EVALUATION OF STEAMFLOODING IN MULTI-LAYERED HETEROGENEOUS RESERVOIR

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การฉีดอัดด้วยไอน้ำคือกระบวนการฉีดไอน้ำร้อนลงไปในแหล่งกักเก็บน้ำมันที่มีความหนืดสูง เพื่อลดความหนืดให้ต่ำลง ทำให้น้ำมันไหลไปสู่หลุมผลิตได้โดยง่าย ผลกระทบของดรรชนีวิวิธพันธ์ของแหล่งกักเก็บมีความสำคัญต่อการกำหนดสภาวะการดำเนินงานในกระบวนการฉีดอัดด้วยไอน้ำ เช่น คุณภาพของไอน้ำ และ อัตราการฉีดไอน้ำ การเลือกสภาวะการดำเนินงานที่เหมาะสมในการศึกษานี้พิจารณาจากปริมาณน้ำมันที่ผลิตได้ เอนทาลปีที่ใช้ต่อปริมาณน้ำมันหนึ่งบาร์เรลที่ผลิตได้ และปริมาณน้ำที่ผลิต จากผลจากพิจารณาค่าดังกล่าว อัตราการฉีดอัดไอน้ำที่ 80 บาร์เรล เทียบเท่าของเหลวต่อวัน และ คุณภาพไอน้ำที่ 0.6 ให้ผลที่ดีที่สุด และสภาวะการดำเนินงานดังกล่าวได้ถูกเลือกใช้ตลอดการศึกษา

จากการศึกษาพบว่าดรรชนีวิวิธพันธ์ของแหล่งกักเก็บน้ำมันมีความสำคัญต่อการผลิตน้ำมันที่มีความหนืดสูง ในการศึกษานี้ ดรรชนีวิวิธพันธ์ของแหล่งกักเก็บน้ำมันแสดงอยู่ในรูปสัมประสิทธิ์ของลอเรนซ์ ซึ่งมุ่งเน้นไปที่การแปรผันของความสามารถในการซึมผ่านของหิน การเพิ่มขึ้นของดรรชนีวิวิธพันธ์ของแหล่งกักเก็บน้ำมันทำให้คุณภาพของการผลิตด้วยการฉีดอัดด้วยไอน้ำลดลง จากการศึกษาตัวแปรที่สนใจพบว่า ปริมาณน้ำมันที่ผลิตได้แปรผันอย่างมากต่อการเปลี่ยนแปลงสัดส่วนของน้ำในหินที่จุดสูงสุดและจุดต่ำสุดบนกราฟความสามารถในการซึมผ่านสัมพัทธ์ แหล่งกักเก็บที่มีปริมาณน้ำที่ไม่สามารถเคลื่อนที่ได้สูงจะผลิตน้ำในปริมาณที่มาก ความถ่วงเอพีไอของน้ำมันเป็นตัวแปรสำคัญต่อการเลือกอัตราการฉีดอัดและคุณภาพของไอน้ำ น้ำมันที่มีความถ่วงเอพีไอต่ำต้องการปริมาณความร้อนที่มากเพียงพอเพื่อเพิ่มความสามารถในการฉีดอัดที่ต่ำมากในช่วงเริ่มต้น ในแหล่งกักเก็บน้ำมันที่มีความสามารถในการซึมผ่านแนวตั้งต่ำ ไอน้ำจะไหลขึ้นสู่ด้านบนได้น้อยลง ทำให้ประสิทธิภาพในการกวาดน้ำมันเชิงปริมาตรเพิ่มขึ้น อย่างไรก็ดี ผลดีดังกล่าวลดน้อยลงตามดรรชนีวิวิธพันธ์ที่เพิ่มสูงขึ้น แหล่งกักเก็บน้ำมันที่มีความสามารถการซึมผ่านด้านบนต่ำกว่าด้านล่างให้ผลลัพธ์ที่ดีกว่าแหล่งกักเก็บที่มีคุณสมบัติตรงกันข้ามเนื่องจากปัญหาการลอยตัวขึ้นสู่ด้านบนของไอน้ำลดลง การฉีดอัดจากรูปแบบหนึ่งในสี่ส่วนของการผลิตแบบห้าจุดสามารถผลิตน้ำมันได้มากกว่าเมื่อเทียบกับการฉีดอัดแบบหนึ่งในสี่ส่วนของการผลิตแบบเก้าจุดที่อัตราการฉีดอัดไอน้ำรวมคงที่ เนื่องจากความร้อนได้ถูกใช้อย่างมีประสิทธิภาพจากการที่ไอน้ำเคลื่อนที่ด้วยอัตราเร็วต่ำกว่า อย่างไรก็ดี ข้อจำกัดในการผลิตนั้นมีส่วนสำคัญมาก เนื่องจากระยะเวลาการผลิตด้วยกระบวนการฉีดอัดด้วยไอน้ำ ปริมาณน้ำที่ผลิต และพลังงานที่ใช้ในแต่ละกรณี ถูกควบคุมด้วยข้อจำกัดดังกล่าว

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Steamflooding is a process performed by injecting heated steam into heavy oil reservoir in order to reduce oil viscosity, making oil readily to flow to production well. Effects of reservoir heterogeneity are important as it may indicate operational conditions such as steam injection rate and steam quality. Judging of the best operating parameters in this study is based on oil recovery factor, enthalpy consumed per barrel of oil and water production. From judging these three outcomes, steam injection rate of 80 STB/D (in barrel of liquid equivalent) and steam quality 0.6 yields the best result and these are selected for the entire study.

Results show that reservoir heterogeneity plays an important role in heavy oil recovery. Reservoir heterogeneity is represented by Lorenz coefficient which is mainly aimed for variation of permeability. Increase of reservoir heterogeneity results in lower oil recovery by means of steamflooding. From the study of interest parameters, oil recovery is sensitive to change of end point saturation in relative permeability curve. Water production is relatively high in case of high irreducible water saturation. Oil API gravity is a key for choosing proper injection rate and steam quality. Oil with low API gravity requires higher energy that is adequate for initial low injectivity. In reservoir with very low vertical permeability, vertical flow is absent and steam overriding is diminished. This helps increasing volumetric sweep efficiency. However, benefit of low vertical permeability is decreased in reservoir with high Lorenz coefficient. Reservoir with fining upward sequence is more favorable than coarsening upward since steam overriding is mitigated. Quarter 5-spot flood pattern yields better oil recovery compared to 9-spot pattern when total injection rate of steam is kept constant because heat is consumed efficiently due to higher steam retention. Nevertheless, production constrains are also very important as they control period of steam injection, water production and eventually energy consumed of each case.

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LIST OF ABBREVIATIONS

°API	American Petroleum Institute
BBL	Barrel
BHP	Bottomhole pressure
BPD	Barrel per day
Btu	British thermal unit
CMG	Computer Modeling Group
cP	Centipoise
cSOR	Cumulative steam to oil ratio
F or °F	Degree Fahrenheit
ft^3/bbl	Cubic feet per barrel
GOR	Gas-Oil ratio
IWS	Irreducible water saturation
mD	Millidarcy
OOIP	Original oil in place
psia	Pound per square inch absolute
psi/ft	Pound per square inch per feet
PV	Pore Volume
PVT	Pressure-Volume-Temperature
RF	Recovery factor
ROS	Residual oil saturation
SCAL	Special core analysis

scf/stb	Standard cubic feet per stock-tank barrel
STB/D	Stock-tank barrel per day
STO	Stock-tank oil
STW	Stock-tank water

LIST OF NOMENCLATURES

ϕ_i	Porosity
μ_o	Oil viscosity
μ_w	Water viscosity
B_g	Formation volume factor of gas
B_o	Formation volume factor of oil
c_f	Pore volume compressibility
C_o	Corey-oil exponent
C_m	Cumulative storage capacity
C_w	Corey-water exponent
F	Formation resistivity factor
F_m	Cumulative flow capacity
h	Thickness
H_m	Cumulative thickness
k	Absolute permeability
k_h	Horizontal permeability
k_{rg}	Relative permeability to gas
k_{ro}	Relative permeability to oil (Oil/Water function)
k_{rog}	Relative permeability to oil (Gas/Liquid function)
k_{rw}	Relative permeability to water
k_v	Vertical permeability
L_c	Lorenz coefficient
R_s	Solution gas-oil ratio

S_l	Liquid saturation
S_w	Water saturation
S_{wc}	Connate water saturation
S_{wcr}	Critical water saturation
S_{wi}	Irreducible water saturation (connate water saturation)
S_{wmin}	Minimum water saturation (irreducible water saturation)
S_{wmax}	Maximum water saturation
S_{or}	Residual oil saturation

CHAPTER 1

INTRODUCTION

1.1Background

After primary and secondary recovery techniques, several oil fields cannot recover high percentage of oil especially those containing high viscosity or so-called heavy oil reservoir. Therefore, Enhance Oil Recovery (EOR) technique is employed to recover this high residual portion. Existence of major reservoirs in the world that contain billion of barrels of heavy oil and tar sands with extremely high in viscosity was motivation to develop thermal recovery techniques. According to oil production from EOR projects, approximately 200,000 barrel per day of oil was produced by using steamflooding, one of thermal recovery methods. Oil produced by steamflooding far exceed from all other EOR methods combined [1].

In recent years, steamflooding has acquired a major role in tertiary recovery of crude oils, especially heavy, viscous oils. Steam injection is the most widely used and profitable EOR technique available today. The process involves with injection of steam generated at surface or downhole (to reduce heat losses) continuously, or in cycles. Continuous injection, called steam drive or steamflooding, provides a higher ultimate recovery [2]. Basically, steam increases heavy oil recovery by: reducing oil viscosity at in situ conditions, allowing oil to flow more readily. Moreover, steam can also improve heavy oil recovery through other effects such as reducing residual oil saturation, and increasing relative permeability to oil; improving sweep efficiency; increasing formation volume factor; vaporizing and distilling condensable hydrocarbons from the crude; and providing a gas drive mechanism.

All the EOR techniques are ideal for homogeneous reservoir, whereas most of reservoirs in real are heterogeneous. Reservoir heterogeneity exists in both microscopic to macroscopic scales. This controls magnitude and connectivity between wells, compartmentalizing reservoir and influencing balance of capillary, viscous and gravity forces. In displacement mechanism, heterogeneity also affects breakthrough time of injectant that consecutively results in lowering recovery and extra cost of water management. According to Tyler and Finley [1] heterogeneity index, thermal recovery can be implemented in a wide range of heterogeneity. Nevertheless, limitation in terms of heterogeneity of each technique exists and should be documented as well as possible.

In this study, thermal reservoir simulation program is used. A reservoir simulator called STAR® commercialized by Computer Modeling Group (CMG) is chosen in this study. A reservoir model is constructed as multi-layers with variation in permeability. In order to quantify heterogeneity, Lorenz coefficient is employed for each constructed model. The first phase is started by optimization of operational parameters which are steam quality and steam injection rate over based model. After optimized case is identified, it is applied for next step which is sensitivity analysis of interest parameters. This phase of study provides idea how carefully in acquiring petrophysical data in determining effectiveness of steamflooding in heterogeneous reservoir. Chosen properties are relative permeability, oil gravity, ratio of vertical permeability to horizontal permeability, and sequence of permeability in all layers. At the end, different flood patterns are studied to provide guideline for field application that best suits steamflooding process in heterogeneous reservoir. Oil recovery factor is chosen as a major criterion to judge the performance of steamflooding in each model. Oil-water saturation profiles, heat dissipation profile, cumulative water production, and enthalpy consumed per barrel of oil produced are recorded and compared among cases.

1.2 Objectives

1. To study effects of operational parameters on effectiveness of steamflooding in multi-layered heterogeneous reservoir which are steam quality and steam injection rate.
2. To study sensitivity of reservoir parameters including relative permeability, oil gravity, vertical permeability and sequence of

permeability in layers on effectiveness of steamflooding in multi-layered heterogeneous reservoir.

3. To study effect of flood pattern on effectiveness of steamflooding in multi-layered heterogeneous reservoir.

1.3 Outline of Methodology

- Study and review related literatures.
- Construct heterogeneous reservoir models by varying permeability to obtain desire Lorenz coefficient values.
- Simulate waterflooding base case by using medium value of heterogeneity from the chosen range. The result will be used as reference for steamflooding cases.
- Optimize steamflooding operational parameters which are steam quality and steam injection rate by using the model with medium value of heterogeneity.
- Study effects of reservoir heterogeneity: heterogeneous reservoir models with five values of Lorenz coefficient are used to study with optimized steam injection rate and steam quality, obtained from previous step.
- For sensitivity study, all models with various reservoir heterogeneities are applied with variation of reservoir properties including;
    - Relative permeability,
    - Oil gravity,
    - Ratio of vertical permeability to horizontal permeability,
    - Sequence of sand layer (fining/coarsening upward).
- Flood pattern is studied by changing quarter 5-spot to quarter 9-spot pattern while keeping total steam injection rate to be constant.

- Discuss the obtained results from simulations in each section.
- Summarize new findings and indicate magnitude of sensitivity of each parameter on effectiveness of steamflooding in multi-layered heterogeneous reservoir.

1.4 Outline of Thesis

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

Chapter I, this chapter introduces background of steamflooding and indicates objectives and methodology of the study.

Chapter II introduces various literatures related to the study of steamflooding including phenomena occurred inside reservoir and effects of permeability on oil recovery of steamflooding.

Chapter III presents important concepts related to steamflooding process including temperature distribution, effect of steam quality, and also calculation of heterogeneity index (Lorenz coefficient).

Chapter IV provides details of heterogeneous reservoir models construction, reservoir model dimension and input parameters in reservoir simulation model such as rock properties, Pressure-Volume-Temperature (PVT) properties of reservoir fluids, rock-fluid properties and well input data in CMG STARS.

Chapter V presents results and discussion for simulation study for each parameters. Results are not only focused on oil recovery factor, but also the cumulative energy input, water production and also saturation profile of oil and water. Results of steamflooding are also compared with conventional waterflooding in order to observe the benefit of this technique compared to secondary recovery.

Chapter VI provides conclusions of this study and recommendations for further study

CHAPTER 2

LITERATURE REVIEW

This chapter summarizes previous studies related to steamflooding in heterogeneous reservoirs in past decades. Steamflooding is one of EOR techniques widely used in Canada where most oil reserves are found as heavy oil and in some places even as tar sand reservoirs. Reservoir heterogeneity is one of the most concerning parameters in steamflood operation since it could remarkably affect other operational properties such as steam quality, steam injection rate and also wells location. Many investigators from several oil fields operating steamflooding technique have studied effects of heterogeneity in their reservoirs on effectiveness of steamflooding. Discontinuity of shale layer, vertical and horizontal permeability and matrix composition are currently topics mostly concerned.

2.1 Studies of Heterogeneity Effect on Steamflooding

Meddaugh et al. [3] studied impacts of reservoir heterogeneity on steamflooding in Wafra Eocene reservoir located between Saudi Arabia and Kuwait. They studied effects of both horizontal and vertical permeability in this Eocene reservoir which is subdivided by several continuous anhydrite beds known as second anhydrite. According to the study of vertical permeability, they concluded that heterogeneity in vertical direction of the first Eocene dolomite reservoir was not a significant impediment to obtaining reasonable recovery through continuous steamflooding. In contrast to horizontal permeability, it showed rapid response evidences by very quick increment of temperature in producer tubing, suggesting a presence of high permeability pathways between injectors and producers. Such pathways could be due to: 1) fracture 2) karst zones 3) connected very high permeability related to stratigraphic or diagenetic alteration 4) high porosity dolomite reservoir.

Ezeuko et al. [4] used core analysis to construct simulation model with a value of mean porosity of 16% of carbonate reservoir in Grosmont in Alberta, Canada. This field was reported to have vugs, karst and relatively high matrix permeability of about 200mD. These physical aspects resulted in a consideration of interaction between several combinations of non-fractured material, including matrix-matrix, matrix-vug, matrix-karst, vug-karst, karst-karst, and vug-vug. They concluded that extensive heterogeneity in Grosmont is expected to induce a significant distortion of steam chamber conformance. Poor steam conformance occurred in both case with and without marl between. Preferential flow of steam through higher conductivity material led to steam channeling and poor drainage of oil to production well in both scenarios (with and without marl). This is evident in the poor cumulative steam to oil ratio (cSOR) in models.

Williams et al. [5] studied effect of discontinuous shale on multi-zone steamflooding project. In their simulation models, multiple zones were handled as layered models, with uniform (average) properties in a layer. Permeability ranged from 10 to 10,000 mD and oil gravity was 14 ^{o}API. At the end of project, oil recovery from individual zones significantly varied. When shale was discontinuous, lower sands yielded higher oil recovery compared to average recovery, whereas upper sands yielded oppositely lower recovery. In fact, oil recovery decreased from 71 to 52 percent as sand was moved up sequentially from the lowest sand R1 to the middle layer sand K1. Higher oil recovery from the lowest sand is caused by drainage of heated oil from upper zones. As steam injection is expanded vertically upwards, discontinuous shale allows heated oil from upper sand to drain into lower sand. Therefore, lower sand continued to produce oil even though steam injection in that sand has been concluded. This downward oil migration continued until project termination.

Kumar [2] studied new method of steamflooding in multi-sand reservoir by injection scheme called “checkerboard” by simultaneously processing two sands using a single injection string in which adjacent pattern injectors were completed alternately into upper and lower sands. This new scheme performance was compared with other two schemes which were (1) conventional "sequential" injection and (2) the case where steam was injected into the lower sand only and the "hot-platen-heated upper sand is drained by gravity alone. Based on numerical simulation for multi-pattern segment (1/4 of 16 patterns) of a Californian heavy oil field using a 4,000-cell, two-component oil, he concluded that checkerboard (alternate pattern) injection resulted in accelerated production compared to sequential (lower sand followed by upper sand) scheme. Moreover, steam injection into lower sand only and production of hotplate heated upper sand by gravity alone resulted in significantly lower net oil production.

Restine [6] investigated effects of viscosity and sand thickness on steamflooding performance in Kern river field, Bakersfield, California, U.S.A. The Kern river field is a large, shallow and heavy-oil deposited reservoir. In this study, initial steam injection utilized 70% steam quality, based on pattern area or bulk volume. In thin reservoirs, peak oil production rates were shorter and time to reach a subsequent steamflood economic limit arrived earlier, leaving more oil unrecovered. As sand thickness increases from these very thin sands, economics of process allows greater oil recovery while percent oil recovery reaches a maximum in thickness range of 50 to 65 ft. Simulation work also suggested that for sand thickness greater than 90 ft, oil recovery trend reversed back to increasing in oil recovery with increasing of sand thickness. Early in steamflood process, steam zone and transition zone (between steam and oil zones) were thin with high efficiency in transporting heated oil per net unit mass of steam.

Sajjadi and Azaiez [7] studied viscous fingering phenomenon in porous media when performing thermal recovery process. By using numerical simulation model, they compared effects of viscous fingering in both homogeneous and heterogeneous models for isothermal and non-isothermal displacement cases as seen in Figure 2.1. By comparing unstable flow in layered medium heterogeneous reservoir and in homogeneous one, growth rate of viscous fingers increased significantly due to area opened to the flow in a heterogeneous medium is narrowed to the high permeable layer with higher permeability than homogeneous medium, causing flow velocity in permeable layer to increase and breakthrough time to decrease. For non-isothermal case it was quite similar to isothermal one but, the only difference was concentration front and temperature front which made shape of the fingers different.

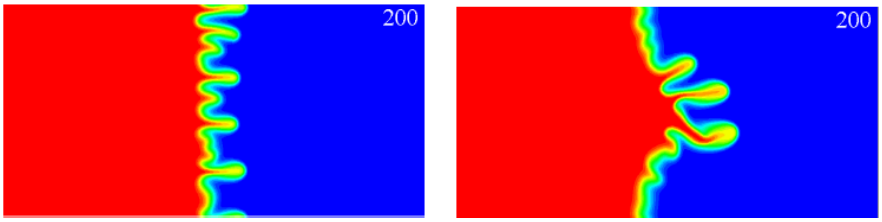


Figure 2. 1 Comparison between concentration profiles of isothermal flows in a homogeneous medium and in a single-layered heterogeneous medium [7]

Mezzomo et al. [8] performed pilot test in Potiguar basin, Brazil and compared results with simulation model. Based on the fact that two steamflooding field pilot attempts were on patterns of 5 and 2½ acres, respectively, it was thought that reservoir heterogeneity could be precursor for the failures. By constructing simulation model, the first heterogeneous model was constructed for the area selected for the pilot test, where well pattern had been reduced to 1¼ acres with 5-spot patterns. Heterogeneous model for 1¼-acre pattern was used to match pilot performance and it improved history matching results.

Ziegler [9] compared performance of steamflooding project for both 5-spot and 9-spot patterns. According to waterflooding test in laboratory, cross-flooding recovered only small amount of additional oil (<3%PV). Results obtained from steamflooding simulation study of a homogeneous reservoir indicated that only a slight improvement (2.1%PV) in ultimate recovery is obtained by pattern realignment and infill drilling. Realignment with infill drilling, it has been found to accelerate oil recovery. Combined with small improvement in ultimate recovery, this acceleration in oil production may justify pattern conversion. By varying well spacing, grid size and well configuration, he concluded that increasing number of active grid blocks in simulation model from 88 (7×4×4) to 312 (15×8×4) grids had a negligible effect on oil recovery from 9-spot pattern. For constant values of well spacing and normalized injection rate, oil recovery from 9-spot pattern was accelerated relatively to 5-spot pattern. At close well spacing (1.25 acres/well), ultimate recovery from 9-spot exceeded that obtained from 5-spot pattern. As well spacing was increased, ultimate recovery from 9-spot pattern decreased relatively to 5-spot pattern, as shown in Figure 2.2.

From literature reviews related to steamflooding in heterogeneous reservoir, most studies concerned different aspects such as reservoir dynamic, problem clarification and mitigation. However, steamflooding performance as a result from quantifiable heterogeneity has not yet been thoroughly studied and this leads to motivation of this study to provide an idea of effects from quantifiable heterogeneity on effectiveness of steamflooding. Results could be guideline for steamflooding implementation in heterogeneous reservoir when heterogeneity can be quantified.

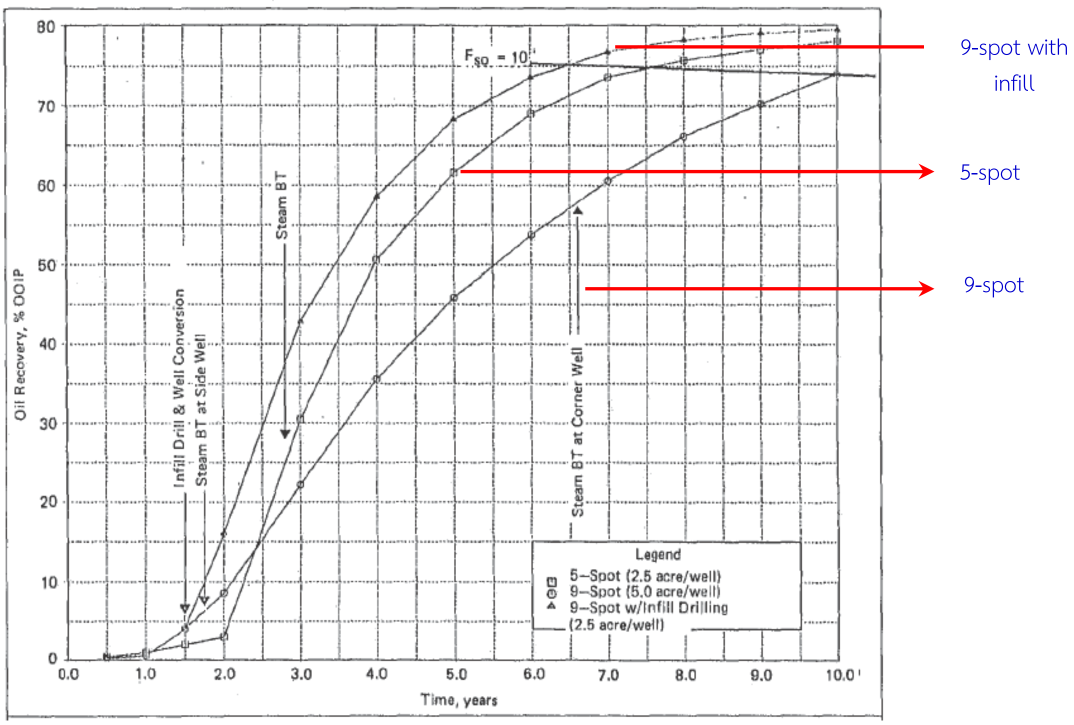


Figure 2. 2 Oil recovery as a function of time obtained from 5-spot, 9-spot, and 9-spot with infill drilling well patterns based on homogeneous reservoir [9]

Bursell and Pittman [10] studied performance of steamflooding in Kern river reservoir. The Kern River field produced 12 to 16.5 °API gravity oil from 500 to 1,300 ft depth. Reservoir and fluid characteristics were very favorable for thermal recovery methods. An average oil viscosity of 4,000 cP at reservoir temperature of 90°F was reduced remarkably at higher temperature levels. The layer thickness, porosity, permeability and oil saturation in Kern river reservoir are illustrated in Figure 2.3.

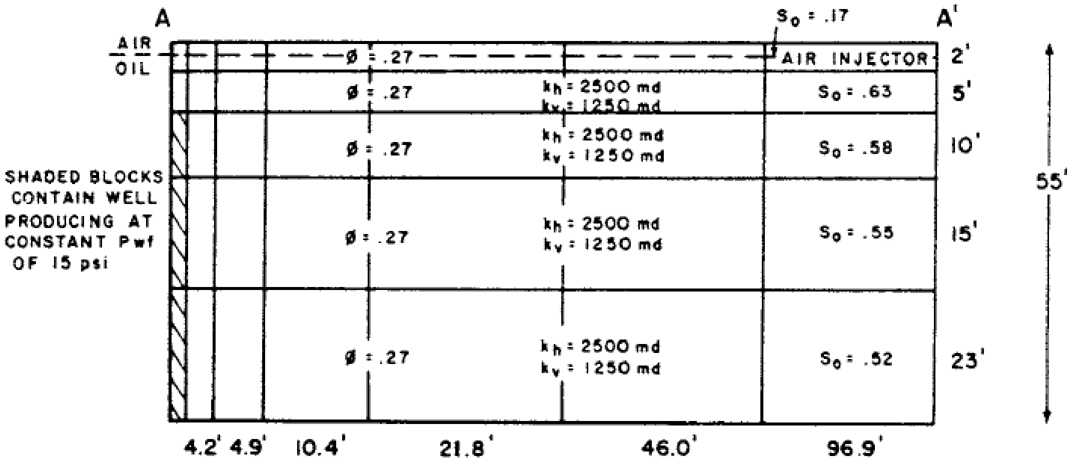


Figure 2. 3 Reservoir properties of Kern river reservoir [10]

2.2 Studies of Temperature and Viscosity Effect on Petrophysical Properties

Wang, Dong and Asghari [11] studied effects of oil viscosity on relative permeability curves for heavy oil-water system with oil viscosity ranging from 430 to 13,550 mPa.s. It was found that, under the same injection rate, relative permeabilities were also a function of oil viscosity. Relative permeability to water was clearly decreased with an increase in oil viscosity. Residual oil saturation increased linearly with log value of oil viscosity.

Lefebvre du Prey [12] concluded that viscosity ratio had an influence on relative permeability curves and displacement mechanism, especially when a non-wetting fluid displaced wetting fluid. Viscosity ratio had considerable influence on dissymmetry of relative permeability curves. The higher the viscosity of one of the liquids, the lower was the relative permeability of another liquid as shown in Figure 2.3.

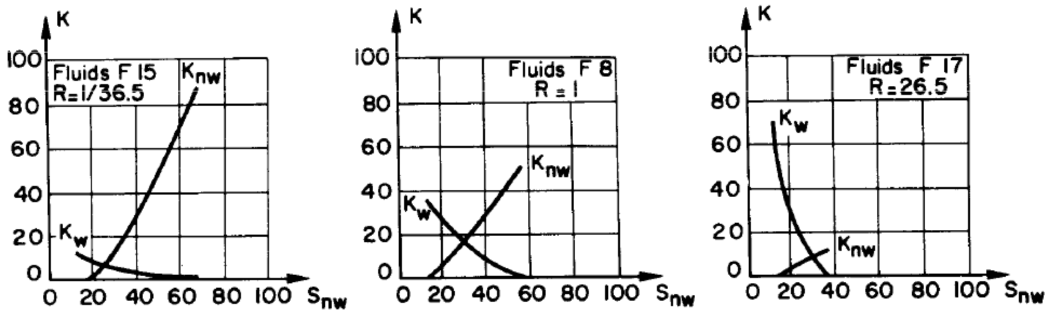
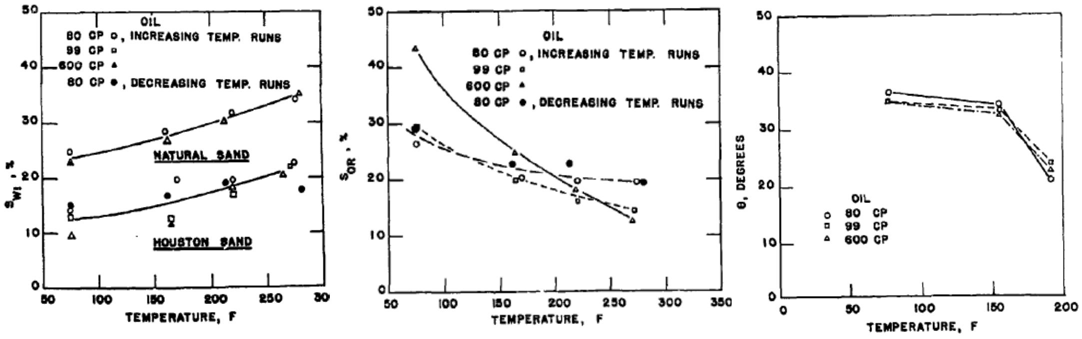


Figure 2. 4 Comparison of relative permeability curves in different viscosity ratios [12]

Poston et al. [13] concluded that irreducible water saturation increased with increasing temperature and residual oil saturation decreased with increasing temperature. Relative permeability curves of oil-water system appeared to be temperature sensitive as both of them generally increase with temperature. Using three refined oil during displacement tests, it was found that surface becomes more water-wet with increment of temperature as shown in Figure 2.4. Effect was indicated by decrease of contact angle for the water-oil-glass system with increase of temperature. This would lead to expectation that both relative permeabilities to oil and to water would increase with temperature for similar system due to reduction of capillary pressure



(a) (b) (c)

Figure 2. 5 Effects of temperature on (a) irreducible water saturation (b) residual oil saturation and (c) contact angle [13]

Nakornthap [14] correlated temperature-dependent relative permeability curves of oil displacement by thermal methods. He concluded that relative permeability can be expressed analytically as functions of water saturation and irreducible water saturation. Moreover, relative permeability can be related to temperature if irreducible water saturation increases with temperature. The use of relative permeability data at higher temperature resulted in fractional-flow curve with higher average water saturation at breakthrough. This was an indication of improved displacement efficiency, leading to higher calculated oil recovery as shown in Figure 2.5.

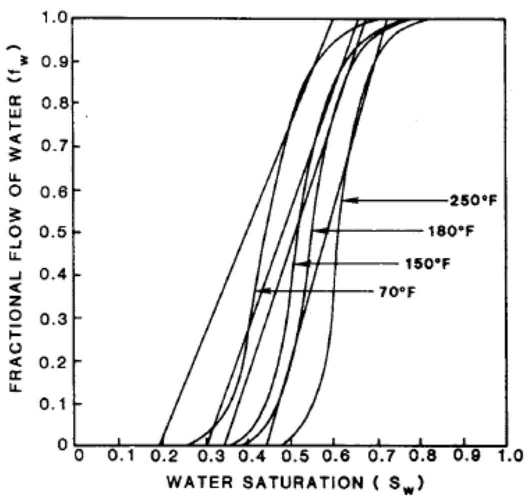


Figure 2. 6 Fractional flow curves showing different average water saturation after flood front at different temperature on sandstone surface [14]

Hing and Mungan [15] studied contact angle measured on flat surface. Results of contact angle measurements on Teflon representing strongly oil-wet surface showed that all three oils readily wet on surface and contact angles were independent from temperature in the test range. Thus, wettability of Teflon systems did not change with temperature as illustrated in Figure 2.6 (a) as same as irreducible water saturation of limestone which was maintained constant compared to sandstone as shown in Figure 2.6 (b) [16].

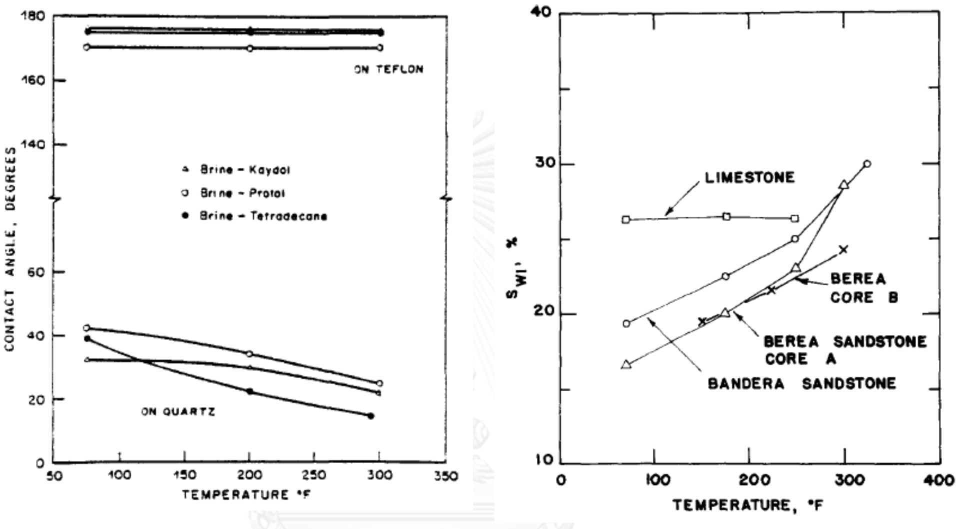


Figure 2. 7 Effects of temperature on (a) contact angle of teflon and quartz [15] and (b) irreducible water saturation of limestone and sandstone [16]

From several previous studies in this section, the change in residual phase saturation is used to generate relative permeability curves in the section of relative permeability curve, (Section 5.4). And as viscosity affects relative permeability curves as well, base case relative permeability curves are modified due to viscosity effect in the section of oil gravity (Section 5.5).

CHAPTER 3
THEORY AND CONCEPT

3.1 Steamflooding

In displacement or flooding process, steam is injected continuously through one or more wells and oil is driven to production wells. Usually wells are placed in regular patterns. Steamflooding is sometimes so-called steam drive. In an inclined reservoir, it is advantageous to drive oil downward, utilizing gravity to keep steam chamber on top and to avoid by-passing of steam in oil zone.

Frequently, other techniques are combined with steam injection such as well stimulation that is generally performed before initiation of steamflooding. When it is desired to produce very viscous oils such as those from oil sands, well stimulation is performed in order to achieve flow communication between injection and production wells.

Typically, steamfloods can recover of about 50% of original oil in place with oil-steam ratio of 0.2. Volume of steam is traditionally measured in terms of volume of equivalent water used to produce steam. One of the most important criteria for a successful steamflooding project is that reservoir should be thicker than 10 ft. Better results tend to be obtained when reservoir thickness is raised. Reason supporting this is that heat losses to overburden and underburden formations are minimized compared to a thinner reservoir.

Typical successful steam drive projects are in relatively shallow, fairly thick reservoirs- e.g., 1,000 to 2,000 ft in depth and 100 ft thick. Usually, these reservoirs consist of unconsolidated or loosely consolidated sand having reasonably high permeability and porosity (e.g., 1 Darcy and 30% porosity) and high oil saturation. It is usual to produce oil by stimulation techniques from both injection and production wells before starting of steamflooding. Stimulation is often continued, even during steam drive mechanism, if temperature of fluids tends to fall. It is also becoming common, as steam flooded fields become depleted, to recover some of remaining oil by waterflooding. In this situation it is still desirable to stimulate producers periodically if temperature at production well tends to fall. Figure 3.1 illustrates the cross section of continuous steamflooding process incorporated with Vogel's approach [17]. The case that Vogel considered was one in which overriding of steam chamber occurs rapidly and production of oil was by gravity drainage, assisted by "steam drag". As production proceeded, the steam chamber thickened. Table 3.1 summarize screening criteria for steamflooding [18].

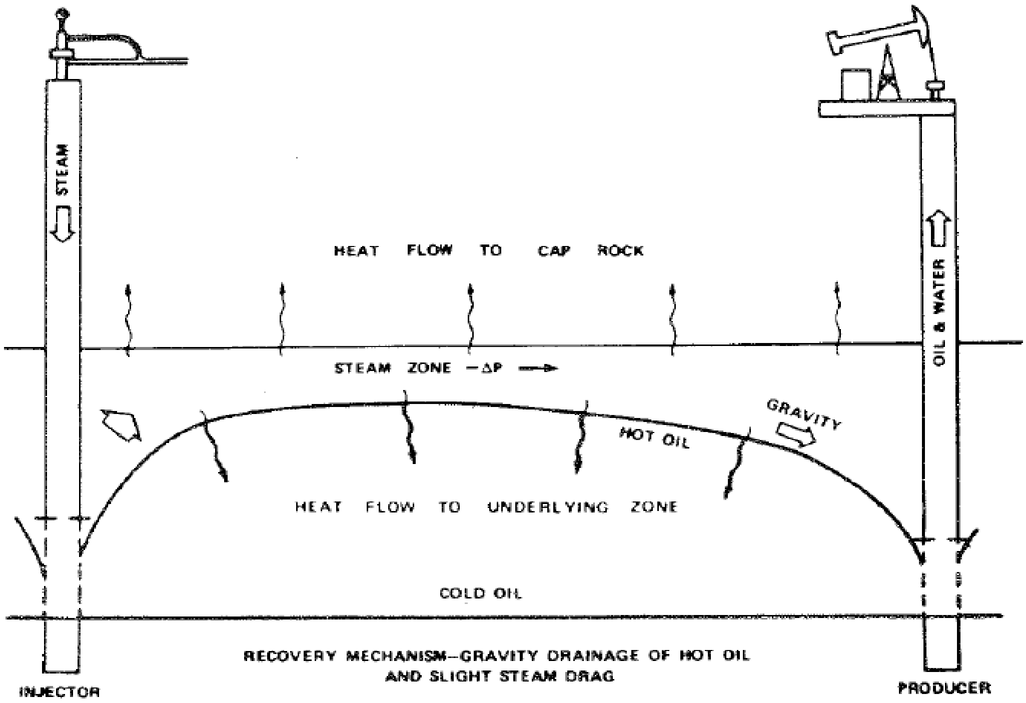


Figure 3. 1 Schematic cross section of continuous steamflooding process [10]

Table 3. 1 Screening criteria for steamflooding process [18]

	ϕS_o	ϕ	S_o	°API	Thickness h(ft)	Depth D(ft)	k(mD)	μ(cp)	kh/μ (mD-ft/cp)
Farouq Ali (1970)	0.15-0.22	0.3		12-15	30	<3,000	~1,000	<1,000	
Geffen (1973)	>0.1			>10	>20	<4,000			>20
Lewin (1976)	>0.065		>0.5	>10	>20	<5,000			>100
Iyoho (1978)	>0.065	>0.3	>0.5	10-20	30-400	2,500-5,000	>1,000	200-1,000	>50
Chu (1985)	>0.08	>0.2	>0.4	<36	>10	>400			

3.2 Temperature Distribution during Steamflooding

Figure 3.2 shows ideal concept of conditions around steam injection well. Temperature in vicinity of injection well is nearly constant and is equal to saturation temperature of injected steam [18]. This temperature prevails to the point where steam starts to condense.

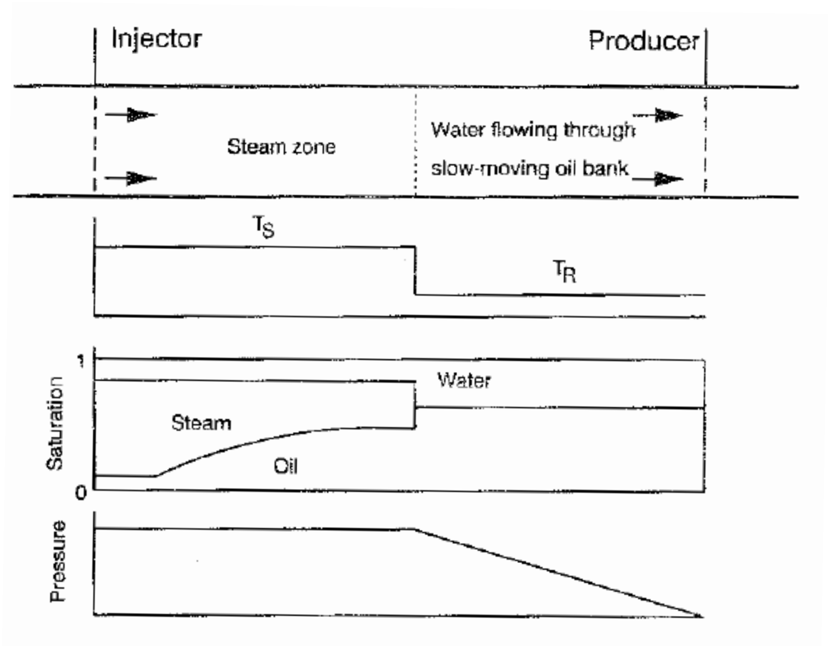


Figure 3. 2 Diagram showing distribution of temperature, pressure and saturations in a hypothetical one-dimensional steamflood [11]

Beyond condensation front, there is a hot-water zone in which temperature falls. Temperature gradient beyond front may be abruptly or slightly changed, depending on reservoir conditions. Much of heat introduced with injected steam is lost to overburden as well as underburden formations through thermal conduction. In Figure 3.2, it is assumed that hot zone is in contact with overburden and underburden formations. In practice, it is possible that conditions making steam zone not to contact with upper or lower limits may exist. A particularly common and important situation is that when steam zone is raised due gravity effects to the top of reservoir, leaving bottom zone untouched by injected steam. Under these conditions, oil below steam zone is being heated but is produced slowly. Potential thermal advantage of having thick reservoir to heat may not be realized. It is a challenge of thermal recovery engineering to design systems to maximize contact of injected steam through thickness of reservoir but in the same time to minimize heat loss due to contact of injected steam with overburden or underburden zones. As elapsed time increases, steam zone expands and area that is being heated above and below increases. As a result, heat losses also increase, and a smaller portion of heat in the injected steam is employed in useful reservoir heating. The heat losses increase up to the point where areal growth becomes limited by interference with the neighboring patterns.

3.3 Well Pattern in Steamflooding

Spacing between injectors and producers is an important factor to determine utilization and efficiency of injected heat. Large spacing results in large contact area with overburden and underburden. For a given flow, it takes longer time to drain oil between injector and producer when spacing is greater.

Design of steamflooding process involves with economic balance between thermal efficiency of close spacing and lower well investment required for a fewer wells involved with larger spacing. Another factor, particularly with tar sands, is difficulty in establishing communication. Sometimes there is also difficulty in maintaining communication, since interconnecting flow paths may tend to be blocked when cold viscous oil drains into them by gravity drainage.

Typical commercial steamflood projects consist of production wells with spacing of two to six acres with either one injection well per one production well (five-spot pattern) or three injection wells per one producer (nine-spot pattern) as shown in Figure 3.3. A feature that is common in many steamflooding projects is the addition of infill wells when fields are getting matured. These infill wells are frequently added when steam breaks through to the producers as a result of gravity override. Infill wells recover by-passed oil which lies below steam zone. When reservoir is inclined it is usually advantageous to inject steam updip in order to take advantage from gravitational force to stabilize displacement front.

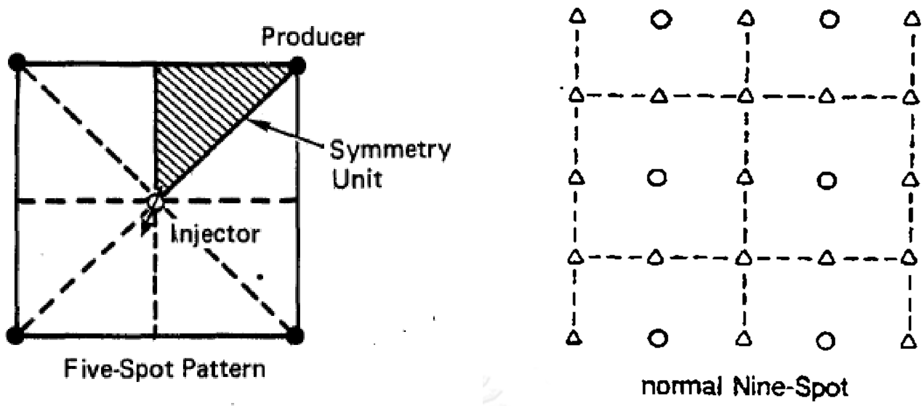


Figure 3. 3 Symmetric pattern elements: five-spot and nine-spot patterns [9]

3.4 Steam Quality

Steam quality or mass percentage of steam mass per total mass of water used to generate steam is one of the most important parameters controlling efficiency of steamflooding process. Intermediate steam quality of 40% has been found to yield the highest thermal efficiency. More heat is required for a given production with steam of lower or higher quality.

Figure 3.4 displays oil saturation profiles obtained from different steam qualities. Higher steam quality results in steam overriding, leaving part of oil untouched by heat below steam zone, whereas using lower steam quality results in underlaying of water, leaving oil un-swept on top of the reservoir. When steam quality is about 40%, this balance of steam volume and fluid viscosity results in the best flood profile, sweeping oil mostly in vertical profile which is an ideal displacement mechanism.

Figure 3.5 illustrates relationship between net heat injected with oil recovery in percentage at different steam quality. It can be seen that, efficiency of moderate steam quality is the highest at the same heat quantity, whereas 100 percent steam quality yields the lowest efficiency in economic point of view.

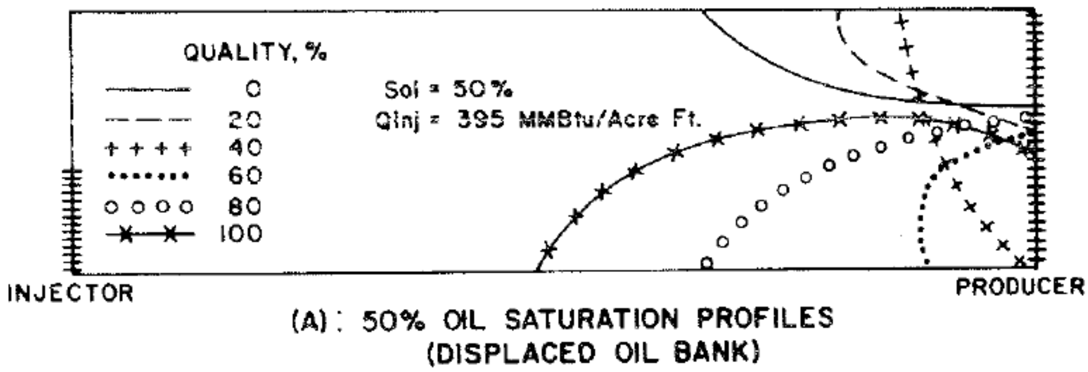


Figure 3. 5 Effect of steam quality on flow regime during displacement mechanism [12]

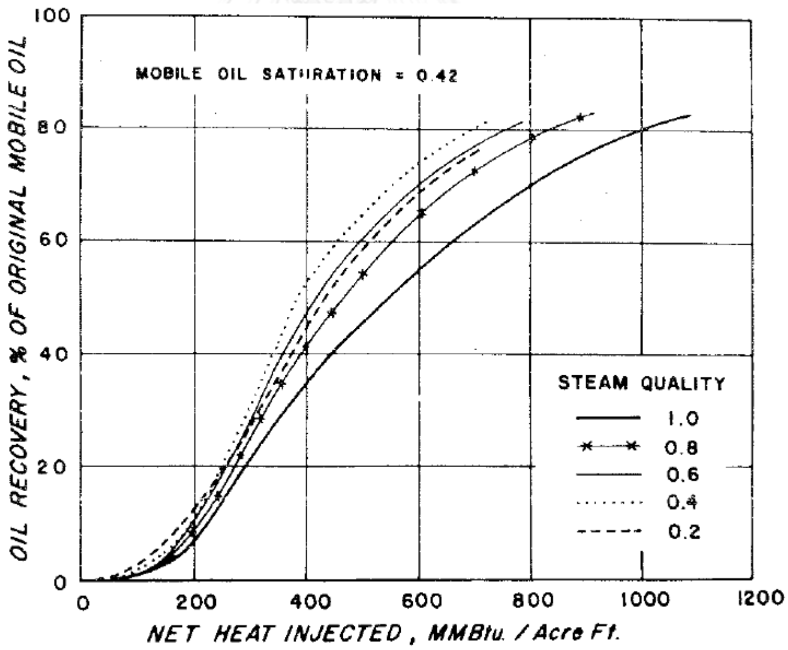


Figure 3. 4 Oil recovery factors as a function of net heat injected for different steam qualities [12]

3.5 Reservoir Heterogeneity

Considering a large-rate displacement through any porous and permeable medium using matched mobility and density, chemically inert, miscible fluids, heterogeneity is a quality of medium causing the flood front, the boundary between displacing phase and displaced phase, to spread as displacement mechanism proceeds. For a homogeneous medium, rate of spreading is zero, whereas when degree of heterogeneity increases, amount of spreading increases. Spreading of flood front can take place both globally and locally. This definition is however, based on flow of fluid. This flow spreading depends not only upon variations in porosity and permeability, but also upon spatial relationships of these variations. However, this does not include influences of gravity, capillarity, and viscosity, whose effects may be altered by heterogeneity but which are not caused solely by properties of the medium.

3.5.1 Lorenz coefficient

Lorenz coefficient (L_c) is one of parameters used to quantify reservoir heterogeneity composing different in properties in vertical direction. A good example that can be quantified by Lorenz coefficient is multilayered reservoir where each layer possesses different value of permeability. This coefficient is obtained from a plot between cumulative flow capacity (F_m) versus cumulative thickness (H_m) where

$$F_m = \frac{\sum_{i=1}^{i=m} k_i h_i}{\sum_{i=1}^{i=n} k_i h_i} \quad (3.1) \text{ and}$$

$$H_m = \frac{\sum_{i=1}^{i=m} h_i}{\sum_{i=1}^{i=n} h_i} \quad (3.2)$$

where F_m = Cumulative flow capacity,

H_m = Cumulative thickness,

m = layer with total layer n,

k = permeability,

h = thickness.

For a reservoir composes of n layers arranged in order of decreasing permeability from top to bottom, $k_{(1)}$ is the layer with thickness $h_{(1)}$ at bottom with smallest value of permeability. The largest permeability is then $k_{(n)}$ located at top layer with thickness of $h_{(n)}$. By definition, cumulative flow capacity and cumulative thickness are in between 0 and 1 and because of ordering layers with permeability, a plot between F_m and H_m determines Lorenz curve with monotonically increment of cumulative data depending on permeability from m=l to m=n with a monotonically decreasing slope. Lorenz coefficient is defined by twice area between the Lorenz curve ABC and diagonal AC, as shown in Figure 3.6 [19]. If the medium is homogeneous, all permeability values are identical and Lorenz curve is the straight line AC. Hence, L_c = 0. Increasing levels of heterogeneity are indicated by changing slope of connecting lines composing Lorenz curve, ABC, away from diagonal AC. L_c is by the way always less than unity. Typical reservoir heterogeneity is in the range of 0.3 to 0.6.

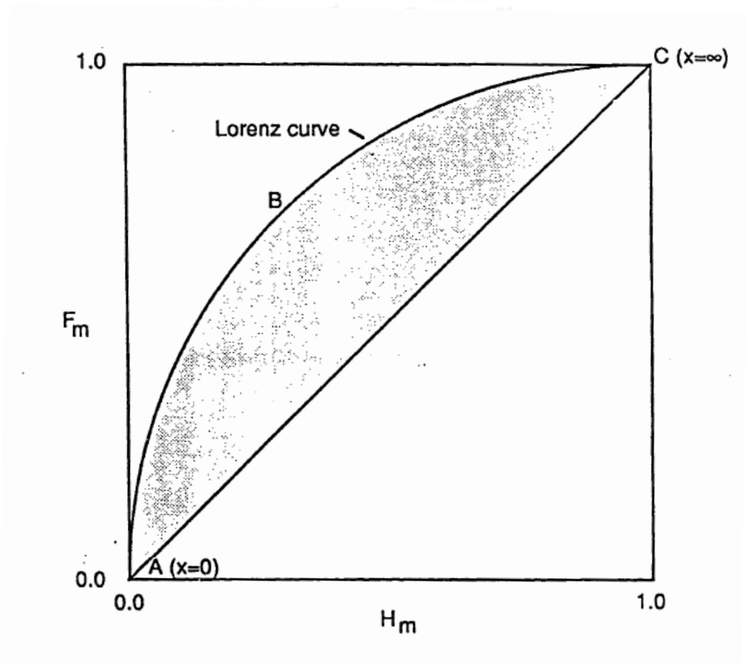


Figure 3. 6 Lorenz curves obtained from a plot between F_m and H_m [13]

3.5.2 Modifications of Lorenz Coefficient

Lorenz coefficient can be modified by including porosity in the calculation. Heterogeneity in terms of capacity is then added in to the form. In place of cumulative thickness, H_m is modified to cumulative storage capacity, C_m which is expressed by:

$$C_m = \frac{\sum_{i=1}^{i=m} \phi_i h_i}{\sum_{i=1}^{i=n} \phi_i h_i} \tag{3.3}$$

where C_m = Cumulative storage capacity,

ϕ_i = Porosity at layer *i*.

L_c is determined by plotting F_m against C_m and is calculated as similar as a plot between F_m and H_m. If porosity is constant, Lorenz curve remains unaltered compared to the previously mentioned method (plot between F_m and H_m). Again, data must be ordered according to the ratio of k/ϕ. The inclusion of porosity variations will not substantially increase L_c.

3.5.3 Estimation of the Lorenz Coefficient

Estimation of L_c requires evaluating of area between the Lorenz curve and the diagonal line from coordinate (0,0) to (1,1) of (H_m,F_m). This is easily accomplished by using a simple algorithm such as trapezoidal rule or Simpson's rule. Another approach is to use the relationship between L_c and Gini's coefficient of concentration, *G*.

$$\hat{L}_c = \frac{1}{2n} \frac{\sum_{i=1}^{n} \sum_{j=1}^{n} \left| k_i - k_j \right|}{\sum_{i=1}^{n} k_i} \tag{3.4}$$

where *G* is Gini's coefficient of concentration equal to the right hand side of equation.

3.6 Petrophysical Properties Related to Steamflooding

As reservoir is heated, petrophysical properties of rock change. Relative permeability is the term that is mostly affected and might show the highest change to result. Changing of relative permeability by means of increasing temperature is generally positive, that is changing toward favorable conditions for oil production that is more water-wet condition. At elevated temperature, adsorbed and precipitated materials onto rock surface, causing unfavorable conditions for oil production, is desorbed, leaving the surface clean and turning to water-wet state. Details of relative permeability are described in the following subsection.

3.6.1 Relative Permeability

Relative permeability is a dimensionless flow ability of a fluid when more than one immiscible fluid is presented, plotted as a function of one fluid saturation. Relative permeability is among the most important parameters to estimate efficiency of flow of reservoir fluids as well as production efficiency.

Absolute permeability measurements are performed by using single fluid filling in pore space. However, this value represents total flow ability value when there is just one fluid in the reservoir such as water zone. When two phases are presented in porous medium, total flow ability from absolute permeability is reduced by trapping effect. This causes the summation of permeability of each phase to be less than total flow ability. Relative permeability is mathematically expressed by permeability of a fluid when another immiscible fluid is presented (effective permeability) divided by base permeability. Therefore, relative permeability to oil (k_{ro}), water (k_{rw}),, and gas k_{rg}, are defined as

$$k_{ro} = \frac{k_o}{k} = \frac{\text{effective permeability to oil}}{\text{base permeability}} \qquad (3.5),$$

$$k_{rw} = \frac{k_w}{k} = \frac{\text{effective permeability to water}}{\text{base permeability}} \quad (3.6)\text{, and}$$

$$k_{rg} = \frac{k_g}{k} = \frac{\text{effective permeability to gas}}{\text{base permeability}} \quad (3.7).$$

Choice of base permeability is not, in itself, critical provided it is consistently applied. Conversion from one base to another is a matter of simple arithmetic. However, experimentally, the base permeability is usually chosen as permeability measured at the beginning of an experiment. For example, an experiment may start by measuring permeability to oil with a presence of irreducible water saturation in the core. Water is then injected into the core, and effective permeabilities to oil and water are measured as water displaces oil in the core. The base permeability chosen here would most commonly be the initial permeability to oil at irreducible water saturation (S_{wi}).

Effective permeabilities thus measured over a range of fluid saturations enable relative permeability curves to be constructed. Figure 3.7 [20] shows an example of relative permeability curves from an unsteady state waterflood experiment. At the beginning of the experiment, core is saturated with 80% oil, and there is an irreducible water saturation of 20% due to nature of water-wet rock. Point A represents relative permeability to oil at these conditions. Note that this value is equal to unity because effective permeability to oil has been taken as the base permeability. Point B represents the beginning of permeability to water. Note that it is equal to zero because irreducible water is, by definition, immobile. Water is then injected into the core at one end at a constant rate. Volume of fluids is measured at another end of core, and the differential pressure across the core is also measured. During this process permeability to oil reduces to zero along the curve ACD, and permeability to water increases along the curve BCE. There is no further production of oil from the sample after k_{ro} is zero at point D, and so point D occurs at the residual oil saturation, S_{or}. Since there is the effect of trapping, summation of k_{ro} and k_{rw} is always less than one at any saturation.

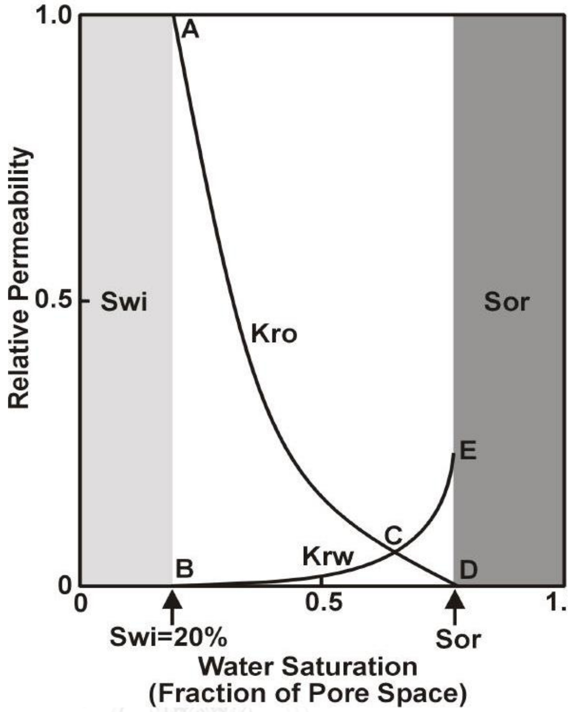
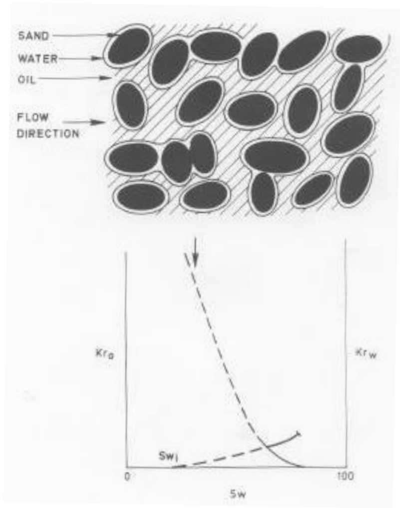


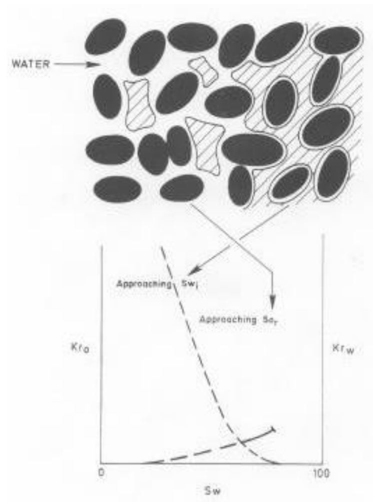
Figure 3. 7 Typical relative permeability curves composing of relative permeabilities to oil and water plotted over water saturation [19]

3.6.2 Wetting Systems

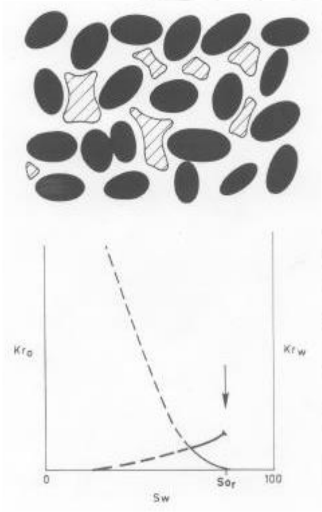
The following sequence occurs as water migrates in to the rock. Water-wet data are characterized by 1) limited oil production after water breakthrough, 2) generally good recoveries, 3) low k_{rw} value at S_{or}. Figures 3.8a to d illustrate important steps occurred in water-wet rock: a) initially at S_{wi}, water is the wetting phase and will not flow (k_{ro}= 1 and k_{rw}= 0); b) water migrates in a piston-like mode, displacing most of the oil ahead of it; c) as water saturation increases oil flow tends to cease abruptly and S_{or} is reached; and d) increasing water flow rate has very small effect on oil production or k_{rw} due to capillary forces providing most of energy required for displacing of oil.



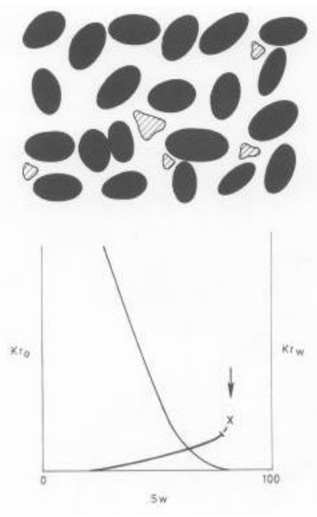
(a)



(b)



(c)



(d)

Figure 3. 8 Relative permeability curves of water-wet system at different important steps of experiment [19]

Consider water entering in an oil-wet pore system containing (typically) very low water saturations, sequence of events starts from S_{wi} illustrated in Figures 3.9a and b. If waterfloods in oil-wet core are carried out at very low flow rate, there may be inappropriate retention of oil at outlet face of the test plug. This is illustrated in Figure 3.9d. At the end of a low rate flood, k_{rw} and the amount of oil produced are relatively low. If the flow rate (and hence the pressure differential) are increased at this stage, substantial further oil production occurs and k_{rw} increases significantly. This situation does not model processes occurring in the reservoir and should be avoided by appropriate choice of waterflood rate at the beginning of the experiment.

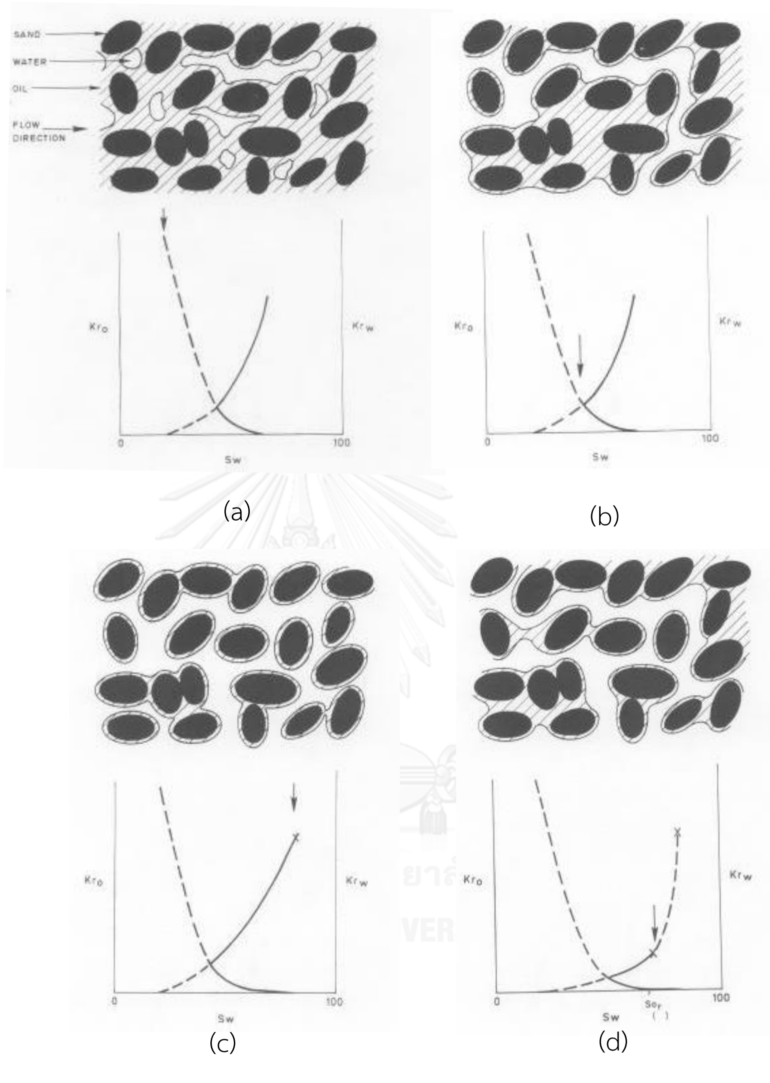


Figure 3. 9 Relative permeability curves of oil-wet system at different important steps of experiment [19]

From Figures 3.9a to d, displacement mechanism in oil-wet system can be explained through the following process: a) capillary pressure indicates that an applied differential pressure is required before water will enter the largest pore; b) water flows through the largest flow channels first, k_{ro} falls whereas k_{rw} rises up rapidly; c) after large volume of water have flowed through the system, S_{or} is reached and this equilibrium is attained slowly, giving the characteristic prolonged slow production of oil after early water breakthrough; and d) micro-saturation and waterflood relative permeability curve for a low rate oil-wet system at S_{or} where a bump is incorporate.

3.6.3 Corey's Correlation

Relative permeability curves are preferentially obtained from special core analysis but this could take times. Several correlations are used to generate relative permeability curves in order to reduce times. For oil-water relative permeability system, Corey's correlation is widely used in reservoir simulation. In the use of Corey's correlation, relative permeabilities to oil and water are calculated by following equations:

$$k_{ro}(S_w)=k_{ro@S_{wmin}}\left[\frac{S_{wmax}-S_{orw}-S_w}{S_{wmax}-S_{orw}-S_{wi}}\right]^{C_o} \tag{3.8}$$

$$k_{rw}(S_w)=k_{rw@S_{orw}}\left[\frac{S_w-S_{wcr}}{S_{wmax}-S_{orw}-S_{wcr}}\right]^{C_w} \tag{3.9}$$

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 3.10 illustrates additional details of relative permeability curves generated from Corey's exponent. In the figure, it shows location of minimum water saturation or irreducible water saturation and critical water saturation which is higher than irreducible water saturation. This means that, prior to a flow of water in the reservoir injected water has to accumulate for while to reach this critical water saturation before it could further propagate into the next pore location.

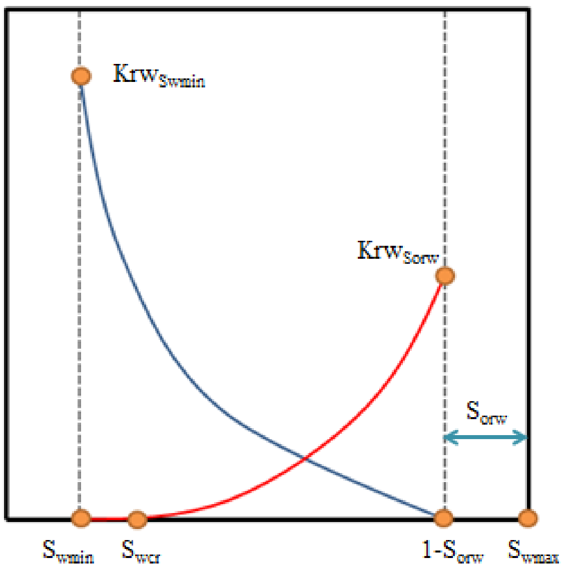


Figure 3. 10 Schematic of parameters used in Corey's correlation

According to the equation 3.8 and 3.9, Corey's correlation calculates the 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, the Corey's correlation for gas-water system is similar to oil-water system mentioned above. In this study, Corey's exponent of 2.0 is used as base value and S_{wcr} is assumed to be equal to S_{wmin}.

3.6.4 Effect of Temperature on Petrophysical Properties

The errors occur in well log analysis and formation evaluation due to the common practice of neglecting temperature effects on the rock properties. The generalizations of the effect from temperature on petrophysical properties are summarized below [21] ;

1) No definite result is known of the temperature on porosity, ϕ. Bulk volume increase slightly ($<$1%) with temperature increase up to 400 °F.
2) Pore volume compressibility, c_f increase significantly (average 21%) as temperature is increased to 400 °F.
3) Absolute permeability, k, decrease sharply with increasing of temperature.
4) Increase in relative permeability to oil, k_{ro}, as temperature increases is observed.
5) Residual oil saturation, S_{or}, decreases and irreducible water saturation, S_{wi}, increases with temperature.
6) Hysteresis loop between drainage and imbibition capillary pressure curves decreases with temperature.
7) Formation resistivity factor, F, probably increases with temperature in common. Assuming negligible temperature effect on porosity, the cementation factor, m, increases with temperature.
8) The relationship between resistivity index, I, and water saturation, S_w, at high temperatures is linear on a log-log plot (the correlation proposed by Archie) although resistivity index at a particular saturation and the saturation exponent, n, are temperature sensitive.

CHAPTER 4
RESERVOIR SIMULATION MODEL AND METHODOLOGY

Details of reservoir model in this study are described in this chapter. First, homogeneous model and heterogeneous models with various degrees of heterogeneity are constructed. Afterwards, a numerical reservoir simulator is used to evaluate performance of steam injection by using thermal and advanced processes reservoir simulator called **STARS®**. Details of methodology are also described in this section. Important input keywords for reservoir simulation model are summarized in the Appendix.

4.1 Reservoir Model

Initially, reservoir dimensions of 165, 165 and 100 ft in x-, y- and z-direction are chosen based on several literature reviews as these data strongly affect optimization process [10]. Numbers of grid block in each direction are 30, 30, and 10 in x-, y-, and z- directions, respectively. Total number of grid block is 9,000. This is still under limitation of educational license. Total area of model is 0.52 acre with thickness of 100 ft. Since injection and production wells are located in model based on quarter five-spot pattern, this results in well spacing of 233 ft which is diagonal of model. Figure 1 illustrates dimensions of reservoir together with locations of injection and production wells.

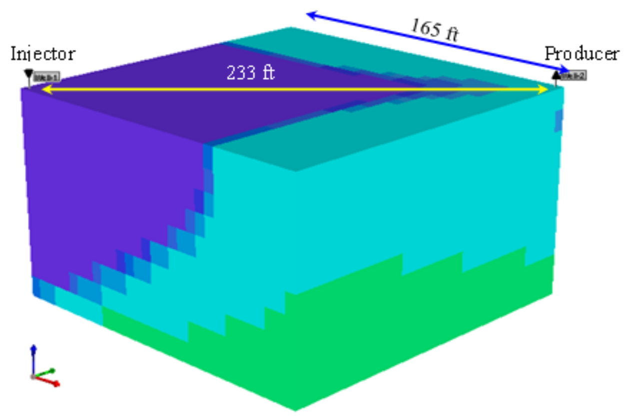


Figure 4. 1 Location of injection and production wells in base case reservoir model, representing quarter 5-spot pattern

First, homogeneous model with permeability of 500 mD is constructed and simulated with waterflooding process. After that, heterogeneous reservoirs are constructed, using Lorenz coefficient to quantify degree of heterogeneity degree. Reservoir properties required for construction of physical reservoir model are listed in Table 4.1. However, variation of reservoir heterogeneity is concerned in this study. Thus, different models are constructed to have five different Lorenz coefficients which are 0.254, 0.310, 0.352, 0.403 and 0.438. Details of permeability values of each heterogeneous model are also shown in this chapter.

Table 4. 1 Reservoir properties required for construction of physical reservoir model

Parameters	Values	Unit
Grid dimension	30×30×10	Block
Grid size	5.5×5.5×10	ft
Porosity (ϕ)	30	%
Horizontal permeability (k_h)	Varied in each layer	mD
Vertical permeability (k_v)	$0.1 \times k_h$	mD
Average permeability	500	mD
Maximum permeability	1,000	mD
Minimum permeability	50	mD
Median of permeability data	500	mD
Datum depth	1,000	ft
Reservoir thickness	100	ft
Initial pressure at datum depth	430	psia
Reservoir temperature	74.3	°F

For base case model, simulation of steamflooding is performed in heterogeneous model with middle value of Lorenz coefficient which is 0.352. As steamflooding process is favorable in shallow reservoir, reservoir model is constructed with top layer fixed at depth of 900 ft. This shallow depth corresponds to initial reservoir pressure of about 387 psi at the top of reservoir based on pressure gradient of 0.432 psi/ft. Maximum bottomhole pressure is limited for injection process to prevent undesired fracture. Calculated maximum bottomhole pressure is 520 psi based on Ben and Eaton's equation. As reservoir is located at very shallow depth, average permeability can be as high as 500 millidarcies. However, reservoir is heterogeneous with variation of maximum permeability at top layer of 1,000 millidarcies and minimum value of 50 millidarcies. This variation of permeability represents coarsening upward sequence.

4.2 Reservoir Model with Heterogeneity

Lorenz coefficient (L_c) is used to quantify heterogeneity of reservoir models in this study. This coefficient is obtained from a plot between cumulative flow capacity (F_m) versus cumulative storage capacity (C_m) where

$$F_m = \frac{\sum_{i=1}^{i=m} k_i h_i}{\sum_{i=1}^{i=n} k_i h_i} \quad \text{(4.1) and}$$

$$C_m = \frac{\sum_{i=1}^{i=m} \phi_i h_i}{\sum_{i=1}^{i=n} \phi_i h_i} \quad \text{(4.2)}$$

where F_m = cumulative flow capacity,

C_m = cumulative storage capacity,

ϕ_i = porosity at layer i.

m = layer with total layer n,

k = permeability,

h = thickness.

In order to calculate Lorenz coefficient of heterogeneous reservoirs, a plot between F_m and C_m is constructed and Lorenz coefficient is defined by twice area between Lorenz curve and triangle beneath diagonal line as shown in Figure 4.2. Values of permeability in each heterogeneity degree are summarized in the following Tables.

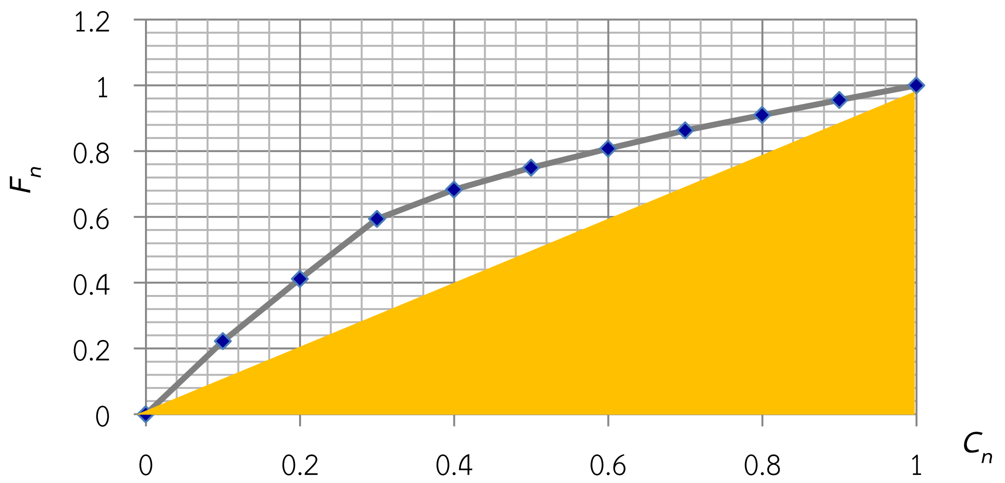


Figure 4. 2 A plot between F_m and C_m illustrating Lorenz coefficient line and area under diagonal line

Table 4. 2 Permeability values of heterogeneous reservoir with L_c of 0.254

Layer	k	h	kh	$h\phi$	cum. kh	cum. $h\phi$	$C_n(x)$	$F_n(x)$	Area
1	1,000	10	10,000	3	10,000	3	0.1	0.20	0.0100
2	630	10	6,300	3	16,300	6	0.2	0.33	0.0263
3	620	10	6,200	3	22,500	9	0.3	0.45	0.0388
4	610	10	6,100	3	28,600	12	0.4	0.57	0.0511
5	600	10	6,000	3	34,600	15	0.5	0.69	0.0632
6	400	10	4,000	3	38,600	18	0.6	0.77	0.0732
7	380	10	3,800	3	42,400	21	0.7	0.85	0.0810
8	360	10	3,600	3	46,000	24	0.8	0.92	0.0884
9	350	10	3,500	3	49,500	27	0.9	0.99	0.0955
10	50	10	500	3	50,000	30	1.0	1.00	0.0995

Table 4. 3 Permeability values of heterogeneous reservoir with L_c of 0.310

Layer	*k*	*h*	*kh*	*hϕ*	*cum. kh*	*cum. hϕ*	$C_n(x)$	$F_n(x)$	Area
1	1,000	10	10,000	3	10,000	3	0.1	0.20	0.0100
2	750	10	7,500	3	17,500	6	0.2	0.35	0.0275
3	700	10	7,000	3	24,500	9	0.3	0.49	0.0420
4	650	10	6,500	3	31,000	12	0.4	0.62	0.0555
5	600	10	6,000	3	37,000	15	0.5	0.74	0.0680
6	400	10	4,000	3	41,000	18	0.6	0.82	0.0780
7	380	10	3,800	3	44,800	21	0.7	0.90	0.0858
8	250	10	2,500	3	47,300	24	0.8	0.95	0.0921
9	220	10	2,200	3	49,500	27	0.9	0.99	0.0968
10	50	10	500	3	50,000	30	1.0	1	0.0995

Table 4. 4 Permeability values of heterogeneous reservoir with L_c of 0.352

Layer	*k*	*h*	*kh*	*hϕ*	*cum. kh*	*cum. hϕ*	$C_n(x)$	$F_n(x)$	Area
1	1,000	10	10,000	3	10,000	3	0.1	0.20	0.0100
2	820	10	8,200	3	18,200	6	0.2	0.36	0.0282
3	780	10	7,800	3	26,000	9	0.3	0.52	0.0442
4	700	10	7,000	3	33,000	12	0.4	0.66	0.0590
5	600	10	6,000	3	39,000	15	0.5	0.78	0.0720
6	400	10	4,000	3	43,000	18	0.6	0.86	0.0820
7	300	10	3,000	3	46,000	21	0.7	0.92	0.0890
8	220	10	2,200	3	48,200	24	0.8	0.97	0.0942
9	130	10	1,300	3	49,500	27	0.9	0.99	0.0977
10	50	10	500	3	50,000	30	1.0	1.00	0.0995

Table 4. 5 Permeability values of heterogeneous reservoir with L_c of 0.403

Layer	k	h	kh	$h\phi$	*cum. kh*	*cum.* $h\phi$	$C_n(x)$	$F_n(x)$	Area
1	1,000	10	10,000	3	10,000	3	0.1	0.20	0.0100
2	980	10	9,800	3	19,800	6	0.2	0.40	0.0298
3	850	10	8,500	3	28,300	9	0.3	0.57	0.0481
4	700	10	7,000	3	35,300	12	0.4	0.71	0.0636
5	600	10	6,000	3	41,300	15	0.5	0.83	0.0766
6	400	10	4,000	3	45,300	18	0.6	0.91	0.0866
7	220	10	2,200	3	47,500	21	0.7	0.95	0.0928
8	120	10	1,200	3	48,700	24	0.8	0.97	0.0962
9	80	10	800	3	49,500	27	0.9	0.99	0.0982
10	50	10	500	3	50,000	30	1.0	1.00	0.0995

Table 4. 6 Permeability values of heterogeneous reservoir with L_c of 0.438

Layer	k	h	kh	$h\phi$	*cum. kh*	*cum.* $h\phi$	$C_n(x)$	$F_n(x)$	Area
1	1,000	10	10,000	3	10,000	3	0.1	0.20	0.0100
2	990	10	9,900	3	19,900	6	0.2	0.40	0.0299
3	980	10	9,800	3	29,700	9	0.3	0.60	0.0496
4	770	10	7,700	3	37,400	12	0.4	0.75	0.0671
5	600	10	6,000	3	43,400	15	0.5	0.87	0.0808
6	400	10	4,000	3	47,400	18	0.6	0.95	0.0908
7	80	10	800	3	48200	21	0.7	0.96	0.0956
8	70	10	700	3	48,900	24	0.8	0.98	0.0971
9	60	10	600	3	49,500	27	0.9	0.99	0.0984
10	50	10	500	3	50,000	30	1.0	1.00	0.0995

4.3 Pressure-Volume-Temperature (PVT) Properties

Pressure-Volume-Temperature (PVT) properties of reservoir fluids are specified by using several correlations. In order to study effect of oil gravity, variation of oil API gravity values from the base value of 14 °API is included in this study. Chosen values are 7.3, 11, 14 and 19.5 °API. Figures 4.3 to 4.7 demonstrate gas and oil PVT properties including dry gas formation volume factor (B_g), oil formation volume factor (B_o), oil viscosity (μ_o) as functions of pressure and temperature, and gas-oil ratio (R_s) for the base case model with oil gravity of 14 °API. Properties of oil with various oil gravities are illustrated in Appendix. Inputs for oil properties in component section such as solution gas-oil ratio, oil viscosity and bubble point pressure are taken from PVT literature of heavy oil and extra heavy oil [22] summarized in Table 4.7.

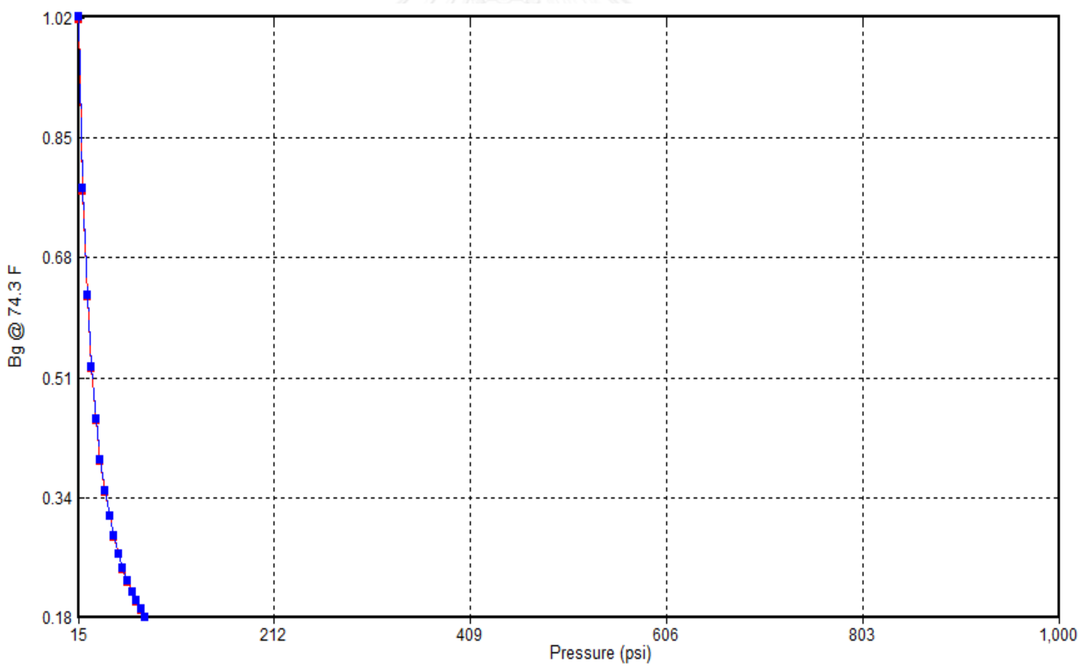


Figure 4. 3 Dry gas formation volume factor (B_g) for base case model as a function of reservoir pressure

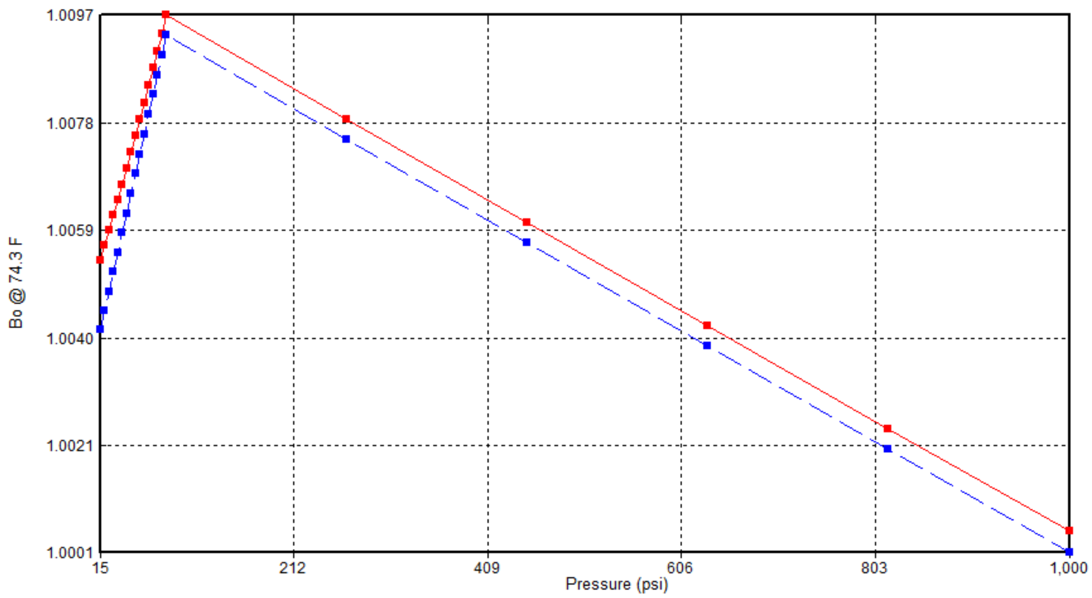


Figure 4. 4 Oil formation volume factor (B_o) for base case model as a function of reservoir pressure

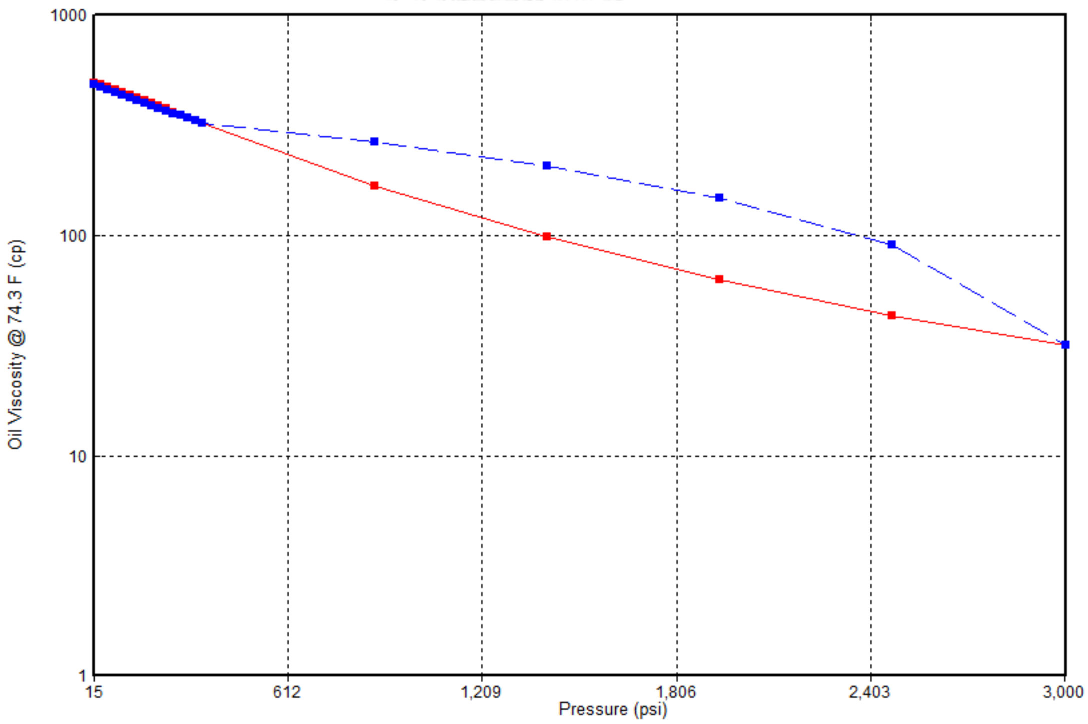


Figure 4. 5 Oil viscosity (μ_o) for base case model as a function of reservoir pressure

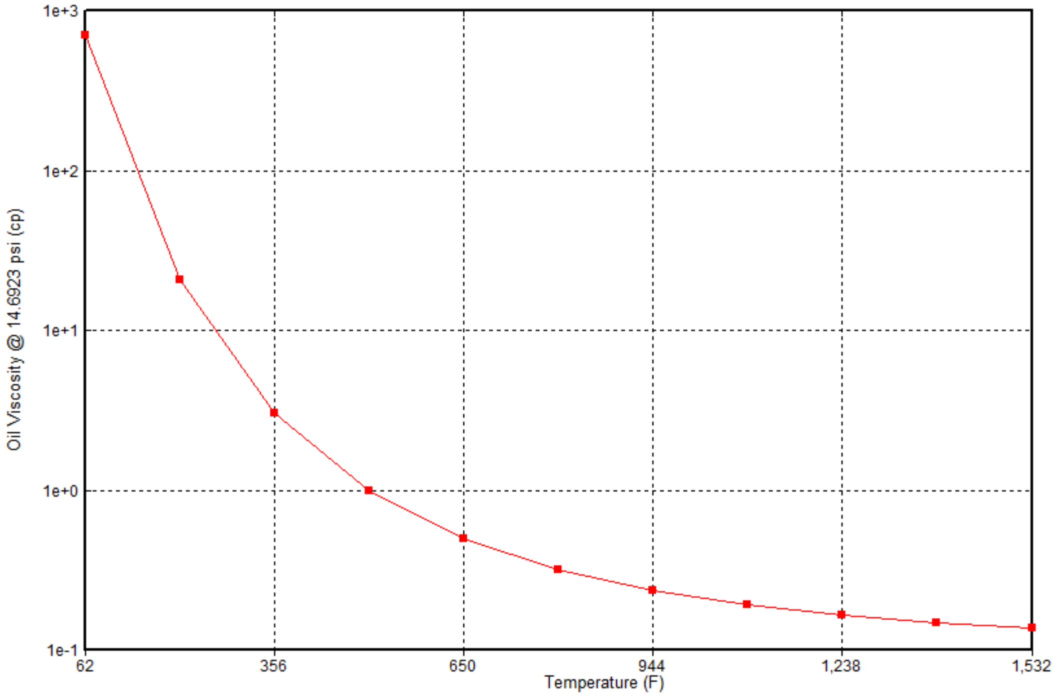


Figure 4. 6 Oil viscosity (μ_o) for base case model as a function of reservoir temperature

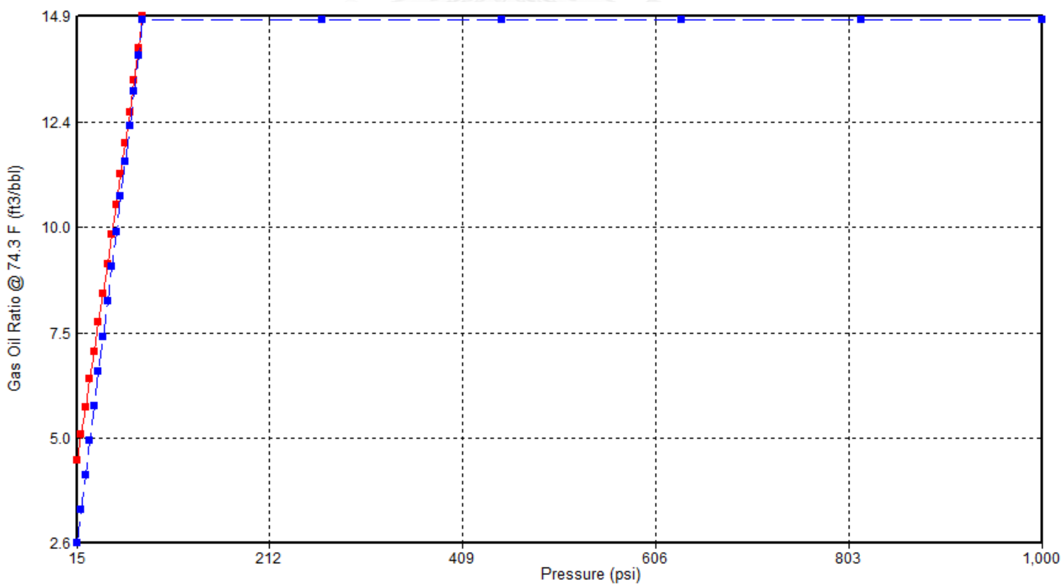


Figure 4. 7 Gas-oil ratio (R_s) for base case model as a function of reservoir pressure

Table 4. 7 Summary of inputs to generate oils with different oil gravities [22]

Oil gravity (°API)	Bubble point pressure (psi)	Solution Gas-Oil Ratio (scf/STB)	Oil viscosity (cP)
7.3	42.15	4.39	25,785.50
11	86.01	11.05	3,601.19
14	96.06	14.88	970.59
19.5	164.13	30.15	150.33

4.4 Special Core Analysis (SCAL) Section

End-point data are used to generate water/oil and gas/oil relative permeability curves, using Corey's correlation equipped within STAR simulator. Simulation of steamflooding process is relied on interpolation between relative permeability curves of original state of rock-fluid and steamflooded state. Figures 4.8 and 4.9 illustrate oil/water and gas/liquid relative permeability systems, respectively which are at normal state of rock or pre-injection of steam (reservoir temperature). Figures 4.10 and 4.11 depict relative permeability curves, comparing between pre-injection of steam and after steamflooding for both oil-water and gas/liquid systems, respectively. Tables 4.8 and 4.9 summarize values of relative permeability in water/oil and gas/liquid systems at different saturations, respectively. Additionally, Table 4.10 summarizes required end-point values to construct relative permeability curves for both oil-water and gas-liquid system. Relative permeability curves of all cases representing different wetting conditions are illustrated in Figure 4.12. Corresponding data required for constructing these relative permeability curves are summarized in Table 4.11.

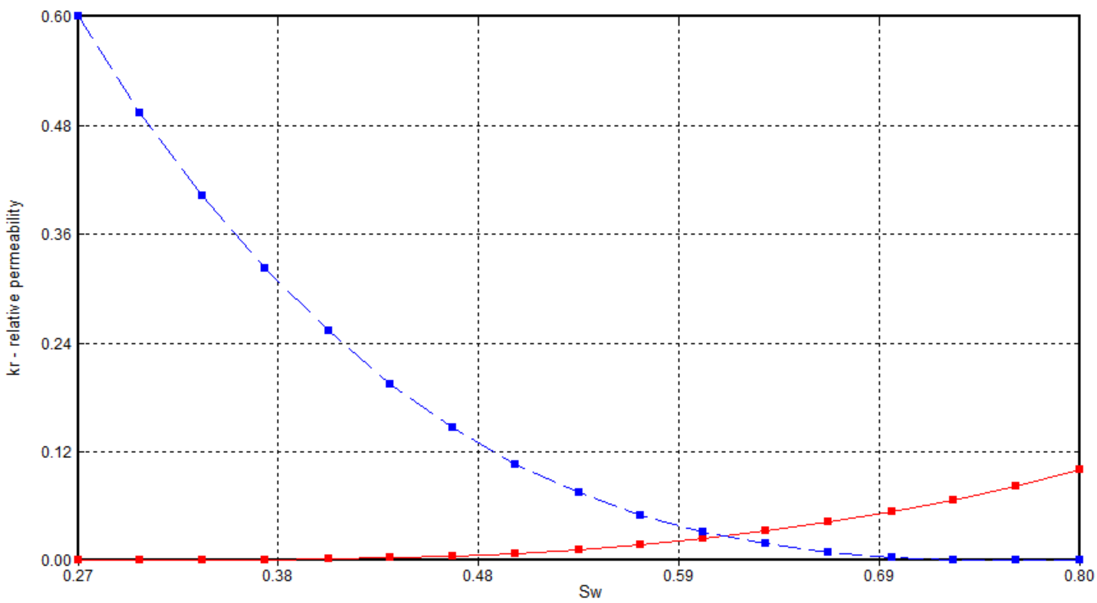


Figure 4. 8 Relative permeability curves of oil/water system for base case model as a function of water saturation

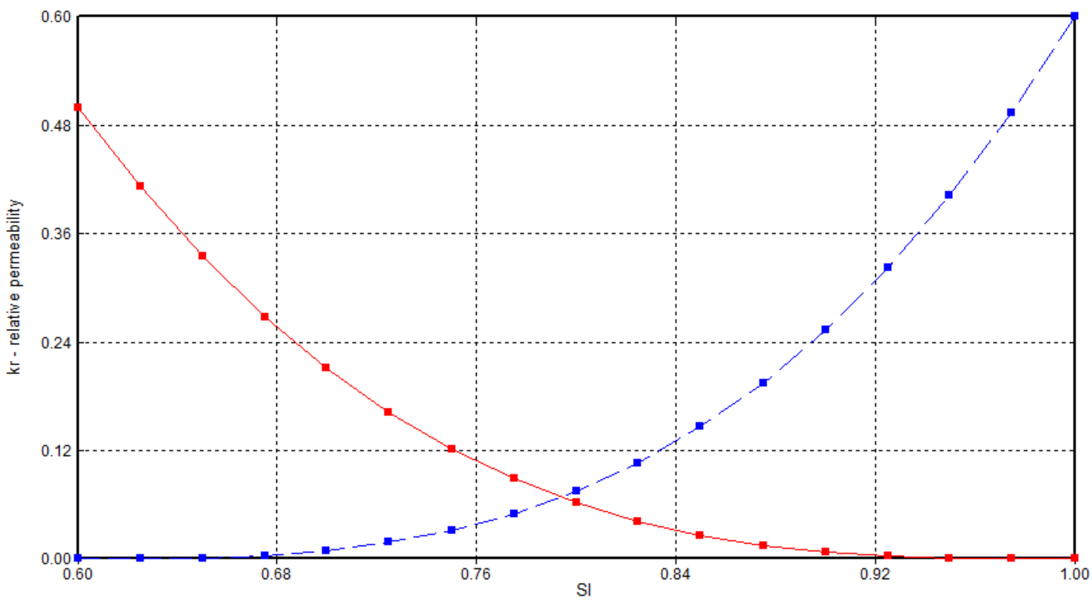


Figure 4. 9 Relative permeability curves of gas/liquid system for base case model as a function of liquid saturation

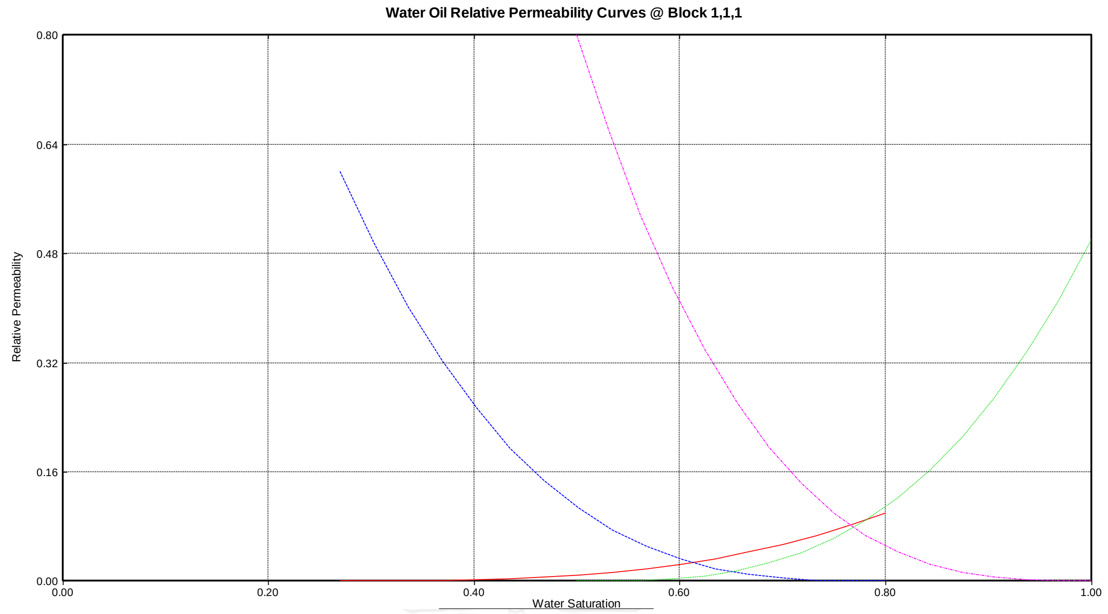


Figure 4. 10 Relative permeability curves of oil/water system before and after steamflooding as a function of water saturation

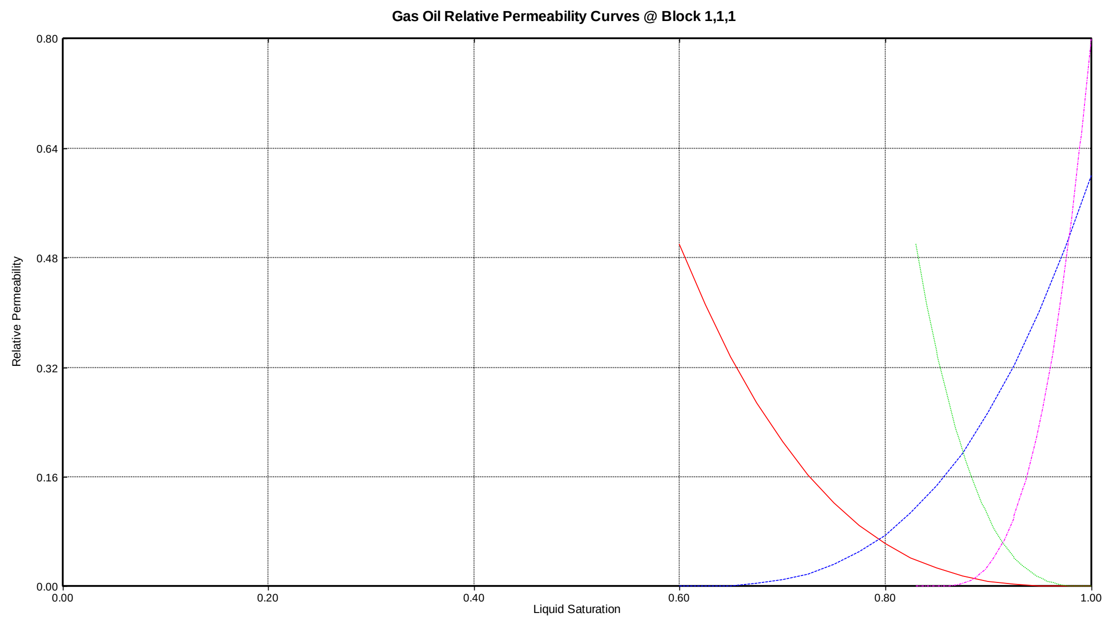


Figure 4. 11 Relative permeability curves of gas/liquid system before and after steamflooding as a function of liquid saturation

Table 4. 8 Relative permeability to water and to oil of base case model at different water saturation

S_w	k_{rw}	k_{ro}
0.270	0	0.600
0.303	2.44×10^{-5}	0.494
0.336	1.95×10^{-4}	0.402
0.369	6.59×10^{-4}	0.322
0.403	0.002	0.253
0.436	0.003	0.195
0.469	0.005	0.146
0.502	0.008	0.107
0.535	0.013	0.075
0.568	0.018	0.050
0.601	0.024	0.032
0.634	0.032	0.018
0.668	0.042	0.009
0.701	0.054	0.004
0.734	0.067	0.001
0.767	0.082	1.46×10^{-4}
0.800	0.100	0

Table 4. 9 Relative permeability to gas and to liquid of base case model at different liquid saturation

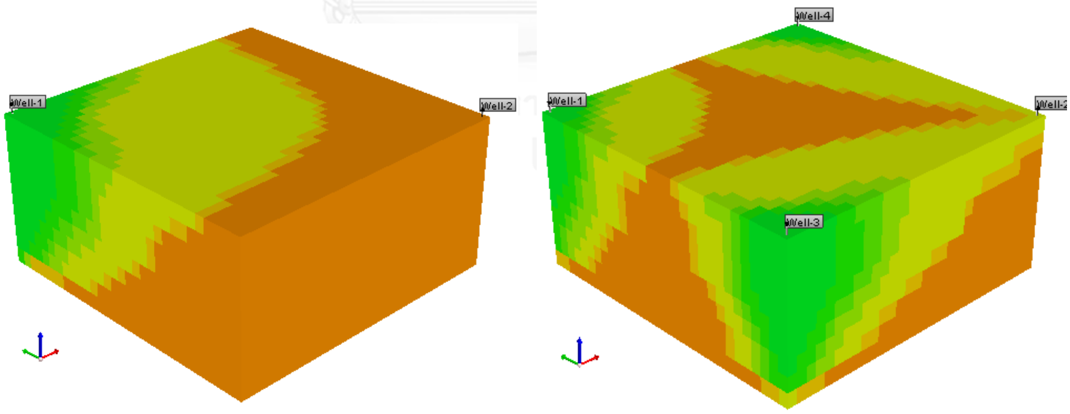
S_l	k_{rg}	k_{rl}
0.600	0.500	0
0.625	0.412	1.46×10^{-4}
0.650	0.335	0.001
0.675	0.268	0.004
0.700	0.211	0.009
0.725	0.162	0.018
0.750	0.122	0.032
0.775	0.089	0.050
0.800	0.063	0.075
0.825	0.042	0.107
0.850	0.026	0.146
0.875	0.015	0.195
0.900	0.008	0.253
0.925	0.003	0.322
0.950	9.77×10^{-4}	0.402
0.975	1.22×10^{-4}	0.494
1.000	0	0.600

Table 4. 10 End-point data and inputs required for construction of relative permeability curves of base case model

Description	Value
SWCON - Endpoint Saturation: Connate Water	0.27
SWCRIT - Endpoint Saturation: Critical Water	0.27
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.2
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.2
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0.33
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.33
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0
KROCW - k_{ro} at Connate Water	0.6
KRWIRO - k_{rw} at Irreducible Oil	0.1
KRGCL - k_{rg} at Connate Liquid	0.5
KROGCG - k_{rog} at Connate Gas	
Exponent for calculating k_{rw} from KRWIRO	3
Exponent for calculating k_{row} from KROCW	3
Exponent for calculating k_{rog} from KROGCG	3
Exponent for calculating k_{rg} from KRGCL	3

4.5 Parameters Related to Injection and Production Wells

Wellbore radius of both injection and production well in this study is 0.28 ft and skin factor is assumed to be zero. All wells are fully-perforated along the reservoir thickness. The injection pattern in base case model is quarter 5-spot with one injector and one producer aligning diagonally to each other. Steam injection rate is determined in a unit of STB/D in equivalent liquid volume. Optimum injection rate is identified together with variation of steam quality. Optimum values of steam injection rate and steam quality are utilized for the entire study. Additional study of more injection well is performed by changing flood pattern. In order to keep this injection pattern comparable to 5-spot, three injection wells and one production well are located at every corner of the model and total injection rate in quarter 9-spot well pattern is kept the same. Figure 4.12a and b illustrate well location for one injection well and three injection wells. Production constraints and economic limits are listed in Tables 4.11 and 4.12 for injection and production wells, respectively. The field is planned to produce for 30 years which is based on ordinary concession period of Thailand.



(a) (b)

Figure 4. 12 Injection and production wells locations of a) single injection well (well1 = injector and well2 = producer) and b) three injection wells (well1, 3, 4 = injectors and well2 = producer)

Table 4. 11 Constraints of injection well

Parameter	Value	Unit
Maximum bottomhole pressure	520	psi
Target injection rate	varied	STB/D
Steam temperature	400	°F

Table 4. 12 Constraints of production well

Parameter	Value	Unit
Minimum bottomhole pressure	200	psi
Maximum oil rate	80	STB/D
Maximum water cut	95	%

4.6 Methodology

1. Construct homogeneous reservoir model with permeability of 500 millidarcies and perform waterflooding on this model to compare results with heterogeneous cases.
2. Construct heterogeneous reservoir models with data previously mentioned by varying Lorenz coefficient values to 0.254, 0.301, 0.352, 0.403, and 0.438. Middle value of Lorenz coefficient (0.352) is initially chosen to represent heterogeneous base case.
3. Perform waterflooding in heterogeneous reservoir chosen in step (2). Oil recovery factor is used as a reference to compated to steamflooding cases.

4. Choosing steamflooding operational parameters including steam quality and injection rate on heterogeneous reservoir chosen from step (2). Four injection rates (40, 60, 80 and 100 STB/D liquid equivalent) and four steam qualities (0.4, 0.6, 0.8, and 1.0) are chosen. Operating steam quality and steam injection rate are chosen based on priority from 70% of oil recovery, 20% of energy consumed per barrel and 10% of water production.
5. In order to study effects of reservoir heterogeneity, all heterogeneous reservoir models with Lorenz coefficient of 0.254, 0.310, 0.352, 0.403 and 0.438 are simulated with optimized injection rate and steam quality, obtained from previous step.
6. Sensitivity analysis is performed on every heterogeneous model in order to observe effects of uncertain parameters. Chosen parameters in this step are relative permeability curves (for both reservoir temperature and elevated temperature), oil gravity (including effect of oil viscosity), ratio of vertical to horizontal permeability, and type of depositional sequence. Once a parameter is studied, other parameters are kept constant at default values.
7. Perform simulation to study effect of flood pattern which is comparison between quarter 5-spot and quarter 9-spot. All heterogeneous models are performed with both steamflood patterns.
8. Discuss all results obtained from reservoir simulation runs using simulation outcomes such as oil recovery factor, water and oil production rates, total steam injection period, enthalpy consumed per oil recovery, saturation profiles and summarize new finding.

The methodology diagrams of this study are illustrated in Figures 4.13 and 4.14.

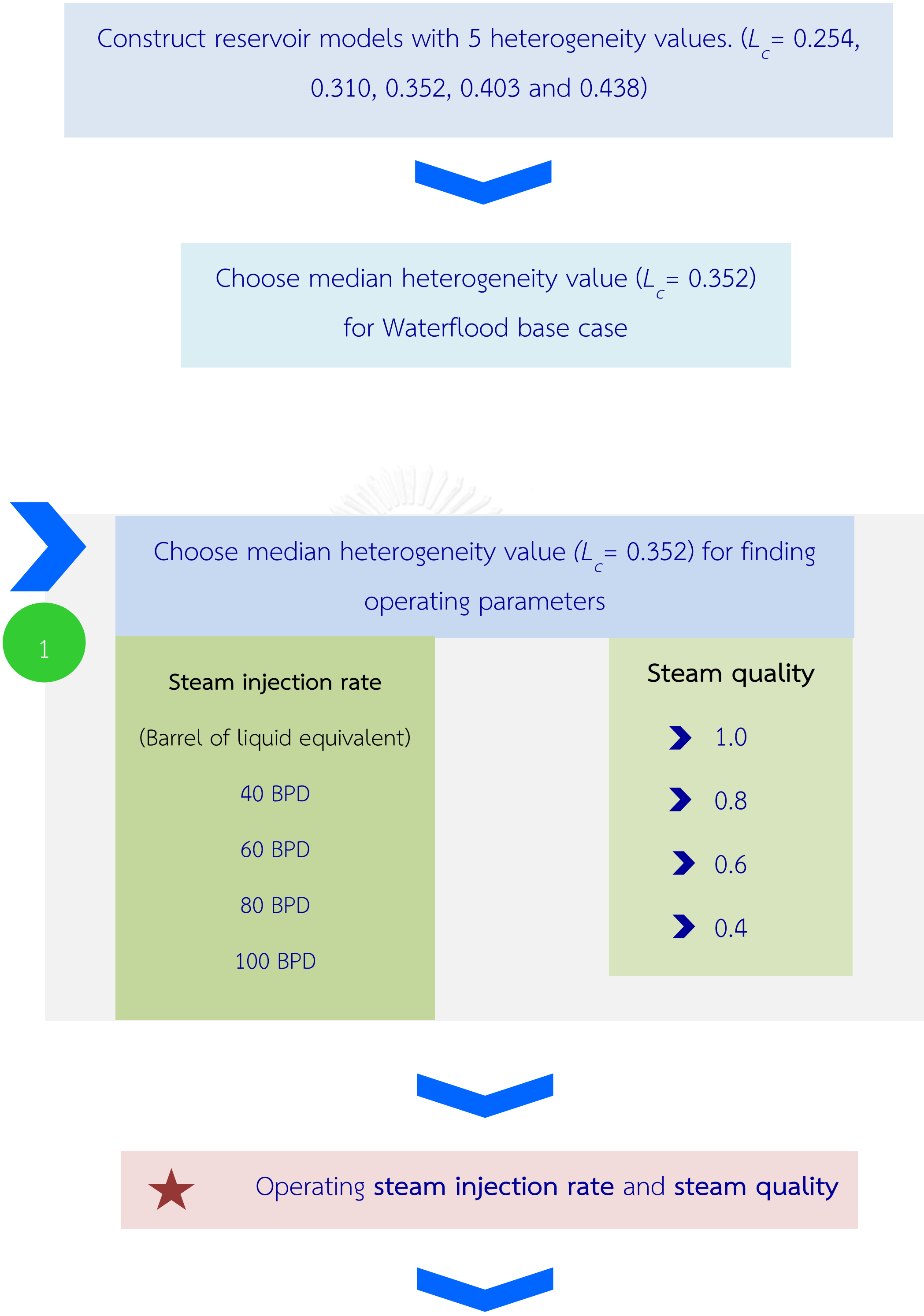


Figure 4. 13 Methodology diagram for optimization process

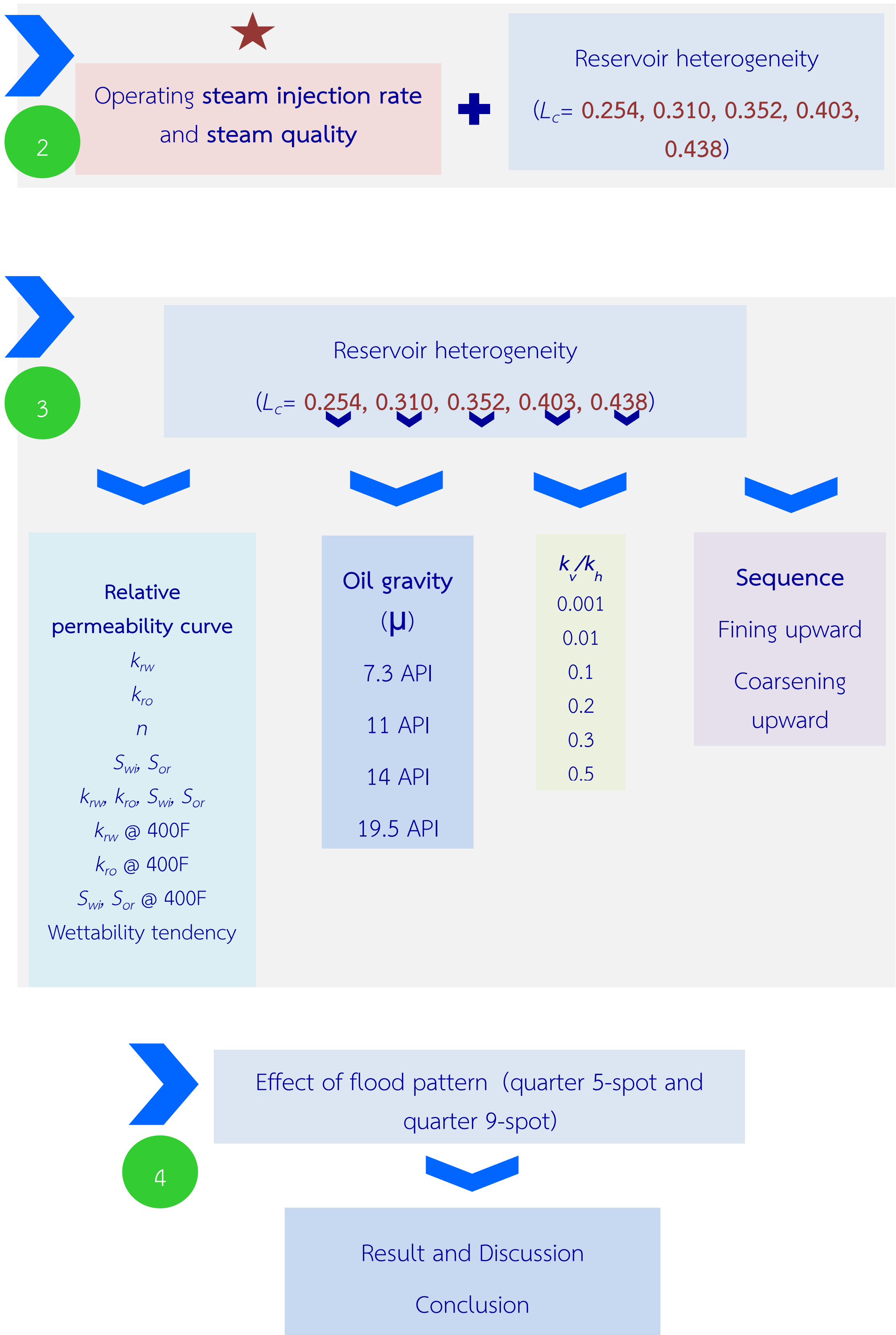


Figure 4. 14 Methodology diagram for study of chosen parameters

CHAPTER 5

RESULTS AND DISCUSSION

After reservoir model is constructed based on chosen properties, simulation of steam injection is performed with varying of study parameters in order to investigate their sensitivities on effectiveness of steamflooding in heterogeneous reservoir. Waterflooding is firstly performed on reservoir model with heterogeneity of 0.352 (representing by Lorenz coefficient (L_c)). This value is middle one among the range of heterogeneity index used in this study. Result obtained from waterflooding is kept as reference. Consequently, steamflooding simulation is performed to determine proper value of operational parameters which are steam injection rate and steam quality. After proper values are selected, reservoir properties consisting relative permeability, oil gravity, ratio of vertical permeability and sequence of permeability are studied for their effects on simulation outcomes. Last, flood pattern is studied by comparing quarter 5-spot and quarter 9-spot patterns while keeping injection rate to be equal. Oil recovery factor is the main simulation outcome used for judging effectiveness of the process. Moreover, water production rate, water cut at producing end, enthalpy consumed per barrel of oil and saturation profiles are used to assist the discussion.

For every case, steam injection rate is set as a major constraint but at the same time, injection well is controlled under the maximum bottomhole pressure of 420 psi. For production well, minimum bottomhole pressure is controlled at 200 psi and economic limit is set at 95 percent water cut. Since this simulation is performed in highly viscous oil reservoir, extremely low oil production rate is foreseen and hence, minimum oil production rate is not concerned for production well in this study. Total production period is 30 years to represent the production period of ordinary concession.

5.1 Waterflooding Base Cases

Waterflooding is simulated first in order to ensure that secondary recovery is not suitable technique for the constructed reservoir model. Simulation of waterflooding is also performed to evaluate additional benefit of thermal process from physical displacement. Oil recovery factor and oil production rate are concerned in this section and used to compare effectiveness of steamflooding and waterflooding. In this study, several reservoir parameters are fixed as follow; Lorenz coefficient 0.352, oil gravity 14 °API, and coarsening upward depositional sequence. Water is injected in quarter 5-spot pattern consisting of one injector and one producer located diagonally on two sides of reservoir model as illustrated in Figure 5.1. Oil production rate by means of waterflooding in homogeneous reservoir with permeability value of 500 mD and 100 STB/D of water injection rate is shown by the blue line in Figure 5.1. Chosen water injection rate in heterogeneous reservoir models are 40, 60, 80 and 100 STB/D.

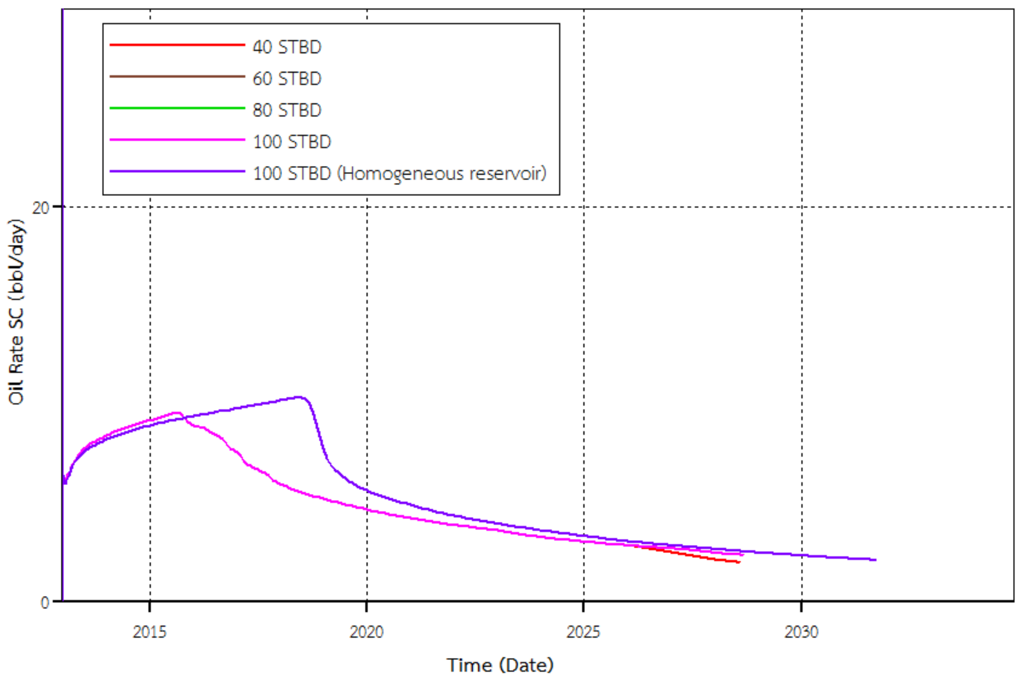


Figure 5. 1 Oil production rates obtained from waterflooding at various injection rates in heterogeneous model as a function of time

From Figure 5.1 it can be seen that oil production rates obtained from cases with various water injection rates are identical. Only oil production rate obtained from homogeneous reservoir that is different. It can be observed that oil production rate can be maintained for longer time in case of homogeneous reservoir. This can be suspected from early breakthrough in case of heterogeneous reservoir that could cause preferential flow channel on top of reservoir. However, identical of oil production rates obtained from different water production rate is suspicious from low injectivity. Figure 5.2 is therefore plotted to illustrate actual injection rates at injection well.

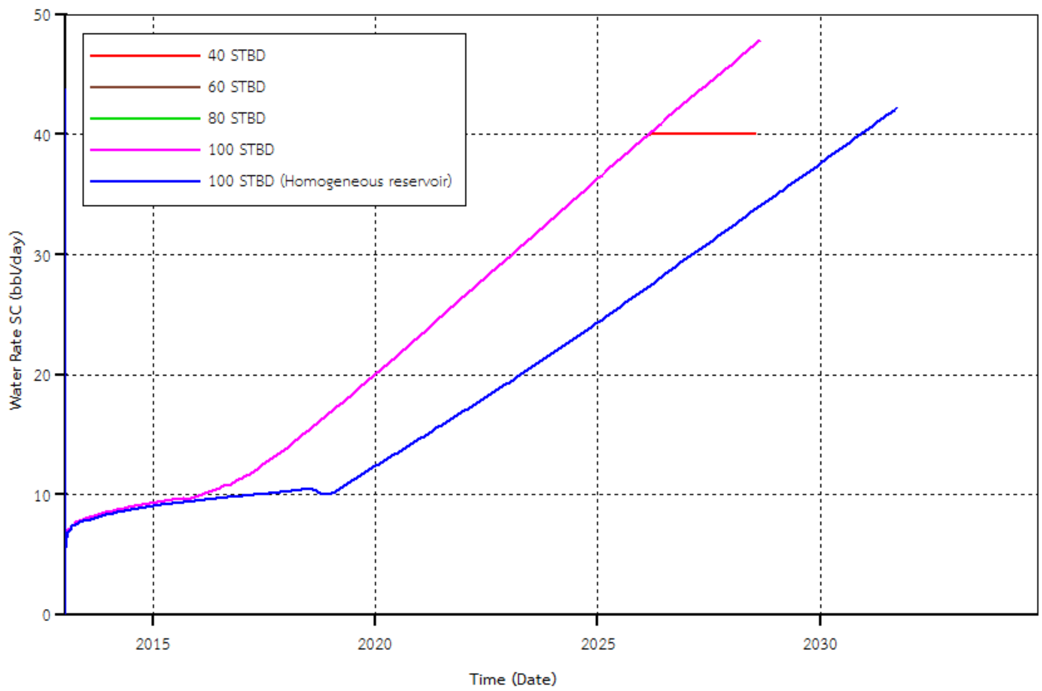


Figure 5. 2 Actual water injection rate at various desired water injection rate in heterogeneous and homogeneous reservoirs

From Figure 5.2, water injection rates for both heterogeneous and homogeneous reservoir are limited by maximum bottomhole pressure in every water injection rate. In heterogeneous reservoirs, as desired water injection rate increases, water can only be injected at the same actual injection rate due to limitation of maximum bottomhole pressure. Oil recovery factors from every water injection rate in heterogeneous reservoir is hence identical around 27 % or 29,000 BBL of oil production. Water injectivity in heterogeneous reservoir is less than homogeneous reservoir because of favorable flow path is located on top layers of heterogeneous reservoirs.

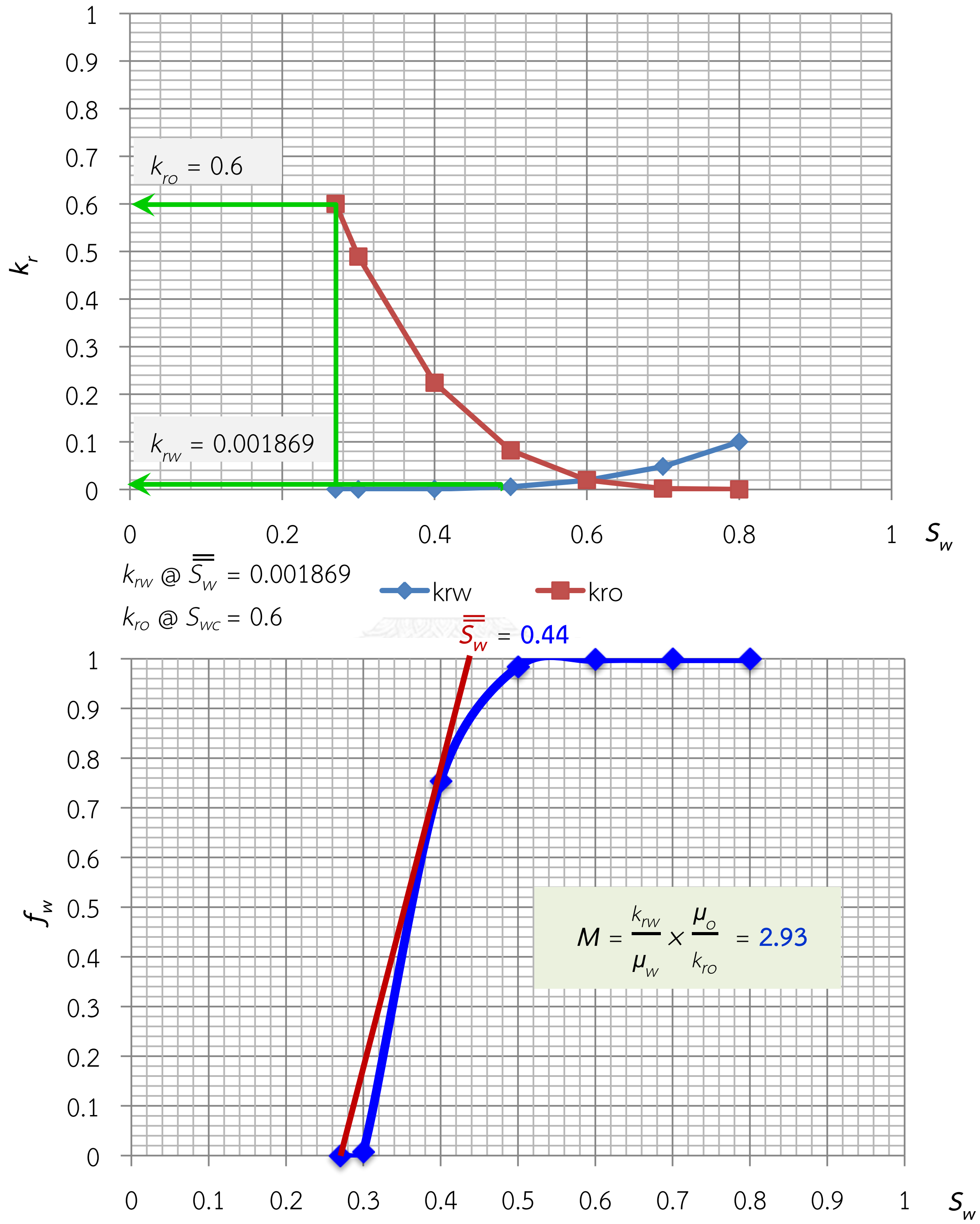


Figure 5. 3 Determination of mobility ratio of waterflooding process

Mobility ratio of waterflooding process is calculated by means of using relative permeability curves and fractional flow equation illustrated in Figure 5.3. The calculated value of 2.93 is obtained which is much higher than unity. This means that waterflooding might result in unfavorable condition. Approximately 55 percent of oil saturation is left when water breakthrough.

From the calculation of mobility ratio, it is obvious that low oil recovery factor is a result from unfavorability of waterflooding process. Difference of viscosity between reservoir oil and displacing water is considered as a major cause. Together with heterogeneity, sweep efficiency is low, reducing oil recovery. Obtained data in this section is used in comparison with those obtained from steamflooding process.

5.2 Selection of Operating Steam Injection Rate and Steam Quality

5.2.1 Oil Recovery Mechanisms in Steamflooding Process

Prior to selection of operating steam injection rate and steam quality, oil recovery mechanism by steamflooding through reservoir simulation model should be thoroughly understood. Reservoir model with middle value of Lorenz coefficient of 0.352 is chosen to describe oil recovery mechanism from the beginning of steam injection until the end of production period. The case of steam injection rate of 80 STB/D in barrel of liquid equivalent and steam quality of 0.6 is taken as a represent case in this section. In order to observe phenomena occurred during steam injection in heterogeneous reservoir, oil and water production rates are plotted with production time in Figure 5.4. Moreover, oil and water saturation profiles during interest periods such as condensed steam breakthrough and hot water breakthrough are also illustrated in the same figure.

Injected steam composes of vapor phase and liquid phase and ratio of both phases determines steam quality. From the beginning of steam injection, steam in vapor phase propagates into top layers of reservoir where permeability is high. This results in early breakthrough of water which is condensed water from steam vapor. The next period is described by an arrival of hot water. Coincident of oil production, hot water production and solution gas production appear at the same period. When steam is injected into the reservoir, steam vapor exchanges carried heat to reservoir oil. Steam possessing higher temperature than condensation moves further to production well, leaving oil and condensed hot water behind. Heated oil is then pushed by hot water that is co-injected with steam, resulting in oil bank. A gas breakthrough which is coincident with oil bank and hot water bank can be explained by oil upgrading process. Steam does not only exchange its heat to reservoir, but high temperature steam also creates in-situ distillation of oil, causing heavy oil upgraded to lighter oil with higher solution gas. This solution gas is therefore liberated from oil mass at producer.

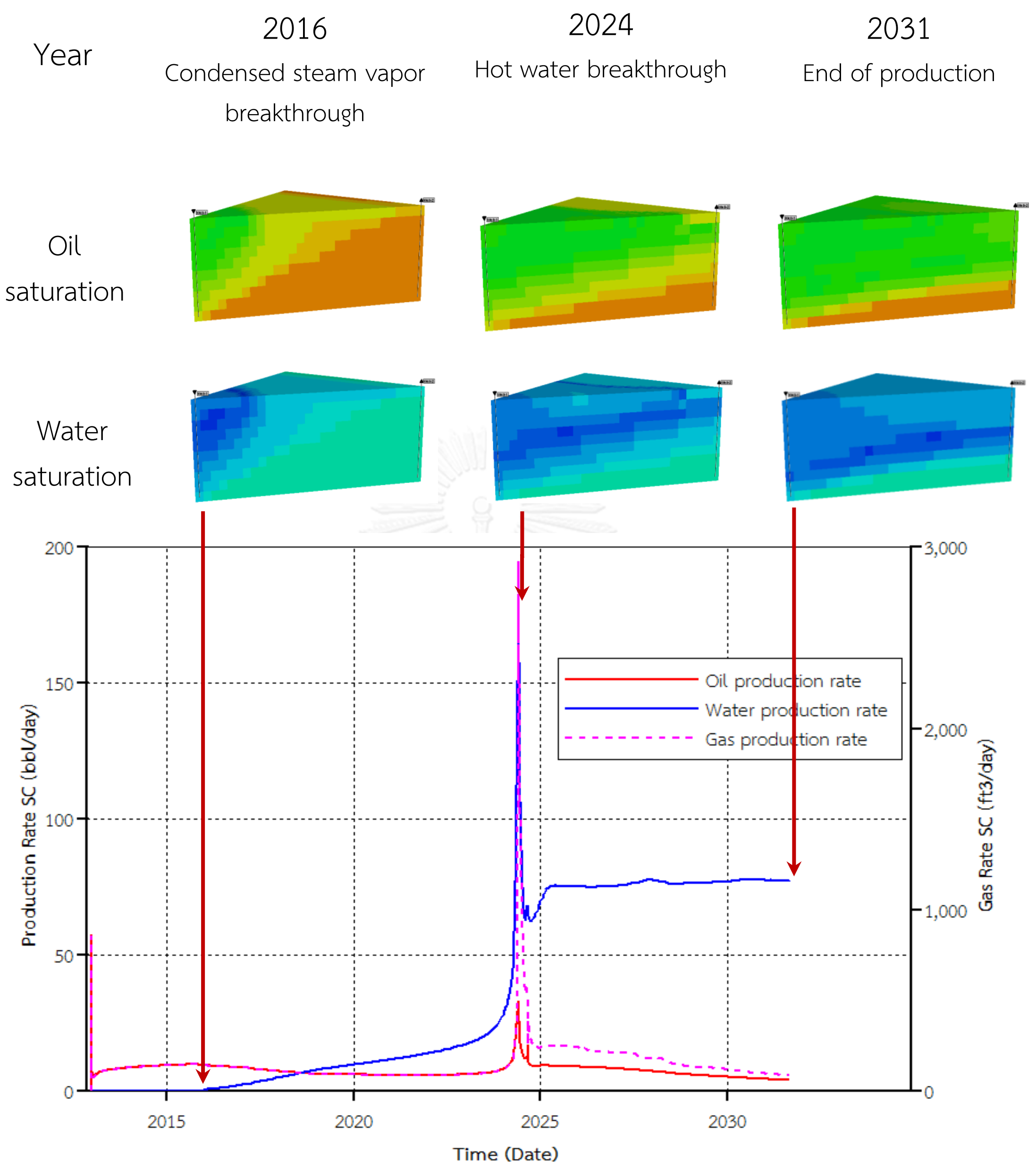


Figure 5. 4 Oil, water and gas production rates at different interest periods together with oil and water saturation profiles

Figure 5.5 illustrates fluid saturations using three phase diagram. It can be observed that after hot water breakthrough, gas saturation appears in the middle of reservoir. As reservoir pressure declines below bubble pressure, solution gas starts to be liberated and occupied top layers of reservoir as can be seen from pink color.

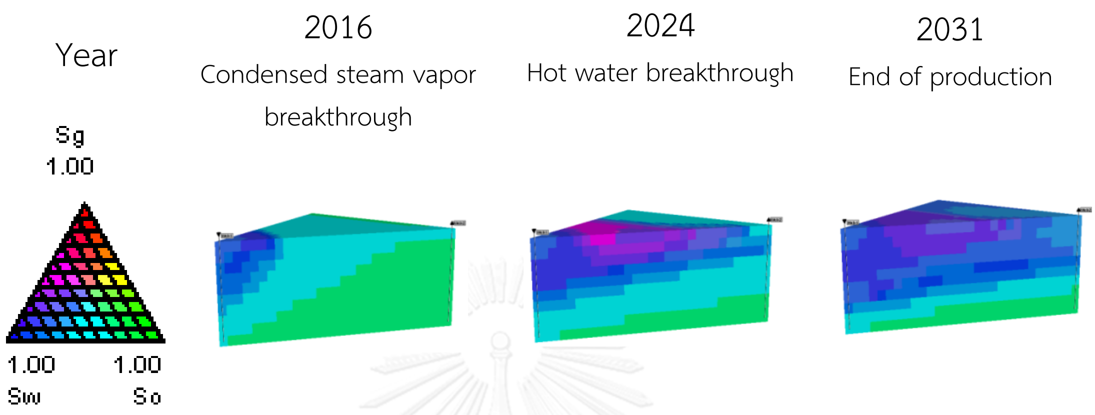


Figure 5. 5 Three phase saturation profiles illustrating liberation of solution gas after hot water breakthrough

Reservoir pressure is sharply reduced as moving oil bank is produced by pushing hot water. Oil and gas productions decrease correspondingly after hot water breakthrough due to fast pressure depletion. As steam is kept injected until the water cut at producer reach to 95%, water production rate is constant.

Since reservoir oil is very viscous, this results in low steam injectivity. Therefore, steam cannot be injected at desired rate from the beginning due to secondary constraint which is maximum bottomhole pressure is reached. Maximum bottomhole pressure is set at 520 psi to prevent undesired fractures related to depth of formation. Figure 5.6 shows evolution of steam injection rate and bottomhole pressure of injection well.

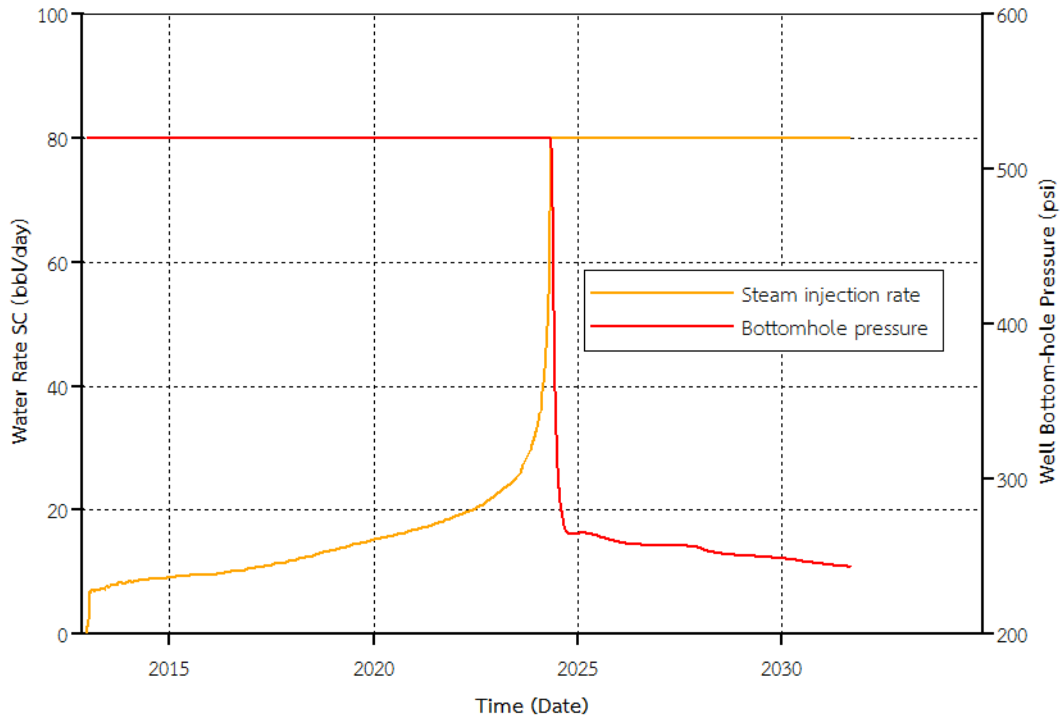


Figure 5. 6 Steam injection rate and bottomhole pressure of injection well as a function of time

5.2.2 Operating Steam Quality and Steam Injection Rate

Steam injection rate and steam quality are important operational parameters in this study. At first, effects of steam quality and steam injection rate on oil and water productions are evaluated.

5.2.2.1 Effect of Steam Injection Rate

In order to observe effects of steam injection rate in heterogeneous model with Lorenz coefficient of 0.352, oil recovery factor is plotted with desired steam injection rate for each steam quality as shown in Figure 5.7.

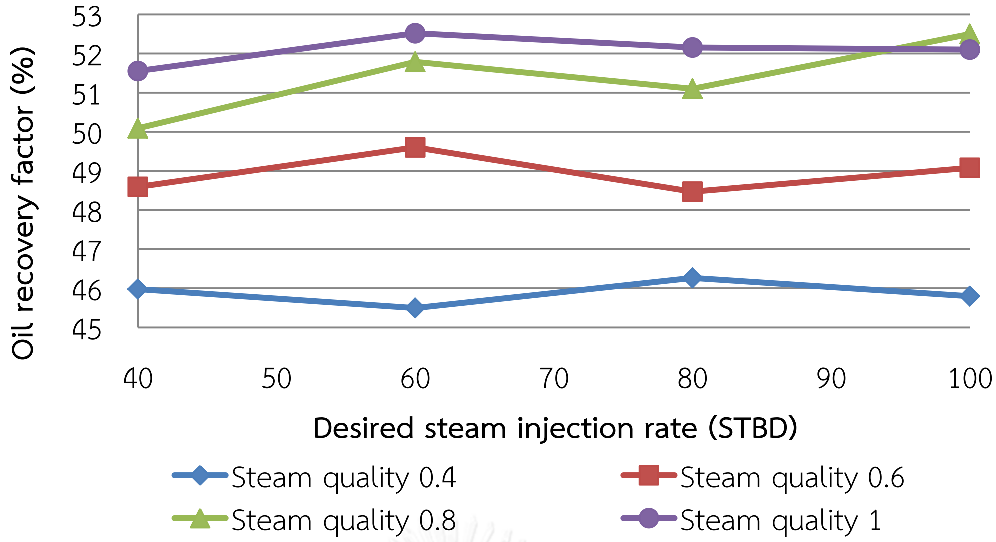


Figure 5. 7 Oil recovery factors obtained from different steam qualities as a function of desired steam injection rate

From Figure 5.7, there is no exact trend in oil recovery factor as a function of desired steam injection rate for every steam quality. Since one of the constraints for the steam injection process is 95% of water cut, this may influent oil recovery by different production period. Figures 5.8 and 5.9 are therefore, plotted to further investigate effects of steam injection rate.

From Figure 5.8, as steam injection rate increases, oil production rate at hot water breakthrough period also increases. It can be seen that at the same steam quality, different injection rates yield almost the same breakthrough time. This can be explained that, desired steam injection rate is limited by maximum bottomhole pressure to prevent fracture pressure. After hot water breakthrough, higher injection rate can be attained and hence, more heat is transferred to reservoir to reduce residual oil. However, steam injection period is not the same for all cases. These cases are terminated by water cut reaching 95%. In other words, certain steam injection rate punishes total oil recovery by reducing total production period from high water production.

Increasing steam injection rate may increase oil recovery due to higher amount of heat carried by steam. However, the operating steam injection should be concerned in terms of energy consumed since incremental of oil recovery might not be balanced with addition amount of heat input.

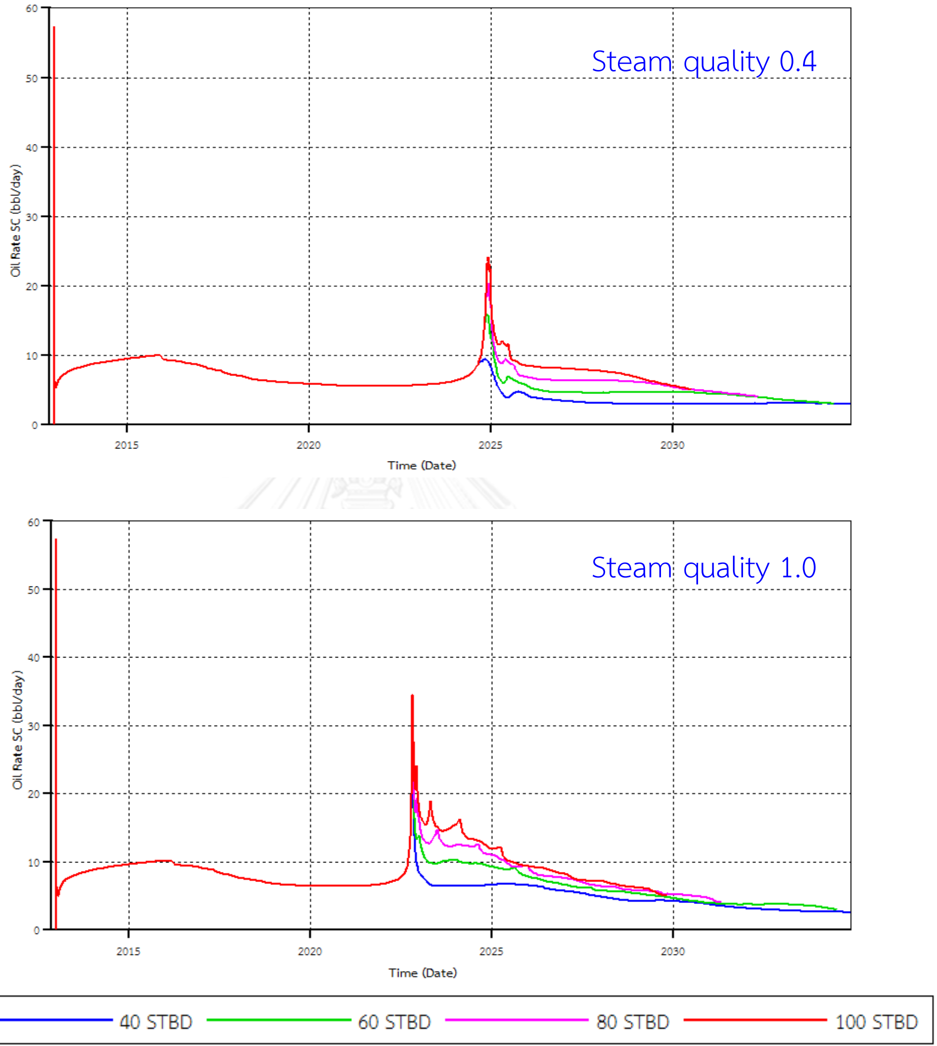


Figure 5. 8 Oil production rates from steam quality of 0.4 and 1.0 with various desired steam injection rates as a function of production time

Figure 5.9 illustrates reduction of total production period for every steam quality due to higher amount of water injected that consecutively results in higher water production and termination due to reaching preset water cut of 95%.

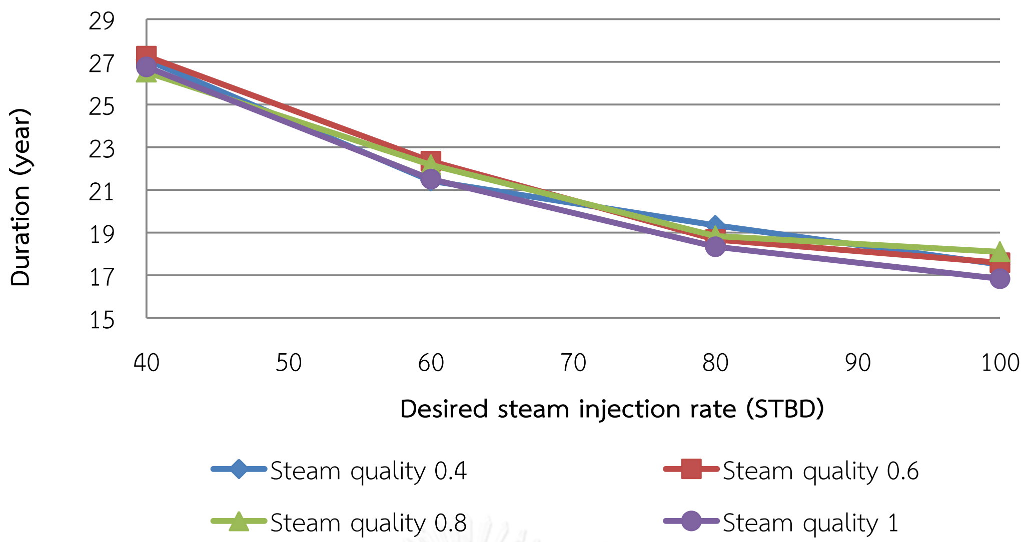


Figure 5. 9 Duration of steam injection of various steam qualities as a function of desired steam injection rate

Water production illustrated in Figure 5.10 is related to total oil production. As explained previously, increasing injection rate also brings higher amount steam vapor and hot water. Nevertheless, reduction of water production at certain steam injection rate (around 80 STBD for most cases) is caused by early termination.

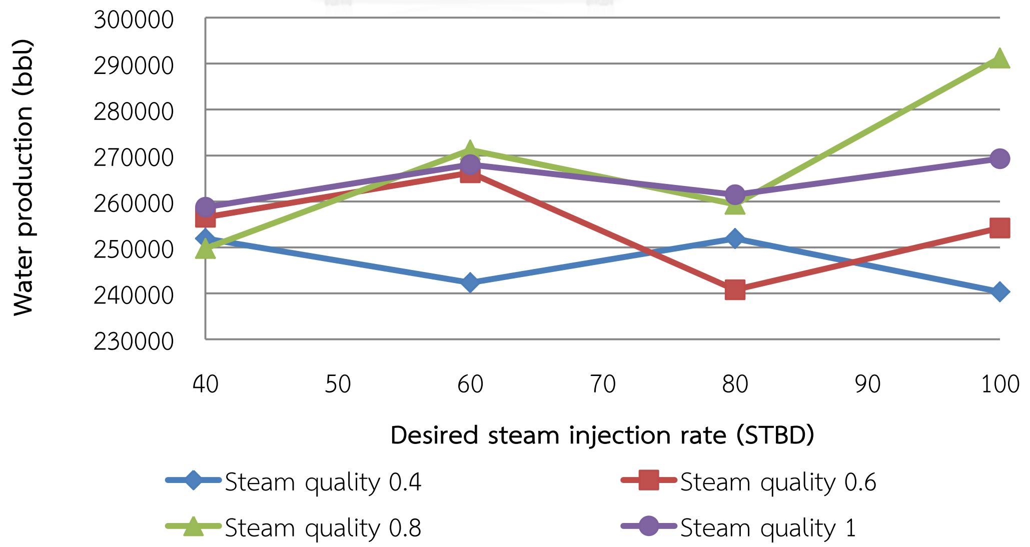


Figure 5. 10 Water production of various steam qualities as a function of desired steam injection rate

An extremely high water production might be due to amount of hot water breakthrough that overcomes effect of shorter production period as can be seen in Figure 5.11. The red lines for both steam qualities show extremely high water production rates.

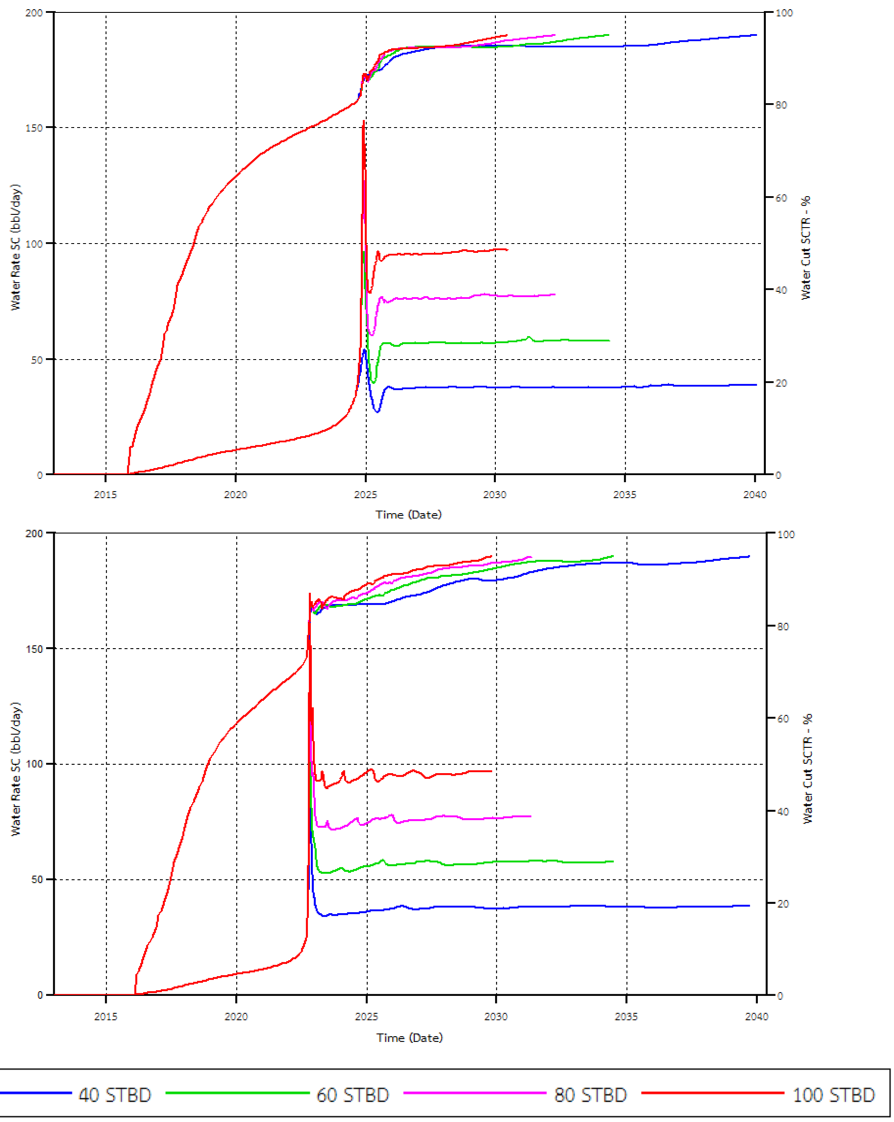


Figure 5. 11 Water production rates and water cut obtained of steam qualities of 0.4 and 1 with various desired steam injection rates as a function of time

In summary increasing of desire injection rate affects effectiveness of steamflooding only the period after hot water breakthrough. Prior to hot water breakthrough, desired injection rate cannot be attained due to maximum bottomhole pressure. However, high amount of oil is produced by high injection rate bringing higher amount of steam and hot water. This also comes together with disadvantage that is early termination due to high water production.

Variation of oil recovery with a change of steam injection rate requires consideration of enthalpy consumed per barrel of oil shown in Figure 5.12 in order to identify operating steam injection rate. This value should be minimized in order to obtain more oil with the smallest given energy.

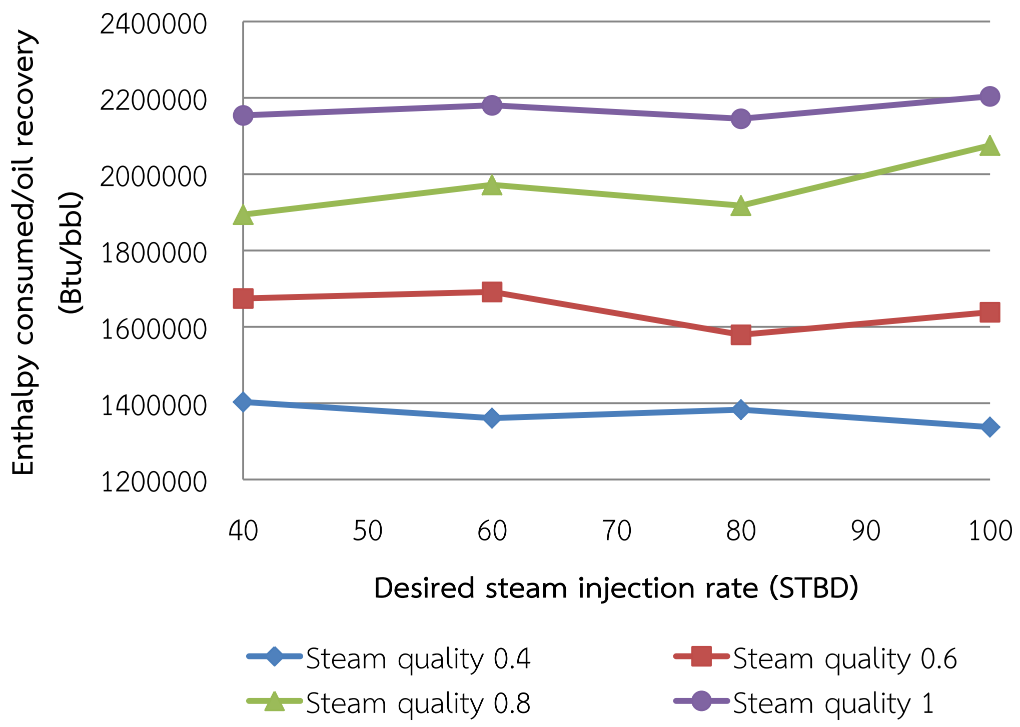


Figure 5. 12 Enthalpy consumed per barrel of oil of various steam qualities as a function of steam injection rate

5.2.2.2 Effect of Steam Quality

Similar to previous section, effect of steam quality is also investigated for model possessing Lorenz coefficient of 0.352. Oil recovery factor is firstly plotted with steam qualities for various desired steam injection rates as shown in Figure 5.13.

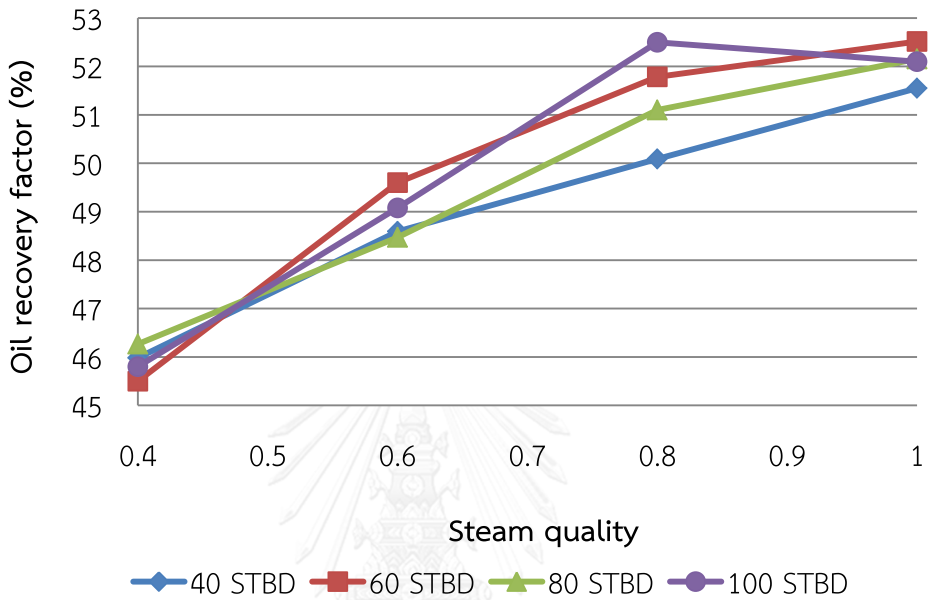


Figure 5. 13 Oil recovery factors of various desired steam injecton rates as a function of steam quality

From Figure 5.13, major trend of oil recovery factor plotted with steam quality can be drawn for most steam injection rates. Higher steam quality results in better oil recovery. However, oil recovery is less diverted with steam injection rate at steam quality of 0.4. Steam quality is a ratio representing quantity in mass of steam portion over total injected fluid. Since steam carries heat more than hot water (latent heat), higher steam quality can deliver more heat to reservoir, resulting in higher oil recovery factor. However, an adverse case of too high injection rate and high steam quality can be seen. At steam quality of 1.0 and steam injection rate of 100 STB/D, too much steam volume carrying heat results in reduction of oil recovery due to early hot water production that is a result from improvement of relative permeability to water due to thermal treatment together with high amount of water introduced.

Plots of oil production rate show different time of hot water breakthrough when injecting steam with different steam qualities as shown in Figure 5.14. Breakthrough of oil bank occurs earlier when injecting steam at higher steam quality because higher steam quality carries higher amount of heat. The higher heat drives relative permeability to oil to be improved at elevated condition. Hence, the earlier change in reservoir temperature, the earlier breakthrough of oil bank.

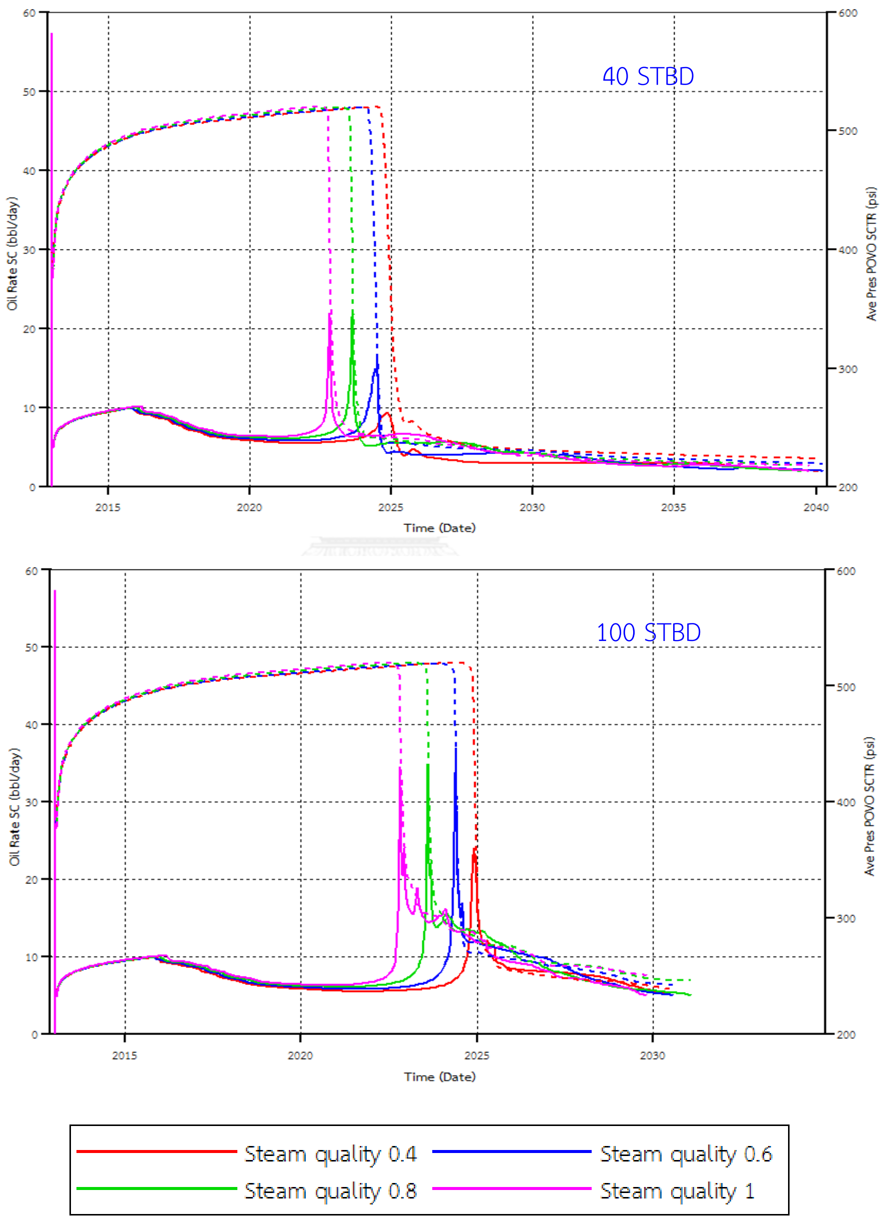


Figure 5. 14 Oil production rates and average reservoir pressures of various steam qualities obtained from steam injection rates of 40 and 100 STB/D as a function of time

Considering total water production in Figure 5.15, exact trend cannot be seen as explained in section of steam injection rate which is effect of total production period. However, variation of water production increases with steam quality. Exact trend of water production rate and water cut as a function of production time in Figure 5.16 can still be observed.

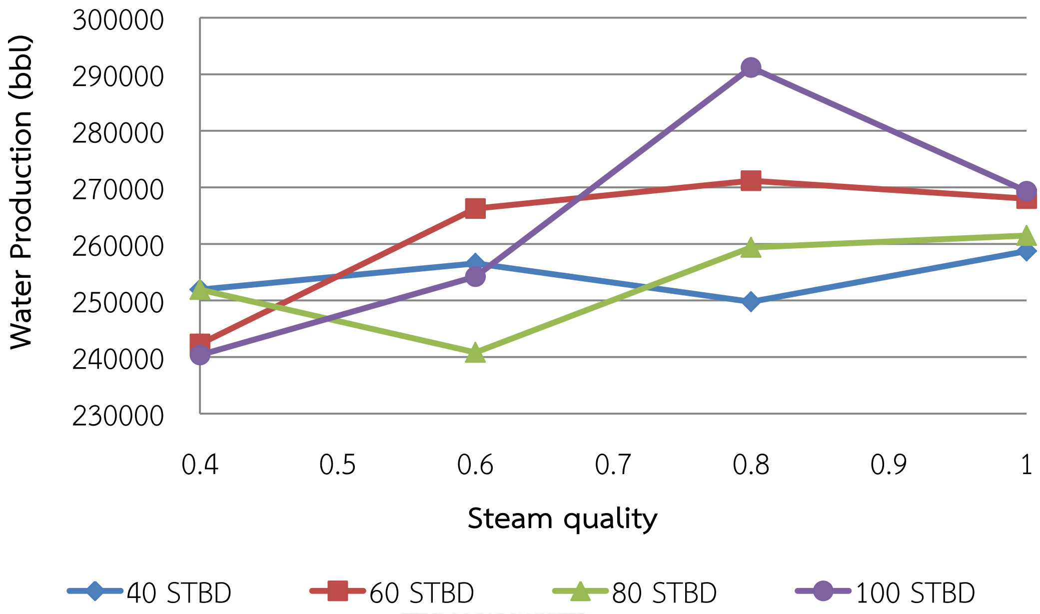


Figure 5. 15 Water production of various desired steam injection rates as a function of steam quality

From Figure 5.16, two examples of water production rate and water cut in various steam qualities show interesting sequence. Considering water cut before hot water breakthrough, fractional flow of condensed steam breakthrough is the highest in case of low steam quality. Another interesting point is the first breakthrough of high steam quality. Similar results can be observed for both low and high injection rates.

Lower steam quality carries less portion of latent heat. This results in slow attainment of relative permeability at elevated temperature. Before breakthrough, the average reservoir temperature which is lower compared to cases flooded by high steam quality results in small increment of irreducible water saturation (higher temperature tends to increase irreducible water saturation, to decrease residual oil saturation and to increase relative permeability to oil and water). Therefore, small increment of irreducible water saturation captures part of water in pore space, leaving the rest to flow to production well.

Higher steam quality quickly develops relative permeability at elevated temperature and hence, irreducible water saturation of 0.5 is achieved and that means, higher amount of water needs to be filled in pore space prior to flowing to production well. Therefore, water cut in low steam quality is higher than cases of higher steam quality.

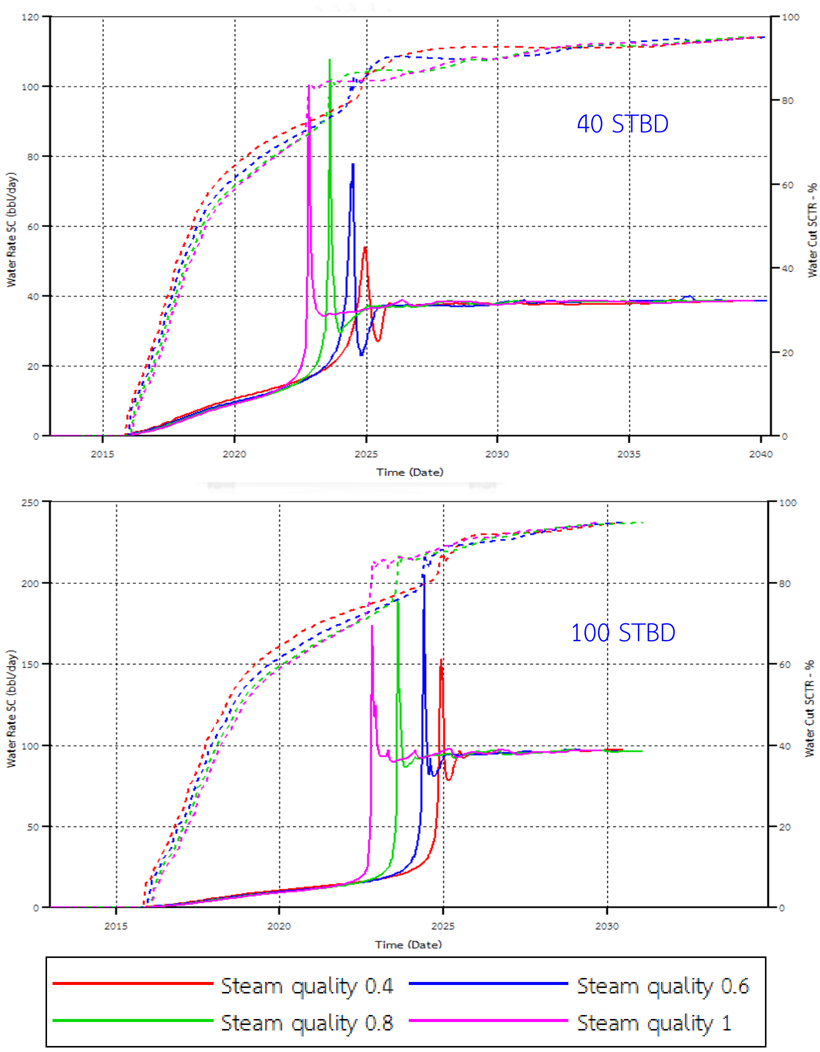


Figure 5. 16 Water production rates and water cut for various steam qualities obtained from desired steam injection rates of 40 and 100 STB/D as a function of time

At hot water breakthrough, it is found that steam quality of 1.0 results in breakthrough first and steam quality of 0.4 at last. It can be explained that, at higher water saturation, relative permeability to water reaches elevated state earlier for higher steam quality. Therefore, water flows better and hence, hot water breakthrough occurs first in cases of higher steam quality. Development of reservoir temperature is compared among cases with low steam quality (0.4) and high steam quality (1.0) in Figure 5.17.

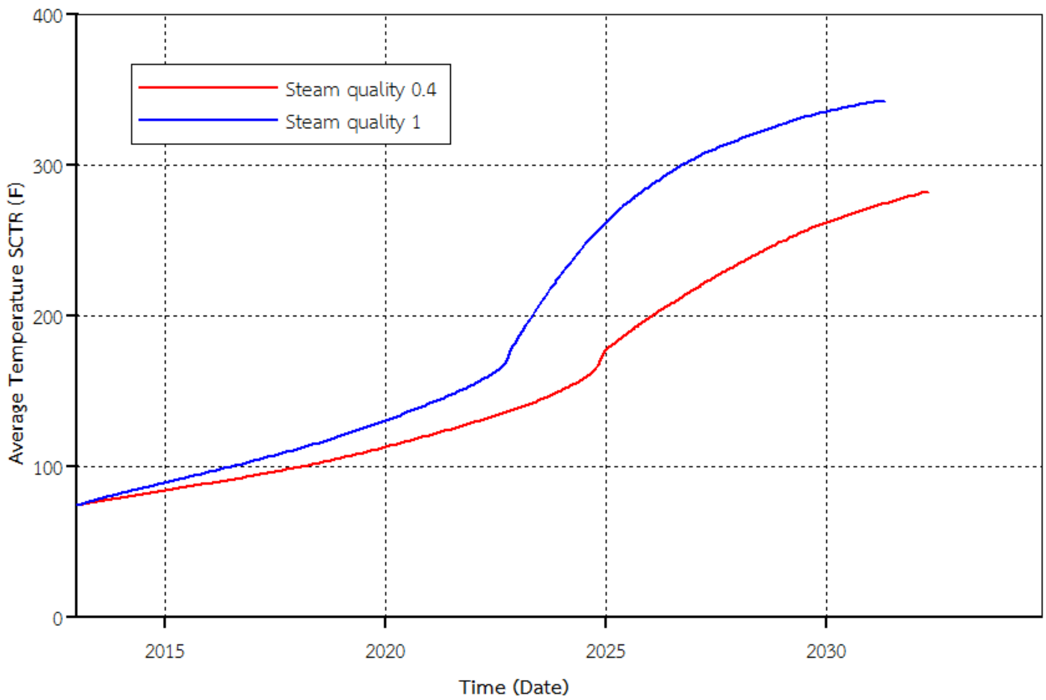


Figure 5. 17 Comparing of average reservoir temperature between cases of low steam quality (0.4) and high steam quality (1.0) at 80 STB/D

In summary, injecting steam with higher steam quality will cause early attaining of flow ability at elevated state (new relative permeability curves are applied). This results in increasing of irreducible water saturation and relative permeability to water at end point saturation. Therefore, at lower water saturation water cut at production end is low since part of water has to be fulfilled in pore space. At higher water saturation, flow ability of water is much improved and this caused an early breakthrough of hot water.

Similar to previous section, enthalpy consumed per barrel of oil is plotted and shown in Figure 5.18. From the figure, increasing steam quality results in more energy consumption for every injection rate. Steam quality of 0.6 tends to lower the trend of energy consumption for moderate injection rates. For this study, low energy consumption is preferred. However, for cases with low steam quality, oil recovery is also low compared to other cases. Therefore, selection of steam injection rate and steam quality should be based on both energy consumption and total oil recovery.

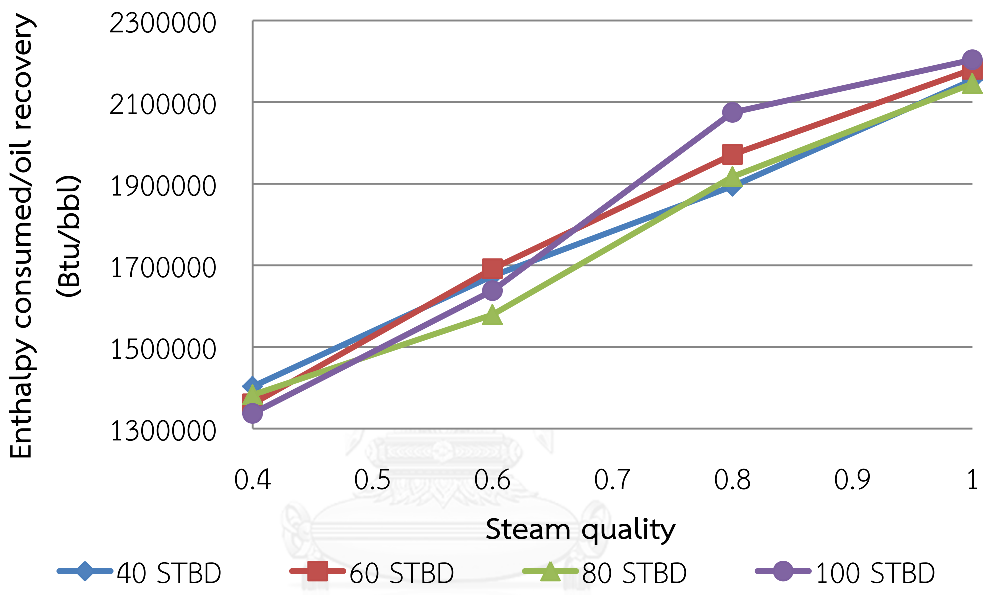


Figure 5. 18 Enthalpy consumed per barrel of oil of various desired steam injection rates as a function of steam quality

5.2.2.3 Selection of Operating Steam Quality and Desired Steam Injection Rate

In this study, selection of operating desired steam injection rate and steam quality is based on several criteria. Oil recovery factor is a major concern therefore; weight function is the highest among others. Not only oil recovery factor is considered in this section, cumulative energy consumed per barrel of oil recovered is also considered. This term shows how much energy is spent and the higher number results in negative consideration. Last criterion is total water production. As water that is produced from steam injection can be acid water, this might cause trouble to production line as well as disposal unit. High water production is therefore unfavorable. In summary, weighting factor for the three criteria are 0.7, 0.2 and 0.1 for oil recovery factor, energy consumed per barrel of oil and total water production.

In order to judge cases, maximum oil recovery, minimum energy consumption and minimum total water production are detected first from whole cases. Raw data is obtained by dividing data by detected maximum/minimum values. Reciprocal of energy consumption and water production is applied to create ratio smaller than unity. In order to create judgment function all the ratios are multiplied by weighting factors and all terms are summed as shown in Equation 5.1. Table 5.1 summarizes all the simulation outcomes and processed data are shown in Table 5.2.

$$\text{Judgment function} = 0.7\times(\text{Recovery factor}/52.5)+0.2\times(1.40\times10^{6}/\text{Energy consumed}) + 0.1\times(2.40\times10^{5}/\text{Water production}) \quad (5.1)$$

Table 5. 1 Summary of processed simulation outcomes to identify optimum steam injection rate and steam quality

Simulation outcomes		Steam quality			
		0.4	0.6	0.8	1
40 STB/D	Oil recovery factor %	45.98	48.59	50.09	51.55
	Oil recovery (bbl)	4.85×10^{4}	5.13×10^{4}	5.28×10^{4}	5.44×10^{4}
	Water production (bbl)	2.52×10^{5}	2.57×10^{5}	2.50×10^{5}	$2,59\times10^{5}$
	Consumed energy (Btu)	6.81×10^{10}	8.58×10^{10}	1.00×10^{11}	1.17×10^{11}
	Consumed energy/oil (Btu/bbl)	1.40×10^{6}	1.67×10^{6}	1.89×10^{6}	2.51×10^{6}
	Duration (year)	27.10	27.27	26.51	26.76
60 STB/D	Oil recovery factor %	45.50	49.60	51.79	52.52
	Oil recovery (bbl)	4.80×10^{4}	5.23×10^{4}	5.46×10^{4}	5.54×10^{4}
	Water production (bbl)	2.42×10^{5}	2.66×10^{5}	2.71×10^{5}	2.68×10^{5}
	Consumed energy (Btu)	6.53×10^{10}	8.85×10^{10}	1.08×10^{11}	1.21×10^{11}
	Consumed energy/oil (Btu/bbl)	1.36×10^{6}	1.69×10^{6}	1.97×10^{6}	2.18×10^{6}
	Duration (year)	21.43	22.34	22.18	21.51
80 STB/D	Oil recovery factor %	46.27	48.47	51.10	52.15
	Oil recovery (bbl)	4.88×10^{4}	5.11×10^{4}	5.39×10^{4}	5.50×10^{4}
	Water production (bbl)	2.52×10^{5}	2.41×10^{5}	2.59×10^{5}	2.61×10^{5}
	Consumed energy (Btu)	6.75×10^{10}	8.08×10^{10}	1.03×10^{11}	1.18×10^{11}
	Consumed energy/oil (Btu/bbl)	1.38×10^{6}	1.58×10^{6}	1.92×10^{6}	2.15×10^{6}
	Duration (year)	19.34	18.68	18.84	18.34
100 STB/D	Oil recovery factor %	45.80	49.08	52.50	52.10
	Oil recovery (bbl)	4.83×10^{4}	5.18×10^{4}	5.54×10^{4}	5.50×10^{4}
	Water production (bbl)	2.40×10^{5}	2.54×10^{5}	2.91×10^{5}	2.69×10^{5}
	Consumed energy (Btu)	6.46×101^{0}	8.48×10^{10}	1.15×10^{11}	1.21×10^{11}
	Consumed energy/oil (Btu/bbl)	1.34×10^{6}	1.64×10^{6}	2.07×10^{6}	2.20×10^{6}
	Duration (year)	17.51	17.59	18.10	16.84

Table 5. 2 Processed data to determine best desired steam injection rate and steam quality from judgment function

Score		Steam quality			
		0.4	0.6	0.8	1
40 STB/D	Oil recovery factor	0.6128	0.6476	0.6676	0.6871
	Consumed energy/oil	0.1914	0.1605	0.1418	0.1068
	Water production	0.0952	0.0934	0.0960	0.0927
	Judgment score	**0.8995**	**0.9015**	**0.9054**	**0.8865**
60 STB/D	Oil recovery factor	0.6064	0.6611	0.6903	0.7000
	Consumed energy/oil	0.1971	0.1586	0.1360	0.1229
	Water production	0.0992	0.0902	0.0886	0.0896
	Judgment score	**0.9027**	**0.9099**	**0.9149**	**0.9125**
80 STB/D	Oil recovery factor	0.6167	0.6460	0.6811	0.6951
	Consumed energy/oil	0.1942	0.1696	0.1396	0.1247
	Water production	0.0952	0.0996	0.0927	0.0920
	Judgment score	**0.9061**	**0.9152**	**0.9133**	**0.9117**
100 STB/D	Oil recovery factor	0.6104	0.6542	0.6997	0.6944
	Consumed energy/oil	0.2000	0.1634	0.1295	0.1218
	Water production	0.1000	0.0945	0.0825	0.0892
	Judgment score	**0.9104**	**0.9121**	**0.9117**	**0.9054**

From Table 5.2, injecting steam with desired steam injection rate of 80 STB/D and 0.6 steam quality yields the highest score based on judgment function (0.9152). At these operating conditions, oil recovery, energy consumed and total water production creates the highest value. Another case where judgment score is almost the same is desired steam injection rate of 60 STB/D and 0.8 steam quality. This can be inferred that in order to compensate effect from injection rate, steam quality must be adjusted.

Nevertheless, since desired injection rate of 80 STB/D and 0.6 steam quality yields the highest computed value from judgment function, these conditions are used for the studies of interest parameters.

5.2.2.4 Additional Study of Formation Thickness

Thickness of reservoir in previous study is fixed 100 ft. Additional one experiment is performed on reservoir thickness of 20 ft. Reservoir still possess 10 layers with Lorenz coefficient of 0.352. Steam is injected at 80 STB/D with 0.6 steam quality. Table 5.3 summarizes simulation outcomes of reservoir with thickness of 20 ft in comparison with 100 ft thickness.

Table 5. 3 Summary of processed simulation outcomes from reservoir with thickness of 20 ft in comparison with reservoir with thickness 100 ft

Simulation outcomes	**20 ft**	**100 ft**
Oil recovery factor %	46.99	48.47
Oil recovery (bbl)	9873.01	5.11×10^{4}
Water production (bbl)	7.29×10^{4}	2.41×10^{5}
Consumed energy (Btu)	2.33×10^{10}	8.08×10^{10}
Consumed energy/oil (Btu/bbl)	2.36×10^{6}	1.58×10^{6}
Duration (year)	30.02	18.68

From Table 5.3, oil recovery factor obtained from reservoir with thickness of 100 ft is higher than that of 20 ft. Higher energy per barrel of oil produced is also obtained in case of 20 ft due to much longer production period compared to 100 ft. In order to explain dynamicity of reservoir during steamflooding process, oil production rate and average reservoir pressure of both cases are plotted and illustrated in Figure 5.19.

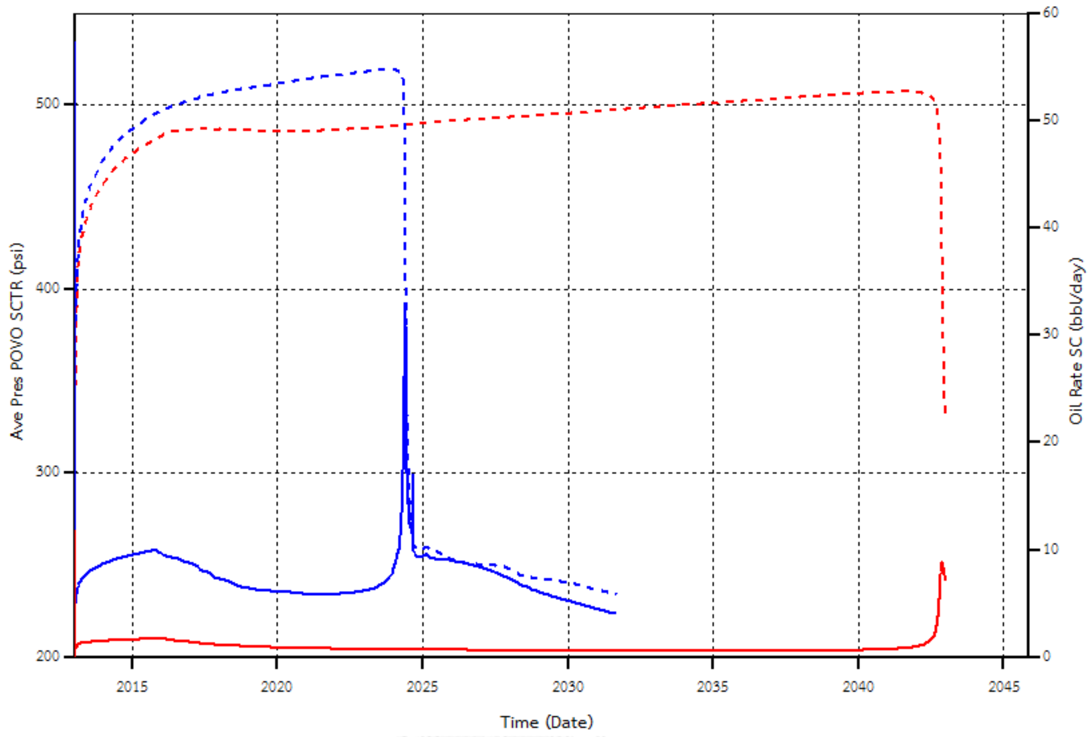
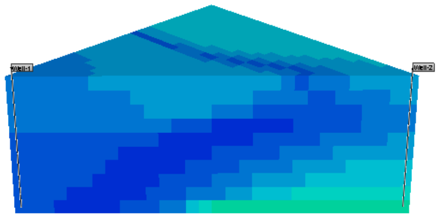
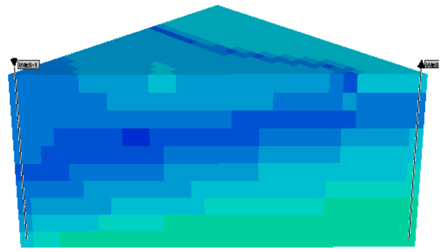


Figure 5. 19 Oil production rates and average reservoir pressures of reservoirs with thickness of 20 ft and 100 ft

From Figure 5.19, oil production rate obtained from reservoir thickness of 20 ft is much lower than the case of 100 ft. As maximum bottomhole pressures in both cases are limited to 520 psi, injecting steam into 100 ft thickness reservoir obtains higher injectivity than that of 20 ft. Thus, oil production rate is higher and production period is shorter in case of 100 ft. Due to much longer production period, water production is much higher in case of 20 ft thickness and this consecutively results in high energy consumption. An arrival of hot water breakthrough is illustrated in Figure 5.20. As steam injectivity is much lower in small thickness, steam and hot water therefore travel with lower speed, resulting in changing phase of steam back into water phase. Higher water saturation at hot water breakthrough is therefore observed in case of small thickness as shown in Figure 5.20.



20 ft



100 ft

Figure 5. 20 Hot water breakthrough in reservoir thickness of 20 ft and 100 ft

Nevertheless, since steamflooding is highly favorable in reservoir with high formation thickness. This study is continued with previous model with formation thickness of 100 ft.

5.3 Effects of Heterogeneity on Steamflooding

In previous section, steam desired steam injection rate of 80 STB/D and 0.6 steam quality yields the highest value of judgment function and hence, these conditions are selected for the rest of study. In this section, heterogeneous reservoirs with Lorenz coefficients of 0.254, 0.310, 0.352, 0.403 and 0.438 are generated and performed under selected conditions. Simulation outcomes including oil recovery factor, total water production and enthalpy consumed per barrel of oil are plotted and illustrated as a function of Lorenz coefficient. In order to observe the effect of heterogeneity thoroughly, oil and water production rate along with saturation profiles are used to assist discussion. Table 5.4 summarizes cumulative enthalpy, total oil production, oil recovery factor, total water production, cumulative enthalpy per barrel of oil produced and total duration are summarized for each Lorenz coefficient.

Table 5.4 Summary of enthalpy consumed, cumulative oil production, oil recovery factor, cumulative water production, enthalpy consumed per barrel of oil and duration of steam injection of heterogeneous reservoirs with various L_c

L_c	Enthalpy consumed (Btu)	Cumulative oil production (bbl)	Oil recovery factor (%)	Cumulative water production (bbl)	Enthalpy consumed per barrel of oil (Btu/bbl)	Duration (year)
0.25	9.45×10^{10}	57,833	54.82	282,462	1.63×10^{6}	21.26
0.31	8.40×10^{10}	53,662	50.87	249,802	1.56×10^{6}	19.59
0.35	8.08×10^{10}	51,131	48.47	240,801	1.58×10^{6}	18.68
0.4	8.15×10^{10}	48,459	45.94	245,502	1.68×10^{6}	18.01
0.44	6.62×10^{10}	43,717	41.44	196,664	1.51×10^{6}	15.76

Oil recovery factor as a function of reservoir heterogeneity is considered first in Figure 5.21. It can be observed that higher heterogeneity results in lowering of oil recovery factor. To observe effect of heterogeneity on oil recovery, oil production rate, average reservoir pressure and oil saturation profile are illustrated together for each Lorenz coefficient as shown in Figure 5.22.

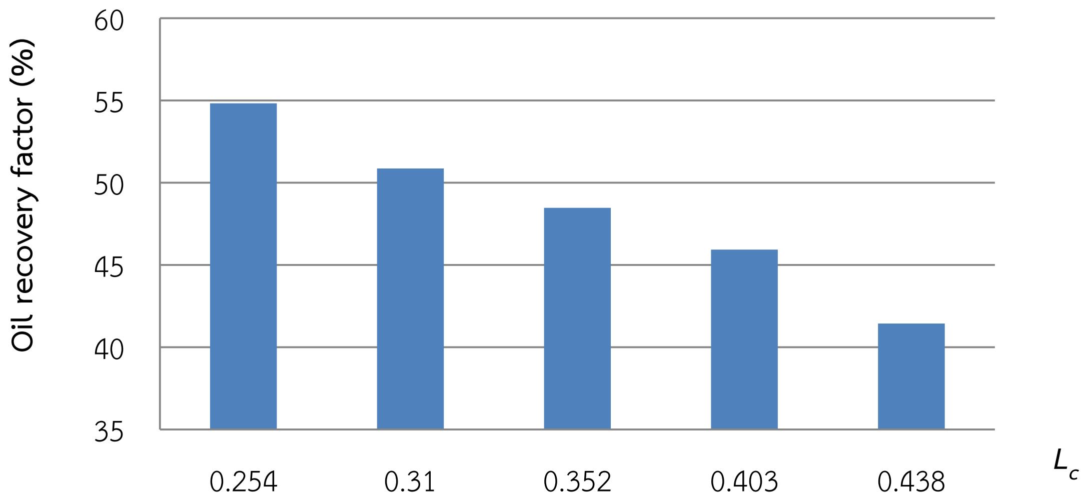


Figure 5.21 Oil recovery factors as a function of Lorenz coefficient

From Figure 5.22, oil production rates before condensed steam breakthrough from all cases are mostly equivalent due to steam injectivity. An increase of oil production rate in first period is due to steam pressurization. Once steam vapor starts breakthrough, case with the highest heterogeneity is the first one facing this. This occurrence is due to distribution of high permeability that is located on top of reservoir. Oil rates start to decrease until oil bank from heat exchanging breakthroughs. This oil breakthrough occurs also earlier compared to other cases. As displaced volume of reservoir is less, displacing phase which is steam travels faster compared to other cases. After breakthrough of oil bank, hot water starts to breakthrough. Smaller displaced volume also results in quick attaining to pre-set water value and hence production well is shut early. Combination of poor volumetric sweep efficiency due to heterogeneity and short total production period results in very low oil recovery factor compared to other cases.

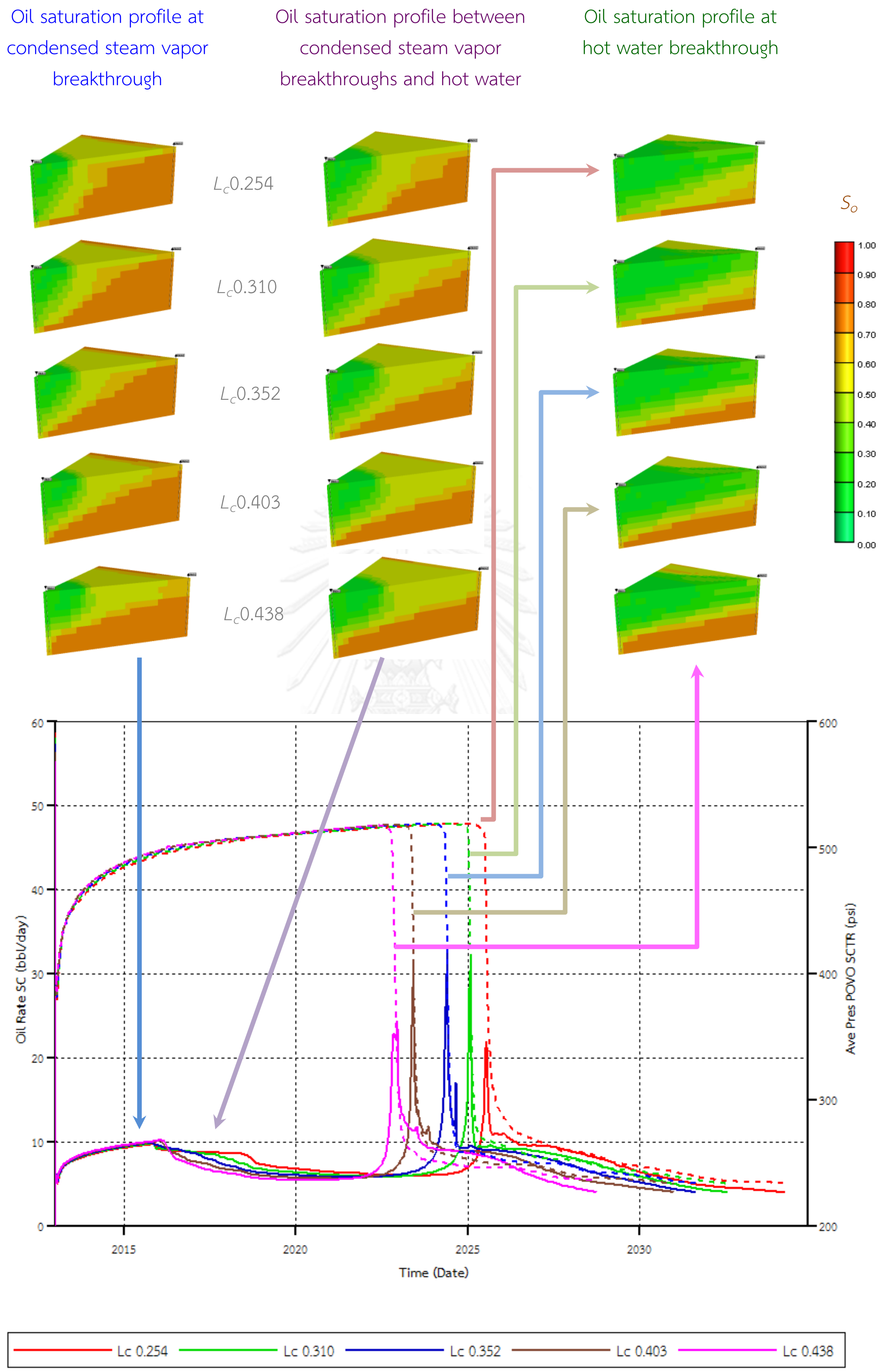


Figure 5.22 Oil production rates, average reservoir pressures and oil saturation profiles at corresponding periods obtained from different heterogeneous reservoirs

Reservoir model with less heterogeneity index tends to prolong production period since steam can volumetrically displace and hence, oil recovery is relatively high. From Figure 5.21, it can be seen that oil recovery factor tends to decrease with an increase of heterogeneity. Higher reduction of oil recovery factor can be seen from Lorenz coefficient from 0.403 to 0.438.

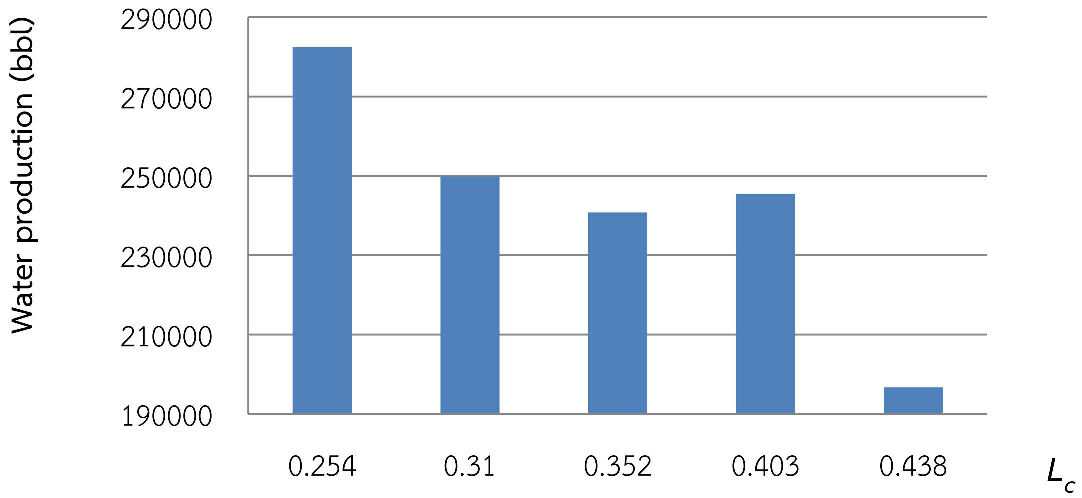


Figure 5.23 Water productions as a function of Lorenz coefficient

Considering water production in Figure 5.23, water production decreases as reservoir heterogeneity increases. Water production is a function of steam injection duration. Longer production period means steam is continuously injected for longer time. An exception of longer water production period is observed in case of long steam injection period, whereas high Lorenz coefficient results in extremely early breakthrough and hence very short steam injection period and small total water production. From Figure 5.24 at time where condensed steam breakthrough occurs, displacement occurs mostly in top layers in reservoir with high heterogeneity. As displaceable volume is smaller compared to cases with lower heterogeneity, water cut at production well is therefore higher at the same operational conditions. At hot water breakthrough, arrival of hot water slug is first is case of 0.438 Lorenz coefficient as displaced volume is mainly found on the top part of reservoir. At the end of production, it can be obviously seen that water cannot displace into lower layers in models with high heterogeneity. Low water production is due to shorter production period as water cut reaches production constraint at 0.95.

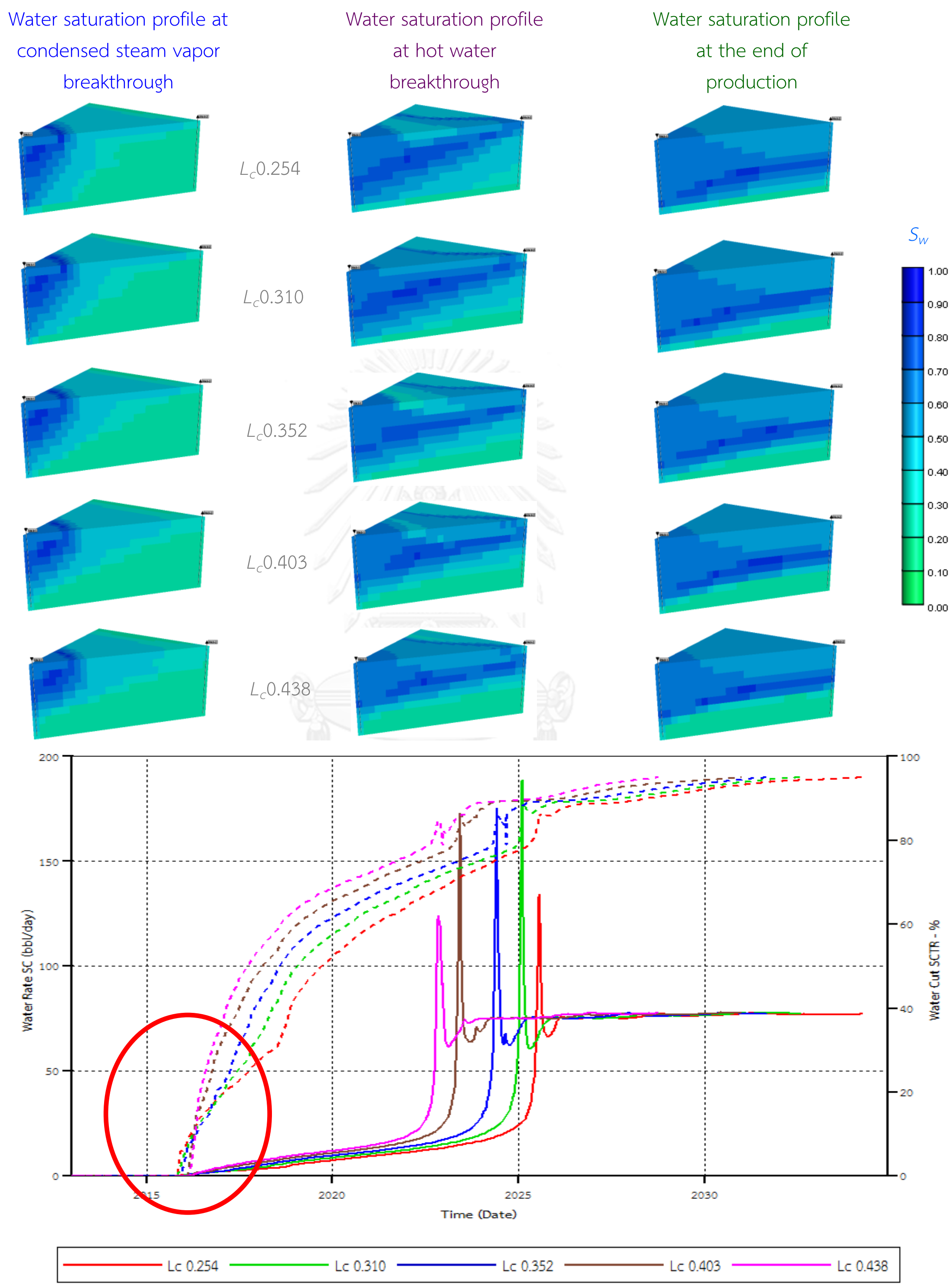


Figure 5.24 Water production rates, water cut and water saturation profile at corresponding periods obtained from different heterogeneous reservoirs

Considering enthalpy consumed per oil recovery shown in Figure 5.25, there is no exact trend from this graph for the whole range. For reservoir model with Lorenz coefficient of 0.254, energy consumed is relatively high since total production period is the longest one. That means, amount of steam injected is the largest. Even though this case yields the highest oil recovery, energy consumed is quite high due to long steam injection period. Reservoir model with the highest reservoir heterogeneity shows an exceptional low energy consumed. Very early production termination results in the smallest amount of steam as well as energy consumed.

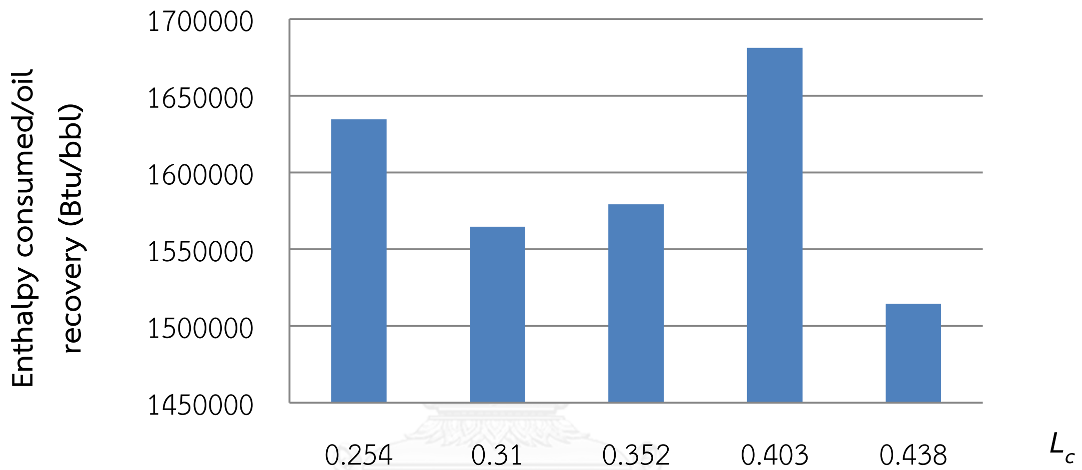


Figure 5.25 Enthalpy consumed per barrel of oil recovery as a function of Lorenz coefficient

The effect of heterogeneity is quite obvious on effectiveness of steam injection process. High value of heterogeneity results in favorable flow path that reduces volumetric sweep efficiency of the process. The higher the heterogeneity, the lower the volumetric sweep efficiency. Reducing of displaceable volume also results in shorter time for breakthrough as well as total production period. Even though, oil recovery factor is directly related to volumetric sweep efficiency, it is also limited by production constraints. Under the same production constraints, energy consumed per barrel of oil produced shows the optimum heterogeneity where steam injection period is not too long and oil recovery is quite high.

5.4 Effect of Relative Permeability

An exact relative permeability curves for any process are difficult to obtain. Many factors can alter shape of relative permeability curves and hence, study of sensitivity of relative permeability should be performed thoroughly. Two sets of relative permeability curves are input to reservoir simulator, which are relative permeability curve set at reservoir temperature and at elevated temperature. Variation of relative permeability to both oil and water has to be investigated individually for both before and after steamflooding. Moreover, as irreducible water saturation increases with temperature, shift of end point saturations are also evaluated.

Simulation outcomes including cumulative oil production, oil recovery factors, total water production and enthalpy consumed per barrel of oil of all reservoir models with variation of relative permeability set and reservoir heterogeneity are summarized in each section.

5.4.1 Effect of Relative Permeability to Water at Reservoir Temperature

In this section, only relative permeability to water at reservoir temperature is varied. Relative permeability to water is varied to 0.05 and 0.15 as the selected base case relative permeability to water is 0.1. By keeping relative permeability to oil constant at 0.6 and keeping the same relative permeability curve after steamflooding in all cases, relative permeability curves in this study are shown in Figure 5.26 and simulation outcomes including oil recovery factor, water production and steam injection duration are shown in Figure 5.27.

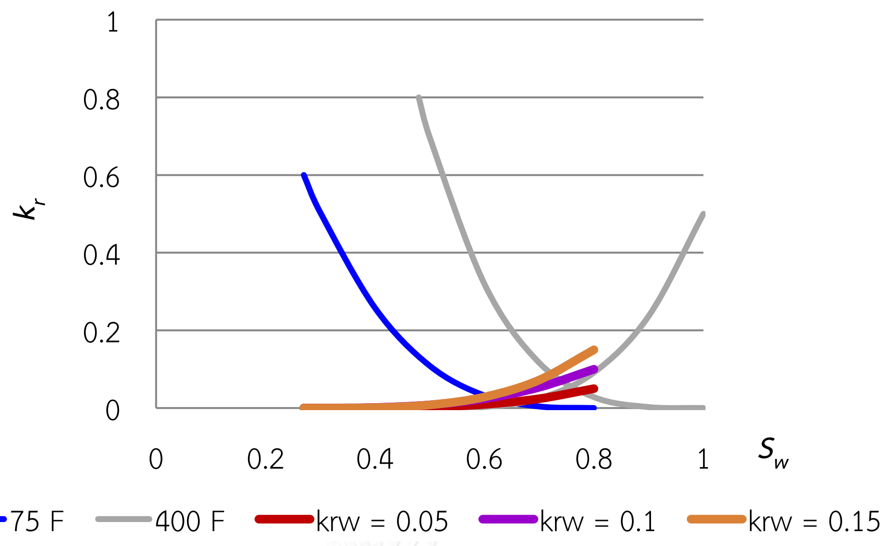


Figure 5. 26 Relative permeability curves for the study of relative permeability to water at residual oil saturation and reservoir temperature

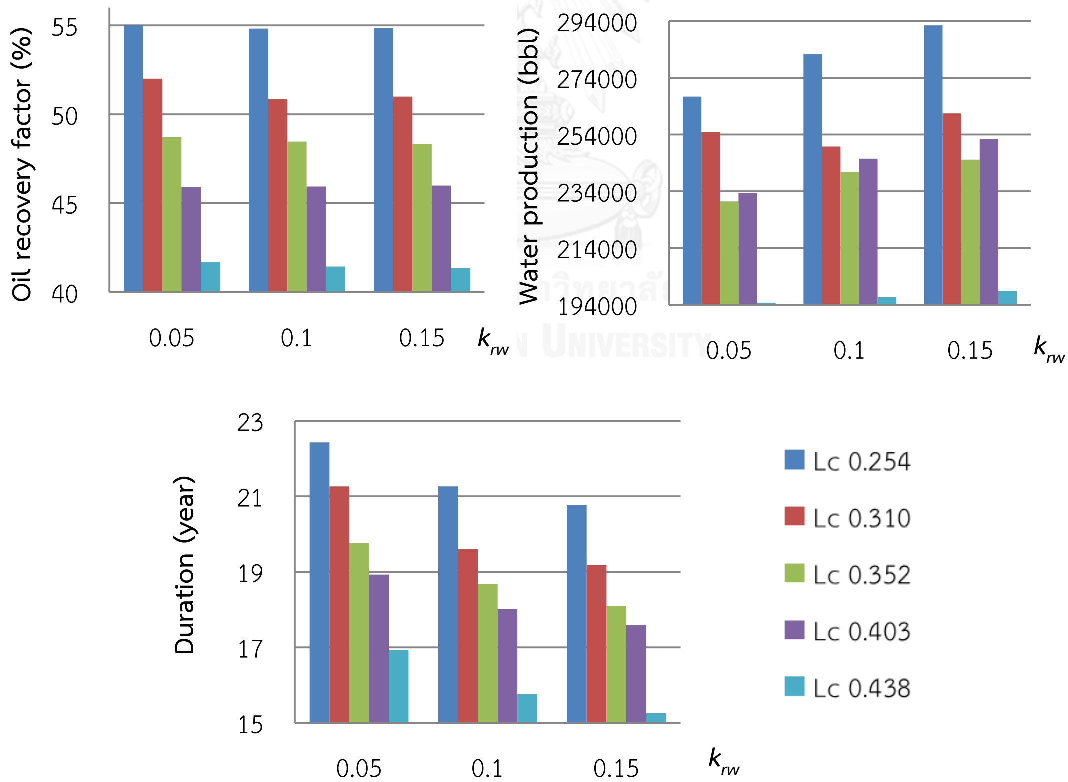


Figure 5. 27 Oil recovery factors, water productions and steam injection duration as a function of k_{rw} at residual oil saturation and reservoir temperature for reservoir models with various heterogeneities

From Figure 5.27, oil recovery factor is almost constant for all cases whereas water production increases with increment of relative permeability to water at residual oil saturation. Total steam injection period however, shows a contrast to water production which is, decreasing with increment of relative permeability to water. Exceptional data is observed for relative permeability to water of 0.05 run in reservoir model with Lorenz coefficient of 0.310 that could be due to long injection period. Higher heterogeneity results in poor sweep efficiency, hence total production period is less since production constraints are early reached. Therefore, oil recovery factor and water production are relatively small compared to cases with smaller heterogeneity. In order to explain better interest simulation outcomes, more observations on oil and water production rates are illustrated in Figure 5.26.

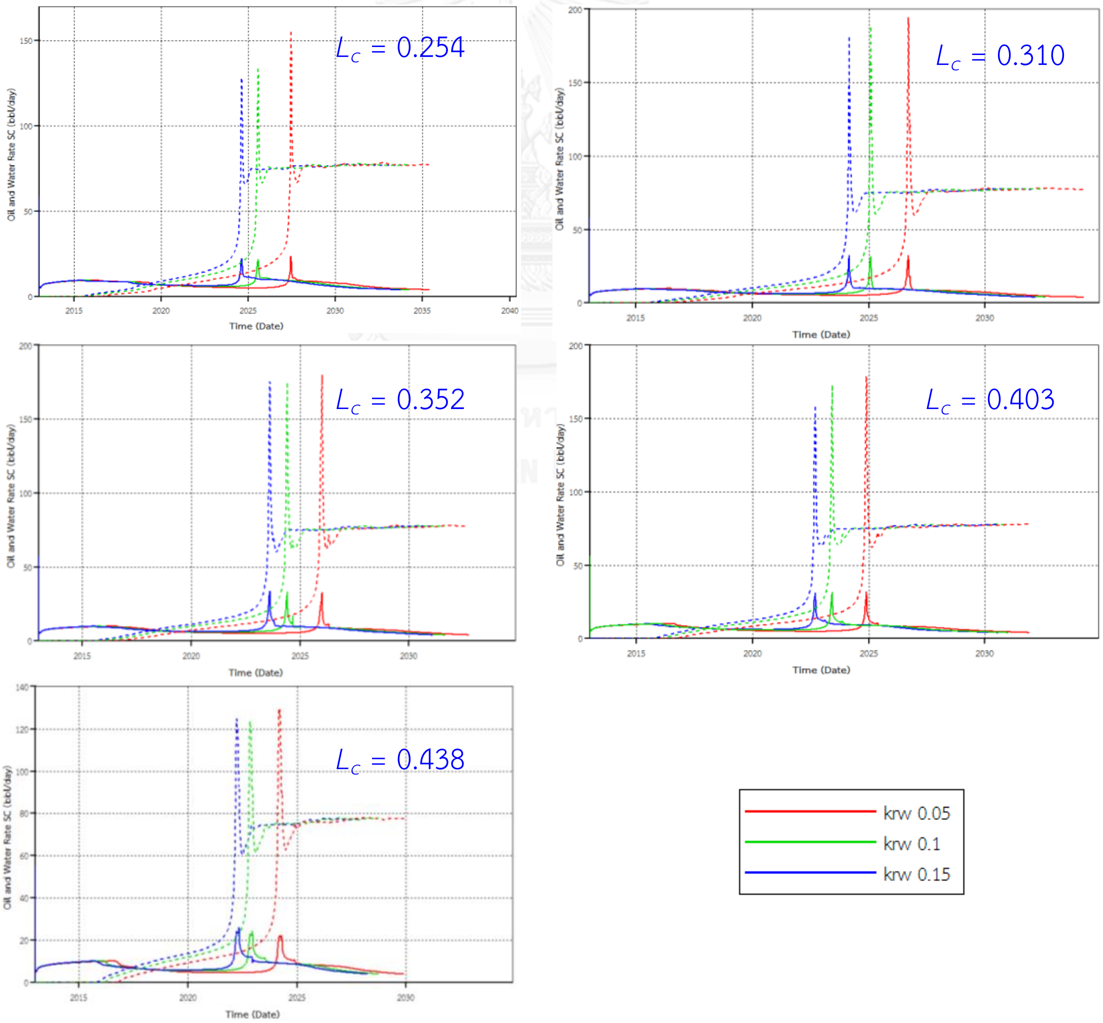


Figure 5. 28 Oil and water production rates as a function of k_{rw} at residual oil saturation at reservoir temperature from various reservoir heterogeneities

From Figure 5.28, hot water breakthrough appears earlier when relative permeability to water increases. Together with hot water breakthrough, oil bank from heat exchanging shows its peak around the same time. Earlier in hot water breakthrough also causes shorter production period as water cut reaches the constraint. Similar oil recovery factor obtained from each model can be explained by the fact that most recoverable oil is obtained after hot water breakthrough and after that oil production is maintained at very low amount. Therefore, different total production time does not change much oil recovery. However, water production does not follow the same trend. Longer steam injection period is resulted from low relative permeability to water. Nevertheless, it can be observed that water production rate in period of condensed steam water is high in early stage in case of high relative permeability to water, resulting in higher amount of total water production even total steam injection duration is shorter. An exception from the case of relative permeability to water of 0.05 run in model with Lorenz coefficient of 0.310 can be explained from the exceptional longer injection period that eventually overcomes amount of water from condensed steam water period.

In conclusion, relative permeability to water shows its effect at early period when reservoir temperature is not heated to elevated state. Higher relative permeability to water results in faster attaining relative permeability at elevated temperature and hence, higher water production rate. Moreover, early hot water breakthrough is also a consequence effect that eventually results in higher water production compared to cases with lower relative permeability to water.

5.4.2 Effect of Relative Permeability to Oil at Reservoir Temperature

Similar to previous section, only relative permeability to oil at reservoir condition is varied. Relative permeability to oil at irreducible water saturation is varied to 0.5 and 0.7. Value of relative permeability to oil in base case is 0.6. Relative permeability to water at residual oil saturation is kept constant at 0.1 and relative permeability curves to both oil and water at elevated temperature are the same in all cases. Relative permeability curves in this section are shown in Figure 5.29 and simulation outcomes including oil recovery factor, water production and steam injection duration are illustrated in Figure 5.30.

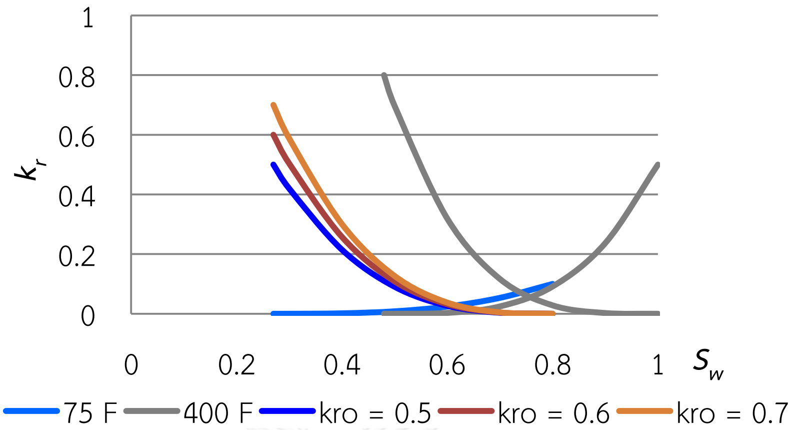


Figure 5. 29 Relative permeability curves for the study of relative permeability to oil at reservoir temperature

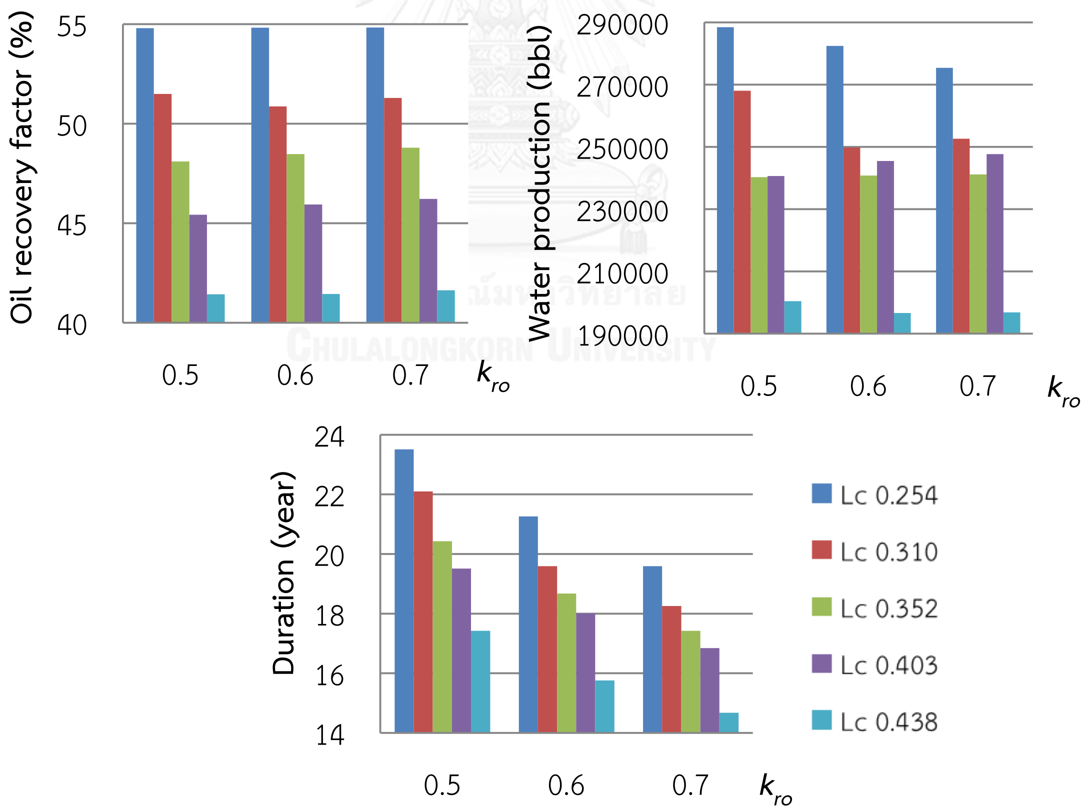


Figure 5. 30 Oil recovery factors, water productions and steam injection duration as a function of k_{ro} at irreducible water saturation at reservoir temperature for reservoir models with various heterogeneities

From Figure 5.30, an increase trend of oil recovery in most heterogeneity can be observed. Water production does not show exact trend whereas, steam injection duration decreases as k_{ro} increases, as same as in case of k_{rw}. Oil and water production rates are therefore, examined to identify reason for inexact trend of water production. Figure 5.31 shows oil and water production rates in every reservoir model as a function of k_{ro} at irreducible water saturation.

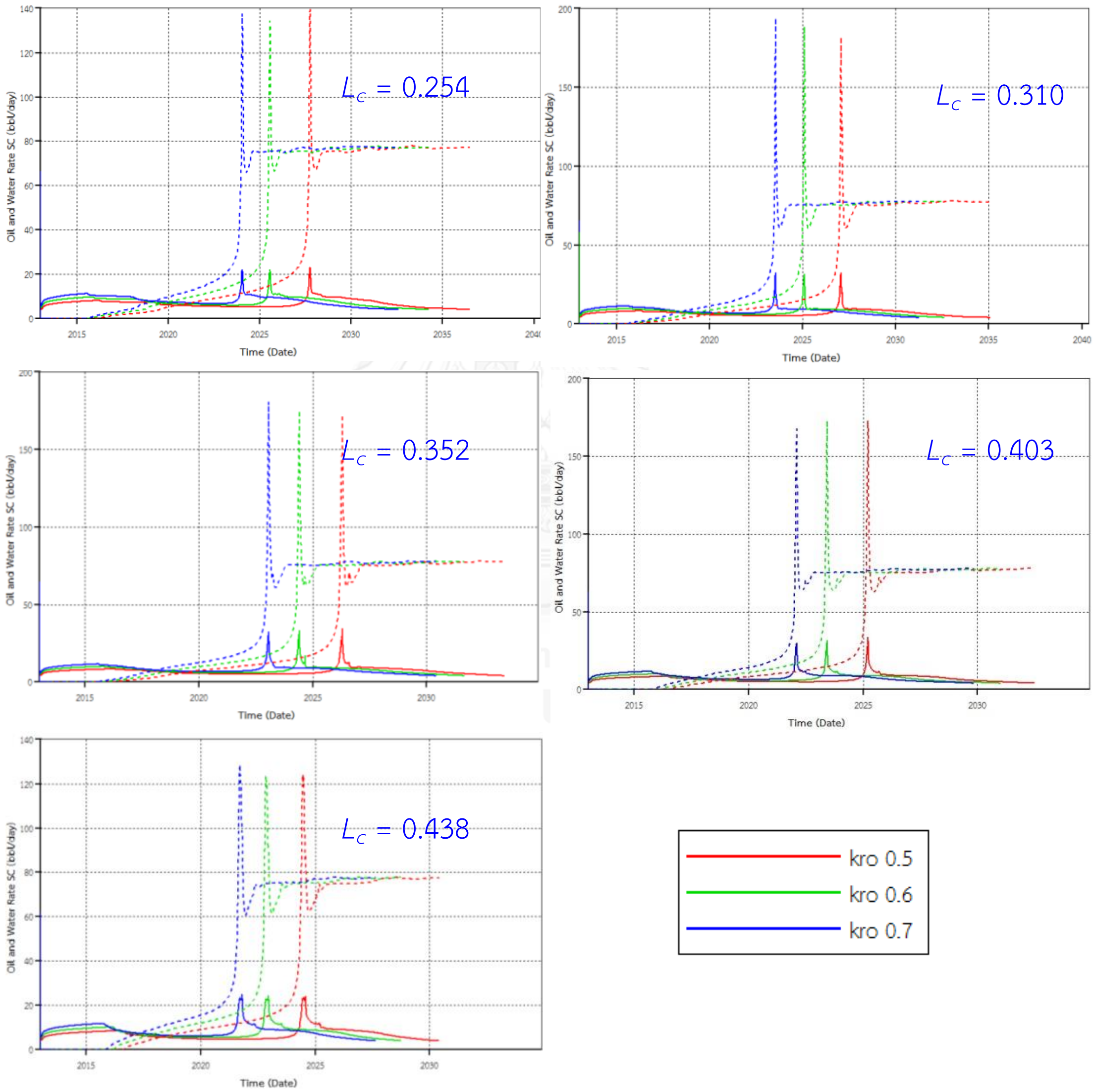


Figure 5. 31 Oil and water production rates as a function of k_{ro} at irreducible water saturation at reservoir temperature from various reservoir heterogeneities

From Figure 5.31, hot water bank together with heated oil bank breakthrough earlier as relative permeability to oil increases in every heterogeneity value. This can be explained that at the condition before elevated temperature, flow ability of oil is better in case of high relative permeability to oil. As a consequent, steam can be injected easier and this results in earlier breakthrough of hot water and heated oil bank. Oil production rate from the start also confirms that oil production rate in case of high relative permeability to oil causes a better flow ability. This part of produced oil could be reason for a slight increasing trend of oil recovery in each reservoir heterogeneity.

As high relative permeability to oil improves steam injectivity, steam is injected easier and hence, production constraint is attained earlier. An expected trend can be seen in case of reservoir with low heterogeneity where permeability is well distributed. The longer steam injection period results in higher water production which is corresponding to the case with low relative permeability to oil.

Trend is diverted as heterogeneity increases. Increasing trend of water production is observed. Even though total production period is decreasing for all reservoir heterogeneity as relative permeability to oil increases, heterogeneity results in irregular high water production. Smaller sweep efficiency causes excessive water production in case of high relative permeability to oil. This high water production overcomes amount of water produced before termination of production. In other words, ratios of water production before and after hot water breakthrough are not constant, resulting in trend that is independent from steam injection duration.

In conclusion, increasing of relative permeability of oil slightly increases oil recovery factor in first period where elevated temperature is not taken place. However, consequence effect is much more important. Higher relative permeability to oil results in higher steam injectivity. Early hot water breakthrough is therefore observed. Increase in reservoir heterogeneity results in water production trend that is independent from total steam injection period.

5.4.3 Effect of Corey's Exponent of Relative Permeability at Reservoir Temperature

In this section, Corey's exponent of relative permeability curves at reservoir temperature is varied from 3 (in base case) to 2 and 4. As Corey's exponent (*n*) increases, relative permeability curves are more curvaceous, meaning that flow ability of any fluid is less or can be explained as that fluid tends to adhere more on rock surface. By keeping end point saturations and relative permeabilities to oil and water at end point saturations constant, relative permeability curves with previously mentioned exponents can be constructed as shown in Figure 5.32. Simulation outcomes including oil recovery factor, water production and steam injection duration are illustrated in Figure 5.33.

From Figure 5.33, oil recovery factor increases as Corey exponent increases. As flow ability of both fluids are substantially decreases at reservoir temperature, this results in longer time for reservoir to attain flow ability at elevated temperature. Hence, production period is prolonged and oil recovery is correspondingly increased. Higher heterogeneity shows a decreasing trend in both oil recovery factor and duration of steam injection. Trend of water production is quite different from oil recovery and steam injection duration. Reduction of water production from Corey's exponent of 2 to 3 is a result from decreasing of flow ability of water even total production period is prolonged. From Corey's exponent of 3 to 4, water production increases again in most case due to much longer production time that overcomes effect of low flow ability of water. In cases of Lorenz coefficient of 0.254, trend of water production does not follow previous explanation. Oil and water production rates are then taken for consideration as shown in Figure 5.34 to solve this case.

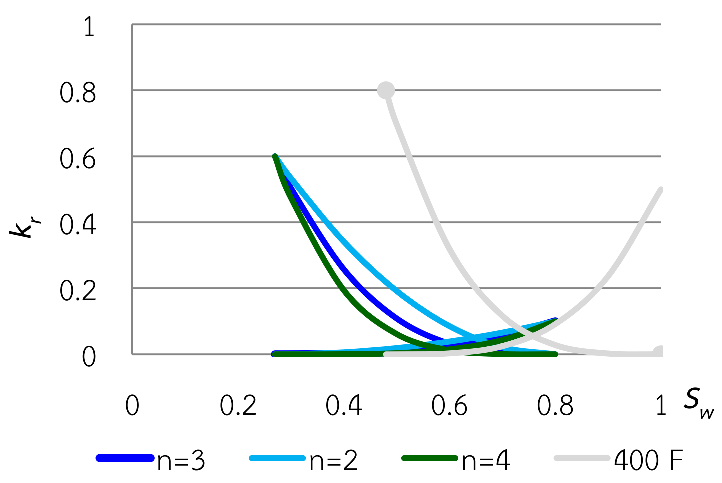


Figure 5. 32 Relative permeability curves with various Corey's exponents at reservoir temperature

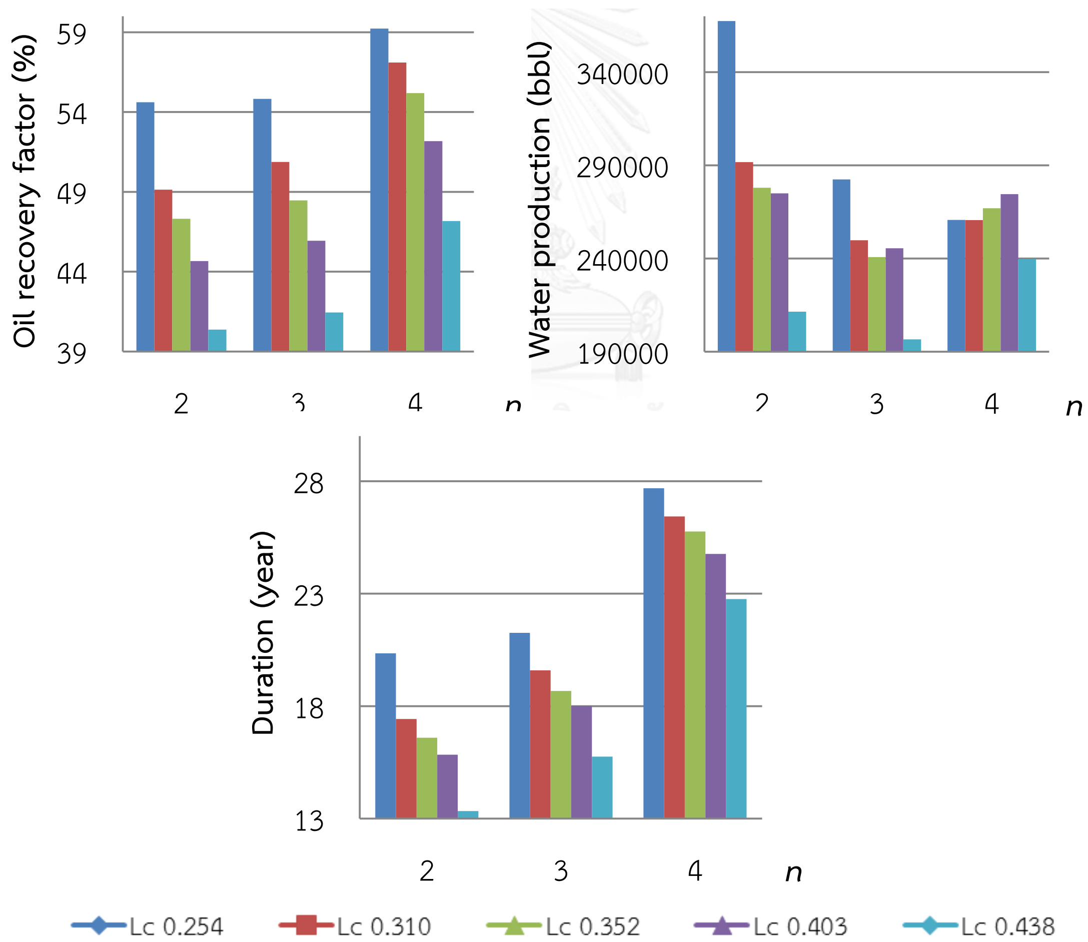


Figure 5. 33 Oil recovery factors, water productions and steam injection duration for reservoir models with various heterogeneities as a function of Corey's exponent (*n*) at reservoir temperature

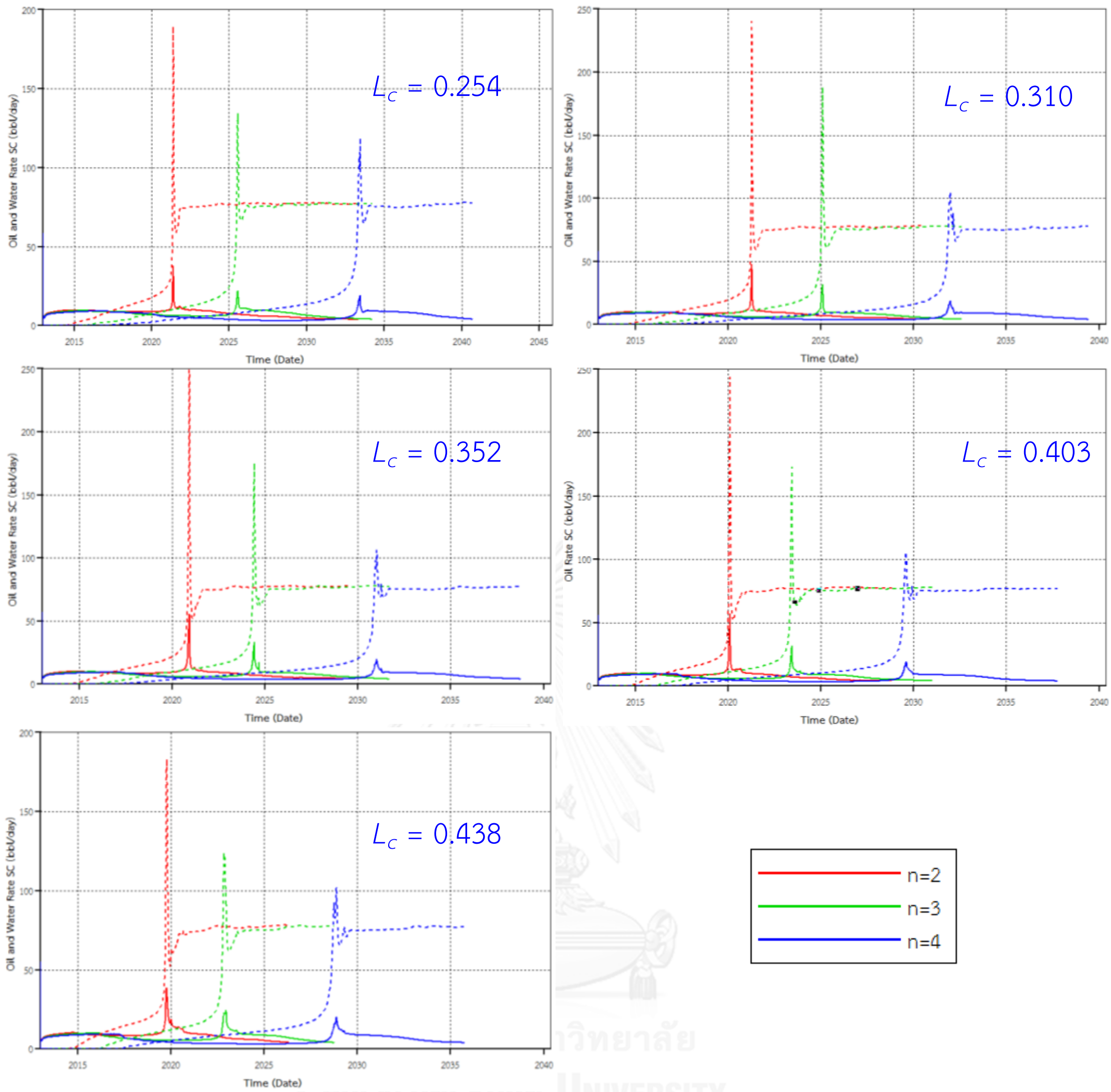


Figure 5. 34 Oil and water production rates of various reservoir heterogeneities and Corey's exponent (*n*) at reservoir temperature as a function of time

From Figure 5.34, it can be seen that water production period after hot water breakthrough in case of Lorenz coefficient of 0.254 is quite short compared to other Lorenz coefficients at the same exponent. This is the main reason why water production is substantially reduced. As permeability distribution is quite good in case of 0.254, water can penetrate downward better than other cases. Breakthrough of water therefore occurs in big portion of producing well and hence, maximum water cut is reached in shorter period.

In conclusion, curvaceous of relative permeability curves plays a major role in both oil and water predictions. Highly curvaceous curves can be inferred to low flow ability or good adherence on rock surface. This causes low fluid rate that could eventually changes production period due to production constraint. Together with reservoir heterogeneity, water production is hardly predicted. From this study, reservoir possessing small heterogeneity tends to reduce water production with an increment of Corey's exponent.

5.4.4 Effect of End Point Saturation of Relative Permeability Curves at Reservoir Temperature

In this section, shape of relative permeability curves is fixed. The only change is end point saturations including irreducible water saturation (S_{wi}) and residual oil saturation (S_{or}). Both are proportionally shifted to left and right. By keeping the same relative permeability curves at elevate temperature, relative permeability curves are shown in Figure 5.35 and simulation outcomes including oil recovery factor, water production and steam injection duration are shown in Figure 5.36.

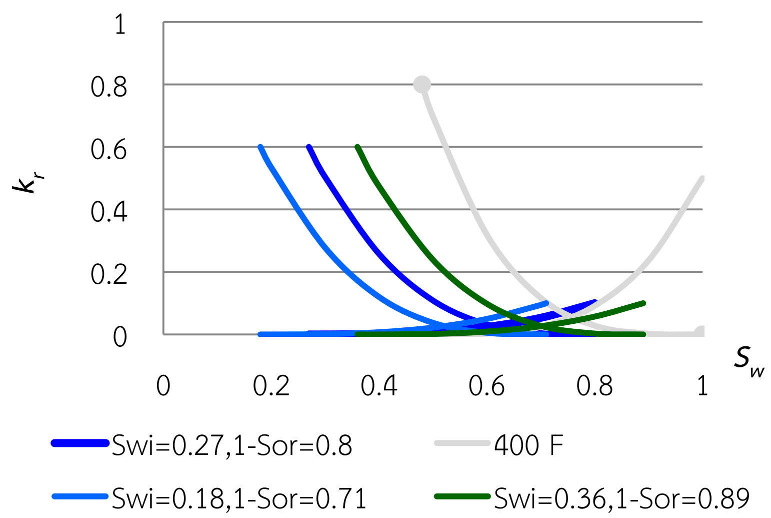


Figure 5. 35 Relative permeability curves with various end point saturations at reservoir temperature

From Figure 5.36, increasing in irreducible water saturation together with reducing residual of oil saturation results in reducing oil recovery in every reservoir heterogeneity. As major target of steamflooding process is to recover residual oil saturation, reduction in residual oil saturation also reduces recoverable amount.

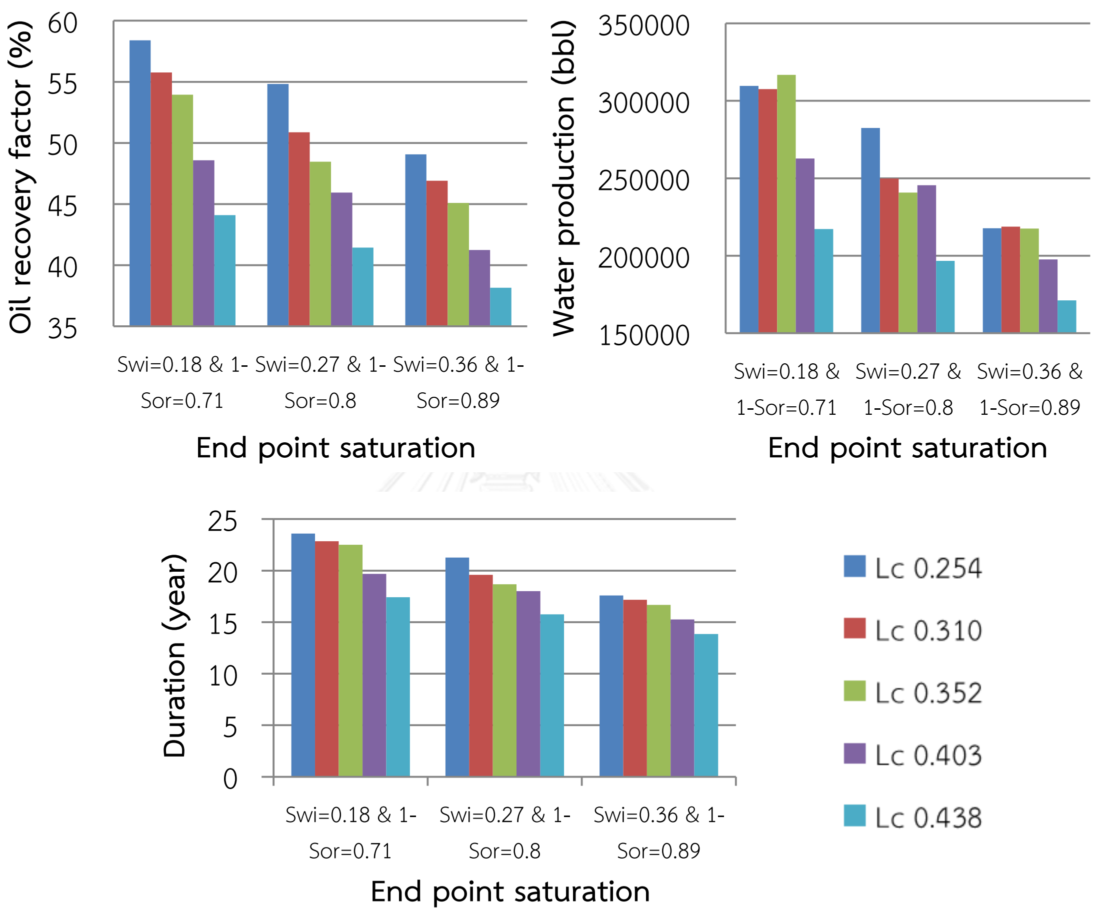


Figure 5. 36 Oil recovery factors, water productions and steam injection duration for reservoir models with various heterogeneities as a function of end point saturation at reservoir temperature

Increasing irreducible water saturation can infer to reduction of displaceable volume. Hence, earlier water breakthrough occurs and hence, steam injection period is reduced. Increasing in heterogeneity tends to decrease oil recovery and steam injection period. Water production however, does not show an exact trend with heterogeneity in all cases. More observation of water production is therefore, performed by considering oil and water production rates shown in Figure 5.37.

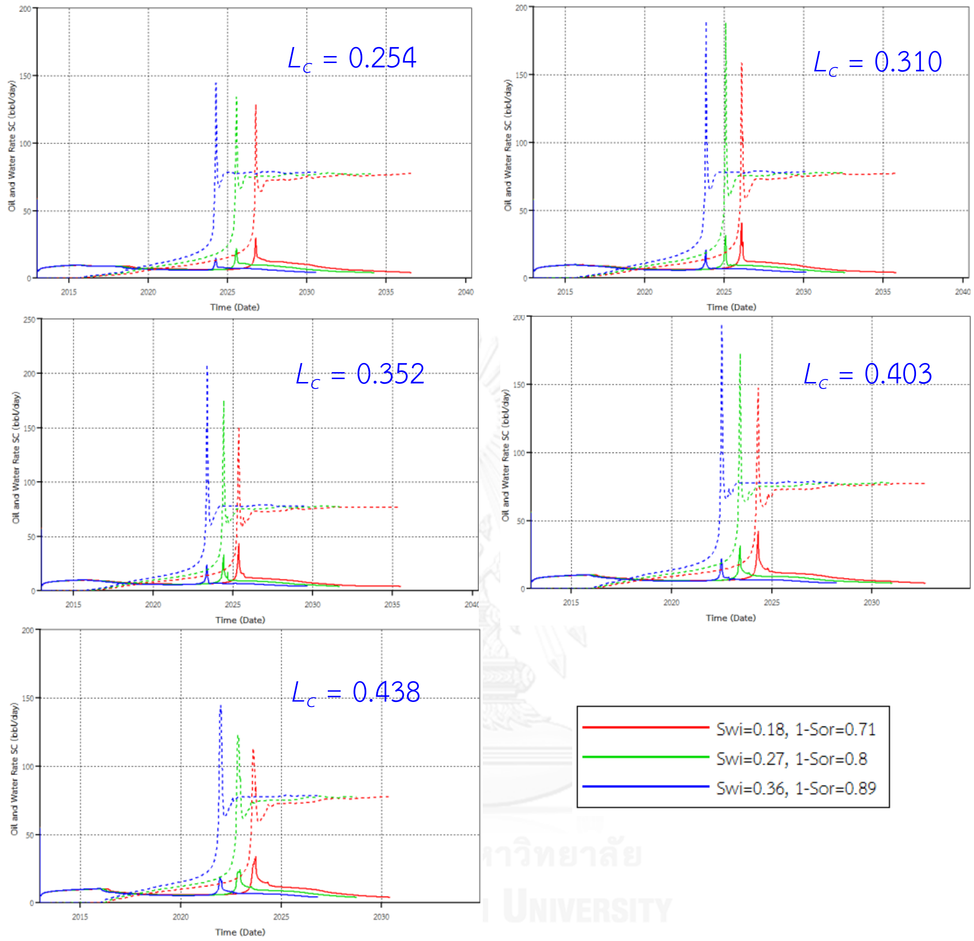


Figure 5. 37 Oil and water production rates from various reservoir heterogeneities and various end point saturations at reservoir temperature

From Figure 5.37, oil production rate increases as residual oil saturation increases. As explained earlier, higher residual oil saturation is the main target of steamfooding and higher oil saturation results in higher oil recovery factor. Effect of reservoir heterogeneity on water production is quite difficult to observe by the way. However, the only explanation can be made here is that total water production is sensitive to balance between hot water breakthrough time and total steam injection period. Different in heterogeneity results in different ratio of these two paces.

Anomaly of high water production is from early hot water breakthrough but still, the formation can maintain production for longer period and hence, summation of water production is high. From this study, this phenomenon occurs from Lorenz coefficient of 0.310 to 0.403 where early breakthrough can occur but reservoir can maintain production above constraint for while.

In conclusion, shifting of end point saturation greatly affects steamflooding performance. Reducing irreducible water saturation increases displaceable volume of reservoir and hence, early breakthrough of water is prolonged. Increasing residual oil saturation increases amount of recoverable oil since this part of oil can be recovered by heat from steam. Heterogeneity shows exact trend on oil recovery factor and steam injection period. However, water production can be different. Periods where hot water breakthroughs and steam injection terminates are important keys to answer this irregular water production. From this study, reservoir with Lorenz coefficient from 0.310 to 0.403 causes irrelevant periods of these events and eventually results in high water production.

5.4.5 Effect of Wettability at Reservoir Temperature

In this section, relative permeability curves at reservoir condition are modified for four parameters: irreducible water saturation, residual oil saturation, relative permeability to oil at S_{oi} and relative permeability to water at S_{or}. Details of relative permeability curves at different end point saturations are shown in Table 5.5. All relative permeability sets are constructed by keeping displaceable oil to be constant. Relative permeability curves after steamflooding is the same in all cases. Relative permeability curves in this section are shown in Figure 5.38 and simulation outcomes including oil recovery factor, water production and steam injection duration are shown in Figure 5.39.

Table 5. 5 Details of relative permeability curves with different wetting conditions at reservoir temperature

Wetting condition	S_{wi}	k_{ro}	$1\text{-}S_{or}$	k_{rw}
Oil-wet	0.18	0.5	0.71	0.15
Neutral wet	0.27	0.6	0.8	0.1
Water-wet	0.36	0.7	0.89	0.05

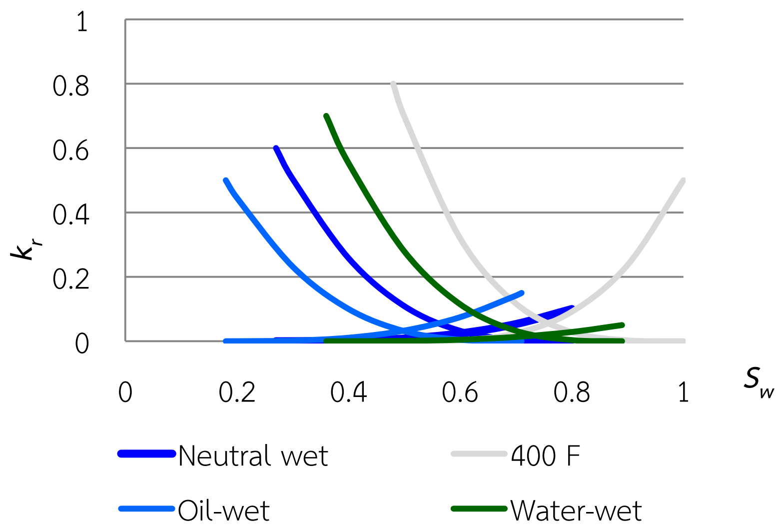


Figure 5. 38 Relative permeability curves at different wetting conditions at reservoir temperature

From Figure 5.39, it can be obviously seen that oil recovery factor decreases as relative permeability curves shift to a more water-wet direction. Comparing to previous sections including effect of relative permeability to water, relative permeability to oil and end point saturations, results follow the same pattern of end point saturations. Therefore, end point saturation is probably the most important parameter that governs effectiveness of steamflooding. As reservoir is flooded by steam and hot water, relative permeability curves to oil and water are altered to those at elevated temperature. Therefore, effects of these parameters are relatively small compared to that of end point saturations that mainly control amount of recoverable oil.

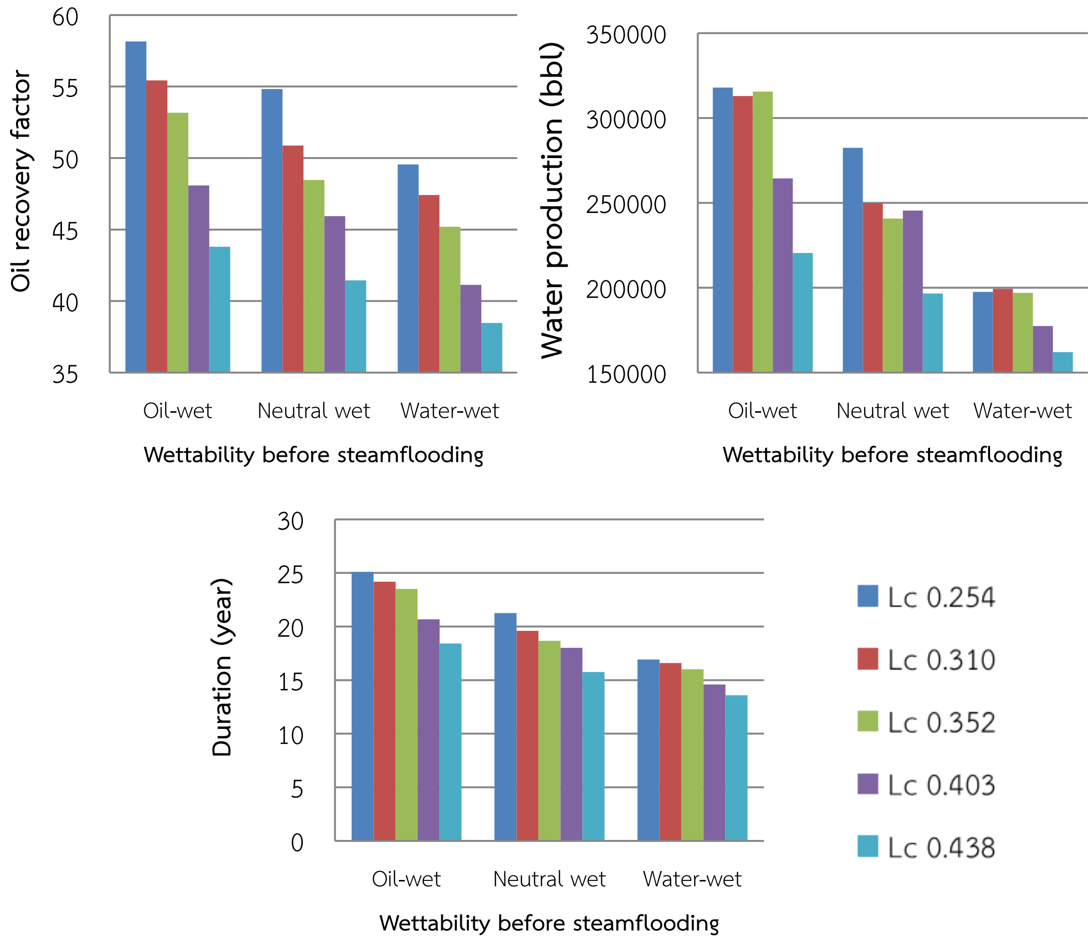


Figure 5. 39 Oil recovery factors, water productions and steam injection duration of various reservoir heterogeneities and different wetting conditions at reservoir temperature

Summation of relative permeabilities and end point saturations results in wetting condition at reservoir condition shows that end point saturation is the one that plays important role on steamflooding performance compared to relative permeability to oil or to water. Increase of residual oil saturation and decrease of irreducible water saturation result in benefit to steamflooding. Invisible effect of relative permeability to oil and to water prior to steamflooding is due to a rapid change to elevated temperature when steam is injected into reservoir.

5.4.6 Effect of Relative Permeability to Water at Elevated Temperature

In this section, only relative permeability to water at elevated temperature is varied. Relative permeability to water is increased from 0.5 to 0.8. By maintaining relative permeability to oil at elevated temperature as well as relative permeability curves at reservoir temperature, two relative permeability sets in this study are shown in Figure 5.40 and simulation outcomes including oil recovery factor, water production and steam injection duration are shown in Figure 5.41.

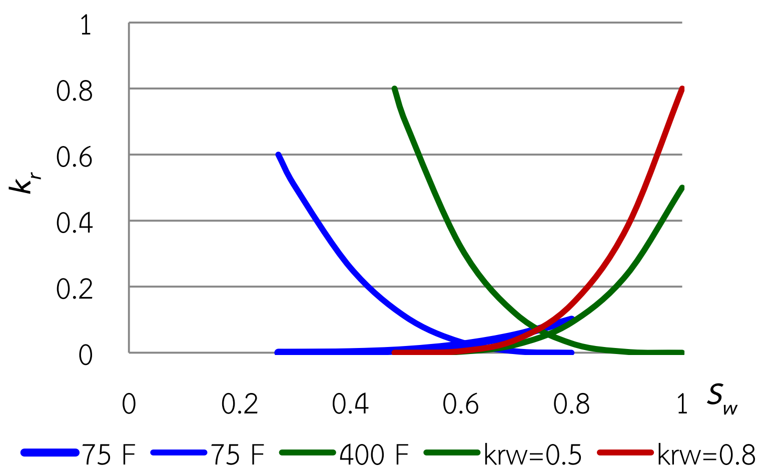


Figure 5. 40 Relative permeability curves for the study of relative permeabilities to water at elevated temperature

From Figure 5.41, oil recovery decreases as relative permeability to water at elevated temperature is increased. As relative permeability to water is increased, condensed steam and hot water flow quickly, resulting in early termination of production well due to 95 percent water cut. However, total production period in several heterogeneity do not follow an explanation. Increasing of relative permeability to water at end point saturation slightly delay termination of steam injection. This consecutively results in higher water production in cases of reservoir with Lorenz coefficient of 0.310 and 0.352. Oil and water production rates obtaining from different two relative permeability curves to water at end point saturation for various reservoir heterogeneities are shown in Figure 5.42.

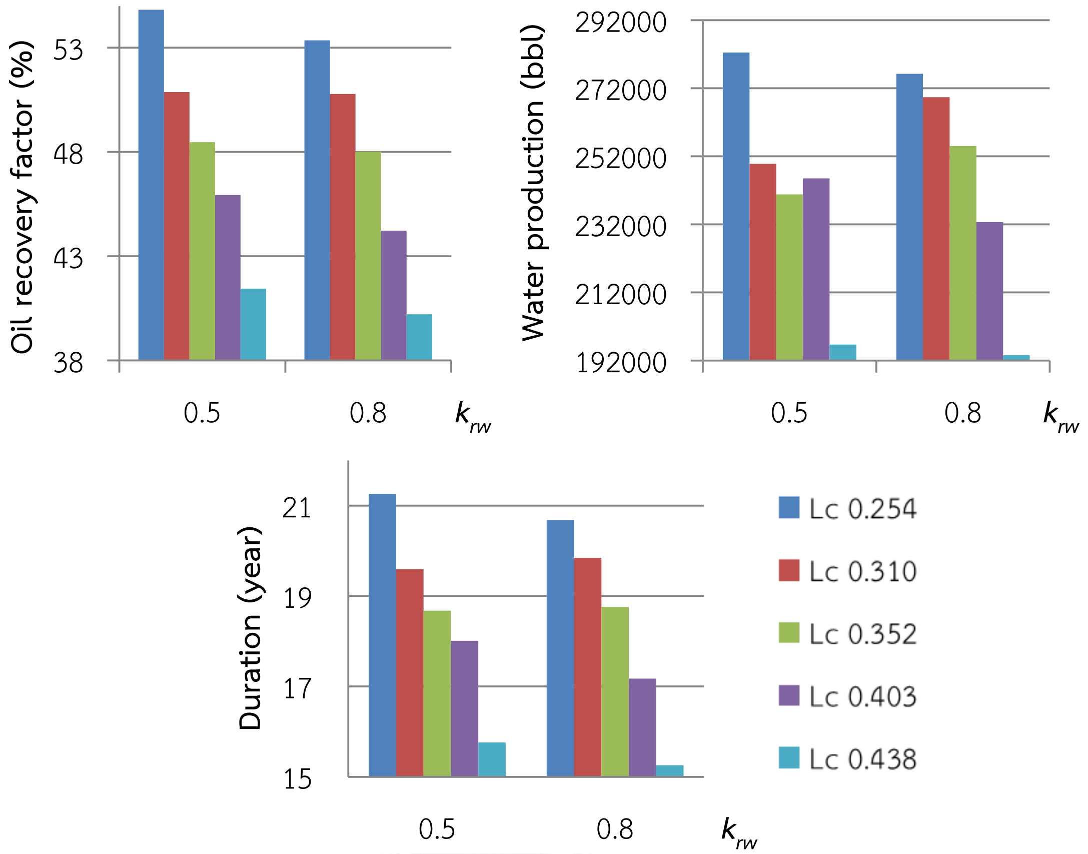


Figure 5. 41 Oil recovery factor, water production and steam injection duration for various reservoir heterogeneities and different relative permeabilities to water at elevated temperature

From Figure 5.42, total production period of cases with Lorenz coefficient of 0.310 and 0.352 are mostly the same when changing relative permeability to water from 0.5 to 0.8. And since hot water breakthrough occurs earlier in case of higher relative permeability to water as explained earlier, higher total water production is observed in these cases.

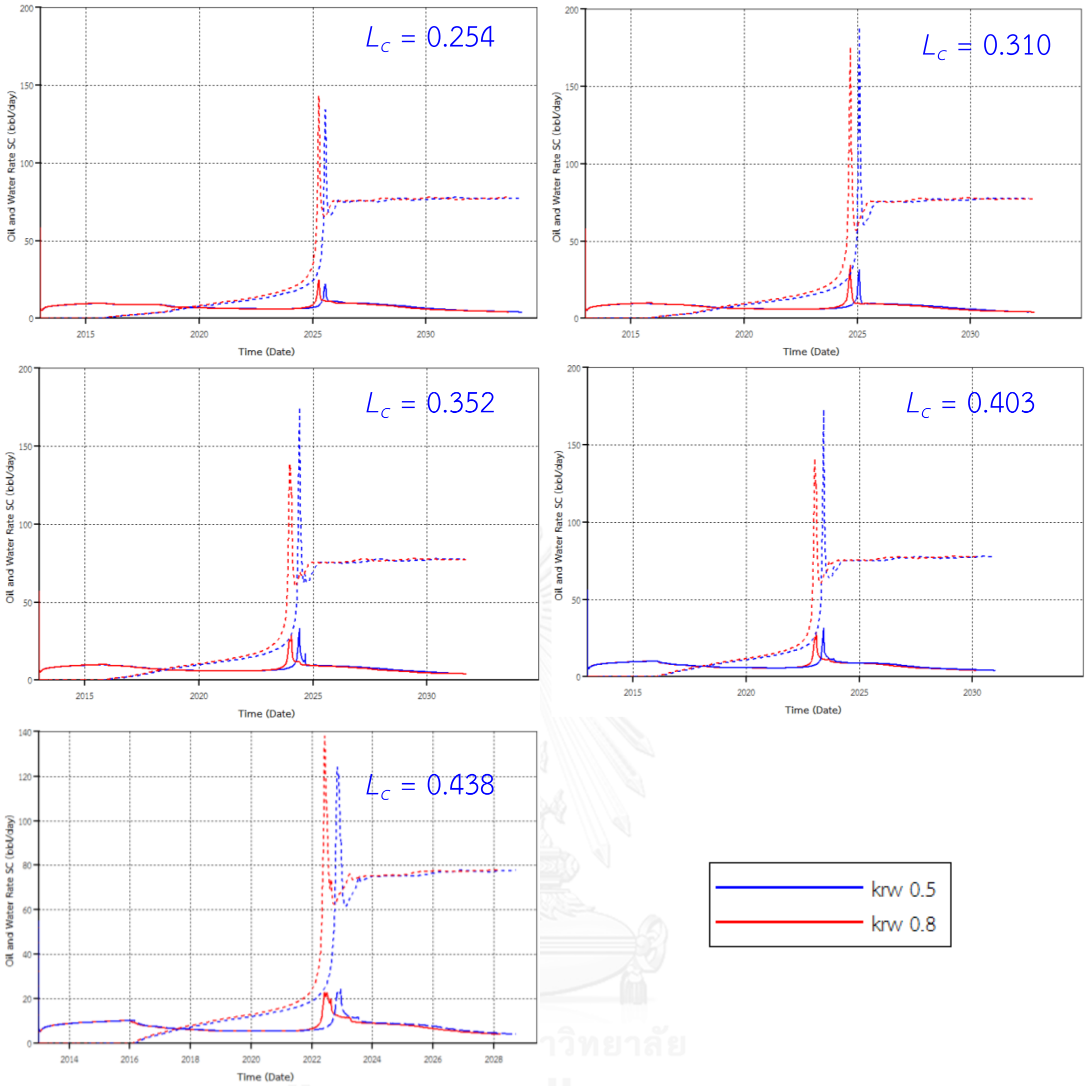


Figure 5. 42 Oil and water production rates for various reservoir heterogeneities and relative permeability to water at elevated temperature as a function of time

In conclusion, increasing relative permeability to water at elevated temperature results in earlier hot water breakthrough and this accelerates termination of steam injection process. However, total injection period and total water production are slightly affected from reservoir heterogeneity. Certain reservoir heterogeneity extends production period that eventually results in difficulty in prediction of water production.

5.4.7 Effect of Relative Permeability to Oil at Elevated Temperature

In this section, only relative permeability to oil at elevated temperature is varied. Value is increased from 0.8 in base case to 1.0 which is the maximum relative permeability. By keeping relative permeability to water at reservoir temperature at 0.1 and at elevated temperature at 0.5, relative permeability curves in this section are shown in Figure 5.43 and simulation outcomes including oil recovery factor, water production and steam injection duration are shown in Figure 5.44.

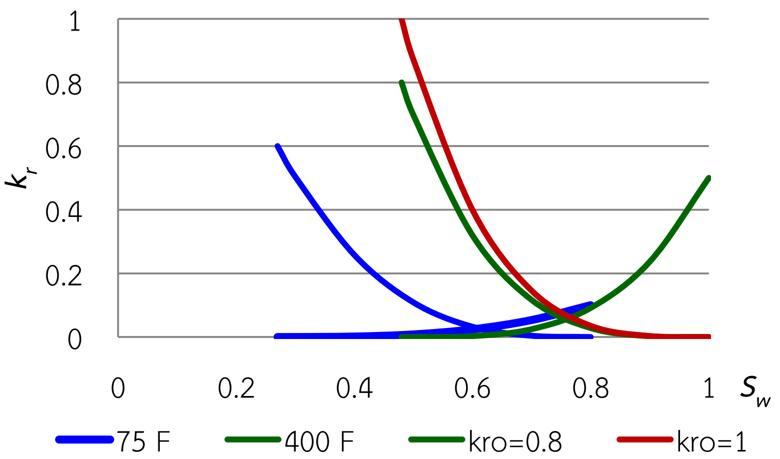


Figure 5. 43 Relative permeability curves for the study of relative permeability to oil at elevated temperature

From Figure 5.44, trends for both oil and water productions are similar in all reservoir heterogeneities. Increasing in relative permeability to oil at elevated temperature increases oil recovery factor and water production. Increment of oil recovery and water production is a result from slight increase of steam injection duration. In order to observe effect of relative permeability to oil at elevated temperature, oil and water production rates of various relative permeabilities to oil at elevated temperature in various reservoir heterogeneities are shown in Figure 5.45.

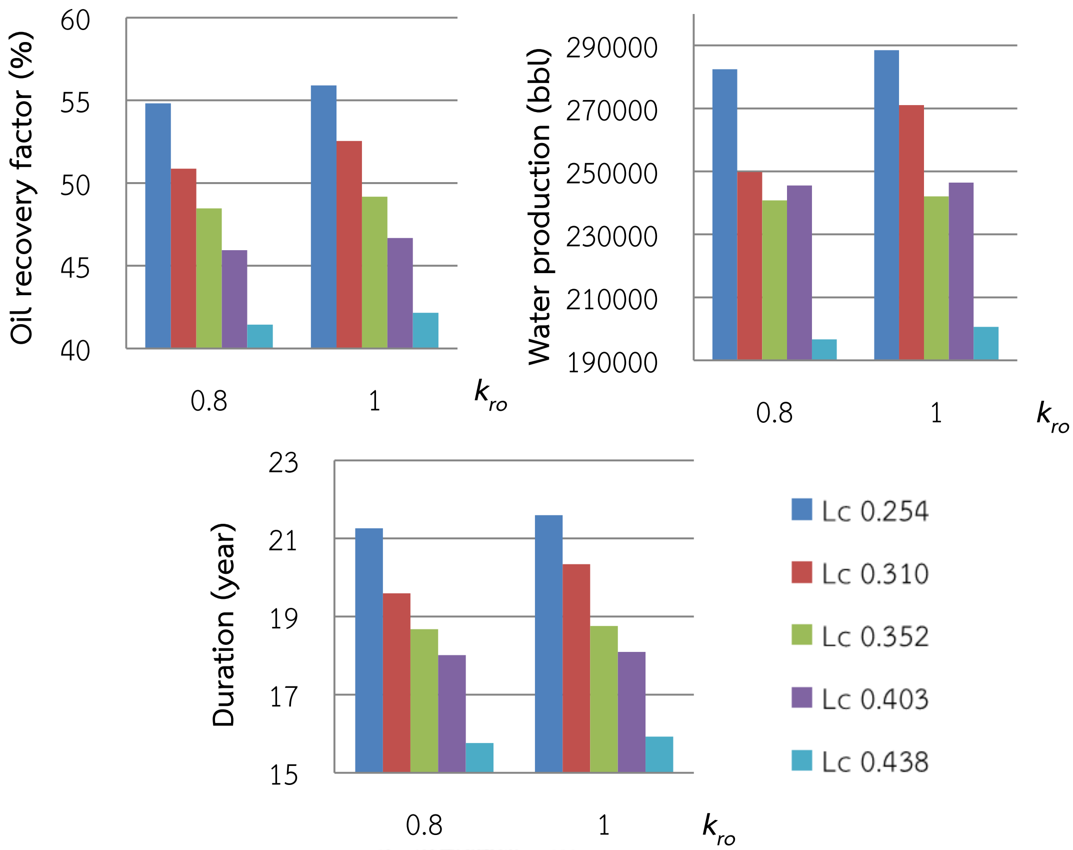


Figure 5. 44 Oil recovery factors, water productions and steam injection duration for various reservoir heterogeneities as a function of relative permeability to oil at elevated temperature

From Figure 5.45, as relative permeability to oil at elevated temperature increases, oil and water production rates are superimposed each other. A gradual shift in hot water breakthrough period can be observed in reservoir with Lorenz coefficient of 0.254. This could be explained that at elevated temperature oil is displaced not only in horizontal direction but also in vertical direction. High permeability to oil also drives oil in vertical direction. Reservoir with good vertical connectivity therefore, allows steam to displace easier when relative permeability to oil is higher. According to this, breakthroughs of oil bank and hot water occur slightly late in case of higher relative permeability to oil. As displacement occur slower, production time is extended due to slower attaining pre-set water cut and hence, oil recovery and total water production are higher compared to lower relative permeability to oil.

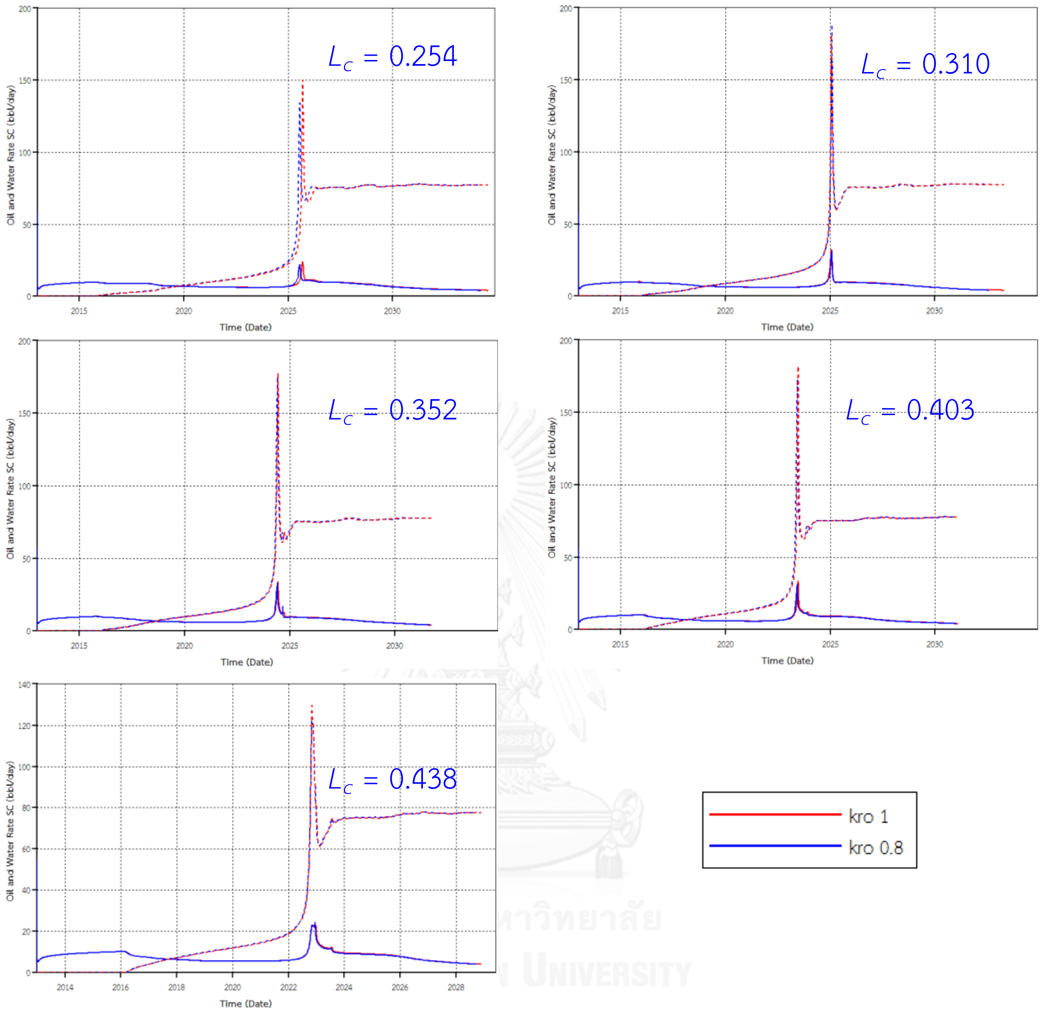


Figure 5. 45 Oil and water production rates for various reservoir heterogeneities and relative permeabilities to oil at elevated temperature as a function of time

As flow ability of oil is improved at elevated temperature, displacement by means of steam is slightly shown. A small extension of steam injection period is observed when higher relative permeability to oil at elevated temperature is used. Hot water retention is slightly longer and consecutively results in slower breakthrough of hot water. However, the difference between these two cases is noticeable in first period when oil saturation is high. The effect of chosen parameter might be more obvious if relative permeabilities to oil in both cases are different in whole range of saturation.

5.4.8 Effect of End Point Saturation of Relative Permeability Curves at Elevated Temperature

In this section, only end point saturations at elevated temperature are varied. Relative permeability to oil and water at end point saturations are kept constant as the base case. Two cases are chosen for the study in this section: 1) reduction just irreducible water saturation while keeping residual oil saturation constant and 2) reducing irreducible water saturation and increasing residual oil saturation (curves shift to left hand side). By keeping the same relative permeability curve at reservoir temperature, relative permeability curves in this study are shown in Figure 5.46. Simulation outcomes including oil recovery factor, water production and steam injection duration are shown in Figure 5.47.

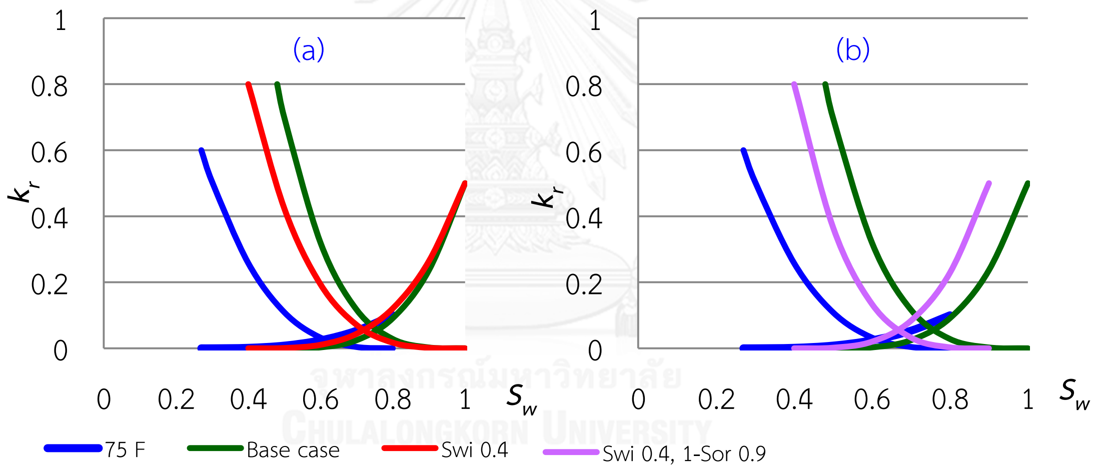


Figure 5. 46 Relative permeability curves of various end point saturations at elevated temperature a) reducing only irreducible water saturation and b) reducing irreducible water saturation and increasing residual oil saturation

From Figure 5.47, results from base case relative permeability curves are illustrated in the middle of every sub figures. When residual water saturation is decreased from 0.5 to 0.4, there is no effect on oil recovery factor as residual oil saturation is kept constant. However, when residual oil saturation is increased, oil recovery from every heterogeneity is declined. As irreducible water saturation decreases, displaceable volume is increased and this results in a well-distribution of data among all heterogeneities. Once residual oil saturation is increased, displaceable volume is decreased again and effect from heterogeneity is not well-distributed as water production in some cases are not differentiate from others. Oil and water production rates from models with various end point saturations at elevated temperature in various reservoir heterogeneities are shown in Figure 5.48.

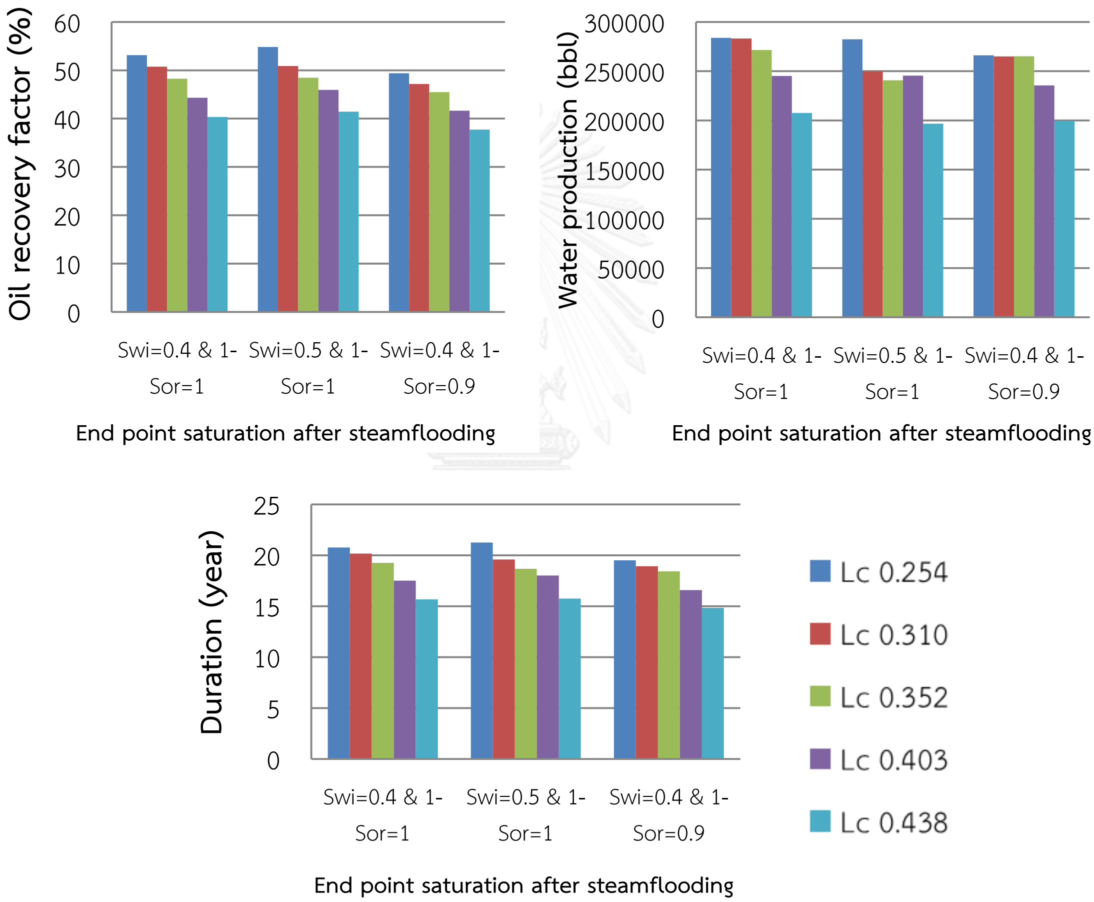


Figure 5. 47 Oil recovery factors, water productions and steam injection duration for various heterogeneities and end point saturations at elevated temperature

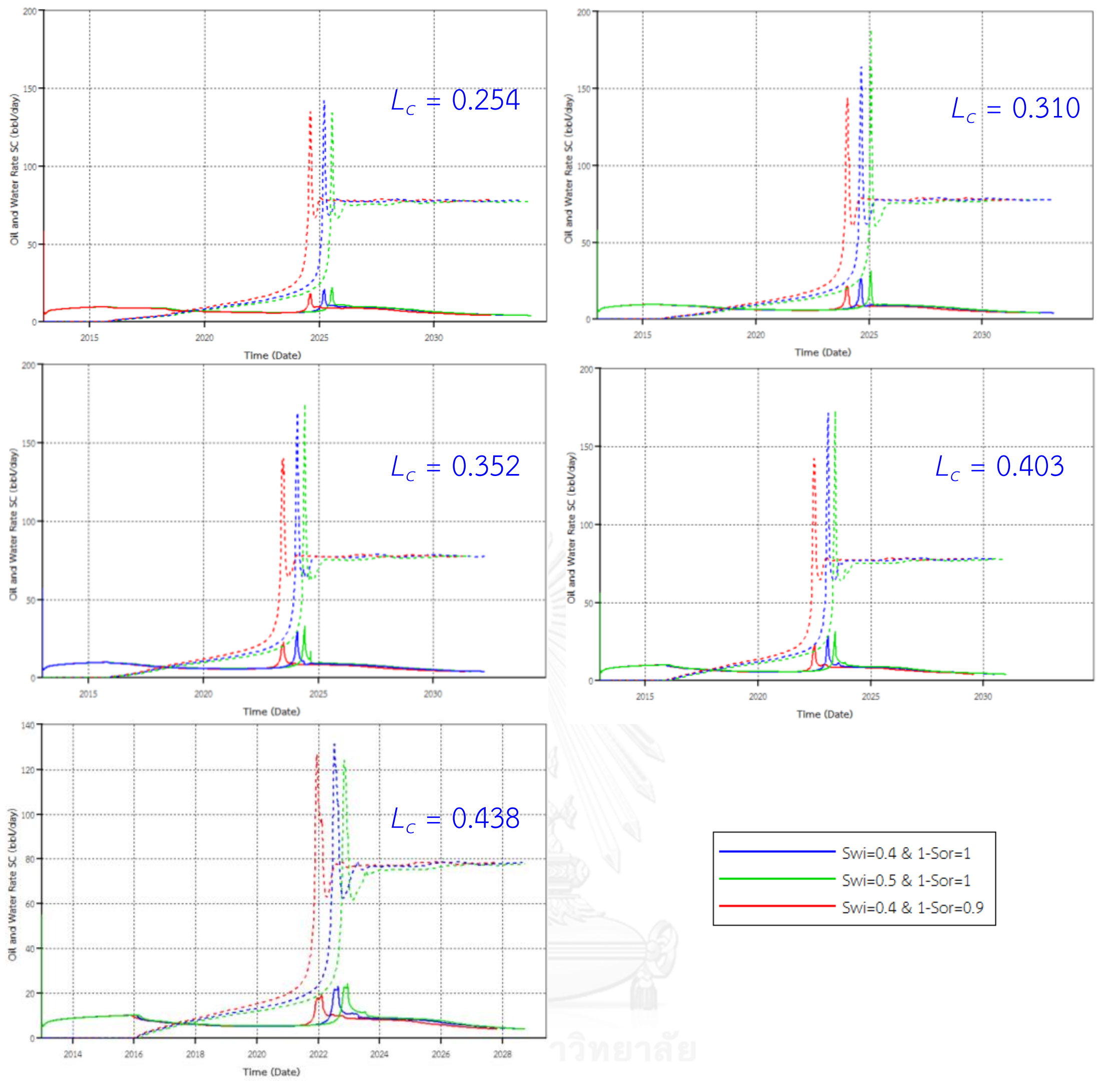


Figure 5. 48 Oil and water production rates for various reservoir heterogeneities and end point saturations at elevated temperature as a function of time

From Figure 5.48, as relative permeability curves shift to the left for both irreducible water saturation and residual oil saturation, early breakthrough of oil bank and hot water occurs. As irreducible water saturation decreases, storage of steam in pore space is less as well. Water starts to flow when water saturation reaches 0.4. Moreover, maximum oil saturation is 0.9. That results in displaceable saturation of 0.5. At certain injection rate, oil bank and hot water breakthrough occur earlier. As residual oil saturation is increased to 1.0, displaceable volume is expanded to 0.6 that results in retardation of breakthroughs compared to the previous case. Results from base case show the last in breakthrough as water saturation needs to arrive 0.5 before moving forward.

In conclusion, changing end point saturations at elevate temperature results in different period of breakthroughs. Reducing irreducible water saturation together with residual oil saturation results in higher displaceable volume of reservoir. Since, more volume is displaceable; effect of heterogeneity is clearly shown (the lower the heterogeneity the longer the production period) as effect from production constraints is diminished.

5.4.9 Effect of Wettability at Reservoir and Elevated Temperatures

In order to make the study more precise, relative permeability curves are constructed with concerning on wettability in both reservoir and elevated. According to literature surveys, contact angle changes after steamflooding process if wettability at reservoir temperature is more water-wet. In contrast, contact angle in strongly oil-wet rock remains the same after steamflooding. In other word, relative permeability curves of strongly oil-wet rock remains the same after steamflooding. Therefore, intermediate wet or neutral wet rock which represents characteristics of both water-wet and oil-wet is included in this study. Shifting of neutral wet rock to more water-wet rock after steamflooding is therefore not as extreme as water-wet rock. Table 5.6 summarizes important values required to construct relative permeability curve for the study of wettability at reservoir and elevated temperatures.

Table 5. 6 Relative permeabilities at corresponding end point saturations for each wetting condition for both reservoir and elevated temperatures

Wettability tendency	Reservoir temperature				Elevated temperature			
	S_{wi}	k_{ro}	$1\text{-}S_{or}$	k_{rw}	S_{wi}	k_{ro}	$1\text{-}S_{or}$	k_{rw}
Oil-wet	0.18	0.5	0.71	0.15	0.18	0.5	0.71	0.15
Neutral wet	0.27	0.6	0.8	0.1	0.5	0.8	1	0.5
Water-wet	0.36	0.7	0.89	0.05	0.6	1	1	1

Calculation of end point saturations and relative permeability values for water-wet rock is based on the study of temperature on relative permeabilities and oil displacement [13]. Relative permeabilities at end point saturation after steamflooding for water-wet case are calculated from calculation shown in Eq. 5.2.

$$\frac{dk_{rw}}{dT} = \left(\frac{2+3\lambda}{\lambda}\right) \times \frac{\left(S_w - S_{wi}\right)^{\frac{2(1+\lambda)}{\lambda}}\left(1-S_w\right)}{\left(1-S_{wi}\right)^{\frac{2(1+2\lambda)}{\lambda}}}\left(\frac{dS_{wi}}{dT}\right) \tag{5.2a}$$

$$\frac{dk_{ro}}{dT} = \left\{\left(\frac{2+\lambda}{\lambda}\right)\frac{\left(S_w - S_{wi}\right)^{\frac{2}{\lambda}}\left(1-S_w\right)^3}{\left(1-S_{wi}\right)^{\frac{2(1+2\lambda)}{\lambda}}} + 2\left[1-\left(\frac{S_w - S_{wi}}{1-S_{wi}}\right)^{\frac{(2+\lambda)}{\lambda}}\right]\frac{\left(1-S_w\right)^2}{\left(1-S_{wi}\right)^3}\right\}\left(\frac{dS_{wi}}{dT}\right) \tag{5.2b}$$

where pore size distribution factor (λ) is 3.7.

From equation 5.2, both relative permeability to oil and water after steamflooding is a function of $\left(\frac{dS_{wi}}{dT}\right)$. Hence, $\left(\frac{dS_{wi}}{dT}\right)$ at 400°F can be calculated from plot between S_{wi} vs T shown in Figure 5.49. $\left(\frac{dS_{wi}}{dT}\right)$ is independent from oil viscosity according to Figure 5.25. In contrast, $\left(\frac{dS_{or}}{dT}\right)$ increases as oil viscosity increases, resulting in higher reduction of S_{or} at elevated temperature. $\left(\frac{dS_{wi}}{dT}\right)$ at 400°F is equal to 0.113 per °F, resulting in S_{wi} at 400°F to be 0.73. However, S_{wi} should not be higher than 0.6 as limitation of irreducible liquid saturation is fixed at 0.6 in gas-liquid relative permeability curve. By using $\left(\frac{dS_{wi}}{dT}\right)$ value to calculate k_{ro} and k_{rw} at S_{wi} and 1-S_{or}, relative permeabilities are higher than 1.0. Thus, relative permeability to oil and to water after steamflooding in this study is fixed at 1.0 and there is no residual oil saturation remained after steamflooding. Finalized relative permeability curves for this section are therefore plotted in Figure 5.50.

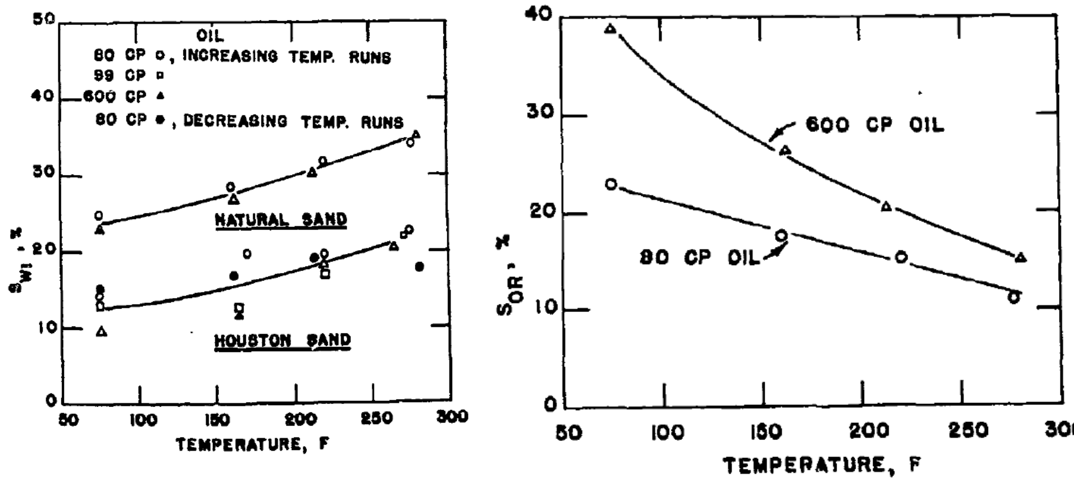


Figure 5. 49 S_{wi} and S_{or} as a function of temperature for water-wet sandstone [12]

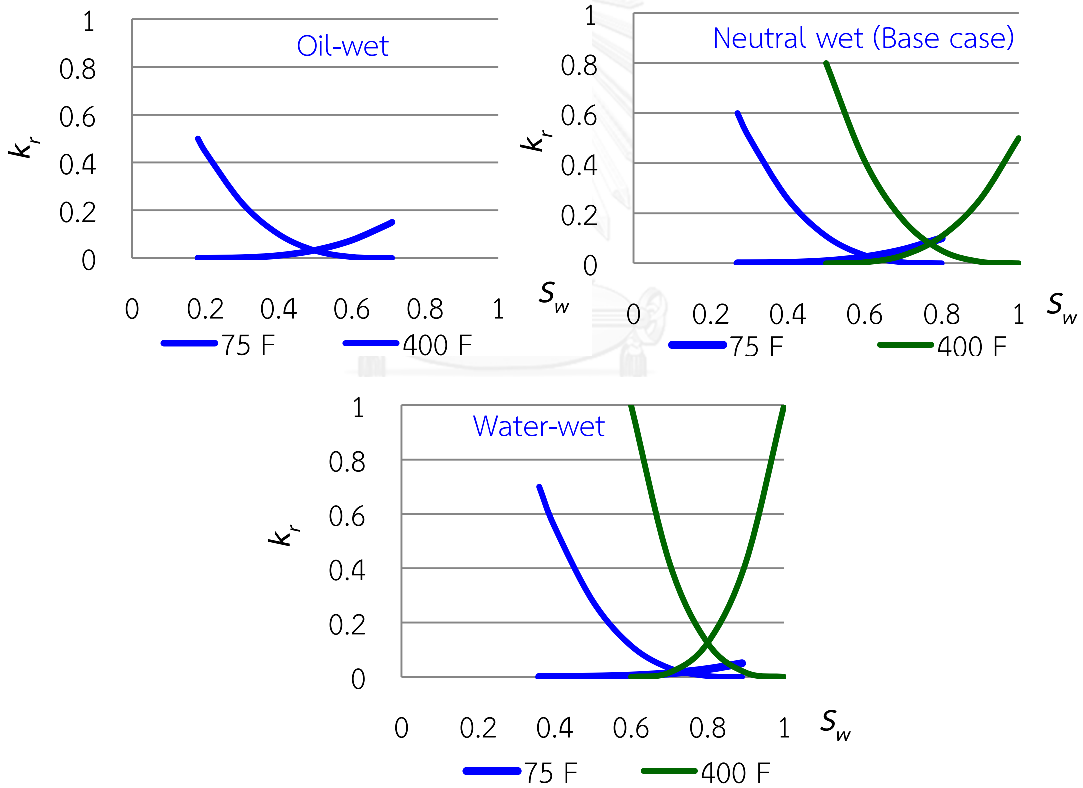


Figure 5. 50 Relative permeability curves for the study of wetting condition at reservoir and elevated temperatures

Reservoir simulation outcomes including oil recovery factor, water production and steam injection duration of these three cases are shown in Figure 5.51.

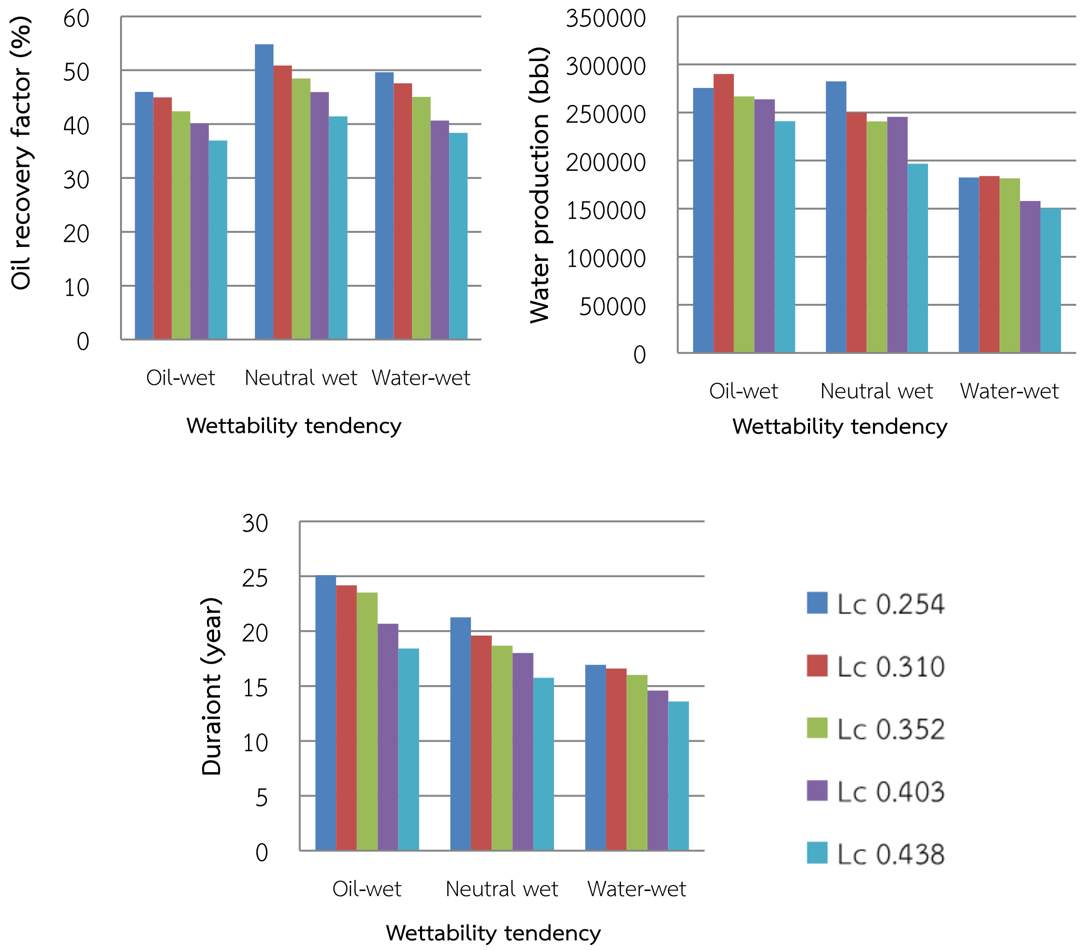


Figure 5. 51 Oil recovery factors, water productions and steam injection duration of different wetting conditions at reservoir and elevated temperature and various reservoir heterogeneities

From Figure 5.51, oil recovery factor in every heterogeneity exhibits similar pattern. Higher heterogeneity reduces oil recovery. Oil-wet reservoir yields the lowest oil recovery factor and neutral wet reservoir yields the highest oil recovery. Considering steam injection period and total water production, water-wet reservoir spends the least time and yields the lowest water production. Even relative permeability to oil is greatly improved, relative permeability to water is also increased and this results in higher water production in case of water-wet reservoir. In case of neutral wet rock, residual oil saturation is greatly reduced while relative permeability curves are moderately improved. These conditions prolong production period since flow ability of water is not too high to put the well reaching quickly production constraints. Steam injection period is the longest in case of oil-wet reservoir due to flow ability that is not improved based on relative permeability. Hence, only viscosity reduction is a major cause of oil recovery mechanism in this case. Oil and water production rates of these three cases for various reservoir heterogeneities are shown in Figure 5.52.

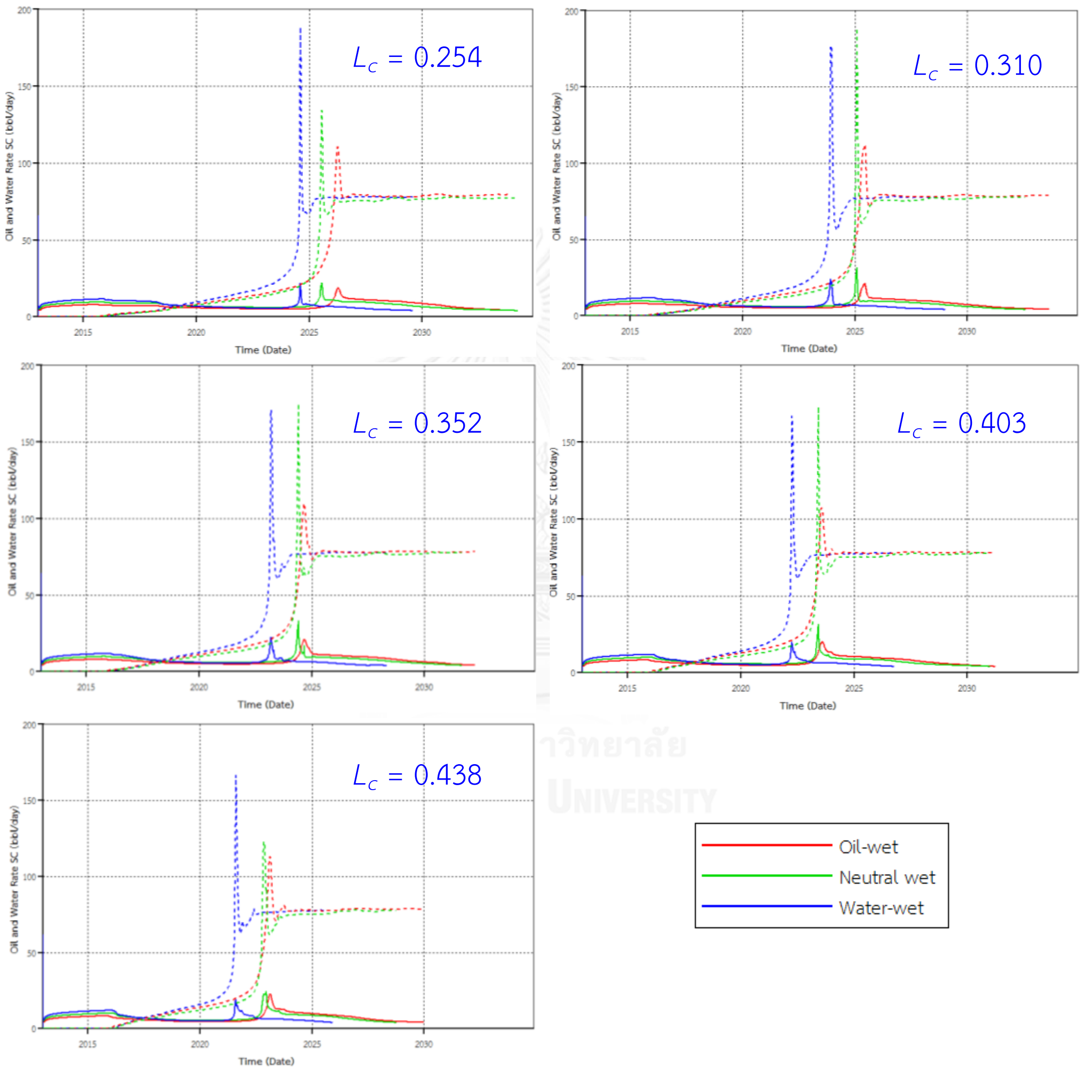


Figure 5. 52 Oil and water production rates of different wetting conditions at reservoir and elevated temperature and various reservoir heterogeneities

As can be expected, great improvement of relative permeabilities to oil and water results in earlier breakthrough of both oil bank and hot water bank in every heterogeneity. The oil-wet case yields the last breakthrough of oil bank and hot water bank due to no change in relative permeability. Moreover, water production rate is relatively small due to very low value of relative permeability to water at end point saturation.

When combining all changes on relative permeability curve, it can be seen that oil-wet rock which is not affected from temperature yields the lowest oil recovery due to no improvement in relative permeability to oil. Neutral wet rock tends to yield the highest oil recovery in all range of heterogeneity. Great advantage of neutral wet rock over water-wet rock is reduction of water production. Hence, production period can be extended.

5.4.10 Sensitivity of Parameters Involved in Relative Permeability Curves

In order to observe sensitivity of parameters involved in relative permeability curve including relative permeability to oil and to water at reservoir temperature, Corey’s exponent at reservoir temperature, end point saturations at reservoir temperature, wettability of rock at reservoir temperature, relative permeability to oil and to water at elevated temperature, end point saturations at elevated temperatures and wettability of rock at reservoir and elevated temperatures. Tornado chart shown in Figure 5.53 is generated based from results obtained from reservoir model with Lorenz coefficient of 0.352. Oil recovery factor from base case is fixed as core of tornado.

From Figure 5.53, shifting in end point saturation at reservoir temperature affects the most on oil recovery factor while changing relative permeability to oil and to water at end point saturation for both reservoir and elevated temperature does not affect much on oil recovery. It can be explained that, modification of relative permeability curves at end point saturation will affect flow ability for just short period. Since fluid saturation changes with time, relative permeability will follow the saturation and this results in less difference of value. Changing Corey’s exponent also shows high sensitivity since the difference of relative permeability curves are obvious in most range of saturation.

It can be concluded that parameters that change of residual phases tend to yield higher sensitivity on oil recovery. Changing magnitude of relative permeability curve will cause sensitivity only when the difference occurs for whole range of saturation. Therefore, changing of Corey's exponent or curvaceous of relative permeability tends to yield high sensitivity on oil recovery as well.

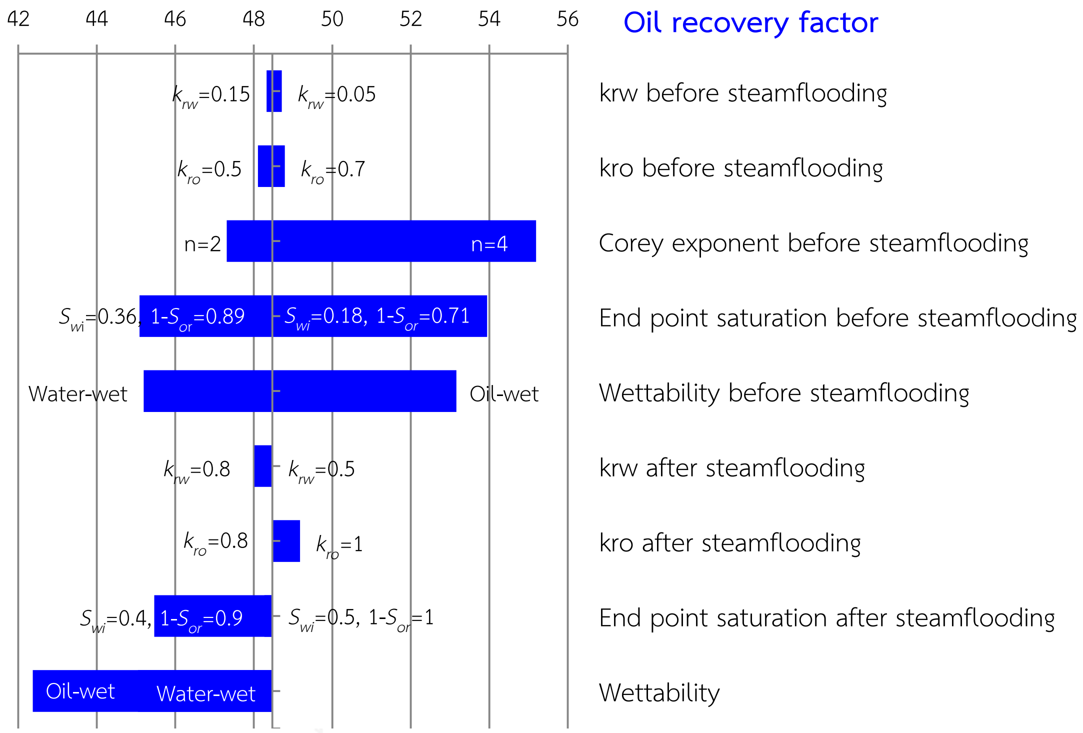


Figure 5. 53 Tornado chart illustrating sensitivity of parameters involved in relative permeability curves on oil recovery

5.5 Effect of Oil Gravity

To study effect of oil gravity, steamflooding is simulated on reservoir models containing various type of oil. Values of oil gravity chosen in this study are 7.3, 11, 14 and 19.5 °API. Oil gravity of 14 °API is previously chosen for base case models. Properties of different oils including bubble point pressure, gas-oil ratio and oil viscosity are based on Pressure-Volume-Temperature data of heavy oil and extra heavy oil literature [22]. Fluid properties in the study of oil gravity are summarized in Table 4.7 in Chapter 4.

At first, effect of oil gravity is studied without modification of relative permeability curves due to oil viscosity. Relative permeability curves at reservoir temperature and at elevated temperature (after steamflooding) are kept the same as those of base cases. Later in this section, effect of oil viscosity on relative permeability and residual oil saturation is studied.

5.5.1 Study of Oil Gravity

Simulation results for the study in this section is summarized in Table 5.7, composing of enthalpy consumed, cumulative oil production and oil recovery factor, whereas Table 5.8 summarizes cumulative water production, enthalpy consumed per barrel of oil and steam injection duration. From Tables 5.7 and 5.8, several graphs are plotted in order to evaluate effects of oil gravity on effectiveness of steamflooding in heterogeneous reservoir.

Table 5. 7 Summary of enthalpy consumed, cumulative oil production and recovery factor of heterogeneous reservoir models with various L_c and oil °API gravities

L_c	°API	Enthalpy consumed (Btu)	Cumulative oil production (BBL)	Recovery Factor (%)
0.254	7.3	1.29×10^{9}	4.12×10^{3}	3.89
	11	1.67×10^{10}	2.60×10^{4}	24.65
	14	9.45×10^{10}	5.78×10^{4}	54.82
	19.5	7.58×10^{10}	6.10×10^{4}	58.20
0.31	7.3	1.29×10^{9}	4.19×10^{3}	3.95
	11	1.81×10^{10}	2.58×10^{4}	24.39
	14	8.40×10^{10}	5.37×10^{4}	50.87
	19.5	7.89×10^{10}	5.91×10^{4}	56.38
0.352	7.3	1.30×10^{9}	4.25×10^{3}	4.01
	11	1.94×10^{10}	2.57×10^{4}	24.35
	14	8.08×10^{10}	5.11×10^{4}	48.47
	19.5	8.05×10^{10}	5.72×10^{4}	54.54
0.403	7.3	1.33×10^{9}	4.32×10^{3}	4.07
	11	2.23×10^{10}	2.65×10^{4}	25.03
	14	8.15×10^{10}	4.58×10^{4}	45.94
	19.5	7.76×10^{10}	5.33×10^{4}	50.86
0.438	7.3	1.35×10^{9}	4.35×10^{3}	4.11
	11	3.37×10^{10}	3.16×10^{4}	29.94
	14	6.62×10^{10}	4.37×10^{4}	41.44
	19.5	5.79×10^{10}	4.69×10^{4}	44.71

Table 5. 8 Summary of cumulative water production, enthalpy consumed per barrel of oil and duration of steam injection of heterogeneous reservoir models with various L_c and oil °API gravities

L_c	°API	Cumulative water production (BBL)	Enthalpy consumed per barrel of oil (Btu/BBL)	Duration (year)
0.254	7.3	2.96×10^{2}	3.13×10^{5}	30.02
	11	3.32×10^{4}	6.42×10^{5}	30.02
	14	2.82×10^{5}	1.63×10^{6}	21.26
	19.5	2.15×10^{5}	1.24×10^{6}	9.92
0.31	7.3	2.42×10^{2}	3.09×10^{5}	30.02
	11	3.83×10^{4}	7.00×10^{5}	30.02
	14	2.50×10^{5}	1.56×10^{6}	19.59
	19.5	2.82×10^{5}	1.33×10^{6}	10.25
0.352	7.3	1.84×10^{2}	3.05×10^{5}	30.02
	11	4.32×10^{4}	7.54×10^{5}	30.02
	14	2.41×10^{5}	1.58×10^{6}	18.68
	19.5	2.35×10^{5}	1.41×10^{6}	10.42
0.403	7.3	2.37×10^{2}	3.08×10^{5}	30.02
	11	5.34×10^{4}	8.44×10^{5}	30.02
	14	2.46×10^{5}	1.68×10^{6}	18.01
	19.5	2.29×10^{5}	1.45×10^{6}	10.01
0.438	7.3	2.82×10^{2}	3.11×10^{5}	30.02
	11	9.23×10^{4}	1.07×10^{6}	30.02
	14	1.97×10^{5}	1.51×10^{6}	15.76
	19.5	1.66×10^{5}	1.23×10^{6}	7.67

Oil recovery factor is firstly plotted in Figure 5.54 for various Lorenz coefficients as a function of oil gravity.

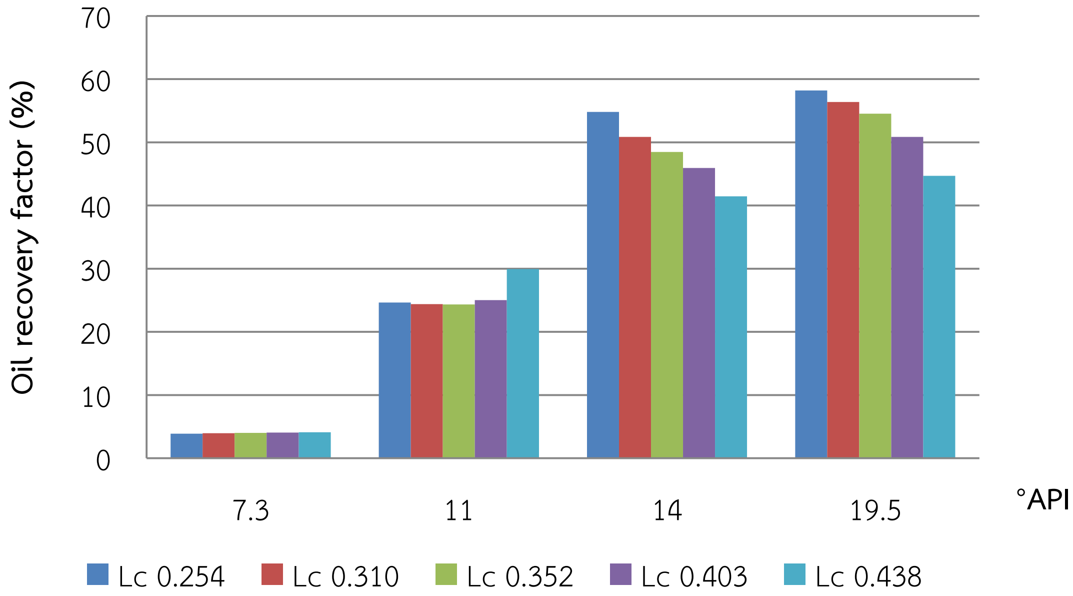


Figure 5. 54 Oil recovery factors of reservoirs with various heterogeneities as a function of °API gravity

From Figure 5.54, it can be obviously seen that sensitivity of oil gravity on oil recovery in every heterogeneous reservoir model is invisible for low oil gravity. Extremely low oil gravity results in difficulty to inject steam into formation. Actual steam injection rate is therefore limited at maximum bottomhole pressure to prevent undesired fractures.

As oil gravity increases, sensitivity of oil gravity shows significance in heterogeneous reservoirs. A higher in reservoir heterogeneity results in less oil production due to early breakthrough in high permeability layers. Comparing within the same Lorenz coefficient, oil recovery factor increases gradually from °API gravity of 14 to 19.5. A slight increment of oil recovery in this case is due to higher of oil mobility as oil viscosity is smaller. Consecutively, steam injectivity is higher in case of high oil gravity. Actual steam injection rates for various reservoir models with different oil gravities are illustrated in Figure 5.55. This figure confirms attaining of desire injection rate within shorter time for oil with high gravity. And moreover, total injection period is very short while oil recovery is high.

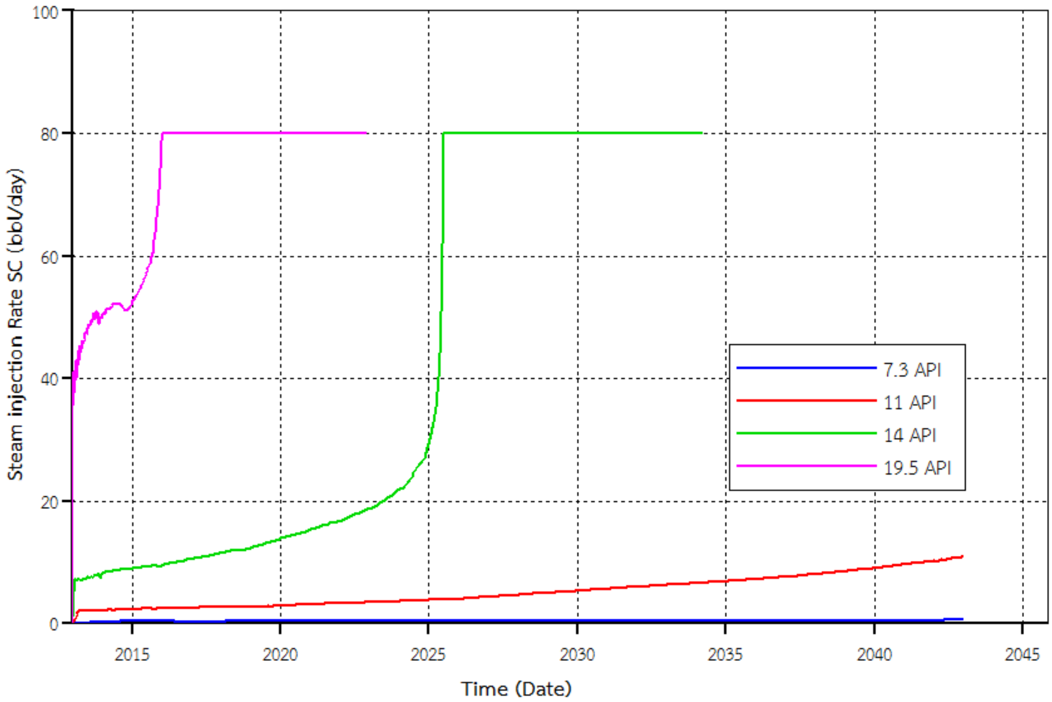


Figure 5. 55 Actual steam injection rates in heterogeneous reservoir with L_c of 0.254 with various oil gravities as a function of time

From Figure 5.55 it can be seen that reservoir containing very heavy oil results in much lower injection rate than expected. In this study, desire injection rate is fixed at 80 STB/D with steam quality of 0.6 which are optimal condition for oil gravity of 14 °API. Since steam injection well is controlled by maximum bottomhole pressure to do not exceed fracture pressure, desired injection rate of 80 STB/D therefore cannot be achieved for reservoir with low oil gravity. From the figure, steam injection rate for 7.3°API-reservoir is extremely low. This causes difference in interpretation of reservoir simulation outcomes compared to other cases.

A plot of water production as a function of °API in Figure 5.56 shows similar trend as oil recovery factor. Water productions are relatively low in case of very heavy oil (°API gravity of 7.3 and 11). This can be explained from very low injectivity. Very viscous oil hardly permits steam to be injected and hence, steam is injected at very low injection rate. Consecutively, this results in extremely low production of condensed water and hot water. For oil gravity of 11°API, difference can be seen in reservoir with various heterogeneities. As oil is lighter, higher permeability layer on top of reservoir favors steam injectivity and therefore, reservoir with higher Lorenz coefficient permits steam to be injected more than lower ones. This results in sensitivity of oil gravity on steamflooding in heterogeneous reservoir. Similar results can be seen also for oil gravity of 14° which can be explained with the same reason.

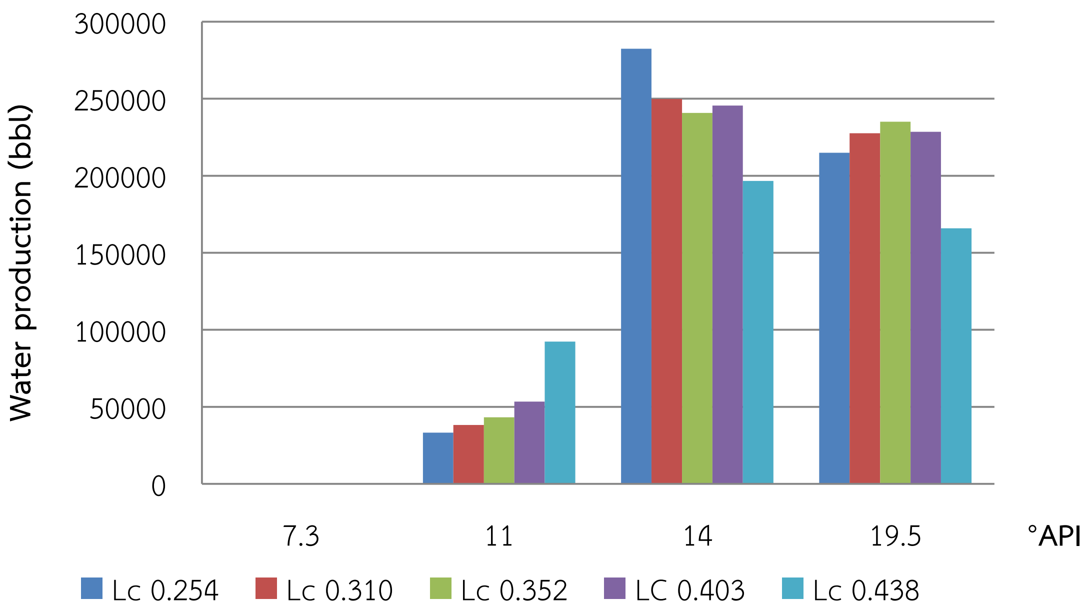


Figure 5. 56 Water productions of reservoirs with various heterogeneities as a function of °API gravity

For the lightest oil, steam can be injected easily into the reservoir and hence, breakthrough of condensed steam and hot water occurs earlier. Therefore, total steam injection period is reduced due to earlier reach of production constraint and hence, water production is less in every Lorenz coefficient.

As steam is hardly injected into reservoir for very heavy oil cases, heat consumed is also small as can be seen in Figure 5.57. Oils with °API of 7.3 and 11 show relatively low enthalpy consumed per barrel of oil produced compared to others. For the rest, energy consumed is higher than 1,000,000 Btu/bbl. It can be seen that for oil gravity of 14 °API which is the base case energy consumption is higher compared to lighter oil (19.5 °API). Based on previous explanation, shorter production period of lighter oil results in less energy for injected steam and hence, energy consumed per barrel of oil is less.

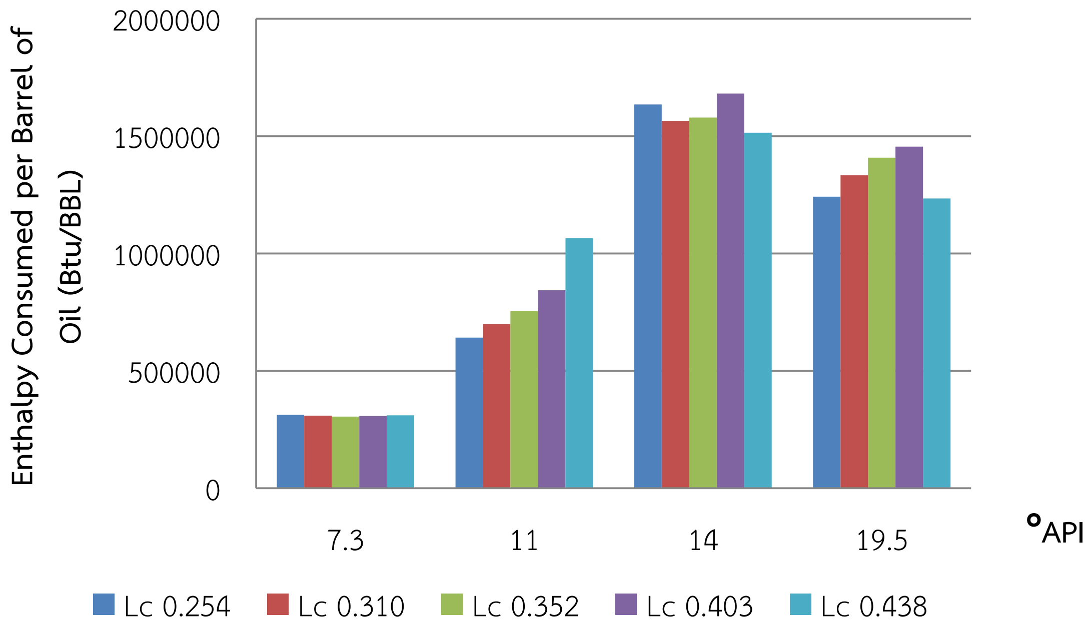


Figure 5. 57 Enthalpy consumed per barrel of oil of reservoirs with various heterogeneities as a function of °API gravity

Oil gravity is one of the properties used for EOR selection technique. Pre-selection of operational conditions is important. Effect of oil gravity in heterogeneous reservoir might be clearly shown in different optimal operation conditions. Nevertheless, under the same operational conditions effects of oil gravity on effectiveness of steamflooding in heterogeneous reservoir is more pronounced in higher oil gravity. This is due to higher injectivity that permits steam to displace and recover oil differently in different models.

5.5.2 Study of Oil Gravity with Concern of Relative Permeability Change

As oil is more viscous or low in oil gravity, this affects change of relative permeability curves. Therefore, effect of oil gravity is studied together with concerning of modification of relative permeability curves. In this section, modification of end point saturation is accomplished based on a literature regarding effect of oil viscosity on heavy-oil/water relative permeability curves [10]. Experimental results of relative permeability curves with S_{or} vs μ and k_{rw} vs μ are shown in Figure 5.58. Simulation is only performed on reservoir model with Lorenz coefficient of 0.352.

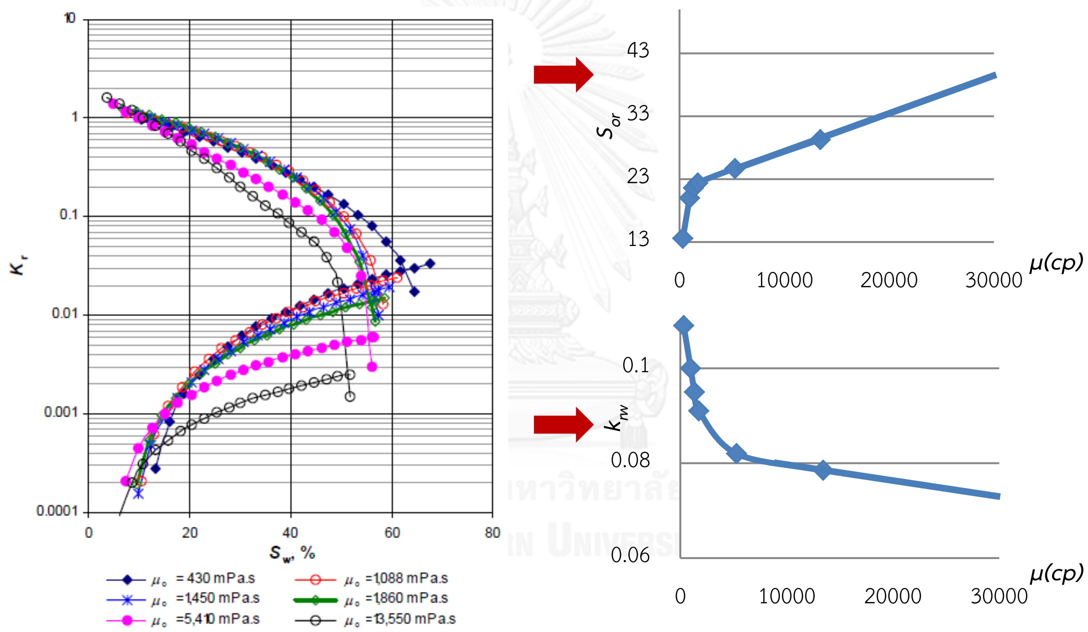


Figure 5. 58 Effects of oil viscosity on relative permeability curves and relationship between oil viscosity and residual oil saturation and relative permeability to water at end point saturations [10]

When oil viscosity is taken into consideration, residual oil saturation and relative permeability to water are modified. Viscous oil with low gravity tends to capture more oil at residual condition. Moreover, flow ability of water at this residual condition is reduced. Residual oil saturation and relative permeability to water at residual oil saturation are therefore modified for all cases in Table 5.9. Figure 5.59

shows tabulated relative permeability curves of various oil gravities including effect of oil viscosity.

Table 5. 9 Tabulated residual oil saturation and relative permeability to water at various oil gravities

°API	μ	S_{or} (%)	k_{rw}
7.3	25,785.50	37	0.074
11	3,601.19	23.5	0.085
14	970.59	20	0.1
19.5	150.33	12	0.115

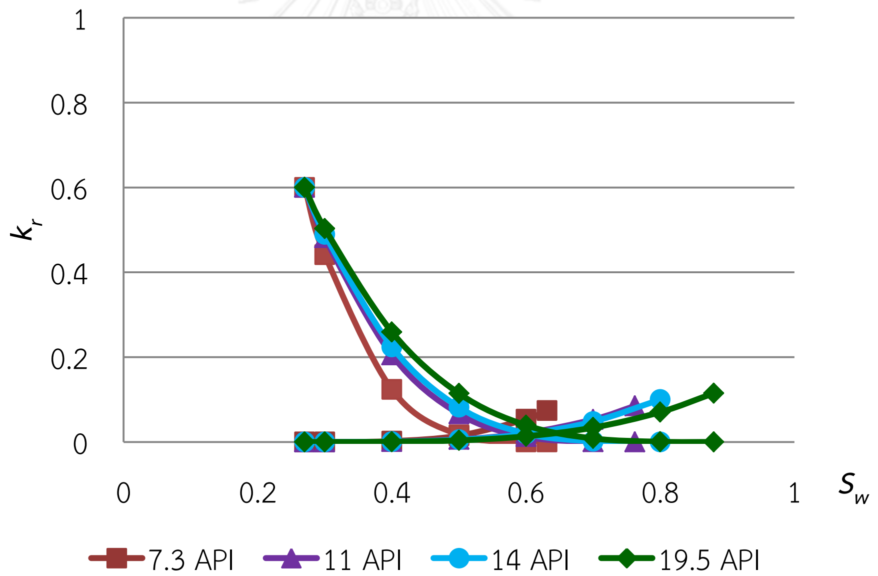


Figure 5. 59 Relative permeability curves of various oil gravities at reservoir temperature including effect of oil viscosity

Figure 5.60 illustrates comparison between cases with and without concerning of effect from oil viscosity. Oil recovery factor, cumulative water production, enthalpy consumed per barrel of oil and steam injection duration are compared for reservoir model with Lorenz coefficient of 0.352. These simulation outcomes from two different cases exhibit similar trend.

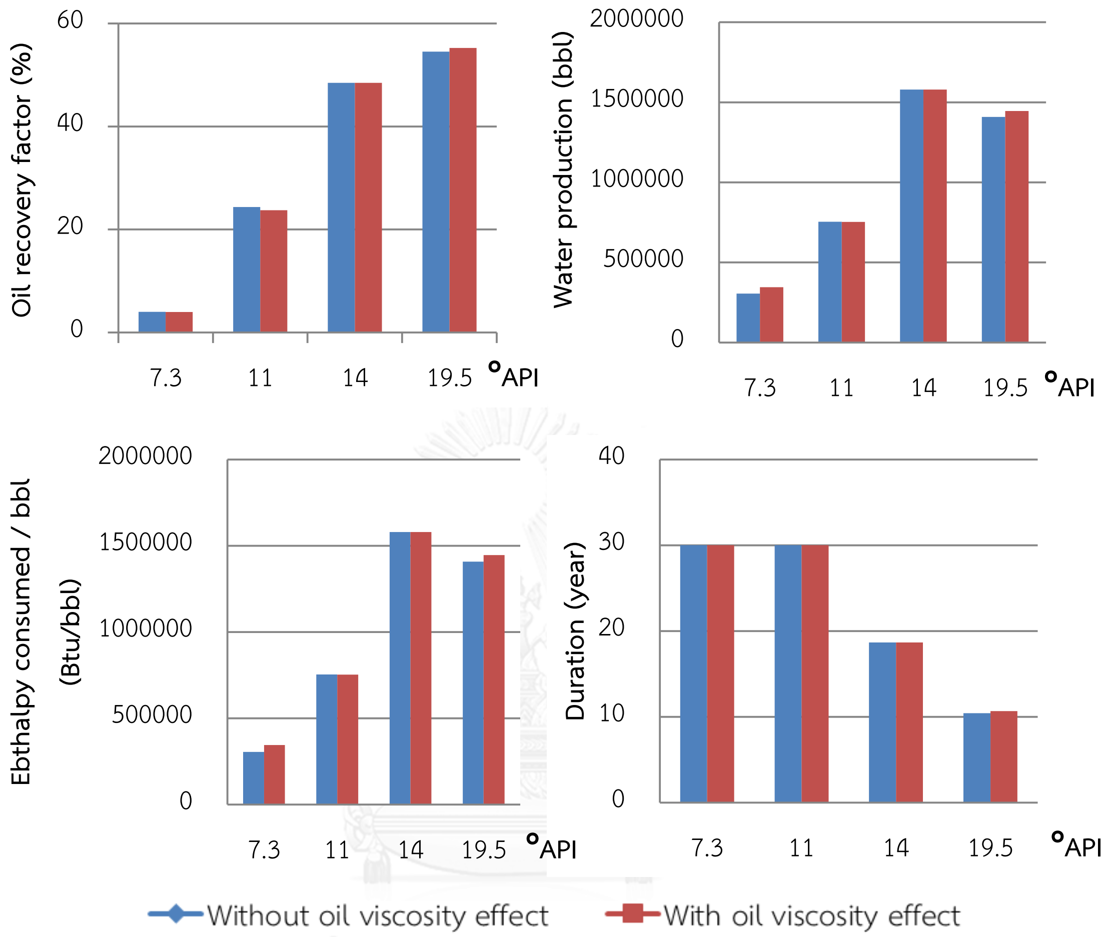


Figure 5. 60 Comparison of oil recovery factors, water productions, enthalpy consumed per barrel of oil and steam injection duration as a function of oil gravity between cases with and without effect of oil viscosity on relative permeability

From Figure 5.60, the bars are identical for whole range of oil viscosity for all simulation outcomes. That can be explained that even relative permeability curves at reservoir temperature are different, flow ability converges to the condition at elevated temperature. Small difference can be still observed and this is a result from different in relative permeability at starting temperature. Flow ability of fluids may follow relative permeability at reservoir temperature first until reservoir temperature is heated up to steam temperature.

In this section, it can be concluded that oil gravity is very important parameter to concern for steamflooding process. Steam temperature, steam injection rate and also steam quality should be optimized for different oil gravity. For very heavy oil reservoir, higher steam temperature and steam quality could result in higher steam injectivity since higher heat amount can suddenly change rock properties to a more favorable condition for oil production. For reservoir containing very light oil, study of waterflooding should be made as comparison since waterflood could result in similar oil recovery. For reservoir containing higher heterogeneity, performance is lower as high permeability layer causes early breakthrough of injected steam and as a consequence, reduces oil recovery and increases water production.

Effect of oil viscosity on relative permeability curves is almost invisible in chosen case. Larger difference in relative permeability together with higher reservoir heterogeneity might differentiate simulation outcomes.

5.6 Effect Vertical Permeability

Effect of vertical permeability is studied through ratio of vertical permeability to horizontal permeability (k_v/k_h). In this study, reservoir models are heterogeneous and vertical permeability values in each layer are varied by multiplying constants. Similar to previous section, steam is injected at selected injection rate of 80 STB/D and steam quality of 0.6. In this section, k_v/k_h ratio is varied from 0.1 in base case model to 0.001, 0.01, 0.2, 0.3 and 0.5. Simulation outcomes including oil and water production rates are observed along with water saturation profiles at interest production periods such as condensed steam breakthrough, hot water breakthrough, and end of production. Enthalpy consumed in Btu, cumulative oil production and oil recovery factor of models with several of k_v/k_h ratios together with reservoir heterogeneity are summarized in Table 5.10. Consecutively, Table 5.11 reviews cumulative water production, final water cut and enthalpy consumed per barrel of oil.

From Tables 5.10 and 5.11, several data are plotted with k_v/k_h ratio together with various Lorenz coefficients. Chosen simulation outcomes are oil recovery factor, cumulative water production, enthalpy consumed per barrel of oil and duration of steam injection process.

Table 5. 10 Summary of enthalpy consumed, cumulative oil production and oil recovery factor of heterogeneous reservoirs with various L_c and various k_v/k_h ratios

L_c	k_v/k_h	Enthalpy consumed (Btu)	Oil recovery (BBL)	Recovery Factor (%)
0.254	0.001	9.53×10^{10}	6.28×10^{4}	59.54
	0.01	9.88×10^{10}	6.19×10^{4}	58.67
	0.1	9.45×10^{10}	5.78×10^{4}	54.82
	0.2	9.11×10^{10}	5.76×10^{4}	54.57
	0.3	9.07×10^{10}	5.70×10^{4}	54.00
	0.5	8.83×10^{10}	5.66×10^{4}	53.61
0.31	0.001	9.71×10^{10}	6.14×10^{4}	58.16
	0.01	9.75×10^{10}	5.97×10^{4}	56.60
	0.1	8.40×10^{10}	5.37×10^{4}	50.87
	0.2	8.29×10^{10}	5.31×10^{4}	50.30
	0.3	8.56×10^{10}	5.31×10^{4}	50.33
	0.5	8.95×10^{10}	5.40×10^{4}	51.23
0.352	0.001	8.90×10^{10}	5.77×10^{4}	54.72
	0.01	9.48×10^{10}	5.72×10^{4}	54.23
	0.1	8.08×10^{10}	5.11×10^{4}	48.47
	0.2	8.44×10^{10}	5.12×10^{4}	48.55
	0.3	8.37×10^{10}	5.08×10^{4}	48.15
	0.5	8.54×10^{10}	5.14×10^{4}	48.77
0.403	0.001	8.11×10^{10}	5.25×10^{4}	49.78
	0.01	8.28×10^{10}	5.15×10^{4}	48.86
	0.1	8.15×10^{10}	4.85×10^{4}	45.94
	0.2	8.05×10^{10}	4.75×10^{4}	45.05
	0.3	7.90×10^{10}	4.73×10^{4}	44.84
	0.5	7.85×10^{10}	4.79×10^{4}	45.37
0.438	0.001	6.22×10^{10}	4.60×10^{4}	43.63
	0.01	6.27×10^{10}	4.50×10^{4}	42.62
	0.1	6.62×10^{10}	4.37×10^{4}	41.44
	0.2	6.44×10^{10}	4.29×10^{4}	40.66
	0.3	6.56×10^{10}	4.32×10^{4}	40.94
	0.5	6.84×10^{10}	4.44×10^{4}	42.07

Table 5. 11 Summary of cumulative water production, enthalpy consumed per barrel of oil and duration of steam injection of heterogeneous reservoirs with various L_c and various k_v/k_h ratios

L_c	k_v/k_h	Water Production (BBL)	Enthalpy Consumed per Oil recovery (Btu/BBL)	Duration (year)
0.254	0.001	2.84×10^5	1.52×10^6	22.59
	0.01	2.96×10^5	1.60×10^6	22.34
	0.1	2.82×10^5	1.63×10^6	21.26
	0.2	2.71×10^5	1.58×10^6	21.18
	0.3	2.70×10^5	1.59×10^6	20.76
	0.5	2.62×10^5	1.56×10^6	20.34
0.31	0.001	2.90×10^5	1.58×10^6	22.10
	0.01	2.92×10^5	1.63×10^6	21.59
	0.1	2.50×10^5	1.56×10^6	19.59
	0.2	2.47×10^5	1.56×10^6	19.34
	0.3	2.55×10^5	1.61×10^6	19.43
	0.5	2.68×10^5	1.66×10^6	19.68
0.352	0.001	2.64×10^5	1.54×10^6	20.48
	0.01	2.84×10^5	1.66×10^6	20.76
	0.1	2.41×10^5	1.58×10^6	18.68
	0.2	2.53×10^5	1.65×10^6	18.93
	0.3	2.51×10^5	1.65×10^6	18.68
	0.5	2.56×10^5	1.66×10^6	18.68
0.403	0.001	2.42×10^5	1.55×10^6	18.59
	0.01	2.48×10^5	1.61×10^6	18.42
	0.1	2.46×10^5	1.68×10^6	18.01
	0.2	2.43×10^5	1.69×10^6	17.68
	0.3	2.38×10^5	1.67×10^6	17.42
	0.5	2.35×10^5	1.64×10^6	17.26
0.438	0.001	1.83×10^5	1.35×10^6	15.84
	0.01	1.84×10^5	1.39×10^6	15.68
	0.1	1.97×10^5	1.51×10^6	15.76
	0.2	1.91×10^5	1.50×10^6	15.34
	0.3	1.95×10^5	1.52×10^6	15.34
	0.5	2.03×10^5	1.54×10^6	15.68

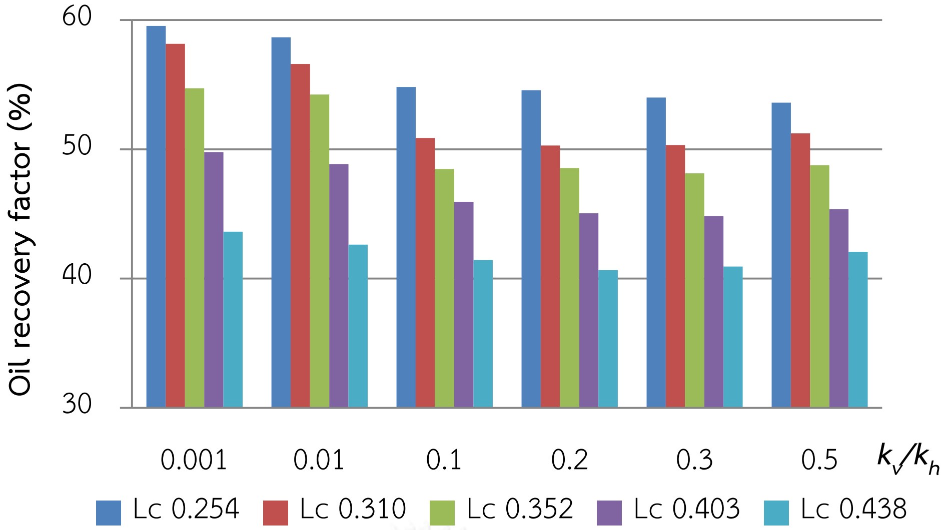


Figure 5. 61 Oil recovery factors of reservoirs with various heterogeneities as a function of k_v/k_h ratio

According to oil recovery factor data shown in Figure 5.61, higher oil recovery is obtained from reservoir with lower heterogeneity value when comparing among the same vertical permeability as explained previously in section of effect from heterogeneity. From Figure 5.61, effect of vertical permeability is obvious when the value is much lower compared to horizontal permeability (k_v/k_h of 0.001 and 0.01). Oil recovery is much higher in case of low vertical permeability. However, effect of vertical permeability tends to disappear when Lorenz coefficient increases to 0.438. In order to observe steam and hot water movement in cases with different vertical permeability, water saturation profiles from reservoir with Lorenz coefficient of 0.254 at year 2025 are first illustrated in Figure 5.62.

After approximately 12 years, hot water firstly breakthroughs in case of k_v/k_h = 0.5. From Figure 5.62, it can be seen that displacement by steam is more uniformed in case of very low vertical permeability. As hot water tends to percolate down, increasing vertical permeability results in hot water breakthrough in lower layers. Sweep efficiently is much improved due to uniform displacement. Effects of vertical permeability on oil production rate are observed together with average reservoir pressure as illustrated in Figure 5.63.

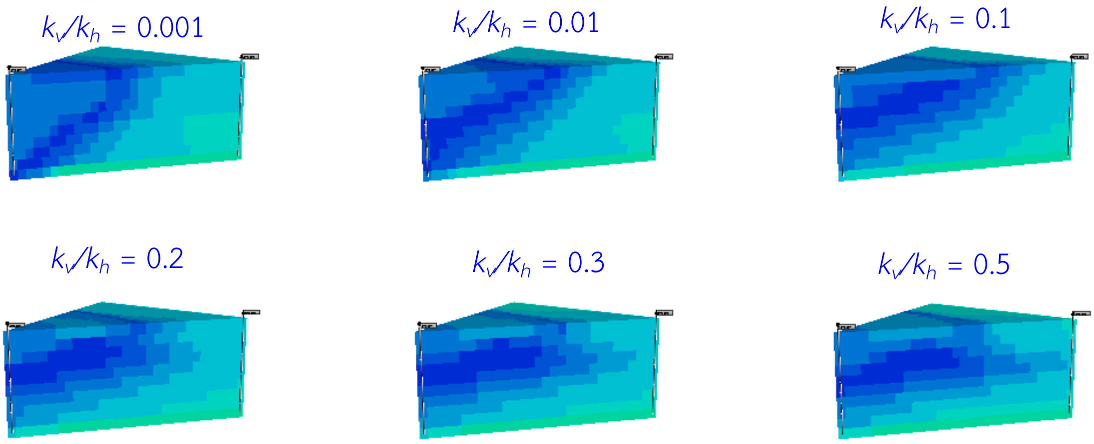


Figure 5. 62 Water saturation profiles at year 2025 for reservoir with Lorenz coefficient of 0.254 with various k_v/k_h ratios

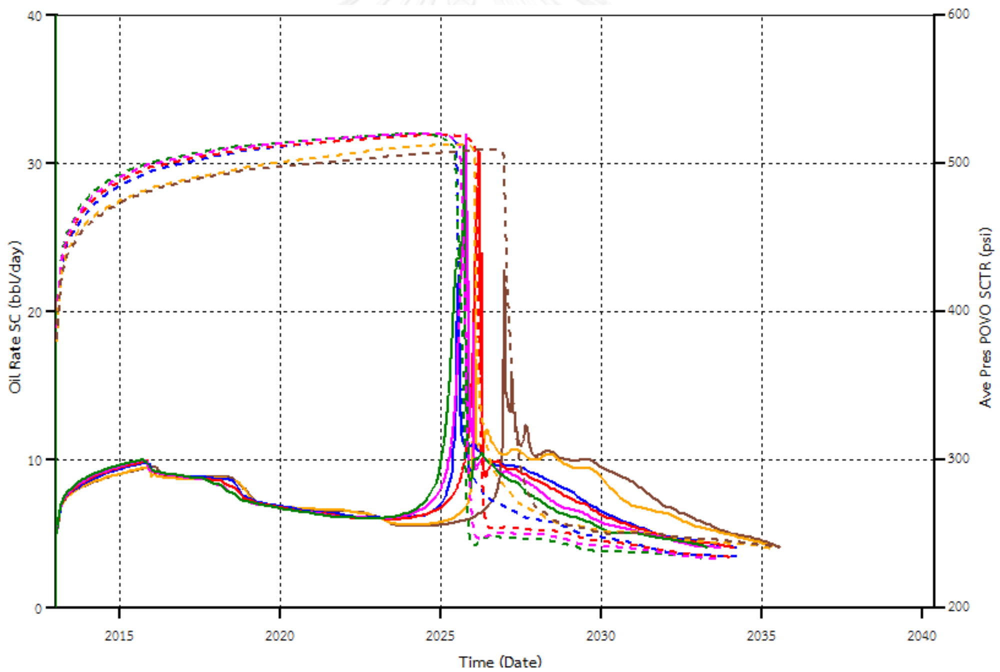


Figure 5. 63 Oil production rates and average reservoir pressures for reservoir models with Lorenz coefficient of 0.254

From Figure 5.63 it can be seen that average reservoir pressure is increased with an increment of vertical permeability. It can be explained that increasing of vertical permeability increases flow ability in vertical direction and hence, steam can be more injected, exerting high pressure to drive heavy oil. This also results in an early arrival of oil bank and thus, early arrival of hot water breakthrough. However, sequence of arrival of oil bank is not totally related to vertical permeability in this case. For a case of k_v/k_h of 0.5, injectant can percolate down effectively and hence breakthrough occurs through middle layers of reservoir instead of top layers as in other cases of higher vertical permeability.

Figure 5.64 compares hot water advancement for Lorenz coefficient of 0.438 with various k_v/k_h ratios at year 2022. As explained previously, oil recovery factor does not change much in high heterogeneity value. This is because very low horizontal permeability is located in bottom layers. Steam and hot water can partially propagate into lower zones in cases of k_v/k_h 0.01 and 0.001 but advancement is much smaller compared to high permeability zone. Therefore, displacement occurs mainly in high permeability zone only and results do not deviate much from each other.

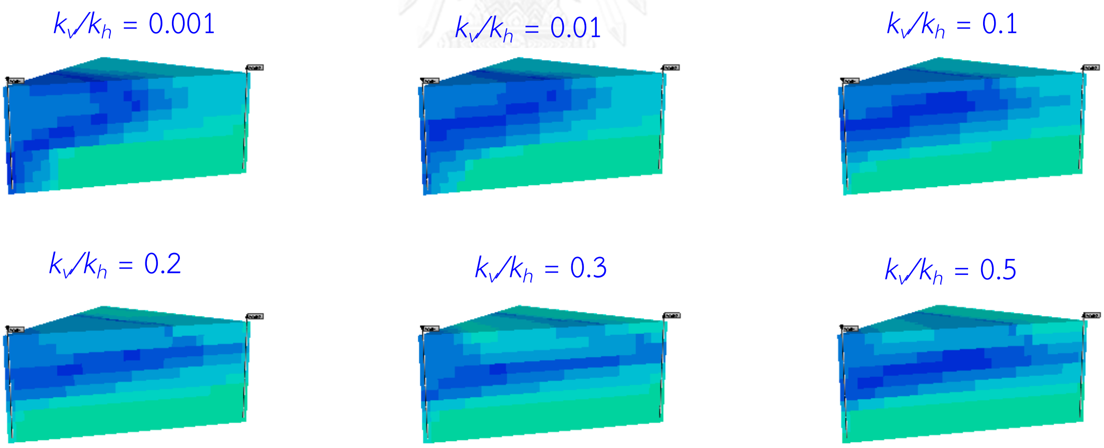


Figure 5. 64 Water saturation profile at year 2022 for reservoir with Lorenz coefficient of 0.438 with various k_v/k_h ratios

From previously explanation, both reservoir heterogeneity and vertical permeability affect displacement mechanism by steam and hot water. However, amount of water production obtained additional effect from production constraints.

Figure 5.65 summarizes total water production as a function of ratio of vertical to horizontal permeability for different reservoir heterogeneities. It can be obviously seen that, water production only show similar trend as in total oil recovery in certain cases. Considering water production together with total production period as illustrated in Table 5.10, it can be seen that longer production time results in longer water production and therefore, reservoirs with low heterogeneity tending to produce oil for longer period also come with large amount of water.

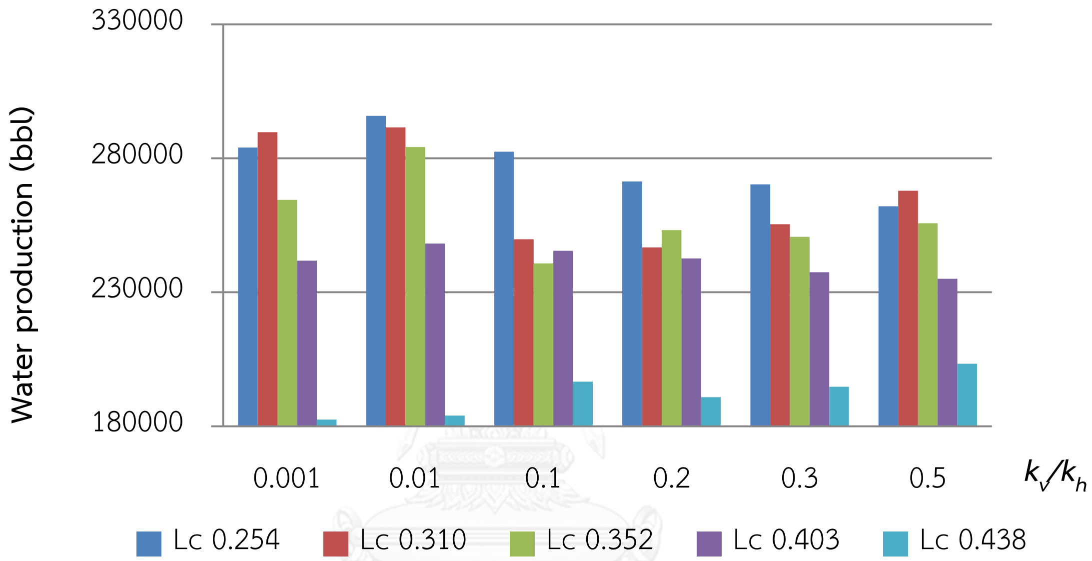


Figure 5. 65 Water productions of reservoirs with various heterogeneities as a function of k_v/k_h ratio

As heterogeneity increases, water production tends to decrease in all vertical permeability due to less displaceable volume and early water breakthrough. Nevertheless, since displacement by steam occurs uniformly in cases of low heterogeneity, water production is much smaller due to arrival of hot water bank together in the same time as can be seen in dark blue zone in Figure 5.64.

Amount of injected steam together with oil recovery determine enthalpy consumed. As effect of vertical permeability tends to masquerade heterogeneity effect, trendless lines are obtained for enthalpy consumed per barrel of oil produced as illustrated Figure 5.66.

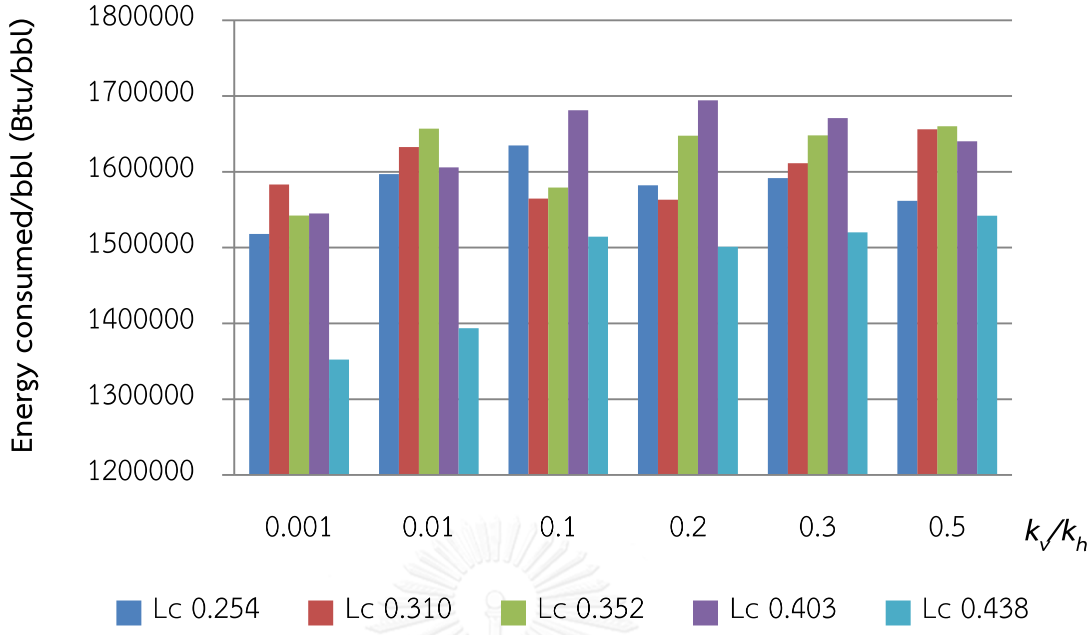


Figure 5. 66 Enthalpy consumed per barrel of oil of reservoirs with various heterogeneities as a function of k_v/k_h ratios

From Figure 5.66, most lines follow the trend of water production. As water production is affected from amount of injected steam, energy consumed through steam injection is therefore related to water production. A quasi- trendless found in water production therefore results in irregularity in trend line of energy consumption when amount of oil produced is added in the term.

In conclusion, lower vertical permeability yields benefit on displacement mechanism by steam in heterogeneous reservoir. Steam overriding is diminished resulting in higher retention of steam vapor inside reservoir. Nevertheless, benefit of low vertical permeability tends to disappear when heterogeneity is higher due to inaccessible to low horizontal permeability zones. In case of high vertical permeability, injectivity of steam is higher than lower vertical permeability. Steam can be injected easier but steam overriding and hot water underrunning are facilitated.

5.7 Effect of Permeability Sequence

In previous section, sequence of permeability is represented by coarsening upward. Fining upward sequence is performed in this section by reversing order of permeability in base case. Lorenz coefficient remains the same as in coarsening upward case. Simulation outcomes including enthalpy consumed, cumulative oil production and oil recovery factor of all heterogeneous reservoir models combining with fining upward sequence are summarized in Table 5.12. Table 5.13 summarizes cumulative water production, enthalpy consumed per barrel of oil and duration of steam injection. Oil and water production rates tracked as a function of time are observed along with saturation profiles during interesting periods of production in chosen Lorenz coefficients. Results in this section are compared to those obtained in section 5.3 where permeability sequence is coarsening upward.

Table 5. 12 Summary of enthalpy consumed, cumulative oil production and recovery factor of heterogeneous reservoirs with various L_c in fining upward permeability sequence

L_c	Enthalpy consumed (Btu)	Cumulative oil production (BBL)	Recovery Factor (%)
0.254	7.26×10^{10}	6.72×10^{4}	63.68
0.310	7.10×10^{10}	6.52×10^{4}	61.78
0.352	7.27×10^{10}	6.31×10^{4}	59.83
0.403	7.38×10^{10}	5.99×10^{4}	56.76
0.438	6.87×10^{10}	5.53×10^{4}	52.40

Table 5. 13 Summary of cumulative water production, enthalpy consumed per barrel of oil and duration of steam injection of heterogeneous reservoirs with various L_c in fining upward permeability sequence

L_c	Water Production (BBL)	Enthalpy consumed per barrel of oil (Btu/BBL)	Duration (year)
0.254	2.03×10^{5}	1.08×10^{6}	21.43
0.310	1.99×10^{5}	1.09×10^{6}	20.43
0.352	2.07×10^{5}	1.15×10^{6}	19.85
0.403	2.13×10^{5}	1.23×10^{6}	19.18
0.438	1.98×10^{5}	1.24×10^{6}	17.93

From Tables 5.12 and 5.13 several plots are made as follows to study effects of fining upward permeability sequence on effectiveness of steamflooding in heterogeneous reservoir with various Lorenz coefficients.

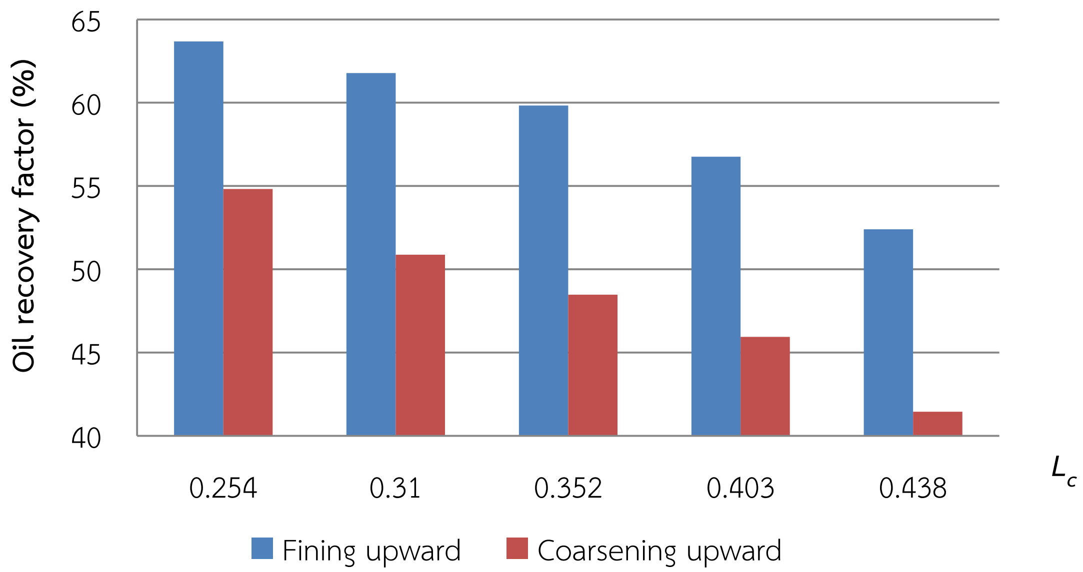


Figure 5. 67 Comparison of oil recovery factors from fining upward and coarsening upward sequences reservoir models as a function of heterogeneity

Figure 5.67 illustrates oil recovery factors obtained from fining upward reservoir models. It can be obviously noticed that, oil recovery declines with increment of Lorenz coefficient as same as in coarsening upward cases. Slope of oil recovery factor is changed at Lorenz coefficient of 0.403. This is caused from early breakthrough of injectant due to less uniformly distribution of permeability.

In general, fining upward sequence is favorable for gas injection since effect of gas overriding is mitigated. In steamflooding, hot water can spread into lower layer of reservoir by its gravity. Results obtained from coarsening upward models in Table 5.4 in section 5.3 shows that oil recovery factor is less than that of fining upward reservoir summarized in Table 5.12. At small value of Lorenz coefficient, oil recovery factor from coarsening upward model is just a bit lower compared to fining upward one. In contrast, if the reservoir possesses higher degree of heterogeneity, oil recovery factor of coarsening upward reservoir is much lower than fining upward reservoir. Higher in oil recovery in fining upward reservoir could be a result from more displacement in the bottom zone where permeability is high by hot water. The upper zone can be well swept due to steam vapor that possesses higher mobility.

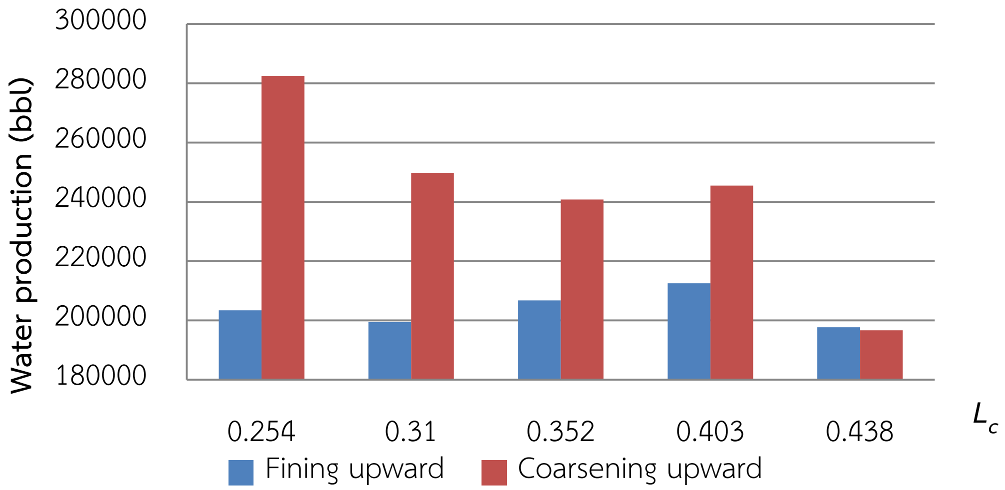


Figure 5. 68 Comparison of water productions from fining upward and coarsening upward sequence reservoir models as a function of heterogeneity

Water production is plotted with Lorenz coefficients as depicted in Figure 5.68. Both fining and coarsening upward sequences show similar trend. Decreasing of water production in first period is caused by shorter injection period. Rising of water production with Lorenz coefficient is responsible by earlier water breakthrough which is not balanced with the period after breakthrough. This results in higher water production. Eventually, water production drops again as total production period is too low due to very early water production. Turn over point in fining upward sequence is found at lower Lorenz coefficient compared to coarsening upward case because breakthrough of hot water starts to arrive early in lower section of the reservoir.

Figure 5.69 compares steam injection duration of fining and coarsening upward sequences. Total steam injection period decreases with increment of Lorenz coefficient in both cases. As explained in section of coarsening upward sequence, higher in heterogeneity results in less displaceable volume of reservoir. Hence water tends to breakthrough earlier, causing shorter period of production. Nevertheless, fining upward sequence can maintain production for longer time compared to coarsening upward sequence. This can be explained that steam vapor can displace upper layers in both cases due to steam energy. However, oil in bottom layers is displaced in higher degree in case of fining upward sequence. Therefore, hot water breakthrough occurs later and steam injection period can be prolonged.

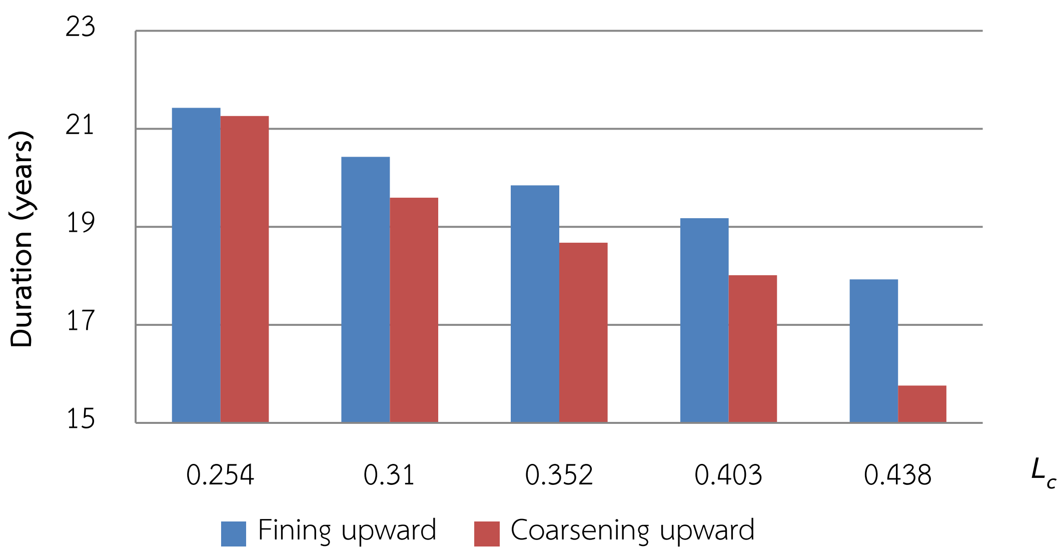


Figure 5. 69 Comparison of duration of steam injection from fining upward and coarsening upward sequence reservoir models as a function of heterogeneity

Enthalpy consumed per barrel of oil is shown for both fining upward and coarsening upward cases in Figure 5.70. Shape of both cases is similar to total water production. Since oil recovery factor goes only in one direction, shape of energy consumed per barrel of oil is therefore depending on energy input which is corresponding to amount of steam injected and water produced. From the figure, the smallest reservoir heterogeneity consumes the least energy to produce barrel of oil in case of fining upward sequence reservoir.

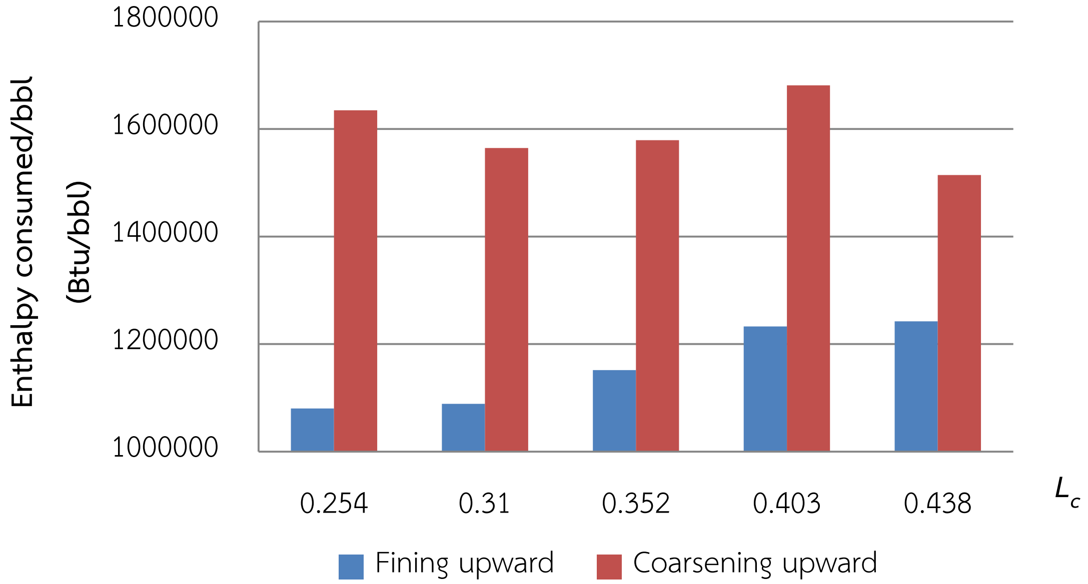


Figure 5. 70 Comparison of enthalpy consumed per barrel of oil from fining upward and coarsening upward sequence reservoir models as a function of heterogeneity

In order to compare dynamic change due to injection of steam in fining upward and coarsening upward models, oil and water production rates plotted with production time are illustrated in Figure 5.71. As explained in section of water production, it can be seen that cases of fining upward sequence can extend breakthrough periods. Great benefit can be obtained from case with Lorenz coefficient of 0.254 where steam injection period is mostly the same but hot water breakthrough is much different. Retarding of hot water breakthrough in fining upward is a result from displacement of hot water in bottom zone of the reservoir. Figure 5.72 illustrates water saturation profile of both chosen cases at different production periods.

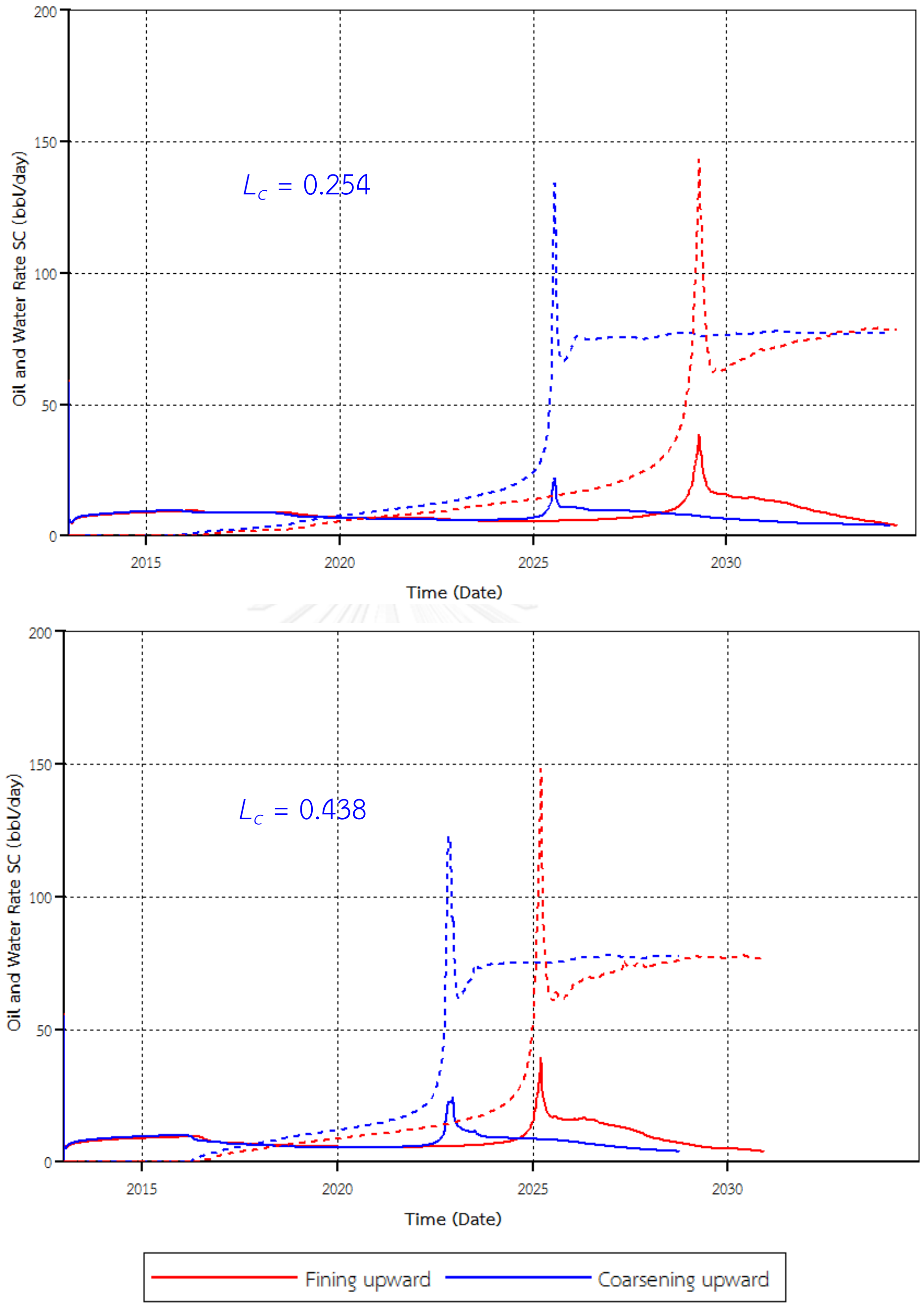


Figure 5. 71 Comparison of oil and water production rates from fining upward and coarsening upward sequence reservoir models with Lorenz coefficient of 0.254 and 0.438

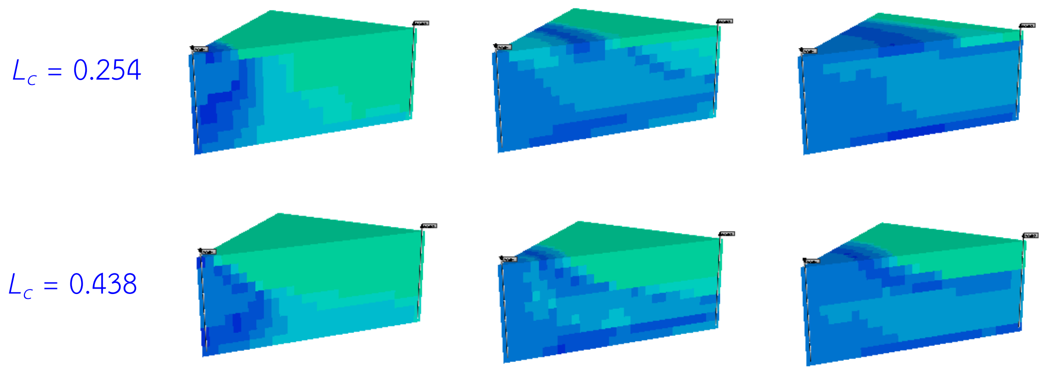


Figure 5. 72 Water saturation profiles at condensed steam breakthrough, hot water breakthrough and final year obtained from fining upward sequence with L_c of 0.254 and 0.438

It can be seen that early breakthrough also occurs in fining upward cases as same as coarsening upward. But breakthrough occurs at the bottom layers instead of top layers. Nevertheless, distribution of hot water is better in case of fining upward. From the figure, steam flows into lower section of the reservoir. Since gas has a tendency to flow up due to gravity segregation, part of steam naturally flows to upper location. As steam loses latent heat to environment, it changes back to saturate hot water and eventually helps displacement in vertical direction. Therefore, low permeability zone which is located at top layer is partly displaced by hot water which is condensed from steam.

Sequence of permeability shows remarkable effect in oil recovery process by means of steamflooding process. Injecting steam in fining upward reservoir yields better sweep efficiency since part of low permeability zone located at top layers can be swept by hot water that is condensed from steam. Extending breakthrough of hot water bank is observed which results in higher oil recovery and less water production. Higher heterogeneity also facilitates early hot water breakthrough and hence, oil recovery is substantially reduced.

5.8 Effect of Flood Pattern

In previous sections, injection and production wells are arranged in quarter 5-spot pattern, consisting of a production well and a steam injecting well locating on two corners diagonally of reservoir model. In this section, an arrangement of steam injection well and producing well is in quarter 9-spot pattern consisting of three steam injectors and one producer located in each edge of reservoir block. Injection rate in this case is divided in order to compare results with single injection well. Two injection wells closer to production well are performed at injection rate of 32 STB/D, whereas another diagonal well is performed at steam injection rate of 16 STB/D. This weighting of injection rate is based on contribution of each well depending on location as can be seen in Figure 5.73. Summation of injection rate in case of three injection wells is 80 STB/D and this summation can be compared with base case of single injection well in quarter 5-spot pattern. Steam quality is still fixed at 0.6. Saturation profile is tracked in three dimensions as locations of well cause flood front in more than one plane.

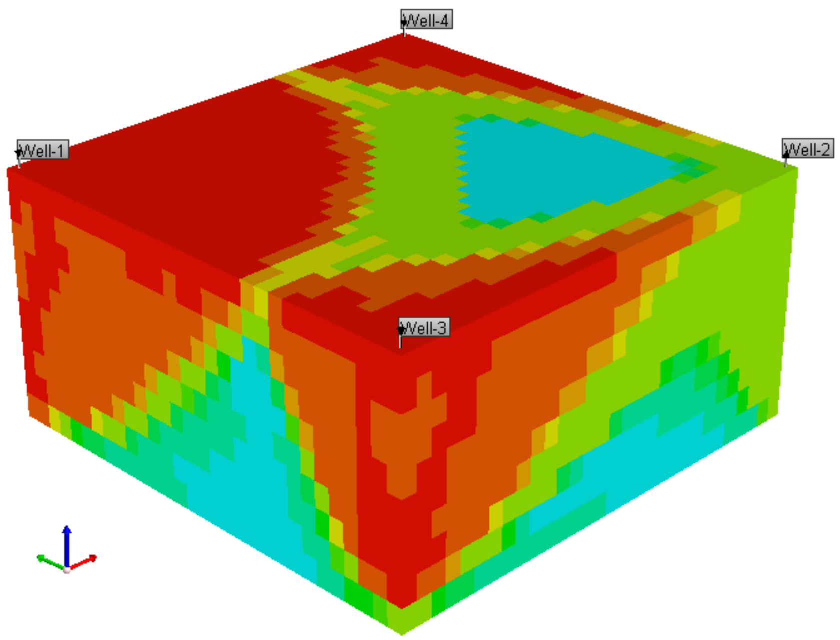


Figure 5. 73 Location of wells in case of quarter 9-spot pattern consisting of injection wells (well 1,3 and 4) and production well (well 2)

Figure 5.74 illustrates location of injection wells together with steam injection rate in each well for single injection well in quarter 5-spot pattern and three injection wells in quarter 9-spot pattern.

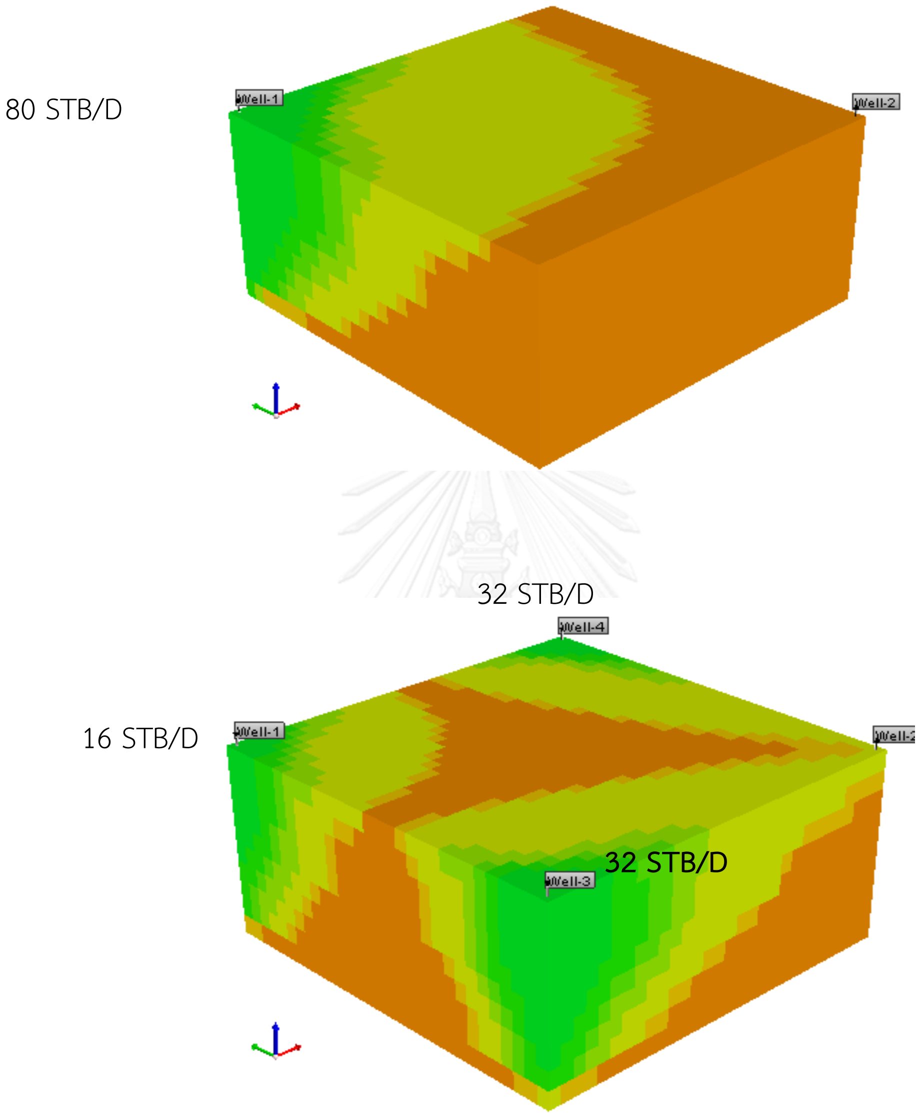


Figure 5. 74 Location of wells and steam injection rate of each well for a) quarter 5-spot pattern and b) quarter 9-spot pattern

Table 5.14 summarizes results from reservoir simulation consisting of enthalpy consumed, cumulative oil production and oil recovery factor, whereas Table 5.15 summarizes cumulative water production and enthalpy consumed per barrel of oil.

Table 5. 14 Summary of enthalpy consumed, cumulative oil production and recovery factor of heterogeneous reservoirs with various L_c in both cases of quarter 5-spot and quarter 9-spot patterns

L_c	Well Pattern	Enthalpy Consumed (Btu)	Cumulative oil production (BBL)	Recovery Factor (%)
0.254	5-spot	9.45×10^{10}	5.78×10^{4}	54.82
	9-spot	1.16×10^{11}	5.71×10^{4}	54.09
0.310	5-spot	8.40×10^{10}	5.37×10^{4}	50.87
	9-spot	9.99×10^{10}	5.19×10^{4}	49.23
0.352	5-spot	8.08×10^{10}	5.11×10^{4}	48.47
	9-spot	1.00×10^{11}	5.03×10^{4}	47.72
0.403	5-spot	8.15×10^{10}	4.85×10^{4}	45.94
	9-spot	8.86×10^{10}	4.60×10^{4}	43.62
0.438	5-spot	6.62×10^{10}	4.37×10^{4}	41.44
	9-spot	7.84×10^{10}	4.27×10^{4}	40.48

Table 5. 15 Summary of cumulative water production, enthalpy consumed per barrel of oil and duration of steam injection of heterogeneous reservoirs with various L_c in both cases of quarter 5-spot and quarter 9-spot patterns

L_c	Well Pattern	Cumulative water production (BBL)	Enthalpy Consumed per Barrel of Oil (Btu/BBL)	Duration (year)
0.254	5-spot	2.82×10^{5}	1.63×10^{6}	21.26
	9-spot	3.56×10^{5}	2.03×10^{6}	17.51
0.310	5-spot	2.50×10^{5}	1.56×10^{6}	19.59
	9-spot	3.06×10^{5}	1.92×10^{6}	15.59
0.352	5-spot	2.41×10^{5}	1.58×10^{6}	18.68
	9-spot	3.08×10^{5}	1.99×10^{6}	15.59
0.403	5-spot	2.46×10^{5}	1.68×10^{6}	18.01
	9-spot	2.71×10^{5}	1.93×10^{6}	13.92
0.438	5-spot	1.97×10^{5}	1.51×10^{6}	15.76
	9-spot	2.39×10^{5}	1.84×10^{6}	12.59

From Tables 5.14 and 5.15 several plots are made as follows to study effects of number of injection well on effectiveness of steamflooding in heterogeneous reservoir with various values of Lorenz coefficient.

From Figure 5.75, oil recovery factors obtained from of quarter 5-spot is always higher than quarter 9-spot approximately 1% in all heterogeneity values. As total injection rate is split in three parts, total injection rate for quarter 9-spot is suspected to face low injectivity at first stage. Hence observation of injection rates as a function of production period is performed and illustrated in Figure 5.76.

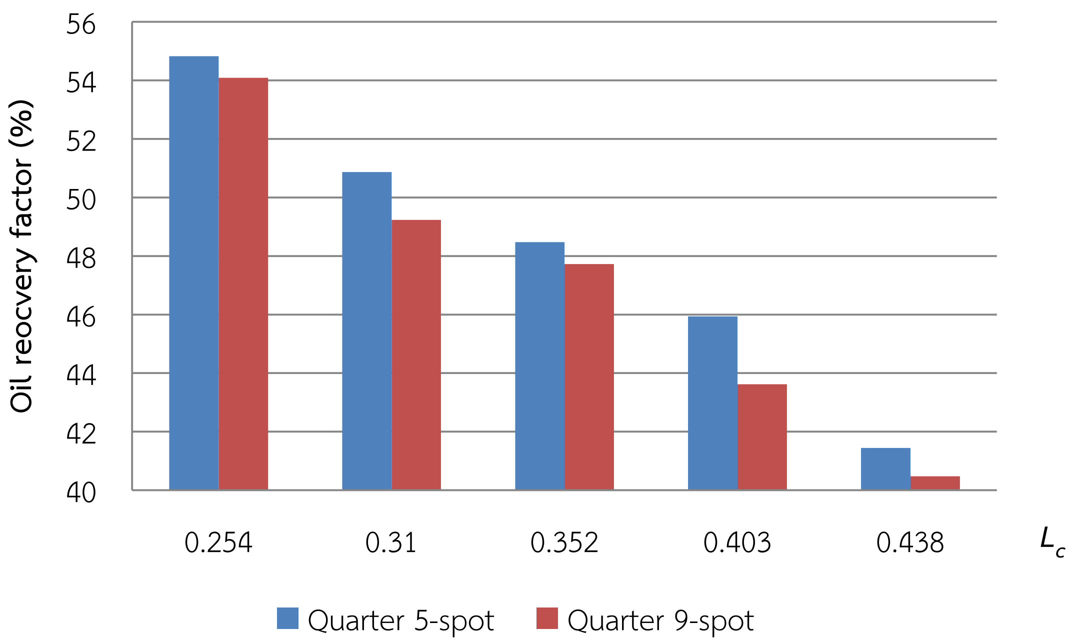


Figure 5. 75 Oil recovery factors for reservoirs with quarter 5-spot and quarter 9-spot patterns as a function of heterogeneity

Figure 5.76 shows that wells no.3 and no.4 which are expected to inject at 32 STB/D cannot achieve this in first period. As same as well 1 which is located at diagonal location, desired rate of 16 STB/D cannot be achieved. Nevertheless, desired rate are attained and when comparing to 5-spot well pattern, injectivity is much improved in case of 9-spot well pattern. Higher steam injection ability also comes with chance of early breakthrough of steam and hot water, resulting in less efficiency in heat exchanging of steam. Eventually, total oil recovery from 5-spot pattern is slightly higher compared to the case of 9-spot pattern.

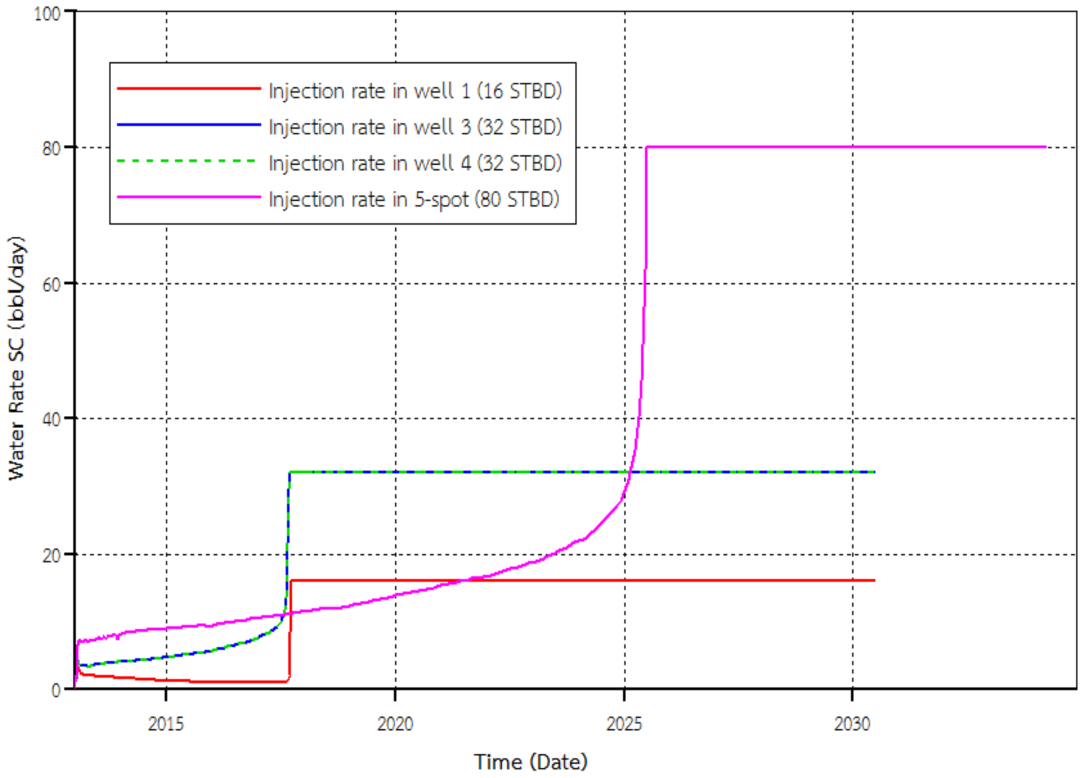


Figure 5. 76 Injection rates in each injection wells in case of quarter 9-spot pattern compared to total injection rate obtained from quarter 5-spot pattern

As expected, water production is much higher in case of quarter 9-spot compared to quarter 5-spot model as can be seen in Figure 5.77. As steam is more injected in case of quarter 9-spot, this results in more amount of condensed steam breakthrough as steam can travel through the top layers of reservoir from three wells. As heterogeneity increases, results obtained from the case of quarter 9-spot are similar to that of quarter 5-spot pattern.

As oil recovery is higher in case of quarter 5-spot pattern, energy consumed per barrel of oil is less compared to quarter 9-spot pattern as can be seen in Figure 5.78. Lowering of energy consumed in case of quarter 5-spot is also caused from lower injectivity. Steam injection is limited from maximum bottomhole pressure for longer period and hence, less amount of heat is consumed. Increasing of heterogeneity results in reduction of energy consumed due to shorter steam injection period. Shape of connecting lines is similar in both cases. Explanation of this is already made in section 5.3

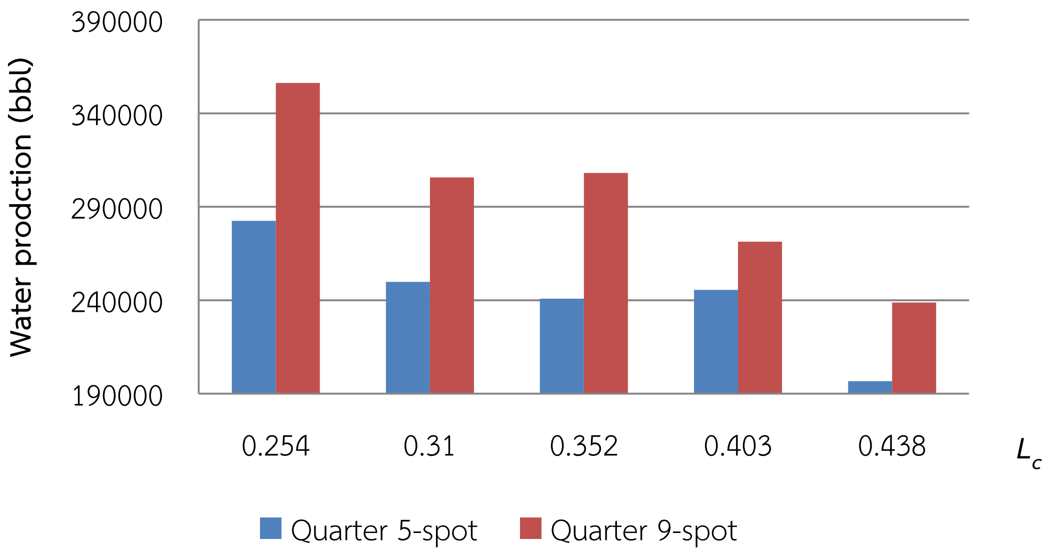


Figure 5. 77 Water productions of reservoirs with quarter 5-spot and quarter 9-spot patterns as a function of heterogeneity

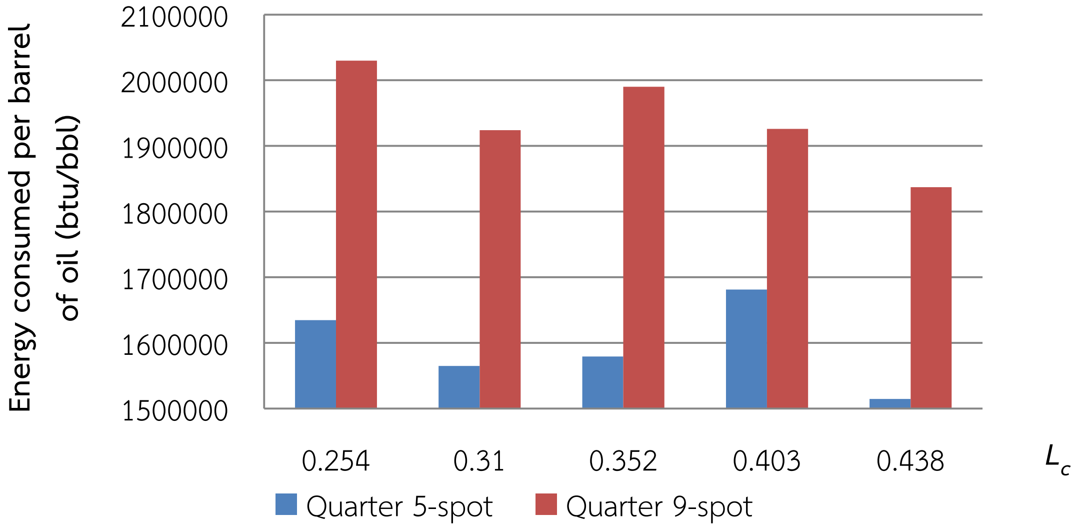


Figure 5. 78 Enthalpy consumed per barrel of oil of reservoirs with quarter 5-spot and quarter 9-spotpatterns as a function of heterogeneity

Oil and water production rates as a function of production time are plotted in Figure 5.79 for both cases of quarter 5-spot and quarter 9-spot patterns. This can confirm explanation previously that oil production rate for 9-spot pattern is higher in first period due to more steam injected from three wells compared just one well. However, condensed steam breakthrough occurs much earlier since steam can travel through higher permeability layers on top of reservoir. Hot water breakthrough from well 3 and well 4 results in high water production from early period and eventually production terminates at earlier period compared to quarter 5-spot case.

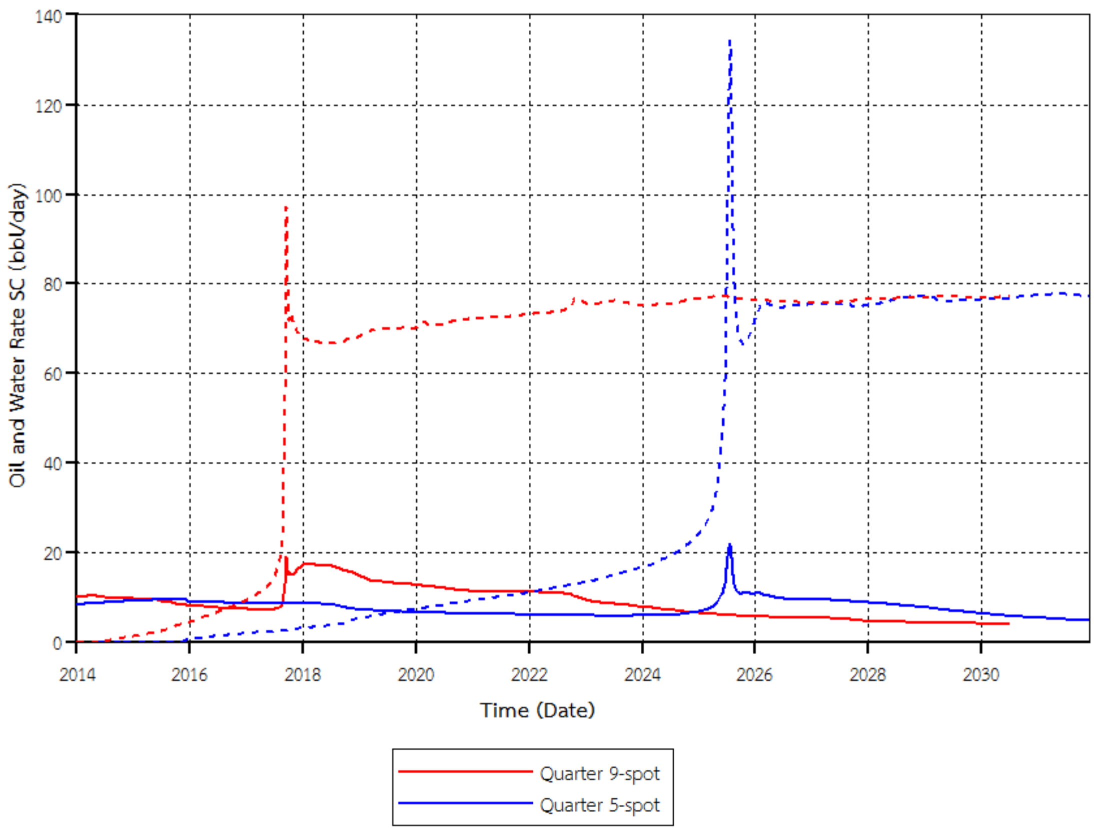


Figure 5. 79 Oil and water production rates obtained from heterogeneous reservoirs with L_c = 0.254 for quarter 5-spot and quarter 9-spot patterns

Comparing among oil production rates obtained from quarter 9-spot pattern with different reservoir heterogeneities as illustrated in Figure 5.80, it can be seen that steam pressurization period is mostly the same for all cases as steam vapor does not breakthrough yet. Deviation starts from arrival of condensed steam breakthrough. Quick drop of oil rate is observed in high heterogeneity case and also early arrival of heated oil bank. Eventually, high heterogeneity results in an early termination of production.

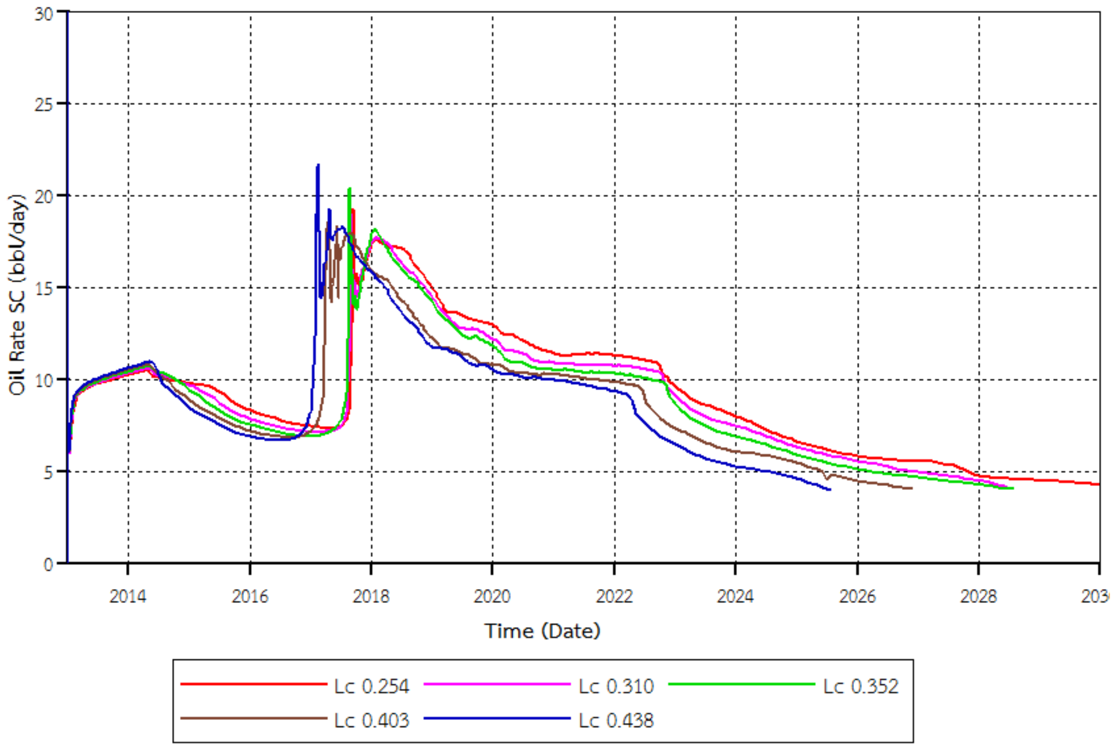


Figure 5. 80 Oil production rates obtained from different heterogeneous reservoirs for quarter 9-spot pattern

Water saturation profiles are compared for cases of quarter 5-spot and quarter 9-spot pattern for reservoir with Lorenz coefficient of 0.438. Figure 5.81 illustrates water saturation profiles at different production periods.

At year 2015, steam breakthrough occurs from adjacent wells number 3 and 4 in 9-spot pattern. Steam breakthrough in 5-spot pattern occurs in 2017, while steam from diagonal well does not breakthrough yet in 9-spot pattern. In 2018, hot water breakthrough occurs in 9-spot pattern while in case of 5-spot, hot water bank does not arrived yet at the middle of reservoir.

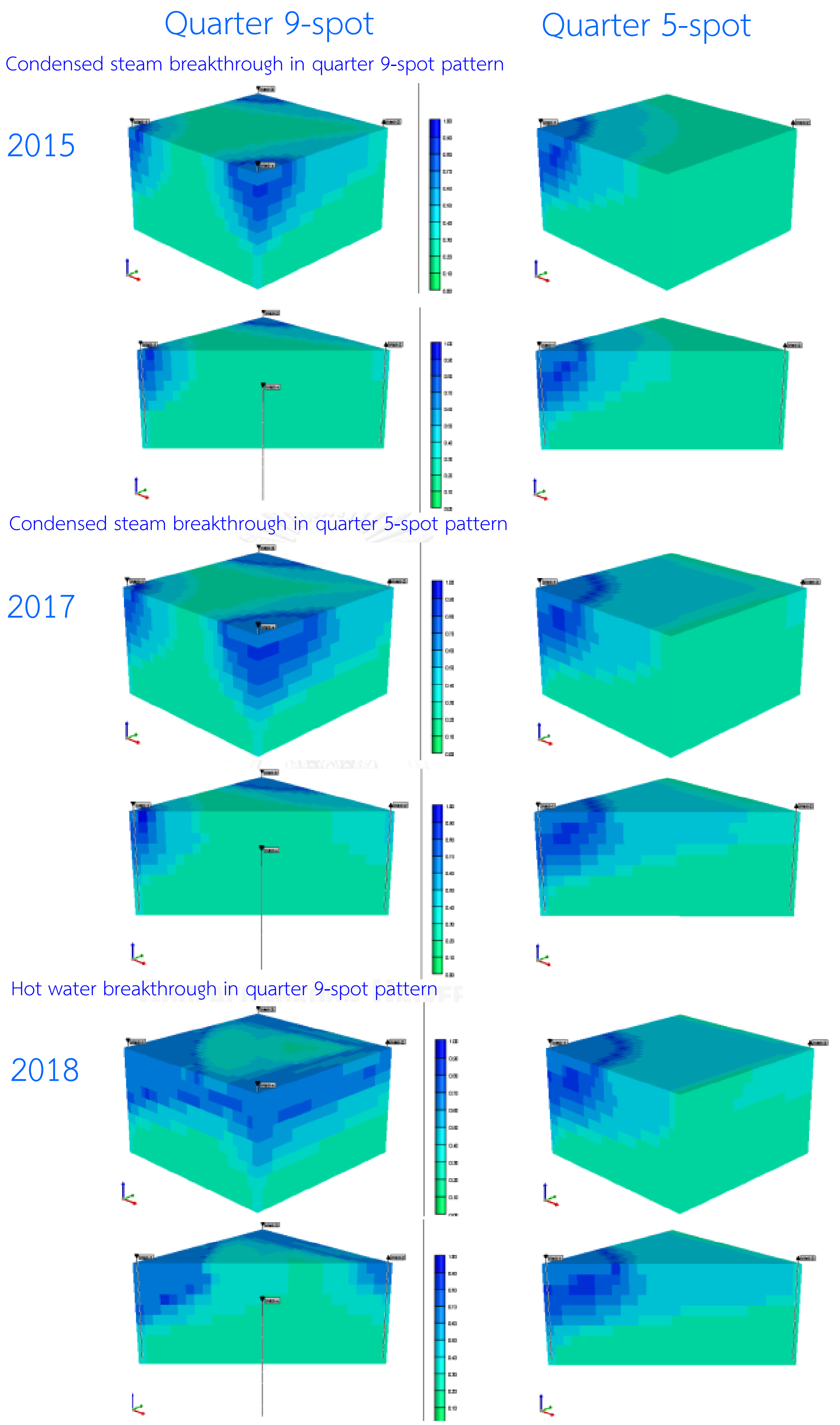


Figure 5. 81 Water saturation profiles at different production periods of quarter 5-spot and quarter 9-spot patterns implemented in heterogeneous reservoir with L_c of 0.438

From explanations in this section, it can be seen that number of injection well together with flood pattern shows effects on effectiveness of steamflooding. High ratio of injector per producer in 9-spot flood pattern is favorable in terms of increasing steam injectivity in shorter period. Nevertheless, higher injectivity also comes with earlier water breakthrough and consecutively results in shorter production period. Under the same production constraints, 5-spot pattern producing oil slowly extends longer production period compared to 9-spot and results in slightly higher oil recovery due to higher retention of steam that causes better heat exchanging.

5.9 Summary of Sensitivity Analysis

In this section, oil recovery factor in the previous sections is summarized in tornado chart shown in Figure 5.82. All oil recovery results in tornado chart are the results from reservoir with Lorenz coefficient of 0.352 with the change in relative permeability curve, oil gravity, k_v/k_h, permeability sequence and flood pattern. For the change in relative permeability, the oil recovery values selected from the case where end point saturation before steamflooding is used to represent cases from relative permeability section since it shows the highest impact on oil recovery.

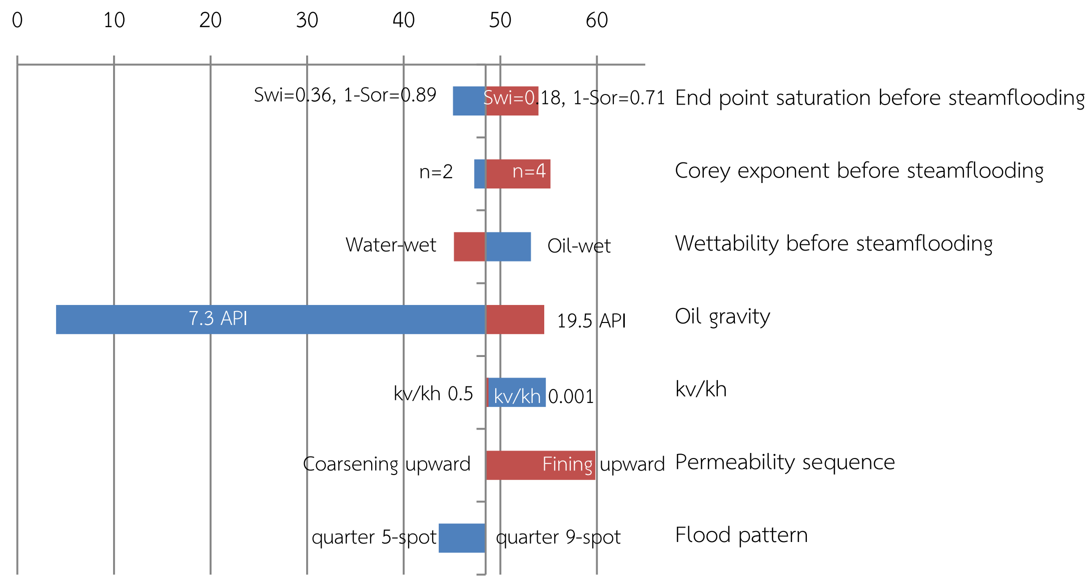


Figure 5. 82 Tornado chart of oil recovery from sensitivity analysis of reservoir parameters

From Figure 5.82, oil recovery variation is maximum when oil gravity is changed since oil gravity influences mobility of heavy oil reservoir. Permeability sequence is no. 2nd that influences oil recovery. In summary, changing oil gravity has shown the highest effect while permeability sequence and changing of relative permeability curve can be considered to have moderate effect on oil recovery. Increasing in vertical permeability has very small effect compared to other properties.

CHAPTER 6
CONCLUSION AND RECOMMENDATION

Effects of reservoir heterogeneity together with operational parameters and interests properties on effectiveness of steamflooding are summarized in this section. Recommendations are also provided for further studies.

6.1 Conclusion

Results and discussion in previous chapter demonstrate that reservoir heterogeneity has significant effects on effectiveness of steamflooding process. Study of interest reservoir parameters provides several guidelines as screening criteria when both heterogeneity and reservoir parameters are uncertain. Conclusions are summarized below.

1 Steam injection rate and steam quality are important operational parameters for designing proper production scheme of steamflooding process. Steam injection rate should be high enough to pressurize reservoir, increasing oil recovery for the first period of production. Steam quality is also very important parameter especially in heterogeneous reservoir. Based on 70% priority in oil recovery factor, 20% on energy consumed per barrel and 10% on water production, injecting steam at the rate of 80 STB/D (liquid equivalent) together with steam quality of 0.6 are best conditions for the average heterogeneity value.

2 Effect of heterogeneity is remarkable on effectiveness of steam injection process. High value of heterogeneity results in favorable flow path that reduces volumetric sweep efficiency of the process. The higher the heterogeneity, the lower the volumetric sweep efficiency. Reducing of displaceable volume also results in shorter time for breakthrough as well as

total steam injection period. Oil recovery factor is both controlled from volumetric sweep efficiency together with production constraints.

3 Relative permeability curves play an important role on effectiveness of steamflooding process. Parameters that involve with changes of residual phases tend to yield higher sensitivity on oil recovery compared to magnitude of flow ability. Changing magnitude of relative permeability curve will show sensitivity only when a whole curve is shifted for whole range of saturation. Therefore, changing of Corey's exponent or curvaceous of relative permeability tends to yield high sensitivity on oil recovery.

4 Oil gravity is very important parameter to concern for steamflooding process. Steam temperature, steam injection rate and also steam quality should be considered for certain oil gravity. For very heavy oil, higher steam temperature and steam quality could result in higher of injectivity since higher heat quantity can suddenly change rock properties to a more favorable condition for oil production. Steamflooding in very light oil yields high oil recovery but other techniques might be better candidates since light oil possesses already high mobility. For reservoir containing higher heterogeneity, performance is lower as high permeability layer causes early breakthrough of injected steam and as a consequence, reduces oil recovery and increases water production. Effect of oil viscosity on relative permeability does not show significant change.

5 Lower heterogeneity yields benefit on steamflooding in heterogeneous reservoir. As vertical permeability increases, overriding of steam vapor is facilitated and this causes lowering of oil recovery. However, benefit of low vertical permeability is diminished when in reservoir with high heterogeneity.

6 Sequence of permeability shows remarkable effects in steamflooding process. Injecting steam into fining upward reservoir yields better sweep efficiency since part of low permeability zone located at top layers can be swept by hot water that is condensed from steam. Delaying breakthrough of hot water bank results in higher oil recovery and less water production in

fining upward model. Higher heterogeneity facilitates early hot water breakthrough through high permeability zone and hence, oil recovery is substantially reduced.

7 In comparison between quarter 9-spot and quarter 5-spot flood pattern, quarter 9-spot flood pattern is favorable in terms of increasing steam injectivity at first. Nevertheless, steam breakthrough earlier and consecutively results in shorter production period. Under the same production constraints, quarter 5-spot pattern which produces oil slowly can extend production period compared to quarter 9-spot pattern, resulting in slightly higher oil recovery due to longer retention of steam that causes better heat exchanging.

8 Range of oil gravity chosen in this study shows it is the most sensitive parameter on oil recovery by means of steamflooding. In fact, oil gravity should be used as a major criterion for steamflooding process and to choose for proper operational conditions. End point saturations on relative permeability curves, depositional sequence, vertical permeability and flood pattern also show moderate sensitivity.

6.2 Recommendation

Several recommendations are provided for perfection of steamflooding simulation.

1 Core flooding should be performed to determine effects of temperature on relative permeability curves and these data should be input in the simulation model. In this study, relative permeability curves are generated from correlation based on theory. Experiment would make result from simulation more precise.

2 In the study of relative permeability effect, rock samples with various wetting conditions should be used to analyze irreducible water saturations and residual oil saturation and its corresponding relative permeability since they seem to be sensitive.

3 In the study of oil gravity effect, viscosity and gas-oil ratio of heavy oil are generated by using correlation. Variability of rock and oil samples should be tested to provide precise input in the rock-fluid section especially in case where viscosity effect of heavy oil should be considered.

4 Heterogeneity should be randomly constructed to give more results in terms of probability

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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. Initial setting conditions of simulator are involved with field unit and single porosity.

1. Reservoir

Reservoir properties specification

Note: Using Hall's correlation for consolidated sand stones compressibility

Property	Value	unit	Notice
Grid top	900	ft	@ layer 1
grid thickness	10	ft	whole grid
porosity	0.3		whole grid
Permeability	follow value at L_c=0.35		(i,j,k)
*Heat transfer coefficient/Unit area	35	Btu/ft2*day*F	(i,j,k)
Rock Compressibility			
* Formation compressibility	3e-6	1/psi	
Porosity reference pressure	350	psi	
Thermal Properties			
*Volumetric Heat Capacity (Rock)	24.714	Btu/(ft3*F)	
T-dependent coefficient	0	Btu/(ft3*F*F)	
Thermal conductivity phase mixing	complex		
*Thermal conductivity (Reservoir rock)	60	Btu/(ft*day*F)	
Thermal conductivity (Water phase)	1.8	Btu/(ft*day*F)	
Thermal conductivity (Oil phase)	1.9	Btu/(ft*day*F)	
Thermal conductivity (Gas phase)	0.15	Btu/(ft*day*F)	
Overburden Heat Loss			
*Overburden Volumetric heat capacity	24.714	Btu/(ft3*F)	
*Underburden Volumetric heat capacity	24.714	Btu/(ft3*F)	
*Overburden Thermal conductivity	60	Btu/(ft*day*F)	
*Underburden Thermal conductivity	60	Btu/(ft*day*F)	

* Prats, M., *Thermal Recovery*. 1982: H.L. Doherty Memorial Fund of AIME. pp. 208

2. Components

Generate PVT table by using correlation with following values

Description	Option	Value
Reservoir temperature		74.3 F
Generate data up to max. pressure of		2000 psi
Bubble point pressure calculation	Value provided	96.064 psi
Oil density at STC(14.7 psia, 60 F)	Stock tank oil gravity (API)	14
Gas density at STC(14.7 psia, 60 F)	Gas gravity (Air=1)	1.295
Oil properties (Bubble point, Rs, Bo) correlations	Standing	
Oil compressibility correlation	Glaso	
Dead oil viscosity correlation	Ng and Egbogah	
Live oil viscosity correlation	Beggs and Robinson	
Gas critical properties correlation	Standing	
Non-hydrocarbon gas correlation	Not used	
H2S mole fraction (optional)		
CO2 mole fraction (optional)		
N2 mole fraction (optional)		

General

Generate water properties using correlation with these values

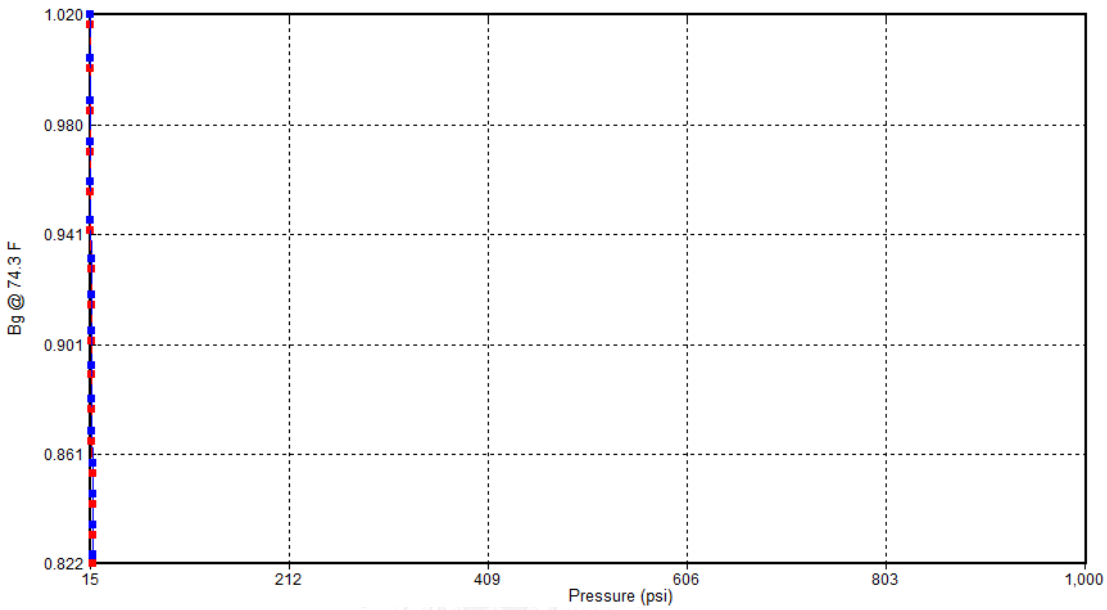
Description	Value
Reservoir temperature (TRES)	74.3 F
Reference pressure (REFPW)	430 psi
Water salinity (ppm)	10000

Generate water properties using correlation with these values

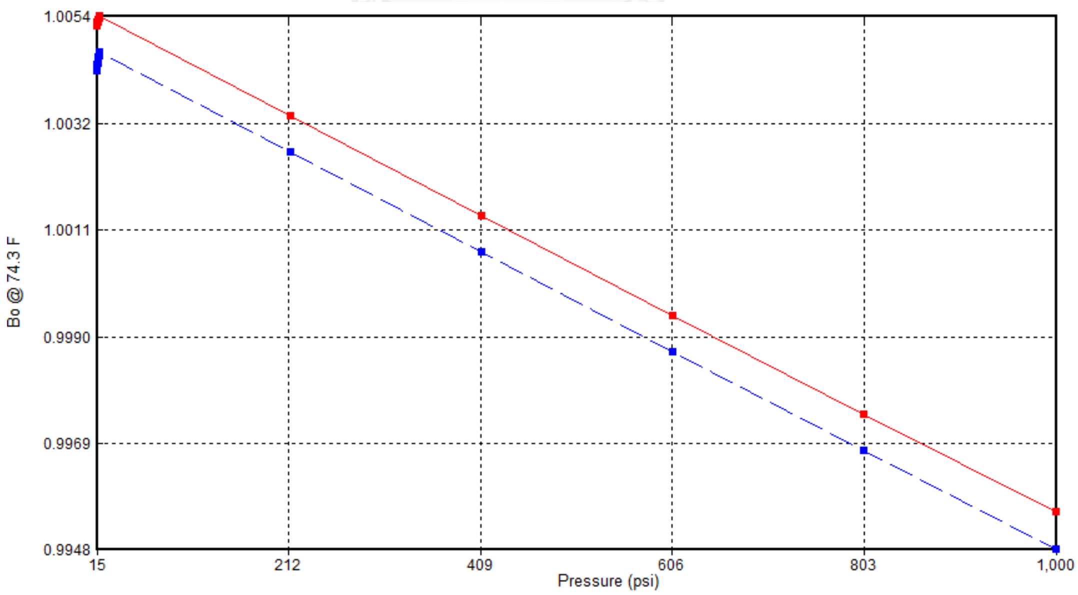
Description	Default	Value
Reservoir temperature (TRES)		74.3 F
DENSITIES		
Oil density (DENSITY OIL)	Stock tank oil gravity (API)	14
Gas density/gravity (DENSITY/GRAVITY GAS)	Gas gravity (Air=1)	1.295
Water phase density (DENSITY WATER)		62.8374 lb/ft3
Vo pressure dependence (CVO)	0 cp/psi	
Undersaturated Co (CO)		1.0e-005 1/psi
Water properties		
Formation Volume Factor (BWI)		0.999987
Compressibility (CW)		3.24527e-006 1/psi
Reference pressure for FVF (REFPW)		430 psi
Viscosity (VWI)	1 cp	1.03067 cp
Pressure dependence of viscosity (CVW)	0 cp/psi	

Oil properties of various oil gravity

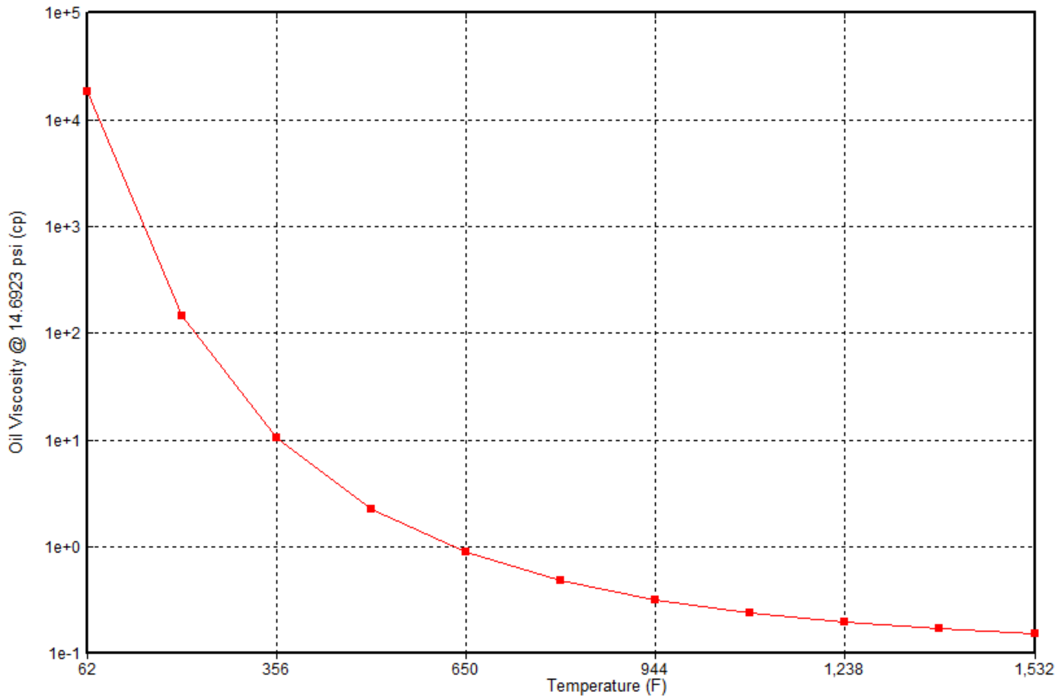
Oil properties of 7.3 API oil



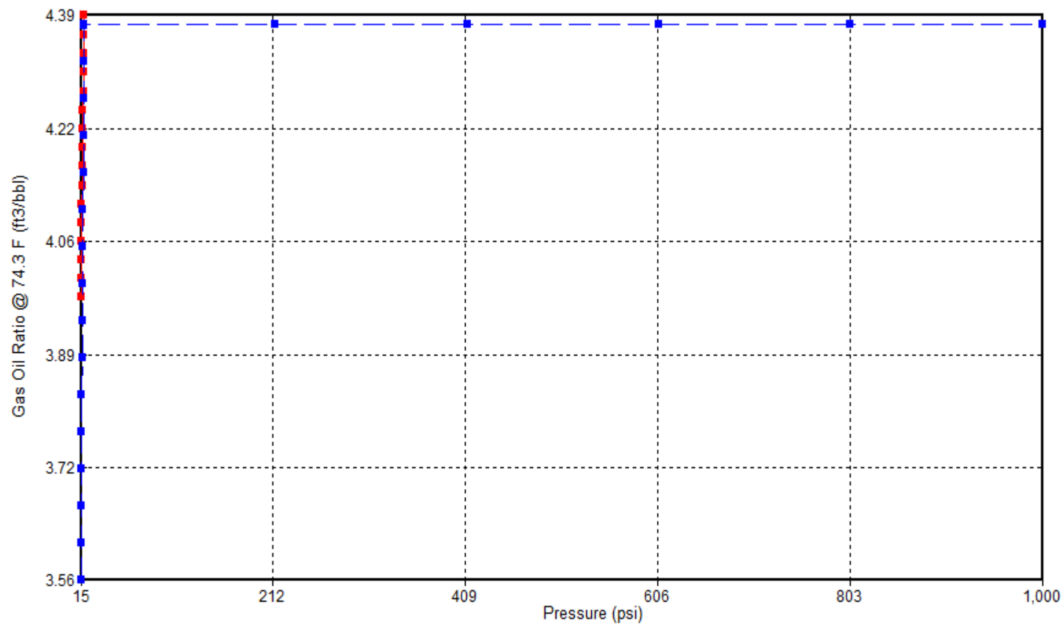
Dry gas formation volume factor (B_g) for 7.3 API oil as a function of reservoir pressure



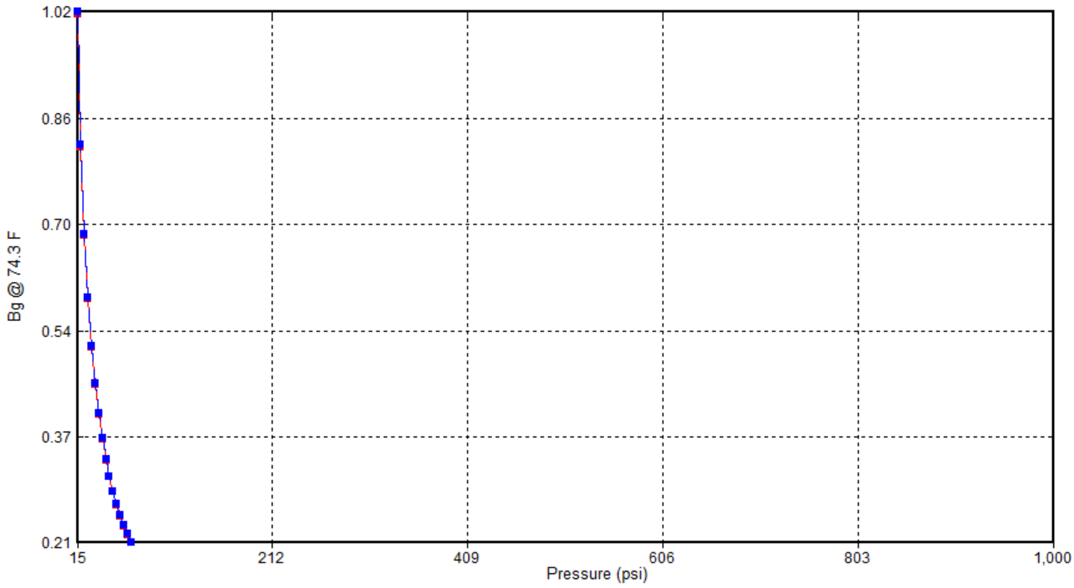
Oil formation volume factor (B_o) for 7.3 API oil as a function of reservoir pressure



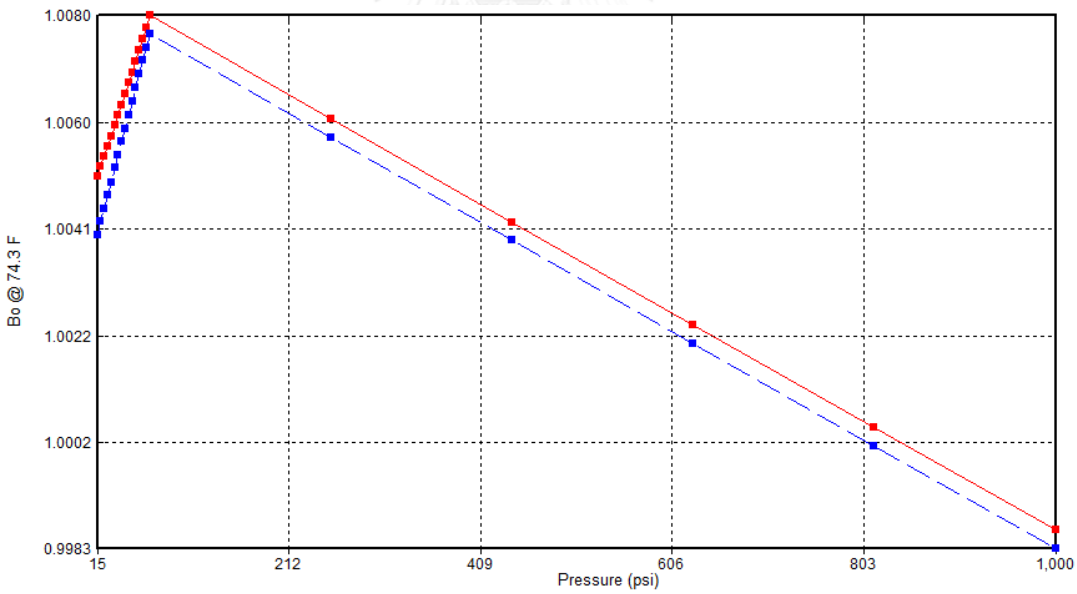
Oil viscosity (μ_o) for 7.3 API oil as a function of reservoir temperature



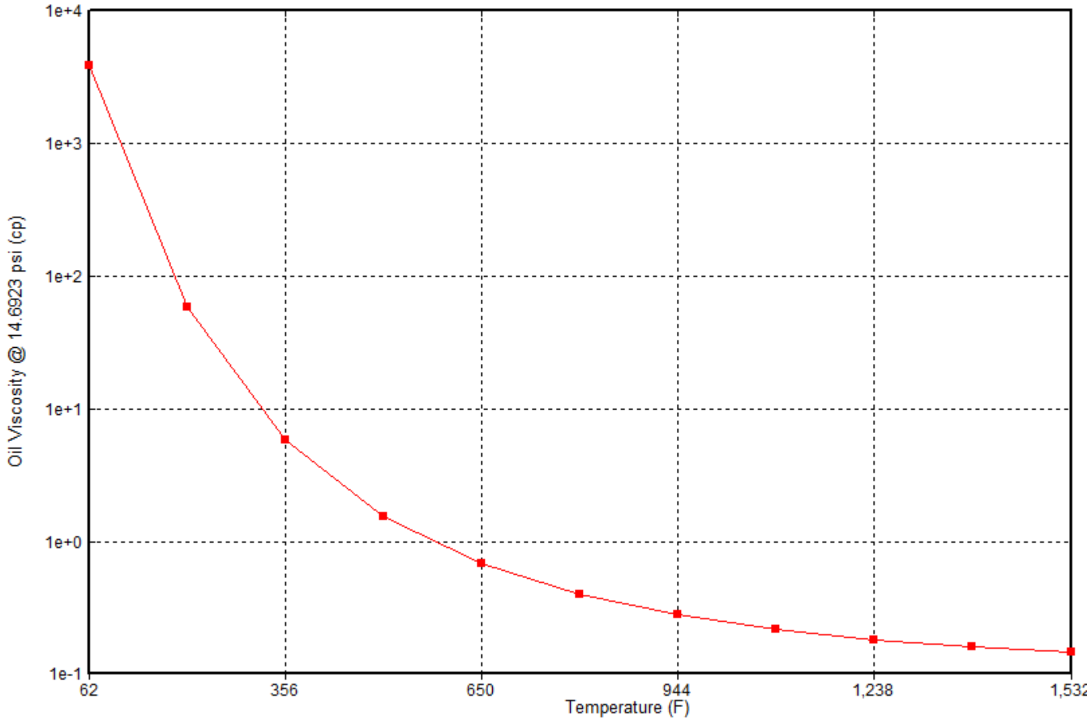
Gas-oil ratio (R_s) for 7.3 API oil as a function of reservoir pressure



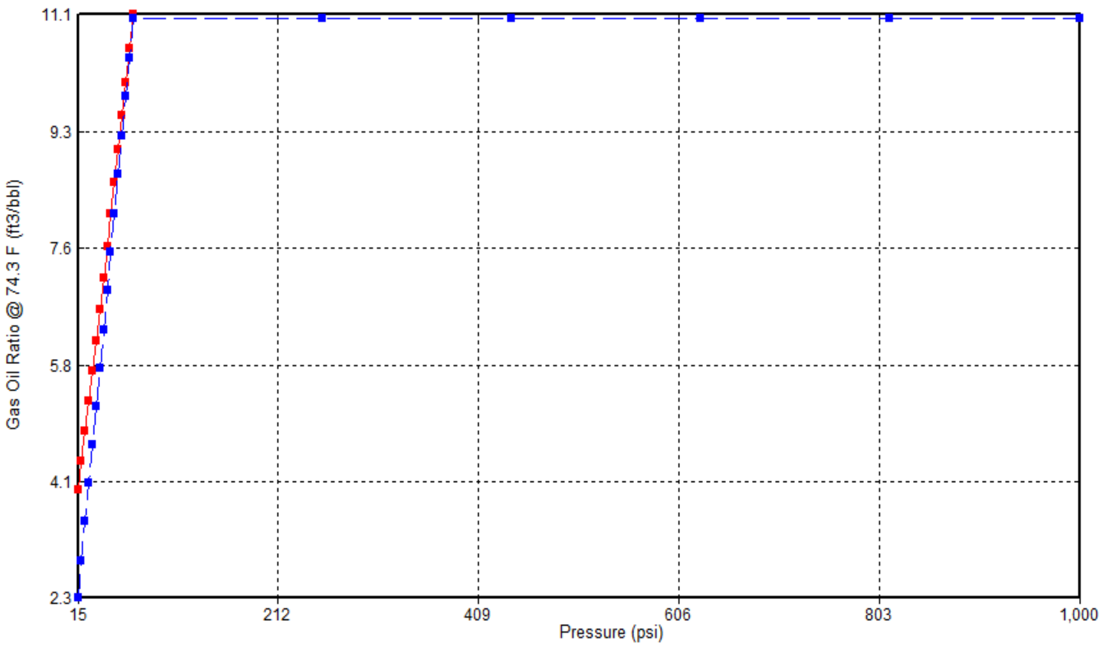
Dry gas formation volume factor (B_g) for 11 API oil as a function of reservoir pressure



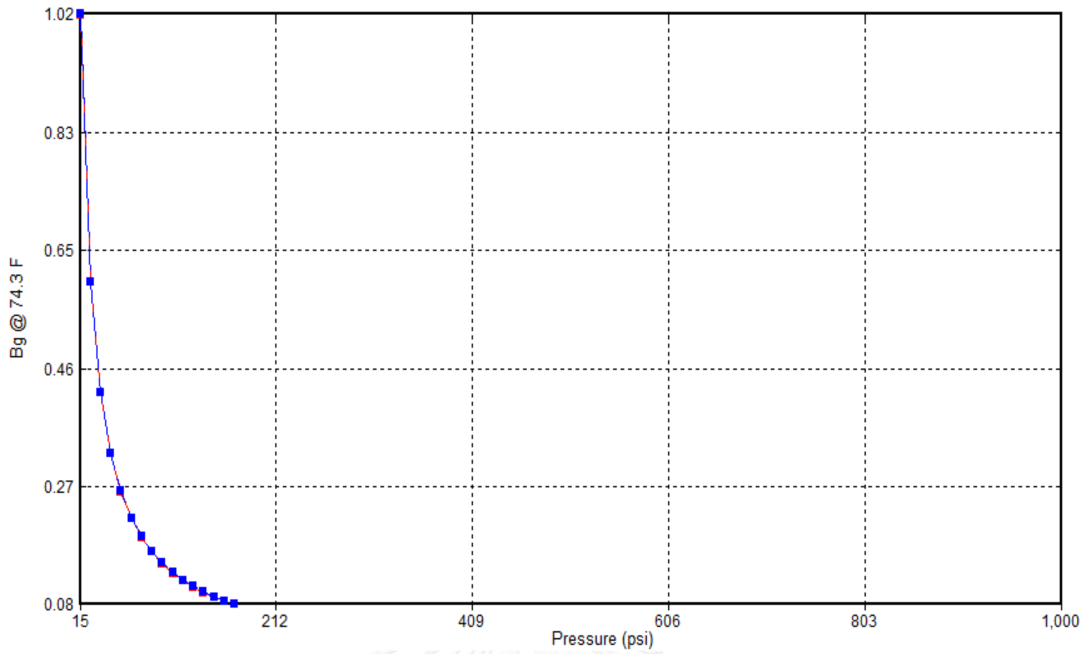
Oil formation volume factor (B_o) for 11 API oil as a function of reservoir pressure



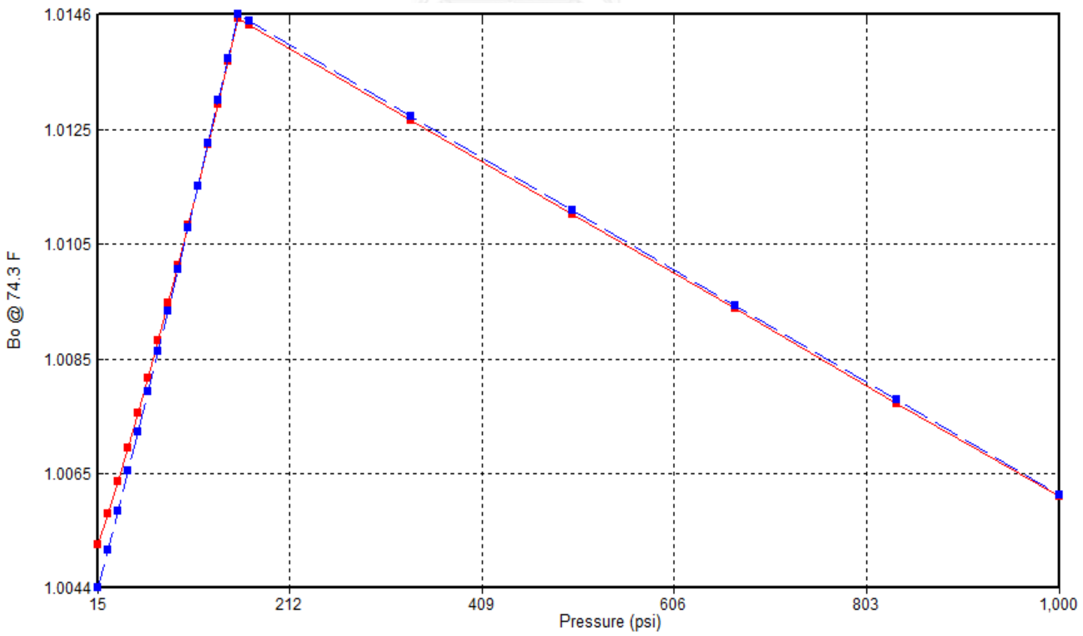
Oil viscosity (μ_o) for 11 API oil as a function of reservoir temperature



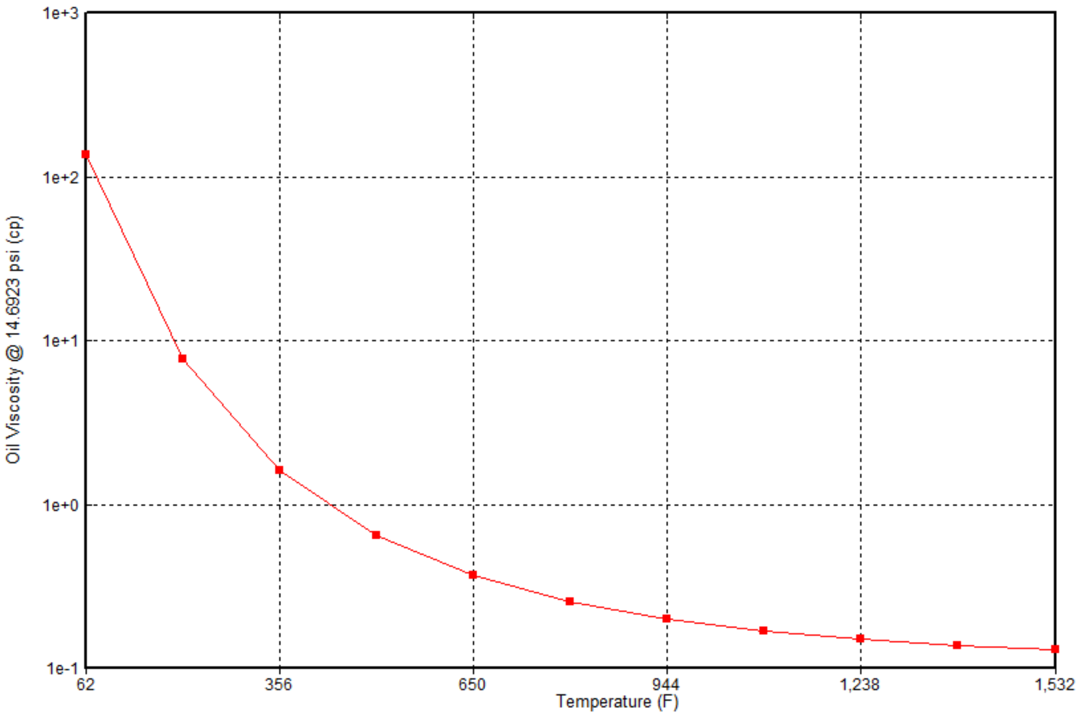
Gas-oil ratio (R_s) for 11 API oil as a function of reservoir pressure



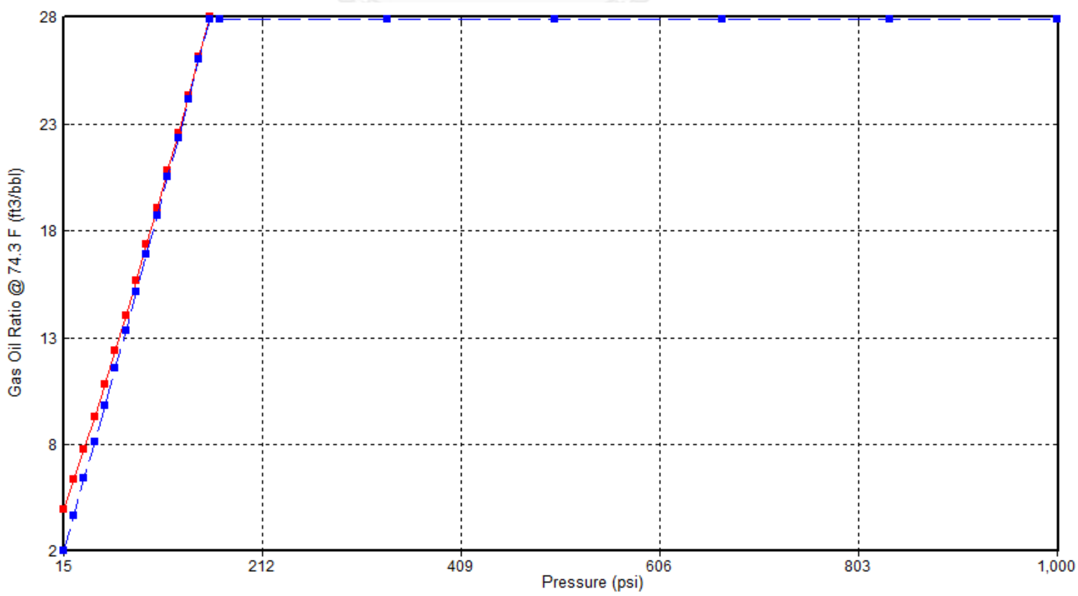
Dry gas formation volume factor (B_g) for 19.5 API oil as a function of reservoir pressure



Oil formation volume factor (B_o) for 19.5 API oil as a function of reservoir pressure



Oil viscosity (μ_o) for 19.5 API oil as a function of reservoir temperature



Gas-oil ratio (R_s) for 19.5 API oil as a function of reservoir pressure

3. Rock-Fluid

Rock type properties (using correlations)

Rock Fluid properties	
Rock wettability	Water Wet
Method for evaluating 3-phase KRO	Stone's Second Model
Interpolation components	Interpolation NOT enabled

Relative permeability tables

Description	**Value**
SWCON - Endpoint Saturation: Connate Water	0.27
SWCRIT - Endpoint Saturation: Critical Water	0.27
SOIRW - Endpoint Saturation: Irreducible Oil for Water-Oil Table	0.2
SORW - Endpoint Saturation: Residual Oil for Water-Oil Table	0.2
SOIRG - Endpoint Saturation: Irreducible Oil for Gas-Liquid Table	0.33
SORG - Endpoint Saturation: Residual Oil for Gas-Liquid Table	0.33
SGCON - Endpoint Saturation: Connate Gas	0
SGCRIT - Endpoint Saturation: Critical Gas	0
KROCW - k_{ro} at Connate Water	0.6
KRWIRO - k_{rw} at Irreducible Oil	0.1
KRGCL - k_{rg} at Connate Liquid	0.5
KROGCG - k_{rog} at Connate Gas	
Exponent for calculating k_{rw} from KRWIRO	3
Exponent for calculating k_{row} from KROCW	3
Exponent for calculating k_{rog} from KROGCG	3
Exponent for calculating k_{rg} from KRGCL	3

Relative Permeability End Points

Temperature dependence Properties including Irreducible water saturation (SWR or SWCON), Residual oil saturation for water injection (SORW) and residual liquid saturation for gas injection (SORG) have to be included in steamflooding process.

Temp(F)	SWR	SORW	SORG	KRWIRO	KROCW
74.3	0.27	0.2	0.33	0.1	0.6
400	0.5	0	0.35	0.5	0.8

Rock type properties

Interpolation Components (INTCOMP)	Interpolation enabled
Rock-fluid interpolation will depend on component:	Water
Phase from which component's composition will be taken:	gas mole fraction

Using Interpolation Sets box

Interpolation sets	**1**
Phase interpolation parameters	**value**
Wetting phase (DTRAPW)	0.2
Non-Wetting phase (DTRAPN)	0.2
Interpolation sets	**2**
Phase interpolation parameters	**value**
Wetting phase (DTRAPW)	0.6
Non-Wetting phase (DTRAPN)	0.6
Relative permeability to gas at connate liquid (KRGCW)	0.8
Relative permeability tables	**Both Oil-water and Liquid-gas**
Smoothing method for table end-points:	Cubic smoothing

4 Initial condition

Reference Pressure = 430 psi

Reference Depth = 1000 ft

5 Numerical

Set first time step size after well change (DTWELL) = 0.001 day

Isothermal option (ISOTERM) OFF

Upstream calculation option (UPSTREAM) KLEVEL

6 Well and recurrent

Injector well (well-1)

Type : INJECTOR MOBWEIGHT EXPLICIT

Constraints

	Constraint	Parameter	Limit/Mode	Value	Action
1	OPERATE	BHP bottom hole pressure	MAX	520 psi	CONT
2	OPERATE	STW surface water rate	MAX	100 bbl/day	CONT

Injected fluid

WATER with mole fraction of 1 at 400 F and Steam quality of 1.

Producer well (well-2)

Type : PRODUCER

Constraints

	Constraint	Parameter	Limit/Mode	Value	Action
1	OPERATE	BHP bottom hole pressure	MIN	200 psi	CONT
2	OPERATE	STO surface oil rate	MAX	80 bbl/day	CONT
3	MONITOR	WCUT water-cut (fraction)		0.95	STOP

Date

2013-11-03

2043-11-03 (STOP)

VITA

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