Strategies for Heavy Oil Production with Thermal Recovery in Heterogeneous Reservoir

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กลยุทธการผลิตน้ำมันหนักโดยใช้ความร้อนในแหล่งกักเก็บวิวิธพันธุ์

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วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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น้ำมันหนักเป็นหนึ่งในแหล่งพลังงานที่สำคัญในอนาคต อย่างไรก็ตามด้วยความหนืดของน้ำมันหนัก ทำให้ต้องใช้การอัดฉีดด้วยไอน้ำซึ่งเป็นเทคนิคที่สำคัญชนิดหนึ่งในการผลิตน้ำมันประเภทนี้ ในปัจจุบัน มีงานหลายชิ้นที่ศึกษาไว้ได้ประเมินวิธีการผลิตไว้หลายวิธีเพื่อที่จะหาสภาวะการใช้งานที่เหมาะสม แต่เป็นที่น่าเสียดายว่าไม่มีค่าใดเลยที่เหมาะสมที่จะใช้สำหรับทุกแหล่งกักเก็บหรือทุกวิธีในการผลิต ในการศึกษาในครั้งนี้ มีจุดประสงค์เพื่อตรวจสอบกลยุทธ์ในการเลือกระยะห่างระหว่างหลุม, อัตราการฉีดและช่วงเวลาที่ใช้ในการพัฒนาพื้นที่ต่างๆโดยอยู่บนพื้นฐานของข้อมูลจริงของพื้นที่

ข้อมูลจริงของพื้นที่จะถูกประยุกต์ใช้กับการสร้างแบบจำลองกระบวนการการอัดฉีดด้วยไอน้ำด้วยรูปแบบหลุม 5 หลุม แบบผกผันโดยใช้สตาร์ซึ่งเป็นโปรแกรมของซีเอ็มจี ระยะเวลาในการผลิตจากแบบจำลองอยู่ที่ 20 ปี ค่าบรรทัดฐานวนการตัดสินปัจจัยที่พิจารณาขึ้นอยู่กับตัวแปรที่ถูกถ่วงน้ำหนักที่สัดส่วน 1.37:1 ของความสามารถในการผลิตน้ำมันได้สูงสุดต่อพื้นที่ต่อหลุมและอัตราส่วนไอน้ำต่อน้ำมันต่อพื้นที่ต่อหลุม

ผลของแบบจำลองแสดงให้เห็นว่าระยะห่างระหว่างหลุมที่ฉีดและหลุมผลิตที่ 282.8 เมตร และอัตราฉีดที่ 120 ลบ.มต่อวัน จะให้สภาวะที่เหมาะสมที่สุด ดังนั้นในกรณีที่พิจารณาช่วงเวลาของการพัฒนาพื้นที่ที่แตกต่างกันในช่วงเวลา 10 ปี ซึ่งช่วง 10 ปีแรกที่ผลิตเฉพาะโซน 1 จะได้ว่า ระยะห่างของหลุมที่ 141.4 เมตร และอัตราการฉีดที่ 120 ลบ.ม ต่อวัน จะให้ค่าที่เหมาะสมที่สุด แต่ในช่วงรวม 20 ปี ระยะห่างของหลุมที่ 141.4 เมตร และอัตราการอัฉีดที่ 30 ลบ.ม ต่อวัน จะให้ค่าที่เหมาะสมมากกว่า

ภาควิชา	วิศวกรรมเหมืองแร่และปิโตรเลียม	ลายมือชื่อนิสิต	....
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Heavy-oil is one of the main energy sources in the future. However, with the high viscosity of heavy oil, steam-flooding is one of the major techniques to produce this oil. To determine a favorable operating condition, many recent studies have evaluated different methods. However, there is no single optimum value for all reservoirs or all modes of operation. In this study, it’s aimed to investigate the strategies of selecting well spacing, injection rate, and different development periods in various areas, based on the real field data.

The practical field data has been applied to simulate the inverted 5-spot steam-flooding process by using STARS, a CMG program. The project life is simulated in 20 years of production. Judging criteria of parameters are dependent on the weighted factors (1.37: 1) of maximum recovery factor/area/well and minimum cumulative steam-oil ratio/area/well.

The simulation results show that the injector - producer distance at 282.8 m with 120 m^3/d injection rate yields the most favorable conditions for the selection of well spacing and injection rates. Therefore, the field is evaluated by operating different areas in 10 years time basis. It's indicated that the injector - producer distance at 141.4 m with 120 m^3/d injection rate is preferred for the first 10 years' operation in zone 1 area only. In terms of 20 years, the injector - producer distance at 141.4 m with 30 m^3/d injection rate is more favorable.

Department:	Mining and Petroleum Engineering	Student's Signature	....
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CHAPTER 1
INTRODUCTION

1.1 Background

Crude oil occurs in various forms over the world. One of the significant characteristics of crude oil is its density and viscosity which can affect the ease of production. Typically, lighter crude oil can be produced more easily and more economical than heavier crude oil (Veil and Quinn, 2008). Historically, most of the oil supplies come from domestic or international light and / or medium crude oil sources. With an increasing of global demands and economic growth over the last century, oil and gas companies were actively looking toward heavier crude oil sources where the large heavy oil reserves located in North and South America as well as tar sands or oil sands in Canada and some fields in California and Venezuela. (Veil and Quinn, 2008)

1.1.1 Properties of Heavy Oil

Although API gravity has no units, it is expressed in degrees. API gravity is graduated on a special hydrometer designed for measuring specific gravities of petroleum liquids so that most values fall between 10° and 70°. This grading, recommended by the U.S. Department of Energy, is followed as a standard used for comparing crude oil samples from different basins and countries. The higher the API, the higher commercial value it is. Interestingly, crude oil with API gravity greater than 10° floats in water; lower than 10°, it sinks. On the basis of its API gravity, crude oil is graded into light (> 31.1°), medium (22.3° – 31.1°), heavy (< 22.3°), and extra heavy or bitumen (< 10°) (Chopra et al., 2010). Moreover, density correlates with many other oil properties. At standard conditions, density is used to define API gravity. Density is not constant but it changes with pressure or temperature. Viscosity is one of the defining attributes to heavy oils. Generally, it increases with a decrease in temperature and in API. Figure 1.1 shows some examples of variation for oil viscosity (or density) with temperature as computed from the empirical relationship given by Beggs and Robinson (1975), which produces a singularity at low temperatures. The data from Eastwood (1993) and Edgeworth et al. (1984) are also plotted. The heavy oil relationship from De Ghetto et al. (1995) is also indicated.

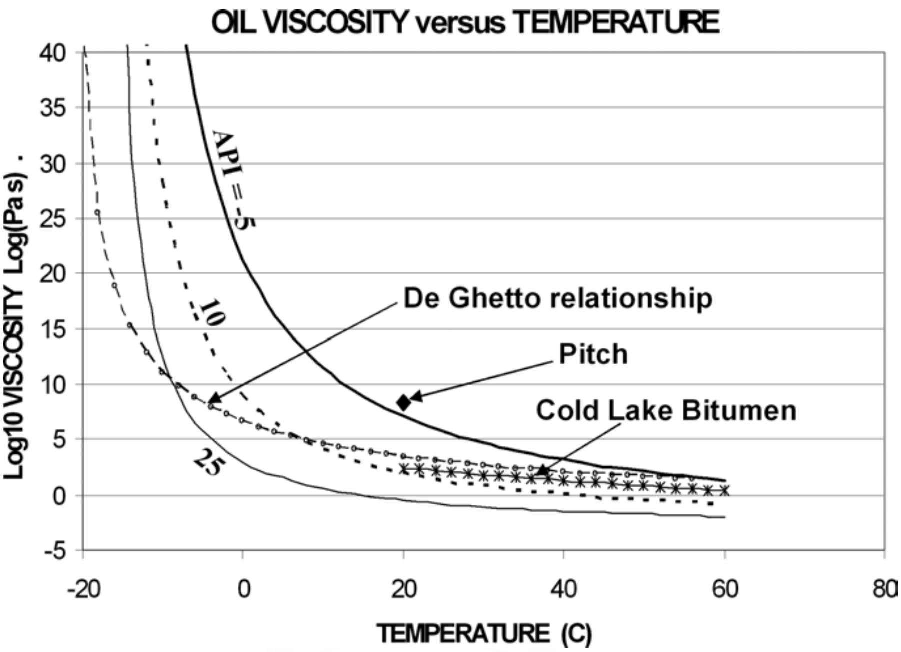

Figure 1.1 Variation of viscosity with temperature. (Batzle et al., 2006)

As heavy oil consists of complex heavy compounds, the simple empirical trends developed for estimating light oil fluid properties such as viscosities, densities, GORs, and bubble points seldom apply. Although some of these empirical trends may be obeyed at higher temperatures, the viscosity of heavy oils is high at lower temperatures, exhibiting different properties that necessitate special consideration. Therefore, the viscosity of heavy oils is very important because production methods exploit this property (Chopra et al., 2010).

The physical properties of heavy oil / bitumen must be understood to anticipate production performance and calculate reserves. These properties are determined from laboratory experiments on samples collected from formations of interest or from the surface. Empirical correlations derived from such experiments are applicable in a well-defined range of reservoir fluid characteristics; thus, when the laboratory pressure-volume-temperature (PVT) data become available, the required information can be derived from the empirical correlations (Chopra et al., 2010).

1.1.2 Heavy Oil Resources

The two main forms of heavy oil typically described in the literature, which are viscous heavy oil and oil sands (bitumen) (Veil, 2008). Oil sands are naturally occurring mixtures of sand, clay, water, and bitumen. Bitumen and synthetic oil extracted from oil sands are often referred to as “unconventional” to distinguish them from the free-flowing crude oil recovered from oil wells. Oil sands have recently been incorporated to the world’s oil reserves because the available technology can help in recovering oil and other useable products that are economically viable in current market conditions.

Heavy oil and oil sands are found in many countries including the United States, Mexico, Russia, China, and some in the Middle East as shown in Figure 1.2. However, the largest deposits of oil sands are found in Canada and Venezuela and their combined reserves equal the world’s total reserves of conventional oil. In Canada, oil sands are found in the Athabasca, Peace River, and Cold Lake regions of Alberta, covering an area of nearly 141,000 km^2. Heavy-oil deposits (8° – 19° API) are also found in the Alberta / Saskatchewan border in the area of Lloydminster.

The Athabasca deposit is the only one in the world where oil sands are present shallow enough they can be mined on the surface. Approximately 10% of the Athabasca oil sands are covered by less than 75 m of overburden. Close to 3400 km^2 of mineable area lies to the north of Fort McMurray. The oil sands below are typically 40 to 60 m thick and reside on top of a limestone formation (Chopra et al., 2010).

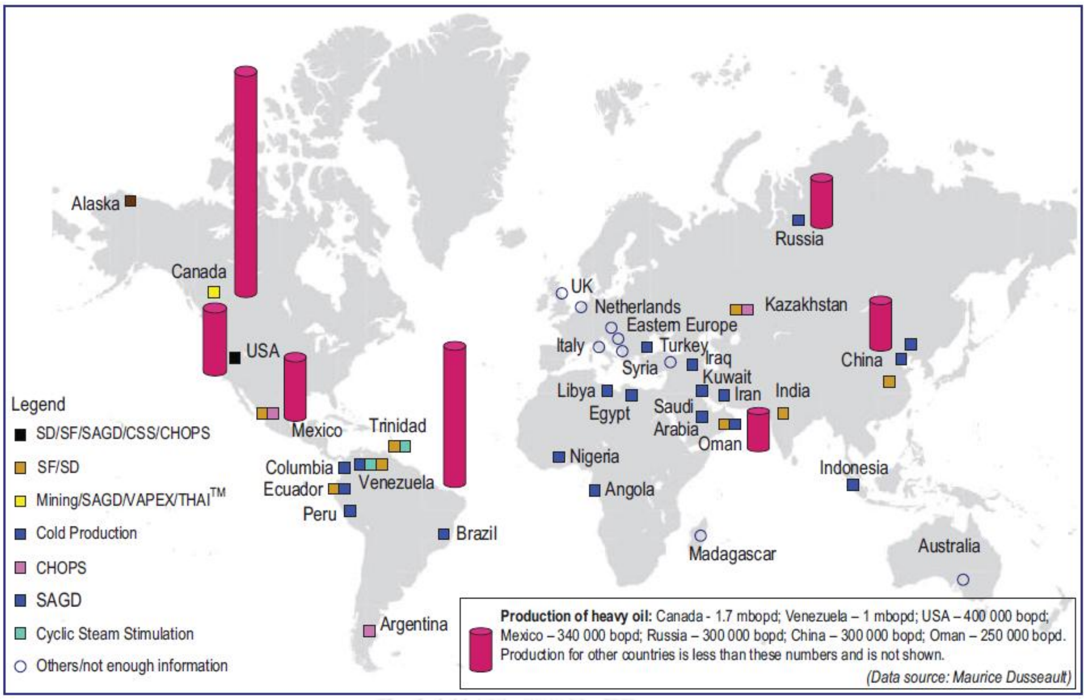

Figure 1.2 Production of heavy oil worldwide in barrels of oil per day.(Dusseault et al., 2008)

1.1.3 Heavy Oil Recovery

Heavy oil deposits are found in many locations of the world. They may have many different geological and climatic conditions. These factors, along with the viscosity and API gravity of different heavy oil deposits, lead to a wide array of technologies for producing the oil.

When heavy oil deposits are located close to the surface, physical removal (or open pit mining) may be a cost-effective technology. However, over 90% of the oil sands being inaccessible by conventional surface mining, there is an economic incentive to develop in-situ recovery technology.

In-situ recovery techniques, usually involving steam injection or underground combustion, are applied to reduce the viscosity of the bitumen, allowing it to be pumped to the surface. Economic recovery of these vast bitumen reserves is dependent on developing new in-situ processes to compete against thermal and secondary / tertiary recovery costs. Steam Assisted Gravity Drainage (SAGD), Cold Flow Production, and Borehole Mining are among those leading the way to lower production costs (Vant et al., 1994). Some of the state-of-the-art technologies will be discussed in details in the next chapter. Basically, any thermal recovery techniques are a kind of thermal processes under Enhanced Oil Recovery (EOR) processes.

1.2 Enhanced Oil Recovery (EOR)

In general, the frontiers beyond the conventional exploration and production strategies is a collection of technologies-involving the use of thermal, gas and chemical means for producing more oil that fall under the broad umbrella called Enhanced Oil Recovery (EOR). EOR refers to oil recovery over and above that obtained through the natural energy of the reservoir. Within this broad definition, a variety of processes is presented in Figure 1.3.

Before initiating EOR, the reservoir and its oil saturation should be understood clearly. This is normally done by using past analytical data and production history of the field and within the limits of economic investment, new geophysical surveys, tracer analyses and core studies to define the reservoir as accurately as possible. This information furnishes the rational basis for prediction of recoverable oil reserves by various proven techniques for EOR. The choice of the EOR techniques is dependent upon the amount of oil in place as well as other considerations such as depth, oil viscosity, formation, etc.

Zekri et al. (2000) indicated the worldwide production statistics that the ultimate recovery from light and medium gravity oils by conventional (primary / secondary) methods is around 25-35 % of the original oil in place (OOIP), while from heavy oil deposits on the average, only 10 % OOIP is recoverable. Hence leaving substantial percentage of oil in place non recoverable by the conventional methods and these reaming reserves are the target of the EOR to increase the recovery percentage.

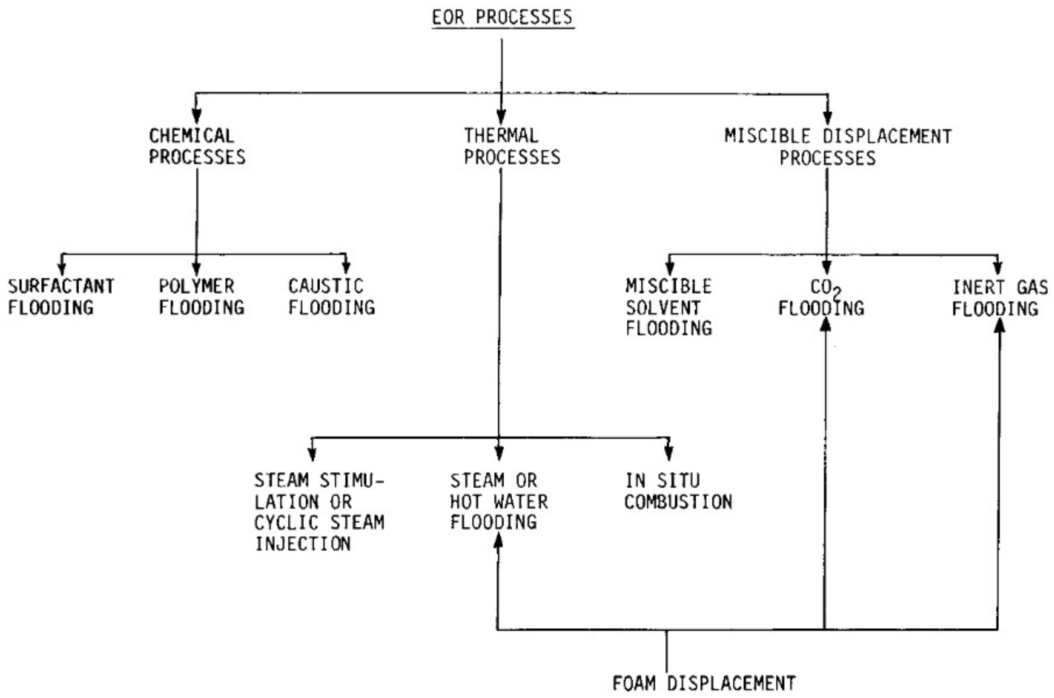

Figure 1.3 Variety of EOR processes. (Donaldson et al., 1989)

EOR processes are traditionally divided into three main groups: thermal processes; gas injection or miscible displacement processes; and chemical processes.

For heavy oil production, thermal processes in form of the steam injection are the first ones to be used in the heavy-oil industry, as the earliest fields discovered and saturated by high viscosity heavy oils is found at depths of just a few hundred meters. The main objective of these processes is to improve the mobility of the oil by reducing its viscosity through heat transfer. However, greater depths increase heat losses, reduce the benefits of heat transfer between steam and the field fluids (the greater the depth, the higher the temperature of the field), and increase the risks of damage to facilities due to the effects of the higher temperature and pressure the steam must possess (Bellussi and Zennaro, 2007)

Regarding the gas injection processes, the gas that is injected into the reservoir should be miscible with oil so that the process of displacement in the pores of the rock will be really effective. It can be applied in both clastic and carbonaceous non-fractured reservoirs, at depths of more than 1,000 m and with a greater than 20 - 30 %

saturation in oil (Bellussi and Zennaro, 2007). There are no constraints linked with temperature; indeed the higher it is, the greater the probability of the miscibility of the gas with the oil. The recommended density and viscosity values of the oil are higher than 22° API and 1.5 mPa·s respectively. Upon contact between the gas and the oil, a cushion of miscibility is generated in the reservoir, which favors the displacement of the oil and reduces the mobility of the gas which would tend to precede the oil to the producer wells, leading to a premature escape and a consequent low recovery. However, if these conditions cannot be achieved, the oil displacement process is not practicable due to problems of miscibility (Bellussi and Zennaro, 2007).

The EOR processes that use chemical products require more complex management than do thermal processes, regarding both choice of products and assessment of the real performance of field applications. Generally, the chemical products in use can simply increase the viscosity of the water used for displacing the oil; so that the mobility of the water decreases and the displacement front is more homogeneous. The fields that can benefit from the application of chemical processes should be located at a depth of less than 5,000 m and at temperatures that should not exceed 90 °C. The oil should have a density of more than 15° API for polymer flooding or 20° API for the other processes, and so the viscosity of the oil should be less than 150 mPa·s for polymer flooding and 35 mPa·s for the other processes. However, most of the chemical processes are costly and its effectiveness is more difficult to determine because of the non-uniform features present in all reservoirs. This is especially true if these reservoirs are in an advanced state of exploitation and therefore have an oil distribution impossible to assess with present methods (Bellussi and Zennaro, 2007).

In terms of heavy oil recovery, thermal processes have been confined as a major technique to recovery this type of crude due to two important parameters. They are viscosity and density (or API gravity), which distinguish the differences between heavy oil and conventional oil. From a reservoir engineer perspective, the viscosity of heavy oil is relatively more important parameter as it decides the production strategy to be applied in the reservoir. For a process engineer, the API gravity is more significant since it determine the yield from distillation and the type of upgrader required (Revana and Erdogan, 2007).

1.3 Heavy Oil Production by Steam-Flooding (SF)

Steam injection is the principal enhanced oil recovery (EOR) method used today. It is one of the most successful techniques for improving oil recovery in heavy oil field. A steam-flooding project typically proceeds through four phases of development: (1) reservoir screening; (2) pilot tests; (3) field implementation; and (4) reservoir managements. Performance prediction is essential to provide information for proper execution of each of these development phases. (Chandra, 2006)

Steam-flooding (SF) is a major EOR process applied to heavy oil reservoirs. SF uses separate injection and production wells to improve both the rate of production and the amount of oil that will ultimately be produced. Injected steam heats the formation around the wellbore and eventually forms a steam zone that grows with continuous steam injection. Steam reduces the oil viscosity and saturation in the steam zone to a low value, pushing the mobile oil out of the steam zone. As the steam zone grows, more oil is moved from the steam zone to the unheated zone ahead of the steam front. Then the oil accumulates to form an oil bank. The condensed hot water also moves across the steam front, heating and displacing the accumulated oil. The heated oil with reduced viscosity moves towards the producing well and usually is produced by artificial lifting.

However, the huge energy consumption in SF operation can impact to operating cost as well as project life. In fact, the steam-flood performance can be linked to several design parameters. Roberts (1961) stated that optimum well spacing is usually controlled by economic considerations rather than reservoir considerations. Normally, closer the well spacing can cause the higher recovery, but the steam consumption is increased at the same time. Besides, Messner (1990) indicated that the heat injection rates are routinely reduced as a steam-flood project approaches its economic limit. The major benefit of this practice is to reduce the fuel costs and thus extend the economic life of the project. As such, the design of steam injection rates and well spacing to produce heavy oils becomes more significant with the respect to the economic impact, in which the project life would be determined by the economic limits.

1.4 Objectives and Outline

Heavy oil is one of the main energy sources in the future. However, the drawback of heavy oil is the high viscosity thus making it difficult and expensive to produce. Based on the actual field data, the objective of this study is to investigate the steam injection strategies by using steam-flooding (SF) in heterogeneous heavy oil reservoir. The strategies include selection of well spacing, injection rate, and the development in different areas in different time basis.

The expected results from this study will allow us to determine favorable production strategies regarding the particular field. Under the current oil price crisis, applying the weighted factors to the judging criteria can screen out a preferable strategy for the current economic environment.

This thesis is divided into five chapters as shown below: Chapter I introduces the background of heavy oil, EOR and indicates the objective and contribution of this study. Various theories and literatures related to the techniques in heavy oil recovery are summarized in Chapter II. Chapter III provides the details of heterogeneous reservoir models, model dimension and input parameters in reservoir simulation model by using CMG STARS software. Moreover, the details of methodology and assumptions are presented in this chapter. Chapter IV presents the result and discussion for simulation study for each proposed strategy. Conclusion and recommendation will be presented in Chapter V.

CHAPTER 2
THEORY AND LITERATURE REVIEW

This chapter summarizes the previous studies related to heavy oil recovery process in past decades. Steam injection is a remarkable technique used in the normal field practice. Many investigators from different oil fields have studied and evaluated various SF operations in terms of thermal process, well pattern, and operating conditions. As such, some of the previous heavy oil projects are also reviewed.

2.1 Technologies for Heavy Oil Production

Basically, most of the successful technologies to heavy oil production are based on pressure driven flow to wells, a process dominated by the permeability of sand and the viscosity of the oil, thermal methods to reduce viscosity and high differential pressures to promote flow are the obvious choice.

Thermal processes linked with steam injection are the first ones to be used in the oil industry, as the earliest fields discovered and saturated by high viscosity heavy oils occurred at depths of just a few hundred meters. The main objective of these processes is to improve the mobility of the oil by reducing its viscosity through heat exchange.

In general, steam injection thermal processes are applied to fields that are between 150 and about 1,500 m deep and that are around 20 m thick. Greater depths increase heat losses, reduce the benefits of heat exchange between the steam and the field fluids (the greater the depth, the higher the temperature of the field), and increase the risks of damage to facilities due to the effects of the higher temperature and pressure the steam must possess (optimal values are between 150 and 200°C). Ideal candidates are the fields having high values for permeability (1,000-4,000 md) and porosity (greater than 20%) and with oil saturations greater than at least 40%. The viscosity of the oil should be between 200 and 1,000 mPa·s and density between 10 and 30°API (Bellussi and Zennaro, 2007). In reality, heterogeneous permeability in a reservoir handicaps any recovery method in which fluids are pushed into the reservoir from one set of wells, while fluids are withdrawn from others. This includes water-flooding as well as all non-thermal EOR methods.

Apart from thermal methods, surface mining and non-thermal methods are other techniques in heavy oil recovery, but implementation of non-thermal EOR is unlikely to be widespread until a gap emerges between demand and the supply capacity from conventional and heavy oil reservoirs. Therefore, there is unlikely to be enough incentive within industry or government to seek major innovations in EOR. In fact, non- thermal methods have had small commercial successes. It's because such concepts have been proven under difficult conditions. Companies often allow any new concepts to be tried only on poor quality assets. That means the initial trials may take place in much less than optimum conditions. (Bellussi and Zennaro, 2007)

Heavy-oil recovery techniques can be divided into surface mining and in situ recovery as below as shown in Figure 2.1 and some techniques are presented in the next section.

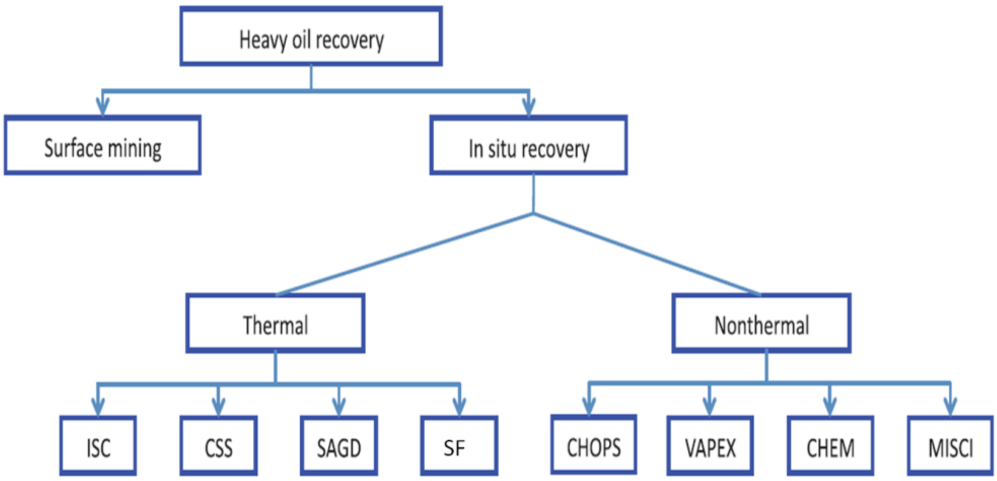

Figure 2.1 Block diagram showing the classification of different heavy-oil recovery methods

2.1.1 Cyclic Steam Stimulation (CSS)

Cyclic steam stimulation (CSS), also called steam soak or “huff-and-puff” method, uses steam injection to recover heavy oil. CSS is a near well bore stimulation process used to increase production from wells producing high viscosity crude oil. This process utilizes a many different recovery mechanisms such as oil viscosity reduction, solution gas drive, formation re-compaction and fluid expansion. This process is often used in the heavy oil fields as a precursor for steam-flooding (SF). Using CSS ensures that the reservoir pressure is sufficiently reduced for large scale SF; meanwhile, it enables the well bores to be sufficiently pre- heated and producing economic amount of oil.

This process is divided into 3 stages: a) Steam Injection; b) Steam Soak; c) Oil Production as presented in Figure 2.2. (Revana and Erdogan, 2007)

These 3 stages together make up one complete cyclic steam stimulation cycle. This process can be repeated over several cycles. The number of cycles to which each well submitted is controlled by surrounding geological parameters and fluid characteristics. One of the major advantages of this process is that all the wells in the field can be simultaneously under production, unlike steam flooding, modifications of this process by injection of additional slugs of gas, diluents or some other cheap refinery cut with steam has a beneficial effect of reducing oil viscosity and providing some solvent and miscibility effects to the viscous heavy oil being stimulated.

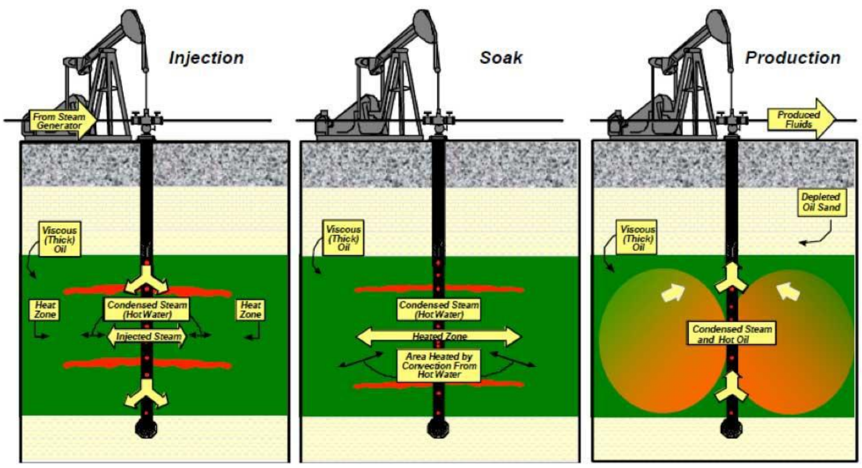

Figure 2.2 Process of Cyclic Steam Injection (“Project Indian,” 2014)

2.1.2 Steam-Assisted Gravity Drainage (SAGD)

SAGD has a much higher recovery factor, potentially more than 70% of the original oil in place, because it overcomes the inherent limitation of CSS — insufficient lateral drive available to move the hot oil to the producer well. Because vertical wells have limited contact with the reservoir, the lateral or radial flow requires considerable pressure, which is not there. The SAGD, pioneered by Butler (1985) and Butler and Stephens (1981), makes use of two long horizontal wells and gravity drainage to move the oil (its viscosity temporarily altered) to the production well.

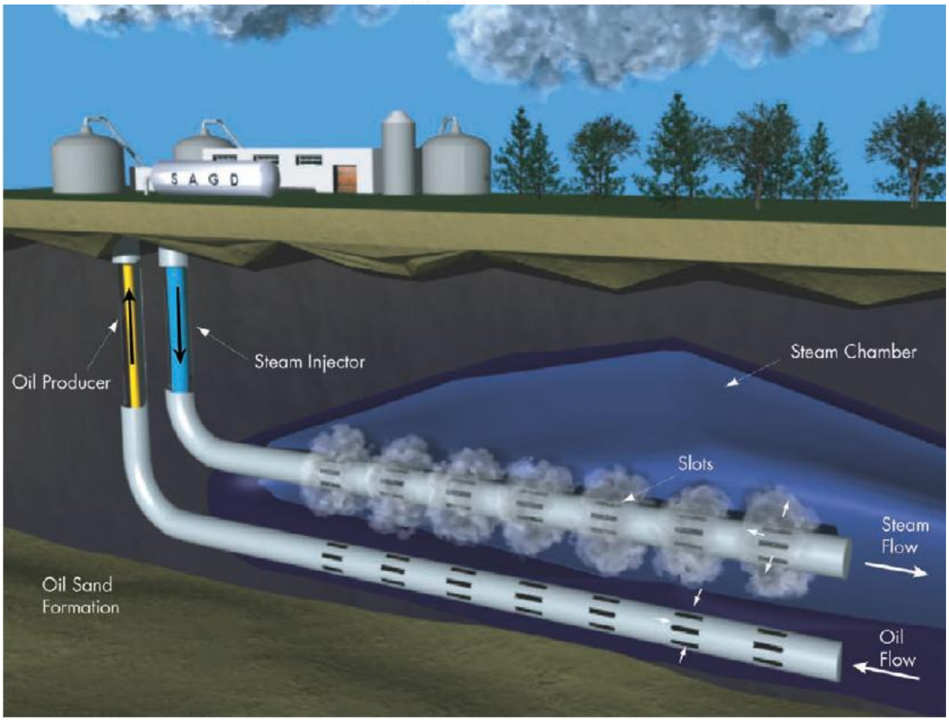

Figure 2.3 SAGD heavy-oil recovery process. Image courtesy of The Pembina Institute

High-pressure steam injection in vertical wells has been used for some time. In steam flooding, as it is called, injection is usually carried out in a pattern, the most common being a five-point pattern, with the steam injection well at the center surrounded by producers. The steam injected at the center produces an expanding heat front into the formation. As it advances laterally, it forms a hot water-flood zone just ahead of the steam zone, which in turn tends to cool down to formation temperature. The gas drive effect that steam exerts outward from the injection point pushes the mobilized oil in the direction of the producers. This method works for heavy-oil formations but not for bitumen, which is difficult to push to start any adequate flow. Steam-flooding has typical recovery factors as high as 50%. (Chopra et al., 2010).

SAGD improves on steam-flooding principles. Two parallel horizontal wells are drilled into the formation in the same vertical plane as presented in Figure 2.3. The upper well is used as a steam injector and the lower well as a producer. As steam is injected into the upper well, it rises to the top of the formation and sideways and forms a steam saturated zone called a “chamber,” which has the almost uniform temperature and pressure of steam. This heat is conducted to the bitumen, reducing its viscosity and making it mobile. As the steam chamber expands with injection, it also condenses at the periphery of the chamber. The bitumen and the condensate drain under gravity to be collected by the producer. For this to happen, the vertical permeability in the reservoir needs to be high. Consequently, the placement of the horizontal wells has to be such that neither shale stringers nor vertical barriers interfere between them (Chopra et al., 2010). To implement SAGD, the horizontal well drilling programs must be carried out before substantial sand production has occurred to avoid lost circulation during drilling. Also, one of the drawbacks is that vertical wells do not have to be completed as expensively as horizontal wells (Dusseault, 2002).

Used most effectively in the Alberta oil sands, SAGD is very suitable for bitumen reservoirs that are too deep to mine but shallow enough to permit high steam pressures. The efficiency of the process increases at higher temperatures and higher steam pressures, although it depends on the viscosity of the bitumen or heavy oil and on the properties of the reservoir zone being drained. Usually SAGD wells are drilled in groups off central pads and their lateral reach in terms of horizontal sections is very large. The distance between two SAGD wells is dependent on the thickness of the reservoir zone, but a 5 m separation is common. For thinner zones, the distance between wells is much shorter, 1 m or less for a 20 m pay (Chopra et al., 2010).

2.1.3 Steam-Flooding (SF)

SF is a displacement process that involves at least 2 set of wells, injector and producer wells. Injector wells inject the desired amount of steam into the formation to displace the heated oil towards the producer wells. Heat from the injected steam reduces the viscosity of the oil as the injected fluid drives the oil from an injector to a producer. SF contacts a larger area of the reservoir and hence recovers a larger percentage of Oil in Place (OIP).

Furthermore, SF involves conversion of some of the production wells into injection wells which requires a continuous steam supply. Basically, steam is pumped through vertical injection wells into a heavy oil formation. The steam rises through the formation until it encounters a barrier, then spreads out laterally. The steam warms the heavy oil and drives it toward the production well. Another important mechanism is the increased reservoir pressure owing to steam injection. Figure 2.4 presents the SF process.

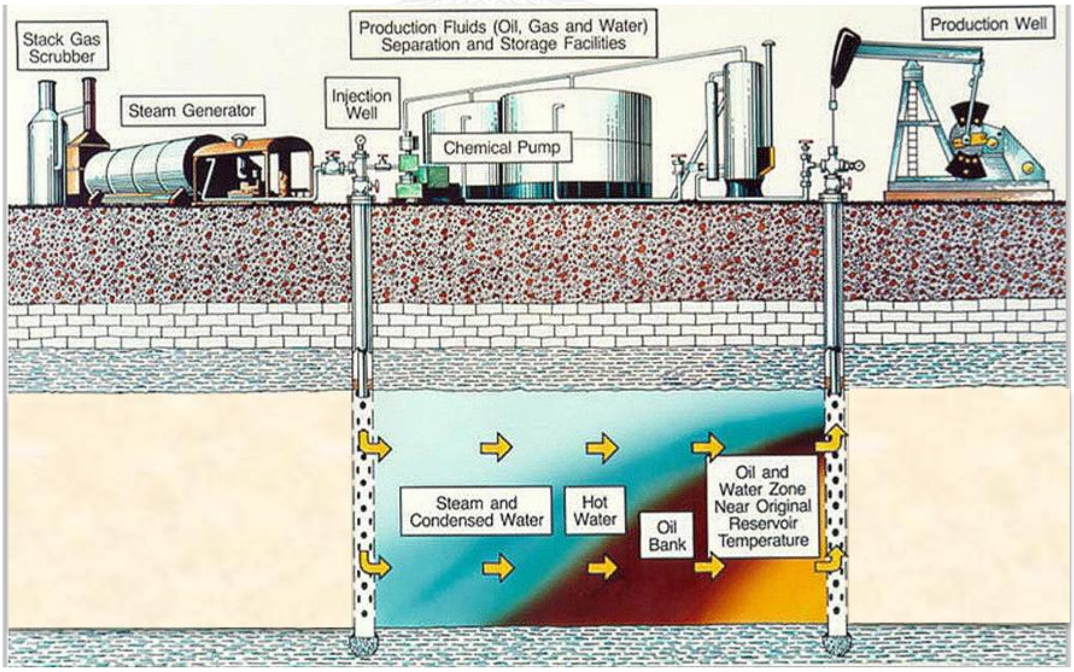

Figure 2.4 2-D diagram showing a SF operation (http://ces-dev.designimations.com/joomla30/enhanced-oil-recovery)

Other mechanisms may include thermal swelling, gas drive, gravity drainage, relative permeability modification and wettability alternation, and emulsification by forming oil / water emulsions. As the temperature is increased, connate water saturation increases, residual oil saturation decreases water relative permeability decreases and oil relative permeability increases. However, the absolution permeability and effective oil relative permeability decrease. Hong (1994) splits the mechanisms according to the primary, horizontal, and vertical processes.

2.2 Thermal Process in SF

The basic principle of the thermal processes is that increasing the temperature in a reservoir, makes the viscosity of the fluids contained therein reduced. In the case of heavy crudes, the reduction in viscosity resulting from an increase in temperature is particular high. Furthermore, the viscosity reduction in crudes is much higher than the corresponding viscosity reduction in water and gas that are associated with the crude in reservoir. There follows a reduction in the water / oil and gas / oil mobility ratios, resulting in an improvement in the areal sweep efficiency. As a consequence, in heavy oil reservoirs, an increase in temperature improves the overall oil recovery. (Chierici, 1980)

In order to estimate how much heat is needed to heat a reservoir, the total volumetric heat capacity of the reservoir (M_R) has to be known. For a reservoir of porosity φ filled with a non-volatile oil, water, and a gas phase containing steam and non-condensable gas, the amount of heat required to increase the temperature of a bulk volume of formation (V_b) by a small amount of ΔT, and at a constant pressure, is

$$Q = V_b M_R \Delta T \tag{2.1}$$

where M_R is the isobaric volumetric heat capacity of the bulk, fluid-filled reservoir. The increase of the heat content of this reservoir by an increase in temperature ΔT is

$$Q = (1-\phi)\rho_r C_r \Delta T + \phi S_o \rho_o C_o \Delta T + \phi S_w \rho_w C_w \Delta T + \phi S_g(\rho_g C_g f_g \Delta T + (1-f_g)(\rho_s C_w \Delta T + L_v \rho_s)) \quad (2.2)$$

where f_g is the volume fraction of non-condensable gas in the vapor phase; C is the heat capacity per unit of mass for a unit temperature change; ρ is the density; S is the saturation, the subscripts r, o, w, g, and s denote rock, oil, water, gas, and steam respectively; φ is porosity in fraction. By equating the above two Q_s, we can find the total volumetric heat capacity:

$$M_R = (1-\phi)\rho_r C_r + \phi S_o \rho_o C_o + \phi S_w \rho_w C_w + \phi S_g\left(\rho_g C_g f_g + (1-f_g)\left(\rho_s C_w + \frac{L_v \rho_s}{\Delta T}\right)\right) \quad (2.3)$$

(Sheng, 2013)

In steam-flooding, it uses separate injection and production wells to improve both the rate of production and the amount of oil that will ultimately be produced. Heat from the injected steam reduces the viscosity of the oil as the injected fluid drives the oil from an injector to a producer.

As steam moves through the reservoir between the injector and producer, it typically creates five regions of different temperatures and fluid saturations as shown in Figures 2.5 (Hong, 1994).

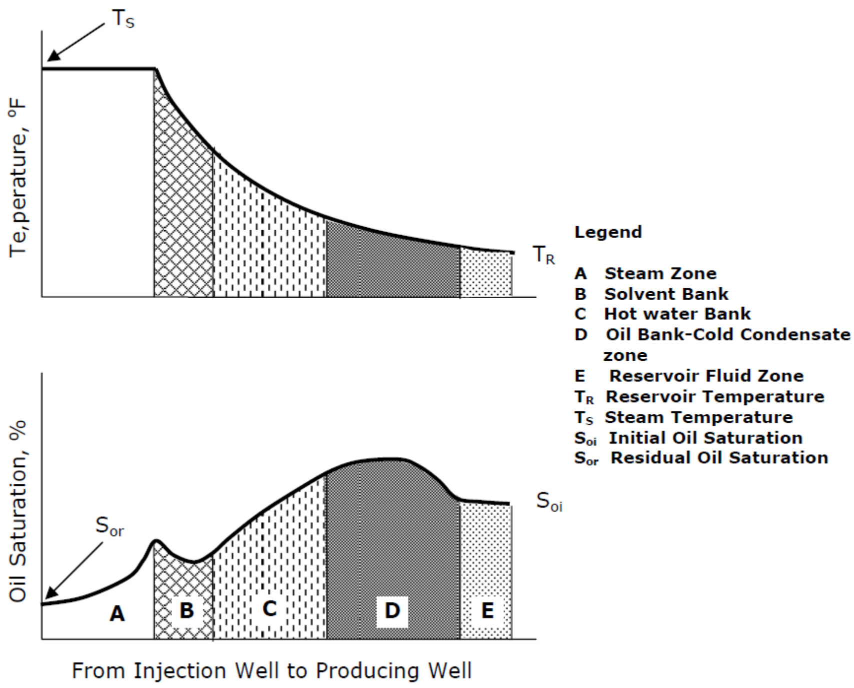

Figure 2.5 Steam-flood typical temperature and saturation profile (Hong, 1994)

As steam enters the reservoir, it forms a steam saturated zone around the wellbore. This zone, at about the temperature of injected steam, expands as more steam is injected. Ahead of the steam saturated zone (A), steam condenses into water as it loses heat to the formation and forms a hot condensate zone (B, C). Pushed by continued steam injection, the hot condensates carries some heat ahead of the steam front into the cooler regions further from the injector. Eventually, the condensate loses its heat to the formation, and its temperature is reduced to the initial reservoir temperature.

Because different oil displacement mechanisms are active in each zone, oil saturation varies between injector and producer. The active mechanism and hence, the saturation depend mainly on thermal properties of the oil. In the steam zone (A), oil saturation reaches its lowest value because the oil is subject to the highest temperature. The actual residual saturation achieved is independent of initial saturation but rather depends on temperature and crude oil composition. Oil is moved from the steam zone to the hot condensate zone (B, C) by steam distillation at the steam temperature, creating a solvent bank (B) of distilled light ends just ahead of the steam front. Gas is also stripped from the oil in this region.

In the hot condensate zone, the solvent bank (B), that generated by the steam zone, extracts additional oil from the formation to form an oil-phase miscible drive. The high temperature in this zone reduces the oil viscosity and expands the oil to produce saturations lower than those found in a conventional water-flood.

The mobilized oil is pushed ahead by the advancing steam (A) and hot water (C) fronts. By the time the injected steam has condensed and cooled to reservoir temperature (in the cold condensate zone), an oil bank (D) has formed. Thus, oil saturation in this zone is actually higher than initial oil saturation. Displacement here is representative of a water-flood. Finally, in the reservoir fluid zone (E), temperature and saturation approach the initial conditions.

The decrease in oil viscosity (μ_o) with increasing temperature is the most important mechanism for recovering heavy oils. With lower oil viscosity, the displacement and areal sweep efficiencies are improved. Thus, a hot water-flood will recover more heavy oil than a conventional water-flood because at high temperatures the heavy oil behaves more like light oil.

2.3 Well Patterns in SF

At present, 5-spot, inverted 7-spot, and inverted 9-spot patterns are used in SF as presented in Figure 2.6. One of the reasons inverted 5-spot is often used is that it can be converted to inverted 7-spot, and inverted 9-spot patterns (Sheng, 2013). Generally, if the reservoir depth is less than 500 m, the well distance is about 100 m. If the reservoir depth is 800 – 1600 m, the distance is 140 – 150 m but not greater than 200 m (Sheng, 2013).

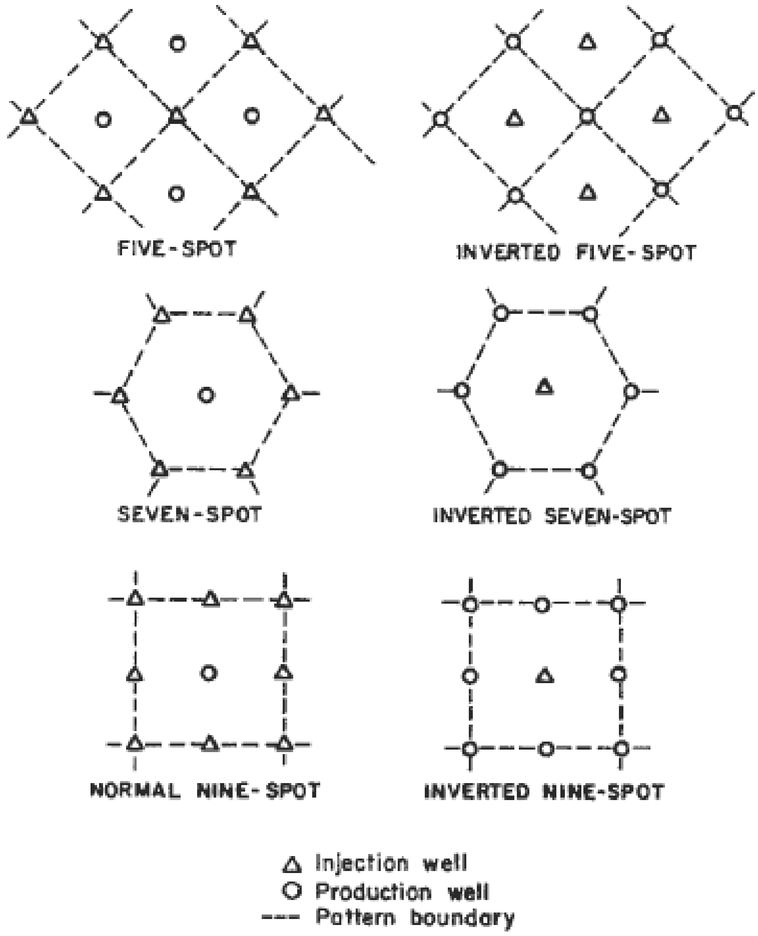

Figure 2.6 Flood patterns (Lyons, 1996)

Moreover, Chu (1979) compared the 5-spot SF pattern with inverted 7-, 9-, and 13-spot patterns. It is found that the oil recovery in a 5-spot pattern (normal or inverted) is greater than in an inverted 7-spot, which in turn is better than in an inverted 13-spot. The worst case is the inverted 9-spot, where one-quarter of the oil normally recoverable by 5-spots remains unproduced. These conclusions are reached on the assumptions that the drainage areas of all producers are the same and that the steam rate is proportional to the pattern size.

Also, Roberts (1961) stated that well spacing is another critical consideration affecting the sweep efficiency and the number of well drills. The more wells drilled, the more fuel energy consumption and hence the higher project cost could be accounted. Besides, the heat transfer would be poor due to heat loss if the distance between injectors and producers is far away.

2.4 Operating Conditions of SF

Regarding the productivity evaluation, the parameters used to monitor the efficiency of oil production processes are based on steam injection, commonly referred to as steam-oil ratio (SOR). It measures the volume of steam required to produce one unit volume of oil. The lower the SOR, the more efficiently the steam is utilized and the lower the associated fuel costs.

Besides, steam quality is the amount of the steam (vapor), by weight, expressed as a fraction (or percent) of the total mass of liquid and vapor.

In the relationship between steam quality and SOR, from a mathematical heat balance model, it is demonstrated that oil-steam ratios are improved with increased steam quality (Messner, 1990). Ali and Meldau (1979) expanded upon these findings.

Hong (1994) pointed out that optimum steam conditions depend on reservoir type and operating mode. Therefore, his team recommended that optimum steam conditions for a specific reservoir will be determined through economic comparison of predicted oil recoveries for ranges of steam conditions. In this study, a comprehensive numerical simulation was conducted to investigate the effects of steam quality and injection rate on steam-flood performance for a variety of steam-flood situations (e.g. pattern flood, dipping reservoir). The analysis shows that steam quality must be as high as possible to maximize steam-flood oil recovery. In practice, however, steam quality seldom exceeds 80% because some of the feed water has to remain in the liquid phase to carry the dissolved solids into the formation. Thus, the optimum steam quality is the highest value that can be obtained economically in a particular situation and can be as high as 80%. As a result, the main conclusion is that no single steam quality or injection rate can be optimum for all reservoirs or all modes of operation. Thus, optimum steam conditions for a given situation should be determined by economic comparison of predicted oil recoveries for ranges of steam qualities and injection rates.

Furthermore, Doscher and Ghassemi (1983) studies the oil viscosity and reservoir thickness in steam drive operations. Based on their model studies, the result indicated that the viscosity of the crude oil is a very important parameter affecting the efficiency of the process. Also, the possibility of the oil/steam ratio in thin reservoirs is as high as, or even higher than in thick reservoirs, excluding the effect contributed by steam stimulation, if steam override occurs in both reservoirs. Meanwhile, if the reservoir fluids have a sufficiently low viscosity, they are displaced frontally, and high oil/steam ratios can be achieved, in contrast to the overlay of the steam and lower oil/steam ratios that are developed when injecting steam into viscous oil reservoirs.

With respect to the economic evaluations in some previous heavy oil projects, Rangel-German et al. (2006) preformed an economic analysis of a thermal simulation project in marine region of the Gulf of Mexico. The analysis was used capital expenditures at that moment for drilling and completion and operation and maintenance cost. Different scenarios for cost, oil and gas prices and capital investment were studied. A sensitivity analysis was performed to determine the variables having the highest impact on the economic value of the project. In this project, different technical options are defined; and each of these options is evaluated separately. Oil and gas production and revenues are estimated as well as operational costs and capital investments, to calculate the before tax cash flows and the related economic indicators. All the economic evaluations were run before royalties and taxes, as after tax evaluations do not have any relevance outside of the specific country and concession used for the fiscal modeling. Deterministic and probabilistic economic evaluations were run.

Galvao et al. (2014) investigated the influence of some operational parameters on heavy oil recovery with the properties similar to those found in Brazilian Potiguar Basin. It was found that the solvents addition to the injected steam not only anticipated the arrival of the heated oil bank to the producer well, but also increased the oil recovery. Lower cold water equivalent volumes were required to achieve the same oil recoveries of the models that injected only steam. Furthermore, much of the injected solvent was produced with the oil from the reservoir, what contributed to the method economic viability in terms of NPV. An optimization of steam injection was performed by calculating the maximum NPV.

According to the selected literature reviews, it is obvious that numerous of operating conditions of SF have been studied previously. However, different types of reservoir or different subsurface conditions may have different favorable operating modes. Also, there are not many studies which consider both economic and technical criteria together. Therefore, based on the specific field data, various production strategies are investigated in this study. The favorable condition is determined by applying the weighted factors to the oil recovery and steam operating costs for both economic and technical judgments.

CHAPTER 3
SIMULATION

3.1 Computer Modeling Group (CMG) Software

Computer Modeling Group Ltd., abbreviated as CMG, is a Canadian company that offers reservoir simulation software for the oil and gas industry. The company provides three reservoir simulation applications:

1. IMEX – a three phase, black oil reservoir simulator used for primary, secondary and enhanced or improved oil recovery processes;
2. GEM - an advanced Equation-of-State (EoS) compositional and unconventional simulator;
3. STARS - an advanced processes and thermal reservoir simulator

As this study is focused on the heavy oil production by using steam-flooding with various strategies in a heterogeneous reservoir, STARS, a CMG program is selected to simulate the thermal processes. In general, STARS is the undisputed industry standard in thermal and advanced processes reservoir simulation. Also, it is a thermal, k-value compositional, chemical reaction and geo-mechanics reservoir simulator ideally suited for advanced modeling of recovery processes involving the injection of steam, solvents, air and chemicals. The robust reaction kinetics and geo-mechanics capabilities make it the most complete and flexible reservoir simulator available. (http://www.cmgl.ca/, 2016)

3.2 Field Data Input for Simulation

Details of heterogeneous reservoir models, model dimension and input parameters in reservoir simulation model such as rock & fluid properties, Pressure-

Volume-Temperature (PVT) properties, and well input data in CMG STARS are described in this section.

Physical properties and required reservoir parameters are based on a practical field data which those details are listed in Table 3.1.

Table 3.1 Physical properties and reservoir properties

Parameters	**Value (SI Unit)**	**Value (Field Unit)**
Grid dimension	37 × 37 × 5 block	
Grid size	50 × 50 × 5 m	164 × 164 × 16 ft
Top of reservoir	789 m	2,589 ft
Effective porosity	(14 - 39) %	
Horizontal permeability	(20 – 19,299.59) mD	
Vertical permeability	(20 – 19,299.59) mD	
Initial oil saturation	80 %	
Initial water saturation	20 %	
Reference pressure at datum depth	8,000 kPa	1,160.3 psi
Datum depth	814 m	2670.6 ft
Fracturing Pressure	11,066 – 12,713.9 kPa	1,605 – 1,844 psi
Reservoir temperature	62.78 ^{o}C	145 ^{o}F
Reservoir pressure	7,825.8 kPa	1,135 psi
Oil gravity	0.91 g/cm^{3}	23.9 ^{o}API
Oil Viscosity	2075 mPa·sec @ 25 ^{o}C	2075 cp @ 25 ^{o}C

Pressure-Volume-Temperature (PVT) properties of reservoir fluids are also received from the nameless company that was the operator of this particular field. Basically, such data are consolidated from the core laboratory. The sampling data and the relevant plots are presented in Table 3.2 and Figure 3.1 respectively.

Table 3.2 Sampling data of oil and water viscosity

Temp (°C)	**Water (cp)**	**Oil (cp)**
60	0.74	558.12
68.3	0.67	402.69
93.3	0.51	183.53
115.6	0.42	106.96
137.8	0.35	68.71
160	0.32	47.16
182.2	0.28	34
204.4	0.25	25.45
226.7	0.23	19.6
248.9	0.21	15.49
271.1	0.19	12.49
287.8	0.18	10.75
343.3	0.15	6.89
371.1	0.14	5.66

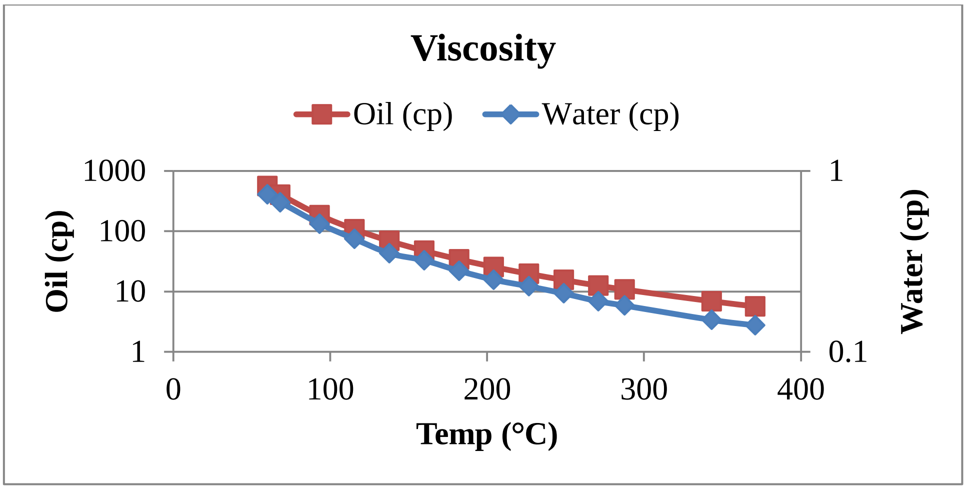

Figure 3.1 Plots of oil and water viscosity at various temperatures

Apart from the fluid viscosities, both the rock and fluid compressibility and thermal conductivity are summarized as below:

Table 3.3 Rock and Fluid Compressibility

Parameters	Value
Porosity ref. Pressure	2000 kPa
Formation Compressibility	3.5×10^{-6} 1/kPa
Water Compressibility	0 1/kPa
Oil Compressibility	0.186325×10^{-6} 1/kPa

Table 3.4 Thermal Conductivities and Volumetric Heat Capacity

Parameters	Value
Volumetric Heat Capacity	2284700 J/(m^3*C)
Reservoir Rock	660413 J/(m*day*C)
Water Phase	53581 J/(m*day*C)
Oil Phase	10592 J/(m*day*C)
Gas Phase	3987 J/(m*day*C)

3.3 Reservoir Physical Model

Referring to the given data in Table 3.1, reservoir model is built in rectangular grid with dimension of 37 X 37 X 5 grid blocks in x, y, and z direction, respectively. The grid size is 50 X 50 X 5 m in respect to the corresponding directions. Each grid is block-centered with variable depth variable thickness. The reservoir is fully heterogeneous with variation of porosity and permeability in each grid. Again, such data is referred to the stochastic studies from the nameless company in the field. The input details are summarized in Appendix-A. Figure 3.2 shows the entire 3D model with the variation of permeability. Also, the permeability in each layer is presented by top view in Figure 3.3.

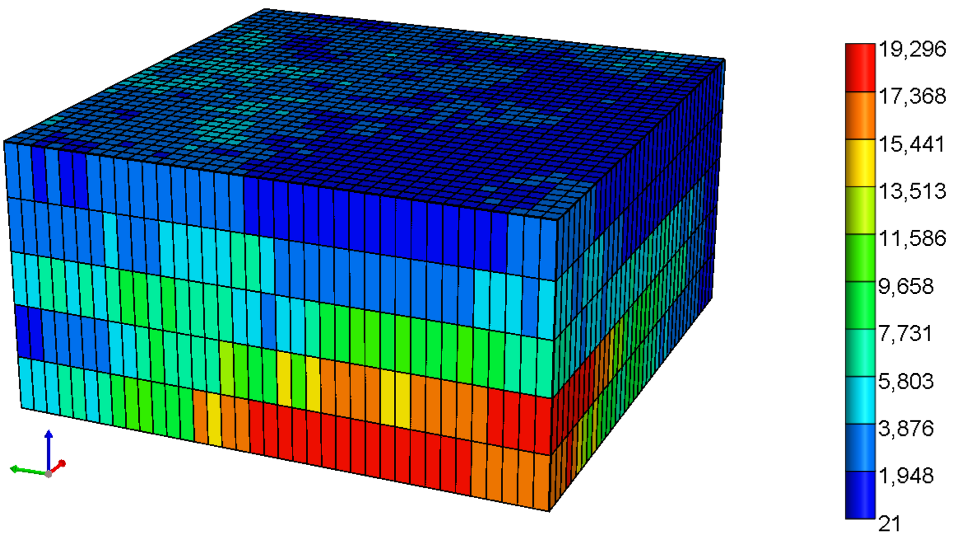

Figure 3.2 3D reservoir modeling with illustrating wide range of permeability

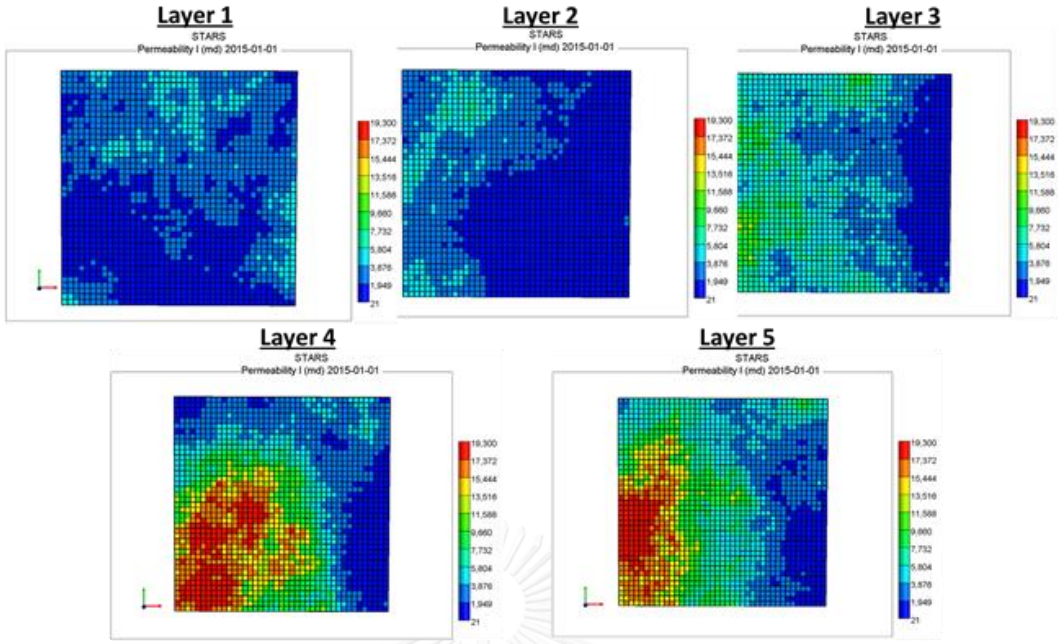

Figure 3.3 Distribution of permeability in each layer

3.4 Parameters Related to Injection and Production Wells

Both injection and production wells are fully perforated along reservoir thickness. Wells are placed in inverted 5-spot pattern, having one injector at the center and four producers surrounding at the corners. Such design is proven to use in commercial nowadays (Lyons and Plisga, 2005). The schematic diagram shows the configuration of wells in Figure 3.4. Steam injection rate is determined in a unit of STB/D which is equivalent to the liquid volume. Steam quality and temperature are defined at 80% and 232.2 ^{o}C, respectively for the entire study (Hong, 1994). The operating constraints are summarized in Tables 3.5. The total operating duration is 20 years. Both steam injection rate and injector – producer distance are varied as kinds of strategies which will be discussed in details in section 3.5.2. Again, most of the fixed values setting are benchmarked from screening criteria and average field data (Sheng, 2013).

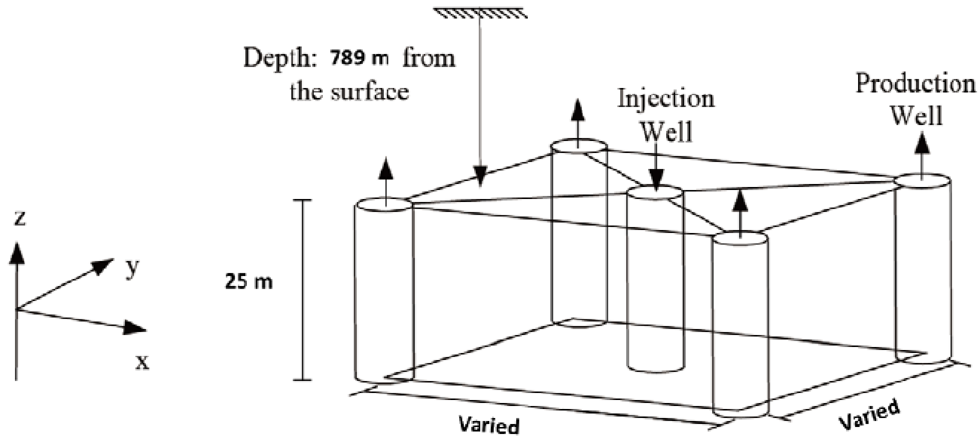

Figure 3.4 Schematic diagram of inverted 5-spot pattern (Maneeintr et al., 2010)

Table 3.5 Operating conditions for SF

Parameters	Value (SI Unit)	Value (Field Unit)
Duration	20 years	
Pattern	Inverted 5-spots	
Injector – Producer Distance	(141.4, 212, 282.8) m	(463, 695, 927) ft
Steam Quality	80 %	
Injection Pressure	≤ 9652 kPa	≤ 1400 psi
Temperature	232.2^{o}C	450^{o}F
Injection Rate	(30, 60, 120) m^3/d	(250, 500, 1000) BWE/d

3.5 Thesis Methodology

This study is divided into two parts; the first part is the selection of base case model based on 27 hypothetical cases. After that, the operating condition from the selected case is fed to the second process which is the injection and production strategies for the entire field (or full field).

3.5.1 Procedure to Create Hypothetical Models

1. Full field heterogeneous reservoir is constructed based on the actual field data as shown in Figure 3.2.

2. Based on the distribution of permeability in each layer as presented in Figure 3.3, layer 4 shows the widest range of permeability among other layers and thus is selected as a representative layer to define three different zones according to the range of permeability. Zone 1, Zone 2, and Zone 3 are defined as below:

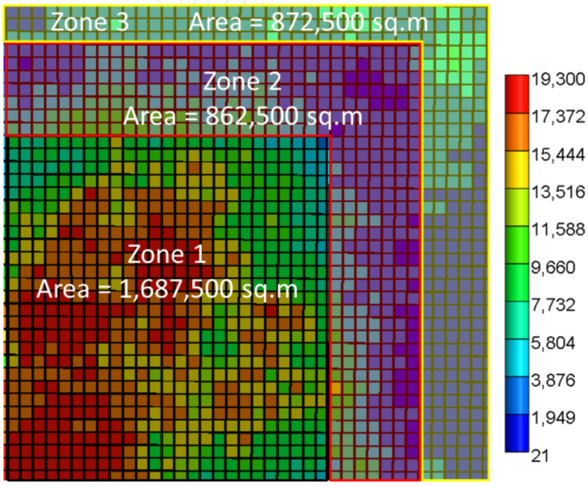

Figure 3.5 Areas of Zone 1, Zone 2, and Zone 3

3. Median values of permeability for each layer of each zone are estimated by statistics and summarized in Table 3.6. The statistical data can be referred to Appendix-A.

Table 3.6 Median values of permeability for each layer in three different zones

	Perm. in zone 1 (md)	**Perm. in zone 2 (md)**	**Perm. in zone 3(md)**
Layer 1	1,741.35	2,407.91	2,411.37
Layer 2	2,007.54	2,018.86	711.01
Layer 3	5,704.32	3,660.72	1,533.31
Layer 4	15,206.35	3,989.72	2,134.54
Layer 5	8,873.08	3,996.99	2,256.55

4. Twenty-seven hypothetical cases are created by multi-layered heterogeneity models based on the median values of permeability in each layer. Then, such 27 cases are trial run by inverted 5-Spot SF simulation for 3 zones with the following conditions:

– Chosen values of injection rates: $30m^3/d$, $60m^3/d$, $120m^3/d$;

– Chosen values of injector – producer distances (pattern): 141.4m (5 X 5 pattern), 212m (7 X 7 pattern), 282.8m (9 X 9 pattern);

The examples of hypothetical models in three different zone with different well patterns are illustrated in the following figures:

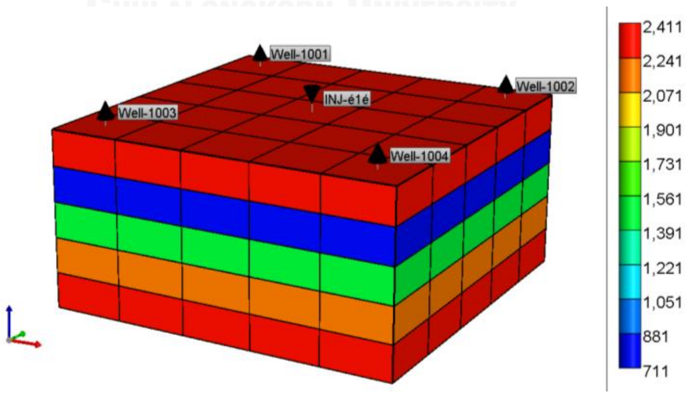

Figure 3.6 Hypothetical model of zone 3 in 5 X 5 X 5 pattern

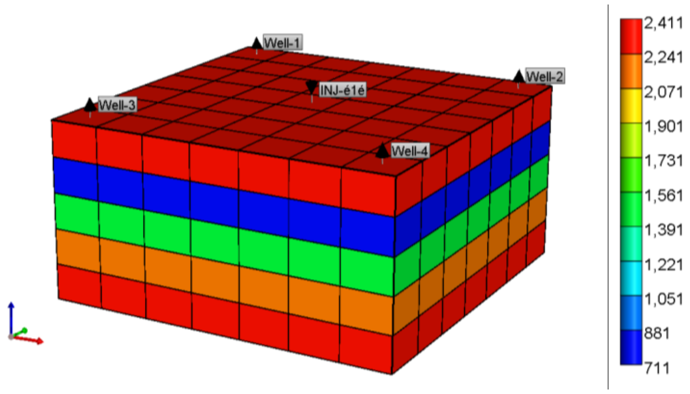

Figure 3.7 Hypothetical model of zone 3 in 7 X 7 X 7 pattern

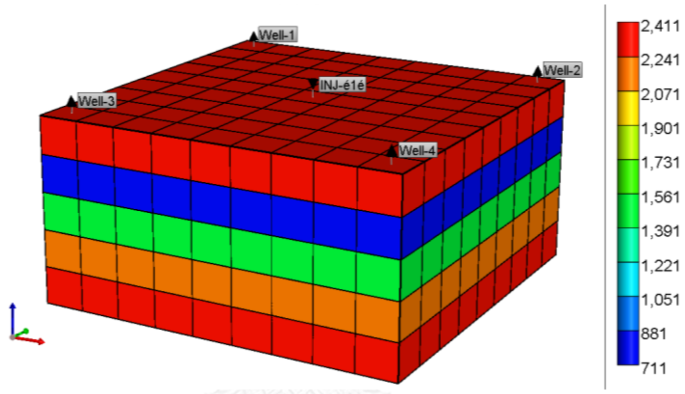

Figure 3.8 Hypothetical model of zone 3 in 9 X 9 X 9 pattern

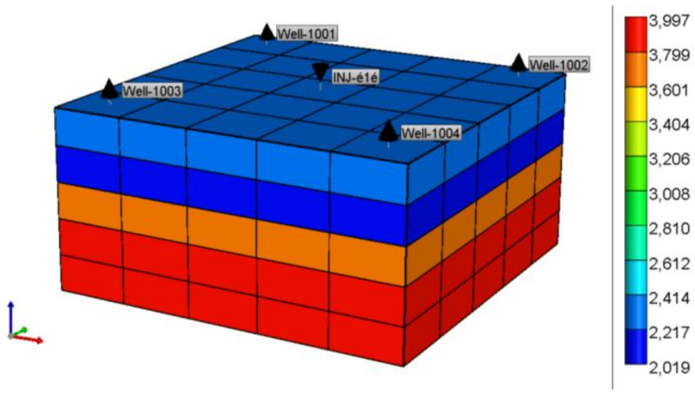

Figure 3.9 Hypothetical model of zone 2 in 5 X 5 X 5 pattern

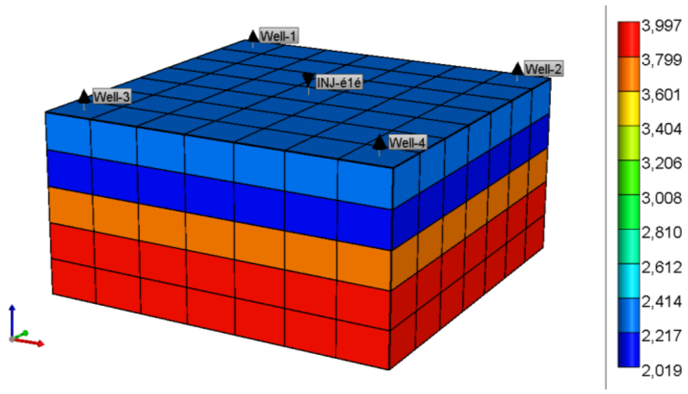

Figure 3.10 Hypothetical model of zone 2 in 7 X 7 X 7 pattern

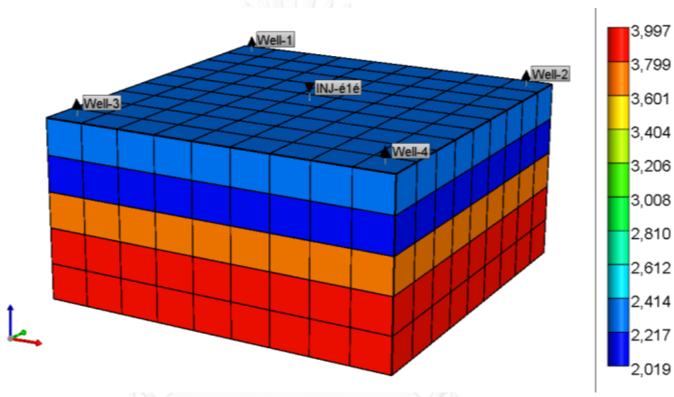

Figure 3.11 Hypothetical model of zone 2 in 9 X 9 X 9 pattern

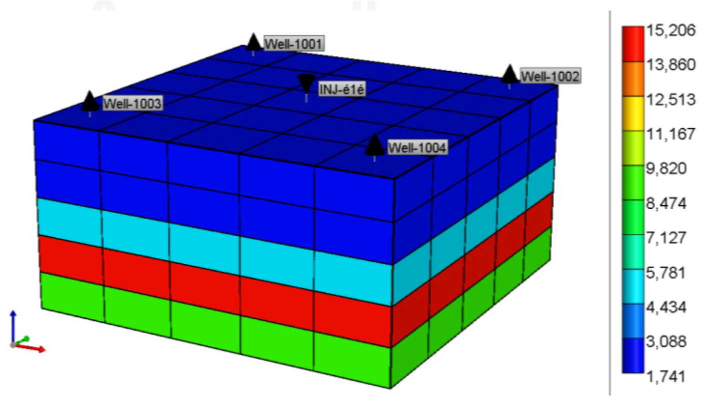

Figure 3.12 Hypothetical model of zone 1 in 5 X 5 X 5 pattern

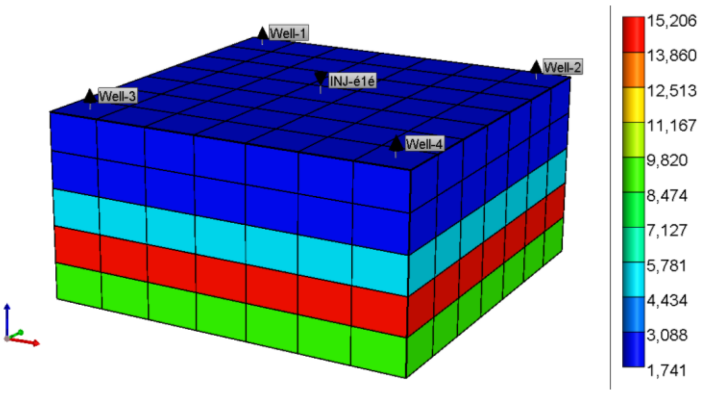

Figure 3.13 Hypothetical model of zone 1 in 7 X 7 X 7 pattern

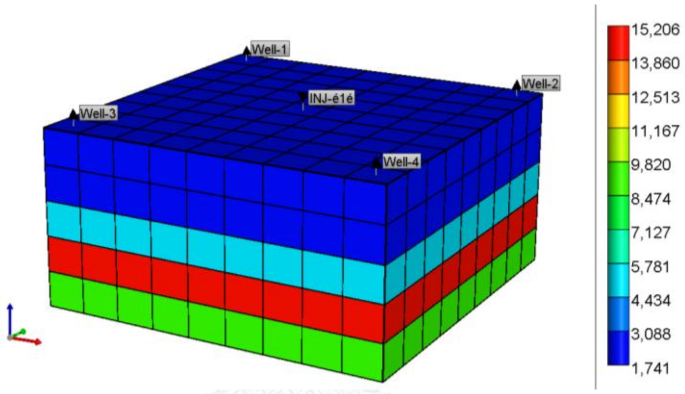

Figure 3.14 Hypothetical model of zone 1 in 9 X 9 X 9 pattern

5. The base case in full field scale is selected from hypothetical simulation results by the judging criteria which are calculated from the weighted factor of the maximum recovery factor/area/well (max RF/area/well) and the minimum cumulative steam-oil ratio/area/well (min Cum SOR/area/well). The selection is based on normalized values from weighting factor of 1.37 to 1. The higher value of the score means the better performance of the case.

This ratio is generated based on the economic data and concept from the ratio between average heavy oil prices to the relevant steam operating costs. Such cost variables are based on the escalation of the known data from the period of 2013 – 2014 and the assumptions are listed in Table 3.7 and Figure 3.15.

Table 3.7 Financial and Cost Variables

Variables	**Values**
Average Inflation rate in Canada(Economics, 2015)	1.5%/2014 yr average and 2%/2015 yr average
Average oil price escalation(EIA., 2016)	Western Canadian Select (WCS) heavy oil
Steam Operating Costs	
Cost of steam injection (Azad et al., 2013)	$10/bbl of water equivalent
Cost of steam generation (Chaar et al., 2014)	$27/ton ($4.3/bbl)
Cost of using artificial lift(Azad et al., 2013)	$1/bbl
Cost of produced water treatment(Azad et al., 2013)	$5/bbl of water
Other operating cost per bbl of oil(Azad et al., 2013)	$5/bbl

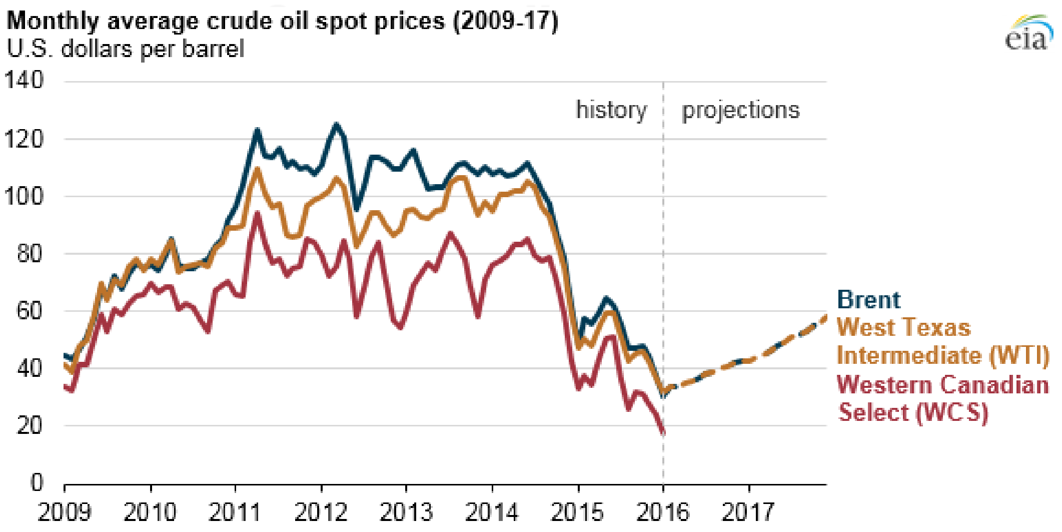

Figure 3.15 Average Crude Oil Prices (EIA., 2016)

3.5.2 Injection and Production Strategies

After selecting the operating conditions of base case from hypothetical models, the outcomes of three strategies are compared with the base case in the same full field scale. The three different strategies are:

a. Strategy 1 –Selection of well spacing or pattern (mixture of 5 X 5, 7 X 7, 9 X 9)
   – Duration (Continuously 20 years)
b. Strategy 2 – Selection of steam injection rates (30, 60, 120 m^3/d)
   – Duration (Continuously 20 years)
   – Matrix with well spacing

Table 3.8 Combinations of strategy 1 and 2

Zone 1	Zone 2 & 3	Inj. rates (m^3/d)
5X5		30, 60, 120
7X7		30, 60, 120
9X9		30, 60, 120
7X7	5X5	30, 60, 120
9X9	5X5	30, 60, 120
9X9	7X7	30, 60, 120

c. Strategy 3 – Development of different areas in different time basis
   – Duration (1st 10 years in the area of Zone 1 only, and then the late 10 years for whole area)
   – Well spacing & injection rate are dependent on the best score from strategy 1 and 2

Based on the same judgment function as hypothetical cases, the simulation results of three proposed strategies are compared and analyzed. Conclusion and further recommendation are stated after the discussion. The work flow of thesis methodology is simplified as the figure below.

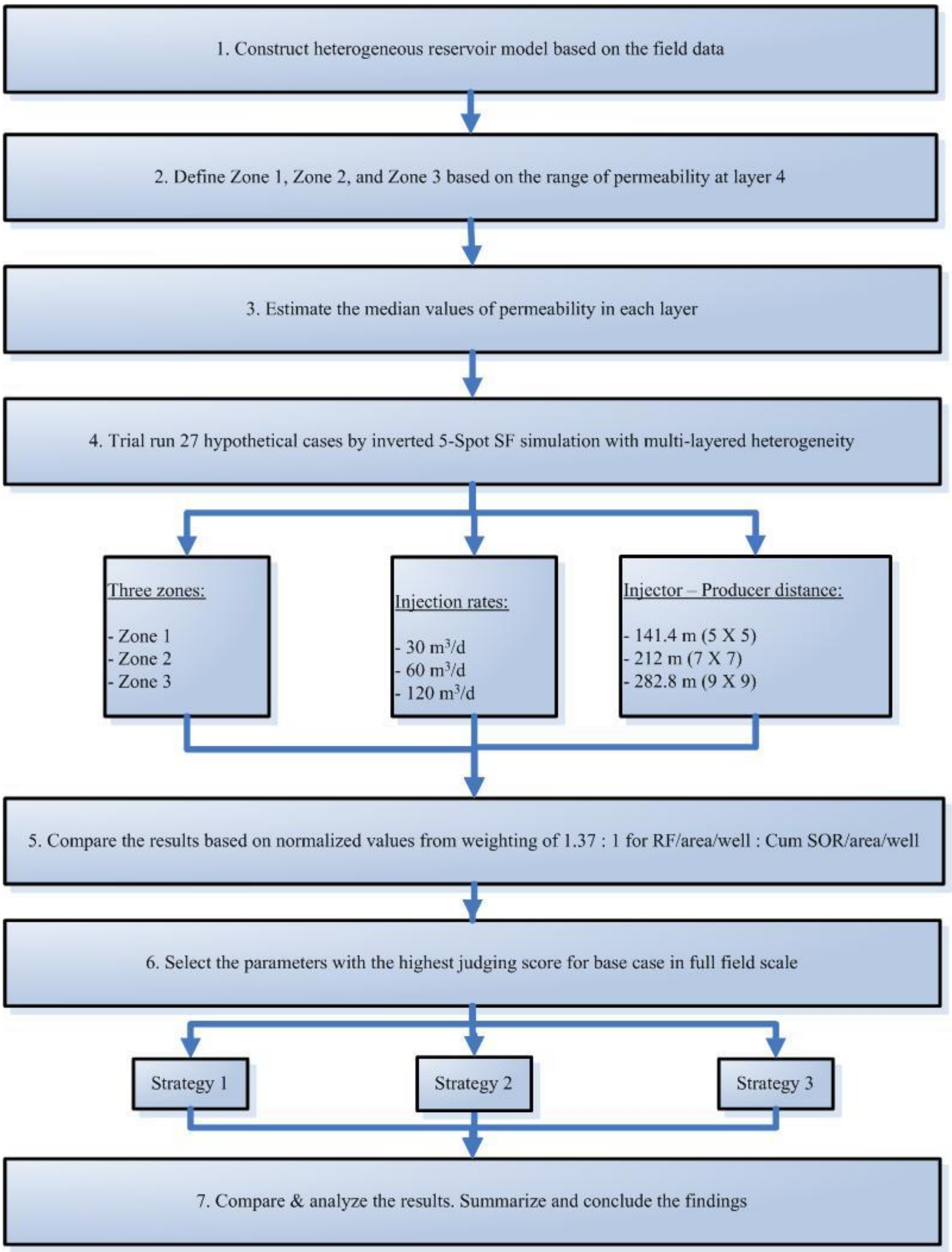

Figure 3.16 Process of Work Flow

CHAPTER 4
RESULTS AND DISCUSSION

4.1 Steam-flooding Base Case

Initially, the statistical study is carried out by the heterogeneous values of permeability from the entire field. Based on the representative layer, three different zones are defined and the hypothetical models are created. After that, the simulation of steam injection in different hypothetical cases is performed with varying of study parameters in order to obtain the operating conditions of base case. The details can be referred to the previous chapter. The best condition among all hypothetical cases is acquired by comparing the max RF/area/well and min Cum SOR/area/well which are used to construct the judgment function together with the weighted factors. Once the best condition is selected from all hypothetical cases, such condition (e.g. well spacing and steam injection rate) is applied to the full field reservoir model as a base case.

4.1.1 Observation of Hypothetical Studies

As explained previously in methodology in Chapter 3, the selection of base case is dependent on the results from hypothetical studies. Actually, the purpose of the hypothetical studies is to observe the behaviors of different zones in different operating conditions by using only one inverted 5-spot pattern. Without putting a lot of wells in the field, this not only can save the processing time in simulation, but also can help to evaluate the performance of the parameters to the reservoir specifically, especially in the heterogeneous reservoir. Therefore, the studying parameters (injection rate and injector - producer distance or well spacing) in the hypothetical studies are the same range as the strategic cases in full field. Also, the run time of the simulation is the same as in 20 years for both hypothetical and full field models.

Regarding the studying parameters, the injection rates are varied from the smallest rate at 30 m^3/d to 60 m^3/d and the highest rate is 120 m^3/d. The chosen values of injector – producer distances (or well spacing) are varied in 141.4 m; 212 m; and 282.8 m, resulting three different patterns in 5 X 5, 7 X 7 and 9 X 9, respectively. With combining three different zones, there are total 27 simulation cases.

From the observation, the higher oil recovery can be obtained by increasing the steam injection rate and/or shorten the injector – producer distances. In terms of oil recovery, the highest injection rate at 120 m^3/d at zone 1 and injector – producer distance in 141.4 m give the highest recovery factor (RF). Figure 4.1 presents the results of oil RF in various cases. In contrast, the lowest injection rate at 30 m^3/d at zone 3 and injector – producer distance in 282.8 m give the least cumulative steam-oil ratio (Cum SOR). Figure 4.2 presents the results of Cum SOR in various cases.

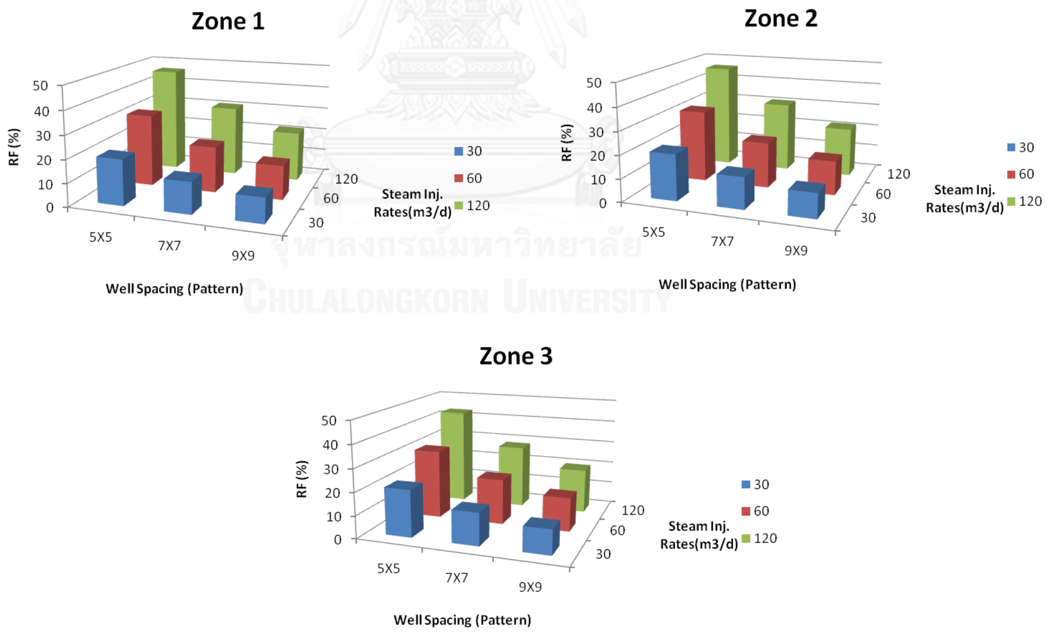

Figure 4.1 Oil recovery factor obtained from various well spacing and various steam injection rates at different zones

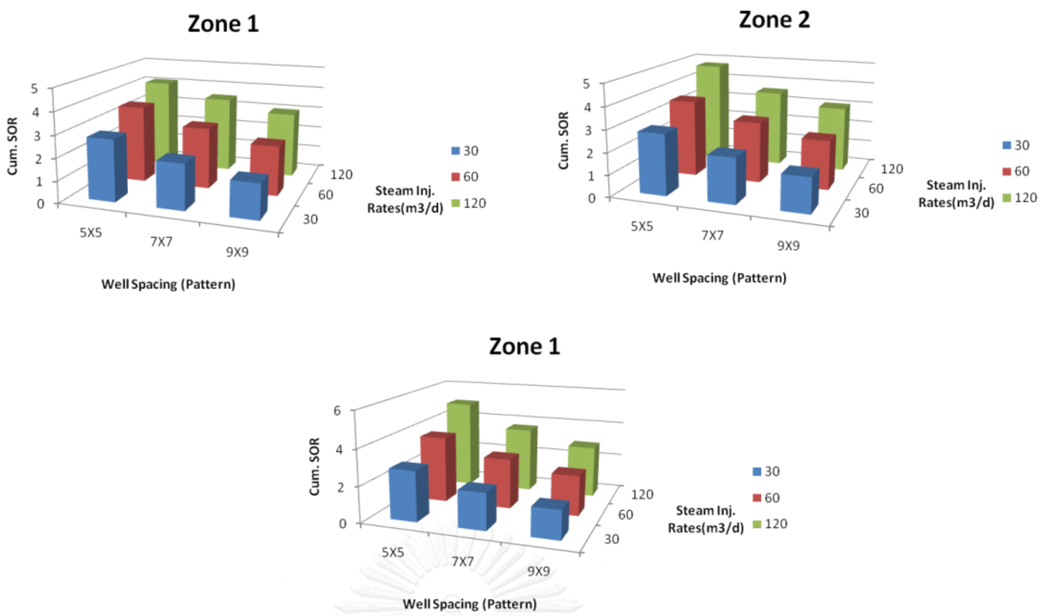

Figure 4.2 Cumulative steam-oil ratio obtained from various well spacing and various steam injection rates at different zones

4.1.2 Selection of Base Case

Practically, the best performance would be as much as oil recovery with as less as steam utilization. In the previous section, the best case for both the highest oil recovery and the lowest cumulative steam-oil ratio is found from those 27 cases. Based on such observation, the selected injection rate and injector - producer distance would be applied to full field as a base case for further comparison with each strategy. The details of selecting the parameters are explained in this section.

Although the higher oil recovery can be obtained by increasing the steam injection rate and/or shorten the well spacing, the Cum SOR is also increased at the same time which means the project cost would be impacted as well. Furthermore, the areas in hypothetical cases are different with different well patterns and the total number of wells would be different in full field studies; therefore, both the criteria of RF and Cum SOR are considered in per area per well. In order to justify such contractible criteria, the weighted factors for RF/area/well and Cum SOR/area/well is fixed at 1.37 : 1 which can be referred to the previous chapter. Once the values of RF/area/well and Cum SOR/area/well are calculated for all cases, the data set are firstly normalized and then multiplied by the corresponding weighting. Max RF/area/well and Min Cum SOR/area/well are used to normalized the whole data. That means, the max RF/area/well and min Cum SOR/area/well will obtain the full score for their categories.

Regarding RF/area/well, Table 4.1 summarizes all the values of 27 hypothetical cases. The maximum RF/area/well is 17.00 X 10^{-5} which is used as the base to normalize the RF/area/well.

Table 4.1 Summary of RF/area/well of all hypothetical cases

	Steam inj. rates (m^3/d)	RF/area/well (10^{-5})		
		5X5	7X7	9X9
Zone 1	30	6.33	2.22	1.06
	60	10.01	3.27	1.47
	120	17.00	5.18	2.20
Zone 2	30	6.45	2.24	1.06
	60	10.03	3.26	1.46
	120	14.78	5.02	2.14
Zone 3	30	6.65	2.33	1.07
	60	9.72	3.28	1.47
	120	13.78	4.59	1.95

Apart from RF/area/well, Table 4.2 summarizes the values of Cum SOR/area/well in all hypothetical cases. As the minimum utilization of steam is the most favorable in this criterion, the min Cum SOR/area/well at 1.55 X 10^{-6} is used as numerator whereas other values are denominator for normalizing.

Table 4.2 Summary of Cum SOR/area/well of all hypothetical cases

	Steam inj. rates (m^3/d)	**Cum SOR/area/well (10^{-6})** 5X5	**7X7**	**9X9**
Zone 1	**30**	8.89	3.35	1.55
	60	11.19	4.52	2.22
	120	13.13	5.70	2.96
Zone 2	**30**	8.95	3.38	1.57
	60	11.36	4.59	2.23
	120	15.17	5.84	3.00
Zone 3	**30**	8.93	3.31	1.56
	60	11.86	4.57	2.20
	120	16.01	5.98	2.86

Normalized data for both RF/area/well and Cum SOR/area/well are summarized in Table 4.3. By the use of weighted factors of 1.37 for RF/area/well and 1 for Cum SOR/area/well, the judgment score is calculated and summarized in Table 4.4.

Table 4.3 Normalized data for RF/area/well and Cum SOR/area/well of all hypothetical cases

	Steam inj. rates (m^3/d)	5X5 Cum SOR/area/well	5X5 RF/area/well	7X7 Cum SOR/area/well	7X7 RF/area/well	9X9 Cum SOR/area/well	9X9 RF/area/well
Zone 1	30	0.174	0.372	0.462	0.131	1.000	0.062
	60	0.139	0.589	0.343	0.193	0.697	0.086
	120	0.118	1.000	0.272	0.304	0.524	0.129
Zone 2	30	0.173	0.380	0.459	0.132	0.989	0.062
	60	0.136	0.590	0.338	0.192	0.694	0.086
	120	0.102	0.869	0.265	0.295	0.516	0.126
Zone 3	30	0.174	0.391	0.468	0.137	0.994	0.063
	60	0.131	0.572	0.339	0.193	0.703	0.086
	120	0.097	0.810	0.259	0.270	0.542	0.115

Table 4.4 Judgment scores of hypothetical studies

	steam inj. rates (m^3/d)	5X5	7X7	9X9
Zone 1	30	0.684	0.641	1.085
	60	0.945	0.606	0.816
	120	1.488	0.689	0.701
Zone 2	30	0.693	0.639	1.075
	60	0.945	0.601	0.812
	120	1.293	0.670	0.688
Zone 3	30	0.710	0.656	1.080
	60	0.914	0.604	0.822
	120	1.207	0.629	0.699

In order to create the judgment function, the normalized data are multiplied by the weighted factors and all terms are summed together as shown as below:

Judgment Score = (1.37)(Normalized RF/area/well) + (1)(Normalized Cum SOR/area/well)

From Table 4.4, the best score is the 5X5 pattern with steam injection rate of 120 m^3/d. This case meets the requirement in terms of high oil recovery and low steam consumption based on the hypothetical studies and weighted factors. Therefore, the parameters of well spacing at 141.4 m (5X5 pattern) and injection rate at 120 m^3/d are applied to the full field heterogeneous model as a base case. The wells' allocation in 5X5 pattern and its production profile in 20 years are shown in Figure 4.3 and 4.4, respectively.

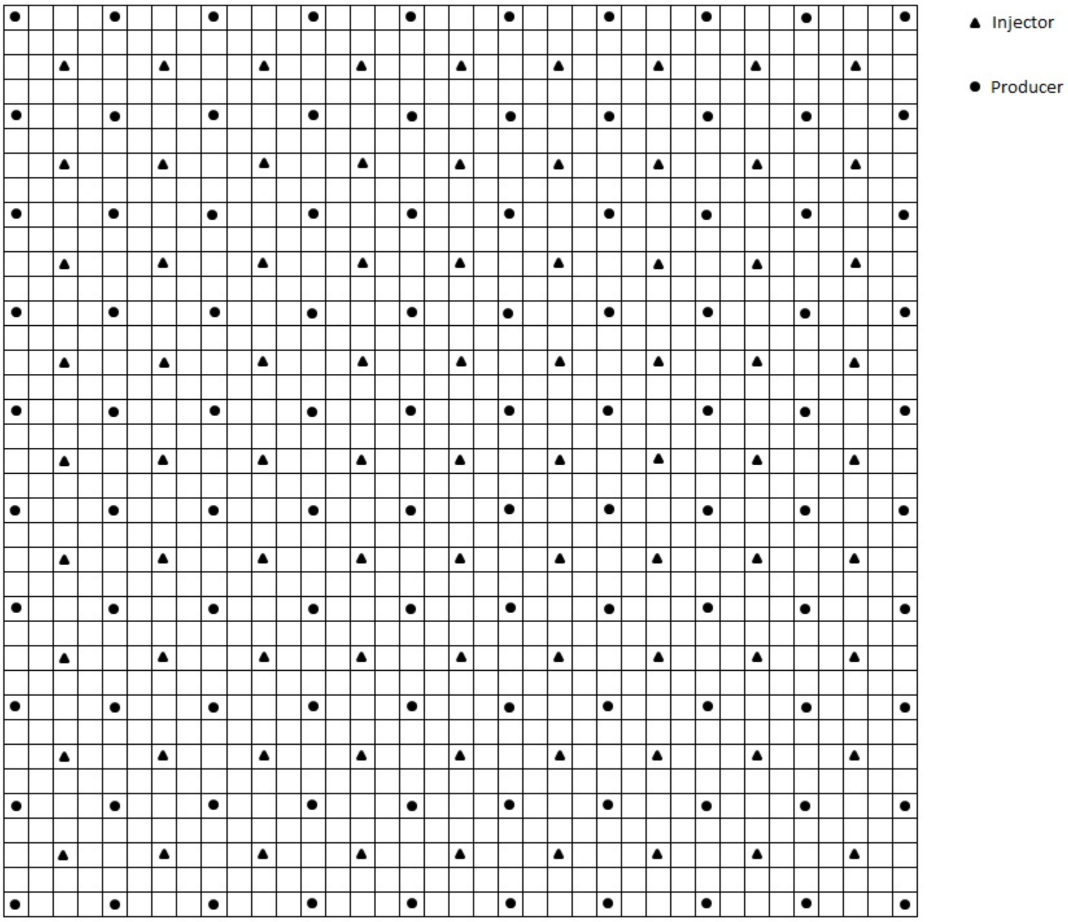

Figure 4.3 Top View of wells' allocation in base case on 5X5 pattern

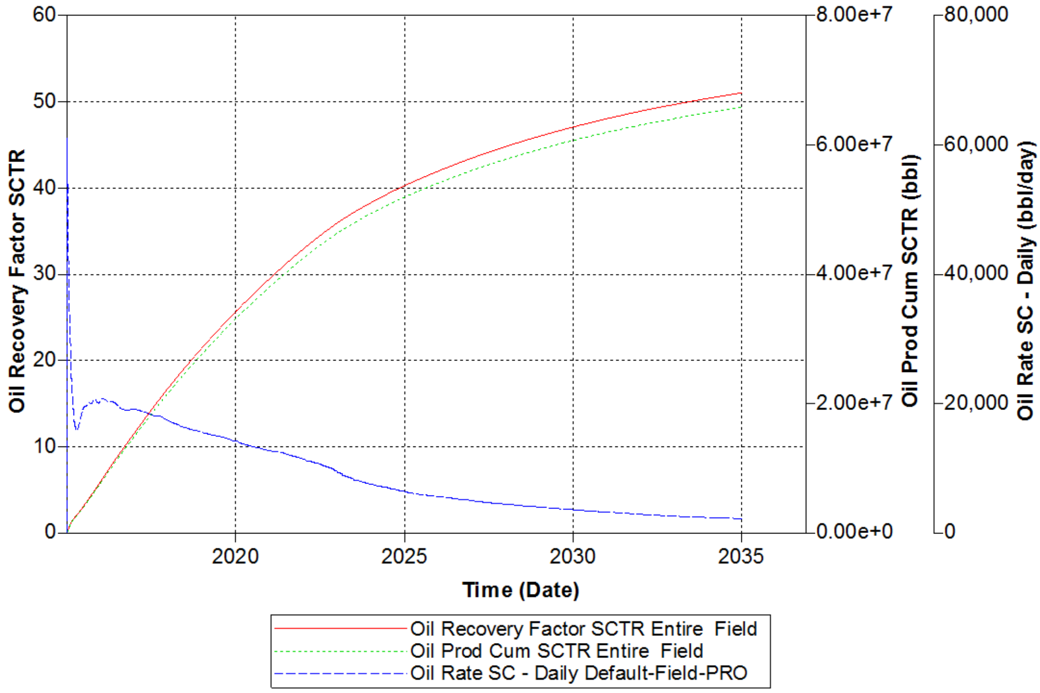

Figure 4.4 Production profile of base case

Regarding the full field scale, the entire production area is about 3,422,500 m^2. With 5X5 pattern, there are total 181 wells placed in the field, in which the inverted 5-spot configuration is formed by 81 injectors and 100 wells producers. As a result in 20 years, the base case can achieve 51% RF with 6.44 Cum SOR. Thus, the RF/area/well and Cum SOR/area/well are 8.24×10^{-8} and 1.039×10^{-8}, respectively as shown in Appendix-B. This selected case will be used in the following section for comparing the performance in different strategies.

4.2 Steam Injection Strategies

In this section, three different steam injection strategies are studied as follows:

Strategy 1. Selection of the size of well spacing;

Strategy 2. Selection of steam injection rate; and

Strategy 3. Development of different areas in different time basis

The judgment criteria are the same as base case section, concerning both RF/area/well and Cum/SOR/well. Normalization of the data in different cases is based on the values obtained from base case.

4.2.1 Strategy 1: Selection of Well Spacing

In full field scale, three different areas, zone 1; zone 2; and zone 3, are defined by the permeability distribution on layer 4. As such, different well spacing may have different performance in different zones. Therefore, all the possible combinations of the wells' patterns in 5X5; 7X7; and 9X9 are studied.

Although all the wells used in this study are vertical well, different zones have different areas which the wells cannot be allocated evenly on the whole field if the patterns are mixed. In order to achieve better RF and Cum SOR, zone 1 is considered to develop in a higher priority due to higher permeability in comparing with other zones. Also, zone 2 and 3 are combined for well allocations if different patterns are mixed. But the integrity of the inverted 5-spot configuration must be maintained. From Figure 4.5 to 4.9, all the combinations of well spacing in different zones are illustrated in the top view of the field, except the base case in 5X5 patterns which is presented in Figure 4.3.

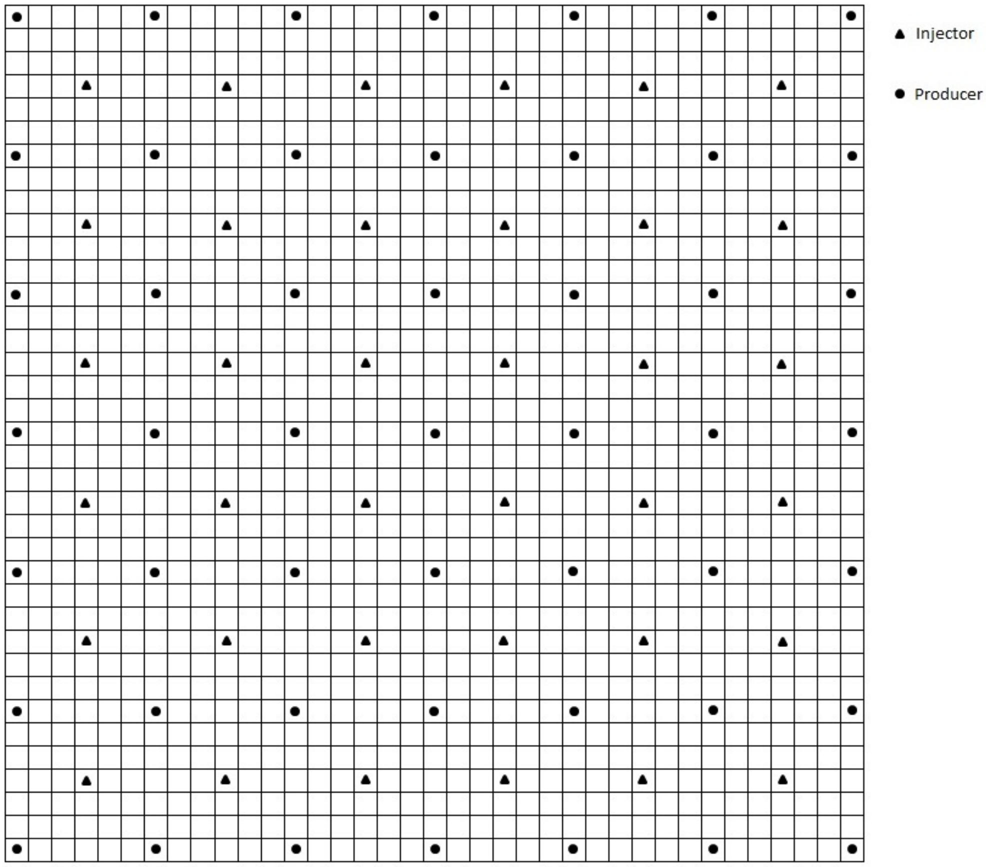

Figure 4.5 Top View of wells' allocation in 7X7 pattern only

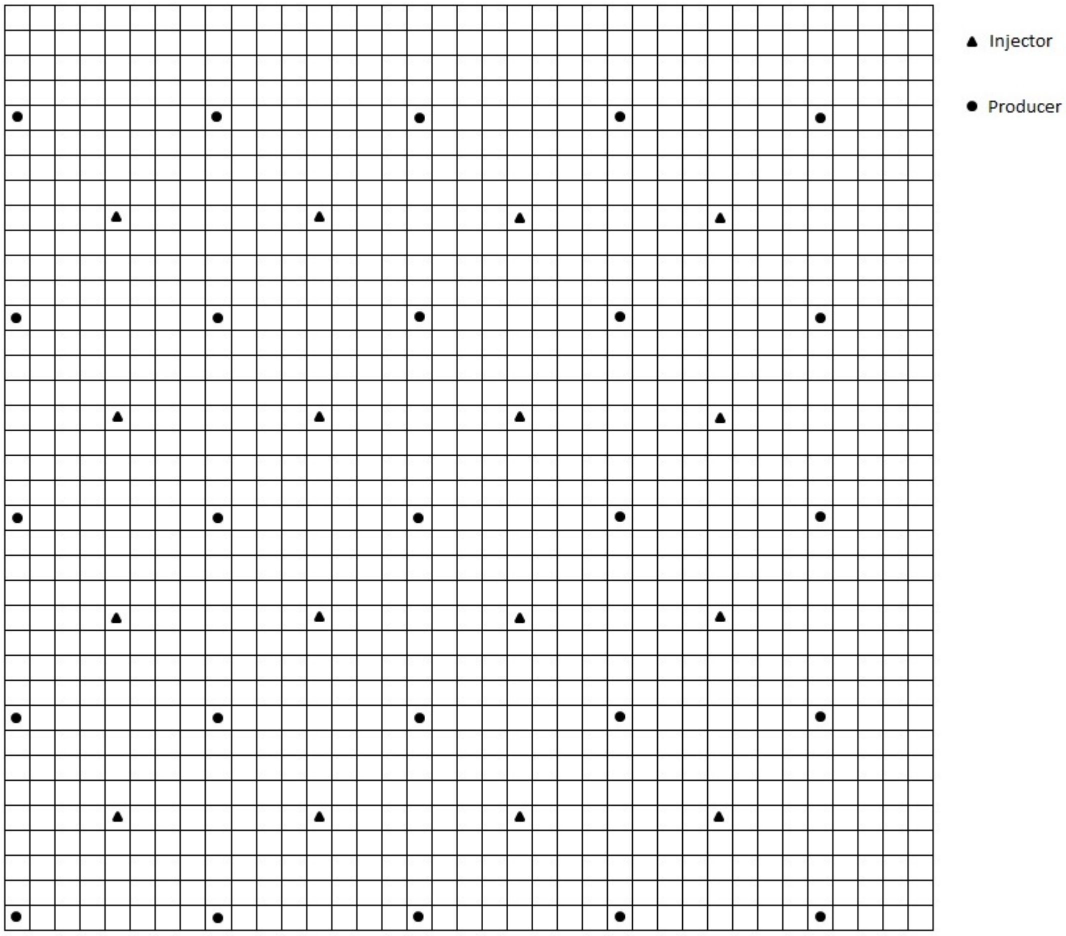

Figure 4.6 Top View of wells' allocation in 9X9 pattern only

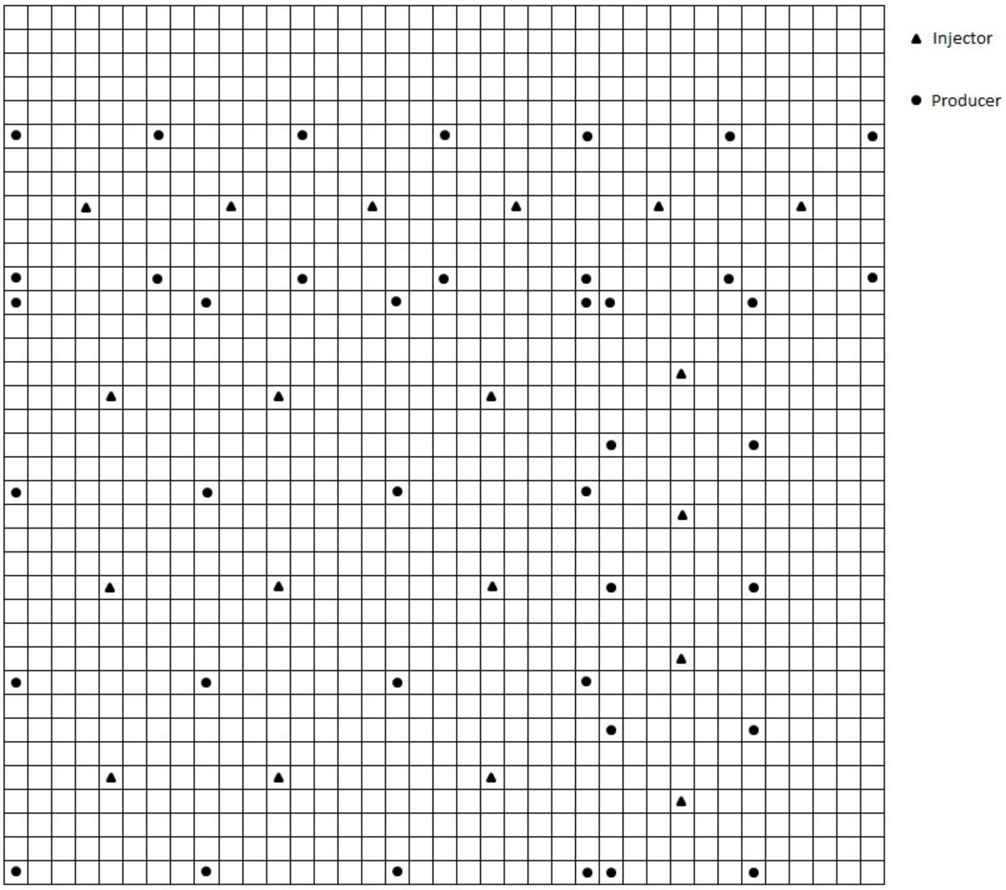

Figure 4.7 Top View of wells' allocation in 9X9 pattern at zone 1 and 7X7 pattern at zone 2 and 3

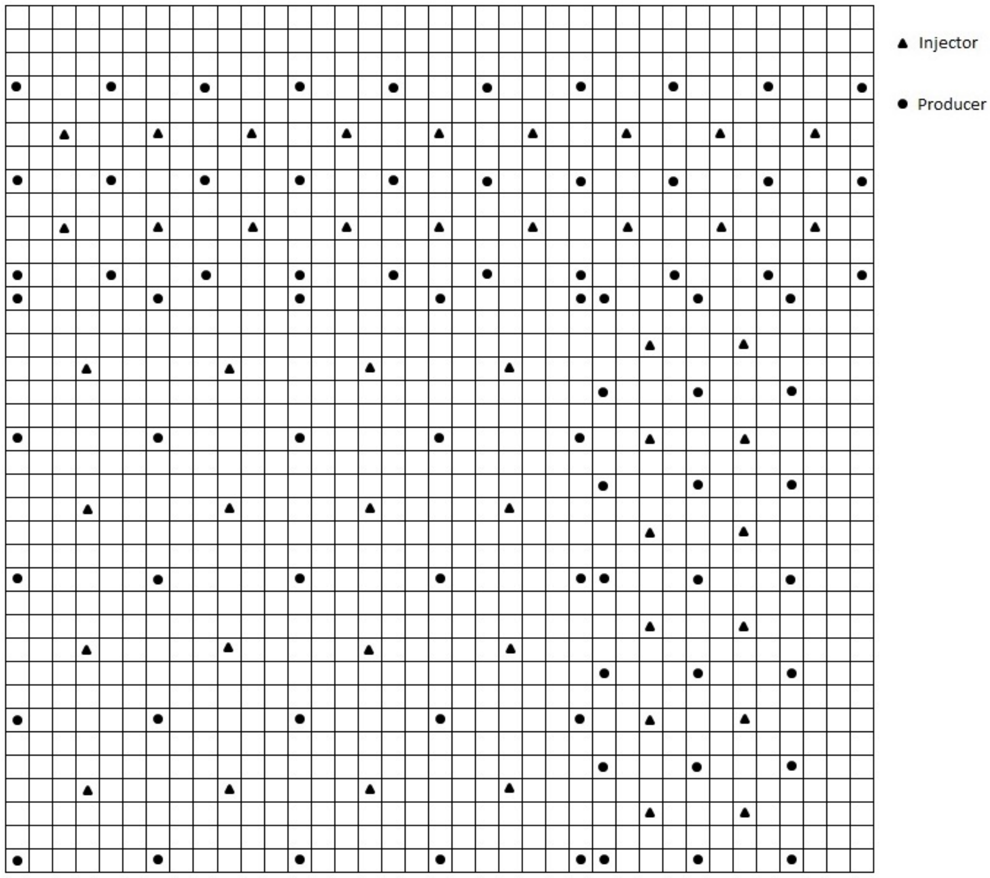

Figure 4.8 Top View of wells' allocation in 7X7 pattern at zone 1 and 5X5 pattern at zone 2 and 3

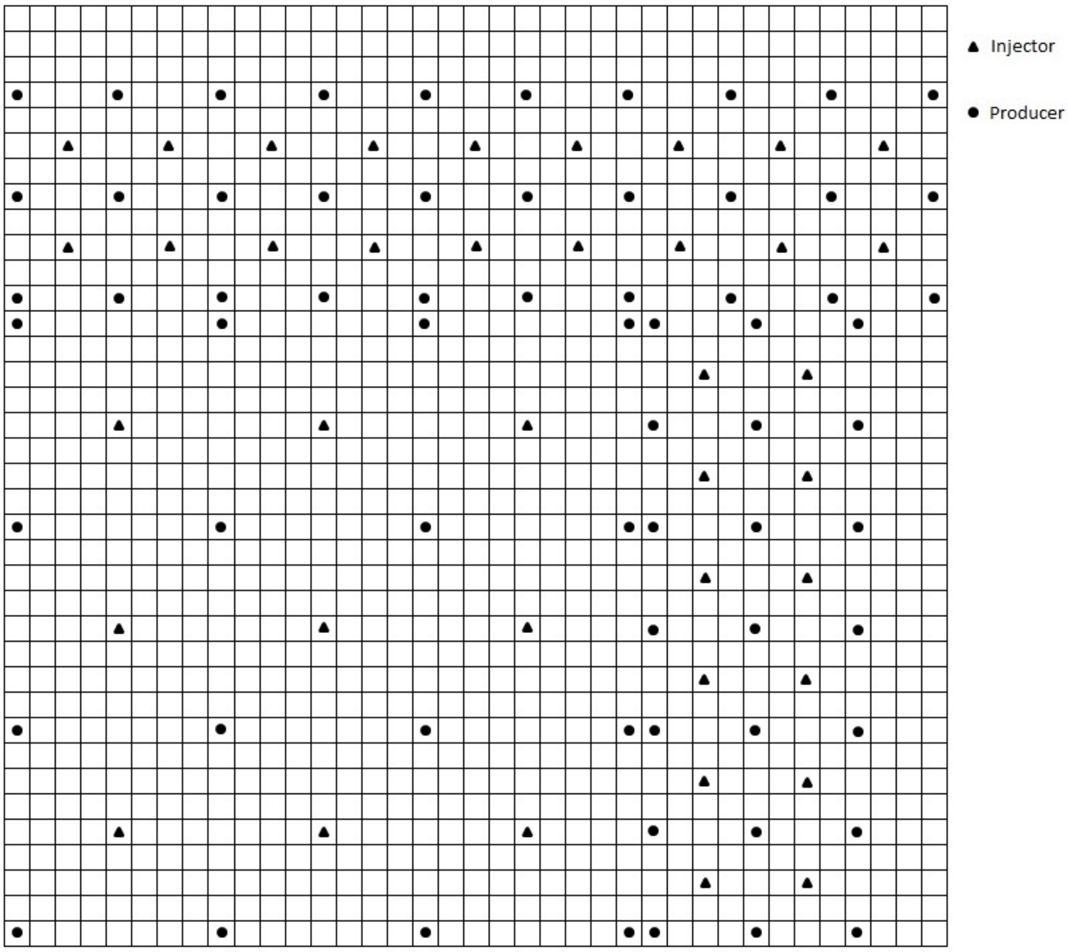

Figure 4.9 Top View of wells' allocation in 9X9 pattern at zone 1 and 5X5 pattern at zone 2 and 3

Since different combination of well spacing may have different number of injectors and producers, this can affect the results of judgment score which the criteria are considered by "per well". Ideally, the optimistic goal is to achieve as high as RF with as less as both Cum SOR and total number of wells. In fact, more wells drilled can impact to the economics as well. In Table 4.5, the total number of wells is summarized for each case.

Table 4.5 Total number of wells in different well spacing

Zone 1 / 2 and 3	Total wells	No. of Injectors	No. of producers
5X5	181	81	100
7X7	85	36	49
9X9	41	16	25
9X9 & 7X7	59	19	40
7X7 & 5X5	122	46	76
9X9 & 5X5	106	39	67

As mentioned in the previous chapter, strategy 1 can be studied together with strategy 2. Therefore, the results of strategies 1 and 2 will be presented together in the next section.

4.2.2 Strategy 2: Selection of Steam Injection Rate

Regarding the studies of steam injection rates in full field scale, the range is basically the same as hypothetical studies. In this section, the results of injection rate from 30 - 120 m^3/d are discussed together with different well spacing stated in previous section. The matrix of strategies 1 and 2 has been shown in Table 3.8.

The results obtained from both strategies 1 and 2 are summarized in Table 4.6. Both strategies are compared with the base case in terms of RF/area/well and Cum SOR/area/well. The judgment score is calculated by the same manner as hypothetical cases.

Table 4.6 Summary of RF/area/well, Cum SOR/area/well, and judgment score for both strategies 1 and 2

Zone 1 / 2 and 3	Inj. Rate (m^3/d)	RF (%)	RF/area/ well (10^{-8})	Cum SOR	Cum SOR/area/well (10^{-8})	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgment Score
7X7 & 5X5	30	16.62	3.981	2.86	0.685	0.483	1.518	2.180
	60	24.26	5.810	3.86	0.925	0.705	1.123	2.089
	120	36.05	8.634	5.12	1.226	1.047	0.848	2.283
9X9 & 5X5	30	15.01	4.136	2.67	0.736	0.502	1.413	2.101
	60	21.26	5.860	3.71	1.023	0.711	1.016	1.990
	120	29.88	8.237	5.18	1.427	0.999	0.728	2.097
9X9 & 7X7	30	10.07	4.986	1.95	0.963	0.605	1.079	1.908
	60	14.33	7.096	2.70	1.338	0.861	0.777	1.956
	120	21.50	10.65	3.55	1.757	1.292	0.592	2.361
9X9	30	9.20	6.557	1.80	1.281	0.795	0.811	1.901
	60	12.97	9.240	2.53	1.799	1.121	0.578	2.113
	120	19.60	13.97	3.30	2.349	1.695	0.443	2.764
5X5	30	24.64	3.977	3.42	0.552	0.483	1.882	2.543
	60	38.50	6.216	4.33	0.698	0.754	1.488	2.521
(Base Case)	120	51.06	8.242	6.44	1.039	1.000	1.000	2.370
7X7	30	15.01	5.159	2.47	0.850	0.626	1.223	2.080
	60	22.29	7.661	3.28	1.129	0.930	0.921	2.194
	120	34.90	11.20	4.12	1.415	1.455	0.735	2.728

During the simulation process, well pattern of 5X5, 7X7, and 9X9 are firstly run with various injection rates. Generally, all cases in 5X5 pattern can achieve better performance in comparing with other cases because its judgment scores are ≥ 2.37 which is the score of base case. Apart from 5X5 pattern, 7X7 with 120m^3/d injection rate also can achieve a better score with more than 2.37. The possible reasons are less number of wells than that in 5X5 pattern and the normalized RF/area/well is higher than 1. However, the best score is obtained by 9X9 with 120m^3/d injection rate, which score is 2.764. It's because this pattern achieves the highest value of normalized RF/area/well and the lowest value of normalized Cum SOR/area/well with the least number of wells.

In order to verify whether the mixture of patterns in different zones can provide even higher score than 1.169 or not, 9X9 and 7X7 are selected for zone 1 because of higher score achievements. Then, 5X5 and 7X7 are selected for zone 2 and 3 to mix with the pattern in zone 1. In comparing with base case, their performance is relatively worse. There are two key reasons. The first one is that the total number of wells is more than 9X9 pattern. Secondly, the wells' pattern of a complete inverted 5-spot cannot be put into some areas in zone 2 and 3 due to the limited space near the borders of the study area.

All in all, the well spacing in 9X9 pattern (or 282.8 m) with 120 m^3/d injection rate yields the most favorable condition for the full field study. Based on the results from strategies 1 and 2, it is used as the main consideration for strategy 3. The details will be discussed in the next section. Also, the comparison among all strategies will be given after the discussion of strategy 3.

4.2.3 Strategy 3: Development of Different Areas in Different Time Basis

In strategy 3, the study is separated into two different time frames at two different areas, the first 10 years in zone 1 only and the later10 years in all zones. According to the production profile from base case as shown in Figure 4.4, the slope of the cumulative oil production starts to be stable after the first 10 years of operation. Therefore, it is implied that the end time of project can be studied in 10 years basis.

Since zone 1 is the area with higher permeability distribution, it is preferred to develop firstly in the first 10 years. Then, all wells are opened from 10th year to 20th year in all zones. The simulation model for the first 10 years focuses on zone 1 only and its model with the example of permeability distribution in layer 4 is demonstrated in Figure 4.10.

The area in zone 1 is about 1,687,500 m^2. Based on the best score obtained from strategies 1 and 2, only 9X9 pattern with $120 m^3/d$ injection rate is compared with the base case in the first 10 years. The base case is 5X5 pattern with $120 m^3/d$ injection rate in the same area as zone 1. The wells' allocation for both 5X5 and 9X9 are shown in Figure 4.11 and 4.12, respectively.

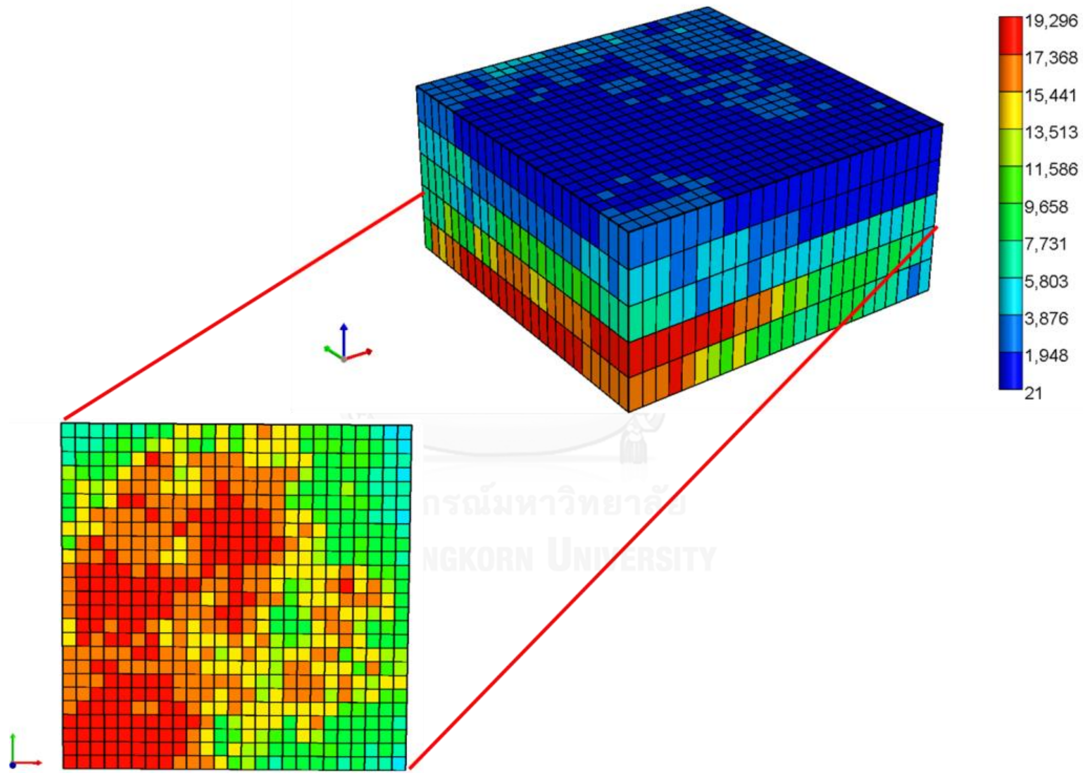

Figure 4.10 3D model of zone 1 with an example of permeability distribution in layer 4

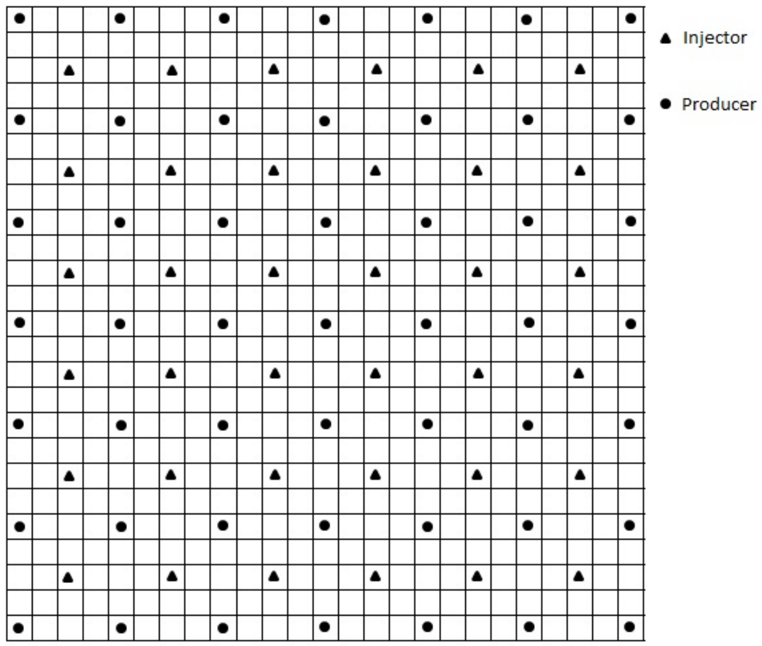

Figure 4.11 Top View of wells' allocation in 5X5 pattern at zone 1 only

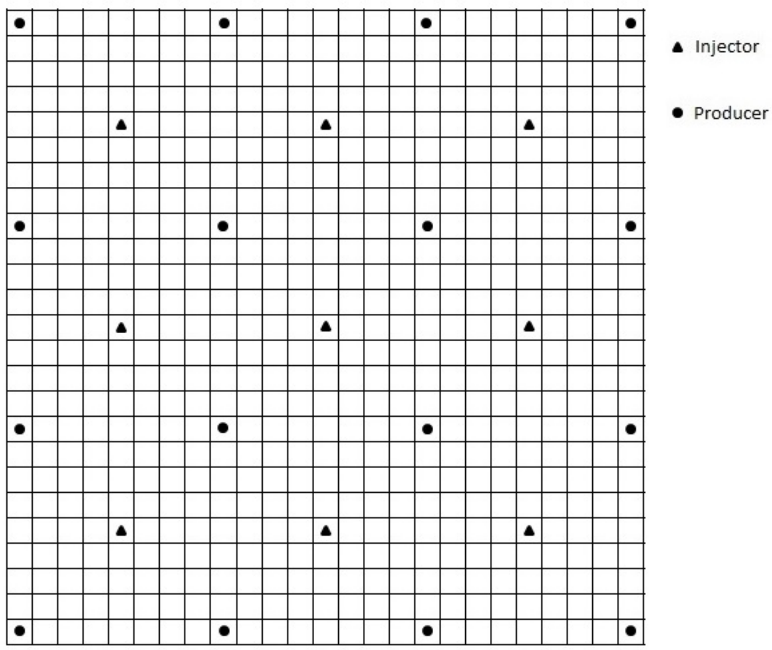

Figure 4.12 Top View of wells' allocation in 9X9 pattern at zone 1 only

Similarly, the judging criteria are RF/area/well and Cum SOR/area/well which is the same as before. The comparison between 9X9 and 5X5 in the first 10 years is summarized in Table 4.7 and Table 4.8.

In fact, the comparison at 10^{th} year is similar to the hypothetical studies as the area is focused on zone 1 only. As a result, this can be reflected by the judgment score which 5X5 pattern with 120 m^3/d injection rate is better than that of 9X9 pattern. It may be due to the high value of Cum SOR/area/well in 9X9 pattern. Although normalized RF/area/well is higher than that of 5X5, a large portion of score is deducted from normalized Cum SOR/area/well.

Table 4.7 Summary of all patterns that are studied at 10^{th} year for strategy 3

	Period (years)	Inj. Rate (m^3/d)	Area (m^2)	Total wells	No. of Injectors	No. of Producers
5X5 (Base)	10	120	1,687,500	85	36	49
5X5	10	30	1,687,500	85	36	49
9X9	10	120	1,687,500	25	9	16
9X9	10	30	1,687,500	25	9	16

Table 4.8 Summary of RF/area/well, Cum SOR/area/well, and judgment score for strategy 3 at 10^{th}year

	Period (years)	RF/area/well (10^{-7})	Cum SOR/area/well (10^{-8})	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgment Score
5X5 (Base)	10	3.078	2.484	1.000	1.000	2.37
5X5	10	1.167	1.668	0.379	1.489	2.009
9X9	10	3.834	5.656	1.245	0.439	2.145
9X9	10	1.917	2.892	0.623	0.859	1.712

For the comparison at 20th year, the base case is exactly the same as strategies 1 and 2 because the full field area is considered. Referring to the Table 4.6, 9X9 pattern provides the highest score from strategies 1 and 2, and hence the combination of well spacing between zone 1 and zone 2 and 3 are based on 9X9. Table 4.9 summarized all the patterns that are studied in 20 years for strategy 3. In this comparison, all the wells at zone 2 and 3 are shut in during the first 10 years and then open in the late 10 years.

Table 4.9 Summary of all patterns that are studied in 20 years for strategy 3

Zone 1 / 2 and 3	Total wells	No. of Injectors	No. of producers
5X5	181	81	100
9X9	41	16	25
9X9 & 7X7	59	19	40
9X9 & 5X5	106	39	67

Table 4.10 Summary of RF/area/well, Cum SOR/area/well, and judgment score for strategy 3 in comparison at 20th year

Zone 1 / 2 and 3	Inj. Rate (m^3/d)	RF (%)	RF/area/well (10^{-8})	Cum SOR	Cum SOR/area/well (10^{-9})	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgment Score
5X5	120	43.74	7.061	5.40	8.721	0.857	1.192	2.366
	60	32.23	5.202	3.72	5.999	0.631	1.733	2.597
	30	20.22	3.265	3.00	4.849	0.396	2.144	2.686
9X9	120	16.84	12	3.03	21.62	1.456	0.481	2.476
	60	11.26	8.022	2.30	16.36	0.973	0.635	1.969
	30	8.11	5.777	1.61	11.48	0.701	0.905	1.866
9X9 & 7X7	120	18.07	8.949	3.11	15.42	1.086	0.674	2.161
	60	12.02	5.953	2.38	11. 80	0.722	0.881	1.870
	30	8.57	4.244	1.69	8.393	0.515	1.239	1.944
9X9 & 5X5	120	26.02	7.171	3.56	9.824	0.870	1.058	2.250
	60	17.42	4.803	2.74	7.559	0.583	1.375	2.173
	30	11.93	3.287	2.05	5.655	0.399	1.838	2.385

From Table 4.10, 5X5 pattern with desired steam injection rate at 30 m^3/d yields the highest score based on the same judgment function as before. Although the favorable well patterns in comparison at 10th and 20th year are the same in 5X5 pattern, the injection rates are obviously in contrast. The possible reason is different number of wells in that more number of wells can yield the smaller values of the criteria. As the smaller Cum SOR/area/well yields the higher normalized value in the comparison at 20th year, 30 m^3/d injection rate gives the higher score whereas the normalized RF/area/well is not varied so much in comparing with the case at 10th year. Therefore, the favorable conditions can be difference if the project development is considered in different times for different areas, even the weighted factors to the judging criteria are the same.

Table 4.11 Summary of Cum Oil Recovery and Cum Steam Injection in water Barrels for strategies 1, 2, and 3

Strategies	Zone 1 / 2 and 3	Inj. Rate (m^3/d)	Cum Oil Recovery (bbls)	Cum Steam Injection (water bbls)	Judgment Score
1 & 2 (20 yrs)	7X7 & 5X5	30	21,433,556	61,278,316	2.180
		60	31,283,700	120,879,496	2.089
		120	46,482,080	237,886,144	2.283
	9X9 & 5X5	30	19,348,496	51,635,548	2.101
		60	27,411,668	101,711,456	1.990
		120	38,530,044	199,501,184	2.097
	9X9 & 7X7	30	12,981,955	25,255,780	1.908
		60	18,475,492	49,927,392	1.956
		120	27,719,374	98,321,200	2.361
	9X9	30	11,863,096	21,330,852	1.901
		60	16,717,913	42,214,160	2.113
		120	25,273,302	83,307,288	2.764
	5X5	30	31,767,084	108,666,656	2.543
		60	49,647,648	214,823,600	2.521
		120	65,836,568	423,944,864	2.370
	7X7	30	19,350,144	47,843,716	2.080
		60	28,738,230	94,386,976	2.194
		120	44,995,928	185,209,376	2.728
3 (10 yrs)	5X5	120	26,915,320	95,896,216	2.37
		30	16,210,775	48,401,428	2.009
	9X9	120	9,859,010	23,524,132	2.145
		30	4,929,514	6,013,500	1.712

Table 4.12 (Con't Table 4.11) Summary of Cum Oil Recovery and Cum Steam Injection in water Barrels for strategies 1, 2, and 3

Strategy	Zone 1 / 2 and 3	Inj. Rate (m^3/d)	Cum Oil Recovery (bbls)	Cum Steam Injection (water bbls)	Judgment Score
3 (20 yrs)	5X5	120	56,397,720	304,670,272	2.366
		60	41,554,736	154,429,792	2.597
		30	26,078,112	78,335,320	2.686
	9X9	120	21,714,604	65,879,708	2.476
		60	14,514,081	33,327,998	1.969
		30	10,453,076	16,839,450	1.866
	9X9 & 7X7	120	23,299,348	72,558,968	2.161
		60	15,499,276	36,944,532	1.870
		30	11,050,079	18,727,688	1.944
	9X9 & 5X5	120	33,546,762	119,563,944	2.250
		60	22,466,074	61,607,344	2.173
		30	15,377,310	31,545,466	2.385

Apart from the judgment score, the comparison between three different strategies can be explained by the amount of cumulative oil recovery and cumulative steam injection in water barrels.

Referring to Table 4.11 and 4.12, it shows that the shorter well spacing and / or higher injection rate are proportional to both amount of oil recovery and steam utilization. Again, this phenomenon has been discussed in the hypothetical studies but it does not mean that the higher oil recovery can yield the favorable result. It's because the amount of steam would be increased together with increasing the injection rate or shortening the well spacing. These can cause the higher Cum SOR. Besides, the shorter well spacing allowed more wells to be drilled based on the same size of area. As such, the higher drilling cost would be incurred in the total project cost which has been considered in the judging criteria before applying weighted factors.

To sum up, the amount of oil recovery and steam injection of each favorable strategy are extracted in Table 4.13 as below.

Table 4.13 Summary of oil recovery and steam injection of each favorable strategy

Strategy	Zone 1 / 2 and 3	Inj. Rate (m^3/d)	Cum Oil Recovery (bbls)	Cum Steam Injection (water bbls)
1 & 2 (20 yrs)	9X9	120	25,273,302	83,307,288
3 (10 yrs)	5X5	120	26,915,320	95,896,216
3 (20 yrs)	5X5	30	26,078,112	78,335,320

In terms of 20 years, strategy 3 yields higher oil recovery than strategies 1 and 2. Meanwhile, less steam utilization can be achieved. This can be explained by the lower injection rate and shorter well spacing in strategy 3. Perhaps, it seems that strategy 3 is more preferable; however, the consideration of total number of wells cannot be reflected here. That's why the judgment score of strategy 1 & 2 is slightly higher than strategy 3 as 5X5 pattern allows more wells drilled than 9X9 pattern based on the same area.

In terms of 10 years, only zone 1 is developed but it achieves the highest amount of oil recovery in comparing with other favorable strategies in 20 years. It's because the highest injection rate and the shortest well spacing are applied together in the zone with relatively higher permeability. In return, this case is suffered by the highest amount of steam injection which is reflected in the judgment score as well.

In conclusion, the highest judgment scorer is obtained by strategies 1 & 2 based on the assumption of steady weightings in 20 years. However, this may not be practical as oil price will not be always steady in the coming 20 years and the steam cost normally is dependent on oil price. Therefore, the weightings should be reviewed from time to time. In addition, another set of weightings in 2.88:1, which is according to the data in 2013, is compared with 1.37:1. The result will be discussed in the next section.

4.3 Sensitivity of Weighted Factors

In this study, the weighted factors are the important ratio to the judging criteria which can dominant the final outcomes of favorable operating conditions. Referring to Chapter 3, the ratio is escalated by the actual data from the year of 2013 - 2014 with several assumptions, such as the average crude oil price, financial and costs variable related to steam operation. From Table 4.14, the raw weightings are 2.88: 1 for RF/area/well: Cum SOR/area/well in 2013. As such, it is interesting to analyze how sensitivity of the weightings between 2.88: 1 and 1.37: 1 to the results. The outcomes of various strategies are re-calculated by replacing the weightings of 2.88: 1 instead of 1.37: 1 to the judging criteria.

Table 4.14 Estimation of Weighted Factors

WCS	Average oil price		Cost of steam		% of Weighting
	($/bbl)	Ratio	($/bbl)	Ratio	
2013	72.77	2.876	25.300	1	2.88: 1
2014	73.60	2.866	25.680	1	2.87: 1
2015	35.28	1.367	25.809	1	1.37: 1

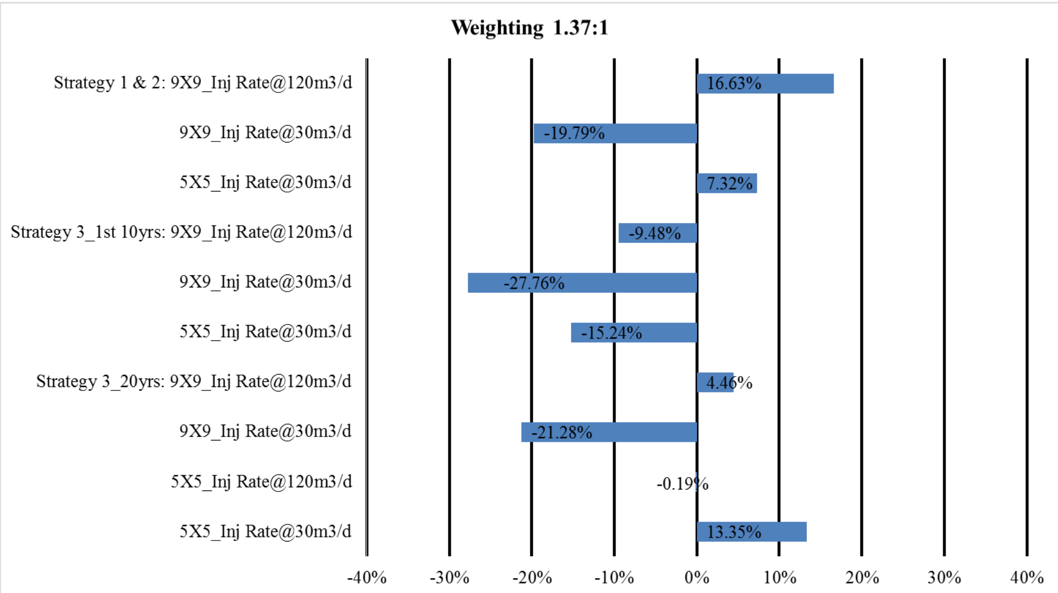

Figure 4.13 Tornado chart of different outcomes from weightings of 1.37: 1

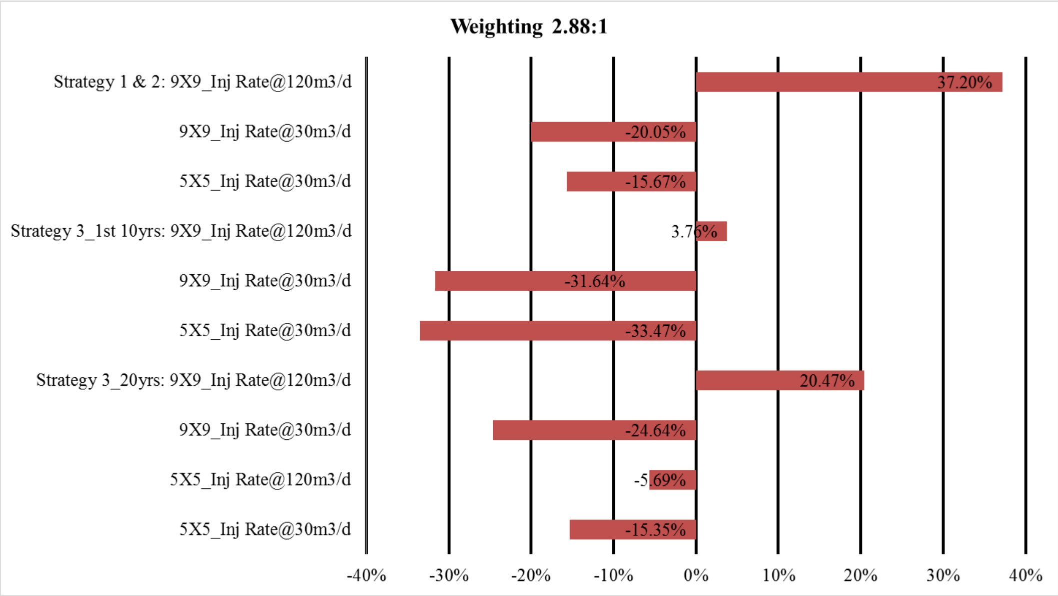

Figure 4.14 Tornado chart of different outcomes from weightings of 2.88: 1

From Figure 4.13 and Figure 4.14, the different charts summarize two different outcomes from the weightings of 2.88: 1 and 1.37: 1. In general, most of the scenarios show the same trend with different breadth of percentage changes in comparing with the respective base cases.

However, some cases, like 5X5 pattern with 30 m^3/d injection rate for strategies 1 and 2, shows in different trend for different weightings. In other words, the weighting of 1.37: 1 obtains a better outcome than its base case in that particular scenario. In contrast, the weighting of 2.88: 1 gets the outcome worse than its base case. Similarly, 9X9 pattern with 120 m^3/d injection rate for strategy 3 at the 10^{th} year and 5X5 pattern with 30 m^3/d injection rate for strategy 3 at 20^{th} year also exhibit the outcomes in different trend.

Regarding the comparison between 2 different weightings, Table 4.15 outlines the selected conditions of each favorable strategy as below:

Table 4.15 Summary of the selected conditions of each favorable strategy in 2 different weightings

Strategies	Weightings of 1.37: 1	Weightings of 2.88: 1
1 & 2 (20 yrs)	9X9 pattern and 120 m^3/d	
3 (10 yrs)	5X5 pattern and 120 m^3/d	9X9 pattern and 120 m^3/d
3 (20 yrs)	5X5 pattern and 30 m^3/d.	9X9 pattern and 120 m^3/d

Basically, two different weightings obtain the same favorable condition in strategies 1 and 2 but there are some differences in strategy 3. In the first 10 years, the favorable condition of 2.88:1 is achieved by longer well spacing than that of 1.37:1 but their injection rates are the same as 120 m^3/d. In terms of 20 years, both well spacing and injection rate in 2.88:1 are difference with 1.37:1. Longer well spacing with higher injection rate is more preferable. The overall result shows that the favorable conditions for 3 different strategies are the same in 9X9 pattern with 120 m^3/d injection rate for the weightings of 2.88:1. According to the same raw data of cumulative oil recovery and cumulative steam injection in Table 4.11 and 4.12, the preferable conditions in 2.88:1 can be implied that less number of wells drilled and less steam utilization are more important during the high oil price situation, even though the cumulative oil production is slightly less than the favorable cases in the weightings of 1.37:1.

In conclusion, longer well spacing has higher effect in strategies 1 and 2. In terms of the same injection rate at 30 m^3/d, the % difference with base cases in 9X9 is about -20% for both weightings; whereas the difference in 5X5 is -15.67% and 7.32% for weightings of 2.88: 1 and 1.37: 1 respectively. For strategy 3, low injection rate gives more effect. For example of 9X9 pattern in 20 years, the % difference with base case of weighting 1.37: 1 at 30 and 120 m^3/d injection rate is 4.46% and -21.28% respectively. Similarly, the % difference with base case of weighting 2.88: 1 at 30 and 120 m^3/d injection rate is -24.64% and 20.47% respectively. For those cases in different trend, weightings of 2.88: 1 shows higher effect than that of 1.37: 1, most of those cases show more than 5% difference with each other trend. Except 9X9 pattern with 120 m^3/d injection rate for strategy 3 at the 10^{th} year, weightings of 1.37: 1

shows -9.48% difference with base case, in which the range is 5% more than that of 2.88: 1.

CHAPTER 5
CONCLUSIONS AND RECOMMENDATION

Steam-flooding provides efficiently ultimate oil recovery for heavy oil. However, the steam consumption can impact to the production efficiency as well as project economics. Based on that particular heterogeneous heavy oil reservoir in this study, various steam injection strategy by using steam-flooding (SF) has been investigated. All the favorable conditions of the aforesaid strategies are summarized in this section. Meanwhile, recommendations for further studies are also provided.

5.1 Conclusion

From the results, different steam injection strategies have different desired outcomes. Conclusions are summarized as below:

1. Although the higher oil recovery could be obtained by increasing the steam injection rate and/or shorten the well spacing, the higher SOR would impact on the project cost at the same time. As such, maximizing RF/area/well and minimizing Cum SOR/area/well are used as judging criteria for each strategy.

2. Regarding the judging criteria, the weighted factors of 1.37: 1 are applied for RF/area/well to Cum SOR/area/well. This ratio is estimated by the reference price and cost.

3. For the selection of well spacing, six different patterns are varied whereas well spacing in 282.8 m (or 9X9 pattern) attains the highest judgment score as the injection rate is fixed as the same as base case at 120 m^3/d.

4. For the selection of injection rate, various rates (30, 60, 120 m^3/d) are varied together with different well spacing. The results demonstrate that the injection rate at 120 m^3/d is more favorable to flood the entire field continuously for 20 years.

5. For the development of different areas in different time basis, it is based on the results from the selection of well spacing and injection rate. The analysis is separated into first 10 years and the whole 20 years. Only zone 1 is developed in the first 10 years. Well spacing in 141.4 m (or 5X5 pattern) with injection rate of 120 m^3/d is preferred. In terms of 20 year period, the whole field is developed, but the wells located in zone 2 and 3 are shut in in the first 10 years and then opened during the last 10 years. The desired outcome is well spacing in 141.4 m (or 5X5 pattern) with injection rate of 30 m^3/d.

6. Based on this particular heavy oil reservoir, either high injection rate with longer spacing or low injection rate with shorter spacing generally achieve positive outcomes in respect to the weighting of 1.37 : 1 for 20 years project life.

7. In the sensitivity analysis, weighted factors of 1.37: 1 and 2.88: 1 are compared with each other. These two ratios are come from the reference price and cost in the years of 2015 and 2013, respectively. The results show that most of the scenarios give the same trend with different breadth of percentage changes in comparing with the respective base cases, except three cases as below:

   - 5X5 pattern with 30 m^3/d injection rate for selection of well spacing and injection rate
   - 9X9 pattern with 120 m^3/d injection rate for development of zone 1 at 10^{th} years

- 5X5 pattern with 30 m^3/d injection rate for development of zone 1 at the first 10 years plus entire field from 10^{th} - 20^{th} year

All in all, both weightings show that the longer well spacing has higher effect in the selection of well spacing and injection rate based on the same injection rates. Furthermore, the lower injection rate gives more effect for the development of different areas in different time basis. Apart from the result at the 10^{th} year, other two cases, which are in different trend, demonstrate the larger effect in weightings of 2.88: 1 than that of 1.37: 1.

5.2 Recommendation

Several recommendations are suggested for the further studies in this particular field:

1. In this study, the weighted factors of 1.37: 1 are estimated by the current oil price and historical steam cost. As the factors are critical to the judging criteria which may cause different final outcomes, so the weighted factors are suggested reviewing from time to time with actual price and cost.

2. If the full actual costs, including CAPEX and OPEX, are available at the moment, economic feasibility studies can be performed, instead of applying weighted factors, to evaluate all the strategies in terms of both technical and commercial aspects. However, it is difficult to acquire the actual costs, especially in the current oil price crisis.

3. Since reservoir simulation program used in this study is a kind of education license, number of grid block is limited. Therefore, the "full field" heterogeneous reservoir constructed in the simulation is only part of the data from the actual field. The more grid provided, the more accurate results can be obtained.

4. As this study is focusing on inverted 5-spot steam-flooding only, other thermal recovery processes, such as CSS and SAGD, can be further studied and compared to this particular field.

5. Regarding the scope of this study, different injection rates are varied in each case but the rates are fixed for the whole period of simulation run time. As different zones have different ranges of permeability, the favorable injection rate and pattern may be different at different zone. Therefore, it is suggested mixing the favorable injection rates and patterns at the respective zones during the same period of run time in the future study.

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APPENDIX

APPENDIX-A
STATISTICAL DATA OF DIFFERENT LAYERS IN FULL FIELD

Layer 4	Zone 1	Zone 2	Zone 3
Area (sq.m)	1,687,500.00	862,500.00	872,500.00
Max	19,191.93	11,869.51	5,761.36
Min	3,466.24	1,171.07	120.74
Most Repeated Range (md)	15000 - 19000	2,000 - 7,000	100 - 4,000
Median	15,206.35	3,989.72	2,134.54
Average or Mean	13,699.81	4,413.23	2,106.58
Perm Range (md)	3,460 - 20,000	1,170 - 11,870	120 - 5,800

	No. of Data		
Range of Perm	**Zone 1**	**Zone 2**	**Zone 3**
< 1000 md	0	0	71
1000 - 2000 md	0	14	78
2000 - 3000 md	0	99	139
3000 - 4000 md	3	66	36
4000 - 5000 md	1	34	14
5000 - 6000 md	12	55	11
6000 - 7000 md	18	38	0
7000 - 8000 md	38	22	0
8000 - 9000 md	61	13	0
9000 - 10,000 md	56	3	0
10,000 - 11000 md	20	0	0
11,000 - 12000 md	18	1	0
12,000 - 13000 md	23	0	0
13,000 - 14000 md	20	0	0
14,000 - 15000 md	22	0	0
15,000 - 16000 md	151	0	0
16,000 - 17000 md	80	0	0
17,000 - 18000 md	64	0	0
18,000 - 19000 md	76	0	0
19,000 - 20000 md	12	0	0
	675	345	349

Layer 5	Zone 1	Zone 2	Zone 3
Area (sq.m)	1,687,500.00	862,500.00	872,500.00
Max	19,295.87	16,153.21	11,878.01
Min	2,423.43	1,429.14	211.27
Most Repeated Range (md)	15000 - 18000	2,000 - 4,000	1,000 - 3,000
Median	8,873.08	3,996.99	2,256.55
Average or Mean	10,933.23	5,306.39	2,939.54
Perm Range (md)	2,400 - 11,000	1,430 - 16,160	210 - 11,880

	No. of Data		
Range of Perm	**Zone 1**	**Zone 2**	**Zone 3**
< 1000 md	0	0	33
1000 - 2000 md	0	15	86
2000 - 3000 md	4	92	117
3000 - 4000 md	18	68	34
4000 - 5000 md	12	33	15
5000 - 6000 md	77	44	36
6000 - 7000 md	82	13	12
7000 - 8000 md	74	20	12
8000 - 9000 md	72	12	2
9000 - 10,000 md	30	14	1
10,000 - 11000 md	17	2	0
11,000 - 12000 md	15	1	1
12,000 - 13000 md	10	5	0
13,000 - 14000 md	8	6	0
14,000 - 15000 md	13	5	0
15,000 - 16000 md	105	13	0
16,000 - 17000 md	46	2	0
17,000 - 18000 md	42	0	0
18,000 - 19000 md	29	0	0
19,000 - 20000 md	21	0	0
	675	345	349

Layer 3	**Zone 1**	**Zone 2**	**Zone 3**
Area (sq.m)	1,687,500.00	862,500.00	872,500.00
Max	12,369.06	8,757.93	8,511.44
Min	1,860.15	1,506.50	47.75
Most Repeated Range (md)	5000 - 7000	2000 - 4000	< 1000 - 2000
Median	5,704.32	3,660.72	1,533.31
Average or Mean	5,312.35	3,841.26	2,394.90
Perm Range (md)	1,860 - 12,370	1,500 - 8,760	47 - 8,510
	No. of Data		
Range of Perm	**Zone 1**	**Zone 2**	**Zone 3**
< 1000 md	0	0	85
1000 - 2000 md	1	16	132
2000 - 3000 md	94	119	40
3000 - 4000 md	106	84	19
4000 - 5000 md	74	43	13
5000 - 6000 md	175	53	36
6000 - 7000 md	110	15	18
7000 - 8000 md	71	8	5
8000 - 9000 md	26	7	1
9000 - 10,000 md	10	0	0
> 10,000 md	8	0	0
	675	345	349

Layer 2	**Zone 1**	**Zone 2**	**Zone 3**
Area (sq.m)	1,687,500.00	862,500.00	872,500.00
Max	6,367.66	7,650.02	6,278.45
Min	20.67	28.67	144.30
Most Repeated Range (md)	< 1000 - 3000	< 1000	< 1000
Median	2,007.54	2,018.86	711.01
Average or Mean	1,858.15	2,166.02	1,253.63
Perm Range (md)	20 - 6,370	28 - 7,650	140 - 6,280
	No. of Data		
Range of Perm	**Zone 1**	**Zone 2**	**Zone 3**
< 1000 md	238	119	229
1000 - 2000 md	99	53	38
2000 - 3000 md	223	83	45
3000 - 4000 md	70	32	18
4000 - 5000 md	30	20	6
5000 - 6000 md	14	26	10
6000 - 7000 md	1	9	3
7000 - 8000 md	0	3	0
8000 - 9000 md	0	0	0
9000 - 10,000 md	0	0	0
> 10,000 md	0	0	0
	675	345	349

Layer 1	**Zone 1**	**Zone 2**	**Zone 3**
Area (sq.m)	1,687,500.00	862,500.00	872,500.00
Max	5,700.54	5,766.91	5,718.01
Min	397.56	859.14	842.42
Most Repeated Range (md)	< 1000 - 3000	1000 - 3000	1000 - 3000
Median	1,741.35	2,407.91	2,411.37
Average or Mean	1,794.50	2,559.65	2,570.21
Perm Range (md)	390 - 5,700	860 - 5,770	840 - 5,720
		No. of Data	
Range of Perm	**Zone 1**	**Zone 2**	**Zone 3**
< 1000 md	142	2	1
1000 - 2000 md	281	99	78
2000 - 3000 md	196	160	194
3000 - 4000 md	37	48	51
4000 - 5000 md	15	25	17
5000 - 6000 md	4	11	8
6000 - 7000 md	0	0	0
7000 - 8000 md	0	0	0
8000 - 9000 md	0	0	0
9000 - 10,000 md	0	0	0
> 10,000 md	0	0	0
	675	345	349

APPENDIX-B
FULL RESULTS OF STRATEGIES 1, 2 AND 3 IN FULL FIELD

Strategies 1 and 2 (Weightings = 1.37:1)

Full Perf. (7X7 & 5X5)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	30	200	61278316	2.85898995	16.6226616	21433556	3422500	122	46	76	3.98105E-08	6.84714E-09	0.482998504	1.518136518	2.179844469
January 1, 2015	January 1, 2035	20	60	200	120879496	3.86397696	24.2618809	31283700	3422500	122	46	76	5.8106E-08	9.25404E-09	0.704968462	1.123282334	2.089089127
January 1, 2015	January 1, 2035	20	120	200	237886144	5.11780357	36.0488892	46482080	3422500	122	46	76	8.63353E-08	1.22569E-08	1.047459184	0.848085901	2.283104983

Full Perf. (9X9 & 5X5)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers					
January 1, 2015	January 1, 2035	20	30	200	51635548	2.66871119	15.0056067	19348496	3422500	106	39	67	4.13623E-08	7.35618E-09	0.501825523	1.413083792	2.100584758
January 1, 2015	January 1, 2035	20	60	200	101711456	3.71051717	21.2589493	27411668	3422500	106	39	67	5.85993E-08	1.02279E-08	0.710953151	1.016330703	1.99033652
January 1, 2015	January 1, 2035	20	120	200	199501184	5.17780876	29.8817368	38530044	3422500	106	39	67	8.23676E-08	1.42724E-08	0.999321022	0.728322094	2.097391894

Full Perf. (9X9 & 7X7)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers					
January 1, 2015	January 1, 2035	20	30	200	25255780	1.94545281	10.0680742	12981955	3422500	59	19	40	4.98598E-08	9.63441E-09	0.604922099	1.078934143	1.907677418
January 1, 2015	January 1, 2035	20	60	200	49927392	2.70235777	14.3285532	18475492	3422500	59	19	40	7.09589E-08	1.33828E-08	0.860905301	0.776734851	1.956175114
January 1, 2015	January 1, 2035	20	120	200	98321200	3.54702091	21.4975891	27719374	3422500	59	19	40	1.06462E-07	1.75658E-08	1.291643906	0.591768561	2.361320712

Full Perf. (9X9)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers					
January 1, 2015	January 1, 2035	20	30	200	21330852	1.79808486	9.20034981	11863096	3422500	41	16	25	6.55657E-08	1.28139E-08	0.795473171	0.811217478	1.901015722
January 1, 2015	January 1, 2035	20	60	200	42214160	2.52508569	12.9654732	16717913	3422500	41	16	25	9.23977E-08	1.79949E-08	1.121010208	0.577658758	2.113442743
January 1, 2015	January 1, 2035	20	120	200	83307288	3.2962563	19.6005535	25273302	3422500	41	16	25	1.39682E-07	2.34906E-08	1.694687134	0.442513484	2.764234858

Full Perf. (5X5)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers					
January 1, 2015	January 1, 2035	20	30	200	108666656	3.42073107	24.6367645	31767084	3422500	181	81	100	3.97706E-08	5.52201E-09	0.482514258	1.882449215	2.543493748
January 1, 2015	January 1, 2035	20	60	200	214823600	4.32696438	38.5039253	49647648	3422500	181	81	100	6.2156E-08	6.98492E-09	0.754104417	1.488191709	2.52131476
January 1, 2015	January 1, 2035	20	120	200	423944864	6.43935251	51.0591431	65836568	3422500	181	81	100	8.24236E-08	1.03949E-08	1	1	2.37

Full Perf. (7X7)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers					
January 1, 2015	January 1, 2035	20	30	200	47843716	2.47252512	15.0068836	19350144	3422500	85	36	49	5.15856E-08	8.49921E-09	0.625859202	1.223043317	2.080470424
January 1, 2015	January 1, 2035	20	60	200	94386976	3.28436971	22.2877579	28738230	3422500	85	36	49	7.66133E-08	1.12899E-08	0.929506666	0.920726225	2.194150357
January 1, 2015	January 1, 2035	20	120	200	185209376	4.11613607	34.8963165	44995928	3422500	85	36	49	1.19955E-07	1.41491E-08	1.455344185	0.734670883	2.728492417

Strategy 3 (Weightings = 1.37:1)

Base Case_(5X5_Zone 1) - 10yrs

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2025	10	120	200	95896216	3.56288576	44.1541138	26915320	1687500	85	36	49	3.07828E-07	2.48393E-08	1	1	2.37
January 1, 2015	January 1, 2025	10	60	200	48401428	2.98575664	26.5934925	16210775	1687500	85	36	49	1.85401E-07	2.08157E-08	0.602287992	1.193294095	2.018428643
January 1, 2015	January 1, 2025	10	30	200	24416902	2.39234257	16.7432137	10206274	1687500	85	36	49	1.16728E-07	1.66786E-08	0.379199405	1.48928745	2.008790634

Strategy 3. (9X9_Zone 1) - 10 yrs

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers					
January 1, 2015	January 1, 2025	10	120	200	23524132	2.38605404	16.1735344	9859010	1687500	25	9	16	3.83373E-07	5.65583E-08	1.245410954	0.439180153	2.145393159
January 1, 2015	January 1, 2025	10	30	200	6013500.5	1.21989715	8.0867815	4929514	1687500	25	9	16	1.91687E-07	2.89161E-08	0.622706578	0.859013054	1.712121066
January 1, 2015	January 1, 2025	10	60	200	11887553	1.75635076	11.1033192	6768325.5	1687500	25	9	16	2.6319E-07	4.1632E-08	0.854989081	0.596639124	1.767974166

Strategy 3. (9X9 & 7X7 - shut in Zone 2 & 3 for 10 yrs)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	120	200	72558968	3.1142056	18.0696659	23299348	3422500	59	19	40	8.94859E-08	1.54224E-08	1.085683317	0.674013129	2.161399274
January 1, 2015	January 1, 2035	20	60	200	36944532	2.3836298	12.0203676	15499276	3422500	59	19	40	5.95281E-08	1.18044E-08	0.72222213	0.880596249	1.870040567
January 1, 2015	January 1, 2035	20	30	200	18727688	1.69480145	8.5698204	11050079	3422500	59	19	40	4.24401E-08	8.39312E-09	0.514902217	1.23850228	1.943918318

Strategy 3. (9X9 Only - shut in Zone 2 & 3 for 10 yrs)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers					
January 1, 2015	January 1, 2035	20	120	200	65879708	3.03388953	16.8406277	21714604	3422500	41	16	25	1.20014E-07	2.16208E-08	1.456060668	0.480781468	2.475584583
January 1, 2015	January 1, 2035	20	60	200	33327998	2.29625273	11.2563047	14514081	3422500	41	16	25	8.02174E-08	1.63641E-08	0.973233476	0.635225315	1.968555177
January 1, 2015	January 1, 2035	20	30	200	16839450	1.61095643	8.1068182	10453076	3422500	41	16	25	5.77728E-08	1.14804E-08	0.700925129	0.905448362	1.865715789

Strategy 3. (9X9 & 5X5 - shut in Zone 2 & 3 for 10 yrs)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers					
January 1, 2015	January 1, 2035	20	120	200	119563944	3.56409788	26.0169849	33546762	3422500	106	39	67	7.17146E-08	9.82427E-09	0.870073925	1.058083321	2.250084597
January 1, 2015	January 1, 2035	20	60	200	61607344	2.74223876	17.4234257	22466074	3422500	106	39	67	4.80269E-08	7.55885E-09	0.58268352	1.375194814	2.173471236
January 1, 2015	January 1, 2035	20	30	200	31545466	2.05142927	11.9257784	15377310	3422500	106	39	67	3.28729E-08	5.65467E-09	0.398828259	1.83828542	2.384680135

Strategy 3. (5X5 - shut in Zone 2 & 3 for 10 yrs)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers					
January 1, 2015	January 1, 2035	20	120	200	304670272	5.402174	43.7388992	56397720	3422500	181	81	100	7.06067E-08	8.7206E-09	0.856632066	1.191992801	2.365578732
January 1, 2015	January 1, 2035	20	60	200	154429792	3.71629858	32.2275162	41554736	3422500	181	81	100	5.20241E-08	5.99913E-09	0.631180122	1.732732818	2.597449586
January 1, 2015	January 1, 2035	20	30	200	78335320	3.00387239	20.2247181	26078112	3422500	181	81	100	3.26483E-08	4.84908E-09	0.396103751	2.143683774	2.686345913

Strategies 1 and 2 (Weightings = 2.88:1)

Full Perf. (7X7 & 5X5)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	30	200	61278316	2.85898995	16.6226616	21433556	3422500	122	46	76	3.98105E-08	6.84714E-09	0.482998504	1.518136518	2.90917221
January 1, 2015	January 1, 2035	20	60	200	120879496	3.86397696	24.2618809	31283700	3422500	122	46	76	5.8106E-08	9.25404E-09	0.704968462	1.123282334	3.153591505
January 1, 2015	January 1, 2035	20	120	200	237886144	5.11780357	36.0488892	46482080	3422500	122	46	76	8.63353E-08	1.22569E-08	1.047459184	0.848085901	3.864768351

Full Perf. (9X9 & 5X5)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	30	200	51635548	2.66871119	15.0056067	19348496	3422500	106	39	67	4.13623E-08	7.35618E-09	0.501825523	1.413083792	2.858341298
January 1, 2015	January 1, 2035	20	60	200	101711456	3.71051717	21.2589493	27411668	3422500	106	39	67	5.85993E-08	1.02279E-08	0.710953151	1.016330703	3.063875779
January 1, 2015	January 1, 2035	20	120	200	199501184	5.17780876	29.8817368	38530044	3422500	106	39	67	8.23676E-08	1.42724E-08	0.999321022	0.728322094	3.606366637

Full Perf. (9X9 & 7X7)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	30	200	25255780	1.94545281	10.0680742	12981955	3422500	59	19	40	4.98598E-08	9.63441E-09	0.604922099	1.078934143	2.821109787
January 1, 2015	January 1, 2035	20	60	200	49927392	2.70235777	14.3285532	18475492	3422500	59	19	40	7.09589E-08	1.33828E-08	0.860905301	0.776734851	3.256142118
January 1, 2015	January 1, 2035	20	120	200	98321200	3.54702091	21.4975891	27719374	3422500	59	19	40	1.06462E-07	1.75658E-08	1.291643906	0.591768561	4.311703011

Full Perf. (9X9)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	30	200	21330852	1.79808486	9.20034981	11863096	3422500	41	16	25	6.55657E-08	1.28139E-08	0.795473171	0.811217478	3.102180209
January 1, 2015	January 1, 2035	20	60	200	42214160	2.52508569	12.9654732	16717913	3422500	41	16	25	9.23977E-08	1.79949E-08	1.121010208	0.577658758	3.806168158
January 1, 2015	January 1, 2035	20	120	200	83307288	3.2962563	19.6005535	25273302	3422500	41	16	25	1.39682E-07	2.34906E-08	1.694687134	0.442513484	5.32321243

Full Perf. (5X5)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	30	200	108666656	3.42073107	24.6367645	31767084	3422500	181	81	100	3.97706E-08	5.52201E-09	0.482514258	1.882449215	3.272090278
January 1, 2015	January 1, 2035	20	60	200	214823600	4.32696438	38.5039253	49647648	3422500	181	81	100	6.2156E-08	6.98492E-09	0.754104417	1.488191709	3.66001243
January 1, 2015	January 1, 2035	20	120	200	423944864	6.43935251	51.0591431	65836568	3422500	181	81	100	8.24236E-08	1.03949E-08	1	1	3.88

Full Perf. (7X7)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	30	200	47843716	2.47252512	15.0068836	19350144	3422500	85	36	49	5.15856E-08	8.49921E-09	0.625859202	1.223043317	3.025517819
January 1, 2015	January 1, 2035	20	60	200	94386976	3.28436971	22.2877579	28738230	3422500	85	36	49	7.66133E-08	1.12899E-08	0.929506666	0.920726225	3.597705423
January 1, 2015	January 1, 2035	20	120	200	185209376	4.11613607	34.8963165	44995928	3422500	85	36	49	1.19955E-07	1.41491E-08	1.455344185	0.734670883	4.926062136

Strategy 3 (Weightings = 2.88:1)

Base Case_(5X5_Zone 1) - 10yrs

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2025	10	120	200	95896216	3.56288576	44.1541138	26915320	1687500	85	36	49	3.07828E-07	2.48393E-08	1	1	3.88
January 1, 2015	January 1, 2025	10	60	200	48401428	2.98575664	26.5934925	16210775	1687500	85	36	49	1.85401E-07	2.08157E-08	0.602287992	1.193294095	2.927883511
January 1, 2015	January 1, 2025	10	30	200	24416902	2.39234257	16.7432137	10206274	1687500	85	36	49	1.16728E-07	1.66786E-08	0.379199405	1.48928745	2.581381735

Strategy 3. (9X9_Zone 1) - 10 yrs

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2025	10	120	200	23524132	2.38605404	16.1735344	9859010	1687500	25	9	16	3.83373E-07	5.65583E-08	1.245410954	0.439180153	4.025963699
January 1, 2015	January 1, 2025	10	30	200	6013500.5	1.21989715	8.0867815	4929514	1687500	25	9	16	1.91687E-07	2.89161E-08	0.622706578	0.859013054	2.652407999
January 1, 2015	January 1, 2025	10	60	200	11887553	1.75635076	11.1033192	6768325.5	1687500	25	9	16	2.6319E-07	4.1632E-08	0.854989081	0.596639124	3.059007679

Strategy 3. (9X9 & 7X7 - shut in Zone 2 & 3 for 10 yrs)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	120	200	72558968	3.1142056	18.0696659	23299348	3422500	59	19	40	8.94859E-08	1.54224E-08	1.085683317	0.674013129	3.800781083
January 1, 2015	January 1, 2035	20	60	200	36944532	2.3836298	12.0203676	15499276	3422500	59	19	40	5.95281E-08	1.18044E-08	0.72222213	0.880596249	2.960595982
January 1, 2015	January 1, 2035	20	30	200	18727688	1.69480145	8.5698204	11050079	3422500	59	19	40	4.24401E-08	8.39312E-09	0.514902217	1.23850228	2.721420666

Strategy 3. (9X9 Only - shut in Zone 2 & 3 for 10 yrs)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	120	200	65879708	3.03388953	16.8406277	21714604	3422500	41	16	25	1.20014E-07	2.16208E-08	1.456060668	0.480781468	4.674236191
January 1, 2015	January 1, 2035	20	60	200	33327998	2.29625273	11.2563047	14514081	3422500	41	16	25	8.02174E-08	1.63641E-08	0.973233476	0.635225315	3.438137725
January 1, 2015	January 1, 2035	20	30	200	16839450	1.61095643	8.1068182	10453076	3422500	41	16	25	5.77728E-08	1.14804E-08	0.700925129	0.905448362	2.924112734

Strategy 3. (9X9 & 5X5 - shut in Zone 2 & 3 for 10 yrs)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	120	200	119563944	3.56409788	26.0169849	33546762	3422500	106	39	67	7.17146E-08	9.82427E-09	0.870073925	1.058083321	3.563896224
January 1, 2015	January 1, 2035	20	60	200	61607344	2.74223876	17.4234257	22466074	3422500	106	39	67	4.80269E-08	7.55885E-09	0.58268352	1.375194814	3.053323351
January 1, 2015	January 1, 2035	20	30	200	31545466	2.05142927	11.9257784	15377310	3422500	106	39	67	3.28729E-08	5.65467E-09	0.398828259	1.83828542	2.986910806

Strategy 3. (5X5 - shut in Zone 2 & 3 for 10 yrs)

Start Date	End Date	Period (years)	Inj. Rate (m3/d)	Prod. Rate Limit (m3/d)	Cum Injection (water bbl.)	Cum SOR	RF (%)	Cum Oil Recovery (bbl.)	Prod. Area (sq.m)	No. of Wells Drilled	No. of Injectors	No. of Producers	RF/area/well	Cum SOR/area/well	Normalized RF/area/ well	Normalized Cum SOR/area/ well	Judgement Score
January 1, 2015	January 1, 2035	20	120	200	304670272	5.402174	43.7388992	56397720	3422500	181	81	100	7.06067E-08	8.7206E-09	0.856632066	1.191992801	3.659093152
January 1, 2015	January 1, 2035	20	60	200	154429792	3.71629858	32.2275162	41554736	3422500	181	81	100	5.20241E-08	5.99913E-09	0.631180122	1.732732818	3.550531571
January 1, 2015	January 1, 2035	20	30	200	78335320	3.00387239	20.2247181	26078112	3422500	181	81	100	3.26483E-08	4.84908E-09	0.396103751	2.143683774	3.284462577

VITA

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