Enhanced Assisted Water Alternating Gas Produced Water Reinjection Injectivity Study

by

Khairunnisa Binti Khairuddin
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Universiti Teknologi PETRONAS
Bandar Seri Iskandar
31750 Tronoh
Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

ENHANCED ASSISSTED WATER ALTERNATING GAS PRODUCED WATER REINJECTION INJECTIVITY STUDY

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KHAIRUNNISA BINTI KHAIRUDDIN

A project dissertation submitted to the
Petroleum Engineering Programme
Universiti Teknologi PETRONAS
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Approved by,

____

(MS SITI SARAH BINTI SALEHUDDIN)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

Sept 2013

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

KHAIRUNNISA BINTI KHAIRUDDIN

ABSTRACT

Water breakthrough from the reservoir needs a proper management. The chemical produced is toxic and non-biodegradable. Worsening the case, releasing directly into the sea may harm the marine environment. The second most common option which is drilling a dumping well is not possible for its high cost. The last option left is only by re-injecting treated water into the reservoir again. Thus, this study is carried out to investigate the potential of injectivity problem that may arise when injecting the produced water containing chemicals by varying the filtration level and oil in water concentration. Several elements were identified as crucial for this study namely produced water reinjection, formation damage, salinity, suspended solids, and water quality. Core flooding test was carried out and it was found that there is no injectivity issue when re-injecting produced water with surfactant and polymer. Detailed analysis are included together with the results and for future research, recommendations are also given at the end of this report.

ACKNOWLEDGEMENT

In the name of Allah, the most Gracious and the most Merciful

Alhamdulillah, I finally completed my final year project and able to come up with this report. I thank Allah for allowing all of these to happen. Without His permission, I might probably not have my project at all for the past two semesters. I would like to extend my upmost gratitude to my previous internship host company, PETRONAS Research Sdn Bhd (PRSB) and UTP for giving me an opportunity and trust to carry out my research project in both UTP and PRSB.

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CHAPTER 1

INTRODUCTION

1. Background of Study

Field A is located offshore Terengganu and operated by ExxonMobil Exploration and Production Malaysia Inc (EMEPMI). This field is made up of six fault blocks with the large gas cap in the Central and smaller gas cap in the East and West fault blocks. The field came on stream in March 1978 with production from Central Processing Platform. After a long time, it is needed to recover the additional reserves beyond the existing waterflood by injecting alternating cycles of water and immiscible hydrocarbon gas. At the current and anticipated reservoir pressures, the hydrocarbon gas is immiscible with the in-situ oil. This enhanced oil recovery technique is widely termed as immiscible Enhance assisted Water Alternating Gas (EWAG). From this project, it is expected to extend the productive life of Field A for another 30 years with recovery increment of 150 MMSTB based on two compositional simulation models study.

2. Problem Statement

Water produced to the surface after the injection during secondary recovery requires a proper management method. From the eco-toxicity data, it is found that Chemical EOR breakthrough to the surface is relatively toxic (surfactant) and non-biodegradable (polymer). The dilution modeling study indicates that continuous overboard discharge may not be allowable as it harms the marine environment. The second option of drilling a dumping well is an expensive option. Study from a different field has shown that Produced Water Reinjection (PWRI) is the best option for offshore field in the application of EWAG.

3. Objective and Scope of Study

The objectives of this study are:

- To study on filtration level of injection fluid.
- To investigate the oil in water concentration of the re-injected water (PWRI).
- To investigate any injectivity issue of produced polymer, surfactant and oil in produced water reinjection (PWRI) application.

The scope of study includes:

- Conducting research in developing operating procedures for conducting lab testing and experiments.
- Finding out the maximum allowable particle size of the reinjection fluid.
- Studying the oil in water saturation before reinjection.

CHAPTER 2

LITERATURE REVIEW

1. Produced Water Reinjection (PWRI)

When a well is drilled, water that is produced along with oil and gas is called produced water. The subsurface water associated with gas and oil reservoirs is called oilfield brine. The determination and implementation of the most appropriate produced water treatment depends on applicable regulatory requirements, the environment protectiveness of the various options and associated economics. Focusing on offshore operations, key factors include concentration of constituents and other characteristics of constituents like toxicity, bioavailability, and form (Rabalais *et* al. 1992). Back then, the most common method taken to handle produced water is by overboard discharge method since most produced water is brackish; water that has more salinity than fresh water, but not as much as seawater. Surfactants and polymers injected have high amount of toxic which can harm marine life. Moreover, the surfactants and polymers are non-biodegradable, thus causing pollution. Hence, produced water reinjection (PWRI) is perceived as the most likely method to cater the environmental impact of produced water to the marine environment at offshore oil production sites. It is an optimum option for polymer and surfactant separation from produced water as the chemicals shall be injected back after mixing with fresh chemicals in the normal injection water. Apart from that, there are high potential of cost, space and weight savings via the optimization of water treatment facilities and PWRI system throughout the life of a field (Hjelmas *et* al. 1996).

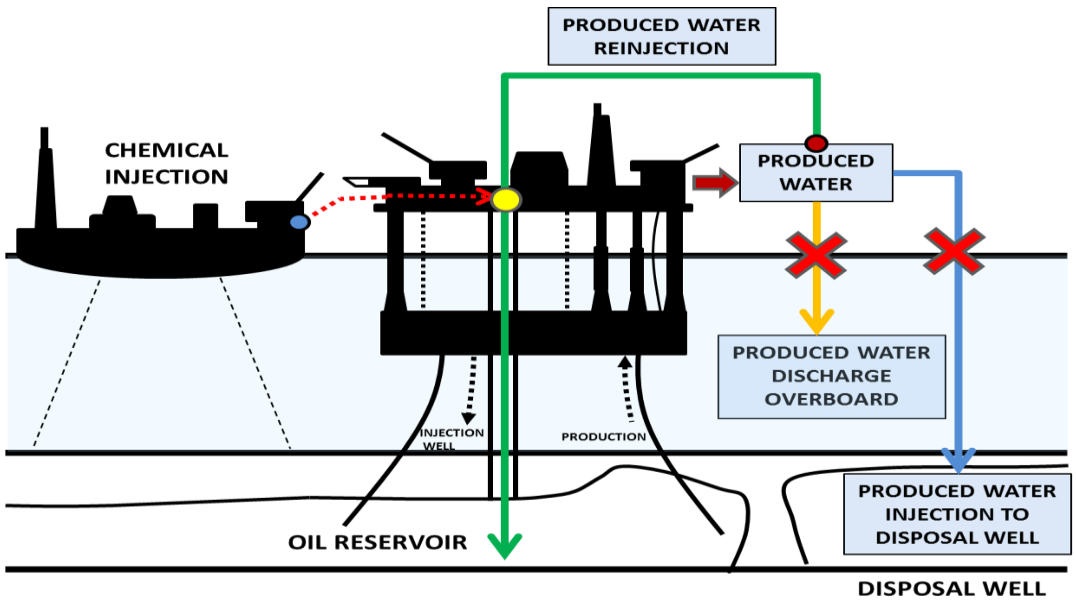


Figure 1 Produced Water Management Concepts

Around the globe, PWRI has been actually evaluated and applied in many fields for many years. Most cases of PWRI applications involve produced water only and not mixture of produced water and seawater prior to injection. According to Mark Reed and Stale Johnson, in most cases some loss in injectivity has been observed while some face even severe issues such as accelerated reservoir souring and increased scaling potential. These cases have stressed out the need for a better understanding of mechanisms that influence impact of produced water reinjection. Thus, it is crucial to carry out PWRI risk assessment study to make sure that it will be able to increase oil productivity while saving the marine environment. Before beginning the assessment, it is important to have data and evaluation of the field and well to be applied with PWRI. Such data and evaluation include well history, location, current production, injection water characterization etc. The types of tests and their respective objectives are listed below:

- Compatibility study of produced water and connate water

  To determine the potential scale formation and potential permeability degradation

- Scaling study

To evaluate whether changes in pressure or temperature and mixture of different chemical composition in water can cause scaling to happen. If scaling happens, its severity is needed to be known.

- Injectivity and formation damage study

To assess injectivity limit of oil-in water, the median particle size and total suspended solids content in produced water. With the results, it is needed to recommend suitable water quality specification for reinjection purpose.

- Reservoir souring study

Souring here refers to the increase of sulphide concentration in a hydrocarbon reservoir. For this test, risk of souring is evaluated and forecast study is carried out to predict future levels of H_2S production will be generated in the injection wells.

- Corrosion study

To determine corrosion level of the existing treated water, study the possibility of corrosion in PWRI and water injection, identify tendency towards pitting corrosion and to suggest preventive actions in avoiding corrosion within the system of PWRI and water injection.

- Surface facilities optimization study

To design PWRI surface facilities system in order to suit water specification for reinjection. This includes the requirement of treating residuals oil in water content, total suspended solids and particle size in produced water prior to reinjection.

- PWRI implication on EOR injection

  The application of PWRI in ASP flooding conditions is more complicated compared to PWRI in polymer flooding. Thus, it is crucial to carry out further feasibility study on low salinity requirements, biocide compatibility and also production chemicals issue like oxygen scavenger.

- Cost implication study

  To come up with detailed cost estimation that includes capital and operational expenditures. However, this study is not a priority since most of case studies found that it is much cheaper to carry out PWRI when comparing with overboard discharge and dumping well.

My final year project will be focusing on injectivity and formation damage study. Further explanation on the fundamental concepts are written in the next part of this literature review.

2. Formation Damage

Technically, formation damage is defined by Brant Bennion as ‘any process that causes a reduction in the natural inherent productivity of an oil or gas producing formation’ or ‘a reduction in the injectivity of a water or gas injection well.’ Impairment or formation damage may occur during several operations of a well. Some of the sources include drilling, completion, production and injection. In the application of produced water reinjection case, damage most likely to take place is from injection. Injection of fluid into the reservoir may include solid particles thus filtration of injection fluid is needed in which normally particles larger than 2µ m are removed. There is also risk of precipitation mainly from the incompatibility of injection fluid and formation water. Precipitation most likely to take place in injection of waters with high concentrations of sulphate or carbonate ions into the formations with divalent cations like calcium, magnesium, or barium. Apart from that, it can also occur even if waters are compatible due to release of divalent cations by cation exchange of clays when the injected fluid has different ionic composition compared to formation. Similar to solid injection, precipitation can be minimize by injecting water compatible with formation water without cation exchange with clays. In spite of these two, presence of bacteria in the formation may contribute to damage, too. Bacteria growth can cause plugging of formation. Hence, there is a need to test for the presence of bacteria and bactericides will be added if necessary. Injectivity decline models for water in injection wells are designed based on two parts; internal filtration and external filtration. Internal filtration is the infiltration of particles in pore space while the latter is build-up of filter cake on formation face. Transition time is when no more particles invade the rock in a formation.

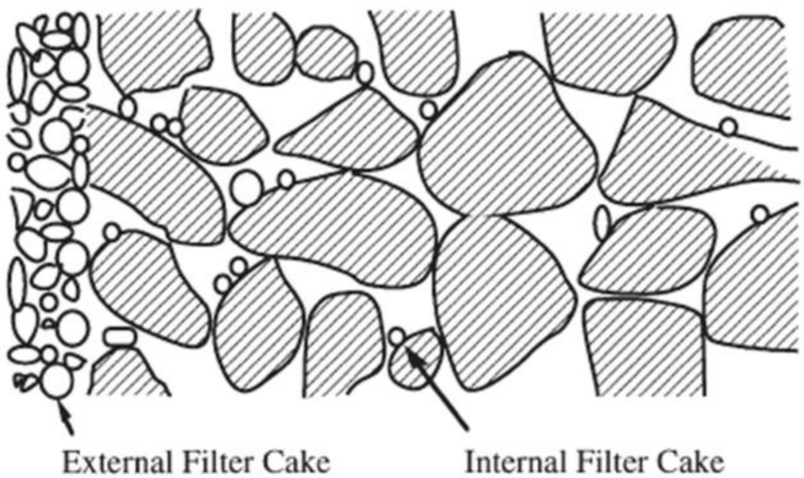


Figure 2 Injection Damage from Injection Water

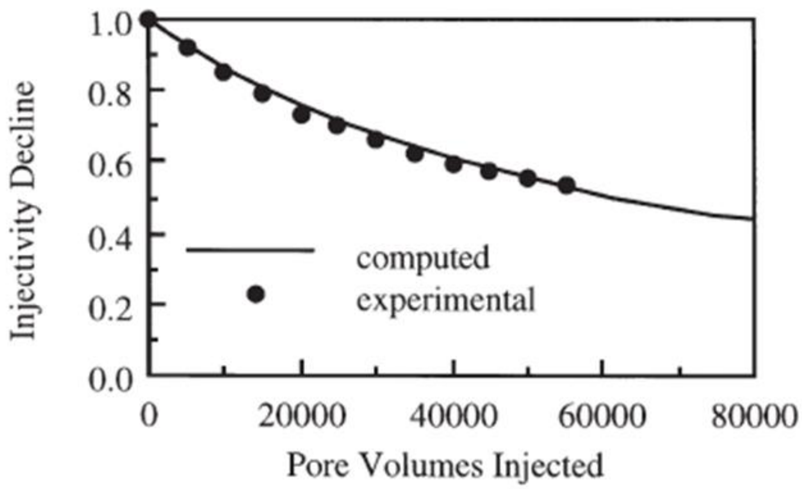


Figure 3 Computed and Experimental Core Flow Injectivity Decline

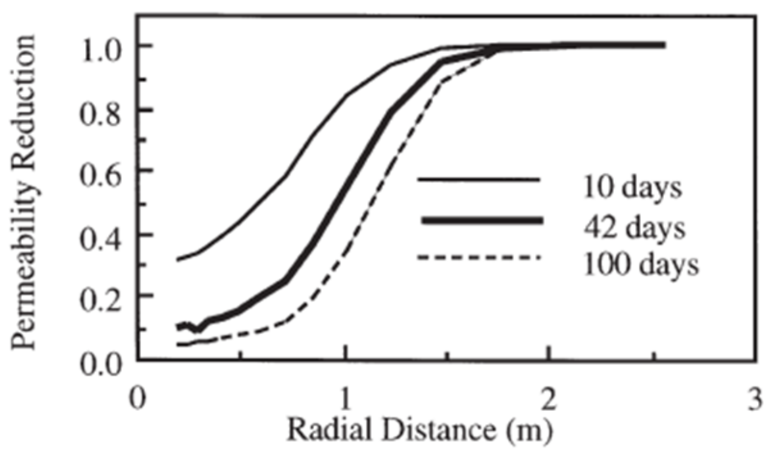


Figure 4 Depth and Extent of Damage Zone

3. Salinity

Salinity is the concentration measure of dissolved mineral salts in water. It is also commonly referred as total dissolved solids. Most commonly found salts include calcium, magnesium, sodium, sulphate and chloride. There are two types of salinity causing factors namely primary and secondary salinity. Primary salinity gets its name by natural processes like weathering of rocks, wind and rain depositing salt over thousands of years. Secondary salinity is produced through the widespread land clearing and altered land use, taking the form of “dryland salinity” or “irrigation-induced salinity”. To relate back to this project, salinity of reinjection fluid may affect the reinjection process which will eventually increasing the risk of formation damage. Hence, it is an important aspect to be included in this formation damage study.

4. Suspended solids

Reinjection fluid is taken from the produced water and may contain a variety of different particulate materials such as formation particles, insoluble carbonates or sulfates, iron compounds, oil droplets and bacteria. Well impairment through injector’s performance and lifetime restriction may happen when these solid particles deposit in the formation pores. Mechanisms of impairment from suspended solids include wellbore narrowing, invasion, perforation plugging and wellbore fillup. Wellbore narrowing happens when the solids form a filter cake on the face of the wellbore while solids invading the formation, bridging and forming an internal filter cake are called solids invasion. Apart from that, perforation plugging is when the solids become lodged in the perforations and when they settle to the bottom of the well by gravity and decreasing the net zone height, it is called wellbore fillup.

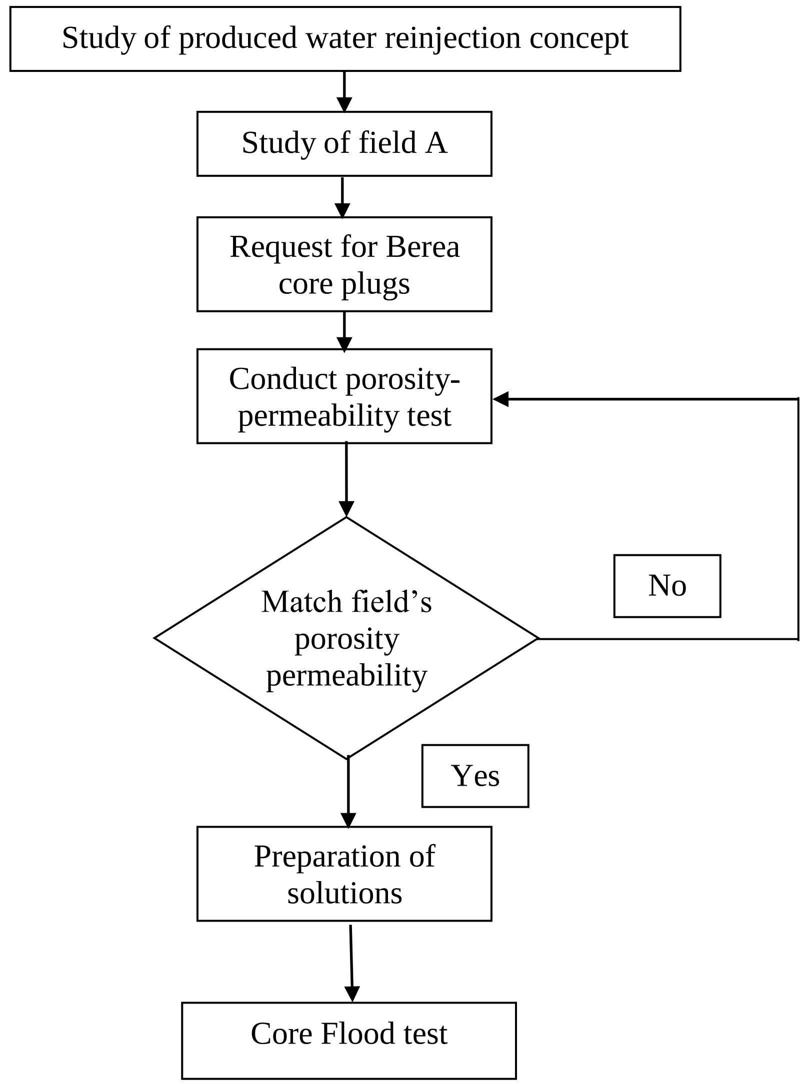
5. Water quality

According to Barkman and Davidson, “water quality is affected by several types of contaminants, including suspended silts, clays, scale, oil and bacteria. Any of these may be the predominant source of impairment in a particular injection water and environment. Formation cores, artificial cores and membrane filters have been used in industry to monitor suspended solids and to evaluate water quality”. Charles C Patton in his paper Injection Water Quality said that in judging the severity of water quality in causing significant problems, experience is the sole guide and little, if any, technical investigation precedes design of the injection system. Measurements such as chemical composition, dissolved gases, corrosivity, bacteria and suspended solids are considered to be essential in characterizing the injection water. Chemical composition is related to scaling tendencies calculation and the likelihood of clay swelling. Measurement like pH value must be taken on site immediately after sampling happens. Dissolved gases tells easily on the possible types of corrosion that may happen in the well. Rate of corrosion is measured on site in order to quantify the water corrosivity. Bacteria identification focus specifically on sulfate-reducing bacteria. For suspended solids, explanation is given in the point above. Dispersion of oil can lower down injectivity, most importantly when combined with suspended solids, iron sulfide for instance. Oil in water or emulsion can also formed in injection wells.

CHAPTER 3

METHODOLOGY

1. Study Methodology



2. Gantt Chart and Key Milestone

Table below shows the Gantt chart to schedule the implementation of the project:

Table 1 Gantt chart for the project implementation

Stage	FYP 1												FYP 2													
	Week																									
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Early Research Developments																										
Research Background																										
Problem statement and Objective																										
Scope of studies																										
Middle Research Developments																										
Detailed research																										
Experimental and laboratories test																										
Analysing data and result obtains																										
Final Research Developments																										
Finalizing the results																										
Completing the documentation																										

3. Materials and testing procedures

3.1 Materials

Spaced electrodes and automatic timer.

Core flooding machines.

Produced water sample.

Weight balance.

Mixer.

3.2 Chemicals

Sodium Chloride

Calcium Chloride

Magnesium Chloride

Potassium Chloride

Sodium Bicarbonate

Sodium Sulphate

Sodium Carbonate

Distilled Water

3.3 Berea Preparations

3.3.1 Berea Core Porosity and Permeability Test

i. Grain volume was determined for each sample by placing it into a stainless steel matrix cup. It was injected with helium from reference cells of known volume and pressure using the Core Lab AutoPorosimeter. Grain volume was calculated using Boyle's law of gas expansion. Grain density was calculated by dividing sample dry weight by grain volume.

ii. The samples were loaded into the CMS300™ for determination of permeability and porosity. Net confining pressure of 300- 500 psi was applied.

iii. Each sample in turn was placed into a rubber sleeve between stainless steel end pieces and appropriate confining pressure applied. Helium was injected into the sample from reference cells of known volume and pressure. A direct pore volume was determined using Boyle's law of gas expansion, then pressure was vented at a known rate and unsteady-state Klinkenberg permeability was determined by pressure decay.

iv. Porosity was calculated for each sample as the pore volume fraction of the summation (grain volume + pore volume) bulk volume.

Pore Volume, Porosity and Permeability Calculation

Pore Volume

PV = [Saturated Weight – Dry Weight]/Water Density

Bulk Volume = $\pi r^2 h$

r = radius of the core

h = length of the core

Porosity

Porosity = [Pore Volume/Bulk Volume] x 100%

Permeability Calculation

1. Assemble the saturated core inside the core holder and complete all the fittings.
2. Flow in the Formation Water at three different flowrate i.e. 1ml/hr, 3ml/hr and 5ml/hr.
3. Take the reading of the Inlet and Outlet pressure and calculate the dP1, dP2 and dP3.
4. Construct a plot of cc/sec by dP.
5. Permeability Calculation

$$\mathbf{K} = \frac{q\mu L}{A\Delta P}$$

With the slope, m is $\frac{q}{\Delta P}$

And viscosity, μ is water viscosity

Figure 5 PoroPerm Test Equipment

3.3.2 Berea Core Saturation

i. Weigh the dry core.
ii. The core must be saturated with synthetic formation water brine. Soak the core with brine in an air tight container and apply vacuum to it. The vacuum is to suck out air trapped inside the core grain.
iii. Place the air tight container with soaked core on the magnetic stirrer. Leave it stirred for 4-5 hours to expel out the air bubbles.
iv. Observe the air bubbles produced and stop the stirrer until no more air bubble observed.
v. Turn off the vacuum pump and leave for 24 hours.
vi. After 24 hours, take out the core and weigh the saturated core.

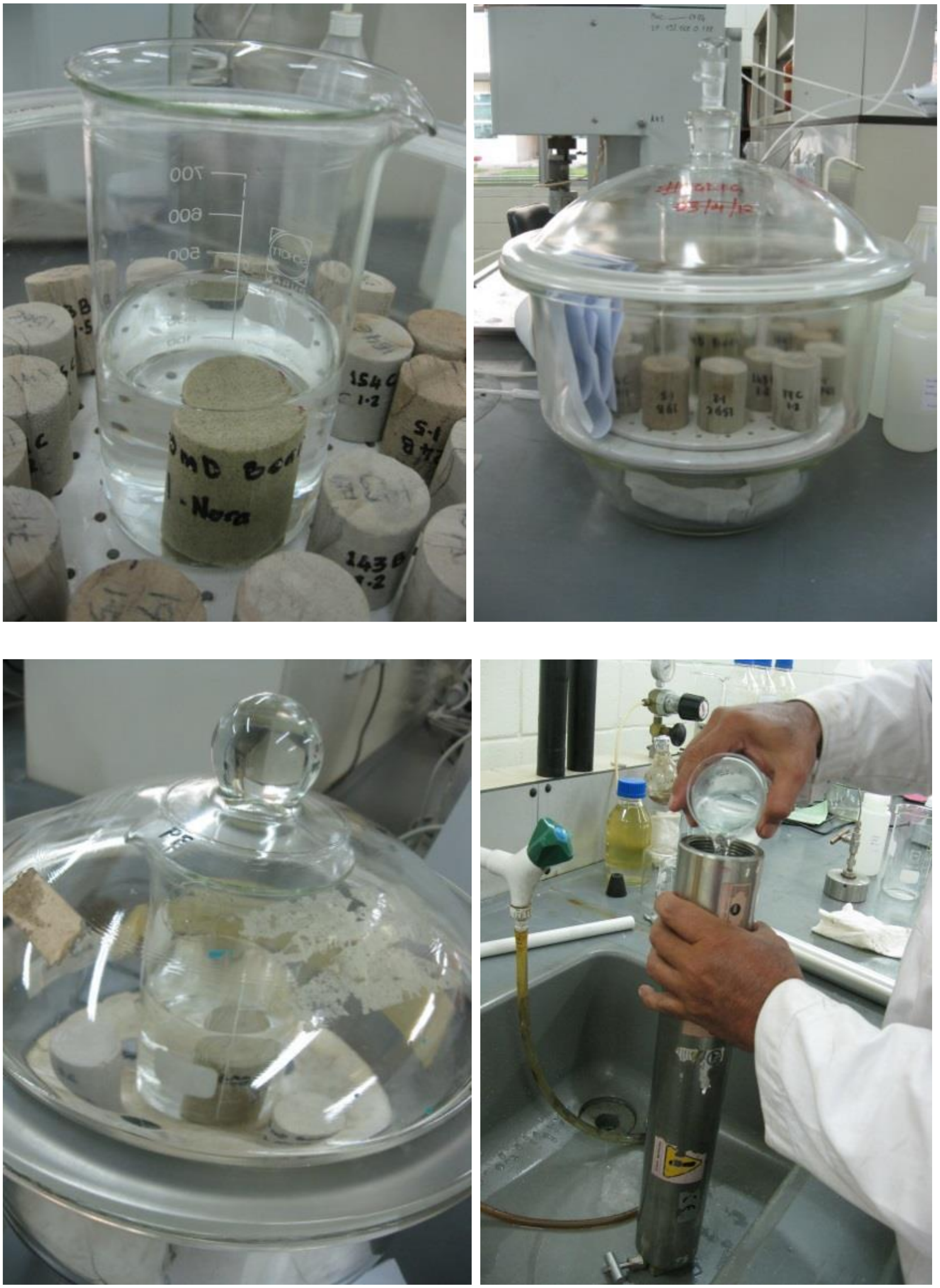


Figure 6 Procedure of Core Saturation

3.4 Solutions Preparations

3.4.1 Synthetic Formation Water

i. Synthetic formation water is prepared using actual water composition.
ii. Filter the solution at 0.45 micron filter paper with the help of vacuum pump.
iii. Remove air from the solution using degas pump until no bubbles are observed.

3.4.2 Produced Water Sample Filtration

i. Filter 10 litres of actual produced water sample at 1.2 micron filter paper size.
ii. After completing the first phase of core flooding, repeat filtering 10 litres of produced water sample at 2.7 micron filter paper size.

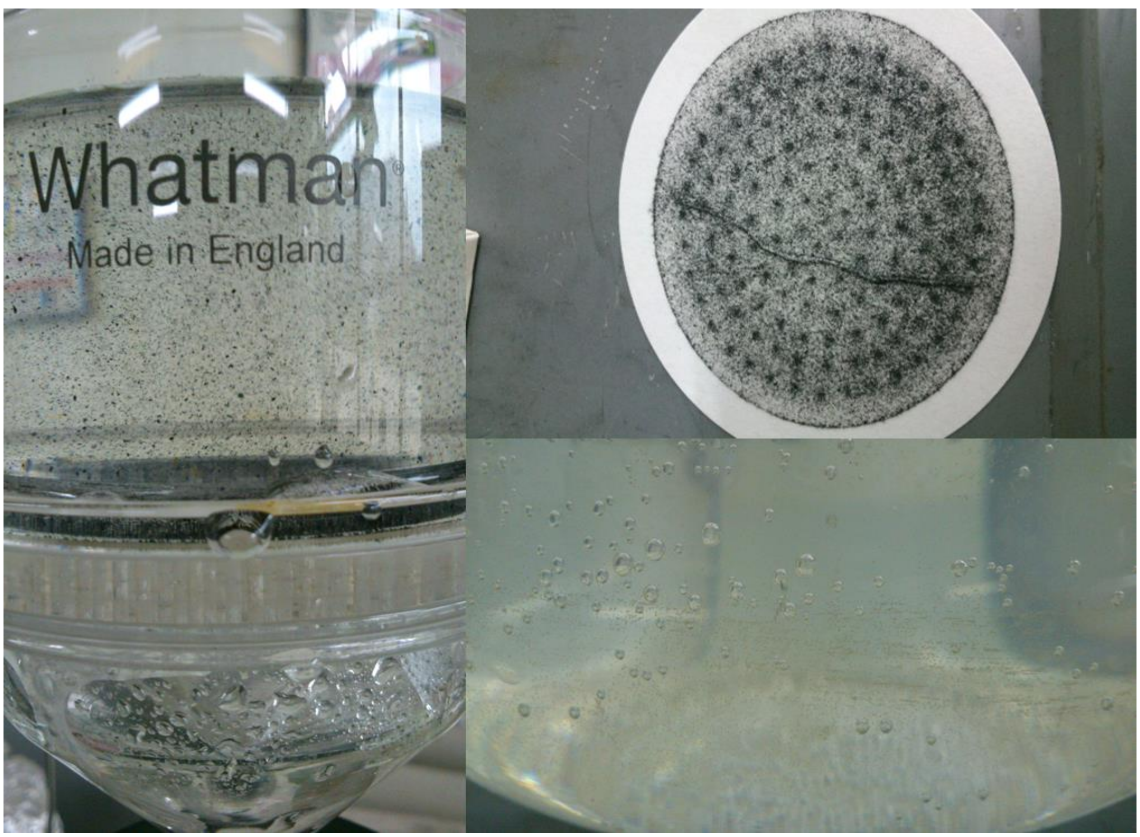


Figure 7 Filtration Process

3.4.3 Mother Polymer Stock

i. Weigh 2 grams of polymer and 398 gram of produced water sample.
ii. Offset the overhead stirrer slightly from the middle of the jar. Set the speed of the overhead stirrer so that the vortex created extends 75% into the water sample, usually the speed set to be 400 rpm.
iii. Sprinkle the polymer powder into the shoulder of the vortex over a period of 30 seconds. Observe the solution. No large slugs or “fish eyes” should be present. If present, start over.
iv. Stir the solution using the overhead stirrer for about 2 hours.
v. Allow the solution to sit overnight before diluting into desired concentration.
vi. Check for undissolved particles. If present, start over again.

3.4.4 Surfactant Polymer Mixing in Produced Water (Injection Chemicals)

i. In a beaker, mix 379.6 gram of polymer stock, 2 gram of surfactant and top up with produced water sample until weight of solution reaches 1000 grams. Stir.

3.4.5 Mixing of Injection Chemicals with Crude Oil

i. Calculation of oil volume for mixing is using the following calculation based on concentration:
   a. 10% = 100 000 ppm
      X% = Xppm
   b. (X% / 100) * 500ml = Y micro liter.

ii. Measure using pipette. Mix using volumetric flask

3.5 Core Flooding Test

1) To identify the brine permeability (Kw) as:
   i. The core is loaded in a hydrostatic coreholder inside an air bath oven. Reservoir confining stress of 2700psi will be applied, and pore pressure is introduced into the core-holder (depending on originally wellbore field

conditions) by passing synthetic formation water through the system and around the sample. Sample and system are elevated to reservoir temperature of 126^0C while maintaining net confining stress and pore pressure.

ii. Approximately 10 pore volumes of injection are injected through each sample at a constant, low flow rate a 0.50 cc/min, to attain rock/fluid equilibrium. Differential pressure is recorded, and initial permeability to synthetic formation water is determined. Prior injection the fluid viscosity will be determined. Effluent fluids will be collected and filtered to capture solids displaced at each flow rate.

2) Produce water base line injectivity will be determined by injecting the composite core with the filtered produced water only with 0.5 flow rates and 10PV, without including the residual chemicals of surfactant and polymer or the oil in water (OIW) concentration. Differential pressure is recorded, and initial permeability to brine (brine referring to produce water) was determined.

3) EOR base line injectivity will be determined by injecting the composite core with mixing of produce water with the residual chemicals of surfactant and polymer without OIW concentration with 0.5 flow rates and 10PV. Differential pressure is recorded, and initial permeability to brine (brine referring to produce water) was determined.

4) OIW sensitivity will be studied by injecting the composite core with mixing of produce water with residual chemicals of surfactant and polymer and different concentration of OIW as 3ppm, 5ppm, 7ppm, 9ppm, 11ppm, 13ppm with 0.5 flow rates and 10PV. Differential pressure is recorded, and initial permeability to injection chemical are determined.

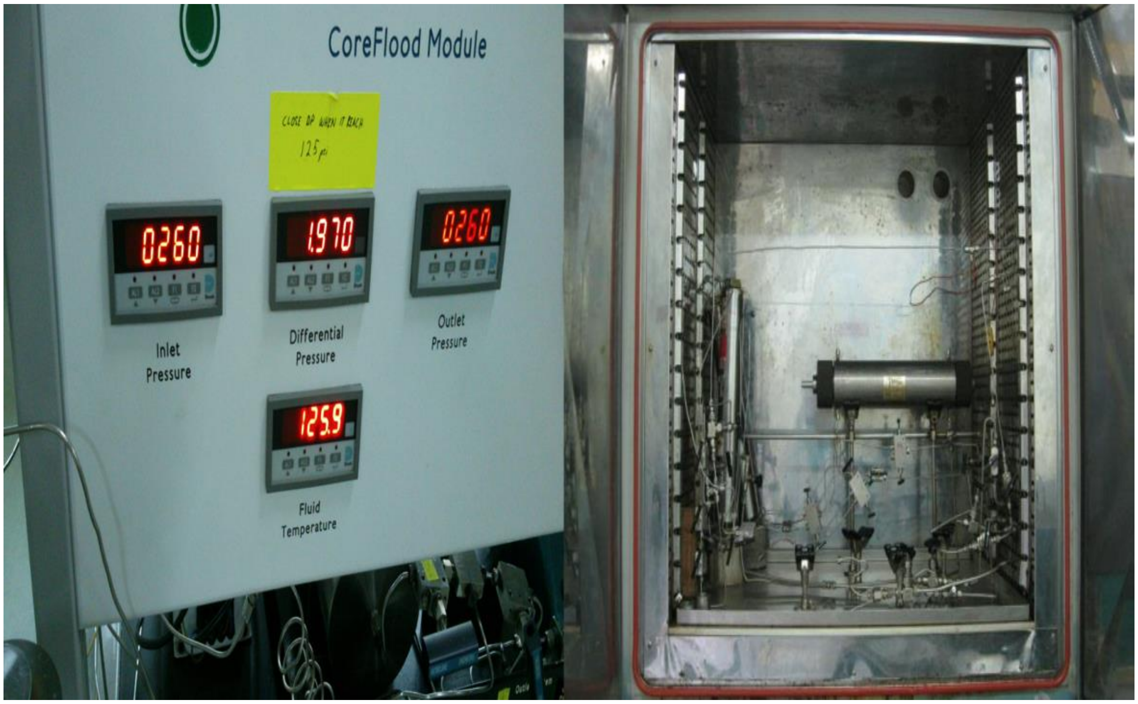


Figure 8 Core Flooding Machine

The whole steps of core flooding are summarized in table below:

Table 2 Core Flood Test Procedure

PROCESS	INJECTION SLUG	SLUG SIZE (10 PV)	FLOW RATE	REMARKS
SATURATE CORE	SYNTHETIC FW		0.1,0.3,0.5 CC/MIN	RECORD Kw AT THESE 2 FLOW RATES
BASELINE INJECTIVITY	PRODUCED WATER (0PPM OIW) VISCOSITY -?	10 X PORE VOLUME	0.5 CC/MIN	- RECORD DP DATA (INTERVAL 5 MINS) - RECORD Kw AT 0.5 CC/MIN
EOR BASELINE INJECTIVITY	PRODUCED WATER (0PPM OIW AND SP)	10 X PORE VOLUME	0.5 CC/MIN	- RECORD DP DATA (INTERVAL 5 MINS) - RECORD Kw AT 0.5

				CC/MIN
1ST OIW SENSITIVITY	PRODUCED WATER (3PPM OIW AND SP)	10 X PORE VOLUME	0.5 CC/MIN	- RECORD DP DATA (INTERVAL 5 MINS) - RECORD Kw AT 0.5 CC/MIN
2ND OIW SENSITIVITY	PRODUCED WATER (5PPM OIW AND SP)	10 X PORE VOLUME	0.5 CC/MIN	- RECORD DP DATA (INTERVAL 5 MINS) - RECORD Kw AT 0.5 CC/MIN
3RD OIW SENSITIVITY	PRODUCED WATER (7PPM OIW AND SP)	10 X PORE VOLUME	0.5 CC/MIN	- RECORD DP DATA (INTERVAL 5 MINS) - RECORD Kw AT 0.5 CC/MIN
4TH OIW SENSITIVITY	PRODUCED WATER (9PPM OIW AND SP)	10 X PORE VOLUME	0.5 CC/MIN	- RECORD DP DATA (INTERVAL 5 MINS) - RECORD Kw AT 0.5 CC/MIN
5TH OIW SENSITIVITY	PRODUCED WATER (11PPM OIW AND SP)	10 X PORE VOLUME	0.5 CC/MIN	- RECORD DP DATA (INTERVAL 5 MINS) - RECORD Kw AT 0.5 CC/MIN
6TH OIW SENSITIVITY	PRODUCED WATER (13PPM OIW AND SP)	10 X PORE VOLUME	0.5 CC/MIN	- RECORD DP DATA (INTERVAL 5 MINS) - RECORD Kw AT 0.5 CC/MIN

CHAPTER 4

RESULTS AND DISCUSSION

Two Berea cores were selected for the injectivity study. Table below shows the relevant core properties.

Table 3 Berea Core Properties

Core	Diameter, cm	Length, cm	Saturated weight, g	Dry weight, g	Pore volume, cc	Porosity
Berea core A	3.80	13.88	363.63	330.78	32.85	20.0
Berea core B	3.77	14.16	370.22	336.52	33.7	17.6

This study involves coreflooding test. Before conducting the test, coreflood machine was set with the data below:

- Confining pressure: 2700 psi
- Back Pressure Regulator: 2400 psi
- Oven temperature: 126˚C
- Synthetic formation water salinity: 3433

4.1 Produced water filtered at 1.2 micron

4.1.1 Water permeability result

Initial water permeability was studied by running core flood machine at three different flow rates. For this set of tests, Berea core A was used. Graph below shows the relationship between pressure difference in the core and accumulated pore volume of formation water.

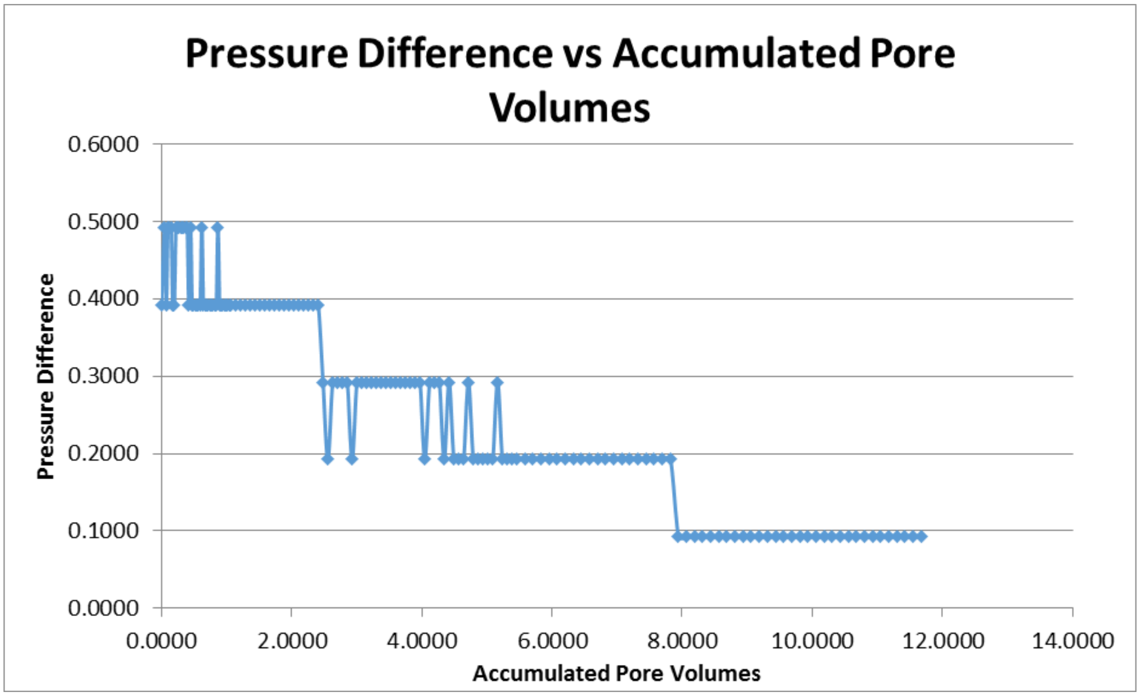


Figure 9 Pressure Difference over Acc Pore Volumes - Berea Core A

From this raw data, stabilized pressure differences were selected and a straight line graph was plotted. This straight line graph plots the flow rate of 0.2, 0.5 and 1 cc/min vs pressure difference.

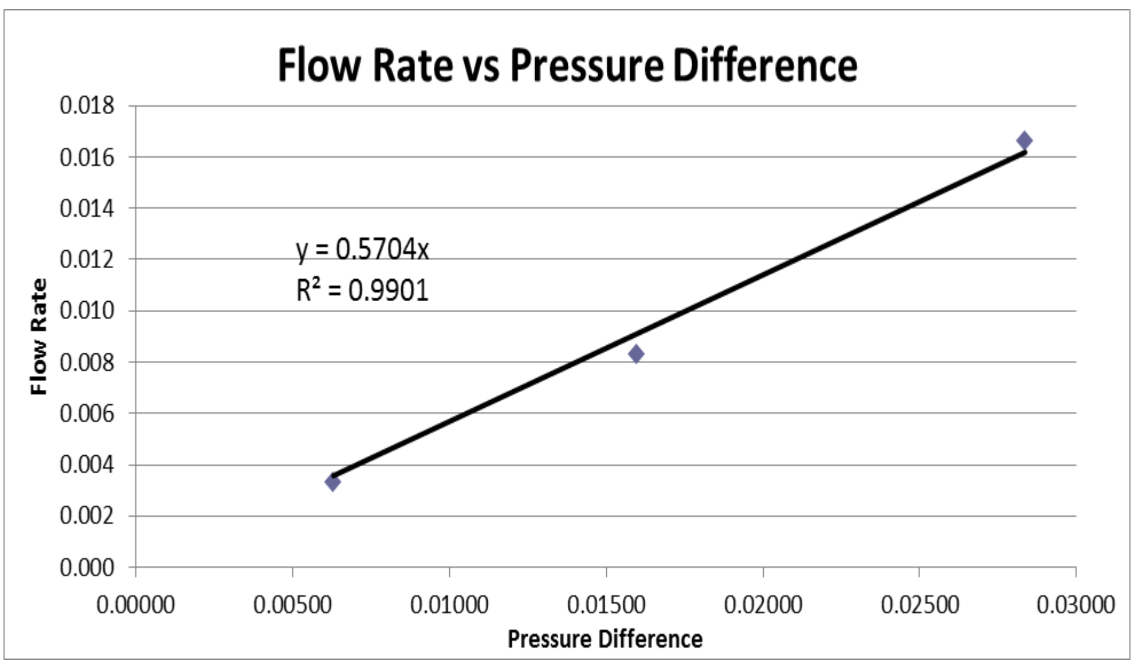


Figure 10 Flow Rate over Pressure Difference - Berea Core A

Permeability, k, was calculated using the slope of the plot. Thus;

$$k = \frac{M\mu L}{A}$$

$$= 698.1009 \text{ mD}$$

4.1.2 Core flooding result

Core flood test was carried out according to the procedure. Graph below shows the change in pressure of different injection slugs at certain duration of time.

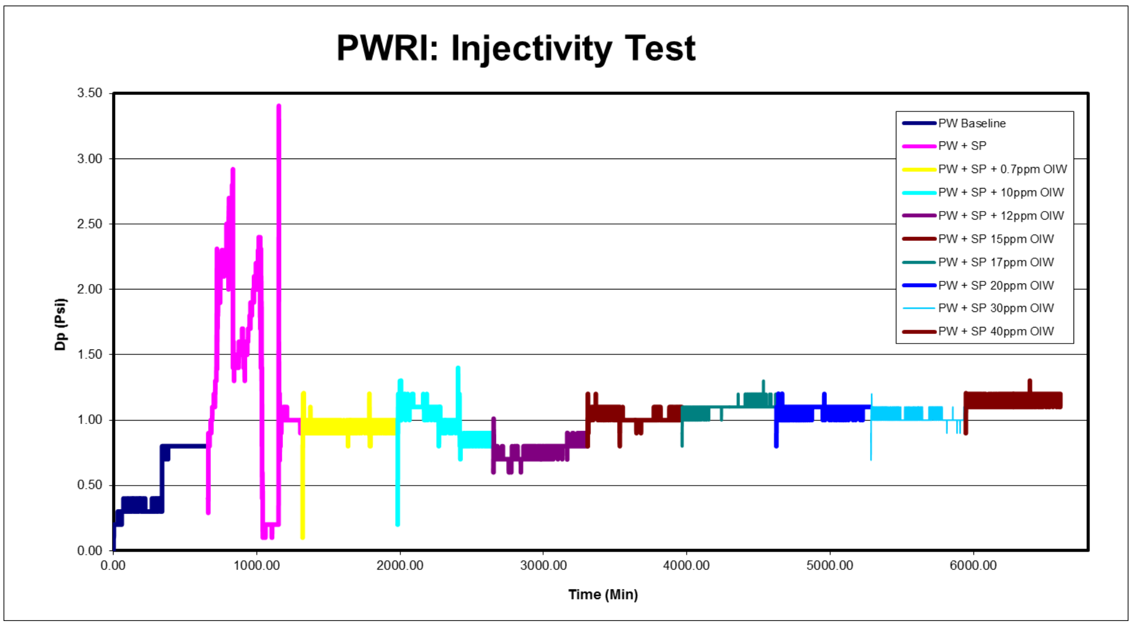


Figure 11 Injectivity Test - Berea Core A

The graph plot above showed a rather constant pressure difference over time, indicating no injectivity impairment. The following sequence of injections with added residual chemicals and oil in water were showing a slightly increase in pressure difference without much concern. Even at 40ppm of oil in water, no significant increase in pressure difference is recorded. Therefore, we can say that from this plot no injectivity issue is present at 1.2 micron particle size of produced water and it is possible to re-inject produced water containing residual chemicals and oil in water up to 40ppm of oil in water concentration.

4.2 Produced water filtered at 2.7 micron

4.2.1 Water permeability result

Initial water permeability was studied by running core flood machine at three different flow rates. For this set of tests, Berea core B was used. Graph below shows the relationship between pressure difference in the core and accumulated pore volume of formation water.

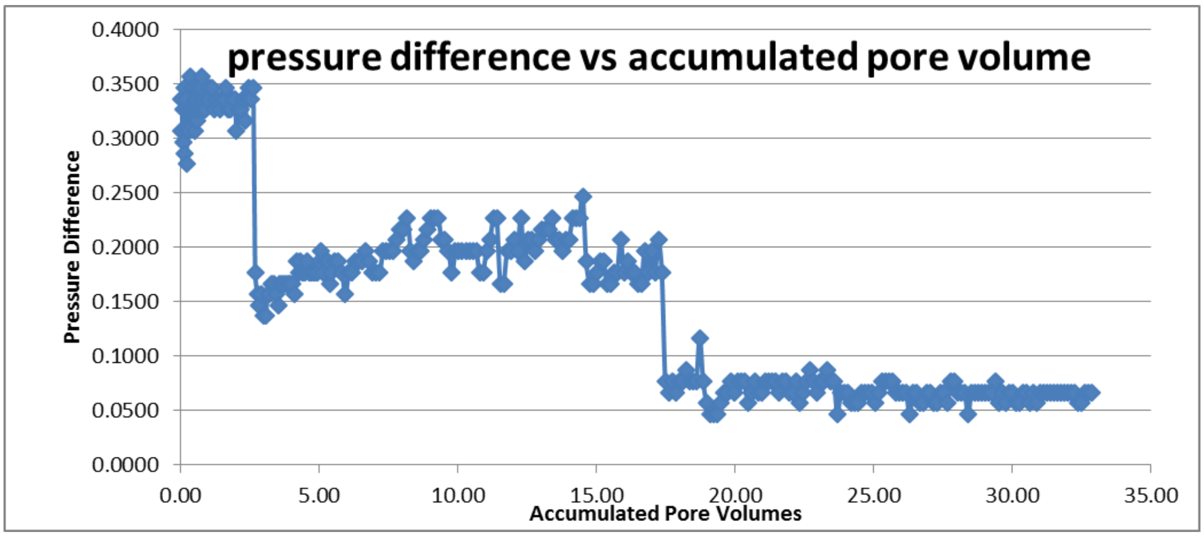


Figure 12 Pressure Difference over Acc Pore Volumes - Berea Core B

From this raw data, stabilized pressure differences were selected and a straight line graph was plotted. This straight line graph plots the flow rate of 0.2, 0.5 and 1 cc/min vs pressure difference.

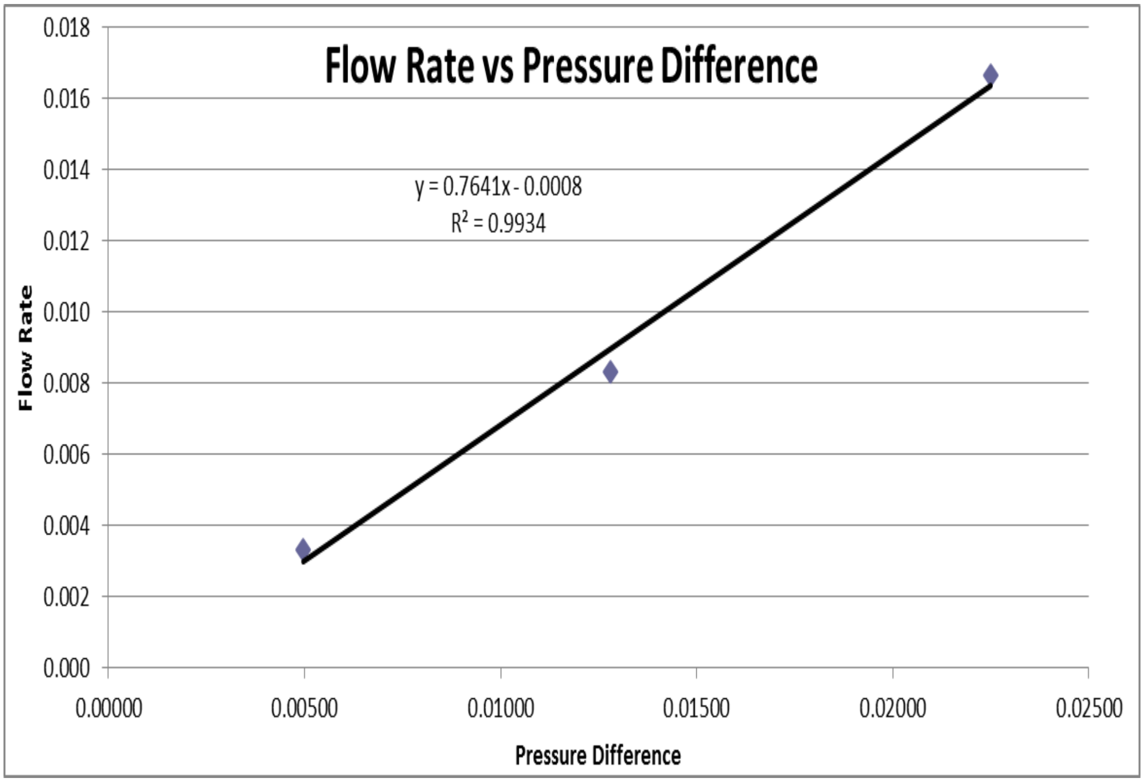


Figure 13 Flow Rate over Pressure Difference - Berea Core B

Permeability, k, was calculated using the slope of the plot. Thus;

k = $\frac{M\mu L}{A}$

= 969.0161 mD

4.2.2 Core flooding result

Core flood test was carried out according to the procedure. Graph below shows the change in pressure of different injection slugs at certain duration of time.

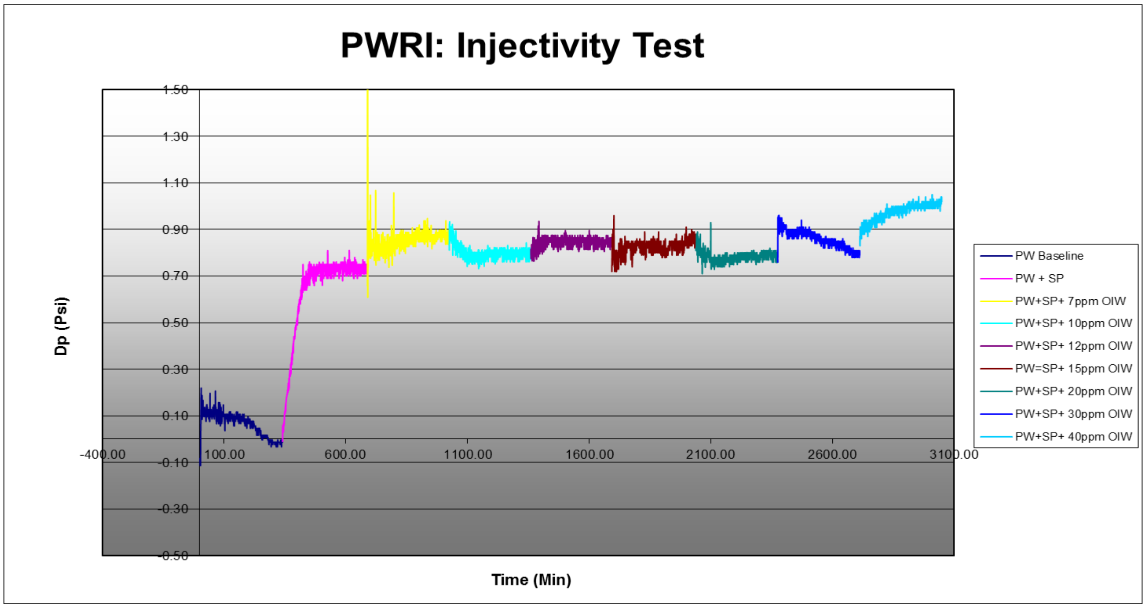


Figure 14 Injectivity Test - Berea Core B

The graph plot above showed a rather constant pressure difference over time, indicating no injectivity impairment. The following sequence of injections with added residual chemicals and oil in water were showing a slightly increase in pressure difference without much concern. At 40ppm of oil in water, pressure difference started to show greater value, indicated by the light blue line. It can be summarized from this plot that no injectivity issue is present at 2.7 micron particle size of produced water and it is possible to re-inject produced water containing residual chemicals and oil in water up to 40ppm of oil in water concentration.

4.3 Data analysis

In order to analyze the findings, we can use Darcy law that relates permeability and pressure difference.

$$q = \frac{kA\Delta P}{\mu L}$$

Rearranging the equation;

$$k = \frac{q\mu L}{A\Delta P}$$

As we can see, permeability is inversely proportional to pressure difference. Injectivity problem is indicated by the drastic increment of pressure difference. When it increases, permeability will reduce. The reduction of permeability indicates that formation damage may occur. However, from the result of core flooding tests carried out, no significant increase of pressure difference happened for both 1.2 microns and 2.7 microns which eventually telling us that there is no risk of injectivity problem to arise.

During the lab test, the first set of injection slugs (1.2 microns) were prepared at 10 pore volume (PV). On the other hand, the slug sizes were reduced to 5 PV for the second set of tests (2.7 microns). The reason behind this was that we are expecting at smaller size of filtration, longer time was needed to allow plugs formation in the Berea core. When changing to a larger filtration size of 2.7 microns, we predicted that larger particle size will plug the pore throats faster, hence reducing the slug size by half. But still, no indication of injectivity can be observed from the results.

Throughout the procedure from the beginning, there are two elements were eliminated as the factors possibly to cause injectivity problem. Firstly, it was found that field A's reservoir rock is permeable. Several Berea cores were selected for porosity and permeability tests during the preparation phase. Since reservoir rock's permeability is about 200mD, Berea cores with the same values were selected. High permeability reservoir eases the flow of fluid in the pore throats, thus eliminating one factor that can cause injectivity problem. Apart from that, core flooding test was run using Berea sandstone cores. Berea cores are sedimentary rocks whose grains are predominantly sand-sized and are composed of quartz held together by silica. A Berea core does not have any clay inside which from production technology's point of view may cause formation damage when it swell. Chemical interaction between clay and produced water containing residual oil and chemicals may result in clay swelling. Absence of clay in Berea core may be a reason that no injectivity problem occurred during the core flood tests.

Produced water reinjection application for Chemical Enhanced Oil Recovery is not a mature approach in the industry. There is no documented statistic to benchmark the recommended reinjection water specification for this field. However, there are two known case studies on CEOR PWRI. The respective water quality specifications are tabulated in table below.

Table 4 Water Quality Specifications - Case Study

Case study	Particle size (microns)	OIW (ppm)
Daqing field, China	<2	<8
Marmul field, Oman	<2	<5

For this study since we are using Berea core, it is logical that the OIW concentration is way higher that the two fields in the table above. To relate with the stated objectives, the filtration level of injection fluid is below 2.7 microns. The OIW concentration of produced water reinjection fluid is 40ppm and finally there is no injectivity issue of produced polymer, surfactant and oil in produced water reinjection (PWRI) application.

CHAPTER 4

CONCLUSIONS

Core flooding test was conducted to study the potential of injectivity which has high possibility to cause formation damage. From the result obtained, there is no injectivity issue observed even after varying the particle size filtration and oil in water concentration. The filtration level of injection fluid allowed is below 2.7 microns. The maximum OIW concentration before reinjection is 40ppm. The reservoir is permeable but still, there is possibility that injectivity may happen since test on clay swelling is not considered when using Berea core. Thus, there are few recommendations can be considered for future study. This project was done using Berea core. In the future, tests shall be done using native core. As native core contains clay, thorough study on mineral content shall be included as well. In order to determine the particle size that may cause injectivity, filtration size shall be more than two sizes. In that way, more accurate result can be obtained. Finally, the slug sizes for each injection shall be increased to lengthen the flow duration and thus allowing plug formation in the core.

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