EFFECTS OF CO_2 SATURATION ON THE RECOVERY OF THE HEAVY OIL USING STEAM INJECTION EOR TECHNIQUE

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES
OF
MIDDLE EAST TECHNICAL UNIVERSITY

BY

FARID GULUZADE

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR
THE DEGREE OF MASTER OF SCIENCE
IN
PETROLEUM AND NATURAL GAS ENGINEERING

December 2014

Approval of the thesis:

EFFECTS OF CO_2 SATURATION ON THE RECOVERY OF THE HEAVY OIL USING STEAM INJECTION EOR TECHNIQUE

Submitted by FARID GULUZADE in partial fulfillment of the requirements for the degree **of Master of Science** in **Petroleum and Natural Gas Engineering Department, Middle East Technical University** by,

Prof. Dr. M. Gülbin Dural Ünver ___________________
Dean, Graduate School of **Natural and Applied Sciences**

Prof. Dr. Mahmut Parlaktuna ___________________
Head of Department, **Petroleum and Natural Gas Eng.**

Assist. Prof. Dr. Çağlar Sınayuç ___________________
Supervisor, **Petroleum and Natural Gas Eng. Dept., METU**

Examining Committee Members:

Prof. Dr. Mahmut Parlaktuna ___________________
Petroleum and Natural Gas Engineering Dept., METU

Asst. Prof. Dr. Çağlar Sınayuç ___________________
Petroleum and Natural Gas Engineering Dept., METU

Prof. Dr. Mustafa Verşan Kök ___________________
Petroleum and Natural Gas Engineering Dept., METU

Asst. Prof. Dr. İsmail Durgut ___________________
Petroleum and Natural Gas Engineering Dept., METU

Dr. Sevtaç Bülbül ___________________
Petroleum Research Center, METU

Date: 02.12.2014

I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

Name, Last Name: Farid, Guluzade

Signature:

ABSTRACT

EFFECTS OF CO_2 SATURATION ON THE RECOVERY OF THE HEAVY OIL USING STEAM INJECTION EOR TECHNIQUE

Guluzade, Farid
M.Sc., Department of Petroleum and Natural Gas Engineering
Supervisor: Asst. Prof. Dr. Çağlar SINAYUÇ

December 2014, 84 pages

Enhanced Oil Recovery processes include all methods that use external sources of energy and/or materials to recover oil that cannot be produced economically by conventional means.

EOR processes can be classified as: thermal methods (in-situ combustion, cyclic steam injection, steam flooding), chemical methods (alkaline, polymer, foam, or surfactant/polymer injection), and miscible methods (CO_2, nitrogen, hydrocarbon, or flue gas injection).

Steam flooding involves continuous injection of steam to displace oil towards producing wells. Normal practice is to start with cyclic steam injection and to continue with steam flooding. The mechanisms of steam injection are heating oil thus reducing its viscosity and supplying pressure to drive the oil towards producing wells.

In this study, to analyze the effects of CO_2 saturation on the heavy oil recovery by steam injection is aimed. A synthetic model is built in Schlumberger's software Petrel, by using basic properties (porosity, permeability, API gravity) of hypothetical field.

Production scenarios are taken to be different for better comparison of recoveries. Sensitivity runs are conducted in Eclipse software. This study should not be compared with real field data since a hypothetical geological model is used. Therefore, no history match can be done in this case.

By the end of the study, water injection implementation and steam flooding are found to be the most appropriate oil recovery techniques for this particular, hypothetical field in terms of both production and pressure support. Therefore, scenario 1 and scenario 6 are the best methods to be applied. By the end of time schedule average reservoir pressure for scenarios 1 and 6 are 650 psi and 464 psi respectively with 283 and 234 stb/d of production. Furthermore, for being more thorough, material balance was also conducted in IPM tool, called MBal for checking the consistency of the model. Thus, close pressure trend was obtained from material balance compared to simulation model.

ÖZ

CO_2 DOYMUŞLUĞUNUN BUHAR BASIMI EOR TEKNİĞİ İLE AĞIR PETROL KURTARIMINA ETKİLERİ

Guluzade, Farid
Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği
Tez Yöneticisi: Yrd. Doç. Dr. Çağlar SINAYUÇ

Aralık 2014, 84 sayfa

Geliştirilmiş petrol kurtarımı (EOR), harici enerji kaynakları ve malzemeler kullanarak, geleneksel yöntemler ile üretilemeyen petrolün üretimini sağlayan tüm yöntemleri içerir.

Geliştirilmiş petrol kurtarımı şu şekilde sınıflandırılabilir: ısıl yöntemler (yerinde yanma, dönüşsel buhar basımı, buhar basımı), kimyasal yöntemler (alkalin, polimer, köpük, veya yüzey aktif madde/polimer basımı), ve karışır yöntemler (CO_2, azot, hidrokarbon, vey abaca gazı basımı).

Buhar basımı, petrolün üretim kuyularına ötelenmesi için sürekli olarak buhar basımını içerir. Normal uygulamaya gore önce dönüşsel buhar basımı ile başlanır ve buhar basımı ile devam edilir. Buhar basımının mekanizması, petrolü ısıtarak akmazlığını düşürmek ve basınç sağlayarak petrolü üretim kuyularına doğru ötelemektir.

Bu çalışmada karbondioksit varlığının, buhar basımı ile ağır petrol kurtarımı üzerine etkilerini analiz etmek amaçlanmıştır. Türkiye’nin güneydoğusunda bulunan Batı-

Raman sahası özelliklerine benzer özellikler (gözeneklilik, geçirgenlik, API gravitesi) kullanılarak yapay bir model oluşturulmuştur. Daha gerçekçi bir yaklaşım için Batı-Raman petrol sahasının üretim geçmişi temel alınmıştır. Varsayımsal bir jeolojik model kullanıldığı için bu çalışma ile gerçek saha verileri karşılaştırılmamalıdır. Bu nedenle tarihsel çakıştırma yapılamaz.

Bu çalışma su basımı ve buhar basımı uygulamalarının bu varsayımsal saha için hem üretim hem de basınç katkısı açısından en uygun geliştirilmiş kurtarım yöntemleri olduğunu göstermiştir. Bunun yanısıra, modelin tutarlı olduğunu kontrol etmek için kütle korunumu incelenmiş ve kütle korunumu ve simülasyon modeli sonuçlarının yakın basınç yönelimine sahip olduğu görülmüştür.

ACKNOWLEDGEMENTS

All praises to Almighty Allah who has never left me alone at any time in my entire life.

I wish to express my deepest gratitude to my supervisor – Asst. Prof. Dr. Çağlar Sınayuç for his guidance, motivation and overall for this continuous support throughout the project. Asst. Prof. Dr. Sınayuç has spent endless hours with me to develop the project and at this point, words are not enough to express my gratitude and appreciation to him.

I want to acknowledge all professors and instructors, with department head, Prof. Dr. Mahmut Parlaktuna, at the top of the list for valuable courses that are taught at Middle East Technical University.

Finally, I want to express my deepest gratitude to family for their support, love and understanding, which always motivates me to overcome any problem that I face in my entire life.

TABLE OF CONTENTS

ABSTRACT v

ÖZ vii

ACKNOWLEDGEMENTS ix

TABLE OF CONTENTS x

LIST OF FIGURES xiii

LIST OF TABLES xvii

CHAPTERS

1. INTRODUCTION 1

2. LITERATURE SURVEY 5

2.1. Enhanced Oil Recovery 5

2.1.1 Chemical techniques 5

2.1.2 Miscible displacement techniques 6

2.1.3 Thermal EOR techniques 6

2.1.4 Microbial EOR methods 6

2.2. CO_2 geological storage 9

2.3. EOR CO_2 11

2.3.1 Miscible CO_2 displacement method 12

2.3.2 Immiscible CO_2 displacement method 15

2.3.3 CO_2 properties 16

2.3.4 CO_2 EOR implementation worldwide 20

2.3.5 Comparison between miscible and immiscible CO_2 flooding... 21

2.4 Steam injection.. 22

2.4.1 Changes in relative permeability 24

2.4.2 Heat loss 26

2.4.2.1 Heat, lost at the surface 26

2.4.2.2 Heat, lost at the wellbore.. 26

2.4.2.3 Heat, lost in the reservoir 27

2.4.3 Types of steam injection... 28

2.4.3.1 Cyclic steam injection 28

2.4.3.2 Continuous steam injection.. 30

2.4.4 Selection criteria 32

2.4.5 Variations and optimization of steam injection......................... 32

2.4.5.1 Steam flooding prior to water injection 32

2.4.5.2 Water alternating steam 33

2.4.5.3 Air injection after steam injection................................. 33

2.4.5.4 Hybric steam techniques 33

2.4.5.5 Fracturing with steam... 34

2.4.6 Steam injection implementation worldwide 34

2.5 Modeling of CO_2 injection and steam injection.................................... 35

2.5.1 Immiscible CO_2 injection simulation 35

2.5.2 Steam injection simulation 36

3. STATEMENT OF THE PROBLEM 39

4. METHODOLOGY 41

4.1 Model setup 41

4.2 Field history 42

4.3 Sensitivity runs 45

4.4 Scenarios 46

4.5 Material balance 48

5. RESULTS AND DISCUSSIONS 51

5.1 Base case 51

5.2 Scenarios 53

5.3 Comparison of all scenarios 59

5.4 Effect of CO_2 on steam injection 67

5.5 Effect of water injection wells 68

5.6 Material balance check 71

6. CONCLUSION 77

REFERENCES 79

LIST OF FIGURES

FIGURES:

Figure 2.1 Depth vs. density of CO_2.. 10

Figure 2.2 a) good recovery, b) viscous fingering 12

Figure 2.3. A schematic view of water alternating gas process of miscible CO_2 injection.. 14

Figure 2.4. Schematic view of immiscible CO_2 injection 15

Figure 2.5. Phase diagram of carbon dioxide.. 17

Figure 2.6. Density of CO_2 with respect to temperature and pressure 17

Figure 2.7. Compressibility of CO_2 with respect to pressure and temperature.......... 18

Figure 2.8. Viscosity of CO_2 with respect to temperature and pressure 18

Figure 2.9. Development of CO_2 displacement techniques and cumulative rates in USA 21

Figure 2.10. Viscosity of 4 oil samples under different temperatures 23

Figure 2.11. Effect of temperature on relative permeability 24

Figure 2.12. Heat content of boiling water and dry saturated steam at different pressure 25

Figure 2.13. Heat loss in the wellbore in comparison with injection rate 27

Figure 2.14. Variation of heat losses to the formation with formation thickness...... 28

Figure 2.15. Huff and puff method 29

Figure 2.16. Steam assisted gravity drainage 30

Figure 2.17. SAGD technique in Tangleflags formation 31

Figure 4.1. Grid model 43

Figure 4.2. Oil relative permeability 44

Figure 4.3. Gas relative permeability 44

Figure 4.4. Water relative permeability 45

Figure 4.5. All well are producers 46

Figure 4.6. Central well is injection CO_2/steam 46

Figure 5.1 Field daily oil production rate 52

Figure 5.2 Average reservoir pressure 52

Figure 5.3 Field daily water production rate 53

Figure 5.4 Comparison of base case and scenario-1 average reservoir pressure 54

Figure 5.5 Comparison of base case and scenario-1 oil production rate 54

Figure 5.6 Comparison of base case and scenario-1 water production rate 55

Figure 5.7 Comparison of base case and scenario-2 average reservoir pressure 55

Figure 5.8 Comparison of base case and scenario-2 oil production rate 56

Figure 5.9 Comparison of base case and scenario-3 average reservoir pressure 56

Figure 5.10 Comparison of base case and scenario-3 oil production rate 57

Figure 5.11 Comparison of base case and scenario-3 water production rate 57

Figure 5.12 Comparison of base case and scenario 4 oil production rate 58

Figure 5.13 Comparison of base case and scenario-5 oil production rate 58

Figure 5.14 Comparison of base case and scenario-6 oil production rate 59

Figure 5.15 Comparison of field average reservoir pressure 60

Figure 5.16 Comparison of field oil production rates 61

Figure 5.17 Comparison of cumulative oil production rates 62

Figure 5.18 Comparison of water production rates 62

Figure 5.19 Reservoir temperature distribution for scenario-6 september 1963 63

Figure 5.20 Reservoir temperature distribution for scenario-6 june 2016 64

Figure 5.21 Reservoir pressure distribution for scenario-6....................................... 65

Figure 5.22 Viscosity distribution for scenario 6 66

Figure 5.23 Effect of water injection and CO_2 injection before steam injection on oil production rate 67

Figure 5.24 Effect of water injection and CO_2 injection before steam injection on cumulative oil production 68

Figure 5.25 Proximity of well locations 69

Figure 5.26 Water production 70

Figure 5.27 Oil production 70

Figure 5.28 Reservoir and wells 71

Figure 5.29 Input paameters for material balance 72

Figure 5.30 PVT inputs 72

Figure 5.31 Production inputs from simulation outputs 73

Figure 5.32 Cumulative injection, production and reservoir pressure 73

Figure 5.33 Matching uncertaion parameters 74

Figure 5.34 Average reservoir pressure comparison between material balance and simulation 75

Figure 5.35 Drive mechanism 75

LIST OF TABLES

Table 2.1 Approximate criteria for enhanced oil recovery techniques 7,8

Table 2.2. Amount of CO_2-eor projects and rates 20

Table 2.3. Essential characteristics of miscible and immiscible projects. 22

Table 2.4. Recovery of different thermal EOR processes 35

Table 4.1 Main parameters 42

Table 4.2. Well locations in the grid model 45

Table 5.1 The summary of the simulation cases 51

Table 5.2 Average oil production rate 60

Table 5.3 Water injection scenarios 69

CHAPTER 1

INTRODUCTION

Crude oil is found in underground deposits that have migrated there millions of years ago. It is defined as a hydrocarbon mixture in liquid state. As name implies, hydrocarbons mainly consists of hydrogen and carbon. However, impurities such as nitrogen, oxygen, metals and sulphur are also contribute to the composition of crude oil. Production as well as physical and chemical properties of crude oil are influenced by its composition.

Source rock plays an essential role in formation of petroleum. It is the fine-grained, organic rich rock that is responsible for generation of petroleum. Crude oil is expelled from source rock once it is fulfilled. Mainly, there are three driving forces of migration, which are buoyancy, water flow and capillary pressure. Migration of petroleum finishes either on the surface or may be stopped by impermeable rock underground called cap rock. In this case oil is trapped in reservoir rock. Reservoir rock itself is a porous and permeable rock from where crude oil is extracted.

The history of petroleum industry clearly demonstrates that there are three main production stages: primary recovery, secondary recovery, and enhanced oil recovery (EOR) or tertiary recovery.

In the onset of petroleum production, which has started in 1840s, due to the absence of technology people rely only on primary production, which means that petroleum comes to surface by means of reservoir energy. Main principle of producing petroleum in this stage is pressure difference between reservoir and sandface of a well that drives oil. In primary stage there are several driving forces, which pressurize reservoir. Main driving forces are: solution gas drive, water drive (aquifer), and gas-cap drive.

The fraction of hydrocarbon that can be extracted by primary recovery is generally in between 5% to 15% (Tzimas and Peteves, 2003).

The end of primary stage and start of secondary recovery stage is at such point of reservoir lifetime when reservoir pressure is so low that there is not sufficient energy to produce hydrocarbons to the surface. The main aim of secondary recovery is to provide energy to reservoir for increasing surface production. There are two main techniques of secondary recovery: water injection (water flooding) and gas injection.

Due to the fact that aquifers are always present, water is preferred during the secondary recovery stage. Basically there are two main purposes of water flooding: pressurizing the reservoir (increasing the reservoir energy) and displacement of hydrocarbons towards production wells. By the end of secondary recovery the overall fraction of extracted hydrocarbons is about 35% - 45% (Tzimas and Peteves, 2003).

At some point of production by water injection, there is a moment when production drops so low that it becomes unprofitable, in economical perspectives, to continue the production. Therefore, in order to produce the remaining oil that cannot be recovered by secondary recovery mechanisms, an enhanced oil recovery technique is implemented, that uses external energy sources for increasing oil mobility, so that oil can easily flow through the reservoir towards the producing wells and to the surface.

Enhanced Oil Recovery is classified as thermal recovery (steam flooding, in-situ combustion, etc.), chemical recovery (alkaline, polymer, etc.) and miscible recovery (CO_2, nitrogen, etc.)

EOR techniques increase microscopic oil displacement and volumetric sweep efficiencies, which, in its turn, leads to mobilization of oil within the field.

This study is mainly concentrated on CO_2 injection and steam flooding applications. Therefore in following paragraphs these techniques will be explained.

One of the most common tertiary recovery methods is CO_2 EOR. Beyond primary and secondary recovery stages, an additional 5% to 20% of oil can be recovered by CO_2 injection. Mainly CO_2 is produced from underground deposits and can also be produced from electric power plant emissions. Once CO_2 is produced, it is transported to the field mainly by pipes. During water injection stage, oil is pushed towards producing wells by means of pressure through straight force. The situation in CO_2 injection differs. CO_2 has a property to dissolve in oil, which implies that CO_2 increase miscibility. Once CO_2 is injected to the reservoir, it starts to dissolve in oil and swelling process starts (oil expands). After absorption of CO_2 in the zone of miscibility the oil viscosity is reduced and it can flow easily throughout the reservoir. The main problem in CO_2 injection is that, due to the fact that CO_2 viscosity is much lower than oil's, CO_2 can start to form channels towards production wells. This indicated that, in this case, CO_2 can leave huge amount of oil bypassed.

If the oil gravity is low, steam injection is one of the most appropriate enhanced oil recovery methods to be used. Since oil has low gravity, which means that it is viscous, steam is injected to the reservoir to reduce its viscosity, so that oil can comparatively easily flow throughout the formation. Another advantage of steam injection method is that, as in the case of water injection, it supplies additional pressure and help to push oil towards the production wells. The most important advantage of steam flooding is that it can be injected to different kind of reservoirs. However there are also some restrictions of this method, which are: depth and formation thickness. The main reason of using steam instead of heated water is that in case of steam injection less water would be produced, which in its turn implies that more heat would remain in the reservoir. One of the main differences between carbon dioxide and water in reservoir conditions is that water is immiscible with oil, which means that the main purpose of water flooding is to push oil towards producing wells and pressurize the reservoir. However, there are two methods of CO_2 injection: one of which is miscible flooding, the purpose of which is to dissolve in oil and reduce its viscosity as well as for oil swelling, and the second one is immiscible CO_2 injection, which does not dissolve in oil. Therefore, the goal of immiscible CO_2 flooding is to create a gas cap, which will lead to reservoir pressure support.

After injection of CO_2 for a long time in a reservoir, the CO_2 saturation increases. The effects of CO_2 saturation on the recovery by steam injection are studied by using a reservoir model. Main parameters as porosity, permeability and API gravity are taken to be appropriate for heavy oil fields with production scenarios implemented in the majority of the reservoirs worldwide.

In this study, the geological model is built and populated using Schlumberger's Petrel Software. Main parameters to be considered for populating the simulation model are permeability, porosity, net to gross (NTG) ratio, and pressure volume temperature (PVT) data. The model has an anticline structure. For production and injection purposes 5-spot well structure was chosen to see the field performance.

After the model is prepared, sensitivity runs were conducted. One of the purposes is to see how CO_2 injection affects production with steam injection, which implies that the only parameter to be taken into consideration as an outcome is oil recovery by different scenarios. However, some other scenarios are also evaluated as well. For instance, the model is run with steam flooding immediately after water injection. Continuation of CO_2 injection scenario is also considered. History matching cannot be applied in this study as only porosity, permeability, API gravity are applied from real reservoir. Production scenarios are taken to be representative to heavy oil reservoirs. All input data are taken hypothetically. However, material balance equation is also used for this study in order to see the consistency of the simulation model.

CHAPTER 2

LITERATURE SURVEY

2.1 Enhanced Oil Recovery Methods

Enhanced Oil Recovery (EOR) includes a vast majority of techniques implemented to increase production, one of which is CO_2 flooding. After primary and secondary recovery processes rock and oil parameters as well as saturations are going to be known in each special case. These differences in reservoir characteristics play an important role in selection of enhanced oil recovery methods for continuation of production from existing fields. An appropriate EOR technique is chosen based on reservoir porosity/permeability, oil structure and mainly accessibility of sufficient amount of material required for EOR method. Generally, summarizing mentioned aspects of selecting EOR technique, main role is played by economics of the project to be implemented (Green and Willhite, 1998). EOR techniques will be discussed shortly:

2.1.1. Chemical techniques:

The main purpose is to inject surfactants and/or alkaline for reduction of capillary forces which negatively influence the motion of oil in the reservoir. Generally speaking, it enhances microscopic and macroscopic sweep efficiency. The best reservoirs for surfactant or alkaline injection are fields which are heterogeneous but with good permeability.

Another chemical process consists of addition of polymer to water, which is injected into the reservoir. Existence of polymers in water decrease its mobility, thus better oil sweep can be achieved.

Due to the fact that mentioned techniques are hard to control, they are mainly implemented in the final stage of the recovery.

2.1.2. Miscible displacement techniques:

Miscible displacement techniques include injection of any kind of fluid that will dissolve in oil. The purpose of these techniques is to inject a gas in order to achieve miscibility with oil. Once it is achieved, capillary forces will be reduced as well as oil will become less viscous, which in its turn would lead to better/easier movement of oil within the porous media. Miscible displacement techniques include injection of nitrogen, methane, flue gases, etc.

2.1.3. Thermal EOR techniques:

Thermal EOR techniques are implemented to increase reservoir temperature to achieve a decrease in oil viscosity. In order to increase reservoir temperature, steam and/or hot water are injected or even some portion of oil in the reservoir is burned. Thermal EOR techniques are implemented mainly for the reservoirs with heavy oil. Microwave EOR consists of sending of microwaves to the reservoir, which would heat up oil, thus reduce its viscosity for better motion.

2.1.4. Microbial Enhanced Oil Recovery methods:

The basic function of microbial EOR technique is to increase oil recovery by the mobilization of oil in the reservoir that is manipulated by microorganisms and this leads to better sweep efficiency. By means of microbial EOR it is possible to produce up to 60% of the remaining oil (Sen, 2008).

A simple list of parameters that would help to identify which EOR technique to implement is shown in Table 2.1.

Table 2.1. Approximate criteria for Enhanced Oil Recovery techniques (Green et al., 1998)

	Oil Properties			
EOR Method	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (%)
Miscible Gas Injection Methods				
CO_2	>22 (36)	<10 (1,5)	High % of C_5- C_{12}	>20 (55)
Nitrogen/ Flue gases	>35 (48)	<0,4 (0,2)	High % of C_1- C_7	>40 (75)
Hydrocarbon (e.g. N. gas)	>23 (41)	<3 (0,5)	High % of C_2- C_7	>30 (80)
Chemical methods				
Miccelar/ Alkaline/ Polymer Flooding	>20 (35)	<35 (13)	Light & Intermediate	>35 (53)
Thermal methods				
Combustion	>10 (16)	<5000 (1200)	Asphaltic components	>50 (72)
Steam	>8 (13,5)	<20000 (4700)	N.C.	>40 (66)

Table 2.1. (cont). Approximate criteria for Enhanced Oil Recovery techniques (Green et al., 1998)

Reservoir Properties				
EOR Method	Net thickness (m)	Average permeability (mD)	Depth (m)	Temperature(^oC)
Miscible Gas Injection Methods				
CO_2	Wide range	Not critical	>833	Not critical
Nitrogen/ Flue gases	Thin	Not critical	>2000	Not critical
Hydrocarbon (e.g. N. gas)	Thin	Not critical	>1333	Not critical
Chemical methods				
Miccelar/ Alkaline/ Polymer Flooding	Not critical	>10 (450)	<3000 (1083)	<90 (26)
Thermal methods				
Combustion	>3	>50	<3833 (1167)	>38 (60)
Steam	7	>200	<1500 (500)	Not critical

2.2 CO_2 Geological Storage

According to Global CCS Institute our planet has an atmosphere that consists mostly of nitrogen and oxygen, but there are also some little amounts of other gases like noble gases (argon, helium, neon and kripton), hydrogen and greenhouse gases. Greenhouse gases themselves include: water vapor (H_2O), carbon dioxide (CO_2), methane (CH4), etc. However CO_2 itself accounts of more than 77 percent of anthropogenic emissions. It has been observed that CO_2 has a huge thermal impact to the climate of the Earth. It is also known as greenhouse effect.

Greenhouse effect makes the life to be possible on the planet. However, the concentrations should be stable within the atmosphere. An unexpected decrease of CO_2 may cause the Earth to come to next ice age, on the other hand a sudden increase in CO_2 concentration would lead to global warming. Occurrence of both ice age and global warming has been seen in the history of the Earth. Today, ratio of atmospheric temperature to CO_2 content is higher than ever seen for last 4000 years because; natural processes of the Earth cannot come up with such high concentration of emissions. Scientists proved that due to high CO_2 emissions the planet is going to enter next global warming the evidence of which is a process of ice caps melting. Today, world CO_2 emissions are about 36000 tons/year (Blok K, et.al 2012). Bryngelsson et al. (2009) explained that in order to reduce carbon amount in the atmosphere it was proposed to capture and store CO_2, because it seems to be one of the most appropriate and immediate way of mitigation the climate change. The technology involves capturing CO_2 at the place where it is emitted by plants, transportation of CO_2 by pipelines to the storage, where it is compressed and injected to the underground reservoir at depths deeper than 800 meters. The reason of why CO_2 is compressed and injected deeper than 800 meters is for CO_2 to become supercritical fluid. On one hand supercritical fluid behave as a gas, so that it easily diffuse through pores. On the other hand it also behaves as a liquid because it occupies less space in comparison with gases. 800 meters is the minimum depth and 72.9 atm. is the minimum pressure at which supercritical fluid can exist.

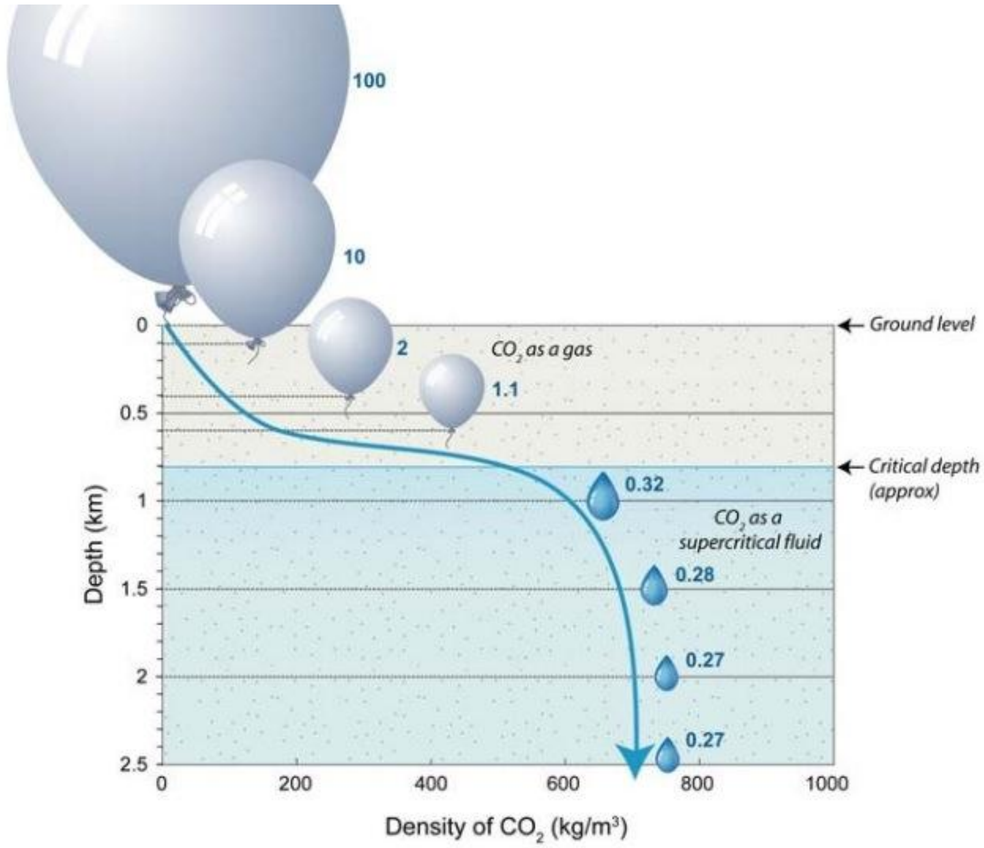


Figure 2.1. Depth vs. density of CO_2 graph (West Virginia carbon sequestration, 2008)

Once CO_2 is injected into an underground reservoir its volume is compressed to circa 500 times smaller, than at the surface. The main purpose of carbon capture and storage (CCS) is to close a circle. It starts from coal, petroleum extraction, continue with combustion factories, plants and closing up with capture of CO_2, transportation, injection and storage underground.

The main question in this case is where these geological storages to be located so that it will be safe and secured. Sedimentary basins are thought to be a reliable place for CO_2 storage, due to the high permeability. According to Burruss (2004) oil and gas reservoirs can store carbon dioxide safely for a long time. The seal of oil and/or gas reservoirs have proved to be effective, preventing oil and gas to escape. Moreover, injection of CO_2 for storage purposes would pressurize the reservoir and increase production of oil. Identically in natural gas fields production would also be increased once CO_2 is injected to the reservoir (Oldenburg et al., 2001). Reservoir rocks can be a good medium to store CO_2. The reason is that reservoir rocks are porous and permeable so that CO_2, being in a liquid state, can easily spread in it. Furthermore, there is a seal rock (cap rock) just above reservoir rock, which is impermeable, therefore fluid cannot escape reservoir up to the surface.

Salt waters found in sandstone formations are characterized to have greater volume for CO_2 storage. Nevertheless, based on Burruss (2004) the main problem linked to mentioned formations is their low permeability.

2.3 EOR CO_2

Based on observations, a significant portion of oil originally in place still remains within a reservoir after secondary recovery process. In areas influenced by water during secondary oil recovery, the saturation of rock with crude oil is around 15 to 35% (Sunnatov, 2010). On the other hand, in unswept regions saturation can be extremely higher. Therefore, an effective EOR technique should be selected which will lead to mobilization of oil left in the reservoir and also to formation of sufficient oil volume that will easily move towards producing wells. Mobilization of oil can be accomplished by CO_2 injection. Once CO_2 is injected to the reservoir physical and chemical reactions take place and leads to interaction of CO_2 with rock and fluid. This process builds suitable conditions that increase oil recovery. The conditions mentioned are: 1) reduction of interfacial tension among rock and oil which will lead to easier flow of oil within pores by decrease in capillary forces, 2) CO_2 dissolve in oil, thus, it expands in volume (swelling) as well as oil viscosity will be decreased (ECL Technology Report 2, 2001).

Usually companies are trying to increase oil production by minimum usage of CO_2. There are two ways of getting CO_2: firstly from a natural CO_2 source and secondly by capturing carbon dioxide from an emission source. This CO_2 will be injected back on a successive way. Second one is to buy CO_2. Through economical evaluations, companies decide whether recycling is cheaper or purchasing of carbon dioxide. Generally, acquisition of CO_2 prior to injection comes up to 50-80% in all proceeding CO_2-EOR operations (Schulte, 2004). Therefore, operating companies look for producing most of injected CO_2 from the production well within the oil. Once CO_2 is produced, it is separated, pumped to the injection area of the field and together with fresh CO_2 injected to the reservoir.

However, nowadays based on economic and ecological perspectives, CO_2 geological storage operations are rising to be important as well. This implies that in recent future CO_2 injection will play two essential roles, which are increasing oil recovery as well as underground storage.

2.3.1. Miscible CO_2 displacement method

Goodwear et al. (2003) claimed that under suitable circumstances, when pressure, temperature and composition of oil are adequate, it is possible to obtain a miscible CO_2 with oil. It means that CO_2 will dissolve in oil and a mixture of petroleum and CO_2 will move as a single-phase liquid within the reservoir. Consequently, oil-swelling process takes place, viscosity reduces as well as interfacial tension decreases.

Once CO_2 is injected it does not mix with oil immediately. Reservoir fluid composition changes once CO_2 is injected and that leads to development of miscible carbon dioxide. A process of miscibility of CO_2 with oil is called as Multiple Contact Miscibility (MCM). A slight change in oil structure/composition creates miscibility among oil and carbon dioxide. However, in real life situation interaction of CO_2 and oil is not as simple as it is thought.

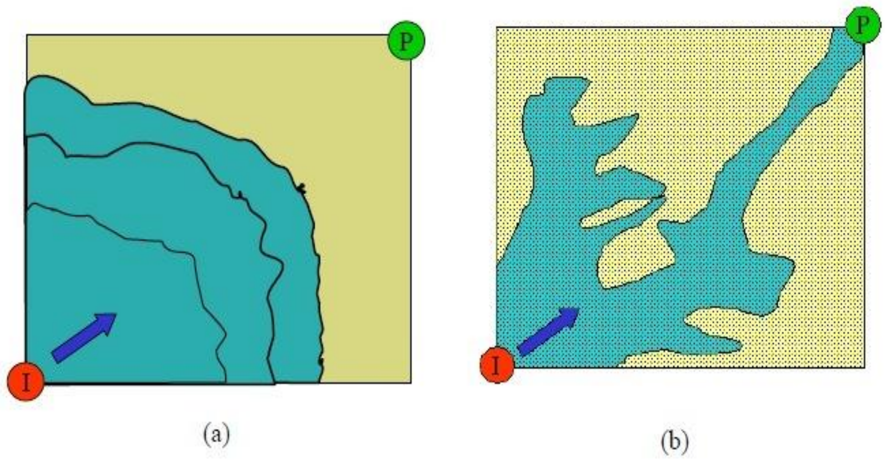


Figure 2.2. a) good recovery, b) viscous fingering (Conaway et al. 1999)

Figure 2.2 shows two different situations that can happen while CO_2 injection. In the left side recovery will increase drastically due to strong and steady front of CO_2 and oil, which sweep oil towards producing well. On the other hand, in the right side viscous fingering emerges. Viscous fingering occurs due to the channels and/or cracks through which CO_2 bypasses oil and consequently reachs production wells, leaving huge amount of oil within the reservoir.

Pressure is mainly responsible for the development of miscibility of CO_2 in oil. For carbon dioxide to be able to entirely mix with oil, a Minimum Miscibility Pressure (MMP) is obligatory. In other words, as mentioned earlier, on the surface CO_2 is compressed to supercritical state and injected to the depth more than 800 meters, so that it remains in supercritical state within the reservoir. This implies that for successful sweep of oil by miscible CO_2, injection pressure must be larger than MMP as well as less than reservoir pressure. Thus, MMP plays an essential role for reliable implementation of miscible CO_2 displacement method for increasing oil recovery.

From theoretical point, it is possible to recover oil which has influenced by CO_2. However, the situation is not so smooth in real life situations. Based on experience, CO_2 injection provides only 5-20% oil recovery (Goodwear et al., 2003). Problems that cause the reduction of recovery are:

1) A certain distance for flowing of carbon dioxide within the reservoir is required for CO_2 to become miscible.

2) Existence of cracks and fractures in the reservoir may manipulate flow of CO_2 to be unstable. In this case, due to high velocity and low viscosity, carbon dioxide will flow faster towards producing well and leads to viscous fingering.

3) By gravitational forces due to different density of oil and CO_2, the latter reaches producing well easier.

4) Prior to CO_2 EOR, water injection technique is basically implemented. Not all water is produced by the end of injection. Some water remains in the reservoir. Some energy of CO_2 is spent to the mobilization of remaining water.

In order to prevent problems mentioned above, CO_2 is usually mixed up with water and injected to the reservoir, which is called Water Alternating Gas technique (WAG). The purpose of addition of water is due to fact that water is more reservoir-friendly and spreads more steadily within the reservoir, thus, increasing recovery.

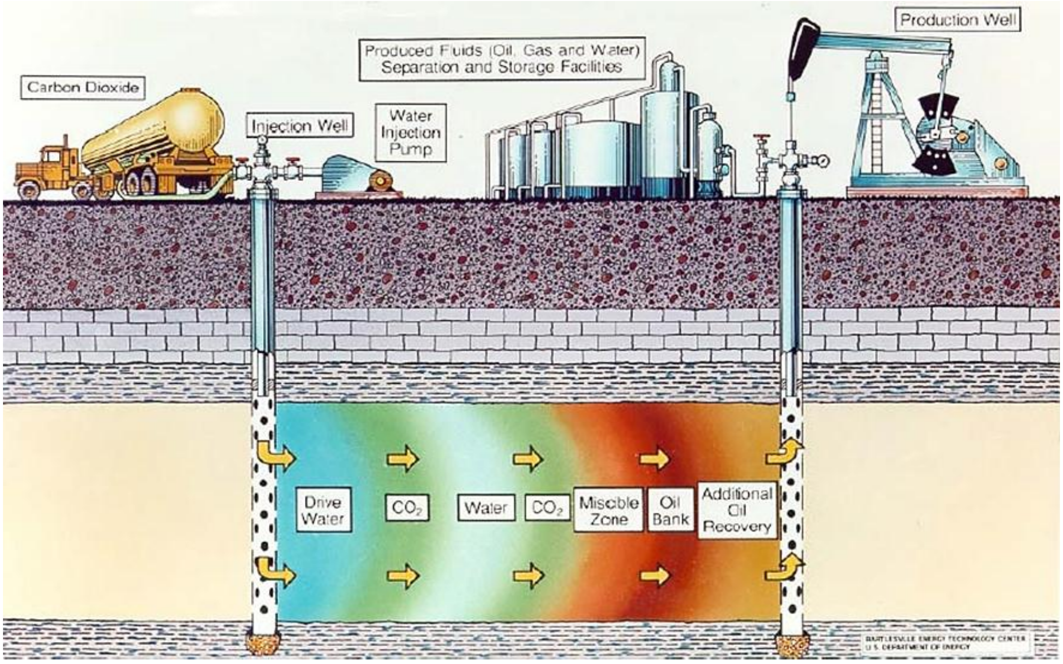


Figure 2.3. A schematic view of water alternating gas process of miscible CO_2 injection. (CO_2 surfactants, 2014)

Miscible CO_2 injection operations are easier to implement. Operations may be implemented as at the end of a reservoir lifetime as immediately after secondary recovery processes such as water injection. Miscible CO_2 flooding is also beneficial, as there is no need of recompletion after water flooding for CO_2 injection implementation. This implies that the same well type is required for both mentioned processes. Moreover, miscible CO_2 injection technique can be employed to a certain areas of the reservoir. The production of additional oil will be increased in first 1-5 years, which directly affected by reservoir parameters (porosity, permeability, etc.) and distance among injectors and producers.

Required extra equipment in the operating area for miscible CO_2 operations are:

1) Equipment to receive and condition CO_2

2) Recompletion of injectors and producers (in case of water-flooding application prior to miscible CO_2 injection, no need to recomplete)

3) Membrane equipment to separate CO_2

4) Additional pipelines for compressing and recycling of CO_2

5) Gauges to monitor.

2.3.2. Immiscible CO_2 displacement technique

According to Kulkarni (2003) in some instances of heavy oil reservoirs or in the reservoirs with low reservoir pressure, it is still possible to increase production with CO_2 injection, despite Minimum Miscible Pressure is not achieved. In this case CO_2 is not miscible. However, some portion of oil still swells, as certain amount of CO_2 will be dissolved in oil, due to high injection pressures. Theories imply that injection of CO_2 to the reservoir containing heavy oil may lead to a considerable reduction of its viscosity. However, this is not the main goal of immiscible CO_2 flooding. As in case of water flooding, the main purpose of immiscible CO_2 injection is to keep or even increase reservoir pressure. Water flooding is more effective technique in comparison with immiscible CO_2 injection, as water has an ability to spread more uniformly throughout the reservoir. Therefore, immiscible CO_2 injection technique has only been used in few cases, when geologic parameters or permeability are not appropriate for water injection. The crest is the best part of the reservoir where CO_2 is injected and where it starts to feel the pore volume. Immiscible CO_2 injection looks like gas injection of secondary recovery technique. As oil is heavier than carbon dioxide, the latter starts to gather at the top of the trap, hence creating a gas cap that consequently push oil downward, towards production well (Figure 2.4).

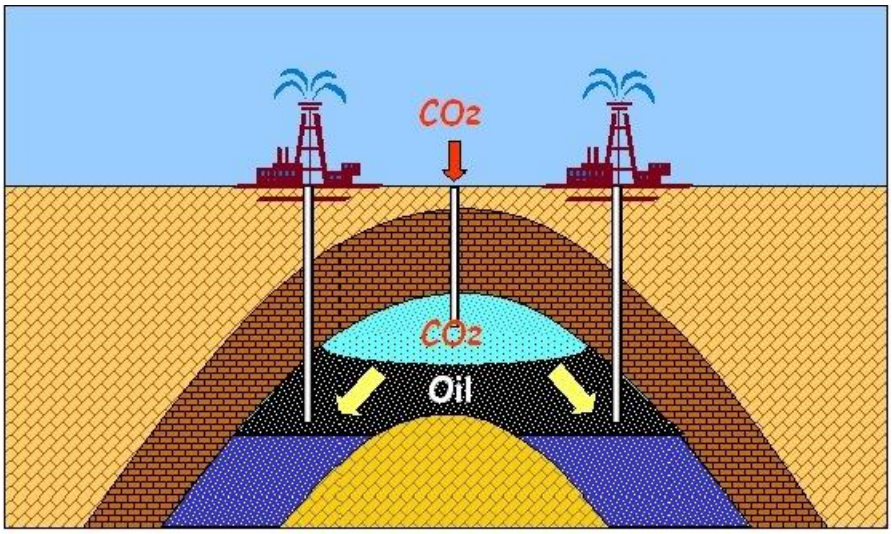


Figure 2.4. Schematic view of immiscible CO_2 injection (Tzimas et al, 2005)

Due to the fact that water slows down the motion of oil in the reservoir, it is not recommended to implement immiscible CO_2 flooding after water injection, as the latter would stop the effectiveness of immiscible CO_2 injection.

The implementation of immiscible CO_2 injection can rarely be seen nowadays, due to the undesirable economical aspects. A requirement of a huge amount of CO_2 as well as certain quantity of new wells will not be compensated by a little and slow oil recovery. Until additional oil is produced, ten years of injection may be required. Moreover, implementation of immiscible technique in a certain part of the reservoir is impossible, which means that immiscible technique can generally be applied to the whole reservoir (Green, 2003).

However, after an international agreement of Kyoto protocol, carbon capture and storage (CCS) is becoming to be under interest. Immiscible displacement schemes can store significant amounts of CO_2 underground, which may play an essential role in decision-making. As we know, in miscible displacement techniques CO_2 left in the reservoir depends on the amount of it dissolved in oil and produced to the surface. However, in immiscible displacement projects the amount of CO_2 retained in the reservoir is dictated by the reservoir pore volume. Moreover, in miscible CO_2 injection technique breakthrough cannot be avoided, but with correct project design it is possible to exclude such breakthrough in case of immiscible displacement (Kulkarni, 2003).

2.3.3. CO_2 Properties

Simple carbon dioxide has no color and cannot be smelled. It is an inert gas which cannot be burned. The molecular weight of CO_2 is 1.5 times greater than that of air. In spite of the fact that carbon dioxide is more temperature dependent, pressure also plays an important role in its physical properties. Solid form of carbon dioxide can be reached at low temperatures and pressures. Once mentioned parameters start to be increased solid CO_2 transforms to liquid one. There is also a point when gaseous, liquid and solid CO_2 are in equilibrium. This point is called a triple point (Figure 2.5).

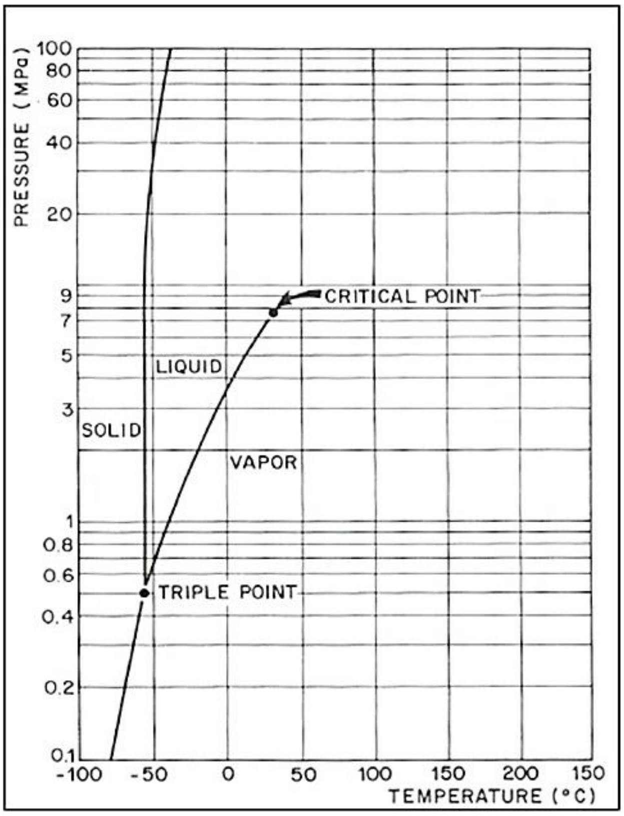


Figure 2.5. Phase diagram of carbon dioxide (Baviere, 1980)

CO_2 phase behavior can also be expressed based on density, compressibility, viscosity.

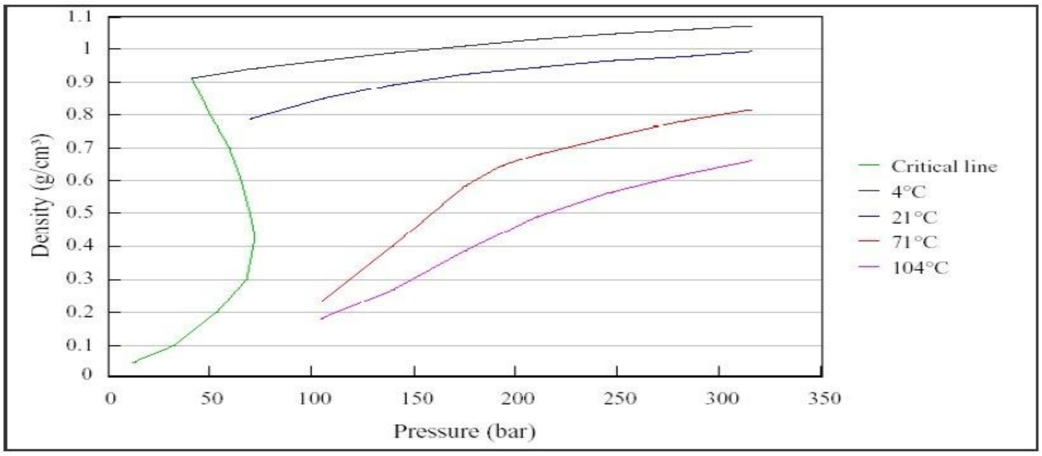


Figure 2.6. Density of CO_2 with respect to temperature and pressure (Holm, 1987)

As can be seen in Figure 2.6, when temperature is above critical positions, increase in pressure causes an increase in the density. However, unexpected disturbances appear once temperature falls below the critical conditions.

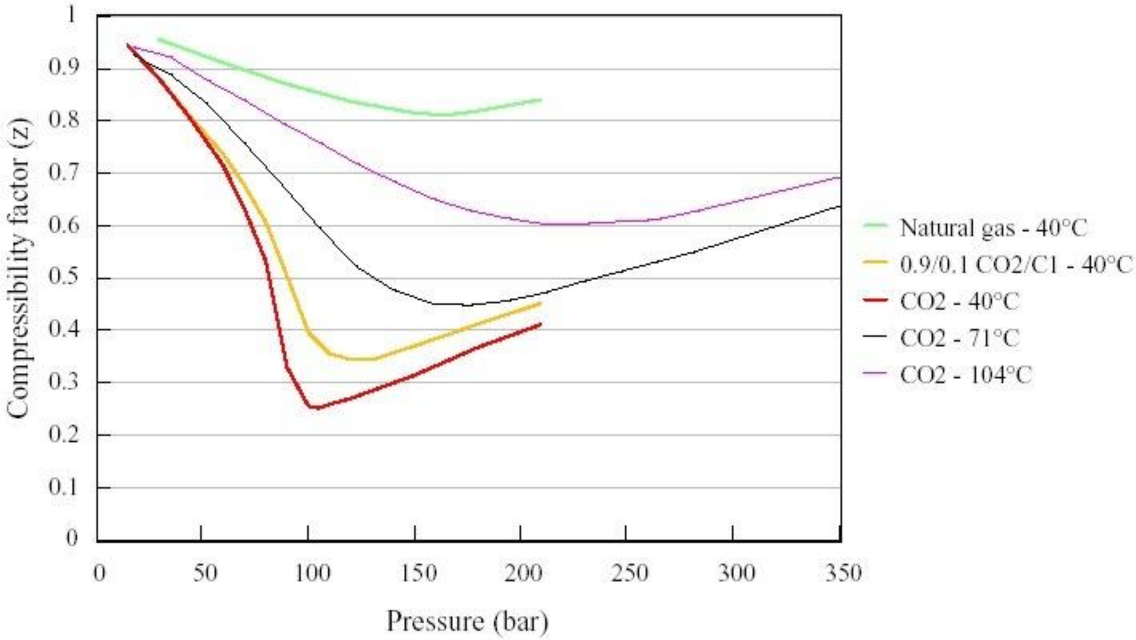


Figure 2.7. Compressibility of CO_2 with respect to pressure and temperature (McQuarrie, Donald A. (1999))

Figure 2.7 shows compressibility behavior of carbon dioxide, natural gas and mixture of CO_2 and methane.

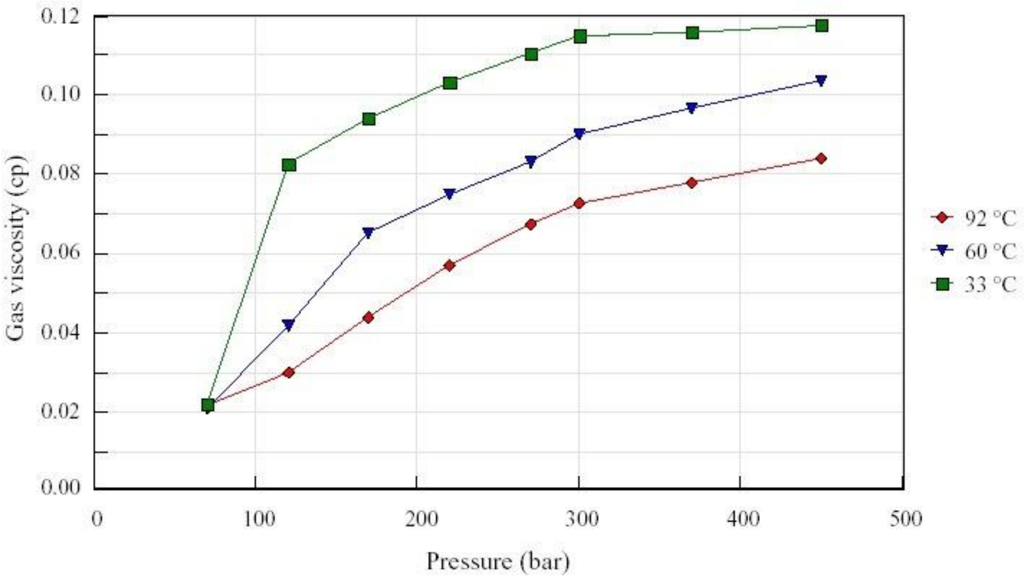


Figure 2.8. Viscosity of CO_2 with respect to temperature and pressure (Lee, A.L.et.al .1966)

From Figure 2.8 above it can be noted that viscosity of carbon dioxide depends on pressure and temperature. In case of a constant reservoir temperature, increase in pressure will lead to viscosity build up.

Awareness of physical properties of carbon dioxide is essential, especially in case of CO_2 flooding operations. It is usually assumed that injected carbon dioxide enters the formation in supercritical state. This implies that CO_2 pressure and temperature are set properly. However, during injection processes CO_2 is injected in a liquid state due to simplicity in operations compared to supercritical carbon dioxide. Nevertheless, problems may occur in this case as well. For instance, thermal stresses influenced by carbon dioxide and/or phase changes within the tubing, formation may lead to the occurrence of some problems. Liquid carbon dioxide is more effective to be injected than supercritical one, due to the fact that the density of the latter is less than that of CO_2 in liquid state. Therefore, injection of liquid CO_2 would lead to less overpressure as in surface so in the reservoir.

After initialization of injection the process of heat transfer takes place as in tubing so in the formation. According to Lu and Connell (2008) lateral heat transfer occurs in the tubing and it is represented by formula:

$$Q = -2\pi R_p U_\infty (T - T_{geo}(z)) \qquad (1)$$

In this formula U_∞ is the parameter showing heat transfer. It includes all properties of injection well and fluid which is injected through it. The radius of the injection well is represented by R_p. Geothermal temperature throughout the pipe is set as $T_{geo}(z)$. Thermal characteristics of parts of injection well play a key role in heat transfer coefficient behavior. Of course, time and temperature are also responsible for changes. However, temperature plays a considerable role only in case of high temperatures, otherwise, little impact will be on overall heat transfer coefficient.

As mentioned earlier, CO_2 is injected in liquid state and transformed into supercritical one at the bottom hole. In order to keep liquid CO_2 from outer formations' heat, tubing is recommended to thermally insulate. Thermal insulation of pipe would lead to overall heat transfer coefficient to be reduced, which leads to relatively lower temperatures. Thus, density of liquid carbon dioxide will be close to that of water in tubing.

Basically, the ability of an item to conduct heat is called heat conductivity. Higher thermal conductivity of an item, bigger the amounts of heat transfer to the surrounding medium. Therefore for thermal insulation purposes items with lower thermal conductivity are used. On the other hand, materials with higher thermal conductivity are used when spreading of heat into surrounding items is required. Thermal conductivity depends mainly on temperature. Thermal conductivity of CO_2 at temperature of 25°C is 0.0146 W/(m K).

2.3.4. CO_2-EOR implementation worldwide

Based on Schulte (2004), CO_2-EOR has proved to be a successful project worldwide for increasing oil recovery. Generally, most of CO_2 injection operations have been undertaken in North American onshore fields. In 2004 there were 79 CO_2 injection projects in the world. Share of the USA were 70 miscible CO_2 injection operations and 1 immiscible, while the rest are shared between Canada with 2 miscible projects, Trinidad with 5 immiscible carbon dioxide injections and Turkey close this chain up with one immiscible displacement operation in Bati Raman oil field (Table 2.2).

Table 2.2. Amount of CO_2-EOR projects and rates (Moritis, 2006)

Country	Project Type	No of projects	Production rate (stb/day)
USA	Miscible	70	205775
	Immiscible	1	102
Canada	Miscible	2	7200
Turkey	Immiscible	1	6000
Trinidad	Immiscible	5	313

The approximate oil production from these 79 CO_2 injections in 2004 was about 230 Mstb/day, which account to 0.3% of oil produced worldwide. Implementation of miscible CO_2 injection took place in the North Sea only once, when carbon dioxide was injected to the Egmanton oilfield. However, this project was terminated later due to insufficient injection rates.

Undoubtedly, with 94% of CO_2 injection implementation, USA stands in the first place. A rapid increase in oil recovery with CO_2 has been started from 1980s. In 2004,

CO_2-EOR accounted for 31% of all produced oil in the USA in comparison with rest of the EOR techniques and 3.5% of the total recovery (Schulte, 2004). Two biggest CO_2 injection projects implemented in the USA were Wasson-Denver and Means projects where recoveries were 41 Mstb/day and 7.2 Mstb/day respectively. Sacroc field which is located in Permian basin is best known in petroleum industry where first miscible CO_2 injection technique was implemented in 1972. Afterwards a slight increase in CO_2-EOR can be noticed until 1990th, when application of CO_2 displacement methods have rapidly increased in spite of the fact that oil was cheap. Generally, three important changes played an essential role in an increased implementation of CO_2-EOR: 1) Due to development in technology production costs were reduced, 2) Increase in price of carbon dioxide manipulated companies to start producing CO_2 from the natural reservoirs and transporting it to oil fields, 3) New policies of the producers for the reduction of operating costs. An extension of CO_2 displacement methods from the onset of implementation can be seen in Figure 2.9.

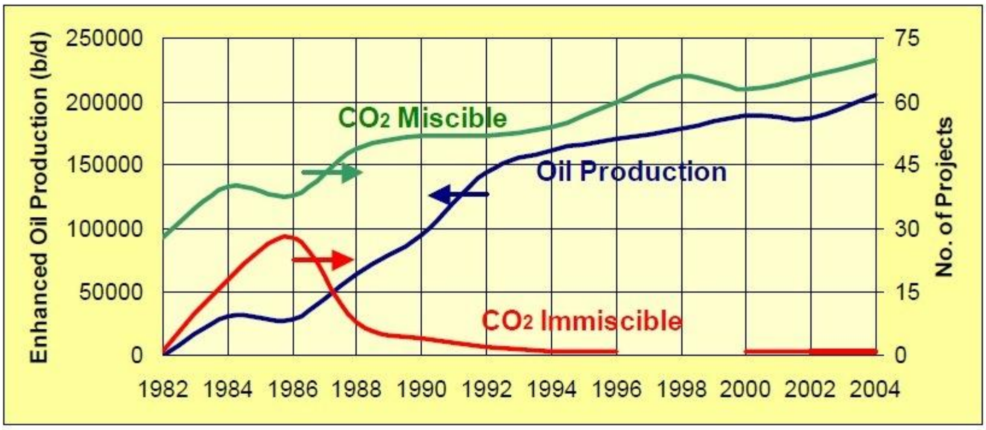


Figure 2.9. Development of CO_2 displacement techniques and cumulative rates in USA (Moritis, 2006)

2.3.5. Comparison between immiscible and miscible CO_2 flooding

The way of how injected carbon dioxide influences petroleum plays an essential role in identification of difference between miscible and/or immiscible CO_2 flooding technique. Once the pressure of CO_2 can be maintained at or above minimum miscible pressure, flowing ability of oil will be improved, which means that displacement method is miscible. On the other hand, in case if MMP cannot be sustained in the reservoir, then the method is immiscible. In this case, CO_2 is generally injected for pressurizing reservoir, thus pushing oil towards producers.

As mentioned earlier, miscible displacement techniques can be implemented at any timescale after water injection, as there is no need to recomplete existing well for miscible CO_2 injection. However, due to requirements in well structure, immiscible CO_2 displacement technique can only be applied when considerable reduction in oil recovery occurs. Table 2.3 shows main differences of mentioned displacement techniques.

Table 2.3. Essential characteristics of miscible and immiscible projects (Kulkarni, 2003)

	Miscible	**Immiscible**
Project duration	Short (<20 years)	Long (min. 10 years)
Project start	Before or after waterflooding	After waterflooding
Oil extraction	Early (1-3 years)	Late (5-8 years)
Scale of project	Smaller	Larger
Recovery mechanism	Complex	Simple
CO_2 recycling	Unavoidable	Avoidable
Oil recovery potential	Lower (4-12 % STOIIP)	Higher (18% STOIIP)
CO_2 storage potential	Lower (0.3 t/bbl)	Higher (up to 1 t/bbl)
Experience	Significant	Little

2.4 EOR Steam injection

Butler (2004) explained that steam injection is an overall name of EOR method used to produce heavy oil from the reservoirs. Despite of diversity of technology, there are mainly two types of steam injection, known as, cyclic steam injection and continuous steam injection. Generally, steam is injected to oil reservoirs, which are not situated deep in the Earth crust. Generally the depth is between 300 meters to 1500 meters. In the reservoirs that possess viscous oil at its natural reservoir temperature, steam is injected to stimulate oil to motion.

Nowadays, the most widely implemented EOR technique is thought to be injection of steam. In 2008, worldwide production rate by EOR techniques raised to 2 MMstb/day, 60% of which was coming to the share of steam injection (Thomas, 2008).

A combination of several processes can be seen once steam is injected to the reservoir. These processes are: decrease in viscosity, fluid expansion by heat, changes in capillary forces and relative permeability, impact of additional drive (solution gas, steam), etc. For successful application of steam flooding, all mentioned above processes need to be satisfied. However, perhaps the first thing that comes to mind is a decrease in oil viscosity once it is heated up.

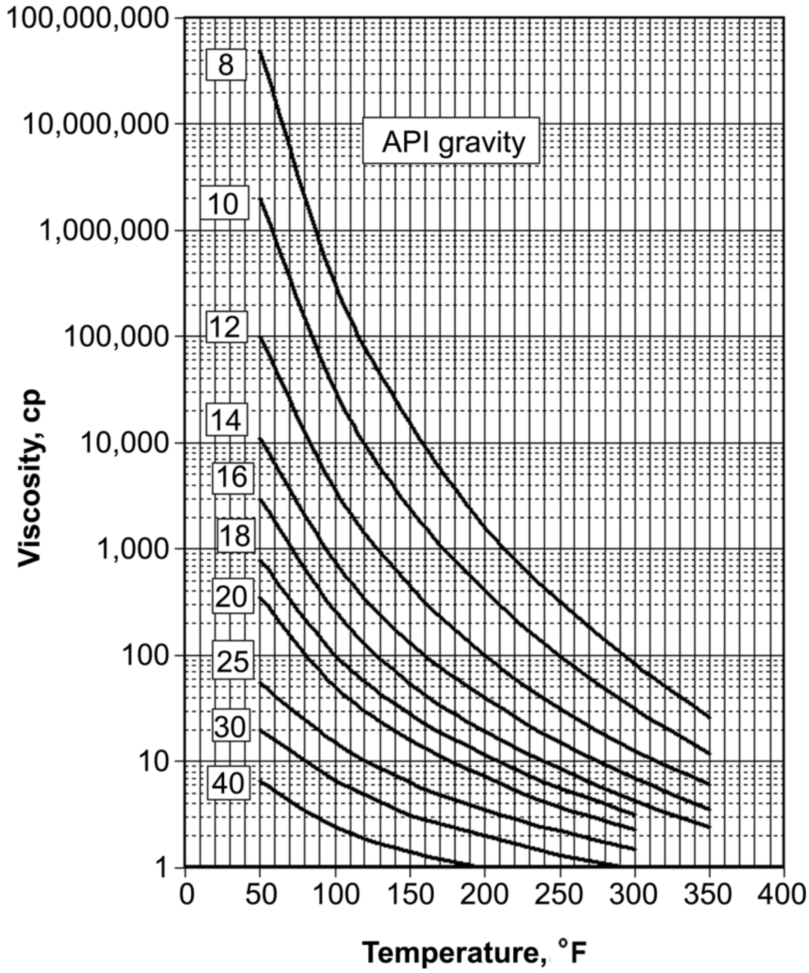


Figure 2.10. Viscosity of oil samples under different temperatures (Doscher and Ghassemi, 1984)

Figure 2.10 shows how the temperature impacts the viscosity of oil. As it can be noted from the graph, trend line of viscosity reduction is steeper at low temperatures. This steep decline is replaced by more normalized line, which implies that there is a certain temperature until which viscosity reduces drastically. Moreover, heat impact is stronger for heavier oils than that of high API gravity oils.

Another important process is the distillation by steam and solvent drive. In case of steam injection, vaporization of less heavier fractions of volatile crudes may take place. This vapor will condense back when it reaches cooler zones. Thus, a miscible bank over steam zone will be developed in this case.

2.4.1 Changes in relative permeability

Injection of steam under high temperature and pressure has a noticeable impact on relative permeability of water, oil and gas.

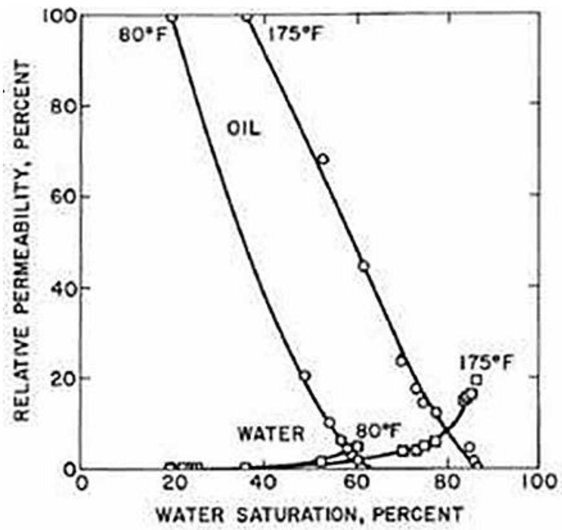


Figure 2.11. Effect of temperature on relative permeability (Weinbrandt and Ramey, 1972)

Overall, in case of temperature increase, relative permeability to oil is also increased. At the same time water relative permeability is reduced. These changes result in the residual oil saturation decrease and increase in irreducible water saturation.

Due to the fact that mobility ratio is dependent on viscosity, it will also be improved, which in turn positively affects sweep efficiency. Oil swelling may come up to 10-20% while steam injection, depending on the oil structure (Butler, 2004). Oil swelling provides extra energy to produce oil from the reservoir.

The ability of water to transport a huge amount of heat per unit mass is due to the fact that it has the highest specific heat and latent heat of vaporization in comparison with other fluids. Thus, if compare latent heat of vaporization of carbon dioxide and water,

CO_2 has 574 kJ/kg while water has 2260 kJ/kg (Perrot, 1998). Figure 2.13 illustrates oscillation of heat proportions of dry saturated steam and boiling water.

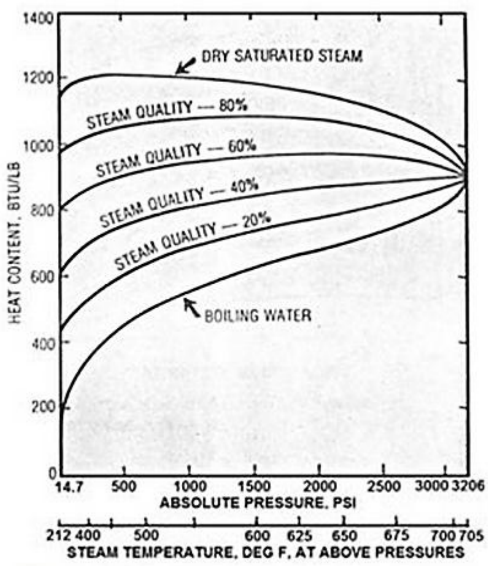


Figure 2.12. Heat content of boiling water and dry saturated steam at different pressure (Ali Farouq, 1989.)

The difference between two lines indicates the latent heat of vaporization. With decreasing pressure, latent heat of vaporization increases. Once critical point is reached (at 3206 psia), it becomes zero. The implementation of steam injection is directed by steam temperature, latent heat of vaporization and pressure.

As pressure increase, the boiling temperature of water also increases. Based on that, in case of reduced injection pressures, heat losses will also be reduced. If rock is less permeable and situated deep in the crust, it oblige operator to inject steam at increased pressures, which in turn will lead higher heat losses.

When steam is injected to the reservoir, under permanent temperature the consumption of its latent heat takes place, until it transforms to water and starts to lose temperature. For keeping steam temperature and heating reservoir rock and oil, companies try to inject steam with high latent heat, so that it can longer be in motion within the reservoir.

2.4.2 Heat loss

The effectiveness of steam injection for heating the reservoir is dependent on several factors of heat lost. While injection from surface into the formation steam undergoes from surface generator straight to injector, down through the well and to the reservoir and in each part of transportation there are heat losses. Heat that is lost depends on the temperature at which steam is injected, formation characteristics and technology applied for injection purposes. Heat, lost on the surface and/or wells, is more favorable, as they can be eliminated. Control of heat loss at the reservoir conditions plays an essential role in evaluation of manageability of the project.

2.4.2.1 Heat, lost at the surface:

Firstly, steam comes out of generator and that is the point when heat starts to be lost. Heat is lost due to the waste gases that come out of the tail pipe. It accounts, approximately, 20% of heat losses.

As mentioned earlier, steam is pumped from generator straight to injection point. Heat, which is lost in this part of injection process, is dependent on tubing type and its length. Based on that, generators are generally built up in the vicinity to the injection point. Furthermore, surface heat losses can also be reduced by burying or insulation heat. Usually, heat losses can be minimized in well-projected surface lines.

2.4.2.2 Heat, lost at the wellbore:

If the bottom of the well is in great distance from the surface, heat loss is a big problem. In this case, steam that is pumped from the surface will become a hot water at the bottom hole.

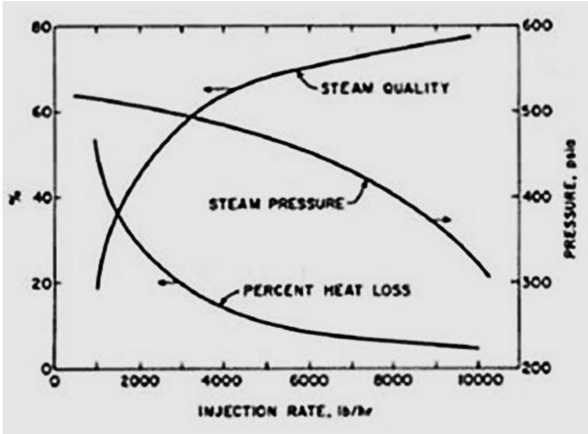


Figure 2.13. Heat loss in the wellbore in comparison with injection rate (Farouq Ali, 1972)

As it can be noted in Figure 2.14, which illustrates the influence of steam injection rate on bottom hole pressure, steam quality and heat loss, that in case of low injection rates, heat losses are increasingly high, which gives a rise to reduced steam quality and subsequently to increased pressure in the well. Generally, in case of small diameter well, heat, lost in the wellbore, will be less than that of bigger diameter. As mentioned earlier, heat losses are more or less dependent on rate of injection and depth. However, it is also influenced by completion and casing types. In order not to lose a heat in the wellbore, it is recommended to sustain it with insulation heat. Thus, considerable amount of heat will contribute to heat the formation. (Satter A. 1965)

2.4.2.3 Heat, lost in the reservoir:

As indicated above, heat loss within the reservoir almost cannot be managed. Once steam penetrated the formation, it starts to heat up upper and lower parts of the reservoir. In this case, conduction plays an essential role in heat losses. As steam zone becomes greater, the rate of heat loss also increases. This implies that the rate of heat loss is influenced by the volume/area that steam is going to contact. Furthermore, the rate of heat loss is also dependent on time. The rate of heat loss goes down once the steam entered the reservoir and started to heat the rock.

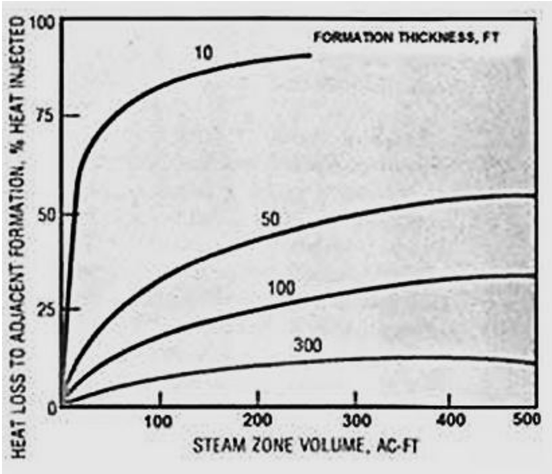


Figure 2.14. Variation of heat losses to the formation with formation thickness (Herbeck et.al. 1978)

In Figure 2.15 steam is injected at a constant rate of 1000 stb/d to the different formation thicknesses. As it can be noted from the figure, the heat loss to the adjacent formation rises with increase in steam zone area. Moreover, formation thickness and heat loss to the reservoir are in counter-clock wise relationship with each other, which implies that injection of steam to small areas will not be efficient. (Farouq Ali, 1974)

2.4.3 Types of steam injection:

Typically, there are two main types of steam injection: Cyclic steam injection and continuous steam injection.

2.4.3.1. Cyclic steam injection:

It was noticed by Butler (1991) that cyclic steam injection is mainly used for stimulation purposes, which leads to decrease in viscosity and cleaning of wellbore, near wellbore area, thus, providing an additional energy for pushing oil towards producing wells. In spite of the fact that oil production is less (only 10-25%) than that for continuous steam injection, it is highly recommended and applied technique for preliminary heating and preparing formation for application of further techniques.

Simplicity of this technique is based on the single-well pattern. First, the steam is injected to the formation, then after a certain time injection is stopped for injected steam to heat reservoir rock up, and finally the well is opened for producing the oil (Figure 2.16). This technique is also called Huff and Puff method.

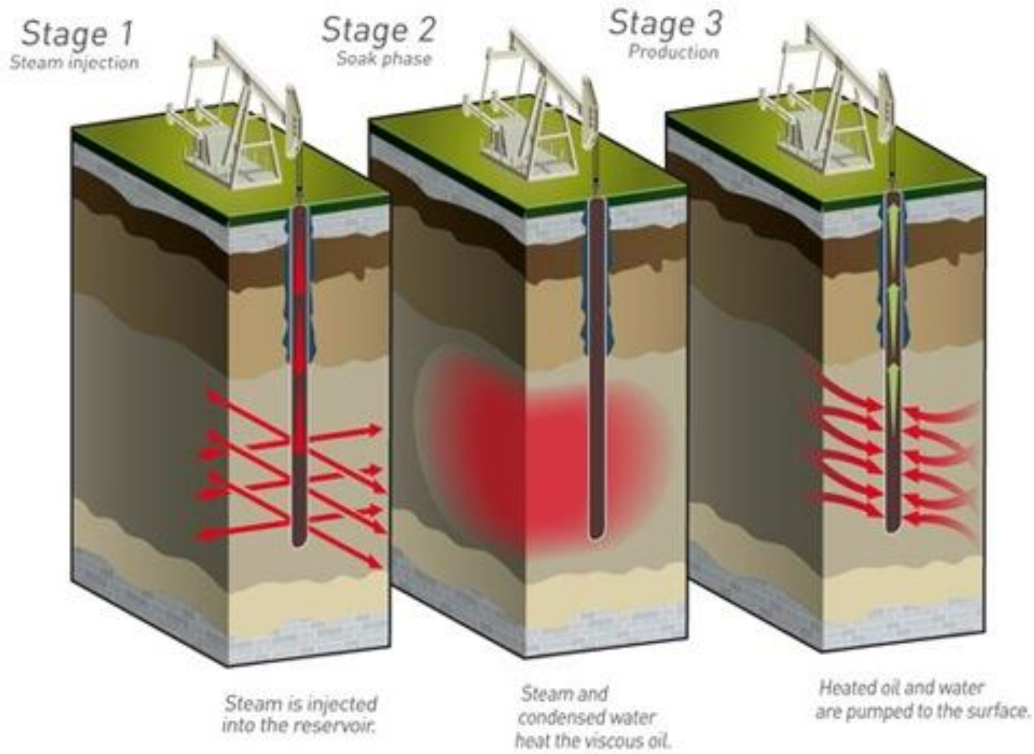


Figure 2.15. Huff and Puff method (Butler, 1991)

Effectiveness of cyclic steam injection depends on the type of the reservoir. For instance, in reservoirs where main recovery mechanism is gravity drainage, it is highly recommended to implement cyclic steam injection, as once heated, oil viscosity will be reduced so that it will easily flow towards production wells. However, in reservoirs with horizontal structure formation energy is exhausted faster, inhibiting the amount of steam cycles.

In 2005, Shell introduced so called "J-well", which work as a vertical separator. By means of J-well steam is properly delivered to the well bottom. J-well eliminates condensation within the wellbore and can store gas and steam in the formation more properly. A pilot test of the J-well that was conducted by Shell provided better oil-steam ratios than that of conventional cyclic steam injection wells. Furthermore, based on 4-D seismic interpretation, it was noticed that heat was more effectively distributed within the formation (Brissenden, 2005).

2.4.3.2. Continuous steam injection (CSI):

The procedure of continuous steam injection resembles that of water injection in secondary recovery. The formation rock and oil are heated up by steam once it penetrates reservoir. Heating process continues until steam condenses to the droplets. As steam vapor reduces oil viscosity, it also provides gas drive to moveable oil. In the formation the capacity of steam vapor is great. In other words, at 200 psi one barrel of water produces 100 barrels of vapor (Farouq Ali., 1997). To recall, the viscosity of oil can be reduced by 1000 times. In the reservoir steam starts to condense, thereby the effective viscosity increases as well, bypassing the efficiency of steam and/or hot water injection alone.

Generally, continuous steam injection technique increases recovery up to 50-60% of OIP (Donaldson, 1989).

According to Das (2005) in case of bitumen reservoirs, conventional steam injection is not sufficient to eliminate the problem of mobilization of bitumen, as it is almost motionless in the formation due to API gravity. Due to immobile oil, the rates at which steam should be injected would fracture the formation. Therefore, Steam Assisted Gravity Drainage (SAGD) was evolved, for preventing the formation from fracturing (Figure 2.17).

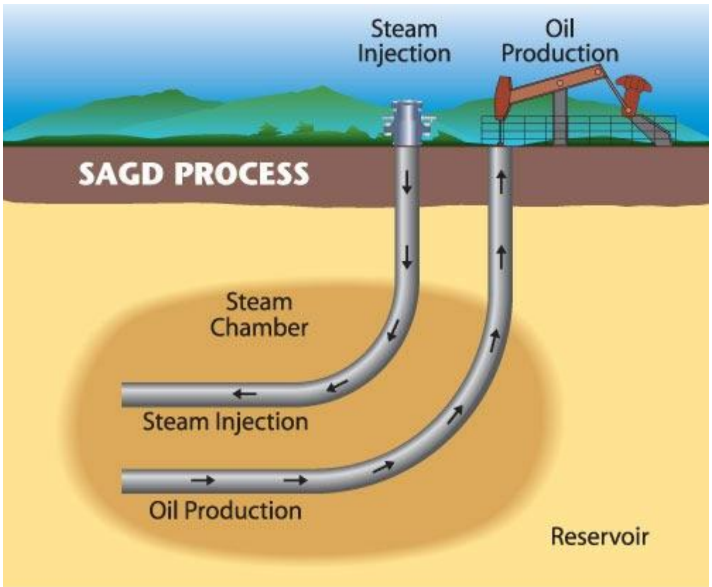


Figure 2.16. Steam Assisted Gravity Drainage. (Das, 2005)

The conceptual design of SAGD consists of a couple of horizontal wells for injection and production**.** The main requirement of this technique is that injection well should be over the producer, so that oil is heated up and moves down to production well by gravity drainage.

The reason of implementation of SAGD for bitumen or immobile oils is that, these play an important role in forming a steam chamber. Furthermore, vertical permeability of the formation should be sufficient enough for heated and mobilized oil to flow down to the production wells by gravity. For SAGD itself to be efficient, steam chamber should be maintained with additional steam injection, which in turn will lead to elimination of formation of liquid above the production well.

One of the first SAGD applications was conducted in the Alberta, for increasing production in Tangleflags where oil viscosity was very high. It is a sandstone formation with thickness about 13 meters, recovery from primary production of which accounts for less than 1% of OIP (Thomas, 2008). Water coning played a negative role in exploitation of the field.

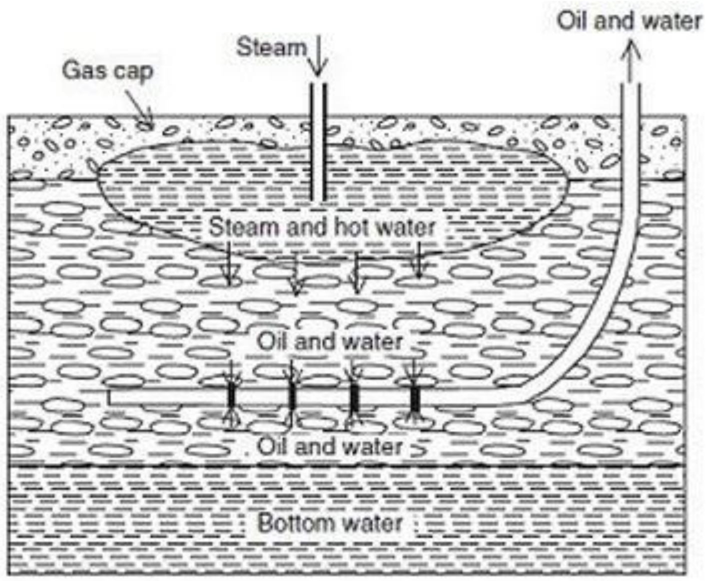


Figure 2.17. SAGD technique in Tangleflags formation (Thomas, 2008)

As it can be seen from Figure 2.17, the injection well was drilled to the gas-oil contact, for mobilization of oil, so that it can flow down to the production well. Favorable pressure gradient towards producers played an essential role in lowering water coning. (Jespersen et.al., 1993)

2.4.4 Selection Criteria

In spite of the fact that steam flood operation is an effective EOR technique, there are some recommendations for implementation.

1) Formation with oil of lower viscosity and API gravity of which fluctuate around 10 to 20 API, are most suggested to be injected by steam.

2) As mentioned earlier, heat losses are lower for the formation which depth is less than 3000 ft.

3) Rock permeability should be 500 md or higher for allowing viscous oil to flow.

4) From economical perspective oil content at 1200 bbl/acre-ft is beneficial

5) Rock thicknesses minimum should be 30-50 ft for inhibiting heat losses.

As noted above, for control of steam injection rate, lower reservoir pressures are more favorable. On the other hand, in case of low reservoir pressure, the problems appear at the production wells, as energy is not sufficient enough to lift oil to the surface. Moreover, oil recovery will be low if steam temperature will be reduced, as in this case oil viscosity will not be decreased sufficiently to flow. (Herbeck, E.F. et.al. 1978)

The main advantages of steam flood operations over other EOR techniques are: the management of steam injection is easier than that of in situ burning. Oil is not cracked in case of steam flooding, which implies that this technique ecologically is more recommended. Furthermore, injection and production wells are not exposed to high temperatures as in in-situ combustion.

2.4.5 Variations and optimization of steam flooding

2.4.5.1 Steam flooding prior to water injection:

By increasing the maturation by steam, oil recovery reduces. This is due to the fact that steam-oil ratio (SOR) goes up to abnormally high numbers. Large SOR implies that reservoir stores large volume of steam in the formation, while another portion of it does not contribute to production.

At the end of 1980s it was recommended to change steam flood operation with water injection. In this case the rearrangement of heat in the formation will take place, which will lead to increase in recovery, as water will contribute to better oil sweep from areas where steam left unswept. (Ault, J.W. 1985)

2.4.5.2 Water alternating steam:

The implementation of water alternating steam plays an important role for eliminating or, at least, inhibiting steam breakthrough. This implies that, in case of Water Alternating Steam injection sweep efficiency and oil production increase.

First application of this technique was effectively conducted in Russia from 1981 to 1984. Each year oil recovery has increased by 25-30%. Furthermore, implementation Water Alternating Steam injection was also applied in California, which prevented early steam breakthrough and increased oil production. (Hong, K.C. 1999)

2.4.5.3 Air injection after steam injection:

Sometimes it is beneficial to inject air after steam flood operations, as this scenario may produce extra oil. British Petroleum experienced this first in Canada. After cyclic steam stimulation, air was injected to the bitumen formation, located under Cold Lake. Oil production increased by two times in comparison with single steam injection and SOR decreased almost by three times from 6.1 to 2.3. (Hallam and Donnelly, 1988)

2.4.5.4 Hybrid Steam techniques:

In recent years, additives that are added to steam to accelerate the process of oil production have captured the interest of petroleum industry. These additives may be natural gas, CO_2, flue gas, etc. The following processes may take place regarding which catalyzer to add: viscosity reduction, decrease in residual oil saturation, lowering interfacial tension, provides gas drive, etc.

From economical and ecological perspectives, co-injectants may lead to reduction in amount of steam to be injected. In case of low amount of injected steam expenses, emissions and usage of row materials will also be reduced.

Expanding Solvent Steam Assisted Gravity Drainage (ES SAGD) is a branch of SAGD and consists of a combined injection of lighter hydrocarbons and steam together. In this case, lighter hydrocarbons dilute in oil, thus reducing its viscosity. This process is supported by steam, which heat rock and oil up. This technique has already been applied with considerable increase in oil recovery, and decrease in SOR. Furthermore, 70% of the injected hydrocarbons could also be recovered after some period of time.

A pilot test in Liaohe oil field, which located in China, was conducted with the combination of steam and flue gas injection. For diffusion and getting through the formation the well was closed for 4 days. Once it was opened, better steam quality at the bottom and decrease of SOR by 30% was obtained. (Zhu, C. Et.al. 2001)

2.4.5.5 Fracturing with Steam:

Experiences show that it is possible to recover petroleum from bitumen formations. In case of the absence of gas cap and aquifer, cap rock acts as a barrier; therefore the injection pressure may be increased to be higher than formation fracture pressure. Consequently, mobilization of bitumen will take place. Fracturing would help to recover bitumen from isolated areas. (Hong, 1999)

2.4.6 Steam injection implementation worldwide

The first implementation of cyclic steam injection (CSI) was in 1959 in Venezuela. Production from the well where steam was injected was higher in comparison with other ones. Afterwards, cyclic steam injection technique earned a big amount of applications in Canada, Trinidad, China, USA etc. As mentioned earlier, steam injection is best EOR technique for the fields with heavy oil. However, it took more than 10 years for CSI technique to be modified and be more effective. In 1970s the amount of steam injection cycles raised and in 1990 the number of stimulation cycles increased to 39 in Mid-Way Sunset field, California. Moreover, 30 cycles were counted by 75 wells, 20 cycles by 350 wells from the overall amount of 1500 (Jones et.al., 1990). Clear image of steam and formation properties as well as conditions under which steam is injected made it easier to increase the amount of cycles.

Development of horizontal wells also played an essential role in application of steam injection technique. More precisely, Canada started application of screen sections in horizontal wells in Cold Lake oil sands. Screen section in turn increases contact between well and the formation.

Better optimization of pressure and temperature also led to the effectiveness of CSI technique. For instance, in California in order to fracture the reservoir, steam was injected at abnormally high pressures. Another example again is in California in Midway-Sunset field, where successive steaming technique was implemented. The purpose of this technique is to heat up the whole formation than individual well, so that the whole reservoir would contribute to production. In such way, amount of oil produced by each well increased by 30%.

Cold Lake field in Canada has undergone a lot of experiments and one of them is Liquid Addition to Steam for Enhancing Recovery (LASER). In case of effectiveness of this technique production can goes up by 3-6% of Oil Originally in Place. Table 2.4 illustrates oil recoveries of different thermal EOR techniques.

Table 2.4. Recovery of different thermal EOR processes. (Thomas, 2008)

Oil recovery factor	
Thermal EOR	**% of OOIP**
CSI	10-40
Steam flooding	50-60
SAGD	60-70
In-situ combustion	70-80

2.5 Modeling of CO_2 injection and Steam injection

Starting from 70s, 80s EOR techniques started to be simulated for better understanding of their impact.

2.5.1 Immiscible CO_2 injection simulation

Immiscible CO_2 injection project has been conducted in Turkey for the Bati Raman Oilfield. Due to the existence of very little amount of dissolved gas within the formation when CO_2 started to be injected, only CO_2 would flow in the reservoir. The pressure required for development of miscibility is significantly higher than pressures that can be reached in real life in the formation. Therefore, the operation is surely immiscible. Based on above mentioned information, black-oil simulation technique was chosen as the best fit for analyzing the process. More precisely, 3-D, dual-porosity, black-oil simulation model was used. Utilization of dual-porosity technique was important as the formation is naturally fractured one. Moreover, transfer of carbon dioxide from matrix to fracture and back around was also important. While building of simulation model it was noticed that the success of the project depends on the diffusion processes of CO_2 within fracture and matrix. For Bati Raman oil field fractures contribute only 10% of whole pore volume, which implies that injection of carbon dioxide would have an impact on recovery up to 10% of the total field. On the other hand, if CO_2 can spread to matrix as well then 90% of the pore volume would be affected, which in turn would have a great impact on recovery. Diffusion depends mainly on the fracture's geometry (Kantar and Karaoğuz, 1985).

2.5.2 Steam injection simulation

In spite of the problems occurring with steam injection in the naturally fractured reservoirs, steam injection has becoming to be under big interest in petroleum industry for the last 20-30 years.

Due to differences in capillary forces between matrix and fracture, it becomes to be a problem to build a numerical model in case of steam injection. Because of non-unique porosity in naturally fractured reservoirs, formation characteristics responsible for flowing of fluid differ from those formations that have unique porosity. A great effort has been consumed for analyzing transient pressure of single-phase flow. Researches of multi-phase fluid flow in naturally fractured reservoirs are generally applied the water injection technique and mainly comprises of black oil and compositional simulation (Chen et al., 1987). The application of thermal simulators is different. Some of the simulators are used for naturally fractured reservoir, while on the other hand the rest of models are used for carbonate reservoirs (Briggs, 1989).

The most difficult problem of naturally fractured reservoirs where steam injection is implemented is the understanding of heat and fluid motion among matrix and fracture. For better understanding of above-mentioned processes, capillary, viscous and gravity forces should be taken into consideration (Thomas et al., 1983).

After some investigations several steam injection modeling techniques were proposed. One of them implies that the thermal dual-porosity within dual-permeability simulation model has to be built to eliminate the problems. The model itself is built in 3-D format, and includes formation heterogeneities. The design of producers and injectors is multi-layer and wells are connected to the reservoir fully implicitly (Dean and Lo, 1988).

CHAPTER 3

STATEMENT OF THE PROBLEM

Throughout last decades a considerable amount of studies and work are concentrated on development of technology, software, etc. to increase production from heavy oil reservoirs. Enhanced oil recovery techniques proved to be an efficient alternative after primary and secondary recoveries. Additional investments are made to increase recovery factor of EOR techniques. Thus, considerable development took place in injection of carbon dioxide and in steam injection operations.

The selection of most convenient EOR technique to apply for an oil field is a challenging process. This study is generated based on production scenarios appropriate for heavy oil field by using geological modeling software (Schlumberger's Petrel). Although, the geological model accounts only the basic (such as: porosity, permeability, API gravity) parameters of heavy oil field, it can be used to evaluate different scenarios of enhanced oil recovery techniques. Several scenarios are constructed, such as: continuing the water injection, steam injection without CO_2 injection, CO_2 injection, etc.

A reservoir model is generated and run using Schlumberger's Eclipse simulator in order to understand the effect of CO_2 injection prior to steam injection. The comparison of recovery performances at different cases helps us to understand the most effective path of applying enhanced oil recovery techniques.

CHAPTER 4

METHODOLOGY

In this study, the simulation model has been built to obtain the production data of a hypothetical reservoir. Simulation runs were prepared according to production scenarios of similar to heavy oil reservoirs. Runs are conducted in order to get data of production, pressure, saturation and temperature. For building the geological model, Petrel software is used. Later, Eclipse simulator is used to perform the dynamic model runs. In order to check the consistency of the simulation model material balance has been conducted as well.

Two different versions of the Schlumberger Eclipse software could be used for this study; black oil simulator, Eclipse 100 and compositional simulator, Eclipse 300. The compositional simulator (Eclipse 300 version 2007.1) is preferred in order to track composition and temperature changes during field life.

4.1 Simulator Characteristics

4.1.1 Eclipse 100

In this version of Eclipse, 3 different phases can be implemented in RUNSPEC section. The keyword DISGAS is used to allow the gas to dissolve in the oil phase. Using the black-oil model to simulate the behavior of oil and gas, the gas is assigned the CO_2 properties and can dissolve only in the oil phase. It is practical as a first approximation, however this is not a good assumption since we know the solubility of CO_2 in the brine or pure water can be significant: around 190 scf/stb in fresh water at 4000 psia (Whitson, 2000). Therefore using a black oil simulator is not convenient for this study.

4.1.2 Eclipse 300

This version of Eclipse, allowing a compositional model is more accurate for this study. The oil phase is represented by hydrocarbon components and carbon dioxide is introduced as another component. The simulation model contains also water. The solubility of the gas in the aquifer is taken into account. In the RUNSPEC section the CO2SOL option illustrate this possibility. Regarding the computation method, it uses the fully implicit method, so that at every time step the pressure dependent terms (such as; density, gas formation volume factor, or viscosity) are evaluated. Peng-Robinson equation of state method is used.

The GRID section comprises physical parameters for the grid blocks, and also keywords as AQUNUM to assign a numerical aquifer to a grid block and AQUCON to specify the connection data for numerical aquifers are used to simulate an aquifer in a grid block.

Table 4.1. Main parameters

Parameter	**Value**
Porosity	17%
Absolute Permeability	50 mD
Depth at the top	4300 feet
Transmissibility	1

The PROPS section sums up the CO_2 properties described earlier, the water and oil relative permeability values are added. The residual oil saturations have been defined so that 20% oil remains after the waterflood and 5% oil after the CO_2-flood.

4.2 Model Setup

Geological model has been built using Petrel software based on a similar anticlinal structure of the Bati-Raman oil field. The model area divided into 3283 elements (67 rows and 49 columns) using regular structured grids with the size of each element is 640 ft by 670 ft (Figure 4.1). The outer boundaries of the model are no-flow boundaries. The model defines a system made up of 20 sub layers. Net to gross (NTG) variation is around 0.38-0.45. Average permeability is around: 40-50 mD. Porosity is around 0.18-0.2. There is no any standard PVT correlation in Eclipse which can be used for heavy oil API<15, therefore heavy oil PVT was calculated based on De Ghetto at al. (1995) correlation, which contains modified PVT correlations for estimating bubble point pressure, solution gas oil ratio (R_S), oil formation volume factor (B_O), oil compressibility (c_o) and oil viscosity (μ_o) for the heavy oil (10<API<22.3). For developing this correlation fluid samples were taken from the Mediterranean Basin, Africa, and the Persian Gulf. When comparing published correlations, De Ghetto et al. (1995) decided that the Vasquez and Beggs correlation estimated the oil formation volume factor with minimal error, and therefore no further modification was needed. Compared to other correlations, pressure and temperature at the separator is mandatory in the De Ghetto et al. (1995) correlation. Eclipse 300 Thermal solution type has been used as “Fully Implicit”.

The model consists of total pore volume of 78 MM rb (total fluid volume) and hydrocarbon pore volume (HCPV) of approximately 63 MM rb with initial average oil saturation of 0.8. The reservoir depth is taken to be 4300 ft with one injection well and four production wells. Well bore diameter is taken as 0.375 ft and wells are produced using minimum bottom hole flowing pressure control mode. Injection pressure is set to be 1900 and 100 psia is specified for production wells as pressure constraints. The simulation is run for 54 years from 1962 to 2016.

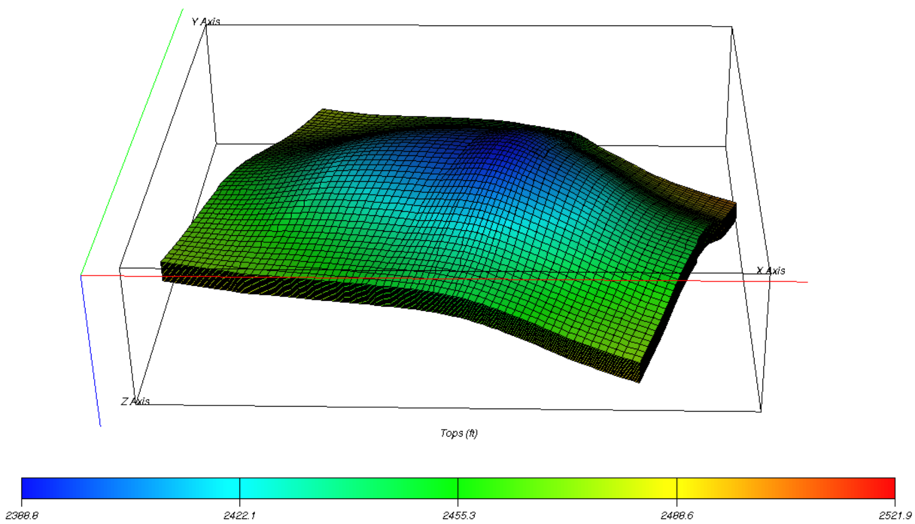


Figure 4.1. Grid model

Corey relative permeability functions were used with residual water saturation set at 0.3, and residual gas saturation as 0.05, while capillary effects were not taken into account. The diffusion coefficients of methane and CO_2 were taken as follows: 10^{-5} m^2/s in the gas phase, $1.5\text{-}2.1\cdot10^{-9}$ m^2/s in the aqueous phase. Figures 4.2, 4.3, and 4.4 show the relative permeability curves for oil, gas and water phases, respectively. Capillary pressure is neglected for simplicity, but it should be emphasized that core data treatment to determine both relative permeability and capillary pressure is an important issue, and of particular interest for long term behavior, and fluid propagation after the injection phase. Rock compressibility is 5×10^{-4} 1/psi. Reference pressure is set as 1800 psia. Rock thermal conductivity is around 24 Btu/ft·day·°F.

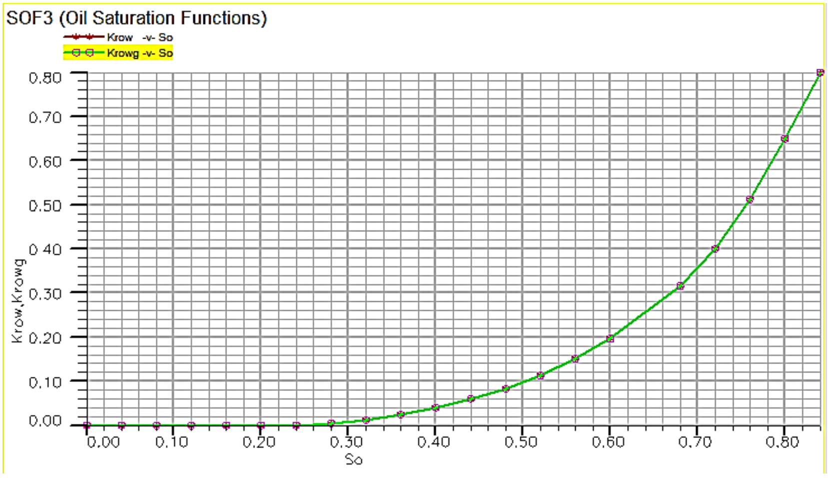


Figure 4.2 Oil relative permeability

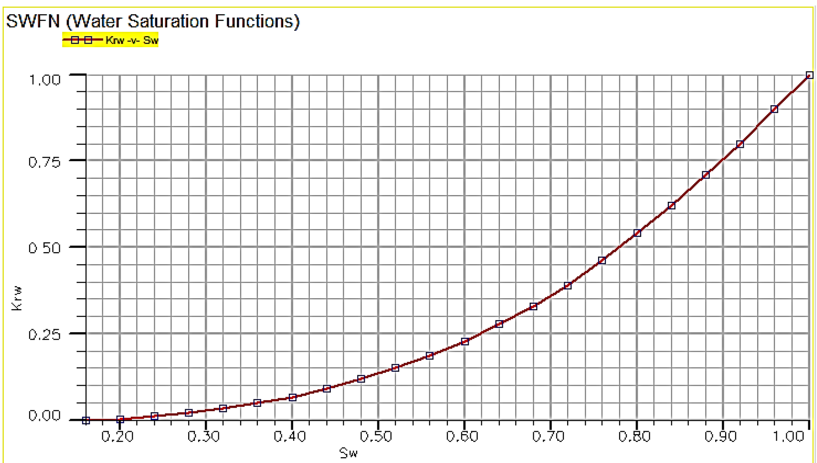


Figure 4.3. Water relative permeability

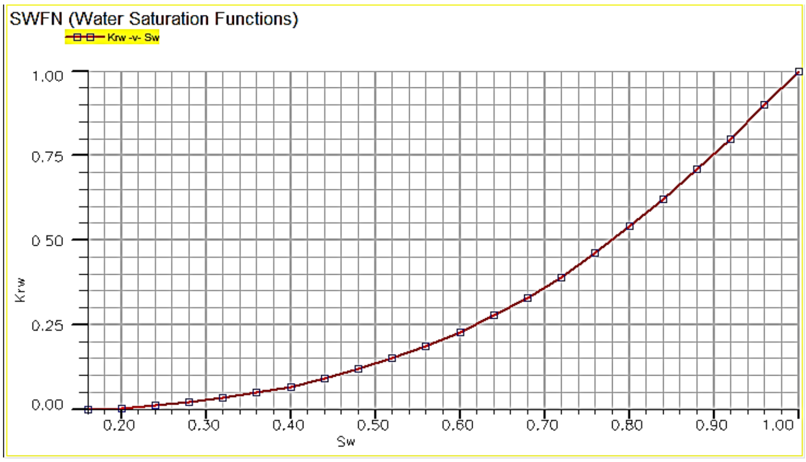


Figure 4.4. Water relative permeability

There are 5 wells in the model (Figure 4.5). The locations of the well blocks are given in Table 4.2.

Table 4.2. Well locations in the grid model

Wells	(i) index	(j) index	(k) index
P1 (production well)	35	22	1-20
P2 (production well)	9	11	1-20
P3 (production well)	13	40	1-20
P4 (production well)	57	40	1-20
P5 (injection well)	57	12	1-20

4.3 Base Case

The base case run is based on field operations of heavy oil field. Theoretical oil field started to operation from 1962 to 2016 with 5 oil producer wells. All 5 wells have been completed to all sub layers (1-20) and produced as comingled. Due to pressure decreasing in the reservoir the central well (P5) converted to normal water injector (W_{inj}) after 10 years in order to support the pressure for the remaining 4 oil production wells. The injection well is perforated only layers 15 to 20 and injects 30 Mstb water per day. Starting from 1972 the field has been operated with 5 spot wells (one injector and 4 producers) until 1986. After that the central water injector well converted as CO_2 injector in order to minimize oil viscosity in the reservoir. Starting from 2013 steam injection started simultaneously with CO_2.

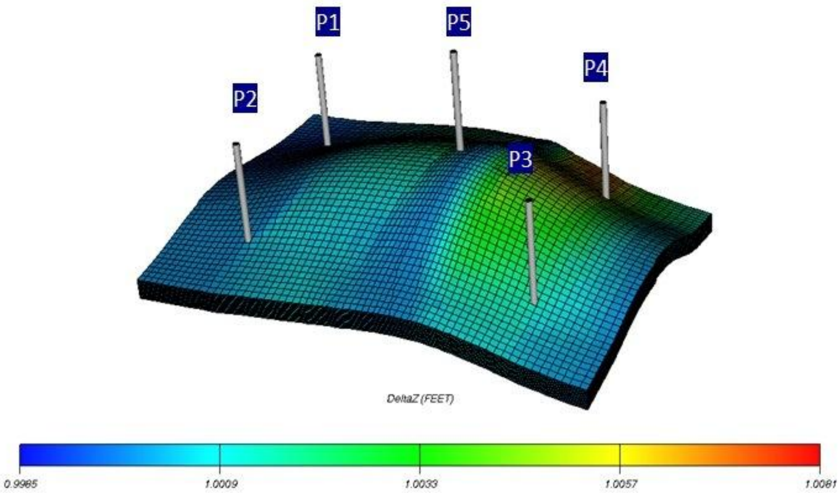


Figure 4.5. All well are producers

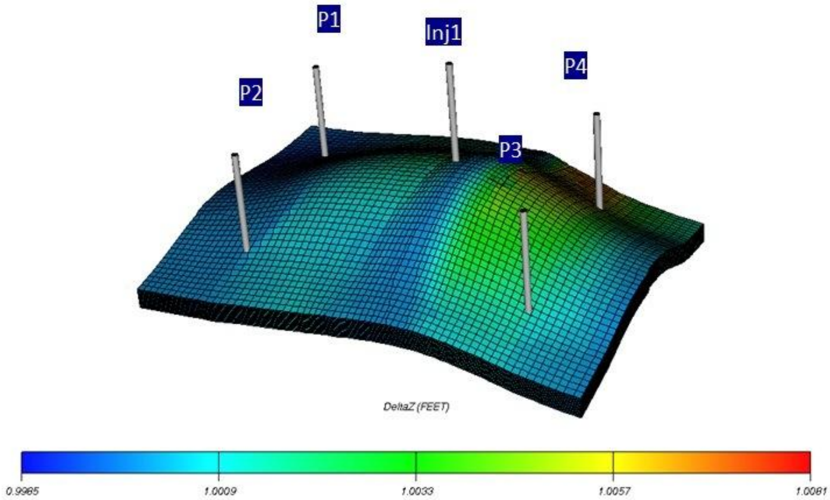


Figure 4.6. Central well is converted to CO_2/Steam injection well

The impact of implemented EOR techniques by the following scenarios can be understood and visualized better by comparing with the base case.

4.4 Scenarios

Simulation model has been run at 6 various scenarios to understand the impacts and efficiency of EOR techniques, specifically the effect of CO_2 injection prior to the steam injection.

4.4.1 Scenario 1:

In this scenario, field started to operation from 1962 with 5 producers without any pressure support (primary production). At the beginning of 1971, central well converted to normal water injector until 2016.

4.4.2 Scenario 2:

In this scenario, simulation model has been run as 5 spot injection of CO_2 from the central well after a primary production phase between 1962 and 1971. CO_2 injection started at 1 January 1971 and continued until 2016.

4.4.3 Scenario 3:

In this scenario steam is injected starting from 1971 without any prior water injection. During 1962 to 1971, all 5 wells are used for production. The steam injection continued until 2016.

4.4.4 Scenario 4:

This case covered steam and immiscible CO_2 injection simultaneously from starting at the same injection time on 1971. Although it is difficult to implement simultaneous CO_2 and steam injection from the same well in real situations, it is aimed to see the effect on the recovery. The primary recovery takes place between 1962 and 1971 as before and the injection ends on 2016.

4.4.5 Scenario 5:

In this scenario the options of immiscible CO_2 flooding followed by steam injection is analyzed. Following the primary recovery between 1962 and 1971, CO_2 is injected from the central well until 1986, then it is replaced by a steam injector and run has finished on 2016. The difference between this scenario and the base case is the lack of water injection in this case.

4.4.6 Scenario 6:

In this case, water flooding (1971 to 1986) instead of CO_2 injection is implemented before the steam injection starting after the primary recovery period of 1962 to 1971.

The steam injection takes place between 1986 and 2016. The comparison of this scenario with the Scenario 5 shows the effect of water injection and CO_2 injection prior to steam injection.

4.4.7 Scenario 7:

In this scenario water injection started in 1971, immediately after primary production stage. The difference of this scenario with scenario 1 is that for this case water was injected to all 20 zones.

4.4.8 Scenario 8:

This scenario represents the same water injection technique, which started in 1971. The main difference is that the distance of producing wells was reduced (2 km towards injection well)

4.5 Material Balance

Nowadays, there is a belief that numerical simulation modeling technique is more advantageous over material balance concept that has been used in oil industry. However, usage of the numerical simulation techniques together with the material balance concept would reduce the risk of errors that are hard to identify when using numerical techniques alone.

In order to identify the average pressure decline trend, material balance can be used with only production and pressure histories and with awareness of fluid PVT properties. Thus, no geological models are required in case of material balance, which calculates STOIIP and identify reservoir drive mechanism. Therefore, it is the easiest and fastest technique in oil industry since it is the minimum assumption route through the subject of reservoir engineering.

Material balance and simulation modeling are not competitors at all. Conversely, they should be used in supportive purposes of one another: material balance defines the system and transported to the simulation model as an input. As a matter of fact, material balance is a powerful tool in applying for history matching production performance, nevertheless, prediction is the disadvantage of this technique. Therefore, for prediction simulation modeling technique should be used.

A material balance evaluation tool is used to compare the pressure data obtained from the simulation run. Material Balance evaluation is done in Integrated Production Modeling software (IPM), called MBal. The tool uses analytical techniques for investigation of fluid dynamics of the field, basic principle of which is classical material balance equation. It is possible to obtain a realistic profiles by means of MBal with or without history matching. (IPM Products. 2010)

CHAPTER 5

RESULTS AND DISCUSSIONS

5.1 Base Case

Simulation model has been built and computed using the THERMAL option of the Eclipse 300 simulator. The cases applied in the study are summarized in Table 5.1. Figure 5.1 shows daily oil production and cumulative oil production obtained using the base case. In the Base case all 5 wells produce heavy oil without any pressure support and stimulation. Those wells penetrated and completed for each zone. Well control has been set to minimum flowing bottom hole pressure (BHFP) of 100 psia for each well.

Table 5.1. The summary of the simulation cases

Case	Primary production	Water injection	CO_2 injection	Steam injection
Base case	1962 - 1971	1971- 1986	1986 - 2013	2013 - 2016
Scenario 1	1962 - 1971	1971 - 2016	-	-
Scenario 2	1962 -1971	-	1971 - 2016	-
Scenario 3	1962 - 1971	-	-	1971 - 2016
Scenario 4	1962 - 1971	-	1971 - 2016	1971 - 2016
Scenario 5	1962 - 1971	-	1971 - 1986	1986 – 2016
Scenario 6	1962 - 1971	1971 - 1986	-	1986 - 2016

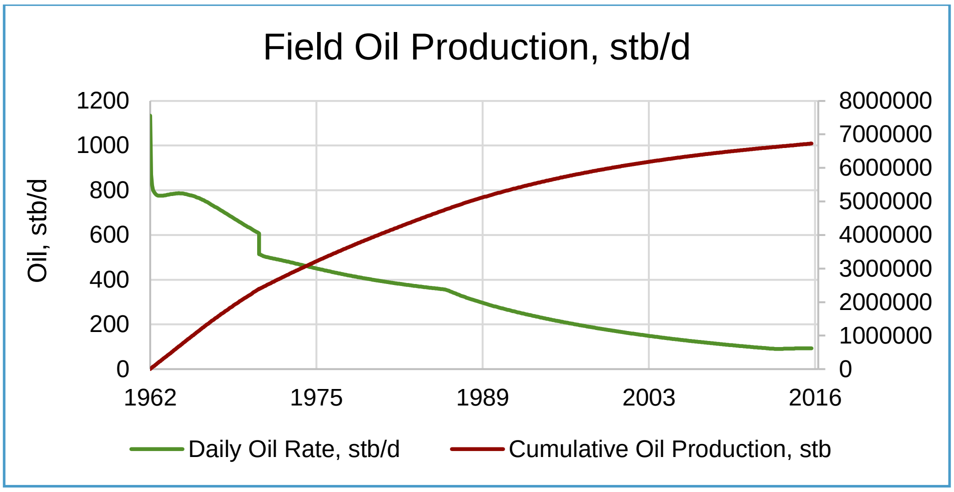


Figure 5.1 Field daily oil production rate

Figure 5.1 shows the quick rate decrease in production wells is followed by a short recovery period. Then the rate continues to decrease until end of primary production period. The decline in production rate is slowed down with the start of water injection on 1971. The sharp decrease seen on rate in 1971 is because of the conversion of one of the producers to an injector. Starting to inject CO_2 on 1986 has a negative effect on the production rate as seen from the changing trend of the rate.

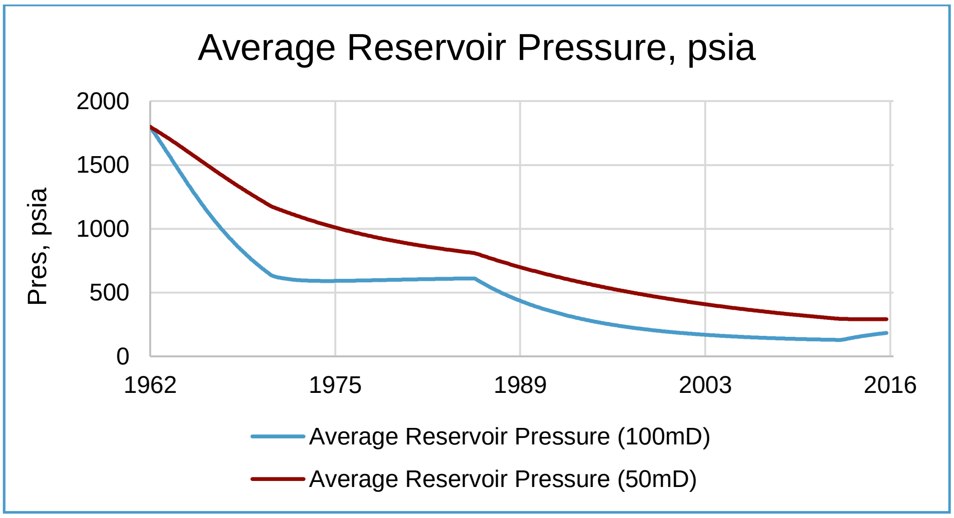


Figure 5.2 Average reservoir pressures

Two different permeability values have been used to understand the effect of permeability on the reservoir pressure. Figure 5.2 shows average reservoir pressure based on 50 mD and 100 mD. Higher permeability caused the waterflooding period (between 1971 and 1986) to be more effective comparing the lower permeability case. Similarly the steam injection at the end of the run shows an increase in the reservoir pressure. The average reservoir pressure reduces more in higher permeability case due to higher production rates. However, all the scenarios and the base case model have been run with 50 mD permeability.

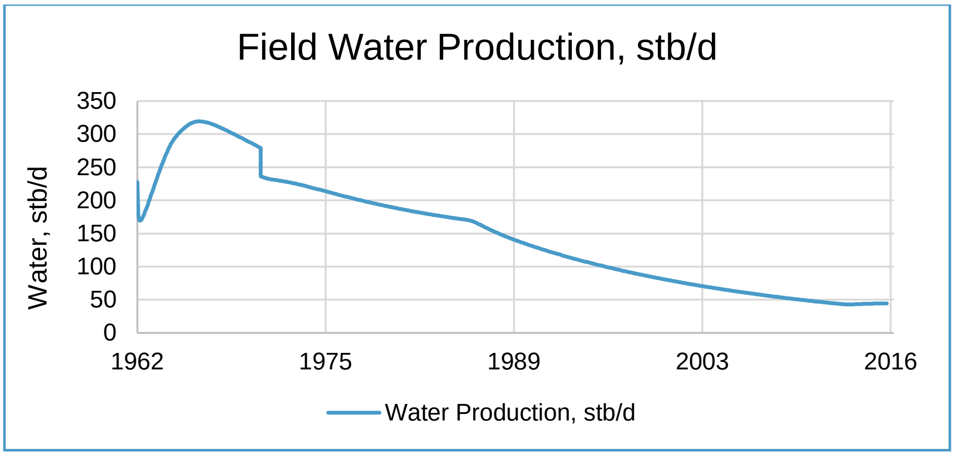


Figure 5.3 Field daily water production rate

Figure 5.3 shows the total water production rate obtained using the base case. The water production rate reaches the peak point during primary production and starts decreasing. The effect of the waterflooding can be seen between 1971 and 1986 period when some of the injected water has been produced at the same time. Similarly injection of steam has also affected the water production although it lasts only three years in this case. During the CO_2 injection period, a considerable decrease in water production is achieved. The sharp drop in 1972 is due to the conversion of a producer to an injector.

5.2 Scenarios

<u>5.2.1 Scenario 1</u>

The reason of creating this scenario is to see impact of water injection to the oil recovery compared with the base case.

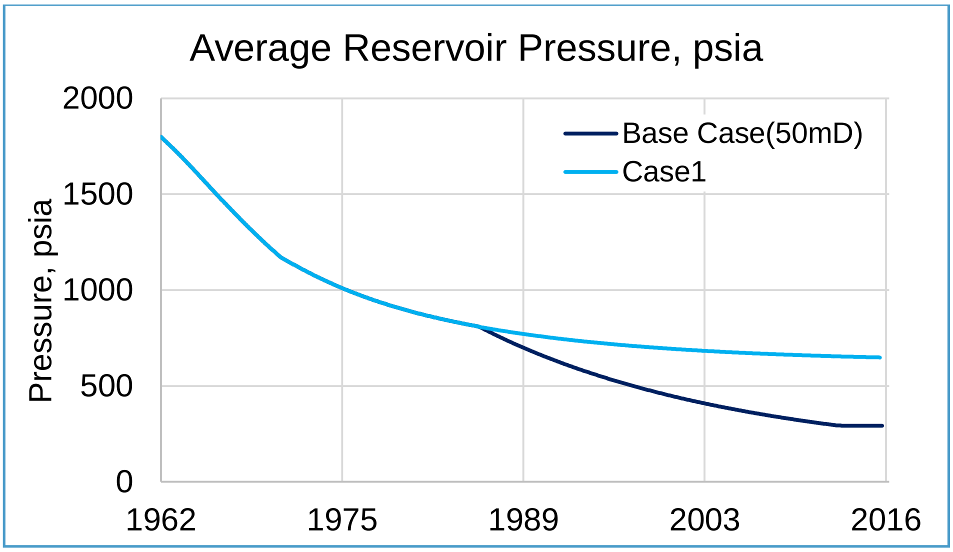


Figure 5.4. Comparison of base case and scenario-1 average reservoir pressure

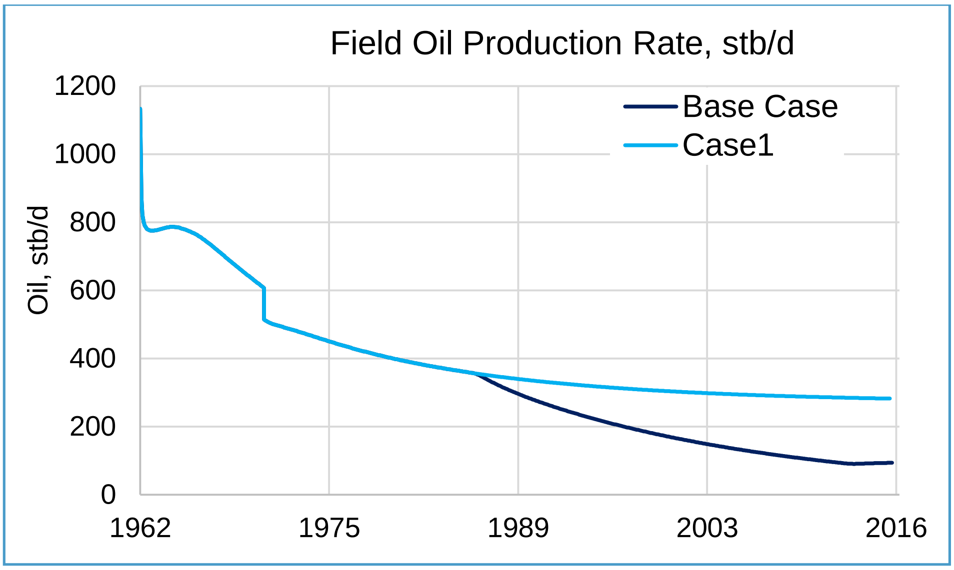


Figure 5.5. Comparison of base case and scenario-1 oil production rates

Figure 5.4 shows that water injection supports the reservoir pressure. The effect of this pressure support can be seen on the oil production rate as well (Figure 5.5). On the other hand, Figure 5.6 shows the high water production rates due to water flooding.

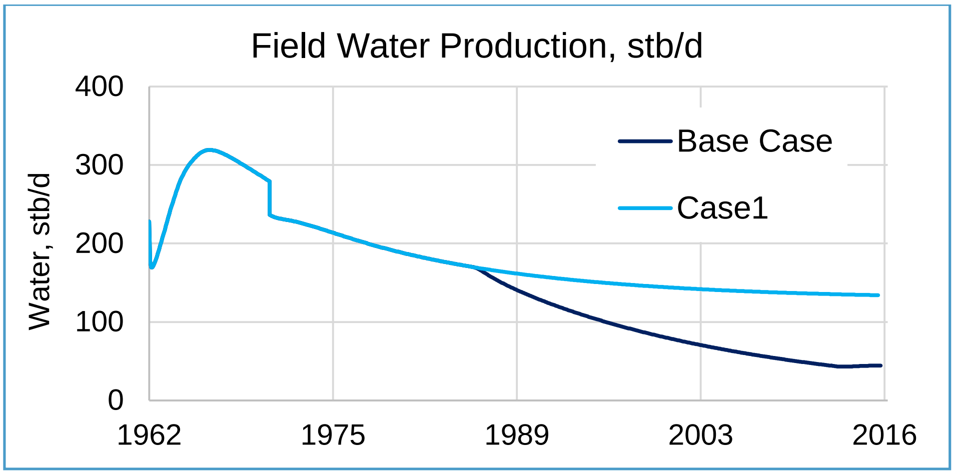


Figure 5.6. Comparison of base case and scenario-1 water production rates

5.2.2 Scenario 2

In this scenario the effect of the CO_2 injection can be observed. Figure 5.7 shows the drop in reservoir pressure in 1971 when the CO_2 injection starts. Comparing to water flooding, CO_2 injection is less effective in supporting the pressure in the reservoir. As CO_2 injection is immiscible, it acts like a simple gas injection technique by gathering at the top as a gas cap.

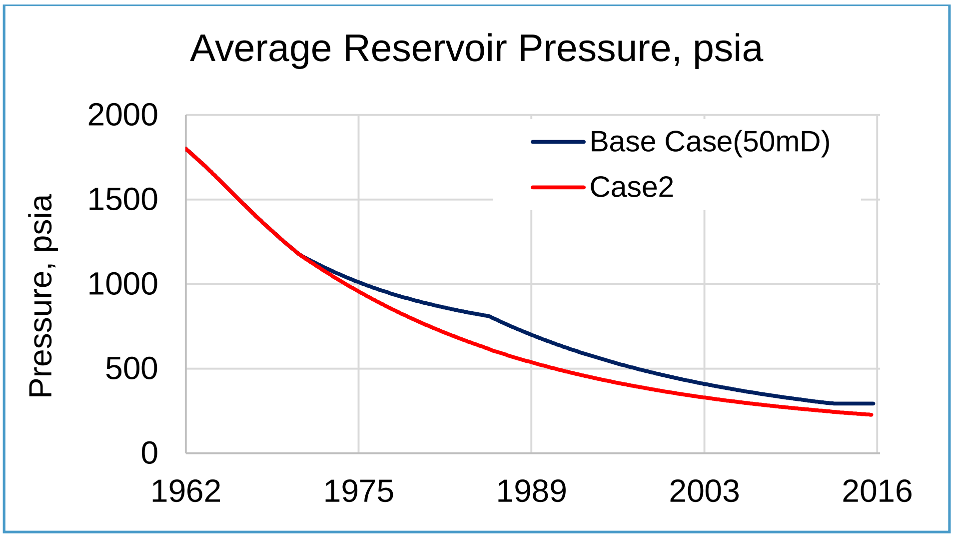


Figure 5.7. Comparison of base case and scenario-2 average reservoir pressure

Figure 5.8 shows the decrease in the production rate during CO_2 injection period.

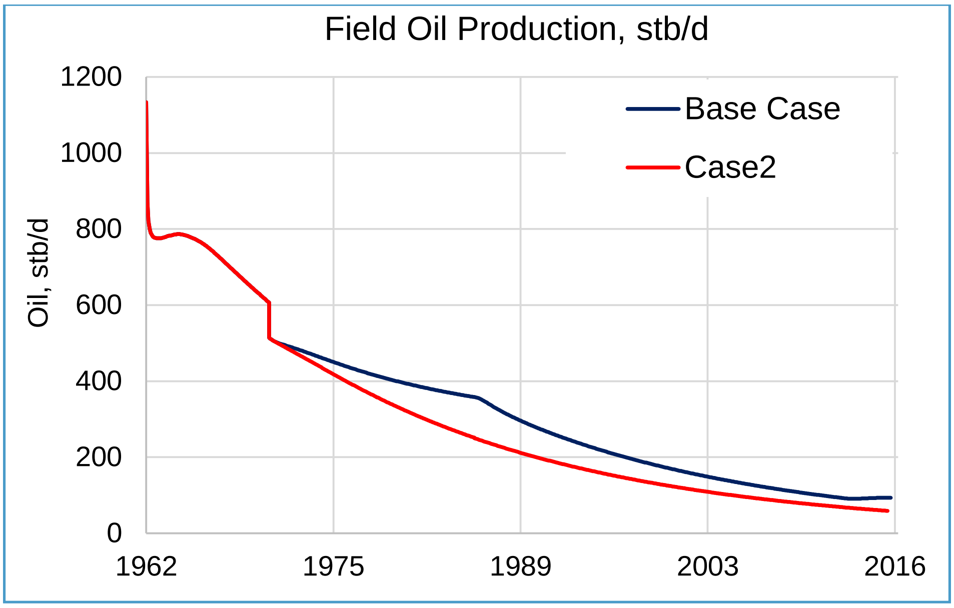


Figure 5.8. Comparison of base case and scenario-2 oil production rates

<u>5.2.3 Scenario 3</u>

In this scenario steam is injected to the all layers to increase the oil mobility by minimizing its viscosity between 1971 and 2016.

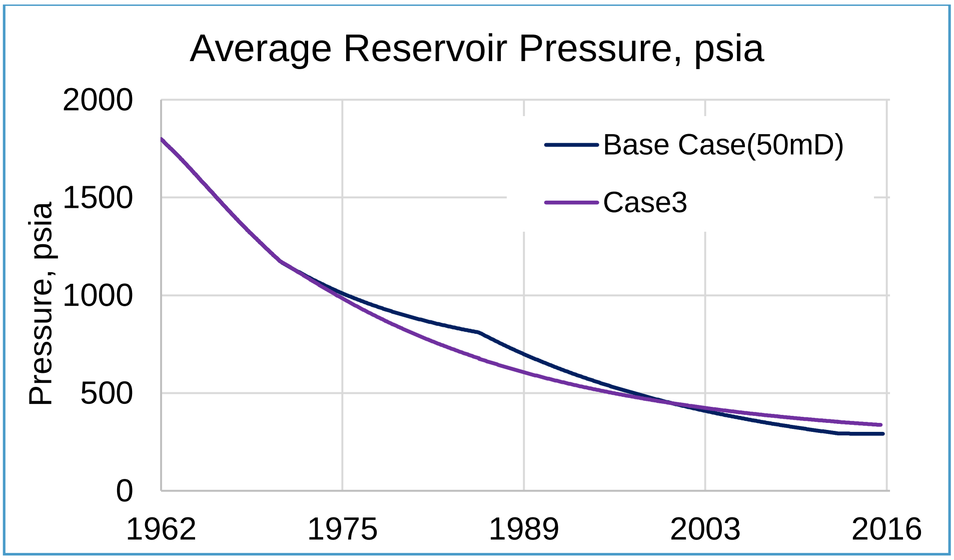


Figure 5.9. Comparison of base case and scenario-3 average reservoir pressure

The pressure, oil production and water production responses of the field to steam injection after 1971 are very similar as seen from Figure 5.9, Figure 5.10 and Figure 5.11. In the long run, steam injection becomes more effective comparing to water injection.

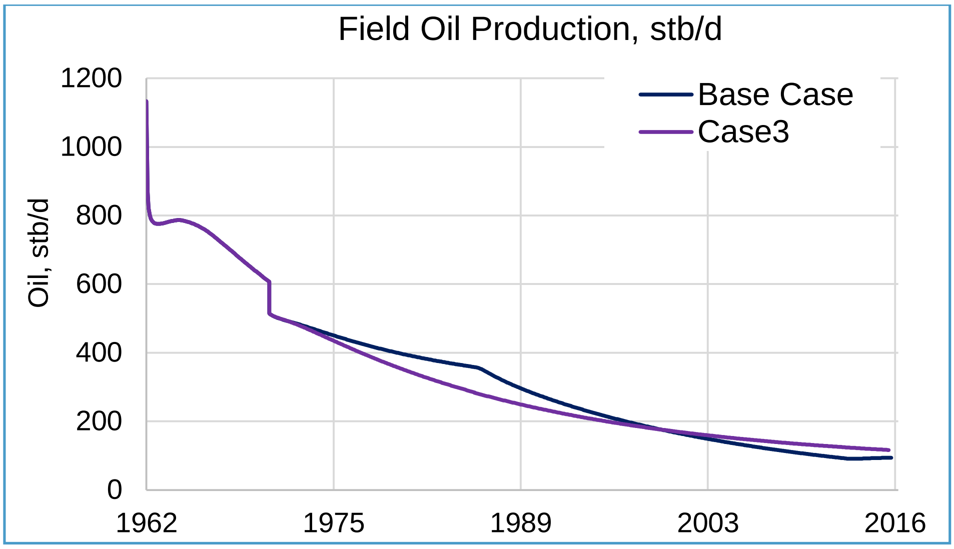


Figure 5.10. Comparison of base case and scenario-3 oil production rates

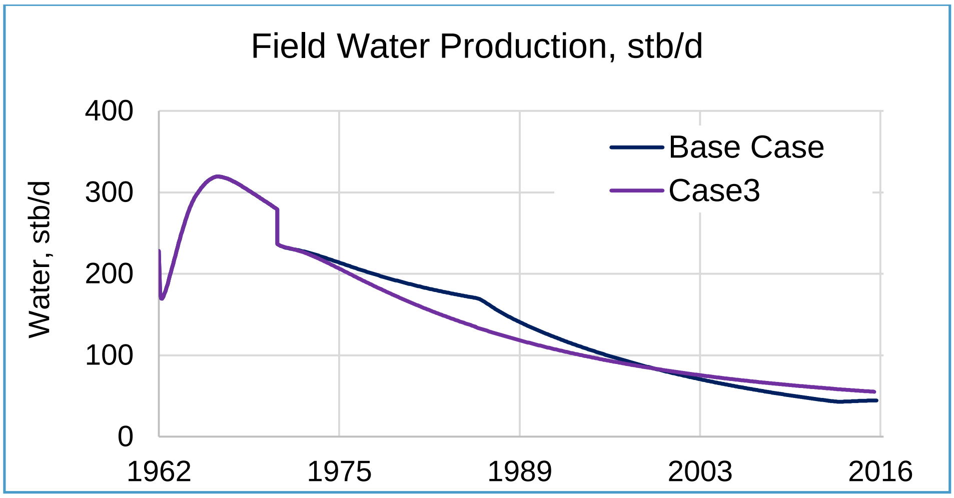


Figure 5.11. Comparison of base case and scenario-3 water production rates

5.2.4 Scenario 4

This case covers steam and CO_2 injection from starting at the same injection time as in scenario 3. Actually the purpose of running this combination case is to identify which EOR method has more benefit for this field during various life of field. In spite of the fact that in real life it would be hard to implement such a technique, in Eclipse there is such a function that allows the injection of CO_2 and steam at the same time from the same well.

Figure 5.12 shows that steam injection combined with CO_2 injection is almost equal to steam injection case (scenario-3).

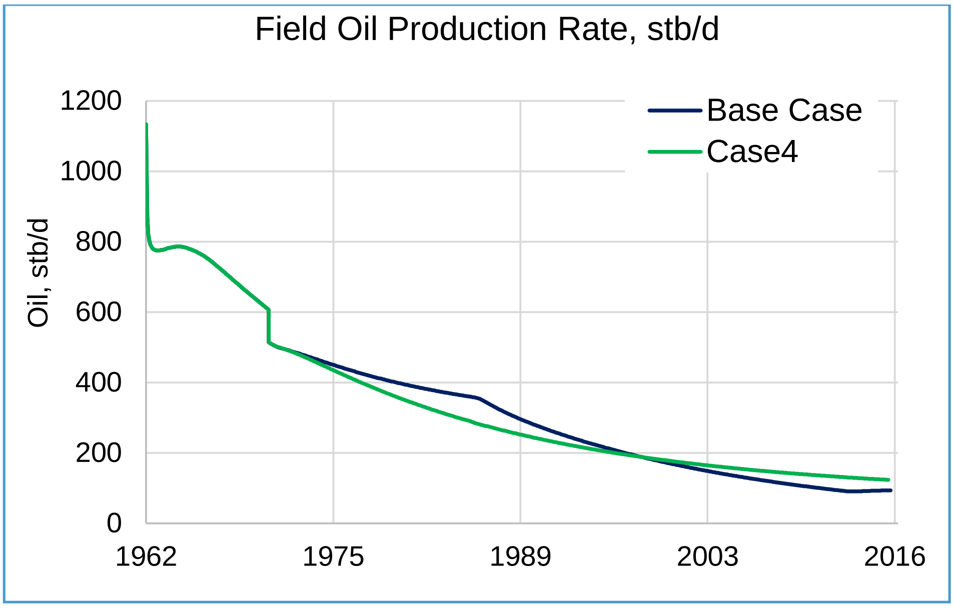


Figure 5.12. Comparison of base case and scenario-4 oil production rates

5.2.5 Scenario 5

In this scenario after the primary recovery stage, in 1971 central well is converted to CO_2 injector until 1986. After 1986 steam injection technique is implemented.

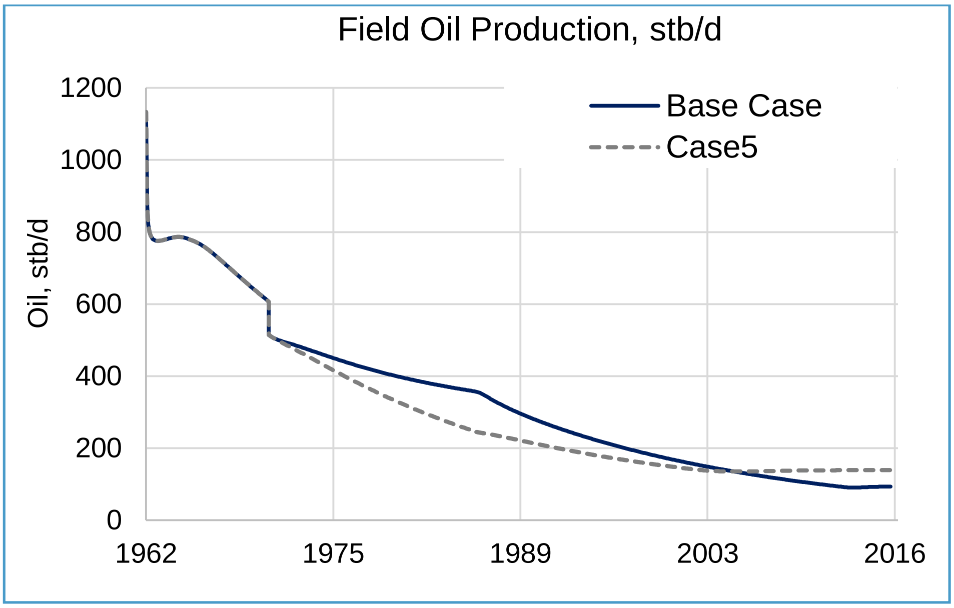


Figure 5.13. Comparison of base case and scenario-5 oil production rates

Figure 5.13 shows the increase in the oil production rate after implementation of steam injection method.

5.2.6 Scenario 6

In this scenario primary recovery stage starts in 1962 and lasts until 1971 when central well is converted to water injection well. From 1986 onwards steam injection technique is implemented in the field.

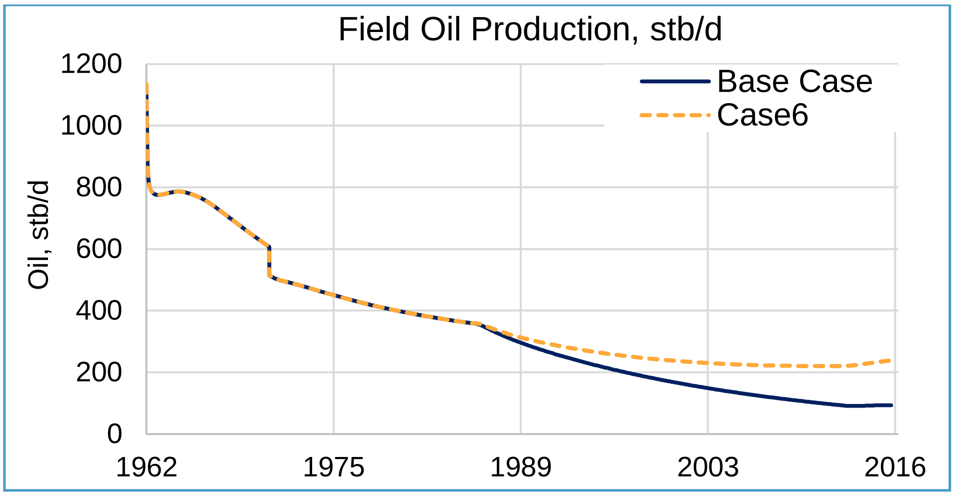


Figure 5.14. Comparison of base case and scenario-6 oil production rates

Figure 5.14 shows the improvement in oil production rate due to steam injection. CO_2 is injected in base case starting from 1986 instead of steam.

5.3 Comparison of all Scenarios

If the pressure responses of all the cases are compared, it can be seen from Figure 5.15 that scenario-1 is the most effective one in terms of supporting reservoir pressure. In scenario-1 water injection keeps the pressure level high.

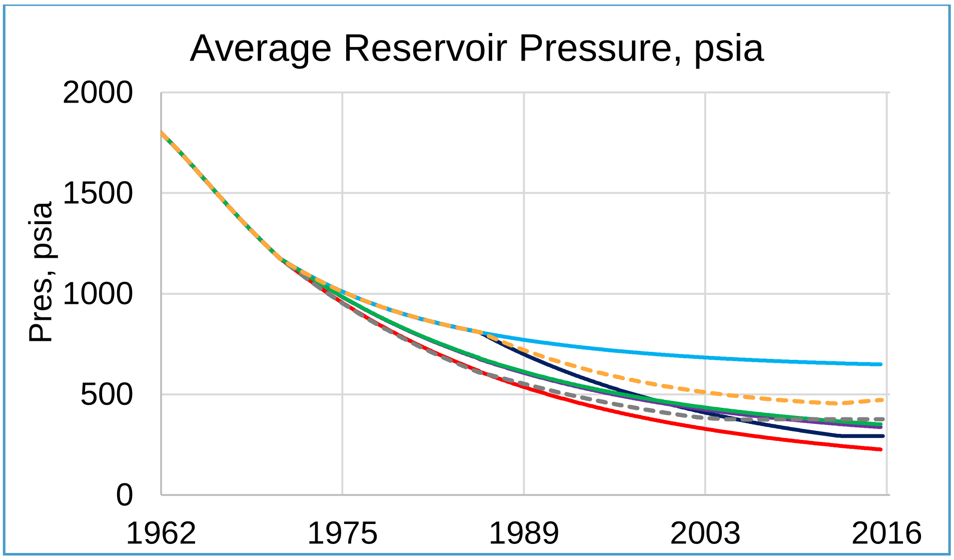


Figure 5.15 Comparison of field average reservoir pressure

Table 5.2. Oil production rates

Year	**Base Case**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**	**Scenario 5**	**Scenari o 6**
1962	776	776	776	776	776	776	776
1970	607	607	607	607	607	607	607
1971	514	514	514	514	514	514	514
1980	394	394	322	348	350	326	394
1990	273	333	196	235	239	212	289
2000	165	303	121	169	175	148	291
2010	102	287	75	130	137	138	283
2015	94	283	60	117	125	139	280

Oil production rates are given in Table 5.2 and in Figure 5.16.

The comparison of oil production rates show that scenarios 2, 3 and 4 represent intermediate options. From Figure 5.16 it can be noted that scenario 2 (CO_2 injection) is the least efficient technique, compared to scenarios 3 (steam injection) and scenario 4 (steam + CO_2 injection). However, the impact of scenarios 3 and 4 to the reservoir pressure is slightly different (better for scenario 4). On the other hand from economical perspectives comingled injection of steam/CO_2 would require more financial contribution to the project, with slight impact of pressure support. Therefore comparing scenarios 2, 3, and 4; the best solution is to implement steam injection technique.

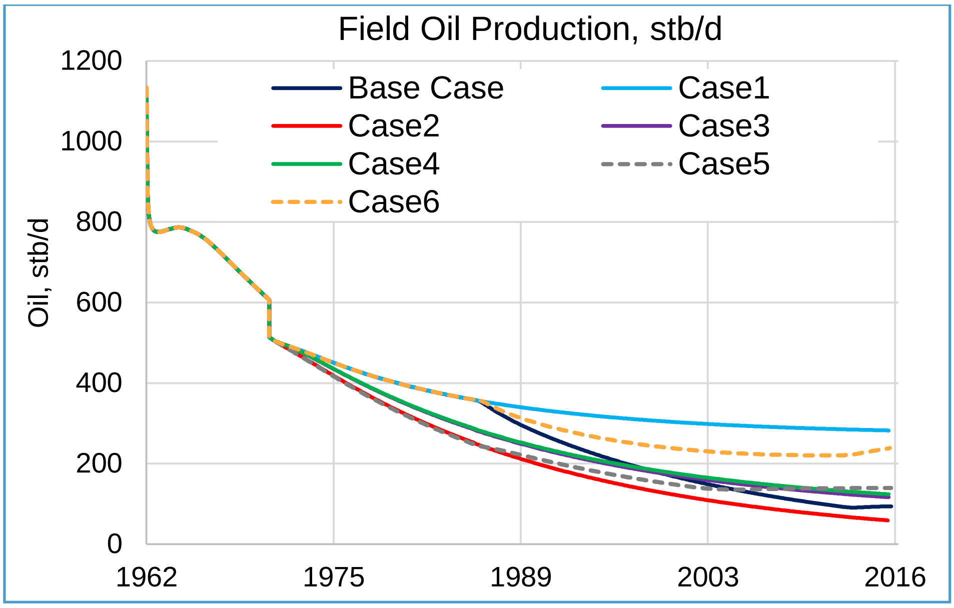


Figure 5.16 Comparison of field oil production rates

As it can be noted from Figure 5.15 and Figure 5.16, the trendline of scenario 5 is the same with that of scenario 2. However after 1986, due to the implementation of steam flood operation, pressure started to increase. By the end of time schedule reservoir pressure even overpasses scenarios 2, 3, and 4 as well as the base case. Outcome of scenario 5 clearly demonstrates that steam flood technique should be implemented in the field as early as possible in terms of reservoir pressure support.

In scenario 6 immediately after primary recovery stage, water injection technique is implemented in the field. Therefore the trendline is the same as that of the scenario 1. However, after 1986 water injection is replaced by steam injection. If we compare base case and scenarios 1 and 6 we can clearly find out that until 1986 all three follow the same trendline. Afterwards reservoir pressure for the base case declines too fast as carbon dioxide is injected to the reservoir. It can be noted from scenarios 1 and 6 that pressure response for scenario 1 is much better which may be due to the fact that water spreads throughout the reservoir more uniformly. On the other hand it can be noted that steam injection implementation has a long-term goal, because it takes more time for steam to heat up the oil and mobilize it. Therefore, after 2010 reservoir pressure even started to increase as steam injection heat oil up as well as has an impact in additional drive.

Cumulative oil production for scenario 1 is around 8 Mstb which is 2 Mstb higher than that of base case. However, it should be mentioned that techniques implemented for base case, was conducted properly. So that the cumulative oil production of the base case represents the highest trend compared to scenarios 2, 3, and 4.

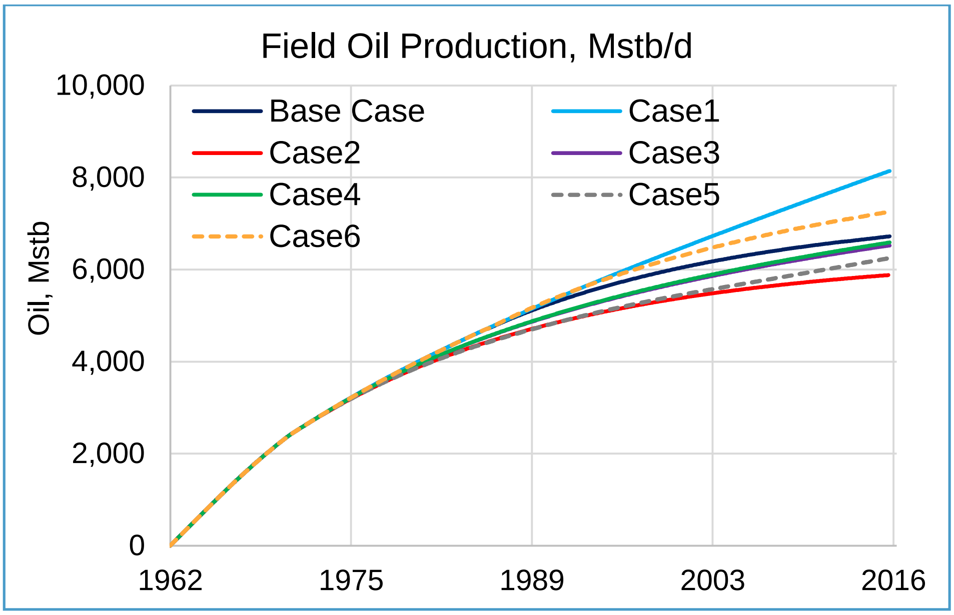


Figure 5.17 Comparison of cumulative oil production

Based on pressure responses and cumulative oil production seen in Figure 5.17, among the applied techniques it would obviously be recommended to implement scenario 1 or scenario 6 to the field.

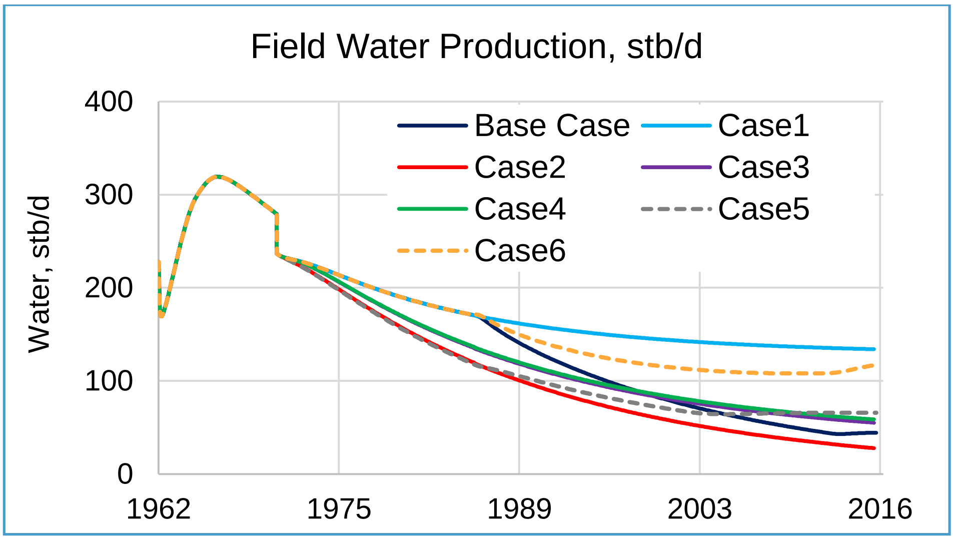


Figure 5.18 Comparison of water production rate

Figure 5.18 shows field water production rate. The highest water production is in scenario 1. The reason of such huge water amount is due to the fact that in scenario 1, water injection well is online until the end of time schedule. For cases 5 and 6, the steam injection technique is implemented from 1986 and water production starts to decrease. However, once steam is condensed to droplets, water production starts to increase which can be seen after 2008. The lowest water production is in scenario 2, which is CO_2 injection technique.

Figure 5.19 and Figure 5.20 show the temperature distribution for scenario-6 on September 1963 and June 2016, respectively. As it can be noted, at the beginning of the production, when all wells are producers, the temperature starts to decrease in near wellbore areas due to pressure decrease, with outer boundaries remain at high temperatures. By the end of time schedule, temperatures at producers are minimum, while central, injection well has the highest temperature as steam is injected.

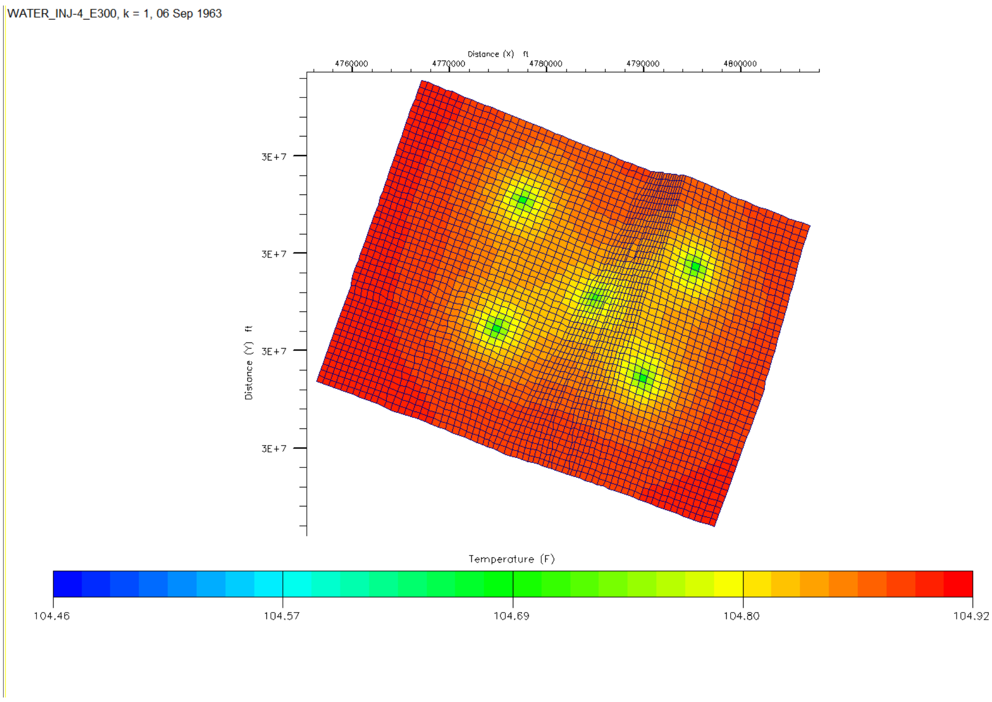


Figure 5.19 Reservoir temperature distribution for scenario-6 on September 1963

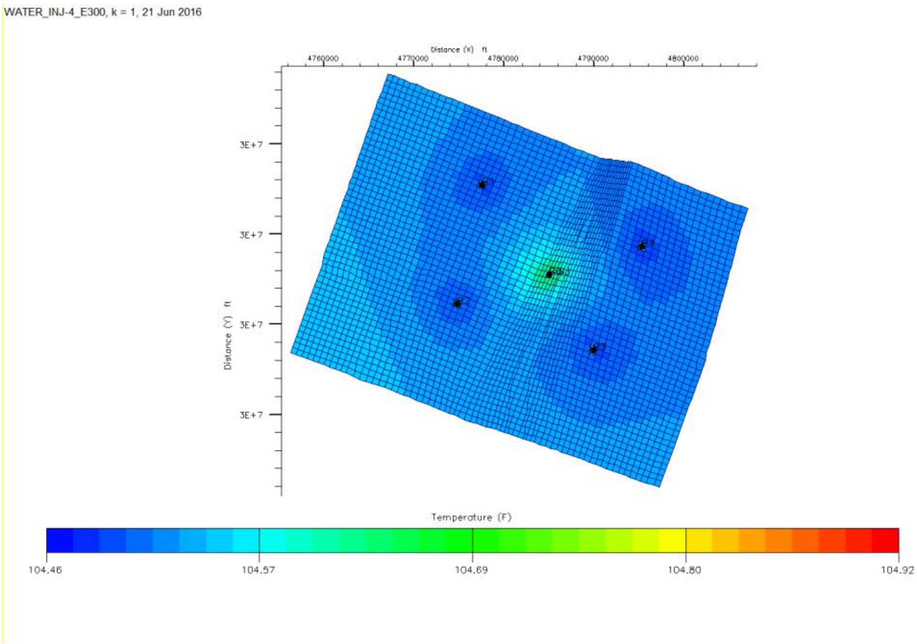
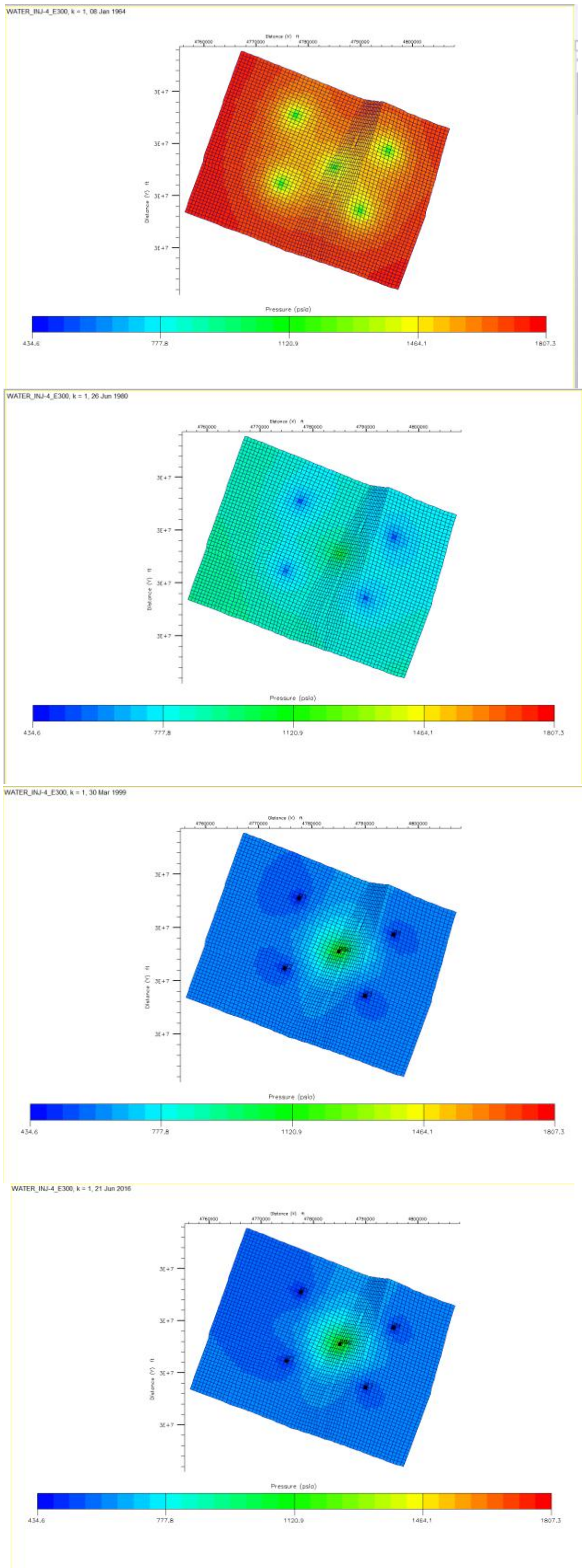


Figure 5.20 Reservoir temperature distribution for scenario-6 on June 2016

Figure 5.21 shows the pressure changes within the reservoir in scenario-6. As it can be noted, at the onset of production pressure response can only be seen at near wellbore areas (Figure 5.21, a). Once water started to be injected, pressure started to be supported as considerable pressure reductions are found only in near wellbore areas of producing well (Figure 5.21, b). As more and more oil is produced from the field, the whole picture does not change. The only difference is that further areas started to influence to production as they are drained and pressure decrease can be seen there. (Figure 5.21, c and d)



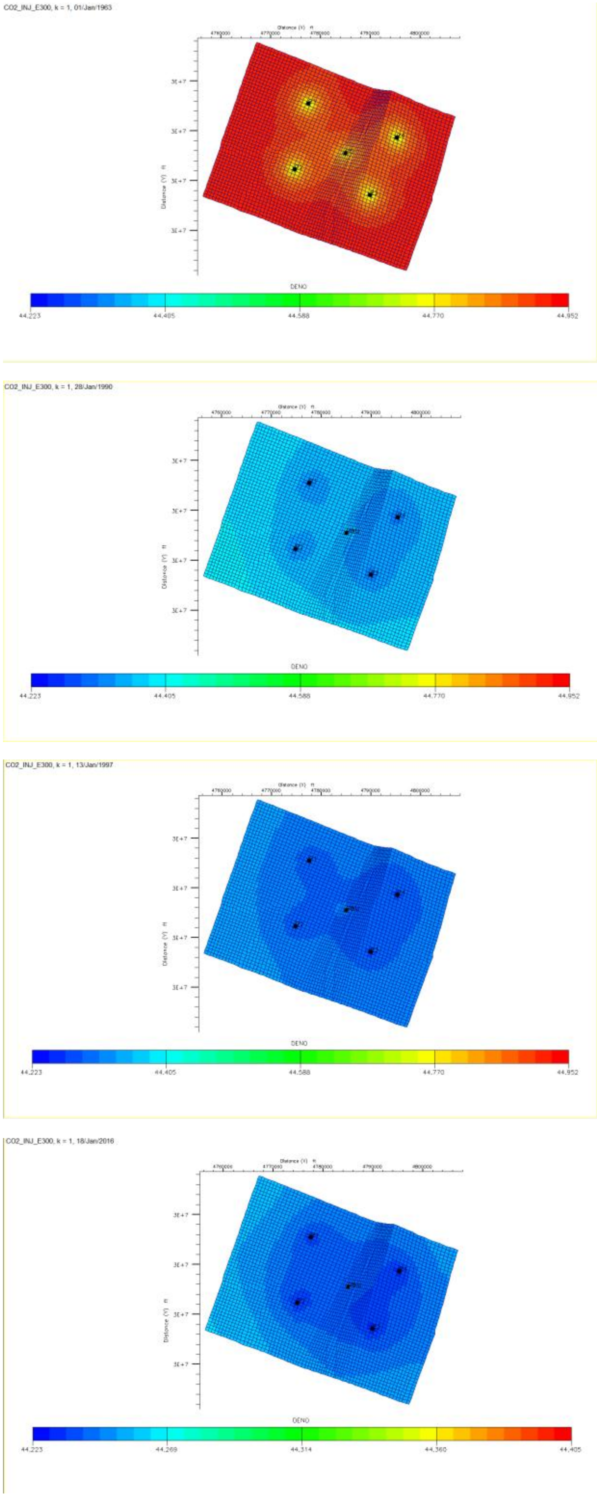
a) Reservoir pressure distribution for scenario-6 on January 1964

b) Reservoir pressure distribution for scenario-6 on June 1980

c) Reservoir pressure distribution for scenario-6 on March 1999

d) Reservoir pressure distribution for scenario-6 on March 1999

Figure 5.21 Reservoir pressure distribution for scenario-6



a) Viscosity distribution for scenario 6 in 1963

b) Viscosity distribution for scenario 6 in 1990

c) Viscosity distribution for scenario 6 in 1997

d) Viscosity distribution for scenario 6 in 2016

Figure 5.22 Viscosity distribution for scenario 6

Figure 5.22 shows viscosity changes within the reservoir in scenario-6. As it can be noted, at the onset of production viscosity reduction can only be seen at near wellbore areas and the reduction is not big, as reservoir contains a viscous oil (Figure 5.22, a). After water injection and 4 years of steam flooding it can be noted that viscosity reduction distribution is higher in the right hind-side of the figure (figure 5.22 b). As more steam is injected to the field, the whole picture of viscosity reduction does not change so far. The only difference is that viscosity has reduced in further areas further areas started to influence to production as they are drained and pressure decrease can be seen there. (Figure 5.21, c and d)

5.4 Effect of CO_2 on steam injection

The effect of CO_2 injection on recovery from steam injection can be compered using scenario 5 (CO_2 injection followed by steam injection) and scenario 6 (water injection followed by steam injection).

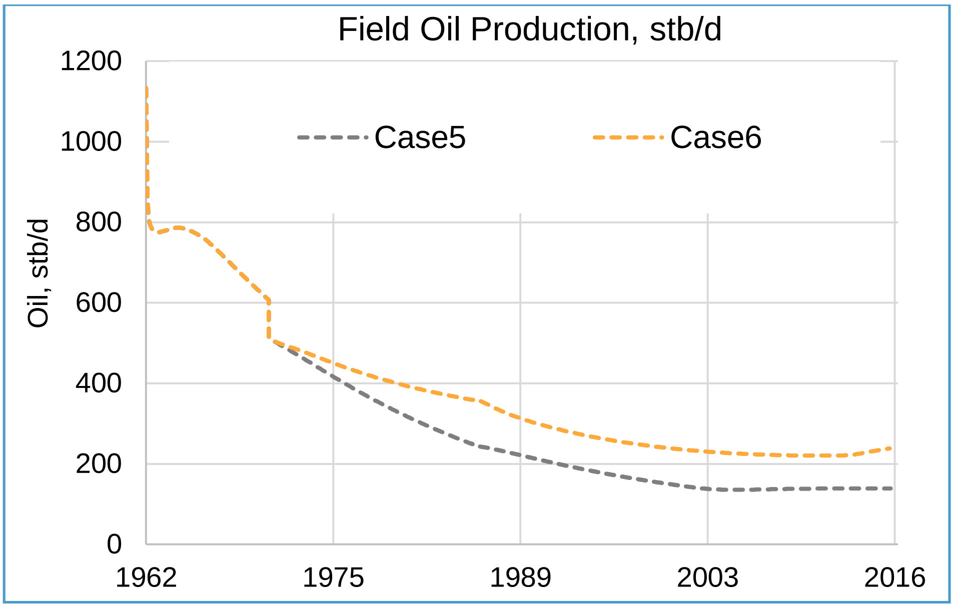


Figure 5.23 Effect of water injection and CO_2 injection before steam injection on oil production rates

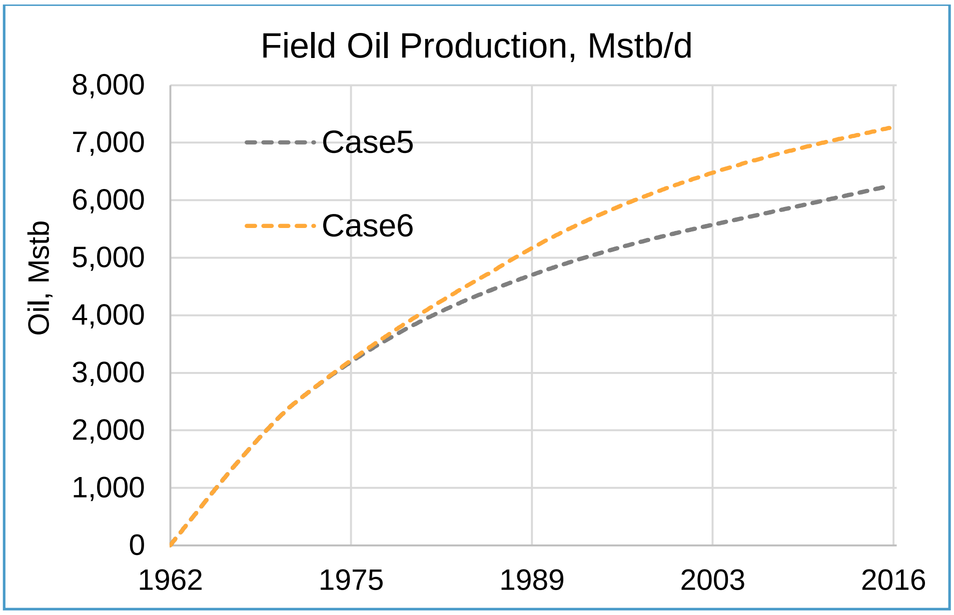


Figure 5.24 Effect of water injection and CO_2 injection before steam injection on cumulative oil production

The water injection between 1971 and 1986 has increased the production rate comparing to CO_2 injection. Therefore it is not easy to see the effect of water injection or CO_2 injection on recovery by steam injection on Figures 5.23 and 5.24. However the cumulative oil production can be compared between 1986 and 2016. Additional cumulative oil production following water injection is 4716 Mstb. During the same period additional oil recovery becomes 1828 Mstb by steam injection followed by CO_2 injection. This shows that it is better to apply steam injection after water injection rather than CO_2 injection. The reason of this behavior can be based on the fact that water has a greater latent heat comparing to CO_2. Therefore although heating the reservoir saturated by water is more difficult, it also takes more time to cool down.

5.5 Effect of Water Injection Wells

In order to understand the effect of water injection wells' position and completion interval on oil and water production two additional runs have been performed. The water injection well has been completed in all layers instead of 5 layers in the first case. In the second case the production wells are located closer to the injection well (Figure 5.25). The new scenarios are summarized in Table 5.3.

Table 5.3. Water Injection Scenarios

Case	Primary production	Water injection	Properties
Scenario 1	1962 - 1971	1971 - 2016	Injection well is completed in 5 layers
Scenario 7	1962 - 1971	1971 - 2016	Injection well is completed in all 20 layers
Scenario 8	1962 - 1971	1971 - 2016	Proximity of well location is changed

Location of oil producer wells (P1, P2, P3, P4) have been moved (~2 km) to close to water injection well in order to see water injection impact on them.

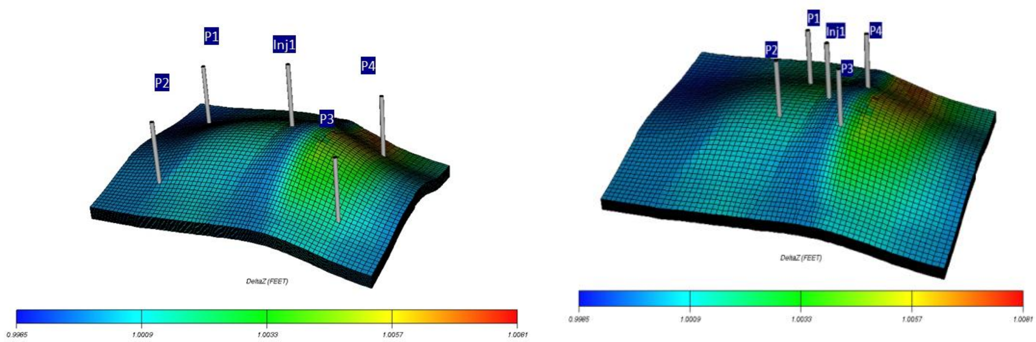


Figure 5.25. Proximity of well locations

The effect of these scenarios can be seen in Figures 5.26 and 5.27. Overall oil production is significantly improved in Scenario 7 (injection to all sub layers), but water production is also increased. Until 1972 Scenario 1 and Scenario 7 behaviors are same because no water injection has been started, but from 1972 Scenario 7 looks different because of completion in all 20 layers. Placing producers closer to each other.

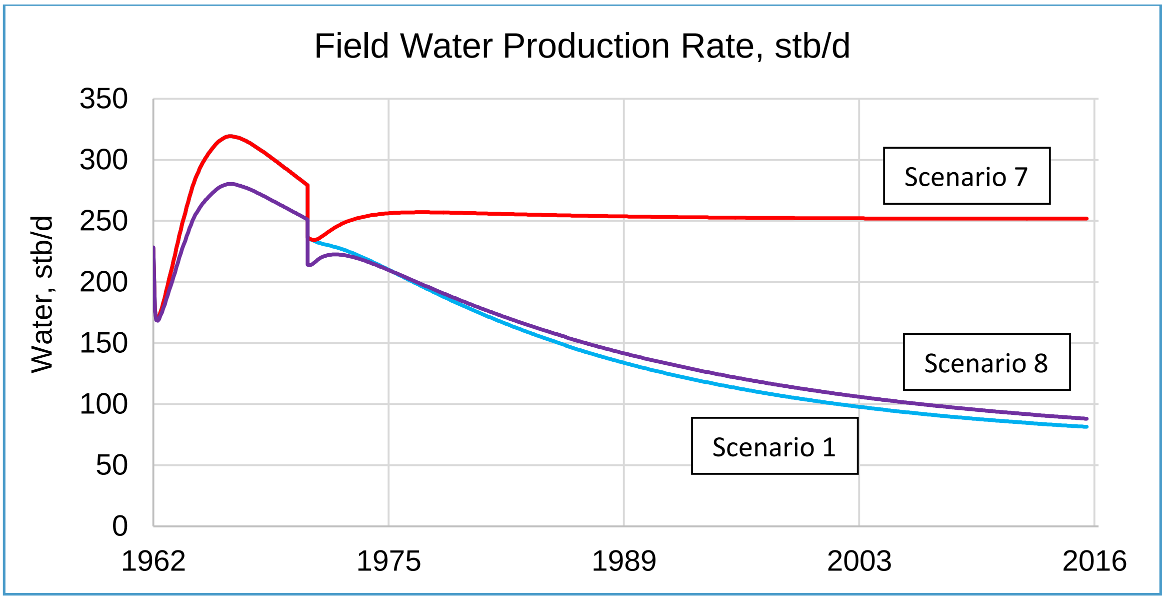


Figure 5.26. Water Production

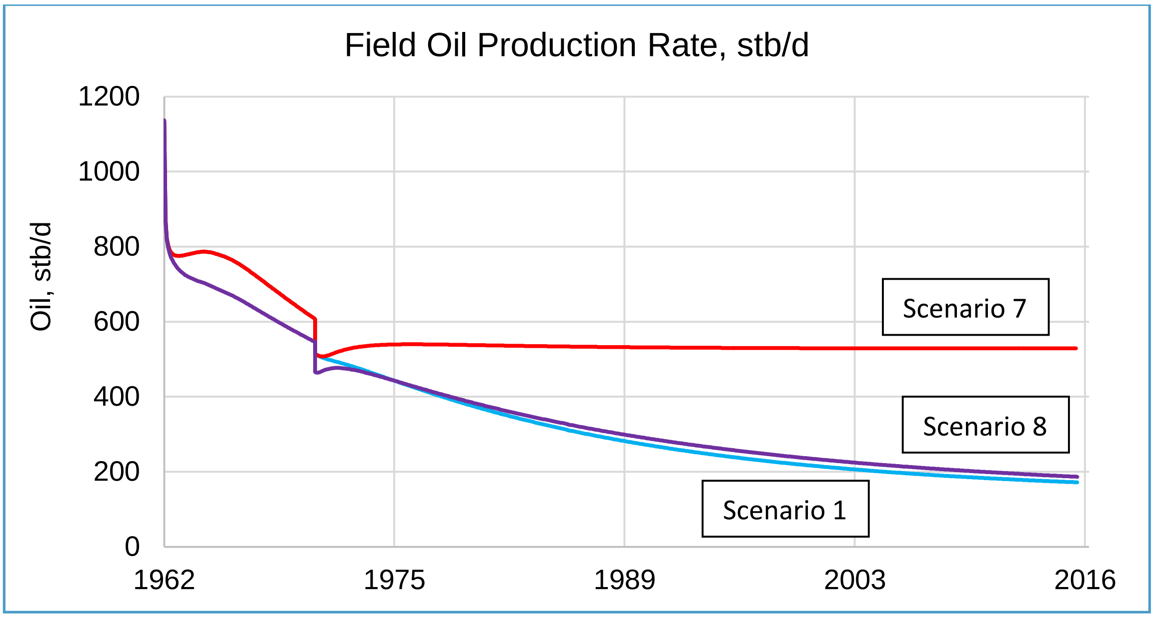


Figure 5.27. Oil Production

5.6 Material Balance Check

The main purpose of doing material balance evaluation is to check the consistency of the simulation model and clarify the energy of the reservoir. Due to lack of actual history data we used simulation history (production and average reservoir pressure) for material balance study. For checking purposes reservoir pressure trend of Base Case has been used. Exported all well history file from Eclipse and imported to Material Balance software in order to identify uncertain values. Material balance evaluation has been analyzed in Integrated Production Modeling software (IPM) tool "MBAL". Schematic wells connection to the reservoir is shown Figure 5.29. There are 5 producer wells, one of them converted to water injector starting from 1972. Due to the fact that it is impossible to convert the well from production to injection and vice versa in IMP tool, one producer was just stopped production in 1972 and one new injection well was added (Figure 5.28).

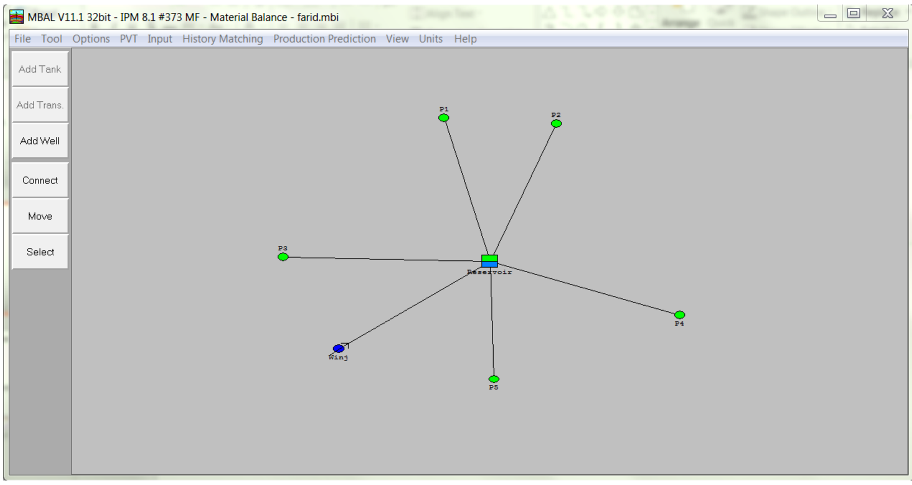


Figure 5.28. Reservoir and Wells

Preliminary input parameters are taken same as base case simulation model input. MBAL tool input parameters are shown in Figure 5.29.

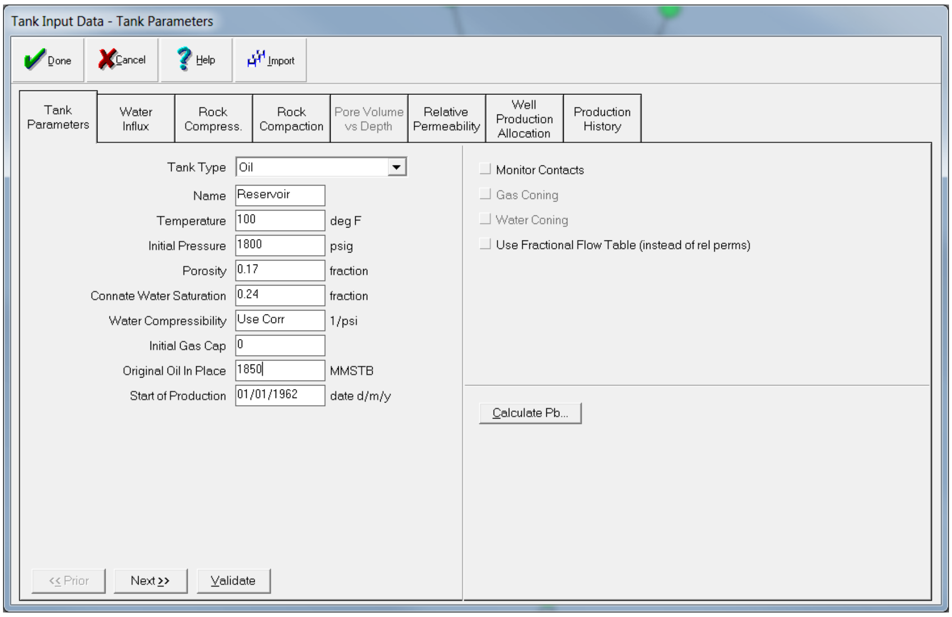


Figure 5.29. Input Parameters for Material Balance

PVT data have been adjusted to the simulation PVT data (Figure 5.30).

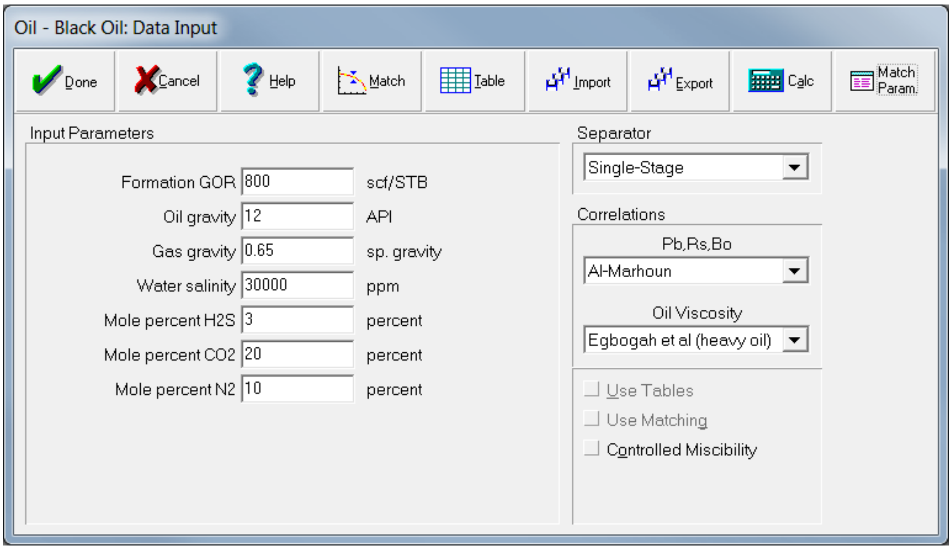
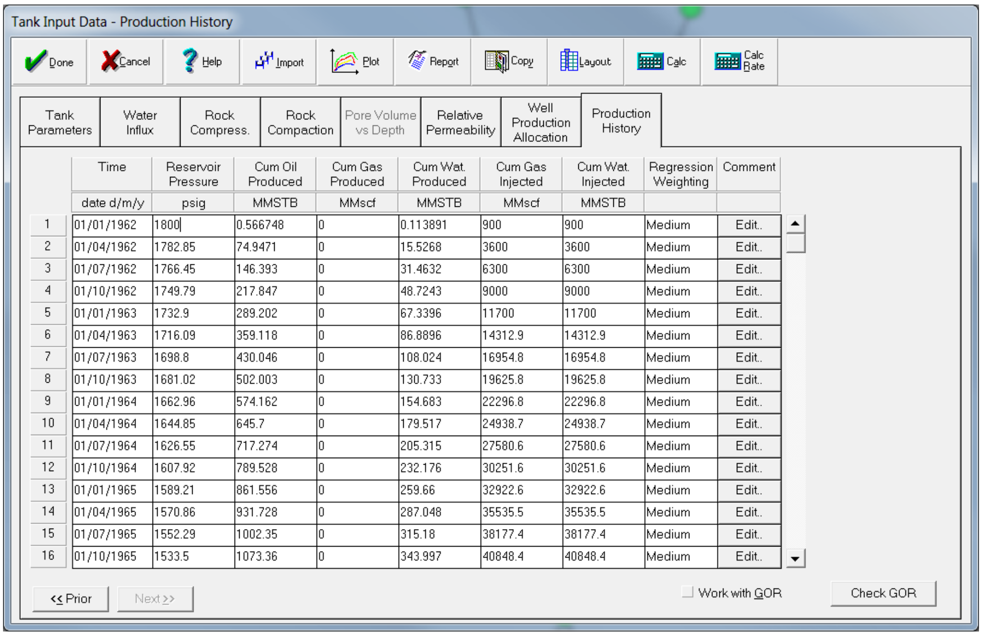


Figure 5.30. PVT inputs

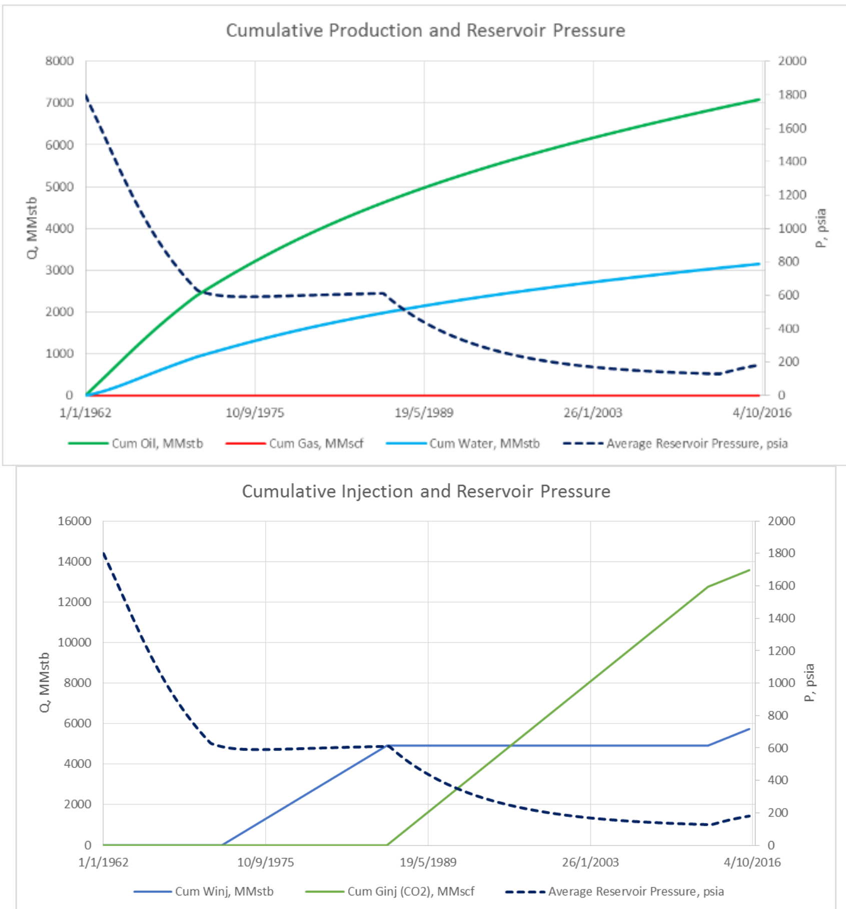
Simulation output, production history data has been used as input to the material balance software. MBAL calculates total production using well data (Figure 5.31).



	Time	Reservoir Pressure	Cum Oil Produced	Cum Gas Produced	Cum Wat. Produced	Cum Gas Injected	Cum Wat. Injected	Regression Weighting	Comment
	date d/m/y	psig	MMSTB	MMscf	MMSTB	MMscf	MMSTB		
1	01/01/1962	1800	0.566748	0	0.113891	900	900	Medium	Edit..
2	01/04/1962	1782.85	74.9471	0	15.5268	3600	3600	Medium	Edit..
3	01/07/1962	1766.45	146.393	0	31.4632	6300	6300	Medium	Edit..
4	01/10/1962	1749.79	217.847	0	48.7243	9000	9000	Medium	Edit..
5	01/01/1963	1732.9	289.202	0	67.3396	11700	11700	Medium	Edit..
6	01/04/1963	1716.09	359.118	0	86.8896	14312.9	14312.9	Medium	Edit..
7	01/07/1963	1698.8	430.046	0	108.024	16954.8	16954.8	Medium	Edit..
8	01/10/1963	1681.02	502.003	0	130.733	19625.8	19625.8	Medium	Edit..
9	01/01/1964	1662.96	574.162	0	154.683	22296.8	22296.8	Medium	Edit..
10	01/04/1964	1644.85	645.7	0	179.517	24938.7	24938.7	Medium	Edit..
11	01/07/1964	1626.55	717.274	0	205.315	27580.6	27580.6	Medium	Edit..
12	01/10/1964	1607.92	789.528	0	232.176	30251.6	30251.6	Medium	Edit..
13	01/01/1965	1589.21	861.556	0	259.66	32922.6	32922.6	Medium	Edit..
14	01/04/1965	1570.86	931.728	0	287.048	35535.5	35535.5	Medium	Edit..
15	01/07/1965	1552.29	1002.35	0	315.18	38177.4	38177.4	Medium	Edit..
16	01/10/1965	1533.5	1073.36	0	343.997	40848.4	40848.4	Medium	Edit..

Figure 5.31. Production inputs from simulation output

Cumulative injection, production and average reservoir pressure trend are shown in Figure 5.32.



a)

b)

Figure 5.32. Cumulative Injection, Production and Reservoir Pressure

STOIIP preliminary was 1850 MMstb based on simulation model. During history matching process it has matched to 1833 MMstb (Figure 5.33).

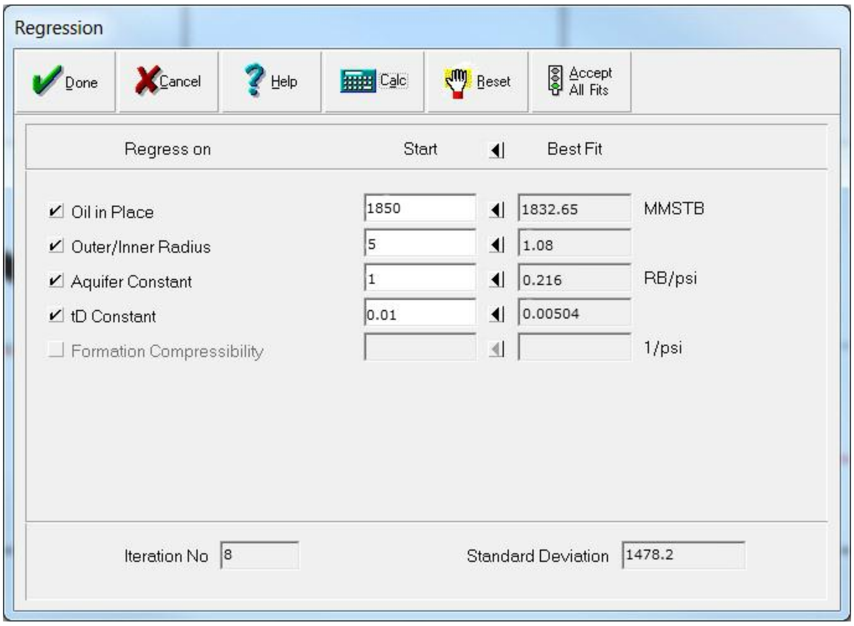


Figure 5.33. Matching Uncertain Parameters

After 8 iterations average reservoir pressure of MBal matched average reservoir pressure trendline of simulation model. Average reservoir pressure comparison between material balance and simulation is shown in Figure 5.34. However, those pressures are not matched ideally, but overall depletion trend is similar. The purpose of usage of material balance was to check the correctness of simulation model. Thus, Figure 5.34 provides the outcome of reservoir pressures both from simulation modeling and material balance. The similarity of reservoir pressure can easily be seen from Figure 5.34.

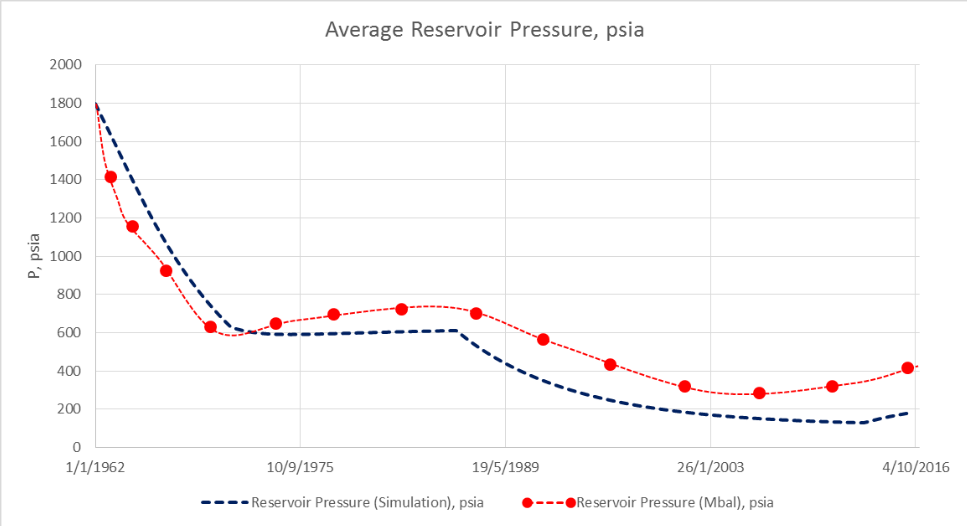


Figure 5.34. Average Reservoir Pressure comparison between Material Balance and Simulation

Figure 5.35 shows prevailing drive mechanism versus time. When the reservoir pressure is less than bubble point pressure, the dominant drive mechanism was fluid expansion effect from 1962 to 1972 (Figure 5.35). Water injection effect started to dominate after 1975. Pore volume compressibility effect is negligible for this type of reservoir. Figure 5.35 clearly demonstrates that for this particular, hypothetical field implementation of water injection technique is the best case for reservoir energy support.

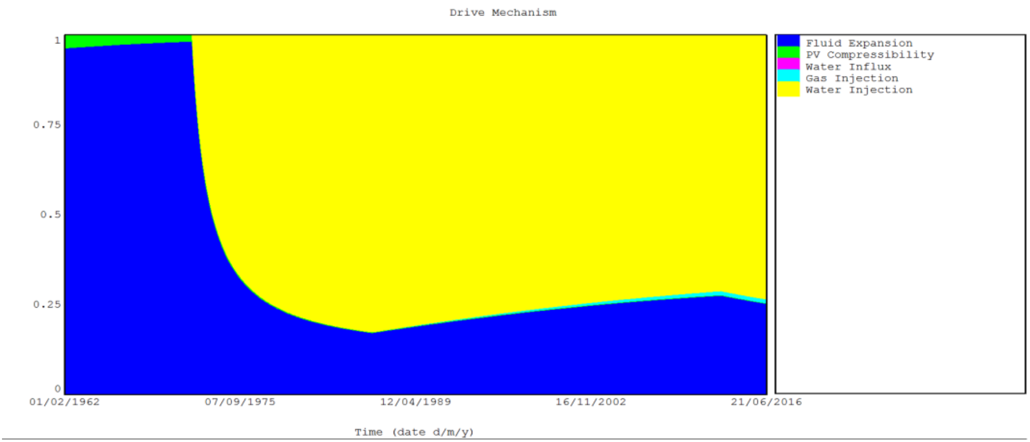


Figure 5.35. Drive Mechanism (MBal)

CHAPTER 6

CONCLUSION

For this study a hypothetical but representative model has been built. This work has been conducted to find out the best way for exploitation of a heavy oil field having basic properties to be close to heavy oil reservoirs. The effect on recovery of CO_2 injection on the success of steam injection is the main point that is analysed during the study. However, several other scenarios are also implemented to compare recoveries and find out the optimum method that can be used to manage the field. First of all, a geological model has been built which was later exported to Eclipse for sensitivity runs. Furthermore, for checking the consistency of the simulation model material balance has also been done. The main analysis criteria in this study are production data.

Following are the conclusions drawn from this study:

- As study shows, implementation of water injection technique is the best way to increase recovery compared to other cases.

- Based on outcomes of sensitivity runs the implementation of CO_2 was the incorrect decision in this hypothetical case. As model shows injection of CO_2 did not have a great impact on production and pressure. Furthermore existence of carbon dioxide within the reservoir limits effectiveness of steam injection (Case 5).

- Water and steam have a greater impact on this hypothetical field. Therefore, after the primary production, injecting water and finally injection of steam (scenario 6) is the one of the best approach in terms of pressure support and incremental resource with cumulative production value of 7200 Mstb and 465 psi of reservoir pressure.

- Pressure outcomes of material balance shows that the simulation model works properly, as there is a good match among reservoir pressure of simulation model and material balance.

REFERENCES

Ali, Farouq S. M. (1974) "Current Status of Steam Injection as a Heavy Oil Recovery Method." Journal of Canadian Petroleum Technology. Volume 13, Number 1.

Ali, Farouq, S. M. and Abou-Kassem, J. H. (1989) "Simulation of thermal recovery process", First and second international reservoir simulation, Paul Steiner, Leoben, Austria.

Ault, J.W., Johnson, W.M., and Kamilos, G.N. (1985) "Conversion of Steamfloods to Low-Quality Steam and/or Hot-Water Injection Projects", paper SPE 13604, presented at the SPE California Regional Meeting, Bakersfield, California, March 27-29.

Baviere, M., 1980. Basic Concepts in Enhanced Oil Recovery Processes. Elsevier Applied Science, London, New York.

Blair Jr., C. M., Scribner, R. E., and Stout, C. A. (1982) "Chemical Enhancement of Oil Production by Cyclic Steam Injection", Journal of Petroleum Technology 34 (12): 2757-2762.

Blok K, Höhne N, Van der Leun K and Harrison N. "Bridging the greenhouse gas emissions gap". 2012

Briggs, P. J. (1989) "A simulator for the recovery of heavy oil from naturally fractured reservoirs using cyclic steam injection", paper SPE 17954.

Brissenden, S. J. (2005) "Steaming Uphill: Using J-Wells for CSS at Peace River", Canadian International Petroleum Conference, Calgary, Alberta, Jun 7 - 9.

Bryngelsson, M.; Westermark, M. (2009) "CO_2 capture pilot test at a pressurized coal fired CHP plant", Energy Procedia 1: 1403–10.

Burruss, R. (2004) "Geologic Sequestration of Carbon Dioxide in the Next 10 to 50

Years: An Energy Resource Perspective."

Butler, R. (1991). Thermal Recovery of Oil and Bitumen.

Butler, R. M. (2004) “Thermal Recovery of Oil and Bitumen”, 4th edition, GravDrain Inc, Calgary, Alberta.

Chen, W. H. et. al. (1987) “Thermal simulator for Naturally Fractured Reservoirs”, paper SPE 14902.

CO_2 Surfactants. (n.d.). Retrieved from http://www.novomer.com/co2-surfactants, September 20, 2014

Conaway, C. F. (1999) “The Petroleum Industry: A Nontechnical Guide”, Pennwell, Tusla, USA.

Counihan, and Thomas M. A. (1977) “Successful in-situ Combustion Pilot in the Midway-Sunset Field, California”, SPE 6525-MS.

Das, S. (2005) “Improving the Performance of SAGD”, presented at the SPE/PS-CIM/CHOA International Thermal Operations and Heavy Oil Symposium, Calgary, Alberta, Canada Nov. 1-3.

De Ghetto, G., Paone, F., and Villa, M. (1995) “Pressure-Volume-Temperature Correlations for Heavy and Extra Heavy Oils”, SPE 30316.

Dean, R. H., Lo, L. L. (1988) “Simulation of naturally fractured reservoirs”.

Donaldson, E.C., Chilingarian, G.V., Yen, T.F., Sharma, M.K. ″Enhanced Oil Recovery, II Processes and Operation.″ New York, NY, U.S.A. Elsevier Science Publishing Company INC. Original publication. ISBN 0-444-42933-6, 1989.

Doscher, T. M. and Ghassemi, F. (1984) ″Limitations on the Oil/Steam Ratio for Truly Viscous Crudes”.

ECL Technology Report 2 (2001) “CO_2 EOR Issues: Phase 1: Literature Review”. UK DTI SHARP Programme, CO_2 dissemination area of DTI SHARP website.

Gozalpour, F. et al. (2005) “CO2 EOR and Storage in Oil Reservoirs”, Oil and Gas Science and Technology, 60, 3, pp. 537-546.

Goodwear, S. G., Hawkyard, I. R., Masters, J. H. K., Woods, C. L., and Jayasekera, A. J. (2003). Subsurface issues for CO_2 flooding of UKCS reservoirs, Trans. IchemE, 81, Part A.

Green, D. W., Willhite, G. P. (1998) “Enhanced Oil Recovery”

Green, D. W. and Willhite, G. P. (2003) “Enhanced Oil Recovery”, Society of Petroleum Engineers, SPE Textbook Series Vol. 6, Richardson, TX, USA.

Hallam, R.J. and Donnelly, J.K.: “Pressure-Up Blowdown Combustion: A Channelled Reservoir Recovery process”, presented at the 63rd Annual Technical Conference and Exhibition of the SPE, Houston, TX, Oct. 2-5, 1988.

Hatzignatiou, D. G., Lu, Y. (1994) “Feasibility Study of CO_2 Immiscible Displacement Process In Heavy Oil Reservoirs”, Annual Technical Meeting, Calgary, Alberta.

Heinrich, J., (2002) “Legal Implications of CO2 Ocean Storage”, Working Paper, M.I.T., MA, USA, July.

Herbeck, E.F., Heintz, R.C. and Hastings, J.R. (1978) “Fundamentals of Tertiary Oil Recovery: Part 8 - Thermal Recovery by Hot Fluid Injection”, Petroleum Engineer, pp. 24-34.

Hong, K.C. (1999) “Recent Advances in Steamflood Technology”, Paper 54078-MS presented at the International Thermal Operations/Heavy Oil Symposium, Bakersfield, California, March 17-19.

IPM products, MBal (2010). Retrieved from

http://www.petex.com/products/index.php

Jayasekera, T. et al. (2005) “Optimisation of CO2 Injection into UKCS Oilfields”, 26th IEA EOR Symposium, Tokyo.

Jespersen, P.J. and Fontaine, T.J.C. (1993) “Tangleflags North Pilot: A Horizontal Well Steamflood”, J. Can. Petrol. Technol. Vol. 32, No. 5, pp. 52-57.

Jessen, K., Kovscek, A. R. and Orr, Jr., F.M. (2005) “Increasing CO_2 storage in oil recovery”. Energy Conversion and Management 46 (2):293-311.

John, F., Cook, M., Graham, M. (1998) “Hydrocarbon Exploration and Production” Developments in Petroleum Science No. 46, Elsevier, The Netherlands.

Jones, J. and Cawthon, G. J. (1990) “Sequential Steam: An Engineered Cyclic Steaming Method”.

Kantar K., Karaoguz, D., Issever, K.and Vrana, L. (1985) “Design Concepts of a Heavy Oil Recovery Process by an Immiscible Process”. Jour. Pet. Tech. February.

Kantar, K., Karaoguz, D., Issever, K., Vrana, L. (1985). "Design Concepts of a Heavy-Oil Recovery Process by an Immiscible CO_2 Application". Journal of Petroleum Technology 37 (2): 275–283

Kazemi, H., Merrill, L. S. Jr., and Zeman, P. R. (1976) “Numerical Simulation of Water-Oil Flow in Naturally Fractured Reservoirs”, SPEJ, December.

Khan, J. and Parag, D. (1992) “Twenty-Five Years of Oil Recovery by Steam Injection.” SPE 24198-MS.

Kulkarni. M. M. (2003) “Immiscible and Miscible Gas-oil Displacements in Porous Media”

Leaute, R.P. and Carey, B.S. (2005) “Liquid Addition to Steam for Enhancing Recovery (LASER) of Bitumen with CSS: Results from the First Pilot Cycle”, paper 2005-161 presented at the Petroleum Society’s 6th Canadian International Petroleum Conference (56th Annual Technical Meeting), Calgary, Alberta, June 7-9.

Lee, A.L., Gonzalez, M.H., and Eakin, B.E. 1966. The Viscosity of Natural Gases

Lu M, Connell, L. D. (2008) “Non-isothermal flow of carbon dioxide in injection wells during geological storage”.

McQuarrie, Donald A. and Simon, John D. (1999). Molecular Thermodynamics.

Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L.A. Meyer (eds.) (2005) “IPCC special report on Carbon Dioxide Capture and Storage”, Prepared by working group III of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

Moritis, G. Worldwide EOR Survey. Oil Gas J. 2006.

Oldenburg, C.M., K. Pruess and S. M. Benson, 2001: Process modeling of CO2 injection into natural gas reservoirs for carbon sequestration and enhanced gas recovery.

Reis, J.C. (1990) “Oil Recovery Mechanisms in Fractured Reservoirs during Steam Injection,” paper SPE 20204 presented at the SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, OK, April 22-25.

Sahuquet, B. C. and Ferrier, J. J. (1982) “Steam-Drive Pilot in a Fractured Carbonate Reservoir: Lacq Superieur Field,” J. Pet. Tech. April, pp. 873-880.

Satter A., “Heat losses during flow of steam down a wellbore” J. Petroleum Technology, Vol. 17, 1965

Schulte, W. (2004) “Experience for Use in CO_2 for Enhanced Oil Recovery in the USA”, CO_2 conference proceedings, Norway.

Sen, R.,”Biotechnology in petroleum recovery (2008) The microbial EOR”, Progress in Energy and Combustion Science.

Snøhvit LNG Project PDO support documentation CO2 deposition. Retrieved from www.statoil.com, 07 June 2001.

Sunnatov, D. (2010) “Experimental Study of Steam Surfactant Flood for Enhancing Heavy Oil Recovery After Waterflooding”, Master's thesis, Texas A&M University.

Sweet, William (2008) "Winner: Clean Coal - Restoring Coal's Sheen". IEEE Spectrum45: 57–60.

Thomas, L. K. et.al. (1983) “ Fractured reservoir simulation”

Thomas, S. (2008) “Enhanced Oil Recovery – An Overview”, Oil and Gas Science and Technology, Vol. 63, pp. 9-19.

Tzimas, E. and Peteves, S. (2003) “Controlling Carbon Emissions: The Option of Carbon Sequestration”, European Commission, EUR Report 20752 EN.

Tzimas, E., Georgakaki, A., Cortes, C. G., and Peteves, S. D. (2005) “Enhanced Oil Recovery using Carbon Dioxide in the European Energy System”, European Commission, Report EUR 21895 EN.

Warren, J. E. and Root, P. J.: “The Behavior of Naturally Fractured Reservoirs” SPEJ, September, 1963., Trans. AIME, 228.

Weinbrandt, R. M. and Ramey, H. J., Jr. (1972) “The Effect of Temperature on Relative permeability of Consolidated Rocks”, SPE 4142, Annual Meeting, San Antonio, Oct. 8-11.

West Virginia, carbon sequestration (2008). Retrieved from http://www.wvcarb.org 20 September 2014

Whitson C. and Brule M.: “Phase Behavior”, SPE Monograph Volume 20, Henry

L Doherty Series, Richardson, Texas (2000).

Zhu, C., Zhang, F., and Zhou, J.Z.Q.: “An EOR Application at Liaohe Oil Field in China – Tests of Pumping Flue Gas into Oil Wells”, presented at the First National Conference on Carbon Sequestration, Washington D.C., May 15-17, 2001