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Implementation of low salinity water flooding to improve recovery in Gullfaks field

Case study: K1 / K2 segment

Master's thesis in Petroleum Engineering

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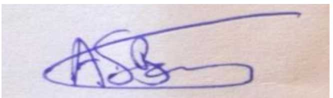
DISCLAIMER

I hereby certify that this report is my own original work and has not been submitted before to any other institution. All other source of information used have been acknowledged and cited in the reference section.



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ABSTRACT

Low salinity water flooding is the type of Enhanced Oil Recovery (EOR) method where the injected water has low salinity than formation water. In recent years, it emerged as one of the most researched EOR in petroleum field. It started in 1967 whereby researchers started the investigation on how salinity of the injected water could affect the efficiency of oil recovery. They claimed that injecting low salinity water in a sandstone formation containing clay improves recovery much better than using brine water.

This research focus on investigating and implementing low salinity water flooding as EOR method in K1/K2 area of Gullfaks field. The objective is mainly achieved through reservoir simulation using ECLIPSE 100 black oil simulator. The data used in this work was found in Gullfaks database. Before simulation the method was screened to validate its suitability in the field. At this stage TechLog a petrophysics software was used to prove the presence of sandstone with clay in the formation which is the strong evidence that low salinity method can be successfully used.

Before formulation of improved simulation cases, a tracer injection work was performed to assess communication in K1/K2 segment. The study concluded that there is no or very limited communication between K1 and K2, layers 11, 12 and 13 communicate with each other and other part of the reservoir, layers 10, 14 and 15 have no communication with each other and with other part of the reservoir, some part of the reservoir have thief zones which will result to loss of fluid if selected for injection.

Two simulation scenarios were formulated. The first scenario involves injection of low salinity water using the three injectors already present in the field, the only work was to convert from injecting sea water to low salinity water. In this scenario the parameter changed were only salt concentration. The second scenario involves the introduction of new injection well. Parameters changed in this scenario were salt concentration and position of injector introduced. This resulted to formulation of five different cases.

The results indicated that salt concentration of 500 ppm improved recovery much better than the rest. The recovery improved from 46.4% to 48.3 and 46.4% to 50.1% for scenario 1 and 2 respectively. In addition, the introduction of the injector increases oil recovery and the economic analysis results showed higher NPV of $ 91,212,346.

Sensitivity analysis performed involved Operating Expenses (OPEX), Oil price, Capital expenditure (CAPEX) and discount rate. All parameters are sensitive to project, but the most sensitive parameter was found to be the oil price having the most impact on the NPV change. For example, increase of oil price by 15% resulted to rise of NPV by 41.7% and 71.67% for scenario 1 and 2 respectively. Also decrease in oil price by 15% resulted to decrease of NPV by 41.7% and 71.67% for scenario 1 and 2 respectively. The result of the analysis was then presented in spider diagrams. The observation from spider diagram is that for both scenario oil price has the most impact on NPV followed by CAPEX, discount rate and the parameter with the least impact is OPEX.

Scenario 1 with no addition injector was finally recommended for possible real field implementation because it was found to have less risk. Analysis performed by changing economical parameters by ±5%, ±10% and ±15% resulted to positive NPV in scenario 1 even in worst case unlike scenario 2 which resulted to negative NPV in worst case.

This work involved only simulation with no laboratory experiment performed. As part of the recommendation for further work, practical side of the work can be performed through core flooding experiments.

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NOMENCLATURE

Abbreviations

ANTHEI	Angola-Tanzania Higher Education Initiative
OWC	Oil Water Contact
GWC	Gas Water Contact
MSL	Mean Sea Level
EOR	Enhanced Oil Recovery
IOR	Improved Oil Recovery
NPV	Net Presence value
MIE	Multicomponent Ionic Exchange
EOS	Equation of State
ppm	Parts per Million
GOR	Gas Oil Ratio
FOE	Field Operating Efficiency
FOPR	Field Oil Production Rate
FOPT	Field Oil Production Total
FWPT	Field Water Production Total
FPR	Field Pressure
FTPT	Field Tracer Production Total

FTIT	Field Tracer Injection Total
GRmax	Maximum Gamma Ray
GRmin	Minimum Gamma Ray
CAPEX	CAPital EXpenditure
OPEX	OPerating EXpenses

CHAPTER ONE

1 INTRODUCTION

Gullfaks is a Norwegian offshore oil and gas field discovered in 1978 and started production in 1986. It is located in Tampen area in the Northen part of the Norwegian North Sea and lies in block 34/10 at water depth of 130-230meters (Equinor, 2018). Gullfaks field was developed with three production platforms namely Gullfaks A, B and C platforms. Gullfaks A platform started production first among other platforms on 22nd December 1986 followed by Gullfaks B on 29th February 1988 and then Gullfaks C platform on 4th November 1989 (Equinor, 2018). The owners of the field are Equinor Energy AS (51%), Petoro AS (30%) and OMV(Norge) AS (19) (Norwegian Petroleum Directorate, 2018).

Gullfaks main field is made up of four reservoir formations namely; The Brent Group, the Cook Formation, Statfjord Formation and Lunde Formation. Brent Group is the most important reservoir in Gullfaks field as it contains 73% of initial hydrocarbon in place (Saifullah Talukdar, Rune Instefjord, 2008). Each reservoir is subdivided in to different segments as presented in reservoir management plan (StatoilHydro, 2007).

Gullfaks area also consist of four satellite fields namely Gullfaks South, Rimfaks, Skinfaks and Gullveig. These satelites consist of subsea wells remotely controlled from Gullfaks A and C platforms. The map of Gullfaks field, nearby fields and satelites is shown in Figure 1.1.

Oil in place discovered in Gullfaks main field was 792.6 $\times 10^6$ m^3. Original recoverable oil was 379.77$\times 10^6$ m^3, therefore recovery factor was 47.9% (Norwegian Petroleum Directorate, 2018). The field have been in production since 1986 and reach its peak production on 7 October 1994 where the oil production was 96,338 m^3 per day (Equinor, 2018). Amount of recoverable reserve remain as of 31st, December 2017 was 14.76$\times 10^6$ m^3 (Norwegian Petroleum Directorate, 2018) which can be produced by existing drainage strategies.

The existing recovery techniques already applied in Gullfaks field are Infill drilling, Water injection, Gas injection, Water Alternating Gas injection (WAG), Huff and Puff gas injection, Hydraulic fracturing of low permeable reservoirs, sand control, selective perforation, reperforation and zone isolation (Saifullah Talukdar, Rune Instefjord, 2008). Those techniques were able to improve recovery factor to 59% as of 2018 (Equinor, 2018).

The company has set its target to improve recovery factor to 62% (Equinor, 2018). This can be achieved by continue applying recovery techniques. This can involve applying new technologies or modifying the existing techniques.

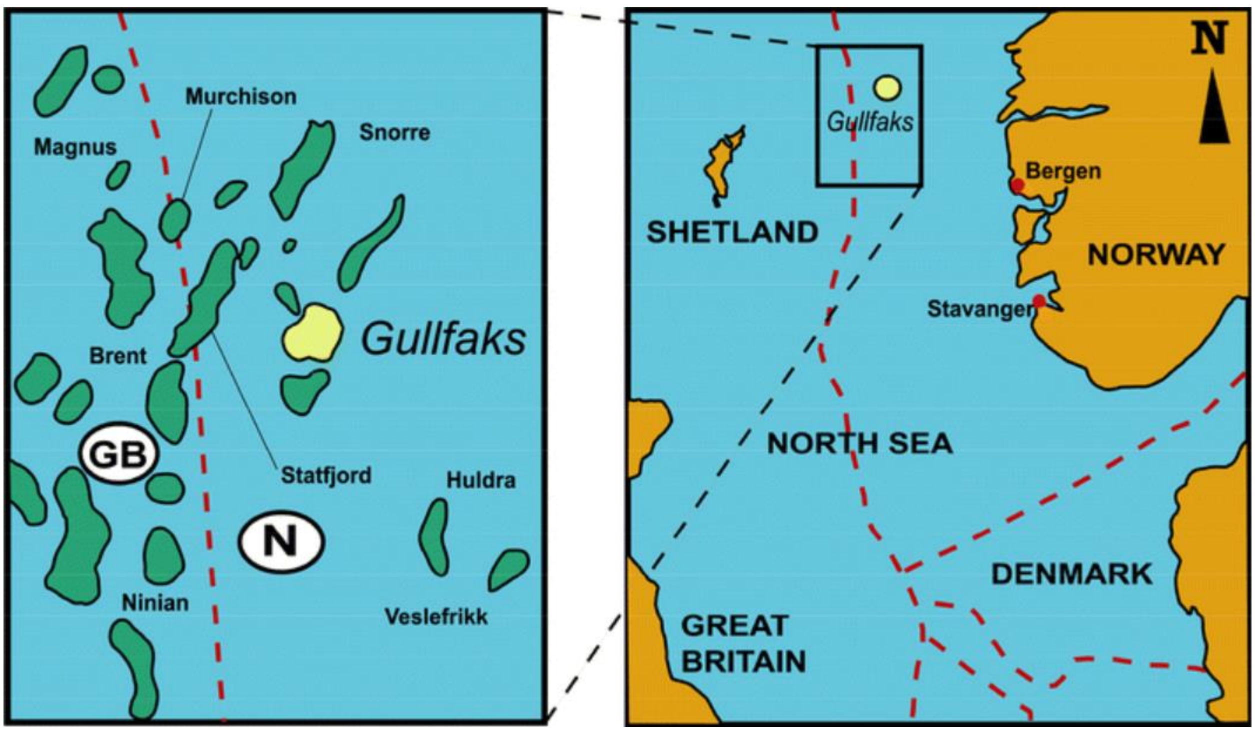


Figure 1.1: Gullfaks main field and satelites (springernature.com, 2019)

1.1 Geology of Gullfaks Field

Gullfaks geological structure is divided in to four formations i.e Brent Group, Statfjord formation, Cook formation and Lunde formation. Oil is produced from Middle Jurassic sandstone in the Brent Group, Lower Jurassic and Upper Triassic sandstone in the Statfjord, Cook and Lunde formations. Also amount of oil is produced from fractured carbonate and shale in the overlying Shetland Group and Lista Formation (Norwegian Petroleum Directorate, 2018).The overall geology of Gullfaks is very complex due to presence of many rotated fault blocks. Also, big permeability contrast ranging from milli-Darcies to Darcies increase its complexity. The geological structure is well presented in Figure 1.2.

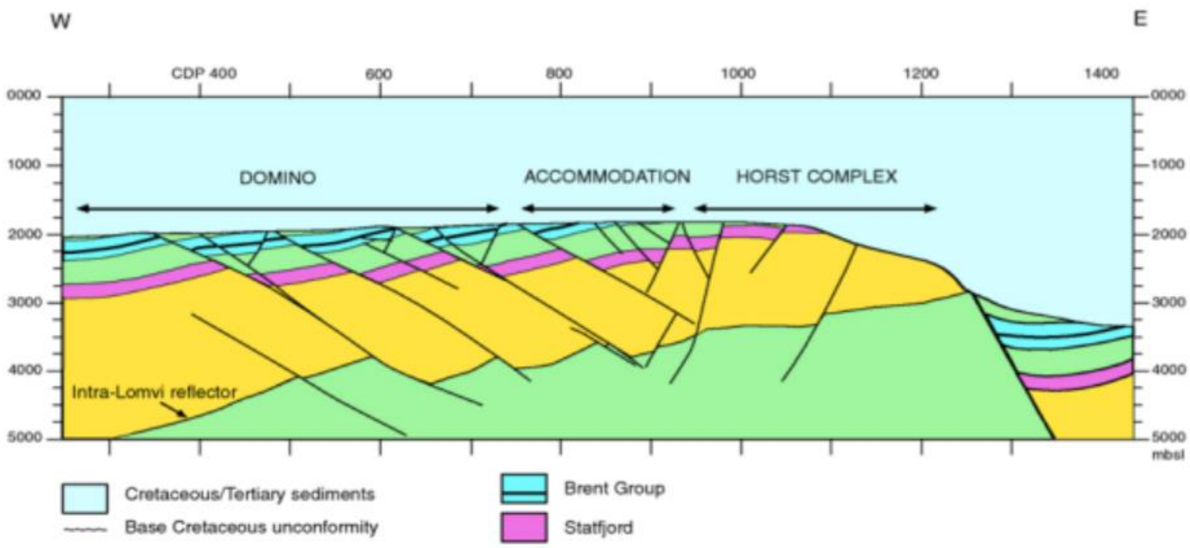


Figure 1.2: Geological structure of Gullfaks field (StatoilHydro, 2007)

1.1.1 Brent group

Brent group represents depositions from northward-building delta system in the mid-durassic period. It is the uppermost reservoir in Gullfaks which contain 73% of total oil in place discovered in Gullfaks area. Oil in Brent Group is filled in three structure traps namely Gullfaks West, the E2/E3 segments and the main Gullfaks filled (StatoilHydro, 2007). Those traps have different initial oil-water contact as summarized in Table 1.1.

Table 1.1: Initial OWC for three structural traps in Brent Group

S/N	Structural trap	OWC, m MSL
1	Gullfaks West	1990
2	E2/E3	1890
3	Main Gullfaks	1947

Sequence-stratigraphic principles was used in the zonation of Brent group which is subdivided to Tarbert Formation, Ness Formation and lower Brent Group. Lower Brent is further subdivided to Etive and Rannoch. A detailed structural zonation of Brent group is shown in Figure 1.3. The picture was taken from Norwegian Management Plan of 2007 therefore some words are in Norwegian language, but the concept of zonation is clearly seen.

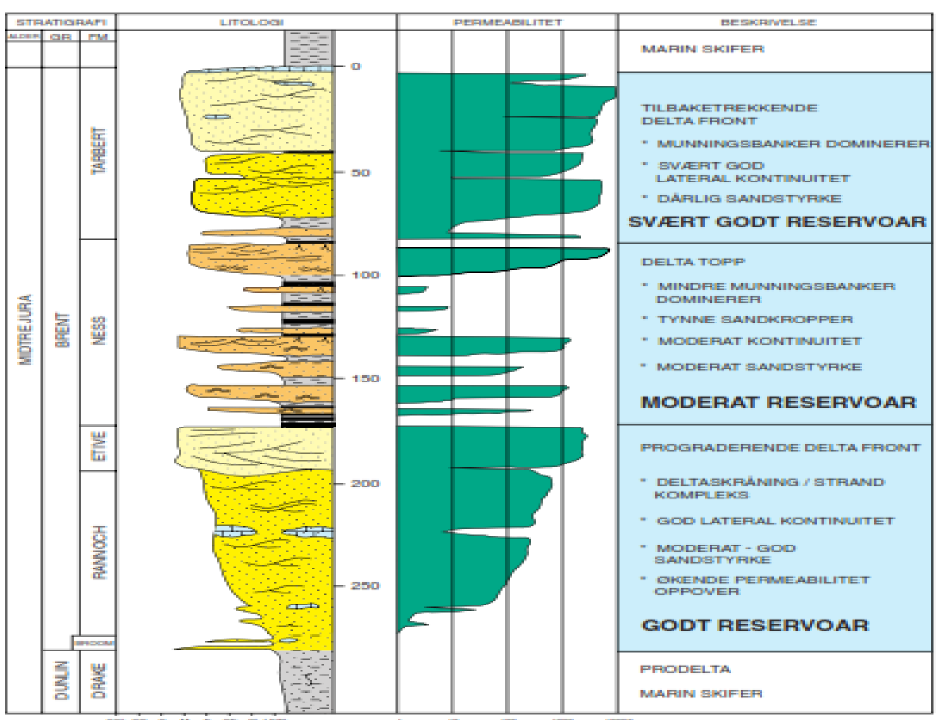


Figure 1.3: Lithostratigraphic column of Brent group (StatoilHydro, 2007).

1.1.2 Statfjord formation

The Statfjord Formation resulted after deposition in the late Triassic/early Jurassic period. The depositions took place during a period of gradual change in the depositional environment, from an alluvial environment with episodic flood deposits in lower parts, to poorly drained alluvial plain with swamps and river channels in the upper parts (StatoilHydro, 2007).

Lithographic criteria were applied for zonation in Statfjord formation of which zones were separated based on their lithologies. Figure 1.4 shows clearly the zonation of Statfjord formation. The zones are S1, S2, S3, S4, S5, S6, S7, S8, S9, S10, S11 plus zones in segment K, I, J, H, G. Segment K contain most of the reserves in Statfjord reservoir. The project will mostly focus in K1 and K2 segments in this formation.

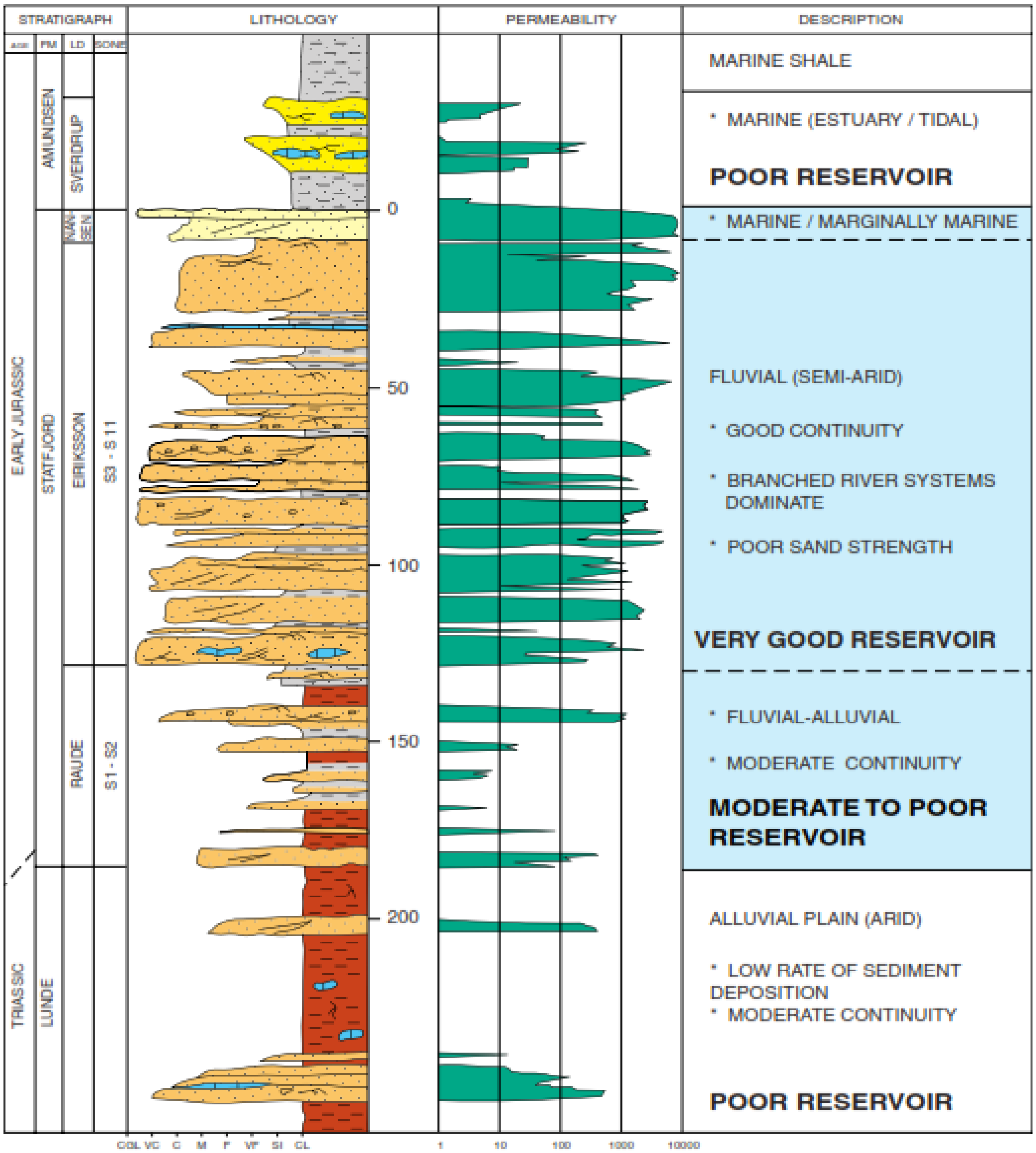


Figure 1.4: Lithostratigraphic column of Statfjord Formation (StatoilHydro, 2007)

1.1.3 Cook formation

The Cook formation is an upward coursing interval, of early Jurassic age which is deposited to shallow marine setting. Like Brent Group, Cook formation also is zoned based on sequence stratigraphic principles. The formation is subdivided in to Cook-1 which is mostly shale and regarded as non-reservoir, Cook-2 and Cook 3 of which both are reservoirs. Figure 1.5 represent Lithostratigraphic column of Cook formation of which each sub formation is seen clearly.

The Cook formation contain both oil and gas filled in the central and eastern part of the field. Oil is filled in five different structural traps and gas is occupied in only one segment. The initial Oil-Water contact, and Gas-Water contact for the structural traps are summarized in Table 1.2.

Table 1.2: Initial OWC and GWC for structural traps in Cook Formation

S/N	Structural trap	OWC,m MSL	GWC, m MSL
1	G1	1947	-
2	H1/H2	1926	-
3	H3/H4	1900	-
4	I1	1786	-
5	I/J	1090	-
6	E2	-	2072

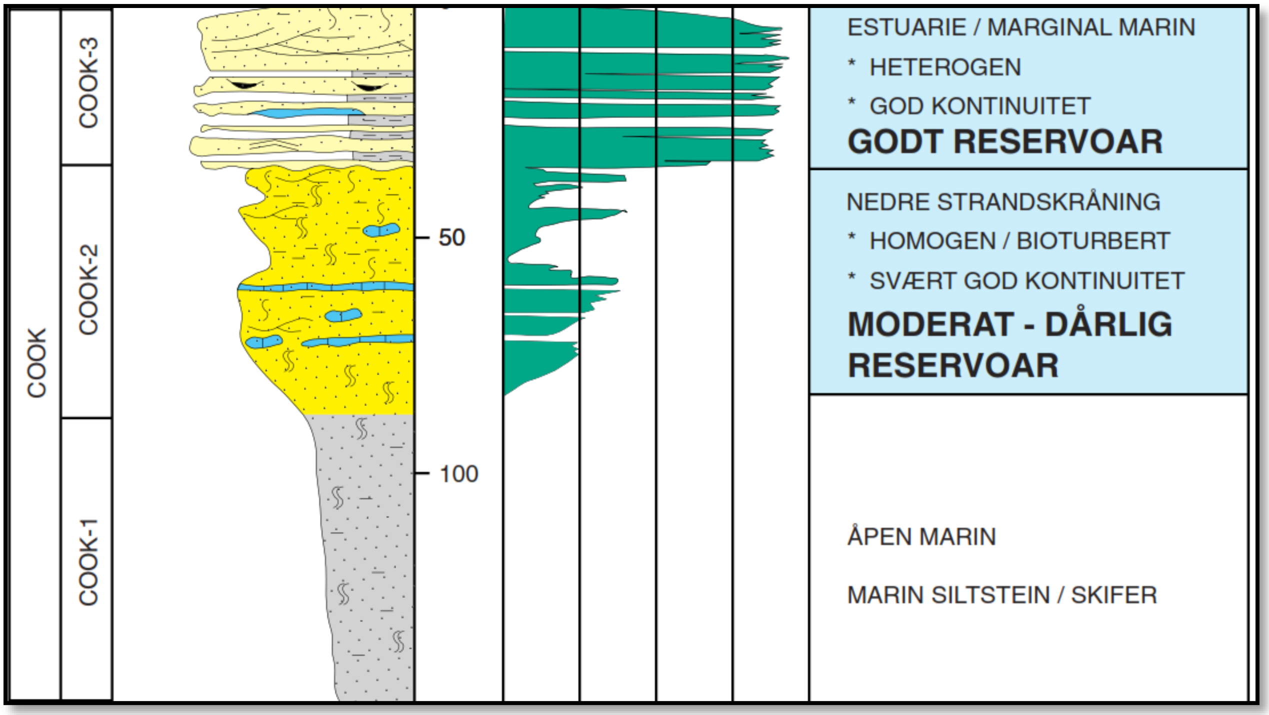


Figure 1.5: Lithostratigraphic column of Cook Formation (StatoilHydro, 2007)

1.1.4 Lunde formation

Lunde is located at the lowest position compared to other reservoirs in Gullfaks area. The deposition in the formation has a total thickness of 800-1200-metre of which some part has poor to moderate reservoir quality. Only northern Tampen area proved to have properties of good reservoir. Lunde is sub divided to lower, middle and upper formations. Figure 1.6 shows a representation of Lithostratigraphic column of upper Lunde formation.

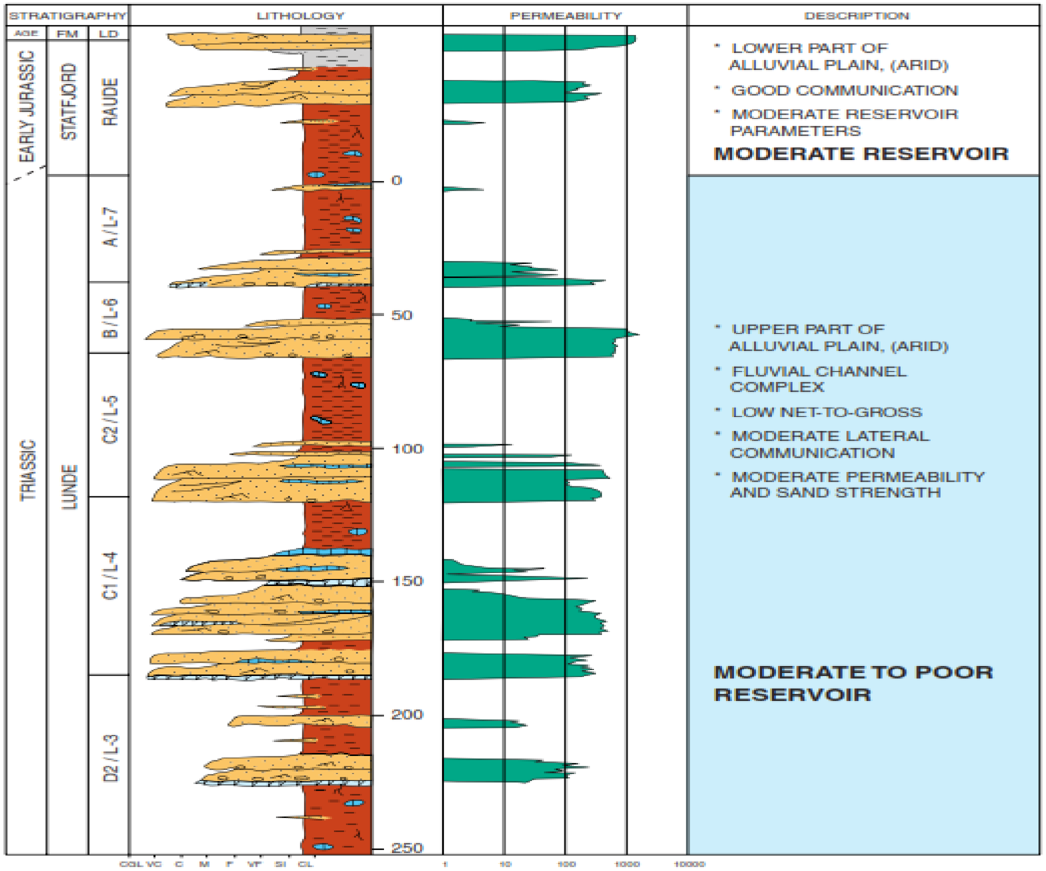


Figure 1.6: Lithostratigraphic column of upper part of Lunde Formation (StatoilHydro, 2007)

1.2 Problem Statement

Oil and gas demand have increased in Norway and the world in general while the Gullfaks field is at its end of production. Oil price being one of the drivers of demand and supply has increased recently and makes oil much valuable. For example, in 2015 the average price of oil was $40 per barrel and in 2019 is $65 per barrel, considering a period of four years ago. On the other hands oil companies with oil fields including Gullfaks are trying different ways to improve recovery to their field to ensure continued oil supply.

One of the most used recovery techniques is waterflooding, which started to be used since 1880 and proved to be dominant technique in oil recovery operations (Bowyer, 1982). In most cases sea water is used in this operation. One of the properties of sea water is to have high salt concentration example 34000 – 35000 ppm in North Sea. Recently, laboratory experiment studies have indicated that water with low salinity can recover more oil than high water salinity. This motivates the study to evaluate the use of low salinity water in oil fields including Gullfaks to improve the oil recovery and hence ensure continued supply to the market.

The aim of this research is to investigate and implement low salinity water flooding technique to Gullfaks field with oil recovery factor of 59% (Equinor, 2018) and the remaining recoverable reserve of 14.76×10^6 m^3 (Norwegian Petroleum Directorate, 2018). This is to determine the viability of the method in terms of production improvement and economics relative to the other existing methods/techniques.

1.3 Objectives

The main objective is to improve oil recovery in Gullfaks field by implementing low salinity water injection. To achieve the objective, the following actions/task have been covered;

1. Validation of the suitability of low salinity water flooding in K1/K2 segment.
2. Simulation of basecase model for K1/K2 and extension of the model to run up to 2025.
3. Assessment of communications between injectors and producers, and between layers in the reservoir through tracer injection.
4. Preparation and simulation of black oil models of low salinity water flooding for new improved cases.
5. Economic and sensitivity analysis.

1.4 Scope of the Research

- Gullfaks area consist of Gullfaks main field and satelites. This research focused on Gullfaks main field, specifically K1/K2 segment in Statfjord formation.

5.1 Methodology

The following methods were applied to achieve the completion of this research. The summary for the approach used is indicated in Figure 1.7.

- Reviewing Statfjord, K1/K2 reservoir properties.

Formation properties such as connate water salt concentrations, lithology, fluids densities and compositions among others have been reviewed to assess the suitability of law salinity water injection in the field.

- Data collection

Data used as a basis for K1/K2 base case model were extracted from Gullfaks database, http://www.ipt.ntnu.no/gullfaks. User name and password have been made available by NTNU through my supervisor Prof. Jon Kleppe. Some reservoir properties used as input for the model was found in reservoir management plan of 2007 (English version). The data include a base case model with include files attached.

- Preparing models for base case, tracer injection and improved cases

Using data found in Gullfaks database, a base case model was extended to run from April 1990 to July 2025. Low salinity models for improved cases and tracer injection models was prepared according to the procedures presented in ECLIPSE software reference manual.

- Simulation of the models prepared

ECLIPSE 100 being a black oil simulator have been used for this research work. The simulation procedures were followed as indicated in the ECLIPSE simulation manual. Several simulation cases were prepared, and the variable parameters are salt concentration, well position, injection rate and tracer.

- Performing economic and sensitivity analysis

Economic analysis performed mainly by calculating the NPV for different cases. Some economical inputs used for calculation have been assumed since there were no real data available. All assumed parameters have been stated in economic analysis section.

Sensitivity analysis mainly involved economical parameters. Oil price, discount rate, CAPEX and OPEX have all been used in spider diagram to observe their impact on final NPV. The parameters changed by up to ±15%; the effect of that changes on NPV have been observed and plotted.

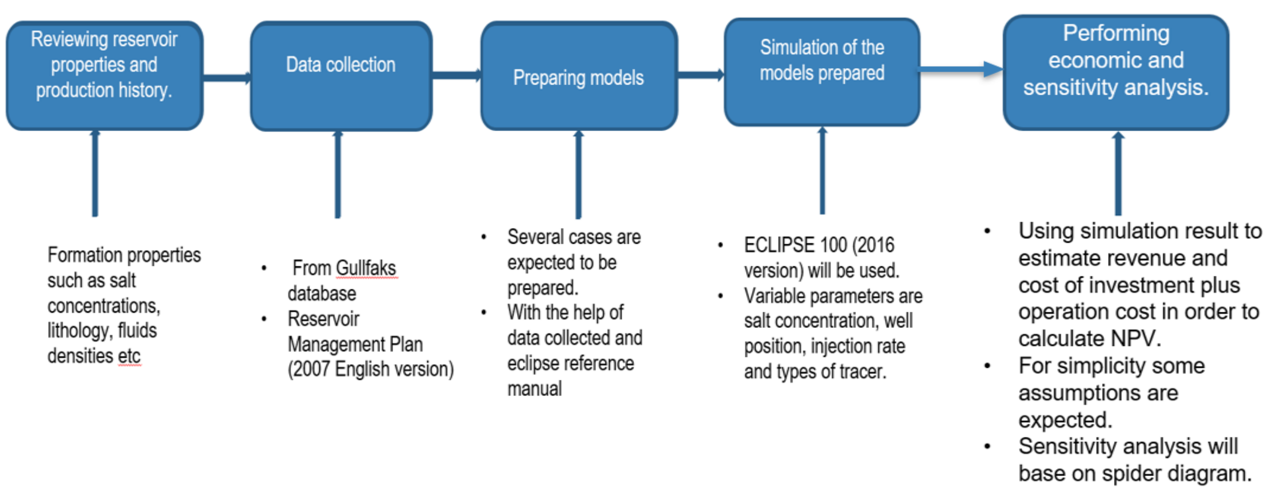


Figure 1.7: Research methods interpretation

CHAPTER TWO

2 LITERATURE REVIEW

2.1 Low Salinity Water Injection

Low Salinity Water Injection is a recent EOR method emerged in oil recovering process whereby injected water has low salt concentration compared to the reservoir brine. It started in small scale by performing flooding experiments in the laboratory up to applying in large petroleum field. Various studies about the method have been carried out and all of them agreed on the impact of low salinity water on improving recovery however they differ on which is the right mechanism behind, detail description about previous studies on low salinity water injection is explained in subsection 2.1.5.

Low salinity Water Injection as a recovery mechanism can be applied in both secondary and tertiary phase. This is because as a water flooding it has a potential to maintain reservoir pressure which is suitable for secondary phase. Also having low salinity, it has properties which can change rock wettability from oil or mixed wet to water wet which result to high oil recovery. Before presenting the mechanisms behind low salinity water flooding, it is worth introducing the general recovery mechanisms phases.

2.1.1 Recovery mechanism

Oil recovery is the process of extracting crude oil from the reservoir to the surface. This process has never been easy especially when field have been in production for many years. In extracting oil from the reservoir some techniques are usually applied depending on the reservoir condition. The techniques are known as reservoir recovery techniques.

Reservoir recovery techniques applied depend much on the recovery phase of the field. There are three different phases of oil recovery i.e Primary recovery, Secondary recovery and Tertiary recovery. To further illustrate on the recovery, Figure 2.1 shows all three recovery phases and some techniques applied to improve recovery.

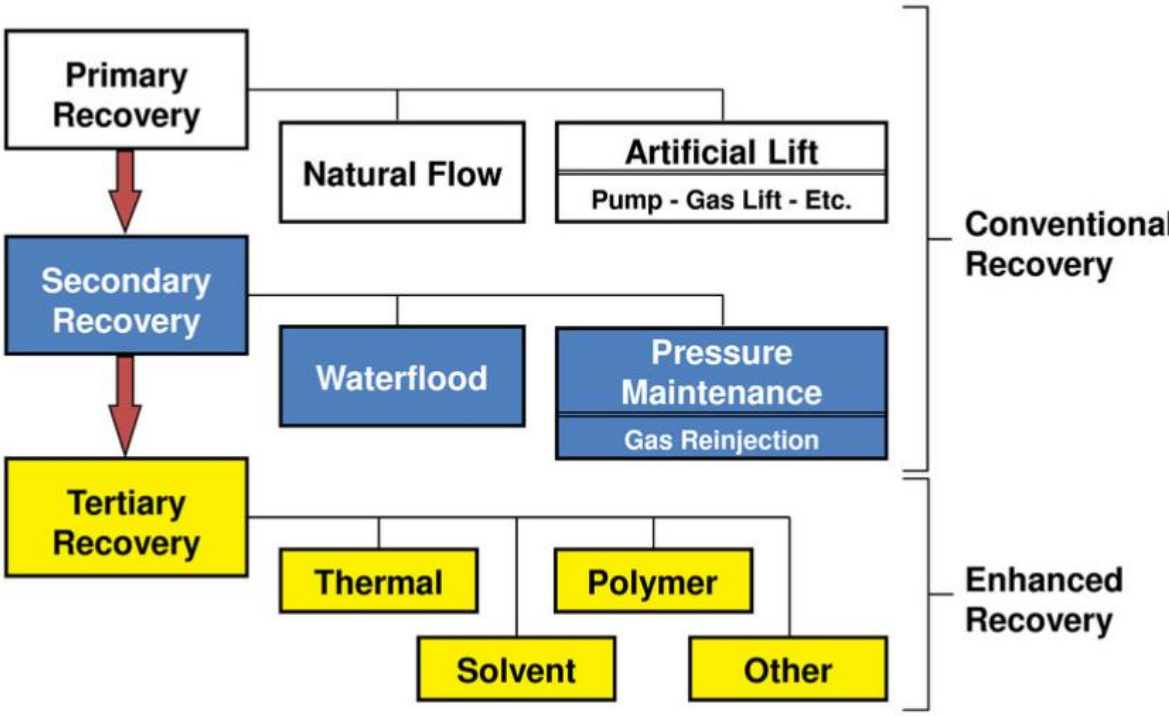


Figure 2.1: Oil recovery mechanism (CARLIFONIA RESOURCES COOPERATION, 2019)

2.1.2 Primary recovery

Primary recovery is the process of extracting oil or gas from the reservoir by taking advantage of natural energy present. The process does not involve injection of materials in the reservoir, therefore this phase involves only placement of production wells. Primary recovery is sometimes referred to as pressure depletion because it necessarily involves the decline of the reservoir pressure (Petrowiki, 2018).

Recovery in this phase involve natural flow of fluid from the reservoir to the surface. The flow is enhanced by pressure difference between the reservoir and the bottom-hole of the well. That pressure difference is called differential pressure and it is the main driving force in production. Pressure maintenance in the reservoir is assisted by presence of gas cap and aquifers. As production continue reservoir pressure will decrease and result to small differential pressure. At this point artificial lift can be used to assist oil production to the surface.

As production continue, it may reach a point where reservoir pressure is too low whereby even artificial lift system is not economical to be used anymore. At this point, fluid injections with pressure can be used to enhance production. Recovery by fluid injection is in another recovery phase known as secondary recovery.

2.1.3 Secondary recovery

Oil and gas recovery assisted by water and gas injections to maintain reservoir pressure is known as secondary recovery. As stated, the main recovery techniques used at this phase are water and gas injection.

In 1880 water injection was discovered to have impact in maintaining reservoir pressure and displacing oil and gas to enhance production (Bowyer, 1982). Since then it has developed to become the dominant technique employed in worldwide oil recovery operations. It is considered as a cheap method in secondary recovery phase due to availability of water especially sea water for an offshore field. Recently, it has been discovered that using low salinity water will have more impact on oil recovery than using sea water direct for injection. In this case, sea water is treated to reduce salt before used for injection. After treatment, water is injected with high pressure using a special kind of pumps installed at the wellhead of an injection well. In some field the injected water is recycled and reinjected. This low salinity water injection technique improve recovery by altering the properties of rock and fluid as well as maintaining reservoir pressure, therefore it can be used in both secondary and tertiary phases. Another injection fluid used in secondary recovery is gas.

Like water injection, gas injection has the same purpose in enhancing oil recovery. The first immiscible gas injection projects in oil industry initiated in 1930s whereby lean hydrocarbon gas was used. Some of the first fields to use gas injection techniques were Oklahoma City field and Cunningham pool in the US and Bahrain field in Bahrain (Petrowiki, 2018).

Gas is injected to the gas cap and expand to maintain pressure as production continue. Gas injection process depend much on its availability. Typically, injected gas comes from produced solution gas or gas-cap gas, gas produced from a deeper gas filled reservoir or gas from a relatively close gas field (Petrowiki, 2018).

Water and gas injection have also got their limit, at that point oil recovery is beyond applying pressure through injections. Techniques used at this point will aim to alter oil properties like viscosity to enhance its flow. Those techniques are generally known as tertiary oil recovery techniques.

2.1.4 Tertiary recovery

Tertiary recovery also referred as Enhanced Oil Recovery (EOR) is a third and final phase of oil recovery. This involve methods attempt to improve the extraction of crude oil by injecting different kinds of materials that can change selected properties of physics and chemistry of fluid (oil and gas) in the reservoir rocks (UGMSC, 2010). In tertiary recovery phase, techniques used are normally divided to three categories i.e thermal methods, gas injection and chemical flooding (Schlumberger, 2018).

Thermal methods involve heating the reservoir with steam injection. Injected steam warms the oil, so its viscosity decreases and become easy to flow. For over 15 years, steam injection enhanced production of 417,675 barrels of oil per day which is equal to 56% of oil produced by all tertiary recovery methods (Petrowiki, 2018).

Another category of tertiary recovery method is gas injection. The method is used in both secondary and tertiary phase. Gases used in this method are carbon dioxide, nitrogen or natural gas.

The last category is chemical flooding which involve injection of water with chemicals such as polymer and surfactants to lower surface tension so that oil flow easily to the surface. Polymer and surfactants are normally used together, water containing surfactant is first injected to a reservoir. The purpose is to reduce interfacial tension between water and oil phase as well as to alter wettability of reservoir rock so that to improve oil sweeping. Water with polymer is then injected with special pump to the reservoir through injection well. Injecting low salinity water also falls in this category. It is one of the recently discovered EOR technology and will be the focus of this project.

2.1.5 Background of Low-Salinity water flooding

In 1967, Bernard performed the first experiment that involve the study of effect of salt concentration in water flooding. It was the laboratory experiment that involved injection of fresh water and brine water in a sandstone cores containing clay. Bernard observed that fresh water can recover more oil than brine water in a sandstone cores containing clay. It was claimed that the reason for high recovery is clay swelling effect caused by fresh water. The swelling clay reduces the pore space containing oil therefore more oil come out of the pore and produced (Ramez A. Nasralla, Hisham A. Nasr-El-Din, Texas A&M University, SPE members, 2011).

More research about low salinity water injection were performed in 1990s. In 1991, Jadhunandan and Morrow performed experiment to study the relation between waterflood oil recovery and rock wettability. They adjusted initial water, oil saturations and aging temperature to play with rock wettability in a core plug. They came to conclusion that high recovery by waterflooding is achieved at very weak-water wet condition (Shaddel, 2014).

In 1999, Tang and Morrow performed a research concerning the impact of water salinity on oil recovery. They concluded that, oil-wet clay particles are easily detached when they are in contact with low salinity water which result to increasing oil mobility (M. Rotondi, C. Callegaro, F. Masserano, and M. Bartosek, eni S.p.A, 2014). The wettability idea was later supported by McGuere et al. who suggested that flooding with low salinity water can lead to in-situ surfactant generation. This will result to wettability changes and reducing of interfacial tension and lead to more oil recovery (Ramez A. Nasralla, Hisham A. Nasr-El-Din, Texas A&M University, SPE members, 2011).

Another study about low salinity water flooding was conducted by Lager et al. in 2006. He suggested that the reason for improving oil recovery by low salinity water flooding is multi-component ionic exchange between rock surface and the invading brine. He claimed that multi-component ionic exchange causes reduction in ionic binding between crude oil and rock surface hence oil is produced easily (Ramez A. Nasralla, Hisham A. Nasr-El-Din, Texas A&M University, SPE members, 2011).

The reason behind recovery increase caused by low salinity water flooding was also suggested by Nasralla and Nasr-El-Din in 2012. They performed experiment to investigate the expansion of electric double layer caused by low salinity water flooding in Barea sandstone cores. They concluded that the increase in recovery by low salinity water flooding is caused by double layer expansion mechanism (Emad W. Alshalabi, Kamy Sepehrnoori, Mojdeh Delshad and Gary Pope, 2014).

In 2015 Sehrabi et al. performed the study of oil recovery mechanism by low salinity water flooding. The investigation was done from pore scale to core scale by advanced flow visualization, fluid characterization and conventional coreflood experiments. The conclusion from the study was that crude oil/brine interaction caused by law salinity effect lead to micro-dispersion formation phenomena which result to high oil recovery (M. Sohrabi, P. Mahzari, S.A. Farzaneh, and J.R. Mills, 2015).

Studies shows that seawater flooding can recover oil up to 50%. However, several experiments performed using sandstone core flooding with water of low salinity managed to improve recovery by 5% - 25 % when water salinity is lower than 5 ppm compared to seawater (Alshakhs, 2018). Figure 2.2 summarize the oil recovery profile for seawater and low water salinity.

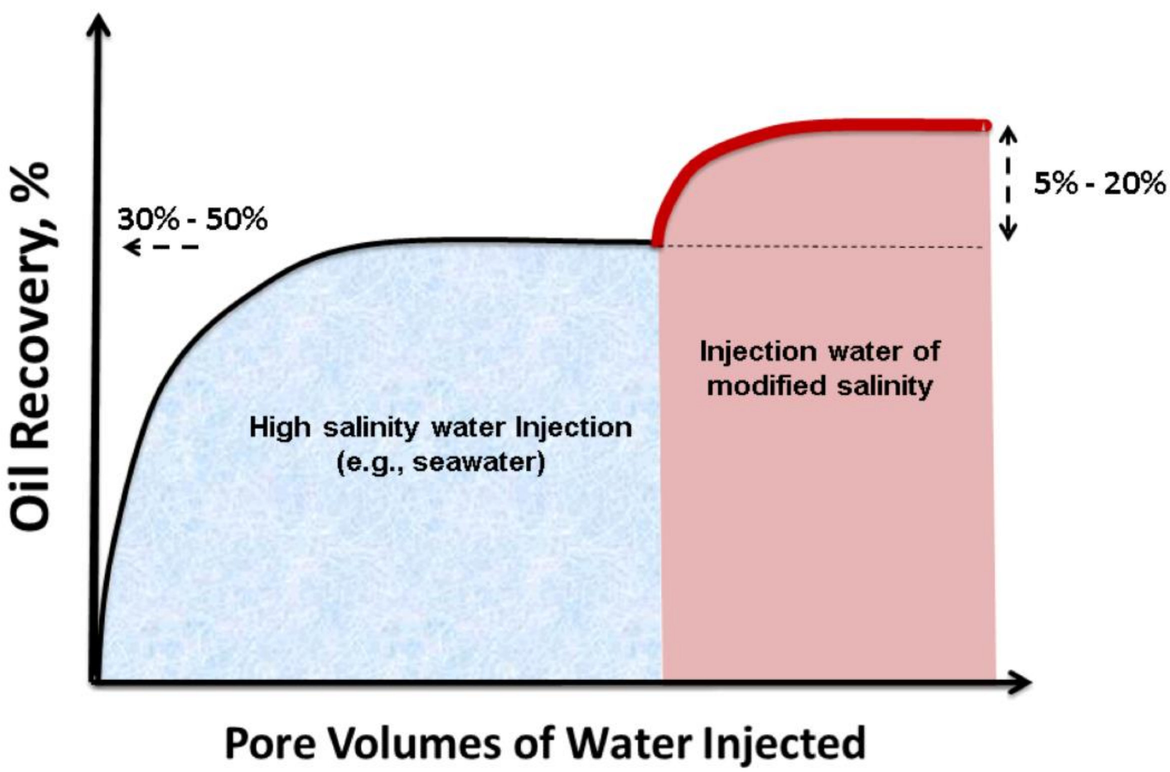


Figure 2.2: Oil recovery for low and high salinity water flooding (Alshakhs, 2018).

2.1.6 Mechanisms behind Low-Salinity water flooding

Proposed mechanisms of oil recovery by low salinity water flooding are summarized in this subsection. Of all mechanism proposed, none of them have been recognized to be the reason for high oil recovery caused by low salinity water flooding. However, many researchers agreed wettability alteration is the strong reason among the proposed. The following are the proposed mechanisms of oil recovery by law salinity water flooding.

- Fine clay migration which result to permeability reduction.

  Clay tends to swell when it come in to contact with low salinity water. The swelling clay become mobile and move with water towards the high permeability paths. The movable clay particles are then lodged to the small pore spaces and reduce the permeability therefore those paths become less permeable. This reduction in permeability will increase the efficiency of oil sweeping by water flooding hence recovery will increase. Figure 2.3 is the representation of this mechanism.

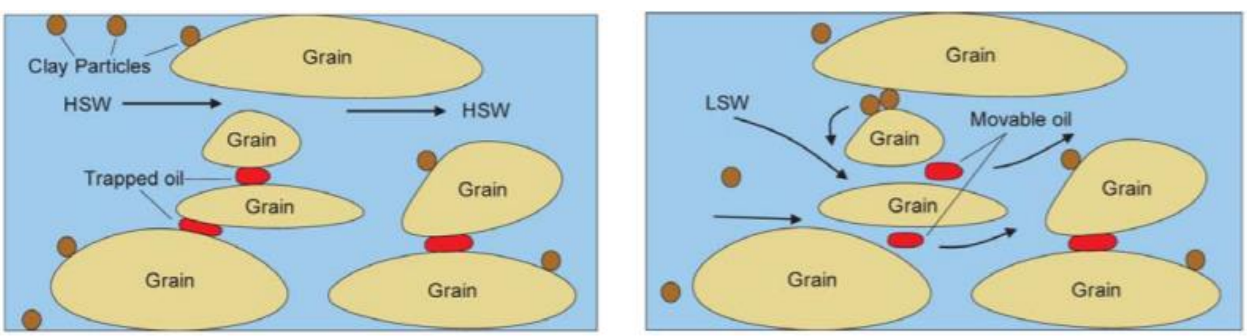


Figure 2.3: Effect of clay particles migration (A. Al-Sarihi, 2018)

- Change of rock wettability.
  Detachment and migration of clay particles from a mixed-wet rock due to low salinity water injection will leave the rock as water wet. A water wet rock will result to more oil recovery upon water flooding than mixed or oil wet rocks. Figure 2.4 is the representation of the wettability change mechanism.

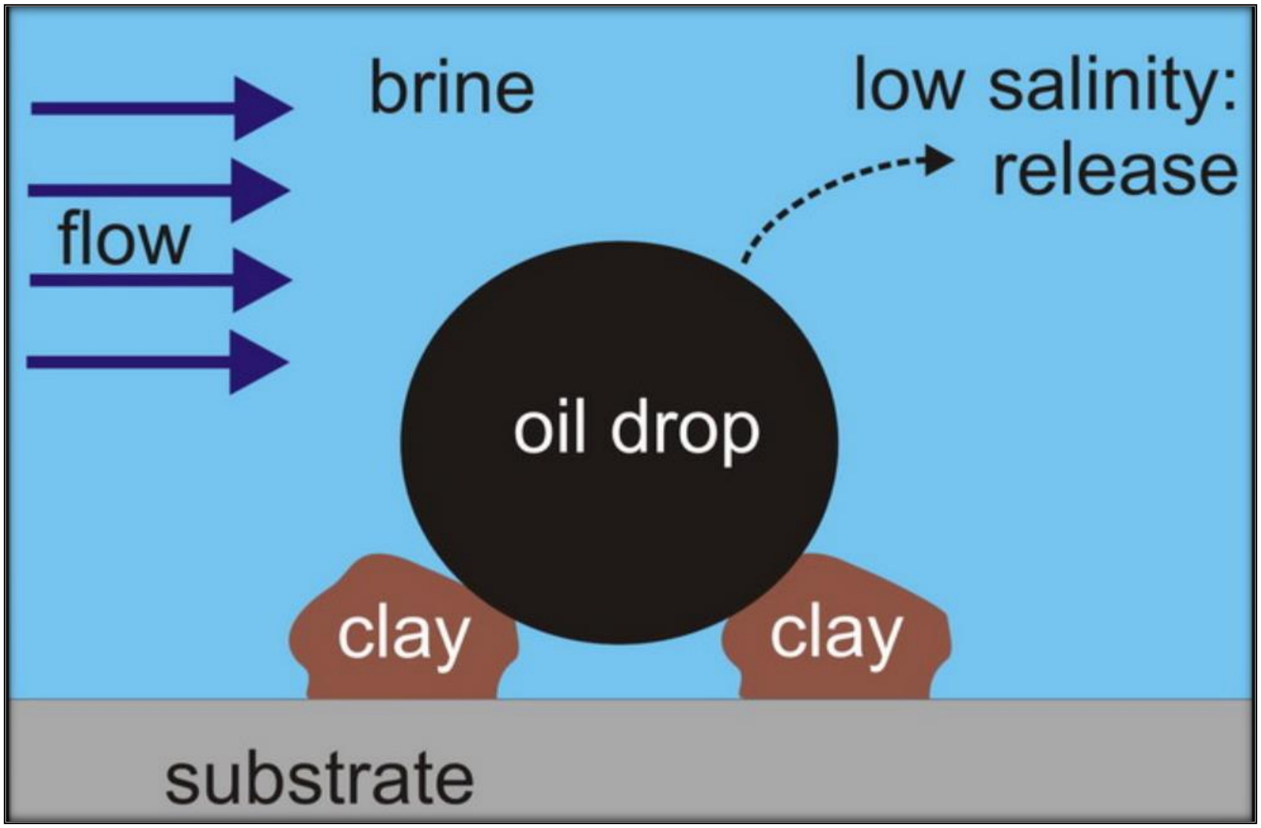


Figure 2.4: Wettability alteration (Bigdeli, 2018)

- pH effect

  Reactions between minerals in the reservoir and the injected low salinity water will result to formation of hydroxyl ions. The generated ion may react with carboxylic acid present in the oil and form surfactant. The formed surfactant will reduce interfacial tension between oil and water which lead to high oil recovery.

- Multicomponent Ionic Exchange (MIE)

  Multivalent cation like Mg^{2+} and Ca^{2+} if present in the injected water usually bonded to a rock surface. Those cations when meet polar component such as resin and asphaltene from oil they can be bonded together and change the wettability of the rock to oil-wet. This will affect the recovery of oil through water flooding. Therefore, law water salinity has advantage because those cations are not present, or they are in small amount. Figure 2.5 is the representation of this mechanism.

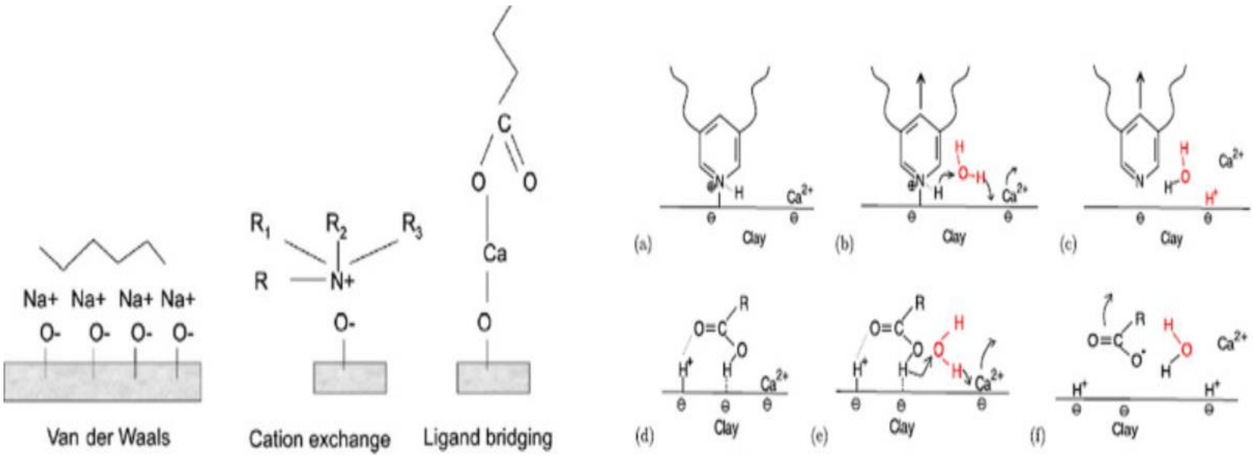


Figure 2.5: Multicomponent ion exchange (Ehsan Pouryousefy, 2016)

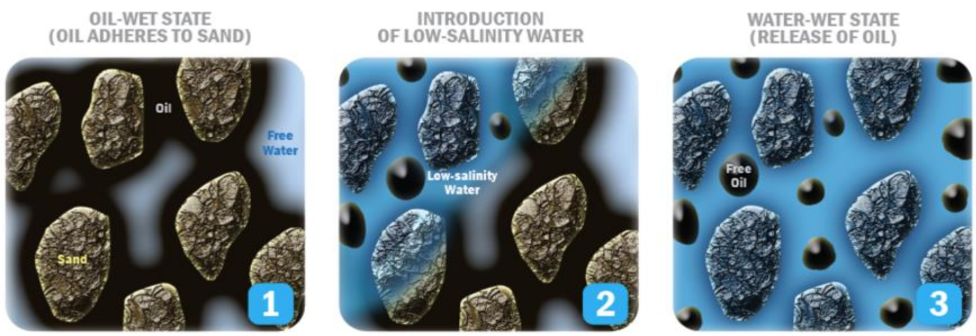


Figure 2.6: Illustration of low-salinity water flooding recovery process (waterstandard.com, 2019)

2.1.7 Low salinity water injection process setup

Depending on the requirement of the client, there are three possible plant setup technologies for the process. Those are thermal process, membrane (reverse osmosis or nanofiltration processes) and combined process. The latter is more efficient, but it can be expensive because it's a combination of the first two process. For this research membrane method is recommended to be used because it's cheaper than the rest.

The process starts with sea water pumped to the plant through pipeline by water intake pumps. Then the pumped water flows to the filtration unit through sealine. In filtration unit seawater is filtered and then the filtrated water is flowing to the main part of the process which is osmotic membrane. In osmotic membrane sea water pass through reverse osmosis process and finally the concentrate salt is removed. Then treated water flows through pipes to water injection pumps where low saline water is finally pumped to water injection wells. The process setup is summarized through block diagram in Figure 2.7.

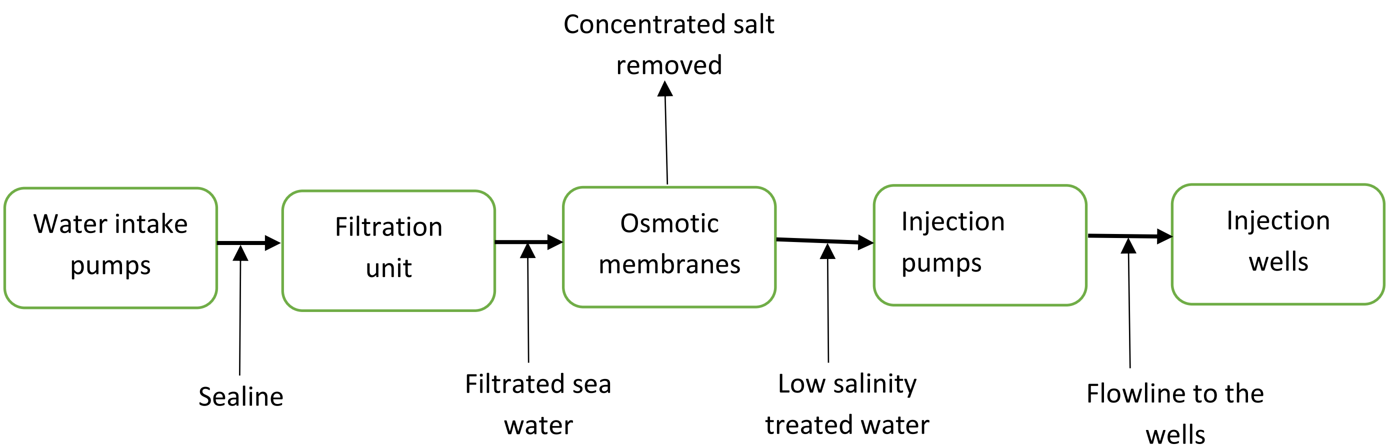


Figure 2.7: Desalination plant setup

2.1.8 Screening criteria

Studies have indicated that low salinity water can recover much oil than high salinity water. Although the exact mechanism on which low salinity water works on improving recovery is not clearly known, researchers proposed different mechanisms as summarized in subsection 2.1.6. Despite different explanation of recovery mechanisms, there are common features on which different mechanisms agreed as summarized below;

- There should be difference between salinity of injected water and in place water.
- There should be clay distributed in the formation
- There should be polar components in oil
- There should be connate water trapped in to the pores of the rock
- There should be divalent cations in the connate water
- The reservoir should be oil wet or mixed wet

2.1.9 Pros and cons of low salinity water injection

2.1.9.1 Pros

- Studies show that the method can improve recovery significantly than other EOR methods
- Relatively cheap compared to other EOR like polymer injection
- Low salinity water flooding is environmentally friendly compared to other EOR methods.

2.1.9.2 Cons

- Extra cost is needed for the processing of low salinity water
- Availability and continuous supply of low salinity water is a challenge
- The mechanism behind low salinity water flooding on improving recovery is still uncertain
- Strong care is needed on controlling the salinity in water injected, injecting too low water salinity may result to damage of formation.

Low salinity water flooding like other recovery mechanism involves big projects which cost a lot of money. To implement any of the recovery technique a deep study must be carried out. Then a model must be prepared and simulated to see prediction of results. Simulation results might not be the same with the actual result when implemented but it gives a clue of what will happen upon implementation. The following section present how the Low-Salinity model is prepared and simulated.

2.1.10 Preparation of models and Simulations.

Model of low salinity water injection is prepared by solving mass conservation equations in each grid block to know salt concentration. Equation 1 represent mass balance equation used for this purpose. In preparing black oil model used for simulation, low salinity key words must be introduced.

$$\frac{d}{dt}\left(\frac{VSwCs}{Bw}\right) = \sum\left[\frac{TKrw}{Bw\ \mu s\ \mathrm{eff}}(\delta Pw - \ \rho wgDz)\right]Cs + QwCs \qquad (1)$$

Where,

ρ_w represent water density

$\sum$ represent the sum of neighboring cells

C_s represent salt concentration in the aqueous phase

μ_{seff} represent effective viscosity of the salt

D_z represent the cell center depth

B_w represent water formation volume

T represent transmissibility

K_{rw} represent water relative permeability

S_w represent water saturation

V is the block pore volume

Q_w is the water production rate

P_w is the water pressure

g is the gravity acceleration

LOWSALT keyword should be introduced first in RUNSPEC section to turn on low salinity option. This will allow the user to modify the saturation and relative permeability end points for water and oil phases as a function of the salt concentration as well as the water-oil capillary pressure. Eclipse use equation 2 for modification of saturation endpoint. The equation can modify the saturation endpoints provided that the two saturations functions are available i.e low and high salinity functions.

$$\begin{aligned}
S_{wco} &= F_1 S_{wco}^{L} + (1 - F_1) S_{wco}^{H} \\
S_{wcr} &= F_1 S_{wcr}^{L} + (1 - F_1) S_{wcr}^{H} \\
S_{wmax} &= F_1 S_{wmax}^{L} + (1 - F_1) S_{wmax}^{H} \\
S_{owcr} &= F_1 S_{owcr}^{L} + (1 - F_1) S_{owcr}^{H}
\end{aligned} \tag{2}$$

Where

F_1 is a function of salt concentration and correspond to the second column of the LSALTFNC keyword.

S_{wco} is connate water saturation.

S_{wcr} is the critical water saturation.

S_{wmax} is the maximum water saturation.

S_{owcr} is the critical oil saturation in water.

Index H and L stands for high and low salinity respectively. Relative permeability end points are modified by equation 3.

$$
\begin{aligned}
k_{rw} &= F_1 k_{rw}^L + (1 - F_1) k_{rw}^H \\
k_{ro} &= F_1 k_{ro}^L + (1 - F_1) k_{ro}^H \\
P_{cow} &= F_2 P_{cow}^L + (1 - F_2) P_{cow}^H
\end{aligned}
\tag{3}
$$

Where

F_2 is a function of salt concentration and corresponds to the third column of the LSALTFNC keyword.

k_{rw} is the water relative permeability.

k_{ro} is the oil relative permeability.

P_{cow} is oil-water capillary pressure.

Another keyword introduced is LSALTFNC which is inserted in PROPS section. It is used to input the weighting factor of low-salinity saturation function as a function of salt concentration.

SATNUM and WSLTNUM keywords are introduced in region section. Those key words are used to define high and low salinity curves respectively. SATNUM is for high salinity saturation function input while WSLTNUM is for low salinity table number to each grid block.

PVTSALT keyword is introduced in PROPS section to replace PVTW. The work of this keyword is to provide water PVT data for the case where brine option is activated. The keyword allows the user to provide formation salt concentration, formation volume factor, water compressibility, water viscosity and water viscosibility.

SALTVD keyword is inserted in SOLUTION section. The keyword supplies table of salt concentration vs depth for each equilibration regions in SCHEDULE section. WSALT keyword allow the user to set the salt concentration of the injected water. It is only used for the case where the brine option is on in RUNSPEC section. It is recommended to specify the value of salt concentration in this case because eclipse will assume zero concentration if not specified. This might have effect because injecting water with zero concentration might damage the formation and affect production.

Preparing and injecting low salinity water in a formation takes time and cost a lot of money. Therefore, one need to be sure of its impacts before deciding to inject. One of the possible assessments before applying is to assess communication in the reservoir to be applied so that to understand the flow paths of the injected fluid. Upon completing the reservoir will be well understood in term of its communication therefore it will be easier to decide where to inject and to produce. The analysis is normally done through tracer injection.

2.1.11 Tracer injection

Tracer is a chemical or other material injected to the reservoir through injection wells and expected to be produced from production wells and provide important information about the formation. Tracer is normally categorized in to two classes i.e passive and active tracers. Passive tracers refer to the type of traces which blindly follows the fluid phase in which it is injected. It is normally used to assess the connectivity in the reservoir through well to well tracer test. Passive tracer to be used in well to well test must have the following properties; have no adsorption to rock materials, have minimal environmental consequences, follows the phase that is being tagged and have minimal partitioning in to other phases, be stable under reservoir condition and have a very low detection limit.

Active tracer usually interacts with other fluid and rock surface in the reservoir to provide information about fluid saturation and rock surface properties. Active tracer injection is expensive to implement therefore it is usually applied when expensive EOR such as surfactant or polymer are to be used in the field.

Tracers are used in oil/gas recovery operations for many purposes. Some of its task are as follows;

Identification of reservoir connectivity; The tracer is injected in one well and observed in producers present in the field. The tracer will be produced from the wells in which there is communication with the injection well. Sometimes connectivity between layers are observed by injecting fluid with tracers in one layer and observe if it is produced in different layer.

To assess volumetric sweeping efficiency; The amount of tracer is injected in a displacing fluid i.e water or gas, then it is assessed on how long it takes to breakthrough. The amount of oil produced until the first fluid with tracer observed is measured. Also amount of tracer is measured and compared with the amount of tracer injected.

Identification of offending injectors; The injected tracer can be used to identify whether there is a problem in injectors or not. For example, if the injected fluid is always not produced in a near producer one possibility is presence of a barrier near the injector and the solution may be to change the position of injector.

2.2 Reservoir Simulation

Reservoir simulation refers to the construction and operation of a model whose behavior assumes the appearance of actual reservoir behavior (Petrowiki, 2018). The aim of reservoir simulation in petroleum engineering is to estimate reservoir performance for example changing of recovery after drilling new wells. Reservoir simulation is divided to simple and simplified black oil models to more complex compositional models.

The assumptions in black oil model are hydrocarbon in the reservoir is formed up by two components i.e oil and gas and hydrocarbon fluid composition remain constant during simulation. The mass transfer between those two components is normally described by solution gas-oil ratio (Rs). In black oil model fluid properties is determined by oil pressure and bubble point pressure.

In composition model all components i.e methane, ethane, propane, butane etc in oil or gas are considered. In this model fluid properties are affected by fluid composition as well as pressure. Composition of component in a phase is determined by equilibrium flash calculation using K values and equation of state (EOS).

Both black oil and compositional models can be used in reservoir simulation to predict reservoir performance for several years. One of the important information from simulation is oil and gas recovery. Those recovery data can be used as input in performing economic analysis to decide on whether to continue with the project or not.

2.3 Economic Assessment

Economic assessment of a project is a measure of its net benefits in monetary terms (Boadway, 2015). The assessment can be done by calculating payback period, Internal Rate of Return (IRR) and Net Presence Value (NPV). Among those, NPV is mostly used in project evaluation therefore this project will also use NPV in economic analysis.

2.3.1 NPV

NPV is the difference between the presence value of cash inflows and the presence value of cash outflows over a certain period (Investopedia, 2018). It is used in capital budgeting to do analysis before making decision to invest. Equation 4 shows how NPV is calculated for any project. A positive NPV means the project generate more money than the cost used, therefore the company will get profit. Negative NPV means cost used for the project is higher than money generated, therefore the company will get loss.

$$\boldsymbol{NPV = \sum_{t=1}^{T} \frac{Ct}{(1+r)^t} - Co} \qquad (4)$$

Where,

Ct = Net cash inflow for time

Co = total cost incurred

R = discount rate

t = time

In NPV calculation, cost used for investment is approximated by using market price at that time. Cash inflow consist of revenue the company will get after selling oil for a market price. Cost and price are not fixed, they may vary with time depending on the market. In this case a certain range of price and cost must be presented on which the project will be profitable i.e NPV will be positive. That can be achieved by selecting important parameters in NPV calculation and perform sensitivity analysis.

2.4 Sensitivity Analysis

Sensitivity analysis is the study of the process to rank the inputs to a model based on their impact on a given output (Petrowiki, 2018). It is normally used to predict the outcome of a decision based on a range of input variables. The analysis is done by changing the inputs and observe how those changes affect the outputs. The analysis can be carried out by creating a plot consist of inputs and output in xyz direction. The plot is simply known as spider diagram. The analysis can also be done in a Tornado chart.

2.4.1 Spider diagram

Spider diagram is a graph that represent a percent changes in an output of a model caused by changes of various inputs. Each input has its own line which resemble spider leg and cause the diagram to have spider shape. The example of the spider diagram is depicted in Figure 2.8.

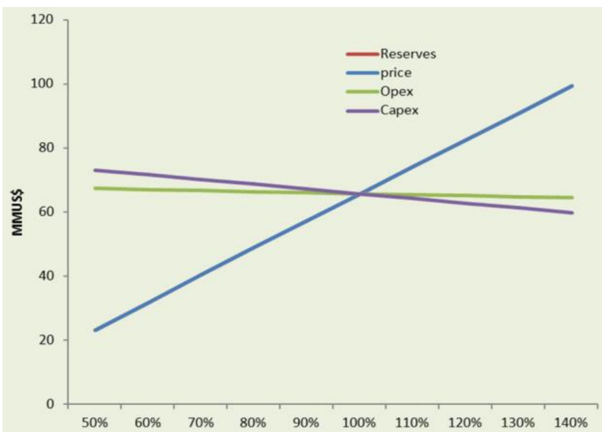


Figure 2.8 : Example of spider diagram used for sensitivity analysis (wordpress, 2018).

2.4.2 Tornado chart

Tornado chart is a special type of bar chart where the inputs data are in vertical axis. The bars in tornado diagram are arranged form the largest bar at the top to the smallest at the bottom. It is used for sensitivity analysis to compare the relative importance of inputs to the output. On changing the input, the plot presents the high, base and low outcomes. The example of the tornado diagram is depicted in Figure 2.9.

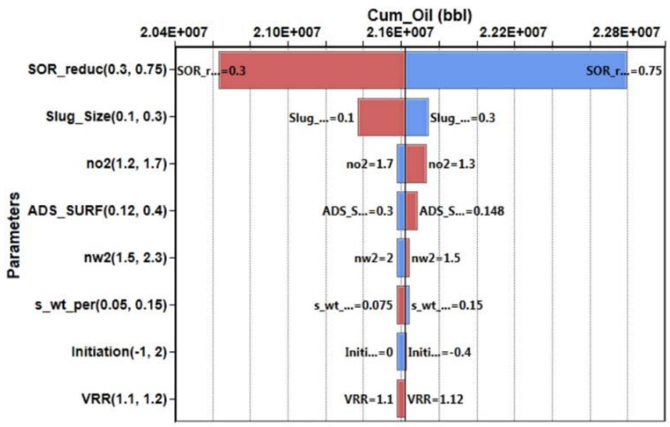


Figure 2.9 : Example of tornado chart used for sensitivity analysis (Das, 2018).

CHAPTER THREE

3 SIMULATION WORK AND PRESENTATION OF RESULT

This chapter is the most important part of this report as it involves the main task performed to achieve the objective of the research. The first subsection involves introduction of the model used and its brief description on how it works. The other task such as low salinity screening, tracer injection, simulation of selected cases, economic and sensitivity analysis are followed. In each task performed the result are presented and interpreted.

3.1 Reservoir Model and Simulation

Figure 3.1.1 represent K1/K2 grid model as presented in eclipse. The Figure shows all wells i.e producers and injectors drilled from 1990. It also shows oil saturation for all 17 layers.

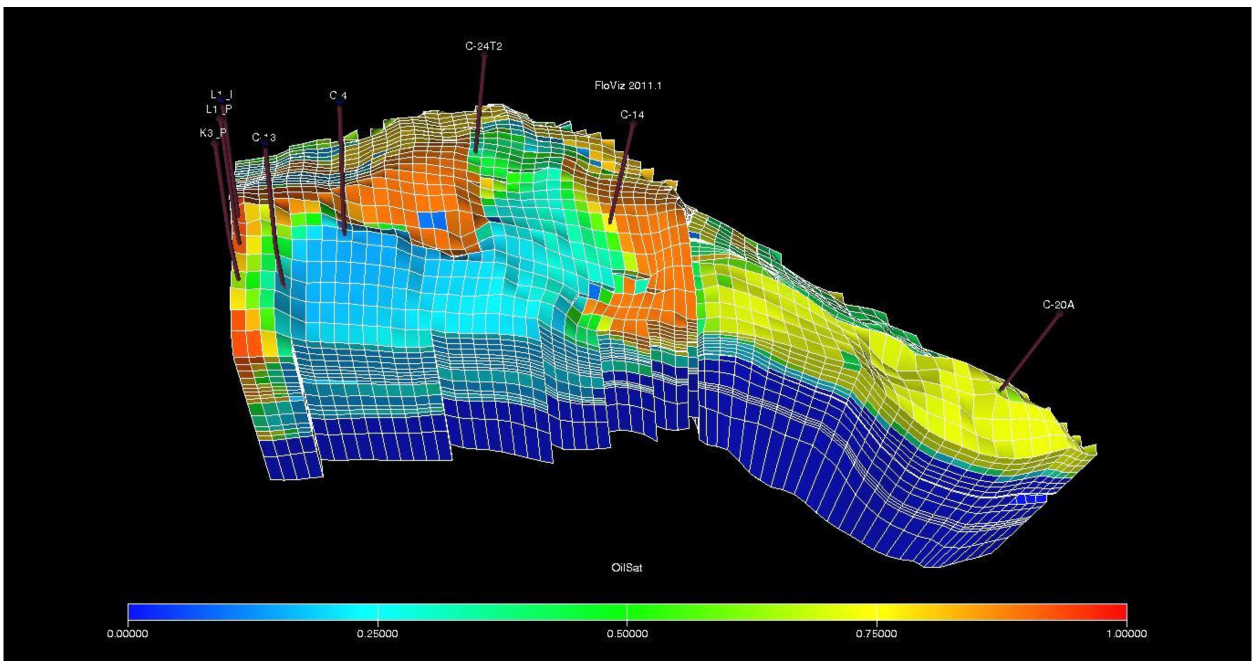


Figure 3.1.1: K1/K2 grid model as represented in eclipse

3.1.1 Model description

To perform reservoir simulation, a reservoir model must be prepared first. As stated, this research focus on K1/K2 segment in Statfjord formation therefore the K1/K2 basecase model will be explained in this part. From Figure 3.1.1, the Eastern part where well C-20A located is K1 and the Western part where the remaining wells located is referred as K2 segment. The two combined segments form K1/K2 segment.

The K1/K2 basecase model is a history matched black oil PVT model created in 2002. The model is extended to run until 2025 for comparison with improved cases. Simulator used to run the model is eclipse 100 (2011 version). Since it takes long time to run the model from 1990 to 2025, a restart file was created so that the model run from 2002 to 2025.

The model has a total of 57375 grids arranged in 17 layers. The top layer is only shale, the remaining 16 layers are sandstone formation. It has 8 wells of which 5 are producers and 3 injectors. Producer wells are C-20A, C-24T2, L1_P, K3_P, C-14 and injector wells are C-4, L1-I and C-13 as seen in Figure 3.1.1. Injection fluid used is water. Reservoir properties for K1/K2 are summarized clearly in Table 3.1.1 as presented in SPE 113260 (Saifullah Talukdar, Rune Instefjord, 2008).

Table 3.1.1: K1/K2 reservoir properties

Property	Quantity		Unit
Segment	K1	K2	
Permeability	0.2-2	0.2-5	Darcy
Porosity	0.27	0.27	fraction
OWC	2043	2043	m MSL
Maximum formation water salt concentration	49000	49000	ppm
OOIP	2.6	14	M Sm^3

The basecase model is then modified to Low Salinity mode that run to 2025. Changes were made by introducing low salinity simulation keywords such as LOWSALT in RUNSPEC section, LSALTFNC in PROPS section and other keywords as explained in Reservoir modelling of low salinity water injection. Basecase and low salinity water injection basecase models were then simulated in eclipse 100 (2011 version) and the result were compared.

3.2 Low Salinity Screening Criteria

This part will focus on assessing screening criteria in K1/K2 segment as presented in subsection 2.1.7 to confirm if it is suitable for implementing low salinity water injection. A brief explanation of how those conditions mentioned fits K1/K2 segment will be presented.

The salinity difference is the first condition to confirm before injection process starts. Salinity of formation water need to be well known so that injected water salinity to be low than formation value. Table 3.1.1 which provide the formation properties indicate the maximum salt concentration in the formation water is 49000 ppm, therefore the expected injection values should be far less than that. Another screening condition is polar component in oil.

Polar component in oil plays a big role in low salinity water flooding mechanism as proposed in multicomponent ionic exchange mechanism in subsection 2.1.6. The mechanism involves the reaction of multivalent cation such as calcium from injected water with polar component from oil which result to change of rock wettability.

Oil produced from K1/K2 consist of polar component such as resins and asphaltenes. Therefore, it is possible for multicomponent ion exchange mechanism to occur upon low salinity water injection in K1/K2 segment. Another condition is to have connate water trapped in to the pores of the rock.

All mechanisms indicated in subsection 2.1.6 depends on the different in salinity between injected and connate water. Therefore, there should be connate water trapped in the pores of the rock for those mechanisms to work. K1/K2 meet this condition as can be seen in Figure 3.2.1 which represent water saturation in different part of the rock for different years. It can be observed that some water remains unproduced, trapped in the rocks.

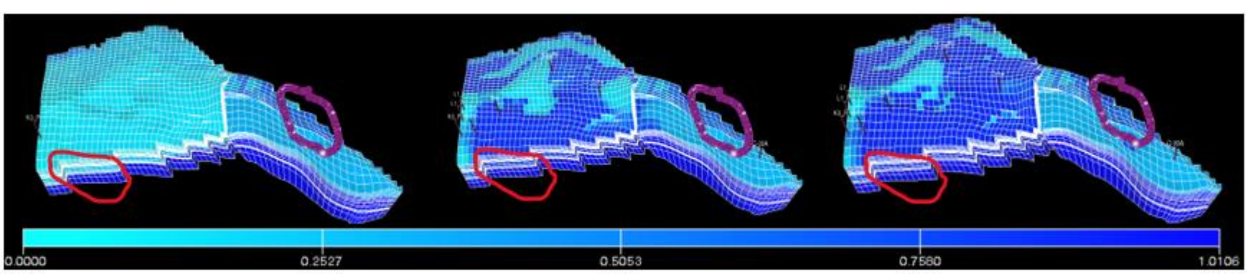


Figure 3.2.1: Water saturation for 1990, 2005 and 2025 respectively

Another condition is to have divalent cations in the connate water. From subsection 2.1.6, mechanism 4 explain multivalent ionic exchange (MIE). From the mechanism, the requirements are polar components from oil and divalent cations from water. Another condition is presence of clay distributed in the formation.

Presence of clay mineral in the reservoir is considered as one of the key reasons for low salinity water injection to have impact. Clay effect in recovery mechanism is explained briefly in subsection 2.1.6. Studies shows the mechanism does depend on a type of clay presence, Tang, Morrow and Larger proposed that Kaolinite presence in a formation is preferable for low salinity water injection to work (M. Rotondi, C. Callegaro, F. Masserano, and M. Bartosek, eni S.p.A, 2014).

There is an indication of presence of clay mineral in K1/K2 segment. The petrophysical analysis to assess the formation is done by generating log-plots of wells C-14, C-20A and C-24 by using Techlog. Well C-20A is in K1 while C-14 and C-24 are in K2 as indicated from the Structural map of Statfjord formation in Figure 3.2.2. Full log-plots for three wells were produced from Techlog and interested parts are represented in Figures 3.2.3 through 3.2.5 for discussions. From the Figures at some intervals gamma ray reads high which is the strong indication of presence of shale and clay. Presence of shale is also the indication of clay because it is formed from clay and other minerals. To quantify the amount of shale presence at some part of the log sections, approximation calculations of Vshale is performed.

From the formula,

$$Vsh = \frac{GRlog - GRmin}{GRmax - GRmin}$$

For well C-20A, Vshale $= \frac{120-90}{135-90}$ x 100% = 67%

C-24, Vshale $= \frac{135-80}{140-80}$ x100% = 75%

C-14, Vshale $= \frac{105-80}{125-80}$ x100% = 56%

The method used to calculate shale volume has many uncertainties. Among them are non-shaly radioactive formations and non-linear relationship between Vshale and GR reading. Those uncertainties may sometimes lead to the wrong Vshale value, that is why there is a need to use another method for comparison.

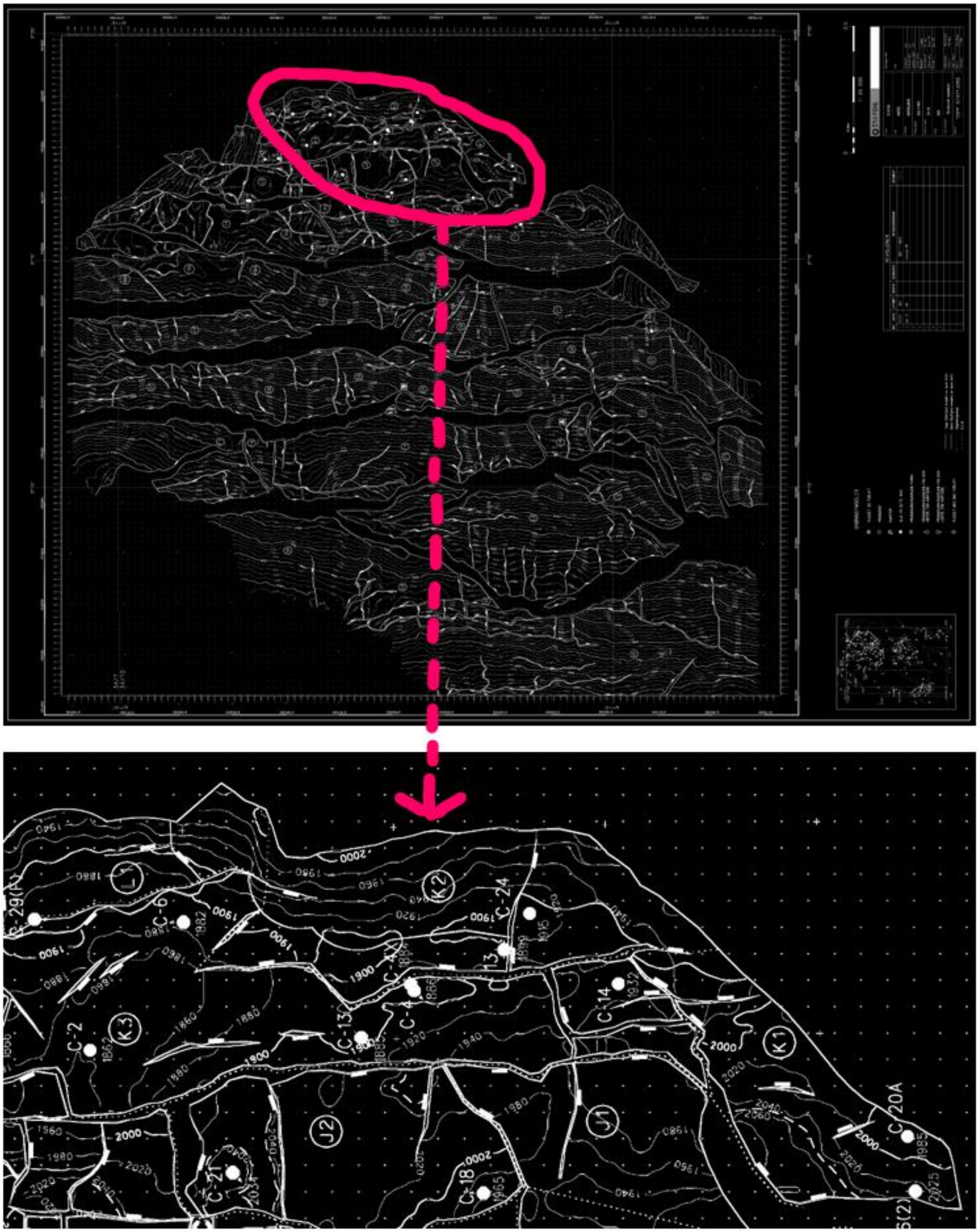


Figure 3.2.2: Structural map of Statfjord formation showing K1/K2 segment

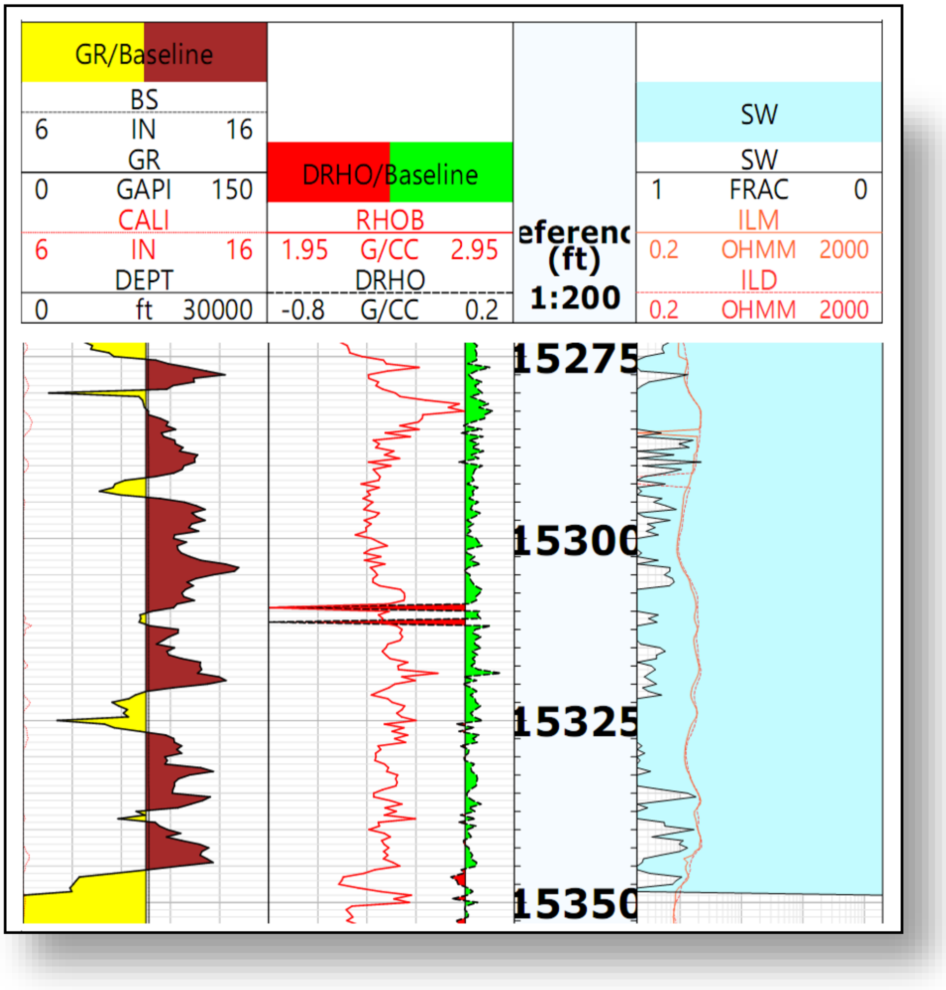


Figure 3.2.3: Log plot section for well C-20A

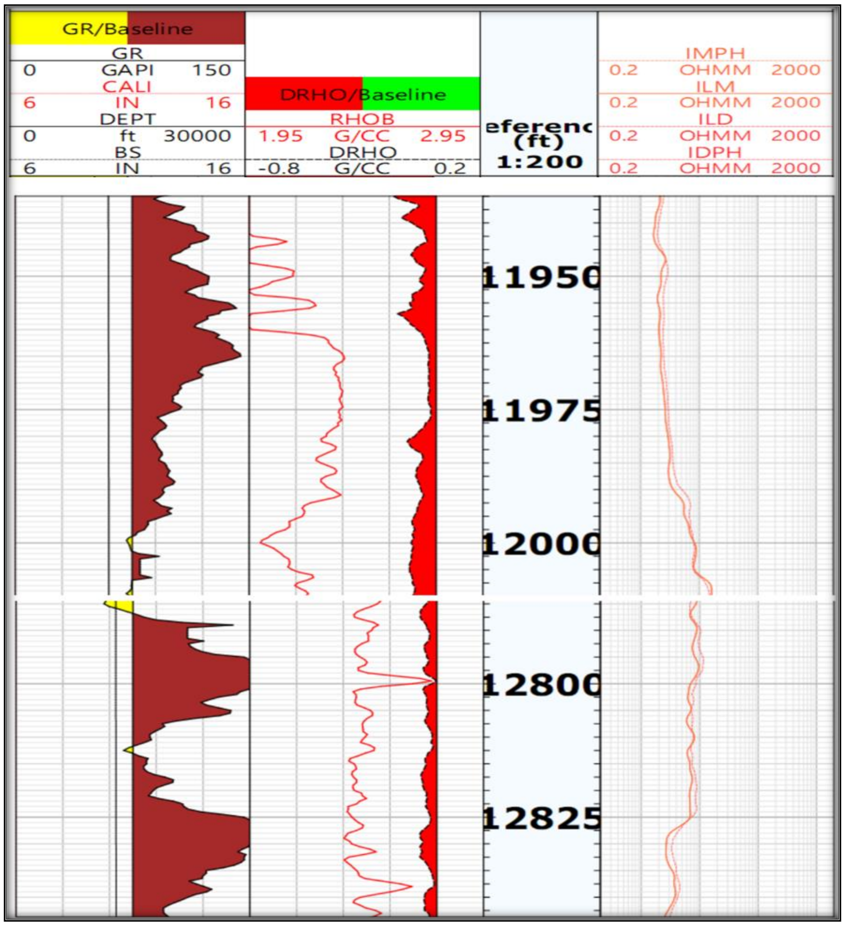


Figure 3.2.4: Log plot section for well C-24

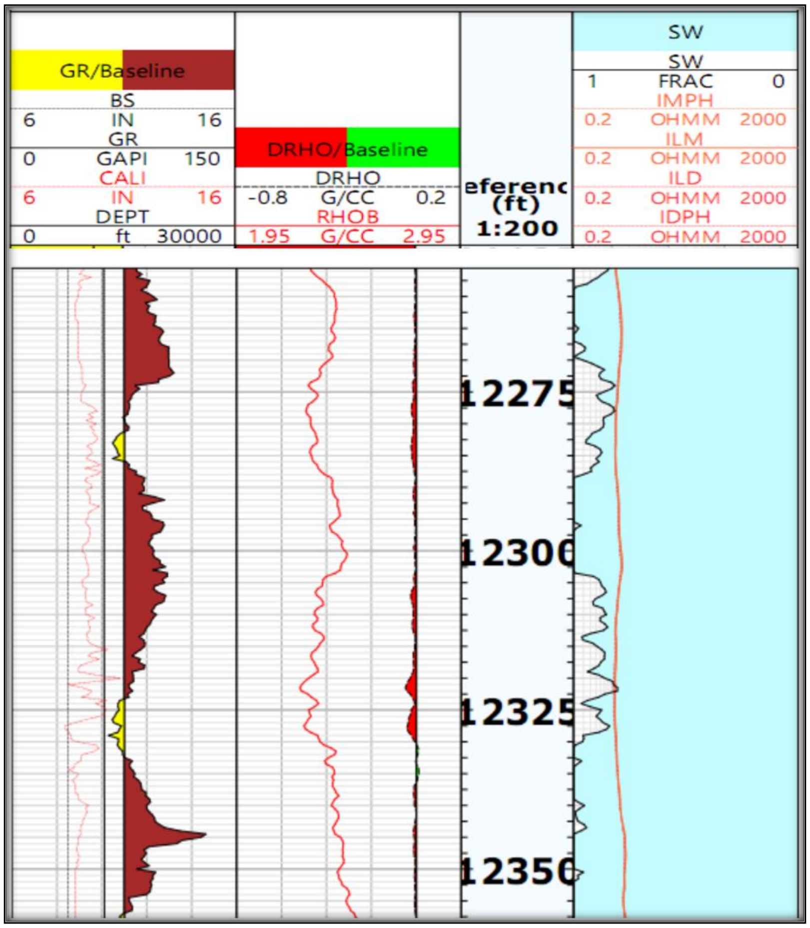


Figure 3.2.5: Log plot section for well C-14

Despite having all those screening criteria for low salinity water flooding, it is almost impossible to confirm whether low salinity will be successful in a field without performing core flood experiment and simulation. However, it is possible to rank the fields for different screening criteria so that to make decision on whether core flood experiment should be done to confirm the suitability of low salinity water flooding in a field. This research will only focus on simulation part to implement the method in the field of K1/K2 segment.

3.3 Tracer Injection

3.3.1 Tracer test result

The aim of tracer injection in K1/K2 Segment is to assess communications between wells so that to identify if there are flow barriers or thief zones which could affect low salinity water injection in the field. Water tracer has been selected for this purpose as it is cheap and simple type of tracer to implement especially for reservoir connectivity task.

In preparing the model, Tracers injected were given the names as TR1, TR2, TR3, TR4, and TR5. TR1, TR2 and TR3 were injected in the existing injectors C-4, C-13 and L1_I respectively. TR4 and TR5 were injected in two new injectors i.e C_15 and C_16 implemented for further analysis of reservoir connectivity. The position and perforation grids of those two injectors were varied for different cases to cover a better analysis. New production well C_17 was used in different locations for this study. Figure 3.3.1 represent a grid system of one of the cases implemented for well to well tracer analysis for K1/K2 segment. All wells can be seen clearly, all new wells i.e C_15, C_16 and C_17 were drilled in 2005.

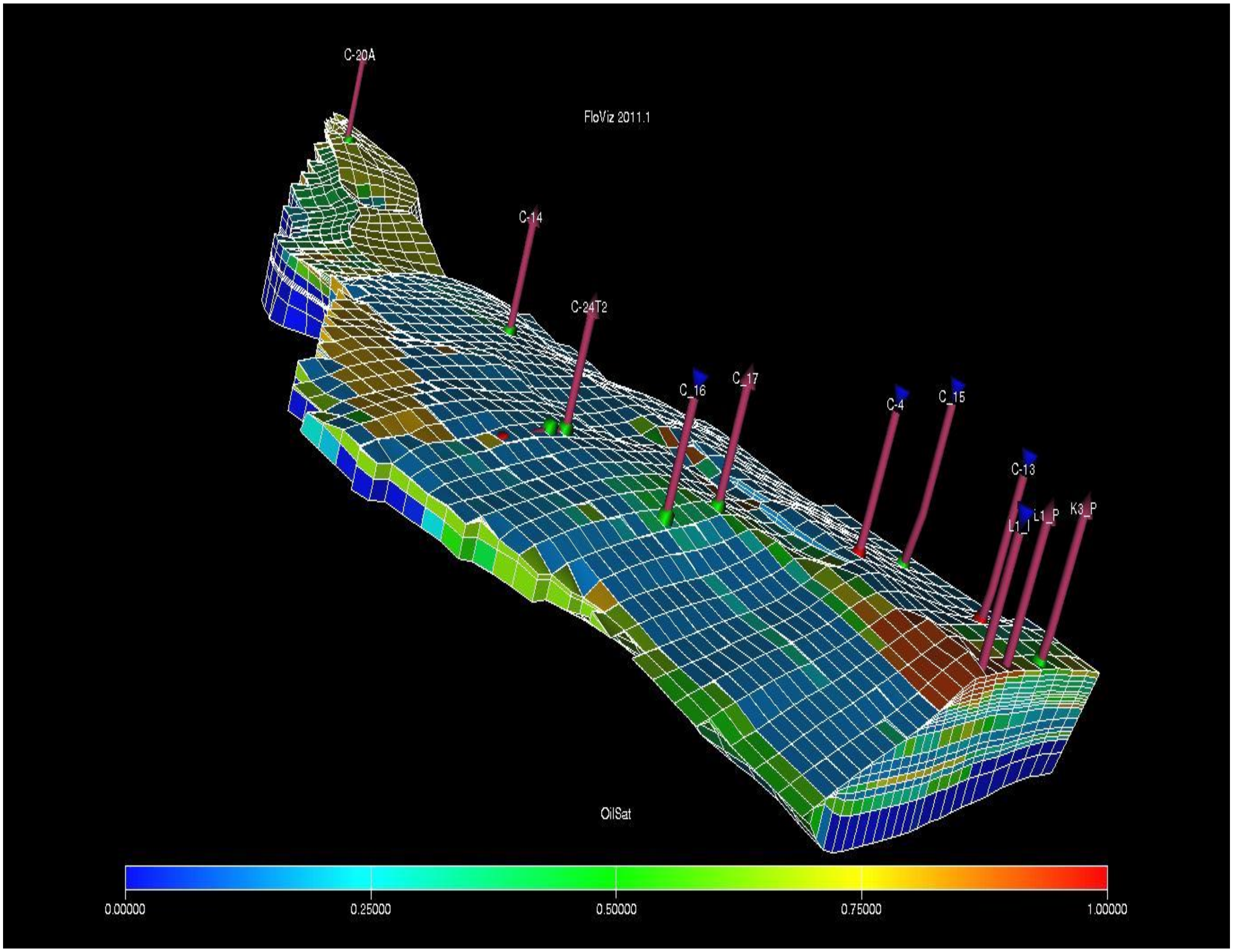


Figure 3.3.1: K1/K2 production and injection wells

TR1 injected in C-4 from the start of injection process in 1991. It is produced in production wells C_17, L1_P, K3_P, C-24T2 and C-14. The only production wells which TR1 is not observed is C-20A located in K1 part of the field. This is the first indication that there are communications within K2 but there is no communication between K1 and K2. To confirm this observation further analysis of other tracers injected in different wells are conducted. Table 1 shows Tracers and wells on which they are injected and produced.

Table 3.3.1: Tracer injection and production wells

S/N	Tracer name	Well injected	Well produced
1	TR1	C-4	C_17, L1_P, K3_P, C-24T2, C-14
2	TR2	C-13	C_17, L1_P, K3_P, C-24T2, C-14
3	TR3	L1_I	C_17, K3_P, L1_P
4	TR4	C_15	C_17, K3_P, L1_P
5	TR5	C_16	C_17

From Table 3.3.1 it can be observed that no tracer produced from well C-20A. This is a strong indication of lack of communication between K1 and K2 because C-20A is in K1 while all five injectors are in K2. TR1 and TR2 injected from C-4 and C-13 respectively are produced from all production wells except C-20A. This is the indication that the two wells have communication with other wells, so they are the best when it comes to use them for waterflooding or other fluid injection.

L1_I and C_15 have limited communication with other wells. TR3 and TR4 injected from those wells are only produced from three wells as indicated in Table 3.3.1. C_16 only communicate with C_17 as shown from the table TR5 injected from C_16 is only produced from C_17.

Not all amount of tracers injected will be produced. Some amount will be lost in the reservoir. There might be many reasons for the tracer lost but one of them is the indication of the presence of thief zones. Figure 3.3.1 through 3.3.6 represent the curves of tracers injected against tracer produced.

From the Figures it can be observed that in all cases not all tracers injected are produced. TR2 and TR5 are the two tracers in which most of the injected amount is produced. This is the indication that there are few or no thief zones between the injected region and the production area. Small amount of TR1, TR3 and TR4 are produced compared to the amount injected as seen in Figures 3.3.2, 3.3.4 and 3.3.5. This is not a good indication especially if injection process of expensive fluid such as polymer, surfactant and low salinity water must be applied. This is because tracer injection in those areas indicate that there might be thief zones which will cause loss of fluid in the process.

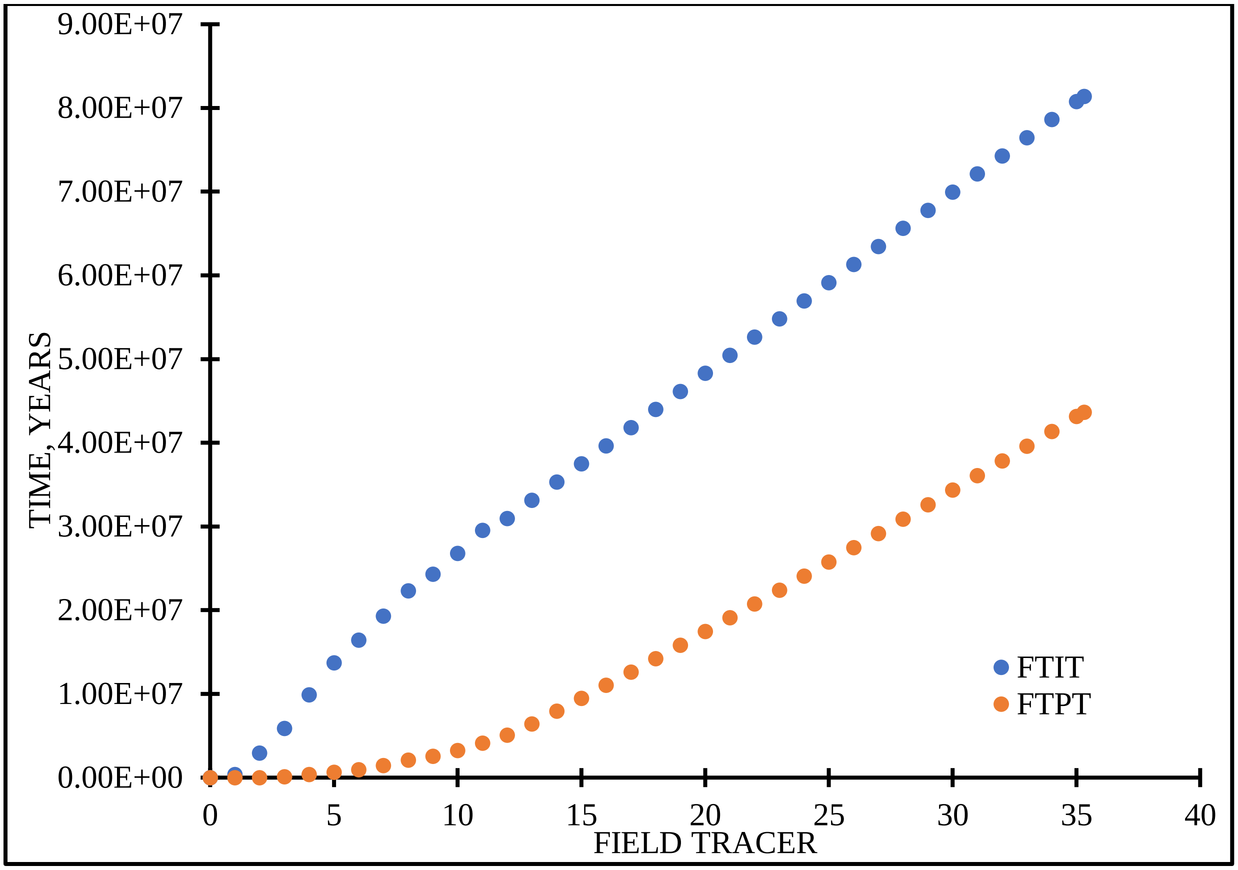


Figure 3.3.2: Time, years vs Field tracer, TR1 injected and produced

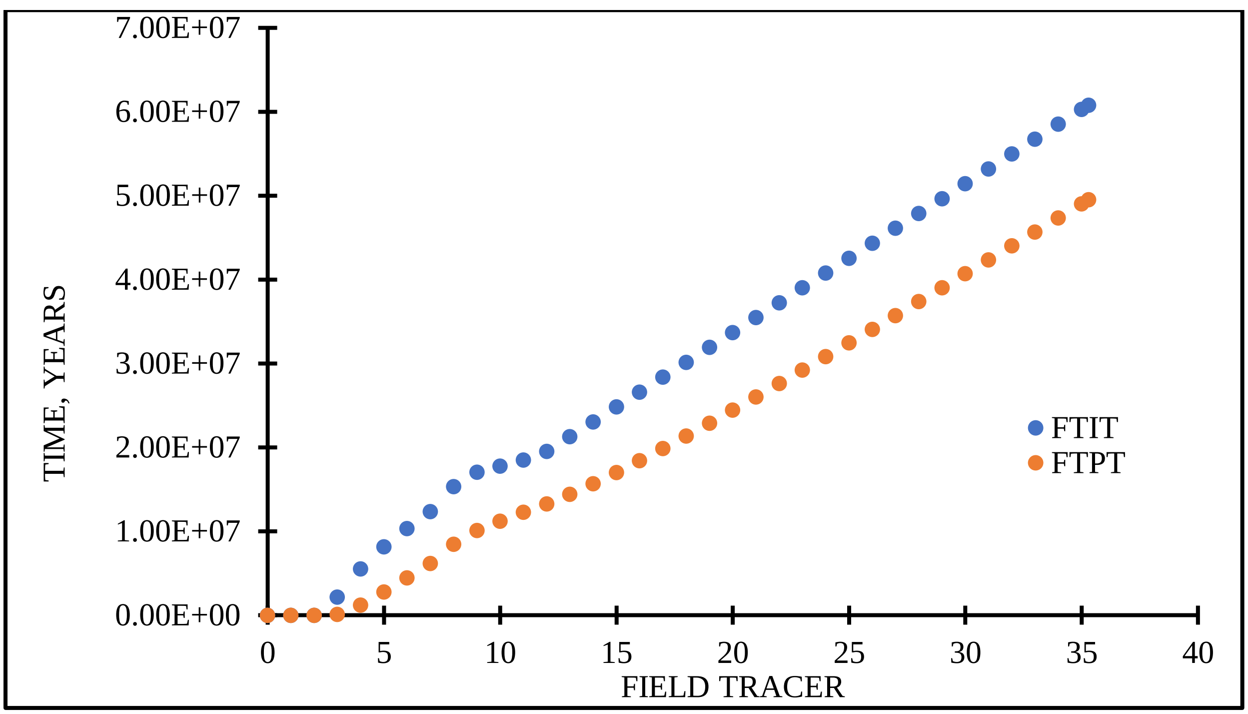


Figure 3.3.3: Time, years vs Field tracer, TR2 injected and produced

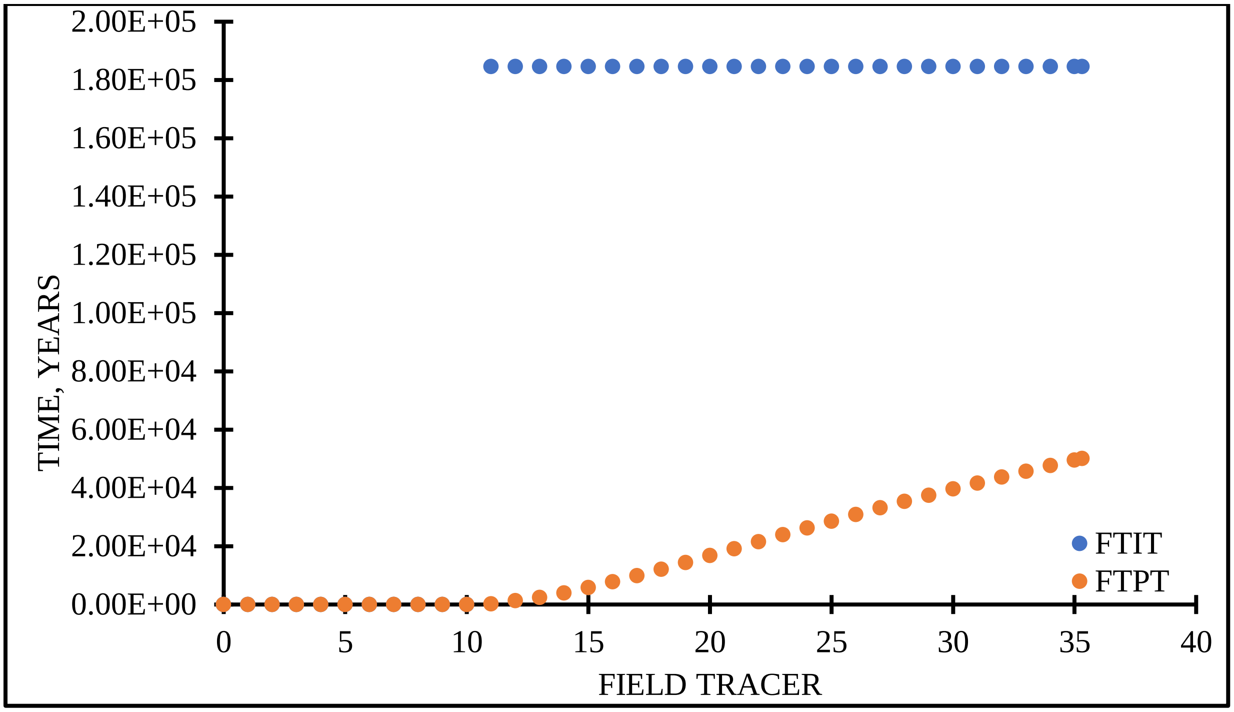


Figure 3.3.4: Time, years vs Field tracer, TR3 injected and produced

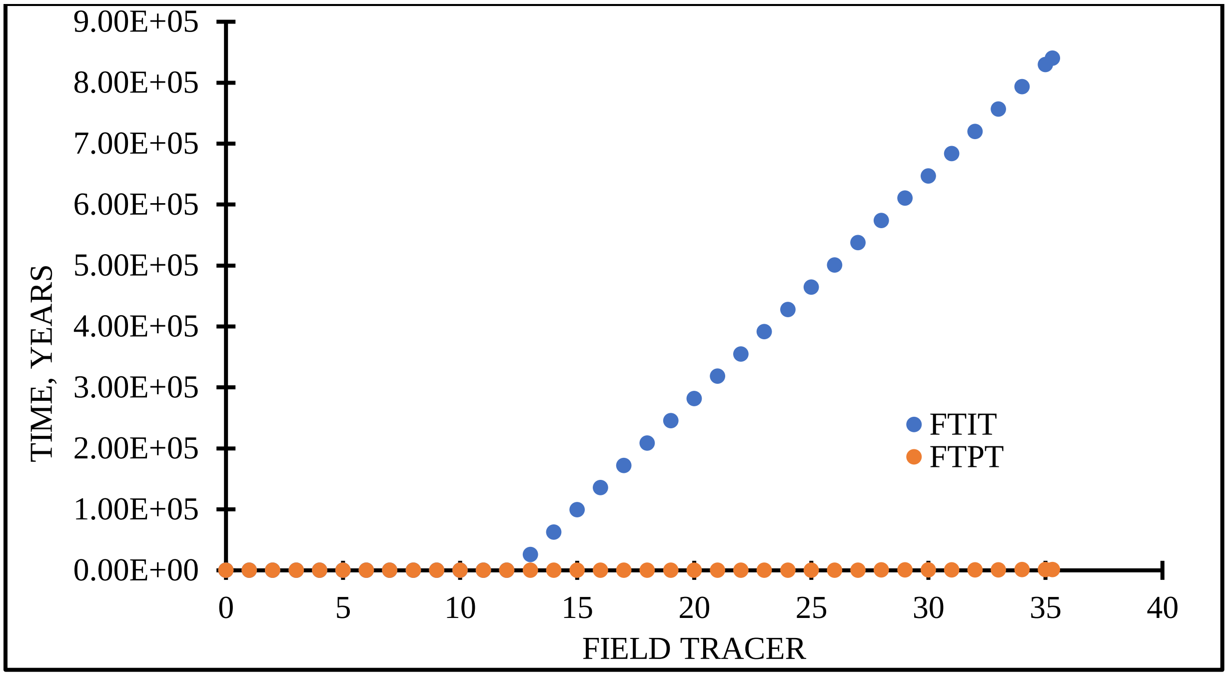


Figure 3.3.5: Time, years vs Field tracer, TR4 injected and produced

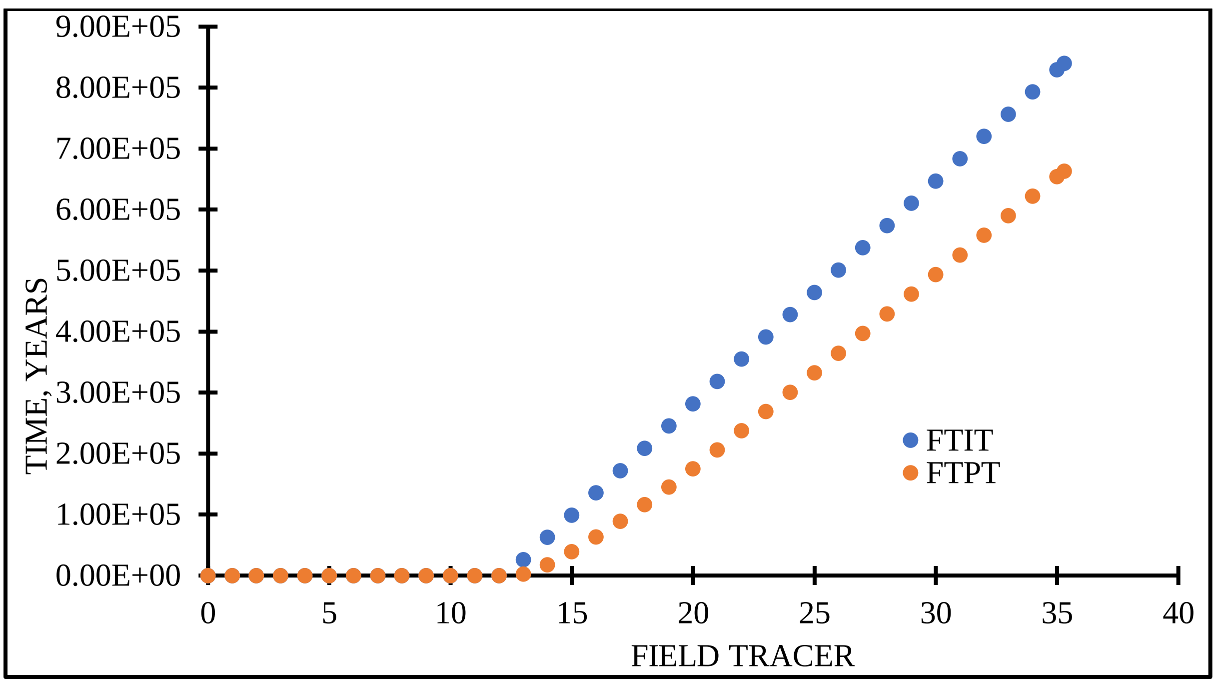


Figure 3.3.6: Time, years vs Field tracer, TR5 injected and produced

3.3.2 Communication between layers

Communication between layers was analyzed by injecting tracer in one layer and observed if it is produced from a different layer. C_16 as injector and C_17 as producer were used for this purpose. The analysis involved all 17 layers in four different positions. The result of the analysis is summarized in table 3.3.2.

Table 3.3.2: Communication between layers

S/N	Layer number	Position 1 Producer 10 16 Injector 10 20	Position 2 Producer 20 19 Injector 24 19	Position 3 Producer 13 27 Injector 16 27	Position 4 Producer 21 29 Injector 24 29
1	2				
2	3				
3	4				
4	5				
5	6				
6	7				
7	8				
8	9				
9	10				
10	10				
11	11				
12	11				
13	12				
14	13				
15	13				
16	14				
16	15				
16	16				
16	16				
16	17				

Key

Communication

No communication

From Table 3.3.2, it can be observed that some layers in the segment communicate with each other while others do not communicate at all. In position 1 and 2, good communication is observed between layer 2 to 10, 11 to 13 and 16 to 17. This is different to position 3 and 4 where there is no communication between layers from 2 to 11. Position 3 have very limited communication between layers where by only layer 11 to 13 communicate. The difference between position 3 and 4 is that in position 4 there is communication between layers 16 to 17. From all 4-position analyzed, one common observation is that there is communication between layers 11 to 13, also there is no communications between layers 10 to 11 and 13 to 15.

3.4 Basecase Simulation Result

The aim of simulating basecase is to understand the reservoir performance before and after performing modifications. Some of the important properties studied for basecase and low salinity basecase are oil saturation, pressure and permeability. Also, production profiles such as oil production rate, cumulative oil production and Gas Oil Ratio (GOR) have been studied. The result for the mentioned properties for basecase and low salinity basecase are presented and compared as follows starting with basecase before compared with low salinity water injection case;

3.4.1 Oil saturation

Oil saturation was higher (0.78-0.93) from layer 2 to 15 in 1990 before production started in K2 section. In K1 Oil saturation was approximately 0.72 from layer 2 to layer 6. The top layer i.e layer 1 is shale and the bottom layers are mostly occupied by water. Oil saturation decreased due to oil production up to 2002 as seen in Figure 3.4.1, but there are still areas with higher oil saturation. The saturation profile in 2025 shows there is still oil left especially in top layers of K1 section.

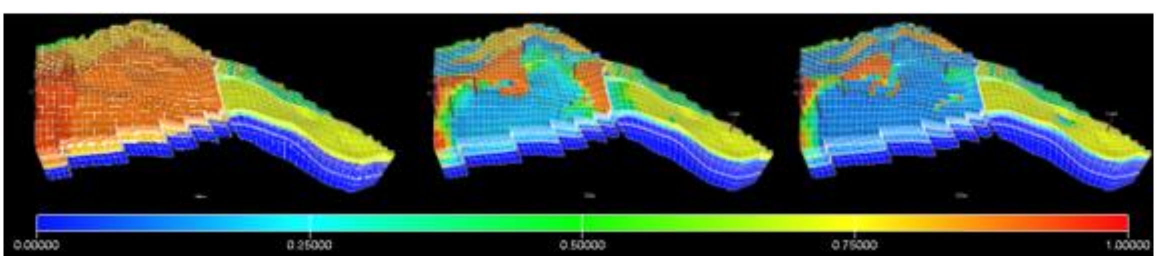


Figure 3.4.1: Oil saturations in 1990, 2002 and 2025 respectively for basecase.

3.4.2 Reservoir pressure

Reservoir pressure in 1990 was between (300 – 350) barsa, oil production was enhanced by water injection to maintain pressure. It can be observed in Figures 3.4.2 and 3.4.3 that, despite the field produced for 12 years large part of K2 still have higher pressure while K1 have low pressure. This is because all three injectors which maintain reservoir pressure are in K2 part. There is only one well located in K1 which is producer well and play part in decreasing of pressure at that part while producing.

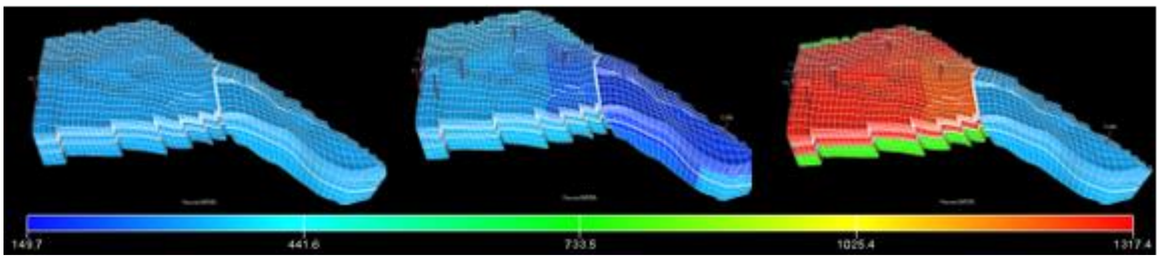


Figure 3.4.2: Reservoir pressure in 1990, 2002 and 2025 respectively for basecase.

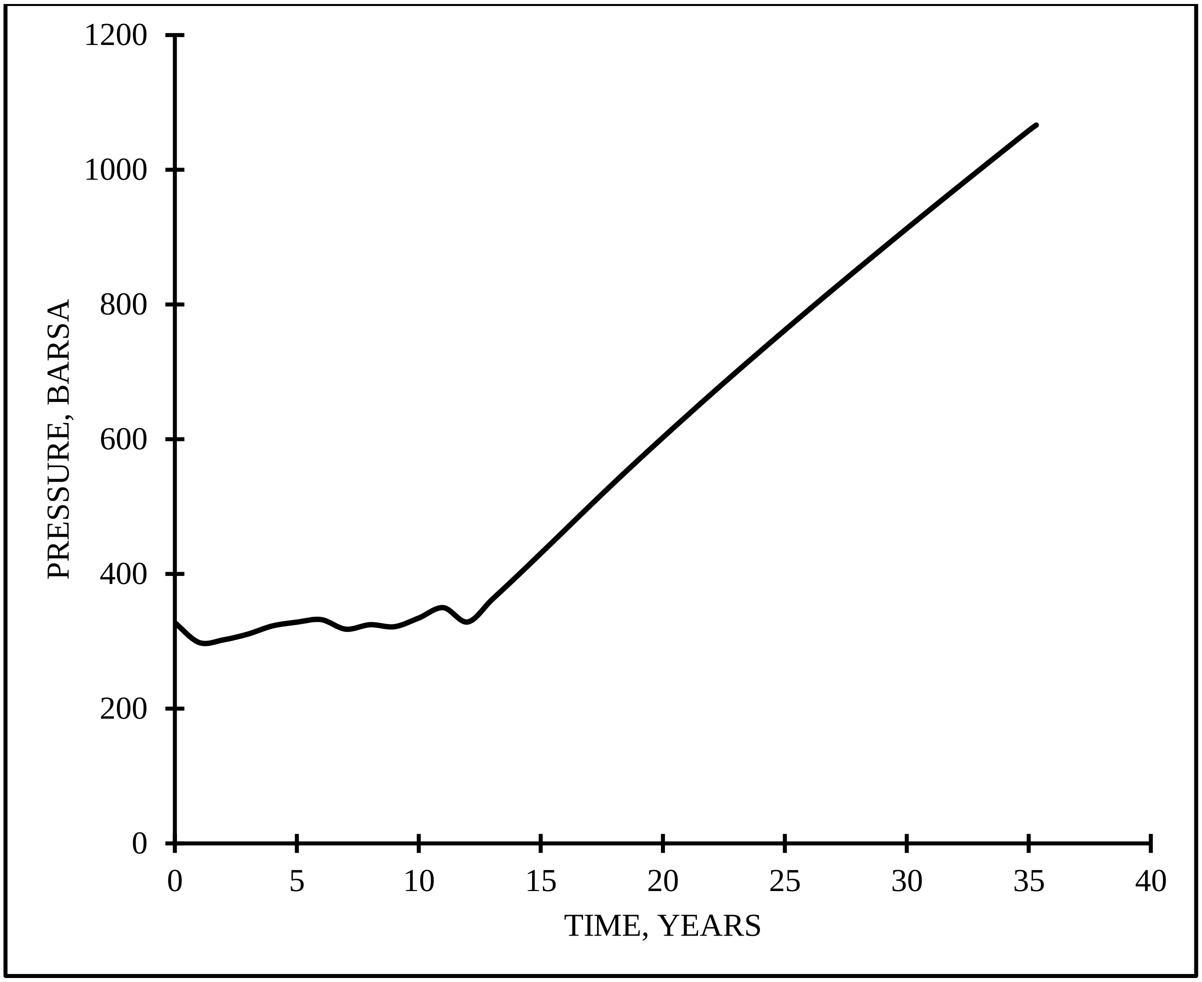


Figure 3.4.3: Reservoir pressure profile

3.4.3 Permeability

There are variations of permeability in the reservoir ranging from low permeability of less than 30 MD to higher permeability of more than 6757 MD. Layers 16 and 17 have relatively low permeability compared to the top layers. Permeability in X, Y, Z looks approximately similar as seen in Figure 3.4.4.

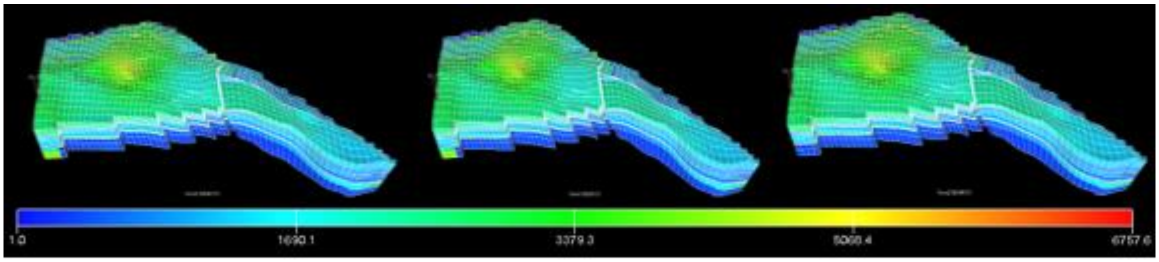


Figure 3.4.4: Permeability in X, Y and Z direction respectively.

3.4.4 Porosity

Porosity varies from 0.21 to a maximum of 0.33. Top layers i.e layer 2 to 5 have higher porosities compared to bottom layers. Layers 16 and 17 have the lowest porosities compared to the rest of layers in the segments. Figure 3.4.5 is the grid representation of porosity distribution in K1/K2.

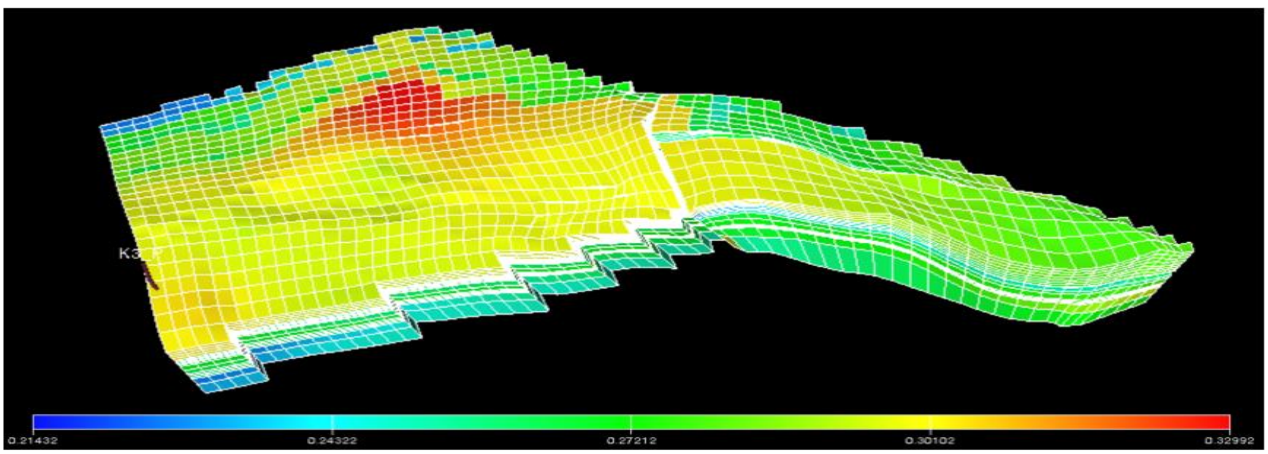


Figure 3.4.5: Porosity distribution in K1/K2 segment.

3.4.5 Production profiles for basecase.

It is worth presenting production profiles of basecase before changing to low salinity water injection case. This will make it easier for later comparison for the two basecase scenarios i.e Convectional water injection and low salinity water injection. Production profiles to be presented are; Field oil production rate, cumulative oil production and Gas Oil Ratio.

3.4.5.1 Field oil production rate

The model shows in 1990 oil production rate was 76.5 Sm^3/day then it increases up to 12503.4 Sm^3/day in 1993 as seen in Figure 3.4.6. The reason is due to drilling of injector well C-4 in February 1991, injector well L1-I in November 1991 and injector well C-13 in August 1992 which all played part in maintaining reservoir pressure which in turn increases oil production rate. Also, producer well C-14 drilled in December 1992 played part in increasing production rate at that time. The production rate then decreases up to 1450.3 Sm^3/day in 2002. The reason is due to oil production for long time without providing any pressure support after drilling last injector well in 1992. Predictions shows that the production rate will continue to decrease up to 188.7 Sm^3/day in 2025. The improved cases models prepared will focus on improving this production rate as high as possible.

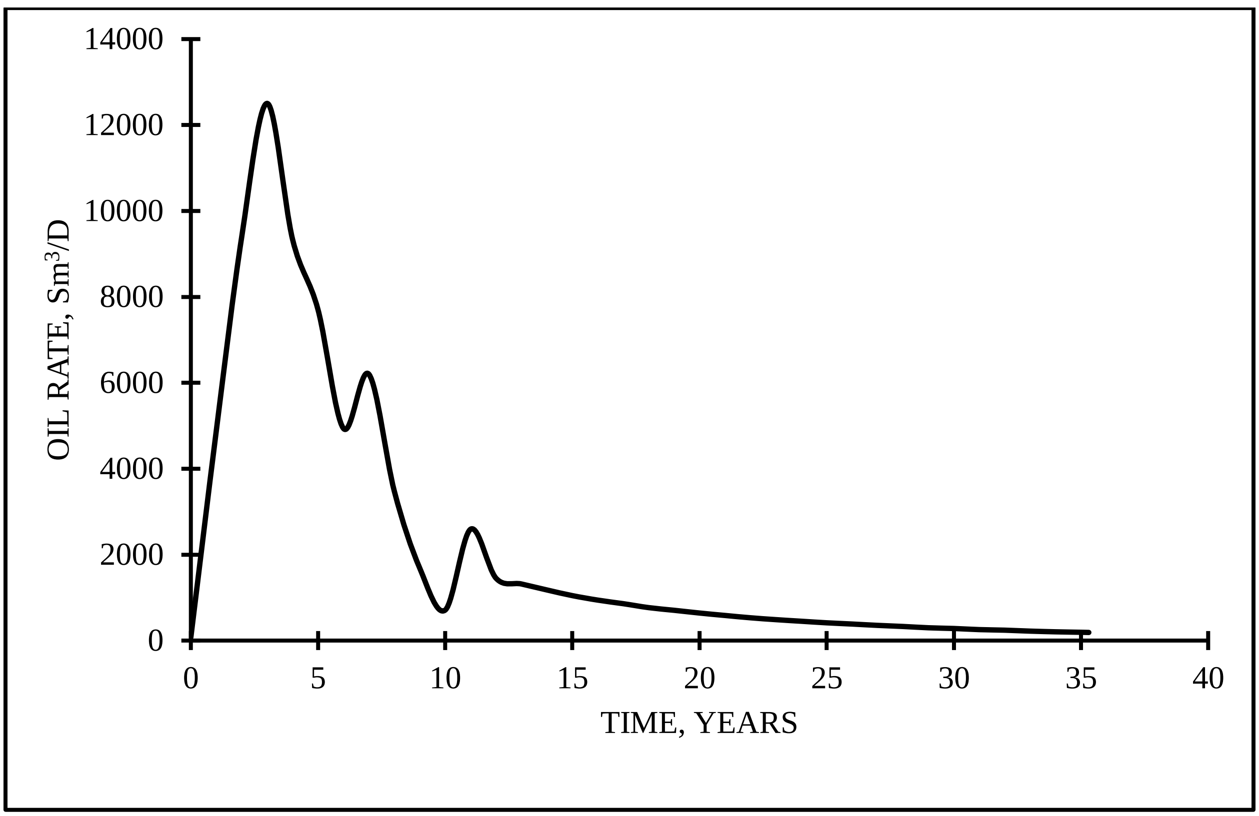


Figure 3.4.6: Oil production rate

3.4.5.2 Field cumulative oil production

Simulation result for basecase shows high increase of oil production in the first three years i.e from 1990 to 1993. The reason is due to drilling of three injectors and one producer well between 1990 and 1993. The injector wells drilled increase pressure support and improve sweeping efficiency which result to increase in production. Cumulative oil production plot shows steep slope in the first few years then it decreases as time goes as seen in Figure 3.4.7. The decrease in oil production after 1993 to 2025 is due to continuing oil production for long time without providing any pressure support.

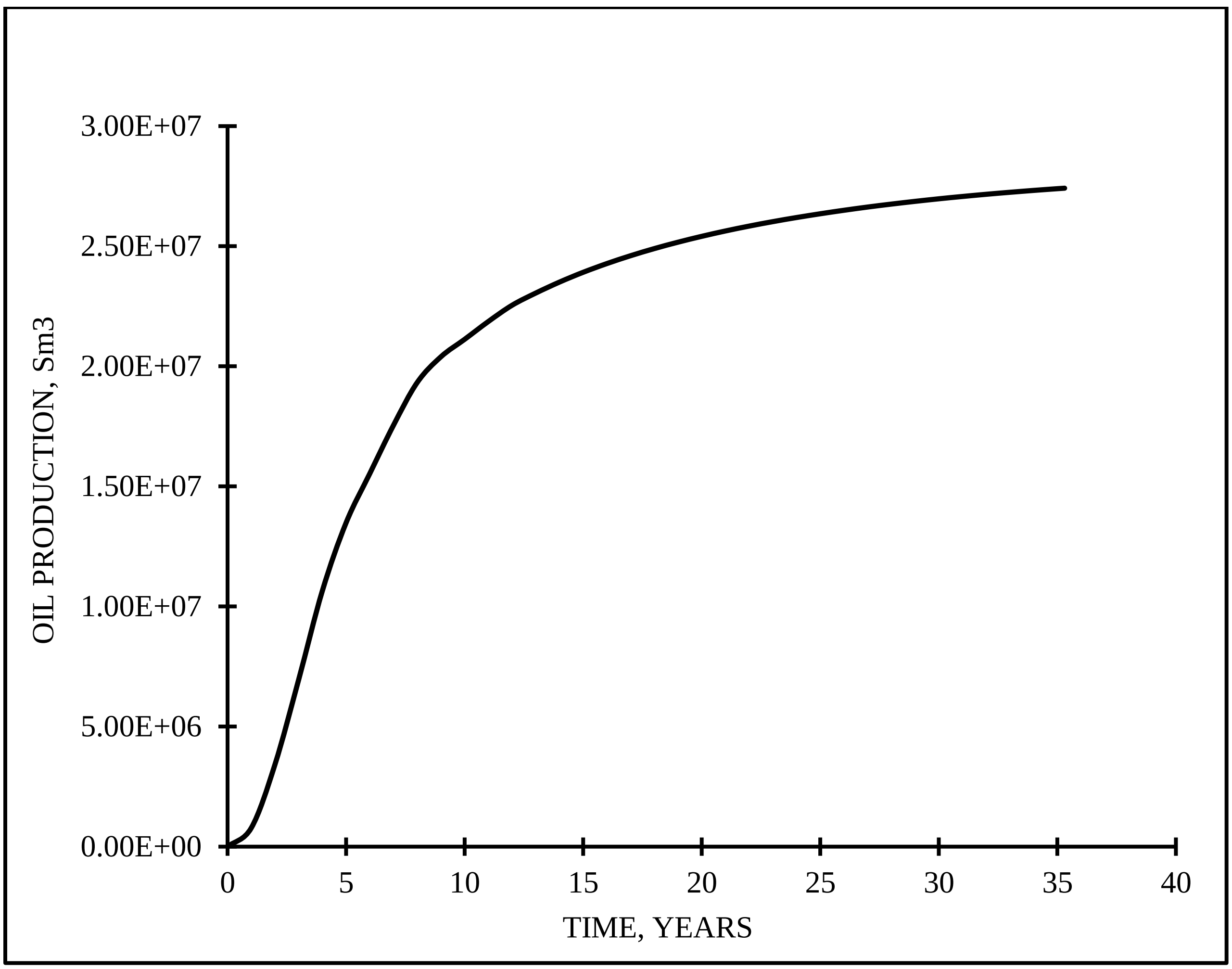


Figure 3.4.7: Cumulative oil production.

3.4.5.3 Gas oil ratio

Large part of GOR plot is horizontal, which means gas produced is constant. This also indicate that there is no free gas in the reservoir, the only gas produced is solution gas. The two peaks of GOR in the plot indicate gas break through which lead to high production of free gas leading to high GOR. This resulted to shut in of wells C-14, C-24T2 and C-20A and in turn result to horizontal GOR curve again as can be seen in Figure 3.4.8.

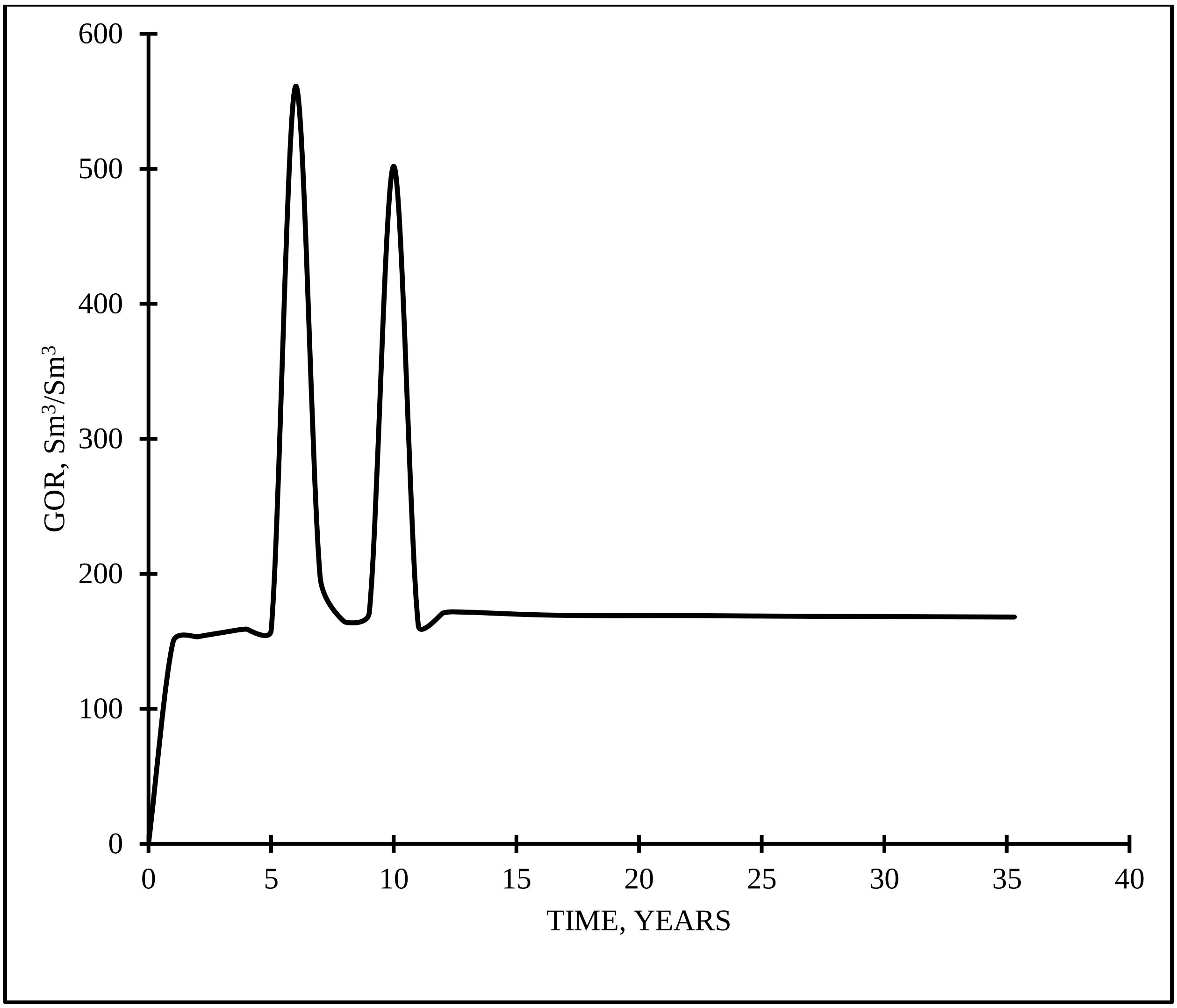


Figure 3.4.8: Gas Oil Ratio

3.5 LOW SALINITY IMPROVED CASES

3.5.1 Scenario 1

Fifty improved cases were simulated in ECLIPSE 100 based on injecting low salinity water. The cases were categorized in to two scenarios. The first scenario involves the injection of low salinity water injection using the three present injectors i.e C-4, C-13 and L1_I. The only changing parameter in this scenario is salt concentration in injected water. Salt concentrations injected were changed from 500 ppm to 20000 ppm and the result is presented in Table 3.5.1. Graphical representation of results is in Figures 3.5.1 and 3.5.2. In Figure 3.5.1, y-axis represent oil recovery while x-axis represent time. From the Figure it can be observed in all cases recovery increases with time. Another observation is that low salt concentration cases have higher recovery than low salt concentration cases. Figure 3.5.2 represent oil recovery against salt concentration. From the Figure it can be observed that oil recovery decreases as salt concentration increased.

Table 3.5.1: Oil recovery for different concentrations in scenario 1

S/N	Cases	Recovery Factor (RF) %	Delta RF %
1	Basecase	46.4	-
2	Salt concentration = 500 ppm	48.3	1.9
3	Salt concentration = 1000 ppm	47.8	1.4
4	Salt concentration = 1500 ppm	47.2	0.8
5	Salt concentration = 2000 ppm	46.6	0.2
6	Salt concentration = 2500 ppm	46.3	-0.1
7	Salt concentration = 3000 ppm	46.2	-0.2
8	Salt concentration = 4000 ppm	46.2	-0.2
9	Salt concentration = 5000 ppm	46.2	-0.2
10	Salt concentration = 10000 ppm	46.2	-0.2
11	Salt concentration = 15000 ppm	46.2	-0.2
12	Salt concentration = 20000 ppm	46.2	-0.3

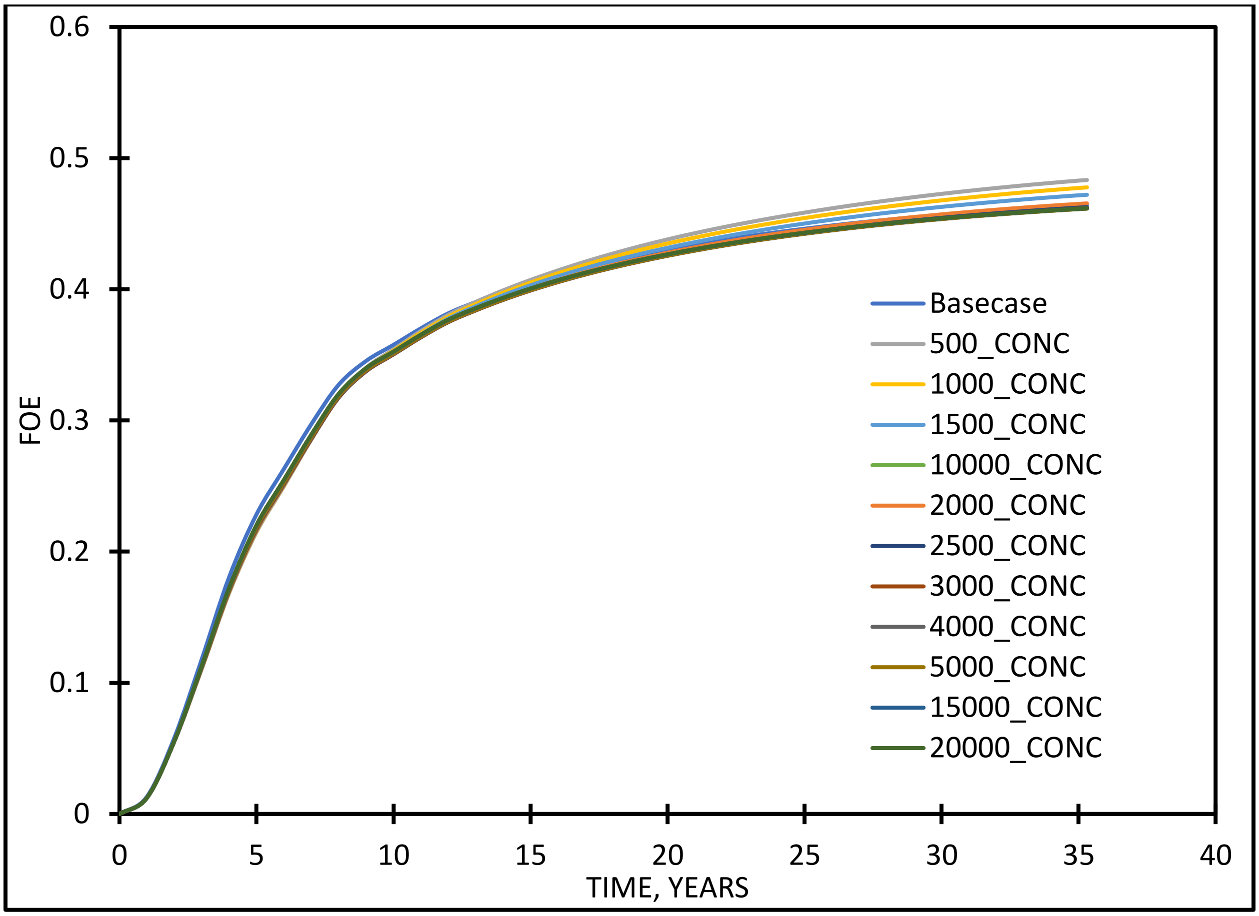


Figure 3.5.1: Oil recovery for different concentrations in scenario 1

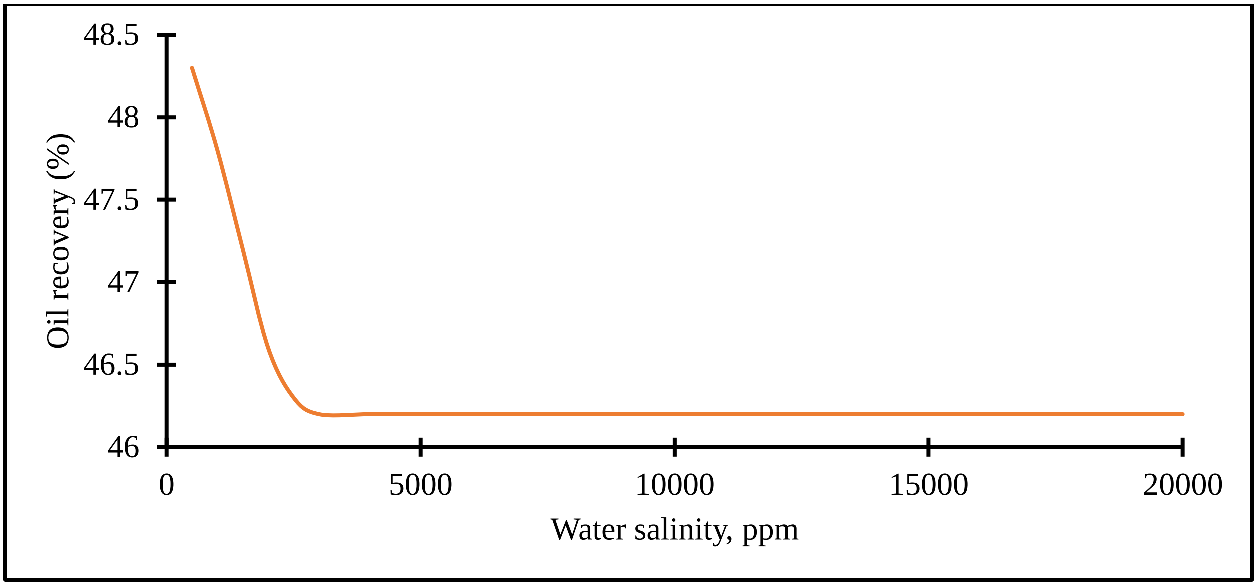


Figure 3.5.2: Recovery factors for different salt concentration in scenario 1

3.5.2 Scenario 2

The second scenario involve the introduction of new injector in the field i.e C_16. In this scenario several cases were formulated but only five cases from this scenario were chosen to be presented and discussed in this research work. The selection of cases was mostly based on well positioning, perforation intervals and concentration of salt injected. Well positioning and perforation intervals were implemented with the help of tracer injection analysis presented in section 3.3. Areas with no or limited communication were ignored, and injection was based on a layer where there is direct communication with expected producers. From tracer analysis it has been observed that layers 11,12 and 13 communicate in large part of the reservoir. Layers 2-10, 16,17 were observed to have limited communication while layers 10,11, 13-15 had no communication in large part of the reservoir (detail of the analysis in Table 3.3.2).

3.5.2.1 Improved case 1

In this case, a new injector C_16 was placed in grid 17 66 in 2005. The target is to use the well to inject low salinity water and improve recovery from production wells already present in the reservoir. Low salinity water injected in C_16 with different concentrations from 2005 to 2025. Concentration selected for all cases analysis are 500 ppm, 1000 ppm, 1500 ppm, 2000 ppm, 2500 ppm, 3000 ppm, 4000 ppm, 5000 ppm, 10000 ppm, 15000 ppm and 20000 ppm. Very low concentration or fresh water for example water with 0 PPM are discouraged first because of the tendency of clay to swell when in contact with fresh water. Also, it is expensive to achieve very low salt concentration in desalination plant especially when sea water is used as raw water.

Concentrations from 500 ppm to 2000 ppm showed positive recovery improvement while the rest result to lower recovery than basecase as presented in Table 3.5.2 and graphical representation in Figure 3.5.3 and 3.5.4. From Figure 3.5.3 it can be observed that oil recovery increases with time, also low salt concentration cases have higher recovery than higher concentration. Concentration of 500 ppm improves much oil recovery than the rest. Figure 3.5.4 shows decrease in oil recovery as concentration increases.

Table 3.5.2: Oil recovery for different concentrations in scenario 2 case 1

S/N	Cases	Recovery Factor (RF) %	Delta RF %
1	Basecase	46.4	-
2	Salt concentration = 500 ppm	48.3	1.9
3	Salt concentration = 1000 ppm	47.8	1.4
4	Salt concentration = 1500 ppm	47.2	0.8
5	Salt concentration = 2000 ppm	46.5	0.1
6	Salt concentration = 2500 ppm	46.3	-0.1
7	Salt concentration = 3000 ppm	46.2	-0.2
8	Salt concentration = 4000 ppm	46.2	-0.2
9	Salt concentration = 5000 ppm	46.2	-0.2
10	Salt concentration = 10000 ppm	46.2	-0.2
11	Salt concentration = 15000 ppm	46.2	-0.2
12	Salt concentration = 20000 ppm	46.1	-0.3

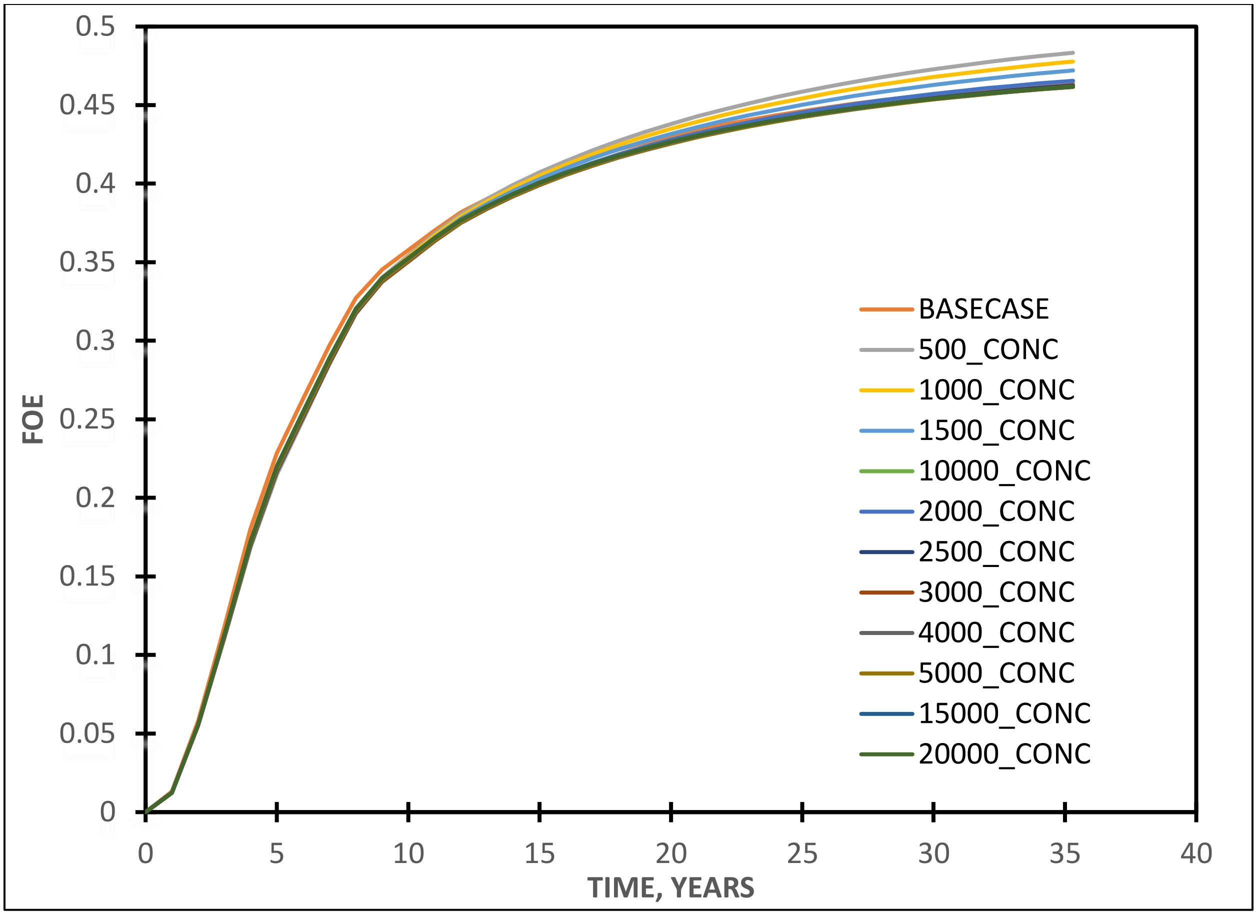


Figure 3.5.3: Oil recovery for different concentrations in scenario 2 case 1

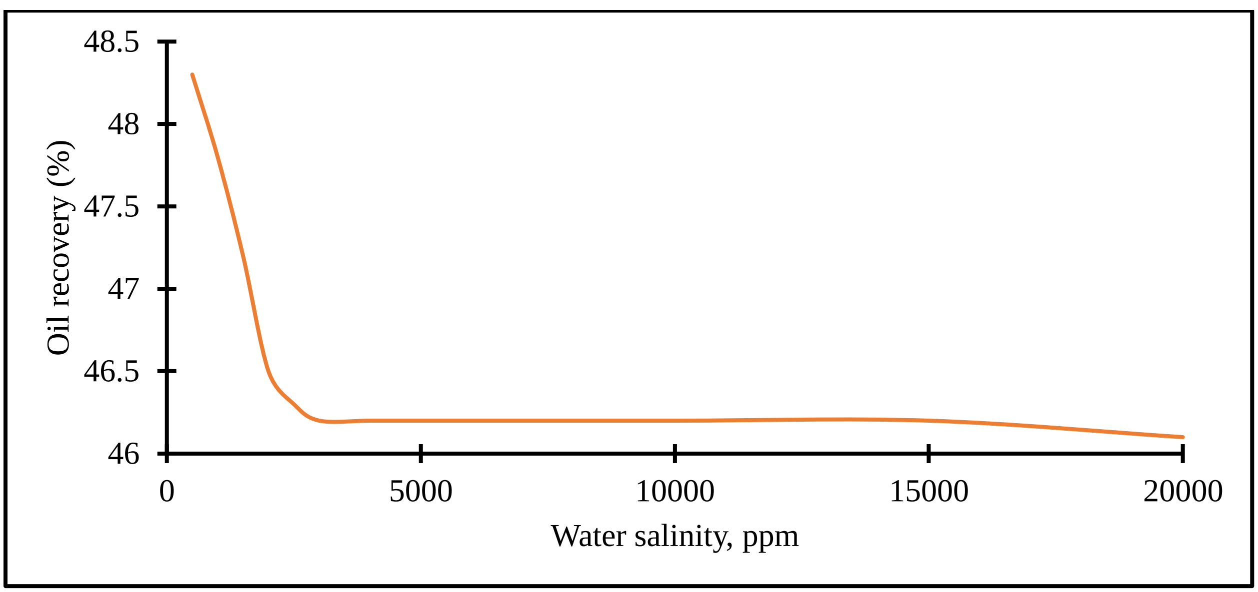


Figure 3.5.4: Recovery factors for different salt concentration in scenario 2 case 1

3.5.2.2 Improved case 2

The challenge of getting lower recovery than basecase in case 1 were analyzed and it was decided to conduct tracer study in the whole reservoir to identify the best areas for injection. Before selecting the position, tracers were injected and observed in production wells to see if the selected position has communication with producers. Also amount of tracers produced were compared to amount injected to see how much have been lost in between in order to observe whether there are thief zones. This analysis was the key in preparing cases 2 to 5.

In this case the same well C_16 was changed to grid 18 38. The same concentrations were applied and the result for improved recovery is presented in Table 3.5.3 and graphical representation in Figures 3.5.5 and 3.5.6. From Figure 3.5.6 it can be observed that oil recovery increases with time, also low salt concentration cases have higher recovery than higher concentrations. Concentration of 500 ppm improves much oil recovery than the rest. Figure 3.5.5 shows decrease in oil recovery as concentration increases.

Table 3.5.3: Oil recovery for different concentrations in scenario 2 case 2

S/N	Cases	Recovery Factor (RF) %	Delta RF %
1	Basecase	46.4	-
2	Salt concentration = 500 ppm	49.8	3.4
3	Salt concentration = 1000 ppm	49.1	2.7
4	Salt concentration = 1500 ppm	48.5	2.1
5	Salt concentration = 2000 ppm	47.7	1.3
6	Salt concentration = 2500 ppm	47.4	1.0
7	Salt concentration = 3000 ppm	47.4	1.0
8	Salt concentration = 4000 ppm	47.3	0.9
9	Salt concentration = 5000 ppm	47.3	0.9
10	Salt concentration = 10000 ppm	47.3	0.9
11	Salt concentration = 15000 ppm	47.3	0.9
12	Salt concentration = 20000 ppm	47.3	0.9

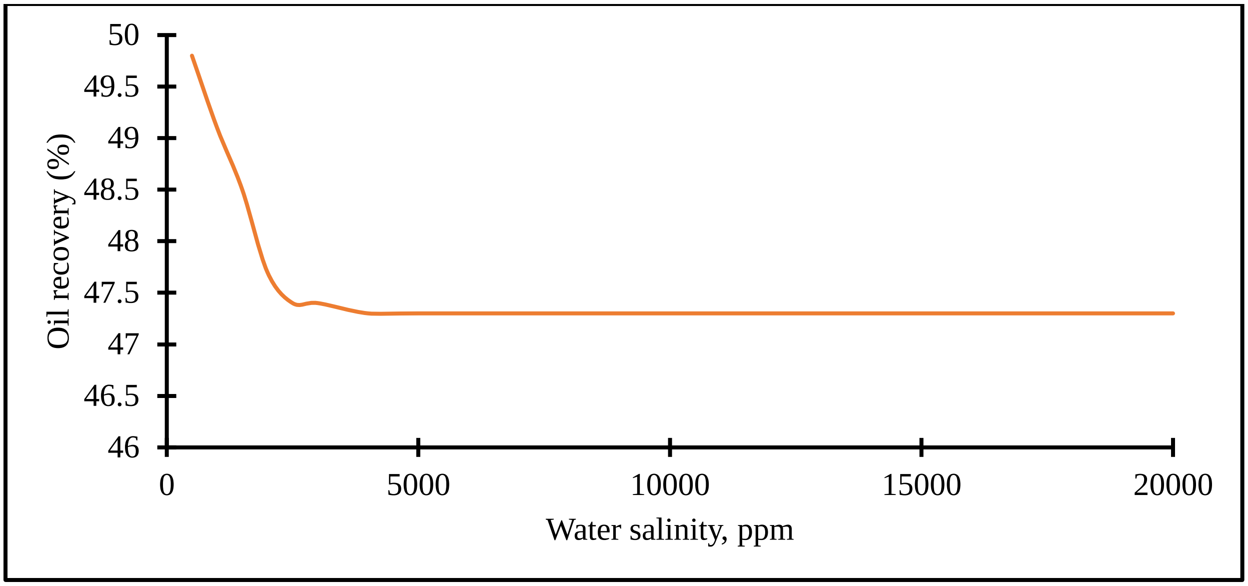


Figure 3.5.5: Recovery factors for different salt concentration in scenario 2 case 2

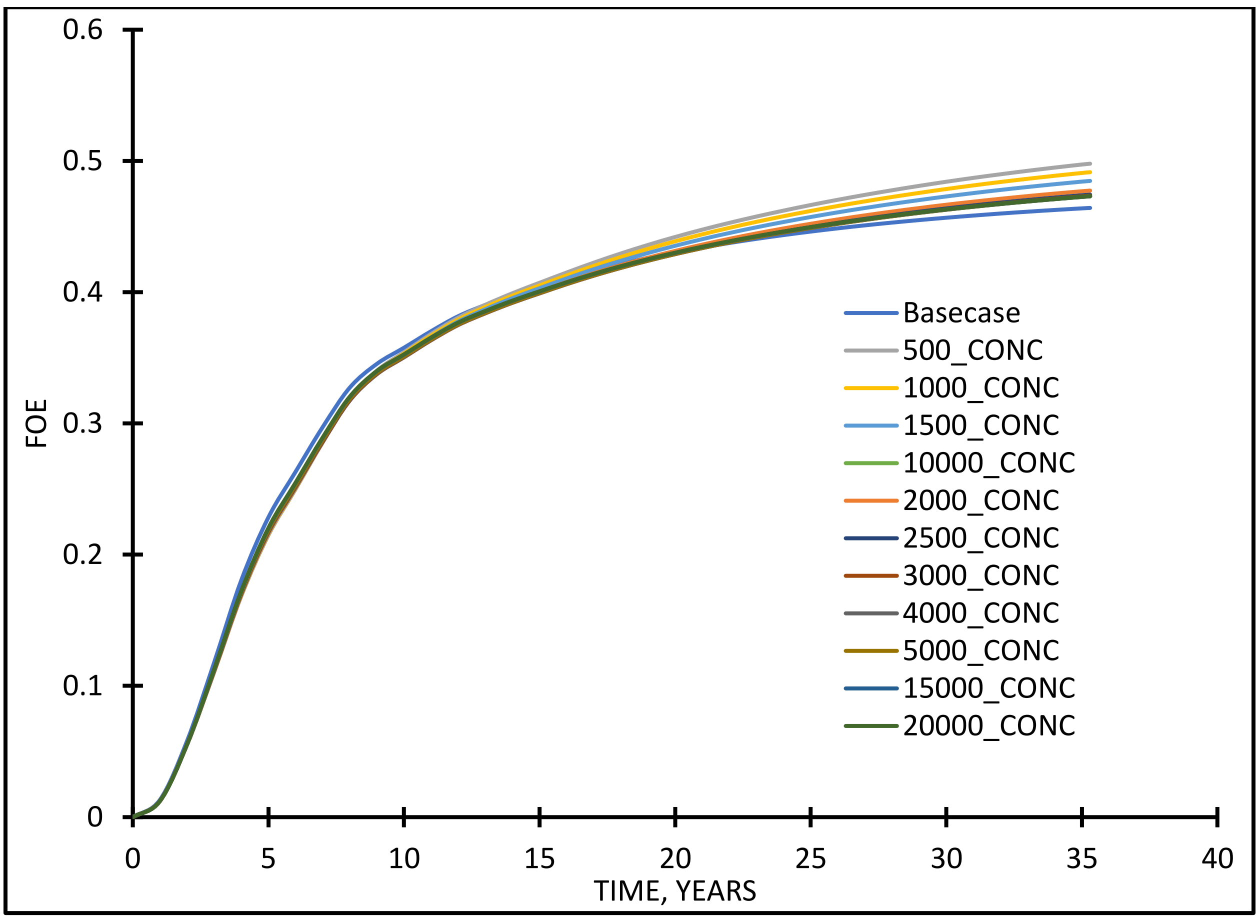


Figure 3.5.6: Oil recovery for different concentrations in scenario 2 case 2

3.5.2.3 Improved case 3

Well C_16 is now moved to position 24 31. The result for improved recovery is presented in Table 3.5.4 and graphical representation in Figures 3.5.7 and 3.5.8. From Figure 3.5.8 it can be observed that oil recovery increases with time, also low salt concentration cases have higher recovery than higher concentration. Concentration of 500 ppm improves much oil recovery than the rest. Figure 3.5.7 shows decrease in oil recovery as concentration increases.

Table 3.5.4: Oil recovery for different concentrations in scenario 2 case 3

S/N	Cases	Recovery Factor (RF) %	Delta RF %
1	Basecase	46.4	-
2	Salt concentration = 500 ppm	49.9	3.5
3	Salt concentration = 1000 ppm	49.2	2.8
4	Salt concentration = 1500 ppm	48.6	2.2
5	Salt concentration = 2000 ppm	47.8	1.4
6	Salt concentration = 2500 ppm	47.5	1.1
7	Salt concentration = 3000 ppm	47.5	1.1
8	Salt concentration = 4000 ppm	47.4	1.0
9	Salt concentration = 5000 ppm	47.4	1.0
10	Salt concentration = 10000 ppm	47.4	1.0
11	Salt concentration = 15000 ppm	47.4	1.0
12	Salt concentration = 20000 ppm	47.4	1.0

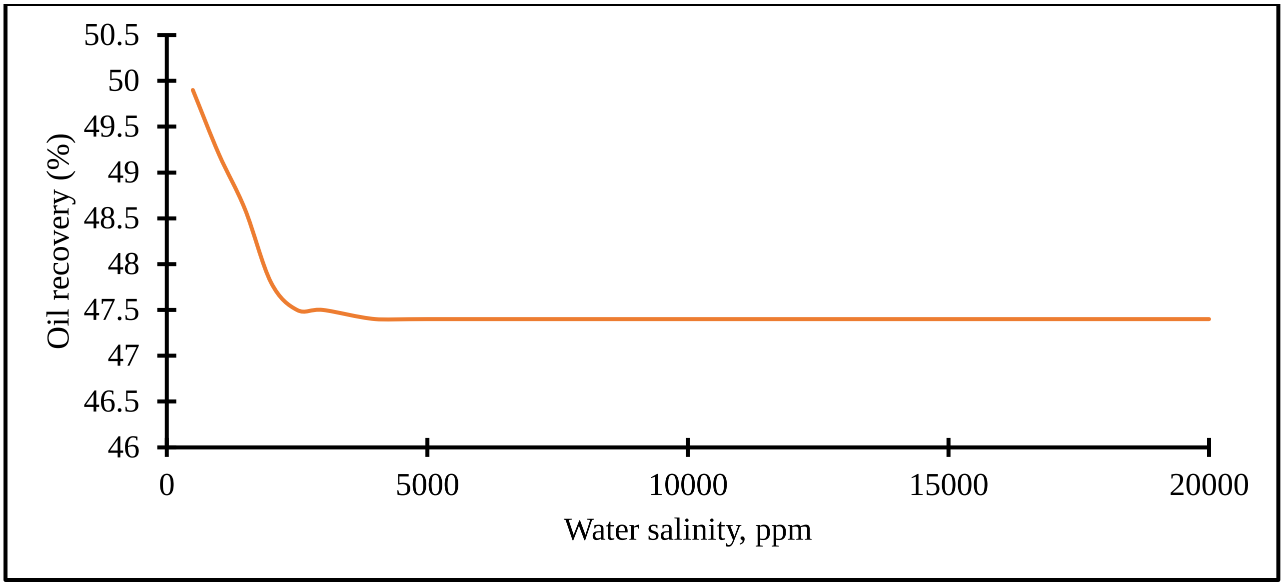


Figure 3.5.7: Recovery factors for different salt concentration in scenario 2 case 3

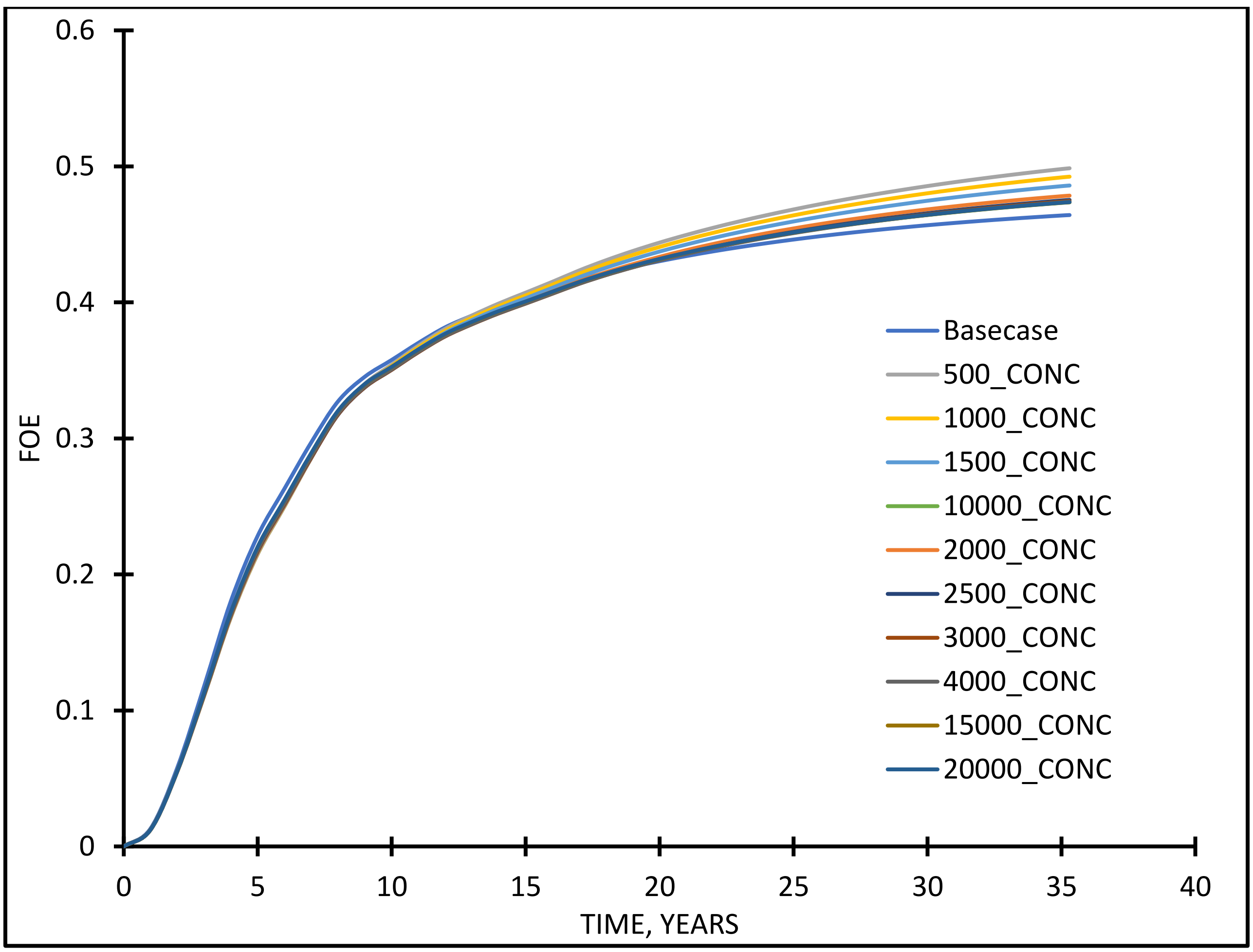


Figure 3.5.8: Oil recovery for different concentrations in scenario 2 case 3

3.5.2.4 Improved case 4

The injector well C_16 is now in position 10 15. The results for improved recovery are summarized in Table 3.5.5 and graphical representation in Figures 3.5.9 and 3.5.10. From Figure 3.5.10 it can be observed that oil recovery increases with time, also low salt concentration cases have higher recovery than higher concentration. Concentration of 500 ppm improves much oil recovery than the rest. Figure 3.5.9 shows decrease in oil recovery as concentration increases.

Table 3.5.5: Oil recovery for different concentrations in scenario 2 case 4

S/N	Cases	Recovery Factor (RF) %	Delta RF %
1	Basecase	46.4	-
2	Salt concentration = 500 ppm	50.1	3.7
3	Salt concentration = 1000 ppm	49.4	3.0
4	Salt concentration = 1500 ppm	48.8	2.4
5	Salt concentration = 2000 ppm	48.1	1.7
6	Salt concentration = 2500 ppm	47.8	1.4
7	Salt concentration = 3000 ppm	47.7	1.3
8	Salt concentration = 4000 ppm	47.6	1.2
9	Salt concentration = 5000 ppm	47.6	1.2
10	Salt concentration = 10000 ppm	47.6	1.2
11	Salt concentration = 15000 ppm	47.6	1.2
12	Salt concentration = 20000 ppm	47.6	1.2

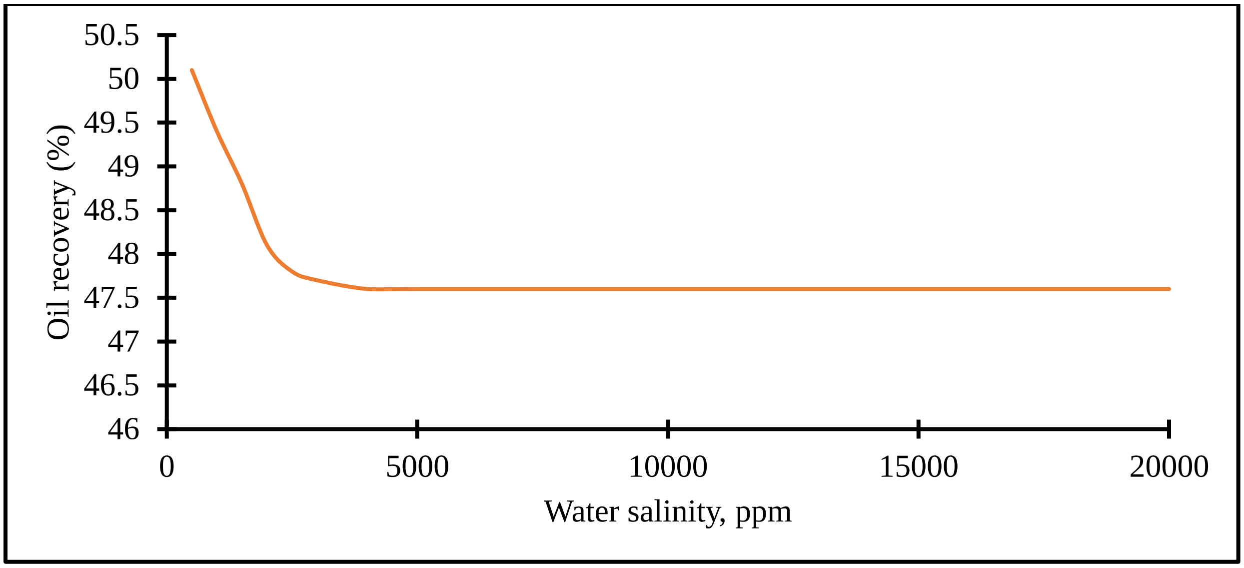


Figure 3.5.9: Recovery factors for different salt concentration in scenario 2 case 4

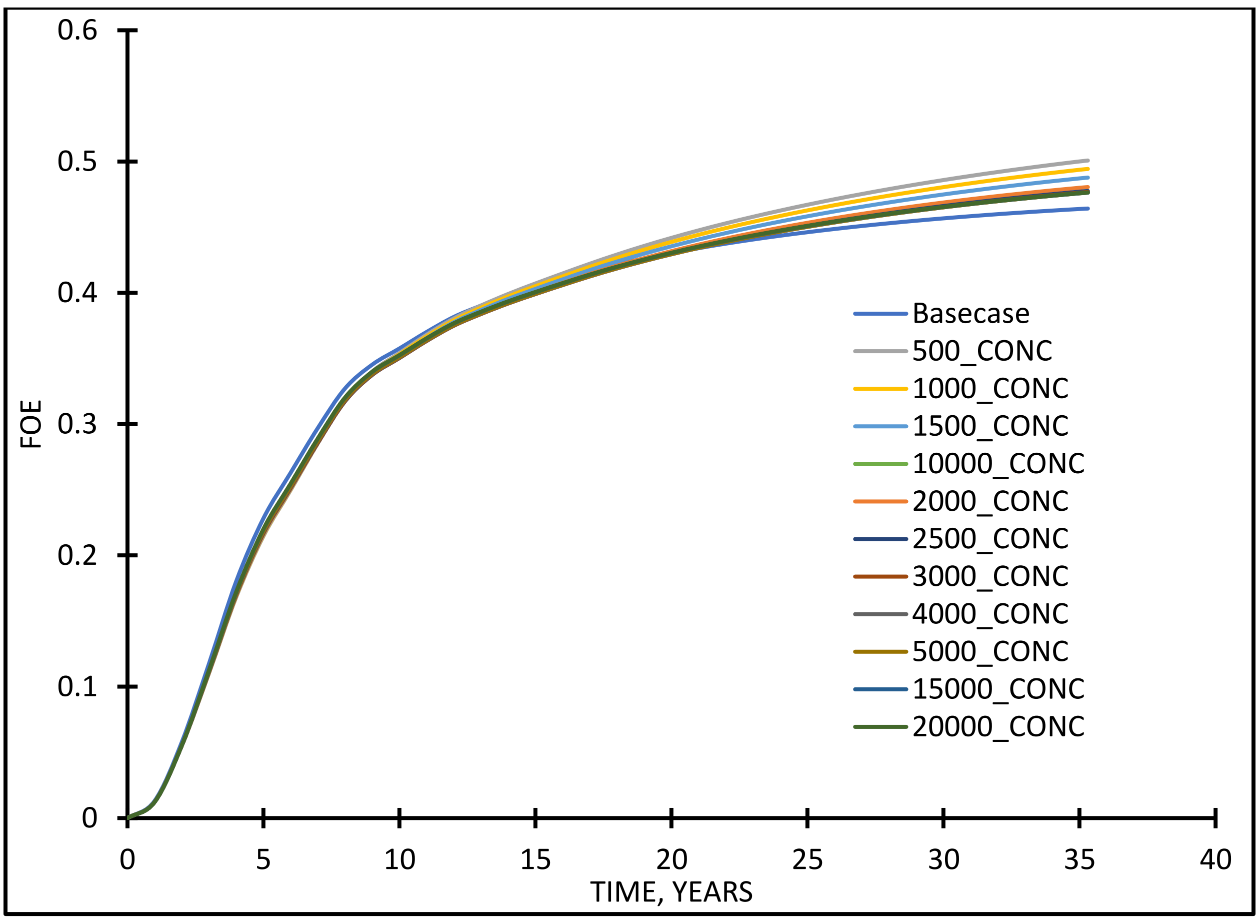


Figure 3.5.10: Oil recovery for different concentrations in scenario 2 case 4

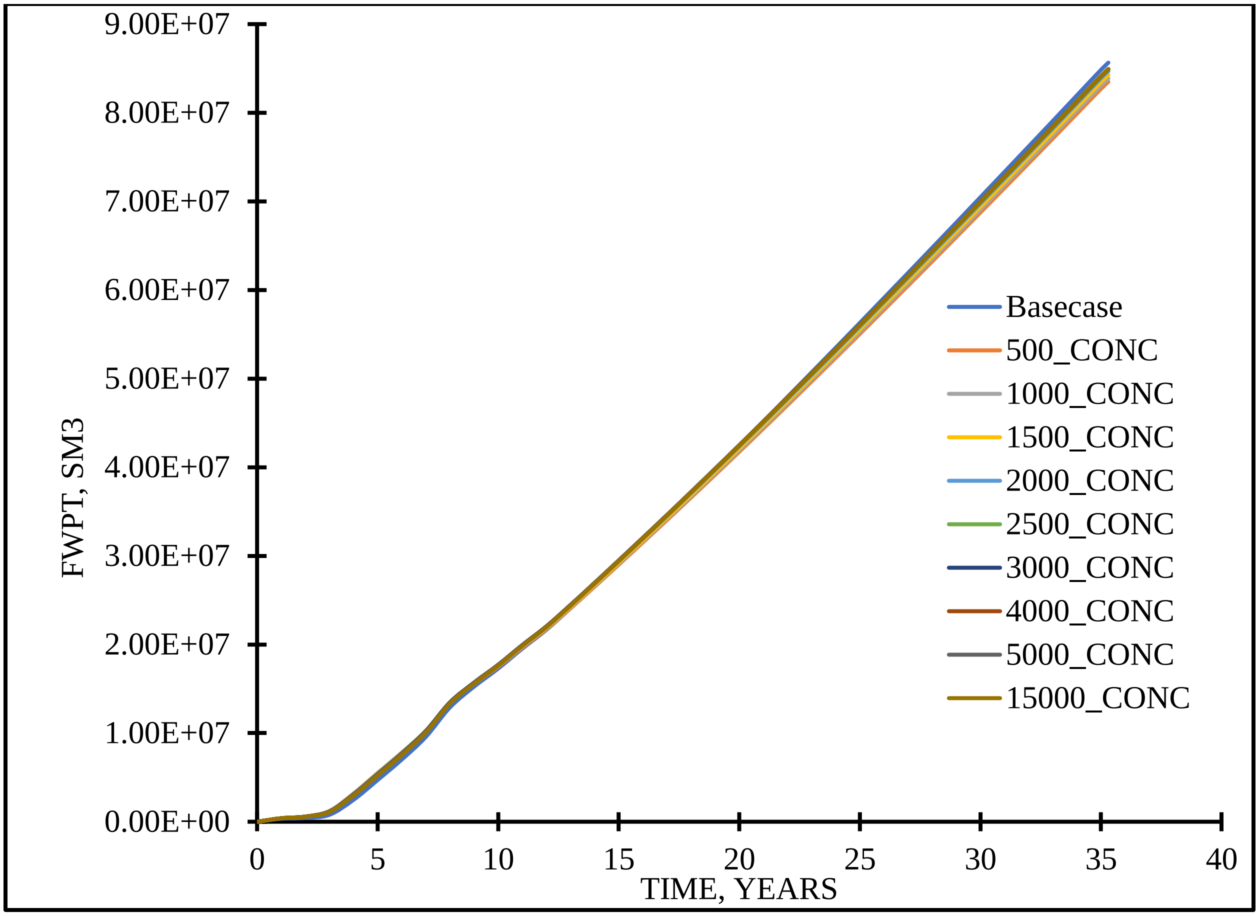


Figure 3.5.11: Total water production for different concentrations in scenario 3 case 4.

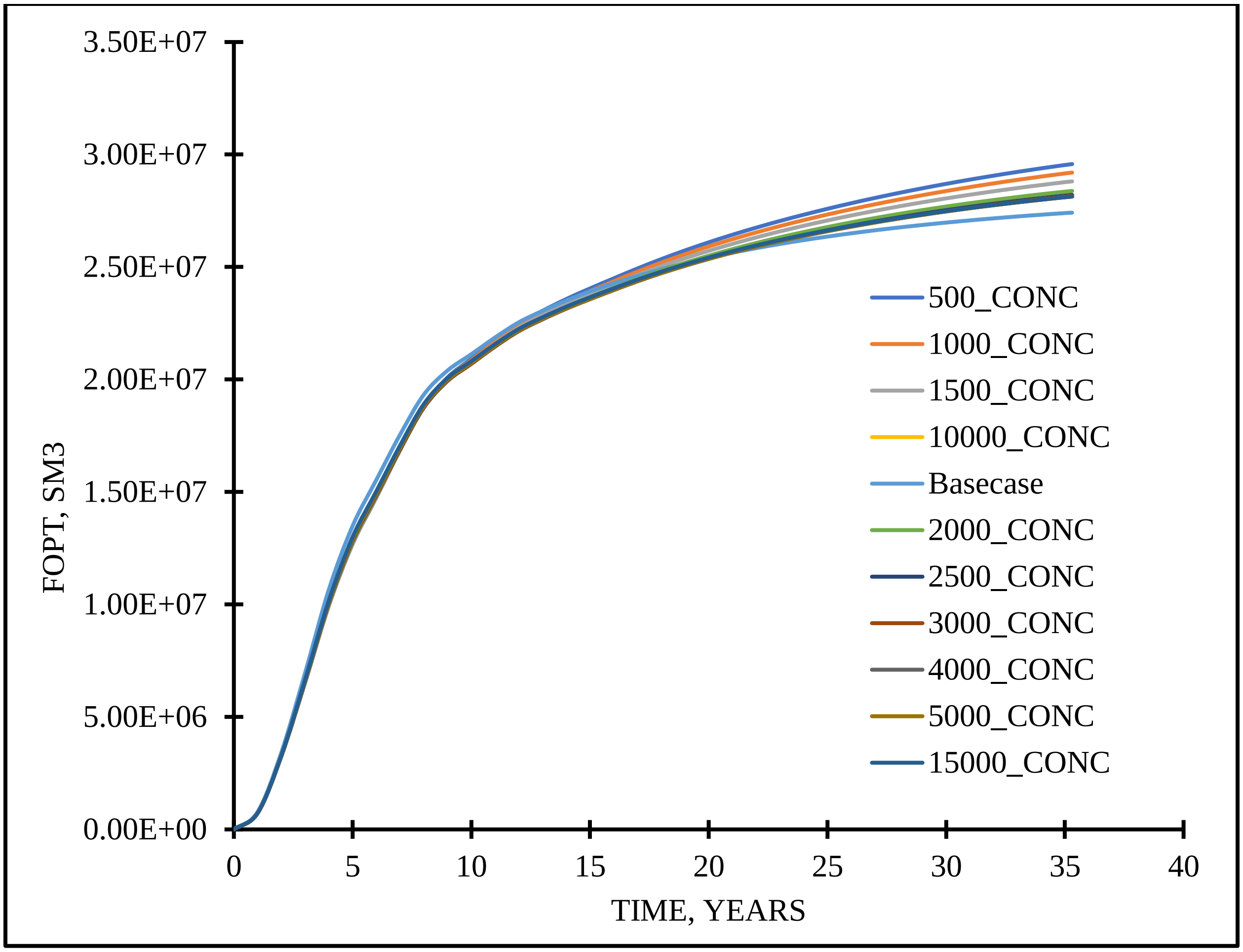


Figure 3.5.12: Oil production for different concentrations in scenario 3 case 4.

3.5.2.5 Improved case 5

The injector well C_16 is in position 8 9. Result for improved recovery are summarized in Table 3.5.6 and graphical representation in Figures 3.5.13 and 3.5.14. From Figure 3.5.14 it can be observed that oil recovery increases with time, also low salt concentration cases have higher recovery than higher concentration. Concentration of 500 ppm improves much oil recovery than the rest. Figure 3.5.13 shows decrease in oil recovery as concentration increases.

Table 3.5.6: Oil recovery for different concentrations in scenario 2 case 5

S/N	Cases	Recovery Factor (RF) %	Delta RF %
1	Basecase	46.4	-
2	Salt concentration = 500 ppm	49.5	3.1
3	Salt concentration = 1000 ppm	48.9	2.5
4	Salt concentration = 1500 ppm	48.3	1.9
5	Salt concentration = 2000 ppm	47.7	1.3
6	Salt concentration = 2500 ppm	47.4	1.0
7	Salt concentration = 3000 ppm	47.3	0.9
8	Salt concentration = 4000 ppm	47.2	0.8
9	Salt concentration = 5000 ppm	47.2	0.8
10	Salt concentration = 10000 ppm	47.2	0.8
11	Salt concentration = 15000 ppm	47.2	0.8
12	Salt concentration = 20000 ppm	47.2	0.8

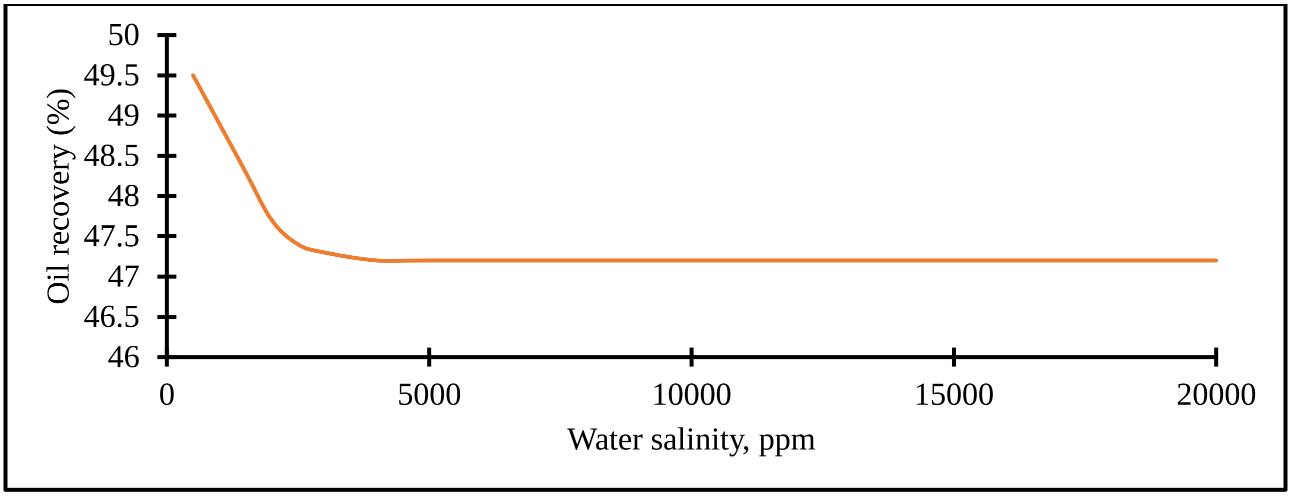


Figure 3.5.13: Recovery factors for different salt concentration in scenario 2 case 5

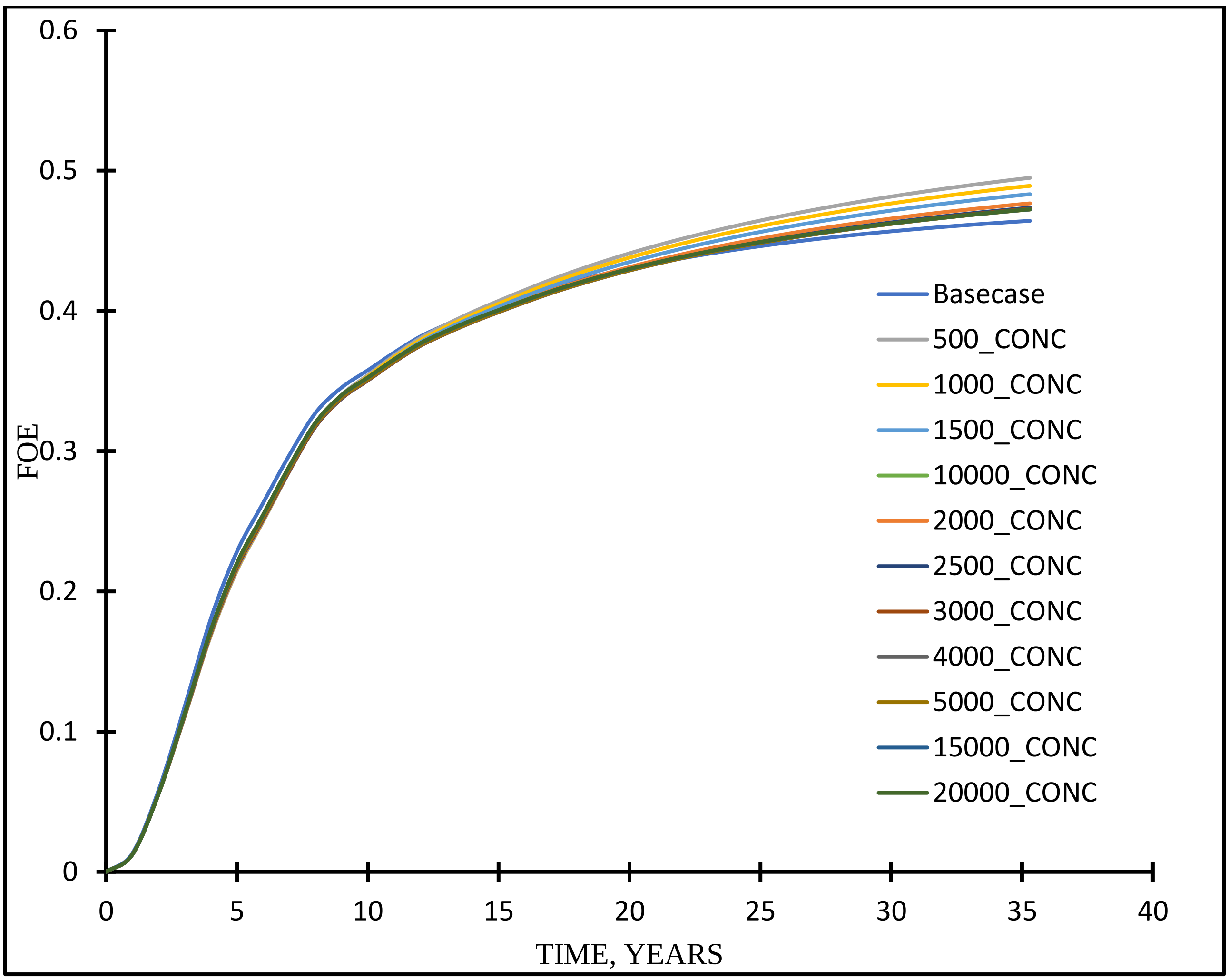


Figure 3.5.14: Oil recovery for different concentrations in scenario 2 case 5

3.6 ECONOMIC AND SENSITIVITY ANALYSIS

3.6.1 Economic analysis

For a Project to be valid, economic analysis must be performed. In this case Net Presence Value (NPV) analysis was used to compare different cases to recommend the best out of many simulated. The process started with evaluating NPV for scenario 2 where the best case in term of recovery was analyzed by calculating NPV for every salt concentration injected. Then the result where compared with NPVs of scenario 1. Those NPV calculations were carried out with the help of different assumptions as presented in section 3.6.1.1.

3.6.1.1 Assumptions

- Oil price = $65 per barrel
- All produced oil is sold
- Interest rate = 8%
- Exchange rate = 8.5NOK/USD
- Drilling and completion cost = $150 millions
- Low salinity plant cost = $120 millions
- CAPEX is invested in 2005
- OPEX is 2.5% of total revenue plus CAPEX
- Each scenario is categorized in term of Base NPV, Worst NPV and Best NPV cases.
- Base NPV-Normal oil price, CAPEX and OPEX.
- Worst NPV= -15% Oil price, +15% CAPEX and +15% OPEX.
- Best NPV= +15% Oil price, -15% CAPEX and -15% OPEX.

3.6.1.2 NPV results

NPV for the best cases in term of recovery were calculated for different concentrations of water injected. The $120 million desalination plant selected has injection capacity of more than 250,000 bbl/day (Rowland, 2013) which is suitable for this case. The NPV result for scenario 1 and 2 cases are presented in the Tables 3.6.1 and 3.6.2 respectively.

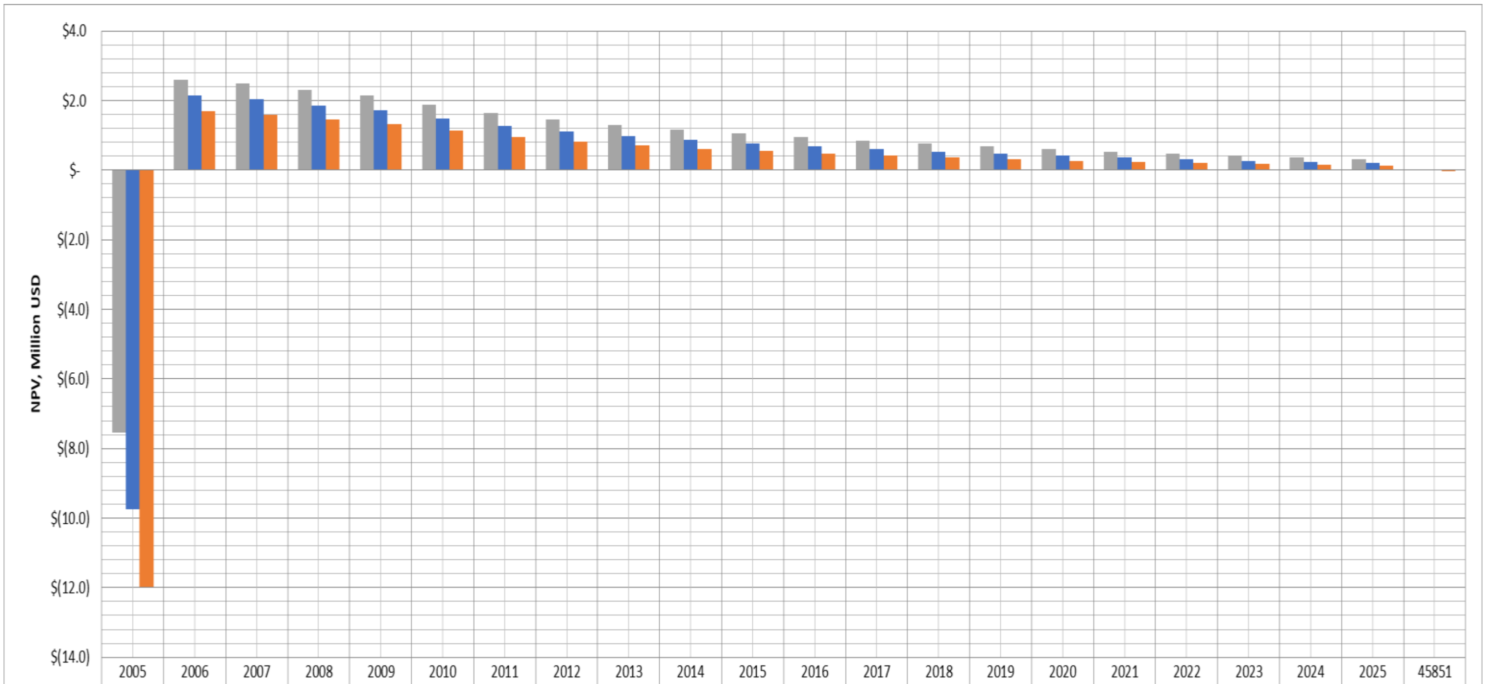
Table 3.6.1: Scenario 1 NPV results

Scenario 1: No additional well drilled	
Concentration injected (ppm)	NPV (USD)
500	86,002,131
1000	66,935,233
1500	7,195,703
2000	-62,211,582
2500	-89,910,070
3000	-99,314,098
4000	-107,810,762
5000	-111,876,925
10000	-122,148,979
15000	-125,740,918
20000	-127,380,307

Table 3.6.2: Scenario 2 NPV result

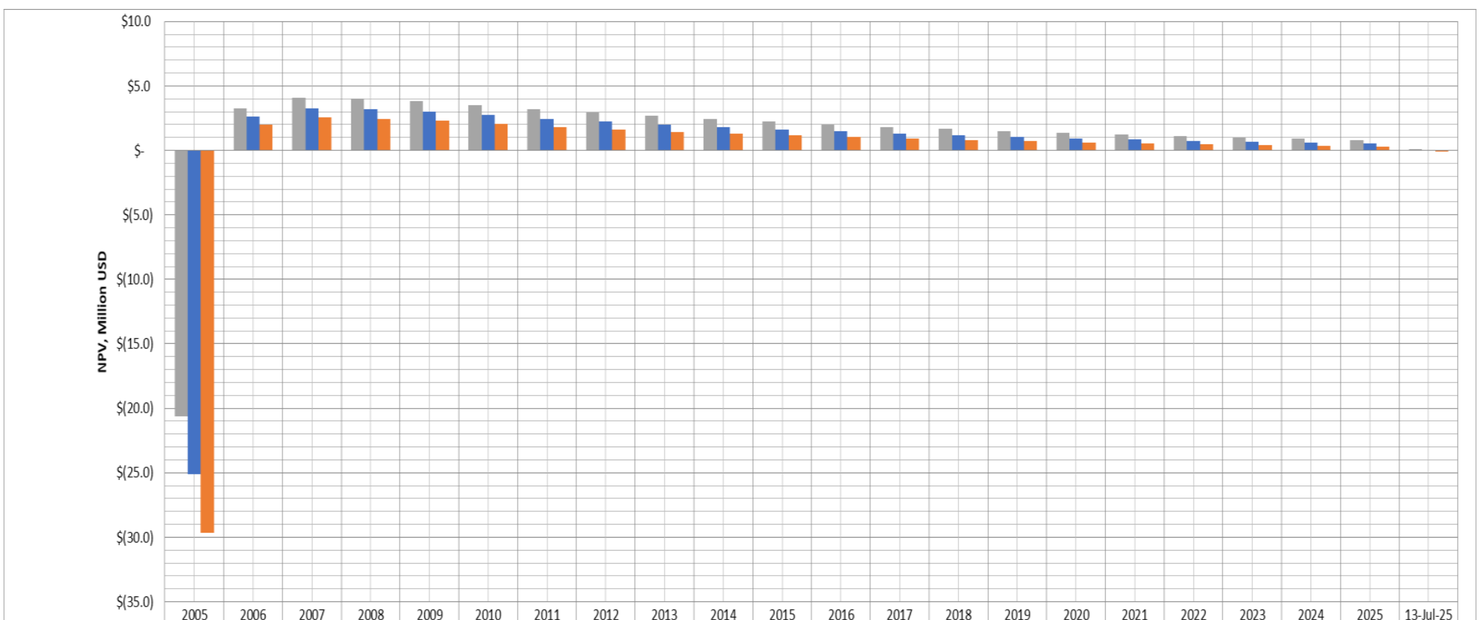
Scenario 2: One additional injector	
Concentration injected (ppm)	NPV (USD)
500	91,212,346
1000	36,170,647
1500	-21,968,997
2000	-84,271,486
2500	-108,724,837
3000	-117,392,506
4000	-125,296,089
5000	-128,639,969
10000	-138,023,197
15000	-141,388,181
20000	-142,602,308

As it can be seen from Tables 3.6.1 and 3.6.2, NPV values are only positive for the first three concentration values. The best NPV for each scenario is when water injected with a concentration of 500 ppm. Also, by comparing the NPVs of 500 ppm for both scenario it is observed that scenario 2 where a new injector is added to the field has higher NPV. Due to assumptions made it cannot be concluded that scenario 2 is the one to be recommended until the stability of the two cases are tested by varying the assumed parameters. Figures 3.6.1 and 3.6.2 present base, best and worst cases NPV result for 500 ppm from 2005 to 2025 for both scenarios.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	45851
Best NPV	$(7.5)	$2.6	$2.5	$2.3	$2.2	$1.9	$1.6	$1.4	$1.3	$1.2	$1.1	$0.9	$0.8	$0.8	$0.7	$0.6	$0.5	$0.5	$0.4	$0.4	$0.3	$0.0
Base NPV	$(9.8)	$2.1	$2.0	$1.9	$1.7	$1.5	$1.3	$1.1	$1.0	$0.9	$0.8	$0.7	$0.6	$0.5	$0.5	$0.4	$0.4	$0.3	$0.3	$0.2	$0.2	$0.0
Worse NPV	$(12.0)	$1.7	$1.6	$1.4	$1.3	$1.1	$0.9	$0.8	$0.7	$0.6	$0.5	$0.5	$0.4	$0.4	$0.3	$0.3	$0.2	$0.2	$0.2	$0.1	$0.1	$(0.0)

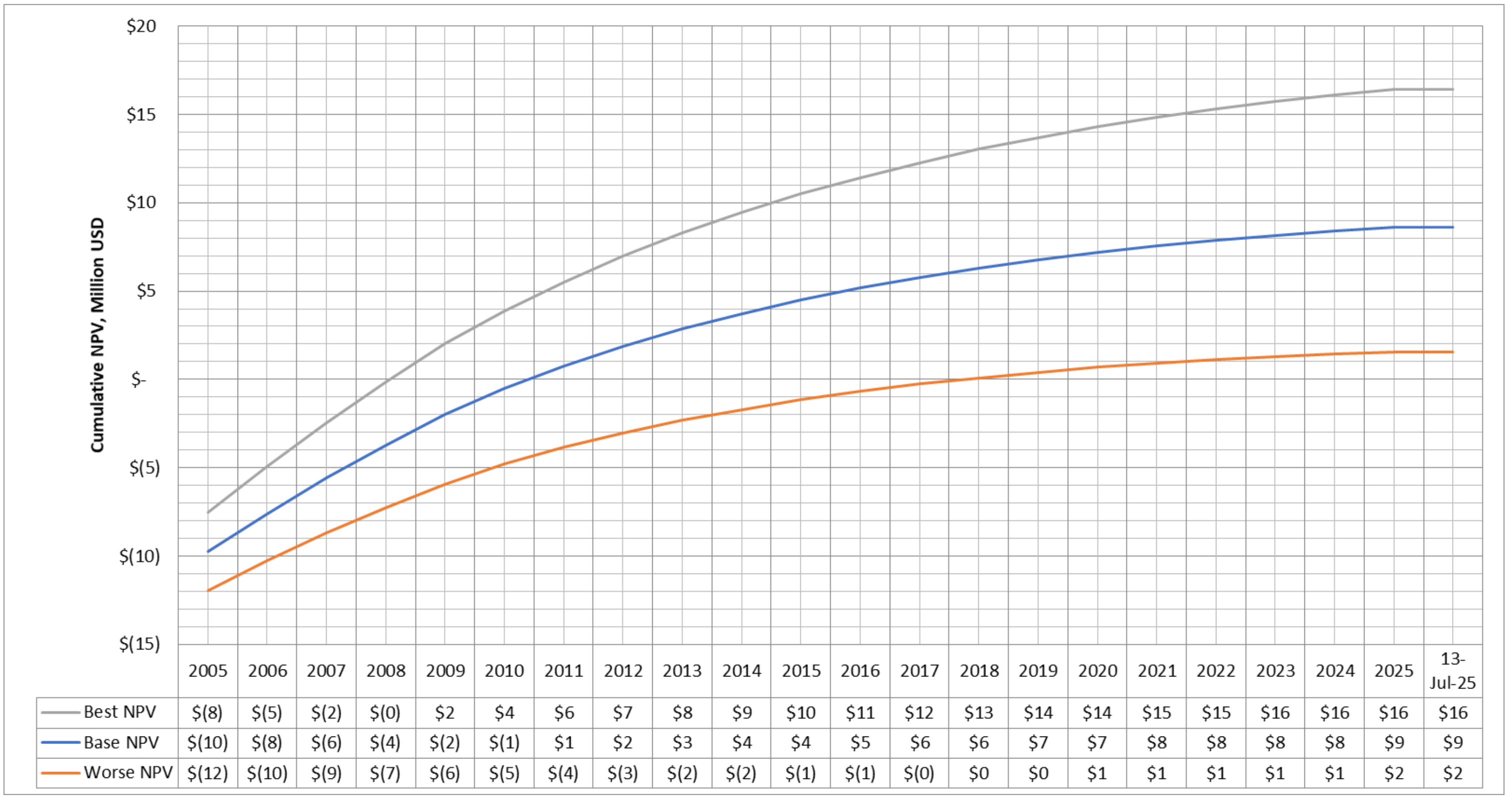
Figure 3.6.1: Illustration of base, best and worst NPV for scenario 1



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	13-Jul-25
Best NPV	$(20.6)	$3.2	$4.1	$4.0	$3.8	$3.5	$3.2	$2.9	$2.7	$2.4	$2.2	$2.0	$1.8	$1.7	$1.5	$1.4	$1.2	$1.1	$1.0	$0.9	$0.8	$0.1
Base NPV	$(25.1)	$2.6	$3.3	$3.2	$3.0	$2.7	$2.4	$2.2	$2.0	$1.8	$1.6	$1.5	$1.3	$1.2	$1.1	$0.9	$0.8	$0.7	$0.7	$0.6	$0.5	$0.0
Worse NPV	$(29.7)	$2.0	$2.5	$2.4	$2.3	$2.0	$1.8	$1.6	$1.4	$1.3	$1.1	$1.0	$0.9	$0.8	$0.7	$0.6	$0.5	$0.5	$0.4	$0.4	$0.3	$(0.0)

Figure 3.6.2: Illustration of base, best and worst NPV for scenario 2

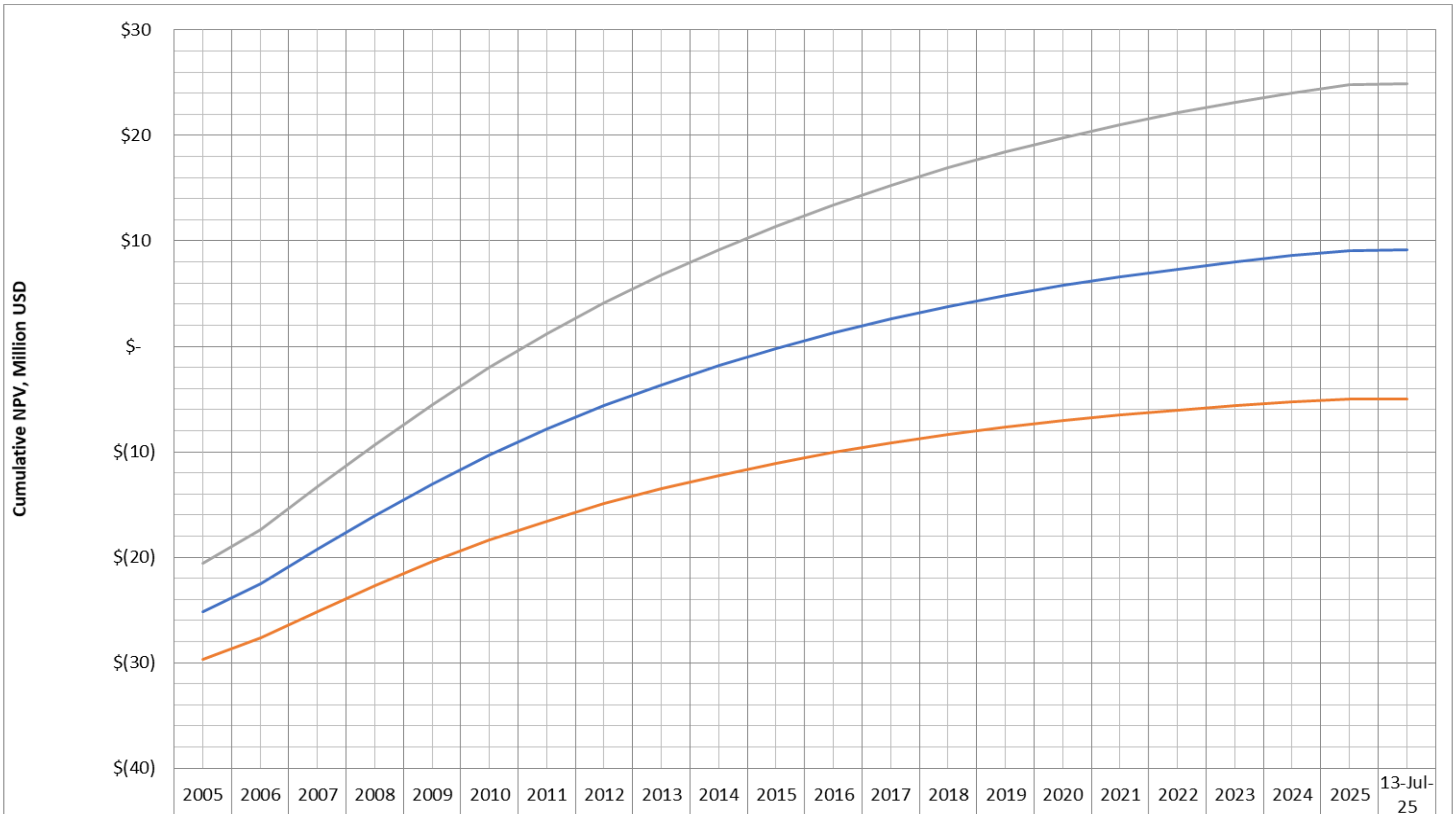
From Figures 3.6.1 and 3.6.2, it can be observed that the Cash flows from the first year are negative for all cases. This is because of the investment made during the start of the project. It can also be observed that there is very low and negative cash flows for some cases in 2025. This is because at that time the field is producing small amount of oil which results to lower revenues. After 2025 it is not economical to continue running the project because it will result to negative NPV.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	13-Jul-25
Best NPV	$(8)	$(5)	$(2)	$(0)	$2	$4	$6	$7	$8	$9	$10	$11	$12	$13	$14	$14	$15	$15	$16	$16	$16	$16
Base NPV	$(10)	$(8)	$(6)	$(4)	$(2)	$(1)	$1	$2	$3	$4	$4	$5	$6	$6	$7	$7	$8	$8	$8	$8	$9	$9
Worse NPV	$(12)	$(10)	$(9)	$(7)	$(6)	$(5)	$(4)	$(3)	$(2)	$(2)	$(1)	$(1)	$(0)	$0	$0	$1	$1	$1	$1	$1	$2	$2

Figure 3.6.3: Cumulative NPV for scenario 1

From Figure 3.6.3, it can be observed that for scenario 1 the best NPV case reach breakeven period (BEP) after one year of production i.e from 2005 to 2006. It takes approximately 5 years for the base NPV case to reach BEP. The worst case from this scenario has never reached BEP, it has only negative NPVs from 2005 to 2025.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	13-Jul-25
Best NPV	$(21)	$(17)	$(13)	$(9)	$(5)	$(2)	$1	$4	$7	$9	$11	$13	$15	$17	$18	$20	$21	$22	$23	$24	$25	$25
Base NPV	$(25)	$(23)	$(19)	$(16)	$(13)	$(10)	$(8)	$(6)	$(4)	$(2)	$(0)	$1	$3	$4	$5	$6	$7	$7	$8	$9	$9	$9
Worse NPV	$(30)	$(28)	$(25)	$(23)	$(20)	$(18)	$(17)	$(15)	$(14)	$(12)	$(11)	$(10)	$(9)	$(8)	$(8)	$(7)	$(7)	$(6)	$(6)	$(5)	$(5)	$(5)

Figure 3.6.4: Cumulative NPV for scenario 2

From Figure 3.6.4, it can be observed that for scenario 2 the best NPV case reach breakeven period (BEP) after three years of production i.e from 2005 to 2008. It takes approximately 8 years for the base NPV case to reach BEP. The worst case from this scenario has never reached BEP, it has only negative NPVs from 2005 to 2025.

3.6.2 Sensitivity analysis

Sensitivity analysis was performed with the purpose of understanding the impact of economical parameters on final project NPV. The aim is to understand which parameters has the most impact on NPV. Parameters involved in sensitivity analysis were OPEX, oil price, CAPEX and discount rate.

- OPEX

Operating Expenses (OPEX) involves all cost used in offshore operations such as maintenance, all cost used in running the desalination plant and all cost used in oil transportation after production. In economic analysis, OPEX was assumed to be 2.5% of the total capital expenditure plus revenue. The assumed value might deviate from the real cost incurred upon implementation. Therefore, sensitivity analysis is done by changing the assumed OPEX by high and low percent to see how the final NPV will be affected. Assumed OPEX was changed by ±5%, ±10% and ±15% to observe how the NPV will be affected. The result of the analysis is summarized in Table 3.6.3 which shows that the final NPV is affected by changing OPEX, but the good thing is that it remains positive for all changes and for both scenarios.

Table 3.6.3: Sensitivity analysis of OPEX for Scenario 1 and 2

Scenario 1 (No additional wells)							
OPEX	**Low**	**Base**	**High**	**Low**	**High**	**Low**	**High**
% Change	-15.00%	0%	15.00%	-10.00%	10.00%	-5.00%	5.00%
NPV (USD)	91814897	86002131	80189365	89877308	82126954	87939720	84064542
% Change	6.76%	0%	-6.76%	4.51%	-4.51%	2.25%	-2.25%
Scenario 2 (New well introduced)							
OPEX	**Low**	**Base**	**High**	**Low**	**High**	**Low**	**High**
% Change	-15.00%	0%	15.00%	-10.00%	10.00%	-5.00%	5.00%
NPV (USD)	103926925	91212346	78497766	99688732	82735959	95450539	86974153
% Change	13.94%	0%	-13.94%	9.29%	-9.29%	4.65%	-4.65%

- Oil Price

Oil price is an economical parameter which always may change depending on the world market. Therefore, there is a need to perform sensitivity analysis to see how change in oil price may affect NPV. Oil price was assumed to be $65 per barrel in economic analysis. The price was then changed by ±5%, ±10% and ±15% to observe how NPV will be affected. The result of the analysis in Table 3.6.4 show that the final NPV is highly affected by oil price. For example, when price dropped by 15% the final NPV decreased by 71.65%. But at the end both scenarios are very stable despite price changes all NPV remains positive.

Table 3.6.4: Sensitivity analysis of Oil Price for Scenario 1 and 2

Scenario 1 (No additional wells)							
Oil Price (USD/BBL)	**Low**	**Base**	**High**	**Low**	**High**	**Low**	**High**
% Change	-15.00%	0%	15.00%	-10.00%	10.00%	-5.00%	5.00%
NPV (USD)	50137098	86002131	121867164	62092109	109912153	74047120	97957142
% Change	-41.70%	0%	41.70%	-27.80%	27.80%	-13.90%	13.90%
Scenario 2 (New well introduced)							
Oil Price (USD/BBL)	**Low**	**Base**	**High**	**Low**	**High**	**Low**	**High**
% Change	-15.00%	0%	15.00%	-10.00%	10.00%	-5.00%	5.00%
NPV (USD)	25859890	91212346	156564802	47644042	134780650	69428194	112996498
% Change	-71.65%	0%	71.65%	-47.77%	47.77%	-23.88%	23.88%

- CAPEX

Capital Expenditure (CAPEX) cost is normally incurred when a fixed asset is purchased or adding value to an existing asset. In economic analysis CAPEX was assumed to be a sum of money used for new injection well and new desalination plant. The well cost was assumed to be $150 million and $120 million cost for desalination plant which sum up to $270 million total CAPEX. A sensitivity analysis performed to observe the impact of CAPEX in the final NPV. The result show that in scenario 2 where new injector is drilled the NPV is highly affected by CAPEX change. For example, decreasing CAPEX by 15% in scenario 2 will affect NPV by 44.4% while it is only affected by 6.76% in scenario 1. Further details are in Table 3.6.5. Despite those changes, all NPV remains positive for both scenarios at the end.

Table 3.6.5: Sensitivity analysis of CAPEX for Scenario 1 and 2

Scenario 1 (No additional wells)							
CAPEX	**Low**	**Base**	**High**	**Low**	**High**	**Low**	**High**
% Change	-15.00%	0%	15.00%	-10.00%	10.00%	-5.00%	5.00%
NPV (USD)	91814897	86002131	80189365	89877308	82126954	87939720	84064542
% Change	6.76%	0%	-6.76%	4.51%	-4.51%	2.25%	-2.25%
Scenario 2 (New well introduced)							
CAPEX	**Low**	**Base**	**High**	**Low**	**High**	**Low**	**High**
% Change	-15.00%	0%	15.00%	-10.00%	10.00%	-5.00%	5.00%
NPV (USD)	131712346	91212346	50712346	118212346	64212346	104712346	77712346
% Change	44.40%	0%	-44.40%	29.60%	-29.60%	14.80%	-14.80%

- Discount Rate

Discount rate was assumed to be 8% annually. Like other economical parameters sensitivity analysis was performed to see its impact on NPV. The assumed value (8%) was changed by ±5%, ±10% and ±15% and its impact on NPV is summarized in Table 3.6.6. From the table, decreasing discount rate by 15% will result to increase NPV up to 33.8%.

Table 3.6.6: Sensitivity analysis of discount rate for Scenario 1 and 2

Scenario 1 (No additional wells)							
Discount Rate (%)	**Low**	**Base**	**High**	**Low**	**High**	**Low**	**High**
% Change	-15.00%	0%	15.00%	-10.00%	10.00%	-5.00%	5.00%
NPV (USD)	100731373	86002131	73022858	95608981	77171921	90703109	81495145
% Change	17.13%	0%	-15.09%	11.17%	-10.27%	5.47%	-5.24%
Scenario 2 (New well introduced)							
Discount Rate (%)	**Low**	**Base**	**High**	**Low**	**High**	**Low**	**High**
% Change	-15.00%	0%	15.00%	-10.00%	10.00%	-5.00%	5.00%
NPV (USD)	122039473	91212346	64232329	111295015	72836902	101028107	81823001
% Change	33.80%	0%	-29.58%	22.02%	-20.15%	10.76%	-10.29%

The result of the analysis for all parameters is plotted in spider diagram as can be seen in Figure 3.65 for scenario 1 and 3.66 for scenario 2. From Figure 3.6.5 it can be observed that oil price has the most impact on NPV compared to other parameters. The second parameter to have more impact on NPV is CAPEX followed by discount rate and the one with the least impact is OPEX.

In scenario 2 it can be observed in Figure 3.6.6 that the parameter with the most impact on NPV is oil price followed by CAPEX then discount rate and the last is OPEX. Details of how NPV is affected by varying economic parameters is in Table 3.6.4.

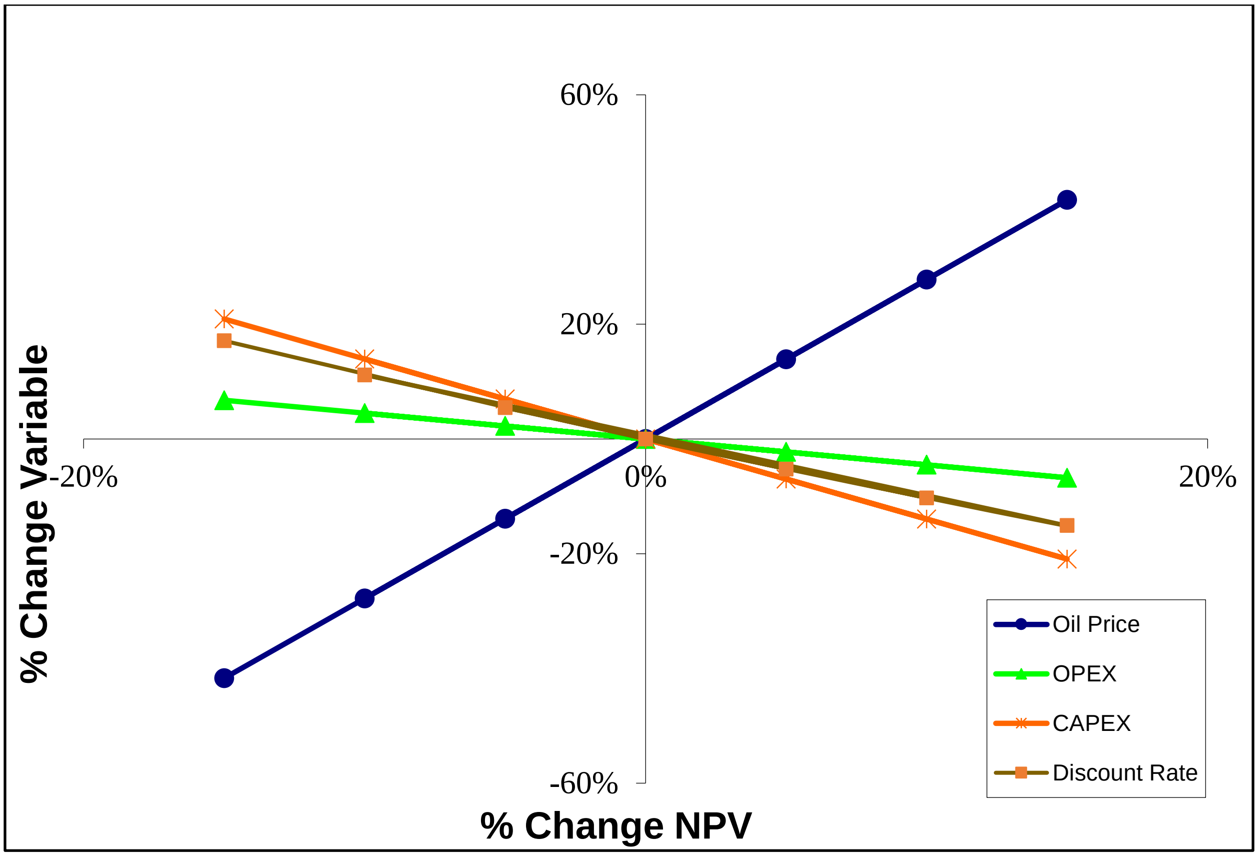


Figure 3.6.5: Spider diagram for scenario 1

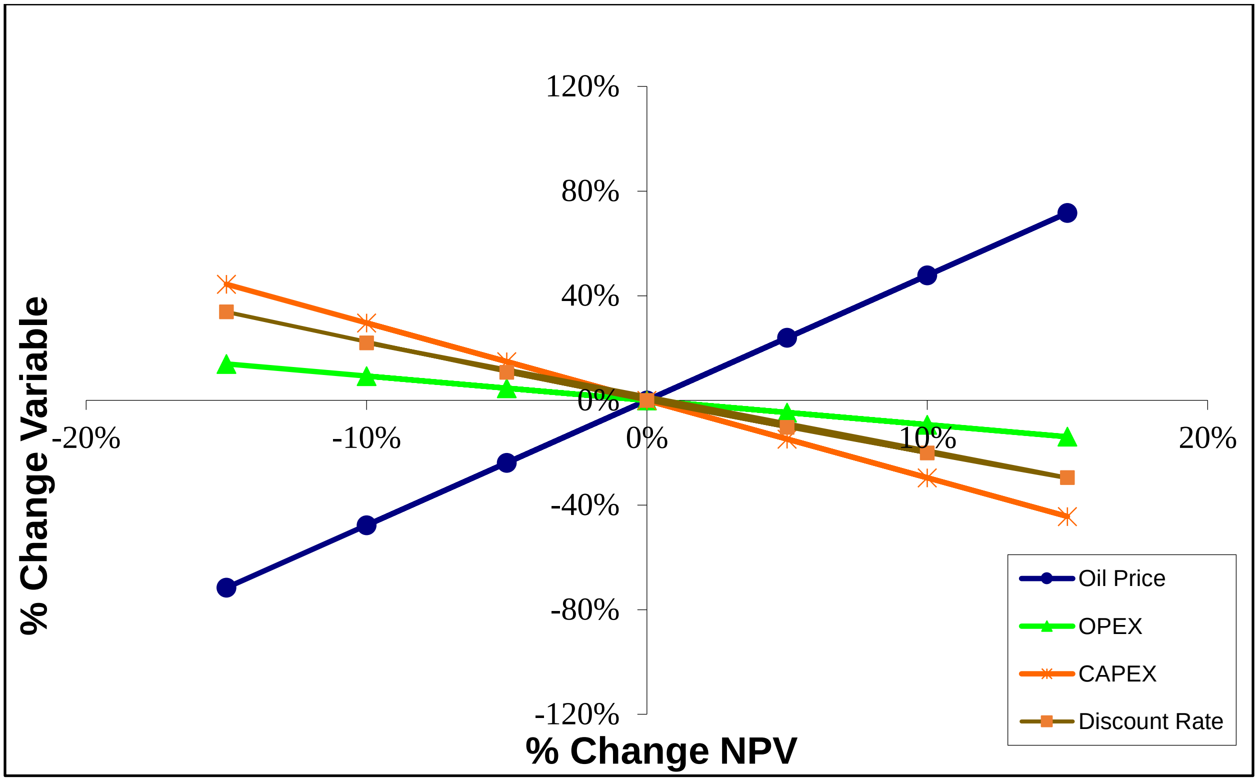


Figure 3.6.6: Spider diagram for scenario 2

CHAPTER 4

4 DISCUSSION OF RESULTS, CONCLUSION AND RECOMMENDATION.

4.1 Discussion of Results

The completion of this research was based on the completion of five dependent tasks i.e validation of the suitability of low salinity water flooding in K1/K2 segment, simulation of basecase model for K1/K2 and extend to run up to 2025, assessment of communications between injectors and producers, and between layers in the reservoir through tracer injection, preparation and simulation of black oil models of low salinity water flooding for new improved cases and performing economic and sensitivity analysis. The tasks were successfully completed, and the result presented in chapter 3.

It was important to start by assessing whether the method will work in a field or not. The first task was based on assessing whether low salinity water injection will work in Gullfaks field specifically in K1/K2 segment. The assessment started by studying the proposed mechanism of low salinity water flooding and gather the basic conditions required for low salinity to work in a field. One of the strongest conditions for a low salinity injection to work is presence of clay in the field. The assessment of clay presence in K1/K2 segment was done with the help of Techlog software. It started by identifying the wells presence in K1/K2 in a structure map of Statfjord formation as seen in Figure 3.2.2. From the Figure, well C-14, C-20A and C-24 were identified and their data were implemented in Techlog. The result presented in section 3.2 and Figures 3.2.3, 3.2.4 and 3.2.5 indicated the presence of clay in the formation. Also, shale volumes (Vshale) were estimated to some sections of the log presented and shows high percentage. This was the strong indication of clay presence because shale is usually made up of clay and other clay sized minerals. All those indications provide enough confidence to start implementing the method in simulation work.

The first part of simulation is usually to study the reservoir through basecase result simulated. The basecase were studied by assessing static and dynamic properties such as pressure, saturations, porosity and permeability. Also, production time were extended to 2025 and several production profiles were plotted and discussed in section 3.4. The saturation profiles gave the information that there are still areas where oil can be found and produced. Pressure grid profile provide the information on where there is enough pressure to produce the present oil. The permeability grid representation profile provides the information on whether the present oil can flow towards the perforated region and produced. Production profiles such as cumulative oil production and oil recovery profile are the quantitative output which mark the starting point of improvement.

After studying the reservoir through basecase simulation, the improved cases simulations were started to be implemented. Many cases that involved drilling of a new injector simulated did not improve recovery at all and some cases even lowered the recovery i.e the found recovery were less than the base case. There was small improvement to some cases, but it was not promising.

The reasons were thought to be presence of thief zones in the field. Also, presence of flow barriers in the reservoir were thought to be the reason. Another possible reason for the problem is lack of communication in the large part of the reservoir. All those were thought to be the possible reasons for the lack of recovery improvement upon implementation of low salinity water injection in the field.

To eliminate this problem, it was decided to implement tracer injection to assess the communications in the field. Areas with direct communication with presence producers should be the favored area to drill an injector. The tracer injection implemented with the aim of assessing both horizontal and vertical communication in the field. The result of tracer injection analysis is presented in section 3.3, communication between layers result is well summarized in Table 3.3.2. Tracer injection assessment result was the most helpful information upon implementing the improved cases. The focus of finding the position for new injector was referred to result in Table 3.3.2. Before injecting low salinity water in any new case, tracer was injected and observed if it is produced in present producers.

Simulation work was divided in to two scenarios. The first scenario involved the injection of low salinity water in the three injectors already present in the field. The wells C-4, C-13 and L1_I was injected water with varying salt concentration. The result for this work is summarized in section 3.5.1. Concentration of 500 ppm was the one that improved recovery by large percent i.e 1.9%. The reason for this is because in this method the driving factor is different in salinity between injected water and formation water. Therefore, the lower the salt concentration the better impact on recovery. It is also because the lower salt concentration has a big impact on altering wettability in sand consisting of clay. The changing of wettability from mixed or oil wet to more water wet in other hand is the reason to why small salt concentration has impact on recovery than high concentration. The summarized result for all salt concentration in scenario 1 is in Table 3.5.1.

Scenario 2 which involved the introduction of new injector had five different cases. The cases were formulated due different position of injection well introduced. As stated previously the selection of positions was possible with the help of tracer injection assessment performed in section 3.3. For the five cases analyzed in this scenario case 4 was the most promising with the maximum recovery improvement of 3.7% when injecting water with 500 ppm salt concentration. This concentration has higher impact on recovery for the same reasons stated in scenario 1. Recovery improvement in this case was higher (3.7%) compared to that of scenario 1 (1.9%) but it is economic analysis decided which one to recommend for implementation. Scenario two has higher recovery but also has extra cost due to introduction of new injection well, therefore this bring the work to the forth task which is economic analysis.

The economic analysis was bases on NPV model analysis. Due to lack of real data for some cases reasonable assumption were made to fulfill the analysis. The result of the analysis is presented in section 3.6. From the result scenario 1 concentration of 500 ppm managed to have NPV of 86,002,131 USD. The same concentration in scenario 2 managed to have NPV of 91,212,346 USD.

Up to this point it can be observed that adding new injector in the field not only result to higher recovery but also higher NPV. But as stated previously assumption were made during economic analysis therefore to analyses the stability of the project despite the assumptions made it is advised to perform sensitivity analysis. The sensitivity analysis marks the end of tasks to accomplish this research.

In sensitivity analysis, four parameters were changed by up to ±15% factor to see how NPV is affected. The parameters changed were Oil price, OPEX, CAPEX and discount rate. The result for sensitivity analysis of the two scenarios are well presented in subsection 3.6.2. The variation of parameters also was grouped to form best NPV case and worst NPV case. Best NPV case is when the oil price rise by +15%, OPEX changed by -15%, CAPEX changed by -15% and discount rate changed by -15%. The best NPV case result 200,359,931 USD NPV for first scenario and 325,072,308 USD for the second scenario. Worst NPV case is when oil price changed by -15%, OPEX changed by +15%, CAPEX by +15% and discount rate by +15%. The worst NPV case result 932,956 USD NPV for first scenario and -79,320,199 USD for the second scenario. From the result it can be observed that, though the first scenario has lower NPV compared to scenario 2 but in term of stability it is more stable because even if we lower the parameters values by 15% it still results to positive NPV.

Of the four parameters changed for both scenarios it can be observed in Figures 3.6.5 and 3.6.6 that oil price is the most sensitive parameter. It is the parameter that has the most impact on NPV compared to the rest. For both scenarios changing the other three parameters separately by ±5%, ±10% and ±15% will always result to positive NPV as seen in Tables 3.6.3, 3.6.4, 3.6.5 and 3.6.6.

4.2 CONCLUSIONS

The study conducted indicated improvement in the recovery of oil in K1/K2 segment when low salinity water used. From the study, the following are concluded:

- Low salinity water injection method screening was achieved and mark the starting point of the implementation of the method through reservoir simulation where cases formulated had positive results.
- Tracer injection to assess reservoir communication was successfully implemented and the result used as the main tool to decide different simulation cases especially in scenario 2 where a new injector was introduced in the field. Positions with possible thief zones were successfully identified and avoided when implementing low salinity injection cases.
- Low salinity water injection had positive impact in term of recovery by improving recovery factor for K1/K2 segment from 46.4% to 50.1% for the best case of scenario 2 where 500 ppm salt concentration used and from 46.4% to 48.3% for scenario 1 where 500 ppm was also used as injecting water salt concentration.
- The lowest salt concentration used i.e 500 ppm had more impact in term of improving recovery and the impact decreases when increasing salt concentration in injected water. This concluded that when implementing this method, you should apply the lowest salinity possible but also being careful because fresh water has negative impact in a formation containing clay because clay usually swell when it encounters fresh water.
- Economic analysis performed from two best cases in term of recovery resulted to higher NPV for scenario 2 (91,212,346 USD) compared to scenario 1 (86,002,131 USD).
- Variation of estimated economic parameters by ±15% which form best and worst NPV cases resulted to positive NPV for scenario 1 (932,956 USD) for worst case and negative NPV for scenario 2 (-79,320,199 USD) for worst case. Therefore, it can be concluded that despite of having lower NPV than scenario 2, scenario 1 is more stable project because it gives positive NPV even in worst case.
- Sensitivity analysis performed concluded that oil price is the parameter with the most impact on the final project NPV.

4.3 RECOMMENDATIONS

The following are the recommendations suggested after the successfully completion of the research work:

- I recommend investigating other EOR methods such as polymer, surfactant, combined low salinity and surfactant and alkaline injections in the field to see if they can improve much more oil than the methods applied in this research.
- I recommend core flooding experiments involving low salinity injection to be conducted in the field in order to identify changes in relative permeability curves so that to use the data later in simulation instead of using theoretical data for this purpose. Also investigating the mechanisms behind improving recovery by low salinity water injection, first I suggest repeating the experiments on the proposed mechanisms by Morrow and others, study them and then try to come up with the new suggested mechanism and finally use the experimental data obtain to perform simulation and compare the results. This is the research work I would like to conduct myself when I get the opportunity.
- On possible implementation of the method in real field, I recommend implementing the first scenario where low water salinity is injected in the well that already present in the field and used in conventional water flooding. This is because even though it has small NPV compared to the other scenario where new injector is drilled it proved to be more stable even when varying the estimated parameters by ±15% in worst NPV case it still gives positive NPV unlike second scenario where it resulted negative NPV. Therefore, second scenario is riskier project than the first.

CHAPTER 5

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CHAPTER 6

6 APPENDIX

6.1 SIMULATION RESULT FOR THE BEST CASES IN TWO SCENARIOS

6.1.1 Scenario 1

SALT CONCENTRATION = 500 ppm

Date	YEARS (YEARS)	FOE	FOPR (SM3/DAY)	FOPT (SM3)	FWCT	FWPR (SM3/DAY)	FWPT (SM3)
1-Apr-90	0	0	75.68	0	0	0.85299993	0
1-Apr-91	1	0.012310729	4690.3193	726875.12	0.065614231	321.2475	392357.9
1-Apr-92	2	0.055297896	8932.2227	3265284.6	0.068247229	666.84509	580857.44
1-Apr-93	3	0.11061141	11162.807	6531922	0.28419375	4837.626	1208570.8
1-Apr-94	4	0.16842061	8775.3535	9946034.7	0.40876353	6153.3794	3181852.5
1-Apr-95	5	0.21479763	7486.1167	12684823	0.48902348	7313.4502	5505260.8
1-Apr-96	6	0.24982956	5241.8276	14753580	0.52957201	5749.4727	7793874.9
1-Apr-97	7	0.28557181	6729.6274	16864245	0.57953757	9429.2666	10260510
1-Apr-98	8	0.31881422	4012.8413	18827558	0.64167255	7823.8589	13398831
1-Apr-99	9	0.34018338	2147.7888	20089811	0.6773448	4767.1772	15551064
1-Apr-00	10	0.3542203	780.44653	20918875	0.69903588	1893.1864	17490650
1-Apr-01	11	0.36815804	2804.0034	21741867	0.73701698	7769.6626	19655530
1-Apr-02	12	0.38057923	1624.97	22475363	0.76973635	6032.2632	21722170
1-Apr-03	13	0.39038245	1500.0385	23054295	0.81450632	6600.9946	24080546
1-Apr-04	14	0.39920463	1355.4159	23575305	0.83222376	6745.6172	26524515
1-Apr-05	15	0.40716028	1228.6602	24045157	0.84753579	6872.3726	29011540
1-Apr-06	16	0.41441748	1125.9407	24473708	0.8601912	6975.0923	31539867
1-Apr-07	17	0.42108592	1033.5304	24867507	0.87127539	7067.5024	34102944
1-Apr-08	18	0.42722609	947.75909	25230111	0.88169349	7153.2739	36705318
1-Apr-09	19	0.43287451	875.06219	25563686	0.89125258	7225.9707	39328619
1-Apr-10	20	0.43806092	799.61847	25869974	0.90016431	7301.4146	41979212
1-Apr-11	21	0.44281886	735.82092	26150955	0.90822692	7365.2119	44655107
1-Apr-12	22	0.44720387	683.53827	26409911	0.91532584	7417.4946	47361125
1-Apr-13	23	0.4512518	633.66968	26648957	0.92150544	7467.3633	50078961
1-Apr-14	24	0.45500528	587.12817	26870607	0.9270894	7513.9048	52814187
1-Apr-15	25	0.45850213	546.09668	27077107	0.9320935	7554.936	55564563
1-Apr-16	26	0.46177715	510.13248	27270513	0.93668967	7590.9004	58336136
1-Apr-17	27	0.46481812	475.8797	27450106	0.94089679	7625.1533	61113416
1-Apr-18	28	0.46765453	445.19974	27617603	0.94478951	7655.833	63902800
1-Apr-19	29	0.47030492	416.34067	27774113	0.94839745	7684.6924	66703162
1-Apr-20	30	0.47279022	388.87076	27920877	0.95177385	7712.1621	69521378
1-Apr-21	31	0.47510016	357.81644	28057279	0.95496242	7743.2163	72341852
1-Apr-22	32	0.47725866	339.27682	28184740	0.95795709	7761.7559	75171270

1-Apr-23	33	0.47927058	311.43668	28303558	0.96078724	7789.5962	78009325
1-Apr-24	34	0.48114833	290.039	28414446	0.96346754	7810.9937	80863417
1-Apr-25	35	0.48289224	269.85455	28517433	0.96599845	7831.1782	83717307
13-Jul-25	35.306849	0.48336294	269.85455	28545228	0.96668887	7831.1782	84523921

6.1.2 Scenario 2

CASE 4 SALT CONCENTRATION = 500 ppm

Date	YEARS (YEARS)	FOE	FOPR (SM3/DAY)	FOPT (SM3)	FWCT	FWPR (SM3/DAY)	FWPT (SM3)
1-Apr-90	0	0	75.68	0	0	0.85299993	0
1-Apr-91	1	0.012310729	4690.3193	726875.12	0.065614231	321.2475	392357.9
1-Apr-92	2	0.055297896	8932.2227	3265284.6	0.068247229	666.84509	580857.44
1-Apr-93	3	0.11061141	11162.807	6531922	0.28419375	4837.626	1208570.8
1-Apr-94	4	0.16842061	8775.3535	9946034.7	0.40876353	6153.3794	3181852.5
1-Apr-95	5	0.21479763	7486.1167	12684823	0.48902348	7313.4502	5505260.8
1-Apr-96	6	0.24982956	5241.8276	14753580	0.52957201	5749.4727	7793874.9
1-Apr-97	7	0.28557181	6729.6274	16864245	0.57953757	9429.2666	10260510
1-Apr-98	8	0.31881422	4012.8413	18827558	0.64167255	7823.8589	13398831
1-Apr-99	9	0.34018338	2147.7888	20089811	0.6773448	4767.1772	15551064
1-Apr-00	10	0.3542203	780.44653	20918875	0.69903588	1893.1864	17490650
1-Apr-01	11	0.36815804	2804.0034	21741867	0.73701698	7769.6626	19655530
1-Apr-02	12	0.38057923	1624.97	22475363	0.76973635	6032.2632	21722170
1-Apr-03	13	0.39038245	1500.0385	23054295	0.81450632	6600.9946	24080546
1-Apr-04	14	0.39920463	1355.4159	23575305	0.83222376	6745.6172	26524515
1-Apr-05	15	0.40716028	1228.6602	24045157	0.84753579	6872.3726	29011540
1-Apr-06	16	0.41478396	1232.8446	24495344	0.84757455	6868.188	31518228
1-Apr-07	17	0.42221669	1169.7184	24934267	0.85484747	6931.3145	34036184
1-Apr-08	18	0.42922747	1094.4418	25348296	0.86404682	7006.5908	36587134
1-Apr-09	19	0.43578407	1025.4523	25735509	0.87303047	7075.5806	39156797
1-Apr-10	20	0.44190443	956.02258	26096947	0.88135919	7145.0103	41752236
1-Apr-11	21	0.44761361	893.31238	26434107	0.88910403	7207.7207	44371953
1-Apr-12	22	0.45296602	835.49603	26750178	0.89613091	7265.5366	47020858
1-Apr-13	23	0.45797321	785.39642	27045878	0.90249646	7315.6362	49682036
1-Apr-14	24	0.46267959	738.51294	27323812	0.90818503	7362.52	52360978
1-Apr-15	25	0.4671264	696.4892	27586411	0.91341179	7404.5435	55055259
1-Apr-16	26	0.47133346	661.4884	27834855	0.91816002	7439.5444	57771790
1-Apr-17	27	0.47529186	621.8009	28068618	0.9226477	7479.2319	60494904
1-Apr-18	28	0.47903637	588.4176	28289752	0.92687658	7512.6152	63230648
1-Apr-19	29	0.48257535	555.70428	28498740	0.93087458	7545.3286	65978538
1-Apr-20	30	0.48592798	527.41998	28696722	0.93460277	7573.6128	68745528

1-Apr-21	31	0.48908725	493.41885	28883289	0.93812749	7607.6138	71515839
1-Apr-22	32	0.49207299	466.76157	29059613	0.94147055	7634.2715	74296394
1-Apr-23	33	0.49489632	441.36545	29226343	0.94464474	7659.6675	77086541
1-Apr-24	34	0.49757262	417.01877	29384394	0.94769371	7684.0142	79893477
1-Apr-25	35	0.50009374	393.6636	29533276	0.95060261	7707.3691	82701466
13-Jul-25	35.306849	0.5007804	393.6636	29573825	0.95140576	7707.3691	83495320

6.2 PLOTS FROM SIMULATION RESULTS

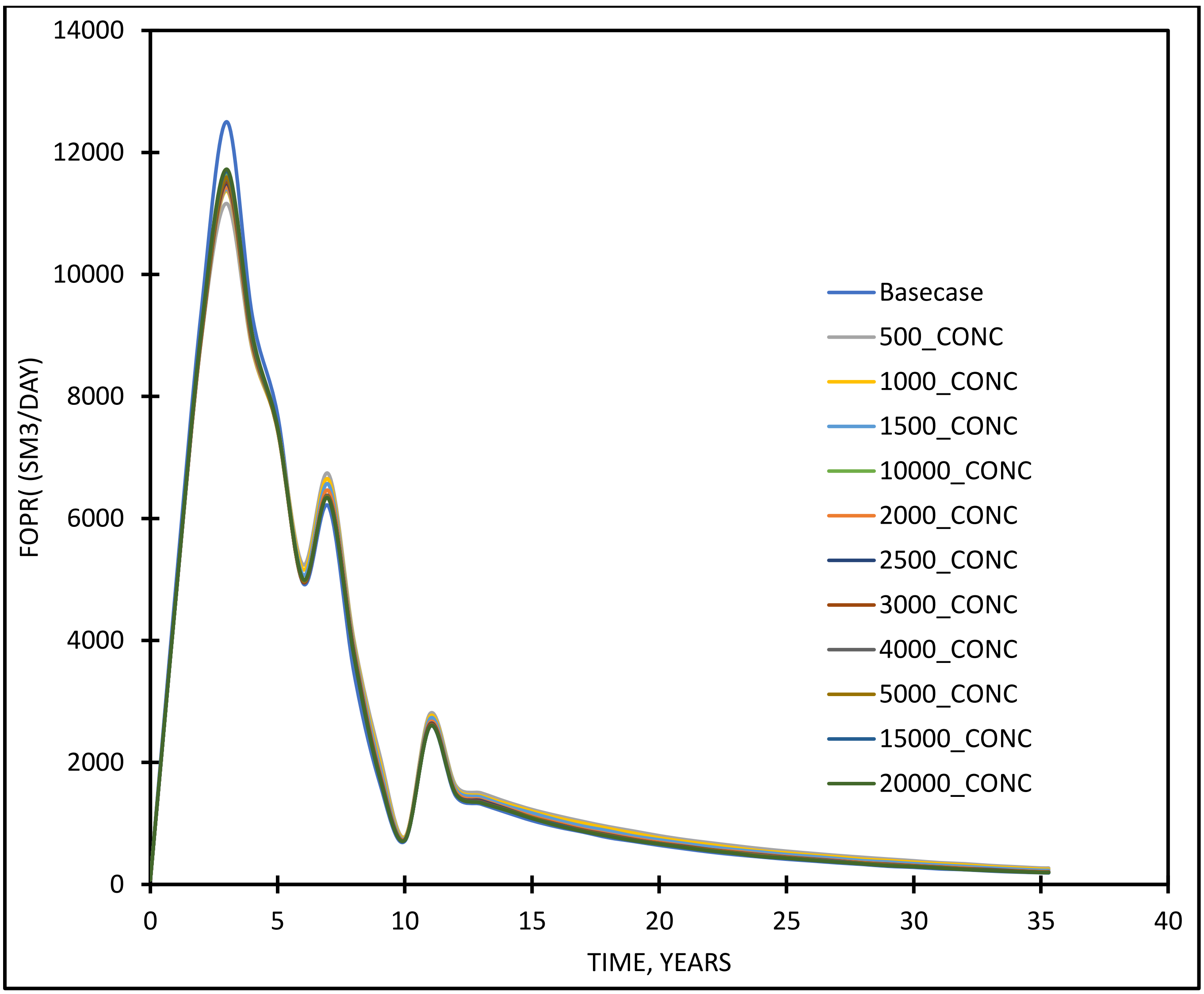

Figure 6.2.1: Oil production rate for scenario 1

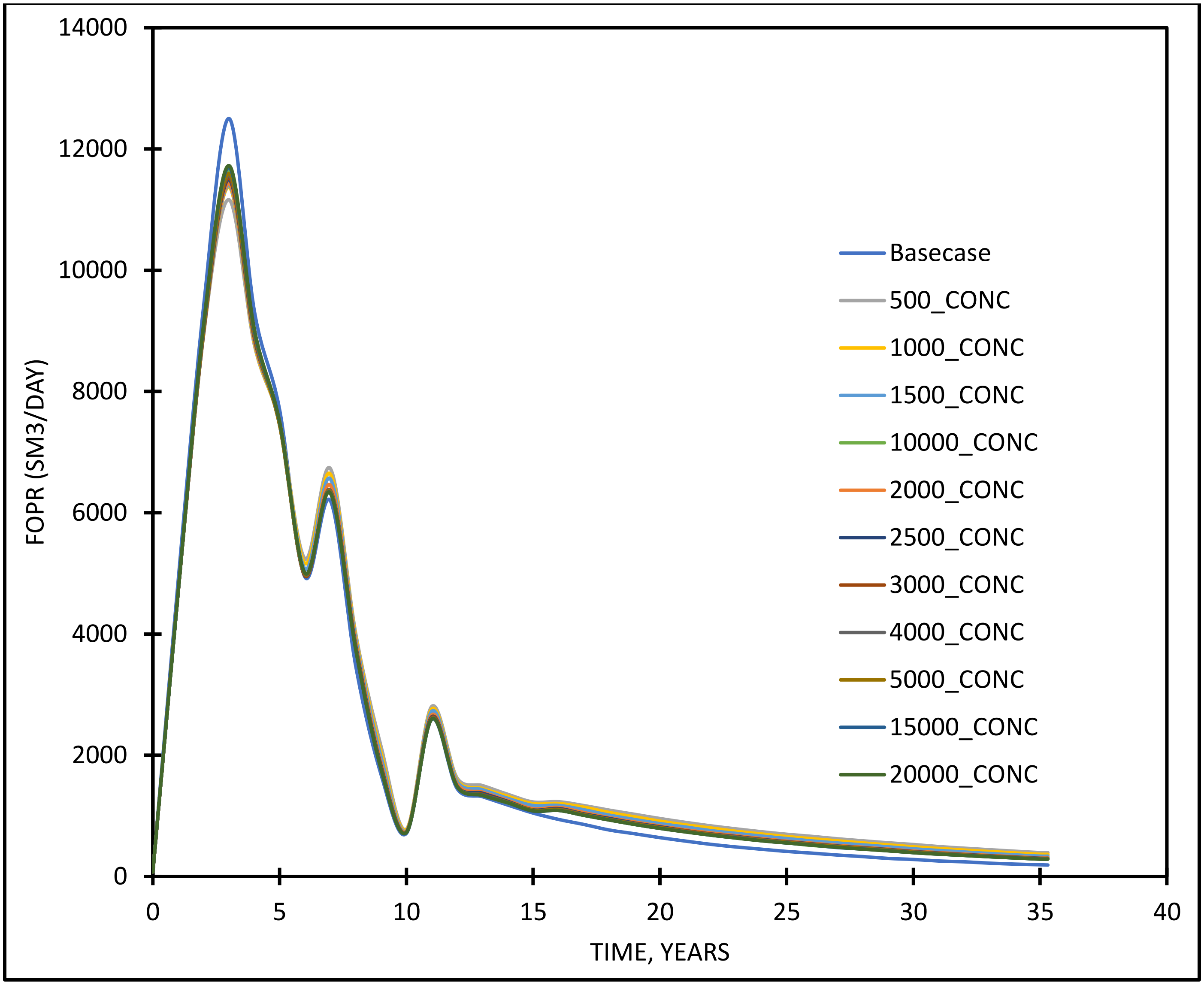

Figure 6.2.2: Oil production rate for scenario 2

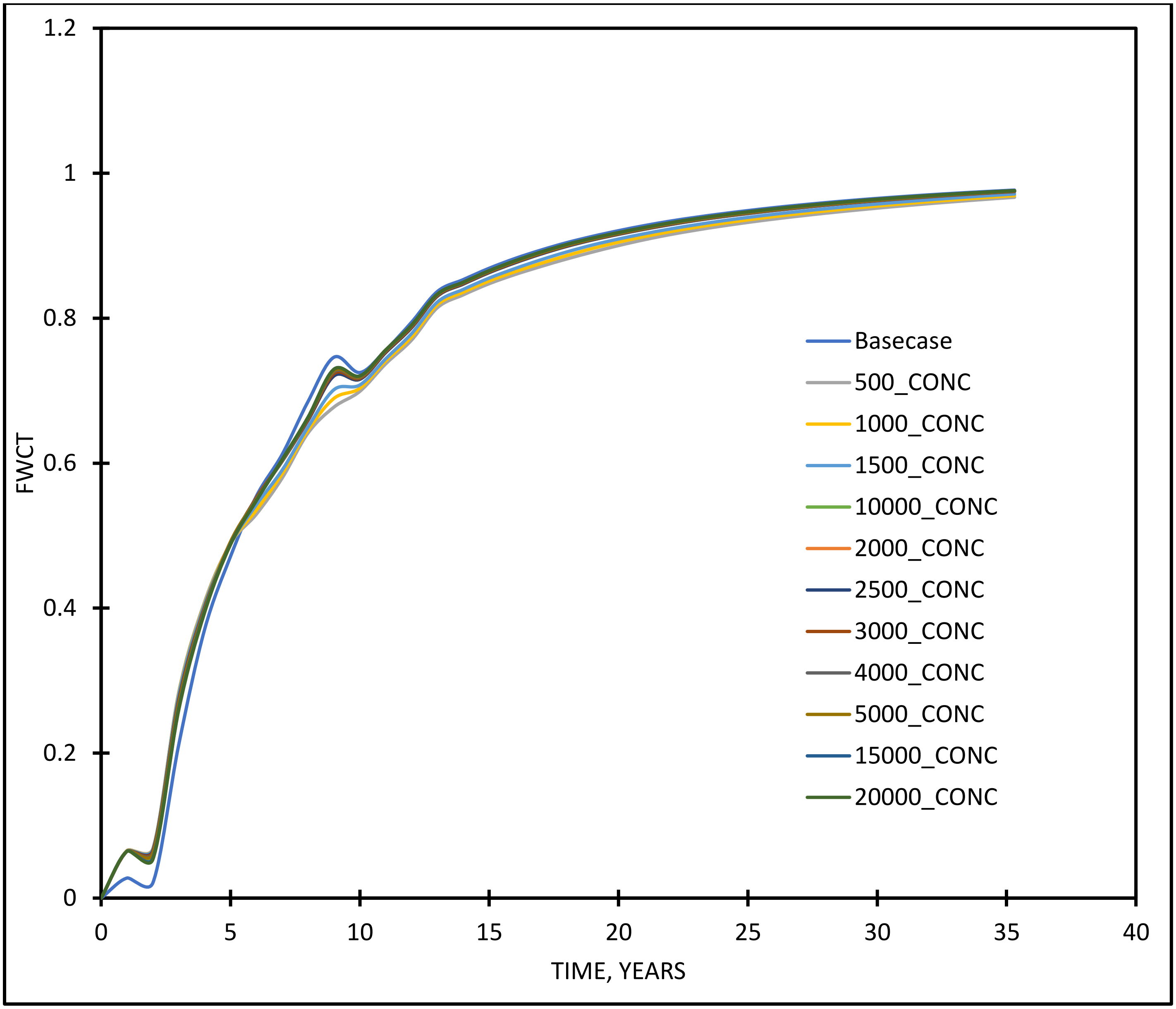

Figure 6.2.3: Field water cut for scenario 1

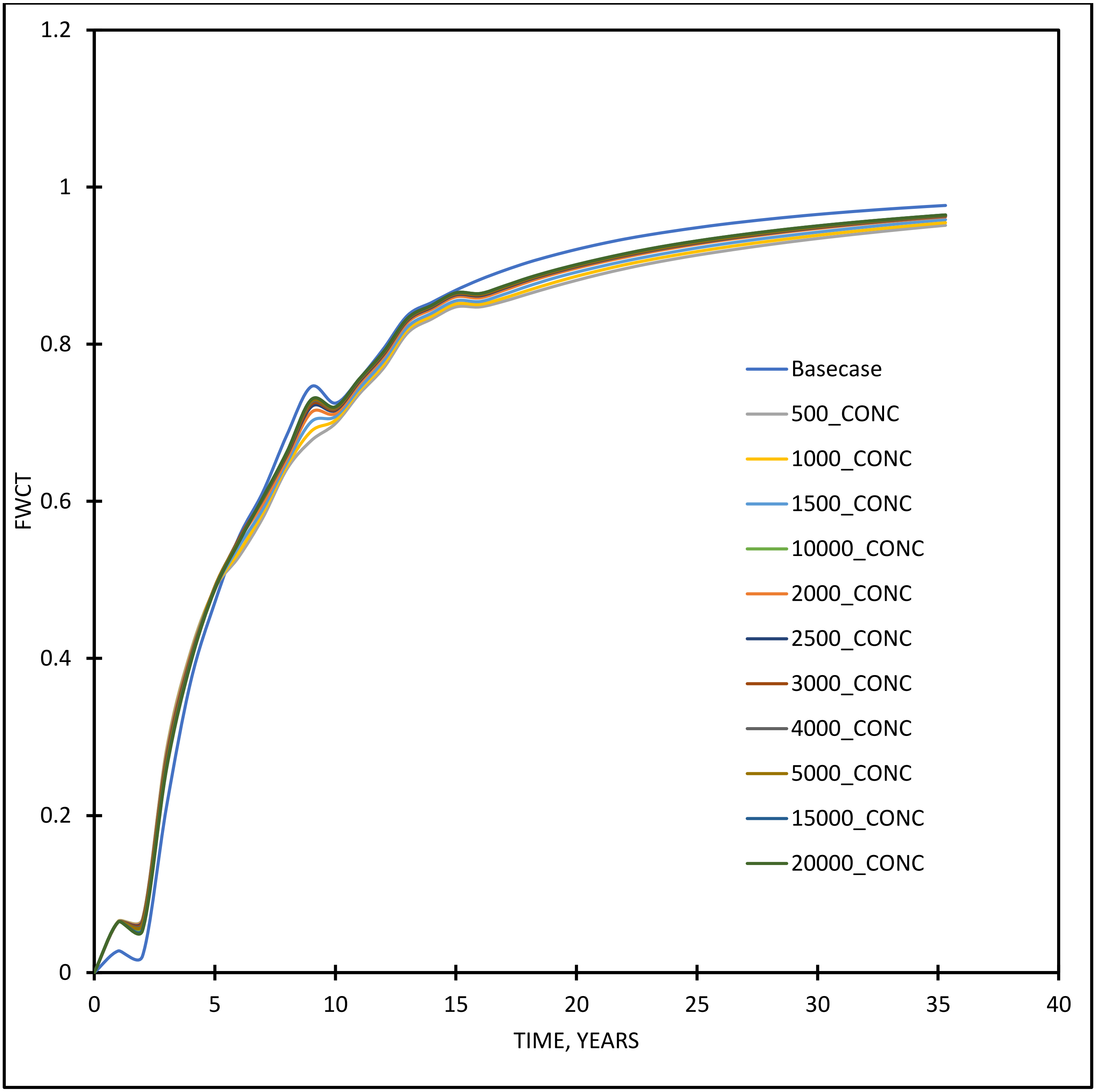

Figure 6.2.4: Field water cut for scenario 2

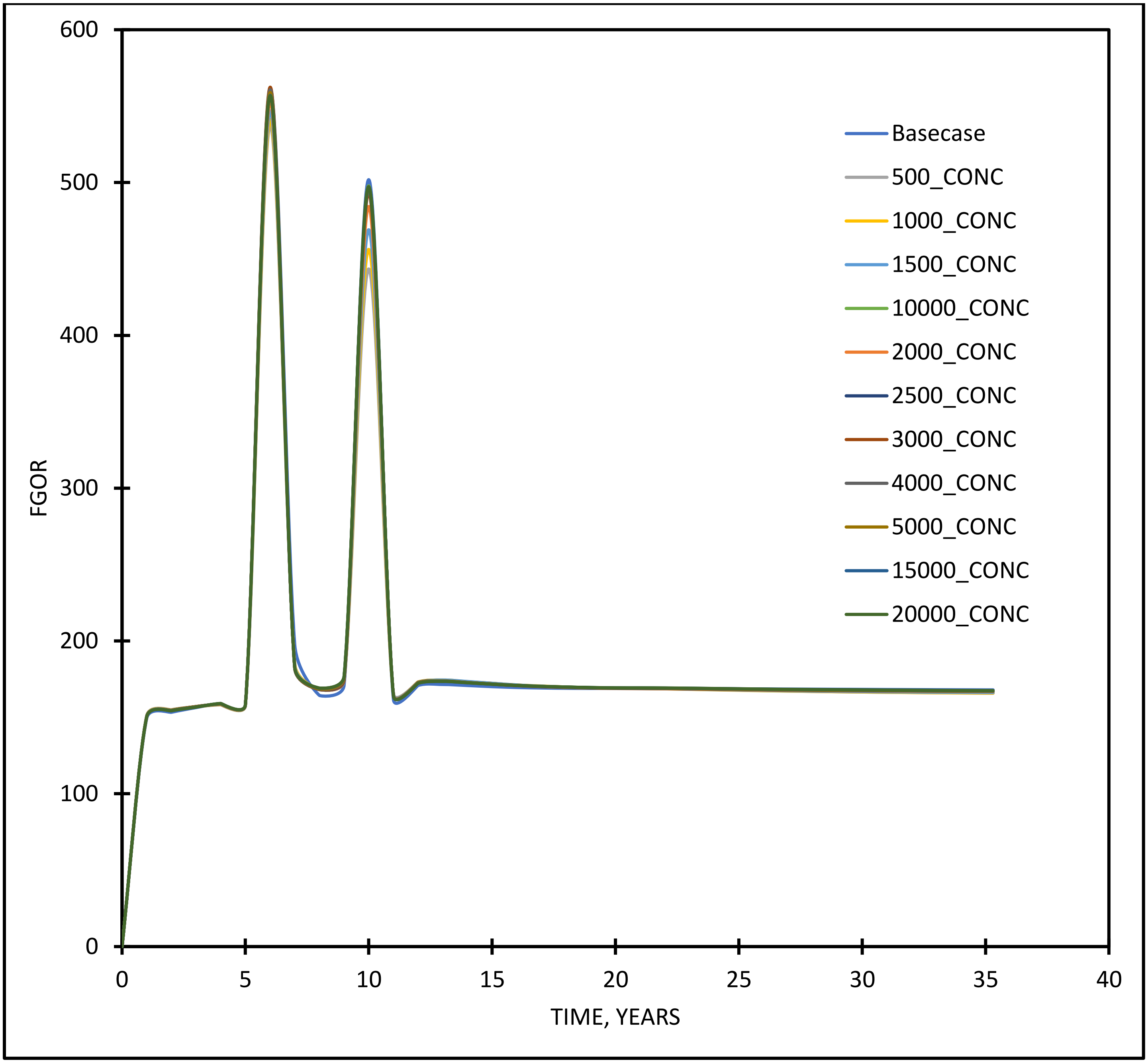

Figure 6.2.5: Field GOR for scenario 1

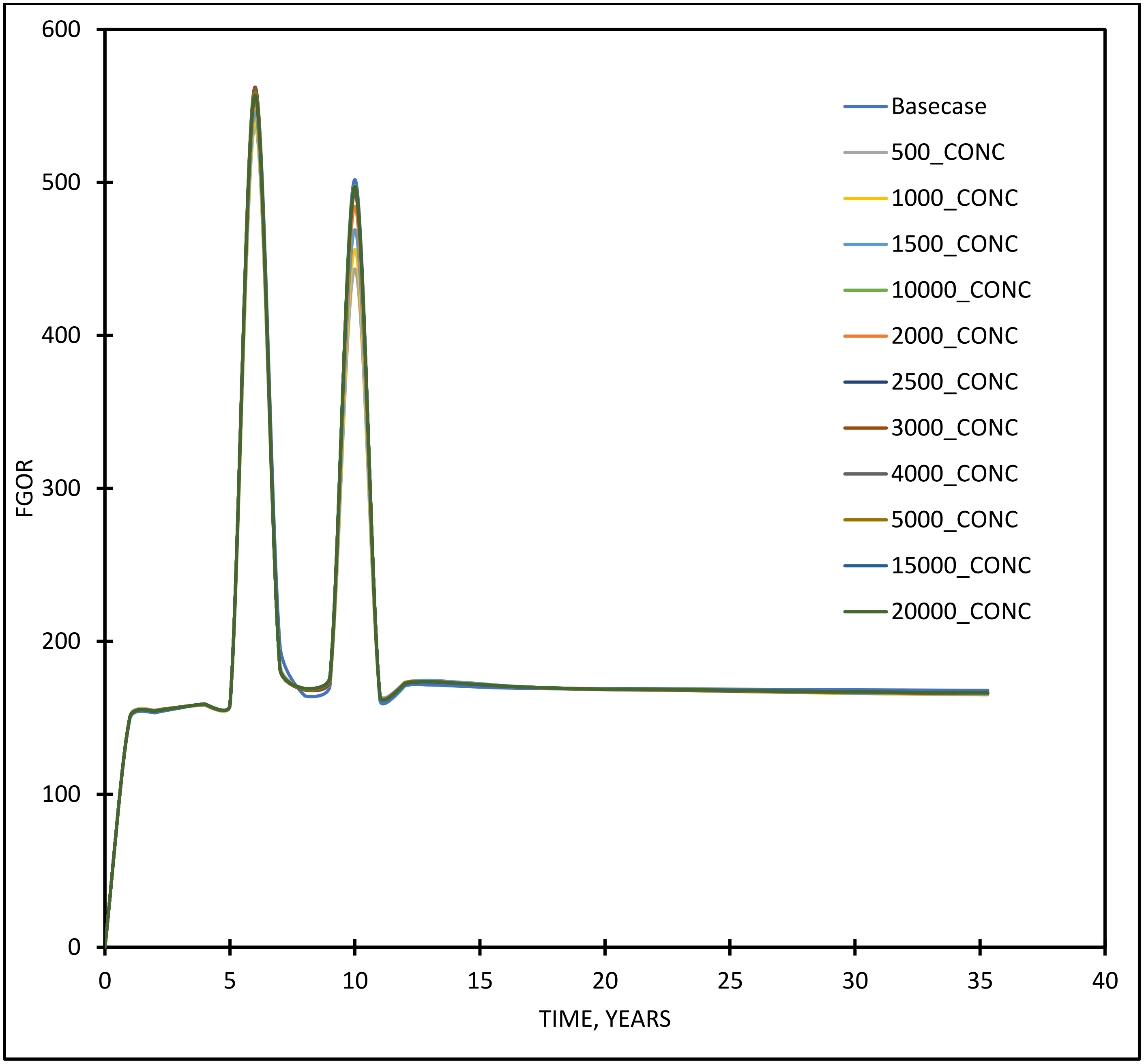

Figure 6.2.6: Field GOR for scenario 2

6.3 SAMPLE ECONOMIC ANALYSIS CALCULATIONS PERFORMED

NPV calculation for scenario 1

$$NPV = \sum_{t=1}^{T} \frac{Ct}{(1+r)^t} - Co$$

Discounted cash inflow = OPEX * (1 + Discount rate)^{time}

OPEX = (CAPEX + REVENUE) * 0.25

= (120000000 + 0) * 0.25
= 3000000
Discount rate = 8%
Time = 0 (since it's the first year i.e 2005)

Discounted OPEX = 3000000 * (1 + 0.008)^0
= 3000000

Cash in flow = REVENUE/(1 + Discount rate)^t

= 25407628/(1 + 0.08)^0
= 25407628
Presence Value(PV) = Cash inflow – Cash outflow

Cash outflow = OPEX + CAPEX
= 3000000 + 12000000
=123000000

PV = 25407628 – 123000000
= - 97592372

The same procedure is followed for years 2006 to 2025 in excel to get PV for each year. The full result for economic analysis is summarized in Figures 6.3.1 and 6.3.2.

NPV = ∑PV

= -97,592,37 + 21355135.61 + 20,374,420.06 + 17,225,181.22 + 14,858,509.44 + 12,731,710.54 + 9,844,138.21 +11,096,346.40 + 8,673,500.33 + 7,749,088.07 + 6,860,620.55 + 6,003,330.55 + 4,174,474.98 + 4,734,037.50 + 5,386,046.93 + 3,630,482.26 + 3,177,274.95 + 2,732,996.59 + 2,379,370.97 + 1,991,042.98 + 19,944.27

= 86,002,131 Tsh.

		65	Data				0.08	
		USD/Bbl					Interest 8%	
	Fiscal Year	Oil Production	CAPEX	PV	PV	Revenue	OPEX	Discounted OPEX
Number of Years	FY		USD	USD	USD, TEN MILLION		USD	
	Total		$120,000,000					
0	2005	$ 25,407,628	$ -	$ (97,592,372.30)	$ (9.8)	$ 25,407,628	$ 3,000,000.00	$ 3,000,000.00
1	2006	$ 26,698,737	$ -	$ 21,355,135.61	$ 2.1	$ 26,698,737	$ 3,635,190.69	$ 3,365,917.31
2	2007	$ 27,432,192	$ -	$ 20,374,420.06	$ 2.0	$ 27,432,192	$ 3,667,468.43	$ 3,144,263.06
3	2008	$ 27,112,481	$ -	$ 18,596,850.79	$ 1.9	$ 27,112,481	$ 3,685,804.80	$ 2,925,910.68
4	2009	$ 27,112,481	$ -	$ 17,225,181.22	$ 1.7	$ 27,112,481	$ 3,677,812.02	$ 2,703,301.63
5	2010	$ 25,509,837	$ -	$ 14,858,509.44	$ 1.5	$ 25,509,837	$ 3,677,812.02	$ 2,503,057.06
6	2011	$ 23,841,370	$ -	$ 12,731,710.54	$ 1.3	$ 23,841,370	$ 3,637,745.93	$ 2,292,396.99
7	2012	$ 22,613,222	$ -	$ 11,096,346.40	$ 1.1	$ 22,613,222	$ 3,596,034.26	$ 2,098,251.45
8	2013	$ 21,786,143	$ -	$ 9,844,138.21	$ 1.0	$ 21,786,143	$ 3,565,330.55	$ 1,926,237.16
9	2014	$ 20,883,021	$ -	$ 8,673,500.33	$ 0.9	$ 20,883,021	$ 3,544,653.58	$ 1,773,209.29
10	2015	$ 20,251,775	$ -	$ 7,749,088.07	$ 0.8	$ 20,251,775	$ 3,522,075.52	$ 1,631,402.45
11	2016	$ 19,502,785	$ -	$ 6,860,620.55	$ 0.7	$ 19,502,785	$ 3,506,294.39	$ 1,503,789.56
12	2017	$ 18,604,977	$ -	$ 6,003,330.55	$ 0.6	$ 18,604,977	$ 3,487,569.62	$ 1,384,961.88
13	2018	$ 18,113,145	$ -	$ 5,386,046.93	$ 0.5	$ 18,113,145	$ 3,465,124.43	$ 1,274,119.06
14	2019	$ 17,357,613	$ -	$ 4,734,037.50	$ 0.5	$ 17,357,613	$ 3,452,828.64	$ 1,175,553.63
15	2020	$ 16,676,081	$ -	$ 4,174,474.98	$ 0.4	$ 16,676,081	$ 3,433,940.33	$ 1,082,521.21
16	2021	$ 15,854,726	$ -	$ 3,630,482.26	$ 0.4	$ 15,854,726	$ 3,416,902.02	$ 997,361.13
17	2022	$ 15,152,343	$ -	$ 3,177,274.95	$ 0.3	$ 15,152,343	$ 3,396,368.15	$ 917,932.86
18	2023	$ 14,299,916	$ -	$ 2,732,996.59	$ 0.3	$ 14,299,916	$ 3,378,808.57	$ 845,543.56
19	2024	$ 13,626,152	$ -	$ 2,379,370.97	$ 0.2	$ 13,626,152	$ 3,357,497.91	$ 777,972.77
20	2025	$ 12,620,820	$ -	$ 1,991,042.98	$ 0.2	$ 12,620,820	$ 3,340,653.79	$ 716,731.28
	13-Jul-25	$ 3,408,480	$ -	$ 19,944.27	$ 0.0	$ 3,408,480	$ 3,315,520.49	$ 711,338.98
20			NPV in 2005	$ 86,002,131	$ 8.6			

Figure 6.3.1: Economic analysis result for scenario 1

		65 USD/Bbl	Data				0.08 Interest 8%		
	Fiscal Year	**Oil Production**	**CAPEX**	**PV**	**PV**	**Revenue**	**OPEX**	**Discounted OPEX**	**Cash inflow**
Number of Years	**FY**		**USD**	**USD**	**USD, TEN MILLION**		**USD**		
	Total		$ 270,000,000						
0	2005	$ 25,407,628	$ -	$ (251,342,372.30)	$ (25.1)	$ 25,407,628	$ 6,750,000.00	$ 6,750,000.00	$ 25,407,628
1	2006	$ 35,544,350	$ -	$ 26,073,295.31	$ 2.6	$ 35,544,350	$ 7,385,190.69	$ 6,838,139.53	$ 32,911,435
2	2007	$ 45,880,584	$ -	$ 32,786,330.26	$ 3.3	$ 45,880,584	$ 7,638,608.74	$ 6,548,875.81	$ 39,335,206
3	2008	$ 48,136,960	$ -	$ 31,943,765.73	$ 3.2	$ 48,136,960	$ 7,897,014.61	$ 6,268,904.80	$ 38,212,671
4	2009	$ 49,041,717	$ -	$ 30,201,122.30	$ 3.0	$ 49,041,717	$ 7,953,423.99	$ 5,846,004.07	$ 36,047,126
5	2010	$ 48,057,236	$ -	$ 27,278,586.70	$ 2.7	$ 48,057,236	$ 7,976,042.94	$ 5,428,360.80	$ 32,706,948
6	2011	$ 46,809,464	$ -	$ 24,487,151.97	$ 2.4	$ 46,809,464	$ 7,951,430.91	$ 5,010,750.25	$ 29,497,902
7	2012	$ 45,963,987	$ -	$ 22,198,163.11	$ 2.2	$ 45,963,987	$ 7,920,236.59	$ 4,621,381.98	$ 26,819,545
8	2013	$ 44,948,434	$ -	$ 20,016,602.74	$ 2.0	$ 44,948,434	$ 7,899,099.68	$ 4,267,637.77	$ 24,284,241
9	2014	$ 43,894,042	$ -	$ 18,019,133.44	$ 1.8	$ 43,894,042	$ 7,873,710.86	$ 3,938,815.73	$ 21,957,949
10	2015	$ 43,187,162	$ -	$ 16,369,170.11	$ 1.6	$ 43,187,162	$ 7,847,351.05	$ 3,634,841.90	$ 20,004,012
11	2016	$ 42,004,394	$ -	$ 14,656,949.52	$ 1.5	$ 42,004,394	$ 7,829,679.04	$ 3,358,015.13	$ 18,014,965
12	2017	$ 40,751,715	$ -	$ 13,085,535.94	$ 1.3	$ 40,751,715	$ 7,800,109.85	$ 3,097,530.94	$ 16,183,067
13	2018	$ 40,041,973	$ -	$ 11,866,781.41	$ 1.2	$ 40,041,973	$ 7,768,792.89	$ 2,856,569.02	$ 14,723,350
14	2019	$ 38,812,598	$ -	$ 10,575,247.28	$ 1.1	$ 38,812,598	$ 7,751,049.33	$ 2,638,930.33	$ 13,214,178
15	2020	$ 37,615,930	$ -	$ 9,424,344.74	$ 0.9	$ 37,615,930	$ 7,720,314.96	$ 2,433,765.25	$ 11,858,110
16	2021	$ 36,364,069	$ -	$ 8,369,571.22	$ 0.8	$ 36,364,069	$ 7,690,398.26	$ 2,244,753.94	$ 10,614,325
17	2022	$ 35,129,379	$ -	$ 7,424,363.13	$ 0.7	$ 35,129,379	$ 7,659,101.73	$ 2,070,017.39	$ 9,494,381
18	2023	$ 33,888,148	$ -	$ 6,571,517.89	$ 0.7	$ 33,888,148	$ 7,628,234.48	$ 1,908,958.27	$ 8,480,476
19	2024	$ 32,908,164	$ -	$ 5,864,854.88	$ 0.6	$ 32,908,164	$ 7,597,203.70	$ 1,760,363.75	$ 7,625,219
20	2025	$ 31,384,426	$ -	$ 5,108,762.26	$ 0.5	$ 31,384,426	$ 7,572,704.10	$ 1,624,710.09	$ 6,733,472
	13-Jul-25	$ 8,622,796	$ -	$ 233,468.20	$ 0.0	$ 8,622,796	$ 7,534,610.65	$ 1,616,537.21	$ 1,850,005
20			NPV in 2005	$ 91,212,346	$ 9				

Figure 6.3.2: Economic analysis result for scenario 2

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