Assessment of Development Methods for a Heavy Oil Sandstone Reservoir

By

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Declaration

I declare that this thesis: “Assessment of Development Methods for a HO Sandstone Reservoir”, is the outcome of my own research under the supervision of Professor Peter King in the department of Earth Science and Engineering at Imperial College London; any ideas and information from other people and sources are duly acknowledged in line with the current standard practice in petroleum engineering and related disciplines.

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Hifaa Alajmi, 2012
Abstract

The combination of growing energy demands, the declining performance of conventional oil fields and attractive oil prices have renewed interest in both Heavy Oil resources (HO) and the methods of exploiting them. The vast volume of these resources notwithstanding, their low reservoir-scale mobility precludes exploitation using traditional primary and secondary recovery techniques, making enhanced oil recovery (EOR) methods (both thermal and non-thermal) natural candidates. However, the influence of several factors, technical and non-technical, require that rigorous studies inform the choice of EOR method(s).

HO is a thick, viscous, tar-like crude oil that does not pump easily or flow well. This presents huge challenges when estimating reserves and extracting them from the reservoir, as does pipeline transportation to refineries. Increasingly, focus is moving towards those technologies that can most efficiently recover and process HO. The challenge here is finding the best way to produce, transport and process the oil. In this study, the focus is on how to identify the best way to recover the HO medium from an unconsolidated sandstone reservoir; to achieve this aim the Lower Fars formation in Kuwait is used as an exemplary case to test our screening methodology and to discover the best strategies.

At present, Kuwait is pursuing a national objective to produce 4 million barrels per day (b/d) of oil by the year 2020. However, this target can only be achieved sustainably with HO development. Although there is evidence in the Kuwait Oil Company’s (KOC) long-term plan that this is understood, there is not yet a clear-cut strategy for its realisation. Hence, the primary objective of this study is to establish possible development options for the medium heavy oil reservoirs. Other objectives include understanding the physics of selected thermal EOR processes in different medium heavy oil reservoirs and developing a robust screening tool for HO resources. Numerical modelling studies will be used to achieve these objectives.

Given the huge number of EOR methods and their various combinations, it is not pragmatic to conduct detailed studies on each method for potential application to the reservoir. To accelerate decision-making, using experiences taken from field performances elsewhere, a relatively simple screening procedure has been developed and implemented. Using this tool, less favourable options
have been eliminated, retaining only the ‘best’ options for further evaluation; these are unheated-water flooding, hot water flooding, Steam flooding (SF) and cyclic steam stimulation (CSS).

For the preliminary numerical simulations, a homogenous, three-phase and multi-component numerical model was constructed using the known (average) geological, petrophysical and fluid properties of the Northern sector of the Ratqa field. Information from analogue fields and correlations was also used to complete the data. The reservoir was considered homogeneous in the first part of the study, allowing for the separation of process effects from reservoir geology. The second part of this study presents the results of the sensitivity study on a small scale model, extracted from a large field scale sector model of 0.9 Million cells.

Several simulation runs were conducted to investigate the effects of petrophysical properties and operating variables on the performance of unheated-water flood, hot water flood, steam flood processes, and CSS. The simulation results show that any positive impacts from thermal injection on oil production are not instantaneous - they only become noticeable after an appreciable number of pore volumes have been injected. This finding is attributed to the time lag required to heat up the reservoir to a temperature that gives reasonable reduction of oil viscosity, creating a more favourable mobility ratio. In addition to giving a higher ultimate recovery rate, the preliminary results also indicate that high-temperature operation accelerates performance. From an economic viewpoint, production acceleration would improve overall project economics by mitigating the negative impact of discounting on the revenue stream. Another important finding from the simulation study is that while hot water flood is characterised by a stable displacement of oil by water, unstable fronts are evident in the cold-water process, resulting in a significant quantity of by-passed oil.

When conducting the study it was also imperative to conduct a detailed economic analysis to assess the economic feasibility of each recovery process/case. To achieve this, a preliminary matrix of the main factors was integrated into the developed economic model. The input for project performance specified cumulative oil recovery (income) versus cumulative energy injected into the reservoir in terms of heated fluids (cost).

Continuing the work to investigate the best development options for a major unconsolidated, shallow HO reservoir a comparative study and a sensitivity analysis of various operational
conditions and reservoir parameters were conducted in order to: (1) find the best conditions to achieve a high RF, and (2) to understand the effect of reservoir heterogeneity on the reservoir’s performance. The operational parameters investigated are injected fluid type, injection swapping time and the perforation location. The reservoir parameters examined are oil viscosity, initial water saturation, porosity and permeability. In addition to studying these reservoir parameters, oil price sensitivity was investigated to evaluate the financial feasibility of the selected recovery methods within both the historical and forecasted oil price range.

The preliminary results show that the recovery factor (RF) is very sensitive to the oil viscosity value and the relationship between them is nonlinear. The simulation results also indicate that an increase in the porosity and permeability accelerates performance; however, the opposite is not true of the initial water saturation value. From an economic perspective, production acceleration would improve overall project economics by mitigating the negative impacts of discounting on the revenue stream due to the low oil price. Economically, successive (combination of injected fluids) cases support successful investment at the lowest (expected) oil price; in contrast, the continuous steam and hot water flooding development options show a higher economic risk after the second year.

This work contributes significantly towards our understanding of the performance of different development options in high permeability HO reservoirs. This is critical for the decision making process when determining the applicability of EOR recovery methods and their successful application in the field.
Acknowledgments

First and foremost I would like to acknowledge God as the giver of all my gifts, all that I am, and have, and will have in the future.

I would like to offer my most sincere gratitude to my supervisor, Prof. Peter King, who has supported me throughout my thesis with his patience and knowledge, whilst allowing me the room to work in my own way. I attribute the level of my PhD degree to his encouragement and effort and without him this thesis would not have been completed or written. I learned a lot from you, not only on an academic level, but much on the human level. One simply could not wish for a better or friendlier supervisor.

Beloved Mom… your faith in me, is what has brought me here today!

Dad… your limitless support, helped me to attain this!

My oldest brother Mishal… my soul mate… your hand in my hand… and only your hand… makes my dreams come true!

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Nomenclature

HO – Heavy Oil

XHO - Extra Heavy Oil

Lower Fars - Lower Fars, the targeted (unconsolidated sand stone) HO reservoir

KOC - Kuwait Oil Company

KISR - Kuwait Institute of Scientific Research

API - American Petroleum Institute

CAPEX - Capital Expenditure

OPEX - Operating Expenditure

PV - Pore Volume

PVT - Pressure-Volume-Temperature

Production Technologies

SF - Steam Flooding

CHOPS - Cold HO Production with Sand

CP - Cold Production

CSS - Cyclic Steam Stimulation (vertical wells)

SAGD - Steam-Assisted Gravity Drainage

VAPEX - Vapour-Assisted Petroleum Extraction

Other Symbols:

UR - Ultimate recovery

b/d – Barrels per day
K - Permeability

OOIP - Original oil in place

P - Pressure

MMP - Minimum miscibility pressure

RF - Recovery factor (of OOIP)

SOR - Steam (water)-to-Oil Ratio

T and temp. - Temperature

Φ - Porosity by percentage

μ viscosity - cP
1. Introduction

Heavy oil (HO) and extra heavy oil (XHO) are becoming important resources within the global energy supply mix, due to a combination of the dwindling levels of discovery of giant conventional oil fields and the maturity of developed assets. Clear evidence of this interest is the steady production and growth of HO, currently at about 2.8 million barrels/day, which is intended to mitigate current and future supply shortfall from conventional resources (Kumar, 2007). However, despite their relatively simpler geology and abundant nature, the complexity of the fluid properties at these sites precludes many definitions based on the oil properties. Instead, such sites are described operationally according to viscosity and density (API).

Due to its stronger correlation with temperature, viscosity is a more useful indicator of the flow characteristics and potential productiveness of HO and XHO than API gravity. Thus, in the industry, the most common definition cites in-situ viscosity (Shafiei et al., 2007; Head et al., 2003; Gibson, 1982). According to the United Nations Institute for Training and Research (UNITAR) (1982), HO is gas-free oil of 100 – 10,000 cP viscosity and with a density between 0.934 and 1 g cm$^{-3}$ (10 and 20 API) at original reservoir temperature and pressure. While the US Geological Survey (USGS, 2007) defines HO as having 10 – 20 API, a viscosity above 100 cP, and the presence of up to 50 wt% asphaltenes, other workers describe it simply as 100 – 10,000 cP at reservoir conditions (Shafiei et al., 2007; Dusseault, 2006a, b; Briggs et al., 1988).

Farouq Ali et al. (2006) highlighted the importance of in-situ oil viscosity when discriminating between different HO reservoirs. For example, despite their comparable API, Venezuelan and Californian reservoirs (1000 - 2000 cP) and those in Cold Lake, Alberta (100,000 cP) have remarkably distinctive flow properties. Moreover, in the case of more general classifications, such as are presented in Table 1.1, the authors describe HO as petroleum-like liquids or semi-solids, occurring in rocks, usually containing 3 wt% or more sulphur, 10 – 30 wt% asphaltenes and about 2000 ppm of Vanadium compounds and with exceptional reservoir characteristics.

Reservoir conditions, especially relative to temperature, have a major influence on the definition and hydraulics of these unconventional resources. For example, the deeper Faja del Orinoco oil in
Venezuela is characterised by about 9 °API and 1,000 - 4,000 cP at 40- 45°C, which is mobile at reservoir conditions. In contrast, typical Canadian reservoirs of a similar density but at a shallower depth and ~ 5°C are semi-solid under reservoir conditions (Dusseault, 2001). Evidently, for practical purposes, the assessment of HO accumulations must consider their in-situ conditions, as these influence the hydraulics and the level of challenge affecting the recovery of these abundant resources. Consequently, this study refers to the initial conditions of 10 - 20°API and < 10,000 cP, and < 10°API and < 10,000 cP for HO and XHO respectively (Danyluk et al., 1984; Schenk et al., 2006).

**Table 1.1: Typical Properties of HO Reservoirs (Farouq Ali et al., 2006)**

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deposit Depth</td>
<td>3000 feet or less</td>
</tr>
<tr>
<td>Permeability</td>
<td>One to several darcies</td>
</tr>
<tr>
<td>Porosity</td>
<td>~ 30%</td>
</tr>
<tr>
<td>Oil Saturation</td>
<td>50 – 80%</td>
</tr>
<tr>
<td>Formation Thickness</td>
<td>50 to several 100 feet</td>
</tr>
</tbody>
</table>

Several geologic theories have been proposed to explain the origins of HO and XHO. Prominent among these are the theories that they are the product of the expulsion of immature oil from their source rocks (Larter et al., 2006) and that they are produced by the biodegradation of light and medium oil when reservoir temperatures fall below 176°F (USGS, 2007; Larter et al., 2006; Head, et al., 2003; Larter et al., 2003). There are also post-accumulation processes that affect the oil, such as oxidation, water washing, bacterial degradation and evaporation (Shafiei et al., 2007). However, it is generally understood that immature oil accounts for a small percentage of the global portfolio (Larter et al., 2006).

In comparison to conventional oils, HO is characterised by high in-situ viscosity, which limits its mobility, hence commerciality, under most reservoir conditions. This low mobility precludes
reliance on natural drive mechanisms for extraction. The deployment of conventional secondary recovery techniques, such as gas and water injection, is inherently non-feasible due to poor microscopic and macroscopic efficiencies. Therefore, exploitation usually requires Enhanced Oil Recovery (EOR) methods, which are designed to reducing the viscous and capillary effects, impacting significantly in a positive way on recovery efficiency.

1.1 HO in a global context

HO and XHO deposits are present in more than 70 countries worldwide (Fig. 1.1), with the largest deposits located in Canada and Venezuela (Dusseault et al. 2008; Hein and Marsh 2008; Hernandez et al. 2008; Marsh and Hein 2008; Meyer et al. 2007; Villarroel 2008). The surge in HO interest is premised on three main factors. First, that estimated global reserves are almost six times those of conventional oil reserves. Second, the rate of depletion of conventional light crude deposits far exceeds the rate at which they are either discovered or brought on stream. Finally, it is imperative to develop cost-effective technologies to exploit HOs in anticipation of unprecedented energy demand and competitiveness in the nearest future (Bagci, 2007). Furthermore, current and expected oil prices encourage the application of the majority of the EOR processes, which are the primary methods for the exploitation of HO and XHO. The transformation of the Alberta tar sands, previously a “neglected” resource, to a key component in the global energy mix clearly attests to the favourable economic conditions in place for EOR application. However, the choice of EOR method(s) for use at a specific reservoir depends on several criteria, including technical, economic and environmental. Consequently, the selection of suitable exploitation methods requires thorough research studies.

Currently, HO is making a significant contribution to the overall energy supply in the US and Canada (Farouq Ali and Thomas, 2007). The Middle East has over 900 billion barrels of proven HO resources, most of which are either undeveloped or at various stages of development (an overview of these developments is given in section 1.2). However, there is a dearth of publications on the suitable application of HO recovery processes within the Middle East.
(Algharaib et al., 2009; Atkins et al., 2008). A summary of light oil reserves and known HO resources in the major oil producing countries, including Kuwait, is presented in Table 1.2.

According to the Alberta Research Council (ARC) (2008), of the total world oil reserves of about 9 - 13 trillion barrels, over 70% is in the form of unconventional oil (Fig. 1.1). In contrast, the USGS estimated the global reserves of HO (above 100 cP) to be about 9 trillion barrels, with Venezuelan and Canadian resources accounting for approximately 90% of all known HO reserves (Safinya, 2008). At present, worldwide production of HO constitutes about 6% of the total oil production of about 84 million barrels per day (MMBPD), and the global annual consumption is currently about 31 billion barrels (Farouq Ali, 2007; Shafiei et al., 2007). It is thought that in the long term, HO will continue to be a key player in the global oil portfolio.

Table 1.2: Worldwide light oil reserves and HO and tar resources in some countries (Dusseault et al, 2008; Farouq Ali and Thomas, 2007)

<table>
<thead>
<tr>
<th>Country</th>
<th>Light Oil (Billion barrels)</th>
<th>HO and Tar (Billion barrels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>World</td>
<td>1212</td>
<td>5000</td>
</tr>
<tr>
<td>U.S.A</td>
<td>22</td>
<td>53</td>
</tr>
<tr>
<td>Canada</td>
<td>180</td>
<td>1670</td>
</tr>
<tr>
<td>Venezuela</td>
<td>73</td>
<td>2000</td>
</tr>
<tr>
<td>Kuwait</td>
<td>99</td>
<td>12 - 15</td>
</tr>
<tr>
<td>Saudi Arabia</td>
<td>259</td>
<td>?</td>
</tr>
<tr>
<td>Oman</td>
<td>6</td>
<td>5</td>
</tr>
</tbody>
</table>
1.2 HO developments in the Middle East

Oman in particular has seen considerable investment in a range of EOR technologies to extract HO. Other countries in the Middle East have been encouraged by Oman’s success, and in response to the increasing oil prices, are becoming more active in HO production; Kuwait, Iran and Iraq all have plans to develop several HO fields (Senergyworld, 2011).

In Bahrain the fields have a tight matrix with low permeability (2mD) and complex fractured carbonates with large volumes of HO; therefore, a trial of steam injection above the fracture gradient was conducted in 2012 (Delamaide, 2010). In 2013, it was decided to expand the Rubble pilot to test different areas of the field and the pilot results will be used to further assess the process and to design a field-wide development if this is merited (Hanley, 2013).
In Oman, four large projects commenced in 2012, with another two expected to start during 2013. A small-scale polymer flood pilot took place in the Marmul Field, in the South of Oman at a sandstone reservoir in the late 1980’s but the method was considered uneconomical at the time (Penney et. al., 2007).

Also in Oman, at Qarn Alam, facilities are close to being commissioned to allow steam injection to be applied by PDO to improve the production of 16 API oil with 200-300 cP viscosity. This will then be the world’s first commercial application of steam-assisted gas-oil gravity drainage in a fractured carbonate reservoir. Investment in the Qarn Alam field is estimated at USD 1.4 billion, and about USD 5 billion is currently being invested at the three largest fields in the country. In addition, pilot steam projects are being carried out at other large fields, such as Amal-West (sandstone) and Al Ghubar South (carbonate) (Penney et al., 2007).

Egypt has large resources of HO. Of these, Issaran is one of the first HO carbonate fields at which steam EOR has been successfully implemented. The field’s fractured reservoirs contain oil with 10-12 API gravity (Petroleum Africa, 2010).

Sudan has many fields containing HO. Some of those with lighter oils (around 20 API) were developed previously using cold production methods, but are now in decline. Numerous resources of more viscous oils are still awaiting development. Indeed, it is anticipated that HO will represent about 50% of the country’s production by 2020 (Tewari et al., 2005)

1.3 Research motivation

At present, Kuwait is pursuing a national objective to produce 4 million b/d of oil by the year 2030, which (excluding the output from the neutral zone) requires an additional capacity of 1.55 million b/d based on 2008 figures (Business Journal, 2009; KOC, 2009). However, it has been established that this target is unlikely to be achieved, in a sustainable manner unless HO development takes place (Figs. 1.2 and 1.3). As the state-owned company, the Kuwait Oil Company (KOC) is taking a key role in realising this objective. Accordingly, KOC has developed a short to mid-term business plan that requires bringing 60,000 b/d of HO on-stream as early as
Furthermore, KOC’s long-term plan, as espoused in its 2020 strategy, cites HO as a major resource (Khebab, 2007). Besides mitigating the expected decline in conventional oil, prospective HO development would add new reserves. In addition, a steam pilot project is currently ongoing in the Wafra field in the Saudi-Kuwaiti neutral zone.

Northern Kuwait has long been identified as the primary location of national HO resources, with an estimated resource volume of about 13 billion barrels (Kuwait Energy Data, 2009). These resources are concentrated at just a few reservoirs; for the purpose of this research the reservoir of interest is the Lower Fars reservoir, the largest known HO resource in Kuwait (Ahmed, et al., 2011). This sandstone asset, containing 10 – 18 °API oil, is referred to as the Lower Fars reservoir throughout this thesis.

Although several studies, including two pilots, have been conducted previously characterising the Lower Fars reservoir (Alajmi et al., 2006; Al-Quabandi, 1995; Sanyal, 2007), there has not been any focused study on associated engineering aspects. Despite the availability of a large database detailing the geologic, petrophysical and fluid properties of this strategic reservoir, there is currently a limited understanding of how it would respond to available HO recovery methods, as well as their variants, and the economics of these methods. Attaining an informed understanding of the applicability (technical and economic) of known recovery methods at the Lower Fars Reservoir is a primary motivation for this study.
Figure 1.2: Kuwait crude oil and lease condensate production forecasts. Dark blue line is the most likely case (Khebab, 2007)

Figure 1.3: KOC’s oil capacity forecast (Source: KOC’s Research and Technology Group)
1.4 Research objectives

The central objective of this study is to identify feasible EOR methods for use at an unconsolidated sandstone HO reservoir. This includes establishing possible development options for medium HO reservoirs. Additional objectives include demonstrating the physics underpinning the selection of thermal EOR processes in different medium HO reservoirs, and developing robust screening tools for HO resources.

1.5 Research methodology

The methodology used to achieve the research objectives is general, and, in principle, can be applied to any project that is characterised by uncertain input parameters. The following tasks have been accomplished:

- **Develop an HO-EOR screening Model:**
  Given the existence of several EOR methods and their various combinations, it is not pragmatic to conduct detailed studies of each method for potential application to the subject reservoir. To accelerate decision-making, using experiences from field performances elsewhere, a relatively simple screening procedure has been developed and implemented. Using this tool, less favourable options have been eliminated, keeping only the ‘best’ options for further evaluation.

- **Modelling and numerical simulation:**
  I. *Simple homogenous model:* In the first stage of this research, the reservoir has been treated as a homogeneous resource, allowing the separation of process effects from the reservoir geology. A commercial compositional and thermal simulator (CMG STARS) can be used to construct a homogeneous, three-phase and multi-component numerical model using the
known (average) geological, petrophysical and fluid properties at the Lower Fars reservoir. Information from analogue fields and correlations are also included. Several simulation runs are conducted, investigating the effects of petrophysical properties and operating variables on the performance of unheated-water flood, hot water flood, and steam flood processes.

II. **Lower Fars Real sector model**: a small scale extracted (from large field scale sector model of 0.9 Million cells) single pattern model. Several simulation runs can be conducted to investigate the effects of petrophysical properties and operating variables on the performances of unheated-water flood, hot water flood, steam flood processes, CSS and other successive cases.

- **Economic model**: It is imperative to conduct an economic analysis to assess the economic feasibility for each recovery process/case. To perform this, a preliminary template of the main factors is integrated into the proposed economic model. The input for project performance involves specifying cumulative oil recovery (income) versus cumulative energy, as injected into the reservoir in terms of heated fluids (cost).

- **Sensitivity study**: Investigating the effects of petrophysical properties and operating variables on performance of the selected EOR methods. This research presents the results of the sensitivity study on both reservoir properties and operating variables.

- **Risk analysis**: This research concentrates on two important risks (has a significant impact, magnitude and likelihood), namely oil price fluctuations and reservoir heterogeneity.
2. Literature Review

2.1 Some HO recovery methods

A combination of growing energy demand, the declining performance of conventional oil fields and attractive oil prices has renewed interest in HO resources and the methods for exploiting them. However, their low mobility precludes reliance on natural drive mechanisms for their extraction. The deployment of conventional secondary recovery techniques, such as gas and water injection, is inherently infeasible because of poor microscopic and macroscopic efficiency. Conventional displacement is primarily characterised by macroscopic transport properties, such as relative permeability, capillary pressure, and/or dispersivity. Therefore, HO recovery typically requires so-called enhanced oil recovery (EOR) methods that are aimed at reducing viscous and capillary effects, resulting in a significant positive impact on recovery efficiency. One definition of EOR is "the recovery of oil by injection of a fluid that is not native to the reservoir". EOR is a means by which to extend the productive life of an otherwise depleted and uneconomic oil field. It is typically practiced after other less risky and more conventional methods, such as pressure depletion and water flooding have been exhausted (Lake and Walsh, 2008).

Based on technical evaluation, which includes analytic, numerical, and laboratory studies, as well as field pilots, a number of EOR methods have been reported and shown to be promising (Dornan, 1990; Farouq Ali and Thomas, 2007; Goodyear et al., 1996; Hong, 1987; Shen, 1989; Sorbie, 1990). However, aside from some thermal techniques, the large-scale commerciality of the majority of these methods remains to be proven, largely due to prohibitive costs and unfavourable oil pricing. Thus far, establishing their commerciality and improving their environmental scorecard demands further active research, to which this study offers a contribution.

There are two main types of EOR methods to evaluate; these are thermal and non-thermal, referring to the class of techniques by which crude production can be achieved by altering the oil’s original properties (Schlumberger, 2011). Heat is used in preference when extracting heavy crudes, while non-thermal methods are used for light crudes, although some may be both
applicable to HO, but have little success when applied in the field (Fletcher et al., 2013). As the thermal processes primarily use heat to alter crude properties, most non-thermal processes depend on dilution. Furthermore, several variants and sub-classes of these methods exist including their combinations. In principle, each method is directed towards improving certain aspects of the hydrocarbon displacement process, both the microscopic and macroscopic, with the overall objective of enhancing recovery performance (Alkafeef and Zaid, 2007; Donaldson, et al., 1985; Nadella, 2010; Taber, et al., 1997a; Tabibi, et al., 1984).

Today, the many worldwide HO recovery projects reveal that the most successful methods are the thermal methods, which include steam injection in various forms, e.g. cyclic steam stimulation (CSS), steam flooding, and steam-assisted gravity drainage (SAGD). Many other recovery methods have been tested, but have met with only limited commercial success. These include in-situ combustion, electrical heating and non-thermal methods. Figure 2.1 shows that different types of EOR methods can be classified into two main categories, thermal and non-thermal processes. Considering that the list of methods is not exhaustive, we have limited our discussion to the most commercially successful methods.
2.1.1 Thermal EOR methods

The basic objective when applying thermal EOR methods is to reduce the viscosity of the oil to improve mobility; therefore it is particularly useful for viscous oils (5-15° API), but is also relevant to petroleum to 45° API (Okeke, 2013). Other benefits of thermal methods include reducing residual oil saturation as a result of thermal expansion, heightening higher areal efficiency due to the improved mobility ratio, distillation with steam, and thermal cracking, among others. Thermal EOR methods are generally classified into two types: those that involve the injection of fluids into the formation, as with the injection of hot water and steam, in two modes, cyclic and continuous, and using the heat generation at the site itself (Andrianov, 2012).
Despite their comparatively high recovery factor of up to 50% (Alkafeef and Zaid, 2007; Mendoza, 2001; Mendoza, 1999), thermal EOR is still an active area of research, as generations of investigators are seeking to advance our current understanding of the underlying physics as well as to improve performance (Algharib et al., 2009; Alajmi et al., 2006; Alajmi et al., 2009; Farouq Ali and Thomas 2007; Osterloh and Jones 2003; Prats 2002; Ramal 2004; Sasaki et al., 2001; Stone et al., 2002). According to the available records, thermal EOR methods in comparison to hot water flood, CSS, SAGD, steam flooding and in-situ combustion, account for the majority of commercial HO and XHO production.

Thermal recovery, and explicitly steam injection, is seemingly the best procedure for enhancement of oil recovery as described in the literature. To overcome decreases in the temperature of the HO following upward in a vertical wellbore, Riyi et al., (2012) developed a new thermal method. This new method, adapted in this study, involves heating the HO by circulating hot water in closed double casing in ultra-deep wells. Considering that both hot water injection temperature and flow rate are the most important factors affecting the temperature of the crude oil, a model was developed to calculate the temperature and the pressure of the fluids produced and the hot water in the wellbore; thus, the effect of hot water on HO temperature was investigated. The model results demonstrate that the hot water circulating in the annuli may efficiently heat the HO in the tubing, so as to significantly reduce both oil viscosity and resistance to oil flow; consequently this will make the oil flow more easily to the surface from the bottom hole.

- **Cyclic steam stimulation (CSS) and steam flooding**

CSS, also known as huff-and-puff, involves injecting high quality steam into the reservoir over a period of months, using a single well, then following this with a cycle soak for a period. Consequently, the oil, the viscosity of which has been significantly reduced by the injected heat, is then produced through the same injection well (Fig. 2.2). This inject-soak-produce cycle may be repeated up to six times, following which a steam flood will be initiated (USGS, 2007). Because of its quick payout and relative robustness, CSS has been the only method successful applied in the Cold Lake, Alberta region. It is also used in some parts of Venezuela. Although average recovery is 10 - 15% of original oil in-place (OOIP), up to 25 and 35% has been reported in Alberta and Venezuela respectively (Farouq Ali and Thomas, 2007). However, in some areas, such as California, it is normal practice to implement CSS as the first stage of a steam flood.
Greenidge (2007) highlighted the relative importance of a soak period. Unlike CSS, which is completed using a single well, steam flooding is a multi-well-pattern driven process, in which steam is injected into the reservoir using a scheme of injection and production wells. The injection rate is an important factor in this process, because a high rate can cause early steam breakthrough, whereas a low rate can aggravate heat losses (Farouq Ali, 2008). In addition to lowering oil viscosity, the injected steam provides drive energy. Compared to CSS, the main advantage of this multi-well-pattern method is that of large areal coverage and higher recovery (50 – 60%); whereas, the disadvantages are higher heat loss, longer payout times and higher costs (operating and capital) due to the higher fuel consumption for steam generation for each barrel of oil recovered. Combined CSS and steam drives often recover more than 50% of the OOIP (Alvarado and Manrique, 2010). Generally speaking, this method is most applicable to oils in the 1000 cP range and at present, 60% of the total oil (light and heavy) produced by EOR methods is attributed to steam injection (Farouq Ali and Thomas 2007).

From experience, steam projects are the ones best suited to classic reservoirs at depths below 4,000 feet, with reservoir thicknesses above 20 feet and oil saturation in excess of 40% of pore volume. For reservoirs at a greater depth, wellbore thermal losses reduce the steam quality significantly, and may effectively turn operations into a hot water flood. Steam injection is usually not a competitive solution for production from carbonate reservoirs, largely because of heat lost through fractures (USGS, 2007).

The Oil and Gas Journal (2000) reported on a worldwide survey of 172 EOR projects. About 90% of these projects were HO developments, with the largest being the Duri Field in Indonesia. Total production from these 172 projects was 1.4 million b/d. Of these, 1.3 million b/d were due to steam drives. In other words, although they accounted for just 90% of the projects surveyed, steam drive processes contributed over 92% to the daily production pool. However, in a similar survey conducted in 2006 (Oil and Gas, 2006), involving 117 projects, virtually all the daily offtake of 1.3 million b/d was from steam EOR (USGS Report, 2007).
- **Steam assisted gravity drainage (SAGD)**

SAGD entails continuous production of viscous oil using gravity drainage, while injecting heating fluids. The process starts with two parallel horizontal wells that are separated by a fixed vertical distance (an optimisation variable) near the base of the formation. Steam is injected into the upper well, while oil and condensed water are drained from the lower well. Injected steam forms a steam chamber, which heats the oil at the interface. The chamber grows laterally and upwards, as the oil is mobilised and produced from the lower well (Fig. 2.3).

Although SAGD is not as robust a method as CSS, it promises higher recovery (> 50%) and production rates. Unlike CSS, for success SAGD requires good vertical permeability, several months of preheating and impermeable cap rock (Yeung, 2007). SAGD has been successfully implemented in reservoirs of up to more than 66 ft (20 m) thickness and in oils of more than 100,000 cP (Dusseault et al. 2008).

Despite this success, SAGD is a complex process, and one that is highly sensitive to geology, for example, shale parries can present a challenge to SAGD as it can restrict the vertical communication of the drainage process. Shale layers, depending on their size, vertical and horizontal locations, and continuity throughout the reservoir, may act as a flow barrier, thereby restricting the vertical communication of the drainage process. Consequently, to improve
productivity in these reservoirs, achieving an understanding of the effects of reservoir heterogeneities is necessary. (Alvarado and Fatemi, 2012; Manrique, 2010). SAGD applicability has been demonstrated in both sandstone and carbonate formations. For example, its application in fractured carbonate reservoirs reportedly afforded recoveries of 40 – 50% (Alkafeef and Zaid, 2007; Farouq Ali and Thomas 2007; Sedaee, Sola and Rashidi, 2006). In 2007, completed and ongoing commercial-scale SAGD projects in Alberta numbered about fifteen (Yeung, 2007).

Fatemi (2012) investigated the effect of geometrical properties of reservoir shale barriers (such as density, discontinuity, location, and dispersion) numerically, as affecting the performance of SAGD when applied to produce H2O. The simulation output confirmed the importance of the properties of shale layers on recovery performance and production rate. Moreover, simulation results showed that recovery was lower where injection wells had continuous shale layers, due to the higher density of impermeable layers, the higher degree of their extension, and their stacked configuration. Conversely, it was found that the sensitivity of the ultimate oil recovery factor and production rates on the above-mentioned parameters was reduced in the presence of discontinuities in the shale barriers.

![Figure 2.3: Steam assisted gravity drainage (EnCana, 2002)](image)

- **Hot water flooding**

Hot water injection is the simplest of all the heat injection processes, and it is the closest to the conventional water flood, in terms of ease of operation and low cost. Heated water is injected into the formation and a combination of heat-induced viscosity reduction and oil displacement by
water drives oil to the producers (Farouq Ali and Thomas 2007; Hong 1994). For a given throughput of injected water, improved mobility denotes that oil recovery will be greater for hot water than for cold-water injection. Relative to steam injection, a major drawback of hot water flooding is that the maximum energy injection rates for the hot water are usually lower because saturated steam vapour has an energy content three times greater than that of hot water at temperatures below 323°F (Alajmi et al., 2009).

The Oil and Gas Journal Survey (2000) shows four hot water floods, one of which is HO with a gravity of 12° API, viscosity of 900 cP, and initial oil saturation of 15%. The production rate was 300 b/d. Two of the three hot water floods included in the 2006 Survey were intended to enhance the production of HO.

- **In-situ combustion (Fire flood)**

  Conceptually, this simply entails setting the reservoir oil on fire and sustaining combustion by injecting air (oxidant). In principle, this method is suited to a wide range of oil gravities (8 - 36° API) and, in theory, it is the most efficient process (Farouq Ali and Thomas, 2007). While the coke formed in-situ provides additional fuel for heating, the injected air supplements the reservoir pressure. However, its commercial success is limited to oils that are mobile at reservoir conditions. In general, this technique is not attractive because of its technical immaturity and the high risks associated with it, such as fire front control and high gas production rates. Thus, safety concerns have limited the number of operating in-situ combustion projects worldwide.

  The Oil and Gas Journal (2000) Survey reported on 14 combustion projects, of which 5 were light oil and the remaining HO, between 13.5 and 19 °API. The HO projects were producing about 7,000 b/d. A follow-up survey in 2006 (Oil and Gas, 2006) listed nine HO combustion projects among 21 combustion projects. The HO projects resulted in about 7,000 b/d of combustion-enhanced oil, ranging from 13.5 to 19°API.
2.1.2 Non-thermal EOR methods

Although a proven technology, thermal recovery is not suitable for some classes of reservoirs, especially those with thin pay zones (< 9 m), moderate viscosity (< 1000 cP) and low permeability (< 1 D). Environmental constraints and depth issues (> 900 m) also contribute to the unattractiveness of thermal techniques (Farouq Ali, 2008; Farouq Ali and Thomas 2007; Nghiem et al., 2004).

Fundamentally, most non-thermal EOR methods are premised on enhancing the mobility ratio in favour of oil (displaced fluid). For example, solvent addition either reduces oil viscosity, while increasing that of the displacing fluid, or lowers interfacial tension. In general, flooding agents such as carbon dioxide, nitrogen, and light hydrocarbon gases induce complex and unusual phase and viscosity behaviour over practical pressure and temperature ranges (Nghiem et al., 2004). Common non-thermal EOR methods include water flooding, cold HO production with sand (CHOPS), vapour-assisted petroleum extraction (VAPEX), chemical flooding, as well as miscible and immiscible processes.

- Water flooding

This is commonly implemented as a follow-up to primary recovery. In its simplest form, it is a secondary recovery process used to maintain pressure. Despite its simplicity, the incremental recovery over primary mechanisms may reach 10% of OOIP (Taber and Martin, 1983; Taber et al., 1997a, b). In general, water flooding leaves 50 – 70% oil in the formation, providing a business case for chemical, thermal and gas injection processes (Tabary and Bazin, 2007).

Although this process has been applied with mixed success in some HO fields around the world. Specific cases of success include Lloydminster fields in Canada, 16-24° API and 400-1500cp (Adams, 1982), North Nocona Field (27° API) and Inglewood Field (21° API) in California (Farouq Ali, 1976). Field data and fine-scale modelling show that the majority of oil recovery events occurs at high water cuts and that viscosity (or mobility) ratio control performance. In 2009, a field experiment was conducted by Singhal (2009) to compare the performance of three waterfloods in the HO reservoirs of Southern Alberta at different water injection strategies. The rate of the first of these waterfloods was steady and this gradually decreased at the second, and
increased at the third reservoir. It was inferred from the analyses of the three waterfloods that there
was an economically best water injection rate strategy for each specific reservoir and that
gradually lowering the processing rates can decrease the channelling of water in the short term
thus enhancing the ultimate oil recovery (Singhal, 2009). Generally speaking, water injection in
HO reservoirs is characterised by several operational challenges, explaining why it is less
competitive (Sahin, et al., 2008). Water issues related to HO production have been discussed by
Veil et al. (2009), who identified water sourcing, wastewater management and disposal as major
operational issues influencing cost. For the purpose of alleviation, Veil et al. (2009) recommended
that during the project planning phase, water supplies should be shown similar considerations as
oil reserves. From a sustainability perspective, such an analysis is useful for assessing the
competitiveness of potential projects. Further, the heterogeneity effect is critical for HO
waterflood, compared to light oil waterflood (Kumar, 2007).

- **Cold heavy oil production with sand - CHOPS**

CHOPS is a primary HO production method that is widely used in Canada, and more specifically
in Alberta. Although oil recovery rates are relatively low, the cold production of HO requires much
less energy than the thermal production methods, such as CSS or SAGD, and therefore this results
in much less hydrocarbon usage at the recovery stage and also reduces carbon dioxide emissions to
the atmosphere (Lines, et al., 2008).

CHOPS means that a significant amount of formation sand (> 0.1% by volume) is deliberately
produced along with the viscous oil. This is a high gradient process, because wells are drawn
down causing annulus pressures as low as one atmosphere. The screening criteria for successful
CHOPS comprise the following (Dusseault, et al., 2008):

- An unconsolidated and uncemented sand reservoirs;
- Absence of free water or close-by (~500-750 m) lateral water;
- Sufficient solution gas (CH4) present in the oil phase;
- A lifting and sand management system to cope with continuing sand influx; and
- In situ viscosity of less than ~20,000 cP
Instead of blocking sand ingress using screens or gravel packs, sand is encouraged to enter the wellbore via aggressive perforation and swabbing strategies. Wells (vertical to 45°) are operated with rotary progressive cavity pumps instead of reciprocating pumps. When CHOPS is applied, productivity increases factors to as high as ten or twenty over conventional primary production methods, as has been regularly shown in Canada. CHOPS increases productivity for four main reasons:

- Basic permeability to fluids is enhanced with sand movement;
- As more sand is produced, a growing zone of greater permeability is generated which generates better productivity;
- Continuous sand production means that asphaltene or fine plugging of the near wellbore environment cannot occur (skin effect), avoiding the inhibition of the free flow of liquids; and
- Gas exsolution in HO does not generate a continuous gas phase; instead, bubbles flow with the fluid and sand mixture and do not coalesce, but expand down-gradient, generating an initial gas drive, referred to as foamy oil.

CHOPS is commonly used as a primary production approach in unconsolidated sandstone, and many fields in deep deposits in Canada are now producing oil using CHOPS method. The method described here is also similar to the CHOPS processes used at Jilin Oil Field in China (Dusseault et al. 2002). Furthermore, in some oil fields (e.g. Karazhanbas, Kazakhstan), CHOPS has been successfully implemented at low-viscosity HO (300-450 cP). Finally, because massive sand production creates a large disturbed zone, the reservoir may be positively affected for later implementation of thermal processes.

- **VAPEX – Vapour assisted petroleum extraction**

The VAPEX process is a newly developed EOR process to recover HO and bitumen; it has been studied theoretically and experimentally and found to be a promising EOR method for certain HO reservoirs (Reza, et al., 2007; Kok, et al., 2009). However, although VAPEX has been approved as an environmentally sustainable oil recovery method at both the lab scale and field scale, field
test results have shown that due to low mass transfer and low horizontal well efficiency, this process is considered inefficient and not economically viable (Zhu et al., 2013). The basic design of a VAPEX well is similar to that of a SAGD; two horizontal well pairs are spaced approximately 5 m apart. In VAPEX wells, a gas/solvent mix is injected into the reservoir through the upper well to stimulate gravity-enabled production in the lower well. This method has not yet been commercialised as a stand-alone process, and is most likely to succeed only as a process for production from lower viscosity oils (<1000 cP). As there are minimal associated heat costs or water requirements, it is an attractive concept, and in some cases RF values could potentially be very high. A potential limitation is asphaltene precipitation that may impair permeability. VAPEX cannot break through shale barriers, nor can thermal shear dilation improve reservoir transport properties.

In theory, VAPEX can be combined with SAGD and/or CCS, and, in fact, Imperial Oil began using a hydrocarbon solvent to improve efficiency in its Cold Lake operations in 2007 (Kirk, 2007). In future, injecting aliphatic hydrocarbons with steam (or in alternating gravity dominated phases) to combine solvent thinning with thermal effects may have great promise, by reducing heat costs and water needs through several effects such as reducing upward heat flux and achieving a lower SOR value. According to this combination, shear dilation still delivers benefits, and the sharpness of the fronts mean excellent solvent recovery (Dusseault et al., 2008).

Zhu et al. (2013) presented a new approach, whereby hybrid processes of ERH with VAPEX are applied together. This work shows, using numerical evaluation, that a hybrid process could enhance horizontal well efficiency and overall oil production rates, with less environmental impact than other steam-related thermal processes. The factors affecting this hybrid process, such as electrode placement, voltage, well distance and heterogeneity effect, lateral pattern and water saturation, were also deliberated upon in this paper. The main conclusion from this study was that the hybrid process shows a better oil recovery performance than VAPEX; suggesting hybrid process could improve the oil rate 2–5 times over VAPEX. Also, the simulation results show that in a hybrid process, lower water saturation and higher reservoir heterogeneity would generate higher oil recovery; while the opposite is true for VAPEX.

In general, the advantages of VAPEX are possible higher recovery rates, efficiency and less pollution than when using other methods. Moreover, it is applicable to all grades of HO. In
In contrast to other methods, VAPEX is relatively untested; some combinations of solvents will probably not work so it may be expensive to conduct trials for this technology.

![Extraction schematic drawing of the VAPEX process (Source: Dusseault, 2008)](image)

**Figure 2.4:** Extraction schematic drawing of the VAPEX process (Source: Dusseault, 2008)

- **Chemical flooding methods**

  Chemical floods can be used for oils that are too viscous for gas injection. However, these conditions require a higher permeability than the current threshold for gas injection, but a lower threshold than that required for thermal processes (Alkafeef and Zaid, 2007; Martin and Taber, 1992; Mearker and Gale, 1990). Theoretically, reservoirs with active water drives are inherently unsuitable for chemical flooding because the “residual” oil saturation after water flooding might be too low to make chemical flooding cost effective. Similarly, formations with a high clay-content are undesirable, because in-situ clay can potentially adsorb injected chemicals (which are expensive), inhibiting their possible recovery and reuse (Alkafeef and Zaid, 2007). Common variants of the chemical method are polymer, alkaline, surfactant and surfactant/polymer flooding.

  In principle, chemical methods either work to reduce capillary effects by lowering interfacial tension or by improving the mobility ratio. Polymer invasion is a modification of the water injection method, a high molecular weight polymer is added to the water before it is injected into the reservoir, this insures that the mobility ratio improves, resulting in a better and more complete
sweep displacement than is achieved using conventional water invasion. Polymer invasion forms a bank that pushes the oil, as in conventional water flooding (Mitchell, 2009). On the other hand, injecting alkaline solutions creates an emulsification process on the site; thus, this method requires the addition of water EOR injection chemicals, such as sodium hydroxide, sodium silicate, caustic soda or sodium carbonate to react with the acids contained in the organic oil reservoir. The main objective of surfactant injection is to recover residual oil, so that 20 to 40% of pore volume remains after recovery of primary or water injection. As a side benefit, this may also improve volumetric sweep efficiency. In some early research into invasions with surfactants, it was expected to occur as miscible displacement, without the disadvantages of unfavourable mobility characteristics and gravity segregation (Davis, 2006). However, by implementing appropriate process combinations, such as surfactant/polymer flooding, it is possible to achieve both objectives through the same operation.

The Oil and Gas Journal (2000) survey shows five HO polymer/chemical floods of 15°API in sandstone reservoirs at about 4,000 ft. The data was collected from reservoirs producing in the region of 366 b/d and the projects rated as either successful or promising. A typical project life for surfactant/polymer injection is seven years, with incremental recovery appearing in the third year (Alkafeef and Zaid, 2007; Taber, et al., 1997a, b). However, as of 2007, few surfactant flood projects had reported success and none had been reported for HO reservoirs (Farouq Ali and Thomas 2007; Sorbie, 1990).

Polymer flooding was reported as successful at Huntington Beach, California and at Taber South in Canada. In other places such as Lloydminster, only marginal success was reported. The Oil and Gas Journal (2000) survey listed 22 polymer flood projects, of which five involved HO. These five projects produced around 7,140 b/d, of which 2,120 b/d were attributed to EOR. The 2006 survey indicated 20 polymer floods, with five exploiting HO resources (Oil and Gas, 2006). Three of the five produced around 7,140 b/d total oil and 2,120 b/d of enhanced production (~35% increase). Polymer flooding is most effective when applied during the early life of the reservoir, particularly when applied to improve water flood performance. However, this process is very expensive for HO systems (Farouq Ali and Thomas, 2007).

In a recent study, Abass and Fahmi (2013) designed and conducted a core and sand pack flood test to study the salinity alteration under stabilised hot water displacement conditions. Their
experimental results confirmed that the injection of low salinity hot water significantly increases oil recovery rates. This study approved the effects of injecting low salinity hot water, when applied to residual oil after a high salinity hot water flood, showing recovery of more than 25% additional oil. This study was conducted under specific reservoir conditions and mainly related to HO at the BAW Sudan oil field.

- **Miscible/immiscible carbon dioxide flooding**

Oil displacement by gas may either be a miscible or an immiscible process, depending on the in-situ conditions of the reservoir fluids. Typical injectants include inert gas (N₂), flue gas, natural gas, liquefied petroleum gas (LPG) and CO₂. The distinction between miscible and immiscible operations is governed by the minimum miscibility pressure (MMP) which, in turn, depends on reservoir temperature and oil composition (USGS, 2007). While miscible displacement occurs above the MMP, a sub-MMP operation is primarily immiscible, and characterised by negligible mass transfer and mixing between injected stream and reservoir fluid.

The Oil and Gas Journal (2000) reported a project using immiscible nitrogen gas drive to develop a sandstone reservoir with 16°API oil at 4,600 feet depth. It was reported to be producing 1,000 barrels per day (b/d) of enhanced production. Another survey (Oil and Gas, 2006) reported one each of nitrogen-based miscible and immiscible HO projects. The miscible project was 19°API, located in the Bay of Campeche, with 19 wells, however performance statistics were not available. The immiscible project targeted 16°API oil in a sandstone formation at 4,600 ft. Its total offtake was reportedly 1,500 b/d, of which 1,000 b/d was attributed to the presence of the immiscible nitrogen.

According to Sahin et al. (2008), conventional use of CO₂ for improving oil recovery has been in the miscible mode. Although somewhat successful for light and medium oil systems, combining CO₂ with HOs poses several operational challenges, including a poor mobility ratio and the difficulty of achieving the best miscibility conditions—temperature, pressure, and oil composition. However, where CO₂ miscibility with HO is extremely high at relatively low pressures, it will potentially function as a solution gas drive. In particular, CO₂ is soluble in both oil and gas and causes fluids to swell; this is an important effect that renders CO₂ more efficient than LPG and natural gas as flooding agents.
Of the 77 CO₂ projects surveyed (Oil and Gas, 2000), 70 were based on miscible CO₂. However, none targeted HO. A subsequent study (Oil and Gas, 2006) identified 86 CO₂ projects devoted to light oil exceeding 28°API. Of note was the data for the West Raman field in Turkey, containing about 2 billion barrels of 13°API oil in-places at a depth of 4,265 ft, and was producing some 8,000 b/d. The significant success of this project influenced Taber et al. (1997a, b) to relax their screening criteria for immiscible CO₂ flood, hitherto fixed at > 13 °API, to include 12°API. In a follow-up survey (Oil and Gas, 2006), there were eight immiscible CO₂ projects detailed, five of which were targeting HO and delivering around 7,174 b/d. The two largest projects were implemented in areas with carbonate rocks. Preliminary projections indicated that CO₂ flood might recover as much as 40% of OOIP.

In general, non-thermal methods have been largely unsuccessful for use in HO applications (Farouq Ali and Thomas, 2007). A review of several field projects that came on stream prior to 2006 showed that, among the non-thermal methods, only immiscible CO₂ has had slight success on a commercial scale (Oil and Gas, 2000; 2006). Tables 2.1 – 2.3 provide a relative comparison of some of the major EOR processes, and highlight some critical issues to be addressed in this research, as it pertains to the Lower Fars reservoir.

Table 2.1: Performance comparison for chemical EOR processes (Lake, 1996)

<table>
<thead>
<tr>
<th>Process</th>
<th>Recovery Mechanism</th>
<th>Issues</th>
<th>Estimated Incremental Recovery (%)</th>
<th>Typical Agent Utilisation</th>
</tr>
</thead>
</table>
| Polymer                  | Improves volumetric sweep by reduction of the mobility of the displacing fluid | * Injectivity  
* Stability  
* High salinity  
* Adsorption | 5                                                 | 0.3 – 0.5 lb polymer / bbl oil produced   |
| Surfactant polymer       | * Improves volumetric sweep through mobility reduction  
* Reduces capillary effects | * Injectivity  
* Stability  
* High salinity  
* Chemical availability  
* Retention time       | 15                                                | 15-25 lb surfactant / bbl oil produced     |
| Alkaline polymer         | * Improves volumetric sweep by mobility reduction  
* Reduces capillary effects  
* Oil solubilisation and wettability alteration | * Injectivity  
* Stability  
* High salinity  
* Chemical availability  
* Retention time  
* Oil composition     | 5                                                 | 34-45 lb chemical / bbl oil produced       |
**Table 2.2:** Performance comparison for thermal EOR processes (Lake, 1996)

<table>
<thead>
<tr>
<th>Process</th>
<th>Recovery Mechanism</th>
<th>Issues</th>
<th>Estimated Recovery (%)</th>
<th>Typical Agent Used</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam (drive and stimulation)</td>
<td>* Reduces oil viscosity</td>
<td>* Fuel and water supply</td>
<td>50 - 65</td>
<td>0.5 bbl oil consumed / bbl oil produced</td>
</tr>
<tr>
<td></td>
<td>* Vaporization of light ends</td>
<td>* Space</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>* Increases permeability ($P_{inj} &gt; P_{fracture}$)</td>
<td>* Depth</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>* Pressure maintenance</td>
<td>* Heat losses / thermal efficiency</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>* Override</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>* Pollution (emission and waste water)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>In-situ combustion</td>
<td>* Reduces oil viscosity</td>
<td>* Depth</td>
<td>10 - 15</td>
<td>10 Mscf air / bbl oil produced</td>
</tr>
<tr>
<td></td>
<td>* Vaporisation of light ends</td>
<td>* Heat losses</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>* Override</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>* Pollution</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>* Combustion control</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>* Safety</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table 2.3:** Performance comparison for solvent EOR processes (Lake, 1996)

<table>
<thead>
<tr>
<th>Process</th>
<th>Recovery Mechanism</th>
<th>Issues</th>
<th>Estimated Recovery (%)</th>
<th>Typical Agent Utilization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Immiscible</td>
<td>* Reduces oil viscosity * Oil swelling * Solution gas</td>
<td>* Stability * Override * Supply * Corrosion</td>
<td>5 - 15</td>
<td>10 Mscf solvent / bbl oil produced</td>
</tr>
<tr>
<td>Miscible</td>
<td>* Reduces oil viscosity * Oil swelling * Solution gas * Development of miscibility</td>
<td>* Stability * Override * Supply * Corrosion</td>
<td>5 - 10</td>
<td>10 Mscf solvent / bbl oil produced</td>
</tr>
</tbody>
</table>
2.2 Review of some technical studies

Adams and Khan (1969) examined the performance of steam flood and CSS. Whereas CSS showed a production decline over a relatively short interval, steam flood maintained a plateau rate for much longer. In a theoretical analysis of in-situ combustion and steam flood, it was concluded that steam was more efficient than air for heating thick formations. However, for larger areas and deeper reservoirs, prohibitive heat losses make steam a less competitive option than in-situ combustion (Farouq Ali and Thomas, 2007).

In laboratory experiments, Shen (1989) and Hong (1987) studied the effect of switching between hot water and steam flood. Shen (1989) found that a steam flood following a hot water flood recovered more oil than a steam flood alone. This was explained by the tendency of post-water steam to channel through the path created by the preceding hot water, rather than a gravity override (ascending to the upper region of the formation). Consequently, injected steam moves along the lower region of the formation, contacting an increased volume of oil, thereby enhancing the sweep efficiency.

Conversely, Hong (1987) investigated the conversion of a steam flood project to a hot water flood, reporting a minimal impact on oil recovery. In this case, the hot water front sweeps the oil bypassed by the preceding steam flood. This practice reduces the fuel consumption and re-saturates the steam zone with liquid water, which might thereby reduce the possibility of subsidence resulting from sand production. In addition, guidelines were provided regarding the ideal time frame to convert steam flood projects into a hot water flood.

In a field application, Dornan (1990) assessed the conversion of 275 steam displacement patterns to hot water pilots in the Kern River field, California. For some reasons, the performance of the hot water flood was reportedly inefficient at improving recovery after a steam flood. First, the rock and fluid properties hindered the formation of an effective immiscible displacement bank. Second, oil re-saturation occurred in areas where the injected water filled the steam-swept zone. Third, the hot water process was ineffective at transferring heat to the lower portions of the reservoir, as indicated by the temperature data from the observation wells.
Afterwards, Messner and Stelling (1990) tested a dual injection of hot water and steam in the same Kern River field. Hot water was injected down the tubing into a previous steam flood formation, while high quality steam was injected down the tubing-casing annulus into an active steam flood zone. Due to heat transfer from the annulus steam to the tubing hot water, the project was considered to represent a low to mid-quality (10 – 40%) steam flood, showing the benefits of introducing hot water flood following a steam flood.

Bousaid (1991) performed a series of laboratory experiments to assess the effect of injection rate on hot water and steam flooding. The effect of injecting water and steam at 240 °F was evaluated for the Kern River viscous oil (13˚ API) using a fine graded silica sand. It was observed that hot water floods mobilise oil effectively above a specific temperature of 200 °F, high injection rates enhance heat propagation and mobility but residual oil saturation is controlled mainly by the oil to water viscosity ratio. On the other hand, steam flooding at a high injection rate resulted in a high-velocity thermal front that accelerated oil recovery until steam breakthrough, but also led to the bypassing of a significant volume of oil behind the front.

Using reservoir simulation studies, Goodyear et al. (1996) examined the potential of hot water floods to improve the recovery of a 400 cP oil reservoir with underlying water. The studies confirmed that this process can recover significant quantities of incremental oil, up to 18% OOIP, when compared to a cold water flood. In addition, they argued that the thermal expansion of water plays a key role in incremental recovery.

Pederson and Sitorus (2001) proposed a novel approach for the reduction of costs associated with hot water flood projects. Water from geothermal sources was recommended as a substitute for on-site generation of hot water. The proposal comprises injecting water from a high-temperature geothermal reservoir into the oil formation disposing of produced water from the oil reservoir into the depleted geothermal reservoir for the purpose of inventory. From a subsequent field simulation study, related to a reservoir in Indonesia, it was shown that this approach promised up to 7% incremental recovery over that from a cold water flood.

Bhat and Kovscek (1998), and Kovscek and Diabria (2000) published studies on the alteration of porosity and permeability induced by hot water flood in diatomites. To take advantage of wettability alterations in hot water processes, Al-Hadhrami and Blunt (2001) proposed the use of
hot water injection in an oil-wet fractured carbonate reservoir in Oman. They argued that the water would heat the rock, and then undergo a thermally-induced wettability reversal in addition to lowering the oil viscosity, and then the hot water imbibes into the water-wet rock matrix, resulting in favourable oil recoveries. They developed an analytical solution, showing a 30% oil recovery rate over 700 days of hot water injection, compared to the base case of 2% recovery after 20 years.

Furthermore, Tang and Kovscek (2004) reported laboratory hot water flood tests evaluating the effect of temperature on rock wettability, using diatomite cores. The results showed a positive correlation between recovery and temperature, and attributed this to more favourable mobility ratios and alterations to wettability.

Still in the Middle East, Alajmi et al. (2009) performed laboratory studies on the performance of hot water injection in a Middle Eastern sandstone reservoir (13°API, 500 cP) to determine the best design parameters in respect of injection temperature and slug size. Their findings indicated that implementing hot water operations after cold water injection delivered the best recovery. They attributed this observation to the higher heat conduction obtained when hot water flows following the “exhaustion” of the fluid displacement mechanism. Further, increasing the alternation of cold water and hot water slug sizes had a negligible impact on oil recovery.

In reference to the Senex field of Alberta, Cassinat et al. (2002) presented the planning, testing and modelling of a hot water flood pilot. They proposed the injection of hot water to overcome the viscous effect and permeability reduction resulting from paraffin deposition. Their simulation studies showed incremental oil recovery of up to 25%.

There is scope for augmenting the performance of a hot water flood with chemical additives. Karkas et al. (1986) developed a mathematical model to describe the concurrent injection of chemical additives and hot water. Their results showed significant enhancement of oil recovery. In particular, the best results were obtained when the additives resided entirely in the heated zone rather than travelling ahead of the heated zone.

Conversely, experimental results published by Heinemann et al. (1986) indicated that augmenting hot water with chemical additives resulted in marginal (~ 9%) improvements on the base-case oil recovery. This minimal enhancement was explained by the likelihood of injected chemicals being
converted from a vapour or liquid state into a solid crystalline form, which may precipitate a hot water front as the temperature declines, thereby causing permeability impairment.

Zeigler (1988) performed a number of laboratory tests, evaluating the applicability of surfactants in steam flood operations to improve oil recovery from zones invaded by hot water. Incremental oil recovery of up to 14% was reported.

Using reservoir simulation modelling, Alajmi et al. (2006) examined HO recovery by hot water flooding following different patterns, well configurations and injection temperatures. It was observed that for low oil viscosity, increasing the injection temperature had a minimal effect. However, for viscous oil, raising the injection temperature had a pronounced impacts. Additionally, it was concluded that a 5-spot with shortest well length (almost vertical injector) is the most beneficial.

Liu et al. (2007) carried out a sand-pack flood test for a HO sample. Their results indicated that recovery could reach 24% of OOIP when injecting a 0.5 pore volume (PV) chemical slug. Increasing the sand-pack length did not deteriorate the oil recovered. Remarkably, the findings demonstrated the importance of forming an oil-in-water emulsion and oil bank for improved HO recovery in sand-pack flood tests.

Zhang, et al. (2012) conducted an experiment to evaluate a displacement agent consisting of non-ionic and an ionic surfactants and emulsion stabilisers to recover oil from a HO reservoir. From the results of this experimental work, it was established that flooding with a solution of the developed displacement agent advances oil recovery significantly, by more than 20%, compared with water flooding. Other key findings from this experimental work related to the different recovery mechanisms that took place during this recovery process. The first mechanism was when the viscosity of the fluid to be displaced was significantly reduced and the volumetric sweep efficiency improved as a result of the displacement agent promoting the formation of an emulsion. Also, the displacement agent decreases the interfacial tension between the oil and the water, which leads to an increase in capillary numbers and consequently increases the oil’s displacement efficiency. Moreover, the wetting contact angle decreases in the presence of the displacement agent and the rock surface becomes water-wet, thus the capillary effect enhances the displacement of oil from pores, which result in improved oil displacement efficiency.
Jung et al. (2012) conducted experiments to investigate the potential impact of an alkali-polymer flood on HO recovery. To achieve this objective, the polymer flooding characteristics of partially hydrolysed polyacrylamide (HPAM) solution with the addition of NaOH were tested in homogeneous glass-bead packs. Results showed that HPAM solution is sensitive to many parameters, mainly the reservoir temperature, reservoir salinity, and alkali. The oil recovery from the polymer flood and the alkali-polymer flood were tested and compared. The key finding of this work is that alkali-polymer solutions are more efficient, in term of improving the viscosity, than conventional polymer solutions. This conclusion was reached after the alkali-polymer solution showed an increase in oil recovery by 30% over water-flooding when the water-cut reached 95%, indicating that alkali-polymer could be more effective in improving sweep efficiency than a polymer flood. The output of this experimental work can assess polymer flooding projects by evaluating project feasibility in the early stages.

In addition, when thermal methods are not effective for enhancing the recovery of HO then alkaline flooding may have a great potential. Pei et al., (2012), evaluated the potential of alkaline flooding to enhance HO recovery through water-in-oil emulsification. For that purpose, a series of micromodel flood tests and sandpack flood tests were conducted. Also, the effect of the injection parameters on displacement efficiency were investigated in this work. The results of the micromodel tests indicated that the sweeping efficiency was significantly improved after the alkaline solution diffused into the crude oil and the subsequent formation of water-in-oil (W/O) emulsion reduced the mobility of the water phase and diverted the injected water into the unswept region. The sandpack flood results show that alkaline flooding can reach about 20% of the initial oil in place (IOIP), using 1.0% NaOH; and the oil recovery was found to increase as the alkaline concentration did so. This work concluded that alkaline flooding, if properly designed and controlled, can lead to enhanced HO recovery through the mechanism of water-in-oil emulsification.

Shuker et al. (2012) revisited the screening criteria for the selection of the EOR method published by several authors. In this work, the screening methodology was defined to screen the EOR method for the targeted reservoir. After which, the screening criteria was then applied to Pakistani reservoirs. The approach developed was integrated into the software to make repetitive analysis simple. Finally, the best EOR methods were selected and the future directions set and cost analysis
given in order to examine the economic feasibility of the intended development projects. The methods adapted in this study were: water injection, water alternating gas injection (miscible and immiscible), polymer, and surfactant–polymer, steam (cyclic and continuous). This work assists in the choice of the best EOR method in order to advance the recovery factor in a fast and efficient way.

Kok, and Ors (2012) conducted a study to evaluate an immiscible-CO2 enhanced Oil recovery technique for heavy crude oil reservoirs. Kok and Ors discussed in their paper the key parameters, which must be evaluated, such as oil gravity, reservoir temperature and pressure, minimum miscibility pressure, and remaining oil saturation, before considering a field for the CO2 displacement. In the first part of this study, the suitability of targeted HO fields for CO2-enhanced oil recovery application was evaluated. In the second part of the study, economic feasibility was conducted. The study concluded that although the reservoir considered did not meet the required criteria for the miscible flood, these fields can be considered for CO2-enhanced oil recovery applications for as long as the project is economically feasible. This investment decision was justified by Kok and Ors (2012) as CO2 sequestration is important for Turkey; it will be the first project of this kind in this country.

The EOR screening process entails a simulated network algorithm for a multi-layered cascade feed forward back propagation, implemented by proxy models found in the toolbox. These models can be applied across a wide range of rock characteristics and reservoir fluids. The development plan for the field accounts for factors such as operating conditions, spacing and varying patterns of the well. Notable features of the ANN testing tool are: first, its ability to forecast reservoir performance in terms of the rate of oil production, cumulative production and approximate production time; and second, its flexibility in terms of providing a way to clearly compare the hydrocarbon output with respect to different input sets. This, in turn, makes it possible to compare different depletion approaches (Parada and Ertekin, 2012).

It is evident, from the results of this study that the ANN is capable of identifying the strong relationship that exists between the characteristics of the reservoir and the displacement mechanism. This is due to the fact that it accurately predicts the hydrocarbon output from different reservoirs. This tool, therefore, represents a breakthrough in terms of feasibility and efficiency when it comes to designing artificial intelligence-based IOR projects. Therefore, it is instrumental
in providing for the assessment of a wide range of cases in terms of field development approaches, as well as enabling a reservoir performance evaluation within various sets of production plans.

Urdaneta et al. (2012) conducted a study to assess a wide range of thermal processes that occur specifically in the Boyacá area in Venezuela’s Guárico state. Boyacá contains XHO with an API gravity ranging between 4 to 8; a permeability of 2-15 Darcies and 25-32% porosity. Out of the seven wells in Block 06, only two failed to produce. An additional two were subjected to CSS as an experiment and they produced. Data from neighbouring blocks was collected and synthetic correlations used to estimate rock and fluid properties. From the refinement of the whole Boyacá area, the resultant Geoestatistical model was categorised into 3 areas of continuous net sand thickness.

As a first step, a screening criteria was applied to this block in order determine the most suitable thermal processes to use. The most highly recommended approach was a steam flooding-based technology. This was due to the fact that this technology had a significant chance of increasing the recovery factor. The next step was to construct sector models to simulate each of the thermal processes and production in one of the CSS wells as well as to maximise the factors of operation. Both SAGD and CSS were then simulated concurrently. As these simulations would reveal, this technology makes it possible and therefore viable to optimise recovery up to approximately 30% at this block. A combination of both CSS and SAGD gave the best value economically, with a net present value (NPV) of $1521M, a 15% return rate and $16B in operating costs over the next twenty years (Urdaneta et al., 2012).

2.3 Reservoir Simulation

“Numerical reservoir simulators are used widely, chiefly because they can solve problems that cannot be solved in any other way. Simulation is the only way to describe quantitatively the flow of multiple phases in heterogeneous reservoir having a production schedule determined not only by properties of the reservoir, but also by market demand, investment strategy, and government regulations” (Mattax and Dalton, 1990).
When using any reservoir simulator, the following limitations should be considered;

- The model is not identical to the reservoir, it is a numerical representation and can only reflect the reservoir’s behaviour if the physics of the flow are accurately represented.
- A simulator solves a discrete representation of the continuum equations of flow, but how accurately it does this depends on the number of grid blocks used. However, there is some balance; too many grid blocks and the simulator takes too long to run, but too few and a numerical solution is usually no longer close to the continuum one.
- Model performance depends on data quality and quantity.

### 2.3.1 Modelling Heat-Transport in Petroleum Reservoirs

The injection of heat-carrying fluids, steam or hot water, represents a common thermal operation for developing viscous-oil deposits (Edmunds et al.; 1994; Farouq-Ali, 1994). In these operations, heating is the key mechanism for enhancing in-situ oil mobility (Carcoana, 1992; Prats, 1982). When a saturated vapour, such as steam, is injected and comes into contact with the colder reservoir, the vapour condenses, releasing its latent heat into the colder reservoir.

The hot water flooding process and its mechanisms can be found to take place in each of the other processes, and so this is the most basic processes. Convective and conductive heat transference in the formation are the key mechanisms that control the placement of heat and driven the effect of the thermal EOR processes.

In its simplest form, steam stimulation is a process by which steam is injected to heat the part of a reservoir near to the wellbore, attaining increased production rates through reduced oil viscosities and a corresponding reduced resistance to flow in this critical area (Mattax and Dalton, 1990). The same mechanisms also occur during the cyclic steam stimulation process (CSS). Steam fluid properties such as vapour pressure, density and enthalpy dominate. Specifically, the latent heat of steam provides a significant excess source of energy over that produced by hot water at the same temperature, leading to a quicker heat spread. However, because heat losses at steam temperature
are supplied by latent heat, the steam spread rate slows down after a period of steam injection, due to the creation of a hot water condensate zone ahead of the steam front. The relative oil permeability \((K_{ro})\) as a middle phase affects oil production directly. Gas/liquid relative permeabilities assist with calculating the in situ flowing and producing a gas-liquid ratio (GOR), which influences the delivery of steam and gaseous additives. Gravity override and drainage become important for thicker formations because of the very low density of steam (STARS, 2009).

2.3.2 Simulation’s Equations

Considerable progress has been made in numerically simulating thermally enhanced oil recovery processes over the last few decades. This is mostly true for processes involving steam.

From a modelling point of view, as stated by Mattax and Dalton (1990), the major difficulty with steam processes is their computational stability. The mass and energy balance equations are nonlinear and closely tied, causing serious stability problems. The physical process leading to these computing problems can be explained as follows. As steam moves through the reservoir it condenses, thereby greatly changing in volume. This volume change affects the mass balance, which sequentially determines how fluids, including steam, move through the reservoir. Therefore, the volume change also affects the energy balance, which determines how much steam condenses. In general, the movement of fluids strongly effects the movement of energy. This close link between energy and fluid movement means that those equations that represent them must be solved simultaneously (Mattax and Dalton, 1990).

Another computing problem facing steam modelling arises because steam processes are so complex. The properties of fluids depend on composition, pressure, and temperature. Phase behaviour at various temperatures must be computed and the heat lost to overburden and underburden must be accounted for (Farouq-Ali, 1997; Mattax and Dalton, 1990).

This section presents a general overview of the mathematical equations used for steam injection and steam drive modelling. These equations express the relevant physical phenomena in
In compositional simulations, the hydrocarbon material-balance is used to represent the multi-components of the reservoir oil.

The hydrocarbon equation accounts for the flow (of component \( v \)) in both oil and gas phases:

\[
\nabla \cdot \left( x_v \xi_o \lambda_o \nabla \phi_o + y_v \xi_g \lambda_g \nabla \phi_g \right) + q_v = \frac{\partial}{\partial t} \left[ \phi \left( x_v \xi_o S_o + y_v \xi_g S_g \right) \right] \tag{Eq 2.1}
\]

Where;

\[
\lambda = \text{Phase mobility} = \frac{kk_r}{\mu}, \text{ m}^2/\text{Pa.s}
\]

\( o = \text{oil}, \ w = \text{water and } g = \text{gas} \)

\( \phi = \text{Medium porosity} \)

\( \xi = \text{Phase potential, Pa} \)

\( x_v = \text{Molar density, kmol/m}^3 \)

\( y_v = \text{Mole fraction of component } v \text{ in liquid phase, dimensionless} \)

\( q_v = \text{Mole fraction of component } v \text{ in vapour phase, dimensionless} \)

\( q_v = \text{Injection or production rate of component } v, \text{ kmol/s.m}^3 \)

Further, the water material balance equation must reveal the fact that water can be in both the aqueous and the vapour phase;

\[
\nabla \cdot \left( \xi_w \lambda_w \nabla \phi_w + y_w \xi_g \lambda_g \nabla \phi_g \right) + q_w = \frac{\partial}{\partial t} \left[ \phi \left( \xi_w S_w + y_w \xi_g S_g \right) \right] \tag{Eq 2.2}
\]

And the energy equation can be expressed as follows;

\[
\nabla \cdot \left( k_h \nabla T + H_o \xi_o \lambda_o \nabla \phi_o + H_w \xi_w \lambda_w \nabla \phi_w + H_g \xi_g \lambda_g \nabla \phi_g \right) + q_H =
\]

Hifaa Alajmi, 2012
\[
\frac{\partial}{\partial t} \left[ (1 - \phi) \rho_f C_f T + \phi \left( U_o \xi_o S_o + U_w \xi_w S_w + U_g \xi_g S_g \right) \right]
\]  
\text{(Eq 2.3)}

Where:

- \( k_h \) = Thermal conductivity of rock and contained fluids, J/m.s.K
- \( T \) = Temperature, K
- \( H \) = Specific enthalpy, J/kmol
- \( U \) = Specific internal energy, J/kmol
- \( \rho_f \) = Rock density corresponding to zero porosity, kg/m³
- \( C_f \) = Heat capacity of rock, J/kg.K
- \( q_H \) = Injection or production rate of enthalpy, J/s.m³

Using the definition of the enthalpy \((H)\) of the system as the sum of the internal energy and the external work done (at a pressure \( p \) to create a volume \( V \)),

\[ H = U + pV \]  
\text{(Eq 2.4)}

Using the fact that the saturations and mass fractions must add up to one, three more equations are provided, as shown below:

\[ S_o + S_g + S_w = 1 \]  
\text{(Eq 2.5)}

\[ \sum_{y=1}^{NC} x_y = 1 \]  
\text{(Eq 2.6)}

\[ \sum_{y=1}^{NC} y_v + y_w = 1 \]  
\text{(Eq 2.7)}

If we assume that oil can be treated as a non-volatile compound, thus, it can be represented as a single component, and the hydrocarbon material balance equation Eq 2.8 can be reduced to:

\[ \nabla \cdot (\xi_o \lambda_o \nabla \phi_o) + q_o = \frac{\partial}{\partial t} (\phi \xi_o S_o) \]  
\text{(Eq 2.8)}
One of the methods applied by Chase and O’Dell (1973), and Weinstein (1974) as an approach towards the calculation of energy lost is the Vinsome and Westerveld (1980) semi analytical approximation. One critical aspect of thermal oil recovery schemes entails heat transfer through conduction from the reservoir to adjacent strata of low permeability. In hot water floods and steam these present a heat loss that may have substantial effects on the process cost (Thompson, 1971). Pruess and Wu (1993) observed that in steam soak operations, heat lost to base rock and cap during injection can be conducted partially back to the reservoir during the production cycle, providing valuable additional heating. There can be a large heat interchange with impermeable strata and this must be incorporated in the numerical simulation of thermal recapture. In the initial stages, there is a steep gradient in the conductive temperature profile near the conductive zone surface, while in the last moments it spreads to a great distance away from the boundary. Therefore, a realistically precise representation of heat transmission by numerical methods such as finite differences require numerous grid blocks which can significantly increase the computational work (Pruess & Wu, 1993). The semi-analytical approximation method of energy loss calculation can be faulted in a number of ways. Firstly, given the presupposed assumptions, the method fails to derive accurate analytical solutions for heat exchange with a cube deemed to have uniform temperature. The method can, however, be estimated to have better results in an oil reservoir. These results are appraised to be suitable from the fact that the challenges encountered in energy loss calculations are not as severe for oil reservoir estimations.

Boundary conditions in the oil reservoir simulation of thermal injection in practice include specified heat flux, specified temperature, radiation and convention (Carlson, 2006). Boundary conditions are included by allocating specific temperatures in line with the boundary nodes. In this case, when there is transfer of heat under stable conditions, it is assumed that all heat transfer is into the volume element from all surfaces for ease in formulation. However, this does not include the stated heat flux given that its direction is already specified. Specific heat flux is considered a negative quantity if out of the medium and a positive quantity if into the medium (Gaëlle et al., 2012). Heat transfer under boundary conditions is steady. The heat transfer calculation method is based on subdividing the medium into a sufficient number of volume elements and then applying this as an energy balance to each element. The heat flow equation in the boundary condition is
usually specified in various ways. This depends mainly on ambient temperature, reservoir thickness and thermal conductivity.
3. EOR Screening Criteria for a Typical Sandstone Reservoir

3.1 First-pass Screening Tool

Considering the virtually limitless list of EOR methods and their various combinations, conducting a detailed study on each method to assess its suitability for application to a specific asset may not be pragmatic. Therefore, at this stage in the study it is imperative to assess the available options by screening them for feasibility. To facilitate this decision-making, a systematic procedure for eliminating the less competitive commercialised options using criteria based on worldwide field experiences is applied (Al-Bahar et al., 2002; Alkafeef and Zaid, 2007; Chugh et al. 2000; Dusseault, 2006; Dusseault and El-Sayed, 2000; Shafiei et al., 2007; Taber et al., 1997a, b; USGS report, 2007). However, in the case of relatively immature methods, which have to date not been assessed in the field at scale, we can only measure potential risk exposure. Where possible screening may incorporate elements covering the physics informing the process (Taber and Martin, 1983). Thus, additional evaluation may include laboratory measurements and field pilot studies.

This study focuses on the suitability of methods as relevant to the case study area, which requires assessment of methods that are suited to fields of varying viscosity. This is achievable as to date, the area in question has hosted a number of pilot studies (Ahmed et al., 2011), because it is known that any official decision regarding any EOR application to KOC regarding its Kuwaiti portfolio would first be deployed in the case study area, specifically its Northern sector. Hence, to some extent this chapter is seeking to identify data highlighting suitable EOR methods that are feasible for use in the Northern portion of the Lower Fars reservoir. However, the screening tools presented here are general, and the EOR screening strategy proposed in this chapter could be readily applied to other fields.
3.2 Screening Procedure and Development of a Screening Tool

3.2.1 EOR Screening Criteria

EOR screening criteria relies on first establishing a set of fluid reservoir parameters such as net-pay thickness, depth, permeability, porosity, oil saturation, initial reservoir pressure, viscosity, etc. to restrict the scope for investigating the right set of EOR processes (Al-Bahar et al., 2002; Taber et al., 1997). The values associated with these criteria are obtained by either analysing several successful field cases to establish their EOR histories, or by applying knowledge of the physics of the EOR process. Comparisons of these criteria against values from the reservoir of interest indicate the possible future success of EOR.

For the purposes of this research, selected screening criteria have been chosen based on a combination of reservoir and oil characteristics and other projects from around the world. In this study, these criteria have been adapted to conditions that arise in unconsolidated sandstone formations, which form the subject of this research. The first-order screening criteria applied in this study are listed for sixteen production technologies in Table 3.1. Appendix A includes a summary of the screening criteria for other EOR categories, such as chemical flooding. Copies of selected pages and tables from cited literature are reproduced.
Table 3.1: Technical screening criteria for selected HO production technologies.

<table>
<thead>
<tr>
<th>Prod. Method</th>
<th>Screening Criteria</th>
<th>Reference(s)</th>
</tr>
</thead>
</table>
| CP (Cold Production)                | o Permeability > 2 – 4 D, but much less for lower viscosities  
  o Net pay thickness > 7 – 8 meters  
  o Porosity >25% in current implementation, but lower porosities OK with high k  
  o Viscosity < 5,000 cP  
  o Produceability factor (F) - kh/μ - > 15-20 mD-m/cP  
  o High solution gas content needed  
  o No free water zones (CP is a high-pressure-gradient approach) | Dusseault and El-Sayed, (2000); Chugh et al. (2000); Dusseault (2006-c) |
| CHOPS (Cold HO Production with Sand) | o Permeability > 1 D average  
  o Net pay thickness > 5-6 m  
  o Viscosity < 15,000 cP  
  o High solution gas content is needed  
  o Unconsolidated sandstones only (solids production is needed)  
  o Minimal free water zones | Dusseault (2006-a)                                                                 |
| ISC (In Situ Combustion)            | o Depth > 150 m  
  o Permeability > 50 mD  
  o Porosity > 18%  
  o Oil Saturation > 50% PV  
  o Net pay thickness > 10 m  
  o Oil Content (Porosity * Oil Saturation) > 0.065  
  o Viscosity < 5,000 cP  
  o Local or no bottom water  
  o Local or no gas cap | Greaves and Al-Shamali (1995); Moore et al. (1997); Prath (1999) |
| SF - Steam Flooding                 | o Depth < 1,400 m  
  o Permeability > 200 mD  
  o Porosity > 20 – 25%  
  o Oil Saturation > 50% PV  
  o Net pay thickness > 6 – 10 m (100%), 20 m (80%), > 20 m (75%)  
  o Produceability factor (F) - kh/μ - > 15 mD-m/cP  
  o Oil Content > 0.065  
  o Current pressure < 1500 psi  
  o Viscosity < 2,000-5,000 cP  
  o No steam drive likely with active water  
  o Local or no gas cap present  
  o Low clay volume  
  o Thin shale beds < 2.5 m thick, lateral flow dominated process | Taber and Martin (1983); King et al. (1984); Taber et al. (1997a); Dusseault (2006-c) |
| CSS (Cyclic Steam Stimulation)      | o Depth < 1,400 m  
  o Permeability > 1 D  
  o Porosity > 20 – 25%  
  o Oil Saturation > 60% PV, preferably >80%  
  o Net pay thickness >8 – 10 m – 100% net-to-gross, 20 m – 90%, >20 m – 85%  
  o Viscosity < 500,000 cP  
  o Formation must be unconsolidated  
  o No CSS possible if active water is present  
  o Thin shale beds only, < 1 m, or too slow recovery | Fialka et al., 1993; Al-Qabandi et al., 1995; Donnelly, 2000, Dusseault, 2006-c |
| SAGD (Steam Assisted Gravity Drainage)| o Depth of 200 – 1,000 m  
  o Net pay thickness >15 mo Oil Saturation > 60% PV  
  o Permeability > 2 D kₚ, > 1 D kᵥ for oils >10,000 cP  
  o Porosity > 20%  
  o Can handle mobile bottom water, whereas pressure-gradient methods cannot  
  o Low strength formation is better (shear enhancement of permeability)  
  o Viscosity – no limits have been identified | Edmunds and Sugget (1995); Ito et al. (1988); Longuemare et al. (2002); Dusseault (2006c) |
3.2.2. Studies involving EOR screening

A study arranged by a joint team from the Kuwait Institute for Scientific Research (KISR) and KOC evaluated EOR potential at 81 Kuwaiti reservoirs, covering light, medium and heavy crudes (Al-Bahar et al., 2004). While the primary objective was to screen and rank HO recovery methods according to attractiveness, the conclusion was that thermal methods are most appropriate for the HO accumulations. This study addressed existing technical challenges using chemical flooding methods, such as water salinity and high temperature. However, the conclusions reached were based on the average properties of the selected reservoirs, ignoring uncertainties surrounding their properties minimum and maximum ranges. Additionally, the EOR ranking procedure exclusively used performance prediction analysis and software developed by the US Department of Energy (DOE). No other tools for performance prediction were used, making it impossible to confirm the repeatability of the results.

Although the aim of this chapter is to present a generalised investigation into EOR screening protocols; due to the significance of the case study area, a number of the studies referred to herein were undertaken there. Dusseault and Oskui (2007) assessed and screened prospective production technologies for the Lower Fars reservoir, concluding that, compared to Canadian deposits, its lower oil, shallower disposition and higher average permeability meant that technologies such as SAGD and CSS, were likely to be of limited success for the development of the reservoir. Furthermore, it is argued that to bring the oil viscosity in the Northern area within the range 1-10 cP, which is the predicted threshold for economic production rates, it would be necessary to either raise the average reservoir temperature to 105 – 125 °C, or to dilute the resident oil with a typical C5 - C9 naphtha in a volume ratio of approximately 0.15 - 0.20 %.

Research has shown that to conduct screening on a first-pass assessment, it is necessary to locate drilling and geophysical log data, as well as the results of field and laboratory tests conducted on the target reservoir by KOC and KISR, as reported elsewhere (Alajmi, et al., 2006; KOC and KISR, 2009; Sanyal, 2007). Current screening methods focus on the production technology for HO, and it is assumed that methods such as high-pressure-gradient gas injection, surfactant or
dispersant injection, bacteriological approaches, polymer displacement approaches, and other techniques that are suitable for low-viscosity oils, are unlikely to be competitive for HO extraction. This is for several reasons, which include gravitational and capillary instabilities, excessive costs and uneconomic production rates (Shafiei et al., 2007).

However, there are concerns with data quality, dependent on the conditions at the reservoir being tested. These concerns, which are largely attributed to data gaps, include measurement uncertainties. Some key issues are:

- Poor or inadequate geological data, due to limitations with core sampling and poor seismic data (Zhang et al., 2011). The large size of the reservoir, its shallow depth and complex geology are not favourable, for seismic data acquisition and interpretation.
- Data is limited. This stems from the historic lack of interest in heavy-oil assets; explaining why relatively few measurements were taken, even in pilot studies.
- Measurement and interpretation errors. Susceptible measurements include fluid and petrophysical properties.

Following the procedures used by other researchers (Al-Bahar et al., 2002; Dusseauult and El-Sayed, 2000; Shafiei et al., 2007; Taber et al., 1997a, 1997b USGS, 2007), we have developed a relatively simple tool for performing a preliminary assessment of prospective methods for developing unconsolidated HO reservoirs in general (which apply to the Lower Fars reservoir in particular). The input parameters for this first-order evaluation include those that relate to the geological and lithostratigraphical disposition, fluid and petrophysical properties, such as reservoir depth, in-situ oil viscosity, net pay thickness, permeability, and oil saturation as shown in Table 3.2.
Table 3.2: Lithostratigraphical, geographical and fluid properties for the Lower Fars HO reservoir

(Sources: KOC and Kuwait Institute of Science Research -KISR database)

<table>
<thead>
<tr>
<th>Screening criteria</th>
<th>Units</th>
<th>Input data</th>
<th>Min</th>
<th>Max</th>
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<td>27</td>
<td>38</td>
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</tr>
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<td>cP</td>
<td>110</td>
<td>300</td>
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<td>Md</td>
<td>200</td>
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<td>Yes</td>
<td>Yes</td>
<td></td>
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<td>Bottom Water</td>
<td>Yes/No</td>
<td>Yes</td>
<td>Yes</td>
<td></td>
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<td>Gas Cap</td>
<td>Yes/No</td>
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<td>Yes</td>
<td></td>
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<td>Low</td>
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<td>Psi</td>
<td>139</td>
<td>2316</td>
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<td>Fraction</td>
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<td>Oil Transmissibility</td>
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</table>

*** MMP = Minimum Miscibility Pressure

3.3 The operational process of the screening tool

The selection of enhanced recovery methods is based on both technical and economic standards. In this chapter, we consider the application process on a technical level only.

Several computer programs have been developed as tools to screen reservoirs for applicable EOR methods, these were found in the work of Abass and Song (2011), Chung et al. (1995), Elemo and Elmtalab (1993), Gharbi (2000) Guerillot (1988), Maksimov (1992). For this screening tool, the EOR rule base has been developed to cover sixteen processes, classified in five groups: primary
processes (as a base case), cold production processes, miscible and immiscible gas flooding, chemical processes, thermal processes.

We developed a simple EOR screening tool to evaluate the applicability of the various EOR methods to be used at the targeted HO reservoir. The Tool is a Microsoft Excel file with included Visual Basic code. The program code and input and output data is integrated with the spreadsheet functions of Excel. This combination facilitates transfer of data from the users’ databases to the tool.

The main analytical process used involves providing all the feasible EOR processes for a particular reservoir in three steps (sheets), which been integrated using a face sheet, which is another Excel functionality (Appendix B).

**Step 1** - Input: Data, Lithostratigraphical, geographical and fluid properties of the Lower Fars field (See Table 3.2)

**Step 2**: Screening guides conducted in this screening exercise were developed in more explicit criteria to achieve a specific rule. Table 3.3 formulated new criteria and listed the rules for selecting the proper EOR technique as a function of Maximum-Minimum reservoir and crude oil properties.

**Step 3**: Logical formulas sheet. See Table 3.4

This process follows the steps below:

1. For each EOR method, each input parameter of permeability, porosity, viscosity, etc. (Table 3.2), is searched to match the minimum ("min") and maximum ("max") values for each saved parameter associated with the application of a successful EOR method (Table 3.4).

2. If the value of the reservoir parameter is in the range of, or equal to the minimum/maximum value of the EOR screening criteria, then: match value = 1.

3. If the value of the reservoir parameter is NOT in the range or equal to the minimum/maximum value of the EOR screening criteria, then: match value = 0.

4. Calculate the total matching value for each method: total = match1 * match2 * match3 ...... etc.
• If the total match value is equal to ONE, then the EOR method is considered feasible (PASS).
• If the total match value is equal to ZERO, then the EOR method is considered unfeasible (FAIL).

**Step 4:** All the results from the selection process are transferred into a final report designed with matching information and comments for each EOR method (*Table 3.5*). The screening tool reports the feasibility of each EOR method and all the input parameters for the targeted reservoir must match all the EOR method criteria to be considered as feasible methods “PASS”, otherwise the findings will be returned as unfeasible, indicated by “FAIL”.
Table 3.3: Technical Screening Criteria for production technologies

<table>
<thead>
<tr>
<th>Screening Criterion</th>
<th>units</th>
<th>Water-Flooding</th>
<th>Cold Heavy Oil Production with Sand-Chops</th>
<th>Cold Production CP</th>
<th>Polymer Flooding</th>
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<td>Reservoir Temperature</td>
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<td>&gt;70</td>
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<td>&lt;70</td>
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<tr>
<td>Live Oil Viscosity @p_0</td>
<td>cp</td>
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<td>&lt;1500</td>
<td>&lt;5000</td>
<td>&lt;150</td>
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<td>Horizontal Permeability</td>
<td>md</td>
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<td>&gt;2000</td>
<td>&gt;5000</td>
<td>&gt;50</td>
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<td>Yes/No</td>
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<td>2</td>
<td>2</td>
<td>2</td>
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<tr>
<td>Bottom Water</td>
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<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
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<tr>
<td>Water/Salinity</td>
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<td>&lt;50000</td>
<td>&lt;50000</td>
<td>NC</td>
<td>NC</td>
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<td>Reservoir Type</td>
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<td>Sandstone preference</td>
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<tr>
<td>Oil Gravity</td>
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<td>Oil Density</td>
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<tr>
<td>Clay &amp; shale Content</td>
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<tr>
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<td>Porosity</td>
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<tr>
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<td>&lt;10</td>
<td>&lt;10</td>
<td>&lt;10</td>
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<tr>
<td>Oil Content (porosity/oil saturation)</td>
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<td></td>
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<tr>
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<td>&gt;35%</td>
<td>&gt;35%</td>
<td>&gt;25%</td>
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<tr>
<td>Vertical Permeability</td>
<td>md</td>
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</table>

Table 3.3 (continued)

<table>
<thead>
<tr>
<th>Screening Criterion</th>
<th>units</th>
<th>Alkaline/Polymer Flooding</th>
<th>Surfactant/Polymer Flooding</th>
<th>Alkaline/Surfactant/Polymer (ASP) Flooding</th>
<th>Carbon Dioxide Miscible</th>
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<tr>
<td>Reservoir Temperature</td>
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<td>&lt;70</td>
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Hifaa Alajmi, 2012
Table 3.3 (continued)

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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Formation Type</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Gravity (API)</td>
<td></td>
<td>&gt;23</td>
<td>&gt;35</td>
<td>&gt;12</td>
<td></td>
</tr>
<tr>
<td>Oil Density (Kgm3)</td>
<td></td>
<td>&lt;910</td>
<td>&lt;850</td>
<td>&lt;580</td>
<td></td>
</tr>
<tr>
<td>Clay &amp; shale Content</td>
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<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depth (m)</td>
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<td>&gt;1200</td>
<td>&gt;1800</td>
<td>&gt;200</td>
<td>&lt;1400</td>
</tr>
<tr>
<td>Initial Pressure (psi)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MMP - Frac. Pressure (psi)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Pay Thickness (m)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Net Pay/Gross Pay (fraction)</td>
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<td></td>
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<td>Porosity (fraction)</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Water Oil Ratio (fraction)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Content (porosity/oil saturation) (fraction)</td>
<td>&gt;0.30</td>
<td>&gt;0.30</td>
<td>&gt;0.35</td>
<td>&gt;0.1</td>
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</tr>
<tr>
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<td>&gt;40%</td>
<td>&gt;60%</td>
<td>&gt;50%</td>
<td></td>
</tr>
<tr>
<td>Cyclic Steam Parameter (md<em>ft</em>psi/cp)</td>
<td>&gt;5000</td>
<td>&gt;5000</td>
<td>&gt;500</td>
<td>&gt;500</td>
<td></td>
</tr>
<tr>
<td>Fracturing</td>
<td>Yes/No/NC</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Transmissibility (md<em>ft</em>psi/cp)</td>
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<td>&gt;5000</td>
<td>&gt;500</td>
<td>&gt;500</td>
<td></td>
</tr>
<tr>
<td>Vertical Permeability (md)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Composition</td>
<td>Yes/NC</td>
<td></td>
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</table>

<table>
<thead>
<tr>
<th>Screening Criteria</th>
<th>units</th>
<th>Steam Flooding - SF</th>
<th>Steam Assisted Gravity Drainage - SAGD</th>
<th>In Situ Combustion - ISC</th>
<th>Horizontal Well CYCLIC STEAM STIMULATION - HCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir Temperature</td>
<td>C</td>
<td>NC</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Live Oil Viscosity (cp)</td>
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<td>&lt;5000, &gt;50</td>
<td>&gt;2000</td>
<td>&gt;5000</td>
<td>&gt;5000, &gt;500</td>
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<td>Horizontal Permeability (md)</td>
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<td>&gt;200</td>
<td>&gt;1000</td>
<td>&gt;50</td>
<td>&gt;500</td>
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<tr>
<td>Active Water Drive</td>
<td>Yes/No</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bottom Water</td>
<td>Yes/No</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas Cap</td>
<td>Yes/No</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water Satinity</td>
<td>ppm</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Formation Type</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Gravity (API)</td>
<td></td>
<td>&gt;23</td>
<td>&gt;35</td>
<td>&gt;12</td>
<td></td>
</tr>
<tr>
<td>Oil Density (Kgm3)</td>
<td></td>
<td>&lt;1000, &gt;825</td>
<td>&lt;1000, &gt;825</td>
<td>&lt;1000, &gt;825</td>
<td></td>
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<tr>
<td>Clay &amp; shale Content</td>
<td>High/medium/low/NO</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Depth (m)</td>
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<td>&gt;1400, &gt;200</td>
<td>&gt;3500, &gt;150</td>
<td>&gt;1400, &gt;200</td>
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<tr>
<td>Initial Pressure (psi)</td>
<td></td>
<td></td>
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<tr>
<td>MMP - Frac. Pressure (psi)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Net Pay Thickness (m)</td>
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<td>&gt;15</td>
<td>&gt;3</td>
<td>&gt;15</td>
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<tr>
<td>Net Pay/Gross Pay (fraction)</td>
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<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Porosity (fraction)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water Oil Ratio (fraction)</td>
<td></td>
<td>&gt;20%</td>
<td>&gt;20%</td>
<td>&gt;18%</td>
<td>&gt;20%</td>
</tr>
<tr>
<td>Oil Content (porosity/oil saturation) (fraction)</td>
<td>&gt;0.065</td>
<td>&gt;0.065</td>
<td>&gt;0.065</td>
<td>&gt;0.065</td>
<td></td>
</tr>
<tr>
<td>Oil Saturation So pv%</td>
<td></td>
<td>&gt;40%</td>
<td>&gt;60%</td>
<td>&gt;50%</td>
<td>&gt;60%</td>
</tr>
<tr>
<td>Cyclic Steam Parameter (md<em>ft</em>psi/cp)</td>
<td>&gt;16</td>
<td>&gt;16</td>
<td>&gt;16</td>
<td>&gt;16</td>
<td></td>
</tr>
<tr>
<td>Fracturing</td>
<td>Yes/No/NC</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Transmissibility (md<em>ft</em>psi/cp)</td>
<td>&gt;16</td>
<td>&gt;16</td>
<td>&gt;16</td>
<td>&gt;16</td>
<td></td>
</tr>
<tr>
<td>Vertical Permeability (md)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Composition</td>
<td>Yes/NC</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Notes: Use 1 as YES, Use 2 as NO. Oil composition/Formation type/Clay and shale content are out of formulation in this work and shall be considered in future work. These tables show quantitative criteria only.
The EOR screening results are summarised in Table 3.5 and show that the following processes are to be progressed to the next phase of the research:

- **Primary Production**: CHOPS
- **Cold Production**: Water flooding
- **Thermal**: Steam Flooding, and CSS

In Table 3.5, the “reason” column explains the parameters that result in the failure of a particular technology for that reservoir. Based on the technical screening data for the Lower Fars reservoir, which is the case study site, none of the chemical processes is attractive. Although hot water...
flooding has not been considered in the screening exercise, it is considered to be a ‘Pass’ technology in the research context. This position is premised on the confidential results of the laboratory studies performed by KISR on the performance of hot water injection at the case study site. Specifically, their studies concluded that implementing hot water plug operations after a cold water injection delivered the best oil recovery.

Table 3.5: Screening of production technologies for Lower Fars reservoir (HO sandstone reservoir)

<table>
<thead>
<tr>
<th>No.</th>
<th>Methods</th>
<th>PROCESS</th>
<th>Result</th>
<th>Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Primary Production</td>
<td>Cold Heavy Oil Production with Sand - CHOPS</td>
<td>Pass</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Horizontal and Multilateral Wells</td>
<td>Fail</td>
<td></td>
<td>Depth; Vertical Permeability;</td>
</tr>
<tr>
<td>3</td>
<td>Cold Production</td>
<td>Vapor Extraction - Vapex</td>
<td>Fail</td>
<td>Permeability; Vertical Permeability; Net Pay/Gross Pay</td>
</tr>
<tr>
<td>4</td>
<td>Waterflooding</td>
<td>Pass</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Chemical</td>
<td>Polymer Flooding</td>
<td>Fail</td>
<td>Live Oil Viscosity @pb; Water Salinity; Oil Gravity;</td>
</tr>
<tr>
<td>6</td>
<td></td>
<td>Alkaline/Polymer Flooding</td>
<td>Fail</td>
<td>Live Oil Viscosity @pb; Water Salinity; Oil Gravity;</td>
</tr>
<tr>
<td>7</td>
<td></td>
<td>Surfactant/Polymer Flooding</td>
<td>Fail</td>
<td>Live Oil Viscosity @pb; Water Salinity; Oil Gravity;</td>
</tr>
<tr>
<td>8</td>
<td></td>
<td>Alkaline/Surfactant/Polymer Flooding</td>
<td>Fail</td>
<td>Live Oil Viscosity @pb; Water Salinity; Oil Gravity;</td>
</tr>
<tr>
<td>9</td>
<td>Miscible &amp; Immiscible flooding</td>
<td>Carbon Dioxide Miscible</td>
<td>Fail</td>
<td>Live Oil Viscosity @pb; Oil Gravity; Depth;</td>
</tr>
<tr>
<td>10</td>
<td></td>
<td>Hydrocarbon Miscible</td>
<td>Fail</td>
<td>Live Oil Viscosity @pb; Oil Gravity; Depth;</td>
</tr>
<tr>
<td>11</td>
<td></td>
<td>Nitrogen Miscible</td>
<td>Fail</td>
<td>Live Oil Viscosity @pb; Oil Gravity; Oil Density (Surface); Depth;</td>
</tr>
<tr>
<td>12</td>
<td></td>
<td>Immiscible Gas Flood</td>
<td>Fail</td>
<td>Depth;</td>
</tr>
<tr>
<td>13</td>
<td>Thermal</td>
<td>Cyclic Steam Stimulation - CSS</td>
<td>Pass</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td></td>
<td>Steam Flooding - SF</td>
<td>Pass</td>
<td></td>
</tr>
<tr>
<td>15</td>
<td></td>
<td>Steam Assisted Gravity Drainage - SAGD</td>
<td>Fail</td>
<td>Live Oil Viscosity @pb; Horizontal Permeability; Vertical Permeability;Net Pay/Gross Pay</td>
</tr>
<tr>
<td>16</td>
<td></td>
<td>In Situ Combustion - ISC</td>
<td>Fail</td>
<td>Reservoir Temperature; Depth</td>
</tr>
</tbody>
</table>
3.4 Reservoir Development Options

- Cold production - water flooding, VAPEX, horizontal and multilaterals wells

There is a great opportunity for cold production (CP) applications in medium HO reservoirs (12-18 API) because of the low in-situ viscosity. Nevertheless, given the relative weakness of the main drive mechanism (solution gas drive) at the case study location, the oil recovery factor is not likely to exceed 10% (Dusseault et al., 2008; Bernard et al., 1997). Due to the low initial reservoir pressure, 150-300 psi, CP development would be economical at pressures below the bubble point. On the basis of findings by Dusseault and others (2008), the operating costs for CP in Kuwait are expected to be very low (~$2.00-3.00 /bbl). Therefore, there is a great motivation to employ CP as first extraction technology, perhaps followed by heating.

From an economic standpoint, horizontal and multilaterals wells have reportedly been successful in zones as thin as 3 m and with oil viscosities in the range 1000-5000 cP in Canada (Dusseault, et al., 2008; Nasr and Ayodele, 2005), with oil recovery factors reportedly in the range of 10-20% (Dusseault, et al., 2008). However, although this data is of value, at sites where the depth of a reservoir are shallow serious limitations must be imposed on the drilling of horizontal and highly deviated wells (Shafiei et al., 2007).

In the case of the VAPEX process, possible limitations for their application arise when there is asphaltene precipitation and the existence of shale barriers that may impede convective fluid flow, the primary mechanism for mass transport and in-situ viscosity reduction in the VAPEX process. VAPEX cannot break through shale barriers, nor does thermal shear dilation exist to improve reservoir transport properties. However, since VAPEX is not yet a commercial technology, it was not evaluated in the numerical simulations performed in this study.

From field experience on other projects, the advantages of implementing the CP process as a precursor of thermal processes have been highlighted (Alajmi et al. 2009). Therefore, in subsequent chapters of this thesis, we describe detailed numerical simulations to investigate the
feasibility of implementing the CP process prior to the thermal recovery methods for the development of the Lower Fars deposit.

- **CHOPS in the Lower Fars**
  In general, analytical data suggests that Lower Fars meets the CHOPS technical screening criteria (in situ viscosity less than 2000 cP, absence of free water, and an unconsolidated sand reservoir). However, the solution gas content in the region is very low compared to that at deeper deposits where the CHOPS technique has been successfully implemented, such as in Canada (Dusseault et al., 2002). Indeed, despite technical screening criteria suggesting that the CHOPS process would be an attractive one for the Lower Fars, a pilot project in the Northern part of Lower Fars (conducted between 2008 and 2009) failed to produce more than 8 b/d. This is not to discount CHOPS as an EOR method in other cases, as additional factors might be implicated in the results; i.e. poor reservoir characterisation. However, the pilot results provide adequate justification to eliminate this technology from the development options considered for Lower Fars in this work, and until future understanding indicates otherwise.

- **Thermal recovery options**
  Kuwait in general exhibits a number of existing conditions that make the development of HO particularly attractive. There are alternative sources of low and medium-grade heat available for thermal processes, regional availability of large amounts of natural gas and diluents, and even sources of inert gas. Low-grade heat sources, properly used, can provide much of the heat requirement for the thermal-solvent process, involving heating diluents, and if steam injection is needed, additional heat can be added to the already hot fluids, especially during the summer seasons. Some local low-grade heat sources in Kuwait include solar heat and exhaust heat from power plants and compressor stations (Dusseault and Oskui, 2007; Popov, 2011). The shallow depth and API range of about 11-17 API makes any reservoir an interesting target for thermal recovery processes.
1. **Cyclic Steam Stimulation - CSS**

From the foregoing results and technical screening results, CSS appears to be a suitable method for the case study site because of the relatively high oil mobility conditions at the reservoir.

In CSS pilot projects in the 1980s, steam injection as a well stimulation method followed by a short steam soak period, is likely to become widely used during the operating phase of development. In thin zones, because of the associated heat losses, the application of this method will be limited to the restoration of well rates only, rather than as a drive mechanism. The excellent response from pilots suggests that even in zones as thin as 16ft (5 m), following a CP or a CHOPS phase, continued economic production rates can be attained by occasional episodes of stimulation with steam (Dusseault et al., 2008).

2. **Steam Assisted Gravity Drainage-SAGD**

In SAGD, thermal dilation can rupture “thin” shale barriers effectively and enhance the reservoir permeability, both vertically and laterally. However, injected steam may not be able to break “thick” shale barriers, such as those at the case study site; thereby providing a major limitation for the successful application of the SAGD technique.

Nevertheless, in suitable reservoirs it is the technology of choice, although the experience range remains small at present (only viscous oil, thick zones with good permeability, and high net-to-gross pay ratios - >0.9). In general application, the economic limit for SAGD is considered to be dependent on the presence of thin net-pay sands. Where oils are highly mobile (considered medium HO in some references), with good response to steam injection, this relaxes the need for closely spaced horizontal wells. Although preliminary studies (Dusseault et al., 2008) indicate that the Lower Fars has some zones where SAGD is applicable, thick, oil-saturated zones are generally limited and poorly mapped (KOC confidential reports).
3. **Steam Flood - SF**

In a process that depends primarily on the convective heat transport in a steam flooding process, there must be effective flow communication between paired injectors and producers before significant productivity can be established upon initiation of a project. (Dusseault, 2006c; King et al., 1984; Taber et al., 1997a).

The principle of thermal EOR is that heat increases the mobility of oil by reducing its viscosity;

\[ M = \frac{\lambda_w}{\lambda_o} = \left[ \frac{k_{rw}(S_w)\mu_o}{k_{ro}(S_o)\mu_w} \right] \]  

**(Eq. 3.1)**

Oil mobility is increased relative to that of water and mobility ratio is reduced allowing a more favourable displacement.

As with all thermal processes, thickness, net-to-gross ratio, and oil saturation must be reasonable so that a sufficient quantity of oil can be accessed in a reasonable time (5-8 years in most cases) to offset heat costs and other expenses (Petit et al., 1989). Free water must be absent, and injection pressures must remain well below overburden stress values.

According to our current understanding, the Lower Fars reservoir, which forms the case study area, has a high likelihood of responding to the SF method because its \( k/\mu \) ratio generally exceeds 5. Consequently, high recovery factors are expected, likely at steam-oil ratio (SOR) values that will be substantially lower than 1.0 for the entire project life. However, it is important to be wary of the performances of relatively thinner zones, which are likely to experience a higher SOR for the same recovery factors as thicker zones.
3.5 Conclusion

Based on the evidence presented in this chapter and the current oil price regime, it is reasonable to presume that thermal and other enhanced-oil recovery processes have a high chance of commercial success at the, study reservoir, and any other reservoirs that have similar properties. Therefore, a detailed techno-economic evaluation is necessary for the selection of the best recovery option. Although this is unknown at this stage, from the results of the technical screening and discussions in this chapter, the following inferences can be drawn.

- The application of a First-pass screening tool to select EOR method is both important and useful. The development of this tool shows that expert systems are powerful applications that can help experienced reservoir engineer users save time and effort when selecting an appropriate EOR process on the basis of a reservoir’s characteristics.
- Because of the encouraging reservoir conditions at Lower Fars, we anticipate that it will respond positively to most EOR technologies, ranging from cold to thermal methods.
- Due to the high heterogeneity in the investigated reservoir, different technologies are likely to be suitable for different formation zones. The selection of the technologies will doubtless be influenced by several factors, which include formation thickness, oil saturation, and oil viscosity.
- A suitable technology sequence depends on reservoir thickness and fluid characteristics, among other considerations. In thin zones, such as the one we are investigating, options are limited. However, thick zones present a challenge in the choice of an optimum approach to maximize recovery factor at reasonable heat costs.
- Cold production methods are likely to be economical in medium HO reservoirs (12-18 API), but probably low recovery factors suggest that this should be planned as the first technology in a sequence, to be followed by other methods.
- Hot water flooding and combinations of hot water flooding and other technologies have yet to be proved as highly effective with viscous oils.
- SAGD is yet to be proved as highly effective with mobile oils, but holds promise at the Lower Fars reservoir because of the relatively shallow depth and the small net pay
thickness. Furthermore, the existence of continuous and non-continuous shale layers at Lower Fars puts SAGD at risk in this heavy-oil deposit.

- Clearly, it is necessary to construct and apply a general screening approach to facilitate the identification and selection of the best recovery candidates for the different Lower Fars zones at different conditions.

- In the future, it will be important to evaluate fossil fuels as a heat source for thermal processes because of cost and environmental considerations (greenhouse effects). In Kuwait, other heat source alternatives include heat from power generation facilities, and solar power.

- The EOR screening computer program developed in this study can be applied to future EOR studies for other HO reservoirs.
4. Lower Fars reservoir - The case study

4.1 General Information

Kuwait, located in the Middle East, has abundant natural petroleum resources within its borders. Today Kuwait can undoubtedly be regarded as one of the major oil producing countries, possessing the fourth largest oil reserves on the planet. The origin of the oil industry in Kuwait dates back to the 1920s. Since then, the country has established a number of Oil companies in addition to those organisations that serve to facilitate communication between these companies. Moreover, Kuwait has also adapted various new technologies to exploit the resources in different regions of the country to improve and enhance the levels of oil production. One of the important regions for exploration and exploitation is the Lower Fars formation and the Lower Fars reservoirs. This research aims to analyse these oil reservoirs by presenting their unique characteristics in a case study format to exemplify current extraction methods. This chapter details the background features and geography of this reservoir, highlighting its fluidic and geological characteristics. The information and data about the case study location was taken from Ahmed et al. (2011), Al Ajmi et al. (2006), Al-Qabandi (1995), Dusseault et al. (2008) Farouq Ali (2008) and Sanyal (2007). In addition, extra data was available due to a confidentiality agreement between Imperial College and the KOC that facilitated retrieval of information from the KOC database.

The subsurface in the country can be categorised into two main units. These include the Hasa Group including Dammam, Radhuma and Rus formations and the Kuwait Group including the Ghar and Lower Fars formations (Alajmi et al., 2006). It is important to note that the HO used in Kuwait comes from Middle Miocene, where it lies in an evaporate sequence overlying Iran’s Asmari limestone. In the Northern Kuwait region, the Lower Fars formation is a long established and prolific reservoir (Al-Bahar et. al, 2004).
4.2 Background

Lower Fars is located in the Ratqa field in Kuwait; it is an unconsolidated sandstone reservoir that is both shallow and heterogeneous. Moreover, the reservoir is saturated with huge quantities of oil. These reservoirs are situated next to the border with Iraq, to the Northwest of Kuwait City. Figure 4.1 depicts the location of these reservoirs.

Figure 4.1: Lower Fars formation Location, Kuwait.

(Source: Research and Technology Group of Kuwait Oil Company)

Ratqa Field was first discovered in 1978. However, interestingly, the field serves as an extension of the Rumalia field, which is associated with five major Northern oil fields, and can undoubtedly be regarded as the largest and most unusual field in Iraq (Ahmed et al., 2011; Al-Qabandi et al., 1995; Dusseault et al., 2008), (Abdali, Bahra, Ratqa, Raudhatain, and Sabriya).
Several studies and researchers have confirmed that the Lower Fars represents the largest quantities of accumulated HO in Kuwait. With viscosity measured as greater than 100 cP, the Lower Fars offers the country HO approximately in the range of twelve to sixteen billion barrels in-situ. Moreover, the oil from these Lower Fars is distributed across an area of around 1200 km$^2$ intersecting with the Northwest region of Kuwait City and the border of Iraq. There have been several techniques attempted to retrieve and collect the HO that lies deep within the fields of Ratqa-Rumaila. The most prominent methodology remains vertical migration, followed by the biodegradation conducted at shallow depth (Ahmed et al., 2011).

The HO that these reservoir contains lies in the range of around 12-15 Bb (Oskui et al, 2009). It must be noted that in Kuwait, there are many other accumulations of HO, the most important lying in naturally fractured carbonate strata. However, the majority of these oil reserve accumulations are of a lower quality and a smaller size (Sanyal, 2009). Hence, both quality and quantity wise, these reserves will not contribute significantly to oil production in the country (Sanyal, and Sarmiento, 2007). Although the Lower Fars reservoir is regarded as a small resource when compared to the Venezuelan and Canadian HO resources, these reservoirs nevertheless represent a huge proportion of Kuwait’s entire oil resources (Majdi et al, 2003).

Therefore, the Lower Fars Reservoir holds an important position to the Kuwait Oil Industry and hence the country’s overall economy. In Kuwait, exploitation of these reservoirs will mean increasing production up to 4 million b/d of oil by 2020 compared to the current three million b/d. Moreover, with the depletion of the various oil fields that are currently in operation, it has been observed that only the al-Ratqa crude oil fields possess enough reserves to offer Kuwait sufficient oil quantities to compensate. In addition, the case study area it is also the only HO field that has the capability to deliver additional barrels to meet the 2018 targets set by the major Oil Companies and the Government of the State (Dusseault, 2011).

Despite the time that has elapsed since the discovery of the Lower Fars oil fields there remains a need for further development of the infrastructure of the fields to increase the production of oil (Banat, 1995; Carman, 1996). With the announcement of the authorities to plan and implement a strategy for doubling oil production by 2020 to 4 million barrels, development of the Lower Fars reservoirs became imperative. Since this time several studies have explored the characteristics and structure of the Lower Fars reserves, with the intention of assisting experts to plan strategies to
better exploit the available resources and maximise oil production (Dusseault et al, 2008; Majdi et al, 2003).

4.3 Characteristics of the Lower Fars Reservoir

Table 4.1 provides a Summary of the reservoir and fluid characteristics for the Lower Fars accumulation. These details were retrieved from the KOC and the KISR databases.

<table>
<thead>
<tr>
<th>Lower Fars SUMMARY: RATQA-MUTRIBA AREA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lithology</td>
</tr>
<tr>
<td>Depth</td>
</tr>
<tr>
<td>Thickness</td>
</tr>
<tr>
<td>Area</td>
</tr>
<tr>
<td>Facies (Depositional environment)</td>
</tr>
<tr>
<td>Formation Temperature</td>
</tr>
<tr>
<td>Reservoir pressure</td>
</tr>
<tr>
<td>Porosity</td>
</tr>
<tr>
<td>Permeability</td>
</tr>
<tr>
<td>Oil Saturation, $S_o$</td>
</tr>
<tr>
<td>Water Saturation, $S_w$</td>
</tr>
<tr>
<td>API°</td>
</tr>
<tr>
<td>Viscosity, $\mu$</td>
</tr>
<tr>
<td>Net Pay</td>
</tr>
<tr>
<td>Most Likely Case Oil in-place</td>
</tr>
<tr>
<td>General Volumetric $B_o$</td>
</tr>
<tr>
<td>General Oil Characteristic</td>
</tr>
</tbody>
</table>

Hence, it can be concluded that when compared to many other viscous oil deposits and reserves elsewhere on the planet, the Lower Fars asset is a shallow reserve with higher permeability and
porosity and, a relatively lower viscosity. These reserves show a significant variation in the properties of the fluid with respect to both location and depth in the large HO reservoirs. These characteristics have led to the development and deployment of a wide range of production technologies, which share only some similarities with the methods deployed in Canada. It is important to note that the methods and technologies adopted in Canada have the capability to lower costs and increase and enhance recovery factors.

4.4 Geological Disposition of Lower Fars

The formation of Lower Fars is a combination of various elements including thin fossiliferous limestone, shale, sandstone, conglomerate and fine sediments. The deeper strata found in the underlying fields of Ratqa-Rumaila were the original deposits. However, these migrated with the help of lateral and vertical migration accompanied by the shallow-depth biodegradation that results upon the exposure to various appropriate conditions (Ahmed et al., 2011; Dusseault et al., 2008). These conditions include access to nutrients that are not present at depth; the presence of different bacteria, including sulphate-reducing bacteria and sufficient groundwater flux creates varied geochemical composition, and so on (Adams et al., 2004, Head et al., 2003). Emission of a small amount CO$_2$ and greater concentrations of CH$_4$, high molecular weight and higher viscosity are the results of the biodegradation process. Generally, the HOs in the case study area are characterised by the existence of high sulphur content and the presence of heavy metals such as nickel, vanadium, etc.

A great deal of variability is experienced from the South to the North in terms of the properties and characteristics of the HO. For instance, the sit oil viscosity in the deepest field parts up to 270 m can be very low up to 100 cP at 40°C, where it can reach up to 1000 cP at 25-30°C in several shallower areas around 70-100 m deep. Moreover, the oil API increases as we move from the Southern regions of the fields in the Northern part and the range here is from 12 to 18°. The reservoir rock has a high-porosity that falls in the range of 25-35%, whereas the burial depth for Lower Fars is around 100-225m. The high-permeability of the unconsolidated sandstone lies in the range 0.2 – 8 Darcies where the oil saturation is around 80%, this is most likely to be greater in the
coarser-grained sands. Moreover, the oil-saturated thickness mean is found to be approximately 10-11m, with 50km$^2$ having an accumulation of more than 15m thick. Typically, this is regarded as the lower limit for particular thermal technologies (Dusseault et al., 2008; Farouq Ali, 2008; Sanyal, 2007). *Figures 4.2* and *4.3* provide further examples of the Lower Fars.

*Figure 4.2* below explains the Net Pay thickness map of the Lower Fars fields at Ratqa field. A general dip towards the North is represented in the figure by the view of the South-North cross section. The oil in place is predicted to be greater than twelve billion barrels for a cut-off of 20ft (Farouq Ali, 2008).

*Figure 4.2: Net Pay thickness map of the Ratqa Lower Fars field: A North –South cross section through the field shows a general dip towards North (Source: KOC’s Research and Technology Group; Sanyal, 2007). For 20 ft cut-off, the oil in place is estimated to be more than 12 billion barrels (Farouq Ali, 2008).*
4.5 Lower Fars Structure

The sand shale sequence of the Miocene Lower Fars is fluvial to the near offshore deposition. A shale cap that is non-continuous, bounds this sequence at the middle and top shale separates the F1 and F2, which are the two key sand bodies. Well-developed sub-units including F2A/ F2B and F1A/ F1B are occasionally used to characterise the two sand bodies F1 and F2. A classic sequence, either fine-grained or shale, is used to separate the sub-units (Dusseault et al., 2008; Sanyal, 2007; Al-Qabandi, 1995).

The general stratigraphy followed for reservoir from top to bottom includes (Dusseault et al., 2008; Al-Qabandi, 1995):

- Cap rock shale
- Reservoir’s upper member
- The lower shale bed which separates the two reservoir members
- Reservoir’s lower member (non-oil bearing)

A typical geophysical log through the thicker North-eastern part of the Lower Fars is presented in **Figure 4.4**

![A typical geophysical log in the Lower Fars showing the oil-bearing zones.](image)

**Figure 4.4:** A typical geophysical log in the Lower Fars showing the oil-bearing zones.

(Source: KOC’s Research and Technology Group; Dusseault et al., 2008)

It has been explained earlier in this chapter that a regionally enveloping shale bed of around 8-10m separates the two sandstone units, F1 and F2, which resulted in the formation of Lower Fars. It is essential to note that these two units must be regarded as two separate and independent reservoirs. Moreover, F2A/ F2B and F1A/ F1B are also separated, or isolated, by the oil-saturated reservoir units that consist of thin shale layers less than 0.5m. It is important to note that the sub sandstone units F2A/ F2B and F1A/ F1B, that cover a huge area, are rarely continuous. Furthermore, these
sub sandstone units do not serve as an obstacle to the thermal procedure in any case, particularly from the context of heat transport conduction.

An OWC (Oil-Water Contact) is seen in various of the deeper areas of the Lower Fars reservoirs. However, the two Lower Fars zones have a majority of their portions free from the mobile basal water zone. In the South and South-west regions of the Lower Fars, around 80% of the area is found to be free of the active basal water. However, several cases have shown that avoiding these water regions completely is impossible. For instance, experiences in Canada and Venezuela have shown that disconnected water legs have been occasionally found. It is important to note that in most cases, these water portions exist only to a limited extent. Hence, they are unlikely to obstruct the development of thermal methods (Dusseault et al., 2008).

Table 4.2 presents the details of a preliminary comparison conducted between the Lower Fars in Kuwait and the HO accumulations in Venezuela and Canada. The comparison is conducted with respect to lower viscosity deposits found in Canada, as compared to the highly viscous Athabasca and Cold Lake oil sands. It must be noted that this is a formal comparison that has encompassed and accommodated only some of the necessary minutiae. Therefore, to conduct a more comprehensive and accurate relative evaluation of the Lower Fars asset as relevant to the production technologies, and to elaborate on these, comparative research must be conducted that includes data on HO reservoirs from worldwide in the unconsolidated sandstones is important and essential. Table 4.2 below shows information form a comparison conducted between Venezuelan HOs, Canada and Kuwait (Dusseault et al., 2008).
Table 4.2: Comparison of Kuwait, Canadian and Venezuelan HOs.

(Adapted from Dusseault et al., 2008)

<table>
<thead>
<tr>
<th>Property</th>
<th>Kuwait Lower Fars</th>
<th>Canadian HO Belt</th>
<th>Venezuelan Orinoco HO Belt</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity (%)</td>
<td>25-35</td>
<td>28-31</td>
<td>29-31</td>
</tr>
<tr>
<td>Permeability (D)</td>
<td>0.2-8</td>
<td>2-3</td>
<td>4-5</td>
</tr>
<tr>
<td>Depth (m)</td>
<td>100-225</td>
<td>325 – 800</td>
<td>350 – 1050</td>
</tr>
<tr>
<td>API Gravity (specific gravity)</td>
<td>12-18 (0.97-0.99)</td>
<td>10-16 (0.94-1.0)</td>
<td>7-9.5 (1.01-1.03)</td>
</tr>
<tr>
<td>In-situ Oil Viscosity (cP)</td>
<td>~100-400</td>
<td>500-25,000</td>
<td>800-5,000</td>
</tr>
<tr>
<td>Reservoir temperature (°C)</td>
<td>22-33</td>
<td>15-35</td>
<td>35-55</td>
</tr>
<tr>
<td>Reservoir pressure (MPa)</td>
<td>0.9-2.5</td>
<td>2.5-8.0</td>
<td>3.5-11</td>
</tr>
<tr>
<td>Rock type</td>
<td>Quartzose sands</td>
<td>Quartzose to arkose</td>
<td>Quartzose sands</td>
</tr>
</tbody>
</table>

4.6 Field Experiences on Lower Fars

The first development activities took place in the Lower Fars in 1982 and 1986, where two CSS pilots were conducted as demonstration projects, also shown in Figure 4.5 below. It must be noted that both these tests offered essential information and insight into the steam injection sustainability at the reservoir and hence both tests can be considered successful (Al-Qabandi, 1995). Nevertheless, there a number of queries remain unanswered, as the performance of the two pilot areas was recorded as inconsistent in spite of their proximity and geological similarity (Al-Qabandi, 1995; Milhem and Ahmed, 1987; Sanyal, 2007). The two pilot projects were destroyed and the production stopped after Iraq invaded Kuwait in 1990.

Figure 4.5 below represents the areal distribution of the Lower Fars in the Northern regions of Kuwait, showing the pilot locations as small rectangles.
**Figure 4.5:** Areal distribution of Lower Fars in Northern Kuwait, showing the pilot locations as small rectangles. (Source: KOC’s Research and Technology Group)

**Table 4.3** below offers a summary of the findings obtained from the two pilots in Lower Fars that were conducted in the 1980s. It must be noted that the summary was received from the KOC, which provided these records under the confidentiality agreement mentioned above (Ahmed *et al.* 2011; Sanyal, 2007; Al-Qabandi, 1995).
Table 4.3: Summary of the findings from the two pilots conducted in Lower Fars field in the 1980s.

<table>
<thead>
<tr>
<th></th>
<th>Pilot 1</th>
<th>Pilot 2</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Location</strong></td>
<td>Northern part of the field</td>
<td>Northern part of the field</td>
</tr>
<tr>
<td><strong>Number of wells¹</strong></td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td><strong>Type of wells</strong></td>
<td>Four vertical wells intersecting 68 feet of net pay</td>
<td>Vertical wells each with a net pay thickness of 48 feet</td>
</tr>
<tr>
<td><strong>Number of steam cycles applied²</strong></td>
<td>One</td>
<td>One</td>
</tr>
<tr>
<td><strong>Injection strategy</strong></td>
<td>Steam injection</td>
<td>Steam injection</td>
</tr>
<tr>
<td></td>
<td>Steam quality: ~76%, 423-441°F</td>
<td>Steam quality: ~75%, 421-438°F</td>
</tr>
<tr>
<td></td>
<td>Injection rates: 965-1250 bbl/day</td>
<td>Injection rates: 652-837 bbl/day</td>
</tr>
<tr>
<td></td>
<td>Injection period: 15-30 days</td>
<td>Injection period: 20-28 days</td>
</tr>
<tr>
<td></td>
<td>Soak period: 3 to 9 days</td>
<td>Soak period: 2 to 8 days</td>
</tr>
<tr>
<td><strong>Pilot performances</strong></td>
<td>Total production for the wells over a period of four years leads to an estimate of steam-oil ratio (SOR) less than 0.15 stb/stb. For this pilot, the water-to-oil ratios were less than 0.25 cumulative, indicating an excellent response to thermal stimulation.</td>
<td>Total production of 42,000-65,000 bbl for the wells leads to an estimated SOR of 0.35 tb/stb. Low water production ratios indicated no communication with active water, similar to the first pilot.</td>
</tr>
</tbody>
</table>

1: It must be noted that the two pilots were known to be limited to the four wells, where each well pillar initially experienced some expansions afterward.

2: No optimisation was associated with the various pilot operations to determine the best strategy as compared to the volume rates and cycle size.

In 2011 an interesting discovery was made in these pilot regions. The down-hole fluid sampling method was used to obtain the first live oil samples of PVT-quality. The drilling of five new wells took place in the Northern region, that is the Pilot area 1, and each well was around 335 m deep. The study indicated that all the wells were to be cored, whereas the fluid samples were taken from all the major sand units. The research further concluded two important points. Firstly, that the rock formation has a very low compressive strength. Secondly, that at reservoir conditions, the state of the oil is not as heavy as envisaged (Ahmed et al, 2011).

It is important to note that unless the concept and principles behind the working of the Pilots is not well understood, recognised and acknowledged, the development of the reservoir projects...
would be a huge challenge. Taking into account this important fact, research was adapted to introduce simulation studies to discuss the inconsistencies and instabilities reported in the performance of the different wells tested in the 1982 pilot. Irrespective of the similarity shared by the wells in regards to the operating conditions and geological settings, they exhibited completely different performance. For instance, Well-4 indicated that the CSS was satisfactory, whereas a dissatisfactory CSS was observed at Well-2 (Sanyal, 2007). Research was conducted on the possible factors that contributed to these performance gaps. Stream loss, because of channelling behind the casing to the overlying water zone was identified as the root cause of the disparity in the performances and working of the wells.

Therefore, to conclude, the Middle East contains approximately 75% of the planet’s oil reserves, and Kuwait is capable of producing huge petroleum quantities every year. The Lower Fars reservoirs remain the biggest source of oil reserves in the country. The Lower Fars are located in the Ratqa field in Kuwait. Spread across a wide geographical span, the reservoirs have the capacity to produce huge quantities of HO every year. When compared to many other viscous oil deposits and reserves elsewhere, the Lower Fars asset is characterised as a shallow reserve with higher permeability and porosity and, a relatively lower viscosity. Studies have shown that the formation of Lower Fars combines numerous elements such as thin fossiliferous limestone, shale, sandstone, conglomerate and fine sediments. The overall structure of these reservoirs can generally be categorised into four layers that include capping shale, upper sand, middle shale and lower sands. In the years 1982 and 1986, two CSS pilots were conducted in the Lower Fars reservoir as demonstration projects. Using different wells in different locations within the pilot regions, numerous essential findings were obtained.
5. Application of the selected EOR method on a simple model

An important deduction from the pilot tests conducted at the Lower Fars reservoir was the ability to detect the technical feasibility of the thermal flood method, especially in the Northern sector of this reservoir. In particular, steam was used as the heat-carrying fluid. Considering that the test sector contained the least viscous oil (see Figures 4.3 and 4.5), it is not unreasonable to hypothesise that unheated-water (cold water) flood, which entails injecting water at roughly the reservoir temperature, or the less heat-intensive hot water flood would be more competitive, at least in this region.

Hot water flooding is the least costly thermal recovery technique, and it is similar to conventional water flooding procedures (Farouq, 1976). Although the heat carrying capacity of water is less than steam, hot water provides displacement effect advantages over steam (Diaz-Munoz, 1975). The potential success is that it is cheaper as it is unnecessary to heat the water to steam temperatures and therefore the energy cost is lower. Less challenging processes would permit the delay of the steam-based operations to other sectors and later phases of the development where/when they were likely to be more favourable. Consequently, by using numerical modelling techniques we have investigated the applicability of thermal and cold floods within a HO, sandstone reservoir. Unless stated otherwise, all discussions treat the unheated-water flood as the reference case.

5.1 Analytic modelling - Buckley-Leverett analysis

To gain physical insight into the dynamics of the flooding processes, Buckley-Leverett analyses were conducted (Willhite, 1986). Although the Buckley-Leverett theory (Buckley and Leverett, 1942) is strictly limited to mass conservation, we adapted it to the hot water process by assuming an average oil viscosity which was evaluated as the arithmetic average of the initial and injection temperatures. Instead of modelling both the heat and mass balance we assumed that the heat was simply convected by the hot water. Thus we could use the position of the water front as an...
approximation to the position of the thermal front; and could subsequently use simple frontal advance theory for the water saturation (as described by Equation 5.1) as a proxy for the thermal front. Most of the input data is presented in Table 4.1.

The Buckley-Leverett equation is derived under the assumptions of incompressible fluids, one dimensional flow and immiscible flow. Capillary pressure and gravitation are neglected and the permeable medium is assumed to follow Darcy’s law, stating that the velocity of each phase is proportional to the gradient of its pressure (Buckley and Leverett, 1942; El-Khatib, 2001).

Firstly, we have noted that a change in water saturation can be written in terms of the partial derivatives of the change in saturation, $S_w$, with respect to position, $x$, and time, $t$:

$$dS_w = \frac{\partial S_w}{\partial x} dx + \frac{\partial S_w}{\partial t} dt$$  \hspace{1cm} (Eq 5.1)

In the standard Buckley-Leverett theory, we follow a fluid front of constant saturation during the displacement process: By definition, a constant saturation is when $dS_w = 0$ and therefore:

$$0 = \frac{\partial S_w}{\partial x} dx + \frac{\partial S_w}{\partial t} dt$$  \hspace{1cm} (Eq.5.2)

Substituting into the Buckley-Leverett equation, we obtain:

$$\left( \frac{dx}{dt} \right)_{S_w} = q_t \left( \frac{df_w}{dS_w} \right)$$  \hspace{1cm} (Eq 5.3)

Integration in time:

$$\int \left( \frac{dx}{dt} \right)_{S_w} dt = \int q_t \left( \frac{df_w}{dS_w} \right) dt$$  \hspace{1cm} (Eq.5.4)

This gives an expression for the position of the fluid front:

$$X_f = \frac{q_t}{\phi A} \left( \frac{df_w}{dS_w} \right) f$$  \hspace{1cm} (Eq 5.5)

Hifaa Alajmi, 2012
Equation 5.5 is called the frontal advance equation.

Where,

\( q_t = \text{gross rate (oil and water), m}^3/\text{s}; \)

\( f_w = \text{fractional flow, dimensionless}; \)

\( \phi = \text{porosity, dimensionless}; \)

\( S_w = \text{water saturation, dimensionless}; \) and

\( A = \text{cross sectional area, m}^2; t = \text{time, s}; \left( \frac{dx}{dt} \right)_{S_w} = \text{velocity of plane } S_w, \text{ m/s.} \)

### 5.2 Reservoir and fluid properties

The porosity and horizontal permeability were 30% and 400 md, respectively. The \( kv/kh \) ratio was 0.1. Endpoint saturations and relative permeability were assumed independent of temperature (Figure 5.1). The initial reservoir pressure and temperature were 250 psia and 100F, respectively. The initial oil saturation was 80%, the initial water saturation was 20% and the crude gravity was 18 API. Figure 5.2 provides the crude oil viscosity as a function of temperature.
**Figure 5.1:** Oil-water relative permeability curves based on laboratory data (Source: KOC confidential database, made available for this research based on a confidential agreement).

**Figure 5.2:** Viscosity versus temperature, for the heavy component.
5.3 Results of analytic modelling

Figure 5.3 shows the fractional flow curve for one of the several examined cases. The data used to generate this curve was provided by KOC for the Lower Fars formation, the studied field. Its corresponding derivative plot is also shown. In this particular case, the breakthrough water saturation was 0.31, and the associated water-cut into the wellbore was approximately 60% (in reservoir units). However, just at the breakthrough, the average water saturation behind the shock front of $S_w = 0.31$ was predicted to be some 35.5%. Apparently, this relatively low average water saturation at the trailing edge of the shock front has provided a clear indication of a significant bypassing of oil. Obviously, this case provides a good incentive for the deployment of the EOR methods, although the prospective incremental recovery would need to prove its competitiveness in terms of its economics and other performance indices.

Water saturation ($S_w$), and oil saturation ($S_o$), vary with distance $X$, but because oil and water are assumed to be incompressible, the total volumetric flow rate, at any time $t$, is constant for every position $x$ in the linear system. Figure 5.4 shows the spatial variation of water saturation at three instants – 1000, 1500 and 1823 days. After 1823 days of continuous water injection, while the leading edge ($S_w = 0.31$) of the water front would have moved approximately 134 ft away from the injection well, one of the trailing planes of $S_w = 0.5$, would simply be covering a distance of 18 ft. It is apparent from this plot that, regardless of the saturation plane, the distance travelled increases with time, and thus the correlation is linear as shown in Equation 5.5.
**Figure 5.3:** Fractional flow curve and its derivative.
5.4 Numeric modelling - for validation purposes

5.4.1 Simulator and reservoir grid

The commercial reservoir simulator, STARS, developed by the Computer Modelling Group (CMG) Ltd, Canada, was deployed for numeric modelling. The 1D and 3D homogeneous models were based on a Cartesian system, comprising 50 x 1 x 1 and 34 x 34 x 1 grid blocks along the x, y and z axes respectively, maintaining the same bulk volume and pore volume sizes and the same well spacing. The reservoir rock was assumed to be water-wet, and the capillary pressure was ignored. Other input data is summarised in Table 5.1. Furthermore, neither geomechanical changes (mechanical and thermal-induced) nor thermal losses to adjacent formations were considered. Again, oil and water miscibility was neglected.

Figure 5.4: Water saturation profile at different times.
The model pore volume was $1.31 \times 10^7 \text{ m}^3$ with an initialised OOIP of $1.05 \times 10^7 \text{ m}^3$. The well configuration consisted of one injector and a producer, both of which were vertical, located in the opposite corners of the model, as represented in Figure 5.5. In essence, this configuration approximated a ¼ five-spot scheme. The injector and production wells were opened to the entire sand interval. The simulation run time was 7305 days (twenty years), with 100% well uptime.

![Initialised simulation model showing initial oil saturation profile and wells.](image)

**Figure 5.5**: Initialised simulation model showing initial oil saturation profile and wells.

**Table 5.1**: Summarised input data, fluid and rock properties for the simple homogenous model-for validation purposes.

<table>
<thead>
<tr>
<th>Input</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Model area</td>
<td>(462,400 ft²) (43,000 m²)</td>
</tr>
<tr>
<td>Model grid (x, y and z)</td>
<td>34, 34, 1 (3D)</td>
</tr>
<tr>
<td></td>
<td>50, 1, 1 (1D)</td>
</tr>
<tr>
<td>Initial oil saturation</td>
<td>80%</td>
</tr>
<tr>
<td>Porosity</td>
<td>30%</td>
</tr>
<tr>
<td>Absolute permeability</td>
<td>400 md</td>
</tr>
<tr>
<td>Kv/Kh</td>
<td>0.1</td>
</tr>
<tr>
<td>Oil gravity, $^0\text{ API}$</td>
<td>18</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>120 cP</td>
</tr>
<tr>
<td>Initial reservoir pressure</td>
<td>250 psi</td>
</tr>
<tr>
<td>Reservoir temperature</td>
<td>$38^\circ\text{C} / 100^\circ\text{F}$</td>
</tr>
</tbody>
</table>
5.5 Comparison of the analytic and numeric results

With the purpose of confirming the results, for cold water flooding, generated through the use of the STARS-CMG simulator, dimensionless oil production relative to pore volume ($N_{Pd}$) versus the dimensionless time ($t_D$, also named PVI) a plot was generated to compare the behaviour of the production using simulation with that using Buckley-Leverett analysis. The constant oil formation volume factor and lack of capillary pressure effect have been assumed for this comparison. In addition, for agreeable comparison, the water injection rate was reduced to 200 b/d to keep the injection rate constant.

Plots of dimensionless oil production ($N_{Pd}$) versus dimensionless time ($t_D$) for the analytic and numeric models are shown in Figure 5.6. There is a large difference between the 3D results and the analytical model due to the reduced areal sweep in the 3D model. The match between the 1D model and the analytical solution is better although not perfect. One reason is that the STARS simulation includes heat transfer whilst the analytical solution does not. Another reason for the discrepancy is that numerical errors occur in the simulation due to the discretization of the flow equations. The effect is known as numerical dispersion is that it tends to smooth out the front and produces an earlier breakthrough.
5.6 Application of the selected EOR on a simple homogenous model

The reservoir was considered homogeneous for this part of the study, which allowed the separation of the process effects from the reservoir geology. The main purpose for using a simple model is:

a) To gain an understanding of the processes which determine the EOR methods for recovery improvement;
b) To establish a methodology for effectively studying this problem without additional complexity regarding the effects of heterogeneity; and

c) To provide a benchmark against which other (more realistic) cases can be compared.

5.6.1 Reservoir grid and fluid properties

The homogeneous model, which was developed for this part of the study, was based on a Cartesian system, comprised of 20 x 20 x 15 grid blocks (6000 grid blocks) along the x, y and z axes respectively. In dimensions, each block was 2.5 m x 2.5 m x 1 m. The initial pressure and temperature were 250 psi and 100 °F respectively. The relative permeability is shown in Figure 5.4, whereby the reservoir rock was assumed to be water-wet, and the capillary pressure was ignored. Other input data is summarised in Table 5.2, most of which are typical of the Lower Fars reservoir so the reservoir heterogeneity effect can be investigated when the real sector model for LF is used in the next Chapter. Furthermore, neither geomechanical changes (mechanical and thermal-induced) nor thermal losses to adjacent formations were considered, and oil and water miscibility were again neglected.

The model formation pore volume was 1.1245 x 10⁴ m³ with an initialised OOIP of 8.9960 x 10³ m³. The well configuration consisted of one injector and a producer, both of which were vertical, located in the opposite corners of the model (Figure 5.7). In essence, this configuration approximated a ¼ five-spot scheme. The injector and production wells were opened to the entire sand interval.

The reservoir was considered homogeneous for this study, which allowed the separation of the process effects from the reservoir geology. The porosity and horizontal permeability were 30% and 400 md, respectively. The \( K_v/K_H \) ratio was 0.1. Endpoint saturations and relative permeabilities were assumed to be independent of temperature (Figure 5.4). The initial reservoir pressure and temperature were 250 psia and 100F, respectively. The initial oil saturation was 80% and the initial water saturation was 20%. The crude gravity was 18° API. Figure 5.8 provides the crude oil viscosity as a function of temperature.
**Table 5.2:** Summarised input data, fluid and rock properties.

<table>
<thead>
<tr>
<th>Input</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Model area</td>
<td>160 ft. *160 ft. (25,600 ft²)</td>
</tr>
<tr>
<td>Model grid (x, y and z)</td>
<td>20, 20, 15 (6000 blocks)</td>
</tr>
<tr>
<td>Initial oil saturation</td>
<td>80%</td>
</tr>
<tr>
<td>Porosity</td>
<td>30%</td>
</tr>
<tr>
<td>Absolute permeability</td>
<td>400 md</td>
</tr>
<tr>
<td>$K_v/K_H$</td>
<td>0.1</td>
</tr>
<tr>
<td>Oil gravity, ⁰API</td>
<td>18</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>500 cP</td>
</tr>
<tr>
<td>Initial reservoir pressure</td>
<td>250 psi</td>
</tr>
<tr>
<td>Reservoir temperature</td>
<td>$38^0C/100^0F$</td>
</tr>
<tr>
<td>Rock compressibility</td>
<td>0.069 psi⁻¹</td>
</tr>
</tbody>
</table>

**Figure 5.7:** Initialised simulation model showing wells configuration and the grid top in meters, total thickness is 14m.
Rock/fluid thermal conductivity properties are required to calculate the mixed conductivities of rock and phases. In the absence of this data, STARS default thermal rock and fluid properties were used.

Table 5.3: Rock/fluid thermal conductivity properties used in the real sector model.

<table>
<thead>
<tr>
<th>Thermal properties</th>
<th>The default values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rock heat capacity (ROCKCP)</td>
<td>35 Btu/ft3-F</td>
</tr>
<tr>
<td>Thermal conductivity of reservoir rock (THCONR)</td>
<td>44 Btu/ft.-day-F</td>
</tr>
<tr>
<td>Thermal conductivity of the water phase (THCONW)</td>
<td>8.6 Btu/ft.-day-F</td>
</tr>
<tr>
<td>Thermal conductivity of the oil phase (THCONO)</td>
<td>1.8 Btu/ft.-day-F</td>
</tr>
<tr>
<td>Thermal conductivity of the gas phase (THCONG)</td>
<td>0.3 Btu/ft.-day-F</td>
</tr>
<tr>
<td>Volumetric heat capacity overburden (OVERBUR)</td>
<td>35 Btu/ft3-F</td>
</tr>
<tr>
<td>Volumetric heat capacity under burden (UNDERBUR)</td>
<td>35 Btu/ft3-F</td>
</tr>
<tr>
<td>Thermal conductivity overburden (OVERBUR)</td>
<td>24 Btu/ft.-day-F</td>
</tr>
<tr>
<td>Thermal conductivity underburden (UNDERBUR)</td>
<td>24 Btu/ft.-day-F</td>
</tr>
</tbody>
</table>
5.6.3 Design injection cases

In this simplified study, the maximum pressure of the targeted reservoir is 500 psi and based on the saturated steam tables, to maintain the saturated steam conditions, the injected fluid temperature should not be higher than 241°C. Conversely, the minimum injection temperature should not go below 206°C to avoid steam condensation. In addition, it should be recalled that technically hot water can never have a 0% steam fraction in nature; and there must be an extremely small amount of steam (gas) in it. Therefore, hot water has been treated similarly to steam and therefore in this simulation model it has been assumed that the hot water pressures and temperatures followed the steam saturation tables.

Based on the above, the simulator injection process constraints were as follows:

- **Unheated water injection: (reservoir temperature 38°C)**
  Pressure (psi):
  250
  305
  405
  500

- **Hot water cases:**
  Temperature °C  Steam quality 0%
  206
  215
  230
  241

- **Steam injection cases:**
  Temperature °C  Steam quality 40%, 60% and 80%
  206
  215
  230
  241

Several runs were conducted, investigating the effects of the petrophysical properties and operating parameters for both the thermal and non-thermal processes. The simulation strategy is summarised in Table 5.4.
Table 5.4: Overview of the simulation strategy applied in this study.

| Model parameters and control | • 1 injector and 1 producer  
|                             | • Vertical wells  
|                             | • Wells completed to bottom-hole conditions |
| Operational variables       | • Injected fluid (unheated water, hot water and steam)  
|                             | • Injected temperature (206°C, 215°C, 230°C and 241°C)  
|                             | • Injection pressure (250 psi, 305 psi, 405 psi and 500 psi)  
|                             | • Steam quality (40%, 60% and 80%) |
| Injection constraints       | • Maximum injection pressure 500 psi (for hot water and steam injection)  
|                             | • Maximum injection rate 200 bbl./day. |
| Producer constraints        | • Minimum BHP 50 psi. |
| Injection strategy          | • Continuous steaming, hot water and cold-water  
|                             | • Combination (successive) of the above |

5.7 Results and discussion

- Unheated-water flood

With an initialised OOIP of $8.9960 \times 10^3$ m³, Figure 5.9 shows that the cold process would potentially reach 46% OOIP after injecting for the period of twenty years. In addition to giving higher ultimate recovery, high injection-pressure operation also accelerated performance. For example while at the injection pressure of 500 psi unheated-water flood recovered some 30% of OOIP after ten years of continuous water injection, corresponding performances for the injection-pressure of 305 and 405 psi processes were 19% and 25% respectively. Moreover, at the minimum injection pressure of 250 psi the process would probably reach no more than 16% OOIP after ten years of continuous unheated-water injection process.
Figure 5.9: Cumulative oil (bbl), average pressure (psi), water injection rate (bbl/day) and WOR at different injection pressures versus time.
- **Hot water flood**

Figure 5.10 illustrates the variation of cumulative oil recovery at different injection temperatures. From the results, a clear positive correlation is shown to be evident between the recovery and injection temperature.

With regards to Figure 5.10, within the first year, it can be inferred that the reservoir response was practically independent of the injection temperature. This observation can be explained by the delay time, which has been required to heat up the reservoir to such a temperature, which would give a reasonable reduction of oil viscosity, hence enabling a favourable mobility ratio. However, ultimately, the cumulative recovery has shown a small positive response to the higher injection temperatures. For example, achieving the cumulative oil recovery of 44,000 bbl. was delayed for more than two years in the case of 206°C hot water flood compared with the 241°C hot water flood case at the same injection rate. From an economic viewpoint, production acceleration would improve the overall project economics by mitigating the negative impact of discounting on the revenue stream. A comparable conclusion, that hot water flood increasingly gives better production performance than unheated water process with increasing oil viscosity, was reached by Alajmi et al. (2009).
Figure 5.10: Hot water injection performance at different injection temperatures. Cumulative oil (bbl.), oil production rate (bbl./day), water injection rate (bbl./day) and enthalpy injection rate (Btu/day) versus time.
• Steam flood

Among the various investigated cases, the case regarding the high rate of steam injection provided the best recovery performance. This was due to higher heat conduction when the steam followed down the reservoir. Figure 5.11 shows the cumulative oil recovery at different injection temperatures and steam qualities. It was evident that the steam quality had no significant impact on the oil recovery at the lower temperature, 206°C, and at the higher steam temperature, 241°C. However, the impact of increasing the steam quality values became considerable at mid steam temperatures, in this case at 215°C and 230°C. For example, the ultimate oil recovery after fifteen years of steam injection process at 215°C and at steam qualities of 40% and 80% were approximately 26% and 74% respectively. Conversely, it was also obvious that only the steam temperature had control over the steam performance efficiency. For example, the cumulative oil recovery achieved when steam was injected at 241°C and 40% steam quality was higher than the cumulative oil recovery achieved when steam was injected at 230°C and 80%.

![Figure 5.11: Cumulative oil (bbl) at different injection temperatures and steam qualities.](image-url)
**Successive combination of injection fluids**

In this part of the study, the effectiveness of the successive combination of injection fluids has been investigated. The objective has been to determine the optimum design configuration in terms of injection fluids sequences. These results could be used as a tool for the successful design of thermal injection to recover HO in these types of reservoir. In addition, they can provide the condition under which a given design could give better recovery performance.

It is also worth mentioning that the commercial simulator used in this study does not support the slugging injection system and is unable to use the same well for different injection fluids. Because of the above limitation, it was decided to find another way of applying these cases outside the builder screen and undertake the changes through the ‘dat’ file which was considered to be the simplest and most correct way for achieving this target.

**Design of the successive injection cases**

A set of successive injection cases were implemented to study the effect of alternate injection fluids on the ultimate oil recovery. To achieve this, a combination of unheated-water/hot water/steam slug successions were designed. Different design cases were performed as shown in Table 5.5.

**Table 5.5:** The injection cases (all switching after four years 60 - 70% WC).

<table>
<thead>
<tr>
<th>The Injection Scenarios (switching after 4 years – 60-70% wc)</th>
</tr>
</thead>
<tbody>
<tr>
<td>WF-HWF</td>
</tr>
<tr>
<td>WF-SF</td>
</tr>
<tr>
<td>HWF-WF</td>
</tr>
<tr>
<td>HWF-SF</td>
</tr>
<tr>
<td>SF-HWF</td>
</tr>
</tbody>
</table>
Figure 5.12 shows an illustration of how an alteration in the injection fluids influenced the cumulative oil recovery. Since the relative permeability models of all cases were unchanged, differences in the performances primarily resulted from the viscosity effects on the mobility ratio. However, previously the viscosity effect on the reservoir response was not noticeable, with the system behaving as though it were isothermal. However, the case of unheated water flood following the steam flood indicated a declining performance when reducing the energy (heat) injected into the reservoir.

![Graph showing cumulative oil recovery from different injection scenarios.](image)

**Figure 5.12:** Cumulative oil recovery (bbl) obtained from different successive injection scenarios.

**Case 1:** WF-HWF and WF-SF.

The objective of these simulation runs was to evaluate the heat influence on recovery after the unheated water had broken through. The unheated water was first injected for four years, until the breakthrough time, followed by a slug of either hot water or steam until ultimate recovery was achieved. **Figure 5.13** shows the oil recovery which was obtained from these two cases. Relative to the base case, the continuous unheated-water flood, an extra 35% and 33% in the oil recovery were obtained by the hot water slug and steam slug, respectively. The ultimate oil recovery from the WF-HWF was slightly higher than the WF-SF as a result of the higher
density of the hot water than the steam, which helped the hot water slug to achieve better sweeping efficiency than the steam slug.

**Figure 5.13:** Oil recovery obtained from case 1, the WF-SF and WF-HWF cases.

**Case 2:** SF-WF.

This case represents a reverse sequence of the floods in case 1. Firstly the steam was injected and this was subsequently followed by a slug of unheated water until ultimate recovery was reached. **Figure 5.14** shows the recovery curve which has shown a significant oil recovery improvement during the unheated water flood when compared to the continuous unheated water flood process. However, the oil recovery in the case of the continuous steam flooding process significantly overcame the SF-WF scenario.
Figure 5.14: Oil recovery obtained from case 2, SF-WF, representing a significant oil recovery improvement during the unheated water flood, when compared with the continuous unheated water flood process.

Case 3: SF-HWF and HWF-SF.

Case 3 studied the effect of switching from hot water flood to steam flood and the opposite on the oil recovery. Figure 5.15 shows the oil recovery performance of case 3. As indicated, switching to steam flood after hot water injection had a minimum improvement on the oil recovery. The simulation results have also shown that a reduction in the heat injection rate after the steam breakthrough to be beneficial. Therefore, by decreasing the heat injection rate and switching to hot water flood, after steam injection this could improve both the steam utilisation and its economics.
Figure 5.15: Oil recovery performance of case 3, SF-HWF and HWF-SF, showing that the switching to steam flood after hot water injection had minimum improvement on the oil recovery.
5.8 Conclusion

• As expected, injecting steam and hot water provided a higher recovery when compared with injecting unheated water because the higher temperature reduced the viscosity of the oil and helped it to move easily to the producing well.
• Injecting hot water would have a favourable effect on oil production from the points of displacement efficiency and volumetric sweep.
• The added cumulative oil recovery at higher temperatures required economic justification to sustain the additional cost.
• Based on the cumulative oil recovery attained by the steam injection in the homogenous model, it was indicated that there was no significant impact on the cumulative oil recovery values if using a steam quality of 40% or 80%; and only the steam temperature had a significant influence on the efficiency of the steam performance.
• Among the various investigated cases, the case pertaining to steam injection followed by hot water flooding provided the best recovery performance. This was due to higher heat conduction when steam was introduced before the hot water displacement mechanism had been established.
• Results also indicated that switching to cold water injection after steam/hot water injection had a minimum improvement on the oil recovery.
6. Simulation study: Lower Fars formation, Ratqa Field, Kuwait

The commercial reservoir simulator, STARS, developed by the Computer Modelling Group (CMG) Ltd, Canada, was deployed for numeric modelling. The targeted unconventional resource is an unconsolidated sandstone reservoir filled with HO (12 to 18 API, oil viscosity>100 Cp) located in the Southern part of Ratqa field in Kuwait.

The main objectives of this simulation study are:

- To provide technical and reservoir simulation to assist the upcoming HO recovery development projects with an EOR screening study of a typical unconsolidated sandstone HO reservoir in order to determine the most suitable recovery method for similar resources.
- To determine the feasibility and benefits of utilising thermal and non-thermal methods in the development of a typical HO reservoir, Lower Fars, and simulate their impact on production and ultimate recovery.

6.1 Dynamic model discussions

All geological descriptions pertain to those provided in the general description of the Lower Fars formation in Chapter 3. The sector model which has been used for this research has been provided by the Kuwait Oil Company as per the confidentiality agreement signed between Imperial College and KOC for using the Ratqa field database. For the purpose of the research, the details of the technical simulation modelling of the Lower Fars Formation, Ratqa HO field has been provided as a representative example of HO in a sandstone reservoir. In addition, it is important to mention that the provided sectors had no injection or production wells.
6.1.1 Grid and properties

Five 3-D dynamic models were provided to us each of which described a specific area of the Ratqa field. From this data, it was decided to select two models which would best describe the ongoing development plan of KOC and would also fulfil the following considerations:

a. Being a priority for short and middle term development.
b. Providing sufficient fluid and rock data available for the selected area.
c. That the selected area would include the future planned pilot pattern in order for the outcomes of this work to be validated with the pilot results.

It was decided to extract a 12 * 12 km sub-model from the Northern part of the field which contained some 870,232 grid blocks (GB) of which 456,023 GB were active. For the purpose of this study, for simplicity and to take a shorter time when using the simulation, a 900 * 900 ft. sub-model was extracted to later use on EOR screening, as shown in Figure 6.1 (a).

For the Southern part of the reservoir, a sub-model which covered approximately 36,089 * 42,650 ft. of the reservoir was used to extract 900 x 900 ft. sub-models (a similar area to the Northern sub-model), and the sub-model was later used for the EOR screening, as shown in Figure 6.1 (b).

Conversely, the large differences in permeability and saturations vertically through the Lower Fars reservoir allowed the definition of a 62-layer reservoir model, of which the layers are numbered 1 to 62 from the top to the base (Northern sector). Three groups of layers, 15-18, 30-34 and 46-50, were modelled as permeability barriers (F1 shale, Mid. shale and F2 shale, respectively) which retarded the vertical flow of fluids through the reservoir. Another four groups of layers, 1-14, 19-29 and 51-62, have represented the main pay zones at the Lower Fars reservoir, F1A, F1B, F2A and F2B, respectively.
6.1.2 Permeability

The statistical distribution analysis of permeability showed that approximately 4.7% of the grid blocks had a permeability of more than 8000 md. Overall, the permeability distribution ranged from 0 md to 20,000 md.

The Logarithmic Galilean Conformal Algebra (GCA) permeability correlation was used in this model by CMG. The GCA correlation showed a smoother distribution with a maximum permeability of 4000 md. This is represented in Figures 6.2 and 6.3.

Logarithmic (prepared by GCA):

\[ K_{\text{sand}} = 10^{(1.51 \times \phi + 3.05)} \quad K_{\text{shale}} = 10^{(7.98 \times \phi + 0.19)} \]  

(Eq 6.1)

Figure 6.1: (a) Northern sector; (b) Southern sector, Lower Fars Ratqa Field, Kuwait.
**Figure 6.2:** Geological permeability I (md), Lower Fars Ratqa Field, Kuwait (Source: KOC).

**Figure 6.3:** Permeability distribution after the application of the GCA correlation, Lower Fars Ratqa Field, Kuwait (Source: KOC).
6.1.3 The shale study

There are two different assumptions with regards to heat loss to non-reservoir (shale) areas. The reservoir simulation software which has been used in this study, was able to consider both situations which may have existed in the same reservoir. These two assumptions are as outlined in the following manner:

First assumption: The shale is finely inter-bedded with the sand. In this type of system the shale is heated at the same time as the sand and there is no bypassing of the shale with regards to heat loss.

Second assumption: The shale exists as a separate horizontal layer. In this type of system the shale is heated very slowly by conduction. In many cases, the shale is almost completely bypassed with regards to heat loss.

Gamma ray logs of the Lower Fars formation showed definite shale zones labelled F1-shale, mid shale and F2 shale as shown in Appendix C, Figure C.1 to Figure C.4. However, this shale may not have existed in separate discrete layers or the shale may have been discontinuous between wells, thereby allowing vertical communication which resulted in huge uncertainty in this reservoir case.

The heat properties such as the shale heat capacity and shale thermal conductivity are used to account for heat-loss due to non-reservoir rocks (shale). In the studied reservoir the actual heat properties of the rock are not available for this sector model and therefore default values were used.

6.1.4 Overburden and underburden heat loss

Overburden and underburden heat losses entails heat flow between a semi-infinite part of a formation that is adjacent to a boundary grid block and the block itself. The rate of heat loss may be calculated as a function of temperature. Vinsome and Westerveld (1980) presented a simple
fitting function that reduces the solution of this problem to one of simple algebra. The simplicity and accuracy of this model has led to this being the preferred model for heat loss calculations in thermal reservoirs for many years. These calculations may be directly used in the energy conversation equation (Uddin and Coombe, 2011; Vinsome and Westerveld, 1980).

The STARS’s manual (STARS, 2009) explains that the heat loss rate and its derivative with respect to temperature are calculated by STARS using the following equations:

The total energy in the overburden is:

\[
\frac{k}{\lambda} \int_{\theta}^{\infty} T dz = \frac{k}{\lambda} \int \left[ d \left( \theta + P d + 2q d^2 \right) \right]
\]  

(Eq 6.2)

The heat loss rate from the block to the overburden is:

\[
-k \frac{\partial \tau}{\partial z} = k \left( \frac{\theta}{d} - P \right)
\]  

(Eq 6.3)

Where,

\( \theta \) = the temperature at the interface between the reservoir and cap or base rock;

\( k \) = thermal conductivity;

\( d \) = the diffusion length;

\( z \) = distance from the reservoir interface;

\( T \) = temperature; and

\( p \) and \( q \) = isolating parameters; defined by Vinsome and Westerveld (1980).

The outputs of these calculations are used directly in the energy conservation derivatives (STARS, 2009).

The numerical simulation performed these calculations for each grid block faces adjacent to the cap or base rock. The only information required for calculating the heat loss rate to
over/underburden were thermal conductivity and heat capacity of the base and cap rock. The data used in this model is mentioned in Table 6.1.

### 6.1.5 Rock/fluid thermal properties

Rock/fluid thermal conductivity properties were required to calculate the mixed conductivities of rock and phases. In the absence of this data, STARS default thermal rock and fluid properties were used.

**Table 6.1:** Rock/fluid thermal conductivity properties used in the real sector model.

<table>
<thead>
<tr>
<th>Thermal properties</th>
<th>The default values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rock heat capacity (<em>ROCKCP</em>)</td>
<td>35 Btu/ft³-F</td>
</tr>
<tr>
<td>Thermal conductivity of reservoir rock (<em>THCONR</em>)</td>
<td>44 Btu/ft.-day-F</td>
</tr>
<tr>
<td>Thermal conductivity of the water phase (<em>THCONW</em>)</td>
<td>8.6 Btu/ft.-day-F</td>
</tr>
<tr>
<td>Thermal conductivity of the oil phase (<em>THCONO</em>)</td>
<td>1.8 Btu/ft.-day-F</td>
</tr>
<tr>
<td>Thermal conductivity of the gas phase (<em>THCONG</em>)</td>
<td>0.3 Btu/ft.-day-F</td>
</tr>
<tr>
<td>Volumetric heat capacity overburden (<em>OVERBUR</em>)</td>
<td>35 Btu/ft³-F</td>
</tr>
<tr>
<td>Volumetric heat capacity underburden (<em>UNDERBUR</em>)</td>
<td>35 Btu/ft³-F</td>
</tr>
<tr>
<td>Thermal conductivity overburden (<em>OVERBUR</em>)</td>
<td>24 Btu/ft.-day-F</td>
</tr>
<tr>
<td>Thermal conductivity underburden (<em>UNDERBUR</em>)</td>
<td>24 Btu/ft.-day-F</td>
</tr>
</tbody>
</table>

However, the above values could be replaced once the measured data has become available. This could potentially have an impact on the results of the study and it is therefore recommended that appropriate laboratory data from real cores be acquired for future studies.

### 6.1.6 PVT analysis
The calculation of reserves in an oil reservoir or the determination of its performance and economics requires a good understanding of the fluid physical properties (Hemmati and Kharrat, 2007). However, during the course of this study, it was learned that much of the Lower Fars PVT data was inconsistent. This finding highlights the need for further investigation. See Appendix-C.

The viscosity model

Viscosity data from the Northern part of the field showed lower viscosity when compared to the Southern part (see Figure 6.4). Moreover, viscosity was seen to increase versus depth in both the Northern and Southern parts of the field.

Since the shale layers separating F1A/F1B and F2A/F2B were dis-continuous; this meant that liquid (oil and injected fluid) could flow vertically within the reservoir; and therefore the viscosity model should be capable of modelling the viscosity of the mixing oil. In order to model this phenomenon we would have to tune a single viscosity correlation and vary the composition by depth. To utilise this viscosity model, the EOS would also have to be modelled to represent the composition variation with depth. See Appendix-C.
6.2 Model Initialisation

6.2.1 Initial pressure

The initial reservoir pressure was 250 psi at 600 ft. for the Northern area.
For the Southern sub-models, the initial pressure of 184 psi at 358 ft. was assigned.

6.2.2 Water saturation

The initial water saturation for the study sub-models from North and South Ratqa Field, Lower Fars, are shown in Figures 6.5 and 6.6 respectively. Further details, from KOC are included in Appendix-C.
Figure 6.5: Initial water saturation, North Ratqa Field, Lower Fars, Kuwait from the study sub-model.
6.3 Forecast model and input parameters

6.3.1 Grid and properties

The heterogeneous model was based on a Cartesian system, comprised of 14 x 14 x 62 grid blocks (12,152 grid cells) along the x, y and z axes respectively. In dimensions, the pattern area was 28 acres. The initial pressure and temperature was 250 psi and 100°F respectively. The reservoir rock was assumed to be water-wet, and capillary pressure was ignored. In addition, the oil and water miscibility was neglected.

The model pore volume was 3.708 x 10^7 ft³ with an initialised OOIP of 1.808 x 10^7 ft³. The well configuration consisted of one injector and one producer, both of which were vertical, and located in the opposite corners of the model. In essence, this configuration approximated a quarter five-spot scheme for simplicity and to help understand the fluid behaviour as we started to inject the fluids.

6.3.2 Design of injection cases

Since the maximum pressure of the targeted reservoir is 500 psi and, to maintain the saturated steam conditions, the injected fluid temperature should always be lower than 450°F (based on the saturated steam tables). Conversely, the minimum injection temperature should not go below 400°F to avoid steam condensation. In addition it is equivalent to the best injected fluid conditions (temperature, steam quality and injection pressure) from the first stage of this study, the simple homogeneous case.

In this study, the effectiveness of the continuous (one type injected fluid) and successive (combination of different injection fluids) was investigated. The objective was to determine the
optimum design configuration in terms of injection fluids sequences. These results could be used as a tool for the successful design of thermal injection to recover HO in these types of reservoir. In addition, they provide the condition under which a given design may give better recovery performance.

Injection fluid constraints:

1. All injection wells have the same injection pressure and injection rate constraints. The first constraint was the “maximum injection pressure” at 430 psi. The second constraint was the “maximum injection rate- all phases” at 1000 bbl./day.
2. Production well have a minimum bottom hole pressure (BHP) constraint of 100 psi and no production rate constraint was used.
3. Other conditions associated with the injected fluids are:
   • Unheated water flooding @ temperature 100°F.
   • Hot water injection @ 450°F.
   • Steam injection @ 450°F and 40% steam quality.
   • CSS @ 450°F and 40% steam quality.
4. For the successive cases, it was decided to stop the first injected fluid and switch to the second injected fluid after four years from the first day of the flooding project. This was based on several trials to determine the best altering injected fluids time, details of which are included in Chapter 8.

Different design cases were performed as shown in Table 6.2.

**Table 6.2:** The different injection cases evaluated in this research (→ means followed by).

<table>
<thead>
<tr>
<th>Continuous cases</th>
<th></th>
<th></th>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Unheated water</td>
<td>Hot water</td>
<td>Steam</td>
<td>CSS</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Successive cases</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>CSS→steam</td>
<td>Hot water→steam</td>
<td>Steam→hot water</td>
<td>Unheated-water→steam</td>
<td></td>
</tr>
<tr>
<td>CSS→hot water</td>
<td>Hot water→unheated-water</td>
<td>Steam→unheated-water</td>
<td>Unheated-water→hot water</td>
<td></td>
</tr>
<tr>
<td>CSS→unheated-water</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
6.3.3 Results and discussion

- *Unheated-water flood*

Figure 6.7 shows that the cold process provided a low recovery, 5.2% OOIP after injecting the unheated water (at reservoir temperature) for ten years. In addition, interestingly the results showed that high injection-rate operation did not accelerate performance as expected. In fact, the results showed early water breaks through, almost at the same time, in all cases and this phenomenon was due to the adverse mobility ratio combined with severe water channeling, which led to a decrease in oil recovery. For example whilst at the injection rate of 1300 bbl./day the unheated-water flood recovered some 5.2% of OOIP after ten years of continuous water injection, and the corresponding performances for the injection-rate of 1000 bbl./day processes was 5%.
**Figure 6.7:** The water injection rate (bbl./day), water cut (%). The oil production rate (bbl./day) and oil recovery factor (%) at different injection rates.
• Hot water flood

**Figure 6.8** illustrates the variation of the cumulative oil recovery at different injection temperatures (hot water and unheated water). In comparison with the unheated water injection process, a positive correlation was evident between the recovery and injection temperature.

With regards to **Figure 6.8**, within the first year, it can be inferred that reservoir response was practically independent of injection temperature. This observation can be explained by the delay time required to heat up the reservoir to such a temperature that would give reasonable reduction of oil viscosity, hence enabling a favourable mobility ratio. However, ultimately, cumulative recovery showed a reasonable response to the higher injection temperatures. For example while the 450°F hot water flood recovered some 3.1% of OOIP after ten years, corresponding performances for the unheated water processes were (approximately) 2.9%. From an economic viewpoint, production acceleration would improve overall project economics by mitigating the negative impact of discounting on the revenue stream.

A comparable conclusion, that a hot water flood increasingly gives better production performance, in the case of high oil viscosity, than a unheated water process with increasing oil viscosity, was reached by Alajmi *et al.*, (2009).
Among the various investigated cases, the case of steam injection provided the lowest recovery performance. This was due to the steam override phenomenon which led to heat loss of the upper non-reservoir layers. Although the heat carrying capacity of water is less than steam, hot water offers displacement effect advantages over steam (Diaz-Munoz, 1975).

**Figure 6.9** shows the cumulative oil recovery at steam injection together with continuous unheated water flooding and hot water flooding. It would appear obvious that steam had no significant impact on the ultimate oil recovery, after ten years of the steam injection process at 450°F and at steam qualities of 40% oil recovery was approximately 2.3%.


**Figure 6.9**: Oil recovery obtained from steam flooding, hot water flooding and unheated water flooding cases.

- **Cyclic Steam Stimulation – CSS**

Compared to the various investigated cases, the case of CSS provided the best recovery performance. This was due to two reasons. The first was due to the higher heat conduction when the steam flowed down to the reservoir. The second reason was related to the fact that the two wells were used as injectors and producers at the same time which meant two production wells instead of one well in the other cases. **Figure 6.10** shows the cumulative oil recovery after seven cycles within ten years of project life. The ultimate oil recovery after ten years of CSS, steam injection, hot water and unheated water processes were approximately 3.3%, 2.3%, 3.1% and 2.9% respectively.
Successive combination of injection fluids

A set of successive cases were implemented to study the effect of altering the injected fluids on the ultimate oil recovery. Figure 6.11 depicts how altering the injection fluids affected the cumulative oil recovery. Similar to the homogenous model case, as the relative permeability models of all cases were unchanged, differences in performances primarily resulted from the viscosity effects on the mobility ratio. However, at early times the viscosity effect on the reservoir response was not noticeable, with the system behaving as if it were isothermal. However, the case of unheated water flood following the steam flood indicated declining performance with reduction of energy (heat) injected to the reservoir. In addition, another explanation can justify this phenomena as after the unheated water break through, the following injected fluid would pass through.
through the same path through which unheated water had passed (limited sweeping efficiency); and the higher water saturation after the water flooding process took place would reduce the heating efficiency.

**Figure 6.11:** Cumulative oil (bbl.) at different successive injection cases. UR does not allow conclusive discrimination

*Case 1: WF-HWF and WF-SF.*

The objective of these simulation runs was to evaluate the heat influence on recovery after the unheated water had broken through. The unheated water was first injected for four years, until the break through time, followed by a slug of either hot water or steam until ultimate recovery was achieved. **Figure 6.12** shows the oil recovery obtained from these two cases. When compared to
the base case, the continuous unheated-water flood, there was no significant increase in the oil recovery obtained by the hot water slug and steam slug, respectively. We can simply justify why the ultimate oil recovery from the WF-HWF was slightly higher than WF-SF as a result of the higher density of the hot water compared to the steam, which helped the hot water slug to achieve better sweeping efficiency than the steam slug.

**Figure 6.12:** Oil recovery obtained from case 1, WF-SF and WF-HWF cases.

*Case 2: SF-WF and HWF-WF.*

This case represents a reverse sequence of floods to that of **Case 1.** The steam, hot water in the other case, was first injected and this was subsequently followed by a slug of unheated water until ultimate recovery was reached. **Figure 6.13** shows the recovery curve which shows a significant oil recovery improvement during the unheated water flood, when compared to continuous steam flood process. This is due to steam override in such a small thickness reservoir this leads to heat
loss to upper non-reservoir layers. Higher heat conduction when steam follows down to the reservoir. The oil recovery in the case of the continuous hot water flooding process was slightly better than SF-WF, HW-WF cases.

Figure 6.13: Oil recovery obtained from case 2, SF-WF and HWF-WF cases.
**Case 3: SF-HWF and HWF-SF.**

Case 3 studied the effect of switching from hot water flood to steam flood and the opposite on the oil recovery. **Figure 6.14** shows the oil recovery performance of case 3. As indicated, switching to steam flood after hot water injection had a minimum improvement on the oil recovery. The simulation results also show that a reduction in the heat injection rate after steam break through to have been beneficial. Therefore, decreasing the heat injection rate and switching to hot water flood, after steam injection could improve the steam utilisation and its economics.

**Figure 6.14:** Oil recovery performance of case 3, SF-HWF and HWF-SF. This shows that switching to steam flood after hot water injection had minimum improvement on the oil recovery.
Case 4: CSS-SF, CSS-HWF and CSS-WF.

Case 4 studied the effect of switching from CSS flood to steam flood, hot water flood and unheated water flood on the oil recovery. Figure 6.15 shows the oil recovery performance of case 4. As indicated, switching to continuous steam flood, hot water and unheated water after CSS injection had no improvement on the oil recovery. In fact the oil recovery declined significantly after the switching process. Again it is worth considering that in the case of CSS the two wells acted as both an injector and producer at the same time. Conversely, it is essential to investigate the CSS best cycles number, because in the usual practice the CSS stopped after the production declined sharply. However, in this case the production rate continued to increase even after the seventh cycle.

Figure 6.15: Oil recovery performance of case 4, CSS-WF, CSS-HWF, CSS-SF and the base case of the continuous CSS process, indicating that switching to different injection fluid following the CSS process had minimum improvement on the oil recovery.
6.4 The effect of overburden and underburden heat losses

These heat losses behave like bottom water zones when it comes to thermal recovery methods in thin reservoirs. To study the effects of overburden and underburden heat losses, the following three thermal properties can be investigated: thermal diffusivity, thermal conductivity, and volumetric heat capacity (Strom, 1984). As increasing overburden and underburden heat losses cause the cumulative steam oil ratio to increase, where a minimum heat loss versus time ratio is necessitated by efficiency, this study could help to save time and resources against inefficiency (Nguyen et al., 2012).

In this work, the effects of neglecting the overburden and underburden heat losses may be studied with the application of numerical models. To do this the following range of values were used:

- Volumetric heat capacity of formation adjacent to the reservoir in the indicated direction (35 Btu/ft$^3$-F). Thus the lower limit is 0; and a value of zero will result in no heat loss.
- Thermal conductivity of formation adjacent to the reservoir in the indicated direction (24 Btu/ft.-day-F). The lower limit is 0; and a zero value results in no heat loss.
- Initial temperature of formation adjacent to the reservoir, used by the heat loss calculation (90 F). The value kept the same.

Figure 6.16 shows that not considering the heat lost to the overburden and underburden in the energy balance calculations had almost no impact on the cumulative oil recovery from the hot water flooding process. However, taking into account the heat loss to the overburden and underburden in the oil reservoir would significantly affect the steam injection process performance. Thus, the heat loss rate to the overburden and underburden was found to be a critical factor effecting the numerical evaluation of the thermal processes, mainly steam floods.
Figure 6.16: Cumulative oil at different cases, with and without heat loss to overburden.
6.5 Conclusion

• CSS and hot water flooding will provide a higher recovery than injecting unheated water because the temperature will reduce the viscosity of the oil and help it to move easily to the producing well.

• Steam injection provided a low oil recovery when compared to the hot water flooding and the unheated water flooding. This was due to steam override which led to great heat loss of the upper shale layer (non-reservoir zone).

• Improvements could be made to model the effect of shale on heat transfer if an improved net to gross map could be assigned into the model. Improving the net to gross ratio distribution within the sub-models will help to model fluid flow and heat transfer more accurately.

• Injecting hot water has a favourable effect on oil production from the points of displacement efficiency and volumetric sweep.

• Among the various investigated cases, the cases with continuous CSS and steam injection followed by hot water injection provided the best recovery performance.

• Results also indicated that switching to cold water injection after steam/hot water injection had a minimum improvement on the oil recovery.

• Comparing the performance figures obtained with a homogeneous model with those obtained with a heterogeneous one indicated the following:
  ▪ Continuing the hot water injecting in homogenous and heterogeneous models provided the best recovery performance in comparison to the unheated water flooding and steam injection. However, in the homogenous case the steam injection provided higher oil recovery when compared to the unheated water flooding; whereas the opposite was true in the heterogeneous case. This was due to the adverse effect of the reservoir heterogeneity on the steam injection performance.
  ▪ If we exclude the CSS cases which we did not apply in the homogenous case, then among the various investigated cases, the cases with: (1) steam injection followed by hot water injection and (2) unheated-water flooding followed by hot water injection gave the best recovery performance in both the heterogeneous model and homogenous models.

• The simulation results also showed that a reduction in the heat injection rate after
steam break through to be beneficial. Therefore, by decreasing the heat injection rate
and switching to hot water flood, after steam injection this could improve both the
steam utilisation and the economics.

• As indicated, switching to continuous steam flood, hot water and unheated water after
CSS injection had no improvement on the oil recovery. In fact the oil recovery
decreased significantly after the switching process. Again it is worth considering that in
the case of CSS the two wells acted as both an injector and producer at the same time.

• It is essential to investigate the CSS best cycles number, because in the usual practice
the CSS stopped after the production declined sharply. However, in this case the
production rate continued to increase even after the seventh cycle.
7. Techno-economics of the HO development project

In the previous sections, we have shown that the steam flooding, CSS, hot water flooding and unheated-water processes are technically feasible, with both continuous and successive cases, for the in-situ production of HO, in particular for the investigated unconsolidated HO reservoir. However, when compared to the technical prospects, the economic viability and the commercial feasibility often have greater influence on the decision-making process (Yang et al., 2009 and Frauenfeld et al., 2006). Thus, in this chapter we have been assessing both the economics as well as the commercial and technical risks of the processes under exposition.

7.1 Economic evaluation

As indicated from the ultimate recovery graphs for different injection cases in both, the homogenous and the heterogeneous models, from Figures 5.11, 5.13, 6.12 and 6.13, the ultimate recovery does not really discriminate between the different production strategies. Therefore, an economic analysis was performed to assess the economic feasibility of each recovery process/scenario for both the simple homogenous model and the real sector model. To perform this, an accurate indication of the reservoir characteristics, drilling and production costs, energy efficiency, infrastructure availability and other key economic and technical parameters was necessary. However, in this work not all of the above information could be firmly assessed or generalised. Thus, only a preliminary matrix of the main factors to be accounted for was integrated into the developed economic model. The reason for this simplicity was to generalise our study to be applicable and if additional details needed to be used by a specific company, CAPEX and OPEX rates applied for that region could be modified or added directly and subsequently easily calculated.

The annual net cash flow is the balance of annual revenue and expenditure streams. The annual net cash flow is estimated from the following relation (Petit et al., 1989):

\[ N_{CF} = R_v - C_{ca} - C_r - C_t \]  \hspace{1cm} (Eq 7.1)

Where, \( R_v \): The gross revenue (oil revenue) = oil price \times \text{oil produced in that year.}
The oil price is relative to the OPEC average. The average price for OPEC was $95/bbl. as at September/October 2011 (US. EIA., 2011). As heavy crude fetches a lower price than lighter crudes, a $15 differential between light oil and HO was applied (Reuters, 2010; Bunkerworld, 2011). This results in the base-case HO price of $80/bbl. as at October 2011 (US. EIA., 2011). One reason for using an average HO price rather than a fluctuating price is to simplify the NPV calculations, the other is that since the price appears linearly in the revenue expression it is possible to use a simple average.

\( C_{\text{op}}: \) The OPEX.

The two components of the OPEX which were considered in this model and their assumed values are:

- Heat injection: $16.8/GJ, 70% boiler thermal efficiency (CIBO, 2003) and it was decided to use the HO as fuel due to the high shortage in natural gas resources in the state of Kuwait (resources limitation in the operation area was deemed a project risk).

\( C_{\text{ca}}: \) The CAPEX

The items related to the wells, flow lines, injection/production/treatment facilities. For simplicity, we assumed that all the CAPEX would be incurred in the year prior to the project start-up and it was assumed that the cost of drilling and completion, flow-lines, processing facilities and CAPEX contingency and decommissioning cost were equal for all evaluated processes. Therefore, in our calculation we only considered the incremental cost of the hot water and steam boiler units as $ 2.2 million/Mstb water (Birrell et al., 2005).

\( C_r \) and \( C_t \) are the royalty and tax payments, respectively. These two terms were eliminated from this calculation since the Kuwait Oil Company is 100% owned by the Kuwaiti government.

The NPV is estimated from the annual net cash flow according to the following expressions:

\[
N_{pv} = \sum_{i=1}^{nt} \frac{N_{CF}}{(1+R_d)^i} \quad \text{(Eq 7.2)}
\]
Where $R_d$ and $n_t$ are the discount rate and number of years, respectively. The discount rate as used here is 8% and all the analysis presented based on twenty and ten years for the simple model and the real sector model, respectively.

7.2 Example of the DCF calculation

I. Heat cost calculator
   a. Assumptions:
      - Heating fluid to: $T_2 230^\circ C$
      - Initial water Temp.: $T_1 38^\circ C$
      - $\Delta T = 192^\circ C$
      - Boiler efficiency: 70%
      - Fuel cost (HO): $17.72 \$/MMBtu, $16.80 \$/GJ
        (Source: Bloomberg; Energy and Oil prices - Market data).
      - Hot water is single-phase (no latent heat).
      - To simplify the calculations saturated steam of 100% quality is assumed.
      - Basis: 1 Kg of heating fluid (heating water).
      - Specific heat capacity of water ($cp$) is 4.19 KJ/Kg.$^0C$
   
   b. Hot water:
      The sensible heat of a thermodynamic process calculated as the product of the body's mass ($m$) with its specific heat capacity ($C_p$) and the change in temperature ($\Delta T$):
      \[ Q_{out} = m \times C_p \times \Delta T = 814.8 \text{ KJ} \]  
      \[ \text{(Eq 7.3)} \]
       
      $Q$ is the amount of energy released or absorbed during the change of phase of the substance.
      However it is necessary to discount the initial sensible heat of feed water at $38^\circ C$.
      \[ Q_{feed} = 1\text{kg} \times 4.2 \text{ KJ/Kg} \times (38 \text{ } - \text{ } 0) = 159.6 \text{ KJ} \]  
      \[ \text{(Eq 7.4)} \]
      \[ \therefore \text{Actual } Q_{out} = Q_{out} - Q_{feed} = 655.2 \text{ KJ} \]  
      \[ \text{(Eq 7.5)} \]
Since the boiler efficiency is 70%:

\[ \therefore Q_{\text{in hot - water}} = \frac{Q_{\text{out}}}{\text{boiler efficiency}} = 936 \text{ KJ} \quad \text{(Eq 7.6)} \]

c. **Steam:**

At 230\(^{0}\)C saturated steam of 100% quality.

\[ Q_{\text{out}} = Q_{\text{sensible}} + Q_{\text{latent}} \quad \text{(Eq 7.7)} \]

\[ Q_{\text{out}} \text{ (from steam table) } @ 230^{0}\text{C} = 2804 \text{ KJ/Kg} \]

However we have to discount the initial sensible heat of feed water at 38\(^{0}\)C

\[ Q_{\text{feed}} = 1\text{kg} \times 4.2 \text{ KJ/Kg} \times (38 - 0) = 159.6 \text{ KJ} \]

\[ \therefore \text{Actual } Q_{\text{out}} = Q_{\text{out}} - Q_{\text{feed}} = 2644.4 \text{ KJ} \]

Since the boiler efficiency is 70%:

\[ \therefore Q_{\text{in hot - water}} = \frac{Q_{\text{out}}}{\text{boiler efficiency}} = 3777.714286 \text{ KJ} \]

Net calorific value for heavy fuel oil = 41300 M J/Kg

*This value is the quantity of heat obtained per kilogram for HO fuel.*

- **Net heating value for heavy fuel oil** = 41300 / Specific heat capacity of water (Cp)  
  = 9866.2 M Cal/Kg

- **Hot water cost** (from 38 \(^{0}\)C to 230 \(^{0}\)C) = \( Q_{\text{in hot water}} \times \text{Fuel price} = 0.01572 \$/Kg \)  
  hot water = 15.72125 \$/ton hot water.

- **Steam cost** (from 38 \(^{0}\)C to 230 \(^{0}\)C) = \( Q_{\text{in steam}} \times \text{Fuel price} = 0.063451277 \$/Kg \)  
  Steam = 63.45127691 \$/ton steam.

For optimisation purposes, the heat cost calculations were conducted for different injected fluid temperatures (hot water and steam). See **Table 7.1**.
Table 7.1: Data obtained from the economic model calculator.

<table>
<thead>
<tr>
<th>Energy Content of Heating Fluids</th>
<th>Cost of injected fluids</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>206°C</strong></td>
<td></td>
</tr>
<tr>
<td>Hot water</td>
<td>7.80E+02</td>
</tr>
<tr>
<td>Steam</td>
<td>3.77E+03</td>
</tr>
<tr>
<td><strong>215°C</strong></td>
<td></td>
</tr>
<tr>
<td>Hot water</td>
<td>8.43E+02</td>
</tr>
<tr>
<td>Steam</td>
<td>3.77E+03</td>
</tr>
<tr>
<td><strong>230°C</strong></td>
<td></td>
</tr>
<tr>
<td>Hot water</td>
<td>9.36E+02</td>
</tr>
<tr>
<td>Steam</td>
<td>3.78E+03</td>
</tr>
<tr>
<td><strong>241°C</strong></td>
<td></td>
</tr>
<tr>
<td>Hot water</td>
<td>9.90E+02</td>
</tr>
<tr>
<td>Steam</td>
<td>3.78E+03</td>
</tr>
</tbody>
</table>

*Conversion formula (from KJ/Kg to Btu/ton) = 1 KJ/Kg * 1 Btu/1.005 KJ * 1000 Kg/1 ton.

II. Outflow

a. Cost of heated fluid $/year:
   - Accumulative injected enthalpy (Btu)/year - From simulation output.
   - Energy content of heating fluid (Btu/ton) - Table 7.1.
   - Cost of heating fluid ($/ton) - Table 7.1.

\[
\text{Mass of heating fluid injected (ton)/year} = \frac{\text{Energy content of heating fluid (Btu/ton)}}{\text{Accumulative Injected Enthalpy (Btu) /year}} \quad (\text{Eq. 7.8})
\]

\[
\text{Cost of heated fluid $/year} = \text{Mass of heating fluid injected (ton/year)} \times \text{Cost of heating fluid ($/ton)} \quad (\text{Eq. 7.9})
\]

b. Cost of produced water treatment $/year:

Some studies have estimated the cost of treating one metric ton of produced water using conventional means at US $0.91. Modern concepts and technologies have demonstrated that this cost could be brought down to about $0.27/metric ton (Shell, 2011).

- It is assumed that the average water treatment cost = (0.27 + 0.91) /2 = $0.59/ metric ton
  
  = $0.59 /1000 Kg.
• Cumulative produced water SC (Kg)/year - From simulation output.

Cost of produced water treatment $ = \frac{\text{Produced water SC (kg)/year}}{1000 \times 0.59}$ \hspace{1cm} (Eq 7.10)

**III. Cumulative oil cash inflow:**

• Yearly cumulative oil SC (bbl.) - From simulation output.
• Assumption: water flooding is my base case. Thus, the cost of unheated water flooding is zero.
• Neglect heat loss.
• US $ Interest rate (global forecast 2010) = 8%.
• Oil price = $100.
• HO discount = $20.
• HO estimated price ($) = 80.

Finally, it is very important to understand in advance if the project is going to be profitable or not. For this reason, the discounted cash flow (DCF) was calculated in order to evaluate each development scenario before we decided the best development options.

Net cash flow (NCF) = Cash out flow + Cash in flow \hspace{1cm} (Eq 7.11)

Discounted cash flow (DCF) = \frac{C_{F_1}}{(1+r)^1} + \frac{C_{F_2}}{(1+r)^2} + \cdots + \frac{C_{F_n}}{(1+r)^n} \hspace{1cm} (Eq 7.12)

• CF = Cash flow
• r = Discount rate
• n = the time in years before the future cash flow occurs

The conversion and calculation tables for the cost and benefits (heat cost calculator, cost of heated fluid, cost of produced water calculator, cumulative oil - cash flow, discounted cash flow calculator) are presented in Appendix-D.
7.3 Economic evaluation - for the simple homogenous model

Although the NPV should only include cash flow contributions while the field is economic, in some cases the negative DCF was presented because we want maintain the same economic evaluation period for all investigated scenarios. Figures 7.1, 7.2 and 7.3 illustrate the DCF curves for the injection of unheated-water, hot water and steam, respectively. These figures clarify the variation of DCF at different injection conditions such as the fluid temperature, pressure and the steam quality (the injection rate maintained the same for all cases).

Figure 7.1 shows the DCF curves of the injection scenario where the unheated water was injected from the beginning until the end of the project life at different injection pressures. As shown, there was an accelerated decline in profitability from all cases, which obviously would indicate that the unheated-water injection, in the short-term, is economically feasible. However, the long-term favour was, of course, at the highest injection pressure.

Figure 7.1: DCF curves for the injection of unheated-water at different injection pressures.
Figure 7.2 represents the DCF curves of the injection cases where the hot water was injected from the beginning until the end of the project life at different temperatures. As shown, there was accelerated profit from hot water injection at 241°C, which obviously outperformed the other cases during the early life of the project. However, the long-term favoured the hot water flooding at the lowest temperature, 206°C but with no significant profits. It was concluded from this analysis that using hot water as the first stage would have a preferable impact on oil recovery.

![DCF for the Hot-Water flooding](image)

**Figure 7.2**: DCF curves for the injection of Hot-Water at different injection temperatures.

For the steam injection there were twelve different injection conditions, steam temperature and the steam quality, as has been explained in the previous section. Figure 7.3 illustrates the DCF curves for all the injection cases associated with the steam flooding. These curves clarify the variation of DCF at the different injection conditions. Please bear in mind that the injection rate was kept the same for all cases.

Since the difference between the DCF of different steam injection cases were too small in order to make a decision about the best scenario between them, we decided to extend the project life to twenty years to see the performance of both cases in the longer term which indicated an accelerated profit from steam injection at 241°C and 230°C at all steam quality...
levels, which obviously outperformed the other cases in the mid-term. However, in the long-term the steam injection at the high temperatures included a high risk of loss.

Conversely, in the long-term the steam injection at lower temperatures $206^\circ C$ and $215^\circ C$ showed a very low profitability but with a minimum risk of loss.

**Figure 7.3:** DCF at different injection temperatures and steam quality, continuous steam flooding.

**Figure 7.4** represents a comparison between the DCF curves of the injection cases where the unheated water, hot water and steam were injected from the beginning until the end of the project life. As shown, there was an accelerated profit from the hot water injection, which obviously outperformed the other cases. However, the long-term favoured the unheated water flooding due to the low operating cost for injecting the unheated water compared to the steam and hot water.

In order to obtain a clear insight into the total welfare gain over the whole life of each recovery process, the NPV analysis was conducted and its results are shown in **Figure 7.5**. It is worth considering that these NPV values were calculated based on ten years of project life in order to obtain a realistic comparison with the heterogeneous reservoir case; as no company is going to operate a field once it stops making a profit. According to the twenty
years DCF curves, reducing the project life for these injection cases would dramatically change the NPV ranking.

**Figure 7.4:** DCF ($) versus year for all three recovery methods. Accelerated profits from steam injection @ 241°C and hot water @ 241°C, long-term favours unheated-water flooding.

**Figure 7.5:** NPV ($) for all injection cases (one type injected fluid) of the homogenous model case.
Based on Figure 5.11, it was obvious that the ultimate recovery did not allow a conclusive discrimination between the different combined injection cases. However, by calculating the DCF for each scenario, Figure 7.6, it is very clear that the accelerated profit was performed by SF- HWF and HWF-SF cases. However, from the NPV analysis, Figure 7.7, in the long-term the HWF-SF scenario was favoured.

**Figure 7.6:** DCF ($) versus year for the successive cases accelerated profits from HWF-SF. Long-term favours SF-WF.
**Figure 7.7:** NPV ($\) for all successive injection cases at the homogenous model case.

**Figure 7.8** illustrates the overall conclusion. From the NPV diagram for all injection cases, it was concluded that hot water flooding followed by steam flooding injection achieved the highest profit. However, NPV analysis indicated that all other successive/continuous cases contained a low risk of loss under the ten years’ project life. Again this regarded the case of the homogenous system.
Figure 7.8: NPV ($) analysis for all injection cases: SF-WF achieved the highest profit.

7.4 Economic evaluation - for the real sector  (heterogeneous model)

Similar to the homogenous model case, Figures 6.12 and 6.13 shows that the ultimate recovery did not allow a conclusive discrimination between the different injection cases. However, by calculating the DCF for each scenario, Figures 7.9 and 7.10, it has become very clear that the accelerated profits were performed by HWF-SF, CSS-SF and CSS-WF cases and the long-term favour was for the HWF-SF and CSS-SF cases.

Figure 7.9 represents the DCF curves of the injection cases where the CSS, unheated water, hot water and steam were applied from the beginning until the end of the project life. As shown, accelerated profit from the unheated water flooding, obviously outperformed the other cases.

Figure 7.11 illustrates the overall conclusion. From the DCF diagram for the best injection cases, it was concluded that the CSS-SF achieved higher profit within a shorter time when compared to the other cases.
Figure 7.9: DCF ($) versus year and accelerated profits from different continuous injection cases.

Figure 7.10: DCF ($) versus year for all injection cases; and CSS-SF achieved higher profit within a longer time when compared to the other cases.
7.5 Conclusion

- In the simple homogenous model, injecting one type of fluid from the beginning until the end of project life provided better profitability than other successive injection cases, with the exception of the SF-WF.
- In contrast to the homogenous model case, the economic evaluation of the heterogeneous model (real sector) performance confirmed the favourite of the successive cases.
- The evident variation in the NPV ranking of the different injection strategies between the homogenous model and the real sector model assured the significant influence of the reservoir heterogeneity/uncertainty.
- The economic evaluation of the hot water and steam injection at different temperatures and steam qualities indicated the essentiality of optimising the injected fluid temperature and quality for each individual reservoir parameter.
- From the DCF and NPV analyses for both continuous hot water injection and steam
flooding in the real sector model, it is obvious that these injection strategies contained a high risk of losses.

- In the real sector model, CSS followed by steam flooding and hot water flooding followed by unheated-water flooding provided a higher profit than all other cases.
- Among the various investigated cases, the cases with CSS as a first stage provided the best economic performance.
- Results also indicated that switching to unheated-water injection after steam/hot water injection had a minimum improvement on the oil recovery but a positive impact on the economic successes.
- Thermal injection is costly, and careful design and heat management are the keys to economic success.
8. A comparative study, sensitivity analysis and risk evaluation

Uncertainty and risk are two issues which should be considered when analysing oil field development projects. Risk analysis attempts to predict the threats, opportunities and the impact of uncertain input parameters on the project outcomes (Joshi, 2004). There are many uncertainties which can affect the success of any oil field development project as well as affecting the rank of the optimum development strategies. These uncertainties include the reservoir model, the operational design parameters, the oil price, the operating expenditure (OPEX), and the capital expenditure (CAPEX).

In this chapter, a comparative study and a sensitivity analysis of various operational conditions and reservoir parameters have been investigated in order to: (1) find the optimum conditions for achieving a high oil recovery; and (2) understand the effect of reservoir heterogeneity on the reservoir performance. The investigated operational parameters were the steam injection rate, the injection swapping time, the perforation location, and the injection water temperature. The investigated reservoir parameters were initial water saturation, porosity and permeability. In addition to investigating these reservoir parameters, the oil price sensitivity was investigated to evaluate the economic feasibility of the selected recovery methods within a historical and predicted oil price range.

Again, the current assessment has focused on sandstone, HO reservoir, using Lower Fars (Lower Fars) as the case study. However, the analysis and some of the deductions from this example should, in principle, be of relevance to other fields.

8.1 Uncertainty in the reservoir model

Due to the high variation in the targeted reservoir properties, it was necessary to undertake a comparison study to investigate the performance variation when using the same production methods at different parts of Lower Fars, North and South.

The data from Lower Fars, as shown in Figures 4.1 to 4.4, showed that the net-pay thickness, oil viscosity, reservoir pressure varied from the relatively deeper sections in the North to the shallower levels in the South. As a result of the high heterogeneity in the field, it can be
concluded that the best development options established for the North may not necessarily be valid for the Southern part of Lower Fars. Therefore, we have assessed the suitability of the best seven recovery cases established for the North in the Southern sector.

8.1.1 The reservoir heterogeneity effect

From the available data, the reservoir properties such as permeability (K), porosity (φ), initial water saturation (S_{wi}) and oil viscosity (μ) showed significant variation from the deeper part (North) to the shallower part (South) of the Lower Fars reservoir. Thus, in this work, we have examined the functional relationships between several reservoir parameters and the displacement performance of HO during the steam flood (SF), hot water flood (HWF) and unheated water flood (WF) processes.

To distinguish between the process and petrophysical/geologic effects, this study has used the same homogenous model as constructed in Chapter 5. Several simulation runs were conducted which investigated the effects of the petrophysical properties on the performances of the thermal and non-thermal flood processes. The main considered reservoir properties are presented in Table 8.1.

<table>
<thead>
<tr>
<th>Reservoir parameter</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Case A: Changing the porosity</strong></td>
<td>Φ= 15%</td>
</tr>
<tr>
<td></td>
<td>Φ= 25%</td>
</tr>
<tr>
<td></td>
<td>Φ= 35%</td>
</tr>
<tr>
<td><strong>Case B: Changing the vertical and horizontal permeability</strong></td>
<td>I. K_h = 1000 md , K_v = 100 → K_v/K_h = 0.1</td>
</tr>
<tr>
<td></td>
<td>II. Anisotropic (vary kv/kh): 0.1, 0.2 and 0.5</td>
</tr>
<tr>
<td><strong>Case C: Changing the initial water saturation, S_{wi}</strong></td>
<td>1. S_{wi} = 30%</td>
</tr>
<tr>
<td></td>
<td>2. S_{wi} = 40%</td>
</tr>
</tbody>
</table>
8.1.2 Results and discussion

Within the range of the studied parameters, the simulation results indicated that the following conditions were unfavourable for the enhanced oil recovery processes:

- Low porosity.
- High initial water saturation.
- Low reservoir permeability.

In this sensitivity study, the results have been presented in terms of the oil recovery factor against the hydrocarbon pore volumes (PVI). Thus the PVI represents dimensionless time and is computed via \( Q_w/V_p \) whereby \( V_p \) is the hydrocarbon pore volume of the system and \( Q_w \) is the total water injection rate.

In order to explain some of the simulation results, we have referred to the simulation graphs which have clearly shown the three-slugs-flow phenomenon, as depicted in Figure 8.1. From this, it was expected that a thermal-injection process (hot water and steam injection) would give two breakthroughs of the injected fluid. The first produced slug was the unheated oil (the cold oil).

The first breakthrough was defined to be when the leading edge of the heated oil front reached the producer. Before and at breakthrough, the amount of displacing fluid injected was equal to the produced displaced fluid, disregarding compressibility. Assuming piston-like displacement, the injected volume was related to the area swept at this stage.

Finally, providing that the injection and production were continuous, the second breakthrough, which was the “actual” breakthrough, occurred when the leading edge of the heating fluid (hot water or steam front) reached the producer (the first appearance of water in the produced fluids). After breakthrough, both oil and water and the condensed steam were produced and the water cut gradually increased.
**Figure 8.1:** A simplified sketch for the three slugs during the thermal injection process in a HO reservoir.

**Case A:** The effect of porosity.

The total porosity is defined as the fraction of the bulk rock volume $V$ that is not occupied by solid matter. The total porosity can be simply calculated using following equation:

$$\phi = \frac{V - V_s}{V} = \frac{V_p}{V} = \frac{\text{Pore Volume}}{\text{Total Bulk Volume}}$$

Where, $V_s$ is the volume of solids, $V_p$ is the pore volume

If $V_p$ = effective pore volume, the porosity is the effective porosity. Obviously, the effective porosity will correlate better with permeability than the total porosity. However, the difference between the total and effective porosities is generally very small for sedimentary rocks and therefore has been neglected (Ma and Morrow, 1996). In addition it must be noted that the porosity does not offer any information concerning pore sizes, their distribution, and their degree of connectivity. Consequently rock of the same porosity can have a high variety in the physical properties.

Before proceeding with this sensitivity analysis, it is useful to recall the meaning of sweep efficiency and the porosity contribution.

For piston-like displacement, the areal sweep efficiency is:
\[ E_A = \frac{A_s}{A_T} \]  

(Eq 8.1)

Where \( A_s \) is the swept area and \( A_T \) is the total area.

Assuming piston-like displacement, injected volume is related to the area swept
\[ V_I = A_s \ h \ \phi \ \Delta S \]  

(Eq 8.2)

Where \( V_I \) is the volume of displacing fluid injected, \( h \) is the thickness of the formation, and is \( \phi \) porosity. Hence,
\[ E_A = \frac{A_s}{A_T} \left( \frac{V_I}{(A_T \ h \ \phi \ \Delta S)} \right) = \frac{t_D}{\Delta S} \]  

(Eq 8.3)

Where \( t_D = \frac{V_I}{A_T \ h \ \phi} \) the number of pore volumes of fluid injected, also commonly called dimensionless time.

For \( \Delta S = 1 \) and \( E_A = t_D \) before and at breakthrough.

After breakthrough,
\[ E_A = \frac{V_I - V_P}{A_T \ h \ \phi \ \Delta S} \]  

(Eq 8.4)

Where \( V_P \) is volume of the displacing fluid produced.

Equations 8.2 to 8.4 explain how the porosity effecting, during piston-like displacement, on the aerial sweep efficiency. However, apart from the areal sweep, there is also the contribution of vertical sweep. In addition, porosity also affects the formation thermal capacity and hence, the rate of heat propagation.

**Relationship between thermal properties and porosity**

Thermal properties (thermal conductivity, heat capacity, specific heat, and thermal diffusivity) of earth materials are significant parameters for modelling the thermal structure
and transport of heat and fluid in the reservoir (Ochsner et al., 2001 and Goto and Matsubayashi, 2009). As shown by several theoretical and experimental studies, the thermal properties of rock depend on various factors including porosity, fracturing, mineral composition, rock structure, and the type of fluid in the pores and cracks. These studies have confirmed the significance of porosity and fracturing on rock thermal conductivity, and have shown that between these properties there exists a complicated relationship which is mainly dependent on the pore space structure. Detailed data on this relationship has been presented by Somerton (1992), Zimmerman (1989), Horai (1991) and Schon (1996).

**Relationship between thermal conductivity and porosity**

The thermal conductivity of rocks is highly dependent upon porosity (Stefansson, 1997). The difference in thermal conductivity measurements for various different rock types is largely due to the variation in porosity of the rock samples measured (Ouali, 2009). Beck´s study (1976) specified four main empirical Eqs, e.g. Maxwell’s equation, showing the effects of porosity on the thermal conductivity of rocks. Three of these equations have been the subject of a study by Stefansson (1997) in defining the best equation describing the relationship between thermal conductivity and porosity. The results of Stefansson’s experimental study showed that the geometrical average equation (Equation 8.5) provided the best relationship.

\[
\log K = \varnothing \log K_w + (1 - \varnothing) \log K_r
\]

(Eq 8.5)

Where,

\( \varnothing = \) Porosity, here as a fraction;
\( K = \) Thermal conductivity [Wm\(-1\)°C\(-1\)];
\( K_w = \) Thermal conductivity of water [Wm\(-1\)°C\(-1\)]; and
\( K_r = \) Thermal conductivity of rock matrix [Wm\(-1\)°C\(-1\)].

**Heat capacity and specific heat**

The heat capacity and specific heat of materials are scalar quantities. The heat capacity of the earth material, which is an aggregate of two-phase components of solid and fluid, is expressed arithmetically (Garcia et al., 1991) as:
\[ \rho_s C_s = \varphi \rho_w C_w + (1 - \varphi) \rho_g C_g \]  

(Eq 8.6)

Where,

- \( \rho_s \) = density of the of the grain part of the earth material, lb/ft³;
- \( C_s \) = specific heat of the of the grain part of the earth material, Btu/lbm-°F;
- \( \rho_g \) = heat capacity of the of the grain part of the earth material, Btu/ft³.°F;
- \( \rho_w \) = density of the fluid that fills in the pore spaces of the material, lb/ft³;
- \( C_w \) = specific heat of the fluid that fills in the pore spaces of the material, Btu/lbm-°F; and
- \( \rho_w C_w \) = heat capacity of the fluid that fills in the pore spaces of the material, Btu/ft³.°F.

From Figure 8.2, graphs A, B and C, it can be deduced that porosity variation (from 15% to 35%) had a significantly greater impact on oil recovery and well injectivity (PVI) for the steam-injection process than the unheated water and hot water processes. This inference can readily be explained by the dependency of the reservoir thermal capacity on porosity. Considering that the steam-injection process was primarily driven by heat transport (convective and conductive), it showed that the percentage recovered is lower for the low porosity case with steam flooding than for hot water flooding. Similarly, the hot water process also depended on heat transport, although to a lesser extent when compared to steam injection. However, the cold-water process did not include any thermal effect, and hence its independence on the effect of porosity on reservoir heat capacity, and rate of heat transport.

The results have indicated that reservoir porosity had a significant impact on oil displacement efficiency in the thermal processes but not on the cold process. For the cold process, for the same injection period and rate, higher porosity results in lower well injectivity due to the lower PVI were achieved.

In addition, it was indicated that the break through times, during the hot water and steam injection, happened faster when porosity was increased. Moreover, both hot water flood and steam injection, reached the same ultimate recovery factor but at different times. In the high porosity reservoir the highest recovery value, 70%, was reached after 45 PVI, 60 PVI and 70 PVI at the porosity values of 35%, 25% and 15%, respectively.
Another observation from this analysis was that the porosity increase impacted negatively on the early-life performances of the hot water and steam injection processes, but not on the unheated-water case. It is interesting to note that after approximately 18 and 5 PVI during the hot water flooding and steam injection processes, respectively, there was a reversal of the impact of porosity on the oil-recovery rate, with the recovery rate increasing with porosity after the initial inverse relationship. This can be explained by the effect of porosity on the formation of the thermal capacity. Initially, for a high-porosity system, the bulk volume of the formation is higher than that of a low-porosity system. Therefore, it takes a shorter time to heat-up a low-porosity formation than a high-porosity formation. However, as time progresses, and increased fraction of the reservoir is heated and more oil mobilised, the rate of oil flow is governed by the in-situ oil volume, which is higher for a high-porosity system.
Figure 8.2: The sensitivity of the oil recovery factor to the reservoir porosity during:
A) Unheated water flooding; B) Hot water flooding; and C) Steam flooding.
Case B: Effects of vertical and horizontal permeability

Oil reservoir heterogeneity is a term of technical and financial significance for a reservoir engineer. It refers to the anisotropy between the vertical and horizontal permeability of exploration sites. During oil mining projects, it affects the performance parameters like the steam oil ratio, oil recovery and the project life. Other important reservoir parameters include porosity, saturation, well spacing and stratification.

Numerically, oil reservoir heterogeneity is expressed as $k_v/k_h$ where $k_v$ and $k_h$ denote vertical and horizontal permeabilities respectively. The term permeability is the degree of flow ability of a fluid through a formation. It is a critical reservoir property which controls hydrocarbon production. Permeability is generally anisotropic or directionally variant, and therefore it will lead to non-uniform distribution of injected fluids (hot water, steam etc.) used for the purpose of oil mining. Permeability also affects the rate of fluid flow from the production side. Changing permeability in the desirable direction can lead to an appreciable increase in the oil recovery volume. In this way, oil reservoir heterogeneity affects oil exploration efficiency. It also reduces cost input and raises the process economy (Prasad et al., 2000).

I. Anisotropic (vary $k_v$/$k_h$): 0.1, 0.2 and 0.5

The oil recovery sensitivity due to the vertical to horizontal permeability ratio was studied by changing the ratio from 0.1 to 0.2 and 0.5.

Figure 8.3 shows the effect of the $K_v/K_h$ ratio on the cumulative oil recovery (bbl.), cumulative injected enthalpy (Btu) and on the project life (years). The oil recovery increased with the higher $K_v/K_h$ ratio during both the hot water and steam injection processes. The increase in oil recovery during the injection of steam gradually increased to a certain value after which it increased abruptly and finally approximated a constant value. If hot water flooding was undertaken, the relation was similar with the exception that a higher rate of change of oil recovery with change in $K_v/K_h$ being observed. Conversely, even though all cases reached the same cumulative oil recovery at the end, the project life decreased as the permeability ratio increased (Fig. 8.3). In addition the amount of heat required was greater for the higher $K_v/K_h$ ratios for obtaining the same oil recovery and water break through was delayed with the lower $K_v/K_h$ ratio. For the steam this may have been because of the somewhat greater tendency for gravity override at higher $K_v/K_h$. During the hot water
flooding, a higher effect of the $K_v/K_h$ ratio on oil recovery was observed. This may have been caused in part by the high pressure gradients, and the fact that horizontal velocities were much greater than those that would have been associated with gravity flow. In general, oil recovery was not significantly affected by the $K_v/K_h$.

**Effects of the permeability ratio ($k_v/k_h$)**

1. It affects the transmission potential in a given direction (Darcy’s law).

2. The permeability ratio determines the number of wells to be drilled for oil recovery. If the value is high more oil can be obtained from a lesser number of wells. Thus it helps in making a decision regarding the feasibility of sites being explored for mining.

3. The permeability ratio affects the flow ability of both the injected fluid and the oil being produced.

4. The permeability ratio helps to assess the financial viability (payback period, profitability) and helps in raising the process economy and oil exploration project management.

**II. Changing the horizontal permeability while keeping $k_v/k_h$ constant.**

As would be expected, the simulation results indicated that there was a significant increase in the oil recovery with permeability. **Figure 8.4** (A B and C), has shown a significant increase in oil recovery factors for all process for increased permeability. However, similar to the porosity effect, the impact of increasing the reservoir permeability on the unheated-water flood was minimal when compared to the two thermal processes.

In this case, the permeability effect can be explained by the relative contribution of convection to the overall heat transport in the reservoir. Through the dependence of the convective-heat transport rate on the fluid velocity, the effect of the in-situ permeability on the overall heat propagation can readily be rationalised. However, in the cold-water process, the convective heat effect was not applicable. Rather, permeability only impacted upon the rate of fluid flow, both from the injection and production sides.
Figure 8.3: The sensitivity of the oil recovery factor to the reservoir heterogeneity anisotropic (vary kv/kh) during hot water flooding and steam flooding.
**Figure 8.4**: The sensitivity of the oil recovery factor to the reservoir permeability during: A) Unheated water flooding; B) Hot water flooding; and C) Steam flooding.
**Case C:** The effect of initial water saturation/oil saturation.

To study the effect of changing the initial water saturation (increasing the volume of oil in place) on the cumulative oil recovery under different recovery processes, the reservoir saturations properties were modified and recalculated in the simulator while keeping the relative permeabilities unchanged.

From **Figure 8.5** (A, B and C) it has shown that the low initial water saturation had a positive impact while applying the different recovery methods due to presenting oil recovery in terms of reservoir pore volumes rather than hydrocarbon pore volumes.

Thus, for the same injection rate the flooding recovery efficiency depended on the oil saturation at the beginning of the injection and consequently the possibility of economic success could be much greater.

In **Figure 8.5**, during the hot water and steam floods, the oil recovery factor reduced by approximately 10% when the initial water saturation increased from 30% to 40%. Conversely, the oil recovery reduced by approximately 5% when the unheated water flood took place. This is because the water acted as a heat sink which reduced the injected heat efficiency. More specifically, the in-situ water was largely connate water, which was immobile. Therefore, the larger the initial water-saturation, the larger the volume of the in-situ water, which implies that the unproductive heat was retained in the reservoir increases. From a thermal efficiency viewpoint, increased initial water saturation reduces the effective amount of heat that is available for mobilising the HO, thereby jeopardising oil recovery.
Figure 8.5: The sensitivity of the oil recovery factor to the reservoir initial water saturation during: A) Unheated water flooding; B) Hot water flooding and C) steam flooding.
8.2 A performance comparison between the Northern and Southern Lower Fars

As mentioned in the Lower Fars description, Chapter 4, a gradual decline in API values, an increase in viscosity values and a decrease in net-pay thickness from the Northern to Southern area were indicated. As already has been established, the API gravity was higher in the Northern area (14-18°), which was a down-dip area and decreased towards the South (11-15°). This may have been because of biodegradation and the escaping of lighter hydrocarbon components into the atmosphere.

From the results of the simulations, we can generally infer that the Southern sector of the model showed much lower recovery factors and was less thermally efficient than the Northern area. The results showed that the CSS remained the best recovery option for the Southern area in concurrence to the Northern area case (Figures 8.8 and 8.9). The oil recovery factors with this process were 3.2% with a steam oil ratio (SOR) of 5 and 2.1 STB/STB with a steam oil ratio (SOR) of 9.2 at Northern and Southern areas respectively. Due to the varying reservoir thicknesses throughout the Lower Fars reservoir, this method may not be best or even applicable in all areas.

Conversely, Figures 8.6 to 8.10 have shown that the ranking for the other best methods were changed dramatically from the North to the South based on the recovery factor values. Table 8.2 illustrates the ranking for the top best recovery methods for the Northern and Southern sectors within the Lower Fars reservoir.

Table 8.2: Ranking of the best strategies based on oil recovery at the Northern and Southern sectors of the Lower Fars, from simulation runs (“→” this sign means followed by).

<table>
<thead>
<tr>
<th>Ranking</th>
<th>Southern sector of the Lower Fars</th>
<th>Northern sector of the Lower Fars</th>
</tr>
</thead>
<tbody>
<tr>
<td>1st</td>
<td>CSS</td>
<td>CSS</td>
</tr>
<tr>
<td>2nd</td>
<td>CSS → SF</td>
<td>Hot water flooding</td>
</tr>
<tr>
<td>3rd</td>
<td>CSS → HWF</td>
<td>HWF → WF</td>
</tr>
<tr>
<td>4th</td>
<td>Unheated water flooding</td>
<td>Unheated water flooding</td>
</tr>
<tr>
<td>5th</td>
<td>Hot water flooding</td>
<td>Steam flooding</td>
</tr>
<tr>
<td>6th</td>
<td>HWF → WF</td>
<td>CSS → SF</td>
</tr>
<tr>
<td>7th</td>
<td>Steam flooding</td>
<td>CSS → HWF</td>
</tr>
</tbody>
</table>
In the Southern area development, using CSS as a first stage had a preferable impact on oil recovery. However, switching to hot water or steam flood after CSS had a negative impact on the overall oil recovery. See Figures 8.6 and 8.9.

However in the South, the continuous steam injection resulted in the lowest recovery factor from the beginning until the end of the project. In contrast, at the Northern area, the continuous steam flooding displacing efficiency was enhanced during the last two years of the project life and overcome the CSS-HW and the CSS-SF (see Figures 8.6 and Figure 8.7). This can be justified as the oil viscosity being much higher in the Southern part when compared to the Northern part.

Figure 8.8 shows the production from the continuous HW injection and HW injection followed by the UHW. The hot injection scenario of hot water followed by unheated water had a better performance for the Northern sector model when compared to the Southern sector model and this was because the mobility ratio in the North was higher than the mobility ratio in the South due to the viscosity value variation from the North to the South ($kr_{we}$ and $kro_{e}$, end point relative permeability for water and oil respectively, are assumed to be the same for the North and South). The mobility ratio had a great impact on the displacement efficiency and therefore this is the main reason behind the variation in the recovery methods performance from the North to South.

Figure 8.10 provides a very interesting result whereby the unheated water flooding resulted in a higher recovery factor than the continuous steam flooding at both areas. However, the gap between steam flooding and unheated water flooding was higher at the Northern sector than the Southern sector. This was due to the lower viscosity in the Northern area (~150-400 cp) when compared to the Southern area (~800-1000 cp) which helped the unheated water flooding to perform better in the Northern area, again because of the favourable mobility ratio at the Northern sector than the Southern sector (the mobility ratio is greater than one in both sectors).

In conclusion, the outputs of the EOR screening work have exposed a significant difference in the recovery factors between the Southern and Northern model areas. This is indicative of the heterogeneity of the Lower Fars reservoirs along with the fact that additional refinement of the input data and models is necessary.

Hifaa Alajmi, 2012
Figure 8.6: The oil recovery factors obtained from different injection cases at the Southern side of the Lower Fars.

Figure 8.7: The oil recovery factors obtained from the different injection cases at the Northern side of the Lower Fars.
Figure 8.8: A comparison between the oil recoveries factors obtained from: (1) Continuous hot water; and (2) Hot water followed by unheated-water at the Northern and Southern areas within the Lower Fars.

Figure 8.9: A comparison between the oil recovery factors obtained from: (1) Continuous CSS; (2) CSS followed by hot water; and (3) CSS followed by steam flood at the Northern and Southern areas within the Lower Fars.
After running the real sector model of the studied reservoir, it was noticed that the simulator was working based on the assumption that the shale was finely inter-bedded with the sand. In this type of system the shale is heated at the same time as the sand and there is no bypassing of the shale with regard to heat loss during the thermal flooding.

In 2010 Masnan et al., reviewed several cases and concluded that there was no significant difference in the thermal properties between shale (non-reservoir area) and sand (pay zone). Consequently, this means that the heat flow (by conduction) through the shale layers is almost the same as that for the sand layers. Therefore, thermal conductivity of the shale rock has no significant impact on the heat transfer through the shale. This argument can be supported with a well-known situation whereby shale in the reservoir is never pure shale. It always consists of a mixture of shale rock, sand rock and fluids inside the porous medium (oil, water and gas) and all these materials are accounted for in the total thermal conductivity of the shale layer.

**Figure 8.10:** The oil recovery factors obtained from continuous steam and continuous unheated-water cases at the Northern and Southern areas within the Lower Fars.
For this analysis, many cases have been tested to help to understand the effect of changing shale rock properties (which KOC do not have) on the reservoir performance, oil recovery versus thermal injection efficiency.

To serve our research objective, it was decided to solely test realistic assumptions, and thus, the zero porosity (no fluids in the shale, 100% rock) assumption was eliminated from the beginning. Although, no papers have stated that the thermal conductivity of shale is a significant factor in heat flow, it is not sensible to assume zero thermal conduction or zero thermal convection for the shale zones. Three investigated cases for this sensitivity study are represented below:

**Case A:** The base case, where the shale has the same thermal conductivity properties of the reservoir rock (Table 5.3), but has a different range of porosity and permeability.

**Case B:** Reduce the values of thermal properties for the shale rock by 50%.

**Case C:** Thermal properties remain as the base case (Table 5.3) and extract the lowest values of porosity and permeability from the real model (18% porosity and 49 md permeability). These values are used for the shale layers.

### 8.3.1 Results and discussion

Studying the effect of changing the shale rock thermal properties (Case-B) confirmed no significant effect of thermal properties on the heat flow through the shale rock, Figures 8.11, 8.12 and 8.13.

In case C, the results showed that reducing the porosity and permeability in the shale rock, in other words reducing the fluid flow through the shale zone, would significantly reduce the heat transfer by convection through the shale rock during the steam injection process. Consequently, the oil recovery increased significantly due to the increase in the efficiency of injected heat.

Figures 8.12 and 8.13 shows that the effect of applying these cases with unheated-water flood and hot water flood has a minimum effect.
Figure 8.11: The effect of changing the shale rock properties, cases A, B and C having almost no effect during the unheated water flooding.

Figure 8.12: The effect of changing the shale rock properties, cases A, B and C having a minimum effect during the hot water flooding.
By analysing these three cases we can understand/predict the influence of the uncertainty in the thermal properties and petrophysical properties of the shale rock. Taking this into consideration will help to reach a flexible development plan that can mitigate the risk of uncertainties in shale properties.

8.3 Optimisation of operational parameters

The operational variables greatly influence the oil recovery process performance, and thus operation variables sensitivity analysis was performed to determine the effect of input data and modelling parameters. The important operational parameters include, yet not limited to, the following concepts:

- The steam injection rate (The steam quality already discussed in Chapter 5);
- The swapping time;
- The injection well perforation location; and
- The injected water temperature.
8.3.1 The steam injection rate

There are several criteria for the determination of the best steam injection rate, including economic factors, the steam production cost, the steam generator capacity, in addition to injectivity, wellbore facilities, surface facilities and oil price (Bahonar et al., 2007). In this section we have been investigating the influence of increasing the steam injection rate on the cumulative oil recovery to guide us to select the best steam injection rate for our simulation study.

In this study, the best steam injection rate was optimised according to the steam-oil ratio. For this purpose, three injection rates have been investigated. Figure 8.14 shows the cumulative oil production for different steam injection rates. In general, the cumulative production increased with an increasing steam injection rate. However, in the Lower Fars sector model, as the steam injection rate increased, the cumulative oil production from the field decreased. Figure 8.15 explains these results. The high steam rate caused an early break through and steam to bypass much of the oil. Thus, the increased steam rate in this sector resulted in lower steam use efficiency.

![Figure 8.14: Cumulative oil production as a function of time for different steam injection rates, the break through is not observed here as the model was ran for 10 years only.](image)
Figure 8.15: (a) Oil saturation distribution before the steam injection. (b) Oil saturation distribution after ten years of continuous steam injection at the rate of 1300 bbl./day. (c) Oil saturation distribution after ten years of continuous steam injection at the rate of 500 bbl./day.

A steam-oil ratio (SOR) between forty and sixty and producing a gas-oil ratio (GOR) lower than 500 ft³/bbl. provided reasonable amounts of oil, gas and water from the field when compared to the higher and lower steam rates. Therefore the best injection rate was selected based upon these criteria. Table 8.4 demonstrates that the injection rate of 1000 bbl./day was the best injection rate for this reservoir.

Table 8.4: Final simulation data for different steam injection rates.

<table>
<thead>
<tr>
<th>Injection rate (bbl./day)</th>
<th>Steam oil ratio (SOR)</th>
<th>Cumulative production (bbl.)</th>
<th>Oil recovery factor (%) *</th>
</tr>
</thead>
<tbody>
<tr>
<td>500 (low rate)</td>
<td>26</td>
<td>63,700</td>
<td>1.9</td>
</tr>
<tr>
<td>1000 (base case)</td>
<td>46</td>
<td>74,000</td>
<td>2.3</td>
</tr>
<tr>
<td>1300 (high rate)</td>
<td>73</td>
<td>60,000</td>
<td>1.8</td>
</tr>
</tbody>
</table>

*The oil recovery values at the end of the project life (10 years) are too small due to the small pattern size and because we are producing from a single well perforated at single layer.
8.3.2 Swapping time (altering the injected fluid)

In this section the effect of the swapping time on the reservoir recovery performance has been studied. Two recovery methods were selected for this analysis, which included: (1) CSS followed by steam injection; and (2) Hot water followed by unheated-water injection.

The examined project life was ten years and three swapping times were assumed:

- **Base case:** Switching from hot water to unheated-water/ from CSS to steam injection after four years.
- **Early swapping time:** Switching from hot water to unheated-water/ from CSS to steam injection after two years.
- **Late swapping time:** Switching from hot water to unheated-water/ from CSS to steam injection after six years.

8.3.3 Results and discussion

Figures 8.16 and 8.17 shows that stopping the hot water injection at an earlier time slightly enhanced the overall recovery factor. However, injecting hot water for a longer period did not have a positive impact on the oil recovery. Conversely, it was obvious that the greater the steam cycles at an early life of the development project, the better the recovery performance that would be achieved.

From Figures 8.11 and 8.12 we can see that implementing the CSS method as a first stage development method had a significant positive impact on the oil recovery. In Figures 8.16 and 8.17, interesting results were evidenced which showed that the use of hot water followed by unheated-water, at all swapping cases, resulted in a higher cumulative oil recovery than the case of CSS followed by steam flood. These results can be explained as a result of the density of the hot water being higher than the steam, which helped the hot water slug to achieve better sweeping efficiency than the steam slug.
Figure 8.16: A graph illustrating the impact of changing the swapping time for the case of hot water flooding followed by unheated-water flooding.

Figure 8.17: A graph illustrating the impact of changing the swapping time for the case of CSS followed by steam flooding.
8.3.4 Injection well perforation location

The well completion strategy is an extremely important operational parameter and is deemed to be most critical during the steam injection process. Through sensitivity analysis, the best injection well perforations location can be identified for the steam flooding operation. Four different cases were studied, as follows:

- **Case 1:** All layers were perforated across the pay zone.
- **Case 2:** The bottom layers were perforated.
- **Case 3:** The mid layers were perforated.
- **Case 4:** The top layers were perforated.

Figure 8.18 shows that changing the perforation location within the real sector model had an insignificant impact and this could have been the result of the system heterogeneity. Thus, it was also decided to test the impact of changing the perforation location on the simple homogeneous model. The sensitivity analysis here is divided into two sections: a simple homogenous model and a real sector model. However, the perforation locations assumptions are the same for the both models. For reference, Table 8.5 illustrates the difference between these two models.

Table 8.5: A comparison between the injector and producer wells arrangements in the homogenous model and the real sector model.

<table>
<thead>
<tr>
<th>The simple homogeneous model</th>
<th>The real sector model (heterogeneous)</th>
</tr>
</thead>
<tbody>
<tr>
<td>The net pay thickness is 45 ft.</td>
<td>The net pay thickness at the real model is 20 ft., (F1B SAND)</td>
</tr>
<tr>
<td>Formation pore volume $3.2 \times 10^5$ ft$^3$</td>
<td>Formation pore volume $3.7 \times 10^7$ ft$^3$</td>
</tr>
<tr>
<td>OOIP $8.996 \times 10^3$ m$^3$</td>
<td>OOIP $1.8 \times 10^7$ ft$^3$</td>
</tr>
<tr>
<td>Maximum injection rate is 200 bbl./day</td>
<td>Maximum injection rate is 1000 bbl./day</td>
</tr>
<tr>
<td>Distance between the injector and producer is 230 ft.</td>
<td>Distance between injector and producer is ~1200 ft.</td>
</tr>
<tr>
<td>Model grid (x, y and z) 20 x 20 x 15 (6000 blocks)</td>
<td>Model grid (x, y and z) 14 x 14 x 62 (12,152 blocks)</td>
</tr>
<tr>
<td>Oil gravity API$^0$18</td>
<td>Oil gravity API$^0$ 13-18</td>
</tr>
<tr>
<td>Oil viscosity 500 cP</td>
<td>Oil viscosity &gt; 300 cP</td>
</tr>
<tr>
<td>Initial reservoir pressure 250 psi</td>
<td>Initial reservoir pressure 250 psi</td>
</tr>
<tr>
<td>Initial reservoir temperature 100$^0$F</td>
<td>Initial reservoir temperature 100$^0$F</td>
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</table>
Figure 8.18: Cumulative oil production as a function of time for the different well perforations in the real sector model.

Figure 8.19: Cumulative oil production as a function of time for the different well perforations in the homogeneous reservoir model.
Figure 8.19 illustrates the homogenous model results where it can be seen that case 4 (injection at the top layers) was the best perforation strategy. This can be explained in terms of steam, water and oil gravities. Steam has low gravity compared to oil and water; hence it goes to the upper layers and presses the oil down to the bottom layers. Additionally, early water breakthrough can be delayed in this case. In reality, if cases 1 or 2 were applied, as the steam condensates and changes into water, it would move from the top layers (of the perforated section) and would quickly reach the producer well, whilst large amounts of reservoir area would be kept un-swept.

8.3.5 The impact of the injected water temperature

The displacement of a viscous crude oil by conventional recovery methods at the reservoir temperature was not very efficient due to the low mobility of the oleic phase. Taking advantage of the favourable change in the viscosity of the oil achieved at high temperatures, a variety of thermal processes were successfully implemented for the economic recovery of HOs. The aim of this section is to present illustrative examples which highlight the issues associated with injection temperature in a typical medium HO sandstone reservoir. The temperature could be increased in a reservoir setting through steam or hot water injection; however, in this section we have limited our discussion to the area of hot water injection.

The reservoir was considered homogeneous for this study, which allowed the separation of injected heat effects from reservoir geology.

Figure 8.20 illustrates the variation of cumulative oil recovery with the number of pore-volume injected (PVI). From the results, regardless of the injection temperature, a clear positive correlation was evident between the recovery and PVI. However, the dependency diminished after the first 0.2 PVI, going asymptotic at later PVI (times). Most importantly, it can be inferred that the positive impacts of thermal injection on oil production were not instantaneous - they only became noticeable after an appreciable number of PVI.

With regards to Figure 8.21, within the first 0.2 PVI, it can be inferred that the reservoir response, swap and displacement, were practically independent of the injection temperature. This observation can be explained by the delay time which was required to heat up the
reservoir to such a temperature that would give a reasonable reduction of oil viscosity, hence enabling favourable mobility ratio. However, ultimately, the cumulative recovery has shown a positive response to the injection temperature.

In addition to giving a higher ultimate recovery, high-temperature operation accelerates performance. For example while the 300°C hot water flood recovered some 65% of OOIP after 10 PVI, corresponding performances for the unheated-water processes were approximately 35% and 52% respectively. Moreover, the unheated-water injection process would probably reach 40% OOIP after injecting 20 PV of water. From an economic viewpoint, production acceleration would improve the overall project economics by mitigating the negative impact of discounting on the revenue stream.

**Figures 8.21 and 8.22** show the post-production water saturation profiles for the unheated-water and hot water processes respectively. While the hot water flood has clearly indicated a fairly stable displacement of oil by water towards the producer, unstable fronts have been evident in the unheated-water process, resulting in significant oil by-pass. The difference in the displacement processes have evidently manifested in the profiles of the produced water-cut and oil production rate (**see Figure 8.23**). Obviously, a higher water-cut would increase treatment costs and other operational expenses.

![The Effect of the Injected Fluid Temperature](image)

**Figure 8.20**: Cumulative recovery for different injection temperatures; unheated water (38°C) and hot water (200 and 300°C).
Figure 8.21: Top surface map showing the water saturation profile at the end of simulation, unheated water injected at 38°C (reservoir temperature).

Figure 8.22: Top surface map showing the water saturation profile at the end of simulation, hot water injected at 300°C.
Figure 8.23: Water-cut (%) and oil production rate for the unheated-water floods (38°C as reservoir temperature.) and hot water floods (300°C)

For a thermal operation, it is helpful to consider the amount of heat injected into the formation as one of the criteria for discriminating between the prospective options. In this regard, Figure 8.24 is a plot of the cumulative oil recovery as a function of the absolute quantity of thermal energy supplied. Perhaps, this quantity is one of the most important indicators of costs associated with thermal projects. For the unheated-water (38°C - reservoir temperature) operation, the maximum oil recovery factor was projected to be about 48%, and as would be expected, no subsurface heat input was required.

Conversely, for the 200°C hot water process to realise the predicted recovery of ~ 78% OOIP, it was estimated that some $1.2 \times 10^{11}$ BTU of heat energy would need to be available to the reservoir. In comparison, the 300°C hot water option would give a similar oil recovery of 78% OOIP after consuming $4.5 \times 10^{10}$ BTU of heat available through the injected hot water. However, the highest recovery factor did not exceed 81% in this case. Obviously, making an investment decision on these three prospective development options has provided a strong case for economic analysis, with some of the key factors being production acceleration, incremental recovery, downstream transportation, energy costs and manpower. For example, although the cold-water flood may not incur heat-related expenses in producing the oil, the oil viscosity, which remains essentially the same, may inhibit its subsequent
transportation. Conversely, oil produced by hot water floods would retain a fraction of the injected heat, which would continue to lower its viscosity, hence saving transportation costs. Therefore, a pragmatic economic evaluation of these competing operating schemes would consider life-cycle economics.

![Figure 8.24: Variation of oil recovery with cumulative injected heat for different injection temperatures.](image)

8.4 The price of oil

8.4.1 Oil price assumptions

Instability in the oil prices, which is subject to the stability of the world oil supply and demand, has often become an economic liability. Fluctuation in oil prices can make a very profitable reservoir development project now to completely uneconomic investment in the future without any prior indication.

To check the sensitivity of the oil price in this study we have changed the price of oil while keeping the cost of treating the produced water and producing hot water and steam injection unchanged. In this study we have examined three possible cases for reflecting oil price
uncertainties. Oil prices of $100, $160 and $60 have been used as the reference, high and low cases, respectively. However, the $15 differential between the light oil price and HO has also been considered (Reuters, 2010).

8.4.2 Results and discussion

Figure 8.25 shows the NPV versus the oil price and illustrates the overall performance of all continuous injection cases at the Northern sector of the Lower Fars. From this plot, it is obvious that the CSS and unheated-water flood, at all prices cases, are potentially more profitable development options at all the prices investigated. Hereby, we have defined profitability as a positive NPV (NPV>0), see Chapter 7. Conversely, the same plot has provided clear evidence that the economic evaluation of the other methods, steam flood and hot water flood, suggests a high risk of economic loss at all examined price levels ($60 to $160).

![Oil Price Sensitivity Analysis for Continuous Cases – North Sector](image)

**Figure 8.25:** Accelerated profits from different continuous injection cases at different oil price rates.
The NPV analysis for all the successive cases (injecting different fluids in sequences) as shown in Figure 8.26, approved that the successive injection strategy in such sandstone HO reservoir was profitable development and no economic risk even at the low oil price scenario. Figures 8.27 and 8.28, representing unheated-water followed by hot water or steam has shown expected results where the NPV has increased with the increasing oil price.

Figure 8.28 indicates that the steam flood followed by unheated-water flood, at all price cases, has provided a higher NPV than the unheated-water followed by hot water flood. Although injecting hot water after the steam flood increases the cumulative oil recovery, from the economic point of view, the case of steam flood followed by unheated-water flood is more profitable. Thus, the initial heating up of the reservoir by steam injection has enabled the accumulation of heat within the formation. For the subsequent production period, the available heat has continued to be useful for maintaining the mobility of the in-situ crude.

Figure 8.26: Accelerated profits from different successive injection cases at different oil price rates.
Figure 8.27: Accelerated profits from the different injection cases, WF-HWF and WF-SF, at different oil price rates.

Figure 8.28: Accelerated profits from different injection cases, SF-HWF and SF-WF, at different oil price rates.
Furthermore, Figure 8.29 shows that the hot water followed by cold water-flood, at all price cases, provided a higher NPV than the hot water followed by steam flood. In essence, the former option has used less amount of energy, thereby reducing the costs, which include fuel, related to the generation of heat.

**Figure 8.29:** Accelerated profits from different injection cases, HWF-WF and HWF-SF, at different oil price rates.

**Figure 8.30** shows that the NPV of CSS followed by steam flood has been higher at all price cases. This has been due to the high oil recovery achieved by injecting steam during the life of the project. Consequently, the reservoir temperature has increased, with a corresponding significant reduction of the oil viscosity which, in turn, has resulted in greater oil mobility.
The overall results from this sensitivity analysis are shown in Figure 8.31 which has shown the NPV versus the oil price for all investigated development strategies. Thus as the oil price increases we can figure that the gap between the different injections cases have decreased which confirms that if the oil price increases most EOR projects would be a profitable solution to use. Nevertheless, a high economic risk would be associated with any EOR project initiated under such unpredictable oil market behaviour.

In addition, it was observed that the difference between the NPVs for most of the successive cases was small whilst the differences between the continuous recovery strategies were significantly higher. This conclusion could potentially guide us to another debate, whether lower NPV means a bad choice comparing to the other or not. From Figure 8.31 we can suggest that since the difference between the profitable strategies, in general, was small, it would be moderately possible that any option would be feasible. Other investigations (like CAPEX and OPEX calculations) could be made to further refine the analysis and determine the final answer for the optimum NPV.
Finally, from the oil price sensitivity study, the following recovery strategies show the best NPVs among all oil prices assumptions;

1. Hot water flooding followed by unheated water flooding;
2. CSS followed by steam flooding;
3. CSS followed by hot water flooding;
4. CSS followed by unheated-water flooding;
5. Unheated-water flooding followed by hot water flooding;
6. Steam flooding followed by unheated-water flooding; and
7. Steam flooding followed by unheated-water flooding.

![Figure 8.31: NPV versus oil price for all injection strategies.](image-url)
8.5 Conclusion

In this section, the sensitivity of reservoir and operational parameters in a sandstone HO reservoir has been investigated. The main conclusions are:

- The simulation study has shown that geologic conditions including initial water saturation, porosity and permeability of reservoir heavily have influenced EOR performance. Thus, it is very important to develop suitable screening criterion before deciding upon the HO reservoir development strategy.
- Within the range of parameters studied, the simulation results have indicated that the following are unfavourable conditions, each on their own, for an enhanced oil recovery processes:
  - Low porosity;
  - High initial water saturation;
  - Low reservoir permeability; and
  - Low permeability ratio $K_v/K_h$.
- The performance of the steam and hot water processes was the most negatively influenced by increasing the system porosity. Thus, it is extremely important to develop suitable screening criterion and economic feasibility study before conversion to thermal flooding.
- As the initial water saturation increased, the oil recovery factor by thermal processes reduced by (approximately) twice compared to the case of unheated-water flooding.
- As the reservoir permeability increased, the oil recovery factors for all injection processes also significantly increased. However, similar to the porosity effect, the impact of increasing the reservoir permeability on the unheated water was minimal compared to the thermal processes.
- The outputs of the simulation work have exposed a significant difference in recovery factors between the Southern and Northern model areas of the same field. This is indicative of the heterogeneity of the studied reservoirs, particularly the effect of the oil viscosity variation between the North and South sectors, along with the fact that additional refinement of the input data and models is necessary in similar cases.
• In general the Southern sector of the real sector model (higher viscosity) showed much lower recovery factors and was less thermally efficient than the Northern area (lower viscosity).
• The ranking for the best methods were changed dramatically from the North to the South based on the recovery factor values. Though, due to the varying reservoir thicknesses throughout the studied reservoir, some methods may not be best or even applicable in all areas.
• The shale study has confirmed that no significant effect of thermal properties on the heat flow through the shale rock. Conversely, reducing the porosity and permeability in the shale rock would significantly reduce the heat transfer by convection through the shale rock during the steam injection process.
• The simulation study has shown that the operational parameters including steam injection rate, injected fluid swapping time, injection well perforation location and injected water temperature to heavily influence EOR performance. Thus, it is extremely important to develop a sensitivity and optimisation study for the operation parameters before deciding upon the HO reservoir development strategy.
• Unlike other HO reservoirs, increasing the steam injection rate had no significant effect on oil recovery for this HO reservoir. Therefore, for economic reasons, the steam injection should be carefully optimised and parameters such as the steam-oil ratio (SOR) must be considered.
• In successive cases, the swapping time is deemed a critical decision which would have a significant effect on the cumulative oil recovery. Thus, an intensive optimisation study should take place to make a decision about the best switching time.
• The steam injection efficiency has been considered a critical issue. As a consequence, a sensitivity study must be conducted to investigate the best perforation location for injecting the steam into the reservoir. The best injection well perforation strategy, for the steam injection process, in this type of reservoir was obtained when the top layers were perforated.

In order, to generalise this study and minimise the uncertainty of the results, we have examined three possible cases for reflecting the oil price uncertainties and to determine at which price our results would still be valid.

Hifaa Alajmi, 2012
• CSS and unheated-water floods are potentially more profitable development options at all prices cases.
• The price sensitivity analysis confirmed that steam floods and hot water processes were of high risk of economic loss at all examined price levels ($60, $100 and $160).
• Economically, all successive injection strategy in such sandstone HO reservoirs support a successful investment at the lowest (estimated) oil price. In contrast, the continuous steam and hot water flooding development options have shown a high economic risk after the second year, at all oil price cases.
• As the oil price increases, the differences between the different injections cases are decreased which confirms that if the oil price increases most of EOR projects would be a profitable solution to use. However the opposite was found to be true which resulted in a high economic risk associated with any EOR project initiation under such unpredictable oil market behaviour.
• The difference between the profitable strategies, in general, is small and thus it is moderately possible that any option will be feasible. Other investigations (like CAPEX and OPEX calculations) can be made to further refine the analysis and determine the final answer for the optimum NPV.
• From the oil price sensitivity study, the following recovery strategies represent the best NPVs among all oil prices assumptions;
  1. Hot water flooding followed by unheated water flooding;
  2. CSS followed by steam flooding;
  3. CSS followed by hot water flooding;
  4. CSS followed by unheated-water flooding;
  5. Unheated-water flooding followed by hot water flooding;
  6. Steam flooding followed by unheated-water flooding; and
  7. Steam flooding followed by unheated-water flooding

• This work has contributed significantly towards our understanding of the sensitivity of different reservoir and operational parameters on the oil recovery performance of a typical unconsolidated HO reservoir. This is critical in the decision on the applicability of EOR recovery methods and its field application success.
9. Conclusions and Recommendations

9.1 Conclusion

In conclusion, we have observed that a combination of growing energy demand, the declining performance of conventional oil fields and attractive oil prices have renewed interest in both HO resources (HO) and the methods of exploiting them. The vast volume of these resources notwithstanding, their low reservoir-scale mobility precludes exploitation by traditional primary and secondary recovery techniques, making both thermal and non-thermal EOR methods the natural candidates. However, the influence of several factors, technical and non-technical, affect the choice of EOR method(s) requiring rigorous studies. Increasingly attention is being directed towards those technologies that can most efficiently recover and process HO. The challenge lies in finding the best way to produce, transport and process oil.

In this study, the focus was on developing a practical methodology to determine the best strategies to recover medium HO from an unconsolidated sand stone reservoir. The primary objective of this study has been to establish possible development options for medium HO reservoirs. Other objectives included understanding the physics of selected thermal EOR processes in different medium HO reservoirs and developing a robust screening tool for HO resources. Numerical modelling studies have been used here to achieve these objectives.

In this work, thermal and non-thermal recovery methods, which were considered feasible by screening models, have been investigated to highlight the in-situ exploitation of HO resources. These are: (1) unheated Water Flooding (WF); (2) Hot water Flooding (HWF); (3) Steam Flooding (SF) and (3) Cyclic Steam Stimulation (CSS). In terms of oil recovery and economics, in the homogenous model, all the injection strategies investigated showed promise. However, in the real model, successive injection cases show most promise, while injecting one type of fluid is less attractive and less beneficial in cases of continuous steam flooding and hot water flooding.

The novelty of this research lies in the development of a screening model to determine the applicable EOR methods for any type of reservoir. The development of this process showed that screening tools are powerful artificial intelligence applications that can assist
experienced reservoir engineers to save time and effort when selecting an appropriate EOR process based on a reservoir’s characteristics.

We expanded on previous research by conducting a reservoir simulation study to determine the best development options for the studied reservoir by changing the reservoir parameters (heterogeneity effect) and several operational parameters.

In this study, the effectiveness of the continuous (one type injected fluid) and successive (combination of different injection fluids) was investigated to identify the best design configuration in terms of injection fluids sequences. These results can be used as a tool to inform the successful design of thermal injection to recover HO in these types of reservoir. In addition, they provide the conditions under which a given design may deliver better recovery performance.

We have applied this study to a sandstone reservoir, but the general methodology could be extended to any other type of reservoir, leading to the best recovery rate overall. However, the results acquired in this work are applicable to the studied field because of the reservoir parameters used in the model. However, similar conclusions are valid for other HO reservoirs as long as they have similar properties. For example, if we have a different viscosity or relative permeability, then this will change the fractional flow of the system, which might lead to different mobility and sweep efficiency, hence altering the structure of the system. Thus, if we change the injection rate or the well configuration the conclusion obtained will be the same, as long as the same methodology and approach is applied.

It is understood that different reservoirs (e.g. carbonate type reservoirs, light oil resources, etc.) will have different characteristics like permeability, such as fractures, etc., but that does not mean that we cannot apply this methodology to other types of reservoirs. The decision-making methodology developed here is applicable to all reservoirs, as long as they apply the same structure.

Another novelty of this research is the extensive sensitivity analysis conducted in this research. The reservoir parameters, shale study and operational conditions were investigated to check the uncertainty and accuracy of the final results. Also, we performed a sensitivity analysis to test the relationship with the oil price, due to the large impact of this in the short term.
This analysis highlighted how sensitive EOR projects are to reservoir heterogeneity and oil price and indicates, based on the graphs and plots shown, that this can help identify one technique from another.

Finally, we re-emphasised that all the results obtained in this research are only valid for the case study or unconsolidated HO reservoirs in similar fields; however, the methodology used in this study to attain the best development options is a general approach that can be applied to all types of reservoirs with different properties. The parameters we have investigated are essential to any analysis, regardless of the kind of the reservoir.

To reach this conclusion, a number of issues were addressed. In addition to the specific conclusions that have been stated at the end of each chapter in this thesis, the following are the main findings from this work:

**Chapter 3: First-pass Screening Tool**

Chapter 3 demonstrates that reservoir development decisions can be made without the necessity for sophisticated techniques and time consuming studies. Proper engineering judgment and physically sound analysis represented key variables in this type of evaluation. It is also important to remember that management decisions and business opportunities do not necessarily operate on a timeframe that is consistent with extensive testing.

Therefore, to facilitate decision-making, we applied a systematic procedure for eliminating less competitive options using criteria based on worldwide field experiences, where such methods have been commercialised.

Under the current oil price regime, it is reasonable to presume that thermal and other enhanced-oil recovery processes have a high chance of commercial success at HO reservoirs. According to the results of the technical screening and discussions in this chapter, the following inferences were drawn.

- The application of First-pass screening tool to select EOR method is critical and useful. The development of this tool shows that expert systems are powerful applications that help experienced reservoir engineers save time when selecting an appropriate EOR process on the basis of the reservoir characteristics.
- In strong reservoir heterogeneity, similar that at the investigated reservoir, different technologies are likely to be suitable for different formation zones. The selection of
technologies is likely to be influenced by several factors, which include formation thickness, oil saturation, and oil viscosity.

- The suitable technology sequence depends on reservoir thickness and fluid characteristics, among other considerations. In thin zones, such as the one we are investigating, options are limited. However, thick zones present a challenge in terms of the choice of the best approach to maximize recovery factor at reasonable heat costs.
- SAGD is yet to be proven as highly effective for mobile oils, but holds promise at relatively shallow depths and for the small net pay thickness reservoirs, similar to our case study. Furthermore, the existence of continuous and non-continuous shale layers puts SAGD at risk in this HO deposit.
- In the future, it will be necessary to assess the use of fossil fuels as a heat source for thermal processes because of cost and environmental considerations (greenhouse effects). In Kuwait, other heat source alternatives include heat from power generation facilities, and solar power.
- The EOR screening computer program developed in this study can be applied to future EOR studies at other HO reservoirs.

Chapter 5: Application of the selected EOR method on a simple model

The reservoir was considered homogeneous for this portion of the study, which allowed the separation of process effects from reservoir geology. The main purpose of using a simple model is a) to gain understanding about the processes that determine what EOR methods improve recovery, b) establish a methodology for studying this problem that can be understood without the additional complexity of the effects of heterogeneity, and c) provide a benchmark against which other (more realistic) cases can be compared. For quick reference, the following are the overall conclusions of this chapter;

- As expected, injecting steam and hot water will give a higher recovery rate than injecting unheated water because the higher temperature will reduce the viscosity of the oil and help it to move easily to the producing well.
- Injecting hot water would have a favourable effect on oil production from the points of displacement efficiency and volumetric sweep.
• The added cumulative oil recovery at higher temperatures needs to be justified economically to sustain the additional costs.

• Based on cumulative oil recovery attained by steam injection in the homogenous model, it was indicated that there is no significant impact on the cumulative oil recovery values if we use steam quality of 40% or 80%, and only the steam temperature has a significant influence on the steam performance efficiency.

• Among the various cases investigated, the case with steam injection followed by hot water flooding gave the best recovery performance. This is due to higher heat conduction when steam following before hot water displacement mechanism is established.

• Results also indicated that switching to cold water injection after steam/hot water injection led to a minimum improvement on oil recovery.

Chapter 6: Simulation Study: Lower Fars formation Ratqa field

• CSS and hot water flooding gave a higher recovery than injecting unheated water, because the temperature reduced the viscosity of the oil and helped it to move easily to the producing well.

• Steam injection gave a low oil recovery compared to hot water flooding and the unheated water flooding; this is due to the steam override phenomena, which leads to greater heat loss to the upper shale layer (non reservoir zone).

• Improvements could be made to model the effect of shale (cap and bottom) on heat transfer if an improved net to gross map could be assigned to the model. Improving the net to gross ratio distribution within the sub-models will help to model fluid flow and insure heat transfer more accurately.

• Injecting hot water has a favourable effect on oil production from the points of displacement efficiency and volumetric sweep.

• Among the various injection strategies investigated, the cases with continuous CSS and steam injection followed by hot water injection gave the best recovery performance.
• Results also indicated that switching to cold water injection after steam/hot water injection had a minimum improvement on the oil recovery.

• Comparing the performance figures obtained with a homogeneous model with those obtained with a heterogeneous one indicated the following:
  
  • Continuing hot water injecting in homogenous and heterogeneous models gave the best recovery performance in comparison to unheated water flooding and steam injection. However, in the homogenous case the steam injection gave higher oil recovery compared to the unheated water flooding, whereas the opposite was true in the heterogeneous case. This is due to the adverse effects of the reservoir heterogeneity on the steam injection performance.

  • If we exclude those CSS cases which we did not applied in the homogenous case, then among the various investigated cases, the cases with (1) steam injection followed by hot water injection and the (2) unheated-water flooding followed by hot water injection gave the best recovery performance for both the heterogeneous model and homogenous models.

  • The simulation results also show that a reduction in heat injection rate after steam break through is beneficial. Therefore, decreasing heat injection rate, and switching to hot water flood, after steam injection can improve steam utilization and economics.

  • As indicated, switching to continuous steam flood, hot water and unheated water after CSS injection had no effect on the oil recovery rate, in fact oil recovery declined significantly after switching. Again its worth remembering that in the case of CSS the two wells acted as injector and producer simultaneously.

  • It is essential to the investigate the CSS best cycle number, because in usual practice the CSS stopped after production declined sharply; however, in this case the production rate continued to increase even after the 7th cycle.

**Chapter 7: Techno-Economics of the HO development project**

To evaluate the EOR process, economic considerations are the most important aspect. The oil price and the heating energy costs are the most important economic factors relevant to HO
development projects. For quick reference, the following are the overall conclusions of this chapter;

- In the simple homogenous model, injecting one type of fluid from the beginning until the end of project life delivered better profitability than other successive injection cases, except for the SF-WF.
- In contrast to the homogenous model case, the economic evaluation of the heterogeneous model (real sector) performance confirmed the preference for successive cases.
- The evident variation in the NPV ranking of the different injection strategies between the homogenous model and the real sector model assured a significant influence from reservoir heterogeneity/uncertainty.
- The economic evaluation of hot water and steam injection at different temperatures and steam qualities indicated the importance of optimising the injected fluid temperature and quality for each individual reservoir parameter.
- From the DCF and NPV analyses for both continuous hot water injection and steam flooding in the real sector model, it became obvious that injection strategies carry a high risk of losses.
- In the real sector model, CSS followed by steam flooding and hot water flooding followed by unheated-water flooding will give a higher profit than all other cases.
- Among the various cases investigated, those with an initial stage of CSS gave the best economic performance.
- Results also indicated that switching to unheated-water injection after steam/hot water injection resulted in a minimum improvement to oil recovery but a positive impact on economic successes.
- Thermal injection is costly, and careful design and heat management are the keys to economic success.

**Chapter 8: A Comparative Study, Sensitivity Analysis and Risk Evaluation**

The objective of introducing the case study as a context was to determine the functional relationship between oil recovery performance, several design parameters and reservoir conditions. Results showed that these parameters play an important role in the displacement
behaviour of HO, with reservoir heterogeneity having a more significant effect. The study suggests that there exist critical values for these parameters, under which recovery methods can be either profitable investments or contain a high risk of losses. For cases of quick reference, the following are the overall conclusions of this chapter;

- The simulation study shows that geologic conditions, including initial water saturation, and the porosity and permeability of reservoir heavily influence EOR performance. Thus, it is very important to develop suitable screening criteria before deciding on a HO reservoir development strategy.
- Within the range of parameter studied, the simulation results indicated that the following conditions are unfavourable to an enhanced oil recovery processes:
  - Low porosity
  - High initial water saturation
  - Low reservoir permeability
- The performance of steam and hot water processes was the most negatively influenced by increasing the system porosity. Thus, it is very important to develop suitable screening criterion and perform an economic feasibility study before converting to thermal flooding.
- As initial water saturation increases, the oil recovery factor by thermal processes reduced by (approximately) twice, compared to cases of unheated-water flooding.
- As the reservoir permeability increases, the oil recovery factors for all injection processes significantly increase also. However, similar to the porosity effect, the impact of increasing reservoir permeability on unheated water is minimal compared to the thermal processes.
- The outputs of the simulation have led to a significant difference in recovery factors between the South and North model areas for the same field. This is indicative of the heterogeneity of the reservoirs studied, combined with the fact that additional refinement of the input data and models is necessary in similar cases.
- In general the Southern sector of the real sector model (higher viscosity) shows much lower recovery factors and is less thermally efficient than the Northern area (lower viscosity).
- The ranking for the best methods changed dramatically between North and South, based on recovery factor values. However, due to the varying reservoir thicknesses throughout the studied reservoir, some methods may not be best suited to, or even applicable in all areas.
• The shale study confirms no significant effects of thermal properties on the heat flow through shale rock. On the other hand, reducing the porosity and permeability in shale will significantly reduce the heat transfer by convection during the steam injection process.

• The simulation study shows that the operational parameters, including steam injection rate, injected fluid swapping time, injection well perforation location and injected water temperature heavily influence EOR performance. Thus, it is very important to develop a sensitivity and optimisation study for the operation parameters before deciding the HO reservoir development strategy.

• Unlike other HO reservoirs, increasing the steam injection rate has no significant effect on oil recovery at Lower Fars HO reservoir. Therefore, for economic reasons, steam injection should be carefully optimised and parameters such as steam-oil ratio must be considered.

• In successive cases, swapping time is a critical decision that significantly effects cumulative oil recovery. Thus, in intensive optimisation a study would be necessary to determine the best switching time.

• Steam injection efficiency is a critical issue; for this reason a sensitivity study must be conducted to investigate the best perforation location to inject the steam into the reservoir. The best injection well perforation strategy, for the steam injection process, in this type of reservoir was obtained when the top layers were perforated.

In order, to generalise this study and minimise the uncertainty of the results, we have examined three possible cases to reflect oil price uncertainties to see at what price our results will still be valid.

• CSS and unheated-water floods are potentially more profitable development options for all cases.

• The price sensitivity analysis confirmed that steam floods and hot water processes represent a high risk of losses at all price levels ($60, $100 and $160).

• Economically, all successive injection strategies in sandstone HO reservoirs support successful investment based on the lowest (estimated) oil price; in contrast, the continuous steam and hot water flooding development options show a higher economic risk after the second year, for all oil price cases.

• As the oil price increase, the differences between different injections cases decreased, which confirms that if the oil price increases most EOR projects will be profitable.
solutions; yet, the opposite is true, showing a high economic risk associated with EOR project initiation under unpredictable oil market conditions.

- The difference between profitability strategies, in general, is small and thus it is moderately possible that any option will be feasible. Other investigations (like CAPEX and OPEX calculations) can be made to further refine the analysis and determine the final answer for the best NPV.

- From the oil price sensitivity study, the following recovery strategies show the best NPVs among all oil prices assumptions;
  1. Hot water flooding flowed by unheated water flooding
  2. CSS followed by steam flooding
  3. CSS followed by hot water flooding
  4. CSS followed by unheated-water flooding
  5. Unheated-water flooding followed by hot water flooding
  6. Steam flooding followed by unheated-water flooding
  7. Steam flooding followed by unheated-water flooding

- This work has contributed significantly towards our understanding of the sensitivity of different reservoirs and operational parameters for oil recovery performance at a typical unconsolidated HO reservoir. This is critical when making decisions about the applicability of EOR recovery methods and their field application success.
9.2 Recommendations

In order to advance the contributions made by the current research, the following further studies are proposed:

**Numeric reservoir simulations**

- Historically match past pilot production data from two historical steam pilots in the Lower Fars in the early 1980s with the North area model (and South if applicable) to improve the validity of the models.
- Improvements could be made to model the effect of shale on heat transfer if an improved net to gross map could be assigned to the model. Improving the net to gross ratio distribution within the sub-models will help to model fluid flow and heat transfer more accurately.
- A field optimisation study to improve and optimise production is also recommended. Areas that could be investigated include best injection rates, cycle times and wells configuration.
- Consider carbonate reservoirs. Study currently limited to sandstone formations.

**Feasibility of un-heated water/hot water/steam/CSS processes**

- Although the current study has shown the feasibility, risks and competitiveness of the selected processes, it is necessary to conduct further assessments on the basis of more representative technical and economic datasets. Further investigation in the laboratory and the field are also recommended.

Due to the shortage in natural gas resources, and increasing regulatory stringency regarding the environment, solar thermal energy should be implemented in steam-flood and hot water development in Kuwait to replace heat provision from fossil fuels.

In general, screening the EOR processes can become an open-ended problem. This type of study needs a lot of analysis and investigation and also a good level of appraisal to identify the best development options for different reservoir categories to culminate in a profitable investment.
10. References


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Hifaa Alajmi, 2012


APPENDIX A: Catalogue of EOR Screening Criteria

This appendix presents sets of screening criteria gathered from the literature search. This appendix consists of actual pages copied from the references. The screening criteria are for miscible, chemical, and thermal EOR.

Screening Criteria

<table>
<thead>
<tr>
<th>Screening Parameters</th>
<th>Steam Drive</th>
<th>In-Situ Combustion</th>
<th>CO₂ Miscible</th>
<th>Miscella/ Polymer</th>
<th>Improved Water flood</th>
</tr>
</thead>
<tbody>
<tr>
<td>Viscosity, cp at reservoir conditions</td>
<td>NC&lt;sup&gt;a&lt;/sup&gt;</td>
<td>NC</td>
<td>&lt;12</td>
<td>&lt;20</td>
<td>&lt;200</td>
</tr>
<tr>
<td>Gravity, °API</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other than California crudes</td>
<td>&gt;10°&lt;sup&gt;a&lt;/sup&gt;</td>
<td>10 to 45°&lt;sup&gt;a&lt;/sup&gt;</td>
<td>&gt;30°&lt;sup&gt;a&lt;/sup&gt;</td>
<td>&gt;25°&lt;sup&gt;a&lt;/sup&gt;</td>
<td>&gt;18°&lt;sup&gt;a&lt;/sup&gt;</td>
</tr>
<tr>
<td>California crudes</td>
<td>&gt;10°&lt;sup&gt;a&lt;/sup&gt;</td>
<td>10 to 45°&lt;sup&gt;a&lt;/sup&gt;</td>
<td>&gt;25°&lt;sup&gt;a&lt;/sup&gt;</td>
<td>&gt;25°&lt;sup&gt;a&lt;/sup&gt;</td>
<td>&gt;18°&lt;sup&gt;a&lt;/sup&gt;</td>
</tr>
<tr>
<td>Fraction of oil remaining in area to be flooded (before EOR), % PV</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Concentration before and after flooding (porosity x oil saturation)</td>
<td>&gt;500</td>
<td>&gt;400</td>
<td>NC</td>
<td>NC</td>
<td>NC</td>
</tr>
<tr>
<td>Depth, ft</td>
<td>&gt;6,000</td>
<td>&gt;500</td>
<td>NC</td>
<td>NC</td>
<td>NC &lt;sup&gt;(5,500)&lt;sup&gt;°&lt;sup&gt;b&lt;/sup&gt;</td>
</tr>
<tr>
<td>Temperature, °F</td>
<td>NC</td>
<td>NC</td>
<td>&gt;1,500</td>
<td>NC</td>
<td>NC</td>
</tr>
<tr>
<td>Original bottom-hole pressure, psi</td>
<td>NC</td>
<td>NC</td>
<td>NC</td>
<td>NC</td>
<td>NC</td>
</tr>
<tr>
<td>Net pay thickness, ft</td>
<td>&gt;20</td>
<td>&gt;10</td>
<td>NC</td>
<td>NC</td>
<td>NC</td>
</tr>
<tr>
<td>Permeability, md</td>
<td>NC</td>
<td>NC</td>
<td>NC</td>
<td>&gt;20 (with polymer drive)</td>
<td></td>
</tr>
<tr>
<td>Transmissibility, (permeability x thickness/viscosity)</td>
<td>&gt;100</td>
<td>&gt;20</td>
<td>NC</td>
<td>NC</td>
<td>NC</td>
</tr>
<tr>
<td>Natural water drive&lt;sup&gt;a&lt;/sup&gt;</td>
<td>none to weak</td>
<td>none to weak</td>
<td>none to weak</td>
<td>none to weak</td>
<td>none to weak</td>
</tr>
<tr>
<td>Gas cap&lt;sup&gt;a&lt;/sup&gt;</td>
<td>none to minor</td>
<td>none to minor</td>
<td>none to weak</td>
<td>none to weak</td>
<td>none to weak</td>
</tr>
<tr>
<td>Fractures unless extreme lithology</td>
<td>NC</td>
<td>NC</td>
<td>NC</td>
<td>sandstone only&lt;sup&gt;a&lt;/sup&gt;</td>
<td>NC</td>
</tr>
<tr>
<td>Lithology</td>
<td>NC</td>
<td>NC</td>
<td>NC</td>
<td>&lt;50,000 ppm&lt;sup&gt;a&lt;/sup&gt;</td>
<td>NC</td>
</tr>
<tr>
<td>Salinity, ppm total dissolved solids</td>
<td>NC</td>
<td>NC</td>
<td>NC</td>
<td>&lt;1,000 ppm&lt;sup&gt;a&lt;/sup&gt;</td>
<td>NC</td>
</tr>
<tr>
<td>Hardness, ppm, calcium and magnesium</td>
<td>NC</td>
<td>NC</td>
<td>NC</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Comments</td>
<td>Porosity&lt;sup&gt;a&lt;/sup&gt; thickness (high) preferred</td>
<td>Thin pay preferred</td>
<td>Homogeneous formation preferred</td>
<td>Use with or before</td>
<td>Low clay content</td>
</tr>
<tr>
<td>Porosity&lt;sup&gt;a&lt;/sup&gt; thickness (high)</td>
<td></td>
<td></td>
<td>Low clay formation preferred</td>
<td>Low calcium and clay content</td>
<td></td>
</tr>
<tr>
<td>10-acre spacing</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Economic fresh water available</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Economic fuel available</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High net to gross pay &lt;sup&gt;a&lt;/sup&gt;</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low clay content</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<sup>a</sup>NC = Not a critical factor (for all).
<sup>b</sup>fraction of oil to be flooded: Assuming 80% of area of reservoir contains 98% of remaining oil, the oil saturation for the total field becomes 42% PV.
<sup>c</sup>5,500 ft is approximately the depth at which the temperature constraint of 220°F will be reached.
<sup>d</sup>These criteria are applicable to reservoirs with substantial remaining primary recovery.
<sup>e</sup>Considered a constraint under current technology.
<sup>f</sup>This table is an analytic tool based on analysis of numerous EOR projects; it should not, however, be interpreted as a strict guide to the applicability of a given process to a specific reservoir.

Table 1. Summary of Technical Screening Criteria for EOR Candidates

<table>
<thead>
<tr>
<th>Chemical Flooding Type</th>
<th>Reservoir Characteristics</th>
<th>Flow Properties</th>
<th>Permeability</th>
<th>viscosity</th>
<th>Oil</th>
<th>Water</th>
<th>Gas</th>
<th>Sedimentation</th>
<th>Solubility</th>
<th>Flowability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Polymer</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sandstone preferred,</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbonate permeable</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>&gt;10</td>
<td>&lt;3000</td>
<td>&lt;200</td>
<td>&gt;20</td>
<td>&gt;50</td>
<td>&gt;90%</td>
<td></td>
<td></td>
<td>&gt;80</td>
<td>&lt;100</td>
</tr>
<tr>
<td></td>
<td>N.C.</td>
<td>&lt;3000</td>
<td>&gt;40</td>
<td>&gt;20</td>
<td>&gt;90</td>
<td>&gt;80%</td>
<td></td>
<td>Light or</td>
<td>&gt;20</td>
<td>&lt;100</td>
</tr>
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<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
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<td>intermediate</td>
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<td></td>
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<td></td>
<td></td>
<td>are preferred</td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>&lt;100,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>good potential</td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>in O.W.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
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<td></td>
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<td></td>
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<td></td>
</tr>
</tbody>
</table>

*Note: All criteria are satisfied.*

- N.C. = Not Critical
- W.H. = Water-hydraulic
- O.W. = Oil-wet
- API = American Petroleum Institute
<table>
<thead>
<tr>
<th>Table 3—SUMMARY OF SCREENING CRITERIA FOR EOR METHODS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Gas Injection Methods (miscible)</strong></td>
</tr>
<tr>
<td><strong>Detail</strong></td>
</tr>
<tr>
<td>1</td>
</tr>
<tr>
<td>2</td>
</tr>
<tr>
<td>3</td>
</tr>
<tr>
<td>1-3</td>
</tr>
<tr>
<td><strong>(Enhanced) Waterflooding</strong></td>
</tr>
<tr>
<td><strong>Detail</strong></td>
</tr>
<tr>
<td>4</td>
</tr>
<tr>
<td>5</td>
</tr>
<tr>
<td><strong>Thermal/Mechanical</strong></td>
</tr>
<tr>
<td><strong>Detail</strong></td>
</tr>
<tr>
<td>6</td>
</tr>
<tr>
<td>7</td>
</tr>
<tr>
<td>—</td>
</tr>
</tbody>
</table>

NC = Not Critical.
Underlined values represent the approximate mean or average for current field projects.

aSee Table 3 of Ref. 16.
bSeal from some carbonate reservoirs if the intent is to sweep only the fracture system.
cTransmissibility > 20 md-ft/psi
dTransmissibility > 50 md-ft/psi
*See depth.

<table>
<thead>
<tr>
<th>Screening Parameters</th>
<th>Values Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Viscosity at Reservoir Conditions</td>
<td>&lt;12</td>
</tr>
<tr>
<td>API Gravity</td>
<td>&gt;30</td>
</tr>
<tr>
<td>Fraction of oil before EOR, [% PV]</td>
<td>&gt;25</td>
</tr>
<tr>
<td>Oil Concentration, [bbls/acre-ft]</td>
<td>NC</td>
</tr>
<tr>
<td>Depth, [ft]</td>
<td>&gt;3000</td>
</tr>
<tr>
<td>Original Bottomhole Pressure, [psi]</td>
<td>&gt;1500</td>
</tr>
<tr>
<td>Net Pay Thickness, [ft]</td>
<td>NC</td>
</tr>
<tr>
<td>Permeability, [md]</td>
<td>NC</td>
</tr>
<tr>
<td>Temperature, [°F]</td>
<td>NC</td>
</tr>
<tr>
<td>Transmissibility, [md-ft/cP]</td>
<td>NC</td>
</tr>
</tbody>
</table>

NC: Not a Critical Factor


Results obtained with the three simulators compare quite well and indicate that on the average, the best reservoir for carbon dioxide injection should have an oil gravity of 36 °API, a temperature of 150 °F, a permeability of 300 mD, an oil saturation at the start of the injection of 60 %, a reservoir pressure at the time of injection of around 200 psi over minimum miscibility pressure, a porosity of 20 %, a net sand thickness of 40 ft and a reservoir dip of 20 °.
Results of simulations studies indicate that the reservoir properties which most influence CO₂ flooding performance are API gravity, oil saturation and pressure. Reservoirs with an oil gravity around 37 °API, an oil saturation around 60 % and a pressure 1.3 the minimum miscibility pressure should be preferred for the process. A comparison of the simulators used here indicates that the semi-analytical predictive type model does a good job predicting CO₂ flooding performance, often in agreement with the fully compositional simulator.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Optimum</th>
<th>Worst (left)</th>
<th>Worst (right)</th>
<th>Weight</th>
</tr>
</thead>
<tbody>
<tr>
<td>Api Gravity</td>
<td>37</td>
<td>20</td>
<td>71</td>
<td>0.24</td>
</tr>
<tr>
<td>Temperature, [°F]</td>
<td>160</td>
<td>130</td>
<td>200°</td>
<td>0.14</td>
</tr>
<tr>
<td>Permeability, [md]</td>
<td>300</td>
<td>18</td>
<td>2500°</td>
<td>0.07</td>
</tr>
<tr>
<td>Oil Saturation, [%]</td>
<td>60</td>
<td>30</td>
<td>92</td>
<td>0.20</td>
</tr>
<tr>
<td>Pressure/PMM</td>
<td>1.3</td>
<td>0.089</td>
<td>1.3°</td>
<td>0.19</td>
</tr>
<tr>
<td>Porosity, [%]</td>
<td>20</td>
<td>9</td>
<td>33</td>
<td>0.02</td>
</tr>
<tr>
<td>Net Oil Sand Thickness, [ft]</td>
<td>50</td>
<td>5</td>
<td>180</td>
<td>0.11</td>
</tr>
<tr>
<td>Dip, [degree]</td>
<td>20</td>
<td>5</td>
<td>20°</td>
<td>0.03</td>
</tr>
</tbody>
</table>

PMM denotes the MMP

<table>
<thead>
<tr>
<th>Parameters of Successful Reservoirs</th>
<th>Light Oils</th>
<th>Medium Oils</th>
<th>Heavy Oils</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Viscosity (cp)</td>
<td>0.4 to 8</td>
<td>32 to 46</td>
<td>415 to 3000</td>
</tr>
<tr>
<td>Oil Gravity (°API)</td>
<td>23 to 38</td>
<td>17 to 23</td>
<td>11 to 14</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>13 to 32</td>
<td>25 to 32</td>
<td>12 to 32</td>
</tr>
<tr>
<td>Depth (feet)</td>
<td>1200 to 12870</td>
<td>2600 to 4200</td>
<td>1150 to 4125</td>
</tr>
<tr>
<td>Thickness (feet)</td>
<td>6 to 60</td>
<td>36 to 220</td>
<td>200</td>
</tr>
<tr>
<td>Permeability (mD)</td>
<td>10 to 3000</td>
<td>150 to 388</td>
<td>250 to 350</td>
</tr>
</tbody>
</table>

Factors Favorable to Huff ‘n’ Puff Operations
- High oil saturations
- Thick pay intervals
- Mild pressure support to production
- Soak intervals 2 to 4 weeks
- High injection volumes and rates
- Deep reservoirs
- Maximum of 3 cycles

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Optimum</th>
<th>Weight</th>
</tr>
</thead>
<tbody>
<tr>
<td>API Gravity</td>
<td>37</td>
<td>0.24</td>
</tr>
<tr>
<td>Oil saturation, %</td>
<td>60</td>
<td>0.20</td>
</tr>
<tr>
<td>Pressure/ MMP</td>
<td>1.30</td>
<td>0.19</td>
</tr>
<tr>
<td>Temperature, °F</td>
<td>160</td>
<td>0.14</td>
</tr>
<tr>
<td>Net oil thickness, ft</td>
<td>50</td>
<td>0.11</td>
</tr>
<tr>
<td>Permeability, md</td>
<td>300</td>
<td>0.07</td>
</tr>
<tr>
<td>Dip, °</td>
<td>20</td>
<td>0.03</td>
</tr>
<tr>
<td>Porosity, %</td>
<td>20</td>
<td>0.02</td>
</tr>
</tbody>
</table>

Table 2: Worst Parameters from Louisiana's Reservoir Database.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Lower Limit</th>
<th>Upper Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>API Gravity</td>
<td>24</td>
<td>48</td>
</tr>
<tr>
<td>Oil saturation, %</td>
<td>8</td>
<td>80</td>
</tr>
<tr>
<td>Pressure/ MMP</td>
<td>0.10</td>
<td>1.47</td>
</tr>
<tr>
<td>Temperature, °F</td>
<td>80</td>
<td>276</td>
</tr>
<tr>
<td>Net oil thickness, ft</td>
<td>5</td>
<td>175</td>
</tr>
<tr>
<td>Permeability, md</td>
<td>17</td>
<td>3485</td>
</tr>
<tr>
<td>Dip, °</td>
<td>0.03</td>
<td>64</td>
</tr>
<tr>
<td>Porosity, %</td>
<td>17.6</td>
<td>34</td>
</tr>
</tbody>
</table>

Table 3  
HYDROCARBON MISCELLY FLOODING

<table>
<thead>
<tr>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrocarbon miscible flooding consists of injecting light hydrocarbons through the reservoir to form a miscible flood. Three different methods are used. One method uses about 5% PV slug of liquified petroleum gas (LPG) such as propane, followed by natural gas or gas and water. A second method, called Enriched (Condensing) Gas Drive, consists of injecting a 10-20% PV slug of natural gas that is enriched with ethane through hexane (C2 to C6), followed by lean gas (dry, mostly methane) and possibly water. The enriching components are transferred from the gas to the oil. The third method, called High Pressure (Vaporizing) Gas Drive, consists of injecting lean gas at high pressure to vaporize C2 - C6 components from the crude oil being displaced.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Mechanisms</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrocarbon miscible flooding recovers crude oil by:</td>
</tr>
<tr>
<td>-- generating miscibility (in the condensing and vaporizing gas drive)</td>
</tr>
<tr>
<td>-- increasing the oil volume (swelling)</td>
</tr>
<tr>
<td>-- decreasing the viscosity of the oil</td>
</tr>
</tbody>
</table>

## TECHNICAL SCREENING GUIDES

### Crude Oil

| Gravity | > 35° API |
| Viscosity | < 10 cp |
| Composition | High percentage of light hydrocarbons (C2 - C6) |

### Reservoir

| Oil Saturation | > 30% PV |
| Type of Formation | Sandstone or carbonate with a minimum of fractures and high permeability streaks |
| Net Thickness | Relatively thin unless formation is steeply dipping |
| Average Permeability | Not critical if uniform |
| Depth | > 2000 ft (LPG) to > 5000 ft (High Pressure Gas) |
| Temperature | Not critical |

### Limitations

The minimum depth is set by the pressure needed to maintain the generated miscibility. The required pressure ranges from about 1200 psi for the LPG process to 3000-5000 psi for the High Pressure Gas Drive, depending on the oil.

A steeply dipping formation is very desirable to permit some gravity stabilization of the displacement which normally has an unfavorable mobility ratio.

### Problems

- Viscous fingering results in poor vertical and horizontal sweep efficiency. Large quantities of expensive products are required.
- Solvent may be trapped and not recovered.
Table 6
SURFACTANT/POLYMER FLOODING

Description

Surfactant/polymer flooding, also called micellar/polymer or microemulsion flooding, consists of injecting a slug that contains water, surfactant, electrolyte (salt), usually a co-solvent (alcohol), and possibly a hydrocarbon (oil). The size of the slug is often 5-15% PV for a high surfactant concentration system and 15-50% PV for low concentrations. The surfactant slug is followed by polymer-thickened water. Concentrations of the polymer often ranges from 500-2000 mg/L; the volume of polymer solution injected may be 50% PV, more or less, depending on the process design.

Mechanisms

Surfactant/polymer flooding recovers oil by:
-- lowering the interfacial tension between oil and water
-- solubilization of oil
-- emulsification of oil and water
-- mobility enhancement

TECHNICAL SCREENING GUIDES

Crude Oil

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Criterion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity</td>
<td>&gt; 25° API</td>
</tr>
<tr>
<td>Viscosity</td>
<td>&lt; 30 cp</td>
</tr>
<tr>
<td>Composition</td>
<td>Light intermediates are desirable</td>
</tr>
</tbody>
</table>

Reservoir

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Criterion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Saturation</td>
<td>&gt; 30% PV</td>
</tr>
<tr>
<td>Type of Formation</td>
<td>Sandstones preferred</td>
</tr>
<tr>
<td>Net Thickness</td>
<td>&gt; 10 ft</td>
</tr>
<tr>
<td>Average Permeability</td>
<td>&gt; 20 md</td>
</tr>
<tr>
<td>Depth</td>
<td>&lt; about 8000 ft (see Temperature)</td>
</tr>
<tr>
<td>Temperature</td>
<td>&lt; 175°F</td>
</tr>
</tbody>
</table>

Limitations

An areal sweep of more than 50% on waterflood is desired.
Relatively homogeneous formation is preferred.
High amounts of anhydrite, gypsum, or clays are undesirable.
Available systems provide optimum behavior over a very narrow set of conditions.
With commercially available surfactants, formation water chlorides should be < 20,000 ppm and divalent ions (Ca++ and Mg++) < 500 ppm.

Problems

Complex and expensive system.
Possibility of chromatographic separation of chemicals.
High adsorption of surfactant.
Interactions between surfactant and polymer.
Degradation of chemicals at high temperature.
Table 7

POLYMER FLOODING

Description

The objective of polymer flooding is to provide better displacement and volumetric sweep efficiencies during a waterflood. Polymer augmented waterflooding consists of adding water soluble polymers to the water before it is injected into the reservoir. Low concentrations (often 250-2000 mg/L) of certain synthetic or biopolymers are used; properly sized treatments may require 15-25% reservoir PV.

Mechanisms

Polymers improve recovery by:

-- increasing the viscosity of water
-- decreasing the mobility of water
-- contacting a larger volume of the reservoir

TECHNICAL SCREENING GUIDES

Crude Oil

<table>
<thead>
<tr>
<th>Property</th>
<th>Criterion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity</td>
<td>&gt; 25° API</td>
</tr>
<tr>
<td>Viscosity</td>
<td>&lt; 150 cp (preferably &lt; 100)</td>
</tr>
<tr>
<td>Composition</td>
<td>Not critical</td>
</tr>
</tbody>
</table>

Reservoir

<table>
<thead>
<tr>
<th>Property</th>
<th>Criterion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Saturation</td>
<td>&gt; 10% PV mobile oil</td>
</tr>
<tr>
<td>Type of Formation</td>
<td>Sandstones preferred but can be used in carbonates</td>
</tr>
<tr>
<td>Net Thickness</td>
<td>Not critical</td>
</tr>
<tr>
<td>Average Permeability</td>
<td>&gt; 10 md (as low as 3 md in some cases)</td>
</tr>
<tr>
<td>Depth</td>
<td>&lt; about 9000 ft (see Temperature)</td>
</tr>
<tr>
<td>Temperature</td>
<td>&lt; 200°F to minimize degradation</td>
</tr>
</tbody>
</table>

Limitations

If oil viscosities are high, a higher polymer concentration is needed to achieve the desired mobility control.

Results are normally better if the polymer flood is started before the water-oil ratio becomes excessively high.

Clays increase polymer adsorption.

Some heterogeneities are acceptable but, for conventional polymer flooding, reservoirs with extensive fractures should be avoided. If fractures are present, the crosslinked or gelled polymer techniques may be applicable.

Problems

Lower injectivity than with water can adversely affect oil production rate in the early stages of the polymer flood.

Acrylamide-type polymers lose viscosity due to shear degradation, or increases in salinity and divalent ions.

Xanthan gum polymers cost more, are subject to microbial degradation, and have a greater potential for wellbore plugging.
Table 8
ALKALINE FLOODING

Description

Alkaline or caustic flooding involves the injection of chemicals such as sodium hydroxide, sodium silicate or sodium carbonate. These chemicals react with organic petroleum acids in certain crudes to create surfactants in situ. They also react with reservoir rocks to change wettability. The concentration of the alkaline agent is normally 0.2 to 5%; slug size is often 10 to 50% PV, although one successful flood only used 2% PV, (but this project also included polymers for mobility control). Polymers may be added to the alkaline mixture, and polymer-thickened water can be used following the caustic slug.

Mechanisms

Alkaline flooding recovers crude oil by:

-- a reduction of interfacial tension resulting from
the produced surfactants
-- changing wettability from oil-wet to water-wet
-- changing wettability from water-wet to oil-wet
-- emulsification and entrainment of oil
-- emulsification and entrainment of oil to aid in mobility control
-- solubilization of rigid oil films at oil-water interfaces
(Not all mechanisms are operative in each reservoir.)

TECHNICAL SCREENING GUIDES

Crude Oil

Gravity 13° to 35° API
Viscosity < 200 cp
Composition Some organic acids required

Reservoir

Oil Saturation Above waterflood residual
Type of Formation Sandstones preferred
Net Thickness Not critical
Average Permeability > 20 md
Depth < about 9000 ft (see Temperature)
Temperature < 200°F preferred

Limitations

Best results are obtained if the alkaline material reacts with the crude oil; the oil should have an acid number of more than 0.2 mg KOH/g of oil.

The interfacial tension between the alkaline solution and the crude oil should be less than 0.01 dyne/cm.

At high temperatures and in some chemical environments, excessive amounts of alkaline chemicals may be consumed by reaction with clays, minerals, or silica in the sandstone reservoir.

Carbonates are usually avoided because they often contain anhydrite or gypsum which interact adversely with the caustic chemical.

Problems

Scaling and plugging in the producing wells.
High caustic consumption.
Table 9

IN-SITU COMBUSTION

Description

In-situ combustion or fireflooding involves starting a fire in the reservoir and injecting air to sustain the burning of some of the crude oil. The most common technique is forward combustion in which the reservoir is ignited in an injection well, and air is injected to propagate the combustion front away from the well. One of the variations of this technique is a combination of forward combustion and waterflooding (OCFCAW). A second technique is reverse combustion in which a fire is started in a well that will eventually become a producing well, and air injection is then switched to adjacent wells; however, no successful field trials have been completed for reverse combustion.

Mechanisms

In-situ combustion recovers crude oil by:

-- the application of heat which is transferred downstream by conduction and convection, thus lowering the viscosity of the crude
-- the products of steam distillation and thermal cracking which are carried forward to mix with and upgrade the crude
-- burning coke that is produced from the heavy ends of the crude oil
-- the pressure supplied to the reservoir by the injected air

Technical Screening Guides

Crude Oil

<table>
<thead>
<tr>
<th>Property</th>
<th>Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity</td>
<td>&lt; 40° API (normally 10-25°)</td>
</tr>
<tr>
<td>Viscosity</td>
<td>&lt; 1000 cp</td>
</tr>
<tr>
<td>Composition</td>
<td>Some asphalitic components to aid coke deposition</td>
</tr>
</tbody>
</table>

Reservoir

<table>
<thead>
<tr>
<th>Property</th>
<th>Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Saturation</td>
<td>&gt; 500 bbl/acre-ft (or &gt; 40-50% PV)</td>
</tr>
<tr>
<td>Type of Formation</td>
<td>Sand or sandstone with high porosity</td>
</tr>
<tr>
<td>Net Thickness</td>
<td>&gt; 10 ft</td>
</tr>
<tr>
<td>Average Permeability</td>
<td>&gt; 100 md</td>
</tr>
<tr>
<td>Transmissibility</td>
<td>&gt; 20 md ft/cp</td>
</tr>
<tr>
<td>Depth</td>
<td>&gt; 500 ft</td>
</tr>
<tr>
<td>Temperature</td>
<td>&gt; 150°F preferred</td>
</tr>
</tbody>
</table>

Limitations

If sufficient coke is not deposited from the oil being burned, the combustion process will not be sustained.

If excessive coke is deposited, the rate of advance of the combustion zone will be slow, and the quantity of air required to sustain combustion will be high.

Oil saturation and porosity must be high to minimize heat loss to rock.

Process tends to sweep through upper part of reservoir so that sweep efficiency is poor in thick formations.

Problems

Adverse mobility ratio.

Complex process, requiring large capital investment, is difficult to control.

Produced flue gases can present environmental problems.

Operational problems such as severe corrosion caused by low pH hot water, serious oil-water emulsions, increased sand production, deposition of carbon or wax, and pipe failures in the producing wells as a result of the very high temperatures.
Table 10

STEAMFLOODING

Description

The steam drive process or steamflooding involves the continuous injection of about 80% quality steam to displace crude oil towards producing wells. Normal practice is to precede and accompany the steam drive by a cyclic steam stimulation of the producing wells (called huff and puff).

Mechanisms

Steam recovers crude oil by:

-- heating the crude oil and reducing its viscosity
-- supplying pressure to drive oil to the producing well

TECHNICAL SCREENING GUIDES

<table>
<thead>
<tr>
<th>Crude Oil</th>
<th>Reservoir</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gravity</td>
<td>Oil Saturation</td>
</tr>
<tr>
<td>Viscosity</td>
<td>&gt; 500 bbl/acre-ft (or &gt; 40-50% PV)</td>
</tr>
<tr>
<td>Composition</td>
<td>Type of Formation</td>
</tr>
<tr>
<td></td>
<td>Sand or sandstone with high porosity and permeability preferred</td>
</tr>
<tr>
<td></td>
<td>Net Thickness</td>
</tr>
<tr>
<td></td>
<td>&gt; 20 feet</td>
</tr>
<tr>
<td></td>
<td>Average Permeability</td>
</tr>
<tr>
<td></td>
<td>&gt; 200 md (see Transmissibility)</td>
</tr>
<tr>
<td>Transmissibility</td>
<td>Depth</td>
</tr>
<tr>
<td></td>
<td>&gt; 100 md ft/cp</td>
</tr>
<tr>
<td>Temperature</td>
<td>Temperature</td>
</tr>
<tr>
<td></td>
<td>300-5000 ft</td>
</tr>
</tbody>
</table>

Limitations

Oil saturations must be quite high and the pay zone should be more than 20 feet thick to minimize heat losses to adjacent formations.

Lighter, less viscous crude oils can be steamflooded but normally will not be if the reservoir will respond to an ordinary waterflood.

Steamflooding is primarily applicable to viscous oils in massive, high permeability sandstones or unconsolidated sands.

Because of excessive heat losses in the wellbore, steamflooded reservoirs should be as shallow as possible as long as pressure for sufficient injection rates can be maintained.

Steamflooding is not normally used in carbonate reservoirs.

Since about one-third of the additional oil recovered is consumed to generate the required steam, the cost per incremental barrel of oil is high.

A low percentage of water-sensitive clays is desired for good injectivity.

Problems

Adverse mobility ratio and channeling of steam.
<table>
<thead>
<tr>
<th>Gas Injection Methods</th>
<th>Oil Properties</th>
<th>Reservoir Characteristics</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gravity (API)</td>
<td>Viscosity (cp)</td>
</tr>
<tr>
<td>Hydrocarbon</td>
<td>&gt; 35</td>
<td>&lt; 10</td>
</tr>
<tr>
<td>Nitrogen &amp; Propane</td>
<td>&gt; 24</td>
<td>&lt; 10</td>
</tr>
<tr>
<td>Carbon Dioxide</td>
<td>&gt; 26</td>
<td>&lt; 15</td>
</tr>
</tbody>
</table>

| Chemical Flooding     |                |                |                |                |                |                        |                |                |                |
| Surfactant/Polymer    | > 25          | < 30            | Light inter-molecular desired | > 500 PV | Sandstone preferred | > 10 | > 20 | < 2000 | < 175 |
| Polymer               | > 25          | < 150           | N.C.           | > 100 PV | Mobile oil | Sandstone preferred; Carbonate possible | N.C. | > 10 | < 5000 | < 100 |
| Alkaline              | 20-35         | < 200           | Some Organic Acids | Above Waterflood Residual | Sandstone preferred | N.C. | > 20 | < 9000 | < 200 |

| Thermal               |                |                |                |                |                |                        |                |                |                |
| Combustion            | < 40          | < 1000          | Soot Components | > 40-500 PV | Sand or Sandstone with high permeity | > 10 | > 100 | > 500 | > 150 preferred |
| Steamflooding         | < 25          | > 20            | N.C.           | > 40-500 PV | Sand or Sandstone with high permeity | > 10 | > 200 | > 300-3000 | N.C. |

N.C.: Not Critical

*Transmissibility > 20 m² ft/cp
**Transmissibility > 100 m² ft/cp

<table>
<thead>
<tr>
<th></th>
<th>Steam Injection Implemented Technology</th>
<th>Steam Injection Advanced Technology</th>
<th>In Situ Combustion Implemented Technology</th>
<th>In Situ Combustion Advanced Technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth (ft)</td>
<td>≤ 3,000</td>
<td>≤ 5,000</td>
<td>≤ 11,500</td>
<td>-</td>
</tr>
<tr>
<td>Net Pay (ft)</td>
<td>≥ 20</td>
<td>≥ 15</td>
<td>≥ 20</td>
<td>≥ 10</td>
</tr>
<tr>
<td>Porosity*</td>
<td>≥ 0.20</td>
<td>≥ 0.15</td>
<td>≥ 0.20</td>
<td>≥ 0.15</td>
</tr>
<tr>
<td>Oil Saturation x Porosity</td>
<td>≥ 0.10</td>
<td>≥ 0.08</td>
<td>≥ 0.08</td>
<td>≥ 0.08</td>
</tr>
<tr>
<td>Permeability (md)</td>
<td>≥ 250</td>
<td>≥ 10</td>
<td>≥ 35</td>
<td>≥ 10</td>
</tr>
<tr>
<td>Oil Gravity (*API)</td>
<td>10 to 34</td>
<td>-</td>
<td>10 to 35</td>
<td>-</td>
</tr>
<tr>
<td>Oil Viscosity (cp)</td>
<td>≤ 15,000</td>
<td>-</td>
<td>≤ 5,000</td>
<td>≤ 5,000</td>
</tr>
<tr>
<td>Transmissibility (md*ft/cp)</td>
<td>≥ 5</td>
<td>-</td>
<td>≥ 5</td>
<td>-</td>
</tr>
<tr>
<td>Current Reservoir Pressure (psia)</td>
<td>≤ 1,500</td>
<td>≤ 2,000</td>
<td>≤ 2,000</td>
<td>≤ 4,000</td>
</tr>
</tbody>
</table>

*Ignored if oil saturation x porosity criteria are satisfied.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Lazar (1990)</th>
<th>DOE</th>
<th>Reviewed Projects Range</th>
<th>24 Norwegian fields range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity, %</td>
<td>≥ 20</td>
<td>&lt; 32</td>
<td>8 - 32</td>
<td>11 - 35</td>
</tr>
<tr>
<td>Permeability, md</td>
<td>≥ 150</td>
<td>&gt; 50</td>
<td>0,1 - 5770</td>
<td>1 - 20000</td>
</tr>
<tr>
<td>Reservoir Temperature, oC</td>
<td>≤ 70</td>
<td>&lt; 80</td>
<td>19 - 82</td>
<td>61 - 155</td>
</tr>
<tr>
<td>Salinity, g/l</td>
<td>≤ 150</td>
<td>≤ 150</td>
<td>1,4 - 104</td>
<td>14 - 273</td>
</tr>
<tr>
<td>Oil Viscosity, cp</td>
<td>5 - 50</td>
<td>3 - 50</td>
<td>0,1 - 4,83</td>
<td></td>
</tr>
<tr>
<td>Reservoir depth, m</td>
<td>&lt; 2347</td>
<td>122 - 2103</td>
<td>1300 - 4208</td>
<td></td>
</tr>
</tbody>
</table>

Table 3: Screening criteria for MEOR / MIOR processes

Criteria for each EOR process are listed below.

**Waterflooding**
- Oil mobility $> 0.1$ md/mPa.s.
- Oil viscosity (at bubble point) $< 2000$ mPa.s.
- Oil saturation $> 50\%$
- Current water oil ratio $< 10$ bbl/bbl
- No active water drive
- The condition of free gas/mobile water saturation:
  \[ (1 - \text{connate water saturation} - \text{current oil saturation})^2 \ast \text{(oil viscosity)} < 0.5 \]
- Current pressure / Initial Pressure $> 0.7$

**Polymer Flooding**
- Reservoir temperature $< 158^\circ F$
- Oil viscosity (at bubble point) $< 150$ mPa.s.
- Horizontal permeability $> 50$ md
- Oil saturation $> 60\%$
- Current water oil ratio $< 10$ bbl/bbl
- No active water drive
- Local or no bottom water
- Local or no gas cap
- Water hardness $< 1000$ ppm
- Water salinity $< 100,000$ ppm

**Alkaline/Polymer Flooding**
- Sandstone formation
- Reservoir temperature $< 158^\circ F$
- Oil gravity $< 35$ °API
- Oil viscosity (at bubble point) $< 150$ mPa.s.
- Horizontal permeability $> 50$ md
- Oil saturation $> 50\%$
- No active water drive
- Local or no bottom water
- Local or no gas cap
- Low clay content
- Water hardness $< 1000$ ppm
- Water salinity $< 50,000$ ppm
**Surfactant/Polymer Flooding**
Reservoir temperature < 158F
Oil viscosity (at bubble point) < 150 mPa.s.
Horizontal permeability > 50 md
Oil saturation > 35%
No active water drive
Local or no bottom water
Local or no gas cap
Low clay content
Water hardness < 1000 ppm
Water salinity < 50,000 ppm

**Alkaline/Surfactant/Polymer Flooding**
Sandstone formation
Reservoir temperature < 158F
Oil gravity < 35 °API
Oil viscosity (at bubble point) < 150 mPa.s.
Horizontal permeability > 50 md
Oil saturation > 35%
No active water drive
Local or no bottom water
Local or no gas cap
Low clay content
Water hardness < 1000 ppm
Water salinity < 50,000 ppm
**Nitrogen Miscible**
Depth > 1800 meter
Oil saturation > 35%
MMP (Minimum Miscibility Pressure) < (original reservoir pressure)
Oil gravity > 35 °API
Oil viscosity (at bubble point) < 2 mPa.s.
Local or no gas cap present
Initial pressure > MMP

**In Situ Combustion**
No fracture
Local or no bottom water
Local or no gas cap
Net pay thickness > 3 meter
Depth between 150 and 1800 meters
Permeability > 50 md
Oil transmissibility > 16 md-m/mPa.s.
Oil viscosity (at bubble point) between 2 and 5000 mPa.s.
Porosity > 18%
Oil Content (Porosity * oil Saturation) > 0.065

**Steam Flooding**
Depth < 1400 meters
Permeability > 200 md
Porosity > 20%
Net pay thickness > 6 meters
Current pressure < 1500 psi
Oil viscosity (at bubble point) between 50 and 5000 mPa.s.
Low clay volume
Local or no gas cap present
No fractures present
Water oil ratio < 10 bbl/bbl
Oil transmissibility > 16 md-m/mPa.s
Oil Content > 0.065
**Immiscible Gas Flood**
Depth > 200 meter
Oil saturation > 50%
Oil gravity > 13 °API
Oil viscosity (at bubble point) < 600 mPa.s.
No active water drive
Local or no bottom water
Local or no gas cap

**Carbon Dioxide Miscible**
Local or no gas cap present
Reservoir temperature > 86F
MMP (Minimum Miscibility Pressure) < (original reservoir pressure)
Oil gravity > 22 °API
Oil viscosity (at bubble point) < 10 mPa.s.
Oil saturation > 25%
Depth > 600 meters

**Hydrocarbon Miscible Flood**
Depth > 1200 meter
Oil saturation > 30%
Oil density < 24 °API
Oil viscosity (at bubble point) < 5 mPa.s.
Local or no gas cap present
Screening Criteria References

APPENDIX B: The Technique Followed to Display Data in Face Page
(Screening Report)

This is the simple technique followed to display data in face page:

1. Hide all sheets except L. F. Input Data (by right clicking on the corresponding tab and click hide).

2. Fill Columns for Result and Reason of L. F. Input Data sheet by mapping corresponding cells from Calculations sheet using the formula shown below:

3. Use small macro to fill the cell color as Red if result is Fail and has hidden the macro too.

Hence, there is no Visual Basic code involved in populating data in the face page. However a small VB code snippet is used to fill the cell color for "Fail" case.
APPENDIX C: Simulation Study – Lower Fars Formation (Ratqa Field)

C.1 Shale study

Figure C.1: Ratqa Field, Lower Fars formation, SR-XX (Presence of Shale)
Figure C.2: Ratqa Field, Lower Fars formation, SR-XX (Presence of Shale)
Figure C.3: Ratqa Field, Lower Fars formation, SR-XX (Presence of Shale)
Figure C.4: Ratqa Field, Lower Fars formation, SR-XX (Presence of Shale)
C.2 Viscosity Model

Viscosity data from the North part of the field shows lower viscosity compared to samples from the South (see Figure-C.5). Moreover, viscosity was seen to increase versus depth in both the North and South parts of the field. RFT analysis showed that the layers are connected which was confirmed by the KOC team; this means, that liquid may flow vertically in the reservoir; so the viscosity model should be capable of modeling the viscosity of the mixing oil. To model that phenomenon means to tune a single viscosity correlation and vary the composition by depth. To utilize this viscosity model, the EOS also has to be modeled to represent the composition variation with depth.

Viscosity of the North and South areas of the field cannot be represented by one correlation so separate correlations had to be applied and this had to be reflected in the EOS model.

In view of the complexity of the reservoir’s PVT, two different models were developed for the North and South areas. For each area, samples from different zones, F1A, F1B and F2A were used to tune a general viscosity correlation, Table-C.1 shows the results.

![Figure C.5: Oil viscosity vs depth in Ratqa Field. (Source: KOC)](image-url)
Table C.1: Results Summary of viscosity match in Lowr Fars.

<table>
<thead>
<tr>
<th>Well</th>
<th>Sample</th>
<th>Depth (ft)</th>
<th>T (°F)</th>
<th>Formation</th>
<th>Viscosity (cp)</th>
<th>Remark</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Lab</td>
<td>Model</td>
</tr>
<tr>
<td>SR-5</td>
<td>2</td>
<td>702</td>
<td>325</td>
<td>F1A</td>
<td>56.3</td>
<td>3.53</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>300</td>
<td></td>
<td>3.45</td>
<td>0.015</td>
</tr>
<tr>
<td>SR-13</td>
<td>3</td>
<td>737</td>
<td>90</td>
<td>F1B</td>
<td>186</td>
<td>180</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>325</td>
<td></td>
<td>3.05</td>
<td>2.91</td>
</tr>
<tr>
<td>SR-1</td>
<td>1</td>
<td>765</td>
<td>96</td>
<td>F2A</td>
<td>379.7</td>
<td>3.90</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>300</td>
<td></td>
<td>5.53</td>
<td>0.015</td>
</tr>
<tr>
<td>SR-9</td>
<td>1</td>
<td>627</td>
<td>90</td>
<td>F1A</td>
<td>755.7</td>
<td>77.11</td>
</tr>
<tr>
<td>SR-11</td>
<td>2</td>
<td>677</td>
<td>90</td>
<td>F1B</td>
<td>1116</td>
<td>1249.7</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>695</td>
<td>90</td>
<td>F2A</td>
<td>1500</td>
<td>1190.5</td>
</tr>
</tbody>
</table>

C.3 Fluid Components in the STARS dataset

After matching the data in WinProp, there are 3 options to import viscosity into the STARS data deck as follows:

1) Match dead oil

This method uses WinProp’s viscosity model to calculate the viscosities of all components that are liquid at the reference pressure and the specified temperature in the table, then calculates the apparent liquid viscosities of the gaseous components using STARS’ mixing rule.

2) Scale viscosity

This method will locate 2 temperatures for each component at which the component is in the liquid state. The viscosities at these two temperatures are extrapolated over all temperatures in the table.
3) 2-Parameters corresponding states model

This model uses the component “acentric factor” as an interpolating parameter, with the viscosities of ethane (C2) and eicosane (C20) used as reference values.

Option 1 is a new method that generates apparent liquid viscosities of light components by perturbing the dead oil at each temperature. This method gives more accurate intermediate component viscosities, whereas option 2 will give smoother curves. WinProp generated output for STARS was loaded into the model and composition variation by depth was assigned to account for viscosity variation by depth. It has to be noted that the models have just one viscosity type that varies versus depth by changing composition.

Figure C.6 and C. 7 show the viscosity after initializing the model for the North and South areas.
Figure C. 7: Oil viscosity (cp) - South Lower Fars
C.4 Water Saturation

Water saturation distribution of the North and South areas shows an acceptable match when compared against resistivity logs.

Figure C.8 : Resistivity Log, North, Ratqa Field, Lower Fars
Figure C.9: Resistivity Log, North, Ratqa Field, Lower Fars
Figure C.10: Water saturation, North, Ratqa Field, Lower Fars
Figure C.11 : Water saturation, North, Ratqa Field, Lower Fars
Figure C. 12: Resistivity Log, South, Ratqa Field, Lower Fars
Figure C. 13: Resistivity Log, South, Ratqa Field, Lower Fars
Figure C.14 : Water saturation, South Ratqa Field, Lower Fars
Figure C. 15: Water saturation, South Ratqa Field, Lower Fars.
APPENDIX D: Economic Model Calculation Sheets

The conversion and calculation tables for the cost and benefits (heat cost calculator, cost of heated fluid, cost of produced water calculator, cumulative oil - cash flow, discounted cash flow and NPV calculator) are presented here. Rather than give the spreadsheet alone, I give the algorithm that the spreadsheet used.
# Table D.1: Heat Cost Calculator

<table>
<thead>
<tr>
<th>Assumptions:</th>
<th>IN PUT</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heating fluid at</td>
<td>232</td>
<td>C</td>
</tr>
<tr>
<td>Initial water Temp</td>
<td>38</td>
<td>C</td>
</tr>
<tr>
<td>Boiler Efficiency</td>
<td>0.7</td>
<td></td>
</tr>
<tr>
<td>Fuel is Heavy Oil</td>
<td>17.72</td>
<td>$/MMBtu</td>
</tr>
<tr>
<td>Hot water is single-phase (No latent heat)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Saturated Steam of 100% quality</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Basis</td>
<td>1</td>
<td>Kg of heating fluid (heating water)</td>
</tr>
</tbody>
</table>

## Hotwater:

\[ Q_{\text{out}} = m \cdot C_p \cdot \Delta T \]

\[ Q_{\text{feed}} = 1\text{kg} \cdot 4.2 \text{ KJ/kg} \cdot (38 - 0) = 159.6 \text{ KJ} \]

\[ Q_{\text{out}} = 655.2 \text{ KJ} \]

With 70% Boiler efficiency:

\[ Q_{\text{out/eff.}} = Q_{\text{in hotwater}} = 936 \text{ KJ} \]

## Steam:

At 232 °C saturated steam of 100% quality

\[ Q_{\text{out}} = Q_{\text{sensible}} + Q_{\text{latent}} \]

\[ Q_{\text{sensible}} = 2804 \text{ KJ/kg} \]

\[ Q_{\text{latent}} = 2644.4 \text{ KJ} \]

With 70% boiler efficiency:

\[ Q_{\text{in steam}} = 3777.714286 \text{ KJ} \]

## Fuel Prices, Heavy fuel oil

- **Fuel Price, Heavy fuel oil**
  - 16.80 $/GJ

## Fuel Costs

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Hot water cost</strong> = ( Q_{\text{in hotwater}} \times \text{Fuel price} )</td>
<td>0.01572</td>
<td>$/kg hotwater</td>
</tr>
<tr>
<td></td>
<td>15.72125</td>
<td>$/ton hotwater</td>
</tr>
<tr>
<td><strong>Steam cost</strong> = ( Q_{\text{in steam}} \times \text{Fuel price} )</td>
<td>0.063451277</td>
<td>$/kg Steam</td>
</tr>
<tr>
<td></td>
<td>63.45127691</td>
<td>$/ton Steam</td>
</tr>
</tbody>
</table>

## Energy content of heating fluid (Btu/ton)

To find out these values: I used steam table and interpolation calculator in http://www.ajdesigner.com/phpinterpolation/linear_interpolation_equation.php and Convertor http://www.unitconverters.net/fuel-efficiency-mass-converter.html

<table>
<thead>
<tr>
<th>Temp. C</th>
<th>Kg (KJ/Kg)</th>
<th>Btu/ton</th>
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</thead>
<tbody>
<tr>
<td>206</td>
<td>2796.792</td>
<td>2950936.5</td>
</tr>
<tr>
<td>215</td>
<td>2800.792</td>
<td>2953650</td>
</tr>
<tr>
<td>230</td>
<td>2804.811</td>
<td>2957490</td>
</tr>
<tr>
<td>241</td>
<td>2804.955</td>
<td>2959360</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Energy content of heating fluid (Btu/ton)</th>
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<tbody>
<tr>
<td>Hotwater</td>
<td>780</td>
</tr>
<tr>
<td>Steam</td>
<td>3776.417</td>
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<td>Hotwater</td>
<td>284</td>
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<td>Steam</td>
<td>3773.117</td>
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<td>Hotwater</td>
<td>896</td>
</tr>
<tr>
<td>Steam</td>
<td>3777.714</td>
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<tr>
<td>Hotwater</td>
<td>990</td>
</tr>
<tr>
<td>Steam</td>
<td>3778.649</td>
</tr>
</tbody>
</table>

1 Btu = 1055.05585262 Joule

Conversion Formula (from KJ/Kg to Btu/ton) = 1 KJ/Kg * 1 Btu/1.005 KJ * 1000 Kg/1 ton
Table D.2: Cost of heated fluids $
<table>
<thead>
<tr>
<th>Date</th>
<th>Cumulative Produced Water SC (kg)</th>
<th>Cost of Produced Water Treatment $</th>
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</thead>
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<td>31/12/2012</td>
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<tr>
<td>31/12/2013</td>
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<td>31/12/2014</td>
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<td>31/12/2016</td>
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<td>31/12/2017</td>
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<td>31/12/2018</td>
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<tr>
<td>31/12/2019</td>
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<td>31/12/2020</td>
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<tr>
<td>31/12/2024</td>
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Notes:
- Modern concepts and technologies have demonstrated that this cost could be brought down to about $0.27/metric ton.
- 1 ton water = 8.5 bbl
### Yearly Cumulative Oil SC (bbl)

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<tbody>
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<td><strong>Net Water</strong></td>
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<td>1979.33</td>
<td>2028.20</td>
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<td>705.51</td>
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<td>718.46</td>
<td>778.25</td>
<td>778.14</td>
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<td>1979.33</td>
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</table>

*Hifaa Alajmi, 2012*