OPTIMAL WELL DESIGN FOR WATER DUMPFLOOD

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
Department of Mining and Petroleum Engineering
Faculty of Engineering
Chulalongkorn University
Academic Year 2015

การออกแบบหลุมที่เหมาะสมสำหรับการอัดน้ำแบบถ่ายเทในแหล่งกักเก็บน้ำมัน

นางสาวพิชิตา บูรณ์เจริญ

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
สาขาวิชาวิศวกรรมปิโตรเลียม ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม
คณะวิศวกรรมศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย
ปีการศึกษา 2558

Thesis Title	OPTIMAL WELL DESIGN FOR WATER DUMPFLOOD
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Field of Study	Petroleum Engineering
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Accepted by the Faculty of Engineering, Chulalongkorn University in Partial Fulfillment of the Requirements for the Master's Degree

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กระบวนการอัดน้ำแบบถ่ายเทเข้าสู่แหล่งกักเก็บน้ำมันเป็นเทคโนโลยีที่ได้รับการพิสูจน์ที่ช่วยรักษาความดันของแหล่งกักเก็บและเพิ่มปริมาณน้ำมันที่นำขึ้นมา กระบวนการนี้ช่วยประหยัดต้นทุนและค่าใช้จ่ายในการดำเนินงานของปั๊มและท่อสำหรับอัดน้ำ แต่เนื่องจากปริมาณน้ำที่อัดที่มีจำนวนจำกัด ทำให้ปริมาณน้ำมันที่นำขึ้นมาโดยกระบวนการอัดน้ำแบบถ่ายเทยังมากไม่เพียงพอ ดังนั้นการออกแบบหลุมอัดน้ำและหลุมผลิตน้ำมันที่เหมาะสมเป็นปัจจัยสำคัญในการเพิ่มประสิทธิภาพในการแทนที่น้ำมัน

ในการศึกษาครั้งนี้การจำลองการไหลในแห่งกักเก็บใช้ในการเปรียบเทียบประสิทธิภาพของชนิดหลุมที่แตกต่างกัน (หลุมแนวตั้งและแนวนอนสำหรับหลุมถ่ายเทน้ำและหลุมผลิต), ความยาวของหลุมแนวนอน (ในกรณีการเจาะแนวนอนในแหล่งกักเก็บน้ำมัน) สำหรับแหล่งชั้นน้ำขนาดต่างๆ แบบจำลองแหล่งกักเก็บถูกสร้างจากลักษณะของแหล่งกักเก็บและคุณสมบัติของของไหลอ้างอิงจากแหล่งน้ำมันบนบกในประเทศไทย ในการศึกษาชนิดของหลุม ผลการศึกษาบ่งชี้ว่า หลุมถ่ายเทน้ำแนวตั้งและหลุมผลิตแนวนอนสามารถผลิตน้ำมันขึ้นมาได้ 30.78% ในขณะที่ปริมาณการผลิตน้ำมันจากหลุมถ่ายเทแนวตั้งและหลุมผลิตแนวตั้งสามารถผลิตน้ำมันขึ้นมาได้ 14.67% ผลจากการจำลองพบว่า การเพิ่มของความยาวหลุมแนวนอนช่วยเพิ่มปริมาณน้ำมันที่นำขึ้นมาจากกระบวนการอัดน้ำแบบถ่ายเทและปริมาณน้ำที่นำขึ้นมาน้อยกว่า สำหรับเวลาที่เริ่มการอัดน้ำ เวลาที่เริ่มการอัดน้ำไม่ส่งผลกระทบอย่างมากกับปริมาณน้ำมันที่นำขึ้นมา โดยสรุปแล้วกระบวนการอัดน้ำแบบถ่ายเททำให้ประสิทธิภาพในการผลิตดีกว่าการผลิตแบบธรรมชาติ แต่ประสิทธิภาพในการผลิตแย่กว่ากระบวนการอัดน้ำแทนที่

ภาควิชา	วิศวกรรมเหมืองแร่และปิโตรเลียม	ลายมือชื่อนิสิต	....
สาขาวิชา	วิศวกรรมปิโตรเลียม	ลายมือชื่อ อ.ที่ปรึกษาหลัก	....
ปีการศึกษา	2558		

5771215321 : MAJOR PETROLEUM ENGINEERING
KEYWORDS: WATER DUMPFLOOD / HORIZONTAL WELL

PICHITA BOONCHAROEN: OPTIMAL WELL DESIGN FOR WATER DUMPFLOOD. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 105 pp.

Water dumpflood is a proven technology that can help maintain reservoir pressure and improve oil production. This process helps save capital and operating costs of pump and injection pipeline. However, due to limited control of the amount of water being dumped, oil recovery from water dumpflood may not be very high. Thus, there is a need to design appropriate water dumpers and oil producers in order to displace oil as much as possible in such situation.

In this study, a numerical reservoir simulator was used to compare the performance of different well types (vertical versus horizontal dumpers and producers), well lengths (in the case of horizontal penetration in the oil zone), and starting time for dumpflood for different aquifer sizes. The reservoir simulation model is based on reservoir and fluid properties of an onshore oilfield in Thailand. For well type, results from simulation indicate that vertical dumper and horizontal producer can yield oil recovery of 30.78% while oil recovery of vertical dumper and vertical producer is 14.46%. Simulation results also indicate that longer horizontal well length yields higher oil recovery and less water production. For starting time of water dumpflood, it does not have a significant effect on oil production. In summary, water dumpflood has better production performance than natural depletion and worse performance than conventional waterflood.

Department:	Mining and Petroleum Engineering	Student's Signature	....
		Advisor's Signature	....
Field of Study:	Petroleum Engineering		
Academic Year:	2015		

ACKNOWLEDGEMENTS

The completion of this study could not have been possible without the guideline and assistance of many people whose names may not all be listed. Their contributions are sincerely appreciated and gratefully acknowledged.

First of all, I would like to express my sincere thanks to my thesis advisor, Assistant Professor Suwat Athichanagorn, for his invaluable help and constant encouragement throughout the course of this study.

In addition, I am grateful to all professors and faculty members in Department of Mining and Petroleum Engineering for knowledge, suggestion and all support. Also, I would like to thank thesis committee members for their recommendations.

I would like to thank Schlumberger for providing ECLIPSE reservoir simulator software to Department of Mining and Petroleum Engineering, Chulalongkorn University.

Finally, I appreciate all of my petroleum engineering colleagues for their friendship and sharing knowledge during Master's Degree study life.

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List of Abbreviations

cp	Centipoise
Ft	Feet
GOR	Gas-oil ratio
mD	Millidarcy
psi	Pound per square inch
psia	Pound per square inch absolute
PV	Pore volume
PVT	Pressure- Volume- Temperature
SCAL	Special core analysis Lab
SCF/STB	Standard cubic feet per stock tank barrel
SCF	Standard cubic feet
STB	Stock tank barrel
STB/D	Stock tank barrel per day
TVD	True vertical depth

Nomenclatures

B_g	Gas formation volume factor, RB/SCF
B_o	Oil formation volume factor, RB/STB
B_{oi}	Initial oil formation volume factor, RB/STB
B_w	Water formation volume factor, RB/STB
B_{winj}	Injected water formation volume factor, RB/STB
°C	Degree Celsius
c_f	Rock compressibility, psi^{-1}
c_w	Water compressibility, psi^{-1}
E_A	Areal sweep efficiency, -
E_D	Displacement efficiency, -
E_i	Vertical sweep efficiency, -
E_V	Volumetric sweep efficiency, -
°F	Degree Fahrenheit
h	Net formation thickness of the oil reservoir, ft
$\bar{k}$	Average permeability, mD
k	Permeability, mD
k_o	Effective permeability to oil, mD
k_{ro}	Relative permeability to oil, -
k_{rw}	Water relative permeability
k_{rg}	Relative permeability to gas
k'_{ro}	Maximum relative permeability to oil in modified Brooks-Corey function
k'_{rg}	Maximum relative permeability to gas in modified Brooks-Corey function

k'_{rw}	Maximum relative permeability to water in modified Brooks-Corey function
L_w	Completed length of horizontal well, ft
M	Mobility ratio, -
MSTB	Thousand stock tank barrel
MMSTB	Million stock tank barrel
MMSCF	Million standard cubic feet
N	Original oil in place, STB
N_p	Cumulative oil production, STB
n_o	Corey oil exponent
n_w	Corey water exponent
n_o	Corey oil exponent
n_g	Corey gas exponent
n_w	Corey water exponent
Δp	Reservoir pressure drop, psi
p	Average reservoir pressure, psi
p_{inj}	Water-injection pressure, psi
p_p	Pore pressure, psi
p_f	Fracture pressure, psi
P_D	Dimentionless pressure
P_R	Average reservoir pressure, psia
P_{wf}	Bottom-hole flowing pressure, psia
q_{inj}	Injection rate, STB/day
r_e	Well's drainage radius, ft

r_w	Wellbore radius, ft
W_{inj}	Cumulative injected water, STB
μ	Viscosity, cp
μ_o	Oil viscosity, cp
μ_w	Water viscosity, cp
b_H	Length in direction along on the wellbore, ft
$\sum s$	Damage skin, turbulence, and other pseudoskin factors
d_z	The shortest distance between horizontal well and z boundary ,ft
Q_o	Oil flow rate at standard conditions, STB/D
r_e	External boundary radius, ft
r_w	Wellbore radius, ft
μ_w	Water viscosity, cp
RF	Overall recovery efficiency
S_{oi}	Initial oil saturation at start of flood
S_o	Average oil saturation in the flood pattern at a particular point during the flood
S_o	Oil saturation
S_g	Gas saturation
S_w	Water saturation
S_{or}	Residual oil saturation
S_{gr}	Residual gas saturation
S_{wc}	Connate water saturation
γ	Poisson’s ratio
σ_o	Vertical overburden stress, psi

$\overline{\sigma_H}$	Average horizontal matrix stress, psi
σ_v	Vertical matrix stress, psi

CHAPTER 1
INTRODUCTION

1.1 Introduction

Due to a sharp decrease in oil price, which leads to significant revenue shortfalls in many oil producers, oil companies attempt to save cost while maintaining high performance. There are various techniques for improving oil production in a mature oil field. One of these approaches is water dumpflood or natural waterflood. Water dumpflood can help maintain the reservoir pressure and enhance the oil production without surface facilities.

Water dumpflood concept is implemented where a single well is used as a source of water supply and dumps water into the target oil reservoir by the natural force of gravity and the potential difference between the two reservoirs. Source of water can be an overlying and underlying aquifer. An overlying aquifer may have higher porosity due to shallower depth of burial and higher deliverability (higher permeability). On the contrary, pressure of an underlying aquifer may be quite high due to higher formation pressure gradient at deeper depths in certain geological environments. A successful water dumpflood requires a large volume of water from aquifer and pressure support that are enough to maintain pressure and improve oil production over long life period.

This study evaluates water dumpflood via finite difference numerical reservoir models which are simulated by ECLIPSE 100 and aims to investigate performance of dumpflooding design parameters: 1) starting time for water dumpflood, 2) well type, and 3) length of horizontal well for different aquifer sizes.

1.2 Objectives

This objectives of this study are mainly two purposes including:

1. To find appropriate staring time of water dumpflood, well type, and horizontal well length for water dumpflood from an overlying aquifer

2. To compare water dumpflood performance with natural depletion and conventional waterflooding

1.3 Outline of thesis

The thesis is divided into six chapters as follows:

Chapter 1 introduces the background of water dumpflood into an oil reservoir and defines the objectives for this study.

Chapter 2 reviews the previous studies which are related to water dumpflooding, conventional waterflooding, and horizontal wells.

Chapter 3 describes the fundamental theories and concepts related to water dumpflooding and conventional waterflooding in the oil reservoir.

Chapter 4 explain the reservoir model construction including the details of reservoir model, rock and fluid properties, wellbore design, production constraints, and methodology used in the simulations.

Chapter 5 presents simulation results and discussions with various parameters. The comparison among natural depletion, conventional waterflood, and water dumpflood is also concluded in this chapter.

Chapter 6 concludes the simulation results and provides recommendations for this study.

CHAPTER 2
LITERATURE REVIEW

There are several studies related to water dumpflooding and waterflooding into oil reservoir that are summarized in this chapter.

Fujita [1] studied on water dumpflood from shallow aquifer into a depleted oil limestone reservoir after 6 years of production. The reservoir is divided into 3 layers: light oil (33° API), heavy-oil mat, and water. The reservoir system was depleted to 2650 psig, about 1000 psi below its original pressure with a rapid increase in GOR. Since GOR increased to 1550 scf/STB, the oil production rate dropped to 30 Mbopd. Then, a simulation was conducted to find the most efficient and economic method of maximizing the ultimate oil recovery. The best choice was water dumpflood. Gas injection was not an option due to low permeability and low dip of the structure. After dumping water for 5 years, the reservoir pressure has been maintained at 2600 psig and oil production rate was 40-45 MBOPD. GOR had been 1000 SCF/STB. The pilot dumpflood could increase only light oil recovery but had no effect on heavy oil recovery. The dumping reached stabilized pressure 1 year later. Breakthrough time ranged from 4 to 21 months, depending on the distance between dumper and producer and relative quantities of dumped water. As a result of this pilot, water dumpflood technique had been achieved in the reservoir pressure maintenance and GOR reduction.

Quttainah and Al-Huaif [2] discussed water dumpflood pilot project in carbonate oil reservoir with an overlying aquifer after 40 years of production. The reservoir pressure dropped to 1500 psi. This project was initiated to design a well that can handle water production which is highly acidic due to high H_2S content and prove the applicability of water dumping into the unswept oil reservoir by natural gravity force and differential pressure. The authors performed water injection because it could show a clear results of sweep efficiency and reservoir responce under a short period. However, water injection was not the best method because it had high cost. Thus, dumpflood was an alternative but the concern was casing corrosion. There were 2 options for corrosive remedy: 1) repair casing by squeezing cement or suitable gel behind pipe, and 2) install Fiberglass-lined tubing across zone of corrosion damage. Since commissioning of water dumpflood, there were four production logs which recorded injection rate in the oil reservoir. In the first dumpflood test, the dumpflood rate was 1300 bbl/D which resulted from partially damage from perforation. The author decided to re-perforate and dumpflood rate had increased to 1600, 2467, and 3350 bbl/D with increasing time. As a result, oil production can be extended for longer plateau. The authors recommended the injector to be located on the crest which can uniformly sweep from top structure toward flank structure. This strategy can decrease a possibility of bypassing oil.

Quttainah and Al-Maraghi [3] investigated extension of production plateau as long as economically possible in Umm Gudair Field by three main development options including water injection, infill drilling, and combined development. In case of water injection, the authors emphasized on comparison of source of injected water between surface injection and dumpflood, pattern and peripheral injection, and location for injection between oil column and water zone. The authors recommended a combination of dumpflood in peripheral area to provide pressure maintenance and optimize oil sweeping and infill producers to improve recovery of remaining oil. This way gave plateau length of 11 years from 4.5 years that was forecast by simulation.

Westermark et al. [4] evaluated a field test of a horizontal water flooding process for the recovery of additional oil from a low permeability sandstone reservoir in northeast Oklahoma. This water flooding process in three-well-pattern consisted of a central horizontal injection well and two adjacent and parallel horizontal producing wells. The Bartlesville sandstone is the target oil reservoir. Oil recovery by a natural depletion was low, usually less than 20% of original oil in place due to: 1) solution gas-drive mechanism, which resulted in rapid pressure depletion, 2) low initial reservoir pressure where reservoir was located on the shallow depth, and 3) existence of natural fractures and low permeability. Initially, the authors attempted to perform water injection below fracture pressure in Woolaroc field. On the contrary, the conventional waterflood was not effective because of inability of adequate injectivity below the fracture pressure. Thus, the authors concentrated on nearby Woolaroc field which was 23 acre un-flooded area having the same stratigraphy. The main oil reservoir was Bartlesville sandstone. It had a thickness of 85 ft, average porosity of 16%, and estimated permeability in range of 30 to 100 mD. Both horizontal injector and producers were single lateral horizontal wells. The injector was located 20 ft above the bottom of the reservoir, and the producers were located 20 ft below the top of reservoir. These wells were drilled by a curve drilling assembly and the lateral drilling assembly in which short radius wells were achieved. The horizontal length of three wells was 500 ft in pattern of inverted line drive. Simulation indicated a horizontal waterflood would generate $2.9 million cumulative revenue over 6 years of operation, compared to $1.4 million cumulative revenue over 30 years of operation for a five-spot vertical waterflood. Thus, horizontal waterflood accelerated oil production, resulting in significant amounts of incremental oil produced.

Suriyawutithum [5] determined optimal completion for horizontal injector and producers by ECLIPSE 100 reservoir simulation without skin effect. There were one horizontal injector and two horizontal producers. The producers were placed in the top layer while the injector was placed in the bottom layer. The horizontal wells were divided into 11 segments with one vertical segment (top segment and 10 horizontal segments as illustrated in Figure 2.1.

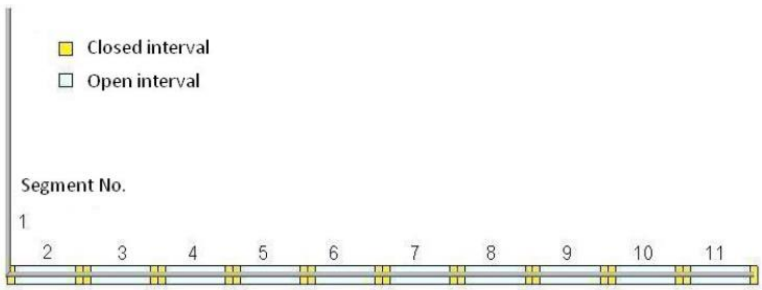


Figure 2.1: Multi-segment well model representing the cased and perforated horizontal wells [5]

The wells were set on inverted line drive pattern due to the better sweep efficiency and slow water breakthrough time, comparing to a direct line drive pattern. Since the author could not generate a uniform water front, so the adjustment on the open/closed interval was needed to generate the most uniform water front to optimize waterflood performance. This completion was called “optimal completion” and can be achieved by increase of injection rate and production rate on the heel and toe because the heel and toe have more un-penetrated area than the middle. The optimal completion yielded 3% incremental recovery factor, comparing to open completion and delayed water breakthrough by 151 days. The bottomhole pressure of injector in the optimal completion was 150 psi higher than open completion. On the contrary, the bottomhole pressure of producer in the optimal completion was lower than open completion that a low pressure in producer well may cause insufficient fluid flow from the bottomhole to the surface. The installation of downhole pump in producer can be solved this problem. The author studied the flow distribution, open interval, pressure drop, and mobility ratio on different flow rates. At high operating flow rate, open interval near heel was less in order to keep a uniform flood front resulting in a slight decrease in the productivity and higher pressure drop due to high fluid velocity. In the case of high mobility ratio in which water moves faster than oil, the optimal completion required less flow rate at the heel and toe than the case with low mobility ratio.

Anansupak [6] studied viability of the water dumpflood technique via vertical well in Pattani basin, Gulf of Thailand. The significant factor was source of energy from aquifer. Comparing edge well injector to center well injector, the author found the best one is edge well injector due to more capability of recovery from oil-water contact. Oil production performance is related to average reservoir pressure. A smaller aquifer size which had lower reservoir pressure led to lower oil and water rate. The ratio of aquifer to reservoir volume had a moderate impact on recovery. The incremental recovery factor can be up to 3.5% when the ratio of aquifer to reservoir volume is 43. However, oil production was limited by water cut. Larger ratio implied increase of water production. For effect of productivity index, increase of productivity index yielded higher production rate. Average reservoir pressure decreased related to high GOR, resulting in rapid drop in production rate. Moreover, the overlying aquifer provided higher cross flow rate compared to underlying aquifer dump flood. The author recommended dumpflood was appropriate when API gravity was 30 to 40^{o}API. Oil recovery varied between 33% and 37% with different starting times for water dumpflood. The highest recovery efficiency was obtained when dumpflood was started when the pressure is at the bubble-point pressure at which the oil viscosity is smallest.

CHAPTER 3
THEORY AND CONCEPT

The theory and concept for this study emphasize on water injection and water dumpflood into oil reservoir. There are 8 sections including 1) water dumpflood, 2) water injection 3) productivity index, 4) water displacing oil, 5) relative permeability in two-phase and three-phase system, 6) fracture pressure, 7) horizontal well trajectory and limitation, and 8) well arrangement of injectors and producers

3.1 Water dumpflood

3.1.1 Material balance

Water dumpflood into oil reservoir can be implemented from overlying or underlying aquifer. In case of overlying aquifer, water can flow from aquifer to the target reservoir by gravitational support. On the other hand, if the aquifer is below the target reservoir, water can flow upward due to its high formation pressure gained with depth. For the oil reservoir without initial gas cap, the material balance [7] can be written as Equation (3.1):

$$N_p\left[B_o + B_g\left(R_p - R_s\right)\right] + W_pB_w = N\left(B_o - B_{oi} + B_g(R_{si} - R_s) + B_{oi}\left(\frac{c_f + c_wS_{wi}}{1 - S_{wi}}\right)\Delta p\right) + W_e \quad (3.1)$$

where

B_o	= oil formation volume factor, RB/STB
B_{oi}	= initial oil formation volume factor, RB/STB
B_g	= gas formation volume factor, RB/SCF
B_w	= water formation volume factor, RB/STB
c_f	= rock compressibility, psi^{-1}
c_w	= water compressibility, psi^{-1}
N	= original oil in place, STB
N_p	= cumulative oil production, STB

Δp	= reservoir pressure drop, psi
R_p	= cumulative producing gas-oil ratio (G_p/N_p), SCF/STB
R_s	= solution gas-oil ratio, SCF/STB
R_{si}	= Initial solution gas-oil ratio, SCF/STB
S_{wi}	= initial water saturation
W_p	= cumulative water produced, STB
W_e	= cumulative water influx, RB

The reduction in pore volume and connate water expansion term is very small, so it is neglected. For water dumpflood, W_e represents water dumping into the oil reservoir. In terms of material balance, dumped water can be considered as additional driving force for oil production.

3.2 Water injection

3.2.1 Material balance

In case of water injection from surface, it can be explained by modified oil material balance[7] as shown in Equation (3.2).

$$N_p[B_o + B_g(R_p - R_s)] + W_pB_w - W_{inj}B_{winj} = N\left(B_o - B_{oi} + B_g(R_{si} - R_s) + B_{oi}\left(\frac{c_f + c_wS_w}{1 - S_w}\right)\Delta p\right) \tag{3.2}$$

Similar to Equation (3.1), the rock compaction and connate water expansion terms can be neglected as its value is small.

3.2.2 Injectivity

When water is injected into the oil reservoir, a pressure funnel develops and declines logarithmically away from the wellbore. The shape of the funnel can be described by the diffusivity equation. Assuming radial flow under pseudo-steady state conditions, the injection rate [8] can be expressed as Equation (3.3):

$$q_{inj} = \frac{kh}{141.2[ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + s]} \int_{\bar{P}}^{P_{inj}} \frac{k_{rw}}{\mu_w B_w} dp \tag{3.3}$$

where

q_{inj} = injection rate, STB/day

k = permeability

k_{rw} = water relative permeability

h = reservoir thickness, ft

p = average reservoir pressure, psi

p_{inj} = water-injection pressure, psi

r_e = well's drainage radius, ft

r_w = wellbore radius, ft

μ_w = water viscosity, cp

B_w = water formation volume factor, bbl/STB

s = skin factor

The injection pressure is based on reservoir pressure, and any potential damage or skin caused by incompatibility of water or scales which are significant parameters for formation transmissibility.

The water injection rate, which can vary throughout the life of the project, is influenced by many factors. The variables affecting the injection rates include the following:

- Reservoir geometry
- Rock and fluid properties. Low injectivity is associated with tight rocks, skin, and viscous fluids
- Mobility of fluids

3.2.3 Injectivity index (II)

The injectivity index [8] is used for evaluating performance of injection well. The injectivity index during pseudo-steady state is commonly calculated as equation (3.4):

$$II = \frac{Q}{P_{inj}-P_R} = \frac{k_w \times h}{141.2 \times \mu_w \times B_w \times \left(\ln {}^{r_e}/_{r_w} - \frac{3}{4} + S\right)} \tag{3.4}$$

As shown in Figure 3.1, a sharp decline of water injectivity during an early period of injection into a depleted oil reservoir by solution gas drive. After fill-up of solution gas, the injectivity variation depends on the mobility ratio (M) defined in Equation (3.10) .The injectivity increases when M >1 which is an unfavorable condition. On the other hand, the injectivity decreases when M ≤ 1 which is a favorable condition.

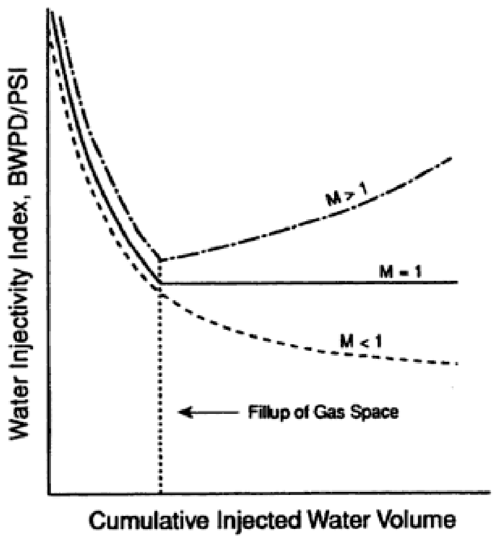


Figure 3.1 Water injectivity variations in a radial system [9]

3.2.4 Optimal beginning time to perform water dumpflood

Anansupak [6] studied an optimum time to initiate water dumpflood. The conclusion is that the starting time for injection should be at the bubble-point pressure since the oil viscosity is minimum at this point. As a result, the mobility of oil is highest, giving the best sweep efficiency.

3.3 Productivity index

3.3.1 Productivity index for a vertical well

Oil productivity index (J_o) for vertical well [10] is a relationship between flow rate of oil and pressure drawdown. Most of well life is spent in a flow regime that is approximating the pseudo-steady state and can be numerically calculated in term of pseudo steady state flow condition as Equation (3.5):

$$J_o = \frac{Q_o}{P_R - P_{wf}} = \frac{k_o h}{141.2 \times [\ln\left(\frac{r_e}{r_w}\right) - \frac{3}{4} + s]} \left(\frac{1}{\mu_o B_o}\right) \tag{3.5}$$

where

Q_o = oil flow rate at standard conditions, STB/D

P_R = average reservoir pressure, psia

P_{wf} = bottom-hole flowing pressure, psia

k_o = effective permeability to oil, mD

h = thickness of the oil reservoir, ft

r_e = external boundary radius, ft

r_w = wellbore radius, ft

s = skin factor

μ_o = oil viscosity, cp

B_o = oil formation volume factor, RB/STB

3.3.2 Productivity index for a horizontal well

There are several solution for estimating oil productivity index in a horizontal well. The general and applicable method for this study is Economides et al. method [11] as shown in Equation (3.6):

$$J_o = \frac{\bar{k} b_H}{887.22 B\mu (P_D + \frac{b_H}{2\pi L_w \sum s})} \tag{3.6}$$

where

$\bar{k}$ = average permeability, mD

μ = viscosity, cp

b_H = length in direction along on the wellbore, ft

L_w = completed length of horizontal well, ft

$\sum s$ = damage skin, turbulence, and other pseudoskin factors

P_D = dimentionless pressure as defined for a constant-rate production which is determined by using equation (3.7) to (3.9)

$$P_D = \frac{b_H C_H}{4\pi h} + \frac{b_H}{2\pi L_w} s_c \tag{3.7}$$

$$s_c = ln\left(\frac{h}{2\pi r_w}\right) - \frac{h}{6L_w} + s_e \quad (3.8)$$

$$s_e = \frac{h}{L_w}\left[\frac{2d_z}{h} - \frac{1}{2}\left(\frac{2d_z}{h}\right)^2 - \frac{1}{2}\right] - \ln\left[\sin\left(\frac{\pi d_z}{h}\right)\right] \quad (3.9)$$

where

s_c = convergence skin

s_e = skin resulting in eccentricity effects in the vertical direction

d_z = the shortest distance between horizontal well and z boundary ,ft

h = net formation thickness, ft

The productivity index is a valuable methodology for predicting the future performance of wells. Furthermore, it is possible to determine if the well has become damaged due to completion, production, injection operations, or mechanical problems.

3.4 Water displacing oil

3.4.1 Immiscible displacement

Mobility ratio [10] is defined as mobility of displacing fluid divided by the mobility of the displaced phase. For an oil-water system, it can be determined as

$$M = \left(\frac{k_{rw}}{k_{ro}}\right)\left(\frac{\mu_o}{\mu_w}\right) \quad (3.10)$$

where

M = mobility ratio

k_{rw} = relative permeability to water

k_{ro} = relative permeability to oil

μ_o = oil viscosity, cp

μ_w = water viscosity, cp

The magnitude of the mobility ratio also impacts the displacement as detailed below.

M $\leq$1: velocity of oil is equal to or greater than velocity of water. So, it results in smooth flood front and leads to stable displacement which is favorable condition.

M >1: water moves faster than oil. Some oil will be by-passed which is unfavorable and results in viscous fingering.

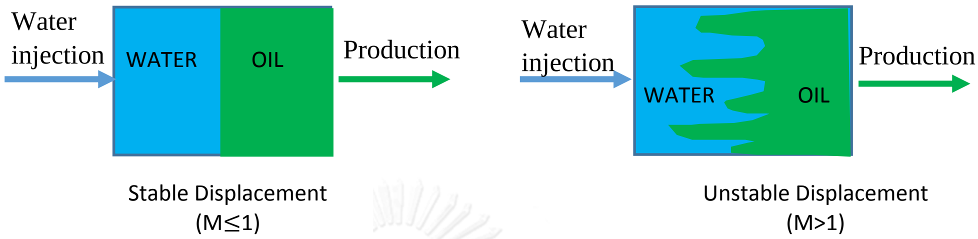


Figure 3.2 A sketch of stable and unstable displacement in horizontal plane

3.4.2 Overall recovery

The overall recovery efficiency [10] is the product of a combination of three individual efficiency values as given by the following generalized expression (3.11):

$$RF = E_D E_A E_i \tag{3.11}$$

where RF = overall recovery efficiency

E_D = displacement efficiency

E_A = areal sweep efficiency

E_i = vertical sweep efficiency

Displacement efficiency (E_D)

The fraction of movable oil that has been displaced from the swept zone at any given time or pore volume injected. Factors affecting displacement efficiency are:

- Oil and water viscosities
- Oil formation volume factors at the start and end of flood
- Oil saturations at the start and end of flood

• Relative permeability characteristics

Displacement efficiency that is governed by rock and fluid properties is given by:

$$E_D = \frac{\frac{S_{oi}}{B_{oi}} - \frac{\overline{S_o}}{B_o}}{\frac{S_{oi}}{B_{oi}}} \tag{3.12}$$

where

S_{oi} = initial oil saturation at start of flood

B_{oi} = oil formation volume factor at start of flood, bbl/STB

S_o = average oil saturation in the flood pattern at a particular point during the flood

B_o = oil formation volume factor at a particular point, bbl/STB

Areal sweep efficiency (E_A)

The areal sweep efficiency is the fractional area of the pattern that is swept by the displacing fluid. It increases steadily with injection from the start of the flood until breakthrough occurs, after which E_A continues to increase at a slower rate. The major factors determining areal sweep efficiency are fluid mobility, pattern type, areal heterogeneity, and total volume of injected fluid.

If directional permeability trends can be identified, injection and production wells can be arranged to take advantage of the trends to enhance areal sweep efficiency. It is also possible to maximize areal sweep efficiency through a careful management of pressure distribution and proper injection–production pattern selection.

Vertical sweep efficiency (E_I)

The vertical sweep efficiency is the fraction of the vertical section of the pay zone that is contacted by injected fluids. The vertical sweep efficiency is primarily a function of:

• Vertical heterogeneity

• Degree of gravity segregation

• Fluid mobility

• Total injection volume

Volumetric Sweep efficiency

Volumetric sweep efficiency,E_v, is a product of areal sweep efficiency and vertical sweep efficiency. It represents the overall fraction of the flood pattern that is contacted by the injected fluid.

3.5 Relative permeability in two-phase flow

Relative permeability is a flow ability of each fluid in multi-phase system in porous media by representing the ratio of the effective permeability of fluid at a given saturation to absolute permeability. For instance, in multi-phase system, relative permeability of each fluid is not the same as absolute permeability of each fluid in single-phase flow. In the oil-gas-water system, relative permeability on each fluid is defined as in Equations (3.13) to (3.15)

$$k_{rg} = \frac{k_g}{k} \tag{3.13}$$

$$k_{ro} = \frac{k_o}{k} \tag{3.14}$$

$$k_{rw} = \frac{k_w}{k} \tag{3.15}$$

There are several correlations developed for relative permeability. Corey [12] is one of the famous correlations and also used in ECLIPSE100. Modified Brooks-Corey function proposed that the gas-oil-water relative permeability can be calculated as shown in Equations (3.16) – (3.18)

$$k_{ro} = k'_{ro}\left(\frac{S_o - S_{or}}{1 - S_{or} - S_{wc} - S_{gr}}\right)^{n_o} \tag{3.16}$$

$$k_{rw} = k'_{rw}\left(\frac{S_w - S_{wc}}{1 - S_{or} - S_{gr} - S_{wc}}\right)^{n_w} \tag{3.17}$$

$$k_{rg} = k'_{rg}\left(\frac{S_g - S_{gr}}{1 - S_{or} - S_{gr} - S_{wc}}\right)^{n_g} \tag{3.18}$$

where

k_{ro} = relative permeability to oil

k_{rw} = relative permeability to water

k_{rg} = relative permeability to gas

k'_{ro} = maximum relative permeability to oil in modified Brooks-Corey function

k'_{rg} = maximum relative permeability to gas in modified Brooks-Corey function

k'_{rw} = maximum relative permeability to water in modified Brooks-Corey function

S_o = oil saturation

S_g = gas saturation

S_w = water saturation

S_{or} = residual oil saturation

S_{gr} = residual gas saturation

S_{wc} = connate water saturation

n_o = Corey oil exponent

n_g = Corey gas exponent

n_w = Corey water exponent

3.6 Fracture pressure

According to water injection, oil recovery is directly related to injection rate but limitation is fracture pressure. The injecting pressure must be below formation fracture pressure in order to avoid fracture propagation in the target reservoir. It can be calculated by using Eaton's approach [13] as represented in Equations (3.26) – (3.28)

$$p_p = \sigma_o - \sigma_v \quad (3.26)$$

$$\overline{\sigma_H} = \left(\frac{\gamma}{1+\gamma}\right)\sigma_v \quad (3.27)$$

$$p_f = \overline{\sigma_H} + p_p \quad (3.28)$$

where

p_p = pore pressure, psi

p_f = fracture pressure, psi

γ = Poisson's ratio

σ_o = vertical overburden stress, psi

$\overline{\sigma_H}$ = average horizontal matrix stress, psi

σ_v = vertical matrix stress, psi

The fracture pressure of the A field[14] can be calculated using correlation defined in Equations (3.29) – (3.30) for shallow depth.

$$Fracture\ pressure = \frac{FRAC.S.G. \times TVD}{10.2} \quad (3.29)$$

$$FRAC.S.G. = 1.22 + (TVD \times 1.6 \times 10^{-4}) \quad (3.30)$$

where

$FRAC.S.G.$ = fracture pressure gradient, bar/meter

TVD = true vertical depth below rotary table, meter

3.7 Horizontal well trajectory and limitation

Horizontal well is used for improving both production rate and recovery efficiency due to more intersection between an extensive reservoir and a portion of well. The first section of horizontal well drills from a surface is a vertical or inclined linear bore and the last point is located above a target oil or gas reservoir, so called "kickoff point" as illustrate in Figure 3.3. After that, the well turns to be a curve before entering the target reservoir. This point is the first point where enter target reservoir called "entry point". Then, the well continues at a near-horizontal attitude tangent to the arc to substantially or entirely remain within the reservoir until the desirable bottom hole location is reached.

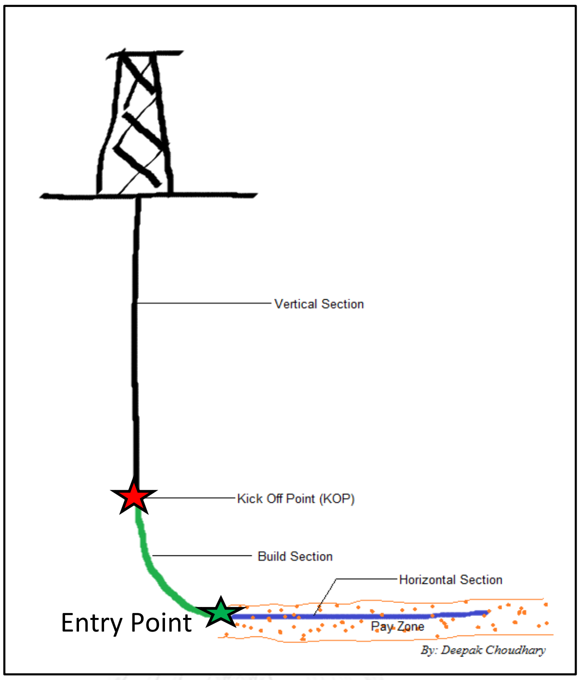


Figure 3.3 A sketch of horizontal wells shows kick off point and entry point

Depending on the intended radius of curvature and the hole diameter, the arc section of a horizontal well may be drilled either conventionally or by use of a drilling fluid-driven axial hydraulic motor or turbine motor mounted downhole directly above a bit. In the latter instance, the drill pipe above the downhole motor is held rotationally stationary at the surface. The near-horizontal portions of a well are drilled using a downhole motor in virtually all instances.

There are three main kinds of horizontal well classified by radius of the arc described by the wellbore as it passes from the vertical to horizontal and build rate which is the change of angle that increase from the verticle over length.

- Short-radius horizontal well with arcs of 3 to 40 foot radius and build rates as much as 3 degree per feet drilled. Typical horizontal section extends 200 to 400 ft, with a record reach of more than 1200 ft.The small displacement required to reach a near-horizontal attitude favors the use of short-radius drilling in small lease blocks or in a difficult overlying formation that can kick off near the bottom of target reservoir or below. The advantage of this type of horizontal well is a lower capital cost. However, a limitation of short-radius horizontal well is that the target reservoir should be suitable for an open hole or slotted liner completion, since hole diameter can only range up to about 6 inches.

- Medium-radius horizontal well with arcs of 200 to 1000 foot radius and build rates of 8 to 30 degree per 100 feet drilled. It allows the use of larger hole diameters, near-conventional bottom hole (production) assemblies, and more experienced and complex methods. It can be drilled on leases as small as 20 acres.
- Long-radius horizontal well with arcs of 1000 to 2500 feet radius and build rates up to 6 degree per 100 feet. It can be drilled using either conventional drilling tools and methods, or the newer steerable systems. More than 4000 ft of horizontal section can be drilled after reaching a 90° inclination.

The required horizontal displacement, length of a horizontal section, position of the kickoff point, and completion constraints are generally considered when selecting a radius of curvature. Most new wells are drilled with longer radii, while recompletions of existing wells most often employ medium or short radii. Longer radius tend to be suitable to development of longer horizontal section and to easier completion for production.

There are numerical parameters, impacting on the design based on bit and casing size, setting depth of casing and drilling fluid density, casing grades, well profile, drill-string load, and hydraulic requirement.

On this study, stimulation is set at long-radius horizontal well with build rate of 5 degree per 100 feet drilled.

3.8 Well arrangement of injectors and producers

Not only well arrangement, but also a suitable water injection rate impact good recovery efficiency. Typically, there are two types of flooding patterns that are used including peripheral flooding and pattern flooding.

Pattern flooding is frequently used in reservoirs with a flat structure and a large surface area. The common pattern arrangements are shown in Figure 3.4. The most effective pattern flooding is five-spot pattern. If the reservoir can take lower injection rate than what we want, we can increase injection wells per pattern to increase the rate by considering seven- or nine-spot pattern as shown in Table 3.1.

Table 3.1: Ratio of producing wells to injection wells for several pattern arrangements (after Dake [10])

Pattern	Ratio of producing wells to injection wells
Four-spot	2
Five-spot	1
Seven-spot	1/2
Nine-spot	1/3
Direct-line-drive	1
Staggered-line-drive	1

The injectors are grouped together in peripheral flooding while pattern floods intersperse injectors with the producers. Figure 3.5 illustrates two cases in which the peripheral floods are sometimes used. Figure 3.5(a) displays a schematic of an anticlinal reservoir with an underlying aquifer. The injectors are placed so that the injected water either enters the aquifer or is near the aquifer-reservoir interface. The well pattern on the surface, shown in Figure 3.5(a), is a ring of injectors surrounding the producers. A monoclinal reservoir with an underlying aquifer is shown in Figure 3.5(b). In case of the injectors which are again located so that the injected water either enters the aquifer or enters near the aquifer-reservoir interface. When underlying aquifer is located on dipping reservoir, all the injectors are grouped together as shown in Figure 3.5(b).

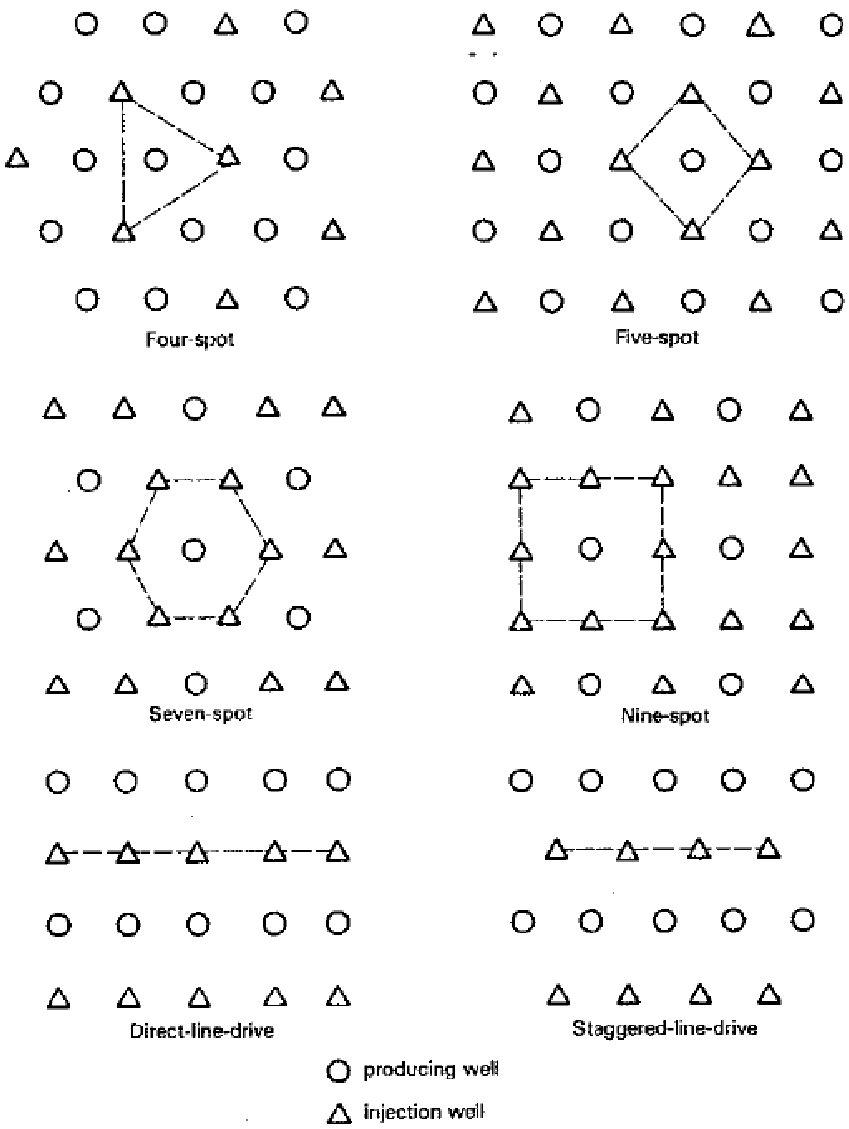


Figure 3.4: Geometry of common pattern floods (after Dake [10])

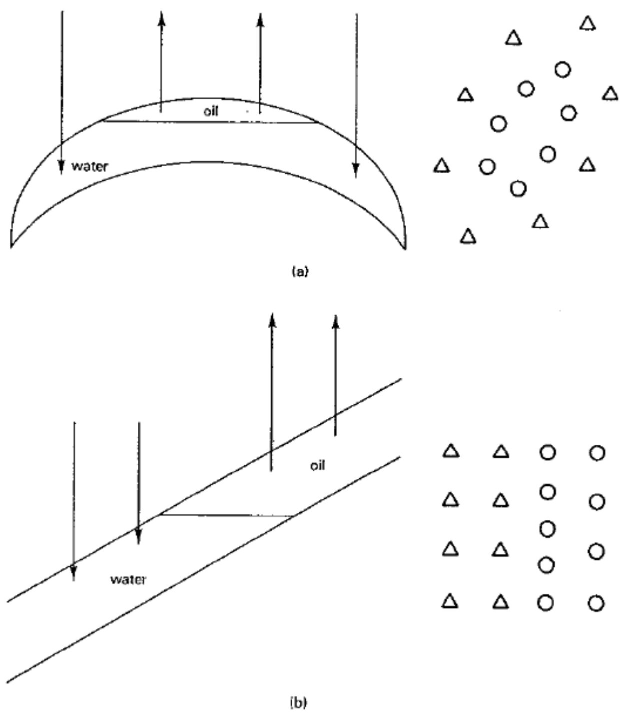


Figure 3.5: Well arrangements for anticlinal (a) and monoclinal (b) reservoirs with underlying aquifers (after Dake [10])

Moreover, alternatives for economic consideration, concern on the cost of drilling new wells and loss of revenue, are the direct-line-drive and staggered-line-drive patterns due to the lowest investment. Those two patterns can switch existing well to an injector.

CHAPTER 4
RESERVOIR MODEL CONSTRUCTION

In this study, water dumpflood is evaluated via finite difference numerical reservoir model which is simulated in ECLIPSE®100 (Black oil). The reservoir model is created using block center under simple geometry and homogeneous condition. For the conceptual model, there are two layers including an overlaying aquifer and oil reservoir which are separated by 1000 ft of shale. Rock and fluid properties are based on an onshore oilfield in Thailand.

4.1 Reservoir model

The conceptual model is a simple rectangular reservoir with no dipping. The grid dimensions of the oil reservoir are 45 × 19 × 8 blocks of which size is 100 × 100 × 5 cu ft. Above the reservoir, there is a water aquifer with the thickness of 140 feet located at depth of 1980 ft. Since aquifer size is one of the parameters that are investigated in this study, two different sizes are constructed in the model as shown in Table 4.1. The datum depth is set on the first layer of the aquifer at 1980 ft. The oil reservoir is below the aquifer at 3120 ft (top of oil reservoir) with 40 ft thickness. The reservoir models are shown in Figures 4.1 and 4.2 for weak and strong aquifer, respectively.

The sensitivity of grid size was performed by generating different grid sizes and comparing the result. The x-dimension and y-dimension were divided into 3 resolutions including 50, 100 and 200 ft while z-dimension in the aquifer was divided into 5 resolutions which are 5, 10, 20, 35, 70 ft thick and the z-dimension in the oil zone was divided into 3 sizes which are 1, 2, and 5 ft thick. Simulation runs indicate that the resolution of 100 ft in the x and y-dimension and the resolution of the z-dimension in the aquifer and oil reservoir of 70, and 5 ft, respectively, give comparable results with finer resolutions.

Table 4. 1 Reservoir model

Layer	Parameter	Value	Unit
Aquifer	Top structure (top of aquifer)	1980	ft
	Thickness	140	ft
	Length (10.33PV)	6500	ft
	Width (10.33PV)	3900	ft
	Length (50.68PV)	12500	ft
	Width (50.68PV)	9900	ft
Shale	Thickness	1000	ft
Oil reservoir	Top structure (top of the reservoir)	3120	ft
	Thickness	40	ft

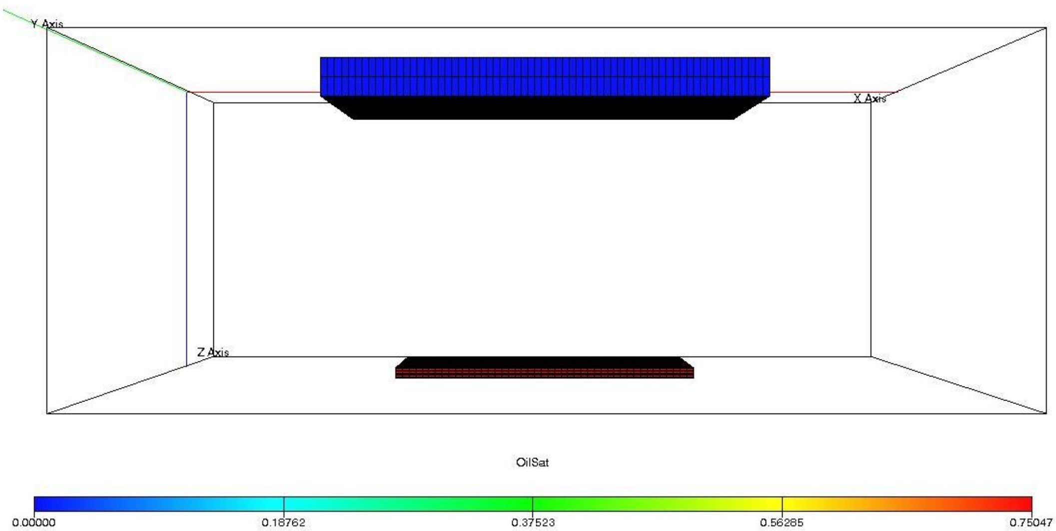


Figure 4. 1 A side-view of a reservoir model which a weak aquifer (10.33PV) is overlaying oil reservoir.

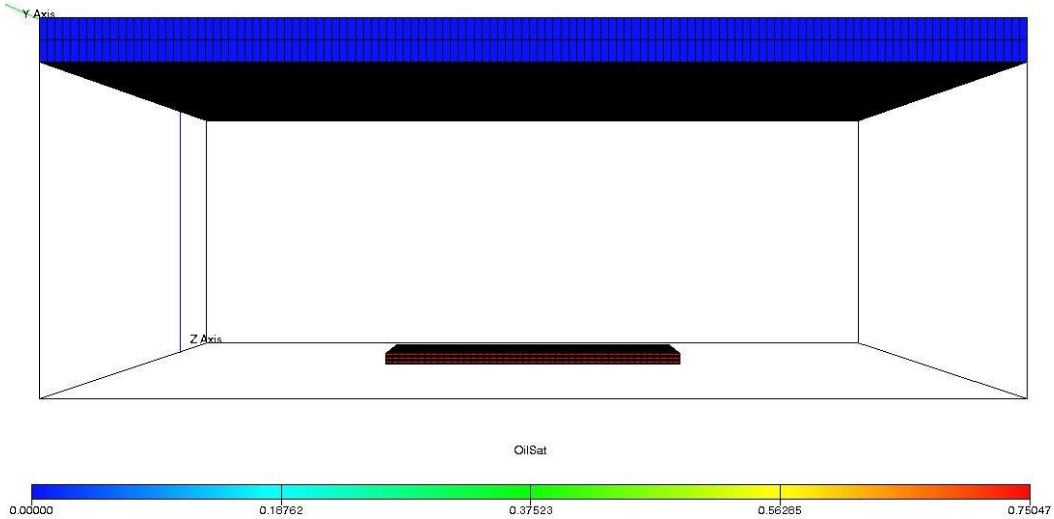


Figure 4. 2 A side-view of a reservoir model which a strong aquifer (50.68PV) is overlaying oil reservoir.

4.2 Rock and fluid properties

4.2.1 Rock properties

Rock properties are selected based on a representative value at particular sand from the field report such that porosity is 20 %, horizontal permeability is 100 mD, and vertical permeability is 10 mD. At initial condition at 3120 ft TVD, reservoir temperature and reservoir pressure are 145°F, and 1354.7 psia, respectively. These properties are summarized in Table 4.2.

Table 4. 2 Rock properties

Layer	Parameter	Value	Unit
Aquifer	Top structure (top of aquifer)	1980	ft
	Reservoir pressure	911.7	psia
	Reservoir temperature	126.6	°F
	Porosity	0.2	fraction
	k_x and k_y	100	mD
	k_Z	10	mD
Shale	Thickness	1000	ft
Oil reservoir	Top structure (top of the reservoir)	3120	ft
	Reservoir pressure	1354.7	psia
	Reservoir temperature	145	°F
	Porosity	0.2	fraction
	k_x and k_y	100	mD
	k_Z	10	mD

4.2.2 Fluid properties

Reservoir fluid properties which are required input parameters in ECLIPSE®100 are obtained from the field data including oil gravity, gas gravity, bubble-point pressure, water salinity, gas components, oil viscosity, and solution gas-oil ratio at an initial condition. These input parameters are used to calculate water viscosity, oil formation volume factor, water and rock compressibility, water viscosibility, pore volume of water and original oil in place for the basecase as shown in Table 4.3 by using an appropriate correlation provided in ECLIPSE®100. Figure 4.3 shows the generated oil formation volume factor, solution gas oil, and oil viscosity as a function of pressure.

Table 4. 3 Fluid properties and pore volumes

Parameter	Value	Unit
Oil gravity*	25.4	°API
Gas gravity* ($\gamma_{\text{air}} = 1$)	0.80	-
Water salinity*	6000	ppm
H_2S content*	0.0	percent
CO_2 content*	0.02	percent
N_2 content*	0.02	percent
Solution gas-oil ratio* @ initial condition	200	scf/STB
Bubble-point pressure of oil	1148.19	psia
Rock compressibility	3.060×10^{-6}	(psi^{-1})
Oil formation volume factor @ initial condition	1.123	RB/STB
Oil viscosity@ initial condition	3.047	cp
Water formation volume factor @ initial condition	1.0008	RB/STB
Water compressibility	3.039×10^{-6}	(psi^{-1})
Water viscosity@ initial condition	0.444	cp
Water viscosibility	1.006×10^{-6}	(psi^{-1})

*Input data required in ECLIPSE 100

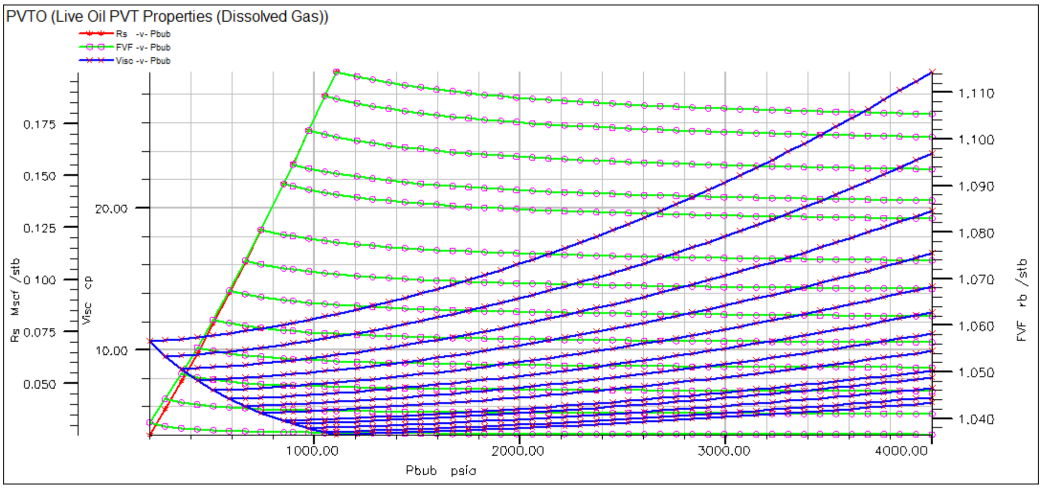


Figure 4. 3 PVT properties from ECLIPSE 100

4.3 **Special core analysis (SCAL)**

Both relative permeability values are obtained from the Corey correlation of which parameter are stated in Table 4.4. The relative permeability curves based on Corey correlation are shown in Figure 4.4 and Figure 4.5.

Table 4. 4 Input parameters for Special Core Analysis

Parameter	Value
Oil Corey exponent, n_o	3
Water Corey exponent, n_w	3
Gas Corey exponent, n_g	3
Connate water saturation, S_{wc}	0.25
Water relative permeability at S_{orw}	0.3
Water relative permeability at $S_{w,max}$	1
Residual oil saturation to water, S_{orw}	0.3
Residual oil saturation to gas, S_{org}	0.3
Oil relative permeability at S_{wc}	0.6
Oil relative permeability at S_{gc}	0.6
Critical gas saturation, S_{gcr}	0.15
Initial gas saturation, S_{gi}	0.15
Gas relative permeability at S_{org}	0.6
Gas relative permeability at S_{gmax}	0.6

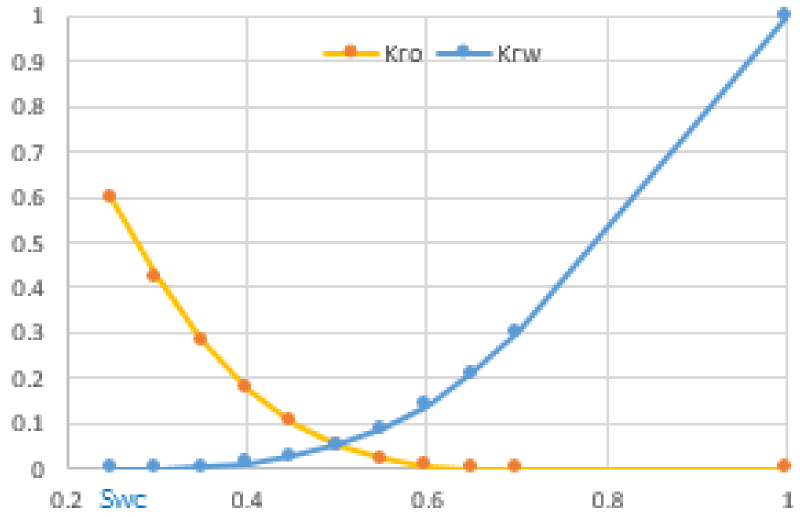


Figure 4. 4 Oil-water relative permeability curves

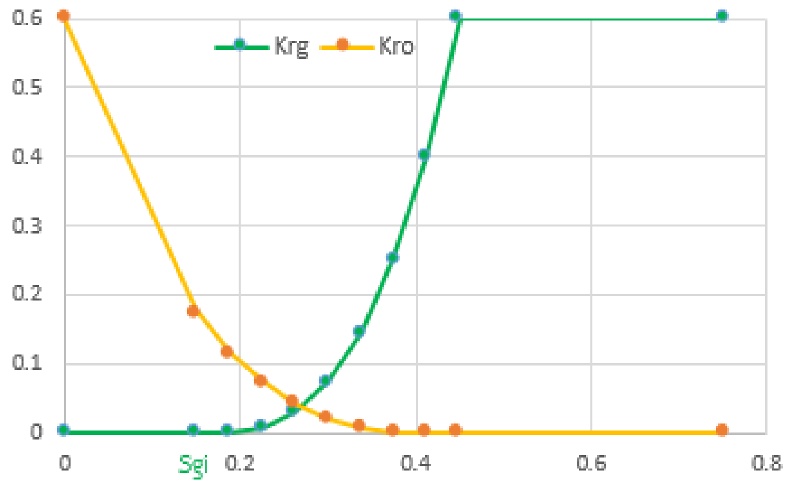


Figure 4. 5 Gas-oil relative permeability curves

4.4 Wellbore

In this study, there are two well types: vertical and horizontal wells. Both vertical and horizontal well design was obtained from a generic well completion design with 2-7/8 inch production tubing. The vertical well was designed to penetrate full-to-base in the aquifer and reservoir zones while the horizontal well was designed to penetrate full-to-base in the aquifer zone but only the bottommost/uppermost grid block in the oil reservoir. Figure 3 illustrates the profile of directional well in this study.

The horizontal well trajectory was set as long-radius horizontal well with a build rate of 5° per 100 ft and a kickoff depth of 2120 ft TVD (the bottom of aquifer).

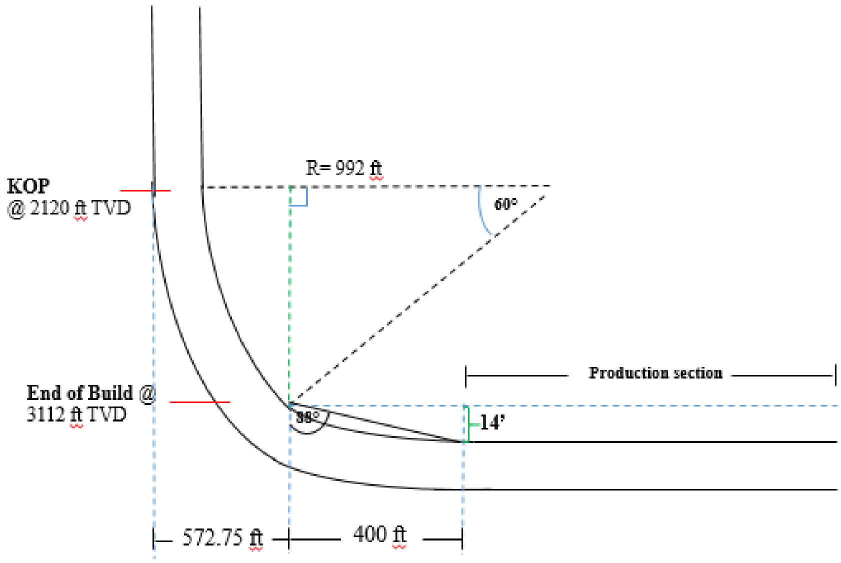


Figure 4. 6 Horizontal well trajectory for both producing and dumping wells

4.5 Production constraints

The production constraints for the production well were set as shown in Table 4.5, i.e., maximum liquid production rate of 2,000 STB/D with the minimum bottom-hole pressure of 200 psia, economic limit of 50 STB/D of oil production rate and maximum water cut of 0.95. The production well was shut when either one of economic limit was reached. The minimum bottomhole pressure of 200 psia was based minimum bottom-hole pressure with electrical submersible pump (ESP).

Table 4. 5 Production constraint and economic limit

Parameters	Value	Unit
Maximum liquid rate	2000	STB/D
Minimum oil rate	50	STB/D
Maximum water cut	0.95	Fraction
Minimum bottom-hole pressure with ESP	200	psia

4.6 Detail of methodology

1. Construct a model consisting of an oil reservoir with an overlaying water aquifer by using black oil reservoir simulator ECLIPSE®100. This reservoir model is created using block center under simple geometry and homogeneous condition.
2. Simulate base case of which water dumpflood cases as shown in Figure 4.7

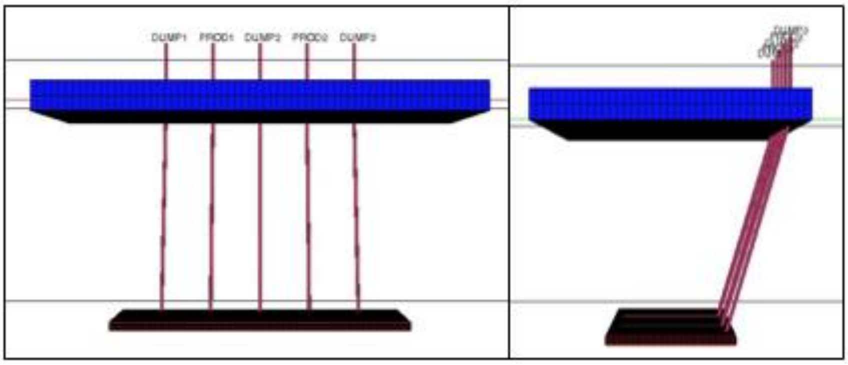


Figure 4.7 The base case of water dumpflood

3. Simulate water dumpflooding cases with various parameters for sensitivity study as follows:

   3.1 Aquifer size by variation of area with constant thickness: 10.33 PV_{oil} (intermediate aquifer) and 50.68 PV_{oil} (strong aquifer) as shown in Figures 4.1 and 4.2, respectively.

   3.2 Well type: one-lateral horizontal well and vertical well

   Option I: vertical producer and vertical dumper

   Option II: vertical producer and horizontal dumper

   Option III: horizontal producer and vertical dumper

   Option IV: horizontal producer and horizontal dumper

   Figures 4.8 - 4.19 illustrate the four combinations of the well type.

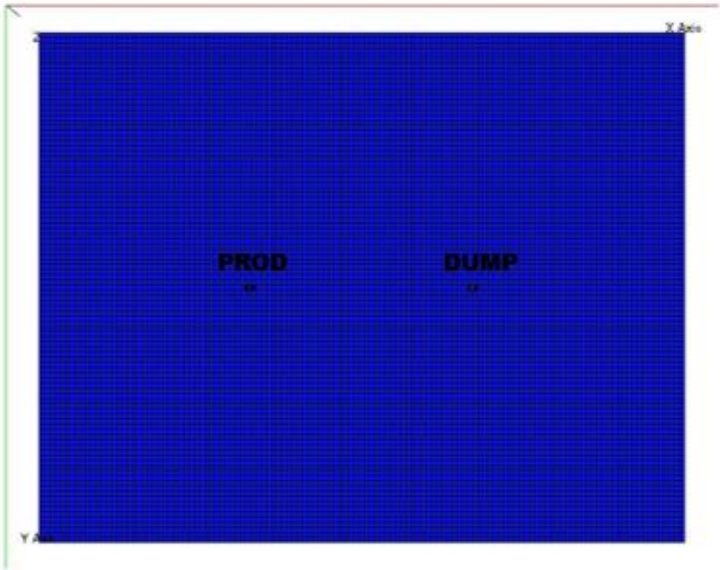


Figure 4. 8 Top view of a strong aquifer showing location of the vertical dumper and the vertical producer (Note that both two wells are not completed in the aquifer layer)

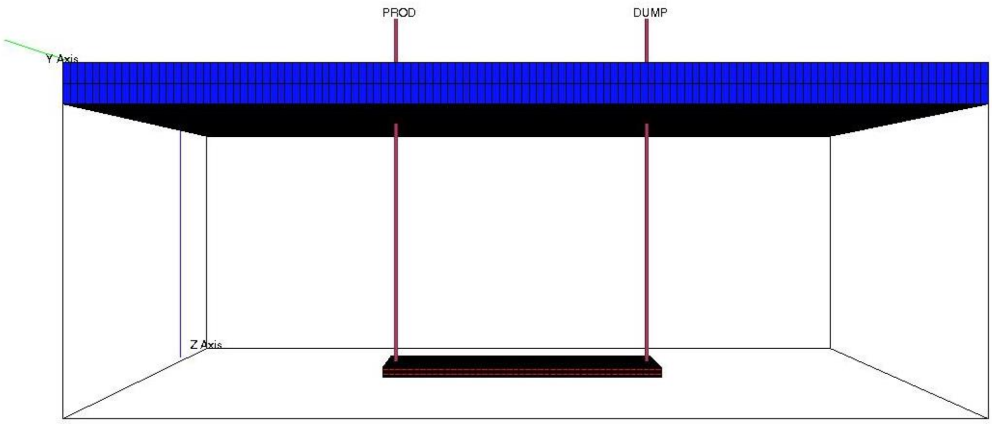


Figure 4. 9 Side view (xz plane) of a strong aquifer and oil reservoir with the vertical dumper and producer

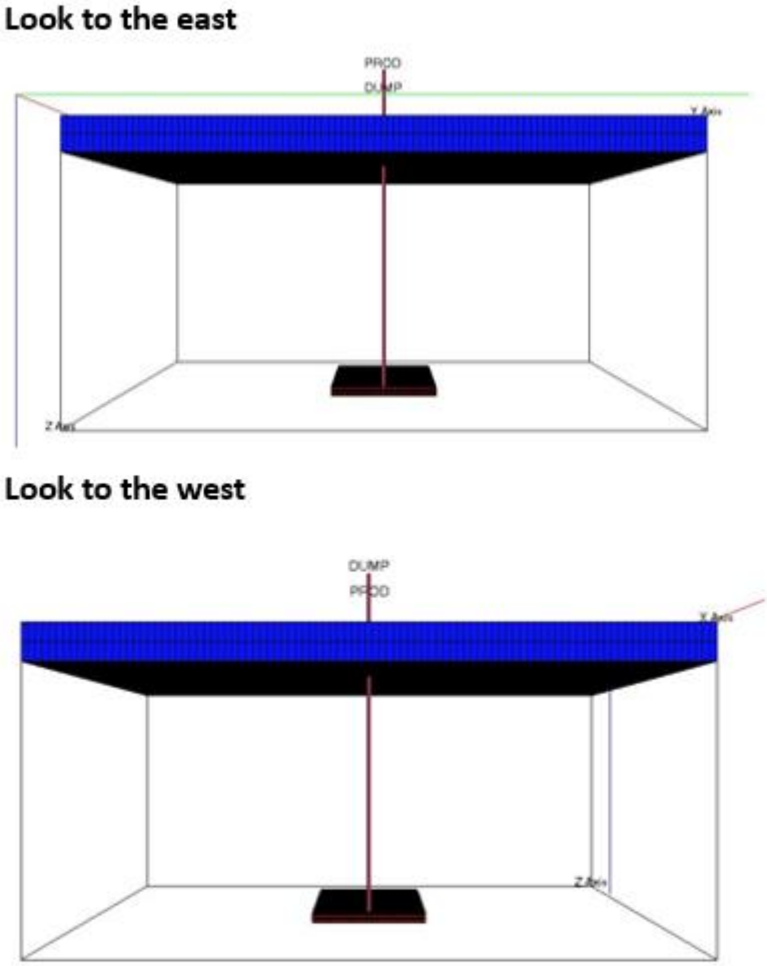


Figure 4. 10 Side view (yz plane) of a strong aquifer and oil reservoir with the vertical dumper and producer

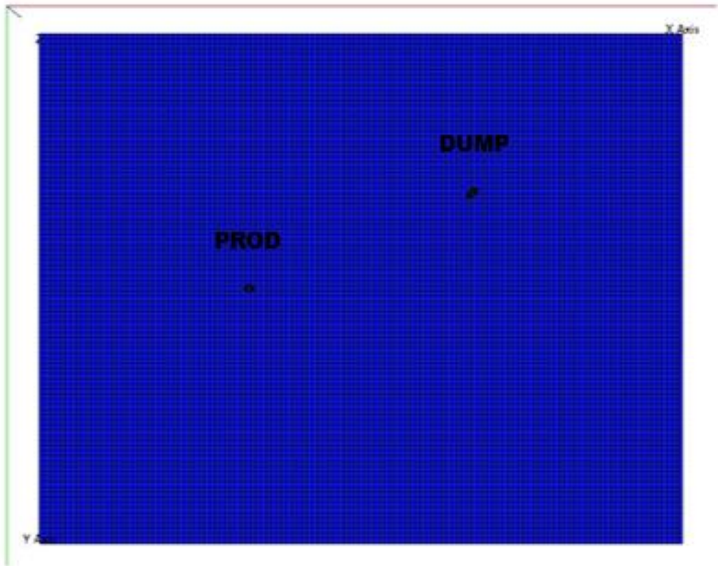


Figure 4. 11 Top view of a strong aquifer showing location of the horizontal dumper and the vertical producer (Note that both two wells are not completed in the aquifer layer)

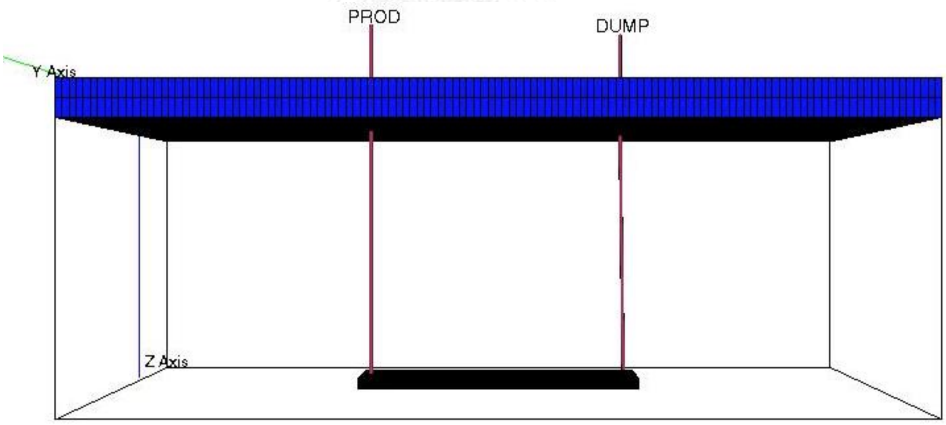


Figure 4. 12 Side view (xz plane) of a strong aquifer and oil reservoir with the horizontal dumper and the vertical producer

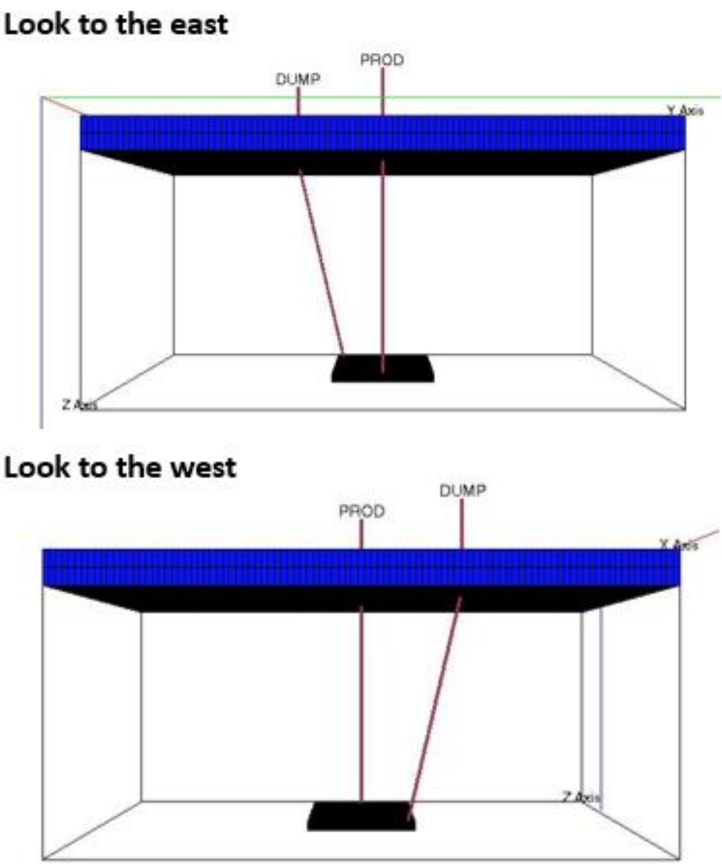


Figure 4. 13 Side view (yz plane) of a strong aquifer and oil reservoir with the horizontal dumper and the vertical producer

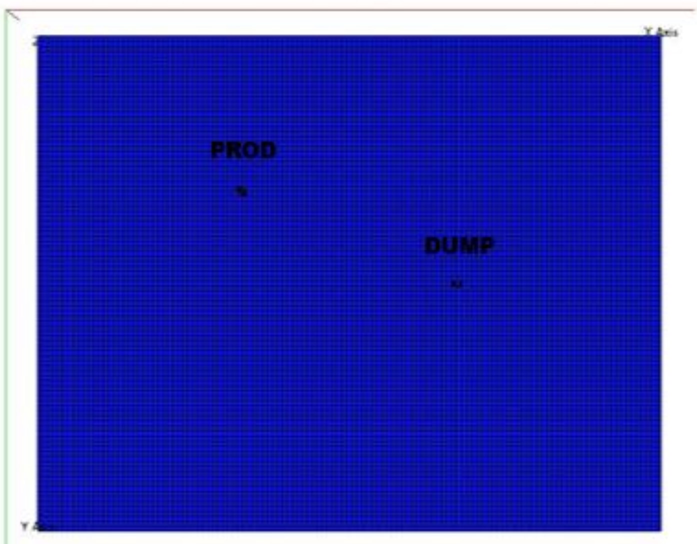


Figure 4. 14 Top view of a strong aquifer showing of the vertical dumper and the horizontal producer (Note that both two wells are not completed in the aquifer layer)

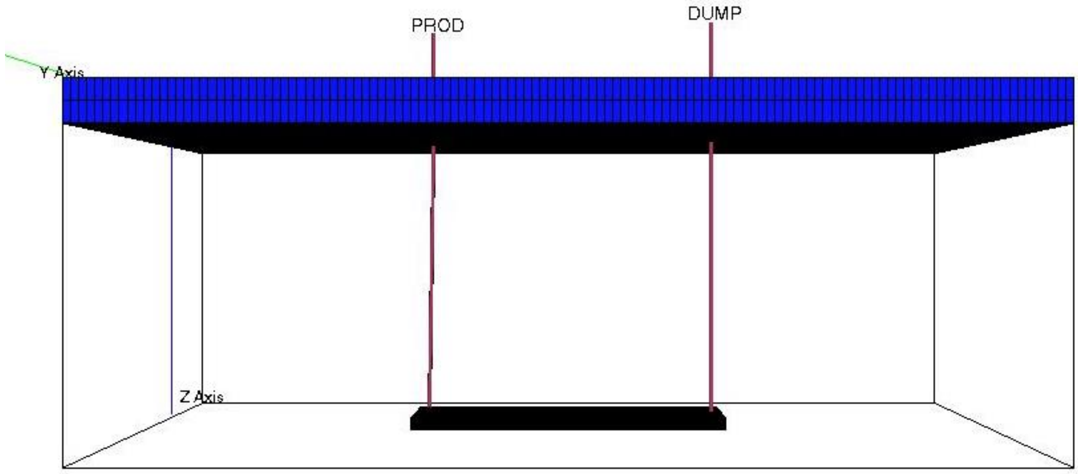
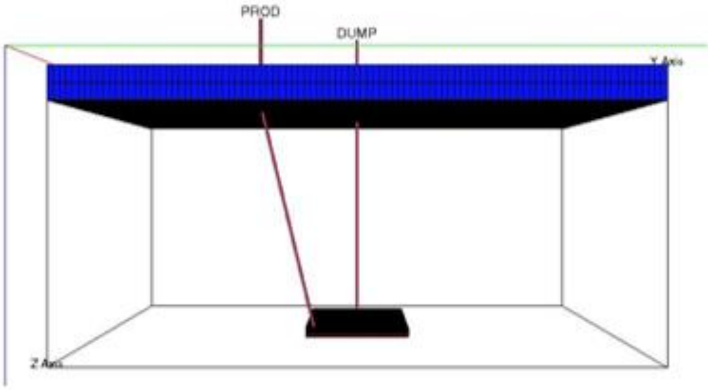


Figure 4. 15 Side view (xz plane) of a strong aquifer and oil reservoir with the vertical dumper and the horizontal producer

Look to the east



Look to the west

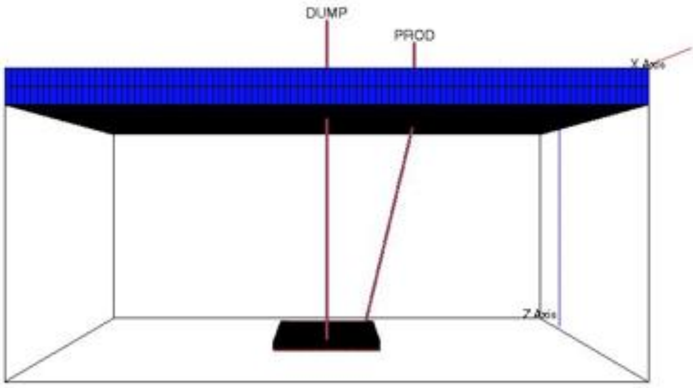


Figure 4. 16 Side view (yz plane) of a strong aquifer and oil reservoir with the horizontal dumper and the vertical producer

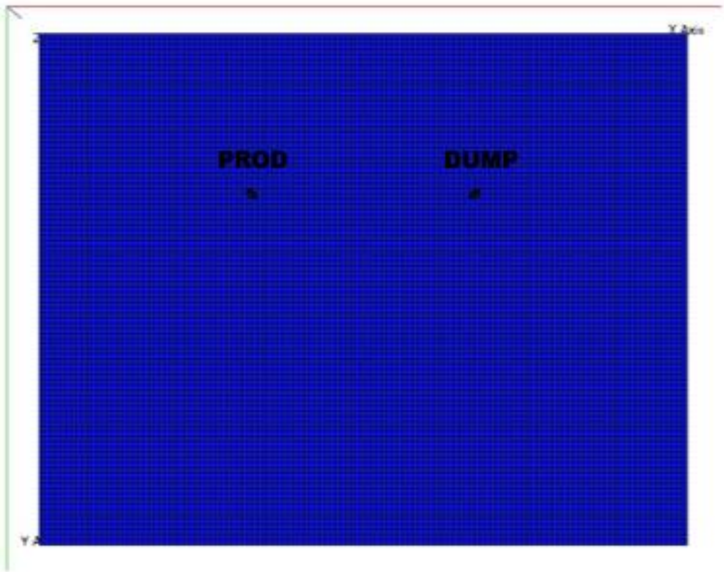


Figure 4. 17 Top view of a strong aquifer showing location of the horizontal dumper and the horizontal producer (Note that both two wells are not completed in the aquifer layer)

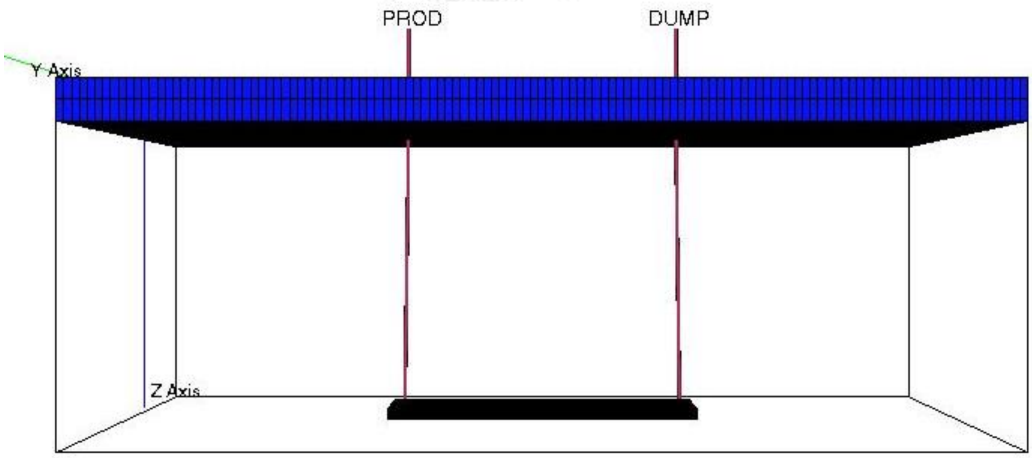


Figure 4. 18 Side view (xz plane) of a strong aquifer and oil reservoir with the horizontal dumper and producer

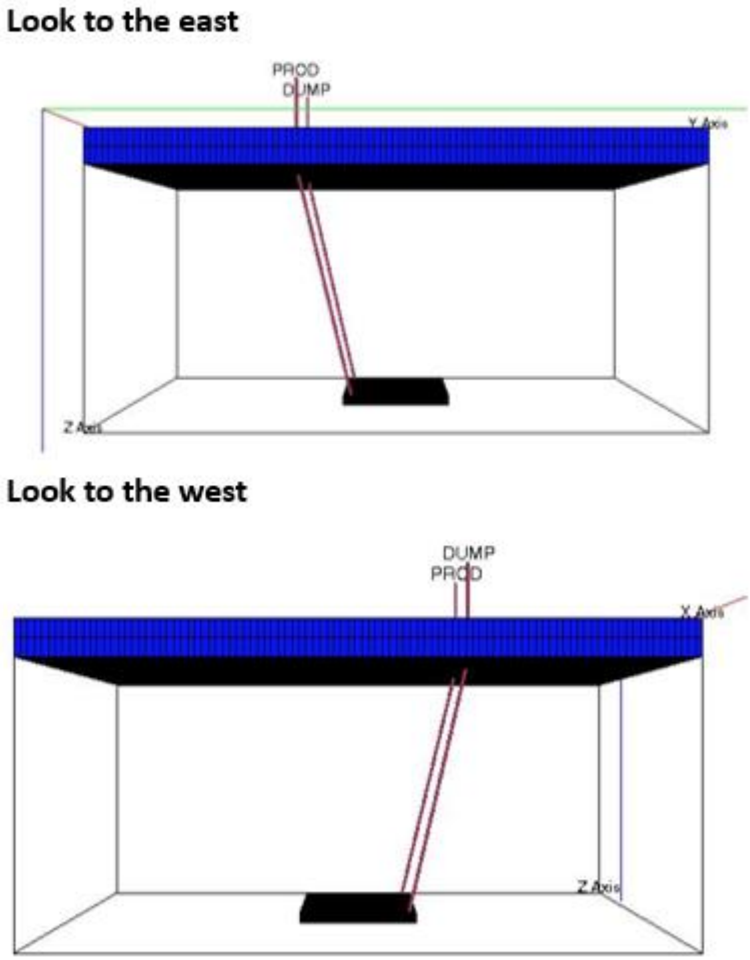


Figure 4. 19 Side view (yz plane) of a strong aquifer and oil reservoir with the horizontal dumper and producer

3.3 Well length of horizontal penetration in the oil zone

3.3.1 Horizontal length of 1700 ft

3.3.2 Horizontal length of 1300 ft

3.3.3 Horizontal length of 900 ft

3.4 Starting time for water dumpflood cases:

3.4.1 Option I: At early stage, all wells are used to produce oil under natural depletion and then some of the wells is/are converted to dumping well(s) when reservoir pressure reaches bubble-point pressure. For the cases of 4,200 feet spacing, two wells are used as production wells at the beginning, and then, one well is converted to be a dumper. For 2,100 feet well spacing, three wells are used as production wells at the beginning, and then two wells are converted to dumping wells. For 800 feet well spacing, five wells are used as production wells at the beginning, and then three wells are converted to dumping wells.

3.4.2 Option II: A certain number of well(s) is/are used to produce oil at an early stage. When reservoir pressure reaches bubble-point pressure, more well(s) is/are drilled for dumping. For the cases of 4,200 feet spacing, one well is used to produce oil at the beginning. When reservoir pressure drops to bubble-point pressure, another well is drilled for dumping. For 2,100 feet well spacing, one well is used to production well at the beginning. When reservoir pressure drops to bubble-point pressure, two wells are drilled for dumping. For 800 feet well spacing, two wells are used as producers at the beginning. When reservoir pressure reaches bubble-point pressure, three wells are drilled for dumping.

3.4.3 Option III: Water dumpflood is started at the same time when the production well(s) start(s) producing.

Each section as determined effects on various parameters studied on three different well arrangements as follows:

1) Option I: large well spacing with one dumper and one producer. The distance between the dumper and producer is 4,200 ft.
2) Option II: intermediate well spacing with two dumpers along the edges of the reservoir and one producer in the middle. The distance between wells is 2,100 ft.
3) Option III: small well spacing with three dumpers and two producers. The distance between wells is 800 ft.

All simulation cases are summarized in Figure 4.20.

4 Compare the performance from simulations.

5 Simulate base case for natural depletion and conventional waterflood as compare to the performance of water dumpflood case at the same scenario.

6 Discuss and conclude the result on each parameters.

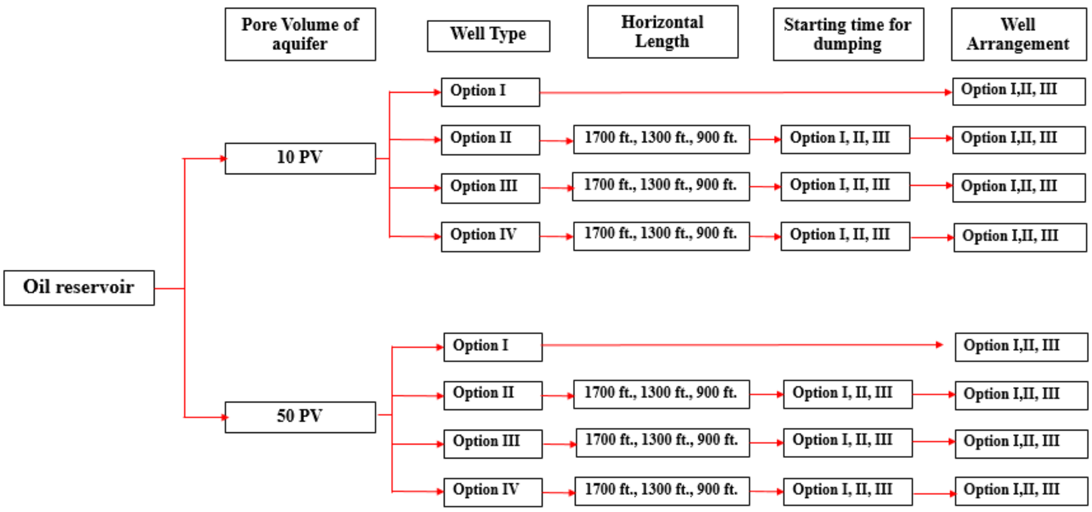


Figure 4.20 Flow chart of simulation cases

CHAPTER 5
RESULTS AND DISCUSSIONS

Several simulation cases are simulated in ECLIPSE®100 using reservoir and fluid properties from an onshore oil field in Thailand. This chapter emphasizes on the performances of variable parameters of well design which impact to water dumpflood on each aquifer size as follows:

- Well type
- Horizontal length
- Staring time for water dumpflood cases

The performances of different cases are evaluated based on total oil production, gas production, and water production under economic limit. After all simulation cases of water dumpflood are evaluated, the best performance of water dumpflood is compared with the base case including natural depletion and conventional waterflood cases.

5.1 Base case of water dumpflood

The model consists of an oil reservoir and an overlaying aquifer 1000 ft above. The base case is two horizontal producers and three horizontal dumpers with the 1700-foot horizontal well length and 800-foot well spacing which dumping water from a strong aquifer (50PV) as shown in Figure 5.1. Note that the left most well and the right most well are located 650 feet away from the left boundary and the right boundary, respectively.

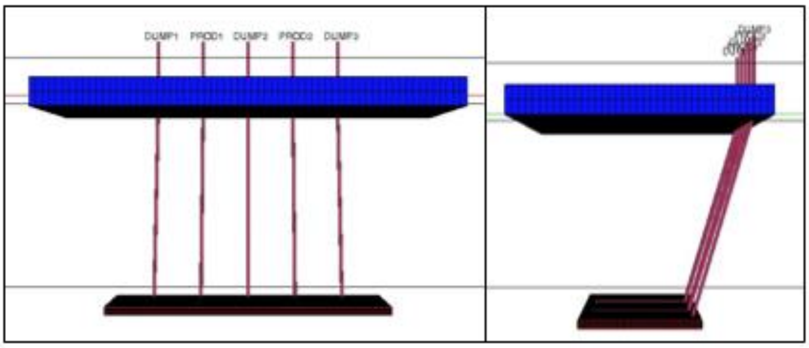


Figure 5.1 Schematic of base case of water dumpflood

As illustrated in Figure 5.2, the oil production rate is initially 4000 STB/D and then drops sharply as the reservoir cannot support such high rate anymore. After three and a half years of production, the oil production rate drops again to another trend due to water breakthrough at the producers. The gas production sharply increases at early stage, and after that, gas production gradually increases due to water breakthrough as well. At the end, the oil recovery factor is 31.17%. The oil and gas production are 2.537 MMSTB, and 564.96 MMSCF, respectively. Moreover, the water production is as high as 694.257 MSTB. In term of production time, this base case takes 9.4 years to reach abandonment. In additional to oil, gas, and water production, water cross flow rate from the aquifer into the oil reservoir is shown in Figure 5.3. After a few days of production, water dumping rate keeps increasing until reaching its highest point at 1800 STB/D after 2 months due to the difference in fluid potentials between the aquifer and the oil reservoir. After a while, water dumping rate declines as the two porous media get into more equilibrium in fluid potentials.

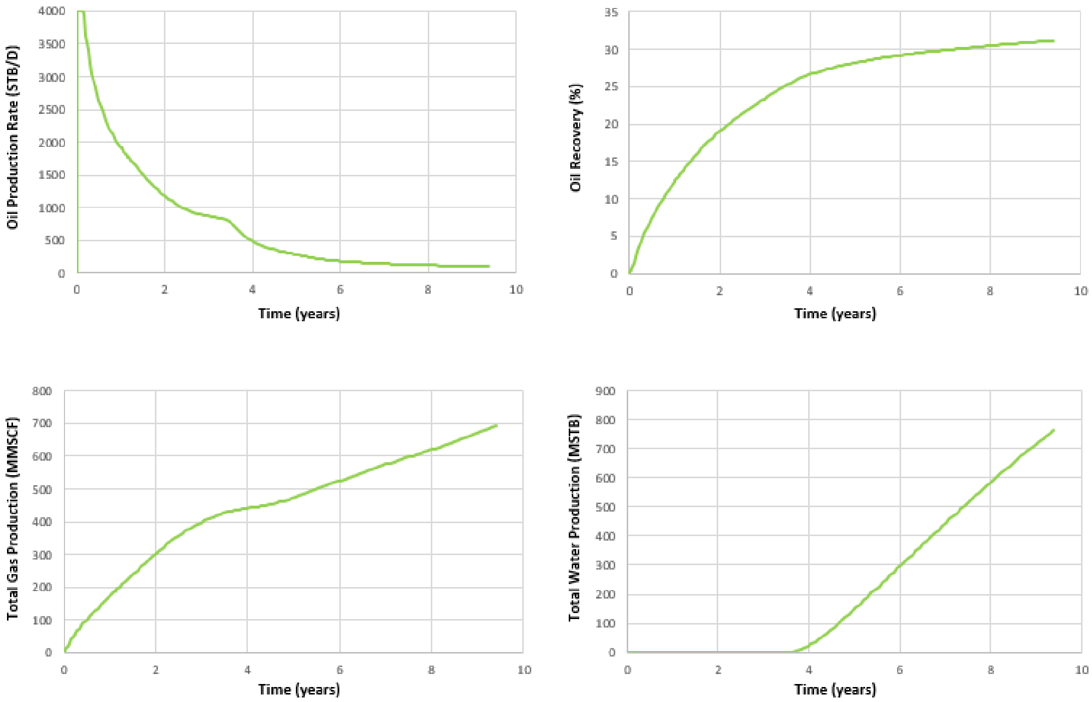


Figure 5.2 Production performances for base case of water dumpflood

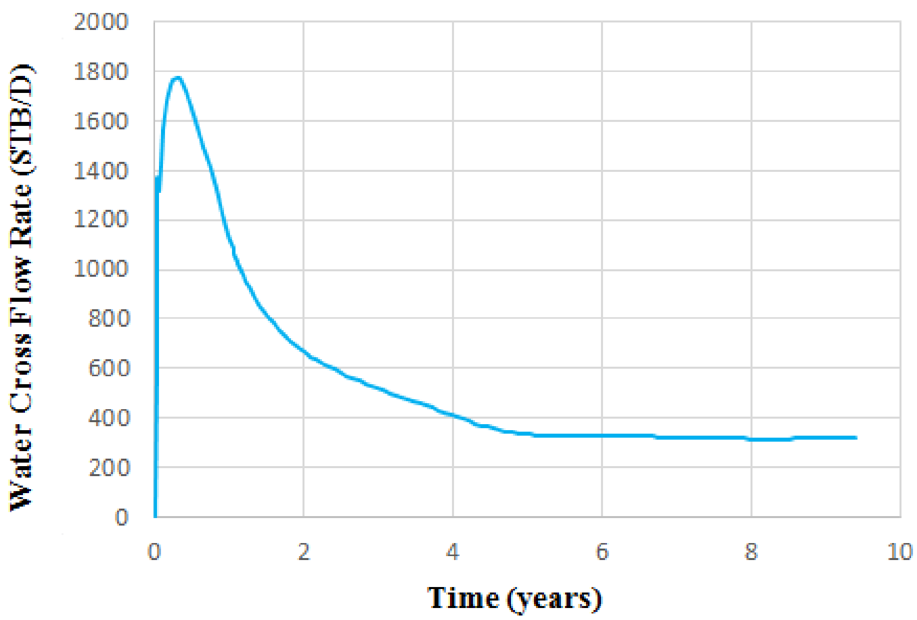


Figure 5.3 Water cross flow rates from the aquifer for base case

5.2 Effect of well type

5.2.1. Effect of well type for well arrangement option 1

In order to determine the effect of well type (vertical versus horizontal) on production performance of water dumpflood with well arrangement option 1, different combinations of producing and dumping well types were investigated:

Option 1: One vertical producer and one vertical dumper with 4200 ft well spacing

Option 2: One vertical producer and one horizontal dumper with 4200 ft well spacing

Option 3: One horizontal producer and one vertical dumper with 4200 ft well spacing

Option 4: One horizontal producer and one horizontal dumper with 4200 ft well spacing

The schematics of these options are shown in Figure 5.4. Note that distance between wells is 4200 feet with one producer and one dumper.

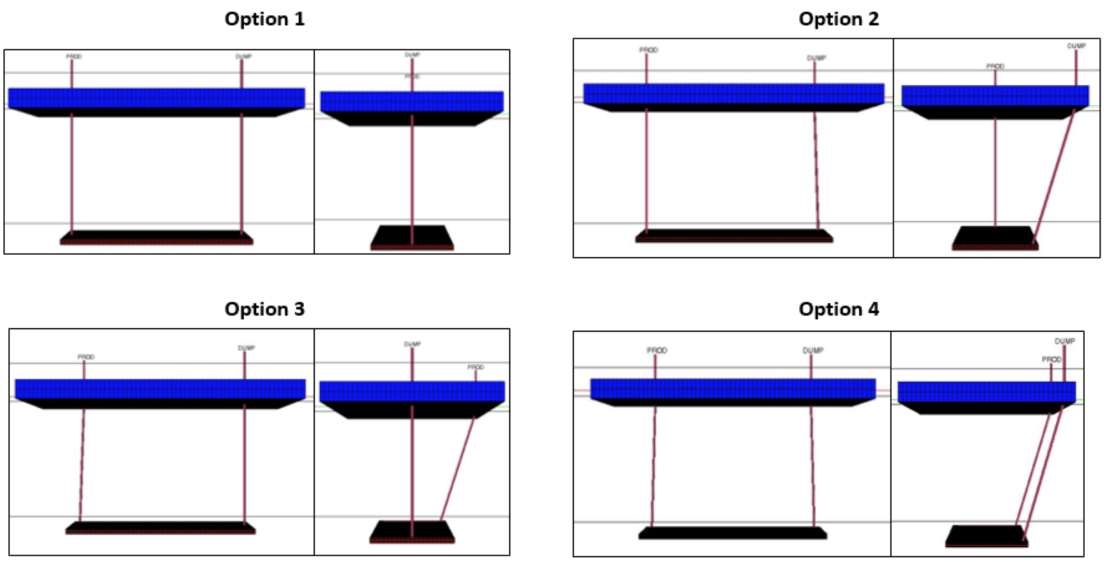


Figure 5.4 Schematics of four different well combinations in case of one producer and one dumper

Simulation results for the four options for these cases of dumping water from an intermediate aquifer (10PV) with different horizontal well lengths are plotted in

Figure 5.5 and summarized in Table 5.1. The oil production of the cases with horizontal producer (Options 3 and 4) are higher than those of the cases with vertical producer (Options 1 and 2) due to better exposure to the reservoir. Also, gas productions of the cases with horizontal producer are higher than the cases with vertical producers. Total gas productions for the cases with horizontal producer is more than twice as much as the ones for the cases with vertical producer. In addition, water productions from the cases with horizontal producer are much higher than those from cases with vertical producer. When making comparison between Options 3 and 4, Option 4 with the horizontal dumper has a slightly better oil recovery factor, slightly more gas production and slightly more water production as well. In term of effect of horizontal well length on each different well types, there is no significant difference in the amount of oil, gas and water productions in cases of Option 2 while in Options 3 and 4, increasing horizontal well length yields slightly higher oil, gas and water productions. In brief, there is no distinguishable difference on any kind of dumping well in the results, but horizontal producer can yield higher oil, gas, and water production.

Table 5.1 Results for different well types for well arrangement option 1 when dumping water from an intermediate aquifer (10PV).

Well type	Horizontal well length (ft)	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	-	0.818	0.201	132.17	10.05	20.0
Option 2	900	0.825	0.200	133.94	10.14	20.0
	1300	0.826	0.199	134.13	10.14	20.0
	1700	0.826	0.199	134.20	10.15	20.0
Option 3	900	1.219	0.733	327.83	14.97	20.0
	1300	1.275	0.903	384.66	15.67	20.0
	1700	1.303	1.018	416.72	16.01	20.0
Option 4	900	1.229	0.734	331.19	15.10	20.0
	1300	1.287	0.904	388.74	15.81	20.0
	1700	1.315	1.021	421.18	16.16	20.0

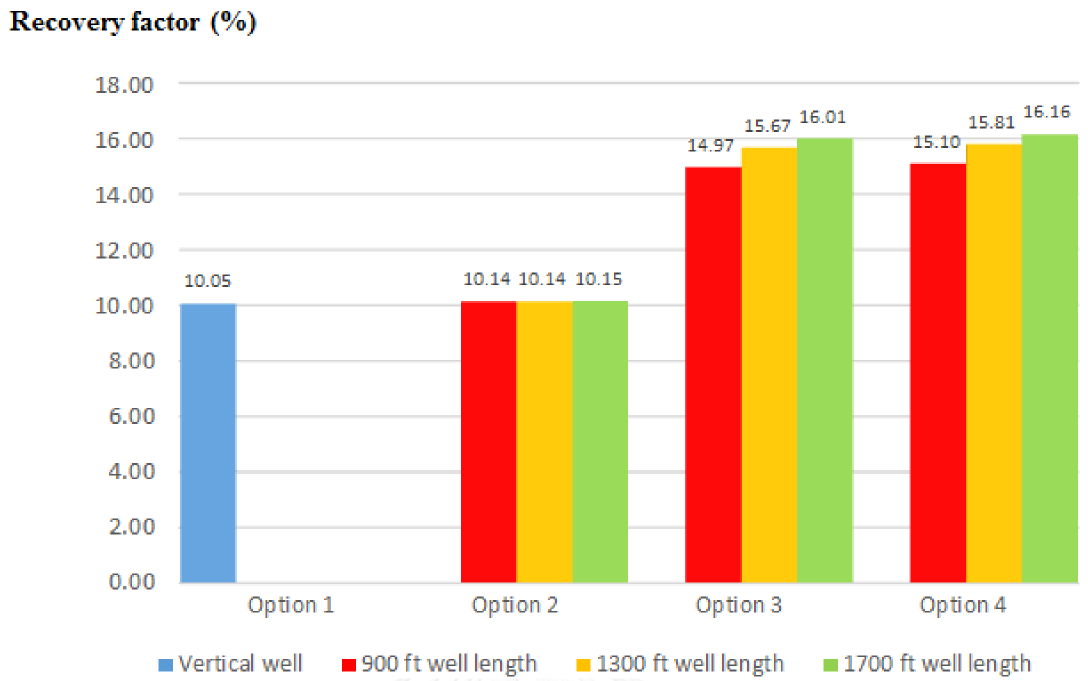


Figure 5.5 Recovery factor for different well types for well arrangement option 1 when dumping water from an intermediate aquifer

In case of strong aquifer, the cases with horizontal producer (Options 3 and 4) have better performance than the cases with vertical producer (Options 1 and 2) as illustrated in Figure 5.6. When making comparison between Options 3 and 4, Option 4 with horizontal dumper has a slightly higher oil recovery, slightly more gas production, and slightly more water production than Option 3 with vertical dumper as summarized in Table 5.2. In term of effect of horizontal well length, there is a no difference in the amount of oil, gas and water productions when horizontal well length increases in case of Option 2 while in Options 3 and 4, increasing horizontal well length yields slightly higher oil, gas and water productions. In summary, when a strong aquifer is available as a water source for dumpflood, any kind of dumping wells can be used as there is no significant difference in the results. For production, horizontal well should be used as producer as it has better production performance.

Table 5.2 Results for different well types for well arrangement option 1 when dumping water from a strong aquifer (50PV)

Well type	Horizontal well length (ft)	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	-	0.866	0.193	138.54	10.64	20.0
Option 2	900	0.999	0.181	171.40	12.21	20.0
	1300	1.004	0.181	172.41	12.26	20.0
	1700	1.006	0.181	172.87	12.29	20.0
Option 3	900	1.320	0.769	299.66	16.21	20.0
	1300	1.385	0.957	351.45	17.01	20.0
	1700	1.418	1.086	381.41	17.42	20.0
Option 4	900	1.370	0.777	305.12	16.82	20.0
	1300	1.449	0.977	359.18	17.80	20.0
	1700	1.488	1.115	390.15	18.27	20.0

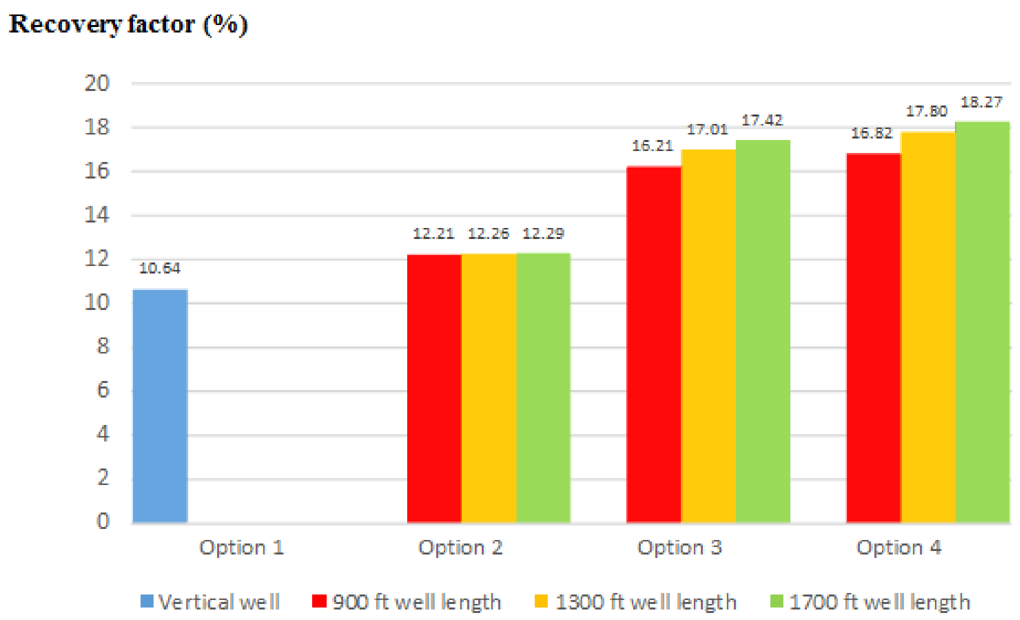


Figure 5.6 Recovery factor for different well types for well arrangement option 1 when dumping water from a strong aquifer

5.2.2. Effect of well type for well arrangement option 2

In order to determine the effect of well type (vertical versus horizontal) on production performance of water dumpflood with well arrangement option 2, different combinations of producing and dumping well types were investigated:

Option 1: One vertical producer and two vertical dumpers with 2100 ft well spacing

Option 2: One vertical producer and two horizontal dumpers with 2100 ft well spacing

Option 3: One horizontal producer and two vertical dumpers with 2100 ft well spacing

Option 4: One horizontal producer and two horizontal dumpers with 2100 ft well spacing

The schematics of these options are shown in Figure 5.7. Note that distance between wells is 2100 feet with one producer and two dumpers.

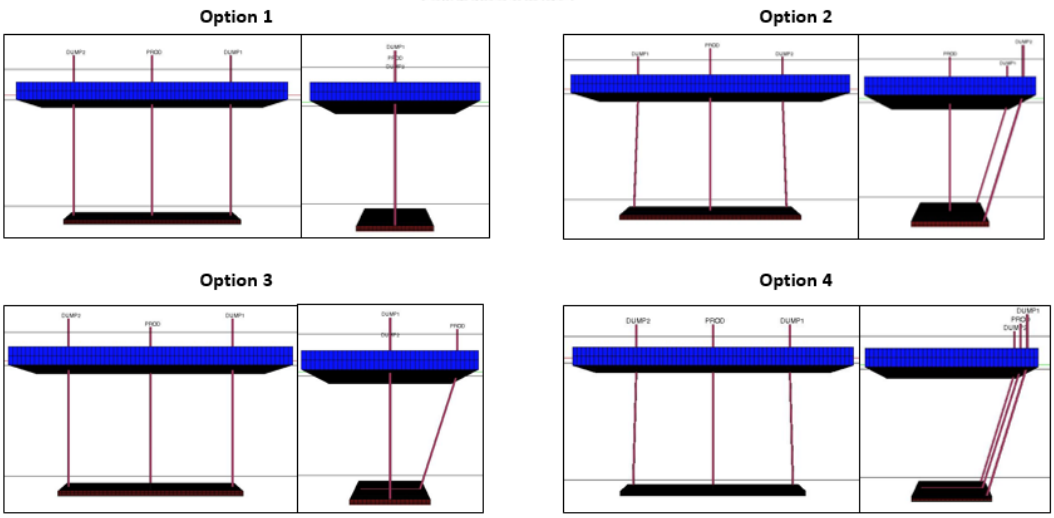


Figure 5.7 Schematics of four different well combinations in case of one producer and two dumpers

Similar to the result in case of well arrangement option 1, the oil productions of cases with horizontal producer (Options 3 and 4) are higher than productions of cases with vertical producer (Options 1 and 2) due to better exposure to the reservoir as depicted in Figure 5.8 and Table 5.3. In the same manner, gas productions of the cases with horizontal producer are higher than those for the cases with vertical producer. Total gas productions for the cases with horizontal producer are around three to five times of the cases with vertical producer. In addition, water productions from the cases with horizontal producer are more than those from cases with vertical producer. When making comparison between Options 3 and 4, Option 4 with the horizontal dumpers has a slightly better oil recovery factor with small differences in gas and water production. In term of effect of horizontal well length, there is no significant difference in the amount of oil, gas, and water productions in Option 2 while longer horizontal well length in Options 3 and 4 provides slightly higher oil, gas, and water productions.

Table 5.3 Results for different well types for well arrangement option 2 when dumping water from an intermediate aquifer (10PV).

Well type	Horizontal well length (ft)	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	-	1.033	0.175	170.78	12.69	20.0
Option 2	900	1.039	0.175	172.45	12.76	20.0
	1300	1.039	0.175	172.74	12.77	20.0
	1700	1.040	0.175	172.96	12.78	20.0
Option 3	900	1.839	0.885	659.61	22.59	20.0
	1300	1.928	1.135	941.60	23.69	20.0
	1700	1.939	1.292	1027.97	23.82	18.9
Option 4	900	1.848	0.882	661.89	22.71	20.0
	1300	1.939	1.127	909.26	23.81	20.0
	1700	1.967	1.300	1018.50	24.17	19.7

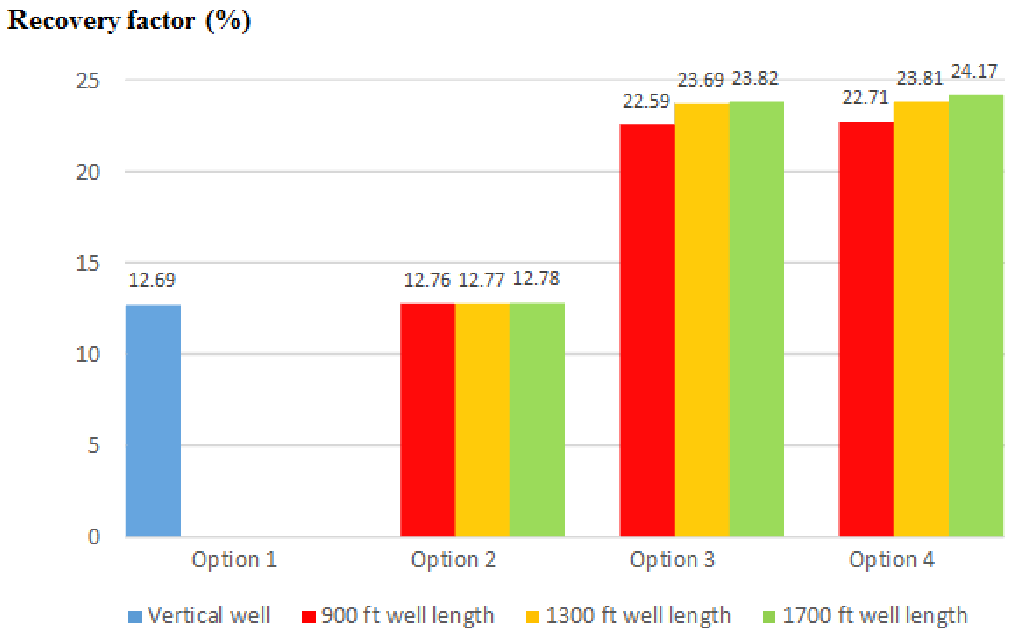


Figure 5.8 Recovery factor for different well types for well arrangement option 2 when dumping water from an intermediate aquifer

For cases with strong water-drive aquifer as water source, the cases with horizontal producer (Options 3 and 4) have better performance than the cases with vertical producer (Options 1 and 2) as illustrated in Figure 5.9. The cases with horizontal producer have higher gas productions and much higher water productions. When making comparison between Options 3 and 4, Option 4 with horizontal dumper has a slightly higher oil recovery than Option 3 with comparable gas and water productions as summarized in Table 5.4. For effect of horizontal well length, there is no significant difference in the amount of oil and gas productions when horizontal well length increases while oil and gas productions in Options 3 and 4 increase when horizontal well length increases. In summary, when a strong aquifer is available as a water source for dumpflood, any kind of dumping wells can be used as there is no significant difference in the results, but horizontal well should be used as producer as it has better production performance.

Table 5.4 Results for different well types for well arrangement option 2 when dumping water from a strong aquifer (50PV).

Well type	Horizontal well length (ft)	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	-	1.178	0.147	202.92	14.46	20.0
Option 2	900	1.339	0.143	245.40	16.35	20.0
	1300	1.341	0.143	246.03	16.38	20.0
	1700	1.344	0.142	246.66	16.42	20.0
Option 3	900	2.246	0.959	484.82	27.58	20.0
	1300	2.377	1.229	569.69	29.20	20.0
	1700	2.506	1.584	657.12	30.78	20.0
Option 4	900	2.326	0.946	508.83	28.57	20.0
	1300	2.519	1.299	619.79	30.95	20.0
	1700	2.599	1.486	662.33	31.93	20.0

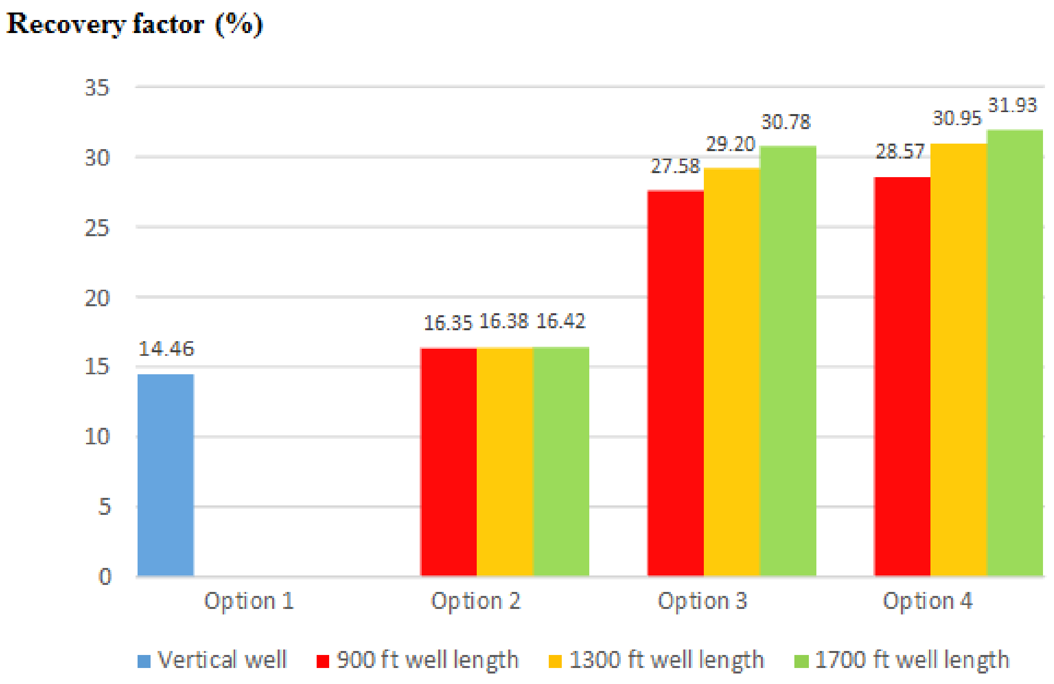


Figure 5.9 Recovery factor for different well types for well arrangement option 2 when dumping water from a strong aquifer

5.2.3. Effect of well type for well arrangement option 3

In order to determine the effect of well type (vertical versus horizontal) on production performance of water dumpflood when well arrangement option 3 is used, different combinations of producing and dumping well types were investigated:

Option 1: Two vertical producers and three vertical dumpers with 800 ft well spacing

Option 2: Two vertical producers and three horizontal dumpers with 800 ft well spacing

Option 3: Two horizontal producers and three vertical dumpers with 800 ft well spacing

Option 4: Two horizontal producers and three horizontal dumpers with 800 ft well spacing

The schematics of these options are shown in Figure 5.10. Note that distance between wells is 800 feet with two producers and three dumpers.

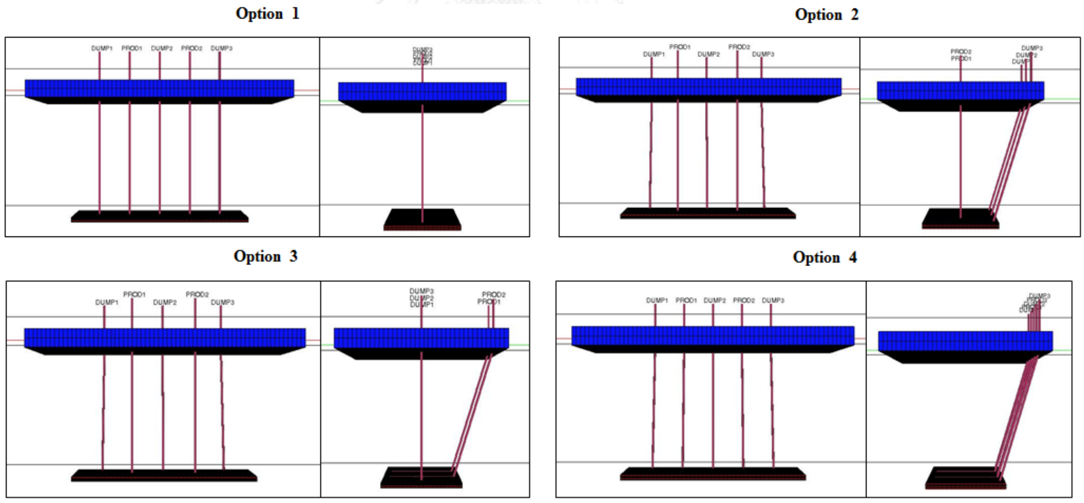


Figure 5.10 Schematics of four different well combinations in case of two producers and three dumpers with well distance of 800 ft.

Simulation results for the four options for the cases of dumping water from an intermediate aquifer (10PV) are plotted in Figure 5.11 and summarized in Table 5.5. The oil recovery factors of the cases with horizontal producers are higher, so are the total gas productions. In addition, water productions from the cases with horizontal producers are higher than those from cases with vertical producers except the case of 1700-ft horizontal producers with vertical dumpers (Option 3). In this case, the well length is very long such that the sweep efficiency between the dumpers and producers is very good, resulting in low water production. In term of production time, the cases with horizontal producers take less than 11 years to produce the oil until reaching abandonment condition while the cases with vertical producers take about 18 years. When making comparison between Options 3 and 4, Option 4 with the horizontal dumpers has a slightly better oil recovery factor with small differences in gas and water productions. For effect of horizontal well length on different well types, oil recovery in Options 2 and 3 increases slightly when horizontal well length increases while option 4, longer horizontal well length yields moderately higher oil recovery. In addition, longer horizontal well length provides lower water production in Options 3 and 4 due to better sweep efficiency as shown in Figure 5.12.

Table 5.5 Results for different well types for well arrangement option 3 when dumping water from an intermediate aquifer (10PV).

Well type	Horizontal well length (ft)	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	-	1.389	40.217	226.71	17.07	17.2
Option 2	900	1.366	45.504	223.40	16.78	15.6
	1300	1.415	46.649	231.09	17.38	16.4
	1700	1.443	46.712	235.55	17.72	16.8
Option 3	900	1.961	92.539	871.50	24.09	10.8
	1300	2.012	47.509	1004.07	24.72	9.2
	1700	2.034	25.886	1079.11	24.98	8.6
Option 4	900	1.995	127.638	725.24	24.51	10.3
	1300	2.124	106.660	884.19	26.09	9.1
	1700	2.207	76.839	971.40	27.11	8.3

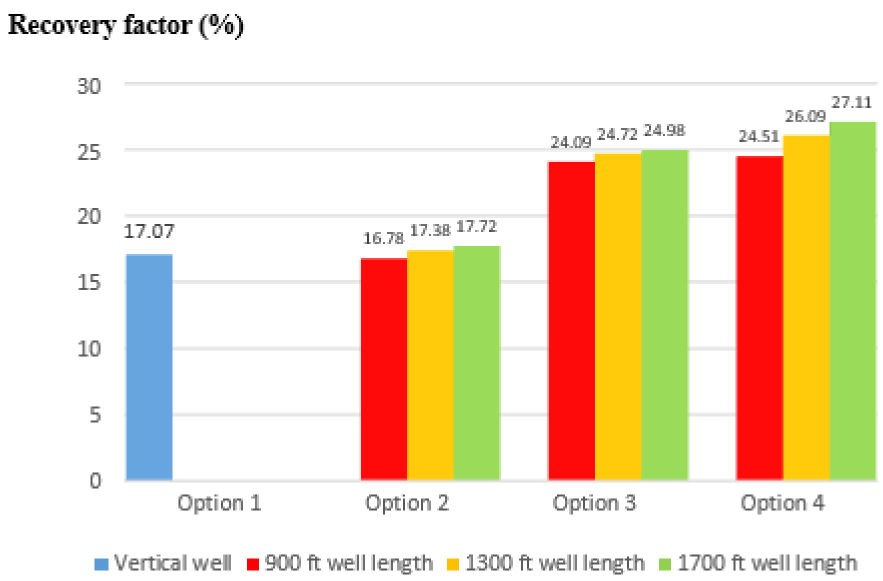
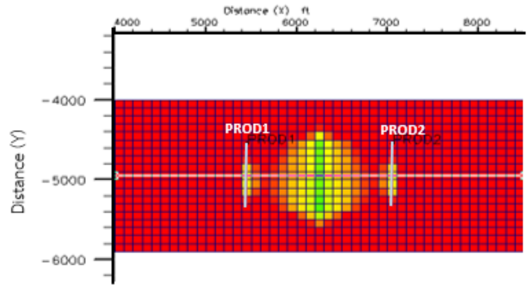
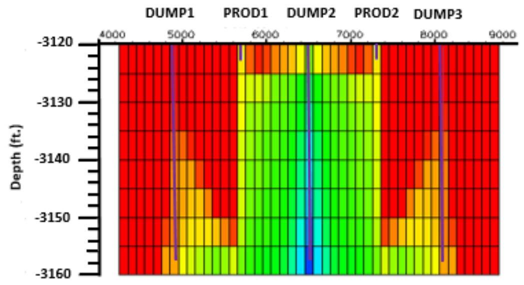


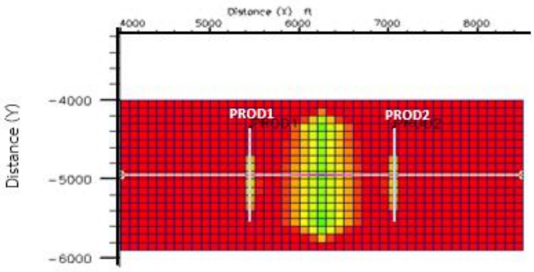
Figure 5.11 Recovery factor for different well types for well arrangement option 3 when dumping water from an intermediate aquifer



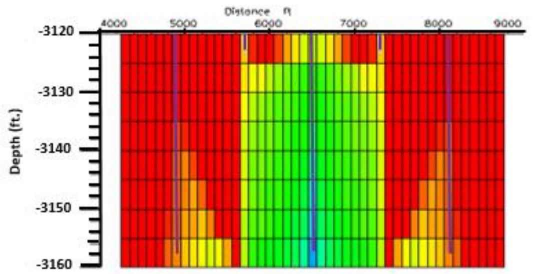
a) Top view of top of the oil layer for Option 4 with 900 ft. well length



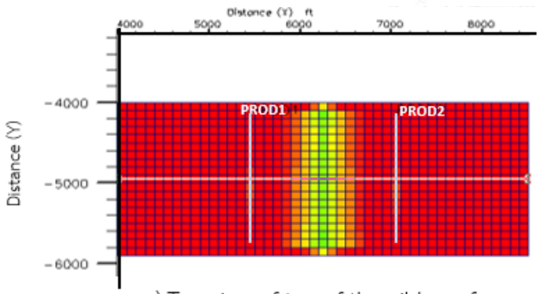
b) Side view (xz plane) for Option 4 with 900 ft. well length



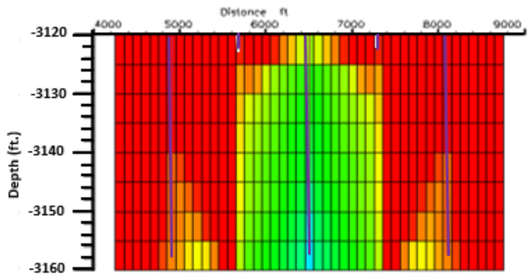
c) Top view of top of the oil layer for Option 4 with 1300 ft. well length



d) Side view (xz plane) for Option 4 with 1300 ft. well length



e) Top view of top of the oil layer for Option 4 with 1700 ft. well length



f) Side view (xz plane) for Option 4 with 1700 ft. well length

Figure 5.12 Water saturation profile for different horizontal well lengths in Option 4 when dumping water from an intermediate aquifer after dumping water for 6 years

As shown in Figure 5.13 and summarized in Table 5.6, oil and gas productions in the cases with horizontal producers (Options 3 and 4) yield higher than the cases with vertical producers (Options 1 and 2). In addition, water productions of the cases with horizontal producers are higher than the cases with vertical producers. When making comparison between Options 3 and 4 (the cases with horizontal producers), Option 4, having three horizontal dumpers, yields slightly higher oil recovery factor, less gas production, and higher water production than Option 3 with vertical dumpers due to better areal sweep efficiency. For effect of horizontal well length on different well types, oil recovery in Options 2 and 3 increases slightly when horizontal well length increases while in Option 4, longer horizontal well length yields moderately higher oil recovery. In addition, longer horizontal well length provides lower water production in Options 3 and 4. In summary, when a strong aquifer is available as a water source for dumpflood, the producer wells should be horizontal well as it provides better production performance.

Table 5.6 Results for different well types for well arrangement option 3 when dumping water from a strong aquifer (50PV).

Well type	Horizontal well length (ft)	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	-	1.203	151.543	209.86	14.77	14.0
Option 2	900	1.521	164.291	280.27	18.59	14.4
	1300	1.606	172.168	294.91	19.63	15.5
	1700	1.700	175.236	310.99	20.78	16.7
Option 3	900	2.194	768.777	558.22	26.95	12.2
	1300	2.381	770.611	765.41	29.25	11.2
	1700	2.515	729.399	894.13	30.90	11.0
Option 4	900	2.216	868.034	517.25	27.22	12.5
	1300	2.428	832.632	638.13	29.82	10.7
	1700	2.537	765.316	694.26	31.17	9.4

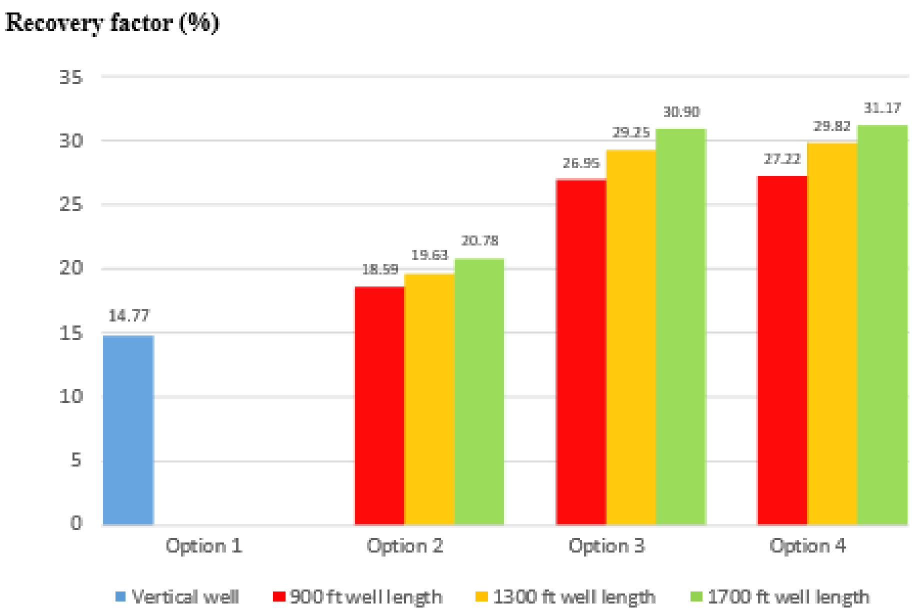


Figure 5.13 Recovery factor for different well types for well arrangement option 3 *when dumping water from a strong aquifer*

5.3 Effect of horizontal well length

In case of horizontal well, the horizontal well length penetrating in the oil zone is one of significant parameters for production performance. In this study, three different well lengths, namely, 900 ft, 1,300ft, and 1,700 ft were investigated.

5.3.1 Effect of horizontal well length for horizontal producer and horizontal dumper

For the cases of intermediate aquifer, longer horizontal well length can yield higher oil recovery factor when horizontal wells are used for both dumping and producing wells as illustrated in Figure 5.14. Longer horizontal well length on producer and dumper moderately increases oil recovery in all well arrangements but increasing horizontal well length in well arrangement option 3 results in significantly increasing oil recovery.

The amount of water production generally increases when horizontal well length is increased in accord with higher oil production. However, when the horizontal well length is increased from 1,300 ft to 1,700 ft in the case of well arrangement option

3, water production decreases from 106.660 to 76.839 MMSTB due to direct movement of water between dumpers and producers (excellent sweep efficiency).

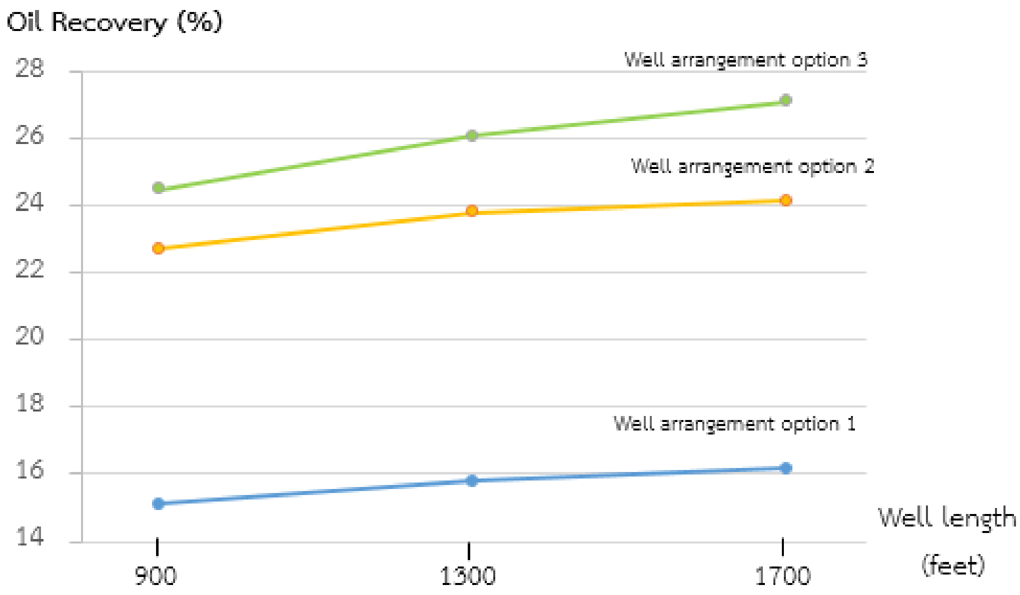


Figure 5.14 Oil recovery factor for different horizontal well lengths for horizontal producer and horizontal dumper for intermediate aquifer (10 PV).

As depicted in Figure 5.15, horizontal well length of 1,700 ft has better production performance due to longer penetration into the oil reservoir. Oil recovery increases moderately when horizontal well length increases in well arrangement option 1 but oil recovery in well arrangement options 2 and 3 has significantly increased when horizontal well length increases. In case of horizontal producer(s) and horizontal dumper(s) with well arrangement option 3 for strong aquifer, oil recovery factor increases from 27.22% to 31.17% when the horizontal well length is increased from 900 to 1,700 feet. However, in case of well arrangement option 3, longer horizontal well results in lower water production due to better sweep efficiency between horizontal dumpers and horizontal producers.

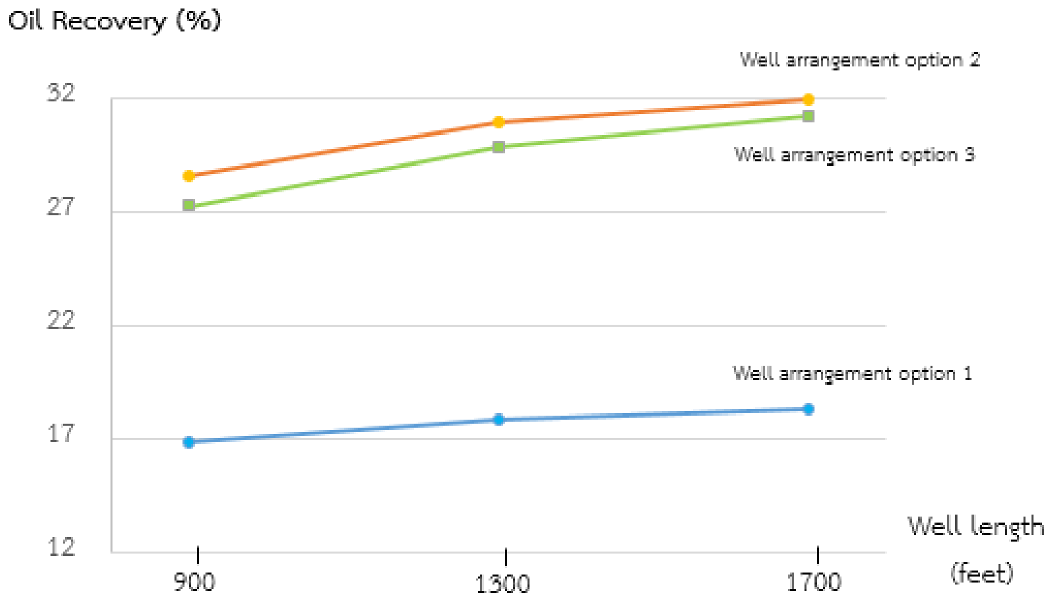


Figure 5.15 Oil recovery factor for different horizontal well lengths for horizontal producer and horizontal dumper for strong aquifer (50 PV).

5.3.2 Effect of horizontal well length for horizontal producer and vertical dumper

As shown in Figure 5.16, simulation results for intermediate aquifer indicate longer horizontal well length provides moderately higher oil production in all options of well arrangements. In addition, longer horizontal well length of producer generally increases water production in accord with increase in oil production. However, in case of horizontal producer and vertical dumper with well arrangement option 3, longer horizontal well length results in lower water production due to better sweep efficiency between the dumper(s) and producer(s).

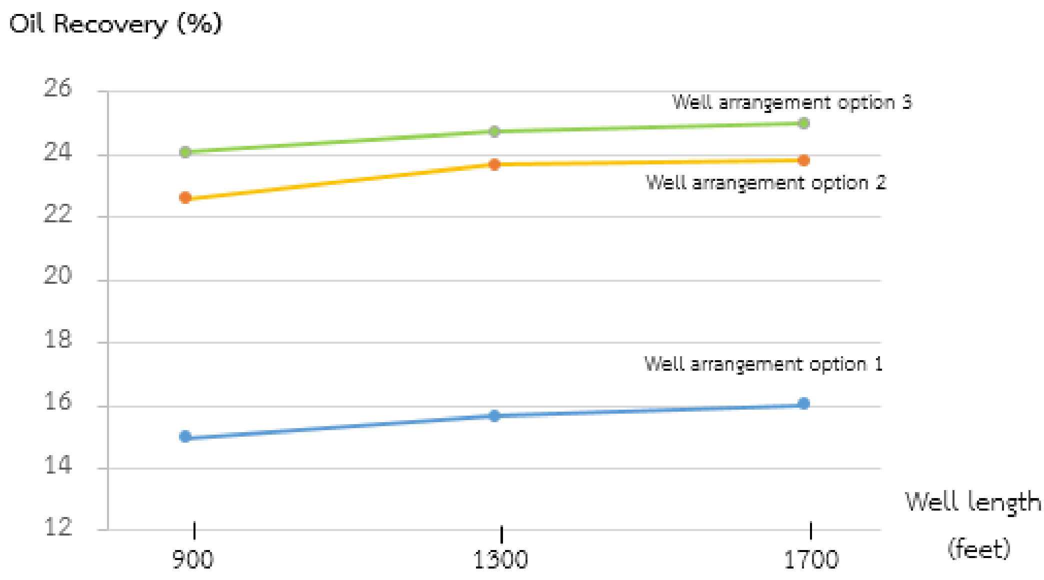


Figure 5.16 Oil recovery factor for different horizontal well length for horizontal producer and vertical dumper for intermediate aquifer (10 PV).

Similar to the result for intermediate aquifer, simulation results show that longer horizontal well length has better production performance due to better exposure into the oil reservoir in producing wells as shown in Figure 5.17. Effect of horizontal well length in well arrangement option 1 slightly increases while oil recovery in well arrangement options 2 and 3 increases significantly when horizontal well length increases from 900 to 1700 feet. In addition, the longer horizontal well length in producer generally increases water production except the case of horizontal producer and vertical dumper with well arrangement option 3 in which water production generally decreases with horizontal well length due to better sweep efficiency.

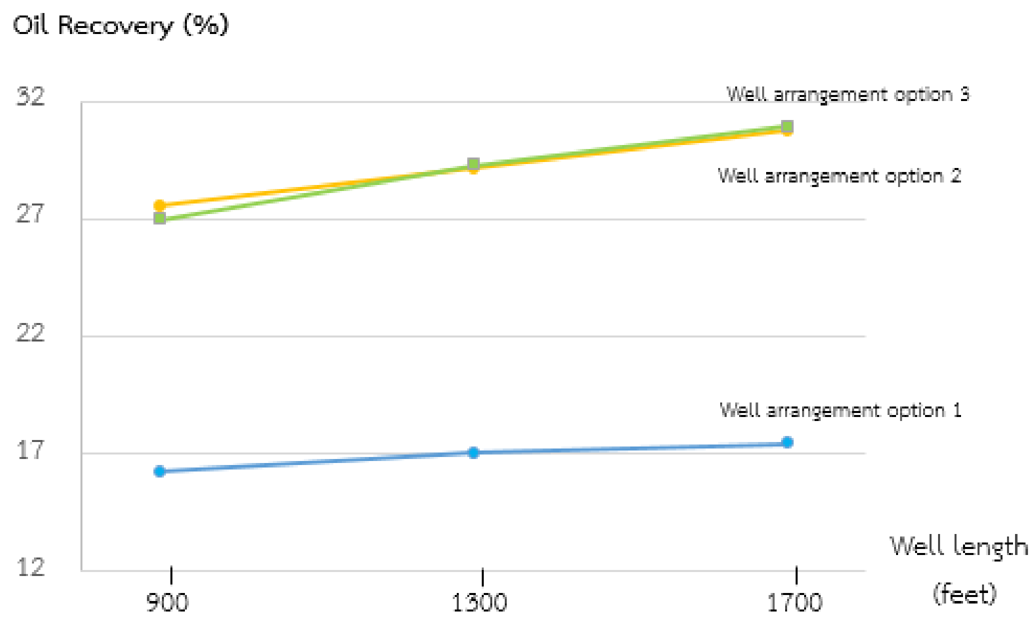


Figure 5.17 Oil recovery factor for different horizontal well length for horizontal producer and vertical dumper for strong aquifer (50 PV)

5.3.3 Effect of horizontal well length for vertical producer and horizontal dumper

As depicted in Figure 5.18, the oil recovery factor increases by longer well length only in the case of well arrangement option 3. In this case, oil recovery factor increases from 16.78% to 24.98% when horizontal well length is increased from 900 to 1,700 feet. For cases of well arrangement options 1 and 2, increasing the well length does not have any effect on oil production. Furthermore, in case of well arrangement option 3, long horizontal well length has slightly more gas production but lower water production due to better sweep efficiency.

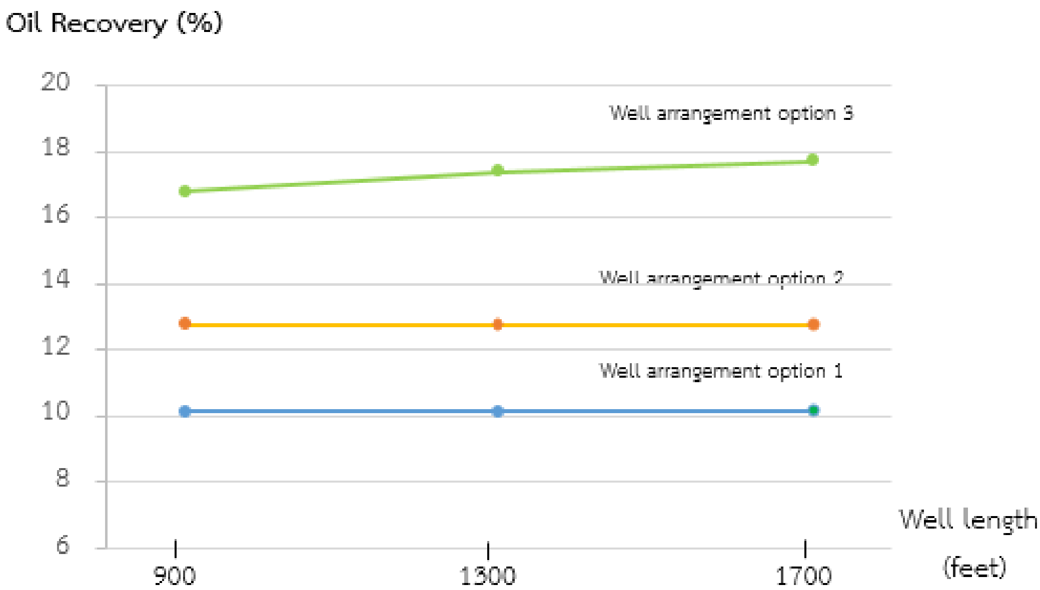


Figure 5.18 Oil recovery factor for different horizontal well length for vertical producer and horizontal dumper for intermediate aquifer (10 PV)

For strong aquifer, simulation results show that oil recovery factor slightly increases by longer horizontal well length in case of well arrangement option 3 but does not change in the cases of well arrangement options 1 and 2. In case of vertical producer and horizontal dumper for strong aquifer with well arrangement option 3, oil recovery factor increases from 18.59 to 20.78% when horizontal well length in dumping well increases from 900 to 1700 feet. Moreover, 1700-ft horizontal well length has slightly more gas production and more water production.

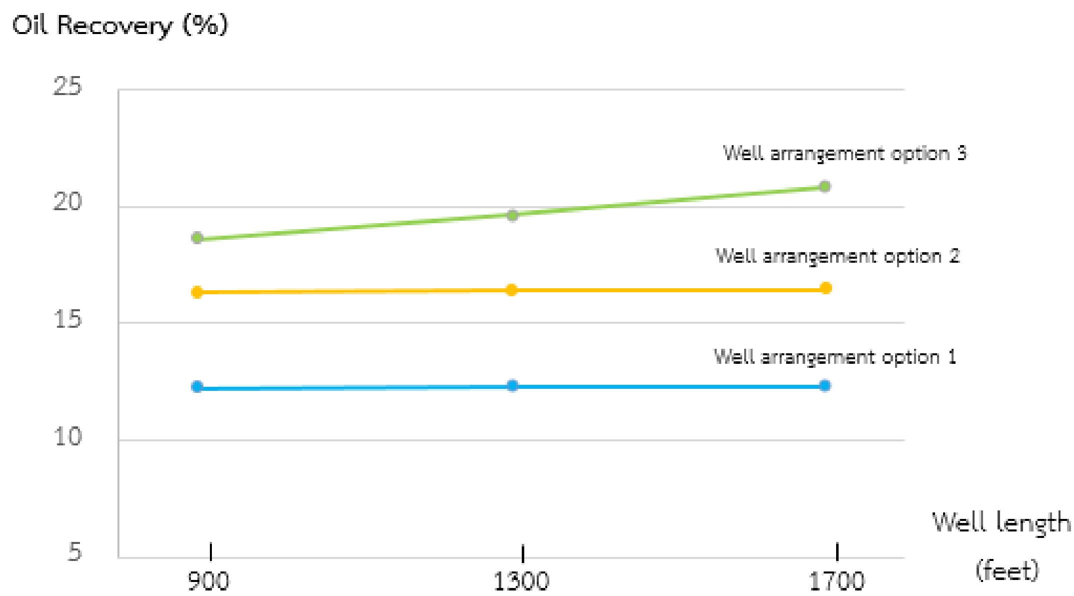


Figure 5.19 Oil recovery factor for different horizontal well length for vertical producer and horizontal dumper for strong aquifer (50 PV)

5.4 Effect of starting time for water dumping

Starting time for water dumping was evaluated in this study. Different scenarios were investigated as follows:

- Option I: At early stage, all wells are used to produce oil under natural depletion and then some of the wells is/are converted to dumping well(s) when reservoir pressure reaches bubble-point pressure. For the cases of well arrangement option 1, two wells are used as production wells at the beginning, and then one well is converted to be a dumper. For well arrangement option 2, three wells are used as production wells at the beginning, and then two wells are converted to dumping wells. For well arrangement option 3, five wells are used as production wells at the beginning, and then three wells are converted to dumping wells.
- Option II: A certain number of well(s) is/are used to produce oil at an early stage. When reservoir pressure reaches bubble-point pressure, more well(s) is/are drilled for dumping. For the cases of well arrangement option 1, one well is used to produce oil at the beginning. When reservoir pressure drops to

bubble-point pressure, another well is drilled for dumping. For well arrangement option 2, one well is used to production well at the beginning. When reservoir pressure drops to bubble-point pressure, two wells are drilled for dumping. For well arrangement option 3, two wells are used as producers at the beginning. When reservoir pressure reaches bubble-point pressure, three wells are drilled for dumping.

- Option III: Water dumpflood is started at the same time when the production well(s) start(s) producing.

5.4.1 Effect of starting time for water dumping for horizontal producer and horizontal dumper

As summarized in Table 5.7 to Table 5.12 and illustrated in Figure 5.20 to Figure 5.31, oil recovery factors for the three options of starting time are almost the same for all cases of horizontal well length, well arrangement, and aquifer size. However, water production in Option 3 of starting time for dumpflood is higher than those of the other two options in all cases when the well arrangement is option 3. In addition, Option 3 of starting time for dumpflood also yields less gas production when the well arrangement is option 3. Therefore, water dumpflood should not be started at the beginning when the well arrangement is option 3 of starting time for dumpflood to avoid excessive water production as a result of early water breakthrough. For well arrangement option 1, Option 1 of starting time for dumpflood can yield the highest oil production and small amount of water production. For well arrangement option 2, either Option 1 or Option 3 of starting time for dumpflood can be used. For instance, in case of 1700 ft horizontal producer and horizontal dumper, oil production in Option 3 of starting time for dumpflood is 1.967 MMSTB while oil production in Option 1 of starting time for dumpflood is 1.940 MMSTB. However, production time in Option 1 of starting time for dumpflood takes 10 months shorter than in Option 3 of starting time for dumpflood. For well arrangement option 3, either Option 1 or Option 2 of starting time for dumpflood can be used depending on the economic analysis or operation constraints. If Option 1 of starting time for dumpflood is implemented, initial oil rate is high as all wells are designated as producers at the beginning, generating early cash income. However, it incurs the cost of drilling all wells at the same time. If Option 2 of starting time for dumpflood is chosen, oil production is delayed as well as the well cost.

Table 5.7 Results for different starting times for water dumping for horizontal producer and horizontal dumper with 1700-ft horizontal well length for intermediate aquifer (10PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	1.345	1.020	432.46	16.52	20.0
	Option 2	1.314	1.021	421.15	16.15	20.0
	Option 3	1.315	1.021	421.18	16.16	20.0
Option 2	Option 1	1.940	1.274	1024.18	23.84	18.9
	Option 2	1.939	1.282	1022.29	23.82	19.2
	Option 3	1.967	1.300	1018.50	24.17	19.7
Option 3	Option 1	2.196	33.275	1024.21	26.97	8.7
	Option 2	2.191	32.057	1023.00	26.92	8.7
	Option 3	2.207	76.839	971.40	27.11	8.3

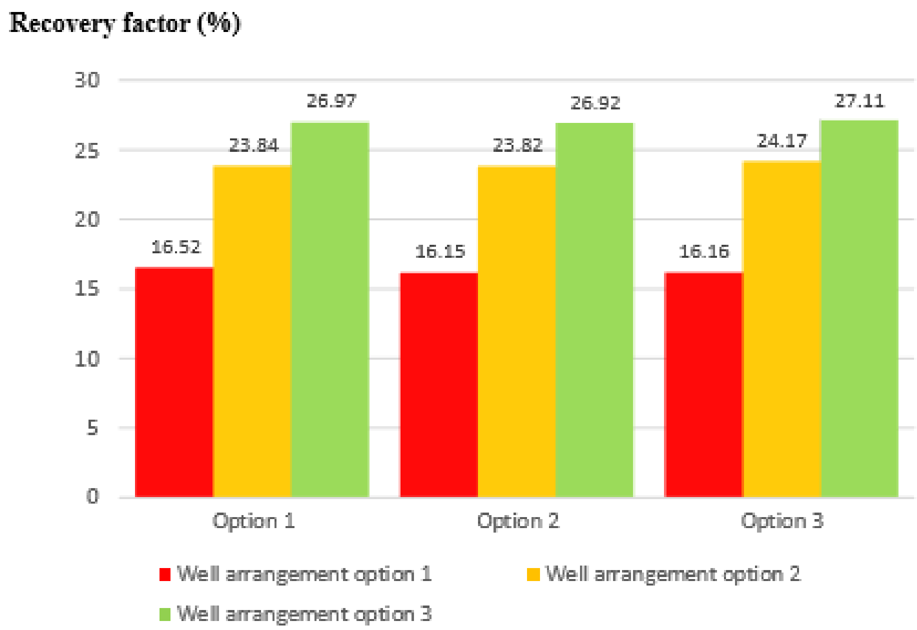


Figure 5.20 Oil recovery factor for different starting times for water dumping for horizontal producer and horizontal dumper with well length of 1700 ft for intermediate aquifer (10PV)

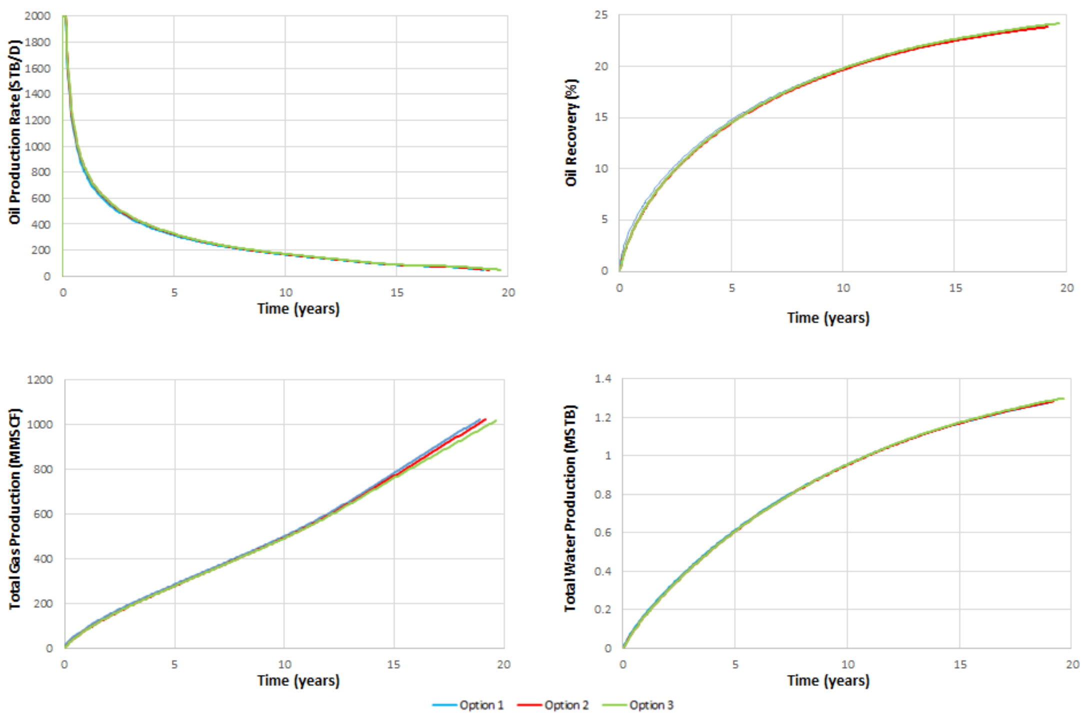


Figure 5.21 Production performance for different starting times in case of 1700-foot horizontal producer and horizontal dumpers with well arrangement option 2 for the case of intermediate aquifer (10PV)

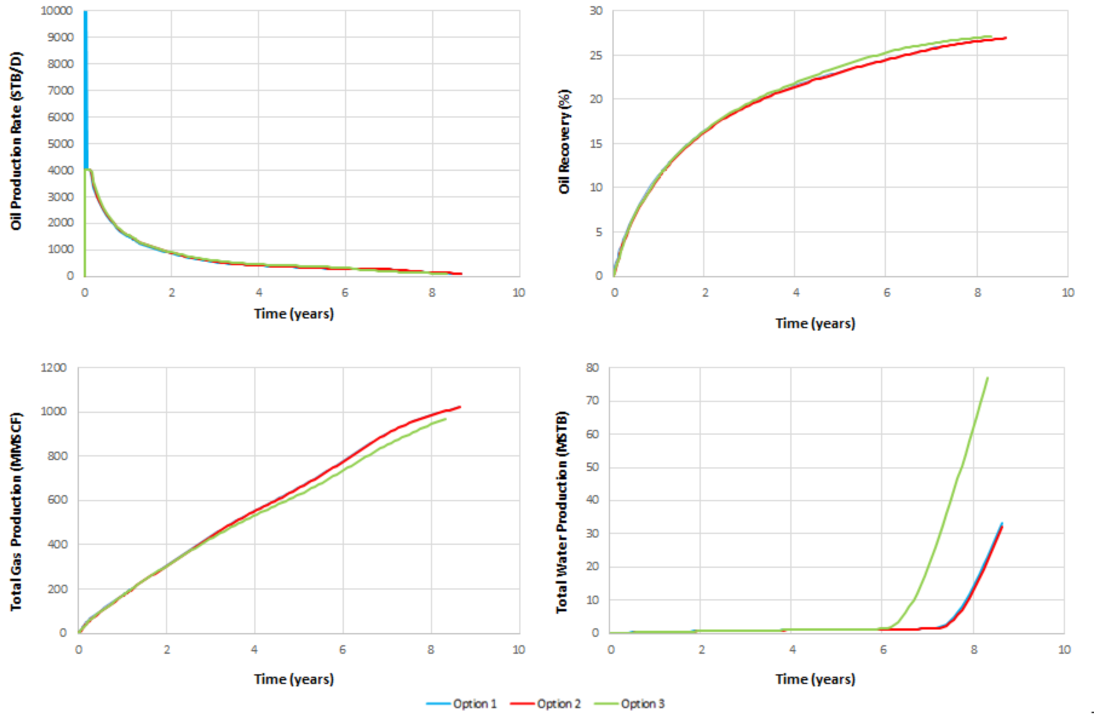


Figure 5.22 Production performance for different starting times in case of 1700-foot horizontal producers and horizontal dumpers with well arrangement option 3 for the case of intermediate aquifer (10PV)

Table 5.8 Results for different starting times for water dumping for horizontal producer and horizontal dumper with 1700-ft horizontal well length for strong aquifer (50PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	1.532	1.122	401.58	18.82	20.0
	Option 2	1.488	1.115	390.02	18.27	20.0
	Option 3	1.488	1.115	390.15	18.27	20.0
Option 2	Option 1	2.565	1.475	673.30	31.50	20.0
	Option 2	2.552	1.472	671.13	31.35	20.0
	Option 3	2.599	1.486	662.33	31.93	20.0
Option 3	Option 1	2.517	600.125	702.08	30.92	9.1
	Option 2	2.516	606.469	704.15	30.91	9.1
	Option 3	2.537	765.316	694.26	31.17	9.4

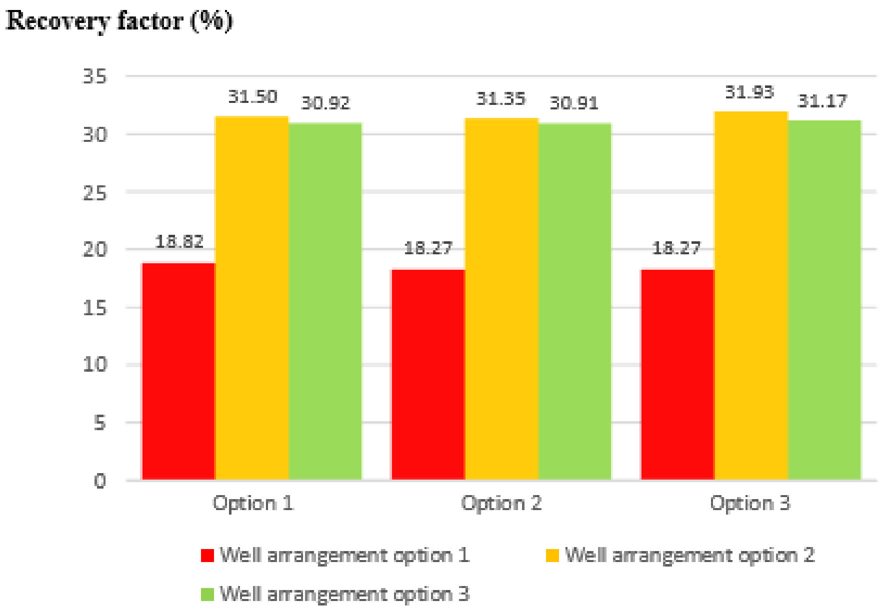


Figure 5.23 Oil recovery factor for different starting times for water dumping for horizontal producer and horizontal dumper with well length of 1700 ft for strong aquifer (50PV)

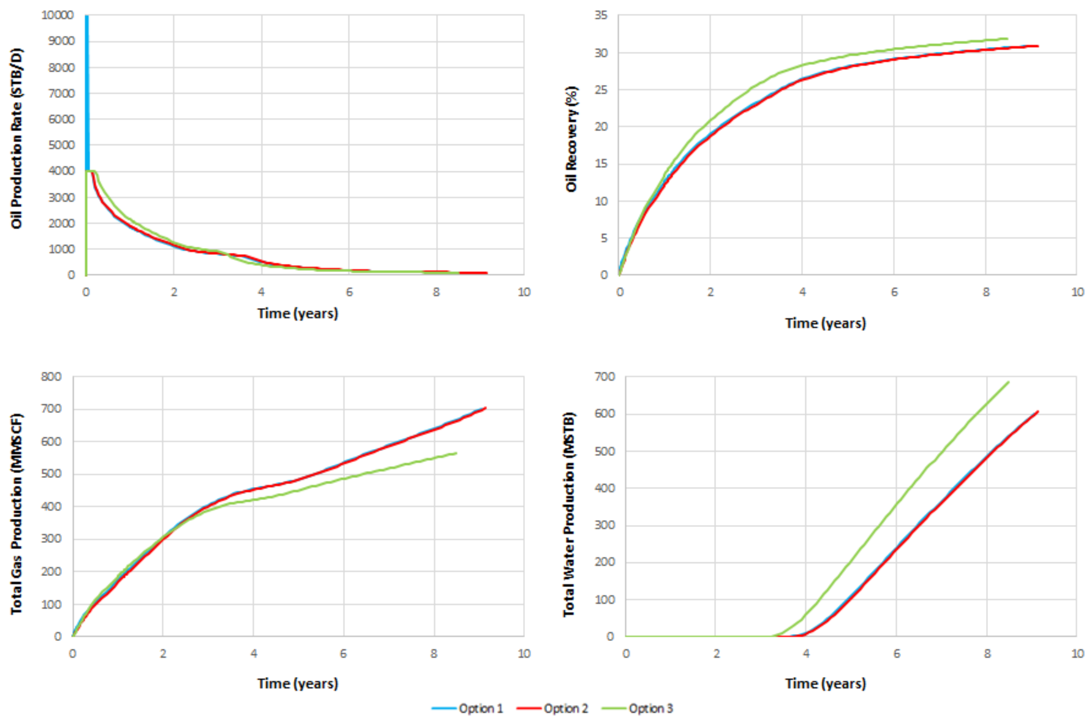


Figure 5.24 Production performance for different starting times in case of 1700-foot horizontal producers and horizontal dumpers with well arrangement option 3 for the case of strong aquifer (50PV)

Table 5.9 Results for different starting times for water dumping for horizontal producer and horizontal dumper with 1300-ft horizontal well length for intermediate aquifer (10PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	1.307	0.908	399.50	16.06	20.0
	Option 2	1.280	0.902	389.53	15.73	20.0
	Option 3	1.287	0.904	388.74	15.81	20.0
Option 2	Option 1	1.928	1.125	954.90	23.69	20.0
	Option 2	1.922	1.122	935.63	23.61	20.0
	Option 3	1.939	1.127	909.26	23.81	20.0
Option 3	Option 1	2.098	81.402	897.90	25.78	8.9
	Option 2	2.094	85.043	890.89	25.73	8.9
	Option 3	2.124	106.66	884.19	26.09	9.1

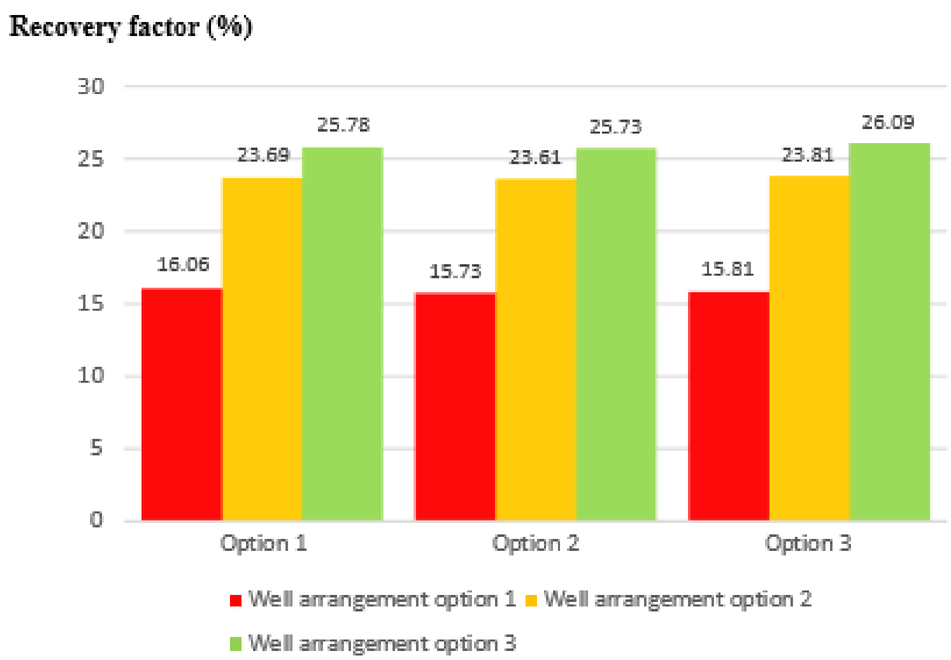


Figure 5.25 Oil recovery factor for different starting times for water dumping for horizontal producer and horizontal dumper with well length of 1300 ft for intermediate aquifer (10PV)

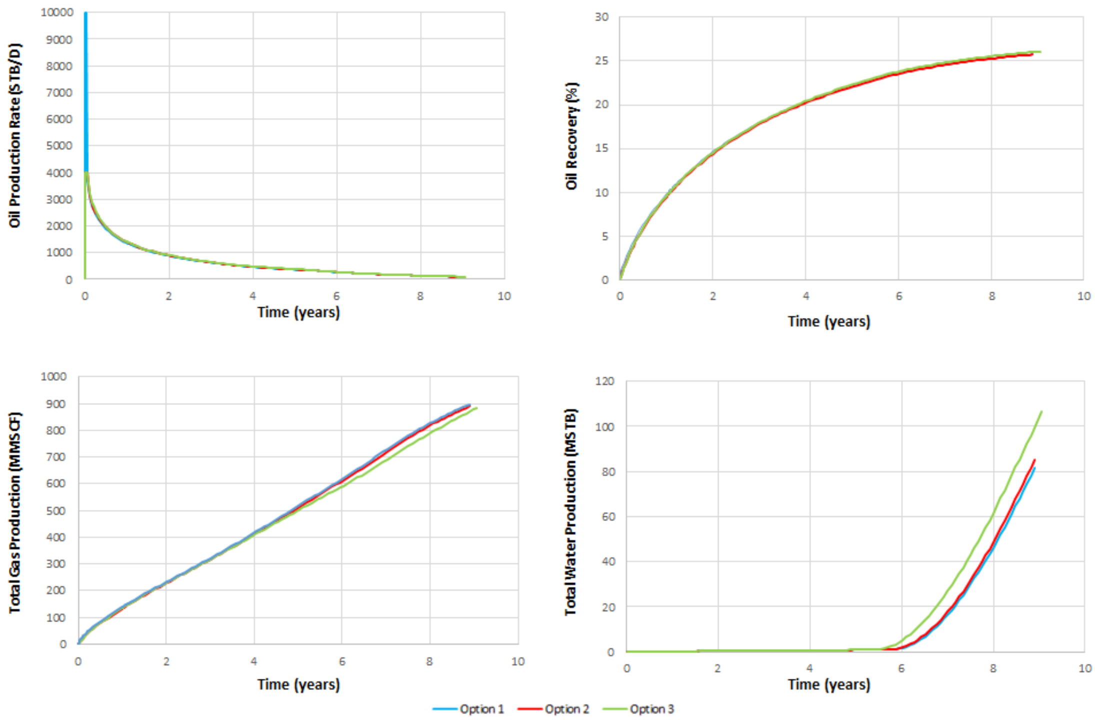


Figure 5.26 Production performance for different starting times in case of 1300-foot horizontal producers and horizontal dumpers with well arrangement option 3 for the case of intermediate aquifer (10PV)

Table 5.10 Results for different starting times for water dumping for horizontal producer and horizontal dumper with 1300-ft horizontal well length for strong aquifer (50PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Producti on time (years)
Option 1	Option 1	1.489	0.990	368.99	18.28	20.0
	Option 2	1.448	0.978	358.83	17.79	20.0
	Option 3	1.449	0.977	359.18	17.80	20.0
Option 2	Option 1	2.487	1.297	629.69	30.55	20.0
	Option 2	2.476	1.289	628.07	30.41	20.0
	Option 3	2.519	1.299	619.79	30.95	20.0
Option 3	Option 1	2.421	744.845	656.04	29.74	10.6
	Option 2	2.421	750.353	655.87	29.74	10.7
	Option 3	2.428	832.632	638.13	29.82	10.7

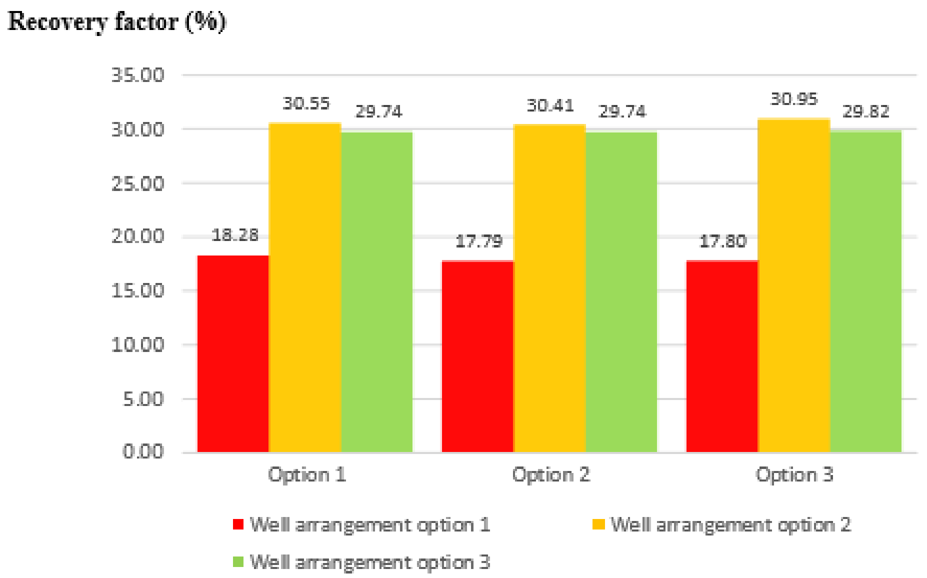


Figure 5.27 Oil recovery factor for different starting times for water dumping for horizontal producer and horizontal dumper with well length of 1300 ft for strong aquifer (50PV)

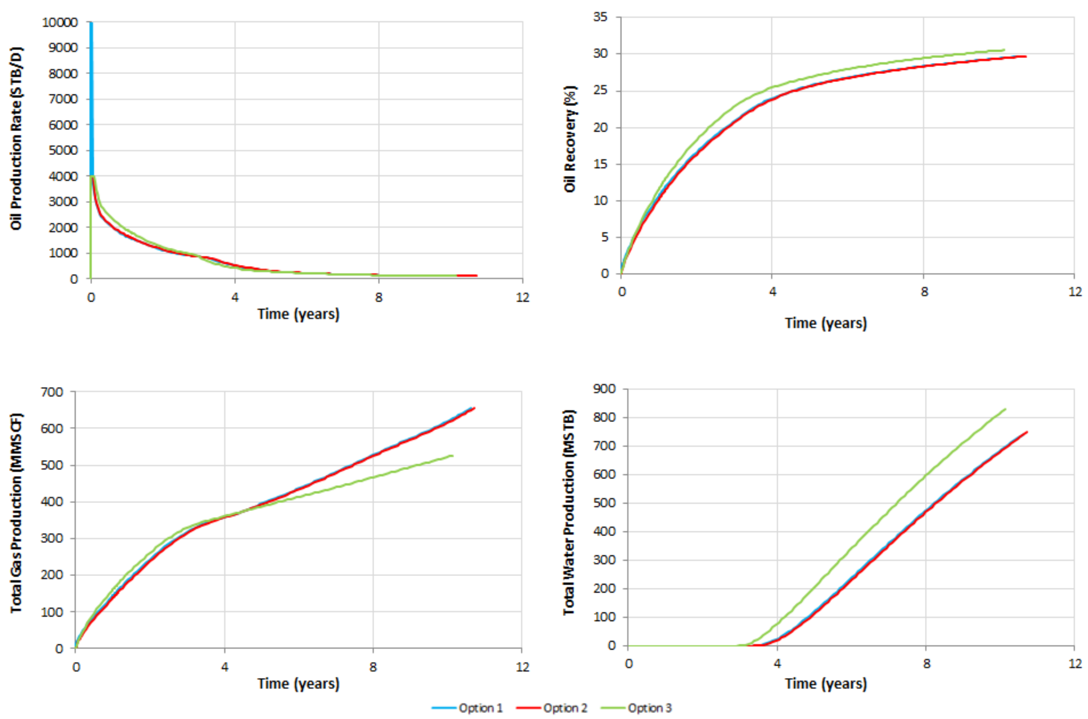


Figure 5.28 Production performance for different starting times in case of 1300-foot horizontal producers and horizontal dumpers with well arrangement option 3 for the case of strong aquifer (50PV)

Table 5.11 Results for different starting times for water dumping for horizontal producer and horizontal dumper with 900-ft horizontal well length for intermediate aquifer (10PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	1.250	0.745	338.70	15.36	20.0
	Option 2	1.228	0.734	330.90	15.08	20.0
	Option 3	1.229	0.734	331.19	15.10	20.0
Option 2	Option 1	1.843	0.890	684.79	22.64	20.0
	Option 2	1.835	0.880	672.31	22.54	20.0
	Option 3	1.848	0.882	661.89	22.71	20.0
Option 3	Option 1	1.997	43.591	756.11	24.53	9.9
	Option 2	1.988	53.871	738.95	24.43	9.9
	Option 3	1.995	127.638	725.24	24.51	10.3

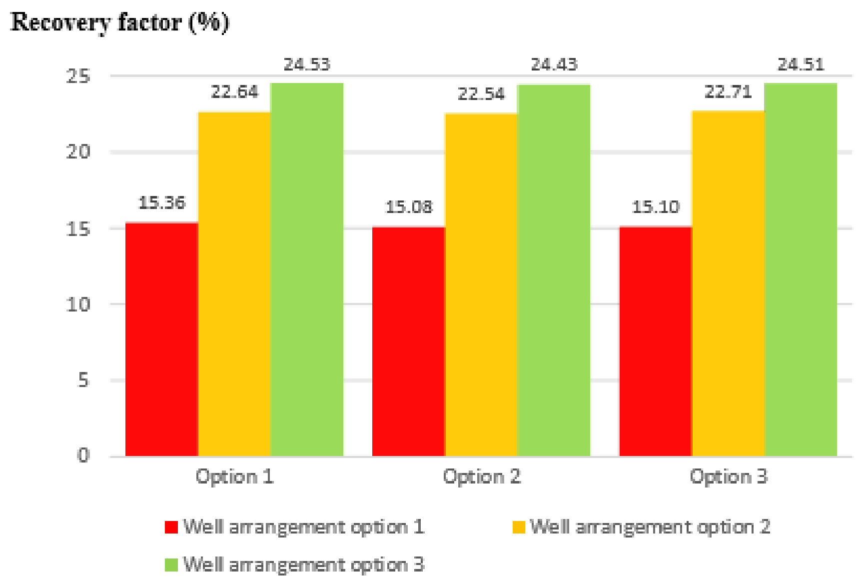


Figure 5.29 Oil recovery factor for different starting times for water dumping for horizontal producer and horizontal dumper with well length of 900 ft for intermediate aquifer (10PV)

Table 5.12 Results for different starting times for water dumping for horizontal producer and horizontal dumper with 900-ft horizontal well length for strong aquifer (50PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Producti on time (years)
Option 1	Option 1	1.397	0.790	311.80	17.16	20.0
	Option 2	1.369	0.778	304.60	16.81	20.0
	Option 3	1.370	0.777	305.12	16.82	20.0
Option 2	Option 1	2.300	0.955	516.38	28.25	20.0
	Option 2	2.290	0.943	513.96	28.13	20.0
	Option 3	2.326	0.946	508.83	28.57	20.0
Option 3	Option 1	2.196	718.168	523.25	26.98	11.9
	Option 2	2.206	810.471	514.75	27.10	12.2
	Option 3	2.216	868.034	517.25	27.22	12.5

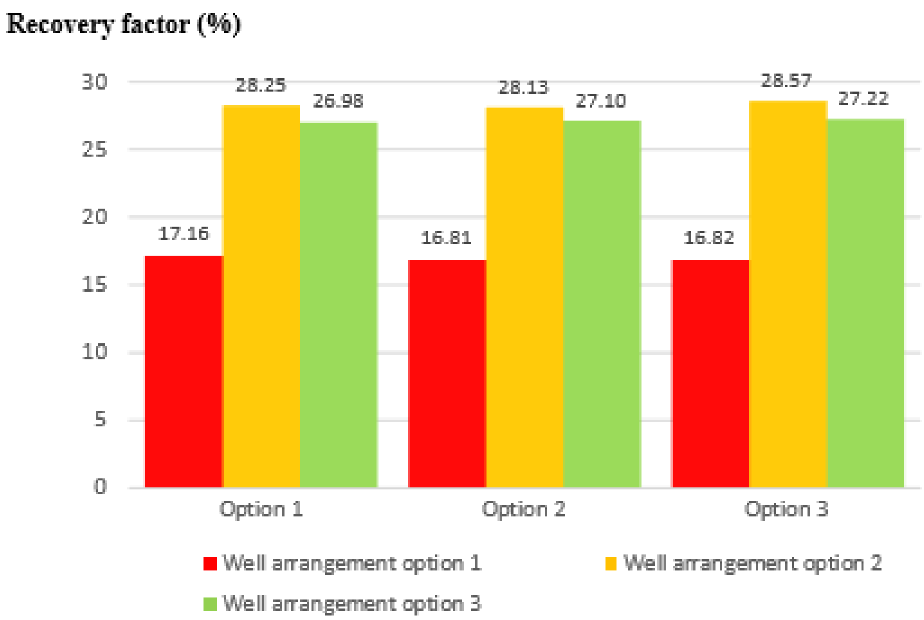


Figure 5.30 Oil recovery factor for different starting times for water dumping for horizontal producer and horizontal dumper with well length of 900 ft for strong aquifer (50PV)

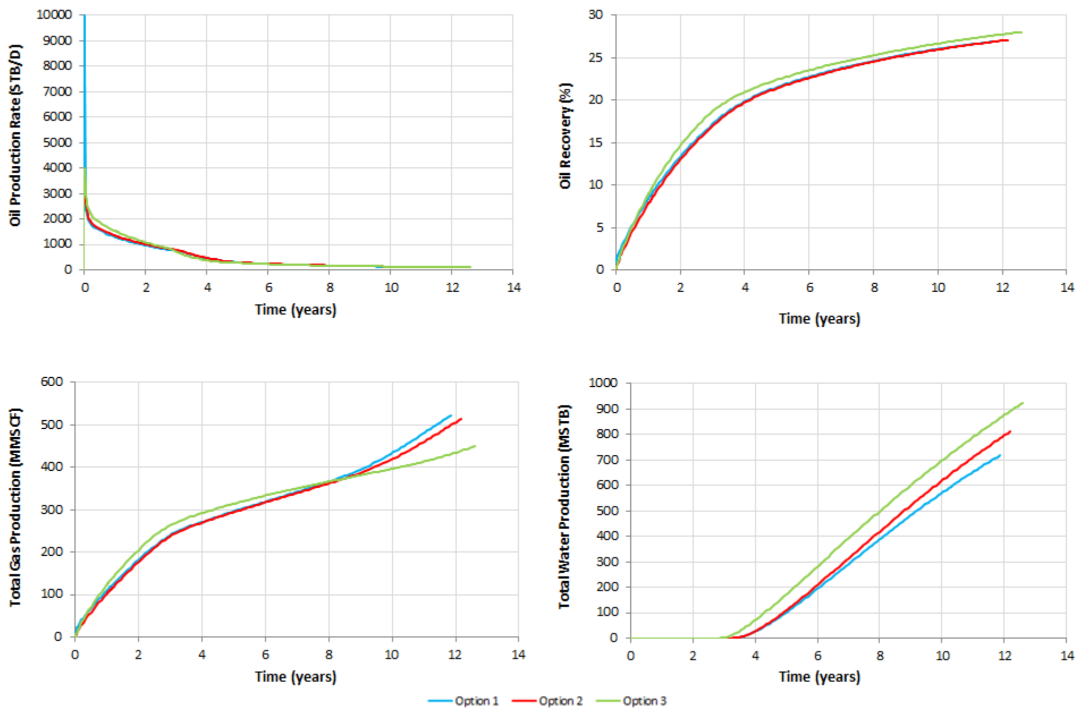


Figure 5.31 Production performance for different starting times in case of 900-foot horizontal producers and horizontal dumpers with well arrangement option 3 for the case of strong aquifer (50PV)

5.4.2 Effect of starting time for water dumping for horizontal producer and vertical dumper

As summarized in Table 5.13 to Table 5.17 and shown in Figure 5.32 to Figure 5.41, starting time of water dumpflood does not have a significant effect on oil production. However, water production in Option 1 of starting time for dumpflood is always the lowest among the three options when the well arrangement is Option 3. For other options of well arrangement, there is no significant difference in water production. Similar to oil recovery, there is no distinctive difference among the three options of starting time for gas production. Option 3 of starting time for dumpflood is recommended in well arrangement options 1 and 2 for strong aquifer due to high oil production and small amount of water production. For intermediate aquifer in well arrangement options 1 and 2, Option 1 of starting time for dumpflood is used except the case of 1700 ft horizontal producer and vertical dumper which Option 3 of starting time for dumpflood is recommended.

Table 5.13 Results for different starting times for water dumping for horizontal producer and vertical dumper with 1700-ft horizontal well length for intermediate aquifer (10PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	1.300	1.012	419.30	15.97	20.0
	Option 2	1.298	1.016	418.02	15.95	20.0
	Option 3	1.303	1.018	416.72	16.01	20.0
Option 2	Option 1	1.912	1.272	1025.73	23.49	18.4
	Option 2	1.919	1.279	1032.32	23.57	18.7
	Option 3	2.097	1.133	796.83	25.63	18.9
Option 3	Option 1	2.015	18.608	1086.68	24.75	8.6
	Option 2	2.034	25.221	1078.49	24.98	8.6
	Option 3	2.034	25.886	1079.11	24.98	8.6

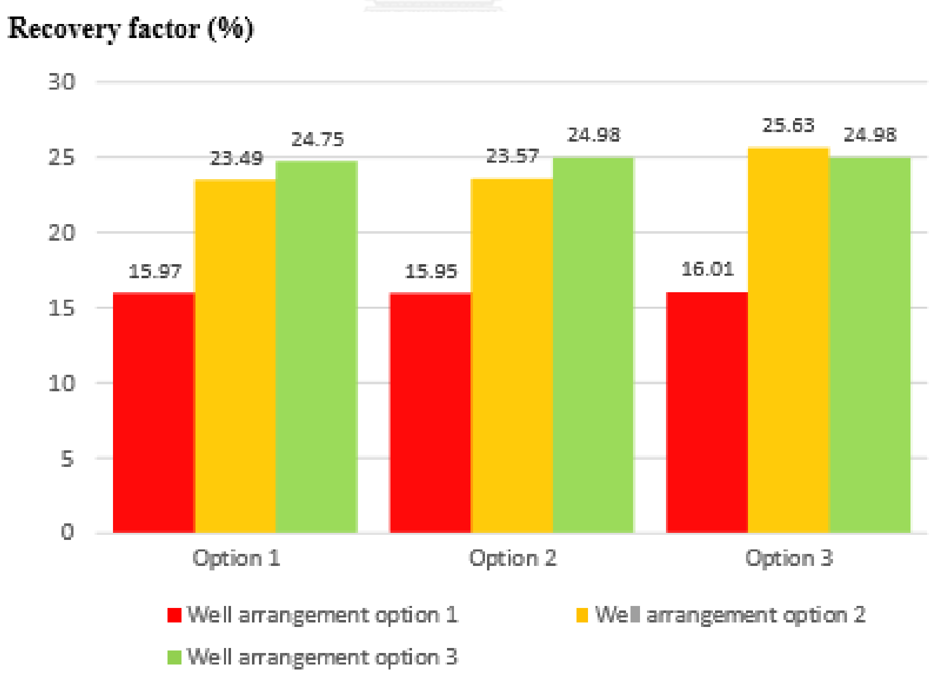


Figure 5.32 Oil recovery factor for different starting times for water dumping for horizontal producer and vertical dumper with well length of 1700 ft for intermediate aquifer (10PV)

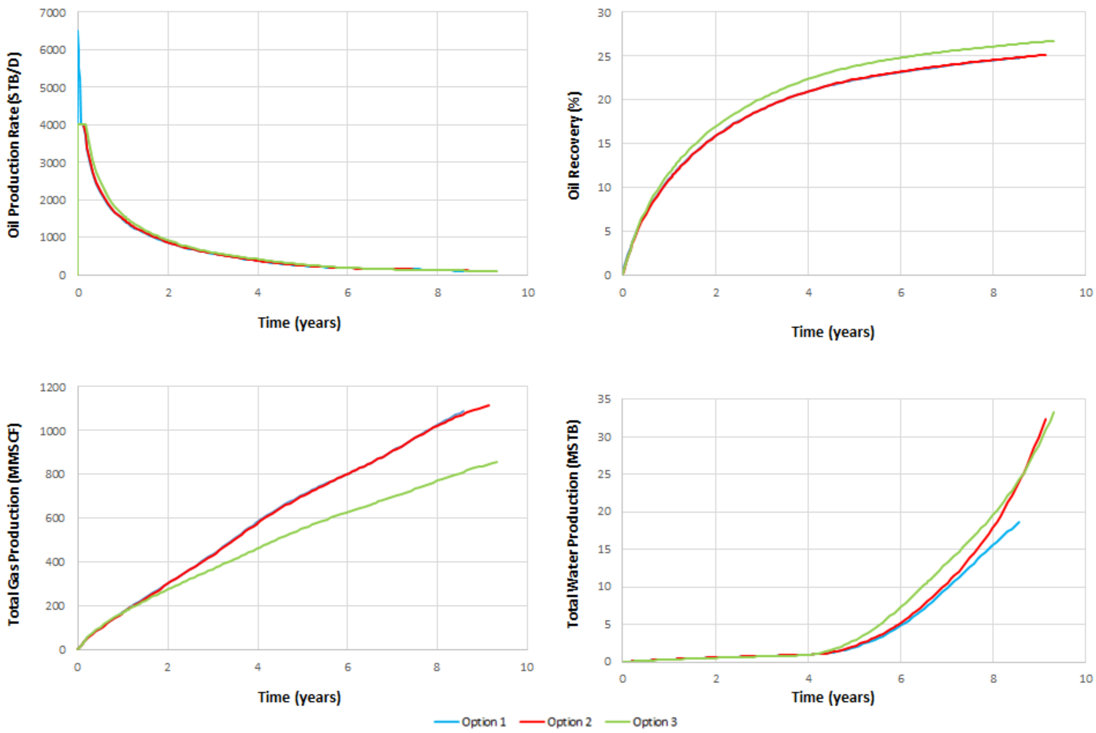


Figure 5.33 Production performance for different starting times in case of 1700-foot horizontal producers and vertical dumpers with well arrangement option 3 for the case of intermediate aquifer (10PV)

Table 5.14 Results for different starting times for water dumping for horizontal producer and vertical dumper with 1700-ft horizontal well length for strong aquifer (50PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	1.407	1.076	384.92	17.28	20.0
	Option 2	1.413	1.083	382.95	17.35	20.0
	Option 3	1.418	1.086	381.41	17.42	20.0
Option 2	Option 1	2.446	1.562	669.25	30.04	20.0
	Option 2	2.469	1.569	667.32	30.33	20.0
	Option 3	2.506	1.584	657.12	30.78	20.0
Option 3	Option 1	2.506	683.335	906.52	30.79	11.1
	Option 2	2.516	725.046	892.38	30.91	11.0
	Option 3	2.510	729.399	894.13	30.90	11.0

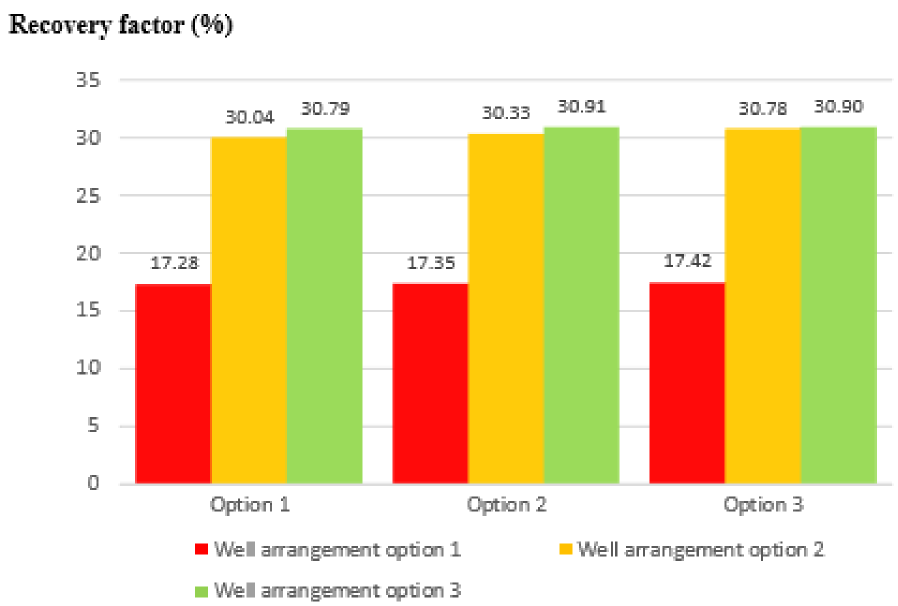


Figure 5.34 Oil recovery factor for different starting times for water dumping for horizontal producer and vertical dumper with well length of 1700 ft for strong aquifer (50PV

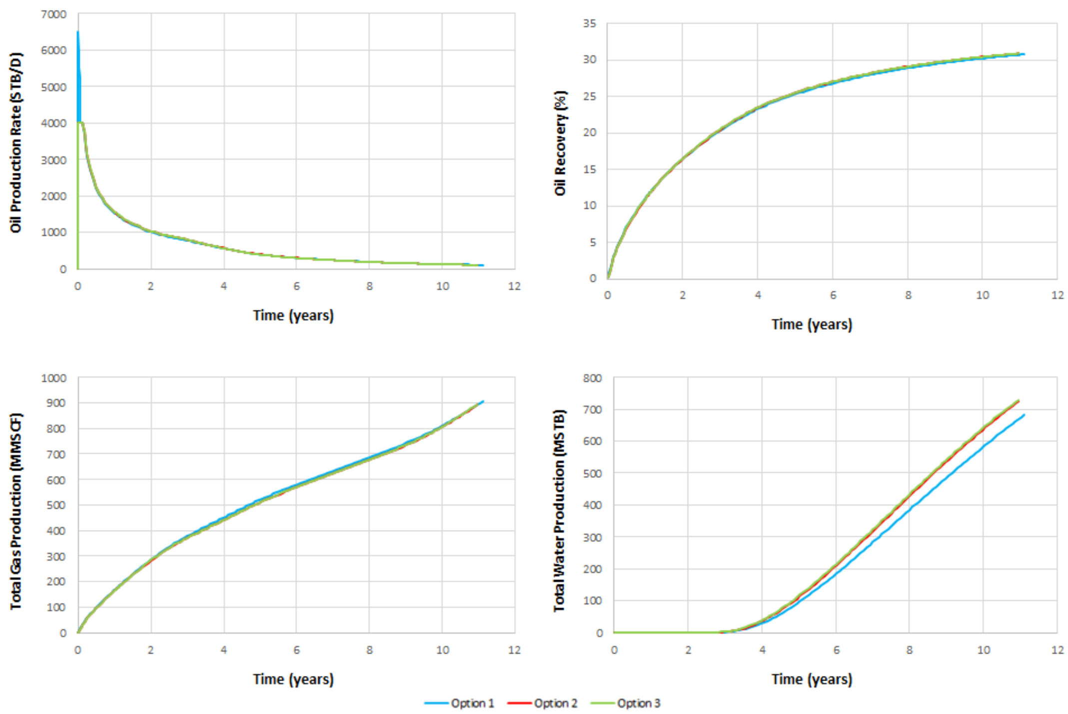


Figure 5.35 Production performance for different starting times in case of 1700-foot horizontal producers and vertical dumpers with well arrangement option 3 for the case of strong aquifer (50PV)

Table 5.15 Results for different starting times for water dumping for horizontal producer and vertical dumper with 1300-ft horizontal well length for intermediate aquifer (10PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	1.277	0.901	386.03	15.69	20.0
	Option 2	1.275	0.903	384.50	15.66	20.0
	Option 3	1.275	0.903	384.66	15.67	20.0
Option 2	Option 1	1.911	1.129	974.94	23.48	20.0
	Option 2	1.913	1.129	963.23	23.50	20.0
	Option 3	1.928	1.135	941.60	23.69	20.0
Option 3	Option 1	1.998	34.228	1010.36	24.54	9.2
	Option 2	2.013	46.602	1003.58	24.72	9.2
	Option 3	2.012	47.509	1004.07	24.72	9.2

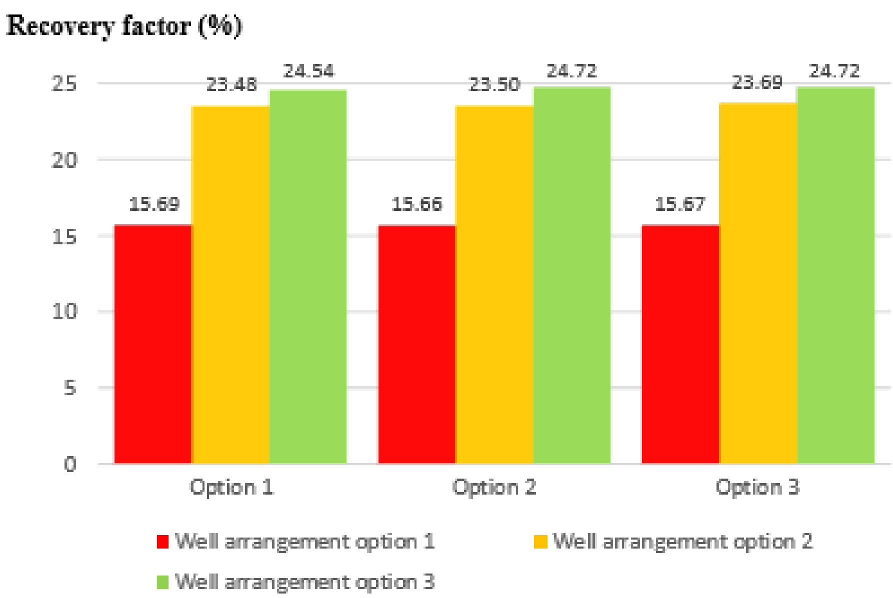


Figure 5.36 Oil recovery factor for different starting times for water dumping for horizontal producer and vertical dumper with well length of 1300 ft for intermediate aquifer (10PV)

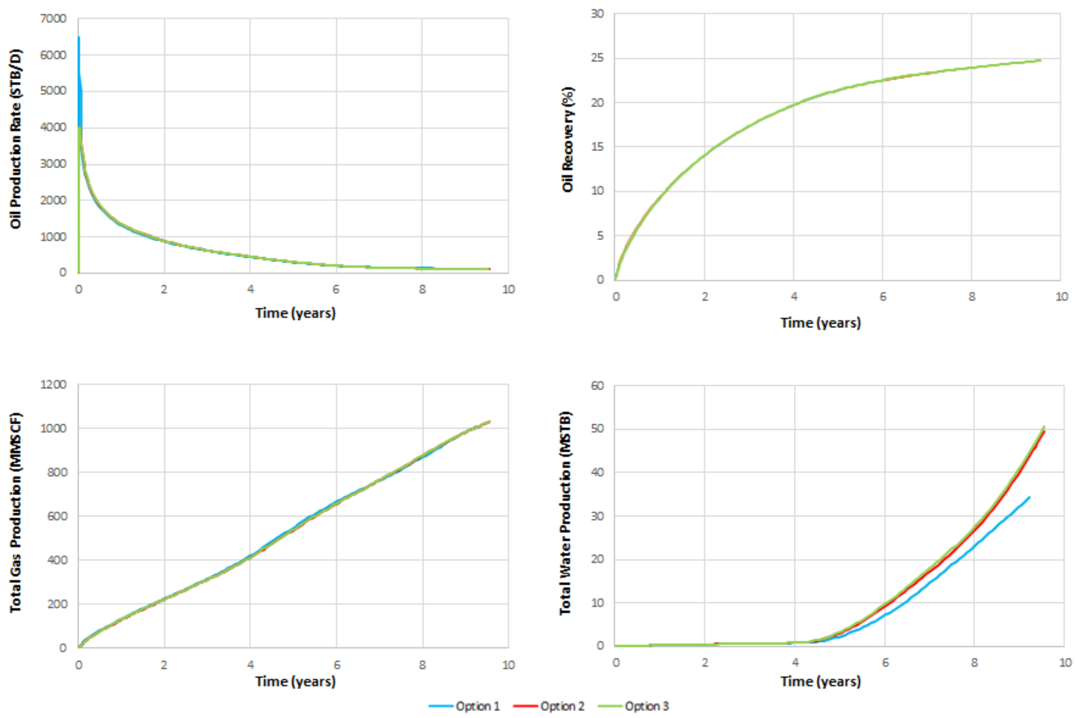


Figure 5.37 Production performance for different starting times in case of 1300-foot horizontal producers and vertical dumpers with well arrangement option 3 for the case of intermediate aquifer (10PV)

Table 5.16 Results for different starting times for water dumping for horizontal producer and vertical dumper with 1300-ft horizontal well length for strong aquifer (50PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	1.374	0.950	355.02	16.87	20.0
	Option 2	1.379	0.955	352.75	16.94	20.0
	Option 3	1.385	0.957	351.45	17.01	20.0
Option 2	Option 1	2.327	1.221	579.59	28.58	20.0
	Option 2	2.346	1.221	578.10	28.82	20.0
	Option 3	2.377	1.229	569.69	29.20	20.0
Option 3	Option 1	2.380	714.117	792.96	29.24	11.5
	Option 2	2.382	766.496	764.21	29.26	11.2
	Option 3	2.381	770.611	765.41	29.25	11.2

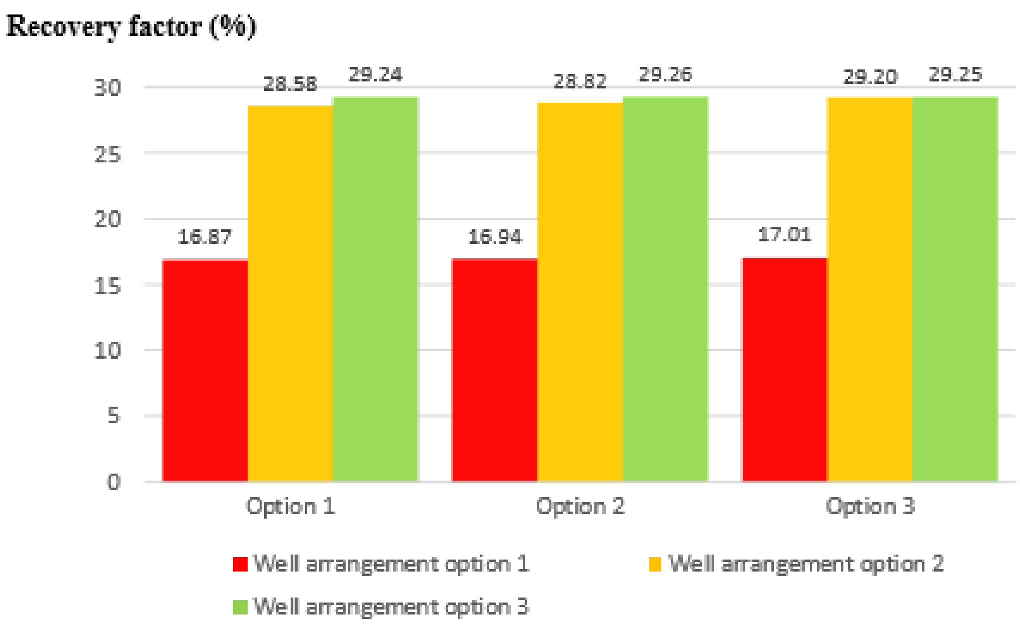


Figure 5.38 Oil recovery factor for different starting times for water dumping for horizontal producer and vertical dumper with well length of 1300 ft for strong aquifer (50PV)

Table 5.17 Results for different starting times for water dumping for horizontal producer and vertical dumper with 900-ft horizontal well length for intermediate aquifer (10PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Producti on time (years)
Option 1	Option 1	1.224	0.735	329.49	15.03	20.0
	Option 2	1.218	0.734	327.61	14.97	20.0
	Option 3	1.219	0.733	327.83	14.97	20.0
Option 2	Option 1	1.828	0.886	677.71	22.46	20.0
	Option 2	1.827	0.883	670.66	22.44	20.0
	Option 3	1.839	0.885	659.61	22.59	20.0
Option 3	Option 1	1.948	72.267	845.31	23.93	10.5
	Option 2	1.951	78.740	871.85	23.96	10.7
	Option 3	1.961	92.539	871.50	24.09	10.8

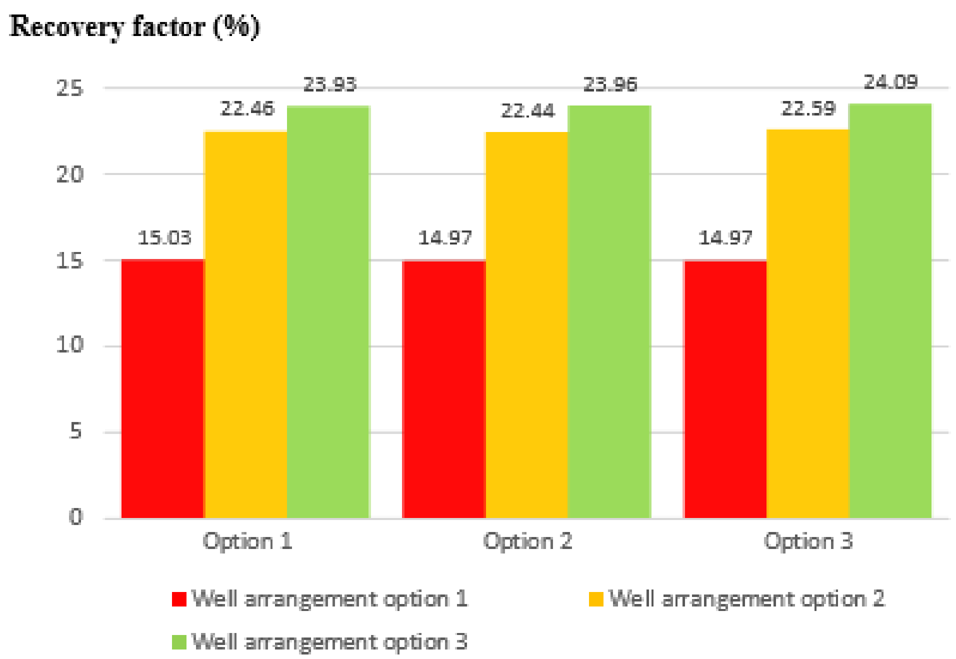


Figure 5.39 Oil recovery factor for different starting times for water dumping for horizontal producer and vertical dumper with well length of 900 ft for intermediate aquifer (10PV)

Table 5.18 Results for different starting times for water dumping for horizontal producer and vertical dumper with 900-ft horizontal well length for strong aquifer (50PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Producti on time (years)
Option 1	Option 1	1.317	0.768	302.04	16.17	20.0
	Option 2	1.318	0.769	299.31	16.19	20.0
	Option 3	1.320	0.769	299.66	16.21	20.0
Option 2	Option 1	2.229	0.963	484.81	27.38	20.0
	Option 2	2.244	0.960	484.49	27.57	20.0
	Option 3	2.246	0.959	484.82	27.58	20.0
Option 3	Option 1	2.183	684.936	556.80	26.82	11.9
	Option 2	2.195	765.134	557.59	26.97	12.2
	Option 3	2.194	768.777	558.22	26.95	12.2

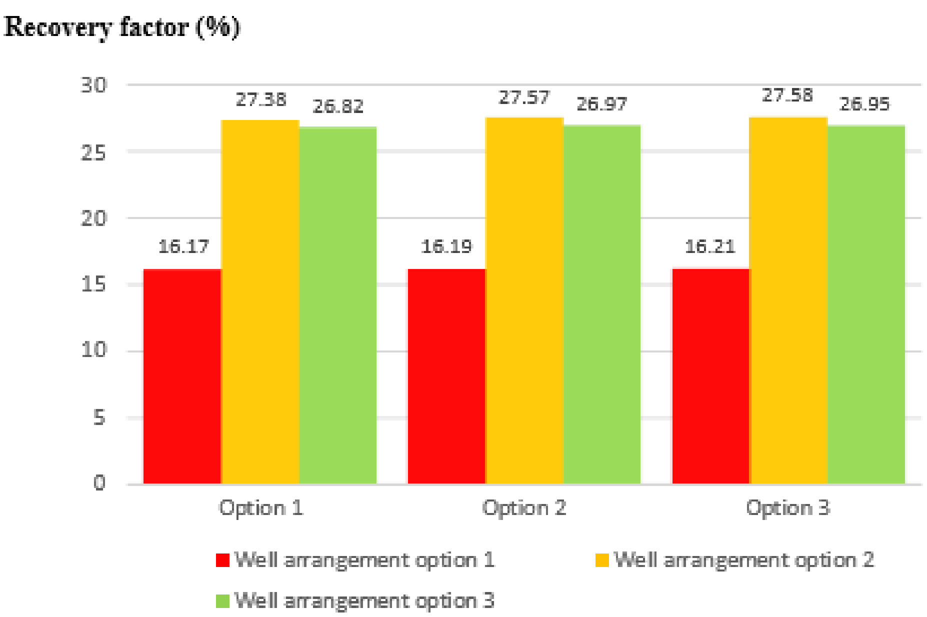


Figure 5.40 Oil recovery factor for different starting times for water dumping for horizontal producer and vertical dumper with well length of 900 ft for strong aquifer (50PV)

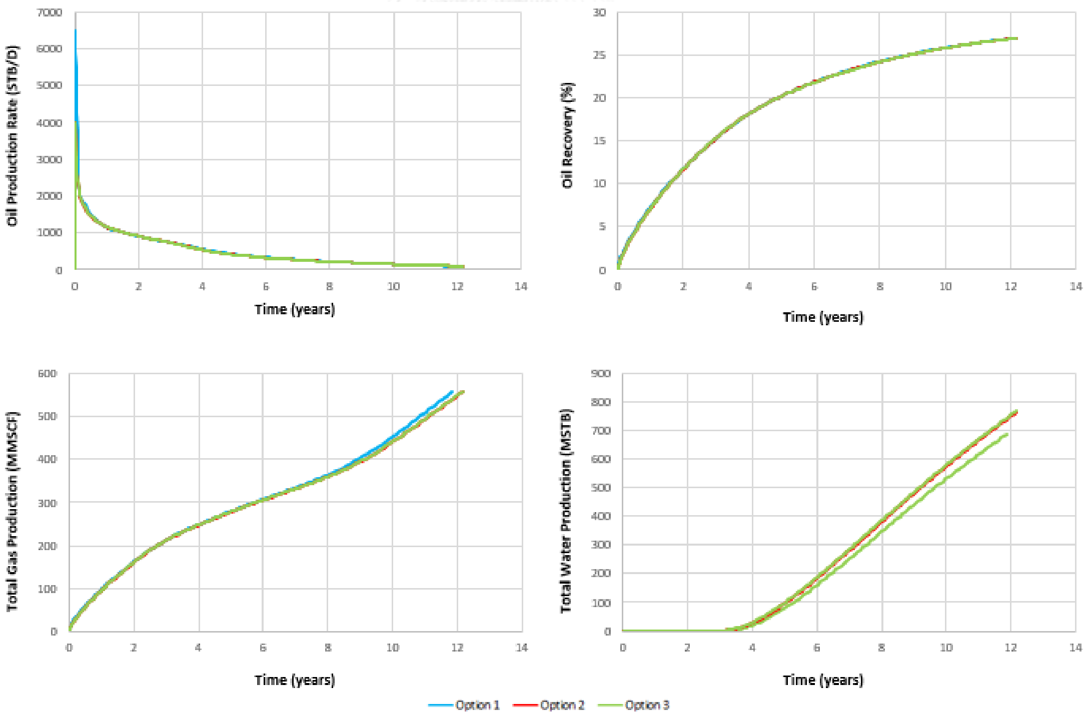


Figure 5.41 *Production performance for different starting times in case of 900-foot horizontal producers and vertical dumpers with well arrangement option 3 for the case of strong aquifer (50PV)*

5.4.3 Effect of starting time for water dumping for vertical producer and horizontal dumper

As summarized in Table 5.19 to Table 5.24 and shown in Figure 5.42 to Figure 5.47, all cases have similar oil production. However, Option 3 of starting time for dumpflood has slightly high water and gas productions when well spacing is 800 feet. For other well spacing, there is no substantial difference in water production. For gas production, there is no significant difference among the three options of starting time. In summary, Option 1 of starting time for dumpflood is recommended for intermediate aquifer due to higher oil production with small amount of water production while Option 3 of starting time for dumpflood is recommended for strong aquifer due to higher oil production with lower water production than the other two options.

Table 5.19 Results for different starting times for water dumping for vertical producer and horizontal dumper with 1700-ft horizontal well length for intermediate aquifer (10PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Producti on time (years)
Option 1	Option 1	0.891	0.241	144.95	10.95	20.0
	Option 2	0.824	0.199	133.66	10.12	20.0
	Option 3	0.826	0.199	134.20	10.15	20.0
Option 2	Option 1	1.032	0.219	164.58	12.67	20.0
	Option 2	0.966	0.187	156.67	11.87	20.0
	Option 3	1.040	0.175	172.96	12.78	20.0
Option 3	Option 1	1.473	42.565	238.16	18.10	16.7
	Option 2	1.450	45.857	156.67	17.81	16.9
	Option 3	1.443	46.712	235.55	17.72	16.8

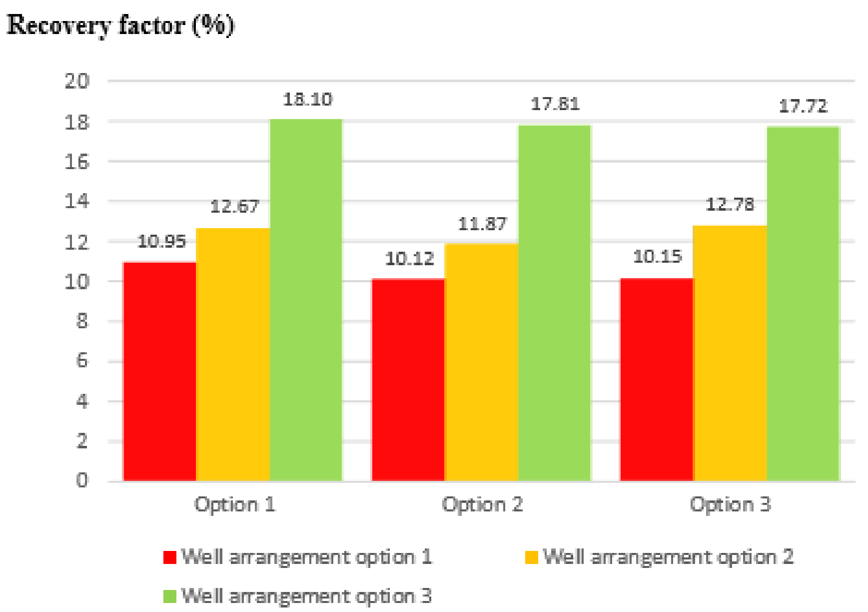


Figure 5.42 Oil recovery factor for different starting times for water dumping for vertical producer and horizontal dumper with well length of 1700 ft for intermediate aquifer (10PV)

Table 5.20 Results for different starting times for water dumping for vertical producer and horizontal dumper with 1700-ft horizontal well length for strong aquifer (50PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Producti on time (years)
Option 1	Option 1	0.977	0.227	158.16	12.00	20.0
	Option 2	0.895	0.188	144.80	10.99	20.0
	Option 3	1.006	0.181	172.87	12.29	20.0
Option 2	Option 1	1.283	0.174	219.79	15.76	20.0
	Option 2	1.210	0.145	212.19	14.86	20.0
	Option 3	1.344	0.142	246.66	16.42	20.0
Option 3	Option 1	1.679	163.874	289.92	20.63	17.7
	Option 2	1.667	165.430	289.85	20.47	18.0
	Option 3	1.700	175.236	310.99	20.78	16.7

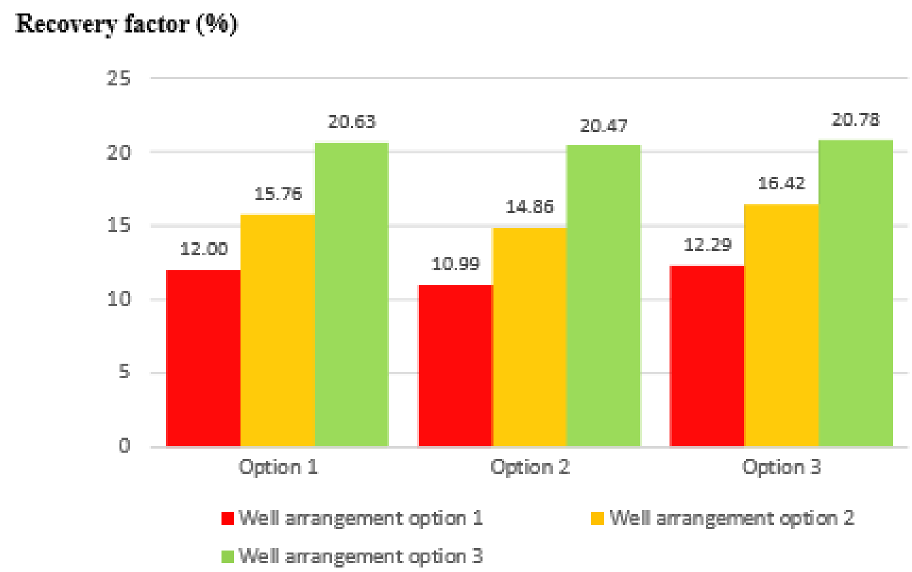


Figure 5.43 Oil recovery factor for different starting times for water dumping for vertical producer and horizontal dumper with well length of 1700 ft for strong aquifer (50PV)

Table 5.21 Results for different starting times for water dumping for vertical producer and horizontal dumper with 1300-ft horizontal well length for intermediate aquifer (10PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	0.881	0.237	143.02	10.82	20.0
	Option 2	0.821	0.200	133.19	10.09	20.0
	Option 3	0.826	0.199	134.13	10.14	20.0
Option 2	Option 1	1.076	0.196	175.53	13.22	20.0
	Option 2	1.033	0.176	171.02	12.69	20.0
	Option 3	1.039	0.175	172.74	12.77	20.0
Option 3	Option 1	1.431	37.382	230.93	17.57	16.1
	Option 2	1.401	40.969	228.69	17.21	16.3
	Option 3	1.415	46.649	231.09	17.38	16.4

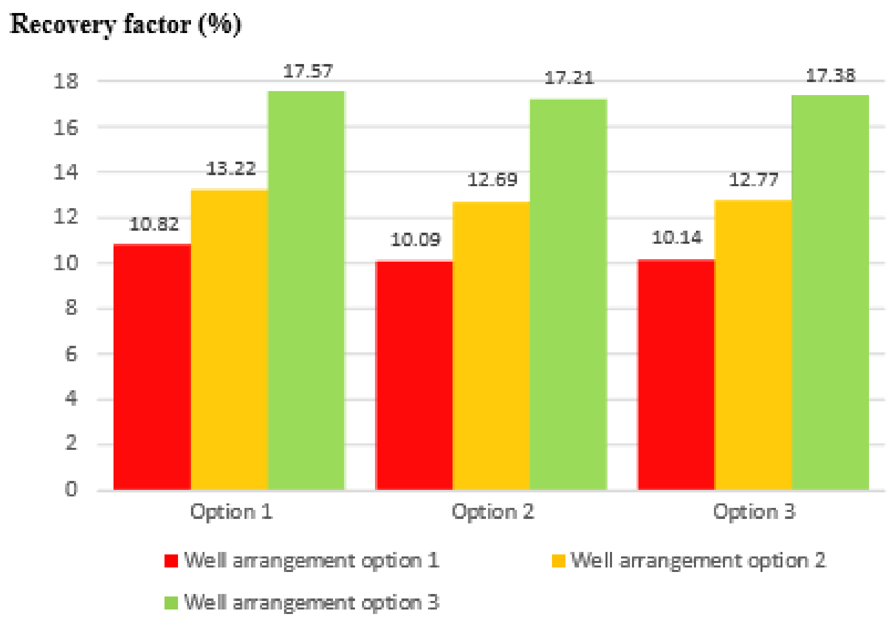


Figure 5.44 Oil recovery factor for different starting times for water dumping for vertical producer and horizontal dumper with well length of 1300 ft for intermediate aquifer (10PV)

Table 5.22 Results for different starting times for water dumping for vertical producer and horizontal dumper with 1300-ft horizontal well length for strong aquifer (50PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Producti on time (years)
Option 1	Option 1	0.967	0.223	156.44	11.87	20.0
	Option 2	0.893	0.188	144.44	10.98	20.0
	Option 3	1.004	0.181	172.41	12.26	20.0
Option 2	Option 1	1.275	0.181	218.78	15.66	20.0
	Option 2	1.208	0.145	211.62	14.84	20.0
	Option 3	1.341	0.143	246.03	16.38	20.0
Option 3	Option 1	1.567	152.585	270.82	19.24	16.0
	Option 2	1.578	162.834	275.71	19.39	16.8
	Option 3	1.606	172.168	294.91	19.63	15.5

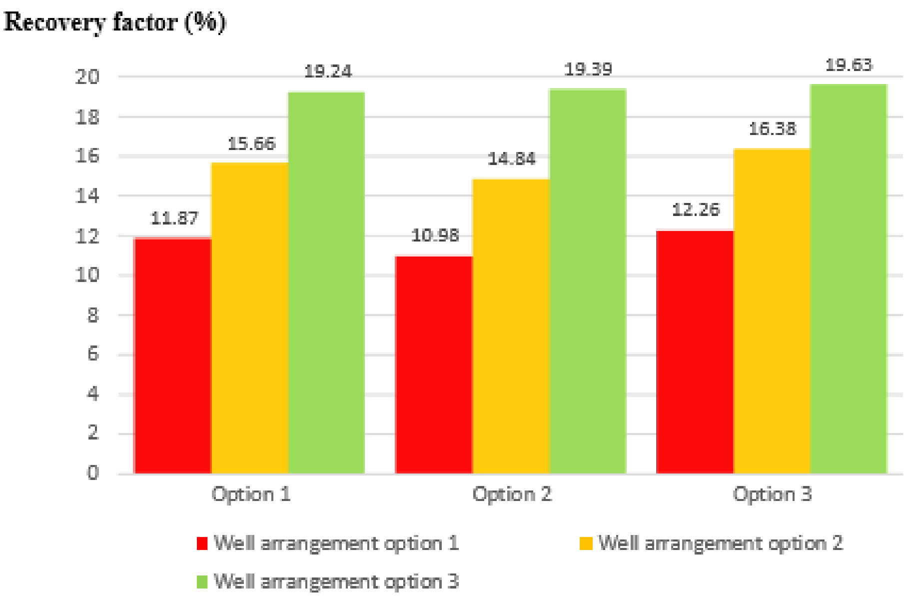


Figure 5.45 Oil recovery factor for different starting times for water dumping for vertical producer and horizontal dumper with well length of 1300 ft for strong aquifer (50PV)

Table 5.23 Results for different starting times for water dumping for vertical producer and horizontal dumper with 900-ft horizontal well length for intermediate aquifer (10PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	0.864	0.227	139.92	10.61	20.0
	Option 2	0.823	0.200	133.42	10.11	20.0
	Option 3	0.825	0.200	133.94	10.14	20.0
Option 2	Option 1	1.075	0.197	175.98	13.21	20.0
	Option 2	1.037	0.175	171.87	12.74	20.0
	Option 3	1.039	0.175	172.45	12.76	20.0
Option 3	Option 1	1.566	37.667	256.57	19.23	18.3
	Option 2	1.565	41.703	262.14	19.22	19.1
	Option 3	1.366	45.504	223.40	16.78	15.6

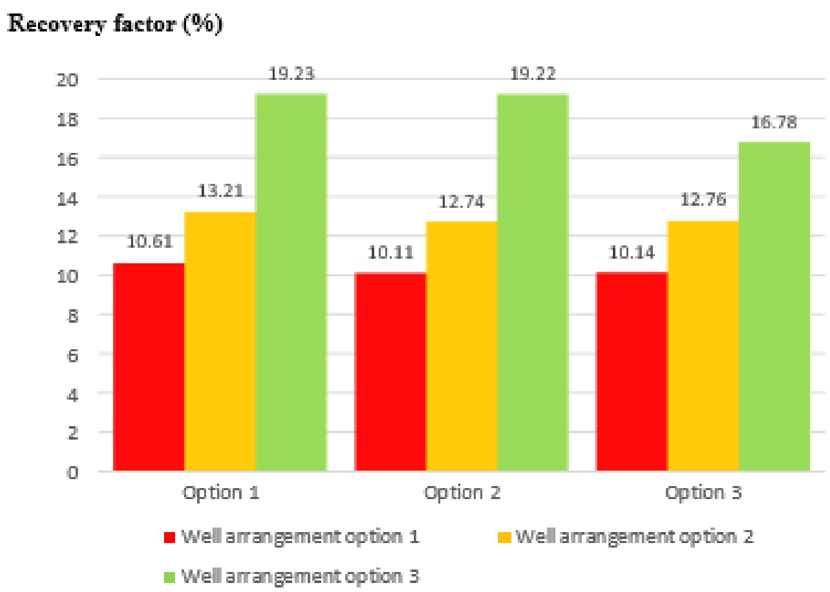


Figure 5.46 Oil recovery factor for different starting times for water dumping for vertical producer and horizontal dumper with well length of 900 ft for intermediate aquifer (10PV)

Table 5.24 Results for different starting times for water dumping for vertical producer and horizontal dumper with 900-ft horizontal well length for strong aquifer (50PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Producti on time (years)
Option 1	Option 1	0.942	0.215	151.90	11.57	20.0
	Option 2	0.890	0.189	143.63	10.93	20.0
	Option 3	0.999	0.181	171.40	12.21	20.0
Option 2	Option 1	1.267	0.179	217.69	15.56	20.0
	Option 2	1.206	0.145	211.02	14.81	20.0
	Option 3	1.339	0.143	245.40	16.35	20.0
Option 3	Option 1	1.500	155.168	259.91	18.43	15.3
	Option 2	1.501	158.605	263.30	18.44	15.8
	Option 3	1.521	164.291	280.27	18.59	14.4

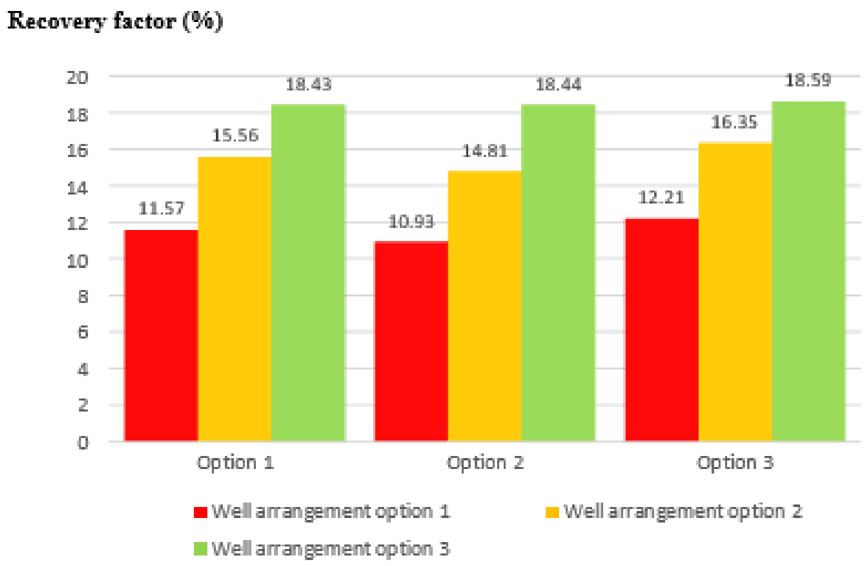


Figure 5.47 Oil recovery factor for different starting times for water dumping for vertical producer and horizontal dumper with well length of 900 ft for strong aquifer (50PV)

5.4.4 Effect of starting time for water dumping for vertical producer and vertical dumper

As summarized in Table 5.25 and Table 5.26 and shown in Figure 5.48 and Figure 5.49, there is small difference in oil recovery and gas production among the three options of starting time. Option 1 of starting time for dumpflood has slightly lower water production when well spacing is 800 feet. For other well spacing, there is no significant difference in water and gas productions. in summary, Option 1 of starting time for dumpflood is recommended that the cases provides the highest oil production with small amount of water production. In addition, production time in Option 3 of starting time for dumpflood takes shorter than the other two cases for well arrangement option 3.

Table 5.25 Results for different starting times for water dumping for vertical producer and vertical dumper for intermediate aquifer (10PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	0.832	0.209	133.99	10.22	20.0
	Option 2	0.817	0.201	131.81	10.03	20.0
	Option 3	0.818	0.201	132.17	10.05	20.0
Option 2	Option 1	1.042	0.183	170.60	12.80	20.0
	Option 2	1.027	0.176	169.51	12.62	20.0
	Option 3	1.033	0.175	170.78	12.69	20.0
Option 3	Option 1	1.409	36.763	228.15	17.30	17.2
	Option 2	1.392	38.929	226.90	17.10	17.2
	Option 3	1.389	40.217	226.71	17.07	17.2

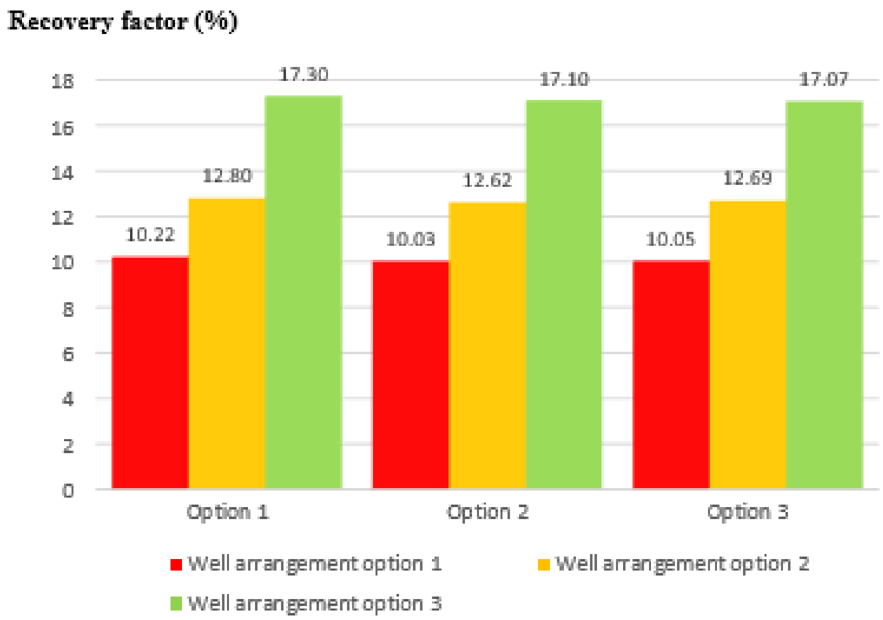


Figure 5.48 Oil recovery factor for different starting times for water dumping for vertical producer and vertical dumper for intermediate aquifer (10PV)

Table 5.26 Results for different starting times for water dumping for vertical producer and vertical dumper for strong aquifer (50PV)

Well arrangement	Staring time	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	Option 1	0.880	0.202	140.13	10.81	20.0
	Option 2	0.864	0.194	138.08	10.62	20.0
	Option 3	0.866	0.193	138.54	10.64	20.0
Option 2	Option 1	1.184	0.154	201.52	14.55	20.0
	Option 2	1.172	0.147	201.17	14.39	20.0
	Option 3	1.178	0.147	202.92	14.46	20.0
Option 3	Option 1	1.220	130.589	208.55	14.98	13.9
	Option 2	1.209	140.284	209.52	14.86	14.1
	Option 3	1.203	151.543	209.86	14.77	14.0

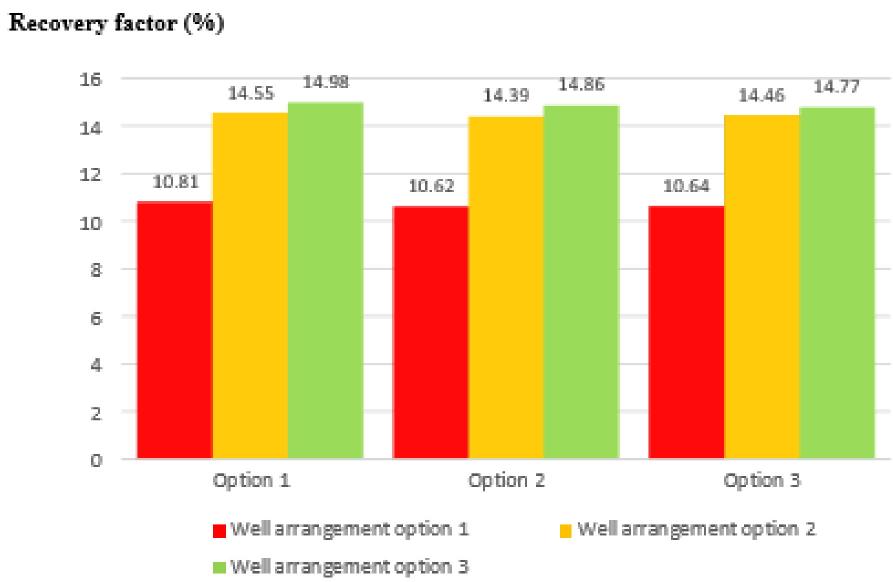


Figure 5.49 Oil recovery factor for different starting times for water dumping for vertical producer and vertical dumper for strong aquifer (50PV)

5.5 Comparison among natural depletion, conventional waterflood, and the best case of water dumpflood

5.5.1 Natural depletion

In order to evaluate the primary production performance of the oil reservoir for comparison purpose with water dumpflood, the following cases were investigated:

Option 1: Three vertical producers

Option 2: Three horizontal producers

Note that the length of horizontal well in this section is 1,700 ft which is the optimal length in the cases of water dumpflood.

The oil production rate is 2,000 STB/D. Abandonment condition is minimum oil rate is 50 STB/D and water cut is 0.95. Horizontal well is designed to long-radius which build rate of 5° per 100 feet.

As shown in Figure 5.50 and Table 5.27 for natural depletion, in general, oil and gas recovery from horizontal producers are higher than the vertical producers. The horizontal producers can increase oil recovery factor from 18.57% to 22.48% compared to the vertical producers due to the maximum penetration into the oil reservoir. Furthermore, water and gas productions from horizontal producers are higher than the ones from vertical producers. In term of production time, horizontal producers require a shorter period of time than vertical producers.

Table 5.27 Results of three producers for natural depletion with different well types

Well arrangement	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Option 1	1.511	0.443	299.68	18.57	13.3
Option 2	1.830	1.27	1010.40	22.48	4.6

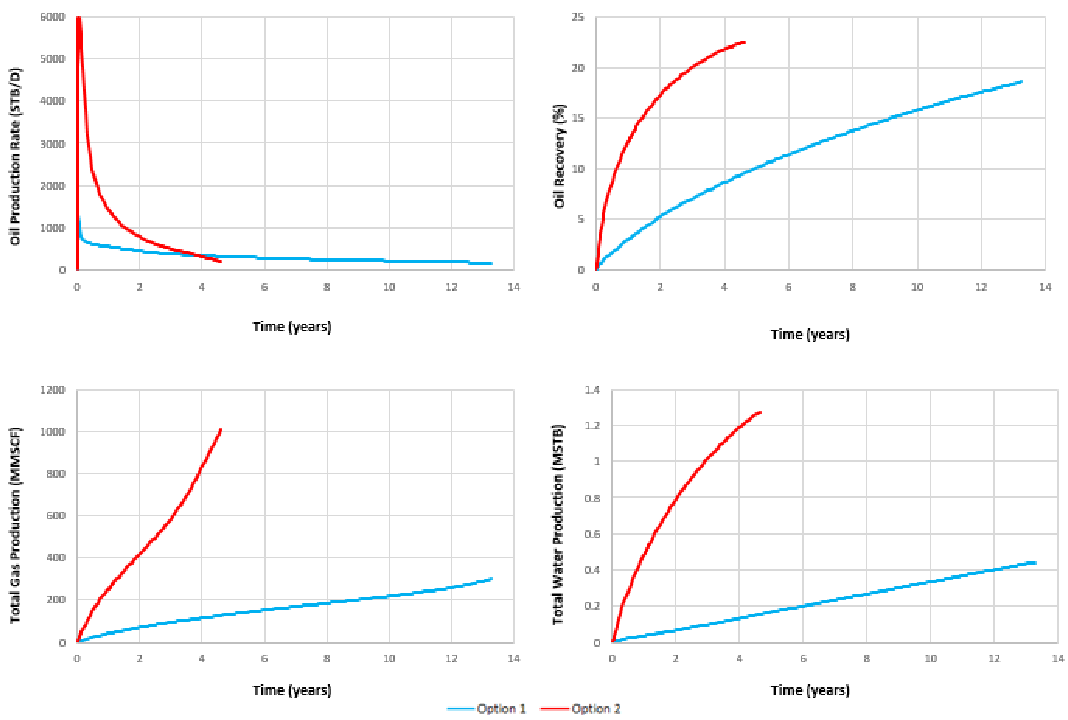


Figure 5.50 Production performances in case of three producers for different well types for natural depletion

5.5.2 Conventional waterflood

Conventional waterflood via injection from the surface was examined in this study such that the results can be used for comparison with water dumpflood. In this section, different combinations of producer and injector were evaluated as follows:

Option 1: One vertical producer and two vertical injectors

Option 2: One vertical producer and two horizontal injectors

Option 3: One horizontal producer and two vertical injectors

Option 4: One horizontal producer and two horizontal injectors

Note that the distance between the three well is 2100 ft which is the best distance obtained in the case of water dumpflood and the horizontal length of horizontal well in this section is 1,700 ft, which is the best length earlier obtained in water dumpflood cases. The injection parameter is shown in the Table 5.28.

Table 5.28 Injection parameters for conventional waterflood

Parameters	Value	Unit
Injection rate	2000	STB/D/injector
Fracture pressure	1500	psia

Simulation results for four options of conventional waterflood are plotted in Figure 5.51 and summarized in Table 5.29. The oil production rates of the cases with vertical producer (Options 1 and 2) are lower than those of the cases with horizontal producer (Options 3 and 4) due to limited exposure to the oil reservoir. Oil recovery factors for the cases with vertical producer are 23.68% and 27.54% for Options 1 and 2, respectively while those for the cases with horizontal producer are 40.20% and 42.30% for Options 3 and 4, respectively. Gas productions from the cases with horizontal producer are higher than the productions from the cases with vertical producer. In addition, water productions from the cases with horizontal producers are much more the productions from the cases with vertical producer. When comparing between Options 3 and 4, oil production rate of the case with horizontal injector (Option 4) is generally higher than that in Option 3 due to better sweep efficiency between horizontal injectors and horizontal producer. Thus, oil recovery factor of Option 4 is higher than that of Option 3 (42.30% versus 40.20%). In addition, there are more gas and more water production in Option 4. This cases has too much water production but small gain in oil recovery and much higher cost of drilling two horizontal injectors. Thus, Option 3 should be chosen in practice. In conclusion, horizontal producer is the option that significantly increases the oil recovery while vertical injector slightly helps improve oil production and reduce water production.

As shown in Figures 5.52 and 5.53, fracture pressure is a significant parameter that limits injectivity.

Table 5.29 Results for waterflood in cases of one producer and two injectors with different well types

Well arrangement	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)
Option 1	1.928	4.919	384.54	23.68
Option 2	2.242	0.658	447.44	27.54
Option 3	3.273	1310.196	513.69	40.20
Option 4	3.444	2639.954	569.51	42.30

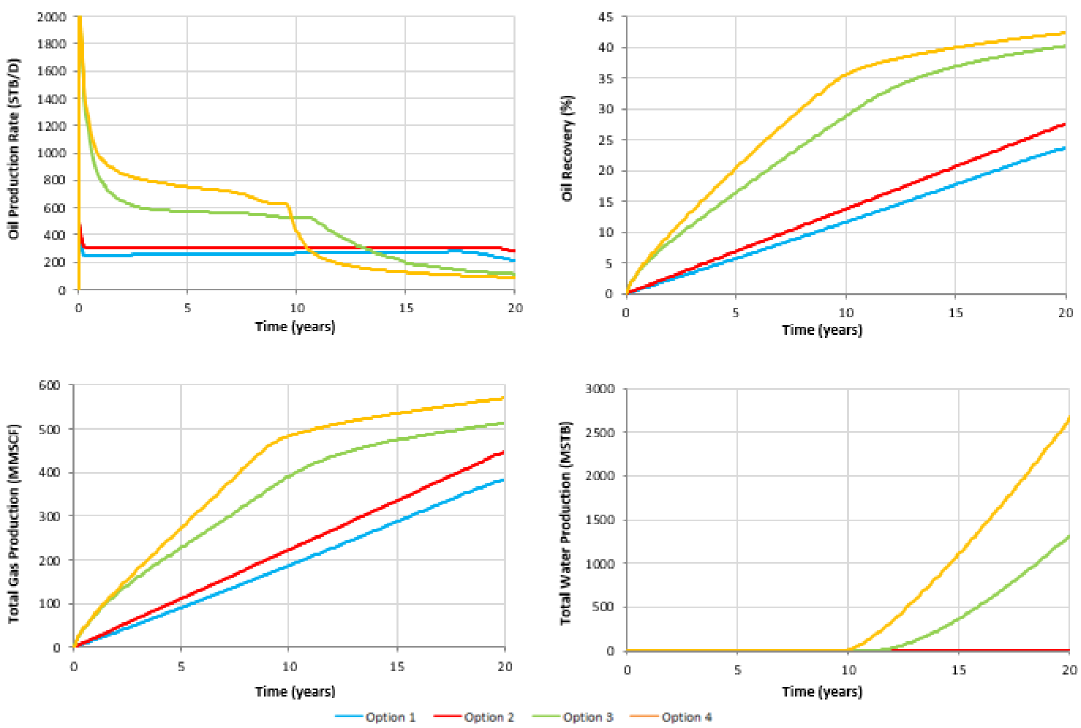


Figure 5.51 Production performances for different well types in case of conventional waterflood

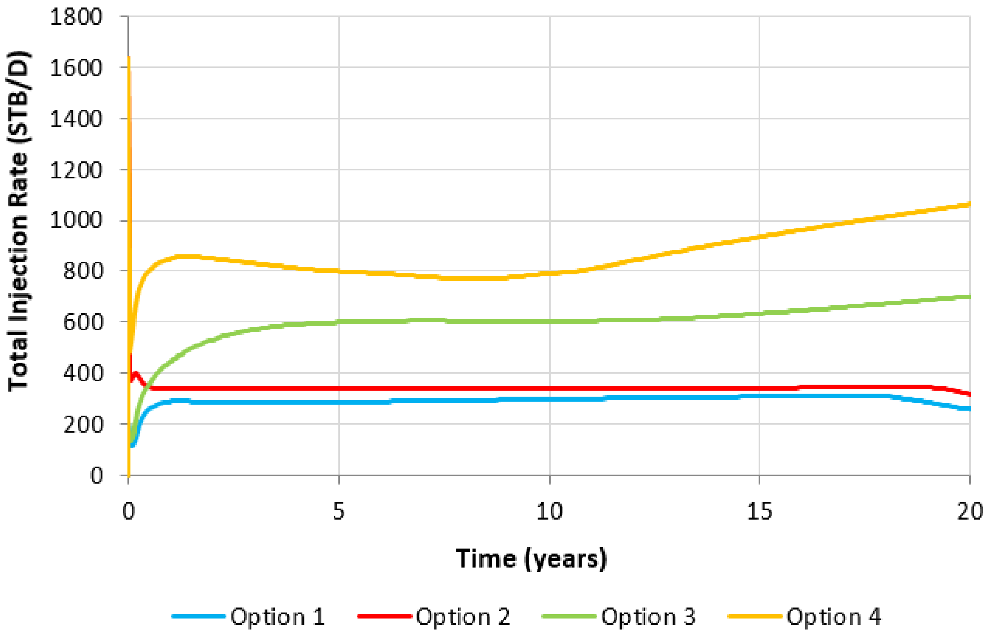


Figure 5.52 Injection rate for different well types in case of conventional waterflood

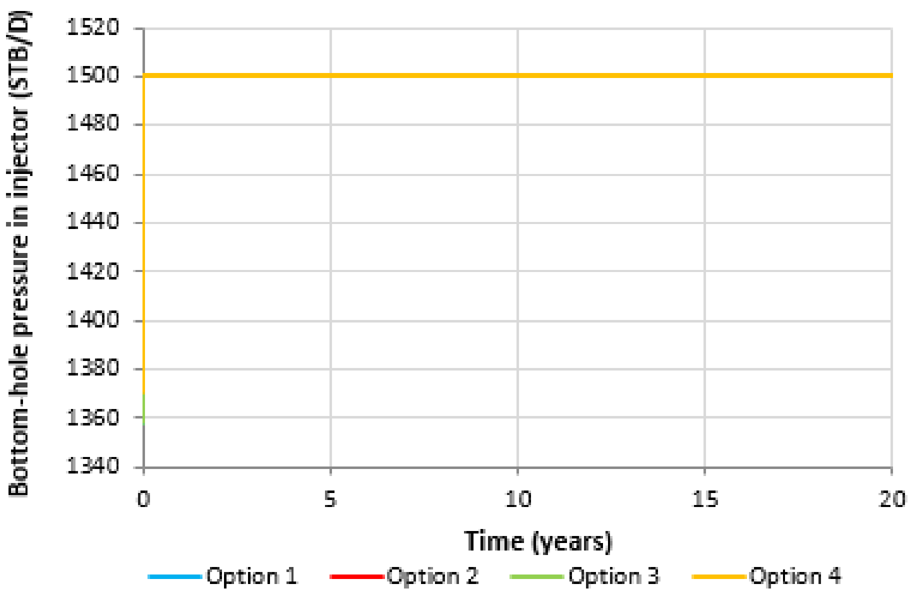


Figure 5.53 Bottom—hole pressure in injector for different well types in case of conventional waterflood

5.5.3 Performance comparison among natural depletion, conventional waterflood, and water dumpflood

The simulation results for water dumpflood show that the case of 1,700 ft horizontal producer and two vertical dumpers with well spacing of 2,100 feet is the best combination for both intermediate and strong aquifers available for dumpflooding. Oil recovery factor for intermediate and strong aquifer is 30.78% and 23.82%, respectively. The best choice for natural depletion is three horizontal producers due to maximum exposure into the oil reservoir. For conventional waterflood, one horizontal producer and two vertical dumpers with horizontal well length of 1,700 feet is the best combination due to less water production and lower cost of drilling.

The comparison among natural depletion, conventional waterflood, and water dumpflood is summarized in Table 5.29. Conventional waterflood can yield the highest oil recovery factor with a tremendous amount of water production. Since conventional waterflood produce a tremendous amount of water production and requires higher investment and operating cost, water dumpflood might be better alternative under certain circumstances. The cases of water dumpflood for intermediate and strong aquifers can yield oil recovery as much as 30.78% and 23.82%, respectively in comparison to 40.20% for conventional waterflooding. The two cases of water dumpflood have better production performance than natural depletion with small increment in water production. Oil recovery factor of the natural depletion case is only 22.48%.

Table 5.30 Comparison table among natural depletion, conventional waterflood, and water dumpflood

	Well arrangement	Total oil production (MMSTB)	Total water production (MSTB)	Total gas production (MMSCF)	Oil recovery factor (%)	Production time (years)
Natural depletion	Three 1700-ft horizontal producers	1.830	1.270	1010.40	22.48	4.6
Conventional waterflood	1700-ft horizontal producer and two vertical injectors	3.273	1310.196	513.69	40.20	20.0
Water dumpflood	1700-ft horizontal producer and two vertical dumpers for strong aquifer (50PV)	2.506	1.584	657.12	30.78	20.0
	1700-ft horizontal producer and two vertical dumpers for intermediate aquifer (10PV)	1.939	1.292	1027.97	23.82	18.9

CHAPTER 6
CONCLUSIONS AND RECOMMENDATION

In this study, the performance of water dumpflood with various well designs was evaluated by black oil reservoir simulator ECLIPSE®100. The parameters of well design consisting of well types (vertical versus horizontal dumpers and producers), well spacing, and horizontal well length for intermediate and strong aquifers were investigated. The following conclusions can be drawn:

1) For well type, horizontal producer(s) and vertical dumper(s) can yield as much as 23.82% and 30.78% oil recovery factor in comparison to 12.69% and 14.46% obtained in the case of vertical producer(s) and vertical dumper(s) when water is dumpflooded from intermediate and strong aquifers, respectively. The main increment comes from changing the producer form vertical to horizontal well while only a small increment is obtained when changing the dumper from vertical to horizontal.
2) For horizontal well length, longer horizontal well length can yield slightly to moderately higher oil recovery and lower water production due to uniform movement of water between dumpers and producers.
3) In term of starting time for water dumpflood cases, three options were investigated: (i) all wells are initially production wells, then some wells are later converted to dumping wells, (ii) a few wells are initially used to produce oil, and later, more wells are drilled for dumping, (ii) water dumpflood is started at the beginning. Oil recovery factors for the three options of starting time are almost the same but there are small difference on water and gas productions in the cases of well arrangement options 1 and 2.
4) When making comparison among of natural depletion, water dumpflood, and water flood at the same condition, conventional waterflood can yield oil production higher than the other two cases but with higher amount of produced water and higher cost of investment and operation. Water dumpflood is good alternative if a large aquifer is available.

5) The best case is 1700-ft horizontal producer and two vertical dumpers when dumping water from a strong aquifer in this study.

For recommendation, this simulation model was created under simple geometry and homogenous condition. Reservoir complex geometry and heterogeneity will result in different flow behavior and thus different performance. Implementation to actual field needs to be performed on a case by case basis.

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