

**INVESTIGATION OF ITM IN-SITU COMBUSTION FOR
THERMAL ENHANCED OIL RECOVERY**

BY

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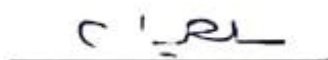
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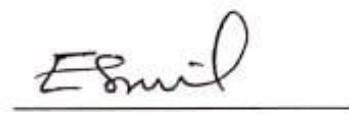
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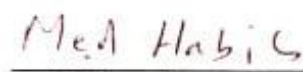

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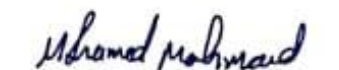

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To my Father, my mother, my wife, and my kids

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LIST OF ABBREVIATIONS

A	:	The Arrhenius constant
A_{cell}	:	Cell area
atm	:	Atmospheric pressure
a, b	:	Reactions order with respect to oxygen partial pressure and fuel concentration respectively.
CSS	:	Cyclic Steam Stimulation
C_f	:	Fuel concentration
E	:	The activation energy
D	:	Sweep or feed side nozzle (slot) width
D_{ij}	:	Diffusion coefficient of the component i in the component j.
$D_{i,m}$	:	Diffusion coefficient in the gaseous mixture
D_v	:	Coefficient of bulk diffusion through the membrane
$dppO_2$	:	Differential partial pressure of O_2
H	:	Distance between the nozzle and the membrane velocity vector
hr	:	hour
h_j	:	Enthalpy of phase j
H_{rk}	:	Enthalpy of reaction k
h^*_j	:	Enthalpy of phase j at injection or production
ITM	:	Ion transport membrane
J_{O_2}	:	Oxygen permeation rate

K	:	Reaction rate constant
k	:	Permeability
k_f	:	Forward reaction rate constant
k_r	:	Reverse reaction rate constant
k_{rj}		Relative permeability
MW	:	Molecular weight
m	:	The molar ratio of carbon dioxide to carbon monoxide produced
$\dot{m}$	:	Mass flow rate
n	:	The hydrogen/carbon of the coke burned.
P	:	Pressure
P_j	:	The pressure of phase j
P_w	:	The pressure of the wellbore
p_{O_2}'	:	Partial pressure of oxygen at the feed side
p_{O_2}''	:	Partial pressure of oxygen at the sweep side
Q_{hc}	:	The heat loss source/sink term.
Q_{ij}		Injection/Production term of component i in phase j
R	:	Universal gas constant
R_c		Reaction rate
r_{ik}	:	The rate of k^{th} reaction

$\vec{r}$	:	Position vector
$\vec{s}$	:	Direction vector
$\hat{s}$	:	Scattering direction vector
S_i	:	Term of the oxygen source/sink
S_i	:	Term of the oxygen source/sink
S_j	:	Saturation of phase j and x_{ij} is mole fraction of component i in phase j
T	:	Temperature
TCF	:	Thermochemical Flooding
U	:	Velocity vector
U_r	:	Rock internal energy
U_s	:	Solid internal energy
u_i	:	Velocity of component i
V_{cell}	:	Cell volume
W_i	:	The well productivity index
x_{ij}	:	Mole fraction of component i in phase j
Y_i	:	Mass fraction
Z	:	Gridblock thickness
μ	:	Viscosity

λ	:	Thermal conductivity of the formation
π	:	Number of phases
ρ	:	Density
σ_s	:	Scattering coefficient
θ_j	:	Mass production rate per unit volume
φ^f	:	Fluid porosity
φ_v	:	Void porosity

ABSTRACT

Full Name : [Mohamed Hamdy Abdel Raheem Mohamed]

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In-Situ Combustion (ISC) is considered one of the most effective thermal enhanced oil recovery (EOR) methods. Using O_2/CO_2 as oxidizer in ISC may help in reducing CO_2 emission and give an acceptable performance in terms of oil recovery. Carrying out ISC with Oxygen or Oxygen/enriched air as an oxidizer requires oxygen separation technology. The present dissertation is aimed at studying ion transport membrane (ITM) ISC as a method of thermal enhanced oil recovery. Oxygen is separated from air by $Ba_{0.5}Sr_{0.5}Co_{0.8}Fe_{0.2}O_{3d}$ (BSCF) ITM perovskite-type ceramic membranes. Parametric study was conducted to optimize the use of ITM in oxygen separation. ITM numerical results showed that the single impingement flow gives better results compared to the double impingements with a difference of 35.7%. Results also revealed that the optimum configuration is the parallel flow with vacuum in the sweeping side, which gives the highest permeation flux with an increase of more than 41% from that of the parallel configuration with a sweeping gas. Laboratory and field scale ISC numerical simulations showed that, injecting a mixture of O_2/CO_2 gives better results in terms of cumulative oil than injecting oxygen-enriched air. For the lab scale, the maximum improvement ratio was 13.0 %, in case of (21% O_2 +79% CO_2) rather than (21 % O_2 + 79% N_2). For the field scale, the maximum improvement ratio was 1.94%, in case of using (30 % O_2 +70% CO_2) rather than (30 % O_2 +70% N_2). It was also found that the ISC process using O_2/CO_2 , as oxidizer, can store one million cubic meters of CO_2 inside the reservoir for one well

in less than one year. Within this period a round 500,000 m³ of CO₂ can be produced from the production well, which can be collected and stored again. To get the required area of ITM for the described one well ISC process, it was found that the maximum permeation flux from the ITM was 5.503 μmole/cm²-s, which is equivalent to 114.31 m³/m²-day, that means the required area is around 51 m² for the one well. An experimental work was performed to investigate and compare the use of steam and thermochemical flooding for EOR. In this investigation, thermochemical reactants were injected at different temperatures (100, 50, and 30 °C), into Berea sandstone core samples saturated with heavy oil and brine. It was observed that the pressure generated at the inlet of the core due to 100, 50, and 30 °C injection temperatures of the thermochemical fluids was 1600, 1200, and 280 psi, respectively; while the recovery factor was 83%, 66% and 54% of original oil in place (OOIP), respectively. In comparison, from the injection of steam generated at 250 °C, the pressure at the inlet of the core was 212 psi and the recovery factor was 71% OOIP. Another numerical study was developed to simulate the cyclic steam stimulation (CSS) and exhaust gases for EOR using vertical and horizontal wells over a period of 10 years. It was found that one horizontal well gives better results in terms of cumulative oil recovery compared to two vertical wells, despite decreasing the injected fluids by half.

ملخص الرسالة

الاسم الكامل: محمد حمدي عبدالرحيم محمد

عنوان الرسالة: فحص استخدام غشاء النقل الأيوني في الاحتراق داخل الخزان للاستخلاص المعزز الحراري للنفط

التخصص: الهندسة الميكانيكية

تاريخ الدرجة العلمية: سبتمبر 2020

يعتبر الاحتراق داخل الخزان (ISC) أحد أكثر الطرق الحرارية فاعلية للاستخلاص المعزز للنفط. قد يساعد استخدام O_2/CO_2 كمؤكسد على تقليل انبعاثات ثاني أكسيد الكربون ويعطي أداءً مقبولاً من حيث استخراج النفط. تتطلب عملية الاحتراق داخل الخزان باستخدام الأكسجين أو الهواء المخصب كمؤكسد تقنية لفصل الأكسجين. تهدف هذه الأطروحة إلى دراسة الاحتراق داخل الخزان مع غشاء النقل الأيوني كطريقة للاستخلاص المعزز الحراري للنفط. يتم فصل الأكسجين بواسطة غشاء النقل الأيوني من نوع $[Ba_{0.5}Sr_{0.5}Co_{0.8}Fe_{0.2}O_{3d} (BSCF)]$ ، والتي لديها أعلى كمية تدفق كما ورد في الأبحاث السابقة. تم إجراء دراسة بارامترية للاستخدام الأمثل لغشاء النقل الأيوني في فصل الأكسجين. أظهرت النتائج أن تدفق الارتطام الفردي يعطي نتائج أفضل من الإصطدام المزدوج بفارق حوالي 35.7%. وكشفت النتائج أيضاً أن الشكل الأمثل هو التدفق المتوازي مع ضغط سحب في الجانب الكاسح، والذي يعطي أعلى تدفق بنسبة تزيد عن 41% من التكوين الموازي بغاز كاسح.

بالنسبة للمحاكاة العددية لعملية الاحتراق داخل الخزان في المختبر والميدان، وجد أن خليط الحقن من O_2/CO_2 يعطي نتائج أفضل، من حيث إنتاج النفط التراكمي عن الحقن المخصب O_2/N_2 . في حالة الاحتراق داخل الخزان بمقياس المختبر، نسبة التحسين القصوى بلغت 13.0% في حالة $(CO_2/21\%O_2+79)$ بدلاً من $(N_2/21\%O_2+79)$. وفي المقياس الميداني بلغت نسبة التحسين القصوى 1.94% في حالة استخدام $(CO_2/30\%O_2+70)$ بدلاً من $(N_2/21\%O_2+79)$. وقد وجد أيضاً أن عملية ISC، باستخدام O_2/CO_2 كمؤكسد، يمكن أن تعزل حوالي مليون متر مكعب من ثاني أكسيد الكربون داخل الخزان لبئر واحد في أقل من عام واحد. خلال هذه الفترة، يمكن إنتاج حوالي 500000 متر مكعب من ثاني أكسيد الكربون من بئر الإنتاج، والتي يمكن جمعها وعزلها مرة أخرى. للحصول على المساحة المطلوبة من غشاء النقل الأيوني لعملية الاحتراق داخل الخزان للبئر الموصوفة، وجد أن الحد الأقصى لتدفق النفاذية من ITM كان 5.503 ميكرومول / سم مربع ثانية وهو ما يعادل 114.31 متر مكعب / متر مربع. يوم، وهذا يعني أن المساحة المطلوبة هي حوالي 51 متر مربع للبئر الواحدة.

تم إجراء عمل تجارب معملية لتحقيق ومقارنة استخدام حقن البخار والمواد الكيميائية الحرارية للاستخلاص المعزز للنفط. بالنسبة للحقن الكيميائي الحراري (TCF) كوسيلة من طرق الاستخلاص المعزز الحرارية. تم حقن المواد الكيميائية الحرارية المتفاعلة،

عند درجات حرارة مختلفة (100 و 50 و 30 درجة مئوية) ، في عينات من الحجر الرملي Berea المشبعة بالنفط الثقيل والمحلول الملحي. ولوحظ أن الضغط المتولد في مدخل العينة بسبب درجات حرارة الحقن 100 و 50 و 30 درجة مئوية للسوائل الحرارية ارتفع إلى 1600 و 1200 و 280 رطل / بوصة مربعة ، على التوالي ؛ بينما كان عامل استرداد النفط 83٪ و 66٪ و 54٪ من النفط الكلي داخل العينة ، على التوالي. وبالمقارنة مع حقن البخار المتولد عند درجة 250 مئوية ، كان الضغط عند مدخل القلب 212 رطل / بوصة مربعة وكان عامل استرداد النفط 71٪ من النفط الكلي داخل العينة.

كما تم تطوير دراسة رقمية أخرى لمحاكاة حقن البخار الدوري (CSS) وغازات العادم للاستخلاص المعزز للنفط باستخدام الآبار الرأسية والأفقية على مدى 10 سنوات. وقد وجد أن بئر أفقي يعطي نتائج أفضل من حيث النفط التراكمي من بئرين رأسيين ، على الرغم من انخفاض المواعع المحقونة إلى النصف.

CHAPTER 1

INTRODUCTION

1.1 Background

The GCC (Gulf Cooperation Council) region is considered one of the largest oil producers and has the largest oil reserve in the world. The oil production started last century in this region, and it is considered one of the most important national income e, especially in the Arabian Gulf. Thus, some of the oil reservoirs became matured (aged). It is known that traditional methods of the primary and secondary oil productions recover about third of the original oil in place (OOIP) while leaving the rest behind, which would be more expensive to extract compared with the production from a newly discovered oil field.

As shown in Figure 1.1, the U.S. EIA (Energy Information Administration - EIA - Official Energy Statistics from the U.S. Government.) [1] has predicted continual increase in energy consumption by the world from 549 quadrillion Btu in 2012 to 815 quadrillion Btu in 2040. The increasing demand on energy initiated the need to use the Enhanced oil Recovery (EOR) techniques to extract the heavy oil from aged reservoirs to keep its high rate of oil production. EOR techniques utilize different methods such as thermal recovery or injection of gas or chemicals or brine water. Gas and brine injection push the oil up to ease its extraction. Chemical injection utilizes polymers or surfactants or other chemicals to improve the oil flow and ease its extraction. Thermal EOR is based mainly on providing a heat into the oil reservoir to heat its heavy oil and make it less viscous and easy to flow during the production process.

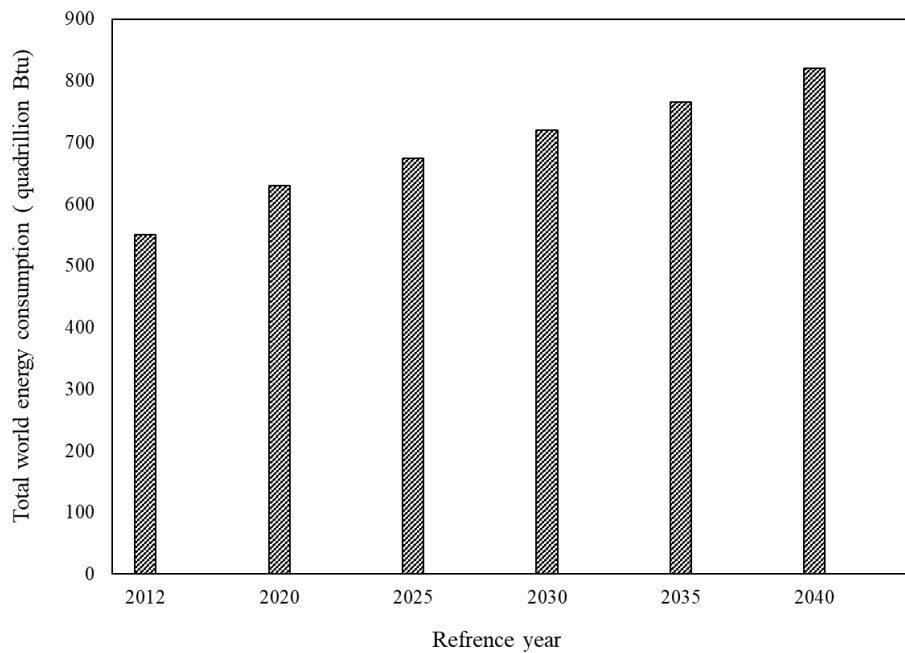


Figure 1. 1 Projection of world total energy consumption, reference case year 2012 – 2040 (source: U.S. EIA [1]).

1.2 EOR Stages and Techniques

The oil production from any well passes through three stages. Firstly, natural extraction under the well pressure, when the well pressure goes down then the second stage starts. The second stage is carried out by water flooding via pumping sea or brackish water to the well, which increase the well pressure and push the oil up enhancing the oil recovery. After these two stages only around one third of the well reserve is extracted. The well is said to be depleted while around two thirds of the oil are left over. After that, the enhanced oil recovery or tertiary recovery is started, which is the third stage. The Enhanced oil recovery methods can be broadly divided to fall into five groups:

1. Chemical methods
2. Microbial methods
3. Miscible and immiscible Fluid methods

4. Thermal methods
5. Unconventional Methods

These five groups can be further classified as follows in Figure 1.2:

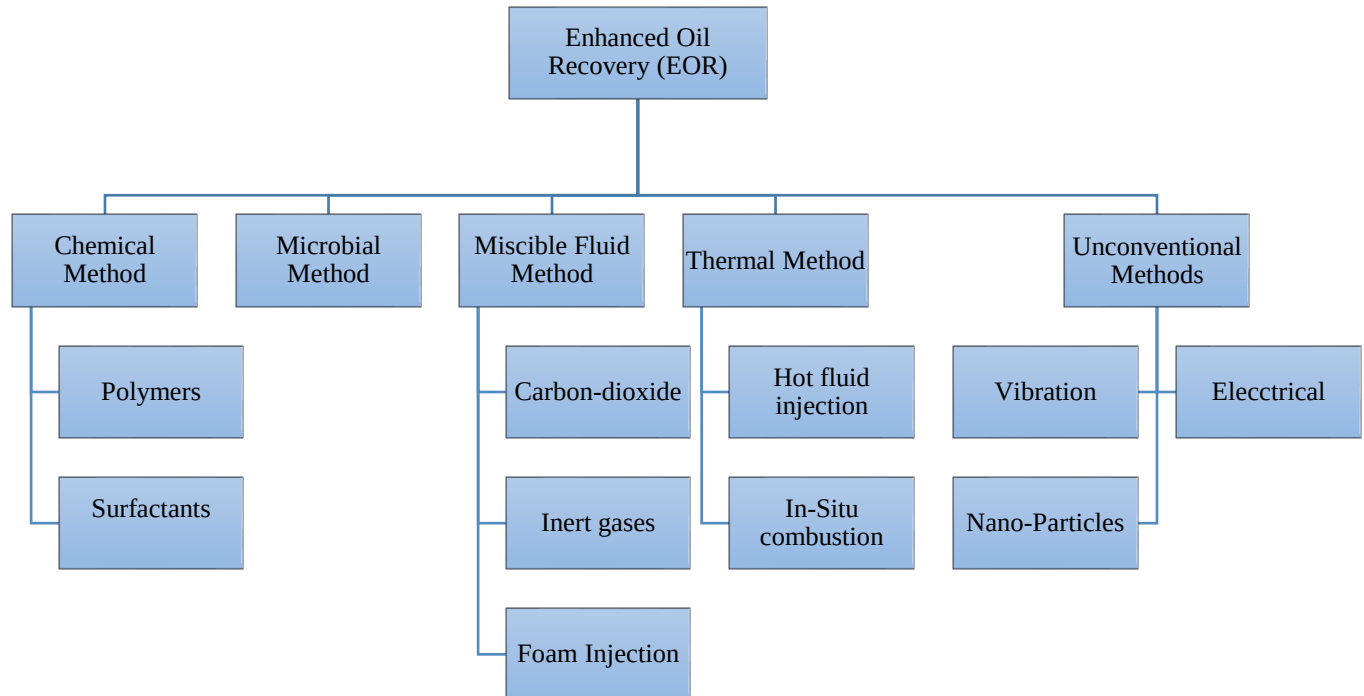


Figure 1. 2 Enhanced oil recovery methods.

Chemical Methods incorporate injection of surfactant, polymers, and alkaline solutions. Surfactants help in EOR by reducing the interfacial tension, increasing the mobility of oil, and thus making it easier to extract. Polymers increase the viscosity of the water injected into the well, helping it to exert more pressure on the oil without passing through the oil by mobility control. Some Alkalies when injected into the well react with oil to form surfactants which assist in oil extraction by reducing the viscosity [2-4]. Microbial injection is a rarely used method mostly due to its high cost. Microbes are injected in the oil field function either by digesting the long hydrocarbon molecules, by producing bio-surfactants or by producing carbon dioxide [3-6]. The Miscible fluid methods mostly include injection of gases like carbon dioxide, nitrogen and some of the inert gases [2-4, 7-9]. Carbon dioxide is mixed with the oil causing

the oil to swell, consequently the viscosity and surface tension is reduced thereby enhancing the oil recovery process. Similar trend is observed with some of the inert gases. Foams are injected into the oil well and helps in oil recovery [7].

The most prominent thermal EOR techniques are hot water flooding, Cyclic Steam Stimulation (CSS), steam flooding, Steam Assisted Gravity Drainage (SAGD) and ISC [2-4, 10]. The other thermal EOR type is the non-aqueous methods which supply heat to the reservoir without injecting any fluids, such methods include electric heating and electromagnetic heating. The non-aqueous methods are however rarely applicable due to technical and environmental constraints, subsequently, more future work is required in order to make them more competitive. A recent development towards that involves the combination of the non-aqueous methods with water or solvent injection.

Apart from the above well-developed methods some unconventional techniques are being investigated which have yet to gain commercial feasibility like using downhole vibration to stimulate oil flow and maintaining electric potential gradient between the injection well and producing well to aid mobility of oil [11]. The more recently investigated method involves the use of nano-particles for EOR [12].

1.3 Motivation and Scope of the present Work

Thermal EOR methods are considered the most dominant EOR methods because of its high oil productivity [13-20]. Steam injection is the widely and commonly used technology for enhancing oil recovery [19]. The production of steam required for EOR requires a separate system for producing steam. Combustion of considerable amount of fossil fuel is required for steam generation, which makes it expensive while it is associated with high environmental impact due to the high CO₂ emission [19]. The increase of CO₂ emission from this process and

other industries will affect the environment (Greenhouse effect) [21]. For example, 22 % of the natural gas demand in Oman is used to generate steam for thermal EOR [22]. Steam flooding also is limited to viscous oil in high permeable sandstone or unconsolidated sandstone reservoirs and not applicable to carbonate reservoirs. In addition to that one third of the recovered oil is used as a fuel for steam generation process [23].

It is concluded that the conventional thermal EOR methods have several limitations such as the huge capital and operating costs, flue gas emissions, high consumption of water and heat losses. All the previous mentioned limitations are our motivation to the present work. Using Insitu process rather than surface process my help to solve these limitations. In this work the focus was on testing ITM optimization and studying two different techniques of Insitu process, the first is ISC, as a traditional technique, and second is TCF, as a novel technique. So, the main objective of the proposed thesis is to numerically develop an In-situ combustion thermal EOR system with O_2/N_2 and O_2/CO_2 as oxidizers with produced oxygen using ITM and experimentally investigate the use of thermochemicals flooding for EOR. Also, investigate the use of Exhaust gases for EOR, instead getting rid of them.

1.4 Objectives

Specifically, the following outlined the present research objectives:

- I. To develop a numerical model for oxygen separation by ITM and validate it with the available experimental work. The model will be developed based on comprehensive analysis of the literature. Tuning of the model will be introduced to enhance the validation of the model.
- II. To use the developed codes of the ITM to optimize the design of the ITM system.

- III. To develop a numerical model for ISC/EOR and validate it with the available experimental work. The model will be developed via modification of existing model for oxygen enriched air ISC to Oxygen- CO_2 ISC.
- IV. To use the developed codes to optimize the ISC/EOR process.
- V. Sizing of the overall system, ITM and required heated air for ISC used in the selected reservoir.

1.5 Significance of the present Work

The present work has been performed to overcome some of the mentioned limitations by generating steam and gases inside the reservoir using ISC, as a traditional technique, or thermochemicals flooding, as a novel technique. The present work is expected to provide a novelty in the use of different new technologies such as ITM and thermochemical into the EOR. Also, to make use of the massive amount of the produced CO_2 from different industries, injecting CO_2 with oxygen, as oxidizer for ISC, instead of nitrogen is demonstrated and studied. ISC is carried out by injecting oxidizer in the reservoir and igniting it. That leads to increase temperature of oil to thereby reducing its viscosity [24-28]. In ISC, the combustion is occurred inside the reservoir, which reduce or even avoid the heat transfer losses [21]. ISC is preferred for the heavy oil reservoirs and reservoirs where the other thermal process not applied. Heavy oil represents about 67% of the world's total petroleum resource. So, economically and technically ISC is considered an attractive process. Also, thermochemicals injection leads to downhole generation of heat and pressure from exothermic chemical reaction.

To finalize, the focus will be on ITM/ISC and thermochemicals flooding as methods of in-situ thermal EOR. ISC is considered a combination of various EOR techniques such as gas

injection, water flooding, steam drive and chemical method [29], as such as thermochemicals flooding..

1.6 Organization of Thesis

This thesis comprises 8 chapters which are summarized as below in Figure 1.3. **Chapter One** provides a brief introduction to the problems to be solved. These problems are regarding the thermal EOR, which are the motivation for this work. The significance of the work in solving these problems is also provided in this chapter by developing a numerical ISC/EOR system with O_2/N_2 and O_2/CO_2 as oxidizers with produced oxygen using ITM and experimentally investigate the use of thermochemicals flooding for EOR. The next chapter is **chapter Two** which summarizes the published literature on thermal EOR (steam, ISC and hot water flooding) and ITM. In this manner, many numerical and experimental investigations had been introduced with the aim of developing different Thermal EOR techniques and for optimizing the ITM for oxygen separation. The gap of the literature is discussed also at the end of this chapter. **Chapter Three** introduces the ITM numerical study for optimizing different geometries and boundary conditions with the aim of increasing the oxygen permeation flux. ANSYS fluent CFD codes and User defined function have been developed to model the ITM. **Chapter 4 and 5** introduced the ISC numerical study for lab and field scale, with the aim of optimizing different oxidizers and operating conditions with the aim of increasing the oil recovery. At the end of chapter 5, the required area of ITM, required to produce a certain oxygen volume flow rate for the specified field, was calculated. This chapter is followed by **Chapter 6**, which experimentally compared the performance of thermochemical flooding to that of steam as a novel technique, with the aim of improving the heavy oil recovery. In **Chapter 7**, instead of getting rid of the huge amount of exhaust gases, a numerical model was developed and applied to field scale to

simulate exhaust gases injection Cyclic Steam Stimulation (CSS) for EOR. **Chapter 8** presents concluding remarks for this research studies along with recommendations for future.

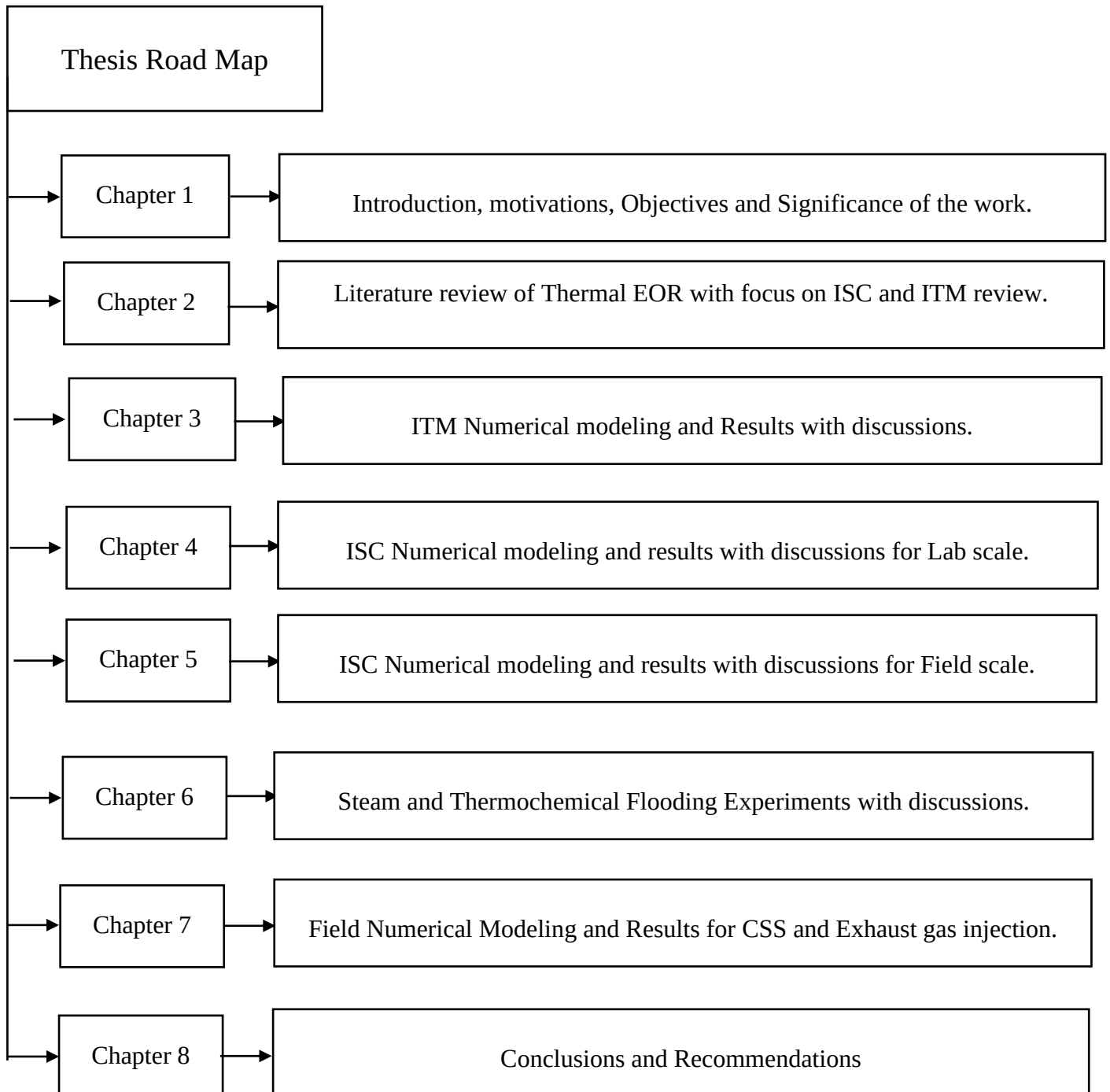


Figure 1. 3 Thesis road map.

CHAPTER 2

LITERATURE REVIEW

This chapter is devoted to a comprehensive review of the thermal EOR methods and ITM separation technology. This chapter will focus on thermal EOR, as it is widely used over the world for several decades and it is still being used and developed. Thermal EOR (steam, ISC and hot water flooding) is the dominant method employed for EOR globally with 67% global usage. It also revealed that many numerical and experimental investigations had been carried out with the aim of developing different EOR techniques, many of which were introduced and discussed. For the ITM, this chapter introduces some studies about the ITM performance including change of different parameters such as the operating conditions, direction of flow of fluids in feed side or sweep side.

2.1 Overview

Enhanced oil Recovery is a widely accepted oil production technique that helps minimizing shortages in the crude oil and its high prices. It is a technique by which huge amount of crude remaining in wells after natural extracting process is recovered. The natural extracting process (primary recovery), which employs the reservoir natural pressure for crude oil extraction, leaves huge amount (more than 70% in some cases) of original oil in place (OOIP) unextracted, due to reduction in reservoir pressure. Consequently, the use of secondary oil recovery that involves fluid (mainly water and gas) injection to augment the reservoir pressure, as well as EOR, also known as tertiary recovery, becomes imperative to improve oil recovery. While secondary recovery involves injecting water or gas to help sweep the oil through the wells without changing the actual properties of the hydrocarbon, EOR techniques involves

changing the reservoir make-up. In essence important properties like density and viscosity of the crude oil changes, making oil displacement easier in the reservoir [30-33]. Oil recovery can reach as high as 75% of OOIP, depending on the employed EOR technique. EOR is projected to change the oil production forecast in the Middle East and the entire world as, shown in Figure 2. 1. Figure 2. 1(a) shows that EOR market in the world is expected to increase dramatically, which gives an indication to the importance of this process in the future [34]. The Organization of the Petroleum Exporting Countries (OPEC) estimated the role of EOR in increased oil production in the Middle East up to 2050, as shown in Figure 2. 1 (b) [35].

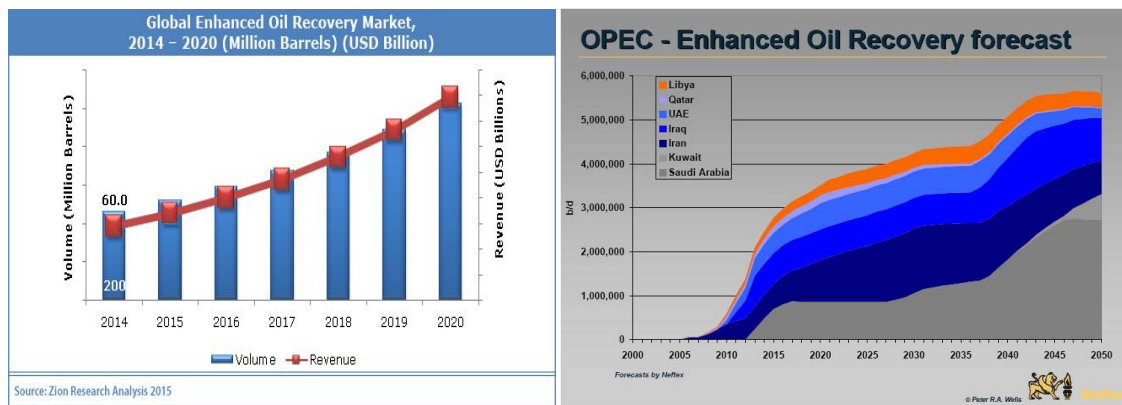


Figure 2. 1 (a) worldwide EOR market contribution through 7 years [34], (b) EOR forecast in the Middle East up to 2050 by (OPEC) [35]

EOR process can be classified as thermal and non-thermal technique. As the name implies, thermal EOR uses thermal energy to increase the temperature of the reservoir, as a result the viscosity of the oil is reduced [36, 37]. Thermal EOR is considered one of the most advanced EOR processes and it currently provides a significant amount of oil in overall global oil outlook. There are different thermal EOR methods, but we focused in this review on the established methods which are in use for the past 30–40 years in the field. These include hot fluid injection such as hot water flooding and steam injection, and ISC which also called fire flooding. High porosity sand/sandstone formation in reservoirs is the most suitable for thermal recovery processes [2]. Thermal recovery processes are commonly used for thick, high density,

viscous oils having API gravities of less than 20. By characterization, oils with API less than 22 are heavy oils, while oils having less than 10 API degrees are categorized as extra-heavy and Bitumen that are denser than water [38].

The thermal energy used during thermal recovery lowers the oil viscosity, specific gravity, and interfacial tension, thereby facilitating oil flow in the production well. Figure 2.2 depicts the temperature effect on the kinematic viscosity of gas-free oil, which decreases with increasing temperature [39]. Apart from changes in oil physical properties, its chemical properties also change through cracking and dehydrogenation among other chemical reactions. As mentioned before, thermal processes commonly include hot fluid injection, ISC, and electrical heating and a less conventional electromagnetic heating.

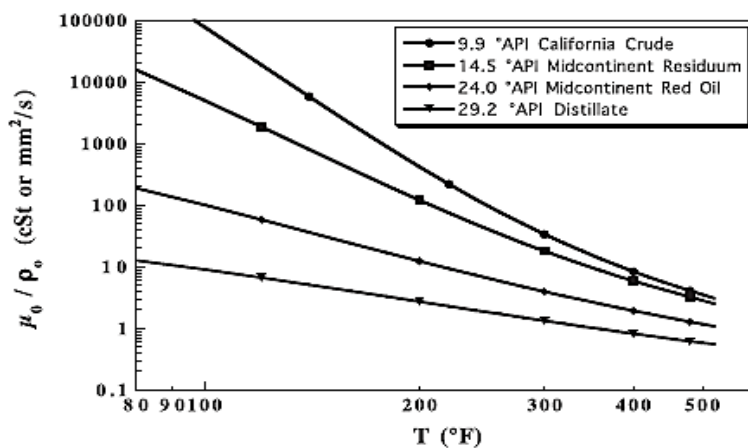


Figure 2. 2 Kinematic viscosity of gas-free oils as a function of temperature [39]

2.2 Non-Thermal EOR Classification

The non-thermal methods are classified into three recovery methods according to Naqvi [36].

These methods are summarized as shown in Figure 2. 3.

Reports revealed that non-thermal methods are not widely in use compared with thermal EOR as shown in Figure 2. 4 [40].The Figure depicts a summary of the EOR production rates using different methods around the world.

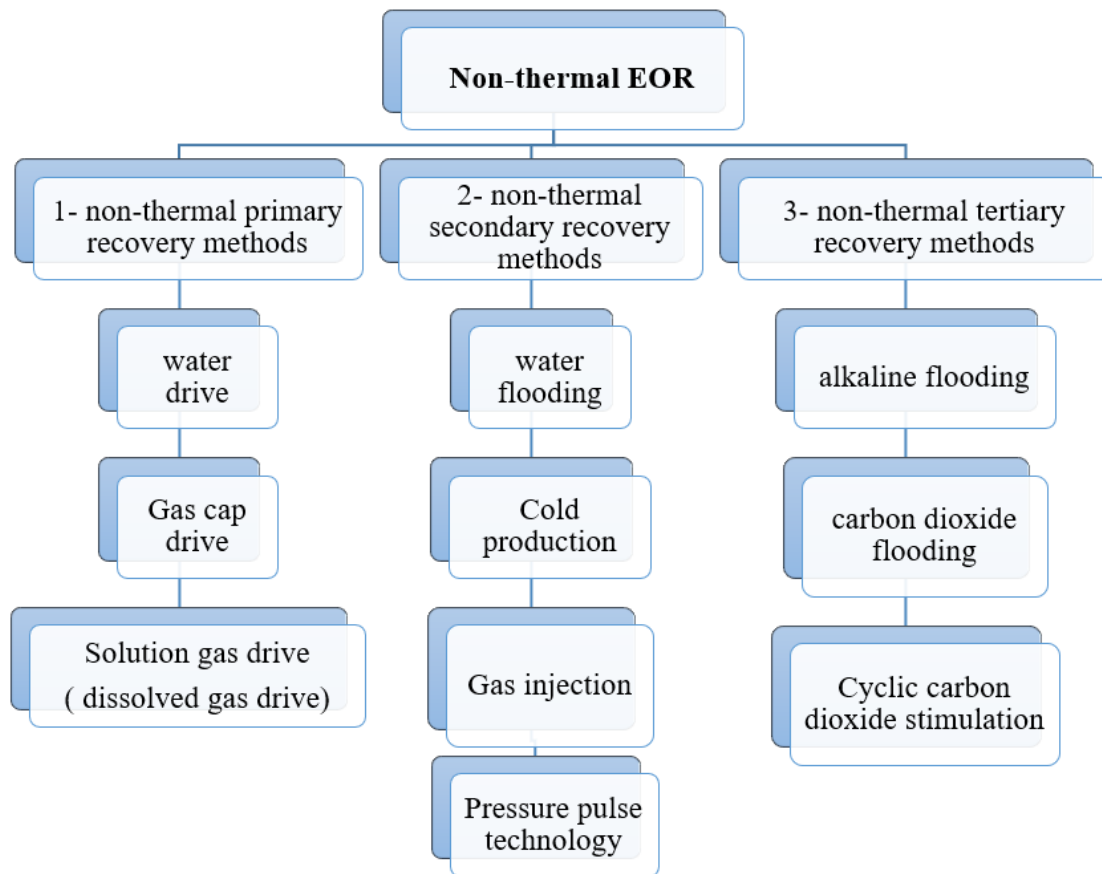


Figure 2. 3 Non thermal enhanced oil recovery technologies [36]

It is clear from Figure 2. 4 that at 67% global usage, the thermal EOR is the dominant method employed for EOR globally. This is partly due to its high performance and other benefits which we will be detailed further in the remaining parts of this paper.

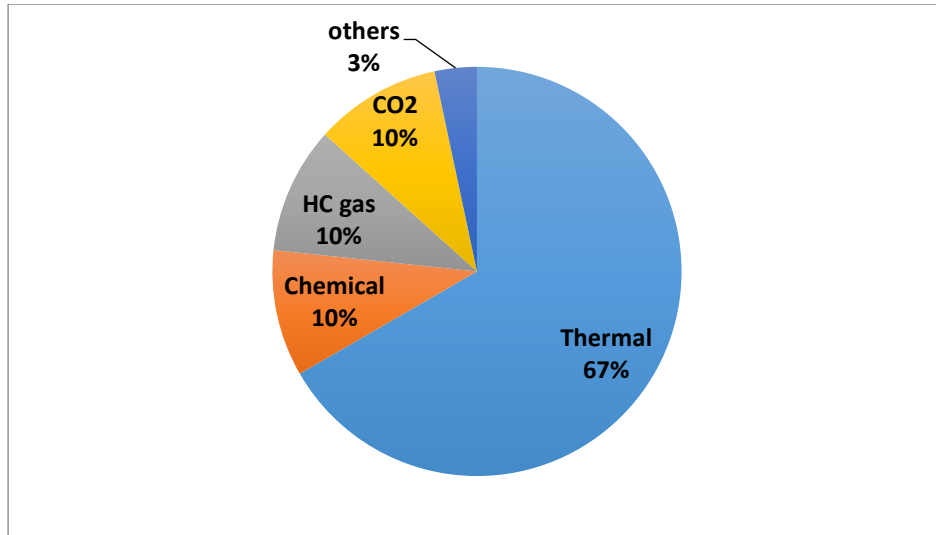


Figure 2. 4 Ratio of different EOR methods used in projects around the world [40]

2.3 Thermal EOR Classifications

As reported in the literature, thermal EOR methods are very important and are widely applicable worldwide [37]. Different types of aqueous methods, which are related to water and its derivatives are widely used over the last few decades. Processes such as CSS, hot water flooding, SAGD and ISC are the most prominent thermal EOR techniques. The other thermal EOR techniques are the use of non-aqueous methods which supply the thermal energy to the reservoir without injecting water or its derivatives. Such methods include electric heating and electromagnetic heating. The non-aqueous methods are rarely applicable due to technical constraints and environmental issues, subsequently, future work is required in order to make the non-aqueous methods more competitive. A recent development towards that involves the combination of the non-aqueous methods with water or solvent injection. Details about thermal EOR methods will be presented in hereinafter. Figure 2.5 depicts the various thermal EOR methods.

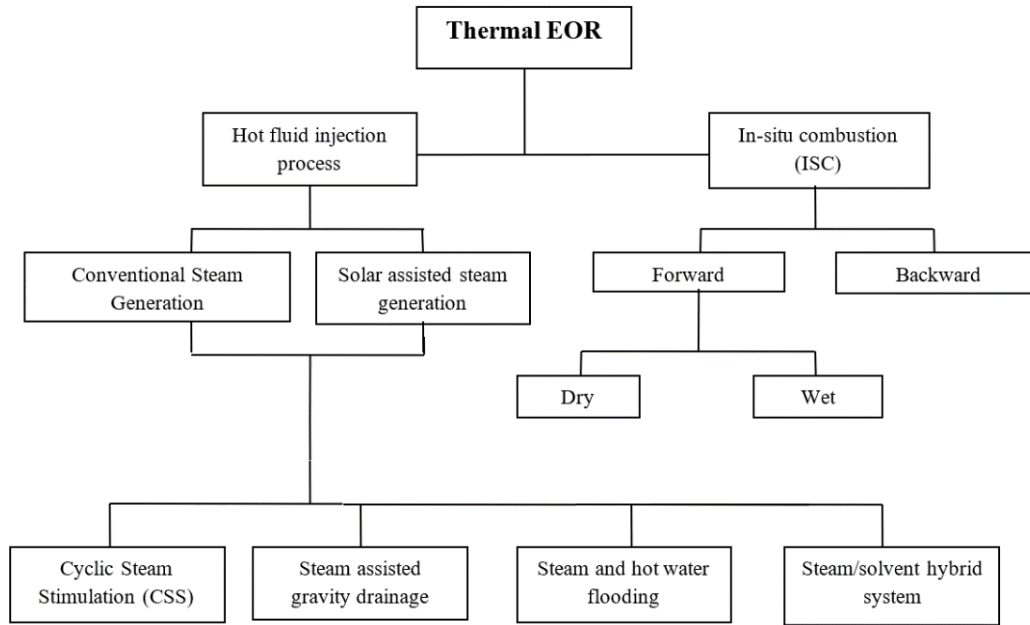


Figure 2. 5 Thermal EOR processes

2.4 Electrical and Electromagnetic Heating

This is an EOR technique that uses electrical current to heat the heavy oil in its reservoir. Due to the oil heating process, there will be a formation of vapor chamber in the reservoir, and subsequent easy mobility of oil. Electric EOR method is divided into three main types; the first one is low-frequency Ohmic heating also called resistive heating. Secondly, high frequency or radiofrequency / microwave heating and finally medium frequency or inductive heating. In the Ohmic heating, a potential difference is applied between anode and cathode. In the field, this can be applied by using two oil wells using one as cathode and the other as anode [41]. This technique is shown to have advantages and improves oil recovery, but it has some disadvantages such as generating steam during heating, which decreases the amount of water and, as a result, decreases the thermal energy transferred by water. Using water injection along with this method had been suggested [42], it is expected that this will enhance the heating process especially in low-permeability zones. Numerical simulation using CMG software [43], had been reported [44], where, down hole electric heating method was used together with

injection of a working fluid for enhancing the heat transfer. The working fluids such as water, pure solvents (butane, hexane, and natural gas condensate), or combined water and solvents were used in the study. The study shows that the use of the combined water-solvent as the working fluid was more effective than using the solvent only, due to the dilution effect of the solvent that improves heat transfer characteristics of the solvent and water, thereby accelerating the process. Consequently, economic improvements were reported through the reduction of the amount of surface water-oil-ratio to be 3–10 times smaller than those of SAGD, and by the decreased amount of needed steam.

Electromagnetic Heating (EM) is a relatively new technique for EOR that is gaining huge attention recently. In this method, electromagnetic waves produce electrical energy, which is transferred to the dielectric and resistive materials in the form of thermal energy, which is used in EOR. Therefore, EM technique converts EM energy to thermal energy for use in EOR [45-52]. The EM method for EOR has a lot of advantages including reduction of carbon emission, minimization of excessive water usage, and relatively higher performance when used together with solvent injection. As an improvement to EM heating, adding solvent during the process was suggested [50, 53, 54]. Many research papers covering different aspects of EM heating for EOR are available in the literature [55-59].

Preheating is very important in EOR for energy saving and for accelerating the process. Down hole EH and EMH had been suggested for this purpose to reduce the preheating time with energy savings [60]. Some EOR processes such as SAGD requires time period of 3-6 months to complete the heating process. In the end, it was concluded that the electromagnetic heating (EMH) clearly increases the energy saving. Investigations carried out to explore this EOR technique revealed important conclusions about its potentials in oil recovery, the literature however is still evolving in that regard [37]. Using Microwaves for thermal energy generation

is another technique that has huge potential. The energy transformation from microwave to thermal energy in the presence of microwaves absorbers can be exploited in reservoir heating for EOR. The fact that crude oil in itself is not a good microwave absorber entails the use of other materials having high microwave absorptivity such as activated carbon, Nano-metal-oxides, and polar solvents, which make the heating process faster. The use of enhanced metal-nanoparticles incorporating electromagnetic heating for field scale EOR application was proposed as a future work by Greff et.al [52]. The challenge is optimizing a way of injecting the nanoparticles into reservoirs during the EM heating process. One suggestion is the injection of Nano-fluid at different stages of EM heating after viscosity reduction.

2.5 Hot Fluid Injection Processes

Tot fluid injection as an EOR process involves the use of hot fluid in an oil reservoir to ease the flow of oil for production. Thermal energy is transferred (in form of heat)to the reservoir by the combined effect of convection and conduction mechanisms [37].This thermal energy leads to high viscosity reduction and thermal expansion of oil in the reservoir. Injecting steam is the most common technique in this technology of thermal EOR and it is the most commercially successful [61-65]. In steam injection processes, there are three methods, which are CSS, steam flooding and SAGD [37]. In steam flooding, the injected steam through injection wells reduces the oil viscosity in addition to the sweeping effect generated by flooding of steam. However, this method requires more steam than CSS despite being more effective.

2.5.1 Cyclic Steam Stimulation

Cyclic steam stimulation (CSS) (huff and puff method) involves three stages, which are namely: injecting of steam, soaking period, and production of oil. In this technique, steam is injected into the well for a period to raise the oil temperature resulting in reduced oil viscosity,

which facilitates its mobility. After ensuring that there is enough amount of steam in the well, it is shut-in for a period extended from few days to few weeks to make sure that the thermal energy is spread out well, as shown in Figure 2. 6. Subsequently, the well can produce oil due to the pressure generated by the injected steam. The production continues to a point at which its rate decreases significantly to warrant cycle re-start as the oil cools with time resulting from thermal energy losses. The same previous steps are repeated, but naturally the effectiveness of this process decreases after few cycles. Li et al. [66] conducted experimental and numerical analysis for the huff and buff process using CO₂ instead of steam; it was found that at the fifth CO₂ cycle, the recovered oil reached 31.56%. Every EOR method has its effectiveness which is measured by the amount of oil recovered percent of the total capacity of the well. The maximum recovery by CSS is relatively low (around 10–40% of OOIP compared with SAGD which has higher recovery average) [67, 68]. Smart water which can be designed by optimizing the chemical composition of injected brine has been carried out by Jalilian [69] to see its effect on pure limestone carbonate rocks. Increasing the sulphate ion concentration and reducing the total salinity, Jalilian [69] found that the oil recovery factor has increased by 14.5%. Low-salinity water flooding has a weak effect on the oil recovery less than 2%.

In CSS technique, a single well is used interchangeably as a steam injector well and as an oil producer well. Since the steam used in the process, for practicability, is generated on the surface, to be injected using surface lines and wellbore, thermal energy losses from these surfaces need to be considered. Subsequently, limiting parameters such as reservoir depth, pressure, and lithology must be considered for an efficient oil recovery using steam injection. The steam, after injection, is allowed for enough time to soak (soaking time) due to which its high temperature (200-300°C) help reduce oil viscosity while the high pressure (about 1Mpa) fractures the reservoir rock. As the soaking time lapses, with oil ready for production, the

production time follows when oil can be produced at high rates. Such production continuous, until eventually it begins to rapidly decrease meriting another steam injection that will trigger another cycle. The three stages of this cycle can be repeated several times within the limiting case of technical and economic viability [70]. The injection and soaking times normally takes days or weeks while the production time generally takes weeks to months. An optimum injection time and extension of the soaking time depend on mechanical and operational considerations while the oil production rate limits the production time. From the production viewpoint, it is vital to determine the number of cycles that will achieve maximum oil recovery by the process, as it generally becomes less efficient with increasing number of cycles.

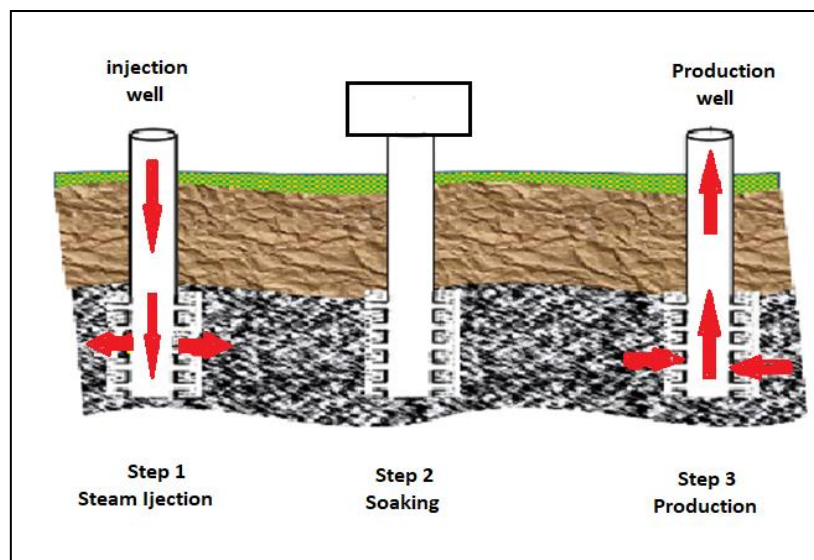


Figure 2. 6 Schematic illustration of cyclic steam Stimulation

Cyclic steam stimulation (CSS), has been widely employed for EOR since its accidental discovery in 1959 in Eastern Venezuela by Shell Oil Company of Venezuela when testing a steam drive [68]. It has been successfully used in various heavy oil fields in Canada, Venezuela, Brazil, and in California, USA, where it is used as a first stage before continuous steam injection [71]. The main advantage of cyclic steam stimulation is a rapid pay-out during early production. Its percentage of oil recovery vis-à-vis original oil in place (OOIP) is

comparatively low ranging from 10 to 20% [72]. To improve this low oil recovery in CSS, enhancements such as the use of horizontal rather than vertical well, the use of chemical additives in the steam, and hydraulic fracturing are introduced with the process. Consequently, studies focusing on either the optimization of chemical additives in the steam and fracture design are common in recent literatures [73, 74]. Such enhancements were reported to achieve improvements of up to 40% of OOIP; a recovery that is still lower than its other thermal EOR counterparts [68]. Wu et. Al [75] studied the effect of gas breakthrough with CSS and gas stimulation in offshore heavy oil reservoir, they introduced a new concept for gas breakthrough degree and named it gas breakthrough coefficient, this coefficient depends on some parameters such as reservoir thickness, injection strength, permeability and injection production pressure. Another consideration in CSS is the steam generation process for the system. Early on, some oil field made use of the produced crude oil in steam generators through direct combustion. Environmental as well as economic considerations led to the use of other fuels like natural gas in the steam generation process over time. Those same considerations resulted into targeting other sources like coal, biomass, and solar energy with each having different economic and environmental footprint. Apart from the choice of energy source in steam generation, options of using combined power cycle for more efficient energy utilization were considered in some occasions. The use of natural gas for instance in a cogeneration power cycle to produce both electricity and steam for CSS have been actualized in Californian oil fields with an installed electrical generating capacity of about 2000 MW [19]. Use of solar energy in concentrating solar trough for steam generation to be used in EOR systems is another approach that promises huge environmental benefits [10, 76]. Another approach involves the combination of CSS with air injection in a process called Air assisted cyclic steam stimulation (AACSS). This method is used for heavy or ultra-heavy oil reservoir after CSS become non efficient, where it can compensate for the low reservoir pressure, poor steam sweep efficiency and high water cut.

Wang et al. [77] conducted a study on ultra-heavy oil reservoir of Liaohe oilfield (China) using a numerical technique validated with experimental work and their study revealed that adding air to CSS can improve oil recovery with 11% of the incremental oil production. Another numerical study in AACSS had been done by the same authors [78], it was reported that the rate of oil recovery is better than CSS only beside improving the energy efficiency and decreasing the CO₂ emissions. Leaute et al. [73] patented a new idea of LASER-CSS, which is summarized as mixing liquid hydrocarbon with the injected steam instead of injecting it alone in front of the steam stimulation cycle and that will improve the recovery efficiency. Lu et al. [79] studied the in-situ formed oil water emulsion droplets transport and plug in porous media. One of their conclusions was that higher pressures can displace larger size of oil water emulsion droplets out of the pore-throat and reduce their retention volumes.

2.5.2 Steam and Hot Water Flooding

Hot water and steam flooding are a thermal EOR technique which requires a huge amount of water or steam to be injected in the high viscous oil in the well to raise its temperature as shown in Figure 2.7. 3-D sand-packed displacement model and experimental work have been developed to simulate the water flooding and immiscible CO₂ flooding processes[80]. On the other hand, the driving power of the water is higher than that of the steam. The steam injection process involves continuous steam injection into an oil-bearing porous medium. This results in a formation of an almost constant temperature, slow advancing steam zone around which the viscosity of the oil is drastically reduced thereby increasing oil mobility. This highly mobilized oil within the steam zone is subjected to a vaporizing gas drive as a result of which the initial oil saturation is reduced to as low as 10%. Mohebbifar et al. [81] used Nano and biomaterials simultaneously; they used three types of biomaterials including biosurfactant, bio emulsifier, and biopolymer beside two types of nanoparticles including SiO₂ and TiO₂ at different

concentrations was used as injection fluids. The highest efficiency of 78% was observed while injecting one pore volume of biopolymer and SiO₂ nanoparticles. Steam flooding has a typical recovery factor ranging from 50% to 60% of OOIP. However, being a pattern driven process, its performance will ultimately depend on the pattern size and geology [82, 83]. Experimental study has been carried out using steam flooding for reservoir with ultra-heavy oil as in AL-1 Block, Shengli Oilfield, China [84], good results have been got for ultra-heavy oil. A numerical study conducted on steam injection in heavy oil revealed that it improves oil recovery up to 60% during a fixed period of time, and that only 30% of OOIP can be recovered by hot water injection method [85]. Hossain M.E. [86] developed dimension less scaling parameters for thermal flooding in porous media. He proposed numbers that measure the thermal diffusivity and hydraulic diffusivity of a fluid in a porous media.

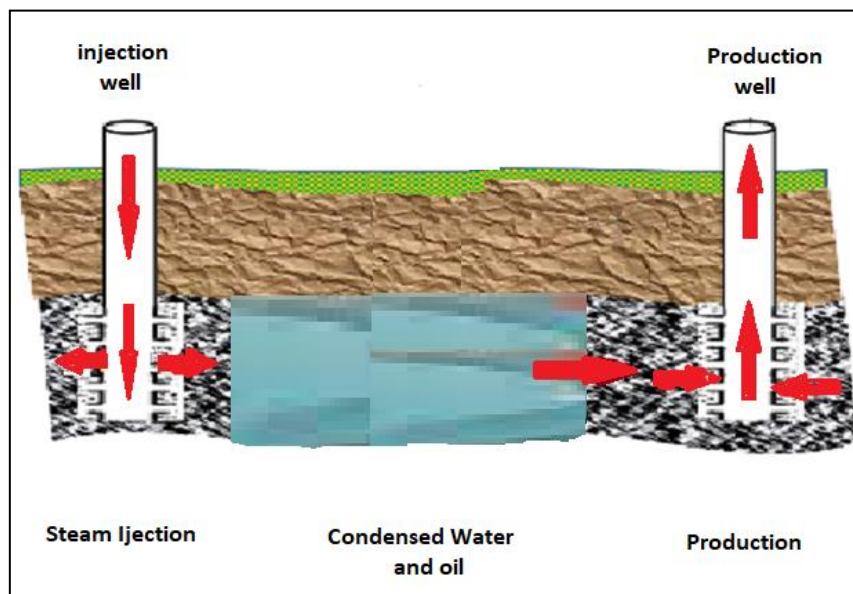


Figure 2. 7 Schematic illustration of steam flooding process

Another study focusing on heterogeneous heavy oil field located in southern Oman had been conducted to establish the optimum thermal energy transfer conditions via steam injection in the reservoir [87]. A CMG-STARS model was developed in the study to simulate steam injection process with the valve control of steam trap sub-cooled. They concluded that the

valve control gives a faster distribution of thermal energy after steam injection. In addition to that, it gives higher production with low amount of steam required. The use of nitrogen thermal foam flooding to overcome steam override and steam channeling problems was also reported in the literature [88]. It was found that in single sand-pack experiment, the displacement efficiency of steam flooding can be increased from 43.30% to 81.24% by using nitrogen foaming.

The economic as well as technical success of steam flooding process highly depends on the steam generation unit. Consequently, efficient operation and maintenance of the steam generators that considers the fuel used in the generators, its availability and cost, as well as feed water treatment and cost are highly important. From operation viewpoint, the two most important challenges in steam flooding are the concerns with steam override and that of excessive thermal energy losses. The thermal energy loss can be attributed to the losses in surface lines that transfer the steam from its generating unit to the injection wells. Other losses occur during steam passage into the wells since the steam temperature is much higher than geothermal temperatures. Another source of losses occurs inside the reservoir from the heated portion of the formation to the adjacent lower temperature regions.

2.5.3 Steam Assisted Gravity Drainage

In this method, high pressurized steam is injected continually in a horizontal well to provide thermal energy in the well that reduces the oil viscosity. After heating, the injection well is drained into the lower well where it is pumped out as shown in Figure 2. 8. This method is best suited for heavy oil extraction in carbonate reservoirs as reported by Hussein et al. [89]. These are mostly naturally fractured reservoirs but only few studies had been conducted in this area. It is considered highly promising technique and it needs more work and research in order to

fully explore its potentials. The effect of fracture properties like fracture orientation, fracture spacing and fracture permeability on the SAGD performance in naturally fractured reservoirs was studied by Hussein et al. [89] through experimentations and modelling using CMG-STARs thermal simulator [43]. Experimentally, the combination of the SAGD and multiple thermal fluids assisted gravity drainage (MFAGD) was also tested by the authors. They reported that fracture orientation affects the steam expansion and oil production from the horizontal well pairs. It is also reported that horizontal fractures have a negative effect on oil production, while vertical fractures have a higher production rate compared to its horizontal counterpart. Similarly, increase in fracture permeability was shown to positively improve oil production. Furthermore, they reported that an increase in fracture spacing enhances oil production, because in wider fractures, the steam accompanied with its thermal energy will take more time to diffuse into matrices and provides thermal energy to the entire reservoir. Literature is available on the use of an optimization simulation method called proportional-integral-derivative (PID) coefficient to optimize the steam injection process while achieving higher oil production and lower steam-oil ratio [90].

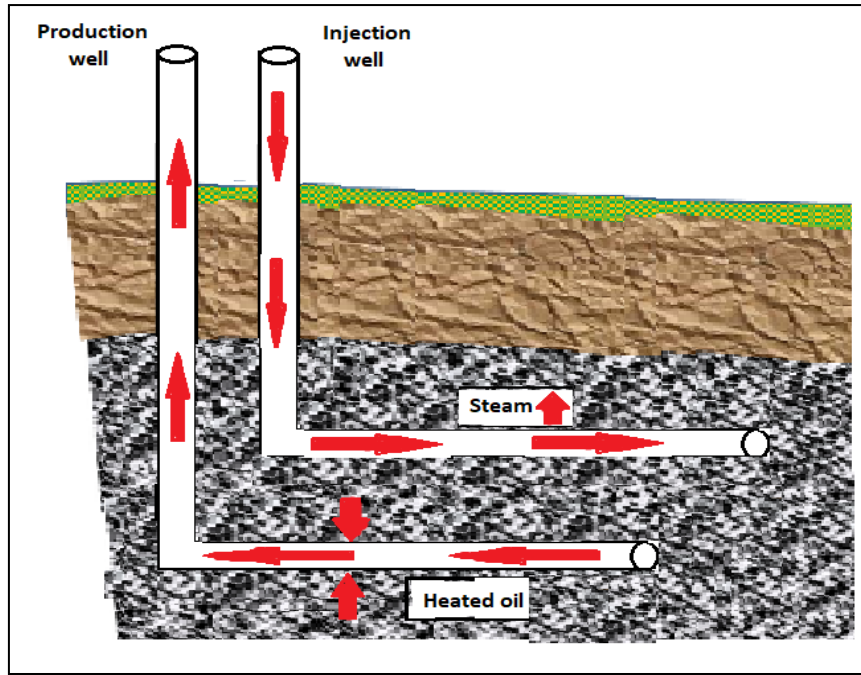


Figure 2. 8 Schematic illustration of steam-assisted gravity drainage process

Process Integration (PI) tools had been applied in some instances to increase efficiencies in SAGD. This was conducted by Forshomi et al. [91] in which a distributed effluent treatment system was designed to improve the economics while tackling environmental issues. Different configurations of water treatment technologies and steam generation options in SAGD were employed to target an optimum process. An energy cost savings of up to 19.5% and 12% in water treatment system of SAGD operations was reported by the authors simply by diverting flows in wastewater streams. Artificial intelligence (AI) approaches are used for predicting SAGD recovery performance and using it in assisting conventional SAGD analysis [92].

Horizontal wells are always used in SAGD and it is proven to be successful in the field and many studies are available in the literature in this regard. Recently, vertical well as alternative method for SAGD had been developed [93]. The well consists of two strings, the first one is used as a producer on the bottom and the other is used as an injector on the top, with the distance between injector and producer perforations being changed gradually. It is reported by Suranto

et al. [93] that increasing the steam injection rate directly increases production rate. Furthermore, their results showed that vertical well SAGD can improve the drainage radius to 85 meters using both multi-level injector and multi-level injection rate. However, the good performance of the multi-level injector can be achieved if the injector perforation is moved gradually. They recommended using vertical well SAGD in the case of thick reservoir. Vertical wells method has advantages like decreasing cumulative steam oil ratio (CSOR), increased drainage area, and enhance steam chamber volume, as a result, it can increase the efficiency of steam injection.

2.5.4 Steam/Solvent hybrid system

Many researches had been done and are still on-going towards the improvement of EOR in terms of efficiency and economics in all its stages. As example, start-up process is an important process to take in mind. Experimental and numerical study which uses the solvent assisted start-up had been carried out by Yuan et al. [94], where, injection of solvent instead of steam near the wellbore had been explored. Following that, there is a need to improve the sweep area by high-temperature steam circulation which also reduces the oil viscosity. It can be concluded that injection of solvent into an initial reservoir can shorten the start-up process and reduce steam consumption. Using injection of solvent with steam to improve the performance of SAGD had been conducted both in a lab scale and actual field. In the references [95-100], numerical simulations were reported by the authors for the case of SAGD and they found that it shortens the preheating time and reduces steam consumption; also the production rate and the cumulative oil production improve especially at the early production period. Steam flooding assisted with flue gases and n-hexane had been studied experimentally in the lab by Li et al. [101]. It was reported that the flue gases injected in the heavy oil can reduce the oil viscosity and increase the flow capability. It is worth reporting that the n-hexane has more effect than

that of the flue gases, where it can reduce heavy oil viscosity and surface tension more rigorously. So the two types have positive effect on the steam flooding, where the oil recovery efficiency can reach up to 80%. An experimental was carried out in a lab scale by Mohsenzadeh et al. [102] in which non-hydrocarbon gases like pure CO₂, pure N₂, and their mixture as in flue gas were injected into a core of a fractured carbonate reservoir. This process is followed by steam injection with specific steam/gas ratio. It was concluded that the injection of these non-hydrocarbon gases with co-injection of steam gas could enhance the oil recovery values to 58.4%, 73.8%, 47% for CO₂, flue gas, N₂, respectively, after gas breakthrough (GBT). These results are considered highly acceptable for oil recovery. New emerging ideas for heavy oil recovery are being proposed to add Deep Eutectic Solvents (DESs) like Choline Chloride; Glycerol (DES1) and Choline Chloride; Urea (DES2) [102]. This process, when followed by steam injection process was shown to increase the recovery rate by 12%.

Another alternative composition for improving the EOR process is called thermal–chemical flooding after steam injection. This composition is steam, nitrogen (N₂), and viscosity breaker (VB). Compared with steam flooding thermal–chemical flooding had higher displacement efficiency with a ratio 11.7% higher than that of pure steam flooding [103].

2.5.5 Solar Assisted Steam Injection for Enhance Oil Recovery (SEOR)

Solar thermal steam generation involves production of steam using energy from the sun. The idea has been around since the early 80s [104]. Mirrors are used to concentrate and focus sunlight on receivers containing water or brine solution. The heated fluid is then either directly or indirectly used to generate steam in a flash tank. The use of solar energy reduces the reliance on fossil fuels for steam production. However, due to the intermittent nature of solar energy supply, a hybrid system utilizing the conventional fossil fuels integrated in a power cycle with

the solar thermal steam generation system is utilized. The hybrid system comes in handy in the absence of solar thermal energy storage systems and/or during cloudy weathers and the nighttime when solar energy is not available.

Glass Point built the first commercial Solar Enhanced Oil Recovery (SEOR) project in Kern County, California [81]. It utilized parabolic troughs to heat water and directly generates steam for well injection, generating 300 kW of thermal energy. The parabolic troughs were kept inside a glasshouse to protect it from dirt and sandstorms. The system could produce steam at 2500 psi and 950 °F. The BrightSource pilot project in Coalinga, California utilized a solar tower to produce 29 MW of thermal energy capable of generating 13 MW of electrical energy. It uses 3822 heliostats and is based on a land area of 100 acres [81]. Another pilot project [10] by Glass Point based in Oman near Amal oilfields utilizes glass-skinned structure enclosed parabolic trough similar to the one in Kern County on a 4.2 acres field. The plant can produce 7 MW of thermal energy, resulting in production of 14.8 tons of steam per hour at 100 bars having 80% quality. The plant is supplemented with a gas fired steam production system to produce steam at night. For a constant steam rate, the gas consumption could be reduced by up to 25%. Furthermore, by injecting more steam during the day the gas consumption could be reduced by up to 80%. Another solar steam plant of 1GW thermal energy is under construction for the same oilfield.

The use of solar and conventional steam production technique enables the use of a cyclic method of steam injection. In this method more amount of steam is injected during the day, and during the night, the injection rate is kept at a minimum. This prevents closing injection during the night, which could lead to problems associated with well start-up and thermal fluctuations along the wellbore. Injection during the night can be carried out either using conventional fossil fuel-based steam generation methods or using energy from solar thermal

energy storage systems. A recent study [105] has shown that small amount of nightly steam injection increases the cumulative oil production in comparison to no nightly steam injection. However, the effectiveness also depends upon the property of oil being recovered. In a study [106] for recovering heavy oil from Hamca field in Venezuela, no significant improvement in oil production was found by injecting steam at night regardless of the quantity injected. Thus, the use of 100% solar generated steam was deemed viable in this case.

EMA Mokheimer and MAM Habib [107] disclosed and granted a patent for enhanced oil recovery, which is based on a hybrid system that utilizes the solar thermal energy at the day time and oxy-fuel combustor at the night time, as shown in Figure 2.9. At the daytime the solar heater generates steam that is injected into the oil field to enhance the oil recovery. At the nighttime the oxy fuel combustor is used, instead, to generate the combustion gases, which are mainly carbon dioxide and water vapor in addition to oxygen-depleted air (nitrogen). The water vapor is separated from the combustion gases by cooling. The combustion gases and Nitrogen are injected separately into the oil field for the same purpose. The carbon dioxide is injected for miscible enhanced oil recovery, while the nitrogen is injected for immiscible enhanced oil recovery.

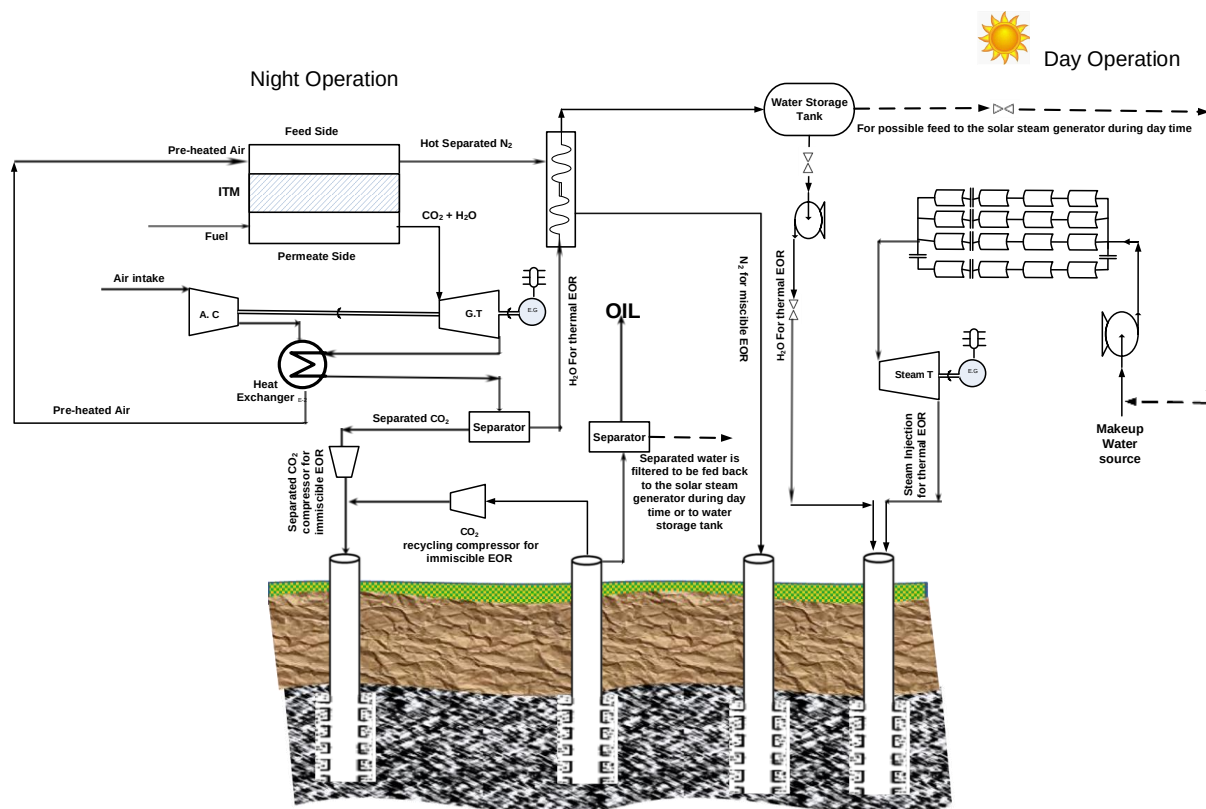


Figure 2. 9 Schematic diagram of the hybrid solar thermal enhanced oil recovery system with oxy-fuel combustor,
Patent number 9845667B2, December 19-2017 [107]

Continuous variable rate injection scenario was investigated by Sandler et al. [108] using established reservoir simulation model of steam drive through vertical wells in heavy-oil sand. The model also accounted for seasonal variations with greater injection rate during summer. The steam injection rate during evening and night, using conventional steam generation method, was reduced by 96%. Oil recovery and other parameters were compared with constant rate injection. The cyclic solar steam injection was at par with constant rate steam injection using conventional steam. The oil rate recovery was found to be independent of daily and annual cycles for multiple year timescales. Similar conclusions, was reached by Van Heel et al. [109]. Furthermore, economic analysis showed that the solar thermal steam generation with 100% solar fraction had the lowest operational cost and was least sensitive to natural gas prices fluctuations. This also leads to a significant reduction in CO₂ emission from production of crude oil. It should be noted that the direct normal irradiation received is the primary factor in

deciding the feasibility of SEOR projects. It is viable in areas which receive high solar radiance throughout the year and may prove economically unjustifiable for other areas. In a study by Yegane et al. [110] using TRNSYS software, a heavy oil field in Turkey utilizing parabolic trough collector was observed not to have enough and available solar power for continuous steam injection all year round. The maximum solar fraction reached was about 42%, which did not economically justify the investment cost of the project.

2.6 Thermochemicals Injection

The effort to produce heavy oil in more economical and environmentally friendly ways is presently receiving increasing attentions [111, 112] Accordingly, in the recent times, an environmentally benign and cost-effective technology, for in situ heat generation through exothermic chemical reactions, has been proposed for thermal stimulation of reservoir [113-116]. Generally, the interest in the in-situ steam or heat generation through thermochemical processes is due to the advantage it offers for lower capital and/or operating costs and higher overall thermal efficiency, compared to the steam and thermal fluid injection methods. Moreover, this technology can be used for different operations such as; hydraulics fracturing, recovery of deep heavy oil and tight oil reservoirs, and can be applied to onshore and offshore fields. Compared to the conventional surface steam generation and injection methods, it has lower cost, less labor intensive and efficient thermal deliverability, since no steam facilities or plants are required and no toxic emission [114].

Thermochemical stimulation of the reservoir, especially for thermal EOR, is relatively a new technology. Nonetheless, in order to mitigate the tar play in certain Saudi Arabia conventional oil reservoir, Al-Nakhli et al. [114] reported an innovative and environmentally friendly technology, originally launched by the Saudi Aramco research team, to mobilize the highly viscous bituminous oil for improve production flow. The method, termed EXO-Clean

technology, essentially concerns downhole generation of heat (steam) and nitrogen gas by exothermic chemical reaction. As an advantage over the traditional steam flooding method, through numerical simulation, it was shown that the generated nitrogen could be utilized to reduce the steam-oil ratio by increasing the heated area; hence, oil can be mobilized through thermal and mechanical forces. From a typical thermochemical reaction conducted in an autoclave using the EXO-Clean reactant, it was reported that the generated heat and pressure increased significantly from the ambient conditions to 315 °C and 3,470 psi, respectively. In addition, from a field scale simulation of the EXO-Clean technology involving a candidate steam flood field (with 13° API oil), the oil production doubles that of injecting high-quality steam.

2.7 IN-SITU COMBUSTION (ISC)

Among the thermal EOR technologies, in-situ combustion and down-hole heating have great potential as the emerging generation of thermal Enhancement of Oil Recovery (EOR) technologies. However, like all other thermal EOR technologies, in-situ combustion and down-hole heating require the use of huge amount of natural fuel (usually gas). Since all thermal EOR methods suffer from its environmental footprint due to the associated CO₂ emission, the search for new thermal EOR methods such as in-situ combustion and downhole heating are thought to be the next generation thermal EOR technologies.

In-situ combustion, also called “fire flooding”, is one of the thermal EOR systems being widely used since its inception in the early 1950s in USA’s Pennsylvania. Like any conventional combustion process, it requires fuel, oxidizer and igniter. However, in ISC the combustion happens inside an oil well, as shown in Figure 2.10. The process involves the adequate injection of compressed, heated air, enriched air, or oxygen into an oil reservoir at pressures equivalent to the reservoir pressure. Initial reservoir pressures of up to 22 bars [117]. The injected air will

cause the oxidation of some of the oil components in the reservoir. This high temperature oxidation (HTO) process is accompanied with thermal energy generation (with about 500 to 900°C in temperature rise) which continues till the temperature reaches the ignition temperature [118]. Consequently, the mixture will be ignited establishing a combustion front that releases thermal energy and combustion gases like CO₂, CO, and H₂O which dissolves and displaces the reservoir fluids towards the production well. Cold air needs to be injected as the combustion front is established in order to ensure continuity of the combustion. There are two types of ISC; forward and reverse combustion according to the direction of oxidizer and combustion front. If the two are in the same direction it is called forward otherwise it is called reverse combustion.

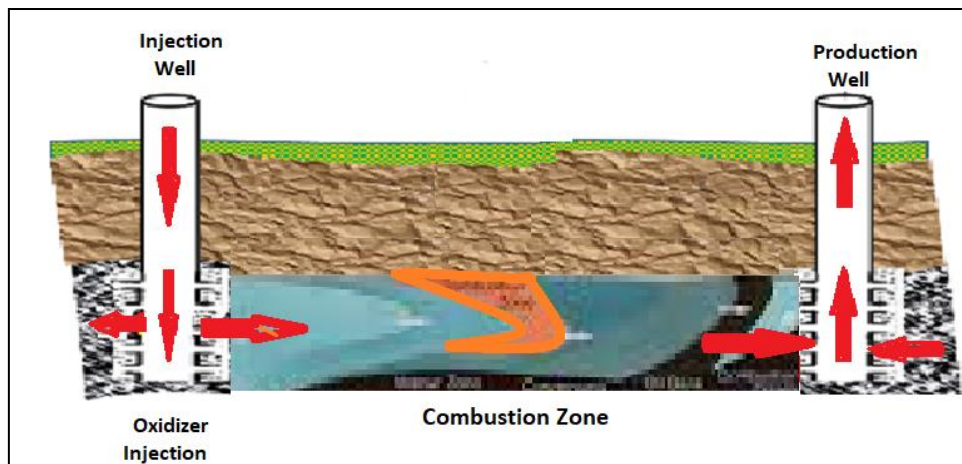


Figure 2. 10 Schematic illustration of In-situ combustion process

It is however important to note that for heavy oils and reservoirs having low temperatures, the injection well may be heated through other means to achieve the ignition in the reservoir. During ISC, the reservoir oil undergoes series of physical and chemical changes that includes thermal cracking and distillation of residual crude. Due to the thermal cracking, a solid fuel, in form of carbon residue is produced. This fuel that is formed and deposited, together with the distillates produced, sustains the combustion in presence of oxidizer. The successes recorded for in-situ combustion projects as well as some inconclusive or unsuccessful ones over the last

decades were reviewed by Alvarado and Manrique [2]. Specifically in carbonate formations, ISC have shown a steady growth since the end of the 1990s [119]. It has successfully been implemented in field scale applications for heavy oil sandstone reservoirs in Canada, India, Romania, and the USA.

ISC presents an opportunity in terms of water requirement since the constraints of water availability for steam injection for thermal EOR system is taken care of. Additionally, the process provides an opportunity in terms of CO₂ emission reduction to the atmosphere since the products from the combustion is composed mainly of CO₂ and CO that can be collected and recycled together with the air during subsequent injection. Although, as the amount of the recycled gases gets higher with time, more oxygen will be needed in the air for combustion to be sustained, which lends credence to air-enriched or oxy fuel combustion practices [120]. It is reported based on experimental studies that enrichment of air with a 35% volume of oxygen enhances the overall oil recovery but using 100% oxygen in the process was shown to reduce oil recovery [121, 122]. Consequently, an optimum amount of oxygen needs to be established for different scenarios. The higher oil recovery tendency of oxygen enriched ISC can be the result of higher amount of steam generated in the combustion products which facilitate further the process of dissolution and oil displacement for EOR. This higher steam production rate for oxygen-enriched air is evident in the steam front velocities of 0.077, 0.084, and 0.110m/h reported for 21%, 30%, and 35% oxygen by volume in the air respectively [121]. In a combustion tube experiment for crude oil from Liaohe Oilfield in Liaoning Province (Bohai Basin), China, it was found that the oil recovery factor reach 78.6% and the combustion front movement velocity of 0.20 cm/min [123].

Furthermore, ISC is comparatively more energy efficient, having relatively lower amount of energy consumed to produce a barrel of oil because the HTO process happens directly in the

reservoir. This energy efficiency is related to the air-to-oil ratio (AOR) defined as the volume of air needed for injection for the recovery of a certain volume of oil. AOR is a function of oil saturation in place at the beginning of the combustion, the well geometry, as well as the fuel formed and deposited that eventually get burned [19]. Another critical parameter for ISC is the amount of fuel present per bulk volume of the reservoir as it ultimately determines the air required to burn a unit bulk volume of the reservoir. A detailed review of fundamental concepts of ISC as well as detailed chemical kinetics of the process is carried out by Mahinpey et al. [124]. An average AOR of 1890 m³-air/m³-oil was reported for good performing field projects (equivalent to 302m³ of air producing 6120MJ of crude oil energy) [125], but varies under different conditions from 880 to 8,860 m³-air/m³-oil [126]. For air at temperature and pressure T₁ and P₁ respectively, a compressor efficiency η , the energy, as a shaft work, W_s required to compress certain volume of air to be delivered at pressure P₂ can be estimated using the following equation:

$$W_s = \left(\frac{1}{\eta}\right) \left(\frac{\gamma R T_1}{\gamma - 1}\right) \left[\left(\frac{P_2}{P_1}\right)^{\frac{\gamma-1}{\gamma}} - 1\right]$$

Where R is the ideal gas constant and γ is the ratio of constant pressure and volume heat capacities.

The most important challenges associated with in-situ combustion are the combustion temperature and gas override (gravity segregation) due to density difference between oil and gas, leading to premature combustion zone breakthrough in the producers. Another challenge that arises during oil recovery is a result of unfavorable gas/oil ratio due to density variations. Depending on the lithology, issue related to decomposition of rock, turning into a powder-like material, which can easily result into plugging, is also a source of concern. Oil fields with limestone lithology are shown to be susceptible to such tendencies. Heterogeneity in the rock

formation can also lead to channeling that could be unfavorable. Furthermore, fractures resulting from the combustion thermal energy release could lead to the release of trapped oxygen that impact on the whole system and could even lead to its failure. Before implementing in-situ combustion EOR project on any reservoir, therefore, feasibility study needs to be conducted to ascertain its suitability vis-à-vis oil type and nature of the rock in the reservoir. These studies include the use of thermo-metric test using rigs like thermo-gravimetric analyzer (TGA) and differential scanning calorimeter (DSC) [127].

One of the improvements to in-situ combustion process is THAI (Toe-to-Heel Air Injection) that combines the process with a horizontal well system. In this case, the injection is carried out just like explained before, using vertical well thereby generating the burning front. A horizontal well at the bottom of the reservoir is used instead as oil producer in this case [128]. This is said to achieve up to 80% oil recovery [129]. A survey done in 2014 had shown that oil production using thermal EOR (steam, in-situ combustion, and hot water injection) in the USA has reached 307,018 bbl/day [130].

To increase the mobility of the recovered oil, Hart [131] developed a design for a system that introduces air and ammonia gas into the subterranean formation during the in-situ combustion. Air assists in establishing a combustion front, while ammonia gas contacts the hydrocarbons ahead of the combustion front and reacts in-situ with naphthenic acid in the hydrocarbon to form a surfactant. Another design by Paurola [132] injects high temperature oxygen-rich gas into the formation, leading to combustion, which reduces the viscosity of said hydrocarbon mixture and generates CO₂-rich gas. Hot hydrocarbon is obtained in the recovery stage. Provision to capture at least a portion of CO₂ from said CO₂-rich gas is also included.

Canas [133] used ISC in conjunction to SAGD method for hydrocarbon recovery. In addition to horizontal well for steam injection, this process also includes another horizontal well for oxidizing gas injection. Hydrocarbons are produced from a hydrocarbon production well of the SAGD well pair; this hydrocarbon producing well is located below the steam injection well. The oxidation well is positioned above the two SAGD wells, but closer to the surface of the oil reservoir.

ISC like any combustion process releases the combustion gases to the environment. Das [134] proposed the idea of separating hot nitrogen from the combustion gases coming out of the reservoir and utilize it to generate electricity by using mobile turbines. Another patent by Warren [135] aims to improve the ISC performance by using a proper water gas ratio by introducing foaming agent with water in wet ISC. The foam has good capability to carry water through heated reservoirs and prevents separation from the gas. As a result, more thermal energy is transferred through the steam which increases the oil recovery.

ISC process is considered the most effective method in cases of difficult conditions where the other methods are not applicable; these conditions might be low permeability, high temperature, and deep oil reservoirs [136]. This process has been used in more than two hundred fields around the world, as mentioned before it is used in the difficult reservoir as a secondary or tertiary process. ISC releases a significant amount of thermal energy accompanied with hot flue gas mixture which consists of carbon dioxide, nitrogen and steam, which are considered as a driving force for oil recovery [137]. But ISC is also considered one of the complex methods in comparison to other EOR methods due to complex reactions, heat and mass transfer.

MAM Habib and EMA Mokheimer [138] proposed a novel solar thermal EOR system based on ITM oxyfuel combustion. The proposed novel system is based on in-situ oxy-combustion

that is based on ITM that separates the oxygen from the air. The separated oxygen is injected into the oil well to burn part of the well oil generating the required heat for thermal EOR. The air is heated before entering to the ITM unit as shown in Figure 2. 11.

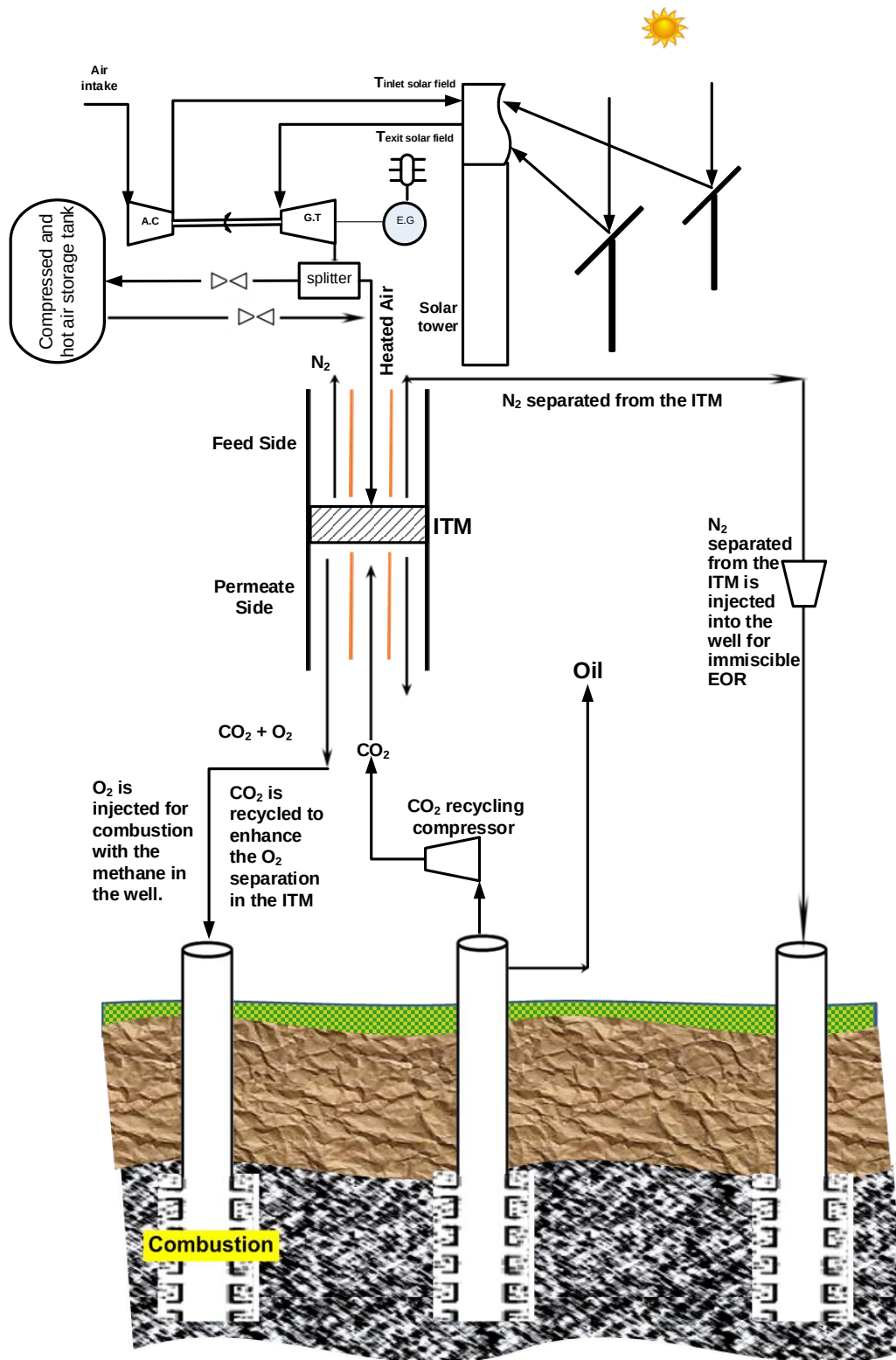


Figure 2. 11 Schematic diagram for a Solar-Assisted EOR System [138]

There are two types of ISC, Wet and Dry. Wet combustion is considered a way to improve in-situ combustion process in comparison to dry combustion, where the heat capacity of the steam

is high which enhances the oil recovery process [139]. The amount of oil well required for ISC is 5-10% from the original oil in place [140]. Due to some difficulties in feasibility studies, unknown properties, non-homogeneity of the reservoirs and different components of the crude oil. It has been reported that the global average success of dry ISC to be only 44.6%, which is considered low and unsatisfactory. There are some drawbacks which may decrease the efficiency of the ISC process such as the non-uniform advancement of the combustion front, which may decrease the sweeping efficiency, and presence of a cold oil bank in front of the mobilized oil which is considered like a resistance for the oil transfer [141].

Much research had been done to improve the in-situ combustion process by different techniques; one of them is adding Nano-particles to combustion process [137], [142, 143]. Rezaei et al. [142] studied the effect of adding Nano-particles (NP) experimentally, which may overcome the problem of large particles that negatively affects recovery process, and also examined the effect of using Nano-particles on the thermal behavior of crude oil. Some extra thermal, magnetic, electrical and chemical properties had been transferred with this NP. Improvement of the rate of combustion has been noticed by Amanam et al. [143] by addition of 1000 ppm nano-particles (Cu-NP) on combustion and greater front temperature.

2.7.1 Dry Combustion

In dry combustion process, air (or enriched air) is first injected into an injection well, for a short time (few days) and then, the oil is ignited. For ignition process, different methods can be used such as downhole gas burners, electric heaters or through injection of a pyrophoric agent or a hot fluid such as the steam. In some cases, auto ignition of the in-situ crude occurs, in this cases the reservoir temperature must be greater than 180°F and the oil sufficiently reactive [144].

2.7.2 Wet Combustion

Most researches conducted in this regard proved that wet combustion is preferred to dry combustion. One reason is that, in the dry forward combustion process, large amount of thermal energy is generated during combustion is stored in the sand behind the burning front and is considered as thermal energy losses not used for oil recovery. Another reason is the higher heat capacity of water than air, so water can absorb and transport thermal energy many times greater than air. Water is injected together or alternately with air with certain ratios to give the optimum combustion process. This injected water absorbs heat thermal energy from the burned zone, and then it vaporizes, after that it passes through combustion front and then release its thermal energy as it condenses in a cool section of the reservoir. This leads to faster thermal energy transfer and oil displacement.

2.7.3 ISC zones:

Different zones are generated during the ISC. These zones are many and some of them are overlapping, and they move in the direction of air flow. They simply can be summarized to 7 zones [126], as shown in Figure 2. 12:

1. The burned zone.
2. The combustion zone
3. Cracking zone
4. Condensation zone
5. Water bank
6. Oil zone
7. The native zone

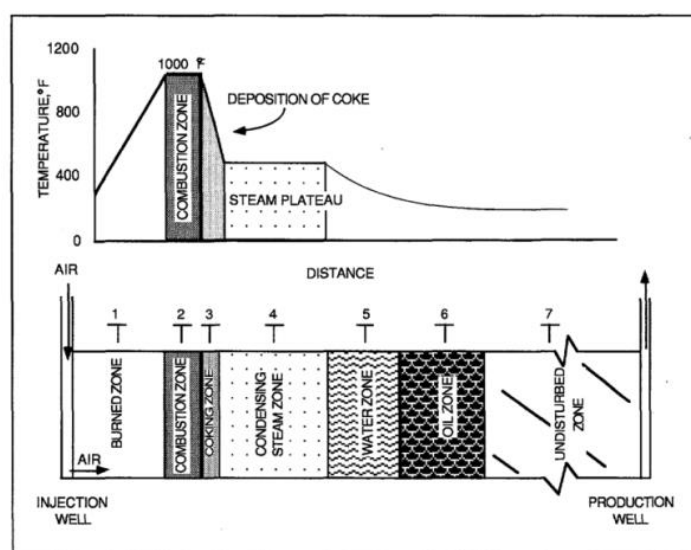


Figure 2. 12 ISC schematic Temperature profile [126]

2.7.4 Chemical Reactions Associated with ISC

The chemical reactions involved in ISC are numerous, complex, and occur over different ranges of temperatures; these reactions have been simplified by most researchers and are grouped into three classes: (1) low temperature oxidation (LTO), (2) intermediate temperature, and (3) high temperature oxidation (HTO) or combustion of the solid hydrocarbon residue (coke).

2.7.4.1 Low Temperature Oxidation

LTO is highly complex and not easy to understand, but it is believed that it consists of condensation of low molecular weight components to higher molecular weight products. It occurs below 400 °F and yields water and partially oxygenated hydrocarbons such as carboxylic acids, aldehydes, ketones, alcohols, and hydro-peroxides[145]. LTO is considered an oxygen addition reaction and is caused by the dissolution of oxygen in the crude oil. Light oils are more affected to LTO than heavy oils. It has been found that LTO increase the

Asphaltene content of the oil and decreases its aromatic and resin contents [146-148]. LTO increases the original oil's viscosities, boiling range and densities [147, 149]. LTO reaction is the process that generates fuel available for combustion [150]. It is better to minimize the LTO reactions promotion during the in-situ combustion of heavy oils as the pre-oxidation of the heavy crude at lower temperatures greatly increases the fuel availability and subsequent air requirements for combustion. The major outcome of LTO is Coke production, but the use of LTO reaction for an extended period can cause the oil to be permanently trapped in the pores.

2.7.4.2 Negative Temperature Gradient Region (NTGR):

The negative temperature gradient region (NTGR) is an important temperature region in ISC, where it is considered a transition between the LTO and HTO, where the temperature decreases after increasing. NTGR should be achieved for effective ISC, as failure of the reaction temperatures to reach NTGR leads to very low oil displacement efficiency. This is because the oxygen addition reactions cause vapor phase to contract significantly and make the oil less mobile [126]. In NTGR the global oxygen-uptake rates decrease with increasing temperature. The negative temperature gradient region depends on some parameters like oil and the core properties as well as on the operating conditions. As example the NTGR temperature range for Athabasca bitumen is approximately between 300°C and 350°C [151, 152].

2.7.4.3 Medium Temperature Reactions (MTO)

Middle temperature oxidation (MTO) reactions are homogeneous reactions occurring primarily in the gas phase. In MTO reactions of pyrolysis and distillation produce mainly hydrogen and some light hydrocarbons in gas phase [153]. Most of the hydrocarbons are formed without oxidation, however, some oxygen reacts with other hydrocarbons to form heavier hydrocarbon fuels which are later utilized for combustion at higher temperatures [154]. This process is also called as fuel deposition due to heavy oil residue being deposited on the solid matrix [155,

156]. Excessive fuel deposition is known to reduce the rate of propagation of the combustion front, while lower fuel deposition rate may not provide enough heat to sustain the combustion front [157]. In clean sands, MTO reactions are considered to be rate determining step [124].

2.7.4.4 High Temperature Oxidation HTO

In this range of temperature, oxygen reacts with unoxidized oil, fuel and the oxygenated compounds to give carbon oxides and water. The thermal energy generated from these reactions provides the energy required to sustain and propagate the combustion front. MTO is followed by high temperature oxidation (HTO) reaction, in which fuel formed by MTO is oxidized [154]. At higher temperatures oxygen reacts with unoxidized oil, fuel and the oxygenated compounds to give carbon oxides and water. This reaction zone is the main combustion region inside the reservoir. HTO reactions are kinetically controlled and are not affected by diffusion effects. HTO reactions are slower than MTO reactions in clean sand matrix [153]. The heat generated from these reactions provides the thermal energy to sustain and propagate the combustion front. The viscosity and specific gravity of the produced oil decreases significantly during HTO [124].

2.7.5 Draw backs of in-situ combustions

ISC has some drawbacks which can be summarized as:

- The control of ISC process is difficult.
- Safety issues such as avoiding uncontrolled oxygen break-through.
- Numerous reactions and huge number of components.

ISC, as mentioned before, is considered the promising thermal EOR techniques as it applicable in a much wider range of fields than only heavy oil fields, in deeper reservoirs of light or medium oil. But, on the other hand, ISC has some drawbacks; one of them is that it considered

complicated method with safety. The insufficient coke deposited from the oil could not sustain the combustion process. However, the excessive amount of fuel deposited leads to decreasing in the combustion rate as the amount of injected air is considered small. There are also some drawbacks which may decrease the efficiency of the ISC process such as the non-uniform advance of the combustion front, which may decrease the sweeping efficiency, and presence of a cold oil bank in front of the mobilized oil which considered like a resistance for the oil transfer [141]. So, the control of ISC process is difficult so there are some safety issues such as avoiding uncontrolled oxygen break-through and the numerous reactions and huge number of components.

2.7.6 ISC Models

Crude oils contain hundreds of different compounds which makes it very difficult to represent all the reactions, and almost impossible to simulate it. Consequently, most studies use a simplified model based on the Arrhenius reaction expressions defined as [153, 158]:

$$R_c = \frac{dC_f}{dt} = K p_{O_2}^a C_f^b$$

Where;

R_c : crude oil reaction rate

C_f : fuel concentration

p_{O_2} : partial pressure of oxygen

K : reaction rate constant

a, b : reactions orders with respect to oxygen partial pressure and fuel concentration, respectively.

$$K = A \exp (-E / RT)$$

Where;

A: the Arrhenius constant

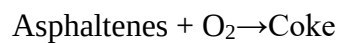
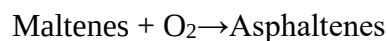
E: energy of activation

T: the absolute temperature

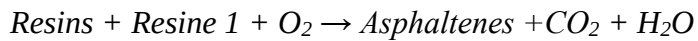
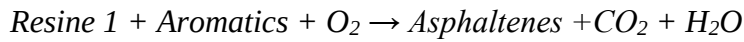
R: the universal gas constant.

Kinetic parameters can be determined using a variety of experimental techniques, and it could be obtained from the literature [126]. As mentioned before, authors grouped the reaction model into pseudo-components of similar properties. Selection of the pseudo-components must model the phase behavior of the original hydrocarbons. So, the oil results are characterized in terms of Maltenes and Asphaltenes or in terms of Saturates aromatics, Resins and Asphaltenes (SARA) fractions [159].

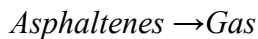
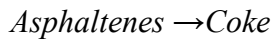
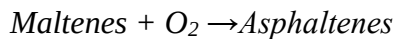
The first proposed reaction model for LTO was done by Adegbesan et al. [160]. They proposed the model for Maltenes, Asphaltenes and Coke for the Athabasca Bitumen. The used reaction mechanism is:



Sequera et al. [161] proposed another model for LTO, but used SARA components. This model provides acceptable results:



Hayashitani [162] proposed model for MTO reaction to model the fuel deposition process and gas production within the MTO:



A numerical model had been proposed by Gonçalves and Trevisan [139] to simulate the wet forward ISC process of a combustion tube experiment with the properties of an onshore heavy oil field located at Espírito Santo state in Brazil. Analysis of different parameters had been done such as water-air ratio, initial saturations, operating pressure and water-air alternation. The dead oil used in this study was subdivided into two pseudo-components: a medium oil pseudo-component (C6-C29) with a molecular weight of 254.2 and a heavy oil pseudo-component (C30-C44) with a molecular weight of 781.3. According to the reaction rate, the kinetic-controlled reaction model had been considered by the simulator, four chemical reactions included are three HTO combustion reaction and one cracking reaction as shown:

Cracking: $12.1 \text{ Heavy OIL} \rightarrow .1721 \text{ Medium OIL} + 33.4 \text{ COKE}$

Medium Oil Oxidation: $00.1 \text{ Medium OIL} + 22.6 \text{ O}_2 \rightarrow 18 \text{ H}_2\text{O} + 15 \text{ CO}_2$

Heavy Oil Oxidation: $00.1 \text{ Heavy OIL} + 8.9 \text{ O}_2 \rightarrow 5.9 \text{ H}_2\text{O} + 21 \text{ CO}_2$

Coke Oxidation: $00.1 \text{ COKE} + 18.1 \text{ O}_2 \rightarrow 5.0 \text{ H}_2\text{O} + 95.0 \text{ CO}_2$

It is concluded in the study that oil recovery increases with increasing water injection ratios until an optimum value then it starts to decrease. Higher initial oil saturations and operating pressure presented higher oil recovery factors. Water-air alternation resulted in a negligible effect.

Yang and Gates [163] studied experimentally the combustion using Athabasca Bitumen in a 1D Combustion tube to get a set of kinetic parameters and transport parameters for the system. From the literature there are different available schemes, these schemes differ due to their definitions of pseudo-components. In this study they used the one developed by Belgrave et al.[164] for Athabasca bitumen as shown:

1. Thermal Cracking Reactions (first order):

$\text{Maltenes} \rightarrow 0.372 \text{ Asphaltenes}$

$\text{Asphaltenes} \rightarrow 83.223 \text{ Coke}$

$\text{Asphaltenes} \rightarrow 37.683 \text{ Gas}$

2. LTO Reactions

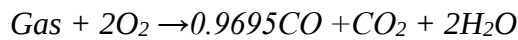
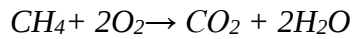
$\text{Maltenes} + 3.431 \text{ O}_2 \rightarrow 0.4726 \text{ Asphaltenes}$

$\text{Asphaltenes} + 7.513 \text{ O}_2 \rightarrow 101.539 \text{ Coke}$

3. HTO or coke combustion

$\text{cokeCH}_{1.13} + 1.232 \text{ O}_2 \rightarrow \text{CO}_x + 0.565 \text{ H}_2\text{O}$

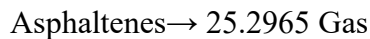
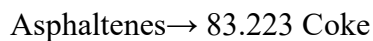
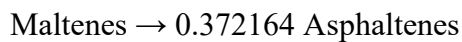
4. Gas Phase Combustion



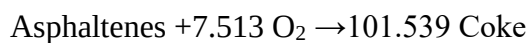
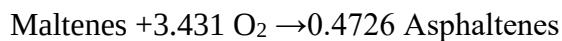
They also simulated their model using The STARS™ thermal reservoir simulator (CMG, 2007). In their conclusion they suggested from their results that Coke is originated from the LTO not from the thermal cracking as known, so it is important to control the LTO for sufficient combustion process.

Kapadia et al. [165] proposed a kinetic model for combustion of the Athabasca Bitumen which include thermal cracking, LTO, HTO, gasification, water –gas shift reaction, methanation, hydrogen generation, hydrogen and monoxide combustion, as shown:

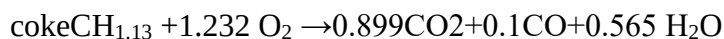
- Thermal cracking reaction [162]:



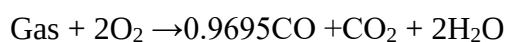
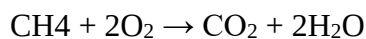
- LTO reaction [160]:



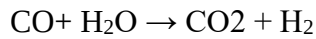
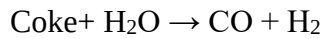
- HTO reaction [160]:



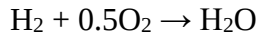
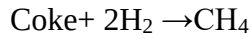
- High temperature gas oxidation Reaction [163]:



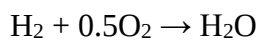
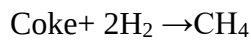
- Hydrogen generation reaction:



- Hydrogen Consumption reaction:



- Carbon monoxide Reaction:



2.8 Evaluation of Different Thermal EOR Systems

Evaluation of different EOR methods in comparison with each other does not necessarily have credibility due to several parameters distinguishing the processes. These parameters such as crude oil properties whether it is heavy or extra heavy. Other parameters include the properties and geography of the well such as permeability, porosity, area, depth, available thermal energy, etc. Due to all these reasons, it is difficult to compare thermal EOR with each other. But we can mention the reported features from the literature for each method, as shown in Table 1. 1. Table 1. 2 contains a detailed case study for each technique.

Table 2. 1 Thermal EOR systems: advantages, disadvantages, and limits

Method	Examples (Location)	Permeability limits (mD)	Porosity limits (%)	Depth limits (ft)	Viscosity limits (cP)	Reservoir Pressure (psi)	API Gravity	Oil Saturation (%)	Special features	Improvements To the process	Cost source	Advantages	Drawbacks
1. Hot Fluid Injection Processes													
1.1 Cyclic Steam Stimulation (CSS)	-Canada, Venezuela, Brazil, U.S.A (California) [71]	Minimum: 2000[166]	Minimum: 20 [166]	Minimum: 1000 Maximum: 3000 [166]	Minimum: 300 [166]	<4000	<20	20	-steam temperature: 200-300 °C -used as a first stage before continuous injection	-using horizontal wells - add chemicals to steam - using AICSS - using hydraulic fracturing [73, 74]	Cost of steam generation by: -coal -biomass -solar [10, 76] -natural gas [19]	-Rapid payout during early production [71]. - environmentally preferred [167]. - Preferable with small thicknesses [167].	-Low recovery (around 10–40%) [[67], [68], [166] -Consume large quantities of water and fuel, so it is costly.
1.2 Steam and hot water flooding		-Minimum for steam : 100 - For water: 3-2800 [166]	-For steam 36 -For water 15 [166]	-For steam 500-3000 -Max. for water: 10,000	-Minimum for steam: 300 Maximum for water: 2000	-For steam: <4000	-For steam: <20 - For water >14	20 [166]	- Requires a huge amount of water or steam to be injected[37]	-Using N2 thermal foam flooding can improve RF from around 43% to 81 %	-Steam generators -Fuel used -Feed water treatment	-higher water driving power -Steam flooding has RF 50-60% of OOIP [82, 83]	-Less efficient than steam injection [37] -Steam override -Excessive thermal energy loss

					[166]								
1.3 Steam assisted gravity drainage (SAGD)	Canada (Alberta) [37]	Minimum: 50 [166]	Minimum: 18 [166]	Maximum: 5000 [166]	50:350,000 [166]	<4000 [166]		20 [166]	-The best for heavy oil recovery in carbonate reservoir [89]	- conducting with distributed effluent treatment system[91] -injecting of solvent with steam - using vertical wells [93]	-High cost of steam production	-Oil recovery (%): 60-80[63] -Much more economic than CSS, as the efficiency is twice	-Consumes large quantities of water and fuel.
1.4 Steam/ solvent hybrid system	Is used with any steam injection process such as steam flooding and SAGD.								-at start up then followed by steam injection process. -Examples of solvents: 1.Glycerol (DES1) 2. Urea (DES2)			- Shorten the start-up process - improve the production rate at early production period. [94] -Reduce the steam consumption [94] -oil recovery efficiency reached 80%	

1.5 Solar enhanced oil recovery (SEOR)	-USA (California) -Oman [10] -Venezuela [106] -Turkey [110]	Is used with any steam injection processes.										-lower operating cost compared with Natural gas. -Reduction in CO2 Emission.	-Available solar energy only in the day time. -Thermal storage system is required.
2. In-Situ Combustion (ISC)	Canada, India, Romania, USA[46]	< 10[126]	16-38[126]	300-11500 [126]	<5,000[126]	-up to 22 bar [117]	10-40[126]	700 bbl/ac-ft. [126]	-No depth limit with taking in mind the injection pressure	-using (THAI) which use horizontal wells [128].		-CO2, CO reduction. -more energy efficient - allows wider well spacing than steam	-Decomposition of rock turning into powder -heterogeneity leads to channeling -High Capital and operating Expenditure requirements [166]-Planning and combustion design requirements is more difficult than steam injection. -Limitation of numerical simulation

3. Electric heating method									-Enhance the heating effect especially in the low permeability zone.	-using water injection with it[42]., or use it with solvent -use it with SAGD[44]		-Production rate is 7.6% higher than the SAGD /CSS methods. [168] -Efficient to increase the temperature of the surrounding fluid. [168] -Does not require the additional investments required for a steam distribution system	- decreasing the heat transferred by water
4. Electromagnetic method									-Using microwave absorber[60] -using it with solvent injection -with SAGD gives good results [169], and nano-particles [52]			-reduction of carbon emissions -minimize excessive water usage -increases energy Saving	

Table 2. 2 One case study for each process.

Method	Example (Location)	Temperature F	Porosity (%)	Depth (ft)	Viscosity (cP)	Reservoir Pressure (psi)	API Gravity	AOR, Mscf/ bbl	Average Oil Prod.,B/D	Notes	Reference
1. Hot Fluid Injection Processes											
1.1 Cyclic Steam Stimulation (CSS)	Alta Province, cold lake, Canada 2002	55	32	1395			10		---	-area = 32 acres	[119]
1.2 Steam flooding	San Ardo, California USA		32	2100			12		253	-area = 700 acres	[119]
1.3 Steam assisted gravity drainage (SAGD)	Orion, Canada 2007	60	33	1350			10		10000	- area =5120 acres	[119]
1.4 Steam/ solvent hybrid system	North Burbank, California USA,2007		16.8	2900			39			-area = 480 acres	[119]
1.5 Solar enhanced oil recovery (SEOR)	Bati Raman field, Southeast Turkey [study]	535 - 635	10.8-20	1722 m		1800-2000	9.5-13.5		45	-steam injected 250-2000 bpd	[110]

2. In-Situ Combustion (ISC)	Balaria field, Romani	118	30	2625	120	284.5 : 570	19	14	750		[170] , [171]
3. Electric heating methods	Bakers field, California	120		1400	14.3		14.3		10-20	-total Power Output 25.7 kW -Voltage 600 V -Inrush Current (at 20C) 69 amps	[172]
4. Electromagnetic method	Wildmere field, Alberta, Canada			600	20 Pa.s				3.18 tonnes/day		[58]

2.9 Ion Transport Membrane Literature Review

Producing oxygen is one of the significant processes in industry for many processes such as metal production, oxy-combustion, welding, petroleum refining, and coal gasification. Oxygen production process is still expensive, so researchers are still conducting more research to produce oxygen with low cost via developing different methods. There are two methods for producing oxygen, one is based on cryogenic technologies [173], and the other is based on ion transport membrane (ITM) technologies. Ion transport membrane (ITM) is considered as one of the latest technologies for separating oxygen from air due to its flexibility for different applications [174, 175]. Membrane reactors can be used also for hydrogen production [176, 177]. The high purity of the produced oxygen is considered one of the most important advantages of the ITM [178].

Many researchers investigated the ITM performance including change of different parameters such as the operating conditions, direction of flow of fluids in feed side or sweep side (e.g., it is counter flow or parallel flow), also two channels or three channel membranes. Oxygen permeation through ITM is highly affected by some parameters such as temperature of the membrane, feed and sweep gas flow, the feed side oxygen concentration, but the membrane temperature has higher effect than other parameters [178-180]. The results showed that the oxygen permeation rate increases with increasing temperature, feed side oxygen partial pressure and flow rates, while it decreases with permeate side oxygen partial pressure and membrane thickness [180-182]. For large scale ITM has been used to promote net efficiency of an integrated gasification combined cycle power plants [183]. As an improvement to the separation process, conducting it with oxidation reaction in the permeate side for achieving higher permeation flux has been explored [178, 179, 184-188]. There are two sides for the membrane, the first is the feed side while the other is the sweeping side. Xu and Thomson [179]

reported that increasing the oxygen partial pressure in the feed side, directly increases the permeation flux. This partial pressure has a larger effect than those induced by the feed gas flow rates, but membrane temperature has the highest effect. In addition, increasing the sweep gas and fuel fraction increases the oxygen permeation rate to a certain level and after that it nearly remains constant. Nemitallah et al. [189] have studied some parameters for optimizing the ITM performance with oxidation for gas turbine reactor. The results revealed that counter-current flow design improves oxygen permeation flux and improves heat transfer characteristics. But, unfortunately, the counter-current flow design gives unacceptable membrane temperature, which cannot be neglected. On the other hand, decreasing the channel width below a certain value leads to a higher viscous pressure drop, which inversely affects the permeation rate. Increasing the methane amount in the permeate side over 5% was found to be inapplicable because of oxygen permeation flux limitation and the combustion was lost due to the increased flow velocity. Hong et al. [190] used a model to study the effect of membrane surface conditions and detailed chemistry and transport in the vicinity of the membrane on the oxygen permeation rate. It was concluded that increasing the temperature of the sweep gas inlet and increasing the fuel concentration up to 15%, directly, increases the oxygen permeation flux. To overcome the problem of non-uniformity of temperature distribution at the surface of ITM, three-channel configuration instead of two-channel configuration. Porous plate is used to separate the fuel stream from the permeate stream allowing the fuel to diffuse gradually into the permeate side [191]. This uniform temperature distribution prevents the membrane from damage, improves its performance and gives more uniform oxygen permeation. Habib et al. [192] tried to overcome this problem via introducing the new idea of using a reactor with divided three channels membrane. The membrane was divided into 10 parts of equal length with different porosities for uniform temperature distribution.

$\text{Ba}_{0.5}\text{Sr}_{0.5}\text{Co}_{0.8}\text{Fe}_{0.2}\text{O}_{3-\delta}$ (BSCF) perovskite-type ceramic membrane is considered one of the most promising materials for ITM. BSCF has the highest permeation flux as reported. However, it has some problems at high temperature [193]. Wagner equation is considered the mostly accepted equation for predicting oxygen permeation flux through perovskite membranes. In this equation, the effect of bulk diffusion only is considered, and surface-exchange reactions are neglected. For the large scale power plant an experimental work has been carried out to determine the coefficients of the Wagner equation [194]. Membrane tubes have been used in the experiment considering the tubular membrane for industrial application in future oxyfuel power plants [194, 195], however, there is still an important issue in this approach, which is the membrane area and the related net efficiency for the plant. Hollow fiber BSCF membrane has been tested [196] for high purity oxygen, higher than 99.5% at high flow rate.

The structural stability and oxygen permeation flux of (BSCF) have been studied [197]. Oxygen permeability through BSCF membrane was studied and the results were reported in references [198-200]. Conductivity and stability studies were reported in [201, 202] respectively, and mechanical properties studies were reported in [203, 204]. On the other hand, the oxygen permeation flux through BSCF membranes decreases with time in long-term experiments [205]. A modification to the surface of the BCSF to use it in the industrial applications has been explored [206]. In this regard, a porous layer has been added to improve the oxygen permeation properties of this material [206]. The surface exchange reaction area was increased. It was found that adding the porous layer may increase the permeation rate up to 3.6 times of a similar sample without the surface layer.

oxygen permeation rate increases as the CH_4 % increase in the sweep side, also it increases with increasing the operating temperatures [207]. Using CO_2 as a sweeping gas with BSCF

membrane leads to some problems such as of degradation of the oxygen permeation flux. Arnold et al. [208] reported that with pure CO₂ as sweep gas, an immediate stop of the oxygen permeation flux is occurred, but can it can be easily recovered by sweeping with pure helium. To overcome this problem, Zhang et al.[209] prepared a SrFe_{0.8}Nb_{0.2}O_{3-δ}/Ba_{0.5}Sr_{0.5}Co_{0.8}Fe_{0.2}O_{3-δ} (SFN/BSCF) dual-layer membrane structure by pulsed laser deposition of SFN thin layer onto polished BSCF membranes. This coating gives 90% performance of BSCF, that means with error around 10%.

2.10 Summary of Chapter 2

2.10.1 Summary and Gaps of Thermal EOR investigations

A comprehensive review on the Thermal EOR methods has been presented in this paper. The Oil recovery can reach as high as 75% of OOIP, depending on the employed EOR technique. The revenue from the global enhanced oil recovery will reach around 80 USD Billions by 2020. This review chapter has been focused on thermal EOR as it is widely used around the world for several decades and it is still being developed. Thermal EOR is the dominant method employed for EOR globally with 67% global usage. The review indicated that oil production using thermal EOR (steam, in-situ combustion, and hot water injection) in the USA has reached 307,018 bbl/day in 2014. Our review also revealed that many numerical and experimental investigations had been carried out with the aim of developing different EOR techniques, many of which were introduced and discussed in this chapter. Different steam injection techniques like pure steam or steam with different additives had been introduced. Steam injection techniques are considered the dominant among all EOR techniques, as steam has higher energy content and can easily be produced.

In-situ combustion is also considered one of the important methods, where it can work at initial reservoir pressures of up to 22 bars, and the amount of the required well oil, to be burned, for ISC is 5-10% from the original oil in place. It was found that the oil recovery factor reach 78.6% in laboratory experiment using crude oil from Liaohe Oil field in Liaoning Province (Bohai Basin), China, ISC fields can be found in Canada, India, Romania and USA. Also, it was reported that the global average success of dry ISC is only 44.6%, which is considered low and unsatisfactory. ISC techniques can be used over a wide range of well conditions. It can be used for wells with permeability lower than 10 mD and depth of up to 11,500 ft. However, ISC EOR techniques still have its own difficulties of design requirements as well as their high capital and operational cost in comparison to hot fluid injection technique.

Advantages and disadvantages of all thermal EOR techniques had been highlighted. For future work, the combination between these conventional methods and renewable energy should be explored.

From the review of Thermal EOR, it was concluded that the main problems which are associated with Thermal EOR are the high capital and operating cost of producing and injection heat to the reservoir. In addition to the higher heat losses during these operations, higher consumption of water and higher CO₂ emissions. All the mentioned problems need to be solved or at least decreased. So, the ultimate target of this thesis is to decrease the cost required for heating while keeping the environmental footprint of the used EOR technique as minimum as possible.

2.10.2 Summary and Gaps of ITM investigations

Several studied have been done to optimize using of ITM in oxygen separation process. Effects of membrane temperature, feed and sweep gas flowrate and feed side oxygen concentration have been studied. Conducting ITM with oxidation reaction in the permeate side for achieving

higher permeation flux has been explored. Conductivity, stability, and mechanical properties studies were reported.

But, in all the previous studies the produced oxygen was mixed with the sweeping gas or used already in oxidation process. The problem was that the ratio between the permeated oxygen and the sweeping gas is very low, which cannot be used in ISC process. So, in this work we studied the effect of some boundary conditions and geometries to get the highest permeation flux of oxygen from the ITM. Producing a pure oxygen in the sweep side of ITM has been performed. That will be introduced in the next chapter.

CHAPTER 3

ION TRANSPORT MEMEBRANE:

NUMERICAL MODELLING

In this chapter, numerical model of oxygen permeation flux through a non-reactive ITM is presented. In this regard, the numerical model was developed for the specific problem of optimizing different geometries and different boundary conditions. The numerical model was built using computational fluid dynamics (CFD) codes. The conservation equations for mass, momentum, energy and species and Radiative transport equation (RTE) were solved using the finite volume approach of CFD. The CFD code used in this study is ANSYS Fluent; a commercial code based on the finite volume scheme. User Defined Function (UDF) has been used to model the ITM membrane, as there is no membrane model in ANSYS Fluent. This UDF allows us to model the ITM accurately, with respect to the available experimental data, and predict the local oxygen flux across the ITM at any point of the membrane. The model was solved and as a result gives an approximate solution by solving the algebraic equations.

This study is focused on exploring the effect of changing the flow configurations of the flow gases in the feed and permeate sides in ITM of BSCF type. Effect of changing dimensions of flow channels was considered. Different impingement configurations such as single and double impingements and distances between the pins in the double impingement configuration were studied. Impingements with different angles were included, and the oxygen permeation rate was recorded. The effect of creating a vacuum in the sweep side for parallel flow configuration without any sweeping gas was recorded.

3.1 Numerical Model

In this numerical model, a flow impingement (stagnation flow) configuration is used for analyzing the oxygen separation process in the ITM system as shown in Figure 3.1. This flow impingement configuration has been selected to simplify the analysis by reducing the dimensionality of the problem [178]. This simplification is attributed to the fact that, in the vicinity of the stagnation line, profiles of velocity, temperature, density and species concentrations follow a self-similar solution in the direction normal to the membrane. As shown in Figure 3.1, the membrane separates the physical domain into two computational domains which are governed by the governing equations outlined hereinafter. To simulate and study the performance of this model, a numerical model has been developed using the FLUENT CFD code to study the effect of flow configurations of the nonreactive ITM on the oxygen permeation flux.

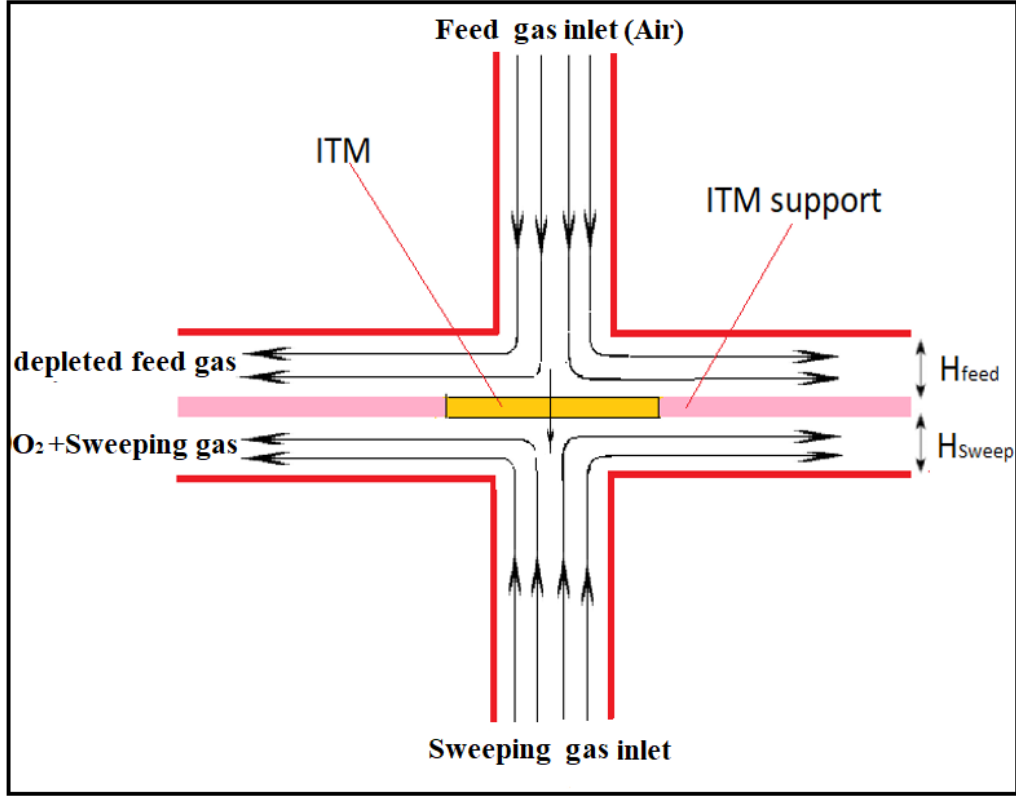


Figure 3. 1 Impingement flow configuration for ITM system. The feed gas enters from the upper side and the sweeping gas enters from the lower side, and the outlet is from the sides as shown

3.1.1 Governing Equations

Numerical model has been developed for this specific problem with different geometries and different boundary conditions. So, the numerical model will be solved and as a result gives an approximate solution by solving the algebraic equations. The physical processes within the ITM include transport phenomena of mass, momentum, and species. The governing equations of the whole mathematical model for these processes are solved using the finite volume approach of Computational Fluid Dynamic to get pressure and velocity. The transport model is assumed to be 2D-steady laminar flow with species, the conservation equations of mass, momentum, energy and species equations can be expressed as follows [210]:

$$\text{Conservation of mass: } \nabla \cdot (\rho U) = S_i \quad (3.1)$$

$$\text{Conservation of Momentum: } \nabla \cdot (\rho U U) = - \nabla p + \mu \nabla^2 U \quad (3.2)$$

$$\text{Conservation of Energy: } (\rho C_p) U \cdot \nabla T = \nabla \cdot (\lambda \nabla T) \quad (3.3)$$

$$\text{Conservation of Species: } \nabla \cdot (\rho U Y_i) = \nabla \cdot (\rho D_{i,m} \nabla Y_i) + S_i \quad (3.4)$$

Where p is the pressure, S_i is the oxygen source/sink, U is the velocity vector, μ is the viscosity, ρ is the density and λ is thermal conductivity. The diffusion coefficient in the gaseous mixture, $D_{i,m}$ is calculated as [210].

$$D_{i,m} = \frac{1-x_i}{\sum_{j,j \neq i} \left(\frac{x_j}{D_{i,j}} \right)} \quad (3.5)$$

The oxygen source/sink term, S_i , is presented by the following equation using oxygen flux, cell area, molecular weight of oxygen and cell volume as follows:

$$S_i = \begin{cases} \frac{+J_{O_2} A_{cell} MW_{O_2}}{V_{cell}} & \text{at the permeate side} \\ \frac{-J_{O_2} A_{cell} MW_{O_2}}{V_{cell}} & \text{at the feed side} \end{cases} \quad (3.6)$$

The oxygen permeation through ITM is considered to include the overall permeation process including the adsorption and dissociation of oxygen in the feed side and diffusion of oxygen ions and electrons on the permeate side of the membrane. The mechanism of oxygen separation process consists of 5 steps which are presented in detail in [178, 211-214]. These steps can be summarized graphically as shown in Figure 3. 2.

This model was initially used by Xu and Thomson [179], where the following equation expresses the permeation rate as a function of oxygen partial pressure and reaction rate, it is widely used up till now, which has been got experimentally for the measured oxygen permeation rates [179], and we used it in our case as in [180].

$$J_{O_2} = \frac{\left(\frac{K_r}{K_f}\right)\left[\left(\frac{1}{p_{O_2}''^{0.25}}\right) - \left(\frac{1}{p_{O_2}'^{0.25}}\right)\right]}{\frac{1}{K_f p_{O_2}'^{0.25}} + \frac{2L}{D_v} + \frac{1}{K_f p_{O_2}''^{0.25}}} \quad (3.7)$$

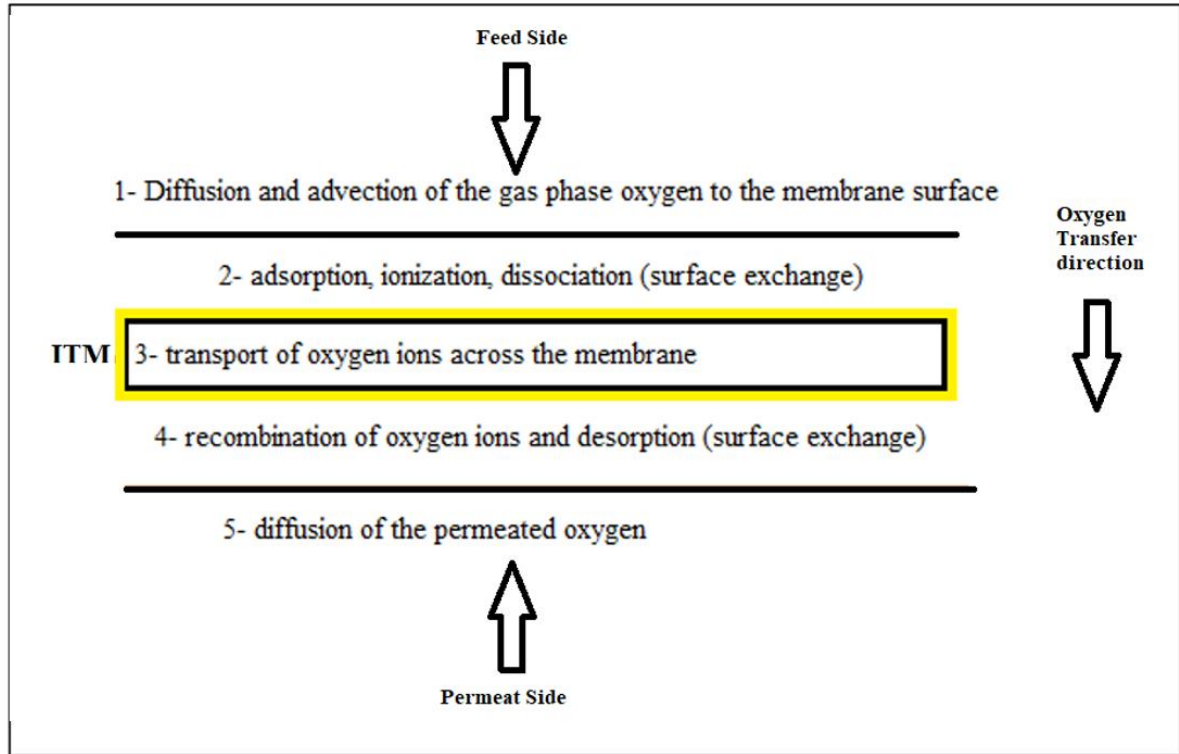


Figure 3. 2 Five steps of oxygen transport processes within the ITM. The process starts from the upper side passing through the membrane then to the lower side following the steps

The permeation driving force coming from the oxygen partial pressure at the feed and sweep side p_{O_2}' and p_{O_2}'' respectively. D_v , k_f and k_r are the bulk diffusion coefficient and the forward and reverse reaction rate constants.

These coefficients can be expressed as follows [180]:

$$\begin{aligned} D_v &= 5.9807 \times 10^{-5} \exp\left(-\frac{E_D}{RT}\right) \\ k_f &= 4.1688 \times 10^{+1} \exp\left(-\frac{E_f}{RT}\right) \\ k_r &= 1.1660 \times 10^4 \exp\left(-\frac{E_r}{RT}\right) \end{aligned} \quad (3.8)$$

The discrete ordinates (DO) radiation model is used in the present work. This model solves the radiative transfer equation (RTE) for emitting, scattering and absorbing medium. The RTE equation in the direction $\vec{s}$ is given as [215].

$$\frac{dI(\vec{r},\vec{s})}{ds} + (a + \sigma_s)I(\vec{r},\vec{s}) = \frac{an^2(\sigma T^4)}{\pi} + \frac{\sigma_s}{4\pi} \int_0^{4\pi} I(\vec{r},\vec{\hat{s}}) \phi(\vec{s},\vec{\hat{s}}) d\hat{\Omega} \quad (9)$$

Where a is the coefficient of absorption, n is the refractive index, I is the radiation intensity and s is the length of path.

3.1.2 Geometry

The geometry of the tested ITM comprised two separated domains, one for the feed side and the other for the permeate side, with different flow impingement configurations as shown in Figure 3. 3. Air is flowing in the feed side, while CO₂, as the sweep fluid, is flowing in the permeate side. Figure 3. 3-a shows single impingement configuration in both feed and sweep sides, Figure 3. 3-b shows the double impingement configuration with two open ends, Figure 3. 3-c shows single impingement configuration with angle in the sweep side, and Figure 3. 3-d shows the double impingement configuration with one end open and the other closed. Figure 3. 3-e shows the parallel configuration with open ends and Figure 3. 3-f shows the parallel configuration with vacuum in the permeate side.

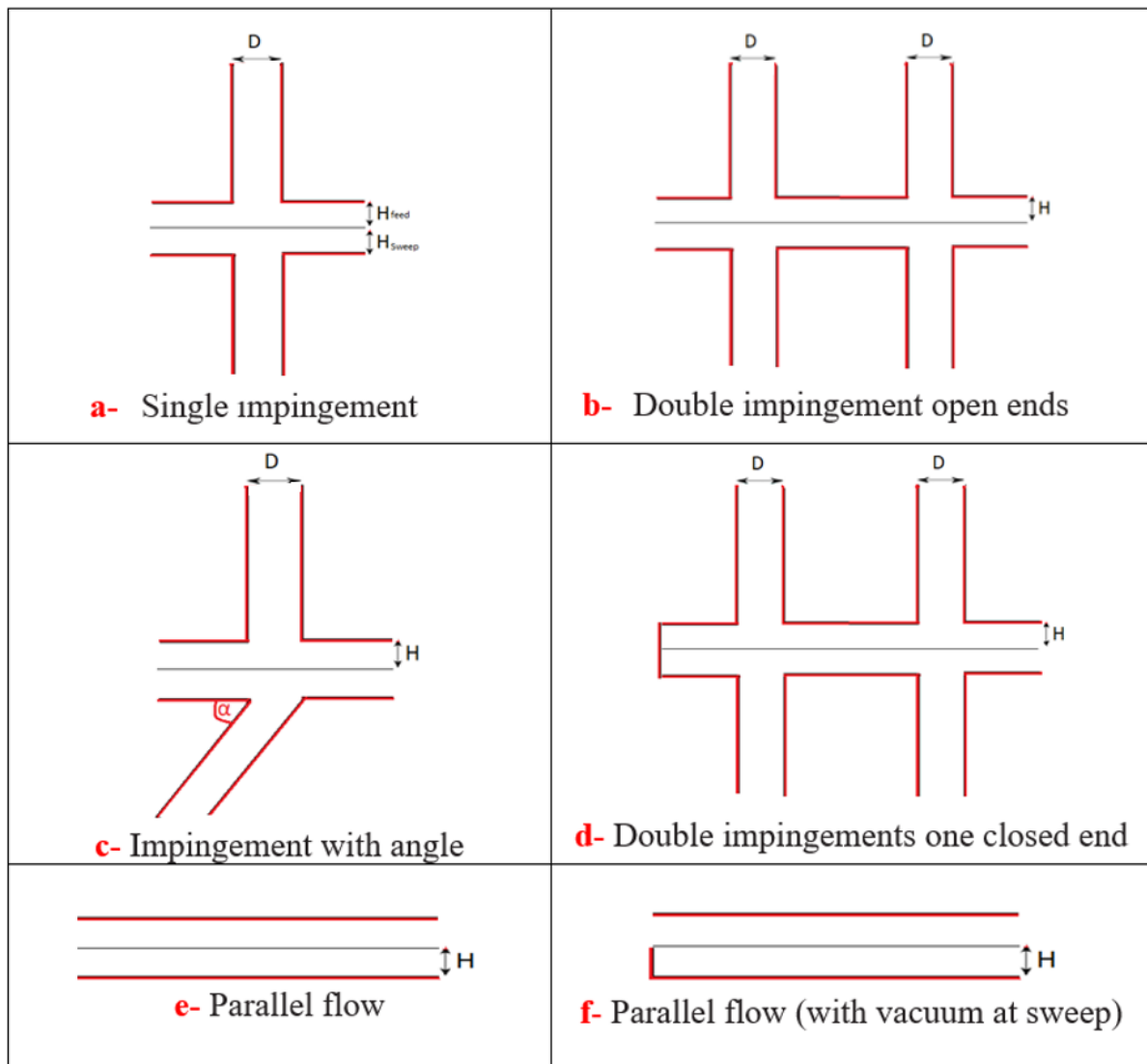


Figure 3. 3 Different flow impingement configurations for the ITM. In these geometries the inlet slots are open for the feed and permeate side, but the outlet slots are sometimes open, and others closed as shown in the figure

3.1.3 Boundary Conditions

The mass flow rate of the air (23% O₂+77% N₂) is kept at 1.7230×10^{-3} kg/s. The sweep gas (CO₂) mass flow rate is kept at 2.1790×10^{-3} kg/s. In the present study the inlet temperature of all gases is 1173 K and the thermal conductivity and density of the ITM are 202.4 W/m K and 2719 kg/m³, respectively. All boundary conditions are summarized in Table 3.1.

Table 3. 1 Summary of boundary conditions used in the present study

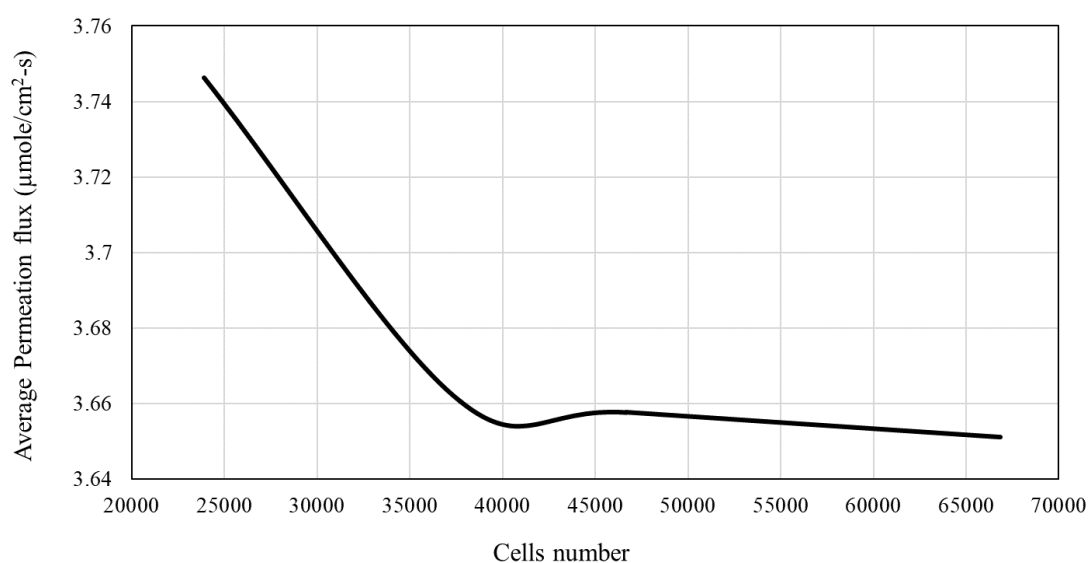
Boundary conditions	
Feed gas	Air (O ₂ /N ₂)
Sweep gas	CO ₂
T _{in} (for Air and CO ₂) , K	1173
Pressure, Pa	101325
K _{BSCF} (ITM thermal conductivity), W/m K	202.4
ρ _{BSCF} (ITM density), kg/m ³	2719
$\dot{m}_{\text{air}}$, kg/s	1.7230×10^{-3}
$\dot{m}_{\text{CO}_2}$, kg/s	2.1790×10^{-3}

3.1.4 Mesh Refinement Test

To conduct the mesh refinement test, the model was initially built with a coarse mesh. Finer grids were tested after this to identify the mesh size at which the permeation flux changes were negligible. Increasing the mesh size beyond this will produce no effect on the permeation flux, increase the CPU time taken to run the model. So, the purpose of mesh refinement test is not to get the highest permeation flux, but to select the optimum cell numbers for the numerical grid. As shown in Table 3. 2 the optimum number is 37700 cells for the single impingement configuration. Table 3. 2 shows that the change of cell numbers from 23894 to 37700 leads to change in the permeation flux with ratio 2.288%, that means finer grids are required. After increasing the number of grid blocks, the change of the cell numbers from 37700 to 46676 leads to a change ratio equal to 0.08 %. That means from cell number 37700 the change in the permeation flux can be neglected, and that is shown in Figure 3. 4.

Table 3. 2 Mesh refinement test results

Grid	Cells Number	Permeation Flux ($\mu\text{mole}/\text{cm}^2\text{-s}$)	% change with respect to previous grid
1	23894	3.746307	-----
2	37700	3.660575	2.288
3	46676	3.657639	0.08
4	66855	3.651119	0.17

**Figure 3. 4 change of permeation flux with cells number and percent deviation with respect to previous grids number**

3.1.5 Model Validation

To make sure that the model is reliable, it was validated with experimental work [180]. The validation results are presented in Figure 3. 5. The permeation flux for different membrane temperatures for two different partial pressures of oxygen have been compared with the pertinent experimental results. The figure depicts the comparison at oxygen partial pressure in the feed side of $P_{O_2} = 0.9 \text{ atm}$ and $P_{O_2} = 0.3 \text{ atm}$. The operating conditions as in [180] are feed flow rate = $300 \text{ (cm}^3/\text{min)}$, sweep gas flow rate= $60 \text{ (cm}^3/\text{min)}$ and thickness = 1 mm. The deviation of the permeation flux between the experimental data and the data

predicted using the current model is considered small for all points especially at higher temperatures.

Figure 3. 5 also indicates that the percent deviation on the secondary axis is decreasing with increasing the temperature, and that is because of an increase in the permeation flux values with increase in the temperature. As known from the literature, ITM is working with higher efficiency at higher temperatures. As shown in the figure, in case of $P_{O_2} = 0.3$ atm the maximum deviation is 31.68 % and occurs at 650 °C. However, the high deviation is due to small values of permeation flux at low temperatures. At temperature 900 °C the deviation is 3.755 % which is small and acceptable. On the other hand, in case of $P_{O_2} = 0.9$ atm the maximum deviation is 37.13% and occurs at temperature 650 °C, as mentioned before the deviation is high due to small permeation flux at low temperatures which are out of our working range, but at 900 °C the deviation is 1.17%. According to this validation, the current model gives acceptable results. This high accuracy of the results predicted proves that the developed numerical model can be used to accurately simulate the performance of the ITM that is usually working with higher separation efficiency at high temperatures.

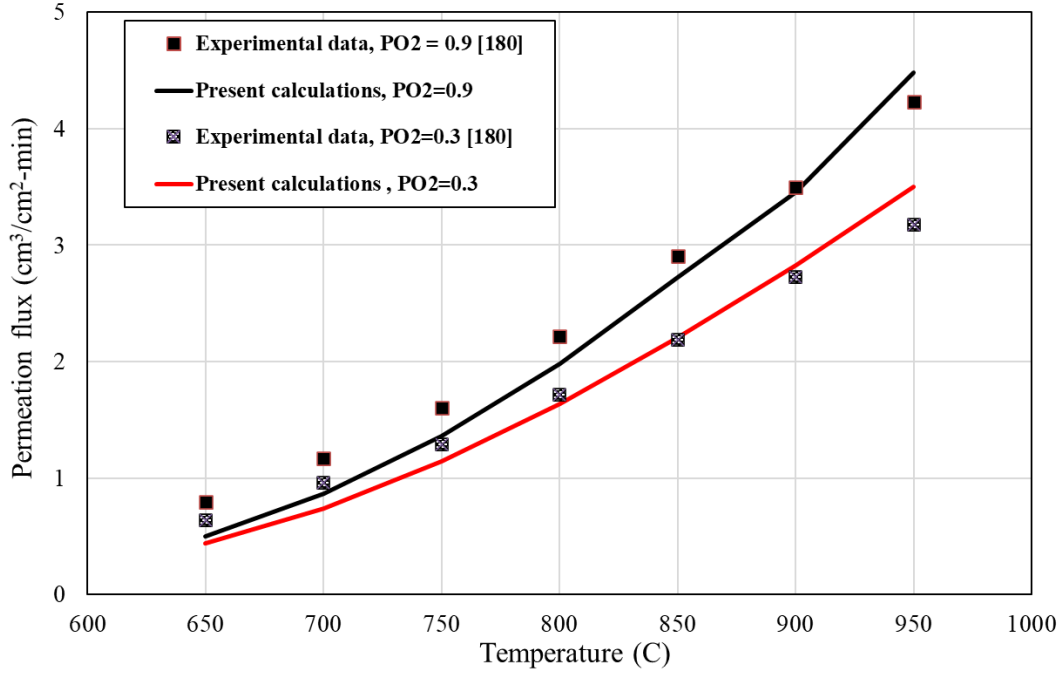


Figure 3. 5 Validation of the present model with experimental results [180] with different PO₂ in the feed side

3.2 Results and discussion

In this part, a comparative analysis was conducted to select the optimum configuration for the feed and sweep sides according to the oxygen permeation rate. The local oxygen flux in kg/m²s is usually converted to a molar flux in $\mu\text{mole}/\text{cm}^2\text{-s}$ using the molecular weight of oxygen. The results of the model validation will be presented first followed by an analysis of different flow configurations.

3.2.1 Effect of Sweep and Feed Flow Rates on the Permeation Flux

Sweep flow rate is considered an effective parameter on the permeation flux. Figure 3.6 illustrates this effect, for the single impingement with the boundary conditions given in Table 3.1 which are $P_{\text{in}} = 101325 \text{ pa}$, $T_{\text{in}} = 1173 \text{ K}$ and $\dot{m}_{\text{air}} = 1.7230 \times 10^{-3} \text{ kg/s}$ with different sweep gas mass flow rates. Increasing the sweep flow rate increases the permeation flux directly. The reason is that increasing the sweep flow rate increases the stream velocity and decreases the

pressure, as a result, the oxygen removal rate increases. The increase in the sweep flow rate results in high rates of purging of the permeated oxygen from the sweep side. Thus, P_{O_2} is reduced in the permeate side causing high partial pressure difference of O_2 across the membrane resulting in high oxygen flux.

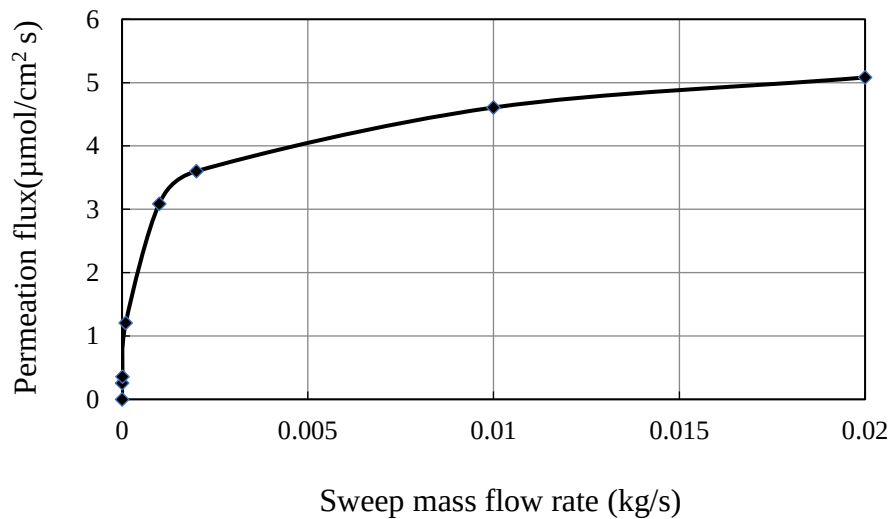


Figure 3. 6 Effect of sweep flow rate on the permeation flux

Changing the feed flowrates was studied to investigate its effect on the permeation flux as shown in Figure 3. 7. Decreasing the feed flow rate as shown in the figure directly decreases the permeation flux. Reducing the feed mass flow rate from $\dot{m}$ to a fourth ($\dot{m}/4$), decreases the permeation flux with 4.575% which is considered a small change. The reason is that the most sensitive parameter in the feed side is the oxygen partial pressure. Figure 3.7-b illustrates that the average permeation flux per pumping power increases dramatically with decrease in the feed mass flow rate. That means quarter of the feed mass flow rate is the optimum value.

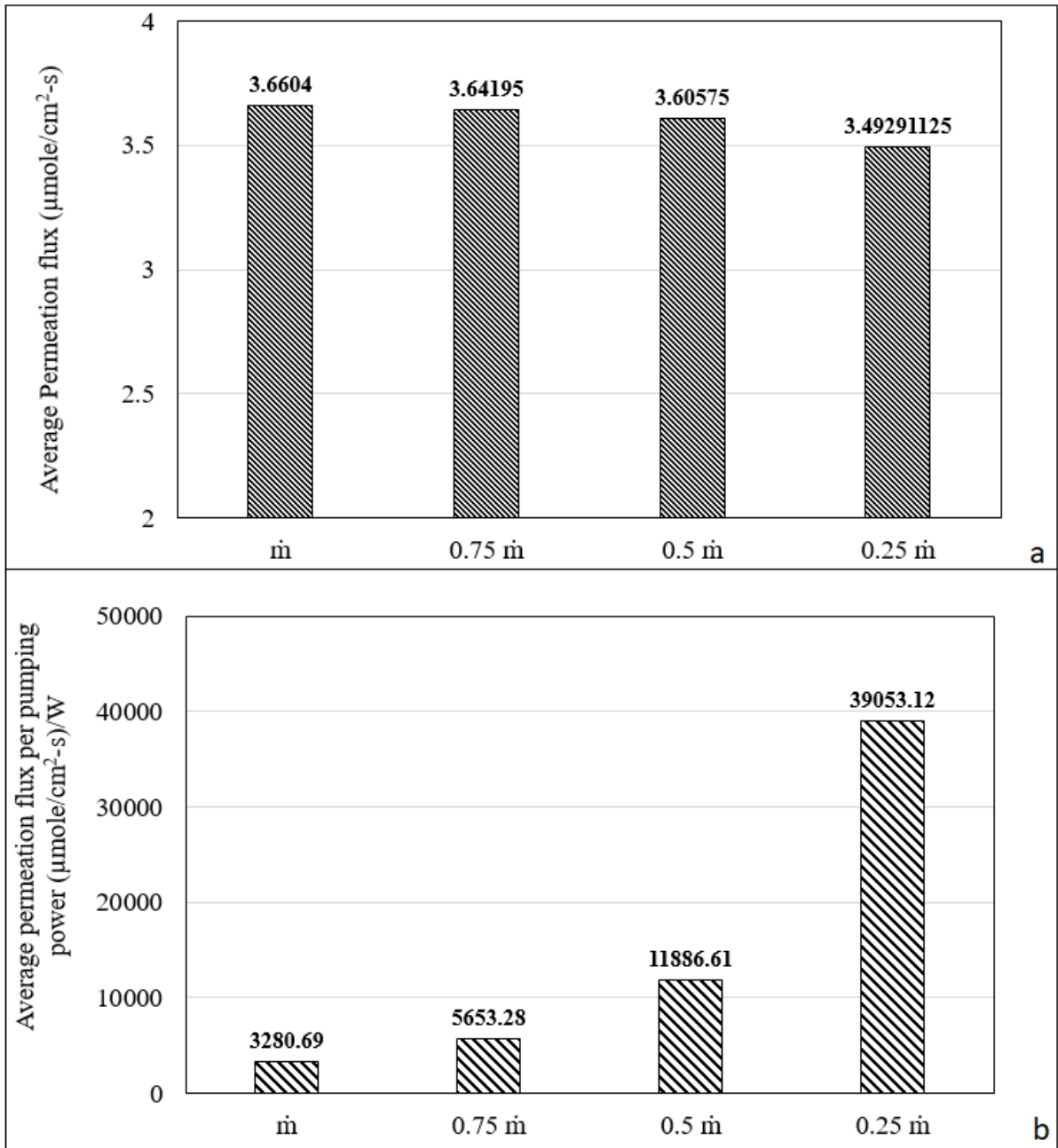


Figure 3. 7 Effect of feed flow rate on the average permeation flux for feed mass flow rate, $\dot{m}_{\text{air}} = 0.001723 \text{ kg/s}$

3.2.2 Impingement Flow Effect on Membrane Permeation - Single Impingement Point

In this case of single impingement (Figure 3. 3-a), dimensions of the feed and sweep side nozzle (slot) width (D) are kept constant while the distance between the nozzle and the membrane (H) in the sweep side is reduced to increase the D: H aspect ratio as shown in Figure 3. 3-a. As shown in Figure 3. 8, the variations of permeation flux along the membrane for the base case

D: H = 1, is symmetric about the center of the membrane where the peak permeation flux is observed. The area of the membrane with the peak permeation flux coincides with the membrane areas on both feed and sweep sides which experiences direct impingements of air and sweep gas, respectively. The total pressure in the feed side has a maximum value at the impingement point due to the formation of stagnation point, which is characterized by high pressure. The high total pressure at the point of impingement creates a high differential partial pressure of oxygen (dppO₂) across the membrane as shown in Figure 3. 9. The dppO₂ drives permeation across the membrane and as such more oxygen is permeated at the impingement point. The partial pressure of oxygen at the feed side is 0.21 atm. The permeation flux decreases gradually from the membrane center towards the exit. This is because the pressure in the feed side decreases in the flow direction, away from the impingement point, which results in decrease in dppO₂ along the membrane and invariably decreases the oxygen permeation flux.

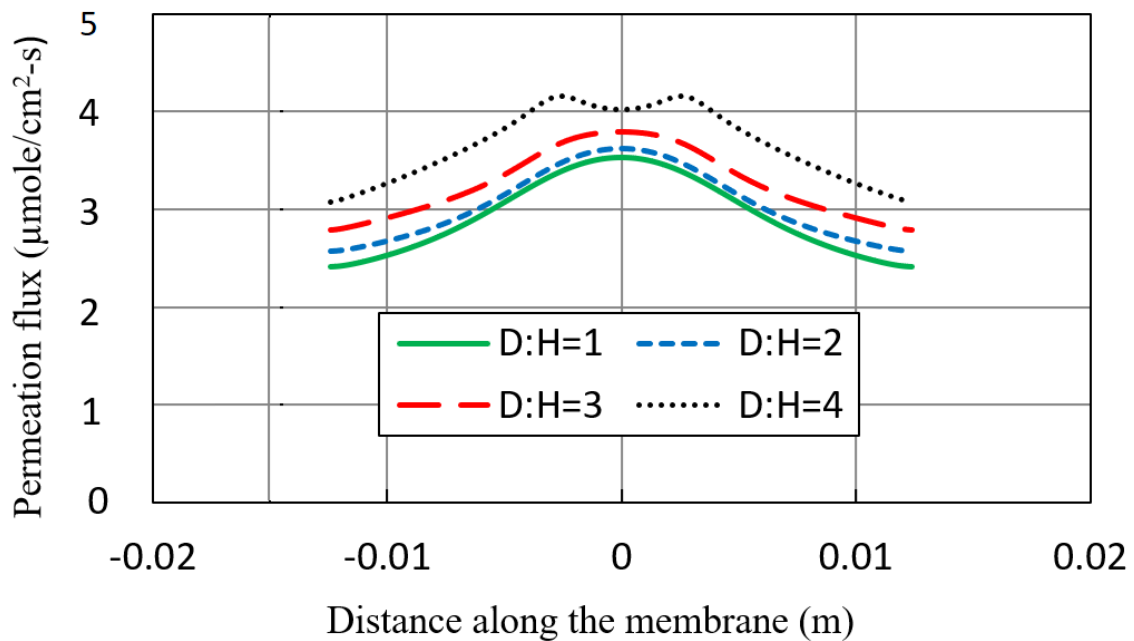


Figure 3. 8 Permeation flux variations along the membrane length for different H in sweep side

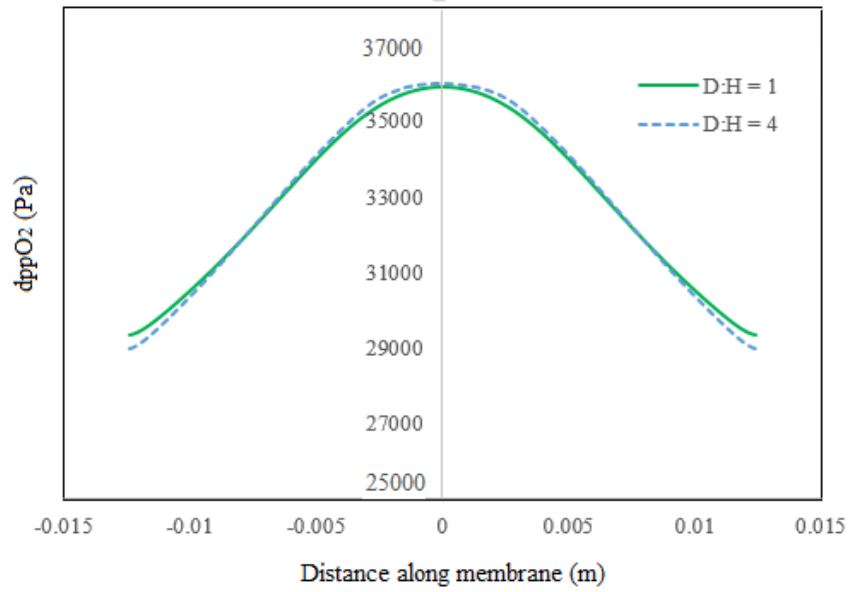


Figure 3. 9 Variation of differential partial pressure of oxygen along the membrane

Similar variation was observed for $D:H = 2$ and 3 . In the case of $D:H = 4:1$ where the membrane distance from the wall (H) is a quarter of inlet size (D), the axial variation of permeation flux shows a local crest corresponding to the site of direct impingement located between two equidistant peaks. As earlier stated, direct impingement occurs at the center of the membrane where high permeation flux is observed due to high $dppO_2$. The equidistant peaks occur at membrane surfaces (sweep zone) adjacent to point (corner) of sudden contraction. The sharp decrease in flow area brings about sudden accelerated sweep gas flow which increases oxygen pick-up as shown in Figure 3. 10-b. Hence, oxygen mole fraction is least at these sites on the membrane surface as shown in Figure 3. 10-a, which translates to smaller partial pressure of oxygen. This increases the $dppO_2$ and as such enhances oxygen permeation. It can also be clearly observed from Figure 3. 8 that the oxygen permeation flux is enhanced by decreasing H i.e. increasing aspect ratio, $D:H$ from 1 to 4. This can be attributed to the reduced partial pressure of oxygen caused by enhanced oxygen pick-up due to area contraction-induced-accelerated sweep gas. The influence of oxygen pick-up is more pronounced as the aspect ratio becomes larger.

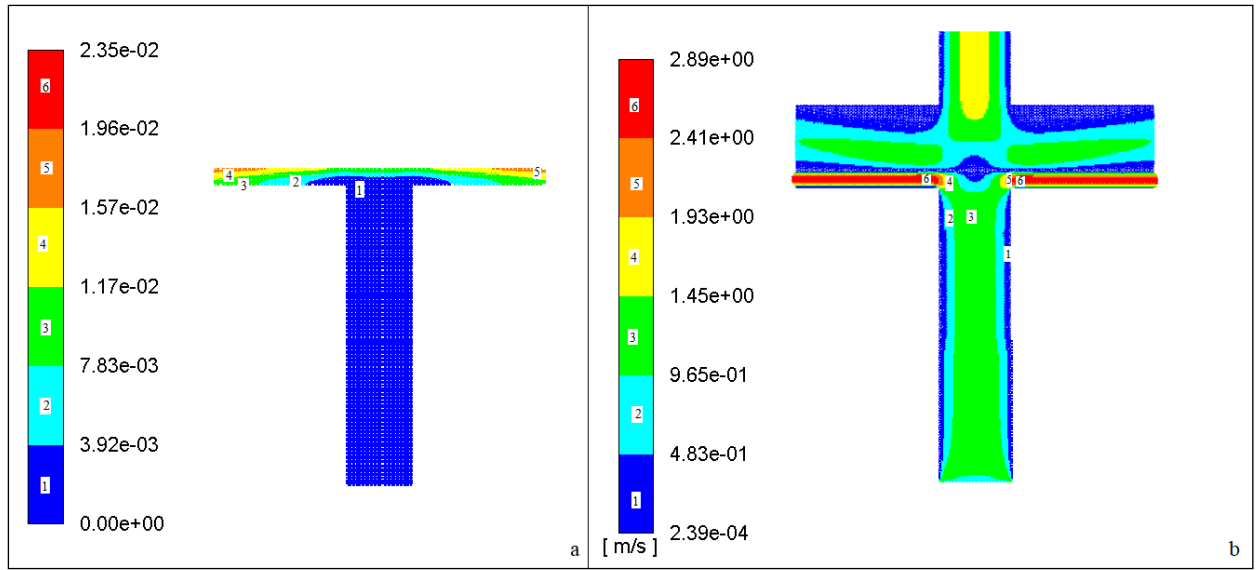


Figure 3. 10 Contour plot of a) mole fraction of oxygen, b) velocity magnitude of gases, in case of D:H=4:1

Figure 3. 11 depicts the effects of decreasing aspect ratio on oxygen permeation flux. In these cases, the feed side dimensions are kept constant; the distance between the nozzle and the membrane (H) in the sweep side is kept constant while the nozzle (slot) width (D) in the sweep side is reduced to decrease the D:H aspect ratio. It can be seen that as D decreases, the permeation rate increases, especially around the impingement point. This observation may be due to the increase in the velocity of the sweeping gas due to the reduction in D (flow inlet area) which aids oxygen permeation rate. The axial distribution of oxygen permeation flux is symmetric about the center of the membrane and the peak permeation flux is observed at this point for aspect ratios 1:1 to 1:4. The permeation flux peak increases from around 3.5 to 5 $\mu\text{mole}/\text{cm}^2\text{-s}$ for cases D:H = 1:1 to 1:4, respectively. At the flow outlet, the permeation flux remains constant for all cases except for D: H = 1:4, which has a lower value.

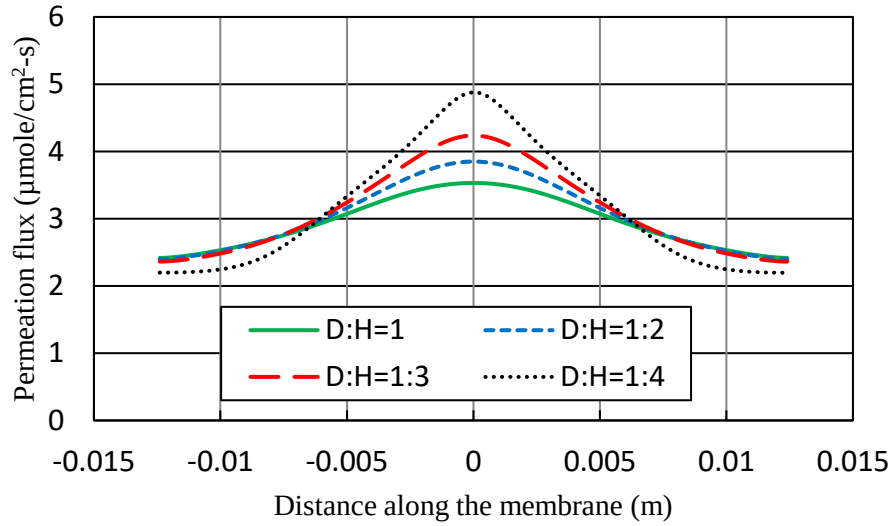


Figure 3. 11 Permeation flux change along the membrane length for different D in sweep side

A comparison of the highest and lowest aspect ratios with the base case $D: H = 1:1$ is shown in Figure 3. 12. It can be observed that the lowest aspect ratio ($D: H = 1:4$) gives higher permeation at the point of impingement but lower permeation downstream of the impingement point. Whereas the highest aspect ratio ($D: H = 4:1$) produces higher permeation flux over the membrane surface except at the impingement point. These observations can be attributed to the rate of oxygen pick-up due to accelerated sweep gas flow induced by flow area contraction at both flow inlet and outlet channels. So, we can deduce that decreasing D leads to enhanced permeation at the impingement point while decreasing H gives increased permeation flux downstream of the impingement point.

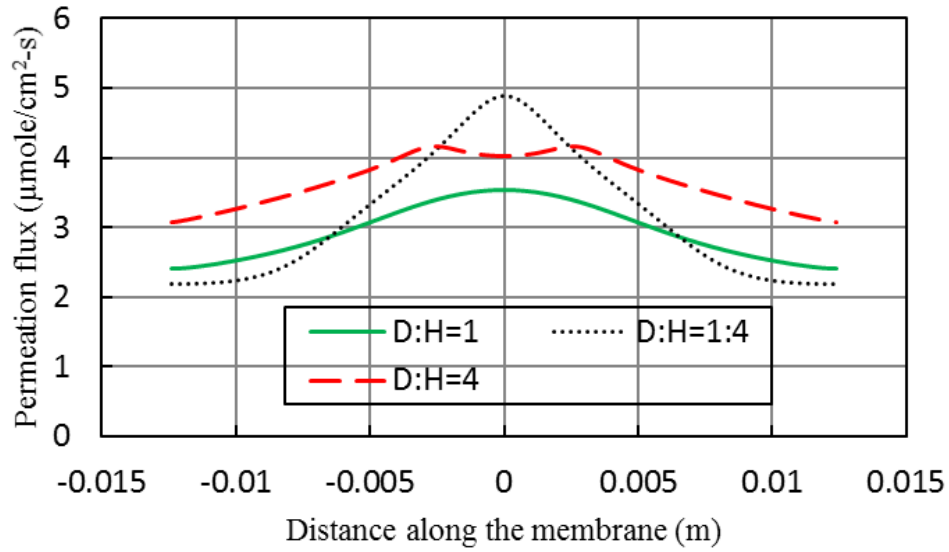


Figure 3. 12 Summary of permeation flux with different aspect ratios along the membrane length

The average permeation flux over the membrane area as a function of the aspect ratio, whether by decreasing H (D: H) or decreasing D (H: D) is represented in Figure 3. 13. It can be seen that as D:H (decreasing H) and H:D increases(decreasing D), the average permeation flux increases and it is approximately equal for aspect ratios up to 2 while the average permeation flux differs and the increment rate is more prominent for D:H >2 than for H:D >2 i.e. decreasing D has lesser effect on permeation flux than H for aspect ratios greater than 2. The Figure indicates that the permeation flux increases from around 2.95, 3.04, 3.27, 3.66 $\mu\text{mole}/\text{cm}^2\text{-s}$ with increasing D:H from 1 to 4. It can be deduced that the closer the sweep gas impingement nozzle is placed to the membrane; the more oxygen gas permeation is achieved.

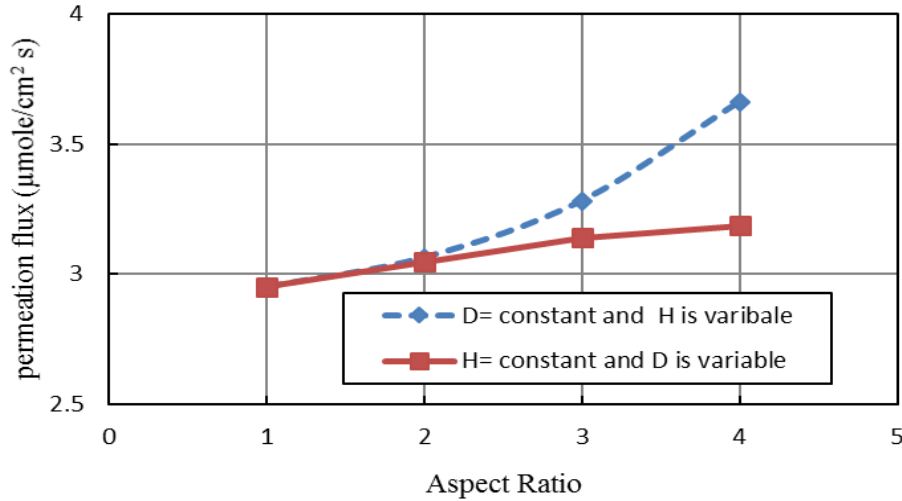


Figure 3. 13 Summary of permeation fluxes with different aspect ratios

3.2.3 Effect of Impingement Angle

The impingement angle is controlled by varying the tilt angle of the sweep gas nozzle as shown in Figure 3. 3-c. Effects of impingement angle on axial variation of oxygen permeation flux is shown in Figure 3. 14. Impingement angles of 30° , 45° , 60° , and 90° are studied in a single pin configuration with aspect ratio of $D:H = 4:1$. This aspect ratio was chosen since it produced the highest permeation flux. The profile of axial permeation flux for 90° impingement angle is slightly different from the others especially around the membrane center. The 30° impingement angle has the maximum peak permeation flux, which is located slightly away from the membrane center, on the part of the membrane the sweep gas nozzle is tilted towards. This peak can be attributed to the large change in the flow direction (obtuse 150°) which engenders high impingement that causes low ppO_2 at the point of impact. Low ppO_2 results into high dppO_2 across the membrane which increases oxygen permeation. The other half of the membrane produces smaller permeation because the tilt angle is acute with the direction of flow. Hence, a smaller change in flow direction is causing low rate of impingement. Similar profiles were observed for impingement angles 45° and 60° .

As the impingement angle increases, the peak value of permeation flux decreases, and the peak location becomes farther from the membrane center on the tilt side and there is a higher tendency of second peak occurring on the other side. The permeation flux decreases with impingement angle but with negligible effect as reported in Figure 3. 15.

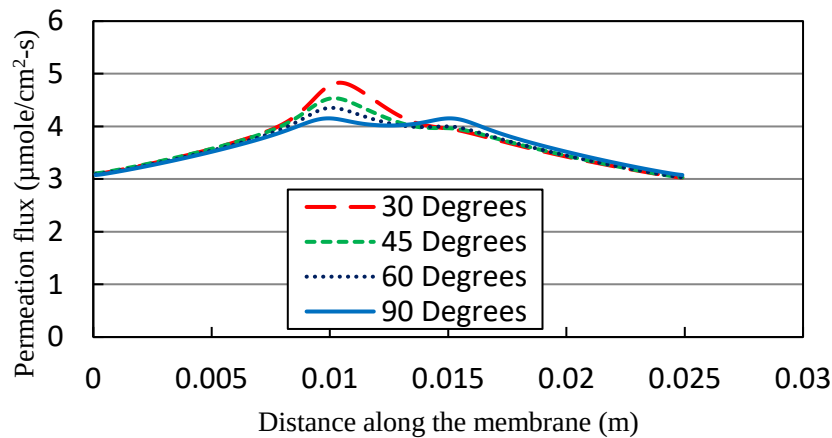


Figure 3. 14 Permeation flux change along the membrane length for different impingement angle

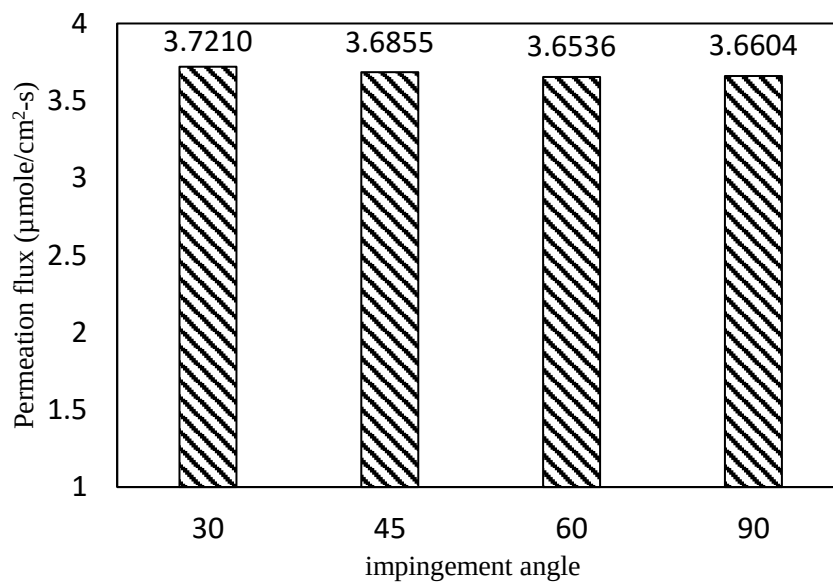


Figure 3. 15 Summary of average permeation fluxes with different impingement angles

3.2.4 Double Impingements Configuration

The effects of increasing the number of impingement points on oxygen permeation flux was studied with the double impingement schematics shown in Figure 3. 3-b and 3. 3-d. The same mass flow rate has been entered to every jet in single and double impingements, with doubling the membrane area in case of double impingements. Two impingement points with varying inter-jet spacing (distance between the two jets) of 1D to 4D was investigated using the D: H = 4 aspect ratio as it produces the highest permeation flux.

Firstly, oxygen permeation flux produced by double impingement 4D inter-jet spacing with open-ended and one closed-end sweep side outlets was studied as shown in Figure 3. 16. Axial variation of permeation flux for double impingement open-ended is symmetric about the membrane center as shown in Figure 3. 16-a. The least flux is observed around the membrane center while two peak fluxes occurred at points equidistant from the center. The least permeation flux may be a result of high ppO_2 at the middle of the membrane due to stagnant flow (low flow) between the slots resulting in low permeation in this stagnant flow area and as result low $dppO_2$ as shown in Figure 3. 16-a. In similitude to the permeation flux observed in single impingement, the twin equidistant peak permeation fluxes are caused by very low ppO_2 at the membrane surface adjacent to the corner wall towards the outlets due to high impingement induced by change in flow direction coupled with high rate oxygen pick up influenced by accelerated flow.

In the case of double impingement one-closed end, variation of permeation flux along the membrane starting from the closed end goes thus least value observed around the closed end, as shown in Figure 3. 16-b, due to high ppO_2 caused by accumulated oxygen, peak value attained around the outer corner of the first jet due to low ppO_2 caused by the coupling of impingement induced by change in flow direction and accelerated flow oxygen pick up as a

result to high $dppO_2$ as shown in Figure 3. 16-b, a local minimum occurring around the second jet opening due to locally high ppO_2 , and as a result low $dppO_2$ caused by sudden expansion which reduces oxygen pick up, followed by a local increase around the outer corner of the second jet towards the outlet due to low ppO_2 caused by a similar coupling effect as earlier explained for the first peak but with a slow continuous oxygen fill up by incoming sweep gas flow.

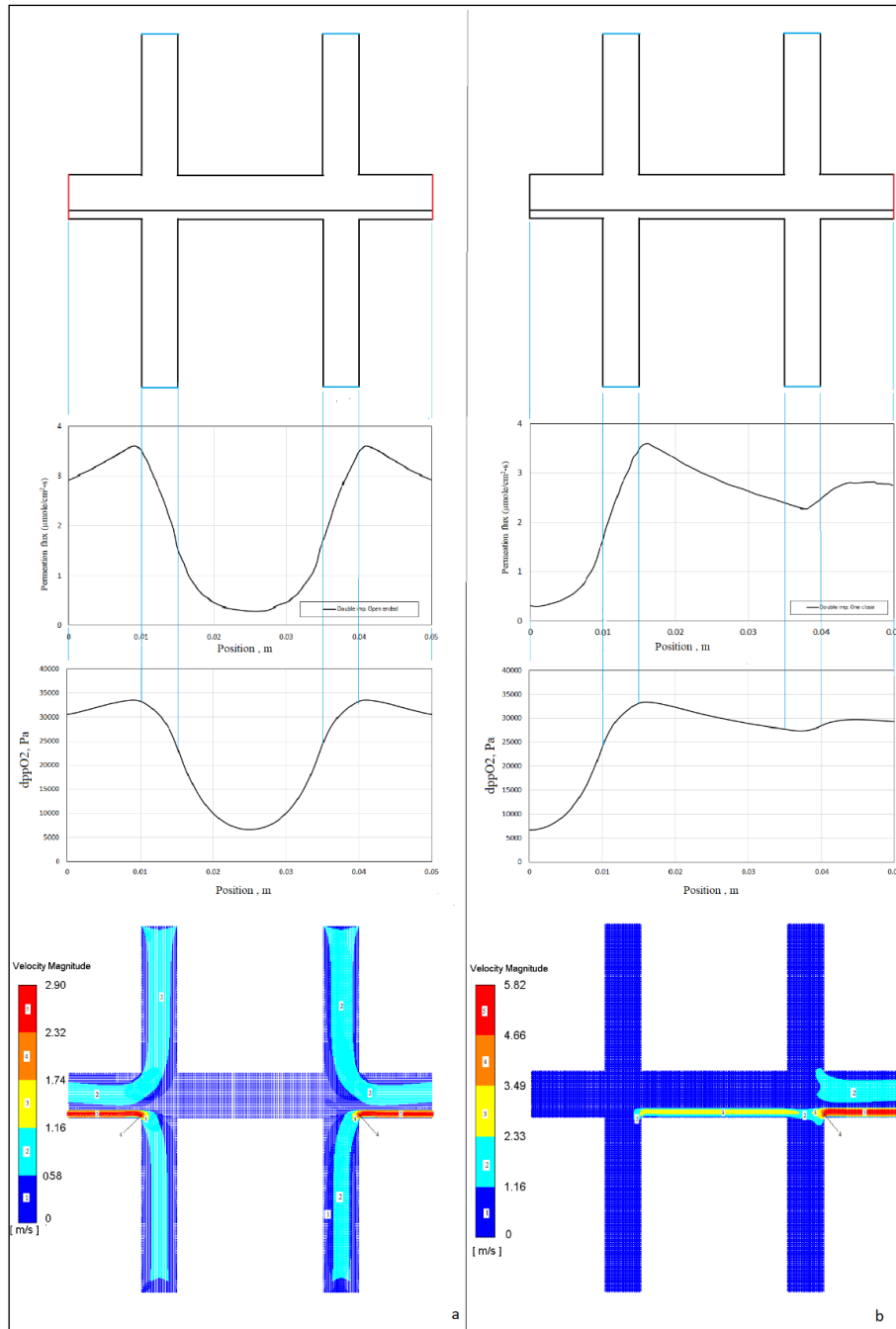


Figure 3. 16 Permeation flux change, Oxygen differential partial pressure(dppO2) distribution and velocity magnitude along the membrane length for different double impingement configuration, a) double impingements open ended. b) double impingements one close

Comparing the total permeation flux in single and double impingement configurations for aspect ratio $D:H=4:1$, one can see that the single jet with 90° impingement angle has the highest value of permeation flux while double impingement open-ended has the least permeation flux

as illustrated in Figure 3. 17. The high permeation can be attributed to the absence of oxygen accumulation region (stagnant flow). Oxygen accumulation region (stagnant flow) is characterized by high ppO_2 which limits oxygen permeation in the double impingement configurations. The double impingement open-ended configuration has the least permeation flux because of the large oxygen accumulated region (flow stagnation) between the two jets. Total permeation is $2.352 \mu\text{mole}/\text{cm}^2\text{-s}$ for double impingement with one close ends, $2.09 \mu\text{mole}/\text{cm}^2\text{-s}$ for double impingement with two open ended and $3.66 \mu\text{mole}/\text{cm}^2\text{-s}$ for single impingement. The single impingement has higher permeation flux due to the increase in the effective membrane area.

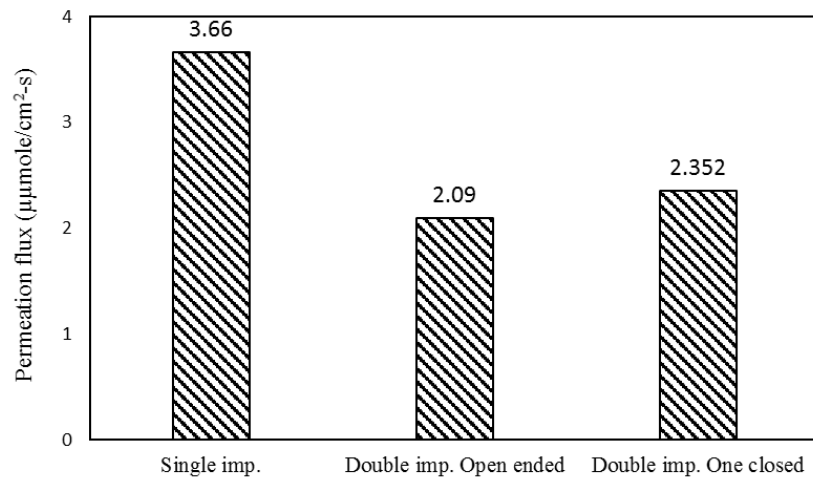


Figure 3. 17 Comparison between average flow for single and double flow impingements with constant flow rate of feed and sweep gases

3.2.5 Double Impingement Points - Effect of Inter Jet Spacing

The effect of inter jet spacing on permeation flux was investigated using double impingement one closed-end configurations since it has higher permeation flux. The inter-jet spacing considered are 1D, 2D, 3D and 4D, where spacing is made with respect to the fixed leftmost jet. The profiles of permeation flux for the different inter spacing have similar features as explained earlier. The location of the local minimum and second peak from the first peak

increases with increasing inter jet spacing. It can be deduced from Figure 3. 18 that the permeation flux increases as the inter jet spacing decreases and that inter jet spacing does not have significant effect on permeation flux. The permeation flux-inter jet spacing relationship can be explained as thus; the membrane part occupying the inter slot spacing constitutes an ineffective permeation area with high ppO_2 due to stagnant flow area. So, an increase in inter jet spacing increases the stagnant flow area, which makes more membrane area ineffective permeation sites, which results in a decrease in the permeation flux.

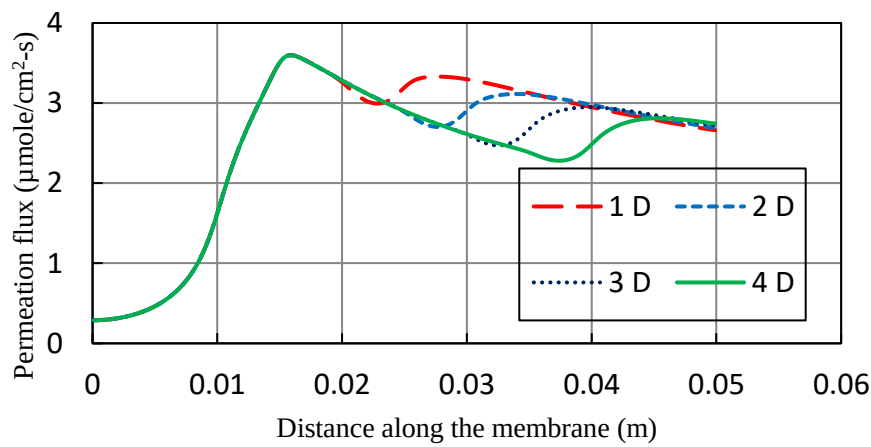


Figure 3. 18 Permeation flux change along the membrane length for different inter jet spacing

As shown in Figure 3. 19, the highest average permeation flux among all the various inter jet spacing is produced by the shortest inter jet spacing of 5 mm with a value of $2.559 \mu\text{mole}/\text{cm}^2\text{-s}$. This permeation value is still lower than that of the single impingement which is $3.66 \mu\text{mole}/\text{cm}^2\text{-s}$ and this made the latter geometry as the best for permeation.

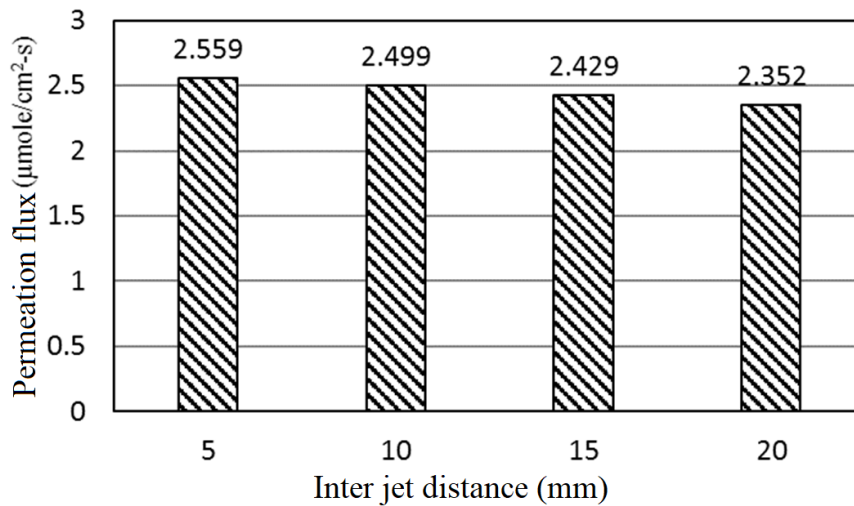


Figure 3. 19 Average permeation flux for different inter jet spacing

3.2.6 Different Configurations for Single Impingement Case

As observed from previous results, single impingement gives better permeation flux than double impingements. Therefore, the single impingement geometry was adopted for studying the effect of flow configurations on oxygen permeation flux. As shown in Figure 3. 20, impingement on the sweep side of the membrane reduces permeation flux as depicted by the first and third bars of Figure 3. 20, when compared with parallel flow permeation flux represented by the fourth bar. This is because the flow splits into two streams after impingement, which results in reduced sweep velocity, causing reduced oxygen to pick up and thereby increases the partial pressure of oxygen on the sweep side. As a result, $dppO_2$ across the membrane decreases and the permeation flux decreases. It can also be observed that more permeation flux can be achieved by feed side impingement as depicted by the second bar. This can be attributed to higher $dppO_2$ created by high feed side ppO_2 caused by slow post impingement feed flow velocity. By increasing the $dppO_2$, the oxygen permeation flux increases.

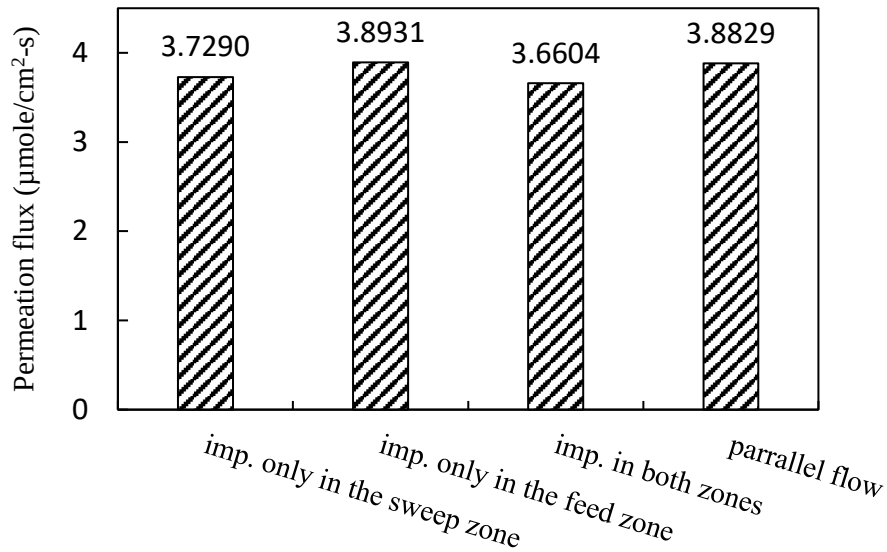


Figure 3. 20 Average permeation fluxes for different geometry configurations for single impingement point.

3.2.7 Effects of Type of Sweep Gas and Sweep Gas Flow Rate

The effects of the type of the sweep gas on the permeation flux were investigated by substituting CO_2 with helium gas in the sweep zone of the computational domain. Single pin with $D:H = 4:1$ was adopted and it was discovered that the permeation flux obtained with CO_2 as sweep gas is higher than that obtained with helium at equal flow rates as shown in Figure 3. 21. This is due to the higher density of the CO_2 which translates to high momentum drive that sweeps more oxygen thereby creating high differential partial pressure of oxygen across the membrane and forcing more oxygen to be permeated. The same argument can be made for the observed increase in permeation flux as the sweep gas flow rate increases irrespective of the type of sweep gas.

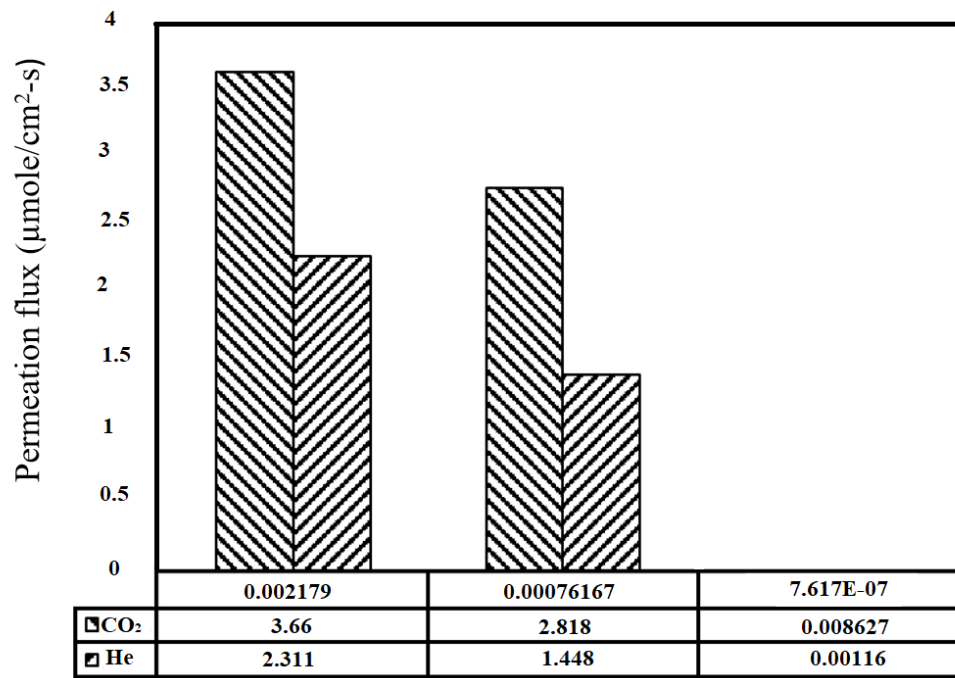


Figure 3. 21 Effects of type of sweeping gas and sweeping gas flow rate on oxygen permeation flux

3.2.8 Parallel Flow: Pressure Effect

Figure 3. 22 shows the effect of creating a vacuum in the sweep side (Figure 3-f) for parallel flow configuration without any sweeping gas. Increasing the vacuum in the sweeping side, directly, increases the permeation flux up to 5.503 $\mu\text{mole}/\text{cm}^2\text{-s}$ for 0.99 bar vacuum. In comparison with the parallel configuration with sweeping gas ($P_s=P_f= 1\text{bar}$) 3.8829 $\mu\text{mole}/\text{cm}^2\text{-s}$, higher permeation flux is produced from the vacuum case with an increase of more than 41%. This means that the high vacuum has a great effect on the oxygen permeation flux than sweeping gas.

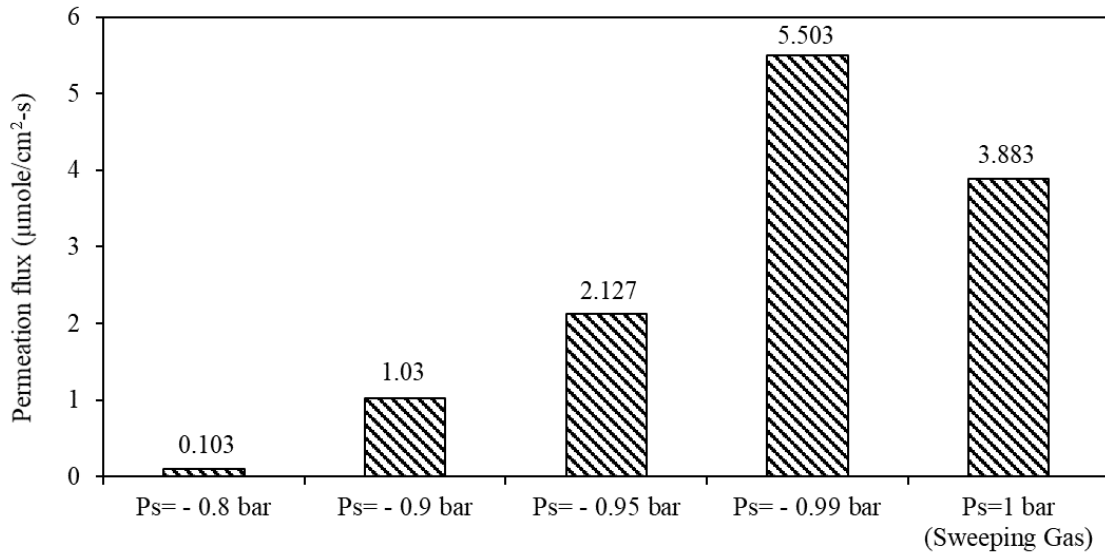


Figure 3. 22 Average permeation fluxes for different sweep partial pressure configuration.

3.3 Summary of chapter 3

In this chapter, oxygen permeation flux through membrane impingement has been studied. In this regard, the effects of parameters such as geometry aspect ratio, number of impingements, angle of impingement and configurations and applying vacuum at the sweep side have been investigated. The permeation flux increased with decreasing impingement angle, the impingement angle does not have significant effect on the permeation, as the difference in the permeation flux between the lowest and highest angles is around $0.06 \mu\text{mole}/\text{cm}^2\text{-s}$. The number of impingement points was increased to two and the effects of number of sweep gas outlet and inter-pin spacing on permeation flux were investigated. Compared with single impingement, permeation flux achieved by double impingement is lower. Double impingement with one closed end showed a higher permeation flux than that with the open-ended and the permeation flux increases with decreasing inter-pin spacing. The effect of sweep gas type (density) on permeation flux showed that less dense sweep gases decreases the permeation flux. Lastly, the effect of pressure on permeation flux showed that vacuum flow in the sweeping side

gives the highest permeation flux with a value $5.503 \mu\text{mole}/\text{cm}^2\text{-s}$ higher than the parallel configuration with sweeping gas with 41%.

To calculate the area required of the ITM that is used to separate the required amount of oxygen for use in the ISC, In the next chapter, ISC numerical model is introduced with the governing equations, components properties and comprehensive chemical reaction scheme for Athabasca bitumen. The numerical model is used for lab and field scale with different dimensions and different numerical mesh. It is used also to compare using O_2/CO_2 and O_2/N_2 as oxidizers in terms of cumulative oil and output gases. In the next chapter (chapter 4), ISC is introduced for lab scale only, then in chapter 5, it is introduced at field scale. At the end of field scale study (chapter 5), the required area of ITM is calculated.

CHAPTER 4

IN SITU COMBUSTION MODELING

The in-situ combustion (ISC) process offers multiple advantages in heavy oil production compared to other thermal enhanced oil recovery technologies. In such a system, the combustion process that occurs in the reservoir generates heat, which subsequently reduces the viscosity of oil.

In this chapter, numerical model for ISC process is prepared. The conservation equations for mass, energy and Darcy law are presented. The ISC chemical reactions for Athabasca bitumen, are presented. The components and properties used in the simulation are tabulated.

The ultimate focus is to develop a more environmentally friendly technology to improve the performance of the traditional ISC method. The study was performed using numerical modelling and simulation tools. The code used in this study is CMG Stars; a commercial code based on the finite difference scheme.

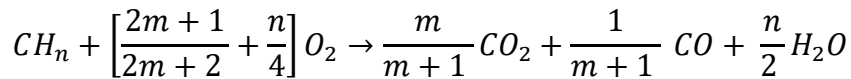
4.1 Chemical Reactions

One of the objectives of the present work is to develop and use a comprehensive model to simulate the ISC process for Athabasca bitumen in lab and field scales. The ISC chemical reactions for Athabasca bitumen, which have been collected from the literature [163, 164, 216-221] , have been applied in the present study. For simulating the ISC for Athabasca bitumen, Yang and Gate [163] used only 8 chemical reactions model which are 3 for thermal cracking and 2 for low temperature oxidation and 3 for high temperature oxidation. But in the present model, more chemical reactions have been added from the literature, that is to be more precise

in simulating the ISC process. The present model is consisting of pyrolysis, LTO, HTO, Hydrogen generation and Hydrogen consumption reactions. The chemical reactions model and kinetics for the selected heavy oil are listed in Table 4.1. The presented model is a modified version of the model used by Kapadia et al.[219]. For tuning the model with enriched air published experimental data, the reaction kinetics for low temperature oxidations have been taken from Yang and Gate [163]. The hydrogen generation reverse reaction (No. 17) has been added from [217, 218], and hydrogen consumption reaction kinetics (No. 21, 22) from [218, 219].

Many models have been created to simulate ISC process for air and enriched air. For the current work, the presently developed model has been used for O₂/CO₂ ISC process. That is to investigate the effect of CO₂ on the combustion process and oil production rate. The components and properties used in the simulation have been provided using CMG (computer modelling group ltda.) [43] software. The components and properties used in the simulation are tabulated in Tables 4.2 to 4.5.

From the literature [222] the general form of the coke combustion reaction is:



Where m is the molar ratio of carbon dioxide to carbon monoxide produced, and n is the hydrogen/carbon of the coke burned.

As in [153, 158], the simplified model which is based on the Arrhenius reaction expressions with the temperature dependence of the rate constants is:

$$R_c = \frac{dC_f}{dt} = K p_{O_2}^a C_f^b$$

Where;

R_c : the reaction rate

C_f : fuel concentration

P_{O_2} : oxygen partial pressure

K : reaction rate constant

a, b: reactions order with respect to oxygen partial pressure and fuel concentration respectively.

$$K = A \exp (-E / RT)$$

Where;

A: the Arrhenius constant

E: the activation energy

T: the absolute temperature

R: the universal gas constant.

Table 4. 1 Chemical Reactions and Kinetics Parameter used Simulation

Reaction	Heat of reaction (J/mol)	Frequency factor A (day ⁻¹)	Activation energy E (J/mol)	References
Pyrolysis reactions				
1) 2.687MALTENE → ASPHALTENE	0	1.174×10^{18}	2.358×10^5	[220, 223]
2) ASPHALTENE→ 11.89 Coke	0	3.11×10^{15}	1.897×10^5	[220, 223]
3) ASPHALTENE → 77.4415H ₂	0	2.227×10^5	9.963×10^4	[220, 223]
4) ASPHALTENE → 9.7312 CH ₄	0	2.565×10^8	1.122×10^5	[220, 223]
5) ASPHALTENE→ 5.5735 CO	0	6.36×10^1	4.892×10^4	[220, 223]
6) ASPHALTENE → 3.5473 CO ₂	0	1.87	2.313×10^4	[220, 223]
7) ASPHALTENE → H ₂ S	0	3.358×10^6	9.721×10^4	[220, 223]
8) ASPHALTENE → HMWG	0	6.172×10^{15}	2.013×10^5	[220, 223]
Low temperature oxidation				
9) MALTENE + 3.431 O ₂ → 0.4726 ASPHALTENE	1.295×10^6	2.116×10^5	4.611×10^4	[163]
10) ASPHALTENE + 7.513 O ₂ → 101.539 COKE	2.857×10^6	1.085×10^5	3.312×10^4	[163]
High temperature oxidation				
11) COKE + 1.232 O ₂ → 0.8996 CO ₂ + 0.1 CO + 0.565 H ₂ O	4.95×10^5	3.881	8.205×10^2	[163]
12) CH ₄ + 2 O ₂ → 1 CO ₂ + 2 H ₂ O	8.91×10^5	3.020×10^{10}	5.945×10^4	[163]
13) GAS + 2 O ₂ → 0.9695 CO + 1 CO ₂ + 2 H ₂ O	4.436×10^5	1.311×10^8	2.662×10^5	[163]
14) H ₂ + 0.5 O ₂ → 2 H ₂ O	2.86×10^5	8.986×10^{13}	1.255×10^5	[163]
15) CO+0.5O ₂ →CO ₂	2.83×10^5	1.123×10^{13}	1.255×10^5	[163]
Hydrogen generation reactions				
16) COKE+H ₂ O→CO+H ₂ (forward)	-1.314×10^5	2.117×10^7	9.20×10^4	[217, 218]
17) COKE+H ₂ O→CO+H ₂ (Reverse)	1.314×10^5	5.291×10^2	3.46×10^4	[217, 218]
18) CO+H ₂ O→CO ₂ +H ₂ (forward)	4.1×10^4	5.573×10^7	1.4×10^5	[217, 218]
19) CO+H ₂ O→CO ₂ +H ₂ (reverse)	-4.1×10^4	4.214×10^9	1.9×10^5	[217, 218]
Hydrogen consumption reactions				
20) COKE+2 H ₂ → CH ₄ (forward)	7.489×10^4	3.162×10^4	4.14×10^4	[218, 219]
21) COKE+2 H ₂ → CH ₄ (reverse)	-7.489×10^4	7.113×10^9	1.163×10^5	[218, 219]

Table 4. 2 Data for Model Components by Belgrave et al. [164]

Component	Molecular Weight (g/mol)	Tc (C)	Pc (kPa)
Maltenes	407	619	1480
Asphaltenes	1090	904	792
Coke	13.1	—	—
Water	18.0	374	22,100
O ₂	32.0	-119	5050
Gas	43.2	21.9	7180
CH ₄	16.0	-82.6	4600
CO ₂	44.0	31.1	7380
CO	28.0	-140	3490
N ₂	28.0	-147	3390

Table 4. 3 Gas–Liquid K-Value Correlations: K-Value = (k_{v1}/P) e(k_{v4}/T-k_{v5}) [43]

Component	k _{v1}	k _{v4}	k _{v5}
Maltenes	1.89 × 10 ⁷	- 6560	-80.1
Asphaltenes	0	0	0
Water	1.18 9 10 ⁷	-3820	-227
Gas	8.62 9 10 ⁸	-3100	-273
CH ₄	5.45 9 10 ⁵	-879	-266
CO ₂	8.62 9 10 ⁸	-3100	-273
CO	2.32 9 10 ⁵	-530	-260

Table 4. 4 Gas Heat Capacity Correlations: C_{pg} (J/gmol C) = C_{pg1} + C_{pg2} T + C_{pg3} T² + C_{pg4} T³ [43]

Component	C _{pg1}	C _{pg2}	C _{pg3}	C _{pg4}
Maltenes	0	0	0	0
Asphaltenes	0	0	0	0
O ₂	28.1	-3.68 x 10 ⁻⁶	1.75 x 10 ⁵	-1.06 x 10 ⁻⁸
Gas	19.8	7.34 x 10 ⁻²	-5.60 x 10 ⁵	1.71 x 10 ⁻⁸
CH ₄	19.3	5.21 x 10 ⁻²	1.20 x 10 ⁵	-1.13 x 10 ⁻⁸
CO ₂	19.8	7.34 x 10 ⁻²	5.60 x 10 ⁵	1.71 x 10 ⁻⁸
CO	30.9	-1.29 x 10 ⁻²	2.79 x 10 ⁵	-1.27 x 10 ⁻⁸
N ₂	31.2	-1.36 x 10 ⁻²	2.68 x 10 ⁵	-1.17 x 10 ⁻⁸

Table 4. 5 Liquid Heat Capacity Correlations: C_{pl} (J/gmol C) = $C_{pl1} + C_{pl2} T + C_{pl3} T^2 + C_{pl4} T^3$ [43]

Component	C_{pl1}	C_{pl2}	C_{pl3}	C_{pl4}
Maltenes	994	0	0	0
Asphaltenes	2510	0	0	0
O ₂	46.4	3.95×10^{-1}	-7.05×10^{-3}	3.99×10^{-5}
Gas	-3980	5.25×10^1	-2.27×10^{-1}	3.29×10^{-4}
CH ₄	-0.02	1.20	-9.87×10^{-3}	3.17×10^{-5}
CO ₂	-3980	5.25×10^1	-2.27×10^{-1}	3.29×10^{-4}
CO	126	-1.70	1.07×10^{-2}	4.19×10^{-6}
N ₂	76.5	-3.52×10^{-1}	-2.67×10^{-3}	5.01×10^{-5}

4.2 Governing Equations

In the reservoir, either water or gaseous hydrocarbon or both may exist beside liquid petroleum. Such a scenario may lead to phase change and heat addition. Therefore, ISC is considered a multiphase reactive transport system [43, 224, 225]. The mathematical model adopted for the present study is outlined hereunder.

1- Mass balance

Mass flow in – Mass flow out = Accumulated mass + Mass sources

Generally, the mass for component i is the summation over number of phases π and number of reactions n_r as shown [225]:

$$-\nabla \cdot \sum_{j=1}^{\pi} \rho_j u_j x_{ij} = \frac{\partial}{\partial t} \sum_{j=1}^{\pi} \rho_j \phi_j S_j x_{ij} - \sum_{j=1}^{\pi} q_{ij} + \sum_{k=1}^{n_r} r_{ik} \quad (4.1)$$

Where, S_j is the saturation of phase j and x_{ij} is mole fraction of component i in phase j .

2- Energy Balance

The energy balance is given by [225]:

$$\begin{aligned} \frac{\partial}{\partial t} [\sum_{j=1}^{\pi} \phi_f \rho_j S_j U_j + (1 - \phi_v) U_r + \phi_v C_s U_s] = \nabla \cdot (\lambda \nabla T) - \nabla \cdot \sum_{j=1}^{\pi} \rho_j h_j u_j \\ + \sum_{j=1}^{\pi} \rho_j h_j u_j + \sum_{j=1}^{\pi} q_j h^*_{*j} + \sum_{k=1}^n H_{rk} r_{ik} + q_{hc} \end{aligned} \quad (4.2)$$

Where:

$\nabla \cdot \sum_{j=1}^{\pi} \rho_j h_j u_j$ is the advection or convection term and h_j is the enthalpy of phase j .

$\nabla \cdot (\lambda \nabla T)$ is the conduction term and λ is the thermal conductivity of the formation.

$\sum_{j=1}^{\pi} q_j h^*_{*j}$ is the heat source/sink, and h^*_{*j} is the enthalpy of phase j at injection or production.

$\sum_{k=1}^n H_{rk} r_{ik}$ is the heat source or sink due to reaction, and H_{rk} is the enthalpy of reaction k and r_{ik} is the rate of k^{th} reaction.

q_{hc} is the heat loss source/sink term.

3- Darcy's Law and Injection/Production Equation

For multiphase flow the relationship between the flow rates and pressure gradient can be got using Darcy's law [224].

$$v_j = \frac{-k k_{rj}}{\mu_j} \nabla (\phi_j) \quad (4.3)$$

Where, the subscript j , in the above equation, refers to the phase (water, oil or gas), v_j is the velocity vector, K is the absolute permeability, k_r is the relative permeability and μ is the fluid viscosity. The phase potential gradient has the form of $\nabla \phi_j = (p_j - \rho_j g h)$ where p refers to fluid pressure, ρ refers to fluid density, g and h are, respectively, the gravitational acceleration and the block depth measured from a reference datum.

4.3 Lab Scale ISC

A 1-D porous combustion tube simulation is conducted and validated against published experimental data. Lab scale results for the 1D combustion tube are presented. Co-injection of pure oxygen with carbon dioxide (CO₂); and co-injection of oxygen with nitrogen gas were investigated by a numerical model for lab scale. Essentially, numerical modelling of the porous combustion tube experiment has been performed using the CMG Stars (2017.10) software, to simulate the process. The conservation equations for mass, energy and Darcy law are solved.

4.3.1 The Numerical Model for Lab Scale

ISC model using CMG (computer modelling group ltda.) [43] software has been developed for 1D Athabasca bitumen combustion tube experiment which was conducted by the ISC Research Group at the University of Calgary as reported in [163]. Model validation has been done to make sure that the model is working well. After that, the model can be used for studying the ISC process with CO₂ injection. The experimental data which includes temperature profiles, cumulative gas and cumulative oil have been published by Yang and Gates [163] and the validation of the model is based on these data.

4.3.2 Geometry and Numerical Mesh Generation.

As stated earlier, the main objective of the present work is to simulate the in situ combustion in a one-dimensional (1D) Athabasca bitumen combustion tube experiment that was conducted by the ISC Research Group at the University of Calgary as reported in [163]. The ISC experiment, as reported in [163], was conducted in a vertical porous tube of 1.83 m height and 0.1 m diameter. The tube was first saturated with heavy oil then it is positioned vertically with the injection of the oxidizer is at the top face of the tube while the production is at its bottom.

Therefore the present simulation was conducted for a vertical combustion tube of the same dimension as that used ISC combustion tube used by the ISC Research Group at the University of Calgary as reported in [163] and as shown in Figure 4.1. This configuration was used to validate the developed numerical model against the experimental results obtained for the same configuration for ISC under oxygen-enriched air injection with different Oxygen to Nitrogen contents. The tube has been simulated as a vertical 1D model with two hundred 0.00915 m grid blocks as shown in Figure 4.1. The simulation lasted for the same time of the experiment, which is 19.67 hours, as reported in [163]. Having the numerical model well validated against the experimental results, the numerical model has been used to simulate the injecting of O_2/CO_2 for ISC with different O_2/CO_2 ratios.

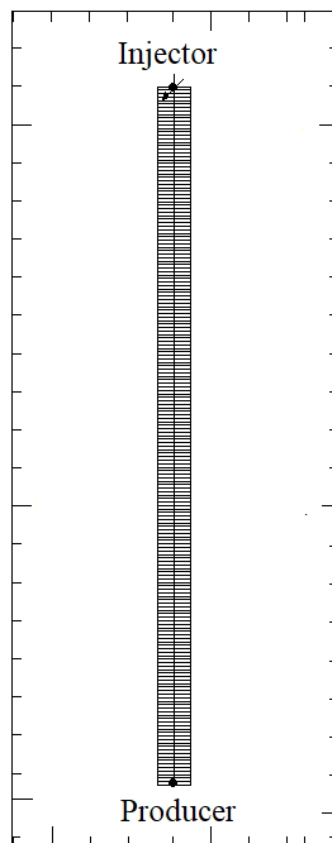


Figure 4. 1 grid blocks for the combustion tube, length of 1.83 m and diameter of 0.1 with 200 of 0.00915 m thick grid blocks

4.3.3 Initial Conditions and Components Properties for the Lab Scale

The properties of the oil components such as molecular weight, critical temperature and critical pressure and other properties such as viscosity correlations, relative permeability data, gas /liquid relative permeability values and vapor heat capacity given in [163] were used as input to CMG (computer modelling group ltda.) software [43]. The initial core temperature is 90 °C, the initial water, gas and oil saturation in the core are 12%, 18% and 70 % of the pore volume of the core, respectively. Maltenes and Asphaltenes represent 91.5 % and 8.5 % of the oil (Bitumen) composition, respectively. The initial conditions are summarized in Table 4.6.

The heat transfer at the outer surfaces of the porous tube is calculated using a semi-analytical model [226]. This model gives solutions quite close to exact answers to many heat transfer problems with a maximum error around 17 % [226]. The only data required to simulate the heat loss in CMG are the volumetric heat capacity and thermal conductivity of the tube, which surrounded the porous tube. In this regard, the volumetric heat capacity and thermal conductivity of the tube are $6.2 \times 10^4 \text{ J/m}^3 \text{ }^\circ\text{C}$ and $6.5 \times 10^5 \text{ J/m day }^\circ\text{C}$, respectively [163]. For the heat transfer model details, see appendix A.

Table 4. 6 Simulation Initial Conditions for core [163]

Initial water saturation	0.12
Initial oil saturation	0.7
Initial gas saturation	0.18
Initial bitumen mole fraction—Maltenes	0.915
Initial bitumen mole fraction—Asphaltenes	0.085

4.3.4 Inlet Conditions

The time variation of the inlet pressure and temperature of the injected oxygen-enriched air are shown in Figure 4.2-a, as adopted from [227]. The volume flow rate used in this

experiment is $1.344 \text{ m}^3/\text{day}$ and it is fixed throughout the experiment for a total time of 19.67 hours. The simulated experiment starts by injection of nitrogen gas for a small period, then the injection of oxygen-enriched air is started with oxygen content of 0 %, which is increased till it reaches 95% in the time interval from 0 to 0.7 hr, with linear increase of oxygen content as shown in Figure 4.2-b.

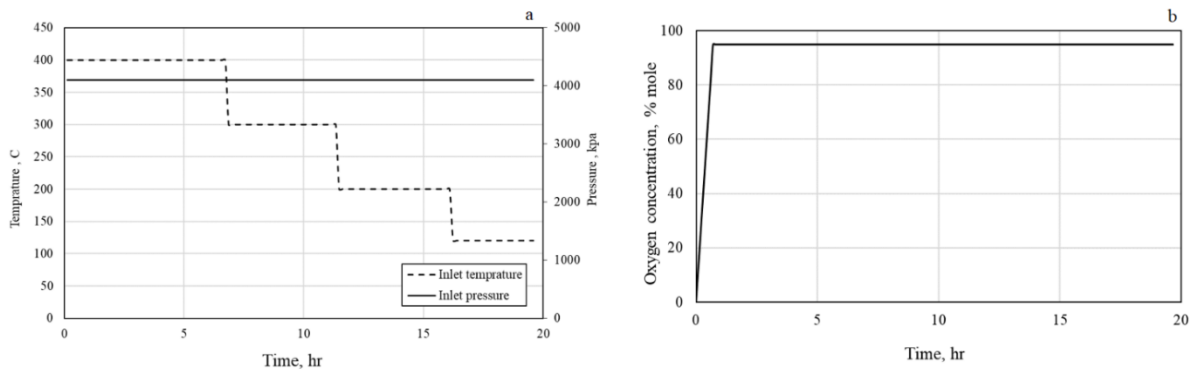


Figure 4. 2 The inlet pressure and temperature for the enriched air, b) oxygen concentration with time.

4.4 Results and Discussions for Lab Simulation Experiment

Numerical studies have been carried out to simulate the ISC process of bitumen considering injection of O_2/N_2 as oxidizer for validating the model and study the effect of different oxygen contents on the oil recovery and the produced gases with enriched air. The injection of O_2/CO_2 as oxidizer with different ratios for studying its effect on the oil recovery is to be studied after the code validation as outlined hereunder.

4.4.1 Model Validation

To validate the ISC model with oxygen-enriched air, temperature profiles and cumulative oil and gas recovery for the porous combustion tube as predicted from the presently

developed model have been compared with the pertinent experimental results as reported by Yang and Gates [163].

In order to ensure reliability of the model, the profiles for two different temperature along the porous combustion tube were validated against the corresponding experimental and numerical temperature profiles reported by Yang and Gates [163] at time = 5.05 and 7.92 hours after the injection starts in Figures 4.3 and 4.4, respectively. These temperature profiles indicate that the maximum temperatures are around 600 °C. The maximum temperature is associated with the location of the high temperature oxidation reactions region, which is also called the leading edge of the front. Therefore, the location of the maximum temperature of the temperature profile indicates the location of the leading edge of the front and its distance from the oxidizer injection and ignition point. The comparison depicted in Figure 6.3 indicates that the deviation between the present calculations and the pertinent experimental results reported by Yang and Gates model [163] is less than the deviation between the numerical results presented by Yang and Gates model [163] and their experimental data. The numerical temperature profile estimated using our presently developed model has maximum deviation of 10.6 % from the pertinent experimentally measured temperature profile compared with a deviation of 13 % deviation between the numerical temperature profile predicted by Yang and Gates model [163] compared with their experimentally measure temperature profile. The presently obtained numerical data of the temperature profile as well as that obtained by Yang and Gates model [163] are in excellent agreement with the experimental measurements of the temperature profile over the distance from the leading edge of the front to the end of the core as reported by Yang and Gates [163]. The same observations are applied to the temperature profile at time = 7.92 hours from the start of the ignition, as shown in Figure 4.4. The maximum deviation of presently predicted numerical temperature profile at time = 7.92 hours from the pertinent

experimentally measure temperature profile is around 14 % while the numerical temperature profile predicted using Yang and Gates model [163] has a maximum deviation from the same pertinent experimentally measure temperature profile of about 16.7%.

The cumulative oil and gas recovery are also compared graphically as presented in Figure 4.5 and Figure 4.6, respectively. The result for the cumulative oil and gas recovery, as shown in Figures 4.5 and 4.6, reveal that the present simulation shows a good agreement with the experimental data. However, at the end of the experiment, the simulated oil production volume is slightly higher than that of the experiment. This is the same as in case of Yang and Gates model [163]. This might be attributed to nonhomogeneous properties of the core, which have been taken as constant throughout the experimental simulation time while it is changing due to the oxidation chemical reactions and the associated temperature variation along the whole core (porous combustion tube).

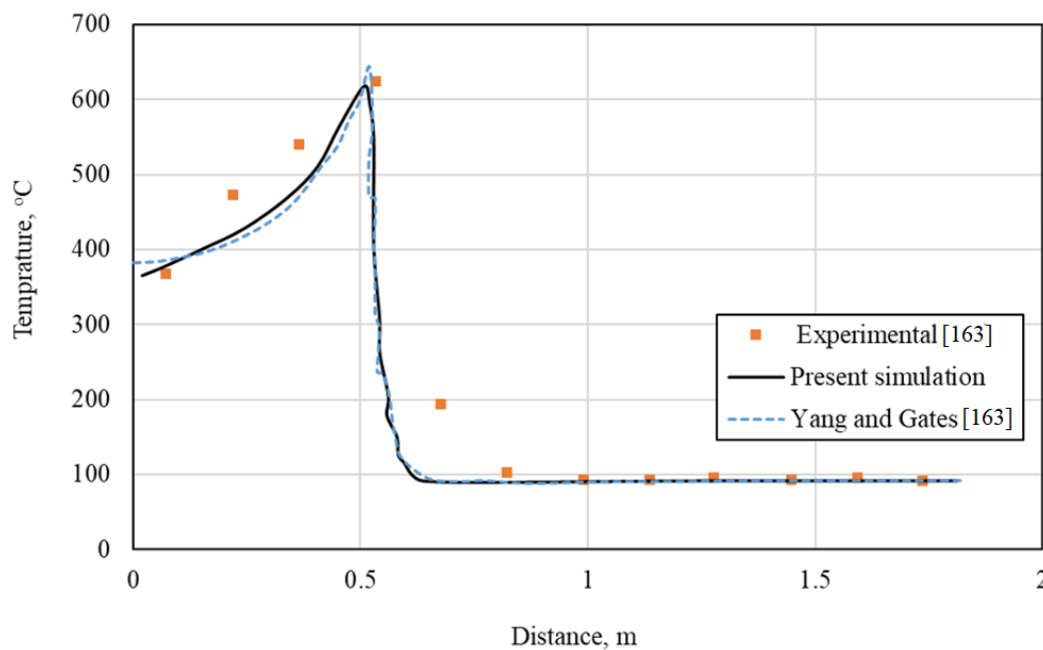


Figure 4. 3 Validation of the present calculations' temperature profile with the experimental and numerical data presented by Yang and Gates [163] at time 5.05 hours

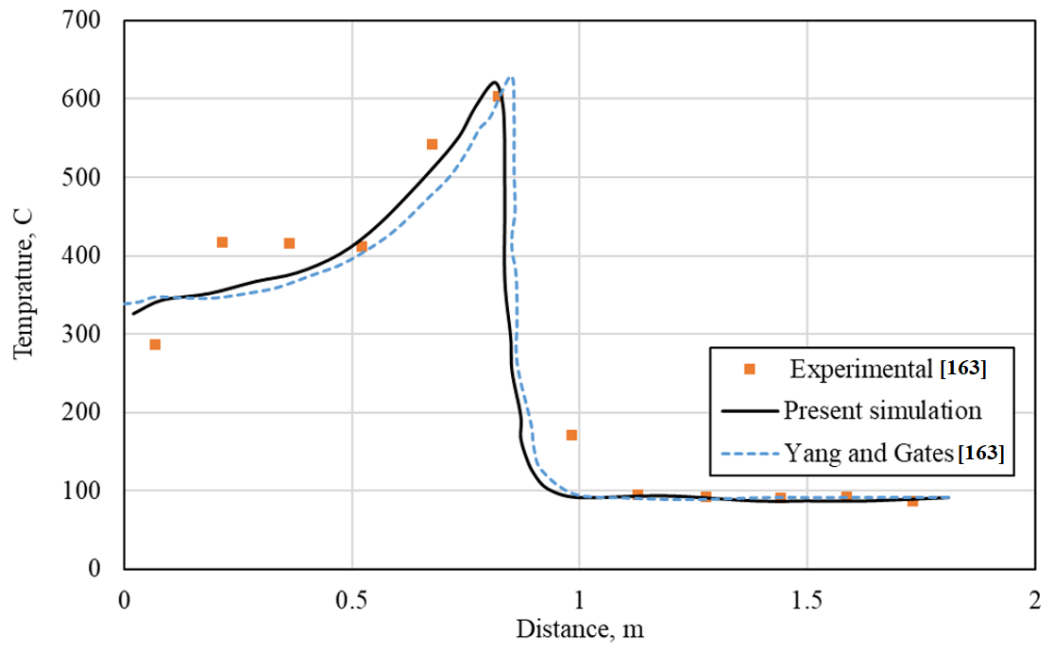


Figure 4. 4 Validation of the present calculations' temperature profile with the experimental and numerical data presented by Yang and Gates [163] at time 7.92 hours

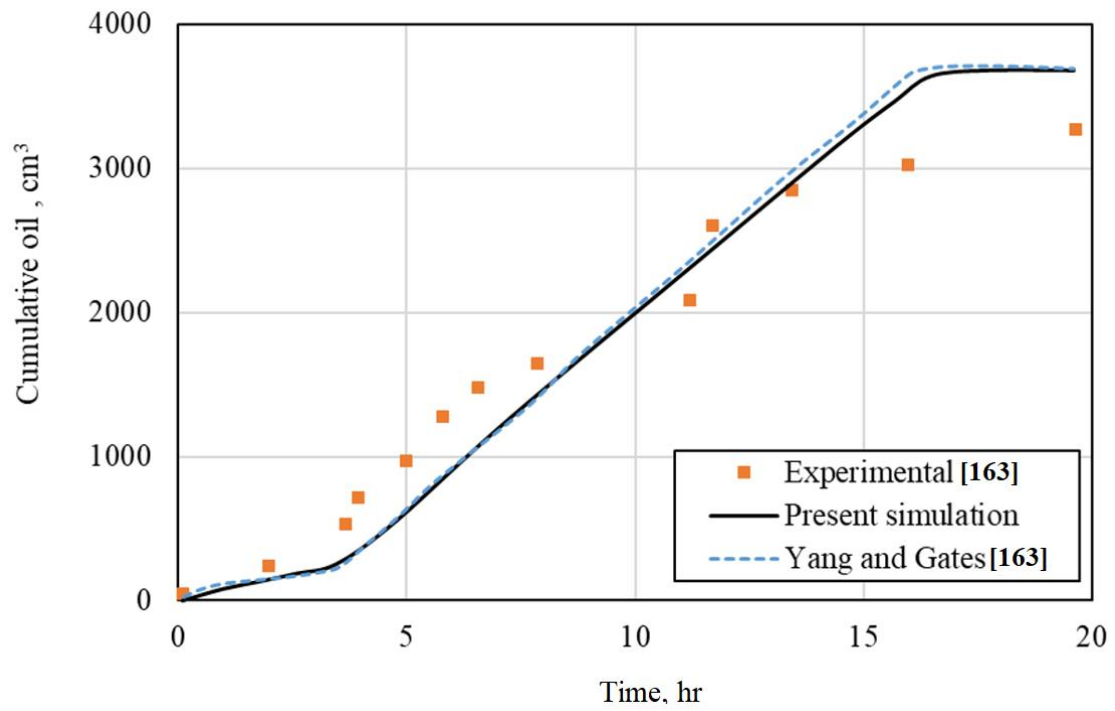


Figure 4. 5 Validation of the present calculations cumulative oil production with the experimental and numerical data presented by Yang and Gates [163]

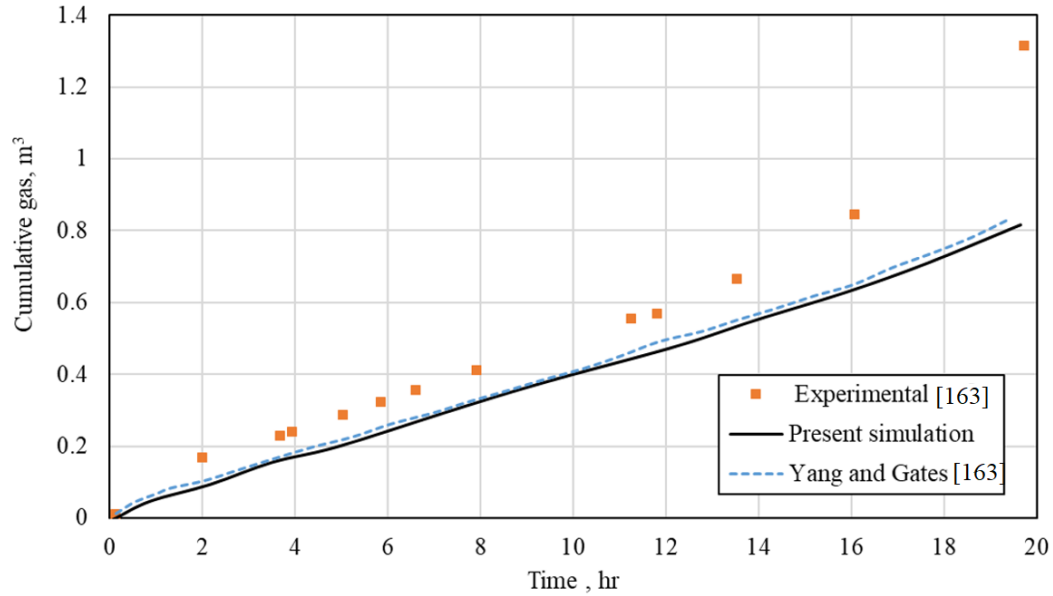


Figure 4. 6 Validation of the present calculations cumulative gas production with the experimental data and numerical data presented by Yang and Gates [163].

4.4.2 Effects of Oxygen Ratio in the Case of Co-Injection of O₂ and N₂

Figure 4.7 illustrates the effect of oxygen ratio in the oxygen-enriched air, on the temperature profile and its highest temperature value and location at the leading edge of the front at same time, after 7.92 hours from the starting. In case of using (95%O₂+5% N₂) as oxidizer, the temperatures at the leading edge of the front is more than 600 °C. This temperature decreased to around 540 °C in case of decreasing oxygen ratio to 50% (50% O₂+50% N₂) and to 430 °C in case of decreasing oxygen ratio to 21% (21% O₂+79% N₂). This result is expected due to the decreasing of oxygen contents, which leads to decreasing of the amount of oil burned and consequently decreasing the temperature resulting in a decrease in the reaction rate and that leads to changing the position of the leading edge of the front as shown in Figure 4.7 and temperature contours in Figure 4.8.

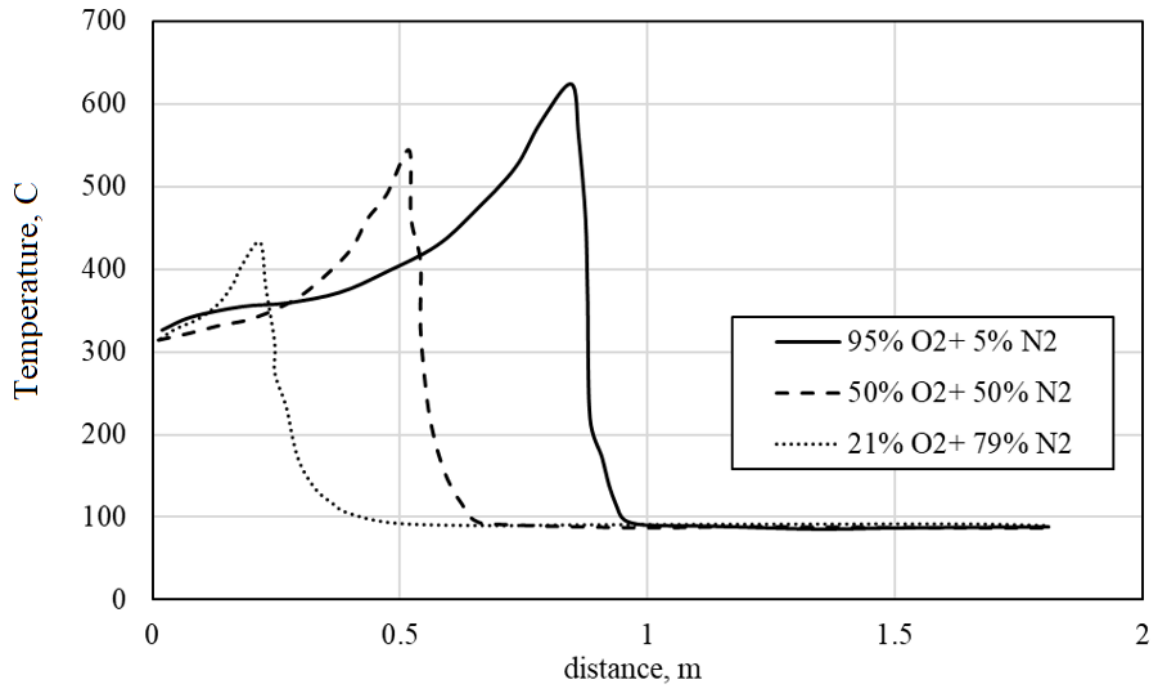


Figure 4. 7 Temperature profile at the same time for different O₂/N₂ ratios

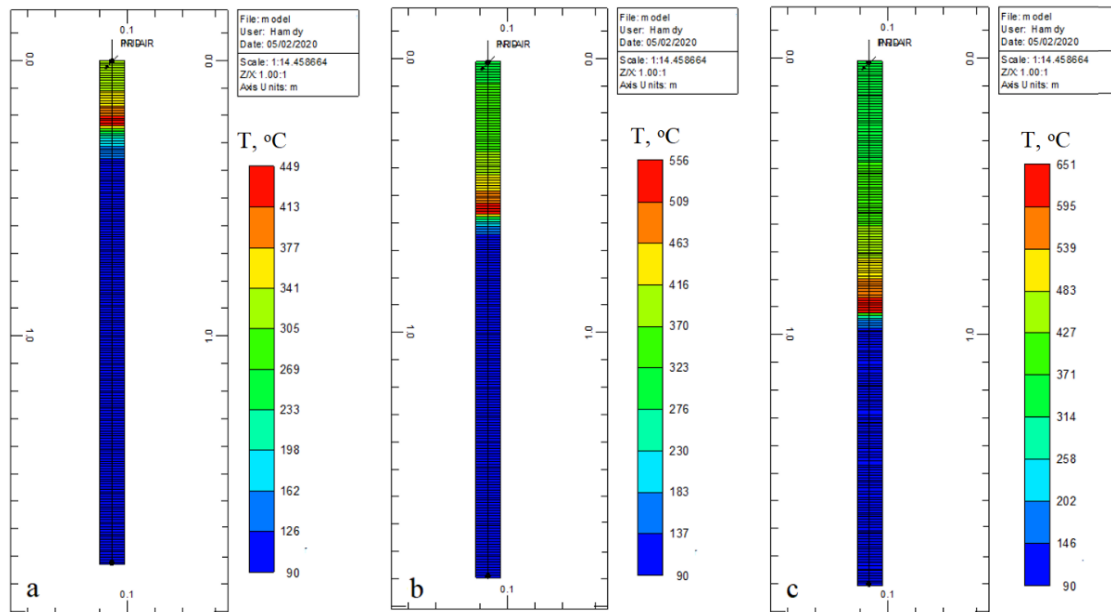


Figure 4. 8 Temperature contours for a) 21% O₂+79%N₂ b) 50% O₂+50%N₂ and c) 95% O₂+5%N₂

4.4.3 Effect of O₂ Ratio in the Enriched Air (Co-Injection of O₂ and N₂) on the Oil Production

Using oxygen-enriched air in ISC as oxidizer instead of air leads to several potential technical and economic advantages [120, 121]. Table 4.7 indicates the details of the initial oil in the core, the cumulative recovered oil, the oil recovery factor and the burned oil for different O₂/N₂ ratios. For the simulated lab experiment, increasing the oxygen ratio in the oxygen-enriched air directly leads to higher cumulative oil as shown in the table. The higher oil recovery tendency of oxygen-enriched ISC can be the result of higher heat release, which reduce the oil viscosity and facilitate the oil production. With increasing the oxygen content in O₂/N₂ mixture, the burned oil is increased. For example, increasing the oxygen ratio from 21 % to 95 % leads to increasing the burned oil from 7.27 % to 10.77 % from the initial oil in the core.

Table 4. 7 Initial oil in the core, cumulative productive oil, oil recovery factor and burned oil for different O₂/N₂ ratios.

O ₂ /N ₂	Initial oil in core, m ³	Cumulative recovered oil, m ³	Oil Recovery Factor, %	Residual Oil in Core, m ³	Burned oil, m ³	Burned oil, %
95 %O ₂ +5% N ₂	0.004124	0.00368	89.23	0	0.000444	10.77
50 %O ₂ +50% N ₂	0.004124	0.002755	66.80	0.000994	0.000375	9.09
21%O ₂ +79% N ₂	0.004124	0.001306	31.65	0.002518	0.0003	7.27

Starting with oxygen ratio of 21% by mole and the rest is nitrogen as in the atmospheric air. The oil recovery factor, which is a percentage ratio of volume of the recovered oil over volume of original oil in place, is the least as shown in Figure 4.9. Increasing the oxygen ratio from 21% to 50% leads to increasing the oil recovery factor from 31.65 % to 66.8 %, respectively. Increasing the oxygen ratio from 50% to 95 % leads to increasing in the oil recovery factor to 89.23 % (i.e. with ratio around 33.5 %). That is due to effect of oxy-combustion and increasing

the flame temperature due to decreasing the heat gained by nitrogen as well as increasing the amount of burned oil that leads to higher heat release and as a result higher cumulative oil.

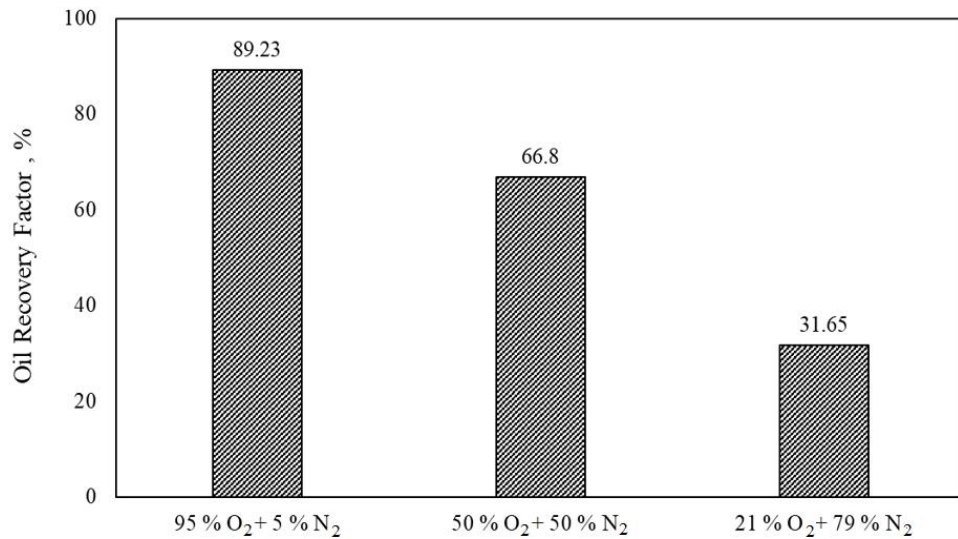


Figure 4. 9 Effect of different Oxygen ratio in enriched air on the oil recovery factor

4.4.4 Effects of Oxygen Ratio in Case of Co-Injection of O₂/CO₂

Figure 4.10-a illustrates the effect of oxygen ratio in the O₂/CO₂ on the temperature at the leading edge of the front at same time, 7.92 hours. The results give the same behavior as in cases of enriched air combustion. At oxygen ratio of 95% the temperatures at the leading edge is higher than that in case of oxygen ratio 50%. The lowest value of the leading-edge temperature is achieved in the case of using oxygen ratio 21%, as shown in Figure 4.10. Different oxygen ratios give different positions of the leading edge of the front as shown in Figure 4.10-a and Figure 4.11. Temperature contours are depicted in Figure 4.11. It can be seen that the temperature in case of injecting O₂/CO₂ is higher than that in case of injecting oxygen-enriched air and the leading-edge position of the front is moved forward. This is attributed higher temperature and the consequent higher reaction rates associated with O₂/CO₂ injection. The higher temperature associated with O₂/CO₂ injection is attributed to the fact that the

amount of heat injected in case of O_2/CO_2 is higher than that in the case of oxygen-enriched air as shown in Figure 4.12. That is due to the higher molecular weight for CO_2 than that of N_2 for the same volume flow rate, as a result higher thermal capacity (see Appendix B).

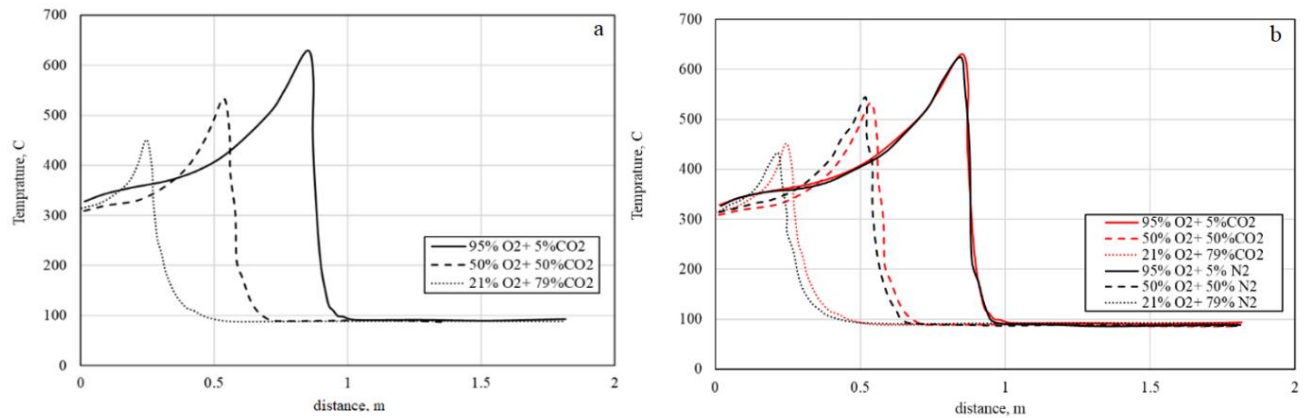


Figure 4. 10 Temperature profile for a) different O_2/CO_2 ratios and, b) both different O_2/CO_2 and O_2/N_2 ratios

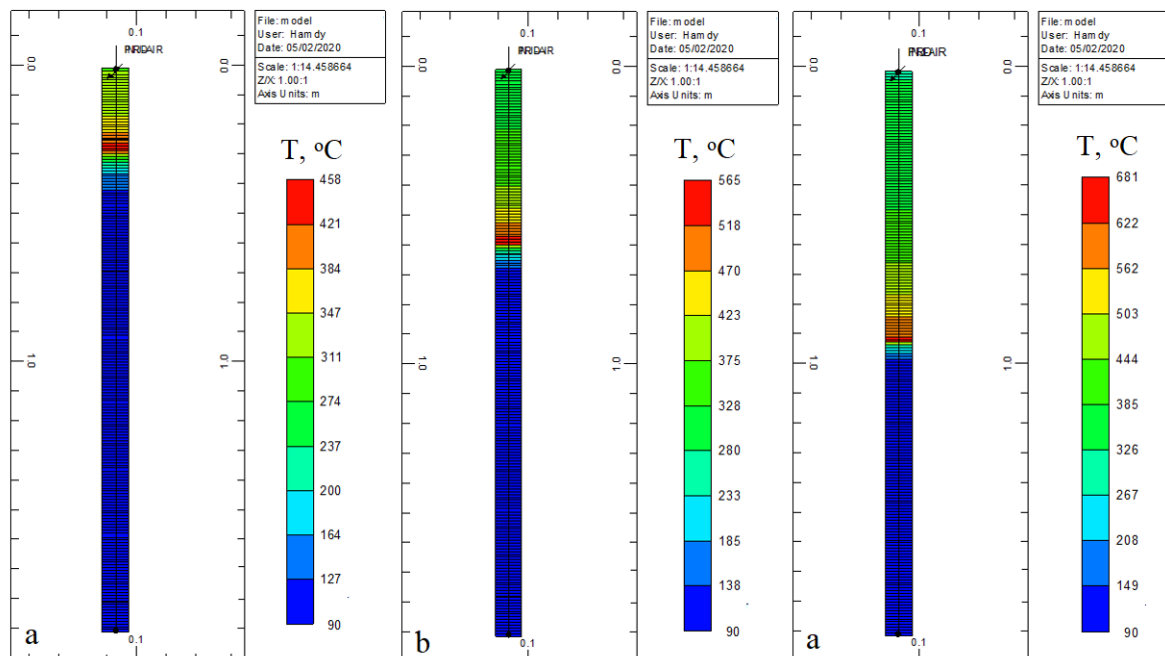


Figure 4. 11 Temperature contours for a) 21 % O_2 + 79 % CO_2 , b) 50 % O_2 +50% CO_2 and c) 95 % O_2 +5 % CO_2

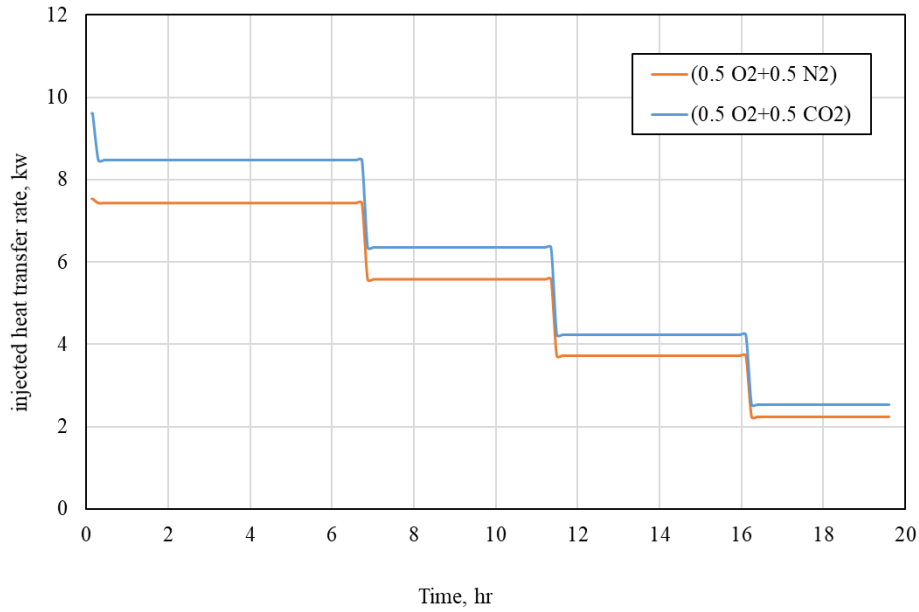


Figure 4. 12 Injected heat in case of (50 %O₂+50% CO₂) and (50 %O₂+50% N₂)

4.4.5 Effect of O₂ Ratio in O₂ /CO₂ Mixture on the Oil Production

Table 4.8 indicates the details of the initial oil in the core, the cumulative productive oil, the oil recovery factor and the burned oil for different O₂/CO₂ ratios. For co-injection of O₂/CO₂ gases as oxidizer with different ratios, increasing the oxygen ratio in the mixture directly increase the produced cumulative oil, as seen in Table 4.8. Increasing the oxygen content in O₂/CO₂ mixture leads to increasing the burned oil. Increasing the oxygen ratio from 21 % to 95 % leads to increasing the burned oil from 7.49 % to 10.76 % from the initial oil in the core.

In case of (21%O₂ + 79% CO₂), the oil recovery factor is the least as shown in Figure 4.13. Increasing the oxygen ratio from 21% to 50% leads to increasing the oil recovery factor from 35.76 % to 70.32 %, respectively. Increasing the oxygen ratio from 50% to 95 % leads to increasing in the oil recovery factor to 89.22 % (i.e. 26.8 % improvement). That is also due to

effect of oxy-combustion and increasing the flame temperature due to decreasing the heat gained by CO₂ as well as increasing the amount of burned oil that leads to higher heat release and as a result higher cumulative oil.

Table 4. 8 Initial oil in the core, cumulative productive oil, oil recovery factor and burned oil for different O₂/CO₂ ratios

O ₂ /CO ₂	Initial oil in core, m ³	Cumulative recovered oil, m ³	Oil Recovery Factor, %	Residual Oil in Core, m ³	Burned oil, m ³	Burned oil, %
95 %O ₂ +5% CO ₂	0.004124	0.00368	89.22	0	0.000444	10.76
50%O ₂ +50% CO ₂	0.004124	0.0029	70.32	0.000847	0.000377	9.14
21 %O ₂ +79% CO ₂	0.004124	0.001475	35.76	0.00234	0.000309	7.49

To conclude, for all O₂ ratios, using O₂/CO₂ as oxidizer gives higher oil recovery factors than that given using oxygen-enriched air as shown in Figure 4.14. The oil recovery factor in case of using (21%O₂ + 79% N₂) and (21%O₂ + 79% CO₂) is 31.65% and 35.76%, respectively, (i.e. we could achieve an improvement of 13.0 % in case of using O₂/CO₂). In case of using (50%O₂ + 50% N₂) and (50%O₂ + 50% CO₂) the oil recovery factor is 66.8 % and 70.32%, respectively, (i.e. we could achieve an improvement of 5.27 % in case of using O₂/CO₂). The change in oil recovery factor in case of 95.0 % O₂, is negligible, and that is attributed to the lower contents of the inert gas (N₂ or CO₂) and its effect on the heat produced from the combustion process, so the effect on oil recovery factor is negligible.

In case of injecting O₂/CO₂ as oxidizer, the higher heat capacity of the injected CO₂, in addition to the CO₂ produced from combustion process, leads to higher displacement efficiency of the oil.

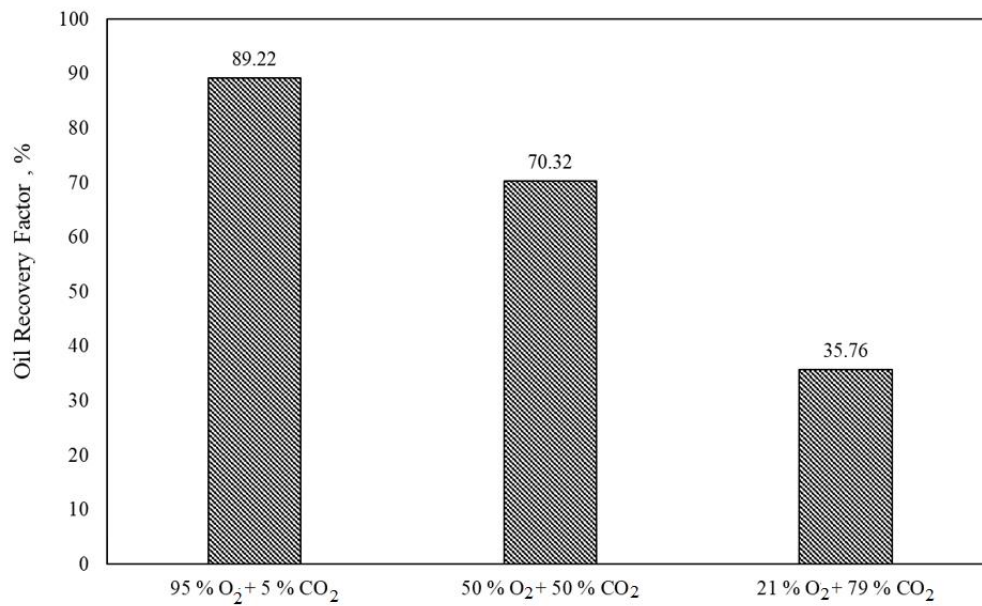


Figure 4. 13 Effect of different Oxygen ratio in O₂/CO₂ mixture on the cumulative oil

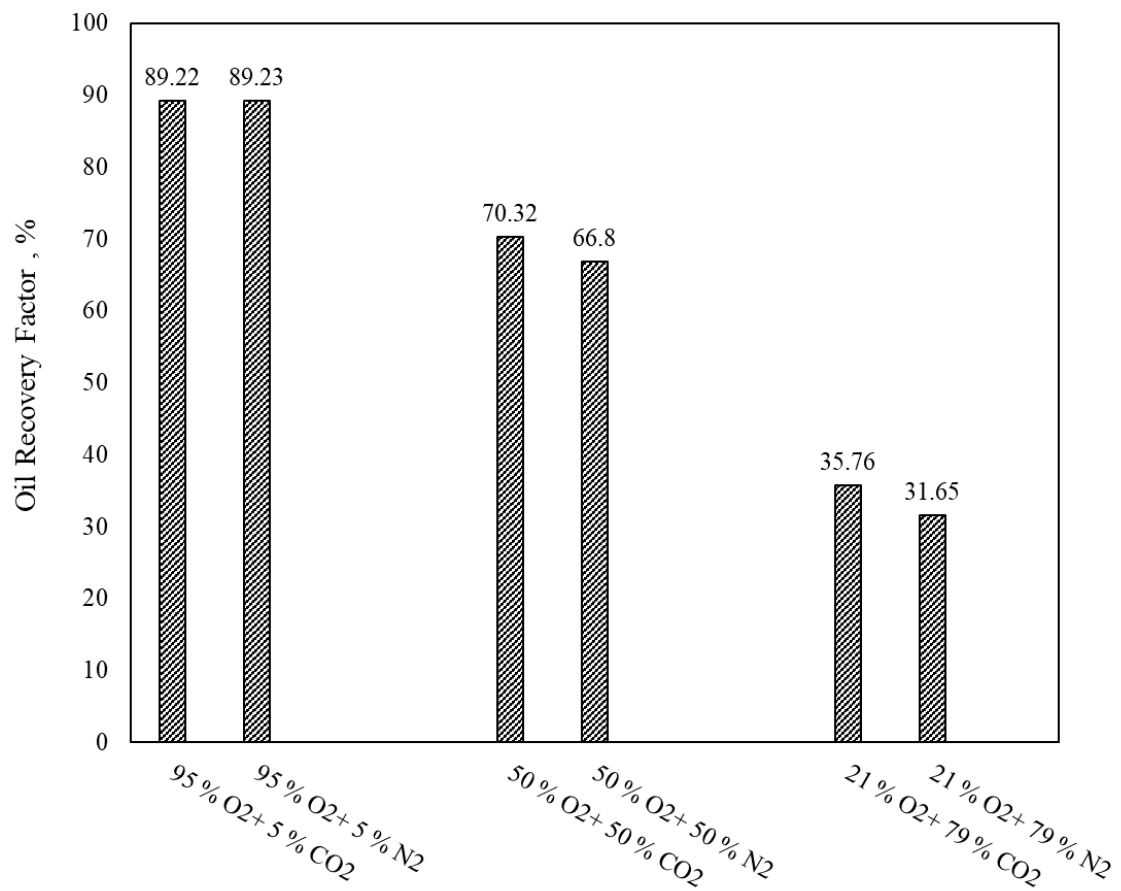


Figure 4. 14 Comparison between oil recovery factor for different Oxygen ratios in case of O₂/N₂ mixture and O₂/CO₂ mixture

4.4.6 CO₂ and CO Production from The ISC in case of Using O₂/N₂ or O₂/CO₂ as Oxidizer

The main components of the exhaust gases from the in-situ combustion will be CO₂ and CO. The amounts of these gases will differ when using O₂/N₂ as oxidizer from that when using O₂/CO₂, and with the ratio of O₂ in the mixture. With O₂/N₂ as oxidizer, CO₂ concentration will increase with increasing the oxygen ratio. This is due to increasing the amount of burned oil, and the higher heat release. Also, the higher heat release leads to decreasing the produced CO. The CO₂ volumes increased from 0.149 m³ to 0.347 m³ due to increasing the oxygen ratio from 21% to 50%, respectively, and increased to 0.544 m³ at oxygen concentration of 95%. In case of O₂/CO₂ as oxidizer, the same behavior will occur in addition to the injected amount of CO₂; as a result, the concentration will be higher than that in case of using O₂/N₂ for all ratios as shown in Figure 4.15. But in case of using O₂/CO₂ as oxidizer, the produced volume of CO₂ is increasing relatively with decreasing the oxygen ratio, in the injected mixture, because of increasing the CO₂ fraction at the inlet.

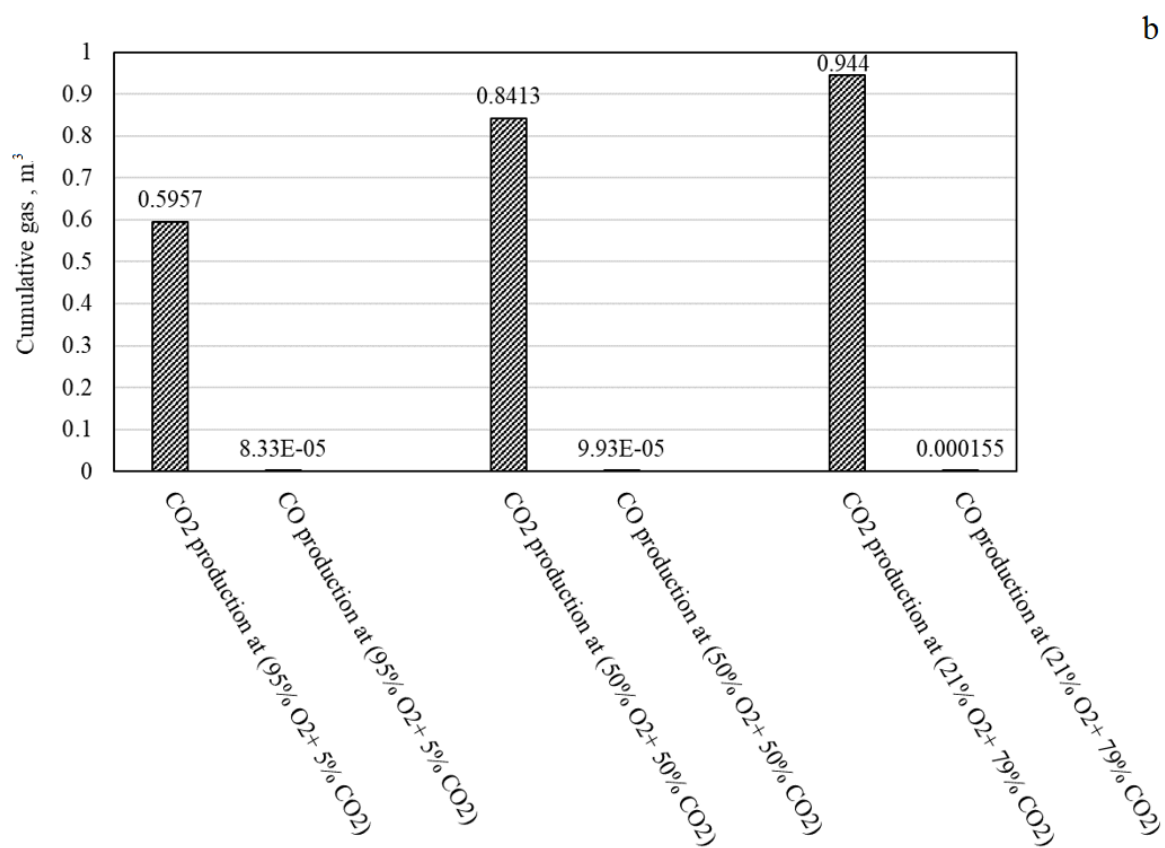
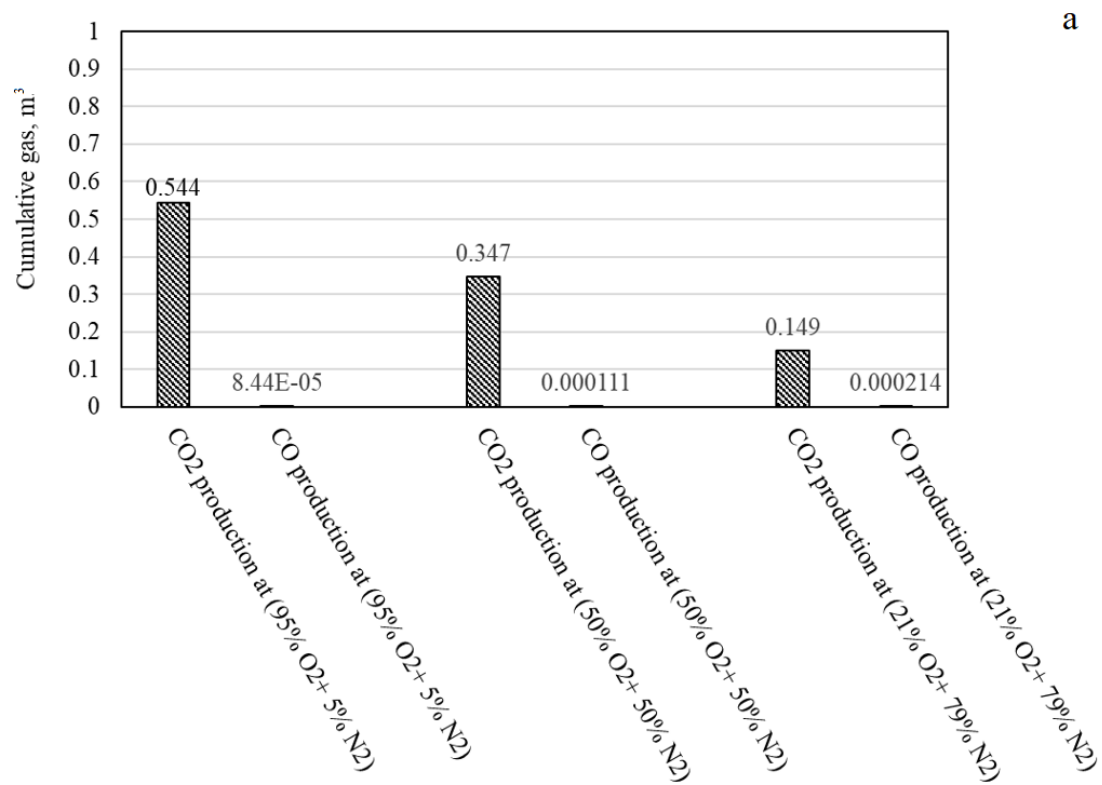


Figure 4. 15 CO₂ and CO production in case of using a) (O₂+N₂) and b) (O₂+CO₂) as oxidizer with different ratios.

4.4.7 H₂ and H₂S Production

Hydrogen and hydrogen sulfide are considered output gases from the in-situ combustion process; however, they have very small concentrations as shown in Figure 4.16. In case of using (O₂+CO₂) as oxidizer, the amount of produced H₂ will be slightly higher than in case of using oxygen-enriched air. That is considered an advantage point of using (O₂+CO₂) as oxidizer, as the increase in the produced H₂ values will lead to higher oxidation reaction rate. Increasing H₂ is due to existence of a significant amount of coke (reactions 2 and 10 in Table 4.1, as shown below), which accelerates hydrogen generation reactions (reactions 3 and 16 in Table 4.1, as shown below), where thermal cracking and low temperature oxidation dominates, and that is also due to the higher injected heat [219].



For H₂S (Reaction 7 in Table 4.1, as shown below), the produced amount will be higher in case of using (O₂+CO₂) rather than oxygen-enriched air, and that considered a disadvantage point. Increasing H₂S ,in case of using(O₂+CO₂), is due to the higher temperature as reported in [228], and that is due to the higher injected heat which leads to increasing the rate of pyrolysis reactions.



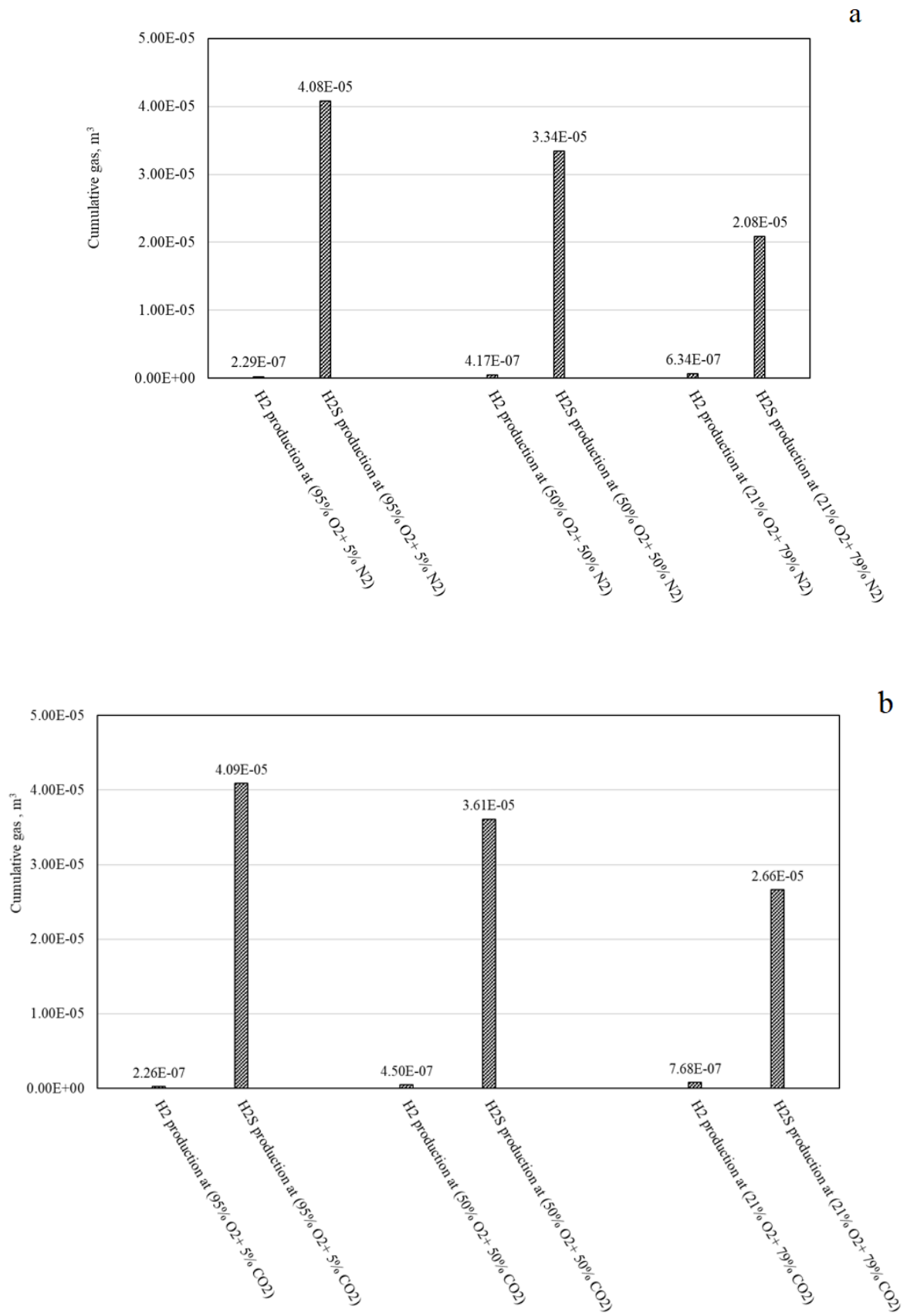


Figure 4. 16 H₂ and H₂S production in case of using a) (O₂+N₂) and b) (O₂+CO₂) as oxidizer with different ratios

4.5 Summary of Chapter 4

In this chapter, a combustion in a 1D porous tube saturated with heavy oil has been simulated to investigate the effect of different injected oxidizer compositions and different injection strategies. Effect of different oxygen ratios, in the oxidizer, on the oil recovery factor has been studied with injection of oxygen-enriched air or O_2/CO_2 as oxidizer. The improvement ratio of oil recovery factor increased with a percent ratio 5.27 % in case of using (50 % O_2 + 50% CO_2) as oxidizer compared with the case of using (50 % O_2 + 50% N_2) as oxidizer. This ratio increased to 13.0 % in case of (21 % O_2 + 79% CO_2) as oxidizer compared with the case of using (21 % O_2 + 79% N_2) as oxidizer, where the effect of CO_2 is more obvious. The injected heat in case of injecting O_2/CO_2 rather than O_2/N_2 will be higher for the same volume flow rate. It is concluded that co-injecting of carbon dioxide with oxygen instead of oxygen-enriched air has a good effect on the oil recovery factor. Using O_2/CO_2 as oxidizer has low effect on the produced amounts of hydrogen and hydrogen sulfide.

In the next chapter, numerical results for 3D ISC field scale is introduced. Effect of using O_2/CO_2 rather than O_2/N_2 is investigated. The results showed the difference between using the two oxidizers in terms of cumulative oil, combustion process and amount of sequestered CO_2 .

CHAPTER 5

IN SITU COMBUSTION FOR FIELD SCALE

In the current chapter, a 3D reservoir simulation based on the mentioned governing equations and components properties (in chapter 4) was conducted and validated against published practical field data. Essentially, numerical modelling of the ISC in field scale has been performed using the CMG Stars (2017.10) software to simulate the process. Co-injection of pure oxygen with carbon dioxide (CO₂); and co-injection of oxygen with nitrogen gas have been investigated by a numerical model for the field scale.

5.1 The Numerical Model for Field Scale

In situ combustion model has been developed using CMG (computer modelling group Ltda.) [43] software for a 3D reservoir. The developed model has been validated against the practical field data as reported in [223] to make sure about the precision of the model. Having good agreements between the numerically results estimated using our developed model with the practical results reported by Kapadia et al. [223] for oxygen-enriched air ISC, the model has been used for studying the ISC process with O₂/CO₂ injection for ISC.

5.1.1 Geometry and Numerical Mesh Generation.

A 3D numerical model using CMG software has been developed to simulate the ISC for practical field. The reservoir and oil properties have been taken from Kapadia et al. [223] as shown in Table 5.1. The 3D simulated reservoir model has been created with dimensions of (30×20m)× (9×20 m) × (37×0.8 m), with one injection well and one production well as reported in [223], as shown in Figure 5.1. This configuration was used to validate the

developed numerical model against the practical field results obtained for the same configuration for ISC under oxygen-enriched air injection. The simulation lasted for the same time of the reported results [223], which is around 230 days. Having the numerical model well validated against the practical results, the numerical model has been used to simulate the injecting of O₂/CO₂ for ISC with different O₂/CO₂ ratios.

Table 5. 1 Simulator input parameters for field scale simulation [223]

Input Parameter	Value
Reservoir Initial Pressure, kpa	2000
Reservoir Temperature, °C	15
Porosity	27%
Average Horizontal Permeability, mD	1836
Average Vertical Permeability, mD	982
Average oil saturation	55 %
Average water saturation	38 %
Rock heat capacity, J/m ³ C	2.6×10 ⁶
Rock thermal conductivity, J/m day C	6.6×10 ⁵
Water phase thermal conductivity, J/m day C	5.35×10 ⁴
Oil phase thermal conductivity, J/m day C	1.15×10 ⁴
Gas phase thermal conductivity, J/m day C	5.0×10 ³

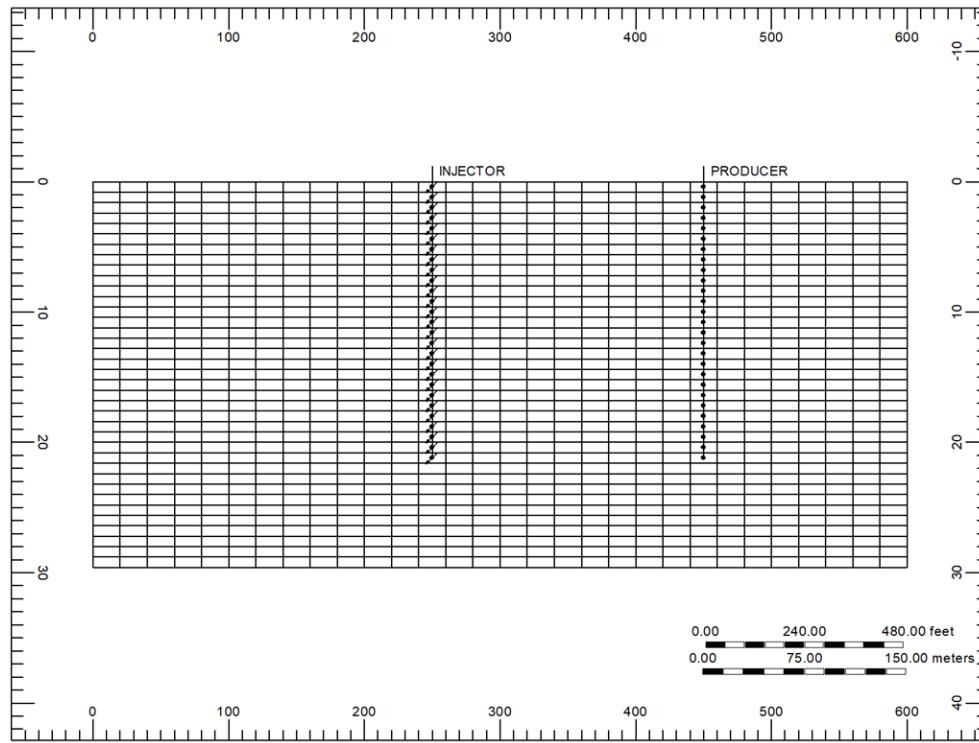


Figure 5. 1 grid blocks for the simulated reservoir [223]

5.1.2 Initial Conditions and Components Properties for the Field Scale

The properties of the oil components such as molecular weight, critical temperature and critical pressure and other properties such as viscosity correlations, relative permeability data, gas /liquid relative permeability values and vapor heat capacity given in [44] were used as input to CMG software [43]. The initial reservoir temperature, initial water, initial gas saturation and initial oil saturation in the reservoir are as reported in Table 5.1.

The heat transfer to the formation adjacent to the block surfaces of the reservoir is calculated using a semi-analytical model [226]. This model gives solutions quite close to exact answers to many heat transfer problems with a maximum error around 17 % [226]. The only data required to simulate the heat loss in CMG are the volumetric heat capacity and thermal conductivity of the adjacent formation to the simulated reservoir. In this regard,

the volumetric heat capacity and thermal conductivity of adjacent formation are 1.169×10^6 J/m³ °C and 7.49×10^4 J/m day °C, respectively [227]. For the heat loss model details, see appendix A.

5.1.3 The Inlet Conditions

According to [223], the injected enriched air and water to the injection well through the simulated period are shown in Figure 5.2. The air flow rate was injected with variable amounts in a period around 75 days, after which pure nitrogen has been injected for two weeks. After that, the air injection has been resumed for two weeks. Then the water injection started and continued for 100 days, with high flow rate at the beginning, then with lower flow rate as shown in the figure. Finally, the air injection was resumed to the end of the period. Figure 5.3 shows the total liquid production rate from the production well, which is used as a constraint during the simulation. Before starting of the ISC process, steam has been injected for stimulation. The steam injection properties are assumed to be as the conditions reported in [229] with a bottom hole pressure 10000 kpa and quality 0.8. For the injected enriched air, the bottom hole pressure is assumed to be 10000 kpa and temperature 250 °C, and for the injected water the temperature is assumed to be 50 °C. According to [223] and [230], The enriched air roughly was with O₂/N₂ ratio 0.596/0.404, respectively.

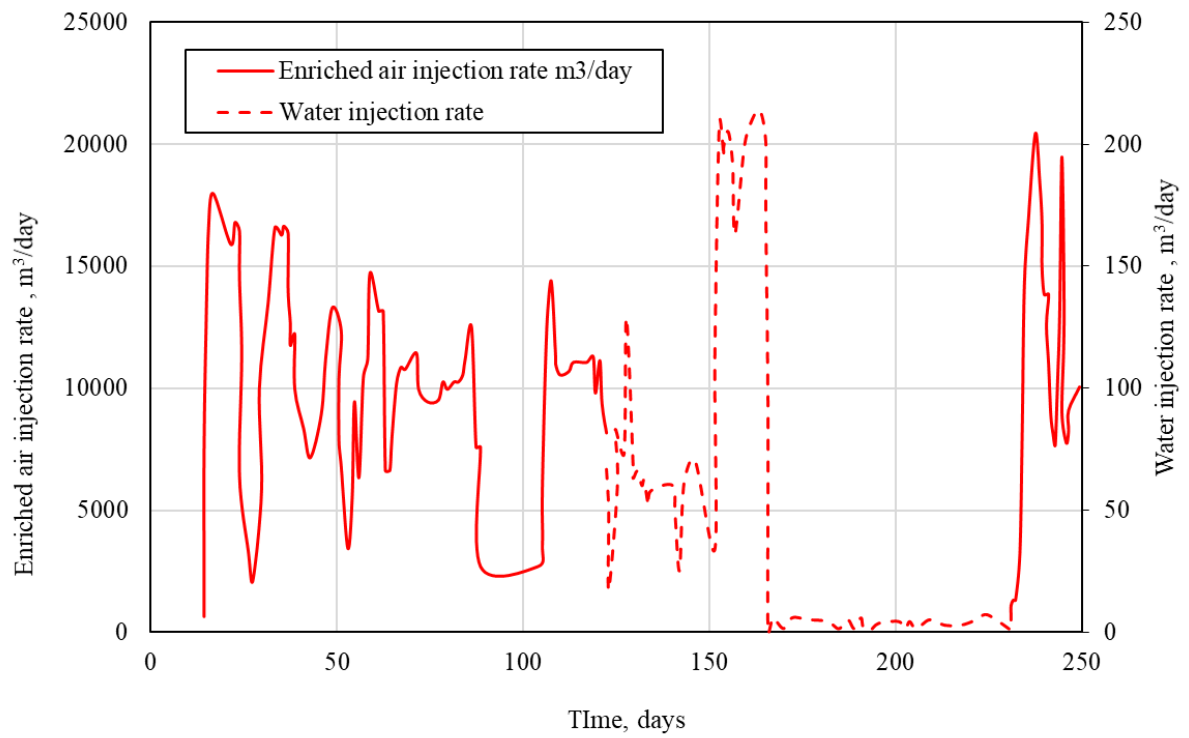


Figure 5. 2 Field data for air and water injection rates imposed for the injection well [223]

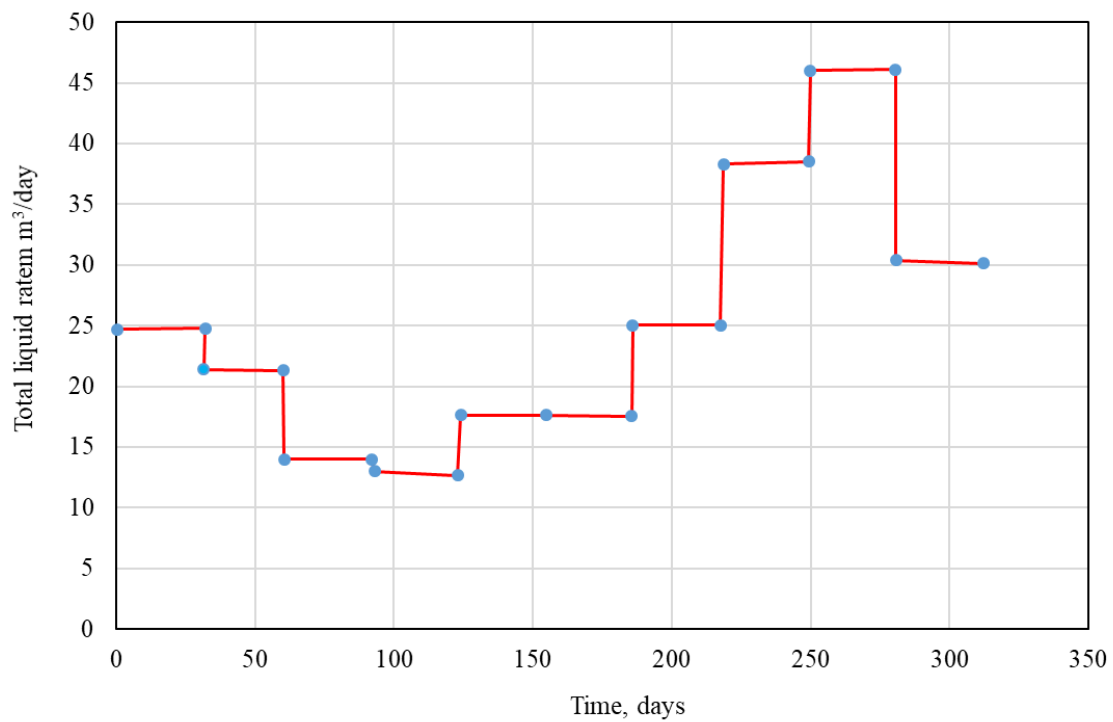


Figure 5. 3 Total liquid production rate from the production well, used as constraint during simulation [223]

5.2 Field Scale Results and Discussions

Numerical studies have been conducted to simulate the ISC field scale process. Injection of enriched air with different O_2/N_2 ratios, as an oxidizer, has been simulated for validation and study the effect of different oxygen contents on the cumulative oil. The injection of O_2/CO_2 as oxidizer with different ratios for studying its effect on the oil recovery is to be studied after the code validation as outlined hereunder.

5.2.1 Model Validation

In order to ensure the reliability of the model, the cumulative oil obtained numerically from the simulation model has been compared graphically with the practical data from the field [223], as shown in Figure 5.4. The numerical results from the simulation reveal that the present simulation shows a good agreement with the practical field data. However, there are some deviations between the numerical model and the field data as shown in the figure. The reasons are due to the complexity of simulating the ISC process, which contains a huge and unknown number of chemical reactions and components beside the reservoir heterogeneity. On the other hand, in the simulation process, a limited number of chemical reactions were used, and some reservoir properties have been used as a fixed number, which mean that the reservoir is homogenous.

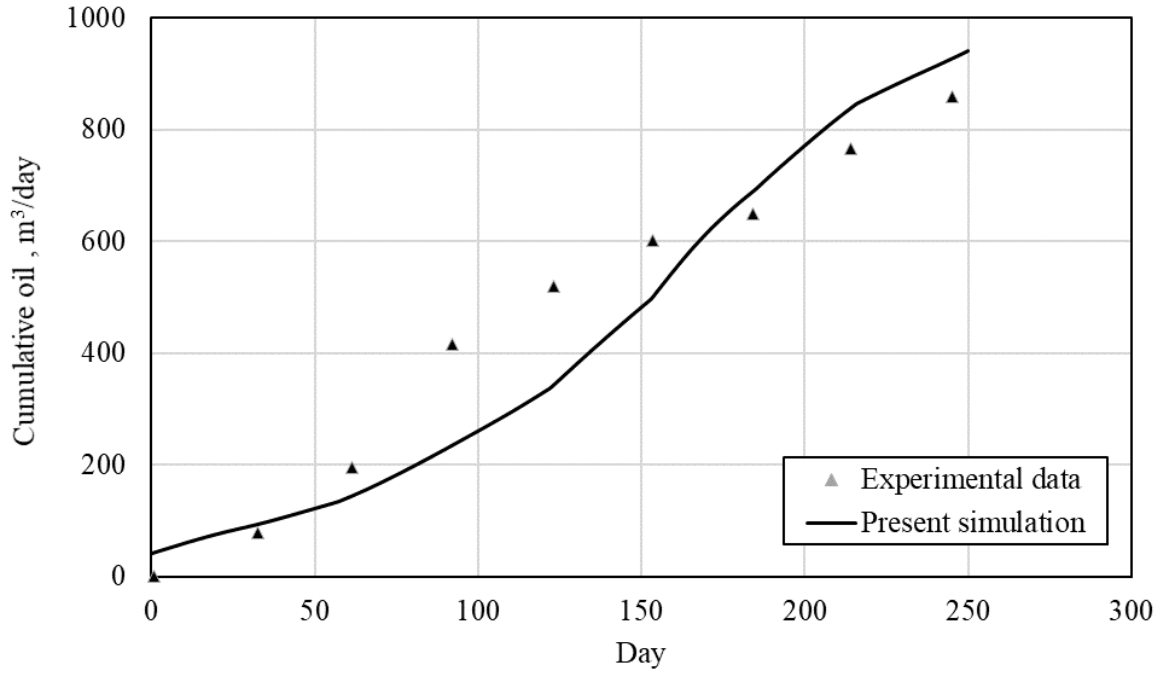


Figure 5. 4 Validation of the present simulation cumulative oil production with the actual field data [223]

5.2.2 Effect of O₂ Ratio in the Enriched Air (O₂/N₂) on the Oil Production

Increasing the oxygen ratio in the enriched air directly leads to higher cumulative oil as seen in Figure 5.5. With oxygen ratio of 21% and 30%, the cumulative oil is around 876.7 m³. Increasing the oxygen ratio to 59.6 % leads to increasing in the cumulative to 940.4 m³ and increasing the oxygen ratio to 95 % leads to increasing in the cumulative oil to 991.5 m³. The cumulative oil tendency of oxygen-enriched ISC can be the result of higher heat release, due to effect of oxy-combustion which decreases the heat gained by nitrogen. This higher heat release reduces the oil viscosity and facilitates the oil production. Figures 5.6 and 5.7 illustrate the temperature contours for (59.6% O₂+40.4% N₂) and (30%O₂+70%N₂) after 125 days and 250 days, respectively. The higher temperature leads to lower oil viscosity as shown in Figure 5.8, and lower oil saturation as shown in Figure 5.9.

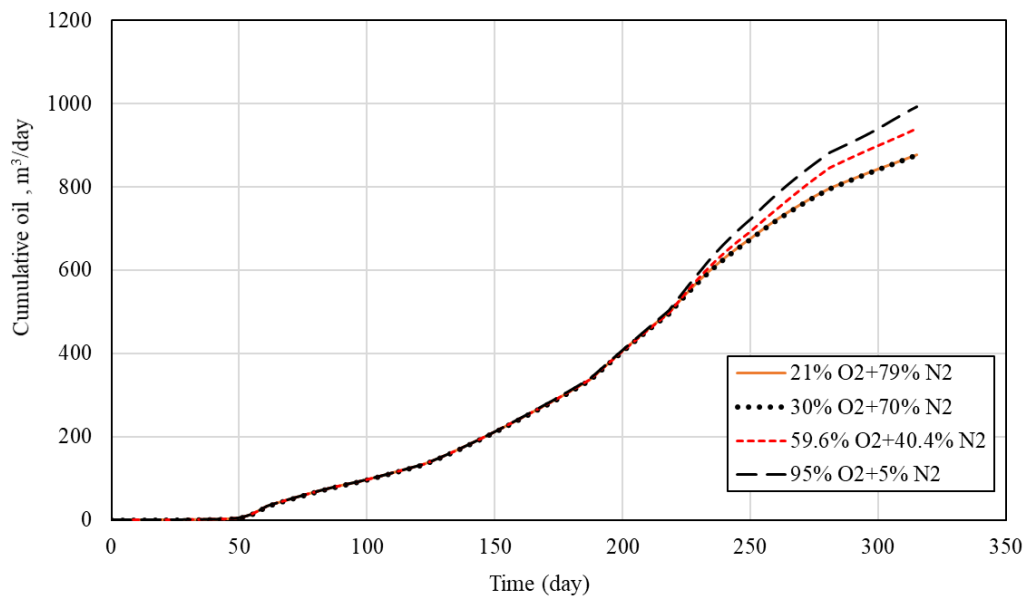


Figure 5. 5 Effect of different Oxygen ratio in enriched air on the cumulative oil

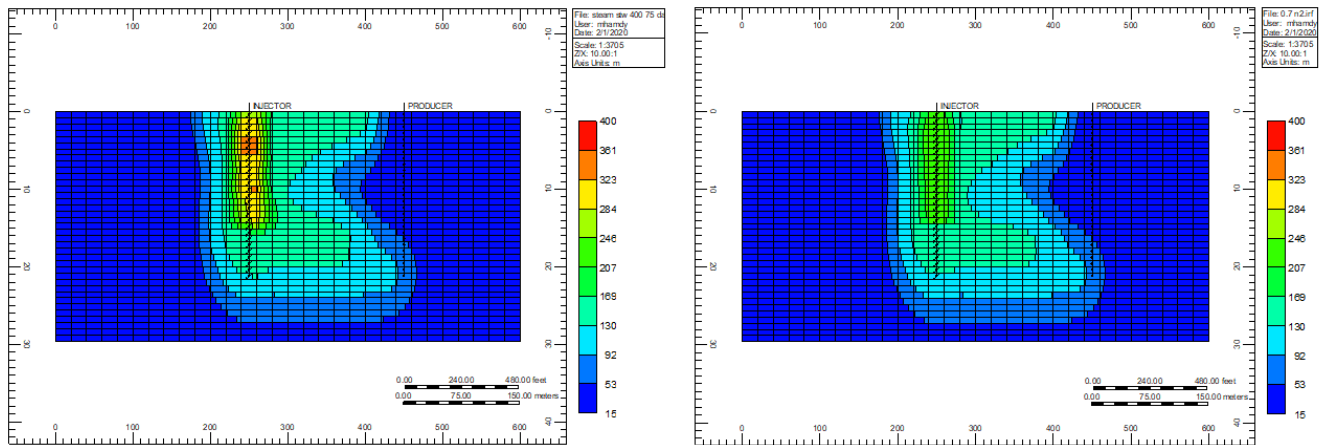


Figure 5. 6 Temperature contours for (59.6%O₂+40.4% N₂) and (30%O₂+70% N₂) 125 days

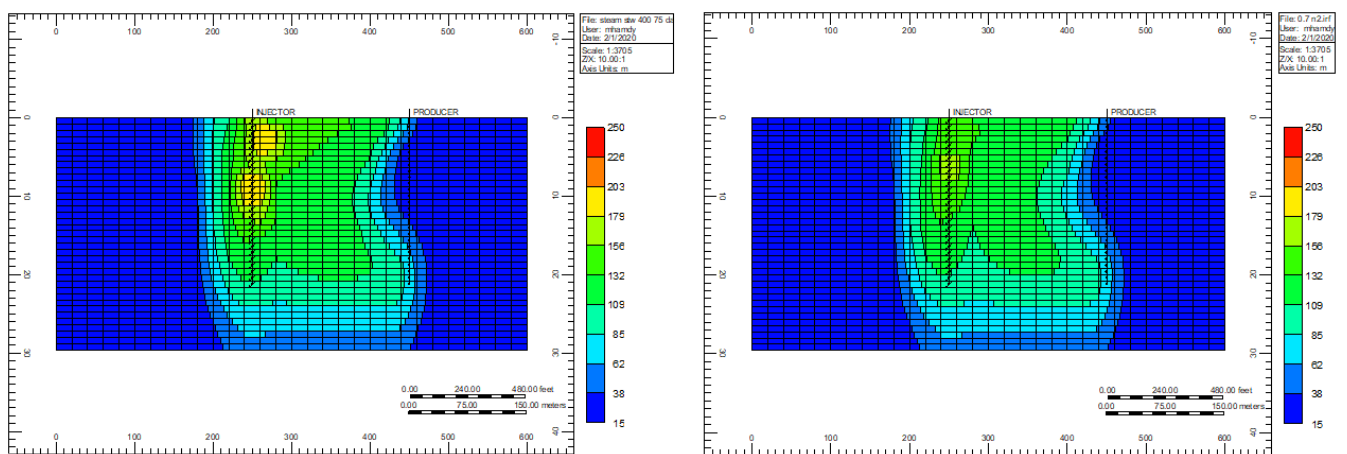


Figure 5. 7 Temperature contours for (59.6%O₂+40.4% N₂) and (30%O₂+70% N₂) 250 days

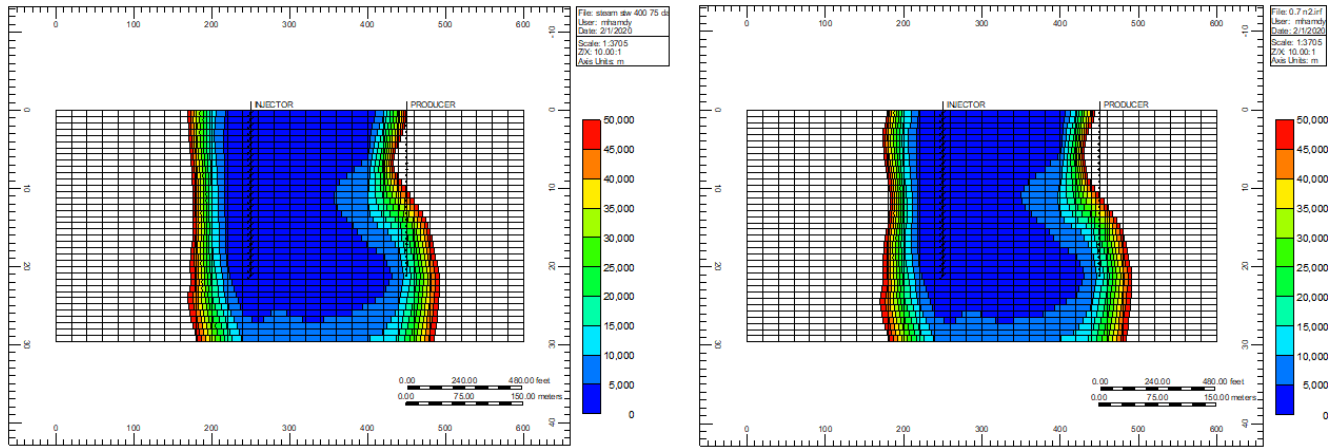


Figure 5. 8 Oil Viscosity contours for (59.6%O₂+40.4% N₂) and (30%O₂+70% N₂) 250 days

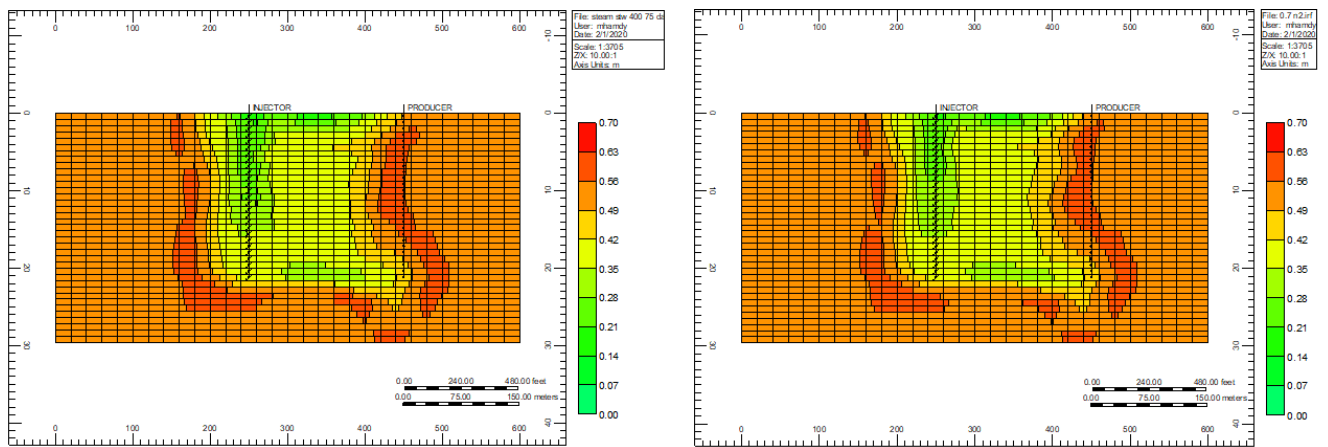


Figure 5. 9 Oil Saturation contours for (59.6%O₂+40.4% N₂) and (30%O₂+70% N₂) 250 days

5.2.3 Effect of O₂ Ratio in case of Co-Injection of O₂ and CO₂ on the Oil Production

In case of using O₂/CO₂ mixture as oxidizer, increasing the oxygen ratio in O₂/CO₂ mixture directly increases the cumulative oil as shown in Figure 5.10. Increasing the oxygen ratio from 21% to 30% leads to increasing the cumulative oil from 886.7 m³ to 893.8 %, respectively. While increasing the oxygen ratio from 59.6% to 95 % leads to increasing the cumulative oil from 949.2 m³ to 993.6 m³%, respectively. That is the result of higher heat release, due to effect of oxy-combustion which decreases the heat gained by CO₂. As shown in Figure 5.11, injecting mixture of O₂/CO₂ gives better results, in terms of cumulative oil, than injecting enriched air

(O_2/N_2) but with a small value. This increasing in the cumulative oil is due to the higher molecular weight and heat capacity of the mixture O_2/CO_2 than the enriched air, which means more displacing and driving force of the low viscous oil at the reached temperature. Figure 5.11 indicates the differences in the cumulative oil with different O_2/CO_2 and O_2/N_2 ratios. The improvement ratio in the cumulative oil is 1.14% in case of injecting (21% O_2 +79% CO_2), as oxidizer, rather than injecting atmospheric air (21% O_2 +79% N_2). This improvement ratio increased to 1.94% in case of using 30% oxygen ratio. With 59.6% oxygen ratio, the improvement ratio is 0.94%, and for 95% oxygen ratio this value decreased to 0.212 %.

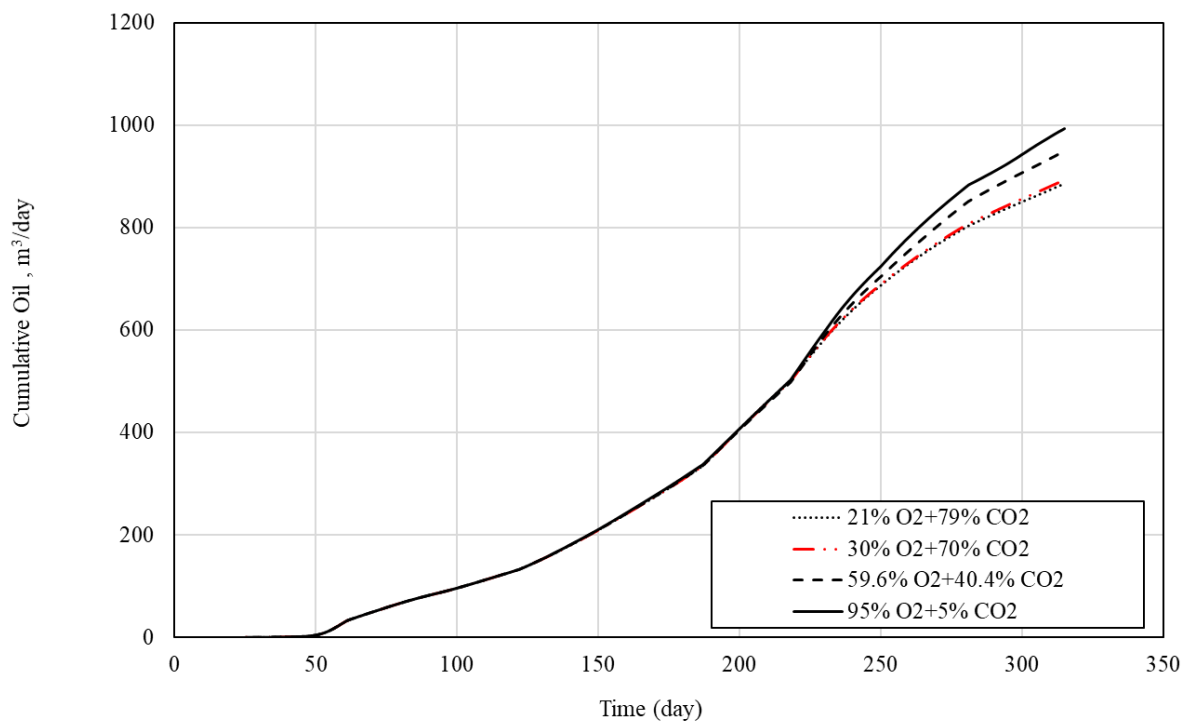


Figure 5. 10 Effect of different Oxygen ratio in the mixture of (O_2+CO_2) on the oil recovery factor

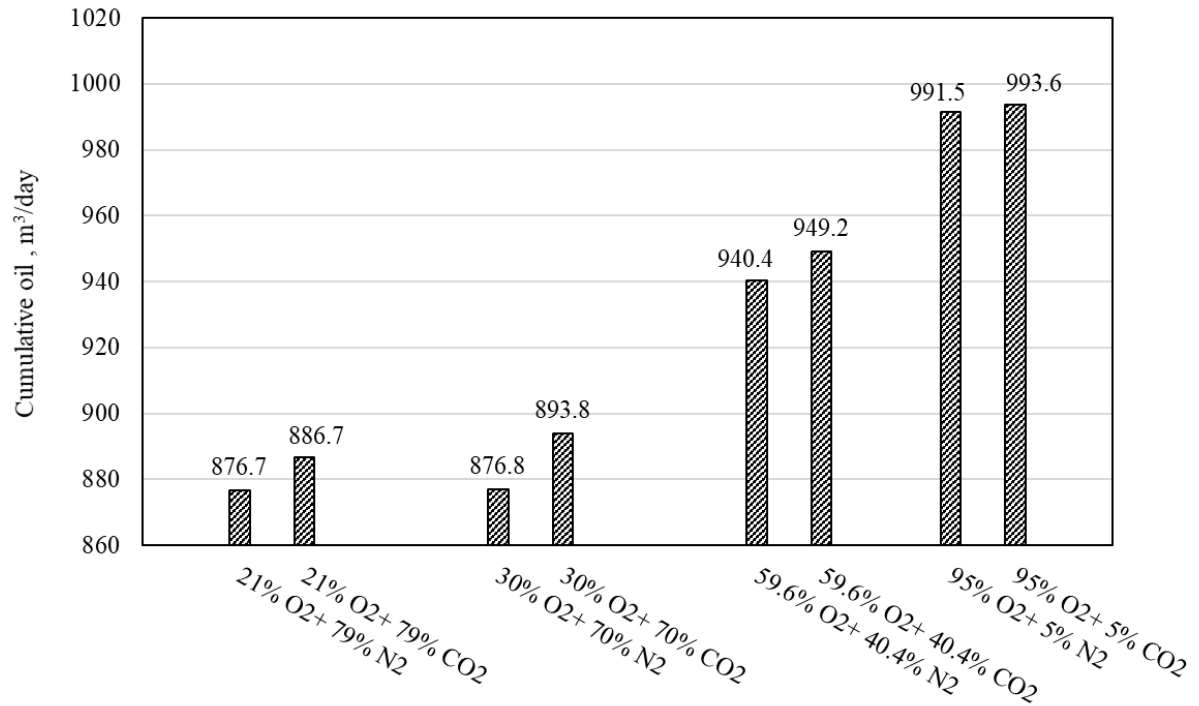


Figure 5. 11 Comparison between cumulative oil for different Oxygen ratios in case of O₂/N₂ mixture and O₂/CO₂ mixture.

5.2.4 Effect of Injecting O₂/N₂ and O₂/CO₂ on the Formation Properties

Due to the injection of the oxidizer and steam prior it, the in-situ combustion process is started, and the reservoir temperature is raised. In case if injecting O₂/CO₂ or O₂/N₂ as oxidizers, the temperature contours after 125 days are mostly close for the same oxygen ratios, (59.6% O₂ + 40.4% N₂) and (59.6% O₂ + 40.4% CO₂), as shown in Figure 5.12. Despite, the injected heat in case of O₂/CO₂ is slightly higher than the case of enriched air, as shown in Figure 5.13. As the temperature contours are mostly the same for the same oxygen ratio, the oil saturation contours for the two oxidizers also are close to each other as shown in Figure 5.14. The figure

gives an indication about the remaining oil in the reservoir at the wells cross section at the end of the period.

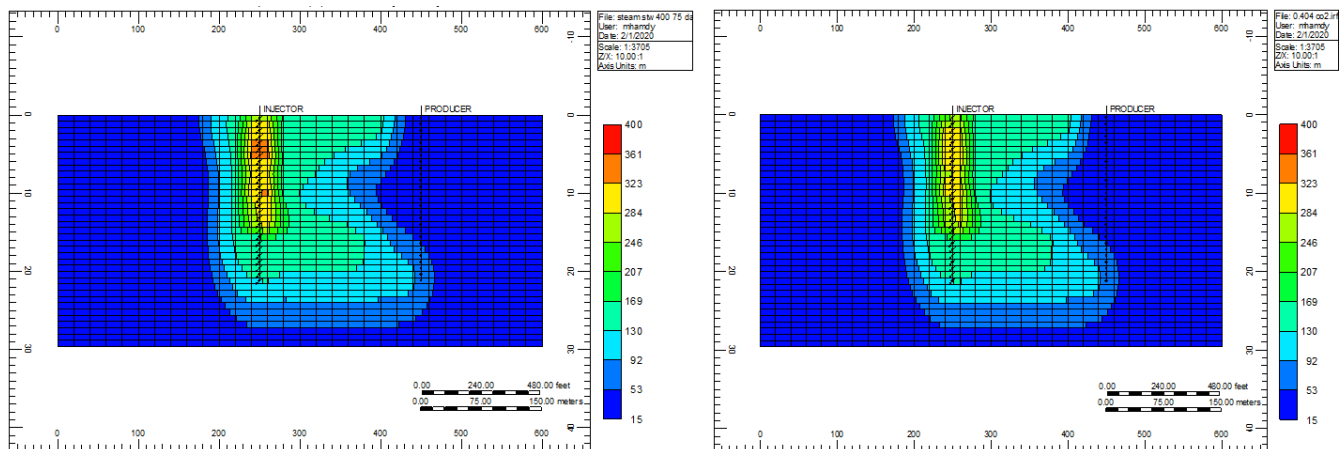


Figure 5. 12 Temperature contours for (59.6%O₂+40.4% N₂) and (59.6%O₂+40.4% CO₂)125 days

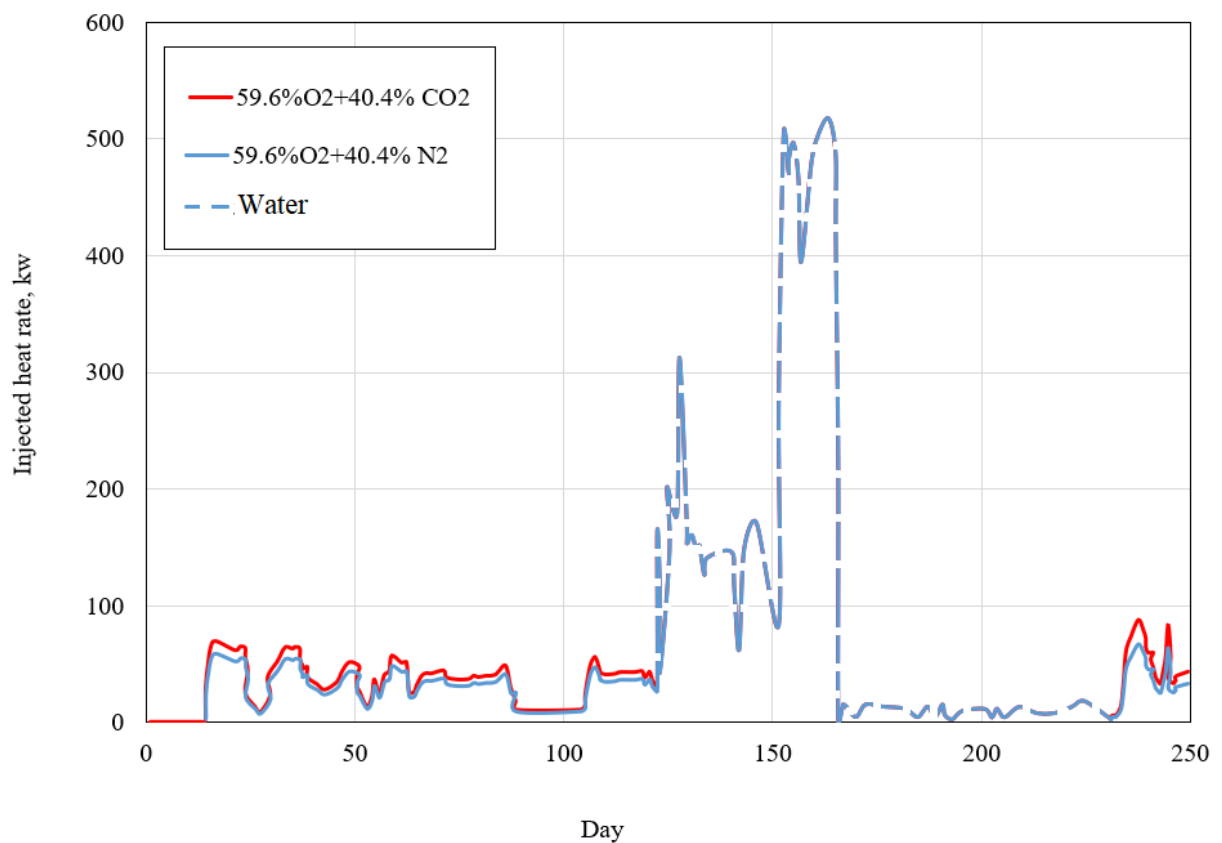


Figure 5. 13 Injected heat rate in case of using (59.6%O₂+40.4% N₂) and (59.6%O₂+40.4% CO₂) as oxidizer.

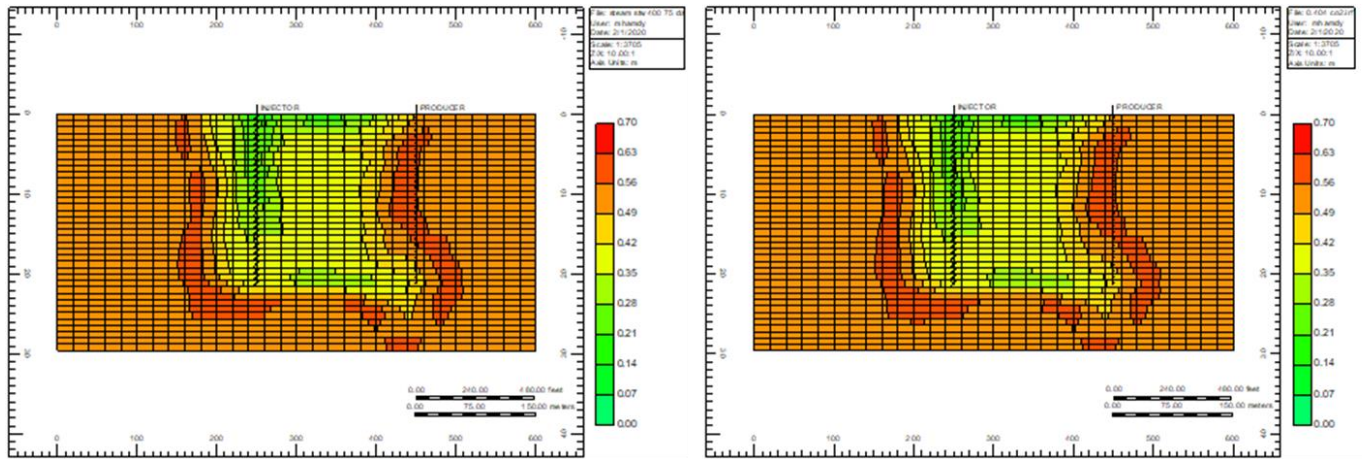


Figure 5. 14 Oil saturation contours for (59.6%O₂+40.4% N₂) and (59.6%O₂+40.4% CO₂) 250 days

5.2.5 Effect of Injected Water Properties on the Cumulative Oil for (59.6%O₂+40.4% CO₂)

During dry ISC combustion (i.e. only oxidizer is injected) a huge amount of heat is released, and a huge part of this heat is stored in the burned zone. The low gases capacity cannot transfer the stored heat efficiently to other places. To make use of this stored heat, water is injected simultaneously or alternatively with the oxidizer. That could capture and advance more heat to other regions, due to the higher heat capacity of water. Water properties may affect on the produced oil, especially its viscosity. Increasing the injected water temperature will decrease the oil viscosity, and increases the recovered oil, but with small values, as shown in Figure 5.15. Injecting the same mass flow rate as a steam rather than liquid water gives higher effect, in terms of cumulative oil. Increasing the steam quality directly decreases the oil viscosity and increases the cumulative oil. That is due to increasing the heat content in case of high-quality steam. As shown from the figure, increasing the liquid water temperature from 50 °C to 100 °C leads to an improvement ratio, in the cumulative oil, around 0.6 %, which is considered low value. But, increasing the temperature from 50°C as a liquid water to 100°C as a steam with quality 0.8 leads to an improvement ratio, in the cumulative oil, around 7.7 %, which is

considered a reasonable improvement. Increasing the temperature from 100°C and quality 0.8 to 350°C and quality 0.8, leads to an improvement ratio around 0.7% which is considered low, which reinforces the mentioned justification about the low impact of temperature change.

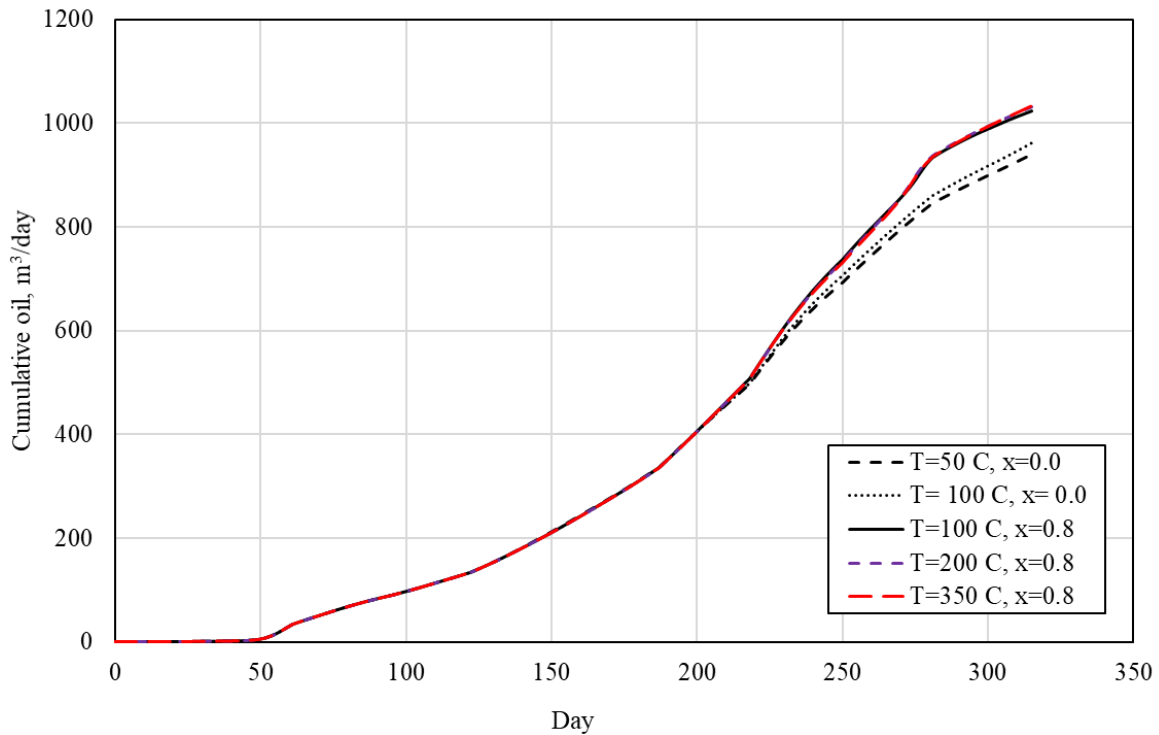


Figure 5. 15 Effect of injected water properties on the cumulative oil

5.2.6 Effect of different injected gases and water Flow rates on the cumulative oil

The injected gases and water flow rates have a great effect on the cumulative oil. In this manner, three injection cycles have been used to see their effects. The first cycle is the one which has been used for the validation [223]. The second and third cycles have been used as in Figures 5.16 and 5.17, respectively, such as the cycles used in [229], but with the same reservoir and injection conditions as in the first cycle (i.e. the validated case). The output liquid constraint is assumed to be as in Figure 5.3 for both cycles. In case of the second cycle (i.e. Figure 5.16), the water and enriched air are injected simultaneously and alternatively with low water rate after 300 days as shown in Figure 5.16-a. For the third cycle, (i.e. Figure 5.17), the water and

enriched air are injected alternatively for around 150 days, then low water flow rate continued to the end of the cycle. Figure 5.18 indicates the cumulative oil for the three mentioned cycles. The cumulative oil is close in case of the first (i.e. validated case) and third cycles. In the first cycle, the period is smaller than the third one, but the injection flow rate of the first cycle is higher, which accelerates the oil production. For the second cycle, which gives the higher cumulative oil, the injection period and the injected mixture flowrate are greater, as a result high injected heat and high production.

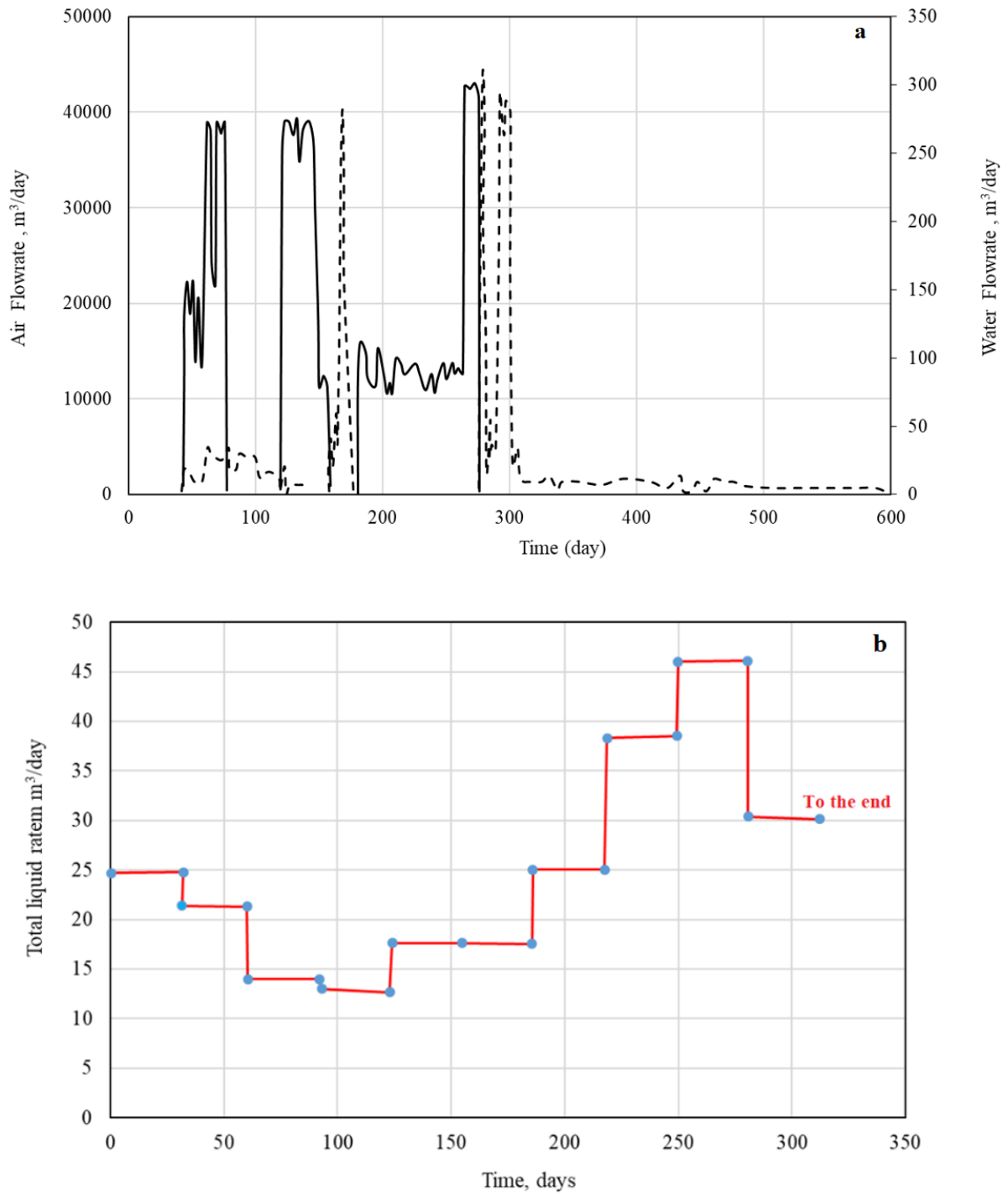


Figure 5. 16 a) Enriched Air and water injection flow rate, b) Maximum liquid flow rate from the production well, for second cycle

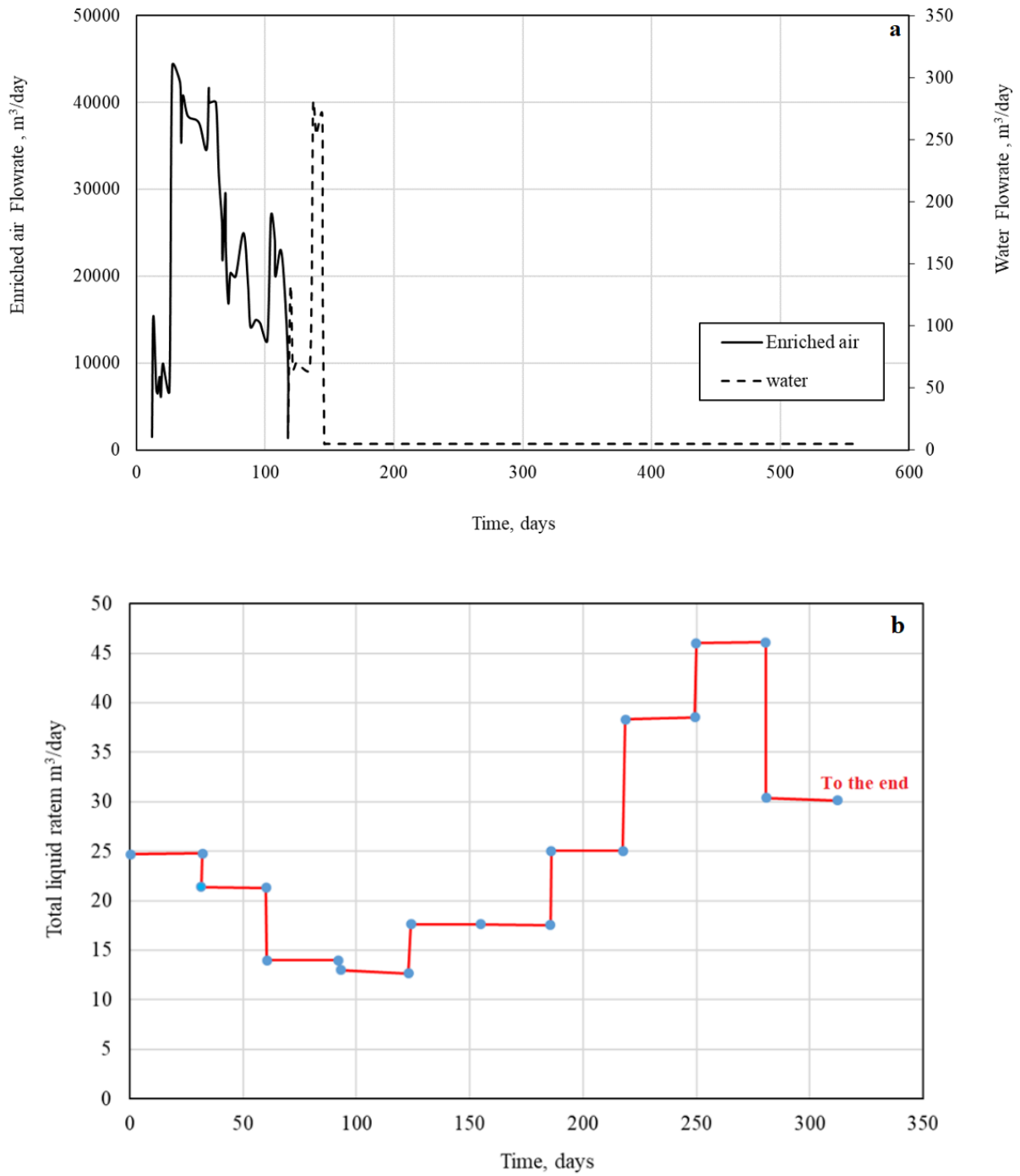


Figure 5. 17 a) Enriched Air and water injection flow rate, b) Maximum liquid flow rate from the production well, for third cycle

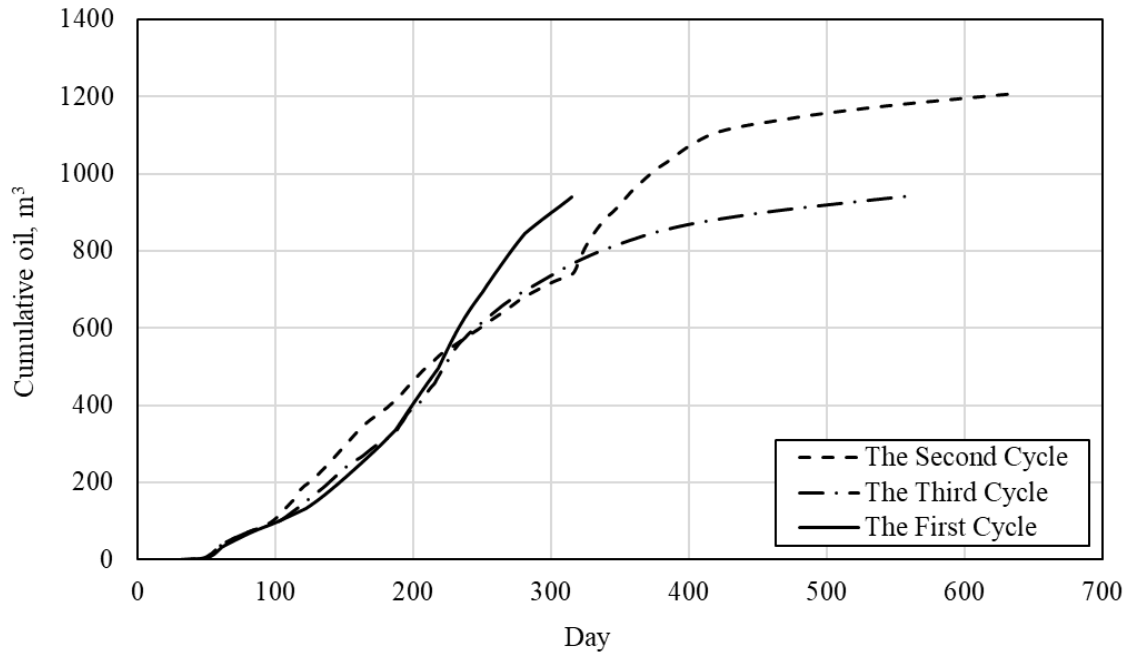


Figure 5. 18 Effect of different injected gases and water cycles on the cumulative oil

5.2.7 CO₂ Sequestration as a Benefit with ISC

As mentioned before, one of the main objectives of this work is to demonstrate using of CO₂ in ISC. Carbon dioxide may be used as a carrier of oxygen instead of nitrogen. The last few discussions proved that using CO₂ with oxygen instead of using N₂ in ISC gives better performance in terms of cumulative oil. There is another important benefit of using CO₂ in ISC, which is CO₂ sequestration. As shown in Figure 5.19, the injected volume flow rate of CO₂ in case of using (21% O₂+79 % CO₂) as oxidizer, is around One million cubic meter. This value of the sequestered CO₂ is injected only in one well and in a period less than one year. The sequestered volume of CO₂ is decreasing with increasing the oxygen concentration in the oxidizer. As a result, it is environmentally recommended to use O₂/CO₂ as an oxidizer in ISC process. But using O₂/CO₂ in ISC process leads to increasing the produced amounts of CO₂, as shown in Figure 5.20. The produced amounts of CO₂ as a result of chemical reactions are increasing with decreasing the oxygen ratios in the oxidizer for O₂/CO₂ and O₂/N₂. But in case

of using O_2/CO_2 as oxidizer, the produced CO_2 will be higher than in case of using O_2/N_2 . That is due to the higher injected amounts of CO_2 in addition to the amounts produced as exhaust gas. The produced amounts of CO_2 through production wells can be recirculated again with oxygen for ISC.

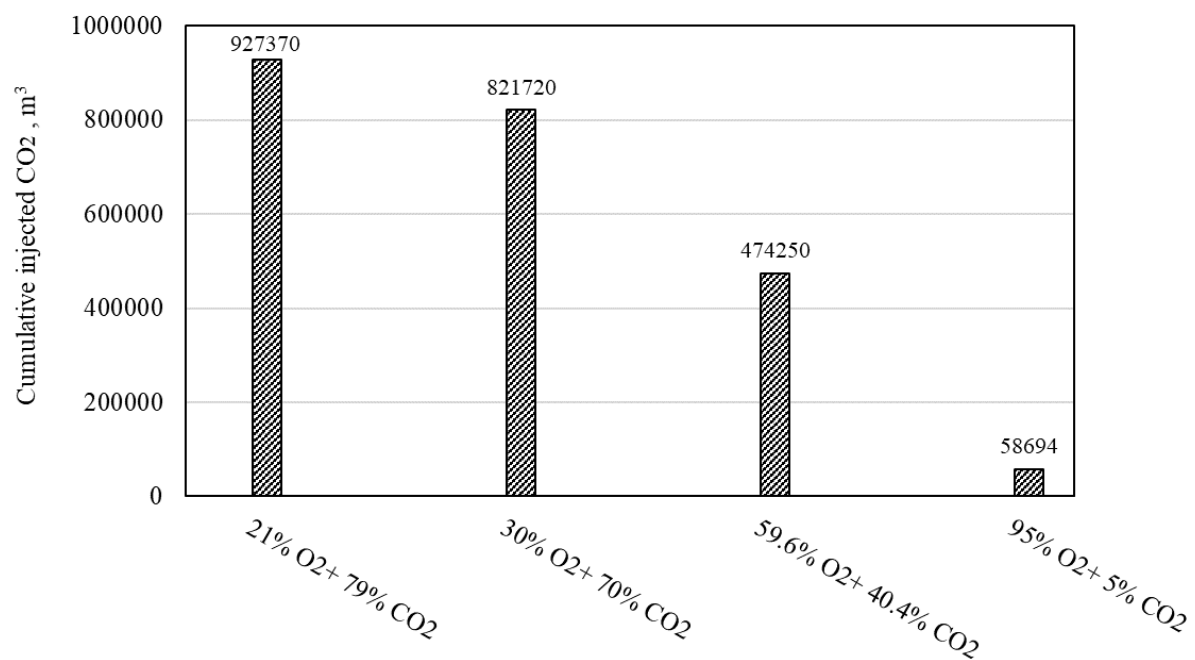


Figure 5. 19 Cumulative injected CO_2 in case of injection different ratios of O_2/CO_2 as oxidizer

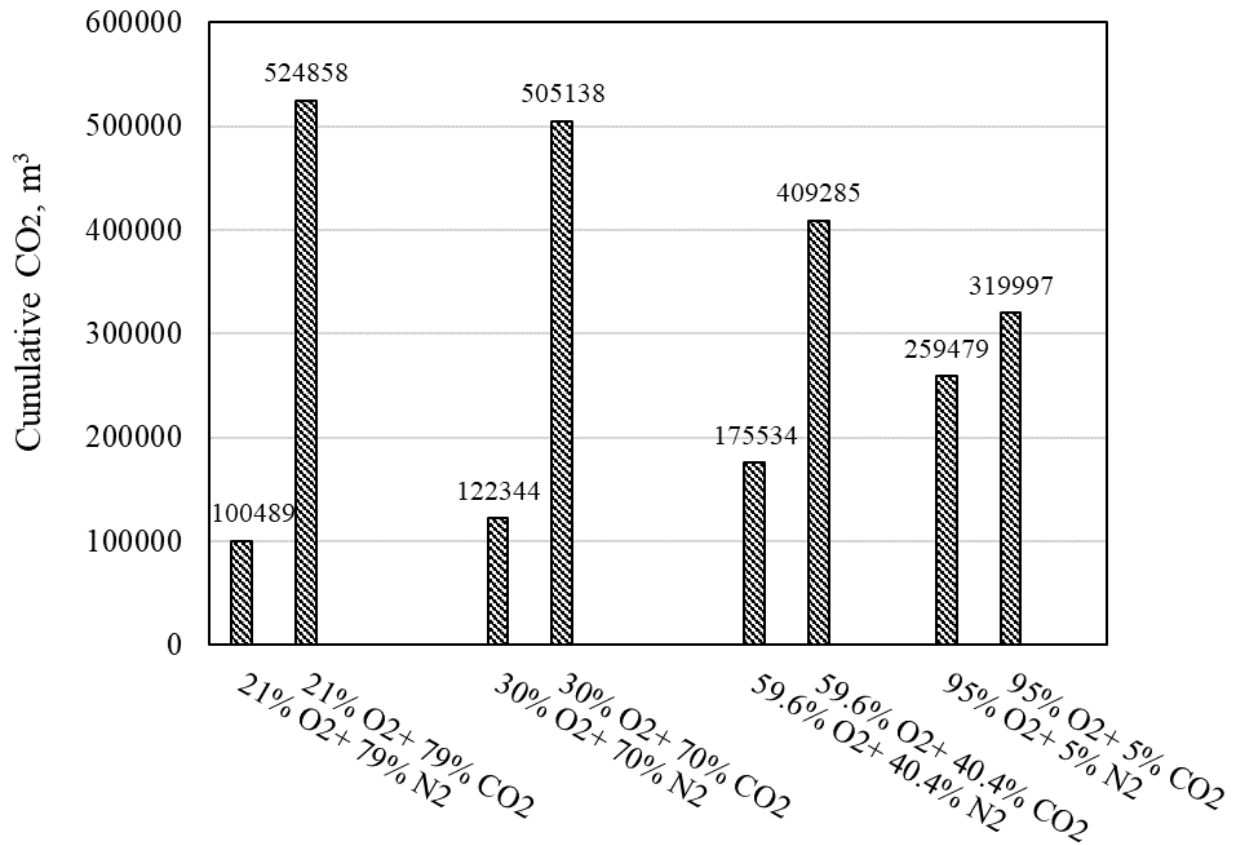


Figure 5. 20 Cumulative produced CO₂ at different ratios of O₂/N₂ and O₂/CO₂

5.3 SIZING OF ITM FOR ISC

In this part sizing the ITM for the described ISC process, in this chapter, is presented. ITM sizing can be done by calculating the required oxygen volume flowrate for the ISC process and the required area of the ITM, which can provide this volume flow rate of oxygen.

As mentioned before, there are two methods for producing oxygen, one is based on cryogenic technologies [173], and the other is based on ion transport membrane (ITM) technologies. Ion transport membrane (ITM) is considered as one of the latest technologies for separating oxygen from air due to its flexibility for different applications [174, 175]. Membrane reactors can be

used also for hydrogen production [176, 177]. One of the most important advantages of the ITM is the high purity of the produced oxygen in the permeate side of the membrane [178].

Based on our previous study in Chapter 3, The results show that increasing the vacuum in the sweeping side, directly, increases the permeation flux up to $5.503 \mu\text{mole}/\text{cm}^2\text{-s}$ for 0.99 bar vacuum, as shown in Figure 5.21. In comparison with the parallel configuration with carbon dioxide as a sweeping gas ($P_s=P_f=1\text{bar}$) $3.89 \mu\text{mole}/\text{cm}^2\text{-s}$, higher permeation flux is produced from the vacuum case with an increase of more than 41%.

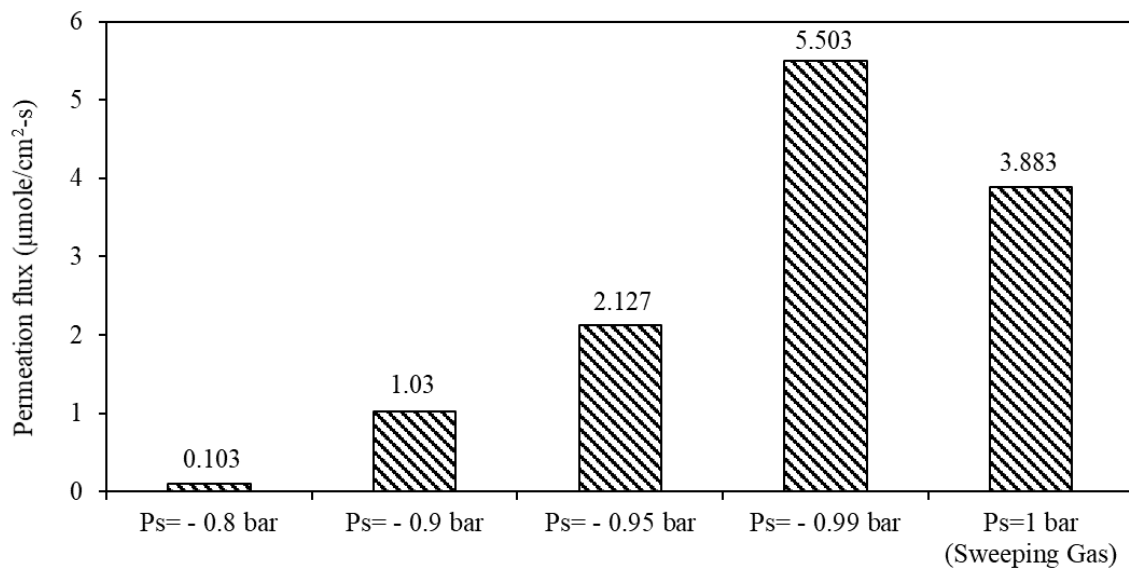


Figure 5. 21 Figure Average permeation fluxes for different sweep partial pressure configuration

To get the required volume flow rate of pure oxygen, vacuum in the sweeping side is preferred. Because using sweeping gas in the sweep side will produce a mixture of O_2/CO_2 with a very high concentration of CO_2 , which cannot be used for ISC process.

5.3.1 The Required ITM Area for the Described Problem

For the described base case of ISC process in this chapter (chapter 5), it was concluded that using O_2/CO_2 as oxidizer is better than using enriched air in terms of oil recovery. For the mentioned base case, the oxygen ratio in the oxidizer was around 59.6 %. The total oxygen

volume within this period was around 700000 m^3 , as shown in Figure 5.2. That means for around 120 days, the required volume flow rate is $5833 \text{ m}^3/\text{day}$ which is equivalent to 7.763 ton/day . The maximum permeation flux is $5.503 \mu\text{mole}/\text{cm}^2\text{-s}$ which is equivalent to $114.31 \text{ m}^3/\text{m}^2\text{-day}$. That means the required area **51 m^2** for one well.

The shape of the ITM modules may be such as the one produced by Air Products company as shown in Figure 5.22. The module in the figure is used with oxy combustion power generation system.

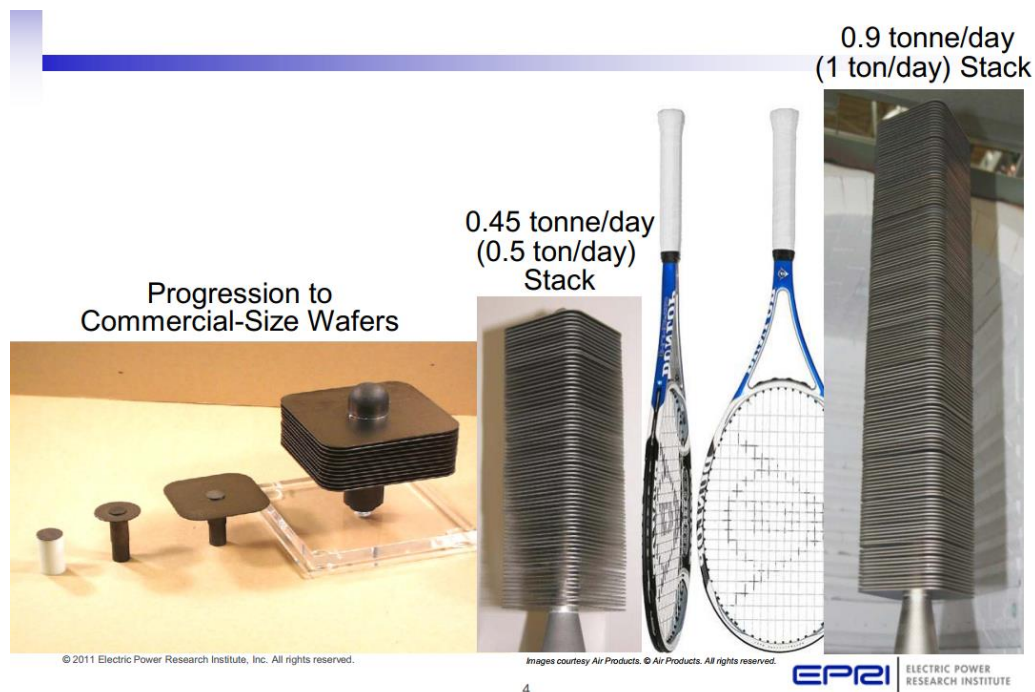


Figure 5. 22 ITM oxygen wafers and module scale up [231]

5.4 Summary of chapter 5

3D reservoir simulation has been conducted and validated against published practical field data. Co-injection of pure oxygen with carbon dioxide (CO_2); and co-injection of oxygen with nitrogen gas have been investigated by a numerical model for field scale. Increasing the oxygen ratio from 21% to 59.6 % leads to increasing the cumulative oil from 876.7 m^3 to 940.4 m^3 ,

respectively. Increasing the oxygen ratio to 95 % leads to increasing in the cumulative oil to a value of 991.5 m³. Increasing the oxygen ratio in, O₂/CO₂ mixture, from 21% to 30% leads to increasing the cumulative oil with from 886.7 m³ to 893.8 %, respectively. Increasing the oxygen ratio from 59.6% to 95 % leads to increasing in the cumulative oil from 949.2 m³ to 993.6 m³. Injecting a mixture of O₂/CO₂ gives better results, in terms of cumulative oil, than injecting enriched air, in addition to CO₂ sequestration. The area required from ITM to produce the required oxygen flow rate for the ISC process for one well has been calculated.

Due to safety issues such as overheating and pressure, the ISC could not be performed experimentally. But, as mentioned in the literature that ISC process is considered a combination of various EOR techniques such as gas injection, thermal recovery, steam drive, chemical reactions, and water flooding. So, In the next chapter, Thermochemicals flooding experiments will replace the ISC, as it has the same operating principle. ISC process and thermochemicals injection are considered an in-situ steam and gas generation process due to a chemical reaction.

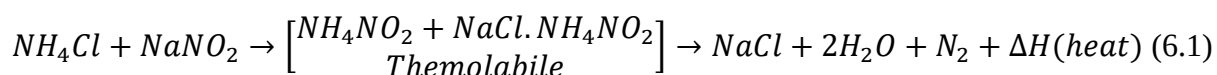
CHAPTER 6

EXPERIMENTAL STEAM AND THERMOCHEMICALS FLOODING

This chapter experimentally compared the performance of thermochemical fluid injection to that of steam for the recovery of heavy oil. The steam and thermochemicals injection experiments were carried out at King Fahd University of petroleum and Minerals (KFUPM). The experimental equipment, methodology and results are presented. Results are presented in terms of oil recovery factor, temperature and pressure.

6.1 Overview

The present experiments seek to investigate the thermal performances of the thermochemical reactants under different temperatures, compared with continuous steam injection method, with the aim of harnessing the technical potential of this technology for heavy oil recovery. Commercial production of heavy oil has heavily relied upon steam injection method due to its effectiveness to reduce the oil viscosity and improved the mobility. However, due to the uncertainties in the oil price, high energy cost, water requirement, heat loss, and environmental issues, attention is being given to new thermal EOR technologies such as in-situ steam generation using thermochemical fluid (TCF) injection. This technology essentially involves downhole generation of heat and pressure from an exothermal chemical reaction, according to equation 6.1.



In this investigation, thermochemical reactants were injected, at different temperatures (100, 50, and 30 °C), into Berea sandstone core samples saturated with heavy oil (18 %wt. /wt. asphaltene content and 11° API) and brine.

6.2 Experimental Apparatus and Procedure

The experimental equipment used for steam and thermochemicals injection process is located in King Fahd University of Petroleum and Minerals' labs. The setup is a one-dimensional cell used for studying the steam and thermochemicals injection process through the selected core. Fluid injection system injects steam or thermochemicals into the core, which is adjusted inside the holder and then the produced oil is collected in tubes, as shown in Figure 6.1.

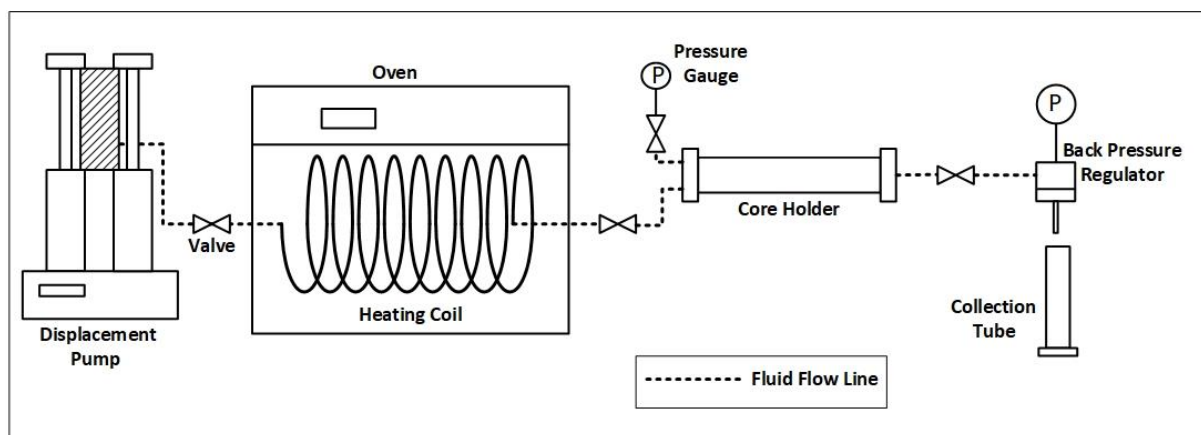


Figure 6. 1Schematic diagram for the main experiment setup

There are several steps and equipment which are used in the experiment, starting from preparing the core sample for saturation and ending with the flooding process and collecting the produced oil. All equipment used is shown below.

6.2.1 Core Heating Furnace

As a first step, a furnace is used for drying the cores by heating it up to 90 °C for 24 hours.

That is to remove the humidity from the core and make sure that it is dry, as shown in figure 4.6.



Figure 6. 2 Core Heating furnace

6.2.2 Water Saturation System

To saturate the core with water, vacuuming the core from air and gases is performed using a vacuum pump for one hour as shown in Figure 6.3-a. That is to make sure that the core does not contain any gases inside. After that, the weight of the dry core is recorded. The core is then saturated with water inside the core holder by injecting pressurized water (using positive displacement pump) to the core with pressure 25 bars for 24 hours. After that, the weight of the water-saturated core is recorded using a balance as shown in Figure 6.3-b. This is done to know the amount of water inside the core.



Figure 6. 3 Vacuum pump and core holder for water saturation process, b) balance for measuring the core mass

6.2.3 Oil Saturation System

Oil saturation is performed by displacing the water from the core by oil, using positive displacement pump through a transfer cell, as shown in Figure 6.4. Continuous injection of the oil to the core is done until no more water is produced at the outlet. This implies that the core is saturated with oil. The amount of displaced water is recorded. This is to know the water and oil saturations in the core.



Figure 6. 4 Oil saturation setup

6.2.4 Fluid Injection System

After that, steam or thermochemicals are injected to the core by passing through the oven for temperature control. At the end of the core holder, a backpressure unit is fixed to represent the actual backpressure as in the reservoir as shown in Figure 6.5. Then, waiting until the production process is started and recording the produced volume with time until the end of the experiment.



Figure 6.5 Steam or thermochemicals injection system

6.2.5 Piston Pump for Steam Production

Positive displacement pump with a continuous maximum flow rate of 60 ml/min, as shown in Figure 6.6. The distilled water source is a plastic tank of volume 4 liters. The volumetric flow rate can be controlled through the pump and then it is injected to the oven, to convert it to steam or used to push the thermochemicals.



Figure 6. 6 Positive displacement pump

6.2.6 Steam Generator

An oven is equipped with a temperature controller to generate steam at the required temperature, with maximum temperature of 250 °C, as shown in Figure 6.7. Inside the oven, there is a long stainless-steel coil with diameter 1 mm to make sure that all the injected water is converted to steam with the required temperature. This oven also is used to control temperature of the injected thermochemicals.



Figure 6. 7 Oven for steam generation

6.2.7 Core Holder System

The core holder is a stainless-steel tube with two flanges at the ends and lined with a rubber sleeve to control the overburden pressure, as shown in Figure 6.8. The core holder is used in the water saturation process, oil saturation and oil production process.

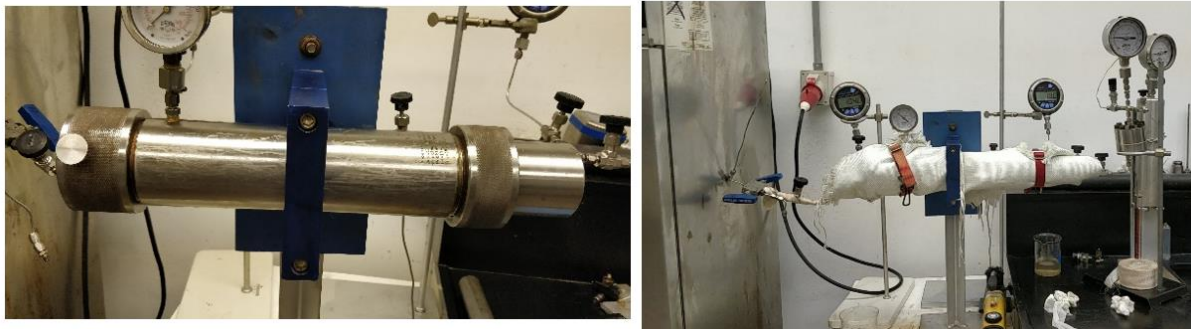


Figure 6. 8 Core holder system

6.2.8 Core Properties Measurements

The porosity and permeability of the core has been measured using helium porosimeter and gas permeameter respectively, as shown in Figure 6.9.



Figure 6. 9 a) Gas permeameter, b) Helium porosimeter

6.3 Material and Methodology

6.3.1 Materials

Heavy oil sample with 18 % weight fraction. C₇-soluble asphaltene content, 11° API, and 11.2 m/Nm IFT (Interfacial tension) at room temperature, was used in this study. The viscosity-temperature relationship of the sample as well as the C₁₀+ fractional composition supplied by Saudi Aramco is shown in Figures 6.10 and 6.11, respectively. Thermochemical solution, Berea sandstone core samples, whose properties are detailed in Table 6.1, were used in the core-flooding experiments.

Table 6. 1 Properties of the Core samples used in the experiment

S/N	System	Diameter (cm)	Length (cm)	Porosity	K(md)
1	Steam	3.79	15.11	19.95	119.56
2	TCF 100 °C	3.80	15.10	21.25	120.75
3	TCF 50 °C	3.80	15.11	20.41	121.43
4	TCF 30 °C	3.79	15.10	19.82	119.14

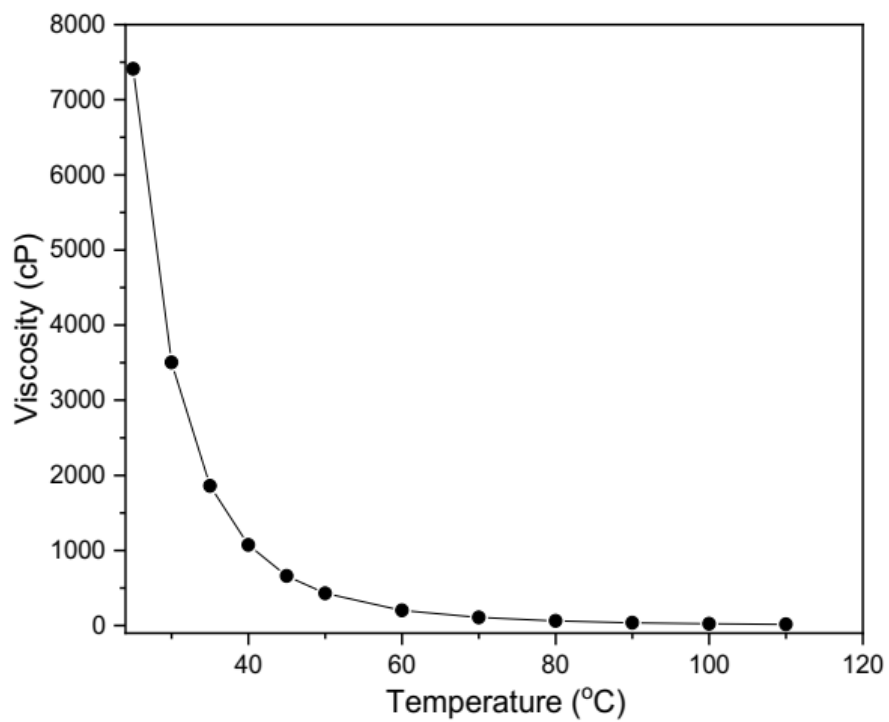


Figure 6. 10 Viscosity-temperature relationship of the heavy oil sample

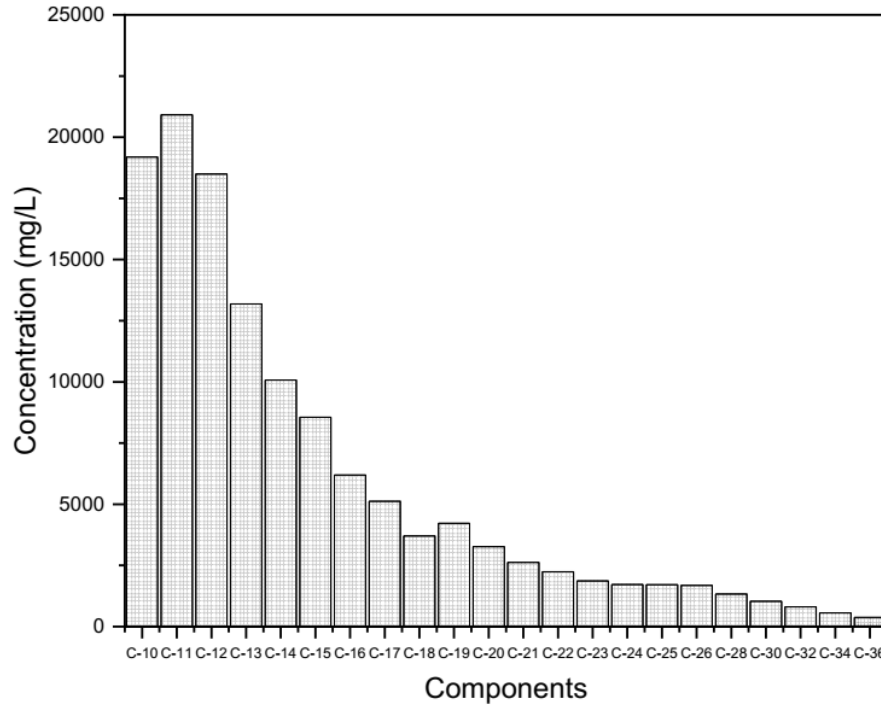


Figure 6. 11 Fractional composition of the heavy oil sample

6.3.2 Methodology

To carry out steam flooding or TCF experiment, several steps must be done for preparation and performing the experiment as outlined below:

- A heating furnace is used, first, for drying the cores by heating them up to 90 °C for 24 hours. That is to remove the humidity from the core and make sure that it is dry.
- The core is, then, placed in a cell and is vacuumed for one hour using a vacuum pump. As a result, air and gases are removed from the core. This is to make sure that the core does not contain any fluids inside it. After that, the weight of the dry core is recorded.
- Saturating the core with the water is done inside a core holder by pressurizing the core holder with water (using positive displacement pump). The core holder is pressurized to a pressure of 25 bars for 24 hours and the water inside. After that, the weight of the water-saturated core is recorded.

- Oil saturation is carried out by displacing the water from the core by oil, using the positive displacement pump through a transfer cell. The oil is injected to the core until the water is displaced by the oil, to the maximum possible extent (i.e., pure oil exits the core). That means the core is saturated with oil. Then, the amount of displaced water is recorded to know the water and oil saturation ratio of the core.
- After that, the steam injection process is carried out. Steam is injected into the core at a fixed flow rate until the production process starts.
- The produced oil volume with time is recorded until the end of the experiment.

6.3.2.1 Thermochemical Reaction

Series of batch experiments were performed in a close insulated reactor with equal volume of the reactants. When required, both the reactants and the reactor was heated separately to the desired temperature (50 and 100 °C). The set up includes high pressure and temperature cylindrical reactor, nitrogen gas cylinder for pressure control, heater and the temperature and pressure sensors interfaced with computer, as shown in Figure 6.12.

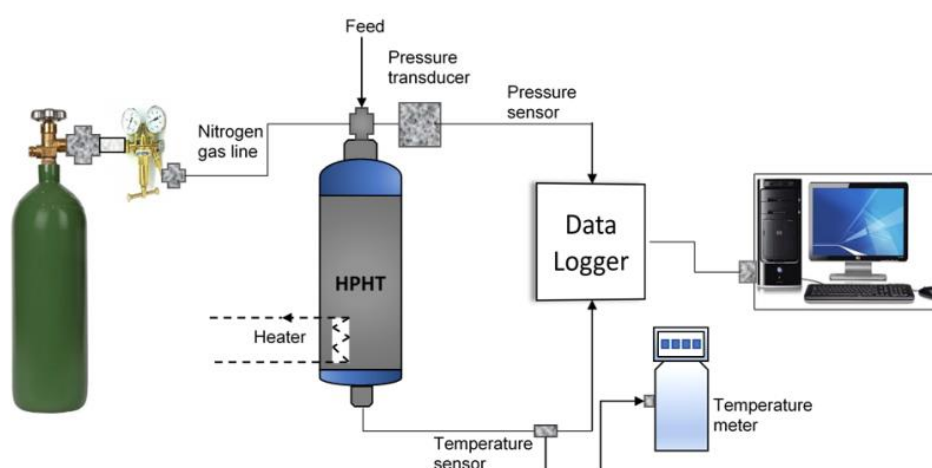


Figure 6. 12 Set up for measuring the Thermochemicals Thermal Reactivity

The progress of the system was followed by collecting data for increase in temperature and pressure at equal time interval. The effect of pH on the reactivity of the system was also studied using different grades of the stock solution of the reactants (pH 4.5, 5.8, and 8).

6.3.2.2 Flooding Experiments

Different core flooding experiments were performed to compare the performance of thermochemical fluid and continuous steam injection for the recovery of heavy oil. The setup is shown in Figure 6.13. After brine saturation (using 30000 ppm KCl), the core sample was saturated with heavy oil (preheated to 70 °C to improve the flow) at injection rate of 0.25 cm³/min and high overburden pressure. Then, it was allowed to age for 48 hours.

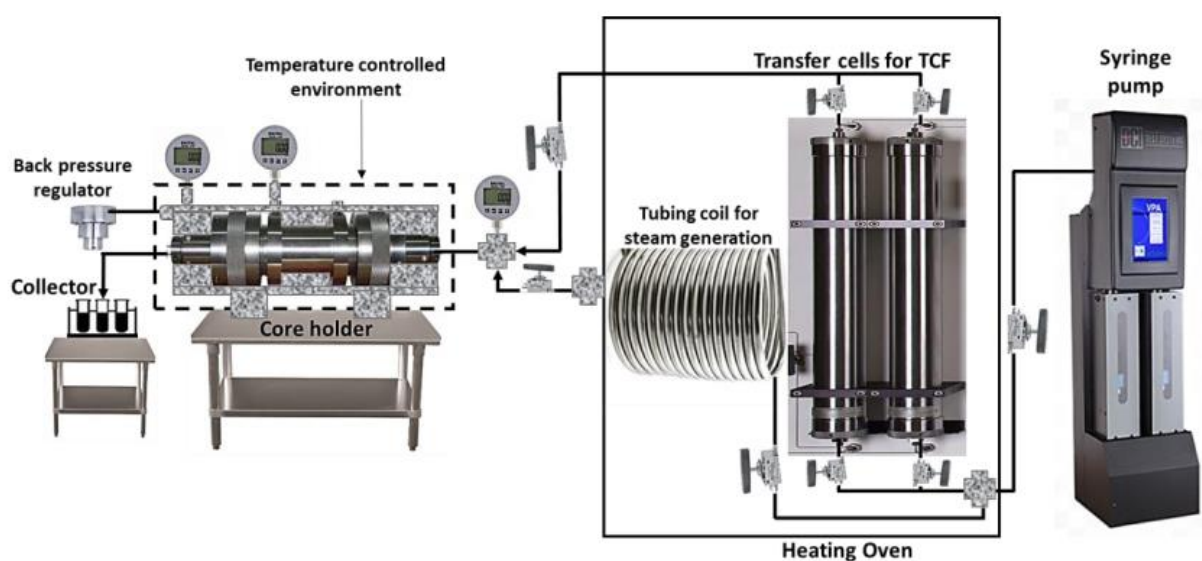


Figure 6. 13 Set-up for the steam and TCF flooding experiments

For steam injection method, steam was generated in the oven at 250 °C. Similarly, the chemicals were heated separately, to the desired temperature, in the transfer cells placed in the oven. Thus, four cases viz. (1) continuous steam injection (at 250 °C), (2) thermochemical fluid injection at 100 °C (TCF 100 °C), (3) thermochemical fluid injection at 50 °C (TCF 50 °C), and

(4) thermochemical fluid injection at 30 °C (TCF 30 °C) were considered. The fluids were injected via the transfer cell into the core under the overburden pressure, which was adjusted according to the injection pressure. The injection rate was 0.5 cm³/min with the backpressure maintained at 22 psi for each run. The system was well insulated to minimize heat loss during injection and production.

6.4 Results and Discussion

6.4.1 Thermal Performances and Reactivity

The purpose of this work is to provide basic information on the thermal performance of the reaction process. As stated in the methodology section, thermochemical fluid injection under different temperatures (30, 50, and 100 °C) was compared with steam injection. Typical fresh sample of the chemical, and the reacting sample are shown in Figure 6.14.

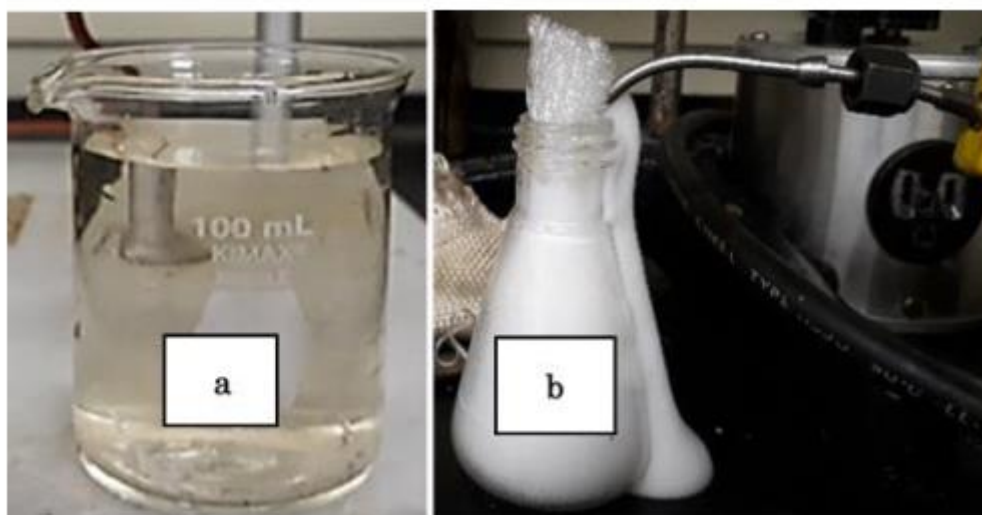


Figure 6. 14 (a) Fresh chemical (b) Reacting (foamy) sample

Figure 6.15 is the temperature and pressure profiles performance of the reaction under the three operating conditions (TCF 30C, TCF 50C, TCF 100C). The reaction started immediately with heat and pressure generation. It can be observed that the temperature increased to 89 °C, 116 °C, and 165 °C from 30 °C, 50 °C, and 100 °C, respectively. In addition, at the operating temperature of 30 °C, the pressure of the systems increased to 280 psi; while at the operating temperatures of 50 °C, and 100 °C, pressure spike was observed which reached 1200 psi and stabilized at 697 psi; and reached 1600 psi and stabilized at 1285 psi, respectively. The conversion was achieved after 750 secs, 480 secs, and 280 secs, respectively.

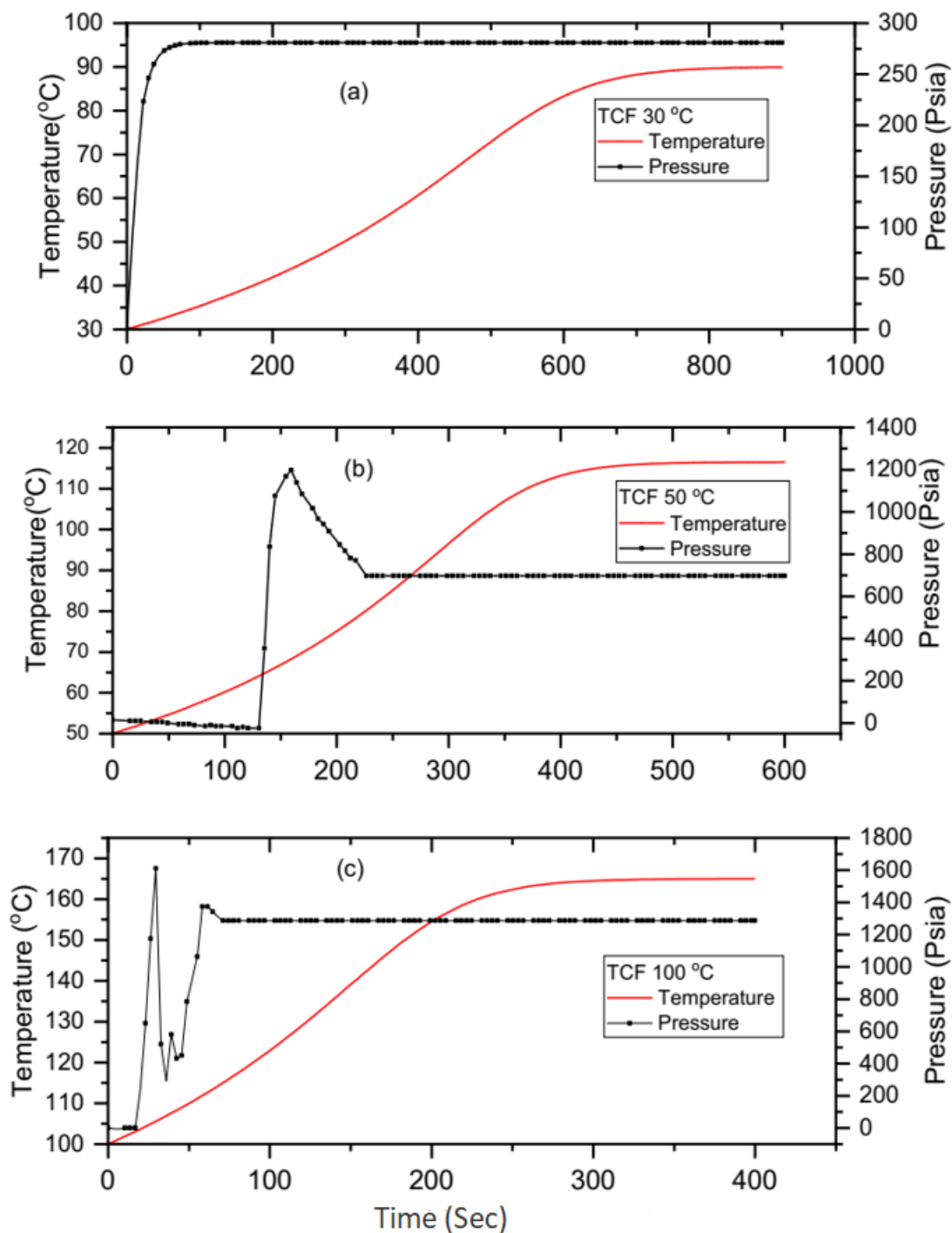


Figure 6. 15 Temperature and pressure profiles at the different operating temperatures

Furthermore, Figure 6.16 shows the performance of the system under different pH values using equimolar concentration of the reactants. The figure shows that the conversion was faster at lower pH (4.5 and 5.8) compared to pH 8. Both observations (Figures 6.15 and 6.16) are the

indications that the reaction rates and/or the overall performance can be controlled by the temperature and the pH depending on the conditions of the reservoir.

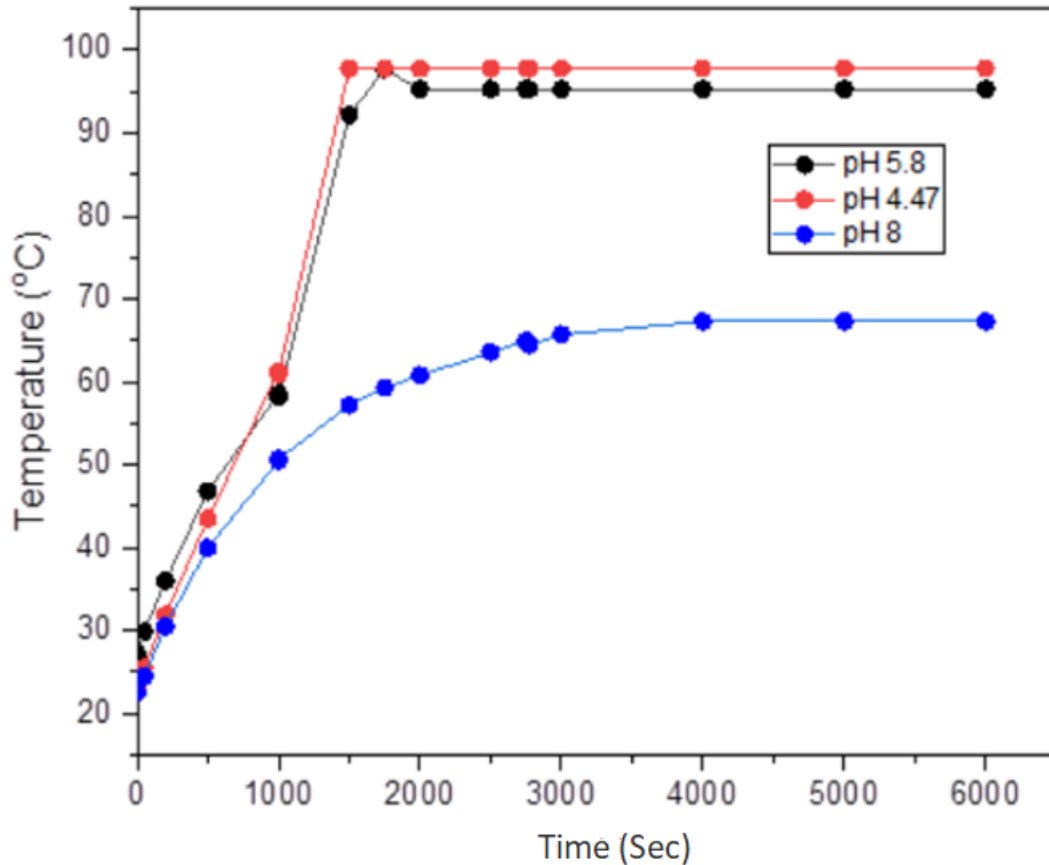


Figure 6. 16 Temperature profiles due to different pH

6.4.2 Heavy Oil Recovery

During the core flooding tests, the injection pressure and the oil recovery were monitored with time for the four cases that were investigated. The results of the experiments are presented in Figures 6.17 – 6.20. Figure 6.17 is the recovery from continuous steam injection. The pressure at the inlet of the core can be observed to vary between 212 psi and 170 psi during the recovery. The highest recovery is 71 % OOIP at 1.85 PV. In comparison, Figures 6.18, 6.19, and 6.20 are the profiles of heavy oil recovery from injection of thermochemical fluid at different

temperatures (100 °C, 50 °C, and 30 °C, respectively). From Figure 6.18, the inlet pressure was observed to spike to 1480 psi, which then decreased to lowest value of 450 psi. The highest recovery is 83% OOIP at 1.67 PV. On the other hand, the thermochemical fluids injection reached the highest inlet pressures of 533 psi and 294 psi at 50 °C and 30 °C, respectively, which decreased to 340 psi and 225 psi, lowest, respectively. The highest recovery from these systems are 66% (1.85 PV) and 54% (1.85 PV) OOIP, respectively. In comparison with lab scale ISC, it was found that in case of ISC with oxygen ratio 95%, the oil recovery factor was 89.23 %, which is higher than the oil recovery factor in case of (TCF 100 °C), which was 83%.

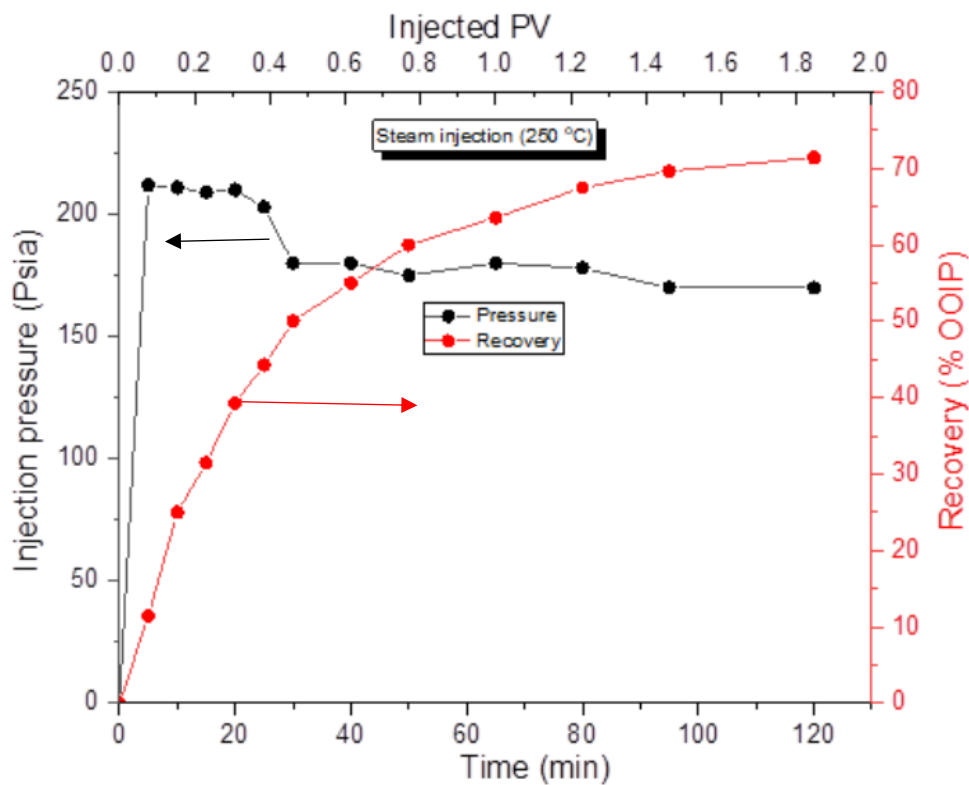


Figure 6. 17 Recovery performance from continuous steam injection

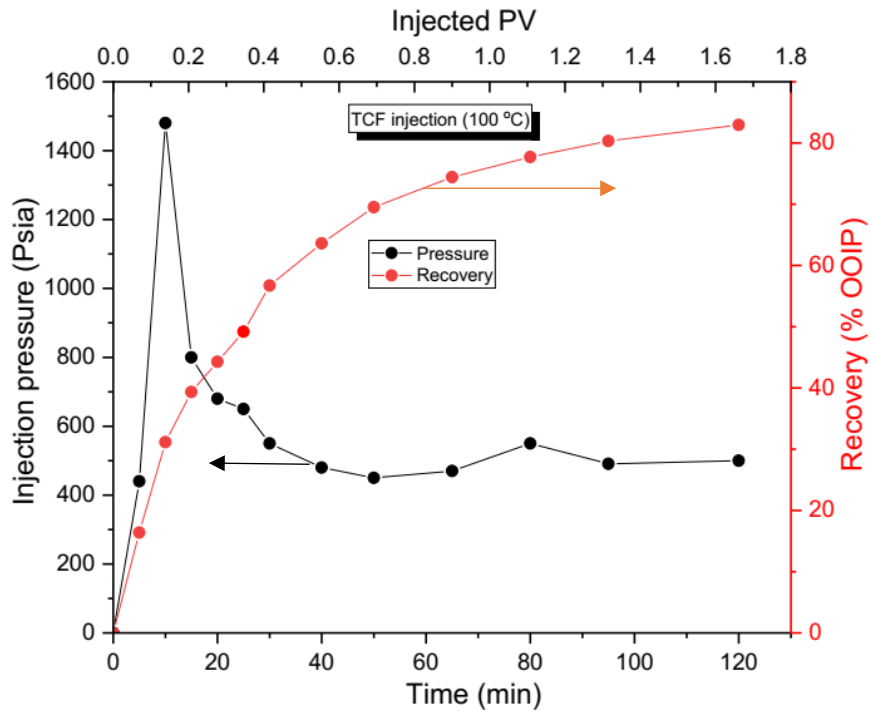


Figure 6. 18 Recovery performance from thermochemical fluid injection at 100 °C

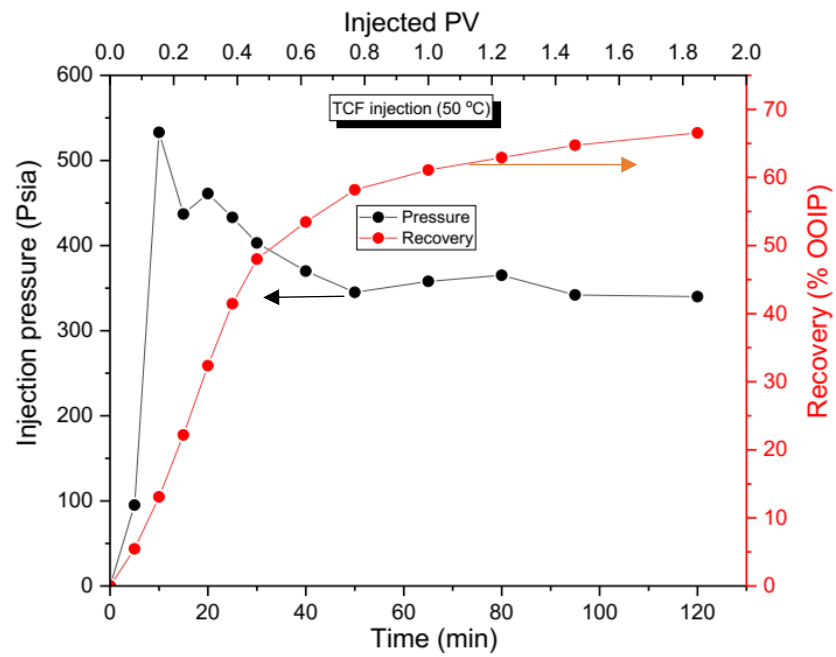


Figure 6. 19 Recovery performance from thermochemical fluid injection at 50 °C

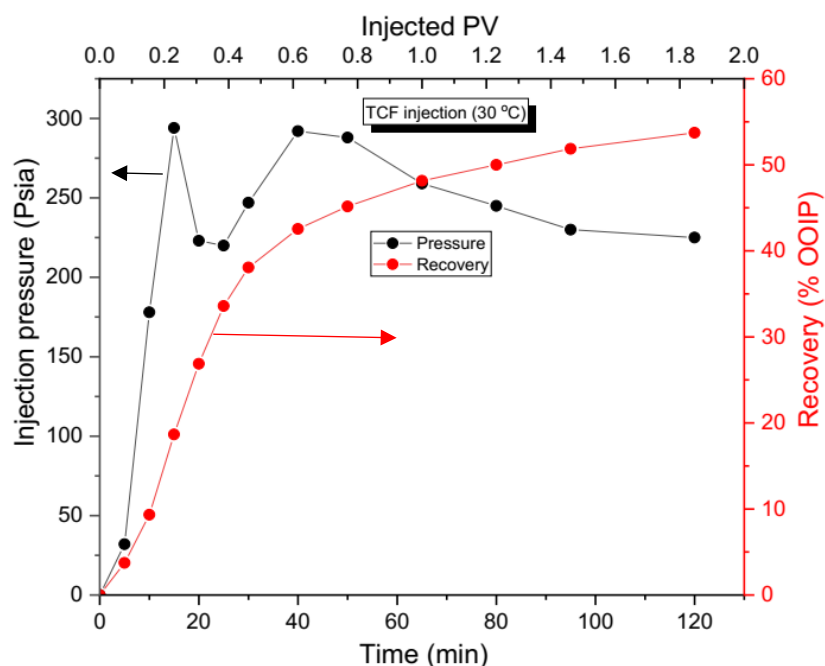


Figure 6. 20 Recovery performance from thermochemical fluid injection at 30 °C

Considering the present conditions of operation, the results clearly show that thermochemical injection at 100 °C performed better than that of the steam. In comparison, the performance of the thermochemical fluid at 50 °C was comparable to that of the steam. However, the performance of the thermochemical at 30 °C yielded the lowest recovery. As seen in Figure 6.15, both temperature and pressure were generated by the system. Thus, for the present case, the driving factors mainly include the increase in temperature, which decreases the viscosity of the heavy oil and increase the mobility. More so, the pressure also enhances further displacement of the fluid.

6.4.3 Thermochemical Reactions and Effect on Bitumen Sample

During the conventional steam injection method, heat is transferred from the hot steam to the cold bitumen in the reservoir. Not only that the steam reduces viscosity of the oil, usually, the particles of the steam penetrate the oil matrix at high temperature and is dispersed as water-in-

oil emulsion. In the present case, the scanned microscopic (SEM) images of the treated samples (B1 and B2) and original bitumen sample (B0) are compared in Figure 6.21. Apart from the suspended water particles observed in the samples B1 and B2, which is susceptible due to emulsification, it can be observed from the images that treatment with thermochemical reactants created conspicuous open cavities on the solid bitumen (B2). In addition, the elemental distribution (EDX) Map confirms the presence of other elements such as sodium and chlorine in the TCF treated sample [B2: elemental composition (wt.%): Carbon (77.7), Oxygen (10.8), Sulphur (4.9), Chlorine (4.8), Sodium (1.7)] compared to the steam-treated sample, B1 [B1: elemental composition (wt.%): Carbon (94.2), Sulphur (3.2), Oxygen (2.4), Copper (0.2)] and B0 [B0: elemental composition (wt.%): Carbon (93.7), Sulphur (4.3), Oxygen (1.9), Copper (0.1)], where those elements are absent. It can be clearly understood that the presence of sodium and chlorine in B2 emanated from deposition of brine due to the thermochemical reaction (see equation 6.1). In this case, the heat generated softens the matrix of the bitumen, which aided the swelling and penetration by the nitrogen gas (pressure), and the brine.

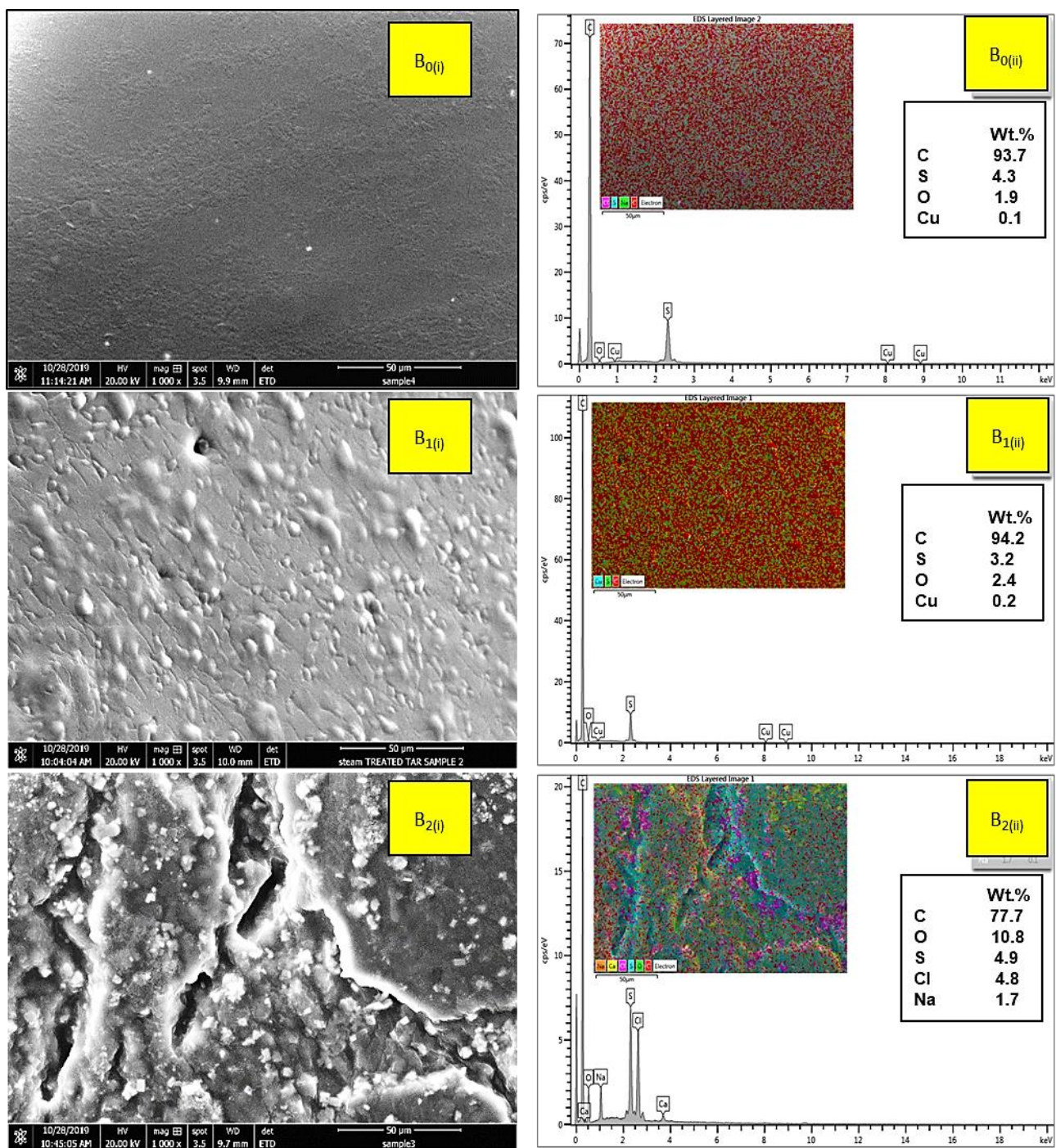


Figure 6. 21 The SEM-EDX images of the original bitumen sample (B0), Steam-treated sample (B1) and TCF-treated sample (B2). B0(i), B1(i), B2(i) are the electron images at 1000 X magnification and 50μm size. B0(ii), B1(ii), B2(ii) are the EDX layered Images and elemental distribution

6.5 Summary of Chapter 6

The main purpose of this chapter was to compare the performance of thermochemical fluid injection to that of steam for the recovery of heavy oil. Evaluation of thermal performance of the thermochemical reactants show that the temperature increased to 89 °C, 116 °C, and 165 °C from 30 °C, 50 °C, and 100 °C, with the pressure of 280 psia; 1200 psia and 1600 psia, respectively. Generally, the rate of reaction was observed to be affected by both operating temperature and the pH. The recovery from the thermochemical injection at 50 °C, and 30 °C yielded 66% and 54% OOIP, respectively. Moreover, the highest recovery of 83% OOIP was achieved from the thermochemical fluid injection at 100 °C, compared to 71% OOIP obtained from steam injection.

In the next chapter, a good idea is introduced, which is using Exhaust Gases in EOR instead getting rid of them. In this manner, 3D field scale numerical model is introduced for simulating this process and for CSS. The results are introduced in terms of oil recovery factor and amount of injected heat.

CHAPTER 7

ON THE USE OF STEAM AND EXHAUST GASES FOR HEAVY OIL RECOVERY IN A FIELD SCALE

In this chapter, a developed numerical model was applied to field scale in order to simulate Cyclic Steam Stimulation (CSS). The oil recovery by CSS is assessed over 10 years. Using exhaust gases in EOR is considered an idea to make use of the huge amount of exhaust gases. A mixture of water and carbon dioxide, representing exhaust gases from oxyfuel combustion, were injected as another approach. Two main configurations of wells were tested with all previous cases, vertical and horizontal wells. Comparison between the two configurations was done to select the best configuration in terms of oil production and injected gas flow rate.

7.1 The Numerical Model

A numerical model was developed to simulate CSS in the reservoir using CMG (Computer Modelling Group Ltd.) software [43]. Mathematical model for mass and energy conservation in addition to multiphase flow through porous media, governed by Darcy's law, is modeled in CMG. A brief outline of the governing equation modeled in the CMG software is given below.

i. Mass Conservation

The conservation of mass for each specie i which can exist in a number of phases π , is given in equation 1:

$$-\nabla \cdot \sum_{j=1}^{\pi} \rho_j u_j x_{ij} = \frac{\partial}{\partial t} \sum_{j=1}^{\pi} \rho_j \phi_f S_{j,i} x_{ij} - \sum_{j=1}^{\pi} \theta_{ij} \quad (7.1)$$

Where:

$\sum_{j=1}^{\pi} \rho_j u_j x_{ij}$ term represents the mass flux for specie i that is in j phase.

$\sum_{j=1}^{\pi} \rho_j \varphi_f S_j x_{ij}$ term represents the accumulation of specie i that is in j phase.

φ_f is the fluid porosity, which is the fraction of total pore volume that is occupied by fluids.

$\sum_{j=1}^{\pi} \theta_{ij}$ is the rate of mass production for specie i that is in j phase.

S_j represents the saturation of phase j

x_{ij} represents the mole fraction of specie i that is in j phase

ii. Conservation of Energy

The conservation of energy for the flow through the porous media and the chemical reaction process is governed by the equation,

$$\begin{aligned} \frac{\partial}{\partial t} [\sum_{j=1}^{\pi} \varphi_f \rho_j S_j U_j + (1 - \varphi_v) U_r + \varphi_v C_s U_s] = \nabla \cdot (\lambda \nabla T) - \nabla \cdot \sum_{j=1}^{\pi} \rho_j h_j u_j \\ + \sum_{j=1}^{\pi} \rho_j h_j u_j + \sum_{j=1}^{\pi} \theta_j h_j^* + q_{hc} \end{aligned} \quad (7.2)$$

Where:

$\nabla \cdot \sum_{j=1}^{\pi} \rho_j h_j u_j$ term represents the convection heat transfer and h_j is the enthalpy of phase j .

$\nabla \cdot (\lambda \nabla T)$ term represents conduction heat transfer, where the thermal conductivity is represented by λ

$\sum_{j=1}^{\pi} \theta_j h_j^*$ term represents the heat source/sink, and the enthalpy for injection/production of phase j is represented by h_j^* , θ_j is the mass production rate per unit volume.

q_{hc} represents the heat losses.

iii. Darcy's Law

For multiphase flow in porous media, the relation between pressure and velocity is given by Darcy's law.

$$v_j = \frac{-K k_{rj}}{\mu_j} \nabla (\varphi_j) \quad (7.3)$$

In the equation above, the subscript j represents the phase which could be oil, water or gas. v_j refers to the velocity, μ represents the viscosity of the fluid, K represents absolute permeability while, k_r represents the relative permeability. The phase potential gradient ($\nabla \varphi_j$) can be written as $\nabla \varphi_j = (p_j - \rho_j g l)$ where p is the pressure of the fluid, ρ is the density of the fluid, g and l are, the gravitational acceleration and the depth of the block, which is measured from a reference datum, respectively.

7.1.1 Geometry and Numerical Mesh Generation.

A 3D numerical model using CMG software has been developed for steam injection for field scale. The reservoir and oil properties have been taken from Kapadia et al. [223], for heavy oil production as shown in Table 7.1. The numerical model has been created to be used for studying the effective parameters to optimize the oil production performance for CSS within 10 years. The cycle contains 15 days injection then 3 days soaking followed by 8 days of production.

Table 7. 1 Simulator input parameters [223]

Input Parameter	Value
Reservoir Initial Pressure, kpa	2000
Reservoir Temperature, °C	15
Porosity	27%
Average Horizontal Permeability, mD	1836
Average Vertical Permeability, mD	982
Average oil saturation	55 %
Average water saturation	38 %
Rock heat capacity, J/m ³ C	2.6×10 ⁶
Rock thermal conductivity, J/m day C	6.6×10 ⁵
Water phase thermal conductivity, J/m day C	5.35×10 ⁴
Oil phase thermal conductivity, J/m day C	1.15×10 ⁴
Gas phase thermal conductivity, J/m day C	5.0×10 ³

The 3D simulated reservoir model has been created with a dimension of (50×8m)× (50×8m) ×(8×10m). Two different well configurations have been introduced in this study with different cyclic injection fluids. The first configuration is two vertical injection wells and one vertical production well between them. The second configuration is one horizontal injection well and one horizontal production well as shown in Figure 7.1. A comparison has been conducted between the two configurations in terms of cumulative oil and oil recovery factor.

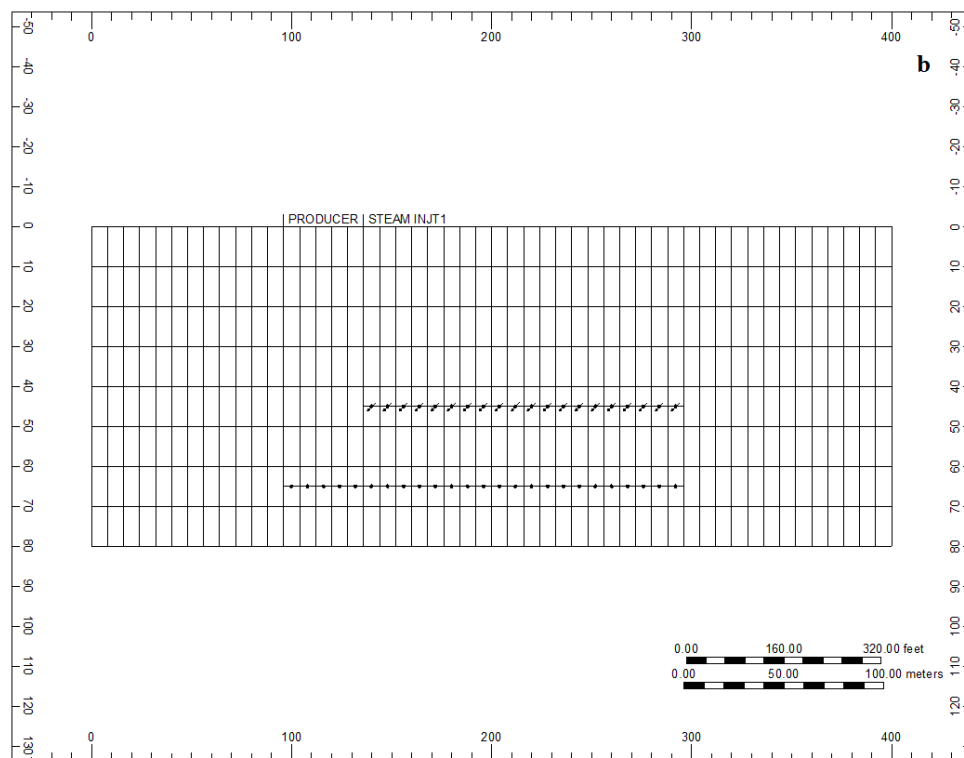
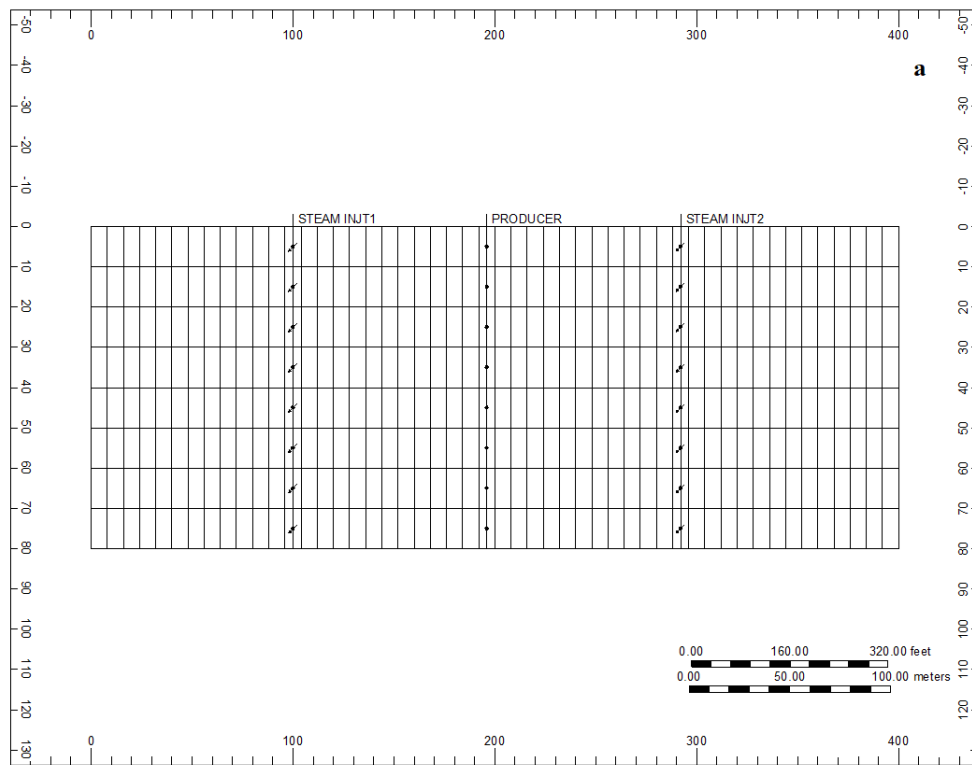


Figure 7. 1 Two main well configurations a) vertical wells b) horizontal wells

7.2 Results and Discussion

Numerical studies have been carried out to investigate and simulate CSS and Exhaust gases for EOR, considering parametric study for improving the oil recovery. The results of the study are included as below.

7.2.1 Two Vertical Injection Wells Configuration for CSS.

Results from the field scale simulation show that steam injection temperature has low effect on the oil recovery process. There is a very small change in cumulative oil production and oil recovery factor. The maximum oil recovery factor is occurred at temperature of 250 °C for the same steam quality 0.9. The change of the oil recovery factor between injection temperatures 150 and 250 °C is around 2.4 % as shown in Figure 7.2, and this value is considered small for a period of 10 years of CSS.

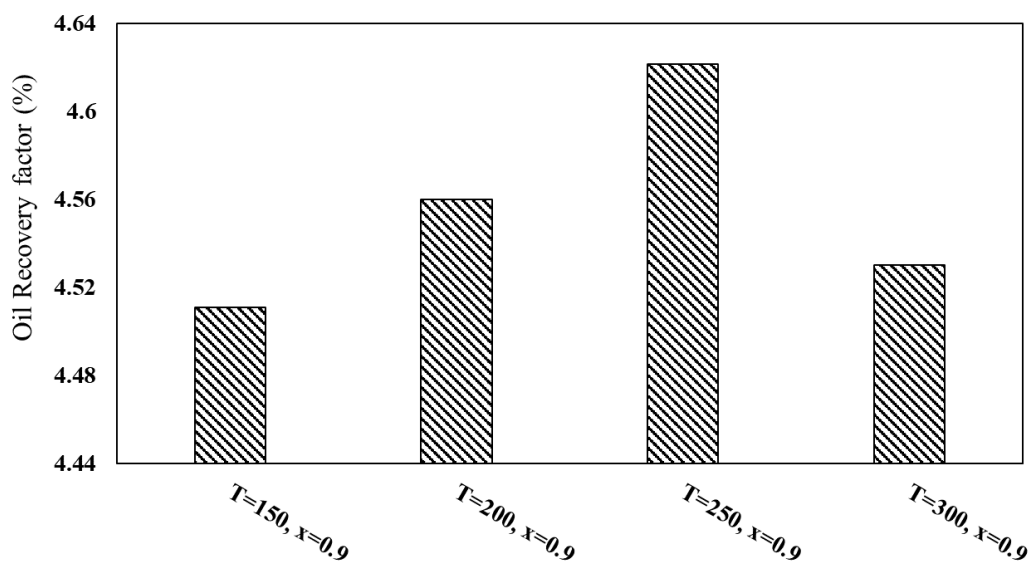


Figure 7. 2 Oil recovery factor for different steam injection temperature with fixed quality 0.9

Steam quality has a significant effect on the oil recovery process due to the higher heat content. Figure 7.3-a indicates the change of the cumulative oil due to change in steam quality from 0.5 to 0.9 at temperature of 200 °C. The cumulative oil production increases by 47.4 % when steam

quality is changed from 0.5 to 0.9, and the oil recovery factor increased from 3.1 to 4.55 % as shown in Figure 7.3-b.

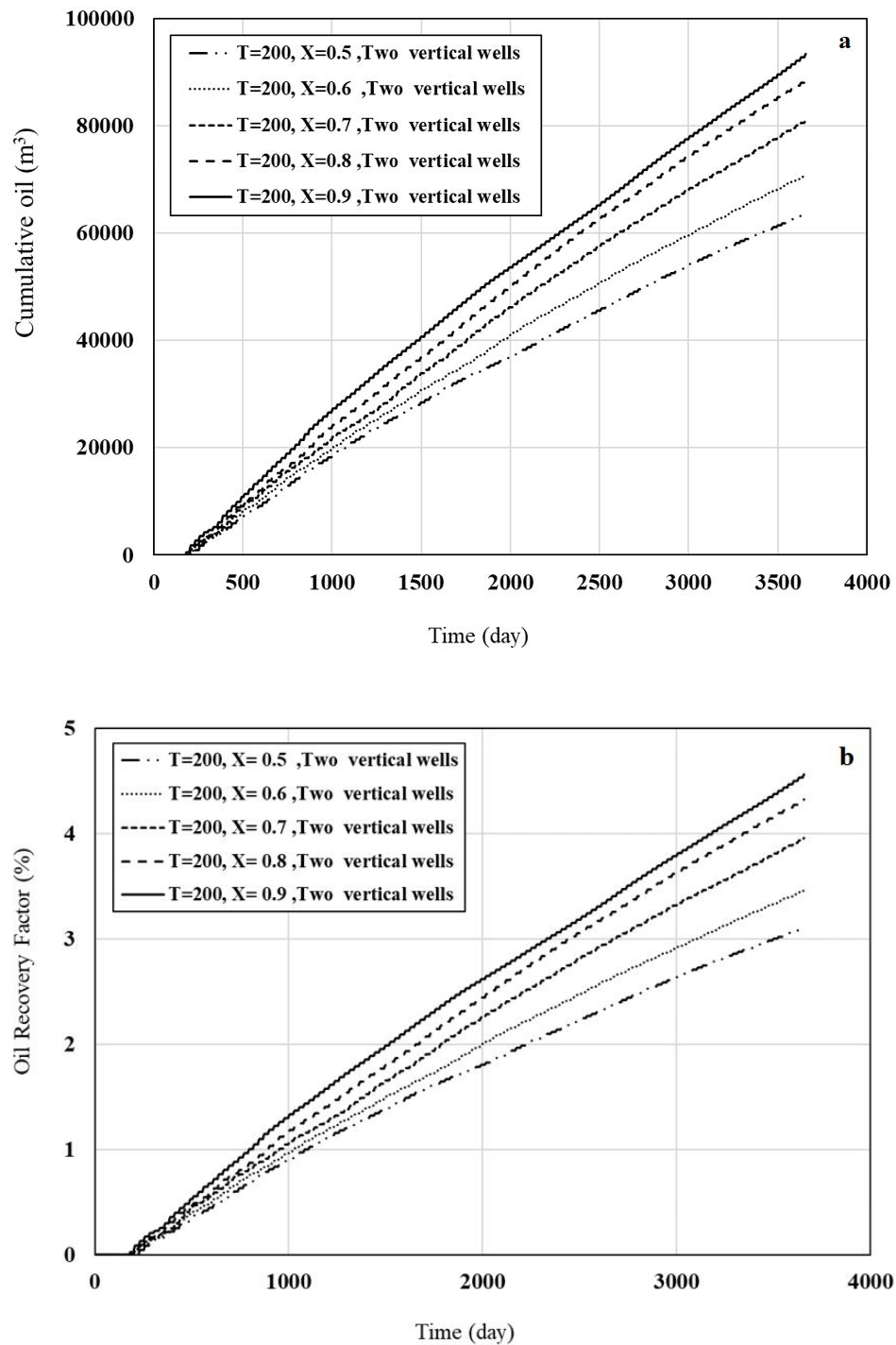


Figure 7. 3 Effect of steam quality on a) Field cumulative oil, b) Field oil recovery factor, for vertical wells

Figure 7.4 illustrates the oil saturation in the cross section of the vertical wells after 15, 100, 1000, 3657 days. After 15 days of cyclic steam injection, there is a small effect of the injected steam on the oil saturation. After 100 days, as the steam continues to diffuse in the reservoir, the oil saturation decreases near the injection wells due to displacement of the low viscous oil by the steam. After 1000 days up to the end of the 10-year period, the oil saturation continues to decrease due to displacement by the volume of steam/water. Figure 7.5 indicates the sequence of the oil viscosity change with time. The same period used for presenting the oil saturation was used for presenting the oil viscosity. As shown from the figure, the oil viscosity decreases with time, and that is due to injection of heat from the steam.

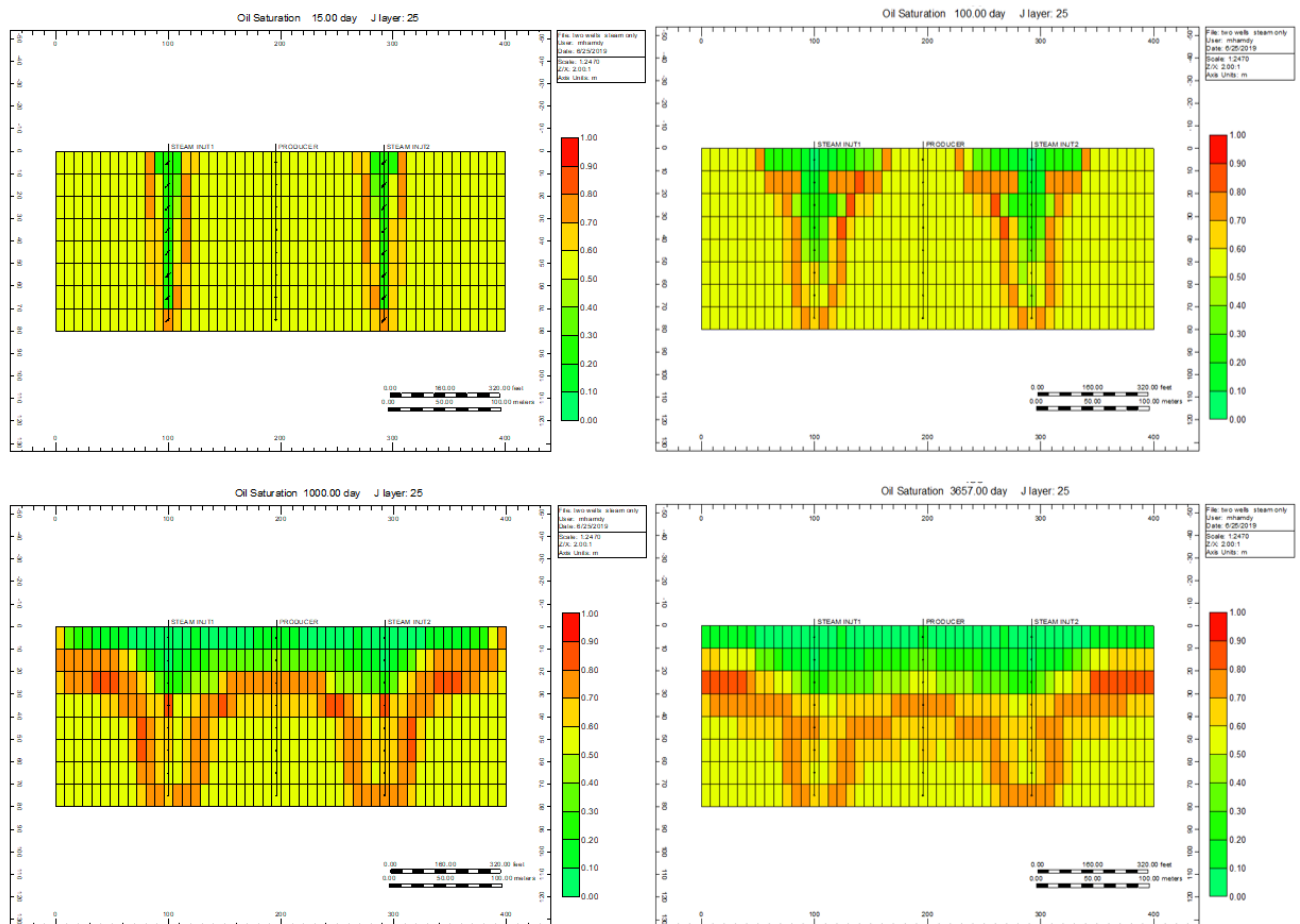


Figure 7. 4 Change of the field oil saturation at the vertical wells cross section after 15, 100, 1000, 3657 days

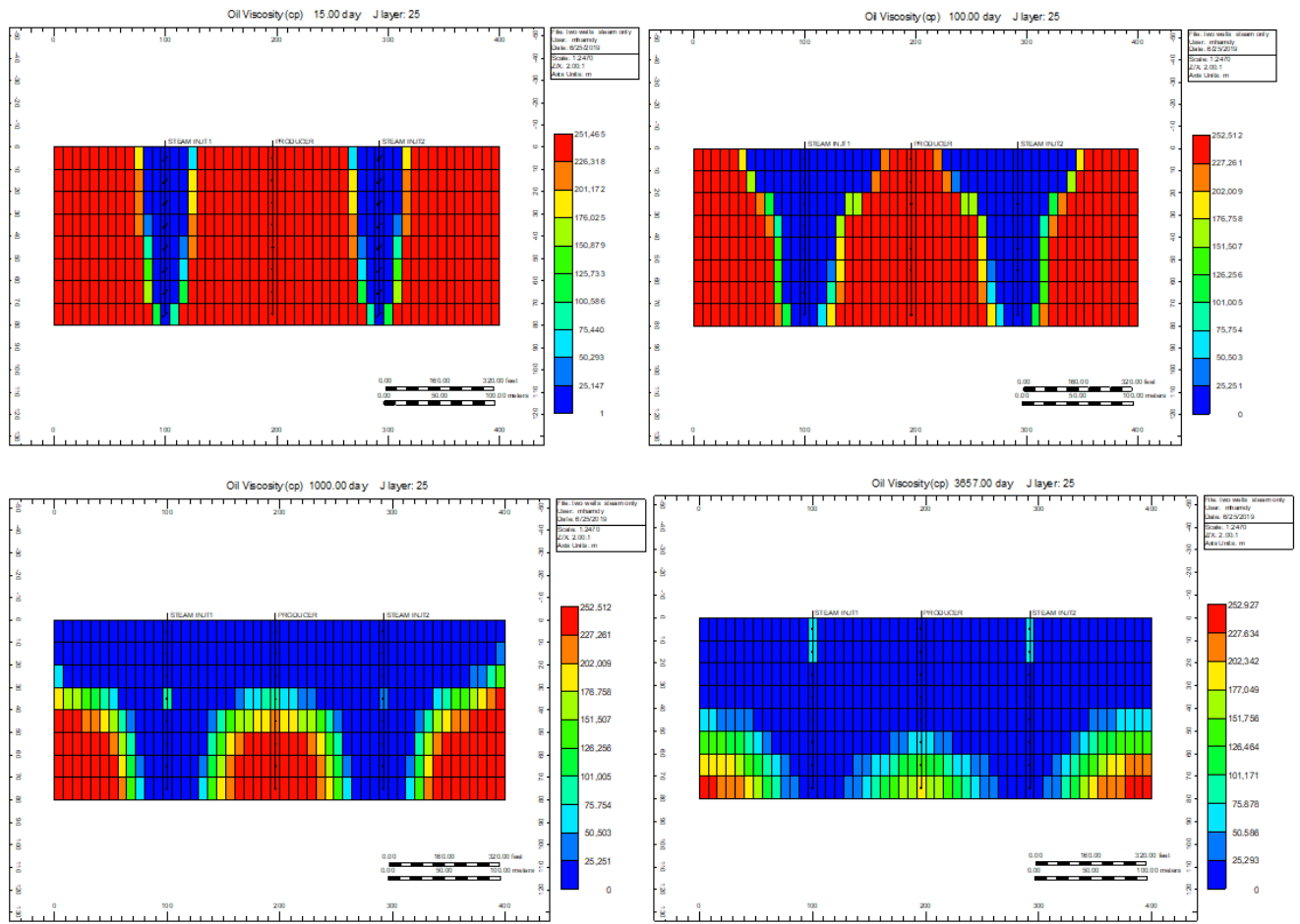


Figure 7. 5 Change of the field oil viscosity at the vertical wells cross section after 15, 100, 1000, 3657 days

7.2.2 One Horizontal Injection Well Configuration for CSS

One horizontal injection well and one production well has been tested instead of the vertical ones for the same period of CSS (10 years). In comparison with the vertical configuration, the horizontal wells give higher production of oil by 65 %, despite injecting half the volume of steam, as it has one injection well. Therefore, in terms of economics, the horizontal wells have much better performance in terms of oil production and steam injection than the vertical wells. This means that it is recommended to use the horizontal wells rather than vertical wells for steam injection process.

The horizontal wells give better performance than the vertical due to the gravity, because in this configuration the injection well is located above the production well, so the gravity facilitates oil drain down in the direction of the production well. The same idea as in the case of Steam Assisted Gravity Drainage (SAGD).

As reported before, the steam injection temperature has low effect on the production process for vertical or horizontal wells. Only 4% change in cumulative oil from temperature 150 to 250 °C, and as a result small change in the oil recovery factor. This ratio is considered small for CSS process carried out for 10 years. But for steam quality, it gives much higher change in terms of oil production, which reached to 89 % for change of quality from 0.5 to 0.9 at 200°C as shown in Figure 7.6-a, resulting in higher increase in oil recovery factor as shown in Figure 7.6-b. This change is considered highly effective in terms of oil production performance.

Figure 7.7 shows the oil saturation in the cross section of the horizontal wells after 15, 100, 1000, 3657 days. As shown, from the figure, with increase in time from 15 days to the end of the period, the oil saturation near the horizontal injection well is decreasing as expected. At the end of 3657 days a significant amount of oil above the horizontal injection well has been drained through the horizontal production well, as evident from the decrease of oil saturation levels. As mentioned before this is due to displacement of the low viscous oil by the steam in direction of the production well. Figure 7. 8 shows the sequence of the oil viscosity change with time. The viscosity of oil around the wells decreases with time, and that is due to injection of heat via the steam. At day 100, the viscosity of the oil above the injection well is reduced much more than that of the oil below the well, suggesting that the heat from the steam is mostly transferred to the oil above the injection well. By comparing the contours in case of vertical and horizontal wells, the figures indicate that the horizontal wells give better performance than

the vertical wells in terms of oil saturation and viscosity, which could be translated into higher production rate.

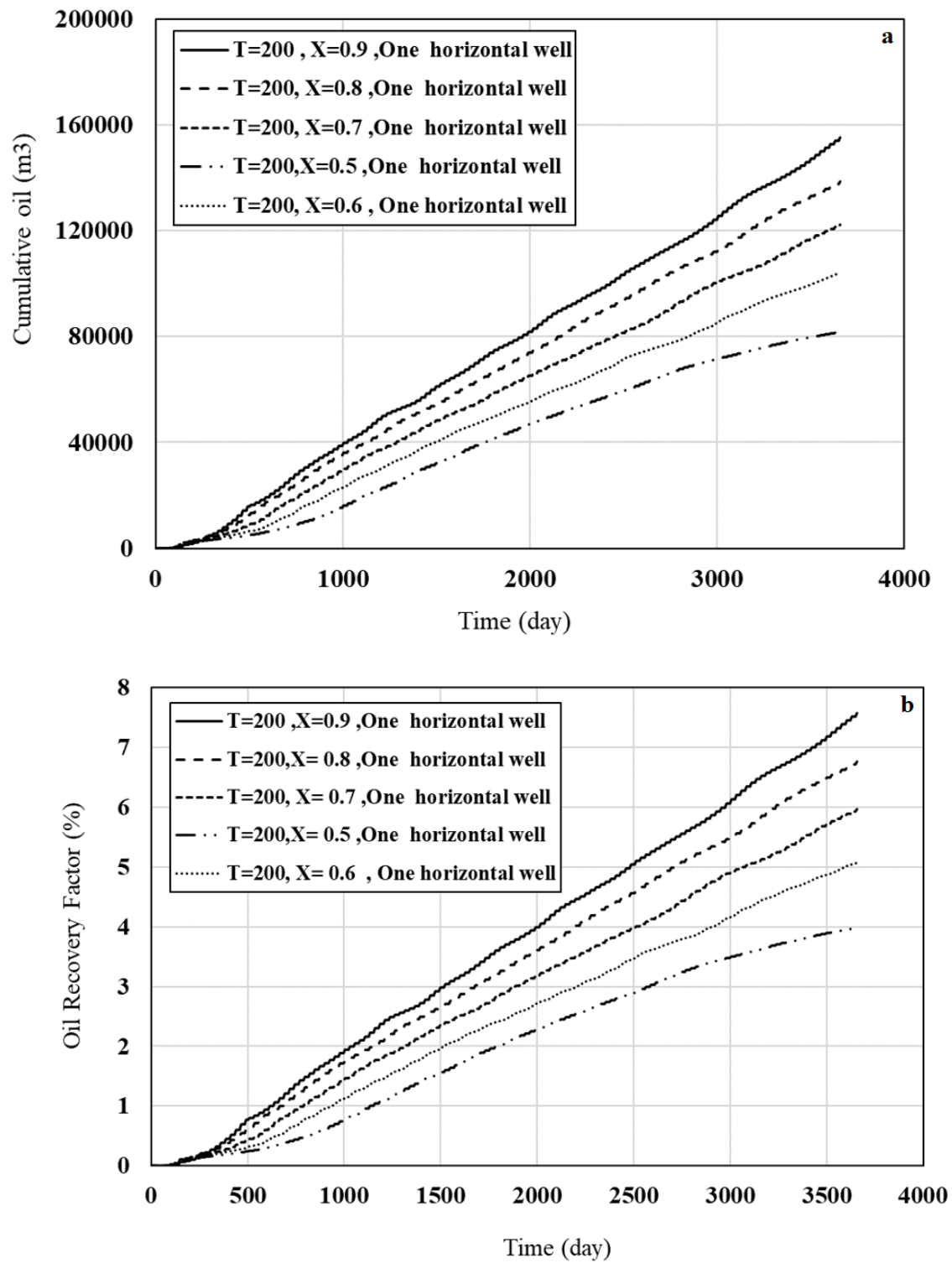


Figure 7. 6 Effect of steam quality on a) Field cumulative oil, b) Field oil recovery factor, for horizontal wells

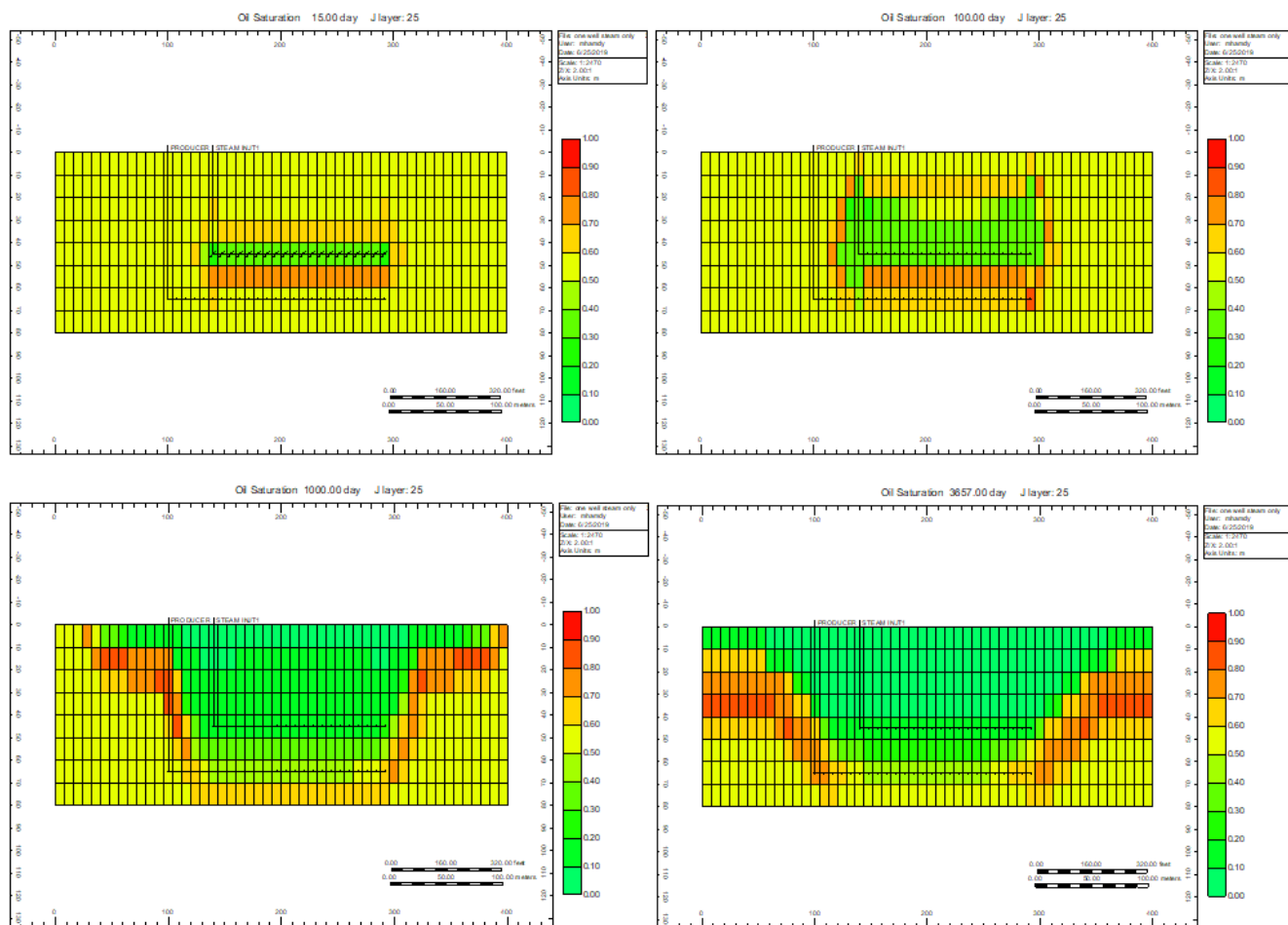


Figure 7. 7 Change of the field oil saturation at the horizontal wells cross section after 15, 100, 1000, 3657 days

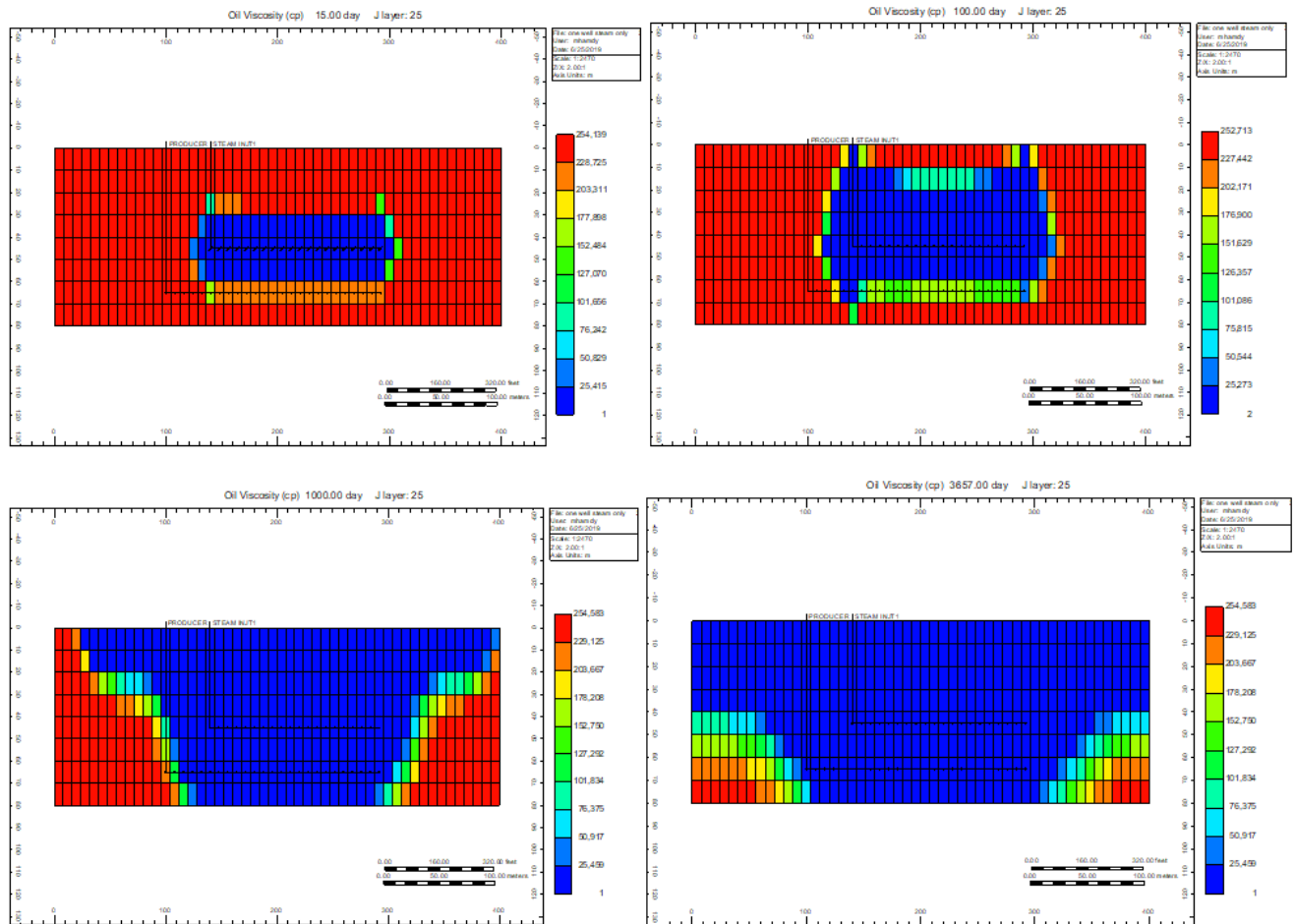


Figure 7. 8 Change of the field oil viscosity at the horizontal wells cross section after 15, 100, 1000, 3657 days

7.2.3 Comparison between One Horizontal and Two Vertical Injection Wells

For comparison between vertical and horizontal well in CSS process for 10 years, it was found that the horizontal wells give much higher performance rather than vertical wells. From this study, in addition to saving half of the injected steam, the producing oil increased from 93278 m³ to 154050 m³ at temperature 200 °C and steam quality 0.9. That means, the oil production increased by 65 % in case of using one horizontal injection well rather than two vertical injection wells as shown in Figure 7.9-a. The oil recovery factor for this reservoir increased from 4.56 to 7.57 % in case of horizontal wells rather than vertical wells as shown in Figure

7.9-b. This clearly shows that using the horizontal wells is much better than using the vertical wells in CSS for EOR.

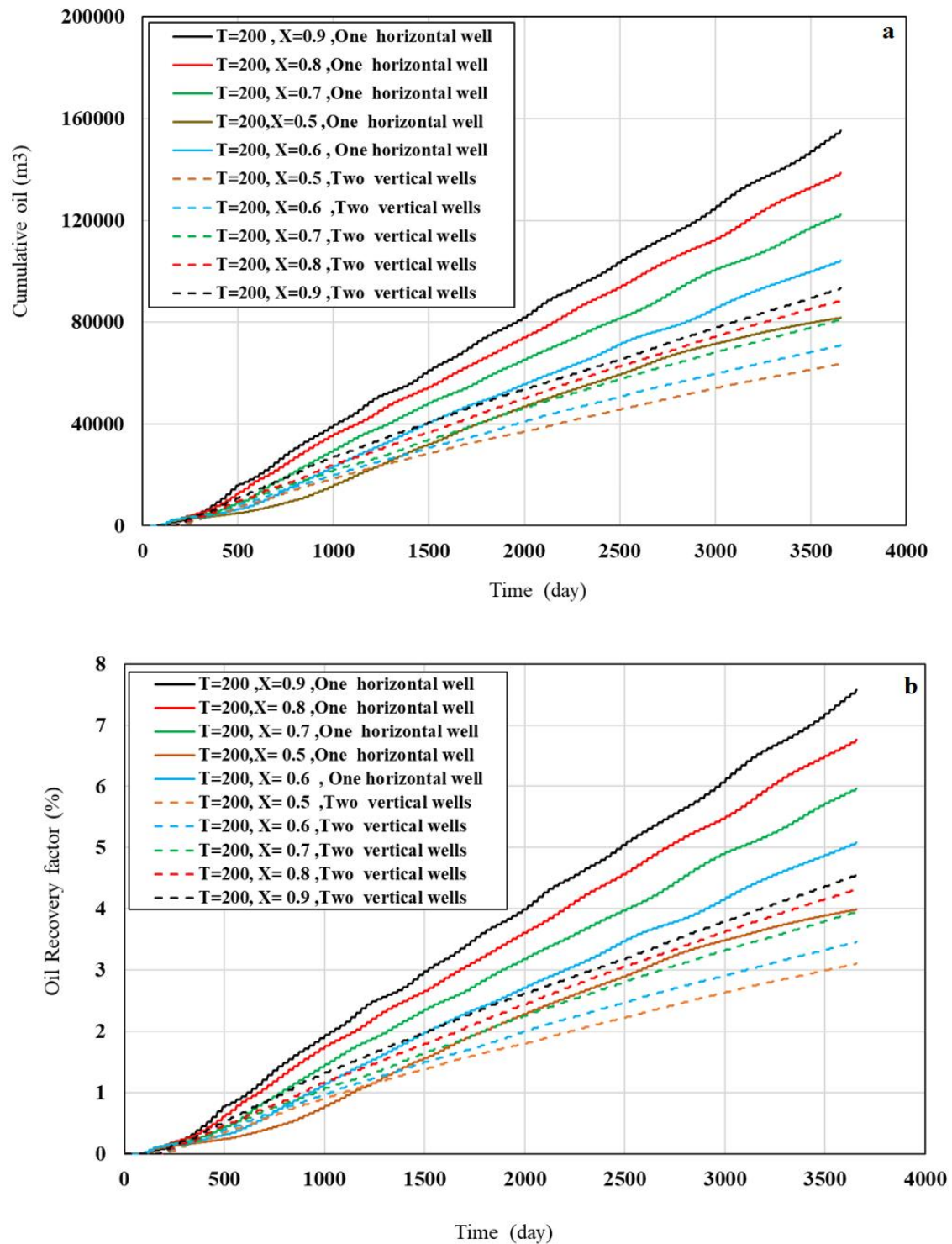


Figure 7. 9 Comparison between vertical and horizontal wells at the same temperature and different qualities in terms of a) Cumulative oil recovery b) Oil recovery factor, for CSS

7.2.4 Exhaust Gases Injection for Two Vertical and One Horizontal

Injection Wells

The exhaust gases from oxy-combustion processes such as in gas turbines and other applications are almost carbon dioxide and water as shown in the methane combustion equation 7.4. In this step, the effect of injecting these exhaust gases to the reservoir, as a method of enhanced oil recovery, will be studied on the same previous reservoir.



The output is one mole of carbon dioxide and two moles of water. This ratio will be injected to the reservoir with certain flow rate. Cyclic injection process for 10 years will be simulated using the numerical model, developed using CMG software. The same previous configurations of vertical and horizontal wells will be investigated.

Using the horizontal wells for exhaust gas injection gives better results such as in CSS as reported before. In case of exhaust gases injection, the difference in the oil production between the vertical and horizontal is very high as shown in Figure 7.10-a. The maximum oil recovery factor raised from 3.11 to 5.583 % when using horizontal well rather than vertical wells, while using of half of the injected exhaust gases as shown in Figure 7.10-b.

Figures 7.11 and 7.12 indicate the change of the field oil saturation and viscosity in case of using vertical wells along the cross section after 15, 100, 1000, 3657 days, for the case of exhaust gases injection. As shown from the figures, the oil viscosity and saturation are decreasing with time such as in case of CSS but with lower rate as shown in the figures. That is reflected in the higher oil production in case of CSS in comparison to injecting hot exhaust gases. Figures 7.13 and 7.14 indicate the change of the oil viscosity and saturation in case of using the horizontal wells along the cross section after the indicted days, in case of injecting

exhaust gases. As mentioned before, the horizontal wells give better performance than the vertical wells for all cases. In general, the CSS gives better performance than the injection of exhaust gases.

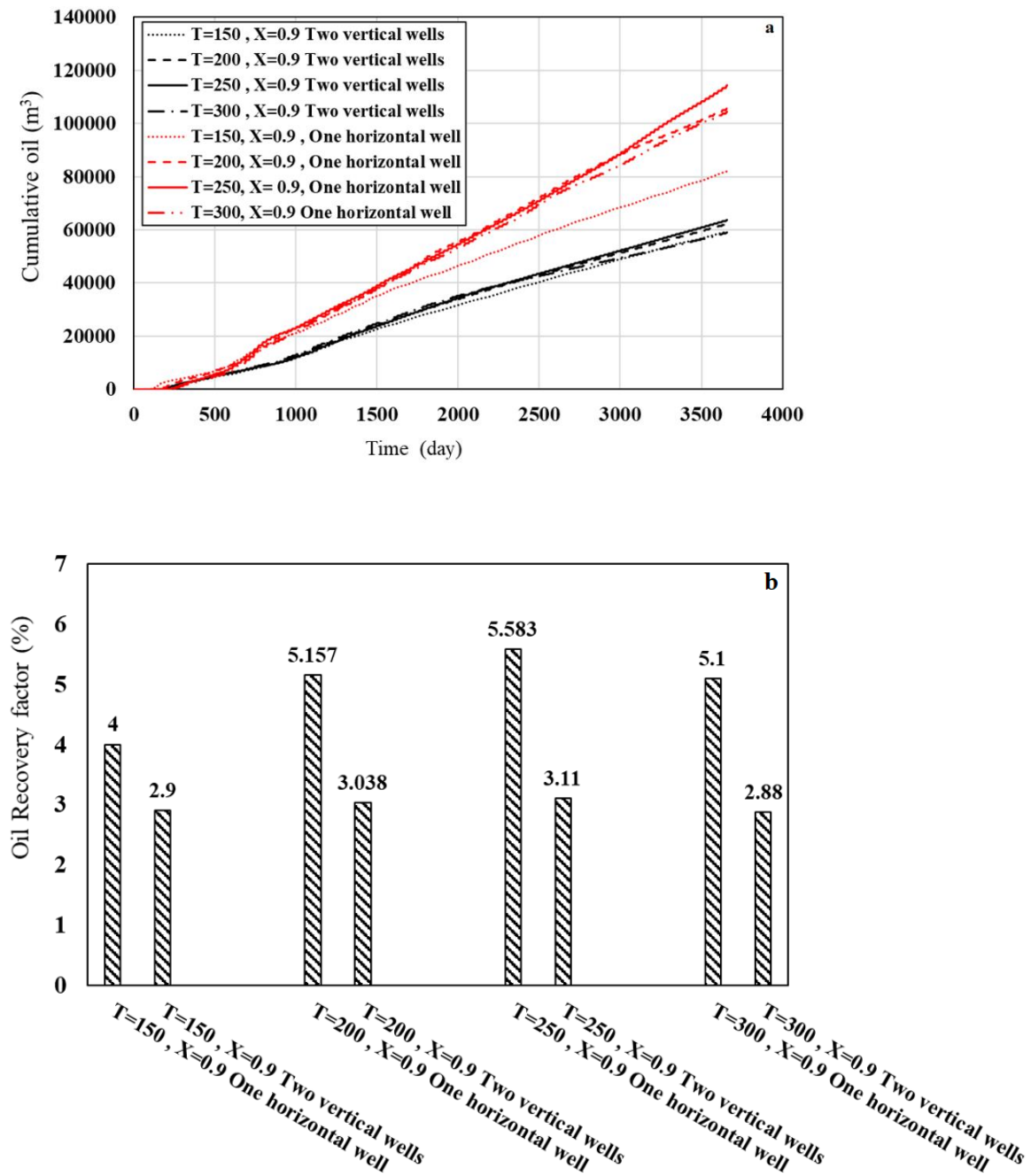


Figure 7. 10 Effect of exhaust gas temperature at fixed steam quality on a) Field cumulative oil, b) Field oil recovery factor, for horizontal wells

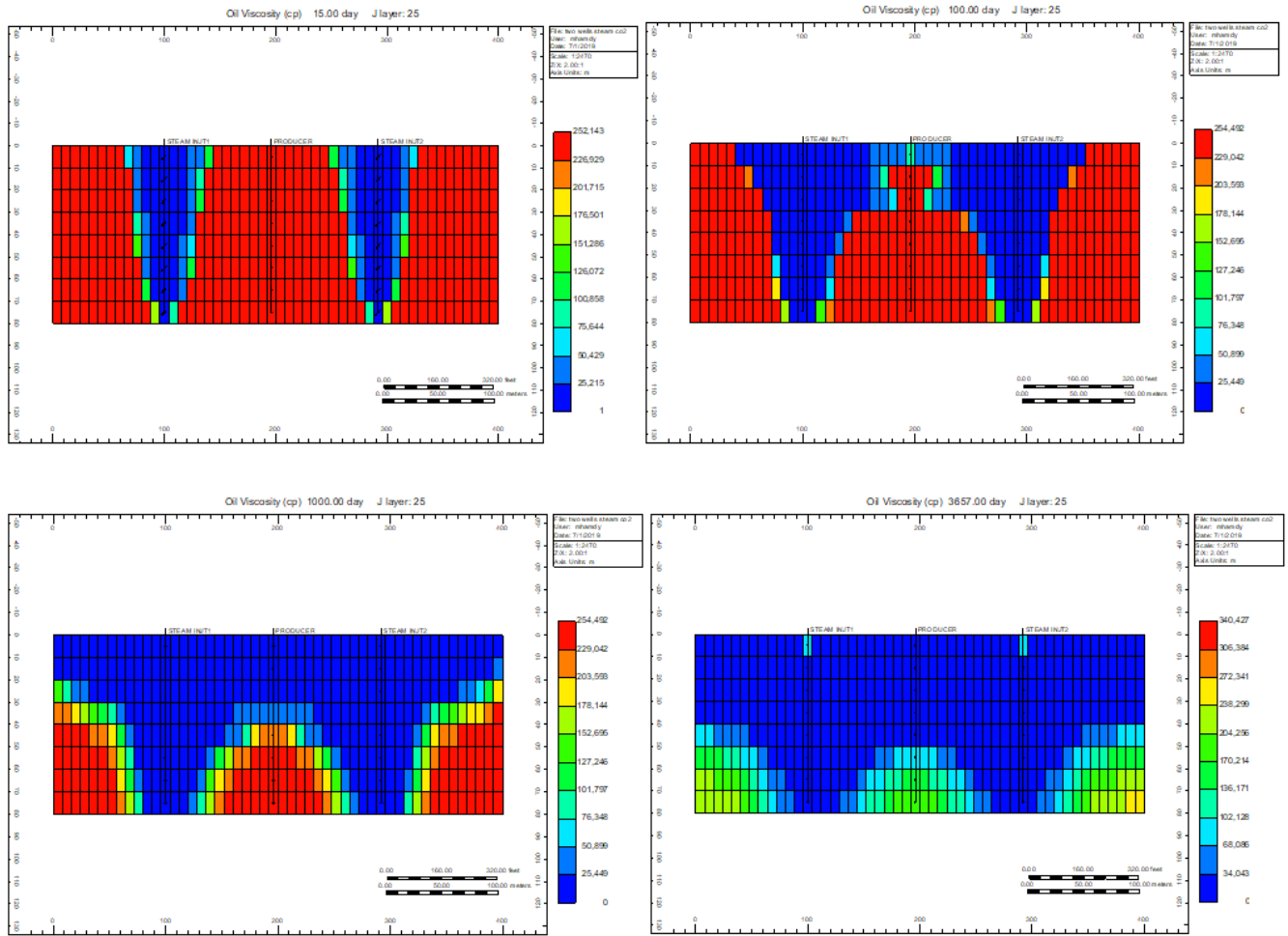


Figure 7. 11 Change of the field oil viscosity at the vertical wells cross section after 15, 100, 1000, 3657 days in case of exhaust gases injection

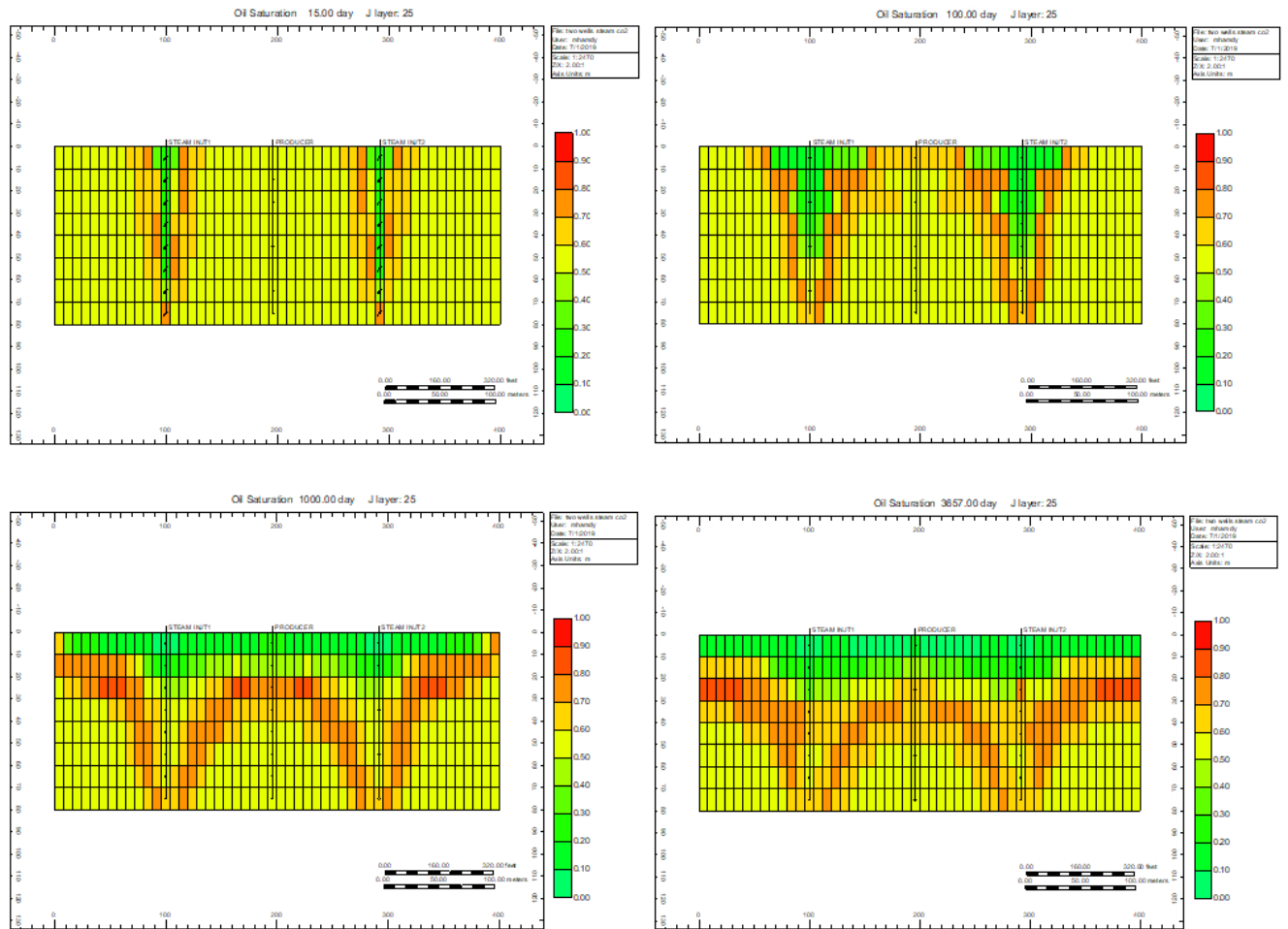


Figure 7. 12 Change of the field oil saturation at the vertical wells cross section after 15, 100, 1000, 3657 days in case of exhaust gases injection

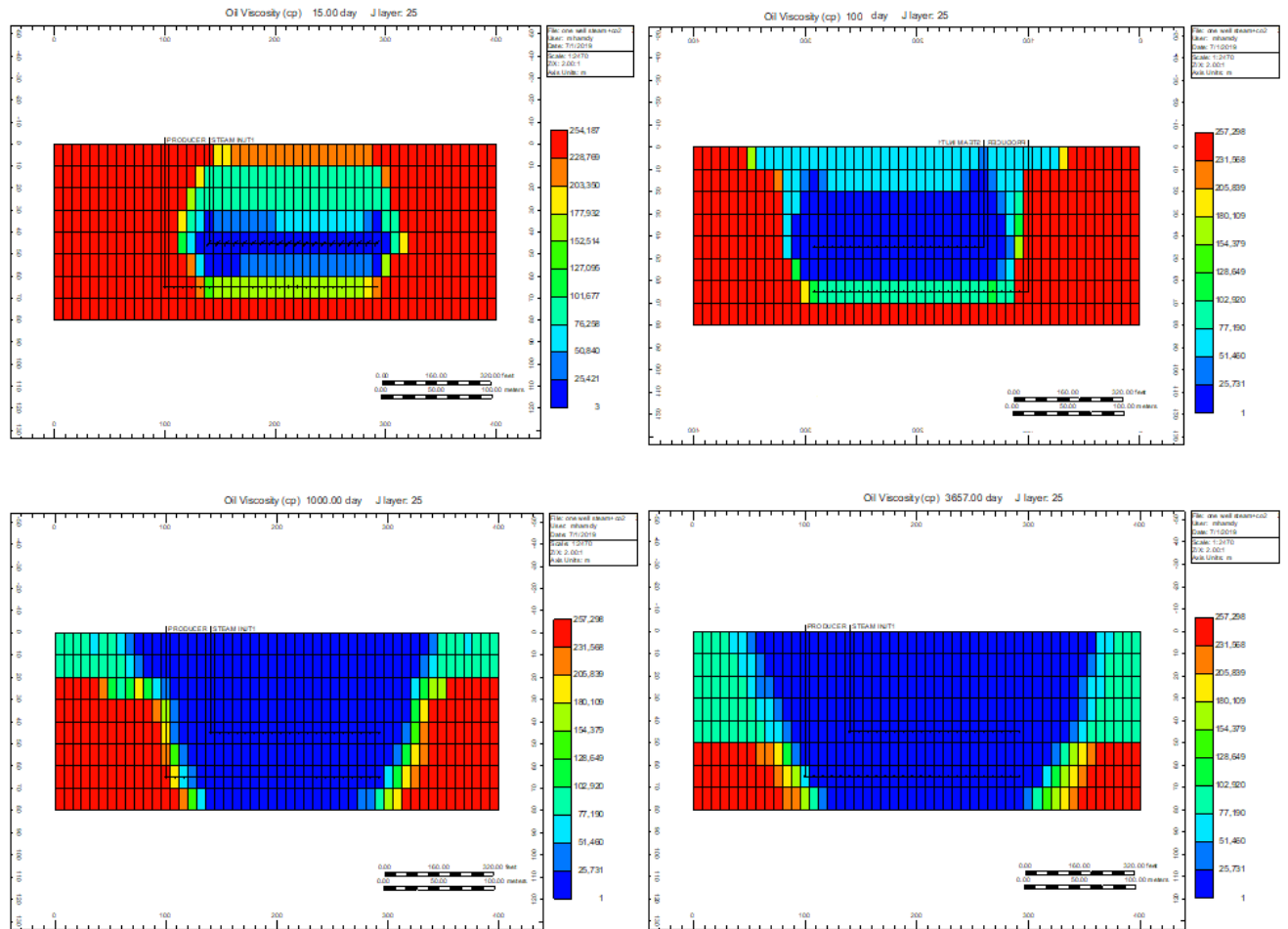


Figure 7. 13 Change of the field oil viscosity at the horizontal wells cross section after 15, 100, 1000, 3657 days in case of exhaust gases injection

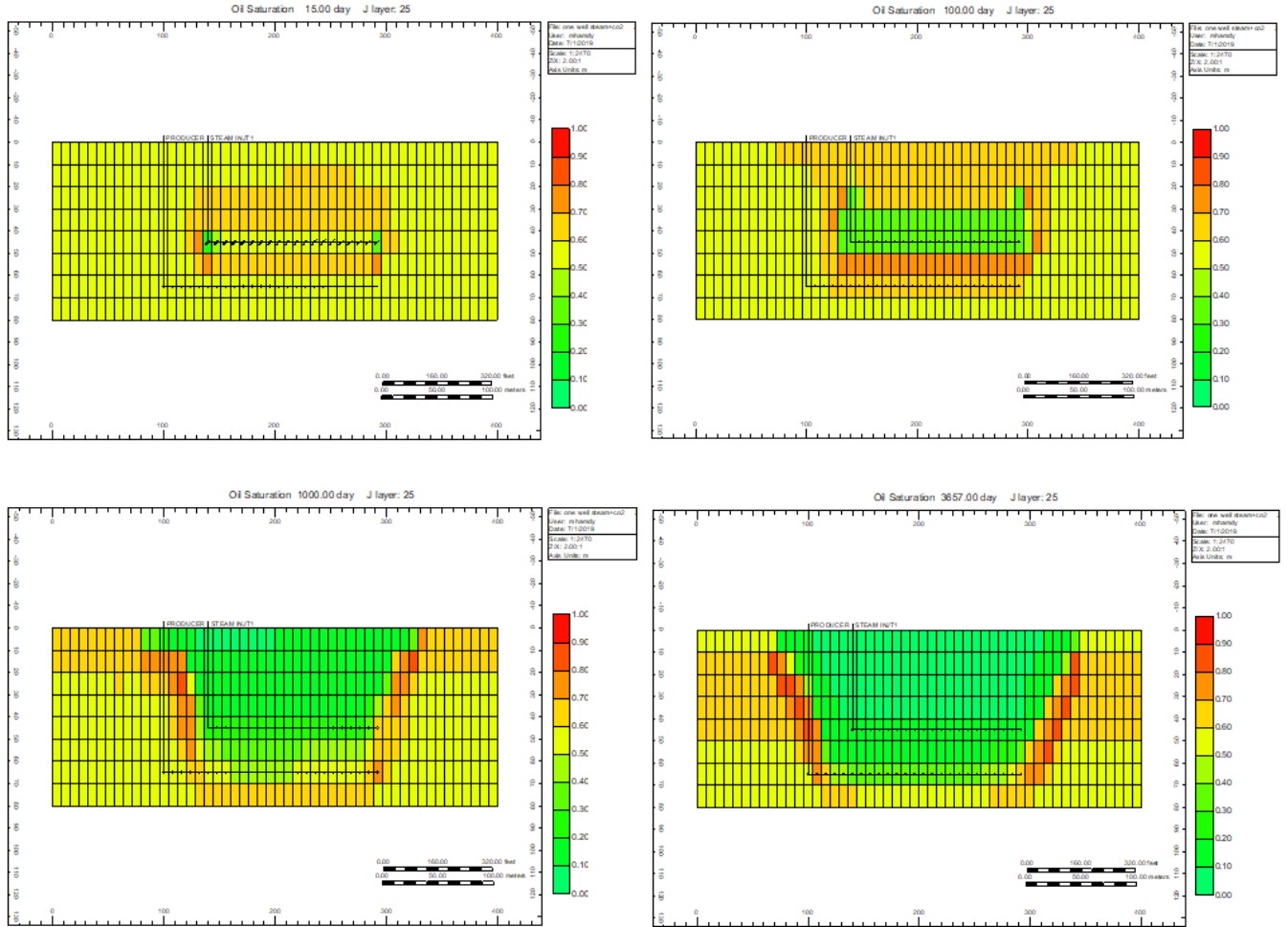


Figure 7. 14 Change of the field oil saturation at the horizontal wells cross section after 15, 100, 1000, 3657 days in case of exhaust gases injection

7.2.5 Comparison between Injection of Steam only or Exhaust Gases

Figure 7.15 shows the amount of injected heat in case of steam only and exhaust gases injection for the two different configurations. From the previous results, the maximum oil recovery in case of steam injection only is around 7.695 %, and in case of exhaust gases, injection the maximum oil recovery is around 5.58 %. Both occur at temperature of 250 °C and quality of 0.9 and in one horizontal well. The corresponding injected heat of these cases are 2.21×10^{12} kJ and 1.47×10^{12} kJ, respectively, as shown in Figure 7.15. Two injection vertical wells, in comparison with one injection horizontal well, was found that to give lower oil recovery and higher injected heat, which means low performance.

The maximum oil recovery in case of two vertical wells steam injection only is around 4.618%, and in case of exhaust gases injection, the maximum oil recovery is around 3.11 %. Both occur at temperature 250 °C and quality 0.9. The corresponding injected heat of these cases are 4.42×10^{12} kJ and 2.94×10^{12} kJ, respectively. These results reflect the importance of using horizontal wells, which save half of the energy and increase the oil production.

Figure 7.16 illustrates oil viscosity and saturation contours for the horizontal wells for both cases CCS and exhaust gases injection after 1000 days. Figure 7.16-a shows the oil saturation contours in case of CCS, while Figure 7.16-b shows the oil saturation contours in case of exhaust gases. It can be seen from Figure 7.16-a and b that in case of CSS, the oil saturation is lower than the case of exhaust gases, which means more extracted oil. That is a result of lower viscosity in case of CSS than exhaust gases injection due to the higher injected heat, as shown in the oil viscosity contours Figure 7.16-c and d.

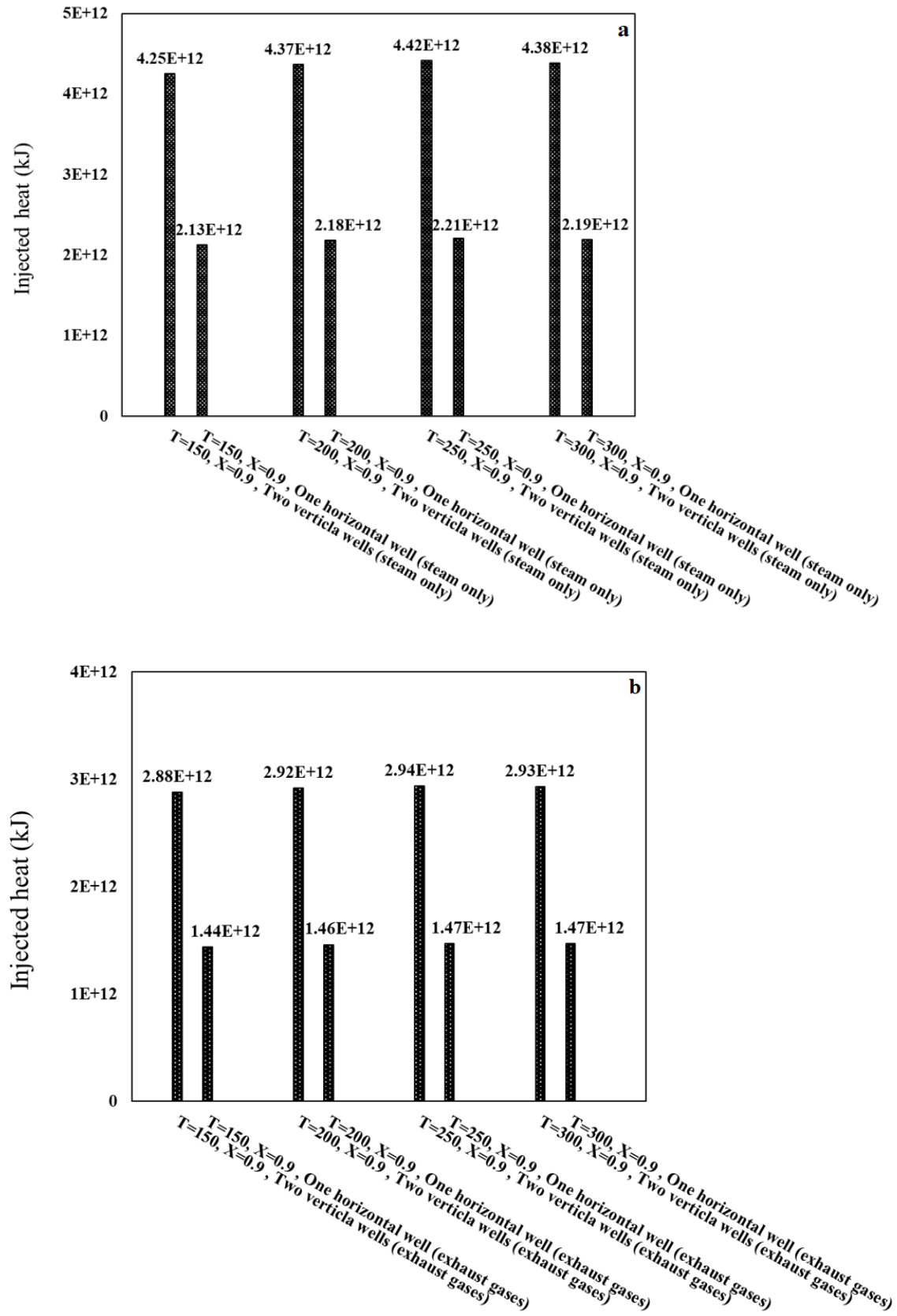


Figure 7. 15 The injected heat in case of a) steam only injection b) exhaust gases injection, for the two different configurations

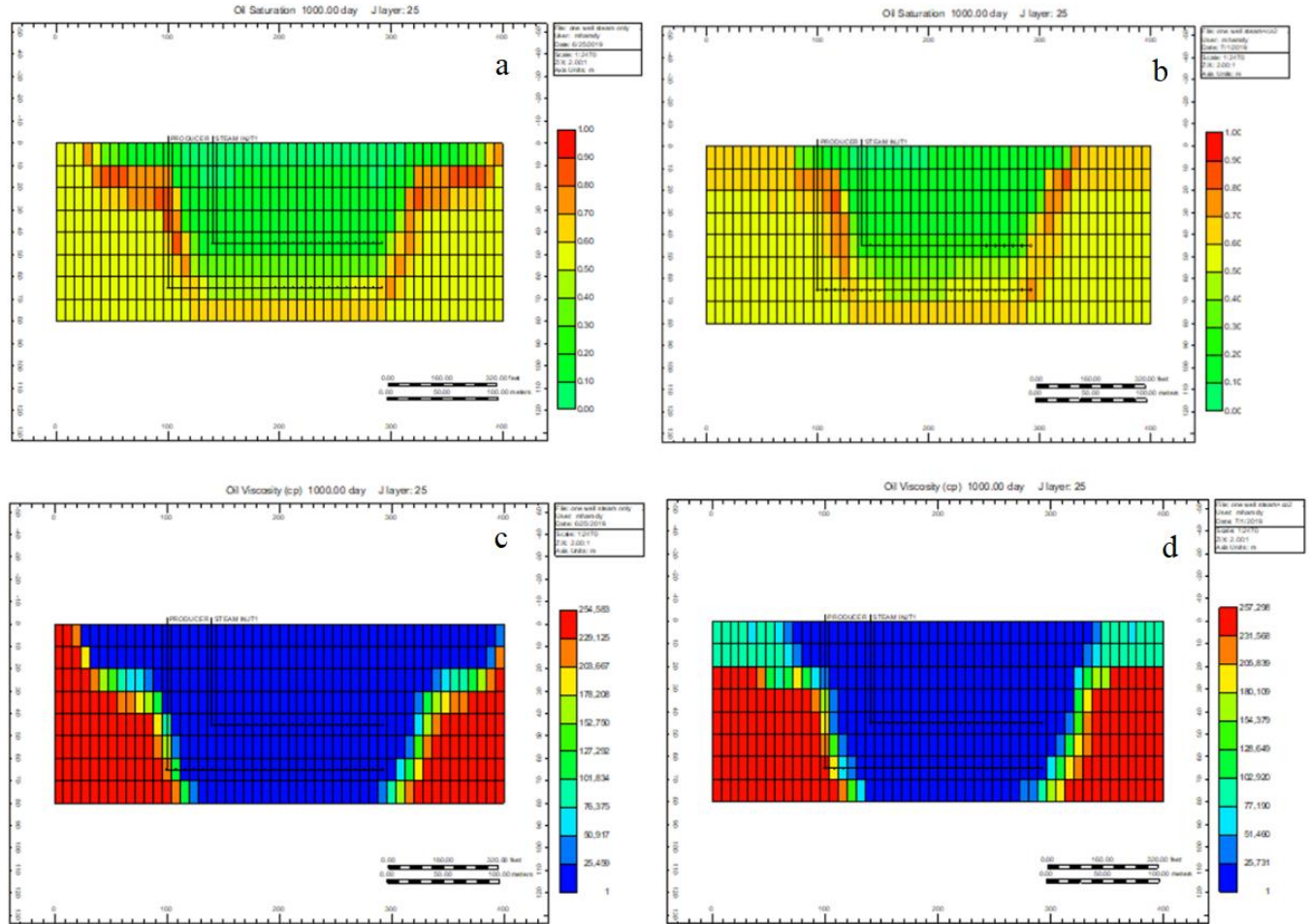


Figure 7. 16 Oil saturation contours after 1000 days for a) CSS and b) exhaust gases injection, and oil viscosity contours after 1000 days in case of c) CSS and d) exhaust gases injection

7.3 Summary of Chapter 7

Field scale numerical model field has been developed for CSS for a period of 10 years. Cyclic Steam Stimulation (CSS) and injection of exhaust gases, which are mainly water and carbon dioxide to the reservoir, has been studied. Different well configurations have been studied and a comparison between these configurations has been done for all the previous cases. It was found that the horizontal wells give better performance than the vertical ones. The oil recovery factor increased from 4.56 to 7.57 % in case of using the one horizontal well rather than two vertical wells for steam injection at 200 °C and quality 0.9. For exhaust gases injection, the oil

recovery factor will exceed 5.58% in case of one horizontal well rather than 3.11% for two vertical wells.

CHAPTER 8

CONCLUSIONS AND RECOMMENDATIONS

8.1 Conclusions

8.1.1 ITM Optimization

In this work, oxygen permeation flux through membrane impingement has been studied. In this regard, the effects of parameters such as geometry aspect ratio, number of impingements, angle of impingement and configurations and applying vacuum at the sweep side have been investigated. The impingement nozzle on the sweep zone should be placed as close as possible to the membrane to achieve the highest permeation flux. The permeation flux in case of D:H=4:1 is around $3.66 \mu\text{mole}/\text{cm}^2\text{-s}$, which is the highest among that of different aspect ratios.

The impingement angle does not have significant effect on the permeation, as the difference in the permeation flux between angle 30 and angle 90 is around $0.06 \mu\text{mole}/\text{cm}^2\text{-s}$. The number of impingement points was increased to two and the effects of number of sweep gas outlet and inter-pin spacing on permeation flux were investigated. Compared with single impingement, permeation flux achieved by double impingement is lower because of the increased effective membrane surface area. The maximum double impingement permeation flux of $2.559 \mu\text{mole}/\text{cm}^2\text{-s}$ was achieved at the optimum inter-pin spacing of 5 mm. Double impingement with one closed-end showed a higher permeation flux than that with the open-ended and the permeation flux increases with decreasing inter-pin spacing.

The permeation flux due to impingements has been compared with that due to parallel flow in the feed and sweep sides of the membrane. It was observed that impingement on the membrane sweep side irrespective of impingement or parallel flow on the membrane feed side decreases permeation. In case of sweeping gas in the sweep side, the parallel flow on both sides of the membrane showed the second highest permeation flux under similar operating conditions after the configuration of impingement in the feed side only, and it considered the optimum value which gives a permeation flux $3.88 \mu\text{mole}/\text{cm}^2\text{-s}$. The effect of sweep gas type (density) on permeation flux showed that less dense sweep gases decreases the permeation flux. Lastly, the effect of pressure on permeation flux showed that vacuum flow in the sweeping side gives the highest permeation flux with a value $5.503 \mu\text{mole}/\text{cm}^2\text{-s}$ higher than the parallel configuration with sweeping gas with 41%.

8.1.2 ISC using O_2/CO_2 as Oxidizer for Lab Scale

In this regard, 1D combustion tube simulation has been conducted to investigate the effect of different gases ratio and different injection strategies. Effect of different oxygen ratios on the oil recovery factor has been studied with injection of enriched air or O_2/CO_2 as oxidizer. The improvement ratios of oil recovery factor increased with a percent ratio 5.27 % in case of using is (50 % O_2 + 50% CO_2) rather than (50 % O_2 + 50% N_2). This ratio increased to 13.0 % in case of (21 % O_2 + 79% CO_2) rather than (21 % O_2 + 79% N_2), where the effect of CO_2 is obvious. The injected heat in case of injecting O_2/CO_2 rather than O_2/N_2 will be higher for the same volume flow rate. It is concluded that co-injecting of carbon dioxide with oxygen instead of enriched air has a good effect on the oil recovery factor. Using O_2/CO_2 as oxidizer has low effect on the produced values of hydrogen and hydrogen sulfide.

8.1.3 ISC using O₂/CO₂ as Oxidizer for Field Scale

3D reservoir simulation has been conducted and validated against published practical field data. Co-injection of pure oxygen with carbon dioxide (CO₂); and co-injection of oxygen with nitrogen gas have been investigated by a numerical model for field scale. increasing the oxygen ratio from 21% to 59.6 % leads to increasing the cumulative oil from 876.7 m³ to 940.4 %, respectively. Increasing the oxygen ratio to 95 % leads to increasing in the cumulative oil to a value of 991.5 m³. Increasing the oxygen ratio in, O₂/CO₂ mixture, from 21% to 30% leads to increasing the cumulative oil with from 886.7 m³ to 893.8 %, respectively. Increasing the oxygen ratio from 59.6% to 95 % leads to increasing in the cumulative oil from 949.2 m³ to 993.6 m³. Injecting mixture of O₂/ CO₂ gives better results, in terms of cumulative oil, than injecting enriched air.

8.1.4 Sizing of the Required ITM

for the described field scale base case ISC process, the required size of the ITM can be demonstrated using the required oxygen volume for the field and the oxygen flux from the ITM. The oxygen ratio in the oxidizer was around 59.6 %. The total required oxygen volume within this period was around 700000 m³. That means for around 120 days, the required volume flow rate is 5833 m³/day which is equivalent to 7.763 ton/day. The maximum permeation flux from the ITM is 5.503 μmole/cm²-s which is equivalent to 114.31 m³/m²-day, that means the required area 51 m² for one well.

8.1.5 Steam and Thermochemical EOR

The main purpose of this part is to compare the performance of thermochemical fluid injection to that of steam for the recovery of heavy oil. Evaluation of thermal performance of the thermochemical reactants show that the temperature increased to 89 °C, 116 °C, and 165 °C from 30 °C, 50 °C, and 100 °C, with the pressure of 280 psi; 1200 psi and 1600 psi, respectively.

Generally, the rate of reactions was observed to be affected by both operating temperature and the pH. The recovery from the thermochemical injection at 50 °C, and 30 °C yielded 66% and 54% OOIP, respectively. Moreover, the highest recovery of 83% OOIP was achieved from the thermochemical fluid injection at 100 °C, compared to 71% OOIP obtained from steam injection. In comparison with lab scale ISC, it was found that in case of ISC with oxygen ratio 95%, the oil recovery factor was 89.23 %, which is higher than the oil recovery factor in case of (TCF 100 °C), which was 83%.

8.1.6 Use of Steam and Exhaust Gases for EOR

Field scale numerical model field has been developed for CSS for a period of 10 years. Injection of exhaust gases, which are mainly water and carbon dioxide to the reservoir, has been studied. Different well configurations have been studied and a comparison between these configurations has been done for all the previous cases. It was found that the horizontal wells give better performance than the vertical ones. The oil recovery factor increased from 4.56 to 7.57 % in case of using the one horizontal well rather than two vertical wells for steam injection at 200 °C and quality 0.9. For exhaust gases injection, the oil recovery factor will exceed 5.58% in case of one horizontal well rather than 3.11% for two vertical wells.

8.2 Recommendations

In this work, Numerical studies for optimizing the ITM, ISC for lab and field scale and injection Exhaust gases for EOR were developed. Experimental study for measuring the reactivity and performance of Thermochemical reactants was carried out. Based on the outcomes of the work, the following possible areas for future work are recommended:

- Design the ITM air heating system with conventional heating system and solar heating system with performing overall economic study for all the configurations.
- Design and perform a combustion tube experiment to study ISC using O_2/CO_2 as oxidizer and compare the results with case of using enriched air as oxidizer.
- Experimentally compare using of ISC and TCF in terms of Oil recovery factor and economically.

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Appendixes

Appendix A

A semi-analytical model is used for heat transfer to or from an adjacent formation of infinite extent. It assumes a temperature profile in the base or cap rock as a function of time and distance z from the reservoir interface, i.e.,

$$T(t, z) = (\theta + pz + qz^2)e^{-z/d}$$

The diffusion length is $d = \sqrt{\lambda t/2}$. This profile satisfies both $T(t, 0) = \theta$ (grid block temperature) and $T(t, \infty) = 0$. At the interface, the profile must satisfy

$$\frac{\partial \theta}{\partial t} = \lambda \left. \frac{\partial^2 T}{\partial z^2} \right|_{z=0}$$

Or

$$\frac{\theta - \theta^N}{\Delta t} = \lambda \left(\frac{\theta}{d^2} - \frac{2p}{d} + 2q \right)$$

when the time derivative is discretized. The conservation of energy is expressed as

$$\frac{\partial \theta}{\partial t} \int_0^\infty T dz = \lambda \left. \frac{\partial T}{\partial z} \right|_0^\infty$$

Or

$$\frac{\theta d - pd^2 + 2qd^3 - I^N}{\Delta t} = \lambda \left(\frac{\theta}{d} - p \right)$$

where $I^N = \theta^N d^N + p^N (d^N)^2 + 2q^N (d^N)^3$.

Isolating parameters p and q gives

$$p = \frac{\left[\frac{\lambda \Delta t \theta}{d} + I^N - \frac{d^3(\theta - \theta^N)}{\lambda \Delta t} \right]}{[3d^2 + \lambda \Delta t]}$$

$$p = \frac{\left[2pd - \theta + d^2 \frac{\theta - \theta^N}{\lambda \Delta t} \right]}{2d^2}$$

The total energy in the overburden, i.e. under the temperature profile, is

$$\frac{k}{\lambda} \int_0^\infty T dz = \frac{k}{\lambda} d[\theta + pd + 2qd^2]$$

The rate at which heat is lost from the block to the overburden is:

$$-k \frac{\partial T}{\partial z} \Big|_{z=0} = k \left[\frac{\theta}{d} - p \right]$$

The heat loss rate and its derivative with respect to temperature can be calculated and used directly in the energy conservation derivatives. The energy lost is used directly in the energy balance statistics.

One set of these calculations is performed for each grid block face which is adjacent to cap or base rock. The only data required are thermal conductivity and heat capacity of the base and cap rock, both of which are quite standard data. This model gives solutions quite close to exact answers to many heat transfer problems.

Thermal diffusivity (m²/s) = thermal conductivity(w/m.k) / volumetric heat capacity (j/m³.k) .

Appendix B

- For calculating the injected heat in the combustion tube experiment.

$$\dot{q} \text{ (kw)} = \dot{m} \text{ (kg/s)} \times C_p \text{ (kj/kg C)} \times T \text{ (C)}$$

For the flow rate, $\dot{v} = 1.344 \text{ m}^3/\text{day}$

$$\dot{m} = \text{volume fraction} \times \dot{v} \times \rho / t$$

$$\dot{m}_{O_2} = 0.5 \times 1.344 \times 1.284 / (24 \times 60 \times 60) = 9.98667 \times 10^{-6} \text{ kg/s}$$

$$\dot{m}_{N_2} = 0.5 \times 1.344 \times 1.165 / (24 \times 60 \times 60) = 9.06111 \times 10^{-6} \text{ kg/s}$$

And in case of CO₂

$$\dot{m}_{CO_2} = 0.5 \times 1.344 \times 1.842 = 1.41867 \times 10^{-5} \text{ kg/s}$$

Then $q = \dot{q} \times t = \text{ in kj}$

In case of (0.5O₂+0.5N₂) injection the injected heat:

$$q = 361732.3 \text{ kj}$$

In case of (0.5O₂+0.5CO₂) injection the injected heat:

$$q = 412412 \text{ kj}$$

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