EFFECT OF ANISOTROPY ON MULTILATERAL WELL PERFORMANCE IN BOTTOM WATER DRIVE RESERVOIR

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
Department of Mining and Petroleum Engineering
Faculty of Engineering
Chulalongkorn University
Academic Year 2013

ผลกระทบของแอนไอโซทรอปีที่มีต่อสมรรถภาพของหลุมน้ำมันหลายแขนงในแหล่งกักเก็บที่ขับ
เคลื่อนด้วยชั้นน้ำข้างล่าง

นายโลรองท์ ฟิน

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
สาขาวิชาวิศวกรรมปิโตรเลียม ภาควิชาวิศวกรรมเหมืองแร่และปิโตรเลียม
คณะวิศวกรรมศาสตร์ จุฬาลงกรณ์มหาวิทยาลัย
ปีการศึกษา 2556

Thesis Title	EFFECT OF ANISOTROPY ON MULTILATERAL WELL PERFORMANCE IN BOTTOM WATER DRIVE RESERVOIR
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โลรองท์ ฟิน : ผลกระทบของแอนไอโซทรอปีที่มีต่อสมรรถภาพของหลุมน้ำมันหลายแขนงในแหล่งกักเก็บที่ขับเคลื่อนด้วยชั้นน้ำข้างล่าง. (EFFECT OF ANISOTROPY ON MULTILATERAL WELL PERFORMANCE IN BOTTOM WATER DRIVE RESERVOIR) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: อ. ดร. ฟ้าลั่น ศรีสุริยชัย, อ.ที่ปรึกษาวิทยานิพนธ์ร่วม: ผศ. ดร. สุวัฒน์ อธิชนากร, 189 หน้า.

ในช่วงเวลาสองทศวรรษที่ผ่านมา การพัฒนาการเจาะหลุมผลิตแบบมีทิศทาง และ หลุมน้ำมันแนวนอนได้นำไปสู่เทคโนโลยีหลุมผลิตหลายแขนง สำหรับทั้งแหล่งน้ำมันและก๊าซธรรมชาติ ความสามารถในการเจาะหลุมผลิตหลายแขนงจากหลุมหลักเพียงหลุมเดียวนี้ นำไปสู่การพัฒนาโดยเฉพาะอย่างยิ่ง การเพิ่มพื้นที่สัมผัสแหล่งกักเก็บน้ำมันที่มีความสามารถในการผลิตต่ำ ดรรชนีวิวิธพันธ์ และ แอนไอโซทรอปีของค่าความซึมผ่าน เป็นข้อมูลวิกฤติที่ทำให้เกิดความไม่แน่นอนของสมรรถภาพของหลุมผลิต การศึกษานี้มุ่งเน้นไปที่ผลกระทบของแอนไอโซทรอปีของค่าความซึมผ่านทั้งในแนวระนาบ และ ในแนวตั้ง ที่มีต่อสมรรถภาพการผลิตของหลุมน้ำมันหลายแขนง ในแหล่งกักเก็บน้ำมันซึ่งได้รับแรงขับเคลื่อนด้วยชั้นน้ำด้านล่าง ผลกระทบของขนาดของชั้นน้ำด้านล่าง ความยาวของหลุมผลิต และ ค่าความหนาแน่นเฉพาะของน้ำมัน ได้ถูกทำการทดสอบด้วยแบบจำลองทางคณิตศาสตร์ แบบจำลองของหลุมน้ำมันสองแขนง และ หลุมน้ำมันสี่แขนง ได้ถูกทดสอบและผลที่ได้ถูกนำไปเปรียบกับหลุมน้ำมันแนวนอนแขนงเดี่ยวในแหล่งกักเก็บน้ำมันที่มีคุณสมบัติแตกต่างกันออกไป

ผลการศึกษาแสดงให้เห็นว่า ประโยชน์ของหลุมน้ำมันหลายแขนง ช่วยลดผลกระทบจากความไม่แน่นอนของแอนไอโซทรอปีของค่าความสามารถในการซึมผ่านในแหล่งกักเก็บ ซึ่งได้รับแรงขับเคลื่อนด้วยชั้นน้ำข้างล่าง รูปทรงเรขาคณิตของหลุมน้ำมันสี่แขนงสามารถเฉลี่ยการผลิตในแต่ละแขนง ช่วยให้ลดความไม่แน่นอนจากแอนไอโซทรอปีของค่าความสามารถในการซึมผ่าน และให้ผลดีกว่าเมื่อเทียบสมรรถภาพภาพกับหลุมน้ำมันแนวนอนแขนงเดียว

ขนาดของชั้นน้ำข้างล่าง ทำให้ผลกระทบของแอนไอโซทรอปีของค่าความสามารถในการซึมผ่านที่มีต่อสมรรถภาพของหลุมผลิตเด่นชัดขึ้น หลุมน้ำมันสองแขนงตรงข้าม และ หลุมน้ำมันสี่แขนงช่วยลดการลดต่ำของความดันของแหล่งกักเก็บ ทำให้สามารถลดปริมาณน้ำที่ไหลเข้ามาจากชั้นน้ำข้างล่าง ประโยชน์ที่ได้จากหลุมน้ำมันหลายแขนงเพิ่มสูงขึ้นเมื่อขนาดของชั้นน้ำข้างล่างเพิ่มมากขึ้น ขนาดของชั้นน้ำข้างล่างที่ใหญ่จนเกินไปเมื่อเทียบกับขนาดของแหล่งกักเก็บ อาจจะทำให้ผลกระทบต่อสมรรถภาพของหลุมลดลงอันเนื่องมาจากปริมาณน้ำที่เข้ามามากในหลุมผลิต ในแหล่งกักเก็บที่มีแอนไอโซทรอปีต่ำ ควรที่จะต้องทำการหาขนาดความยาวของหลุมน้ำมันขั้นต่ำสำหรับหลุมน้ำมันสี่แขนง เพื่อลดการรบกวนของการผลิตจากแต่ละแขนง ซึ่งเป็นผลทำให้เกิดการลดลงของความดันในแหล่งกักเก็บ

ภาควิชา	วิศวกรรมเหมืองแร่และปิโตรเลียม	ลายมือชื่อนิสิต	....
สาขาวิชา	วิศวกรรมปิโตรเลียม	ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์หลัก	....
ปีการศึกษา	2556	ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์ร่วม	....

5571213921 : MAJOR PETROLEUM ENGINEERING
KEYWORDS: MULTILATERAL WELLS / HORIZONTAL WELLS / ANISOTROPY / WATER DRIVE RESERVOIR

LAURENT FINE: EFFECT OF ANISOTROPY ON MULTILATERAL WELL PERFORMANCE IN BOTTOM WATER DRIVE RESERVOIR. ADVISOR: FALAN SRISURIYACHAI, Ph.D., CO-ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 189 pp.

In the last two decades, development of directional and horizontal drilling has led to the upcoming of multilateral well technology in the oil and gas industry. This ability to drill multiple laterals from a single bore has enabled new possibilities of development, especially to maximize reservoir exposure in low productivity reservoirs. Heterogeneity and particularly anisotropy of reservoir permeability are critical information that may lead to major uncertainties in well performance. This study focuses on effects of both horizontal anisotropy and vertical anisotropy on performance of multilateral well in bottom water drive reservoirs. Effects of aquifer size, effective well length and oil gravity are also investigated through reservoir simulation. Dual lateral and quadrilateral wells simulations are performed and results are compared to that obtained from horizontal wells in several reservoir models.

Results demonstrate the benefits of multilateral wells to reduce uncertainty of permeability anisotropy in bottom water drive reservoirs. Quadrilateral well geometry enables to average oil production within each lateral and thus, decrease uncertainty of anisotropic reservoirs compared to horizontal wells.

Aquifer size amplifies effects of anisotropy on well performance. Dual-opposed and quadrilateral wells both decrease pressure drop, reducing water influx from bottom aquifer and increasing oil drainage. Benefits of multilateral wells are increased with aquifer strength. An extremely large ratio of aquifer to oil reservoir pore volume would lower its sensitivity due to large water influx in the well. In low anisotropic reservoirs, a minimum effective length of well has to be identified to obtain benefits of quadrilateral wells to decrease lateral interferences which consequently causes pressure drop.

Department:	Mining and Petroleum Engineering	Student's Signature	....
Field of Study:	Petroleum Engineering	Advisor's Signature	....
Academic Year:	2013	Co-Advisor's Signature	....

ACKNOWLEDGEMENTS

I would like to express my gratitude and sincere appreciation to Dr. Falan Srisuriyachai, my thesis advisor and Assistant Professor Dr. Suwat Athichanagorn, my thesis co-advisor for their support, encouragement, guidance and patience through of my Master study. Without their assistance, this work would not have been accomplished. I extend my thanks to Assistant Professor Dr. Jirawat Cheewaroungroaj, and the thesis committee members for their support and recommendations.

I am grateful to all professors and faculty members in Department of Mining and Petroleum Engineering, Chulalongkorn University for offering me the opportunity to acquire knowledge of petroleum engineering as well as their useful insights, suggestions and guidance throughout my studies.

I would like to thank especially Chevron Thailand Exploration and Production, Ltd. for financial support for this study.

I am also grateful to Schlumberger for providing ECLIPSE®100 reservoir simulation software for the department of Mining and Petroleum Engineering which was utilized in this study. I also would like to thank Mr. Wattanon Kullasit for his technical advice on the simulation software.

Finally, I would like to thank all of my petroleum engineering classmates who have helped me during the last two years in Thailand and offered me sincere friendship.

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LIST OF ABBREVIATIONS

°API	American Petroleum Institute gravity
BHP	Bottomhole pressure
cP	Centipoise
ft	Feet
°F	Degree Fahrenheit
GOR	Gas-oil ratio
k_v/k_h	Ratio of vertical to horizontal permeability
k_x/k_y	Ratio of x-direction to y-direction permeability
mD	Millidarcy
PI	Productivity Index
psia	Pound per square inch absolute
PV	Pore volume
PVT	Pressure-Volume-Temperature
STB/D	Stock tank barrel per day
T	Reservoir temperature in Rankin or Fahreneit
WOC	Water-oil contact

NOMENCLATURES

$\frac{\partial P}{\partial L}$	Pressure gradient in flow direction
ϕ	Porosity
ρ	Fluid density, (lbm/ft^3)
μ	Fluid viscosity
μ_o	Oil viscosity
μ_w	Water viscosity
B_g	Formation volume factor of gas
B_o	Formation volume factor of oil
g	Gravitational acceleration, (ft/s^2)
k	Absolute permeability
k_h	Average horizontal permeability
k_v	Average vertical permeability
k_{rg}	Relative permeability to gas
k_{ro}	Relative permeability to oil for Water-Oil system
k_{rw}	Relative permeability to water for Water-Oil system
$m(\overline{P_R})$	Pseudo pressure evaluated at average reservoir pressure, (psi^2/cP)
$m(p_{wf})$	Pseudo pressure evaluated at well flowing, (psi^2/cP),
$m(p_i)$	Pseudo pressure evaluated at initial pressure, (psi^2/cP)
P_e	Pressure at the boundary
$q_{g,sc}$	Gas flow rate, (Mscf/d)
$q_{,o,sc}$	Oil flow rate, (Mscf/d)
r_e	External drainage radius
r_{eH}	Radius of investigation
r_w	Wellbore radius
R_s	Solution gas-oil ratio

S_{or} or S_{orw}	Residual oil saturation to water
S_w	Water saturation
S_{wc} or S_{wcr}	Critical water saturation
S_{wi}	Initial water saturation
S_{wmin}	Minimum water saturation (irreducible water saturation)
v	Velocity, (ft/s)

CHAPTER 1
INTRODUCTION

1.1 Background

Horizontal wells have been successfully implemented around the globe and have demonstrated great advantages compared to vertical wells in terms of productivity and sweeping efficiency. In the last two decades, the development of directional and horizontal drilling has led to the upcoming of multilateral well technology in oil and gas fields. This ability to drill multiple laterals from a single bore has enabled new possibilities of field development.

At the early stage, the use of multilateral well technology was only aimed for multi-target reservoirs to access compartmentalized, layered and dispersed geological structures from a single wellbore, reducing number of wells and, as a consequence, reducing project execution time, infrastructure and operational costs. Since then, multilateral wells have also been developed to improve oil recovery in single target structures, but remained limited to specific conditions such as naturally fractured reservoirs and heavy oil deposits. Indeed, multilateral well technology has become a solution to maximize reservoir contact in low productivity reservoirs at lower cost instead of multiplying the number of wellbore. In high productivity reservoirs, multilateral well technology has also become a mean to minimize wellbore friction which limits the length of a single wellbore. These specific situations have therefore justified the implementation of several multilateral wells to effectively drain single layered reservoirs.

Single layered reservoirs may face different types of heterogeneity. On this particular aspect, permeability anisotropy has a direct impact on the productivity of horizontal and multilateral wells that can be quantified. New field development possibilities are now accessible for reservoir engineers, but feedbacks and forecasts of multilateral wells are still lacking and further studies are necessary to optimize field performance in various types of reservoir.

The implementation of non-conventional wells requires high capital investments and shall be justified by an increase in productivity and ultimately with a higher net present value of the project. Non-conventional wells such as multilateral wells offer great potential for oil production. However, the optimization of such wells is very complex to determine because of the large number of possible scenarios and variables to consider such as the number of laterals, the orientation of the laterals, the completion, the well trajectory and location in the reservoir. Heterogeneity and permeability anisotropy in particular is also responsible for adding uncertainty in the performance prediction. Multiple scenarios shall then be considered to assess the relevance of a multilateral well.

This particular work will highlight the effect of anisotropy on multilateral well performance in bottom water drive reservoirs. In the first step of the study, a homogeneous reservoir model is constructed with the black oil simulator **ECLIPSE®100** commercialized by **GeoQuest Schlumberger**. Multiple well configurations are constructed and their performances are analyzed with varying conditions. Recovery factor and production rates are primarily analyzed for each simulation run and used as major judgment criteria. Besides, other simulation outcomes such as water cut, reservoir pressure, cumulative water and gas are used to accompany the discussion. A sensitivity analysis is performed to study the effect of the aquifer size, anisotropy and oil gravity over the selected base cases from the first section.

1.2 Objectives

This study is performed to investigate and compare effectiveness of single horizontal, dual lateral or quadrilateral wells in an anisotropic reservoir with bottom drive aquifer. Major objectives of the study are:

1. To investigate the effect of the aquifer size on effectiveness of single horizontal well, dual lateral wells and quadrilateral wells together with different operational parameters which are effective length and depth of lateral well.
2. To study the effect and sensitivity of vertical anisotropy representing by ratio between vertical permeability to horizontal permeability (k_v/k_h) and horizontal anisotropy representing by ratio between permeability in x direction to horizontal permeability in y direction (k_x/k_y) on effectiveness of single horizontal well, dual lateral wells and quadrilateral wells in reservoir supported by bottom drive aquifer.

3. To evaluate the sensitivity of interest parameters concerning reservoir and operational parameters which are oil gravity and different location of each laterals for multilateral wells on effectiveness of single horizontal well, dual lateral wells and quadrilateral wells in reservoir supported by bottom drive aquifer.

1.3 Outline of Methodology

The investigation of this thesis is performed by the use of reservoir simulation program. A black oil simulator called ECLIPSE®100 commercialized by GeoQuest Schlumberger is utilized for the entire of this study. The outline of methodology is listed in following step:

1. Construct three isotropic reservoir models possessing different aquifer size which are a) the same size of reservoir pore volume, b) 10 times of reservoir pore volume, and c) 50 times of reservoir pore volume.
2. Construct different well geometries which are a) single horizontal well, b) dual-opposed wells, c) dual-opposed wells with different lateral depths, and d) quadrilateral wells. All well geometries are constructed to have effective lengths of 1,200 ft, 2,000 ft, and 2,800 ft and depth of laterals are located differently at 6,850 ft, 6,900 ft, and 6,950 ft. Total number of cases is 36.
3. Select appropriate flow rate for the study
4. Evaluate performance of each well configuration based on reservoir simulation outcomes and select base cases to represent well geometry for the following step of study.
5. Perform simulations on selected dual lateral wells by changing spacing between the 2 laterals to the values of 20, 40 and 60 ft.
6. Perform simulations on selected well geometry by adding anisotropy into the reservoir model a) varying k_x/k_y to 10, 3, 1, 0.33, and 0.10, and b) k_v/k_h to 0.05, 0.10, 0.20 and 0.50.
7. Perform simulations on selected well geometry by changing oil gravity to the values of 45, 35, and 25 °API.
8. Discuss and analyze new finding from the study.

1.4 Thesis Outline

This thesis is divided into six chapters as shown below:

Chapter I introduces background of multilateral wells and indicates the objectives and methodology of this study.

Chapter II introduces the various literatures related to the study of the effect of anisotropy in multilateral well performance in bottom water drive aquifer.

Chapter III presents the important concepts related to the study.

Chapter IV provides the details of reservoir simulation models in Eclipse.

Chapter V presents the results and discussions from simulation cases for each configuration studied. Results are mainly investigated by comparing oil production with the base cases.

Chapter VI provides the conclusions and recommendations of this study.

1.5 Expected Usefulness

This study focusses on the effect of anisotropy on multilateral well performance in bottom water drive reservoirs. The obtained results should be useful for reservoir engineers to consider the importance of anisotropy in the implementation of a multilateral well with valuable inputs and direct comparison with single wellbore models.

CHAPTER 2
LITERATURE REVIEW

This chapter summarizes previous studies related to reservoir anisotropy and its impact on multilateral well performance as well as the influence of bottom water drive reservoirs. A large number of studies have been published on multilateral wells technology and performance. However, studies have mainly emphasized on technological aspect of multilateral well drilling as well as completion strategies, associated to multilateral well. Fewer studies have been dealing with detailed analysis of successful reservoir for multilateral well.

2.1 Effects of Water Coning in Horizontal Well

Several studies have been performed on water coning (or so called water cresting in horizontal well) along horizontal wells. Karcher and Giger [1] proved in 1986 that the value of critical coning rate for a horizontal well is high and may reach two times the critical coning rate estimated for a vertical well.

Chaperon [2] developed in 1986 the first correlation to determine the critical coning rate of horizontal wells. The author provided a simple estimation of the critical coning rate at steady state condition for both isotropic and anisotropic formations. Joshi [3] went further than Chaperon by deriving an equation to estimate the critical oil rate under steady state or pseudo steady-state conditions for an anisotropic formation.

2.2 Multilateral Well Technology

Bosworth et al. [4] provided guidelines of key issues in multilateral technologies. This study compared the use of multilateral wells and single wellbore wells for different types of formations: stacked layers reservoirs, geological compartment reservoirs and single layer reservoir. Bosworth developed a decision making flow chart to analyze the usefulness of a multilateral well. His conclusions showed that multilateral wells are more productive compared to single bore wells in anisotropic and heterogeneous reservoirs.

2.3 Multilateral Well Performance

The prediction of multilateral well performance takes lateral interference into account. Salas et al. [5] used analytical and numerical modeling techniques derived from Joshi equations for horizontal wells to predict performance of multilateral wells. It was demonstrated that the well productivity was dependent on wellbore geometry and that reservoirs with greater heterogeneity were shown to have greater potential benefits with multilateral side-branches. Multilateral wells also appeared particularly interesting in cases where gas or water coning are involved due to lower friction loss for a same effective length and thus, a lower pressure drop near the mother bore.

In a case study for application of a multilateral well in the AV1(1-2) unit of Samotlor field in Russia, Sunagatullin et al. [6] performed a feasibility study to evaluate the successful parameters to implement a multilateral well and improve economics of the project rather than implementing single wellbores. Criteria included viscosity, permeability, reservoir depth, net oil-pay thickness, remaining reserves, and presence or absence of an aquifer or gas cap. The Samotlor field reservoir is located at 1,500-2,500 m depth, with low permeability (5 to 30 md) and high heterogeneity (thin interbedded shales and sandstones). Fracturing was originally considered but led to an increased volume of water production with an insignificant increase in oil production. Thus, a dual-lateral well with simple completion was studied to increase the sweep efficiency and the reservoir contact. Results were finally compared to a horizontal well. Cumulative oil production ratio of multilateral to horizontal well (*QoMW/QoHW*) was evaluated and analyzed with the multilateral to horizontal well cost ratio (ratio of 1.5 was assumed as the breakeven point). Sunagatullin et al. raised the following key questions: 1) Where to drill multilateral wells? 2) How much greater is multilateral well production than that with other well types for various reservoir parameters? and 3) What well-design-complexity level should be selected? This research is especially interesting for its assessment procedure to compare efficiency between conventional horizontal well and multilateral well. Results gave a precise “window” of opportunities for multilateral well, including key parameters which are reservoir permeability, net pay zone thickness and ratio of multilateral well flow rate over conventional well and angle between dual laterals.

Shadizadeh et al. [7] analyzed and proposed a model of inflow well performance for multilateral wells. In this study, researchers used the concept of well interference as well as Joshi's relations. Results proved that Joshi's equation for horizontal well performance and a concept of well-interference could be used accurately to predict performance of multilateral well performance. The concept of equivalent length has been used to compare directly multilateral to single bore wells.

The relation between reservoir anisotropy and multilateral well performance has been studied by Retnanto et al. [8]. Researchers worked on four well configurations: vertical, horizontal and two multilateral well configurations with four and eight laterals to compare each well performance. Different anisotropy ratios were tested in the horizontal plane. Conclusions showed that multiple laterals in low to moderate permeability reservoirs are able to maintain high production rate compared to monobores. In higher permeability reservoirs, the incremental benefits for multilateral wells are reduced. Too large number of laterals occurred to be counterproductive. Retnanto et al. also showed that formation thickness, number of laterals and anisotropy of reservoir directly affect production rate of multilateral wells and finally confirmed the effectiveness of multilateral in anisotropic reservoirs.

2.4 Multilateral Well Architecture

For unconventional reservoirs, multilateral wells can also provide innovative solutions to optimize production. Sarfare [9] studied new multilateral well architecture for more efficient and effective field drainage. He analyzed the effect of design parameters such as the branch density and penetration extent of laterals on well performance for homogeneous reservoirs. He showed that multilateral wells are efficient to improve production from a homogeneous reservoir when compared to conventional wells. Results of this study also showed that there were an optimum number of laterals to drain hydrocarbon from reservoirs. Beyond certain number, increasing laterals does not produce a significant difference in production. Four laterals are usually sufficient to drain the reservoir efficiently. This study proved also that the productivity index in the case of an isotropic permeability distribution was almost always twice as much as for anisotropic permeability in the reservoir. The lower vertical permeability is the mostly accountable for this decrease.

Jia [10] performed an analysis of how reservoir heterogeneity affects architecture of multilateral well (up to 60 laterals) in comparison with vertical wells. Similarly to previous studies, Jia demonstrated that different multilateral well architectures show better overall productivity index than vertical wells and that anisotropy influences the reservoir productivity. This research also emphasized on the fact that deviated laterals yields better performance compared to horizontal laterals when heterogeneity in the reservoir is increased. It appeared in this study that heterogeneous properties of reservoirs influence productivity of horizontal laterals more than deviated laterals.

In a different study, Retnanto et al. [11] studied optimal configurations of multilateral wells. Six different configurations were chosen in this study: multi-branched wells, forked wells, branches in a horizontal mother hole (fishbone), branches in a single vertical mother hole, dual opposing laterals and stacked laterals. Performance results showed that the length and number of branches could be optimized for a specific reservoir. Retnanto also explained the benefits of using symmetrical multilateral wells in low to medium permeability reservoirs.

CHAPTER 3
THEORY AND CONCEPT

3.1 Characterization of Anisotropic Reservoirs

Formation anisotropy is a result from either depositional processes or tectonic processes. In sediment rock, anisotropy occurs with a presence of grain-scale or layer-scale heterogeneities which have a preferred orientation. This phenomenon is related to depositional process and often corresponds to deltaic deposition. Sedimentary rocks are anisotropic with respect to permeability when the magnitude of permeability at a given sample point changes with the direction of fluid flow through that sample [12]. Permeability anisotropy is one of the most important parameters in predicting production performance. Permeability anisotropy in a plane is usually represented by two directions: the direction of maximum permeability, and the direction that is normal to the direction of maximum permeability. This procedure establishes a natural coordinate system for describing directional permeability.

Anisotropy controls single-phase fluid flow as well as two-phase effective mobility of immiscible phases such as oil-water system. Therefore, anisotropy is of great importance to predict and guide hydrocarbon recovery at the time scale of a few decades, but also to model secondary hydrocarbon migration processes over geologic time. Vertical permeability anisotropy directly affects oil and water production [13]. Indeed, the larger the anisotropy, the higher the productivity index. However, a low vertical permeability may not be economically attractive for horizontal wells.

Horizontal wells have a specific pattern of drainage as represented in Figure 3.1. For horizontal wells, anisotropy in horizontal plane becomes equally important as vertical anisotropy. Horizontal anisotropy is caused by depositional process, tectonic stress or fractures in the formation. A well drilled normal to the larger horizontal permeability will give a much better production than one drilled in an arbitrary direction. The measure of permeability is, therefore, a major issue for reservoir engineers [13]. Horizontal wells optimization requires parallel drilling to the direction of the minimum horizontal permeability.

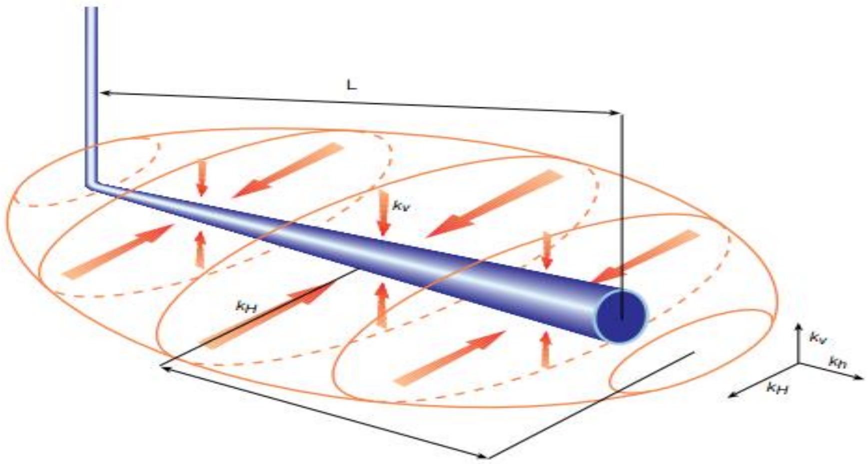


Figure 3.1 Horizontal well drainage pattern, exposing to different directions of permeability [13]

3.2 Effect of Gas and Water Coning

Coning is a term used to describe the upward movement of water and/or the downward movement of gas into a producing well. Under static conditions, water remains below hydrocarbon fluids, and gas higher as per their densities. However, once production starts, reservoirs with a gas cap and/or bottom aquifer are subjected to rapid gas or water movement towards the well as a result of a pressure drop in the direction of the well and Water-Oil Contact (WOC) and Gas-Oil Contact (GOC) are modified and form a cone or a crest in case of horizontal wells. Several parameters directly affect coning phenomenon such as density difference between produced fluids, fluid viscosities, reservoir thickness, anisotropy ratio, and pressure drawdown [14]. Pressure drawdown is supposed to have the most significant impact on coning. Coning indeed occurs when the pressure drawdown near the well is larger than the gravity pressure differential, which tends to keep the oil on top of the water. Water and gas coning may then become a major problem as water or gas tends to enter the well and thus, reduce oil production rate. Coning increases the cost of production and reduces the depletion mechanism efficiency; therefore, it decreases the overall recovery. The height of a water cone in any particular vertical well depends on flow rate and vertical permeability. It has been proven that horizontal wells are more adapted to mitigate coning problems compared to vertical wells since the pressure drawdown into the well is less important. It has been estimated that 40% of all horizontal wells are drilled to arrest coning problems.

Fluid flow and distribution around the wellbore are affected by the combination of viscous, gravity and capillary forces. Water coning typically occurs when viscous force at the wellbore exceeds gravitational forces. The coning tendency can be determined using the gravity number which corresponds to the ratio of gravity forces to viscous forces. If the gravity number is lower than unity, reservoir with that specific production would undergo high tendency of water coning.

Water coning impacts directly the well productivity as early water production will reduce driving pressure and oil production. The critical flow rate is defined as the maximum oil flow rate that can be produced to avoid water production from coning. Many correlations have been developed for this calculation such as Schols correlation for oil-water systems in vertical wells [15]:

$$Q_c = \frac{0.001535\,(\rho_w-\rho_o)\mathrm{k}\,(\mathrm{h}^2-\mathrm{D}^2)}{\mu_o B_o \ln\left(\frac{r_e}{r_w}\right)} \tag{3.1}$$

where *h* is the oil zone thickness (ft); *D* is the completion interval thickness (ft); r_e is the external drainage radius (ft) and r_w is the wellbore radius (ft).

Unlike the vertical wells where the upward movement of the water creates a cone shape, the rising water at horizontal wells forms a crest which is so-called the water crest. The value of the critical coning rate for a horizontal well is high and may reach two times the critical coning rate estimated for a vertical well.

For horizontal wells, several correlations have been developed. Joshi equation may be taken as a reference for calculations:

$$Q_c = \frac{0.246\times10^{-5}(\rho_w-\rho_o)\mathrm{k}_h(\mathrm{h}^2-(\mathrm{h}-l_v)^2)}{\mu_o B_o \ln\left(\frac{r_{eh}}{r_{we}}\right)} \tag{3.2}$$

where *L* is the horizontal well length (ft); r_{eh} the horizontal well drainage radius (ft) and l_v the distance between OWC and the horizontal well (ft).

3.3 Multilateral Wells

In 1949, Grigoryan [4] developed a theory to add branches to a borehole in productive zone in order to increase surface exposure and tested it successfully in

Bashkortostan field (Russia) at shallow depth. However, this technology had not been adopted by oil companies at that period due to economic and technical reasons. The multilateral technology has evolved in a great manner only since mid-1990s. At this time, a group of companies (Amoco, BP, Baker, Chevron, Halliburton, Mobil, Norsk Hydro, Phillips, Saga, Schlumberger, Shell, Smith International, Statoil, TIW, Texaco, Total and Weatherford) with multilateral experiences formed a consortium called Technology Advancement of Multilaterals (TAML) [9] in order to promote the development of multilateral technology within petroleum industry through information exchange. They defined multilateral well as “a well in which there is more than one horizontal or near horizontal lateral well drilled from a single main bore and connected back to that main bore”.

Multilateral well technology is now viewed as an important change in oil and gas industry as it opens new opportunities and gives solutions to face the oil industry challenges which are:

- complex geological conditions such as compartmentalized or stacked reservoirs,
- difficult reservoir conditions such as viscous fluids or tight formations,
- hostile environments such as deep water, and
- efficient reservoir management and development plans with high productivity.

Over last decade, multilateral well technology has been one of the most rapidly evolving production technologies both for new as well as mature reservoirs. It is applied in a wide range of reservoirs from heavy oil to gas condensate reservoirs and from small isolated pockets to giant field development.

3.3.1 Geometry of Multilateral Wells

Multilateral wells are generally referred to non-conventional wells with horizontal or highly deviated wells, whereas vertical or slightly deviated wells refer to conventional wells. Multilateral wells may have different configurations of lateral and even sub-lateral branches. The heel point is determined as the part of lateral near mother-bore, whereas the toe point is referred to the further part of the lateral in the formation. Figure 3.2 illustrates basic multilateral well types based on TAML [16].

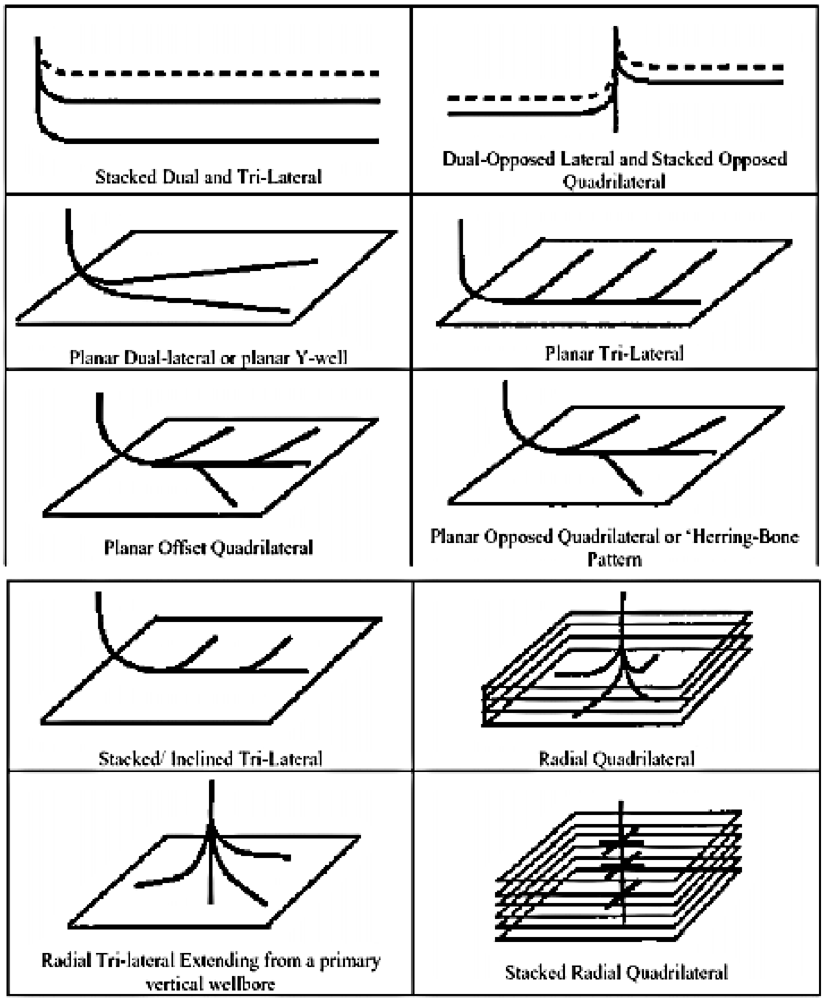


Figure 3.2 Basic multilateral well types [16]

Drilling of multilateral wells has become standard practice during the past decade. Multilateral wells may indeed be more cost effective than multiple vertical wells in terms of drilling and completion costs. Multilateral wells are suited for complex reservoirs and can increase drainage in different situations such as:

- multi target formations, compartmentalized, layered and dispersed geological structures,
- single target structures in low productivity reservoirs to maximize reservoir contact,
- single target formations in high productivity reservoirs to minimize wellbore friction and then to increase potential length of the wellbore.

Moreover, multilateral and non-conventional wells can operate at low drawdown, reducing undesired coning problem in many cases. Compared to conventional wells, multilateral wells may provide better reservoir exposure with fewer wells, hence improving reservoir management. As a consequence, higher implementation costs may be compensated by a better drainage and productivity and ultimately reduce overall project cost (capital expenditures and operating costs) [17]. This ability to reduce number of well drilled from surface may also be a solution for new field developments with limited surface facility installations. Oil producers are therefore reconsidering fields which were previously not profitable.

Nevertheless, multilateral wells also show disadvantages associated with its advanced technology. Indeed, drilling and operation of multilateral wells carry more risks than conventional wells, especially mechanical failures and difficulties to maintain an accurate trajectory. This part remains difficult to evaluate on an economic point of view but plays a major role in the decision process from reservoir management teams.

3.3.2 **Completion Type for Multilateral Wells**

TAML has defined the TAML classification system, which divides multilateral well completion into six levels and one sub-level [16]. The definitions of the TAML levels are based on the type of support and functionality at the junction between a mother-bore and a lateral. TAML classifies multilateral wells as follows:

- Level 1 - Open, unsupported junction,
- Level 2 - Mother bore is cased and cemented; lateral is opened,
- Level 3 - Mother-bore is cased and cemented; lateral is cased but not cemented,
- Level 4 - Both mother-bore and laterals are cased and cemented,
- Level 5 - Both mother-bore and laterals are cased and cemented; junction pressure integrity is achieved with the completion,
- Level 6 - Junction pressure integrity is achieved with casing (cement is not acceptable), and
- Level 6S - Junction pressure integrity is achieved with a downhole splitter.

Recently, multilateral well completion has often been associated with smart completion systems such as Inflow Control Valves (ICV) as it may help to reduce water and gas coning problems. However, all types of completion are available for multilateral wells including: openhole completion (only in specific cases), slotted liner completion (to prevent collapse of the hole), liner with partial isolations, and cemented and perforated liners.

3.3.3 **Performance Prediction of Multilateral Wells**

The well inflow potential depends on several factors in the well design and in the reservoir such as the length of laterals, number of laterals, reservoir heterogeneity, lateral separation, lateral build-up angles, wellbore damage, and hole and tubing diameter. Performance prediction calculations depend on reservoir behavior which is commonly divided in three states steady state, pseudo steady state, and transient or unsteady state.

A steady state behavior is reached when the flow rate, the upstream and the downstream pressures no longer change with time in a system that has reached equilibrium for the measurement or phenomenon concerned. This behavior occurs when there is pressure support, either naturally through an aquifer or gas-cap drive, or artificially through water or gas injection.

Pseudo steady state is observed when a well reaches stabilized production from a limited drainage volume. For constant-rate production, under pseudo steady state, the difference between flowing wellbore pressure and average reservoir pressure in the drainage volume is constant, and pressure drawdown is a linear function of time, resulting in a unit slope in the log-log pressure derivative. The late-time buildup pressure will level off to the average reservoir pressure if the buildup duration is sufficient long, resulting in a sudden drop in the log-log pressure derivative. Pressure depletion occurs with continued pseudo steady state production.

Unsteady state behavior is a system that is in a transient state, i.e, a flow where the velocity and pressure changes over time.

For performance calculations, a multilateral well may be considered as an extension of a horizontal well [18]. However, it has been proven that wells located in the same area of drainage, interfere with each other. Well interference is defined as a change in pressure at one well caused by production from one or more other wells. Hence laterals from a multilateral well will also interfere with each other, especially in higher permeability formations. Indeed, the lower the permeability, the later the interference will be shown. This interference reduces multilateral well productivity. Interference may also take place downstream inside the tubing as several horizontal wells join together in the mother-bore tubing. Therefore, multilateral well performance shall be considered as a resultant of equivalent horizontal well performances affected by reservoir and tubing interferences. The concept of "equivalent producing length" has been developed to compare multilateral wells with horizontal wells.

Compared to a vertical well, the inflow performance of a long, highly deviated or horizontal well is generally more sensitive to pressure profile in the wellbore, being a function of friction, pressure loss and gas slippage effects. These effects are difficult to model realistically in conventional reservoir simulators due to the lack of accurate well trajectory and inadequate wellbore flow modeling. The reservoir deliverability depends on several factors such as reservoir geometry, pressure, pay zone thickness and permeability, reservoir boundary type and distance, wellbore radius, reservoir fluid properties, near-wellbore condition, and reservoir relative permeability.

<u>Flow Calculations – Single phase oil reservoir</u>

- *Vertical wells - Steady state flow (constant pressure circular boundary)*

The following equation describes the oil flow rate at standard conditions.

$$q_o, sc = \frac{kh(p_e - p_{wf})}{141.2\mu_o B_o\left(\ln\left(\frac{r_e}{r_w}\right) + S\right)} \tag{3.3}$$

where P_e is the pressure at the boundary.

Water coning effect in a vertical well for steady state flow is represented in Figure 3.3.

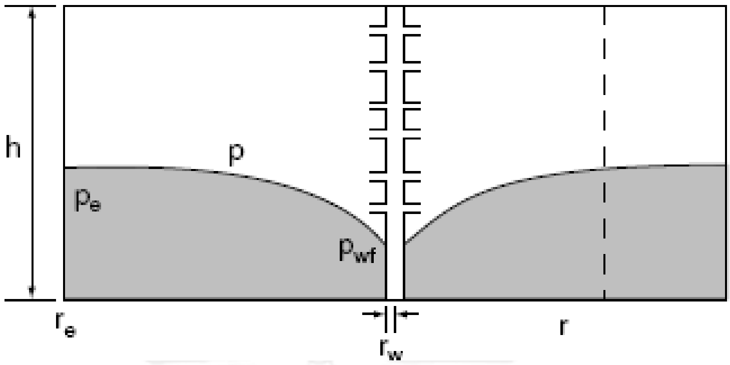


Figure 3.3 Water coning with steady state flow

- *Vertical wells - Pseudo steady state flow (closed circular boundary)*

The oil flow rate calculation is different in pseudo steady state flow as it is displayed below.

$$q_{o,sc} = \frac{kh(\bar{p}_R - p_{wf})}{141.2\mu_o B_o\left(\ln\left(\frac{r_e}{r_w}\right) - \left(\frac{3}{4}\right) + S\right)} \tag{3.4}$$

where $\overline{P_R}$is the average reservoir pressure.

Figure 3.4 shows the different steps of water coning with pseudo steady state flow.

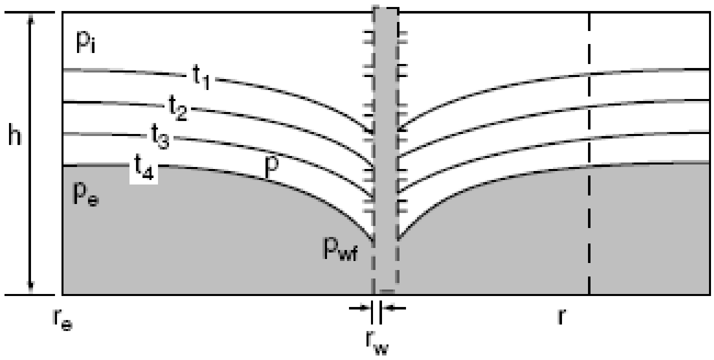


Figure 3.4 Water coning with pseudo steady state flow

- *Horizontal Wells* - Steady state flow in the horizontal plane and pseudo steady state in the vertical plane [3]

$$q_{o,sc} = \frac{k_H h(p_e - p_{wf})}{141.2\mu_o B_o\left(\ln\left(\frac{a+\sqrt{a-(\frac{L}{2})^2}}{L/2}\right)+\left(\frac{I_{ani}h}{L}\right)\ln\left(\frac{I_{ani}h}{r_w(I_{ani}+1)}\right)+S\right)} \qquad (3.5)$$

where:

$$a = L/2\sqrt{\frac{1}{2}++\sqrt{\left(\frac{1}{4}+\left(\frac{r_{eH}}{L/2}\right)^4\right)}}\,, \quad I_{ani} = \sqrt{\frac{k_H}{k_V}}\,,$$

k_H is the average horizontal permeability, (md), k_v is vertical permeability, (md), r_{eH} is radius of investigation, (ft), and L is the length of horizontal wellbore ($L/2 < 0.9\ r_{eH}$), (ft).

However, this calculation model only applies for fully penetrating horizontal wells. The wellbore length is then set equally to drainage length, whereas horizontal wells are rarely drilled fully penetrating. Hence, the reservoir beyond the wellbore length is assumed to be non-producing, which results in underestimating well performance of partial penetrating wells.

<u>Flow calculation – Single phase gas reservoir</u>

- *Vertical well - Transient flow*

$$q_{g,sc} = \frac{kh(m(p_i)-m(p_{wf}))}{1.638T\left(logt+log\left(\frac{k}{\emptyset\mu c_t r_w^2}\right)+0.8686S-3.2274\right)} \qquad (3.6)$$

where $q_{g,sc}$is gas flow rate, (Mscf/d), $m(p_{wf})$ is pseudo pressure evaluated at well flowing, (psi^2/cP), $m(p_i)$ is pseudo pressure evaluated at initial pressure (psi^2/cP) and T is reservoir temperature, (Rankin).

- *Vertical well* - Steady state flow (circular boundary)

$$q_{g,sc} = \frac{kh(m(p_e)-m(p_{wf}))}{1,424T\left(\ln\left(\frac{r_e}{r_w}\right)+S\right)} \qquad (3.7)$$

where $m(p_e)$ is pseudo pressure at the circular boundary, (psi^2/cP).

- *Vertical well* - Pseudo steady state flow (circular boundary)

$$q_{g,sc} = \frac{kh(m(\bar{p}_R) - m(p_{wf}))}{1{,}424T\left(\ln\left(\frac{r_e}{r_w}\right) - \left(\frac{3}{4}\right) + S\right)} \tag{3.8}$$

where $m(\overline{P_R})$ is pseudo pressure evaluated at average reservoir pressure, (psi^2/cP).

Productivity Index – Single Phase Oil Reservoir

The Productivity Index (*PI*) is a data that is very important to evaluate multilateral wells productivity and also used to compare multilateral with conventional wells. It expresses ability of a reservoir to deliver fluids to the wellbore. PI is usually stated as volume delivered per psi of drawdown at the sand face (bbl/d/psi). The productivity index is denoted by *J* and for each flow behavior possesses different calculation of *J* as followed:

- Transient flow

$$J_o^* = \frac{q}{P_i - P_{wf}} \tag{3.9}$$

- Steady state flow

$$J_o^* = \frac{q}{P_e - P_{wf}} \tag{3.10}$$

- Pseudo steady state flow

$$J_o^* = \frac{q}{\bar{P}_R - P_{wf}} \tag{3.11}$$

where * refers to the condition above the bubble point (single-phase oil).

Multiphase reservoirs- Vogel Equation for under-saturated reservoirs

For pressure above the bubble point

$$q = J^*\left(\bar{p}_R - p_{wf}\right) \tag{3.12}$$

At the bubble point

$$q_b = J^*(\bar{p}_R - p_b) \tag{3.13}$$

For pressure below the bubble point

$$q = J^*(\bar{p}_R - p_b) + \frac{J^* p_b}{1.8}\left[1 - 0.2\left(\frac{p_{wf}}{p_b}\right) - 0.8\left(\frac{p_{wf}}{p_b}\right)^2\right] \tag{3.14}$$

<u>**Flow Calculation for Multilateral wells**</u>

A method has been developed by Shadizadeh et al. [7] from Joshi equation to estimate the performance of a multilateral well drilled in an isotropic reservoir with constant pressure at the drainage boundary. The concept of equivalent length is utilized. It is defined as the length of a horizontal well that has the same performance of that of multilateral wells.

The productivity index of a two-branch multilateral well may be obtained from the following expression:

$$PI = \left(2\left(\frac{2\pi k_o h}{\mu_o B_o}\right)\right)/\left(\ln\left(\left(a + \frac{\sqrt{a^2 - \left(2Lsin\left(\frac{\alpha}{2}\right)\right)^2}}{2Lsin\left(\frac{\alpha}{2}\right)}\right)\left(a + \frac{\sqrt{a^2 - \left(\frac{L}{2}\right)^2}}{\frac{L}{2}}\right)\right)\right) \tag{3.15}$$

where *r* is well half-length (L/2), (ft) and *a* is half major axis of a drainage ellipse in a horizontal plane.

For multiple branches wells it can be subdivided into two cases which are cases where number of braches is even and where number is odd. For an even number of branches (n = 2, 4, 6, 8), PI is evaluated from the following equation:

$$PI = \frac{n\left(\frac{2\pi k_o h}{\mu_o B_o}\right)}{\ln\left(\left(a + \sqrt{a^2 - \left(\frac{L}{2}\right)^2}\right)\left(a + \sqrt{a^2 - (2L)^2}\right)\frac{\prod_{i=2}^{n=2}\left(a + \sqrt{a^2 - \left(2Lsin\left(\frac{180i}{2n}\right)\right)^2}\right)^2}{4^{n-1}\left(\frac{L}{2}\right)^n \prod_{i=2}^{n=2}\left(\sqrt{\sin\left(\frac{180i}{2n}\right)}\right)^2}\right)} \tag{3.16}$$

For an odd number of branches (n = 3, 5, 7, 9):

$$PI = \frac{n\left(\frac{2\pi k_o h}{\mu_o B_o}\right)}{\ln\left(\left(a + \sqrt{a^2 - \left(\frac{L}{2}\right)^2}\right)\frac{\prod_{i=3}^{n}\left(a + \sqrt{a^2 - \left(2Lsin\left((180/n)*int\left(\frac{i}{2}\right)\right)\right)^2}\right)^2}{4^{n-1}\left(\frac{L}{2}\right)^n \prod_{i=3}^{n}\left(\sqrt{sin\left((180/n)*int\left(\frac{i}{2}\right)\right)}\right)^2}\right)} \tag{3.16}$$

where “int” refers to integer part of the parentheses.

Nevertheless, productivity of multilateral wells can only rarely be calculated as the sum of productivity of individual branches. Indeed, adding branches to a multilateral well may not be interesting. The benefits of additional productivity gains can be offset by losses in lift performance and branches interference. To assess those effects, a proper nodal analysis must be performed for both inflow and outflow performance of the well.

Outflow Performance

Another major factor that determines performance of multilateral wells is wellbore hydraulics. Indeed, wellbore friction has an important impact on the outflow of well and shall be considered when evaluating multilateral well performances. The pressure gradient can then be expressed as:

$$\frac{dp}{dL} = (\frac{dp}{dL})_{elevation} + (\frac{dp}{dL})_{acceleration} + (\frac{dp}{dL})_{friction} \quad (3.17)$$

$$\left(\frac{dp}{dL}\right)_{elevation} = \left(-\frac{1}{144}\right)\left(\frac{\rho g}{g_c} sin\theta\right) \quad (3.18)$$

$$\left(\frac{dp}{dL}\right)_{acceleration} = \left(-\frac{1}{144}\right)\left(\rho \frac{v}{g_c}\frac{dv}{dL}\right) \quad (3.19)$$

$$\left(\frac{dp}{dL}\right)_{friction} = \left(-\frac{1}{144}\right)\left(\frac{f\rho v^2}{2g_c d}\right) \quad (3.20)$$

where p is pressure, (psi), v is velocity, (ft/s), L is length of pipe, (ft), d is pipe diameter, (ft), g is gravitational acceleration, (ft/s^2), g_c is conversion constant, (32.174 lb$_m$-ft / lbf s^2), ρ is fluid density, (lbm/ft^3), f is Moody or Darcy-Wiesbach friction factor, and θ is angle of the pipe with horizontal axis

Vertical and horizontal flow correlations may be calculated using Beggs and Brill correlations.

CHAPTER 4
RESERVOIR SIMULATION MODEL

The investigation of this study is based on reservoir simulation using the black oil simulator ECLIPSE®100 commercialized by GeoQuest Schlumberger. Three isotropic reservoir models with varying aquifer size are being constructed in order to perform the simulation tests. Details of reservoir model are described in this section, comprising reservoir geometry, fluid properties, petrophysical properties, well geometry and production schedule. Details of methodology are also extended from introduction section in this chapter.

4.1 Reservoir Structure

Three reservoir models are constructed as a parallelepiped with respectively 35, 35, and 20 blocks in X, Y and Z directions. It is thus corresponded to a total number of 24,500 grid blocks with each grid block measuring 100×100×10 feet respectively in X, Y and Z directions. This corresponds to a top view area of 281.2 acres and volume of 2.45 billion cubic feet. Reservoir models are constructed based on grid block centered points and Cartesian coordinates. Table 4.1 summarizes physical reservoir model in terms of size and location.

Table 4.1 Summary of reservoir geometry

Parameters	Values	Unit
Number of grid blocks (X,Y,Z directions)	35 × 35 × 20	Grid blocks
Grid block size (X,Y,Z directions)	100 × 100 × 10	ft
Top view area	3,500 × 3,500	ft^2
Reservoir thickness	200	ft
Top depth of reservoir	6,800	ft

4.2 Description of Aquifer

As reservoir is supported by a bottom aquifer, description of bottom aquifer is explained in this section. In this study, three different aquifer sizes are constructed and applied to all reservoir models. Size of aquifer is described by time of pore volume and in this study aquifer sizes are 1 time, 10 times, and 50 times of oil-bearing zone pore volume. Once location of reservoir models are fixed by top depth and oil bearing zone is not varied, changing in aquifer size results in different total thickness of reservoir including bottom aquifer. Total thicknesses are therefore 200, 2,000 and 10,000 ft for aquifer size of 1 time, 10 times and 50 times, respectively. Table 4.2 summarizes size of each reservoir model.

Table 4.2 Summary of reservoir model including bottom aquifer

Parameters	Aquifer size (PV of reservoir)	Thickness (ft)
Model 1	1	200
Model 2	10	2,000
Model 3	50	10,000

4.3 Initial Reservoir Conditions

Initial conditions of reservoir are being calculated using equilibrium method. Initial saturations of each phase and pressure gradients are determined based on contact depth and bubble point pressure gradient in the reservoir. Table 4.3 summarizes initial reservoir conditions including datum depth, pressure at datum, oil-water contact, fluid saturations, temperature and bubble point pressure.

Table 4.3 Summary of initial reservoir conditions

Parameters	Values	Unit
Datum depth	6,800	ft
Initial pressure at datum depth	3,000	psia
Oil-water contact	7,000	ft
Initial water saturation	0.3	fraction
Initial oil saturation	0.7	fraction
Reservoir temperature	200	°F
Bubble point pressure	2,500	psi

4.4 Rock and Petrophysical Properties

Rock properties describe absolute physical properties of rock itself whereas petrophyscial properties are related to interaction of rock and fluid enclosed. Porosity and absolute permeability represent rock properties that indicate capacity of storage and transmission of fluid respectively. Relative permeability and capillary pressure are both petrophysical properties are instead important properties, controlling flow ability and fluid distribution.

4.4.1 Porosity and Permeability

In this study, reservoir is composed of consolidated sandstone and is set as homogeneous, i.e., porosity and absolute permeability are constant throughout reservoir model. However, absolute permeability can also be divided into horizontal and vertical permeability due to anisotropy caused by deposition of sand grains and lithification process.

Table **4.4** summarizes rock properties of reservoir model.

Table 4.4 Summary of reservoir rock properties

Rock properties	Values	Unit
Porosity	0.15	fraction
Horizontal permeability	50	mD
Vertical permeability	5	mD

4.4.2 **Relative Permeability and Capillary Pressure**

As reservoir model is set as sandstone, relative permeability is based on typical values of water-wet rock which is rock condition normally found in sandstone reservoir. In this study, capillary pressure is negligible. This leads to an explanation of reduction of flow ability due to presence of immiscible phase. Table 4.5 summarizes values of relative permeability to oil and to water and capillary pressure at different water saturation.

Table 4.5 Summary of relative permeabilities to oil and water and capillary pressure at different water saturation

S_w	k_{rw}	k_{ro}	P_c (psia)
0.3000	0.0000	0.4500	0.0000
0.3440	0.0019	0.3556	0.0000
0.3889	0.0074	0.2722	0.0000
0.4333	0.0167	0.2000	0.0000
0.4778	0.0296	0.1389	0.0000
0.5222	0.0463	0.0889	0.0000
0.5667	0.0667	0.0500	0.0000
0.6111	0.0907	0.0222	0.0000
0.6556	0.1185	0.0056	0.0000
0.7000	0.1500	0.0000	0.0000
1.0000	1.0000	0.0000	0.0000

Relative permeability values of oil and water are consecutively plotted and illustrated in Figure 4.1 as a function of water saturation.

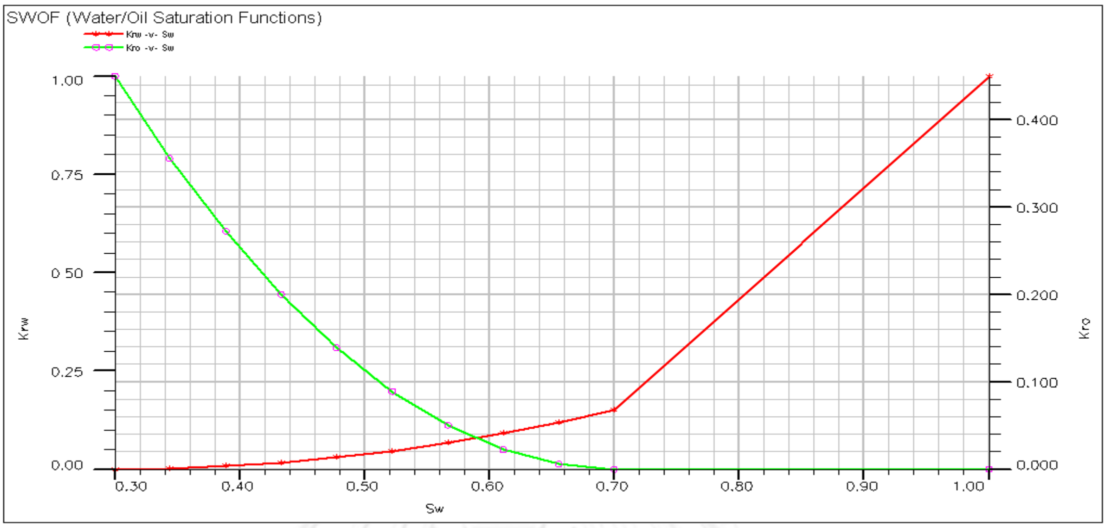


Figure 4.1 Relative permeabilities to oil and water as a function of water saturation

For gas phase, flow ability of gas is summarized and plotted as a function of gas saturation in Table 4.6 and Figure 4.2.

Table 4.6 Summary of relative permeability to gas and oil saturation functions

S_g	k_{rg}	k_{ro}
0.0000	0.0000	0.4500
0.0500	0.0000	0.3719
0.1125	0.0086	0.2847
0.1750	0.0344	0.2092
0.2375	0.0773	0.1453
0.3000	0.1375	0.0930
0.3625	0.2148	0.0523
0.4250	0.3094	0.0232
0.4875	0.4211	0.0058
0.5500	0.5500	0.0000
0.7000	1.0000	0.0000

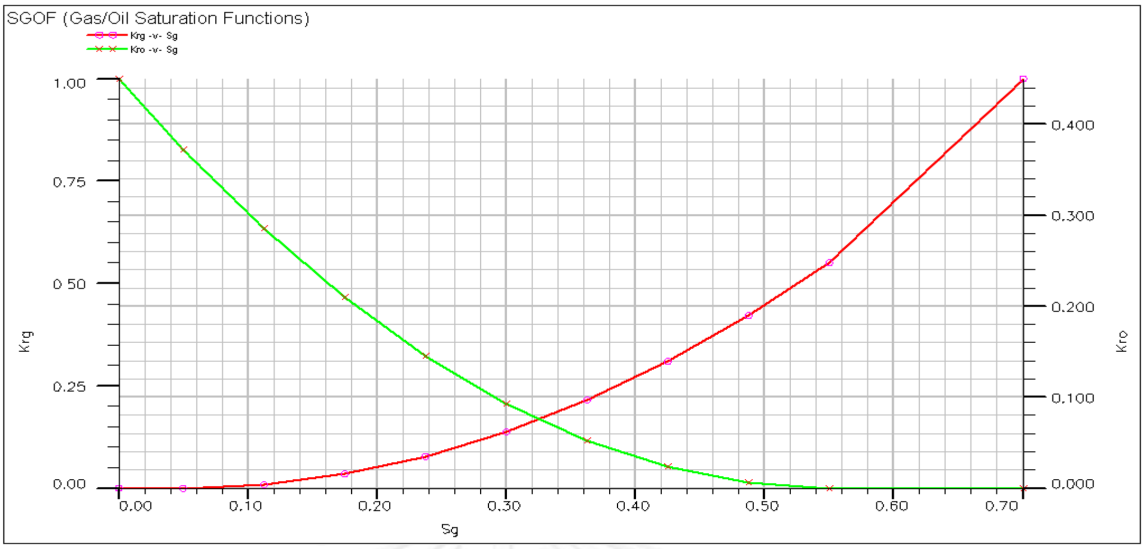


Figure 4.2 Relative permeabilities to gas and oil as a function of gas saturation

4.5 Fluid Properties

Fluid properties describe phase behavior of reservoir fluids at different pressures. The Pressure-Volume-Temperature (PVT) properties of reservoir fluids are calculated by built in program in Eclipse software using several correlations.

Density and gravity of fluids at surface conditions are shown in Table 4.7. Light oil is used to represent hydrocarbon in base case.

Table 4.7 Summary of density and gravity of fluids at surface conditions

Parameter	Values	Unit
Oil density	49.99914	lb/ft^3
Gas density	0.043699	lb/ft^3
Water density	62.42797	lb/ft^3
Oil gravity	45	°API
Gas specific gravity	0.7	fraction

4.5.1 Water PVT Properties

PVT properties of formation water are calculated by the following correlations summarized in Table 4.8. Base on initial reservoir conditions initial water properties are calculated by these correlations and values are summarized in Table 4.9.

Table 4.8 Correlations used for PVT properties of water

Parameter	Correlation
Water viscosity	Meehan
Water formation volume factor	Meehan
Water compressibility	Meehan

Table 4.9 Summary of initial water properties

Input parameter	Values	Unit
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	3.374063×10^{-6}	psi^{-1}

4.5.2 Oil PVT Properties

PVT properties of reservoir oil are calculated by the following correlations summarized in Table 4.10. PVT properties of reservoir oil including solution gas ratio (R_s), viscosity (μ_o), and oil formation volume factor (B_o) are calculated by these correlations and illustrated in Figure 4.3 as a function of bubble point pressure.

Table 4.10 Correlations used for PVT properties of oil

Parameter	Correlation
Solution gas ratio	Standing
Bubble point pressure	Standing
Viscosity	Beggs
Oil formation Volume Factor	Standing
Oil compressibility ($P>P_b$)	Vaquez
Oil compressibility ($P\leq P_b$)	McCain

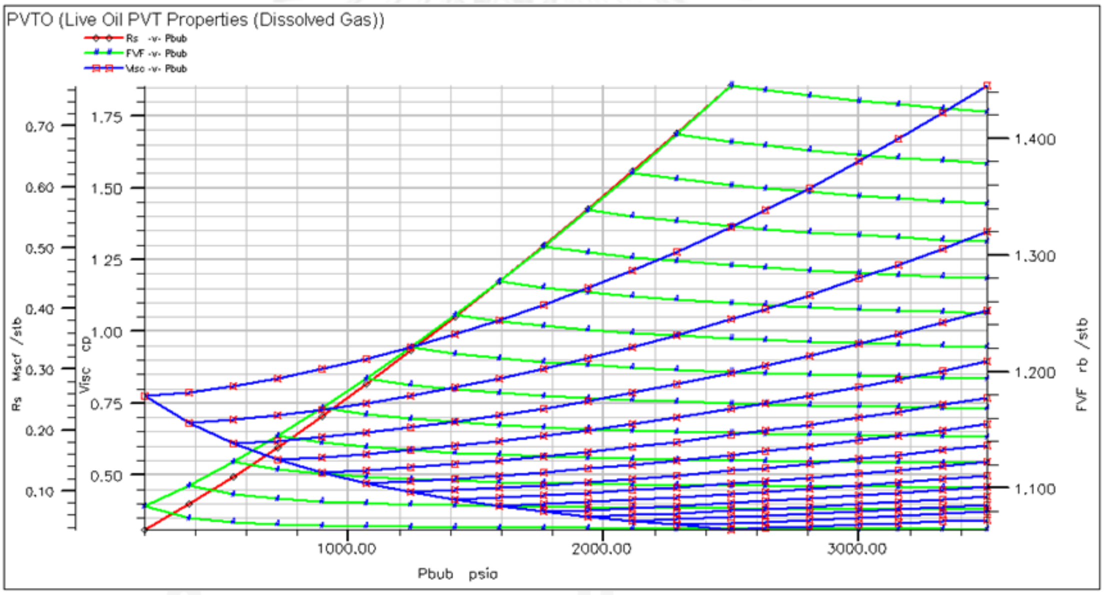


Figure 4.3 Live oil PVT properties (with dissolved gas) as a function of bubble point pressure

4.5.3 **Gas PVT Properties**

PVT properties of reservoir gas are calculated by the following correlations summarized in Table 4.11. PVT properties of gas including dry gas viscosity (μ_g) and gas formation volume factor (B_g) are calculated by these correlations and illustrated in Figure 4.4 as a function of bubble point pressure.

Table 4.11 Correlations used for PVT properties of oil

Parameter	Correlation
Gas compressibility factor (Z)	Hall and Yarborough
Gas viscosity	Lee
Gas formation Volume Factor	Ideal Gas
Critical properties	Thomas et alia

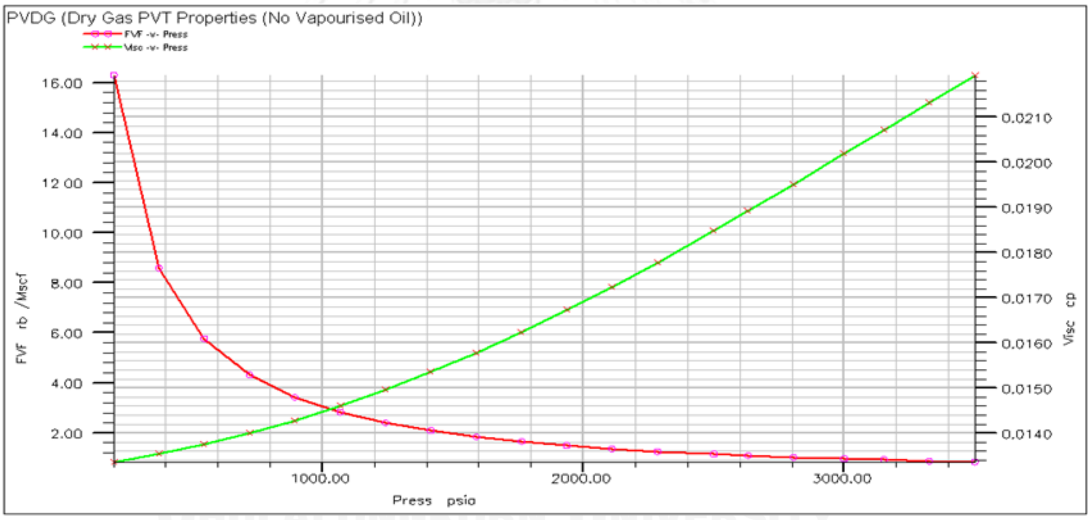


Figure 4.4 Dry gas PVT properties (without vaporized oil) as a function of reservoir pressure

4.6 Well schedule

4.6.1 Total Production Period

Simulation is performed within a maximum period of 30 years which corresponds to the average time of concessions allocated to oil companies. One month time-step is chosen to analyze the results.

4.6.2 Well Specifications

For each reservoir model (small, medium and large aquifers as labeled as model 1, 2, and 3, respectively), different well geometries are being implemented. Producing length, depth of the laterals and types of wells are varied for each reservoir model and each combination is simulated. Total length of 250 ft adjacent to a vertical mother bore is not considered as producing part as it is accounted for radius of curvature for drilling. Table 4.12 summarizes values of chosen producing length and depth of laterals and type of well geometries in this study. Figure 4.5 illustrates top and side views of horizontal well and multilateral wells.

In total 108 cases are tested for three reservoir models with small, medium and large aquifers in order to determine the base cases.

Table 4.12 Summary of chosen producing length and depth of laterals and type of geometries in this study

Parameter	Values/Types		
Producing Length	1,200 ft	2,000 ft	2,800 ft
Depth of laterals	6,850 ft	6,900 ft	6,950 ft
Well geometry	horizontal	Dual laterals -opposite at the same depth -opposite set at different depths	quadrilaterals

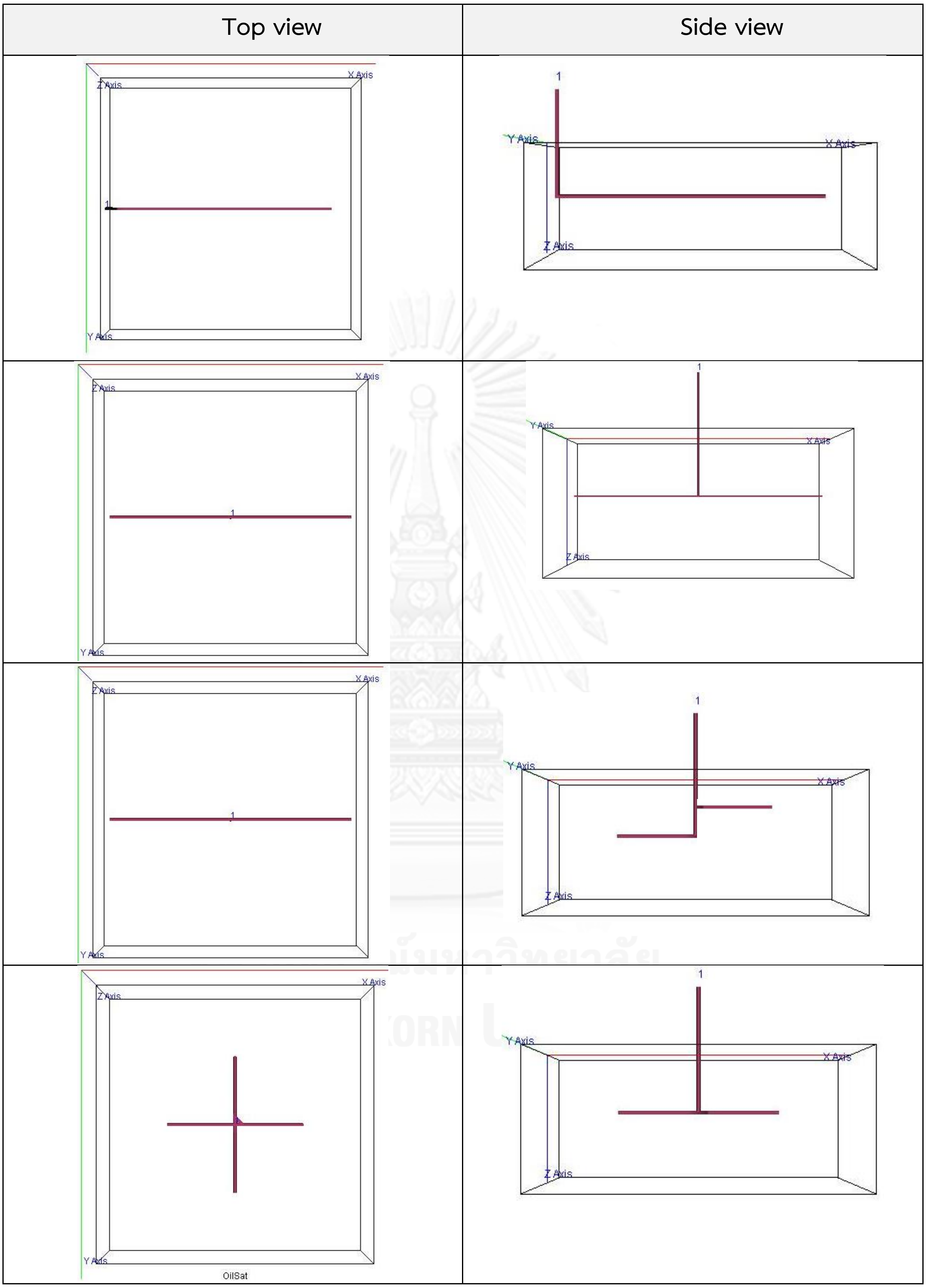


Figure 4.5 Top and side views of each well geometry chosen in this study

4.6.3 **Well Control and Economic Limits**

All wells are completed openhole with a 0.552 ft tubing size diameter which corresponds to industry standards. Base on the chosen tubing size diameter, optimum production rate is required. This part of study is explained in methodology section and optimum production rate is chosen based on reservoir simulation result. Bottomhole pressure (BHP) is fixed at 200 psi which is suction pressure of downhole pump installed to lift fluid up to surface.

Production constraints will cause termination of production if one of these three following conditions: 1) oil production rate declines below 100 STB/D; 2) Water cut reaches as high as 95% and 3) Total production period is terminated at 30 years. Table 4.13 summarizes well control and production constraints used in all horizontal/multilateral wells.

Table 4.13 Summary of well control and production constrains

Well control and production constraints	Value
Bottomhole pressure	200 psi
Minimum oil rate	100 STB/D
Maximum water cut	95 %
Duration	30 years

4.7 Methodology

Methodology of this study is detailed in the following section.

4.7.1 **Construction of Reservoir Models**

Three reservoirs are being constructed in the black oil simulator ECLIPSE®100. Size, shape and properties are previously described in section 4.1. Three reservoirs are similar in all terms except for bottom water aquifer size. Reservoir model 1 is supported by an aquifer with an equivalent size to oil-bearing reservoir. Reservoir model 2 and 3 are supported by an aquifers equivalent to 10 and 50 times, respectively. Increasing of aquifer size results in thicker bottommost part of the aquifers. Size in time of aquifer refers to comparative size in pore volume of aquifer zone compared to oil-bearing zone.

4.7.2 **Construction of Different Well Geometries**

For this study, different well geometries are performed in the three constructed reservoir models explained in previous section. Effective producing length, Depth of laterals and type of well geometries are combined to 36 different cases for each reservoir model that is totally 108 cases. Chosen values for each study parameter are:

- Effective length: 1,200 ft, 2,000 ft, and 2,800 ft

- Depth of lateral well: 6,850 ft, 6,900ft, and 6,950 ft

- Well geometry: single horizontal well, dual-opposed wells, dual-opposed wells with different lateral depths (20 ft above and 20 ft below a major well) and quadrilateral wells. Combination of every study parameters in terms of operation and reservoir are summarized in Table 4.14.

Table 4.14 Summary of reservoir simulation cases

Effective length (ft)	Aquifer size (Reservoir pore volume)	Depth of laterals (ft)	Types of wells
1,200	1	6,850	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,900	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,950	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
	10	6,850	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,900	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,950	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
	50	6,850	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,900	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,950	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals

Table 4.14 Summary of reservoir simulation cases (continued)

Effective length (ft)	Aquifer size (reservoir pore volume)	Depth of laterals (ft)	Types of wells
2,000	1	6,850	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,900	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,950	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
	10	6,850	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,900	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,950	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
	50	6,850	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,900	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,950	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals

Table 4.14 Summary of reservoir simulation cases (continued)

Effective length (ft)	Aquifer size (reservoir pore volume)	Depth of laterals (ft)	Types of wells
2,800	1	6,850	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,900	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,950	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
	10	6,850	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,900	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,950	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
	50	6,850	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,900	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals
		6,950	Horizontal
			Opposite dual laterals
			Dual laterals
			Quadrilaterals

4.7.3 **Flow Rate Selection for the Study**

A first simulation is performed on conditions which are expected to be appropriate for all well geometries and reservoir models studied. Reservoir model 2 exploited by dual-opposed multilateral well with 2,000 ft effective length at 6,900 ft is chosen to represent this part of study. Flow rate is varied from 1,000 to 8,000 STB/D while bottomhole pressure is kept constant at 200 psi. Performance of well at different flow rates is compared in terms of oil recovery, plateau production period and total production period in order to choose the optimum flow rate. The selected flow rate will be used for the entire study.

4.7.4 **Evaluation of Performance of Well Geometries in Reservoir Models**

Simulations are performed with different well geometries in different reservoir models as mentioned earlier. Well control and economic limits are fixed as per the previous section. Performances of each configuration are then compared in terms of production period, recovery factor, oil, water and gas production rates. The base cases are chosen for each producing length and reservoir model.

4.7.5 **Sensitivity Analysis to Investigate Effects of Anisotropy**

Prior to this section, reservoir model is isotropic in horizontal plane (ratio of permeability in x to y direction is equal to 1.0) and anisotropic vertically (ratio of permeability in v to h direction is equal to 0.1). Variation of anisotropy in both horizontal plane and vertical direction is added in this study. Once the base cases are chosen, values of permeability are varied in order to adjust both anisotropy ratios: vertical to horizontal permeabilities and horizontal plane permeabilities. The following values are being varied in the chosen models with each of the base cases in order to evaluate the sensitivity of multilaterals well to anisotropy.

- Variation of horizontal anisotropy ratio (k_x/k_y) = 10, 3, 0.33, 0.01
- Variation of vertical anisotropy ratio (k_v/k_h): 0.05, 0.2, 0.5

However, for the case of variation of horizontal anisotropy ratio, summation of vector permeability in x direction and y direction is kept constant to allow all cases comparable.

4.7.6 **Sensitivity Analysis to Investigate Effect of Oil Gravity**

Oil gravity is being varied for each base case to evaluate its effects on well performance. In previous section, oil gravity is fixed at 45°API and in this section oil gravity is varied to 25 and 35 °API. PVT properties of oil are also adjusted to concordantly match with these oil gravities.

4.7.7 **Sensitivity Analysis to Investigate Effect of Vertical Spacing between Laterals**

The spacing between laterals is being varied on dual-opposed wells to evaluate its effect on well performance. The spacing between laterals will be compared with the following values 20, 40 and 60 ft. Both laterals will be adjusted 10, 20 and 30 feet above the setting depth (6,900 ft) for the first lateral and below for the second one

4.7.8 **Analysis of Results and Conclusion**

Results from both base case selection and sensitivity analysis are discussed to identify proper well geometry to be implemented in a bottom water drive reservoir with several uncertainties of anisotropy and oil property. Impact of anisotropy but also oil gravity and lateral spacing are discussed to assess the potential favorable well geometry for specific conditions.

CHAPTER 5
SIMULATION RESULTS AND DISCUSSION

Results obtained from reservoir simulation explained in chapter 4 are discussed in this chapter. First, production rate is investigated for all runs. Base cases are then identified for each well length and aquifer size and used as references to perform sensitivity analysis of uncontrollable reservoir parameters. All simulations are performed within 30 years of maximum production period as it is common concession in Thailand.

Simulations are performed to evaluate performance of well geometry described in previous section. Results are compared in terms of total production period, recovery factor, oil, water and gas production. All graphs use the same description for each well geometry with the depth of horizontal section of the well followed by number of laterals. For example, D6850ft-2L refers to a well drilled laterally at 6,850 ft with two laterals. 1L refers to single horizontal well and 2L-2/D refers to a dual lateral well with the laterals located at two different depths (20 ft above and 20 ft below given depth. For example, D6900ft-2L-2/D refers to a dual lateral well with a lateral located at 6,880 ft and another one at 6,920ft.

5.1 Optimization of Production Rate

Different production rates are studied in order to define an appropriate production rate for all simulations, using total production period, oil recovery, water and gas production to assist a judgment. In this section, simulations are just performed on a well geometry which should give an appropriate performance among all simulations. Therefore, reservoir model no.2 with a medium aquifer size, equivalent to ten times of pore volume in oil bearing, is chosen to implement with a dual-opposed well of 2,000 ft producing length located at 6,900 ft in the middle of the reservoir. Simulations are performed at maximum liquid flow rates targeted between 1,000 and 8,000 STB/D. Results shown in Figures 5.1, 5.2, 5.3, and 5.4 are discussed to define an appropriate liquid flow rate for the rest of the study.

After 30 years, oil recovery of all production rates reaches in a range between 25-28% as shown in Figure 5.1. Lower liquid production rates yield higher recovery but this spends much time, whereas higher flow rates yield lower recovery in a short period. Total production period for all cases varies in a range between 14-30 years.

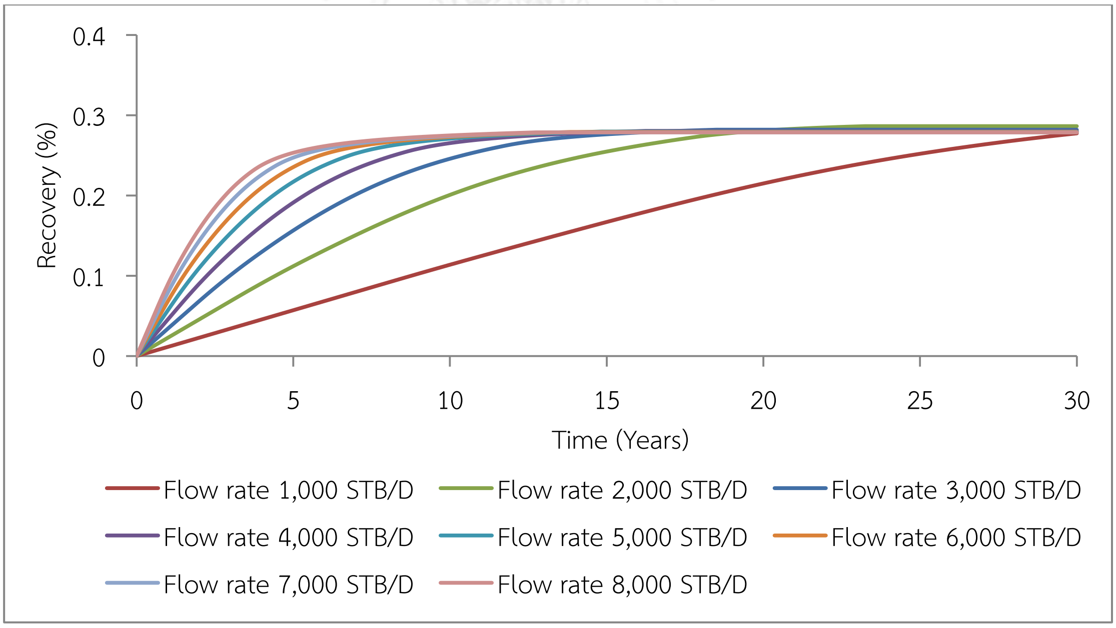


Figure 5.1 Oil Recovery factors of different maximum liquid rates a function of production period

Adjustment of the liquid flow rate aims at maximizing oil production and obtaining a regular production throughout the years. Liquid production flow rates are illustrated in Figure 5.2. Too short or too long plateau rate have to be avoided in order to cope with different simulations and sensitivity analysis. Both scenarios provide advantage and disadvantage: fast but lower recovery due to a high depletion rate and higher water influx from bottom aquifer or long duration but higher recovery due to a lower water influx. Middle range flow rates (3,000 – 4,000 STB/D) offer an appropriate plateau for 8 to 12 years.

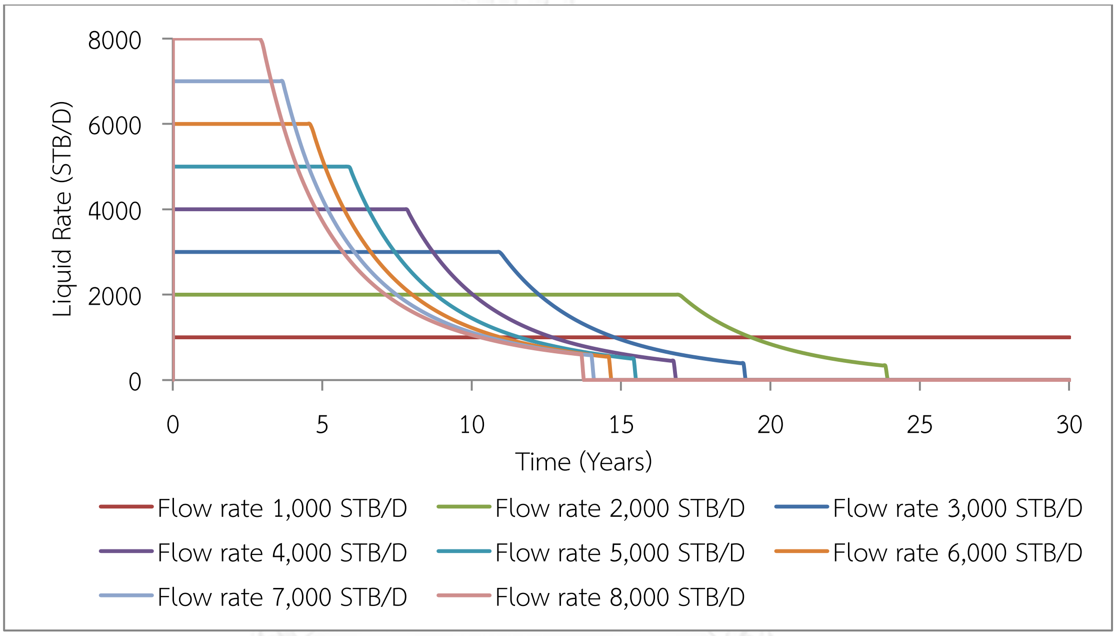


Figure 5.2 Liquid production rate and plateau period of different maximum rates as a function of production period

Oil rates are directly linked to liquid rates as shown in Figure 5.3. The higher the liquid flow rate, the faster the oil rate decline. In order to keep an appropriate production as long as possible, high liquid flow rates should be avoided. Too low flow rates should also be avoided to keep a sufficiently high amount of oil production.

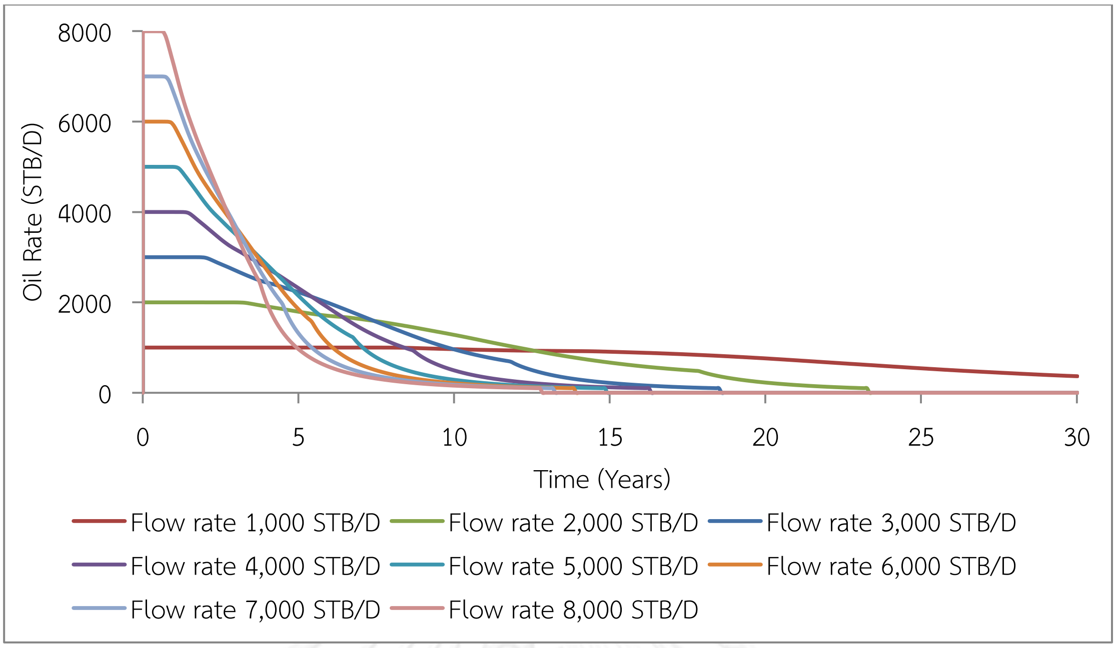


Figure 5.3 Oil production rates of different maximum flow rates as a function of production period

Water production is major problem for reservoirs with bottom aquifers. Indeed, production of reservoir and declining of reservoir pressure favor water influx from bottom aquifer, causing water cresting around lateral wellbore. Once water breakthrough occurs, i.e., water from bottom aquifer is produced, reservoir drainage decreases and thus, oil production falls. Moreover, water production rises and may hit economic limits of 95% water cut. Liquid rate production has a direct impact on water production and high flow rates should be avoided to prevent early water production as shown in Figure 5.4.

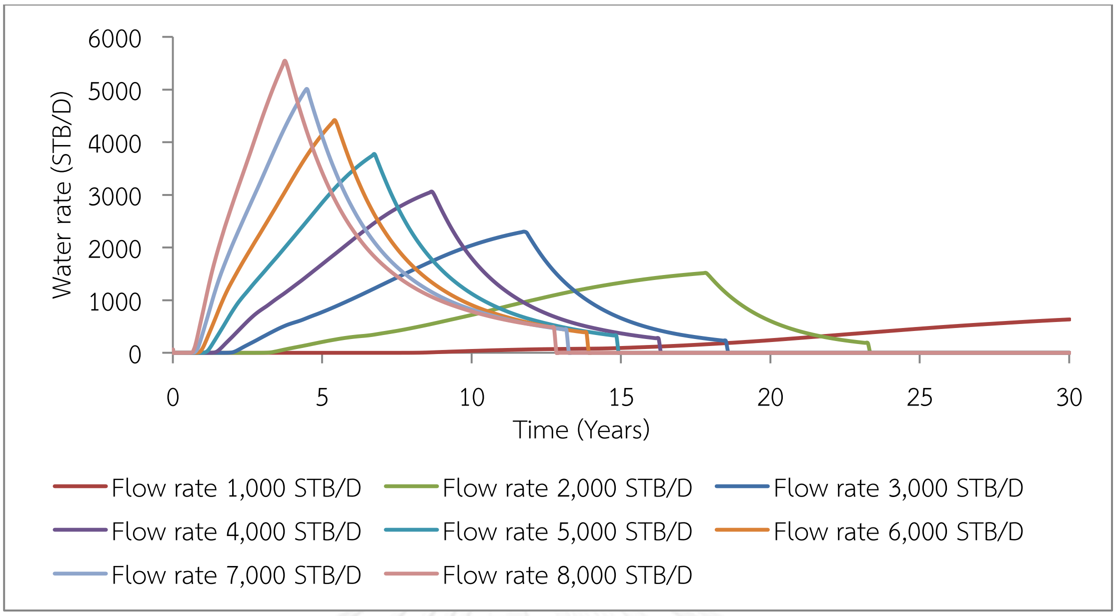


Figure 5.4 Water production rates of different maximum flow rates as a function of production period

With a relatively low gas production as can be seen in Figure 5.5, gas rate is not as problematic as water flow rate. Gas is only present as solution gas in the reservoir. However, once reservoir pressure drops below bubble point pressure (2,500 psi), a secondary gas cap is created in the upper part of the reservoir. Gas cap expansion slows down pressure depletion in the reservoir and enables better oil drainage.

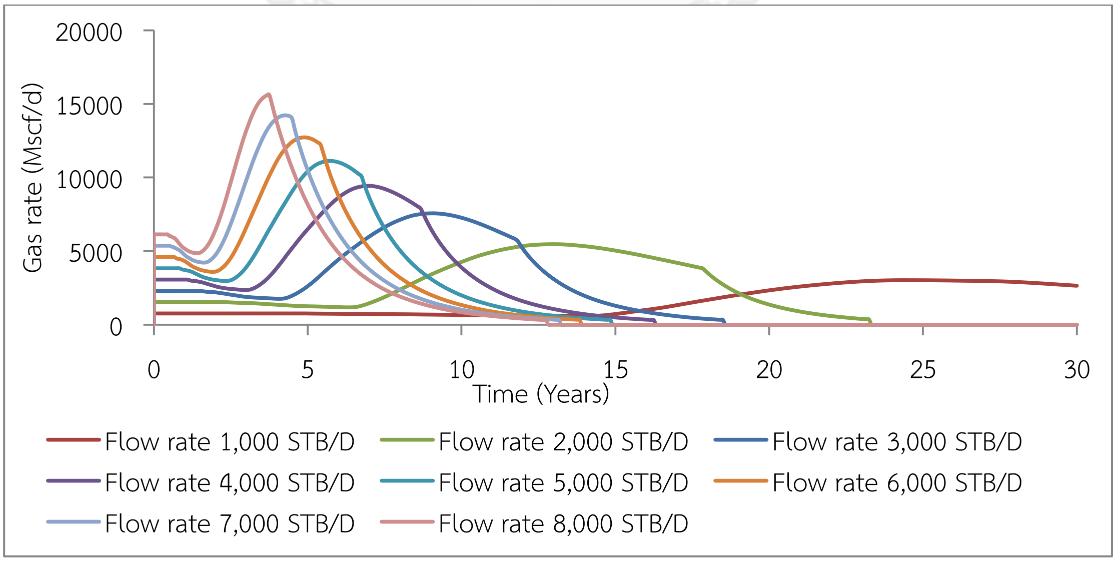


Figure 5.5 Gas production rates of different maximum liquid flow rates as a function of production period

As explained above, an appropriate flow rate should be able to optimize oil recovery within total period and delay water cresting. It should also fit to the different reservoir models studied in this project with smaller and larger aquifers as well as the different well geometry. Tests are performed on an appropriate geometry to cope with the constraints. From above results, it is decided to use the maximum liquid flow rate limit of 4,000 STB/D for the entire study. This liquid flow rate indeed provides a good oil recovery within proper production period and delays water and gas production.

5.2 Performance of Each Well Geometry in Different Models

5.2.1 Effective Producing Length of 1,200 ft

Effective producing length of 1,200 ft is the shortest length in this study. Four well geometries, with 1,200 ft of effective producing length are implemented in the reservoir models for this section, including horizontal, dual opposed, dual laterals located at different depths and quadrilateral wells.

<u>Reservoir Model 1 Small Aquifer Size (1PV)</u>

Four well geometries with 1,200 ft effective length are implemented in reservoir model 1, which is supported by a small aquifer, equivalent to 1 pore volume of hydrocarbon bearing zone. Effective length is divided by number of laterals for each well geometry. Therefore, horizontal well (1L) has an effective length of 1,200ft, dual lateral (2L/2D) and dual-opposed (2L) wells have two laterals of 600 ft effective length and quadrilateral well has four laterals of 300 ft each. This length is intentionally small to assess impact of lateral interference.

Simulations are performed at three different depths for lateral section 6,850, 6,900 and 6,950 ft. As shown in Figure 5.6, the highest oil recoveries are obtained by wells located at 6,850 and 6,900 ft due to a further distance from bottom aquifer and thus, a later water breakthrough. Upper wells suffer from gas influx from a secondary gas cap which is formed when reservoir pressure is below bubble point pressure. Lateral placement at the middle depth obtained the best balance between water and gas encroachments.

At each depth where lateral sections are placed, dual-opposed wells shows the best drainage and the highest oil recovery compared respectively to dual laterals set at different depths, quadrilateral and horizontal wells. Results between the two dual lateral geometries remain very close. Oil recoveries from each well geometry show very different trends in the first ten years. Horizontal wells yield higher pressure drawdown around the wellbore and especially at the heel side due to friction along the well. The larger pressure depletion increases water influx and thus decreases oil recovery because of the flow preference. For the same producing length, the friction loss along the wellbore is more important for horizontal wells than for multilateral wells where total effective length is divided into two or four laterals. Moreover, production is dispatched in two to four laterals, decreasing drawdown around the wellbore.

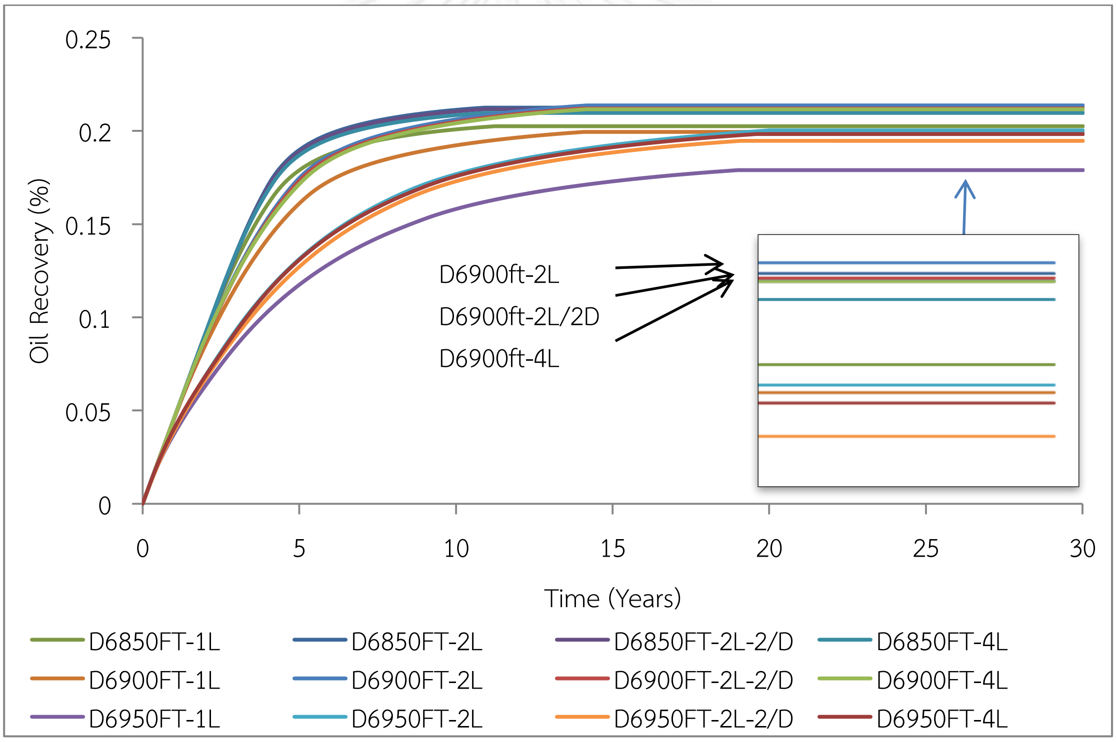


Figure 5.6 Oil Recovery factors of 1,200-ft well with different geometries in reservoir model 1 (driven by small aquifer) as a function of production period

Pressure in the reservoir model 1 driven by small aquifer size depletes at a relatively early production as illustrated in Figure 5.7. However, pressure depletion is slower when wells are located at the lower location in the reservoir because free gas is not produced. Major change occurs when pressure is below 2,500 psia which corresponds to bubble point pressure of reservoir hydrocarbon. Below this pressure, gas is liberated and a secondary gas cap is formed at the top of reservoir. The gas cap slows down pressure decline in the reservoir. Because of the lower viscosity, gas tends to crest faster into lateral wells, depending on location and time which explains a faster pressure decrease for wells located in the upper part of the reservoir.

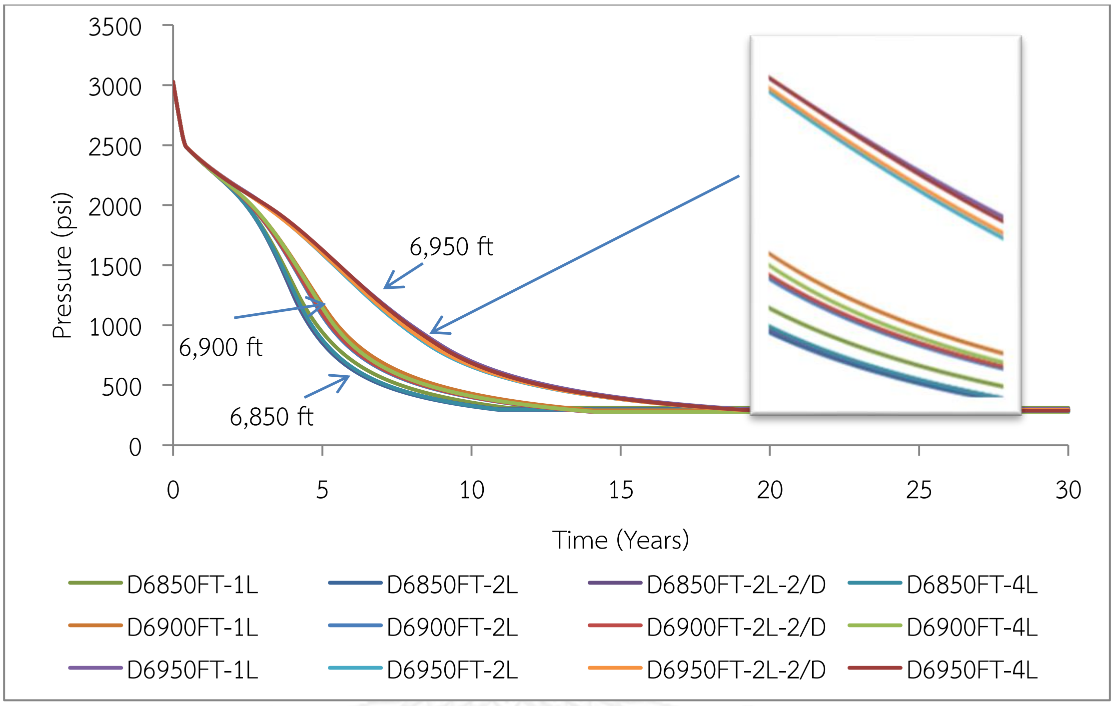


Figure 5.7 Reservoir pressure obtained from implementation of 1,200-ft well with different well geometries in reservoir model 1 as a function of production period

Liquid production rate curves of each well geometry show various trends at different depths as can be seen in Figure 5.8. Wells located at deeper location can maintain higher liquid production rates for longer time compared to wells located at shallower depth due to distance of lateral to bottom aquifer.

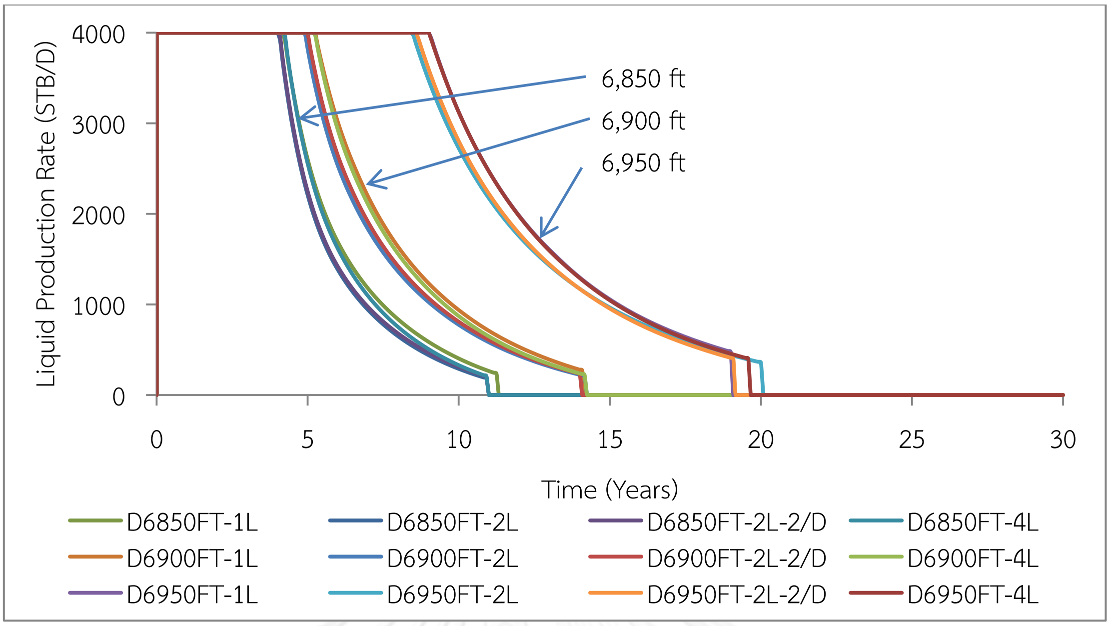


Figure 5.8 Liquid production rates obtained from implementation of 1,200-ft well with different well geometries in reservoir model 1 as a function of production period

Depth where lateral wells are located in the reservoir has a direct impact on oil production rates as shown in Figure 5.9. Wells located at 6,850 ft depth maintain higher production rate during the first four years and the rate decreases at a very fast pace. Minimum oil production rate limit (100 STB/D) for the shallower wells is reached after approximately eleven years and the well is automatically shut off. This trend is similar for the wells located at 6,900 ft depth but with a longer plateau and longer time of production before economic limit is reached. Wells located at 6,950 ft show the best results as oil is produced at a lower but steadier rate for approximately 19 years.

Dual-opposed well shows better result compared to quadrilateral, dual lateral set at different depths and horizontal wells.

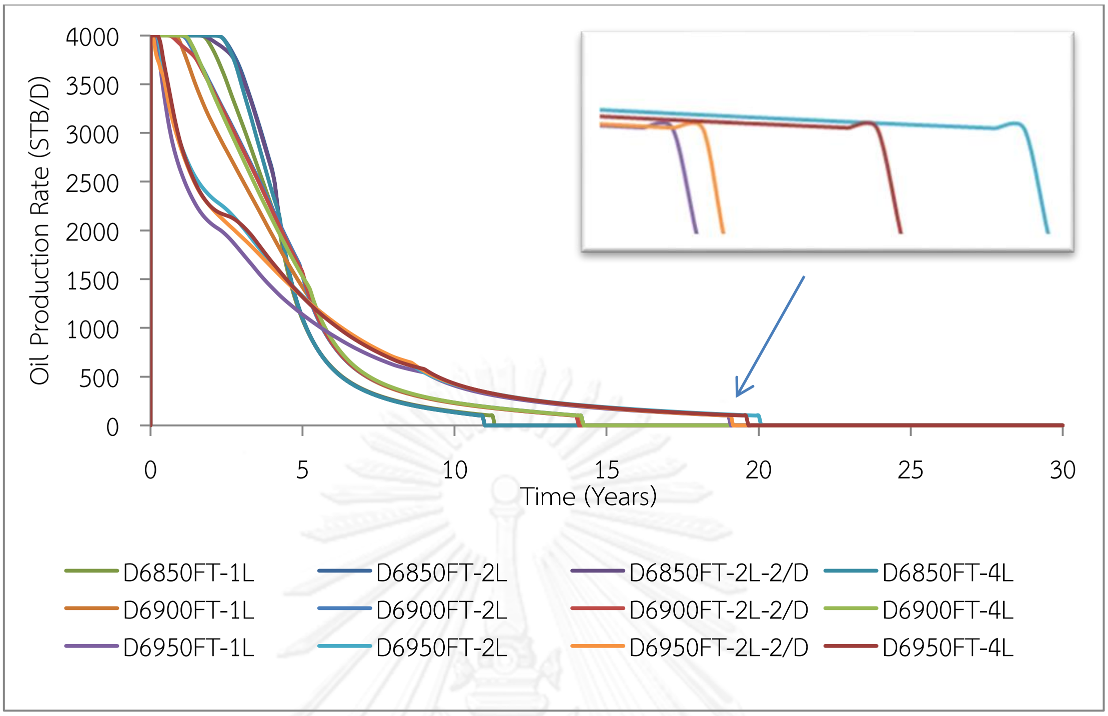


Figure 5.9 Oil production rates obtained from implementation of 1,200-ft well with different well geometries in reservoir model 1 as a function of production period

In this study, source of gas is only dissolved gas in oil. Hence, at early stage, gas production only relies on soluble gas as illustrated in Figure 5.10. Once reservoir pressure falls below bubble point pressure at 2,500 psia, gas starts to liberate from reservoir oil, creating a secondary gas cap in upper part of the reservoir. Therefore, during production period, gas breakthrough into the well tends to occur sooner at shallower locations.

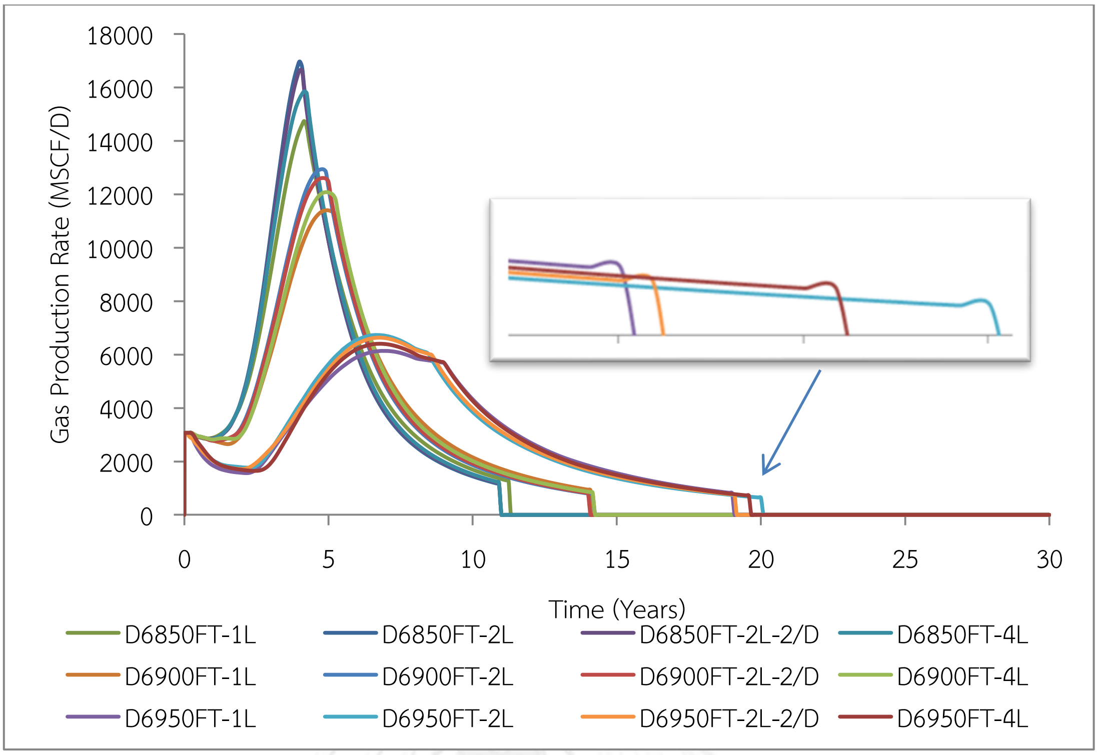


Figure 5.10 Gas production rates obtained from implementation of 1,200-ft well with different well geometries in reservoir model 1 as a function of production period

Water production rate depends directly on distance of lateral wells to oil-water contact located at 7,000 ft. However, at all depths, the highest water rates are always encountered by horizontal wells due to a higher pressure drop close to the main bore as shown in Figure 5.11. The closer to the oil-water contact, the higher the improvement due to multilaterals compared to horizontal wells. For the reservoir model 1, the economic limit linked to maximum water cut (95%) is not reached.

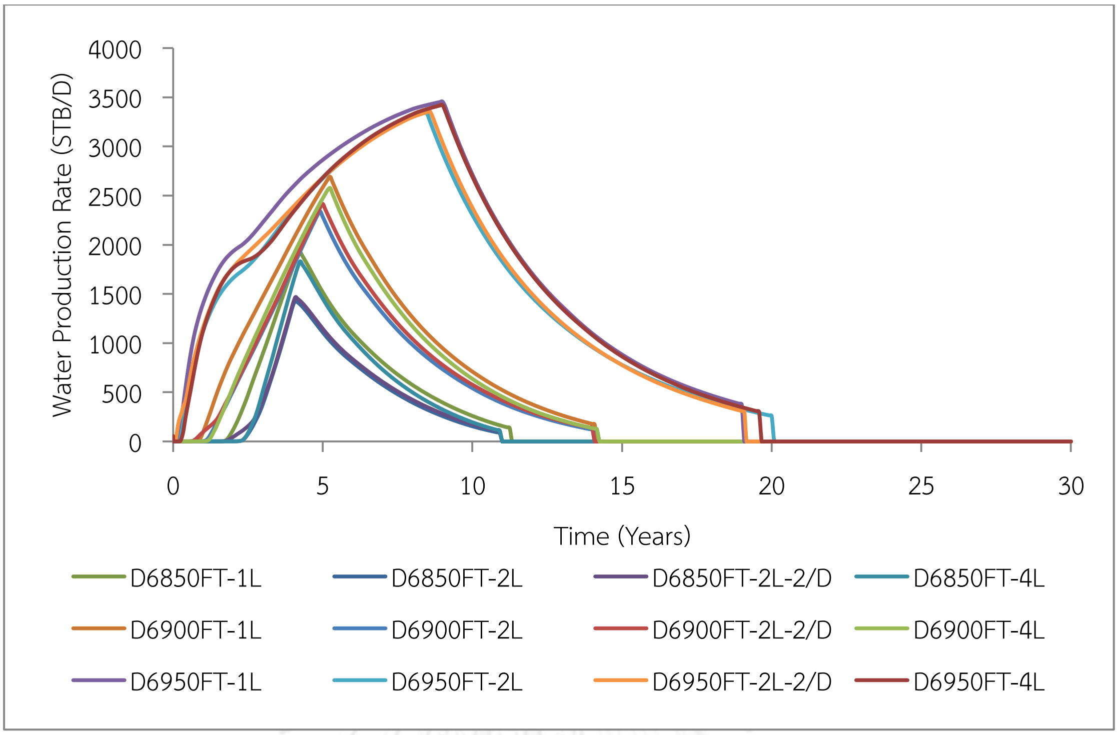


Figure 5.11 Water production rates obtained from implementation of 1,200-ft well with different well geometries in reservoir model 1 as a function of production period

Out of twelve simulations performed in three reservoir models, range of oil production is relatively similar. However, total production period of recovery and water production differ in a broad range. Recovery factors range from 17.62 to 21.37 %. The best oil recovery is obtained by dual-opposed well located at 6,900 ft. Both dual lateral geometries (2L and 2L/2D) located at 6,850ft and 6,900 ft yield the same range of oil recovery with just 0.2% difference.

Total water production varies approximately 6.5 times between extremes as observed Table 5.1. Since water cut limit is not reached, water production mainly delays oil recovery with time and increases treatment costs. Gas production gives also similar results at the end of simulation due to the full production of soluble oil as well as gas cap.

Table 5.1 Simulation outcomes obtained from all well geometries with total producing length of 1,200 ft performed in reservoir model 1

Depth of Laterals (ft)	Number of Laterals	Oil Recovery (%)	Total Oil Production (STB)	Total Water Production (STB)	Total Gas Production (MSCF)
6,850	1	20.03%	6,410,322	2,676,723	21,150,500
	2	21.01%	6,723,678	1,767,057	21,433,350
	2/D	21.17%	6,774,060	1,941,950	22,509,110
	4	20.74%	6,635,665	2,255,346	21,338,954
6,900	1	19.71%	6,307,469	5,424,312	21,162,062
	2	21.37%	6,838,626	4,247,210	21,490,114
	2/D	21.20%	6,785,409	4,552,708	22,643,218
	4	20.92%	6,695,185	4,839,190	21,394,778
6,950	1	17.64%	5,643,374	12,948,268	20,270,550
	2	19.72%	6,310,611	11,722,455	20,662,574
	2/D	19.47%	6,230,879	12,043,203	21,904,634
	4	19.56%	6,260,102	12,401,416	20,546,816

Multilateral wells show a remarkable different in oil production compared to horizontal wells as can be seen in Table 5.2. This difference increases particularly in cases where water production increases also. Dual laterals yield better performance compared to quadrilaterals because of reduction of interferences between laterals. Pressure drawdown is indeed stronger at the heel of laterals and is therefore increased for quadrilateral wells, especially for short length laterals. In the case of quadrilateral well, access to oil is reduced compared to dual lateral well due to overlapping drainage.

Table 5.2 Differences of simulation outcomes compared to horizontal well for multilateral well geometries with total producing length of 1,200 ft performed in reservoir model 1

Depth of Lateral (ft)	Number of Laterals	Oil production difference with 1L	Water production difference with 1L	Gas production difference with 1L
6,850	1			
	2	4.888%	-33.984%	1.337%
	2/D	5.674%	-27.450%	6.424%
	4	3.515%	-15.742%	0.891%
6,900	1			
	2	8.421%	-21.700%	1.550%
	2/D	7.577%	-16.068%	6.999%
	4	6.147%	-10.787%	1.100%
6,950	1			
	2	11.823%	-9.467%	1.934%
	2/D	10.411%	-6.990%	8.061%
	4	10.928%	-4.223%	1.363%

Following figures demonstrate evolution of fluid distribution during production period from four different well geometries at 6,900 ft depth.

Figure 5.12 shows evolution of oil saturation in reservoir model 1 with a 1,200-ft horizontal well after 1, 3 and 15 years. Low oil saturation is characterized by the blue color while the red color describes the highest saturation. After 1 year, oil production around the wellbore is started and water influx from bottom aquifer comes up as can be seen from green color. After 3 years of production, oil saturation is redistributed. Oil saturation is reduced in a whole reservoir, especially in the top of the reservoir due to gravity drainage and development of a secondary gas cap. Gas cone can be assessed at the top of the reservoir from secondary gas cap whereas water breakthrough already occurred. After 15 years, production is terminated; two major oil patches remain un-produced due to short well length. Bottom aquifer has risen in the reservoir and gas is present in the upper part.

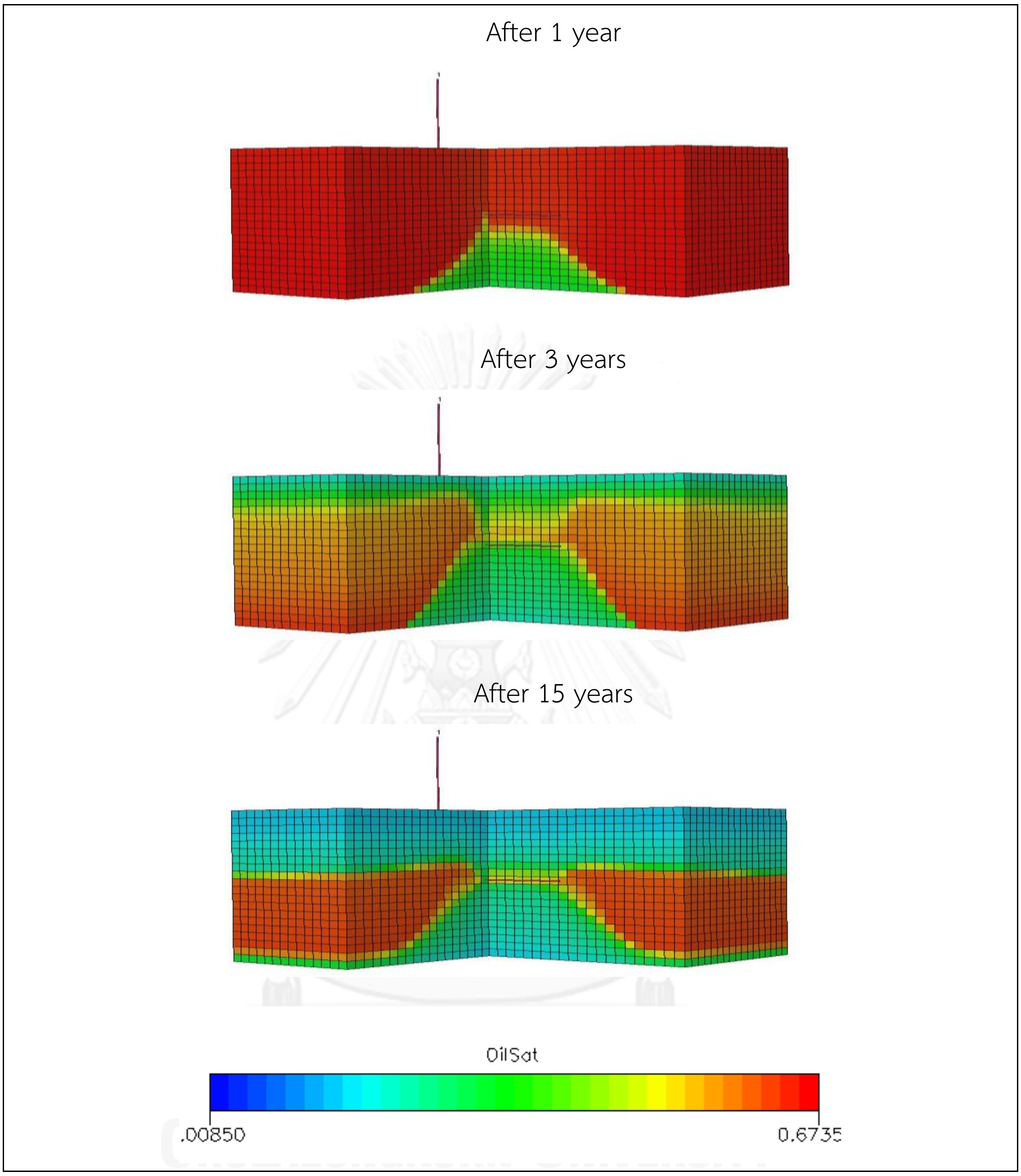


Figure 5.12 Evolution of oil saturation after 1 year, 3 years and at 15 years of horizontal well implemented in reservoir model 1

Figure 5.13 shows oil saturation evolution of 1,200-ft dual-opposed set located at 6,900 ft after 1, 3 and 15 years. The left figure is top view cut at 6,900ft, aiming to assess and indicate drainage while the right figure defines side view along the wellbore. The first year, oil saturation depletion occurs around the two effective laterals, creating water cresting at two different locations underneath the wellbore. After 3 years, drainage increases drastically, water as well as gas breakthrough in wellbore also occur largely. At the end of the production period, drainage appears to be much larger compared to the case of horizontal well.

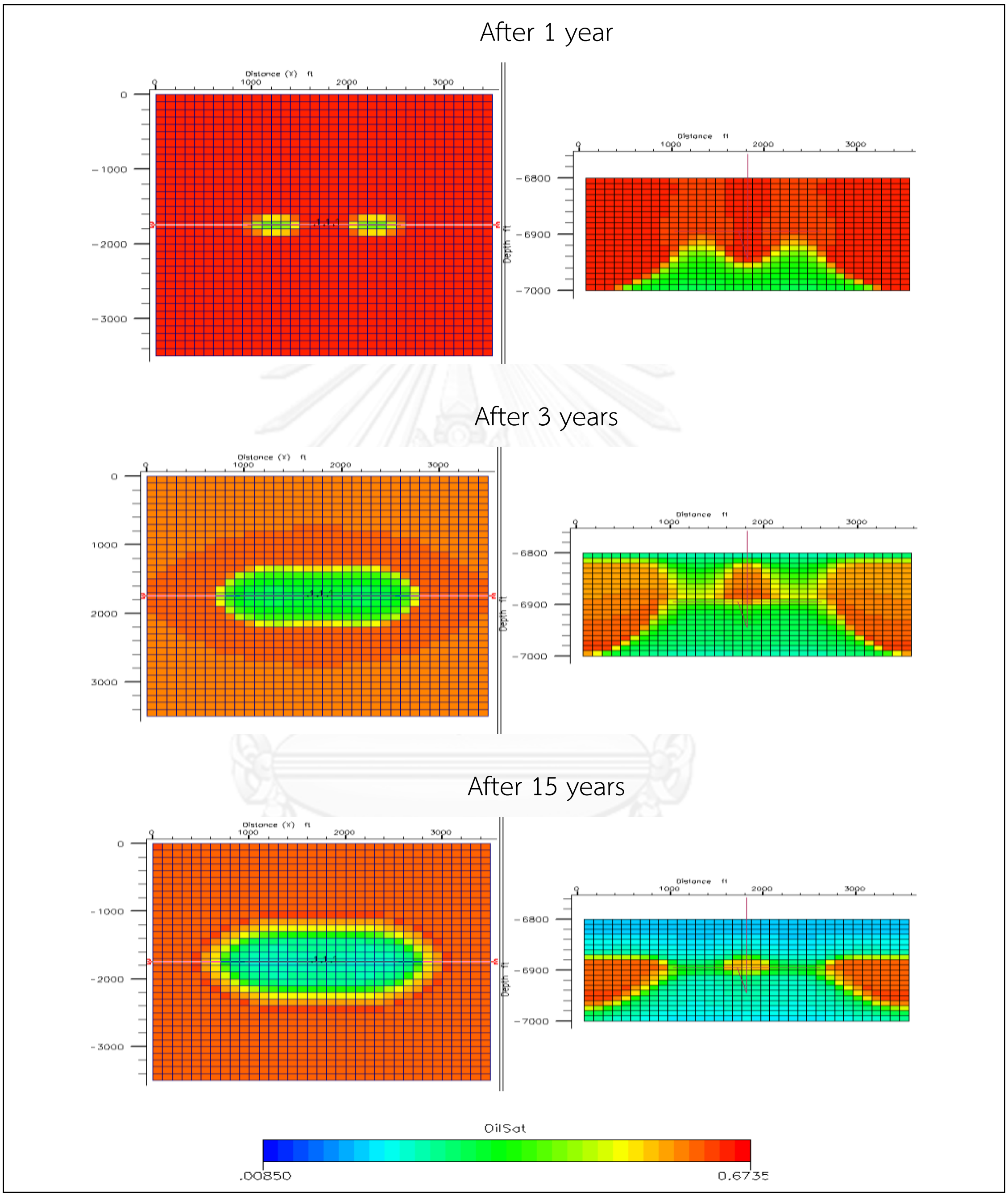


Figure 5.13 Evolution of oil saturation after 1 year, 3 years and at 15 years of dual-opposed well implemented in reservoir model 1

Figure 5.14 illustrates evolution of 1,200-ft dual laterals set at different depths after 1, 3 and 15 years. Results from this well geometry vary from dual-opposed well geometry due to early breakthrough from both water and gas which can be seen in the following figures. Both early breakthroughs decrease oil drainage in the reservoir as can be assessed after 15 years.

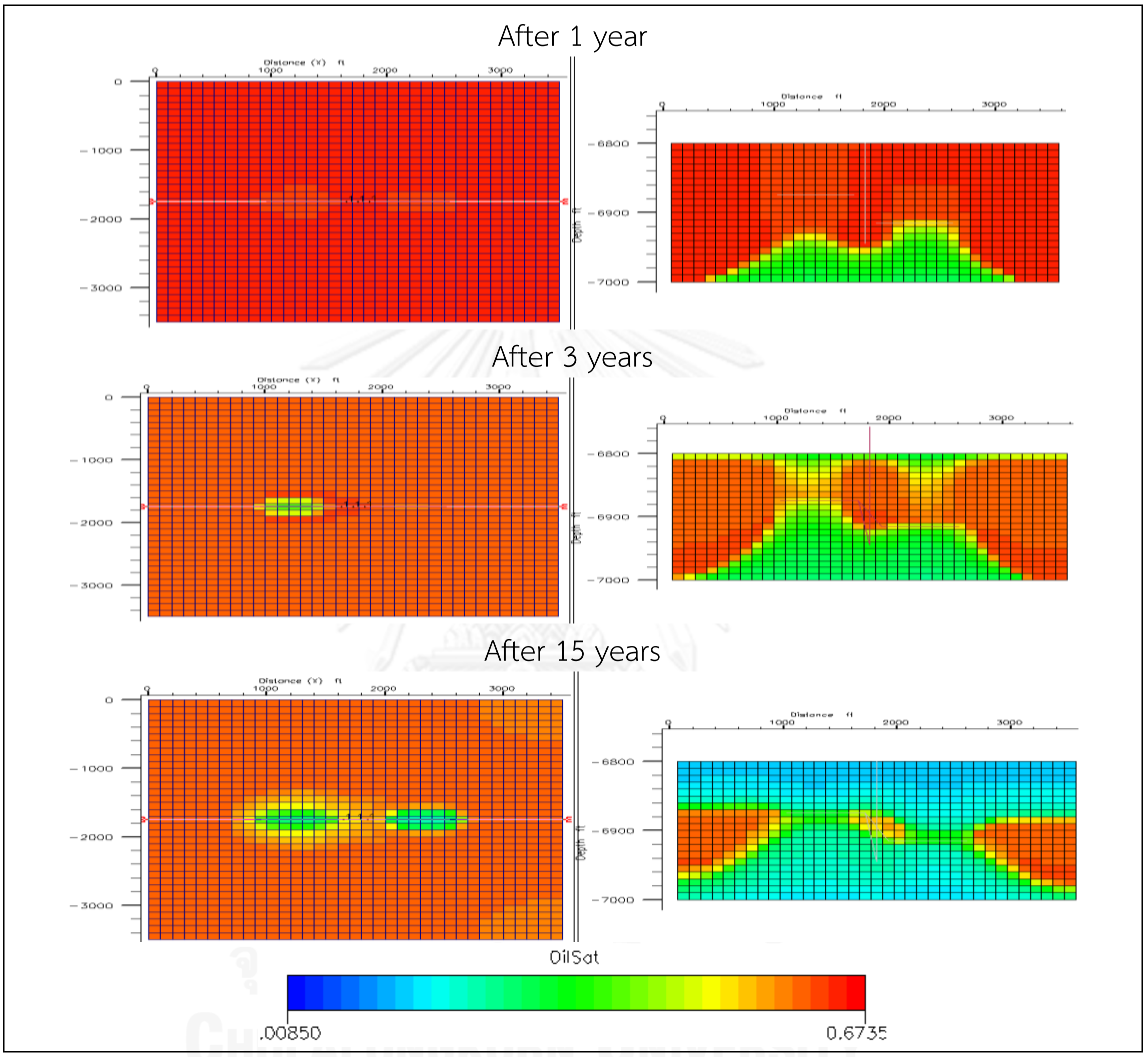


Figure 5.14 Evolution of oil saturation after 1 year, 3 years and at 15 years of dual lateral well located at different depth implemented in reservoir model 1

Figure 5.15 shows evolution of 1,200-ft quadrilateral well located at 6,900 ft after 1, 3 and 15 years. This well geometry enhances symmetrically oil saturation profile in both x- and y-directions. With smaller laterals in two directions, the drainage occurs as a diamond shape from top view. Water and gas encroachment also occurs similarly to dual lateral well geometry. Even if the pressure drop is dispatch between the four laterals, water and gas coning appear to be stronger than for dual lateral wells after 3 years of production, resulting in lower oil drainage after 15 years. This lower performance is due to the overlapping of drainage of each lateral which can be seen from aerial view after 3 years already. Indeed, lower oil saturation is located at the junction of each lateral which is not perforated. This characteristic is not found in dual-opposed well as seen in Figure 5.13 and demonstrates interference between four laterals for a 1,200 ft effective length well.

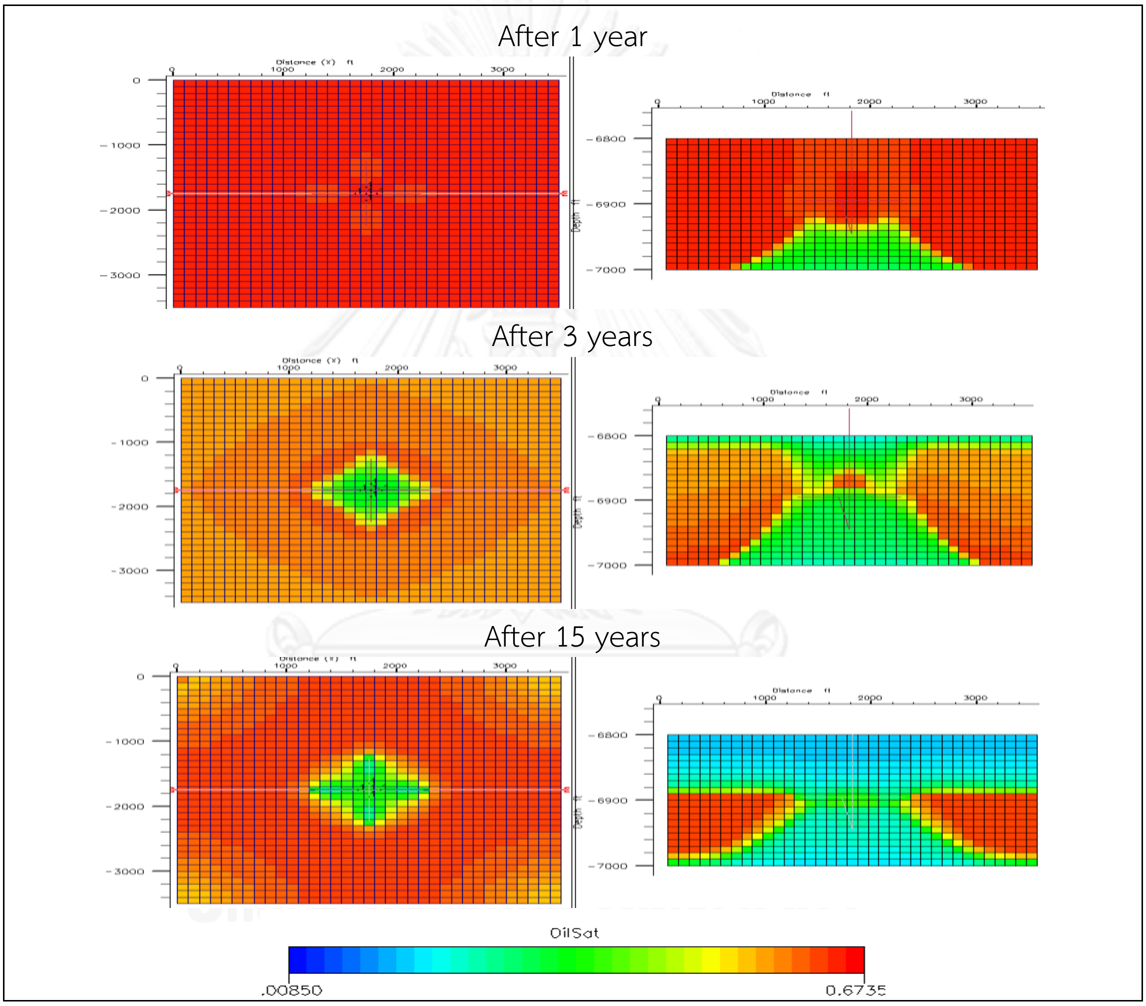


Figure 5.15 Evolution of oil saturation after 1 year, 3 years and at 15 years of quadrilateral well implemented in reservoir model 1

Selection of base case

Dual-opposed lateral well geometry located at 6,900 ft yields the best performance in reservoir supported by small aquifer equivalent to one reservoir pore volume. Oil recovery reaches 21.37% which is also the best among cases in term of period of recovery, water and gas production.

Reservoir Model 2 Medium Aquifer Size (10PV)

With a medium aquifer size, reservoir pressure is expected to decline with a slower rate compared to a small aquifer size and hence, oil recovery should be better improved. However, increase of water influx from bottom aquifer and early crest water breakthrough are also expected.

Lateral wells located at 6,850 and 6,900 ft yield higher oil recovery than well located at deeper location as shown in Figure 5.16. The highest oil recovery is obtained by quadrilateral well located at 6,850 ft, whereas the lowest recovery comes from horizontal well located at 6,950 ft. Two dual lateral well geometries also provide better oil recoveries than horizontal wells. Wells located at lower location show the lowest oil recovery factor due to high water production.

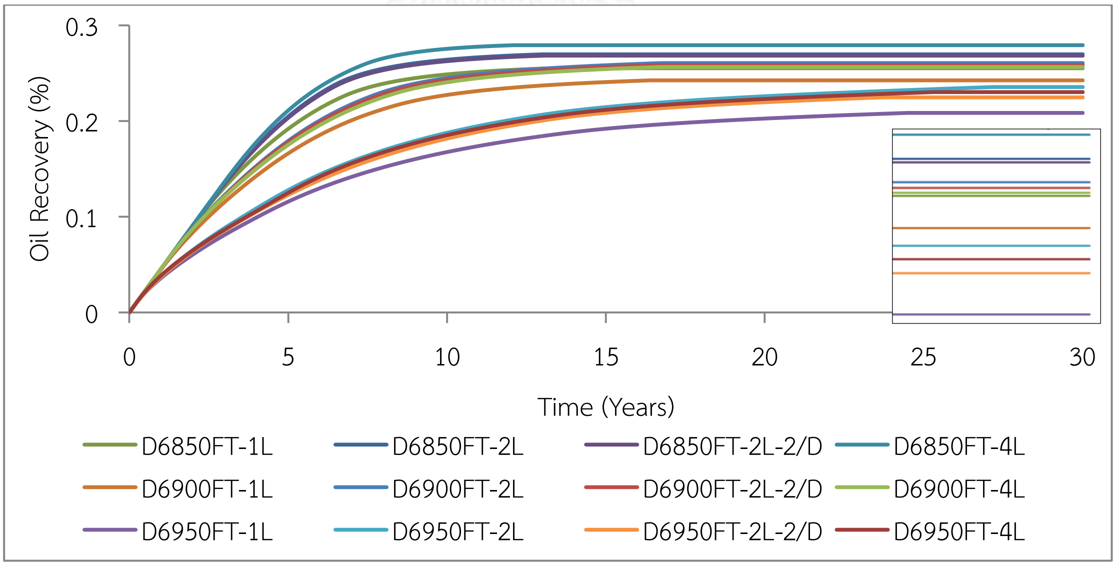


Figure 5.16 Oil Recovery factors obtained from implementation of 1,200-ft well with different well geometries in reservoir model 2 as a function of production period

During production period, reservoir pressure is supported by bottom aquifer and its depletion is reduced by secondary gas cap as seen from Figure 5.17. Wells located in the upper part of reservoir produce gas from the gas cap and reduces drive mechanism, whereas wells located at lower locations produce water from bottom aquifer. Water production from bottom aquifer has a smaller impact on reservoir pressure because of size of aquifer.

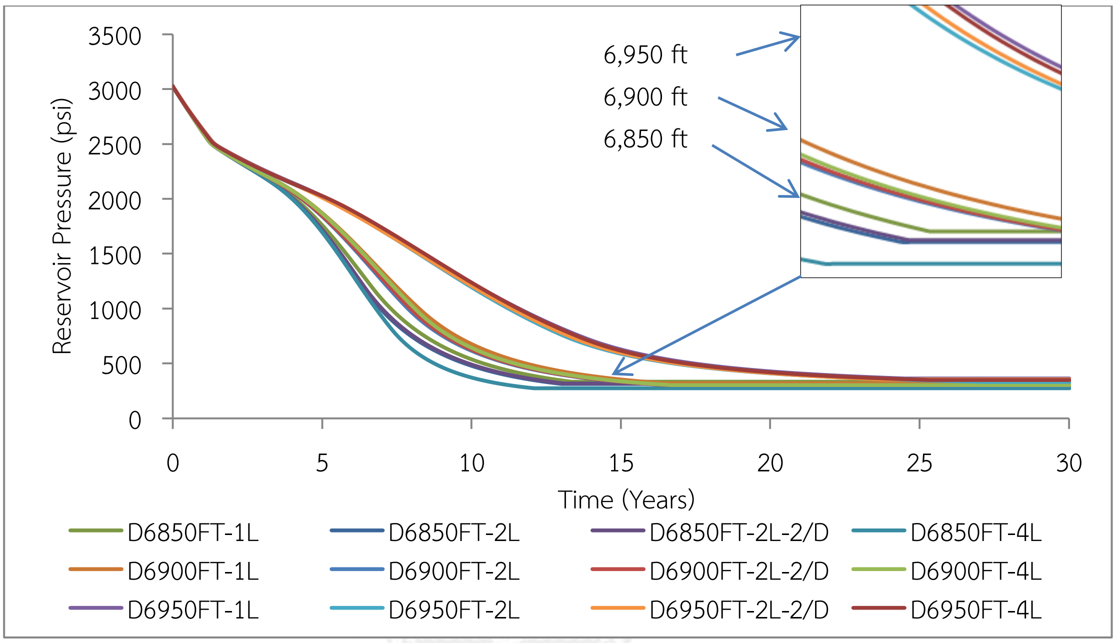


Figure 5.17 Reservoir pressures obtained from implementation of 1,200-ft well with different well geometries in reservoir model 2 as a function of production period

Depending on location of lateral well in the reservoir, very different results are observed. The closer to the oil-water contact, the more water influx in the well and thus the higher the liquid rate throughout time as displayed in Figure 5.18. At 6,900 ft and 6,950ft, opposite dual laterals provide more stable rates than the other configurations.

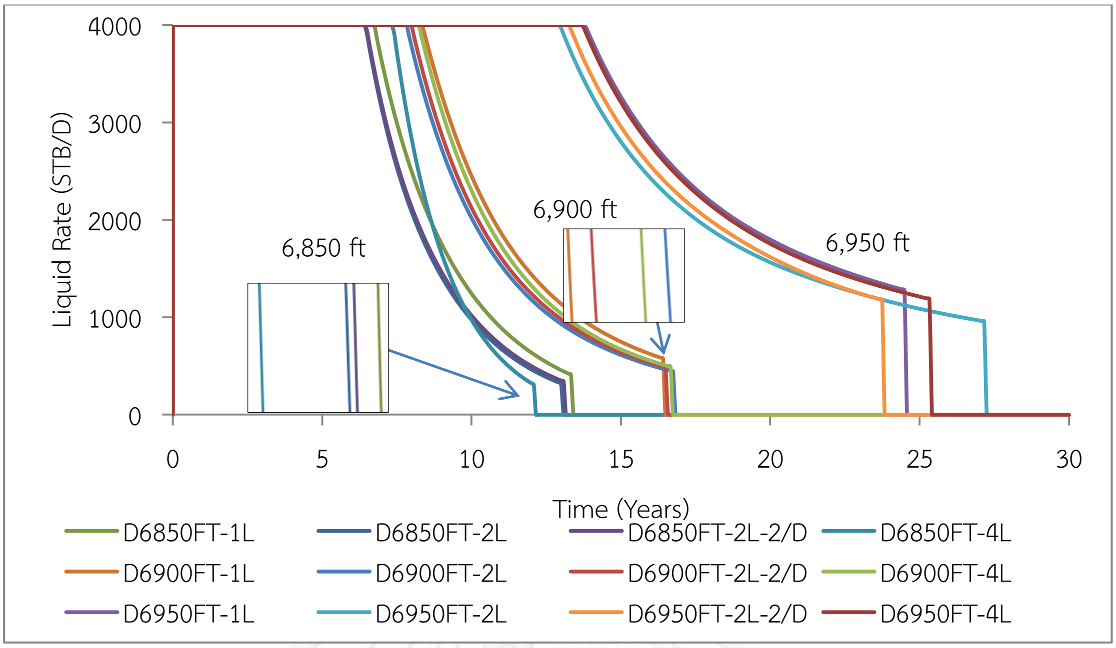


Figure 5.18 Liquid production obtained from implementation of 1,200-ft well with different well geometries in reservoir model 2 as a function of production period

Oil production rates vary depending on location of lateral well and also well geometry as depicted in Figure 5.19. Oil production terminates due to minimum oil rate is reached for all cases. At 6,850ft, wells produce oil at maximum rate during the first four years and then the rates fall rapidly due to gas breakthrough from gas cap and rapid decline of reservoir pressure. At this depth, horizontal well provides the highest liquid rate because of a higher pressure drop which increases water influx and hence liquid rate.

At 6,900ft, oil is produced at a maximum rate for only a few years, but decline of rate is steadier due to a lower production of gas from secondary gas cap and thus a higher reservoir pressure along time compared to 6,850-ft depth wells. Multilaterals provide very similar trend during the production period, whereas horizontal well tend to encounter earlier oil rate decline.

At 6,950ft, dual-opposed and quadrilateral wells provide higher rates and the longest production period due to lower pressure drop. Dual lateral well located at different depths obtains a bigger influx of water from one lateral which is not compensated by another one. This results in shorter production time.

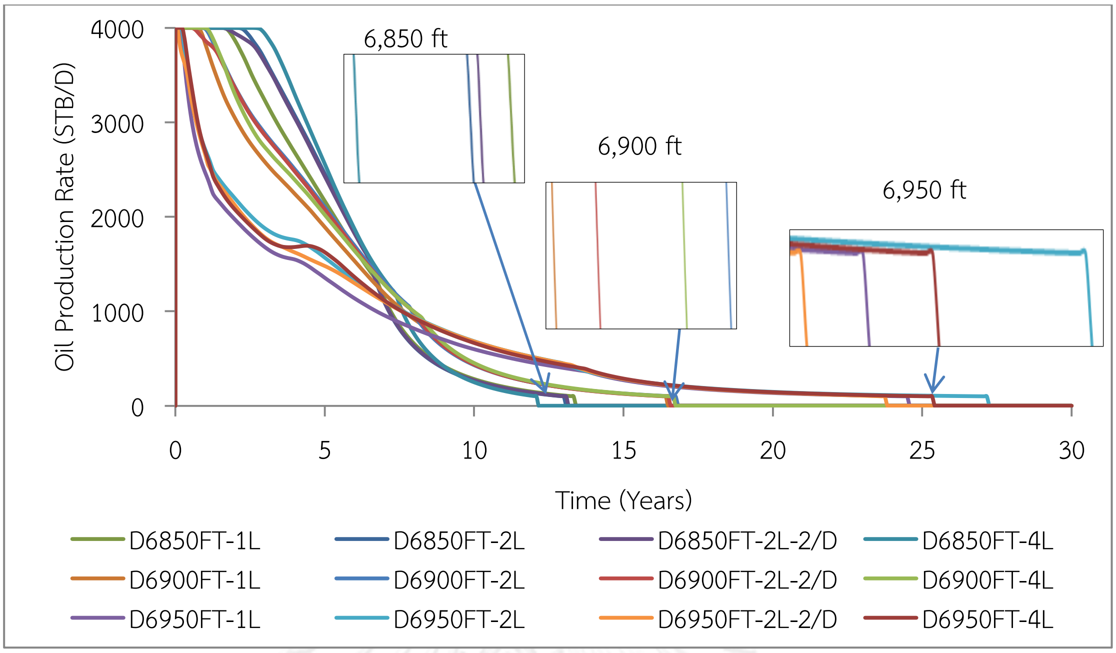


Figure 5.19 Oil production rates obtained from implementation of 1,200-ft well with different well geometries in reservoir model 2 as a function of production period

Medium size aquifer maintains pressure in reservoir and hence increases oil recovery but it also increases water influx in the reservoir. Similarly to the previous sections, location of lateral wells impacts directly water production as shown in Figure 5.20. Similar trend to reservoir model 1 is observed. Indeed, water influx in the reservoir is much higher and water cresting appears all along the well. Once water enters the well, oil production is decreased at a very fast pace.

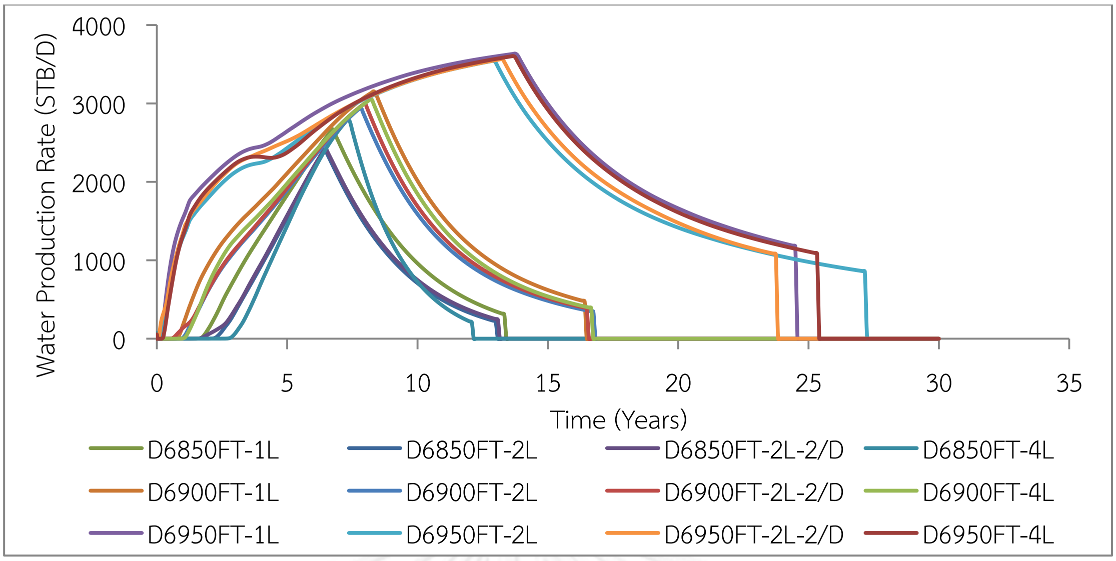


Figure 5.20 Water production rates obtained from implementation of 1,200-ft well with different well geometries in reservoir model 2 as a function of production period

Gas production does not vary much with medium aquifer size as only solution gas represents gas in the reservoir. Trend of gas production is similar to the previous model with time delay due to slower rate of pressure decline as shown in Figure 5.21.

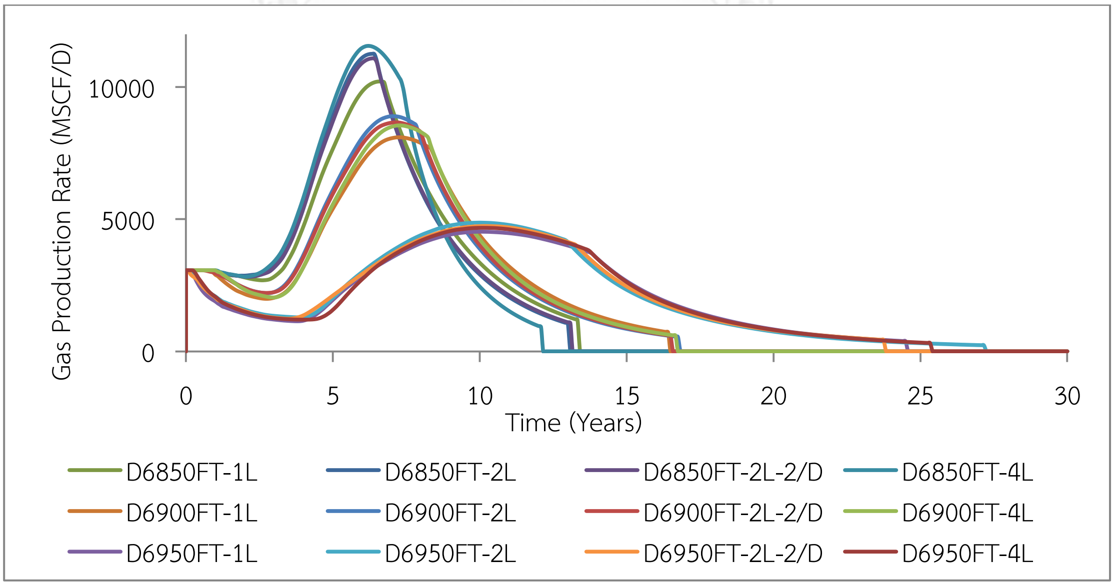


Figure 5.21 Gas production rates obtained from implementation of 1,200-ft well with different well geometries in reservoir model 2 as a function of production period

The highest recovery factor is obtained from the wells located at higher location in the reservoir. These wells indeed delay water production and thus increase reservoir drainage. As described in Table 5.3, quadrilateral well located at 6,850ft obtains the best oil recovery, whereas the lowest oil recovery factor is obtained from horizontal well located at 6,950ft. Dual laterals located at different depths yield low performance because one branch is lower than dual-opposed lateral, resulting in increase of water production, hence, decreases oil production.

Table 5.3 Simulation outcomes obtained from all well geometries with total producing length of 1,200 ft performed in reservoir model 2

Depth of Lateral (ft)	Number of Laterals	Oil Recovery (%)	Total Oil Production (STB)	Total Water Production (STB)	Total Gas Production (MSCF)
6,850	1	25.53%	8,168,766	5,309,292	22,487,464
	2	26.98%	8,633,615	4,088,283	22,812,720
	2/D	26.84%	8,590,110	4,243,735	22,756,034
	4	27.93%	8,938,412	4,262,282	23,274,762
6,900	1	24.26%	7,763,033	9,151,303	22,362,344
	2	26.06%	8,339,748	7,726,614	22,738,804
	2/D	25.84%	8,267,885	7,994,486	22,662,142
	4	25.65%	8,208,513	8,412,111	22,637,028
6,950	1	20.85%	6,673,836	21,871,216	20,559,730
	2	23.56%	7,538,609	20,789,762	21,195,664
	2/D	22.48%	7,193,925	20,160,200	20,841,080
	4	23.03%	7,369,647	21,378,864	20,827,222

From Table 5.4, benefits from multilaterals compared to single horizontal wells can be observed. Multilateral wells can improve oil recovery between 5 to 10% similarly to simulation results obtained from reservoir model 1 with small size of bottom aquifer.

Table 5.4 Differences of simulation outcomes compared to horizontal well for multilateral well geometries with total producing length of 1,200 ft performed in reservoir model 2

Depth of Lateral (ft)	Number of Laterals	Oil production difference with 1L	Water production difference with 1L	Gas production difference with 1L
6,850	1	-	-	-
	2	5.691%	-22.998%	1.446%
	2/D	5.158%	-20.070%	1.194%
	4	9.422%	-19.720%	3.501%
6,900	1	-	-	-
	2	7.429%	-15.568%	1.683%
	2/D	6.503%	-12.641%	1.341%
	4	5.738%	-8.077%	1.228%
6,950	1	-	-	-
	2	12.958%	-4.945%	3.093%
	2/D	7.793%	-7.823%	1.368%
	4	10.426%	-2.251%	1.301%

Selection of base case

Quadrilateral well geometry located at 6,850 ft offers the best performance in reservoir supported by medium size aquifer of ten times reservoir pore volume. Oil recovery reaches approximately 27.93% which is significantly higher than other well geometries. As shown on Figure 5.22, diamond shape drainage is obtained by quadrilateral well. However, with small laterals, reservoir drainage does not reach the boundaries. Interferences can also be assessed at the junction of laterals, enhancing water cresting from bottom aquifer.

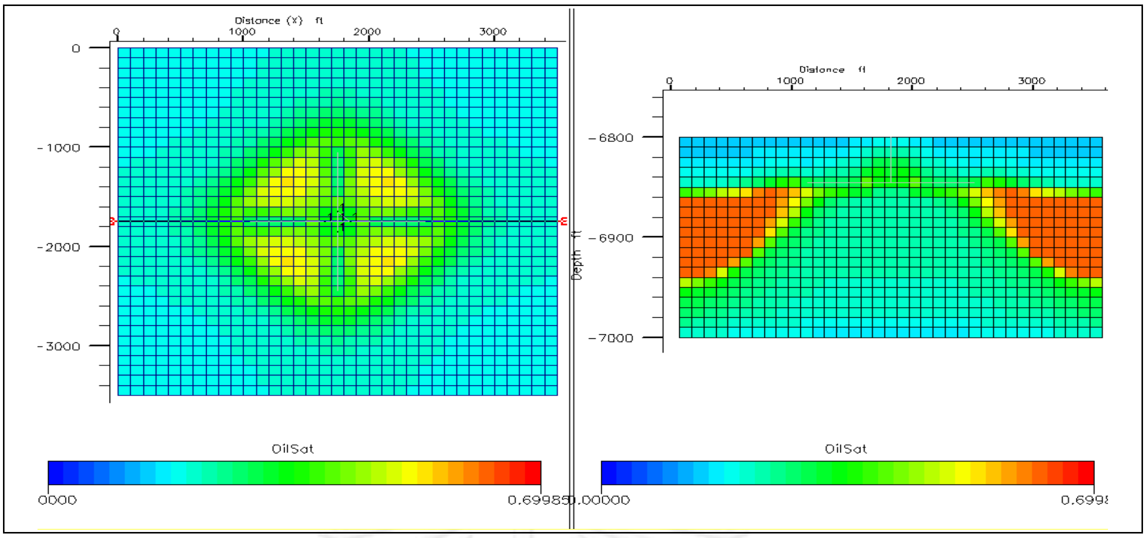


Figure 5.22 Oil saturation profiles of 1,200ft base case in reservoir model 2 at the end of production time

Reservoir Model 3 Large Aquifer Size (50PV)

Supported by a large aquifer size, reservoir pressure is expected to be maintained even during production. Oil production is therefore expected to be higher with a larger drainage. However, as water influx is obviously increased from the aquifer, very early water cresting and high water production are unavoidably expected.

Reservoir model 3 contains a very strong aquifer which enhances water influx into reservoir. Higher oil recovery factor is therefore obtained from well geometries which are located at the furthest point from oil-water contact with the least pressure drop as shown in Figure 5.23. Higher oil recovery factor is obtained from Dual-opposed lateral well located at 6,850 ft with a very similar performance with dual laterals located at different depths, third and fourth performance are obtained by respectively quadrilateral and horizontal wells. On the other hand, lower oil recovery factor is obtained from the horizontal well at 6,950 ft.

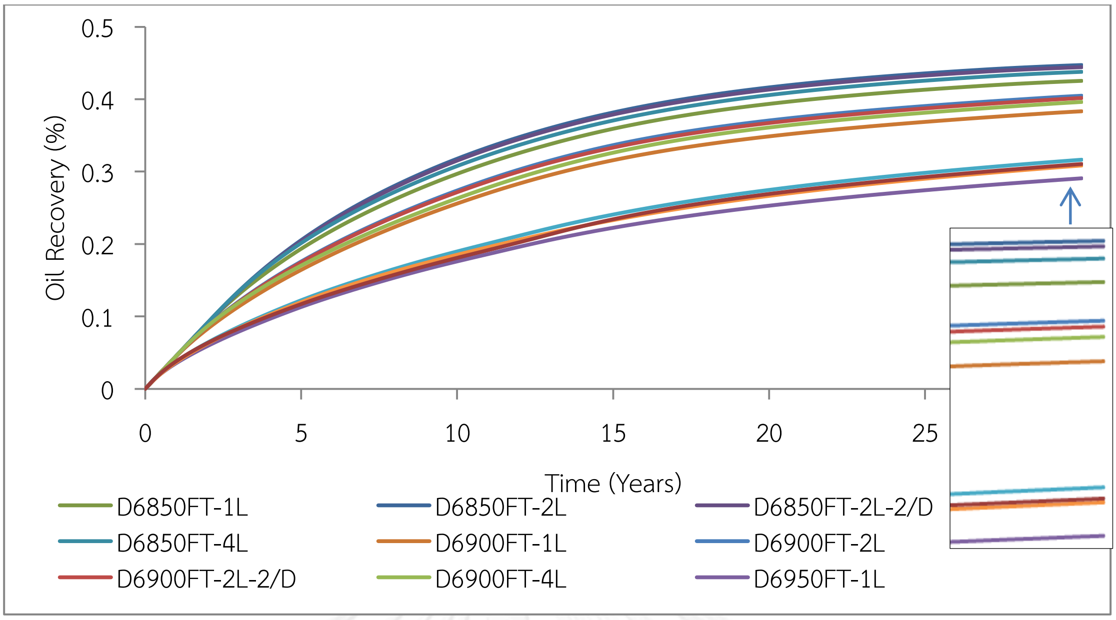


Figure 5.23 Oil recovery factors obtained from implementation of 1,200-ft well with different well geometries in reservoir model 3 as a function of production period

Reservoir pressure is maintained by large aquifer size. It is therefore higher than that of reservoir model 2 as displayed in Figure 5.24. After 10 years of production, similar trend can be observed and wells located at upper location encounter early pressure decline compared to lower wells due to production of gas from gas cap.

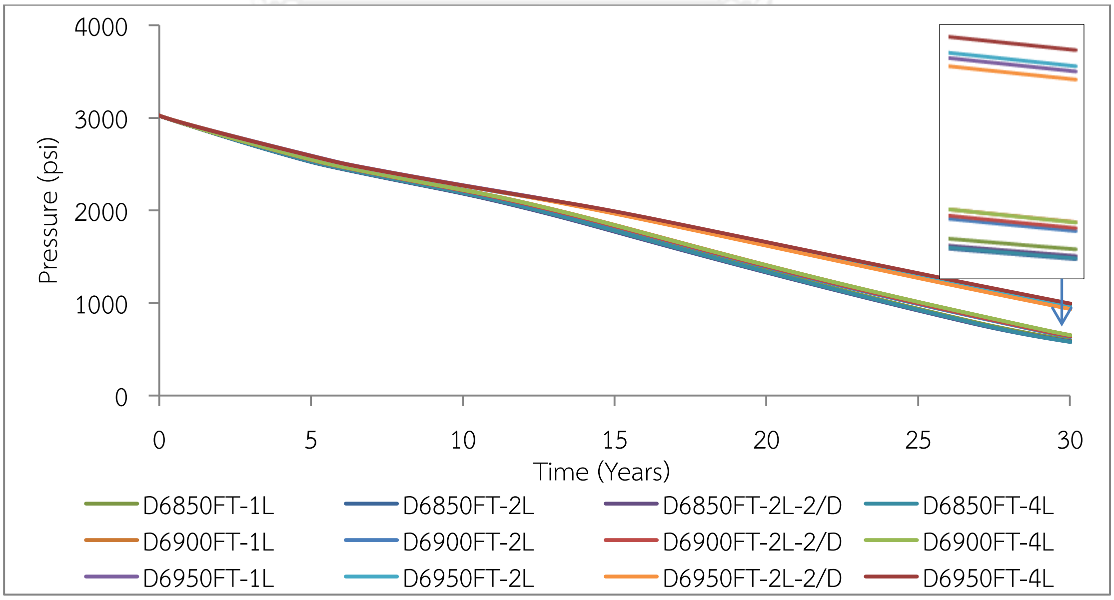


Figure 5.24 Reservoir pressures obtained from implementation of 1,200-ft well with different well geometries in reservoir model 3 as a function of production period

Effects of a large aquifer can be observed on liquid production rate which is at its maximum limit for wells located close to oil-water contact all over 30-year period. Figure 5.25 confirms that the sooner decline of liquid rate for well geometries located at 6,850 ft and 6,900 ft as effect from water influx from the aquifer is smaller.

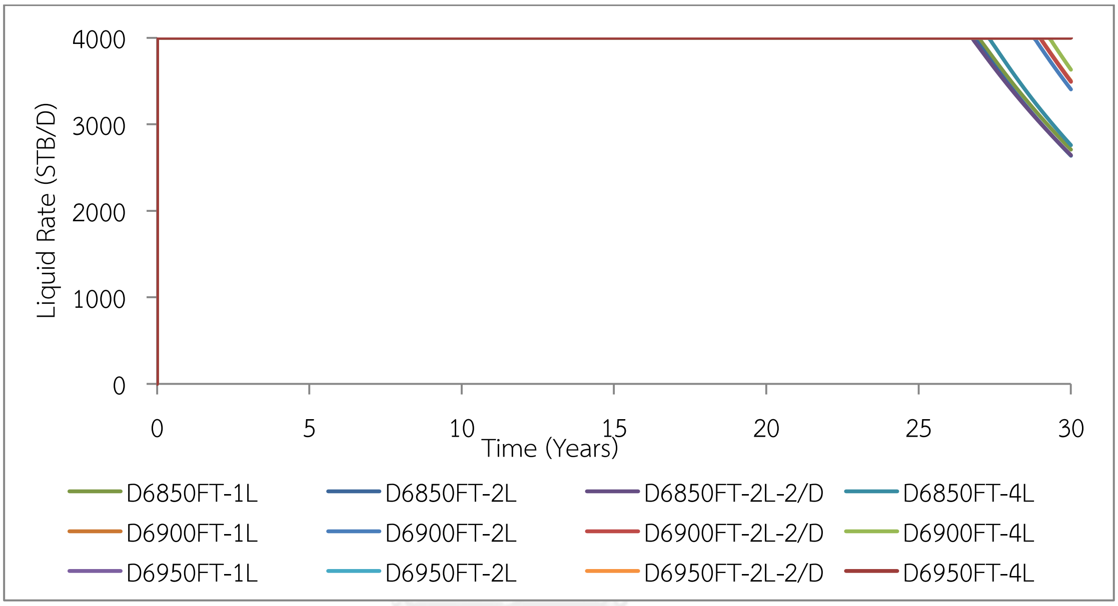


Figure 5.25 Liquid production rate obtained from implementation of 1,200-ft well with different well geometries in reservoir model 3 as a function of production period

Oil production rates are quite different during the first years and then converge to the same rate at the year 20th as shown Figure 5.26. The same trend as in reservoir models 1 and 2 is observed for this case. Wells closer to oil-water contact tend to encounter early water breakthrough and thus produce less oil. On the other hand, less gas is produced and reservoir pressure remains higher, hence a better drainage can be obtained. The balance between water and gas production are major keys to maximize oil production.

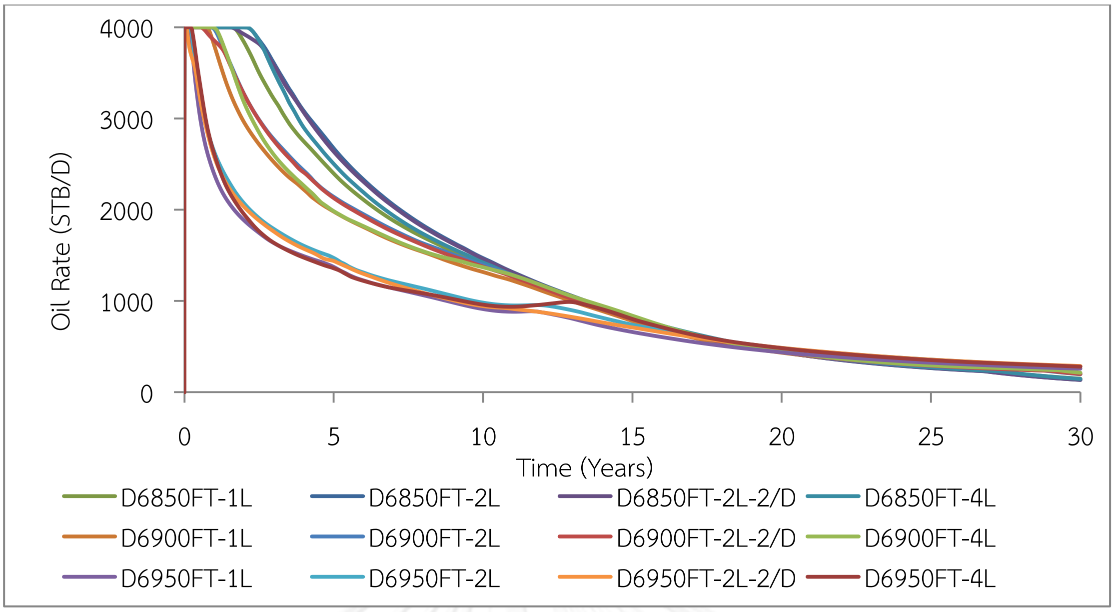


Figure 5.26 Oil production rates obtained from implementation of 1,200-ft well with different well geometries in reservoir model 3 as a function of production period

With a large aquifer, water production becomes a major problem to handle almost reaching water cut economic limit. Water production steadily increases throughout the life of well as depicted in Figure 5.27. Large water production is due to strong aquifer and water breakthrough into the well. Similarly to previous results, distance of lateral well to oil-water contact is key parameter to control water influx in the well. Second parameter to consider is well geometry with less pressure drop created at the heel. Base on simulation results, multilateral wells show significant benefit to reduce water production.

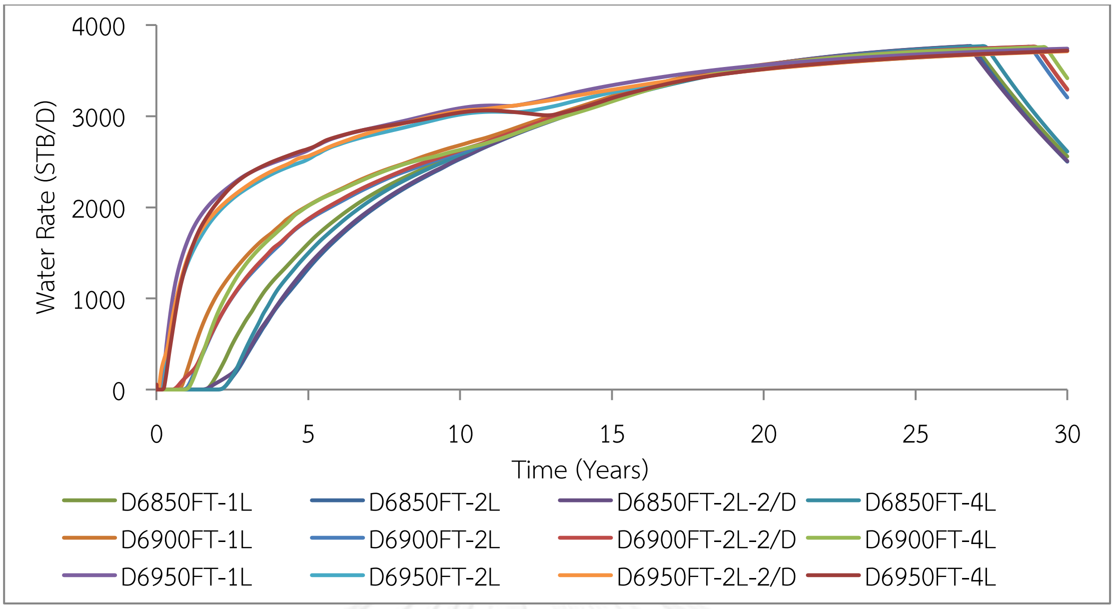


Figure 5.27 Water production rates obtained from implementation of 1,200-ft well with different well geometries in reservoir model 3 as a function of production period

Gas production rates displayed in Figure 5.28 can be divided in three different phases. The first part corresponds to decline of gas production rate. At this period, reservoir pressure is higher than bubble point pressure and only solution gas is produced with a trend following oil production rate. Once reservoir pressure falls below bubble point pressure, gas is liberated at in-situ as free gas and this starts creating a secondary gas cap in the reservoir, slowing down reservoir pressure depletion. The third phase starts when gas from gas cap is produced at a higher rate than released free gas in the reservoir.

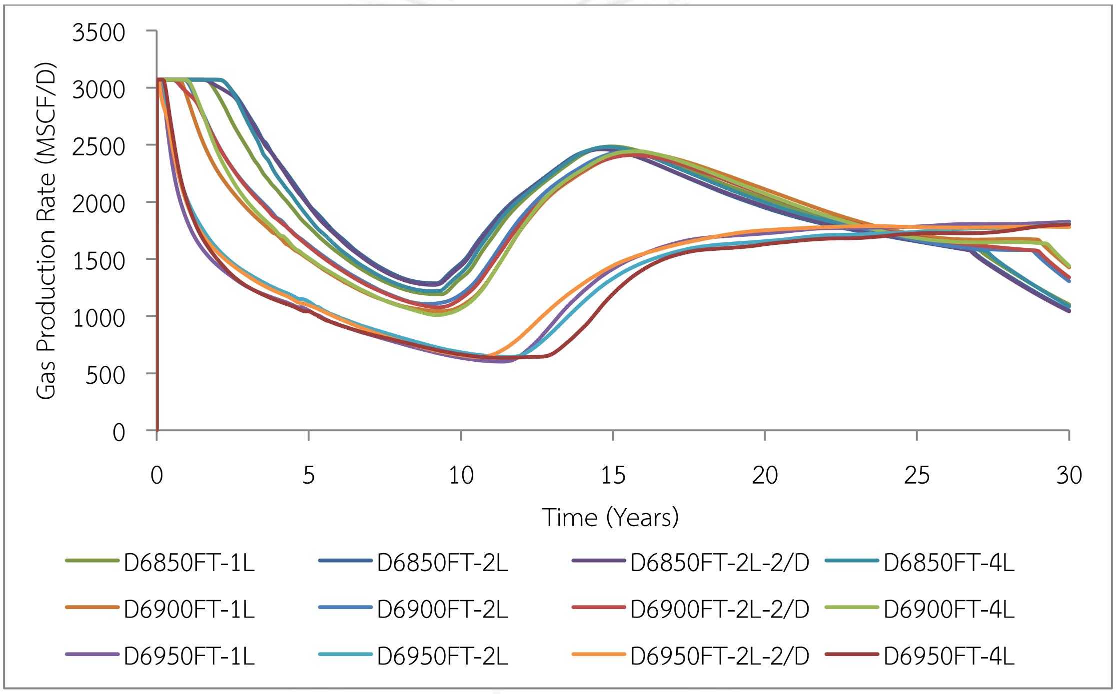


Figure 5.28 Gas production rates obtained from implementation of 1,200-ft well with different well geometries in reservoir model 3 as a function of production period

As shown in Table 5.5, dual-opposed well is the best geometry for 1,200-ft effective length wells in reservoir model 3. For large aquifers, location of lateral well and distance to the oil-water contact play the most important role.

Table 5.5 Simulation outcomes obtained from all well geometries with total producing length of 1,200 ft performed in reservoir model 3

Depth of Lateral (ft)	Number of Laterals	Oil Recovery (%)	Total Oil Production (STB/D)	Total Water Production (STB/D)	Total Gas Production (Mscf/d)
6,850	1	42.54%	13,611,749	29,446,054	21,160,238
	2	44.72%	14,309,323	28,667,800	21,461,946
	2/D	44.42%	14,215,983	28,742,566	21,389,754
	4	43.78%	14,009,121	29,159,204	21,380,544
6,900	1	38.33%	12,266,607	31,463,370	20,239,122
	2	40.48%	12,953,560	30,734,074	20,545,082
	2/D	40.17%	12,853,693	30,873,420	20,456,742
	4	39.62%	12,679,025	31,098,574	20,285,364
6,950	1	29.07%	9,303,878	34,528,120	15,378,060
	2	31.64%	10,125,939	33,706,060	15,354,454
	2/D	30.85%	9,871,312	33,960,688	15,750,269
	4	31.05%	9,935,666	33,896,332	14,777,445

As summarized in Table 5.6, results from reservoir model 3 show slightly lower performances of multilateral wells compared to horizontal wells than in model 2. Multilateral wells offer improvements in terms of oil recovery ranging between 3 to 8 % compared to horizontal wells.

Table 5.6 Differences of simulation outcomes compared to horizontal well for multilateral well geometries with total producing length of 1,200 ft performed in reservoir model 3

Depth of Lateral (ft)	Number of Laterals	Oil production difference with 1L	Water production difference with 1L	Gas production difference with 1L
6,850	1	-	-	-
	2	5.125%	-2.643%	1.426%
	2/D	4.439%	-2.389%	1.085%
	4	2.919%	-0.974%	1.041%
6,900	1	-	-	-
	2	5.600%	-2.318%	1.512%
	2/D	4.786%	-1.875%	1.075%
	4	3.362%	-1.159%	0.228%
6,950	1	-	-	-
	2	8.836%	-2.381%	-0.154%
	2/D	6.099%	-1.643%	2.420%
	4	6.791%	-1.830%	-3.906%

Selection of base case

Dual-opposed well geometry located at 6,850 ft yields the best performance in reservoir supported by a large aquifer equivalent to fifty reservoir pore volume. Water production is also reduced compared to other well geometries and locations. Oil recovery reaches 44.72 % which is significantly higher than other cases.

Figure 5.29 shows reservoir drainage from dual lateral well in reservoir model 3 after 3 years of production and at the end of production time. After 3 years, steep water cresting occurs in the reservoir by means of aquifer support. At the same time, reservoir pressure is maintained higher than bubble point pressure, preventing liberation of gas to form a secondary gas cap as observed in reservoir model 1 and 2. At the end of production, water influx invades wellbore surroundings on the full thickness of the reservoir, leaving oil unproduced oil in major part of reservoir boundaries.

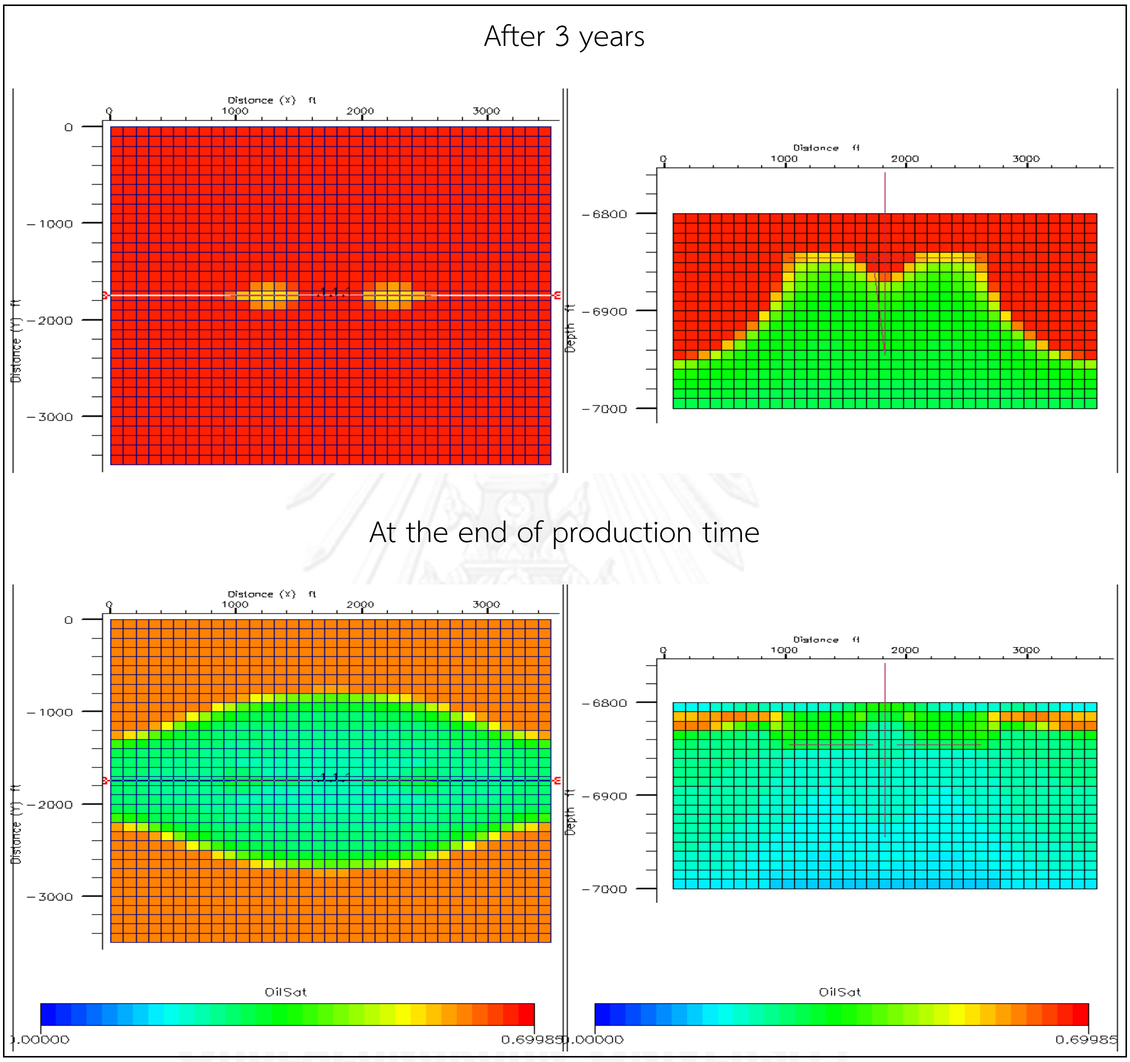


Figure 5.29 Oil saturation profiles of 1,200ft base case in reservoir model 3 after 3 years and at the end of production time

5.2.2 **Effective Producing Length of 2,000 ft**

This section highlights results obtained from medium effective length of 2,000 ft combined with horizontal and multilateral wells. Increase of effective producing length is expected to increase recovery factor thanks to a larger access to oil. Less interference between laterals should also be observed.

Reservoir Model 1 Small Aquifer Size (1PV)

Compared to the 1,200-ft producing length, oil recovery is increased for all well geometries approximately 1.2 to 3.3%. The smallest increments are observed in cases where lateral wells are located at shallow location. On the other hand, big increments are obtained when wells are located at lower depth (6,950ft).

Similarly to 1,200-ft wells, oil recovery depends mainly on location in the reservoir and secondly on well geometry as observed in Figure 5.30. Distances to oil-water contact and to gas-oil contact (secondary gas cap) are both major parameters to determine suitable depth to locate lateral well in order to maximize oil production and decrease gas and water influx in the well.

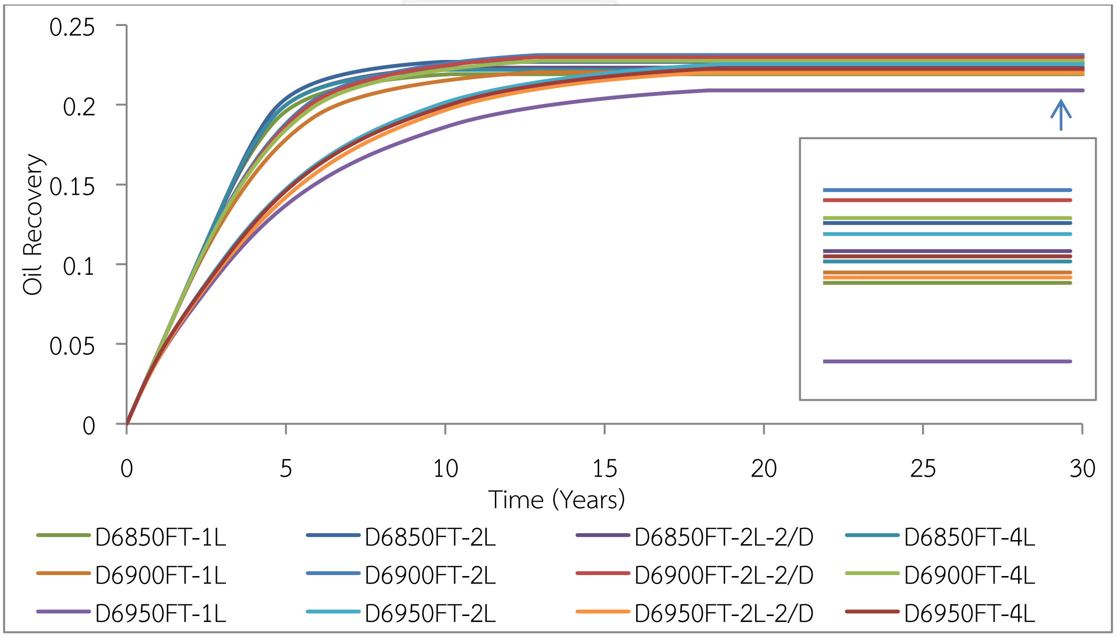


Figure 5.30 Oil recovery factors obtained from implementation of 2,000-ft well with different well geometries in reservoir model 1 as a function of production period

Reservoir pressures observed in this reservoir model follow the similar trend as for shorter wells as shown in Figure 5.31. Wells located closer to oil-water contact tend to keep a higher pressure in the reservoir than other wells because of a smaller production of gas from the secondary gas cap, providing driving force. Bottom water drive is less strong and larger production has a smaller impact on pressure. Thus, reservoir pressure is better maintained with wells located in the middle depth of the reservoir.

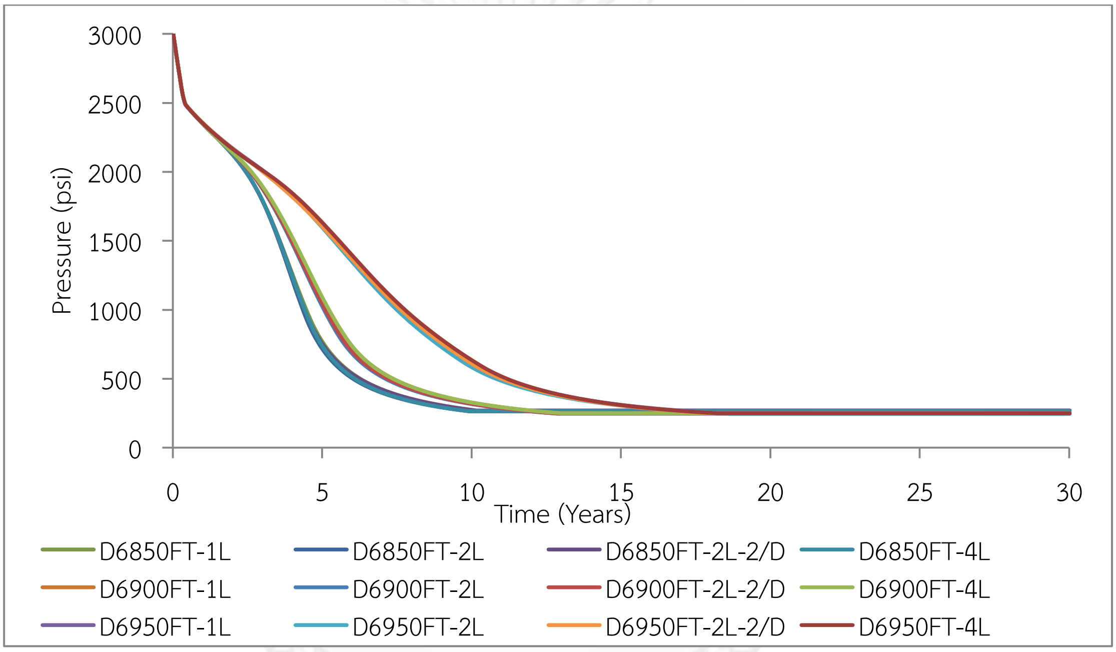


Figure 5.31 Reservoir pressures obtained from implementation of 2,000-ft well with different well geometries in reservoir model 1 as a function of production period

Liquid production rate is closely linked to distance between wells and oil-water contact. Similar trend as previous effective length is observed and illustrated in Figure 5.32.

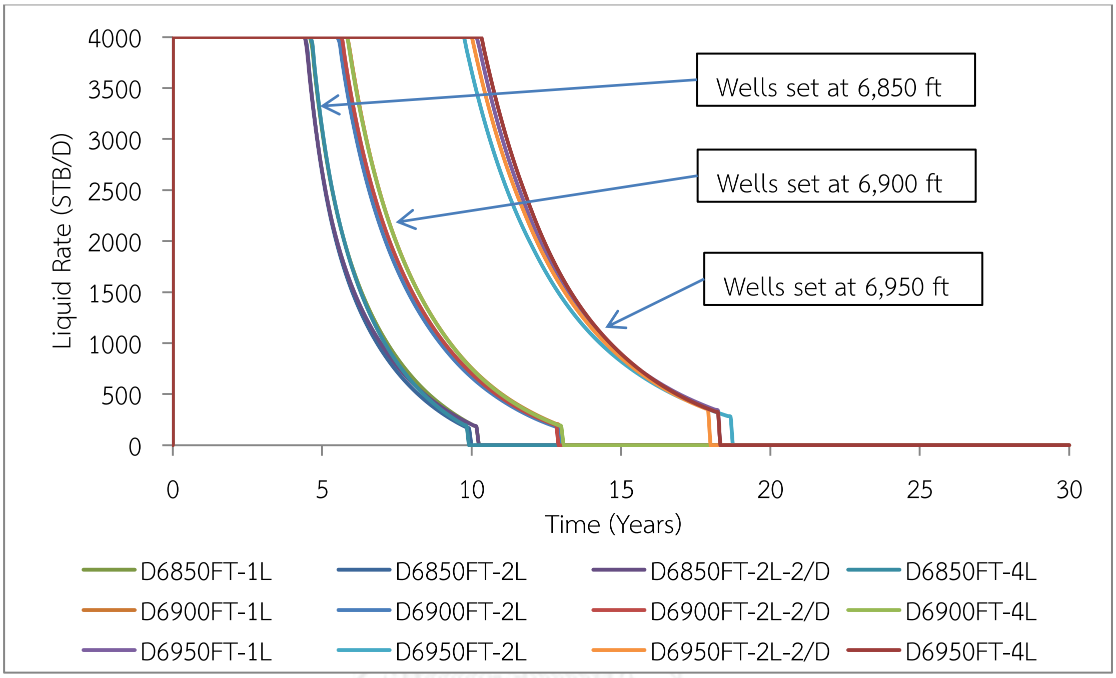


Figure 5.32 Liquid production rates obtained from implementation of 2,000-ft well with different well geometries in reservoir model 1 as a function of production period

For all 2,000-ft wells, oil production rates declines earlier compared to 1,200-ft wells due to a larger drainage and thus faster pressure drop. However, trend of wells located at different location remains the same and multilateral wells show better performance compared to horizontal wells as displayed in Figure 5.33. Decline of oil production rates occurs quickly as soon as water enters the well.

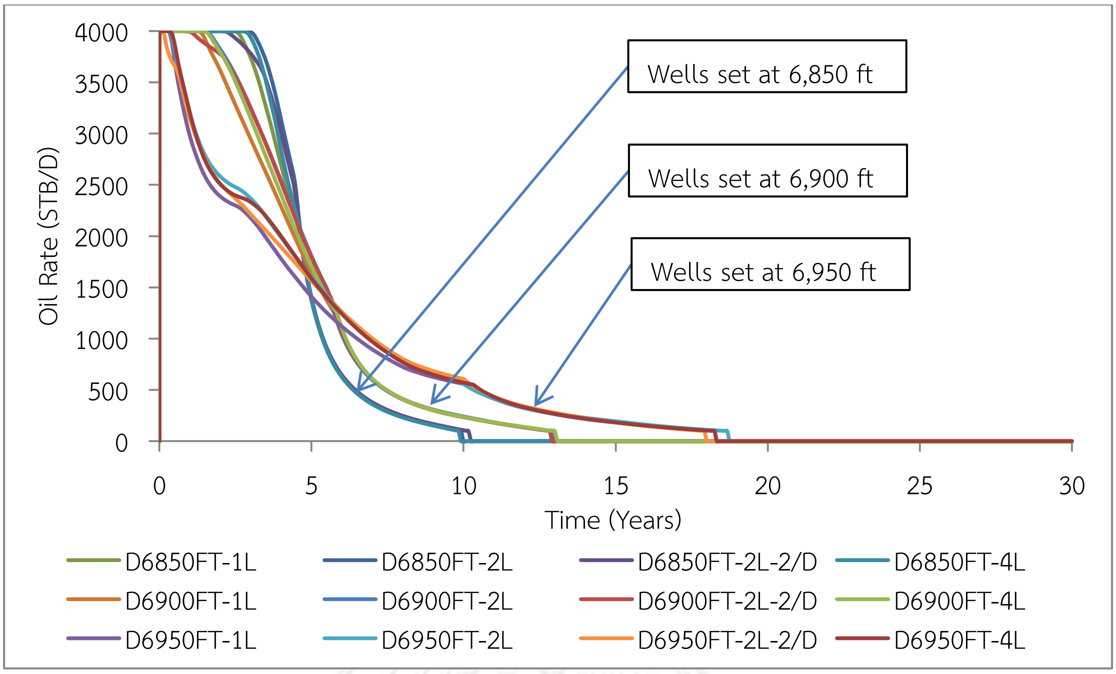


Figure 5.33 Oil production rates obtained from implementation of 2,000-ft well with different well geometries in reservoir model 1 as a function of production period

Effective well length is only parameter which is varied in reservoir model 1. As displayed in Table 5.7, dual-opposed lateral wells show the highest oil recovery compared respectively to dual laterals located at different depths, quadrilateral and horizontal wells. Indeed, Dual-opposed lateral wells offer the best reservoir drainage with lower pressure drop. Oil recovery factor for each well geometry ranges between 20.90 and 23.12%. Dual-opposed lateral well located at 6,900-ft depth is the best case with oil recovery factor of 23.12%.

Longer effective length provides larger reservoir exposure and thus larger drainage for the wells. This directly increases oil production rate at early period. Oil drainage is therefore faster and reservoir depletion occurs earlier. With a larger access to oil, gas production is also produced at much higher rate. Oil and gas are mainly produced in the first ten years of production life, whereas water production builds up with time. Since well life is reduced, water production is also reduced.

Table 5.7 Simulation outcomes obtained from all well geometries with total producing length of 2,000 ft with in reservoir model 1

Depth of Lateral (ft)	Number of Laterals	Oil Recovery (%)	Total Oil Production (STB)	Total Water Production (STB)	Total Gas Production (MSCF)
6,850	1	21.92%	7,014,247	2,145,889	22,953,368
	2	22.69%	7,187,585	1,566,390	22,958,732
	2/D	22.33%	7,145,584	1,731,173	22,941,454
	4	22.19%	7,102,606	1,982,812	22,975,792
6,900	1	22.05%	7,057,033	4,763,549	23,047,138
	2	23.12%	7,328,480	4,028,112	23,089,278
	2/D	22.99%	7,251,841	4,331,300	23,037,962
	4	22.76%	7,282,505	4,527,085	23,072,230
6,950	1	20.90%	6,688,972	12,362,215	22,619,700
	2	22.55%	7,216,172	11,405,062	22,754,968
	2/D	21.99%	7,036,464	11,796,943	22,648,406
	4	22.26%	7,123,937	12,068,510	22,654,568

Dual lateral wells are especially efficient to reduce water production, able to decrease water production in comparison with single horizontal well of about 7 to 30%. Moreover, comparing with quadrilateral well, dual lateral wells can reduce almost 50% performance. For gas production, all cases yield insignificant result.

Results in terms of oil recovery are quite similar for all cases, showing less deviation compared to shorter effective length of 1,200 ft. This can be explained that longer effective producing length can help to decrease interference effects among laterals.

Table 5.8 demonstrates noticeable differences of 2,000-ft well's performance compared to 1,200-ft wells on different points:

- Total oil production is increased between 5.5 and 18%.
- Total water production is decreased up to 19%.
- Total gas production is increased between 2 and 12%.
- Production is terminated earlier for 2,000-ft well because minimum oil rate limit is reached earlier.

Table 5.8 Differences of simulation outcomes compared to horizontal well for multilateral well geometries with total producing length of 2,000 ft performed in reservoir model 1

Depth of Lateral (ft)	Number of Laterals	Oil production difference with 1L	Water production difference with 1L	Gas production difference with 1L
6,850	1	-	-	-
	2	3.528%	-29.646%	0.357%
	2/D	1.872%	-19.326%	-0.052%
	4	1.260%	-7.600%	0.098%
6,900	1	-	-	-
	2	4.833%	-16.815%	0.437%
	2/D	4.241%	-12.311%	0.273%
	4	3.195%	-4.964%	0.109%
6,950	1	-	-	-
	2	7.882%	-7.743%	0.598%
	2/D	5.195%	-4.573%	0.127%
	4	6.503%	-2.376%	0.154%

<u>Selection of base case</u>

Dual-opposed well geometry with total producing length of 2,000 ft located at 6,900 ft depth yields the best performance in the reservoir supported by small aquifer equivalent to one reservoir pore volume. From this selected case, total oil recovery is equivalent to 23.12 %.

Figure 5.34 highlights drainage of 2,000ft dual-opposed well located at -6,900ft in the reservoir model 1 from top view and from side view cut through the middle of the reservoir. After 3 years, reservoir pressure is already below bubble point pressure, creating a secondary gas cap. Water and gas coning both occur around the well, decreasing access to oil. At the end of production time, oil drainage remains located close to the well due to low pressure support.

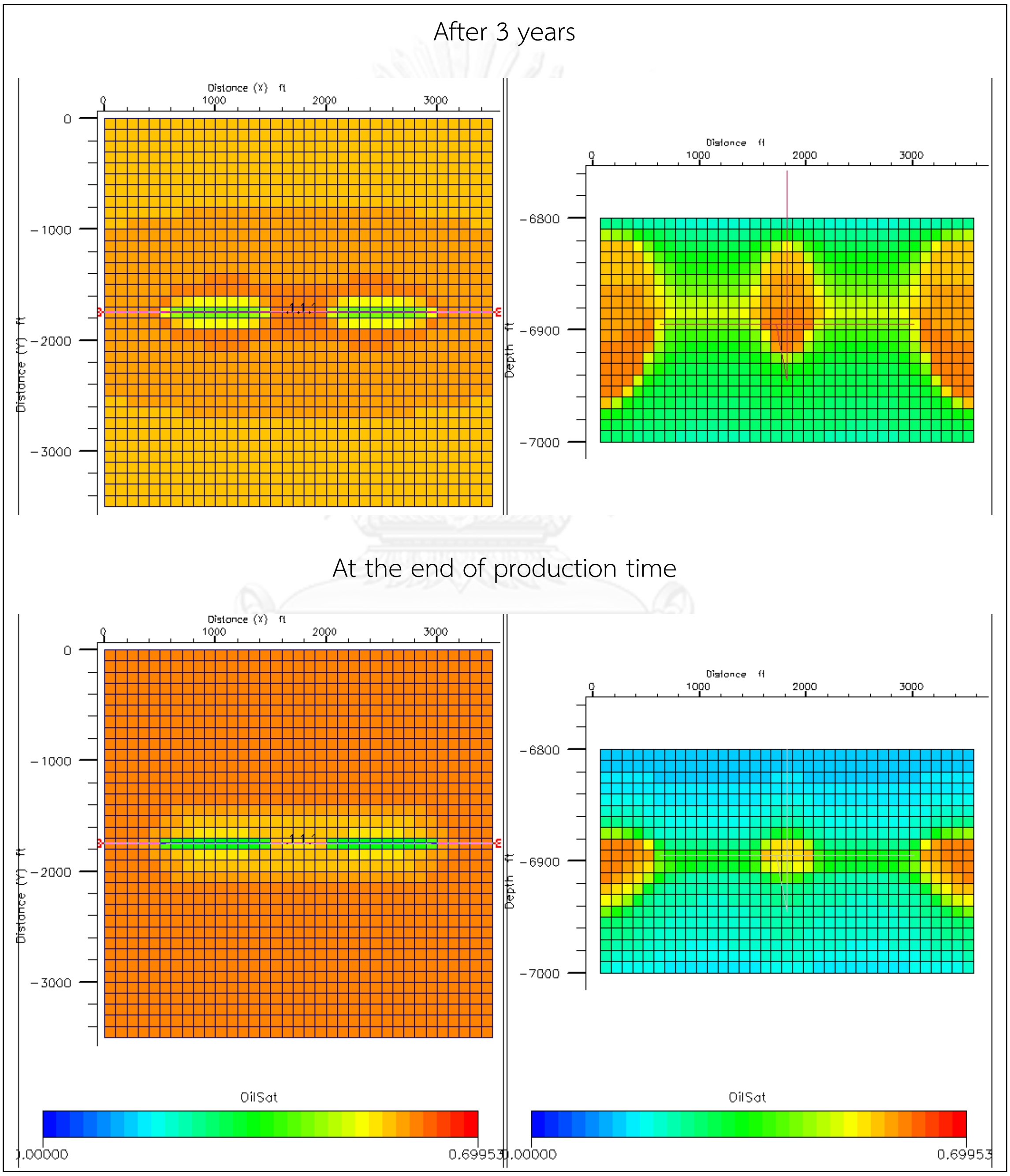


Figure 5.34 Oil saturation profiles of 2,000-ft base case in reservoir model 1 after 3 years and at the end of production time

__Reservoir Model 2 Medium Aquifer Size (10PV)__

In reservoir model 2, reservoir pressure is maintained by the bottom aquifer. Multilateral wells with 2,000-ft producing length therefore perform better in terms of oil recovery as shown in the Figure 5.35. Lateral wells located at 6,850 ft offer the highest recoveries due to late water breakthrough. Dual-opposed well yields the best performance compared to other well geometries.

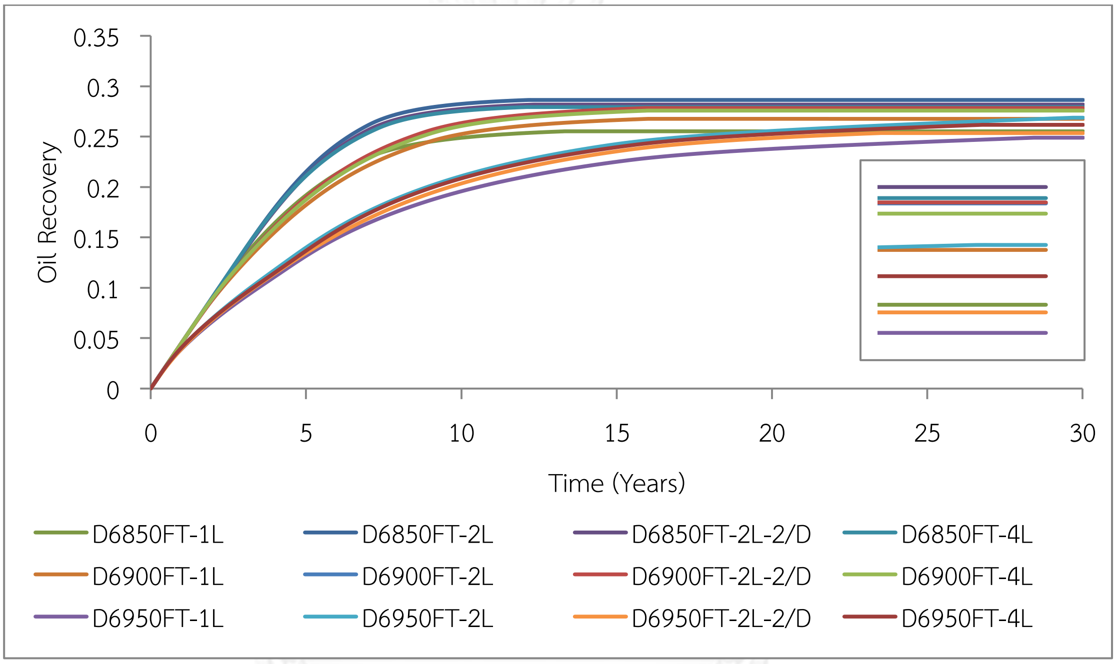


Figure 5.35 Oil recovery factors obtained from implementation of 2,000-ft well with different well geometries in reservoir model 2 as a function of production period

Well length and pressure support both increase production life of well as shown by Figure 5.36. Similarly to the previous cases, wells located closer to bottom aquifer tend to last longer with higher liquid rate due to the large water influx which increases liquid rate.

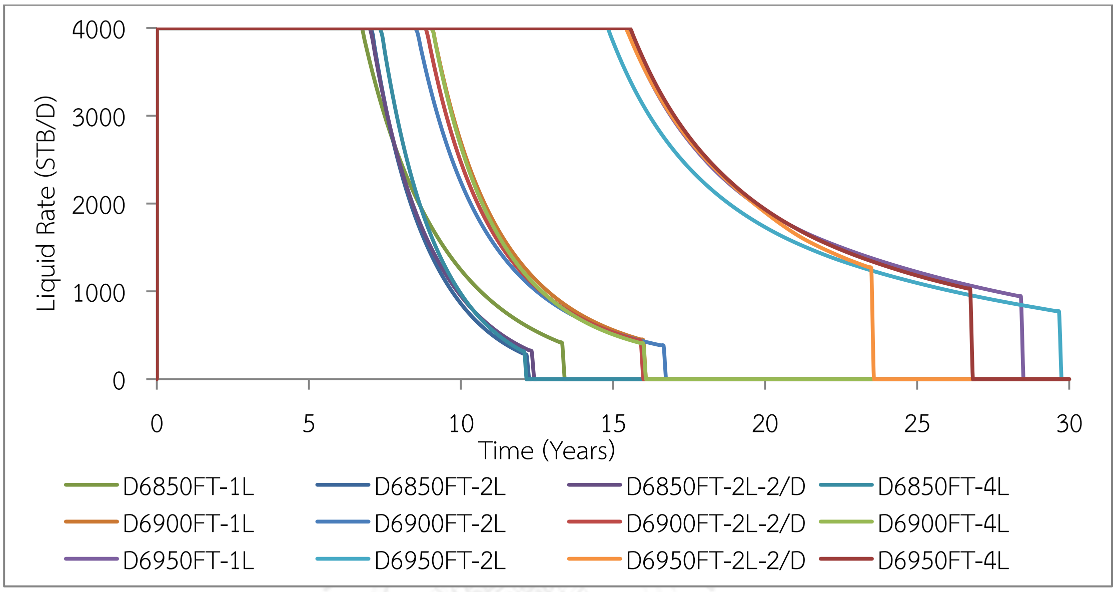


Figure 5.36 Liquid production rates obtained from implementation of 2,000-ft well with different well geometries in reservoir model 2 as a function of production period

With a stronger aquifer support and longer length, desired oil production rate is maintained at plateau for longer period for wells located at 6,850 ft as shown in the Figure 5.37.

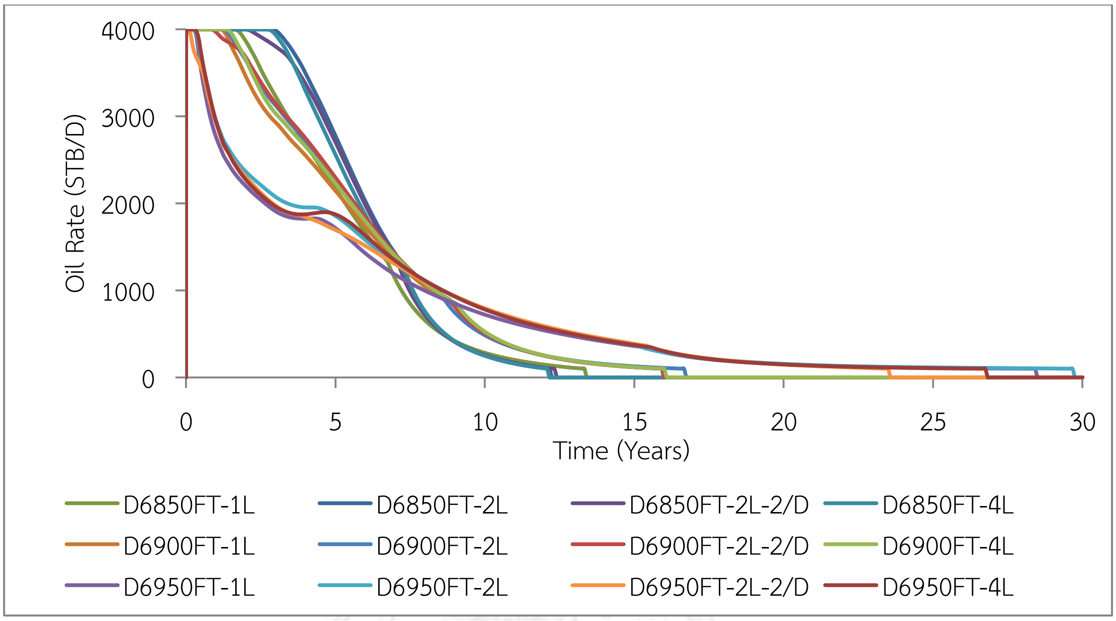


Figure 5.37 Oil production rates obtained from implementation of 2,000-ft well with different well geometries in reservoir model 2 as a function of production period

For these wells, water cut reaches high values ranging between 80 to 92% as shown in Figure 5.38.

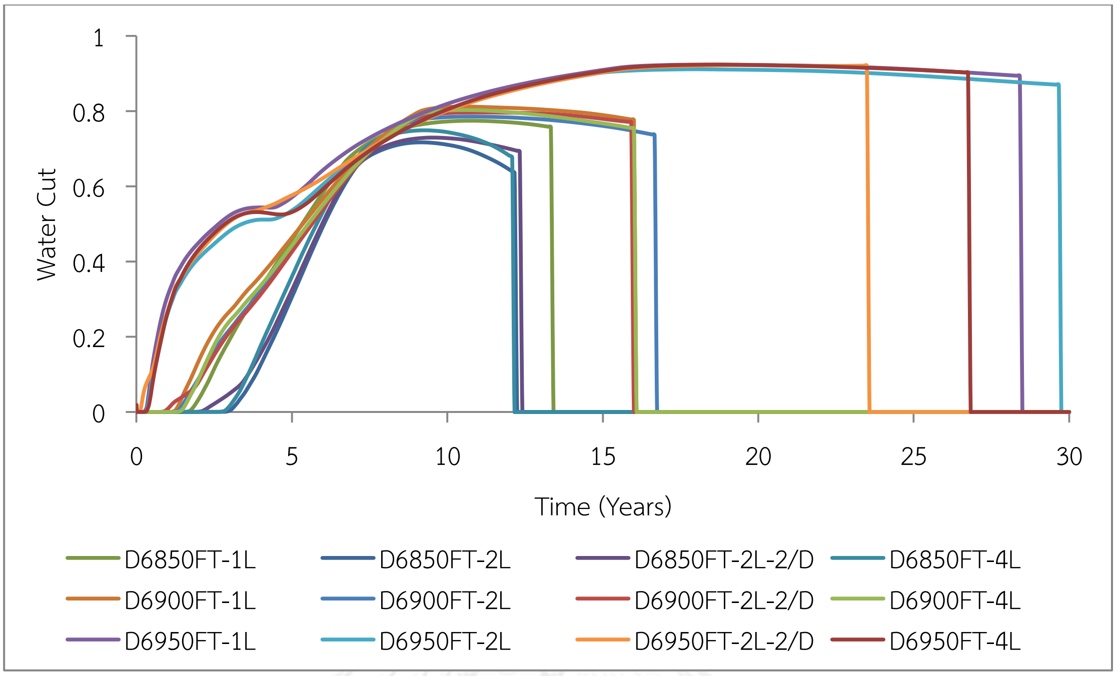


Figure 5.38 Water cut obtained from implementation of 2,000-ft well with different well geometries in reservoir model 2 as a function of production period

Similar trends of simulation outcomes can be observed when wells are performed in reservoir supported by medium size aquifer as described in Table 5.9. Distance from lateral well to oil-water contact and gas-oil contact are major parameters to concern in order to maximize oil production. Well geometry has smaller impact on the well performance in reservoir supported by very large aquifer than low or medium size aquifers. The highest oil recovery factor is obtained from dual-oppose lateral well located at 6,850ft, whereas the lowest oil recovery factor is obtained from horizontal well located at 6,950ft due to large amount of water influx. Oil recovery ranges from 24.89 to 28.64% which is wider than results obtained from reservoir model 1, but the range is smaller than cases of 1,200-ft wells performed in reservoir model 2 (range between 20.85 and 27.93%).

Table 5.9 Simulation outcomes obtained from all well geometries with total producing length of 2,000 ft with in reservoir model 2

Depth of Lateral (ft)	Number of Laterals	Oil Recovery (%)	Total Oil Production (STB)	Total Water Production (STB)	Total Gas Production (MSCF)
6,850	1	27.60%	8,833,076	4,489,854	23,235,612
	2	28.64%	9,165,163	3,671,127	23,330,980
	2/D	28.18%	9,018,080	3,950,540	23,195,636
	4	27.93%	8,938,412	4,262,282	23,274,762
6,900	1	26.76%	8,564,954	8,267,417	23,172,444
	2	28.04%	8,974,777	7,315,299	23,306,074
	2/D	27.83%	8,907,683	7,625,139	23,224,778
	4	27.53%	8,811,137	7,876,905	23,216,598
6,950	1	24.89%	7,965,426	23,212,600	21,826,768
	2	26.87%	8,600,127	21,953,258	22,017,136
	2/D	25.35%	8,113,550	20,923,308	21,618,942
	4	26.12%	8,359,622	22,205,872	21,790,332

Performance comparisons with horizontal wells are summarized in Table 5.10. Multilateral wells show better benefits than horizontal wells to reduce water influx in the well, especially when the distance to the oil water contact is smaller.

Table 5.10 Differences of simulation outcomes compared to horizontal well for multilateral well geometries with total producing length of 2,000 ft performed in reservoir model 2

Depth of Lateral (ft)	Number of Laterals	Oil production difference with 1L	Water production difference with 1L	Gas production difference with 1L
6,850	1	-	-	-
	2	3.760%	-18.235%	0.410%
	2/D	2.094%	-12.012%	-0.172%
	4	1.193%	-5.069%	0.168%
6,900	1	-	-	-
	2	4.785%	-11.517%	0.577%
	2/D	4.002%	-7.769%	0.226%
	4	2.874%	-4.724%	0.191%
6,950	1	-	-	-
	2	7.968%	-5.425%	0.872%
	2/D	1.860%	-9.862%	-0.952%
	4	4.949%	-4.337%	-0.167%

Selection of base case

Dual-opposed well geometry located at 6,850 ft yields the best performance when performed in reservoir supported by medium size aquifer equivalent to ten reservoir pore volume. Water and gas production are still manageable.

Figure 5.39 show reservoir drainage for the base case after 3 years and at the end of production time. Pressure support from aquifer delays appearance and size of secondary gas cap. Thus, it delays gas influx into the well and increases pressure support. On the aquifer side, water cresting is strong which decreases oil drainage in the reservoir.

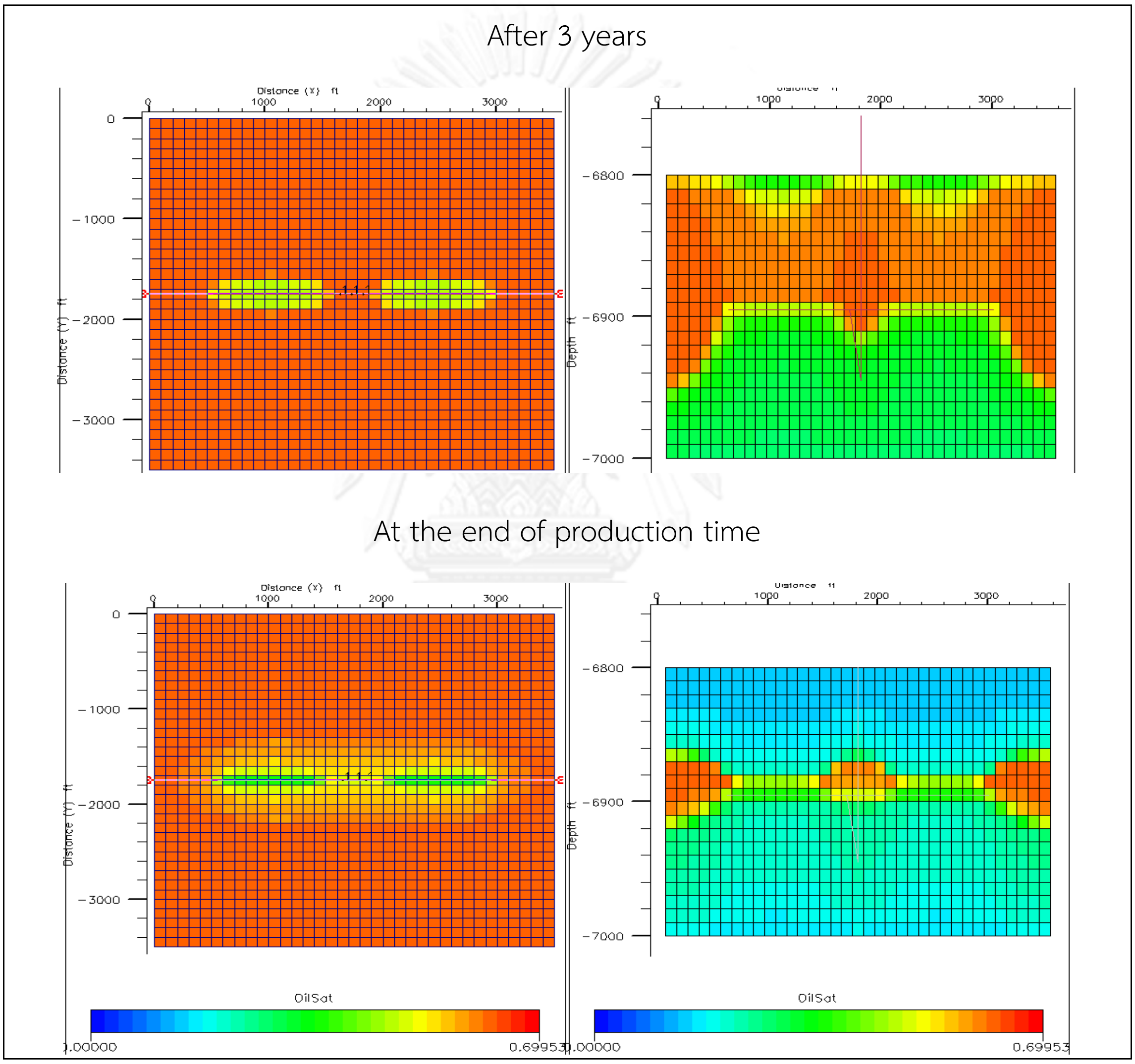


Figure 5.39 Oil saturation profile of 2,000-ft base case in reservoir model 2 after 3 years and at the end of production time

__Reservoir Model 3 Large Aquifer Size (50PV)__

Supported by a large aquifer size, reservoir pressure is expected to be maintained during production life. Oil production is therefore expected to be higher with a larger drainage. However, an increase of water influx from bottom aquifer should result in very early water cresting and high water production.

Figure 5.40 shows oil recovery factor obtained from 2,000-ft wells performed in reservoir model 3. Similar to cases of 1,200-ft well length, reservoir model 3 offers the best conditions to maximize oil recovery due to a large pressure support and thus better reservoir drainage. The best well geometry is still dual lateral well at 6,850 ft, yielding oil recovery of about 45%. Wells located closer to oil-water contact yield lower oil recovery.

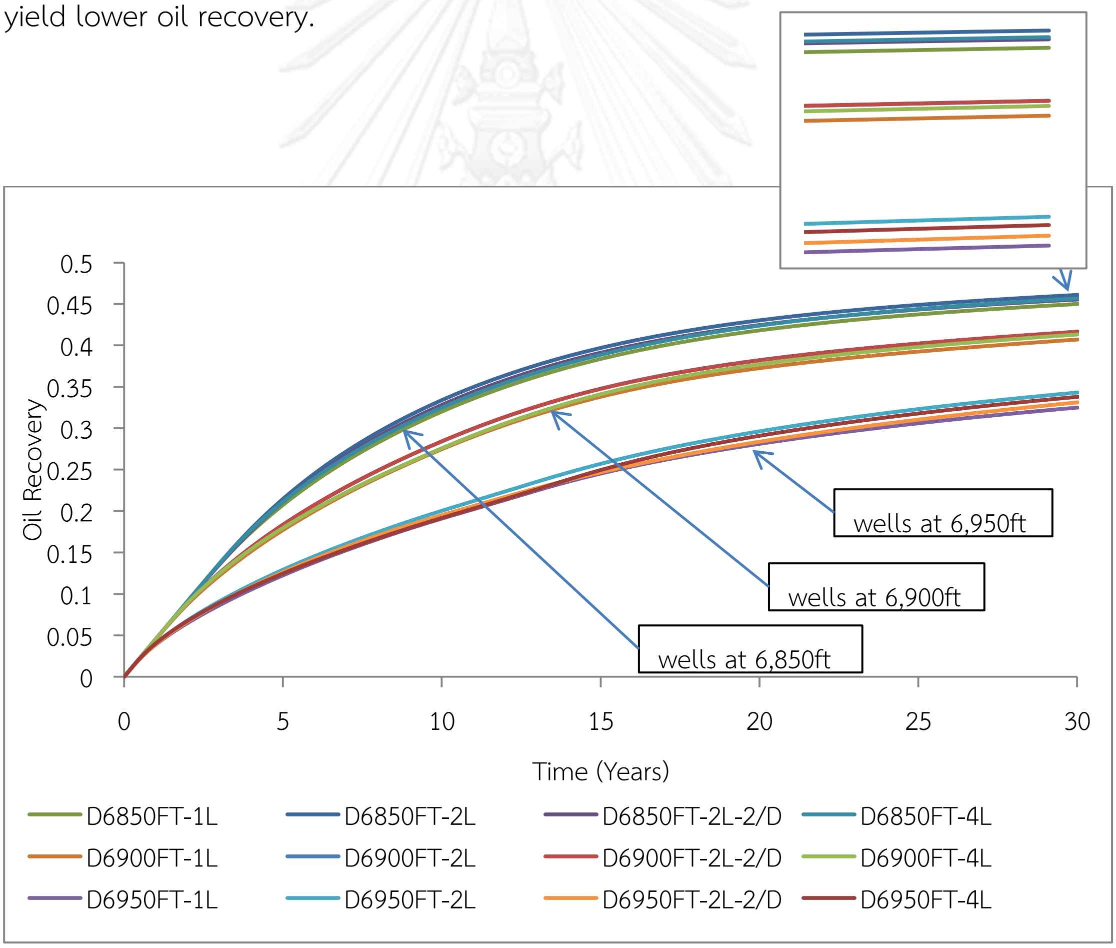


Figure 5.40 Oil recovery factor obtained from implementation of 2,000-ft well with different well geometries in reservoir model 3 as a function of production period

In reservoir model 3, pressure remains relatively high and does not fall below 550 psi for the upper wells and 900 psi for lower as in Figure 5.41. Wells located at lower location obtain larger pressure support due to lower gas production from secondary gas cap as well as lower oil production.

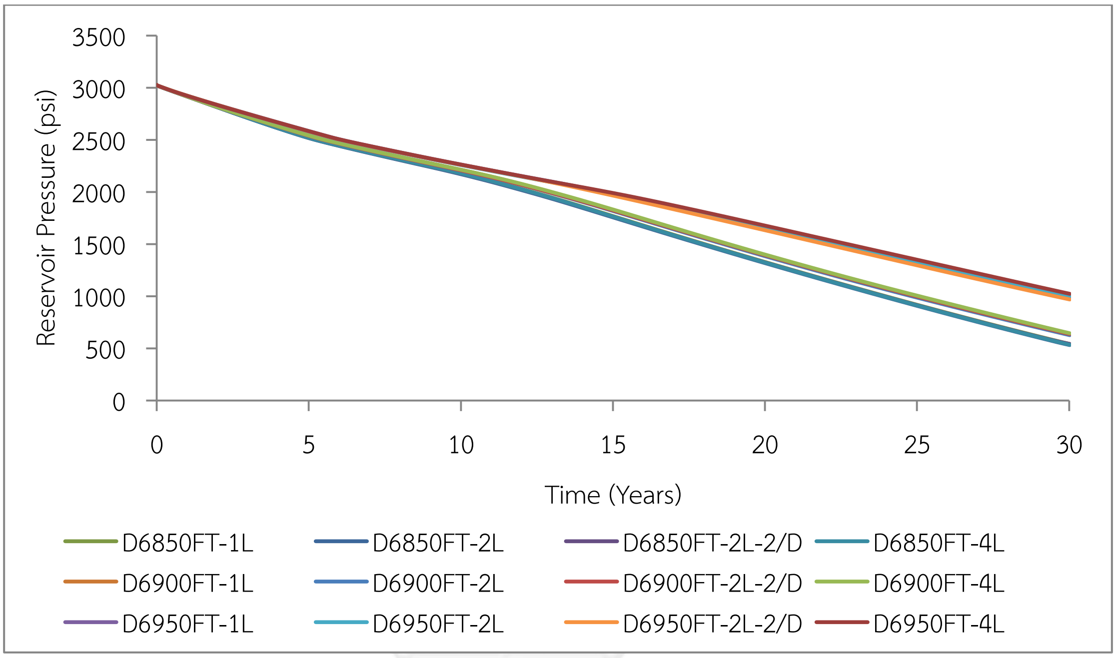


Figure 5.41 Reservoir pressure obtained from implementation of 2,000-ft well with different well geometries in reservoir model 3 as a function of production period

With a large pressure support and large water influx in reservoir, liquid flow rate remains at its maximum during full production period. As shown Figure 5.42, oil production does not terminate due to of well control limits but because of total production period. Reservoir pressure indeed enables larger oil drainage in parallel to a large water influx.

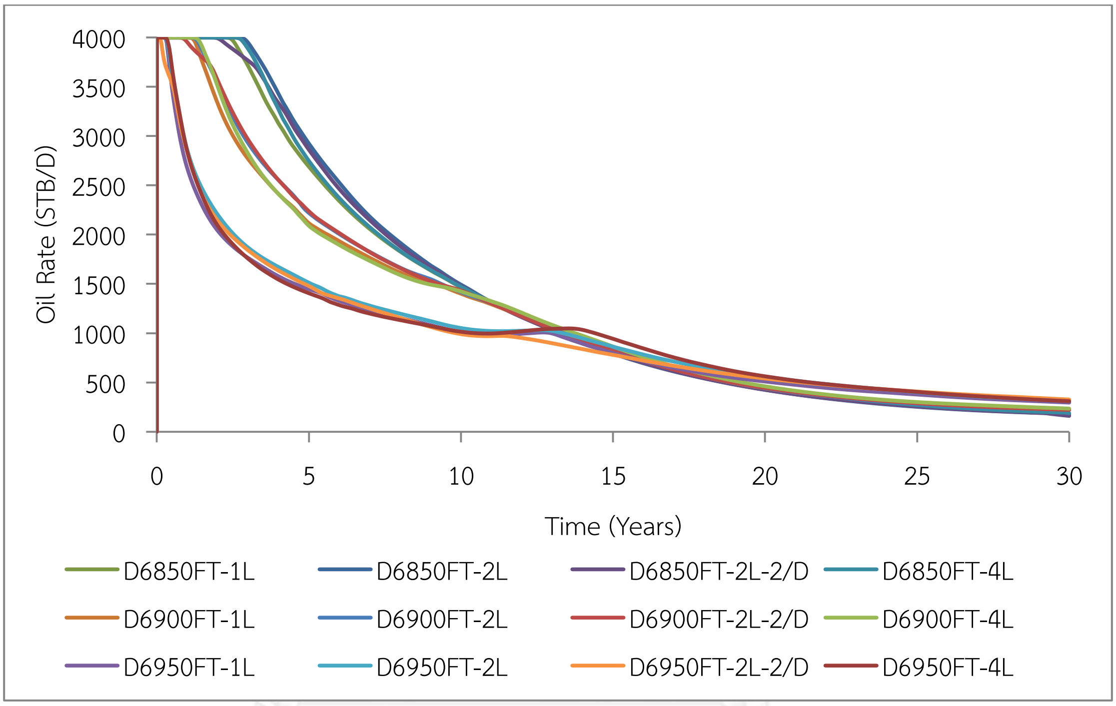


Figure 5.42 Oil production rates obtained from implementation of 2,000-ft well with different well geometries in reservoir model 3 as a function of production period

Reservoir model 3 gives similar trend of performance for 2,000-ft wells as 1,200 ft wells as summarized in

Table 5.11. Reservoir pressure remains high all over the production period and water production is a major constraint for oil production as water cut reaches very high values up to 93%. Higher oil recovery factor is obtained by well geometry which is located at the furthest point from oil-water contact with the least pressure drop.

Table 5.11 Simulation outcomes obtained from all well geometries with total producing length of 2,000 ft with in reservoir model 3

Depth of Lateral (ft)	Number of Laterals	Oil Recovery (%)	Total Oil Production (STB)	Total Water Production (STB)	Total Gas Production (MSCF)
6,850	1	45.00%	14,399,588	29,419,410	21,722,258
	2	46.09%	14,747,971	29,056,168	21,869,524
	2/D	45.53%	14,570,817	29,165,780	21,754,704
	4	45.67%	14,613,376	29,215,618	21,823,400
6,900	1	40.71%	13,026,373	30,805,628	20,507,532
	2	41.93%	13,417,253	30,414,748	20,672,682
	2/D	41.65%	13,328,765	30,503,234	20,527,214
	4	41.32%	13,223,552	30,608,448	20,417,428
6,950	1	32.50%	10,399,143	33,432,858	14,856,683
	2	34.32%	10,981,373	32,850,626	14,807,919
	2/D	33.12%	10,599,485	33,232,516	15,309,271
	4	33.68%	10,778,523	33,053,478	14,438,367

As summarized in Table 5.12, for the best location at 6,850 ft, multilateral well geometries offer slightly better recoveries compared to single horizontal well. Improvements from multilateral remain quite small compared to previous models. The strong pressure support indeed “hides” the benefits of multilateral.

Table 5.12 Differences of simulation outcomes compared to horizontal well for multilateral well geometries with total producing length of 2,000 ft performed in reservoir model 3

Depth of Lateral (ft)	Number of Laterals	Oil production difference with 1L	Water production difference with 1L	Gas production difference with 1L
6,850	1	-	-	-
	2	2.419%	-1.235%	0.678%
	2/D	1.189%	-0.862%	0.149%
	4	1.485%	-0.693%	0.466%
6,900	1	-	-	-
	2	3.001%	-1.269%	0.805%
	2/D	2.321%	-0.982%	0.096%
	4	1.514%	-0.640%	-0.439%
6,950	1	-	-	-
	2	5.599%	-1.741%	-0.328%
	2/D	1.927%	-0.599%	3.046%
	4	3.648%	-1.135%	-2.816%

Selection of base case

Dual-opposed well geometry located at 6,850 ft yields the best performance in a reservoir supported by large aquifer equivalent to fifty reservoir pore volume. Oil recovery reaches approximately 46.09 % which is significantly higher than other well geometries and other reservoir models. Water production is also at its lowest for this model.

Figure 5.43 focuses on oil drainage obtained from the base case with cross sectional views at 6,850 ft for the top view and along the wellbore for side view. High reservoir pressure reduces secondary gas cap size in the first years. Water influx in the reservoir is however strong but cresting shape is not as steep as for 1,200ft. In this case, oil is produced in longer well segments which decrease pressure drop and proportionally decrease water influx.

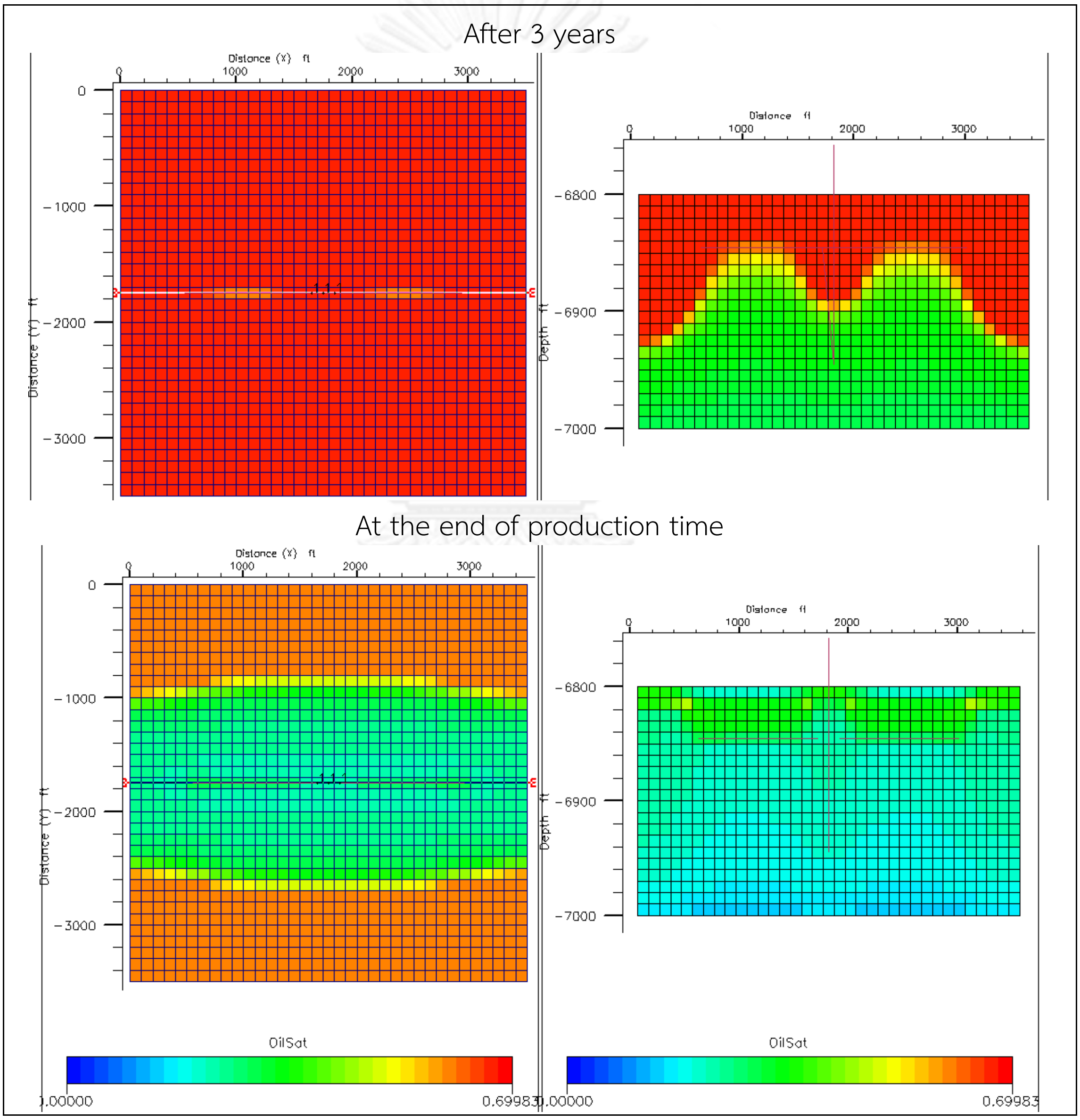


Figure 5.43 Oil saturation profiles of 2,000-ft base case in reservoir model 3 after 3 years and at the end of production time

5.2.3 **Effective Producing Length of 2,800 ft**

This section highlights results obtained from the longest effective producing length which is 2,800 ft. Increase of effective producing length is expected to increase recovery factor thanks to a larger drainage. Less interference between laterals should also be observed but boundary effects may occur.

Reservoir Model 1 Small Aquifer Size (1PV)

In Figure 5.44, quadrilateral wells located at 6,900 and 6,950 ft show the best recovery factors compared to other well geometries. With this producing length, access to oil of quadrilateral well is increased and oil from new parts of the reservoir can be produced. Moreover, interferences between laterals are proportionally reduced and hence overall drainage of laterals is increased.

The best performance is obtained by a quadrilateral well located at 6,950 ft. Distances from lateral wells to oil-water contact and to gas-oil contact (secondary gas cap) are still both major parameters to maximize oil production and decrease gas and water influx into the well. Productions of water and gas directly impact total production period of each well.

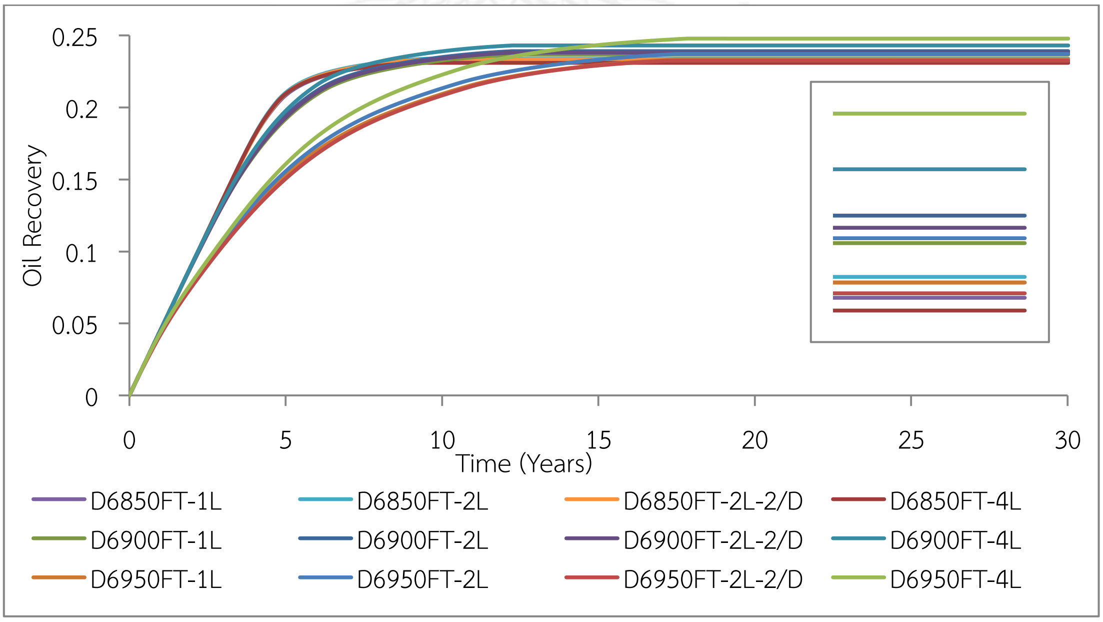


Figure 5.44 Oil recovery factors obtained from implementation of 2,800-ft well with different well geometries in reservoir model 1 as a function of production period

Effective well length is the only parameter which is varied in this section.

Reservoir pressure observed in these cases follow the same trend as for shorter wells. Longer effective length provides larger reservoir contact. This directly increases oil production rate at early times. It also results in faster depletion of reservoir pressure and oil rate limit is reached earlier. With a larger drainage, gas production is also produced at a much higher rate. Oil and gas are mainly produced in the first 10 years of production life, whereas water production builds up with time. Since well life is reduced, water production is also reduced.

Table 5.13 summarizes performances of 2,800-ft well with different well geometries performed in the reservoir model 1. The best performance is achieved by quadrilateral well located at 6,950 ft. Benefits are obtained thanks to large access to oil and gravity drainage. However, water production is almost three times more than quadrilateral well located at 6,900 ft. Therefore, the latter is chosen as best case for the reservoir model 1.

Table 5.13 Simulation outcomes obtained from all well geometries with total producing length of 2,800 ft with in reservoir model 1

Depth of Lateral (ft)	Number of Laterals	Oil Recovery (%)	Total Oil Production (STB)	Total Water Production (STB)	Total Gas Production (MSCF)
6,850	1	23.20%	7,427,641	1,630,391	23,199,868
	2	23.40%	7,484,691	1,495,475	23,208,826
	2/D	23.34%	7,469,670	1,606,189	23,181,620
	4	23.17%	7,416,012	1,374,366	23,246,580
6,900	1	23.70%	7,577,169	4,164,840	23,296,414
	2	23.90%	7,652,528	4,012,010	23,292,514
	2/D	23.81%	7,619,301	4,220,706	23,269,386
	4	24.35%	7,793,009	3,788,676	23,329,870
6,950	1	23.34%	7,469,248	11,516,618	22,940,496
	2	23.72%	7,590,690	11,325,820	22,921,584
	2/D	23.25%	7,439,909	11,805,312	22,859,662
	4	24.83%	7,946,134	11,126,309	22,976,992

Table 5.14 shows that quadrilateral well performance is increased when wells are located closer to oil-water contact. This is due to the better access to oil which maximizes benefit compared to horizontal wells.

Table 5.14 Differences of simulation outcomes compared to horizontal well for multilateral well geometries with total producing length of 2,800 ft performed in reservoir model 1

Depth of Lateral (ft)	Number of Laterals	Oil production difference with 1L	Water production difference with 1L	Gas production difference with 1L
6,850	1	-	-	-
	2	0.768%	-8.275%	0.039%
	2/D	0.566%	-1.484%	-0.079%
	4	-0.157%	-15.703%	0.201%
6,900	1	-	-	-
	2	0.995%	-3.670%	-0.017%
	2/D	0.556%	1.341%	-0.116%
	4	2.849%	-9.032%	0.144%
6,950	1	-	-	-
	2	1.626%	-1.657%	-0.082%
	2/D	-0.393%	2.507%	-0.352%
	4	6.385%	-3.389%	0.159%

Selection of base case

Quadrilateral wells set located at 6,900 and 6,950 ft offer the best performance for 2,800-ft effective length wells. However, water production is very high when all laterals are located at 6,950 ft. Quadrilateral well geometry located at 6,900 ft is therefore chosen.

Figure 5.45 highlights the reservoir drainage for 2,800ft quadrilateral well in reservoir model 1.

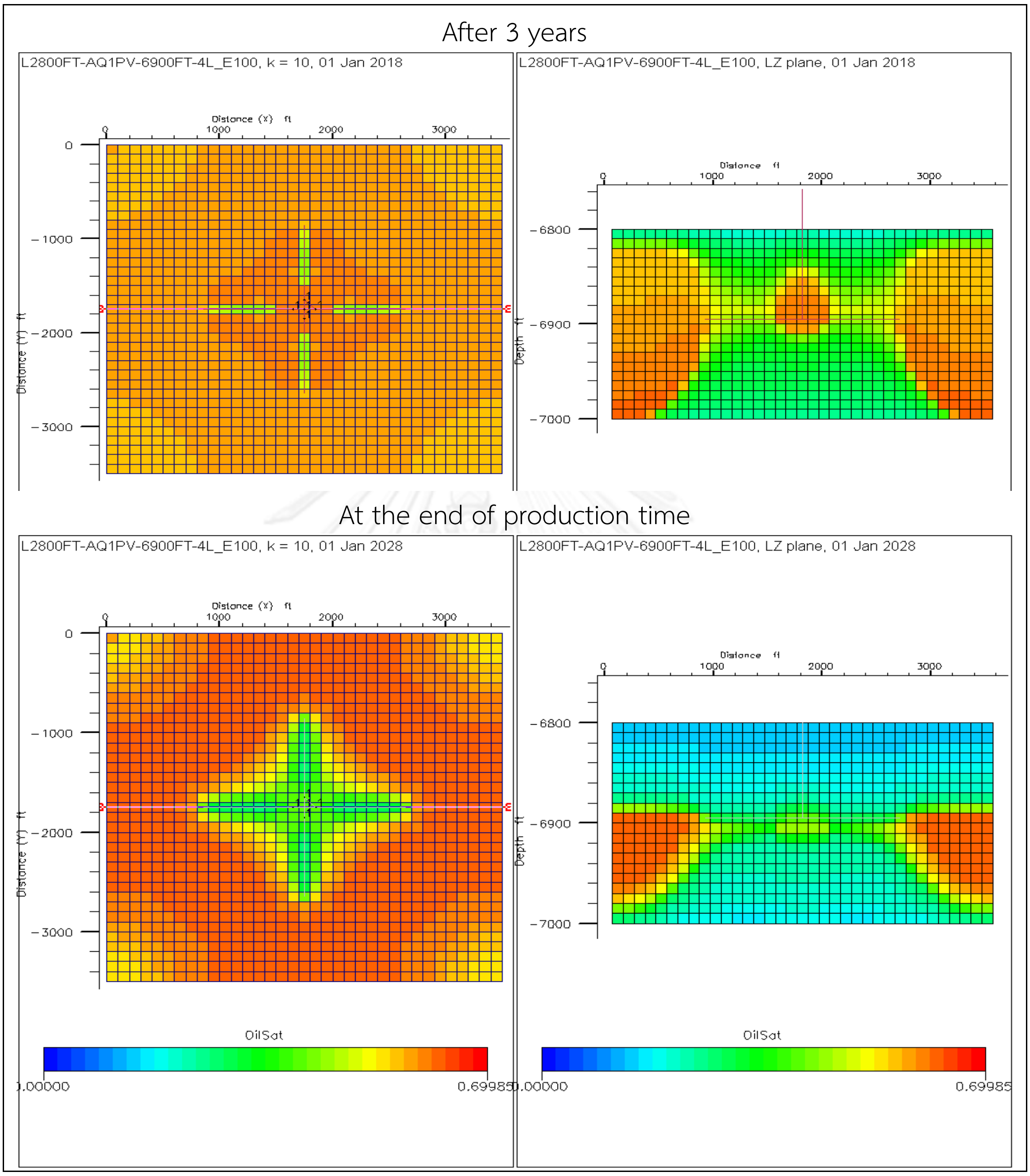


Figure 5.45 Oil saturation profile for 2,800-ft base case in reservoir model 1 after 3 years and at the end of production time

Reservoir Model 2 Medium Aquifer Size (10PV)

In reservoir model 2, 2,800-ft wells provide different results compared to shorter wells as summarized in Table 5.15. Benefits of quadrilateral wells compared to dual laterals and horizontal wells are bigger. Whereas 1,200-ft and 2,000-ft dual opposed wells located at 6,850 ft in reservoir model 2 offer the best performance. The 2,800-ft quadrilateral well located at 6,900 ft yields the best oil recovery up to 29.50%. This is due to larger oil drainage as well as a lower pressure drop from the well when producing at 4,000 STB/D.

Table 5.15 Simulation outcomes obtained from all well geometries with total producing length of 2,800 ft in reservoir model 2

Depth of Lateral (ft)	Number of Laterals	Oil Recovery (%)	Total Oil Production (STB)	Total Water Production (STB)	Total Gas Production (MSCF)
6,850	1	29.06%	9,298,073	3,841,374	23,508,420
	2	29.23%	9,355,623	3,699,207	23,518,066
	2/D	29.11%	9,316,781	3,849,586	23,460,010
	4	29.36%	9,394,994	3,426,941	23,574,742
6,900	1	28.62%	9,159,155	7,555,000	23,497,384
	2	28.87%	9,237,638	7,380,127	23,498,540
	2/D	28.60%	9,153,294	7,671,101	23,385,206
	4	29.50%	9,443,235	6,897,175	23,548,194
6,950	1	27.47%	8,789,765	22,354,980	22,495,290
	2	27.87%	8,918,958	21,736,428	22,091,880
	2/D	26.72%	8,551,258	21,609,382	21,817,618
	4	29.14%	9,325,139	20,902,610	22,191,002

Similarly to the previous case, Table 5.16 assesses benefits of quadrilateral well geometry when the well is located closer to oil-water contact.

Table 5.16 Differences of simulation outcomes compared to horizontal well for multilateral well geometries with total producing length of 2,800 ft performed in reservoir model 2

Depth of Lateral (ft)	Number of Laterals	Oil production difference with 1L	Water production difference with 1L	Gas production difference with 1L
6,850	1	-	-	-
	2	0.619%	-3.701%	0.041%
	2/D	0.201%	0.214%	-0.206%
	4	1.042%	-10.789%	0.282%
6,900	1	-	-	-
	2	0.857%	-2.315%	0.005%
	2/D	-0.064%	1.537%	-0.477%
	4	3.102%	-8.707%	0.216%
6,950	1	-	-	-
	2	1.470%	-2.767%	-1.793%
	2/D	-2.713%	-3.335%	-3.013%
	4	6.091%	-6.497%	-1.353%

<u>Selection of base case</u>

For reservoir model 2, quadrilateral well located at 6,900 ft is chosen as a base case.

Figure 5.46 shows the reservoir drainage for 2,800ft quadrilateral well in reservoir model 2.

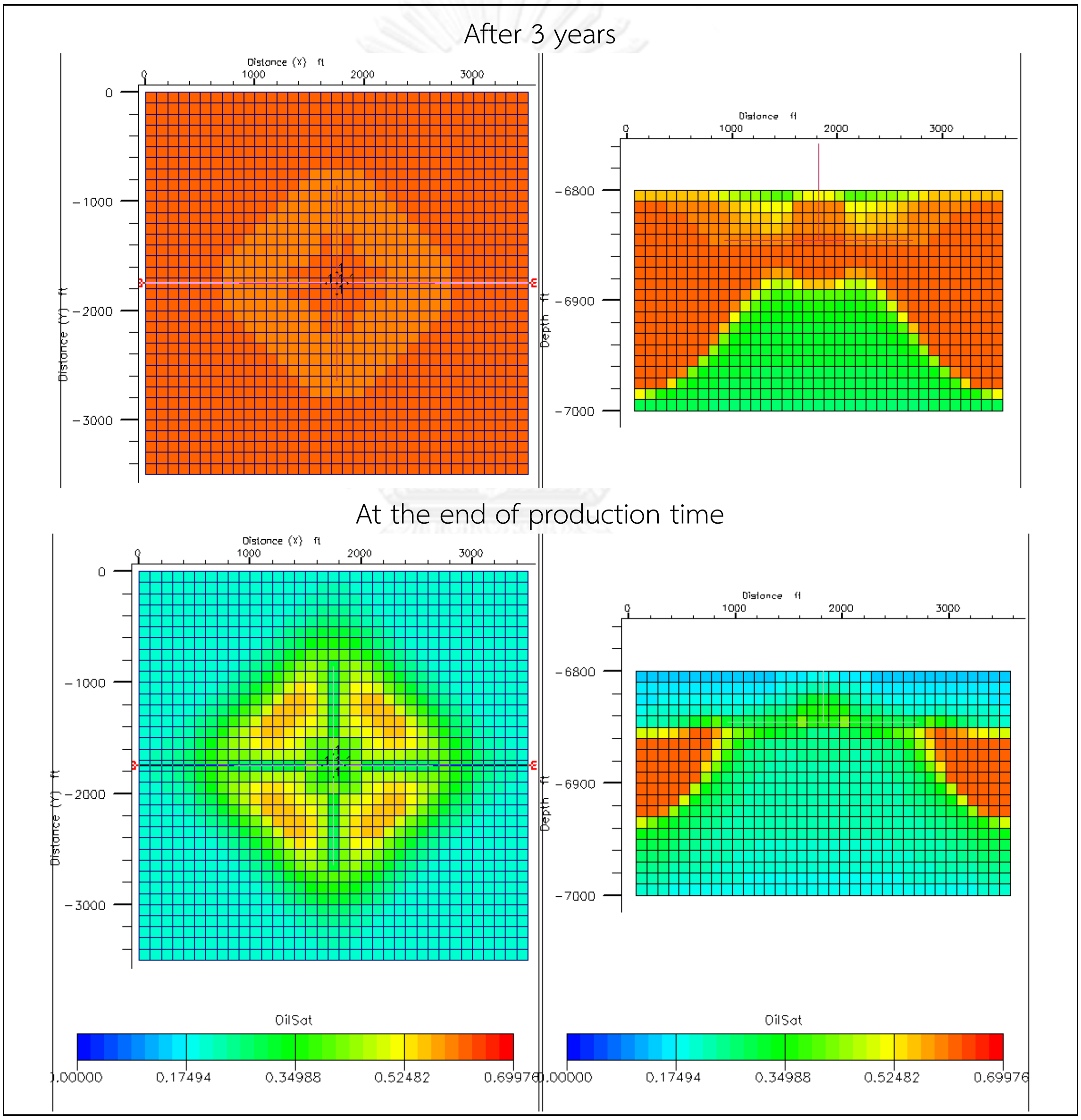


Figure 5.46 Oil saturation profile for 2,800-ft base case in reservoir model 2 after 3 years and at the end of production time

Reservoir Model 3 Large Aquifer Size (50PV)

Reservoir model 3 offers the best performance for all tested geometries. As shown in Figure 5.47, oil recovery reaches 47% for quadrilateral wells located at 6,850 ft. This location enables lower water production and thus a better access to oil, utilizing pressure support from bottom aquifer.

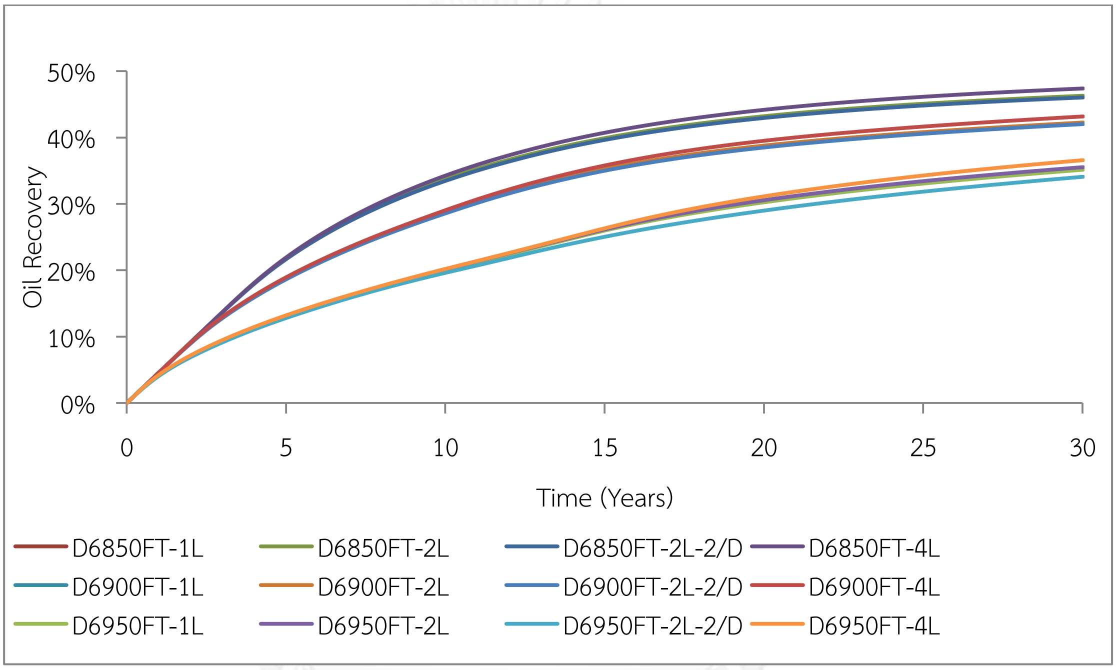


Figure 5.47 Oil recovery factors obtained from implementation of 2,800-ft well with different well geometries in reservoir model 3 as a function of production period

Table 5.17 provides performance of each well geometry performed in reservoir model 3. At every location, quadrilateral wells offer the best performance compared to other well geometries. Overall, quadrilateral well located at 6,850 ft offers the best oil recovery of about 47.5%. Drainage is the main benefit from this well geometry. At the same time, interferences between laterals are also reduced compared to shorter wells.

Table 5.17 Simulation outcomes obtained from all well geometries with total producing length of 2,800 ft with in reservoir model 3

Depth of Lateral (ft)	Number of Laterals	Oil Recovery (%)	Total Oil Production (STB)	Total Water Production (STB)	Total Gas Production (MSCF)
6,850	1	46.15%	14,766,837	29,065,162	21,877,508
	2	46.29%	14,812,935	29,019,064	21,898,560
	2/D	46.03%	14,730,340	29,101,660	21,830,928
	4	47.50%	15,198,951	28,633,050	22,036,916
6,900	1	42.06%	13,460,598	30,371,402	20,518,070
	2	42.26%	13,523,752	30,308,248	20,509,114
	2/D	42.02%	13,447,555	30,384,444	20,334,674
	4	43.28%	13,848,339	29,983,662	20,487,314
6,950	1	35.15%	11,247,576	32,584,424	14,279,089
	2	35.53%	11,370,974	32,461,026	14,199,037
	2/D	34.09%	10,908,066	32,923,934	14,815,626
	4	36.76%	11,763,025	32,068,976	14,002,951

Similarly to the previous models, Table 5.18 shows benefit of quadrilateral increasing when it is closer to the oil-water contact.

Table 5.18 Differences of simulation outcomes compared to horizontal well for multilateral well geometries with total producing length of 2,800 ft performed in reservoir model 3

Depth of Lateral (ft)	Number of Laterals	Oil production difference with 1L	Water production difference with 1L	Gas production difference with 1L
6,850	1	-	-	-
	2	0.312%	-0.159%	0.096%
	2/D	-0.247%	0.126%	-0.213%
	4	2.926%	-1.487%	0.729%
6,900	1	-	-	-
	2	0.469%	-0.208%	-0.044%
	2/D	-0.097%	0.043%	-0.894%
	4	2.881%	-1.071%	7.449%
6,950	1	-	-	-
	2	1.097%	-0.379%	-0.561%
	2/D	-3.019%	1.042%	3.758%
	4	4.583%	-1.582%	-1.934%

Selection of base case

For reservoir model 3, quadrilateral well geometry located at 6,850 ft is chosen as a base case.

Figure 5.48 highlights reservoir drainage for 2,800ft quadrilateral well in reservoir model 3. With strong bottom water drive reservoir, water cresting occurs relatively fast. However, quadrilateral geometry dispatches pressure drop in four segments decreasing tendency of water cresting. Shape of water cone is indeed not as steep as observed on dual-opposed or horizontal wells. Moreover, length of segments decreases even more pressure drop along the wellbore.

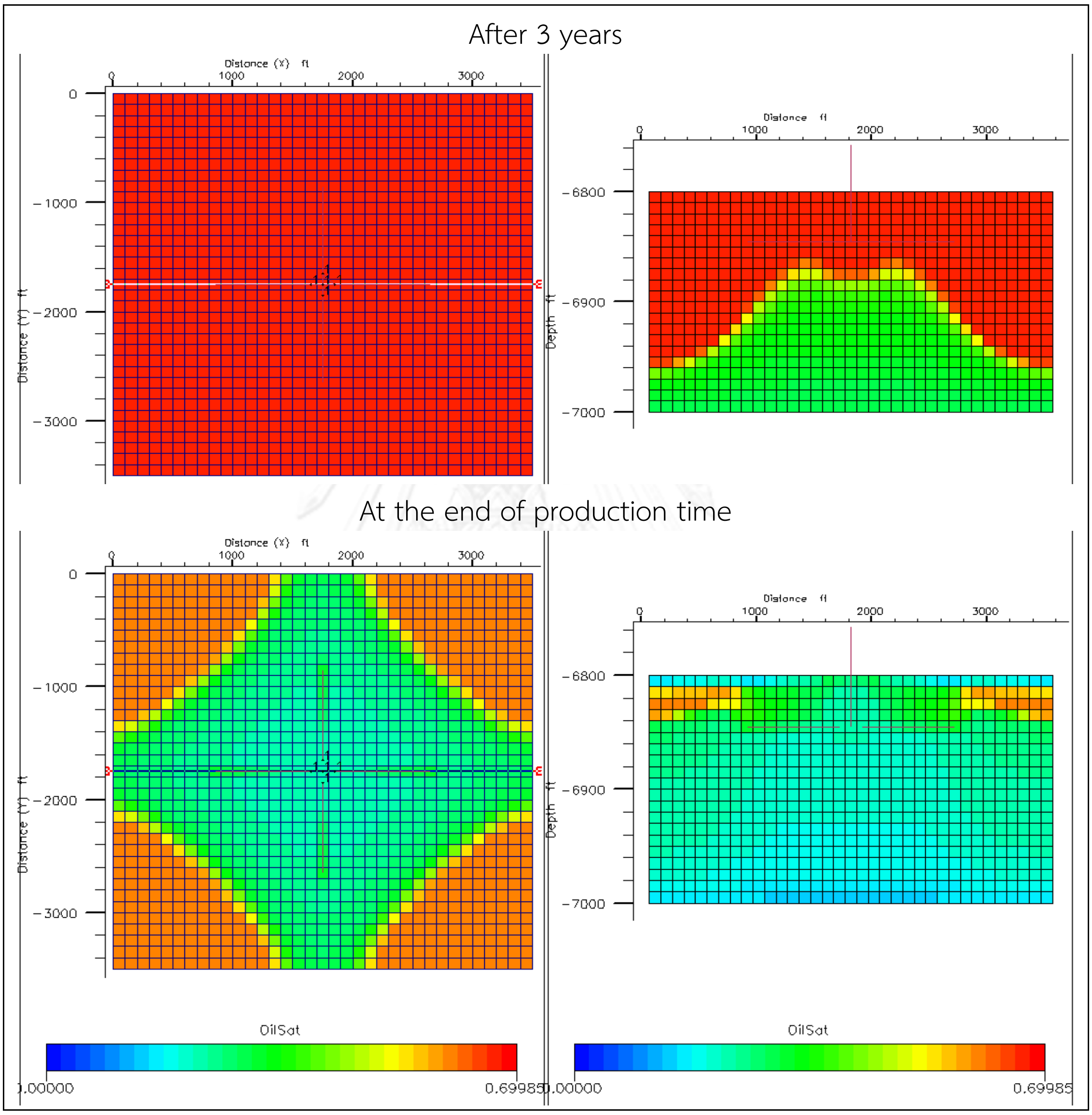


Figure 5.48 Oil saturation profile for 2,800-ft base case in reservoir model 3 after 3 years and at the end of production time

Base cases

Performances of selected base cases are summarized in the Table 5.19, Table 5.20, and Table 5.21. Effective producing length of the wells has a direct impact on choosing best geometry. Indeed, dual-opposed well is the most efficient well geometry below a critical length which lies between 2,000 and 2,800 ft. After this critical length, quadrilateral wells appear to be the most effective well geometry. This is explained by larger drainage and proportionally reduction of well interference between laterals as pressure drawdown is lower for each lateral.

Table 5.19 Summary of production performance of the selected base cases in terms of oil, water and gas production

Length (ft)	Aquifer	Depth of Lateral (ft)	Number of Laterals	Total Oil Production (STB)	Total Water Production (STB)	Total Gas Production (MSCF)
1,200	1	6,900	2	6,785,409	4,552,708	22,643,218
1,200	10	6,850	4	8,938,412	4,262,282	23,274,762
1,200	50	6,850	2	14,309,323	28,667,800	21,461,946
2,000	1	6,950	2	7,216,172	2,035,782	47,061,156
2,000	10	6,850	2	9,165,163	3,671,127	23,330,980
2,000	50	6,850	2	14,747,971	29,056,168	21,869,524
2,800	1	6,900	4	7,779,464	3,800,134	23,304,130
2,800	10	6,900	4	9,443,235	6,897,175	23,548,194
2,800	50	6,850	4	15,163,188	28,668,812	22,019,688

With different effective producing lengths, oil recoveries are improving on a regular basis with the increase of 800ft effective length. In reservoir model 1, the increase of recovery factor lays between 1.25 and 1.85%, whereas the range is 0.7 - 0.8% for reservoir model 2 and 1.2 – 1.3% for reservoir model 3.

Table 5.20 Summary of production performance of the selected base cases in terms of recovery per foot of effective producing length

Length (ft)	Aquifer	Depth of Lateral (ft)	Number of Laterals	Oil Recovery (%)	Recovery /foot
1,200	1	6,900	2	21.20%	0.0177%
1,200	10	6,850	4	27.93%	0.0233%
1,200	50	6,850	2	44.72%	0.0373%
2,000	1	6,950	2	23.05%	0.0115%
2,000	10	6,850	2	28.64%	0.0143%
2,000	50	6,850	2	46.09%	0.0230%
2,800	1	6,900	4	24.30%	0.0087%
2,800	10	6,900	4	29.50%	0.0105%
2,800	50	6,850	4	47.39%	0.0169%

Table 5.21. Performance comparison of the selected base cases

Length (ft)	Aquifer	Depth of Lateral (ft)	Number of Laterals	Oil Production difference with 1,200-ft wells	Oil Production difference with reservoir model 1
1,200	1	6 900	2		
1,200	10	6 850	4		27.24%
1,200	50	6 850	2		110.88%
2,000	1	6 950	2	8.00%	
2,000	10	6 850	2	6.16%	25.06%
2,000	50	6 850	2	3.07%	101.24%
2,800	1	6 900	4	14.65%	
2,800	10	6 900	4	8.52%	20.44%
2,800	50	6 850	4	5.97%	94.91%

5.3 Sensitivity analysis

5.3.1 **Effects of Spacing between Laterals for Dual Lateral Wells**

Spacing between laterals or distance in vertical direction in multilateral wells is varied in case of 2,000-ft dual lateral wells to evaluate its effect on well performance. Spacing between laterals is compared with the following values 20, 40 and 60 ft. So far, dual laterals with laterals drilled at different locations have shown the lowest performance throughout the first part of study. Results from simulations in term of oil production are expressed in Table 5.22 As previously seen, oil production is less when two laterals are located at different depths compared to dual-opposed wells because the closest lateral to oil-water contact tends to produce large amount of water, whereas the upper lateral produces gas from secondary gas cap. Both laterals are not optimized and large breakthrough decreases oil production.

Table 5.22 Performance of 2,000-ft dual lateral wells with various spacing between laterals

Aquifer size	Oil produced with 60-ft spacing	Oil produced with 40-ft spacing	Oil produced with 20-ft spacing	Oil produced with dual-opposed
1PV	7,311,816	7,356,337	7,388,511	7,400,500
10PV	8,949,872	9,018,080	9,061,547	9,164,800

Oil saturation profile in the reservoir at different production period is illustrated in Figure 5.49 for 60-ft spacing between two laterals after two and four years of production. After two years, water influx clearly moves upward to the lower lateral and water production increases rapidly in this particular segment of the well. The upper lateral is more effective in oil production as it is far from oil-water contact and hence it is able to drain larger amount of oil. However, after 4 years, secondary gas cap appears on top of the reservoir and this causes the upper well to produce large amount of gas, decreasing at the same time pressure support. In this study, reservoir thickness is 200 ft, which means 60-ft spacing is very large proportionally. However, the trend remains the same for smaller spacing and dual-opposed well appears to be yield best performance as it delays water and gas coning effects when the lateral is located at suitable depth.

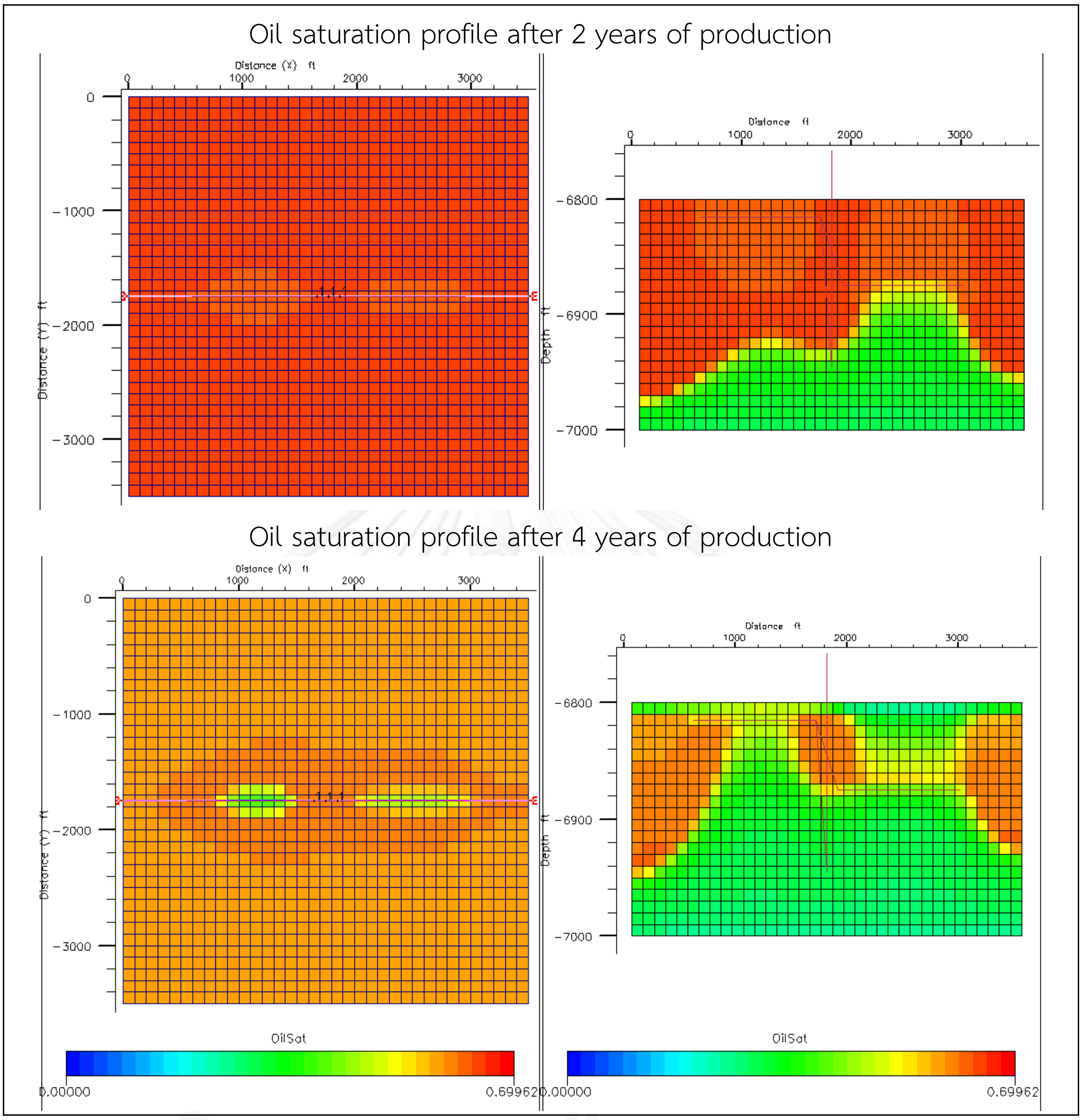


Figure 5.49 Oil saturation profiles in reservoir model 1 implemented by dual lateral well located with 60-ft difference after 2 and 4 years of production

Quadrilateral wells could also be adjusted at different depths. However, presence of bottom aquifer has negative consequences on its performance and different depths of laterals would accelerate both water and gas breakthrough into the well. Dual lateral wells with laterals located at different depths have never yielded positive results compared to other well geometries in terms of significant oil production. Therefore, multilateral wells with laterals located at different locations are further included in the rest of study.

5.3.2 **Effect of Anisotropy**

Effects of anisotropy both in vertical and horizontal plane are evaluated on selected base cases. Chosen values for anisotropy are:

- Variation of the anisotropy in horizontal direction (k_x/k_y): 10, 3, 1, 0.33, 0.10

- Variation of the anisotropy in vertical direction (k_v/k_h): 0.05, 0.1, 0.2, 0.5

For the study of anisotropy in horizontal direction, overall permeability vector is kept constant for all ratios so that comparisons can be made using the following equation: $k_h = \sqrt{k_x \times k_y}$

For each reservoir model, effect of anisotropy on oil recovery and water production is compared to results from isotropic reservoir model.

<u>Anisotropy in Horizontal Direction</u>

Anisotropy ratio in horizontal direction (k_x/k_y) is varied into five different values in order to determine sensitivity of this parameter compared to base cases. Permeabilities along x-direction and y-direction are adjusted in order to keep the same overall magnitude as well as to cope with k_x/k_y ratio. Reservoir is isotropic for a ratio equal to 1.0. When k_x/k_y is above 1.0, reservoir is anisotropic with a larger permeability on x-direction, whereas a value below 1.0, larger permeability is in the y-direction. Permeability values for all five cases are shown in Table 5.23.

Table 5.23 Summary of permeability ratio and permeability values in each direction for all cases with various horizontal anisotropy ratios (k_x/k_y)

Permeability	Case 1	Case 2	Case 3	Case 4	Case 5
k_x/k_y	10.00	3.00	1.00	0.33	0.10
k_x	158.11	86.60	50.00	28.86	15.81
k_y	15.81	28.86	50.00	86.60	158.11

In this study, horizontal and dual-opposed wells are placed along x-direction while laterals from quadrilateral wells are located in both x- and y-directions. Variation of horizontal anisotropy ratio provides specific tendencies for each of the well geometries.

Reservoir model 1

The reservoir model 1 is supported by small aquifer size equivalent to one reservoir pore volume. In this reservoir, dual-opposed wells located at 6,900 ft have shown the best performance among 1,200-ft and 2,000-ft wells, whereas quadrilateral lateral well has shown the best results among 2,800-ft wells. Base cases for reservoir model 1 (small aquifer) are summarized in Table 5.24.

Table 5.24 Summary of base cases in reservoir model 1

Length (ft)	Aquifer size (PV)	Depth of Lateral (ft)	Number of Laterals	Total Oil Production (STB)	% difference with 1,200ft
1,200	1	6,900	2	6,785,409	-
2,000	1	6,900	2	7,328,480	8.0
2,800	1	6,900	4	7,779,464	14.6

Horizontal and dual-opposed wells are placed along x-direction while laterals from quadrilateral wells are set in both x and y-directions. Variation of anisotropy has direct consequences on oil and water production for each well. Percentage variations of oil and water production are compared isotropic condition for each well geometry with same effective producing length base case in varying anisotropy ratio k_x/k_y.

Variation of anisotropy in the horizontal plane demonstrates different trends of sensitivity for horizontal and dual-opposed wells compared to quadrilateral well. When ratio is lower than 1.0, high permeability direction is normal to orientation of both horizontal and dual-opposed wells. A better drainage is therefore obtained from horizontal and dual-opposed well with an increase of 12% of oil production compared to base cases, whereas quadrilateral well shows an increase only 7%. Difference in oil recovery factor among all three well geometries is however below 4% from the best performing well which is horizontal geometry and the worst performance which is obtained from quadrilateral well. This can be explained that half of exposure of quadrilateral well is located along high permeability direction where half is normal to high permeability direction. The branch that is along the high permeability therefore produces less due to unfavorable flow direction.

When the ratio is above 1.0, higher permeability is parallel to horizontal and dual-opposed wells, resulting in a low drainage and at the same time a higher water influx from bottom aquifer. In these two well geometries, oil production decreases up to 11% for a strong anisotropy ratio. Symmetric geometry of quadrilateral well decreases drastically sensitivity of horizontal anisotropy compared to dual-opposed and horizontal wells. Quadrilateral well however is less sensitive to horizontal anisotropy as its laterals are symmetrical and compensate each other. In reservoir model 1 with strong anisotropy, the favorable laterals benefit more and thus, this increases production of 7% compared to a decrease of 7 and 11% for horizontal and dual-opposed wells, respectively.

For ratio ranging from 0.33 and 3.0, directional wells are less sensitive. Variation in oil production for 1,200-ft wells compared to the isotropic case can be observed in Figure 5.50.

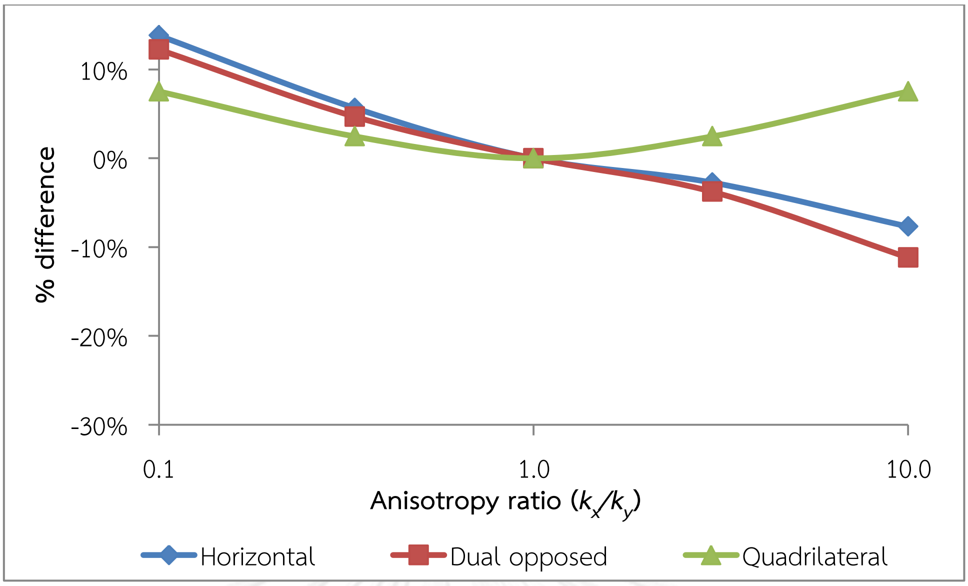


Figure 5.50 Effects of horizontal anisotropy on percentage variation of oil production compared to isotropic condition for 1,200-ft wells in reservoir model1

In Figure 5.51, variation of total water production shows different trends and higher magnitude compared to oil production. For anisotropy ratio in horizontal direction of 0.10, water production increases up to 28% for quadrilateral and horizontal well and decreases about 4% for dual-opposed. In term of water production, performance of each well geometry is significantly different compared to the best case. At the ratio equals 0.33, variation reaches 10, 47 and 60% for dual-opposed, quadrilateral and horizontal wells, respectively. High water production by quadrilateral can be explained by its geometry. Two laterals are located normal to high permeability direction and other two laterals are parallel to high permeability direction. Dual-opposed well geometry however gains benefits from its orientation as well as a lower pressure drop below its laterals which decreases water production. Major difference is high water production in case of horizontal well due to higher pressure drop, thus early water cresting, which is increased by anisotropy in the formation, is observed.

For high anisotropy ratio in horizontal direction above 1.0, variation of water production compared to isotropic condition reaches 82% for dual-opposed well, 45% for horizontal and 28% for quadrilateral geometry. In this case, dual-opposed shows higher sensitivity as anisotropy tends to accelerate water breakthrough and thus, decreases dual-opposed benefit to mitigate water influx. Horizontal well is less sensitive because of an already high water production. Quadrilateral offers the lowest sensitivity.

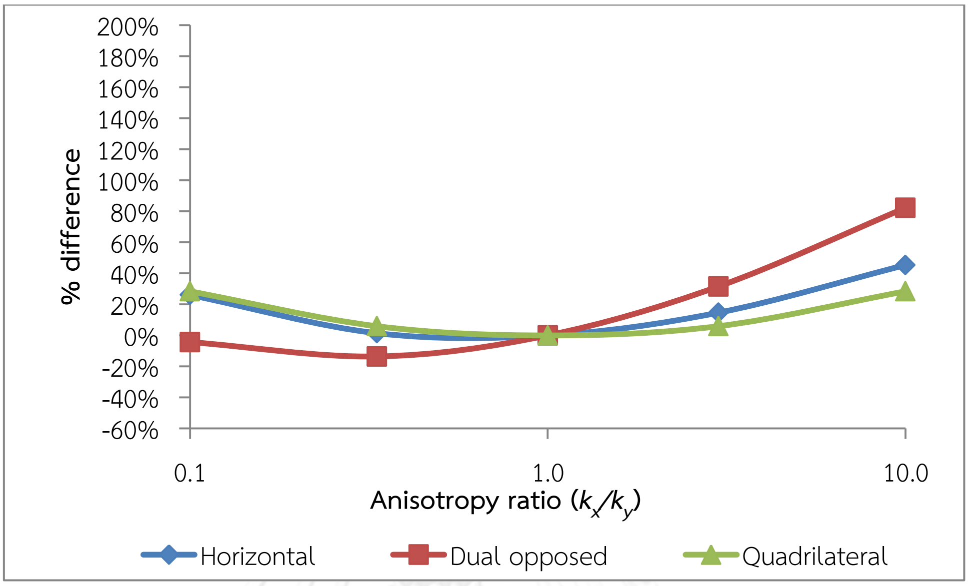


Figure 5.51 Effects of horizontal anisotropy on percentage variation of water production compared to isotropic condition for 1,200-ft wells in reservoir model 1

Evolution of reservoir drainage in anisotropic reservoirs for 1,200-ft horizontal well is shown in Figure 5.52 to Figure 5.57, using lateral and cross sectional views after 3 years of production. Oil drainage shows very different in shape and this proves the importance of well orientation in horizontal anisotropic reservoirs. At k_x/k_y equal to 10, well is parallel to high permeability direction. After 3 years of production, water and gas coning appear with steep slopes around wellbore, whereas oil drainage is enlarged in the same direction of the well. Top view (cut at 6,900 ft) demonstrates smaller drainage compared to other cases where k_x/k_y=1 and k_x/k_y=0.10.

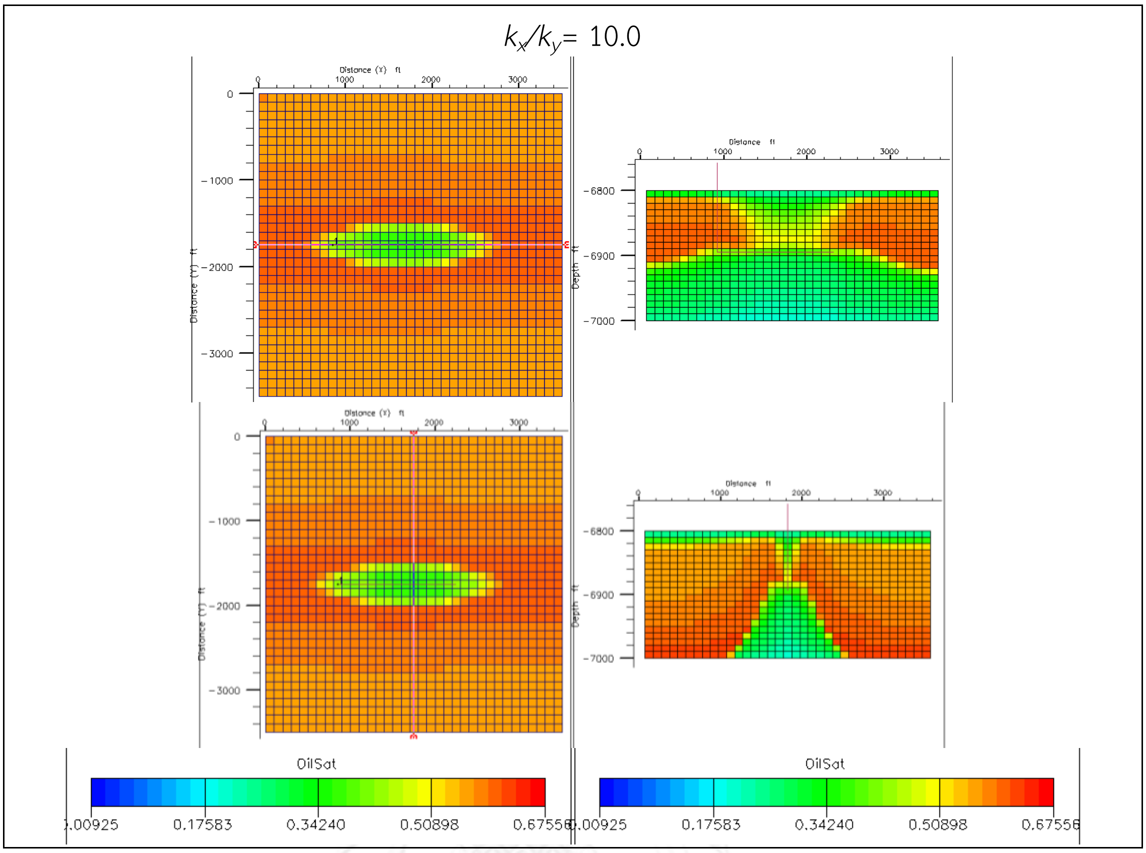


Figure 5.52 Oil saturation profiles in reservoir model 1 after 3 years production implemented by 1,200-ft horizontal well in reservoir containing horizontal anisotropic ratio of 10.0 in x and y-direction

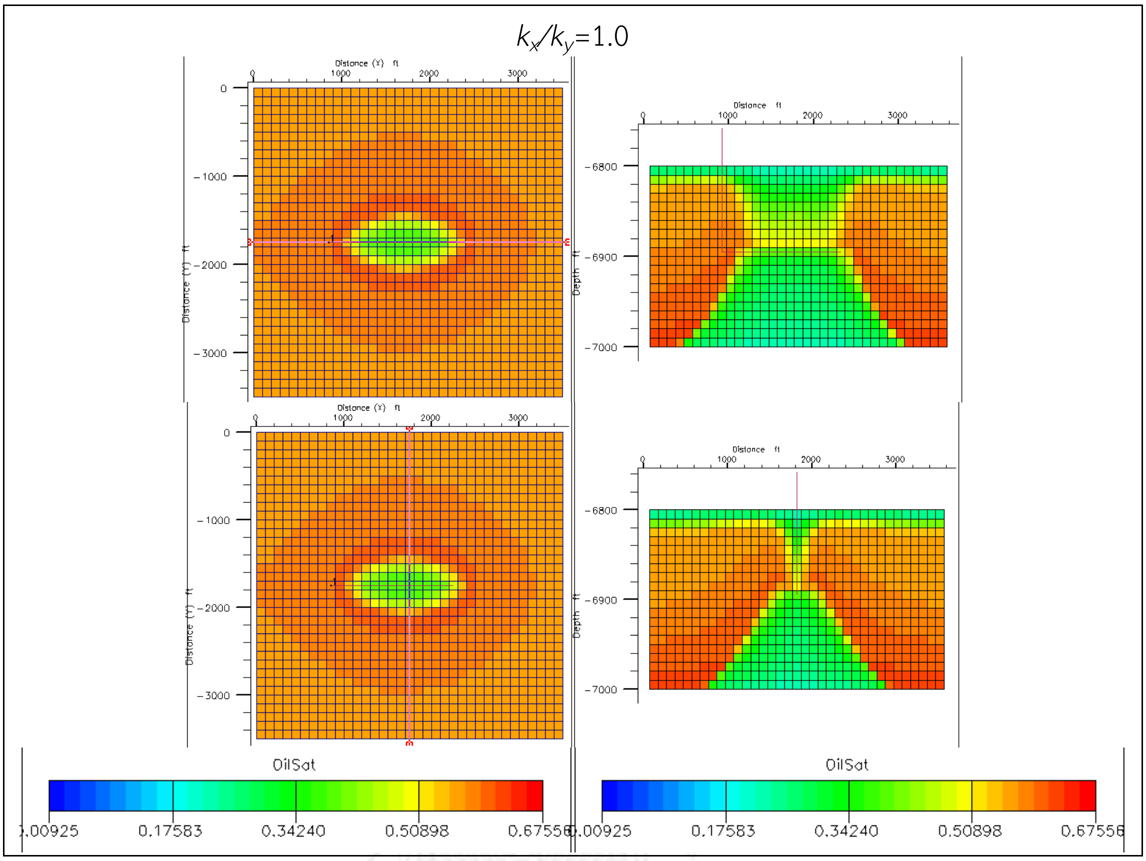


Figure 5.53 Oil saturation profiles in reservoir model 1 after 3 years production implemented by 1,200-ft horizontal well in reservoir containing horizontal anisotropic ratio of 1.0 in x and y-direction

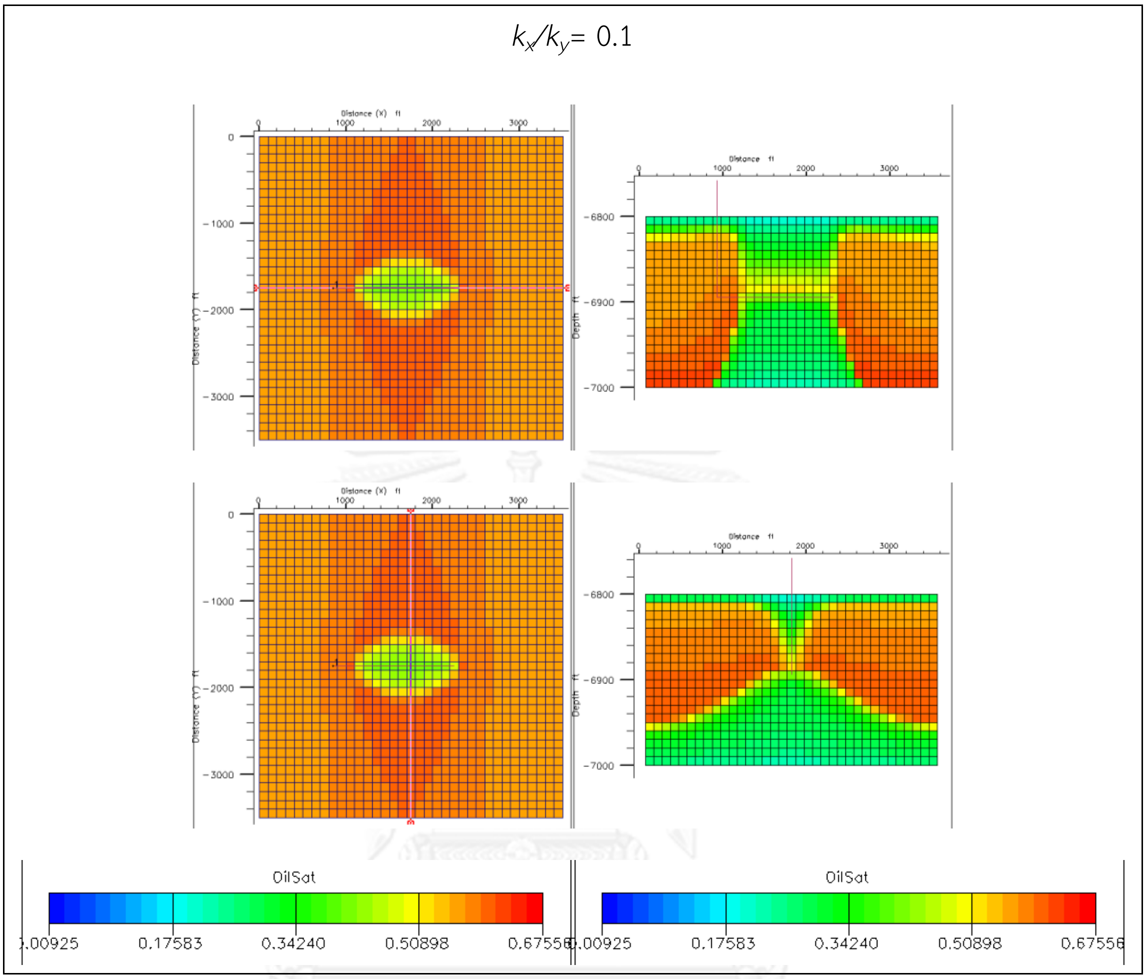


Figure 5.54 Oil saturation profiles in reservoir model 1 after 3 years production implemented by 1,200-ft horizontal well in reservoir containing horizontal anisotropic ratio of 0.1 in x and y-direction

Dual-opposed well geometry shows better drainage compared to single horizontal well because of favorable location of both laterals in the reservoir. The 2 distinct locations in the reservoir as well as the lower pressure drop increases reservoir drainage. This well geometry also delays water cresting phenomenon. However, its respond to horizontal anisotropy shows similar trends to results obtained from using horizontal well as displayed in Figure 5.55, Figure 5.56 and Figure 5.57.

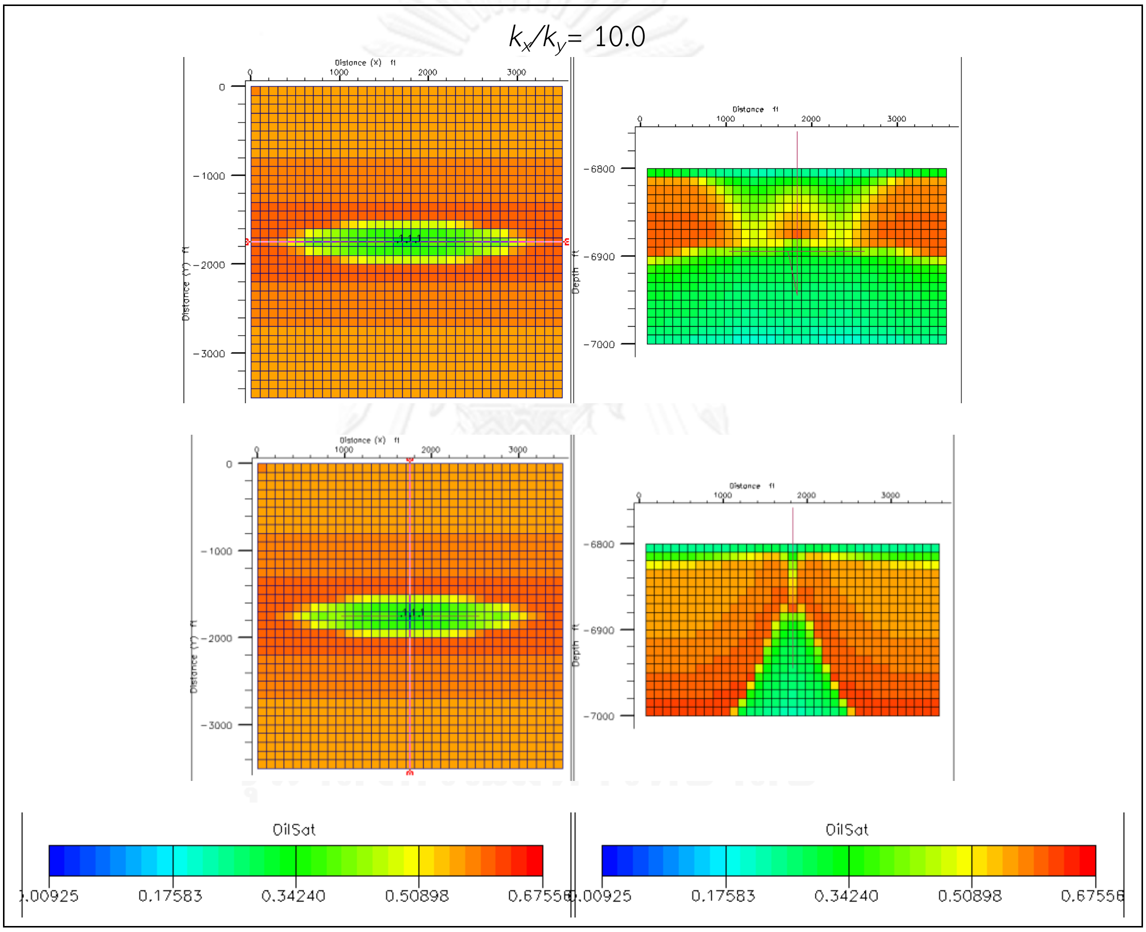


Figure 5.55 Oil saturation profiles in reservoir model 1 after 3 years production implemented by 1,200-ft dual-opposed well in reservoir containing horizontal anisotropic ratio of 10.0 in x and y-direction

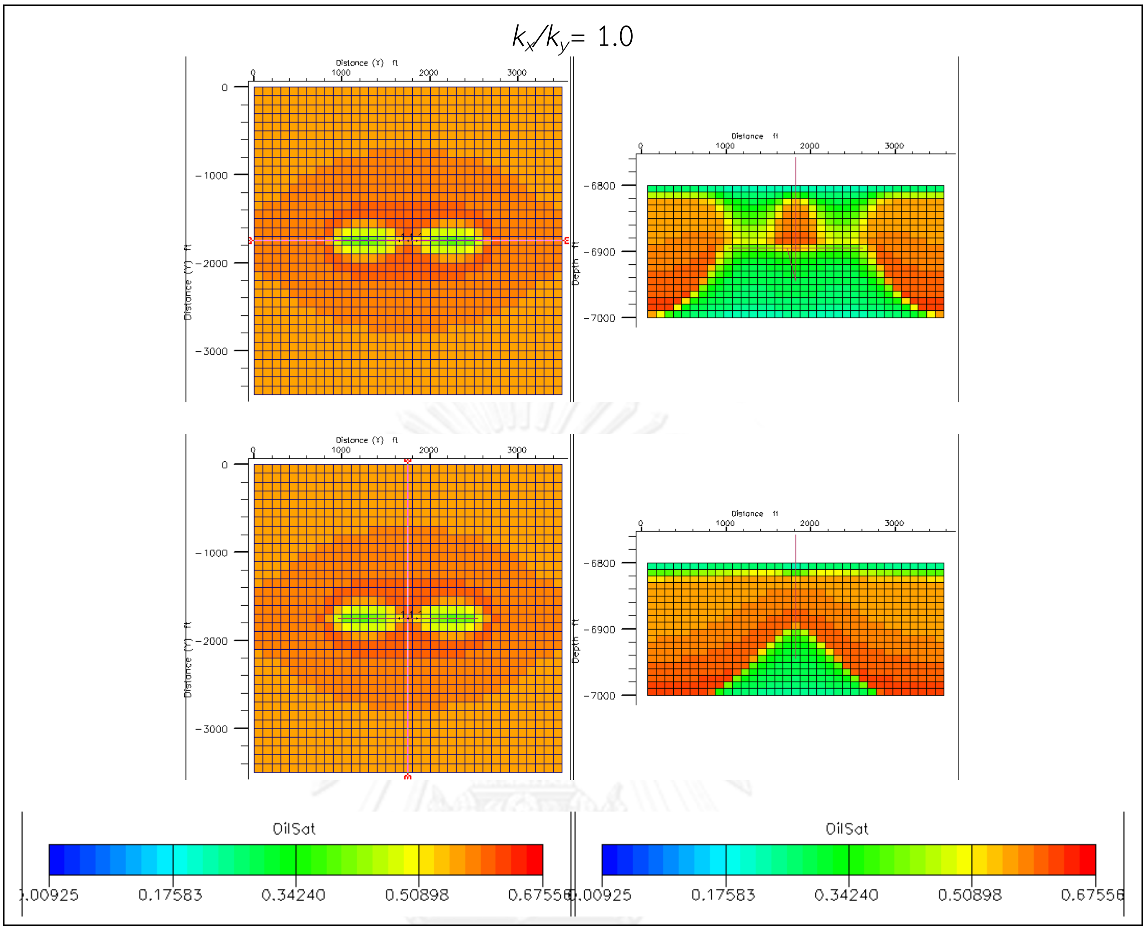


Figure 5.56 Oil saturation profiles in reservoir model 1 after 3 years production implemented by 1,200-ft dual-opposed well in reservoir containing horizontal anisotropic ratio of 1.0 in x and y-direction

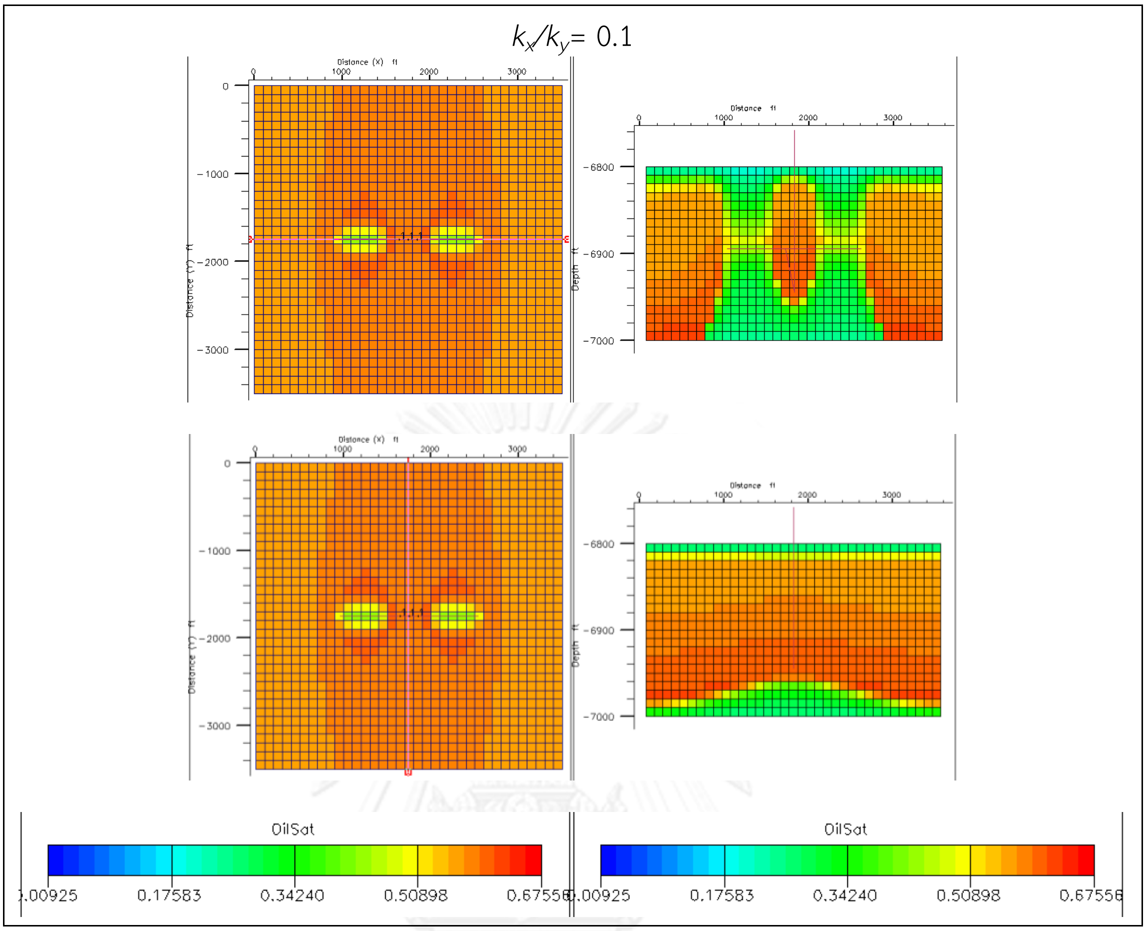


Figure 5.57 Oil saturation profiles in reservoir model 1 after 3 years production implemented by 1,200-ft dual-opposed well in reservoir containing horizontal anisotropic ratio of 0.1 in x and y-direction

Quadrilateral well gains benefits from producing in four different segments, providing better reservoir drainage as well as reducing water influx compared to utilizing of one long segment. As this well is symmetrical, the same results in term of drainage in cases k_x/k_y equals 10.0 and 0.1 are obtained. Reservoir drainage after 3 years of production is illustrated in Figure 5.58 and Figure 5.59.

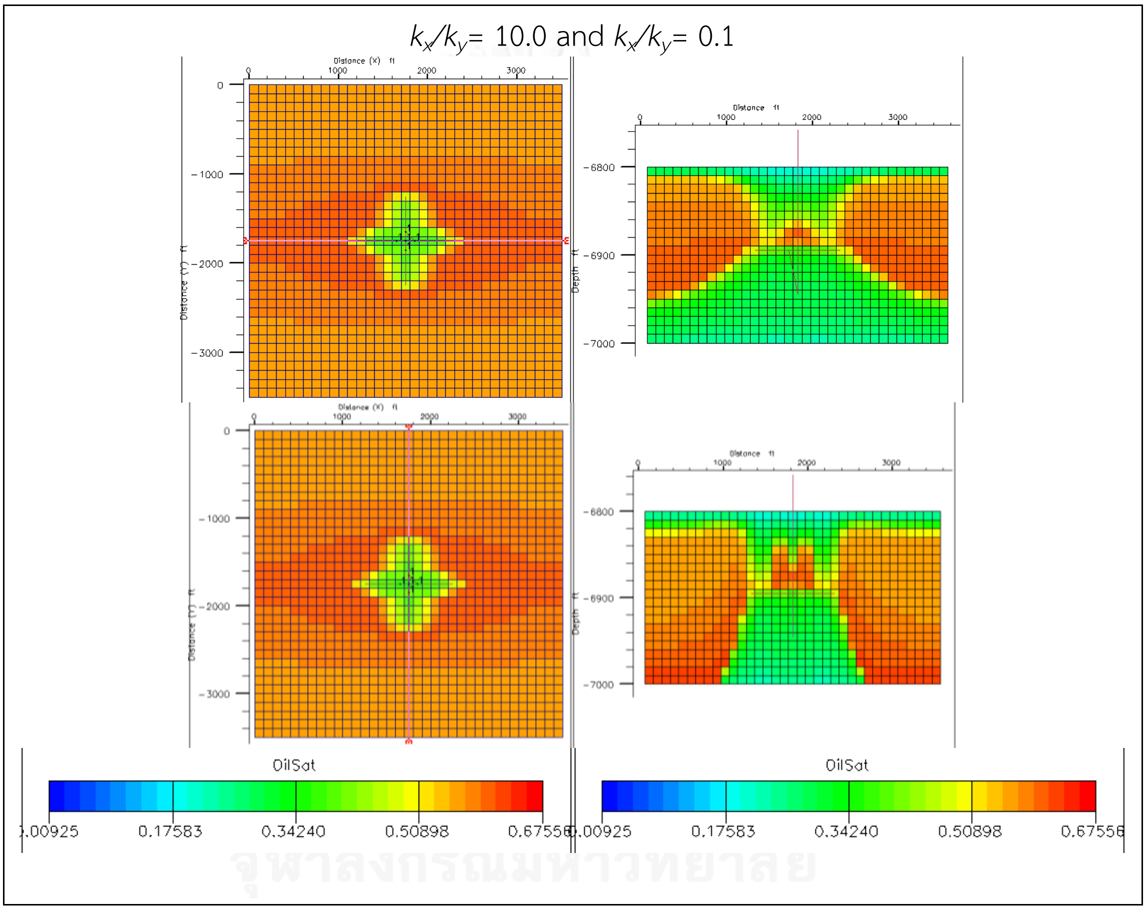


Figure 5.58 Oil saturation profiles in reservoir model 1 after 3 years production implemented by 1,200-ft quadrilateral well in reservoir containing horizontal anisotropic ratio of 10.0 and 0.1 in x and y-direction

k_x/k_y=1.0 (side view and cross-sectional view are the same)

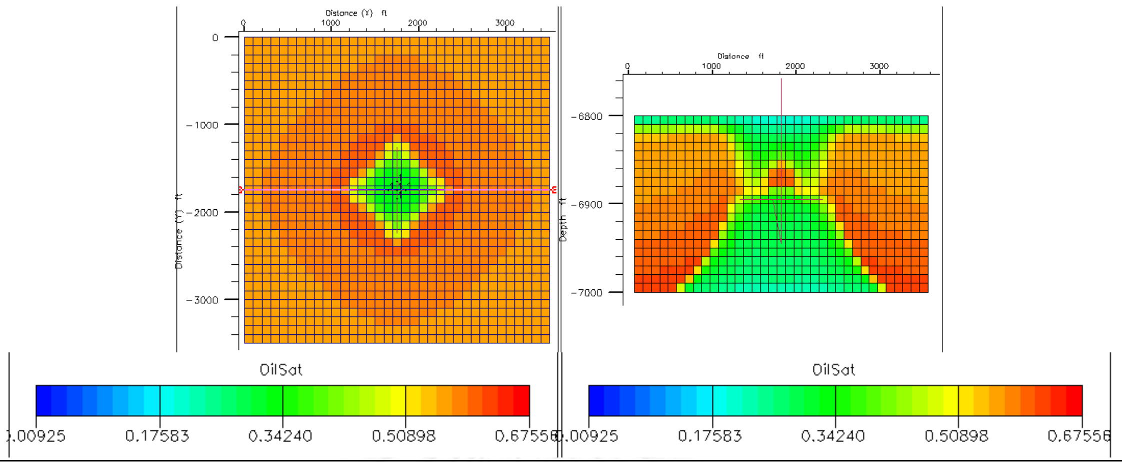


Figure 5.59 Oil saturation profiles in reservoir model 1 after 3 years production implemented by 1,200-ft quadrilateral well in reservoir containing horizontal anisotropic ratio of 1.0

In term of oil production, the same trend as for 1,200-ft wells can be observed for 2,000-ft wells as shown in Figure 5.60. However, benefits of multilateral wells are higher due to lower lateral interference. Multilateral wells are less sensitive to horizontal anisotropy than horizontal well. With low anisotropy ratio, conditions are favorable for directional wells because of large reservoir drainage. Sensitivity of horizontal well is the highest and oil production is increased about 14% compared to isotropic conditions while it reaches 9 and 7% for respectively dual-opposed and quadrilateral wells.

Between ratios of 0.33 and 3.0, sensitivity of both multilateral is especially low compared to horizontal well because of its ability to mitigate water cresting.

Conditions are unfavorable to directional wells when ratio reaches 10.0 due to the direction of higher permeability parallel to the wells. Variation of oil production obtained from dual-opposed and horizontal wells decreases about 15% and 12% respectively compared to isotropic conditions, whereas quadrilateral oil production increases about 7% due to its symmetry. Dual-opposed well shows high sensitivity between ratios of 3.0 and 10.0 compared to other geometries because of much higher water influx (due to unfavorable anisotropy) which accelerates water breakthrough and thus, decreases drastically the benefit of dual-opposed well.

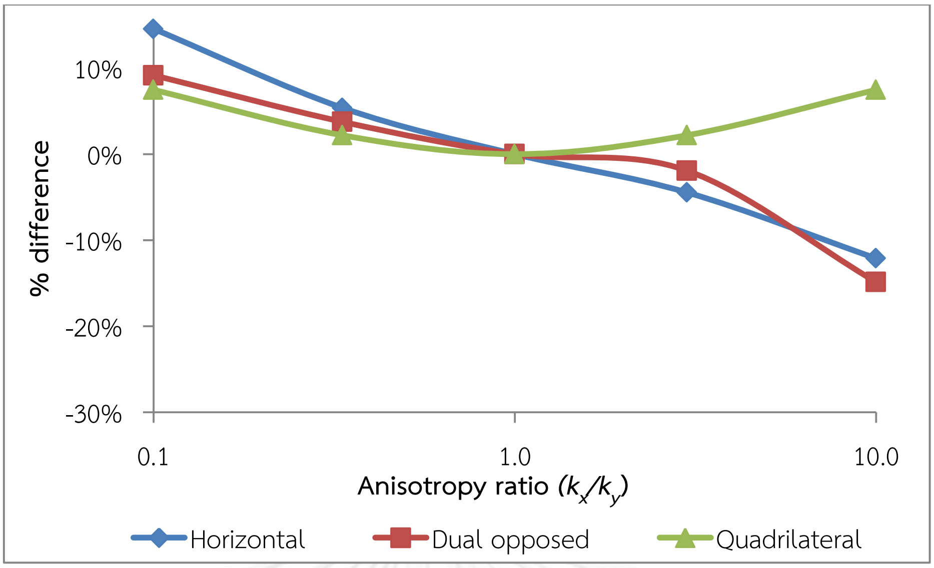


Figure 5.60 Effects of horizontal anisotropy on percentage variation of oil production compared to isotropic conditions for 2,000-ft wells in reservoir model1

Effect of effective producing well length can also be assessed by comparison between total water productions from 1,200-ft and 2,000-ft wells. Indeed, longer effective well length reduces interferences of drainage between each segment of all well geometries and thus, decreases pressure drop. Therefore, dual-opposed and horizontal wells produce significantly less water compared to quadrilateral well when k_x/k_y is 0.1.

At low favorable anisotropy ratio between 1.0 and 3.0, dual-opposed and quadrilateral wells are less sensitive to anisotropy with 5% more water produced compared to 36% for horizontal well.

When ratio reaches 10.0, benefit of quadrilateral is remarkable and both horizontal and dual-opposed show high water production as shown in Figure 5.61. Dual-opposed well is especially highly sensitive in this case due to early water breakthrough which decreases drastically benefits of this well geometry compared to horizontal well.

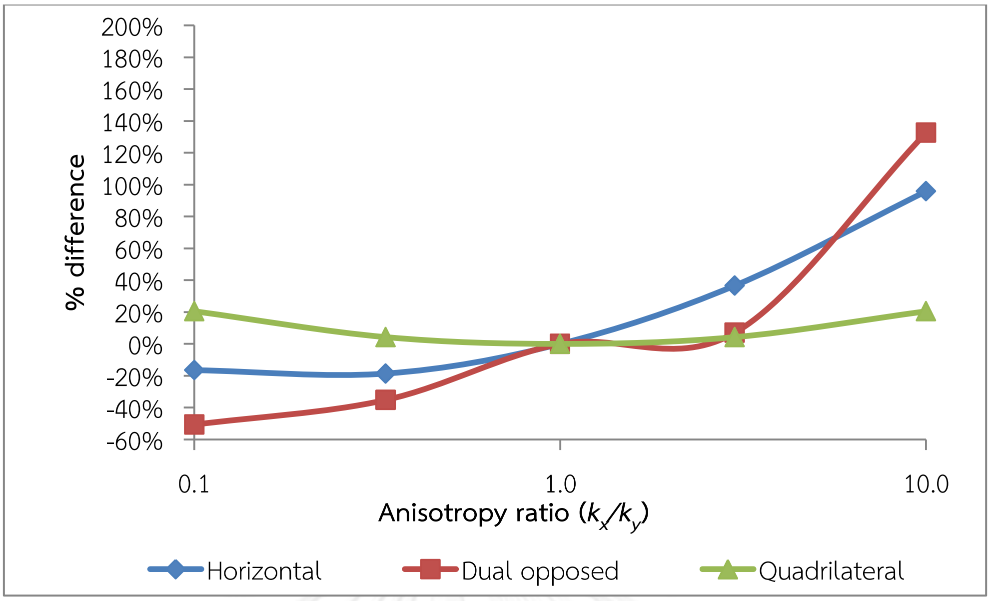


Figure 5.61 Effects of horizontal anisotropy on percentage variation of water production compared to isotropic conditions for 2,000-ft wells in reservoir model 1

For all well geometries with effective producing length of 2,800 ft, oil drainage is large and oil recovery is much higher compared to shorter well length. When horizontal anisotropy ratio is below 1.0, oil productions obtained from horizontal and dual-lateral wells compared to isotropic cases are equivalent. Oil production is improved for horizontal and dual-opposed wells when k_x/k_y equals to 0.33. Drainage is maximized for this type of wells oriented perpendicular to high permeability direction in the formation. Moreover, horizontal and dual-opposed wells penetrate into formation close to the boundaries and therefore, difference in oil production is decreased. Similar to the previous cases, quadrilateral wells obtain increase in oil production of about 7% compared to isotropic conditions due to its symmetry as displayed in Figure 5.62. When horizontal anisotropic ratio is above 1.0, sensitivity of anisotropy on quadrilateral well is equivalent, whereas horizontal and dual-opposed face significant reduction of oil production. Sensitivity on both directional wells is similar and increases with large anisotropy ratio and oil production is decreased down to 17% for ratio of 10.0, whereas quadrilateral increases its oil production of 7% thanks to its geometry.

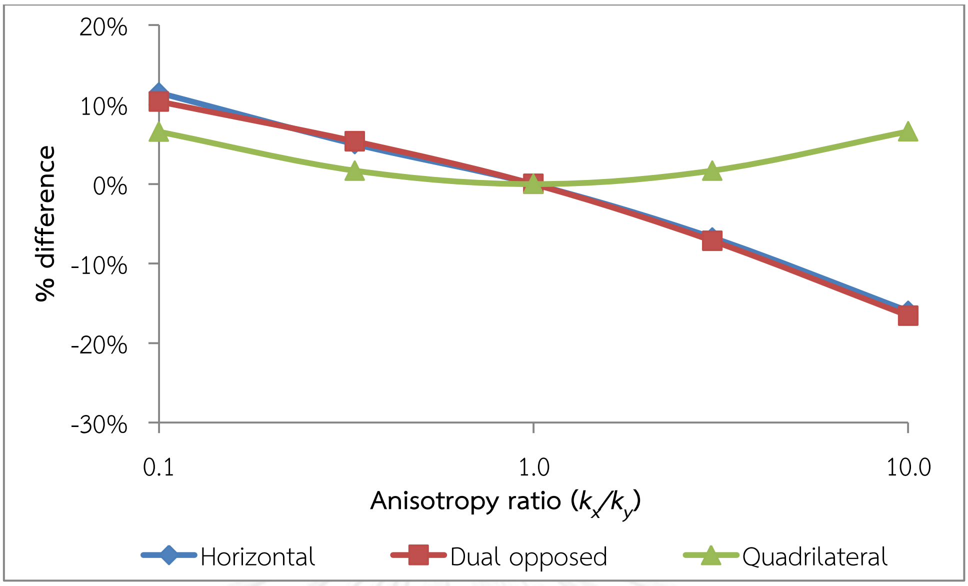


Figure 5.62 Effects of horizontal anisotropy on percentage variation of oil production compared to isotropic condition for 2,800-ft wells in reservoir model 1

In term of water production, effect of effective producing well length is also visible for 2,800-ft wells compared to other lengths. Longer laterals divide the flow along the well, and thus, reduce pressure drop and water produced for all geometries as it can be observed in Figure 5.63. At horizontal anisotropic ratio below 1.0, orientation of horizontal and dual-opposed wells decreases water production and offer better results than in isotropic condition; while quadrilateral well produces 10% more water due to its geometry. When k_x/k_y is above 1.0, difference between directional wells (horizontal and dual opposed) and quadrilateral well increases significantly with anisotropy. When k_x/k_y is as high as 10.0, benefit of quadrilateral well is obtained since it maintained water production of about 10% higher than in isotropic condition while horizontal and dual-opposed well produce water up to 150% compared to isotropic condition.

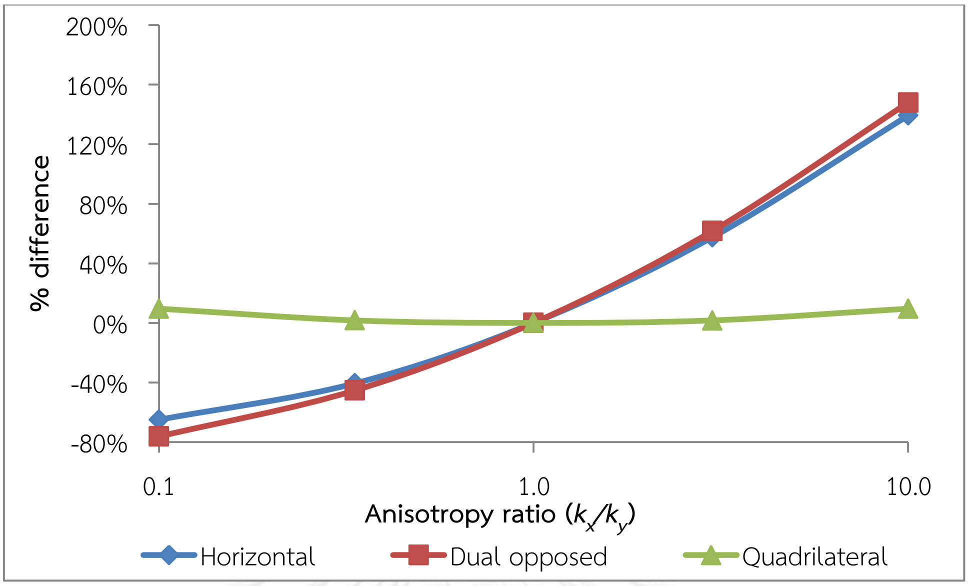


Figure 5.63 Effects of horizontal anisotropy on percentage variation of water production compared to isotropic condition for 2,800-ft wells in reservoir model1

Reservoir model 2

Reservoir model 2 is supported by a medium aquifer size equivalent to 10 reservoir pore volume. In this reservoir, quadrilateral wells located at 6,850 ft have shown the best performance among 1,200-ft and 2,800-ft wells, whereas dual-opposed well has given the best results among 2,000 ft wells. Base cases and their performance for reservoir model 2 are summarized in

Table 5.25.

Table 5.25 Base cases in reservoir model 2

Length (ft)	Aquifer size (PV)	Depth of Lateral (ft)	Number of Laterals	Total Oil Production (STB)	% difference with 1,200ft
1,200	10	6,850	2	8,633,615	-
2,000	10	6,850	2	9,165,163	6.16%
2,800	10	6,850	4	9,369,211	2.23%

Higher pressure support from bottom aquifer increases oil production as well as water and triggers earlier water breakthrough for all well geometries. With larger aquifer, benefits of multilateral wells are increased for isotropic reservoir as shown in the above table. In Figure 5.64, results from reservoir simulation show the same trend as in reservoir model 1 for 1,200-ft wells with increase of sensitivity on dual-opposed well between ratios of 0.33 and 3.0 due to the stronger influx.

Anisotropy in unfavorable direction accelerates water cresting and early breakthrough. Therefore, effect of anisotropy is amplified by aquifer size and multilateral performances are particularly affected. Sensitivity on dual-opposed is increased in reservoir model 2 and overcomes horizontal well (however overall total production remains higher for dual opposed and quadrilateral well than for horizontal well). Benefit of quadrilateral well is also decreased with the combination of reservoir model 2 and horizontal anisotropy, reducing benefit of 3% compared to reservoir 1 at maximum ratio.

For a horizontal anisotropy ratio below 1.0, dual-opposed well yields the best performance due to larger oil drainage together with lower pressure drop. Increase of oil production compared to isotropic condition reaches 10% while this reaches 8% for horizontal and 4% for quadrilateral wells at ratio of 0.1. However, when the ratio is above 1.0, total oil production significantly decreases for both directional wells (11% for horizontal and 15% for dual-opposed), whereas quadrilateral well increases oil production to 4%. Sensitivity on dual-opposed is increased because of the large water influx from the aquifer which reduces its benefits compared to horizontal well.

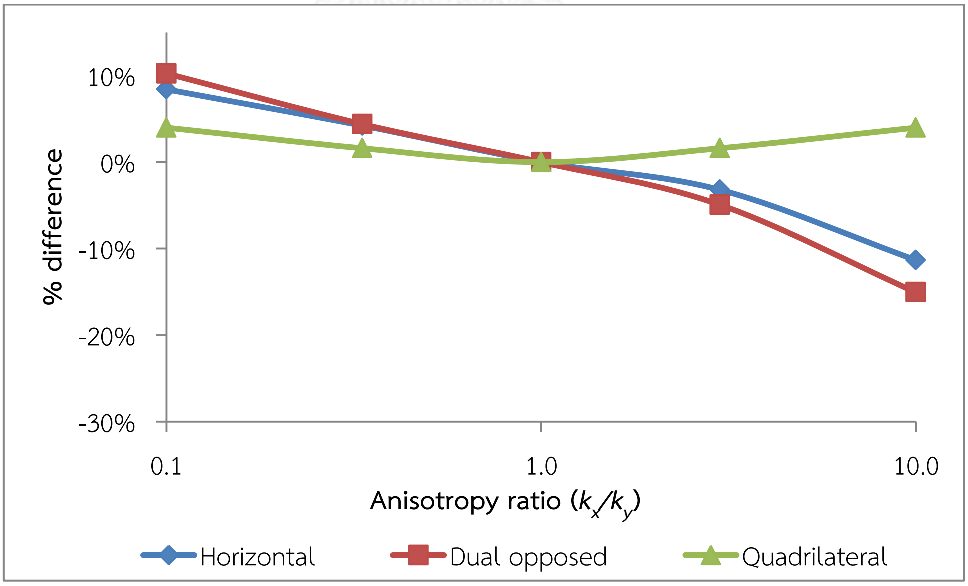


Figure 5.64 Effects of horizontal anisotropy on percentage variation of oil production compared to isotropic conditions for 1,200-ft wells in reservoir model 2

Increase of aquifer size also increases water production for all well geometries, and variation of oil production compared to isotropic condition is also enlarged. 1,200-ft wells are relatively small, creating interferences between each segment of the well and thus, higher pressure drop emerges. This favors water influx for all well geometries, reducing benefits from utilizing multilaterals as observed in Figure 5.65.

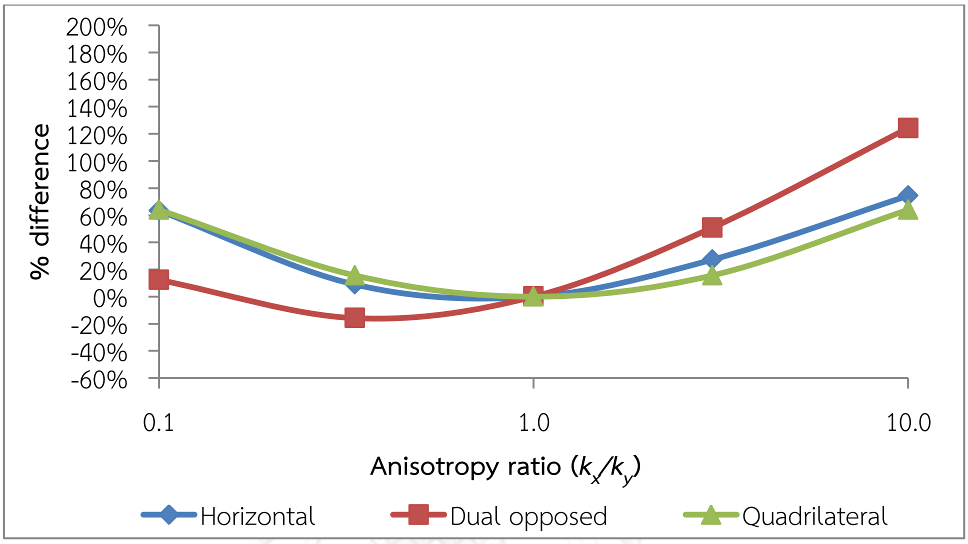


Figure 5.65 Effects of horizontal anisotropy on percentage variation of water production compared to isotropic condition for 1,200-ft wells in reservoir model 2

Figure 5.66 to Figure 5.68 highlight oil drainage after 3 years of production in reservoir model 2 by the use of horizontal well with different horizontal anisotropy ratio. Increase in size of aquifer support enhances pressure support but also accelerates water cresting and thus, water production.

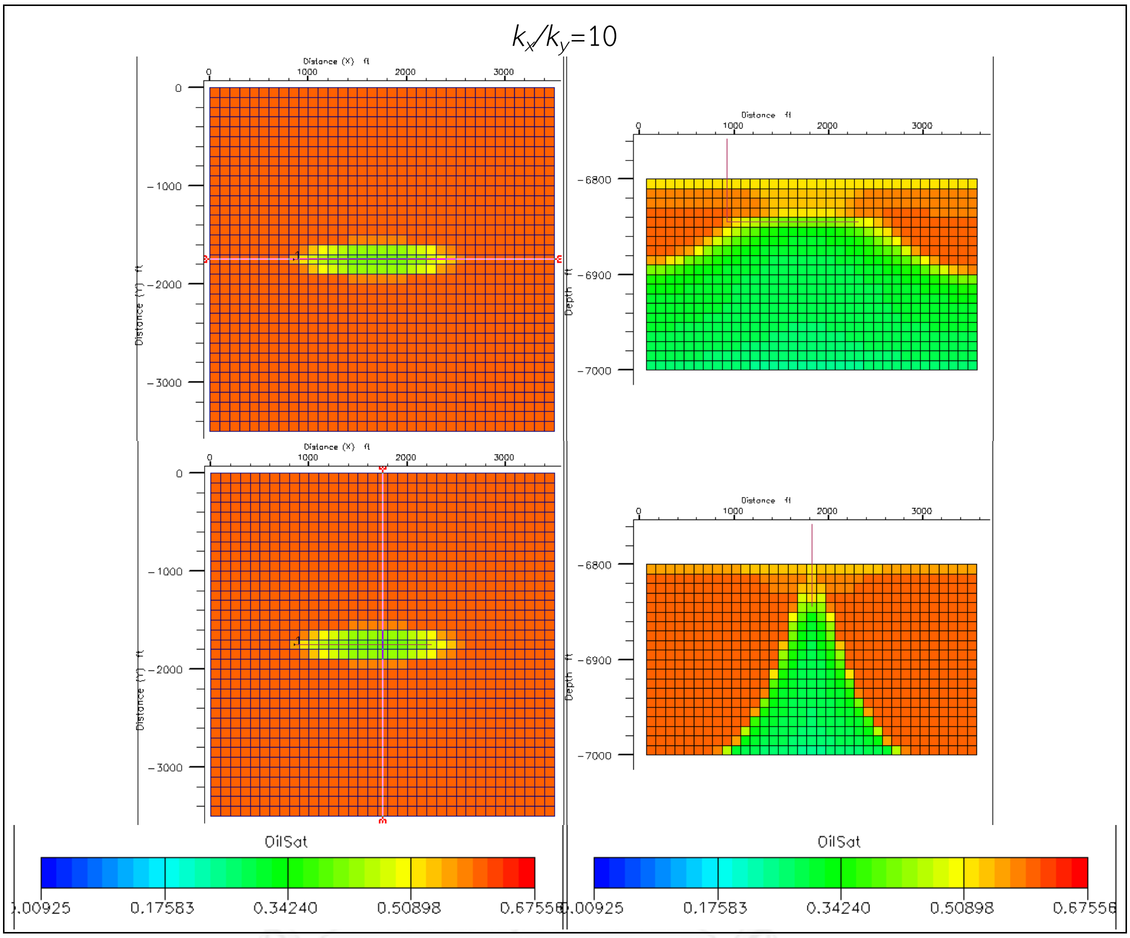


Figure 5.66 Oil saturation profiles in reservoir model 2 after 3 years production implemented by horizontal well in reservoir containing horizontal anisotropic ratio of 10.0

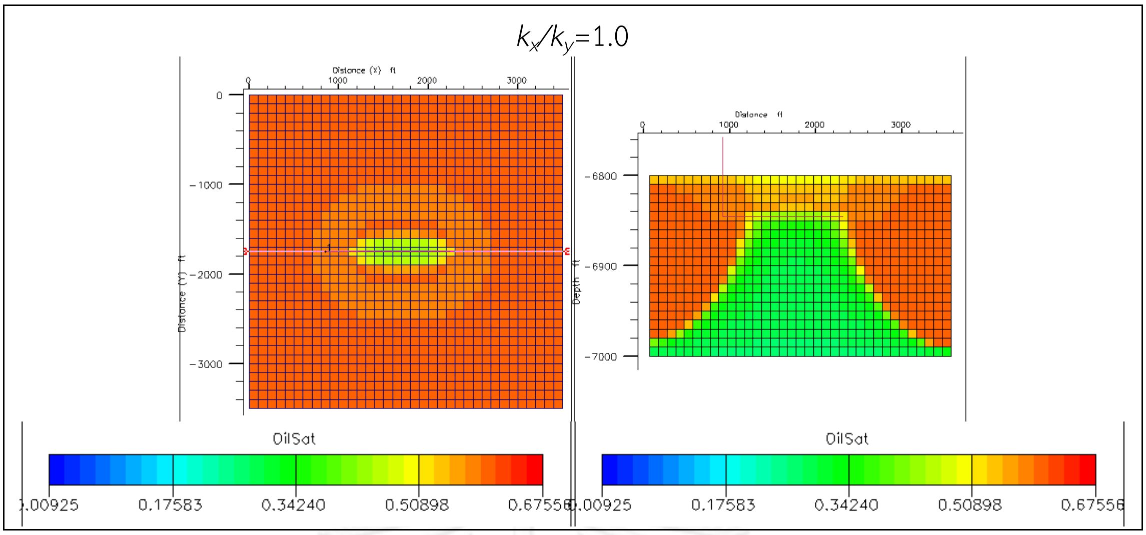


Figure 5.67 Oil saturation profiles in reservoir model 2 after 3 years production implemented by horizontal well in reservoir containing horizontal anisotropic ratio of 1.0

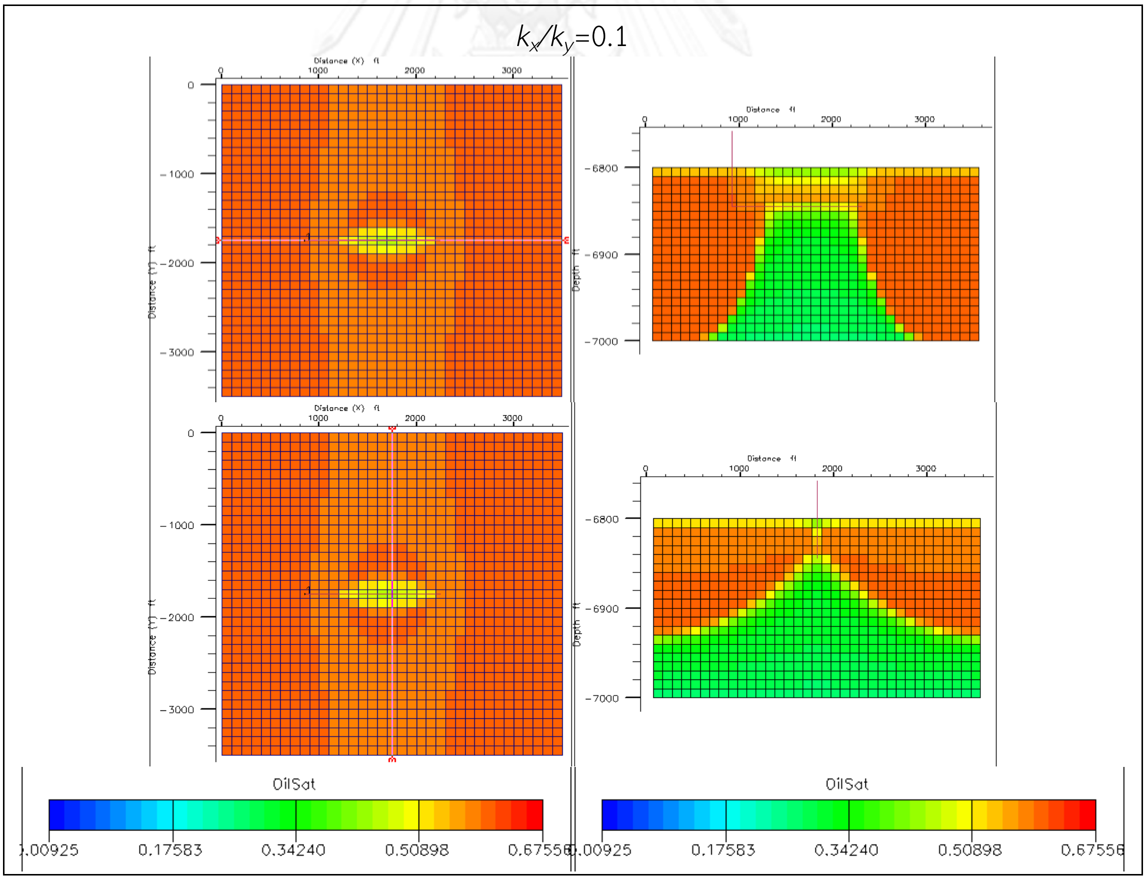


Figure 5.68 Oil saturation profiles in reservoir model 2 after 3 years production implemented by horizontal well in reservoir containing horizontal anisotropic ratio of 0.1

Quadrilateral well also faces early water influx. Moreover, interferences between laterals can be observed at intersection of all laterals as shown in Figure 5.70 and Figure 5.70. Indeed, short length of laterals increases flow per foot on each lateral, creating a stronger pressure drop. At intersection of laterals (heel side), oil saturation is decreasing at a higher rate compared to lateral ends. This oil saturation decreases at faster rate due to interference of production in each lateral.

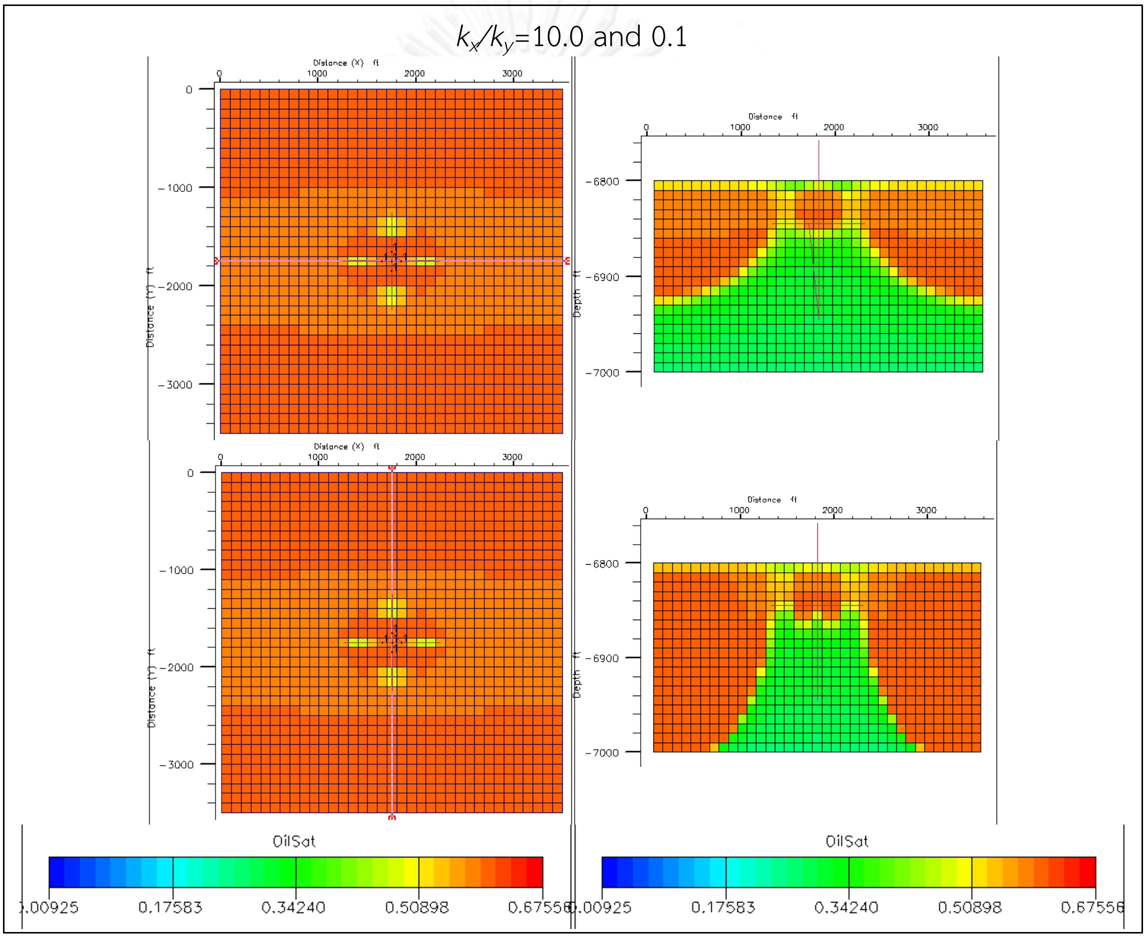


Figure 5.69 Oil saturation profiles in reservoir model 2 after 3 years production implemented by quadrilateral well in reservoir containing horizontal anisotropic ratio of 10.0

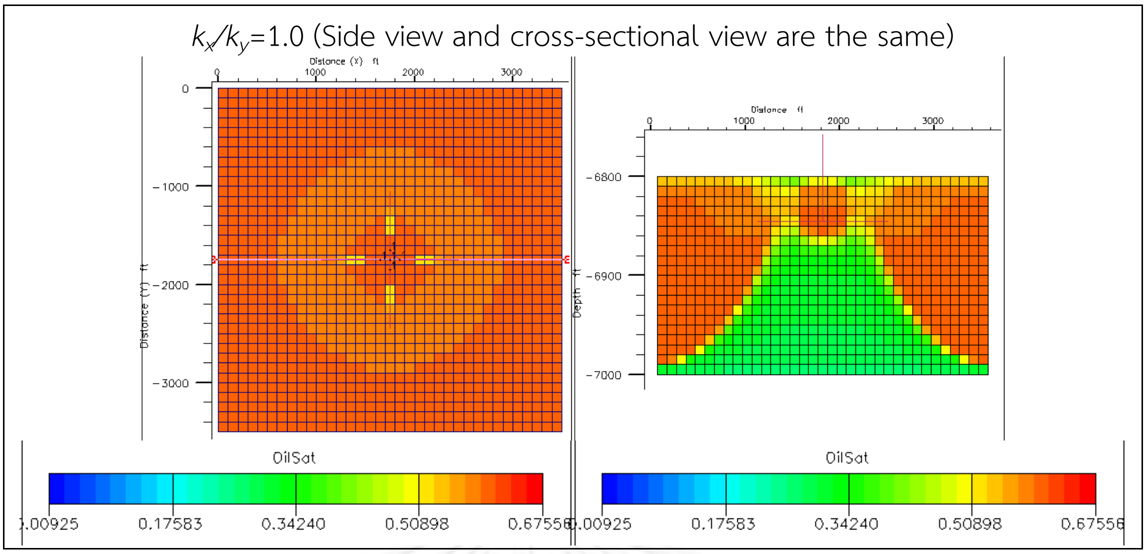


Figure 5.70 Oil saturation profiles in reservoir model 2 after 3 years production implemented by quadrilateral well in reservoir containing horizontal anisotropic ratio of 1.0

Wells with effective producing length of 2,000 ft obtained less interference from each lateral and hence, benefits of multilateral wells compared to horizontal well is more pronounced as shown in Figure 5.71.

Similar tendency is observed in a higher magnitude when aquifer size is enlarged from 1 to 10 times reservoir pore volume. For reservoir with horizontal anisotropy ratio below 1.0, dual-opposed well geometry yields the best performance due to larger drainage together with its orientation which is normal to high permeability direction. At the ratio of 0.1, horizontal and dual-opposed are the most sensitivity compared to isotropic conditions with an increase of oil production of 11 and 8% respectively, while quadrilateral well varies about 5%.

When horizontal anisotropy ratio is above 1.0, oil production decreases with anisotropy up to 15% and 18% for directional wells (horizontal and dual-opposed wells) compared to isotropic condition, while it increases up to 5% for quadrilateral geometry.

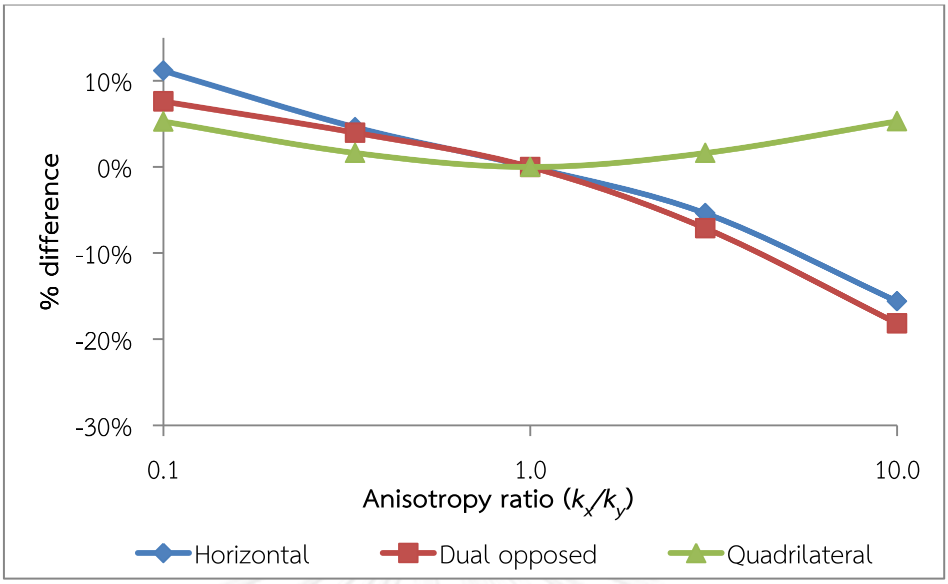


Figure 5.71 Effects of horizontal anisotropy on percentage variation of oil production compared to isotropic condition for 2,000-ft wells in reservoir model 2

Water production is increased in reservoir model 2 and all well geometries are more sensitive to horizontal anisotropy compared to smaller aquifer size as can be observed in Figure 5.72. In term of water production, dual-opposed well shows the highest sensitivity as the acceleration of water breakthrough diminishes the benefit of this geometry.

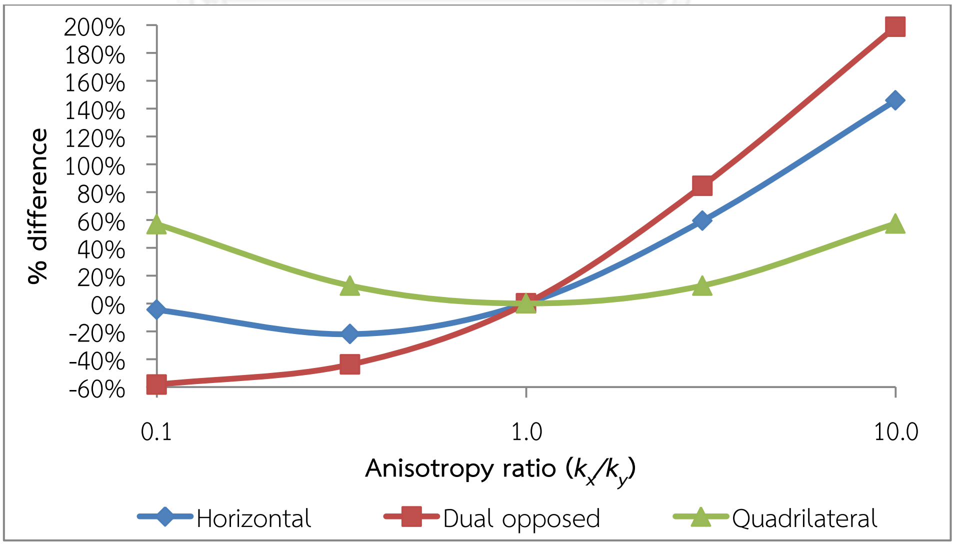


Figure 5.72 Effects of horizontal anisotropy on percentage variation of water production compared to isotropic condition for 2,000-ft wells in reservoir model 2

Effective producing length of 2,800 ft enlarges significantly oil drainage and thus, total oil production is remarkably raised. Longer producing length reduces also interference between laterals and hence, increases benefits of quadrilateral well.

For horizontal anisotropy ratio below 1.0, increase of oil production is slightly lower with 5% for quadrilateral, while it is increased of 8.5% for directional wells. However, for horizontal anisotropy ratio above 1.0, sensitivity on directional well increases at a very high pace, reaching 19% decrease of oil production compared to isotropic condition, 27.5% less than quadrilateral well as shown in Figure 5.73.

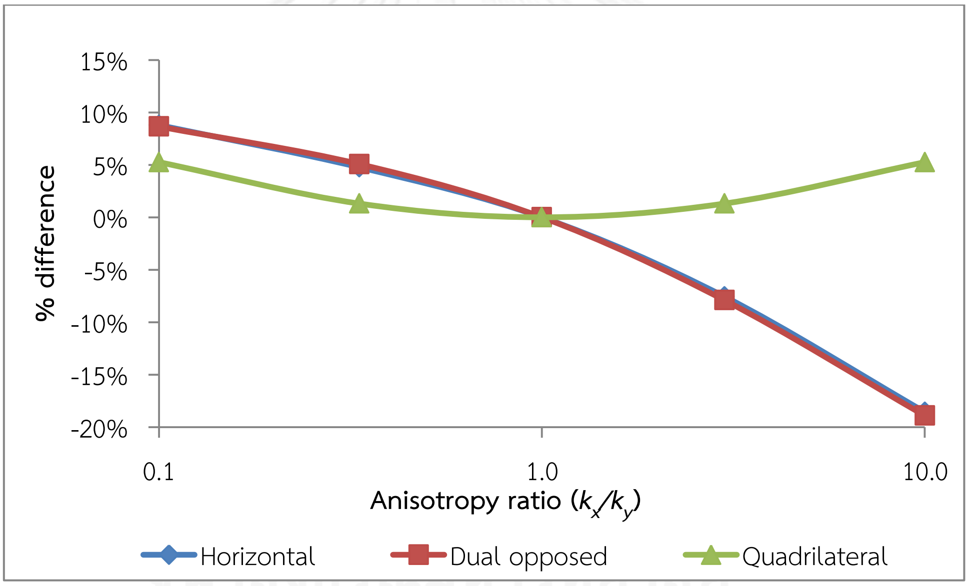


Figure 5.73 Effects of horizontal anisotropy on percentage variation of oil production compared to isotropic condition for 2,800-ft wells in reservoir model 2

Similarly to shorter wells, benefits of quadrilateral well are also significant in term of water production for high anisotropy ratio as displayed in

. Compared to reservoir model 1, magnitude of variation from base case is raised outstandingly.

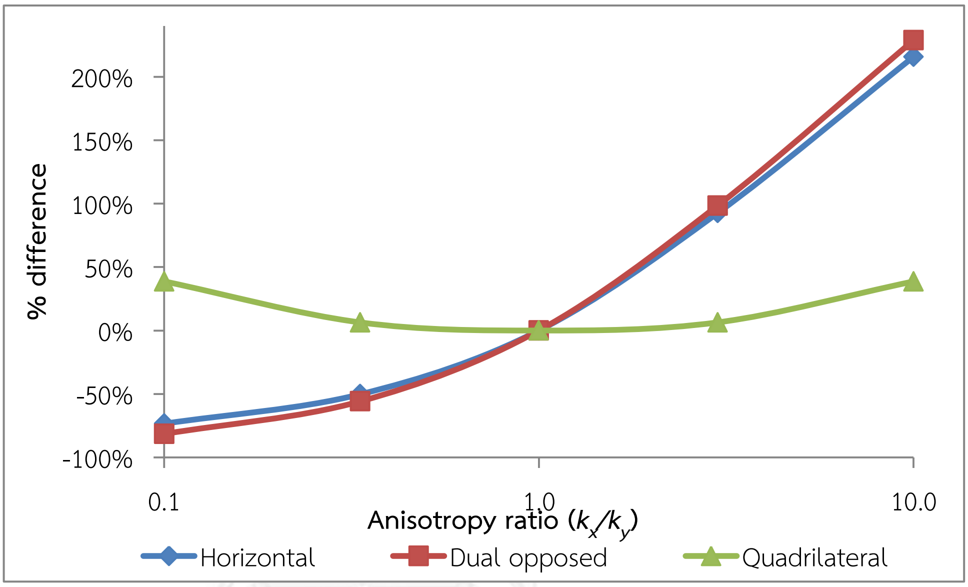


Figure 5.74 Effects of horizontal anisotropy on percentage variation of water production compared to isotropic condition for 2,800-ft wells in reservoir model 2

Reservoir model 3

Reservoir model 3 is supported by a large aquifer size equivalent to 50 reservoir pore volume. In isotropic reservoir supported by large aquifer, dual-opposed wells located at 6,850 ft have shown the best performance among 1,200- and 2,000-ft wells while quadrilateral well provides the best results for 2,800-ft wells. Base cases for reservoir model 3 are summarized in Table 5.26.

Table 5.26 Base cases in reservoir model 3

Length (ft)	Aquifer (PV)	Depth of Lateral (ft)	Number of Laterals	Total Oil Production (STB)	% difference with 1,200ft
1,200	50	6,850	2	14,309,323	-
2,000	50	6,850	2	14,747,971	3.07 %
2,800	50	6,850	4	15,163,188	5.97 %

Sensitivity on horizontal anisotropy on 1,200-ft wells is increased in reservoir model 3 as displayed in Figure 5.75. The trends remain the same as for reservoir models 1 and 2 but higher reduction in oil production is observed with anisotropy for all geometries. Moreover, benefit of quadrilateral well for high horizontal anisotropy ratio is reduced compared to other two directional wells. At large anisotropy, water influx increases with anisotropy due to the lower permeability difference between horizontal and vertical direction. Therefore, earlier water breakthrough occurs and oil production is decreased. The symmetry of quadrilateral well can no longer compensate the high influx of water and therefore, oil production is declined compared to isotropic condition.

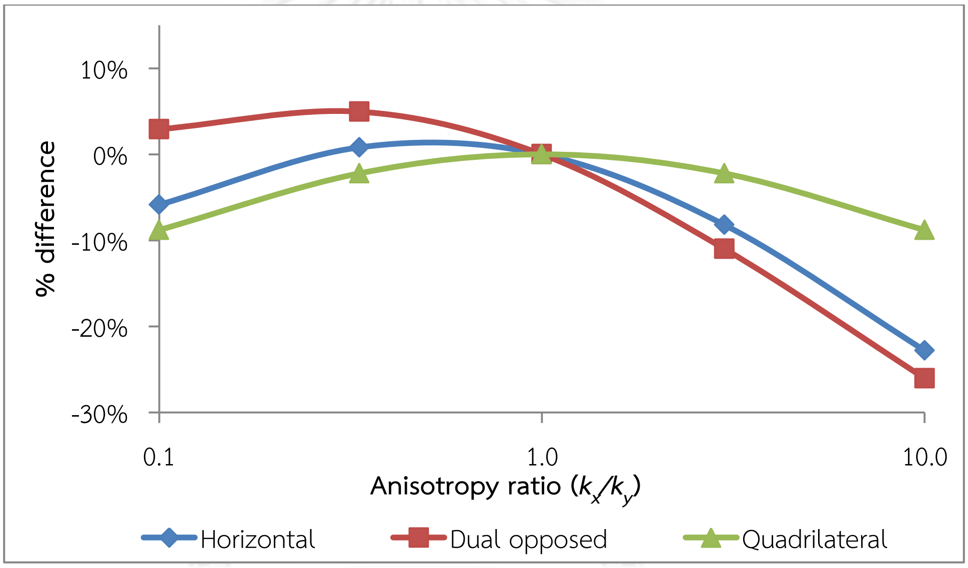


Figure 5.75 Effects of horizontal anisotropy on percentage variation of oil production compared to isotropic condition for 1,200-ft wells in reservoir model 3

Large water production decreases the sensitivity of horizontal anisotropy on all wells. It also decreases benefits of multilateral wells over single horizontal well. With very large water influx and early breakthrough into the well, difference between geometries becomes much smaller, not exceeding 6.5% as displayed in Figure 5.76.

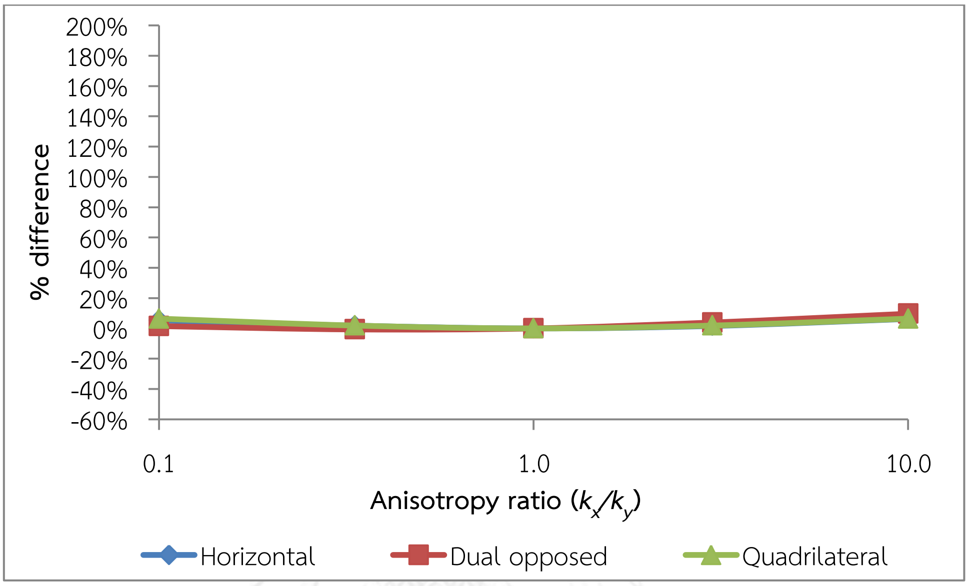


Figure 5.76 Effects of horizontal anisotropy on percentage variation of water production compared to isotropic condition for 1,200-ft wells in reservoir model 3

The trend observed for 1,200-ft wells in reservoir model 3 reappears in cases of 2,000-ft wells as illustrated in Figure 5.78. Oil production indeed decreases more significantly with horizontal anisotropy in reservoir model 3 compared to results obtained from reservoir models 1 and 2. For horizontal anisotropy ratio below 1.0, benefit of dual-opposed well geometry is strengthened, whereas benefits of quadrilateral for ratio above 1.0 remains similar to reservoir model 2. Reduction of interference for 2,000-ft wells decreases sensitivity on dual-opposed as well as quadrilateral wells compared to 1,200ft wells.

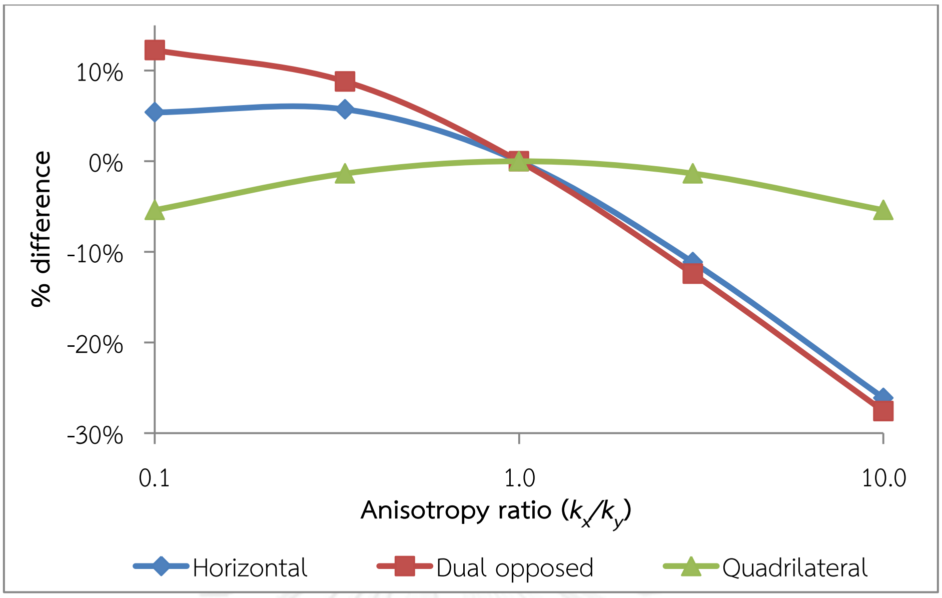


Figure 5.77 Effects of horizontal anisotropy on percentage variation of oil production compared to isotropic condition for 2,000-ft wells in reservoir model 3

Water production is also much less sensitive to horizontal anisotropy in reservoir supported by large aquifer. Water production is already very high for the base case due to high water influx; therefore, rise of water production does not exceed 13% in the worst case as shown in Figure 5.78.

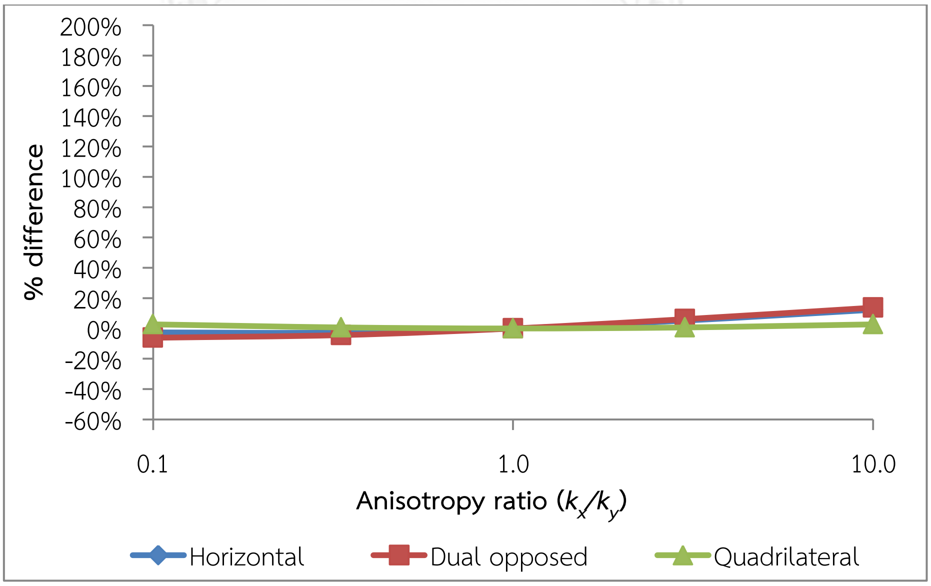


Figure 5.78 Effects of horizontal anisotropy on percentage variation of water production compared to isotropic condition for 2,000-ft wells in reservoir model 3

The consequence of strong aquifer on 2,800-ft wells is similar to 2,000-ft wells with an increase of sensitivity of anisotropy as displayed in Figure 5.79. However, for k_x/k_y below 1.0, both horizontal and dual-opposed wells demonstrate higher benefits compared to 1,200-ft and 2,000-ft wells in reservoir model 3. This can be explained by lower pressure drop due to a longer effective well length which decreases water influx and thus, enables better oil drainage.

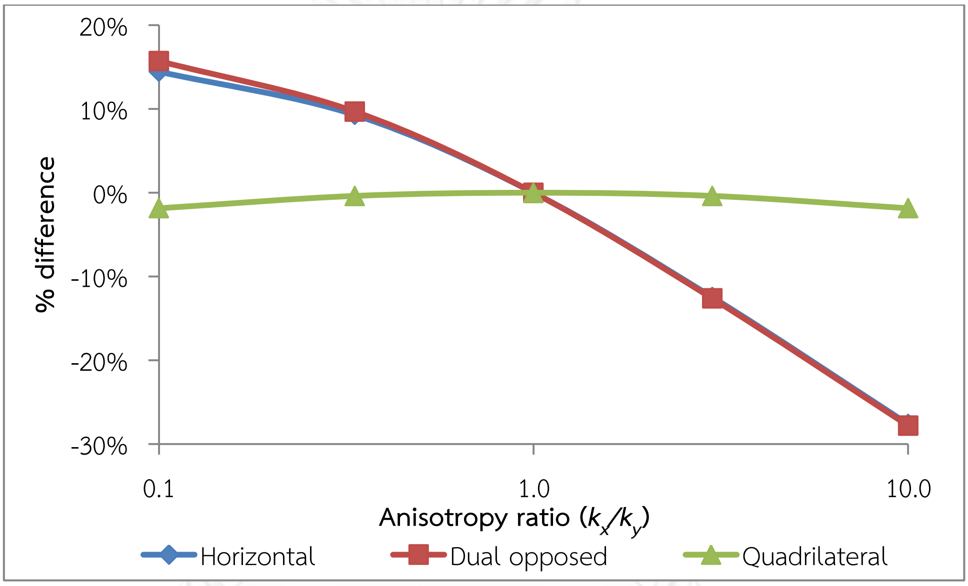


Figure 5.79 Effects of horizontal anisotropy on percentage variation of oil production compared to isotropic condition for 2,800-ft wells in reservoir model 3

Similarly to shorter wells, 2,800-ft wells are less sensitive to horizontal anisotropy in term of water production because of early breakthrough. Indeed, increase in water production does not exceed 25% in the worst case as shown in Figure 5.80.

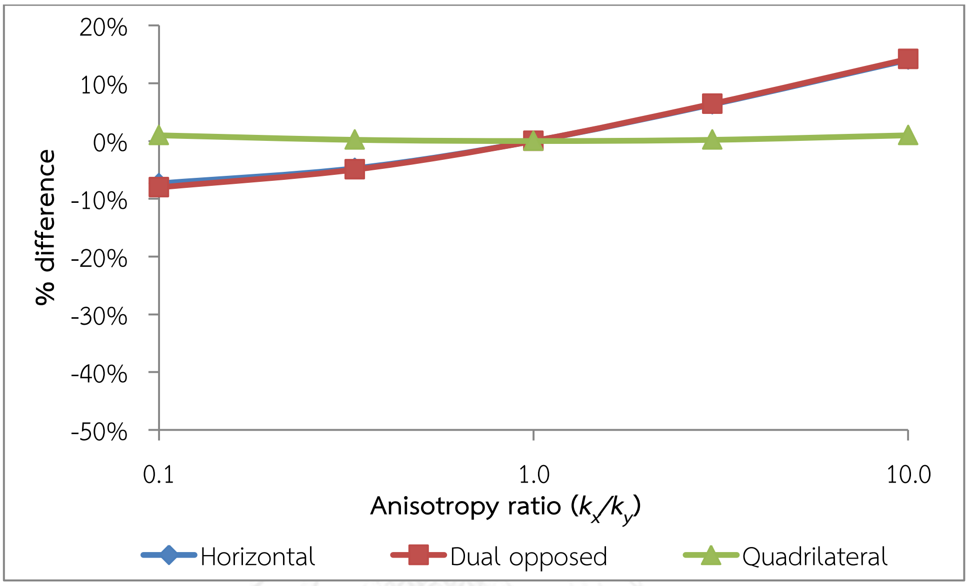


Figure 5.80 Effects of horizontal anisotropy on percentage variation of water production compared to isotropic condition for 2,800-ft wells in reservoir model 3

Effect of horizontal anisotropy on each well geometry compared isotropic condition in all three reservoir models has also been studied for 2,000-ft wells. Percentage variation compared to isotropic condition is plotted to assess sensitivity of horizontal anisotropy on well geometries as shown in Figure 5.81..

In favorable anisotropic conditions, i.e. ratio below 1.0, sensitivity on horizontal well is decreased and benefits from favorable anisotropy direction are reduced with aquifer strength.

In unfavorable anisotropic conditions, i.e ratio above 10.0, sensitivity of horizontal anisotropy is increased with aquifer strength and oil recovery is reduced.

However, low difference in performance is observed in reservoir model 1 and 2; whereas reservoir model 3 decreases oil production significantly.

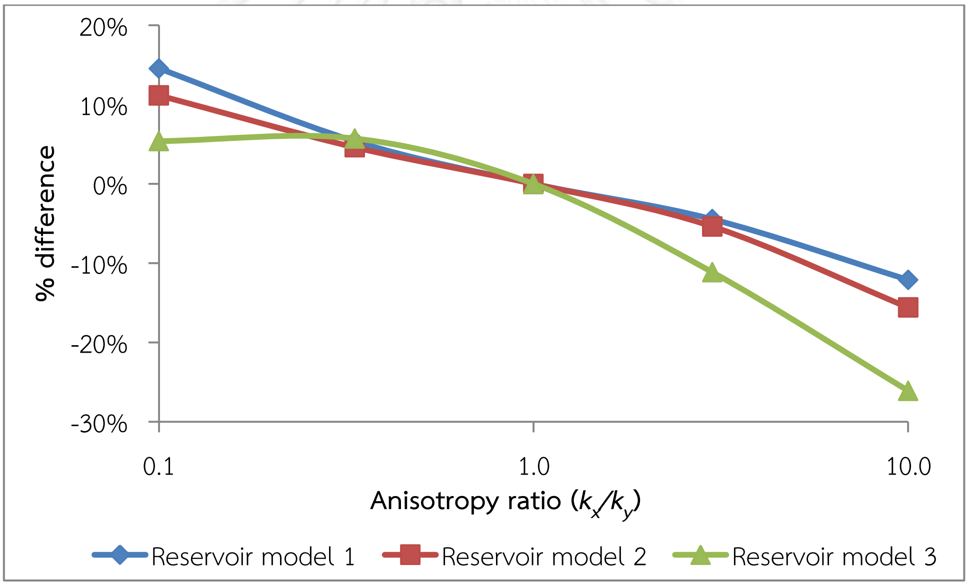


Figure 5.81 Effects of horizontal anisotropy on percentage variation of oil production compared isotropic condition for 2,000-ft horizontal wells in various reservoir models

Similar trend is observed for dual-opposed wells. In reservoir model 1, low sensitivity of medium anisotropy, i.e ratio between 0.33 and 3.0, is observed for dual-opposed well. However, dual-opposed wells are more sensitive of large anisotropic ratios as it enables stronger water influx and thus, decreases the dual lateral ability to delay water breakthrough as it is displayed in Figure 5.82.

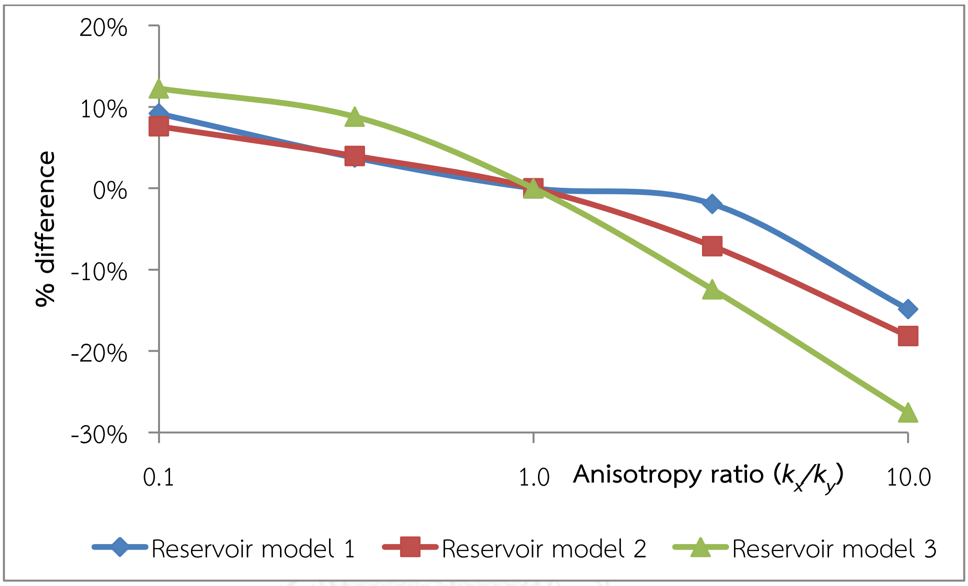


Figure 5.82 Effects of horizontal anisotropy on percentage variation of oil production compared to isotropic condition for 2,000-ft dual-opposed wells in various reservoir models

Figure 5.83 demonstrates the low sensitivity of horizontal anisotropy on quadrilateral wells. It also shows that change in aquifer size has a relatively small impact on the performance of quadrilateral wells in horizontal anisotropic reservoir until it reaches a critical limit. In this particular case, the difference between reservoir models 1 and 2 is small while it increases dramatically when aquifer size is equivalent to 50 reservoir pore volume.

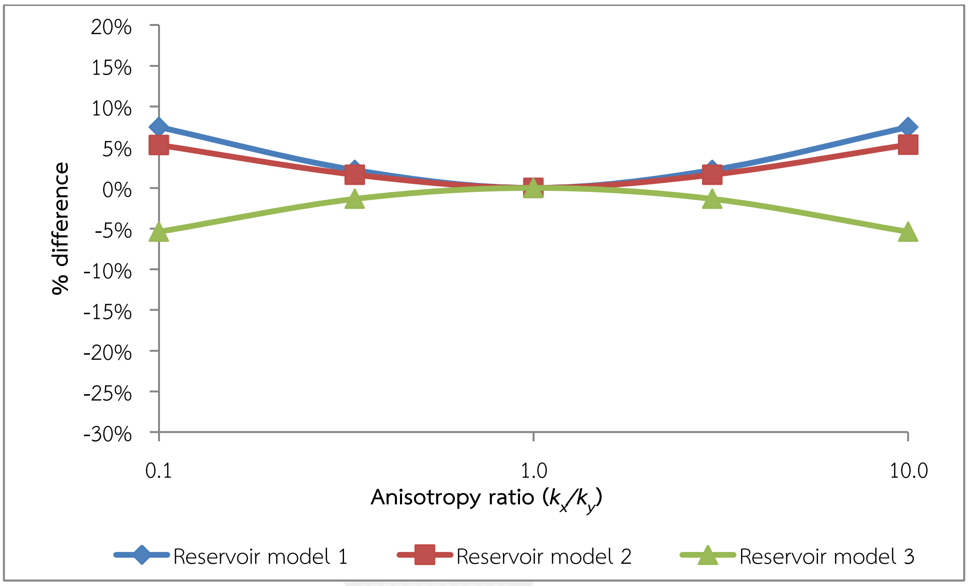


Figure 5.83 Effects of horizontal anisotropy on percentage variation of oil production compared to isotropic condition for 2,000-ft quadrilateral wells in various reservoir models

5.3.3 **Anisotropy in Vertical Direction**

Reservoir anisotropy is also characterized by a difference in permeability between vertical and horizontal directions. Vertical permeability is usually smaller than horizontal permeability due to vertical stress from overburden during lithification process. However, vertical permeability is also varied depending on type and conditions of deposition. In this part, sensitivity of vertical to horizontal permeability ratio on performance of horizontal, dual-opposed and quadrilateral wells is studied by varying k_v/k_h (later in this study the term is so-called vertical anisotropy ratio). Simulations of selected base cases are previously performed with a vertical anisotropy ratio of 0.1 (with fixed value of vertical permeability of 5 mD). In this section, four different ratios of vertical to horizontal permeability are studied: 0.05, 0.1, 0.2 and 0.5. Permeability values for all four cases are summarized in Table 5.27.

Table 5.27 Summary of permeability ratio and permeability values in each direction for all cases with various vertical anisotropy ratios (k_v/k_h)

Cases	1	2	3	4
k_v/k_h	0.05	0.10	0.20	0.50
k_v	2.5	5.0	10	25
k_h	50	50	50	50

Aquifer size plays a major role in well performance as it helps to maintain reservoir pressure but also increases water influx into reservoir. Variation of vertical permeability and thus vertical anisotropy ratio can also amplify or decline aquifer strength. Well geometries can also be used to reduce sensitivity of vertical anisotropy in different aquifer sizes. Sensitivity study is performed on 2,000-ft and 2,800-ft wells to assess more accurately benefits of multiple laterals and avoid critical lateral interferences.

The base cases for 2,000-ft wells in three different reservoir models are summarized in Table 5.28.

Table 5.28 Summary of base cases for 2,000-ft well in three reservoir models

Length (ft)	Aquifer size (PV)	Depth of Lateral (ft)	Number of Laterals	Oil Production (STB)	Comparison with 1PV reservoir
2,000	1	6,900	2	7,400,500	-
	2	6,850	2	9,166,332	23.86 %
	3	6,850	2	14,748,013	99.28 %

Figure 5.84 shows effect of vertical anisotropy on variation of oil production between 2,000ft wells (for all well geometries) and selected base case in reservoir supported by small size aquifer. Under base case conditions, i.e. a ratio of 0.1, horizontal and quadrilateral wells show approximately the same performance with 4% less oil produced than dual-opposed well. However, variation of vertical anisotropy has different consequences for each well geometry. Dual-opposed well demonstrates the best performance in reservoir model 1 with all tested ratio. For vertical anisotropy ratio equal to 0.05, performance of horizontal well is improved faster compared to both dual-opposed and quadrilateral wells. Indeed, low vertical permeability decreases water influx and large pressure drop developed by horizontal well, favoring large oil drainage. Quadrilateral well shows an opposite trend for low vertical permeability. With a lower pressure drop and lateral interferences, oil drainage and performance is reduced compared to the other well geometries. When vertical anisotropy is increasing above 0.1, the trend is changing. Increment of vertical permeability enables stronger water cresting and hence, earlier water breakthrough occurs. Therefore, performance of horizontal well decreases faster than multilateral wells. Quadrilateral well geometry shows the best trend as its performance becomes almost similar to dual-opposed when vertical anisotropy ratio reaches 0.5.

Two major trends can be observed in the Figure 5.84. Below a ratio k_v/k_h of 0.2, performance of three well geometries is quite sensitive to vertical anisotropy. Above a vertical anisotropy ratio of 0.2, sensitivities decrease for all well geometries due to early water breakthrough in wells. Although its performance remains lower than that of dual-opposed well, quadrilateral well shows the least sensitivity to vertical anisotropy below and above the ratio of 0.2. This can be seen from the slope of curve which is flatter than for the two other wells.

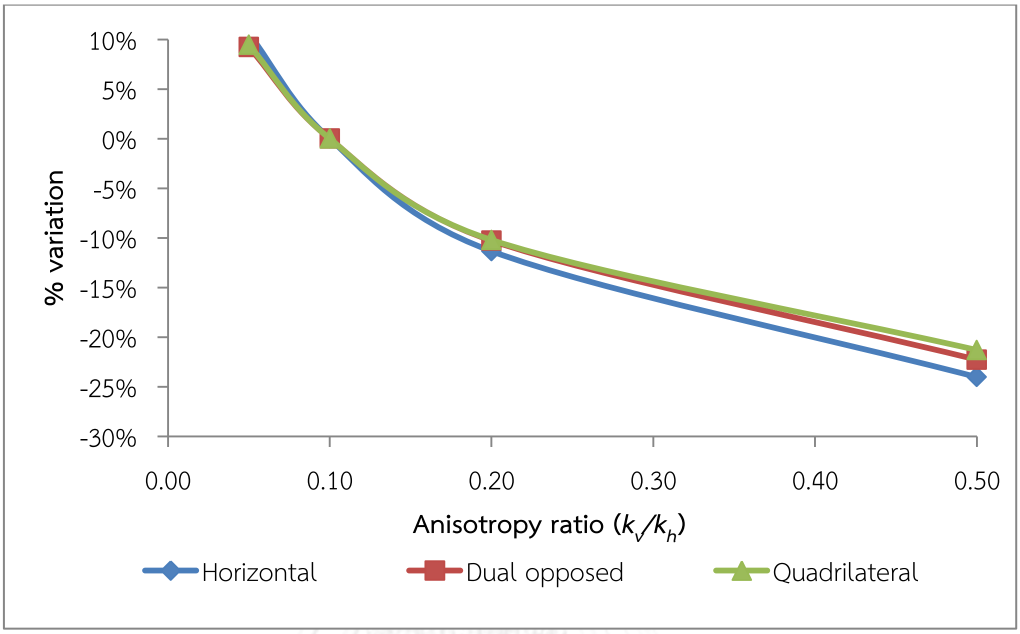


Figure 5.84 Effects of vertical anisotropy on percentage variation of oil production compared to initial ratio of 0.1 for 2,000-ft wells in reservoir model 1

Figure 5.85 depicts high sensitivity of vertical anisotropy on performance of all well geometries in term of water production. Below a ratio of 0.1, horizontal well shows is less sensitive compared to other wells because water production is already low and no longer interferes with oil drainage. However, between a vertical anisotropy ratio of 0.1 and 0.2, dual-opposed well is the least sensitive and thus it shows the best performance compared to, respectively, quadrilateral and horizontal wells. Once the ratio exceeds 0.2, all well geometries are sensitive to vertical anisotropy approximately the same level due to importance of influx of water in the wells.

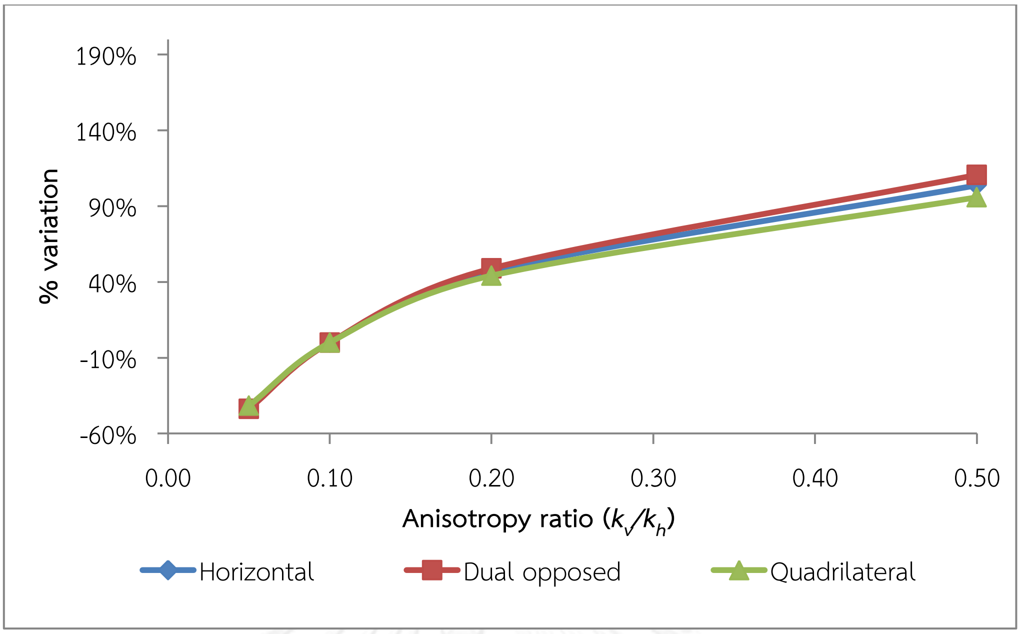


Figure 5.85 Effects of vertical anisotropy on percentage variation of water production compared to initial ratio of 0.1 for 2,000-ft wells in reservoir model 1

Figure 5.86, Figure 5.87 and Figure 5.88 highlight oil drainage in reservoir model 1 with varying in vertical anisotropy for 2,000-ft horizontal, dual-opposed and quadrilateral. For all well geometries, results from simulation clearly show higher influx of water with a higher vertical anisotropy ratio. Higher vertical permeability also accelerates gas coning and gas breakthrough. The sooner gas production decreases gas drive support, thus decreases reservoir pressure and ultimately decreases oil recovery.

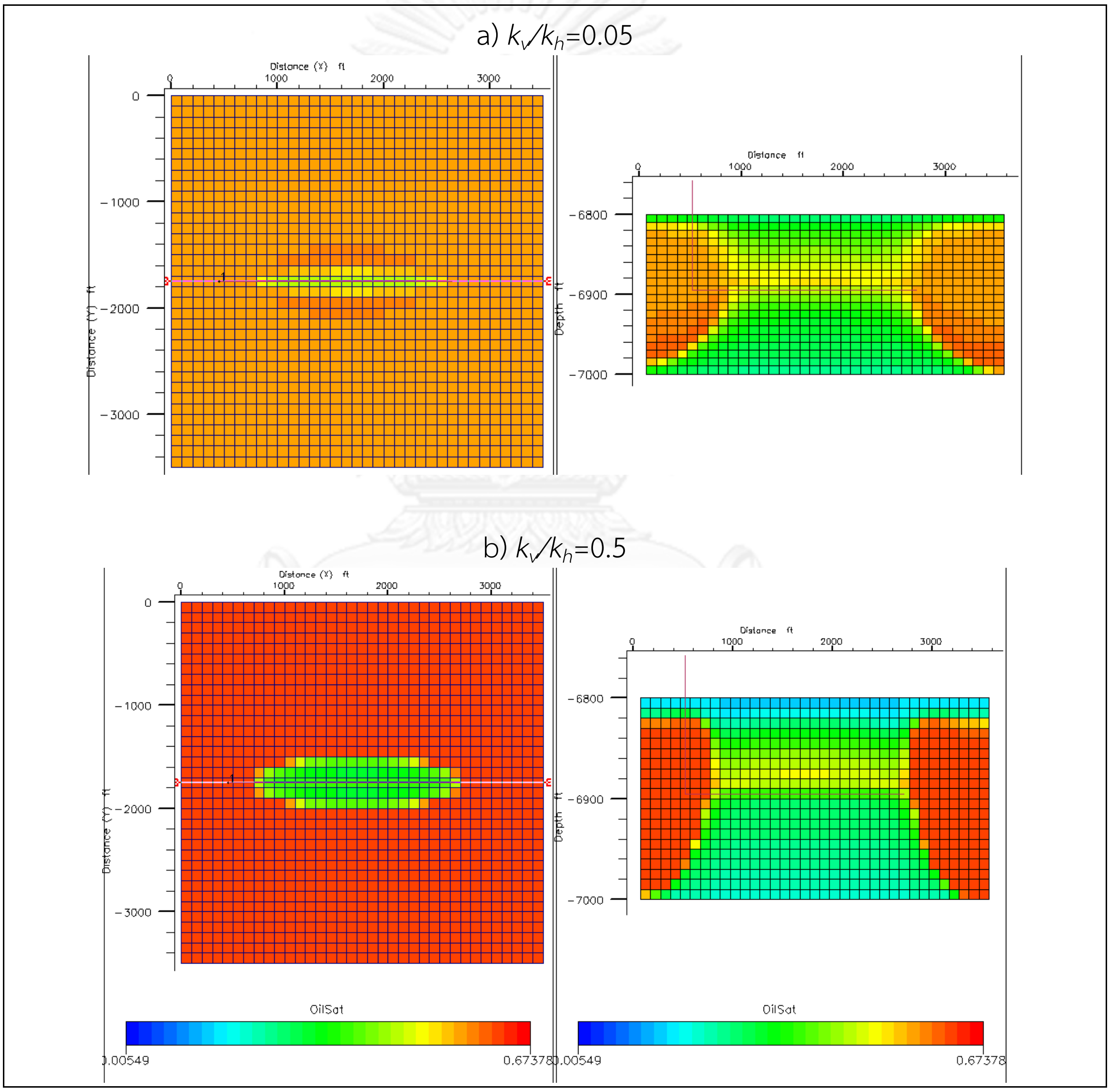
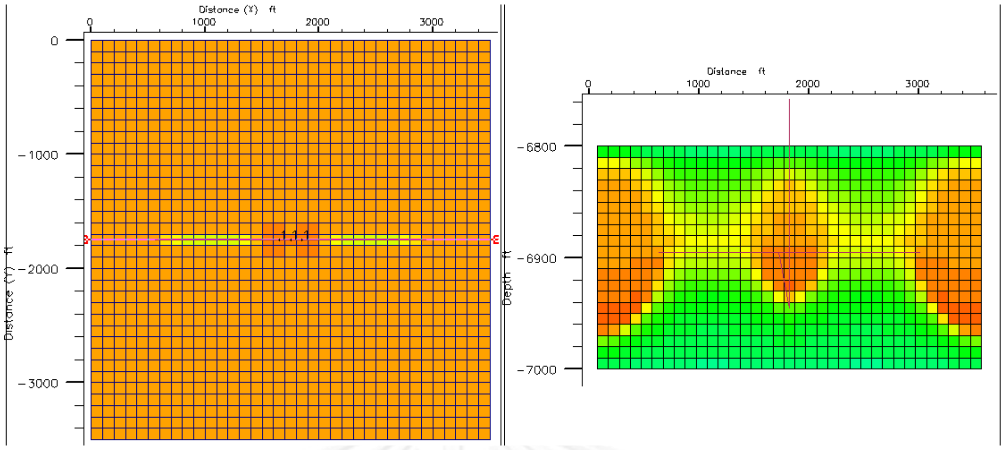


Figure 5.86 Oil saturation profiles in reservoir model 1 after 3 years production implemented by horizontal well in reservoir containing vertical anisotropic ratio of a) 0.05, and b) 0.5

a) k_v/k_h=0.05



b) k_v/k_h=0.5

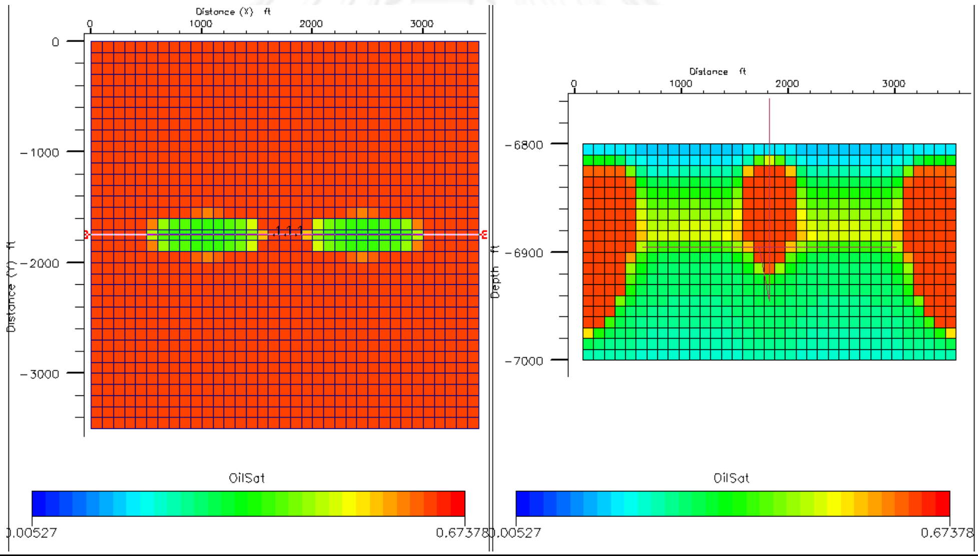


Figure 5.87 Oil saturation profiles in reservoir model 1 after 3 years production implemented by dual-opposed well in reservoir containing vertical anisotropic ratio of a) 0.05, and b) 0.5

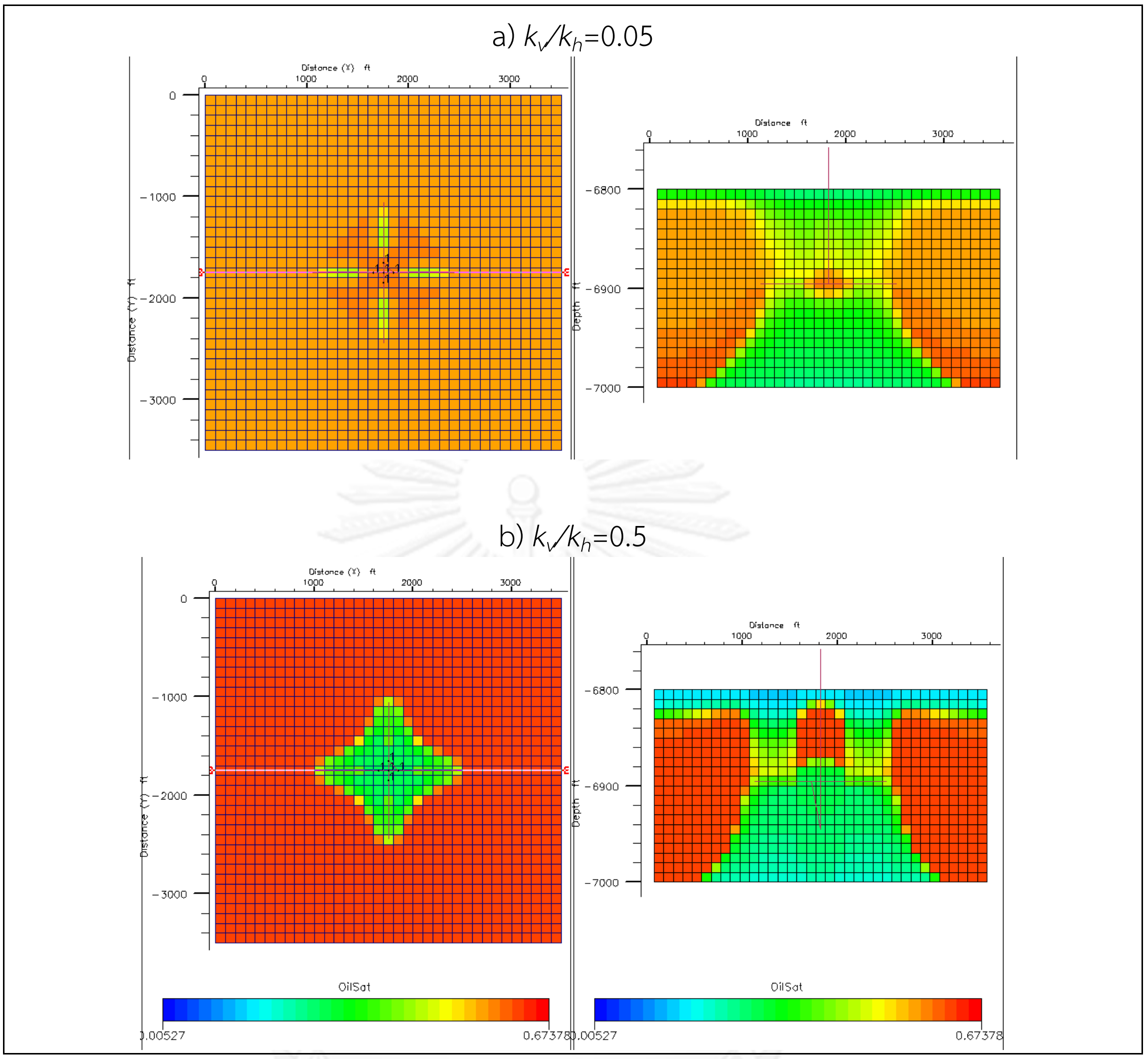


Figure 5.88 Oil saturation profiles in reservoir model 1 after 3 years production implemented by quadrilateral well in reservoir containing vertical anisotropic ratio of : a) 0.05, and b) 0.5

Figure 5.89 shows effect of vertical anisotropy on variation of oil production for 2,000-ft wells compared to base case in reservoir model 2. When vertical permeability is low, sensitivity of all three wells is increased as water influx declines. Compared to reservoir model 1, horizontal well does not show better increase than quadrilateral well. Dual-opposed is less sensitive to vertical anisotropy ratio below 0.1. Between vertical anisotropy ratio of 0.1 and 0.2, three wells geometries are differently affected. Both multilateral wells are less sensitive to vertical anisotropy compared to horizontal well because of a lower water production. Above a ratio of 0.2, which enables large water influx from bottom aquifer, quadrilateral well is less sensitive than other two directional wells to vertical anisotropy.

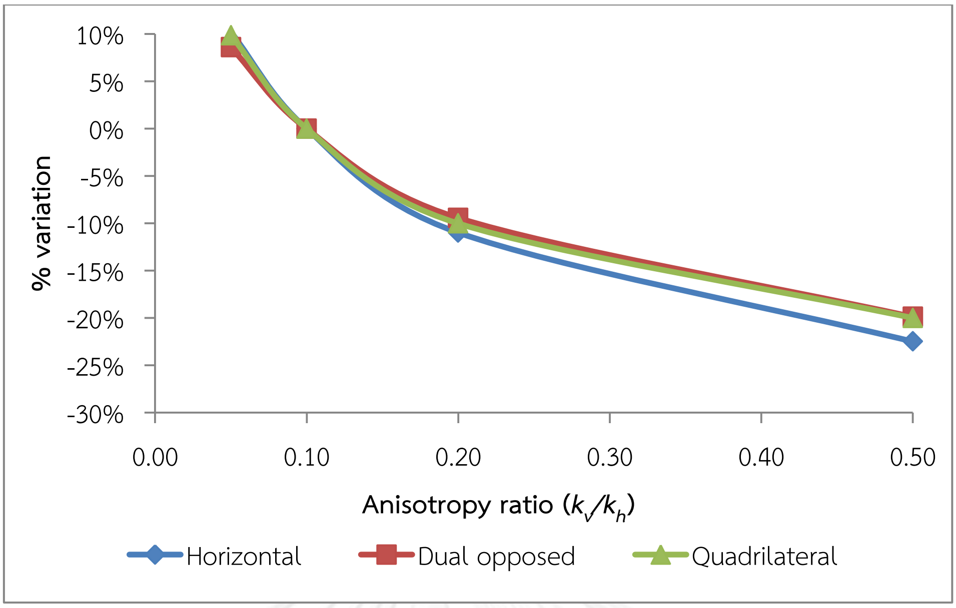


Figure 5.89 Effects of vertical anisotropy on percentage variation of oil production compared to initial ratio of 0.1 for 2,000-ft wells in reservoir model 2

The same trend can be observed in Figure 5.90 which describes the effect of anisotropy on water production change compared to the base case.

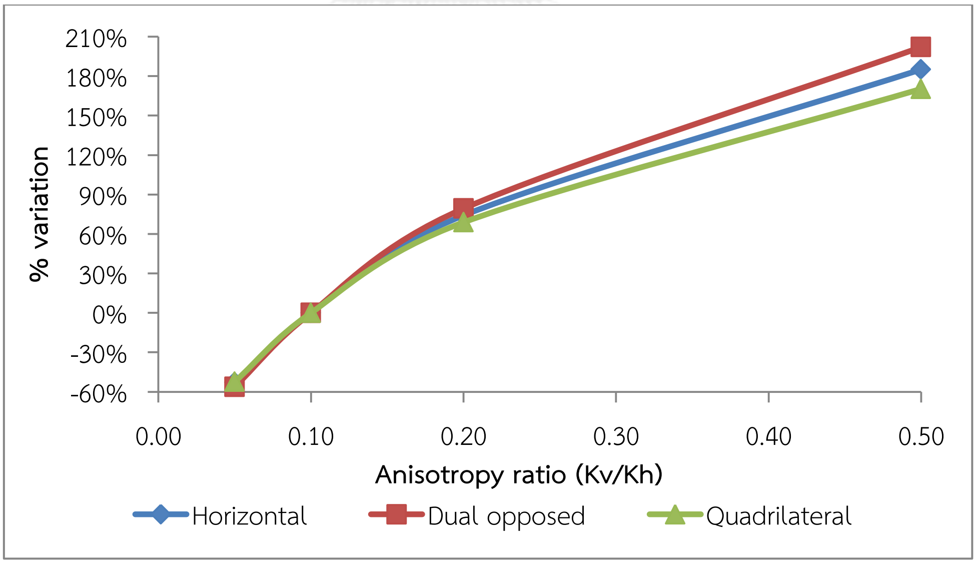


Figure 5.90 Effects of vertical anisotropy on percentage variation of water production compared to initial ratio of 0.1 for 2,000-ft wells in reservoir model 2

Reservoir model 3 is supported by a large aquifer which favors better oil recovery. However, in term of sensitivity of vertical anisotropy, results obtained from ratio below 0.2 are more similar due to high pressure support as displayed in Figure 5.91. Both multilateral wells yield the best performance. Dual-opposed well is less sensitive than quadrilateral well to vertical anisotropy. Above a ratio of 0.2, early water breakthrough occurs in all well geometries, reducing the overall sensitivity of vertical anisotropy. Multilateral wells however confirm their higher performance and are less sensitive compared to single horizontal well.

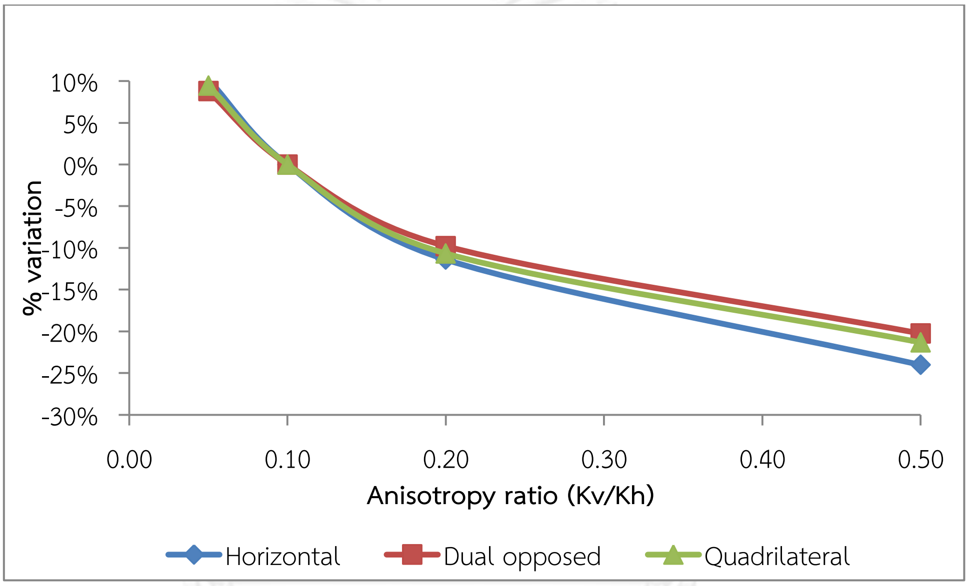


Figure 5.91 Effects of vertical anisotropy on percentage variation of oil production compared to initial ratio of 0.1 for 2,000-ft wells in reservoir model 3

The same trend can be observed in Figure 5.92 with high sensitivity of vertical anisotropy for a ratio below 0.1 and the confirmation of better mitigation of water production by means of multilateral wells.

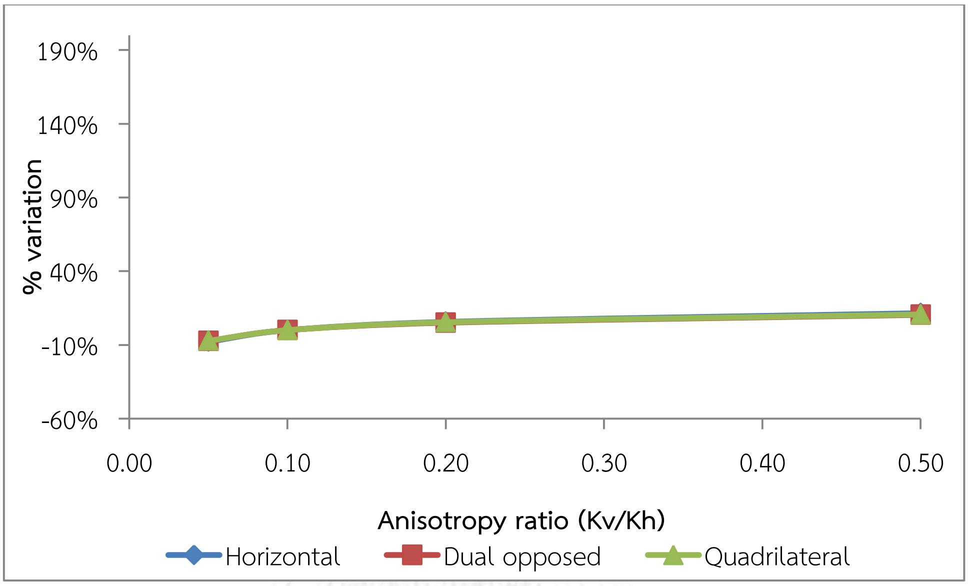


Figure 5.92 Effects of vertical anisotropy on percentage variation of water production compared to initial ratio of 0.1 for 2,000-ft wells in reservoir model 3

The same analysis is performed for 2,800-ft wells. Base cases for all three reservoir models are summarized in Table 5.29. Wells with effective producing length of 2,800 ft have demonstrated less interference between laterals which explains better efficiency of quadrilateral wells compared to 2,000-ft wells.

Table 5.29 Summary of base cases for 2,800-ft well in three reservoir models

Length (ft)	Aquifer size (PV)	Depth of Lateral (ft)	Number of Laterals
2,800	1	6,900	4
	10	6,850	4
	50	6,850	4

In reservoir model 1, the flatter curve of quadrilateral well shows a less sensitivity to vertical anisotropy ratio. Performance of directional wells yields are more sensitive to vertical permeability because of the higher water influx. Figure 5.93 highlights how each well geometry is sensitive to vertical anisotropy. Similar trend is observed with water production variation.

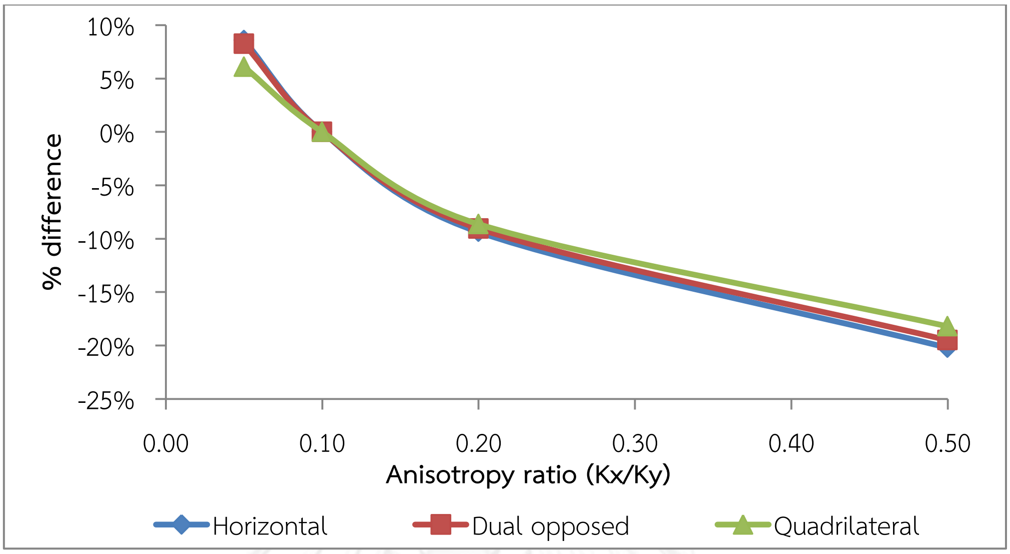


Figure 5.93 Effects of vertical anisotropy on percentage variation of oil production compared to initial ratio of 0.1 for 2,800-ft wells in reservoir model 1

In reservoir model 2, stronger aquifer increases overall oil production and offer a large access to oil. Sensitivity to low anisotropy ratio is also increased for all three wells. However, difference between three well geometries is decreased as shown in Figure 5.94.

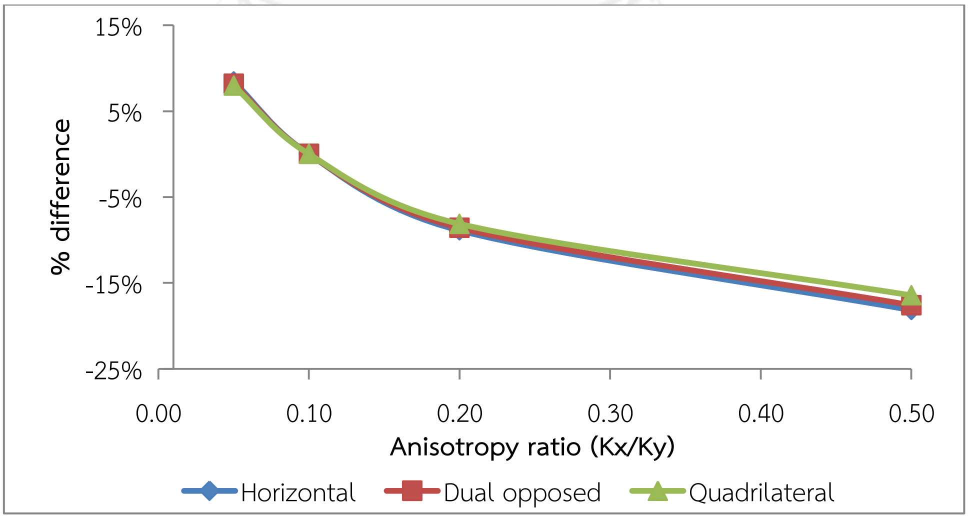


Figure 5.94 Effects of vertical anisotropy on percentage variation of oil production compared to initial ratio of 0.1 for 2,800-ft wells in reservoir model 2

In reservoir model 3, benefits from quadrilateral well can be observed as in Figure 5.95. Quadrilateral well demonstrates lower oil production decrease as well as reduction of large water influx from aquifer in comparison to both horizontal and dual-opposed wells.

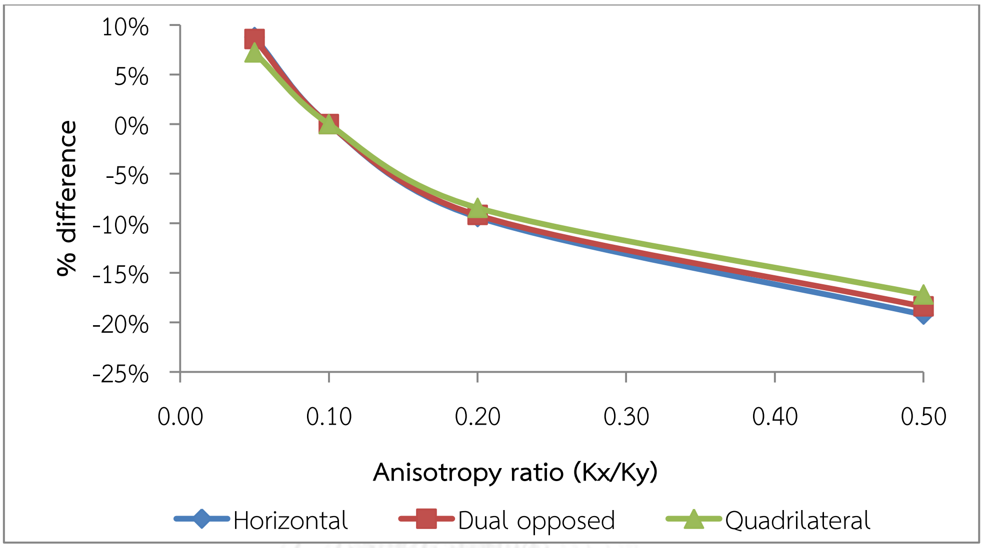


Figure 5.95 Effects of vertical anisotropy on percentage variation of oil production compared to initial ratio of 0.1 for 2,800-ft wells in reservoir model 3

5.3.4 **Effect of Oil Gravity**

Well performance is linked to both reservoir and fluid properties. Oil gravity is indeed one of the keys to consider when planning for production. Oil gravity is varied for each base case to evaluate its effects on well performance. Bubble point pressure is however kept constant and therefore gas-oil ratio is increased. Three different oil gravities are used in this reservoir simulation to investigate sensitivity: 45 °API, very light crude oil (used for base case), 35 °API, i.e. light crude oil and 25 °API, medium crude oil. Results in terms of oil and water productions are then compared to results of base cases in all three reservoir models, i.e. quadrilateral well located at 6,900ft with 45 °API oil gravity. For this analysis, simulations are performed on 2,800-ft wells with varying °API gravities.

Table 5.30 provides summary of oil production results obtained from reservoir model 1.

Table 5.30 Summary of oil production obtained from 2,800-ft wells with different well geometry performed in reservoir model 1 with various oil gravities

Well geometry	Oil production (unit)		
	45 °API	35 °API	25 °API
Horizontal well	7,577,169	6,934,445	5,819,734
Dual-opposed well	7,654,992	7,025,379	5,919,936
Quadrilateral well	7,792,882	7,165,173	6,046,292

Oil saturation profiles after 2 years of production obtained from 2,800-ft quadrilateral well performed in reservoir with various oil gravities (25, 35, 45 °API) are illustrated in Figure 5.96. After 2 years of production, oil saturation distribution evolves differently, depending on oil gravity. Heavier oil tends to allow more water influx into reservoir as viscous oil allows water to flow pass easily due to unfavorable mobility ratio for oil being displaced by water. On the opposite, lighter oil decreases water coning as oil is easily drained from the reservoir due to high oil mobility. In this case, higher oil production also reduces reservoir pressure and favors gas coning from secondary gas cap.

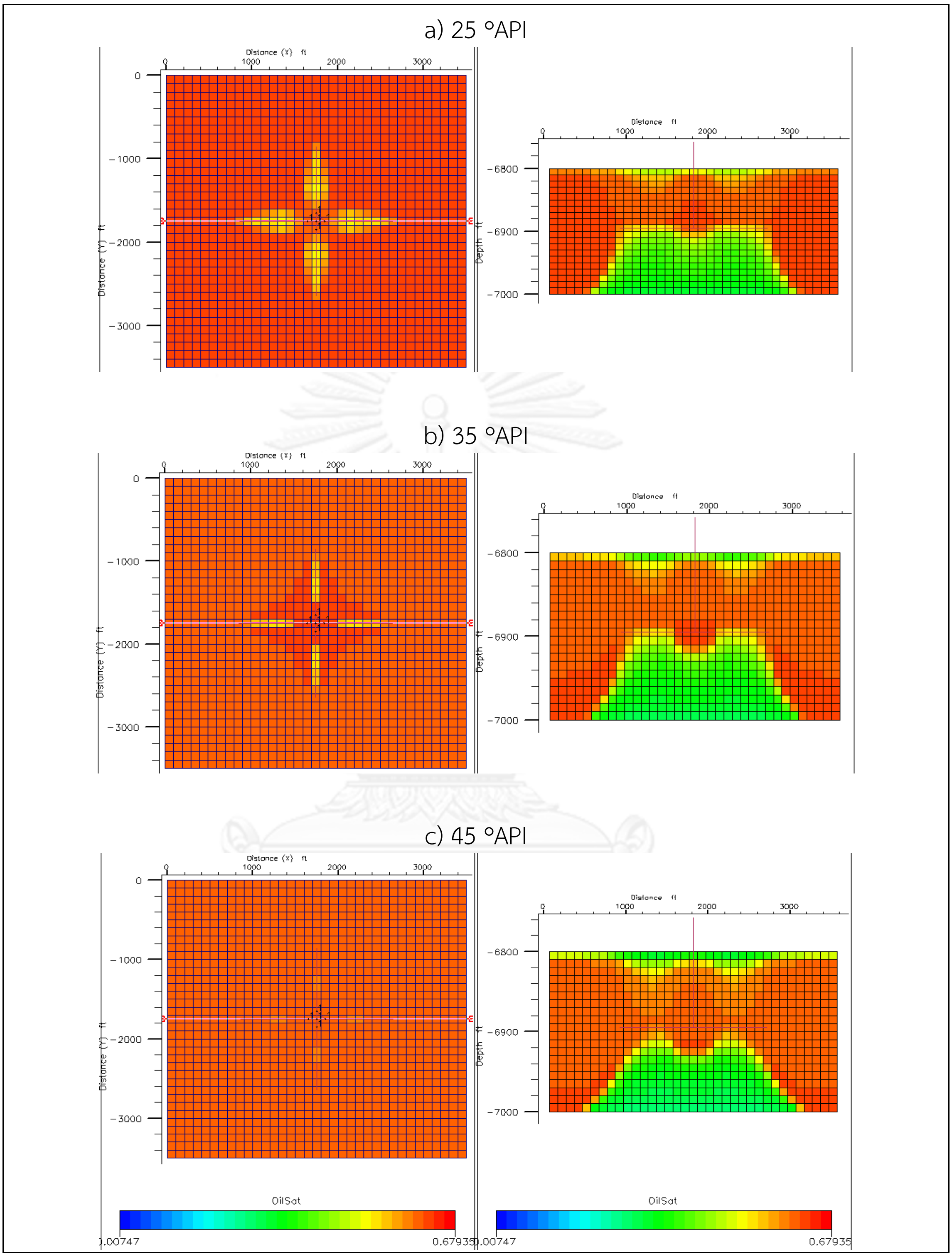


Figure 5.96 Oil saturation profiles in reservoir model 1 after 2 years production implemented by 2,800-ft quadrilateral well in reservoir containing oil gravity of a) 25 °API, b) 35 °API, and c) 25 °API

Figure 5.97 displays sensitivity of oil gravity on performance of 2,800-ft wells, using variation of total oil production compared to result of base case. Oil gravity has direct consequences on oil production performance. Sensitivity of three oil gravity is equivalent on performance of all three well geometries. However, variation is not a straight linear. Sensitivity to well performance is indeed higher for oil gravity in a range between 25 and 35°API (14%), than a range between 35 and 45°API (8%).

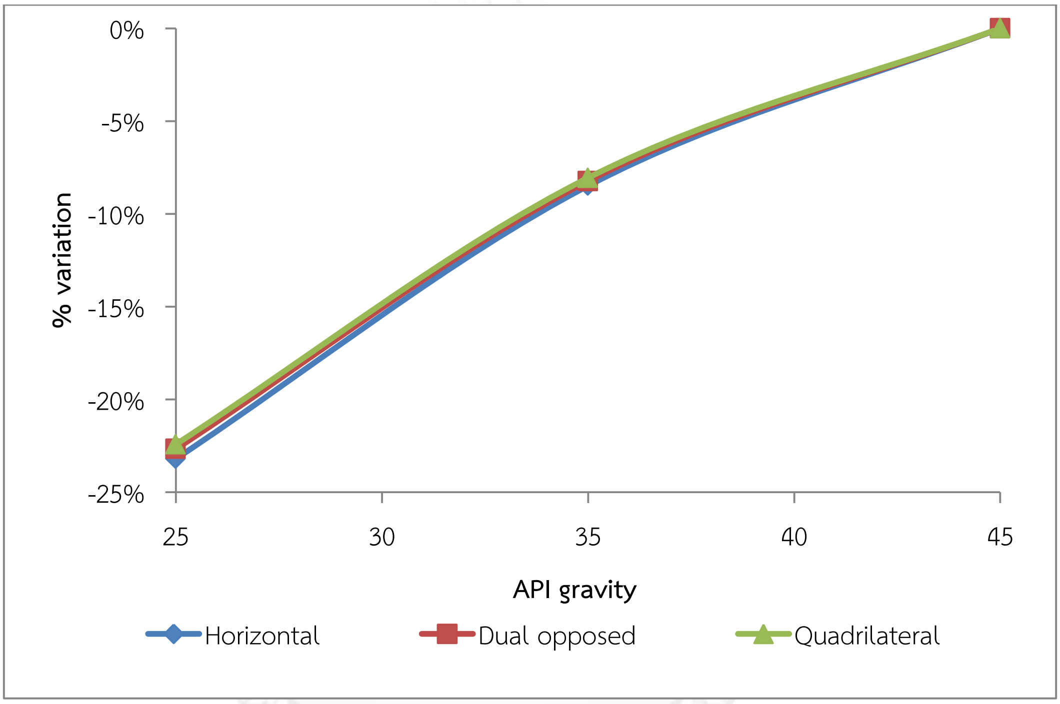


Figure 5.97 Effects of oil gravity on percentage variation of oil production compared to initial API gravity of 45 for 2,800-ft wells in reservoir model 1

Sensitivity to oil gravity on performance of horizontal, dual-opposed and quadrilateral wells is also equivalent in reservoir model 2 supported by a medium aquifer as shown in Figure 5.98. Thanks to higher reservoir pressure and thus better drainage, medium aquifer decreases sensitivity to oil gravity on well performance compared to a small aquifer size. Variation of oil production between 25 and 35 °API cases reaches 11.5%, and is higher than cases with oil gravity between 35 and 45 °API, reaching 4.5%.

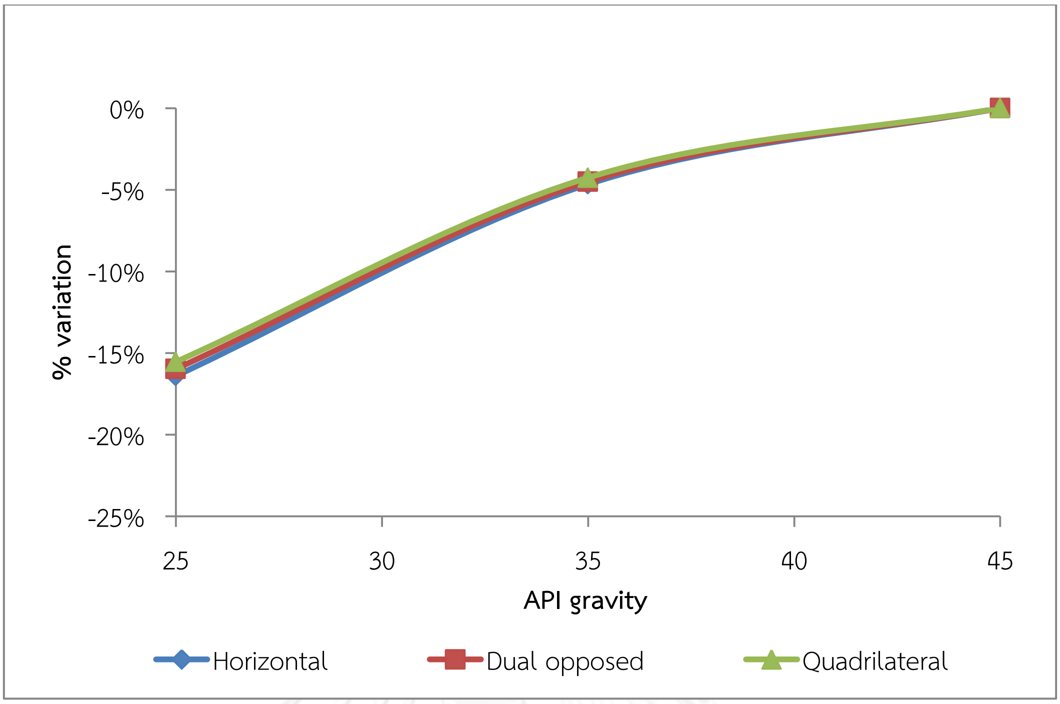


Figure 5.98 Effects of oil gravity on percentage variation of oil production compared to initial API gravity of 45 for 2,800-ft wells in reservoir model 2

The effect of oil gravity in reservoir model 3 is displayed in Figure 5.99. In reservoir supported by large aquifer, sensitivity of oil gravity is also similar for all well geometries. Sensitivity is increased of 13% between oil gravity of 25 and 35°API, while it decreases about 5% between 35 and 45 °API.

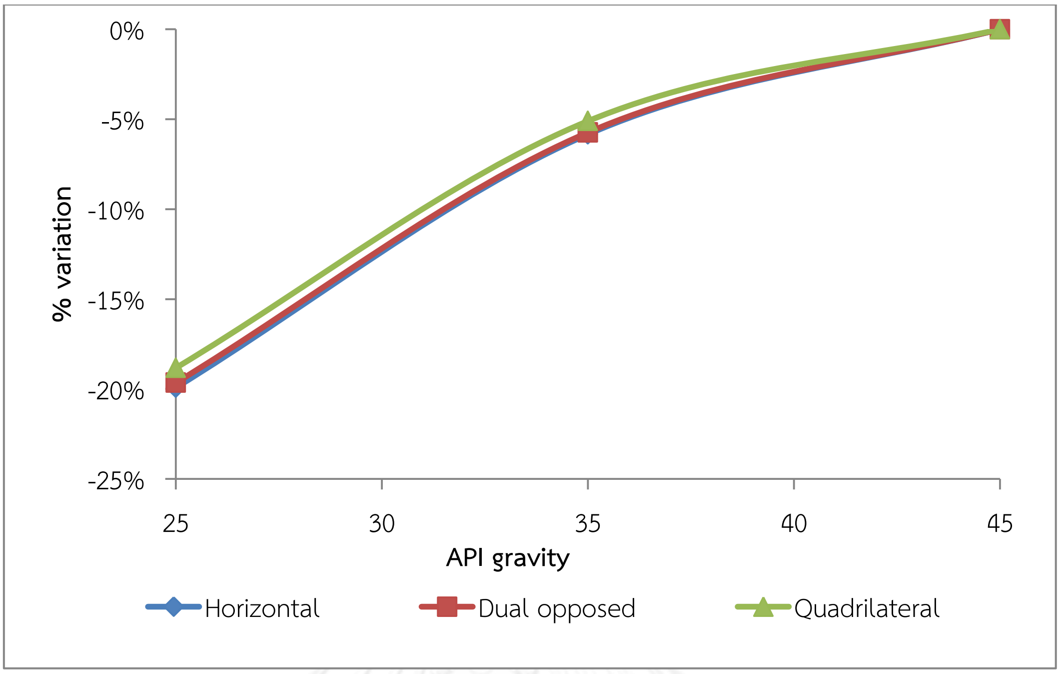


Figure 5.99 Effects of oil gravity on percentage variation of oil production compared to initial API gravity of 45 for 2,800-ft wells in reservoir model 3

Effect of oil gravity on each type of well geometry is studied individually in the following section. Variation of oil production for each case is compared to base cases in reservoir models 1, 2 and 3. Figure 5.100 highlights sensitivity of oil gravity on performance of horizontal wells in the 3 reservoir models. For °API gravity between 25 and 35, horizontal wells in reservoir models 1 and 3 show similar variation in oil production, whereas reservoir model 2 demonstrates less sensitivity of oil gravity on performance of horizontal well. Above 35°API, sensitivity of oil gravity is decreasing. Horizontal well in reservoir models 1 is mostly affected from changes in oil gravity.

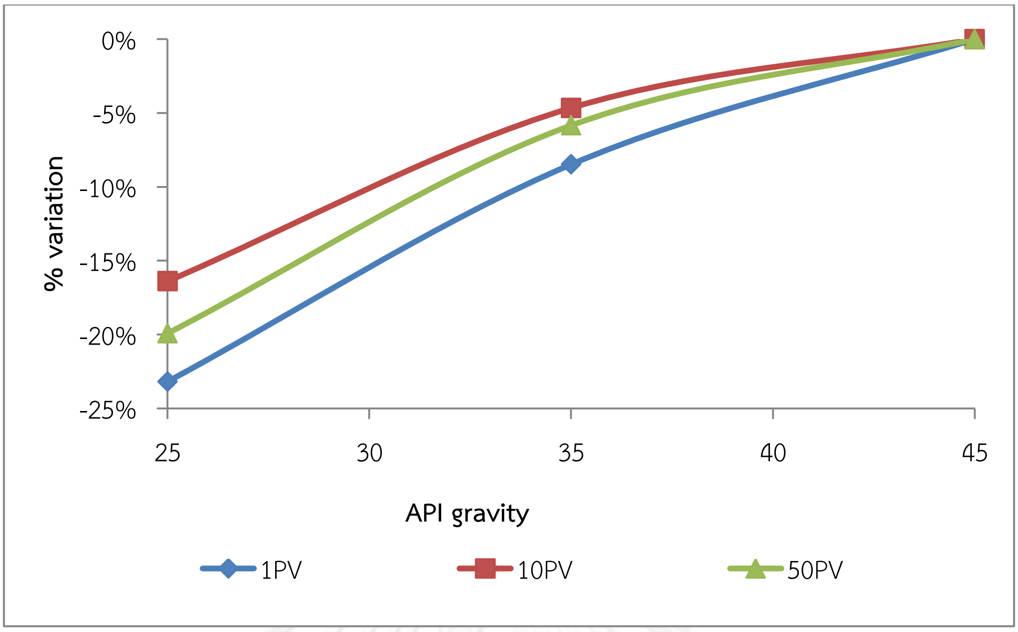


Figure 5.100 Comparison of sensitivity of oil gravity on 2,800-ft horizontal wells compared to initial API gravity of 45 in three reservoir models in term of oil production

Figure 5.101 and Figure 5.102 focus on effect of sensitivity of oil gravity on performance of dual-opposed and quadrilateral performance using results from reservoir model 1 as a reference. Both well geometries show very similar results in term of sensitivity.

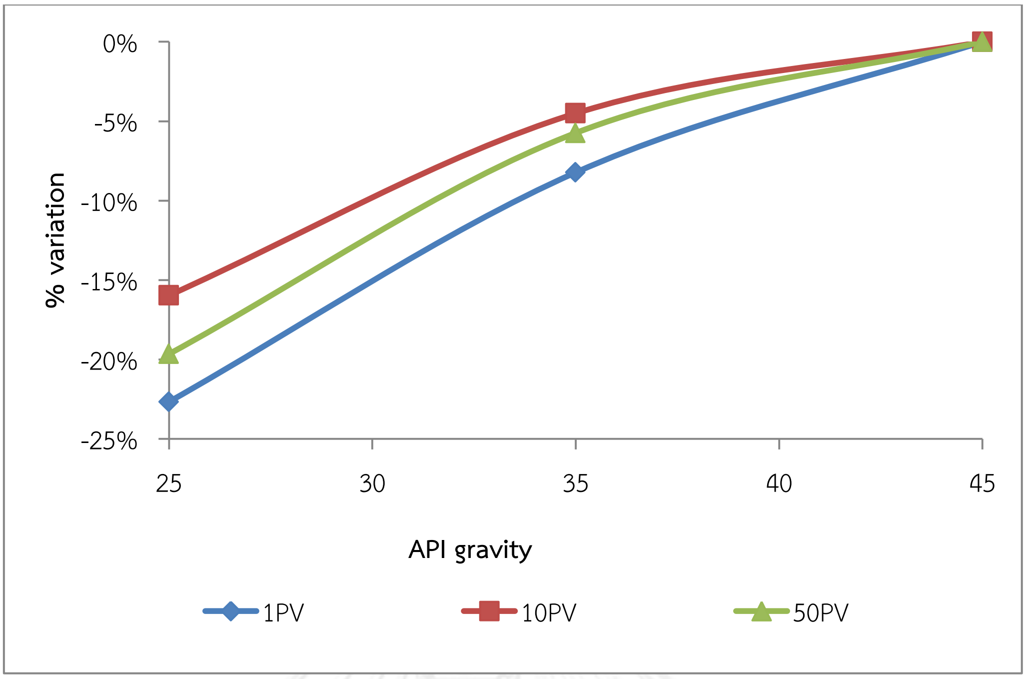


Figure 5.101: Comparison of sensitivity of oil gravity on 2,800-ft dual-lateral wells compared to initial API gravity of 45 in three reservoir models in term of oil production

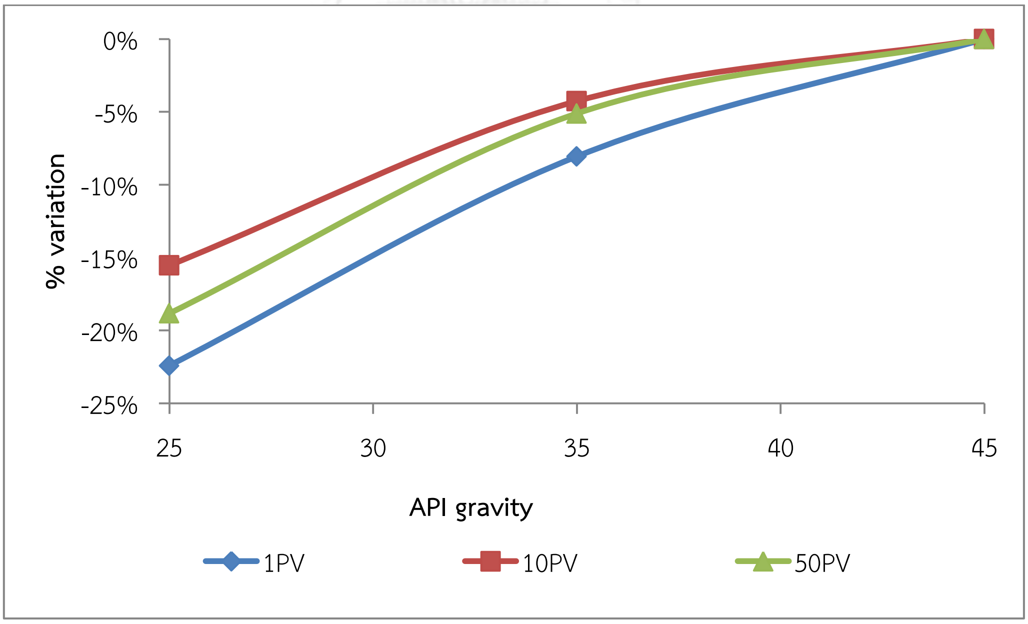


Figure 5.102 Comparison of sensitivity of oil gravity on 2,800-ft quadrilateral wells compared to initial API gravity of 45 in three reservoir models in term of oil production

5.3.5 **Summary of Sensitivity Analysis**

In this section, sensitivity analysis is summarized by means of tornado charts as shown in Figure 5.103, Figure 5.104, Figure 5.105, Figure 5.106 and Figure 5.107.

Reservoirs with strong aquifers show smaller effect of effective producing length on well performance. Horizontal wells are especially sensitive to increase or decrease of effective length. Longer effective producing length wells suffer from reservoir boundary effect and performance is therefore decreased. In reservoir with large aquifer support, dual-opposed wells show less effect from well length because two different producing zones already enhance large drainage in the reservoir.

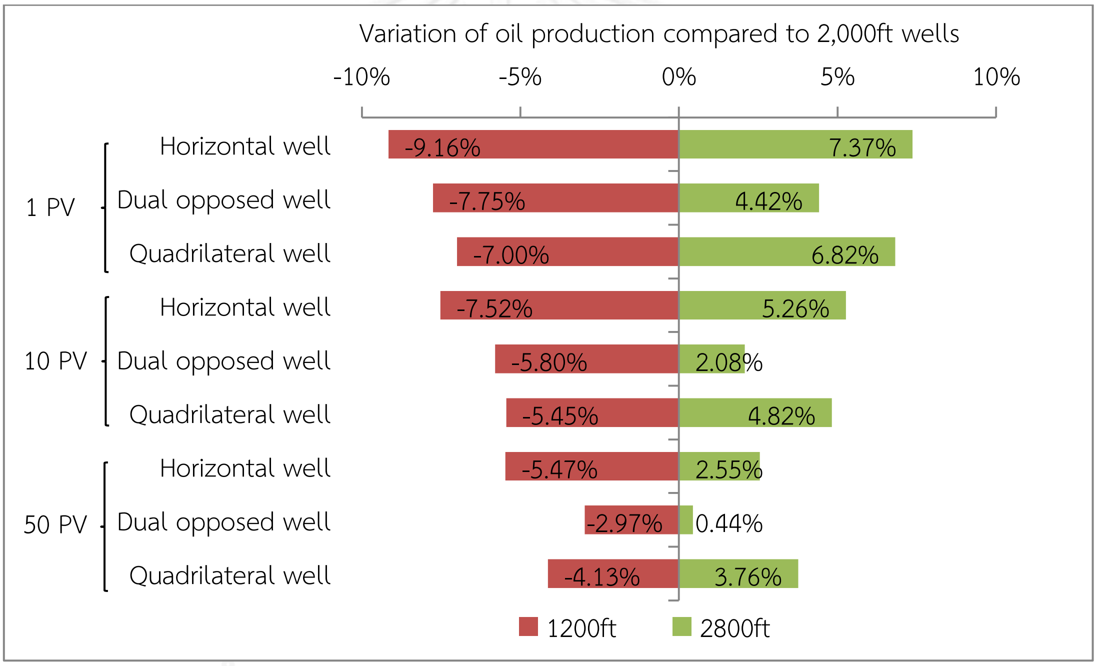


Figure 5.103 Tornado chart summarizing sensitivity of effective producing length of well on oil production (compared to 2,000 ft wells)

Figure 5.104 highlights better performance of quadrilateral well in varying aquifer reservoirs compared to both horizontal and dual-opposed wells. All wells are compared at 2,800-ft effective producing length.

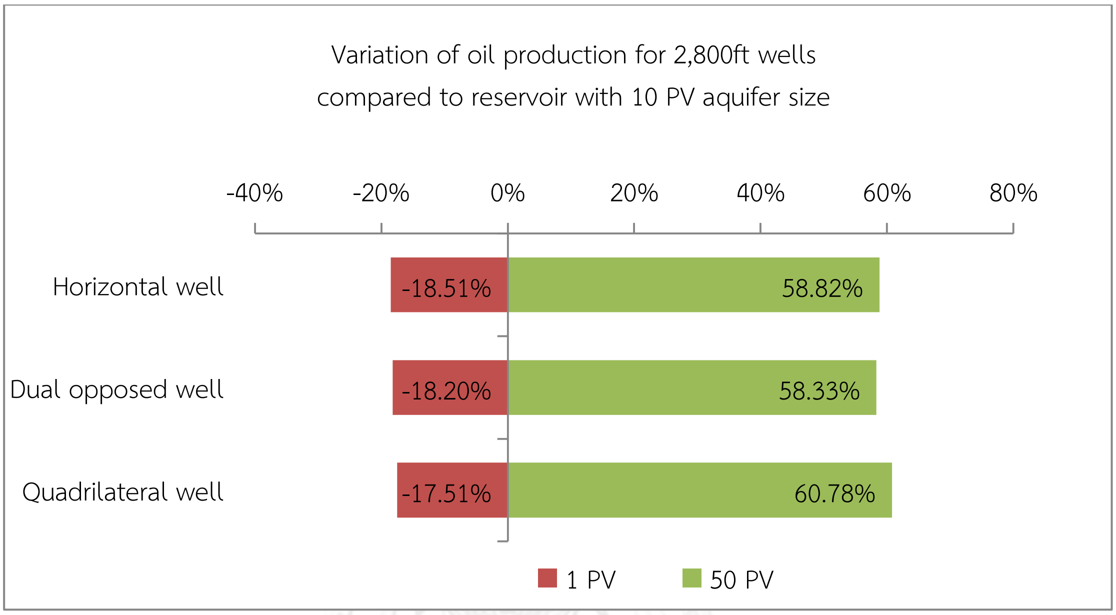


Figure 5.104 Tornado chart summarizing sensitivity of aquifer size to oil production (compared to reservoir model 2, medium aquifer size, 2,800-ft well length)

In next figure, effect of horizontal anisotropy on performance of each well geometry is summarized. In this summary, effective well length is 2,000 ft. Due to symmetrical geometry, quadrilateral wells obtain the same performance for both k_x/k_y ratios of 10.0 and 0.10. Quadrilateral wells are the least sensitive to horizontal anisotropy compared to other well geometries.

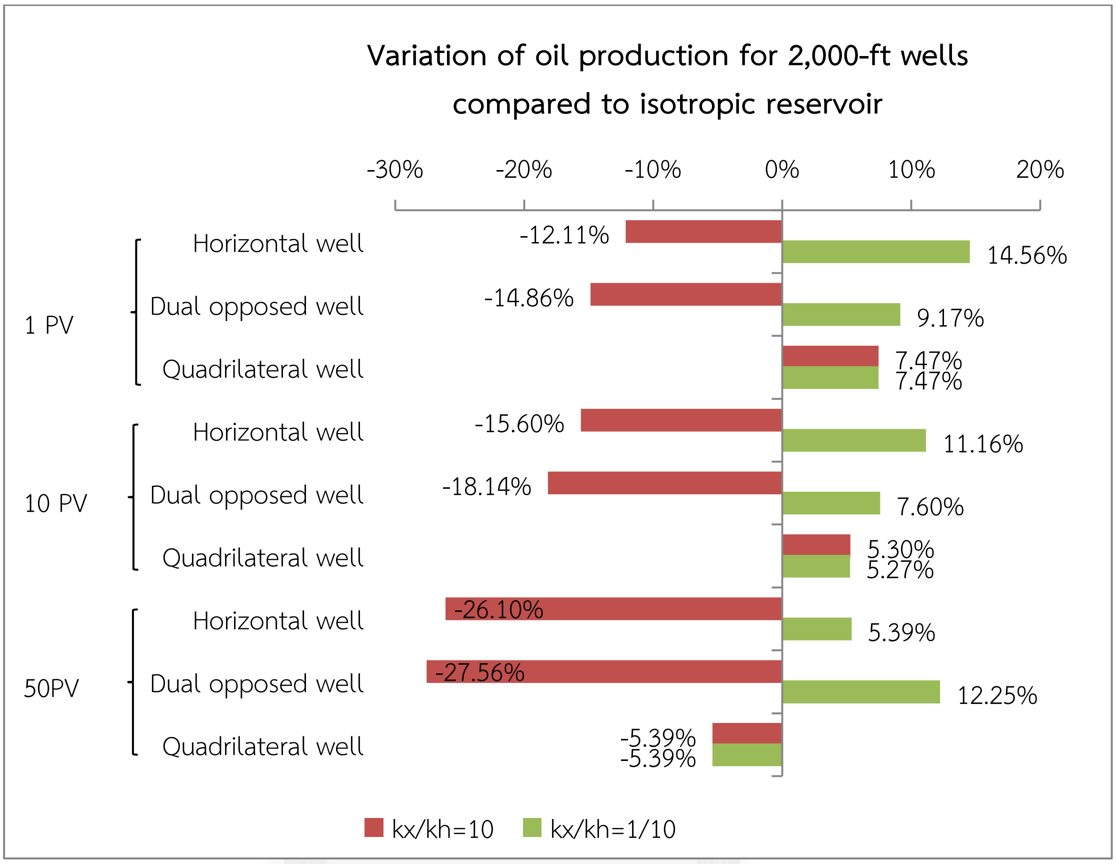


Figure 5.105 Tornado chart summarizing sensitivity of horizontal anisotropy ratio to oil production (compared to isotropic reservoir, k_x/k_y = 1.0, 2,000-ft well length)

Figure 5.106 focuses on effect of vertical anisotropy on 2,800-ft well performance and this demonstrates the benefits of using multilateral wells compared to single horizontal wells.

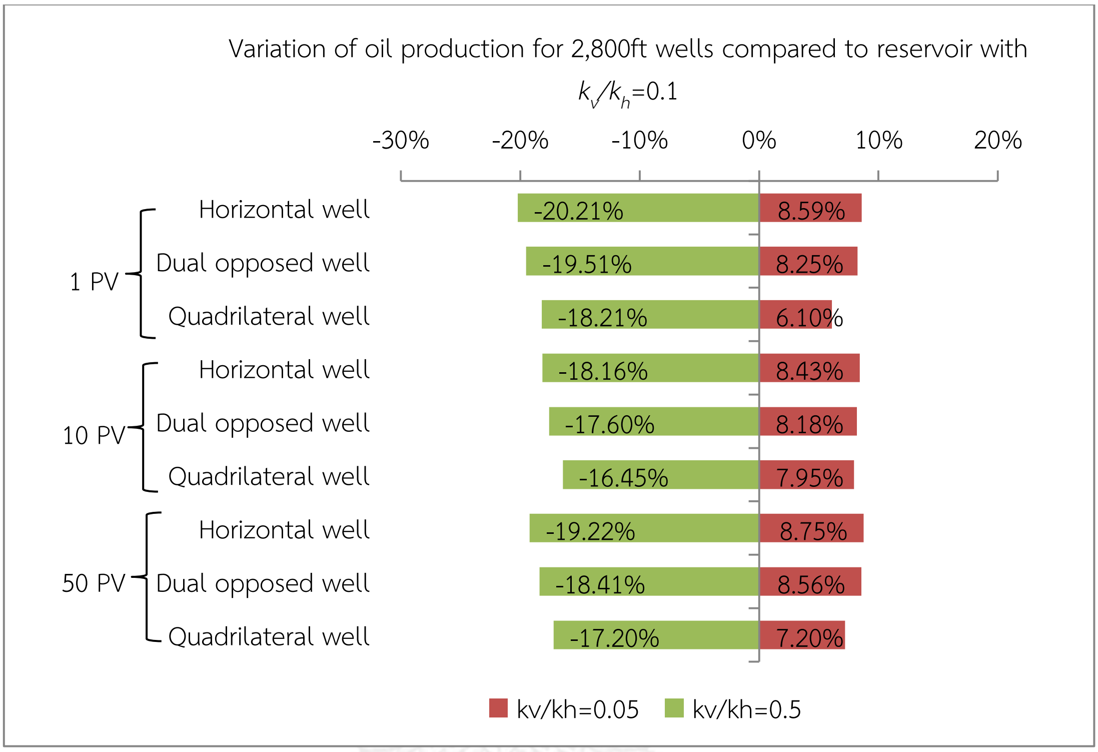


Figure 5.106 Tornado chart summarizing sensitivity of vertical anisotropy ratio on oil production (compared to base value, k_v/k_h = 0.1, 2,800-ft well length)

Finally, effect of oil gravity on effectiveness of 2,800-ft wells is summarized in Figure 5.107 which shows that multilateral and horizontal wells are sensitive almost at the same level to oil gravity.

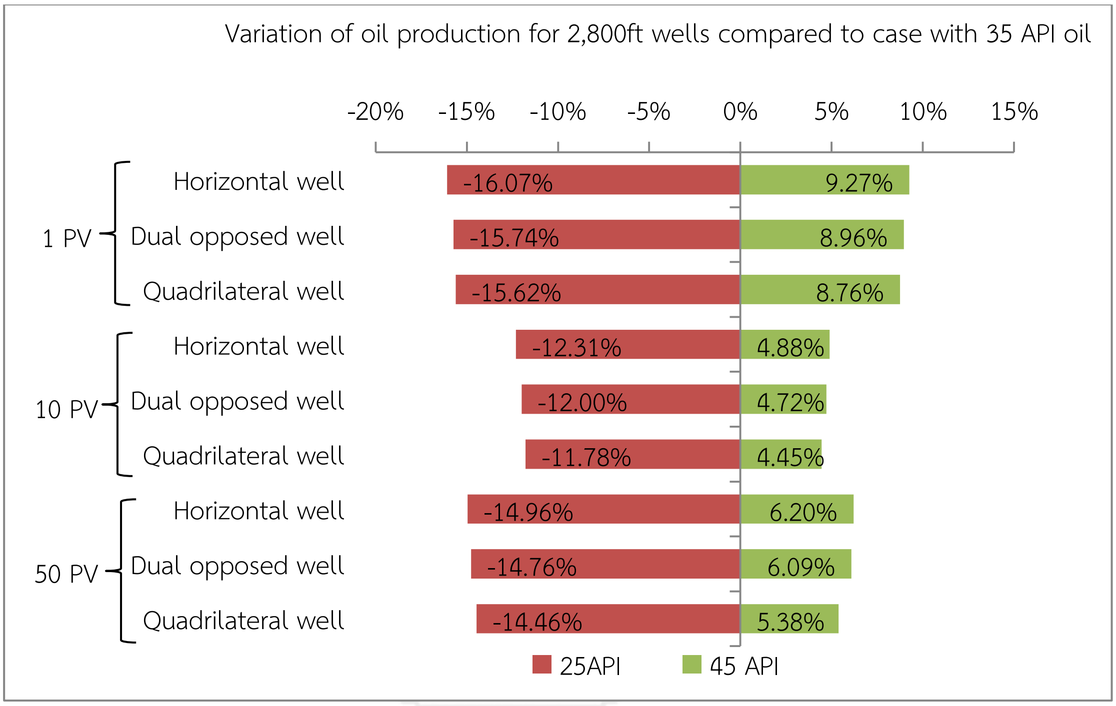


Figure 5.107 Tornado chart summarizing sensitivity of oil gravity on oil production (compared to oil gravity of 35°API, 2,800-ft well length)

CHAPTER 6
CONCLUSION AND RECOMMENDATION

This chapter summarizes the conclusions of the study. These conclusions could be used as preliminary considerations for implementation of horizontal/multilateral wells in reservoir driven by bottom water aquifer. Several recommendations are also suggested for future studying.

6.1 Conclusion

6.1.1 Spacing Between Laterals

Distance between laterals has important consequences on performance of multilateral well. In reservoir driven by bottom water aquifer with small thickness, increasing distance between laterals results in closer placement of inferior lateral to oil-water contact as well as gas-oil contact for superior lateral. Encroachment of gas and water in the well are raised and well performance is declined.

6.1.2 Effect of Effective Producing Well Length

Interferences among laterals are major concern for multilateral wells. The more laterals, the more interferences. Therefore spacing between each producing section is very important and could cause drainage overlapping and thus, reduce pressure drop and faster water influx. Dual- lateral well is the most effective well geometry for relatively small well lengths until a turn-point limit (in this study, the limit appears between 2,000ft and 2,800ft). Beyond this length, quadrilateral wells become the most effective well geometry due to a larger drainage and lower pressure drop compared to well interferences.

6.1.3 **Effect of Aquifer Size**

Multilateral wells have proven ability to reduce water influx from bottom aquifer. Increase of aquifer size also favors water influx in the well.

Aquifer size amplifies effects of anisotropy on well performance. Dual-opposed and quadrilateral wells both decrease pressure drop, reducing water influx from bottom aquifer and increasing oil drainage. Benefits of multilateral wells are increased with aquifer strength. However, an extremely large ratio of aquifer to oil reservoir pore volume would lower its sensitivity due to large water influx in the well. In this study, the turnover point limit stands with an aquifer size between 10 and 50 reservoir pore volume.

6.1.4 **Effect of Horizontal Anisotropy**

Horizontal anisotropy has very large consequence on well performance. Therefore, the knowledge of a potential horizontal anisotropy is a major concern for reservoir engineers. However, this information is scarcely available and multiple laterals could be used to decrease uncertainty of horizontal anisotropy.

In case of horizontal anisotropy, quadrilateral wells have demonstrated important benefits to mitigate the risk compared to directional wells (horizontal and dual-opposed wells).

Well geometry and orientation plays a major role to maximize reservoir performance. Horizontal and dual-opposed wells yield high performance when oriented perpendicular to the higher permeability direction. Oil drainage is declined rapidly for other orientations in the reservoir. In particular, wells set parallel to the higher permeability direction result in the lowest oil production. In case of high anisotropy uncertainty, quadrilateral wells have demonstrated higher performance by averaging the risks of inappropriate orientation.

Sensitivity of horizontal anisotropy on well performance is increased by aquifer strength until a certain point. For horizontal, dual-opposed and quadrilateral higher sensitivity is observed with horizontal anisotropy when aquifer increases. Beyond certain limit, difference among well geometries is decreased because water influx is large.

6.1.5 **Effect of Vertical Anisotropy**

Multilateral wells confirm to be less sensitive to vertical anisotropy compared to horizontal well because of a lower water influx. Quadrilateral wells are especially the least sensitive. Increase of well length also increases benefits of multilaterals in case of high vertical permeability as better oil drainage is obtained with less pressure drop and hence lower water influx.

6.1.6 **Effect of Oil Gravity**

Oil gravity has a minor impact on wells performance compared to anisotropy. Sensitivity of oil gravity is about the same level for horizontal, dual-opposed and quadrilateral wells.

6.2 Recommendations

Further investigation should be performed to obtain more precise results on benefits of other type of multilateral well. Trilateral geometry could especially be studied to assess the effect of lateral interference and calculate the pressure drop obtained at the intersection of laterals compared to dual and quadrilateral wells.

Horizontal anisotropy would also require further study both on the geological side as well as on its consequences on reservoir performance. Indeed, horizontal anisotropy is rarely available for reservoir engineers. Data concerning horizontal anisotropy probability of occurrence and magnitude should be investigated to assess the importance of this information. Moreover, more simulations should be performed with different anisotropy ratio between 0.10 and 10.0 in order to obtain a more precise plot and more accurate regression line in order to correlate anisotropy with reservoir performance.

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APPENDIX

This section describes the data input in Eclipse office simulator for 2,000 ft wells.

1. Case Definition:

Simulator	Black Oil Model dimensions
Grid type	Cartesian
Geometry type	block centered
Number of grid blocks (X,Y,Z directions)	35 × 35 × 20
Oil-gas-water properties	Water, oil, gas and dissolved gas

2. Grid:

Parameters	Value	Unit
X Permeability	50	md
Y Permeability	50	md
Z Permeability	10	md
Porosity	0.15	
Grid block size in x and y direction	100	ft
Grid block size in z direction	10	ft

3. PVT section

- Water PVT

Parameters	Value	Unit
Reference pressure	3000	psia
Water FVF at reference Pressure	1.021734	rb/stb
Water compressibility	3.09988E-6	/ psi
Water viscosity at reference pressure	0.3013289	cP
Water viscosibility	3.374063E-6	/psi

- Dry gas

Press (psia)	FVF (rb /Mscf)	Visc (cp)
1200	2.500435	0.014873
1347.368	2.205831	0.015197
1494.737	1.971475	0.015545
1642.105	1.781273	0.015917
1789.474	1.624417	0.016312
1936.842	1.493369	0.016728
2084.211	1.3827	0.017165
2231.579	1.288393	0.017619
2378.947	1.207404	0.018089
2500	1.149167	0.018485
2673.684	1.076461	0.019066
2821.053	1.023171	0.019569
3000	0.967009	0.020188
3115.79	0.934903	0.020591
3263.158	0.89814	0.021107
3410.526	0.865353	0.021623
3557.895	0.835984	0.022139
3705.263	0.809567	0.022652
3852.632	0.785707	0.023163
4000	0.764073	0.023669

- Live Oil PVT properties

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
0.316935	1200	1.214065	0.447114
	1347.368	1.209645	0.453346
	1494.737	1.20611	0.460403
	1642.105	1.203217	0.468231
	1789.474	1.200806	0.476783
	1936.842	1.198766	0.48602
	2084.211	1.197017	0.495912
	2231.579	1.195501	0.506432
	2378.947	1.194174	0.517555
	2500	1.193203	0.527131
	2673.684	1.191963	0.541539
	2821.053	1.191032	0.554365
	3000	1.190025	0.570661
	3115.79	1.189436	0.581616
	3263.158	1.188747	0.596015
	3410.526	1.188117	0.610914
	3557.895	1.18754	0.626301
	3705.263	1.18701	0.642165
	3852.632	1.18652	0.658497
	4000	1.186066	0.675284
0.364399	1347.368	1.237334	0.423914
	1494.737	1.232983	0.429825
	1642.105	1.229427	0.436436
	1789.474	1.226465	0.443704
	1936.842	1.223959	0.451594
	2084.211	1.221812	0.460073
	2231.579	1.219951	0.469116
	2378.947	1.218323	0.4787
	2500	1.217131	0.486962
	2673.684	1.21561	0.499413
	2821.053	1.214468	0.510509

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
	3000	1.213234	0.524619
	3115.79	1.212511	0.534111
	3263.158	1.211666	0.546592
	3410.526	1.210894	0.55951
	3557.895	1.210187	0.572855
	3705.263	1.209536	0.586616
	3852.632	1.208936	0.600783
	4000	1.20838	0.615346
0.412941	1494.737	1.26145	0.403572
	1642.105	1.257137	0.409197
	1789.474	1.253549	0.415423
	1936.842	1.250515	0.422217
	2084.211	1.247916	0.42955
	2231.579	1.245664	0.437394
	2378.947	1.243695	0.445728
	2500	1.242253	0.452927
	2673.684	1.240415	0.463791
	2821.053	1.239035	0.473488
	3000	1.237542	0.485831
	3115.79	1.236669	0.494141
	3263.158	1.235648	0.505073
	3410.526	1.234716	0.516394
	3557.895	1.233862	0.528094
	3705.263	1.233076	0.540161
	3852.632	1.23235	0.552587
	4000	1.231679	0.565361
0.462474	1642.105	1.286371	0.385567
	1789.474	1.282072	0.390936
	1936.842	1.278442	0.396826
	2084.211	1.275334	0.403211
	2231.579	1.272643	0.410066
	2378.947	1.270289	0.417369
	2500	1.268567	0.423691

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
	2673.684	1.266371	0.433248
	2821.053	1.264722	0.441792
	3000	1.26294	0.452681
	3115.79	1.261897	0.460019
	3263.158	1.260678	0.469679
	3410.526	1.259566	0.479688
	3557.895	1.258546	0.490037
	3705.263	1.257609	0.500715
	3852.632	1.256743	0.511714
	4000	1.255942	0.523024
0.512927	1789.474	1.312061	0.369501
	1936.842	1.307757	0.374638
	2084.211	1.304078	0.380229
	2231.579	1.300893	0.386256
	2378.947	1.298109	0.392697
	2500	1.296072	0.398285
	2673.684	1.293475	0.406749
	2821.053	1.291526	0.41433
	3000	1.289421	0.424005
	3115.79	1.288189	0.430531
	3263.158	1.286748	0.439129
	3410.526	1.285434	0.448045
	3557.895	1.28423	0.457269
	3705.263	1.283122	0.466791
	3852.632	1.282101	0.476602
	4000	1.281155	0.486694
0.564239	1936.842	1.338488	0.355061
	2084.211	1.334165	0.359985
	2231.579	1.330429	0.36531
	2378.947	1.327165	0.371021
	2500	1.324776	0.375986
	2673.684	1.321733	0.383526
	2821.053	1.31945	0.390291

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
	3000	1.316983	0.39894
	3115.79	1.31554	0.40478
	3263.158	1.313854	0.412482
	3410.526	1.312315	0.420474
	3557.895	1.310905	0.428748
	3705.263	1.309609	0.437294
	3852.632	1.308413	0.446104
	4000	1.307306	0.45517
0.616358	2084.211	1.365624	0.341998
	2231.579	1.36127	0.346728
	2378.947	1.357471	0.351813
	2500	1.354693	0.356247
	2673.684	1.351154	0.362995
	2821.053	1.348499	0.369063
	3000	1.345632	0.376833
	3115.79	1.343955	0.382088
	3263.158	1.341996	0.389023
	3410.526	1.340208	0.396227
	3557.895	1.338571	0.403691
	3705.263	1.337065	0.411405
	3852.632	1.335676	0.419361
	4000	1.334391	0.427552
0.669237	2231.579	1.393445	0.330115
	2378.947	1.389048	0.334665
	2500	1.385838	0.338639
	2673.684	1.38175	0.344704
	2821.053	1.378685	0.35017
	3000	1.375375	0.357183
	3115.79	1.373439	0.361932
	3263.158	1.371178	0.368207
	3410.526	1.369115	0.374731
	3557.895	1.367227	0.381496
	3705.263	1.36549	0.388494

Rs (Mscf /stb)	Pbub (psia)	FVF (rb /stb)	Visc (cp)
	3852.632	1.363889	0.395715
	4000	1.362407	0.403153
0.722837	2378.947	1.421926	0.319249
	2500	1.418232	0.322829
	2673.684	1.413539	0.328299
	2821.053	1.410021	0.333241
	3000	1.406222	0.339595
	3115.79	1.404002	0.343904
	3263.158	1.401409	0.349604
	3410.526	1.399043	0.355538
	3557.895	1.396878	0.361696
	3705.263	1.394887	0.36807
	3852.632	1.393052	0.374654
	4000	1.391353	0.381438
0.76738	2500	1.445802	0.31099
	2673.684	1.440558	0.316033
	2821.053	1.436634	0.320593
	3000	1.432399	0.326467
	3115.79	1.429924	0.330456
	3263.158	1.427033	0.335738
	3410.526	1.424397	0.341242
	3557.895	1.421984	0.346959
	3705.263	1.419766	0.35288
	3852.632	1.417721	0.358999
	4000	1.41583	0.365309

- Fluid density at surface condition

Parameter	Value	Unit
Oil density	49.99914	lb /ft^3
Water density	62.42797	lb /ft^3
Gas density	0.04369958	lb /ft^3

- Rock compressibility

Parameter	Value	Unit
Rock compressibility	3.060413E-6	/psi

3. SCAL

- Gas Oil saturation functions

Sg	Krg	Kro	Pc (psia)
0	0	0.45	0
0.05	0	0.3719	0
0.1125	0.0086	0.2847	0
0.175	0.0344	0.2092	0
0.2375	0.0773	0.1453	0
0.3	0.1375	0.093	0
0.3625	0.2148	0.0523	0
0.425	0.3094	0.0232	0
0.4875	0.4211	0.0058	0
0.55	0.55	0	0
0.7	1	0	0

- Water Oil saturation functions

Sw	Krw	Kro	Pc (psia)
0.3	0	0.45	0
0.344	0.0019	0.3556	0
0.3889	0.0074	0.2722	0
0.4333	0.0167	0.2	0
0.4778	0.0296	0.1389	0
0.5222	0.0463	0.0889	0
0.5667	0.0667	0.05	0
0.6111	0.0907	0.0222	0
0.6556	0.1185	0.0056	0
0.7	0.15	0	0
1	1	0	0

4. Initialization

- Bubble Point Pressure : 2500 psi at 6800ft

5. Schedule

<u>Horizontal well</u>

- Well Connection Data

I	J	K Upper	K Lower	Open/Shut Flag	Well Bore ID (ft)	Direction
5	18	1	10	SHUT	0.552	Z
6	18	10	10	SHUT	0.552	X
7	18	10	10	SHUT	0.552	X
8	18	10	10	OPEN	0.552	X
9	18	10	10	OPEN	0.552	X
10	18	10	10	OPEN	0.552	X
11	18	10	10	OPEN	0.552	X
12	18	10	10	OPEN	0.552	X
13	18	10	10	OPEN	0.552	X

I	J	K Upper	K Lower	Open/Shut Flag	Well Bore ID (ft)	Direction
14	18	10	10	OPEN	0.552	X
15	18	10	10	OPEN	0.552	X
16	18	10	10	OPEN	0.552	X
17	18	10	10	OPEN	0.552	X
18	18	10	10	OPEN	0.552	X
19	18	10	10	OPEN	0.552	X
20	18	10	10	OPEN	0.552	X
21	18	10	10	OPEN	0.552	X
22	18	10	10	OPEN	0.552	X
23	18	10	10	OPEN	0.552	X
24	18	10	10	OPEN	0.552	X
25	18	10	10	OPEN	0.552	X
26	18	10	10	OPEN	0.552	X
27	18	10	10	OPEN	0.552	X

- Segmented well definition

First Seg	Last Seg	Branch	Outlet Seg	Length (ft)	Depth (ft)	Diameter (ft)	Roughness (ft)
2	15	1	1	10	10	0.5	0.006
16	37	2	5	100	0	0.5	0.006

- Segmented well completions

I	J	K	Branch	Direction	End
6	18	1	1	Z	15
6	18	5	2	X	27

<u>Dual lateral</u>

- Well connection data

I	J	K Upper	K Lower	Open/Shut Flag	Well Bore ID	Effective k_v	Direction
					(ft)	(mD ft)	
18	18	1	15	SHUT	0.552		Z
6	18	10	10	OPEN	0.552		X
7	18	10	10	OPEN	0.552		X
8	18	10	10	OPEN	0.552		X
9	18	10	10	OPEN	0.552		X
10	18	10	10	OPEN	0.552		X
11	18	10	10	OPEN	0.552		X
12	18	10	10	OPEN	0.552		X
13	18	10	10	OPEN	0.552		X
14	18	10	10	OPEN	0.552		X
15	18	10	10	OPEN	0.552		X
16	18	10	10	SHUT	0.552		X
17	18	10	10	SHUT	0.552		X
18	18	10	10	SHUT	0.552		X
19	18	10	10	SHUT	0.552		X
20	18	10	10	SHUT	0.552		X
21	18	10	10	OPEN	0.552		X
22	18	10	10	OPEN	0.552		X
23	18	10	10	OPEN	0.552		X
24	18	10	10	OPEN	0.552		X
25	18	10	10	OPEN	0.552		X
26	18	10	10	OPEN	0.552		X
27	18	10	10	OPEN	0.552		X
28	18	10	10	OPEN	0.552		X
29	18	10	10	OPEN	0.552		X
30	18	10	10	OPEN	0.552		X

- Segmented well definition

First Seg	Last Seg	Branch	Outlet Seg	Length (ft)	Depth (ft)	Diameter (ft)	Roughness (ft)
2	15	1	1	10	10	0.5	0.006
16	27	2	10	100	0	0.5	0.006
28	39	3	10	100	0	0.5	0.006

- Segmented well completions

I	J	K	Branch	Direction	End
18	18	1	1	Z	15
17	18	10	2	X	6
19	18	10	3	X	30

Quadrilateral wells

- Well connection data

I	J	K Upper	K Lower	Open/Shut Flag	Well Bore ID	Direction
					(ft)	
18	18	1	15	SHUT	0.552	Z
11	18	10	10	OPEN	0.552	X
12	18	10	10	OPEN	0.552	X
13	18	10	10	OPEN	0.552	X
14	18	10	10	OPEN	0.552	X
15	18	10	10	OPEN	0.552	X
16	18	10	10	SHUT	0.552	X
17	18	10	10	SHUT	0.552	X
19	18	10	10	SHUT	0.552	X
20	18	10	10	SHUT	0.552	X
21	18	10	10	OPEN	0.552	X
22	18	10	10	OPEN	0.552	X
23	18	10	10	OPEN	0.552	X
24	18	10	10	OPEN	0.552	X
25	18	10	10	OPEN	0.552	X
18	11	10	10	OPEN	0.552	Y
18	12	10	10	OPEN	0.552	Y
18	13	10	10	OPEN	0.552	Y
18	14	10	10	OPEN	0.552	Y
18	15	10	10	OPEN	0.552	Y
18	16	10	10	SHUT	0.552	Y
18	17	10	10	SHUT	0.552	Y
18	19	10	10	SHUT	0.552	Y
18	20	10	10	SHUT	0.552	Y
18	21	10	10	OPEN	0.552	Y
18	22	10	10	OPEN	0.552	Y
18	23	10	10	OPEN	0.552	Y
18	24	10	10	OPEN	0.552	Y
18	25	10	10	OPEN	0.552	Y

- Segmented well definition

First Seg	Last Seg	Branch	Outlet Seg	Length (ft)	Depth (ft)	Diameter (ft)	Roughness (ft)
2	15	1	1	10	10	0.5	0.006
16	22	2	10	100	0	0.5	0.006
23	29	3	10	100	0	0.5	0.006
30	36	4	10	100	0	0.5	0.006
37	43	5	10	100	0	0.5	0.006

- Segmented well completion

I	J	K	Branch	Direction	End
18	18	1	1	Z	15
17	18	10	2	X	11
19	18	10	3	X	25
18	17	10	4	Y	11
18	19	10	5	Y	25

VITA

Mr. Laurent Fine was born on November, 26th, 1982 in Montpellier, France. He graduated from Grenoble, Ecole de Management with a Master of Science in Management in 2005. He started his career for the French Trade Commission in India as a consultant in the energy, infrastructure and industry sectors until 2012. He has pursued his study in the Master’s Degree program in Petroleum Engineering at the Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University since the academic year 2012.