EVALUATION OF LOW SALINITY BRINE INJECTION
IN SANDSTONE RESERVOIR

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การประเมินผลของวิธีการฉีดอัดน้ำเกลือที่มีความเค็มต่ำในแหล่งกักเก็บน้ำมันแบบหินทราย

นายณัชพล มุจลินทโมลี

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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การฉีดอัดน้ำเป็นกระบวนการเพื่อรักษาความดันของแหล่งกักเก็บและเพื่อแทนที่ไฮโดรคาร์บอนที่หลงเหลืออยู่ไปยังหลุมผลิตเมื่อการผลิตน้ำมันด้วยแรงปฐมภูมิไม่เพียงพอ จากรายงานการศึกษาไม่นานมานี้ พบว่าการฉีดอัดน้ำเกลือที่มีความเค็มต่ำสามารถเพิ่มผลผลิตน้ำมันได้ การฉีดอัดน้ำเกลือที่มีความเค็มต่ำได้ถูกทำการศึกษาโดยการสร้างแบบจำลองแหล่งกักเก็บด้วยโปรแกรม CMG STARS

ผลการศึกษาแสดงให้เห็นว่าตัวแปรต่างๆที่ทำการศึกษามีผลกระทบอย่างมีนัยสำคัญต่อประสิทธิภาพของการฉีดอัดน้ำเกลือที่มีความเค็มต่ำในแหล่งกักเก็บน้ำมันแบบหินทรายที่มีความลาดชัน น้ำเกลือที่มีความเค็มต่ำได้ถูกฉีดอัดตลอดระยะเวลาการผลิตของแหล่งกักเก็บ ผลการศึกษาแสดงให้เห็นว่าการฉีดอัดน้ำเกลือที่มีความเค็มต่ำให้ค่าสัดส่วนปริมาณน้ำมันที่ผลิตได้เพิ่มขึ้น 5.1 ถึง 7.7 เปอร์เซ็นต์ เมื่อเทียบกับการฉีดอัดน้ำแบบทั่วไป นอกจากนี้ผลดีของการฉีดอัดน้ำเกลือที่มีความเค็มต่ำยังเพิ่มขึ้นเมื่อความเค็มของน้ำในแหล่งกักเก็บสูงขึ้น โดยประมาณ 15.2 ถึง 16.7 เปอร์เซ็นต์ เมื่อน้ำในแหล่งกักเก็บมีความเค็ม 100,000 พีพีเอ็ม การปรากฏอยู่ของน้ำในแหล่งกักเก็บที่เคลื่อนที่ได้, น้ำมันที่มีความหนืดสูง, และสภาพความเปียกด้วยน้ำมันของแหล่งกักเก็บจะลดค่าสัดส่วนปริมาณน้ำมันที่ผลิตได้สูงสุด นอกจากนี้ค่าเลขยกกำลังคอรีย์ของน้ำมันที่ไม่เหมาะสมจะส่งผลให้เกิดความผิดพลาดในการศึกษาแบบจำลอง ขนาดปริมาณน้ำเกลือที่มีความเค็มต่ำ 0.25 เท่าของปริมาตรช่องว่างในแหล่งกักเก็บ พบว่าเป็นขนาดที่เหมาะสมที่สุด ในขณะที่การฉีดอัดน้ำเกลือที่มีความเค็มต่ำควรจะกระทำตั้งแต่วันแรกของการผลิต อัตราการฉีดอัดมีผลอย่างมีนัยสำคัญต่อผลผลิตน้ำมันเช่นกัน เนื่องจากอัตราการฉีดอัดที่ไม่เหมาะสมจะนำไปสู่การไหลของน้ำอย่างรวดเร็วในชั้นหินด้านล่าง และทำให้เกิดการผลิตน้ำอย่างรวดเร็ว ภายใต้สภาวะการผลิตที่ใช้ในการศึกษาแบบจำลองพบว่า ค่าความลาดชันที่ 45 องศา เป็นค่าที่ดีที่สุดที่จะทำให้แนวผิวหน้าของน้ำที่ใช้ในการแทนที่ มีเสถียรภาพและส่งผลให้ผลการฉีดอัดน้ำเกลือที่มีความเค็มต่ำมีประสิทธิภาพสูงสุด

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Water injection is a process to maintain reservoir pressure and to sweep remaining hydrocarbon toward a production well when primary recovery is not adequate. Recent studies suggested that injecting Low Salinity Brine (LSB) could yield additional oil recovery. LSB injection is simulated using CMG STARS in this study.

The results show that sensitivity of several parameters significantly affects the effectiveness of LSB injection in inclined sandstone reservoirs. LSB is assumed to be injected throughout the production period of reservoir. The result shows that LSB injection yields 5.1% to 7.7% of additional oil recovery factor compared to conventional waterflooding. Besides, the benefit of LSB injection is greater when formation water salinity is higher, reaching 15.2% to 16.7% when formation water is 100,000 ppm. The presence of mobile connate water, highly viscous oil, and oil-wet reservoir significantly reduces the ultimate oil recovery factor. Besides, unsuitable Corey-oil exponent leads to an error in simulation. The LSB slug size of 0.25 PV seems to be an optimal size, whereas LSB injection should be implemented from the first day of reservoir exploitation. Injection rate also significantly affects the oil recovery since the worst injection rate leads to water tongueing and hence, early water breakthrough is pronounced. Under the production conditions used in this simulation study, the dip angle of 45° is found as the best inclination that stabilizes the waterflood front and provides the best LSB injection result.

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List of Abbreviations

ANS	Alaska North Slope
bbl/day	Barrel per day
BHP	Bottomhole pressure
Ca^{2+}	Calcium ion
$CaCl_2$	Calcium chloride
$CaCO_3$	Calcium carbonate
cP	Centipoise
DLE	Double Layer Expansion
F or °F	Degree Fahrenheit
ft^3/bbl	Cubic feet per barrel
GOR	Gas-Oil ratio
H^+	Hydrogen ion
HSB	High salinity brine
IFT	Interfacial tension
IWS	Irreducible water saturation
lb/lbmole	Pound per pound-mole
LSB	Low salinity brine
LSB-Na&Ca	Low salinity of sodium and calcium brine
mD	Millidarcy
$MgCl_2$	Magnesium chloride
mg/L	Milligram per liter
MIE	Multicomponent ion exchange
MW	Molecular weight
NaCl	Sodium chloride
OH^-	Hydroxide ion
OOIP	Original oil in place
pH	Potential hydrogen
psia	Pound per square inch absolute
psi/ft	Pound per square inch per feet
ppm	Part per million

PVT	Pressure-Volume-Temperature
ROS	Residual oil saturation
SCAL	Special core analysis
scf/stb	Standard cubic feet per stock-tank barrel
stb/day	Stock-tank barrel per day
STC	Stock-tank condition
STO	Stock-tank oil
STW	Stock-tank water
TDS	Total dissolved solid

Nomenclatures

α_d	Dip angle
$\Delta\rho$	Water-oil sensity different
δ_o	displacement-by-oil ratio
δ_w	displacement-by-water ratio
μ_o	Oil viscosity
μ_w	Water viscosity
B_g	Formation volume factor of gas
B_o	Formation volume factor of oil
C_o	Corey-oil exponent
C_w	Corey-water exponent
f_w	Fractional flow of water
g	Acceleration term due to gravity
I	Amott-Harvey wettability index
k	Absolute permeability
k_h	Horizontal permeability
k_{rg}	Relative permeability to gas
k_{ro}	Relative permeability to oil (Oil/Water function)
kr_{og}	Relative permeability to oil (Gas/Liquid function)
k_{rw}	Relative permeability to water
N_c	Capillary number
R_s	Solution gas-oil ratio
S_l	Liquid saturation
S_w	Water saturation
$\bar{S}_w$	Average water saturation behind floodfront
S_{wc}	Connate water saturation
S_{wcr}	Critical water saturation
S_{wi}	Initial water saturation (connate water saturation)
S_{wmin}	Minimum water saturation (irreducible water saturation)
S_{wmax}	Maximum water saturation
S_{orw}	Residual oil saturation (to water)

u_t	Total fluid velocity
V_{osp}	Volume of oil displaced by spontaneous water imbibitions
V_{ot}	Total volume of oil displaced (including the V_{osp})
V_{wsp}	Volume of water displaced by spontaneous oil imbibitions
V_{wt}	Total volume of water displaced (including the V_{wsp})

CHAPTER I

INTRODUCTION

1.1 Background

Secondary recovery is usually considered after the production from natural-stored energy is declined in order to revitalize the oil production. Waterflooding is commonly implemented for several objectives. Water that is used in waterflooding process is generally supplied by produced water (formation water that is produced from a well along with oil and gas, usually has high salt content) and/or seawater. Reinjection of produced water instead of disposal can reduce the treatment cost and also prevent the environmental problem. Besides, seawater is also a good alternative choice since it is abundant especially in case of offshore production.

The oil production from secondary recovery may reach its limit after some periods of time. Prior to performing enhanced oil recovery techniques, the attempt to maximize oil recovery from waterflooding is also a good alternative.

Recent studies mentioned that injection of Low Salinity Brine (LSB) could yield some benefits compared to conventional waterflooding. Consequently, dilution the salinity of injected water is significantly considered. Several oil recovery mechanisms from LSB injection have been proposed. These mechanisms include additional recovery from oil attached on the surface of migrating particles, interfacial tension reduction due to the in-situ saponification as a result from increment of pH, and wettability alteration. However, wettability alteration is believed to be the most pronounce mechanism.

The change of rock preference occurs when the LSB is in contact with pore surface. The alteration requires proper aging time to complete [1]. Therefore, the proper injection rate should be operated to provide some retention times. However, the flow of water is also affected by the inclination of reservoir structure, so called dip angle. At a certain dip angle, inappropriate injection rate may cause water tonguing or under-running situation that leads to an early breakthrough. Thus, the optimal injection rate of LSB and dip angle should be well-considered in order to stabilize the displacement mechanism and lessen the amount of un-swept oil in reservoir.

In the first step of this study, the experiment of Amott-Harvey wettability index will be performed for the interested sandstone core samples. This experiment is aimed to study the effect of salinity on wettability alteration. The value of end-point saturation that is changed during the core analysis will be further used during relative permeability correlation in reservoir simulation study. The reservoir simulator called **STARS®** commercialized by **Computer Modelling Group Ltd. (CMG)** is chosen in this study. Simulation model will be constructed based on the proper reservoir parameters. Sensitivity analysis will be performed to study the effect of initial oil saturation when LSB is injected, initial water saturation, initial rock wettability, reservoir dip angle, and Corey's exponent of relative permeability. Consequently, effect of injection rate and inclination angle is studied. Besides, oil recovery mechanism by wettability alteration is evaluated by comparing with conventional waterflooding.

1.2 Objectives

1. To study the effect of fluid and petrophysical parameters affecting the effectiveness of LSB injection in inclined sandstone reservoirs, including oil viscosity, formation water salinity, initial water saturation, Corey's exponent, and initial wettability.
2. To evaluate the sensitivity of operational parameters for the LSB injection in inclined sandstone reservoirs, including injection slug size, time when starting LSB injection, and injection rate.
3. To evaluate the additional oil recovery from wettability alteration by injected low salinity brine compared to conventional waterflooding.

1.3 Outline of Methodology

1. Study various published literatures and design the laboratory experiment.
2. Conduct the experiment of LSB injection on interested core samples to obtained required data; wettability alteration and end-point saturation.
3. Construct base cases of reservoir simulation model; waterflooding in different inclined reservoirs.
4. Simulate the model with several internal parameters in order to investigate the influence of each parameter on the effectiveness of LSB injection includes
    - Salinity of formation water
    - Initial water saturation (presence of mobile connate water)
    - Oil property (mainly viscosity)
    - Corey's exponent
    - Initial wettability
5. Simulate the models and investigate the effect of operational parameters includes
    - LSB slug size
    - Starting time of LSB injection
    - Injection rate
6. Discuss the results from simulations for each studied parameter.
7. Summarize and indicate the parameters that most affect the effectiveness of LSB injection in inclined sandstone reservoirs.

1.4 Outline of Thesis

This thesis is divided into six chapters as shown in outline following

Chapter I, this chapter, introduces the background of LSB injection process and indicates the objectives and methodology of this study.

Chapter II introduces the various literatures related to the study of the LSB injection in laboratory experiment scale and also indicates the evidences of wettability alteration by LSB injection.

Chapter III presents the important concepts related to the possible mechanisms of LSB injection, the concept of wettability, and also the concept of flow property related to wetting condition.

Chapter IV provides the details of reservoir simulation models construction in CMG STARS. This chapter starts with the details of laboratory experiment, reservoir model dimension and petrophysical properties, pressure-volume-temperature (PVT) properties of reservoir fluids, special core analysis data, and finally, well data.

Chapter V presents the results and discussions for simulation study for each study parameters. The results are mainly investigated on oil recovery factor. However, peripheral data such as water cut and oil saturation gradient are also used in the investigation. The results of LSB injection are also compared with conventional waterflooding in order to observe the benefit of this method.

Chapter VI provides the conclusions and recommendations of this study.

CHAPTER II

LITERATURE REVIEW

This chapter summarizes previous studies related to low salinity brine injection in the past decades and several evidences that wettability alteration is likely responsible for additional oil recovery.

2.1 Studies of LSB Injection

In the past, the quality of the injected water was not as important as the quantity. However, many recent laboratorial results indicated that composition of injected water also plays an important role for design of waterflooding project to yield additional oil production. Injection of Low Salinity Brine (LSB) with proper selected cation can maximize oil recovery in certain cases. Different mechanisms of oil recovery have been discussed to better understanding and optimizing the LSB injection.

Tang and Morrow [2] studied the spontaneous imbibition and waterflooding test on Berea sandstone cores by using three different brines. They observed that oil recovery was increased with less salt content in injected brine and connate water or both of them.

Sharma and Filoco [3] performed waterflooding experiment, studying on water-wet Berea sandstone cores by centrifuge method. Several oils and different concentrations of sodium chloride (NaCl) brine were used. Starting from equal salinity of connate water and injected brine, increasing of oil recovery for Prudhoe Bay crude was observed when salinity was lower (0.3% NaCl brine yielded 70% recovery, while 20% NaCl brine yielded 57% recovery). This result showed a similar trend when using Shell A-1 and Shell A-20 crude. Later, they investigated the effect of connate brine salinity by keeping injected water salinity to be constant. Oil recovery from low salinity connate water was higher than higher salinity. Meanwhile, they also found that oil recovery was the lowest in oil-wet sample and no beneficial gain when using non-polar mineral oil. Therefore, they suggested that oil composition, connate water salinity and wettability are important keys to achieve the goal of LSB injection.

The historical field evidence of using LSB injection in three Minnelusa fields was summarized by Robertson [4]. Water with 1,000 ppm salinity obtained from Madison limestone and Fox Hills sandstone was injected into three reservoirs: West Semlek, North Semlek, and Moran field. Later, the produced water was mixed with makeup water and hence, salinity of injected water was changed with time. To simplify the analysis, he developed the equation that used to calculate for the average salinity of injected water over the waterflooding period. In summary, salinity of formation water and injected brines are shown in Table 2.1. The field data indicated that oil recovery from North Semlek field which has the lowest salinity ratio was the highest as illustrated in Figure 2.1. However, when considering the trend of result, it may be concluded that low salinity ratio tends to yield more oil recovery.

Table 2.1 Salinity of formation water and injected water and salinity ratio for each Minnelusa field

Properties	**Minnelusa filed**		
	North Semlek	**West Semlek**	**Moran**
Formation water salinity (ppm)	42,000	60,000	128,000
Average injected water salinity (ppm)	3,304	10,000	7,948
Salinity ratio	0.0787	0.1667	0.0621

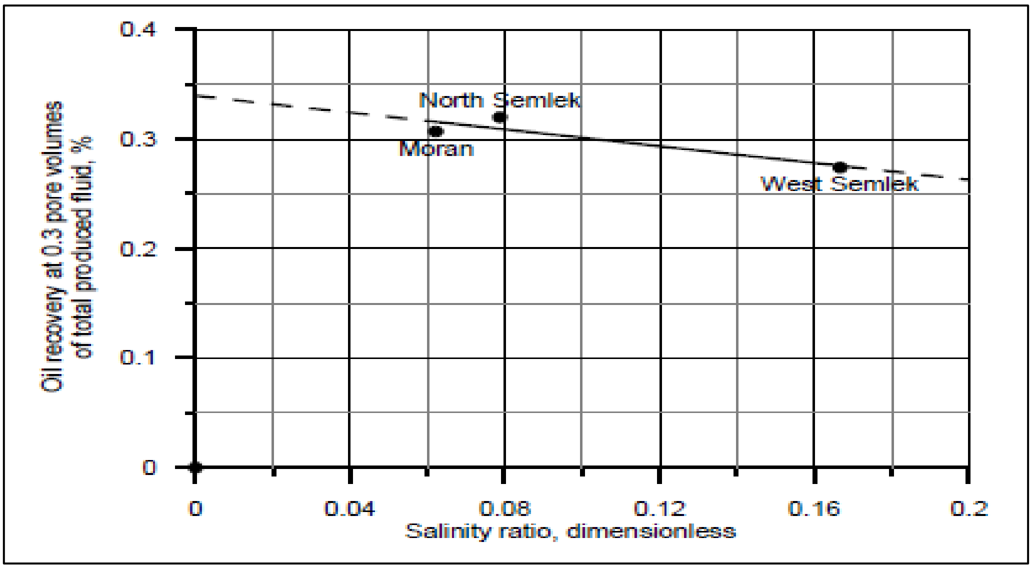

Figure 2.1 Oil recoveries from three fields with different salinity ratio [4]

Zhang et al. [5] studied the performance of brine injection with different salinities and oil properties. Two consolidated reservoir cores and two synthetic brines (with salinity of 29,690 and 1,480 ppm) were used. Similar trends were observed after performing multiple tests for each core. Additional oil recoveries of 3.8-16.5 % of OOIP were obtained after injecting of low salinity brine in tertiary mode. Benefit of LSB injection can also be observed in secondary mode. Injection of LSB increased recovery of about 29.2% of OOIP compared to high salinity reservoir brine in secondary mode.

In 2010, Rivet et al. [1] investigated the effect of salinity of injected water and cation type in brine on residual oil saturation, relative permeability curve, and oil recovery. The experiments were performed dividing in two sections: parallel and serial floods. In parallel floods, several Berea cores (similar properties) and five brines with different salinity and cation composition were used. The result was that low salinity of sodium and calcium brine (LSB-Na&Ca) yielded 15% higher oil recovery compared to the conventional high salinity flooding, while other brines yielded similar recovery. This result demonstrated that type of cation is possibly relevant to the effectiveness of LSB injection. In serial floods, the experiments were conducted in the same core. They found that persistent wettability alteration occurs and eliminates the salinity dependence when the core was exposed to the LSB. However, the core can be restored before reusing by aging in oil. From the relative permeability investigation, the end-point relative permeability to water was increased when higher recovery by LSB was obtained. Consequently, this discovery supports the hypothesis of wettability alteration.

Nasralla and Nasr-El-Din [6] performed a coreflood experiment to investigate the effect of cation type in brine on effectiveness of oil recovery in 2011. They used Berea sandstone cores and single cation brines. The conclusion was that injection of sodium chloride (NaCl) and magnesium chloride ($MgCl_2$) brine increased oil recovery significantly compared to calcium chloride ($CaCl_2$) brine. In their experiments, decreasing the concentration of single cation did not affect much to the oil recovery. Therefore, they suggested that cation types seem to be more dominant effect than salinity. They also proposed that absence of Ca^{2+} in brine allowed Ca^{2+} leaching from rock surface and then caused the surface instability and lead to desorption of crude oil.

There exists an unsuitable condition for low salinity brine injection mentioned by Boussour et al. [7]. In their work, waterflooding experiment was performed on cores from unconsolidated formation. They observed no additional oil production when injecting low salinity brines and suggested that negative result of low LSB injection is maybe obtained from unconsolidated formation.

2.2 Evidences of Wettability Alteration by Low Salinity Brine Injection

Many investigators believed that additional oil recovery is the result from wettability alteration toward a more favorable condition. Patil et al. [8] performed coreflood experiment on Alaska North Slope (ANS) sandstone cores using different salinity of injected water, 22,000 TDS to 5,500 TDS and ultralow salinity ANS lake water (50-60 TDS). Amott-Harvey wettability index was used to determine the wettability alteration. The result showed that wettability index increases with lowering the salinity of injected water, which means the preference is shifted toward a more water-wet condition. Besides, residual oil saturation is reduced from 41% to 32% for new clean cores and from 46% to 38% for oil-aged cores.

Nasralla et al. [9] had proven that the wettability alteration is the main mechanism for low salinity waterflooding by using contact angle method. They used synthetic water with salinity ranging from 0 to 174,000 ppm and used mica sheet to represent the sandstone surface. They found that contact angle is decreased with lowering salinity which is 60° for formation brine (174,000 ppm), 76° for seawater (55,000 ppm), 49° for aquifer water (5,400 ppm), 42° for 10% salinity of aquifer water (54 ppm), and 34° for deionized water (0 ppm). The results indicated that salinity of water has a great impact on the wettability. However, seawater yields different behavior and the authors suggested that this could due to the instability of water film. In addition, the temperature also affected the wettability. The experiment also showed that contact angle is increased when temperature is elevated. However, at the same temperature, contact angle is dependent on salinity as mentioned before. This indicated that low salinity waterflooding has good potential for a wide range of temperature.

Ashraf et al. [10] compared the oil recovery from low salinity waterflooding with various initial wettability conditions (water-wet, neutral-wet, neutral-wet toward oil-wet, and oil-wet). Four long cores with different wettability were prepared (A-D). Each long core was cut into twin plugs that assumed to have the same properties. The schematic of twin cores is displayed in Figure 2.2.

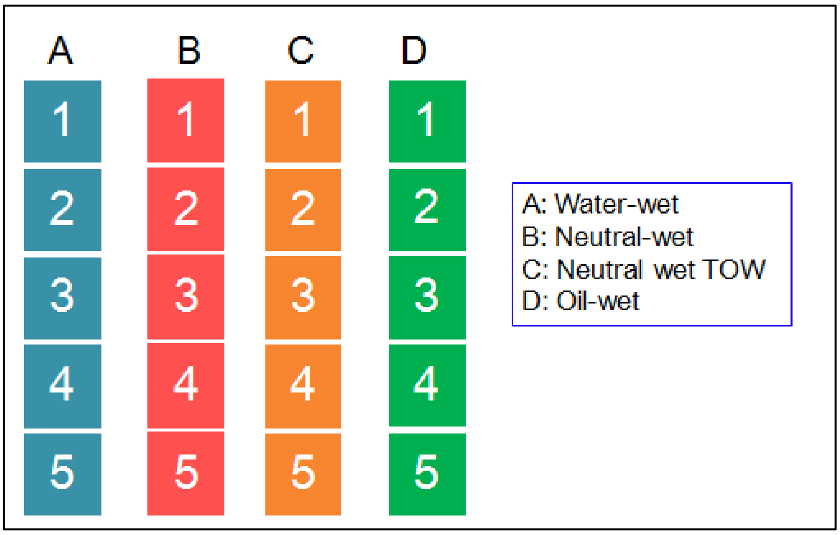

Figure 2.2 Schematic of five twin cores from different wettability long cores

Then, each twin plug was flooded with different salinity from 24,951 ppm (high salinity brine) to 249.51 ppm (low salinity brine). The maximum benefit was observed in water-wet core with 21% additional recovery from high salinity (70% recovery of OOIP using low salinity brine compare to 49% of OOIP using high salinity brine). However, cores with neutral-wet yielded the highest ultimate oil recovery (72% of OOIP). The result indicated that initial wettability condition is also an important parameter.

Vledder et al. [11] studied the data from the Omar field in Seria. In this field, formation water of 90,000 ppm (with 5,000 ppm of divalent cation) was detected. The reservoirs contains 0.5-4.0% of clay which is 95-100% Kaolinite. Water from Euphrates River having salinity of around 500 ppm was used as an injectant in order to prolong the production life. From field observations, they believed that several wells show a change in wettability toward a water-wet state. They suggested that dual-steps in water cut development is the clearly evidence of wettability alteration.

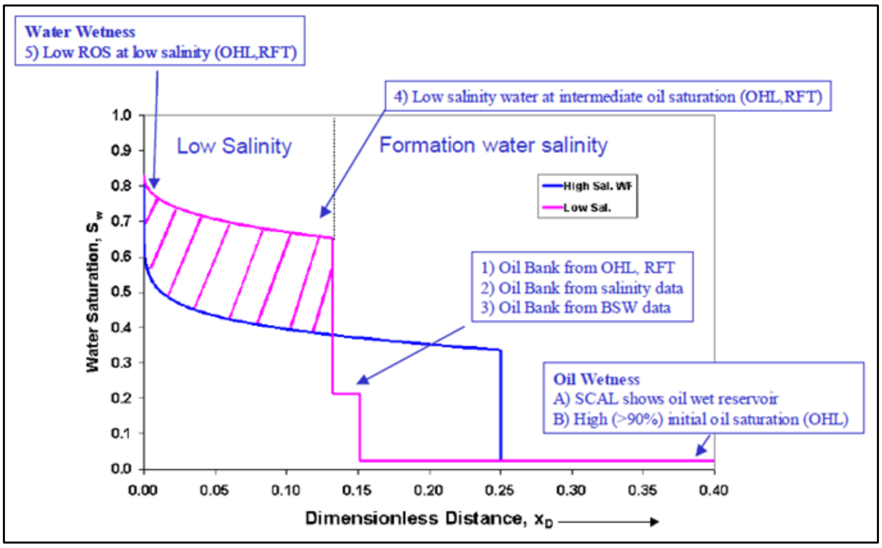

Figure 2.3 Water saturation profile based on Buckley-Leverett theory [11]

There is an oil bank ahead of the shock front due to the accumulation of the desorbed-oil which results in constant water saturation for some distances as portrayed in Figure 2.3 and Figure 2.4. The desorbed-oil was a result from wettability change to a more water-wet condition. Therefore, this work had shown that wettability alteration is able to occur in reservoir scale.

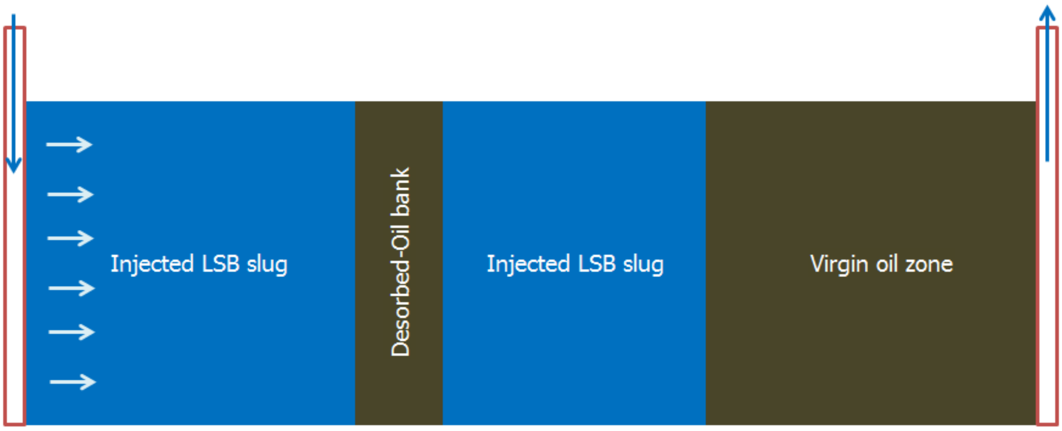

Figure 2.4 Schematic view of desorbed-oil bank ahead of the shock front

CHAPTER III

THEORY AND CONCEPT

In this chapter, the generality of salinity and several possible oil recovery mechanisms of LSB injection are described as well as the concept of wettability and wettability measurement. The concept of relative permeability is also explained in this section as it represents the flow ability of porous medium-fluids system related to wetting condition.

3.1 Salinity

Salinity, or the saltiness of water, is the content of Total Dissolved Solid (TDS) suspending in water. These suspended solid usually refers to mineral salt and are expressed in the unit of part per million (ppm) or mg/L. According to the US Geological survey [12], saline water can be categorized into three types as shown in Table 3.1. Basically, seawater has salinity of about 35,000 ppm, while formation water has extremely high salinity and may have the salinity up to the magnitude of 300,000 ppm [12] in some locations. In a rare case, isolated fresh water can also be found as formation water and this could results in difficulty in well logging interpretation.

Table 3.1 Classification of saline water (US Geological Survey)

Classification	Salinity (ppm)
slightly saline water	1,000-3,000
moderately saline water	3,000-10,000
highly saline water	10,000 – 35,000

3.2 Oil Recovery Mechanisms of LSB Injection in Sandstone Reservoir

For past decades, several oil recovery mechanisms of LSB injection have been proposed. These include recovery from fine migration, interfacial tension reduction due to the in-situ saponification, and wettability alteration from multicomponent ion exchange.

Tang and Morrow [2] believed that fine migration caused by LSB is responsible for the additional oil recovery. Sandstone reservoir usually contains clays which are associated on the pore surface by two main competing colloidal forces: electrostatic repulsion force and Van der Waals attractive force. LSB injection leads to the change of ionic environment, or salinity shock. This situation allows electrostatic repulsion force to be more dominant, resulting in fine particles migration. Besides, some oil droplets that are previously attached to the clay surface will flow and be produced with the migrated particles. However, this mechanism has many contradictions because several experiments observed no fine particle produced after performing LSB injection. Therefore, this mechanism may not be the main mechanism that controls additional oil recovery.

There is an expectation that the positive responds to LSB injection comes from the increasing of capillary number (N_c) associated with interfacial tension (IFT) reduction. Oil recovery could be improved when capillary number is raised to the magnitude of 10^{-4} (typically 10^{-6} in conventional waterflooding) [13]. McGuire et al. [14] suggested that LSB injection results in a rise of pH value and hence, IFT reduction is achieved through the saponification reaction occurred at high pH condition. The rising of pH value is ascribed to the carbonate dissolution reactions as shown below.

$$CaCO_3 \rightleftarrows Ca^{2+} + CO_3^{2-} \qquad (3.1)$$

$$CO_3^{2-} + H_2O \rightleftarrows HCO_3^{-} + OH^{-} \qquad (3.2)$$

Carbonate materials in sandstone reservoir basically refer to cementing materials (Carbonatic arenite). When LSB is injected, the difference of calcium ion concentration at the rock surface and in aqueous phase causes the imbalance of ionic environment and consecutively results in dissolution of calcium ion into aqueous phase. As the dissolution occurs gradually, a large quantity of hydroxide ions (OH^-) is presented due to the reactions mentioned above. Cation exchange also occurs simultaneously and results in declining of hydrogen ions (H^+) content due to the exchange with adsorbed cations. These two phenomena promote the increment of pH value. Once the pH value reaches 9 or above, this condition favors saponification reaction and yields in-situ surfactant. As IFT between oil and brine is decreased due to the surfactant, previously trapped oil is readily to move and then released from the rock surface. In this situation, LSB injection is acting like an alkaline substance in alkali flooding. However, there are some evidences that positive result of LSB injection was observed at the pH below 7. Thus, this theory might not be the main mechanism.

Among these mechanisms, many investigators believed that wettability alteration is the most possible mechanism. Lager et al. [15] believed that when LSB is injected, Multicomponent Ion Exchange (MIE) emerges. MIE allows some adsorbed materials to be replaced by un-complex inorganic cations (monovalent ions) found in brine. Consequently, the adsorbed materials that promoted the oil-wet state are removed and the rock surface is altered toward a more water wetness.

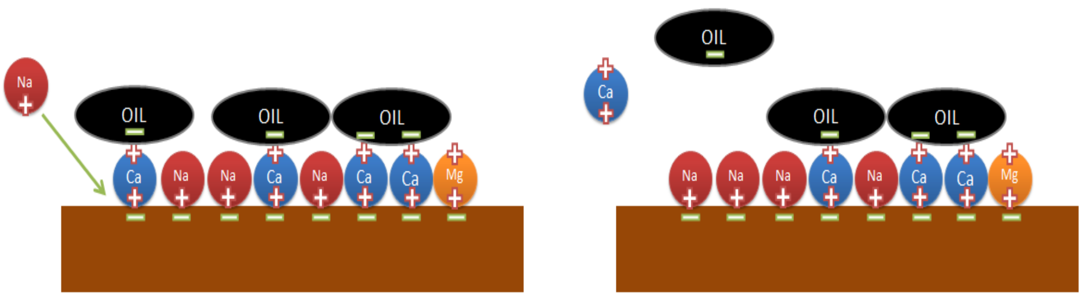

Figure 3.1 Schematic view illustrating MIE mechanism

Additionally, Lee et al. [16] indicated that Double Layer Expansion (DLE) could trigger the occurrence of MIE mechanism. Double-electrical-layered is the structure that is found on the object's surface when it is immersed in liquid. The object might be anything such as gas bubble or solid particle. However, the object is referred to the rock surface in this study. Double-layered system consists of the two parallel layers which are adsorbed layer or Stern layer and diffuse layer as shown in Figure 3.2. In the adsorbed layer, ions are adsorbed directly to the rock surface. The diffuse layer has free ions which move in the fluid (Brownian motion) and hence, water film is developed. Ligthelm et al. [17] suggested that lowering the salinity will expand the double layer and thus, the water film is also thickening and becoming more stable. The water wetness is produced as the water film is more stable and thus, desorption of oil-wet induced materials is facilitated.

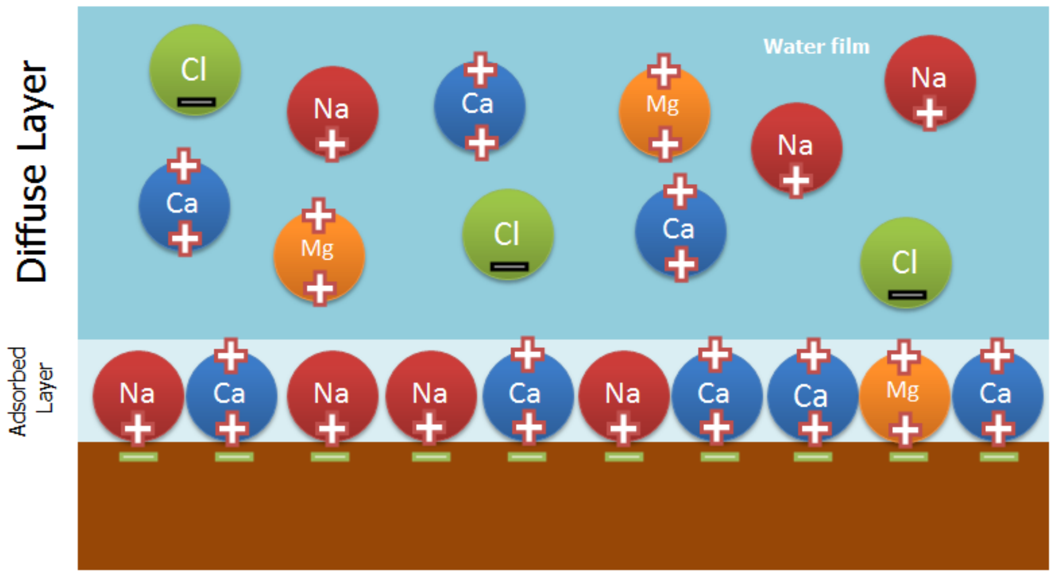

Figure 3.2 Double electric layers

3.3 Wettability

Wettability is the preference of the rock surface to be adhered with a fluid in the presence of other immiscible fluids. A preferential fluid is typically called wetting phase, while other fluids are called non-wetting phase. In oilfield application, wettability of the formation is usually classified into three major types which are water-wet, oil-wet, and intermediate-wet. Water-wet rock has a surface that prefers to adhere by water when there is a presence of oil phase, whereas oil-wet has a surface that has preference to be attached by oil when there is a presence of water phase instead. Intermediate-wet has no preference of either oil or water.

In waterflooding process, wettability is considered an important factor because it controls the flow and distribution of fluid in the reservoir [18]. In oil production, water-wet condition is more favorable than oil-wet because oil-wet allows more oil to be trapped in the reservoir (higher residual oil saturation) and this requires higher amount of pore volume of injected water in order to obtain the same oil recovery compared to water-wet case.

Initially, all reservoir rocks are believed to be a water-wet condition due to the deposition in aqueous environment. Nevertheless, wettability can be altered during the oil migration period due to some induced components in oil. Principally, four mechanisms are involved when sandstone is change toward oil-wet; polar interaction, surface precipitation, interaction with base compounds and ion binding [19].

Generally, wettability can be determined quantitatively by three methods which are contact-angle, Amott method, and USMB method. The contact-angle is a technique to determine the wettability of a pure mineral surface such as calcite and quartz, while Amott and USMB measure the average wettability of a core sample.

3.3.1 Wettability Measurement by Amott-Harvey Method

Amott-Harvey method (or modified Amott method) measures the volume of oil and water displaced by spontaneous imbibition and external force in order to determine the Amott-Harvey wettability index (*I*). In order to obtain the wettability index, laboratory experiment should be conducted. The schematic of the laboratory experiment is shown in Figure 3.3.

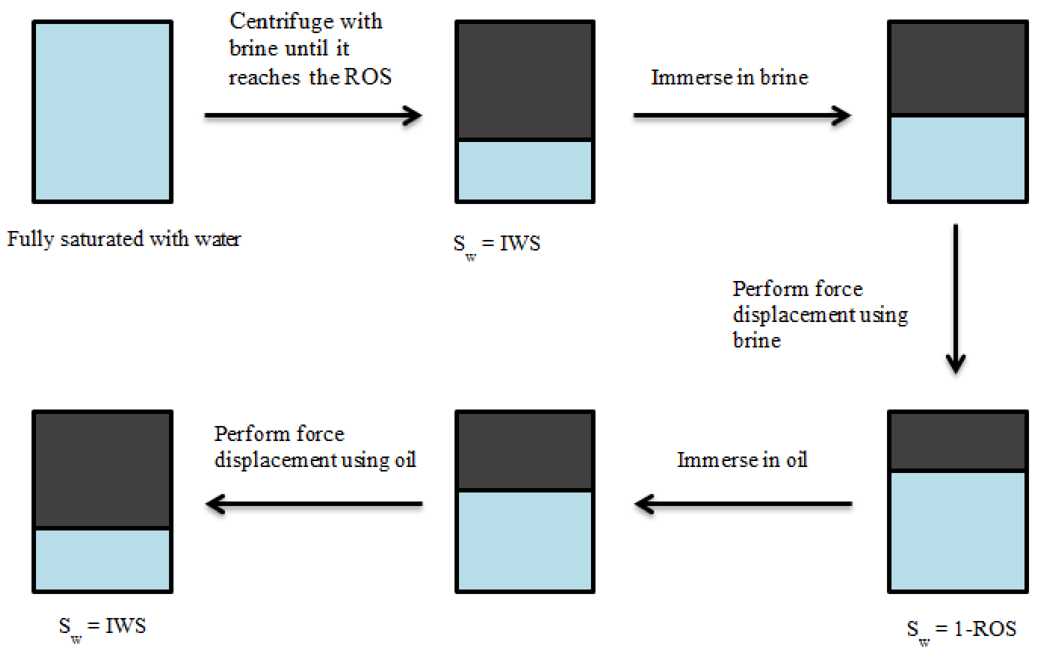

Figure 3.3 Amott-Harvey wettability index experiments

From the experiments, the displacement-by-water ratio (δ_w) and displacement-by-oil ratio (δ_o) are calculated by using equations (3.3) and (3.4) below:

$$\delta_w = V_{osp}/\, V_{ot}, \tag{3.3}$$

$$\delta_o = V_{wsp}/\, V_{wt}. \tag{3.4}$$

where V_{wsp} = volume of water displaced from imbibition of oil,

V_{wt} = total volume of water displaced from forced displacement by oil,

V_{osp} = volume of oil displaced from imbibition of water,

V_{ot} = total volume of oil displaced from forced displacement by water.

Then, the Amott-Harvey wettability index is calculated by

$$I = \delta_w - \delta_o. \quad (3.5)$$

The obtained wettability index can be used to determine the preference of rock surface by using the Amott-Harvey wettability index classification as shown in Table 3.2.

Table 3.2 Classification of the wettability type by using Amott-Harvey wettability index

Classification	**Amott-Harvey wettability index (*I*)**
Oil-wet	$-1 < I < -0.3$
Neutral-wet	$-0.3 < I < 0.3$
Water-wet	$0.3 < I < 1$

3.4 Relative Permeability

Relative permeability is defined as the ratio of effective permeability to base permeability. Base permeability may refer to the absolute air permeability, the absolute water permeability, and the effective permeability to oil at Irreducible Water Saturation (IWS). Basically, the effective permeability to oil at IWS is widely used and thus, relative permeability to oil is 1.0 at IWS.

3.4.1 Relative Permeability Curve

Relative permeability curves are usually plotted with water saturation as shown in Figure 3.4. Relative permeability to oil starts at IWS and decreases as water saturation increases, while relative permeability to water increases as water saturation increases. The water saturation at the crossover point is called crossover saturation. Basically, relative permeability curve is corresponded to the preference of the rock. There is a rule of thumb for the relationship of relative permeability curves and wettability as we can see in Table 3.3.

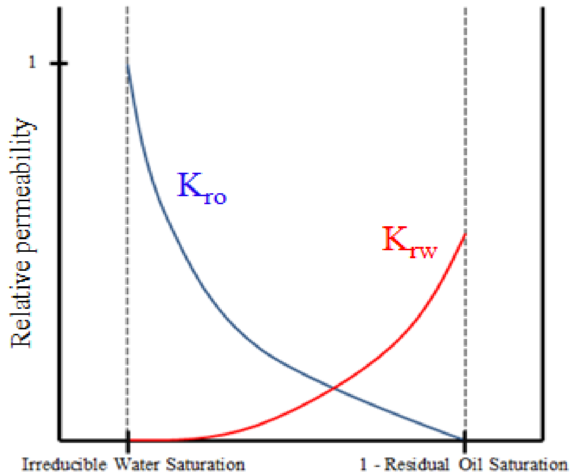

Figure 3.4 Relative permeability curves representing relative permeability to oil and water plotted against water saturation

Table 3.3 Classification of rock wettability from relative permeability curve [20]

Properties	**Water wet**	**Oil wet**
IWS	Usually > 20-25%	Usually < 15%
Crossover saturation	> 50%	< 50%
k_{rw} at ROS	Generally < 30%	> 50% (Can approach 100%)

In reservoir simulation input, relative permeability curves are constructed based on the end point saturation obtained from laboratory experiment and the rule of thumb shown in Table 3.3.

3.4.2 Corey's Correlation

Basically, relative permeability curves may be obtained directly from special core analysis or indirectly by using several correlations. For two-phase relative permeability, Corey's correlation is generally used in reservoir simulator. In the use of Corey's correlation, relative permeability to oil and water is calculated by following equations:

$$k_{ro}(S_w) = k_{ro@S_{wmin}} \left[\frac{S_{wmax} - S_{orw} - S_w}{S_{wmax} - S_{orw} - S_{wi}}\right]^{C_o} \quad (3.6)$$

$$k_{rw}(S_w) = k_{rw@S_{orw}} \left[\frac{S_w - S_{wcr}}{S_{wmax} - S_{orw} - S_{wcr}}\right]^{C_w} \quad (3.7)$$

where S_w = water saturation,

S_{wmin} = minimum water saturation (or irreducible water saturation),

S_{wmax} = maximum water saturation (equal to 1.0),

S_{orw} = residual oil saturation to water,

S_{wi} = initial water saturation (or connate water),

S_{wcr} = critical water saturation,

$K_{ro}(S_w)$ = relative permeability to oil at any water saturation,

$K_{rw}(S_w)$ = relative permeability to water at any water saturation,

$K_{ro@Swmin}$ = relative permeability to oil at minimum water saturation,

$K_{rw}(S_w)$ = relative permeability to water at any water saturation,

C_o = Corey oil exponent,

C_w = Corey water exponent.

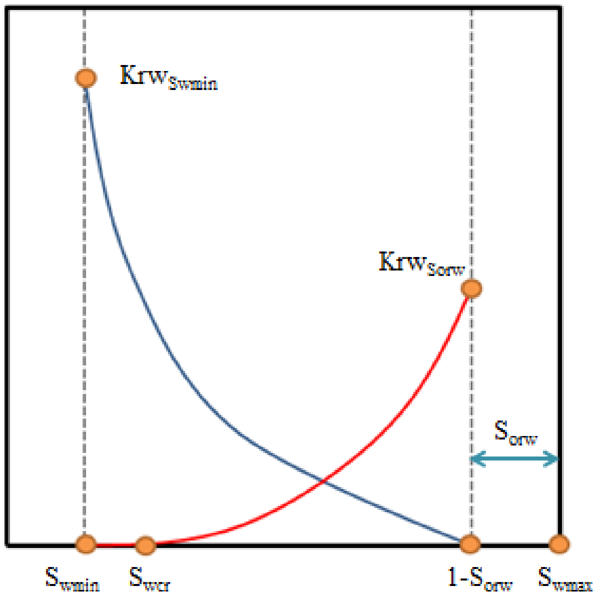

Figure 3.5 Schematic of parameters used in Corey's correlation

According to equation 3.6 and 3.7, Corey's correlation calculates relative permeability values based on normalized water saturation. The exponents can be obtained from experiment or history matching with the measured data. The value of 2.0 is typically appropriate for both relative permeabilities to oil and water. Additionally, Corey's correlation for gas-water system is similar to oil-water system mentioned above. In this study, Corey exponent of 2.0 is used as base value and S_{wcr} is assumed to be equal to S_{wmin}.

3.5 Waterflooding in Inclined Reservoir

The performance of waterflooding process in inclined reservoir is affected by dip angle, direction of displacement, and injection rate. First, consider the effect of direction of displacement from the fractional flow equation. Fractional flow of water is defined as (neglecting the capillary pressure force):

$$f_w = \frac{1 + \frac{k k_{ro}}{u_t \mu_o}[-g\Delta\rho \sin \alpha_d]}{1 + \frac{\mu_w k_{ro}}{\mu_o k_{rw}}} \tag{3.8}$$

where f_w = fractional flow of water,

k = absolute permeability,

k_{ro} = relative permeability to oil,

k_{rw} = relative permeability to water,

u_t = total fluid velocity,

μ_o = viscosity of oil,

μ_w = viscosity of water,

g = acceleration term due to gravity,

$\Delta\rho$ = water-oil density difference,

α_d = dip angle.

The sign convention for dip angle is assigned by positive when water is displacing oil in updip direction and hence, negative when water is displacing oil downdip. Consequently, the value of fractional flow of water (f_w) at any water saturation is lower, while the average water saturation behind flood front ($\overline{S}_w$) is higher when water is displacing oil updip. These facts illustrate the better performance of waterflooding than another way around due to the ease of oil to be swept. This is the reason why displacing oil updip (or injecting water at downdip) is more favorable in waterflooding process. Thus, the reservoir simulation is based on displacing oil updip direction in this study.

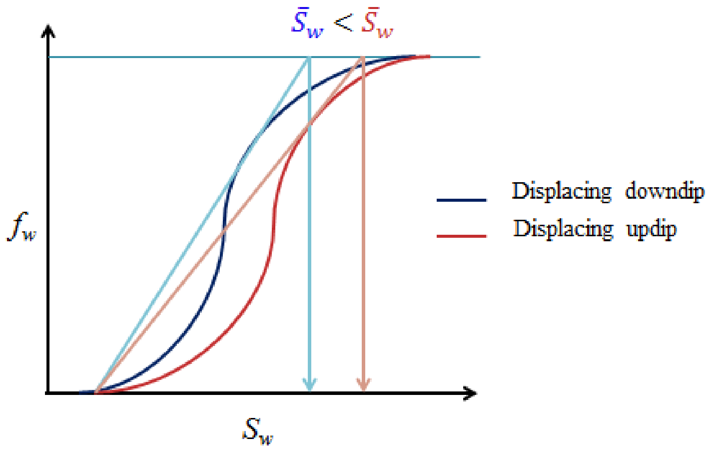

Figure 3.6 Fractional flow curves of waterflooding in both directions

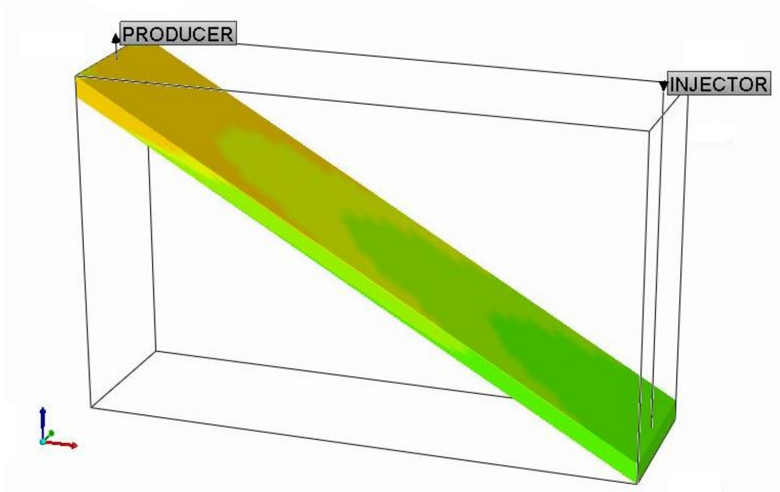

Figure 3.7 Illustration of waterflooding based on displacing oil updip (injecting downdip)

When performing waterflooding in updip direction, injecting water at low injection rate will allow the gravity effect to predominate the total flow property and this helps to maintain the stability of flood front. If injection rate is too high, water tonqueing (or so-called water under-running) will occur as shown in Figure 3.6.

At any flow rate, the performance of waterflooding where oil is displaced updip is increased with increasing the dip angle [17].

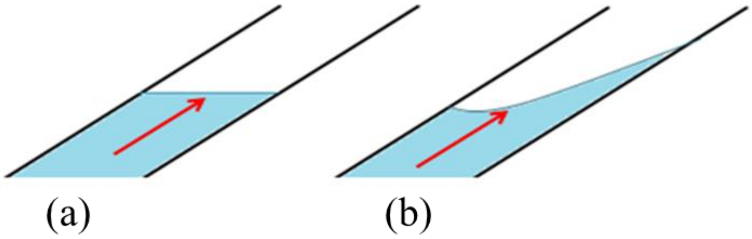

Figure 3.8 Effect of injection rate on waterflooding when displacing oil updip
(a) stable flood front with proper rate (b) unstable flood front with improper rate

3.6 Effect of Wettability on Water Injection Process

3.6.1 Water-wet Rock

When water injection is implemented in the water-wet reservoir, a little amount of oil is left or trapped behind the flood front since water can imbibe oil from small pore into the large pore. When the displacement is piston-liked, $\overline{S}_w$ would equal to 1-S_{or}. Thus, the ultimate oil recovery is independent from the amount of cumulative water injection. Besides, the trapped-oil is presented in a form of spherical globules at the middle of large pore which is surrounded by water as illustrated in Figure 3.9 since water tends to adhere by the rock surface during the imbibition.

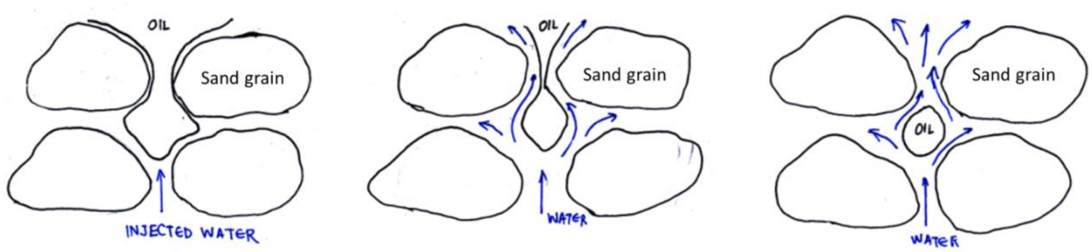

Figure 3.9 Schematic of water imbibition in water-wet rock

3.6.2 Oil-wet Rock

On the contrary, oil is adhered by rock surface instead of water. Thus, injected water will form a continuous path of fingering through the center of large pore as demonstrated in Figure 3.10. Some of oil is displaced by water, whereas most part of oil saturation is still trapped in small pore. However, the amount of recovered oil can be slightly increased by increasing a number of injected water. When the amount of injected water is increased, water can invade into small pore and hence, push trapped oil into the larger pore where it might be displaced by upcoming continuous injected water.

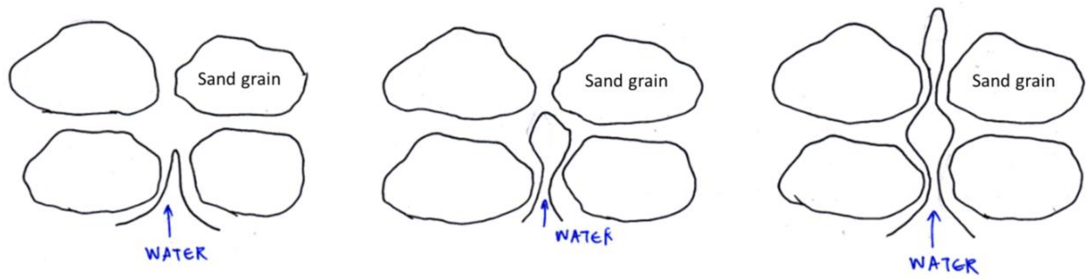

Figure 3.10 Schematic of water imbibition in oil-wet rock

3.7 LSB Injection in CMG STARS 2011

As we mentioned before, wettability alteration toward more water wetness is believed to be the main mechanism of additional oil recovery from LSB injection. As wettability of reservoir rock is corresponded to the relative permeability curve, the wettability alteration from LSB can be simply represented by changing of relative permeability curve. Thus, LSB injection process is modeled based on the relative permeability interpolation in CMG STARS 2011 simulator. Relative permeability is set to be linearly depended on pore water salinity.

Two sets of relative permeability curves are required for LSB injection simulation, which are **relative permeability curve before LSB injection** and **relative permeability curve after LSB injection**. These sets of curves are corresponded to the two threshold salinities of formation water and injected water, respectively. The assumption is that; injected water and formation water are mixed together and hence, a variety of pore water salinity (between the lowest and the highest salinity) is occurred in the reservoir at different location. Accordingly, relative permeability curve for each value of water salinity at any location is interpolated from the two input sets of curve.

CHAPTER IV

RESERVOIR SIMULATION MODEL

The details of reservoir model construction in this study are described in this chapter. First of all, laboratory experiment is conducted on the interested Si Khio sandstone core samples to observe the effect of LSB on wettability alteration and oil saturation after core is displaced by LSB. Afterwards, a numerical reservoir simulator is used to evaluate the performance of LSB injection based on the result from the experiment. The thermal and advanced processes reservoir simulator called **STARS** is chosen as an important tool for such objective. Basically, the corner point grid reservoir models with different dip angle are constructed. The important input keywords are demonstrated in the Appendix.

4.1 Laboratory Experiment

Prior to reservoir simulation step, the Amott-Harvey wettability index measurement is conducted to study wettability reversal by LSB. Core samples obtained from Si Khio sandstone outcrop are used as a representative of sandstone reservoir. Figure 4.1 shows the core samples that used in the laboratory experiment. The methodology of this experiment is previously mentioned in Chapter III. Artificial brine of 35,000 ppm and 100,000 ppm are prepared from several chemical as shown in Table 4.1 to represent the formation water.

Figure 4.1 Si Khio sandstone core samples

Table 4.1 Chemical salts used to prepared artificial brine [21]

Chemical	Mass (gram)	
	35,000 ppm	100,000 ppm
Magnesium Chloride	5.145	14.700
Calcium Chloride	1.155	3.300
Potassium Chloride	0.735	0.210
Sodium Chloride	23.765	67.900
Sodium Sulfate	3.990	11.400
Sodium Hydrogen carbonate	0.210	0.600

The diluted artificial brine of 5,000 ppm brine obtaining from diluting formation water is used as injected water. Core samples are initially prepared at IWS condition and then, oil is displaced by the LSB. As a result, the values of calculated wettability index and residual oil saturation are shown in Table 4.2.

Table 4.2 Result from laboratory experiment

Connate water (ppm)	Before displaced by LSB			After displaced by LSB		
	IWS	1-ROS	δ_w	IWS	1-ROS	δ_w
35,000	0.30	0.70	0.40	0.3	0.75	0.60
100,000	0.30	0.62	0.20	0.3	0.75	0.543

From Table 4.2, only displacement-by-water is measured. This is because the displacement-by-oil ratio is too low to measure by centrifuge method. Thus, the wettability index which is difference between displacement-by-water ratio and displacement-by-oil ratio is approximately equal to the displacement-by-water ratio. According to the rule of thumb of relative permeability curve (Table 3.3) and laboratory result, the end-point saturation and relative permeabilities value that will be used in reservoir simulation is interpolated.

There are assumptions for the interpolation of end-point relative permeability; First of all, wettability index of 1.0 refers to strongly water-wet condition and corresponds to k_{ro} of 0.2. Secondly, wettability index of zero refers to neutral-wet condition which corresponds to k_{ro} of 0.5. The interpolation of relative permeability values is illustrated in Figure 4.2. As a result, end-point saturation and relative permeability values that will be used in reservoir simulation are illustrated in Table 4.3.

$I = 1.0$ Strongly water-wet Estimated $k_{ro} = 0.2$

$I = X$ Estimated $k_{ro} = 0.2 - \frac{(1\text{-X})}{(1\text{-}0)} \times (0.2\text{-}0.5)$

$I = 0.0$ Neutral-wet Estimated $k_{ro} = 0.5$

**Where X = measured wettability index from laboratory experiment.

Figure 4.2 Interpolation of relative permeability from wettability index obtained from laboratory experiment

Table 4.3 End-point saturation and relative permeability for Corey's correlation

Connate water salinity (ppm)		**IWS**	***k_{ro}* @IWS**	**1-ROS**	***k_{rw}*@(1-ROS)**
35,000	Before LSB inj.	0.30	1	0.70	0.38
	After LSB inj.	0.30	1	0.75	0.32
100,000	Before LSB inj.	0.30	1	0.62	0.44
	After LSB inj.	0.30	1	0.75	0.337

4.2 Reservoir Model

The reservoir model is 3,150 × 770 × 100 ft in x-, y-, and z-direction, respectively. According to current academic license of CMG program, the total number of grid block is limited less than 10,000 grid blocks. Thus, 45 × 11 × 20 grid blocks are selected. Additionally, this model is constructed based on corner point grid and Cartesian coordinate. The reservoir is homogeneous and several properties required for reservoir simulation are listed in Table 4.4. The datum depth is located at the bottommost of the reservoir in order to maintain the depth of injection well when different dip angle is considered.

Table 4.4 Reservoir properties

Parameters	**Values**	**Unit**
Grid size	70×70×5	ft
Effective porosity	20	%
Horizontal permeability	30	mD
Vertical permeability	0.1 k_h	mD
Top of reservoir	6500	ft
Datum depth	6600	ft
Reservoir temperature	143	^{o}F
Initial oil saturation	0.7	fraction
Reservoir pressure gradient	0.433	psi/ft

For the base case model, conventional waterflooding with no dip angle is simulated. In this study, conventional waterflooding means injected water has the same salinity as formation water. An injector and a producer are placed at the opposite edge of the reservoir as illustrated in Figure 4.3.

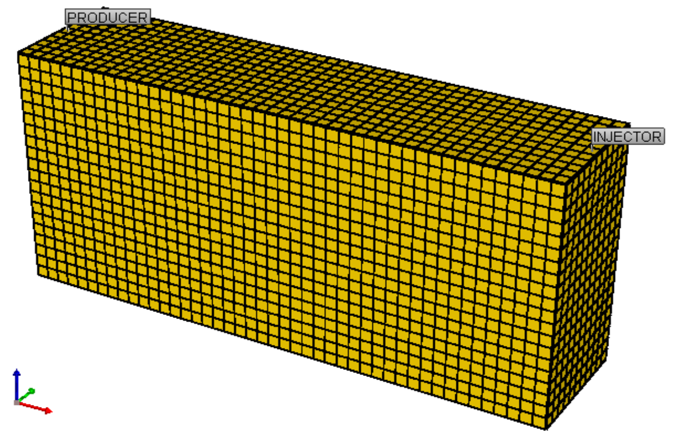

Figure 4.3 Horizontal reservoir model

In case where reservoir dip angle is included, constructing reservoir model with the non-orthogonal corner point grid by CMG program is difficult. Hence, the inclined reservoir is built in **ECLIPSE100** program first and then converted to CMG IMEX format by using **ECL100 Import Assistant**. Finally, the IMEX model will change into STARS model. Figure 4.4 displays all reservoir models with dip angle of 15°, 30°, 45°, and 60°.

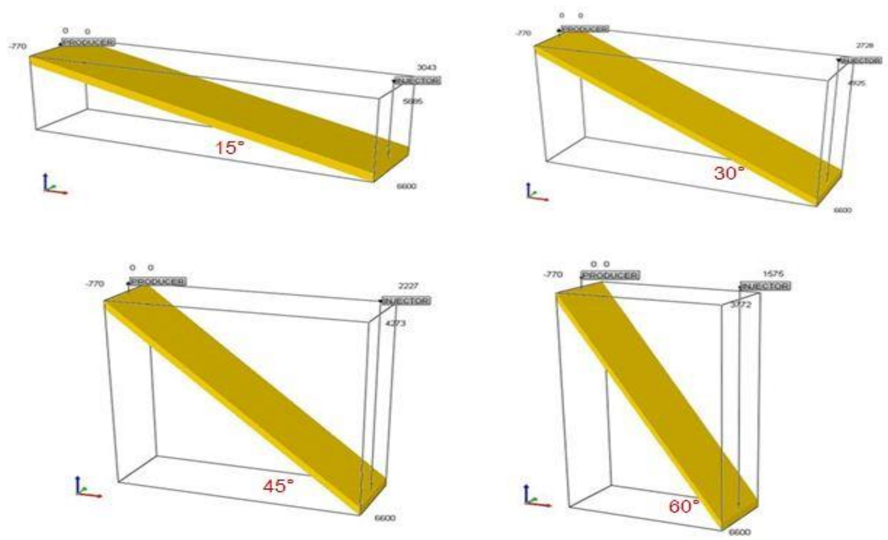

Figure 4.4 Reservoir models with different dip angle

4.3 Pressure-Volume-Temperature (PVT) Properties Section

The PVT properties of reservoir fluids are specified by using correlations. The information of black oil is taken from Whitson and Brulé [22]. Figures 4.5-4.9 demonstrate gas and oil PVT properties which are dry gas formation volume factor, dry gas viscosity, oil formation volume factor, oil viscosity, and gas-oil ratio, respectively.

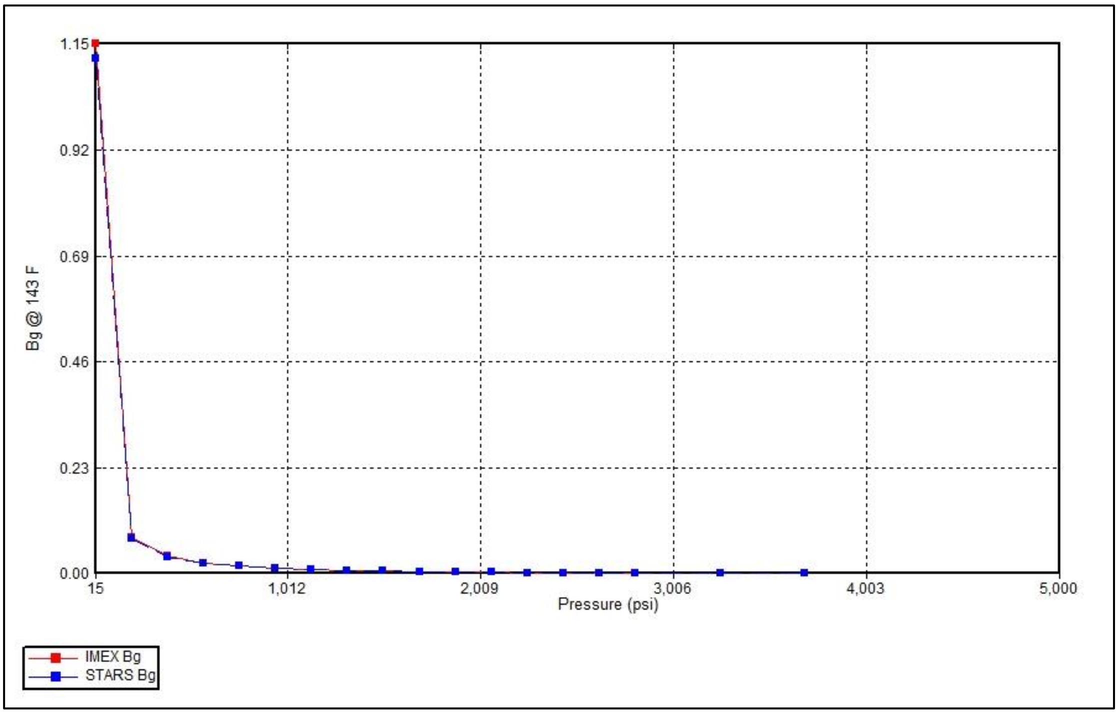

Figure 4.5 Dry gas formation volume factor

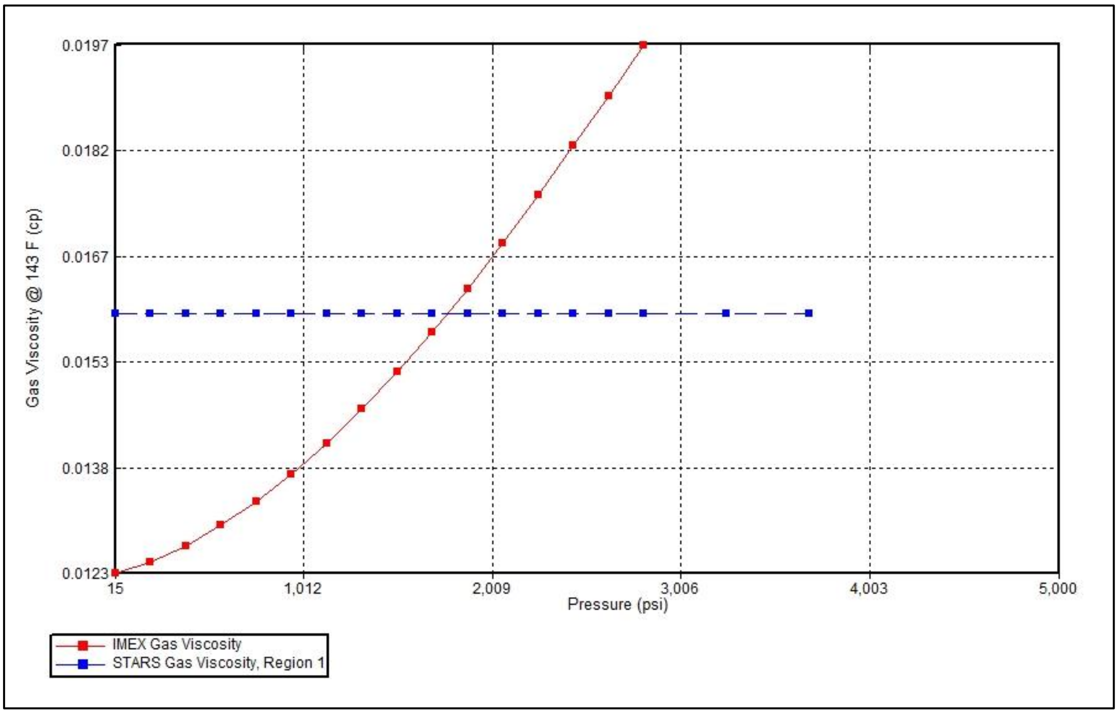

Figure 4.6 Dry gas viscosity

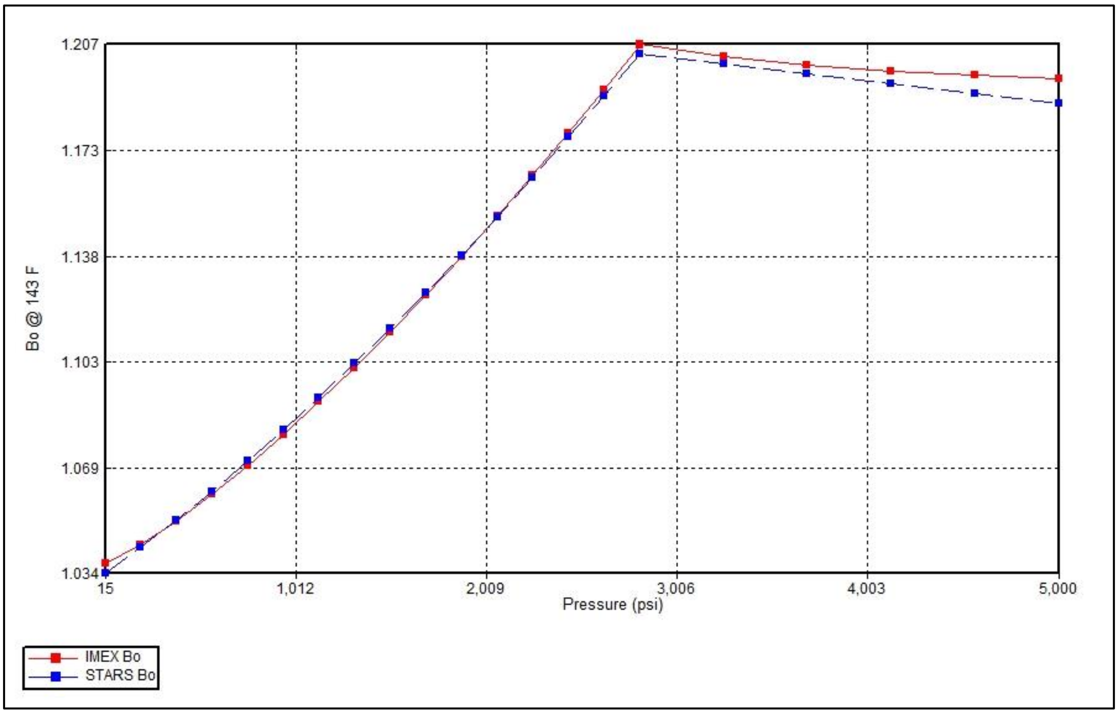

Figure 4.7 Oil formation volume factor

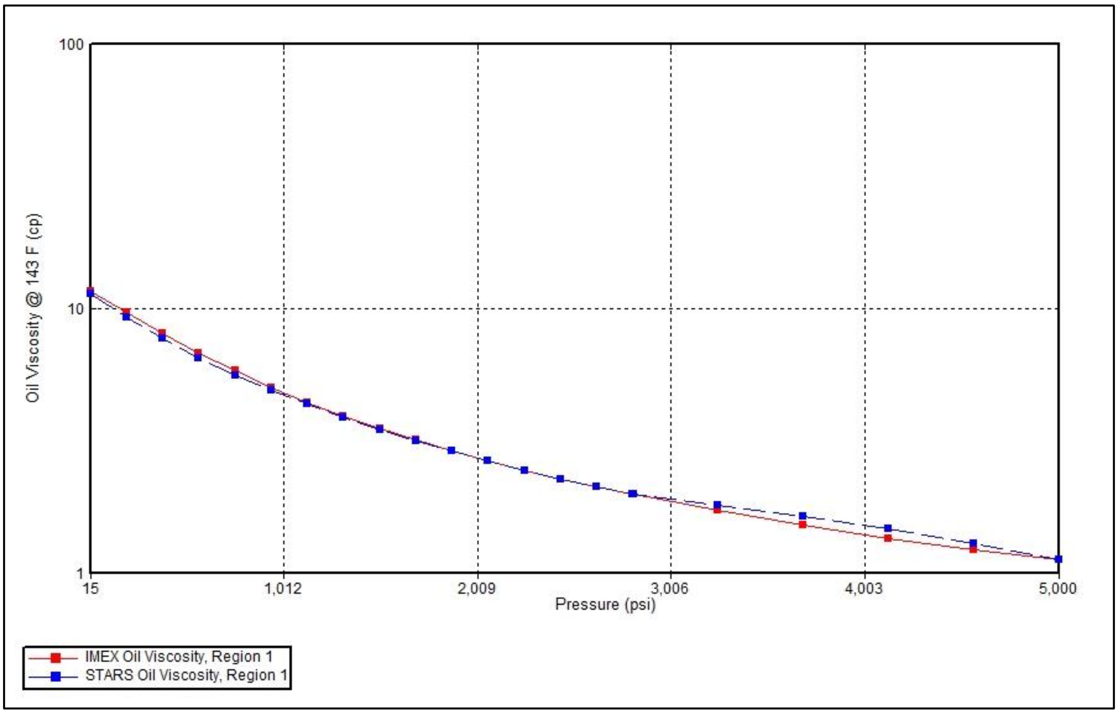

Figure 4.8 Oil viscosity at different pressure

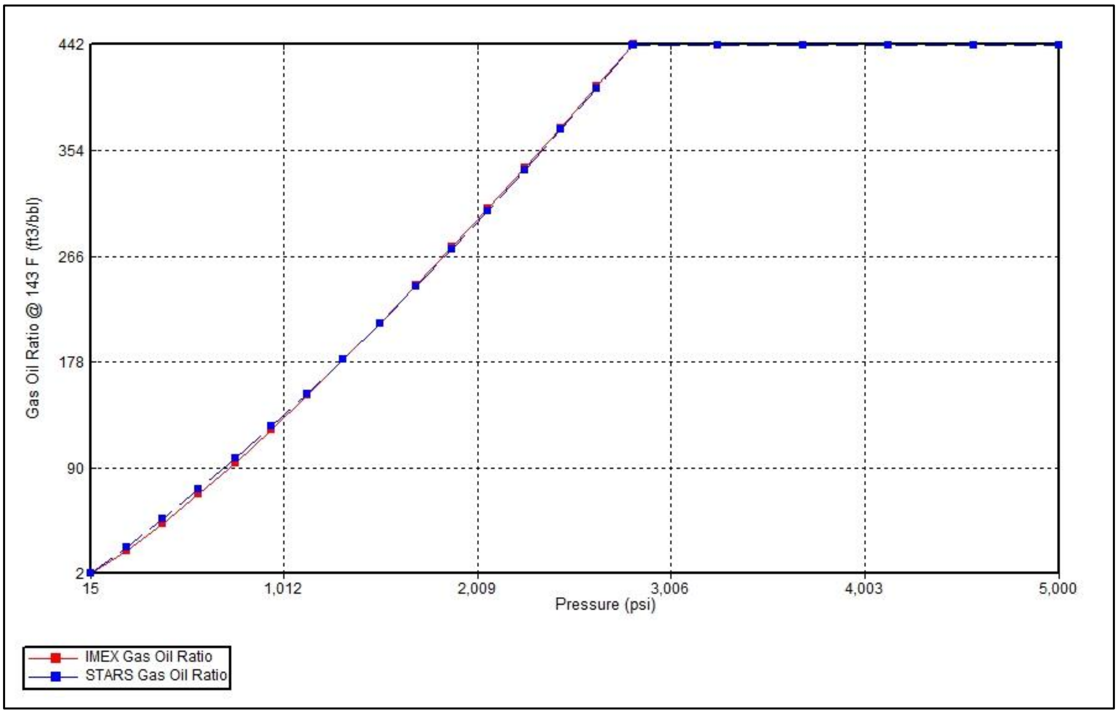

Figure 4.9 Gas oil ratio (GOR)

In order to specify the salinity of water in the system, aqueous component SALT is defined to represent the salt content that suspended in aqueous phase. The properties are set to be the same as WATER phase except molecular weight. The properties of aqueous SALT component (for example, critical temperature, critical pressure, density, etc.) are assumed to be the same as WATER component. This can be achieved by inputting the “0” for every SALT property except for the molecular weight. For example, Enter critical temperature equals to 0 for aqueous component SALT to get the water value of 705.47 °F. Since the fraction of sodium chloride (NaCl) in brine is significantly high compared to other salts, the molecular weight of SALT is assumed to be the same as NaCl molecular weight which is 58.44 lb/lbmole. The mole fraction of SALT and WATER component required in simulator input which represent the salinity of brine are shown in Table 4.5.

Table 4.5 Mole fraction of SALT and WATER for each salinity input

Salinity (ppm)	**Component**	**Weight fraction**	**MW**	**Mole**	**Mole fraction**
5,000	WATER	0.995	18	0.055	0.9985
	SALT	0.005	58.44	0.000	0.0015
	Total	1.000		0.055	1.0000
35,000	WATER	0.965	18	0.054	0.989
	SALT	0.035	58.44	0.001	0.011
	Total	1.000		0.054	1.000
100,000	WATER	0.9	18	0.050	0.967
	SALT	0.1	58.44	0.002	0.033
	Total	1.000		0.052	1.000

4.4 Special Core Analysis (SCAL) section

The end-point data obtained from Section 4.1 is used for generating water/oil relative permeability curves, whereas the data for generating gas/liquid relative permeability curve are obtained from the STARS Tutorial 2012. The simulator uses Corey's correlation to generate the relative permeability curve from end-point data. Since the simulation of LSB injection process relies on the interpolation between the water/oil relative permeability curves of **Before LSB injection** and **After LSB injection**, two sets of relative permeability curves are required. Table 4.6 and Table 4.7 show the water/oil relative permeabilities for the connate water salinity of 35,000 ppm and 100,000 ppm, respectively. Table 4.8 shows gas/liquid relative permeabilities.

Table 4.6 Water/oil relative permeability curves: connate water salinity 35,000 ppm

Before LSB injection			**After LSB injection**		
S_w	k_{rw}	k_{ro}	S_w	k_{rw}	k_{ro}
0.300	0.0000	1.0000	0.3000	0.0000	1.0000
0.325	0.0015	0.8789	0.3281	0.0013	0.8789
0.350	0.0059	0.7656	0.3563	0.0050	0.7656
0.375	0.0134	0.6602	0.3844	0.0113	0.6602
0.400	0.0238	0.5625	0.4125	0.0200	0.5625
0.425	0.0371	0.4727	0.4406	0.0313	0.4727
0.450	0.0534	0.3906	0.4688	0.0450	0.3906
0.475	0.0727	0.3164	0.4969	0.0613	0.3164
0.500	0.0950	0.2500	0.5250	0.0800	0.2500
0.525	0.1202	0.1914	0.5531	0.1013	0.1914
0.550	0.1484	0.1406	0.5813	0.1250	0.1406
0.575	0.1796	0.0977	0.6094	0.1513	0.0977
0.600	0.2138	0.0625	0.6375	0.1800	0.0625
0.625	0.2509	0.0352	0.6656	0.2113	0.0352
0.650	0.2909	0.0156	0.6938	0.2450	0.0156
0.675	0.3340	0.0039	0.7219	0.2813	0.0039
0.700	0.3800	0.0000	0.7500	0.3200	0.0000

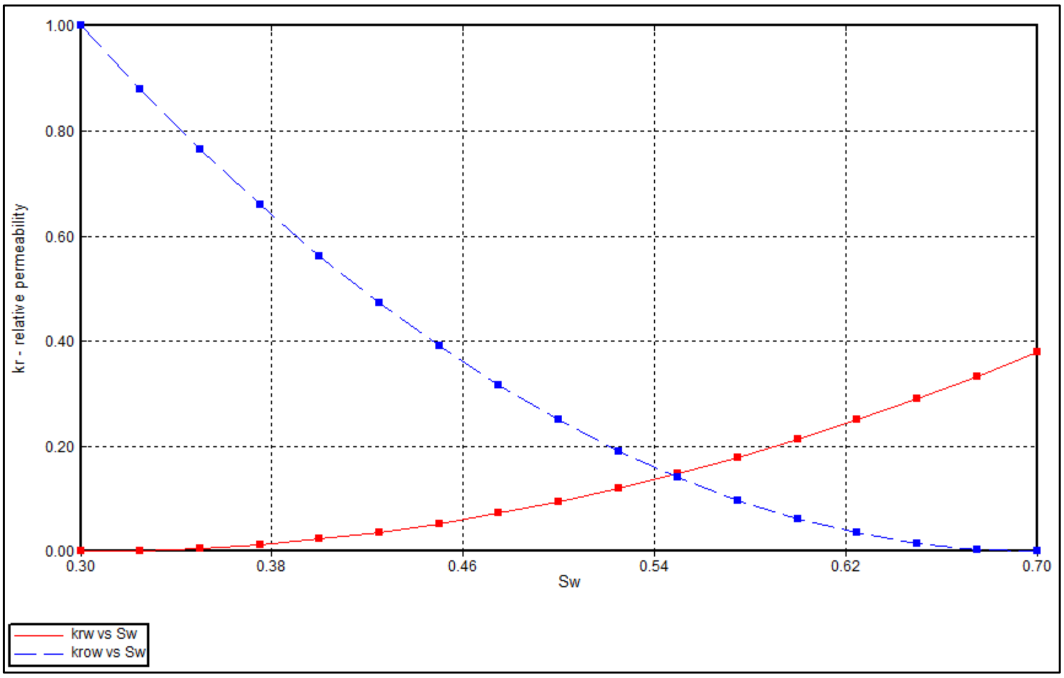

Figure 4.10 Oil/water saturation function for connate water 35,000 ppm (Before LSB injection)

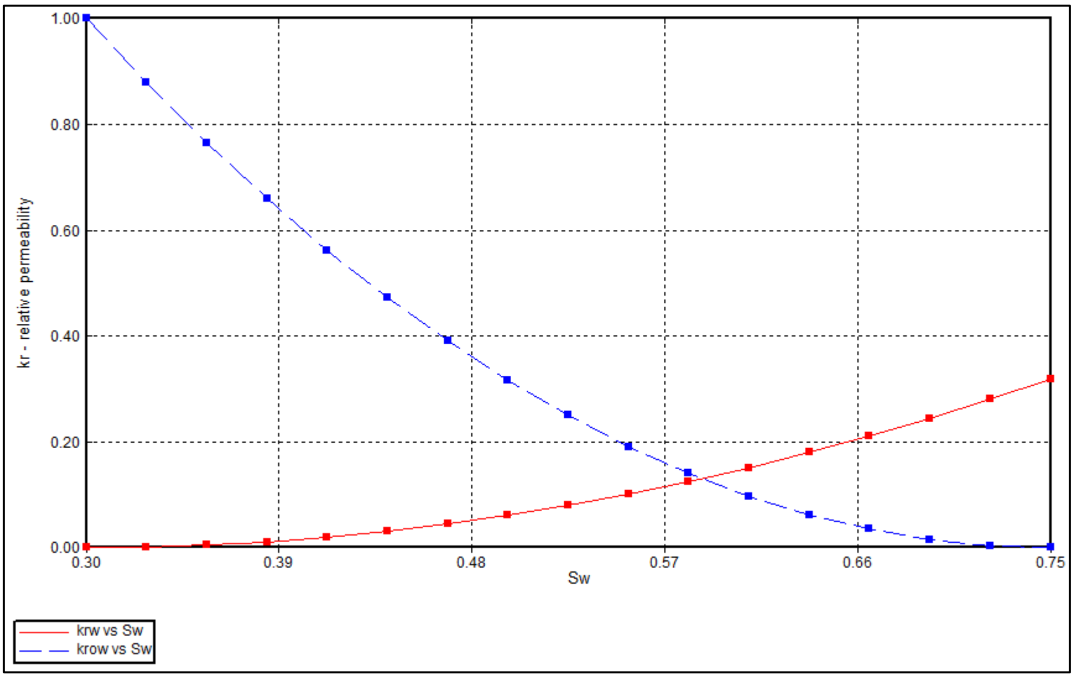

Figure 4.11 Oil/water saturation function for connate water 35,000 ppm (After LSB injection)

Table 4.7 Water/oil relative permeability curves: connate water salinity 100,000 ppm

Before LSB injection			**After LSB injection**		
S_w	k_{rw}	k_{ro}	S_w	k_{rw}	k_{ro}
0.300	0.00	1.00	0.30	0.00	1.00
0.320	0.0017	0.8789	0.3281	0.0013	0.8789
0.340	0.0069	0.7656	0.3563	0.0053	0.7656
0.360	0.0155	0.6602	0.3844	0.0118	0.6602
0.380	0.0275	0.5625	0.4125	0.0211	0.5625
0.400	0.0430	0.4727	0.4406	0.0329	0.4727
0.420	0.0619	0.3906	0.4688	0.0474	0.3906
0.440	0.0842	0.3164	0.4969	0.0645	0.3164
0.460	0.1100	0.2500	0.5250	0.0843	0.2500
0.480	0.1392	0.1914	0.5531	0.1066	0.1914
0.500	0.1719	0.1406	0.5813	0.1316	0.1406
0.520	0.2080	0.0977	0.6094	0.1593	0.0977
0.540	0.2475	0.0625	0.6375	0.1896	0.0625
0.560	0.2905	0.0352	0.6656	0.2225	0.0352
0.580	0.3369	0.0156	0.6938	0.2580	0.0156
0.600	0.3867	0.0039	0.7219	0.2962	0.0039
0.620	0.4400	0.0000	0.7500	0.3370	0.0000

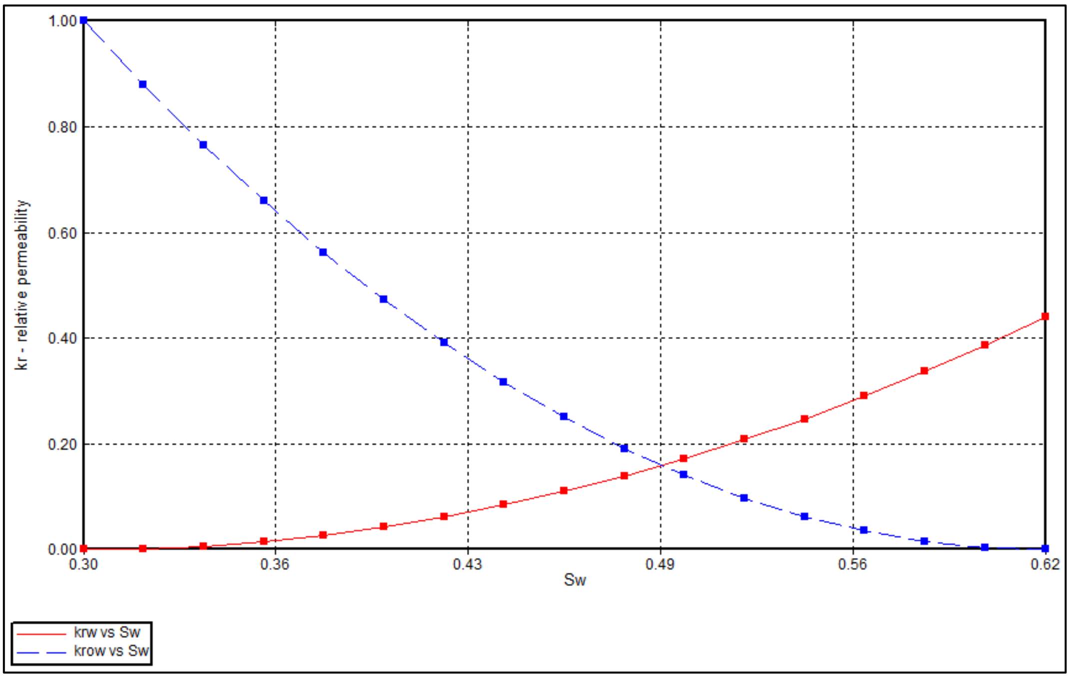

Figure 4.12 Oil/water saturation function for connate water 100,000 ppm (Before LSB injection)

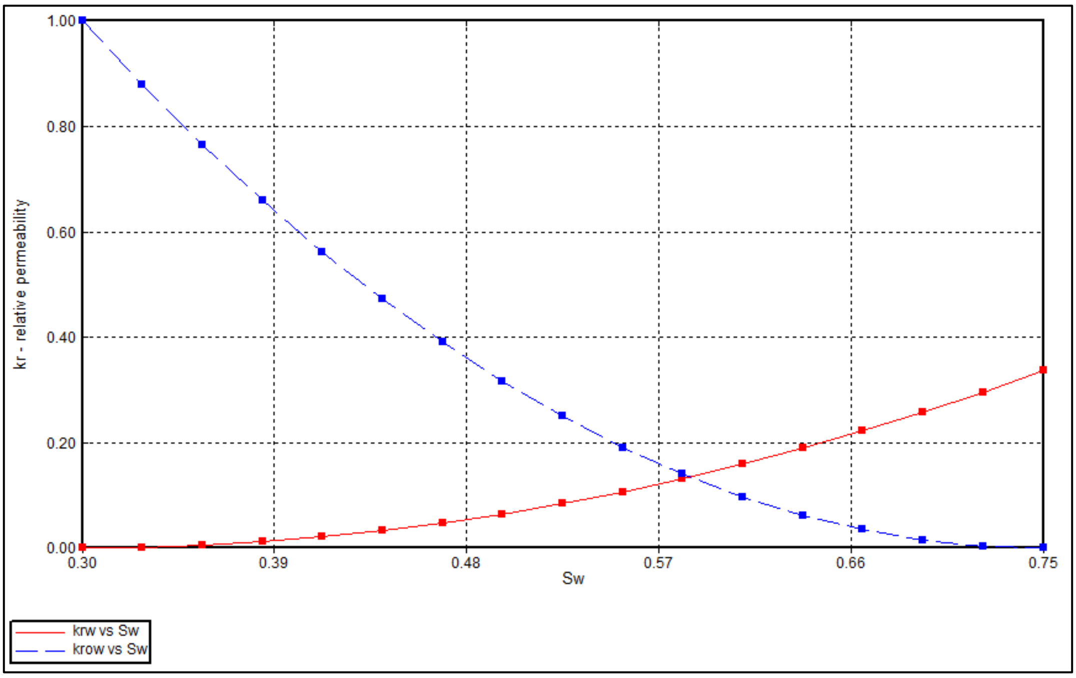

Figure 4.13 Oil/water saturation function for connate water 100,000 ppm (After LSB injection)

Table 4.8 Gas/liquid relative permeability

S_l	k_{rg}	k_{rog}
0.30	0.30	0.00
0.5250	0.1283	0.0000
0.7500	0.0284	0.0000
0.7625	0.0250	0.0025
0.7750	0.0217	0.0100
0.7875	0.0188	0.0225
0.8000	0.0160	0.0400
0.8125	0.0134	0.0625
0.8250	0.0111	0.0900
0.8375	0.0090	0.1225
0.8500	0.0071	0.1600
0.8625	0.0054	0.2025
0.8750	0.0040	0.2500
0.8875	0.0028	0.3025
0.9000	0.0018	0.3600
0.9125	0.0010	0.4225
0.9250	0.0004	0.4900
0.9375	0.0001	0.5625
0.95	0.00	0.64
0.98	0.00	0.81
1.00	0.00	1.00

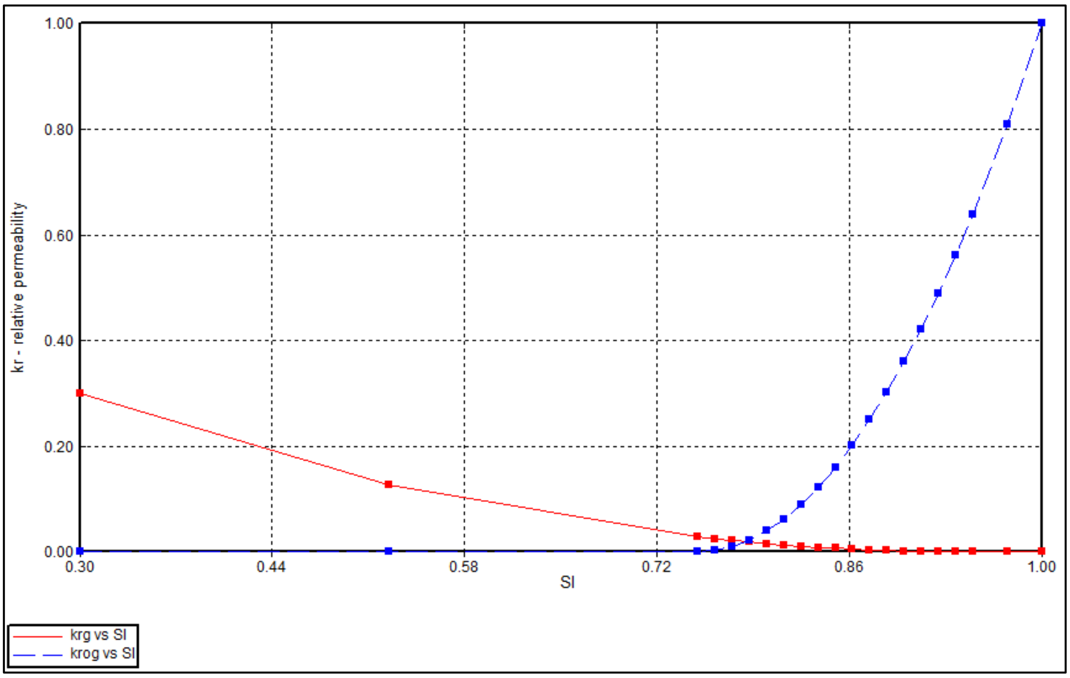

Figure 4.14 Gas/liquid saturation function

4.5 Parameters Related to Injection and Production Wells

In this study, wellbore radius is set to be the default value of simulator for every well and skin is assumed to be zero. All wells are fully-perforated along the reservoir thickness since there is no fluid contact in the reservoir. For inclined reservoir, the injector well is located at the bottom edge of the reservoir in order to achieve the water displacing updip direction. The constraints and economic limits are listed in Table 4.9 and Table 4.10 for injector well and production well, respectively.

Table 4.9 Injector well constraints

Parameter	**Value**
Fracture pressure (psi)	4,400
Max water injection rate (stb/day)	600

Table 4.10 Production well constraints

Parameter	**Value**
Fracture pressure (psi)	4,400
Minimum bottom hole pressure (psi)	200
Maximum oil rate (stb/day)	500
Water cut (%)	95
Minimum oil rate (stb/day)	50

CHAPTER V

SIMULATION RESULT AND DISCUSSION

Once the reservoir model is built, LSB injection is simulated with several study parameters to investigate their sensitivities on the effectiveness of LSB injection. Waterflooding process (without change of relative permeability) on horizontal and different inclined reservoirs (dip angle of 15°, 30°, 45°, and 60°) are primarily simulated and the results are labeled as reference base cases. Consequently, LSB injection simulation is performed with different study parameters for each dip angle. The oil recovery factor is mainly analyzed and compared with the all the reference base cases.

For every case, oil production rate is controlled at the maximum rate of 500 stb/day. Bottomhole pressure of the injector is controlled at 4,400 psi in order to prevent the breakdown of formation. The bottomhole target of the producer is controlled at 200 psi (minimum). Maximum water injection rate is remained constant at 600 stb/day except for the injection rate study section. The economic limit is set at 95% water cut and 50 stb/day oil rate whichever comes first. The simulation time is 30 years to represent the production period of ordinary concession.

From now on, the term “waterflooding” refers to **flooding the reservoir with water having the same salinity as the formation water**. For example, injected water salinity is 100,000 ppm when formation water is 100,000 ppm. And the term “LSB injection” refers to **flooding the reservoir with water having 5,000 ppm salinity**.

5.1 Waterflooding Base Cases

Waterflooding is simulated in order to evaluate the benefit of LSB injection. In this section, waterflooding is implemented from the first day of reservoir exploitation and the results of waterflooding base case are shown here. Both injection and production well are vertical wells and located at (45, 6) and (1, 6), respectively for all cases. In this section, the initial salinity of formation water is set to be equal to the salinity of injected water at 35,000 ppm. For inclined reservoir, water injection downdip (so-called water displacing oil updip) is implemented for the better performance of waterflooding as illustrated in theory. Table 5.1 and Figure 5.1 summarize the results of base case waterflooding at different dip angles.

Table 5.1 Summary of oil recovery factor and total production period from base case waterflooding

Dip angle (°)	**Oil recovery factor (%)**	**Prod. Period (Days)**
0	43.9227	5,356
15	44.6203	5,478
30	44.6599	5,386
45	45.4613	5,875
60	44.0720	5,203

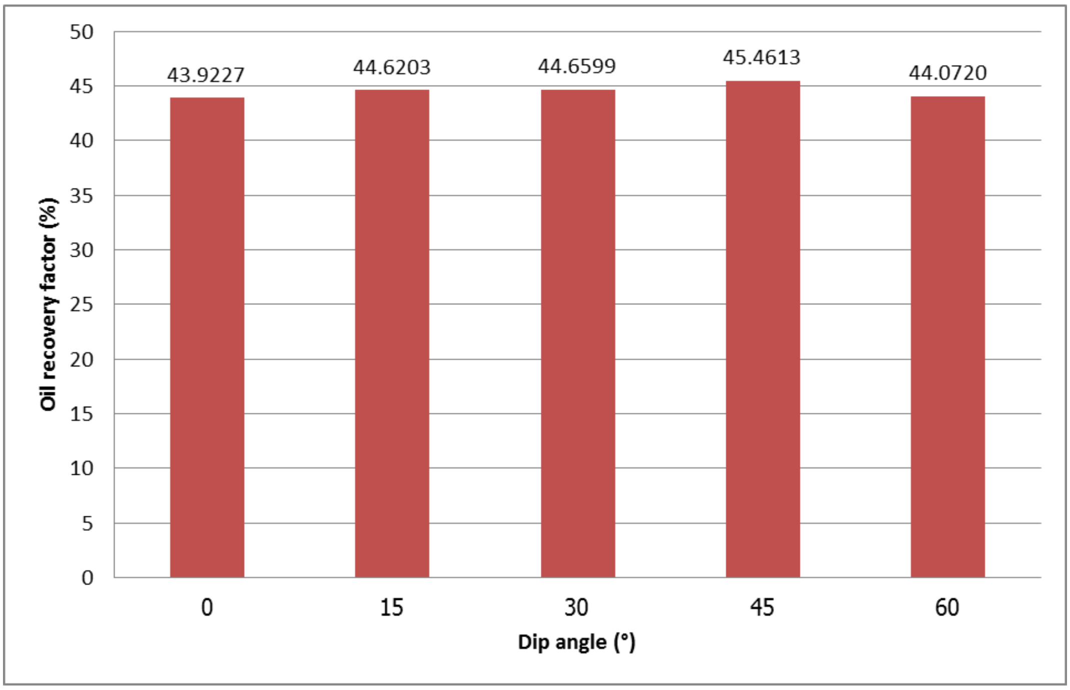

Figure 5.1 Comparison of oil recovery factor for waterflooding at different dip angles

From the Table 5.1 and Figure 5.1, the oil recovery factor is increased as reservoir dip angle increases, however this incremental trend is not obvious. This is due to the gravity effect. Theoretically, the value of flow capacity due to gravity term in fractional flow equation is augmented when the dip angle is increased. And due to the minus sign, the fractional flow of water is reduced at any water saturation as dip angle is increased. This corresponds to higher average water saturation behind the flood front and lower oil saturation trapped behind. As can be seen in Figure 5.2, the green shade area refers to higher oil saturation compared to the deep blue color. For dip angle of 0° to 45°, the higher the inclination, the less area of green shade. However, higher steep reservoir does not yield good waterflooding performance always. It is possible to achieve the negative fractional flow of water (f_w) in certain conditions when performing downdip injection, especially when dip angle is very high. The negative value of f_w means water tends to flow downward by gravity.

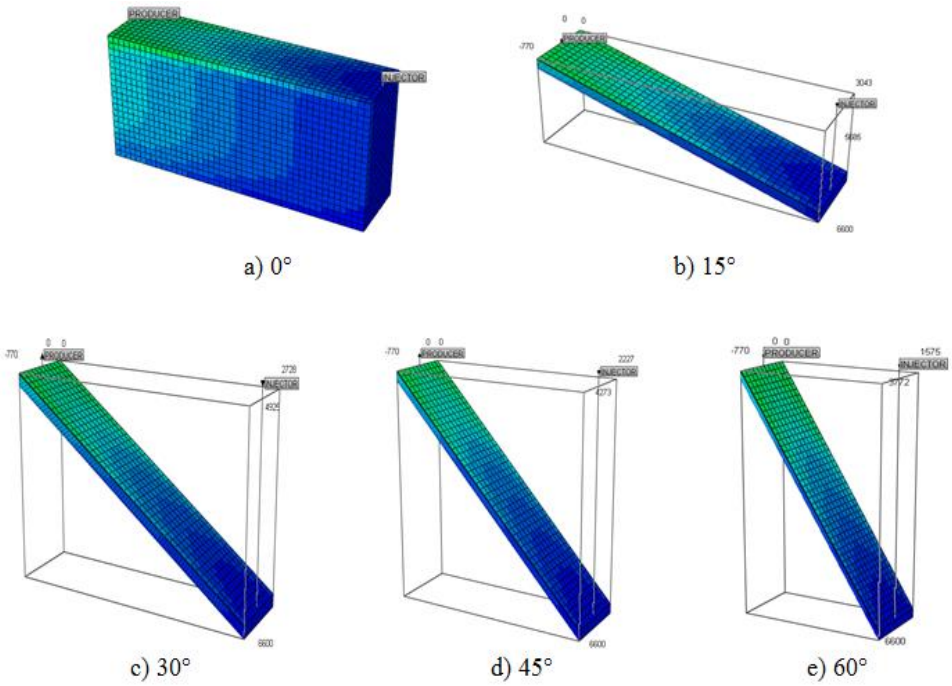

Figure 5.2 Water saturation at the end of waterflooding period

As can be seen in Figure 5.1, the reservoir with 60° dip angle may not be suitable for water injecting downdip because the effect of gravity is overabundant and hence, oil recovery factor is substantially reduced. Moreover, the reduction of oil recovery factor is also caused from vertical permeability. That is reservoir fluids tend to flow in vertical direction (z-axis) instead of horizontal direction (x- and y-axis) when reservoir is steeper. Fluids therefore can flow ineffectively since vertical permeability is only one tenth of horizontal one.

5.2 LSB Injection

In this section, injection and production constraints are mostly set as same as the waterflooding base case except the salinity of injected water. The salinity of injected water is changed from 35,000 ppm to 5,000 ppm, whereas the salinity of formation water is still kept at 35,000 ppm in order to observe the benefit of LSB injection. As a result, the oil recovery factors at the end of production period are summarized in Table 5.2. Similar trend as same as base case waterflooding is observed for the effect of dip angle when LSB injection is performed. However, we can see in Figure 5.3 that 5.1–7.7% of additional oil recovery factor is obtained when LSB injection is implemented due to the change of rock preference toward a more water-wet condition.

Table 5.2 Summary of oil recovery factor and total production period from LSB injection

Dip angle (°)	**Oil recovery factor (%)**	**Prod. Period (Days)**
0	50.5105	9,616
15	51.5390	9,616
30	52.3491	9,131
45	52.3996	9,190
60	49.1351	7,609

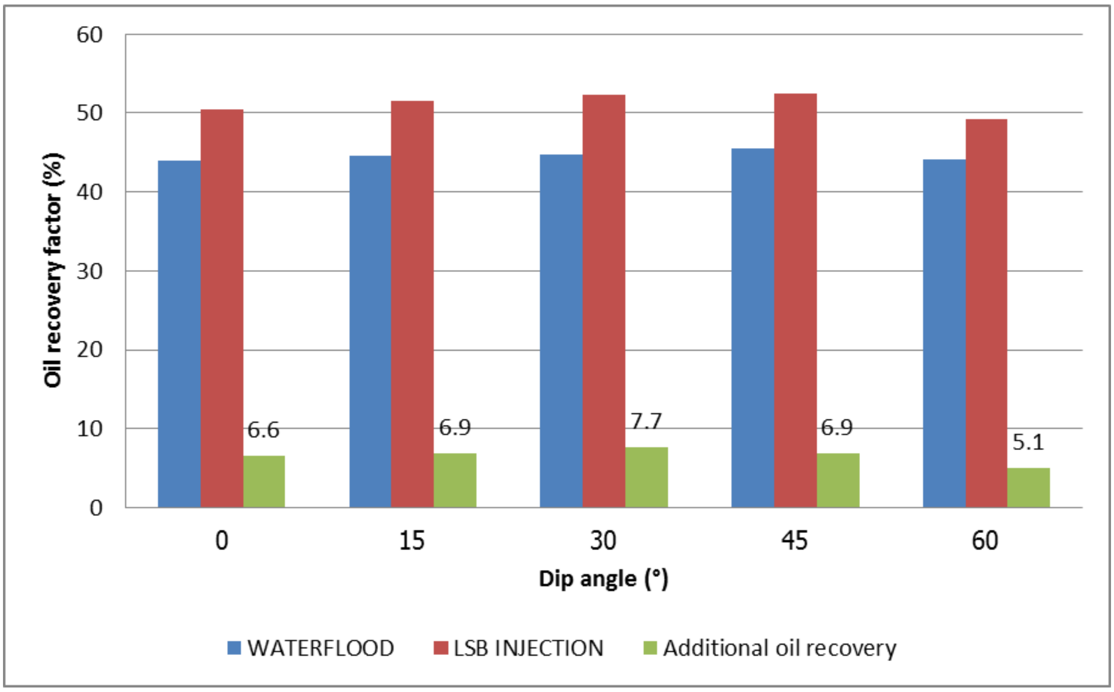

Figure 5.3 Comparison of oil recovery factor between base case waterflooding and LSB injection at different inclination of the reservoir

When the wettability of the reservoir rock turns to a more water-wet condition, part of previously trapped oil is desorbed and hence, more saturation of oil is mobilized and produced. Figure 5.4 shows the additional oil production that corresponds to the desorbed-oil in case 0° dip angle by comparing oil production as a function of production time. After the oil rate is declined from the plateau rate, oil production rate from LSB injection is higher than base case waterflooding and hence, oil production period is extended for approximately 10 years. However, the desorbed-oil shock front can slightly be seen in the white circle in Figure 5.5. The phenomenon is generally occurred when there is the alternation of wettability and hence, there is a shift of relative permeability. From Figure 5.5, the first shock front is represented by the red shade. This represents the oil bank that moves in front of injected water by the viscous force from injected water. The second shock front is presented in the middle of the reservoir where oil saturation values alternation between light blue and green colors. This is due to the desorbed-oil saturation from the change of relative permeability curves which is function of salinity change.

The increment of 7.7 % is the maximum additional oil recovery obtained in this case. This value is found at the dip angle of 30° that is the point where gravity drainage effectively acts on the total flow equation by maintaining flood front stability and do not exaggerate the gravity drainage of injected water. And together with wettability alteration from LSB the maximum additional oil recovery is achieved.

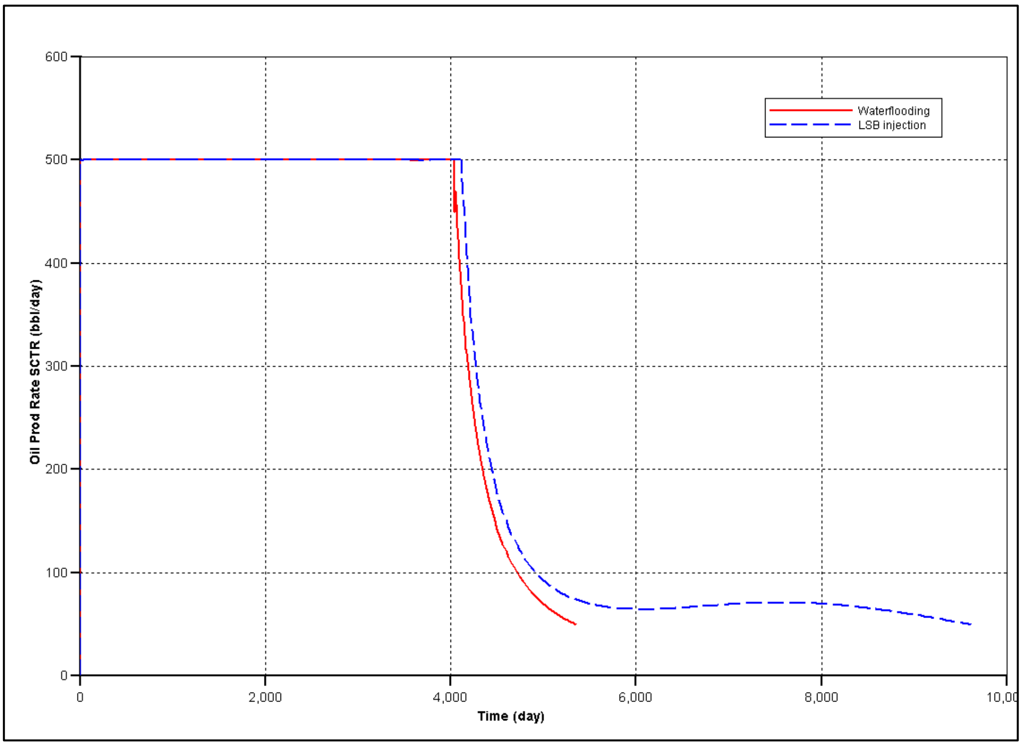

Figure 5.4 Comparison of oil production rate between base case waterflooding and LSB injection from reservoir with 0° dip angle

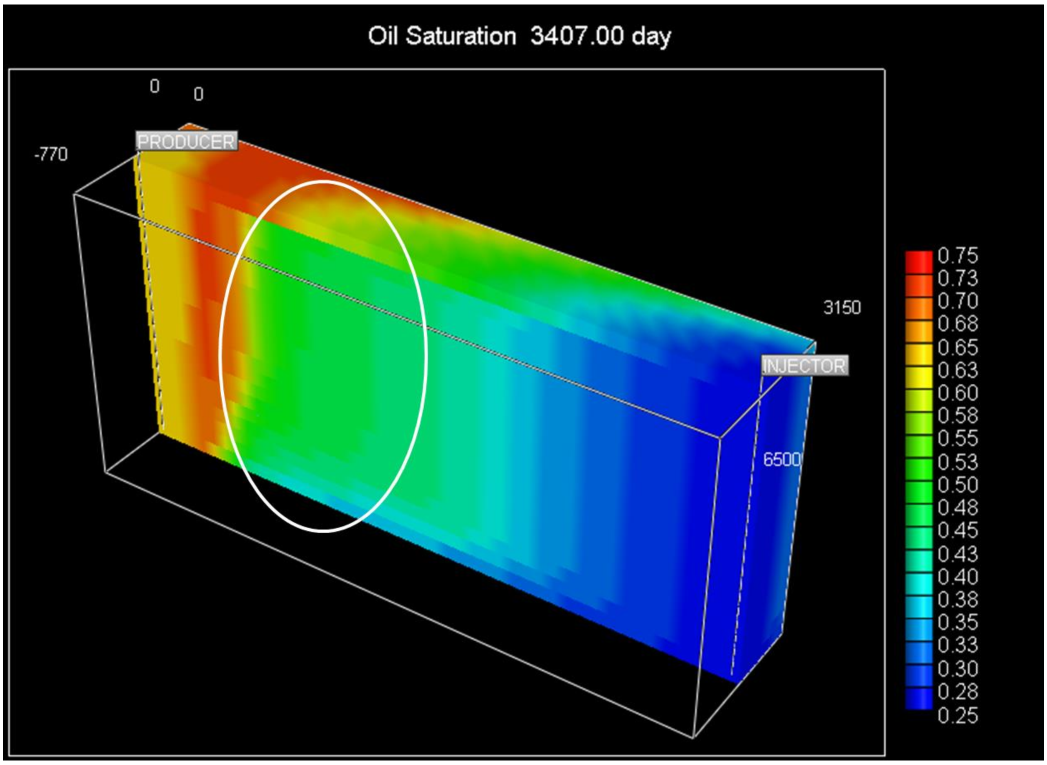

Figure 5.5 Oil saturation gradient during LSB injection (formation salinity is 35,000 ppm, LSB salinity is 5,000 ppm and vertical cut plane-perpendicular to y)

5.3 Effect of Formation Water Salinity

The effect of formation water salinity is studied in this section. Both waterflooding and LSB injection are both simulated to compare the benefit of LSB injection with different salinity of formation water. Two cases of simulation are considered: first the case with the lower formation water salinity of 35,000 ppm and second case of higher formation water salinity of 100,000 ppm. To simplify the explanation, the terms called **case 35,000** and **case 100,000** will be used, respectively. As mentioned previously, the injected water salinity is set to be the same as formation water salinities in case of waterflooding (i.e. injected water is 100,000 ppm for case 100,000). In the contrary, injected water is adjusted to 5,000 ppm for LSB injection. Table 5.3 summarizes the input of water salinity for both cases.

Table 5.3 Summary of salinity input for case 35,000 and case 100,000

Process	Salinity (ppm)			
	Case 35,000		Case 100,000	
	Formation water	Injectant	Formation water	Injectant
Waterflooding	35,000	35,000	100,000	100,000
LSB injection	35,000	5,000	100,000	5,000

Table 5.4 denotes the oil recovery factor for case 100,000. As seen in the table, the oil recovery factors of waterflooding in higher salinity case are less than that of cases 35,000. This is because the high salinity of formation water also comes with the high content of divalent cation which promotes the oil to be adsorbed and hence, reservoir rock is less water-wet as observed from laboratory experiment (less wettability index value).

Table 5.4 Summary of oil recovery factors obtained from waterflooding and LSB injection in different dip angle when formation water salinity is 100,000 ppm

Dip angle (°)	**WATERFLOOD**		**LSB Injection**	
	Recovery factor (%)	**Time (Days)**	**Recovery factor (%)**	**Time (Days)**
0	34.7065	4,414	49.8911	10,439
15	35.3503	4,473	51.0571	10,378
30	35.4427	4,322	52.1706	9,830
45	36.3428	4,626	52.8735	10,135
60	35.4514	4,199	51.0771	9,404

Moreover, the benefit of LSB injection for both case 35,000 and case 100,000 is summarized. The comparison is displayed in Figure 5.6, higher additional oil recovery factors are obtained at case 100,000. Approximately 15.2-16.7% of additional recovery factors for this case are noticed. This high additional oil recovery is a result of high salinity contrast. When fluids with different salinity (or salt concentration) are mixed together, the average salinity is built up due to diffusion of salt concentration. The rate of diffusion is directly proportional to concentration gradient. In another word, the higher the difference of two concentrations, the greater the rate of diffusion is observed. Therefore, the change of relative permeability curves toward a more water-wet condition occurs quicker and consequently results in a better oil recovery mechanism compared to the case 35,000. However, ultimate oil recovery factor from LSB injection of case 100,000 is not significantly altered from case 35,000 since the relative permeability curves after LSB injection that are input into simulator are not much different. The relative permeability curves after LSB flooding for both case 35,000 and case 100,000 are illustrated in Figure 5.7. These relative permeability curves are obtained from laboratorial experiment together with the rule of thumb of wettability as explained in section 4.4. The second shock front in case 100,000 is larger than case 35,000 as seen in Figure 5.8. From Figure 5.8, the second shock front which is a result from wettability alteration can be seen on the location mark directly on the figure.

At different dip angles, the additional oil recovery is also different. The maximum additional oil recovery factor of 16.7% is obtained from the reservoir with dip angle of 30°. Again, this dip angle shows the best results due to combination of gravity effect on reservoir fluids and vertical permeability effect. Hence, flood front may move at high stability.

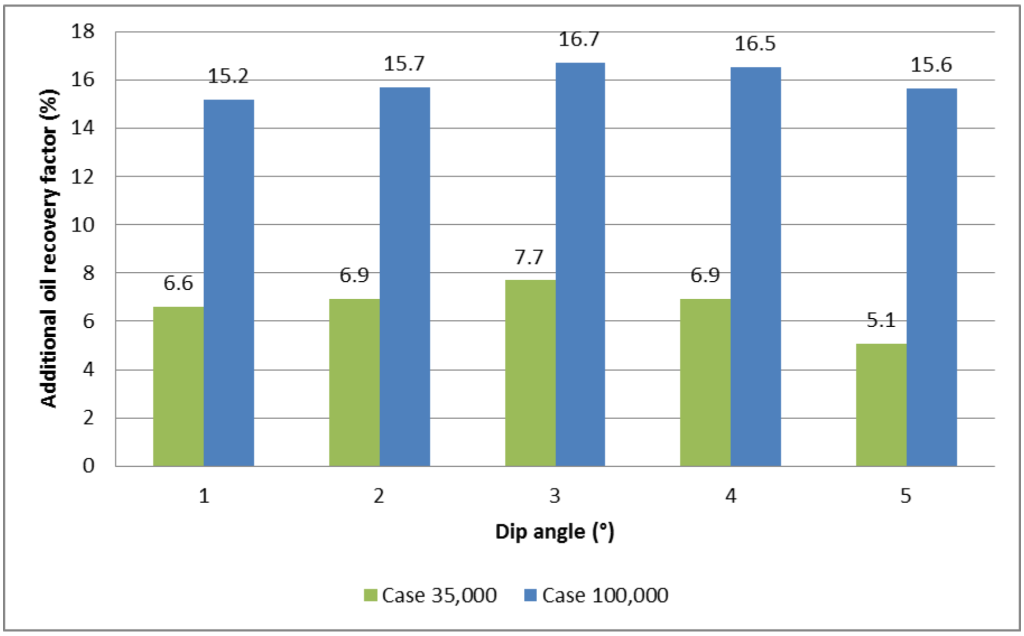

Figure 5.6 Comparison of additional recovery between case 35,000 and case 100,000 at different dip angles

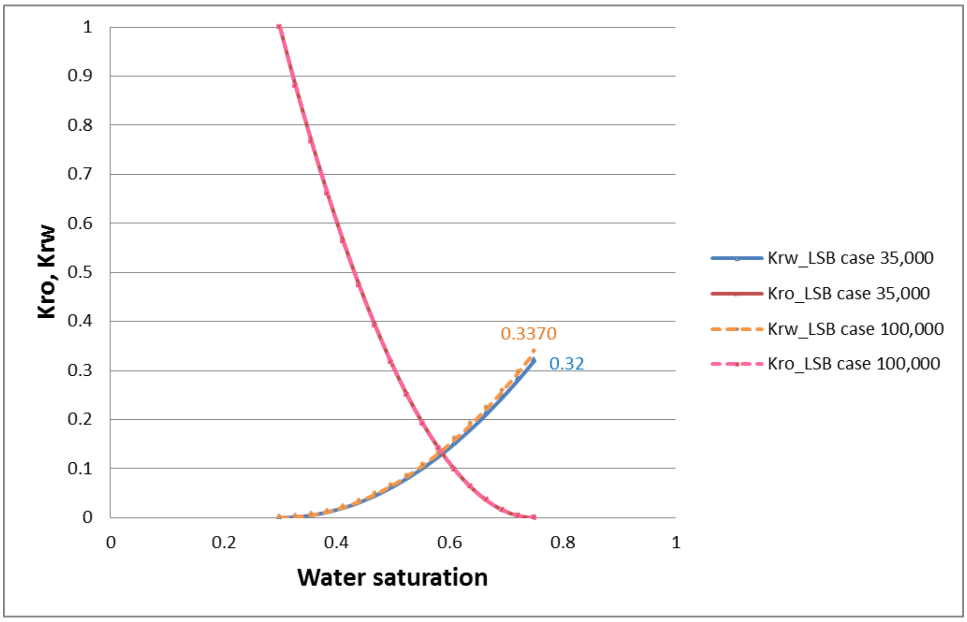

Figure 5.7 Relative permeability curves to oil and water after LSB injection as a function of water saturation for both case 35,000 and case 100,000

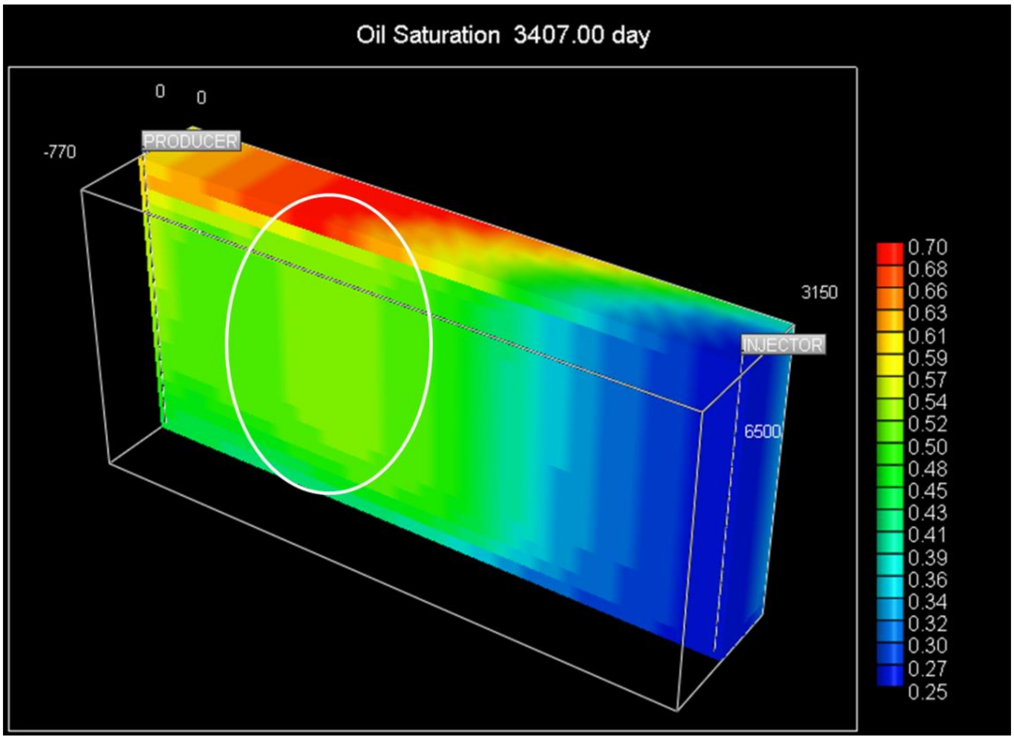

Figure 5.8 Oil saturation gradient during LSB injection (formation salinity is 100,000 ppm, LSB salinity is 5,000 ppm and vertical cut plane-perpendicular to y)

From Section 5.4 onwards, the value of formation water salinity is also considered along with each study parameter. Waterflooding and LSB injection process are simulated to evaluate the benefit of LSB injection. Figure 5.9 summarizes the study of LSB injection for each study parameter.

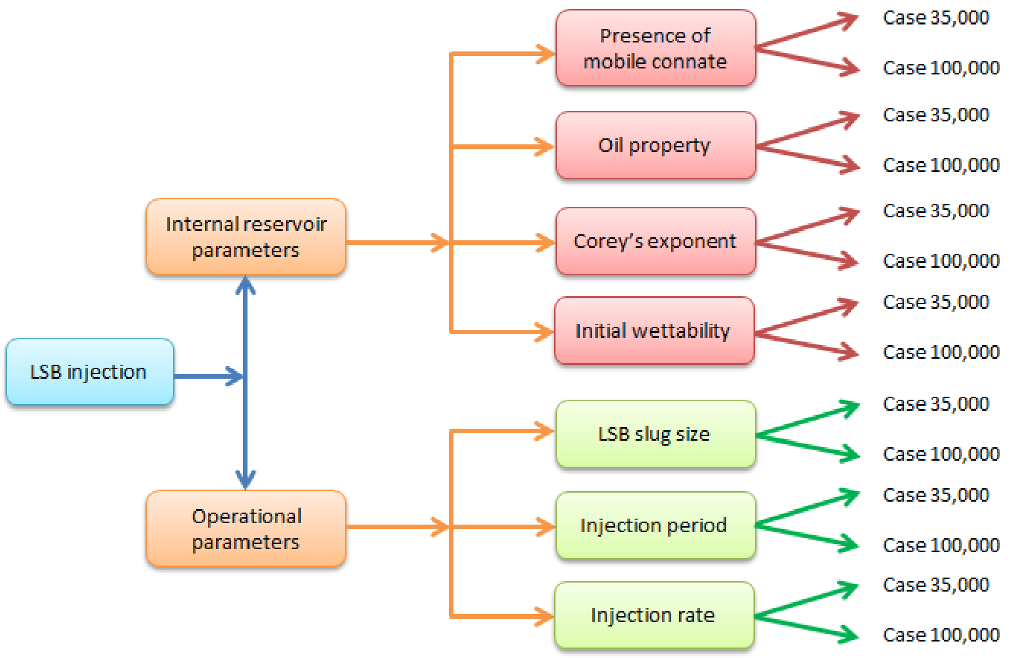

Figure 5.9 Flow chart illustrating study cases of each parameter

5.4 Effect of Mobile Connate Water

According to the base case model, the critical water saturation is fixed 30% water saturation in the simulation and the initial formation water saturation is not exceeded the critical water saturation. This means that formation water is immobile and hence, only hydrocarbon is produced during the water displacement process. In this section, four values of initial water saturation (S_{wi}) beyond critical water saturation are applied which are 35%, 40%, 45%, and 50%. This section is aimed to investigate the influence of mobile connate water saturation on effectiveness of LSB injection.

5.4.1 Formation Water Salinity of 35,000 ppm

The effect of mobile connate water on LSB injection in the reservoir with formation water salinity of 35,000 ppm is studied first. Figure 5.10 portrayed oil recovery factors when different mobile connate water saturations are presented in reservoir with different dip angels. As seen in the figure, at any dip angle, oil recovery factor is lower when higher mobile connate water is presented. This is caused by oil/water saturation function that yields high relative permeability to water (k_{rw}) value and lower relative permeability to oil (k_{ro}) value at high water saturation. In other words, water can flow much better and be produced easier compared to oil. As a consequent, the oil production rate is depleted early. Figure 5.11 also shows the water cut at production well at different S_{wi}. Since all the results show similar trend, the result from 0° dip angle is taken for discussion.

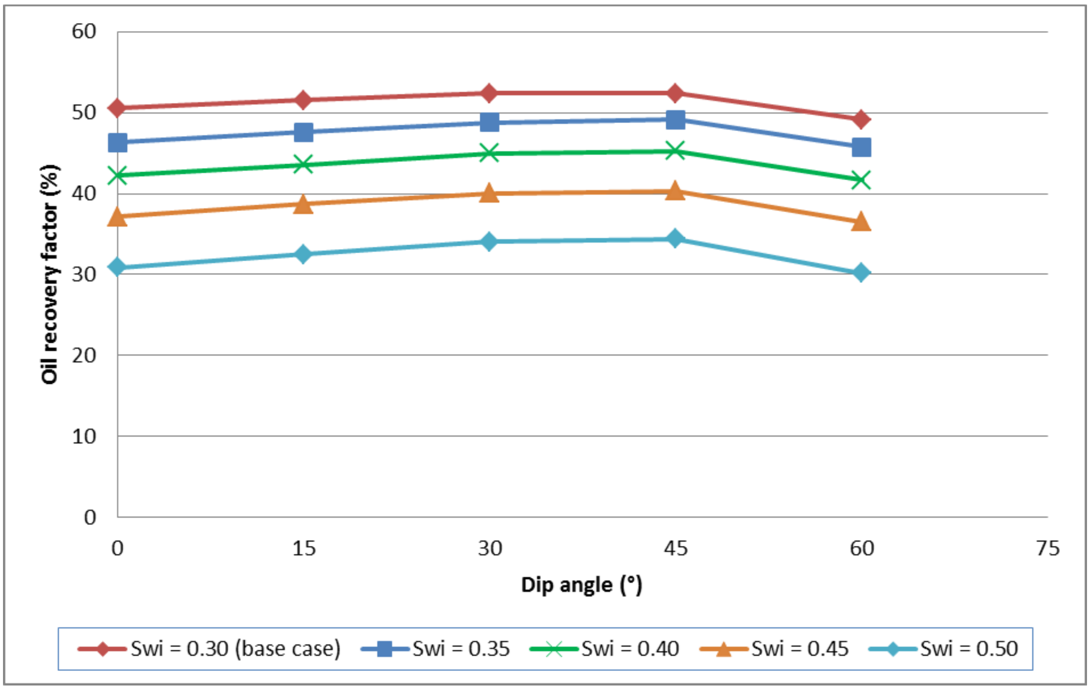

Figure 5.10 Oil recovery factors from reservoirs with different initial water saturation when formation water salinity is 35,000 ppm at different dip angles

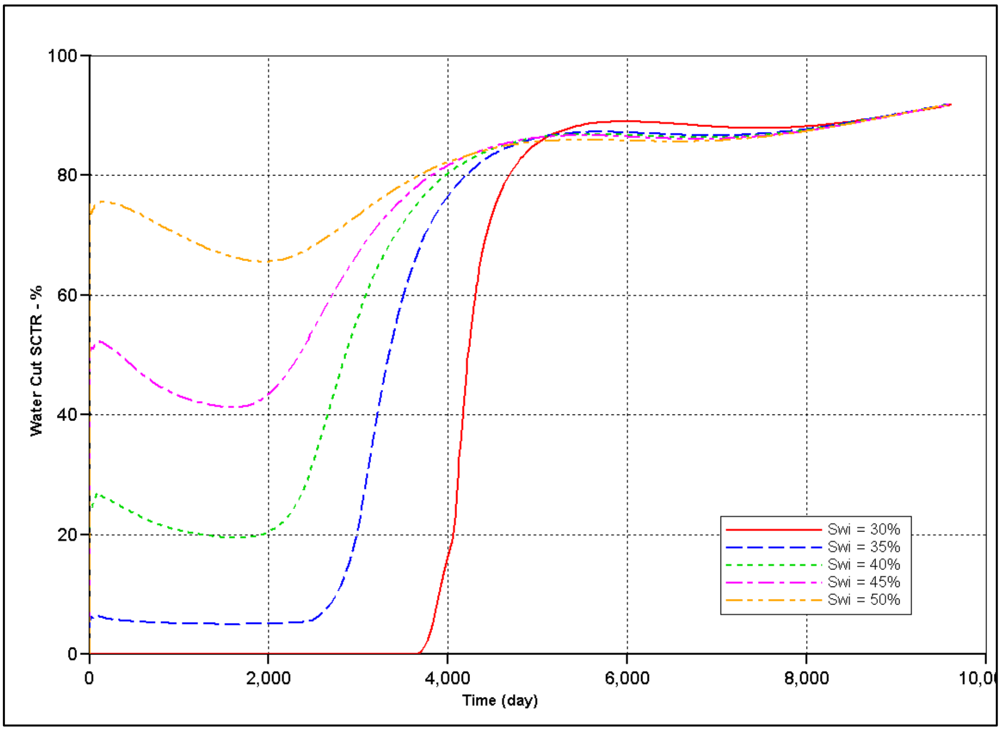

Figure 5.11 Water cut at production well for each initial water saturation (0° dip angle) when formation water salinity is 35,000 ppm

From Figure 5.11, it is obvious that water cut at production well is significantly high from the initial production period especially in the case of initial water saturation of 50% where water cut could reach almost 80%. The higher mobile connate water saturation the higher water production. Hence, the waterflooding project tends to have shorter production life time. Figures 5.12 to 5.16 show the water saturation profile at the same period of injection. As can be seen, darker blue color represents the highest water saturation. When the mobile connate water is presented in the reservoir, not only the bluish-green color appears behind the flood front due to higher water saturation, the flood front is also closer to the production well at the same production time. As the initial water saturation is higher, relative permeability of water is also higher. This high water saturation and relative permeability to water impact many parameters in displacement mechanism by water. One of those is the water injectivity at the injection well. Flood front is more advanced to the production well since water is easily injected due to high water injectivity.

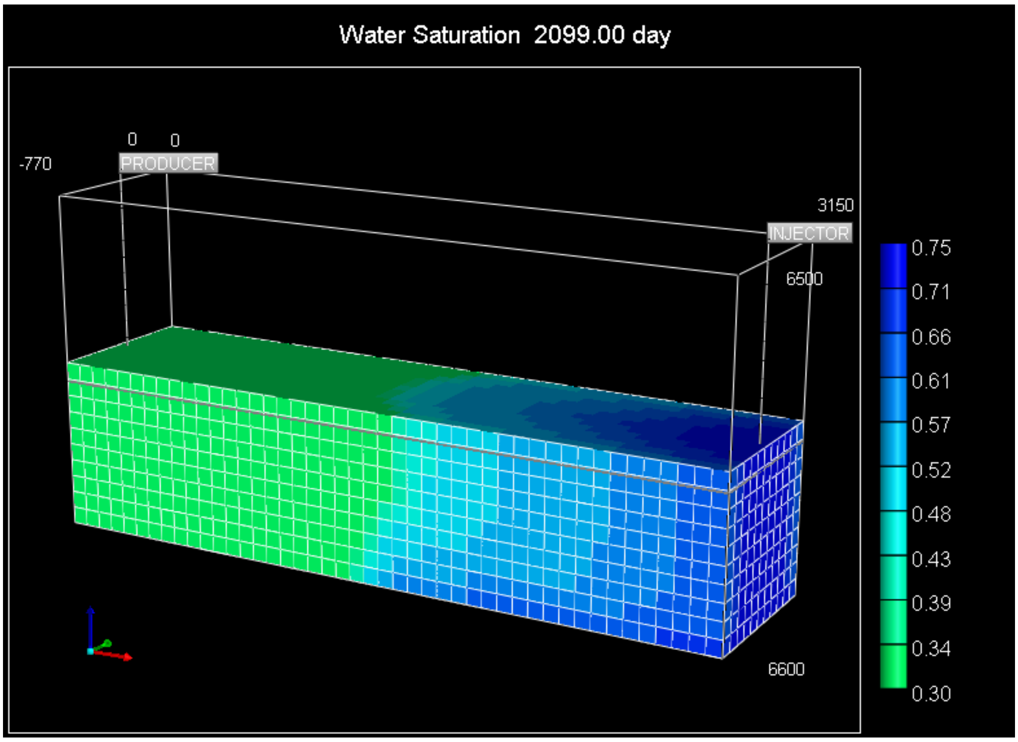

Figure 5.12 Water saturation gradient at 2,099 days of production (S_{wi} = 0.30)

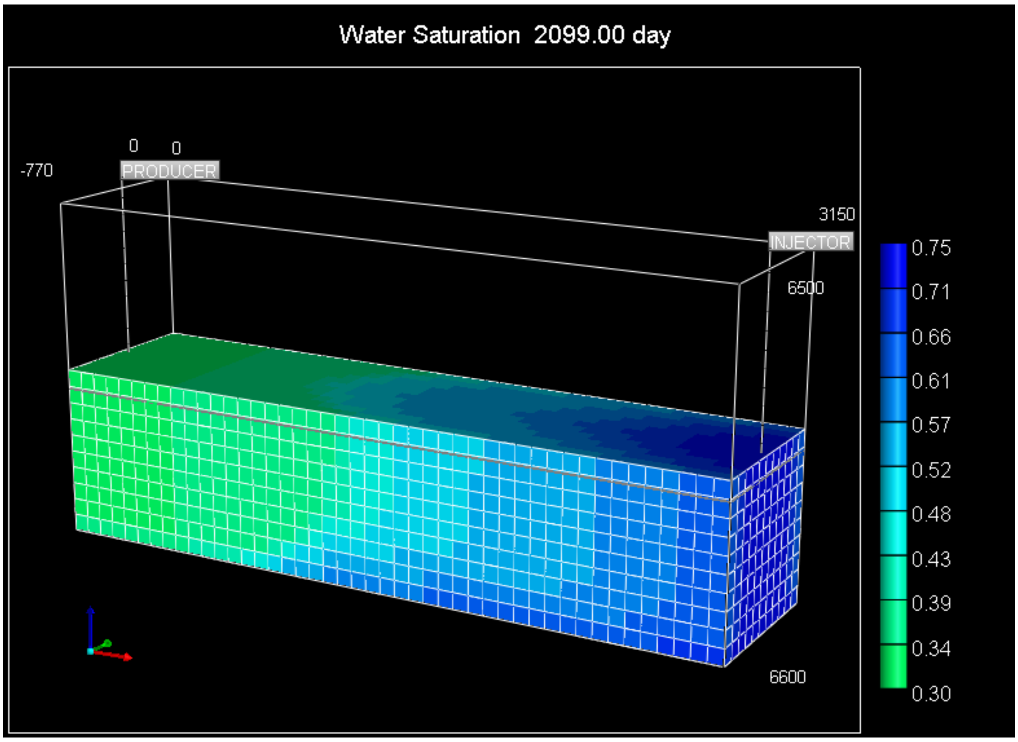

Figure 5.13 Water saturation gradient at 2,099 days of production (S_{wi} = 0.35)

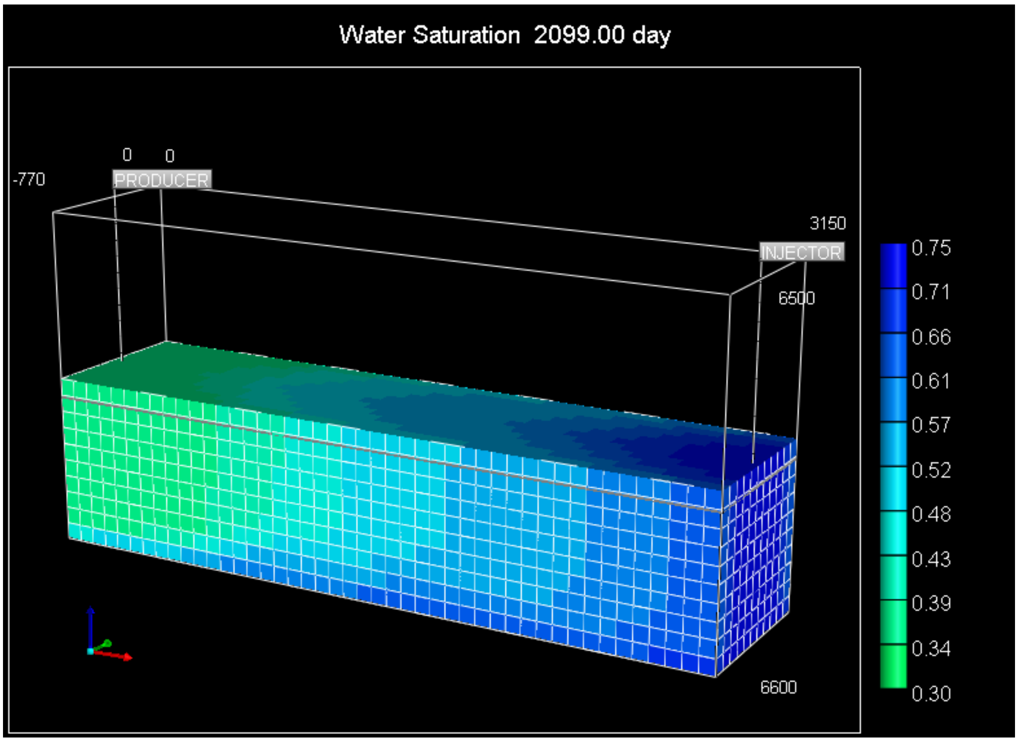

Figure 5.14 Water saturation gradient at 2,099 days of production (S_{wi} = 0.40)

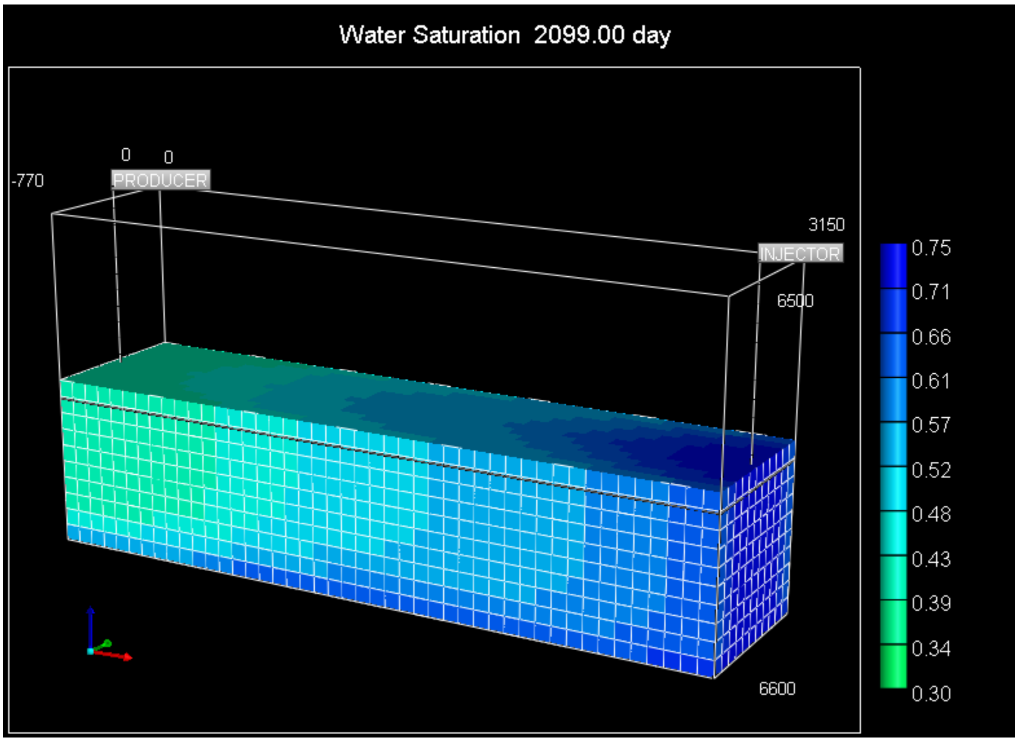

Figure 5.15 Water saturation gradient at 2,099 days of production (S_{wi}= 0.45)

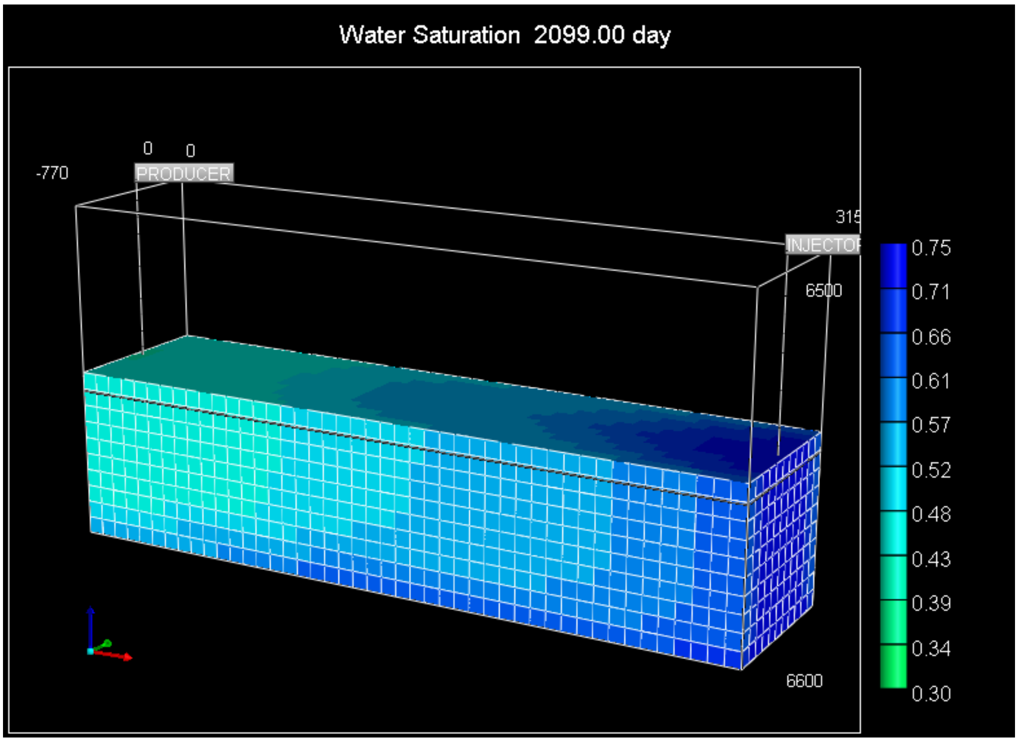

Figure 5.16 Water saturation gradient at 2,099 days of production (S_{wi} = 0.50)

Tables 5.5 to 5.8 summarize comparisons between waterflooding and LSB injection at different S_{wi} and different dip angles. According to these tables, the benefit of LSB injection is evaluated. The oil recovery factors obtained from different angles show that dip angle of 30° yields the highest additional oil recovery, whereas the highest recovery is observed at 45° for all cases.

Table 5.5 Summary of oil recovery factors when S_{wi} is 0.35 and formation water salinity is 35,000 ppm for both waterflooding and LSB injection at different dip angles

Swi 0.35	**WATERFLOOD**		**LSB injection**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	38.7096	5,294	46.3186	9,555	7.6
15	39.6391	5,325	47.5867	9,496	7.9
30	40.6191	5,569	48.8104	9,343	8.2
45	41.6545	6,117	49.0949	9,465	7.4
60	40.0114	5,356	45.7371	7,943	5.7

Table 5.6 Summary of oil recovery factors when S_{wi} is 0.40 and formation water salinity is 35,000 ppm for both waterflooding and LSB injection at different dip angles

Swi 0.40	**WATERFLOOD**		**LSB injection**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	33.8354	5,233	42.2081	9,555	8.4
15	34.8881	5,386	43.5729	9,616	8.7
30	36.0987	5,691	44.9426	9,465	8.8
45	37.1972	6,209	45.2349	9,586	8.0
60	35.2808	5,417	41.6277	8,094	6.3

Table 5.7 Summary of oil recovery factors when S_{wi} is 0.45 and formation water salinity is 35,000 ppm for both waterflooding and LSB injection at different dip angles

Swi 0.45	**WATERFLOOD**		**LSB injection**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	27.8821	5,203	37.1335	9,586	9.3
15	29.1157	5,356	38.6673	9,616	9.6
30	30.3585	5,599	40.0566	9,404	9.7
45	31.5238	6,117	40.3413	9,527	8.8
60	29.4241	5,294	36.5067	8,066	7.1

Table 5.8 Summary of oil recovery factors when S_{wi} is 0.50 and formation water salinity is 35,000 ppm for both waterflooding and LSB injection at different dip angles

Swi 0.50	**WATERFLOOD**		**LSB injection**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	20.6431	5,233	30.8633	9,555	10.2
15	22.0013	5,294	32.4606	9,465	10.5
30	23.3971	5,386	34.0411	9,162	10.6
45	24.6551	5,844	34.3805	9,282	9.7
60	22.1940	4,960	30.2029	7,821	8.0

Table 5.9 Summary of additional oil recovery factors at different $S_{wi}$when formation water salinity is 35,000 ppm

S_{wi}	**Benefit of LSB injection, RF(LSB injection)-RF(waterflooding)**
0.30	5.1-7.7%
0.35	5.7-8.2%
0.40	6.3-8.8%
0.45	7.1-9.7%
0.50	8.0-10.6%

From Table 5.9 the benefit from LSB injection compared to waterflooding is remarkably observed when S_{wi} is high. This can be due to several reasons. First, oil recovery factors obtained from waterflooding cases are relatively low in higher initial water saturation. Therefore, the portion of available improvement is higher as well. Second, this could also be related to the explanation that when mobile connate water is presented, the mix of formation brine and injected brine can occur abruptly and hence, LSB injection can yield more benefit compared to waterflooding due to the higher rate of wettability reversal to a more favorable condition.

5.4.2 Formation Water Salinity of 100,000 ppm

The formation water salinity of 100,000 ppm is considered in this section. The oil recovery factors from LSB injection with different initial water saturation is shown in Figure 5.17. The results are similar to previous study in section 5.4.1 when salinity of formation water is 35,000 ppm except for initial water saturation of 50%. As can be seen in Figure 5.17, oil recovery factor is extremely low except for the dip angle of 15° and 30°.

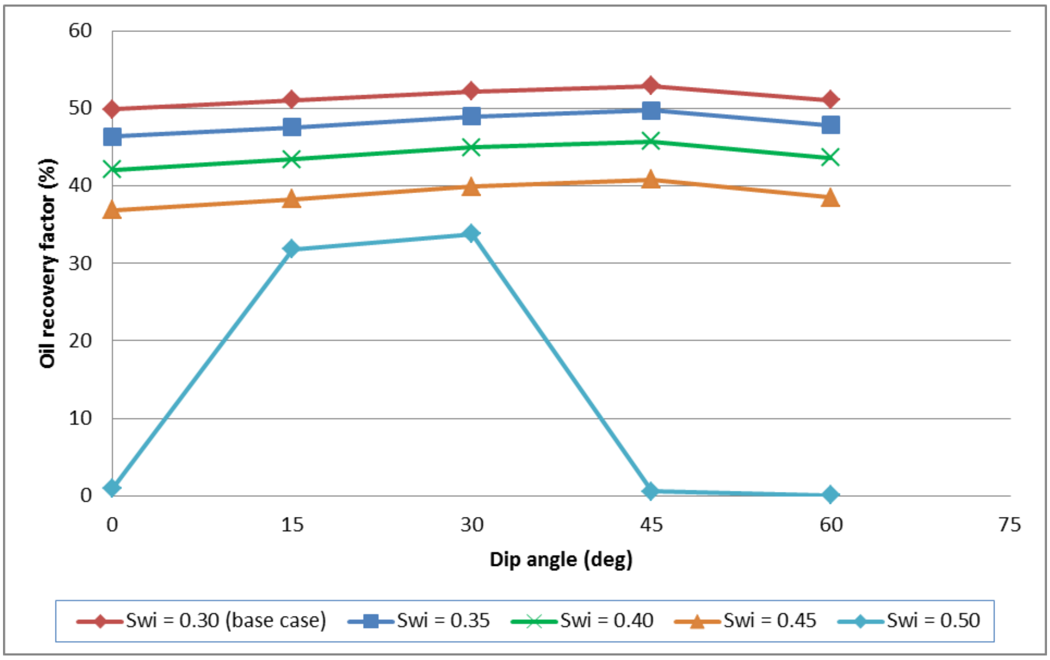

Figure 5.17 Oil recovery factors obtained from LSB injection with different initial water saturations and different dip angles (Formation water salinity is 100,000 ppm)

When initial water saturation is 50%, significant amount of connate water is produced instead of oil for every reservoir models as seen in Figures 5.18 to 5.22. These figures show that water cut is raised to the level of about 90% at the beginning and hence, the oil rate is severely low which corresponds to the short production period since oil rate becomes lower than economic limit. It can be inferred that; oil is produced shortly in horizontal reservoir because of high water cut at the beginning. However, the oil production of reservoir with dip angle of 15° and 30° can be extended. As can be seen Figure 5.23, oil production rate is also low at the beginning for those reservoirs. Fortunately, it is just slightly above the economic limit. Thus, the production is not over yet. The explanation for these phenomena may refer to better displacement mechanism due to the gravity segregation. Oil is lighter than water and as a result, oil tends to move upward when reservoir is inclined and hence, these two inclined reservoirs can produce more oil slightly above the economic. Besides, at the dip angles of 45° and 60°, the effect of gravity force is abundant as both oil and water are moved downward and production is hardly conducted.

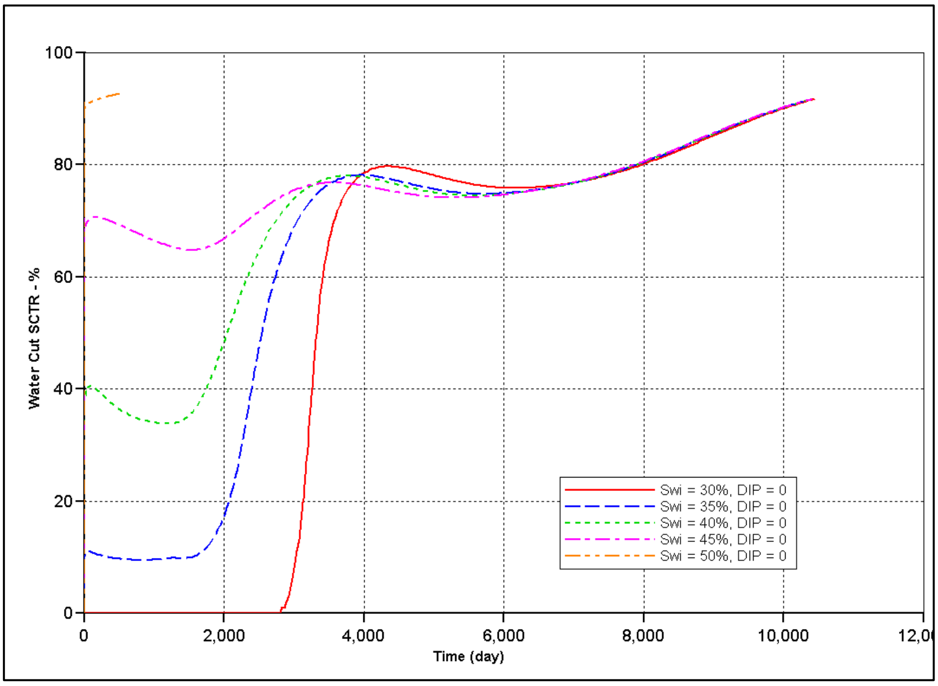

Figure 5.18 Water cut at different initial water saturations when dip angle is 0° and formation water salinity is 100,000 ppm

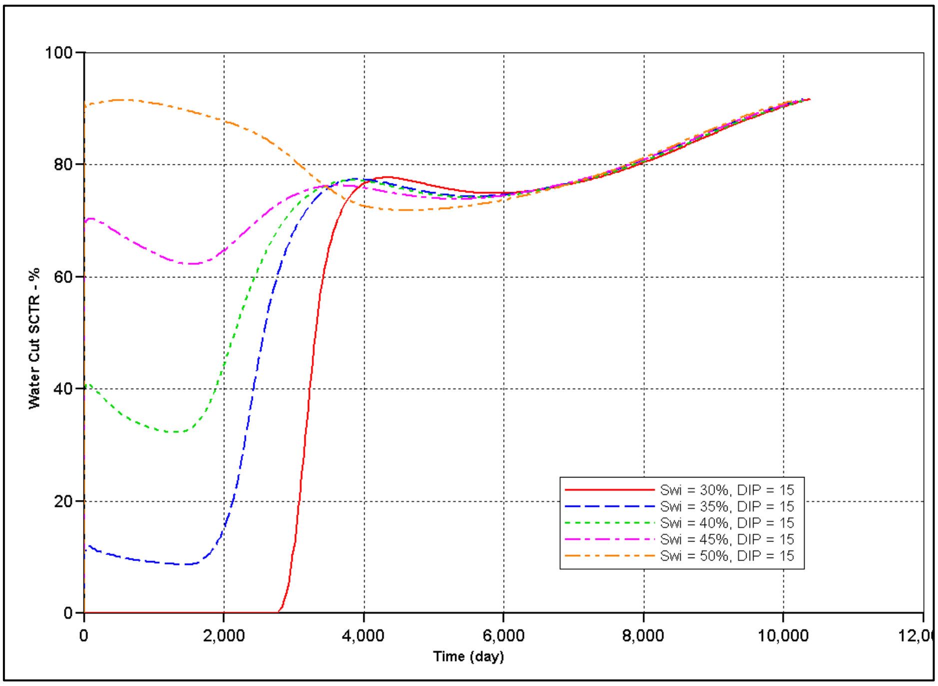

Figure 5.19 Water cut at different initial water saturations when dip angle is 15°and formation water salinity is 100,000 ppm

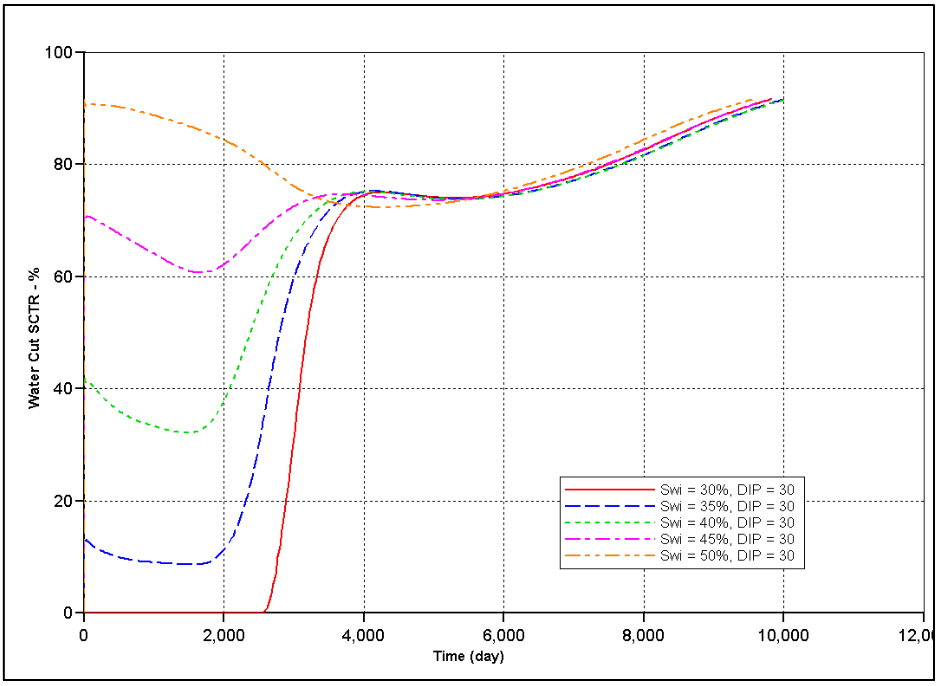

Figure 5.20 Water cut at different initial water saturations when dip angle is 30°and formation water salinity is 100,000 ppm

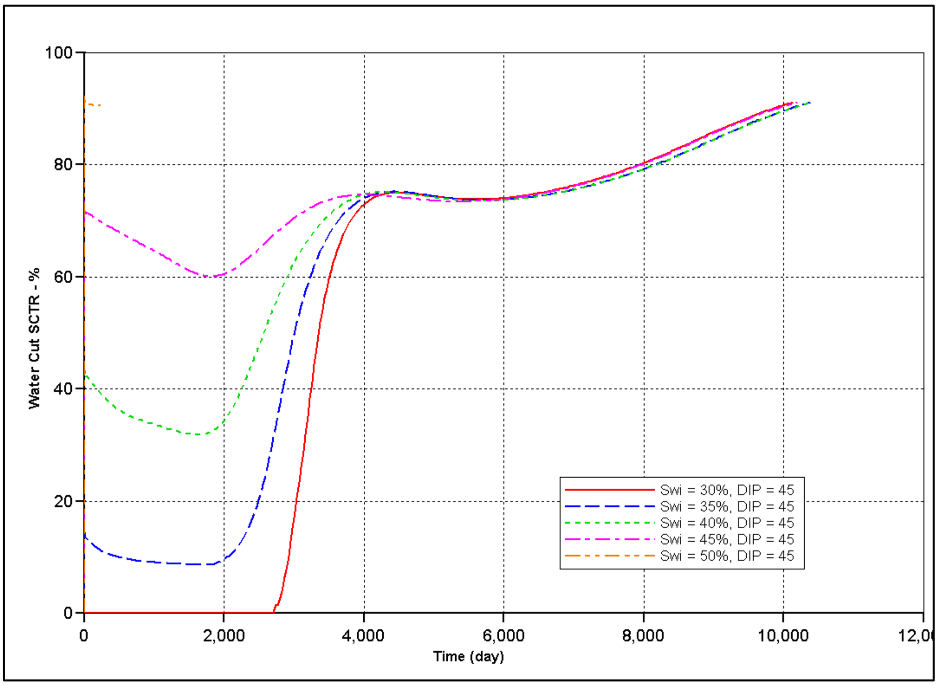

Figure 5.21 Water cut at different initial water saturations when dip angle is 45°and formation water salinity is 100,000 ppm

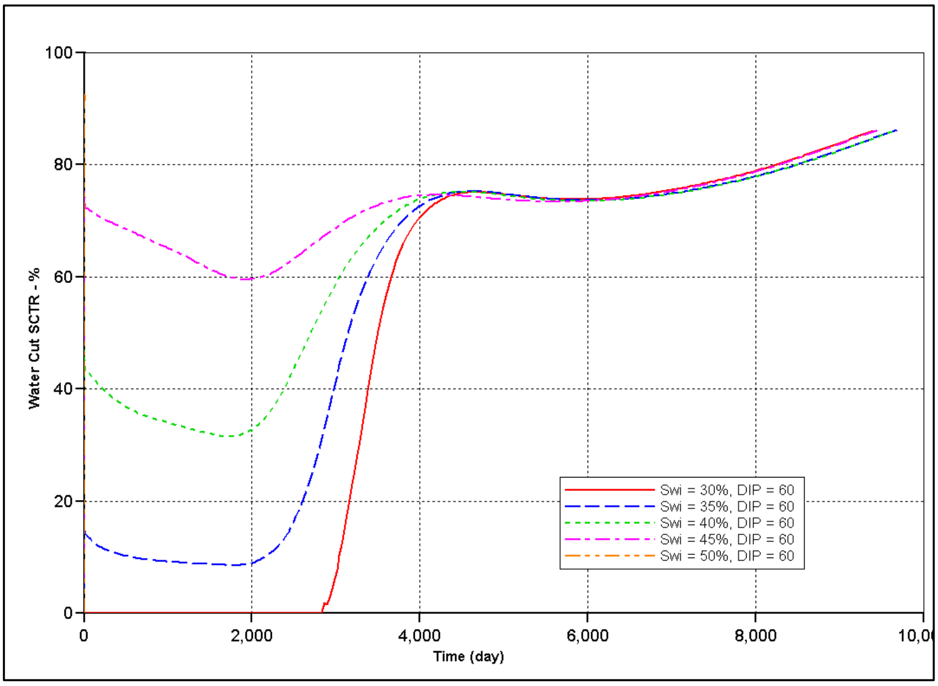

Figure 5.22 Water cut at different initial water saturations when dip angle is 60°and formation water salinity is 100,000 ppm

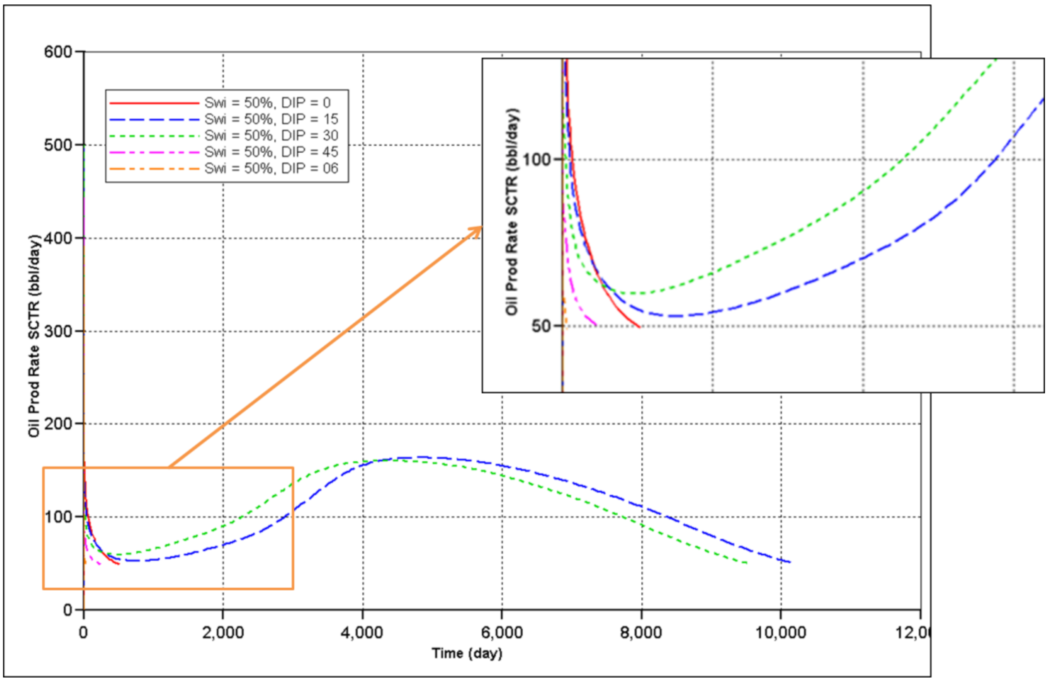

Figure 5.23 Oil production rate as a function of production time when connate water saturation is 50% and formation water salinity is 100,000 ppm

Next, consideration is shifted to the effectiveness of LSB injection for this case. Tables 5.10 to 5.13 represent the comparison between waterflooding and LSB injection at different dip angles and S_{wi}. Within each table, the highest oil recovery factor is obtained from reservoir dip angle of 45^o, whereas the highest increment of oil recovery factor is at dip angle of 30^o. Proper dip angle hence plays a major role in oil recovery improvement in LSB injection and it helps to improve oil recovery also in case that high mobile connate water is presented.

Table 5.10 Summary of oil recovery factors when S_{wi} is 0.35 and formation water salinity is 100,000 ppm for both waterflooding and LSB injection

Swi 0.35	**WATERFLOOD**		**LSB injection**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	29.0015	4,322	46.3502	10,408	17.3
15	29.8114	4,352	47.5427	10,286	17.7
30	30.7434	4,473	48.9387	10,013	18.2
45	31.7845	4,779	49.7118	10,378	17.9
60	30.8175	4,352	47.8039	9,677	17.0

Table 5.11 Summary of oil recovery factors when S_{wi} is 0.40 and formation water salinity is 100,000 ppm for both waterflooding and LSB injection

Swi 0.40	**WATERFLOOD**		**LSB injection**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	23.2223	4,261	42.1071	10,408	18.9
15	24.2026	4,383	43.4277	10,347	19.2
30	25.2511	4,473	44.9805	10,043	19.7
45	26.2610	4,748	45.7341	10,408	19.5
60	25.1639	4,322	43.6380	9,677	18.5

Table 5.12 Summary of oil recovery factors when S_{wi} is 0.45 and formation water salinity is 100,000 ppm for both waterflooding and LSB injection

Swi 0.45	**WATERFLOOD**		**LSB injection**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	16.2651	4,291	36.8877	10,408	20.6
15	17.2813	4,322	38.2861	10,286	21.0
30	18.3987	4,291	39.9175	9,830	21.5
45	19.5086	4,503	40.7954	10,196	21.3
60	18.2733	4,048	38.5262	9,465	20.3

Table 5.13 Summary of oil recovery factors when S_{wi} is 0.50 and formation water salinity is 100,000 ppm for both waterflooding and LSB injection

Swi 0.50	**WATERFLOOD**		**LSB injection**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	1.0284	516	1.0283	516	0.0
15	8.6782	4534	31.7956	10,196	23.1
30	10.1066	4291	33.7967	9,555	23.7
45	0.7442	334	0.5498	243	0.0
60	0.1335	42.68	0.0979	31	0.0

Table 5.14 Summary of additional oil recovery factors at different S_{wi} when formation water salinity is 100,000 ppm

S_{wi}	**Benefit of LSB injection, Formation water 100,000 ppm**	**Benefit of LSB injection, Formation water 35,000 ppm**
0.30	15.2-16.7%	5.1-7.7%
0.35	17.0-18.2%	5.7-8.2%
0.40	18.5-19.7%	6.3-8.8%
0.45	20.3-21.5%	7.1-9.7%
0.50	Almost 0 - 23.7%	8.0-10.6%

Similar to the previous section, the summary benefit of LSB injection is evaluated and illustrated in Table 5.14. The benefit is increased when S_{wi} is high. Hence, the similarity of this result between two formation water salinities is observed. However, compared this table to the results from 5.4.1, the benefit of LSB injection in this case is significantly higher. Again, this is a result from higher salinity contrasts as we investigated in section 5.3. The highest increment of oil recovery factors is found when S_{wi} is 0.5 but as described before, only dip angle of 15^{o} and 30^{o} are exceptional cases.

5.5 Effect of Oil Properties

In the previous sections, the gravity of oil is 24 °API with solution gas-oil ratio of about 420 scf/stb. The solution gas has gas gravity of 0.63. The bubble point pressure is 2,810 psi and oil viscosity is 2.0 cp at reference pressure. In this section, the effect of oil property, mainly oil gravity (this also related to oil viscosity), is studied. Four different values of oil gravity of 20, 18, 16, and 14 °API are considered. These oils with different oil gravity are later labeled as oil type 1, 2, 3, and 4, respectively. The properties of oil, solution gas-oil ratio, are determined first by using correlation [23] while keeping gas gravity to be constant at 0.63. Then, oil properties as shown in column 1-3 of Table 5.15 are input to STARS simulator and hence, estimated bubble point pressure and oil viscosity are obtained as illustrated in column 4-5. Eventually, four oils with different viscosity are used in simulation. After that, LSB injection is investigated for both salinity values of formation water.

Table 5.15 Oil properties including oil gravity, solution gas-oil ratio, bubble point pressure and viscosity at reference pressure

Oil Type	**API(°)**	**R_s (scf/stb)**	**P_b (psi)**	**Viscosity (cP)**
Reference	24	420	2,810	2.0
1	20	394	2,675	3.5
2	18	367	2,482	4.8
3	16	343	2,295	7.0
4	14	320	2,105	10.6

5.5.1 Formation Water Salinity of 35,000 ppm

The effect of oil property on LSB injection is displayed in Figure 5.24 and Figure 5.25. As can be seen from both figures, oil recovery at every dip angle is reduced when oil is more viscous (compared to the reference oil property which is used in previous sections). This reduction mainly results from less displacement efficiency. Basically, LSB injection provides two main oil recovery mechanisms, i.e., immiscible displacement and wettability alteration. Although LSB may alter the rock wettability and allow oil to be desorbed from the rock surface, the desorbed oil is not well-displaced by the LSB slug due to the high contrast of their viscosities. Therefore, oil recovery factors are lower in all cases where oil viscosity is higher.

The trend of oil recovery factors with different dip angle for each oil type leads to the observation that the best dip angle yielding the highest oil recovery factor shifts to the less inclined direction as viscosity is increased. The oil type 1yields the best oil recovery factor at 15^o, whereas the rest oil types yields the highest oil recovery factors at zero dip. For most cases, the recovery is declined as the dip angle is increased. According to the fractional flow equation, oil viscosity takes effect in both viscous and gravity forces. At certain dip angle, the gravity force overcomes viscous force and hence leads to impoverishment of displacement phenomenon. Moreover, the higher viscosity also causes unfavorable condition of mobility ratio that could results in instability of flood front.

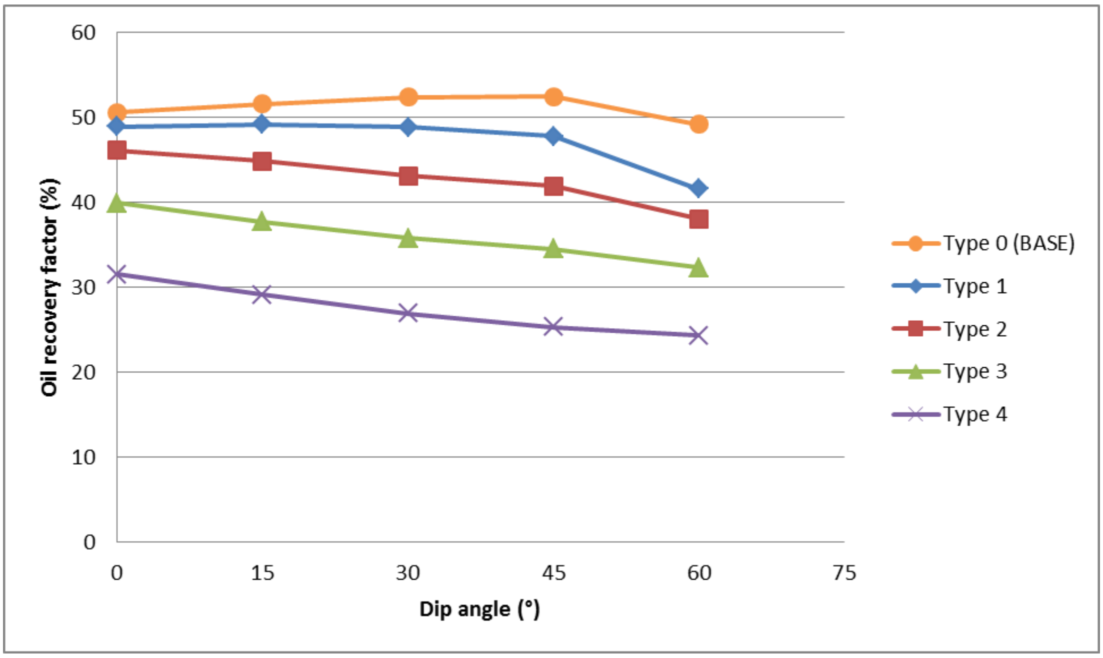

Figure 5.24 Oil recovery factors of different oil properties at different dip angles when formation water salinity is 35,000 ppm

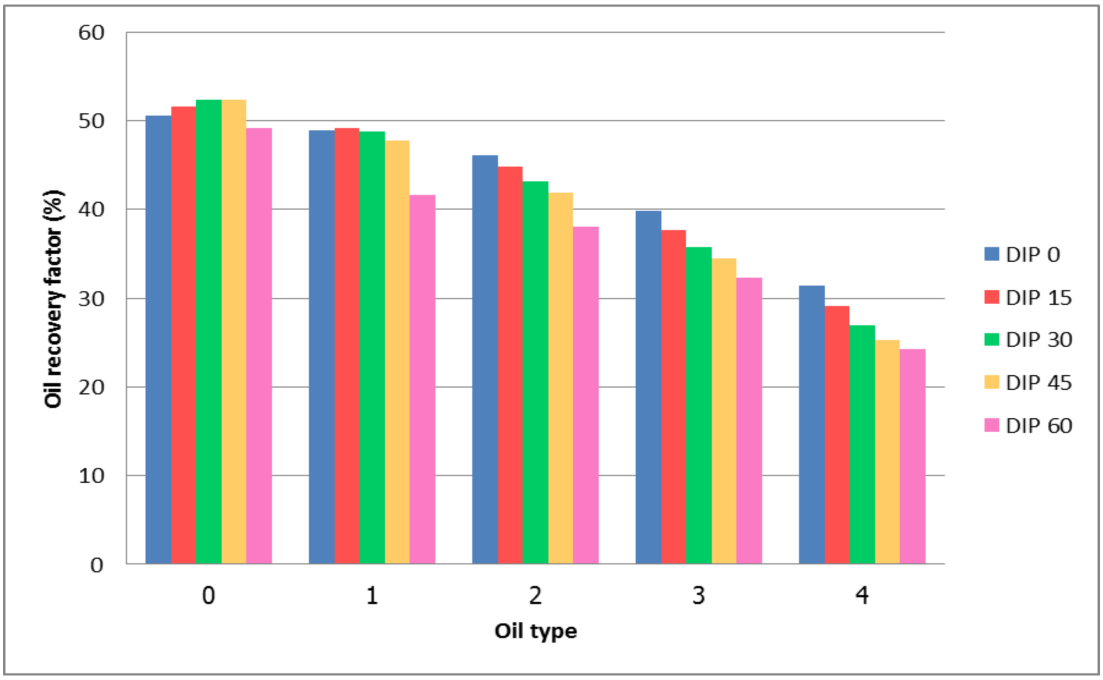

Figure 5.25 Oil recovery factors at different dip angles for each oil type when formation water salinity is 35,000 ppm

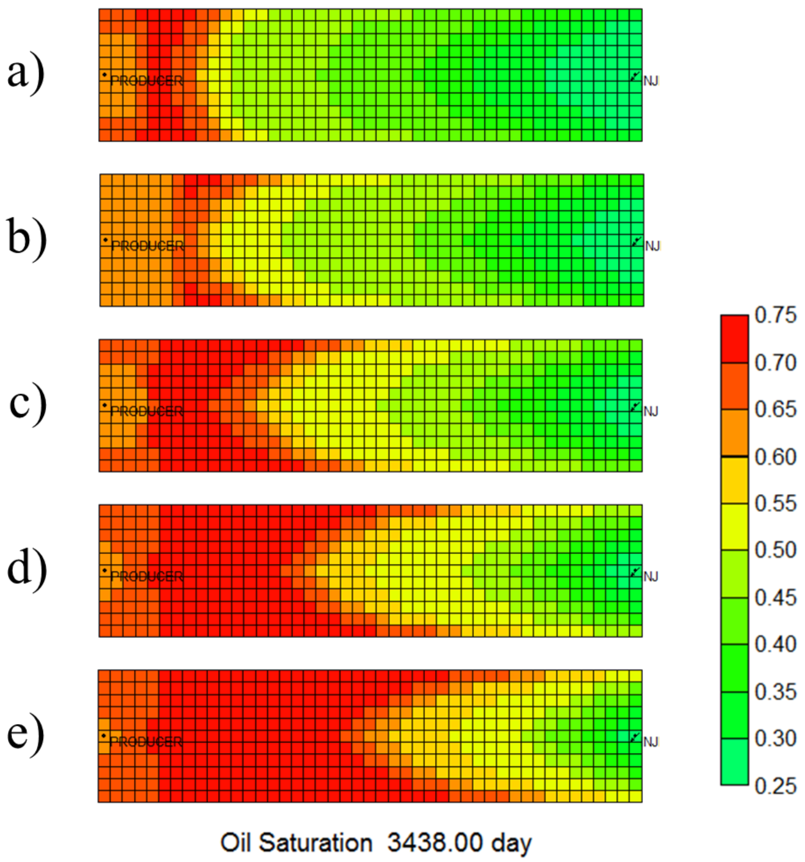

Figure 5.26 Oil saturation gradient for horizontal reservoir at Layer 10 in IJ-2D view at 3,438 days (a) 24 °API (b) 20 °API (c) 18 °API (d) 16 °API (e) 14 °API

Figure 5.26 illustrates the flood front of LSB injection after injecting for 3,438 days. From the figures, the displacement front of LSB is less when oil is more viscous oil. LSB slug almost breakthrough in the least viscous oil. Besides, the shape of flood front is notably different. A more stability can be seen in Figure 5.26a when oil is light whereas, the intrusive front can be obtained from heavier oil as seen in Figure 5.26e. These illustrations describe the flood front stability which is the result from favorability of the mobility ratio.

Then, the additional oil recovery from LSB injection is considered by comparing to results from waterflooding at the same type of oil. Tables 5.16 to 5.19 denote the oil recovery factors of both waterflooding and LSB injection of different oil type.

Table 5.16 Summary of oil recovery factors of oil type 1 and formation water salinity is 35,000 ppm for both waterflooding and LSB injection

Type 1	**WATERFLOOD**		**LSB**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	41.2534	6,847	48.8597	10,773	7.6
15	41.7747	7,364	49.1161	10,957	7.3
30	42.8896	8,186	48.8268	10,957	5.9
45	42.6076	8,369	47.7592	10,957	5.2
60	40.4240	7,305	41.5776	7,882	1.2

Table 5.17 Summary of oil recovery factors of oil type 2 and formation water salinity is 35,000 ppm for both waterflooding and LSB injection

Type 2	**WATERFLOOD**		**LSB**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	40.2932	8,735	46.0652	10,957	5.8
15	40.7314	9,527	44.7953	10,957	4.1
30	41.5738	10,682	43.0973	10,957	1.5
45	40.0279	9,982	41.9063	10,957	1.9
60	37.4381	8,735	38.0522	9,131	0.6

Table 5.18 Summary of oil recovery factors of oil type 3 and formation water salinity is 35,000 ppm for both waterflooding and LSB injection

Type 3	**WATERFLOOD**		**LSB**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	38.4886	10,957	39.8941	10,957	1.4
15	37.3448	10,957	37.679	10,957	0.3
30	35.8078	10,957	35.7772	10,957	0.0
45	34.6870	10,957	34.5104	10,957	-0.2
60	32.1925	9,982	32.2865	10,196	0.1

Table 5.19 Summary of oil recovery factors of oil type 4 and formation water salinity is 35,000 ppm for both waterflooding and LSB injection

API 14	**WATERFLOOD**		**LSB**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	31.6785	10,957	31.4730	10,957	-0.2
15	29.4184	10,957	29.0969	10,957	-0.3
30	27.3053	10,957	26.9359	10,957	-0.4
45	25.6309	10,957	25.2925	10,957	-0.3
60	24.4821	10,865	24.2992	10,957	-0.2

Table 5.20: Summary of oil recovery factors for oil type 4 and formation water salinity is 35,000 ppm for both waterflooding and LSB injection

Oil Type	**Benefit of LSB injection, RF(LSB injection)-RF(waterflooding)**
0	5.1-7.7%
1	1.2-7.6%
2	0.6-5.8%
3	0.1-1.4%
4	No additional recovery

From Table 5.20 the additional of oil recovery factors provided by LSB injection is reduced when oil is getting more viscous. As discussed previously, oil is more difficult to be displaced due to improper mobility ratio. Increment of oil recovery factor from oil type 3 and 4 is not significantly increased at all, while oil type 1 and 2 yield additional oil recovery of 1.2-7.6% and 0.6-5.8%, respectively.

5.5.2 Formation Water Salinity of 100,000 ppm

The influence of oil viscosity on oil recovery from LSB injection when formation water salinity is 100,000 ppm is displayed in Figure 5.27 and Figure 5.28. The tendency of oil recovery factors is similar compared to the previous case in section 5.5.1. The explanation is therefore also identical.

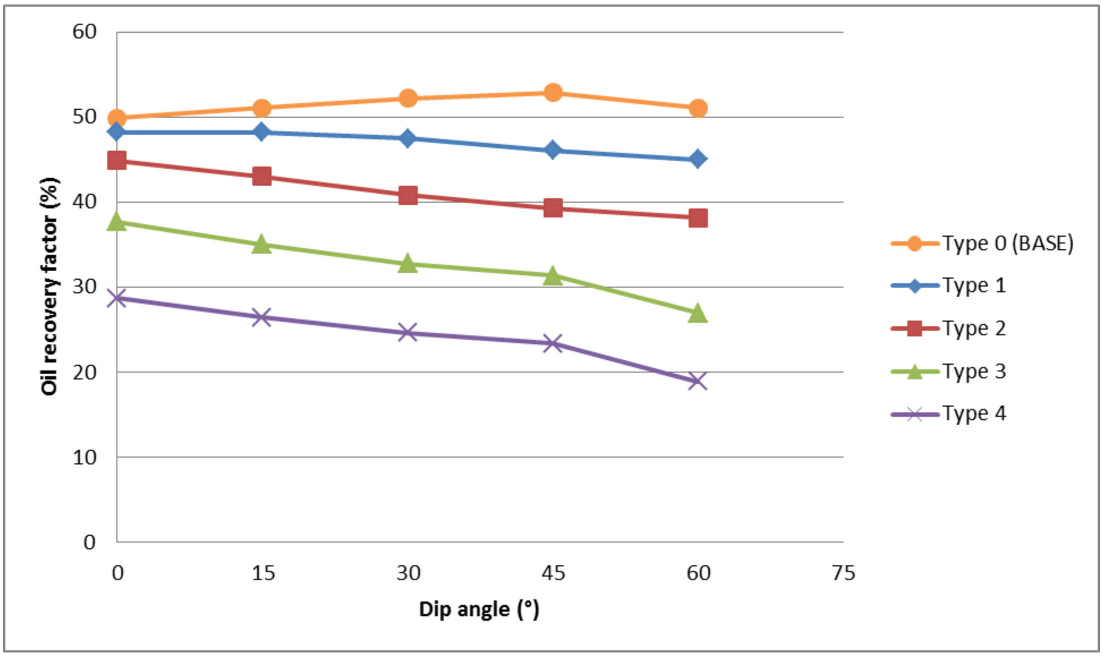

Figure 5.27 Oil recovery factors of different oil viscosity at different dip angles when formation water salinity is 100,000 ppm

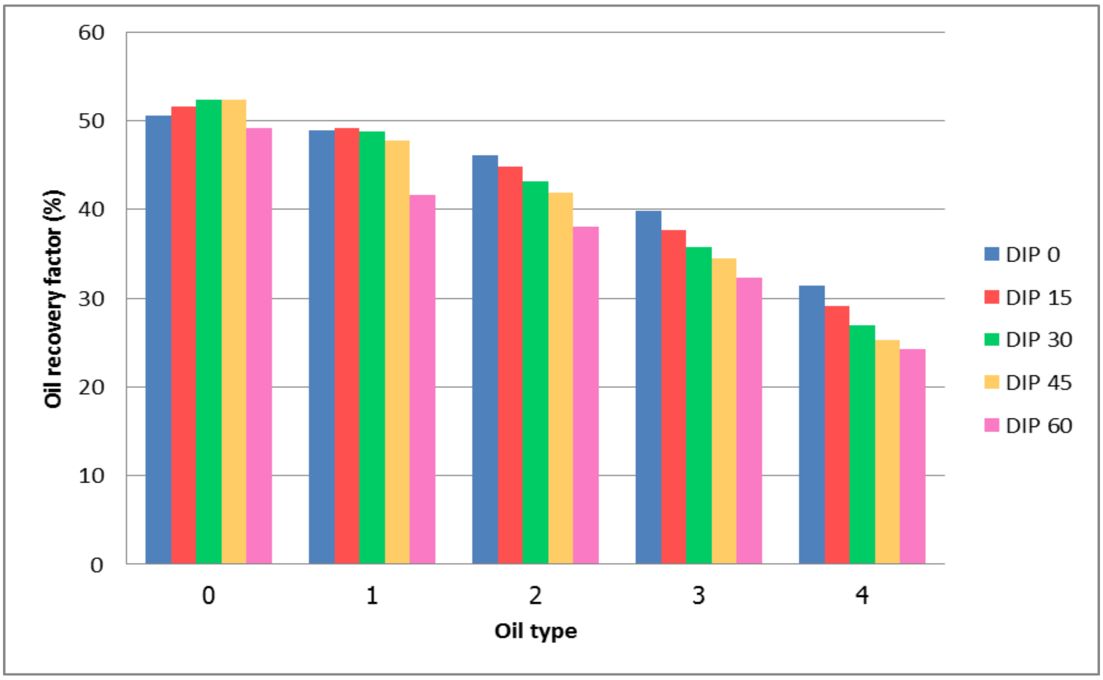

Figure 5.28 Oil recovery with different dip angle for each oil type when formation water salinity is 100,000 ppm

Tables 5.21 to 5.24 summarize the oil recovery factors and additional oil recovery factors of LSB injection in high salinity formation water when oil viscosity is the study parameter. The summary of additional oil recovery factors of these cases compared to the LSB injection in low salinity formation water (case 35,000) is also summarized in Table 5.25.

Table 5.21 Summary of oil recovery factors for oil type 1 and formation water salinity is 100,000 ppm for both waterflooding and LSB injection

Type 1	**WATERFLOOD**		**LSB**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	32.5827	5,569	48.1807	10,957	15.6
15	33.0324	5,903	48.235	10,957	15.2
30	33.9174	6,390	47.5028	10,957	13.6
45	34.4191	6,878	46.0477	10,957	11.6
60	32.5300	5,934	45.016	10,957	12.5

Table 5.22 Summary of oil recovery factors for oil type 2 and formation water salinity is 100,000 ppm for both waterflooding and LSB injection

Type 2	**WATERFLOOD**		**LSB**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	31.7348	6999	44.9016	10,957	13.2
15	32.0800	7517	43.0277	10,957	10.9
30	32.7701	8155	40.8479	10,957	8.1
45	32.3944	8216	39.2593	10,957	6.9
60	30.1569	7091	38.1868	10,957	8.0

Table 5.23 Summary of oil recovery factors for oil type 3 and formation water salinity is 100,000 ppm for both waterflooding and LSB injection

Type 3	**WATERFLOOD**		**LSB**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	30.4163	8,886	37.7179	10,957	7.3
15	30.7464	9,769	35.0148	10,957	4.3
30	31.0831	10,773	32.7465	10,957	1.7
45	29.1231	9,739	31.3399	10,957	2.2
60	26.0500	8,186	27.0006	8,856	1.0

Table 5.24 Summary of oil recovery factors for oil type 4 and formation water salinity is 100,000 ppm for both waterflooding and LSB injection

Type 4	**WATERFLOOD**		**LSB**		**Additional oil recovery (%)**
DIP	**RF (%)**	**Time (Days)**	**RF (%)**	**Time (Days)**	
0	27.8468	10,957	28.6931	10,957	0.8
15	26.4518	10,957	26.4671	10,957	0.0
30	24.9505	10,957	24.6614	10,957	-0.3
45	23.7493	10,957	23.3998	10,957	-0.3
60	19.1609	8,491	18.9085	8,613	-0.3

Table 5.25 Summary of oil recovery factors for oil type 4 and formation water salinity is 100,000 ppm for both waterflooding and LSB injection

Oil Type	**Benefit of LSB injection, Formation water 100,000 ppm**	**Benefit of LSB injection, Formation water 35,000 ppm**
0	15.2-16.7%	5.1-7.7%
1	11.6-15.6%	1.2-7.6%
2	6.9-13.2%	0.6-5.8%
3	1.0-7.3%	0.1-1.4%
4	Almost zero-0.8%	No additional recovery

However, when compare the increment of oil from LSB injection from this case and the case 35,000 it can be seen that the higher percentage of additional oil is obtained for all oil types due to the higher salinity contrast. Moreover, when salinity of formation water is 100,000 ppm, the wetting condition of rock is on a direction to neutral-wet. Basically, neutral-wet rock has less effect of bypassed oil (globules) compared to the water-wet reservoir rock. [20]

5.6 Effect of Relative Permeability Exponents

In the reservoir simulation, relative permeability curve is usually obtained from correlations requiring only end-point saturations and relative permeabilities to be input. Basically, Corey’s correlation is a power law which refers to the relationship between relative permeability and water saturation. The exponent in the correlation can be obtained correctly by matching the result from simulation to the experiment. In this study, both Corey exponents of relative permeability to oil and to water curves are assumed to be 2.0 for the base cases. The sensitivity of each exponent is studied in this section by varying the value of Corey-oil exponent (C_o), Corey-water exponent (C_w), and finally, both exponents. Four values of exponent including 1.0, 1.5, 2.5, and 3.0 are considered.

5.6.1 Relative Permeability Curve when Formation Water Salinity is 35,000 ppm

Figures 5.29 to 5.34 illustrate the relative permeability curves before LSB injection (35,000 ppm brine of formation water) and after LSB injection (5,000 ppm of injected water) at different values of Corey-exponent. As seen in the figures, the higher C_o yields lower k_{ro} value as same as the higher C_w yields lower k_{rw} value at any water saturation.

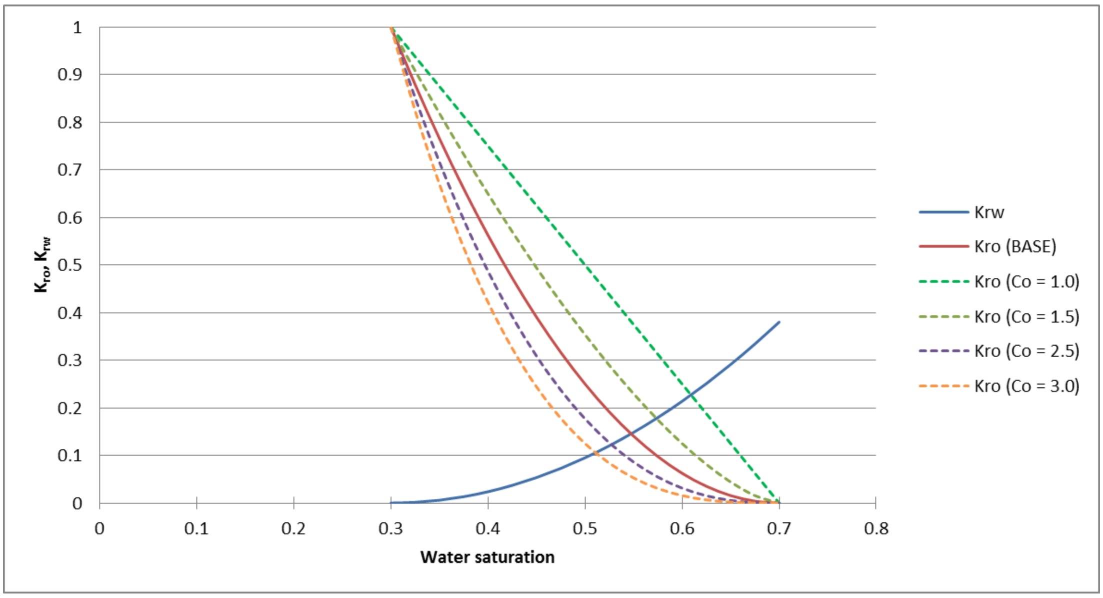

Figure 5.29 Oil/water saturation function related to 35,000 ppm brine (before LSB injection) obtained from correlation at different Corey-oil exponent

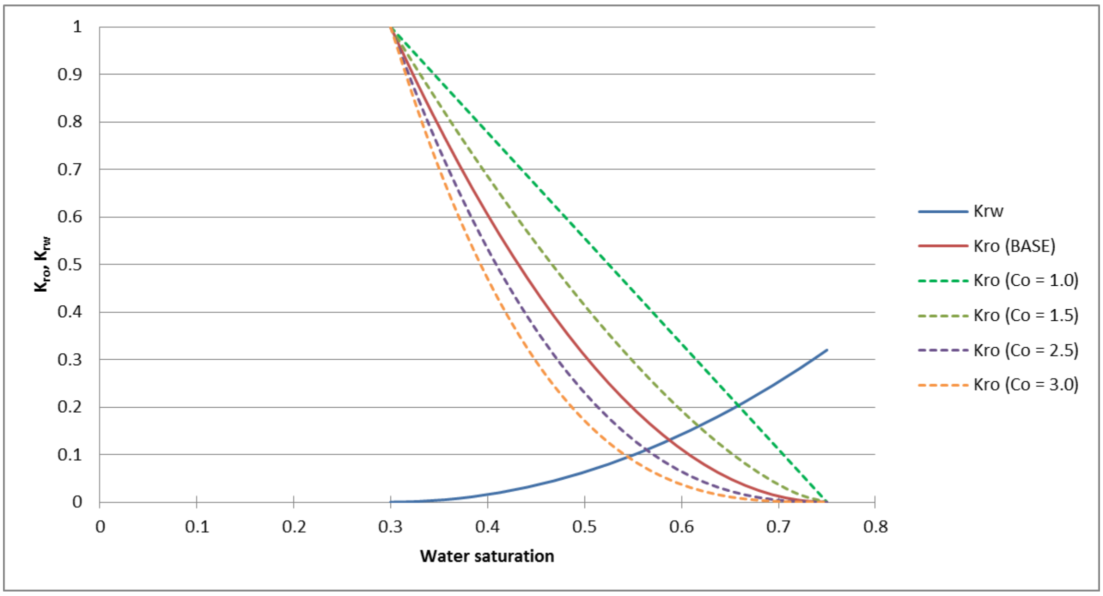

Figure 5.30 Oil/water saturation function related to 5,000 ppm brine (after LSB injection) obtained from correlation at different Corey-oil exponent

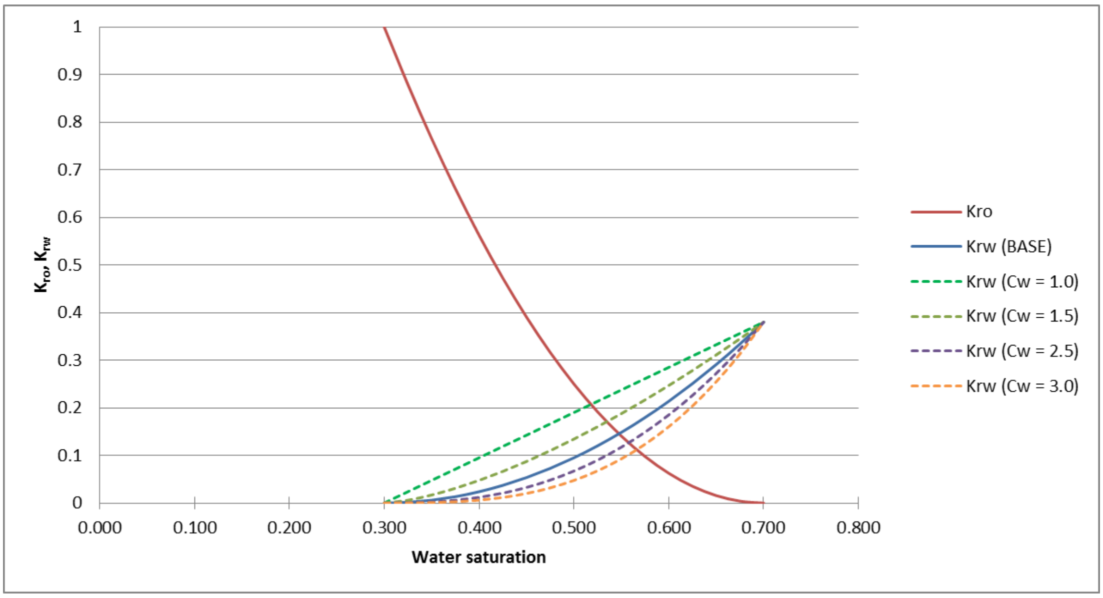

Figure 5.31 Oil/water saturation function related to 35,000 ppm brine (before LSB injection) obtained from correlation at different Corey-water exponent

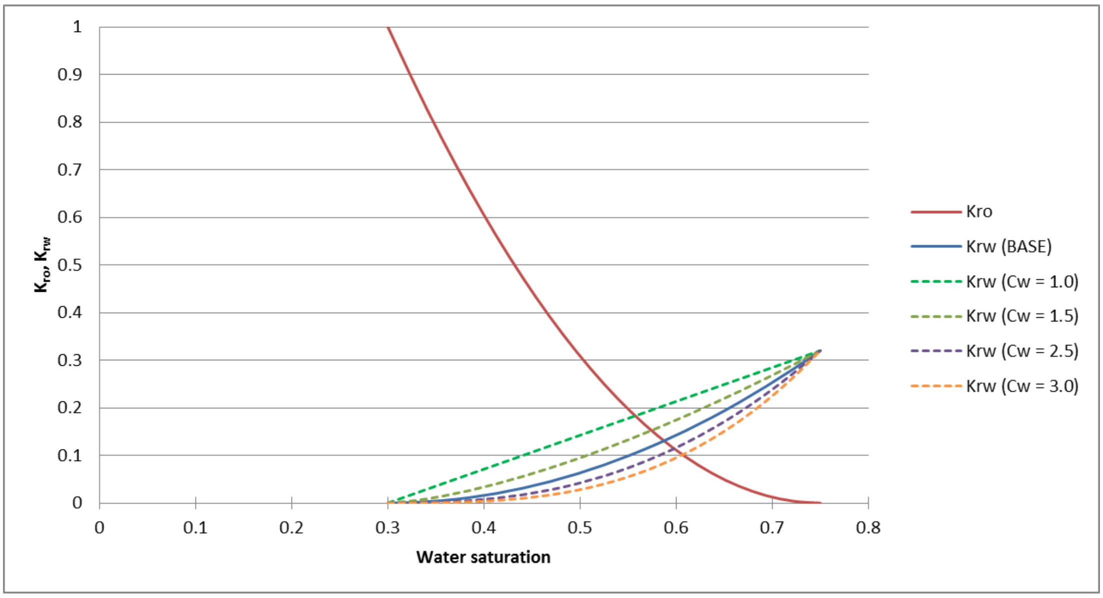

Figure 5.32 Oil/water saturation function related to 5,000 ppm brine (after LSB injection) obtained from correlation at different Corey-water exponent

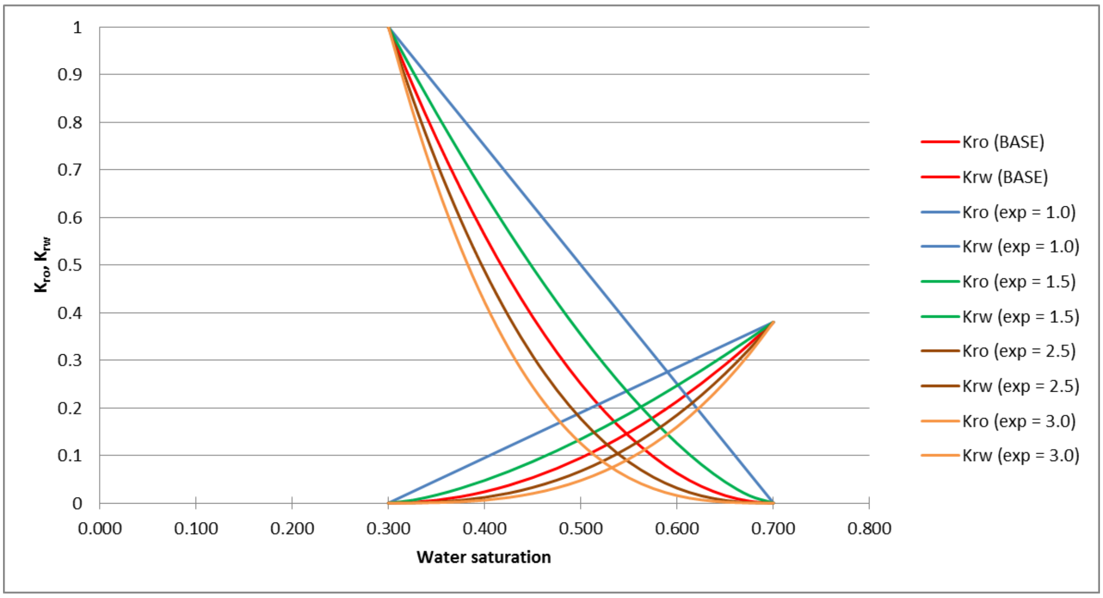

Figure 5.33 Oil/water saturation function related to 35,000 ppm brine (before LSB injection) obtained from correlation at different both Corey exponent

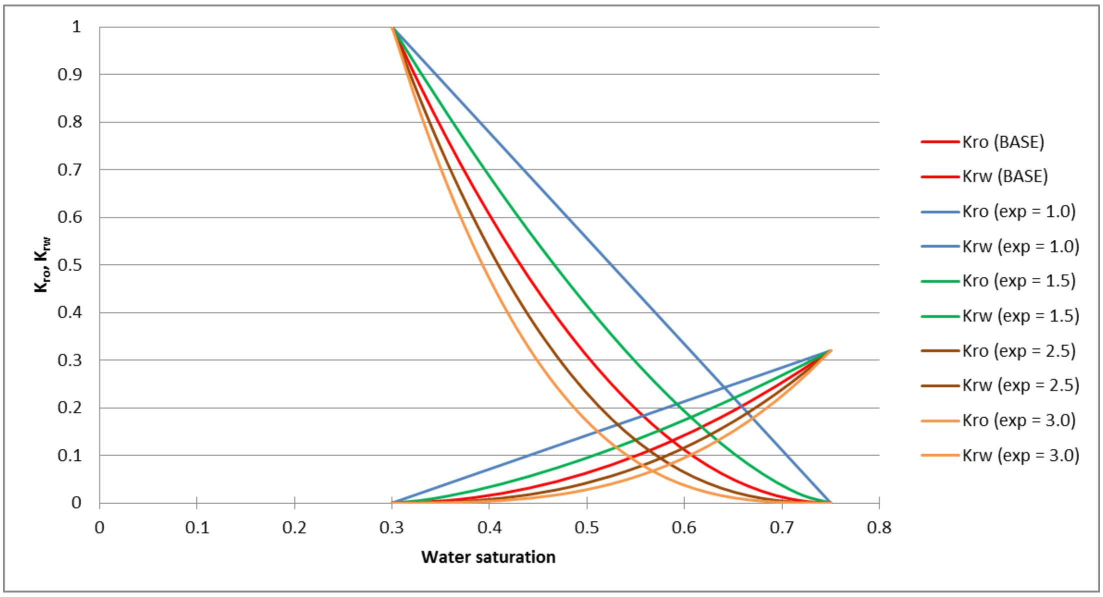

Figure 5.34 Oil/water saturation function related to 5,000 ppm brine (after LSB injection) obtained from correlation at different both Corey exponent

5.6.2 Relative Permeability Curve when Formation Water Salinity is 100,000 ppm

Figures 5.35 to 5.40 illustrate the relative permeability curves before LSB injection (100,000 ppm brine of formation water) and after LSB injection (5,000 ppm of injected water) at different value of Corey-exponents. From these figures, similar trend of relative permeability curves to the previous section, 5.6.1, is observed.

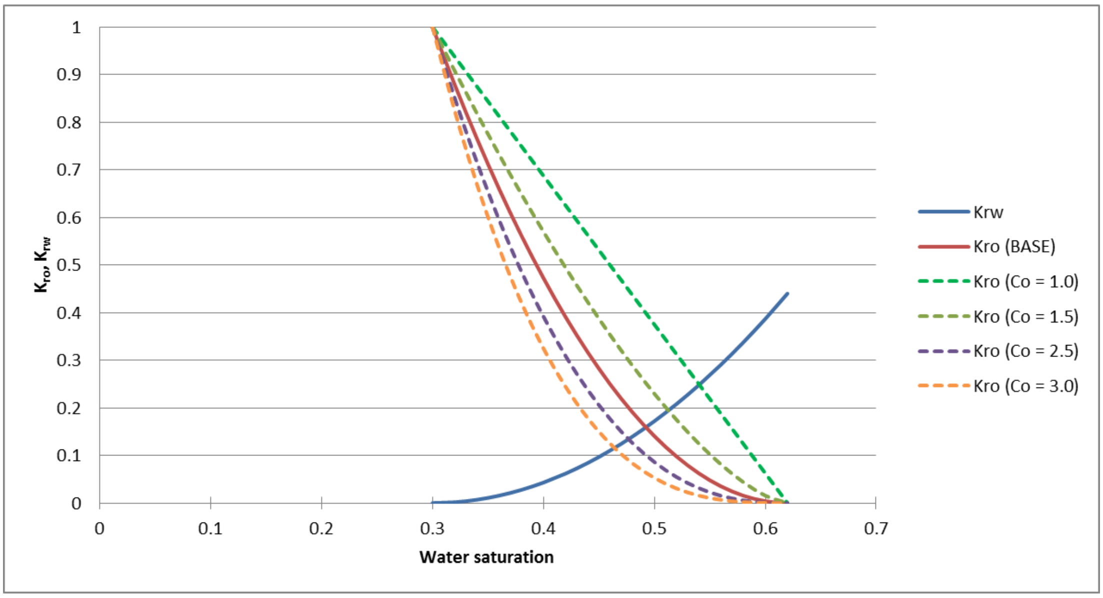

Figure 5.35 Oil/water saturation function related to 100,000 ppm brine (before LSB injection) obtained from correlation at different Corey-oil exponent

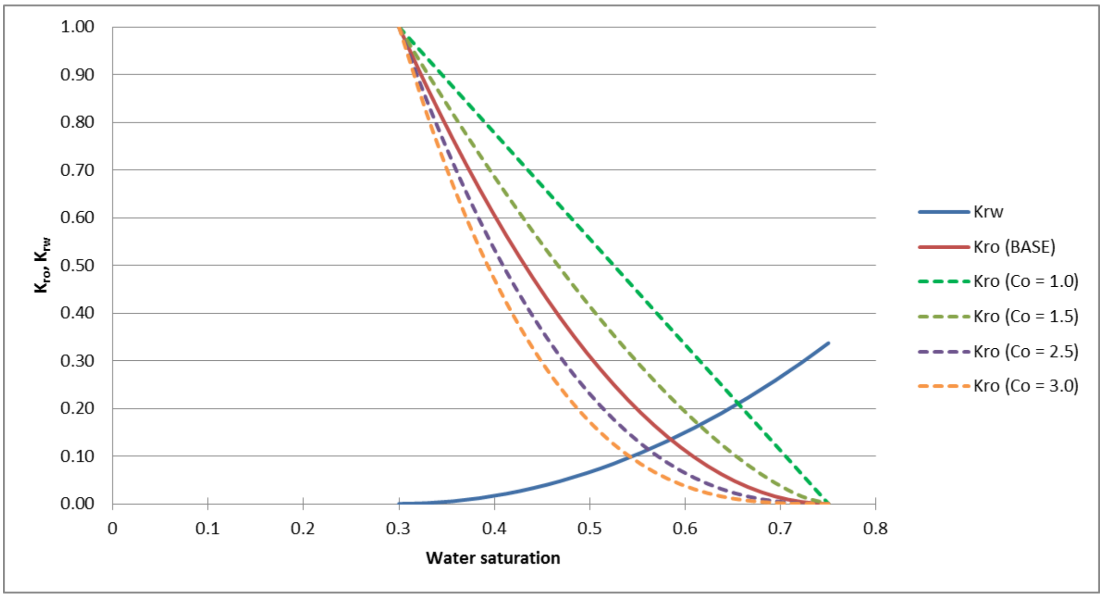

Figure 5.36 Oil/water saturation function related to 5,000 ppm brine (after LSB injection) obtained from correlation at different Corey-oil exponent

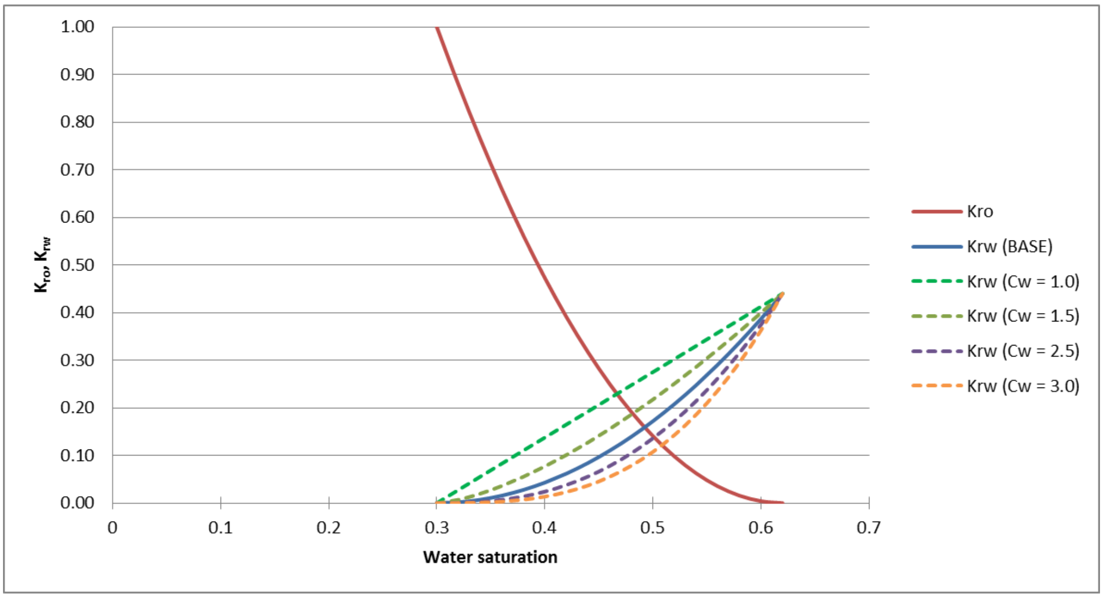

Figure 5.37 Oil/water saturation function related to 100,000 ppm brine (before LSB injection) obtained from correlation at different Corey-water exponent

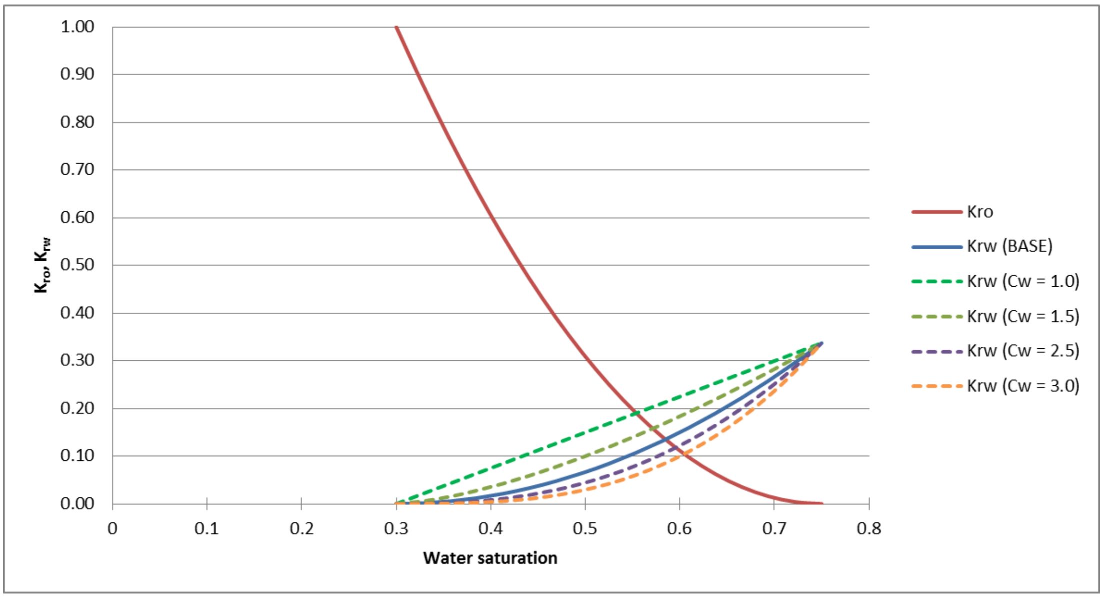

Figure 5.38 Oil/water saturation function related to 5,000 ppm brine (after LSB injection) obtained from correlation at different Corey-water exponent

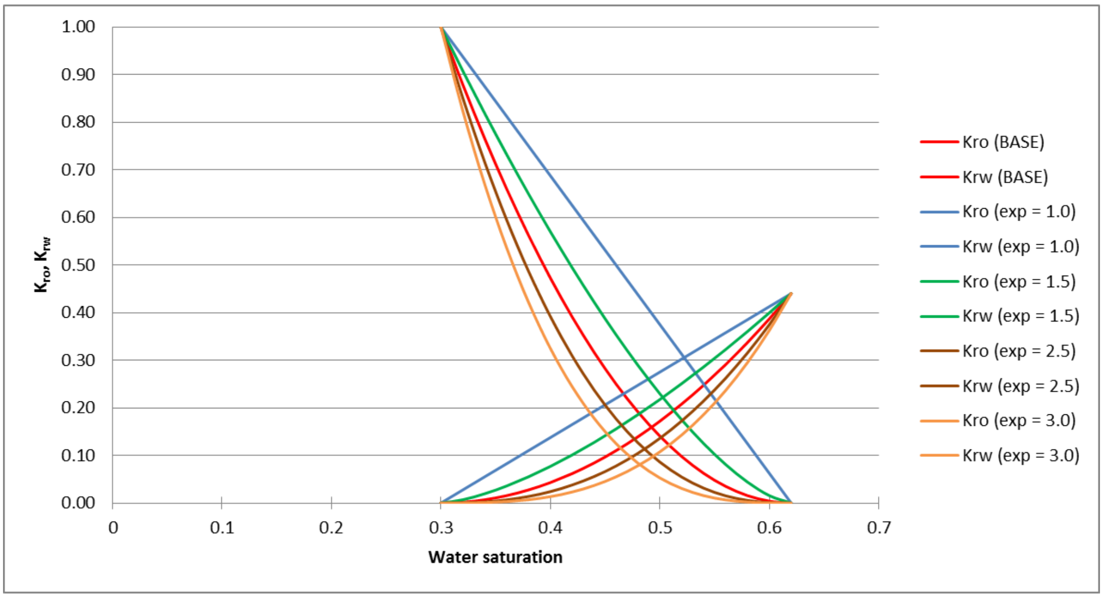

Figure 5.39 Oil/water saturation function related to 100,000 ppm brine (before LSB injection) obtained from correlation at different both Corey's exponents

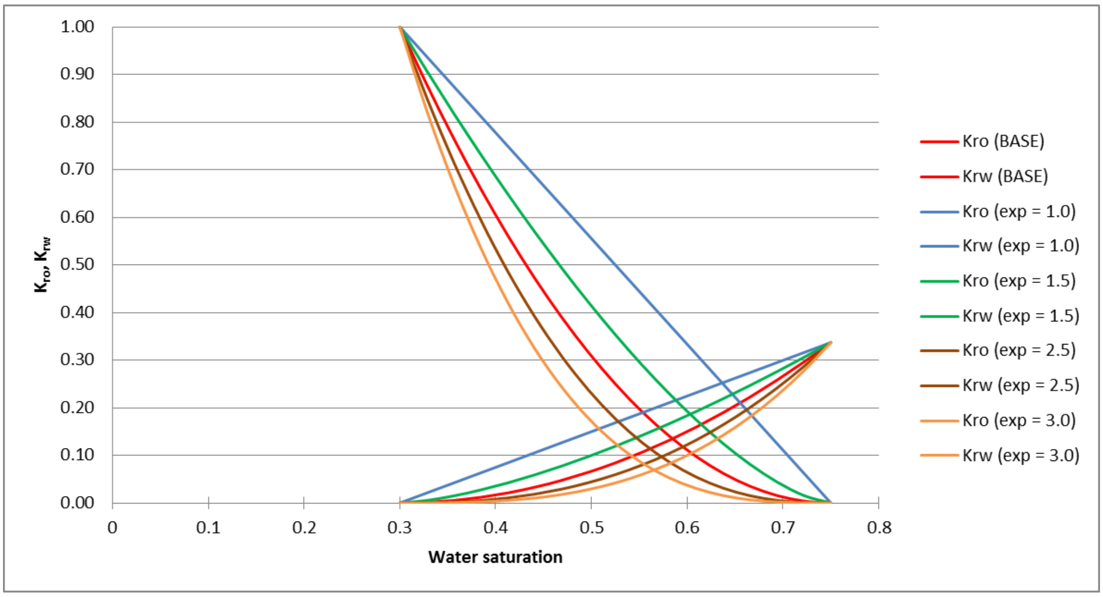

Figure 5.40 Oil/water saturation function related to 5,000 ppm brine (after LSB injection) that obtained from correlation at different both Corey's exponents

5.6.3 Influence of Corey's Exponent on LSB Injection

5.6.3.1 Corey-oil Exponent

Figures 5.41 to 5.45 display the oil recovery factors from LSB injection at different C_o and dip angle when formation water is 35,000 ppm. From these figures, oil recovery factors change significantly as C_o is changed. Additionally, oil recovery factors from LSB injection when formation water is 100,000 ppm also yield the same trends with 35,000 ppm, as illustrates in Figures 5.46 to 5.50. The ultimate oil recoveries for both cases are summarized in Figures 5.51 to 5.52. The highest oil recovery factor is obtained when C_o is 1.0 at every dip angle. This is because the calculated k_{ro} at any water saturation is the highest value compared to k_{ro} calculated from higher C_o. This is directly affected the flow behavior of oil (including desorbed-oil that is released from the surface due to the LSB); oil is more moveable and hence, larger amount of oil can be recovered. Hence, oil recovery factor is quite sensitive to C_o value.

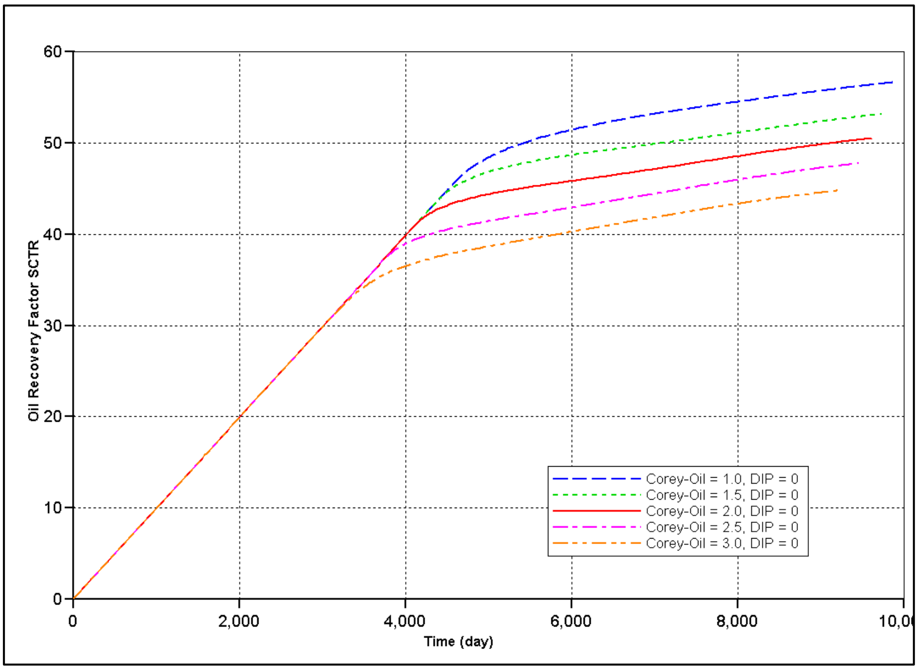

Figure 5.41 Oil recovery at different Corey-oil exponent for horizontal reservoir with 35,000 ppm formation water

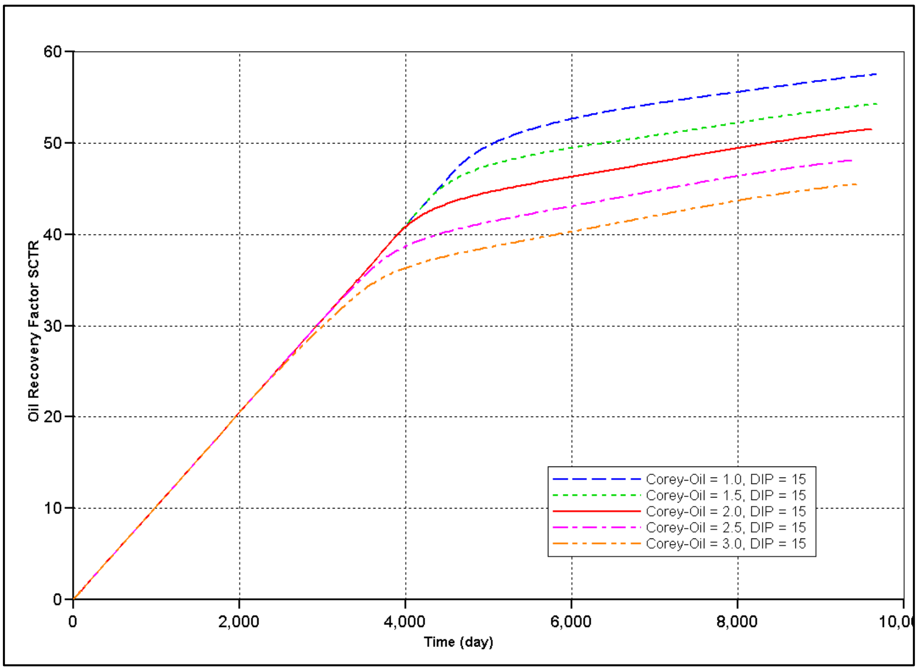

Figure 5.42 Oil recovery at different Corey-oil exponent for 15° reservoir with 35,000 ppm formation water

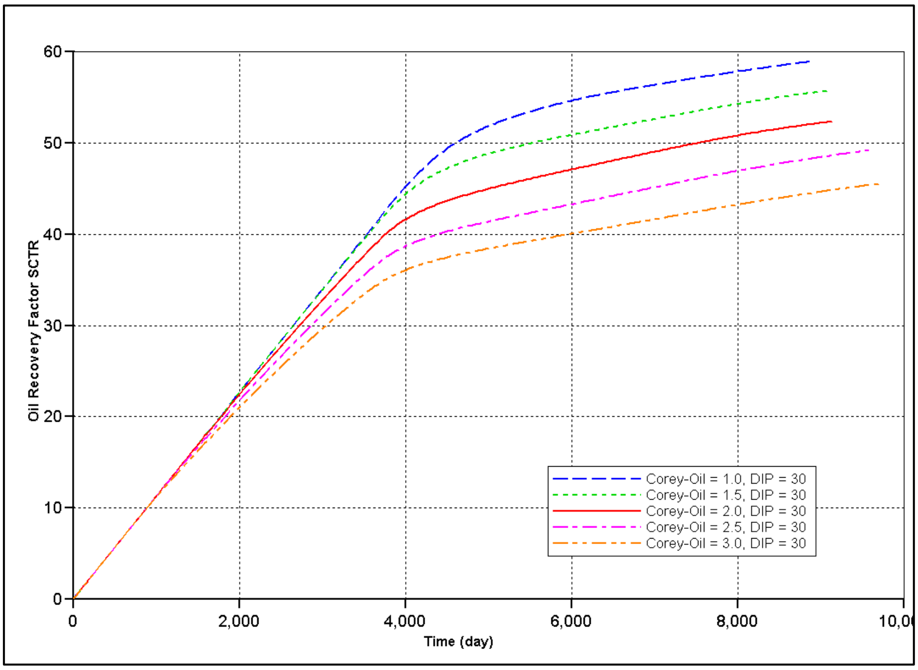

Figure 5.43 Oil recovery at different Corey-oil exponent for 30° reservoir with 35,000 ppm formation water

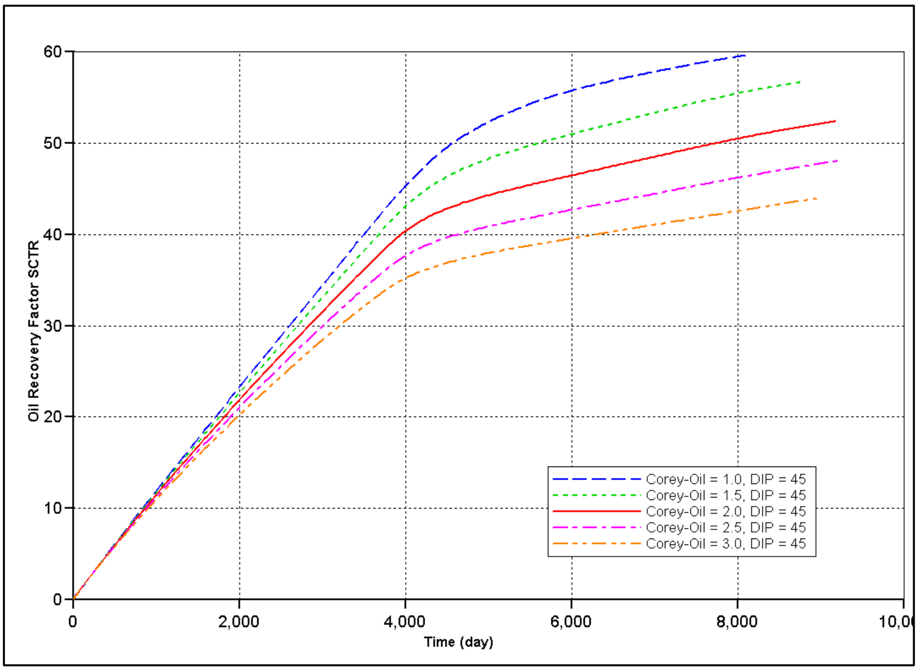

Figure 5.44 Oil recovery at different Corey-oil exponent for 45° reservoir with 35,000 ppm formation water

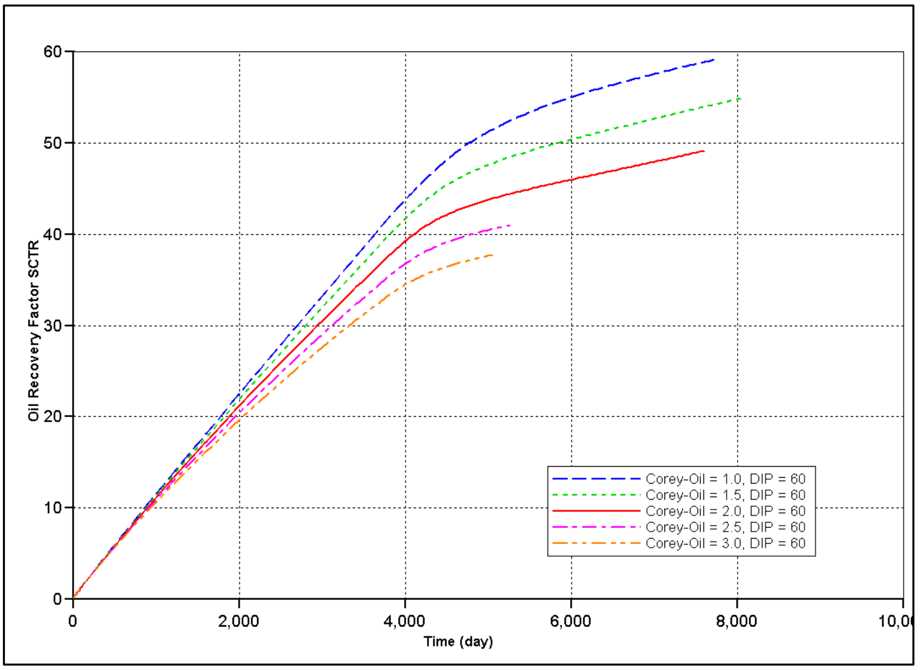

Figure 5.45 Oil recovery at different Corey-oil exponent for 60° reservoir with 35,000 ppm formation water

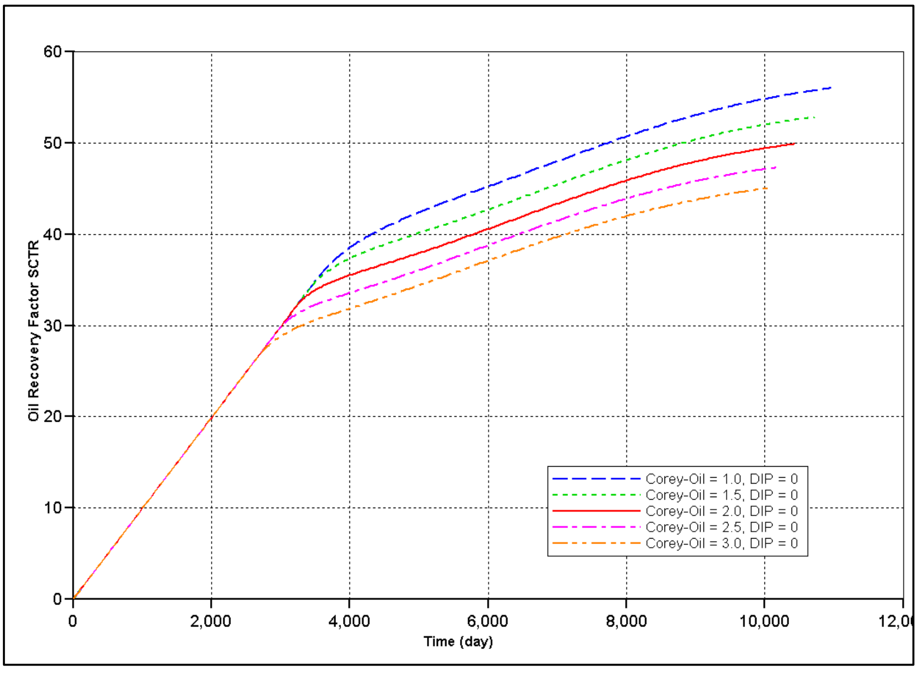

Figure 5.46 Oil recovery at different Corey-oil exponent for horizontal reservoir with 100,000 ppm formation water

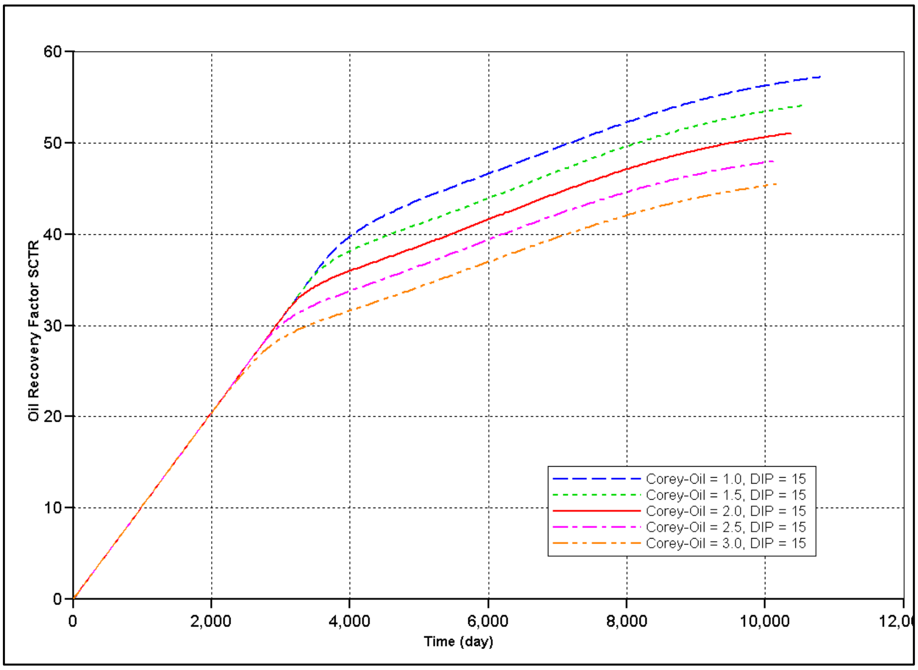

Figure 5.47 Oil recovery at different Corey-oil exponent for 15° reservoir with 100,000 ppm formation water

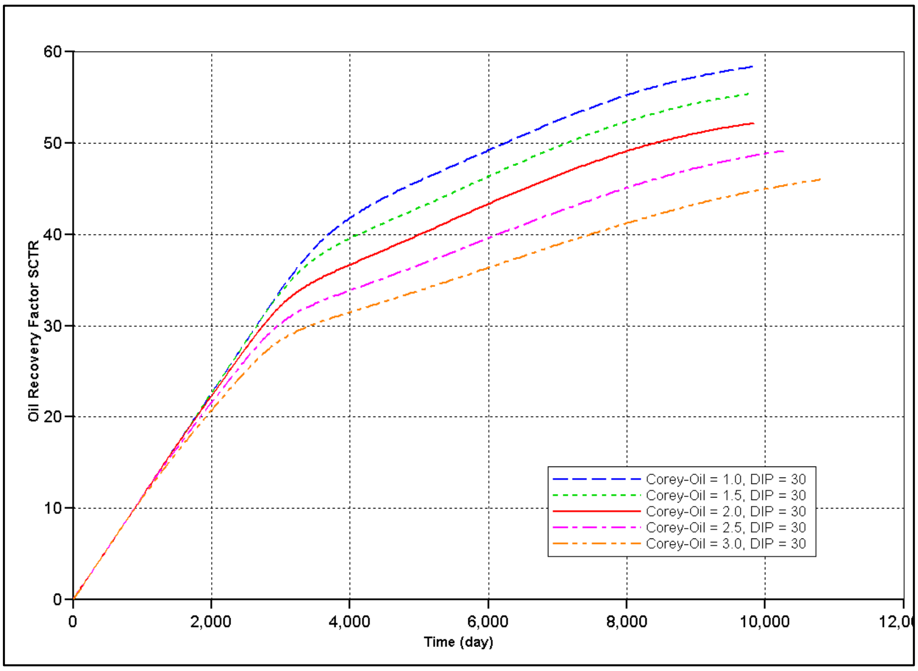

Figure 5.48 Oil recovery at different Corey-oil exponent for 30° reservoir with 100,000 ppm formation water

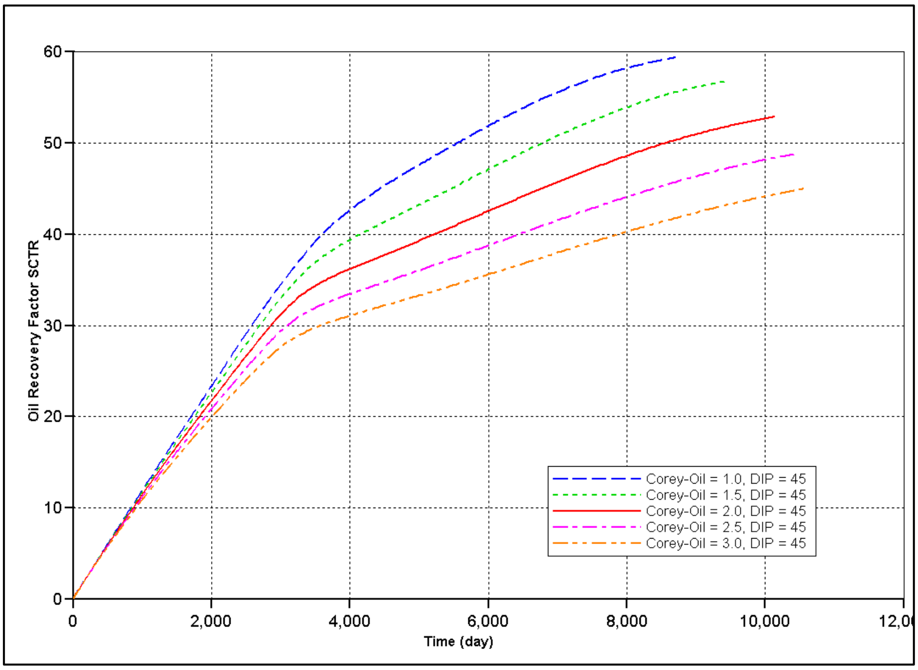

Figure 5.49 Oil recovery at different Corey-oil exponent for 45° reservoir with 100,000 ppm formation water

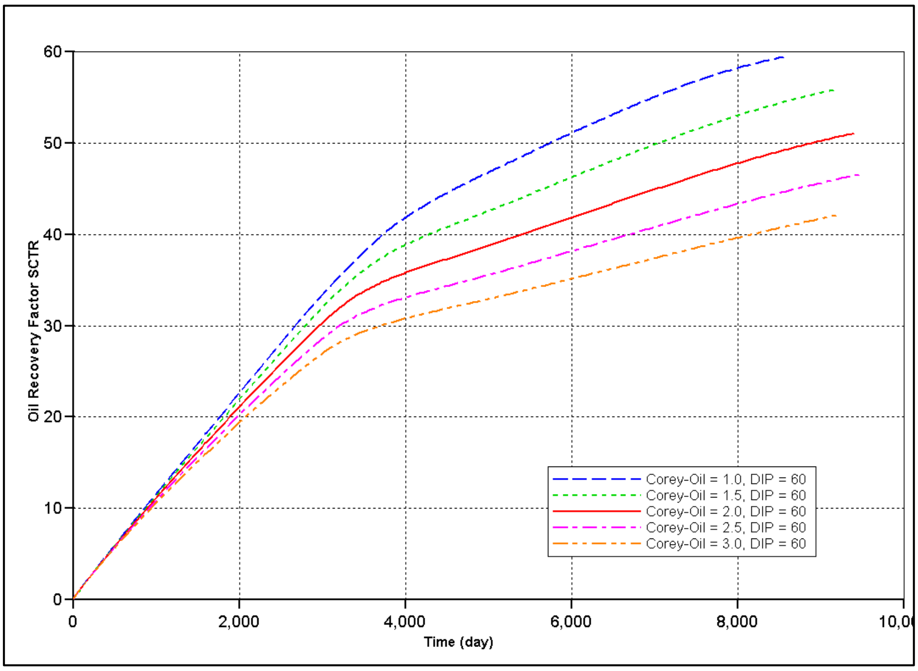

Figure 5.50 Oil recovery at different Corey-oil exponent for 60° reservoir with 100,000 ppm formation water

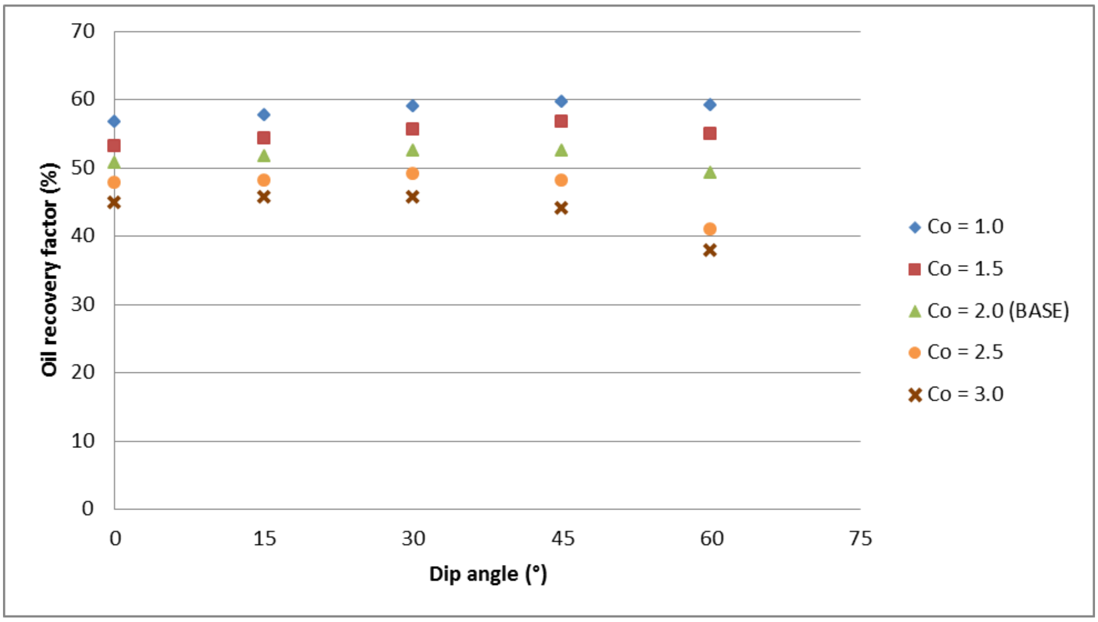

Figure 5.51 Summary of ultimate oil recovery at different dip angles and C_o when formation water is 35,000 ppm

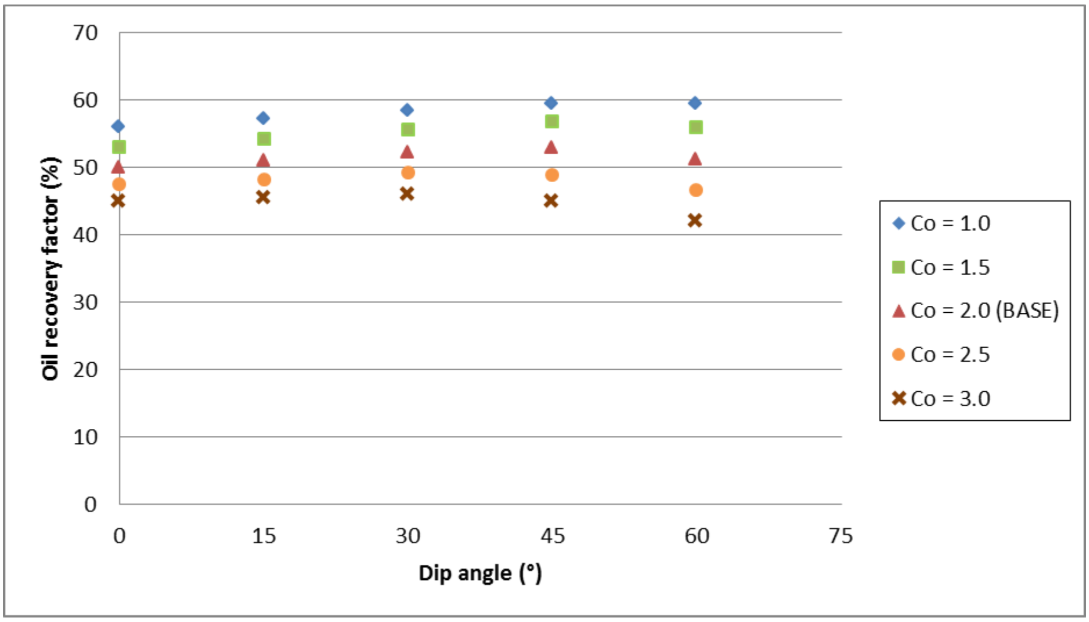

Figure 5.52 Summary of ultimate oil recovery at different dip angles and C_o when formation water is 100,000 ppm

5.6.3.2 Corey-water Exponent

The influence of C_w is explained in this part. Figures 5.53 to 5.57 illustrate oil recovery factors from LSB injection at different C_w and dip angles when formation water is 35,000 ppm. As we shall see, the change of C_w also affects oil recovery factor as well. However, deviation from reference cases (red line) is less than those observed in C_o cases at the same dip angle. This is due to the ability of water to flow does not change much when C_w is varied. As can be seen in previous figures of relative permeability curves, the range of changing k_{rw} is less than the range that k_{ro}. It can be inferred that C_w is less sensitive than C_o. Besides, at the higher dip angle, the smaller variation in ultimate oil recovery is observed as seen in Figure 5.58. This is because C_w only affects the viscous force term in fractional flow equation when oil is displaced by water. For horizontal reservoir, the gravity force term is neglected. Thus, at this condition, we can clearly see the effect of k_{rw} on oil recovery through the viscous force. However, when the reservoir is steeper the gravity force may be dominated over the viscous force. Thus, oil recovery does not change that much when k_{rw} is changed. In the contrary to the previous study of C_o, the wide range of oil recovery factor is still displayed when reservoir is steep. According to equation (3.8), the gravity force is still affected by the k_{ro} value. Therefore, wide range of ultimate oil recovery at high dip angle can be obtained.

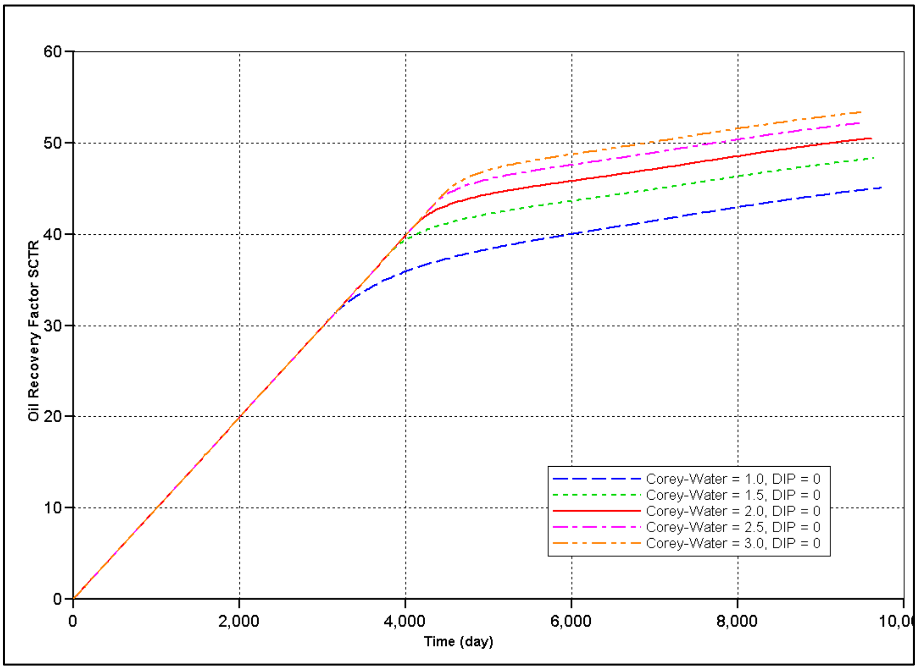

Figure 5.53 Oil recovery at different Corey-water exponent for horizontal reservoir with 35,000 ppm formation water

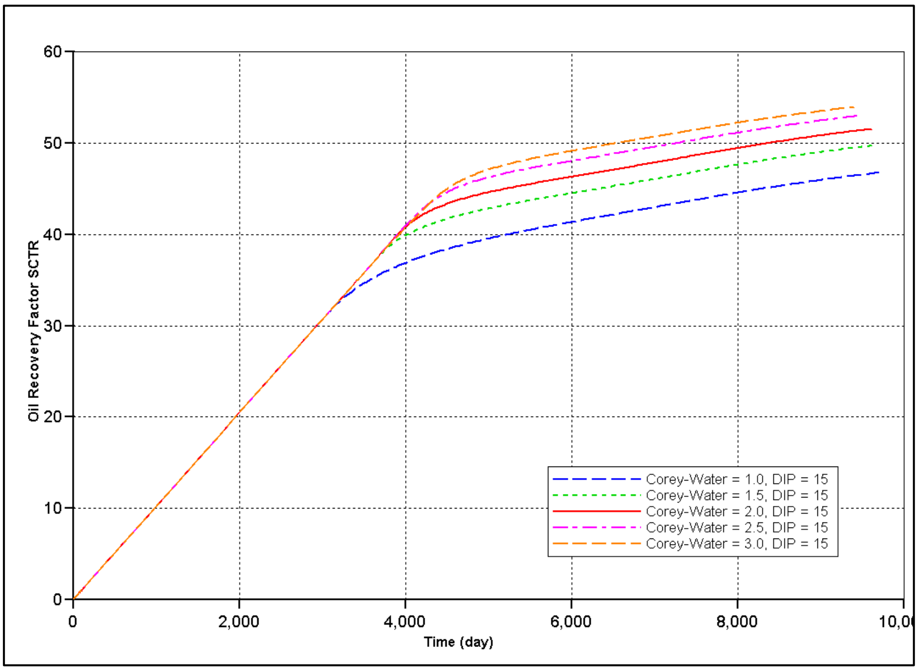

Figure 5.54 Oil recovery at different Corey-water exponent for 15° reservoir with 35,000 ppm formation water

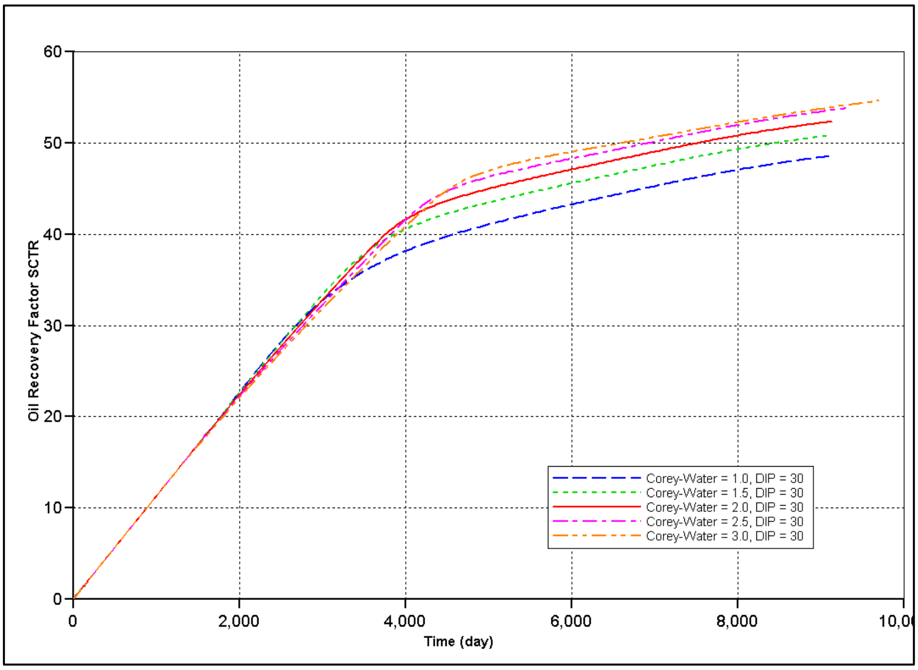

Figure 5.55 Oil recovery at different Corey-water exponent for 30° reservoir with 35,000 ppm formation water

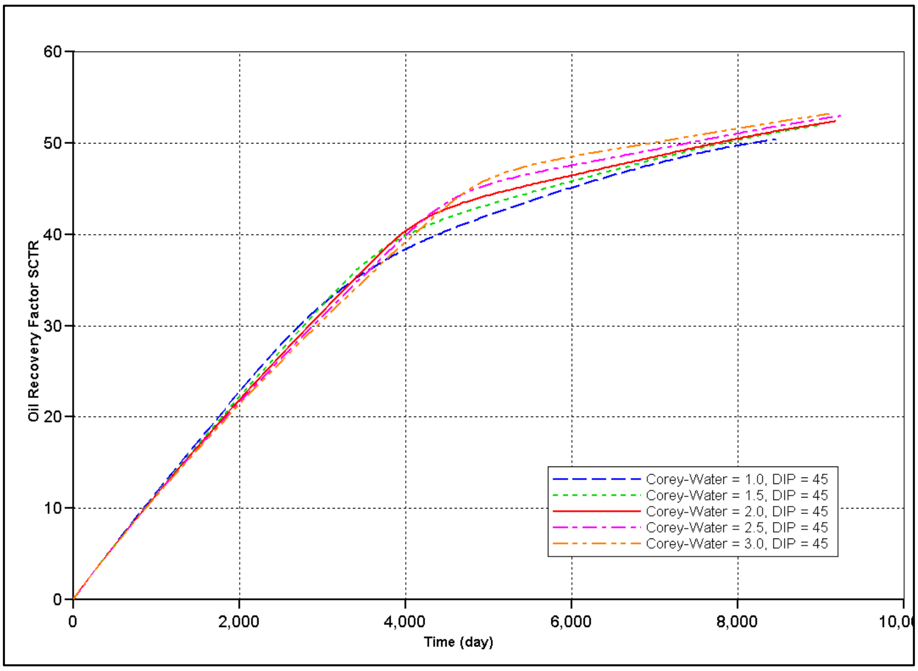

Figure 5.56 Oil recovery at different Corey-water exponent for 45° reservoir with 35,000 ppm formation water

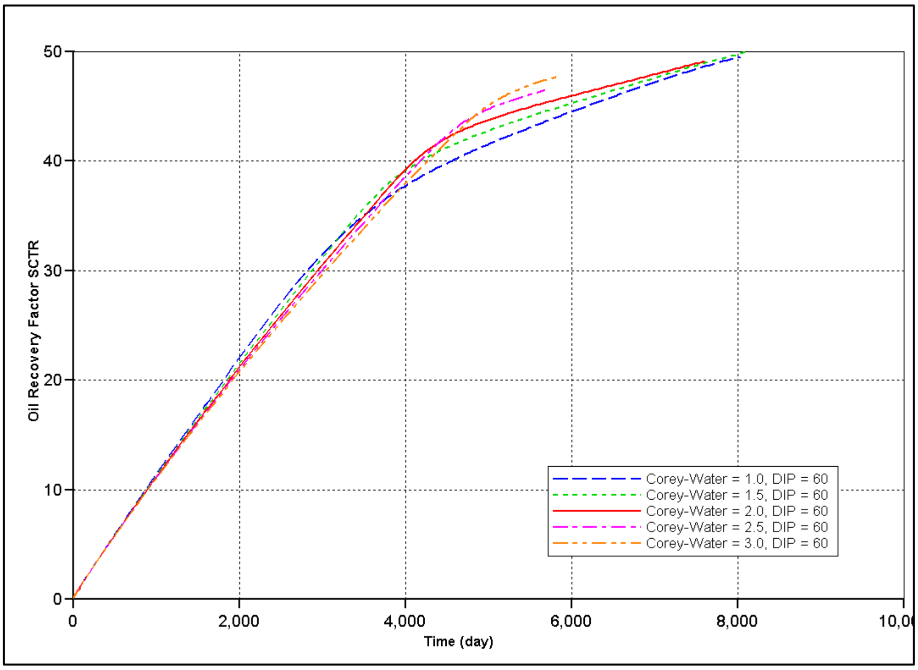

Figure 5.57 Oil recovery at different Corey-water exponent for 60° reservoir with 35,000 ppm formation water

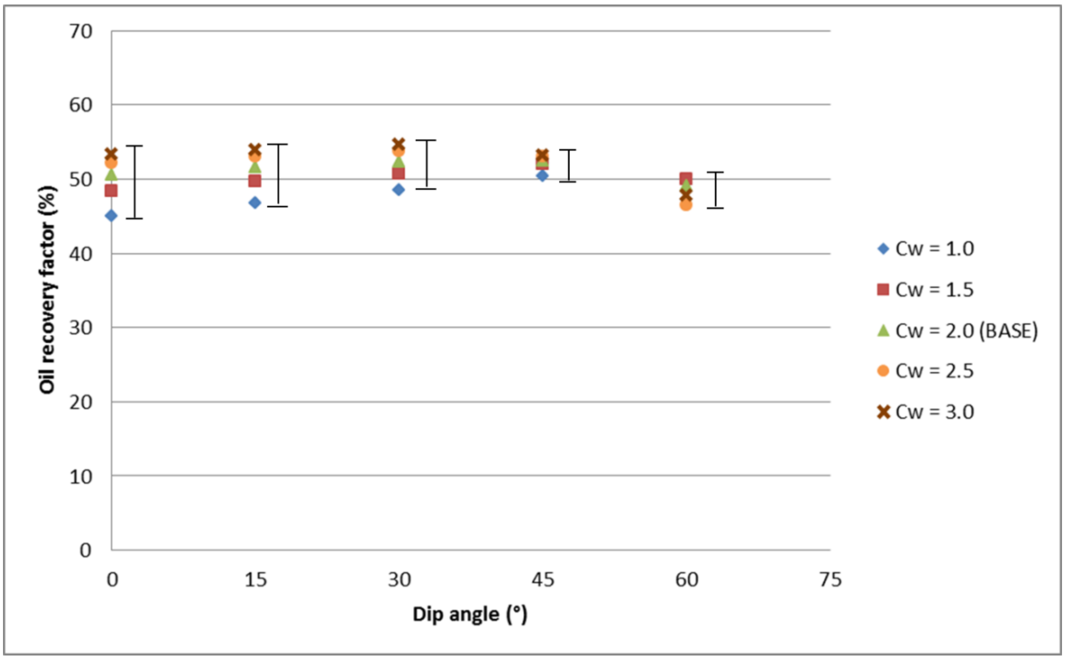

Figure 5.58 Summary of ultimate oil recovery at different dip angle and C_w when formation water is 35,000 ppm

Then, the cases where formation water is 100,000 ppm are interpreted. The results in this case are similar to the previous section of formation water of 35,000 ppm, oil recovery from LSB injection is not significantly affected by the C_w. The summary of ultimate oil recoveries are shown in Figure 5.59. The variation in ultimate oil recovery at high dip angle is also less low dip angle. The reason is as same as mentioned before.

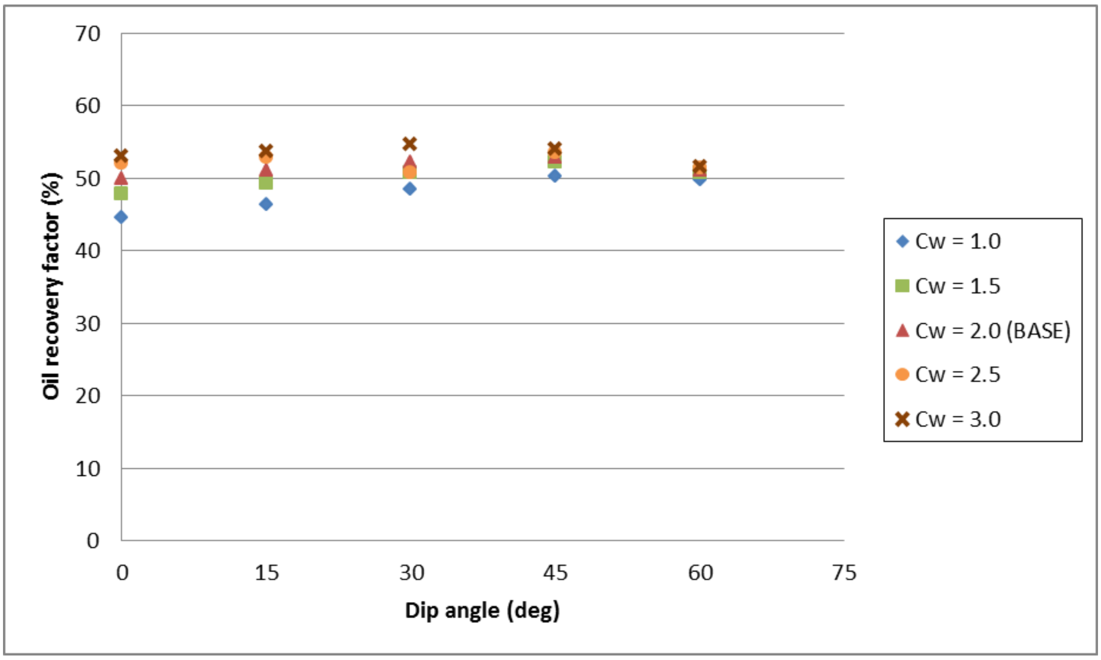

Figure 5.59 Summarize of ultimate oil recovery factor at different dip angle and Corey-water exponent when formation water is 100,000 ppm

5.6.3.3 Both Corey's Exponents

In this section, both Corey's exponents are varied simultaneously. Figure 5.60 and Figure 5.61 summarize the oil recovery at different dip angle and Corey's exponents when formation water is 35,000 ppm and 100,000 ppm, respectively. According to the figures, the results show the similar trend with previous section, 5.6.3.1, when C_o is varied. Considering the oil recovery factor from the same value of each exponent in Figure 5.62 can be clearly seen that oil recovery factor for cases with varying both components is more similar to the case of varying only C_o than cases of varying only C_w. It can be concluded that the effect from varying C_o is more dominant than C_w when both are varied at the same time.

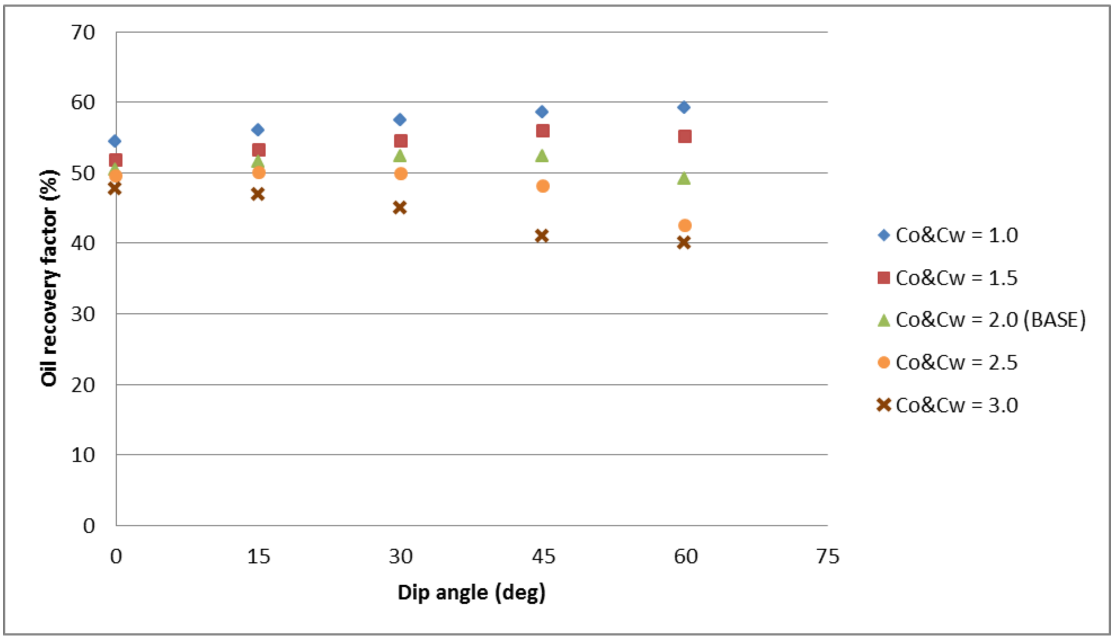

Figure 5.60 Ultimate oil recovery at different dip angle and Corey's exponents when formation water is 35,000 ppm

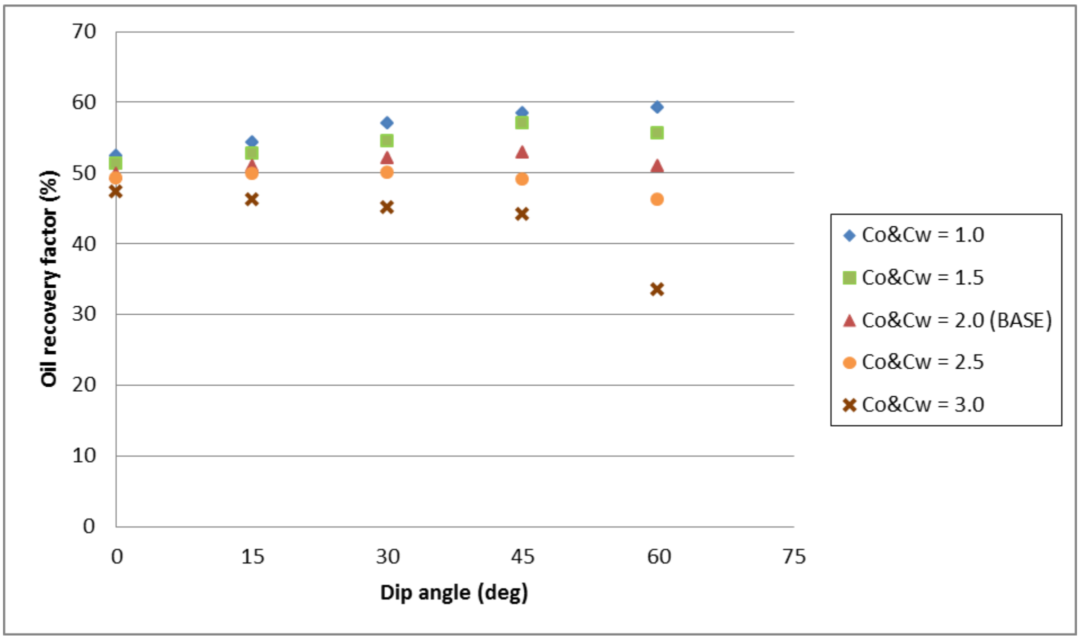

Figure 5.61 Ultimate oil recovery at different dip angle and Corey's exponents when formation water is 100,000 ppm

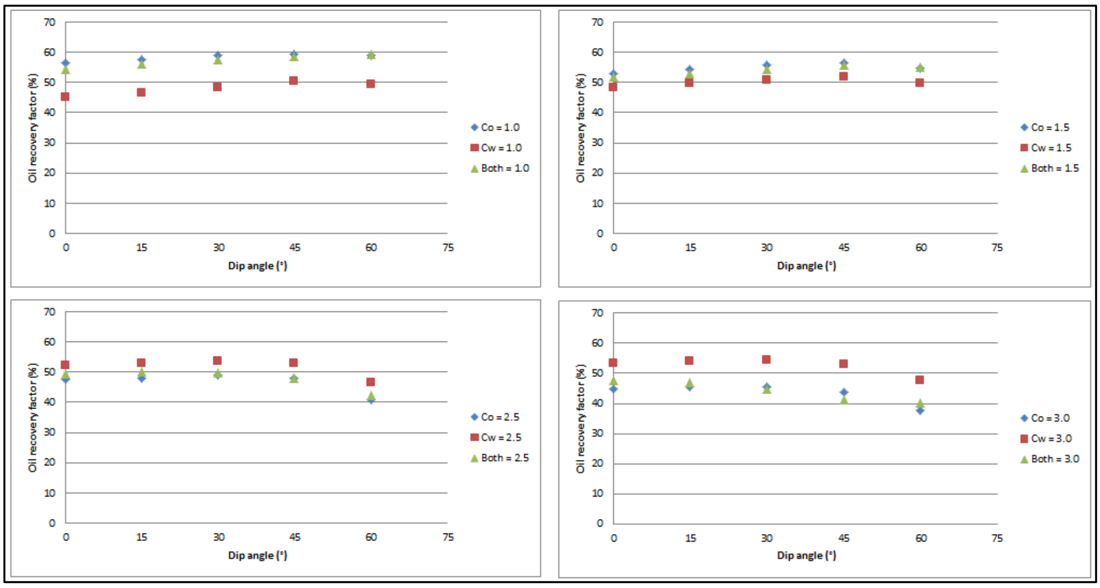

Figure 5.62: Comparison of ultimate oil recovery at the same value of Corey's exponent when formation water is 35,000 ppm

5.7 Effect of Initial Wettability

In previous sections, the initial wettability of reservoir rock is fixed at water-wet when formation water is 35,000 ppm and neutral-wet when formation water is 100,000 ppm. These wetting conditions are obtained from laboratory experiment in section 5.1. However, in this section, the effect of initial wettability of reservoir rock is investigated. Four different rock's preferences are considered in this section including, Type A1, A2, A3 and A4 which are sequentially decreased in water wetness, respectively. However, in the case of 100,000 ppm formation water, the reservoir rock is already at neutral-wet condition from the start. Hence, only two types of wettability for such case; B1 and B2 are considered.

Since the obtained data from experiment is limited, the least water wetness relative permeability curves (A4 and B2) are firstly estimated from the rule of thumb [20]. Interpolation of end-point relative permeability and saturation values for each rock preference is performed. Table 5.26 shows the estimated end-point data used in the reservoir simulation. Besides, capillary pressure data which was neglected in previous sections is input in this section as well in order to represent the adhesive interaction between oil and reservoir rock. Table 5.27 and Table 5.28 show the estimated capillary pressure data for each rock's wettability and formation water salinity.

The simulation in this section is based on assumption that capillary pressure becomes zero after LSB injection.

Table 5.26 Estimated end-point saturations and relative permeabilities

Case	**Wettability**	**IWS**	**k_{rw}@ROS**	**1-ROS**
Formation water 35,000 ppm	A1	0.2625	0.46	0.675
	A2	0.225	0.54	0.65
	A3	0.1875	0.62	0.625
	A4	0.15	0.7	0.6
Formation water 100,000 ppm	B1	0.1875	0.635	0.605
	B2	0.15	0.7	0.6

Table 5.27 Estimated capillary pressure (Formation water salinity is 35,000 ppm)

	A1		A2		A3		A4	
	S_w	P_{cow} (psi)	S_w	P_{cow} (psi)	S_w	P_{cow} (psi)	S_w	P_{cow} (psi)
Formation water is 35,000 ppm	0.2625	0	0.225	0	0.1875	0	0.15	0
	0.2883	-0.125	0.2516	-0.25	0.2148	-0.375	0.1781	-0.5
	0.3141	-0.25	0.2781	-0.5	0.2422	-0.75	0.2063	-1
	0.3398	-0.375	0.3047	-0.75	0.2695	-1.125	0.2344	-1.5
	0.3656	-0.5	0.3313	-1	0.2969	-1.5	0.2625	-2
	0.3914	-0.625	0.3578	-1.25	0.3242	-1.875	0.2906	-2.5
	0.4172	-0.75	0.3844	-1.5	0.3516	-2.25	0.3188	-3
	0.443	-0.875	0.4109	-1.75	0.3789	-2.625	0.3469	-3.5
	0.4688	-1	0.4375	-2	0.4063	-3	0.375	-4
	0.4945	-1.125	0.4641	-2.25	0.4336	-3.375	0.4031	-4.5
	0.5203	-1.25	0.4906	-2.5	0.4609	-3.75	0.4313	-5
	0.5461	-1.375	0.5172	-2.75	0.4883	-4.125	0.4594	-5.5
	0.5719	-1.5	0.5438	-3	0.5156	-4.5	0.4875	-6
	0.5977	-1.625	0.5703	-3.25	0.543	-4.875	0.5156	-6.5
	0.6234	-1.75	0.5969	-3.5	0.5703	-5.25	0.5438	-7
	0.6492	-1.875	0.6234	-3.75	0.5977	-5.625	0.5719	-7.5
	0.675	-2	0.65	-4	0.625	-6	0.6	-8

Table 5.28 Estimated capillary pressure (Formation water salinity is 100,000 ppm)

	B1		**B2**	
	S_w	P_{cow} **(psi)**	S_w	P_{cow} **(psi)**
Formation water is 100,000 ppm	0.1875	0.000	0.1500	0.000
	0.2136	-0.375	0.1781	-0.500
	0.2397	-0.750	0.2063	-1.000
	0.2658	-1.125	0.2344	-1.500
	0.2919	-1.500	0.2625	-2.000
	0.3180	-1.875	0.2906	-2.500
	0.3441	-2.250	0.3188	-3.000
	0.3702	-2.625	0.3469	-3.500
	0.3963	-3.000	0.3750	-4.000
	0.4223	-3.375	0.4031	-4.500
	0.4484	-3.750	0.4313	-5.000
	0.4745	-4.125	0.4594	-5.500
	0.5006	-4.500	0.4875	-6.000
	0.5267	-4.875	0.5156	-6.500
	0.5528	-5.250	0.5438	-7.000
	0.5789	-5.625	0.5719	-7.500
	0.6050	-6.000	0.6000	-8.000

5.7.1 Formation Water Salinity 35,000 ppm

First, flooding with the same salinity as formation salinity, or waterflooding, is considered. The results are summarized in Table 5.29 and Figure 5.63. As can be seen from table and figure, less amount of oil is recovered when reservoir is at the least water-wet (A4). The recovery factors are only 22-27% for such wettability. Accordingly, this wettability also yields narrow range of plateau rate (500 stb/day) as shown in Figure 5.64. This is because oil tends to be adhered by rock surface instead of being produced. Moreover, water tends to finger through the center of large pores and hence most oil is left behind. Besides, high water cut is encountered at the beginning of production since initial water saturation is set at constant of 30%, while critical water saturation is assumed to be equal to IWS for each preference of rock.

Table 5.29 Ultimate oil recovery factor for waterflooding at different dip angles and wettability when formation water is 35,000 ppm

Wettability	**0°**		**15°**		**30°**	
	RF (%)	**Time (days)**	**RF (%)**	**Time (days)**	**RF (%)**	**Time (days)**
Reference case	43.9227	5356	44.6203	5478	44.6599	5386
A1	38.1682	5478	39.0247	5509	39.5262	5447
A2	32.4406	5599	33.4752	5722	34.6661	5660
A3	27.3962	5722	28.4891	5875	29.7613	5752
A4	22.3371	5875	23.4018	5995	24.8074	5844

Wettability	**45°**		**60°**	
	RF (%)	**Time (days)**	**RF (%)**	**Time (days)**
Reference case	45.4613	5875	44.0720	5203
A1	40.7162	5783	39.9306	5417
A2	35.8247	5691	36.0689	5660
A3	30.9862	5660	32.0289	5752
A4	26.0844	5569	27.3868	5509

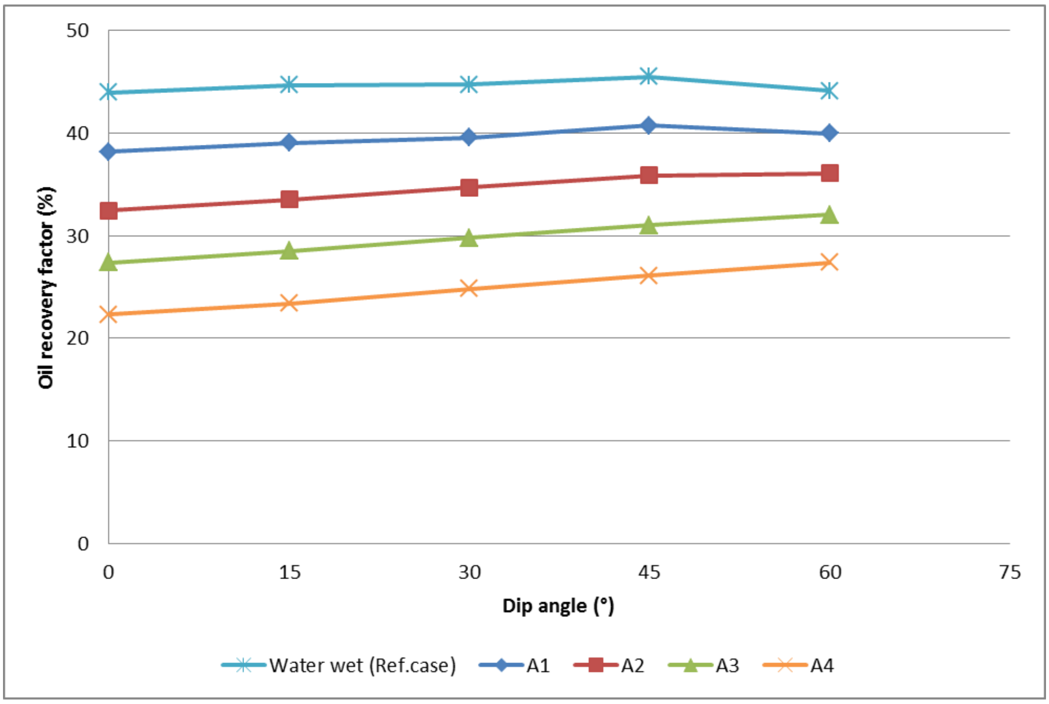

Figure 5.63 Oil recovery factor from waterflooding at different rock wettability

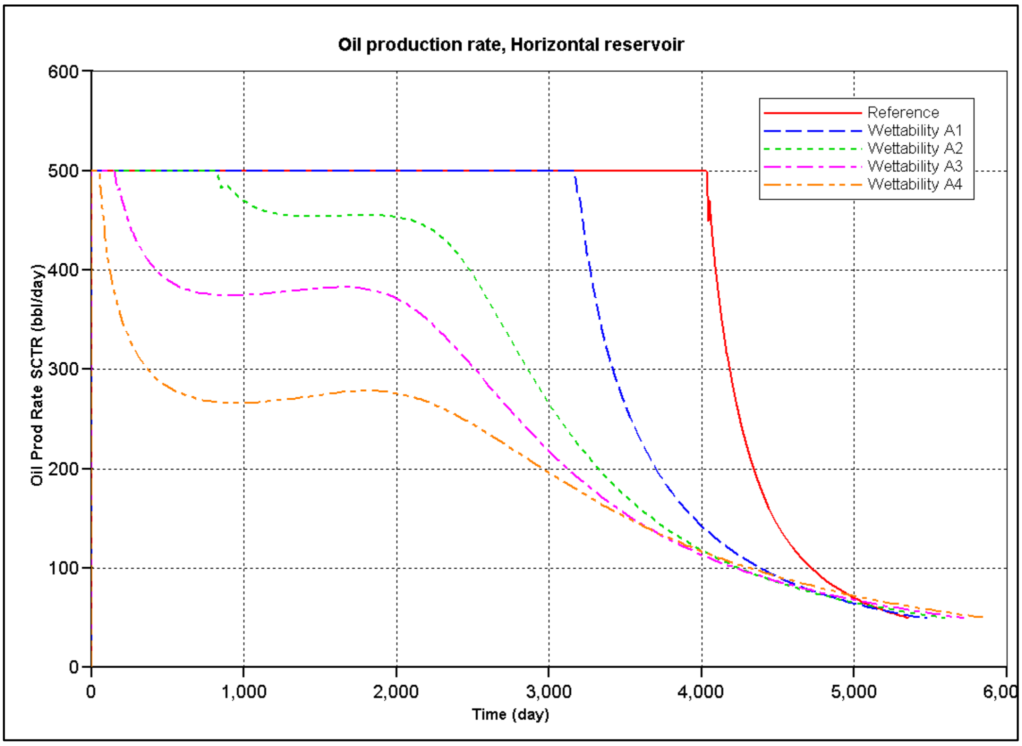

Figure 5.64 Oil production profile obtained from waterflooding in horizontal reservoir

Then, LSB injection is considered. Table 5.30 and Figure 5.65 summarize oil recovery factor at the end of LSB injection. At dip angle of 0°, oil recovery factor of water-wet reservoir (reference case) is slightly less than A1 reservoir which is less water-wet because the production time is less. This results from the phenomena of piston-like water breakthrough causing the high water cut immediately and consecutively a termination of production life. However, oil recovery factor at the same production time should be the best when reservoir is water-wet and the worst when reservoir is at the least water-wet (A4). This is confirmed by the theory that water-wet rock is the most suitable for water displacement mechanism. Considering oil recovery factors at higher reservoir dip angle, it can be seen that the trend is reversed. Figure 5.66 and Figure 5.67 are used to describe these phenomena.

Table 5.30 Ultimate oil recovery factor for LSB injection at different dip angle and wettability when formation water is 35,000 ppm

Wettability	**0°**		**15°**		**30°**	
	RF (%)	**Time (days)**	**RF (%)**	**Time (days)**	**RF (%)**	**Time (days)**
Reference case	50.5105	9616	51.5390	9616	52.3491	9131
A1	50.7330	10470	51.5459	10317	52.7033	9892
A2	50.6479	10957	51.7686	10743	53.0668	10317
A3	50.3669	10957	51.7793	10957	53.2687	10500
A4	49.9822	10957	51.4692	10957	53.2787	10470

Wettability	**45°**		**60°**	
	RF (%)	**Time (days)**	**RF (%)**	**Time (days)**
Reference case	52.3996	9190	49.1351	7609
A1	53.1485	10074	51.4325	9404
A2	53.6811	10500	52.2650	10013
A3	53.9877	10623	52.7002	10258
A4	53.9881	10500	52.8778	10227

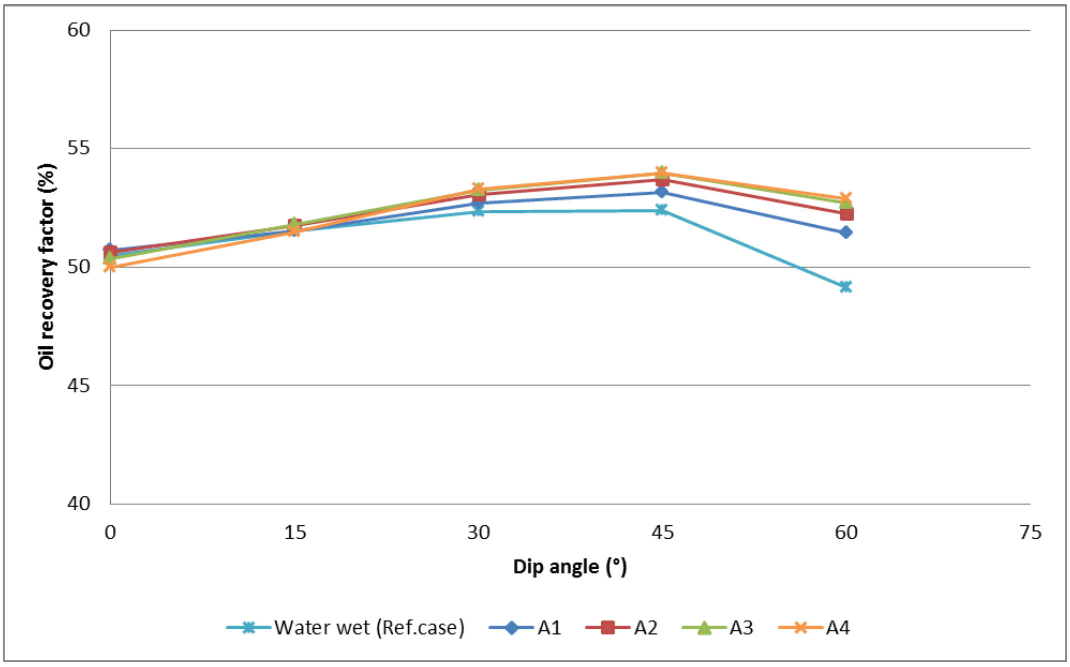

Figure 5.65 Oil recovery factor from LSB injection at different rock wettability

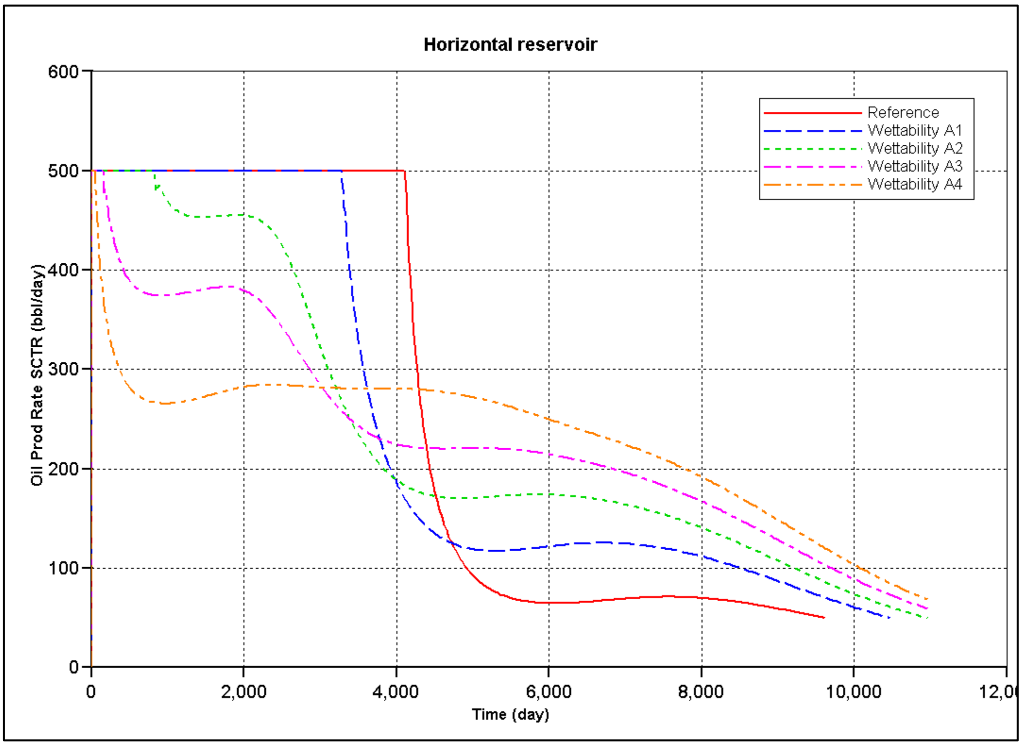

Figure 5.66 Oil production rate for LSB injection in horizontal reservoir at different wettability when formation water is 35,000 ppm

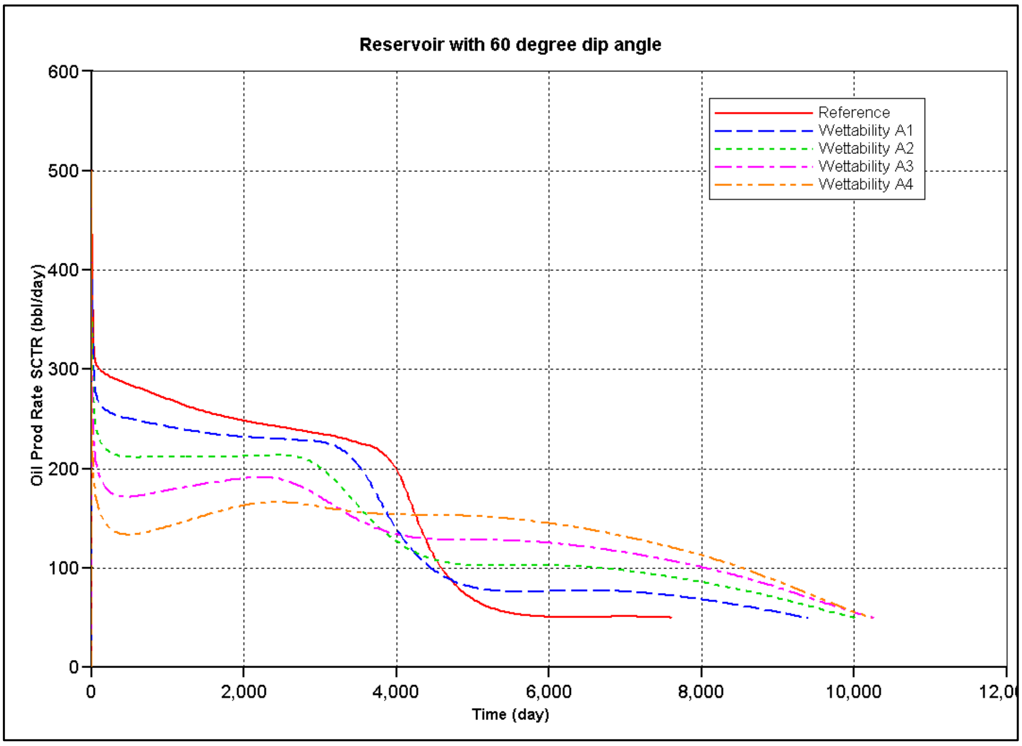

Figure 5.67 Oil production rate for LSB injection in 60° reservoir at different wettability when formation water is 35,000 ppm

As illustrated in Figure 5.66 and Figure 5.67, oil production rate is quite low at the beginning for all initial wettability at dip angle of 60° due to the gravity and vertical permeability effect. After the LSB reaches breakthrough, oil production rate of water-wet reservoir is drastically dropped due to the high water cut. However, the oil production rate of less water-wet reservoir (A4) is not declined for such reason. From Figure 5.67 it can be seen that even oil rate of the A4 reservoir is the lowest at the beginning but the production rate is not declined at late production time due to the characteristic of slightly water-wet reservoir and hence, ultimate oil recovery is higher than water-wet reservoir. Basically, oil recovery from immiscible displacement mechanism in less water-wet reservoir is dependent on the amount of injected water. This is because, when oil tends to be adhered by rock surface, water will form a continuous path of fingers at center of large pore and hence, oil is left behind. As the amount of injectant is increased, LSB would invade into the smaller pore and hence, oil can be more displaced as a number of injected water increases. Besides, chemical effect of LSB can reach to the small pore and also can improve oil recovery through the wettability alteration mechanism. Conversely, oil that was trapped behind is occurred in the form of spherical globules in large pores of water-wet rock. Even a number of injected water increases, this part of oil still cannot be produced.

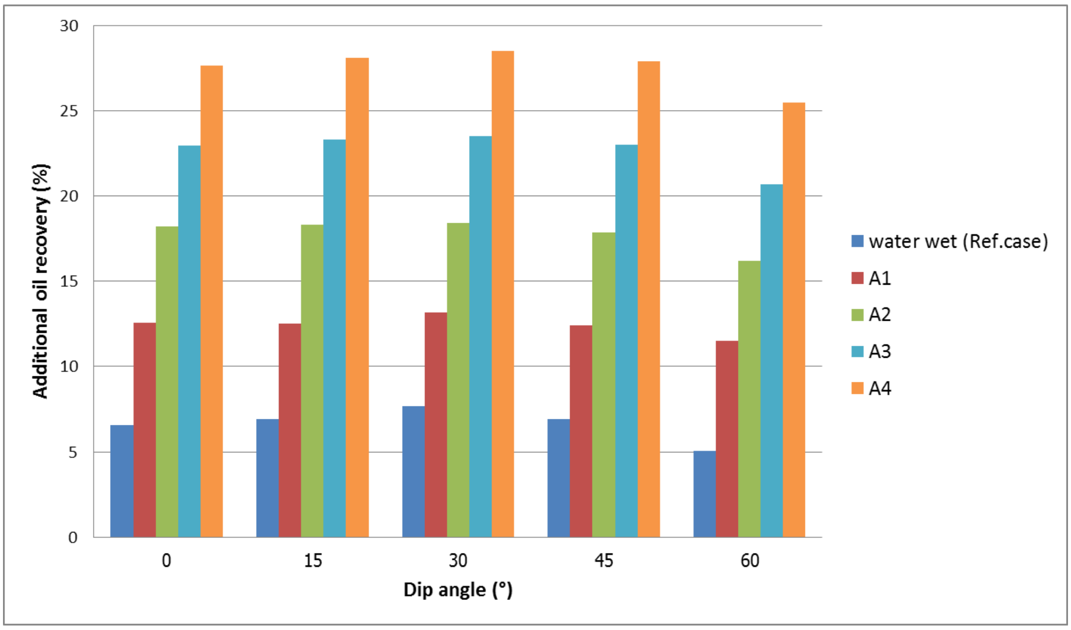

Figure 5.68 Benefit of LSB injection at each initial wettability and inclination (compared to waterflooding)

Figure 5.68 depicts the bar chart comparing the additional oil recovery from LSB injection at different dip angle. From the figure, at any dip angle, the least water-wet reservoir (A4) yields the highest additional oil recovery of 25.5-28.5%, whereas water-wet rock yields the lowest additional recovery. In A4 preference, residual oil saturation is quite high, of about 40%. This means large amount of oil is trapped at the rock surface. LSB injection would change the rock preference which results in residual oil saturation left around 25% (can be seen in relative permeability curve after LSB injection). Since it is assumed that relative permeability curve after LSB injection is the same for all cases (the ultimate oil recovery is not much different), oil-wet rock surface would yield the largest amount of desorbed-oil and also the highest additional oil recovery compared to waterflooding.

5.7.2 Formation Water Salinity 100,000 ppm

Formation water salinity of 100,000 ppm is considered in this section and the results of waterflooding are summarized in Table 5.31 and Figure 5.69. The results are similar to section 5.7.1; less water-wet reservoir is not favorable condition for water injection process however, significant additional oil recovery is obtained when LSB injection is implemented instead of waterflooding. Table 5.32 displays the oil recovery factor for LSB injection and additional oil recovery is illustrated in Figure 5.70.

Table 5.31 Ultimate oil recovery factor for waterflooding at different dip angles and wettability when formation water is 100,000 ppm

Wettability	**0°**		**15°**		**30°**	
	RF (%)	**Time (days)**	**RF (%)**	**Time (days)**	**RF (%)**	**Time (days)**
Reference case	28.2136	5113	29.2575	5233	30.4186	5172
B1	25.2807	5478	26.4669	5660	27.7550	5509
B2	22.2652	5903	23.4519	6025	24.9838	5875

Wettability	**45°**		**60°**	
	RF (%)	**Time (days)**	**RF (%)**	**Time (days)**
Reference case	31.5412	5172	31.9636	5172
B1	28.9496	5386	30.0020	5478
B2	26.2775	5569	27.6722	5569

Table 5.32 Ultimate oil recovery factor for LSB injection at different dip angles and wettability when formation water is 100,000 ppm

Wettability	0°		15°		30°	
	RF (%)	Time (days)	RF (%)	Time (days)	RF (%)	Time (days)
Reference case	49.9893	10957	51.3845	10957	52.7612	10408
B1	49.7520	10957	51.2384	10957	52.89	10500
B2	49.4768	10957	50.9898	10957	52.889	10470
Wettability	**45°**		**60°**			
	RF (%)	**Time (days)**	**RF (%)**	**Time (days)**		
Reference case	53.6912	10531	52.3042	10074		
B1	53.8724	10531	52.6186	10166		
B2	53.8548	10408	52.7003	10105		

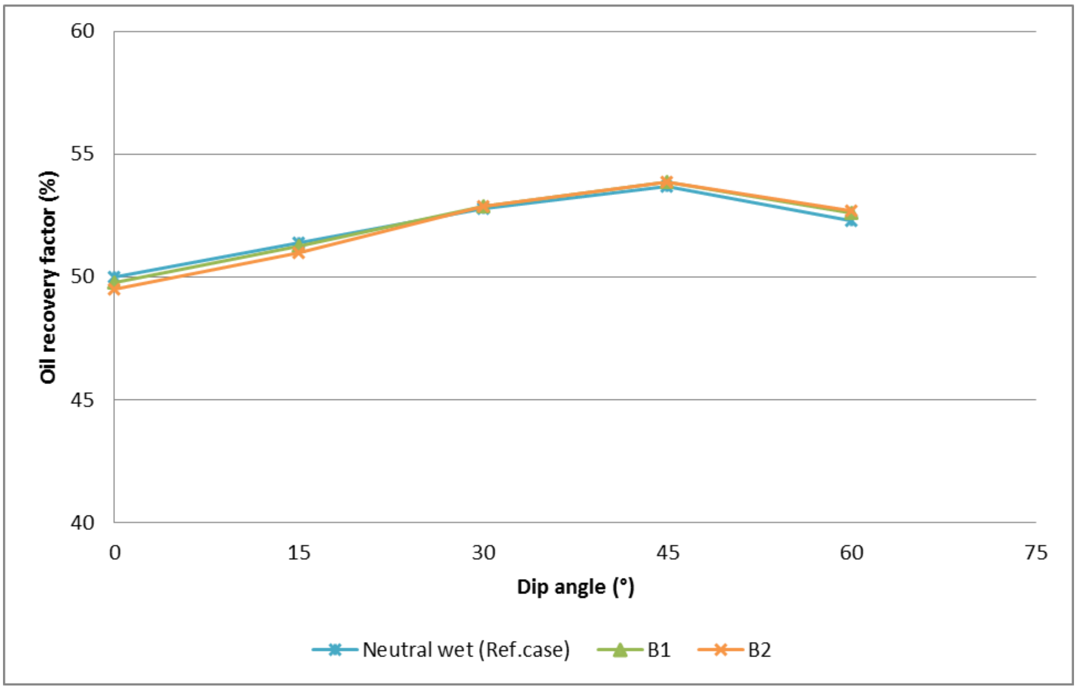

Figure 5.69 Oil recovery factor from LSB injection at different rock wettability

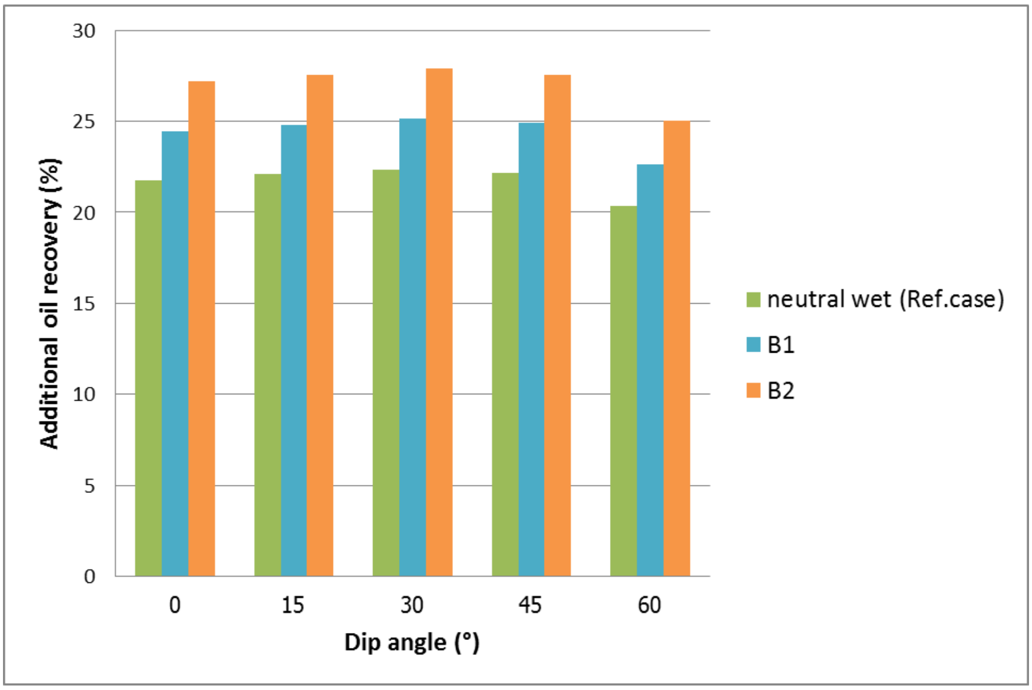

Figure 5.70 Benefit of LSB injection at each initial wettability and inclination (compared to waterflooding)

5.8 Effect of LSB Injection Slug Size

In previous sections, only LSB is injected throughout recovering process. However, in this section, four different slug sizes of LSB including 0.1 PV, 0.15 PV, 0.20 PV, and 0.25 PV are considered. The chasing slug of same salinity as formation salinity (simply called High Salinity Brine, HSB) is injected after the LSB in order to sweep the LSB slug toward production well. Additionally, it can be observed that the mixing of LSB slug and HSB chasing slug is always occurred since both of them are aqueous phase, but different in salinity. Figure 5.71 demonstrates the example of LSB injection at different LSB slug size. Unfortunately, CMG STARS cannot hold relative permeability after LSB injection to be constant. Thus, after injecting HSB chasing slug, relative permeability curve is undesirably changed back to the original one again, which is not true in reality. Hence, the results from simulation contain some avoidably errors but still precise.

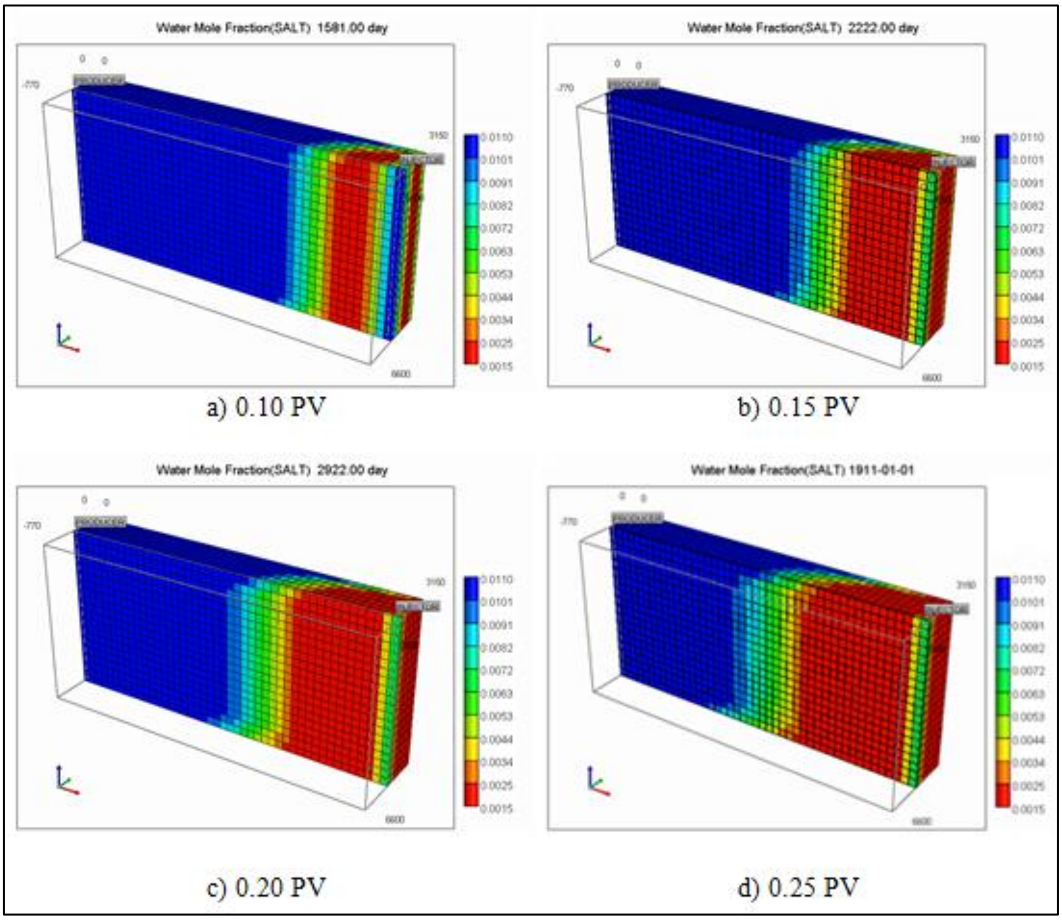

Figure 5.71 Example of schematic of LSB injection with different slug size in horizontal reservoir

5.8.1 Formation Water Salinity of 35,000 ppm

In this section, oil recovery factors plotted versus production time are illustrated in Figure 5.72 and ultimate recovery for each case is summarized in Figure 5.73. Table 5.33 presents total PV of injected LSB (in case of LSB injection without chasing slug) and starting time to inject chasing water.

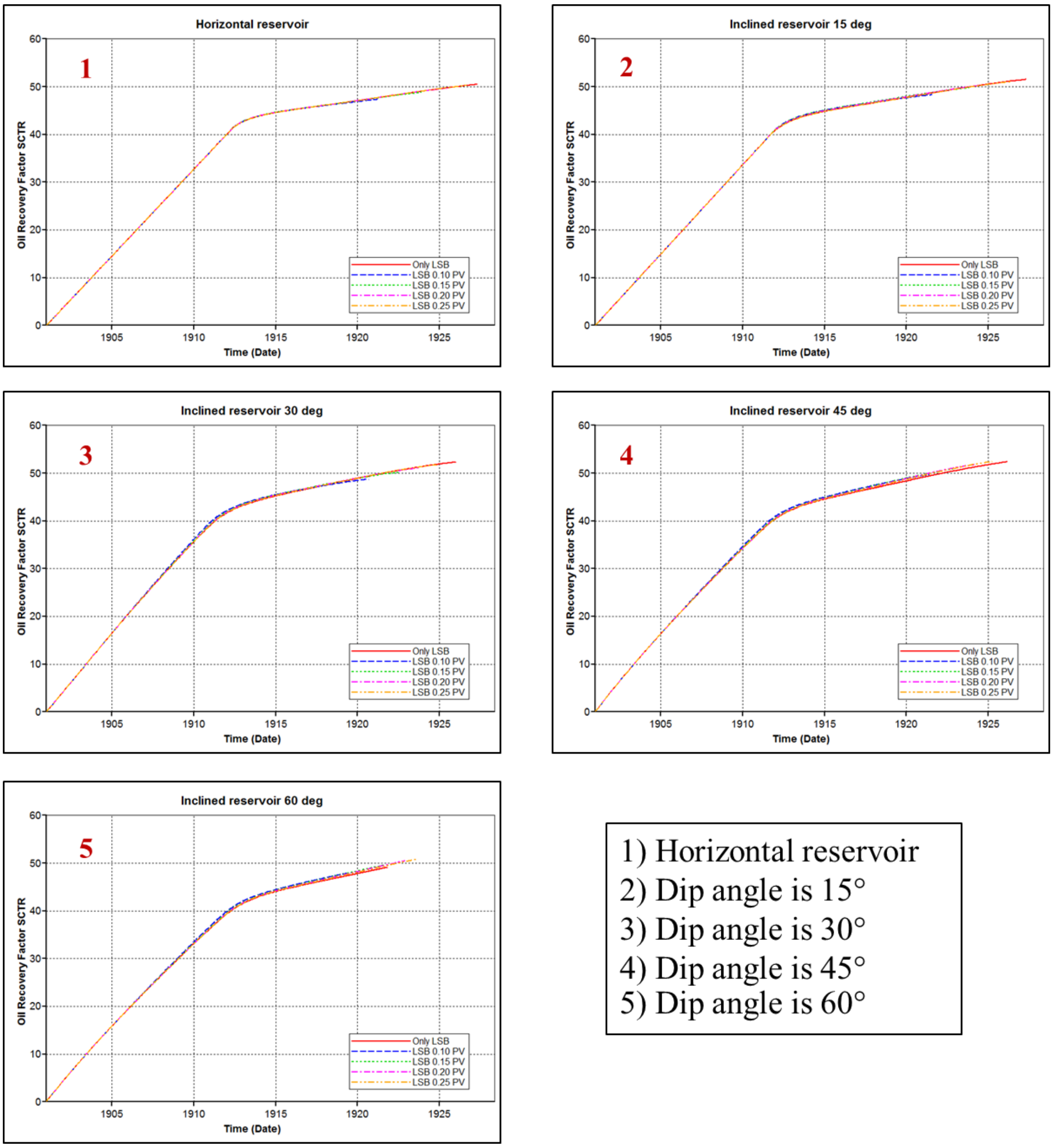

Figure 5.72 Oil recovery factors obtained from LSB injection at different slug sizes and dip angles

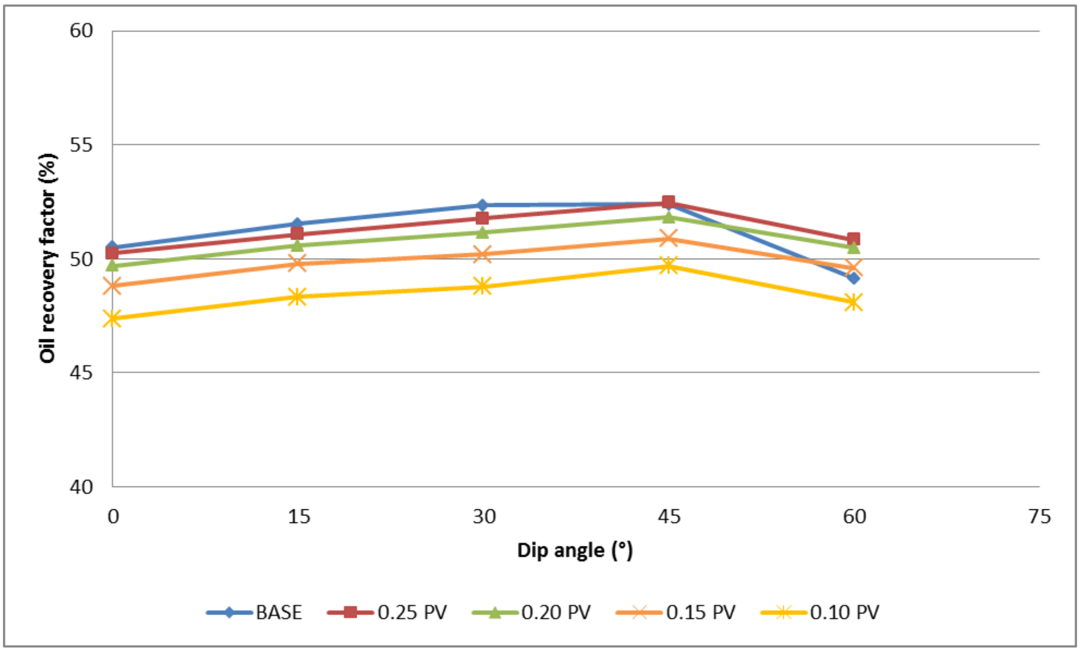

Figure 5.73 Summary of oil recovery from LSB injection with different dip angle when formation water is 35,000 ppm

Table 5.33 Starting time to inject chasing slug after LSB injection (35,000 ppm formation water)

	Starting time (Days, after the first day of production)				
	0°	**15°**	**30°**	**45°**	**60°**
0.10 PV	1461	1400	1339	1369	3833
0.15 PV	2191	2130	2038	2099	3012
0.20 PV	2891	2861	2769	2891	2191
0.25 PV	3621	3621	3499	3683	1430
Total PV of injected only LSB	0.67	0.68	0.89	0.68	0.53

From Figure 5.73, oil recovery factors from LSB injection seem to be directly proportional to the slug size; the higher slug size, the larger amount of oil recovered. However, there is an unusual trend at reservoir with dip angle 60°. Oil recovery factor of injecting only LSB (blue color line) is less than recovery factors of injecting 0.25 PV, 0.20 PV, and 0.15 PV of LSB. This may be caused by the combination of gravity effect and injectivity of water. When the relative permeability curve of reservoir rock is changed to HSB curve, k_{rw} switches to a little bit higher value at any water saturation. Thus, water can flow better than oil and hence, can be injected easily. The cumulative water production is consequently increased. However, the increment is not much as seen in red square in Figure 5.74. A little increment of oil recovery is observed for such reasons as seen in the red square in Figure.5.75.

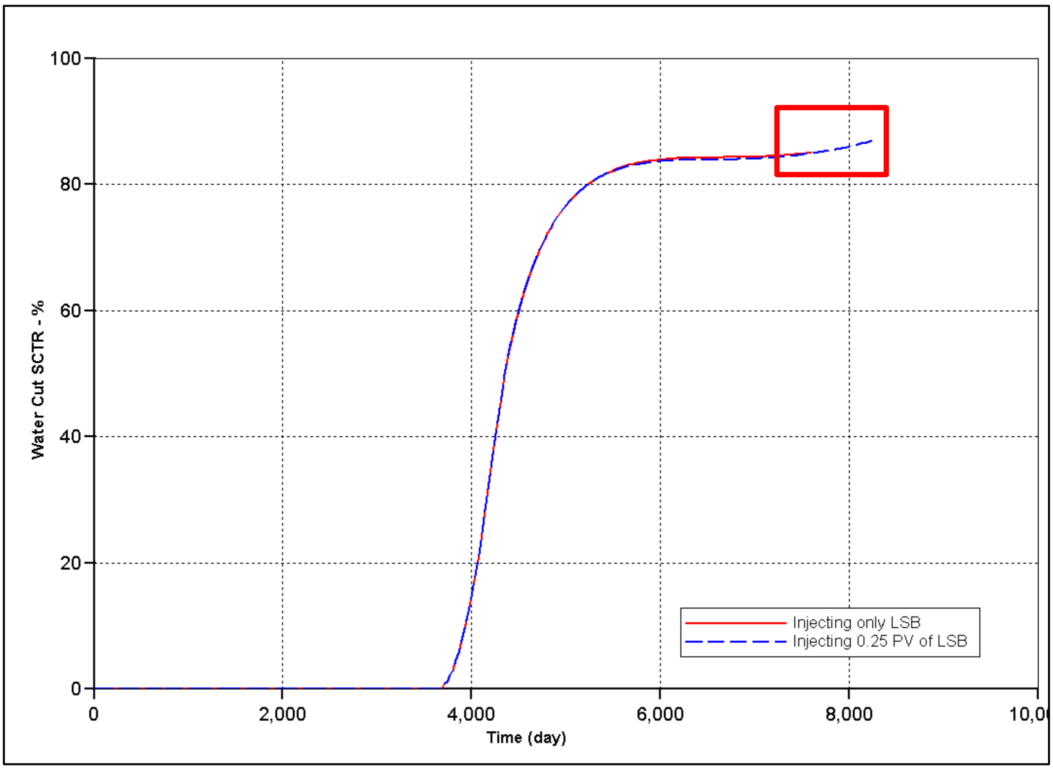

Figure 5.74 Comparison of water cut between LSB injection of 0.25 PV and only LSB

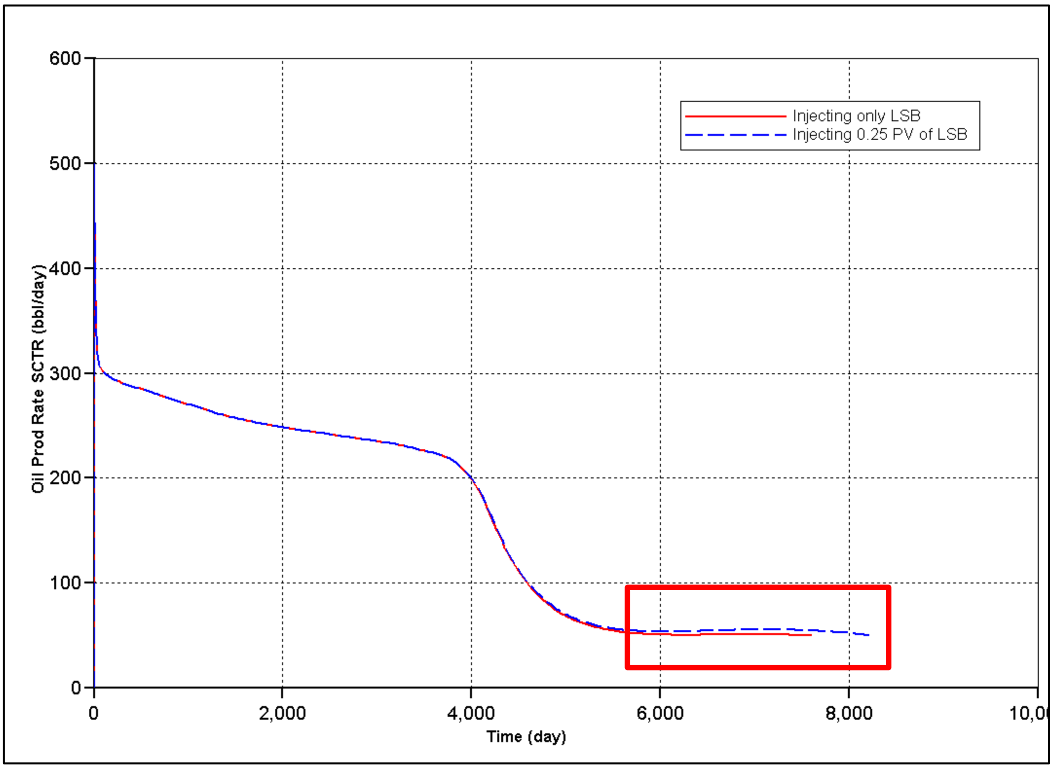

Figure 5.75 Comparison of oil production profile between LSB inject of 0.25 PV and only LSB

The relationship between oil recovery and pore volume of LSB slug at different dip angles are illustrated in Figure 5.76. As can be seen, ultimate oil recovery factor is increased as the dip angle is increased, except for 60°. This can be explained by the similar theory as in section 5.2. Additionally, oil recovery is not significantly improved after the slug size of 0.25 PV. This is because the slug size of 0.25 PV is large enough to provide the LSB mechanism to the most part of reservoir before it is fully mixed with chasing slug. Hence, most of desorbable-oil is already recovered.

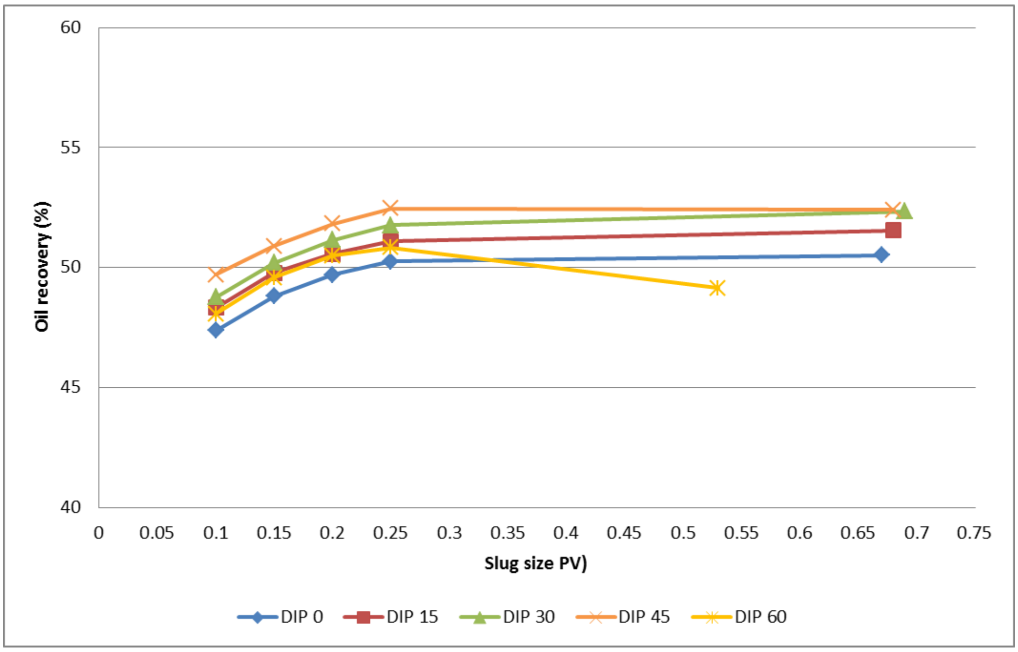

Figure 5.76 Relationship between ultimate oil recovery from LSB injection and slug size when formation water is 35,000 ppm

According to the results, it can be inferred that effectiveness of LSB injection is directly proportional to the slug size of LSB. However, after a certain size of LSB slug, the incremental oil recovery is not obvious. Thus, increase the slug size may be not further economic. Hence, slug of 0.25 PV seems to be an optimal size, whereas the dip angle of 45° yields the maximum oil recovery compared to other dip angles.

5.8.2 Formation Water Salinity of 100,000 ppm

The results from reservoir simulation with formation water salinity of 100,000 ppm are similar to the previous study in 5.8.1. Table 5.34 shows total PV of injected LSB (in case of LSB injection without chasing slug) and starting time to inject chasing water. Figure 5.77 illustrates the plot of relationship between oil recovery factors and dip angle at different slug size of LSB injection, while Figure 5.78 demonstrates the plot of oil recovery factor and slug size at different dip angle.

Table 5.34 Starting time to inject chasing slug after LSB injection (100,000 ppm formation water)

	Starting time (Days, after the first day of production)				
	0°	**15°**	**30°**	**45°**	**60°**
0.10 PV	1430	1430	1339	1369	3803
0.15 PV	2191	2130	2038	2130	3012
0.20 PV	2891	2861	2769	2891	2191
0.25 PV	3591	3591	3438	3683	1430
Total PV of injected only LSB	0.72	0.74	0.76	0.78	0.68

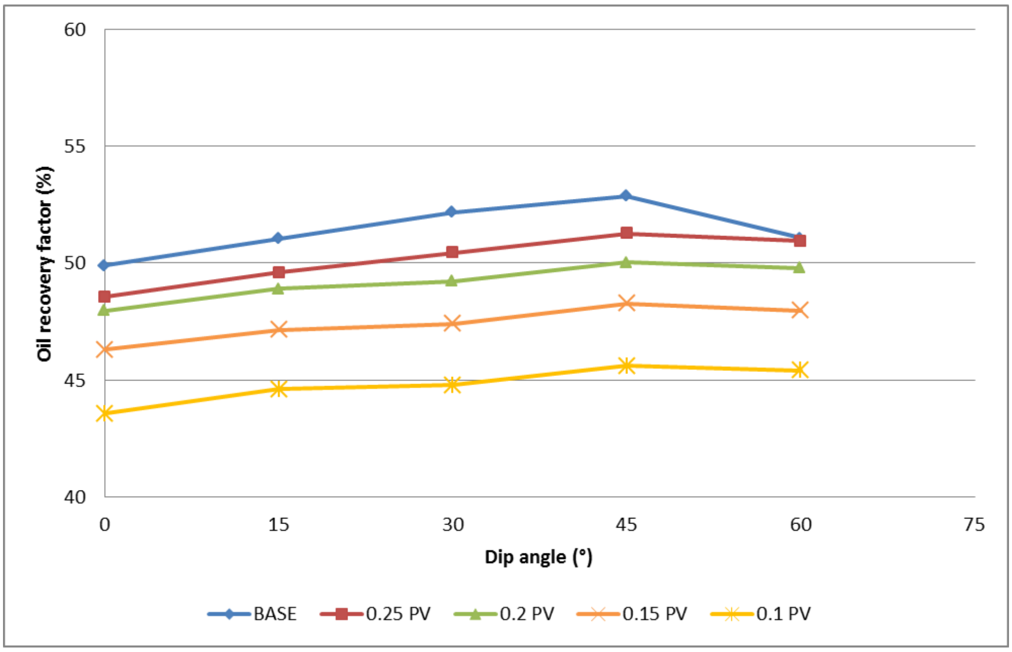

Figure 5.77 Relationship between ultimate oil recoveries and dip angle at different PV of LSB injected when formation water is 100,000 ppm

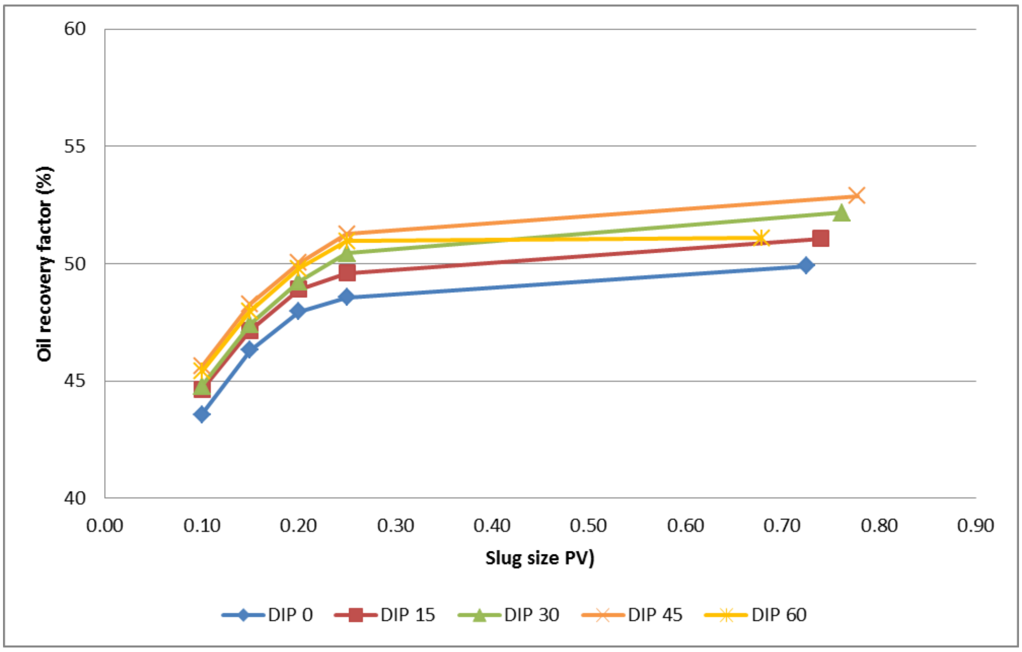

Figure 5.78 Relationship between ultimate oil recoveries from LSB injection and slug size when formation water is 100,000 ppm

From Figure 5.77, it can be observed that the variation between ultimate oil recoveries of each slug size at any dip angle is larger than previous section, 35,000 ppm of formation water. This is due to the higher different of ROS between before and after LSB injection relative permeability curves. The terms **high salinity** and **low salinity relative permeability curves** are respectively used in short. When LSB slug is small, it can be seen in Figure 5.79 in the left pictures that less area is in contact with LSB. Chasing water is also mixed with the LSB and hence, interpolated relative permeability for most part of reservoir would be closed to high salinity relative permeability curve. On the contrary, interpolated relative permeability is closed to low salinity relative permeability curve instead when slug size is large enough to provide enough times before LSB is completely mixed with chasing water. When formation water is 35,000 ppm, the different between two curves is not that much compared to the formation water of 100,000 ppm, and hence oil recovery varies less.

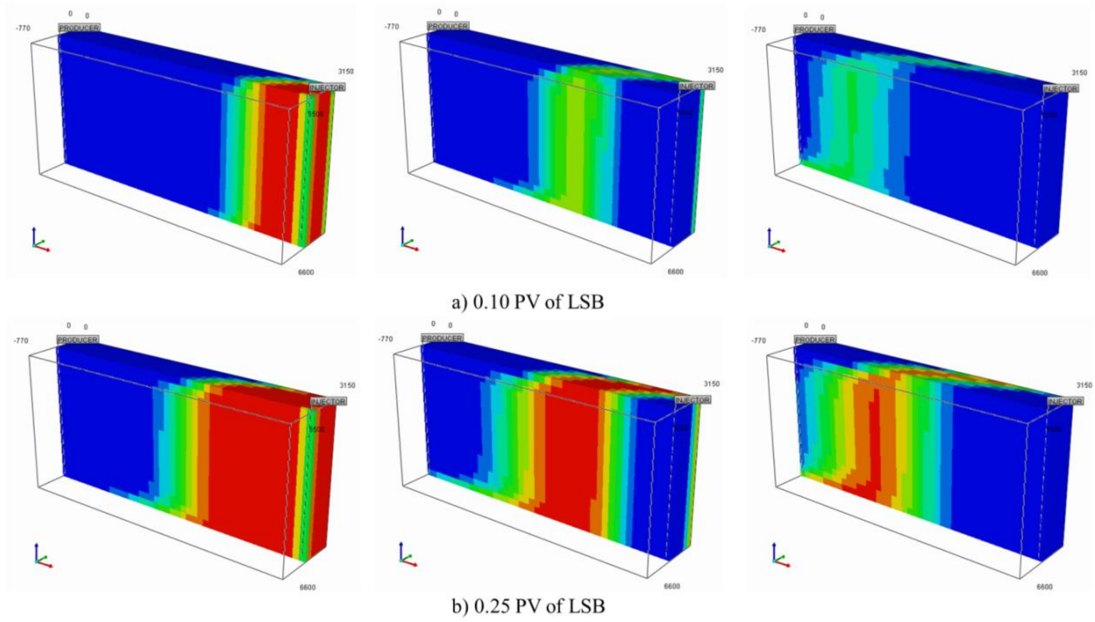

Figure 5.79 Salinity tracking during the LSB injection when formation water is 100,000 ppm (a) slug size 0.1 PV (b) slug size 0.25 PV

5.9 Effect of LSB injection period

In this section, the starting time when LSB injection should be implemented is investigated. LSB injection is started after waterflooding (so-called after preflush) instead of injecting only LSB throughout the production life. The criteria for designing the LSB injection in this study is field average oil saturation. LSB injection is performed when oil saturation in the reservoir decreases to 60%, 50%, and 40%. Figures 5.80 to 5.81 display the average oil saturation along the production period after waterflooded.

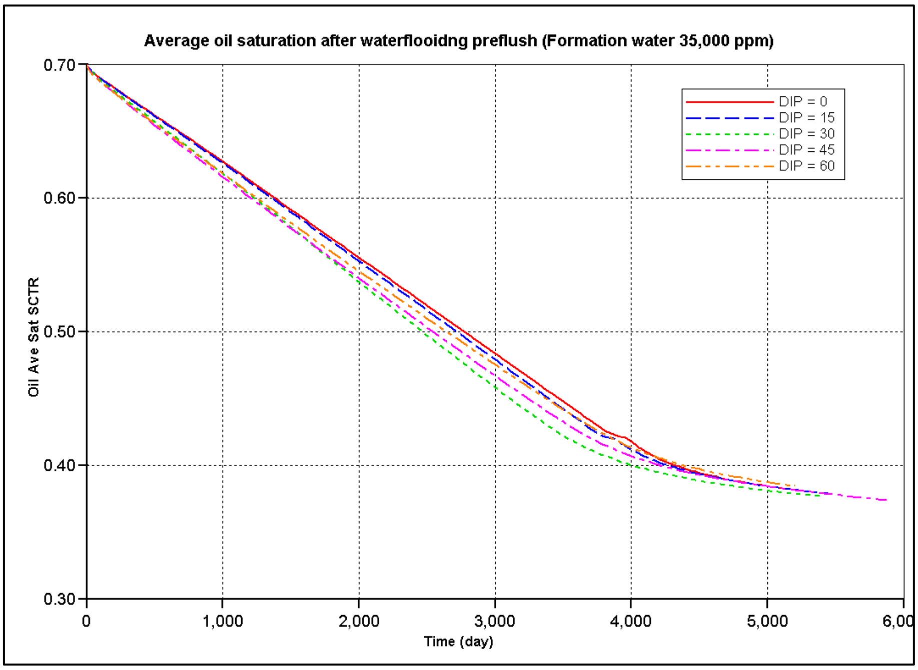

Figure 5.80 Average oil saturation left after flooded when formation water is 35,000 ppm

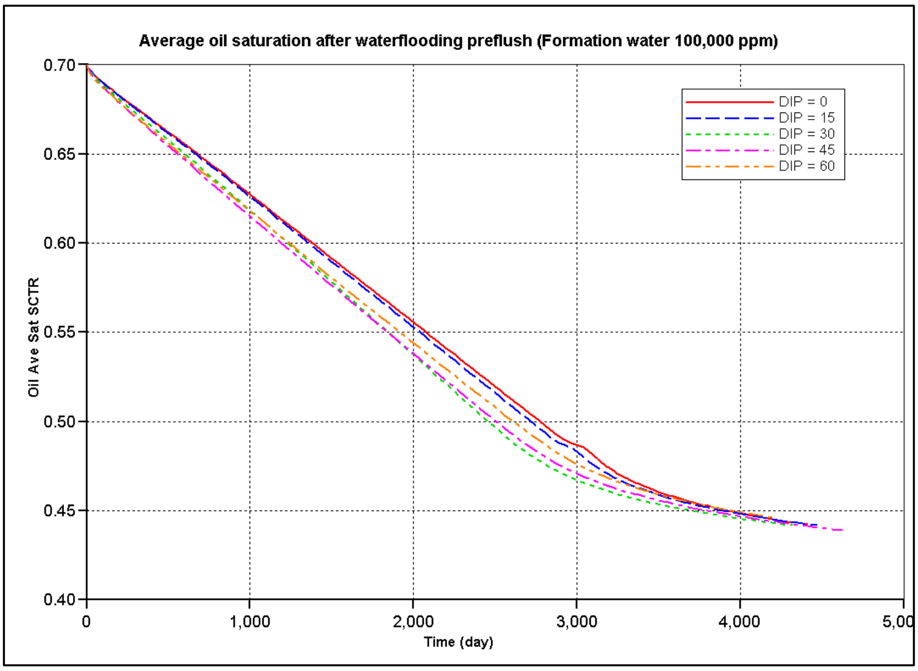

Figure 5.81 Average oil saturation left after flooded when formation water is 100,000 ppm

5.9.1 Formation Water Salinity of 35,000 ppm

LSB injection is started at different field average oil saturation in this study. The injected water which has same salinity as formation water is initially injected. Simulation results are summarized in Table 5.35 and Figure 5.82.

Table 5.35 Summary of oil recovery factors from LSB injection at different starting time (different average S_o) and at different dip angles

So	0°		15°		30°	
	RF (%)	Time (Days)	RF (%)	Time (Days)	RF (%)	Time (Days)
0.6	43.9461	5386	44.6327	5569	52.2144	10317
0.5	43.9205	5356	44.6137	5509	44.6978	5478
0.4	43.9225	5356	44.6199	5478	44.6591	5386

So	45°		60°	
	RF (%)	Time (Days)	RF (%)	Time (Days)
0.6	45.0363	5875	43.6809	5203
0.5	44.8863	5660	43.7595	5144
0.4	45.0941	5691	43.8571	5113

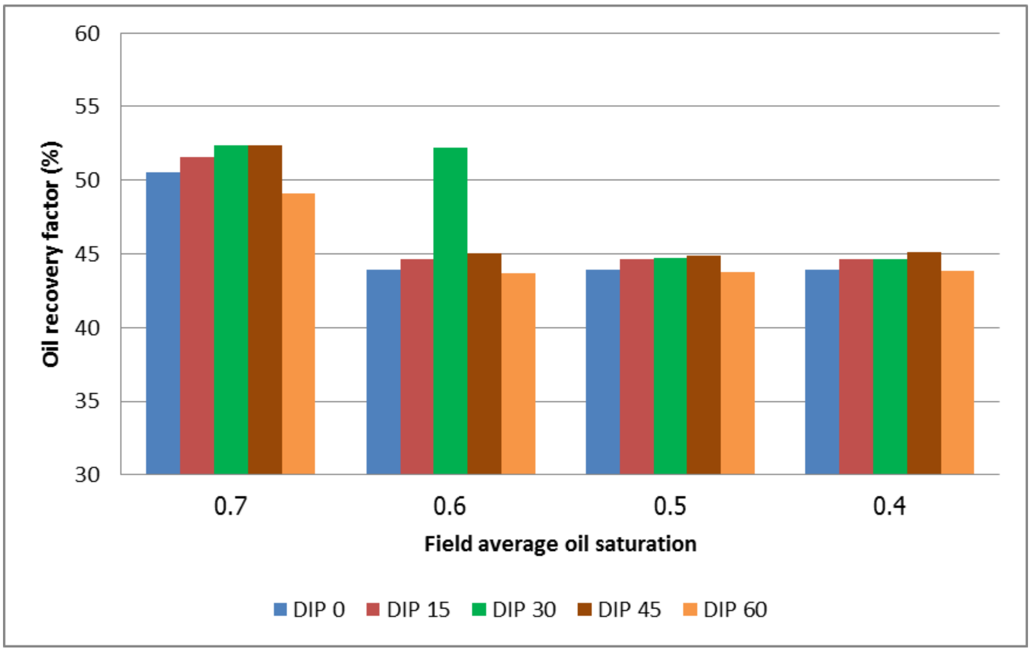

Figure 5.82 Comparison of oil recovery factors from LSB injection at different starting time (different average S_o) and at different dip angles

As demonstrated by Figure 5.82, field average water saturation of 70% is referred as reference cases where injection of LSB is started from initial production life. The ultimate oil recoveries at each dip angle seem to be slightly different when LSB injection is performed in reservoir with average oil saturation less than 60%. This is because large amount of water is already injected into the reservoir prior to performing LSB injection. The second oil bank, or additional oil saturation, (as a result from LSB effect) may not reach to the production well and hence does not yield additional recovery since the production is paused early due to the declination of oil rate below economic limit. However, there is an exceptional case as illustrated in Figure 5.81. The ultimate oil recovery in reservoir with dip angle of 30^o with LSB injection starting when average oil saturation is 60% is significantly high compared to other dip angles. This is an unexpected result. However, Figure 5.83 indicates that oil production rate in this case is almost dropped below the constraint. Fortunately, the well is still in action until the benefit of LSB injection is observed. This may correspond to the balance between gravity force and viscous force. Accordingly, it can be conclude that the dip angle of 30° is the optimal point when LSB injection is performed at field average oil saturation of 60%.

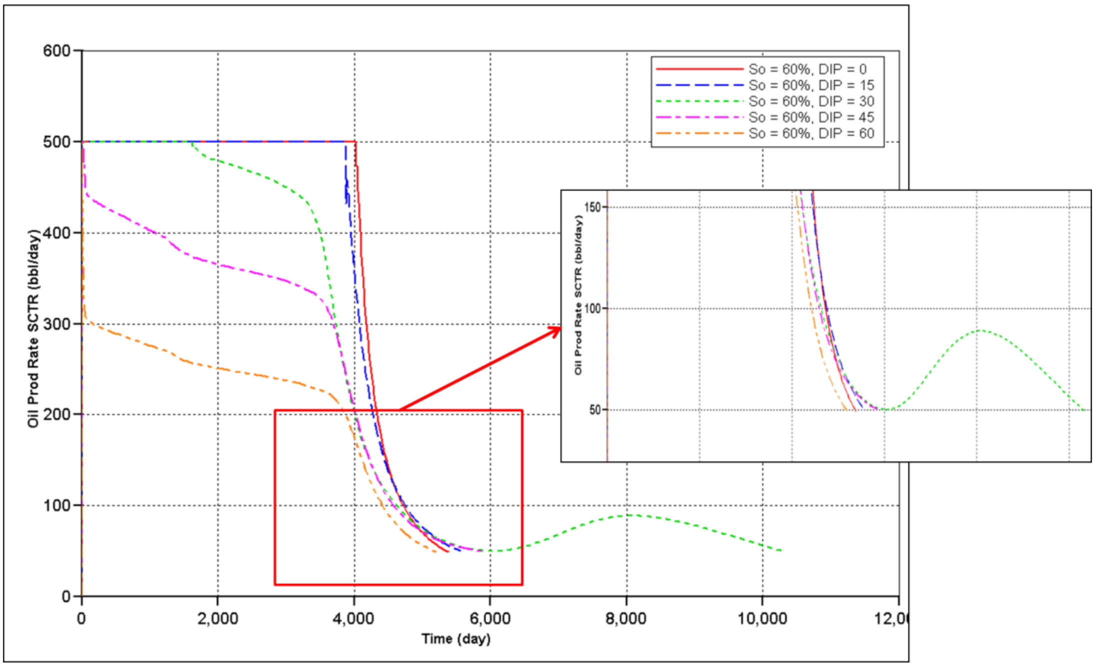

Figure 5.83 Oil production rate for each dip angle when LSB injection is implemented having field average oil saturation of 60% (formation water is 35,000 ppm)

5.9.2 Formation Water Salinity of 100,000 ppm

As before, the study of LSB injection period is now shifted to consider in reservoir with formation water of 100,000 ppm. However, the average oil saturation in this case cannot reach to 40% by waterflooding alone. Hence, consideration is only made on two situations; when average reservoir oil saturation is declined to 60% and 50%. Table 5.36 and Figure 5.84 display the results from reservoir simulation. The results are quite similar to the previous part of section 5.9.1. However, Figure 5.85 shows that at dip angle of 45° the benefit of LSB injection is obtained in addition to only dip angle of 30°. This is due to the balance between gravity and viscous force as discussed previously.

Table 5.36 Summary of ultimate oil recovery from LSB injection at different starting time (formation water salinity is 100,000 ppm)

So	0°		15°		30°		45°		60°	
	RF (%)	Time (Days)	RF (%)	Time (Days)	RF (%)	Time (Days)	RF (%)	Time (Days)	RF (%)	Time (Days)
0.6	34.1472	4352	34.9085	4503	52.1059	10835	52.7427	10957	34.8302	4108
0.5	34.5285	4414	35.1246	4473	35.4597	4352	35.8894	4503	35.0239	4077

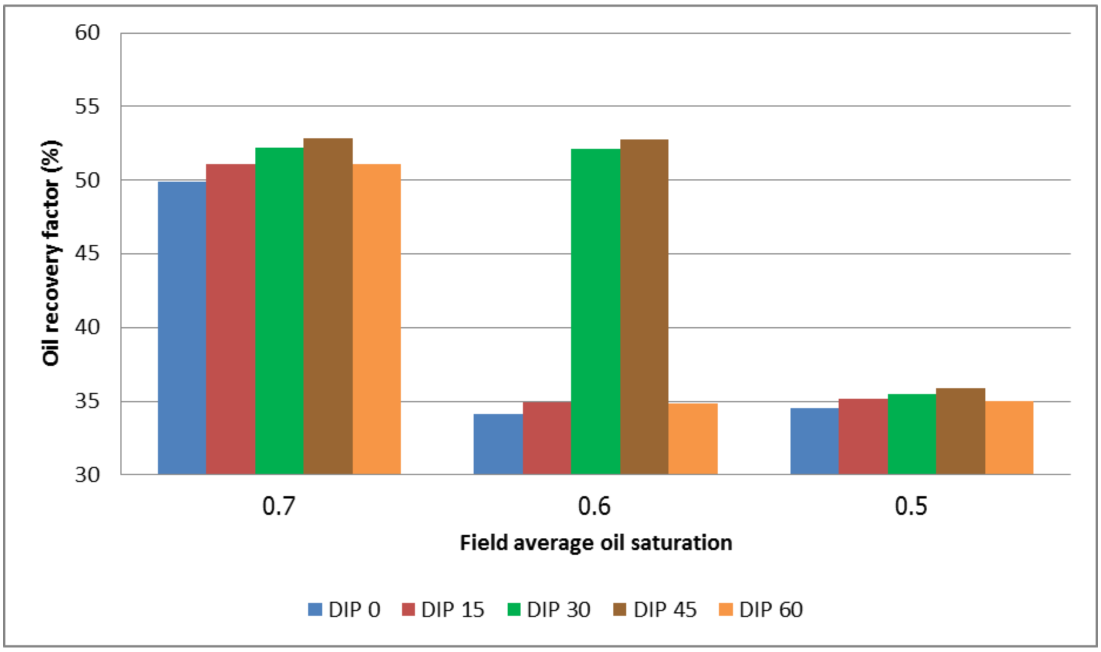

Figure 5.84 Ultimate oil recovery from LSB injection at different starting time

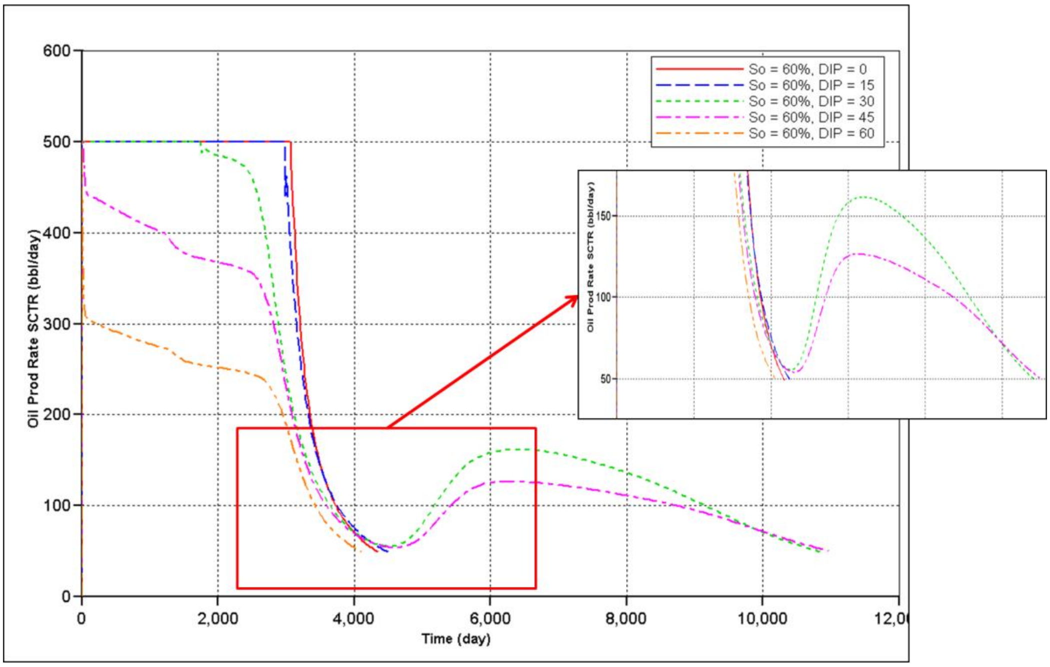

Figure 5.85 Oil production rate for each dip angle when LSB injection is implemented having field average oil saturation reaches 60% (formation water is 100,000 ppm)

5.10 Effect of LSB Injection Rate

The effect of LSB injection rate is studied in this section. The simulations in previous sections are kept at the maximum injection rate 600 stb/day and bottomhole pressure of 4,400 psi. With this constraint, water can be injected continuously at 600 stb/day in horizontal reservoir. However, actual injection rate for reservoir with higher inclination (more than 30°) is less than maximum rate since the bottomhole pressure may exceed the limit. Four values of maximum water injection rate are studied, including 400, 500, 700, and 800 stb/day. The maximum oil production rate and other constraints are kept at the same as previous cases.

5.10.1 Formation Water Salinity of 35,000 ppm

Figures 5.86 to 5.90 illustrate the injection rate profile at each dip angle at different maximum injection rate constraint. From these figures, injection rate of 700 and 800 stb/day cannot be reached at their maximum at the beginning due to the constraint of bottomhole pressure. Furthermore, injection rate cannot reach the target when reservoir is steeper. This is because the gravity effect is excessive and hence, injectivity of LSB is less. Results of LSB injection are shown in Figure 5.91.

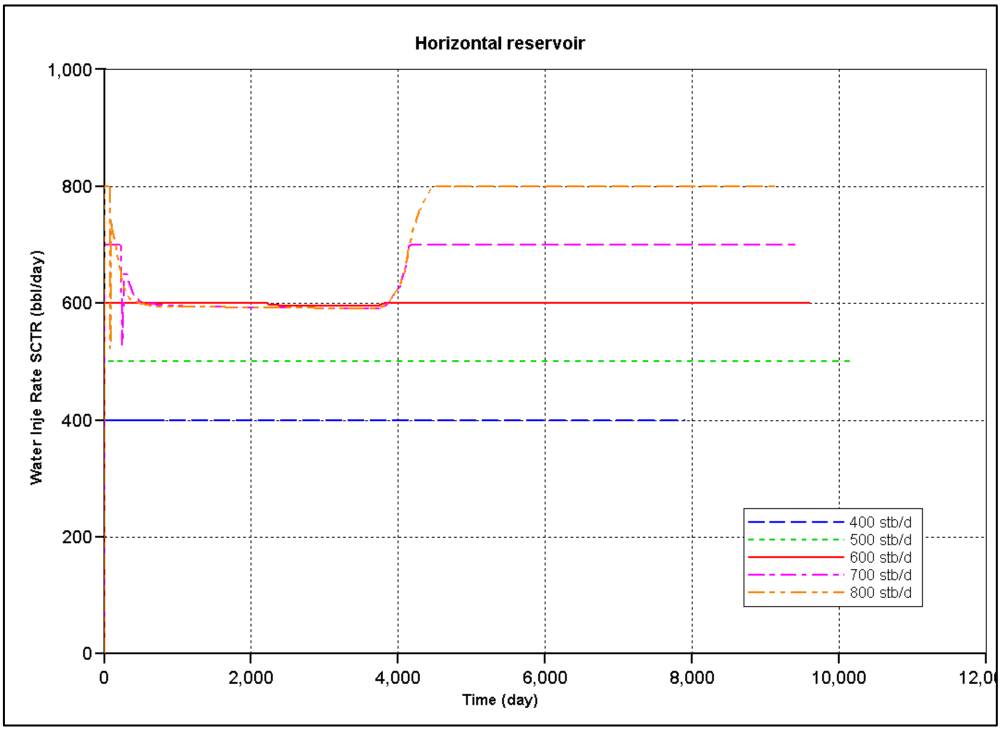

Figure 5.86 LSB injection rate profile when reservoir is horizontal (0^o dip angle)

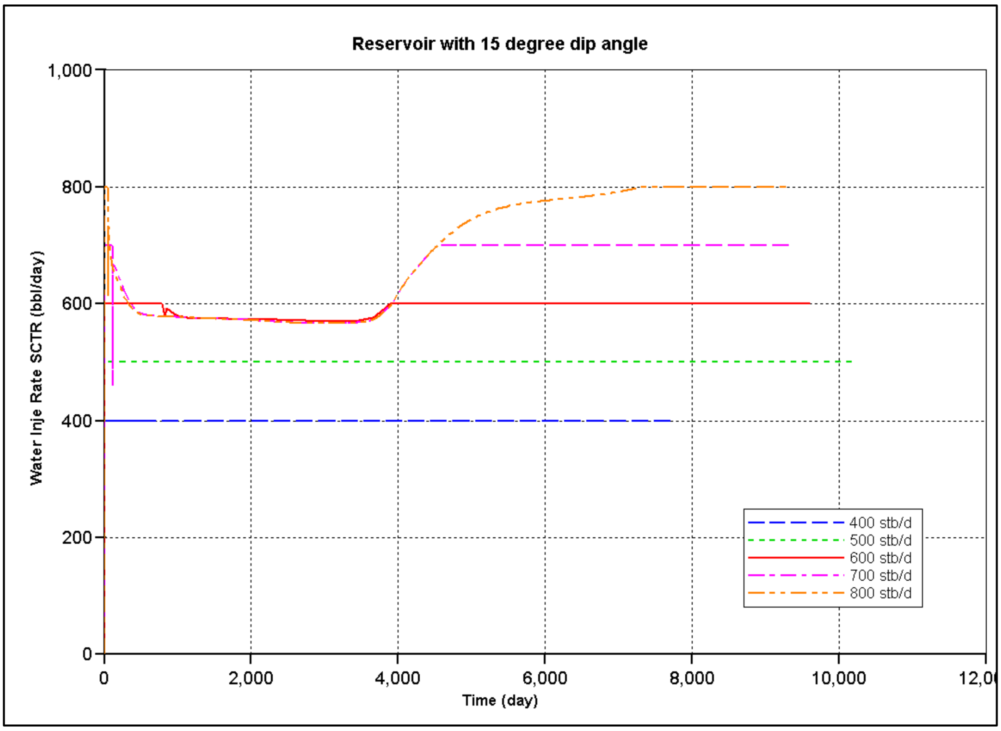

Figure 5.87 LSB injection rate profile when dip angle of reservoir is 15°

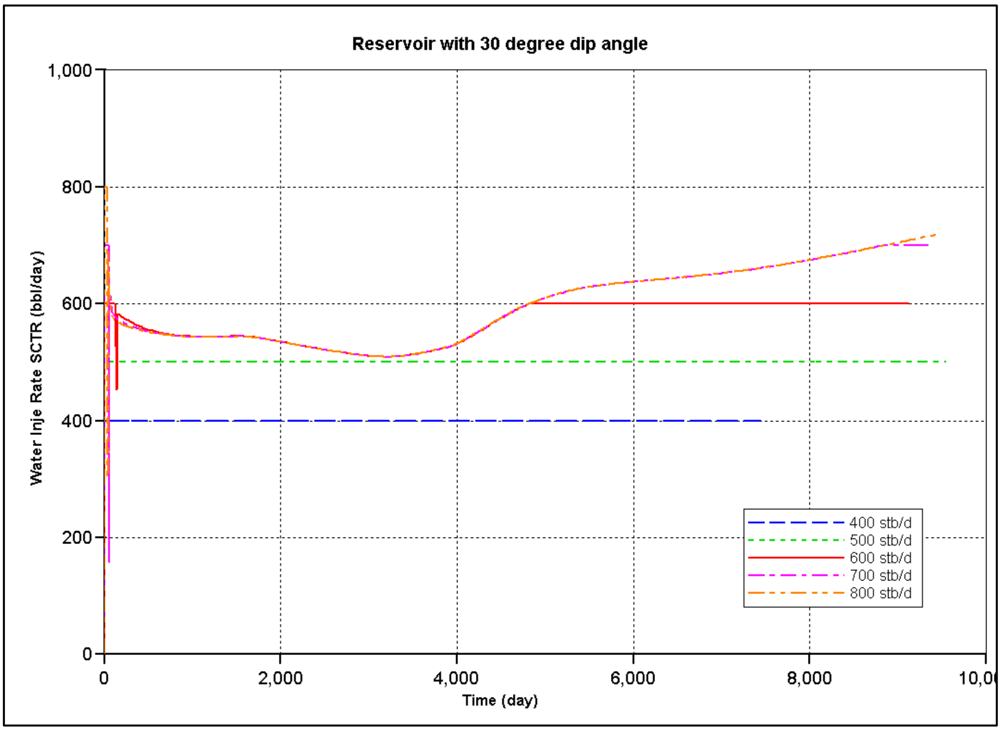

Figure 5.88 LSB injection rate profile when dip angle of reservoir is 30°

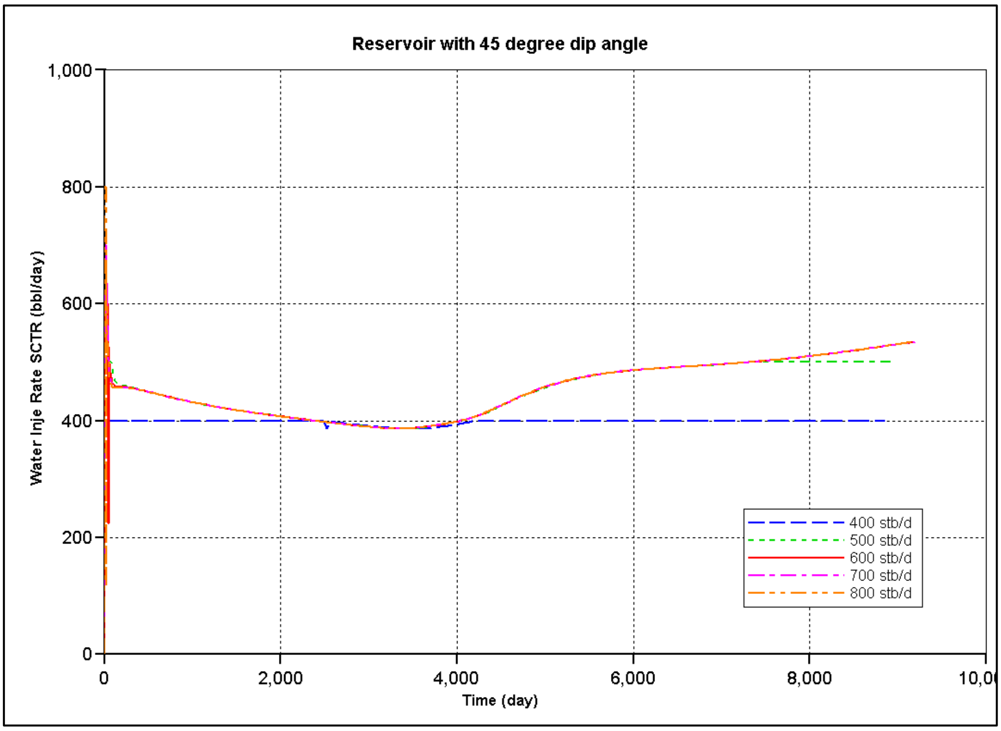

Figure 5.89 LSB injection rate profile when dip angle reservoir is 45°

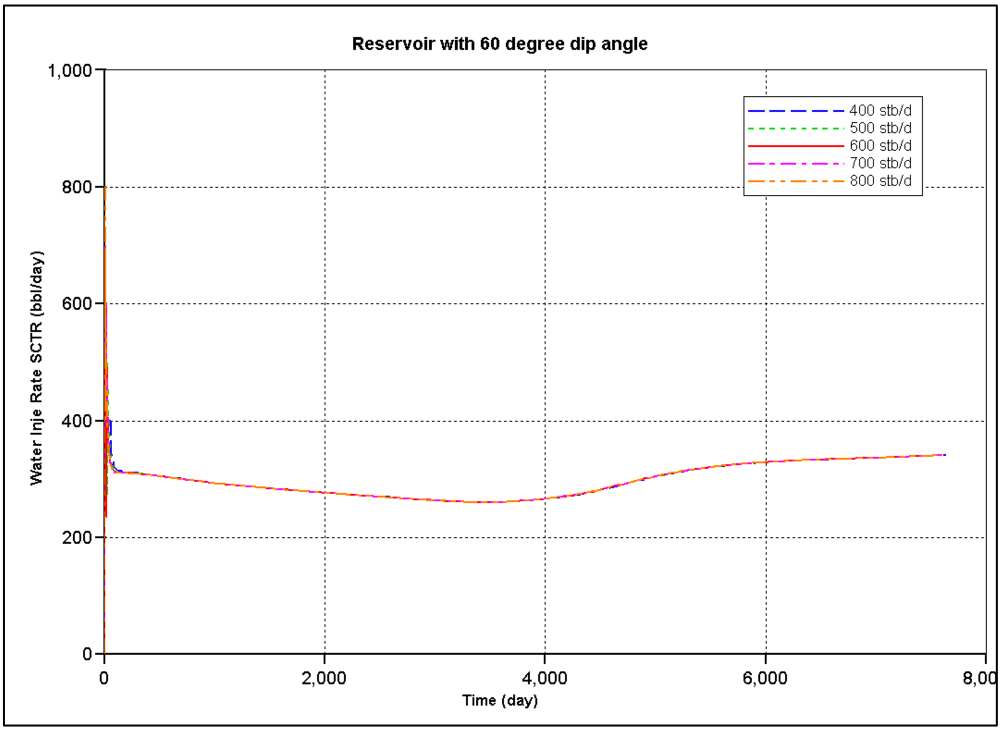

Figure 5.90 LSB injection rate profile when dip angle reservoir is 60°

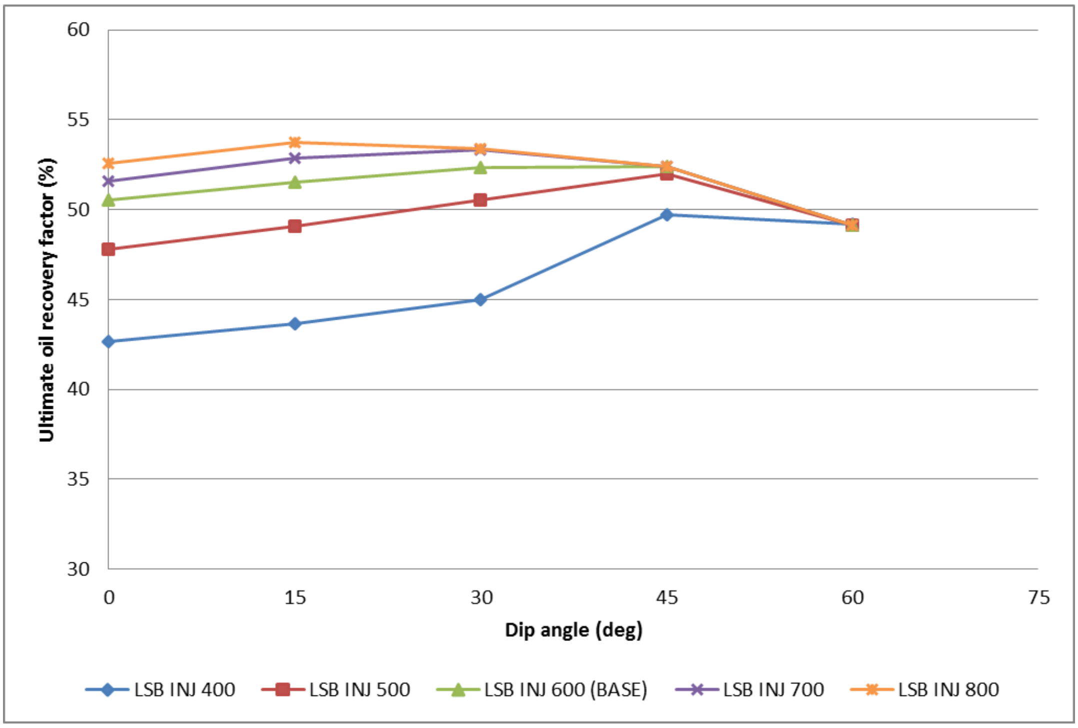

Figure 5.91 Ultimate oil recovery of LSB injection at different dip angles with different injection rate (formation water is 35,000 ppm)

As illustrated in Figure 5.91, ultimate oil recovery is high when injection at high injection rate for most dip angle except when reservoir dip angles are 45° and 60°. This is because these two dip angles yields the same injection rate due to the constraint of injection well. For reservoir with dip angles of 15° and 30°, the obtained results contradict to the theory that lower injection rate should yield better result than higher injection rate when water is displacing oil updip. This can be explained that the range of injection rate used in this study maybe too low and not suitable due to the less pressurization as illustrated in Figure 5.92. The injection rate of 800 stb/day yields more reservoir pressure than injection rate of 400 stb/day. Besides, Figures 5.93 to 5.95 illustrate oil production rate of reservoirs with dip angle of 0° to 30°. As can be seen from figures, injection rate of 800 stb/day yields the highest additional oil production rate from LSB effect (in red-dashed square) since more desorbed-oil is rapidly pressurized toward production well. The influence of injection rate on the additional oil recovery from LSB injection is summarized in Figure 5.96.

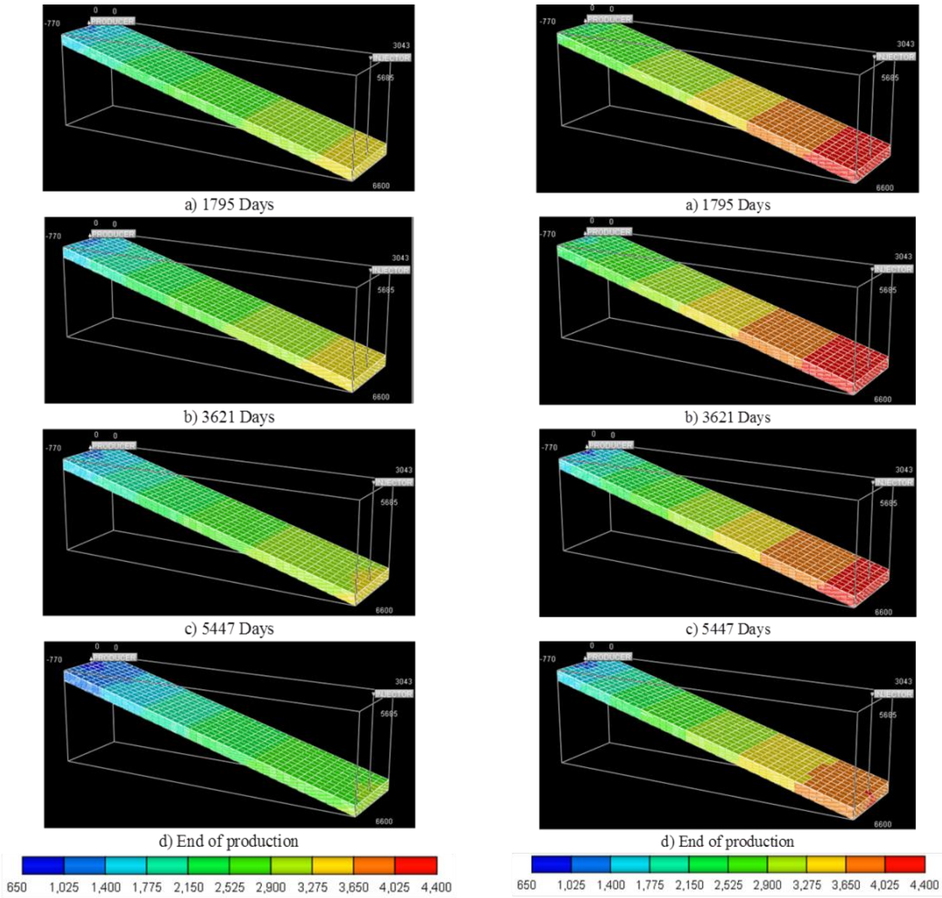

Figure 5.92 Reservoir pressure profile during LSB injection at different time (left) 400 stb/day, (right) 800 stb/day

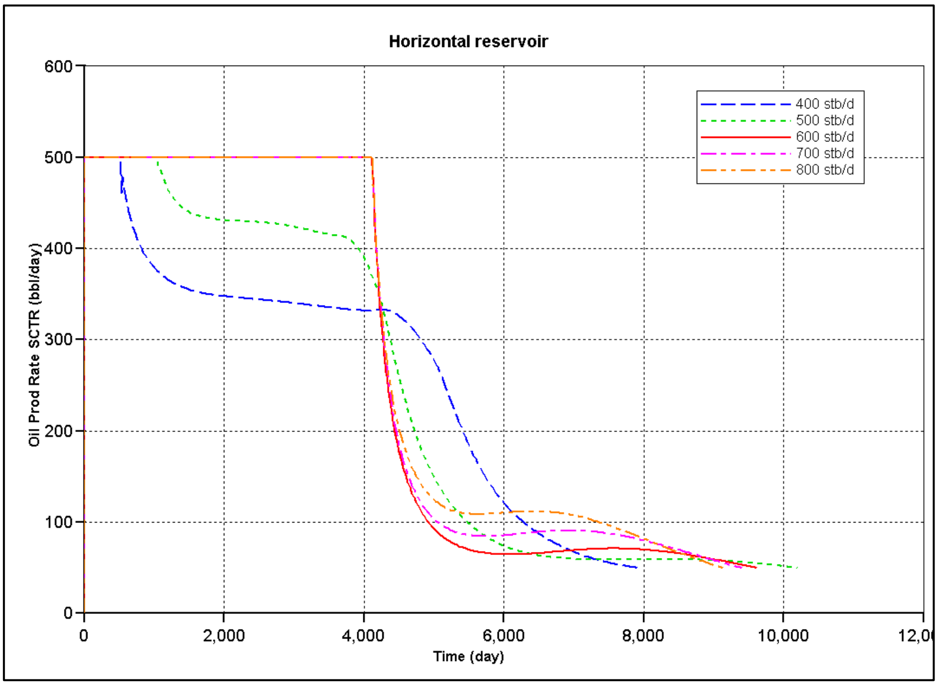

Figure 5.93 Oil production rate obtained from different injection rate in horizontal reservoir

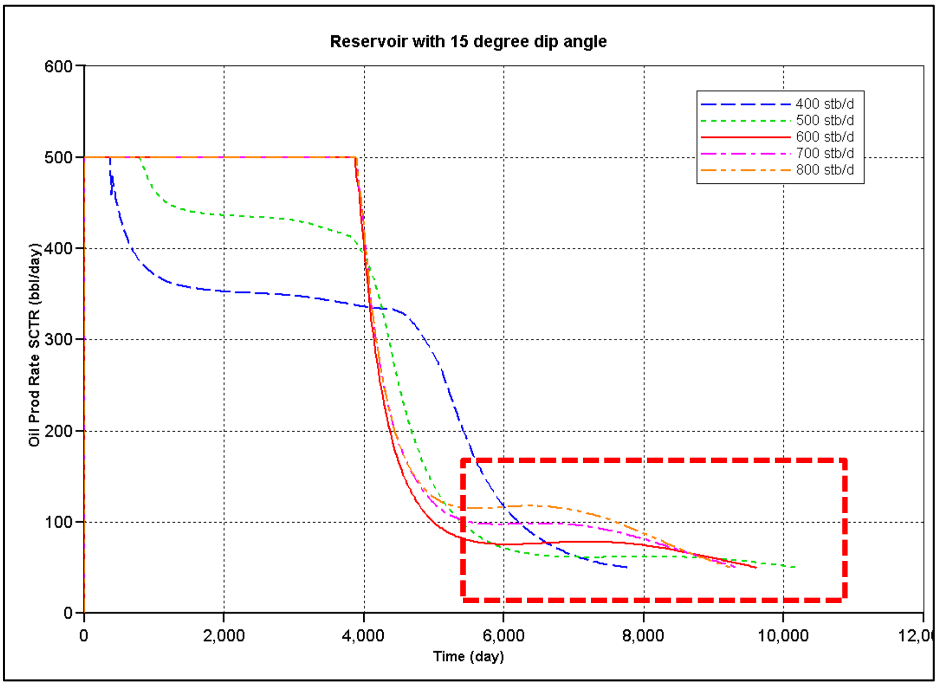

Figure 5.94 Oil production rate obtained from different injection rate in reservoir with dip angle of 15°

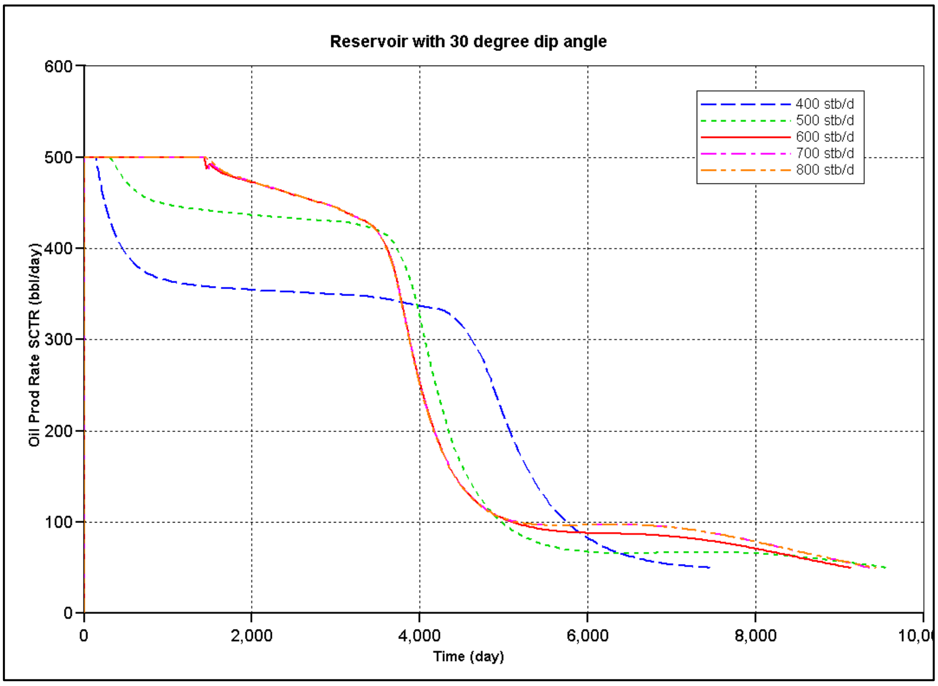

Figure 5.95 Oil production rate obtained from different injection rate in reservoir with dip angle of 30°

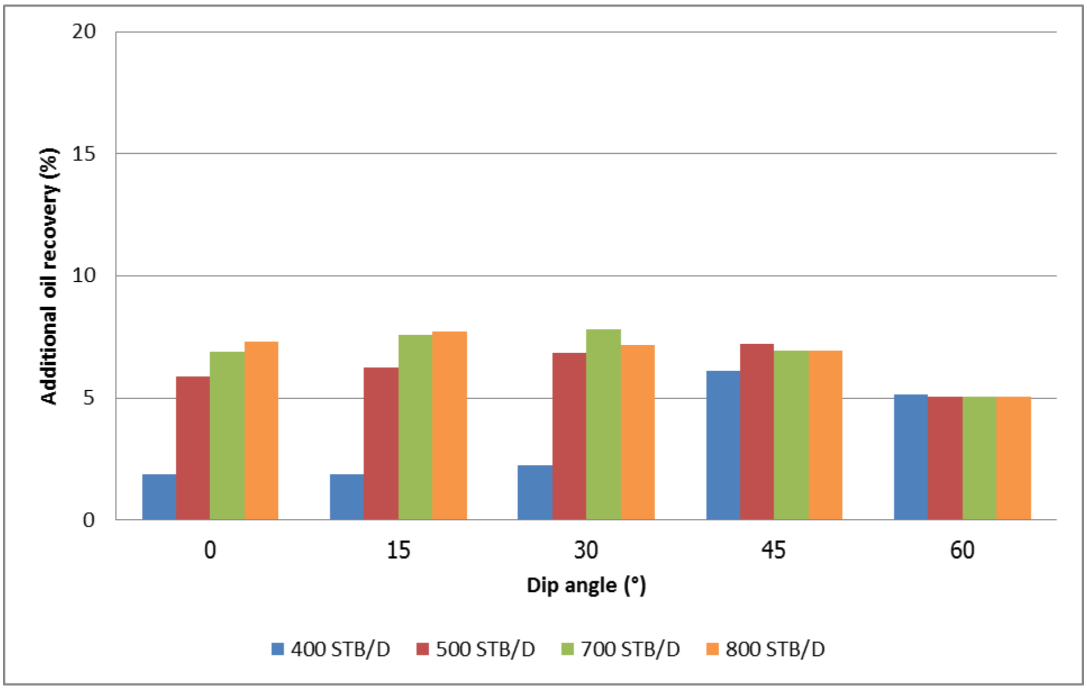

Figure 5.96 Summary of additional oil recovery for each injection rate at different dip angles (formation water is 35,000 ppm)

5.10.2 Formation Water Salinity of 100,000 ppm

The effect of injection rate is also studied in reservoir with formation water salinity of 100,000 ppm. The similar profile of injection rate is observed at each dip angle. The same trend of the results is observed and also summarized in Figure 5.97. Additionally, the benefit of LSB injection is presented in Figure 5.98.

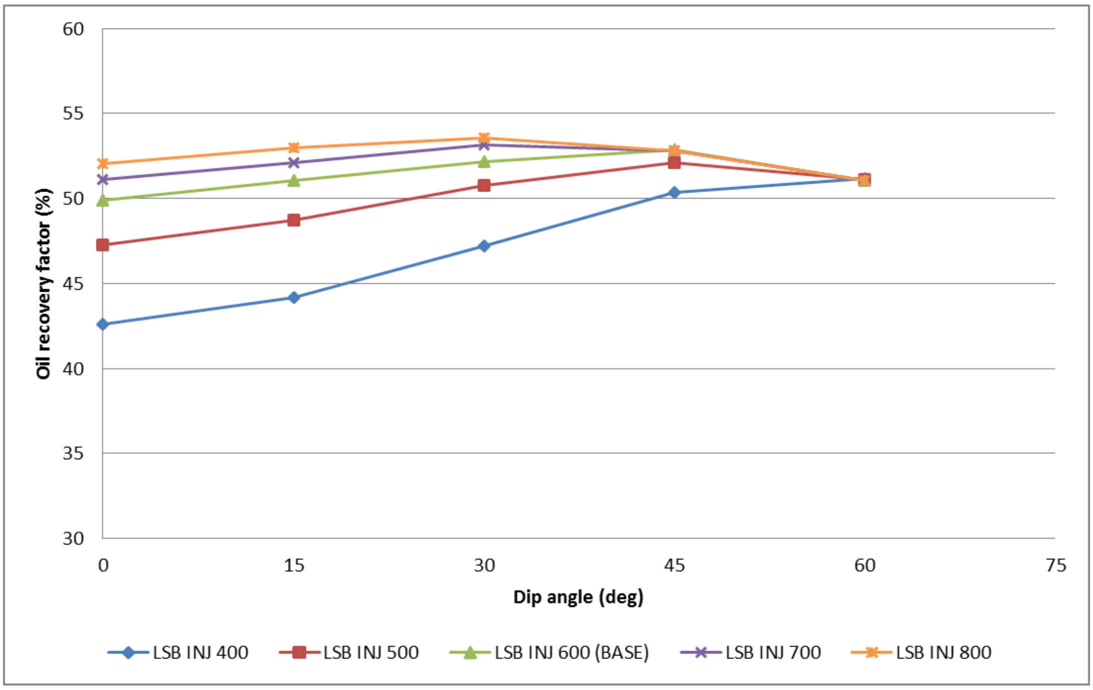

Figure 5.97 Ultimate oil recovery of LSB injection at different dip angles with different injection rate (formation water is 100,000 ppm)

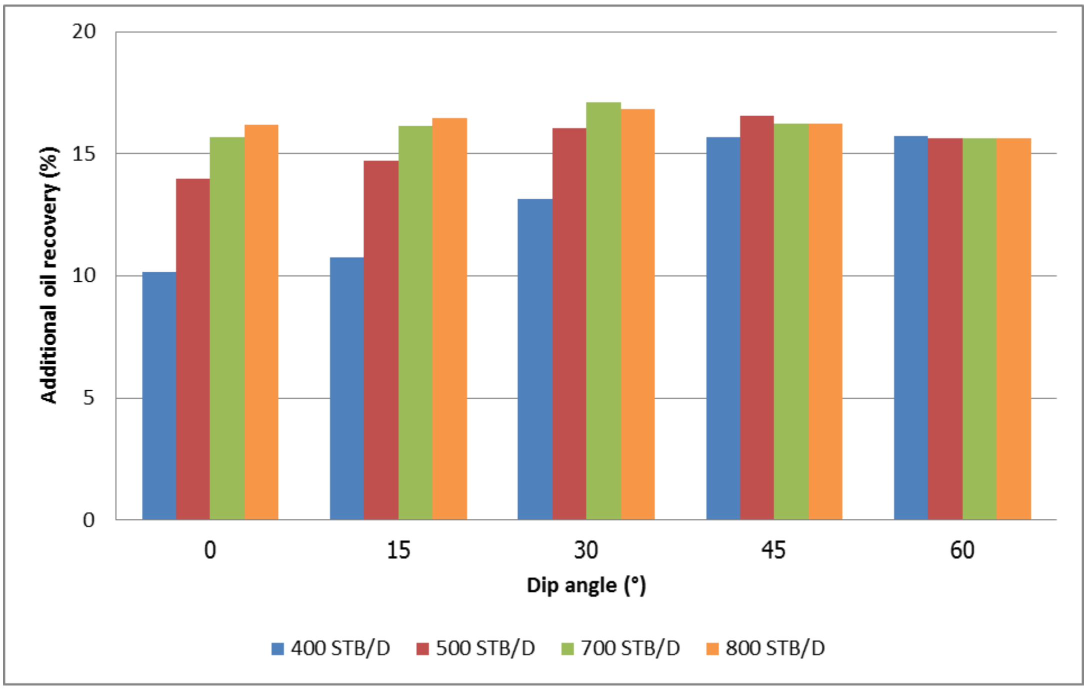

Figure 5.98 Summary of additional oil recovery for each injection rate at different dip angles (formation water is 100,000 ppm)

As illustrated in the bar chart, the additional oil recovery at each dip angle and injection rate is higher than the previous section, 5.10.1. This is because the higher salinity contrast between formation water and injected water improves wettability alteration mechanism and so facilitates desorption of oil as discussed in section 5.2. When more desorbed-oil is presented, the higher injection rate would enhance the displacement mechanism and hence, high oil recovery factor is obtained.

According to the results, it may infer that the injection rate mainly affects the performance of LSB injection through the displacement mechanism. However, there is a theory believing that a certain period of time is required in order to provide some retention times to complete the wettability alteration mechanism. The wettability alteration in simulator is interpolated through the relative permeability change. Unfortunately, the change of relative permeability in simulator is suddenly occurred as the salinity for each block is altered. Thus, the accurate effect of alteration time is excluded from this study due to the limitation of simulator. However, it is believed that retention time significantly affects the performance of the LSB injection

CHAPTER VI

CONCLUSION AND RECOMMENDATION

In this chapter, results from simulation are concluded. Conclusion is subdivided into three main aspects, starting with **the benefit of LSB injection**. Subsequently, the **influences of each internal reservoir parameter** and **operational parameter** on effectiveness of LSB injection process are concluded. Several recommendations are also provided after conclusion.

6.1 Conclusion

6.1.1 The Benefit of LSB Injection

The benefit of LSB injection is evaluated by using CMG STARS simulator after collecting data from laboratory experiment. The obtained data is used in generation of relative permeability curves before/after LSB injection. Oil recovery from waterflooding (flooding the reservoir with water having same salinity as formation water of 35,000 ppm) is compared to oil recovery from LSB injection (flooding the reservoir with 5,000 ppm water) in order to observe the benefit.

The result from simulation indicates that LSB injection seem to be a good candidate as improved oil recovery technique. With the constraint in this study, additional oil recovery of 5.1-7.7% is obtained when implementing LSB injection. The ultimate oil recovery is maximized at the dip angle of 45°. Reservoir dip angle affects water injection-type process directly through the gravity force term in fractional flow equation and through the effect of vertical permeability.

The alteration of the rock preference toward more water-wet state along with immiscible displacement is believed to be the main mechanism of oil recovery. This is because laboratory experiment shows that wettability index after displacement is increased as the salinity of injected water decreases.

Then, the influence of each internal reservoir is investigated. The effect of formation water salinity is initially simulated. Afterward, the formation water salinity is also considered along with each parameter as illustrated previously in Figure 5.9.

6.1.2 The Influence of Internal Reservoir Parameters on Performance of LSB Injection

Sensitivity of several parameters should be observed carefully prior to designing the LSB injection in sandstone reservoir in order to achieve the highest oil recovery as possible.

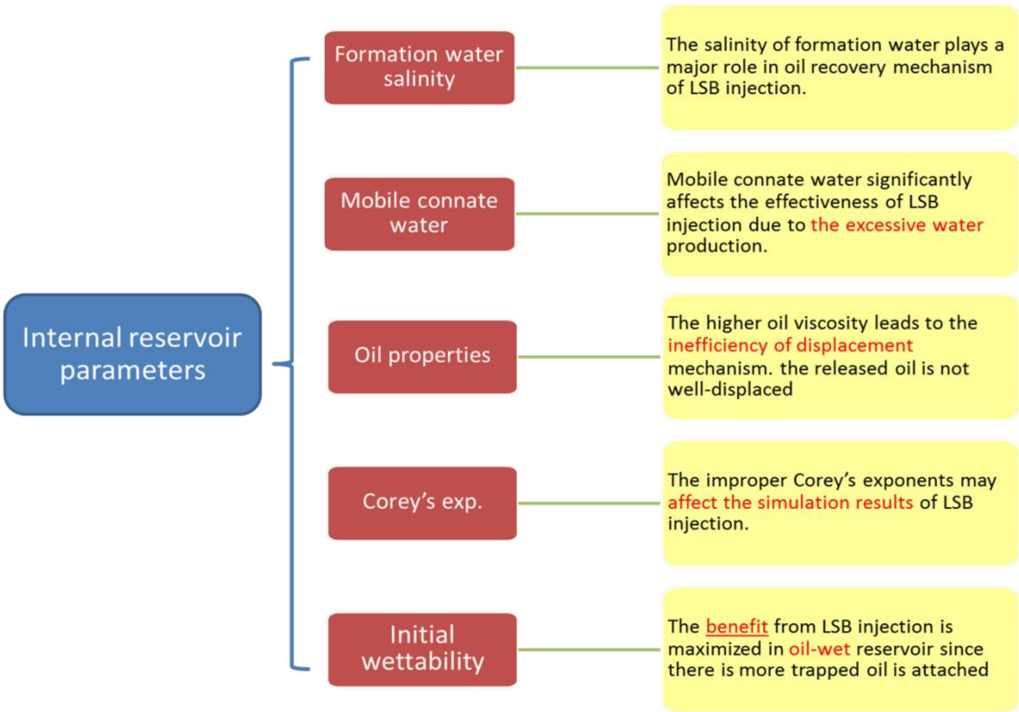

Figure 6.1 Summary of the effect of internal reservoir parameters

According to the simulation results, several internal parameters significantly affect the effectiveness of LSB injection as displayed in Figure 6.1. Firstly, Formation water salinity strongly affects the benefit of LSB injection. From the simulation, additional recovery of 15.2% to 16.7% is observed when formation water salinity is 100,000 ppm. It can be concluded that the higher the salinity contrasts between formation water and injected water the greater the performance of LSB injection. This is conformed to the theory of mass transfer that diffusion rate of salt component is directly proportional to different between two concentrations.

The presence of mobile connate water is also an important parameter as well. It is corresponded to excessive amount of water production. Once water saturation exceeds critical water saturation, formation water can flow and be produced along with oil since the beginning of reservoir exploitation. As a result, oil production rate is drastically dropped and hence, production period is shorter. However, the benefit from LSB injection is remarkably observed when initial water saturation is high since mixing of formation brine and injected brine can occur abruptly. Hence, the optimal initial water saturation of the reservoir should be well-investigated in order to achieve the highest oil recovery.

LSB injection seems to be a good candidate for implementing in less viscous oil reservoir since oil viscosity significantly affects the performance of LSB injection. In oil recovery mechanism, immiscible displacement also plays an important role as well, in addition to wettability alteration. Although some saturations of highly viscous trapped-oil is released from rock surface due to LSB effect, the released oil is not well-displaced by LSB slug due to high contrast between viscosity and hence, mobility ratio is unfavorable.

For the Corey's exponents, they are corresponded to the generation of oil/water saturation function in reservoir simulation. Basically, Corey's exponent can be obtained from matching with the laboratory data. When the laboratory data is absent, improper value of them could probably lead to misinterpretation of LSB injection performance. According to the Corey's equation, too high Corey's exponent could yields underestimated relative permeability, whereas too low value yields overestimated relative permeability. The LSB injection simulation result is more sensitive to Corey-oil exponent than Corey-water exponent.

The initial preference of rock is also an important parameter to be considered. LSB injection is a good candidate for improving oil recovery when reservoir is less water-wet. There is more trapped oil that attached to the rock surface at the beginning. LSB could provide the best benefit for such condition.

6.1.3 The Influence of Operational Parameters on Performance of LSB Injection

Conclusions of influence of operational parameters on the effectiveness of LSB injection are summarized in Figure 6.2 following.

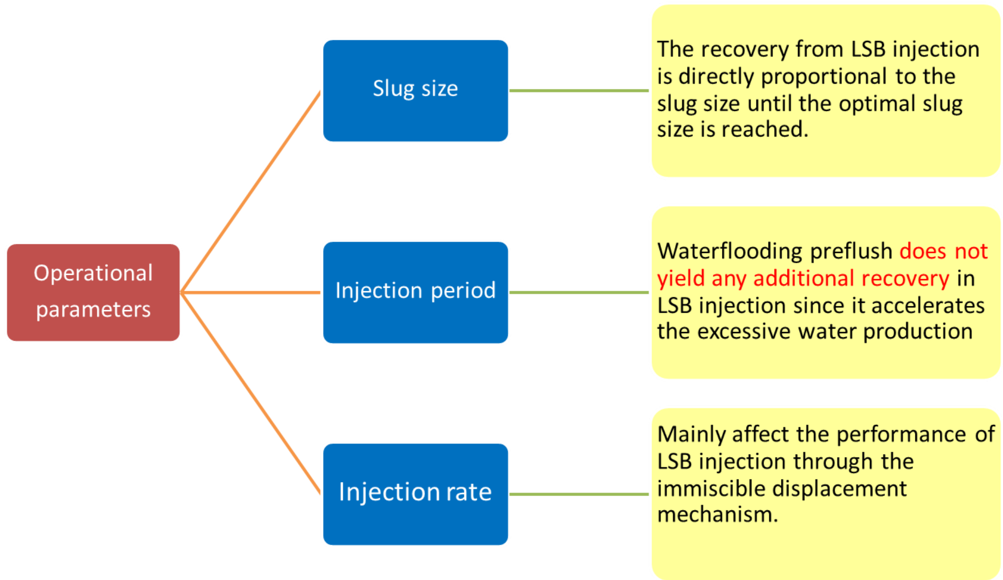

Figure 6.2 Summary of the effect of operational reservoir parameters

In order to reduce operation cost, injecting a certain slug size of LSB following by high salinity chasing slug is considered. Oil recovery from LSB injection is directly proportional to LSB slug size. The LSB slug size of 0.25 PV seems to be an optimal slug size. Slight additional recovery is obtained when injecting LSB larger than 0.25 PV. It can be inferred that this slug size is large enough to provide LSB effect to the most part of reservoir. Most of desorbable-oil is already released. The injection of optimal slug size allows hydrocarbon to be exploited economically.

Waterflooding preflush is not necessary because it accelerates excessive water production. Additional recovered oil may not be reached to production well since production period is reduced.

LSB should be injected with low injection rate in inclined reservoir since the flood front will be stabilized by gravity force. However, the injection rates used in this study may be too low. Thus, injecting with higher injection rate could yield higher oil recovery due to more pressurization. Injection rate seems to affect oil recovery mainly through immiscible displacement mechanism since the wettability alteration period is excluded from this study due to the limitation of simulator.

6.2 Recommendation

The following recommendations are provided for the perfection of LSB injection simulation.

1. Laboratory experiment of wettability measurement is conducted using centrifugal machine and hence, fluids saturation is obtained from material balance calculation from weight of saturated sample. It may contain some errors due to weighting machine. Coreflood equipment should be used instead since residual saturation would be measure precisely.
2. The number of grid blocks used in reservoir simulation model is limited by academic license of CMG 2011. Only 10,000 grid blocks are available per model. In order to model desired reservoir size, larger dimension for each grid block is required. Result might not be as precise as simulation model with larger number of grid blocks but smaller size for each grid block.

3. The interpolated relative permeability is based on the SALT component (also known as salinity). This yields some errors when chasing slug is considered since rock wettability will turn back to original state. In reality, after ion exchange is occurred, rock preference is completely change and not reversible since divalent ions that acts as a bridge is removed. In order to resolve this problem, the relative permeability interpolation should rely on concentration of calcium ion at surface. The latest version of CMG 2012 is likely to be good candidate for the study of LSB injection in the future since the new version is already enhanced LSB injection through ion exchange function.
4. This study only focuses sandstone reservoir. The study of LSB injection in carbonate reservoir would yields different results.
5. Sandstone reservoir in this study is assumed to be clean sand. The study of LSB injection in shaly sandstone should be performed in order to see the sensitivity of clay content. Besides, experiment should be conducted to determine proper formula of brine that not triggered the clay swelling or migrating.

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APPENDIX

APPENDIX

RESERVOIR MODEL CONSTRUCTION BY CMG SIMULATOR

CMG Builder program with the selection of STARS simulator are used. There are 6 sections required for the input of reservoir information including Reservoir, Components, Rock-Fluid, Initial conditions, Numerical, and Wells and recurrent.

Simulator Setting

Simulator	STARS
Working Units	Field
Porosity	Single porosity

1. Reservoir

1.1 Create Cartesian Grid

1.1.1 Horizontal Reservoir

For horizontal reservoir model (No dip angle), reservoir is simply modeled by using “Create Cartesian Grid” wizard. The inputs of creating grid are demonstrated below.

Grid Type	Cartesian
K Direction	Down
Number of Grid Blocks	45, 11, 20
(I, J, K direction respectively)	
Block widths	I direction: 45*70
	J direction: 11*70

1.1.2 Inclined Reservoir

As inclined reservoir is taking in consideration, keyword *INCLUDE is used to read the secondary data file, ECLIPSE grid; COORD and ZCORN file (GRDECL) in this case. For example,

```
*GRID  *CORNER 45 11 20
*KDIR *DOWN
*INCLUDE 'cmg_dip15_coord.GRDECL'
*INCLUDE 'cmg_dip15_zcorn.GRDECL'
```

1.2 Specify Properties

Parameter	**Whole grid**
Thickness (ft)	5
Porosity	0.20
Permeability I (mD)	300
Permeability J (mD)	Equals I(equal)
Permeability K (mD)	Equals I*0.1
Oil saturation	0.7
Water saturation	0.3
Water Mole Fraction (SALT)	0.011 or 0.033*
Water Mole Fraction (SALT)	0.989 or 0.967*
Pressure	Formulas (Depth*0.433)

* (0.011, 0.989) refers to 35,000 ppm and (0.033, 0.967) refers to 100,000 ppm

2. Components

2.1 PVT Using Correlation

Description	Option	Value
Reservoir temperature (°F)		143
Generate data up to max. pressure of		5000 psi
Bubble point pressure calculation	Value provided	2810 psi
Oil density at STC (14.7 psia 60°F)	Stock tank oil gravity (API)	24
Gas density at STC (14.7 psia 60°F)	Gas gravity (Air = 1)	0.63
Oil properties(Bubble point, R_s, B_o) correlation	Standing*	
Oil compressibility correlation	Glaso*	
Dead oil viscosity correlation	Ng and Egbogah*	
Live oil viscosity correlation	Beggs and Robinson*	
Gas critical properties correlation	Standing*	
Set/Update Values of Reservoir Temperature, Fluid Densities in Dataset		Available

*Refers to default of simulator

Water properties using correlation

Description	Option	Value
Reservoir temperature (TRES)		143 °F
Reference pressure (REFPW)		2857.8 psi
Water bubble point pressure		
Water salinity (ppm)		0
Set/Update Values of Reservoir Temperature, Fluid Densities in Dataset		Available

Water bubble point pressure is left to be blank for the default value of water.

2.2 Add Component

Description	
Component name	SALT
Reference phase	Aqueous
Critical pressure (psi)	0
Critical temperature (°F)	0
MW (lb/lbmole)	58.44

3. Rock-Fluid

Generate table using correlation wizard

3.1 Connate Water Salinity 35,000 ppm

Description	HSB	LSB
SWCON	0.3	0.3
SWCRIT	0.3	0.3
SOIRW	0.3	0.25
SORW	0.3	0.25
SOIRG	0	0
SORG	0.45	0.45
SGCON	0	0
SGCRIT	0.05	0.05
KROCW	1	1
KRWIRO	0.38	0.32
KRGCL	0.3	0.3
KROGCG		
Exponent for calculating Krw from KRWIRO	2	2
Exponent for calculating Krow from KROCW	2	2
Exponent for calculating Krg from KROGCG	2	2
Exponent for calculating Krg from KRGCL	2	2

3.2 Connate Water Salinity 100,000 ppm

Description	HSB	LSB
SWCON	0.3	0.3
SWCRIT	0.3	0.3
SOIRW	0.38	0.25
SORW	0.38	0.25
SOIRG	0	0
SORG	0.45	0.45
SGCON	0	0
SGCRIT	0.05	0.05
KROCW	1	1
KRWIRO	0.44	0.337
KRGCL	0.3	0.3
KROGCG		
Exponent for calculating Krw from KRWIRO	2	2
Exponent for calculating Krow from KROCW	2	2
Exponent for calculating Krg from KROGCG	2	2
Exponent for calculating Krg from KRGCL	2	2

3.3 Use Interpolation Set (KRINTRP)

Rock type properties

Rock wettability	Water wet
Method for evaluating 3-phase KRO	Stone's second model
Interpolation components (INTCOMP)	Interpolation enable
Rock-fluid interpolation will depend on component:	SALT
Phase from which component's composition will be taken:	aqueous

Interpolation set parameters

Phase interpolation parameters:

Wetting phase (DTRAPW)	X
Non-wetting phase (DTRAPN)	X

X refers to the mole fraction of SALT in aqueous phase (or salinity).

The following table demonstrates the value of mole fraction of SALT used.

Salinity (ppm)	SALT mole fraction
5,000	0.0015
35,000	0.011
100,000	0.033

4. Initialization

Vertical Equilibrium Calculation Methods	Depth-Average Capillary-Gravity Method
Reference pressure (REFPRES)	2853.47 psi
Reference depth (REFDEPTH)	6590 ft

5. Numerical

First Time Step Size after Well Change (DTWELL)	0.001
Isothermal Option (ISOTHERM)	ON

6. Wells and recurrent

6.1 Injector Well

6.1.1 Perforations

Well radius 0.28 ft

Click **Begin** button to perforate the well

6.1.2 Well Events

ID & Type

Name: PRODUCER

Type: PRODUCER

Constraint:

Constraint	Parameter	Limit/Mode	Value	Action
OPERATE	STW surface water rate	MAX	600 stb/day	CONT
OPERATE	BHP bottom hole pressure	MAX	4400 psi	CONT

Injected fluid:

Injected water salinity	5,000 ppm	35,000 ppm	100,000 ppm
Component	**Mole fraction**	**Mole fraction**	**Mole fraction**
WATER	0.0015	0.989	0.967
SALT	0.9985	0.011	0.033
OIL	0	0	0
DRY GAS	0	0	0

6.2 Producer Well

6.2.1 Perforations

Well radius 0.28 ft

Click **Begin** button to perforate the well

6.2.2 Well Events

ID & Type

Name: INJECTOR

Type: INJECTOR UNWEIGHT

Constraint:

Constraint	Parameter	Limit/Mode	Value	Action
OPERATE	BHP bottom hole pressure	MIN	200 psi	CONT
OPERATE	STO surface oil rate	MAX	500 bbl/day	CONT
MONITOR	WCUT water-cut (fraction)		0.95	STOP
MONITOR	STO surface oil rate	MIN	50 bbl/day	STOP

6.3 Dates

Add a range of dates: 360 months (not include the first month)

Vitae

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