PRODUCTION PERFORMANCE COMPARISON BETWEEN WATER ALTERNATING GAS AND DOUBLE DISPLACEMENT PROCESS

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การเปรียบเทียบสมรรถนะการผลิตระหว่างกระบวนการอัดน้ำสลับแก๊สและกระบวนการแทนที่สองครั้ง

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วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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ภารุจ เชษฐ์เชาวลิต : การเปรียบเทียบสมรรถนะการผลิตระหว่างกระบวนการอัดน้ำสลับแก๊สและกระบวนการแทนที่สองครั้ง (PRODUCTION PERFORMANCE COMPARISON BETWEEN WATER ALTERNATING GAS AND DOUBLE DISPLACEMENT PROCESS) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 212 หน้า.

กระบวนการอัดน้ำสลับแก๊สและกระบวนการแทนที่สองครั้ง เป็นกระบวนการที่มีประสิทธิภาพในการผลิตน้ำมันจากแหล่งกักเก็บเนื่องจากได้รวมประโยชน์ของการฉีดอัดน้ำและการฉีดอัดแก๊สเข้าด้วยกัน ในการทดลองนี้ มีการสร้างแบบจำลองของแหล่งกักเก็บสามแหล่งที่มีความลาดเอียงแตกต่างกันเพื่อศึกษาผลกระทบของตัวแปรการผลิตต่าง ๆ สำหรับกระบวนการผลิตทั้งสามกระบวนการ ได้แก่ การอัดน้ำสลับแก๊สที่ส่วนบนของแหล่งกักเก็บ การอัดน้ำสลับแก๊สที่ส่วนล่างของแหล่งกักเก็บ และการแทนที่สองครั้ง โดยใช้หน่วยเทียบเท่าบาร์เรลน้ำมันดิบเป็นตัวชี้วัดประสิทธิภาพ

การหยุดกระบวนการอัดน้ำขั้นต้นที่อัตราส่วนการผลิตน้ำต่ำ การอัดน้ำด้วยอัตราสูง การอัดแก๊สด้วยอัตราปานกลาง และการอัดน้ำกับแก๊สเป็นเวลาสั้น ๆ สลับกันนับเป็นผลดีต่อการผลิตด้วยวิธีอัดน้ำสลับแก๊ส นอกจากนี้การเพิ่มอัตราส่วนระหว่างน้ำต่อแก๊สยังช่วยเพิ่มประสิทธิภาพสำหรับแหล่งกักเก็บที่ไม่ลาดเอียงแต่ไม่มีผลต่อแหล่งกักเก็บที่มีความลาดเอียง เราสามารถเพิ่มประสิทธิภาพของกระบวนการแทนที่สองครั้งโดยการหยุดกระบวนการอัดน้ำขั้นต้นที่อัตราส่วนการผลิตน้ำต่ำ และการอัดน้ำและแก๊สด้วยอัตราสูง ถึงแม้ว่ากระบวนการแทนที่สองครั้งจะผลิตน้ำมันได้ในปริมาณมาก แต่กระบวนการนี้มีการอัดแก๊สในปริมาณมาก ซึ่งเมื่อคำนวณเป็นหน่วยเทียบเท่าบาร์เรลน้ำมันดิบแล้ว พบว่ากระบวนการอัดน้ำสลับแก๊สมีประสิทธิภาพสูงกว่า กระบวนการที่ดีที่สุดสำหรับแหล่งกักเก็บที่ไม่มีความลาดเอียง แหล่งกักเก็บที่มีความลาดเอียง 15 องศา และ 30 องศา คือ กระบวนการอัดน้ำสลับแก๊สที่ส่วนบนของแหล่งกักเก็บที่มีหลุมผลิตแนวตั้งแปดหลุม กระบวนการอัดน้ำสลับแก๊สที่ส่วนล่างของแหล่งกักเก็บที่มีหลุมผลิตแนวนอนสองหลุม และการบวนการอัดน้ำสลับแก๊สที่ส่วนบนของแหล่งกักเก็บที่มีหลุมผลิตแนวตั้งที่ส่วนบนและหลุมผลิตแนวนอนที่ส่วนล่างของแหล่งกักเก็บ ตามลำดับ

การเพิ่มค่าความสามารถในการซึมผ่านในแนวนอนของแหล่งกักเก็บทำให้ผลิตน้ำมันได้ในปริมาณสูงขึ้น การเพิ่มอัตราส่วนระหว่างความสามารถในการซึมผ่านในแนวตั้งต่อแนวนอนจะเพิ่มปริมาณน้ำมันที่ผลิตได้ ในขณะที่การลดอัตราส่วนนี้ส่งผลให้ต้องใช้แก๊สปริมาณมาก ความสัมพันธ์ของความสามารถในการซึมผ่านสัมพัทธ์ 3 สถานะที่เป็นค่าเริ่มต้นของโปรแกรม สามารถผลิตน้ำมันได้ในปริมาณสูงกว่าความสัมพันธ์แบบสโตน 1 และสโตน 2 การผลิตน้ำมันจากแหล่งกักเก็บที่มีความหนาน้อยสามารถทำได้ในเวลาอันสั้นแต่ประสิทธิภาพการผลิตอาจไม่ดี และน้ำมันเบาที่มีแก๊สปนอยู่ในปริมาณสูงสามารถผลิตได้ง่าย

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม ลายมือชื่อนิสิต ....

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PARUJ CHETCHAOVALIT: PRODUCTION PERFORMANCE COMPARISON BETWEEN WATER ALTERNATING GAS AND DOUBLE DISPLACEMENT PROCESS. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 212 pp.

Water alternating gas process (WAG) and double displacement process (DDP) are two effective methods to recover oil in the reservoir as they combine the advantages of water and gas injection. In this study, reservoirs with different dip-angles are constructed by the reservoir simulation software. The effects of different operating parameters are investigated for WAG with up-dip and down-dip injection and DDP by using barrel of oil equivalent (BOE) as an indicator.

Low water cut criteria, high water injection rate, moderate gas injection rate, and shorter injection durations of water and gas are considered to be beneficial for the two types of WAG. Moreover, the increase of water to gas injection duration ratio enhances the oil production performance in a non-dipping reservoir while this ratio does not have a significant effect for an inclined reservoir. We can improve the performance of DDP by using low water cut stopping criteria for water flooding and injecting water and gas at high rates. The best performance process for all reservoirs is WAG. Although DDP yields higher oil recovery factor than WAG, it consumes much larger amount of gas which results in lower BOE. The optimum production processes for a non-dipping reservoir, a 15° dipping reservoir, and a 30° dipping reservoir are (1) WAG with up-dip injection by eight vertical wells, (2) WAG with down-dip injection by two horizontal wells, and (3) WAG with up-dip injection by a vertical well up-dip and a horizontal well down-dip.

Sensitivity analysis shows that the higher horizontal permeability results in the higher oil recovery factor in an inclined reservoir. The increase of k_v/k_h ratio improves the oil production whereas the decrease of k_v/k_h ratio requires much more amount of injected gas due to the earlier breakthrough. For the three-phase relative permeability correlation, ECLIPSE default model gives more oil recovery factor than Stone 1 and Stone 2 models. We can produce oil from the thinner reservoir in shorter time but not always with more efficiency. Light oil containing large amount of solution gas is easy for production.

Department:	Mining and Petroleum Engineering	Student's Signature	....
		Advisor's Signature	....
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List of Abbreviations

BOE	Barrel of oil equivalent
BSCF	Billion standard cubic feet
DDP	Double displacement process
cp	Centipoise
FRAC.S.G.	Fracturing pressure gradient
ft	Feet
GOR	Gas-oil ratio
lb/ft^3	Pound per cubic foot
md	Millidarcy
MMSCF/D	Million standard cubic feet per day
MMSTB	Million stock tank barrel
MSCF/STB	Thousand standard cubic feet per stock tank barrel
OOIP	Original oil-in-place
psi	Pound per square inch
psia	Pound per square inch absolute
PV	Pore volume
PVT	Pressure-Volume-Temperature
RB/D	Reservoir barrel per day
RB/STB	Reservoir barrel per stock tank barrel
SCAL	Special core analysis
SCF/STB	Standard cubic feet per stock tank barrel
STB	Stock tank barrel
STB/D	Stock tank barrel per day
TVD	True vertical depth
WAG	Water alternating gas

Nomenclatures

μ_g	Viscosity of gas
μ_o	Viscosity of oil
μ_w	Viscosity of water
ρ_w	Density of water
ρ_o	Density of oil
θ, α	Dip angle of the reservoir
A	Cross sectional area
f_g	Fractional flow of gas in reservoir
f_w	Fractional flow of water in reservoir
g	Acceleration due to gravity
k	Absolute permeability
k_h	Horizontal permeability
k_{rg}	Relative permeability to gas
k_{ro}	Relative permeability to oil
k_{rocw}	Oil relative permeability in the presence of connate water only
k_{rog}	Oil relative permeability for a system with oil, gas, and connate water
k_{row}	Oil relative permeability for a system with oil and water only
k_{rw}	Relative permeability to water
k_v	Vertical permeability
P_c	Capillary pressure
$q_{g,crit}$	Critical rate for gas by-passing

q_i	Water injection rate
q_o	Oil flow rate
q_t	Total flow rate
q_w	Water flow rate
$q_{w,crit}$	Critical rate for water by-passing
R_s	Solution gas-oil ratio
S_g	Gas saturation
S_o	Oil saturation
S_{om}	Minimum residual oil saturation
S_w	Water saturation
S_{wco}	Connate water saturation

CHAPTER I

INTRODUCTION

1.1 Background

After primary recovery by natural drive mechanisms, some amount of oil is not recovered but left in a reservoir as residual oil. There is an effort to produce oil as much as possible from the fields by injection of fluids to displace and chase oil ahead. The reservoir pressure is also maintained. Water injection and gas injection are proven as effective methods. These methods have been used worldwide by several oil companies.

Water alternating gas process (WAG) is one of the widely used oil recovery methods. Water and gas are injected in separate small slugs. These slugs are alternately injected into the reservoir in order to flood the residual oil left after the primary recovery. The sweep efficiency of water and the microscopic displacement efficiency of gas improve the performance of this recovery process.

Double displacement process (DDP) is the process of gas flooding to recover residual oil after water flooding. This process starts with down-dip water injection to displace oil up-dip structure and follows by up-dip gas injection to displace oil and water down-dip structure. It can recover oil due to the better microscopic displacement efficiency of gas and the forming of oil film. These two methods are effective for recovery process and should be studied to compare their performances.

In this study, three reservoirs with different dip angles which are 0-degree, 15-degree, and 30-degree are constructed by using ECLIPSE 100. WAG and DDP processes are applied to recover oil from these reservoirs. For WAG, the initial water flooding is performed until water cut of the producer reaches the criteria. Then, WAG injection is started. Thus, the strategies that yield the highest barrel of oil equivalent (BOE) for WAG and DDP are determined, and the effects of the following production parameters are investigated: water cut stopping criteria for initial water flooding, water and gas injection rates, WAG cycle and injection duration (only for WAG), and well pattern. Moreover, WAG process is performed in both up-dip and down-dip injection. After that, the cases that yield the highest BOE for these three reservoirs are analyzed on their sensitivities when reservoir properties (which are horizontal permeability, vertical to horizontal permeability ratio, three phase relative permeability correlation, and reservoir thickness) and oil property are changed.

1.2 Objectives

1. To determine the best production strategy for water alternating gas process in terms of stopping criteria for initial water flooding, water and gas injection rates, WAG cycle and injection duration, and well pattern.
2. To determine the best production strategy for double displacement process in terms of stopping criteria for initial water flooding, water and gas injection rates, and well pattern.
3. To study the effects of reservoir and fluid properties such as horizontal permeability, vertical/horizontal permeability, relative permeability, reservoir thickness, and oil property on water alternating gas and double displacement process.
4. To compare the performances of water alternating gas and double displacement process.

1.3 Outlines of methodology

1. Review previous studies on WAG and DDP.
2. Construct a base case reservoir model in ECLIPSE 100.
3. Perform three base case recovery methods as listed below to study their production characteristics.
   - 3.1 WAG with up-dip injection
   - 3.2 WAG with down-dip injection

3.3 DDP

4. Study the effects of the following parameters on oil recovery efficiency.

   4.1 stopping criteria for water flooding

   4.2 water and gas injection rates

   4.3 WAG cycle and injection duration (only for WAG)

   4.4 well pattern

   This study is performed in a non-dipping reservoir and 15-degree and 30-degree dipping reservoirs.

5. Select the cases, from both WAG and DDP, which give the best results for sensitivity study. Reservoir with dip angle of 0°, 15°, and 30° are studied and rock and fluids parameters are varied as follows:

   5.1 horizontal permeability

   5.2 vertical/horizontal permeability

   5.3 relative permeability

   5.4 reservoir thickness

   5.5 oil property

6. Discuss and compare the performances of WAG and DDP.

7. Draw conclusions from simulation results.

1.4 Outlines of thesis

There are 6 chapters in this thesis as detailed below:

- Chapter I is the introduction of this study.
- Chapter II illustrates the literature review in the topics of WAG and DDP.
- Chapter III summarizes the related theories and concepts.

- Chapter IV is description of reservoir model and its properties.
- Chapter V shows the simulation results for WAG and DDP. The performances of two methods are compared and discussed. In addition, sensitivity analysis is also investigated in this chapter.
- Chapter VI is the conclusion of this thesis.

CHAPTER II
LITERATURE REVIEW

Previous studies of water alternating gas and double displacement process are summarized in this chapter.

2.1 Water alternating gas process

In 1972, Dyes et al. [1] presented the alternate injection of high pressure gas (HPG) and water for Hassi Messaoud oil reservoir in Algeria. The volumetric sweep efficiency for this reservoir had been quite low due to its heterogeneity. Therefore, they tried to improve the volumetric sweep efficiency by performing an alternate injection of gas and water. A pilot operation showed significant improvement in volumetric sweep which were 22% for alternate injection and 10-12% for continuous gas injection at gas breakthrough.

Moffitt and Zornes [2] presented one of the first immiscible WAG. A project of CO_2/waterflood was conducted at the Lick Creek Meakin Sand Unit, Arcansas in 1976. This unconsolidated sandstone reservoir has a depth of 2,550 ft., an average thickness of 8.4 ft., an average permeability of 1,200 md, and a porosity of 30.3%. This reservoir contained 15.8 MMSTB of OOIP. Only 4.5 MMSTB or 28.3% of OOIP had been produced by natural depletion for 20 years. It was reported that this project can recover 1.75 MMSTB of incremental oil over primary recovery or 11.1% OOIP.

Mangalsingh and Jagai [3] studied the effect of WAG ratio by performing a core-flooding experiment. Cores were produced from 80 mesh silica sand. Crude oil with 16 – 29 °API and CO_2 with 99.5% purity were used. This experiment was performed at 900 psi and 28 °C to let the CO_2 WAG occur in immiscible condition. They varied WAG ratio from 1:1 to 1:5 and found that ratio of 1:4 was the optimum ratio. They also concluded that WAG had two important advantages as compared to continuous gas flooding such as higher oil recovery and less volume of gas needed.

Li et al. [4] performed a core test to evaluate feasibility of immiscible WAG in Wennan reservoir. Cores with average permeability of 15.0 md and porosity of 21.58% were collected from Wennan reservoir. Immiscible WAG process yielded 61.90% recovery from injection of 0.453 HCPV at breakthrough time but caused a problem of high water production rate (97.94% water cut). However, the final recovery reached up to 95.22%.

Srivastava and Mahli [5] performed core flooding experiments to study effects of different water alternating gas (WAG) injection cycles and changing slug sizes on the performance of oil production. Core plugs, oil sample, and gas sample were collected from Gandhar field. Porosity and permeability of these sandstone cores were 21% and 323.23 md, respectively. Injection rates were 20 cc/h for water and 10 cc/h for gas. To study the effect of number of WAG cycles, single cycle and five cycles of 1 PV of gas and water were injected with WAG ratio of 1:1 after water flooding. The results showed that single-cycle WAG yielded 12.75% incremental displacement efficiency over water flooding while five-cycle WAG with the same injection volume yielded 19.30% incremental displacement efficiency over water flooding. Better displacement efficiency caused better total oil recoveries which were 71.63% and 64.59% for five-cycle and single-cycle, respectively. Moreover, they also performed tapered WAG methods, changeable WAG ratio in each cycle, as shown in Table 1. Gas and water injection volumes were adjusted to be 1.5 PV in this case in both increasing WAG ratio and decreasing WAG ratio experiments. In case of decreasing WAG ratio, more amount of gas could dissolve in the first cycle; thus caused improvement in mobility and increase in oil recovery. Decreasing WAG ratio in which its recovery factor was 72.57% gave 23.84% incremental displacement efficiency over water flooding while increasing WAG ratio in which its recovery factor was 72.34% gave only 20.73% incremental displacement efficiency over water flooding. However, constant WAG ratio over five cycles yielded 71.63% recovery factor which was lower than those two types of tapered WAG. Thus, decreasing WAG ratio had slightly better performance than other cases.

Table 2.1 WAG ratios for the experiments (after [5]).

Cycles	WAG ratio for tapered WAG (water:gas)	
	Increasing WAG ratio	Decreasing WAG ratio
1	3:1	3:5
2	3:2	3:4
3	1:1	1:1
4	3:4	3:2
5	3:5	3:1

Parracello et al. [6] performed a core flooding test in order to investigate efficiency of immiscible water alternating gas (WAG). They used sandstone core with porosity of 17.8% and permeability of 406 md. Viscous oil sample had viscosity of 180 cp and density of 0.870 g/cm^3. Two different injection orders were studied. Water and gas were injected alternately starting with water slug in the first test but gas slug in the second test. Although the final oil recovery from the first test was slightly higher than the final oil recovery from the second test which was 35.4% and 34.7%, respectively, much more amount of oil was recovered since early time in the first test. In other words, WAG starting with water slug of injection showed better result in oil recovery. However, relative permeability curves were constructed by simulator.

Pitakwatchara [7] performed water alternating gas (WAG) flooding study in a non-dipping reservoir. Water injection alternating gas dumpflood was proposed and compared to conventional WAG in which both gas and water were injected from surface. From the results, three wells with a distance between each well of 2,000 ft provided high sweep efficiency and recovery factor. A high water cut stopping criteria for water injection was not suitable for the recovery processes due to the requirement of large amount of injected water. An increase of water and gas injection rates shortened the production time but slightly lowered oil recovery factor for conventional WAG. However, for water injection alternating gas dumpflood, an increase in water injection rate yielded better oil recovery factor in shorter production period. For both methods, WAG ratio and slug size did not have a significant influence on oil recovery factor. When two methods were compared, she concluded that water injection alternating gas dumpflood yielded lower oil production than conventional WAG. However, water alternating gas dumpflood does not need surface facilities for gas injection. Effects of vertical to horizontal permeability ratio (k_v/k_h) and oil viscosity were also investigated and concluded that a low k_v/k_h ratio and a low viscosity improved the performance of both two types of WAG.

2.2 Double displacement process

Langenberg et al. [8] studied appropriate recovery method to improve oil production for Hawkins Field in Texas. Oil production from this field reached its peak rate at 112,000 BOPD in 1975 and approached its economic limit in 1987. Ways to extend the production life of this field were studied. Eventually, immiscible double displacement process (DDP) was found to be the most suitable method and was then applied to the East Fault Block of the Hawkins Field Unit. They started to perform DDP in August 1987. The oil production rate was around 3,700 BOPD at the starting time and declined to 1,075 BOPD at the end of 1991 with average nitrogen gas injection rate of 24.5 MMscf/D. The average gas-oil contact moved 81 ft. while the average oil-water contact moved 91 ft. downstucture in three years. This meant the size of oil bank grew 10 ft. They concluded that these moving rates were too high for Hawkins Field. Thus, they decided to reduce gas injection rate to 15 MMscf/D in June 1992. As a result, 32 ft. of oil bank increased to 40 ft. from 1992 to 1993. Oil production rate was 900 BOPD in 1992 and 1,300 in 1993. They summarized that DDP was very successful improved oil recovery method and could be applied for other areas of Hawkins Field.

Ren et al. [9] studied the effects of many parameters on the performance of double displacement process (DDP). A dipping reservoir model with a dip angle of 8° was the base case. Dimensions in the x-, y-, and z-direction were 591 m, 305 m, and 91 m, respectively. This model had porosity of 25% and permeability of 1,500 md.

Oil has gravity of 0.865 g/cm^3 and viscosity of 0.9 mPa·s. They constructed a reservoir model with an up-dip gas injector and a down-dip producer and then varied three parameters: injection and production rate, dip angle of the reservoir, and oil relative permeability. Results of this simulation showed that the critical gas injection rate was 510 m^3/day. Bigger dip angle showed better performance due to gravity effect. Stone 2 model was the most suitable three-phase relative permeability model for this simulation compared to Stone 1 model, linear isoperm model, and segregated model.

Wang et al. [10] evaluated double displacement process (DDP) for Hibernia Field. Core plug with 18% porosity and 1,800 md permeability was collected from this field. Core flood experiment was done at 210°F and 4,500 psi. Imbibition and drainage processes were studied prior to performing the DDP test. Critical gas saturation of 0.243 and residual oil saturation of 0.065 after gas flooding were measured by core flooding of gas-displacing-oil process. The water-oil relative permeability was then studied and the core from Hibernia was found to be oil-wet. After that, DDP test was performed by two steps of injection which were water and oil, with ratio of 9:1, injection and gas injection sequentially. Oil bank reached the outlet after 0.025 PV of gas was injected. At that time, oil fractional flow equaled to 0.925. After that, oil fractional flow decreased to 0.205 when 0.280 PV of gas was injected and gas reached the outlet. It was also observed that oil flow rate would be higher than water flow rate after gas breakthrough but with lower two-phase, oil and water, flow rate. Water flooding recovered 54% of OOIP. Additional 14% of OOIP and 18.5% of OOIP were recovered by 1 PV and 11 PV of gas injection, respectively.

Gachuz-Muro et al. [11] compared the performances of natural gas and nitrogen gas in double displacement process (DDP). Core was collected from a naturally fractured reservoir. Density and viscosity of crude oil sample were found to be 32 °API and 0.9 cp, respectively. For natural gas DDP, they performed three recovery mechanisms which were natural depletion, water injection, and gas injection sequentially. Recovery factor for each mechanism was 0.9%, 46.99%, and 16.44%, respectively. Core was then cleaned and used again in the next experiment.

After that, nitrogen gas DDP was studied by performing three recovery mechanisms similar to natural gas DDP experiment but only different in gas type. Recovery factor for each mechanism was 0.5%, 46.7%, and 3.79%, respectively. In their study, natural gas injection yielded higher recovery than nitrogen injection in DDP process.

Suwannakul [12] studied the effect of production strategies especially the location of gas injector on the performance of double displacement process (DDP). He constructed three dipping reservoirs with dip angles of 5°, 10°, and 20°. Four vertical wells are constructed. Well 1 was located at the most up-dip location while well 4 was located at the most down-dip location. He injected gas at different wells to determine the effect on production time. It was found that the shortest production time was obtained when gas was injected at well 2 (the second most up-dip well) in a 5° reservoir and at well 1 (the most up-dip well) in a 10° reservoir. However, there was an insignificant effect of injector location on production time for a 20° reservoir due to an influence of gravitational force. In addition, he studied the effect of three-phase relative permeability correlation and concluded that it moderately affected production time but did not affect oil recovery factor.

The previous studies prove that WAG and DDP are two of effective oil recovery methods. They are not only performed in laboratory or simulator but also applied to the real oil reservoirs in every part of the world. They are considered to be successful because they provide good results and their operations are feasible. However, operational parameters have strong effect on the performance of oil production by WAG and DDP. Therefore, the investigation of each parameter is necessary to optimize the production strategies.

CHAPTER III
THEORY AND CONCEPT

3.1 Water alternating gas

Water alternating gas (WAG) is a process of injecting water and gas alternately into the formation. This process combines advantages of water flooding and gas flooding which are better sweep efficiency and better microscopic displacement efficiency, respectively. As a result, more amount of oil can be recovered compared to water flooding or gas flooding. WAG also has these following benefits [13]:

1. High injectivities

   The injectivity of WAG is higher than the injectivity of water flooding. Gas is not only injected easily but also lowers the bottom-hole pressure requirement.

2. In-situ gas lifting

   The oil rate is enhanced by in-situ lifting provided by circulation of produced gas and injected gas.

3. Suppressed water production

   WAG reduces water management cost because the presence of trapped gas lowers the water mobility. As a result, less amount of water is produced.

4. Well interaction

   WAG is sometimes applied as the tracer. It can determine the communication between the injectors and the producers.

WAG can be divided into two types: miscible WAG and immiscible WAG. Miscible WAG occurs when the pressure is higher than minimum miscibility pressure (MMP) while immiscible WAG occurs when the pressure is below MMP. Efficiency of WAG is affected by [14]:

1. Fluid properties

The performance of WAG is affected by the properties of oil and solution gas in the reservoir. Light oil consisting of high amount of gas can flow easily. However, it involves in the mixing and separating of fluid phases which may have an influence on the flood front.

2. Trapped gas and wettability

The mobilization of oil and the water/gas displacement is affected directly by gas trapping process. It depends mainly on the saturation of initial gas and the rock wettability. In addition, the fluid which is the wetting phase bypasses other phases. As a result, the non-wetting phase fluid will be trapped, thus causing the problem of the decrease in the relative permeability to injected fluid.

3. Reservoir heterogeneity

The ability of fluids to flow between different zones inside the reservoir is the important factor to determine the performance of WAG process. The heterogeneity of the reservoir has a strong influence on this. Additionally, WAG and other displacement processes by water and gas are significantly affected by the viscous force to gravity force ratio.

4. Injection schemes

The important objective of water/gas injection is the improvement of sweep and displacement efficiencies. To improve these efficiencies, the optimization of water and gas injection parameters need to be performed. These parameters include (1) WAG slug size which is the size of water and gas slugs in the basis of pore volume (PV) or duration of slug injection, (2) WAG ratio which is the ratio of water slug size to gas slug size, and (3) cycling frequency which relates to the period of the injection of each cycle.

5. Injection rate

   Oil recovery depends on the viscosity to gravity ratio. A low injection rate can stable the flood front but taking long time for production. On the other hand, a high rate accelerates the production process but causing a problem of viscous fingering effect. Thus, injection rate needs to be optimized.

3.2 Double displacement process

The double displacement process (DDP) is a process of gas flooding to recover water-flooded residual oil in dipping reservoir as shown in Figure 3.1. DDP can recover oil up to 85-95% of OOIP [9]. This process starts with down-dip water injection. In this stage, a production well is located at up-structured location while an injection well is located at down-structured location. Oil is displaced up-structure by water through production well. However, some amount of oil is left after water flooding process is done. This residual oil can be divided into two parts [9]:

1. Bypassed oil, in water-unswept zone, caused by reservoir heterogeneity or well placement.
2. Trapped oil, in water-swept zone, caused by capillary pressure and surface force.

Gas is then injected to displace oil and water down-dip structure. In this stage, location of production well and injection well are alternately changed. Gas flooding can recover bypassed oil due to better microscopic displacement efficiency, as compared to water, and can recover trapped oil due to oil film forming. After that, oil accumulates to form oil bank between water zone and gas zone. In addition, gas-oil system is more effective than water-oil system in gravity drainage due to more density difference between phases. Consequently, water-flooded residual oil is recovered.

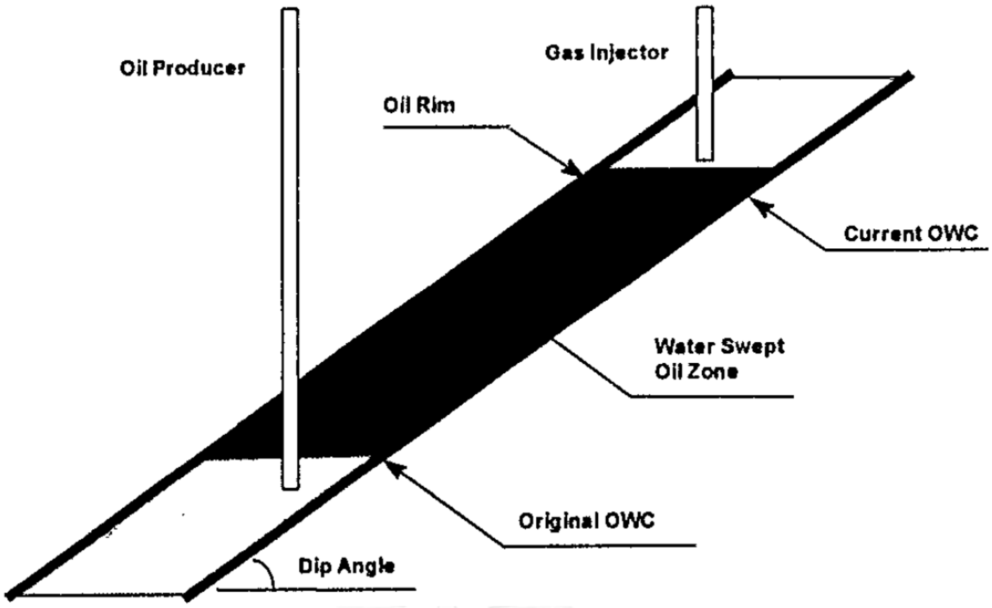


Figure 3.1 Schematic of DDP process (after[15]).

Reservoirs with the following properties are good candidates for DDP [15]:

1. high amount of water-flooded residual oil
2. permeability of 300 md or more
3. dip angle over 10°

3.3 Immiscible displacement in a dipping reservoir

3.3.1 Water displacing oil

For water flooding in a dipping reservoir, water is normally injected down-dip due to higher density of water compared with reservoir fluids. Consequently, injection wells and production wells should be located as shown in Figure 3.2.

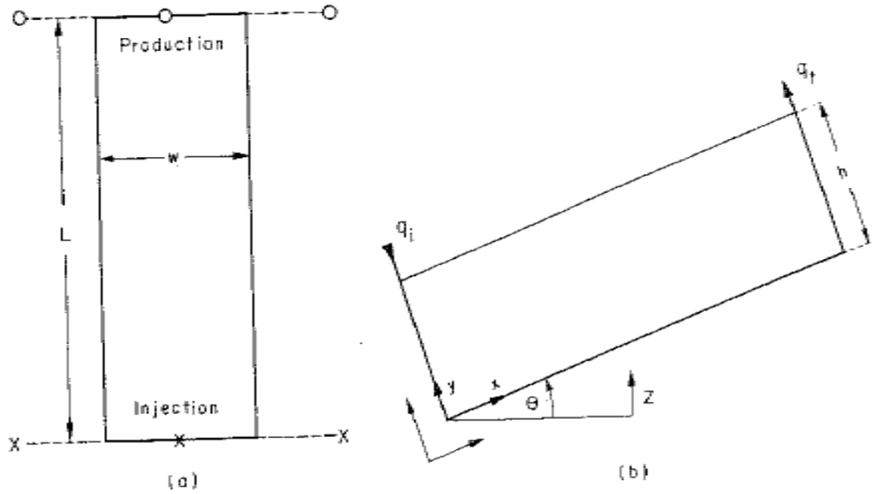


Figure 3.2 Linear prototype reservoir model: (a) plan view, (b) cross section (after [16]).

Reservoir fluids are pushed ahead from the injector through the producer after injection. Both oil and water flow together in separated phases due to immiscibility between them. If two fluids are considered incompressible, the relationship of flow rates will be [16]

$$q_t = q_o + q_w = q_i \tag{3.1}$$

where q_t = total flow rate

q_o = oil flow rate

q_w = water flow rate

q_i = water injection rate

A fraction of water in total flow can be calculated by fractional flow equation. This equation was derived from Darcy's law. It was first introduced by Leverett in 1941 [16].

$$f_w = \frac{1+\frac{k\,k_{ro}\,A}{q_t\,\mu_o}\left(\frac{\partial P_c}{\partial x}-\frac{\Delta\rho\,g\,sin\theta}{1.0133\times10^6}\right)}{1+\frac{\mu_w}{k_{rw}}\cdot\frac{k_{ro}}{\mu_o}} \tag{3.2}$$

where f_w = fractional flow of water in reservoir

k = absolute permeability

k_{ro}	=	relative permeability to oil
k_{rw}	=	relative permeability to water
μ_o	=	viscosity of oil
μ_w	=	viscosity of water
A	=	area
P_c	=	capillary pressure
x	=	distance in direction of flow
$\Delta\rho$	=	$\rho_w - \rho_o$
ρ_w	=	density of water
ρ_o	=	density of oil
g	=	acceleration due to gravity
θ	=	dip angle of the reservoir

The wetting phase and non-wetting phase require minimum saturations for flowing in a two-phase system. For oil/water system, the interstitial water saturation or S_{iw} and the residual oil saturation as S_{or} are required as minimum saturations. These values are affected by rock type, wettability, and IFT.

The flooding front is usually stable during the water flooding with low injection rate in a dipping reservoir, but usually unstable with high injection rate.

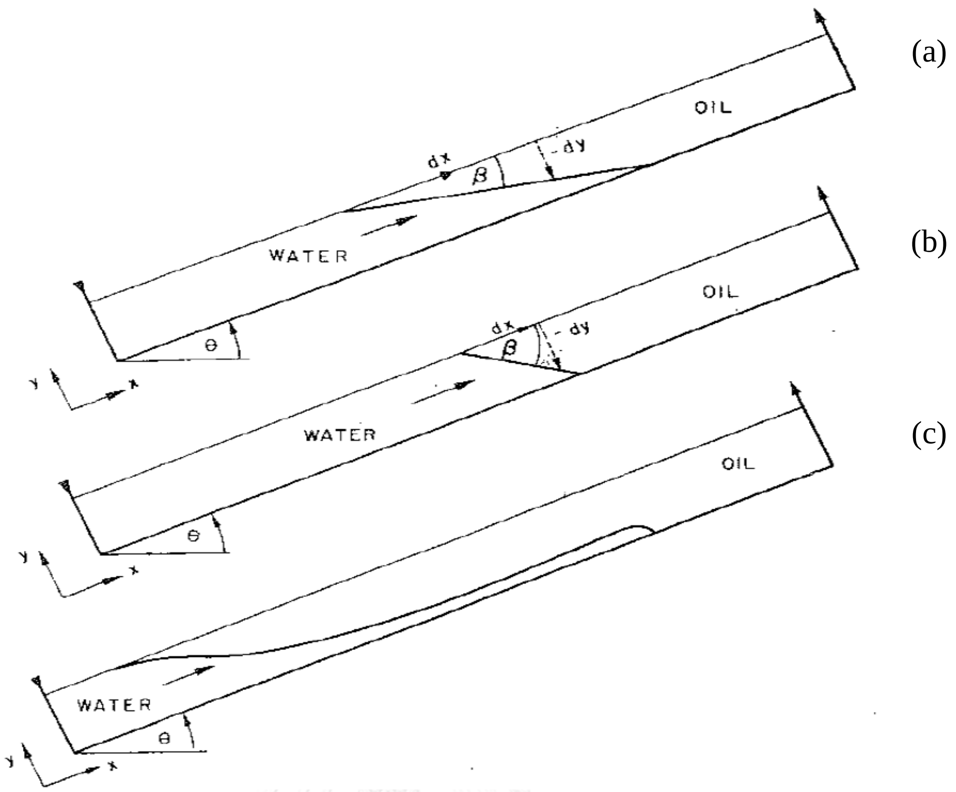


Figure 3.3 Water displacement: (a) stable, (b) stable, and (c) unstable (after [16]).

Stable displacement refers to the flooding with constant angle between the water-oil interface and the bedding plane (β) at any distance from injection well through production well as shown in Figure 3 (a) and (b) which are described by the following equation [16]. In this case, gravity force predominates over viscous force.

$$\frac{dy}{dx} = -\tan\beta = constant \tag{3.3}$$

Conversely, viscous force predominates over gravity force in the condition of high injection rate. This causes water underrun or unstable flood front as shown in Figure 3 (c) which is described by the following equation [16].

$$\frac{dy}{dx} = -\tan\beta = 0 \tag{3.4}$$

Figure 3.3 shows three different displacement patterns as shown below:

(a) stable, $G > M-1$, $M > 1$, $\beta < \theta$

(b) stable, $G > M-1$, $M < 1$, $\beta < \theta$

(c) unstable, $G < M-1$

The dimensionless gravity number (G) and the end point mobility ratio (M) can be calculated from the following equations [16].

$$G = \frac{k\, k'_{rw}\, A\, \Delta\rho\, g\, sin\theta}{1.0133{\times}10^{6}\, q_t\, \mu_w} \tag{3.5}$$

$$M = \left(\frac{k'_{rw}}{\mu_w}\right) \cdot \left(\frac{\mu_o}{k'_{ro}}\right) \tag{3.6}$$

where k'_{rw} = end point water relative permeability

k'_{ro} = end point oil relative permeability

Water tongue normally occurs when the injection rate is higher than the critical rate for by-passing ($q_{w,crit}$) which can be calculated from the following equation [16].

$$q_{w,crit} = \frac{k\, k'_{rw}\, A\, \Delta\rho\, g\, sin\theta}{1.0133{\times}10^{6}\, \mu_w\, (M-1)} \tag{3.7}$$

Thereby, injection rate should be maintained below $q_{w,crit}$ to avoid early breakthrough causing by unstable flood front. Early water breakthrough results in high water cut at the production well. It directly reduces the performance of oil production because high amount of oil is bypassed by this underrunning water. Moreover, the costs of surface facility and management, including separator and waste water management, rise up.

3.3.2 Gas displacing oil

In a dipping reservoir, gas injection well is normally located at up-dip structure location. Gas displaced oil down-dip to the production well. Gas fractional flow can be calculated by Welge equation [17].

$$f_g = \frac{1 + \frac{k\, k_{ro}\, \Delta\rho\, A\, sin\alpha}{q_t\, \mu_o}}{1 + \frac{1}{M}} \tag{3.8}$$

where M = mobility ratio = $\left(\frac{k_{rg}}{\mu_g}\right) \cdot \left(\frac{\mu_o}{k_{ro}}\right)$

f_g = fractional flow of gas in reservoir

k = absolute permeability

k_{ro} = relative permeability to oil

k_{rg} = relative permeability to gas

$\Delta\rho$ = $\rho_g - \rho_o$

A = area of cross section normal to the bedding plane

α = dip angle of the reservoir

q_t = total flow rate

μ_o = viscosity of oil

μ_g = viscosity of gas

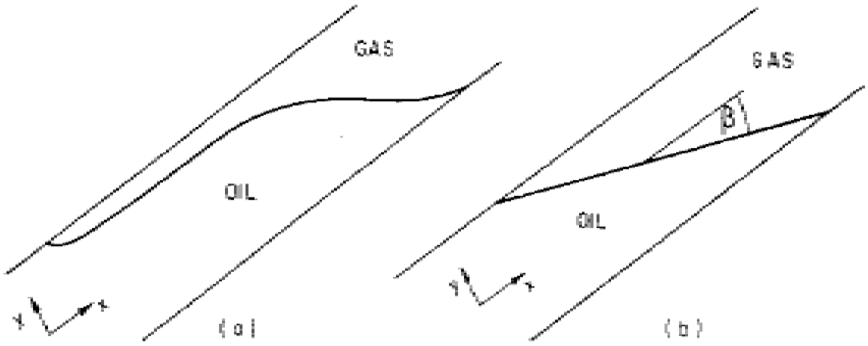


Figure 3.4 Gas displacement: (a) unstable and (b) stable (after [16]).

In contrast to water underrun, gas flooding can cause the problem of gas override due to lower density. The angle between the gas-oil interface and the bedding plane is constant throughout the flooding process in the stable displacement but not constant in the unstable displacement as shown in Figure 3.4. Even though the problem of gas override is more difficult to avoid as compared to the problem of water underrun because of the larger difference in fluid viscosities, gas injection rate is still necessary to be optimized. Too high gas injection rate not only decreases the sweep efficiency, which lowers the production performance, but also increases the operating costs. The examples of these costs affected by gas injection rate are the costs of storage tank, pump, separator, and gas conditioning unit.

The dimensionless gravity number (G), the end point mobility ratio (M), and the critical rate for by-passing ($q_{g,crit}$) can be calculated from the following equations [16]:

$$G = \frac{k\, k'_{rg}\, A\, \Delta\rho\, g\, sin\theta}{1.0133\times10^{6}\, q_t\, \mu_g} \quad (3.9)$$

$$M = \left(\frac{k'_{rg}}{\mu_g}\right)\cdot\left(\frac{\mu_o}{k'_{ro}}\right) \quad (3.10)$$

$$q_{g,crit} = \frac{k\, k'_{rg}\, A\, \Delta\rho\, g\, sin\theta}{1.0133\times10^{6}\, \mu_g\, (M-1)} \quad (3.11)$$

where k'_{rg} = end point gas relative permeability

3.4 Three-phase relative permeability

Relative permeability is defined as the ability of porous medium or reservoir rock to conduct each fluid in several-fluid-phase system. There are three phases of fluid involving in WAG and DDP, namely, oil, water, and gas. In ECLIPSE, there are three models that can be used to indicate three-phase relative permeability according to Schlumberger's simulation software manuals 2007.1 [18].

3.4.1 ECLIPSE default

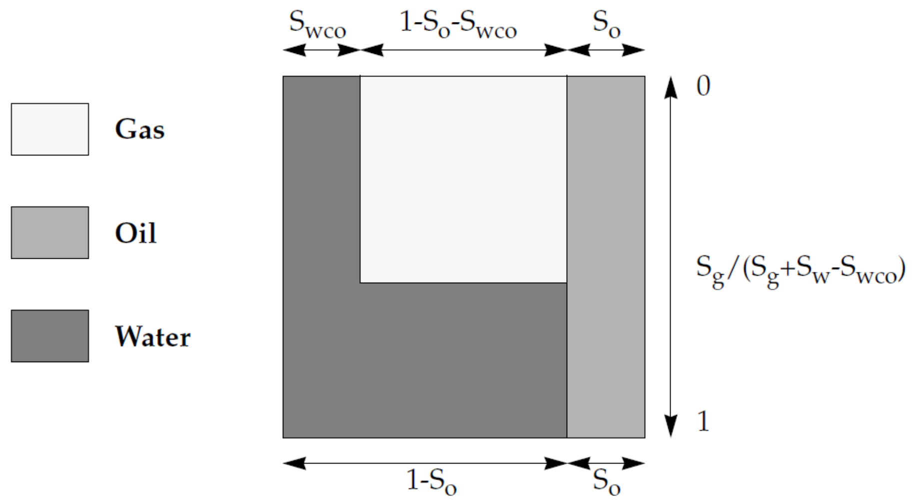


Figure 3.5 Relationship of oil, water, and gas saturations for the ECLIPSE default model (after [18]).

In a fraction $S_g/(S_g+S_w-S_{wco})$ of the cell (the gas zone),

the oil saturation is S_o

the water saturation is S_{wco}

the gas saturation is $S_g+S_w-S_{wco}$

In fraction $(S_w-S_{wco})/(S_g+S_w-S_{wco})$ of the cell (the water zone),

the oil saturation is S_o

the water saturation is S_g+S_w

the gas saturation is 0

The relative permeability is calculated by the following equation.

$$k_{ro} = \frac{S_g k_{rog} + (S_w - S_{wco}) k_{row}}{S_g + S_w - S_{wco}} \tag{3.13}$$

where S_{wco} = the connate water saturation

k_{rog} = the oil relative permeability for a system with oil, gas, and connate water

k_{row} = the oil relative permeability for a system with oil and water only

3.4.2 Stone 1 (modified)

This is the modification of Stone 1 model. The relative permeability is calculated by the following equation.

$$k_{ro} = k_{rocw} SS_o F_w F_g \tag{3.14}$$

where k_{rocw} = the oil relative permeability in the presence of connate water only

SS_o = $(S_o-S_{om})/(1-S_{wco}-S_{om})$ when $S_o > S_{om}$

F_w = $k_{row}/(k_{rocw}\cdot(1-SS_w))$

F_g = $k_{rog}/(k_{rocw}\cdot(1-SS_g))$

SS_w = $(S_w-S_{wco})/(1-S_{wco}-S_{om})$ when $S_w > S_{wco}$

SS_g = $S_g/(1-S_{wco}-S_{om})$

k_{rog} = the oil relative permeability for a system with oil, gas, and connate water

k_{row} = the oil relative permeability for a system with oil and water only

S_{om} = the minimum residual oil saturation

3.4.3 Stone 2 (modified)

This is the modification of Stone 2 model. The relative permeability is calculated by the following equation.

$$k_{ro} = k_{rocw}\left[\left(\frac{k_{row}}{k_{rocw}} + k_{rw}\right)\left(\frac{k_{rog}}{k_{rocw}} + k_{rg}\right) - k_{rw} - k_{rg}\right] \tag{3.15}$$

where k_{rog} = the oil relative permeability for a system with oil, gas, and connate water

k_{row} = the oil relative permeability for a system with oil and water only

k_{rocw} = the oil relative permeability in the presence of connate water only

3.5 Fracturing pressure

The fracturing pressure is the pressure that can cause fracture in reservoir formation. Therefore, any fluid should be injected below this pressure to prevent the reservoir from any damage. Equation 3.16 is used to calculate fracturing pressure for the M Field in the Gulf of Thailand [19].

$$Fracturing\ pressure\ (bar) \ = \ \frac{FRAC.S.G. \times TVD}{10.2} \qquad (3.16)$$

where FRAC.S.G. = fracturing pressure gradient (bars/meter)

= $1.22 + (TVD \times 1.6 \times 10^{-4})$

TVD = true vertical depth below rotary table (meter)

3.6 Barrel of oil equivalent

Barrel of oil equivalent (BOE) is an effective indicator to illustrate production performance for process involving gas injection and production. Produced oil, produced gas, and injected gas are taken into account for the calculation. BOE can be calculated by the following equation [20].

BOE = Cumulative oil production (STB) +
[Cumulative gas production (MMSCF) x 166.7] –
[Cumulative gas injection (MMSCF) x 166.7] (3.17)

CHAPTER IV
MODEL DESCRIPTION

The reservoir model is constructed in order to study and compare two recovery processes which are water alternating gas process (WAG) and double displacement process (DDP). Description of the model is shown in this chapter.

4.1 Reservoir model

The homogeneous reservoir model with following parameters as shown in Table 4.1 is constructed for simulation by BlackOil Simulator in ECLIPSE100. This model consists of 45,260 corner-point Cartesian grids as shown in Figure 4.1. The reservoir size of 6,000 ft x 2,000 ft x 200 ft is represented by 73 x 31 x 20 grid blocks. Grid cells in the x, y, and z–direction are shown in Figures 4.2, 4.3, and 4.4, respectively.

Table 4.1 Parameters of the reservoir model.

Parameters	**Values**	**Units**
Grid number	73 x 31 x 20	block
Reservoir size	6,000 x 2,000 x 200	ft^3
Porosity	15.09	%
X Permeability	126	md
Y Permeability	126	md
Z Permeability	12.6	md
Top of reservoir	5,000	ft
Initial pressure at 5,000 ft	2,242	psia
Bubble point pressure	2,242	psia
Dip angle	15	degree
Initial oil saturation	0.7	-

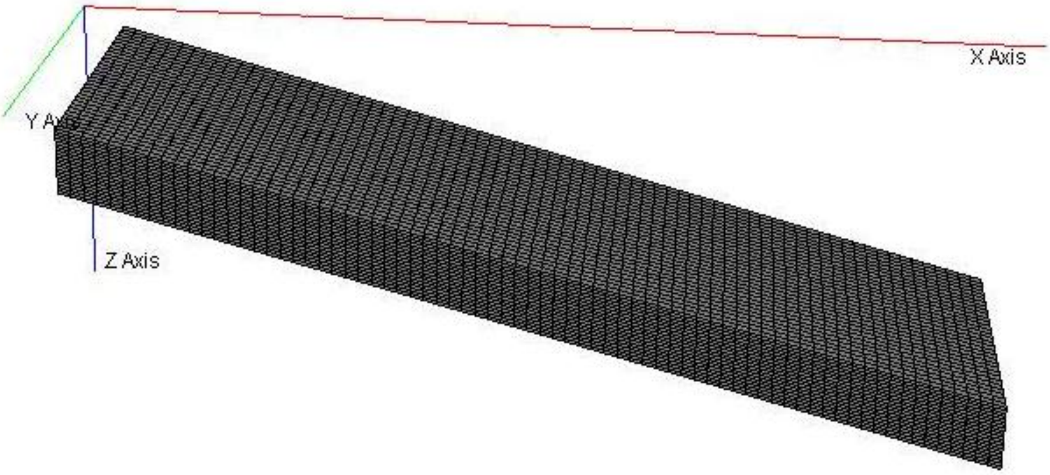


Figure 4.1 The 3D reservoir model.

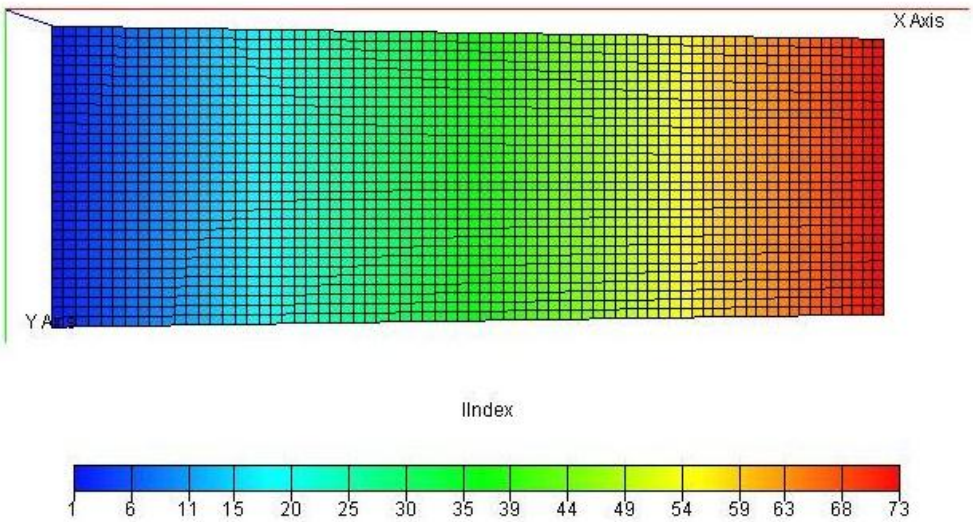


Figure 4.2 Grid cells in the x-direction.

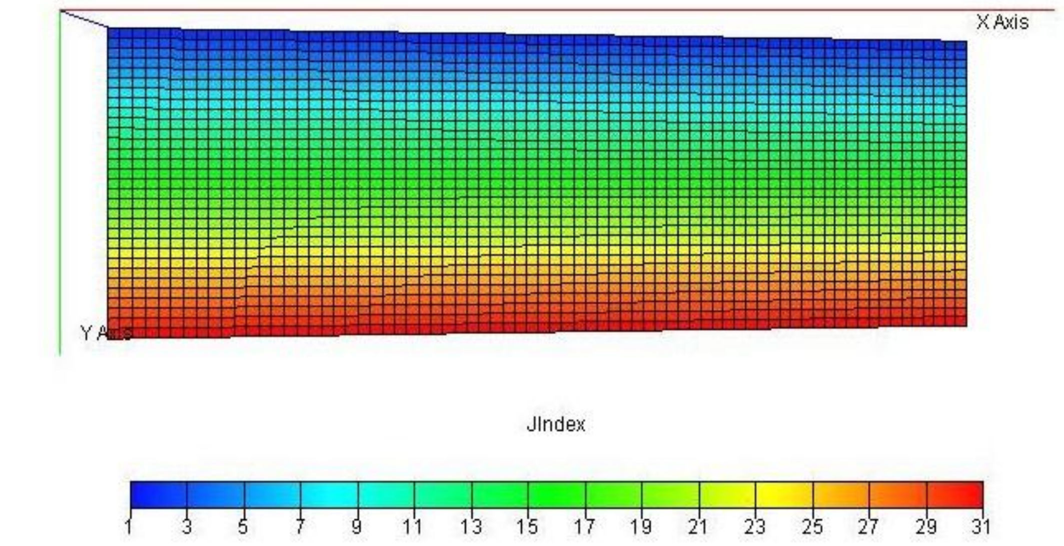


Figure 4.3 Grid cells in the y-direction.

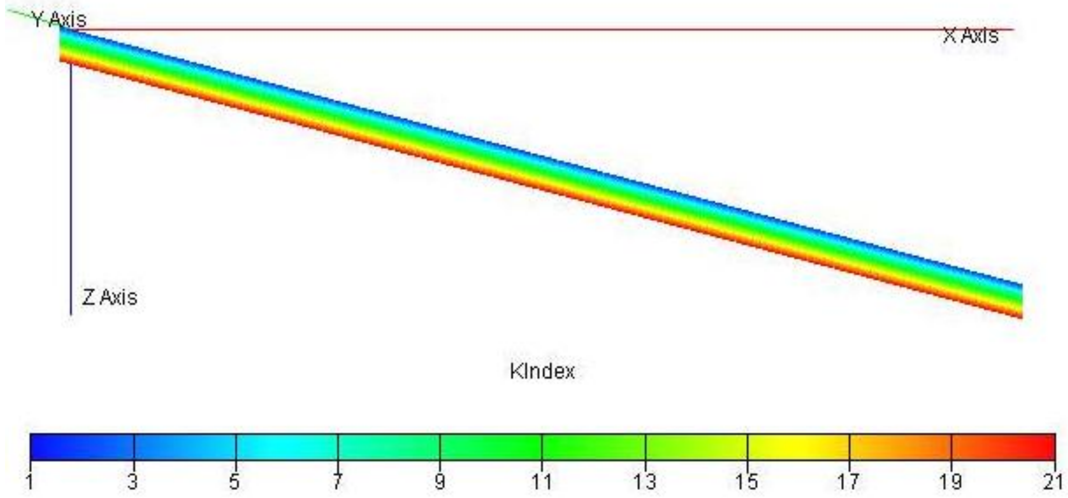


Figure 4.4 Grid cells in the z-direction.

4.2 PVT properties

PVT properties refer to properties of oil, gas, water and rock. The densities of oil, gas, and water at standard conditions are assumed to be 51.45684 lb/ft^3, 0.04369958 lb/ft^3, and 62.42797 lb/ft^3, respectively. Data in Table 4.2 have to be put in PVT correlation section to let ECLIPSE generate live oil PVT properties (Figure 4.5) and dry gas PVT properties (Figure 4.6). Water PVT properties are shown in Table 4.3. The rock compressibility is assumed to be 3.013923 x 10^{-6} psi^{-1}.

Table 4.2 Input data for PVT correlation.

Input Data	Values	Units
Oil gravity	40	°API
Gas gravity	0.7	s.g. air
Gas oil ratio (R_s)	566	SCF/STB
Standard temperature	60	°F
Standard pressure	14.7	psia
Reservoir temperature	200	°F
Reference pressure	3000	psia
Rock type	Consolidated sandstone	-

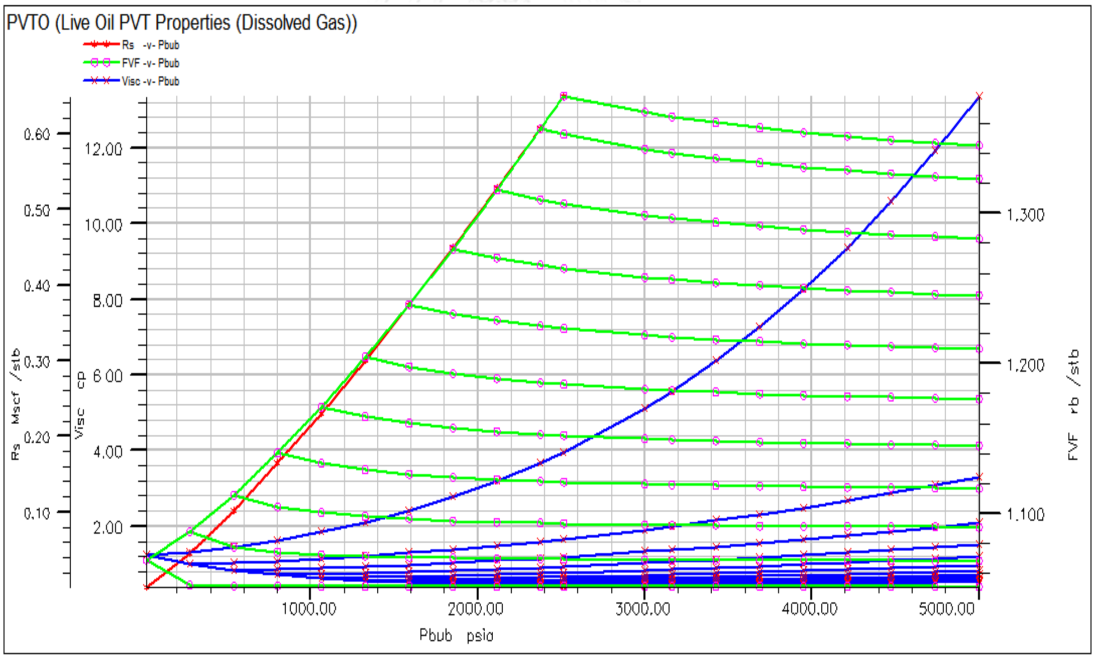


Figure 4.5 Live oil PVT properties.

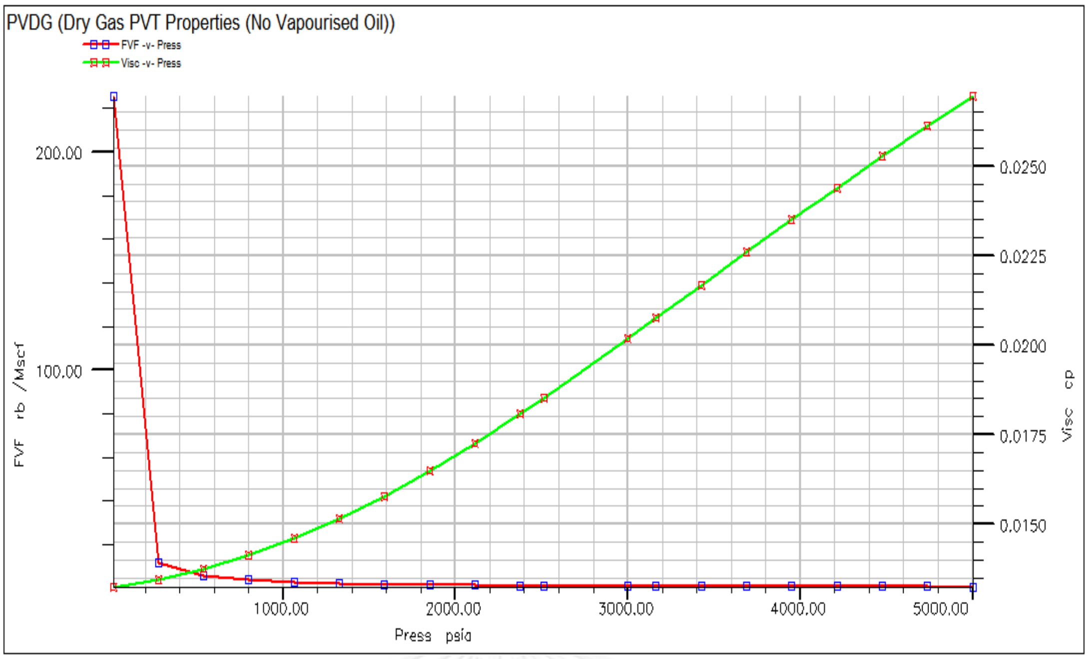


Figure 4.6 Dry gas PVT properties.

Table 4.3 Water PVT properties.

Properties	Values	Units
Water FVF at P_{ref}	1.021734	RB/STB
Water compressibility	3.09988×10^{-6}	psi^{-1}
Water viscosity at P_{ref}	0.3013289	cp
Water viscosibility	3.396041×10^{-6}	psi^{-1}

4.3 SCAL properties

Relative permeability curves are generated by ECLIPSE using Corey's correlation. Input parameters for Corey's correlation are listed in Table 4.4. Gas/oil saturation functions and water/oil saturation functions are shown in Figure 4.7 and Figure 4.8, respectively.

Table 4.4 Input parameters for Corey's correlation.

Corey water	3	Corey gas/oil	3	Corey oil/water	1.5
S_{wmin}	0.25	S_{gmin}	0	Corey oil/gas	1.5
S_{wcr}	0.25	S_{gcr}	0.15	S_{org}	0.1
S_{wi}	0.25	S_{gi}	0.15	S_{orw}	0.3
S_{wmax}	1	$K_{rg}(S_{org})$	0.4	$K_{ro}(S_{wmin})$	0.8
$K_{rw}(S_{orw})$	0.3	$K_{rg}(S_{gmax})$	0.4	$K_{ro}(S_{gmin})$	0.8
$K_{rw}(S_{wmax})$	1				

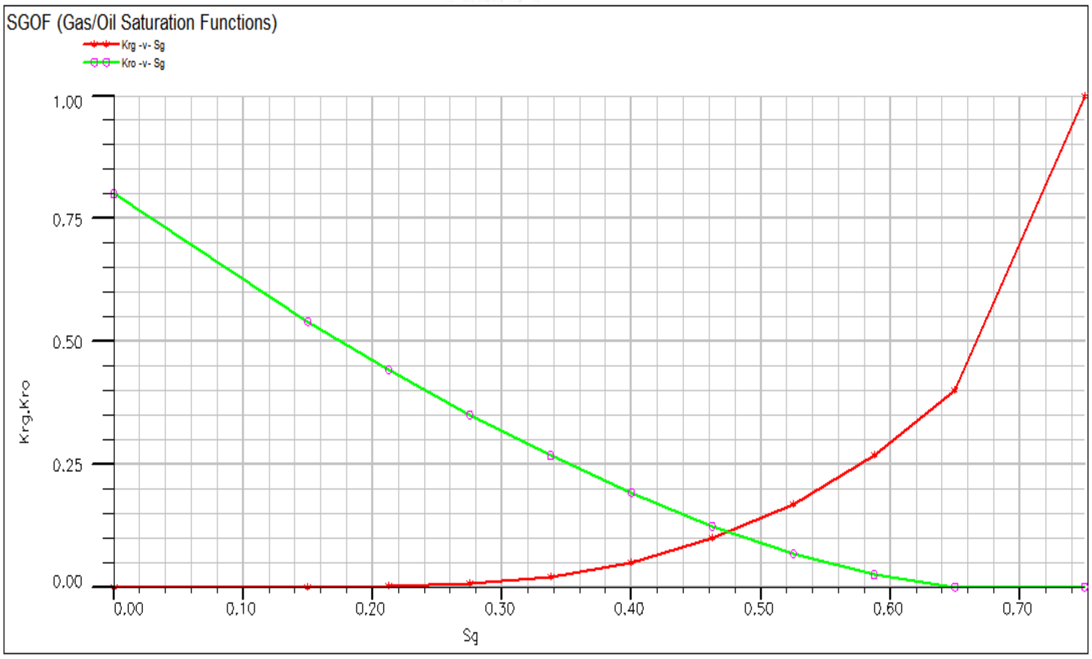


Figure 4.7 Gas/oil saturation functions.

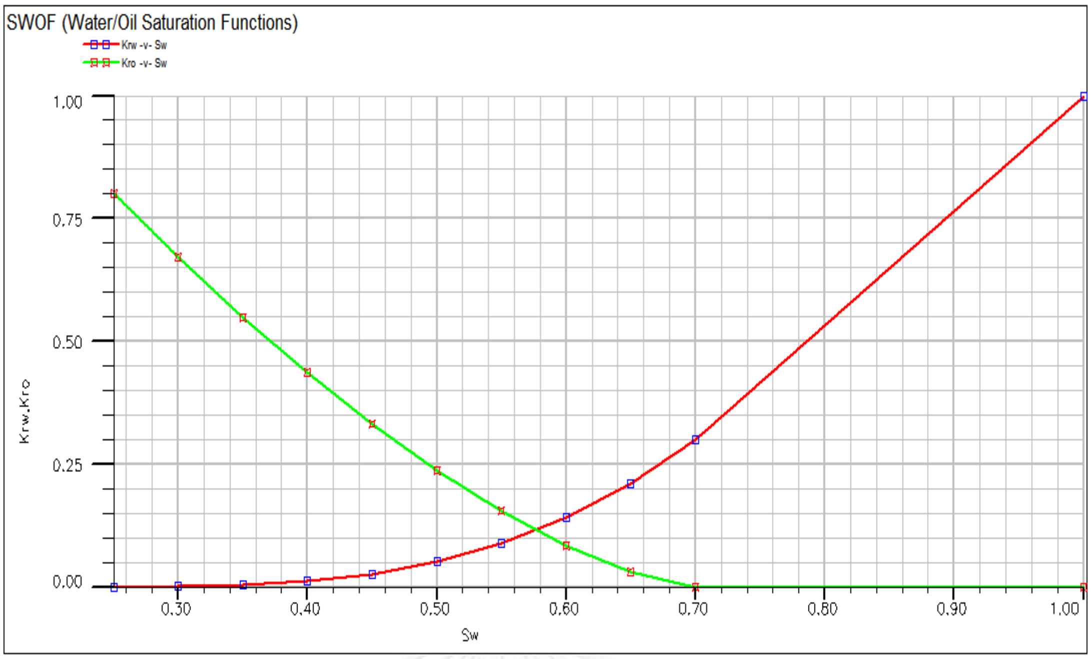


Figure 4.8 Water/oil saturation functions.

4.4 Well schedule

For the base case model, two vertical wells are constructed in the model, one well at up-dip location and another well at down-dip location as shown in Table 4.5 and Figures 4.9 and 4.10. Fracture pressures of well 1 and well 2 are calculated by Eq. 3.16.

Table 4.5 Well location and fracture pressure for the base case model.

Parameters	Values	Unit
Position of well 1	i=12, j=16	-
Position of well 2	i=62, j=16	-
Fracture pressure of well 1	3,260	psia
Fracture pressure of well 2	4,080	psia

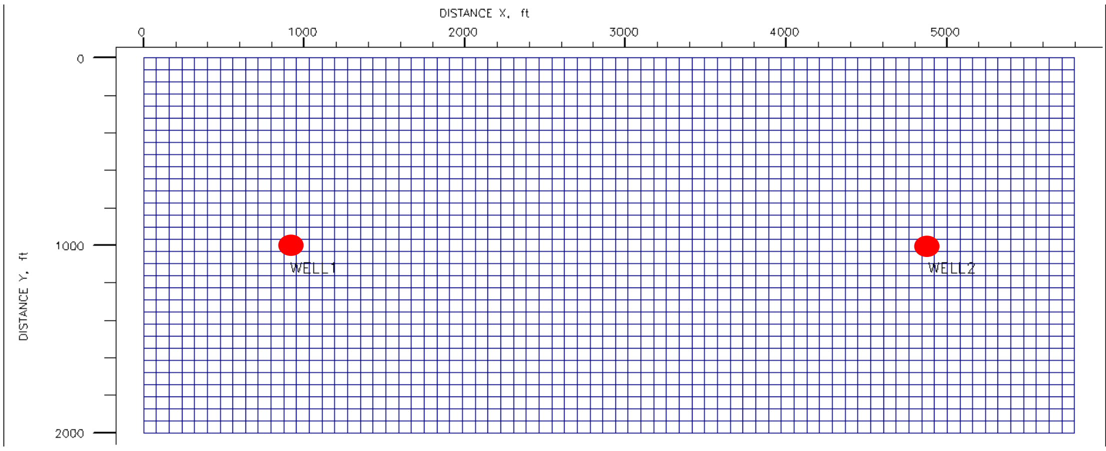


Figure 4.9 Well locations for base case model.

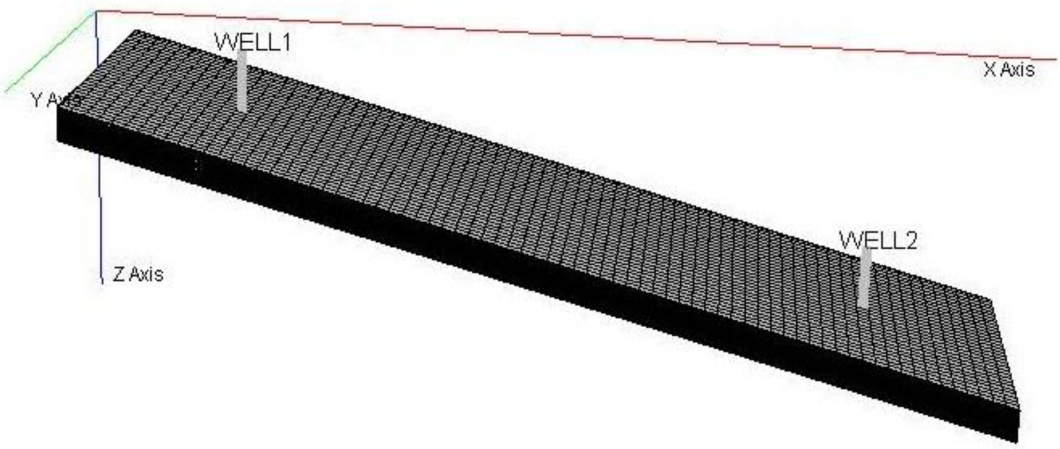


Figure 4.10 Well location in 3D for base case model.

4.4.1 Water alternating gas process (WAG)

In this study, WAG is divided into two types which are WAG with up-dip injection and WAG with down-dip injection. Parameters for well schedule for WAG for the base case are shown in Table 4.6.

Table 4.6 Parameters for well schedule for WAG.

Parameters	Values	Units
Water injection rate	8,000	RB/D
Production rate during water injection	8,000	RB/D
Gas injection rate	8,000	RB/D
Production rate during gas injection	8,000	RB/D
Water cut for stopping time of water injection	60	%
Water injection duration	90	days
Gas injection duration	90	days
Economic constraint	Oil rate < 50	STB/D
Production time	30	years

4.4.1.1 WAG with up-dip injection

For WAG with up-dip injection, well 1 and well 2 are set as producer and water injector, respectively, during the initial water flooding period. After the water cut of well 1 reaches a certain value, both wells are shut for 180 days. Slugs of water and gas are then injected alternately at well 1 while oil is produced at well 2. The production period is limited at 30 years. However, the production is stopped if the oil rate reaches economic constraint.

4.4.1.2 WAG with down-dip injection

For WAG with down-dip injection, well 1 and well 2 are set as producer and water injector, respectively, during the initial water flooding period. After the water cut of well 1 reaches a certain value, both wells are shut for 180 days. Slugs of water and gas are then injected alternately at well 2 while oil is produced at well 1. The production period is limited at 30 years. However, the production is stopped if the oil rate reaches the economic constraint.

4.4.2 Double displacement process (DDP)

For DDP, well 1 and well 2 are set as producer and water injector, respectively, during the initial water flooding period. After the water cut of well 1 reaches a certain value, both wells are shut for 180 days. Gas flooding is then performed by setting well 1 and well 2 as gas injector and producer, respectively. The production period is limited at 30 years. However, the production is stopped if the oil rate reaches the economic constraint. Parameters for well schedule for DDP base case are shown in Table 4.7.

Table 4.7 Parameters for well schedule for DDP.

Parameters	**Values**	**Units**
Water injection rate	8,000	RB/D
Production rate during water injection	8,000	RB/D
Gas injection rate	8,000	RB/D
Production rate during gas injection	8,000	RB/D
Water cut for stopping time of water injection	60	%
Economic constraint	Oil rate < 50	STB/D
Production time	30	years

4.5 Thesis methodology

The details of thesis methodology are summarized below:

1. Construct a 15° reservoir model consisting of 45,260 corner-point Cartesian grids as detailed in Section 4.1. PVT and SCAL properties for the model are shown in Sections 4.2 and 4.3, respectively.

2. Study the production characteristics of long-term water flooding, water alternating gas (WAG), and double displacement process (DDP) by performing four base cases as listed below:

   2.1 long-term water flooding base case

2.2 short-term water flooding followed by WAG with up-dip injection base case

2.3 short-term water flooding followed by WAG with down-dip injection base case

2.4 DDP base case

3. Since WAG and DDP start with initial water flooding, the effect of stopping criteria for water flooding is studied. Water injection is stopped when water cut of the producer reaches 1, 20, 40, 60, and 80%. This study is performed for reservoir with dip angle of 0°, 15°, and 30°. The water cut stopping criteria that yields the highest barrel of oil equivalent (BOE) for each production process and each reservoir are used in the subsequent studies.

4. Determine water and gas injection rates that yield the highest BOE for each production process and each reservoir. These rates are used in the subsequent studies. The 16 cases with the combination of water injection rate (6,000, 8,000, 10,000, and 12,000 RB/D) and gas injection rate (6,000, 8,000, 10,000, and 12,000 RB/D) are applied in this study.

5. Study the effect of WAG cycle and injection duration for WAG with up-dip and down-dip injection processes. Cases with different WAG cycles (1:4, 1:2, 1:1, 2:1, and 4:1) and different durations of injection are performed to find the case that provides the highest BOE for each process and each reservoir.

6. Construct the following well patterns to study their effects on oil production. Water cut stopping criteria, water and gas injection rates, and WAG cycle and injection duration that yield the highest BOE for each process and reservoir from the previous studies are applied in this study.

   6.1 pattern with 2 vertical wells (base case)

   6.2 pattern with 4 vertical wells

   6.3 pattern with 8 vertical wells

   6.4 pattern with 2 horizontal wells

6.5 pattern with an up-dip vertical well and a down-dip horizontal well

7. Compare the production performances of WAG with up-dip injection, WAG with down-dip injection, and DDP. The production process that yields the highest BOE for each reservoir is summarized.

8. Study the effects of the following reservoir and fluid properties on oil production performance. The cases that yield the highest BOE for 0°, 15°, and 30° reservoir are applied in this study.

   8.1 horizontal permeability (25.2, 126, and 630 md)

   8.2 vertical/horizontal permeability ratio (0.01, 0.1, and 0.5)

   8.3 three-phase relative permeability correlation (ECLIPSE default model, Stone 1 model, and Stone 2 model)

   8.4 reservoir thickness (50, 200, and 500 ft.)

   8.5 oil properties (as shown in Table 4.8)

Table 4.8 Cases with different oil properties.

Case	Property	
	Oil gravity [°API]	R_s [SCF/STB]
1	30	400
2	40	650
3	50	1,000

CHAPTER V
RESULTS AND DISCUSSION

The results of two recovery processes which are water alternating gas process (WAG) and double displacement process (DDP) are presented and discussed in this chapter. For WAG, four parameters which are (1) stopping time for water injection, (2) water and gas injection rates, (3) WAG cycle and injection duration, and (4) well pattern are investigated for their effects. For DDP, three parameters which are (1) stopping time for water injection, (2) water and gas injection rates, and (3) well pattern are examined. These studies are performed for reservoir with dip angle of 0°, 15°, and 30°. After that, sensitivity on the change in (1) horizontal permeability, (2) vertical/horizontal permeability ratio, (3) relative permeability correlation, (4) reservoir thickness, and (5) oil property is conducted.

5.1 Base cases

5.1.1 Long-term water flooding

Water flooding process is performed by continuously injecting water at down-dip location (well 2) and producing oil at up-dip location (well 1). This process is stopped when the water cut of the producer reaches 95%.

Figure 5.1 shows water injection rate and bottom-hole pressure of the water injector (well 2). Water injection rate of 8,000 RB/D (or approximately 7,850 STB/D) can be kept constant throughout the production time because the bottom-hole pressure is always lower than the fracturing pressure of 4,080 psia.

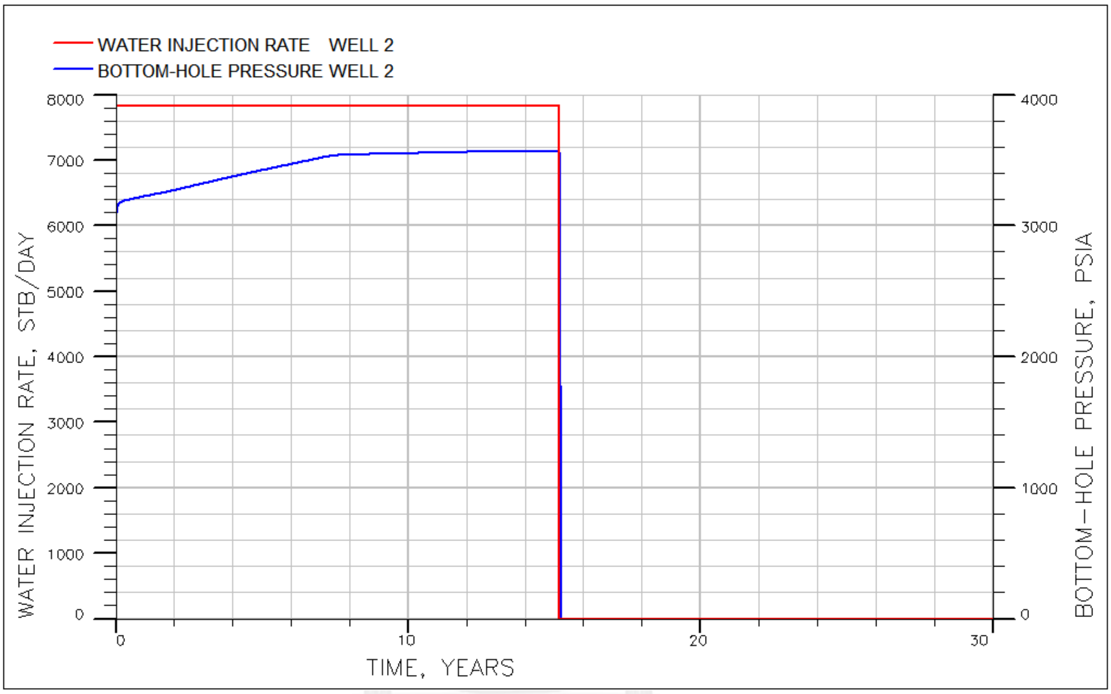


Figure 5.1 Water injection rate and bottom-hole pressure of water injector of long-term water flooding.

Oil and gas are produced at quite constant rates about 7 years before the breakthrough of injected water. After that, their rates drop dramatically while water production rate increases rapidly between the seventh year and the fifteenth year. As the water cut of producer (well 1) reaches 95%, the production is stopped. The total production time of this long-term water flooding base case is 15.17 years. Oil, gas, and water production rates are illustrated in Figure 5.2.

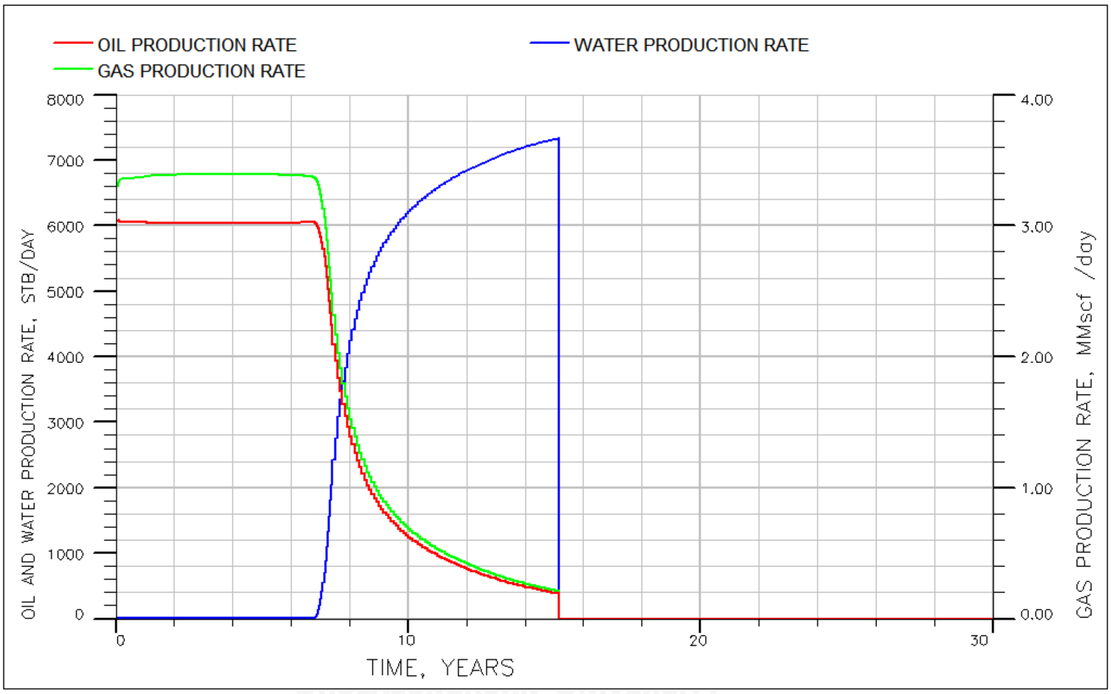


Figure 5.2 Oil, gas, and water production rates of long-term water flooding.

Long-term water flooding can recover 19.675 MMSTB of oil, equivalent to 56.05% of oil recovery in 15.17 years as shown in Figure 5.3.

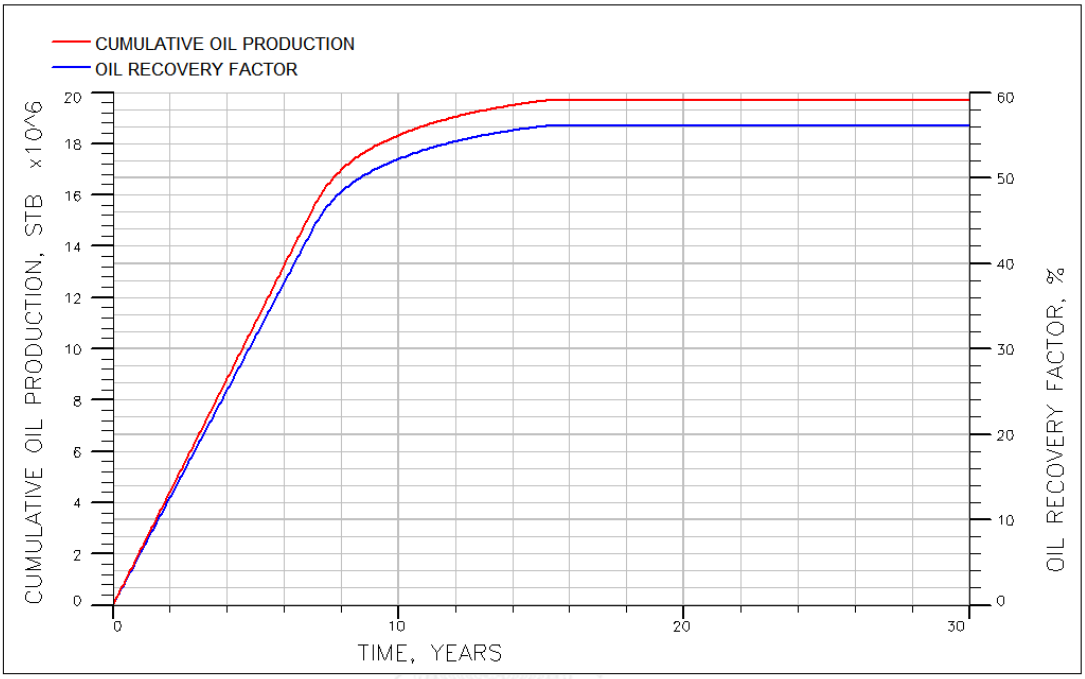


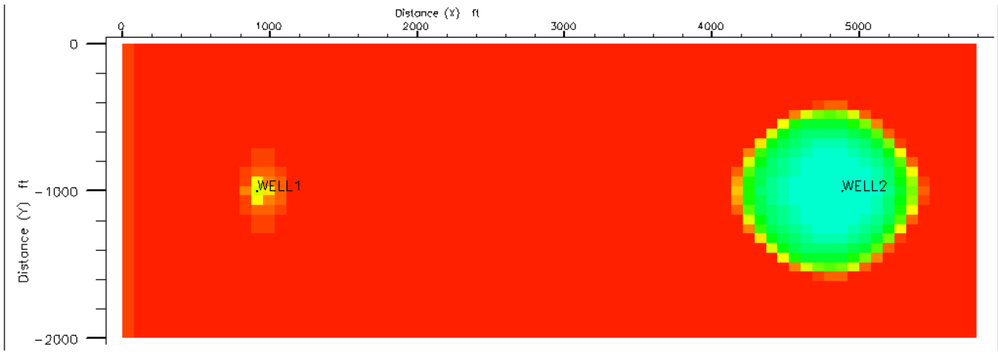
Figure 5.3 Cumulative oil production and oil recovery factor of long-term water flooding.

Figures 5.4 and 5.5 illustrate oil saturation inside the reservoir at different times as listed below:

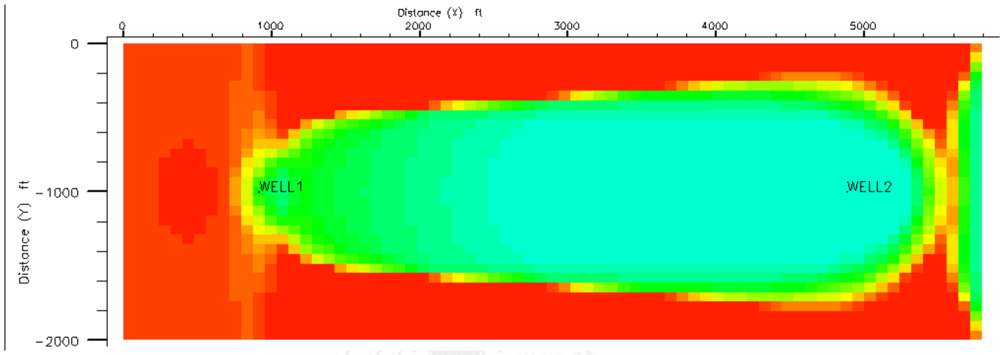
a) At early time of water flooding (1 year of production), injected water displaces oil around the injector. Most area is still unswept.

b) At middle time of water flooding (8 years of production), injected water arrives the producer. There is an accumulation of water to form a water bank at the bottom part of reservoir. Most amount of oil is displaced except in the top reservoir layer (z-direction) and the zone up-dip of well 1.

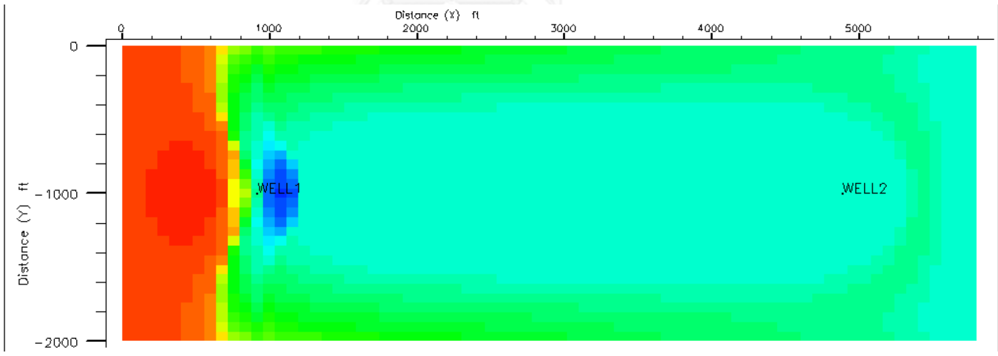
c) At the end of production (15.17 years), there is a small oil bank in the area up-dip of the producer separating from the water bank due to the difference in their densities. However, water sweeps almost all area of the reservoir.



(a) 1 year of production



(b) 8 years of production



(c) At the end of production (15.17 years)

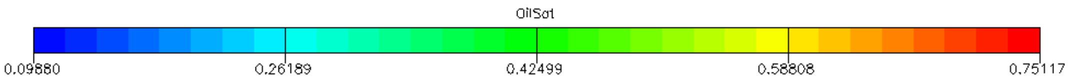
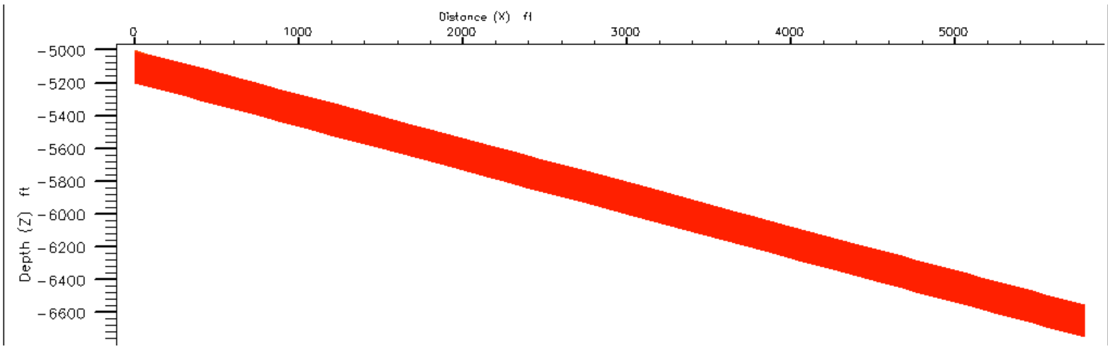
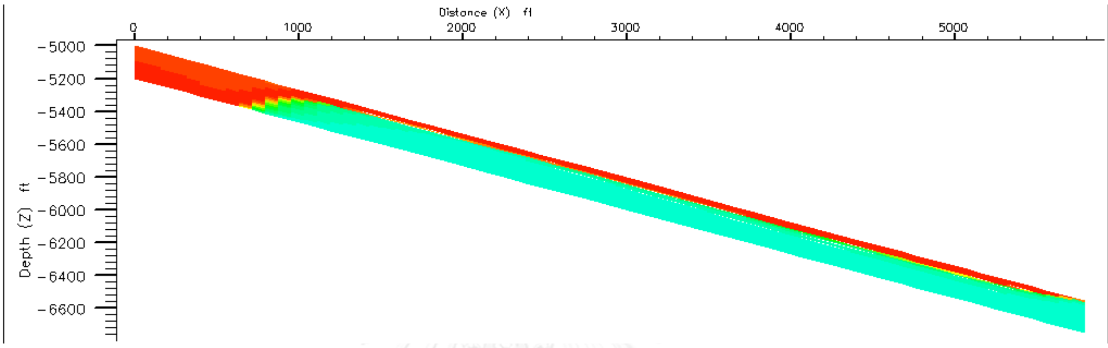


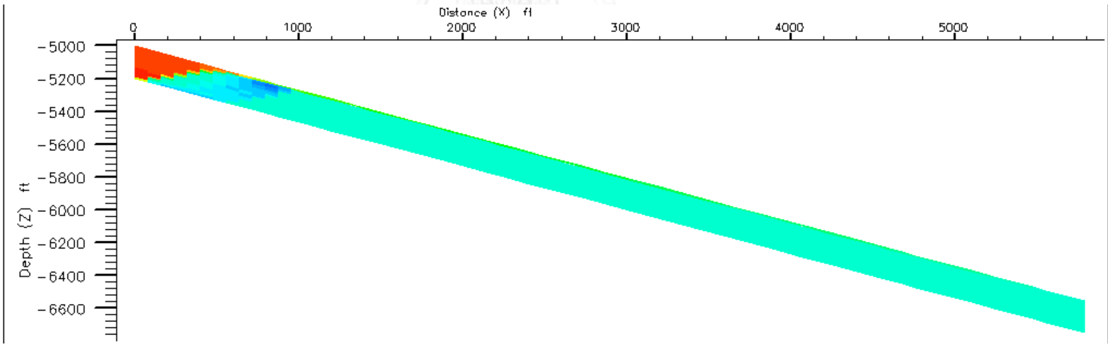
Figure 5.4 Oil saturation at any time of long-term water flooding (top view, k=1).



(a) 1 year of production



(b) 8 years of production



(c) At the end of production (15.17 years)

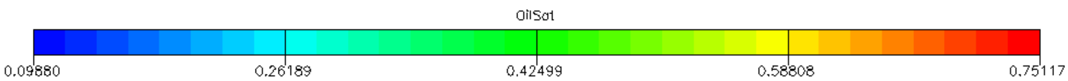


Figure 5.5 Oil saturation at any time of long-term water flooding (side view, j=31).

5.1.2 Short-term water flooding followed by water alternating gas process (WAG) base case

Water alternating gas process (WAG) is the injection of water alternately with gas in separated slugs. In this study, the process starts with water flooding by injecting water at down-dip location (well 2) and producing oil at up-dip location (well 1). All wells are shut for 180 days when the water cut reaches 60%. After that, WAG is performed in two different types which are WAG with up-dip injection and WAG with down-dip injection.

5.1.2.1 WAG with up-dip injection base case

After the water cut in the initial water flooding reaches the criteria of 60%, water and gas are injected alternately at up-dip location (well 1) while the production is done at down-dip location (well 2) of which schedule is shown in Table 5.1.

Table 5.1 Well schedule for WAG with up-dip injection base case.

Step of production	**Well 1 (up-dip)**	**Well 2 (down-dip)**
water flooding	producer (8000 RB/D)	water injector (8000 RB/D)
water cut of well 1 reaches 60%	shut in for 180 days	shut in for 180 days
WAG with up-dip injection	water/gas injector (8000 RB/D)	producer (8000 RB/D)

During the period of water flooding from the first day to the eighth year of production, water is injected at well 2 with the rate of 8,000 RB/D or approximately 7,850 STB/D as shown in Figure 5.6. The bottom-hole pressure of well 2 does not exceed the fracturing pressure of 4,080 psia. This means water can be injected with this rate without fracturing the formation.

For WAG process following the initial water flooding, water and gas injection durations of 90 days are injected alternately at well 1 at the same rate of 8,000 RB/D which are approximately 7,850 STB/D for water and 6.7 MMSCF/D for gas. They also do not cause any fracture because the bottom-hole pressure of well 1 is always lower than the fracturing pressure of 3,260 psia as illustrated in Figures 5.6 and 5.7.

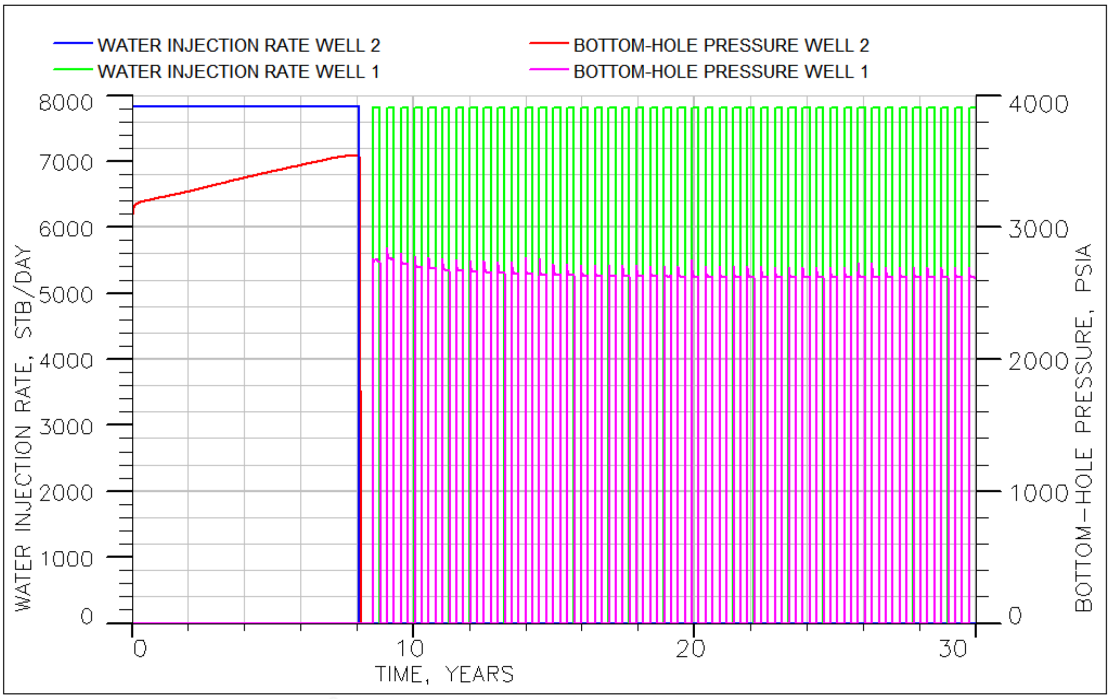


Figure 5.6 Water injection rate and bottom-hole pressure of water injector of the WAG with up-dip injection base case.

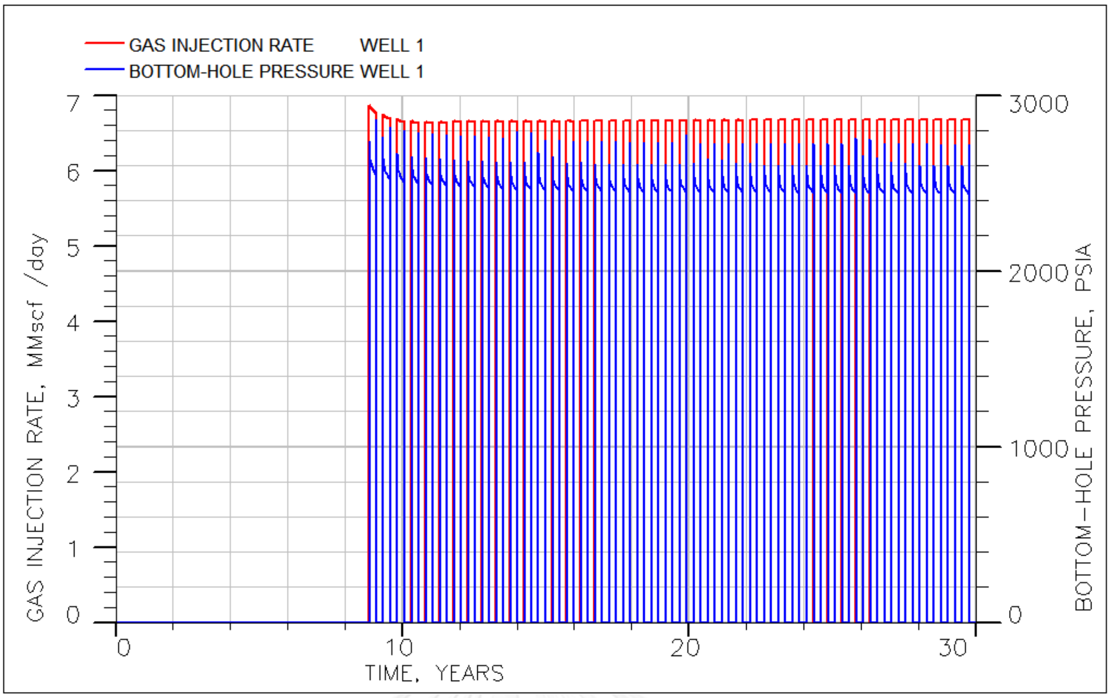


Figure 5.7 Gas injection rate and bottom-hole pressure of gas injector of the WAG with up-dip injection base case.

From Figure 5.8, oil and gas start to be produced by well 1 at quite constant rates which are approximately 6,000 STB/D and 3.4 MMSCF/D, respectively, during the initial water flooding for about 7 years before water breakthrough. After that, oil and gas rates drop very rapidly whereas water rate increases because of the arrival of water at well 1. At 8.59 years, fluids are produced by well 2 with a high amount of water which is formerly injected and accumulates around this well at down-dip location. In the twelfth year, a dramatic increase in gas rate occurs together with a slight increase in oil rate and an expeditious decrease in water rate due to the breakthrough of injected gas.

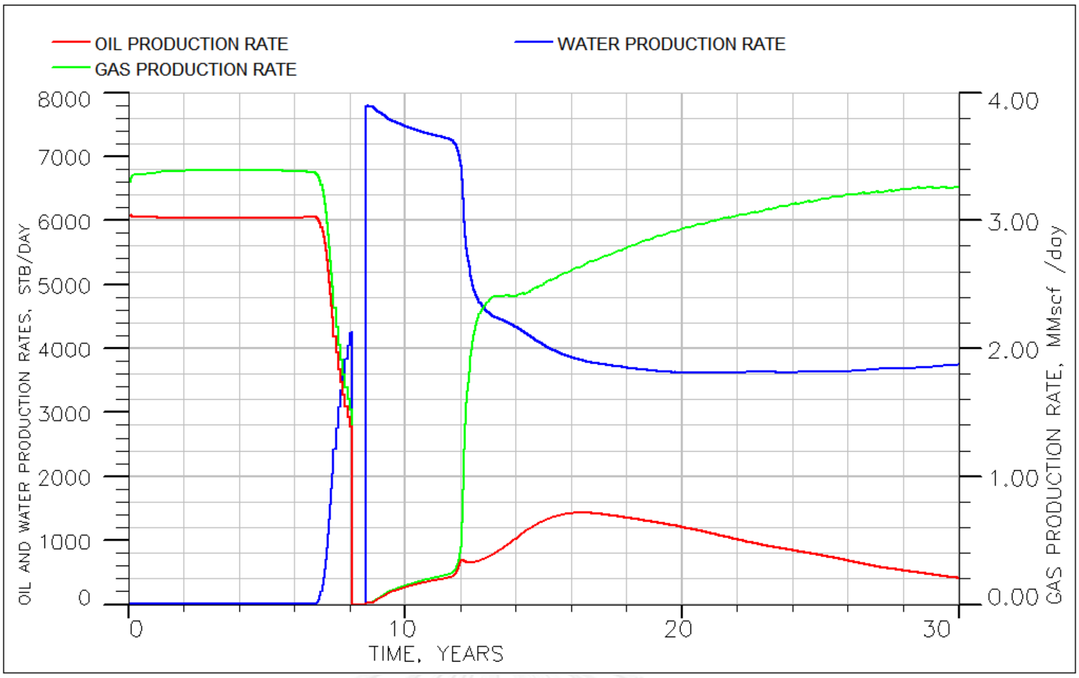


Figure 5.8 Oil, gas, and water production rates of the WAG with up-dip injection base case.

Figure 5.9 shows that the initial water flooding that is implemented until the water cut reaches 60% can recover 17.068 MMSTB of oil or 48.62% recovery while an additional 6.643 MMSTB of oil is recovered by WAG. Therefore, the total amount of oil production reaches 23.711 MMSTB, equivalent to the oil recovery factor of 67.55% in the last year of production.

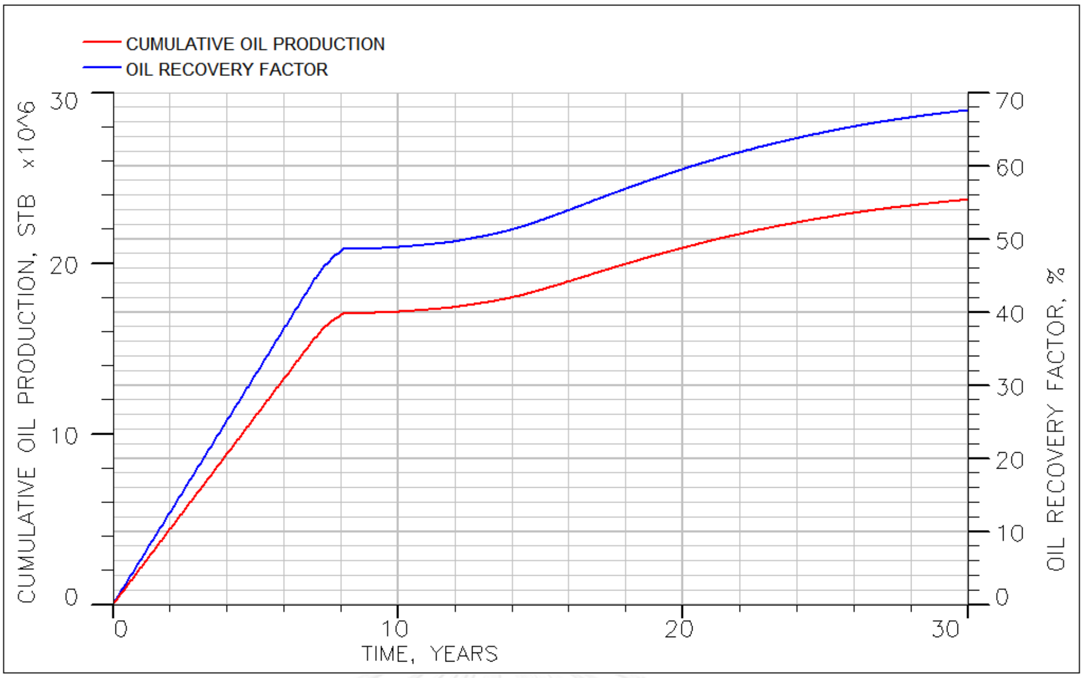


Figure 5.9 Cumulative oil production and oil recovery factor of the WAG with up-dip injection base case.

Water is injected since the first day of production; however, it starts to be produced in the seventh year after breakthrough. The total amount of injected water is 53.990 MMSTB while the total amount of produced water is 35.557 MMSTB.

The total amount of 28.676 BSCF of gas is produced by two mechanisms: water flooding and WAG. Gas injection is performed since the eight year. Consequently, 9.7 BSCF of gas produced before this time is solution gas in the reservoir. The total amount of gas needed for injection is 25.792 BSCF.

Since there is no water in the reservoir, water cut in the early time is zero. It later increases dramatically to 60%, the stopping criteria for water injection, at the eight year because of the breakthrough of water. At the early time of WAG, water cut is very high because of an accumulation of water around well 2. Then, it drops to about 73% at the seventeenth year and finally increases to 90% in the last year.

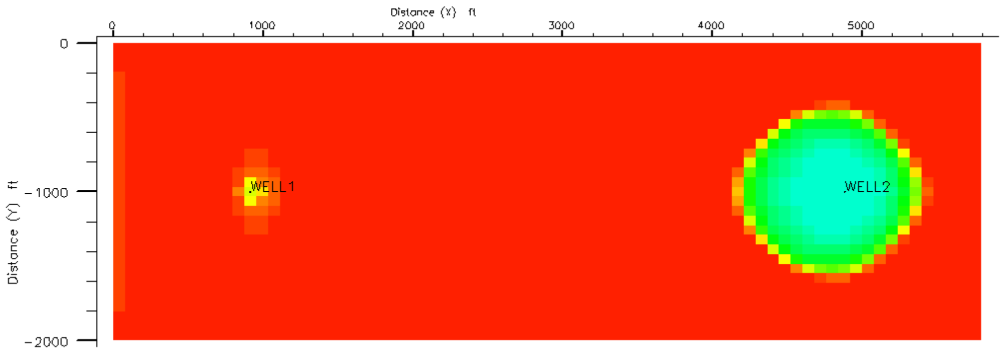
Figures 5.10 and 5.11 illustrate oil saturation inside the reservoir at different times as listed below:

a) At early time of water flooding (1 year of production), oil saturation around well 2 is quite low due to oil being displaced by injected water. Most area is still unswept.

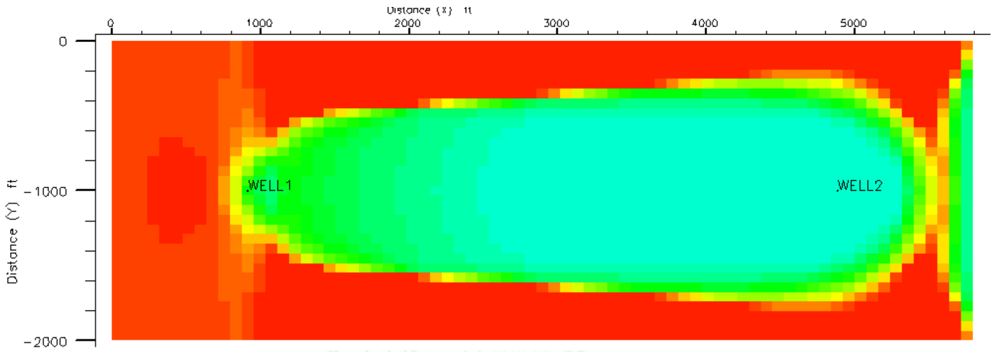
b) At late time of water flooding (8 years of production), oil between well 1 and well 2 is mostly flooded. Oil in the area up-dip of well 1 is unswept.

c) At early time of WAG injection (9 years of production), water and gas displace oil around well 1, causing very low oil saturation in this area.

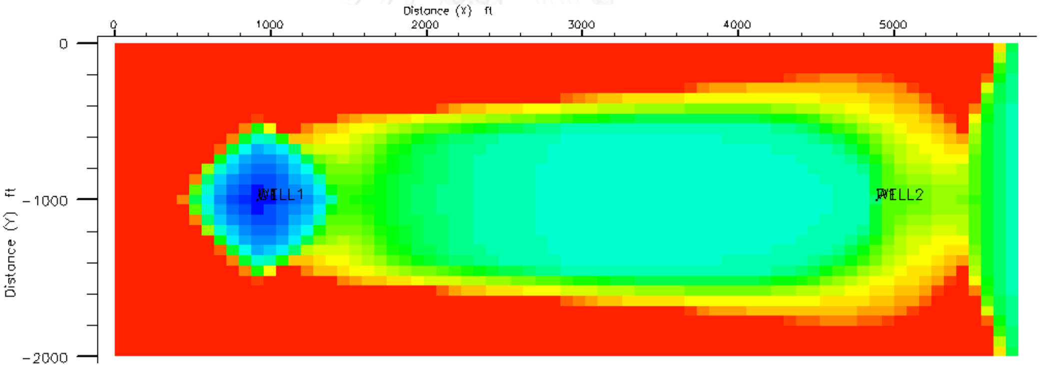
d) At the end of production (30 years), much amount of oil is produced. However, there is some residual oil which cannot be produced at the zone down-dip of well 2. The side view figure shows higher oil saturation in the middle layer (z-direction) than the upper and the lower layers due to the separation of three fluids which are gas, oil, and water in the upper, middle, and lower layers, respectively.



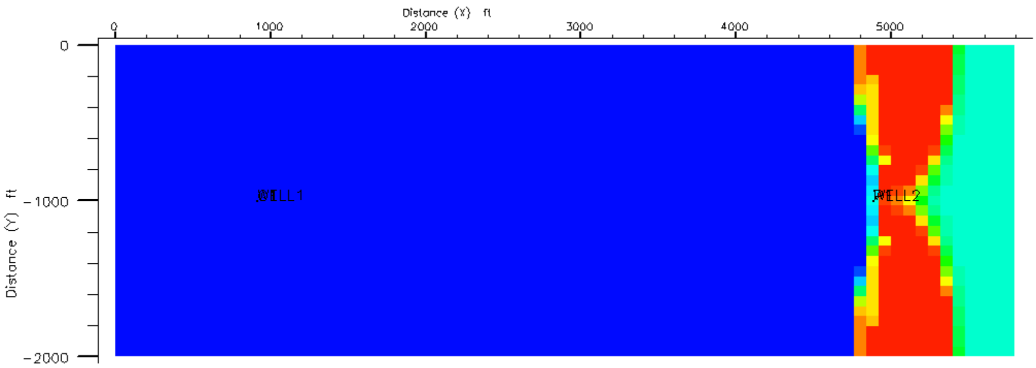
(a) 1 year of production



(b) 8 years of production



(c) 9 years of production



(d) At the end of production (30 years)

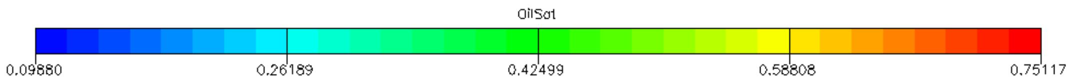
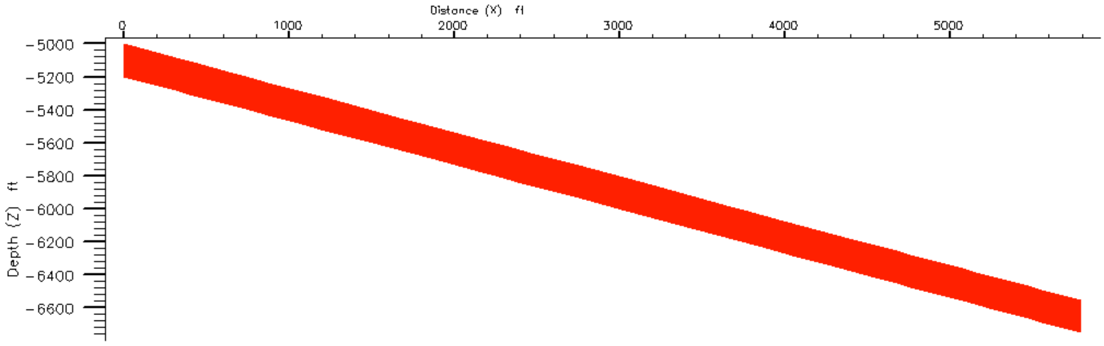
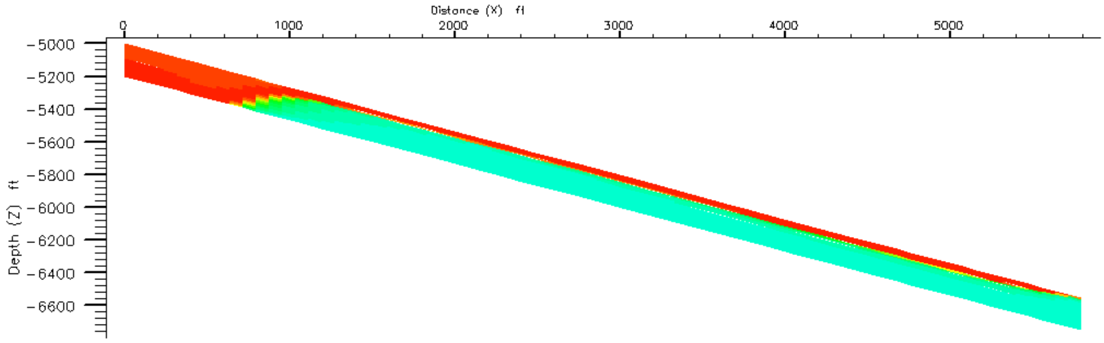


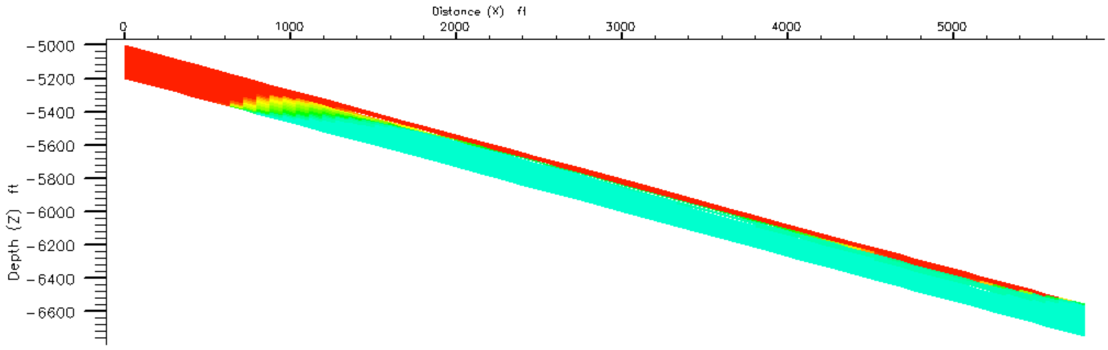
Figure 5.10 Oil saturation at any time of WAG with up-dip injection (top view, k=1).



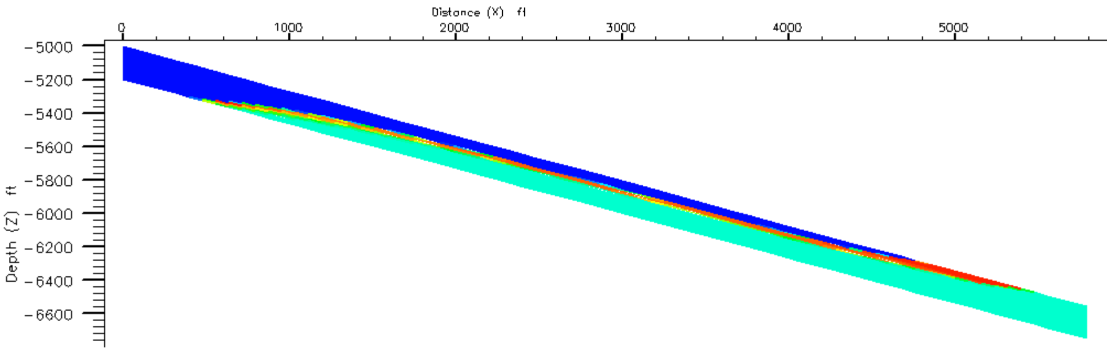
(a) 1 year of production



(b) 8 years of production



(c) 9 years of production



(d) At the end of production (30 years)

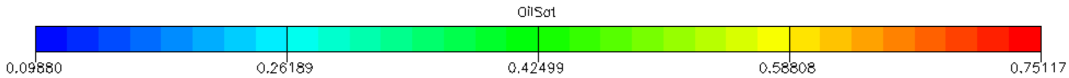


Figure 5.11 Oil saturation at any time of WAG with up-dip injection (side view, j=31).

5.1.2.2 WAG with down-dip injection base case

After the water cut in the initial water flooding reaches the criteria of 60%, water and gas are injected alternately at down-dip location (well 2) while the production is done at up-dip location (well 1) of which schedule is shown in Table 5.2.

Table 5.2 Well schedule for WAG with down-dip injection base case.

Step of production	**Well 1 (up-dip)**	**Well 2 (down-dip)**
water flooding	producer (8000 RB/D)	water injector (8000 RB/D)
water cut of well 1 reaches 60%	shut in for 180 days	shut in for 180 days
WAG with down-dip injection	producer (8000 RB/D)	water/gas injector (8000 RB/D)

Water injection at a rate of 8,000 RB/D or approximately 7,850 STB/D is performed at well 2 as shown in Figure 5.12. It is injected continuously during water flooding but in separated small slugs during WAG injection. The bottom-hole pressure is always lower than the fracturing pressure of 4,080 psia throughout the production time.

Gas is injected at well 2 at a rate of 8,000 RB/D or approximately 7 MMSCF/D in separated small slugs during a WAG injection period. This injection rate always keeps the bottom-hole pressure to be lower than the fracturing pressure of 4,080 psia as shown in Figure 5.13.

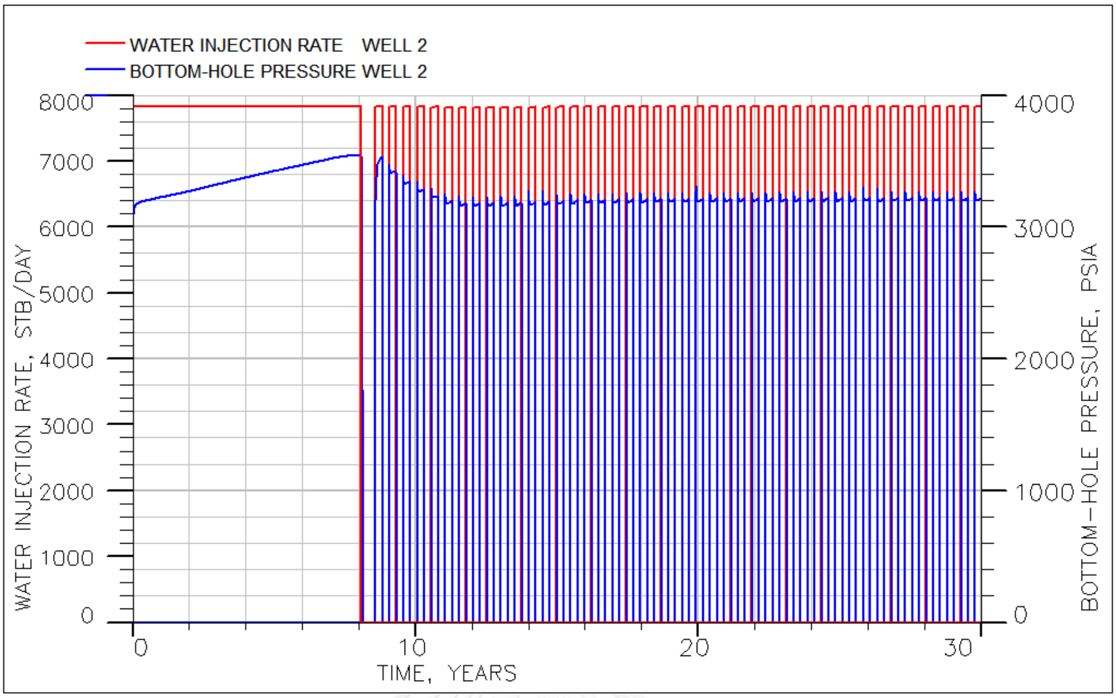


Figure 5.12 Water injection rate and bottom-hole pressure of water injector of the WAG with down-dip injection base case.

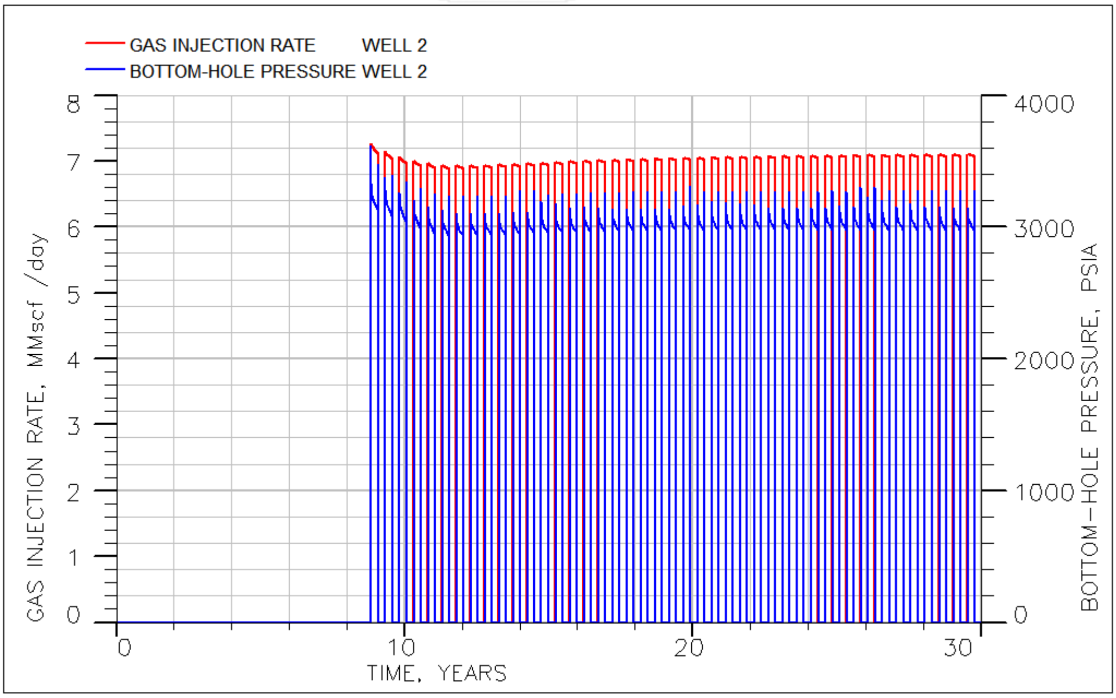


Figure 5.13 Gas injection rate and bottom-hole pressure of gas injector of the WAG with down-dip injection base case.

Oil and gas production rates are quite constant around 6,100 STB/D and 3.4 MMSCF/D, respectively, during the initial water flooding for about 7 years before water breakthrough. After that, they drop expeditiously whereas water rate increases dramatically due to the breakthrough of water at well 1. All wells are then shut for 180 days. At 8.59 years, the fluids are produced by well 1 with the rates similar to their rates on the last day of initial water flooding because a producer is still the same. The breakthrough of injected gas between the tenth and the eleventh year causes a rapid increase of gas production rate and a dramatic decrease of water rate. This also causes a slight increase of oil production rate. Since the fifteenth year, oil rate slightly decreases until the last year as shown in Figure 5.14.

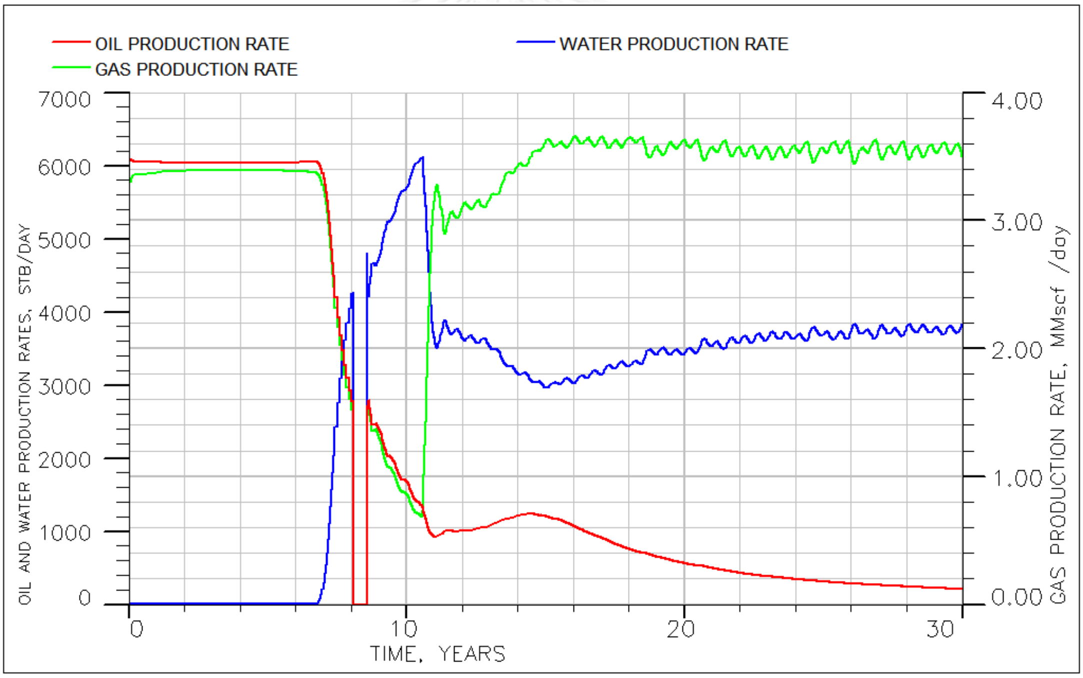


Figure 5.14 Oil, gas, and water production rates of the WAG with down-dip injection base case.

From Figure 5.15, initial water flooding that is implemented until the water cut reaches 60% recovers 17.068 MMSTB of oil while WAG recovers an additional 5.971 MMSTB of oil. At the last year of production, the total amount of oil production is 23.039 MMSTB, equivalent to 65.63% of oil recovery factor.

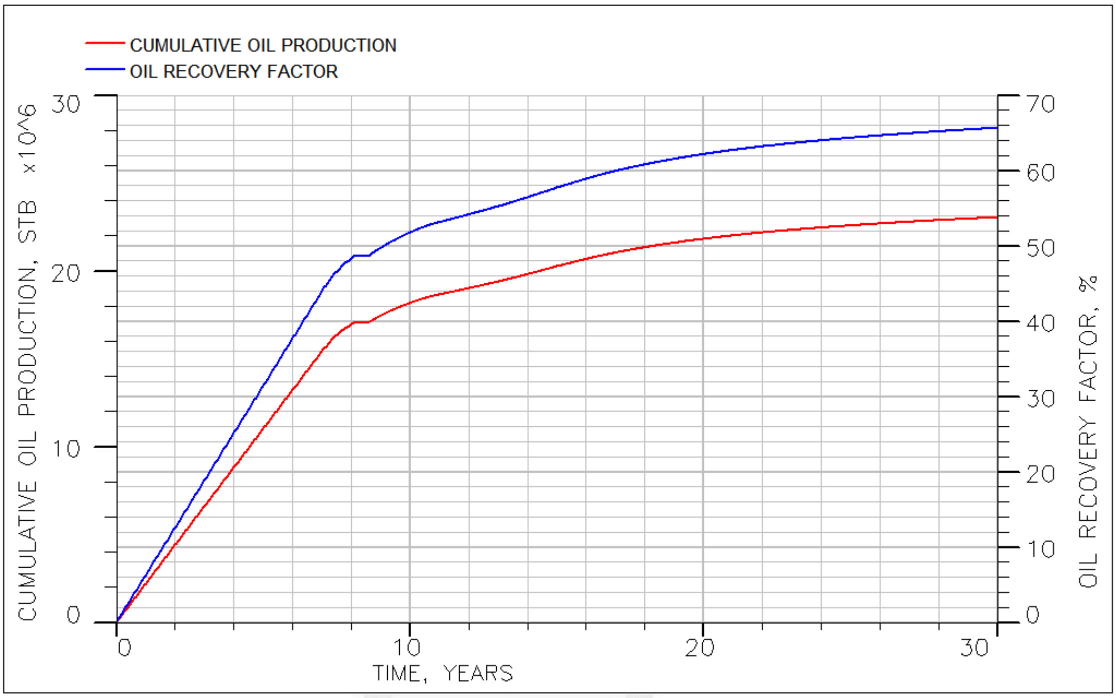


Figure 5.15 Cumulative oil production and oil recovery factor of the WAG with down-dip injection base case.

Water is injected since the first day of production; however, it starts to be produced in the seventh year after breakthrough. The amount of water required during initial water flooding is 23.094 MMSTB while WAG needs 30.909 MMSTB of water. Thus, the total amount of injected water and the total amount of produced water are 54.003 MMSTB and 30.003 MMSTB, respectively.

The total amount of 34.904 BSCF of gas is produced by two mechanisms: 9.544 BSCF by initial water flooding and 25.357 BSCF by WAG. Gas injection starting in the ninth year requires 27.162 BSCF of gas.

Water cut increases rapidly in the eight year and reaches the stopping criteria of 60% in the ninth year. In the WAG period, it increases to 82% in the tenth year, drops to 71% in the fifteenth year, and slightly increases to 95% in the last year.

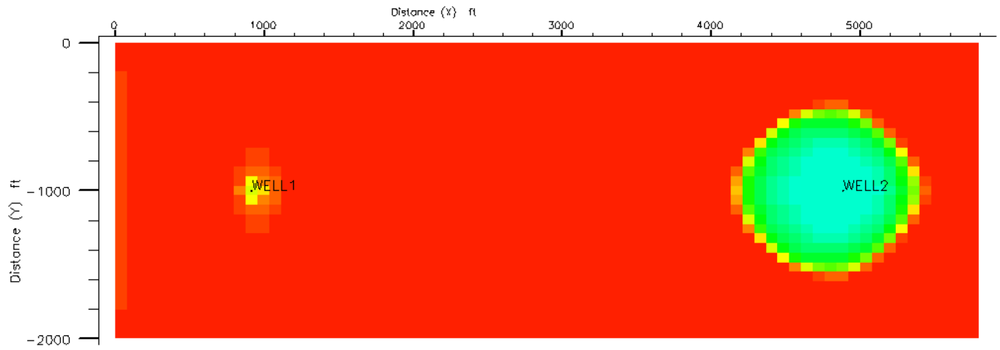
Figures 5.16 and 5.17 illustrate oil saturation inside the reservoir at different times as listed below:

a) At early time of water flooding (1 year of production), oil saturation around well 2 is quite low due to oil being displaced by injected water. Most area is still unswept.

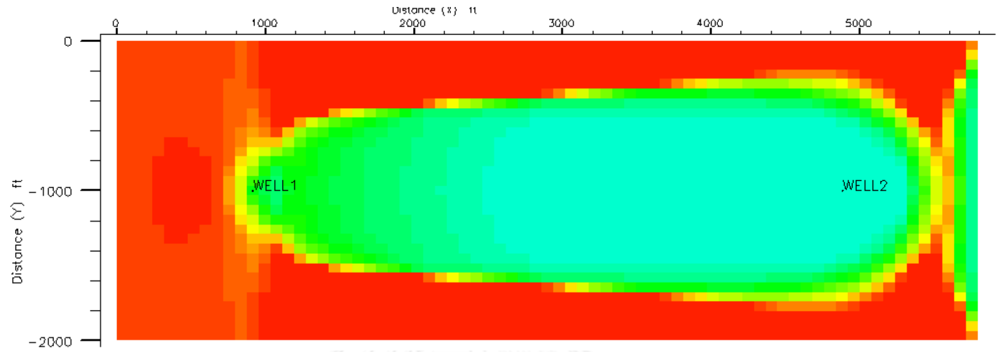
b) At late time of water flooding (8 years of production), oil between well 1 and well 2 is mostly flooded. Oil in the area up-dip of well 1 is unswept.

c) At early time of WAG injection (9 years of production), water and gas displace oil around well 2, causing very low oil saturation in this area.

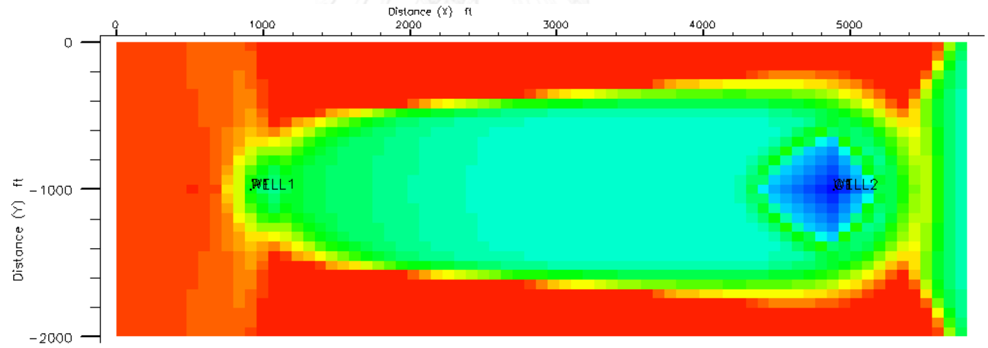
d) At the end of production (30 years), much amount of oil is produced but there is a small layer of oil left in the zone up-dip of well 1.



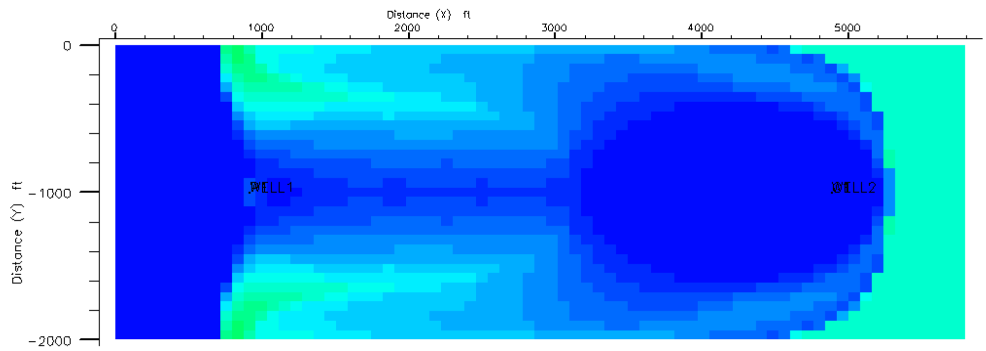
(a) 1 year of production



(b) 8 years of production



(c) 9 years of production



(d) At the end of production (30 years)

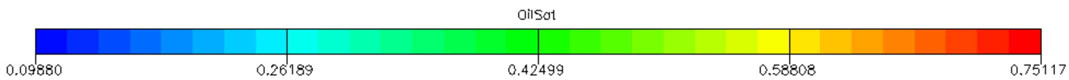
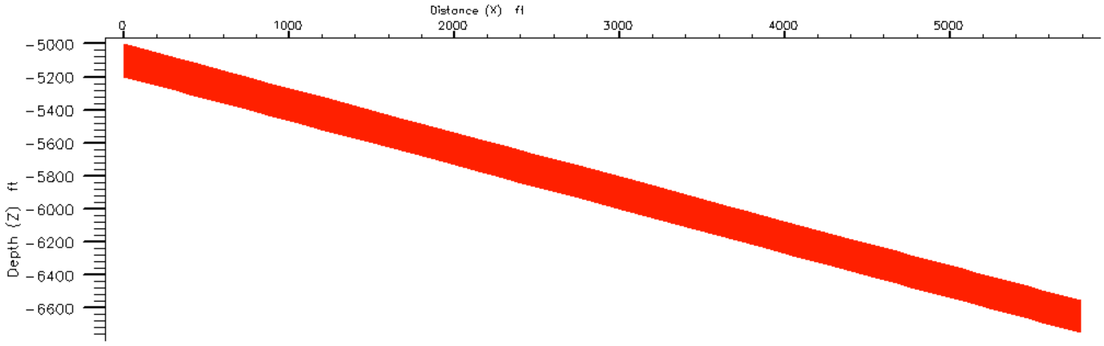
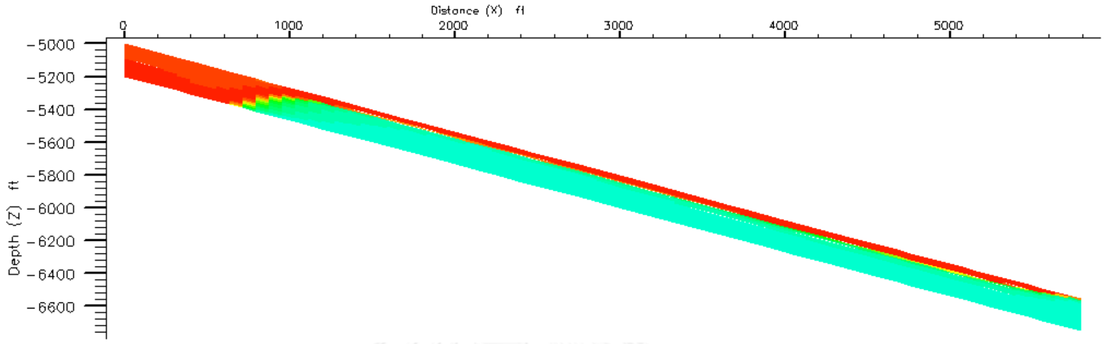


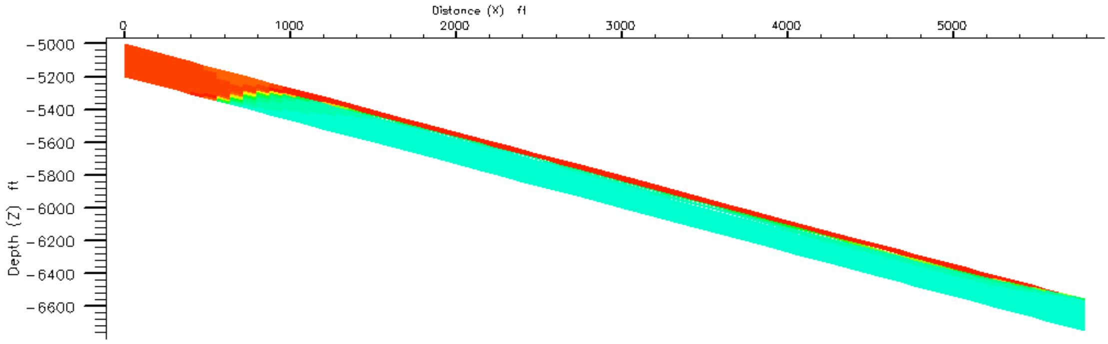
Figure 5.16 Oil saturation at any time of WAG with down-dip injection (top view, k=1).



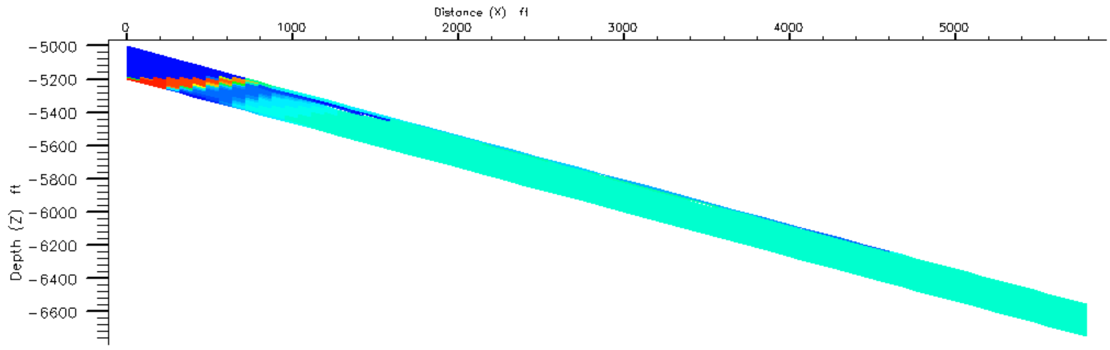
(a) 1 year of production



(b) 8 years of production



(c) 9 years of production



(d) At the end of production (30 years)

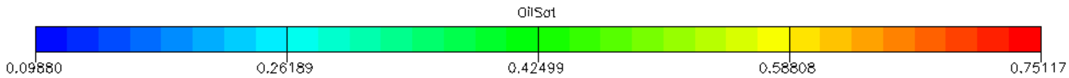


Figure 5.17 Oil saturation at any time of WAG with down-dip injection(side view, j=31).

5.1.3 Double displacement process (DDP) base case

Double Displacement Process (DDP) involves two sequential flooding mechanisms which are water flooding and gas flooding. During water injection, the well at up-dip location (well 1) is set to be a producer while the well at down-dip location (well 2) is set to be water injector. After that, well 1 is switched to be gas injector while well 2 is switched to be producer of which schedule is shown in Table 5.3.

Table 5.3 Well schedule for DDP base case.

Step of production	Well 1 (up-dip)	Well 2 (down-dip)
water flooding	producer (8000 RB/D)	water injector (8000 RB/D)
water cut of well 1 reaches 60%	shut in for 180 days	shut in for 180 days
DDP	gas injector (8000 RB/D)	producer (8000 RB/D)

Water is injected into the reservoir at well 2 at a rate of 8,000 RB/D or 7,800 STB/D since the first day of production. This rate is constant throughout the water flooding period because the bottom-hole pressure of well 2 does not exceed its fracturing pressure. Water injection stops at the eighth year when the water cut reaches the stopping criteria of 60% as shown in Figure 5.18.

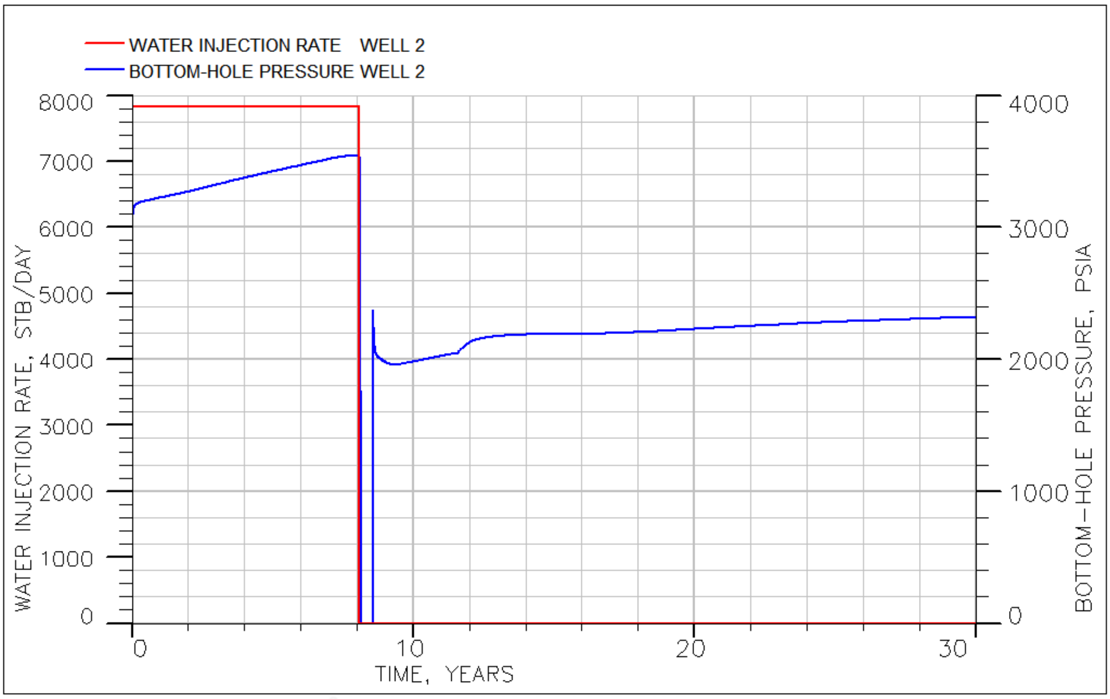


Figure 5.18 Water injection rate and bottom-hole pressure of water injector of the DDP base case.

Figure 5.19 shows gas injection rate and bottom-hole pressure of the injector. After the wells are shut for 180 days, gas is injected continuously into the reservoir until the last year of production at well 1 at a rate of 8,000 RB/D or approximately 6.7 MMSCF/D. Gas injection rate is rather constant because the bottom-hole pressure of well 1 does not exceed its fracturing pressure.

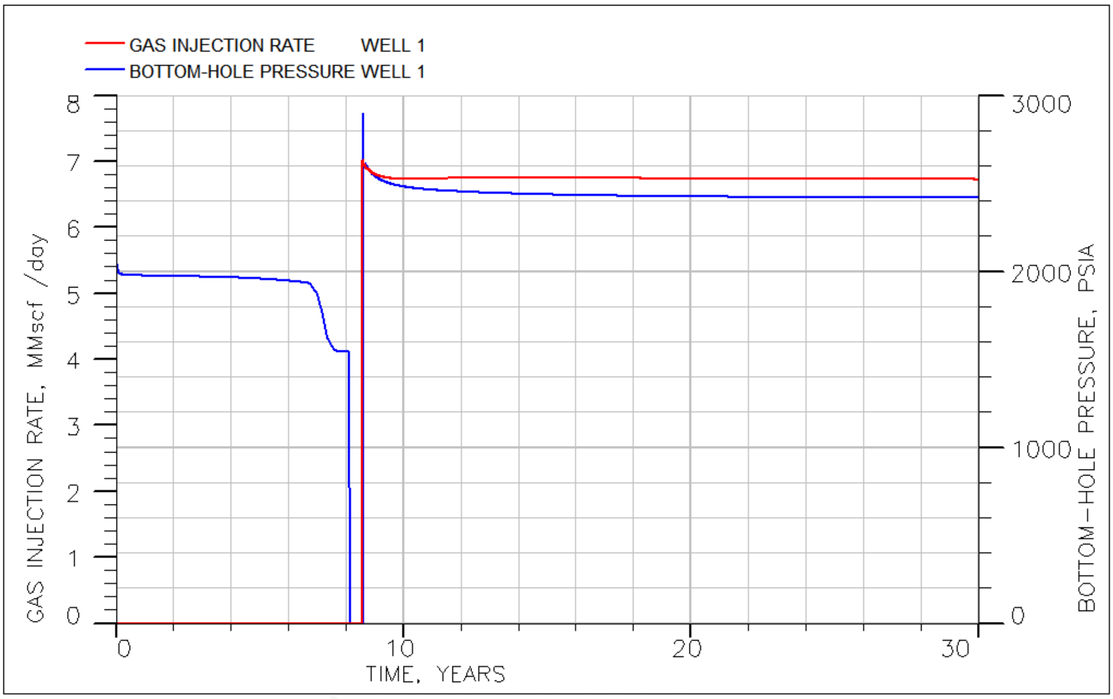


Figure 5.19 Gas injection rate and bottom-hole pressure of gas injector of the DDP base case.

Oil, water, and gas production rates are shown in Figure 5.20. Oil is produced by well 1 at constant rate around 6,050 STB/D for almost 7 years. After that, it drops expeditiously to around 2,750 STB/D. Gas is also produced at constant rate around 3.4 MMSCF/D. Gas rate starts to drop similarly to oil rate at the seventh year due to the breakthrough of injected water. Consequently, water is started to be produced at this time with expeditiously increasing rate. At the eighth year of production, both wells are shut for 180 days. During the early time of WAG, a lot of water is produced because of the accumulation of water around well 2 caused by the former water injection. Water rate drops expeditiously after the eleventh year because there is less amount of water in the reservoir. Oil is produced with an increasing rate until it reaches approximately 1,800 STB/D in the nineteenth year but later with a decreasing rate until the last year of production. The oil production rate at the last year is 771 STB/D. Gas is produced with a low rate for a while but with an increasing rate after the breakthrough of injected gas. Gas production rate at the last year is 6.014 MMSCF/D.

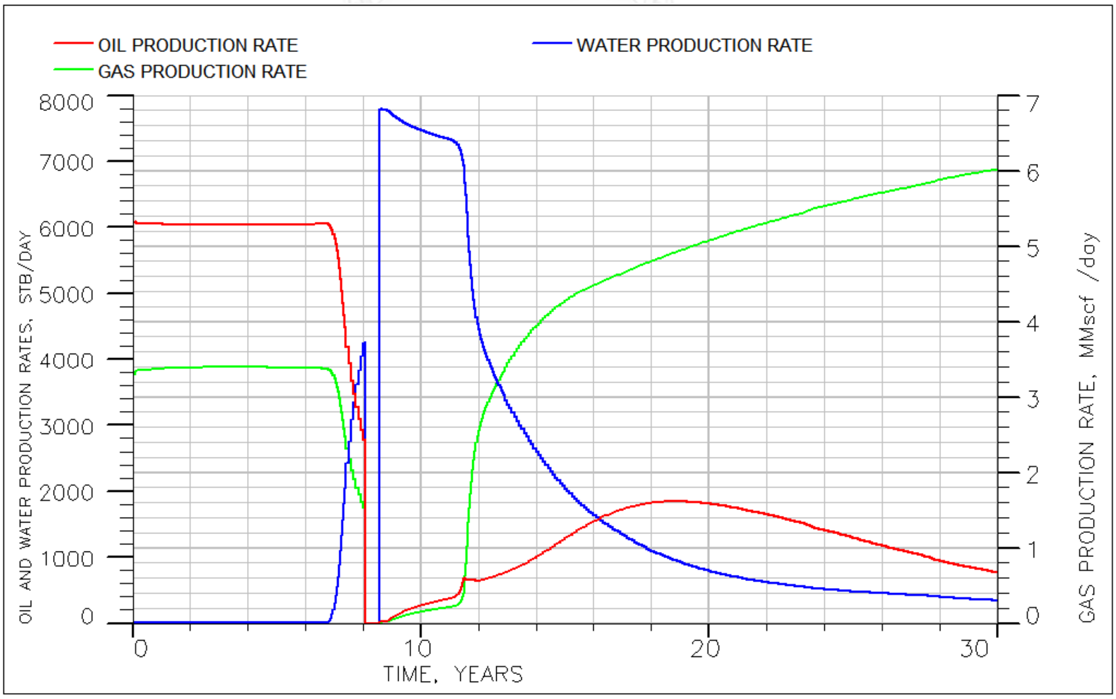


Figure 5.20 Oil, gas, and water production rates of the DDP base case.

More amount of oil is produced in the initial water flooding period as compared to the amount of oil recovered in the gas flooding period; they are 17.068 MMSTB and 9.232 MMSTB, respectively. As a result, the total amount of oil of 26.301 MMSTB is produced, equivalent to the oil recovery factor of 74.92% as shown in Figure 5.21.

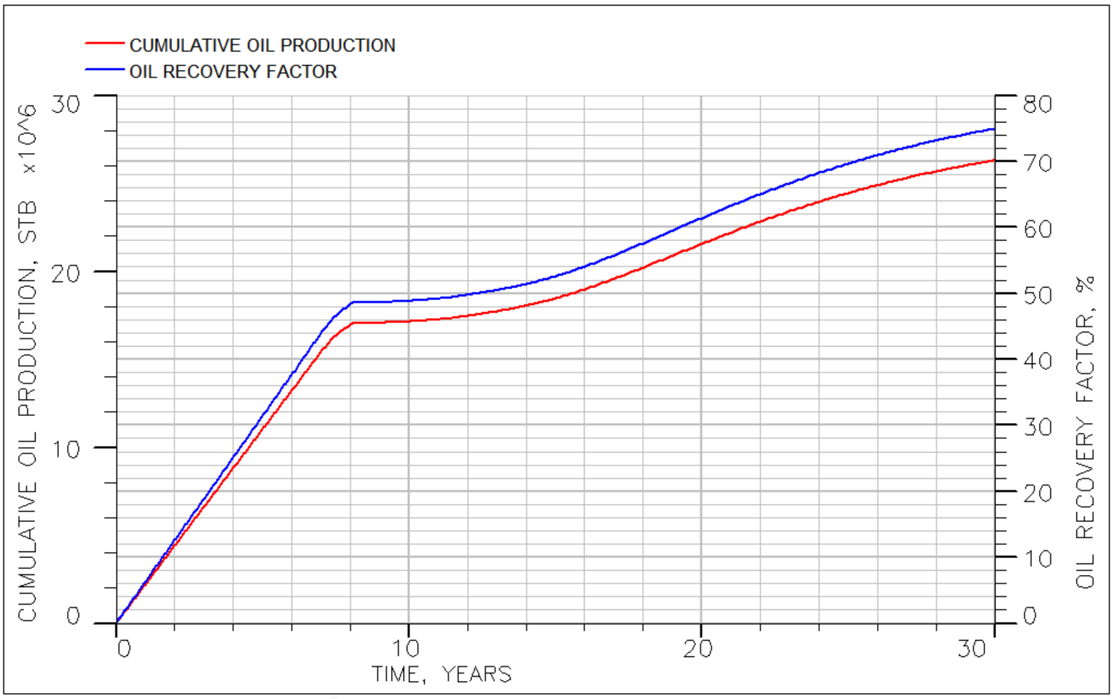


Figure 5.21 Cumulative oil production and oil recovery factor of the DDP base case.

The amount of water required for injection is 23.094 MMSTB. It is produced mainly in the gas flooding period.

An amount of solution gas approximately 9.544 BSCF is produced during the initial water flooding while the injected gas is produced after the breakthrough. At the last year of production, the total amount of injected gas and total amount of produced gas are 52.733 BSCF and 43.000 BSCF, respectively.

In term of water cut, it is zero for almost 7 years. After the breakthrough, it increases expeditiously to 60% which is the criteria for stopping of water flooding. In the early time of gas flooding, water cut reaches 100% because of the accumulation of water around the producer. However, it decreases continuously because much amount of water is displaced by oil and gas from up-dip location, causing this water to be produced back.

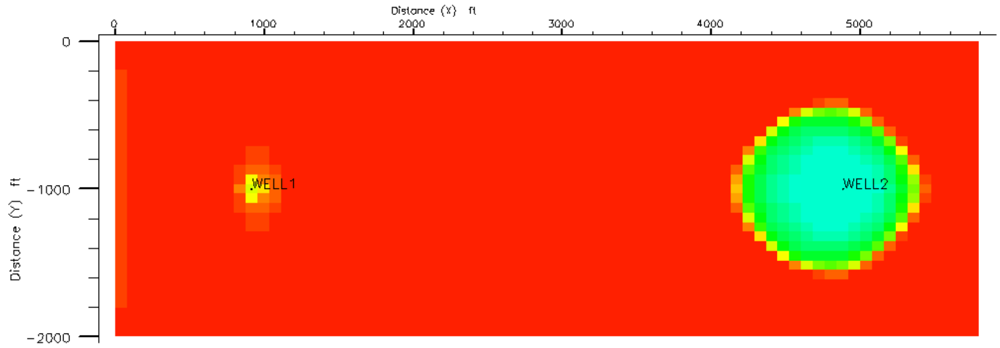
Figures 5.22 and 5.23 illustrate oil saturation inside the reservoir at different times as listed below:

a) At early time of water flooding (1 year of production), oil saturation around well 2 is quite low due to oil being displaced by injected water. Only small area is swept by water while oil saturation of most area is still high.

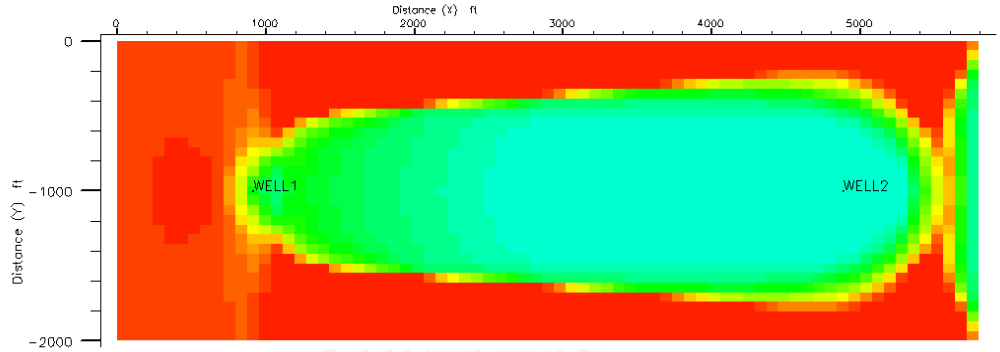
b) At late time of water flooding (8 years of production), oil between well 1 and well 2 is mostly flooded.

c) At early time of gas flooding (9 years of production), gas displaces oil around well 1, causing very low oil saturation in this area.

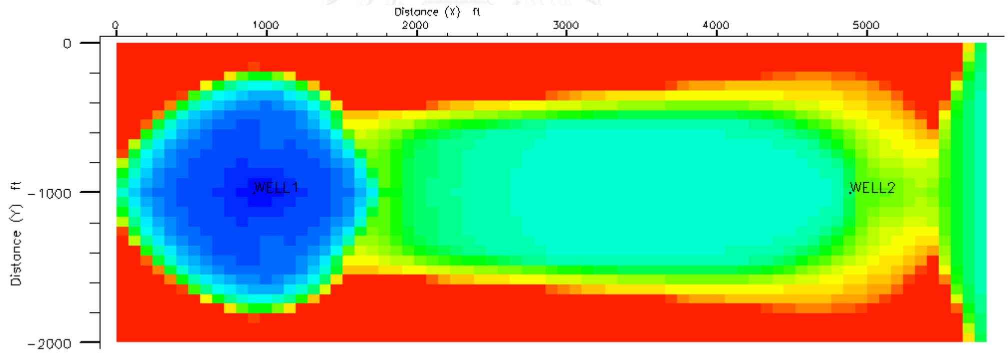
d) At the end of production (30 years), much amount of oil is produced. However, there is some residual oil which cannot be produced at the zone down-dip of well 2.



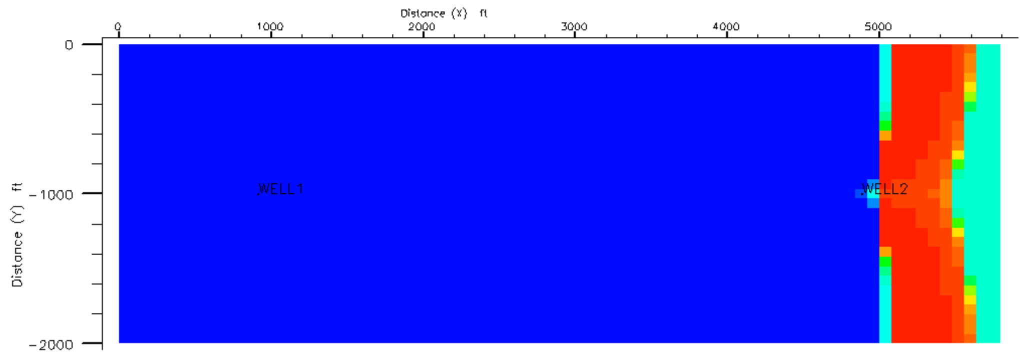
(a) 1 year of production



(b) 8 years of production



(c) 9 years of production



(d) At the end of production (30 years)

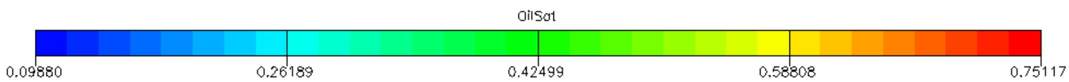
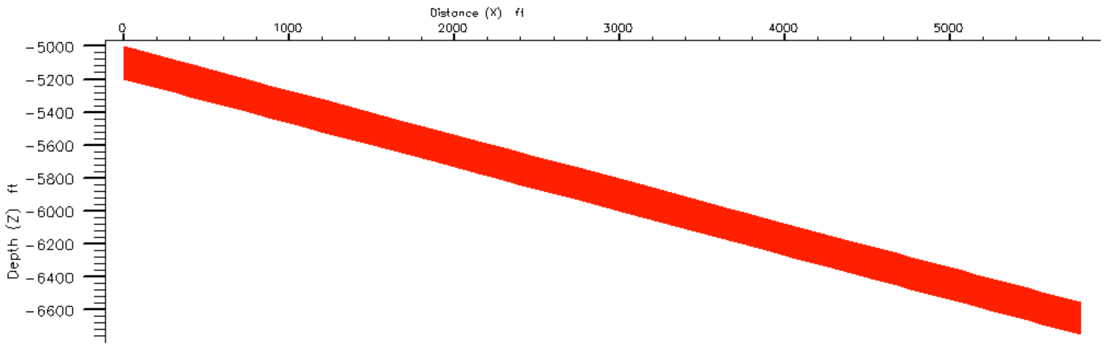
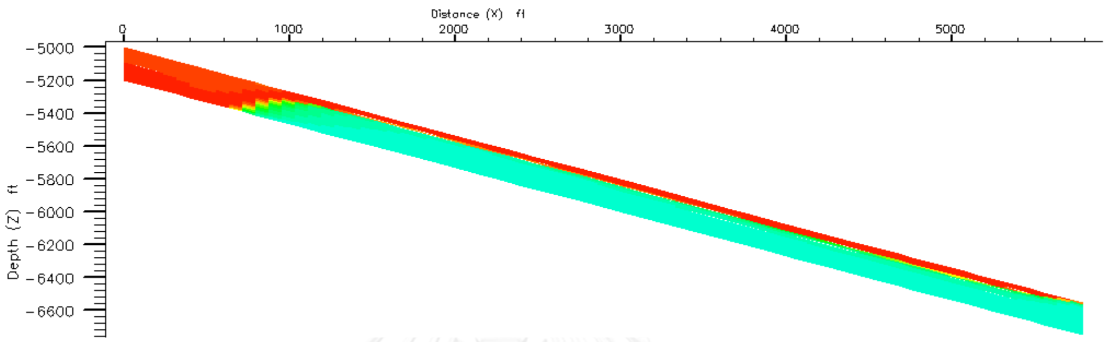


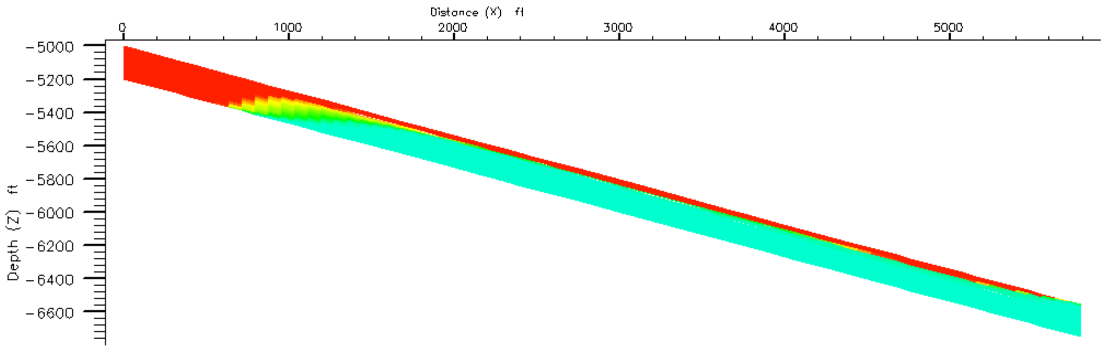
Figure 5.22 Oil saturation at any time of DDP (top view, k=1).



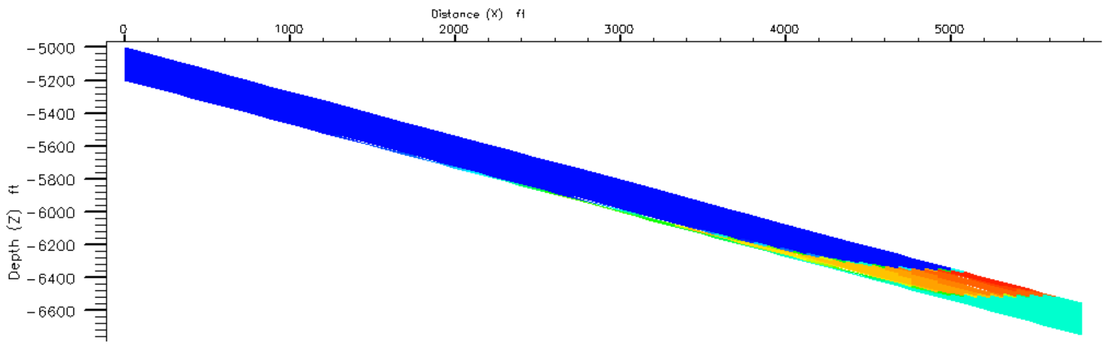
(a) 1 year of production



(b) 8 years of production



(c) 9 years of production



(d) At the end of production (30 years)

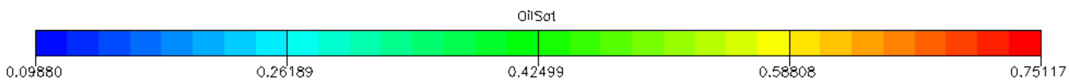


Figure 5.23 Oil saturation at any time of DDP (side view, j=31).

Table 5.4 shows result comparison of WAG with up-dip injection base case, WAG with down-dip injection base case, and DDP base case. The performance of long-term water flooding having abandonment criteria of 95% water cut is also included in the table. Barrel of oil equivalent (BOE) calculated from Eq. 3.17 is an appropriate indicator for production performance comparison than recovery factor because it accounts for two important terms which are amounts of injected and produced gas. From the results shown in Table 5.4, water flooding needs the shortest production time but it results in the lowest BOE. DDP base case yields the highest recovery factor and BOE even though it is the only case having more injected gas than produced gas.

Table 5.4 Result comparison of the base cases.

Case name	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
water flooding	15.17	19.675	56.05	0	10.976	43.310	17.873	21.505
WAG with up-dip injection base case	30	23.711	67.55	25.792	28.676	53.990	35.557	24.192
WAG with down-dip injection base case	30	23.039	65.63	27.162	34.901	54.003	30.003	24.329
DDP base case	30	26.301	74.92	52.733	43.000	23.094	17.516	24.678

5.2 Effect of stopping criteria for water flooding

Effect of stopping criteria for water flooding is studied by using the base case model consisting of two vertical wells as represented in Figure 4.10 and varying the stopping criteria for water flooding based on water cut of well 1 which is the producer before starting WAG or DDP. Water and gas injection rates are still the same as the base case at 8,000 RB/D. When water cut reaches the stopping criteria, well 1 and well 2 are shut for 180 days to prepare for WAG or DDP. Water cut stopping criteria of 1%, 20%, 40%, 60%, and 80% are investigated. This study is performed for reservoir with dip angle of 15° (base case), reservoir without dip angle, and reservoir with dip angle of 30°. Results of WAG with up-dip injection, WAG with down-dip injection, and DDP are presented and discussed in this section.

5.2.1 WAG with up-dip injection

Figures 5.24 and 5.25 show oil production rate and water cut for a reservoir with dip angle of 15°. Production profiles for 0 and 30 degree dip angle are not shown here as the thesis will become too long. In the early time of water flooding period, every case has the same production profile. Oil is produced at the rate of 6,000 STB/D without water cut for more than 6 years. After the water cut reaches the criteria set in each case, the oil rate becomes zero as the wells are shut in for 180 days. Then, the oil rate in each case gradually increases after well 2 (down-dip well) is reopened for production while water and gas is alternatively injected updip. At the beginning of WAG, the oil rates for different cases are very much different but they become more similar during the last 10 years of production. The water cut of all cases abruptly increases to 100% when WAG is started because the water injector downdip is now converted to producer. Then, the water cut gradually decreases as water and gas injected updip chase the oil towards the downdip producer. Similar to oil rate, water cuts during the last 10 years of production for all cases exhibit a similar trend. The case with 1% water cut produces the least amount of oil during water flooding but it results in the highest rate and the highest amount of produced oil in WAG period. On the contrary, the case with 80% water cut produces oil with the lowest amount during WAG period because there is the least amount of residual oil but the highest amount of water in the reservoir after water flooding.

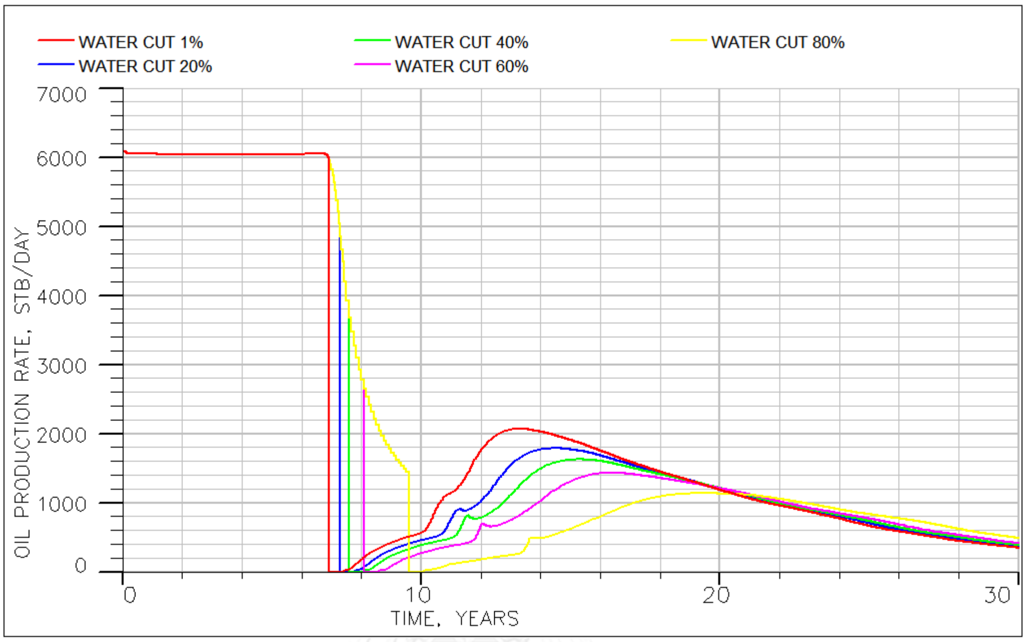


Figure 5.24 Effect of stopping criteria for water flooding on oil production rate of WAG with up-dip injection in a reservoir with dip angle of 15°.

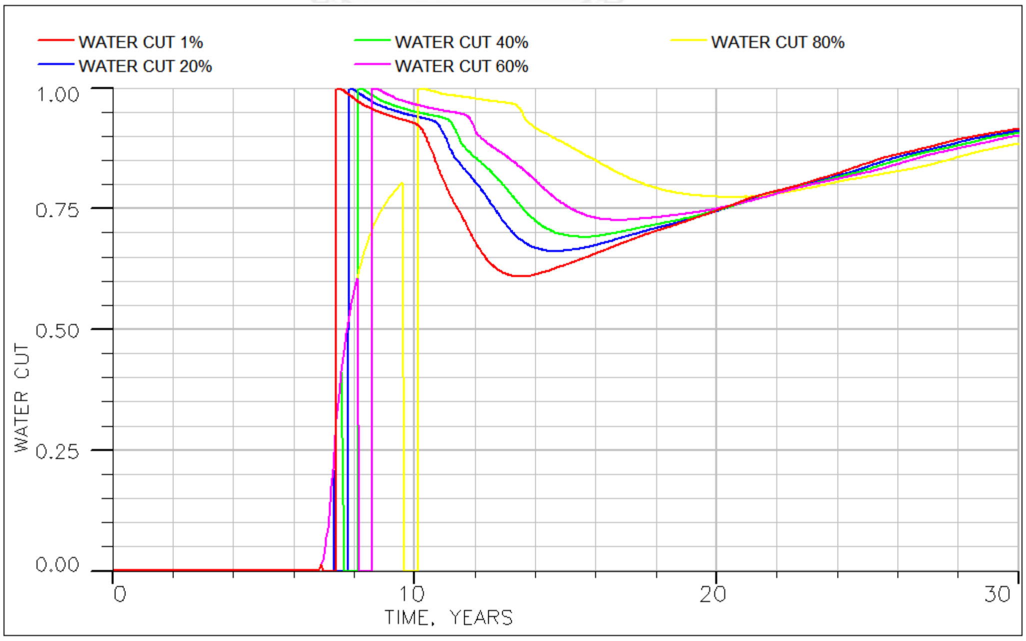


Figure 5.25 Effect of stopping criteria for water flooding on water cut of WAG with up-dip injection in a reservoir with dip angle of 15°.

Table 5.5 shows result comparison of different stopping criteria for WAG with up-dip injection. Results of reservoir with dip angle of 0° and 30° are also presented in the table in addition to results of 15° reservoir. Although, up-dip injection cannot be performed for a non-dipping reservoir, it is done similarly to an inclined reservoir by injection at well 1. Long-term water flooding with abandonment criteria of 95% water cut is performed for all reservoirs to compare their performances.

For a non-dipping reservoir, long-term water flooding recovers 21.020 MMSTB of oil in 29.59 years. WAG having the 1% water cut stopping criteria yields the highest amount of produced oil of 22.318 MMSTB and the highest BOE of 23.772 MMSTB. It requires the highest amount of injected gas but the least amount of injected water.

For a 15 degree reservoir, the highest BOE of 24.356 MMSTB is obtained when the water cut stopping criteria is 1%. This case also results in the highest oil recovery factor of 68.15% while long-term water flooding results in the lowest oil recovery factor of 56.05%.

WAG having 1% water cut stopping criteria also yields the highest oil recovery factor of 74.66% and the highest BOE of 23.105 MMSTB for a 30 degree reservoir. It requires 30.429 BSCF of injected gas of which amount is the highest. Long-term water flooding yields 55.36% of oil recovery factor in 12.42 years of production time.

Although, the highest BOEs of 23.772 MMSTB (0°), 24.356 MMSTB (15°), and 23.105 MMSTB (30°) are obtained from the cases of 1% water cut stopping criteria, different criteria shows slightly different results. In addition, their production profiles have the same trend because they have the same production mechanisms and the same water and gas injection rates.

Table 5.5 Result comparison between different stopping criteria for WAG with up-dip injection.

Case name	Dip angle	Water cut stopping criteria [%]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
water flooding	0°	95	19.59	21.020	58.10	0	11.605	55.903	28.737	22.955
WAG up-dip	**0°**	**1**	**30**	**22.318**	**61.69**	**27.014**	**35.737**	**51.732**	**27.201**	**23.772**
WAG up-dip	0°	20	30	22.255	61.52	26.485	35.188	52.570	28.088	23.706
WAG up-dip	0°	40	30	22.242	61.48	25.802	34.700	53.239	28.562	23.725
WAG up-dip	0°	60	30	22.157	61.25	25.377	34.123	53.983	29.490	23.615
WAG up-dip	0°	80	30	22.096	61.08	23.147	31.903	56.681	32.210	23.556
water flooding	15°	95	15.17	19.675	56.05	0	10.976	43.310	17.873	21.505
WAG up-dip	**15°**	**1**	**30**	**23.923**	**68.15**	**27.589**	**30.183**	**52.099**	**33.796**	**24.356**
WAG up-dip	15°	20	30	23.867	67.99	27.188	29.748	52.585	34.346	24.294
WAG up-dip	15°	40	30	23.810	67.83	26.433	29.276	53.256	34.792	24.284
WAG up-dip	15°	60	30	23.711	67.55	25.792	28.676	53.990	35.557	24.192
WAG up-dip	15°	80	30	23.424	66.73	23.865	26.876	56.060	37.728	23.926
water flooding	30°	95	12.42	17.486	55.36	0	9.803	35.489	12.898	19.120
WAG up-dip	**30°**	**1**	**30**	**23.580**	**74.66**	**30.429**	**27.574**	**51.402**	**38.440**	**23.105**
WAG up-dip	30°	20	30	23.568	74.62	29.980	27.154	51.774	38.777	23.096
WAG up-dip	30°	40	30	23.556	74.58	29.580	26.860	52.371	39.249	23.103
WAG up-dip	30°	60	30	23.536	74.52	29.185	26.364	52.853	39.819	23.066
WAG up-dip	30°	80	30	23.467	74.30	27.667	25.027	54.547	41.328	23.027

5.2.2 WAG with down-dip injection

Figures 5.26 and 5.27 show oil production rate and water cut for a reservoir with dip angle of 15°. During water flooding, all cases have the same production profile as WAG with up-dip injection. Oil is produced with a rate of 6,000 STB/D for more than 6 years. A case with 80% water cut produces the highest amount of oil before shutting in the wells. After that, it produces the least amount of oil during WAG injection. This case gives the highest water production during WAG because of high amount of water present in the reservoir before starting of WAG injection. After 25 years of production, every case tends to have the same production profile. Oil production rate and water cut in the last year are around 200 STB/D and 95%, respectively.

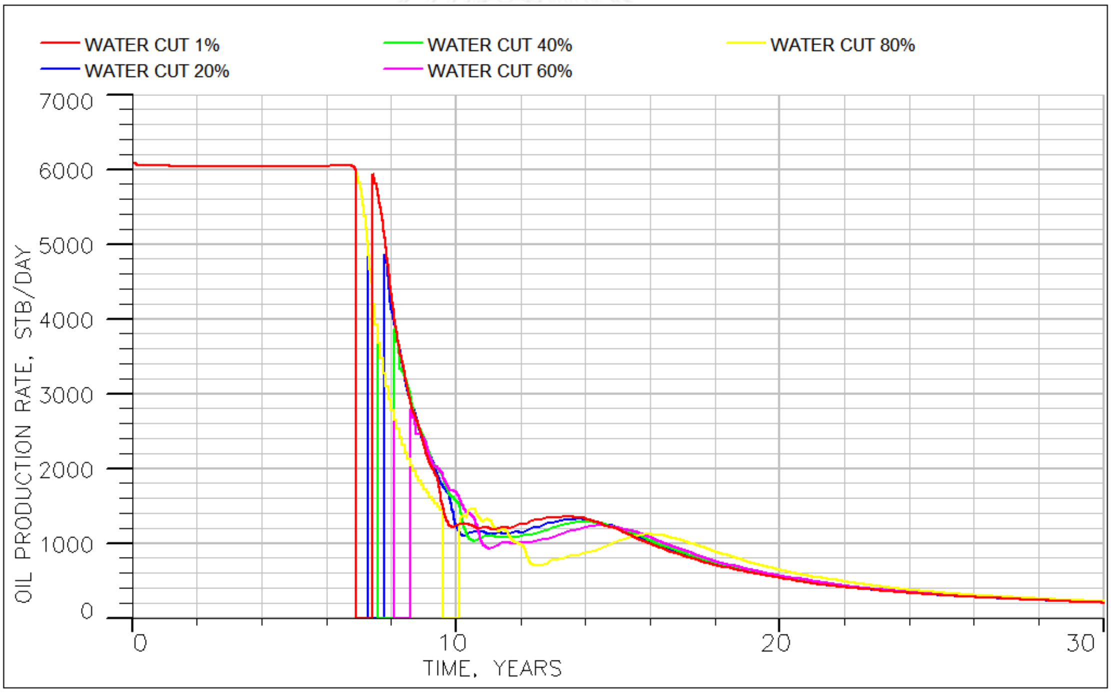


Figure 5.26 Effect of stopping criteria for water flooding on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15°.

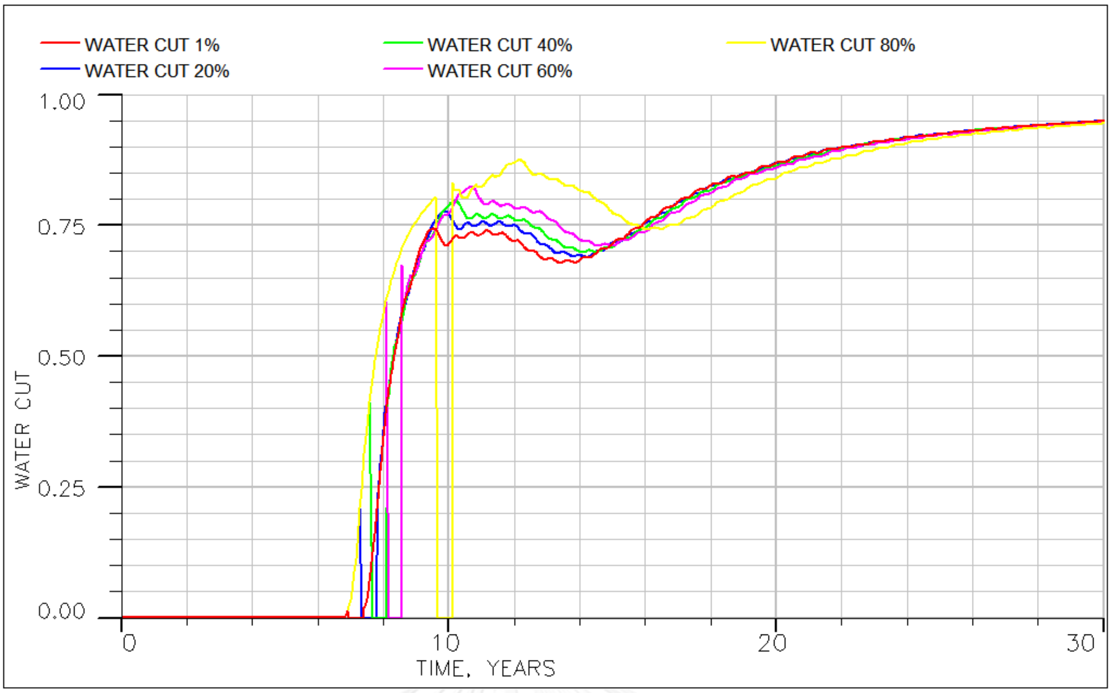


Figure 5.27 Effect of stopping criteria for water flooding on water cut of WAG with down-dip injection in a reservoir with dip angle of 15°.

Table 5.6 shows the result comparison between different stopping criteria for WAG with down-dip injection in a non-dipping reservoir, a reservoir with dip angle of 15°, and a reservoir with dip angle of 30°. For a non-dipping reservoir, injection at well 2 is performed instead of down-dip injection.

For all reservoirs, the amounts of oil production from the cases having different water cut stopping criteria are not much different. However, the cases having lower water cut criteria tend to require more amount of injected gas but less amount of injected water. In term of water production, a case having low water cut criteria produces less amount of water because it has the shorter period of initial water flooding.

The highest BOE of 24.518 MMSTB is yielded from a case with 40% water cut for a non-dipping reservoir. Cases with dip angle of 15° and 30° yield the highest BOE of 24.378 and 22.649 MMSTB, respectively, from 1% water cut.

Table 5.6 Result comparison between different stopping criteria for WAG with down-dip injection.

Case name	Dip angle	Water cut stopping criteria [%]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
water flooding	0°	95	19.59	21.020	58.10	0	11.605	55.903	28.737	22.955
WAG down-dip	0°	1	30	22.989	63.55	27.207	36.170	51.733	26.455	24.483
WAG down-dip	0°	20	30	22.974	63.50	26.656	35.615	52.572	27.298	24.468
WAG down-dip	**0°**	**40**	**30**	**22.991**	**63.55**	**25.946**	**35.106**	**53.240**	**27.754**	**24.518**
WAG down-dip	0°	60	30	22.966	63.48	25.496	34.536	53.985	28.612	24.473
WAG down-dip	0°	80	30	22.954	63.45	23.222	32.326	56.682	31.247	24.471
water flooding	15°	95	15.17	19.675	56.05	0	10.976	43.310	17.873	21.505
WAG down-dip	**15°**	**1**	**30**	**23.127**	**65.88**	**29.057**	**36.564**	**52.114**	**28.248**	**24.378**
WAG down-dip	15°	20	30	23.080	65.75	28.627	36.091	52.601	28.813	24.325
WAG down-dip	15°	40	30	23.071	65.72	27.843	35.580	53.269	29.237	24.360
WAG down-dip	15°	60	30	23.039	65.63	27.162	34.901	54.003	30.003	24.329
WAG down-dip	15°	80	30	22.958	65.40	25.134	32.875	56.081	32.179	24.249
water flooding	30°	95	12.42	17.486	55.36	0	9.803	35.489	12.898	19.120
WAG down-dip	**30°**	**1**	**30**	**21.728**	**68.79**	**32.423**	**37.947**	**51.428**	**30.314**	**22.649**
WAG down-dip	30°	20	30	21.682	68.65	31.930	37.489	51.798	30.679	22.609
WAG down-dip	30°	40	30	21.648	68.54	31.487	37.138	52.395	31.204	22.589
WAG down-dip	30°	60	30	21.608	68.41	31.059	36.579	52.876	31.824	22.528
WAG down-dip	30°	80	30	21.540	68.20	29.432	35.085	54.569	33.412	22.483

5.2.3 Double displacement process

Figures 5.28 and 5.29 show oil production rate and water cut for DDP in a reservoir with dip angle of 15°, respectively. The oil production profiles during initial water flooding period for DDP are the same as those for the two types of WAG previously discussed. A higher water cut criteria results in a longer time for water flooding and more amount of produced oil during this period. In WAG period, every case has similar profile but with slightly different rates due to the difference in amount of residual oil and amount of water present after water flooding.

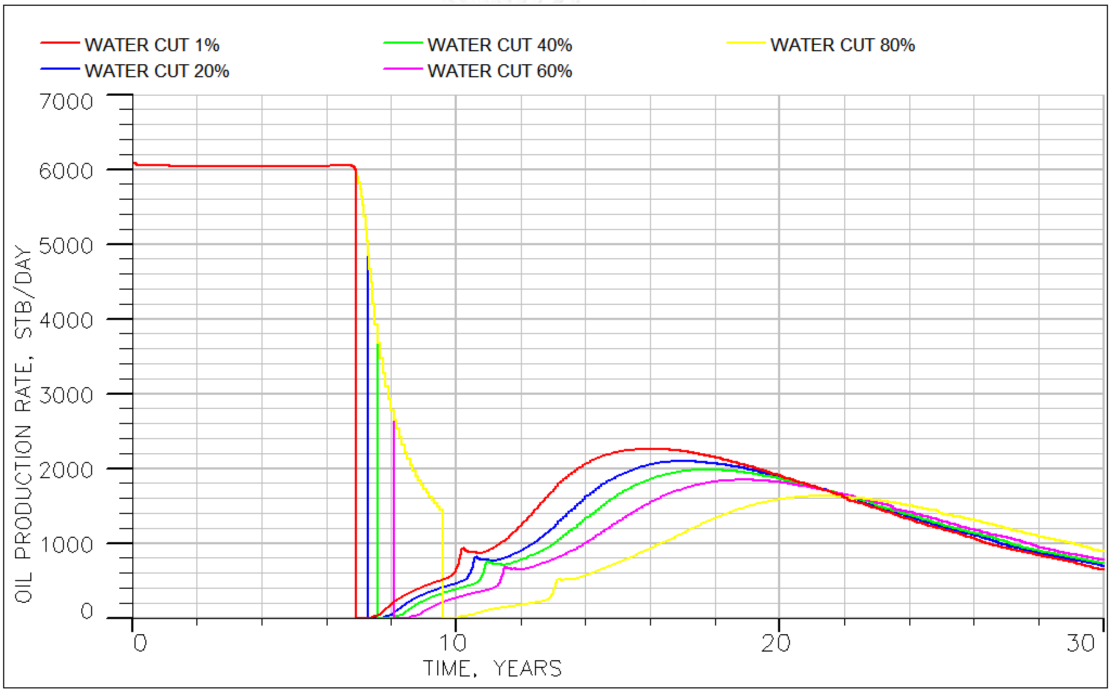


Figure 5.28 Effect of stopping criteria for water flooding on oil production rate of DDP in a reservoir with dip angle of 15°.

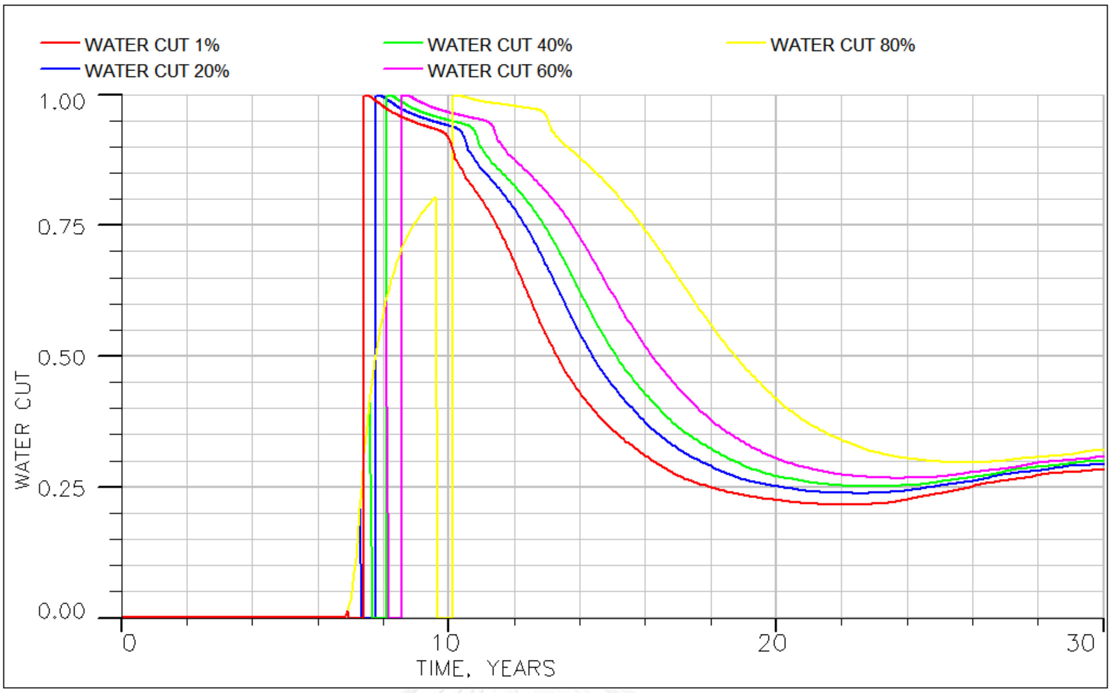


Figure 5.29 Effect of stopping criteria for water flooding on water cut of DDP in a reservoir with dip angle of 15°.

Similar to the two types of WAG previously discussed, a case with the lower water cut stopping criteria results in less amount of water but higher amount of gas required for injection due to the shorter time of initial water flooding period.

For DDP in a reservoir with dip angle of 15°, the highest BOE of 24.914 MMSTB is obtained from the case with 1% water cut stopping criteria. It requires 55.535 BSCF of injected gas and 19.748 MMSTB of injected water. For a reservoir with dip angle of 30°, the case with 20% water cut criteria yields the highest BOE of 23.699 MMSTB while 60.043 BSCF of gas and 19.168 MMSTB of water are required. Although the case with 80% water cut in a non-dipping reservoir yields the highest BOE, its BOE is less than the one for long-term water flooding. Therefore, DDP is not suitable for a non-dipping reservoir. Table 5.7 shows result comparison between different stopping criteria for DDP.

Table 5.7 Result comparison between different stopping criteria for DDP.

Case name	Dip angle	Water cut stopping criteria [%]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
water flooding	**0°**	**95**	**19.59**	**21.020**	**58.10**	**0**	**11.605**	**55.903**	**28.737**	**22.955**
DDP	0°	1	30	18.656	51.57	54.377	49.959	19.147	12.610	17.919
DDP	0°	20	30	19.240	53.18	53.280	49.398	20.688	13.116	18.593
DDP	0°	40	30	19.558	54.06	52.452	48.818	21.639	13.570	18.952
DDP	0°	60	30	19.947	55.14	51.117	47.875	23.304	14.510	19.407
DDP	0°	80	30	20.669	57.13	46.741	44.411	28.550	18.207	20.280
water flooding	15°	95	15.17	19.675	56.05	0	10.976	43.310	17.873	21.505
DDP	**15°**	**1**	**30**	**26.644**	**75.90**	**55.535**	**45.158**	**19.748**	**14.760**	**24.914**
DDP	15°	20	30	26.540	75.61	54.679	44.525	20.815	15.595	24.847
DDP	15°	40	30	26.450	75.35	53.908	43.942	21.651	16.278	24.788
DDP	15°	60	30	26.301	74.92	52.733	43.000	23.094	17.516	24.678
DDP	15°	80	30	25.860	73.67	49.143	39.985	27.369	21.326	24.333
water flooding	30°	95	12.42	17.486	55.36	0	9.803	35.489	12.898	19.120
DDP	30°	1	30	25.682	81.31	60.868	48.964	18.331	13.802	23.698
DDP	**30°**	**20**	**30**	**25.669**	**81.27**	**60.043**	**48.224**	**19.168**	**14.520**	**23.699**
DDP	30°	40	30	25.657	81.23	59.444	47.690	20.005	15.270	23.698
DDP	30°	60	30	25.635	81.16	58.419	46.738	21.188	16.354	23.688
DDP	30°	80	30	25.566	80.94	55.648	44.137	24.291	19.269	23.647

The list of cases resulting in the highest BOEs for each production process and dip angle is shown in Table 5.8. These water cut stopping criteria for initial water flooding will be used in subsequent studies in the following sections. For a non-dipping reservoir, DDP study will not be performed because it results in recovery efficiency lower than water flooding. Even though the cases tabulated in the table yield the highest BOEs, they may not be the most suitable cases because the income and cost of injection are not taken into account.

Table 5.8 Summary of water cut criteria that yield the highest BOE.

Dip angle	Recovery process	Water cut stopping criteria [%]
0°	WAG up-dip	1
	WAG down-dip	40
	DDP	-
15°	WAG up-dip	1
	WAG down-dip	1
	DDP	1
30°	WAG up-dip	1
	WAG down-dip	1
	DDP	20

5.3 Effect of water and gas injection rates

Water and gas injection rates have some influence on production performance of WAG and DDP. A high water injection rate can cause water to underrun while a high gas injection rate causes gas to override. On the other hand, too low rate can take too much production time. Therefore, optimum rates must be found for the most effective performance. In this case, water and gas injection rates are varied from 6,000 RB/D to 12,000 RB/D in 16 cases for WAG as shown in Table 5.15 and 16 cases for DDP as shown in Table 5.10. During the initial water flooding, the production rate is set equal to water injection rate. After that, it is set equal to the highest rate between water and gas injection for WAG and equal to gas injection rate for DDP. This investigation is done for reservoir with a dip angle of 15°, reservoir without dip angle, and a reservoir with a dip angle of 30°. In this study, water cut stopping criteria for initial water flooding from Table 5.8 are used for each recovery process. It is noted that water injection rate of 10,000 and 12,000 RB/D cannot be injected throughout water flooding period for a non-dipping reservoir due to the limitation of fracturing pressure.

Table 5.9 Water and gas injection rates for WAG.

Case no.	Water injection rate [RB/D]	Gas injection rate [RB/D]	Production rate during water flooding [RB/D]	Production rate during WAG [RB/D]
1	6,000	6,000	6,000	6,000
2	6,000	8,000	6,000	8,000
3	6,000	10,000	6,000	10,000
4	6,000	12,000	6,000	12,000
5	8,000	6,000	8,000	8,000
6	8,000	8,000	8,000	8,000
7	8,000	10,000	8,000	10,000
8	8,000	12,000	8,000	12,000
9	10,000	6,000	10,000	10,000
10	10,000	8,000	10,000	10,000
11	10,000	10,000	10,000	10,000
12	10,000	12,000	10,000	12,000
13	12,000	6,000	12,000	12,000
14	12,000	8,000	12,000	12,000
15	12,000	10,000	12,000	12,000
16	12,000	12,000	12,000	12,000

Table 5.10 Water and gas injection rates for DDP.

Case no.	Water injection rate [RB/D]	Gas injection rate [RB/D]	Production rate during water flooding [RB/D]	Production rate during DDP [RB/D]
1	6,000	6,000	6,000	6,000
2	6,000	8,000	6,000	8,000
3	6,000	10,000	6,000	10,000
4	6,000	12,000	6,000	12,000
5	8,000	6,000	8,000	6,000
6	8,000	8,000	8,000	8,000
7	8,000	10,000	8,000	10,000
8	8,000	12,000	8,000	12,000
9	10,000	6,000	10,000	6,000
10	10,000	8,000	10,000	8,000
11	10,000	10,000	10,000	10,000
12	10,000	12,000	10,000	12,000
13	12,000	6,000	12,000	6,000
14	12,000	8,000	12,000	8,000
15	12,000	10,000	12,000	10,000
16	12,000	12,000	12,000	12,000

5.3.1 WAG with up-dip injection

During the initial water flooding, the oil production rate depends only on water injection rate. Cases with water injection rate of 12,000 RB/D produces the highest oil rate at approximately 9,100 STB/D in the shortest time (about 4.5 years) as shown in Figure 5.30d while cases with the lowest water injection rate of 6,000 RB/D need more than 9 years for water flooding as shown in Figure 5.30a. Water flood front of cases with low injection rate travels slowly from injector to producer which means it needs more time to reach 1% water cut before shutting in the wells.

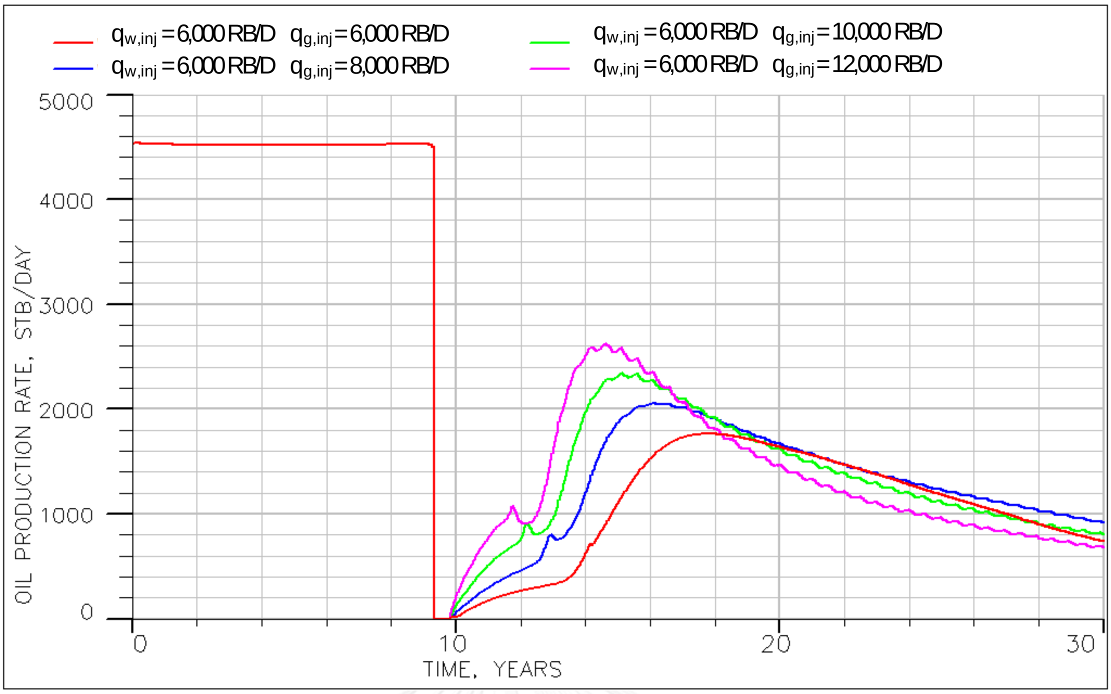
During WAG, Figure 5.30a shows that a higher gas injection rate results in a higher oil production rate at the initial time of WAG because oil is chased rapidly to the producer. However, it results in the lower oil rate at the late time of WAG because there is less oil in the reservoir than those cases with lower gas injection rate.

From Figure 5.30b, case 8, having the water injection rate of 8,000 RB/D and the gas injection rate of 12,000 RB/D, produces oil at the highest rate from the seventh year to the fifteenth year. After that, case 6 results in the lowest oil rate since the twentieth year to the last year of production.

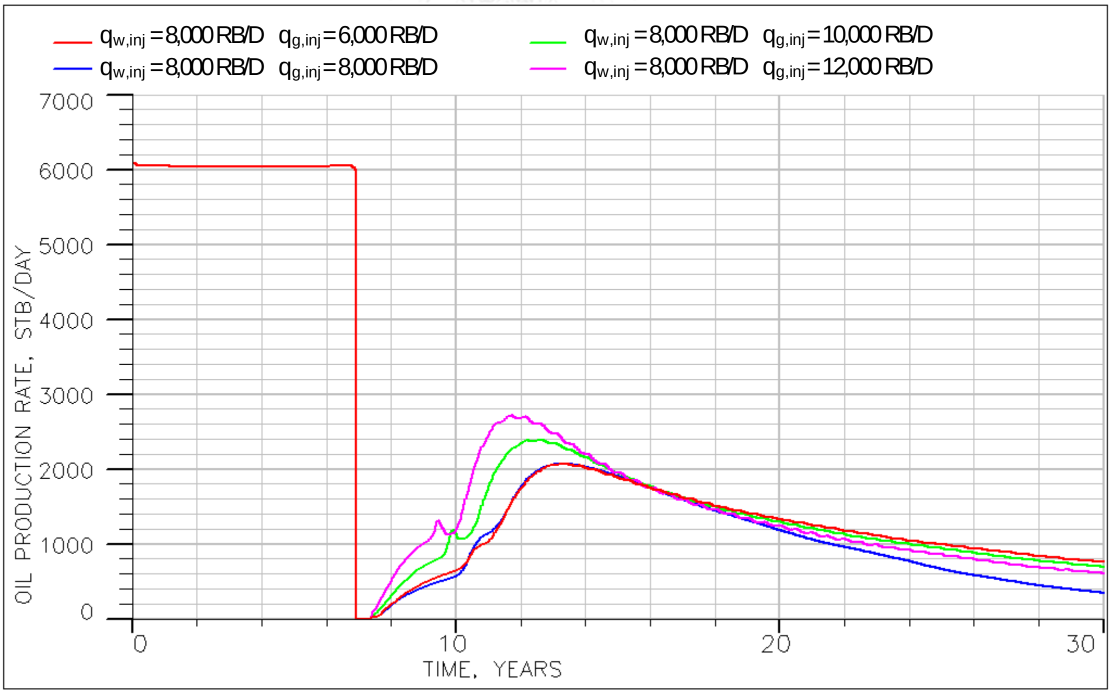
From Figure 5.30c, case 12 provides the highest oil rate while other cases in the same figure have similar oil rate during the early time of WAG period. Then, the case of 10,000 RB/D of both water and gas injection rates results in the lowest oil rate while other cases have the same profile since the fifteenth year to the last year of production.

Case 16, having the highest gas and water injection rates of 12,000 RB/D, does not provide the highest oil production rate as shown in Figure 5.30d. This case tends to have fingering effect because of too high injection rates which results in low sweep efficiency.

Additionally, the oil rates of the cases having the same gas and water injection rates, i.e. cases 4 and 8, are different. Case 8 in Figure 5.30b has the higher oil production rate than case 4 in Figure 5.30a.

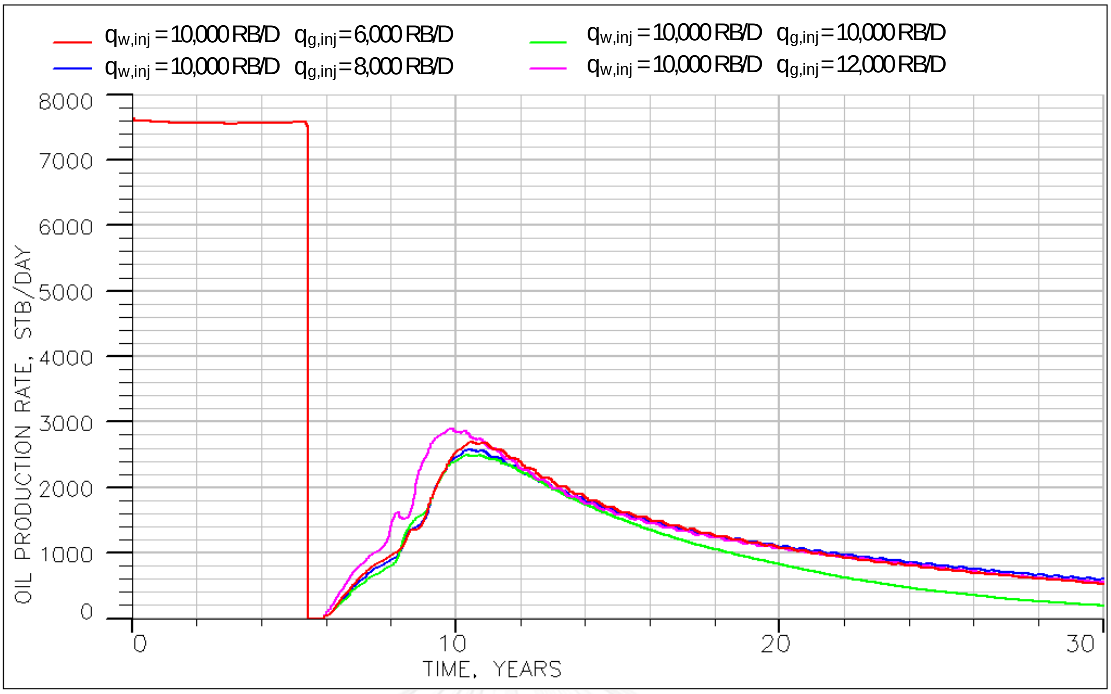


(a)

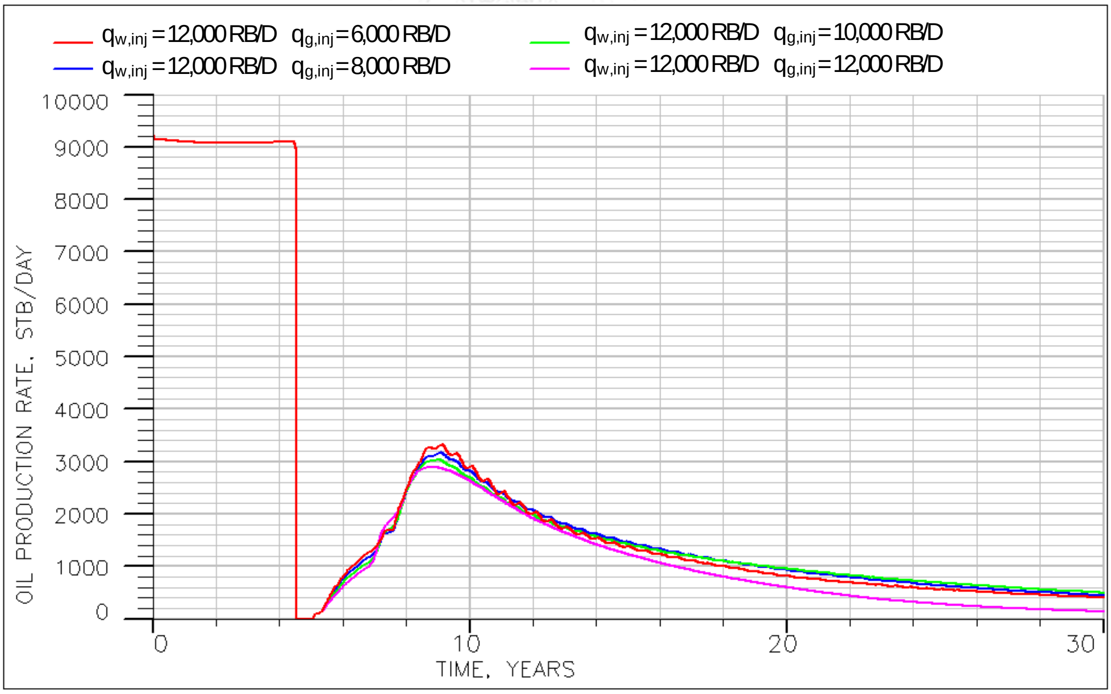


(b)

Figure 5.30 Effect of water and gas injection rates on oil production rate of WAG with up-dip injection in a reservoir with dip angle of 15°.



(c)



(d)

Figure 5.30 Effect of water and gas injection rates on oil production rate of WAG with up-dip injection in a reservoir with dip angle of 15° (continued).

Tables 5.11 to 5.13 depict results for different water and gas injection rates of WAG with up-dip injection in a non-dipping reservoir, a reservoir with dip angle of 15°, and a reservoir with dip angle of 30°. Case 14 gives the highest BOE for a reservoir with dip-angle of 0° and 15° while case 13 yields the largest BOE for 30° reservoir. Their BOEs are 28.760 MMSTB, 28.697 MMSTB, and 27.153 MMSTB, respectively. High water injection rate is good for oil recovery but high gas rate is not. Gas tends to cause a viscous fingering effect more easily than water because of large difference between oil viscosity and gas viscosity. It is noted that BOE is very low when water injection rate is equal to gas injection rate (cases 1, 6, 11, and 16).

Water consumption depends directly on water injection rate while gas consumption does not. For example, case 6 from Table 5.11 requires 27.014 BSCF of injected gas which is larger than the amounts of gas consumed by cases 7 and 8.

From Table 5.13, case 16 is the only case spending the shortest time for production. It ends in 28.58 years due to the economic limit.

Table 5.11 Result comparison between different water and gas injection rates of WAG with up-dip injection in a reservoir without dip angle.

Case no.	Dip angle	Water injection rate [RB/D]	Gas injection rate [RB/D]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
1	0°	6,000	6,000	30	20.572	56.86	18.249	26.590	41.063	18.182	21.962
2	0°	6,000	8,000	30	22.581	62.42	19.101	29.401	41.030	20.705	24.298
3	0°	6,000	10,000	30	23.231	64.22	20.183	32.732	41.012	21.808	25.323
4	0°	6,000	12,000	30	23.379	64.62	21.021	35.482	40.999	22.274	25.789
5	0°	8,000	6,000	30	23.961	66.23	15.439	27.055	51.678	29.147	25.897
6	0°	8,000	8,000	30	22.318	61.69	27.014	35.737	51.732	27.201	23.772
7	0°	8,000	10,000	30	24.407	67.47	25.922	37.205	51.675	29.263	26.288
8	0°	8,000	12,000	30	24.861	68.72	25.894	39.522	51.641	30.396	27.133
9	0°	10,000	6,000	30	25.302	69.94	12.815	27.551	62.018	39.318	27.758
10	0°	10,000	8,000	30	25.324	70.00	20.870	33.086	62.057	38.379	27.361
11	0°	10,000	10,000	30	24.180	66.84	33.808	42.946	62.122	36.437	25.704
12	0°	10,000	12,000	30	25.709	71.06	31.464	43.425	62.058	38.494	27.703
13	0°	12,000	6,000	30	25.753	71.19	10.728	26.853	71.466	47.455	28.441
14	**0°**	**12,000**	**8,000**	**30**	**26.226**	**72.50**	**16.689**	**31.886**	**71.493**	**48.086**	**28.760**
15	0°	12,000	10,000	30	26.458	73.14	25.484	38.089	71.541	47.365	28.559
16	0°	12,000	12,000	30	25.880	71.54	39.177	48.471	71.610	45.534	27.430

Table 5.12 Result comparison between different water and gas injection rates of WAG with up-dip injection in a reservoir with dip angle of 15°.

Case no.	Dip angle	Water injection rate [RB/D]	Gas injection rate [RB/D]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
1	15°	6,000	6,000	30	23.400	66.66	18.600	19.320	41.610	25.765	23.520
2	15°	6,000	8,000	30	24.775	70.58	18.957	24.411	41.574	27.602	25.685
3	15°	6,000	10,000	30	25.211	71.82	20.039	29.096	41.556	27.884	26.721
4	15°	6,000	12,000	30	25.237	71.90	20.845	32.516	41.543	28.113	27.183
5	15°	8,000	6,000	30	25.143	71.63	15.624	23.266	52.040	35.287	26.417
6	15°	8,000	8,000	30	23.923	68.15	27.589	30.183	52.099	33.796	24.356
7	15°	8,000	10,000	30	25.812	73.53	26.147	33.183	52.043	35.675	26.985
8	15°	8,000	12,000	30	26.209	74.66	26.111	36.799	52.006	35.875	27.991
9	15°	10,000	6,000	30	25.987	74.03	13.242	25.837	62.427	43.704	28.086
10	15°	10,000	8,000	30	25.952	73.93	21.683	30.637	62.460	43.628	27.444
11	15°	10,000	10,000	30	24.119	68.71	35.225	39.773	62.536	42.365	24.878
12	15°	10,000	12,000	30	26.470	75.41	32.604	41.079	62.464	44.036	27.883
13	15°	12,000	6,000	30	26.083	74.31	11.379	26.855	73.060	53.059	28.663
14	**15°**	**12,000**	**8,000**	**30**	**26.488**	**75.46**	**18.238**	**31.488**	**73.100**	**52.744**	**28.697**
15	15°	12,000	10,000	30	26.394	75.19	28.230	38.088	73.150	52.453	28.037
16	15°	12,000	12,000	30	24.245	69.07	44.901	50.307	73.250	51.496	25.146

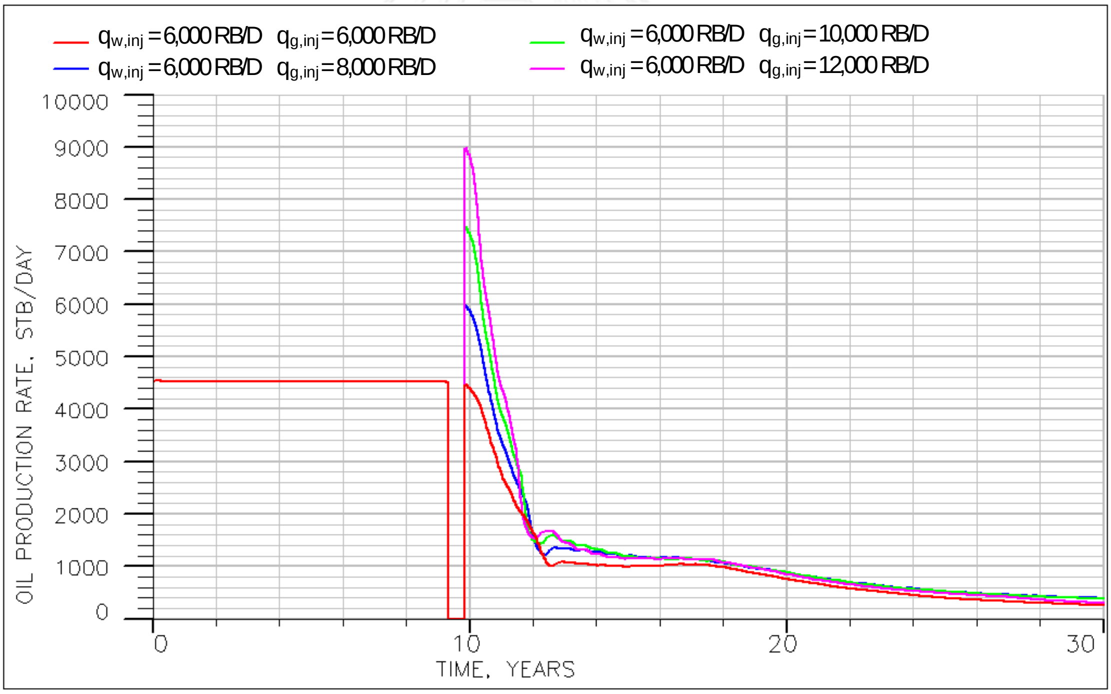
Table 5.13 Result comparison between different water and gas injection rates of WAG with up-dip injection in a reservoir with dip angle of 30°.

Case no.	Dip angle	Water injection rate [RB/D]	Gas injection rate [RB/D]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
1	30°	6,000	6,000	30	23.622	74.79	21.020	16.101	41.109	29.811	22.802
2	30°	6,000	8,000	30	24.829	78.61	19.643	22.291	41.055	31.047	25.270
3	30°	6,000	10,000	30	25.079	79.40	20.311	27.191	41.035	31.166	26.226
4	30°	6,000	12,000	30	24.976	79.07	20.807	30.575	41.020	31.377	26.604
5	30°	8,000	6,000	30	24.879	78.77	16.228	20.437	51.326	39.737	25.580
6	30°	8,000	8,000	30	23.580	74.66	30.429	27.574	51.402	38.440	23.105
7	30°	8,000	10,000	30	25.165	79.67	26.920	30.886	51.319	39.812	25.827
8	30°	8,000	12,000	30	25.466	80.63	26.358	34.650	51.281	39.764	26.849
9	30°	10,000	6,000	30	25.170	79.69	13.444	23.306	61.851	48.383	26.814
10	30°	10,000	8,000	30	25.032	79.25	22.510	27.896	61.875	48.624	25.930
11	30°	10,000	10,000	30	23.272	73.68	39.190	38.386	62.001	47.321	23.138
12	30°	10,000	12,000	30	25.296	80.09	33.586	38.832	61.893	48.725	26.170
13	**30°**	**12,000**	**6,000**	**30**	**24.949**	**78.99**	**11.199**	**24.420**	**72.116**	**57.690**	**27.153**
14	30°	12,000	8,000	30	25.292	80.07	18.225	28.933	72.155	57.411	27.077
15	30°	12,000	10,000	30	25.161	79.66	28.702	35.187	72.212	57.644	26.242
16	30°	12,000	12,000	28.58	23.020	72.88	44.476	45.522	69.369	53.422	23.194

5.3.2 WAG with down-dip injection

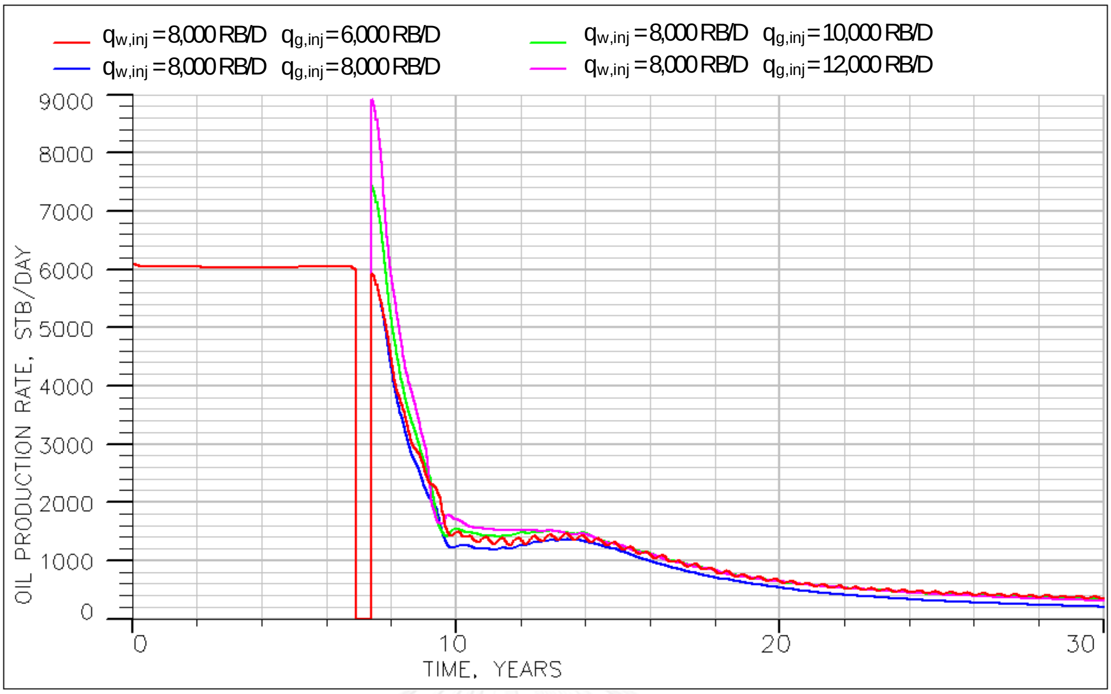
As shown in Figure 5.31, the oil production rate during the initial water flooding is affected only by water injection rate. A higher water rate results in a higher oil production rate but with shorter duration of water flooding. Water injection rate also affects the oil rate during WAG period. Although, cases 4, 8, 12, and 16 have the same oil rate at approximately 9,000 STB/D in the early time of WAG, they result in different oil rate after that. A higher oil rate is obtained from a higher water injection rate.

Figure 5.31 (a) and (b) show that gas injection rate has a big impact on oil rate in the early time of WAG. A higher gas rate results in a higher oil rate. However, in Figure 5.31 (c) and (d), gas rate has less impact on oil rate.

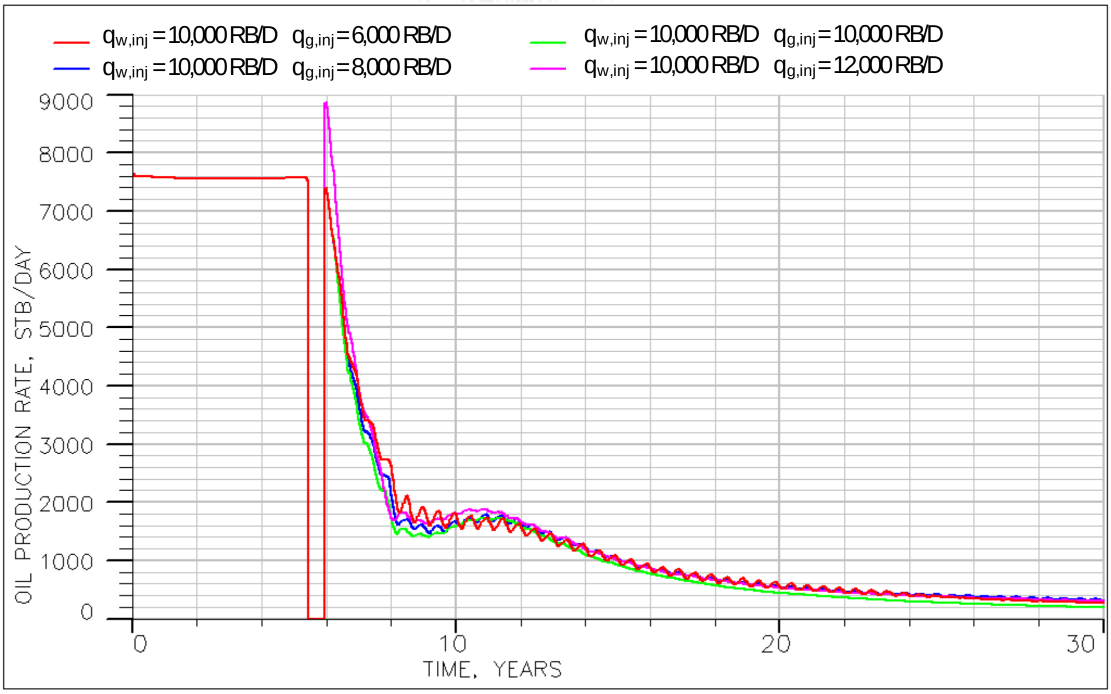


(a)

Figure 5.31 Effect of water and gas injection rates on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15°.

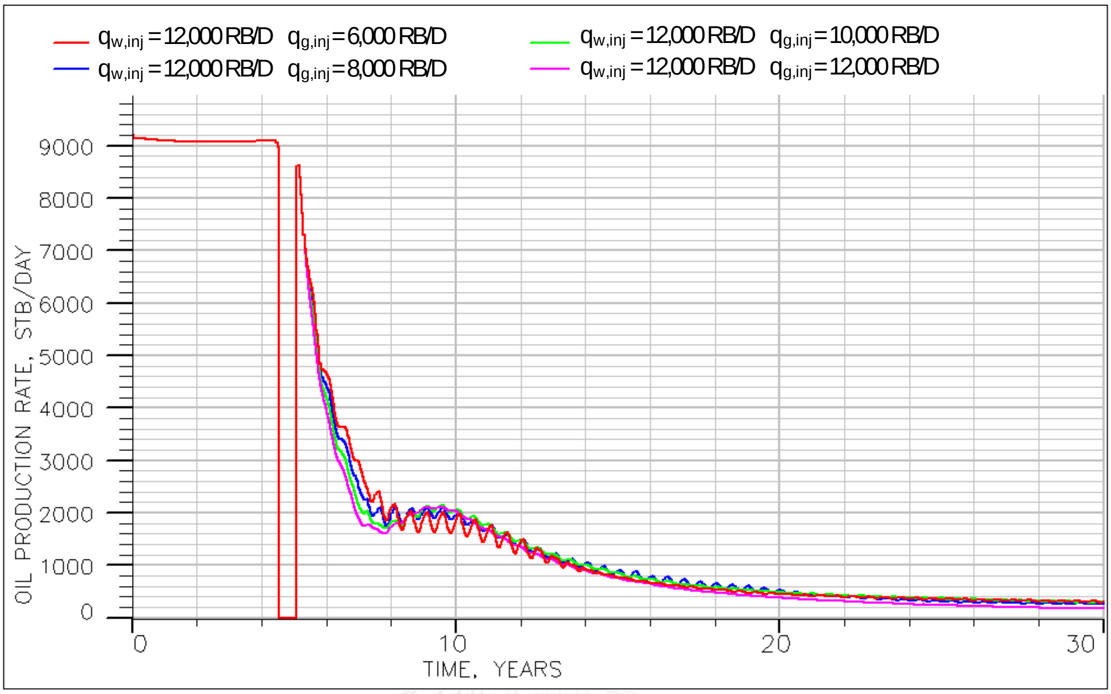


(b)



(c)

Figure 5.31 Effect of water and gas injection rates on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15° (continued).



(d)

Figure 5.31 Effect of water and gas injection rates on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15° (continued).

The case having water injection rate of 12,000 RB/D and gas injection rate of 8,000 RB/D yields the highest BOE for all three reservoirs as shown in Tables 5.14 to 5.16. It yields BOE of 28.843 MMSTB, 27.793 MMSTB, and 25.304 MMSTB for a non-dipping reservoir, a 15° reservoir, and a 30° reservoir, respectively. Similar to WAG with up-dip injection, cases having water injection rate equal to gas injection rate yield significantly low BOE.

Water injection rate affects water consumption. It is clearly seen that a higher amount of water is required when water is injected at a higher rate. However, for gas consumption, it is not affected directly from gas injection rate. From Tables 5.14 to 5.16, cases 6 and 11 require larger amount of gas than the cases with the same water injection rate but with a higher gas injection rate. In WAG period, the production rates of cases 6 and 11 are adjusted equally to both water and gas injection rate. Therefore, the reservoir pressure can be maintained because the systems of these two cases are steady state while the pressures of cases 7, 8, and 12 decline in WAG period. When case 6 is compared to cases 7 and 8, we can inject higher amount of gas (in standard unit) in case 6 even though this case has a lower gas injection rate (in RB unit). Likewise, case 11 requires a higher amount of injected gas than case 12 in all reservoirs.

Table 5.14 Result comparison between different water and gas injection rates of WAG with down-dip injection in a reservoir without dip angle.

Case no.	Dip angle	Water injection rate [RB/D]	Gas injection rate [RB/D]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
1	0°	6,000	6,000	30	21.818	60.31	17.170	26.185	42.593	18.054	23.321
2	0°	6,000	8,000	30	23.483	64.91	17.748	28.979	42.556	20.208	25.355
3	0°	6,000	10,000	30	24.210	66.92	18.633	31.758	42.539	21.764	26.398
4	0°	6,000	12,000	30	24.428	67.52	19.306	34.165	42.523	22.408	26.905
5	0°	8,000	6,000	30	24.401	67.45	14.638	26.820	53.185	29.537	26.432
6	0°	8,000	8,000	30	22.991	63.55	25.946	35.106	53.240	27.754	24.518
7	0°	8,000	10,000	30	24.817	68.60	24.586	36.514	53.187	29.611	26.805
8	0°	8,000	12,000	30	25.377	70.15	24.333	38.409	53.158	31.010	27.724
9	0°	10,000	6,000	30	25.596	70.75	12.136	27.176	63.157	39.982	28.103
10	0°	10,000	8,000	30	25.541	70.60	20.036	32.628	63.197	38.921	27.640
11	0°	10,000	10,000	30	24.760	68.44	32.932	42.285	63.261	36.977	26.319
12	0°	10,000	12,000	30	25.913	71.63	30.235	42.591	63.184	39.025	27.973
13	0°	12,000	6,000	30	25.893	71.57	10.159	26.320	72.264	48.084	28.587
14	**0°**	**12,000**	**8,000**	**30**	**26.267**	**72.61**	**15.814**	**31.266**	**72.293**	**48.823**	**28.843**
15	0°	12,000	10,000	30	26.470	73.17	24.436	37.395	72.339	47.904	28.630
16	0°	12,000	12,000	30	26.372	72.90	37.980	47.294	72.409	46.274	27.925

Table 5.15 Result comparison between different water and gas injection rates of WAG with down-dip injection in a reservoir with dip angle of 15°.

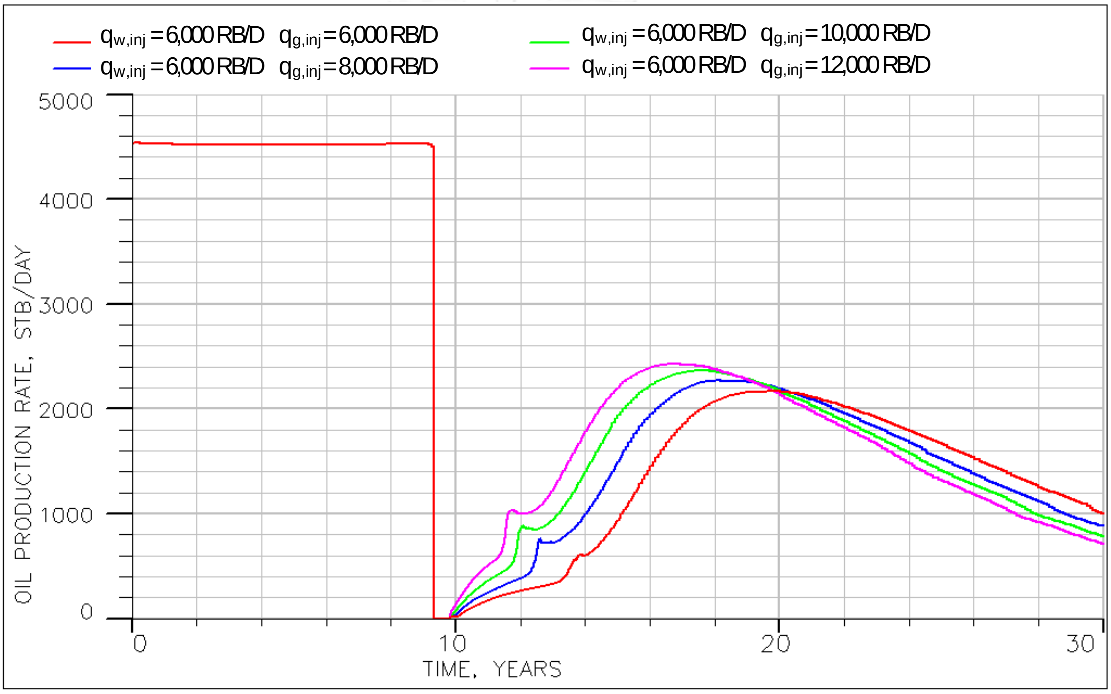
Case no.	Dip angle	Water injection rate [RB/D]	Gas injection rate [RB/D]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
1	15°	6,000	6,000	30	22.326	63.60	19.221	27.018	41.616	18.074	23.626
2	15°	6,000	8,000	30	23.820	67.86	18.887	30.072	41.574	19.443	25.684
3	15°	6,000	10,000	30	24.421	69.57	19.416	32.688	41.553	20.893	26.634
4	15°	6,000	12,000	30	24.667	70.27	19.861	34.620	41.539	21.484	27.128
5	15°	8,000	6,000	30	24.206	68.96	15.530	27.500	52.044	29.217	26.201
6	15°	8,000	8,000	30	23.127	65.88	29.057	36.564	52.114	28.248	24.378
7	15°	8,000	10,000	30	24.638	70.19	26.201	37.740	52.035	29.405	26.561
8	15°	8,000	12,000	30	25.172	71.71	25.406	39.295	52.006	30.705	27.488
9	15°	10,000	6,000	30	25.072	71.42	12.833	27.251	62.429	39.967	27.475
10	15°	10,000	8,000	30	24.943	71.06	21.660	33.835	62.471	39.308	26.972
11	15°	10,000	10,000	30	23.951	68.23	37.717	45.293	62.563	38.424	25.213
12	15°	10,000	12,000	30	25.331	72.16	32.762	44.595	62.470	39.509	27.303
13	15°	12,000	6,000	30	25.391	72.33	12.388	26.644	73.073	49.299	27.767
14	**15°**	**12,000**	**8,000**	**30**	**25.439**	**72.47**	**18.176**	**32.295**	**73.101**	**49.638**	**27.793**
15	15°	12,000	10,000	30	25.364	72.26	28.647	40.899	73.157	49.409	27.406
16	15°	12,000	12,000	30	24.391	69.48	48.592	55.758	73.279	48.790	25.585

Table 5.16 Result comparison between different water and gas injection rates of WAG with down-dip injection in a reservoir with dip angle of 30°.

Case no.	Dip angle	Water injection rate [RB/D]	Gas injection rate [RB/D]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
1	30°	6,000	6,000	30	21.112	66.84	21.555	27.457	41.114	20.119	22.096
2	30°	6,000	8,000	30	22.293	70.58	20.030	30.225	41.058	21.180	23.993
3	30°	6,000	10,000	30	22.714	71.91	19.935	32.263	41.033	22.215	24.769
4	30°	6,000	12,000	30	22.819	72.24	21.026	33.382	41.021	22.035	24.879
5	30°	8,000	6,000	30	22.436	71.03	16.335	27.371	51.337	30.872	24.276
6	30°	8,000	8,000	30	21.728	68.79	32.423	37.947	51.428	30.314	22.649
7	30°	8,000	10,000	30	22.864	72.39	27.778	38.289	51.337	31.102	24.617
8	30°	8,000	12,000	30	23.183	73.40	26.474	38.590	51.293	31.527	25.203
9	30°	10,000	6,000	30	22.938	72.62	13.851	26.130	61.862	40.746	24.985
10	30°	10,000	8,000	30	22.910	72.53	23.036	34.255	61.913	40.937	24.780
11	30°	10,000	10,000	30	22.220	70.35	42.885	48.328	62.036	40.621	23.127
12	30°	10,000	12,000	30	23.286	73.72	35.197	46.003	61.899	41.140	25.087
13	30°	12,000	6,000	30	23.232	73.55	13.991	26.151	72.168	50.419	25.259
14	**30°**	**12,000**	**8,000**	**30**	**23.314**	**73.81**	**19.791**	**31.747**	**72.182**	**50.659**	**25.307**
15	30°	12,000	10,000	30	23.287	73.73	29.791	41.138	72.232	51.096	25.179
16	30°	12,000	12,000	30	22.666	71.76	52.968	58.408	72.382	50.919	23.573

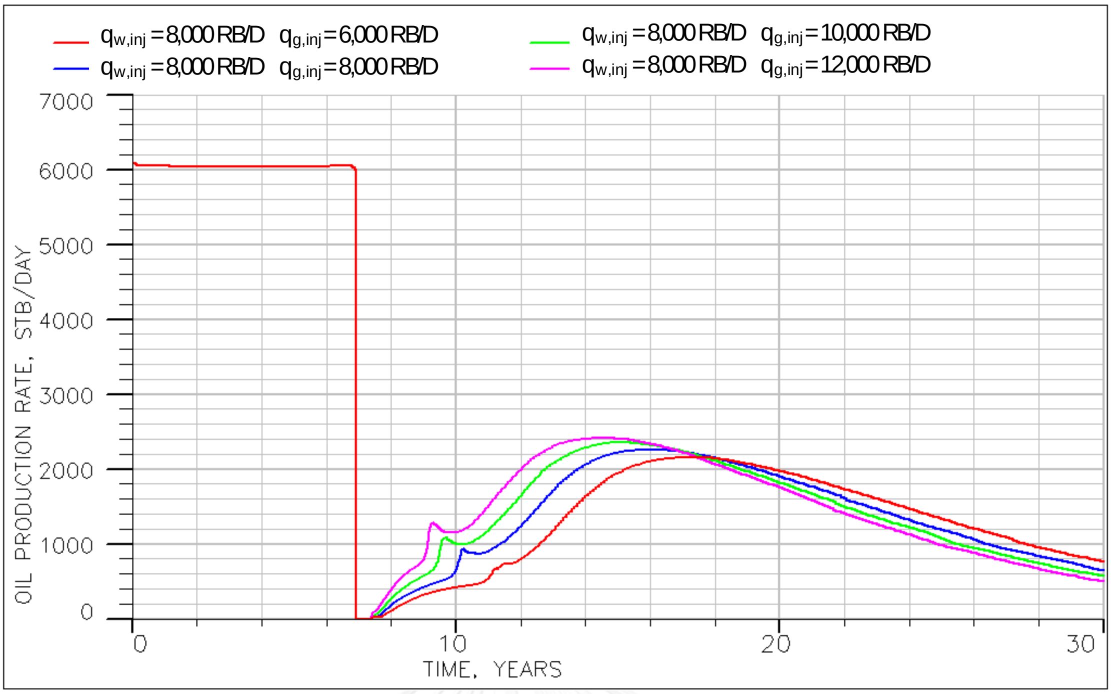
5.3.3 Double displacement process

DDP involves two injection steps which are initial water injection during the water flooding and continuous gas injection. The oil production profile during water flooding is the same as those for the two types of WAG. However, a higher oil rate is caused by higher gas injection rate during gas injection period. However, the oil rate of cases with higher gas injection rate starts to drop earlier because a larger amount of oil has been already produced in the early time of DDP. Figure 5.32 shows effect of water and gas injection rate on oil production rate of DDP in a 15° dipping reservoir.

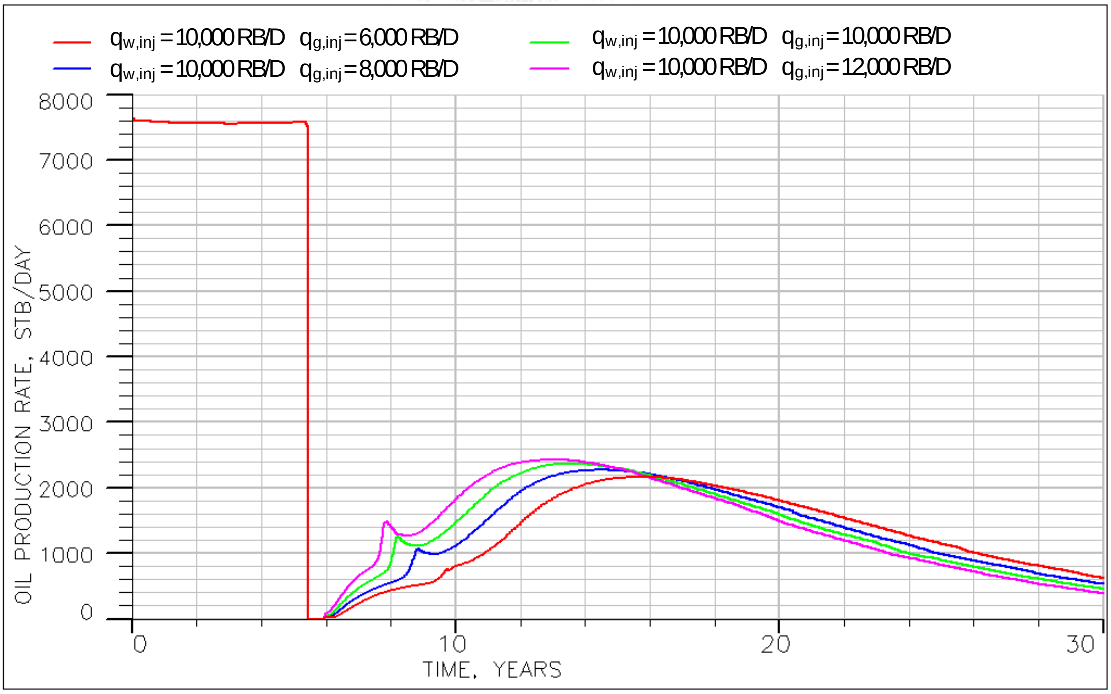


(a)

Figure 5.32 Effect of water and gas injection rates on oil production rate of DDP in a reservoir with dip angle of 15°.

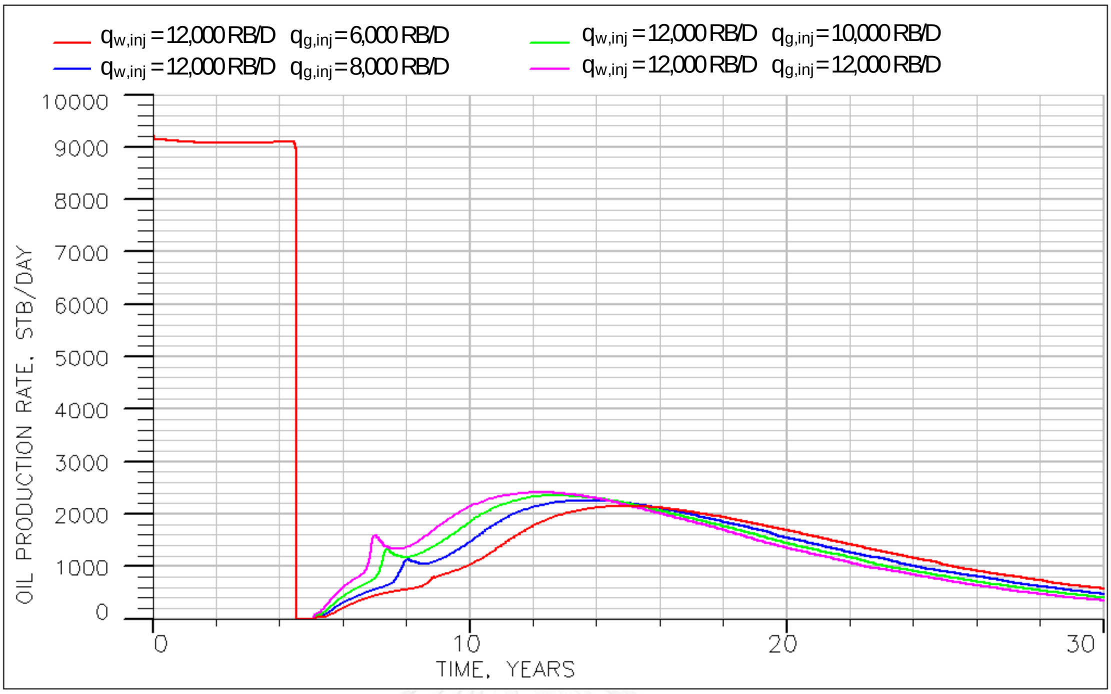


(b)



(c)

Figure 5.32 Effect of water and gas injection rates on oil production rate of DDP in a reservoir with dip angle of 15° (continued).



(d)

Figure 5.32 Effect of water and gas injection rates on oil production rate of DDP in a reservoir with dip angle of 15° (continued).

Tables 5.17 and 5.18 show result comparison between different water and gas injection rates of DDP in a reservoir with dip angle of 15° and 30°. For both reservoirs, case 16 which has water and gas injection rates of 12,000 RB/D yields the highest BOE. It is clearly seen that higher water and gas injection rates result in more oil production. However, these have just slight impact for a 30° reservoir because case 1-16 have similar values of BOE around 23-24 MMSTB as shown in Table 5.18.

In addition, case 16 requires the highest amount of injected gas of 91.048 BSCF for a 15° dipping reservoir and 96.493 BSCF for a 30° dipping reservoir. Water injection rate does not significantly affect the amounts of injected water and produced water. Cases 1-16 require similar amount of water. However, a higher water injection rate results in a higher amount of gas required in gas flooding stage because it accelerates the water flooding mechanism which means there is longer time for gas injection. This effect can be seen from cases 4, 8, 12, and 16 in Tables 5.17 and 5.18.

Table 5.17 Result comparison between different water and gas injection rates of DDP in a reservoir with dip angle of 15°.

Case no.	Dip angle	Water injection rate [RB/D]	Gas injection rate [RB/D]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
1	15°	6,000	6,000	30	25.394	72.34	37.579	28.087	19.982	14.487	23.811
2	15°	6,000	8,000	30	25.987	74.03	49.418	39.714	19.982	14.723	24.370
3	15°	6,000	10,000	30	26.402	75.21	61.194	51.308	19.982	14.931	24.754
4	15°	6,000	12,000	30	26.733	76.16	73.306	63.119	19.982	15.113	25.034
5	15°	8,000	6,000	30	26.157	74.52	42.236	31.995	19.748	14.524	24.450
6	15°	8,000	8,000	30	26.644	75.90	55.535	45.158	19.748	14.760	24.914
7	15°	8,000	10,000	30	26.971	76.84	68.738	58.249	19.748	14.961	25.223
8	15°	8,000	12,000	30	27.232	77.58	82.310	71.574	19.748	15.135	25.443
9	15°	10,000	6,000	30	26.526	75.57	45.054	34.422	19.480	14.399	24.754
10	15°	10,000	8,000	30	26.952	76.78	59.234	48.515	19.480	14.626	25.165
11	15°	10,000	10,000	30	27.233	77.58	73.298	62.504	19.480	14.826	25.434
12	15°	10,000	12,000	30	27.453	78.21	87.761	76.749	19.480	14.996	25.618
13	15°	12,000	6,000	30	26.718	76.11	46.777	35.933	19.453	14.413	24.910
14	15°	12,000	8,000	30	27.107	77.22	61.491	50.589	19.453	14.637	25.289
15	15°	12,000	10,000	30	27.364	77.95	76.055	65.105	19.453	14.837	25.538
16	**15°**	**12,000**	**12,000**	**30**	**27.564**	**78.53**	**91.048**	**79.899**	**19.453**	**15.002**	**25.706**

Table 5.18 Result comparison between different water and gas injection rates of DDP in a reservoir with dip angle of 30°.

Case no.	Dip angle	Water injection rate [RB/D]	Gas injection rate [RB/D]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
1	30°	6,000	6,000	30	25.407	80.44	41.217	29.121	19.729	14.775	23.390
2	30°	6,000	8,000	30	25.527	80.82	53.460	41.896	19.729	14.905	23.599
3	30°	6,000	10,000	30	25.602	81.06	65.611	54.389	19.729	14.982	23.732
4	30°	6,000	12,000	30	25.660	81.24	77.557	66.625	19.729	15.041	23.837
5	30°	8,000	6,000	30	25.577	80.98	46.304	33.894	19.168	14.412	23.509
6	30°	8,000	8,000	30	25.669	81.27	60.043	48.224	19.168	14.520	23.699
7	30°	8,000	10,000	30	25.729	81.46	73.706	62.254	19.168	14.585	23.819
8	30°	8,000	12,000	30	25.776	81.61	87.149	75.997	19.168	14.638	23.917
9	30°	10,000	6,000	30	25.657	81.23	49.410	36.849	18.752	14.063	23.563
10	30°	10,000	8,000	30	25.735	81.48	64.051	52.111	18.752	14.165	23.744
11	30°	10,000	10,000	30	25.787	81.64	78.599	67.046	18.752	14.228	23.861
12	30°	10,000	12,000	30	25.829	81.78	92.896	81.660	18.752	14.282	23.956
13	30°	12,000	6,000	30	25.703	81.38	51.360	38.706	18.567	13.889	23.594
14	30°	12,000	8,000	30	25.773	81.60	66.573	54.552	18.567	13.990	23.770
15	30°	12,000	10,000	30	25.822	81.75	81.670	70.049	18.567	14.053	23.884
16	**30°**	**12,000**	**12,000**	**30**	**25.862**	**81.88**	**96.493**	**85.202**	**18.567**	**14.106**	**23.980**

The cases yield the highest BOE for each recovery process and dip angle are listed in Table 5.19. All recovery processes require the highest water injection rate of 12,000 RB/D but different gas injection rates. These cases will be used in subsequent studies in the following sections. However, these may not be the most suitable cases when the economic reason is considered.

Table 5.19 Summary of water and gas injection rates that yield the highest BOE.

Dip angle	**Recovery process**	**Water injection rate [RB/D]**	**Gas injection rate [RB/D]**
0°	WAG up-dip	12,000	8,000
0°	WAG down-dip	12,000	8,000
0°	DDP	-	-
15°	WAG up-dip	12,000	8,000
15°	WAG down-dip	12,000	8,000
15°	DDP	12,000	12,000
30°	WAG up-dip	12,000	6,000
30°	WAG down-dip	12,000	8,000
30°	DDP	12,000	12,000

5.4 Effect of WAG cycle and injection duration

WAG cycle and injection duration according to Table 5.20 are studied to consider their effect on production performance for WAG with up-dip and WAG with down-dip injection. Water cuts from Table 5.14 and Injection rates from Table 5.19 are combined for this study. For example, case 1 of WAG with up-dip injection in a 15° reservoir has a stopping criteria of 1% water cut, water injection rate of 12,000 RB/D, gas injection rate of 8,000 RB/D, water injection duration of 30 days, and gas injection duration of 120 days.

Table 5.20 WAG cycle and injection duration.

Case no.	WAG cycle	Water injection duration [day]	Gas injection duration [day]
1	1:4	30	120
2	1:4	60	240
3	1:2	30	60
4	1:2	60	120
5	1:2	90	180
6	1:1	30	30
7	1:1	90	90
8	1:1	180	180
9	2:1	60	30
10	2:1	120	60
11	2:1	180	90
12	4:1	120	30
13	4:1	240	60

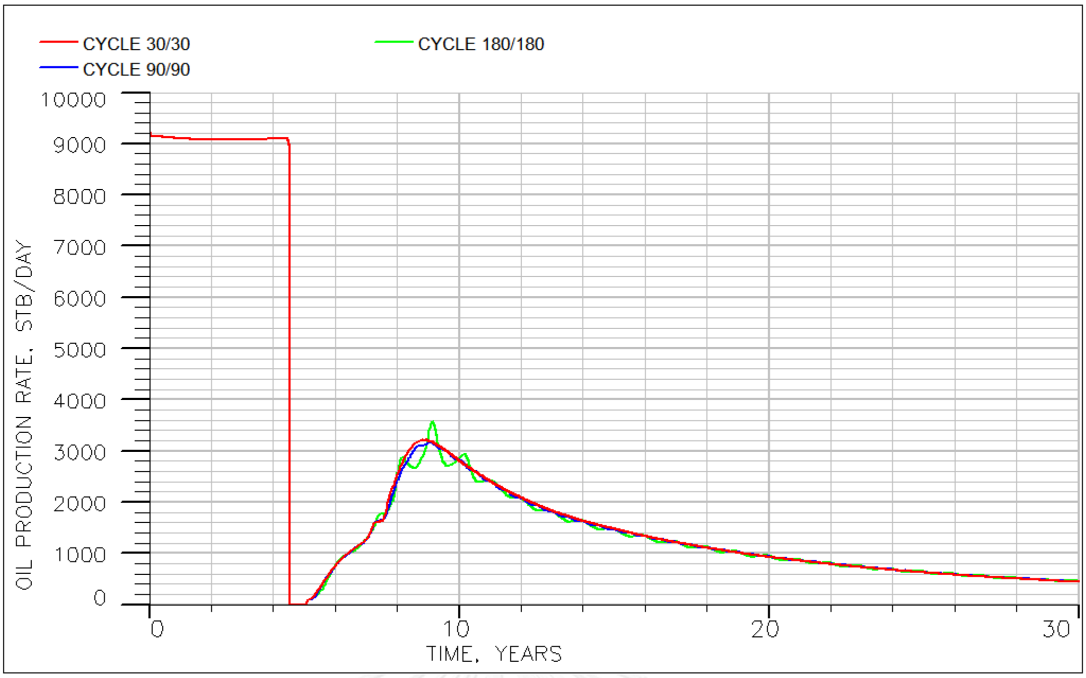
5.4.1 WAG with up-dip injection

Figure 5.33 shows that WAG cycle significantly influences oil rate in the early time of WAG. Between the seventh year and the twelfth year, WAG cycle of 2:1 (see Figure 5.33 (c)) yields the highest oil production rate of approximately 3,400 STB/D while WAG cycle of 4:1, 1:1, 1:2, and 1:4 yield approximately 3,300 STB/D, 3,200 STB/D, 2,800 STB/D, and 2,500 STB/D, respectively.

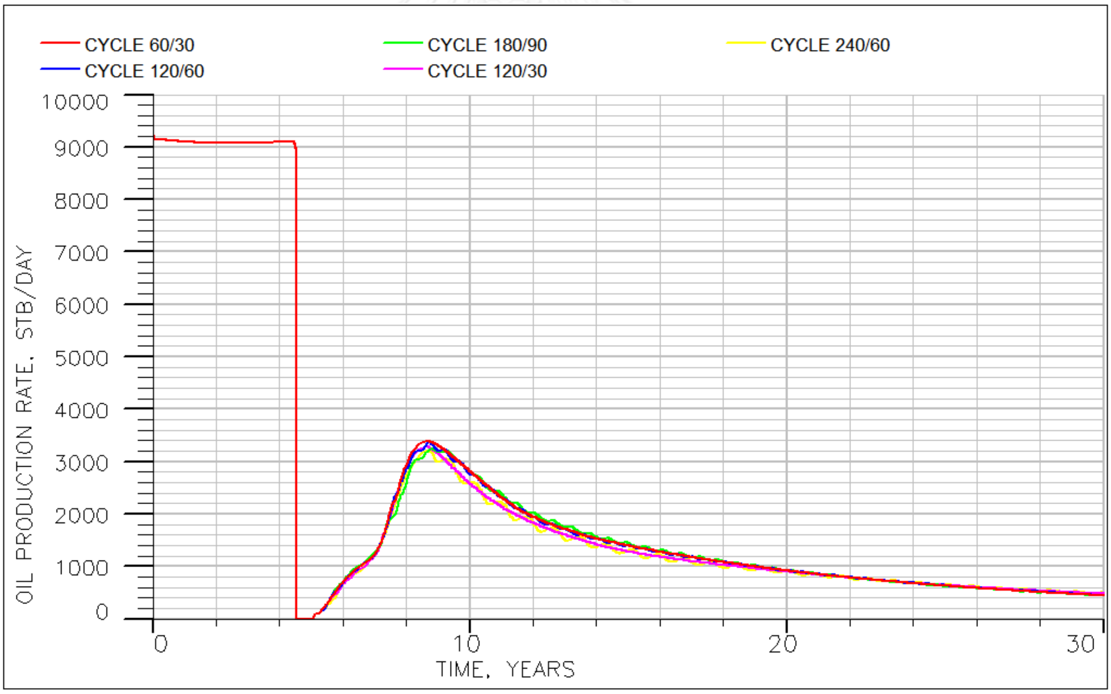
Oil production rate may fluctuate due to the arrival of different types of injecting fluid at the producer. In other words, the fluctuation of oil production depends on the cycle of injection. As a result, the longer injection duration causes non-smooth production profile but has the same trend as cases with shorter injection duration having the same WAG cycle (see Figure 5.33 (b)).

(a)

Figure 5.33 Effect of WAG cycle and injection duration on oil production rate of WAG with up-dip injection in a reservoir with dip angle of 15°.



(b)



(c)

Figure 5.33 Effect of WAG cycle and injection duration on oil production rate of WAG with up-dip injection in a reservoir with dip angle of 15° (continued).

Tables 5.21 to 5.23 show result comparison between different WAG cycle and injection duration of WAG with up-dip injection. Water and gas requirement is affected directly by their injection durations. Cases having longer water injection duration require and produce large amount of water while cases having longer gas injection duration require and produce large amount of gas. For a non-dipping reservoir, we can increase oil recovery factor and BOE by injecting water for longer time than injecting gas (WAG cycle of 2:1 and 4:1) as shown in Table 5.21. Gas has a high tendency to override in this reservoir; consequently, water can efficiently stabilize the flood front which lowers the problem of viscous fingering. In contrast to a non-dipping reservoir, large water slug is not needed to stabilize the flood front in 15-degree and 30-degree dipping reservoirs because a bigger dip angle increases the value of gravity number (G) calculated from Eq. 3.5. Therefore, unstable condition is more difficult to occur in reservoir with bigger dip angle as detailed in Chapter 3. As a result, the ratio of water and gas injection durations has only slightly influence on recovery factor and BOE of dipping reservoirs as shown in Tables 5.22 and 5.23.

Cases 9, 6, and 3 result in the highest BOE for a reservoir with dip angle of 0°, 15°, and 30°, respectively. These three cases have quite shorter injection durations as compared to those cases obtaining lower BOE. In other words, shorter injection duration is appropriate for WAG with up-dip injection because it provides smoother production profile.

In term of WAG cycle, WAG cycle of 2:1, 1:1, and 1:2 yield the highest BOEs for a reservoir with dip angle of 0°, 15°, and 30°, respectively.

Table 5.21 Result comparison between different WAG cycle and injection duration of WAG with up-dip injection in a reservoir without dip angle.

Case no.	Dip angle	WAG cycle	Injection duration [Day]		Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
			Water	Gas								
1	0°	1:4	30	120	30	23.317	64.45	22.984	38.922	39.928	21.502	25.974
2	0°	1:4	60	240	30	23.296	64.40	23.008	38.910	39.938	21.680	25.947
3	0°	1:2	30	60	30	25.161	69.55	20.261	36.184	53.950	32.301	27.815
4	0°	1:2	60	120	30	25.084	69.34	20.254	36.141	53.951	32.509	27.733
5	0°	1:2	90	180	30	25.031	69.19	20.184	36.095	54.526	32.766	27.683
6	0°	1:1	30	30	30	26.350	72.84	16.684	31.942	71.477	47.775	28.893
7	0°	1:1	90	90	30	26.226	72.50	16.689	31.886	71.493	48.086	28.760
8	0°	1:1	180	180	30	26.075	72.08	16.704	31.718	71.496	48.742	28.578
9	**0°**	**2:1**	**60**	**30**	**30**	**26.985**	**74.59**	**12.520**	**26.636**	**89.060**	**64.020**	**29.338**
10	0°	2:1	120	60	30	26.887	74.32	12.517	26.600	89.059	64.198	29.234
11	0°	2:1	180	90	30	26.818	74.13	12.420	26.538	89.416	64.425	29.171
12	0°	4:1	120	30	30	27.134	75.00	8.433	21.403	103.140	76.931	29.296
13	0°	4:1	240	60	30	27.027	74.71	8.426	21.395	103.142	77.051	29.189

Table 5.22 Result comparison between different WAG cycle and injection duration of WAG with up-dip injection in a reservoir with dip angle of 15°.

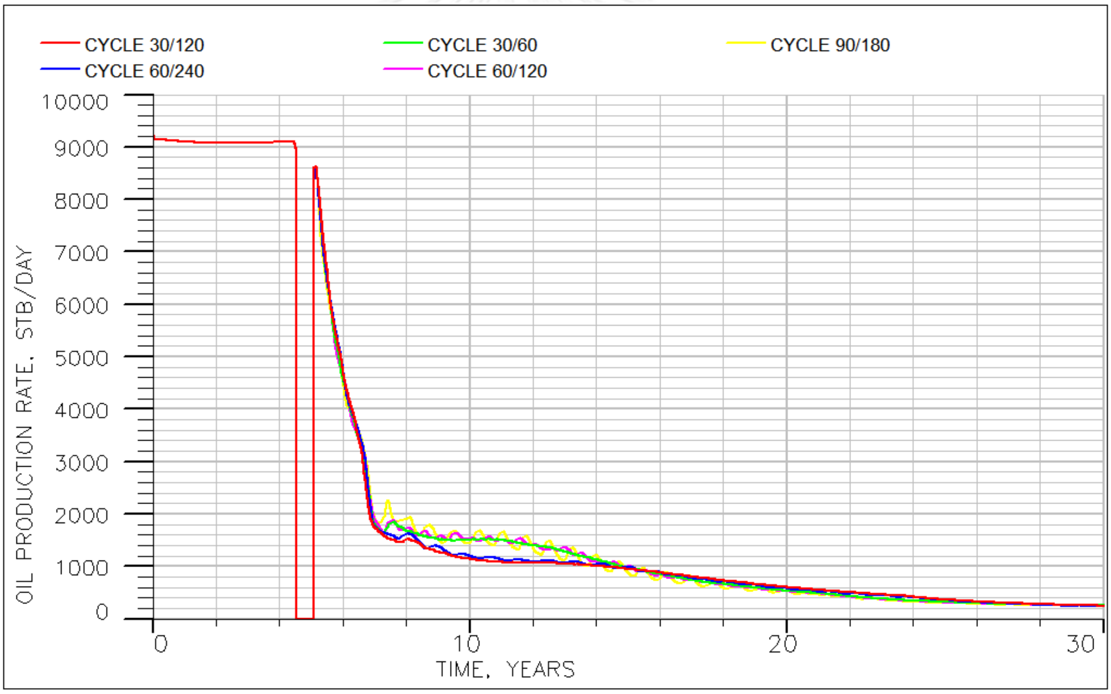
Case no.	Dip angle	WAG cycle	Injection duration [Day]		Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
			Water	Gas								
1	15°	1:4	30	120	30	26.099	74.35	25.710	38.268	40.793	29.034	28.192
2	15°	1:4	60	240	30	25.996	74.06	25.621	38.278	41.160	29.078	28.106
3	15°	1:2	30	60	30	26.413	75.24	22.505	35.631	54.949	38.776	28.601
4	15°	1:2	60	120	30	26.340	75.04	22.443	35.610	55.184	38.881	28.535
5	15°	1:2	90	180	30	26.267	74.83	22.420	35.595	55.191	38.958	28.463
6	**15°**	**1:1**	**30**	**30**	**30**	**26.588**	**75.74**	**18.326**	**31.565**	**72.746**	**52.476**	**28.795**
7	15°	1:1	90	90	30	26.488	75.46	18.238	31.488	73.100	52.744	28.697
8	15°	1:1	180	180	30	26.368	75.12	18.211	31.390	73.218	53.107	28.565
9	15°	2:1	60	30	30	26.519	75.55	13.680	26.098	90.432	68.027	28.589
10	15°	2:1	120	60	30	26.452	75.36	13.583	26.030	90.784	68.232	28.527
11	15°	2:1	180	90	30	26.475	75.42	16.343	29.280	80.589	59.377	28.631
12	15°	4:1	120	30	30	26.027	74.15	9.156	20.682	104.873	80.709	27.949
13	15°	4:1	240	60	30	25.924	73.85	9.150	20.591	104.882	80.952	27.832

Table 5.23 Result comparison between different WAG cycle and injection duration of WAG with up-dip injection in a reservoir with dip angle of 30°.

Case no.	Dip angle	WAG cycle	Injection duration [Day]		Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
			Water	Gas								
1	30°	1:4	30	120	30	25.026	79.23	14.831	28.816	39.559	31.145	27.358
2	30°	1:4	60	240	30	24.944	78.97	14.791	28.817	39.517	31.150	27.283
3	**30°**	**1:2**	**30**	**60**	**30**	**25.109**	**79.50**	**13.357**	**27.062**	**53.917**	**42.873**	**27.394**
4	30°	1:2	60	120	30	25.034	79.26	13.309	27.070	54.193	42.879	27.328
5	30°	1:2	90	180	30	24.963	79.03	13.249	27.053	54.292	42.889	27.264
6	30°	1:1	30	30	30	25.046	79.30	11.297	24.443	71.944	57.693	27.238
7	30°	1:1	90	90	30	24.949	78.99	11.199	24.420	72.116	57.690	27.153
8	30°	1:1	180	180	30	24.814	78.56	11.218	24.452	72.439	57.918	27.021
9	30°	2:1	60	30	30	24.856	78.69	8.775	20.942	89.937	72.707	26.884
10	30°	2:1	120	60	30	24.810	78.55	8.779	20.913	90.219	72.947	26.833
11	30°	2:1	180	90	30	24.759	78.39	8.776	20.910	90.128	72.974	26.782
12	30°	4:1	120	30	30	24.440	77.38	6.173	16.877	104.659	85.497	26.225
13	30°	4:1	240	60	30	24.380	77.19	6.131	16.823	104.872	85.690	26.162

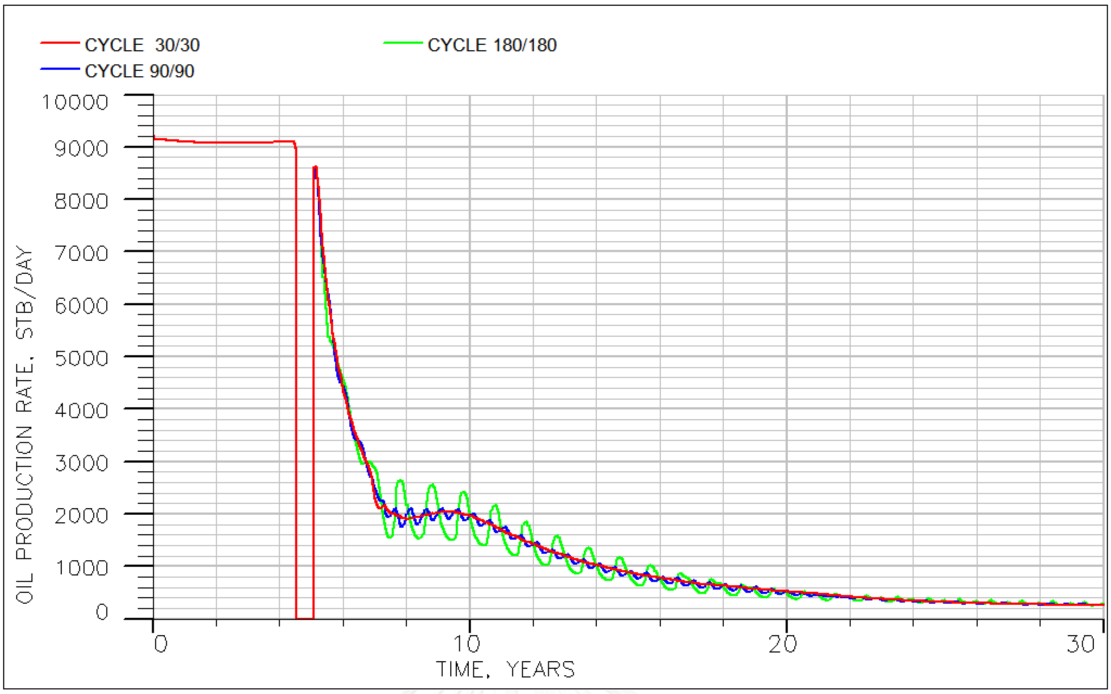
5.4.2 WAG with down-dip injection

For WAG with down-dip injection, WAG cycle significantly affects oil production between the sixth year and the fifteenth year as shown in Figure 5.34. WAG cycle of 2:1 results in higher oil production rate than other cycles during this time. Cases with the same WAG cycle but different injection durations have the same trend throughout 30 years of production. However, smoother production profile is obtained from shorter injection duration as can be clearly seen in Figure 5.34 (b). Since oil is likely to be produced together with water slug, we can clearly see this effect when water and gas are injected in large slugs. The case of 180/180 (water/gas) days of injection durations results in high fluctuation of oil production rate.

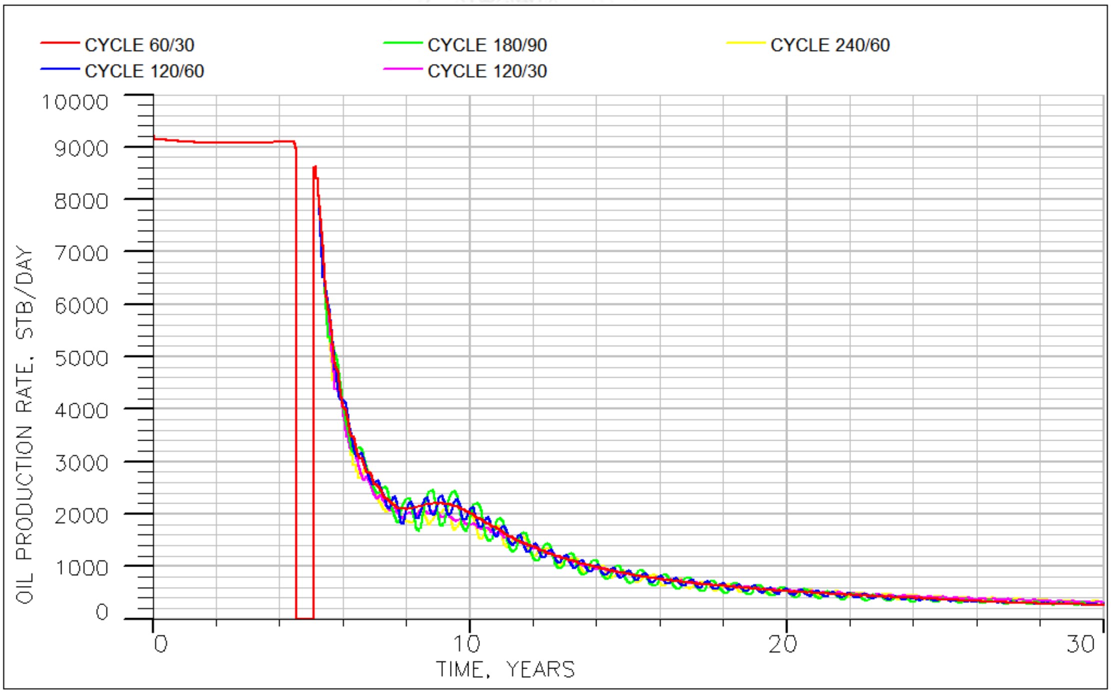


(a)

Figure 5.34 Effect of WAG cycle and injection duration on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15°.



(b)



(c)

Figure 5.34 Effect of WAG cycle and injection duration on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15° (contimued).

WAG cycle involves in the requirement of water and gas. We need larger volume of water when water injection duration is longer than gas injection duration. Conversely, when gas injection duration is longer than water injection duration, total amount of injected gas obviously increases.

The gravity number is a function of degree of dip angle. Reservoir with smaller dip angle easily causes the problem of unstable flood front because it directly lowers the gravity number. Accordingly, it requires large water slugs to avoid gas overriding. Cases having higher water/gas injection durations ratio result in better oil recovery factor in a non-dipping reservoir while different WAG cycles do not apparently affect the performance in dipping reservoirs.

Similar to WAG with up-dip injection, shorter water and gas injection durations yield higher BOE as shown in Tables 5.24 to 5.26. Case 6 is the case with the highest BOE for a 15° reservoir and a 30° reservoir while case 9 gives the highest BOE for a non-dipping reservoir. In addition, water and gas requirement depends mainly on their injection durations. However, these parameters do not significantly affect the performance of WAG with down-dip injection. Cases 1-16 do not have obvious difference in BOE.

Table 5.24 Result comparison between different WAG cycle and injection duration of WAG with down-dip injection in a reservoir without dip angle.

Case no.	Dip angle	WAG cycle	Injection duration [Day]		Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
			Water	Gas								
1	0°	1:4	30	120	30	24.479	67.67	21.560	37.954	41.352	21.729	27.212
2	0°	1:4	60	240	30	24.444	67.57	21.542	37.936	41.656	21.915	27.177
3	0°	1:2	30	60	30	25.595	70.75	19.083	35.317	55.101	33.020	28.301
4	0°	1:2	60	120	30	25.521	70.55	19.073	35.289	55.016	33.142	28.225
5	0°	1:2	90	180	30	25.499	70.48	19.062	35.245	55.378	33.447	28.197
6	0°	1:1	30	30	30	26.380	72.92	15.819	31.318	72.274	48.530	28.964
7	0°	1:1	90	90	30	26.267	72.61	15.814	31.266	72.293	48.823	28.843
8	0°	1:1	180	180	30	26.098	72.14	15.600	31.074	73.154	49.398	28.678
9	**0°**	**2:1**	**60**	**30**	**30**	**26.747**	**73.93**	**11.916**	**26.309**	**89.361**	**64.438**	**29.146**
10	0°	2:1	120	60	30	26.652	73.67	11.950	26.290	89.488	64.703	29.042
11	0°	2:1	180	90	30	26.558	73.41	11.735	26.215	89.994	64.830	28.972
12	0°	4:1	120	30	30	26.763	73.98	8.026	21.338	103.490	77.180	28.982
13	0°	4:1	240	60	30	26.652	73.67	7.945	21.295	103.509	77.282	28.878

Table 5.25 Result comparison between different WAG cycle and injection duration of WAG with down-dip injection in a reservoir with dip angle of 15°.

Case no.	Dip angle	WAG cycle	Injection duration [Day]		Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
			Water	Gas								
1	15°	1:4	30	120	30	24.721	70.42	23.786	39.443	40.821	20.340	27.331
2	15°	1:4	60	240	30	24.779	70.59	23.869	39.444	41.180	20.832	27.375
3	15°	1:2	30	60	30	25.188	71.75	21.599	36.482	54.948	32.844	27.669
4	15°	1:2	60	120	30	25.191	71.77	21.616	36.409	55.196	33.234	27.657
5	15°	1:2	90	180	30	25.166	71.69	21.682	36.388	55.202	33.583	27.618
6	**15°**	**1:1**	**30**	**30**	**30**	**25.566**	**72.83**	**18.219**	**32.430**	**72.742**	**49.220**	**27.935**
7	15°	1:1	90	90	30	25.439	72.47	18.176	32.295	73.101	49.638	27.793
8	15°	1:1	180	180	30	25.322	72.14	18.357	32.249	73.225	49.949	27.637
9	15°	2:1	60	30	30	25.671	73.13	13.895	27.436	90.430	66.089	27.929
10	15°	2:1	120	60	30	25.541	72.76	13.782	27.316	90.788	66.241	27.797
11	15°	2:1	180	90	30	25.451	72.50	13.735	27.241	91.037	66.315	27.702
12	15°	4:1	120	30	30	25.433	72.45	9.543	22.157	104.894	79.576	27.536
13	15°	4:1	240	60	30	25.281	72.02	9.494	22.121	104.900	79.761	27.386

Table 5.26 Result comparison between different WAG cycle and injection duration of WAG with down-dip injection in a reservoir with dip angle of 30°.

Case no.	Dip angle	WAG cycle	Injection duration [Day]		Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
			Water	Gas								
1	30°	1:4	30	120	30	22.933	72.61	25.348	38.241	39.578	20.479	25.082
2	30°	1:4	60	240	30	22.836	72.30	25.506	38.381	39.535	20.721	24.982
3	30°	1:2	30	60	30	23.261	73.65	23.372	35.840	53.953	33.515	25.340
4	30°	1:2	60	120	30	23.201	73.45	23.441	35.849	54.231	33.857	25.269
5	30°	1:2	90	180	30	23.111	73.17	23.464	35.912	54.342	33.901	25.186
6	**30°**	**1:1**	**30**	**30**	**30**	**23.508**	**74.43**	**19.828**	**31.782**	**72.005**	**50.516**	**25.501**
7	30°	1:1	90	90	30	23.314	73.81	19.791	31.747	72.182	50.659	25.307
8	30°	1:1	180	180	30	23.181	73.39	20.127	32.084	72.509	50.948	25.174
9	30°	2:1	60	30	30	23.445	74.23	14.913	26.459	90.019	67.808	25.369
10	30°	2:1	120	60	30	23.316	73.82	14.874	26.421	90.303	68.081	25.241
11	30°	2:1	180	90	30	23.213	73.49	14.977	26.465	90.214	68.110	25.128
12	30°	4:1	120	30	30	23.193	73.43	10.087	21.362	104.757	82.116	25.073
13	30°	4:1	240	60	30	23.015	72.87	9.984	21.309	104.971	82.189	24.903

From Table 5.27, reservoirs with dip angle of 15° and 0° have injection duration (water/gas) of 30/30 and 60/30 that provide the highest BOE, respectively, for both WAG with up-dip and down-dip injection. For a reservoir with dip-angle of 30°, injection duration (water/gas) of 30/60 and 30/30 yield the highest BOE for WAG with up-dip and down-dip injection, respectively. The performances of these cases are considered in term of BOE which takes into account the amount of produced oil and injected gas but not in term of economic.

Table 5.27 Summary of the WAG cycle and injection duration that give the highest BOE.

Dip angle	Recovery process	Water injection duration [day]	Gas injection duration [day]
0°	WAG up-dip	60	30
0°	WAG down-dip	60	30
15°	WAG up-dip	30	30
15°	WAG down-dip	30	30
30°	WAG up-dip	30	60
30°	WAG down-dip	30	30

5.5 Effect of well pattern

This study is performed to investigate oil production performance of different well patterns and to find the appropriate pattern for each reservoir. Five well patterns with different types of well and its location are constructed.

Pattern 1 has two vertical wells at up-dip location (well 1) and down-dip location (well 2) as shown in Figure 5.35. They are fully perforated to allow oil, gas, and water flow into or out of the wells. Each reservoir has its own fracturing pressure which depends on formation depth. Well location and fracturing pressure are listed in Table 5.28.

This well pattern is similar to the base cases but it has parameters which provide the highest BOE. These parameters are stopping criteria of water flooding, water and gas injection rates, and WAG cycle and injection duration from Tables 5.8, 5.19, and 5.27 are applied to yield the highest BOE. Well schedules for all production processes and reservoirs are illustrated in Table 5.29. Every process starts with water injection through well 2 and oil production at well 1. After water cut reaches the criteria, all wells are shut for 180 days. Oil is then produced again until the thirtieth year or the time of economic constraint.

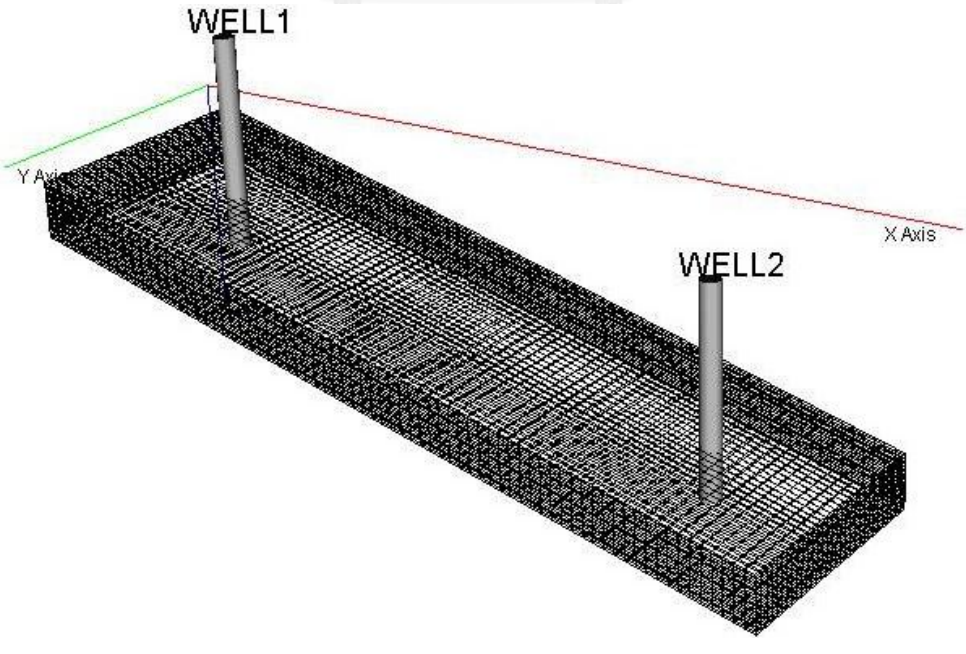


Figure 5.35 Well location in 3D for pattern 1.

Table 5.28 Well location and fracture pressure for pattern 1.

Parameters	Values	Units
Position of well 1	i=12, j=16, k=1-20	-
Position of well 2	i=62, j=16, k=1-20	-
Fracture pressure of well 1 @top depth of 5,000 ft (0°)	3,080	psia
Fracture pressure of well 2 @top depth of 5,000 ft (0°)	3,080	psia
Fracture pressure of well 1 @top depth of 5,234 ft (15°)	3,260	psia
Fracture pressure of well 2 @top depth of 6,298 ft (15°)	4,080	psia
Fracture pressure of well 1 @top depth of 5,452 ft (30°)	3,420	psia
Fracture pressure of well 2 @top depth of 7,507 ft (30°)	5,070	psia

Table 5.29 Well schedule of WAG with up-dip injection for pattern 1.

Dip angle	Step of production	Well 1	Well 2
0°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 60/30 days)	injector - water (12000 RB/D) - gas (8000 RB/D)	producer (12000 RB/D)
15°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/30 days)	injector - water (12000 RB/D) - gas (8000 RB/D)	producer (12000 RB/D)
30°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/60 days)	injector - water (12000 RB/D) - gas (6000 RB/D)	producer (12000 RB/D)

Table 5.30 Well schedule of WAG with down-dip injection for pattern 1.

Dip angle	Step of production	Well 1	Well 2
0°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 40% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 60/30 days)	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)
15°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/30 days)	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)
30°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/30 days)	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)

Table 5.31 Well schedule of DDP for pattern 1.

Dip angle	Step of production	Well 1	Well 2
15°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	DDP	gas injector (12000 RB/D)	producer (12000 RB/D)
30°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 20% criteria	shut in for 180 days	shut in for 180 days
	DDP	gas injector (12000 RB/D)	producer (12000 RB/D)

Pattern 2 consists of 4 vertical wells as shown in Figure 5.36 with their locations and fracture pressures in Table 5.32. Note that the positions of the most up-dip well and the most down-dip well in this pattern is not the same as those in pattern 1. This is because we would like to keep the distance between all wells to be constant. It starts with water injection through well 4 which is the well at the deepest location. Oil is produced at wells 1-3 with the total rate equal to the injection rate at well 4. Then, well 3 is shut in when the water cut reaches the stopping criteria presented in Table 5.8 which is different for each process and dip angle. Wells 1 and 2 are now opened with the total production rate equal to the injection rate at well 4. After well 2 reaches its stopping criteria, it is shut in as oil is continued to be produced by the upper-most well. The production rate at well 1 is set equal to the injection rate at well 4. Oil production is continued until well 1 reaches the stopping criteria. After that, all wells are shut in for 180 days before three different production types (WAG up-dip, WAG down-dip, and DDP) are performed as shown in Tables 5.33-5.40.

For WAG with up-dip injection, water and gas injector is well 1 throughout the production time. Fluid production is from well 2, well 3, and well 4, sequentially. The switching of producer from well 2 to well 3 is done when GOR of well 2 reaches the pre-set value which is different for each dip angle. This value comes from the study of appropriate GOR for switching producer by varying GOR to be 1, 2, 3, 4, and 5 MSCF/STB. GOR resulting in the highest BOE as shown in Table 5.41 is then applied in this section.

For WAG with down-dip injection, it is performed contrarily to WAG with up-dip injection by injecting at well 4 but producing at well 3, well 2, and well 1, sequentially. Switching criteria for producer is obtained from the varying of GOR to be 1, 2, 3, 4, and 5 MSCF/STB.

For DDP, gas is injected continuously at well 1 while oil is produced at well 2. After GOR of well 2 reaches the value which yields the highest BOE, oil production is switched from well 2 to well 3. GOR used for each reservoir is studied by varying it to be 1, 5, 10, 15, 20, and 25 MSCF/STB. After that, the switching of producer from well 3 to well 4 occurs when GOR of well 3 reaches the setting value. Oil production is then performed by well 4 throughout the production time.

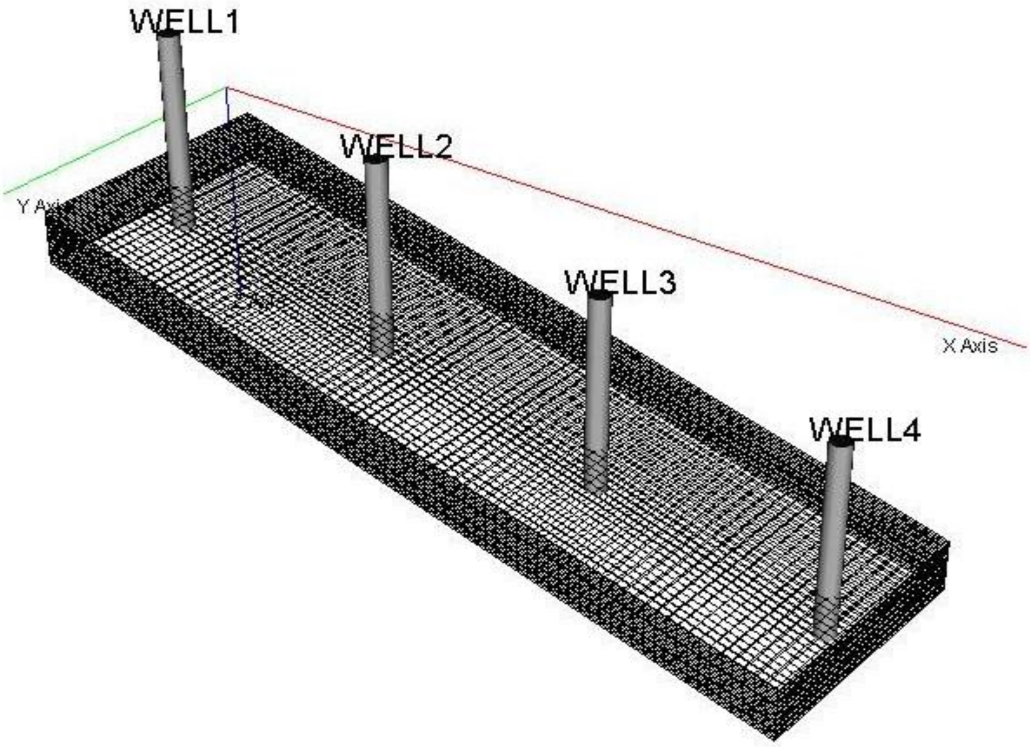


Figure 5.36 Well location in 3D for pattern 2.

Table 5.32 Well location and fracture pressure for pattern 2.

Parameters	Values	Units
Position of well 1	i=4, j=16, k=1-20	-
Position of well 2	i=26, j=16, k=1-20	-
Position of well 3	i=48, j=16, k=1-20	-
Position of well 4	i=70, j=16, k=1-20	-
Fracture pressure of well 1 @top depth of 5,000 ft (0°)	3,080	psia
Fracture pressure of well 4 @top depth of 5,000 ft (0°)	3,080	psia
Fracture pressure of well 1 @top depth of 5,064 ft (15°)	3,130	psia
Fracture pressure of well 4 @top depth of 6,468 ft (15°)	4,220	psia
Fracture pressure of well 1 @top depth of 5,123 ft (30°)	3,180	psia
Fracture pressure of well 4 @top depth of 7,836 ft (30°)	5,360	psia

Table 5.33 Well schedule of WAG with up-dip injection in a non-dipping reservoir for pattern 2.

Step of production	Well 1	Well 2	Well 3	Well 4
water flooding	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 60/30 days)	injector - water (12000 RB/D) - gas (8000 RB/D)	producer (12000 RB/D)	shut in	shut in
GOR of well 2 reaches 2 Mscf/stb	injector - water (12000 RB/D) - gas (8000 RB/D)	shut in	producer (12000 RB/D)	shut in
GOR of well 3 reaches 2 Mscf/stb	injector - water (12000 RB/D) - gas (8000 RB/D)	shut in	shut in	producer (12000 RB/D)

Table 5.34 Well schedule of WAG with up-dip injection in a 15° reservoir for pattern 2

Step of production	Well 1	Well 2	Well 3	Well 4
water flooding	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 30/30 days)	injector - water (12000 RB/D) - gas (8000 RB/D)	producer (12000 RB/D)	shut in	shut in
GOR of well 2 reaches 3 Mscf/stb	injector - water (12000 RB/D) - gas (8000 RB/D)	shut in	producer (12000 RB/D)	shut in
GOR of well 3 reaches 3 Mscf/stb	injector - water (12000 RB/D) - gas (8000 RB/D)	shut in	shut in	producer (12000 RB/D)

Table 5.35 Well schedule of WAG with up-dip injection in a 30° reservoir for pattern 2

Step of production	Well 1	Well 2	Well 3	Well 4
water flooding	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 30/60 days)	injector - water (12000 RB/D) - gas (6000 RB/D)	producer (12000 RB/D)	shut in	shut in
GOR of well 2 reaches 2 Mscf/stb	injector - water (12000 RB/D) - gas (6000 RB/D)	shut in	producer (12000 RB/D)	shut in
GOR of well 3 reaches 2 Mscf/stb	injector - water (12000 RB/D) - gas (6000 RB/D)	shut in	shut in	producer (12000 RB/D)

Table 5.36 Well schedule of WAG with down-dip injection in a non-dipping reservoir for pattern 2.

Step of production	Well 1	Well 2	Well 3	Well 4
water flooding	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	water injector (12000 RB/D)
water cut of well 3 reaches 40% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 40% criteria	producer (12000 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 40% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 60/30 days)	shut in	shut in	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)
GOR of well 3 reaches 5 Mscf/stb	shut in	producer (12000 RB/D)	shut in	injector - water (12000 RB/D) - gas (8000 RB/D)
GOR of well 2 reaches 5 Mscf/stb	producer (12000 RB/D)	shut in	shut in	injector - water (12000 RB/D) - gas (8000 RB/D)

Table 5.37 Well schedule of WAG with down-dip injection in a 15° reservoir for pattern 2.

Step of production	Well 1	Well 2	Well 3	Well 4
water flooding	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 30/30 days)	shut in	shut in	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)
GOR of well 3 reaches 3 Mscf/stb	shut in	producer (12000 RB/D)	shut in	injector - water (12000 RB/D) - gas (8000 RB/D)
GOR of well 2 reaches 3 Mscf/stb	producer (12000 RB/D)	shut in	shut in	injector - water (12000 RB/D) - gas (8000 RB/D)

Table 5.38 Well schedule of WAG with down-dip injection in a 30° reservoir for pattern 2.

Step of production	Well 1	Well 2	Well 3	Well 4
water flooding	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 30/30 days)	shut in	shut in	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)
GOR of well 3 reaches 5 Mscf/stb	shut in	producer (12000 RB/D)	shut in	injector - water (12000 RB/D) - gas (8000 RB/D)
GOR of well 2 reaches 5 Mscf/stb	producer (12000 RB/D)	shut in	shut in	injector - water (12000 RB/D) - gas (8000 RB/D)

Table 5.39 Well schedule of DDP in a 15° reservoir for pattern 2.

Step of production	Well 1	Well 2	Well 3	Well 4
water flooding	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
DDP	gas injector (12000 RB/D)	producer (12000 RB/D)	shut in	shut in
GOR of well 2 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	producer (12000 RB/D)	shut in
GOR of well 3 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	producer (12000 RB/D)

Table 5.40 Well schedule of DDP in a 30° reservoir for pattern 2.

Step of production	Well 1	Well 2	Well 3	Well 4
water flooding	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	water injector (12000 RB/D)
water cut of well 3 reaches 20% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 20% criteria	producer (12000 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 20% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
DDP	gas injector (12000 RB/D)	producer (12000 RB/D)	shut in	shut in
GOR of well 2 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	producer (12000 RB/D)	shut in
GOR of well 3 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	producer (12000 RB/D)

Table 5.41 Effect of GOR criteria for switching the producers on BOE for well pattern 2.

Production type	Dip angle	GOR criteria for switching the producers [MSCF/STB]	BOE [MMSTB]
WAG up-dip	0°	1	30.605
		2	**30.609**
		3	30.594
		4	30.506
		5	30.020
	15°	1	29.090
		2	29.178
		3	**29.270**
		4	29.173
		5	28.830
	30°	1	27.528
		2	**27.542**
		3	27.399
		4	26.898
		5	26.763
WAG down-dip	0°	1	29.927
		2	30.035
		3	30.132
		4	30.211
		5	**30.270**
	15°	1	28.341
		2	28.340
		3	**28.360**
		4	27.856
		5	28.177
	30°	1	25.453
		2	25.449
		3	25.407
		4	25.382
		5	**25.733**
DDP	15°	1	26.283
		5	**26.641**
		10	26.467
		15	26.166
		20	25.776
		25	25.326
	30°	1	23.586
		5	**24.252**
		10	24.205
		15	24.176
		20	24.150
		25	24.121

Pattern 3 is similar to pattern 2 but different in the number of wells. There are 8 wells for this pattern arranged in a single row along the x-axis as shown in Figure 5.37. Their positions and fracture pressures are shown in Table 5.42. In the water flooding period, well 8 is a water injector while wells 1-7 are producers. Well 7, 6, 5, 4, 3, and 2 are shut in sequentially when its water cut reaches the stopping criteria shown in Table 5.8. The production rate is always set equal to the injection rate. After well 1 reaches stopping criteria, all wells are shut in for 180 days. Production strategy is different for each process as tabulated in Tables 5.43-5.50.

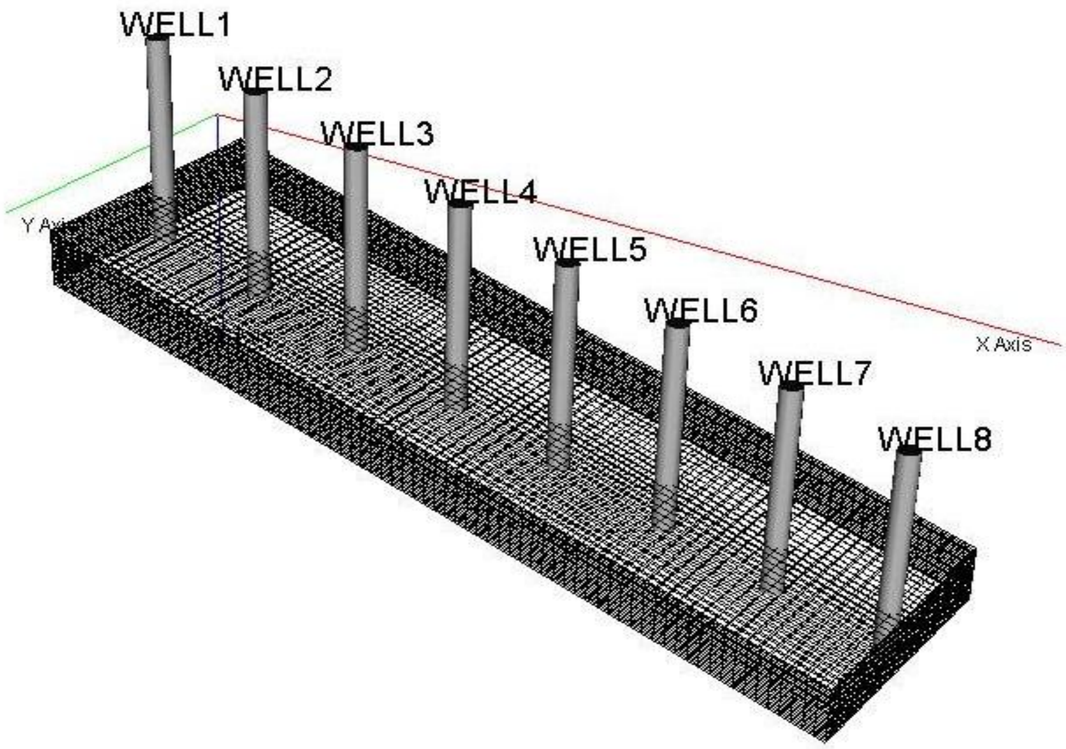


Figure 5.37 Well location in 3D for pattern 3.

Table 5.42 Well location and fracture pressure for pattern 3.

Parameters	Values	Units
Position of well 1	i=2, j=16, k=1-20	-
Position of well 2	i=12, j=16, k=1-20	-
Position of well 3	i=22, j=16, k=1-20	-
Position of well 4	i=32, j=16, k=1-20	-
Position of well 5	i=42, j=16, k=1-20	-
Position of well 6	i=52, j=16, k=1-20	-
Position of well 7	i=60, j=16, k=1-20	-
Position of well 8	i=72, j=16, k=1-20	-
Fracture pressure of well 1 @top depth of 5,000 ft (0°)	3,080	psia
Fracture pressure of well 8 @top depth of 5,000 ft (0°)	3,080	psia
Fracture pressure of well 1 @top depth of 5,021 ft (15°)	3,100	psia
Fracture pressure of well 8 @top depth of 6,510 ft (15°)	4,250	psia
Fracture pressure of well 1 @top depth of 5,041 ft (30°)	3,120	psia
Fracture pressure of well 8 @top depth of 7,918 ft (30°)	5,430	psia

For WAG with up-dip injection, water and gas are injected alternately by well 1. Production is done sequentially and individually from well 2 to well 8. The switching criteria is GOR of the producer which is varied to be 1, 2, 3, 4, and 5 MSCF/STB. The GOR that yields the highest BOE as shown in Table 5.51 is applied for each reservoir.

For WAG with down-dip injection, it is the inverse of WAG with up-dip injection. Production is done sequentially from well 7 to well 1 while water and gas are always injected at well 8. The well GOR for switching criteria comes from the varying of GOR to be 1, 2, 3, 4, and 5 MSCF/STB. It is different for each reservoir.

For DDP, gas is always injected at up-dip location by well 1 throughout the production time. Production is performed sequentially from well 2 to well 8. Switching criteria of production well applied for DDP is the GOR among five values: 1, 5, 10, 15, 20, and 25 MSCF/STB that yields the highest BOE.

Table 5.43 Well schedule of WAG with up-dip injection in a non-dipping reservoir for pattern 3.

Step of production	Well 1	Well 2	Well 3	Well 4	Well 5	Well 6	Well 7	Well 8
water flooding	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	water injector (12000 RB/D)
water cut of well 7 reaches 1% criteria	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 6 reaches 1% criteria	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 5 reaches 1% criteria	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 4 reaches 1% criteria	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 60/30 days)	injector -water(12000RB/D) -gas(8000RB/D)	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in
GOR of well 2 reaches 2 Mscf/stb	injector -water(12000RB/D) -gas (8000RB/D)	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in
GOR of well 3 reaches 2 Mscf/stb	injector -water(12000RB/D) -gas(8000RB/D)	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in
GOR of well 4 reaches 2 Mscf/stb	injector -water(12000RB/D) -gas(8000RB/D)	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in
GOR of well 5 reaches 2 Mscf/stb	injector -water(12000RB/D) -gas(8000RB/D)	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in
GOR of well 6 reaches 2 Mscf/stb	injector -water(12000RB/D) -gas(8000RB/D)	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in
GOR of well 7 reaches 2 Mscf/stb	injector -water(12000 RB/D) -gas(8000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)

Table 5.44 Well schedule of WAG with up-dip injection in a 15° reservoir for pattern 3.

Step of production	Well 1	Well 2	Well 3	Well 4	Well 5	Well 6	Well 7	Well 8
water flooding	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	water injector (12000 RB/D)
water cut of well 7 reaches 1% criteria	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 6 reaches 1% criteria	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 5 reaches 1% criteria	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 4 reaches 1% criteria	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 30/30 days)	injector -water(12000RB/D) -gas(8000RB/D)	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in
GOR of well 2 reaches 3 Mscf/stb	injector -water(12000RB/D) -gas(8000RB/D)	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in
GOR of well 3 reaches 3 Mscf/stb	injector -water(12000RB/D) -gas(8000RB/D)	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in
GOR of well 4 reaches 3 Mscf/stb	injector -water(12000RB/D) -gas(8000RB/D)	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in
GOR of well 5 reaches 3 Mscf/stb	injector -water(12000RB/D) -gas(8000RB/D)	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in
GOR of well 6 reaches 3 Mscf/stb	injector -water(12000RB/D) -gas(8000RB/D)	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in
GOR of well 7 reaches 3 Mscf/stb	injector -water(12000RB/D) -gas(8000RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)

Table 5.45 Well schedule of WAG with up-dip injection in a 30° reservoir for pattern 3.

Step of production	Well 1	Well 2	Well 3	Well 4	Well 5	Well 6	Well 7	Well 8
water flooding	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	water injector (12000 RB/D)
water cut of well 7 reaches 1% criteria	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 6 reaches 1% criteria	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 5 reaches 1% criteria	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 4 reaches 1% criteria	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 30/60 days)	injector -water(12000RB/D) -gas(6000RB/D)	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in
GOR of well 2 reaches 1 Mscf/stb	injector -water(12000 RB/D) -gas(6000RB/D)	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in
GOR of well 3 reaches 1 Mscf/stb	injector -water(12000RB/D) -gas(6000RB/D)	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in
GOR of well 4 reaches 1 Mscf/stb	injector -water(12000RB/D) -gas(6000RB/D)	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in
GOR of well 5 reaches 1 Mscf/stb	injector -water(12000RB/D) -gas(6000RB/D)	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in
GOR of well 6 reaches 1 Mscf/stb	injector -water(12000RB/D) -gas(6000RB/D)	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in
GOR of well 7 reaches 1 Mscf/stb	injector -water(12000RB/D) -gas(6000RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)

Table 5.46 Well schedule of WAG with down-dip injection in a non-dipping reservoir for pattern 3.

Step of production	Well 1	Well 2	Well 3	Well 4	Well 5	Well 6	Well 7	Well 8
water flooding	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	water injector (12000 RB/D)
water cut of well 7 reaches 40% criteria	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 6 reaches 40% criteria	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 5 reaches 40% criteria	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 4 reaches 40% criteria	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 3 reaches 40% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 40% criteria	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 40% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 60/30 days)	shut in	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 7 reaches 3 Mscf/stb	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 6 reaches 3 Mscf/stb	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 5 reaches 3 Mscf/stb	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 4 reaches 3 Mscf/stb	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 3 reaches 3 Mscf/stb	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 2 reaches 3 Mscf/stb	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)

Table 5.47 Well schedule of WAG with down-dip injection in a 15° reservoir for pattern 3.

Step of production	Well 1	Well 2	Well 3	Well 4	Well 5	Well 6	Well 7	Well 8
water flooding	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	water injector (12000 RB/D)
water cut of well 7 reaches 1% criteria	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 6 reaches 1% criteria	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 5 reaches 1% criteria	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 4 reaches 1% criteria	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 30/30 days)	shut in	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 7 reaches 3 Mscf/stb	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 6 reaches 3 Mscf/stb	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 5 reaches 3 Mscf/stb	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 4 reaches 3 Mscf/stb	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 3 reaches 3 Mscf/stb	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 2 reaches 3 Mscf/stb	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)

Table 5.48 Well schedule of WAG with down-dip injection in a 30° reservoir for pattern 3.

Step of production	**Well 1**	**Well 2**	**Well 3**	**Well 4**	**Well 5**	**Well 6**	**Well 7**	**Well 8**
water flooding	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	water injector (12000 RB/D)
water cut of well 7 reaches 1% criteria	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 6 reaches 1% criteria	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 5 reaches 1% criteria	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 4 reaches 1% criteria	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
WAG (cycle 30/30 days)	shut in	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 7 reaches 5 Mscf/stb	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 6 reaches 5 Mscf/stb	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 5 reaches 5 Mscf/stb	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 4 reaches 5 Mscf/stb	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 3 reaches 5 Mscf/stb	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)
GOR of well 2 reaches 5 Mscf/stb	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	injector -water(12000RB/D) -gas(8000RB/D)

Table 5.49 Well schedule of DDP in a 15° reservoir for pattern 3.

Step of production	Well 1	Well 2	Well 3	Well 4	Well 5	Well 6	Well 7	Well 8
water flooding	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	water injector (12000 RB/D)
water cut of well 7 reaches 1% criteria	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 6 reaches 1% criteria	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 5 reaches 1% criteria	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 4 reaches 1% criteria	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 3 reaches 1% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 1% criteria	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
DDP	gas injector (12000 RB/D)	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in
GOR of well 2 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in
GOR of well 3 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in
GOR of well 4 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in
GOR of well 5 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in
GOR of well 6 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in
GOR of well 7 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)

Table 5.50 Well schedule of DDP in a 30° reservoir for pattern 3.

Step of production	**Well 1**	**Well 2**	**Well 3**	**Well 4**	**Well 5**	**Well 6**	**Well 7**	**Well 8**
water flooding	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	producer (1714 RB/D)	water injector (12000 RB/D)
water cut of well 7 reaches 20% criteria	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	producer (2000 RB/D)	shut in	water injector (12000 RB/D)
water cut of well 6 reaches 20% criteria	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	producer (2400 RB/D)	shut in	shut in	water injector (12000 RB/D)
water cut of well 5 reaches 20% criteria	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	producer (3000 RB/D)	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 4 reaches 20% criteria	producer (4000 RB/D)	producer (4000 RB/D)	producer (4000 RB/D)	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 3 reaches 20% criteria	producer (6000 RB/D)	producer (6000 RB/D)	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 2 reaches 20% criteria	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	water injector (12000 RB/D)
water cut of well 1 reaches 20% criteria	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days	shut in for 180 days
DDP	gas injector (12000 RB/D)	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in
GOR of well 2 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in	shut in
GOR of well 3 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in	shut in
GOR of well 4 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in	shut in
GOR of well 5 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in	shut in
GOR of well 6 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)	shut in
GOR of well 7 reaches 5 Mscf/stb	gas injector (12000 RB/D)	shut in	shut in	shut in	shut in	shut in	shut in	producer (12000 RB/D)

Table 5.51 Effect of GOR criteria for switching the producers on BOE for well pattern 3.

Production type	Dip angle	GOR criteria for switching the producers [MSCF/STB]	BOE [MMSTB]
WAG up-dip	0°	1	30.672
		2	**30.690**
		3	30.554
		4	30.077
		5	29.418
	15°	1	29.042
		2	29.065
		3	**29.132**
		4	29.009
		5	28.418
	30°	**1**	**27.510**
		2	27.497
		3	27.058
		4	26.452
		5	25.610
WAG down-dip	0°	1	30.079
		2	30.160
		3	**30.275**
		4	30.033
		5	29.365
	15°	1	28.439
		2	28.436
		3	**28.440**
		4	27.905
		5	26.659
	30°	1	25.521
		2	25.523
		3	25.618
		4	25.367
		5	**26.518**
DDP	15°	1	26.630
		5	**26.840**
		10	26.501
		15	25.739
		20	25.313
		25	25.175
	30°	1	23.833
		5	**24.275**
		10	24.150
		15	24.078
		20	23.986
		25	23.798

Pattern 4 consists of two horizontal wells as shown in Figure 5.38. Well location and fracture pressure are listed in Table 5.52. These two wells are perforated only in the horizontal section. Well schedule for this pattern is the same as the one for pattern 1. It is tabulated in Tables 5.53-5.55.

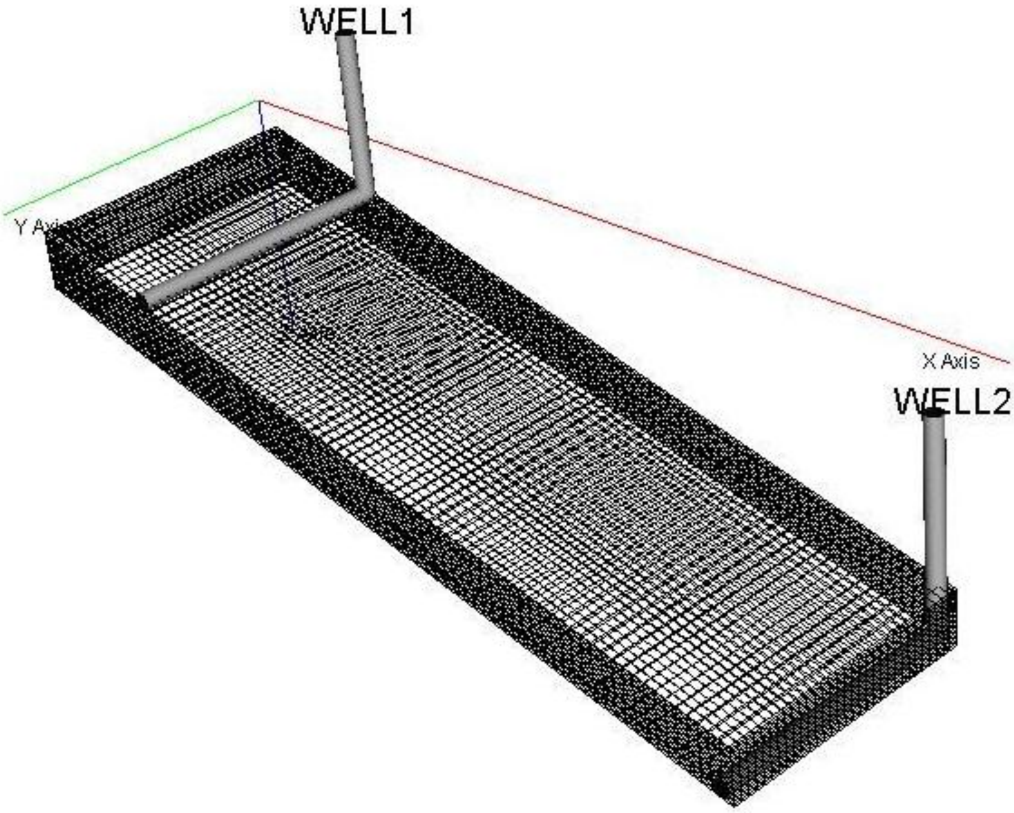


Figure 5.38 Well location in 3D for pattern 4.

Table 5.52 Well location and fracture pressure for pattern 4.

Parameters	Values	Units
Position of well 1	i=12, j=1-31, k=1	-
Position of well 2	i=72, j=1-31, k=20	-
Fracture pressure of well 1 @top depth of 5,000 ft (0°)	3,080	psia
Fracture pressure of well 2 @top depth of 5,190 ft (0°)	3,230	psia
Fracture pressure of well 1 @top depth of 5,234 ft (15°)	3,260	psia
Fracture pressure of well 2 @top depth of 6,700 ft (15°)	4,400	psia
Fracture pressure of well 1 @top depth of 5,452 ft (30°)	3,430	psia
Fracture pressure of well 2 @top depth of 8,108 ft (30°)	5,595	psia

Table 5.53 Well schedule of WAG with up-dip injection for pattern 4.

Dip angle	Step of production	Well 1	Well 2
0°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 60/30 days)	injector - water (12000 RB/D) - gas (8000 RB/D)	producer (12000 RB/D)
15°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/30 days)	injector - water (12000 RB/D) - gas (8000 RB/D)	producer (12000 RB/D)
30°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/60 days)	injector - water (12000 RB/D) - gas (6000 RB/D)	producer (12000 RB/D)

Table 5.54 Well schedule of WAG with down-dip injection for pattern 4.

Dip angle	Step of production	Well 1	Well 2
0°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 40% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 60/30 days)	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)
15°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/30 days)	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)
30°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/30 days)	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)

Table 5.55 Well schedule of DDP for pattern 4.

Dip angle	Step of production	Well 1	Well 2
15°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	DDP	gas injector (12000 RB/D)	producer (12000 RB/D)
30°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 20% criteria	shut in for 180 days	shut in for 180 days
	DDP	gas injector (12000 RB/D)	producer (12000 RB/D)

Pattern 5 consists of a vertical well at up-dip location and a horizontal well at down-dip location as shown in Figure 5.39. Well 1 is fully perforated while well 2 is perforated only in the horizontal section. Table 5.56 shows well location and fracture pressure for each reservoir. Well schedule for this pattern is also the same as that for pattern 1 and pattern 4, which is shown in Tables 5.57-5.59.

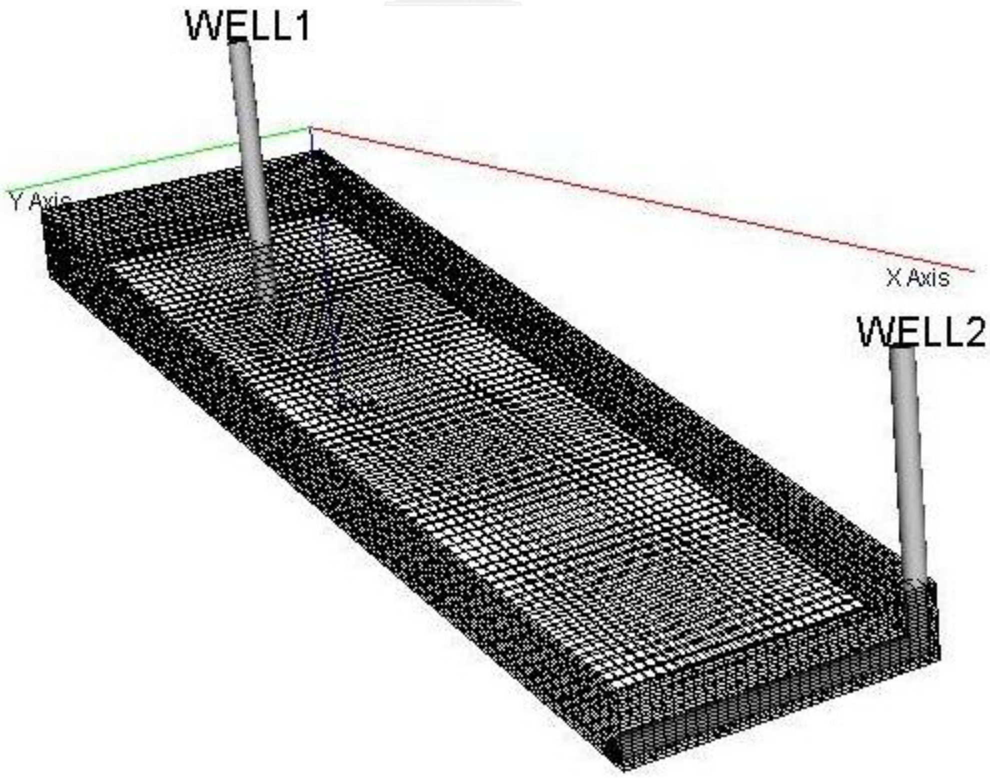


Figure 5.39 Well location in 3D for pattern 5.

Table 5.56 Well location and fracture pressure for pattern 5.

Parameters	Values	Units
Position of well 1	i=12, j=16, k=1-20	-
Position of well 2	i=72, j=1-31, k=20	-
Fracture pressure of well 1 @top depth of 5,000 ft (0°)	3,080	psia
Fracture pressure of well 2 @top depth of 5,190 ft (0°)	3,230	psia
Fracture pressure of well 1 @top depth of 5,234 ft (15°)	3,260	psia
Fracture pressure of well 2 @top depth of 6,700 ft (15°)	4,400	psia
Fracture pressure of well 1 @top depth of 5,452 ft (30°)	3,430	psia
Fracture pressure of well 2 @top depth of 8,108 ft (30°)	5,595	psia

Table 5.57 Well schedule of WAG with up-dip injection for pattern 5.

Dip angle	Step of production	Well 1	Well 2
0°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 60/30 days)	injector - water (12000 RB/D) - gas (8000 RB/D)	producer (12000 RB/D)
15°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/30 days)	injector - water (12000 RB/D) - gas (8000 RB/D)	producer (12000 RB/D)
30°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/60 days)	injector - water (12000 RB/D) - gas (6000 RB/D)	producer (12000 RB/D)

Table 5.58 Well schedule of WAG with down-dip injection for pattern 5.

Dip angle	Step of production	Well 1	Well 2
0°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 40% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 60/30 days)	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)
15°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/30 days)	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)
30°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut in for 180 days	shut in for 180 days
	WAG (cycle 30/30 days)	producer (12000 RB/D)	injector - water (12000 RB/D) - gas (8000 RB/D)

Table 5.59 Well schedule of DDP for pattern 5.

Dip angle	Step of production	Well 1	Well 2
15°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 1% criteria	shut 180 days	shut 180 days
	DDP	gas injector (12000 RB/D)	producer (12000 RB/D)
30°	water flooding	producer (12000 RB/D)	water injector (12000 RB/D)
	water cut of well 1 reaches 20% criteria	shut 180 days	shut 180 days
	DDP	gas injector (12000 RB/D)	producer (12000 RB/D)

5.5.1 WAG with up-dip injection

The oil production rate of each pattern is around 9,000 STB/D during water flooding period. However, the stopping time for water injection is different. Patterns 1, 5, and 4 are stopped before pattern 2 and 3 which have more producers. As water displaces oil up structure, there is much amount of oil accumulated at up-dip location while down-dip location contains water bank. In early time of WAG injection, pattern 3 reaches the highest rate oil before other patterns because it has the shortest well spacing between the injector and the first producer (well 2). Meanwhile, other patterns needs more time to let oil bank travel to the producers. Nevertheless, oil rates of all patterns have a similar trend, gradually decreasing from the seventeenth year to the last year of production as illustrated in Figure 5.40.

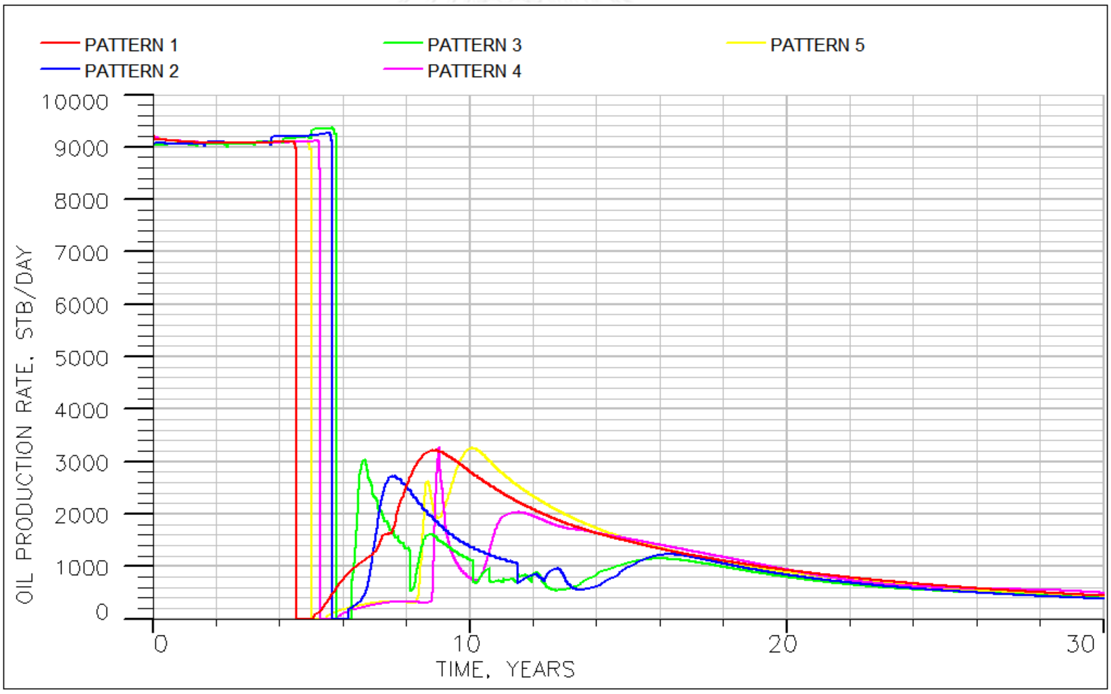


Figure 5.40 Effect of well pattern on oil production rate of WAG with up-dip injection in a reservoir with dip angle of 15°.

Gas production profiles for all patterns are similar during water flooding as the rate is around 5,000 MSCF/D for all cases. In WAG period, patterns 1, 4, and 5 having two wells show smoother profile than patterns 2 and 3 consisting more wells. Figure 5.41 shows gas production rates of the five well patterns.

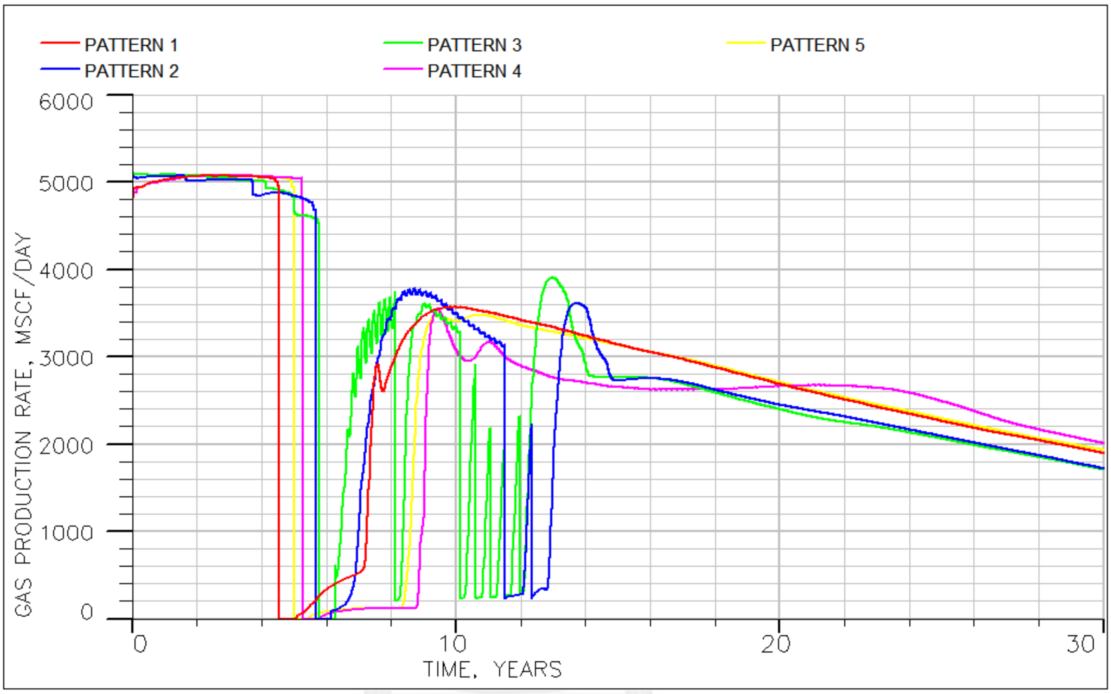


Figure 5.41 Effect of well pattern on gas production rate of WAG with up-dip injection in a reservoir with dip angle of 15°.

During the initial water flooding, water is produced for a short period of time before water cut reaches the stopping criteria. It is then produced with high rate when the producer is opened in WAG period because there is a large amount of water accumulated around the producer which is switched from the water injector. After the 12th year, water production rates of all patterns are around 5,600 STB/D as shown in Figure 5.42.

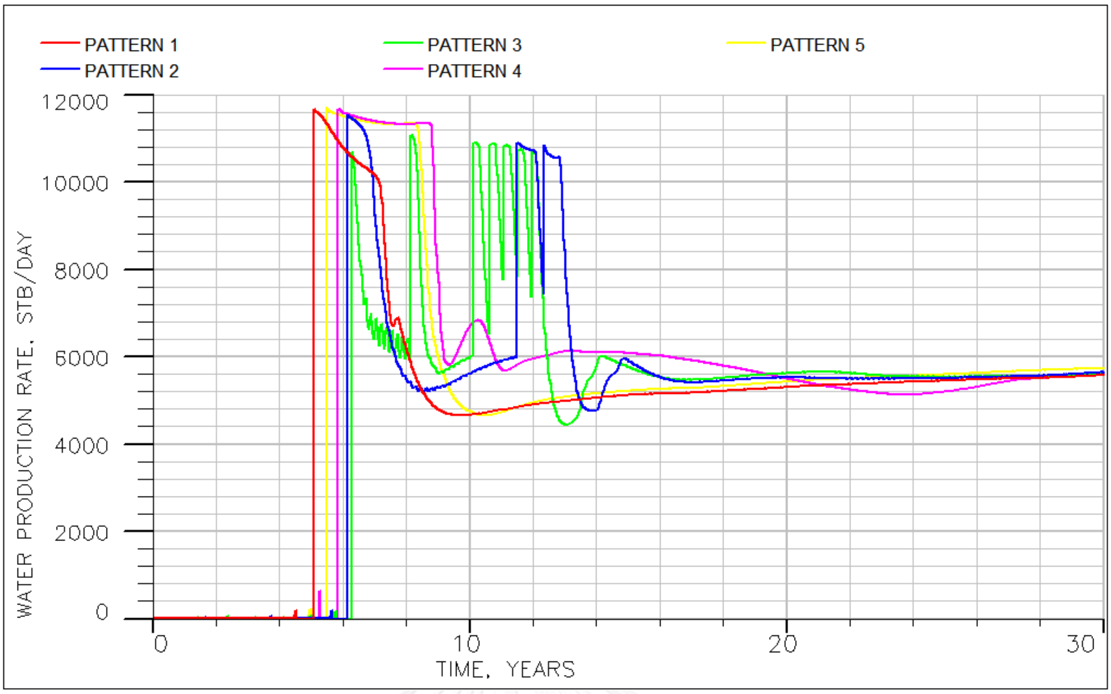


Figure 5.42 Effect of well pattern on water production rate of WAG with up-dip injection in a reservoir with dip angle of 15°.

Table 5.60 shows results comparison among different well patterns of WAG with up-dip injection in three reservoirs. For a non-dipping reservoir, the highest recovery factor and BOE of 78.07% and 30.690 MMSTB, respectively, is obtained from pattern 3 which consists of eight vertical wells. This pattern also needs the lowest amount of injected gas which is 10.579 BSCF among all patterns in the same reservoir. Pattern 4 requires the largest amount of gas while the highest amount of water is required by pattern 5. For a 15° reservoir, patterns with more wells need higher amounts of injected water but less amounts of injected gas due to the longer period of water flooding as discussed in Figure 5.53. Pattern 2, consisting of four vertical wells, yields the highest recovery factor and BOE of 76.60% and 29.270 MMSTB, respectively. This pattern requires 16.530 BSCF of injected gas and 74.967 MMSTB of injected water. For a 30° reservoir, pattern 5 yields the highest recovery factor and BOE of 81.38% and 27.850 MMSTB, respectively. However, this pattern requires the largest amount of injected gas of 13.411 BSCF.

Table 5.60 Result comparison between different well patterns of WAG with up-dip injection.

Dip angle	Well pattern	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
0°	1	30	26.985	74.59	12.520	26.636	89.060	64.020	29.338
0°	2	30	28.161	77.84	10.824	25.511	89.673	63.496	30.609
0°	**3**	**30**	**28.244**	**78.07**	**10.579**	**25.256**	**89.455**	**63.046**	**30.690**
0°	4	30	27.888	77.09	16.882	32.347	74.839	49.409	30.466
0°	5	30	27.010	74.91	12.613	26.472	90.830	65.931	29.410
15°	1	30	26.588	75.74	18.326	31.565	72.746	52.476	28.795
15°	**2**	**30**	**26.887**	**76.60**	**16.530**	**30.825**	**74.967**	**52.951**	**29.270**
15°	3	30	26.735	76.16	16.294	30.672	75.233	53.168	29.132
15°	4	30	26.081	74.30	18.075	29.936	74.282	56.671	28.058
15°	5	30	26.679	76.00	18.294	30.760	73.804	54.963	28.757
30°	1	30	25.109	79.50	13.357	27.062	53.917	42.873	27.394
30°	2	30	25.244	79.92	12.543	26.329	56.585	45.663	27.542
30°	3	30	25.229	79.88	12.620	26.298	56.868	45.961	27.510
30°	4	30	24.918	78.89	13.042	26.535	55.733	45.455	27.167
30°	**5**	**30**	**25.705**	**81.38**	**13.411**	**26.279**	**55.003**	**46.328**	**27.850**

5.5.2 WAG with down-dip injection

Figure 5.43 shows oil production rates of the five well patterns investigated in this study. Oil production profiles during water flooding have the same trend which have a stable rate around 9,000 STB/D. Pattern 1 is the first pattern reaching the stopping criteria between the fourth and the fifth year whereas pattern 3 stops water injection at the latest. During WAG period, patterns with two wells (patterns 1, 4, and 5) produce large amounts of oil in the early time because their producers are located near the oil bank. On the other hand, patterns 2 and 3 produce high amounts of water because their producers are located in water bank area. However, the switching of producers from down-dip to up-dip location results in the increasing of oil production rate around the ninth year. After the twentieth year, all patterns produce oil with quite the same rate throughout the production time.

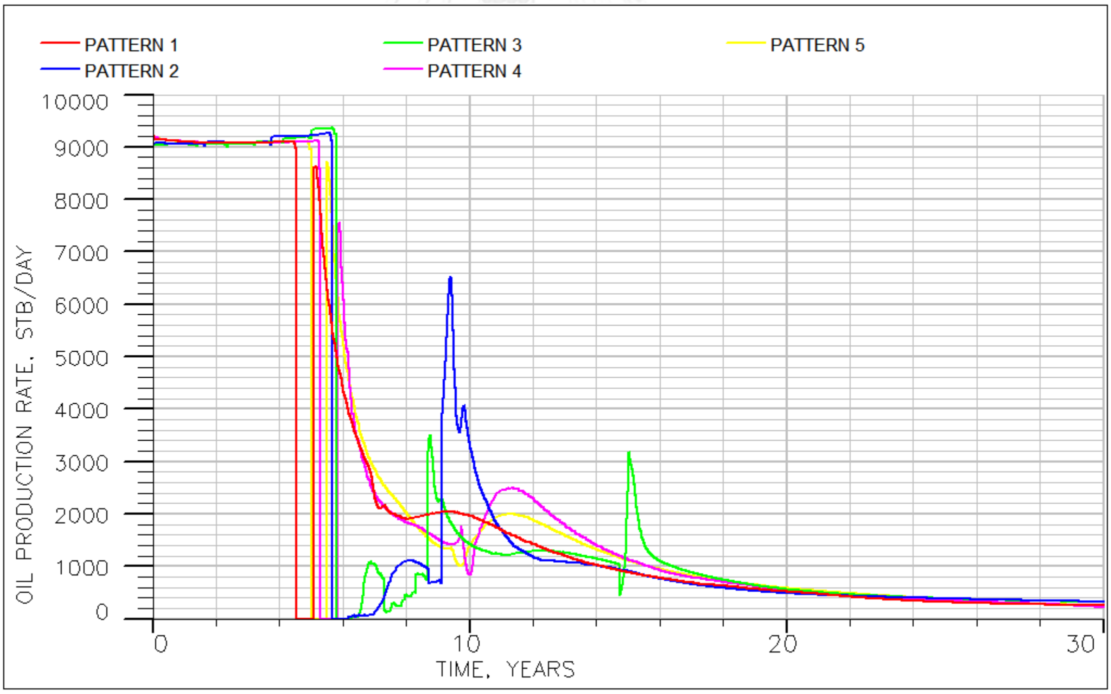


Figure 5.43 Effect of well pattern on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15°.

Gas is produced with the rate around 5,000 MSCF/D during water flooding. However, during WAG injection period, patterns 1, 4, and 5 produce gas with smoother rates than patterns 2 and 3. Gas rates of all patterns slightly decrease until the last year as illustrated in Figure 5.44.

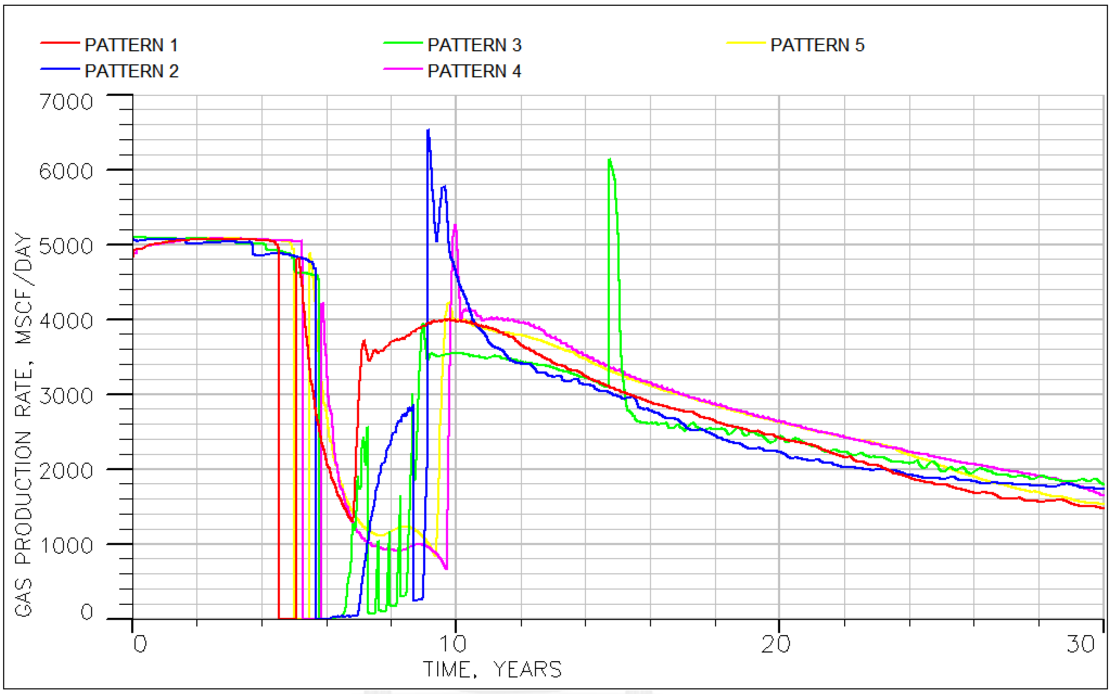


Figure 5.44 Effect of well pattern on gas production rate of WAG with down-dip injection in a reservoir with dip angle of 15°.

As there are only oil and gas in the initial reservoir, water is not produced until it breaks through the producer. Patterns 2 and 3 show the highest water rate around the sixth year after WAG has been started. However, every pattern has a similar rate around 5,200 - 5,600 STB/D after the eighteenth year as shown in Figure 5.45.

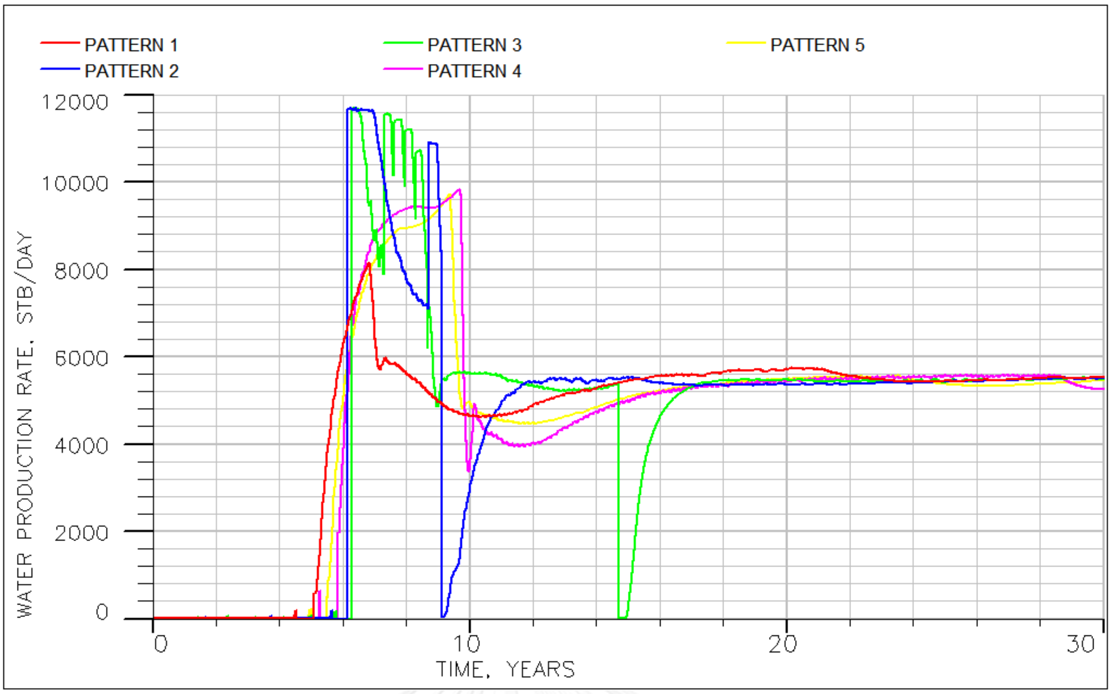


Figure 5.45 Effect of well pattern on water production rate of WAG with down-dip injection in a reservoir with dip angle of 15°.

Result comparison for different well patterns is shown in Table 5.61. For a non-dipping reservoir, the highest BOE of 30.275 MMSTB is obtained by pattern 3. Amounts of water and gas needed for injection are 63.868 MMSTB and 10.298 BSCF, respectively. Moreover, patterns consisting of more vertical wells require less amounts of injected water and gas. For a 15° reservoir, pattern 4 yields the highest recovery factor of 77.72% and the highest BOE of 29.722 MMSTB. The amount of injected gas required for this pattern is the lowest (17.549 BSCF) while 74.276 MMSTB of water is injected. This pattern also yields the highest recovery factor of 79.61% and the highest BOE of 27.175 MMSTB for a 30° reservoir. Patterns 2 and 3 have shorter production times than the other cases performed for a 30° reservoir. Pattern 2 reaches the economic limit in 25.77 years while pattern 3 reaches the limit in 29.18 years. It can be considered that a higher recovery factor is obtained when additional wells are added. Moreover, using horizontal wells instead of vertical wells efficiently improves the recovery factor.

Table 5.61 Result comparison between different well patterns of WAG with down-dip injection.

Dip angle	Well pattern	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
0°	1	30	26.747	73.93	11.916	26.309	89.361	64.438	29.146
0°	2	30	27.814	76.88	10.587	25.317	90.157	64.155	30.270
0°	**3**	**30**	**27.808**	**76.87**	**10.298**	**25.098**	**90.037**	**63.868**	**30.275**
0°	4	30	26.793	74.06	40.308	48.560	82.713	54.573	28.169
0°	5	30	27.570	76.21	12.248	26.332	91.382	65.786	29.918
15°	1	30	25.566	72.83	18.219	32.430	72.742	49.220	27.935
15°	2	30	26.083	74.30	17.604	31.262	74.974	49.931	28.360
15°	3	30	26.198	74.63	17.988	31.435	75.229	49.982	28.440
15°	**4**	**30**	**27.281**	**77.72**	**17.549**	**32.189**	**74.276**	**50.375**	**29.722**
15°	5	30	27.019	76.97	18.113	31.866	73.800	50.404	29.311
30°	1	30	23.508	74.43	19.828	31.782	72.005	50.516	25.501
30°	2	25.77	23.885	75.62	15.781	26.867	64.959	48.199	25.733
30°	3	29.18	24.654	78.06	16.647	27.826	72.453	57.279	26.518
30°	**4**	**30**	**25.146**	**79.61**	**18.593**	**30.759**	**73.222**	**51.716**	**27.175**
30°	5	30	25.093	79.44	20.363	31.200	72.776	51.778	26.899

5.5.3 Double displacement process

The oil rates in water flooding stage are around 9,000 STB/D for all patterns because they have the same water injection and production rates of 12,000 RB/D. After that, in gas injection stage, pattern 1 results in the smoothest oil rate. Patterns 4 and 5 yield extremely high rates for a short period of time between the eight year and the ninth year due to arrival of oil bank at the producers. For pattern 2 and 3, oil is produced by several wells causing a swing of the rate according to number of producers. Figure 5.46 illustrates oil production rates of five different well patterns.

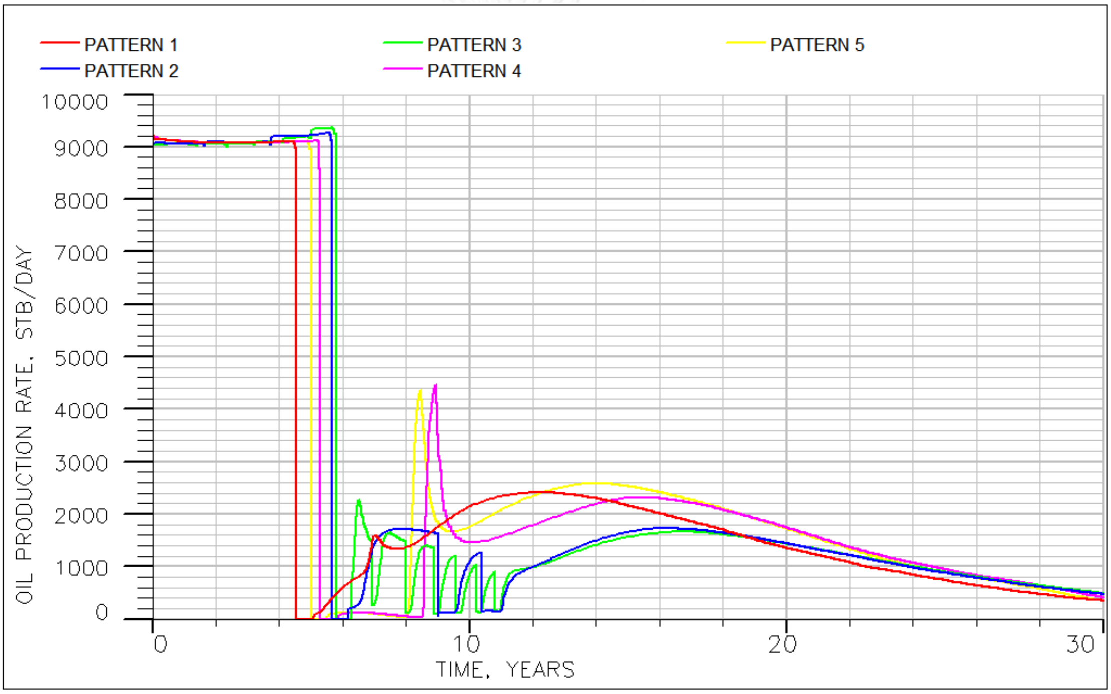


Figure 5.46 Effect of well pattern on oil production rate of DDP in a reservoir with dip angle of 15°.

The gas production rates are around 5,000 MSCF/D until the stopping period of water flooding. During the early time of gas injection, patterns consisting of two wells have similar gas production profile which is smoother than patterns consisting of more wells. However, they have the same trend since the fourteenth year to the last year of production. Figure 5.47 shows effects of well pattern on gas production rate.

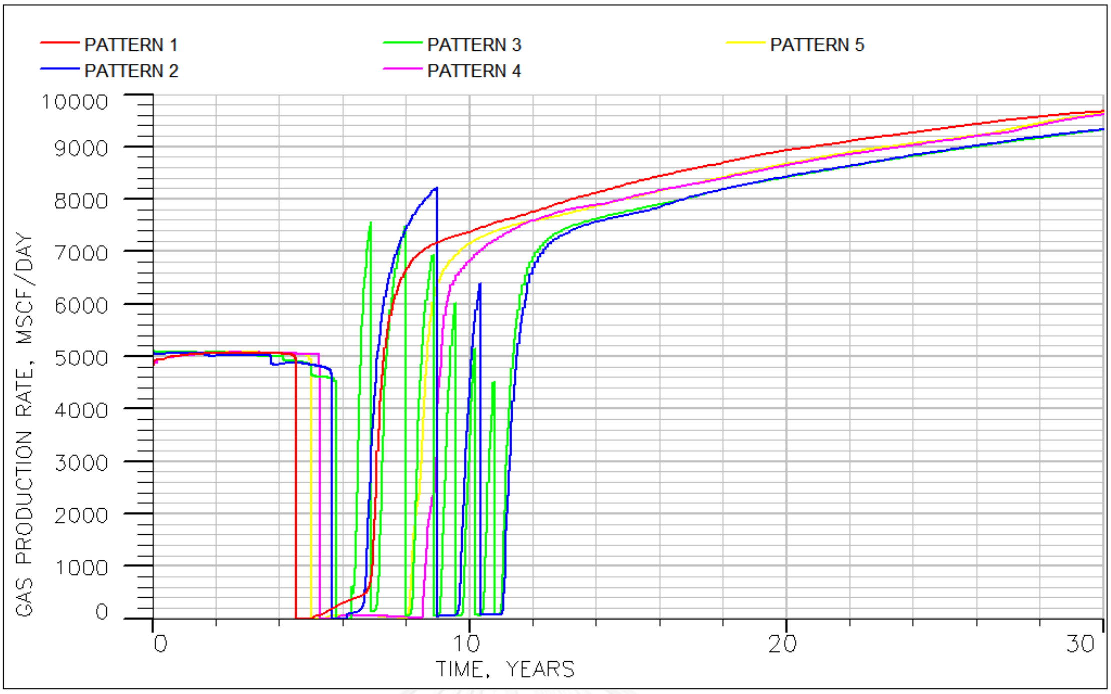


Figure 5.47 Effect of well pattern on gas production rate of DDP in a reservoir with dip angle of 15°.

The highest water production rates of around 11,600 STB/D for all patterns occur in the early time of gas injection. After that, they drop dramatically until there is small amount of water left in the reservoir. Finally, they slightly decrease until the last year of production as shown in Figure 5.48.

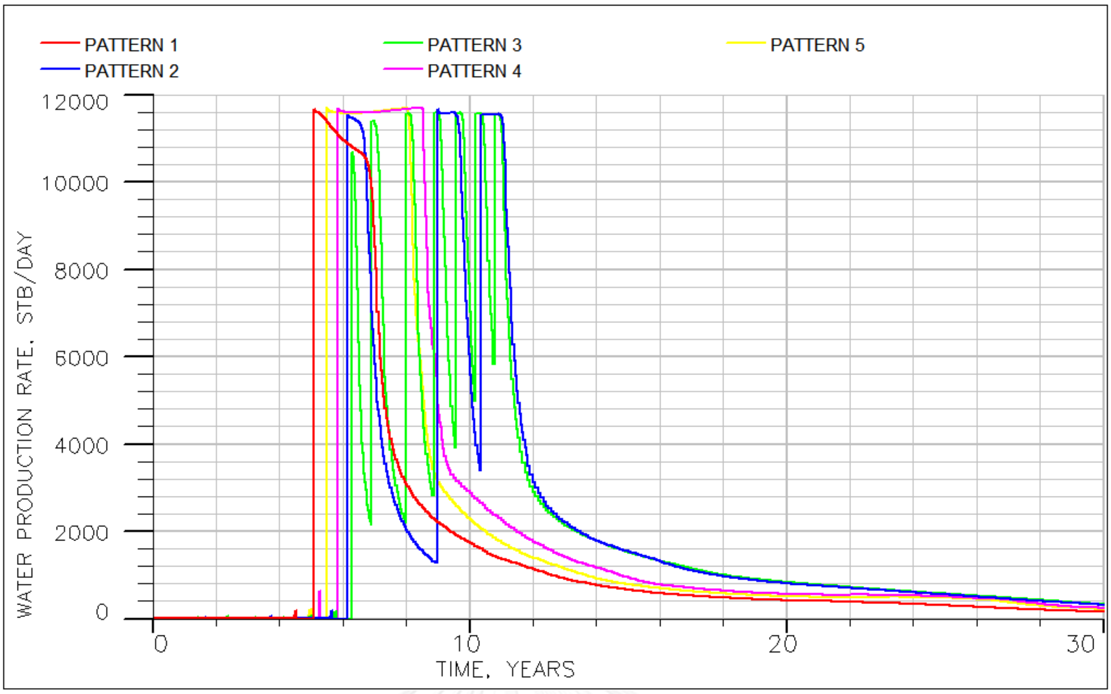


Figure 5.48 Effect of well pattern on water production rate of DDP in a reservoir with dip angle of 15°.

DDP is performed for two reservoirs which are 15° and 30° reservoirs as shown in Table 5.62. For a 15° reservoir, when we consider patterns of vertical wells, patterns consisting of more wells result in higher oil recovery factor and higher amounts of water injection and production but less amounts of gas injection and production. For a 30° reservoir, pattern 3 yields higher oil recovery factor, higher amounts of water injection and production, and higher amounts of gas injection and production than patterns 1 and 2 because pattern 3 has more producers.

When we use horizontal wells (patterns 4 and 5) instead of vertical wells (pattern 1), oil recovery factor is evidently improved. Patterns 4 and 5 require less amounts of injected gas but larger amounts of injected water. Pattern 5, consisting of a vertical well at up-dip location and a horizontal well at down-dip location, yields the highest BOE for both reservoirs. The highest BOE of 27.510 MMSTB and 25.074 MMSTB are obtained in 15° reservoir and 30° reservoirs, respectively.

Table 5.62 Result comparison between different well patterns of DDP.

Dip angle	Well pattern	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
15°	1	30	27.564	78.53	91.048	79.899	19.453	15.002	25.706
15°	2	30	28.668	81.67	85.956	73.798	24.046	20.600	26.641
15°	3	30	28.907	82.35	85.633	73.232	24.493	21.145	26.840
15°	4	30	29.775	84.82	88.853	74.768	22.664	20.041	27.427
15°	**5**	**30**	**29.874**	**85.11**	**89.793**	**75.608**	**21.432**	**18.996**	**27.510**
30°	1	30	25.862	81.88	96.493	85.202	18.567	14.106	23.980
30°	2	30	26.988	85.44	102.981	86.568	22.507	19.564	24.252
30°	3	30	27.273	86.35	106.090	88.104	23.036	20.304	24.275
30°	4	29.11	27.433	86.85	90.952	76.611	20.547	18.461	25.042
30°	**5**	**28.44**	**27.419**	**86.81**	**88.189**	**74.122**	**20.017**	**17.954**	**25.074**

The production parameters which yield the highest BOE for each process and dip angle are considered from the studying of four parameters which are (1) stopping criteria for water flooding, (2) water and gas injection rates, (3) WAG cycle, and (4) well pattern. Table 5.63 shows these parameters and the results of each process and dip angle.

For a non-dipping reservoir, DDP is not performed because it results in lower performance than long-term water flooding as shown in Table 5.7. Thus, there are two types of WAG being compared to find the most appropriate process. WAG with up-dip injection shows slightly higher oil recovery factor and BOE than WAG with down-dip injection. Their BOEs are 30.690 MMSTB and 30.275 MMSTB for WAG with up-dip and down-dip injection, respectively. Moreover, their requirements for injected gas and injected water are slightly different.

For a 15° reservoir, WAG with down dip injection having parameters shown in Table 5.63 yields the highest BOE of 29.722 MMSTB. Even though DDP gives much higher recovery factor, it requires a lot of injected gas resulting in the lowest BOE of 27.510 MMSTB. However, WAG cases need high amount of water for both water flooding and water injection alternately with gas.

For a 30° reservoir, WAG with up-dip injection yields the highest BOE of 27.850 MMSTB. WAG with down dip injection yields slightly lower BOE of 27.175 MMSTB. DDP results in the lowest BOE of 25.074 MMSTB due to high amount of gas requirement. However, DDP requires the lowest amount of injected water and spends the shortest production time because its oil rate reaches economic limit after the twenty-eighth year.

In this study, DDP is considered to be an ineffective method. Although it yields much higher oil recovery factor than the two types of WAG, it yields the lowest BOE in every reservoir due to the gas requirement. On the other hand, WAG needs less amount of injected gas because of the alternate water injection. However, much more amount of injected water is required by WAG process.

Table 5.63 The highest BOEs of different reservoir and process with their parameters.

Dip angle	Process	Water cut criteria for stopping water flooding [%]	Water injection rate [RB/D]	Gas injection rate [RB/D]	WAG cycle (water/gas) [Day]	Well pattern	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
0°	WAG up-dip	1	12,000	8,000	60/30	3	30	28.244	78.07	10.579	25.256	89.455	63.046	30.690
	WAG down-dip	40	12,000	8,000	60/30	3	30	27.808	76.87	10.298	25.098	90.037	63.868	30.275
	DDP	-	-	-	-	-	-	-	-	-	-	-	-	-
15°	WAG up-dip	1	12,000	8,000	30/30	2	30	26.887	76.60	16.530	30.825	74.967	52.951	29.270
	WAG down-dip	1	12,000	8,000	30/30	4	30	27.281	77.72	17.549	32.189	74.276	50.375	29.722
	DDP	1	12,000	12,000	-	5	30	29.874	85.11	89.793	75.608	21.432	18.996	27.510
30°	WAG up-dip	1	12,000	6,000	30/60	5	30	25.705	81.38	13.411	26.279	55.003	46.328	27.850
	WAG down-dip	1	12,000	8,000	30/30	4	30	25.146	79.61	18.593	30.759	73.222	51.716	27.175
	DDP	20	12,000	12,000	-	5	28.44	27.419	86.81	88.189	74.122	20.017	17.954	25.074

The cases resulting in the highest BOE for each reservoir are shown in Table 5.64. It is noted that these cases are considered only in terms of amount of produced oil and amount of consumed gas, not in term of economic.

Table 5.64 The production strategies yield the highest BOE for each reservoir.

Dip angle	Process	Water cut for stopping water flooding [%]	Water injection rate [RB/D]	Gas injection rate [RB/D]	WAG cycle (water/gas) [Day]	Well pattern
0°	WAG up-dip	1	12,000	8,000	60/30	3
15°	WAG down-dip	1	12,000	8,000	30/30	4
30°	WAG up-dip	1	12,000	6,000	30/60	5

5.6 Sensitivity analysis

This part is simulated to consider effects of these following factors: (1) horizontal permeability, (2) vertical to horizontal permeability ratio, (3) relative permeability correlation, (4) reservoir thickness, and (5) oil properties. The operating parameters for each reservoir are the ones tabulated in Table 5.64.

5.6.1 Effect of horizontal permeability

Horizontal permeability (k_h) affects fluid flow in the horizontal direction (x and y directions). It is varied to be five times less and five times higher than the base case of 126 md while the vertical permeability (k_v) is kept constant for all cases as shown in Table 5.65.

Table 5.65 Cases for the studying of effect of horizontal permeability.

Case	k_h [md]	k_v [md]
1	25.2	12.6
2	126	12.6
3	630	12.6

5.6.1.1 Reservoir without dip angle

Horizontal permeability significantly affects oil production rate as can be seen in Figure 5.49. Case 1 has the earliest decline in oil rate but the longest period of water flooding, in which water injection is stopped after the seventeenth year, and WAG is started in the eighteenth year. Case 3, having the highest horizontal permeability, usually has slightly lower oil rate than case 2 except some short periods in the sixth year, the thirteenth year, and from the twenty-fifth to the twenty-seventh year. Fluids flow easily in the reservoir from the injector to the producer in the case of a high horizontal permeability (k_h = 630 md) which lets water arrive the producer early. This case takes the shortest time for initial water flooding because water cut reaches the stopping criteria earlier than the other two cases with lower horizontal permeability. The oil rates of all cases are unstable because the well pattern used in this study has 8 vertical wells. The oil rate abruptly changes when oil production is switched from one well to the adjacent well.

Table 5.66 shows that more amount of gas and water can be injected into the reservoir with higher horizontal permeability because they can flow more easily from the injector in the horizontal direction. However, case 2 with moderate horizontal permeability yields the highest oil recovery factor of 78.07% and the highest BOE of 30.690 MMSTB. Case 3 lets the fluids flow easily in the reservoir, it results in faster gas movement causing earlier gas breakthrough. Therefore, well shutting occurs earlier which yields smaller oil recovery factor. In addition, the results show that case 3 requires larger amounts of water and gas injection.

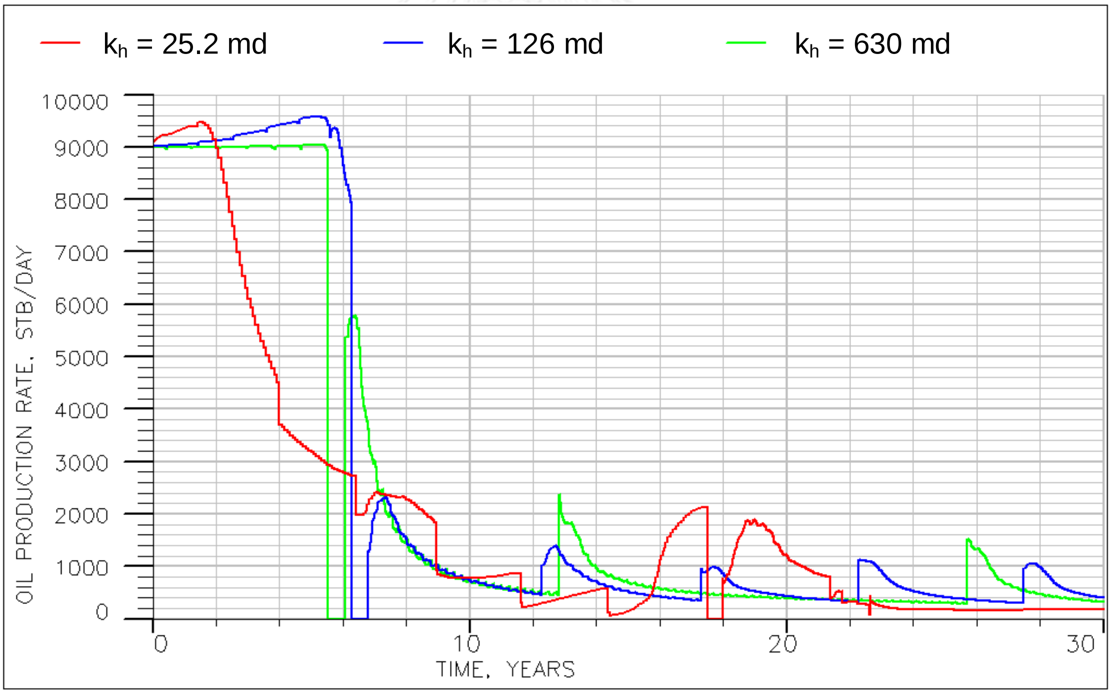


Figure 5.49 Effect of horizontal permeability on oil production rate of WAG with up-dip injection in a reservoir without dip angle.

5.6.1.2 Reservoir with dip angle of 15°

Case 1 with the lowest horizontal permeability produces oil with lower rate than cases 2 and 3. This is because oil in case 1 flows to the producer with the slowest rate. Additionally, water travels slowly from the injector to the producer causing a longer water flooding period of case 1 than the other two cases. Case 2 and 3 have similar oil rate at early time even though their horizontal permeability is not same because of the limitation of maximum production rate set in the simulator. As a result, case 2 has a similar oil production profile as case 3 in the water flooding period. However, case 3 with higher horizontal permeability shows a higher oil rate in WAG period as illustrated in Figure 5.50.

Table 5.66 shows that higher horizontal permeability results in more oil recovery factor and BOE. When we consider the requirement of injected fluids, the case with the lowest horizontal permeability (k_h = 25.2 md) consumes the largest amount of gas but the least amount of water.

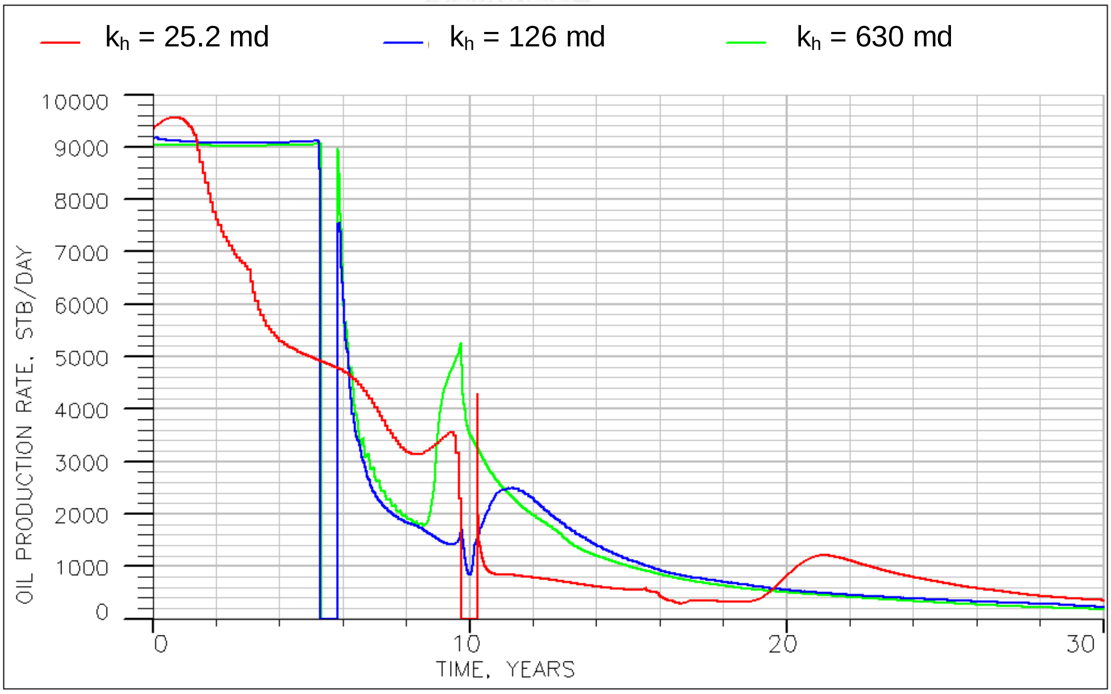


Figure 5.50 Effect of horizontal permeability on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15°.

5.6.1.3 Reservoir with dip angle of 30°

Case 1 has a distinctive oil production profile from the other cases. It takes more than 9 years for water flooding while the other two cases spend less than 5 years. During water flooding, cases 2 and 3 have similar oil rate around 9,000 STB/D while the oil rate of case 1 is much lower. In the duration of WAG, cases with higher horizontal permeability show higher oil production rate. Figure 5.51 shows oil production profile of three cases with different horizontal permeability.

Oil in case 3 can travel with the fastest rate in the reservoir. From Table 5.66, it can be clearly seen that higher horizontal permeability results in higher oil recovery factor with a shorter production time. Case 3 yields the highest oil recovery factor and the highest BOE which are 84.94% and 29.262 MMSTB, respectively, where it requires the shortest production time of 19.59 years due to economic constraint.

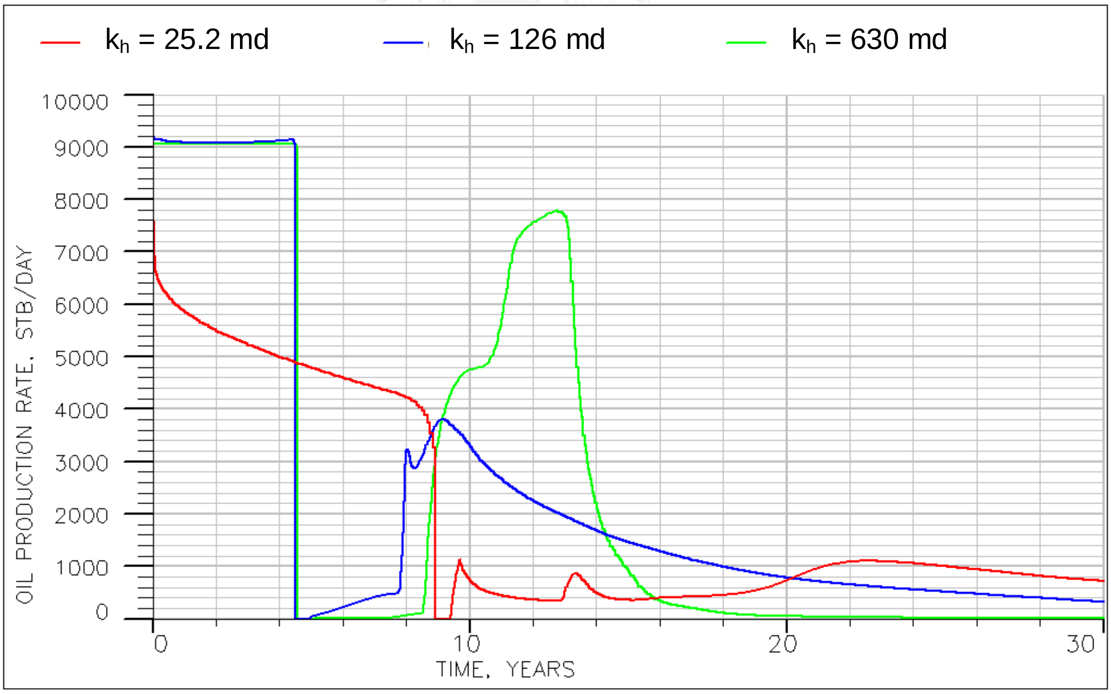


Figure 5.51 Effect of horizontal permeability on oil production rate of WAG with up-dip injection in a reservoir with dip angle of 30°.

Table 5.66 Result comparison between different horizontal permeability.

Dip angle	Process	k_h [md]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
0°	WAG up-dip	25.2	30	20.842	57.61	6.944	19.432	34.404	12.473	22.924
		126	30	28.244	78.07	10.579	25.256	89.455	63.046	30.690
		630	30	25.351	70.08	12.126	25.846	91.766	68.855	27.638
15°	WAG down-dip	25.2	30	24.779	70.59	20.042	29.444	54.959	31.141	26.346
		126	30	27.281	77.72	17.549	32.189	74.276	50.375	29.722
		630	30	28.601	81.48	17.060	32.125	74.494	49.417	31.113
30°	WAG up-dip	25.2	30	21.523	68.14	16.374	25.485	37.933	22.260	23.042
		126	30	25.705	81.38	13.411	26.279	55.003	46.328	27.850
		630	19.59	26.830	84.94	9.334	19.112	25.961	23.993	28.460

5.6.2 Effect of vertical to horizontal permeability ratio

The vertical to horizontal permeability ratio is varied to be 0.01, 0.1, and 0.5 as shown in Table 5.67 in order to study its effect on WAG and DDP. Only the value of vertical permeability (k_v) is changed while the horizontal permeability (k_h) is always constant at 126 md. This factor affects the fluid flow in the vertical direction.

Table 5.67 Cases for the studying of effect of vertical/horizontal permeability ratio.

Case	**k_v/k_h**	**k_h [md]**	**k_v [md]**
1	0.01	126	1.26
2	0.1	126	12.6
3	0.5	126	63

5.6.2.1 Reservoir without dip angle

Form Figure 5.52, vertical to horizontal permeability ratio does not affect oil production rate during water flooding period but has a moderate effect on oil rate during WAG. In WAG period, gas flows easily in the vertical direction. There are 8 vertical wells in this study. Case 1 (k_v/k_h = 0.01) takes nearly the same duration to switch oil production from one well to the other while case 3 (k_v/k_h = 0.5) takes short periods to switch oil production from well 1 to well 2 and subsequentially wells 3, 4, 5, and 6 but longer periods to switch from well 6 to wells 7 and 8 at late time. This is a result of gas movement in the vertical direction. Gas tends to override easily in case 3 because of high vertical permeability. As a result, gas arrives early at each producer and reaches the GOR switching criteria of each producer early.

From Table 5.68, case with more vertical to horizontal permeability ratio requires less gas injection but slightly more water injection. Case 3 has the highest oil recovery factor and BOE which are 82.99% and 32.645 MMSTB, respectively. In addition, even though case 3 consumes the least amount of injected gas, it produces the largest amount of gas because of gas overriding.

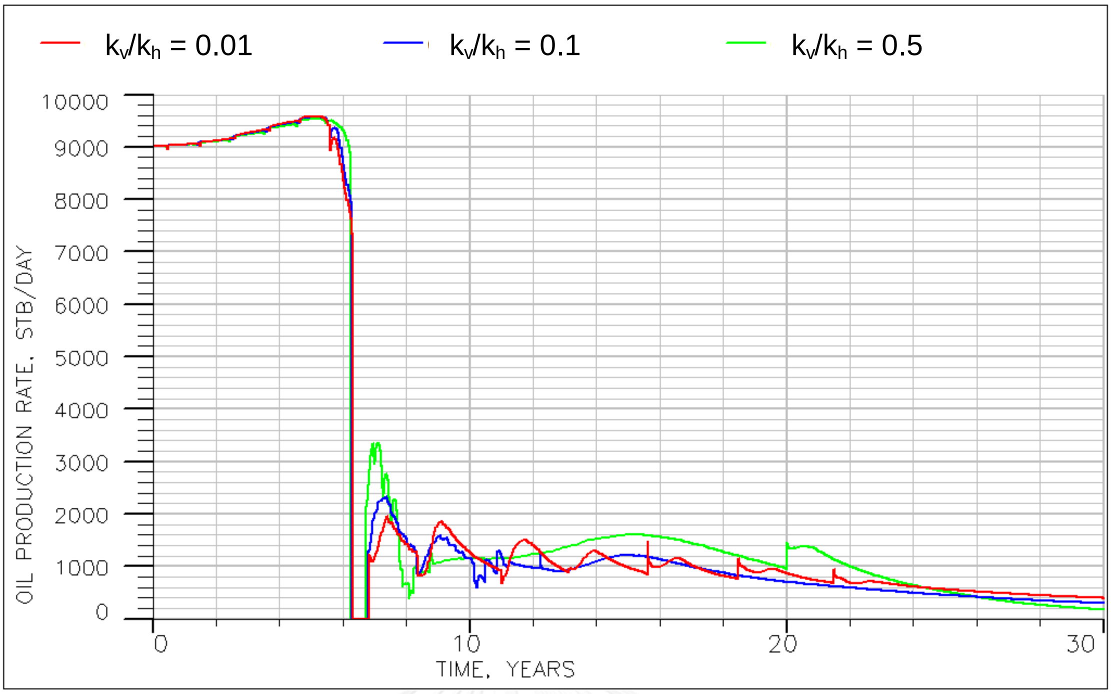


Figure 5.52 Effect of vertical/horizontal permeability ratio on oil production rate of WAG with up-dip injection in a reservoir without dip angle.

5.6.2.2 Reservoir with dip angle of 15°

During water flooding period, every case shows very similar oil production rate as represented in Figure 5.53. After that, oil production rates of all cases are slightly different but follow similar trend throughout the production time of 30 years.

The comparison of results for these three cases is shown in Table 5.68. There is significant difference in gas requirement and production among the three cases. Case 1 requires much more injected gas but produces only few more gas than the other two cases. In term of water, the total water injection and production of every case is not significantly different. Their oil recovery factors are different. Case 1 yields the highest value of 81.83%. However, BOE of case 3 (30.280 MMSTB) is slightly higher than those of case 1 (30.250 MMSTB) and case 2 (29.722 MMSTB).

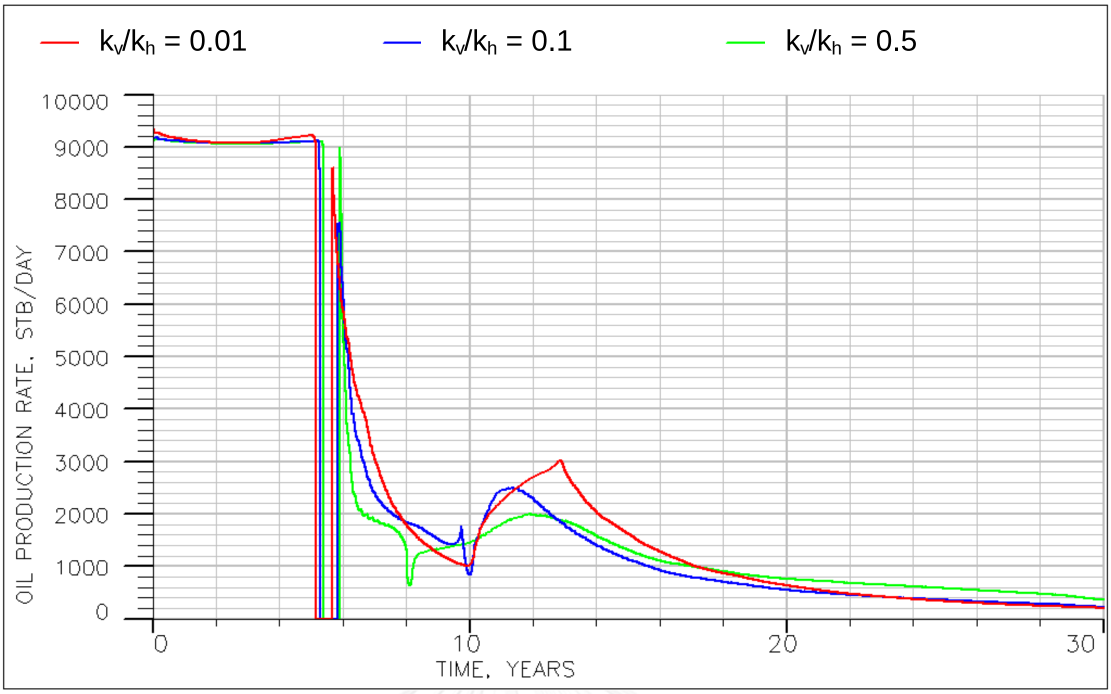


Figure 5.53 Effect of vertical/horizontal permeability ratio on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15°.

5.6.2.3 Reservoir with dip angle of 30°

The oil production rate of the three cases is the same during water flooding period as shown in Figure 5.54. Water flooding of all cases is stopped in the fourth year of production. In the WAG injection period, the three cases have a similar trend of oil production profile.

From Table 5.68, case 3 yields the highest oil recovery factor of 84.23% and the highest BOE of 28.533 MMSTB where it reaches the economic constraint slightly earlier than cases 1 and 2. As a result, it takes 29.58 years for the production while the other two cases take 30 years.

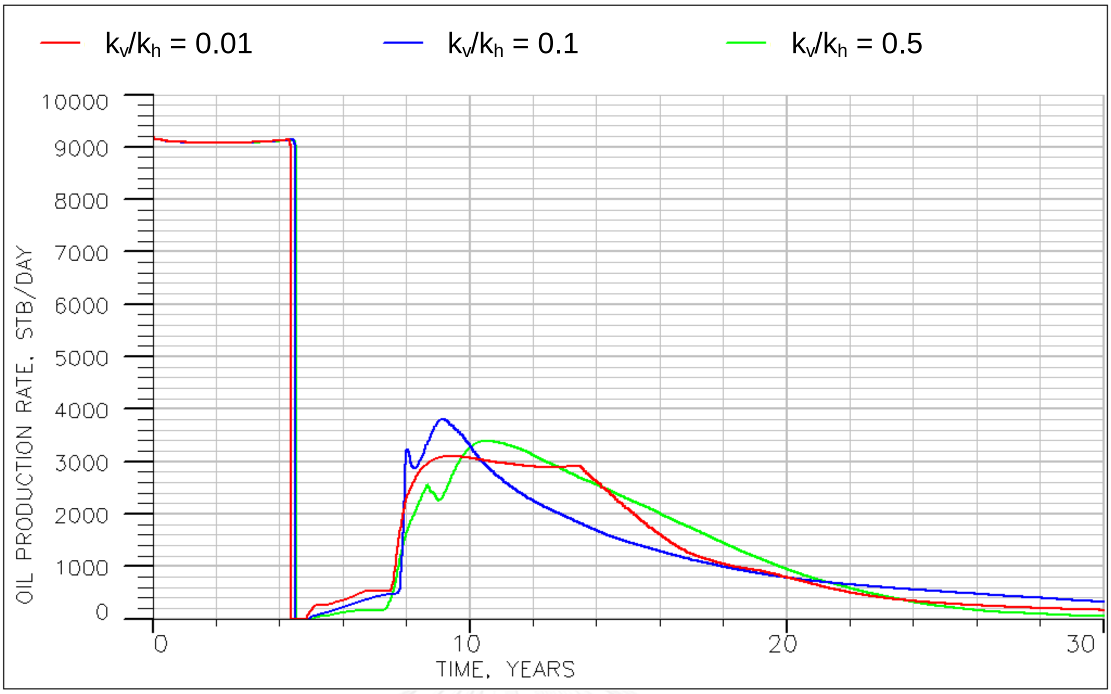


Figure 5.54 Effect of vertical/horizontal permeability ratio on oil production rate of WAG with up-dip injection in a reservoir with dip angle of 30°.

Table 5.68 Result comparison between different vertical/horizontal permeability ratios.

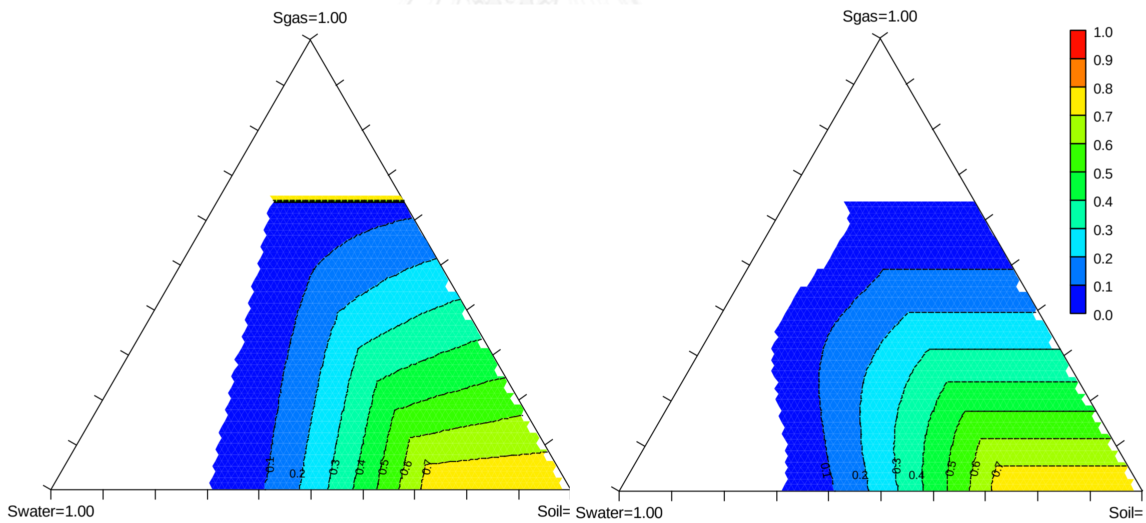
Dip angle	Process	k_v/k_h	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
0°	WAG up-dip	0.01	30	28.776	79.54	12.705	21.443	89.061	65.527	30.232
		0.1	30	28.244	78.07	10.579	25.256	89.455	63.046	30.690
		0.5	30	30.023	82.99	10.502	26.232	89.990	60.882	32.645
15°	WAG down-dip	0.01	30	28.726	81.83	25.221	34.362	73.756	50.864	30.250
		0.1	30	27.281	77.72	17.549	32.189	74.276	50.375	29.722
		0.5	30	27.725	78.98	17.035	32.362	74.691	49.870	30.280
30°	WAG up-dip	0.01	30	25.968	82.21	20.045	29.754	54.525	42.419	27.586
		0.1	30	25.705	81.38	13.411	26.279	55.003	46.328	27.850
		0.5	29.58	26.606	84.23	13.764	25.324	54.468	47.777	28.533

5.6.3 Effect of three-phase relative permeability correlation

The three-phase relative permeability correlation of the base case is ECLIPSE default. This study is performed to consider the production performance when Stone 1 and Stone 2 models are applied instead of ECLIPSE default. Table 5.69 lists three cases with different correlations. Figure 5.55 shows oil relative permeability diagrams as function of three-phase saturation of Stone 1 and Stone 2 models.

Table 5.69 Cases with different relative permeability correlations.

Case	Relative permeability correlation
1	ECLIPSE default
2	Stone 1
3	Stone 2



(a) Stone 1 Model (b) Stone 2 model

Figure 5.55 Oil relative permeability diagrams as function of three-phase saturation.

5.6.3.1 Reservoir without dip angle

Result of this reservoir is similar to result of a 15° reservoir. All three cases provide quite the same oil rate during water flooding and early time of WAG injection. After that, Stone 2 model produces oil with the lowest rate since the thirteenth year. Additionally, oil rate of Stone 1 model is slightly lower than that of ECLIPSE default model since seventeenth year. Figure 5.56 shows oil production profile of three cases with different relative permeability correlations.

From Table 5.70, ECLIPSE default model yields the highest oil recovery factor of 78.07% and the highest BOE of 30.690 MMSTB which are slightly higher than those of Stone 1 model. However, Stone 2 model is the first case that reaches the economic constraint in the twenty third year. It provides significantly lower oil recovery factor and BOE than the other two cases.

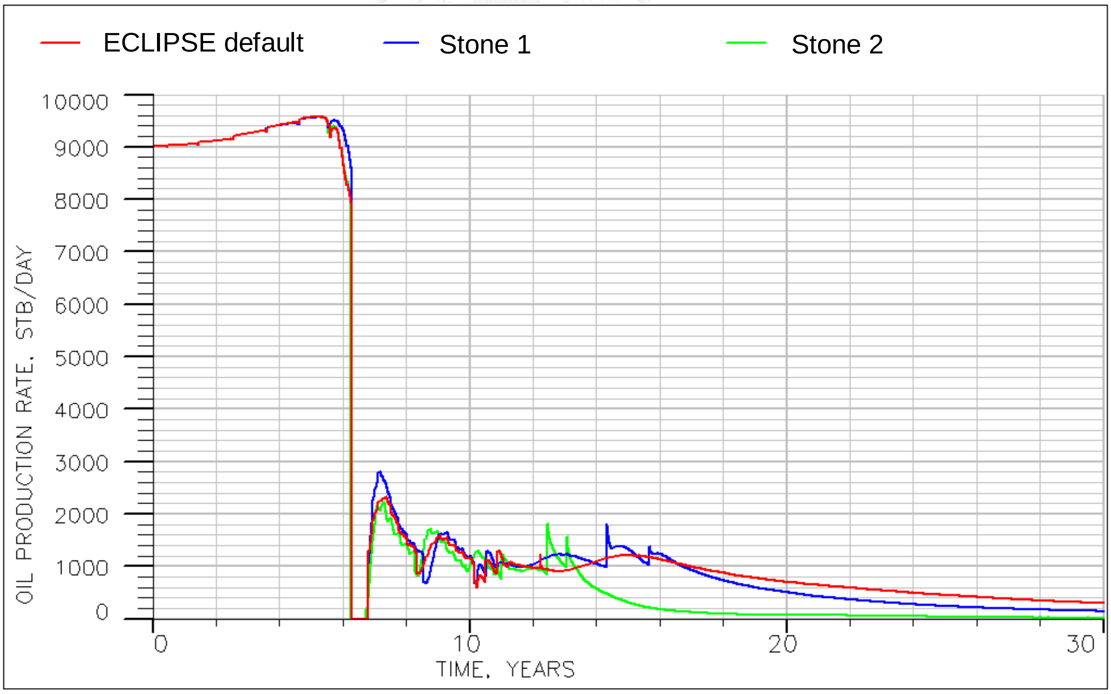


Figure 5.56 Effect of relative permeability correlation on oil production rate of WAG with up-dip injection in a reservoir without dip angle.

5.6.3.2 Reservoir with dip angle of 15°

From Figure 5.57, the three cases have the same oil production profile during water flooding; moreover, their stoppings of water injection occur at the same time in the fifth year. The difference between their oil rates is apparent after the seventh year which is in the WAG injection period. ECLIPSE default model (case 1) show very similar oil production profile to Stone 1 model (case 2) where Stone 2 model (case 3) has a significantly lower oil rate.

Table 5.70 shows that ECLIPSE default and Stone 1 models do not have considerable difference between their oil recovery factors, gas and water injections, and BOEs. Stone 2 model results in the lowest BOE of 26.527 MMSTB and the shortest production time of 24.99 years due to the economic constraint.

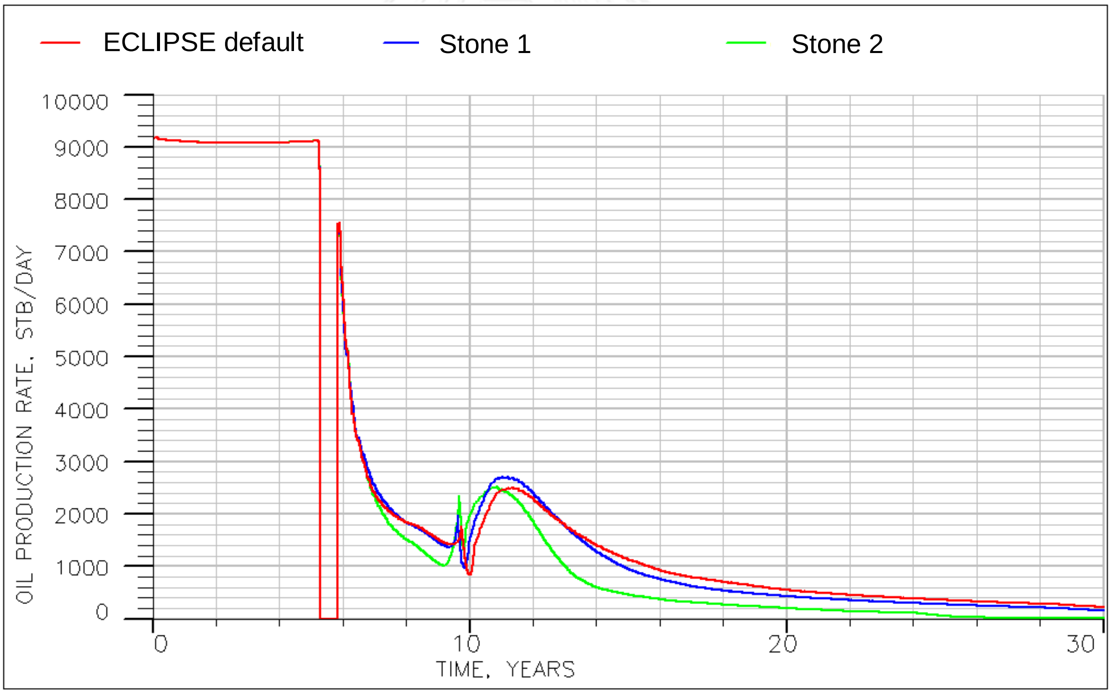


Figure 5.57 Effect of relative permeability correlation on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15°.

5.6.3.3 Reservoir with dip angle of 30°

During water flooding period, oil is produced with the same rate by the three cases having different relative permeability correlations. After that, water flooding is stopped in the fourth year. WAG injection is then performed starting at the same time for all cases. ECLIPSE default and Stone 1 models provide higher oil rate than Stone 2 model as illustrated in Figure 5.58.

In term of production time, ECLIPSE default and Stone 1 models spend 30 years while Stone 2 model is stopped in the twenty eighth year because of the economic constraint as tabulated in Table 5.70. ECLIPSE default model yields higher oil recovery factor than Stone 1 and Stone 2 models which are 81.38%, 81.34%, and 74.84%, respectively. However, the highest BOE of 27.858 MMSTB is provided by case 2 in which Stone 1 model is applied.

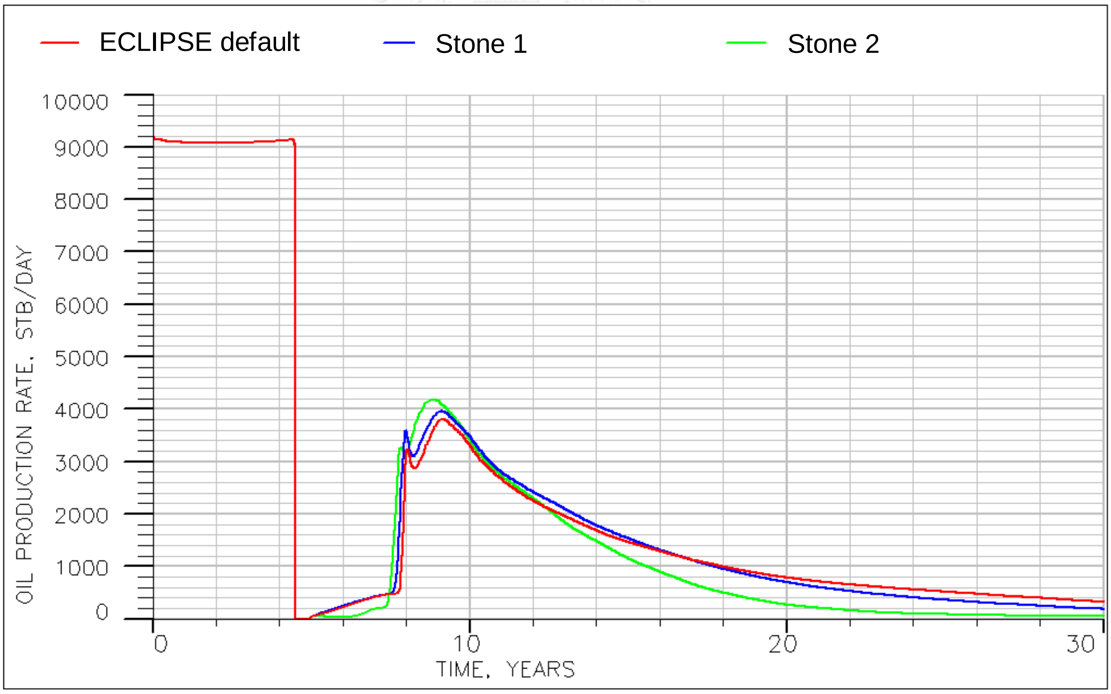


Figure 5.58 Effect of relative permeability correlation on oil production rate of WAG with up-dip injection in a reservoir with dip angle of 30°.

For all reservoir, Stone 2 model results in quite low oil recovery factor because it reaches the economic constraint earlier than Stone 1 and ECLIPSE default models. Figure 5.55 shows the relative permeability to oil diagrams as function of three-phase saturation of Stone 1 and Stone 2 models. Stone 2 model shows lower relative permeability to oil than Stone 1 model in most area of the diagram. Therefore, oil flows more difficultly when Stone 2 model is applied to the simulator. As a result, less amount of oil is produced in this case.

Table 5.70 Result comparison between different relative permeability correlations.

Dip angle	Process	Relative permeability model	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
0°	WAG up-dip	ECLIPSE default	30	28.244	78.07	10.579	25.256	89.455	63.046	30.690
		Stone 1	30	27.766	76.75	10.606	24.935	89.600	63.523	30.155
		Stone 2	23.54	24.658	68.16	8.891	19.869	70.925	48.107	26.488
15°	WAG down-dip	ECLIPSE default	30	27.281	77.72	17.549	32.189	74.276	50.375	29.722
		Stone 1	30	26.844	76.47	17.547	32.070	74.276	50.948	29.265
		Stone 2	24.99	24.413	69.54	15.317	28.002	63.696	42.981	26.527
30°	WAG up-dip	ECLIPSE default	30	25.705	81.38	13.411	26.279	55.003	46.328	27.850
		Stone 1	30	25.693	81.34	13.424	26.412	54.998	45.731	27.858
		Stone 2	28.57	23.638	74.84	12.897	26.375	52.901	41.654	25.885

5.6.4 Effect of reservoir thickness

The effect of reservoir thickness is investigated by construction of three reservoirs with different thickness which is varied to be 50, 200, and 500 ft. as shown in Table 5.71.

Table 5.71 Cases with different reservoir thicknesses.

Case	Reservoir thickness [ft.]
1	50
2	200
3	500

5.6.4.1 Reservoir without dip angle

Figure 5.59 illustrates oil production profiles of three cases of a non-dipping reservoir. The more thickness results in the longer time for water flooding. The stopping time of water flooding for case 1, case 2, and case 3 are in the third, sixth, and thirteenth year, respectively, because of two reasons. Firstly, more amount of original oil in place is obtained when the reservoir is thicker. Secondly, a large cross sectional area perpendicular to the flow direction which depends on reservoir thickness increases the gravity number (G) as can be calculated from Eq. 3.5. As a result, an unstable flood front is more difficult to occur in a thicker reservoir. Therefore, water cut of case 3 having the largest reservoir thickness reaches the stopping criteria for initial water flooding the latest among all cases. Even though these three cases are different in their reservoir size causing different production rates, their profiles have similar pattern.

Table 5.72 shows the result comparison. For a non-dipping reservoir, case 1 requires the shortage production time before it reaches the economic limit of 50 STB/D for oil rate. Cases 2 and case 3 are produced throughout the production time for 30 years. However, case 2 has the highest oil recovery factor among the three cases.

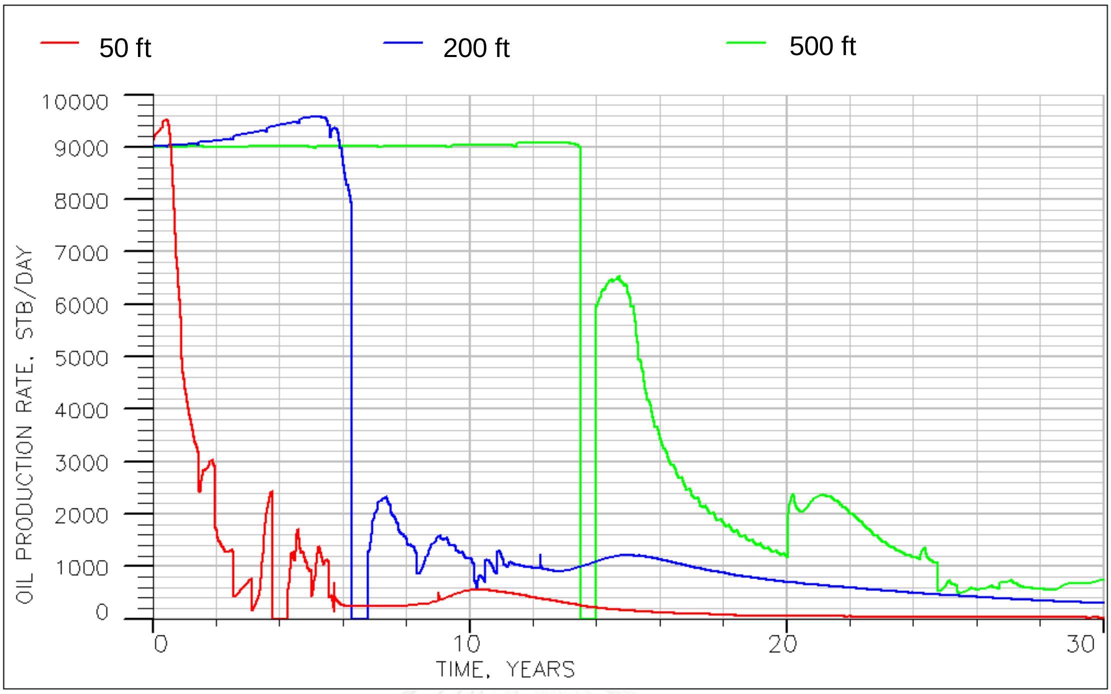


Figure 5.59 Effect of reservoir thickness on oil production rate of WAG with up-dip injection in a reservoir without dip angle.

5.6.4.2 Reservoir with dip angle of 15°

During initial water flooding period, oil rate cannot be kept constant for the 50-ft reservoir while it is constant around 9,000 STB/D for 5 years and 13 years for the 200-ft and 500-ft reservoir, respectively. WAG is started in the second year for the 50-ft reservoir, in the fifth year for the 200-ft reservoir, and in the thirteenth year for the 500-ft reservoir. As shown in Figure 5.60, the three cases have similar profiles but different in magnitude.

From Table 5.72, case 1 takes the shortage production time which is 26.72 years. In term of oil recovery factor, it is higher for the thinner reservoir. Case 3 having the largest thickness of 500 ft requires the largest amount of injected water due to the large pore volume of the reservoir and longest period of initial water flooding. Although we obtain the highest BOE in this case, it results in the lowest oil recovery factor because there is large amount of oil left in the reservoir.

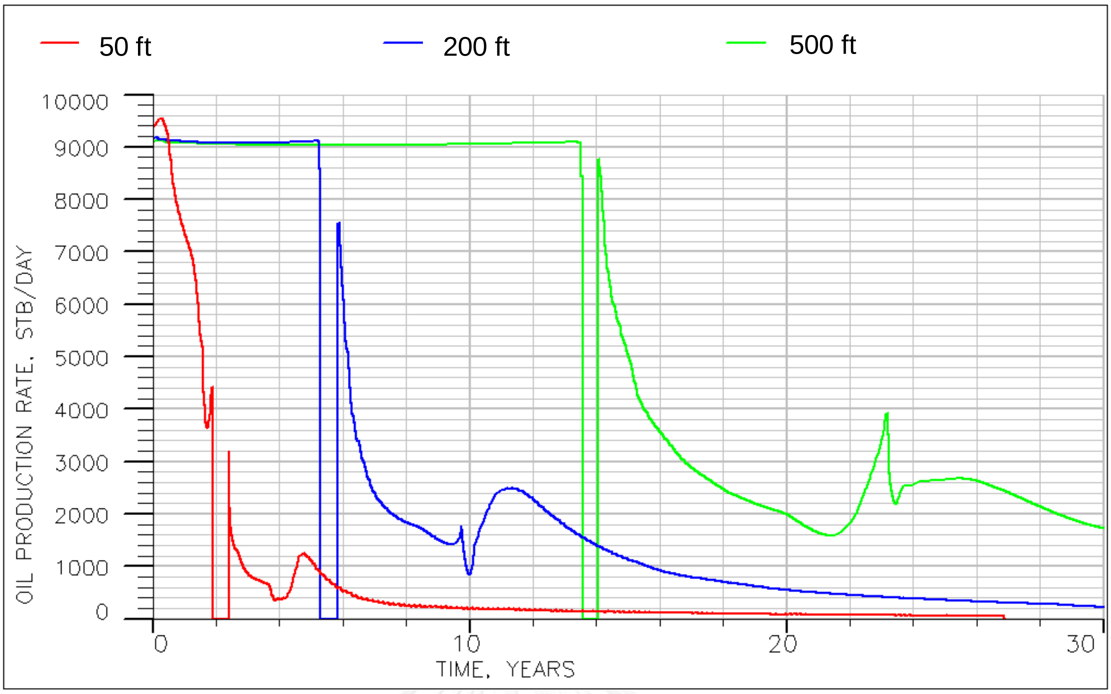


Figure 5.60 Effect of reservoir thickness on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15°.

5.6.4.3 Reservoir with dip angle of 30°

Case 3 having the highest thickness requires the longest time for water flooding around 11 years. In the early time of WAG injection, it also needs the longest period to produce the injected water before oil bank reaches the producer (from the eleventh year to the nineteenth year). For the other two cases with the lower reservoir thickness, they spend shorter time for water flooding and shorter time to produce water bank as shown in Figure 5.61.

From Table 5.72, smaller thickness results in higher oil recovery factor and less amounts of gas and water are needed for injection because of the smaller reservoir size and the shorter time of initial water flooding. Case 1 (50 ft thickness) takes only 21.57 years for production before it reaches the economic limit. Similar to the other two reservoirs with different dip-angles, the highest BOE is yielded from the reservoir with the largest thickness due to the largest amount of STOIIP.

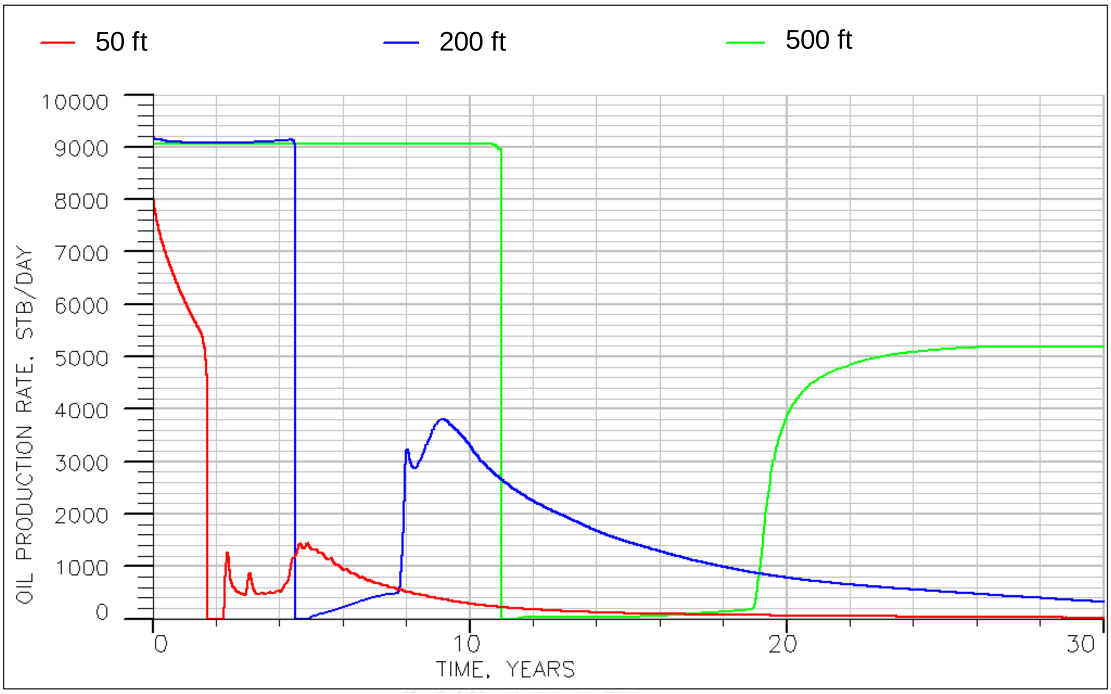


Figure 5.61 Effect of reservoir thickness on oil production rate of WAG with up-dip injection in a reservoir with dip angle of 30°.

Table 5.72 Result comparison between different reservoir thicknesses.

Dip angle	Process	Thickness [ft]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
0°	WAG up-dip	50	20.08	6.692	73.41	8.601	11.958	26.595	19.572	7.251
		200	30	28.244	78.07	10.579	25.256	89.455	63.046	30.690
		500	30	55.638	61.46	10.780	37.620	103.443	44.292	60.112
15°	WAG down-dip	50	26.72	7.220	82.31	15.504	18.852	56.887	50.659	7.778
		200	30	27.281	77.72	17.549	32.189	74.276	50.375	29.722
		500	30	60.570	68.96	16.116	39.721	92.256	37.059	64.505
30°	WAG up-dip	50	21.57	6.485	82.16	8.534	12.155	31.073	26.150	7.089
		200	30	25.705	81.38	13.411	26.279	55.003	46.328	27.850
		500	30	55.706	70.49	15.967	27.944	73.499	54.936	57.702

When the effect of reservoir thickness is considered without the limitation of production time, cases with the thickness of 200 and 500 ft spend more than 30 years for the production. For a non-dipping reservoir, we need 20.08, 76.76, and 217.02 years to produce oil from the reservoir with thickness of 50, 200, and 500 ft, respectively. In fact, the production rate should be increased to a higher value in the cases of 200 and 500 ft thick reservoirs in order to shorten the production time. For a 15° reservoir, we can extend the production time to 46.78 and 166.41 years for cases having reservoir thickness of 200 and 500 ft, respectively. For a 30° reservoir, reservoirs with thickness of 50, 200, and 500 ft spend 21.57, 43.21, and 57.56 years, respectively, for the production before reaching the economic constraint.

Cross sectional area perpendicular to the flow direction affects the gravity number (G). From Eq. 3.5 in Chapter 3, larger cross sectional area, which means larger reservoir thickness, results in higher gravity number. Consequently, production from the thicker reservoir provides higher oil recovery factor due to more stability of floodfront as shown in Table 5.73.

Table 5.73 Result comparison between different reservoir thicknesses of the cases without production time limit.

Dip angle	Process	Thickness [ft]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
0°	WAG up-dip	50	20.08	6.692	73.41	8.601	11.958	26.595	19.572	7.251
		200	76.76	28.048	77.53	24.053	40.422	222.223	193.053	30.776
		500	217.02	74.594	79.88	59.694	103.271	634.282	566.390	81.858
15°	WAG down-dip	50	26.72	7.220	82.31	15.504	18.852	56.887	50.659	7.778
		200	46.78	29.114	82.94	23.209	38.263	110.102	82.986	31.623
		500	166.41	73.455	83.63	76.321	116.662	382.757	314.371	80.180
30°	WAG up-dip	50	21.57	6.485	82.16	8.534	12.155	31.073	26.150	7.089
		200	43.21	26.412	83.62	15.859	30.782	73.495	65.848	28.900
		500	57.56	67.592	84.98	30.247	57.986	112.684	83.190	72.217

5.6.5 Effect of oil properties

Oil properties are important factors affecting production performance. Their effects are investigated by performing three cases of simulation as listed in Table 5.74. Oil gravity, gas gravity, and solution gas/oil ratio (R_s) are taken into account for this study. Figures 5.62-5.64 illustrate fluid properties which are oil formation volume factor, oil viscosity, and solution gas oil ratio, respectively, as functions of pressure for each case

Table 5.74 Cases with different oil properties.

Case	Property		
	Oil gravity [°API]	Gas gravity [s.g. air]	R_s [SCF/STB]
1	30	0.7	400
2	40	0.7	566
3	50	0.7	800

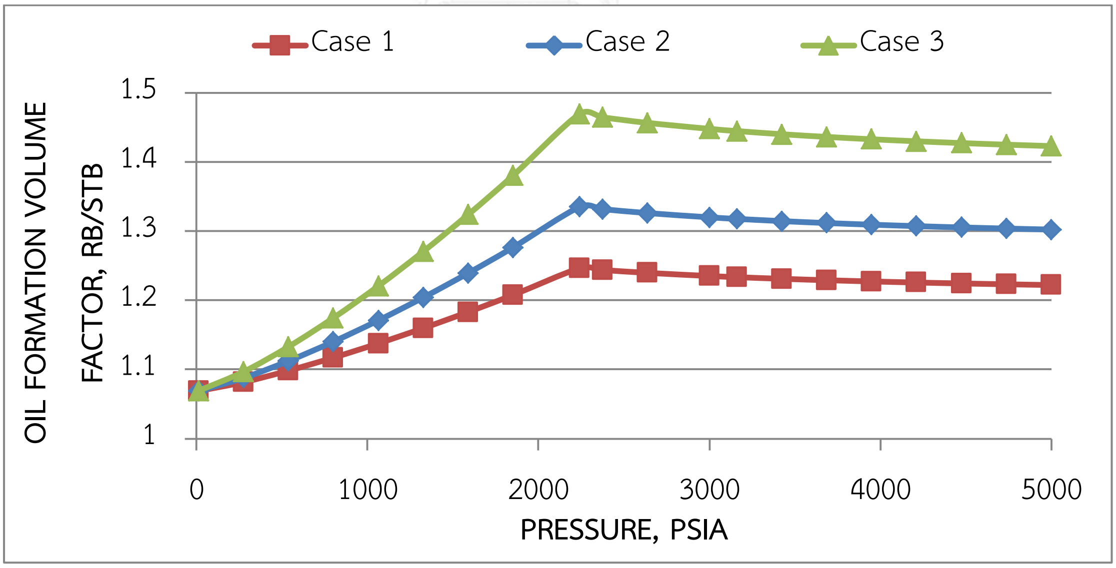


Figure 5.62 Relationship between oil formation volume factor and pressure for the study of an effect of oil properties.

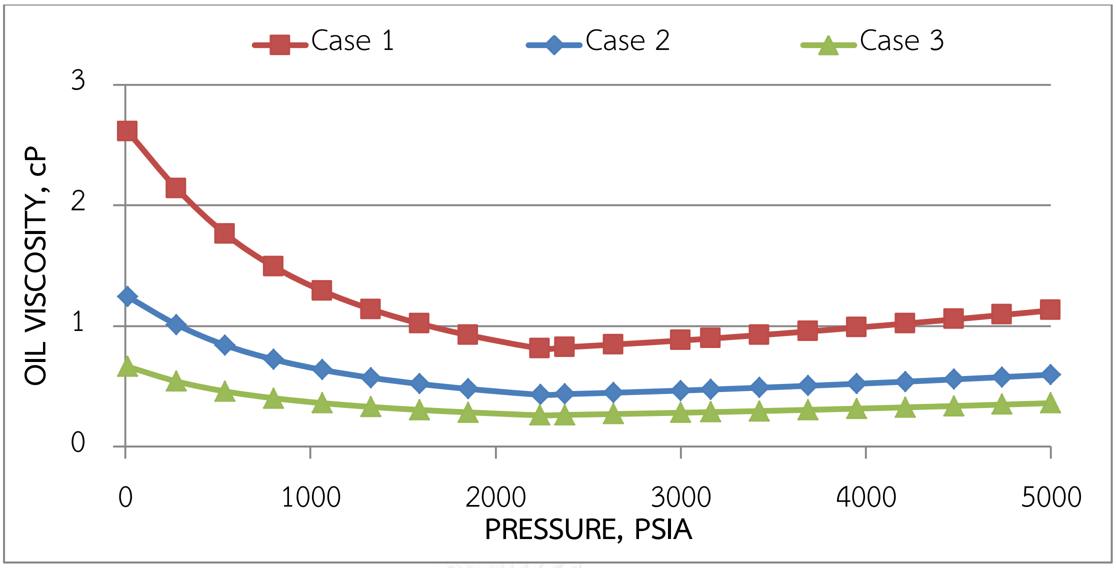


Figure 5.63 Relationship between oil viscosity and pressure for the study of an effect of oil properties.

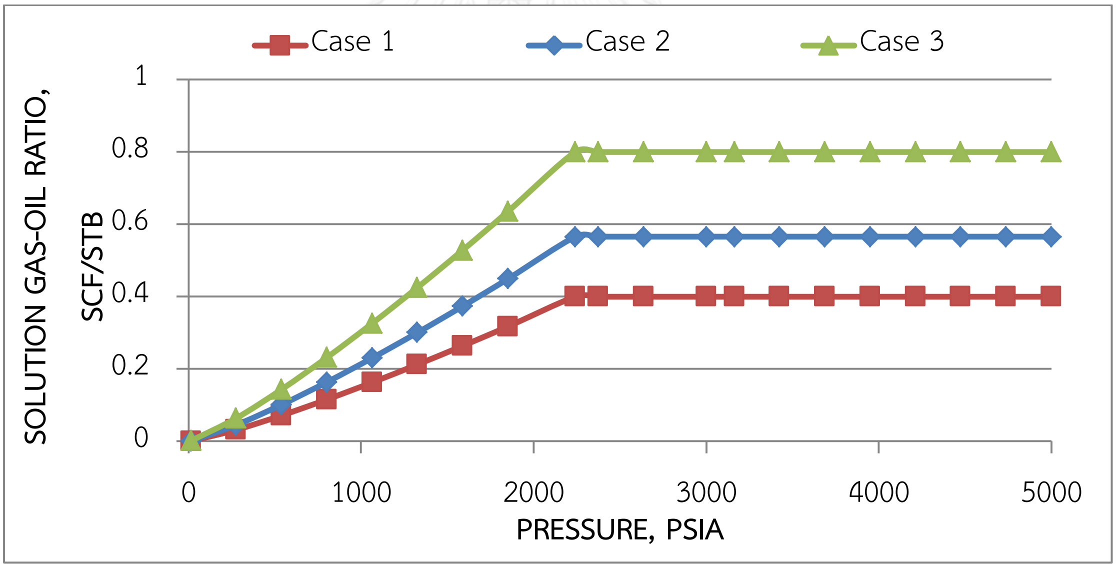


Figure 5.64 Relationship between solution gas-oil ratio and pressure for the study of an effect of oil properties.

5.6.5.1 Reservoir without dip angle

Figure 5.65 shows oil production profile of the three cases with different oil properties. It is clearly seen that oil production rate during water flooding period depends on oil properties. Case 3 shows a lower rate than case 1 and case 2. As shown in Figure 5.62, case 3 has the highest oil formation volume factor (B_o) which results in the lowest oil production rate at standard condition. For the longest initial water flooding period of case 3, it is affected by the lowest oil viscosity as shown in Figure 5.63 which results in a stable flood front due to a lower value of end point mobility ratio (M) as can be calculated by Eq. 3.6. However, the oil production rates of all cases are not much different during WAG injection period.

Table 5.75 shows the comparison of their results. Case 3 shows the highest oil recovery factor of 82.33%, although it provides the lowest amount of oil production of 27.061 MMSTB because of a high formation volume factor which results in the smallest amount of original oil in place (32.870 MMSTB). When gas production is considered, case 3 produces the highest amount of gas because it has the highest solution gas-oil ratio as shown in Figure 5.64.

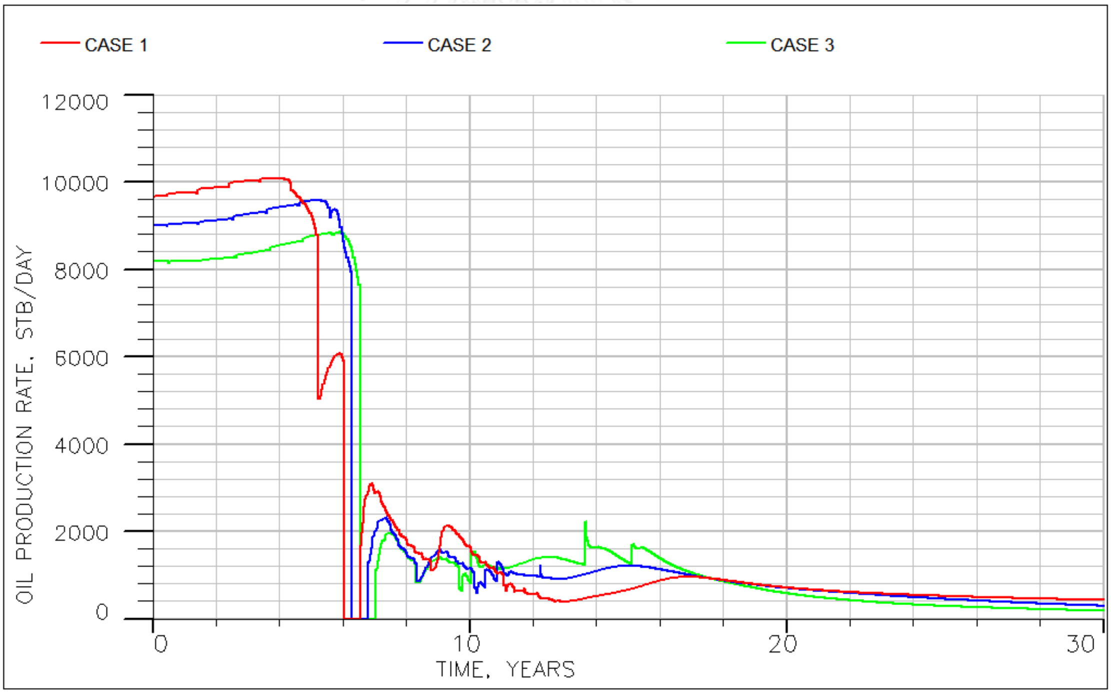


Figure 5.65 Effect of oil properties on oil production rate of WAG with up-dip injection in a reservoir without dip angle.

5.6.5.2 Reservoir with dip angle of 15°

Oil production profiles of all three cases have a similar trend. In water flooding period, case 1 has higher oil rate than case 2 and case 3 which are around 10,000 RB/D, 9,100 RB/D, and 7,800 RB/D, respectively, due to the effect of oil formation volume factor (B_o) as shown in Figure 5.62. A higher oil rate at standard condition is obtained by a lower B_o. For case 1, a high oil viscosity as shown in Figure 5.63 results in a high end point mobility ratio (M) as can be calculated by Eq. 3.6. Therefore, water cut of the producer reaches the stopping criteria early because water tends to underrun. As a result, stopping time for water flooding of case 1 is a little bit earlier than those for the other two cases. Figure 5.66 shows the effect of oil properties on oil production profile.

Similarly to a non-dipping reservoir, case 3 yields the highest oil recovery factor (80.89%), even though it provides the least amount of oil production (25.815 MMSTB) because case 3 has the least amount of original oil in place. This is because case 3 has the highest oil formation volume factor as shown in Figure 5.62. In addition, case 3 produces the largest amount of gas due to the high solution gas-oil ratio as shown in Figure 5.64. However, case 2 yields the highest BOE of 29.722 MMSTB. Their results are tabulated in Table 5.75.

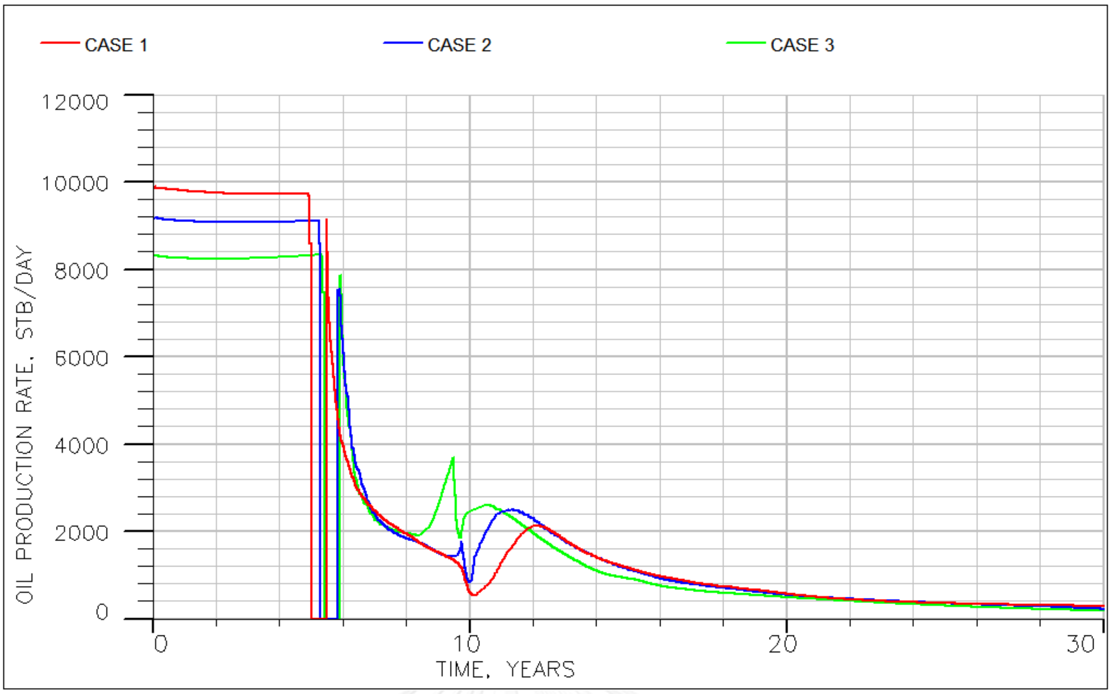


Figure 5.66 Effect of oil properties on oil production rate of WAG with down-dip injection in a reservoir with dip angle of 15°.

5.6.5.3 Reservoir with dip angle of 30°

From Figure 5.67, case 1 has the highest oil rate in water flooding stage while case 3 has the lowest rate. As previously discussed for a non-dipping reservoir and a reservoir with dip angle of 15°, higher oil production rate and shorter period of initial water flooding are affected by lower oil formation volume factor and higher oil viscosity, respectively. However, oil rate of three cases are not much different in WAG injection stage.

Table 5.75 shows result comparison. Case 2 provides the highest oil production of 25.705 MMSTB and the highest BOE of 27.850 MMSTB. Case 3 has the highest oil formation volume factor which results in the lowest amount of original oil in place. Consequently, case 3 provides the smallest amount of oil production although this case yields the highest oil recovery factor of 83.94%. Moreover, the highest solution gas-oil ratio of case 3 gives a high amount of gas production of 31.525 BSCF.

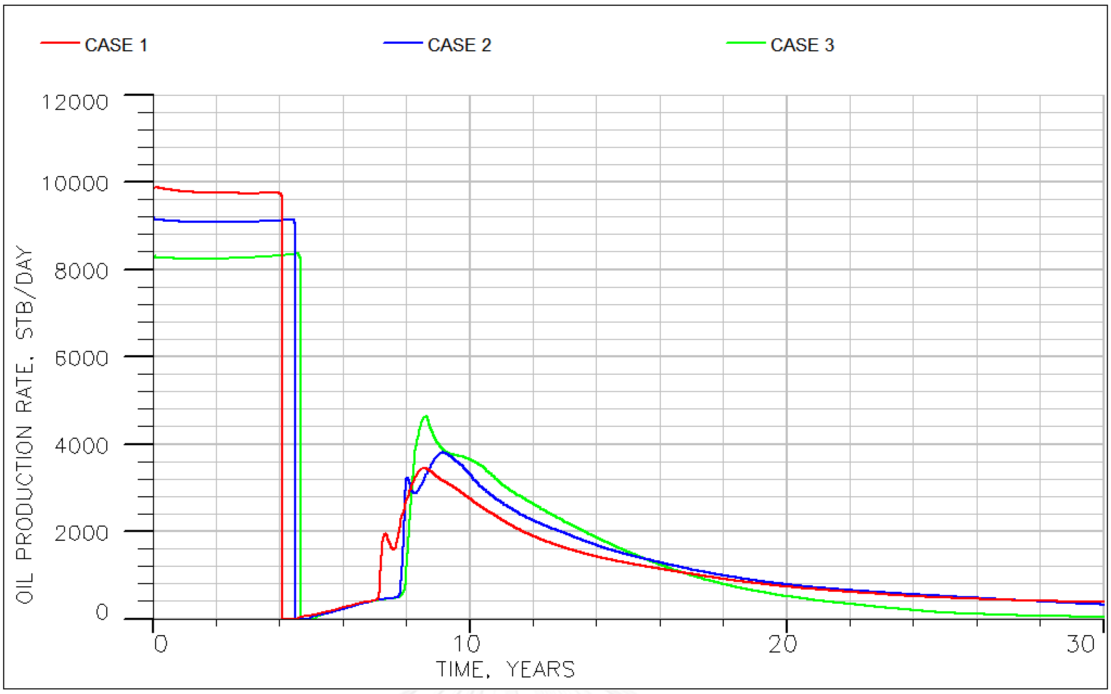


Figure 5.67 Effect of oil properties on oil production rate of WAG with up-dip injection in a reservoir with dip angle of 30°.

Table 5.75 Result comparison between different oil properties.

Dip angle	Process	Case	OOIP [MMSTB]	Production time [Year]	Total oil production [MMSTB]	Oil recovery factor [%]	Total gas injection [BSCF]	Total gas production [BSCF]	Total water injection [MMSTB]	Total water production [MMSTB]	BOE [MMSTB]
0°	WAG up-dip	1	38.748	30	27.678	71.43	12.760	20.413	87.701	63.602	28.954
		2	36.176	30	28.244	78.07	10.579	25.256	89.455	63.046	30.690
		3	32.870	30	27.061	82.33	10.970	31.188	90.279	62.048	30.432
15°	WAG down-dip	1	37.580	30	27.368	72.83	17.618	26.851	73.758	51.367	28.907
		2	35.102	30	27.281	77.72	17.549	32.189	74.276	50.375	29.722
		3	31.914	30	25.815	80.89	18.273	38.071	74.742	49.499	29.115
30°	WAG up-dip	1	33.803	30	24.619	72.83	12.961	22.559	53.761	43.176	26.219
		2	31.585	30	25.705	81.38	13.411	26.279	55.003	46.328	27.850
		3	28.731	28.92	24.116	83.94	14.072	30.327	53.994	45.769	26.825

CHAPTER VI
CONCLUSIONS

The following conclusions are made from the results of the studying of water alternating gas process (WAG) and double displacement process (DDP) after initial period of water flooding and their sensitivity.

1. Water alternating gas process (WAG) and double displacement process (DDP) after initial water flooding have more efficiencies than long-term water flooding. These two methods produce much more amount of oil, although they involve in gas requirement due to the gas injection mechanisms. However, DDP is not the effective method to produce oil from a non-dipping reservoir.
2. Water cut stopping criteria for the initial water flooding have small effect on oil production. Criteria of low water cut results in slightly better production performance because it allows the process to be switched from initial water flooding to WAG or DDP earlier than those cases having higher water cut stopping criteria. Consequently, it contains lower amount of flooded water inside the reservoir which has to be produced back to the surface.
3. The increase of water injection rate in both WAG and DDP provides better results, even though the injection rate cannot be kept constant throughout the injection period in some cases because of the limitation of fracturing pressure. However, we have to handle large amount of injected and produced water when the water injection rate is high. For WAG, moderate gas injection rate is appropriate because it yields the highest barrel of oil equivalent (BOE). DDP provides the highest BOE when gas is injected at the highest rate.
4. Injection of WAG in smaller slugs (shorter injection duration for each slug) tends to have a little more efficiency. WAG cycle significantly influences the requirement of water and gas. For a non-dipping reservoir, large amount of oil

is produced when water injection duration is longer than gas injection duration (cycle of 4:1 and 2:1) because we need water to stabilize the floodfront. For an inclined reservoir, the recovery factor is not much different when we change the WAG cycle because unstable floodfront is more difficult to occur in a reservoir with bigger dip angle.

5. Regarding well locations, different patterns result in different values of BOE. The combination of a vertical well located at up-dip location with a horizontal well located at down-dip location provides the highest BOE for DDP in an inclined reservoir. For WAG with up-dip injection, the highest BOE yielding patterns are (1) eight vertical wells located along the length of reservoir for a non-dipping reservoir, (2) four vertical wells for a 15° dipping reservoir, and (3) the combination of a vertical well and a horizontal well for a 30° dipping reservoir. For WAG with down-dip injection, production by eight vertical wells provides the highest amount of BOE for a non-dipping reservoir while two horizontal wells, one located up-dip and another one located down-dip, are effective for both 15° and 30° dipping reservoirs. Gravity plays an important role in oil production from inclined reservoirs. Therefore, two wells are considered to be efficient for 15° and 30° reservoirs while a non-dipping reservoir needs the pattern with shorter well spacing (pattern of eight wells) to produce oil from every part of the reservoir.

6. Horizontal permeability has a large impact on the performance of oil production. A case of higher horizontal permeability results in higher oil recovery factor in an inclined reservoir because of the ease of oil flowing while the moderate horizontal permeability (126 md) yields the highest oil recovery factor in a non-dipping reservoir because of the problem of early gas breakthrough in a case with the highest horizontal permeability.

7. The case in which vertical to horizontal permeability ratio is 0.5 (k_v/k_h = 0.5) shows higher oil recovery factor than the case in which k_v/k_v = 0.1. However, the recovery factor is also increased when we reduce the value of k_v/k_v to 0.01 but this case requires much more amount of injected gas.

8. Oil recovery factors from different three-phase relative permeability correlations are significantly different. The highest oil recovery factor is obtained when ECLIPSE default model is applied. In addition, Stone 1 model provides larger oil recovery factor than Stone 2 model because oil relative permeability calculated by Stone 1 model is often higher than oil relative permeability calculated by Stone 2.
9. The important factor that is affected when we change the reservoir thickness is the size of reservoir and the reservoir fluids located inside. When the thickness is reduced, oil production reaches the economic limit earlier. However, it does not indicate that oil recovery factor of smaller reservoir will be lower or higher than that for the larger reservoir. On the other hand, a case with too large thickness reaches the limitation of production time while large amount of oil is still not produced; it thus shows very low oil recovery factor. Nevertheless, cases with higher thickness yields higher oil recovery factor when the production time is not limited because higher thickness results in more stability of floodfront.
10. Oil recovery factor increases when oil tends to be lighter and contains higher amount of solution gas. The reason is the improvement in its ability to flow inside the reservoir.

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APPENDIX

APPENDIX

In this study, ECLIPSE 100 is used as a simulator to construct the reservoir model. The input data for the water alternating gas with up-dip and down-dip injection base cases and the double displacement process base case are detailed below:

1. Case definition

Simulator:	Black oil
Model dimension:	Number of cells in X direction: 73
	Number of cells in Y direction: 31
	Number of cells in Z direction: 21
Grid type:	Cartesian
Geometry type:	Corner point
Oil-gas-water properties:	Water, oil, gas, and dissolved gas
Solution type:	Fully implicit

2. Grid

2.1Properties

Active grid blocks:	(I=1-73, J=1-31, K=1-20) = 1
	(I=1-73, J=1-31, K=21) = 0
X Permeability:	126 md
Y Permeability:	126 md
Z Permeability:	12.6 md
Porosity:	0.1509

2.2 Geometry

Grid block coordinate lines:	depend on dip angle
Grid block corners:	depend on dip angle

3. PVT

3.1 Water PVT properties

Reference pressure (P_{ref}): 3000 psia

Water FVF at P_{ref}: 1.021734 rb/stb

Water compressibility: 3.09988×10^{-6} psi^{-1}

Water viscosity at P_{ref}: 0.3013289 cp

Water viscosibility: 3.39604×10^{-6} psi^{-1}

3.2 Dry gas PVT properties (no vapourised oil)

Pressure [psia]	FVF [rb/Mscf]	Viscosity [cp]
14.7	225.77118	0.013252614
277.08421	11.684415	0.013438669
539.46842	5.8604139	0.013738956
801.85263	3.8557057	0.014127064
1064.2368	2.8465392	0.014597939
1326.6211	2.2432054	0.015149735
1589.0053	1.8454849	0.015780049
1851.3895	1.5665663	0.016484167
2113.7737	1.3625791	0.017254274
2376.1579	1.2088291	0.0180796
2515.1229	1.1423563	0.018534756
3000	0.96700949	0.020187742
3163.3105	0.92257588	0.020757503
3425.6947	0.86218077	0.021676481
3688.0789	0.81250833	0.022592519
3950.4632	0.77111488	0.023499222
4212.8474	0.73619385	0.024392134
4475.2316	0.70639432	0.025268362
4737.6158	0.68069512	0.026126207
5000	0.65831597	0.026964832

3.3 Live oil PVT properties (dissolved gas)

R_s [Mscf/stb]	P_{bub} [psia]	FVF [rb/stb]	Viscosity [cp]
0.0013251226	14.7	1.069137	1.2402773
	277.08421	1.0521431	1.3157432
	539.46842	1.0516839	1.4498012
	801.85263	1.0515252	1.6261628
	1064.2368	1.0514448	1.8437304
	1326.6211	1.0513962	2.1048022
	1589.0053	1.0513637	2.4132261
	1851.3895	1.0513403	2.7737872
	2113.7737	1.0513228	3.1919255
	2376.1579	1.0513091	3.6735649
	2515.1229	1.0513031	3.9565081
	3000	1.0512863	5.1109132
	3163.3105	1.0512818	5.563312
	3425.6947	1.0512754	6.3634539
	3688.0789	1.05127	7.2595718
	3950.4632	1.0512653	8.2578239
	4212.8474	1.0512612	9.3639202
	4475.2316	1.0512575	10.582968
	4737.6158	1.0512543	11.919316
	5000	1.0512514	13.376406
0.045575432	277.08421	1.0879253	1.0103244
	539.46842	1.0778477	1.0399163
	801.85263	1.0743875	1.0857309
	1064.2368	1.0726378	1.1443819
	1326.6211	1.0715815	1.2143808
	1589.0053	1.0708747	1.2950212
	1851.3895	1.0703685	1.3859858
	2113.7737	1.0699882	1.487169
	2376.1579	1.0696919	1.5985826
	2515.1229	1.06956	1.6617576
	3000	1.0691957	1.9050329
	3163.3105	1.0690982	1.9950402

R_s [Mscf/stb]	P_{bub} [psia]	FVF [rb/stb]	Viscosity [cp]
	3425.6947	1.068961	2.1482416
	3688.0789	1.0688433	2.3120705
	3950.4632	1.0687413	2.4865287
	4212.8474	1.068652	2.6715637
	4475.2316	1.0685731	2.8670619
	4737.6158	1.068503	3.0728416
	5000	1.0684403	3.2886497
0.10170558	539.46842	1.1124223	0.84002122
	801.85263	1.1044637	0.86288269
	1064.2368	1.100452	0.89456427
	1326.6211	1.0980343	0.93367602
	1589.0053	1.096418	0.97944279
	1851.3895	1.0952613	1.0314041
	2113.7737	1.0943926	1.0892759
	2376.1579	1.0937162	1.152877
	2515.1229	1.0934153	1.1888397
	3000	1.092584	1.3264576
	3163.3105	1.0923615	1.3770001
	3425.6947	1.0920485	1.4625628
	3688.0789	1.0917802	1.5534314
	3950.4632	1.0915475	1.6495173
	4212.8474	1.0913438	1.7507137
	4475.2316	1.0911641	1.8568914
	4737.6158	1.0910043	1.9678962
	5000	1.0908613	2.0835467
0.16395522	801.85263	1.1403543	0.72158197
	1064.2368	1.1333311	0.74074899
	1326.6211	1.1291083	0.76554916
	1589.0053	1.1262889	0.79525994
	1851.3895	1.124273	0.82942227
	2113.7737	1.1227599	0.86772984
	2376.1579	1.1215824	0.90996846
	2515.1229	1.1210587	0.93387599

R_s [Mscf/stb]	P_{bub} [psia]	FVF [rb/stb]	Viscosity [cp]
	3000	1.1196126	1.0253232
	3163.3105	1.1192256	1.0588533
	3425.6947	1.1186814	1.1155173
	3688.0789	1.1182149	1.1755445
	3950.4632	1.1178104	1.2388412
	4212.8474	1.1174565	1.3053076
	4475.2316	1.1171442	1.3748342
	4737.6158	1.1168665	1.4473002
	5000	1.1166181	1.5225719
0.23059392	1064.2368	1.171041	0.63560714
	1326.6211	1.1644833	0.65228139
	1589.0053	1.1601136	0.67288008
	1851.3895	1.1569925	0.69697368
	2113.7737	1.1546518	0.72426358
	2376.1579	1.1528313	0.75453447
	2515.1229	1.1520219	0.77171711
	3000	1.149788	0.83758903
	3163.3105	1.1491905	0.86176289
	3425.6947	1.1483504	0.90260932
	3688.0789	1.1476303	0.94585271
	3950.4632	1.1470062	0.99140586
	4212.8474	1.1464601	1.0391803
	4475.2316	1.1459783	1.089084
	4737.6158	1.14555	1.1410194
	5000	1.1451668	1.1948828
0.30071672	1326.6211	1.204112	0.57047982
	1589.0053	1.1977854	0.58530969
	1851.3895	1.1932748	0.60302932
	2113.7737	1.1898952	0.62335993
	2376.1579	1.1872685	0.6460935
	2515.1229	1.1861013	0.6590514
	3000	1.1828813	0.70892578
	3163.3105	1.1820205	0.72727362

R_s [Mscf/stb]	P_{bub} [psia]	FVF [rb/stb]	Viscosity [cp]
	3425.6947	1.1808105	0.75830077
	3688.0789	1.1797735	0.7911639
	3950.4632	1.1788751	0.82578329
	4212.8474	1.1780892	0.86208063
	4475.2316	1.1773958	0.89997696
	4737.6158	1.1767796	0.93939117
	5000	1.1762283	0.98023889
0.37375579	1589.0053	1.2393217	0.51938469
	1851.3895	1.2330917	0.53277298
	2113.7737	1.2284318	0.54837246
	2376.1579	1.2248131	0.56599062
	2515.1229	1.2232059	0.57608583
	3000	1.218775	0.61515125
	3163.3105	1.2175912	0.62957481
	3425.6947	1.2159274	0.65400197
	3688.0789	1.2145023	0.67990635
	3950.4632	1.2132677	0.70721497
	4212.8474	1.212188	0.73585775
	4475.2316	1.2112357	0.76576565
	4737.6158	1.2103895	0.79686929
	5000	1.2096327	0.82909793
0.44931763	1851.3895	1.2764901	0.47815326
	2113.7737	1.2702713	0.4903721
	2376.1579	1.2654501	0.50433103
	2515.1229	1.2633101	0.51238049
	3000	1.2574146	0.54373676
	3163.3105	1.2558405	0.55536757
	3425.6947	1.2536291	0.57510507
	3688.0789	1.2517354	0.59607444
	3950.4632	1.2500957	0.61820842
	4212.8474	1.2486619	0.64144356
	4475.2316	1.2473976	0.66571844
	4737.6158	1.2462744	0.69097242

R_s [Mscf/stb]	P_{bub} [psia]	FVF [rb/stb]	Viscosity [cp]
	5000	1.24527	0.71714467
0.52711162	2113.7737	1.3154764	0.44411489
	2376.1579	1.3092103	0.4553589
	2515.1229	1.306433	0.46188729
	3000	1.2987883	0.48751927
	3163.3105	1.2967486	0.49707965
	3425.6947	1.2938843	0.51334443
	3688.0789	1.2914326	0.53066473
	3950.4632	1.2893103	0.54897814
	4212.8474	1.2874552	0.56822655
	4475.2316	1.2858199	0.58835452
	4737.6158	1.2843675	0.60930813
	5000	1.2830689	0.63103401
0.60691334	2376.1579	1.3561662	0.41548545
	2515.1229	1.3526287	0.42085551
	3000	1.342916	0.44210218
	3163.3105	1.3403268	0.4500782
	3425.6947	1.3366923	0.46368788
	3688.0789	1.3335828	0.47822137
	3950.4632	1.3308922	0.49362033
	4212.8474	1.3285413	0.50983106
	4475.2316	1.3264694	0.52680291
	4737.6158	1.3246298	0.54448724
	5000	1.3229854	0.56283647
0.64992893	2515.1229	1.3783732	0.40207564
	3000	1.3674175	0.42140791
	3163.3105	1.3645001	0.42868976
	3425.6947	1.3604058	0.44113673
	3688.0789	1.3569038	0.45445068
	3950.4632	1.3538744	0.46857518
	4212.8474	1.3512279	0.48345852
	4475.2316	1.348896	0.49905226
	4737.6158	1.3468257	0.51531007
	5000	1.3449755	0.53218695

3.4 Fluid density at surface conditions

Oil density: 51.45684 lb/ft^3

Water density: 62.42797 lb/ft^3

Gas density: 0.04369958 lb/ft^3

3.5 Rock properties

Reference pressure: 3000 psia

Rock compressibility: 3.013923×10^{-6} psi^{-1}

4. SCAL

4.1 Gas/oil saturation functions

S_w	K_{rw}	K_{ro}	P_c [psia]
0	0	0.8	0
0.15	0	0.53972801	0
0.2125	0.00078125	0.44176066	0
0.275	0.00625	0.35056363	0
0.3375	0.02109375	0.26668279	0
0.4	0.05	0.19082267	0
0.4625	0.09765625	0.12394296	0
0.525	0.16875	0.067466001	0
0.5875	0.26796875	0.023852834	0
0.65	0.4	0	0
0.75	1	0	0

4.2 Water/oil saturation functions

S_w	K_{rw}	K_{ro}	P_c [psia]
0.25	0	0.8	0
0.3	0.00041152263	0.67044199	0
0.35	0.0032921811	0.54874842	0
0.4	0.011111111	0.43546484	0
0.45	0.026337449	0.33126933	0
0.5	0.051440329	0.23703704	0
0.55	0.088888889	0.15396007	0
0.6	0.14115226	0.083805248	0
0.65	0.21069959	0.02962963	0
0.7	0.3	0	0
1	1	0	0

5. Initialization

Datum depth: 5000 ft

Pressure at datum depth: 2242 psia

WOC depth: 12000 ft

GOC depth: 5000 ft

6. Schedule

6.1 During initial water flooding

6.1.1 Producer

Well specification

Well: WELL1

Group: WELL

I location: 12

J location: 16

Preferred phase: OIL

Inflow equation:	STD
Automatic shut-in instruction:	SHUT
Crossflow:	YES
Density calculation:	SEG

Well connection data

Well:	WELL1
K upper:	1
K lower:	20
Open/shut flag:	OPEN
Well bore ID:	0.5522083 ft
Direction:	Z

Production well control

Well:	WELL1
Open/shut flag:	OPEN
Control:	RESV
Reservoir volume rate:	8000 rb/day
BHP target:	200 psia

6.1.2 Water injector

Well specification

Well:	WELL2
Group:	WELL
I location:	62
J location:	16
Preferred phase:	WATER
Inflow equation:	STD
Automatic shut-in instruction:	SHUT
Crossflow:	YES
Density calculation:	SEG

Well connection data

Well:	WELL2
K upper:	1
K lower:	20
Open/shut flag:	OPEN
Well bore ID:	0.5522083 ft
Direction:	Z

Injection well control

Well:	WELL2
Injector type:	WATER
Open/shut flag:	OPEN
Control:	RESV
Reservoir volume rate:	8000 rb/day
BHP target:	4080 psia (depend on dip angle)

6.2 After initial water flooding

6.2.1 Water alternating gas with up-dip injection

6.2.1.1 Producer

Well specification

Well:	P1
Group:	P
I location:	62
J location:	16
Preferred phase:	OIL
Inflow equation:	STD
Automatic shut-in instruction:	SHUT
Crossflow:	YES
Density calculation:	SEG

Well connection data

Well:	P1
K upper:	1
K lower:	20
Open/shut flag:	OPEN
Well bore ID:	0.5522083 ft
Direction:	Z

Production well control

Well:	P1
Open/shut flag:	OPEN
Control:	RESV
Reservoir volume rate:	8000 rb/day
BHP target:	200 psia

6.2.1.2 Water injector

Well specification

Well:	W1
Group:	W
I location:	12
J location:	16
Preferred phase:	WATER
Inflow equation:	STD
Automatic shut-in instruction:	SHUT
Crossflow:	YES
Density calculation:	SEG

Well connection data

Well:	W1
K upper:	1
K lower:	20

Open/shut flag:	OPEN
Well bore ID:	0.5522083 ft
Direction:	Z

Injection well control

Well:	W1
Injector type:	WATER
Open/shut flag:	OPEN
Control:	RESV
Reservoir volume rate:	8000 rb/day
BHP target:	3260 psia (depend on dip angle)

Automatic cycling of wells

Well:	W1
On period:	90 day
Off period:	90 day
Start-up time:	1 day

6.2.1.3 Gas injector

Well specification

Well:	G1
Group:	G
I location:	12
J location:	16
Preferred phase:	GAS
Inflow equation:	STD
Automatic shut-in instruction:	SHUT
Crossflow:	YES
Density calculation:	SEG

Well connection data

Well:	G1

K upper:	1
K lower:	20
Open/shut flag:	OPEN
Well bore ID:	0.5522083 ft
Direction:	Z

Injection well control

Well:	G1
Injector type:	GAS
Open/shut flag:	OPEN
Control:	RESV
Reservoir volume rate:	8000 rb/day
BHP target:	3260 psia (depend on dip angle)

Automatic cycling of wells

Well:	G1
On period:	90 day
Off period:	90 day
Start-up time:	1 day

6.2.2 Water alternating gas with down-dip injection

6.2.2.1 Producer

Well specification

Well:	P1
Group:	P
I location:	12
J location:	16
Preferred phase:	OIL
Inflow equation:	STD
Automatic shut-in instruction:	SHUT
Crossflow:	YES

Density calculation:	SEG

Well connection data

Well:	P1
K upper:	1
K lower:	20
Open/shut flag:	OPEN
Well bore ID:	0.5522083 ft
Direction:	Z

Production well control

Well:	P1
Open/shut flag:	OPEN
Control:	RESV
Reservoir volume rate:	8000 rb/day
BHP target:	200 psia

6.2.2.2 Water injector

Well specification

Well:	W1
Group:	W
I location:	62
J location:	16
Preferred phase:	WATER
Inflow equation:	STD
Automatic shut-in instruction:	SHUT
Crossflow:	YES
Density calculation:	SEG

Well connection data

Well:	W1
K upper:	1

K lower:	20
Open/shut flag:	OPEN
Well bore ID:	0.5522083 ft
Direction:	Z

Injection well control

Well:	W1
Injector type:	WATER
Open/shut flag:	OPEN
Control:	RESV
Reservoir volume rate:	8000 rb/day
BHP target:	4080 psia (depend on dip angle)

Automatic cycling of wells

Well:	W1
On period:	90 day
Off period:	90 day
Start-up time:	1 day

6.2.2.3 Gas injector

Well specification

Well:	G1
Group:	G
I location:	62
J location:	16
Preferred phase:	GAS
Inflow equation:	STD
Automatic shut-in instruction:	SHUT
Crossflow:	YES
Density calculation:	SEG

Well connection data

Well:	G1
K upper:	1
K lower:	20
Open/shut flag:	OPEN
Well bore ID:	0.5522083 ft
Direction:	Z

Injection well control

Well:	G1
Injector type:	GAS
Open/shut flag:	OPEN
Control:	RESV
Reservoir volume rate:	8000 rb/day
BHP target:	4080 psia (depend on dip angle)

Automatic cycling of wells

Well:	G1
On period:	90 day
Off period:	90 day
Start-up time:	1 day

6.2.3 Double displacement process

6.2.3.1 Producer

Well specification

Well:	WELL2
Group:	WELL
I location:	62
J location:	16
Preferred phase:	OIL
Inflow equation:	STD

Automatic shut-in instruction:	SHUT
Crossflow:	YES
Density calculation:	SEG

Production well control

Well:	WELL2
Open/shut flag:	OPEN
Control:	RESV
Reservoir volume rate:	8000 rb/day
BHP target:	200 psia

6.2.3.2 Gas injector

Well specification

Well:	WELL1
Group:	WELL
I location:	12
J location:	16
Preferred phase:	GAS
Inflow equation:	STD
Automatic shut-in instruction:	SHUT
Crossflow:	YES
Density calculation:	SEG

Injection well control

Well:	WELL1
Injector type:	GAS
Open/shut flag:	OPEN
Control:	RESV
Reservoir volume rate:	8000 rb/day
BHP target:	3260 psia (depend on dip angle)

VITA

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