การผลิตน้ำมันอย่างเหมาะสมที่สุดจากชั้นน้ำมันขนาดเล็กระหว่างชั้นแก็สและชั้นน้ำใต้ดิน

นาย ฟาร์ฮาน จามิล

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต

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OPTIMIZING OIL RECOVERY FROM THIN OIL RIMS
HAVING GAS CAP AND AQUIFER

Mr. Farhan Jamil

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
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ฟาร์ฮาน จามิล: การผลิตน้ำมันอย่างเหมาะสมที่สุดจากชั้นน้ำมันขนาดเล็กระหว่างชั้นแก๊สและชั้นน้ำใต้ดิน (OPTIMIZING OIL RECOVERY FROM THIN OIL RIMS HAVING GAS CAP AND AQUIFER) อ. ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 141 หน้า

เป้าหมายในการพัฒนาแหล่งน้ำมันคือการเพิ่มอัตราการไหลของไฮโดรคาร์บอนและการผลิตน้ำมันด้วยค่าใช้จ่ายที่ต่ำที่สุดเท่าที่ทำได้ วัตถุประสงค์นี้กลายเป็นสิ่งที่ท้าทายอย่างมากในการจัดการแหล่งกักเก็บน้ำมันชนิดบางระหว่างชั้นแก๊สและชั้นน้ำใต้ดิน การไหลทะลักของแก๊สและน้ำที่เข้ามาเร็วเกินไปก่อให้เกิดปัญหาและส่งผลเสียต่อการผลิตน้ำมัน ในแหล่งกักเก็บลักษณะนี้ เป็นการยากมากที่จะควบคุมการเคลื่อนตัวของระดับของแก๊สและระดับของน้ำ การรักษาสมดุลระหว่างการขยายตัวของชั้นแก๊สและการเคลื่อนตัวของชั้นน้ำเป็นกุญแจสำคัญของการผลิตน้ำมันให้มากที่สุด ความสำเร็จของโครงการจะต้องมีแผนงานการรักษาระดับพลังงานในแหล่งกักเก็บผ่านการทำการอัดน้ำ หรือการอัดกลับของแก๊สที่ผลิตได้ เพื่อรักษาความดันในแหล่งกักเก็บและเพิ่มปริมาณการผลิตน้ำมัน

การศึกษานี้แสดงการประเมินผลของแหล่งกักเก็บที่มีชั้นน้ำมันชนิดบางจากแหล่งกักเก็บนอกฝั่งอ่าวไทยเพื่อที่จะประมาณประสิทธิภาพการผลิตน้ำมันที่ดีที่สุด โดยใช้หลักสมบัติการไหลแบบพลวัต การออกแบบการทดลองและการวางแผนขั้นตอนการทำงานอย่างเหมาะสมที่สุดถูกนำมาใช้เพื่อศึกษาถึงผลกระทบของตัวแปรต่างๆ ในการไหลแบบพลวัตสำหรับชั้นน้ำมันชนิดบาง การอัดน้ำแทนที่และการอัดแก๊สแทนที่ก็ถูกนำมาประเมินผลเพื่อที่จะสังเกตถึงผลกระทบต่อการเพิ่มขึ้นของปริมาณการผลิต

การศึกษานี้ได้ประเมินผลกระทบของการเปลี่ยนแปลงสมดุลพลังงานต่อการผลิตน้ำมันโดยการเจาะหลุมแนวนอนรวมถึงผลกระทบของความยาวของหลุมแนวนอนและระยะห่างของหลุมจากระดับของแก๊สและระดับของน้ำ ผลการศึกษาพบว่า เราสามารถเพิ่มประสิทธิภาพการผลิตน้ำมัน โดยการเจาะหลุมนอนในแหล่งกักเก็บน้ำมันชนิดบางให้ห่างจากระดับของแก๊สและใกล้กับระดับของน้ำ

ภาควิชา วิศวกรรมเหมืองแร่และ ปิโตรเลียม ลายมือชื่อนิสิต........................

สาขาวิชา วิศวกรรมปิโตรเลียม ลายมือชื่อ อ.ที่ปรึกษาวิทยานิพนธ์หลัก........

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KEYWORDS: /OPTIMIZE/RECOVERY/OIL RIM RESERVOIR

FARHAN JAMIL: OPTIMIZING OIL RECOVERY FROM THIN OIL RIMS HAVING GAS CAP AND AQUIFER. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D. 141 pp.

The goal in any oil field development is to accelerate the hydrocarbon production and optimize the oil recovery at lowest cost possible. This objective becomes very challenging when managing thin oil rim reservoirs where a thin column of oil is overlain by a large gas cap and underlain by a strong aquifer. Early gas breakthrough and water coning can cause serious problems to production and hence jeopardize oil recovery. In this type of reservoir, it is very critical to control the movement of GOC and OWC. Keeping a force balance between gas cap expansion and aquifer movement is the key for maximum oil recovery. A successful project may entail plans to maintain the reservoir energy through water injection or produced gas re-injection to maintain reservoir pressure and enhance oil recovery.

This study presents evaluation of a thin oil rim from Gulf of Thailand (GOT) offshore reservoir to estimate the optimum recovery factor based on dynamic flow properties. An experimental design and optimization workflow is adopted to study the effect of different flow dynamic parameters on overall recovery of a thin oil rim reservoir. Secondary recovery options (water/gas injection) are also evaluated to see their impact on incremental recovery.

In this study, the impact of changing the force balance on oil recovery by horizontal well drilling is evaluated. The effect of horizontal well lateral length and distance from OWC and GOC on oil recovery is also studied. The results show a potential of improving oil recovery factor by drilling horizontal wells in thin oil rims that are farther from GOC and closer to OWC.

Department: Mining and Petroleum Engineering　　Student's Signature..........

Field of Study: Petroleum Engineering　　Advisor's Signature..........

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NOMENCLATURES

GOC	gas oil contact
OWC	oil water contact
GOT	gulf of Thailand
DoE	design of experiments
SRFT	slim repeat formation tester
ø-k	porosity – permeability
S_{or}	residual oil saturation
S_{wc}	connate water saturation
GIGP	gas injection to gas production ratio
GOR	gas oil ratio
K_v	vertical permeability
K_h	horizontal permeability
OOIP	original oil in place
OGOC	original gas oil contact
OWOC	original water oil contact
MMSTB	million stock barrels
EVOL	E volumetrics
R_s	solution gas oil ratio
TVDSS	true vertical depth in subsea
POROS	porosity
PERMX	permeability in x-direction

CDF	cumulative distribution function
OPR	oil production rate
GPR	gas production rate
WPR	water production rate
MAXWCUT	maximum allowable water cut
MAXGOR	maximum allowable gas oil ratio
MAXDDP	maximum allowable drawdown pressure
BHP	bottom-hole pressure
EUR	estimated ultimate recovery
OPC	oil production cumulative
RF	recovery factor
LGR	local grid refinement
BOPD	barrels of oil per day
MMSCFD	million standard cubic feet per day
k_{rg}	relative gas permeability
k_{ro}	relative oil permeability
M	ratio of gas cap to oil reservoir
WI	water injection
GI	gas injection
ORF	oil recovery factor
W. Cut	water cut
VRR	voidage replacement ratio

CHAPTER I

Introduction

An oil rim is generally defined as thin oil column relative to large column of overlain gas cap. Sometimes oil rim is also underlain by aquifer. Oil rims are ribbon like structures that can have very limited lateral extension or in some cases extend laterally across the field but are relatively thinner than the overlain gas cap or underlain aquifer. Figure-1.1 illustrates different types and sizes of oil rims in multi stacked reservoir environment. The oil rims discussed in this study are in the range of 40-60 ft in thickness. Recovery factor from oil rims generally tends to be on the lower side. Gas coning and/or water coning is one of the major issues in producing these thin oil rims. The coning problem is more pronounced in vertical and deviated wells as compared to horizontal wells. Sometimes the well has to flow at very low rates to avoid gas and/or water coning that could not justify the cost of drilling the wells. A number of studies and experiments have been carried out to estimate gas and water free oil rates but unfortunately these rates may turn out to be uneconomical specially in case of vertical wells. If the wells are flowed at higher rates, gas and/or water cone will hamper the overall oil recovery from these types of reservoirs.

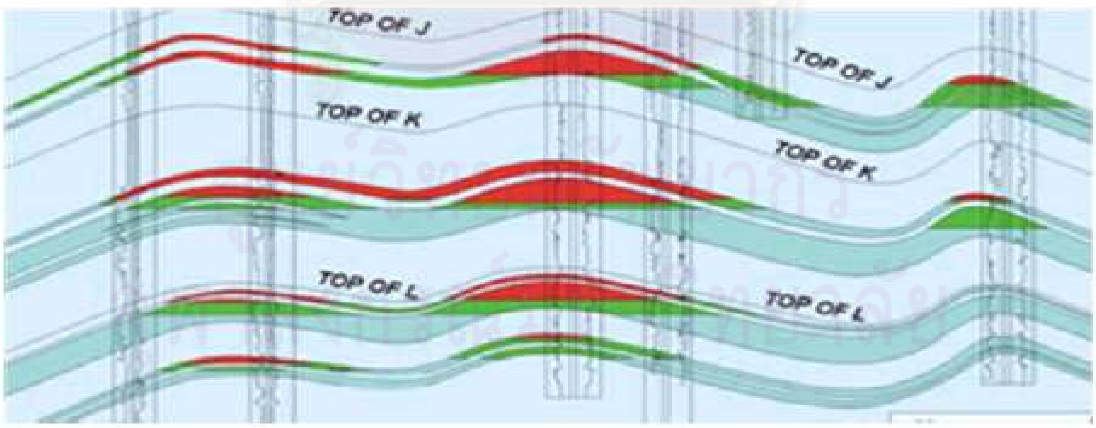


Figure 1.1 Illustration of thin oil rims with gas cap and aquifer

This study will discuss different factors that could affect oil recovery from thin oil rims. Management of these types of reservoirs starts from very beginning when the wells are drilled. The first step to better manage these reservoirs is to properly indentify the fluid contacts. If both gas and water contacts are present, identification of OWC and GOC becomes very critical from recovery stand point.

Rate optimization is an essential factor in optimizing oil recovery from these reservoirs. Rate optimization also sometimes becomes very critical where there is facility constraint for water and/or gas production. It also derives the cash flow once the field is online. Sometimes very low rates to avoid gas and water coning cannot be economically justified. In these cases, horizontal wells are better candidates even though some vertical or deviated wells are already drilled in the same reservoir. This study will use actual field examples to demonstrate how drilling horizontal wells in these thin oil rims can be more economical than the deviated wells already penetrating the reservoir. Different scenarios for placement of horizontal wells with respect to the fluid contacts (OWC and GOC) will also be run to see the impact of well placement on overall oil recovery.

1.1 Objective

The objective of this thesis is to study recovery optimization from an oil rim having gas cap and underlain by an aquifer. The following factors that impact oil rim recovery will be discussed:

1) Rate optimization by studying effect of
    a. gas coning
    b. water coning
2) Type and well placement to optimize recovery
    a. vertical or deviated wells
    b. horizontal wells
    c. horizontal well placement with respect to GOC and OWC
3) Primary versus secondary recovery

1.2 Thesis outline

The thesis consists of five chapters.

Chapter I outlines introduction to the oil rim reservoirs and challenges associated with recovery from oil rim reservoir. It also briefly explains the objectives of this thesis work and methodology to complete this project.

Chapter II is review of literature regarding this topic. Any previous work done, analysis and results are also discussed in this chapter.

Chapter III describes the theories and concepts used in this study including identification of oil rims, force balance concepts in oil rims, coning mechanism, basic simulation concepts, experimental design concepts, water injection and gas injection basic concepts.

Chapter IV introduces the field under study and explains the workflow for model construction, different sources of data and data validation to initialize the model.

Chapter V discusses and compares results for different scenarios. The following scenarios studied in an effort to optimize the oil recovery from thin oil rim reservoir include base case scenario, deviated wells optimization, horizontal well recovery and optimization, comparison of primary depletion scenarios, pressure maintenance with water injection, pressure maintenance with gas injection, pressure maintenance with combination of gas and water injection and finally comparison of all recovery scenarios mentioned above.

1.3 Methodology

The following methodology will be used for this thesis work

1. Data gathering from one reservoir that qualifies as oil rim. The data to be gathered includes:
    a. SRFT data (use to establish the contacts)
    b. Well log data to get porosity, water saturation (data will be used to construct static geologic model)

c. Reservoir permeability (ø-k transform equations will be used if direct permeability measurements are not available)
d. Oil and gas properties for the reservoir to be studied
e. Relative permeability data (regional available data to be used if SCAL data not available)

2. Construct pressure vs depth plot using SRFT data to estimate the contact depths
3. Construct static geologic model using log properties and pressure data.
4. Define grid block size, number of layers in the model and number of grid blocks
5. Export static model to incorporate in dynamic simulation model
6. Initialize the model using initial reservoir conditions
    a. Match initial pressures
    b. Match initial fluid contacts
7. Run base case scenario with deviated wells (production from all available deviated wells penetrating the reservoir)
8. Optimize rates from deviated wells to maximize recovery (rate optimization for gas coning and water coning)
9. Shut in all deviated wells and produce from horizontal well(s). Optimize oil recovery from horizontal well using following factors
    a. Rate optimization for gas and/or water coning using bottom hole drawdown variations
    b. Optimize well placement with respect to distance from GOC and OWC
10. Water injection from down dip location using deviated producers
11. Water injection supplemented with gas injection using deviated producers
12. Steps 10 and 11 using horizontal producers

CHAPTER II

Literature Review

The goal in any oil field development is to accelerate the hydrocarbon production and optimize the oil recovery at lowest cost possible. This objective becomes very challenging when managing thin oil rim reservoirs where a thin column of oil is overlain by a large gas cap and underlain by a strong aquifer. Early gas breakthrough and water coning can cause serious problems to production and hence jeopardize oil recovery. In this type of reservoir, it is very critical to control the movement of GOC and OWC. Keeping a force balance between gas cap expansion and aquifer movement is the key for maximum oil recovery. A successful project may entail plans to maintain the reservoir energy through water injection or produced gas re-injection to maintain reservoir pressure and enhance oil recovery.

Producing from an oil rim reservoir, several studies indicated that primarily, the achievable oil recovery factor can be a function of oil-rim thickness, horizontal permeability, residual oil saturation, well type, well spacing, and well distance to water oil and gas oil contacts. Studies have shown that recovery also depends on balance of gas cap and aquifer expansion and the resulting aquifer water displacement flow geometry. Studies performed by Razak et al. (2010) showed that, for light oil and with piston-like displacement of oil by bottom water, the theoretical maximum vertical sweep efficiency, with an optimized spacing of horizontal wells, is estimated as 52.36%. The maximum vertical sweep efficiency achievable by such favorable flow geometry can be then estimated for different reservoir dynamic properties by 0.5236*(1-Swc-Sor)/(1-Swc). The oil recovery efficiency can be expressed as product of vertical and areal sweep efficiencies. The corresponding areal sweep efficiency for a piston like bottom water displacement can be regarded as 1.

The above mentioned analytical method took into the account of oil rim thickness by mean of estimating the optimal horizontal well spacing by multiplying oil rim thickness with the square root of horizontal to vertical permeability ratio.

2.1 Production and depletion strategy

According to Kabir and Agamini (2004), two depletion strategies may be enacted to improve recovery of the remaining oil. A conventional scheme involves the use of horizontal or vertical wells for reservoir development under natural depletion. The ideal production scenario involves oil withdrawal with minimal depletion from the gas cap to minimize energy loss. During pressure depletion, the gas cap will expand to provide energy support. However, the gas cap recedes with aquifer influx. In this case the operator has to compromise for very low production rates to achieve high recovery factor for oil.

The second strategy involves balancing of GOC and OWC by either water injection into the aquifer or gas re-injection into the gas cap. This allows the operator to produce the well at reasonable rates with little gas cap expansion and oil smearing into the gas cap.

2.1.1 Gas cap blowdown optimization

Conventional production scheme involves the use of horizontal wells for reservoir development under natural depletion. The ideal production scenario involves oil withdrawal with minimal depletion from the gas cap to minimize energy loss. On the other side, the plan for placing horizontal well near the gas cap would increase gas production, thus decreases energy in the reservoir.

To see the effect of gas production to the oil recovery, Hudya et al. (2008) ran sensitivities considering gas production constraints in Gunung Kembang Field, Indonesia. That includes varying gas production rate from existing gas well and planned horizontal wells, from 8 MMSCFD to 32 MMSCFD and also with the gas production schedule based on point of delivery (POD). The result of the gas production sensitivity can be seen in Figure 2.1.

The sensitivity result show that constraining gas rate would decrease the oil recovery since constraining gas production from the planned horizontal well would also mean constraining the oil production.

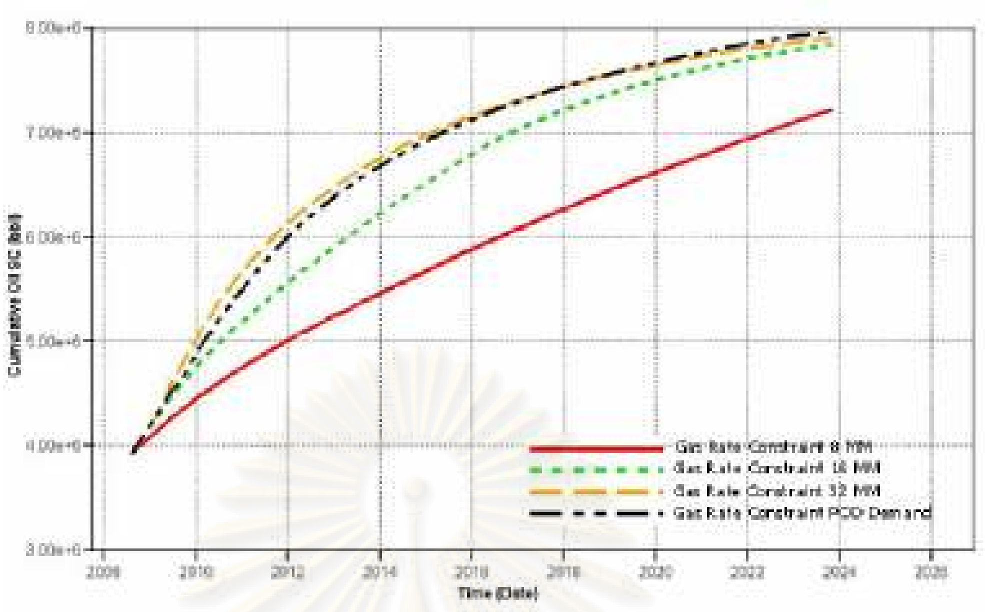


Figure 2.1: Cumulative oil forecasts for gas rate sensitivities – Gunung Kembang field, (Hudya et al, 2008).

In this case there was no gas production constraint and gas blow down strategy helps produce more oil with gas.

2.1.2 Horizontal well landing

Horizontal wells seem to provide a promising solution to the coning problem. In order to avoid pre-mature gas breakthrough, the horizontal wells should normally be positioned as far away from the GOC as possible. But in some studies it has been shown that placing the horizontal wells closer to GOC actually increases oil recovery. In any case it has been shown both analytically and in practice that long horizontal wells have great advantages over vertical and deviated wells as far as coning is concerned.

Two main features of horizontal wells make it possible to obtain high recovery; the lower pressure drawdown required to produce the same volume of oil and the possibility of placing the completion as far away from the unwanted fluid as possible. Horizontal wells are therefore increasingly used in the development of fields with thin oil rims.

Placement of horizontal well in a thin oil rim is a challenge and depends on the relative indices of the gas cap and the aquifer, Hudya et al. (2008). In some field examples, it is seen that placing horizontal well near OWC is not a very good decision due to early water breakthrough. It is also mentioned by the study done by Kabir et al. Their study indicate that by placing horizontal well near the GOC for thick gas cap reservoir would ultimately increase recovery since this practice would avoid displacing oil into large gas cap and also avoid water to invade to the horizontal wells early. But in other cases where gas production is an issue and gas production has to be constrained, this technique is not a good strategy. In this scenario, drilling horizontal well too close to GOC will allow to produce at very high gas rates in the initial life of field production. The required gas oil ratio (GOR) will be achieved very quickly, and the well has to be either shut-down or choked back to reduce the production significantly. This also allows the gas to expand very fast and hence responsible for depleting the reservoir energy significantly.

Wells drilled closer to OWC showed the best performance in terms of minimizing gas production and increasing oil recovery. Well lengths in each case should be optimized on field by field basis. Appropriate placement of horizontal wells is very crucial to ensure successful horizontal well. Fluid breakthrough has a different effect on individual well production depending on the fluids and well type. Highly deviated or horizontal wells experience a reduction of the effective producing length as gas and/or water reaches the horizontal section. In some cases, when the breakthrough occurs at the heel, the flow along the horizontal section may be altogether inhibited. This has been proven in the field while running flow image scanner to capture the fluid distribution and influx profile within the horizontal section.

Practices have been reported to optimize well placement, drilling, completion and stimulation for such cases. Artificial lift may be used to improve the performance of such wells if water is increasing the fluid column density (and therefore bottom hole flowing pressure). When gas breakthrough occurs, well production is controlled by means of increasing tubing head pressure to maximize the production of liquids and minimize re-circulation of the gas. Reservoir geology, combined with the development strategy determines the time of gas and/or water breakthrough as well as the expected amounts of fluids at the wellhead.

2.1.2.1 Horizontal wells below OWC

Haug et al. (1991) proposed that one possible solution to the coning problem is to complete the well some distance below the WOC, thus increasing the distance between the perforations and the GOC. The method is referred to as "inverse coning" and relies on oil down coning into the completions through the water zone as shown in Figure 2.2.

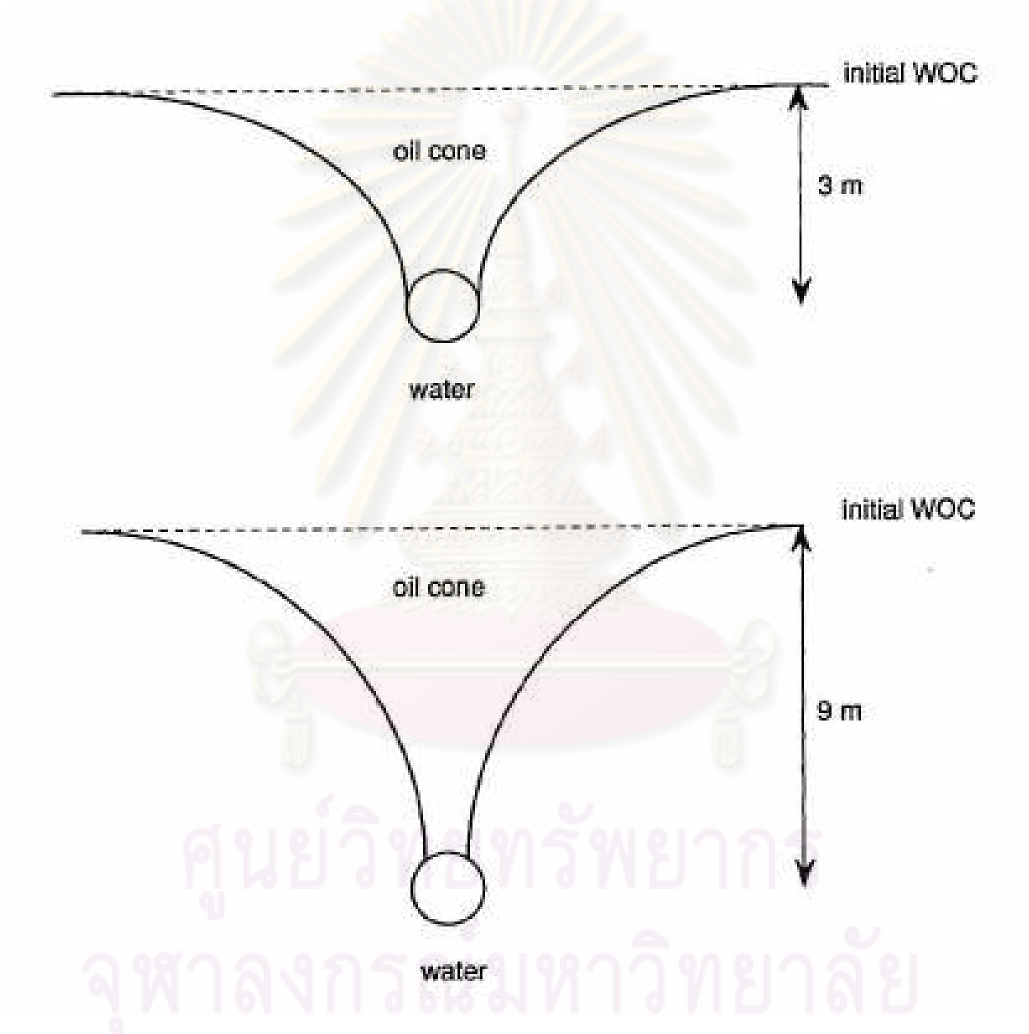


Figure 2.2: Illustration of inverse coning in horizontal wells below OWC. (Haug et al, 1991)

The completion of the well below the OWC was studied by Van Lookeren as early as 1965, and has been further investigated by Cottin and Ombret. In their studies, it has been proved that wells drilled below the OWC are effective in reducing gas coning. Several correlations for critical rates and time to gas/water breakthrough in horizontal wells are presented in the literature, which show that the distance from the completions to the coning fluid strongly influences both time to breakthrough and the maximum liquid rate which can be produced while avoiding free gas production.

Horizontal wells have already been tested in the thin oil zone of the Troll field[1] and have proven effective in reducing gas coning. The objective of Troll field study was to review the possibility of improved oil recovery from the thin oil zone by placing horizontal wells below the OWC. Although the simulations performed in that study were for a specific field, the results should be applicable to other thin oil reservoirs in general. An extensive range of sensitivity studies were performed and was found that the following principle reservoir parameters control production characteristics of inverted horizontal wells:

a. Completion depth
b. Initial liquid production rate
c. Absolute permeability
d. Anisotropy ratio
e. Oil/gas density difference
f. Fluid mobilities
g. Thickness of oil column

A long term test with a horizontal well in the Troll field was performed with varying oil rim thickness and distance of horizontal well from OWC. The horizontal well was completed 3 m above the OWC in a 22-m thick oil rim, and during the test period more than 1 million of oil was produced. The history matched simulation model has been used for long term predictions of production with different completion strategies in the thick oil zones of the Oil Province. The results of a 20-year production period are shown in Figure 2.3. It can be seen that the optimal completion depth is deeper than in the 12-m oil zone in the Gas Province. The optimal depth seems to be about 7 m below the OWC. The relative increase in oil production is considerably less for the thicker oil column, and it takes longer time before the cumulative production from inverted wells exceeds that of conventional wells. The increase in oil production for the well completed 7.5 m below the contact was 20%, and it takes about 7 years for the inverted well to catch up with the conventional one in cumulative production. The increase in water cut was much less with the 22-m rim than with the 12-m rim, and the water cut was also less sensitive to completion depth below the contact. The water cut rose from about 40% at +3 m to 53% at -7.5 m.

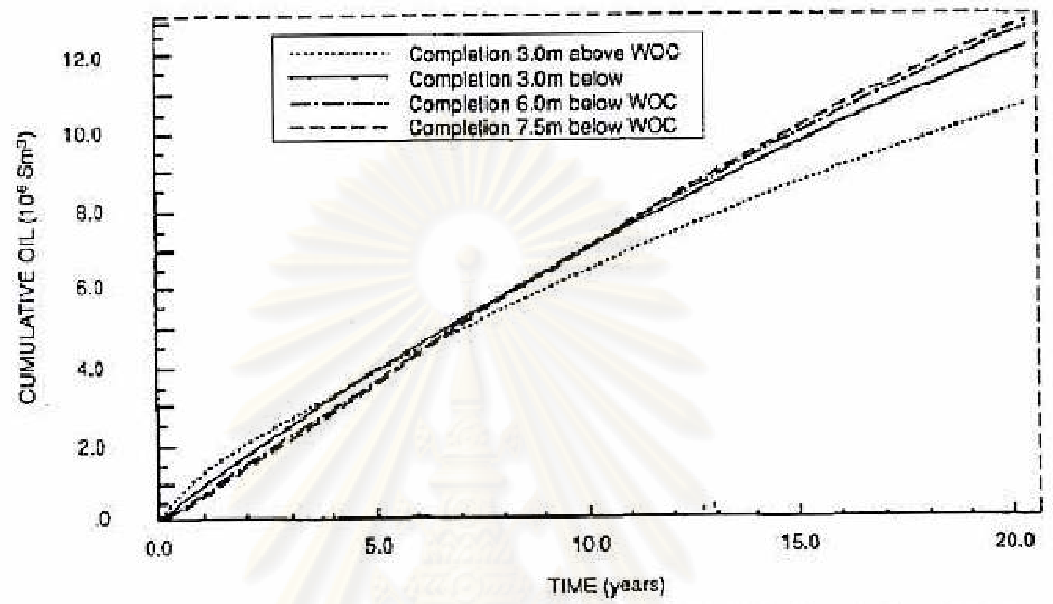


Figure 2.3: Water cut and cumulative oil produced for different completion strategies derived from long term test match, Troll field. (Van Lookeren, 1965)

2.1.3 Impact of produced gas re-injection

The second step, therefore, is to study the effect of produced gas re-injection on gas cap expansion and associated GOC movement with current condition of aquifer drive and the WOC movement.

Injecting produced gas into the gas cap may not be the best way to improve the oil recovery. Some case studies even showed that injecting produced gas back to the oil rim can be more effective. Nevertheless, for a field where produced gas re-injection is being done, the GIGP (ratio of gas injection and gas production) can be shown as a key parameter which can be optimized at different production levels for achieving maximum recovery.

CHAPTER III

Theories and Concepts

3.1 Thin oil rim – Introduction

Thin oil columns overlain by a gas cap and underlain by an aquifer are generally known as thin oil rims. Thin oil rims pose difficult challenges in completion method, production policy, and reserves estimation. Considering the relativity of the term 'thin', in the context of this work, thin oil-rims are those that "will cone either water or gas, or both when produced at commercial rates". This definition also applies to the ultra thin oil columns, with thickness below 30ft discussed by Kabir et al. Generally recovery from these reservoirs depends on completion method, production policy, gas cap size, thickness of oil column, aquifer strength, as well as rock and fluid properties.

3.2 Recovery from thin oil rims

For a thin oil rim with gas cap on top and a strong aquifer below, the art of optimizing the oil recovery is to keep the oil rim in continuous contact with the producing wells in the oil rim. Therefore, the management of gas oil contact and water oil contact movement is extremely critical. For the oil rim reservoirs, the strategy of producing the oil rim first and then blowing down the gas cap is usually adopted, but in some cases the gas is blown down first and then the oil is produced with support from strong aquifer or water injection. In the earlier case where the oil recovery is preferred before gas blow down, most of the produced gas shall be re-injected into the gas cap to maintain the reservoir energy. This also helps to maintain the gas oil contact close to the original level and not allowing the oil to smear into the gas cap.

3.2.1 Force balance in thin oil rims

Production practices for oil rim reservoirs usually centre on conservation of the gas cap (energy) to maximize oil recovery. To achieve maximum results, force balance between aquifer drive, gas cap expansion and viscous withdrawal (production) shall be carefully studied for a given reservoir at various stages of the production life cycle.

Maximum oil recovery can be achieved by keeping oil rim in contact with producing wells at all time and this could be achieved by balancing the OWC and GOC movement by controlling production rates, gas injection into the gas cap or even injecting water into the aquifer. Figure 3.1 illustrates the phenomena of force balance in thin oil rims.

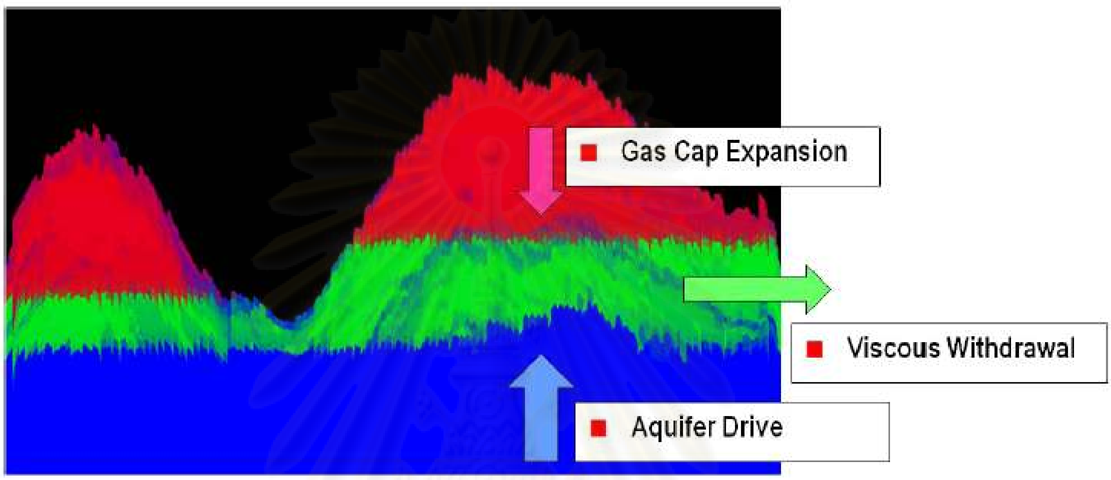


Figure 3.1: Reservoir drive mechanisms and force balance between gas cap expansion, aquifer drive and viscous withdrawal.

With additional gas and water injection schemes, the force balance becomes more complicated. If such unconventional water and gas injection schemes are required, the general consensus is to inject water from down dip location and gas from an updip location usually in the gas cap. But the key task remains the same which is to manage and control the GOC and WOC movement. Displacing oil from the oil rim to the gas cap is to be avoided as it detrimentally reduces the mobile oil and severely incurs loss of oil reserves.

3.2.2 Well type and placement

Planning and drilling wells in thin oil rims is a challenging task. In case of thin oil rims with gas caps, early gas breakthrough and gas cycling can cause serious problems, especially in a commingled production environment and heterogeneous geological conditions. These problems are more pronounced in vertical or deviated wells where gas and water coning is a big issue and starts in early period of production. This hampers the overall oil recovery due to oil smearing in the gas cap.

In order to minimize the coning effect, the well has to be produced at very low rates to minimize drawdown, which can be uneconomical to produce in some cases. Subsequent vertical wells need to be drilled as the oil column moves up due to depletion. The completion strategy in these vertical or deviated wells is very critical, and for better reservoir management stand-off from both GOC and WOC is required to avoid early gas or water coning. Different well types that can be placed in an oil rim are shown in Figure 3.2.

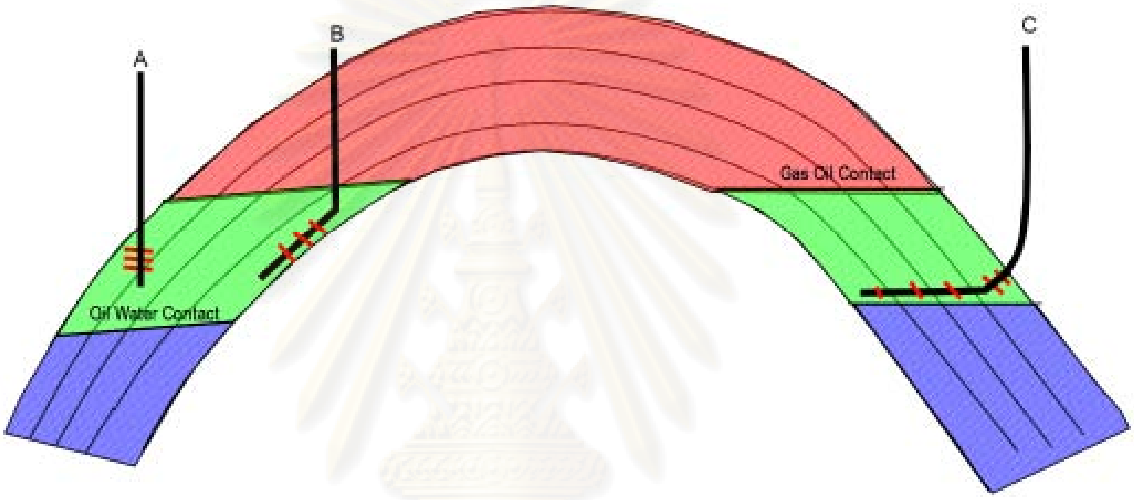


Figure 3.2: Different types and placement of well in the oil leg.

Drilling horizontal wells in these thin oil rims have proved successful in optimizing the oil recovery in most cases. The placement of horizontal wells with respect to GOC and WOC is very critical and depends on the relative indices of the gas cap and the aquifer. Typically, the gas cap expands easily as depletion occurs in the system. However, depending on the strength and connectivity of the aquifer, a time delayed response occurs. The GOC recedes with water influx. Ultimately, cresting causes the well to water out.

According to Kartoatmodjo et al. (2009), one of the most crucial aspects to ensure successful horizontal wells is appropriate placement of horizontal wells. Fluid breakthrough has a different effect on individual well performance depending on the fluid and well type. Highly deviated or horizontal wells experience a reduction of the effective production length as gas and/or water reaches the horizontal section. In some cases, when the breakthrough occurs at the heel, the flow along the horizontal section may be altogether inhibited. This has been proven in some fields by running flow image scanner to capture the fluid distribution and influx profile within the horizontal section. In some wells, water blockage due to trajectory in-conformance at the heel section can cause the loss of all production from respective wells. This situation is depicted in Figure 3.3 which shows the undulating trajectory and the water accumulation in the heel section in the sump. Practices have been reported to optimize well placement, drilling, completion and simulation for such cases.

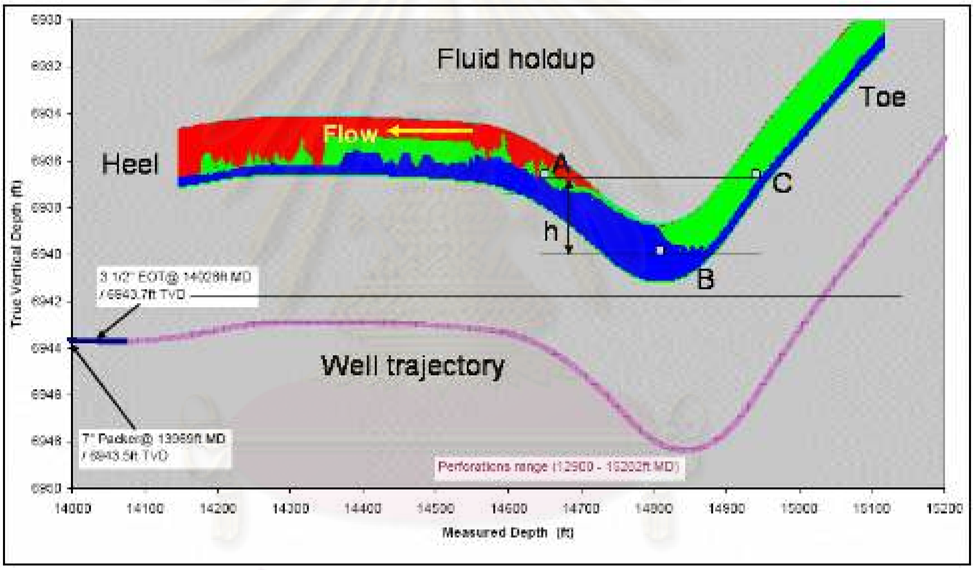


Figure 3.3: Horizontal well water encroachment. (Kartoatmodjo et al, 2009)

Horizontal wells can be placed close to GOC or even above the GOC to avoid oil smearing into the gas zone. In this case, the reverse oil coning takes place. The initial GOR in this case will be very high before significant oil production starts. The drawback in this strategy is that the reservoir losses energy relatively quickly especially if there is not enough aquifer support to maintain the reservoir pressure. To mitigate the problem of excessive gas production in areas where gas could not be sold due to facility constraint or the gas properties themselves, the well can be placed below the GOC or even very close to the OWC.

3.3 Reservoir simulation overview

The dictionary defines simulation as simply "to give an appearance of". To an engineer or analyst, simulation involves the utilization of a model to obtain some insight into the behavior of a physical process. It is a process or mechanism by which a particular problem can be studied in varying depths of detail to obtain answers or to confirm hypothesis. Simulation has long been recognized in many applied sciences as a final resort. Numerical reservoir simulators are used widely, primarily because they can solve problems that cannot be solved in any other way. Simulation is the only way to describe quantitatively the flow of multiple phases in a heterogeneous reservoir having a production schedule determined not only by the properties of the reservoir, but also by market demand, investment strategy and government regulations.

The potential of simulation was recognized in early 1940's and early 1950's by a number of companies. Their commitment of effort both to fundamental research on numerical analysis and to development of practical methods for using available computers resulted in crude, but nonetheless useful simulators by mid 1950's.

3.2.1 Forms of simulation

As mentioned in the definition of simulation, it is a process by which you can guess an unknown character by using the known features of the system. So, as far as petroleum reservoirs are concerned, there are two unknown characters, flow characters of the reservoir fluids and static or rock characters. The requirement is to analyze them separately. A brief introduction to these areas is mentioned in this section.

3.2.2 Purpose of simulation

The purpose of flow simulation is estimation of field performance or broadly speaking a detailed simulation study is conducted to answer reservoir management issues aimed towards reservoir optimization. The point has become very clear that analytical tools become less effective as problems begin to increase in complexity. In the petroleum engineering discipline, complexity in physical processes is more of a rule than exception. The engineer today is required not only to determine the best future performance based on physical behavior of the system, but to become increasingly aware of the interaction of the economic, regulatory, legal and environmental impacts of his decisions. All these forces action together have produced such a complex pattern that any useful analysis must necessarily incorporate them all. Such built in complexity naturally lends itself to some simulation process whereby the effect of various parameters on the solution can be examined rather critically. Therefore, the whole process has to be revised several times in a simulation mode before it is put into practice.

3.4 Coning mechanism

Coning is primarily the result of movement of reservoir fluids in the direction of least resistance, balanced by a tendency of the fluids to maintain gravity equilibrium. The analysis may be made with respect to either gas or water. Let the original condition of reservoir fluids exist as shown schematically in Figure 3.4, water underlying oil and gas overlying oil. For the purposes of discussion, assume that a well is partially penetrating the formation (as shown in Figure 3.4) so that the production interval is halfway between the fluid contacts.

Production from the well would create pressure gradients that tend to lower the gas-oil contact and elevate the water-oil contact in the immediate vicinity of the well. Counterbalancing these flow gradients is the tendency of the gas to remain above the oil zone because of its lower density and the tendency of the water to remain below the oil zone because of its higher density. These counterbalancing forces tend to deform the gas-oil and water-oil contacts into a bell shape as shown schematically in Figure 3.4.

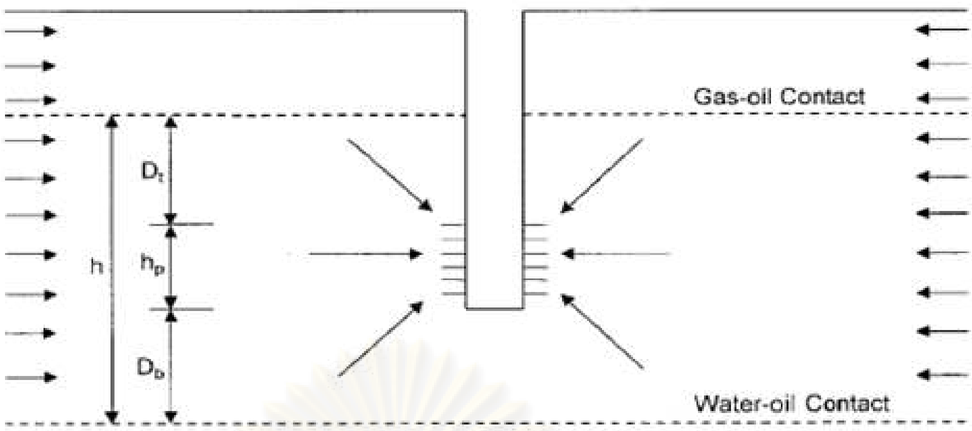


Figure 3.4: Coning mechanism.

There are essentially three forces that may affect fluid flow distributions around the well bores. These are:

- Capillary forces
- Gravity forces
- Viscous forces

Capillary forces usually have negligible effect on coning and will be neglected. Gravity forces are directed in the vertical direction and arise from fluid density differences. The term viscous forces refer to the pressure gradients associated fluid flow through the reservoir as described by Darcy's Law. Therefore, at any given time, there is a balance between gravitational and viscous forces at points on and away from the well completion interval. When the dynamic (viscous) forces at the wellbore exceed gravitational forces, a "cone" will ultimately break into the well as shown in Figure 3.5.

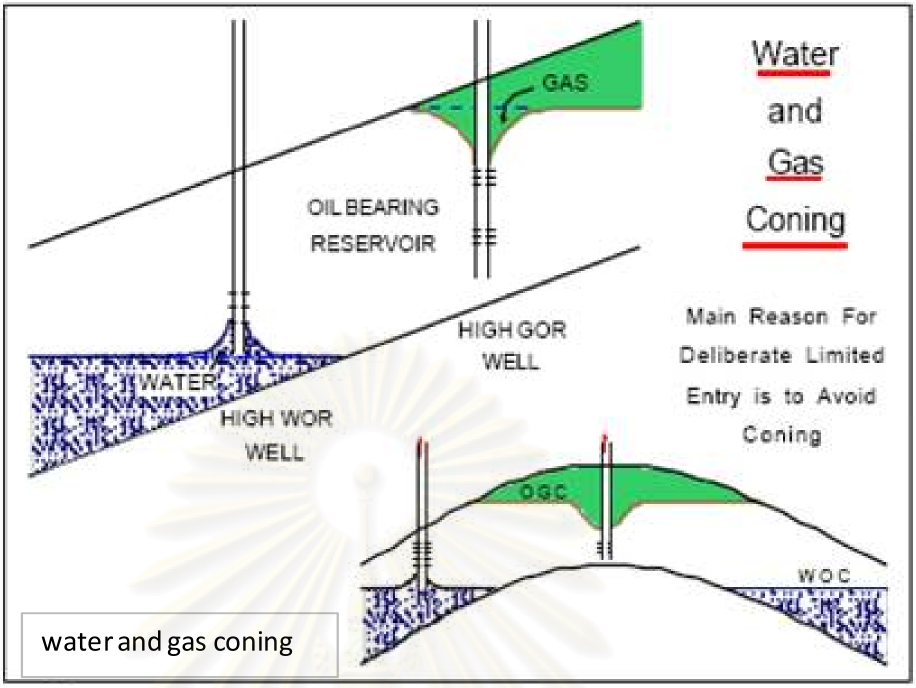


Figure 3.5: Illustration of gas and water coning.

We can expand on the basic visualization of coning by introducing the concepts of:

- Stable cone
- Unstable cone
- Critical production rate

If a well is produced at a constant rate and the pressure gradients in the drainage system have become constant, a steady-state condition is reached. If at this condition, the dynamic (viscous) forces at the well are less than the gravity forces, then the water or gas cone that has formed will not extend to the well. Moreover, the cone will neither advance nor recede, thus establishing what is known as a stable cone. Conversely, if the system is under an unsteady-state condition, then an unstable cone will continue to advance until steady-state conditions prevail.

If the pressure drop at the well is sufficient to overcome the gravity forces, the unstable cone will grow and ultimately break into the well. It is important to note that in a realistic sense, stable cones may only be “pseudo-stable” because the drainage system and pressure distributions generally change. For example, with reservoir depletion, the water-oil contact may advance toward the completion interval, thereby increasing chances for coning. As another example, reduced productivity due to well damage requires a corresponding increase in the flowing pressure drop to maintain a given production rate. This increase in pressure drop may force an otherwise stable cone into a well.

The critical production rate is the rate above which the flowing pressure gradient at the well causes water (or gas) to cone into the well. It is, therefore, the maximum rate of oil production without concurrent production of the displacing phase by coning. At the critical rate, the buildup cone is stable but is at a position of incipient breakthrough. Defining the conditions for achieving the maximum water-free and/or gas-free oil production rate is a difficult problem to solve. Engineers are frequently faced with the following specific problems:

1. Predicting the maximum flow rate that can be assigned to a completed well without the simultaneous production of water and/or free-gas.

2. Defining the optimum length and position of the interval to be perforated in a well in order to obtain the maximum water and gas-free production rate.

Calhoun (1960) pointed out that the rate at which the fluids can come to an equilibrium level in the rock may be so slow, due to the low permeability or to capillary properties, that the gradient toward the wellbore overcomes it. Under these circumstances, the water is lifted into the wellbore and the gas flows downward, creating a cone. Not only is the direction of gradients reversed with gas and oil cones, but the rapidity with which the two levels will balance will differ.

Also, the rapidity with which any fluid will move is inversely proportional to its viscosity, and, therefore, the gas has a greater tendency to cone than water. For this reason, the amount of coning will depend upon the viscosity of the oil compared to that of water. It is evident that the degree or rapidity of coning will depend upon the rate at which fluid is withdrawn from the well and upon the permeability in the vertical direction, k_v, compared to that in the horizontal direction, k_h. It will also depend upon the distance from the wellbore withdrawal point to the gas-oil or oil-water discontinuity.

The elimination of coning could be aided by shallower penetration of wells where there is a water zone or by the development of better horizontal permeability. Although the vertical permeability could not be lessened, the ratio of horizontal to vertical flow can be increased by such techniques as acidizing or pressure parting the formation. The application of such techniques needs to be controlled so that the effect occurs above the water zone and/or below the gas zone, whichever is the desirable case. This permits a more uniform rise of a water table.

Once either gas coning or water coning has occurred, it is possible to shut in the well and permit the contacts to re-stabilize. Unless conditions for rapid attainment of gravity equilibrium are present, re-stabilization will not be extremely satisfactory. Fortunately, bottom water is found often where favorable conditions for gravity separation do exist. Gas coning is more difficult to avoid because gas saturation, once formed, is difficult to eliminate. There are essentially three categories of correlation that are used to solve the coning problem. These categories are:

- Critical rate calculations
- Breakthrough time predictions
- Well performance calculations after breakthrough

These categories of calculations are applicable in evaluating the coning problem in both vertical and horizontal wells.

3.5 **Water flooding**

The displacement of one fluid by another fluid is an unsteady-state process because the saturation of the fluids changes with time. This causes changes in the relative permeabilities and either pressure or phase velocities. Figure 3.6 shows the stages of a typical water flood process. Before start of water injection, initial saturations are uniform as shown in Figure 3.6a. Injection of water at flow rate q causes oil to be displaced from the reservoir. A sharp water saturation gradient develops as seen in Figure 3.6b. Water and oil flow simultaneously in the region behind the saturation change. There is no flow of water ahead of saturation change because the permeability to water is essentially zero. Eventually, water arrives at the end of reservoir, as seen in Figure 3.6c. This point is called breakthrough point. After breakthrough, the fraction of water in the effluent increases as the remaining oil is displaced. Fig 3.6d depicts the water saturation in a linear system late in the displacement.

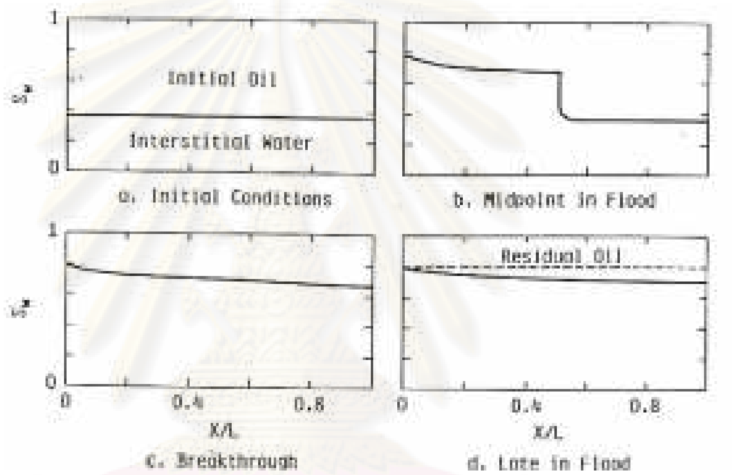


Figure 3.6: Different stages of water flooding. (Buckley and Leverett, 1962)

Buckley and Leverett (1962) defined different production phases during a water flood shown in Figure 3.7. Initially the reservoir is producing on primary depletion. At some point ‘A’ during the decline phase, water injection is started. Depending on the timing of water injection, there will be a time lag before there is interference with reservoir oil marked as point ‘B’ in Figure 3.7. After interference, again depending on the timing of water injection and how much voidage is already created by production, there will be a fill up time. After the fill up time indicated by point ‘C’, there will be water flood response time when the oil production starts increasing till point ‘D’. After which the injection water breakthrough and the decline starts. The decline continues untill abandonment point ‘E’.

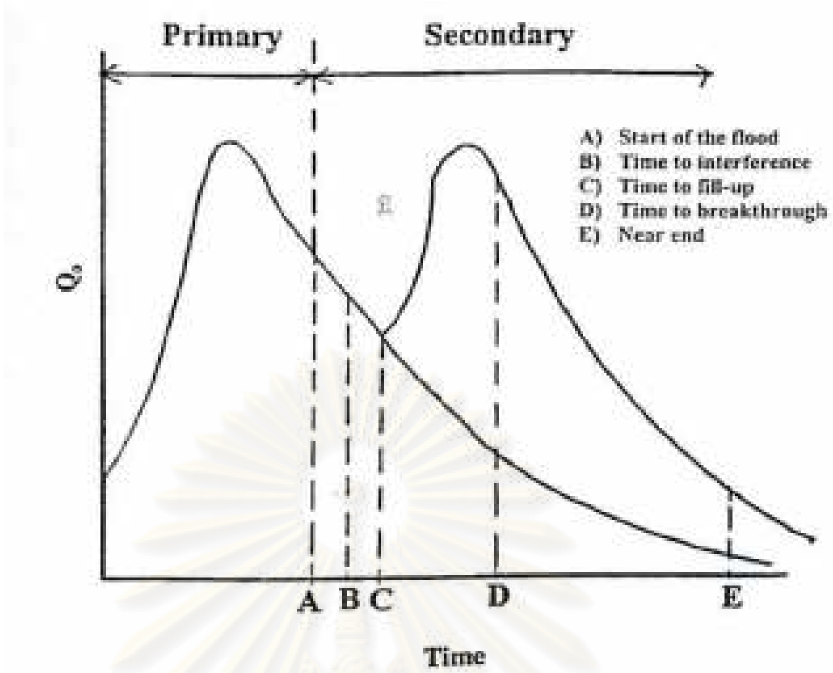


Figure 3.7: Production phases prediction. (Buckley and Leverett , 1962)

3.5.1 Factors to consider in water flooding

In order to determine the suitability of a candidate reservoir for waterflooding, the following reservoir characteristics must be considered:

- Reservoir geometry
- Fluid properties
- Reservoir depth
- Lithology and rock properties
- Fluid saturations
- Reservoir uniformity and pay continuity

Each of these topics is discussed briefly in the following subsections

1) Reservoir geometry

The areal geometry of the reservoir will influence the location of wells and if offshore, influence the number of platforms required. The reservoir geometry will essentially dictate the methods by which a reservoir can be produced through water-injection practices. And analysis of reservoir geometry and past reservoir performance is often important when defining the presence and strength of a natural water drive and, thus, when defining the need to supplement the natural drive. If a water-drive reservoir is classified as an active water drive, injection may be unnecessary.

2) Fluid properties

The physical properties of the reservoir fluids have pronounced effects on the suitability of a given reservoir for further development by water flooding. The viscosity of the crude oil is considered the most important fluid property that affects the degree of success of a waterflooding project. The oil viscosity has the important effect of determining the mobility ratio that, in turn, controls the displacement efficiency.

3) Reservoir depth

Reservoir depth has an important influence on both the technical and economic aspects of a secondary or tertiary recovery project. Maximum injection pressure will increase with depth. The cost of lifting oil from very deep wells will limit the maximum economic water oil ratios that can be tolerated, thereby increasing the total project operating costs and reducing the ultimate recovery factor. On the other hand, a shallow reservoir imposes a restraint on the injection pressure that can be used, because this must be less than fracture pressure of the reservoir. In waterflood operation, there is a critical pressure (approx 1psi/ft of depth) that, if exceeded, permits the injecting water to expand openings along fractures or create fractures. This results in channeling of the injected water or the bypassing of the large portions of reservoir matrix. Consequently, an operational pressure gradient of 0.75 psi/ft is normally allowed to provide a sufficient margin of safety to prevent pressure parting.

4) Lithology and rock properties

Thomas et al. (1989) pointed out that lithology has a profound influence on the efficiency of water injection in a particular reservoir. Reservoir lithology and rock properties that affect flood ability and success are porosity, permeability, clay content and net thickness.

5) Fluid saturations

In determining the suitability of a reservoir for waterflooding, a high oil saturation that provides a sufficient supply of recoverable oil is the primary criteria for successful flooding operations. Note that higher oil saturation at the beginning of flood operations increases the oil mobility that, in turn, gives higher recovery efficiency.

6) Reservoir uniformity and continuity

Substantial reservoir uniformity is one of the major physical criteria for successful waterflooding. For example, if the formation contains a stratum of limited thickness with a very high permeability (thief zone), rapid channeling and by passing will develop. Unless this zone can be located and shut off, the producing water oil ratio will soon become too high for the flooding operation to be considered profitable. The lower depletion pressure that may exist in the highly permeable zone will also aggravate the water channeling tendency due to the high permeability variations. Moreover, these thief zones will contain less residual oil than the other layers, and their flooding will lead to relatively lower oil recoveries than other layers. Areal continuity of the pay zone is also a prerequisite for successful waterflooding project. Isolated lenses may be effectively depleted by a single well completion, but a flood mechanism requires that both the injector and producer be present in the lens. Breaks in pay continuity and reservoir anisotropy caused by depositional conditions, fractures or faulting need to be identified and described before determining the proper well spacing and suitable flood pattern orientation.

3.5.2 Optimum time to water flood

The most common procedure for determining the optimum time to start water flooding is to calculate:

- Anticipated oil recovery
- Fluid production rates
- Monetary investment
- Availability and quality of injection water
- Costs of water treatment and pumping equipment

- Costs of maintenance and operation of the water installation facilities
- Costs of drilling new injection wells or converting existing production wells into injectors

These calculations must be performed for several assumed times and the net income for each case must be determined. The scenario that maximizes the profit and perhaps meets the operator's desirable goal is selected. Cole (1969) lists the following factors as being important when determining the reservoir pressure (or time) to initiate a secondary recovery project:

1) Reservoir oil viscosity

Water injection should be initiated before the reservoir pressure reaches its bubble point pressure since the oil viscosity reaches its minimum value at this pressure. The mobility of the oil will increase with decreasing oil viscosity, which in turn improves the displacement efficiency.

2) Cost of injection equipment

This is related to reservoir pressure. For depleted reservoir pressure, the cost of injection equipment increases. Therefore, a relatively higher reservoir pressure at initiation of injection is desirable.

3) Productivity of producing wells

A high reservoir pressure is desirable to increase the productivity of producing wells, which prolongs the flowing period of the wells, decreases lifting cost and may shorten the overall life of the project.

4) Effect of delaying investment

Delay in water injection usually reduces the benefit of water injection. As the reservoir pressure drops below the bubble point pressure, water injection becomes less effective. So, it is more effective to initiate water injection at early production period to get maximum benefit of water injection.

5) **Overall life of the reservoir**

Because operating expenses are an important part of total project costs, the fluid injection process should be started as early as possible.

3.5.3 Water injection patterns

Due to the fact that oil leases are divided into square miles and quarter square miles, fields are developed in a very regular pattern. A wide variety of injection-production well arrangements have been used in injection projects. The most common patterns, as shown in Figures , are the following:

1. **Direct line drive**. The lines of injection and production are directly opposed to each other. The pattern is characterized by two parameters: a = distance between wells of the same type, and d = distance between lines of injectors and producers.

2. **Staggered line drive**. The wells are in lines as in the direct line, but the injectors and producers are no longer directly opposed but laterally displaced by a distance of a/2.

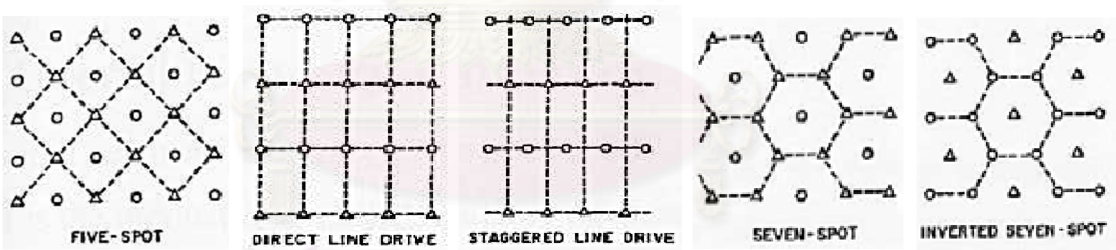


Figure 3.8: Water injection patterns.

3. **Five spot**. This is a special case of the staggered line drive in which the distance between all like wells is constant, i.e., a = 2d. Any four injection wells thus form a square with a production well at the center.

4 **Seven spot**. The injection wells are located at the corner of a hexagon with a production well at its center.

5 **Nine spot**. This pattern is similar to that of the five spot but with an extra injection well drilled at the middle of each side of the square. The pattern essentially

contains eight injectors surrounding one producer. The patterns termed inverted have only one injection well per pattern. This is the difference between normal and inverted well arrangements. Note that the four-spot and inverted seven-spot patterns are identical.

6 **Crestal and basal injection patterns.** In crestal injection, as the name implies, the injection is through wells located at the top of the structure. Gas injection projects typically use a crestal injection pattern. In basal injection, the fluid is injected at the bottom of the structure. Many water-injection projects use basal injection patterns with additional benefits being gained from gravity segregation. A schematic illustration of the two patterns is shown in Figure 3.9.

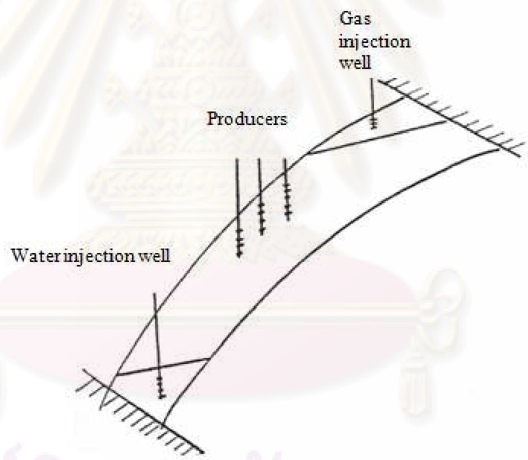


Figure 3.9: Well arrangement for dipping reservoirs

3.6 Gas injection

Gas injection pressure maintenance operations are generally classified into two distinct types depending on where in the reservoir, relative to the oil zone, the gas is introduced. Basically the same physical principles of oil displacement apply to either type of operation. However, the analytical procedures for predicting reservoir performance, the overall objectives and the field applications of each type of operation may vary considerably.

3.6.1 Types of gas injection

3.6.1.1 Dispersed gas injection

Dispersed gas injection operations, frequently referred to as internal or pattern injection, normally use some geometric arrangement of injection wells for the purpose of uniformly distributing the injected gas throughout the oil productive portions of the reservoir. In practice, injection-well/production-well arrays vary from the conventional regular pattern configurations (e.g. five-spot, seven-spot, nine-spot) to patterns seemingly haphazard in arrangement with relatively little uniformity over the injection area. The selection of an injection arrangement is usually based on considerations of reservoir configuration with respect to structure, sand continuity, permeability and porosity variations and the number and relative positions of existing wells. This method of injection has been found adaptable to reservoirs having low structural relief and to relatively homogenous reservoirs having low permeabilities. Because of greater injection well density, dispersed gas injection provides rapid pressure and production response, thereby reducing the time necessary to deplete the reservoir. Dispersed injection can be used where an entire reservoir is not under one ownership, particularly if the reservoir cannot be conveniently unitized. Some limitations to dispersed gas injection are:

- Little or no improvement in recovery efficiency is derived from structural position or gravity drainage.
- Areal sweep efficiencies are generally lower that for external gas injection operations.
- Gas fingering caused by high flow velocities generally tends to reduce the recovery efficiency over that which could be expected from external injection, and
- Higher injection well density contributes to greater installation and operating costs.

3.6.1.2 External gas injection

External gas injection operations frequently referred to as crestal or gas cap injection, use injection wells in the structurally higher positions of the reservoir, usually in the primary or secondary gas cap. This manner of injection is generally employed in reservoirs having sufficient structural relief and average to high specific permeabilities. Injections wells are positioned to provide good areal distribution of the injected gas and to obtain maximum benefit of gravity drainage. The number of injection wells required for a specific reservoir will generally depend on the injectivity of each well and the number of wells adequate to obtain areal distribution. External injection is generally considered superior to dispersed type injection since full advantage can usually be obtained from gravity drainage benefits. In addition, external injection ordinarily will result in greater areal sweep and conformance efficiencies than will similar dispersed injection operations.

3.7 Design of experiments

The objective of this study is to optimize the oil recovery from an oil rim reservoir by studying the effect of parameters that influence oil recovery. The parameters that could affect the oil recovery in an oil rim can be of static or dynamic nature. The static uncertainties were taken into account during geologic model construction, and impact of each parameter on OOIP was also studied. Therefore, the dynamic simulation is performed using dynamic flow parameters and is therefore termed as level one design of experiment (DoE) workflow.

In this workflow, simulation runs are first made to see the impact of different dynamic parameters like oil rate, drawdown pressure and gas oil ratio limit. Results from experimental design are then used to see the impact of different parameters on the oil recovery. After understanding the impact of each parameter on oil recovery, a range of multiple Monte-Carlo iterations are run on these parameters to optimize the oil recovery. These are called optimization runs. A commercial simulator is used to perform all these activities.

3.7.1 Concept of fractional factorial designs at 2 levels – basic idea

In many cases, it is sufficient to consider the factors affecting the production process at two levels. For example, the temperature for a chemical process may either be set a little higher or a little lower, the amount of solvent in a dyestuff manufacturing process can either be slightly increased or decreased, etc. The experimenter would like to determine whether any of these changes affect the results of the production process. The most intuitive approach to study these factors would be to vary the factors of interest in a full factorial design, that is, to try all possible combinations of settings. This would work fine, except that the number of necessary runs in the experiment (observations) will increase exponentially. For example, if you want to study 7 factors, the necessary number of runs in the experiment would be 2**7 = 128. To study 10 factors you would need 2**10 = 1,024 runs in the experiment. Because each run may require time-consuming and costly setting and resetting of machinery, it is often not feasible to require that many different production runs for the experiment. In these conditions, *fractional factorials* are used that "sacrifice" interaction effects so that main effects may still be computed correctly.

3.7.2 Generating the design

A technical description of how fractional factorial designs are constructed is beyond the scope of this introduction. Detailed accounts of how to design 2**(k-p) experiments can be found, for example, in Bayne and Rubin (1986), Box and Draper (1987), Box, Hunter, and Hunter (1978), Montgomery (1991), Daniel (1976), Deming and Morgan (1993), Mason, Gunst, and Hess (1989), or Ryan (1989), to name only a few of the many text books on this subject. In general, it will successively "use" the highest-order interactions to generate new factors. For example, consider Table 3.1 which shows design that includes 11 factors but requires only 16 runs (observations).

Table 3.1 : Example of fractional factorial design

Design: 2**(11-7), Resolution III											
Run	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**
1	1	1	1	1	1	1	1	1	1	1	1
2	1	1	1	-1	1	-1	-1	-1	-1	1	1
3	1	1	-1	1	-1	-1	-1	1	-1	1	-1
4	1	1	-1	-1	-1	1	1	-1	1	1	-1
5	1	-1	1	1	-1	-1	1	-1	-1	-1	1
6	1	-1	1	-1	-1	1	-1	1	1	-1	1
7	1	-1	-1	1	1	1	-1	-1	1	-1	-1
8	1	-1	-1	-1	1	-1	1	1	-1	-1	-1
9	-1	1	1	1	-1	1	-1	-1	-1	-1	-1
10	-1	1	1	-1	-1	-1	1	1	1	-1	-1

11	-1	1	-1	1	1	-1	1	-1	1	-1	1
12	-1	1	-1	-1	1	1	-1	1	-1	-1	1
13	-1	-1	1	1	1	-1	-1	1	1	1	-1
14	-1	-1	1	-1	1	1	1	-1	-1	1	-1
15	-1	-1	-1	1	-1	1	1	1	-1	1	1
16	-1	-1	-1	-1	-1	-1	-1	-1	1	1	1

3.7.3 Reading the design

The design displayed in Table 3.1 should be interpreted as follows. Each column contains +1's or -1's to indicate the setting of the respective factor (high or low, respectively). So for example, in the first run of the experiment, set all factors *A* through *K* to the plus setting (e.g., a little higher than before); in the second run, set factors *A, B*, and *C* to the positive setting, factor *D* to the negative setting, and so on. Note that there are numerous options provided to display (and save) the design using notation other than ±*1* to denote factor settings. For example, you may use actual values of factors (e.g., *90 degrees* Celsius and *100 degrees* Celsius) or text labels (*Low* temperature, *High* temperature).

3.7.4 Randomizing the runs

Because many other things may change from production run to production run, it is always a good practice to randomize the order in which systematic runs of the designs are performed.

3.7.5 The concept of design resolution

The design in Table 3.1 is described as a 2**(11-7) design of *resolution* III (three). This means that we study overall $k = 11$ factors (the first number in parentheses); however, $p = 7$ of those factors (the second number in parentheses) were generated from the interactions of a full 2**[(11-7) = 4] factorial design. As a result, the design does not give full *resolution*; that is, there are certain interaction effects that are confounded with (identical to) other effects. In general, a design of resolution *R* is one where no *l*-way interactions are confounded with any other interaction of order less than *R-l*. In the current example, *R* is equal to 3. Here, no $l = 1$ level interactions (i.e., main effects) are confounded with any other interaction of order less than *R-l* = 3-1 = 2. Thus, main effects in this design are confounded with two- way interactions; and consequently, all higher-order interactions are equally confounded. If we had included 64 runs, and generated a 2**(11-5) design, the resultant resolution would have been $R = IV$ (four). We would have concluded that no l=1-way interaction (main effect) is confounded with any other interaction of order less than R-l = 4-1 = 3. In this design then, main effects are not confounded with two-way interactions, but only with three-way interactions. What about the two-way interactions? No l=2-way interaction is confounded with any other interaction of order less than R-l = 4-2 = 2. Thus, the two-way interactions in that design are confounded with each other.

3.7.6 Graph options

3.7.6.1 Diagnostic plots of residuals

Before accepting a particular "model" that includes a particular number of effects (e.g., main effects for *Polysulfide, Time*, and *Temperature* in the current example), we should always examine the distribution of the residual values. These are computed as the difference between the predicted values (as predicted by the current model) and the observed values. We can compute the histogram for these residual values, as well as probability plots (as shown in Figure 3.10).

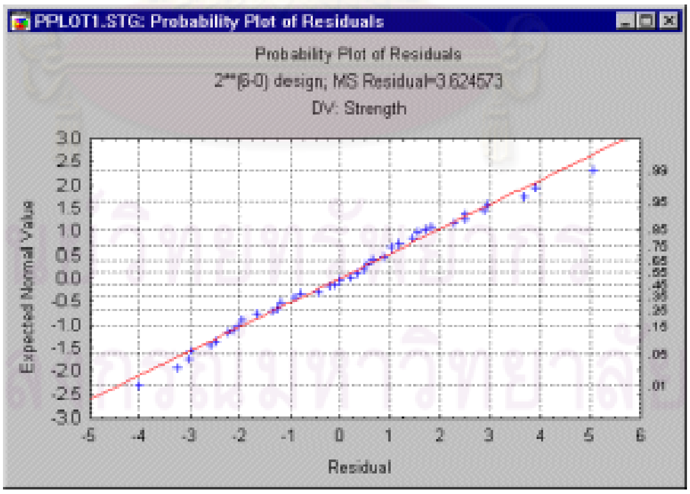


Figure 3.10: Diagnostic plot of residuals

The parameter estimates and ANOVA table are based on the assumption that the residuals are normally distributed. The histogram provides one way to check (visually) whether this assumption holds. The so-called *normal probability* plot is another common tool to assess how closely a set of observed values (residuals in this case) follows a theoretical distribution. In this plot, the actual residual values are plotted along the horizontal *X*-axis; the vertical *Y*-axis shows the expected normal values for the respective values, after they were rank-ordered. If all values fall onto a straight line, then we can be satisfied that the residuals follow the normal distribution.

3.7.6.2 Pareto chart of effects

The Pareto chart of effects is often an effective tool for communicating the results of an experiment, in particular to laymen. Figure 3.11 is an example of Pareto chart of effects.

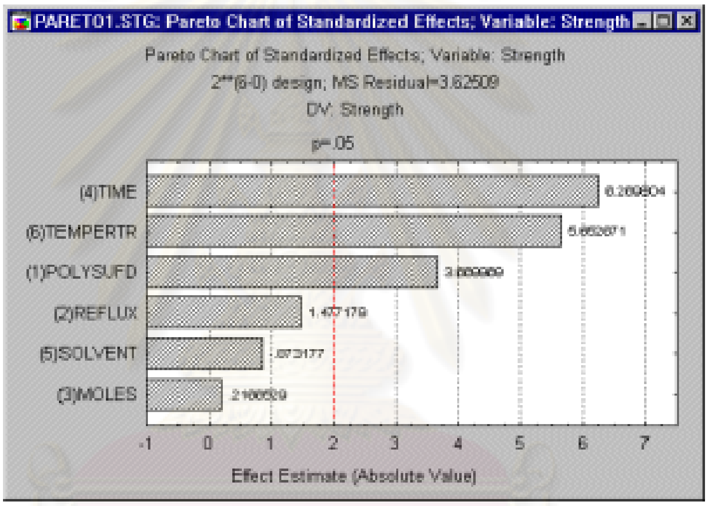


Figure 3.11: Pareto chart of effects.

In this graph, the ANOVA effect estimates are sorted from the largest absolute value to the smallest absolute value. The magnitude of each effect is represented by a column, and often, a line going across the columns indicates how large an effect has to be (i.e., how long a column must be) to be statistically significant.

3.7.6.3 Normal probability plot of effects

Another useful, albeit more technical summary graph, is the *normal probability* plot of the estimates. As in the normal probability plot of the residuals, first the effect estimates are rank ordered, and then a normal *z* score is computed based on the assumption that the estimates are normally distributed. This *z* score is plotted on the *Y*-axis; the observed estimates are plotted on the *X*-axis (as shown in Figure 3.12).

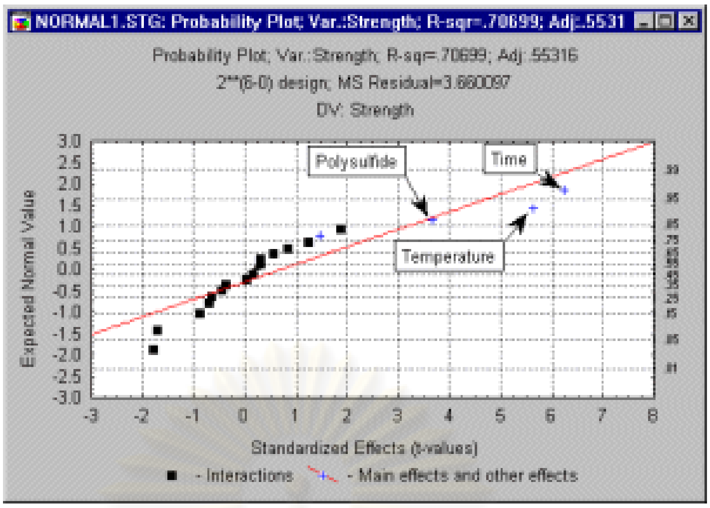


Figure 3.12: Normal probability plot of effects.

CHAPTER IV

MODEL CONSTRUCTION

4.1 Reservoir overview

The reservoir under study is in an offshore field in GOT with an average volume. The reservoir selected for this study is a saturated reservoir at average depth of 6,000 ft TVDSS. The reservoir has an original gas cap with strong aquifer support. The reservoir was discovered by drilling six deviated wells within a single fault block. The reservoir is an elongated structure, and wells were targeted to penetrate the reservoir closer to the fault. The objective was to remain as updip as possible to avoid drilling into the wet zone or aquifer. By doing this, a few wells also penetrate the gas cap. The most downdip well W-01 determines the original oil water contact (OOWC) of the field at 6,662 ft TVDSS. The most updip well drilled is W-05 penetrated most of the gas cap. The original gas oil contact (OGOC) was found at 6,599 ft TVDSS. RFT survey was run in most of the wells. The open-hole well logs and RFT are in close agreement in defining the limits of the field in terms of OOWC and OGOC.

4.1.1 Reservoir map

The depth structure map of the field is shown in Figure 4.1.

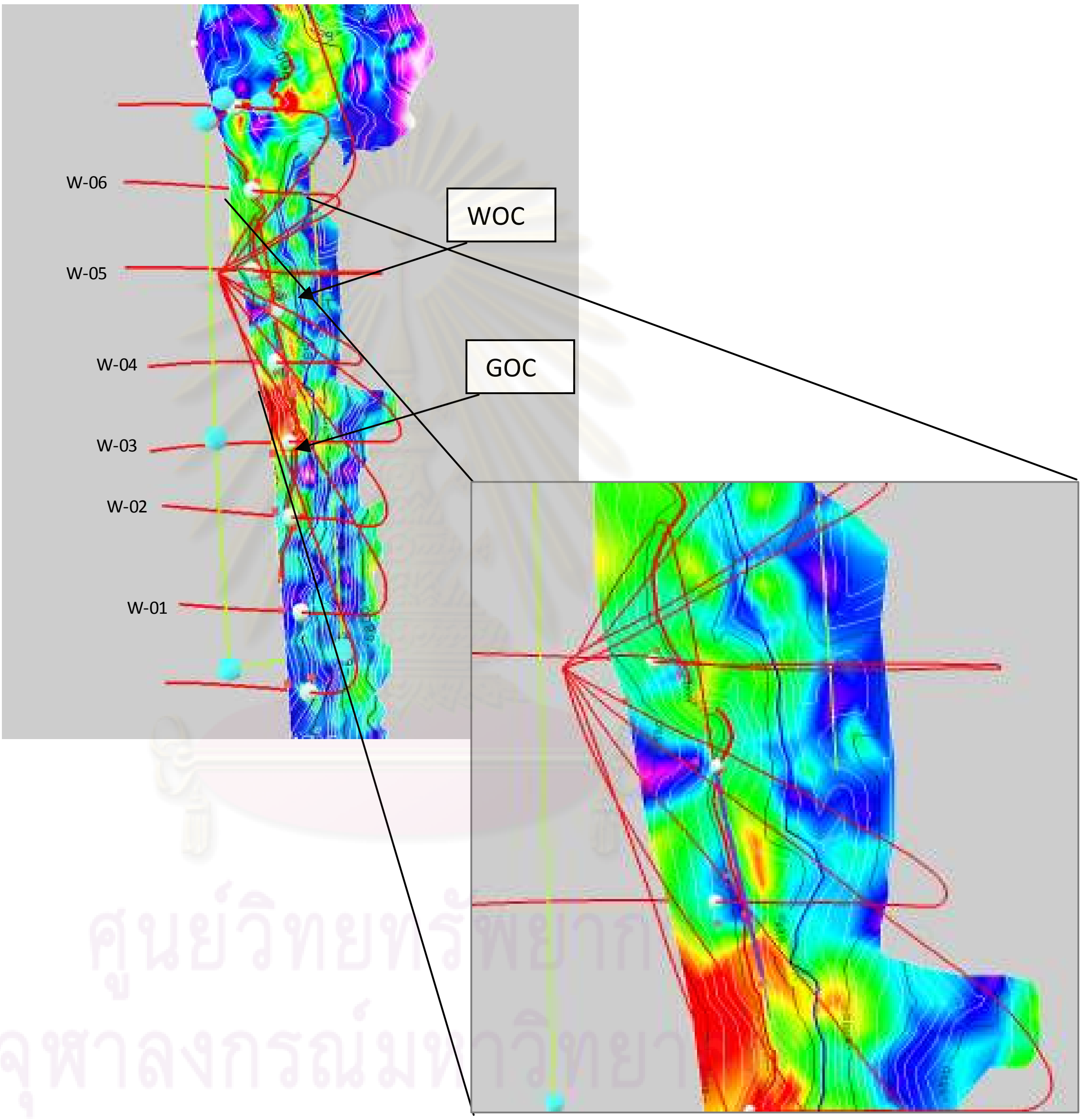


Figure 4.1: Structure map of the field

4.1.2 OOIP estimation

The volumetric original oil in place (OOIP) for this reservoir is shown in Table 4.1. The map shown in Figure 4.1 is used to estimate the OOIP of the reservoir. A number of realizations using EVOL option in GoCAD earth modeling software are run to estimate OOIP. The P10, P50 and P90 OOIP estimated are 1.35 MMSTB, 1.88 MMSTB and 2.47 MMSTB, respectively.

Table 4.1: Reservoir volume estimation

Number of different scenarios = 297

OIL RESERVOIR

	Minimum	P10	P50	P90	Maximum
Avg Thck {Oil} [ft]	18.8324	22.597	23.3605	26.9924	29.4176
Area {Oil} [Acre]	115.419	136.893	147.846	150.787	162.687
GRV {Oil} [AcreFeet]	2173.62	3112.28	3453.74	4001.67	4785.85
NRV {Oil} [AcreFeet]	1831.11	2621.87	3090.65	3769.78	4508.53
NPV {Oil} [AcreFeet]	315.404	451.781	579.144	737.686	901.705
NHPV {Oil} [AcreFeet]	155.171	243.647	338.829	445.856	604.747
STOOIP [MMbbl]	0.859916	1.35022	1.8777	2.47081	3.35134

GAS RESERVOIR

	Minimum	P10	P50	P90	Maximum
Avg Thck {Gas} [ft]	22.3263	22.4885	24.106	25.6176	25.8291
Area {Gas} [Acre]	41.8778	46.2464	50.0121	66.3424	69.665
GRV {Gas} [AcreFeet]	1009.5	1088.15	1228.73	1516.32	1566.66
NRV {Gas} [AcreFeet]	850.432	927.252	1099.56	1356.91	1475.88
NPV {Gas} [AcreFeet]	146.485	171.774	206.042	254.216	295.176
NHPV {Gas} [AcreFeet]	72.0669	93.1781	110.994	154.112	197.965
GIIP [Bcf]	0.510448	0.659977	0.849913	1.09157	1.40218

TOTAL RESERVOIR (GAS AND OIL)

	Minimum	P10	P50	P90	Maximum
Avg Thck {Global} [ft]	25.125	28.4422	29.7315	34.5903	36.5173
Area {Global} [Acre]	126.692	148.166	159.118	162.059	173.959
GRV {Global} [AcreFeet]	3183.12	4214.15	4659.1	5517.99	6352.51
NRV {Global} [AcreFeet]	2681.54	3550.11	4169.28	5198.23	5984.4
NPV {Global} [AcreFeet]	461.889	615.34	784.99	979.169	1196.88
NHPV {Global} [AcreFeet]	227.238	337.726	458.614	597.793	802.712

4.1.3 Aquifer and gas cap size

The reservoir contains a strong aquifer support and a gas cap at original reservoir conditions. The size of the aquifer is 6.6 times larger than that of oil reservoir. The OOIP in the model is 1.58 MMSTB as compared to 1.87 MMSTB in P50 case of volumetric estimation. This is due to the fact that the model is initialized using single value of S_{wi} as compared to volumetric where S_{wi} has different value at each grid cell. The gas cap has 0.85 BCF gas in place as compared to 1.58 MMSTB oil in place in simulation model. The pore volume for gas is 33 MMBBLS as compared to 4.2 MMBBLS pore volume for oil. Therefore the value for m is 8 for this reservoir.

The simulation output file for fluids in place is shown below.

```
**************************************************
 ORIGINAL MASS IN PLACE IN SURFACE UNITS

   SURFACE VALUES OBTAINED BY FLASHING
 RESERVOIR FLUIDS AT FIELD SEPARATOR CONDITIONS
**************************************************

MATERIAL
BALANCE        PORE    HYDROCARBON HYDROCARBON
REGION        VOLUME      LIQUID       GAS         WATER
NAME           BBLS        STB         MSCF         STB
---------  ----------- ----------- ----------- -----------
EQREG1     0.33183E+08 0.15878E+07 0.20767E+07 0.28712E+08
EQOIL1     0.41698E+07 0.15878E+07 0.10079E+07 0.18300E+07
EQAQF1     0.27087E+08 0.00000E+00 0.00000E+00 0.26331E+08
```

4.2 Simulation model overview

4.2.1 Model description

The simulator used to perform this study is CHEARS which is Chevron proprietary simulator. It is a complete simulator having all the capabilities of a commercial simulator like Eclipse or VIP. The formulation used for this study is a black oil simulation. The following are the model dimensions

Grid size = 150 x 150 ft

Model size	= 44 x 124 x 40
	= 218,240 total cells
No of active cells	= 119,000

4.2.2 Model initialization

The model is initialized using original oil-water and gas-oil contacts. The original OWC is obtained from the RFT data from multiple wells (Figures 4.2). The value for RSRLINIT (solution GOR) is adjusted to get the required GOC seen in the SRFT logs. The RSRLINIT value is also used to match the observed and simulation RFT pressures. So it is made sure that the model is initialized using actual reservoir initial equilibrium conditions.

OWC	6662 ft TVDSS
GOC	6606 ft TVDSS
Simulation Model OOIP	1.58 MMSTB
OGIP	0.85 BCF

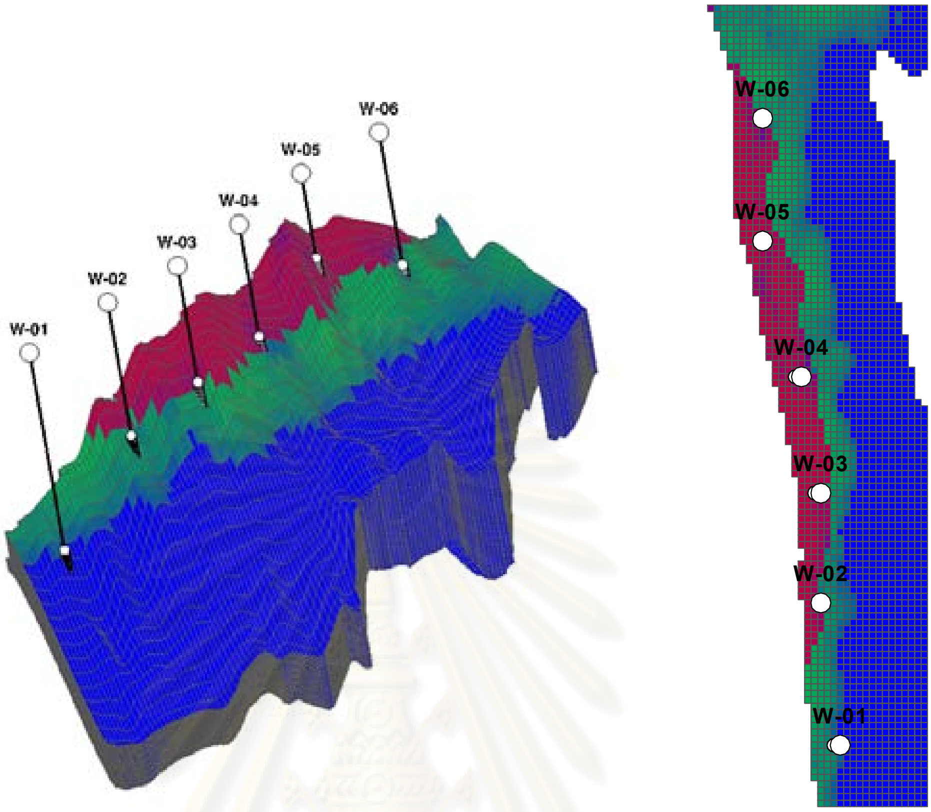
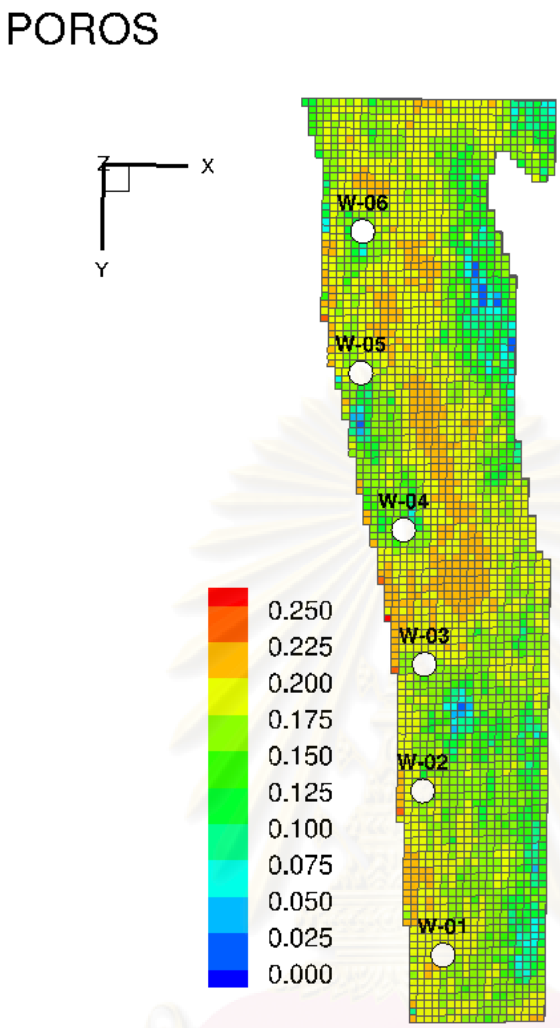


Figure 4.2: 3D and plan view of reservoir under study.

4.2.2.1 Porosity and permeability distribution

The porosity and permeability distribution for the reservoir in the model is shown in Figures 4.3a and 4.3b. The y-direction permeability is same as x-direction permeability. The z-direction permeability is 0.1 times the horizontal or x-direction permeability.


POROS
Z
X
Y
W-06
W-05
W-04
W-03
W-02
W-01
0.250
0.225
0.200
0.175
0.150
0.125
0.100
0.075
0.050
0.025
0.000

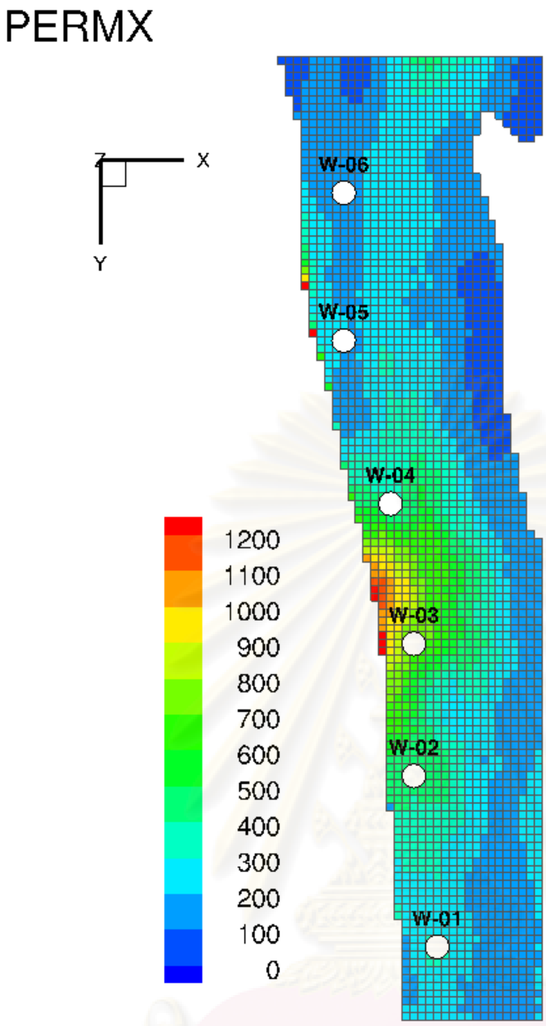
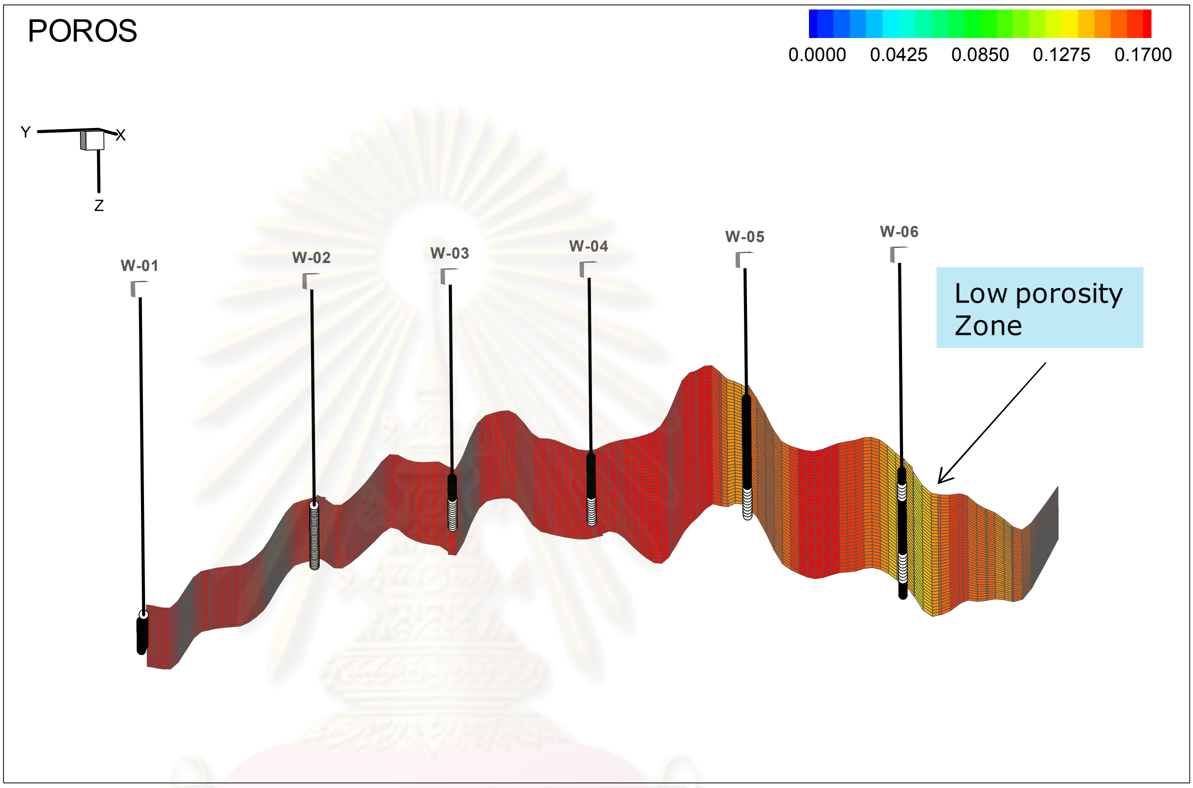


Figure 4.3a: Porosity map **Figure 4.3b: Permeability map**

The porosity map shows most of the reservoir has homogenous porosity with exception at the crest of the structure where the porosity is high due to better reservoir quality. Also from the cross-section shown in Figure 4.4, the porosity



is low in the area closer to W-06.

Figure 4.4: Cross-section showing porosity distribution near wells.

For permeability (k), a porosity permeability (ø-k) transform is used to populate the permeability grid in the model. High permeability areas reflect high porosity areas of the reservoir.

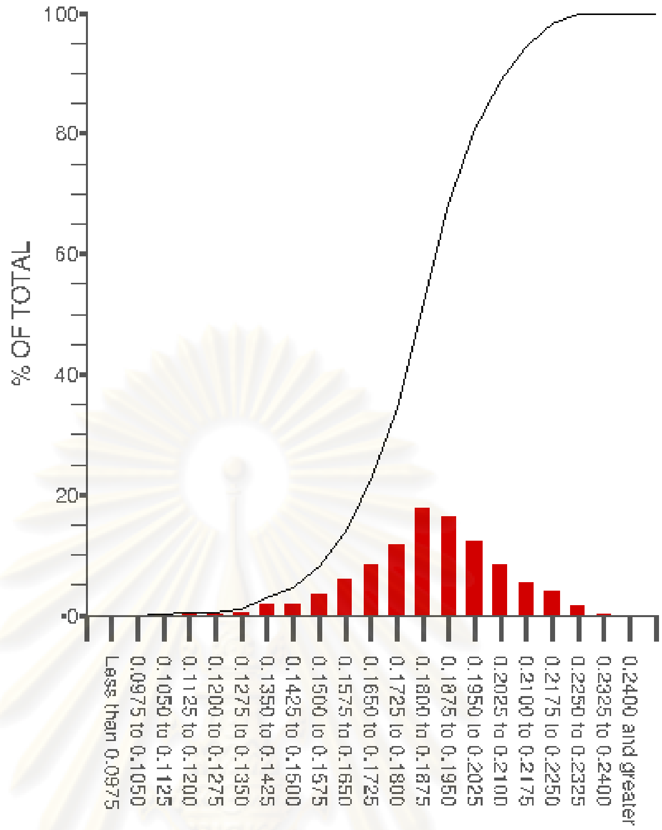


Figure 4.5: Porosity histogram and CDF

The porosity statistics for the model are as follows:

Total number of cells included = 119,000

Min = 0.1

Max = 0.24

Mean = 0.19

Median = 0.19

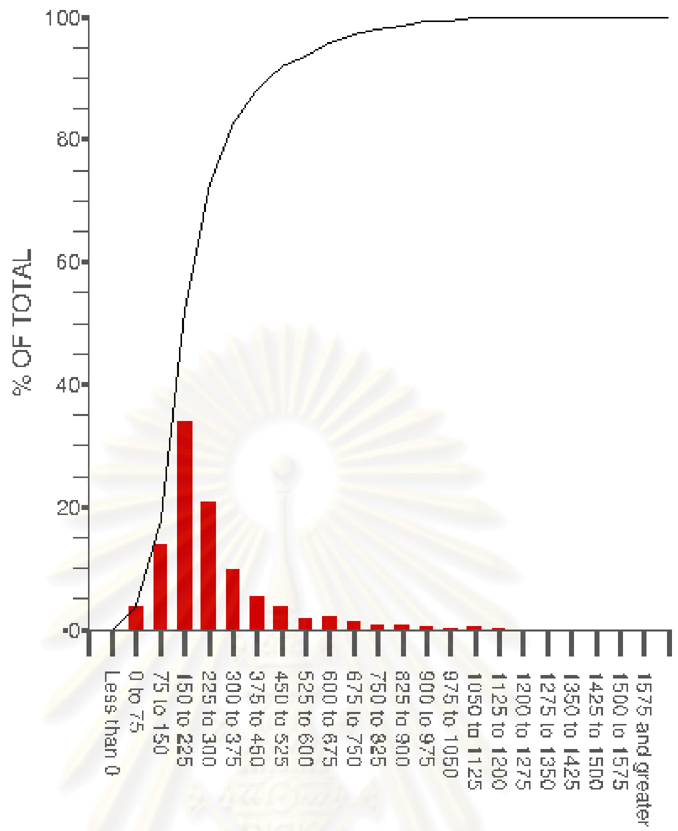


Figure 4.6: Permeability Histogram and CDF

Permeability statistics for the model are as follows:

Total number of cells = 119,000

Min = 24.29

Max = 1605

Mean = 269

Median = 219

4.2.2.2 Fluid contacts

As discussed before, the limits of the reservoir are defined by the original oil-water and gas-oil contacts. The open hole logs and RFT data from most downdip and updip wells are used to confirm the GOC and OWC limits of the reservoir. The RFT pressure data provides good fluid gradients, and the fluid contacts obtained from RFT pressure data is in close agreement with the open hole log contacts. The RFT pressure data and open hole log interpretation from W-01, W-03 and W-05 are shown in Figure 4.7. The GOC in W-05 is a little bit off from RFT but W-03 log GOC matches very well with RFT data. The reason of W-05 being a little bit off may be due to some depth error caused by conversion of measured to true vertical depth. The depth conversion error in this case is within the range of 0.5%.

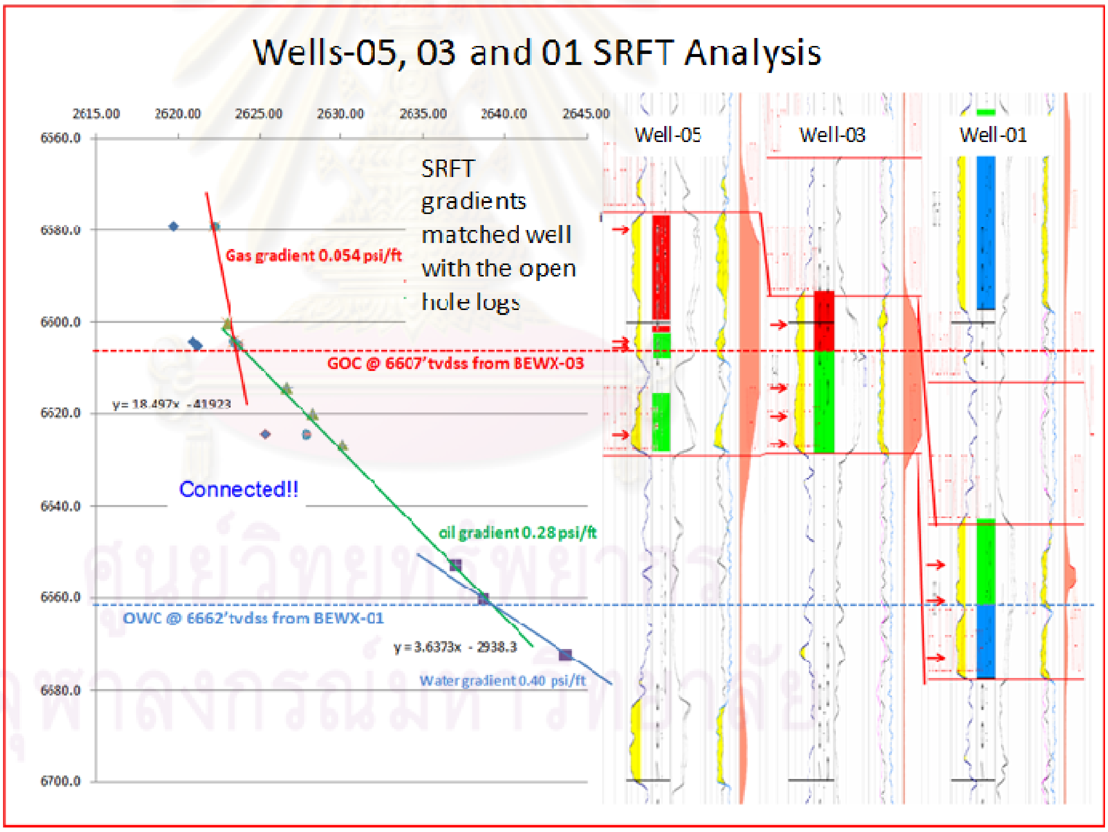


Figure 4.7: Multiwell RFT plots to estimate the original fluid contacts.

4.2.2.3 PVT data

The oil and gas PVT tables used in the simulation model are shown in Tables 4.1 and 4.2 respectively. The oil gravity is 38.6 deg API which tells that the oil is light. The oil and gas PVT tables are derived using actual bottom hole samples of exploration wells drilled earlier in the same basin. The solution GOR at initial reservoir conditions is about 650 scf/bbl, which also indicates that the oil is light. For this study, it is decided to use these PVT tables as the oil produced from this reservoir is almost of same API and is analogous to the oil sample used to generate these PVT tables. The following oil properties corresponding to each pressure are used in Table 4.2

FVF: oil formation volume factor

VISC: oil viscosity

RS: solution gas oil ratio at corresponding pressure

COMPR: oil compressibility

DVIS: change in oil viscosity with respect to pressure at corresponding solution GOR

Table 4.2: Oil PVT data.

Oil API Gravity = 38.6 deg API

PRESSURE (psia)	FVF (rbbl/STB)	VISC (cp)	RS (SCF/STB)	COMPR (1/psi)	DVIS (1/psi)
200.0	1.1266	0.373	32.65	1.4864E-04	6.9497E-05
400.0	1.1443	0.364	70.18	7.9024E-05	6.9722E-05
600.0	1.1642	0.353	111.64	5.6149E-05	7.0025E-05
800.0	1.1859	0.340	155.95	4.4891E-05	7.0400E-05
1000.0	1.2091	0.326	202.53	3.8250E-05	7.0841E-05
1200.0	1.2337	0.312	251.03	3.3903E-05	7.1344E-05
1400.0	1.2595	0.298	301.18	3.0857E-05	7.1903E-05
1600.0	1.2865	0.283	352.80	2.8618E-05	7.2512E-05
1800.0	1.3146	0.269	405.74	2.6914E-05	7.3165E-05
2000.0	1.3438	0.256	459.88	2.5581E-05	7.3856E-05
2200.0	1.3740	0.244	515.13	2.4515E-05	7.4579E-05
2400.0	1.4051	0.232	571.40	2.3649E-05	7.5326E-05
2600.0	1.4371	0.221	628.64	2.2934E-05	7.6090E-05
2800.0	1.4701	0.211	686.78	2.2337E-05	7.6864E-05
3000.0	1.5038	0.202	745.76	2.1835E-05	7.7640E-05

Similarly for gas the properties used in Table 4.3 for each pressure are:

FVF: gas formation volume factor for each pressure

VISC: gas viscosity for each pressure

Table 4.3: Gas PVT data.

Gas Gravity = 0.833 (air = 1.00)

PRESSURE (psia)	FVF (rbbl/MSCF)	VISC (cp)
200.0	18.3415	0.0144
400.0	9.0334	0.0146
600.0	5.9360	0.0148
800.0	4.3924	0.0151
1000.0	3.4705	0.0155
1200.0	2.8600	0.0159
1400.0	2.4279	0.0163
1600.0	2.1075	0.0168
1800.0	1.8617	0.0173
2000.0	1.6683	0.0178
2200.0	1.5129	0.0184
2400.0	1.3861	0.0190
2600.0	1.2811	0.0197
2800.0	1.1932	0.0203
3000.0	1.1188	0.0210

4.2.2.4 Saturation profile and relative permeability data

The model is initialized using actual open hole log data from wells W-01, W-03 and W-05. The depth vs S_w plot for these wells is shown in the Figure 4.8. Figure 4.8 shows that there is some lateral variation in S_w versus depth. This is mainly due to presence of some poor reservoir within the sand body. But overall, the sand looks clean and we can see a consistent trend in S_w values with depth. The well W-01 in Figure 4.8 shows relatively higher S_w values as compared to other wells. This is because this is the most downdip well penetrated in the reservoir and closer to the oil-water contact.

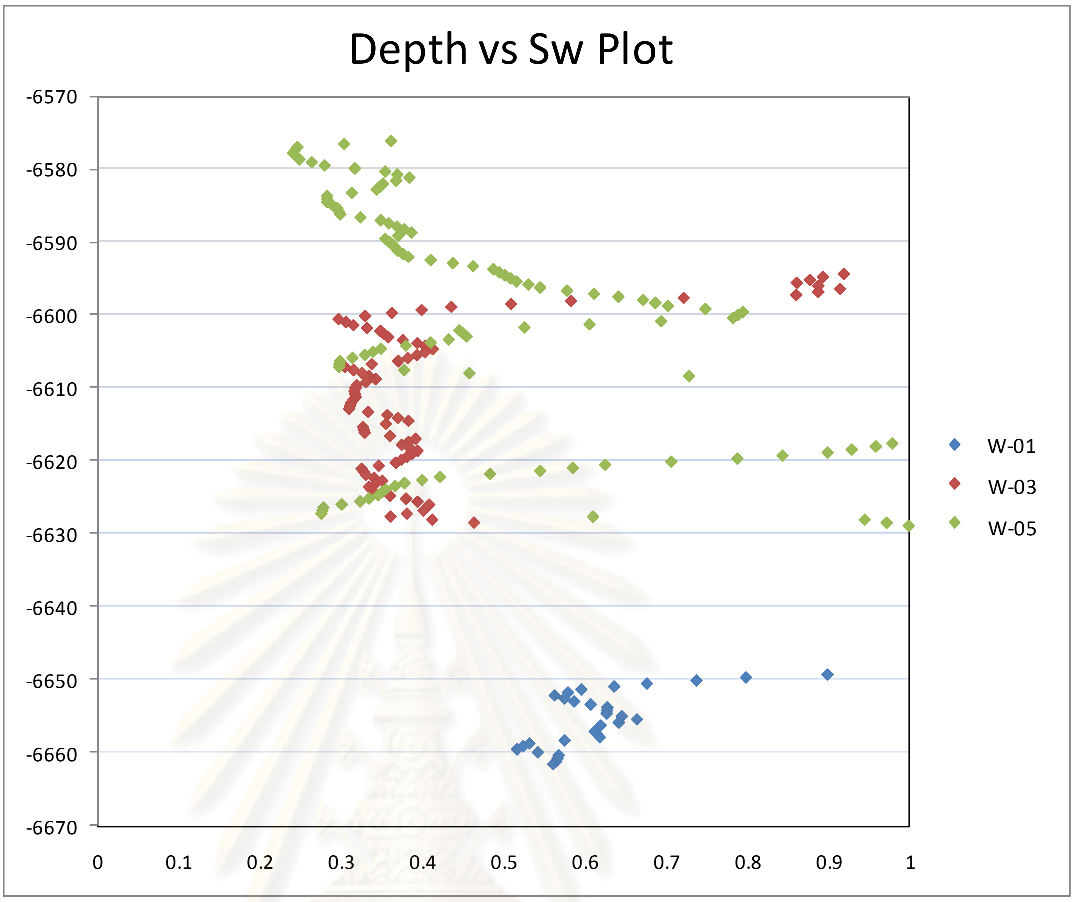


Figure 4.8: Depth vs Sw plot using open hole logs.

Figure 4.9 shows plot of J-Function versus S_w. The J-Function keyword is used in Chears to show that J-Function will be used to initialize water saturations in the model. The following formula is used by Chears to calculate the J-Function

$$J = .22 \frac{Pc}{\sigma \, Cos\theta} \sqrt{k}/\emptyset$$

where

J = Leverett's J-function

Pc = capillary pressure, psi

σ = interfacial tension, dynes/cm

Θ = contact angle, degrees

$\emptyset$ = porosity

A saturation model developed in excel is used to construct J-function curve using actual S_w values from log as shown in Figure 4.9. The J-function versus S_w curve in Figure 4.9 shows that the reservoir has sharp contact with little transition interval. This also corresponds to the good porosity and quality of the reservoir under study.

Figure 4.10 shows the relative permeability curves used in the simulation model. Like PVT data, the relative permeability curves are used from SCAL of an exploration well.

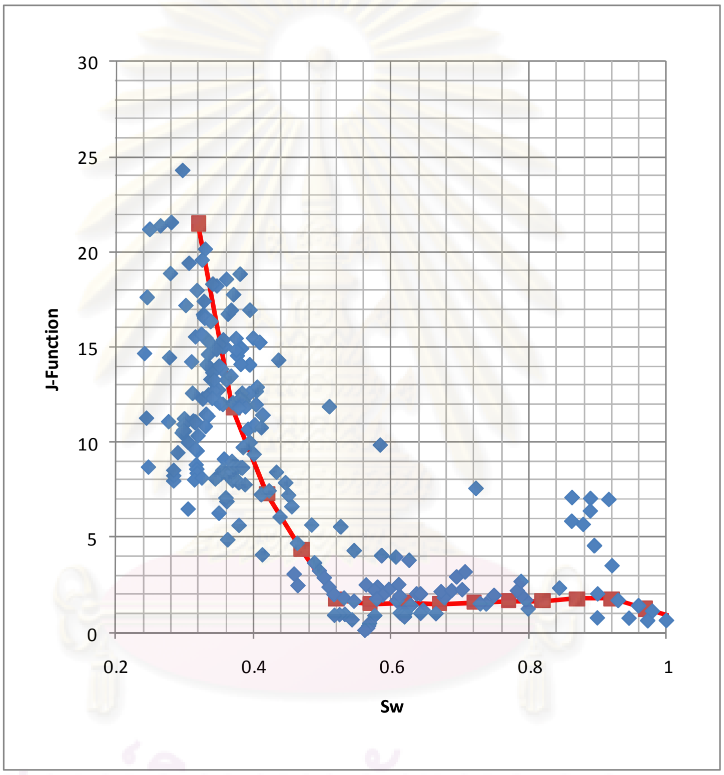


Figure 4.9: Generating J Function using actual log data.

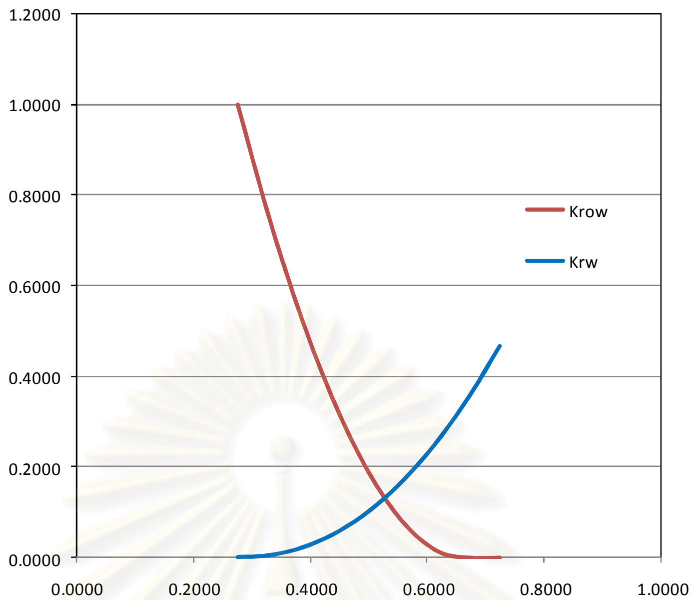


Figure 4.10: Relative permeability curves used in the model.

4.2.2.5 RFT pressure match

The model is calibrated by matching original RFT pressures from the wells. All the wells drilled in this reservoir were found at original reservoir pressure. The RFT pressure match is shown in the Figure 4.11, Figure 4.12 and Figure 4.13. The red dots in the plot are the observed pressure points from actual RFT log and the green line is the simulated pressures. As seen in the plots below, a very reasonable match is obtained between actual and simulated RFT pressures. This gives good confidence on model initialization.

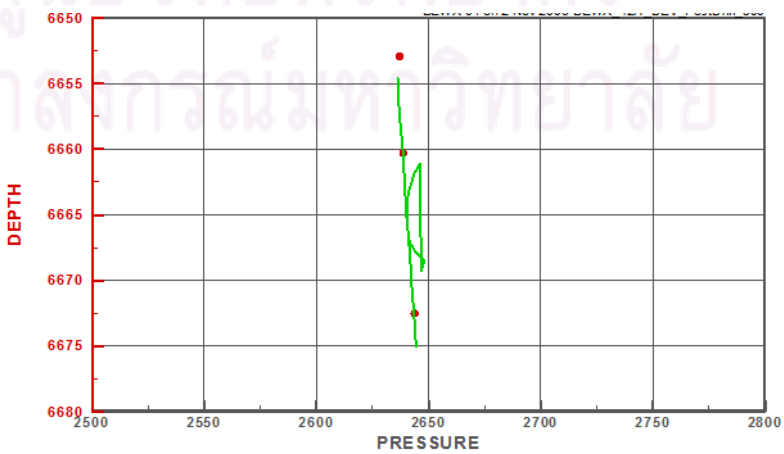


Figure 4.11: RFT match for Well-01.

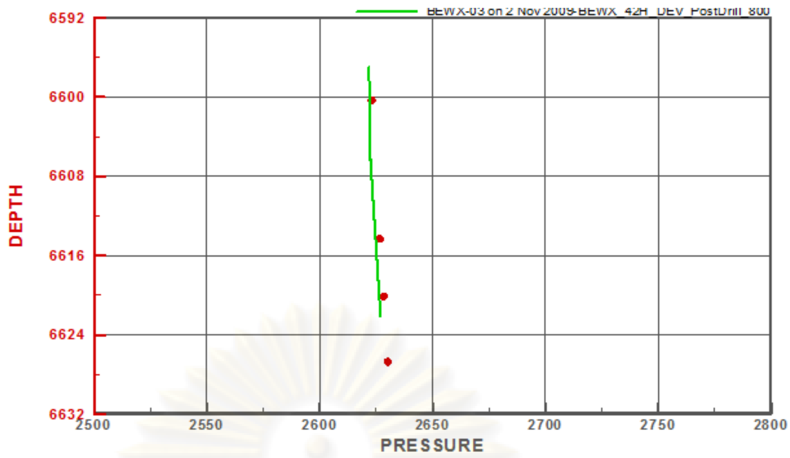


Figure 4.12: RFT match for Well-03.

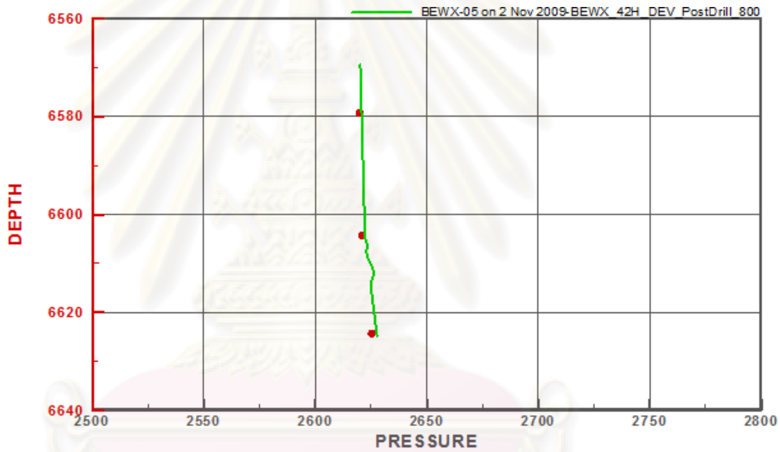


Figure 4.13: RFT match for Well-05.

4.3 Well constraints

The deviated wells in the model are controlled using bottom hole pressure (BHP) constraints. A minimum BHP value of 1450 psia is assigned to all the wells. This is based on the assumption that all the wells have gas lift completion and therefore BHP can be drawn down to 1450 psia.

A lower BHP constraint for horizontal well is however used in the model. This is due to the fact that the lowest gas lift mandrel (orifice) can be set much deeper and closer to the producing reservoir in horizontal wells as compared to deviated wells. In deviated wells, there are multiple reservoirs to be produced and hence the 7” casing could not be set deeper than the top of shallowest reservoir. In the example field, the 6000 ft ss reservoir is not the shallowest reservoir and therefore the BHP constraint for deviated wells is higher than the horizontal well in the model. The minimum BHP constraint used for horizontal wells is 1300 psia.

The maximum oil production rate (OPR) for all the deviated wells in the field are restricted to 500 BOPD for each well. This is based on the properties of reservoir and experience gained from the production performance of deviated wells from similar kind of reservoir and well completion in the basin.

Maximum water cut (MAXWCUT) constraint of 90% is also applied to all the deviated and horizontal wells in the model. This is based on the fact that all the wells are completed with gas lift completion and therefore heavier liquids could be lifted from the wellbore easily.

CHAPTER V

RESULTS AND DISCUSSION

5.1 Base case scenario

5.1.1 Base case definition

The base case scenario is the case when the reservoir is produced from existing deviated wells. The locations of the wells are shown in reservoir overview section of this report in Figure 4.1. In the base case scenario, there is no completion optimization done. The wells are perforated through all reservoir section penetrated by the wellbore as shown in Figure 5.1.

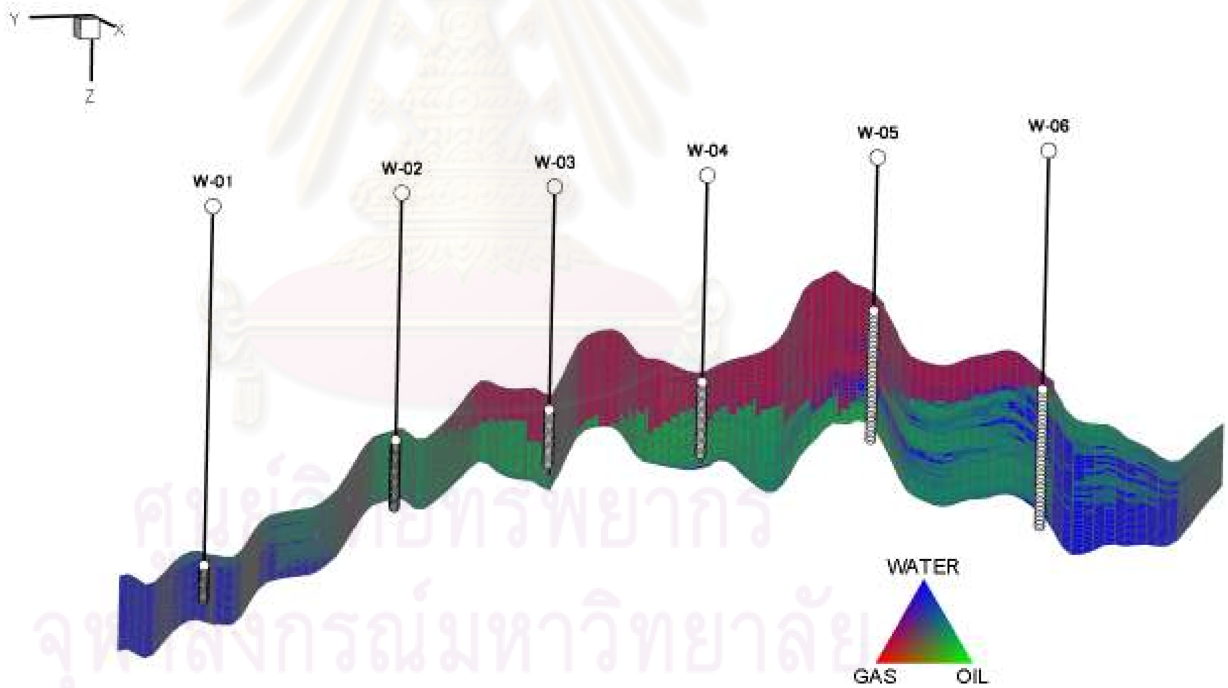


Figure 5.1: Perforations throughout the reservoir section.

5.1.2 Base case recoveries

Base case scenario is in which all the deviated wells penetrating the reservoir are producing. The wells are completed throughout the reservoir section and no completion optimization is done. The well constraints discussed in Section 4.3 are applied for all the wells. It should be noted that all wells in the reservoir are completed with gas lift completion with a bottom hole pressure constraint of 1450 psia. The wells completed in this reservoir also penetrated other reservoirs shallower than this reservoir. Therefore, the bottom most gas lift valve (orifice) is set above the shallowest reservoir penetrated which is not the 6100 reservoir studies in this project. So, the BHP constraint of 1450 psia takes into account this factor. For horizontal wells studies in later sections of this project, the BHP limit is further reduced to 1300 psia. A pressure reduction of 150 psia for horizontal wells is due to the fact that the bottom most gas lift valve (orifice) can be set just above the 6100 reservoir.

There is also a gas oil ratio (GOR) limit of 3000 scf/bbl applied as well limit or constraint. The reasons for applying GOR limit are to conserve reservoir energy, avoid substantial gas expansion and oil smearing into gas cap, and comply with facility constraints for gas handling.

The result from base case scenario is shown from Figure 5.2 to Figure 5.6. Figure 5.2 shows the oil production profile of all the deviated wells. Note that wells W-01, W-05 and W-06 do not produce in the base case scenario. This is because W-01 penetrates most of the water zone. The completion is not optimized in this case, and therefore, the water starts producing at very high water cut and exceeds the water cut limit of 90% right from the beginning of production. Well W-05 is completed mostly in the gas zone and reaches the maximum GOR limit at very early stage of production and therefore, cannot produce any oil. Well W-06 also could not produce any oil as most of the perforations in W-06 covers water zone. The reservoir quality near W-06 is poor as shown in the cross-section in Figure 4.4.

From Figures 5.3 and 5.4, it is clear that wells W-02, W-03 and W-04 seize flowing after reaching maximum GOR limit of 3000 scf/bbl. None of the wells reach the water cut constraint of 90% before they stop flowing. This is because gas coning is more pronounced in all these deviated wells as compared to water coning. The gas being more mobile than water hits the wells very early and shows a very sharp incline in GOR trend as compared to water cut trend. This trend is also very evident in the field GOR and water cut trends shown in Figure 5.5.

The gas and water coning phenomena is also shown in the figures 5.7 and 5.8. Figure 5.8 shows the relative movement of original GOC and OWC. Note that both water coning and gas coning is more pronounced around wells W-02, W-03 and W-04 as compared to areas where wells W-05 and W-06 are drilled and are not producing. This also highlights overall poor sweep even after abandonment conditions.

Figure 5.9 shows the overall oil recovery from the base case scenario which is 11.6% for primary depletion.

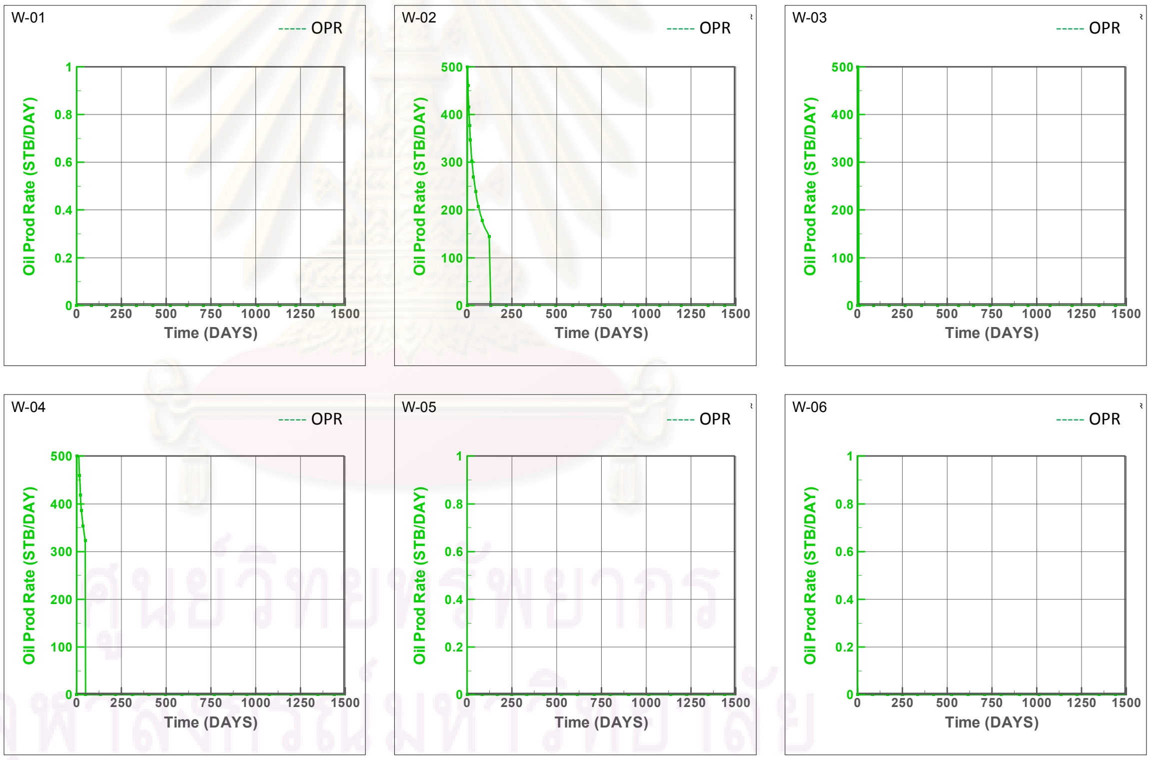


Figure 5.2: Oil production rate for six producers – base case.

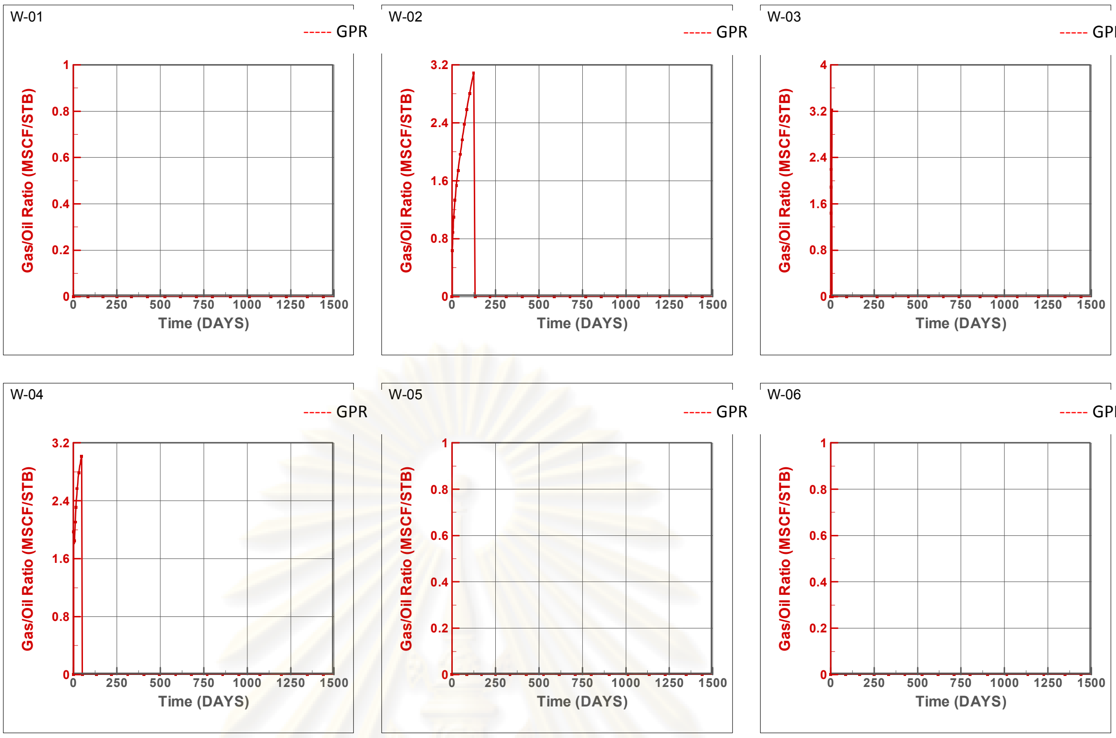


Figure 5.3: GOR trend for all six producers – base case.

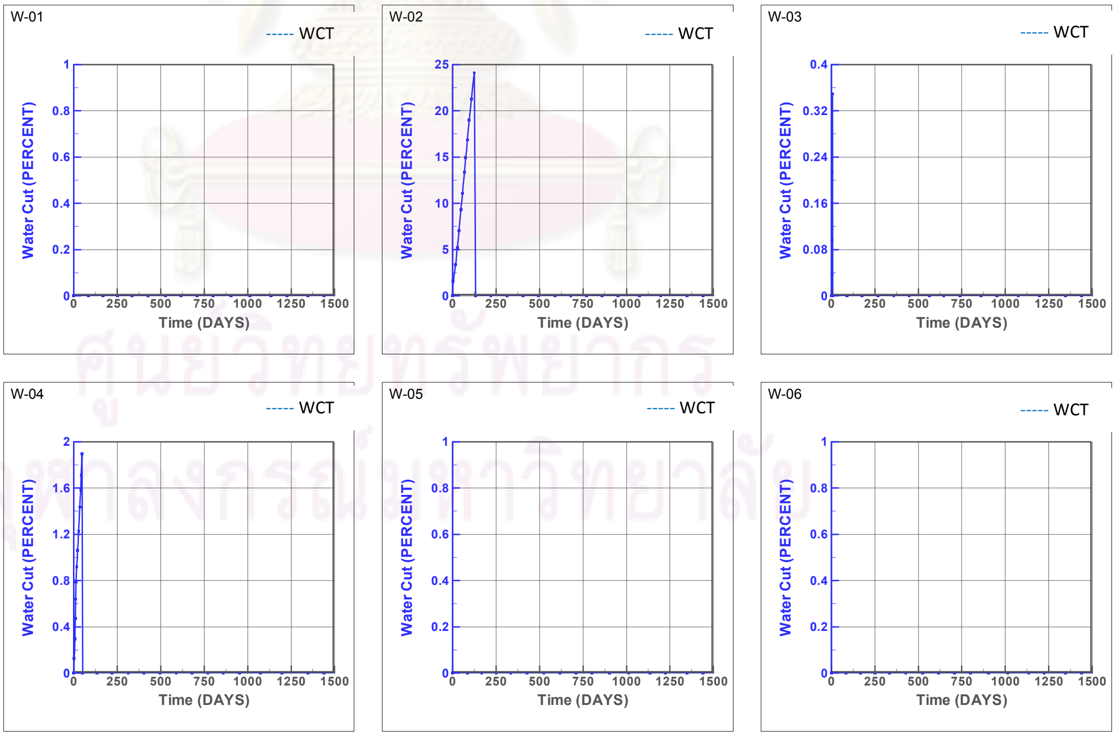


Figure 5.4: Water cut trend for all six producers – base case.

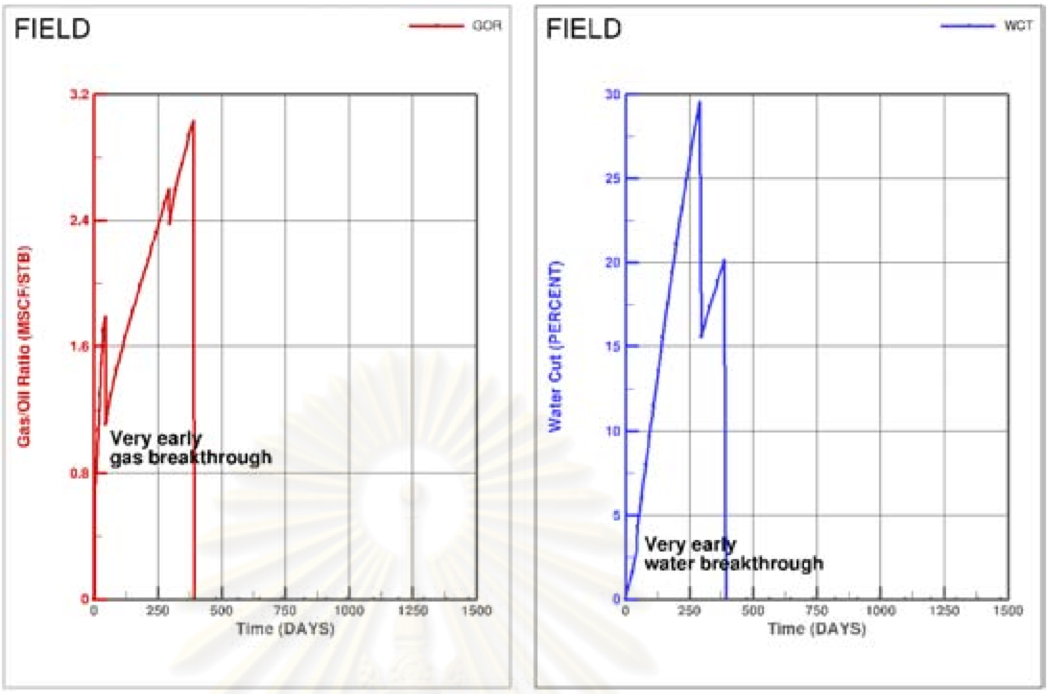


Figure 5.5: Field gas and water breakthrough timing – base case.

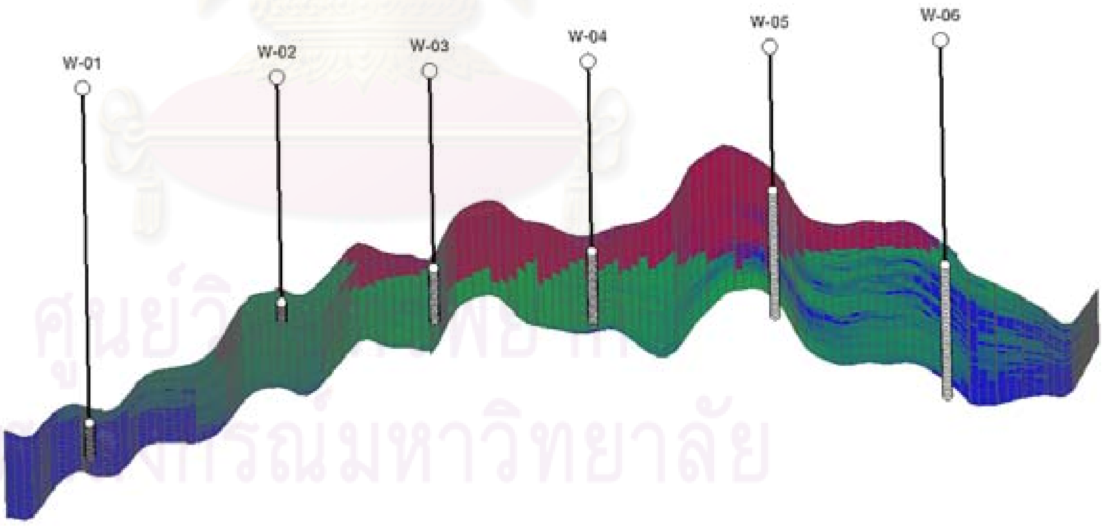


Figure5.6: Field Cross-section showing initial conditions – base case.

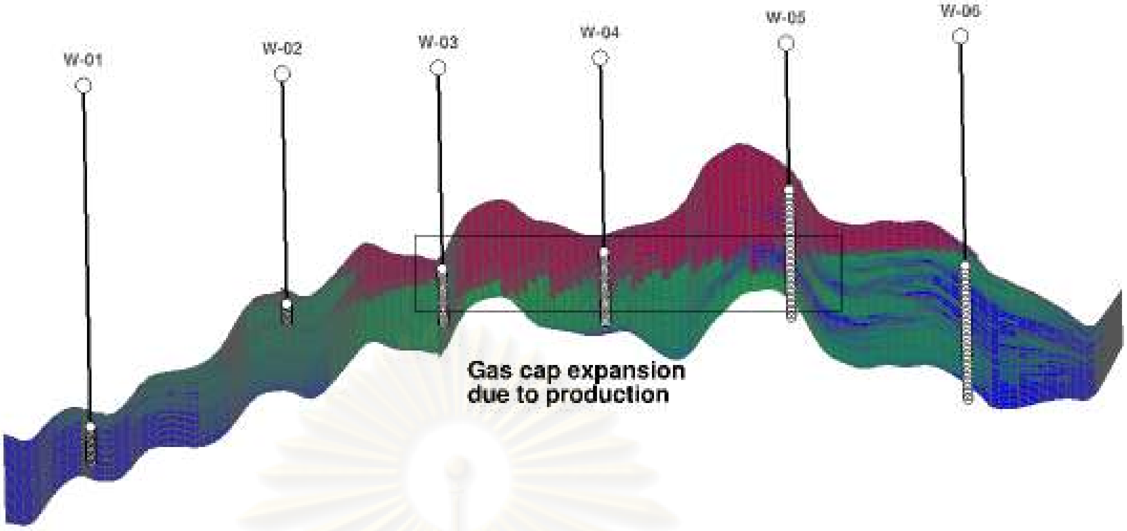


Figure 5.7: Field cross-section gas coning after production – base case.

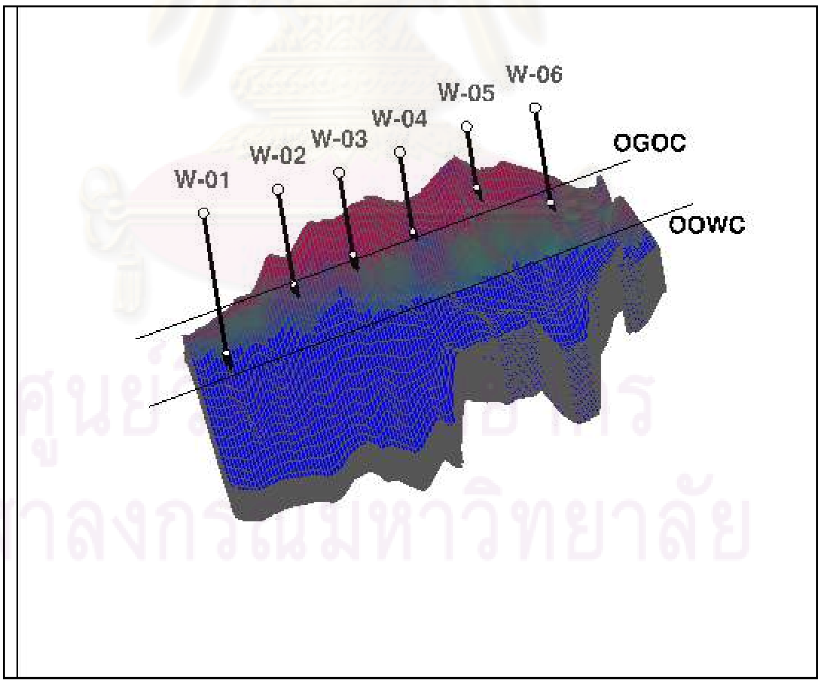


Figure 5.8: Oil and gas contact movement due to gas and water coning.

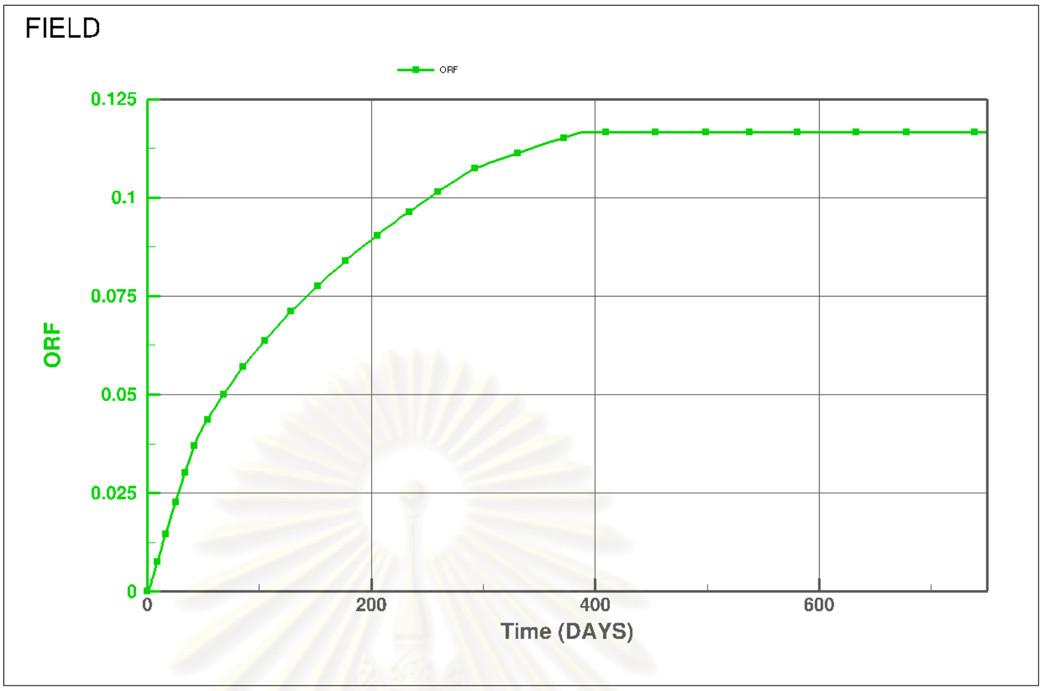


Figure 5.9: Oil recovery plot for field – base case.

5.2 Deviated wells optimization

5.2.1 Optimization using selected completion

In this case, the completion for each deviated well is optimized as shown in Figure 5.10. Well completion optimization is done for wells W-01, W-03, W-04, W-05 and W-06. No completion optimization is required for W-02 as the well penetrates the oil column only. The objective of completion optimization is to reduce or minimize the gas and water coning. Perforations in the gas zone in wells W-03, W-04 and W-05 are closed and perforations in the water zone in wells W-01 and W-06 are closed. The closed or isolated perforations are shown in black in Figure 5.10.

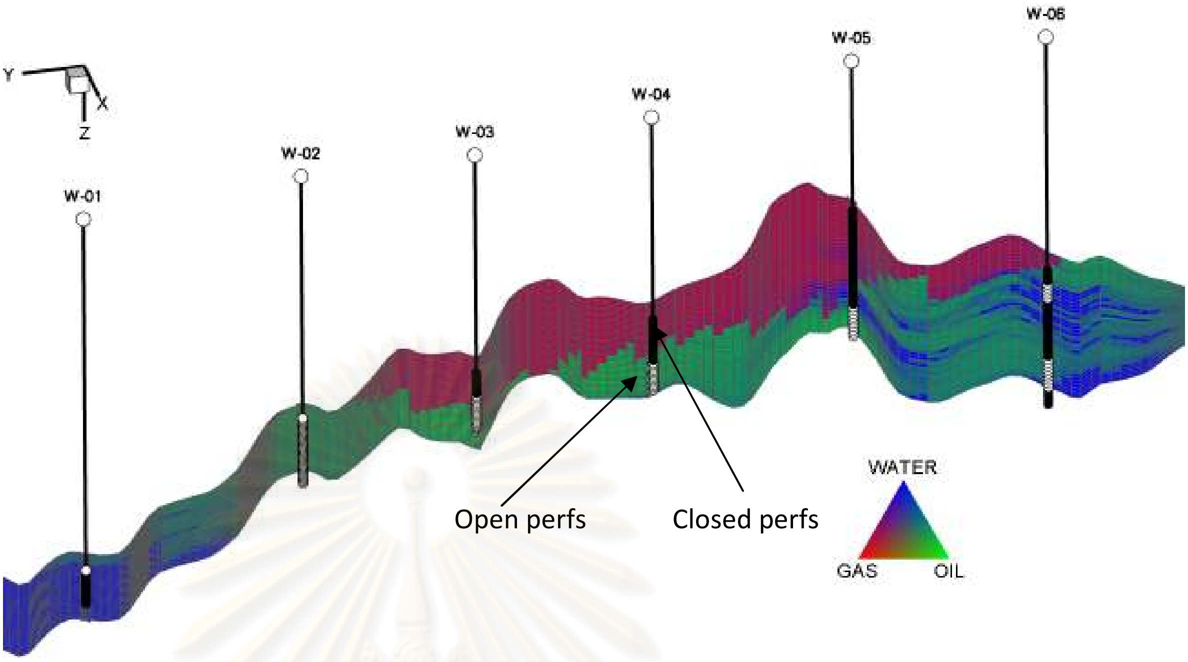


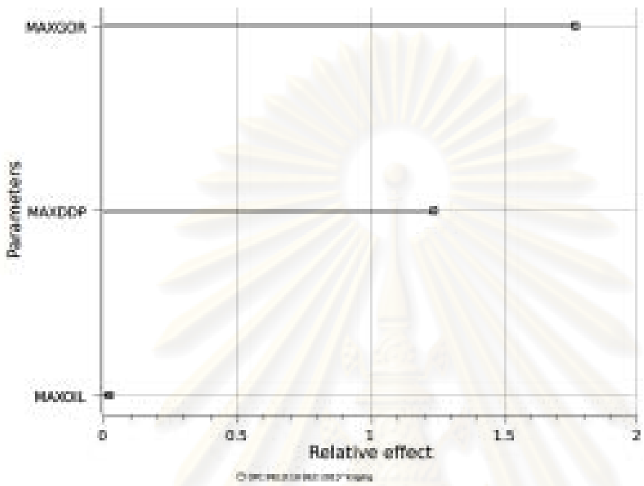
Figure 5.10: Perforations optimized for gas and water coning.

5.2.2 Impact of different variables on oil recovery – DoE runs

Multiple DoE runs (DoE theory explained in Section 2.2) were made to see the impact of initial production rates on the overall recovery of the reservoir. The variables selected for DoE runs are dynamic variables, and hence the workflow is called one level DoE workflow. The other level of DoE could be performed on static properties of the model. It is assumed for this project that there is good confidence on the static properties of the model. The dynamic variables selected are:

I. Initial production rate
II. Bottom hole drawdown pressure
III. Maximum GOR limit

The simulation results for experimental design are shown in Figures 5.11 to 5.14. Figures 5.11 and 5.12 show Pareto and Tornado charts to see the impact of different variables on oil recovery. Both these charts show that there is minimum impact of production rates on the oil recovery factor. Maximum GOR limit has the maximum impact on the oil recovery. This is because in an oil rim, gas production starts from very beginning of production and the wells produces for longer time with increase GOR limit and shut in earlier with smaller GOR by reaching the maximum GOR limit earlier. The drawdown pressure can also be related to the oil production as usually the drawdown is controlled by the surface rates. In the simulation runs they are taken as two separate controlling factors.

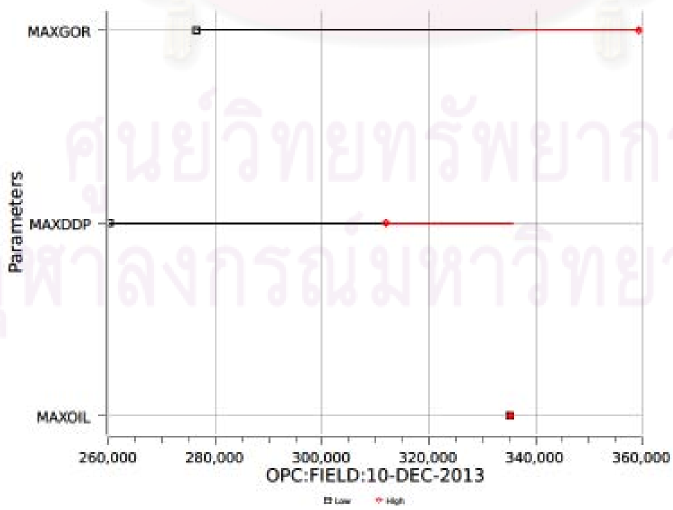


MAXGOR = Maximum GOR limit

MAXDDP =Maximum drawdown pressure

MAXOIL = Maximum oil production rate

Figure 5.11: Pareto chart for impact of different variables on oil recovery.



MAXGOR = Maximum GOR limit

MAXDDP =Maximum drawdown pressure

MAXOIL = Maximum oil production rate

Figure 5.12: Tornado chart for impact of different variables on oil recovery.

In Figures 5.13 and 5.14, the relationship between these dynamic variables and oil recovery is shown. Figure 5.13 shows that the oil recovery increases with increase in drawdown up to some value of drawdown, after which the oil recovery starts decreasing with further increase in drawdown. This is due to the fact that after reaching certain drawdown, the gas coning becomes so dominant that the limiting GOR value is achieved very early in the production period. This might not be the case in an undersaturated reservoir with low bubble point pressure where more drawdown will increase the oil production without increase in GOR till the bubble point is reached. The only concern in an under saturated reservoir with increase in drawdown pressure would be water coning.

Figure 5.14 shows increase in oil recovery with increase in GOR limit of the field. If there is no production constraint for a facility, then higher oil recoveries can be achieved by allowing the wells to produce at much higher GOR. But most of the time, the GOR is maintained up to some level to meet the facility constraints.

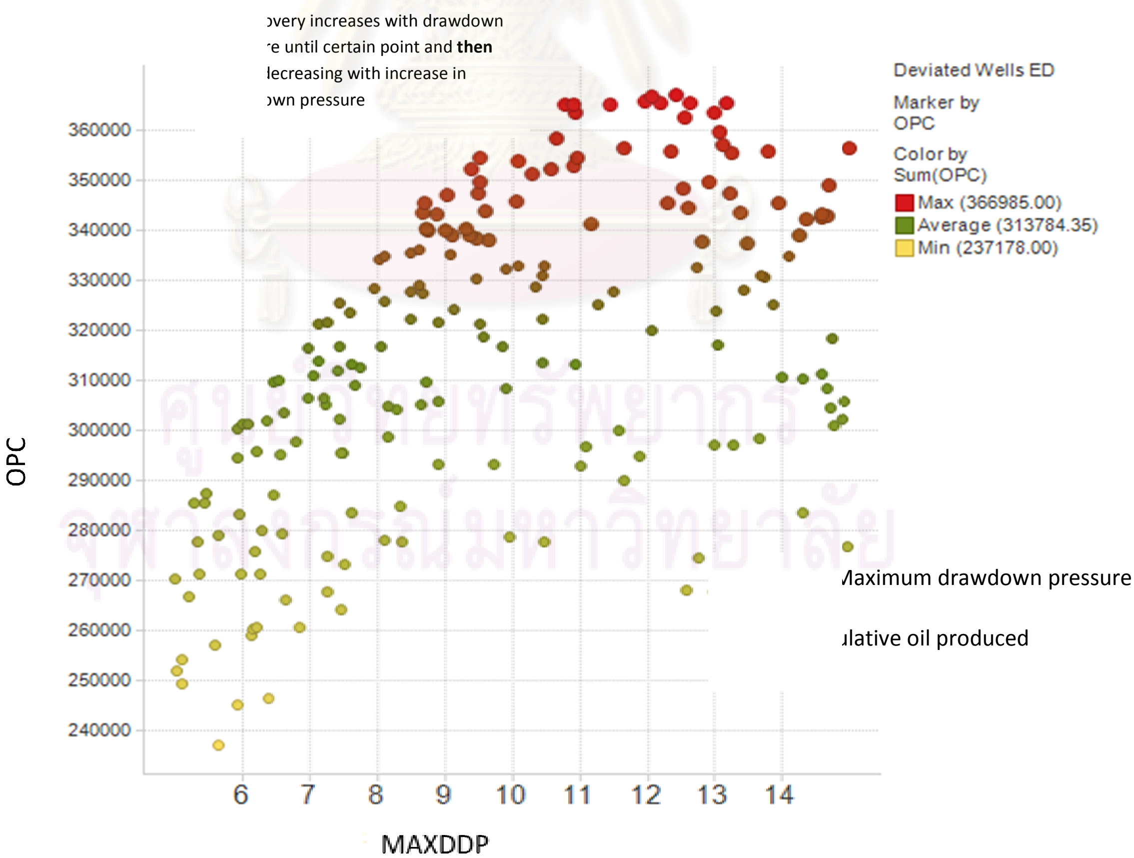


Figure 5.13: Effect of drawdown pressure on oil production cumulative (OPC).

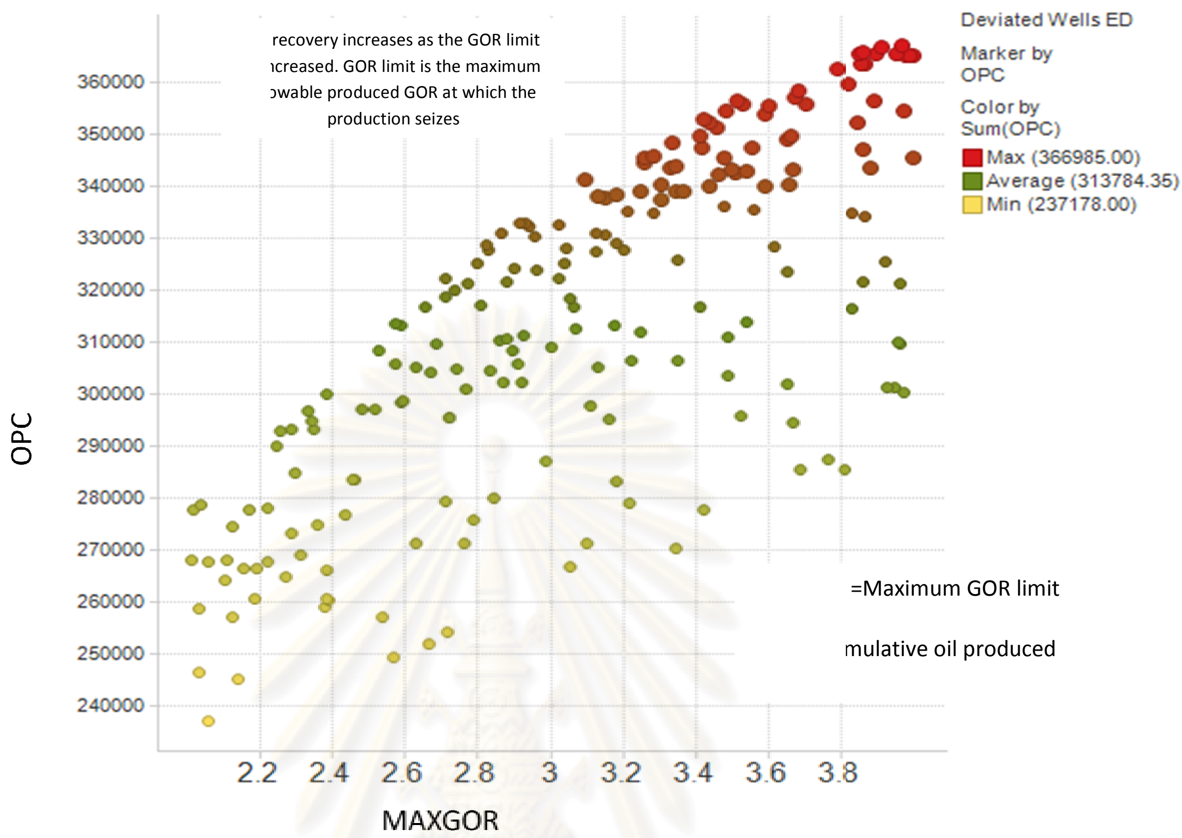


Figure 5.14: Effect of max GOR limit on oil recovery

5.2.3 Deviated wells optimization – optimization runs

After the impact of these dynamic variables on oil recovery had been studied, optimization runs were made. A range of values for each variable discussed in Table 5.1 are used in the simulation runs to achieve the optimized combination of these parameters. The results of the optimization runs are shown from figure 5.15 to 5.21.

In optimization runs, different combinations for the above mentioned parameters were used to generate multiple profiles. The best combination in terms of maximum oil recovery will then be selected as optimized case for development wells. Figure 5.15 shows the oil production profiles for optimization runs. It can be noted that at certain point in time, the rates from all the runs tends to merge. After this time the oil production rate becomes too low to be economical. Also, the rate of change in oil cumulative is very little. Therefore, a time cutoff is applied at 750 days, and oil recovery till that time will be compared to select the most optimized case.

Table 5.1: Description of optimization cases – deviated wells

	Run Label	MAXOIL	MAXDDP	MAXGOR
1	DEV_WELLS_OPT_Run_1_4	600	10	1
2	DEV_WELLS_OPT_Run_1_1	800	10	2
3	DEV_WELLS_OPT_Run_1_5	400	15	2
4	DEV_WELLS_OPT_Run_1_6	400	5	1
5	DEV_WELLS_OPT_Run_1_2	800	10	3
6	DEV_WELLS_OPT_Run_1_7	800	5	2
7	DEV_WELLS_OPT_Run_1_3	400	15	3
8	DEV_WELLS_OPT_Run_1_8	800	15	3
9	DEV_WELLS_OPT_Run_1_11	600	15	2
10	DEV_WELLS_OPT_Run_1_12	400	10	3
11	DEV_WELLS_OPT_Run_1_13	600	5	1
12	DEV_WELLS_OPT_Run_1_9	600	10	3
13	DEV_WELLS_OPT_Run_1_10	600	10	2
14	DEV_WELLS_OPT_Run_2_2	800	10	1
15	DEV_WELLS_OPT_Run_2_5	800	15	1
16	DEV_WELLS_OPT_Run_2_6	400	10	1
17	DEV_WELLS_OPT_Run_3_5	400	5	2

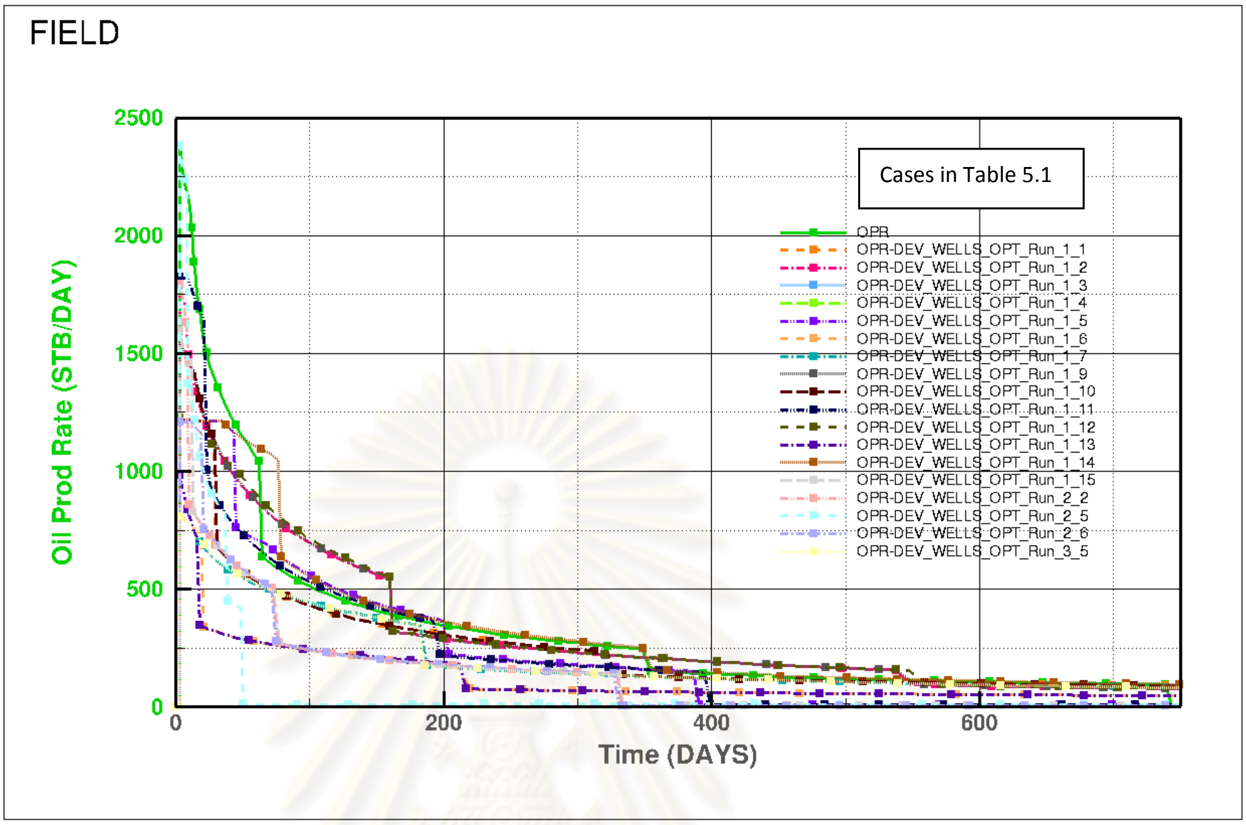


Figure 5.15: Field oil production profiles for optimization runs.

Figure 5.16 shows the oil production cumulative at 750 days for different combination of variables. The best recovery for this case is achieved at drawdown pressure of 15 psi with GOR of 3000 scf/bbl with maximum field oil rate of 2250 bbl/day. The optimized case for deviated wells primary recovery gives a recovery factor (RF) of 15% (Figure 5.16).

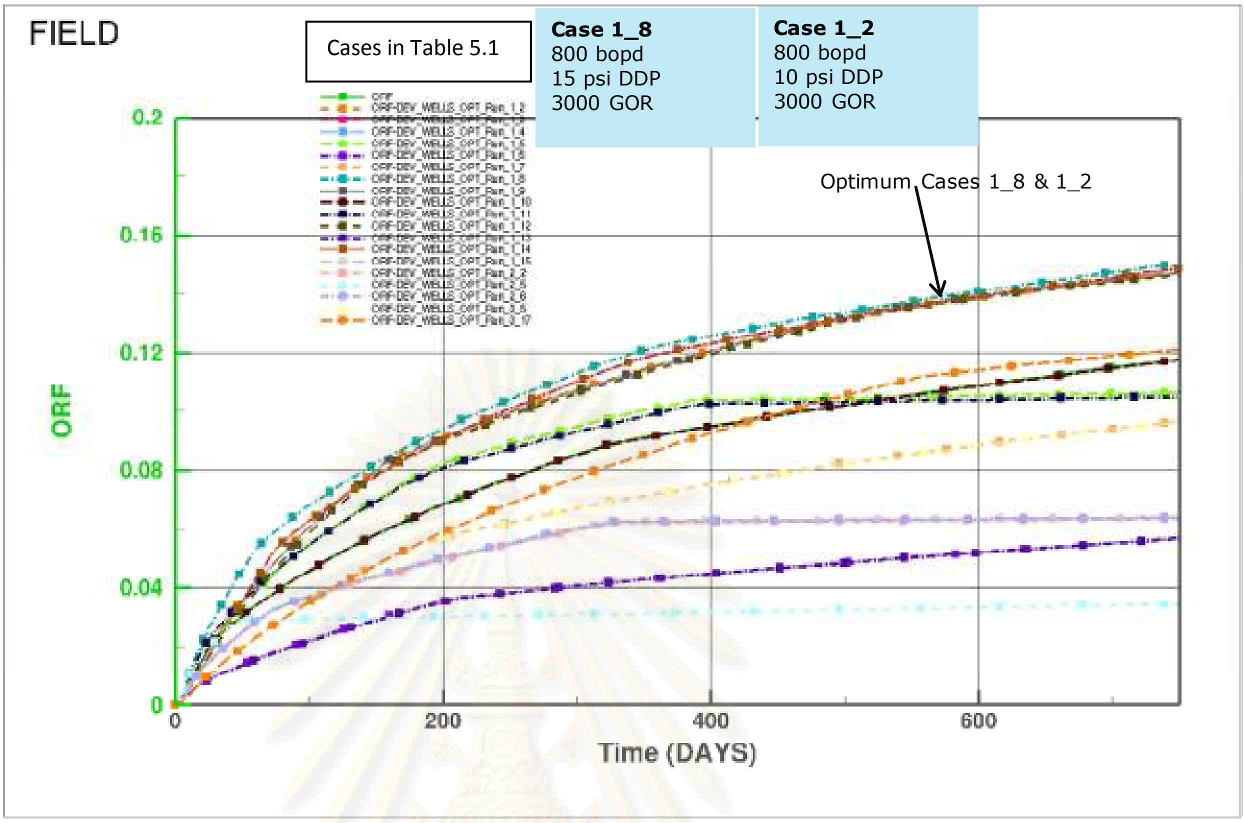


Figure 5.16: Field oil recovery for optimization runs.

The oil rate profile for each well is shown in Figure 5.17. The maximum oil rate for each well is also optimized for the optimum recovery case and estimated as 800 bopd. It should also be noted that wells W-01 and W-05 are not producing. The reason for this is that W-01 is drilled in the OWC and W-05 mostly penetrates the gas cap. These wells are not produced to minimize the water and gas production in order to maintain the reservoir energy.

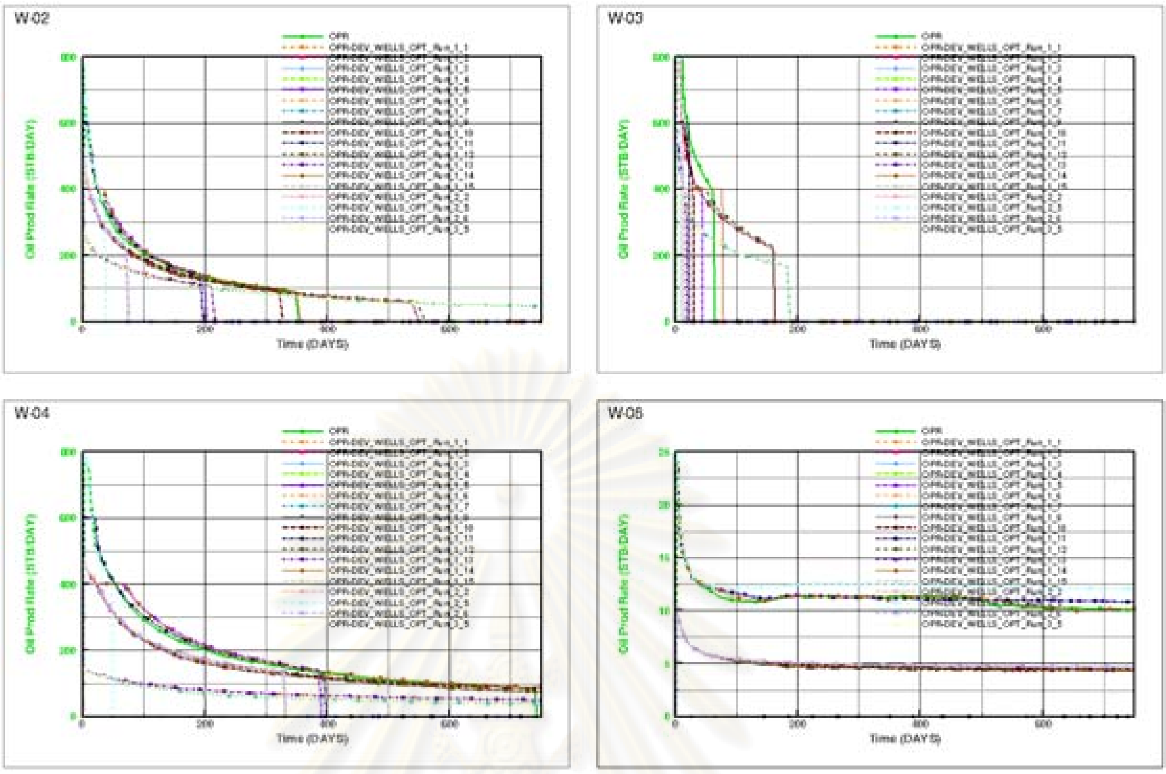


Figure 5.17: Oil production profiles for all producers.

The GOR and water cut trends for all producing wells are shown in Figures 5.18 and 5.19. It can be seen that as the production rates and drawdown pressures are increased, the water and gas coning starts earlier. This is because at higher drawdown pressures and higher production rates, the critical rate for coning is achieved earlier. This will decrease the oil recovery as the wells reach the limiting water cut and GOR constraints earlier. The effect of different parameters on gas and water coning is illustrated in Figures 5.20 and 5.21.

At the same time, the wells produce more oil in the initial phase of production with increased drawdown and rates. Multiple combinations of drawdown pressures, production rates and GOR constraints are run to estimate the most optimum combination to give optimum recovery. Cases 1_8 and 1_2 are the best cases in terms of oil recovery. But when we looked at the cumulative gas and water produced in Figure 5.22, case 1_2 has produced less cumulative gas and water. Also from Figure 5.23, more reservoir energy is lost in case 1_8 as compared to case 1_2. So with less water and gas produced and conservation of reservoir energy case 1_2 is the optimum case for deviated wells. From Table 5.1, case 1_2 is when maximum oil rate for each well is 400 bopd, maximum GOR limit is 3000 scf/bbl and maximum pressure drawdown limit is 10 psi.

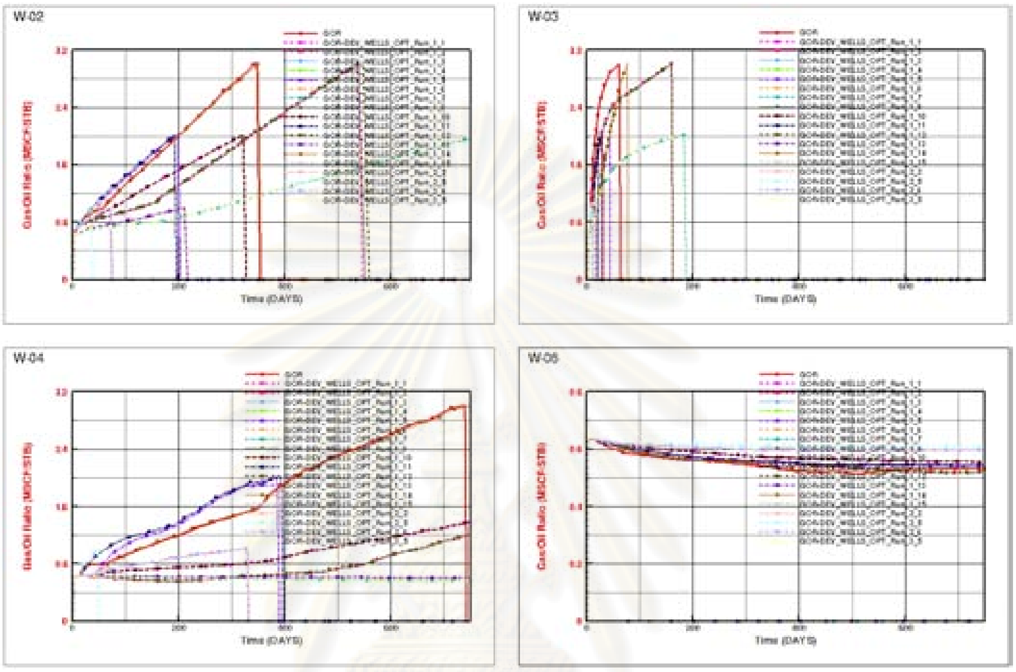


Figure 5.18: Gas oil ratio trend for all producers.

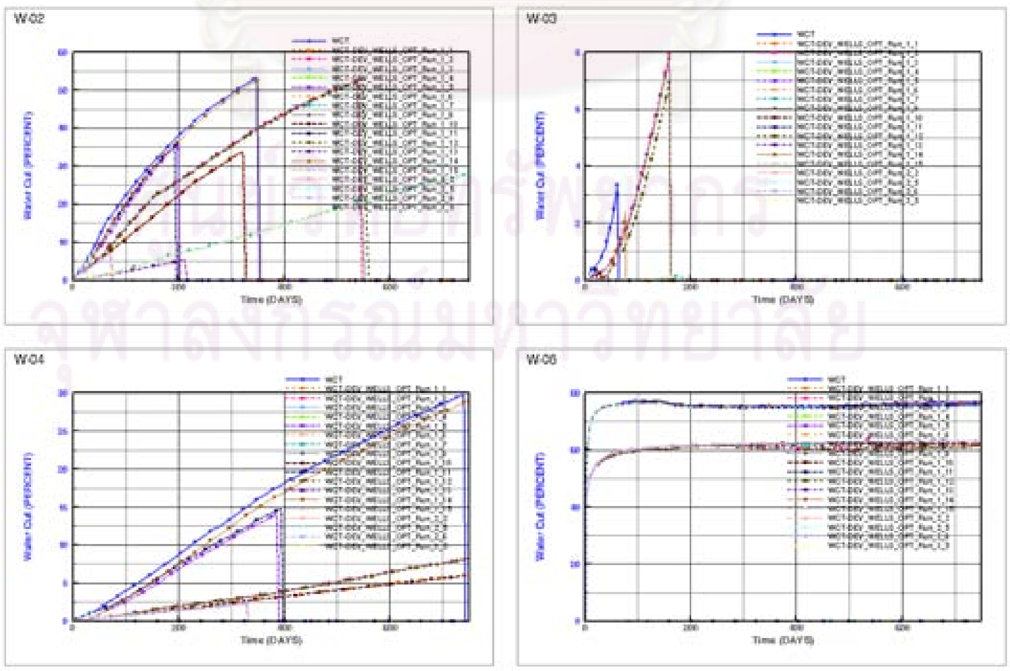


Figure 5.19: Water cut trend for all producers.

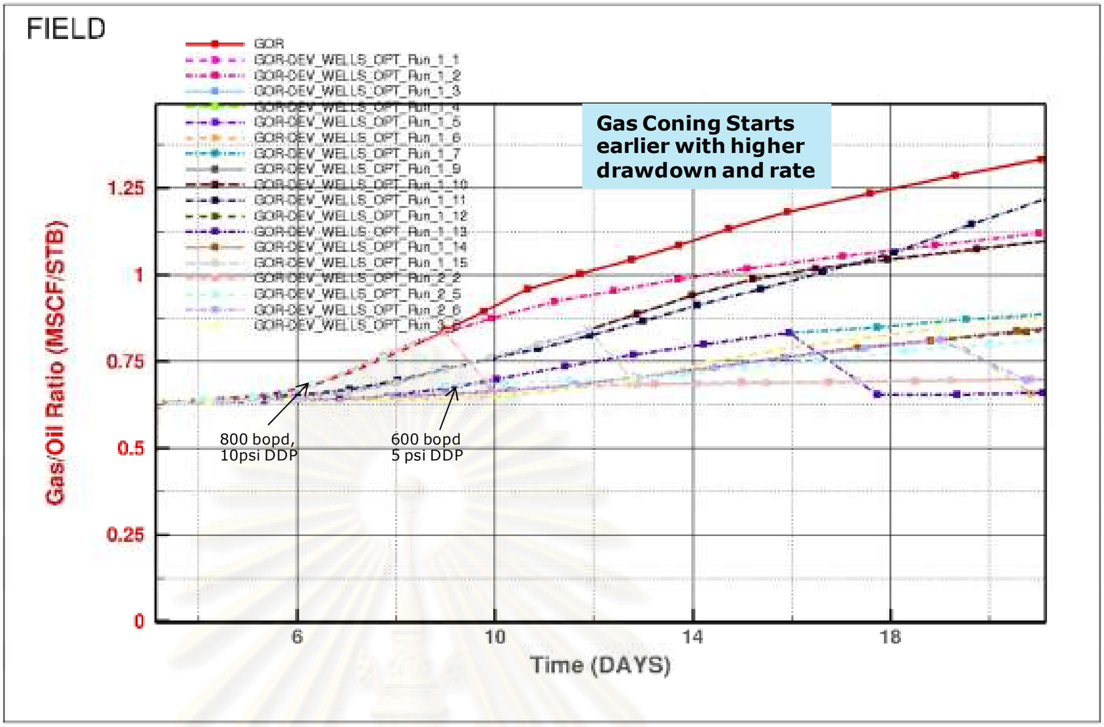


Figure 5.20: Gas coning at different oil rates and drawdown.

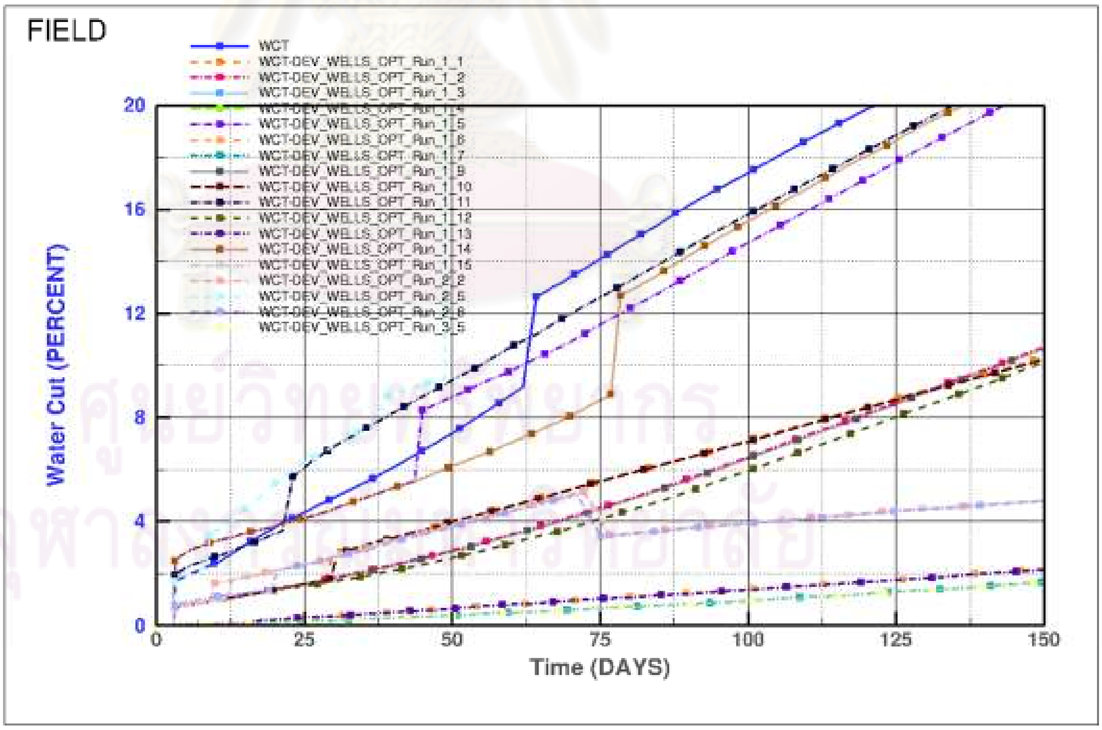


Figure 5.21: Water coning at different oil rates and drawdown.

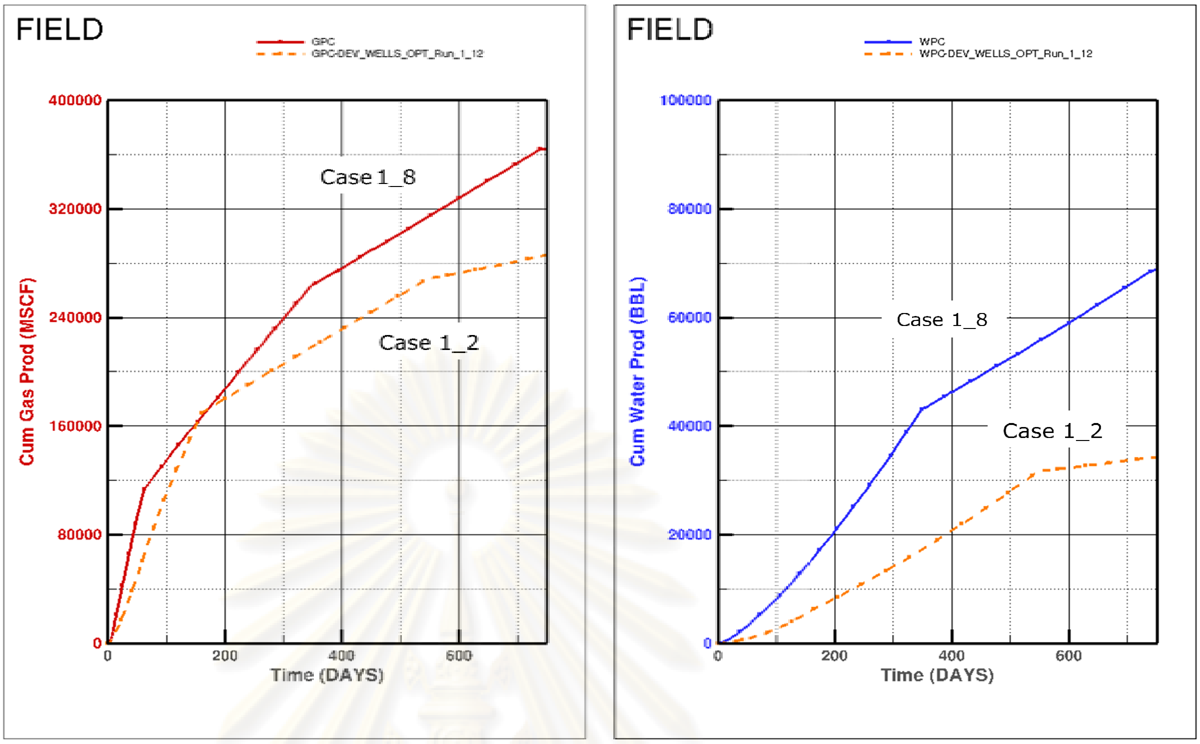


Figure 5.22: Cumulative water and gas production for Cases 1_8 and 1_2.

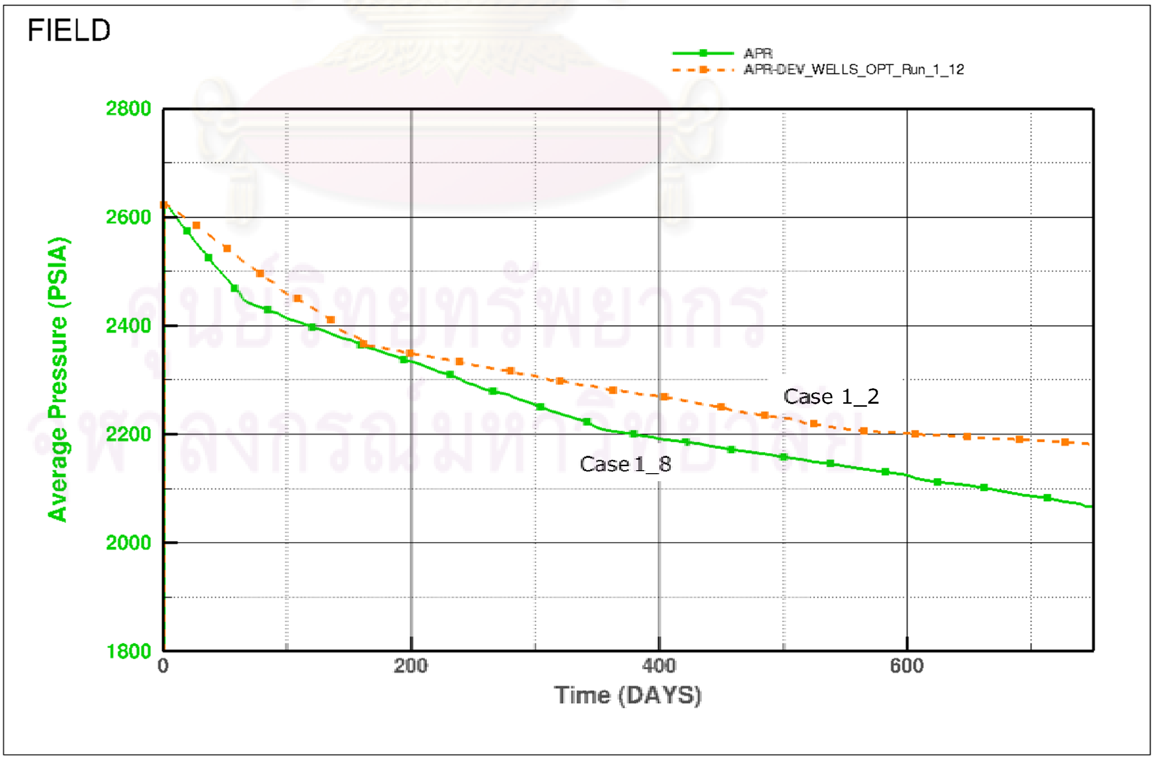


Figure 5.23: Reservoir pressure profiles for Cases 1_8 and 1_2.

5.3 Horizontal well recovery optimization

In this section, oil recovery from horizontal well will be discussed. All the deviated wells will remain shut-in. The location of horizontal well in the field is selected based on good porosity and permeability zone. Only one horizontal well is used for this model, as there is not enough OOIP to economically justify another horizontal well. Obviously two horizontal wells will give a better recovery as compared to one horizontal well, but all the deviated wells are already been drilled to delineate the reservoir. The deviated wells also penetrate other reservoirs in the field, so therefore, a horizontal well will be justified if it gives more recovery as compared to all existing deviated wells. In that case, the deviated wells will be utilized to produce from other penetrated reservoirs. The location of the horizontal well W-07H is shown in Figure 5.24.

For horizontal well, local grid refinement (LGR) is built in the area of the horizontal well (see Figure 5.25). The LGR is done to capture the gas and water coning effect more precisely. Especially in the cases where horizontal well is located very close to GOC or OWC, there are very few cells separating the contact and the horizontal well. With this LGR, the number of cells between the contacts and the horizontal well are increased. This will eliminate any chance of artificial coning due to well located in a cell next to the contact. The LGR constructed in the model is shown in Figure 5.25.

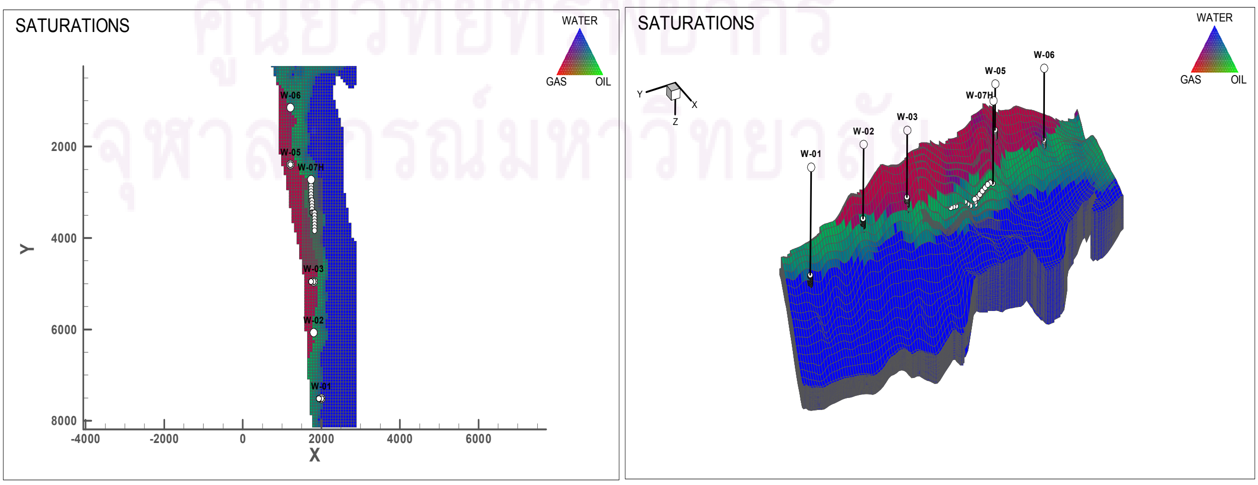


Figure 5.24: Plan and 3-d view showing location of horizontal well.

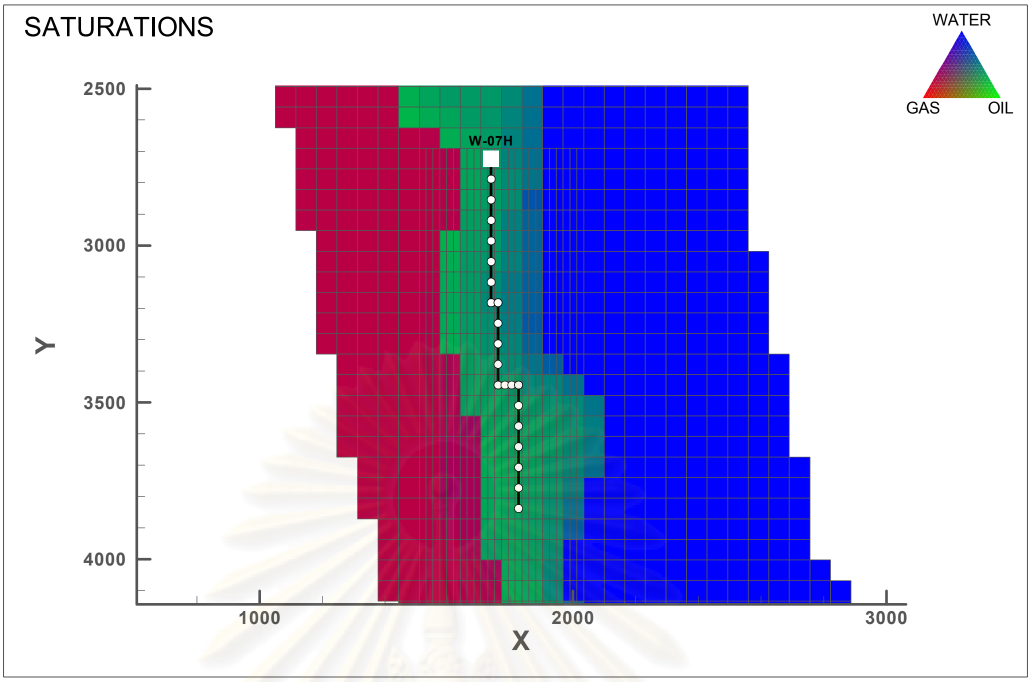


Figure 5.25: LGR constructed to study horizontal well performance.

5.3.1 Impact of different variables on horizontal well recovery – DoE runs

Multiple DoE runs (DoE theory explained in Section 2.2) were made to see the impact of initial production rates on the overall recovery of the horizontal well. The variables selected for DoE runs are dynamic variables. The following variables which are:

i. Initial production rate
ii. Bottom hole drawdown pressure
iii. Maximum GOR limit

The simulation results for experimental design are shown in Figures 5.26 to 5.29. Figures 5.26 and 5.27 show Pareto and Tornado charts to see the impact of different variables on horizontal well oil recovery. Both charts show that there is minimum impact of production rate on the oil recovery factor. Maximum GOR limit has the maximum impact on the oil recovery. This is because, in an oil rim, gas production starts from very beginning, and the wells produces for longer time with increased GOR limit and is shut in earlier with decreased GOR limit due to reaching the maximum GOR limit earlier. The drawdown pressure can also be related to the oil production as usually the drawdown is controlled by controlling the surface rate. In the simulation runs, they are taken as two separate controlling factors. It is also noted from these DoE runs that unlike in deviated wells case, horizontal well recovery is less affected by drawdown pressure.

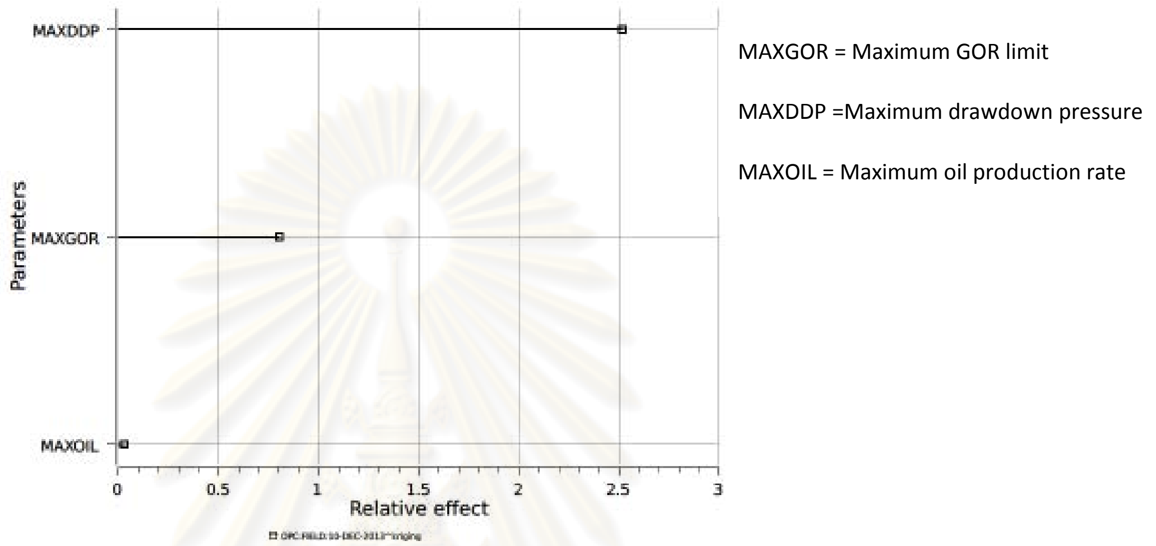


Figure 5.26: Pareto chart for impact of different variables on oil recovery.

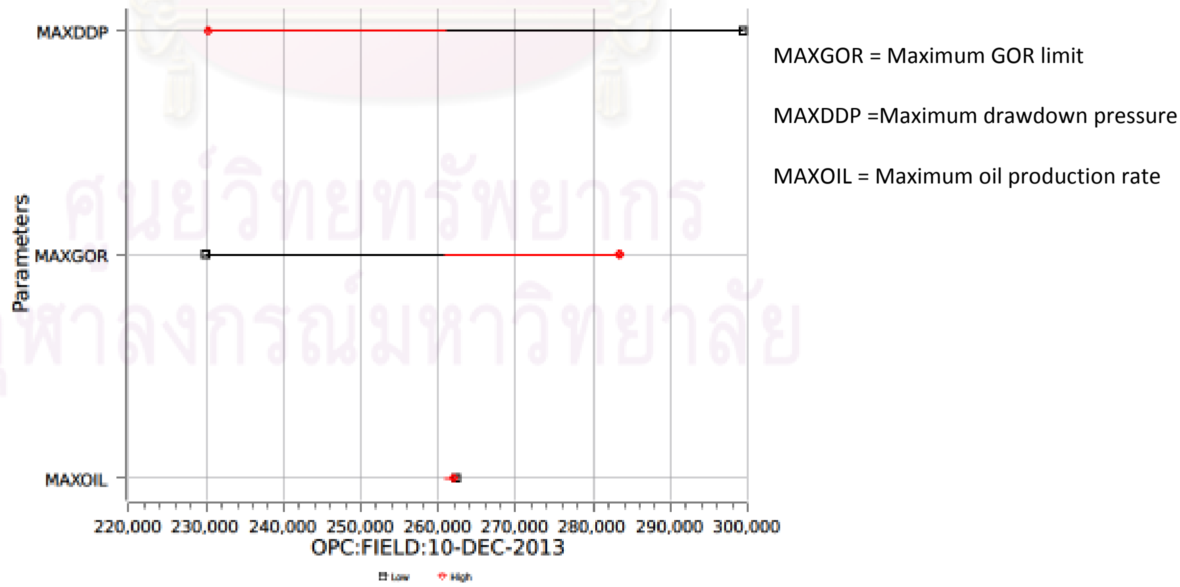


Figure 5.27: Tornado chart for impact of different variables on oil recovery.

In Figures 5.28 and 5.29, the relationship between these dynamic variables and oil recovery is shown. Figure 5.28 shows that the oil recovery decreases with increase in drawdown. Unlike deviated wells case, where oil recovery increases with increase in drawdown up to certain point and then starts decreasing with further increase in drawdown, the horizontal well shows a constant trend of decreasing oil recovery with increasing drawdown. This is due to the fact that in horizontal wells there is very little drawdown required to produce at higher rates (depending on reservoir quality) as more surface area is exposed to the reservoir.

Figure 5.29 shows increase in oil recovery with increase in GOR limit of the field. If there is no production constraint for a facility, then higher oil recoveries can be achieved by allowing the wells to produce at much higher GOR. But most of the time the GOR is maintained up to some level to meet the facility constraints.

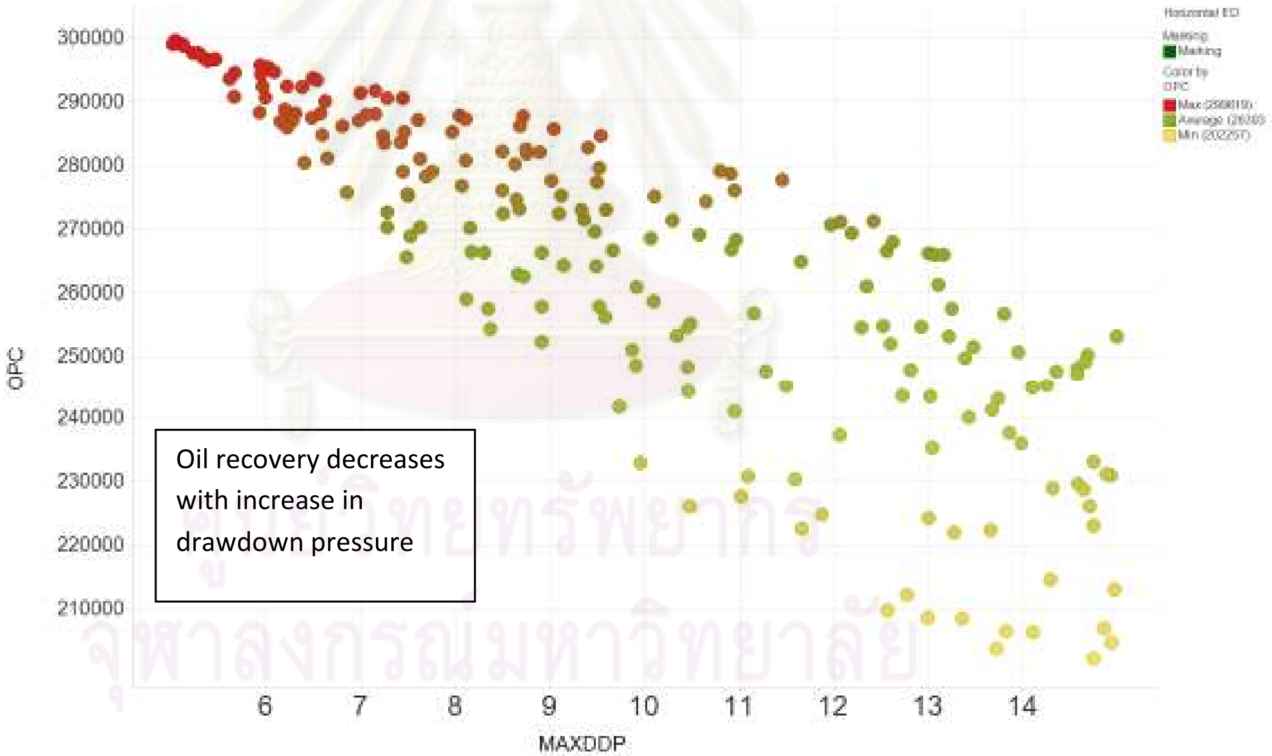


Figure 5.28: Effect of drawdown pressure on oil production cumulative (OPC).

The maximum GOR limit has the same effect on horizontal wells recovery as on deviated wells. As more gas is allowed to produce, the longer the well sustains and hence more oil is recovered. But this has to be done at the expense of losing reservoir energy. So, this strategy can significantly hamper any pressure maintenance strategy for the field.

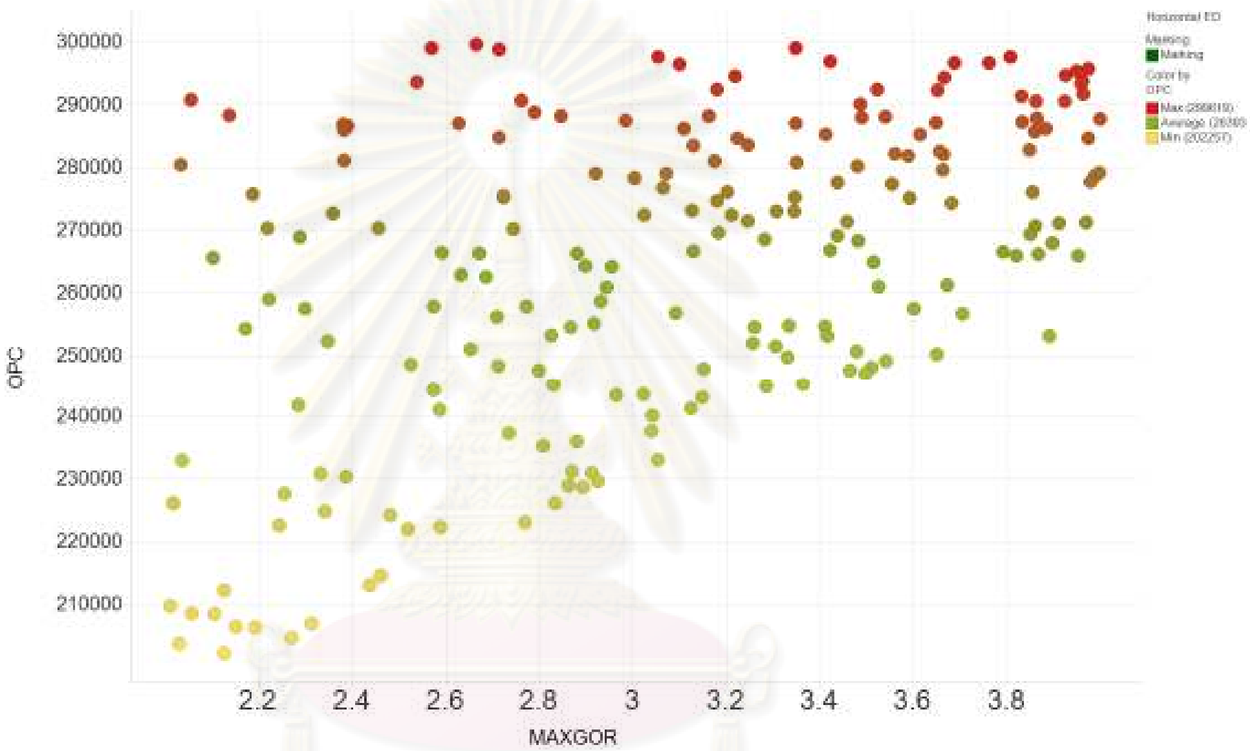


Figure 5.29: Effect of MAXGOR on oil production cumulative (OPC).

5.3.2 Horizontal well optimization – optimization runs

After the impact of different dynamic variables on oil recovery is studied, optimization runs are made by selecting range of different variables as shown in Table 5.2. The simulation is run in optimization mode. Multiple runs are made in order to use different combinations of the dynamic variables and estimate optimum oil recovery for each combination.

The oil production rate profile for optimization runs is shown in Figure 5.30. It is very obvious from the oil production profiles that the plateau is increased as the rate is lower. This is due to delay in gas and water coning. In an oil rim, gas coning is very critical as once the gas cones in, it is almost impossible to control gas coning. After coning starts, the oil rate starts declining and the well is shut in after reaching maximum GOR (MAXGOR) limit. The time to compare the recoveries for different cases is where all production rates merge and after that the oil production rate is considered too low to produce the well economically. As discussed in deviated wells case in Section 5.2.3, the cut-off time for recovery comparison is selected as 750 days and all the recovery comparisons will be done at this time.

Table 5.2: Description of optimization cases – horizontal well.

	Run Label	MAXOIL	MAXDDP	MAXGOR
1	HZ_Well_Centre_Opt_Run_1_1	1200	10	2
2	HZ_Well_Centre_Opt_Run_1_2	1200	10	3
3	HZ_Well_Centre_Opt_Run_1_3	600	15	3
4	HZ_Well_Centre_Opt_Run_1_4	1200	10	1
5	HZ_Well_Centre_Opt_Run_1_5	800	15	2
6	HZ_Well_Centre_Opt_Run_1_6	600	5	1
7	HZ_Well_Centre_Opt_Run_1_7	1200	5	2
8	HZ_Well_Centre_Opt_Run_1_8	1400	15	3
9	HZ_Well_Centre_Opt_Run_1_9	800	10	3
10	HZ_Well_Centre_Opt_Run_1_10	1000	10	2

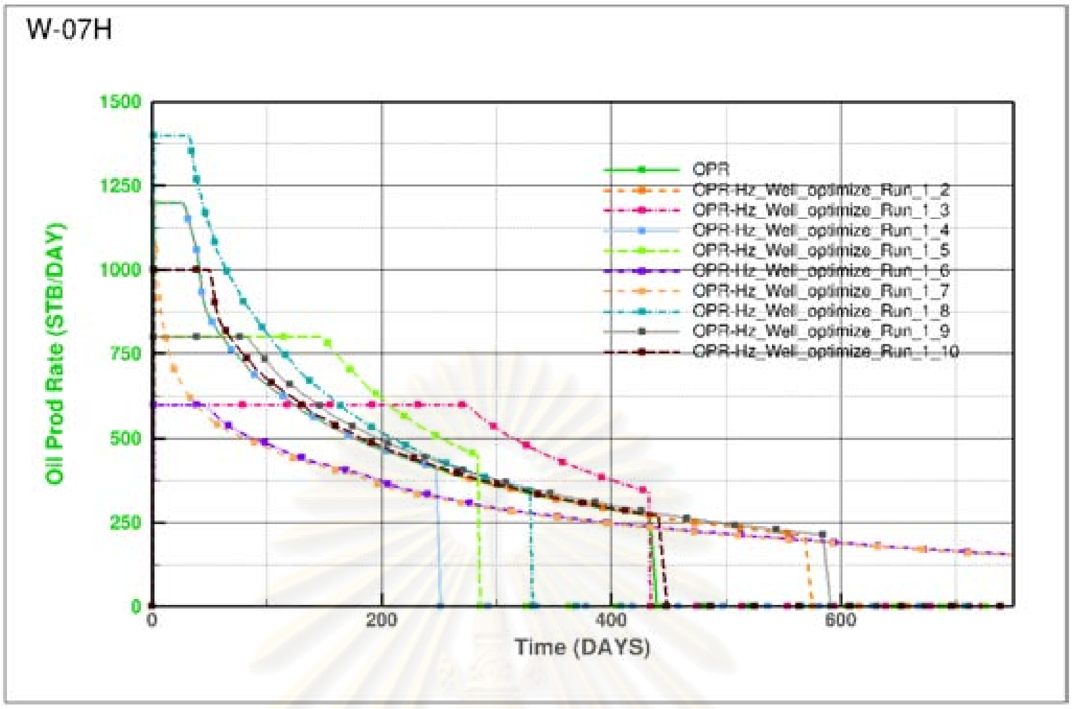


Figure 5.30: Horizontal well optimization runs for oil production rate.

Figure 5.31 shows oil recovery at different optimization runs. The most optimized case is when the well is flowing at 800 bopd rate with 10 psi drawdown pressure. The maximum GOR limit for this case is 3000 scf/bbl. The optimized case when horizontal well is producing under primary recovery gives an oil recovery of 16.5%. Therefore, the primary recovery when single horizontal well is producing is 1.5% more than when the same reservoir is produced by deviated wells. The deviated wells were optimized for completion and dynamic variables as discussed in Section 5.2.3. In this case, the horizontal well is not yet optimized for lateral length and location of horizontal well with respect to GOC and OWC. This will be done in Section 5.3.3.

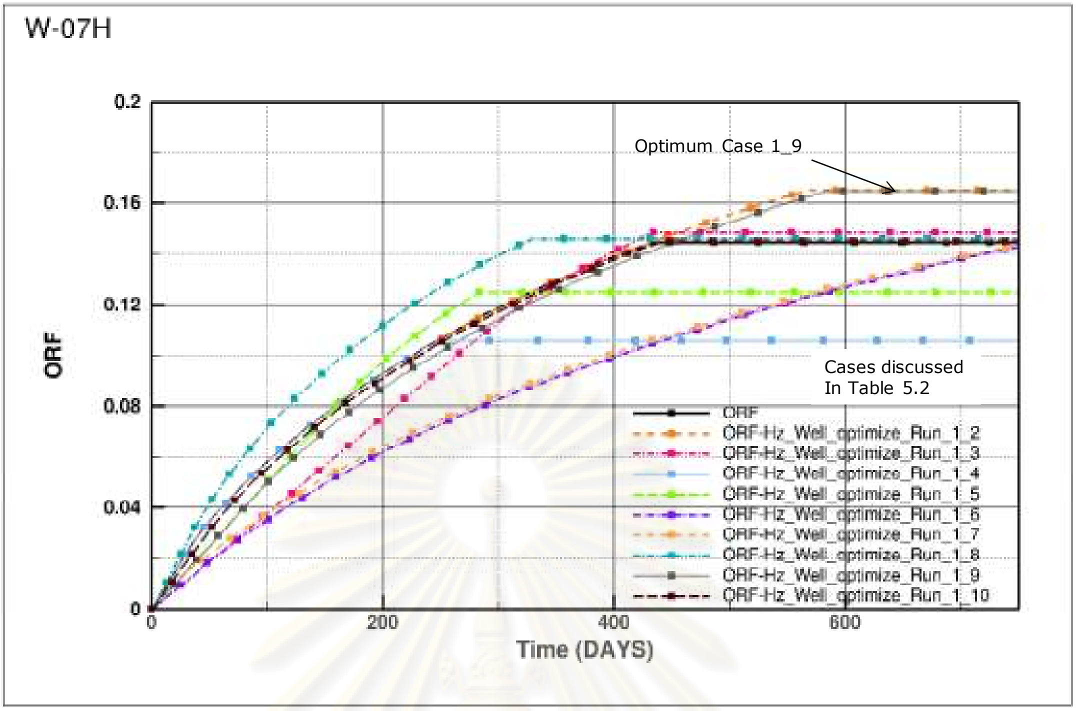


Figure 5.31: Horizontal well optimization runs for oil recovery.

Figure 5.32 shows GOR and water cut trends for all the runs. It should be noted that the gas coning time in horizontal well case is delayed as compared to that in deviated well case. Also, it can be seen from Figure 5.32 that gas coning starts earlier at very high rates and delays as the oil production rates and drawdown pressure are lowered. For the optimum case, the gas breakthrough doesn't happen at very early life of production. It starts after 100 days. At very low rates, the gas coning and water coning is further delayed. But at these very low rates (<800 bopd), the oil recovery is very slow. It takes several years to produce the same amount of oil. But for the same time period selected based on the oil production profile as discussed above, production at very low rate gives less recovery. So, the production rate and recovery becomes un-economical.

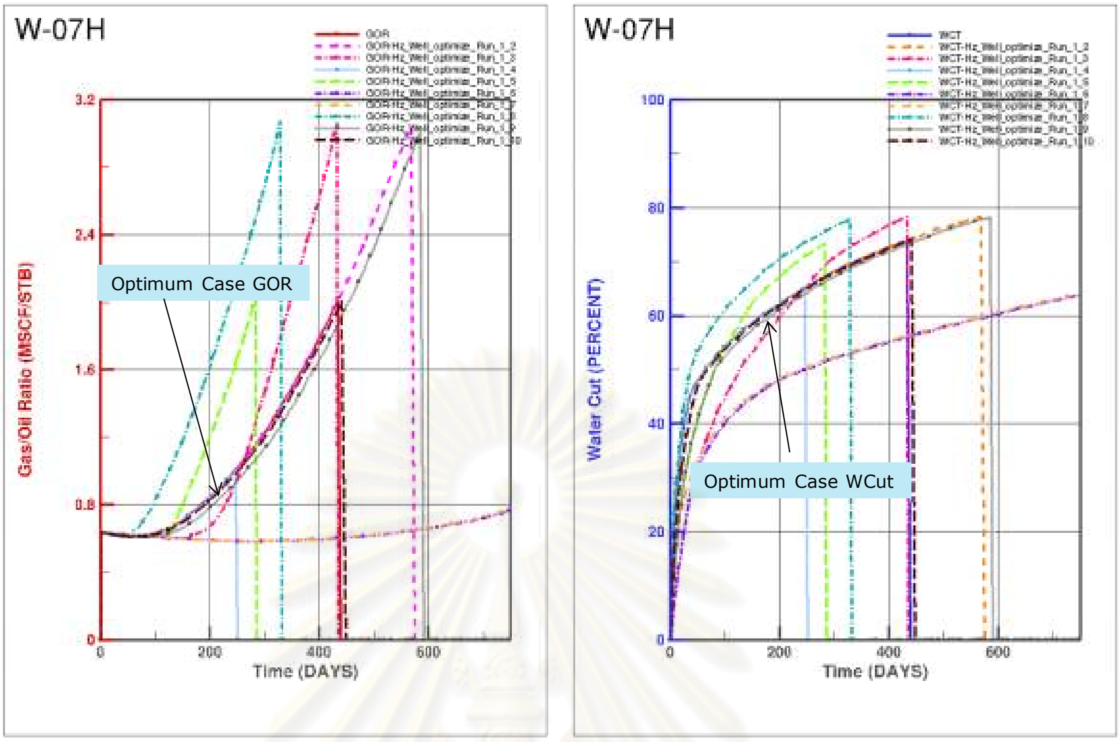


Figure 5.32: GOR and water cut trends for optimization runs.

In Figure 5.33, the gas coning for horizontal well case is studied. The GOR is plotted against time. It can be seen that for optimum case scenario when the well is producing at 800 bopd with 10 psi drawdown pressure, the gas coning is delayed as compared to when well is producing at high drawdown pressure. Also note that the gas breakthrough occurs after 135 days in horizontal well case as compared to only 6 days in optimized deviated well case. There is yet further room for horizontal well to be optimized for lateral length and position of the well with respect to GOC and WOC.

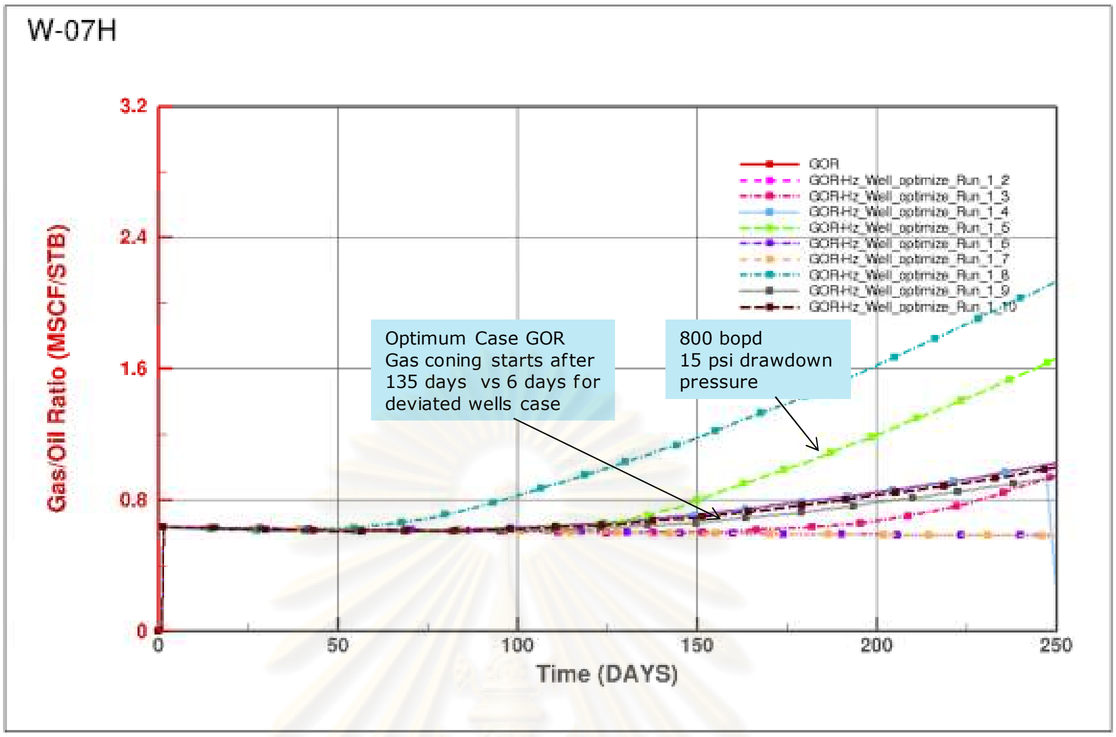


Figure 5.33: Gas coning at different optimization runs.

5.3.3 Effect of lateral length on horizontal well recovery

In this section, we will discuss how lateral length of horizontal well producing from thin oil rim affects the oil recovery. For this purpose, simulation runs are made with horizontal wells having different lateral lengths. The range of lateral length is from 550ft to 2000ft. The range is selected to have enough lateral length to get representative results. Generally, it is desired to have longer wells than shorter ones. But it also depends on the reservoir quality and type of drive mechanism. In strong edge and bottom water drives, horizontal lengths are not extended much to avoid well exposure to possible water zone. We'll discuss the effect of increasing horizontal length in an oil rim environment in this section.

With the same location of horizontal well discussed in Section 5.3.2, simulation runs are made with varying horizontal lateral lengths. For this purpose, separate simulation runs are made for each lateral length. The lateral lengths used for this purpose are 550ft, 800ft, 1000ft, 1200ft, 1400ft, 1800ft and 2000ft. The oil production profile for different lateral lengths is shown in Figure 5.34. All the cases are run with same initial oil production rate of 800 BOPD. It can be seen from Figure 5.34 that as the lateral length of horizontal well is increased, the plateau for oil production is also increased. For shorter laterals, the coning for gas and water starts earlier. This is because of less surface area available for horizontal well in shorter laterals than in longer laterals and higher drawdown required to produce at same oil rate.

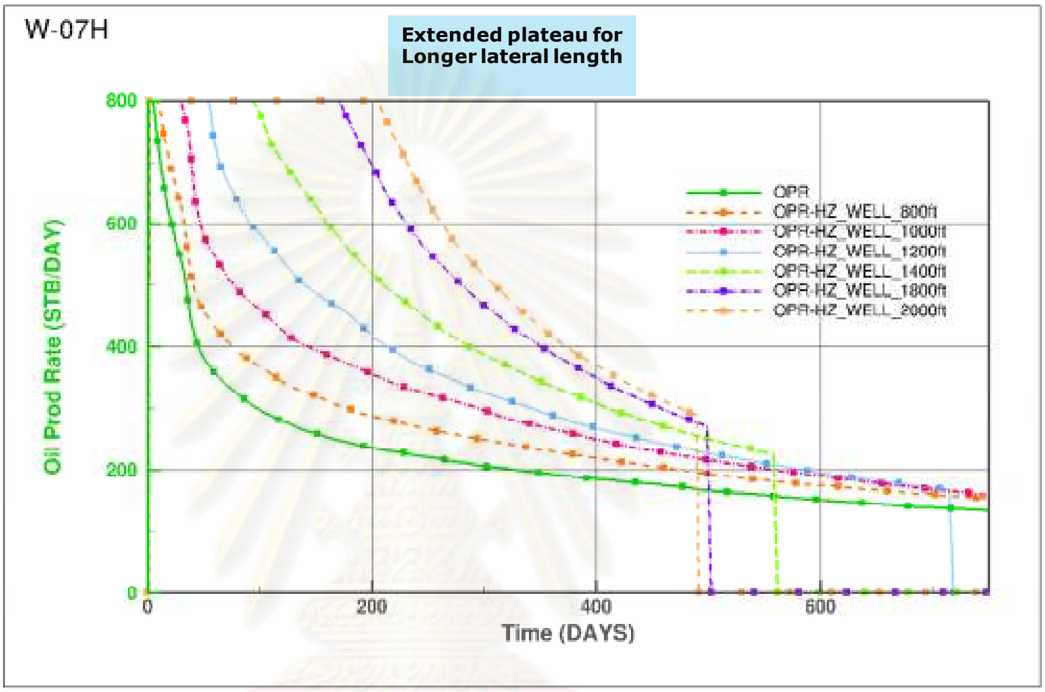


Figure 5.34: Oil rate profile for different lateral lengths.

Figure 5.35 shows oil recovery for different lateral lengths. As the length of the horizontal section increases, the oil recovery also increases. Again, this is mainly because of sustained production for a longer period for longer laterals as discussed earlier. The longer laterals are more exposed to reservoir. In this particular reservoir, the well is not extending to water zone even for longest lateral length of 2000ft. Therefore, well with longer lateral length are more exposed to reservoir and hence sustain oil production for longer time by delaying water and gas coning.

However, it should be noted from Figure 5.35 that after 1200ft lateral length, the rate of increase in oil recovery is reduced. The increase in oil recovery from 1800ft to 2000ft is very small as compared to increase from 800ft to 1000ft or 1200ft to 1400ft. It is very important to evaluate whether an increase in recovery due to increase in lateral length also justifies the cost for drilling any additional footage. In our case, we will assume that the maximum recovery case is the most optimum case. So by optimizing the lateral length of horizontal well, the recovery factor is increased from 16.5% to 18.7%.

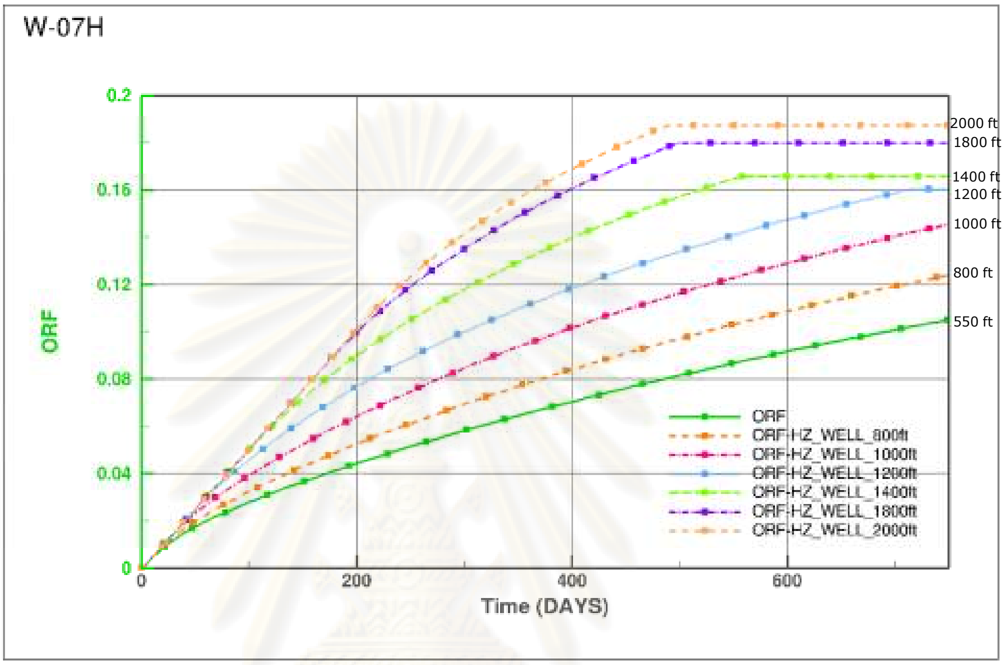


Figure 5.35: Oil recovery for different lateral lengths.

The gas coning and water coning behaviors are shown in more detail in figures 5.36 and 5.37. It can be seen that both gas and water breakthrough time increases as the length of horizontal section is increased. This makes the longer well to produce for longer time before shutting in due to reaching water cut or maximum GOR limit, hence improving the oil recovery. The oil recovery for 2000-ft horizontal well is estimated as 18.7%. All other parameters are identical for flow as discussed earlier.

Therefore horizontal well with optimized rate, drawdown pressure and lateral length gives 3.7% more recovery than optimized deviated wells case.

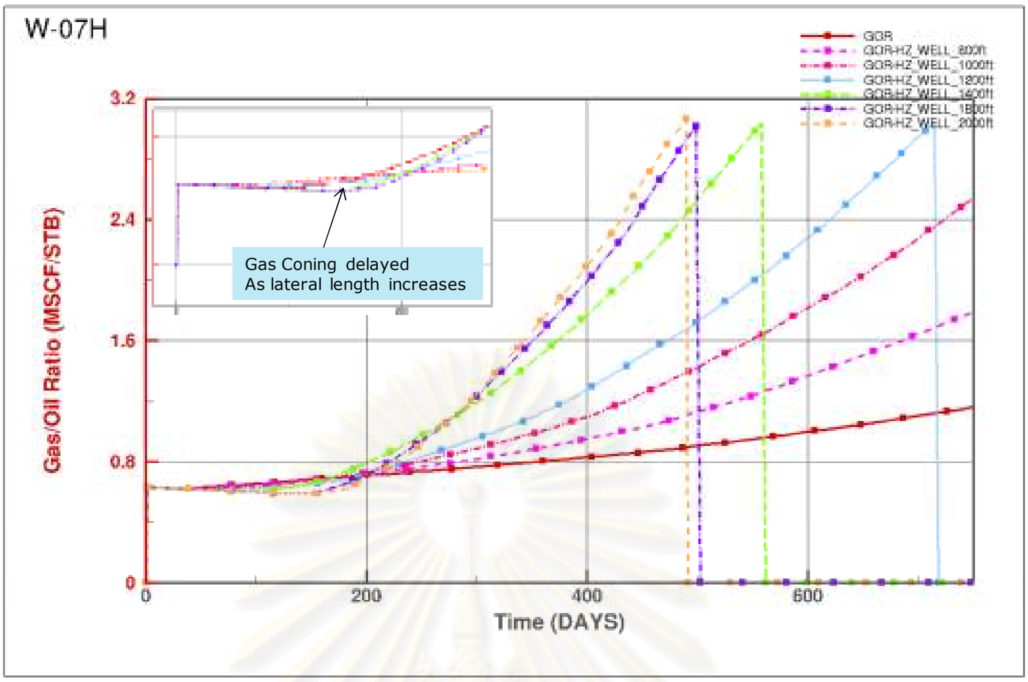


Figure 5.36: Gas coning profile for different lateral lengths.

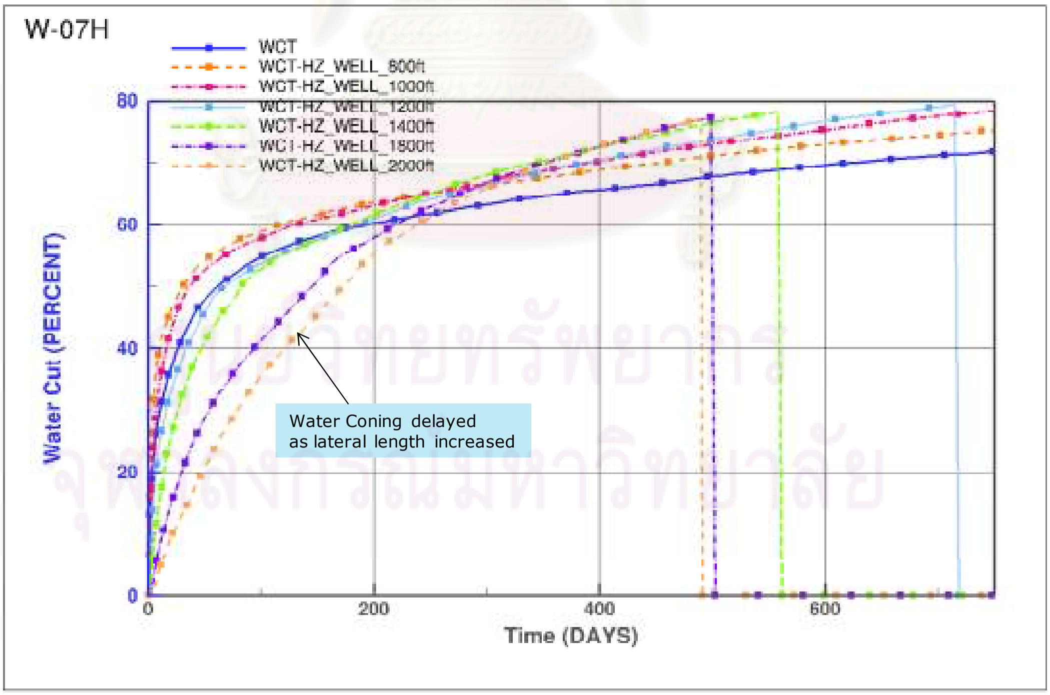


Figure 5.37: Water coning profile for different lateral lengths.

5.3.4 Effect of horizontal well location on horizontal well recovery

In this section, effect of changing location of horizontal well with respect to the GOC and WOC will be discussed. In all the previous cases, the horizontal well was placed in the centre of GOC and OWC. Three cases will be discussed in this section:

1) Horizontal well closer to OWC
2) Horizontal well in the center of OWC and GOC
3) Horizontal well closer to GOC

The location of the well for all three cases in the model is shown in Figures 5.38, 5.39 and 5.40.

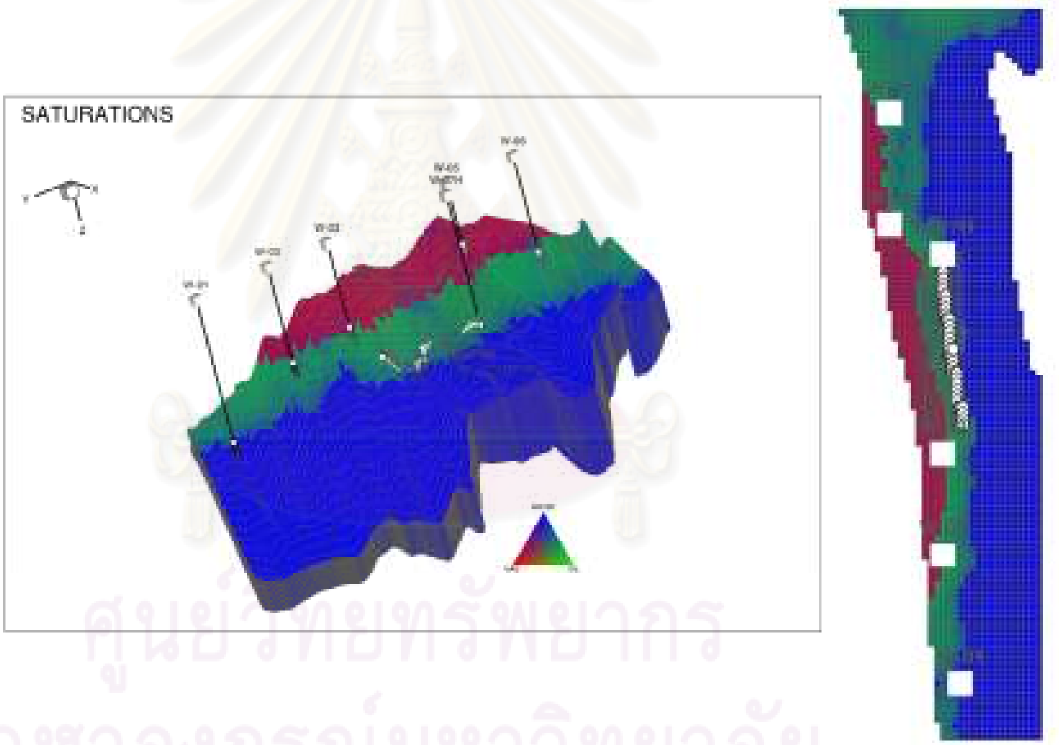


Figure 5.38: Horizontal well closer to OWC.

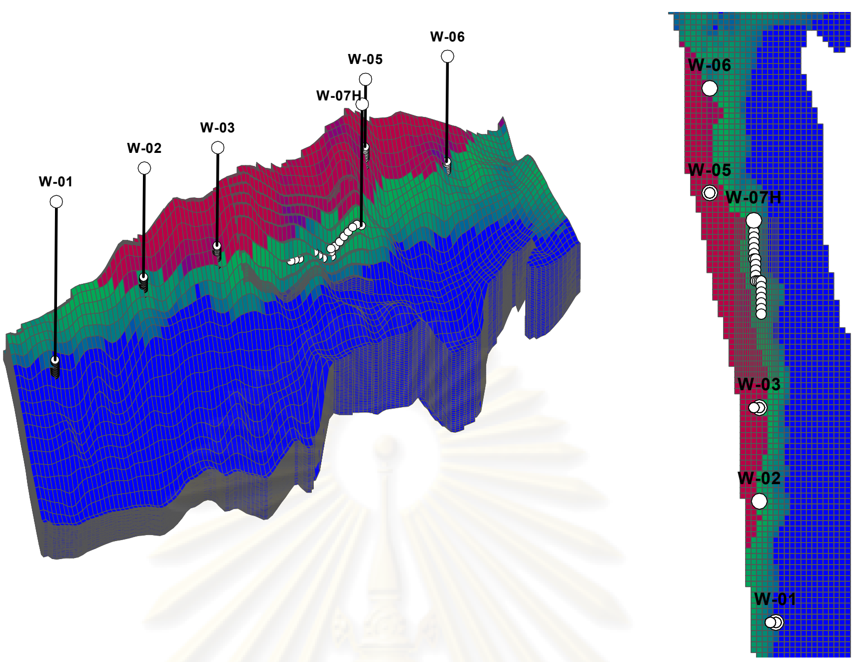


Figure 5.39: Horizontal well at center of OWC and GOC.

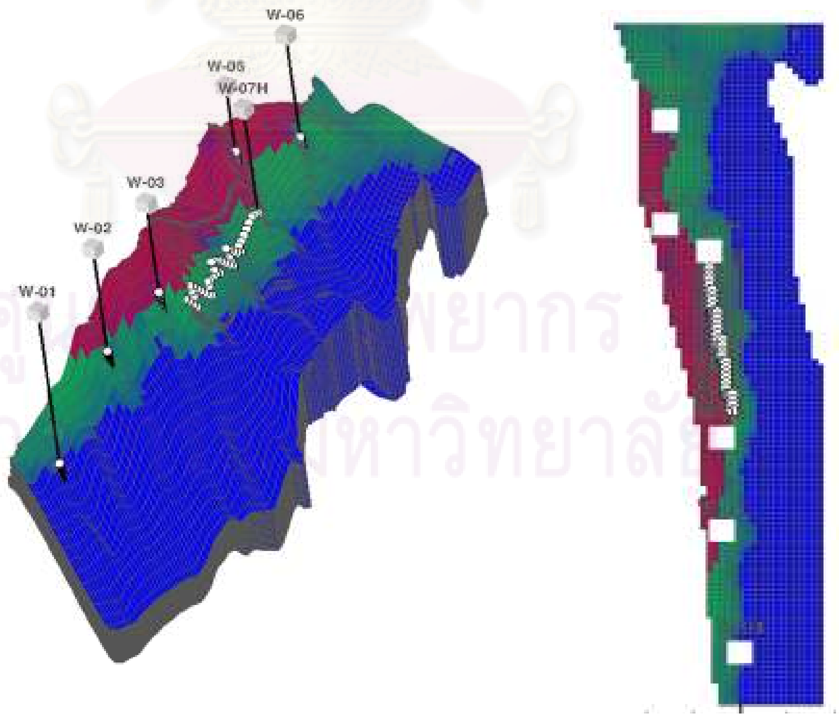


Figure 5.40: Horizontal well closer to GOC.

Placement of horizontal wells is very critical especially in an oil rim reservoir, where gas and water coning can impact the oil recovery significantly. There are certain factors like reservoir permeability, anisotropy ratio (kv/kh), fluid viscosities, production rates and drawdown pressure that control the coning. But along with these factors, the placement of horizontal well with respect to the distance from OWC and GOC also plays pivotal role in controlling the coning and hence enhancing the oil recovery.

The oil production profile for all three well placements is shown in Figure 5.41. The well closer to the GOC has longer plateau than other two cases. With the well being closer to GOC, as the gas coning starts, there is a very sharp decline in oil rate and the well is shut-in after reaching MAXGOR limit of 3000 scf/bbl. The well closer to OWC doesn't have a very long plateau, but the decline rate is less steep than the other two cases, and the production period is extended in this case. Since the gas is much more mobile than water, the gas breakthrough in the well closer to gas cap occurs very early. Once the gas starts coning, the GOR increases rapidly, and well is shut-in at high GOR constraint (see Figure 5.43).

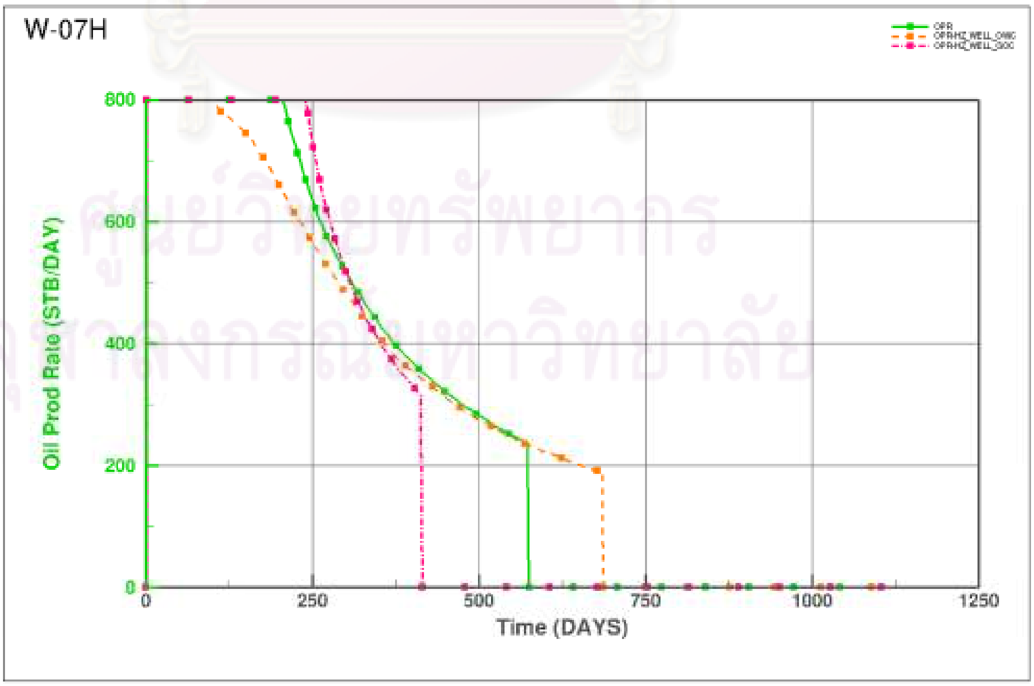


Figure 5.41: Oil rates for different horizontal well locations.

The oil recovery in each case is shown in Figure 5.42. The oil recovery is 19.3% when the well is closer to OWC, 18.7% when the well is at center of two contacts, and 15.3% when the horizontal well is drilled closer to the GOC.

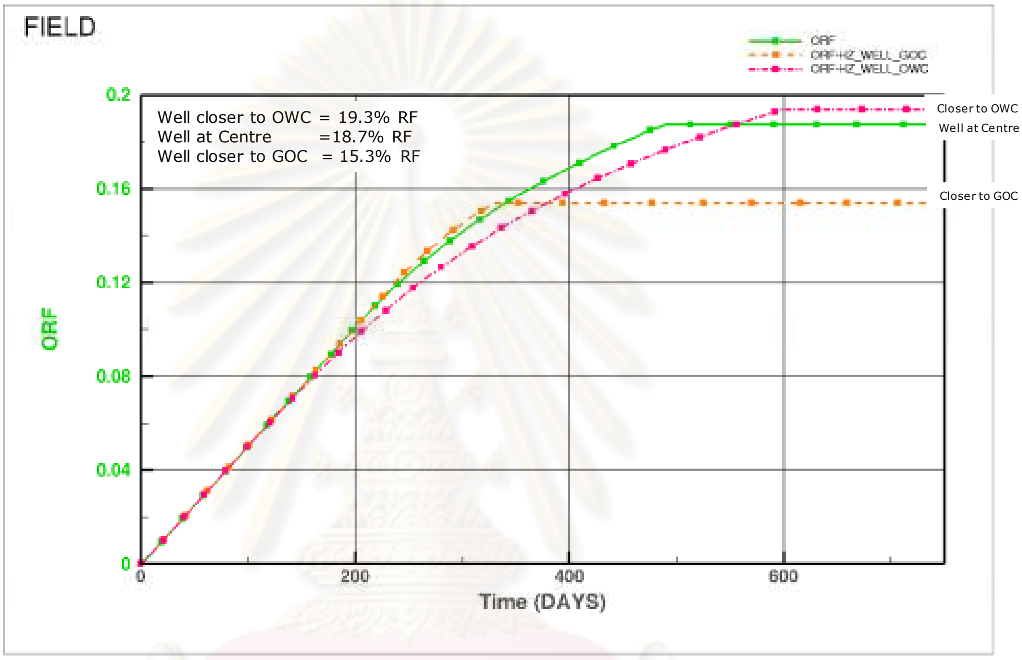


Figure 5.42: Oil recovery factors for different horizontal well locations.

Therefore, the oil recovery from this oil rim reservoir is further improved by optimum placement of horizontal well. After this optimization, the recovery is increased to 19.3% as compared to 18.7% in the previous case where the horizontal well was drilled at the center of OWC and GOC. The increment from base case after this optimization is 7.7%.

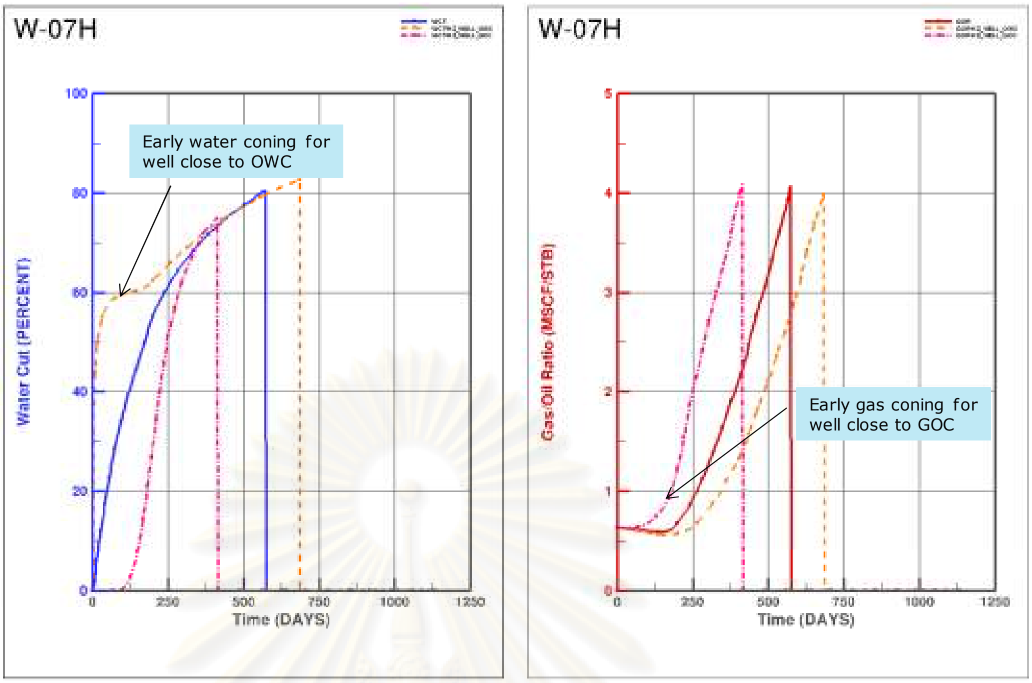


Figure 5.43: Water cut and GOR comparison for different horizontal well locations.

5.3.5 Optimum recovery case for horizontal wells

In this section, results from all the horizontal well cases will be compared and the optimum case is identified. This helps in better planning of horizontal wells in a thin oil rim environment. Obviously, the recovery also depends on static variables of reservoir and will vary from reservoir to reservoir. This study gives a direction as to what factors should be considered to improve recovery when planning to drill a horizontal well in an oil rim.

The comparison of all horizontal well cases is shown in Figure 5.44. It includes optimized cases for dynamic properties, horizontal lateral length and distance from the contacts. The maximum recovery (19.3%) is achieved when the horizontal well is drilled closer to the OWC with lateral length of 2000-ft.

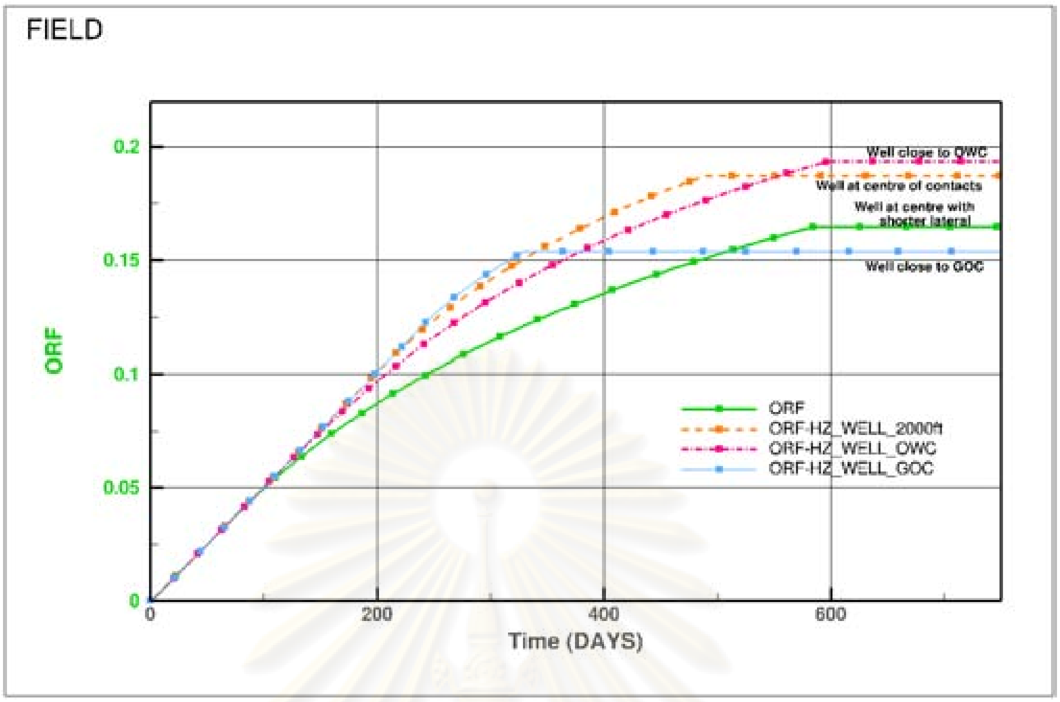


Figure 5.44: Recovery comparison for all horizontal well cases.

5.4 Comparison of primary depletion scenarios

The optimized case for all primary depletion scenarios is compared in Figures 5.45 and 5.46. Figure 5.45 compares the oil recovery for all optimized scenarios for primary depletion. The base case is where the reservoir is being depleted by deviated wells and there was no optimization done for rates or completion. The recovery for this case is estimated as 11.6%. The optimized deviated wells case is where reservoir is depleted by deviated wells. But in this case, the deviated wells were optimized first for completion and then for dynamic variables. The recovery factor achieved in that case is 15%. Then, the deviated wells were replaced by a horizontal well and reservoir was depleted by single horizontal well. Multiple horizontal wells cannot be drilled due to the small size of the reservoir. The horizontal well was first optimized for dynamic variables and then for lateral length and distance from OWC and GOC. The optimized horizontal well case gives an oil recovery of 19.3% which is 7.7% incremental to base recovery and 4.3% incremental to optimized deviated wells case. Therefore, drilling horizontal wells in a thin oil rim reservoir is more efficient and economical as compared to several deviated wells. Especially in a situation, where existing deviated wells can be utilized to drain reserves from other reservoirs, it is more economical and viable to drill horizontal well(s) for these thin oil rim reservoirs.

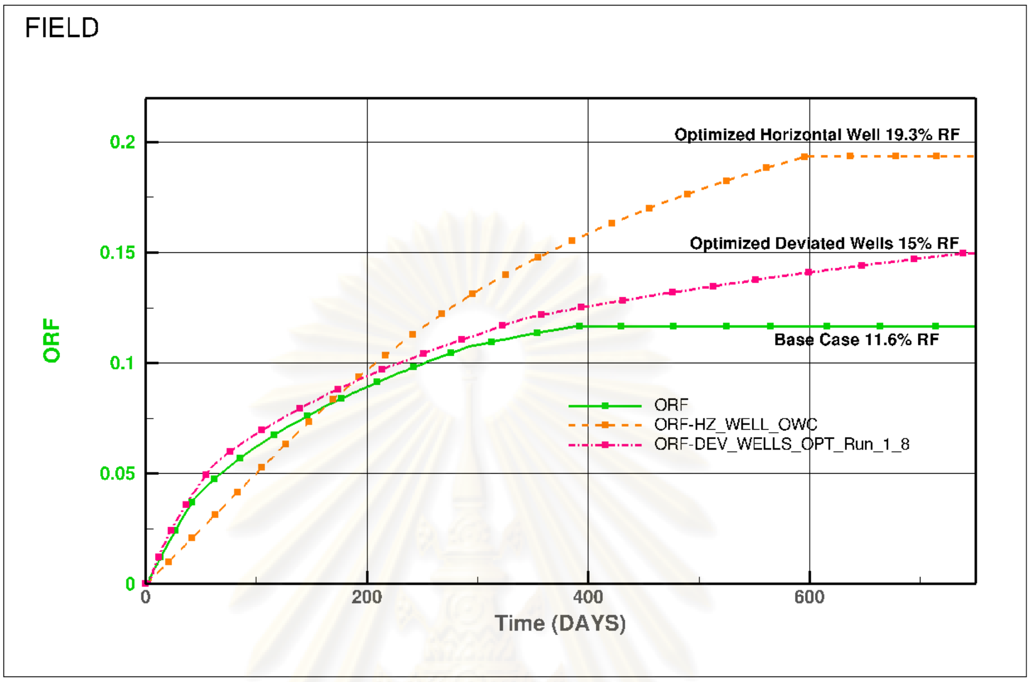


Figure 5.45: Comparison of recoveries - optimized primary depletion scenarios.

The oil rate comparison for these three cases is shown in Figure 5.46. The oil rate comparison shows that the horizontal well produces for longer time at higher rates. The decline rate for horizontal well is much less than deviated wells case. This is because in deviated well case, the water and especially gas coning is very prominent. As the water and gas hits the wellbore, the well experiences a very sharp decline. The well eventually shuts off due to high water cut or exceeding maximum gas production limit.

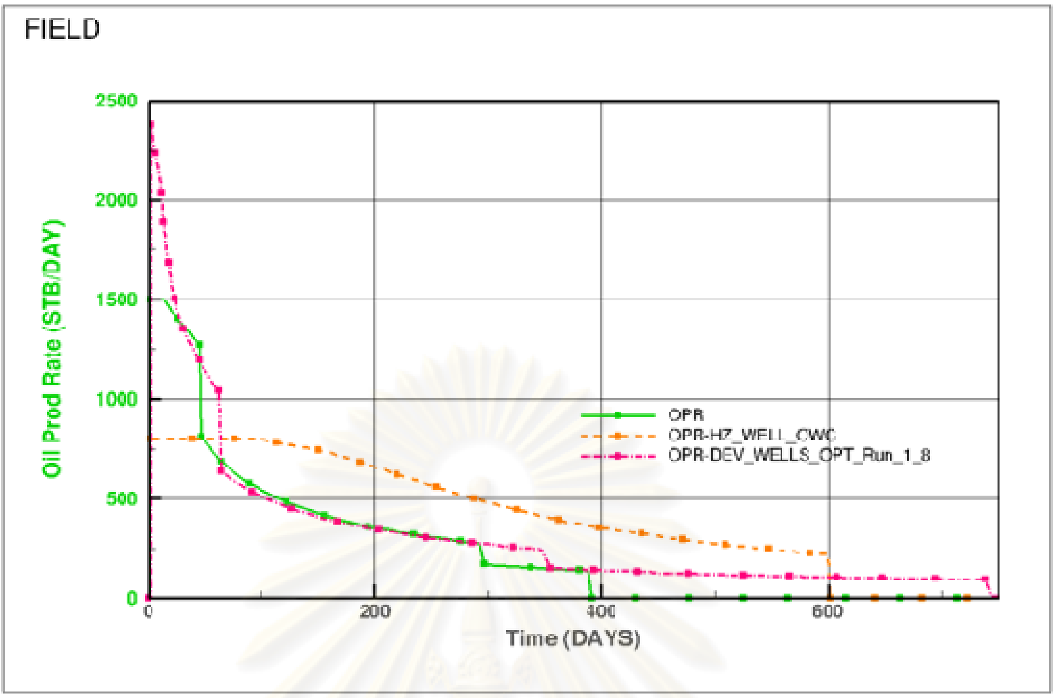


Figure 5.46: Comparison of oil rates - optimized primary depletion scenarios.

5.5 Pressure maintenance with water injection

Combination of gas cap and water drive in an oil rim is theoretically considered to be a very effective drive mechanism. But in practice, primary recovery in this type of reservoirs is very low. This is due to oil smearing or gas cap expansion. In both cases the oil trapped behind the gas is difficult to recover. Force balance plays an important role in recovering oil from oil rim reservoir. To keep this force balance, usually wells have to be produced at uneconomically low rates that do not justify the operating expenses. Therefore, pressure maintenance either by injecting water into aquifer or gas injection in gas cap, can significantly increase recovery from an oil rim.

5.5.1 Water injection with deviated wells producing

Pressure maintenance is done in the subject reservoir by water injection (WI). A peripheral water injection design (injection from reservoir extremes) is adopted in this case (see Figure 5.47 for illustration). One reason for adopting this method here is the utilization of existing wells without drilling additional injectors. Wells W-01 is the most downdip well and W-06 is a poor performer as far as oil production is concerned. For injection rate, a reservoir voidage ratio of 1.0 is used, which means the water injected is equal to the fluids (oil, water and gas) produced from the reservoir

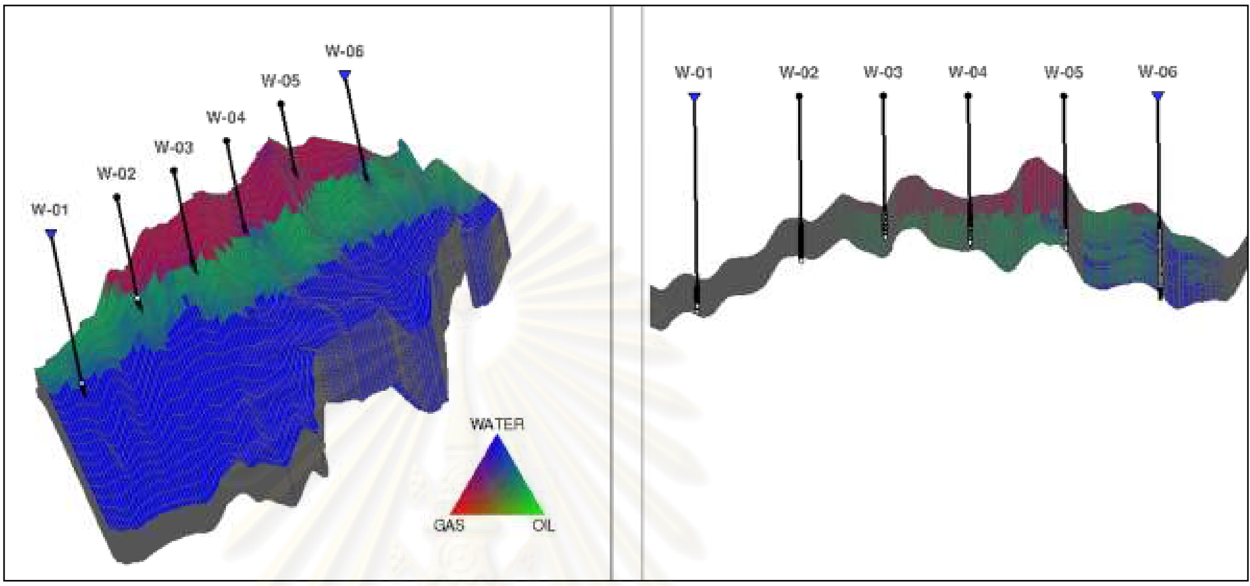


Figure 5.47: Illustration of peripheral water injection.

The oil recovery estimated with water injection is compared with primary recovery cases for deviated wells in Figure 5.48. With water injection, the recovery is increased to 21% from 15% in optimized deviated well case. The deviated well optimized case discussed in Section 5.2.3 is used, and water injection done in wells W-01 and W-06. With water injection in this oil rim reservoir, an increment of 6% RF is achieved.

The reason for this increment is studied in water injection performance curves from Figure 5.49 to 5.51. In Figure 5.50, GOR and WOR versus oil recovery factor (ORF) charts for water injection and without water injection for deviated wells case are shown. It can be seen that in case of WI, the GOR curve is pretty flat as compared to the GOR curve without water injection. Also in WOR vs ORF curve, the increase in rate of WOR for case without water injection is very steep after water breakthrough occurs, whereas rate of WOR increase with ORF is much less in water injection case. Both curves show that both gas and water coning are reduced when the reservoir is produced under water injection.

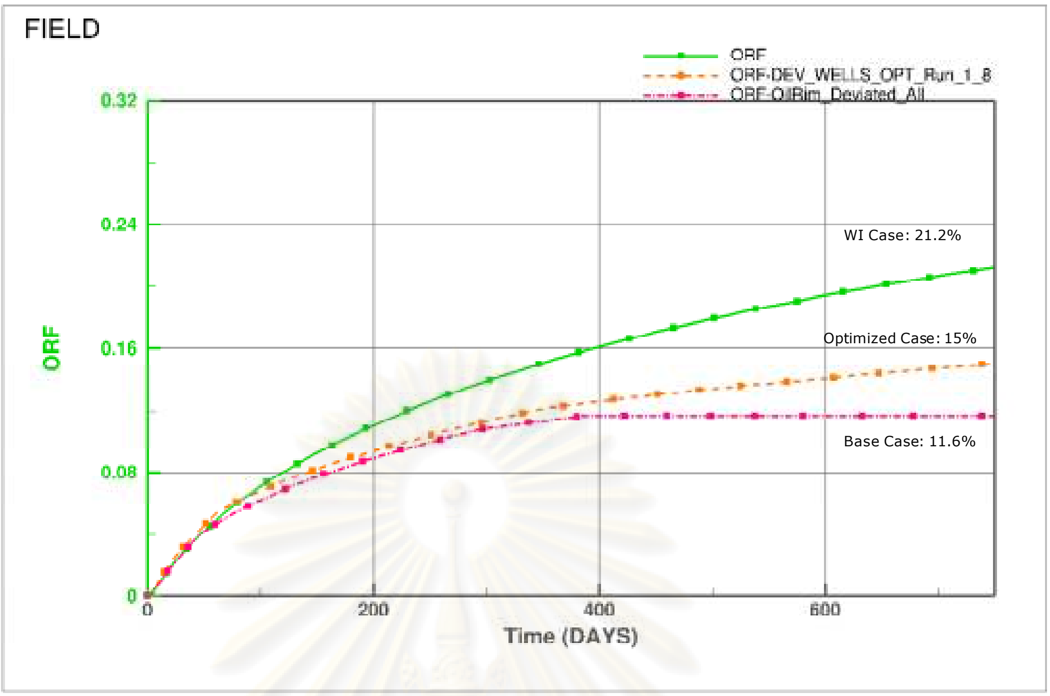


Figure 5.48: WI recovery – deviated wells case.

The oil rate comparison for with and without water injection is shown in Figure 5.50. These oil rates are at the field level. The sudden drop in oil rate at certain points when there is no water injection done as seen in green line in Figure 5.50 is due to deviated wells shutting in at high water cut or reaching MAXGOR limit at those points. Again, this happens due to water and gas coning, whereas in case of water injection, the oil rate is declining consistently and not dropping sharply at any point.

With water injection, the reservoir pressure is maintained and the gas is not allowed to expand neither oil smearing into the gas cap happens. With less gas expansion, oil is not trapped behind the gas. Also with less gas expansion, less gas is produced from the perforated interval due to gas coning. The comparison of reservoir pressure profile for base case, optimized deviated wells case and WI case is shown in Figure 5.51.

So with water injection, the oil recovery in deviated wells case is increased to 21% as compared to optimized deviated well case recovery of 15% and base case recovery of 11.6%. So an increment of 6% RF is gained by water injection in this oil rim reservoir.

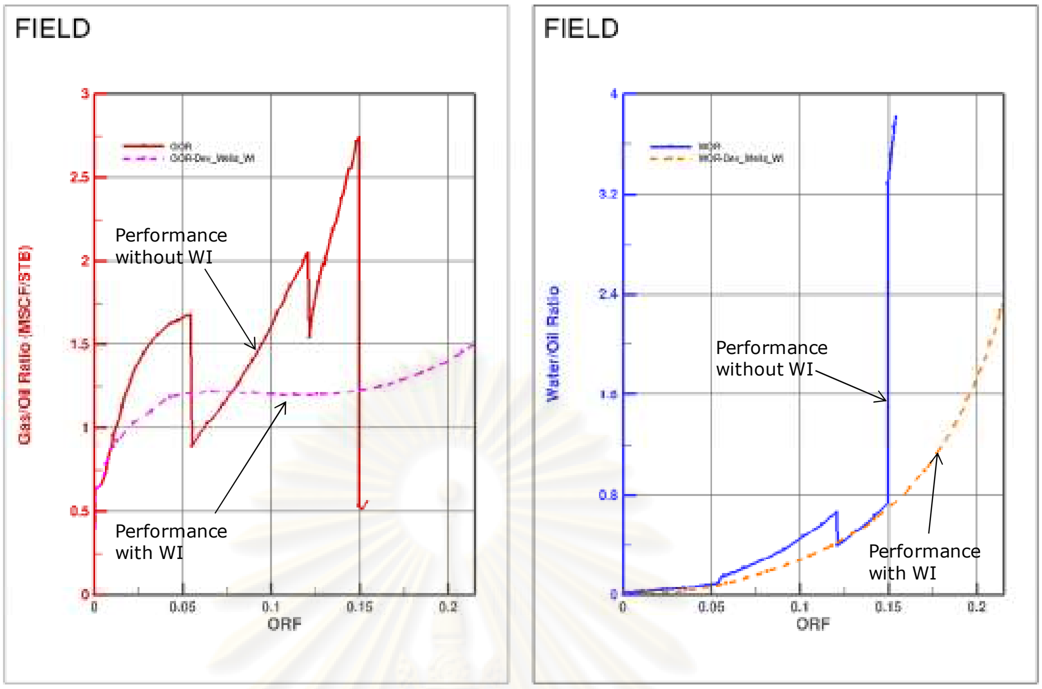


Figure 5.49: WI performance curves – GOR and WOR comparison.

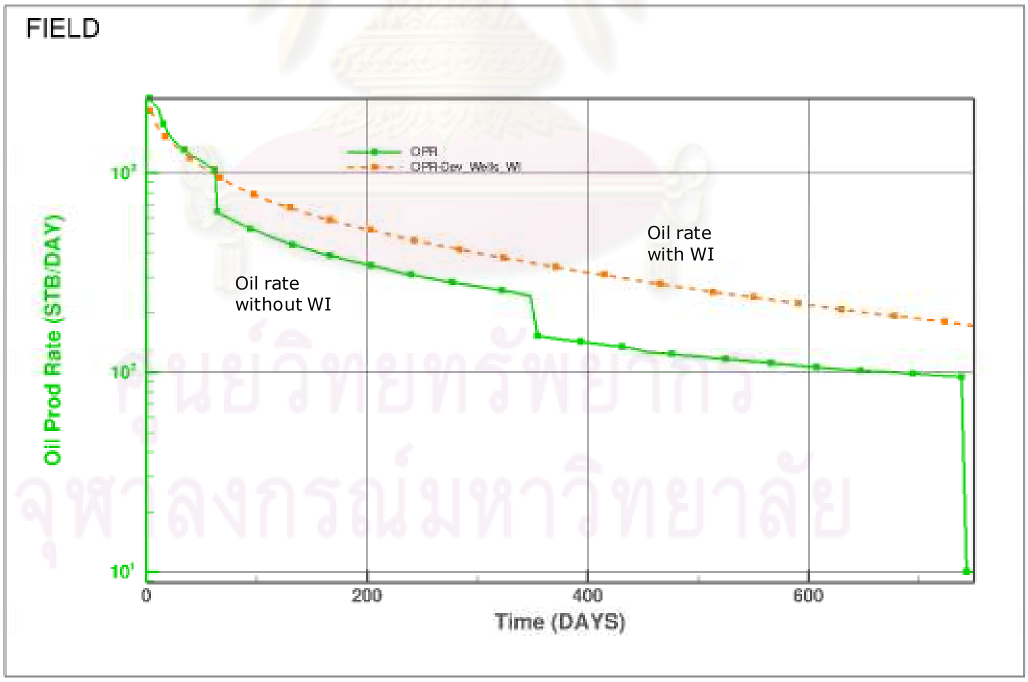


Figure 5.50: WI performance curves – oil rate comparison.

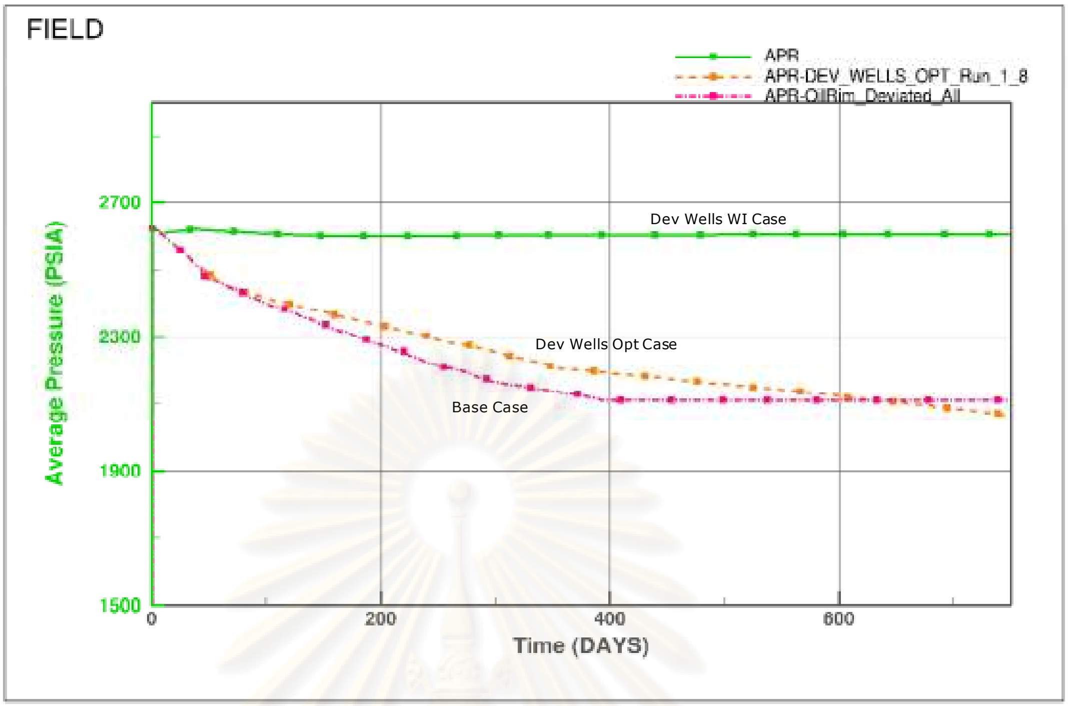


Figure 5.51: WI performance curves – reservoir pressure profile.

5.5.2 Water injection with horizontal well producing

A similar water injection design (peripheral flooding) as shown in Section 5.5.1 is adopted for this case. But in this case, the reservoir is being produced from horizontal well instead of deviated wells. In previous sections, we have seen that horizontal well is very effective in controlling the gas and water coning and increasing the oil recovery of an oil rim reservoir. In this section we will study any increment due to water injection in case of horizontal well producing from oil rim reservoir. The water injection setup and location of horizontal well is shown in Figure 5.52.

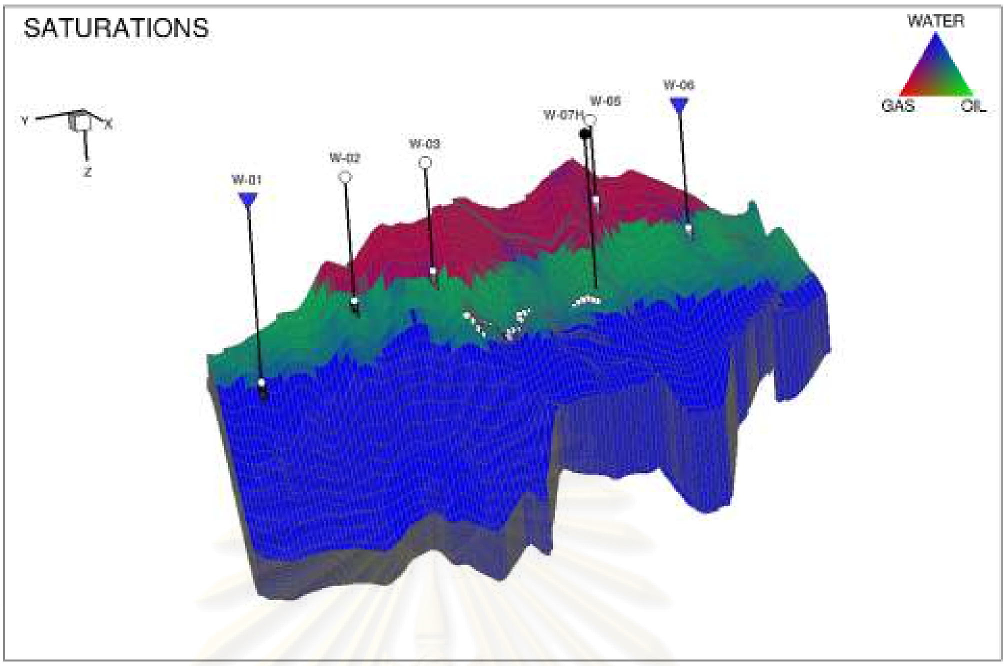


Figure 5.52: Illustration of peripheral water injection – horizontal well case.

The oil recovery estimated with water injection is compared with primary recovery cases for horizontal wells in Figure 5.53. With water injection the recovery is increased to 25% from 19.3% in optimized horizontal well case. The horizontal well optimized case discussed in Section 5.3.5 is used, and water injection is done in wells W-01 and W-06. With water injection in this oil rim reservoir, an increment of 5.7% RF is achieved.

The reason for this increment is studied in water injection performance curves from Figure 5.54 to 5.56. In Figure 5.54, GOR and WOR versus oil recovery factor (ORF) charts for water injection and without water injection for horizontal wells case are shown. It can be seen that in case of WI, the GOR curve is pretty flat as compared to the GOR curve without water injection. Also in WOR vs ORF curve, the WOR is low in water injection case as compared to when there is no water injection done. Both curves show that both gas and water coning are delayed when the reservoir is produced under water injection.

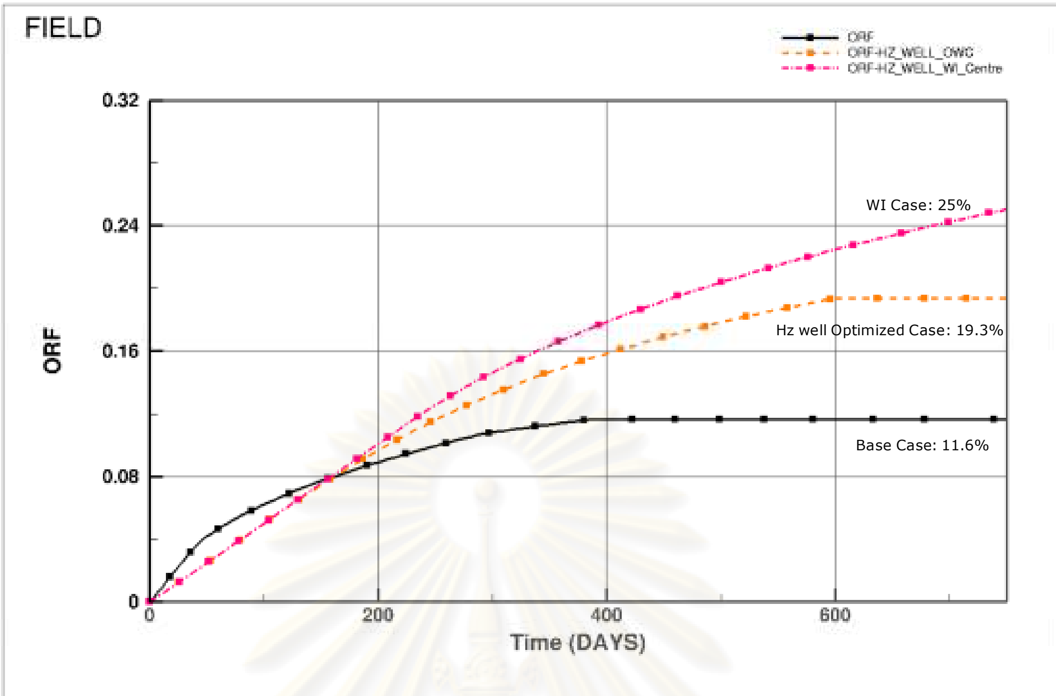


Figure 5.53: WI recovery – horizontal well case.

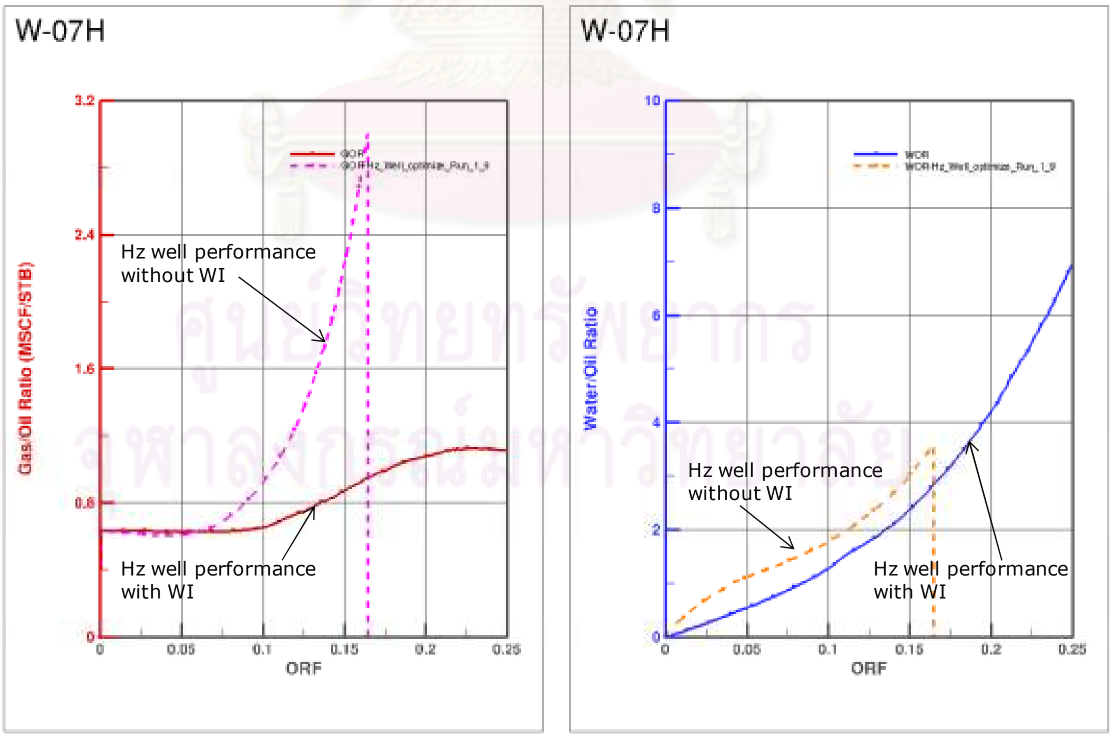


Figure 5.54: WI performance curves – GOR and WOR comparison.

The oil rate comparison for with and without water injection is shown in Figure 5.55. It can be seen that the well has a longer plateau when water is injected as compared to primary depletion case. This is because in case of water injection, the reservoir pressure is maintained and gas expansion is limited. With this, the oil trapped behind the gas cap is reduced. Also, the gas coning is delayed and hence the well produces at higher rates for longer period. The comparison of reservoir pressure profile for base case, optimized deviated wells case and WI case is shown in Figure 5.56.

So, with water injection the oil recovery in horizontal well case is increased to 25% as compared to optimized horizontal well case recovery of 19.3% and base case recovery of 11.6%. So, an increment of 5.7% RF from optimized horizontal well and 13.4% from the base case is gained by water injection in this oil rim reservoir.

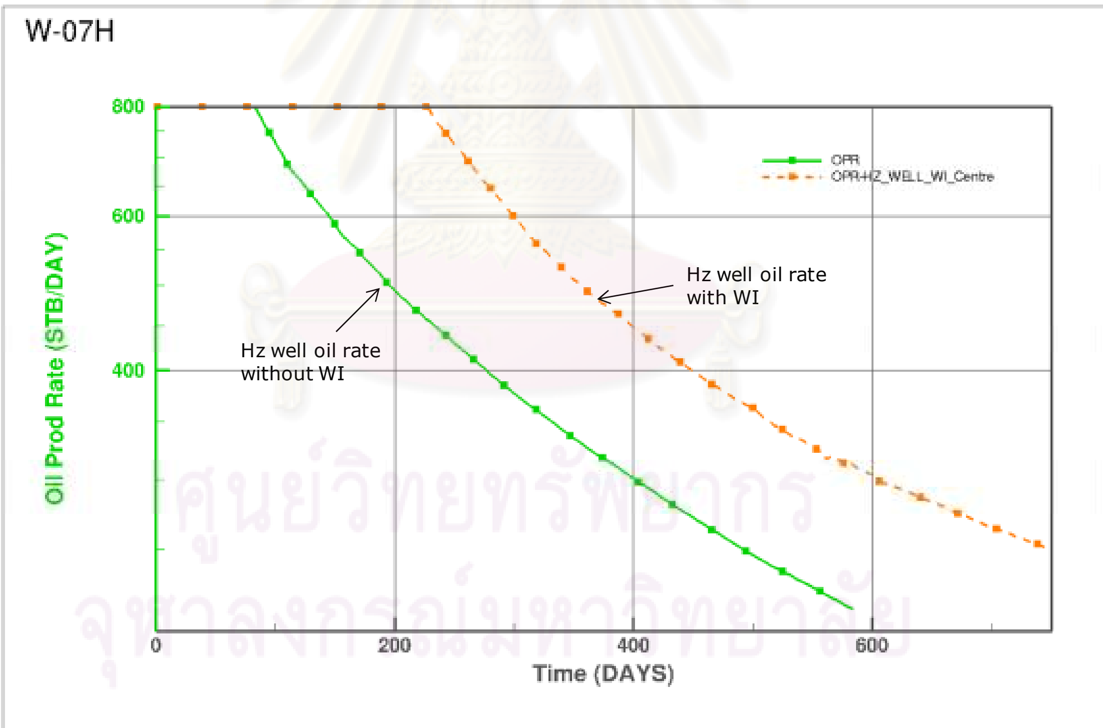


Figure 5.55: WI performance curves – oil rate comparison.

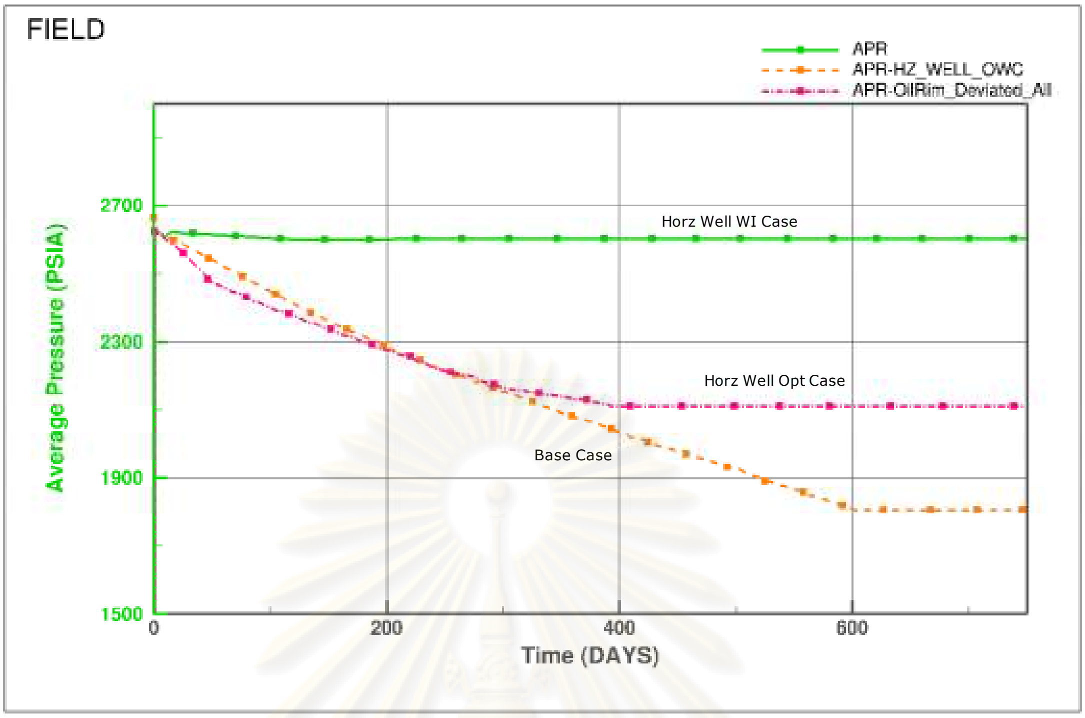


Figure 5.56: WI performance curves – reservoir pressure profile.

5.5.3 Comparison of water injection cases

The recoveries from water injection both in case of deviated wells and horizontal well are compared in this section. In both cases, a peripheral water injection design was adopted as discussed in previous sections. The oil recoveries in both cases are compared in Figure 5.57. Water injection gives an oil recovery of 21% when deviated wells are used and 25% when a horizontal well is producing from the same reservoir. So like primary recovery, horizontal wells are more effective in draining oil from an oil rim reservoir and give higher recoveries. Figure 5.58 shows water cut and GOR plots for both cases. It can be seen from Figure 5.58 that gas coning is more pronounced in deviated wells case even after water injection. For horizontal well, the GOR remains pretty stable after water injection. However, water cut is more pronounced in horizontal well case as compared to deviated well case. This might be due to the reason that the horizontal well is closer to OWC, and after water injection the water OWC moves faster and hits the horizontal well earlier. But in terms of overall oil recovery, horizontal well certainly gives better recovery both in case of primary recovery and water injection cases.

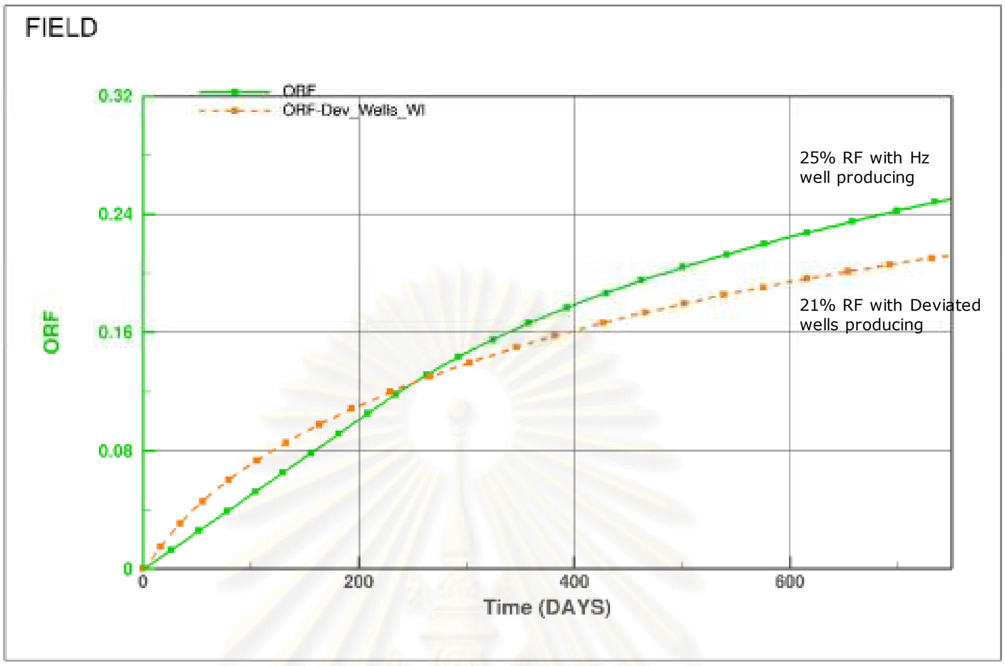


Figure 5.57: WI recoveries – deviated versus horizontal wells.

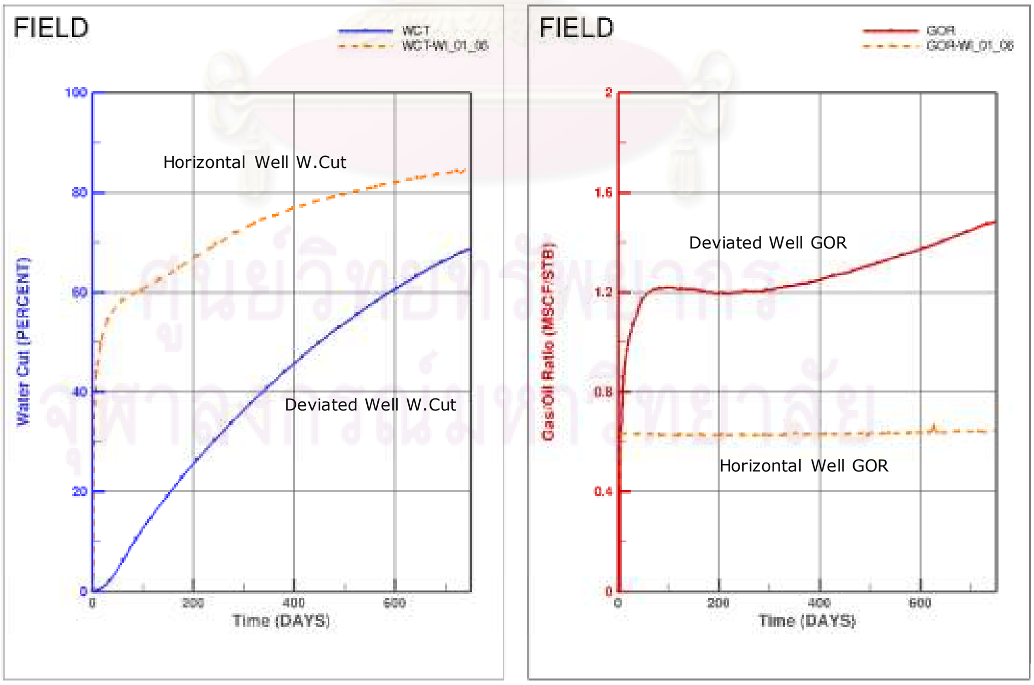


Figure 5.58: Water and gas coning – deviated versus horizontal wells.

5.6 Pressure maintenance with gas injection

In this section the impact of pressure maintenance by gas injection will be discussed. Gas will be injected in the gas cap. Produced gas from the reservoir is being re-injected to maintain the reservoir pressure. In this case, well W-05 which is the most up-dip well, is utilized for gas injection. There are different ways gas can be injected into the reservoir. One way of injecting gas is by dump flood, i.e. injecting gas from other reservoir into the oil rim reservoir by having cross-flow within the wellbore. The control of gas injection rate and surveillance becomes a challenge in this type of gas injection. Other method that is more conventional and has more control on injection rate and surveillance is surface gas injection. Of course, there is more capital expense involved in surface gas injection than dump flood. But at the same time, the results are usually more fruitful in surface gas injection than dump flood. Also, in dump flood, the injection sustains as long as there is enough pressure differential between the source and target reservoir. Declining injection rate with time also affects the efficiency of gas injection in dump gas flood. In the following sections, we will discuss surface gas injection and study the oil recovery both when deviated wells are producing and when only horizontal well is producing from an oil rim reservoir.

5.6.1 Gas injection with deviated wells producing

As mentioned before, gas is injected in well W-05 which is the most up dip well in this oil rim reservoir. Sensitivities are run for gas injection rate to see the impact of injection rate on oil recovery. Gas injection rates of 1.0, 2.0 and 3.0 MMSCFD are used for this sensitivity as shown in Figure 5.59. The runs were submitted as optimization runs as discussed in Section 5.2.3 to optimize the oil recovery. A constant gas is being injected for all injection rates.

The oil recoveries obtained at different gas rates when deviated wells are producing are shown in Figure 5.60. For this optimization run, recoveries are optimized at each gas injection rate. The best recovery factor of 16% is achieved when gas is injected at constant rate of 1.0 MMSCFD. This gives an increment of 1% recovery factor from optimized deviated well case. However, oil recovery with gas injection in this case is 4% less than the case when water is injected into the oil rim reservoir.

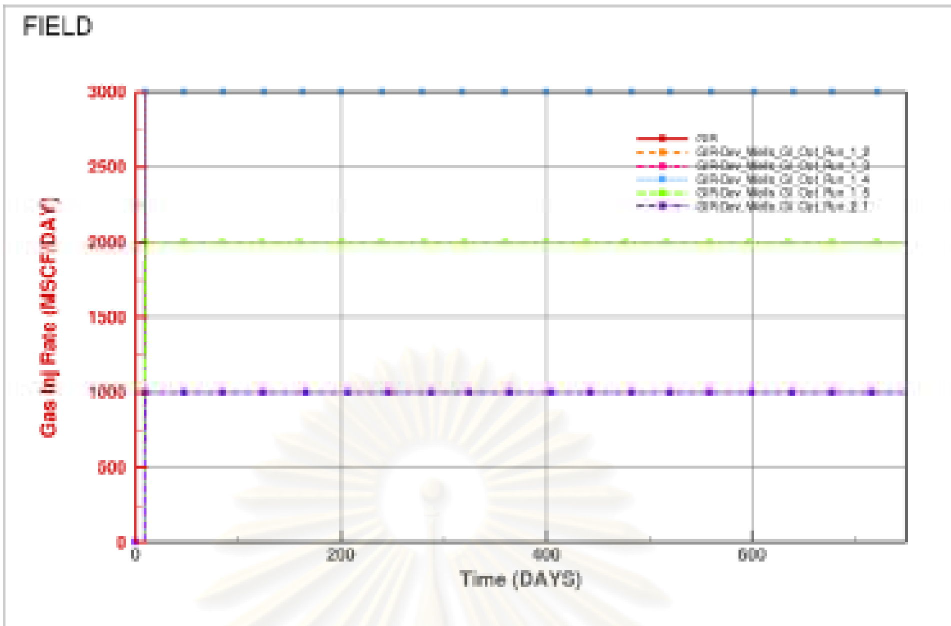


Figure 5.59: Gas injection rates used for gas injection.

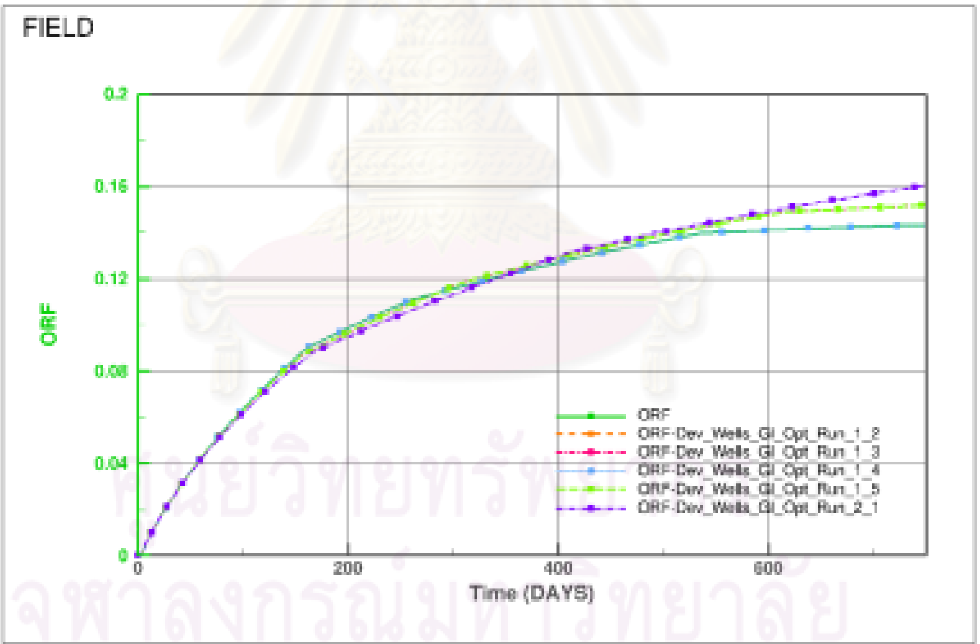


Figure 5.60: Gas injection recoveries at different gas injection rates – deviated wells case.

The initial and abandonment saturations of this oil rim reservoir are shown in Figure 5.61. It is evident from the figure that significant oil saturation is left behind at abandonment conditions. Also the cross-section in Figure 5.61 shows expansion of gas cap at abandonment conditions, and most of the wells shutting in at MAXGOR limit.

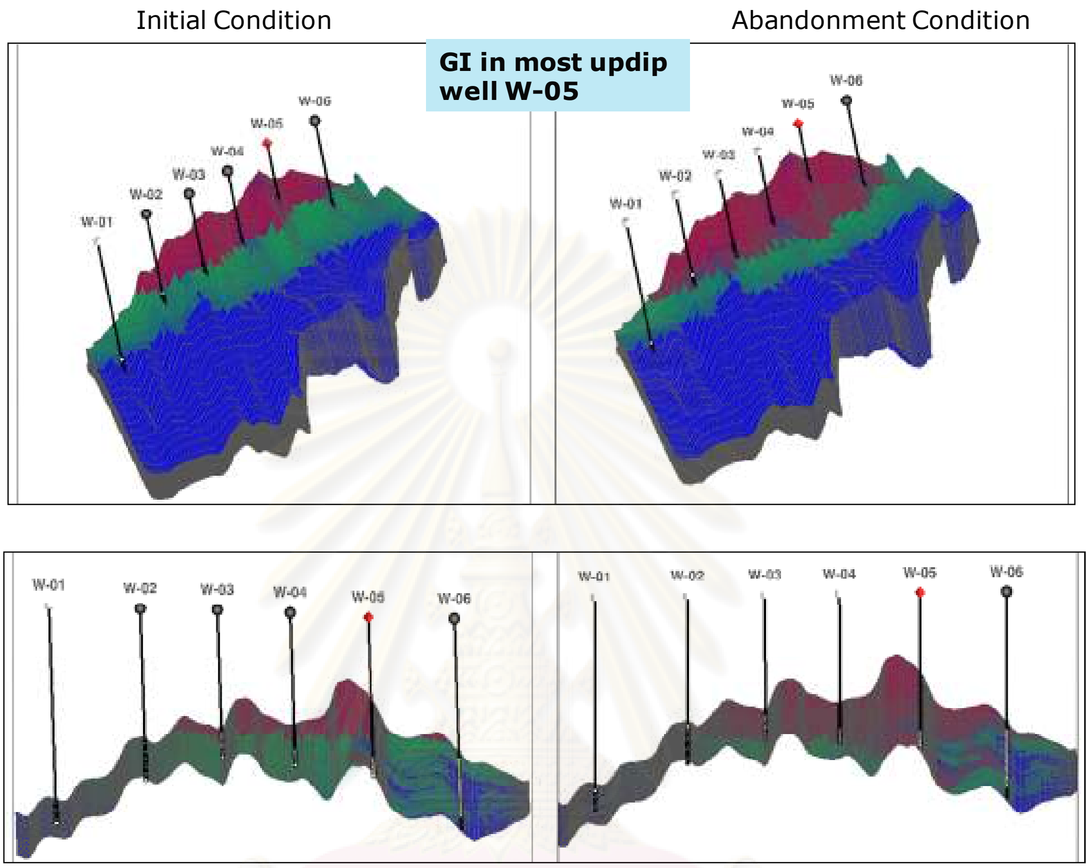


Figure 5.61: Saturation at initial and abandonment conditions for gas injection case.

The GOR and water cut plots for injection at different rates are shown in Figure 5.62. It can be seen that for optimum oil recovery case (1.0 MMSCFD gas injection rate), the GOR of the field is controlled but the water cut increases sharply as compared to other injection rates. The wells are shutting in at MAXGOR limit and not on high water cut limit. Again, this shows that gas being more mobile than water, gas coning is much more critical in an oil rim reservoir than water coning. None of the wells reaches the water cut limit before they are shut in, but all wells are shutting in on reaching MAXGOR limit.

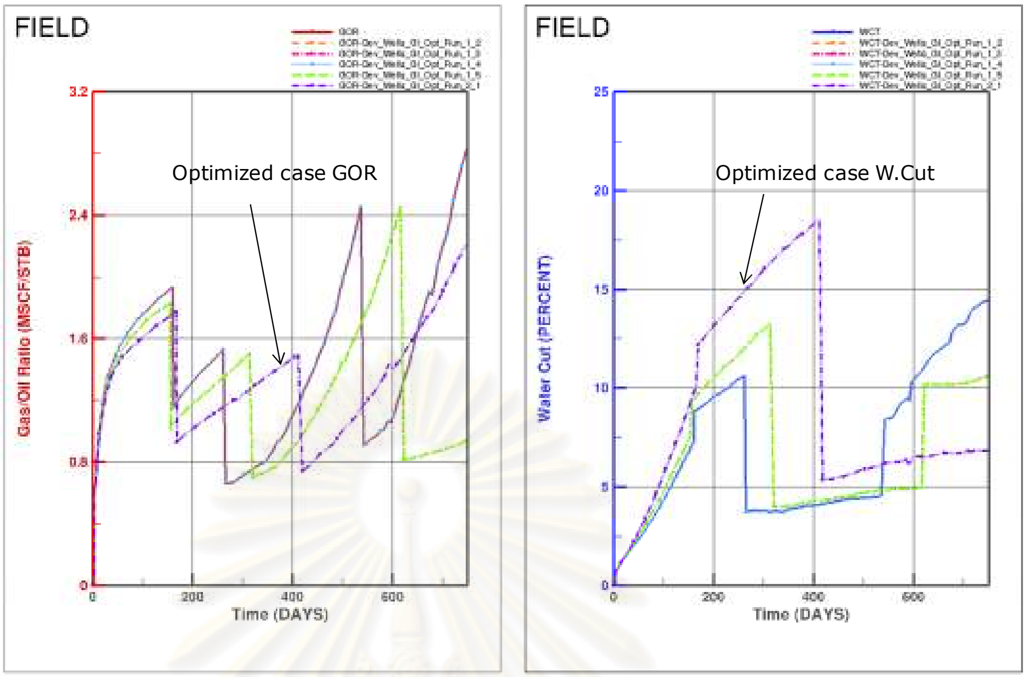


Figure 5.62: GOR and water cut trend at different gas injection rates – deviated wells case.

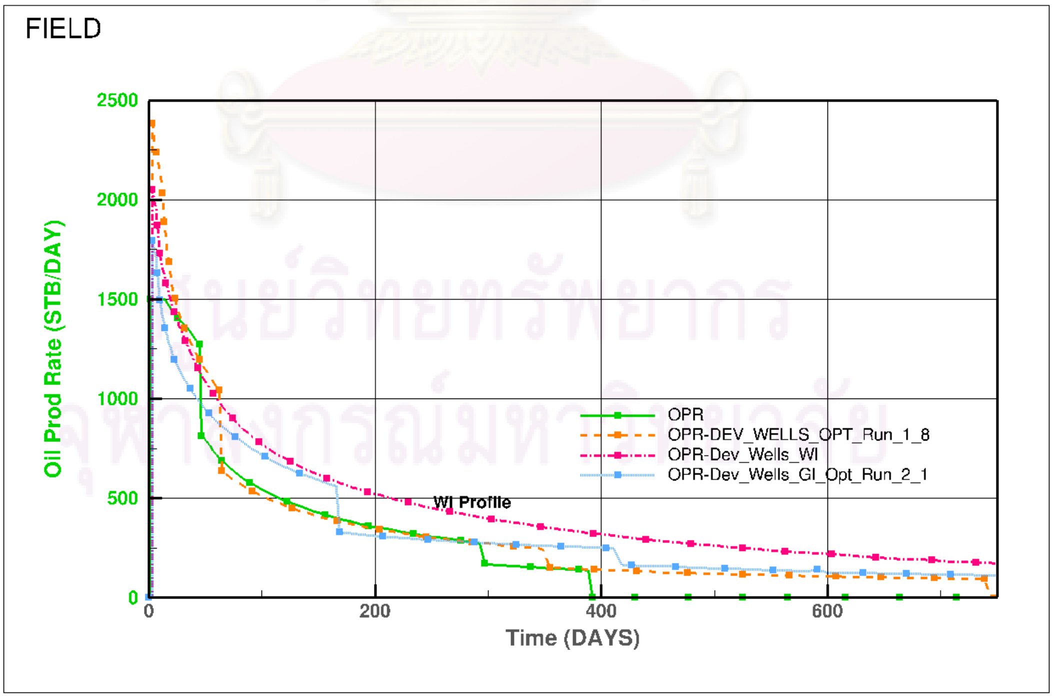


Figure 5.63: Oil rate comparison for different depletion cases.

5.6.2 Gas injection with horizontal well producing

Similar optimization runs for gas injection are made for horizontal well case as done for deviated well case. The same well W-05 is utilized for gas injection into the gas cap. The sensitivities for gas injection rate are also similar to the ones discussed in Section 5.6.1. The oil recoveries at different gas injection rates are shown in Figure 5.64. Again, recovery is optimized for each gas injection rate. The best recovery is achieved at gas injection rate of 1.0 MMSCFD. The optimum case gives a recovery factor of 21% for gas injection when horizontal well is producing from this thin oil rim. This gives an increment of 3.5% from primary depletion case of horizontal well. However, the recovery from gas injection is 4% lower than water injection recovery when horizontal well is producing from oil rim.

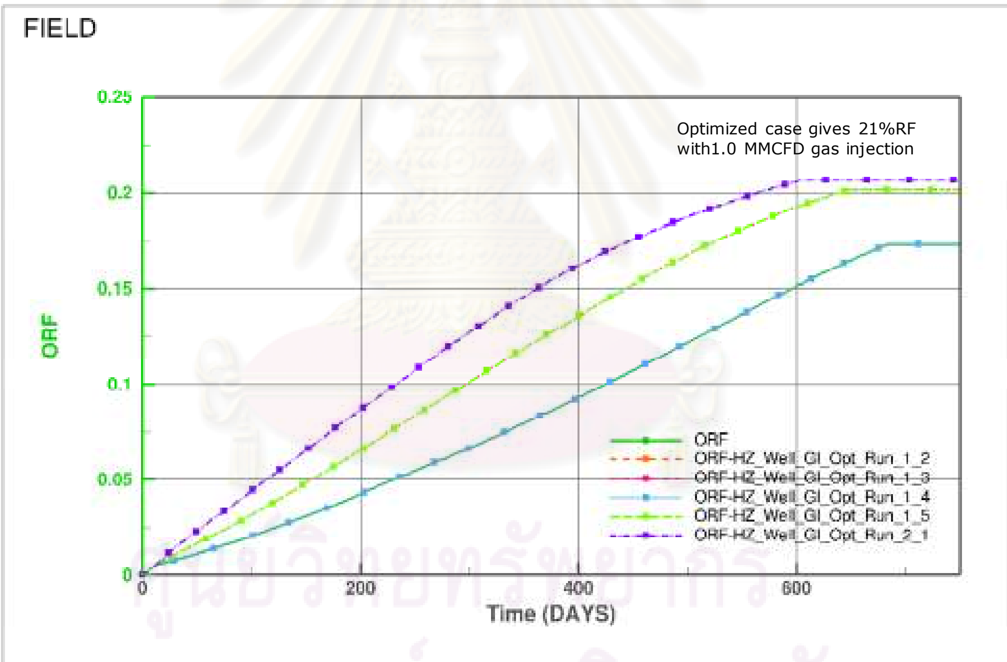


Figure 5.64: Gas injection recoveries at different gas injection rates – horizontal well case.

The initial and abandonment saturations for gas injection case are shown in Figure 5.65. From Figure 5.66, it can be seen that gas cap expansion is very prominent as compared to aquifer movement. The horizontal well is shut in once the gas reaches the well and MAXGOR limit is exceeded. This is also shown in GOR versus time plot in Figure 5.66. But it is also clear that the sweep is much better as compared to the case when deviated wells are producing as shown in Section 5.6.1. Also note that there is good sweep at the heel of the horizontal well as compared to the toe due to higher drawdown at heel as compared to toe (Figure 5.65)..

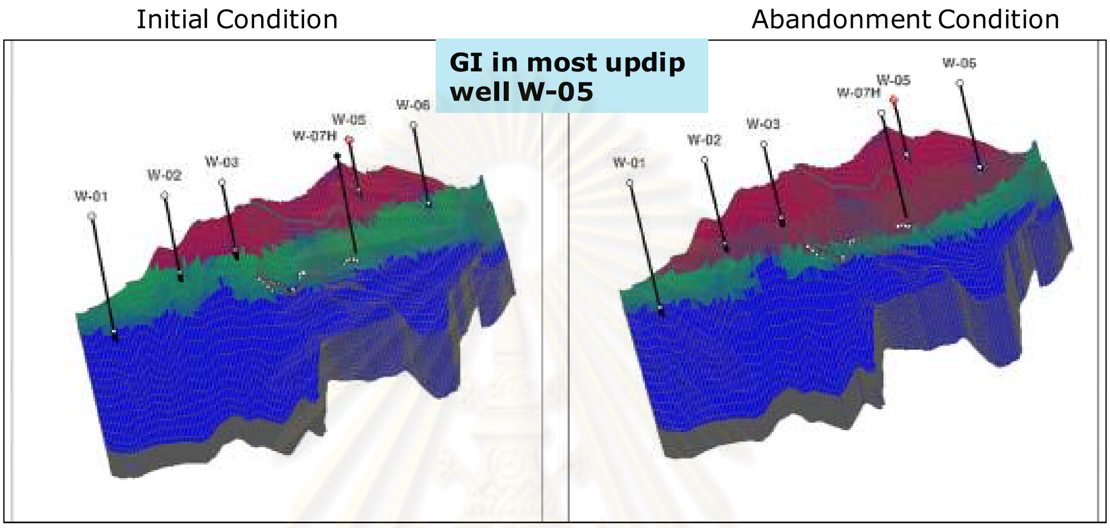


Figure 5.65: Initial and abandonment conditions for GI case – horizontal well producing.

The GOR and water cut plots for injection at different rates are shown in Figure 5.66. It can be seen that for optimum oil recovery case (1.0 MMSCFD gas injection rate), the GOR of the field is controlled but the water coning starts earlier as compared to other injection rates. The well is shutting in at MAXGOR limit and not on high water cut limit. Again, this shows that gas being more mobile than water, gas coning is much more critical in an oil rim reservoir than water coning. None of the wells reaches the water cut limit before they are shut in, but all wells are shut in once reaches the MAXGOR limit.

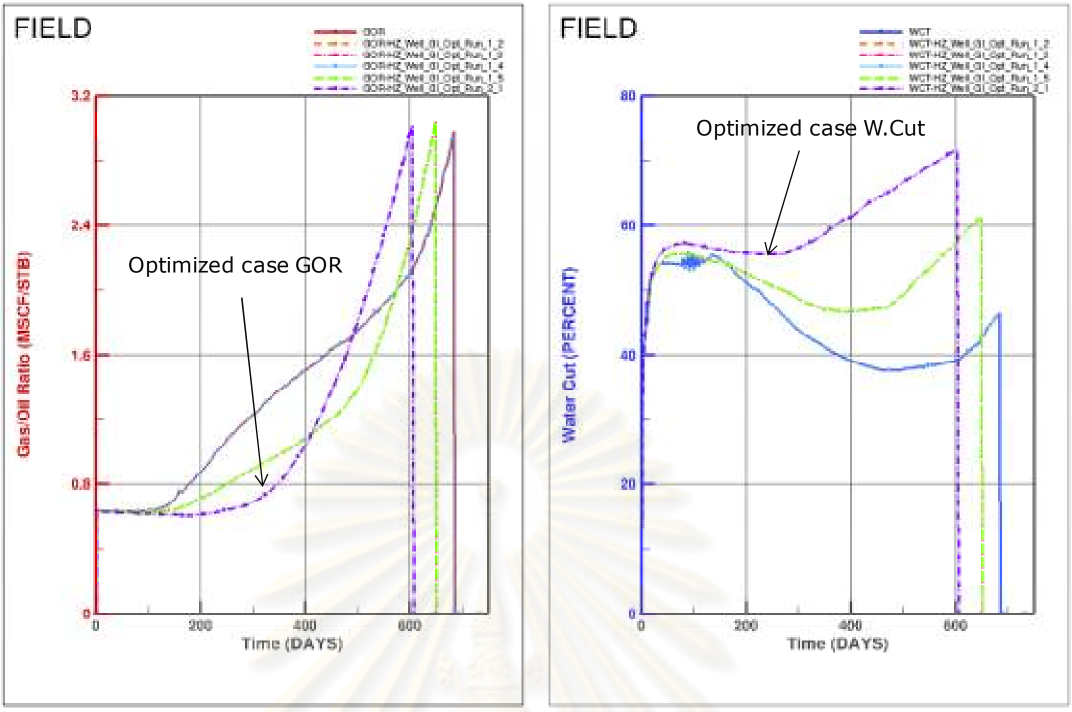


Figure 5.66: GOR and water cut trend at different gas injection rates – horizontal well case.

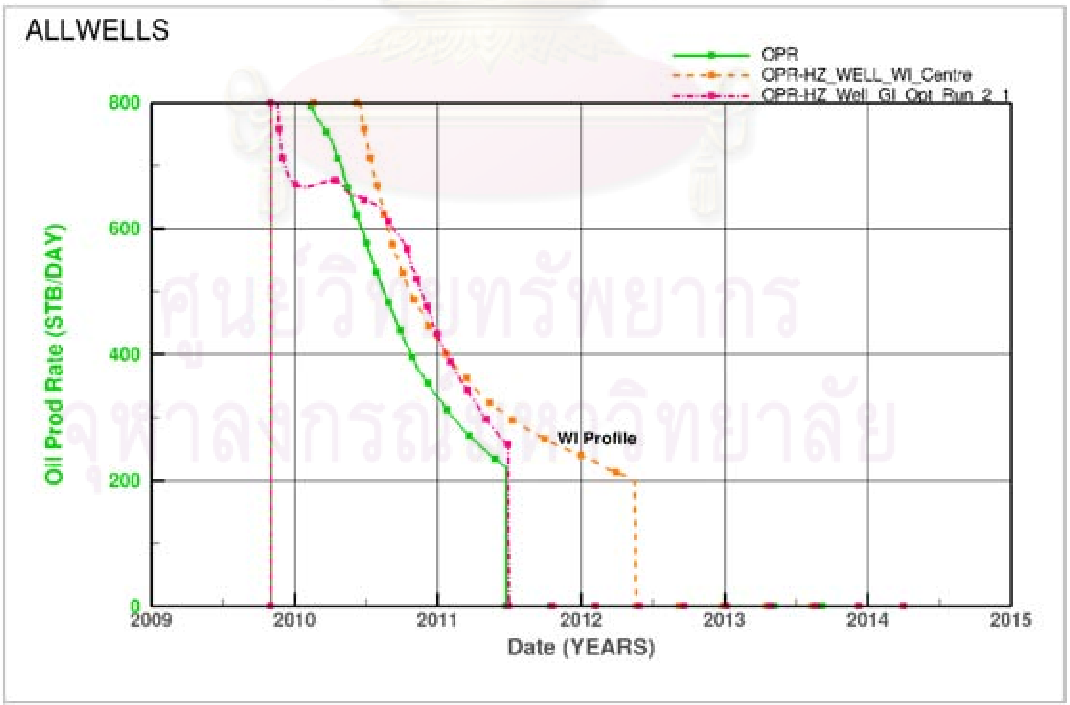


Figure 5.67: Oil rate comparison for different depletion cases.

5.7 Pressure maintenance with combination of water and gas injection

In this scenario, both water and gas were injected simultaneously into the reservoir. Water is being injected in down dip wells W-01 and W-06, and gas is injected in most up dip well W-05. This is done in an effort to keep the force balance between gas cap and aquifer and see the impact on overall oil recovery of this oil rim. Gas and water is being injected to keep reservoir voidage ratio of 1.0. Water and gas injection profiles are shown in Figure 5.68.

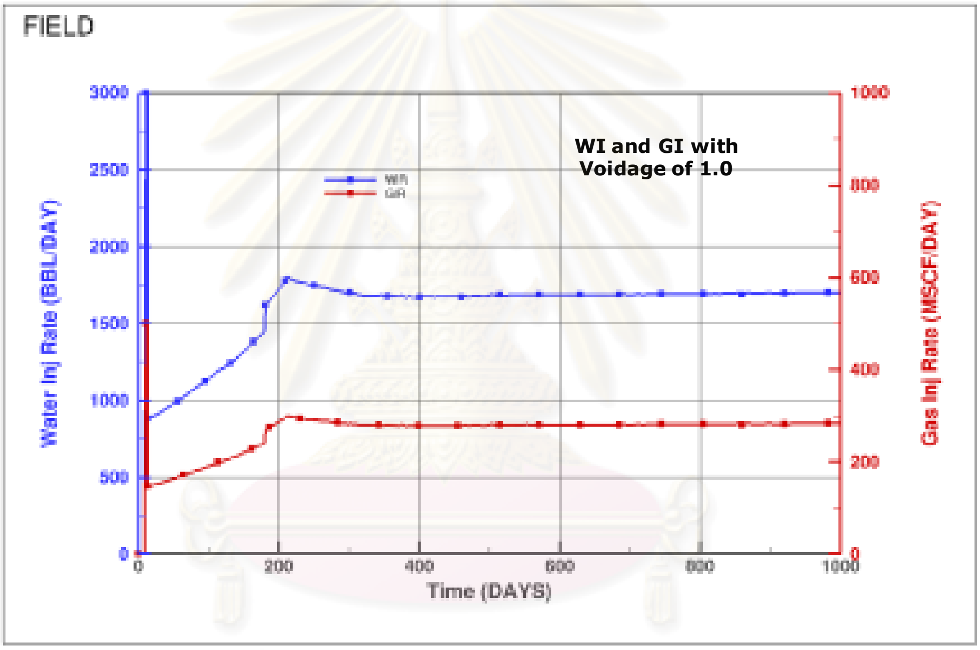


Figure 5.68: Water and gas injection profiles for simultaneous GI and WI.

Comparison of performance between water injection and simultaneous water and gas injection with horizontal well producing is shown in Figures 5.69 to 5.72.

Figure 5.69 shows comparison of oil rate profiles versus ORF. The comparison shows that simultaneous water and gas injection gives a longer oil profile and hence higher recovery factor. However, it should be noted that it takes longer to get higher recovery factor for simultaneous water and gas injection than only water injection Figure 5.70. Figure 5.71 shows comparison of WOR versus ORF for both cases. In WI case the water breaks through early than simultaneous WI and GI case, and hence well loading up earlier at high WOR of 9 (water cut =90%). But in case of GOR versus ORF chart (Figure 5.72), gas breakthrough in simultaneous WI and GI case

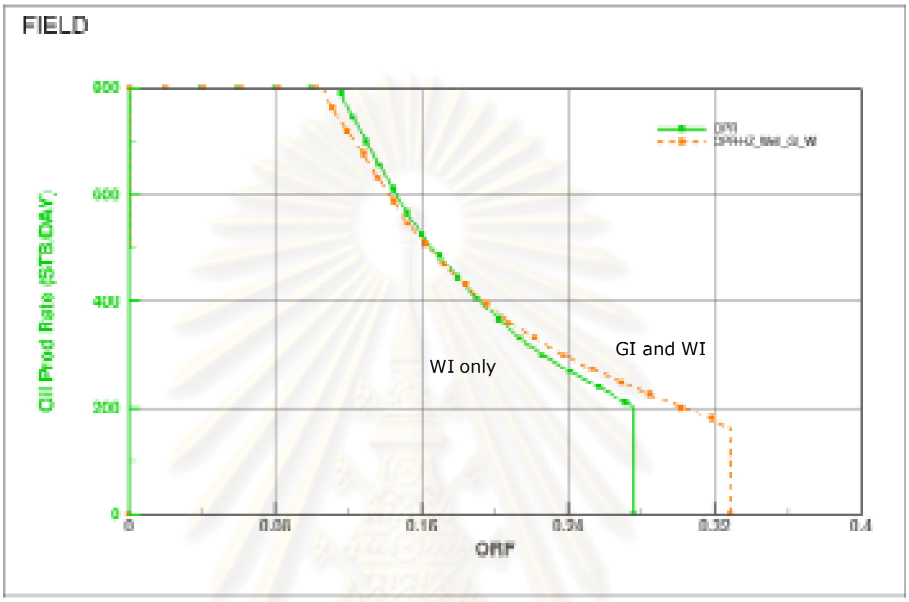


Figure 5.69: Oil production profile comparison for WI and simultaneous WI and GI.

happens earlier than only WI case. But the well is still producing oil as the MAXGOR limit is not reached yet. Therefore, the well produces longer in simultaneous gas and water injection case.

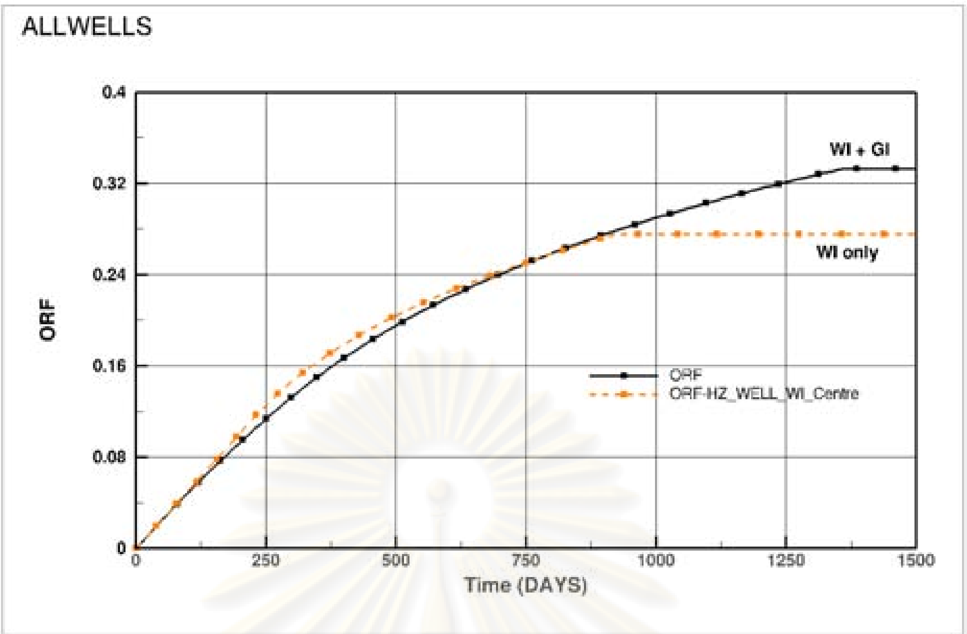


Figure 5.70: Oil recovery comparison for WI and simultaneous WI and GI.

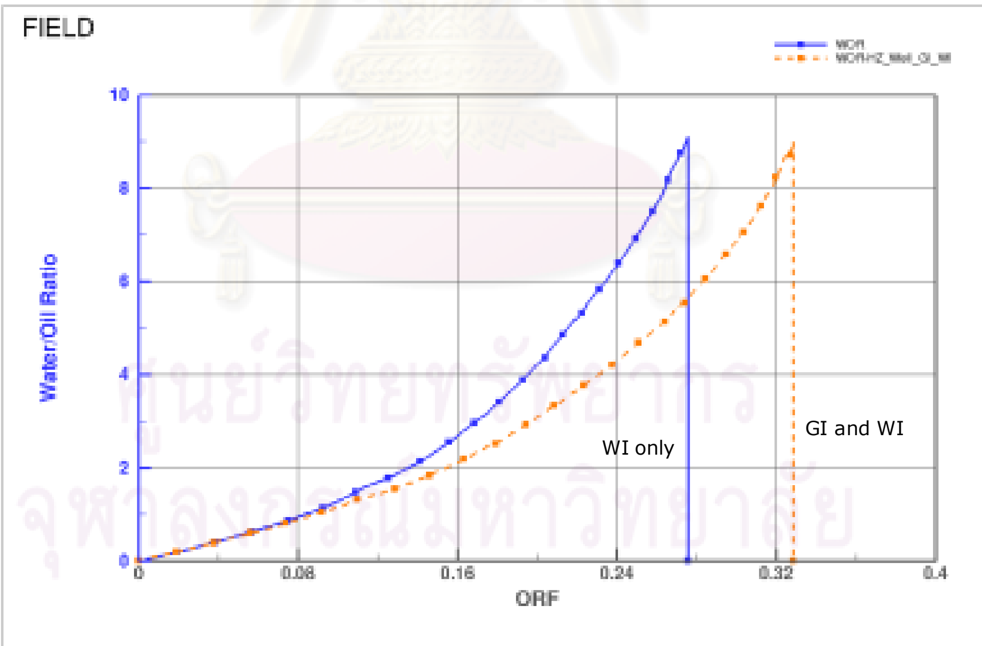


Figure 5.71: WOR comparison for WI and simultaneous WI and GI.

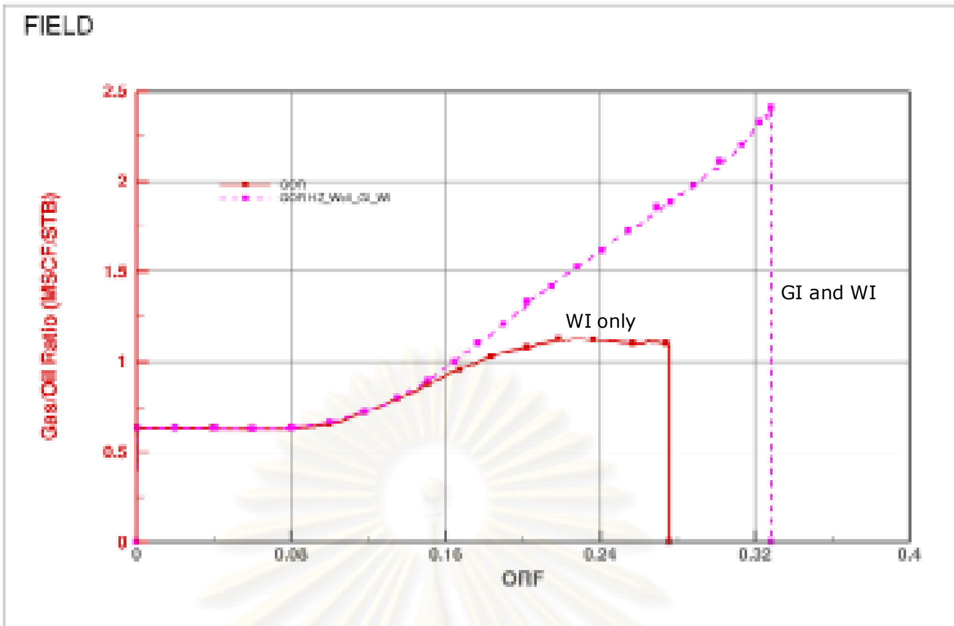


Figure 5.72: GOR comparison for WI and simultaneous WI and GI.

The initial and abandonment saturation conditions for simultaneous WI and GI are shown in Figure 5.73. It can be seen that the sweep is improved in this case as compared to WI or GI cases discussed in previous sections.

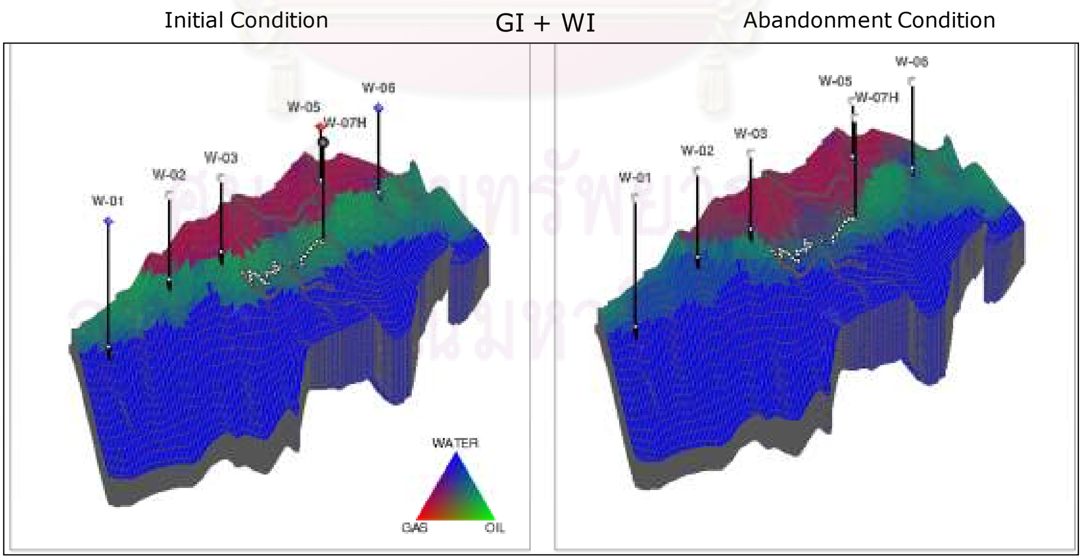


Figure 5.73: Initial and abandonment conditions for simultaneous WI and GI case.

The comparison of reservoir pressure profile for two cases is shown in Figure 5.74. For WI case, the reservoir pressure is maintained at original value while for simultaneous WI and GI case, the reservoir pressure is increased from the original value.

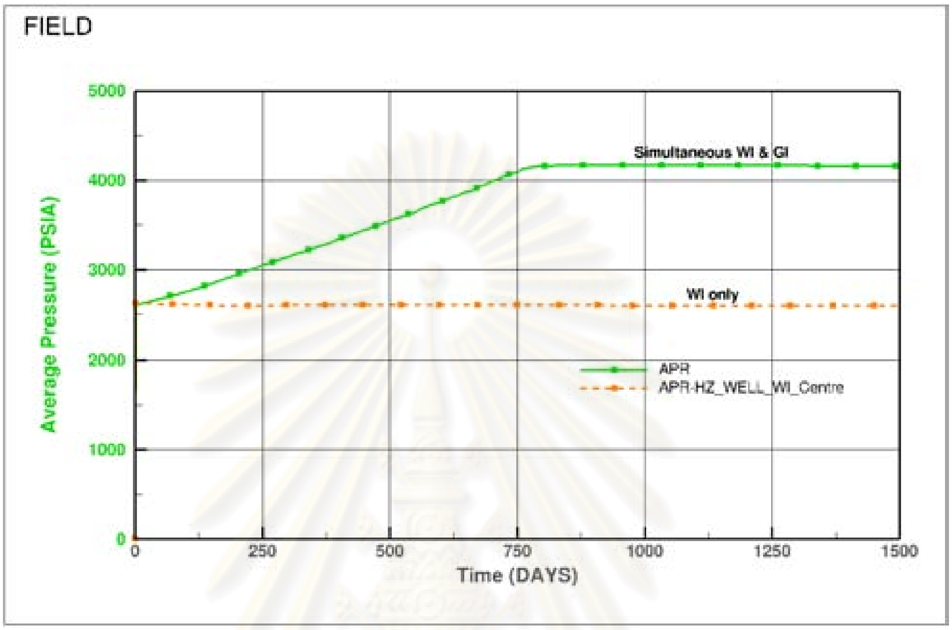


Figure 5.74: Reservoir pressure comparison for WI and simultaneous WI and GI cases

5.8 Recovery comparison of all scenarios

5.8.1 Primary recovery comparison

Comparison for all the primary depletion cases is shown in Figure 5.75. The x-axis represents different primary recovery cases, and the y-axis is the recovery factors. The RF is also labeled on each bar. It shows that horizontal well after optimization gives the highest primary recovery with RF of 19.3%. It gives an incremental of 7.7% from base case and 4.3% from deviated wells optimized case. The average RF for primary cases is shown by horizontal red line which is about 15.5%. The range of RF for primary cases is from 11.6% to 19.3% depending on type of wells drilled and optimization for gas and water coning.

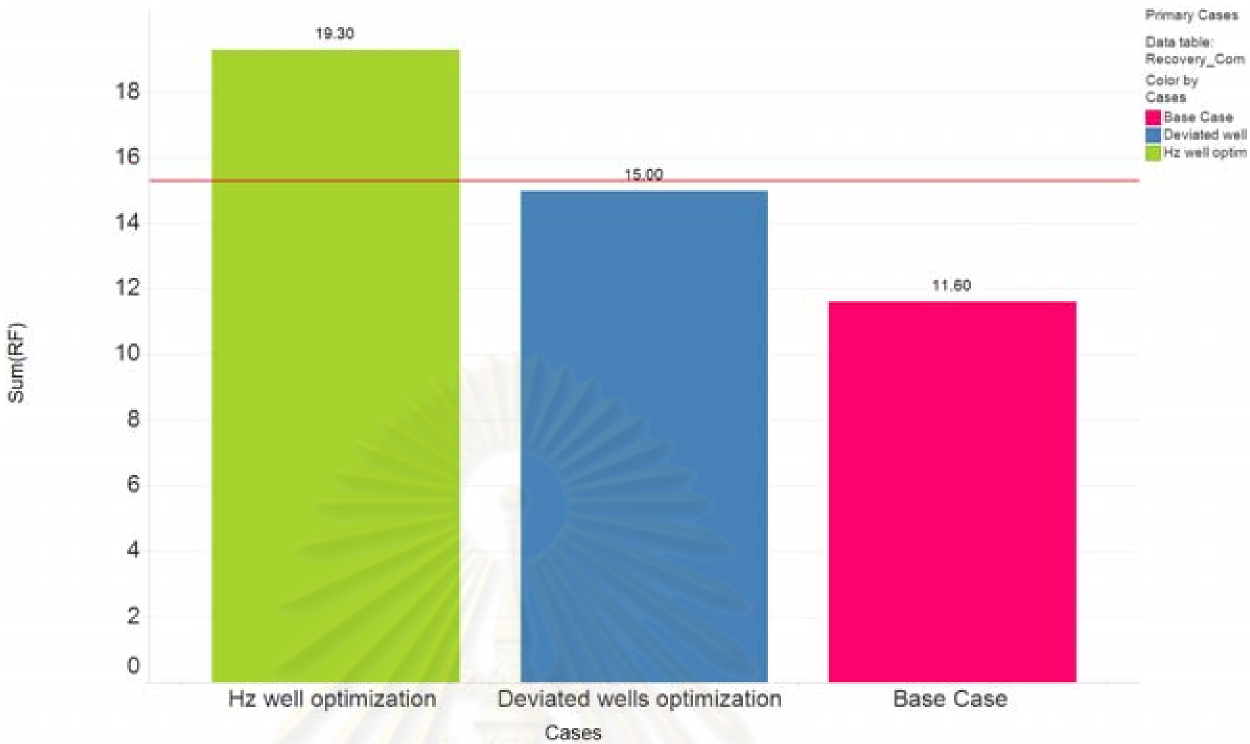


Figure 5.75: Primary recovery comparison.

5.8.2 **Secondary recovery comparison**

Secondary recovery comparison is shown in the Figure 5.76. It does not include the simultaneous GI and WI case. The comparison is between GI and WI for both deviated well and horizontal well production. The highest recovery is achieved with WI as secondary recovery method and with horizontal well producing. A RF of 25% is achieved in this case, giving rise to an incremental of 13.4% from the base case. Note that WI with deviated wells producing gives same recovery as GI with horizontal well producing. The main reason for this is that in horizontal well GI case, the gas breakthrough occurs earlier and well is shut in at MAXGOR limit. But in general, WI gives more recovery as compared to GI for this oil rim reservoir. The average RF achieved with secondary recovery is about 21% indicated by the red line in Figure 5.75 which is about 5.5% more than the average RF obtained from primary depletion. Therefore, secondary recovery either by WI or GI certainly improves the overall oil recovery in an oil rim reservoir.

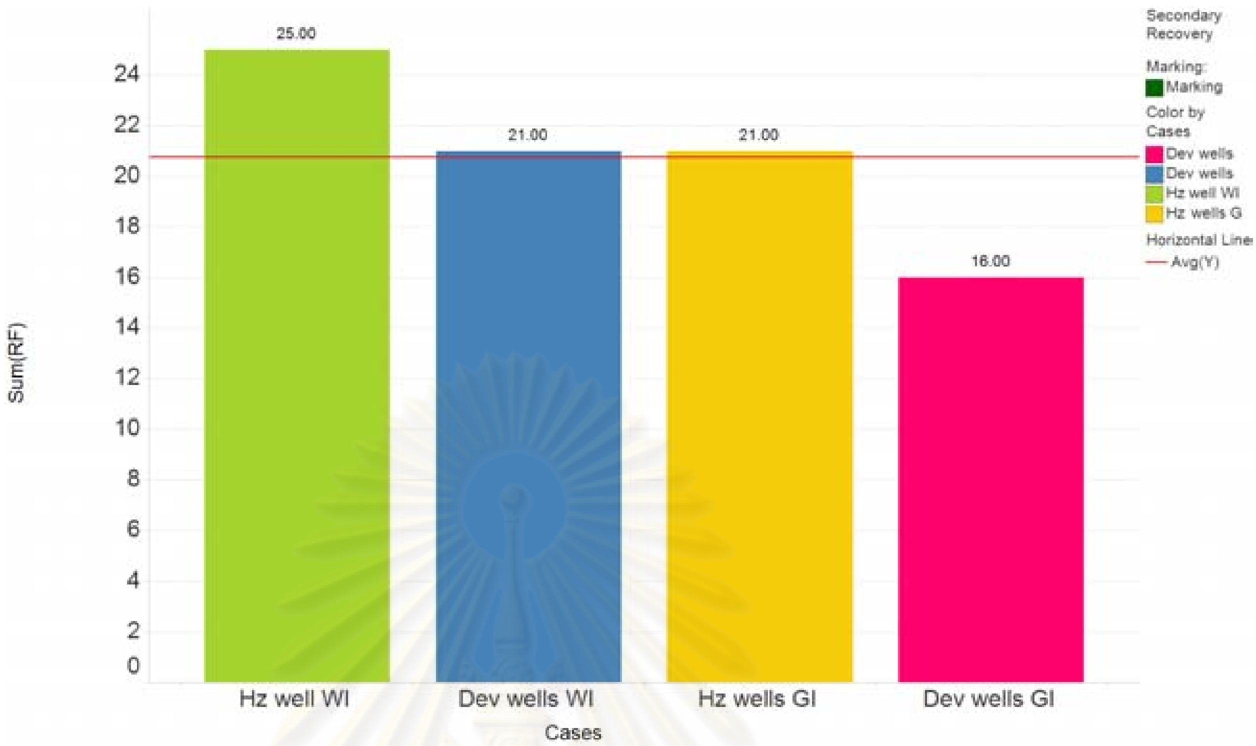


Figure 5.76: Secondary recovery comparison.

5.8.3 Comparison of all scenarios

This section compares recovery from all the scenarios discussed in previous sections of Chapter 5. It also includes the simultaneous WI and GI case. The comparison is shown in Figure 5.77. The chart shows sequence of cases from highest to lowest recovery case. At 750 days, both water injection and simultaneous gas and water injection gives maximum recovery of 25%. However, if the wells are allowed to flow for longer time than 750 days, the highest recovery is achieved when both gas and water is injected and gives a RF of 33%. These two scenarios give maximum recovery mainly due to maintaining force balance discussed earlier. With production from horizontal well and WI as secondary recovery method, a force balance is maintained. Gas and water coning is minimized. This helps increase the overall oil recovery. With simultaneous gas and water injection, the force balance is further improved, giving better recovery than WI or GI alone. But in most cases, it is very expensive and impractical to implement both water injection and gas injection together due to large amount of capital expenditure.

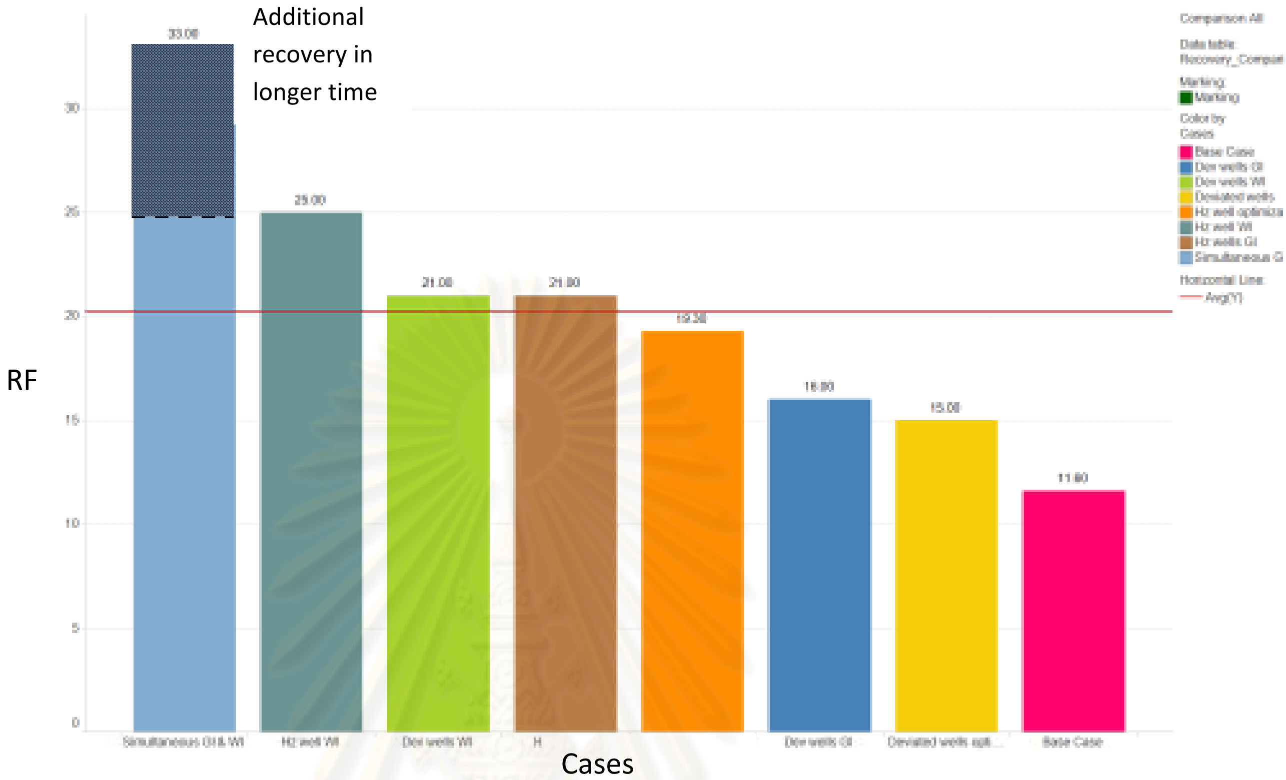


Figure 5.77: Comparison of all scenarios.

The comparison of reservoir pressure profile for all the cases discussed above is shown in Figure 5.78. It can be seen that cases where the reservoir pressure is not allowed to drop a lot give better oil recoveries.

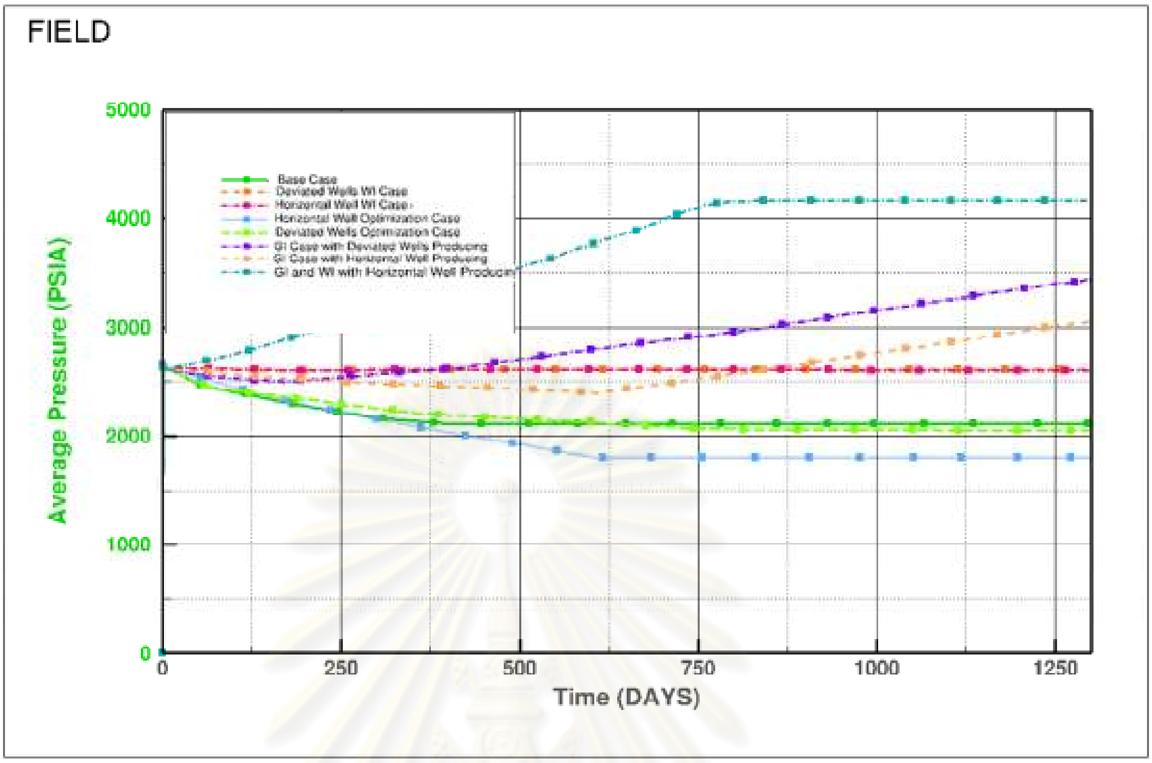


Figure 5.78: Reservoir pressure comparison of all scenarios.

Chapter VI

CONCLUSIONS AND RECOMMENDATIONS

Force balance between GOC and OWC in an oil rim has been studied and thought to be the most critical factor affecting the oil recovery in an oil rim reservoir. An experimental design approach is taken to study the impact of dynamic parameters such as drawdown, oil rate and GOR on the overall oil recovery from thin oil rim reservoir. The oil recovery is then optimized using a range of these dynamic parameters. The results showed that oil recovery increases with drawdown up to some extent, after which further drawdown pressure will decrease the oil recovery. This is mainly due to at very high drawdown pressures, gas and water becomes very prominent. Also in case of deviated wells, wells have to be produced at relatively very low oil rates to increase the oil recovery from thin oil rim reservoirs. Sometime, these rates are so low that it is very difficult to economically justify the production. At high rates and drawdown pressures, the oil recoveries are hampered mainly due to early water and gas breakthrough. Water and gas coning is the biggest challenge while producing from a thin oil rim reservoir. The problem increases as the oil rim becomes thinner. The amount of gas and water coning depends on the thickness of oil rim, size of gas cap and aquifer strength. Usually gas coning is more prominent due to high mobility of gas as compared to oil and water. Gas coning affects the oil recovery from thin oil rim in two ways,

i. With more gas production the reservoir loses energy and reaches abandonment pressures earlier

ii. With gas cap depletion, oil smearing into gas cap or gas cap expansion into oil zone happens

These factors have detrimental effect on oil recovery. In the second case, the oil is trapped behind the gas and very difficult to recover at later stages. Therefore, it is very critical to produce the wells at rates such that the movement of GOC and OWC are kept uniform. In other words, keeping force balance between GOC and OWC becomes very critical in thin oil rim reservoirs. But to achieve this, sometimes the wells have to be produced at economically very low rates.

Horizontal wells are found to be a good solution to improve the rates and recovery from thin oil rim reservoirs. Even with lower drawdown pressures as compared to deviated wells, horizontal wells can be produced at relatively higher rates with less water and gas coning. Water and gas coning is more pronounced in deviated and vertical wells as compared to horizontal wells. Horizontal wells offer much larger surface area to flow that helps in minimizing the coning. Maximum drawdown is achieved at the heel of horizontal wells and minimum drawdown is achieved at the toe of horizontal well.

There are certain factors that should be considered while planning a horizontal well in oil rim reservoir.

- **i.** Horizontal lateral length
- **ii.** Distance from GOC and OWC

For the first factor, generally the oil recovery increases with increase in lateral length. In some cases where there is edge or bottom water drive, horizontal wells extending to water leg can cause problems in production. Even with minimum drawdown at the toe, water can accumulate at areas having sump in lateral section of horizontal well. Also the result of this study showed that rate of increase in oil recovery is not constant per footage increase in lateral length. In our particular reservoir, an increase in oil recovery of 5.5% is observed as lateral length is increased from 550ft to 1200ft (650ft increment). But increasing the lateral length from 1200ft to 2000ft (800ft increment) improves the oil recovery by 2.7%. The results could vary from reservoir to reservoir. Care should be taken while planning the length of horizontal well. A very long horizontal well could add substantial cost to the project while the increment in reserves might be insignificant. This may hamper the overall project economics.

For the second factor, this study shows that drilling horizontal well closer to OWC gives better oil recovery as compared to drilling closer to GOC. Again, this is due to the fact that gas is more mobile than water and oil. Once gas coning starts, it is very difficult to heal the cone. Some literature study also proves drilling horizontal well below the OWC gives better results in term of oil recovery. A reverse water coning effect is studied in that case. In general, horizontal wells in thin oil rim reservoir can give better rate and recovery as coning is minimized in horizontal wells. Horizontal wells can significantly improve the oil recovery as compared to deviated or vertical wells in an oil rim reservoir.

Based on this study, pressure maintenance significantly improves the oil recovery from thin oil rim reservoir. Different pressure maintenance techniques like gas injection, water injection and simultaneous gas and water injection are implemented to see the impact of overall oil recovery. Water injection proves to be a better pressure maintenance technique than gas injection. Water injection maintains the GOR for longer period as compared to gas injection, where, once the gas breakthrough occurs, the GOR increases sharply until the well is shut in on reaching limiting GOR. The pressure maintenance can increase the recovery to 25% as compared to 18% from primary depletion. The third pressure maintenance technique, simultaneous gas and water injection, gives maximum oil recovery with extended production time. With this technique, maximum force balance is maintained and better sweep is achieved at abandonment conditions. But sometimes it is operationally very difficult to implement both gas and water injection due to high capital investment. Where possible, surface water injection with gas dump flood or vice versa can be implemented to save cost and also improve overall oil recovery from thin oil rim reservoir.

Based on this study, the following is recommended to improve the oil recovery from thin oil rim reservoirs.

- ❖ Drawdown pressure is very critical in controlling water and gas coning in oil rim reservoir. It is very important to optimize the drawdown pressure in deviated or horizontal wells to minimize coning effects and at the same time increase reserves.

- ❖ Drill horizontal wells instead of vertical or deviated wells. This helps in reducing gas and water coning. In many cases, horizontal wells can prove more economical to drill as less horizontal wells are required to drain more reserves as compared to deviated wells. Especially in an environment where deviated wells have delineated the oil rim reservoir and also penetrate multiple reservoirs, horizontal wells can prove very economical. The reason being deviated wells can be utilized to drain other reservoirs and at the same time horizontal wells can be utilized to maximize recovery from oil rim.

- Horizontal wells should be drilled away from GOC to avoid early gas breakthrough. It also helps to avoid rapid gas cap expansion and oil smearing into gas cap. The oil trapped behind the gas is very difficult to recover at later stages.

- In general, longer laterals are better than shorter laterals in terms of oil recovery. But in order to increase the lateral length, care should be taken as lateral should not extend to the water leg or poor reservoir area that can hamper production and recovery. With good reservoir properties, increase in lateral length does not always increase the recovery at the same rate. As in this study, it is observed that the reserves increase substantially with increase in lateral length up to some extent. After that, further increase in lateral length does not significantly increase the reserves. So, an economic justification should be made when proposing lateral length for horizontal wells.

- Secondary recovery significantly increases the oil recovery in an oil rim reservoir. Although the gas cap and an active aquifer provide good reservoir energy, external energy support by gas and/or water injection significantly improves the recovery. The force balance between GOC and OWC is disturbed by production under primary depletion, and hence hampers recovery. With secondary recovery, the force balance is well maintained, and it also allows producing at relatively higher rates. Water and gas injection also helps to reduce the gas and water coning specially when producing from horizontal wells.

- The timing of injection is very critical to obtain favorable results. It is recommended to start water and/or gas injection at early phase of production rather than delaying to get maximum benefit of injection. By delaying injection, the force balance is already disturbed, and later injection becomes less effective.

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APPENDICES

APPENDIX A

Fluid Properties Table

The following oil and gas fluid properties are used in the simulation deck

OIL API GRAVITY	Region
OILPROP API 38.61	1

PRESSURE (psia)	FVF (rbbl/STB)	VISC (cp)	RS (SCF/STB)	COMPR (1/psi)	DVIS (1/psi)
200.0	1.1266	0.373	32.65	1.4864E-04	6.9497E-05
400.0	1.1443	0.364	70.18	7.9024E-05	6.9722E-05
600.0	1.1642	0.353	111.64	5.6149E-05	7.0025E-05
800.0	1.1859	0.340	155.95	4.4891E-05	7.0400E-05
1000.0	1.2091	0.326	202.53	3.8250E-05	7.0841E-05
1200.0	1.2337	0.312	251.03	3.3903E-05	7.1344E-05
1400.0	1.2595	0.298	301.18	3.0857E-05	7.1903E-05
1600.0	1.2865	0.283	352.80	2.8618E-05	7.2512E-05
1800.0	1.3146	0.269	405.74	2.6914E-05	7.3165E-05
2000.0	1.3438	0.256	459.88	2.5581E-05	7.3856E-05
2200.0	1.3740	0.244	515.13	2.4515E-05	7.4579E-05
2400.0	1.4051	0.232	571.40	2.3649E-05	7.5326E-05
2600.0	1.4371	0.221	628.64	2.2934E-05	7.6090E-05
2800.0	1.4701	0.211	686.78	2.2337E-05	7.6864E-05
3000.0	1.5038	0.202	745.76	2.1835E-05	7.7640E-05

GAS GRAVITY (air = 1.000)	Region
GASPROP 0.8300	1

PRESSURE (psia)	FVF (rbbl/MSCF)	VISC (cp)
200.0	18.3415	0.0144
400.0	9.0334	0.0146
600.0	5.9360	0.0148
800.0	4.3924	0.0151
1000.0	3.4705	0.0155
1200.0	2.8600	0.0159
1400.0	2.4279	0.0163
1600.0	2.1075	0.0168
1800.0	1.8617	0.0173
2000.0	1.6683	0.0178
2200.0	1.5129	0.0184
2400.0	1.3861	0.0190
2600.0	1.2811	0.0197
2800.0	1.1932	0.0203
3000.0	1.1188	0.0210

APPENDIX B

Relative Permeability Tables

The following oil/water and gas/oil relative permeability (kr) tables are used in simulation

WATEROILPERM 1

Sw	Krw	Krow	Pcow
0.300000	0.000000000	1.0000	10.000000
0.320000	0.000750000	0.9025	7.200000
0.340000	0.003000000	0.8100	6.200000
0.360000	0.006750000	0.7225	5.200000
0.380000	0.012000000	0.6400	4.200000
0.400000	0.018750000	0.5625	3.600000
0.420000	0.027000000	0.4900	2.900000
0.440000	0.036750000	0.4225	2.500000
0.460000	0.048000000	0.3600	2.200000
0.480000	0.060750000	0.3025	1.900000
0.500000	0.075000000	0.2500	1.700000
0.520000	0.090750000	0.2025	1.500000
0.540000	0.108000000	0.1600	1.300000
0.560000	0.126750000	0.1225	1.200000
0.580000	0.147000000	0.0900	1.000000
0.600000	0.168750000	0.0625	0.950000
0.620000	0.192000000	0.0400	0.850000
0.640000	0.216750000	0.0225	0.750000
0.660000	0.243000000	0.0100	0.700000
0.680000	0.270750000	0.0025	0.650000
0.700000	0.300000000	0.0000	0.550000

OILGASPERM 1
*

Sg	Krg	Krog	
0.000000	0.000000	1.000000	0
0.028000	0.000000	0.896178	0
0.030000	0.000000	0.888980	0
0.050000	0.000022	0.818594	0
0.070000	0.000151	0.751111	0
0.090000	0.000485	0.686531	0
0.110000	0.001123	0.624853	0
0.130000	0.002161	0.566077	0
0.150000	0.003698	0.510204	0
0.170000	0.005831	0.457234	0
0.190000	0.008658	0.407166	0
0.210000	0.012277	0.360000	0
0.230000	0.016785	0.315737	0
0.250000	0.022281	0.274376	0
0.270000	0.028861	0.235918	0
0.290000	0.036625	0.200363	0
0.310000	0.045669	0.167710	0

0.330000	0.056091	0.137959	0
0.350000	0.067989	0.111111	0
0.370000	0.081461	0.087166	0
0.390000	0.096604	0.066122	0
0.410000	0.113517	0.047982	0
0.430000	0.132297	0.032744	0
0.450000	0.153041	0.020408	0
0.470000	0.175848	0.010975	0
0.490000	0.200815	0.004444	0
0.510000	0.228040	0.000816	0
0.525000	0.250000	0.000000	0
1.000000	1.00000	0.000000	0

APPENDIX C

Producer Constraints and Optimization Parameters

Optimization parameters are MAXDDP, MAXGOR and MAXOIL

MAXDDP W-01 {$MAXDDP}
MAXOIL W-01 {$MAXOIL}
MINBHP W-01 1450
WELLIMIT MAXWCUT W-01 0.9
WELLIMIT MAXGOR W-01 {$MAXGOR}

MAXDDP W-02 {$MAXDDP}
MAXOIL W-02 {$MAXOIL}
MINBHP W-02 1450
WELLIMIT MAXWCUT W-02 0.9
WELLIMIT MAXGOR W-02 {$MAXGOR}

MAXDDP W-03 {$MAXDDP}
MAXOIL W-03 {$MAXOIL}
MINBHP W-03 1450
WELLIMIT MAXWCUT W-03 0.9
WELLIMIT MAXGOR W-03 {$MAXGOR}

MAXDDP W-04 {$MAXDDP}
MAXOIL W-04 {$MAXOIL}
MINBHP W-04 1450
WELLIMIT MAXWCUT W-04 0.9
WELLIMIT MAXGOR W-04 {$MAXGOR}

MAXDDP W-05 {$MAXDDP}
MAXOIL W-05 {$MAXOIL}
MINBHP W-05 1450
WELLIMIT MAXWCUT W-05 0.9
WELLIMIT MAXGOR W-05 {$MAXGOR}

MAXDDP W-06 {$MAXDDP}
MAXOIL W-06 {$MAXOIL}
MINBHP W-06 1450
WELLIMIT MAXWCUT W-06 0.9
WELLIMIT MAXGOR W-06 {$MAXGOR}
*

APPENDIX D

Injection Constraints and Voidage Ratio Definition

```
==================================================
Defining water injection in W-01 and W-06
==================================================

MAXWATINJ W-01 1500
MAXBHPINJ W-01 4200

MAXWATINJ W-06 1500
MAXBHPINJ W-06 4200

==================================================
Defining gas injection in W-05
==================================================
INJGASCOMP W-05
1.0
MAXGASINJ W-05 1000
MAXBHPINJ W-05 4000

==================================================
Defining VRR of 1.0
==================================================
RECDATALIST GPINCINJ
GRPTARGET VOIDAGE ALLWELLS 1.0
MTBRLIMIT MINAVGPRES EQREG1 2600 GPINCINJ
ENDRECDATALIST

RECDATALIST GPDECINJ
GRPTARGET VOIDAGE ALLWELLS 0.9
MTBRLIMIT MAXAVGPRES EQREG1 2620 GPDECINJ
ENDRECDATALIST

MTBRLIMIT MINAVGPRES EQREG1 2600 GPINCINJ
MTBRLIMIT MAXAVGPRES EQREG1 2620 GPDECINJ
```

APPENDIX E

Simulation Deck

```
 MSc Thesis Simulation - All Deviated Wells - GenOpt Run for Optimization - 2010 Farhan
*
*************************************************************************
**
*CHECKDATA
*=======================================================
*              PROBLEM DESCRIPTION
*=======================================================
*
CHARARRAY  9700
MEGAWORDS  100
SIMULATOR CHEARS BLACKOIL
TITLE BEWX Horizontal Well Model
TITLE FEB 2010
START  01-NOV-2009
NOECHO INPUT
EQNSOLVER CLUB
*         RUN#       FLAG    ECLRSTRT
*RESTART     -1         1
FORMULATION OWG     IMPLICIT
MAXSWPR    5     5     5   5
MAXWELL    7    308    70
MAXGRPR    1
*
JFUNCTION  WATEROIL
NORMSATENDPT
NREGIONS   1     1    1
*                    NX          NY          NZ   NGRIDS
MODELSIZE       44        124         40       2
*MAXFLOT    1   5
MAXMTBRL   2   2
NHISTPI   2
* WMSOPTN SIMFRI
*=====================================================================
*    LGR SPECIFICATION
*=====================================================================
*GRIDDEF LGR1  CARTESIAN  2
*GRIDWINDOW   24     29    42    69     1    20   COARSE
*GRIDSIZE     18    28    20
*GRIDFORM  IMPLICIT

*XDIVISIONS
* 3 3 3 3 3 3
*YDIVISIONS
```

```
* 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
*ZDIVISIONS
* 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
*========================================================================
*                  OUT SPECIFICATION
*========================================================================
*
*MAPORIENT    XY
GRAPHOUTPUT   ECL
XYPOUTPUT     ECL
*MAPSINITIAL   FILE ALL
* TOPDEPTH
GRAPHINITIAL
 TOPDEPTH GROSS POROS PERMX PERMY PERMZ SWIR TRANX TRANY TRANZ
 SORW SORG SGC  PORVOL  MTBREG
GRAPHRECUR
 DATPRESS PRESS WSAT OSAT GSAT
 ORELPERM WRELPERM GRELPERM PCAPW
XYPLOT
 WELLS FIELD GROUP
EXCELFILE
 WELLS  FIELD  REGION
EXCELPRDFREQ  4   1
COMPFREQ      4   1
GRAPHFREQ     4
GROUPFREQ     4  1
WELLFREQ      4  1
XYPLOTFREQ    4  1
*IDEBUG       1  5
WMSFREQ       2
WMSOUTPUT     3  2  2
MTBFILEFREQ   2
MTBPRNTFREQ   2
GRAPHFREQ 1
*RESTARTFREQ  0
**
*
MTBOPT
 EQREG WATER SURFACE PORVOL
 EQOIL WATER SURFACE PORVOL
 EQAQF WATER SURFACE PORVOL
*
*--------------------------------------------------
*    FLUID PROPERTIES
*--------------------------------------------------


*
*      OIL API GRAVITY    Region
OILPROP API  38.61   #   #   1
```

```
*
* PRESSURE     FVF    VISC    RS      COMPR       DVIS
*  (psia)   (rbbl/STB)  (cp)  (SCF/STB)  (1/psi)     (1/psi)
    200.0     1.1266  0.373    32.65  1.4864E-04  6.9497E-05
    400.0     1.1443  0.364    70.18  7.9024E-05  6.9722E-05
    600.0     1.1642  0.353   111.64  5.6149E-05  7.0025E-05
    800.0     1.1859  0.340   155.95  4.4891E-05  7.0400E-05
   1000.0     1.2091  0.326   202.53  3.8250E-05  7.0841E-05
   1200.0     1.2337  0.312   251.03  3.3903E-05  7.1344E-05
   1400.0     1.2595  0.298   301.18  3.0857E-05  7.1903E-05
   1600.0     1.2865  0.283   352.80  2.8618E-05  7.2512E-05
   1800.0     1.3146  0.269   405.74  2.6914E-05  7.3165E-05
   2000.0     1.3438  0.256   459.88  2.5581E-05  7.3856E-05
   2200.0     1.3740  0.244   515.13  2.4515E-05  7.4579E-05
   2400.0     1.4051  0.232   571.40  2.3649E-05  7.5326E-05
   2600.0     1.4371  0.221   628.64  2.2934E-05  7.6090E-05
   2800.0     1.4701  0.211   686.78  2.2337E-05  7.6864E-05
   3000.0     1.5038  0.202   745.76  2.1835E-05  7.7640E-05
*
*   GAS GRAVITY (air = 1.000)  Region
GASPROP   0.8300  #   #   #   1
*
* PRESSURE     FVF       VISC
*  (psia)   (rbbl/MSCF)    (cp)
    200.0    18.3415     0.0144
    400.0     9.0334     0.0146
    600.0     5.9360     0.0148
    800.0     4.3924     0.0151
   1000.0     3.4705     0.0155
   1200.0     2.8600     0.0159
   1400.0     2.4279     0.0163
   1600.0     2.1075     0.0168
   1800.0     1.8617     0.0173
   2000.0     1.6683     0.0178
   2200.0     1.5129     0.0184
   2400.0     1.3861     0.0190
   2600.0     1.2811     0.0197
   2800.0     1.1932     0.0203
   3000.0     1.1188     0.0210

*      PRESS    WDEN    WVISC   WFVF    WCOMP
WATPROP  2200.           1.03      0.22   1.0308  4.32E-6
*
RESTEMP   304
```

*==

```
*              COUPLED ROCK-FLUID PROPERTIES
*======================================================================
*
JFUNCTWATOIL   2    1
   12.5
*
WATEROILPERM 1

**   Sw     Krw        Krow       Pcow
0.300000         0.0000000       1.0000  10.0000
 0.320000        0.000750000     0.9025  7.200000
 0.340000        0.003000000     0.8100  6.200000
 0.360000        0.006750000     0.7225  5.200000
 0.380000        0.012000000     0.6400  4.200000
 0.400000        0.018750000     0.5625  3.600000
 0.420000        0.027000000     0.4900  2.900000
 0.440000        0.036750000     0.4225  2.500000
 0.460000        0.048000000     0.3600  2.200000
 0.480000        0.060750000     0.3025  1.900000
 0.500000        0.075000000     0.25     1.700000
 0.520000        0.090750000     0.2025  1.500000
 0.540000        0.108000000     0.1600  1.300000
 0.560000        0.126750000     0.1225  1.200000
 0.580000        0.147000000     0.0900  1.000000
 0.600000        0.168750000     0.0625  0.950000
 0.620000        0.192000000     0.0400  0.850000
 0.640000        0.216750000     0.0225  0.750000
 0.660000        0.243000000     0.0100  0.700000
 0.680000        0.270750000     0.0025  0.650000
 0.700000        0.300000000     0.00     0.550000
*
OILGASPERM 1
*       Sg    Krg     Krog
 0.0000          0.0000          1.000000  0
 0.028000        0.0000          0.896178  0
 0.030000        0.0000          0.888980  0
 0.050000        0.0022          0.818594  0
 0.070000        0.000151        0.751111  0
 0.090000        0.000485        0.686531  0
 0.110000        0.001123        0.624853  0
 0.130000        0.002161        0.566077  0
 0.150000        0.003698        0.510204  0
 0.170000        0.005831        0.457234  0
 0.190000        0.008658        0.407166  0
 0.210000        0.012277        0.360000  0
 0.230000        0.016785        0.315737  0
 0.2500          0.022281        0.274376  0
 0.270000        0.028861        0.235918  0
 0.290000        0.036625        0.200363  0
 0.310000        0.045669        0.167710  0
```

```
 0.330000         0.056091          0.137959   0
 0.350000         0.067989          0.111111   0
 0.370000         0.081461          0.087166   0
 0.390000         0.096604          0.066122   0
 0.410000         0.113517          0.047982   0
 0.430000         0.132297          0.032744   0
 0.450000         0.153041          0.020408   0
 0.470000         0.175848          0.010975   0
 0.490000         0.200815          0.004444   0
 0.510000         0.228040          0.000816   0
 0.525000         0.2500            0.0000     0
 1.000000          1.00000          0.0000     0
*

*DEFINE RELATIVE PERM for PRODUCING WELL

THREEPHASEPERM        LINE

* Rock Compressibility
*          ROCK COMP.     REF. PRESS.     REGION
RCOMPRESS     8.0E-6         2622           1

*         CT SM ALAMBDA
GASHYST   2.33   1   4    1

*=====================================================
*            INITIALIZATION DATA
*=====================================================
* EQUIL Equilibrium Conditions Specification
* Reservoir is saturated with water/oil contacts
*                     Depth     Pressure OWC      GOC
*                     (ft.)        (psia)   (ft.)    (ft.)
EQUILIBRIUM    6600       2622       6662          #
*
RSRLINIT
 EQUILRSRL
   634.9
*
*          DEPTH
DATUMPRES    6600
*
*
* ----------------------
* GRID BASIC PROPERTIES
* ----------------------
* Grid Structure and Properties
INCLUDE
'/data/pnz_work_02/Humma_Handover/BEWX/Includes/65_9_Sand_20x20x40Layers_cut_2
3NOV09_output.grid
```

```
XPERM
 ALL * 1.00
*
XPERM
 ALL < 4000
*
YPERM
 COPY XPERM
*
ZPERM
 COPY XPERM
*
ZPERM
 ALL * 0.1
*
SWIR
 ALL = 0.27
*
SWIR
 ALL < 0.9719
*
* Sets Sorw to 0.30 (or less if required)
SORW
  COPY  SWIR
SORW
  ALL  - 1.
SORW
  ALL  * -1.
SORW
  ALL  - 0.001

SORW
  ALL  <  0.25
*
*
* Sets Sorg to 0.25 (or less if required)
SORG
  COPY  SWIR
SORG
  ALL  - 1.
SORG
  ALL  * -1.
SORG
  ALL  - 0.050
SORG
  ALL  <  0.15
SORG
  ALL  >  0.01
*
*
```

```
*POREVOLUME
* ALL * 1.00
*
INCLUDE '/data/pnz_work_02/Humma_Handover/BEWX/Includes/BEWX_59-6_Aqux5.dat
*

*MAXDDP W-05 {$MAXDDP}
*MAXOIL W-05 {$MAXOIL}
*MINBHP W-05 1450
*WELLIMIT MAXWCUT W-05 0.9
*WELLIMIT MAXGOR W-05 {$MAXGOR}
*
MAXDDP W-02 {$MAXDDP}
MAXOIL W-02 {$MAXOIL}
MINBHP W-02 1450
WELLIMIT MAXWCUT W-02 0.9
WELLIMIT MAXGOR W-02 {$MAXGOR}
*
MAXDDP W-03 {$MAXDDP}
MAXOIL W-03 {$MAXOIL}
MINBHP W-03 1450
WELLIMIT MAXWCUT W-03 0.9
WELLIMIT MAXGOR W-03 {$MAXGOR}
*
MAXDDP W-01 {$MAXDDP}
MAXOIL W-01 {$MAXOIL}
MINBHP W-01 1450
WELLIMIT MAXWCUT W-01 0.9
WELLIMIT MAXGOR W-01 {$MAXGOR}
*
MAXDDP W-06 {$MAXDDP}
MAXOIL W-06 {$MAXOIL}
MINBHP W-06 1450
WELLIMIT MAXWCUT W-06 0.9
WELLIMIT MAXGOR W-06 {$MAXGOR}
*
MAXDDP W-04 {$MAXDDP}
MAXOIL W-04 {$MAXOIL}
MINBHP W-04 1450
WELLIMIT MAXWCUT W-04 0.9
WELLIMIT MAXGOR W-04 {$MAXGOR}
*
*
GRAPHFREQ 2
DATE   10-NOV-2009
DATE   10-DEC-2009
DATE   10-FEB-2010
GRAPHFREQ 2
DATE   10-APR-2010
DATE   10-JUL-2010
```

```
DATE   10-SEP-2010
DATE   10-DEC-2010
DATE   10-FEB-2011
DATE   10-APR-2011
DATE   10-JUL-2011
GRAPHFREQ 2
DATE   10-SEP-2011
DATE   10-NOV-2011
DATE   10-JAN-2012
DATE   10-MAR-2012
GRAPHFREQ 2
DATE   10-JUN-2012
DATE   10-AUG-2012
DATE   10-OCT-2012
DATE   10-DEC-2012
DATE   10-FEB-2013
DATE   10-MAR-2013
DATE   10-APR-2013
DATE   10-JUL-2013
DATE   10-OCT-2013
DATE   10-DEC-2013
STOP
DATE   10-FEB-2014
DATE   10-APR-2014
DATE   10-JUN-2014
STOP
```

VITAE

Farhan Jamil was born on February 16, 1975 in Lahore, Pakistan. He received his B. Eng in Petroleum Engineering from Faculty of Mining and Petroleum Engineering, University of Engineering and Technology Lahore, Pakistan in 2000. After graduating, he worked for 1 year as Drilling Engineer with OMV, an Austrian Oil And Gas Company operating in Pakistan. He joined BP Pakistan Exploration and Production Inc. in April 2001 and worked as Production Engineer for 1 year and Reservoir Engineer for 6 years. He joined Chevron Thailand Exploration and Production Inc. in October 2007. In April 2009, he continued his study in the Master of Petroleum Engineering program at the Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University.