor can be determined only after investigation and production tests and correlation of inhibitor consumption with its cost.

Types of Corrosion

There are four general types of corrosion of concern in an oil field. Three involve chemical issues while the fourth is electrochemical in nature. The types and general overview are as follows:

- **Carbon Dioxide (sweet corrosion):** Carbon dioxide is found in natural gas, crude oil, and condensate and produced water. When combined with water, carbon dioxide produces carbonic acid (H_2CO_3), which is highly corrosive with steel and other metallurgies. The damage caused by sweet corrosion in oil wells usually results in pitted sucker rods and the formation of hairline cracks.

- **Hydrogen Sulfide (sour corrosion):** Hydrogen sulfide occurs in approximately 40% of all wells. H_2S combines with water in presence of oxygen to form sulfuric acid (H_2SO_4), a strongly corrosive acid. Since hydrogen sulfide combines easily with water, damage to stock tanks below water levels can be severe.

- **Oxygen Corrosion (oxidation**): This form of corrosion is the most common form of corrosion. Oxygen corrosion begins when metal surfaces make contact with the atmosphere and moisture. Under these conditions, the iron, water and oxygen react to form ferric oxide

- (Fe_2O_3, commonly known as rust). As a result, the metal is weakened, usually undergoing embrittlement. Oxidation can also accelerate the damage from sweet corrosion.

- **Electrochemical Corrosion:** The most common type is where two different types of metal are placed in an acidic solution. Electrons from one metal will flow to the other metal. This results in the metal that gives up electrons being eaten away and the other metal building up a brittle coating.

Inhibitors Characteristics: As a rule, surface –active substances which produce a protective film over metal surface are inhibitors. Inhibition is one of the simplest and economical methods of corrosion protection; however, inhibitors must meet following requirements:

- Maximum protective action and minimum consumption.
- They should be soluble or dispersible in water or brine.
- They should pass to an organic phase in insignificant amounts only.
- They should not create emulsions in water and condensates.
- They should be easily separable and ensure a highly protective effect.
- They should prevent the formation of pitting and hydrogenation of steel (in the case of the
- presence of H_2S).
- They should be non-toxic should have strong after-effects.

Experiment – Study of corrosion rate in static condition

Procedure:

- The static corrosion study was undertaken on 7 different N-80 steel coupons.
- Coupons were cleaned and polished.
- After preparation of coupons, their weight and dimensions were measured.
- Different solutions were prepared in the injection water with different concentrations of Oxygen scavenger (sodium sulfite) and Corrosion inhibitor (WIN)
- Before adding Corrosion Inhibitor, the prepared solutions were kept for about 30 minutes after mixing Oxygen Scavenger in them.
- Coupons were then kept hanging in the bottles using Teflon tape.
- These solutions were then kept at reservoir temperature of 80° C for 96 hours. The coupons were then taken out and weighed again.
- The difference in weight is directly related with corrosion rate which is expressed in mils per year (mpy).

Corrosion Rate (mpy) = 36500× (weight diff.)/ (exposure days×density of material×surface area)

Figure: Corrosion experiment setup

Conclusion:

After conducting experiments with varying amounts of Corrosion Inhibitor, it was determined that the optimum corrosion rate of 1.565 mpy was achieved in the sample containing 20 ppm of the corrosion inhibitor. Therefore, a corrosion inhibitor dosage of 20 ppm is recommended for the purpose of corrosion dose optimization.

Ion Exchange Chromatography

- Chromatography is the separation of a mixture of compounds into its individual components based on their relative interactions with an inert matrix.

- Ion exchange chromatography (or ion chromatography) is a process that allows the separation of ions and polar molecules based on their affinity to ion exchangers.

- The principle of separation is thus by reversible exchange of ions between the target ions present in the sample solution to the ions present on ion exchangers.

- In this process two types of exchangers i.e., cationic and anionic exchangers can be used.

Figure: Ion Chromatogram

With the help of Ion chromatograph, we find the following:

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. It is calculated in ppm by Ion Chromatography.

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 Ion Chromatography.

Carbonate & Bicarbonate: Carbonate and Bicarbonate are determined by Auto-titrator. Take 80 ml sample water in Auto-titrator and it will titrate the water sample with 0.1 N HCl. The end point will be at 8.2 pH for Carbonate and 4.3 pH for bicarbonate. The volume of HCl used is noted by Auto-titrator.

Table: Ionic Chromatography Analysis of Formation Water & Injection Water

a) Anion analysis

Anion Analysis		Concentration			
S.NO	**Sample**	**Fluoride**	**Chloride**	**Nitrate**	**Sulfate**
1	N	2.507	24405.15	4.303	1112.2
2	O	0.832	26665.03	6.835	2891.691
3	P	NIL	5797.833	8.099	239.44
4	Q	NIL	1925.342	6116.054	NIL
5	R	NIL	5971.231	NIL	242.041

b) Cation Analysis

Cation Analysis		Concentration			
S.NO	**Sample**	**Sodium**	**Potassium**	**Magnesium**	**Calcium**
1	I	9459.275	375.3	2506.257	NIL
2	J	10270.6	72.299	604.703	315.922
3	K	935.051	NIL	316.311	1099.094
4	L	3274.373	NIL	343.79	192.06
5	M	959.131	55.827	2540.02	205.01

Conclusion:

In conclusion, ion chromatography analysis was performed on the formation water sample from an oil well to determine the concentrations of various ions present. Ion chromatography is a powerful analytical technique used to separate and quantify different ions in a sample. It provides valuable insights into the composition of the formation water, allowing for a better understanding of its chemical properties and potential impacts on oil well operations.

Low Salinity water flooding

Introduction-

Low salinity water flooding is an enhanced oil recovery (EOR) technique used in the oil and gas industry. It involves the injection of water with reduced salinity or specific ion composition into an oil reservoir to improve oil recovery rates.

In conventional practices, water flooding has been extensively employed as a secondary technique to enhance oil recovery. This involves injecting water into the reservoir to displace oil and push it towards production wells. Nevertheless, the concept of low salinity water flooding expands upon this approach by acknowledging the influence of water chemistry on the efficiency of oil recovery.

The change in wettability has a direct impact on the capillary forces responsible for retaining oil within the reservoir. As a result, oil becomes more readily mobile and can flow more easily through the pores of the rock, thus facilitating displacement by the injected water. This process significantly enhances oil recovery by freeing trapped oil and improving the effectiveness of water flooding in sweeping the reservoir. The ideal salinity level or ion composition necessary for optimal low salinity water flooding varies depending on the unique characteristics of each reservoir. Determining the most suitable water chemistry for a given reservoir involves conducting laboratory tests and reservoir simulation studies to identify the most effective approach.

Low salinity water flooding has emerged as a promising and economically viable approach to improve oil recovery, particularly in mature reservoirs where conventional methods have reached their limitations. Nevertheless, the implementation of this technique is still undergoing rigorous examination and demands thorough assessment on an individual basis to ascertain its viability and potential advantages.

Mechanism-

Low salinity water flooding is a method used to enhance oil recovery from reservoirs. It involves injecting water with a lower salt content than the formation brine into the reservoir. The process is typically carried out as a secondary recovery technique, following primary production methods.

The mechanism of low salinity water flooding can be described in several steps:

Low salinity water flooding involves several steps. First, the appropriate water source is selected, which can be freshwater, brackish water, or modified formation water with reduced salinity. The water is treated to achieve the desired salinity level. Laboratory testing is then conducted to evaluate the interactions between the injected low salinity water, reservoir rock, and crude oil. This helps determine the optimal salinity level or ion composition for effective oil recovery. The low salinity water is injected into the reservoir through dedicated injection wells, displacing the oil and pushing it towards production wells.
This process alters the wettability of the rock surfaces by interacting with clays and minerals, reducing capillary forces that hold the oil in place. The modified wettability enables improved fluid flow within the reservoir, facilitating the mobilization of trapped oil and enhancing recovery. Monitoring

techniques such as well logging, pressure measurements, and fluid sampling are employed throughout the process to assess its effectiveness and optimize the low salinity water flooding technique.
It is important to note that the success of low salinity water flooding can vary depending on the reservoir's unique characteristics, such as the rock type, oil properties, and water chemistry. Therefore, each application of low salinity water flooding requires careful evaluation and customization to maximize its benefits.

Benefits-

The outcomes and benefits of low salinity water flooding can vary based on reservoir characteristics such as rock type, oil properties, and water chemistry. However, some common results include increased oil recovery compared to conventional water flooding methods. This is achieved by modifying wettability and reducing capillary forces, improving oil mobility and displacement efficiency. Low salinity water flooding also enhances sweep efficiency, ensuring a larger portion of the reservoir is contacted and producing oil.

Additionally, it can help maintain reservoir pressure, which is crucial for maximizing oil recovery and extending the reservoir's economic life. In terms of cost-effectiveness, low salinity water flooding is often favorable, particularly in mature reservoirs, as it utilizes existing infrastructure and requires minimal modifications. Moreover, it generally has lower environmental impacts compared to other enhanced oil recovery techniques, as it reduces the need for additional chemicals and minimizes waste fluid production. However, it is important to evaluate and monitor the specific results and benefits in each reservoir to assess the technique's effectiveness.

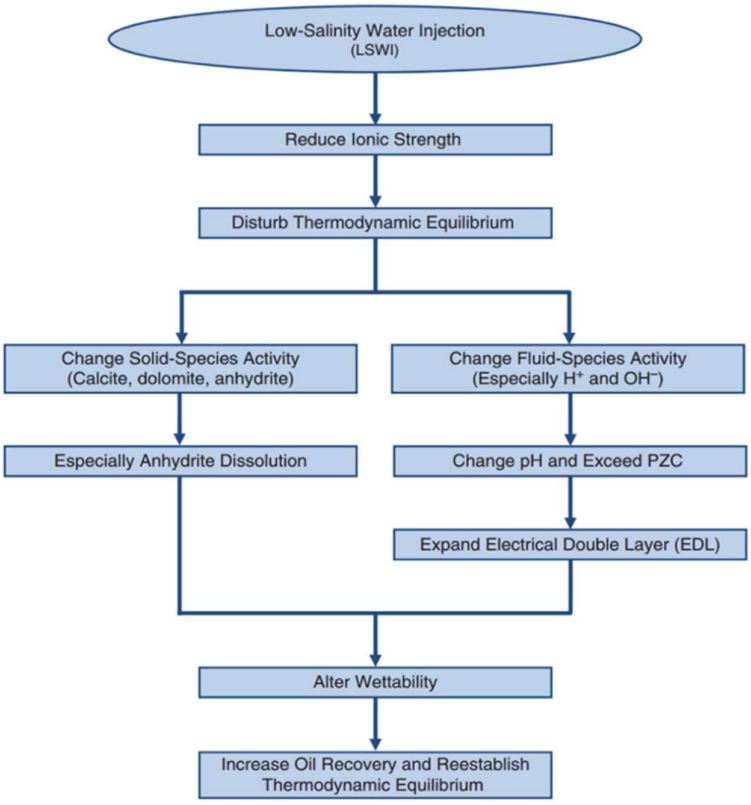


Fig: LSWI in carbonates (AlHammadi et al., 2018)

ROCK-FLUID COMPATIBILITY STUDIES

The objective of this study is to determine the compatibility of injection water with the formation. Different concentrations of additives (mainly 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 following major processes:

- The clays present in the formation may swell and plug the pore space.
- The injection water may cause scale precipitation which will drastically reduce permeability of the formation.
- Injection water may cause fine migration which can improve or deteriorate the permeability.

Preparations for the experiment:

- **Preparation of core pack:**

- Horizontal core plugs were drilled from the whole core using the core cutting machine. The extraction of the core plug was done in soxlet by using a mixture of solvents viz methanol and toluene in the ratio of 20: 80
- After drying at 60^0C for sufficient time, the external surface of the core was coated with resins (araldite).
- Core pack was 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 was filled with molten Cerro metal (an alloy of tin and bismuth).
- After cooling off to room temperature, the ends were smoothened on lathe machine in the mechanical workshop of IRS.

- **Determining of permeability:**

Formation water permeability was measured by flowing nitrogen gas through the pack and measuring the pressure difference and flow rate at reservoir temperature.

- **Evacuation, saturation, pore volume and water permeability determination:**

The core plug was evacuated through vacuum pump for attaining complete vacuum inside the core pack. It was saturated with distilled water. The volume of water taken up by the core pack gave the pore volume.

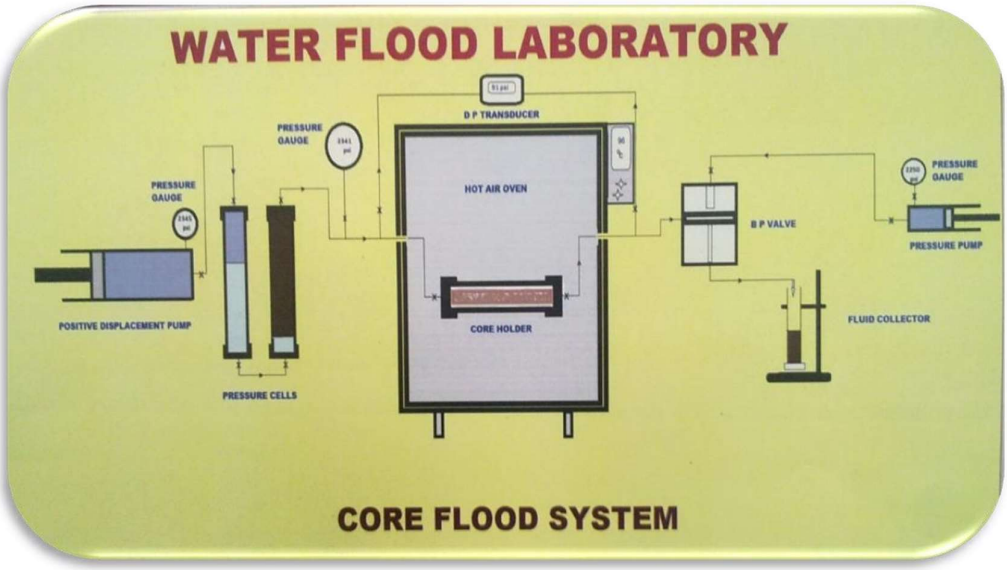


Figure: Core flood experimental setup

Experiment procedure:

- The core pack was placed in the oven at 83°C (the reservoir temperature).
- The inlet of the pack was connected to the outlet of displacement cell.
- The inlet of displacement cell was joined to the micro-syringe pump for injection.
- At the outlet end of the pack, a measuring cylinder was placed to collect produced fluids.
- The formation water was poured in the displacement cell (used in the pump as displacing medium).
- A pressure gauge was connected at the outlet end of the cell to observe injection pressure.
- The flooding was started at the constant rate of 10ml/hour.
- The outlet volume and injection pressure were noted at every 30 minutes.
- The flooding usually continues till the pressure becomes stabilized and it usually takes 40 to 48 hours.
- The permeability was plotted against pore volume injected and deterioration in it was observed.
- Similar process was carried out on two more core packs with different clay stabilizer (CS-X).
- The permeability retention should be more than 80% for better results that is due to injection water, reduction in permeability should not be more than 20%

Length(cm)	**7**
Diameter(cm)	3.72
Area(cm^2)	10.87
Bulk volume	76
Porosity (%)	19.74
Pore volume(cc)	15
Air Permeability(mD)	150.82

Table: Parameters of core plugs used

volume of formation water inside pack(ml)	19
Pore Volume	15
Dead Volume(ml)	6
volume of formation water inside core(ml)	13
Saturation of liquid (%)	86.67

Table: saturation data of core plug for formation water

23-12-2022	**Determination of Base permeability at RT using Formation water , Rate 15 ml/hr**			
S.No.	Time	Gauge Pressure(bar)	Gauge pressure (atm)	Kb
1	12.2	0.201	0.198	5.0033
3	13.15	0.239	0.236	4.2078
7	14.15	0.316	0.312	3.1825
11	15.2	0.354	0.349	2.8409
15	16.15	0.397	0.392	2.5332
19	17.15	0.439	0.433	2.2908
20	17.3	0.448	0.442	2.2448

11.01.2023	Flooding with Injection Water			
S. No.	Time	PV(ml)	G. Pressure(Δ Pi)atm	Ki(mD)
1	17.45	0.0	0.343	2.890
2	18.15	0.6	0.391	2.540
5	19.2	0.4	0.480	2.069
8	20.25	0.5	0.522	1.901
11	21.31	0.5	0.328	3.029
13	22.3	0.6	0.332	2.984
15	23.3	0.6	0.397	2.502
16	24	0.6	0.394	2.520
17	1	1.2	0.415	2.389
18	2	1.2	0.400	2.483
19	3	1.2	0.378	2.626
20	4	1.2	0.375	2.646
21	5	1.2	0.373	2.660
22	6	1.2	0.377	2.633
23	6.3	0.6	0.365	2.718
24	8.4	2.5	0.374	2.653
25	9	0.4	0.369	2.689
26	9.3	0.6	0.370	2.682
27	9.5	0.4	0.357	2.778
27	10	0.2	0.359	2.763
28	11	0.6	0.366	2.711
30	12	0.6	0.376	2.640
32	13	0.6	0.388	2.559
34	14.1	0.4	0.394	2.520

Table: Determination of base permeability with formation water of field A

Base Permeability, Kb= 2.3066 mD

17.01.2023	Flooding with Injection Water			
S. No.	Time	PV(ml)	Cum PV(ml)	Kb/Ki
1	17.45	0.0	0.0	0.798
2	18.15	0.6	0.6	0.908
3	18.40	0.5	1.1	1.039
4	19.00	0.4	1.4	1.021
8	20.25	0.5	3.1	1.000
11	21.31	0.5	4.3	0.966
13	22.30	0.6	5.5	0.936
15	23.30	0.6	6.6	0.922
16	24.00	0.6	7.2	0.915
17	1.00	1.2	8.4	0.918
18	2.00	1.2	9.5	0.910
19	3.00	1.2	10.7	0.878
20	4.00	1.2	11.8	0.872
21	5.00	1.2	13.0	0.867
22	6.00	1.2	14.1	0.876
23	6.30	0.6	14.7	0.849
24	8.40	2.5	17.2	0.845
25	9.00	0.4	17.6	0.834
27	9.50	0.4	18.6	0.825
27	10.00	0.2	18.8	0.820
28	11.00	0.6	19.9	0.815
30	12.00	0.6	21.1	0.805
32	13.00	0.6	22.2	0.795
34	14.10	0.4	23.6	0.785
35	14.30	0.4	23.9	0.780

Table: Flooding with injection water

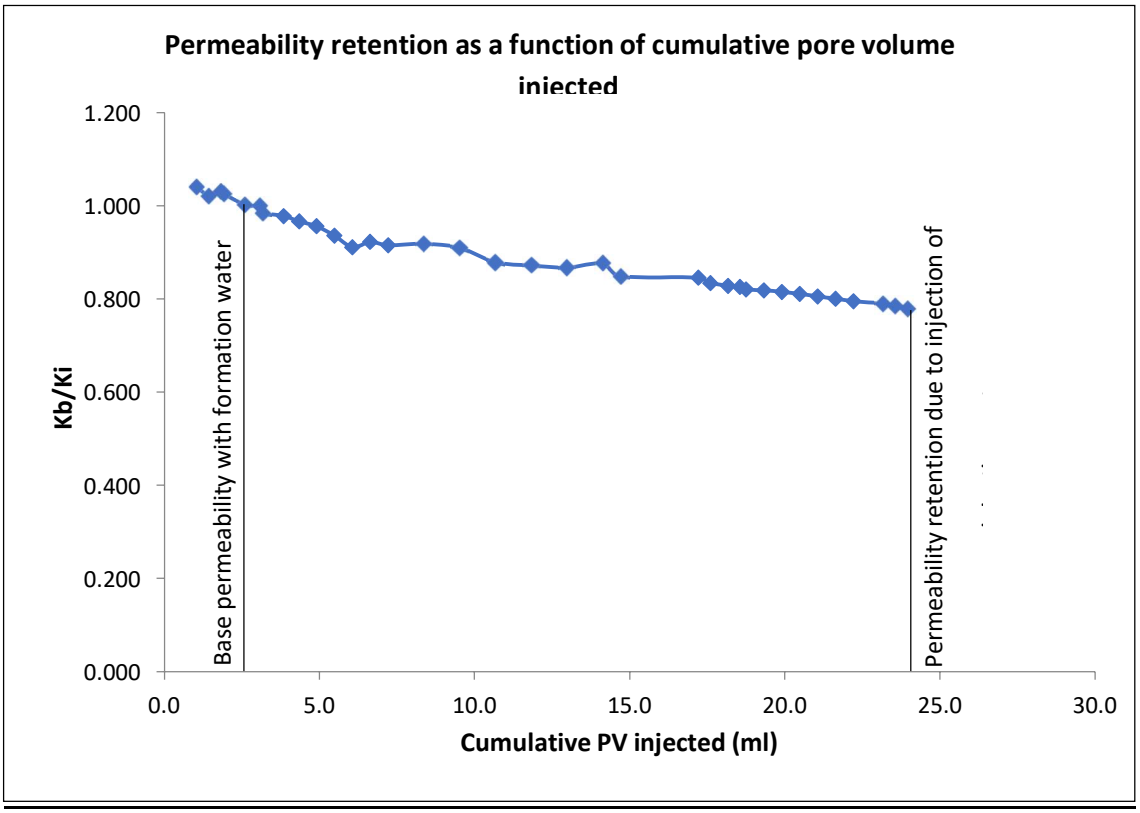


Figure: Permeability v/s cumulative PV injected(ml)

MICROBIAL ENHANCED OIL RECOVERY (MEOR)

Introduction

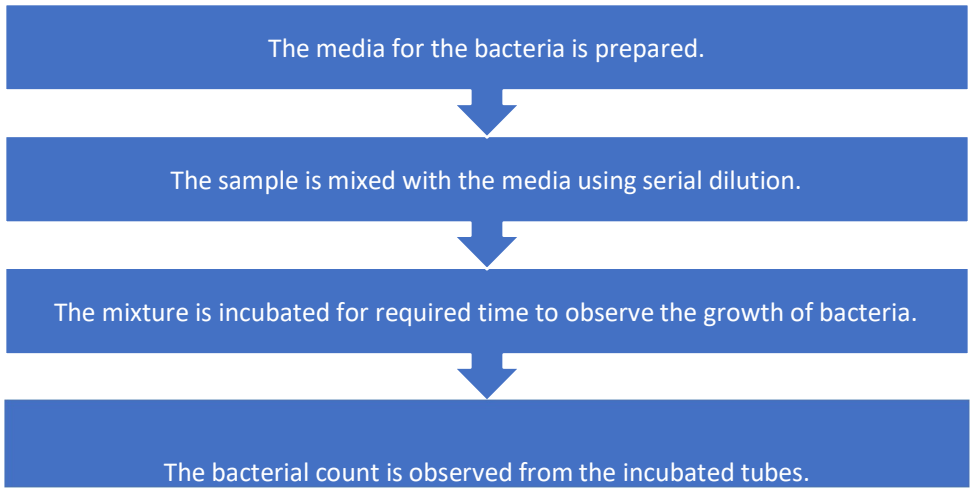
Microbial Enhanced oil recovery (MEOR) represents the use of microorganisms to extract residual oil from dams. This method has the potential to save costs on oil extraction that remains trapped in the capillary pores of rock formations or in areas not flooded with old or modern methods of regenerating oil (EOR), such as heat, heat, erratic migration, flood-related floods, etc. Therefore, MEOR was developed as an alternative to extracting second and higher quality oil from the dams.
MEOR is basically the direct application of biotechnology. It uses biological substances, such as bacteria, microorganisms, and their metabolic products to make the fuel leak out of the source, thus improving oil recovery.

Recovery methods of MEOR

Microorganisms grow between the oil and the well's rock surface to enhance oil recovery by the following methods:

- **Reduction of oil viscosity:** Oil is a thick fluid that is quite viscous, meaning that it does not flow easily. Microorganisms help break down the molecular structure of crudeoil, making it more fluid and easier to recover from the well.
- **Production of carbon dioxide gas:** As a by-product of metabolism, microorganisms produce carbon dioxide gas. Over time, this gas accumulates and displaces the oil in the well, driving it up and out of the ground.
- **Selective plugging:**
  Some microorganisms emit tiny particles that are protected from drying orfalling off other animals. This helps the bacteria to connect the holes in thesource rock so that the oil can easily pass through the stones. Blocking rockholes to facilitate the flow of oil is known as inputs.

PROCESS FOR ANALYSING THE PRESENCE OF BACTERIA IN THE SAMPLE



MEOR Experimental Procedures

PROCESS FOR ANALYSING THE PRESENCE OF BACTERIA IN THE SAMPLE

Prepare the nutrient medium (500ml)

↓

Transfer 9ml of the nutrient medium to 20ml test tubes

↓

Transfer 1ml of the nutrient medium in each test tube using serial dilution method.

↓

Transfer 1ml of the nutrient medium in each test tube using serial dilution bacterial growth.

↓

The bacterial growth is observed after the required incubation time is over.

Procedure for detection of SRB :

- **Preparation of SRB Media**
  1. 500 ml of distilled water is taken in a flask.
  2. 1.5gm beef extract was added in the flask and mixed using a magnetic stirrer.
  3. 2.5 gm tryptone and 0.5 gm glucose was added to the mixture and the mixture was allowed to stir.
  4. The pH of the prepared media was measured using the pH meter.
  5. The media was then dispensed in 9ml test-tubes which were sealed loosely with cotton and packed with aluminum foil.
  6. These tubes were then put in the autoclave oven for sterilization.
  7. The tubes were sealed loosely with cotton to allow the flow of oxygen and keep the sample under aerobic conditions.
- **Preparation of the Sample**
- The entire procedure was performed in the Laminar Flow to ensure the operation was performed without the intervention of other unwanted bacteria.
- Clean the chamber platform with the help of ethyl alcohol. Then, switch on the UV light forebought 30-45 minutes for sterilization of the chamber.
- Open both the gas cylinder nozzles and light up the gas flame using a lighter. This step is
- required as it gives extra sterilized zone for carrying out the required process.
- The samples were prepared using serial dilution process.
- Take 5 test tubes of media for analyzing the bacteria.
- Using a syringe, the first test tube with 9ml media is filled with 1ml of sample.

- Similarly, using a micro-pipette extract 1 ml of sample from the first test tube and add that sample to the next tube, continue the process for further test tubes.
- Two drops of ferric ammonium sulphate is added, to check the blackening in the tube (after 28
- days), and the mixture is stirred properly.
- In order to keep the environment oxygen free, a layer of paraffin is dropped in the tube using the syringe again.
- The test tubes are finally sealed with a lid.
- Keep the test tubes in the incubator for 28 days.

SRB Samples in varying concentration after mixing with media and paraffin sealed.

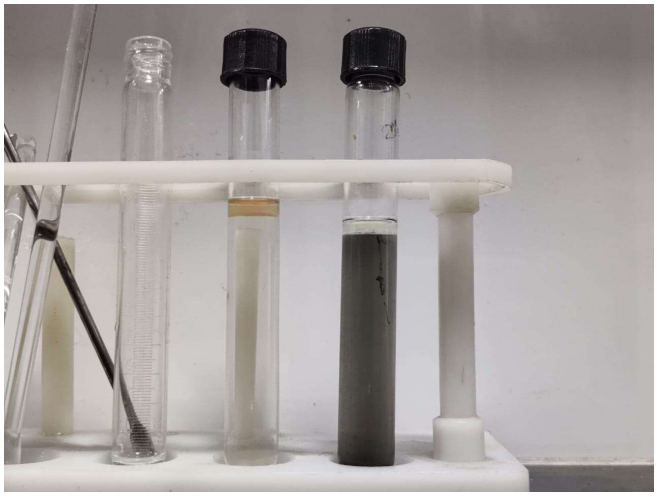
Procedure for detection of GAB :

- **Preparation of GAB Media**
  1. Take 500 ml of distilled water in a conical flask.
  2. Add 5.7 gm Sulphate API broth in the conical flask.
  3. Add 2 ml of sodium lactate to the mixture.
  4. Mix by using a magnetic stirrer.
  5. The pH of the prepared media was measured using the digital pH meter. The pH value should be 7.
  6. 9 ml media was then dispensed into the test tubes.
  7. Seal it using the lids properly so that no oxygen comes in contact with the media.
  8. Put the test tubes in the autoclave for sterilization at a temperature of 121°C at 15 psi for 15 minutes.

- **Preparation of the Sample**

- The entire procedure was performed in the Laminar Flow to ensure the operation wasperformed without the intervention of bacteria.
- Clean the chamber platform with the help of ethyl alcohol. Then, switch on the UV
- light for about 30-45 minutes for sterilizing the chamber environment.
- Open both the gas cylinder nozzles and light up the gas flame using a lighter. This step is required as it gives extra sterilized zone for carrying out the required process.
- The samples were prepared using serial dilution process.
- Take 5 test tubes of media for analyzing the bacteria.
- Using a syringe, the first test tube with 9ml media is filled with 1ml of sample.
- Similarly, using a micro-syringe extract 1 ml of sample from the first test tube taken and continue the process for further test tubes.
- The test-tube is then sealed loosely with cotton and kept in the incubator for 24 hours.

Result:- Turbidity in the tubes which confirms the presence of **GAB** in the sample



Result:- Blackening in the tubes which confirms the presence of SRB in the sample.

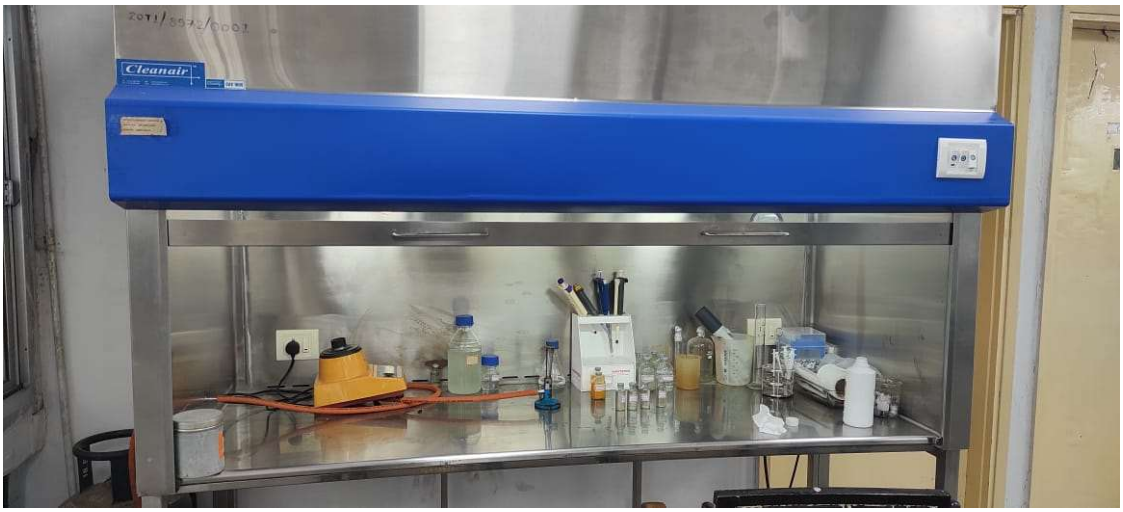


Fig: Laminar air flow setup

Fig: Incubator

Biocide Dosages Optimization Study

Sample collection : Sample received collected from respected field whereby side doses optimization studies required.

GAB & SRB analysis :

Reactivation of Culture:

- After taking the SRB result, vials having maximum growth of SRB are mixed together and reactivated in fresh media vial.
- The above process is repeated until maximum growth of culture is observed in 24 hours. (It takes minimum **10-15 days**).
- After this, the culture is further reactivated in 50 ml

Determination of minimum inhibitory concentration:

- Five/Six biocides are chosen accordingly.
- Concentration of 50 ppm to 1000 ppm of biocide (dosage range depending uponstudy required) is added in 9 ml media vials.
- Reactivated culture, 1ml, is added into above vials along with FAS as indicator and Paraffin to create anaerobic condition.
- These vials are then kept in BOD incubator for **28 days (as incubation period of SRB is 28 days)**
- Weekly observations are made, for four consecutive weeks.

Kill time studies:

- The minimum inhibitory concentration was determined by the above method.
- To find the contact time of biocide with culture, a mother tube is preparedcontaining culture and optimized dose of biocide.
- This is then further added to fresh 9 ml media vials with intervals of 2 hours.
- These vials are then kept in BOD incubator for **28 days.**
- Weekly observations are made, for four consecutive weeks.

Result & Conclusion: -

Bacteriological analysis: As per the standard practices adopted by the industry in case of water injection systems, quality of water from bacterial point of view is considered to be good if the count of SRBS is Nil & the count of GAB is $(1 - 10) \times 10^4$ counts/ml. From bacteriological analysis of the samples the presence of SRBS, $(1\text{-}10) \times 10^0$ counts/ml, was observed. The GAB count for the sample $400m^3$ effluent storage tank was $(1 - 10) \times 10^2$ and for $45m^3$ effluent storage tank was $(1 - 10) \times 10^0$

MEOR Laboratory Equipments

Bioreactor

Bioreactor refers to any device or system designed to support an active environment. In some cases, a bioreactor is a vessel in which chemical processes involving organisms or chemical compounds are found in those organisms. This process can be aerobic or anaerobic.

These bioreactors are commonly cylindrical, ranging in size from liters to cubic meters, and are often made of stainless steel. It may also refer to a device or system designed to grow cells or tissues in the context of cell culture.

Fig: Bioreactors

Digital pH meter

A digital pH meter is an electrical device that acts as a voltmeter. It measures the amount of energy (electrical energy) produced by a desired acid solution, compares it to a known solution strength, and uses the difference in power between them to determine the pH difference. It measures the magnitude of alkalinity or acidity

Fig: pH meter

Autoclave

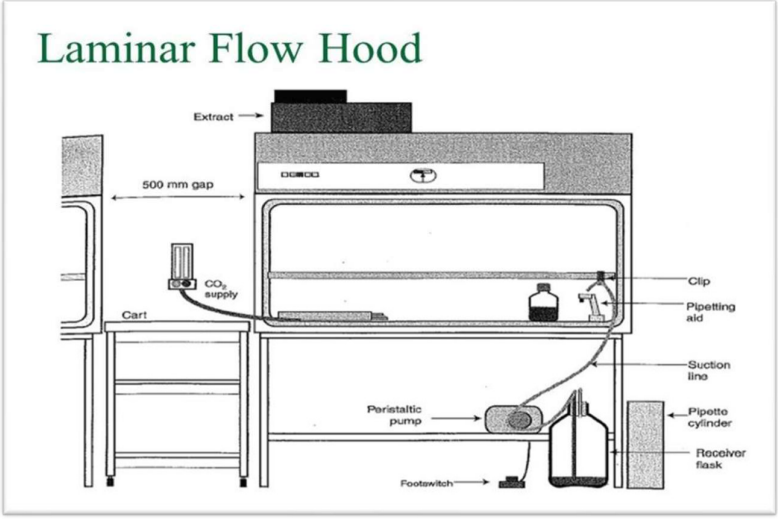
The autoclave is a pressure chamber used to perform industrial processes that require higher temperatures and different pressures than ambient air pressure.

Fertility autoclaves are widely used in the manufacture of insecticides, medical, dental, and implants. Medical autoclave is a device that uses smoke to block machinery and other objects. This means that all bacteria, viruses, fungi and particles do not work.

Fig: Autoclave

Laminar Flow Cabinet

- A laminar flow cabinet or laminar flow closet is a carefully enclosed bench designed to prevent contamination of biological samples.
- The cabinet is usually made of stainless steel with no gaps or joints where spores might collect.
- Laminar flow cabinets may have a UV-C germicidal lamp to sterilize the interior and contents before usage to prevent contamination of experiment. It provides clean air to the working area due to the constant flow of air out of the work area to prevent room air from entering.



Rheometer

- A rheometer is a laboratory device used to measure the flow of fluid, suspension or slurry by reacting to the applied energy.
- It is used for those liquids that cannot be defined by a single viscosity value and therefore require more parameters to be set and measured than what happens on a viscometer.
- It measures fluid rheology. Modern rheometers can be used for shear testing and torsion testing. They work with continuous rotation and rotation.

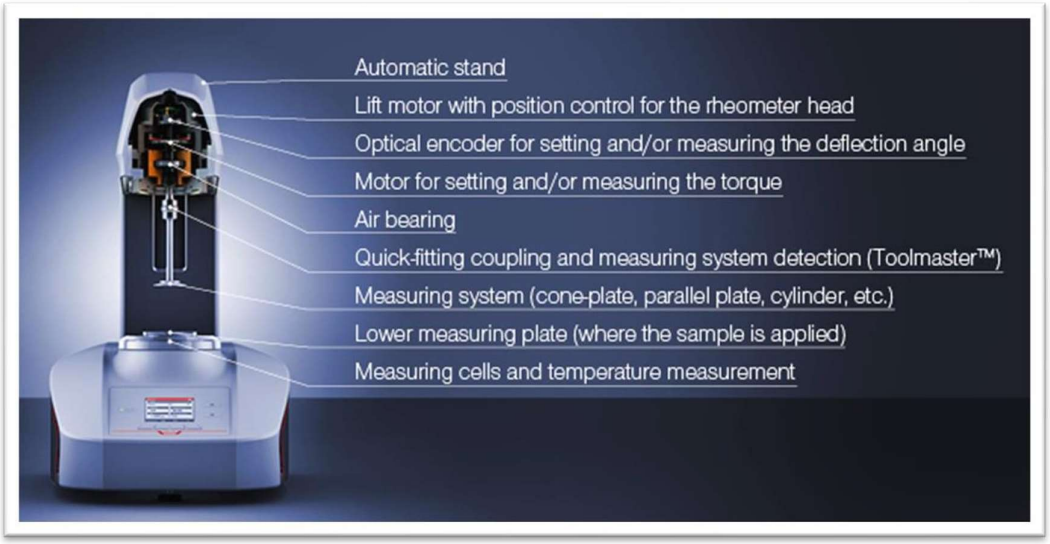


Fig: Rheometer

Bacteriological Incubator

- Incubator is a device used to grow and maintain microbiological cultures or cell cultures. The incubator maintains optimal temperature, humidity and other conditions. Incubators are essential for a lot of experimental work in cell biology, microbiology and molecular biology and are used to culture both bacterial cells.

Fig: Incubators

Digital weighing balance

- A digital weighing scale is the most accurate and precise analogue front-end instrument that uses force sensors to measure the load of an object.
- The digital mass balances are very sensitive instruments used for weighing substancesto the milligram level.

Fig: Digital weighing machine

ONGC IRS Lab Visits

Petrophysical Laboratory:

The setup at Petro-physical lab is established to fulfill two main purposes namely Routine Core Analysis and Special Core Analysis. Routine Core Analysis is to find out basic reservoir parameters like porosity and permeability using helium porosimeter. While special core analysis deals with obtaining rock and fluids properties like relative permeability, wettability and capillary pressure, creating in situ conditions in a core flooding apparatus.

Figure : Core Flooding Apparatus (Photo Courtesy: Vinci Tech)

Probe and Virtual Laboratory:

The main aim of this lab is characterization of reservoir. There are various stages of such characterization. Megascopic characterization includes identifying lithology, hardness, grain size, color, fossils and compaction. Microphysical Studies comprises of studies from thin section for knowing the packing coefficient. Mineralogical studies are carried out by X-ray Diffraction. Reservoir petrographic studies are carried out in SEM (Scanning Electron Microscope) to comprehend the classification of porosity (by 3D view), digenetic changes and elemental composition. It also incorporated identification of various types of clays in SEM images of rocks.

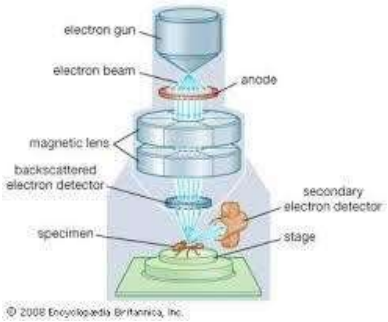


Figure : Scanning Electron Microscope.

Water & Gas Control Laboratory:

The purpose of water and gas control is to stop conning/channeling in order to have maximum recovery of crude oil. Channeling can be stopped by injection of chemicals. Such chemicals are typically responsible for profile modification, viscosity alterations and mobility changes.

Gels are injected into wellbore to fulfill the same. Visual representation, gel types (Flexible and Hard) and uses, breaker types (Weak acids), injection mechanism were briefed during the visit.

Thermodynamic Studies Laboratory:

Introduction to sampling techniques and visual display of surface and subsurface samples was given. The equipment used for constant composition test was elucidated together with the procedure for obtaining bubble point. Flash and Differential liberation tests were also explained for calculating Formation volume factors, solubility, gas oil ratio and gas/oil gravity. SARA (Saturates, Aromatics, Resins and Asphaltene) analysis using chromatography and the solvent used for crude oil analysis was also described. Other instruments in lab were for basic analysis of crude oil and gas liberated during various tests.

Chemical Flood Laboratory:

There are three types of chemical floods namely polymer, surfactant and alkali flooding. Polymers like PAM (poly acrylamide) and PHPA (Hydrolyzed Poly acrylamide) are used for decreasing the mobility and increasing the sweep efficiency. Surfactants can be hydrophobic or hydrophilic and are responsible for changing charges on the rock surfaces, which results in reduction of IFT (interfacial tension) and in return higher recoveries. Alkaline solutions are used for wettability alterations (from oil to water wet) so as to recover oils from bigger pores with lesser interfacial tension.

Thermal Process Laboratory:

Steam injection and in situ combustion are two viable techniques for heavy oil recovery (greater than 100 cp viscosity). There are combustion tube test and steam tube test used to monitor the process in laboratory before taking it to pilot or economic scale. The process of creation of front, propagation and sustenance of front is monitored via thermocouples and heaters on tube apparatus. The concept of dry and wet combustion in tube test was introduced and a previously carried tube test data (pressure and temperature data) along with front propagation were shown. Heavy oil samples and coke were displayed in lab.

Tracer Laboratory:

There are two types of tracer tests. Inter-well Tracer Test used to check conductivity in case of water flooding (pattern flooding) process. Tracers are used for knowing the faults (substructures) and low permeability zones. Tracers should be unique, detectable in low amounts, compatible with the rock, low cost and easily available. Ammonium Thiocynide and Tritium are commonly used tracers. Single well tracer test involves calculation of residual oil saturation by using ethyl acetate as tracer. It sticks with oil and a very small part goes into water.

Microbial Enhanced Oil Recovery:

Microbial injection is normally carried out in huff and puff mode (along with water flooding). Microbes are found in cultures (aerobic/ anaerobic), which on reaction with crude oil generates surfactants, acids, solvents, gases and polymers as byproducts. These all are responsible for increasing the oil recovery by mobility control, pressure maintenance, wettability alterations, IFT (interfacial tension) reduction and near well bore cleanup. Visual cultures of microbes were shown and the way they get preserved was also explained.

Gas injection laboratory:

The primary goal of any gas injection (miscible/immiscible) is to increase pore scale efficiency by reduction of IFT (interfacial tension). Miscible (CO_2, N_2, HC gases, flue gases, exhaust gases) gives much higher recoveries than immiscible gas injection. The first step to design this pressure is to know the minimum miscibility pressure by slim tube setup. This gives a fair idea on fast contact miscibility and multiple contacts miscibility. Ternary diagram was used to explain the miscibility conditions for different gases. WAG (water alternating gas), SWAG (simultaneous water alternating gas) and surfactant gas injection was also explained.

CONCLUSION

Laboratory exposure plays a crucial role in comprehending the research conducted at an industrial level. It provides valuable insights into various properties of injection water, such as its ionic composition, pH level, turbidity, total suspended solids (TSS), and filterability. Before injection, it is essential to identify and prevent any potential issues that may arise in the formation due to the injection process. Coagulation and flocculation studies, along with scaling inhibition techniques, are integral parts of the study which can prevent massive losses from incurring later on.

By studying the formation water from one of ONGC's fields, one can conclude the desirable properties for injection, namely a low TSS and high filterability. The Cerini plot, a graphical representation, has proven helpful in determining the relative plugging index and designing the filtration system within the well. To ensure compatibility, the turbidity of the injection water is reduced by using substances like alum and polyethylene (PE). Additionally, scale inhibitors are added to prevent scale formation, a common issue.

Core flooding studies are conducted to estimate the displacement efficiency (Kw and Ko) of formation water and formation oil, followed by the injection water. This helps in evaluating the improvement in recovery factor (RF). Tertiary recovery studies focus on microbial-enhanced oil recovery (MEOR). It involves preparing the necessary media for detecting specific bacteria, such as GAB (gas-producing bacteria) and SRB (sulfate-reducing bacteria), optimizing the dosage of bacteria and determining the kill time.

During the summer training, we explored the numerous laboratories of IRS ,offering exposure to various aspects of the oil industry. These labs covered topics such as rock composition, rock properties, pressure-volume-temperature (PVT) data analysis, secondary recovery methods like water flooding, and monitoring techniques using tracers. Finally, enhanced oil recovery (EOR) methods were explored, including gas injection, microbial injection, chemical flooding, and thermal EOR and many more.

Overall, this extensive laboratory exposure and training provide invaluable insights into the intricacies of oil field operations and enables researchers and engineers to devise effective strategies for optimizing oil recovery processes.

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