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Abstract:

CO_2-EOR(Enhanced Oil Recovery) is an effective and useful technology that can not only increase the oil production to meet the increasing need for energy around the world, but also mitigate the negtive influence of global green house effect. Different categories of oil recovery methods including primary recovery, secondary recovery, and EOR technologies are introduced at first. Then the history, global distribution, screening criteria, mechanisms, advantages and disadvantages of CO_2-EOR are discussed. Some common CO_2-EOR processes and technologies, such as miscible and immscible CO_2-EOR processes, Water Alternating Gas(WAG) technology, and Carbonated water injection(CWI) are touched on as well. In the simulation part, OLGA-Rocx is used to simulate the process of CO_2-EOR. Primarily, waterflooding through oil reservoir is simulated. Afterwards, CO_2-EOR is simulated by adjusting the relative permeability curves and reducing oil viscosity. The simulation results of both waterflooding process and CO_2-EOR process are compared to evaluate how much extra crude oil can be produced by using CO_2-EOR. Other factors that may influence the simulating results when evaluating the performance of CO_2-EOR, such as reservoir scale, simulation period, reservoir pressure, reservoir porosity, reservoir permeability, relative permeability model, and reservoir heterogeneity are studied as well.

Telemark University College accepts no responsibility for results and conclusions presented in this report.

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Preface

To most students, it is never easy to finsh a maser's thesis. Finally, I have made it, and I really feel like expressing my gratitude to the people who helped me during the peroid when I am writing my master's thesis. Primarilly, I would like to express my special appreciation to my supervisors Prof. Britt M. Halvorsen for her constant encouragement during instrcucting my mater's thesis. Also, I am very grateful for her helpful guidance and kind patience. I may not be able to finish my thesis without her help. And I greatly acknowledge former student Farzan Sahari Moghaddam for the instructions he made about OLGA-Rocx reservoir simulation in the nearwell. His instructions contributes a lot to my professional knowledge about OLGA-Rocx. And I want to express my thanks to Associate Professor Knut Vågsæther for his last year's guidance, help and understanding as well. I would also like to appreciate all the help from my good friend Chao Xi when I was away from school. He really helps a lot. At last, I am quite grateful to the support and help from my family, who give me the power, strength and courage to move on.

Porsgrunn, May 30th , 2014

Yunhang Li

Nomenclature

Ca	Capillary number
CCI	Cyclic CO_2 Injection
CCS	Carbon Capture And Storage
CF	Capillary Forces
CO_2	Carbon Dioxide
CSI	Cyclic Steam Injection
CWI	Carbonated Water Injection
EOR	Enhanced Oil Recovery
IFT	Interfacial Tension
ISC	In-Situ Combustion
K	Permeability of a medium
K_{eff}	Effective relative permeability
K_r	Relative permeability
K_{ref}	Reference permeability
K_{rg}	Relative permeability to gas
K_{rgo}	Relative permeability for gas in gas/oil phase
K_{ro}	Relative permeability to oil
K_{rog}	Relative permeability for oil in gas/oil phase
K_{row}	Relative permeability for oil in water/oil phase
K_{rw}	Relative permeability to water
K_{rwo}	Relative permeability for water in water/oil phase
M	Mobility ratio
MEOR	Microbic Enhanced Oil Recovery
MMP	Minimum Miscibility Pressure
N_c	Capillary number
OOIP	Original Oil in Place
p_c	Capillary pressure
p_{nw}	Non-wetting phase pressure

p_w	Wetting phase pressure
r	Effective radius of the interface
R1	Radii of the shared interface curvature
R2	Radii of the shared interface curvature
S_e	Effective saturation
S_g	Gas saturation
S_o	Oil saturation
S_w	Water saturation
S_{gnor}	Normalized saturation of gas
S_{om}	Minimum saturation of oil for three-phase models
S_{onor}	Normalized oil saturation
S_{wc}	Critical saturation of water
S_{wnor}	Normalized saturation of water
SRB	Sulfate-Reducing Bacteria
SWAG	Simultaneously Water Alternating Gas
SAGD	Steam-Assisted Gravity Drainage
V	Superficial fluid flowing velocity
V_b	Bulk volume of reservoir rock
V_{gr}	Volume of gas
V_{gr}	Volume of grains
V_o	Volume of oil
V_p	Pore volume
V_w	Volume of grains
VF	Viscous Forces
WAG	Water Alternating Gas
WAG	Water Alternating
μ	Dynamic viscosity of the liquid
λ	Mobility
θ	Wetting angle of the liquid on the surface of the capillary

σ_{nww}	Interfacial tension between the non-wetting phase and the wetting phase
ϕ	Flow potential
ϕ	Porosity
θ_c	Contact angle
γ	Surface or interfacial tension between the two fluid phases
dP/dL	Pressure drop per unit length
βw	Factor to allow for oil blockage by water
βg	Factor to allow for oil blockage by gas

Overview of Tables and Figures

Overview of Tables

Overview of Figures

1 Introduction

The global need for energy are increasing all the time with the rapid development of modenization in the world. Fossil fuels, especailly oil, are still the main energy sources to human beings. Therefore, increaing the production of crude oil is a must. Enhanced oil recovery(EOR) is an effective technology that can further increase the oil production. However, the increased oil production means more emission of greenhouse gases to the atmosphere. CO_2-EOR is one type of the enhanced oil recovery technologies that can both achive incremental crude oil production and decrease the amount of CO_2 emission to the atmosphere. Thus it is a promising technology and worth of studying. (Gozalpour et al., 2005)

The first aim is to make a literature review about CO_2-EOR technology to learn more about this technology, which is done in Chapter 2 and Chapter 3. In the literature reiview part, different oil recovery technologies, such as primary recovery, secondary recovery, and tertiary recovery(enhanced oil recovery) are introduced. Then some basic facts about CO_2-EOR, for instance, the history of CO_2-EOR, the global distribution of CO_2-EOR projects, the screening criteria of CO_2-EOR sites, mechanisms of CO_2-EOR, advantages and disadvantages of CO_2-EOR, are touched on. In addition, miscible CO_2-EOR process, immiscible CO_2-EOR process, and near miscible CO_2-EOR process are discussed. Furthermore, different kinds of injection methods and technologies, like cyclic CO_2 injection(CCI), carbonated water injection(CWI), water alternating gas(WAG), and "next generation" CO_2-EOR technology, are introduced. In the last part of literature review, the global potential of CO_2-EOR, carbon capture and storage, and the relationship between carbon capture and storage(CCS) and CO_2-EOR are invovled as well.

Many studies about simulation of CO_2-EOR process have been done. However, few studies have been accomplished to simulate the process of CO_2-EOR by using OLGA-Rocx.

The second objective is to explore the simulation of the CO_2-EOR process and to calculate the oil production potential of different types of reservoirs by using OLGA-Rocx, which is done in Chapter 4. First of all, some fundamental concepts of reservoir properties, such as wettability, fluid saturations, permeability, and relative permeability etc., are introduced. Then a few common relative permeability models are also discussed. The specific case to be simulated is a cuboid-shaped oil reservoir that is 49.6 meters long, 80 meters wide, and 20 meters high. The oil reservoir to be simulated is assumed to be homogeneous.The reservoir properties and feeds are specified in the Rocx file. Then the Rocx file is linked to the near well sources of the PIPELINE in the OLGA file. In this way, the oil reservoir and pipes are connected. Water flooding through the oil reservoir is simlulated first by introducing two feeds, one feed is alomost oil, and the other feed mainly consists of water. As to the complicated process of CO_2-EOR and the limitation of OLGA-Rocx, the CO_2-EOR process is simulated by adjusting the relative permeability curves and reducing the oil viscosity on the basis of the waterflooding process. After the CO_2 is injected into the oil reservoir which has been flooded by water before, the residual oil saturation will decrease because of the reduction of oil viscosity, oil swelling, and other mechanisms. Therefore, the CO_2-EOR process can be simulated by reducing the residual oil saturation and oil viscosity of the waterflooding process. The accumulated oil liquid flow(ACCOIQ) of water flooding process and CO_2-EOR process are compared to evaluate how much extra oil is produced by introduing CO_2-EOR technology. Other factors that may influence the simulating results when evaluating the performance of CO_2-EOR technology, such as reservoir scale, simulation period, reservoir pressure, reservoir porosity, reservoir permeability, relative permeability model etc., are studied as well. Thus the production potential of applying CO_2-EOR technology to diffrent reservoirs with different scale, different reservoir pressure, different reservoir porosity, and different reservoir permeability can be calculated and stuided.

Then the simulation results, such as the accumulated oil volume flow(ACCOIQ) and accumulated liquid volume flow(ACCLIQ) etc. of cases with different simulation scale, simulation period, reservoir pressure, reservoir porosity, reservoir permeability, relative permeability models, and reservoir heterogeneity are demonstrated in Chapter 5. Chapter 6 include the discussion on the various results of different cases. Conclusions are made in Chapter 7 to show how the simulation results, namely the ACCOIQ and ACCLIQ etc. are affected by various factors, such as reservoir pressure, reservoir porosity, reservoir permeability, and so on.

2 Enhanced Oil Recovery

For the recovery of oil reservoirs, there are mainly three stages, that is, primary recovery, secondary recovery and tertiary recovery(also known as enhanced oil recovery or EOR).

2.1 Primary Recovery

In the primary recovery phase, oil is driven from the reservoir to the producing well by natural existing pressures in the oil reservoir. The natural pressures come from the natural gas's expanding force, gravitational force, encroaching water's buoyance force, and expulsion force from the compaction of reservoir rocks, among which the expanding force by natural gas is the main driving force contributing to the oil production. The driving force of encroaching water from the bottom or side of the reservoir is also effective in the oil displacement. These four forces can work together at the same time or in sequence.(Donaldson et al., 1989) Ahmed concluded several natural driving mechanisms in the primary recovery phase as well, including rock and liquid expansion drive, depletion drive, gas cap drive, water drive, gravity drainage drive, and combination drive.(Ahmed et al., 2005) The properties of reservoir rock and fluid, and the heterogeneities of the reservoir determine the performance of primary recovery.The oil recovery of the primary stage can be 20%~30% according to Saleem Qadir Tunio.(Tunio et al., 2011) When the primary natural driving energy decreases to some extent and the production rate of the oil reservoir declines much, it is necessary to add artificial energy to the reservoir system to maintain the high production level. Then secondary recovery methods need to be applied to the process of reservoir oil recovery.(Satter et al., 2008)

2.2 Secondary Recovery

In the secondary recovery, the injection of water or gas into the reservoir after the primary recovery can restore and maintain the reservoir pressure to guarantee the high outflow rate of oil to the producing wells. The recovery strategies in the secondary phase include gas injection, water flooding, or combined water and gas injection, where water and gas are injected sequentially (WAG, Water Alternating Gas) or simultaneously(SWAG, Simultaneously Water Alternating Gas). Among these injection methods, water flooding is the most commonly used because of its low cost, rich source and high specific gravity that promotes the injection.(Dake, 1978; Lyons et al., 2005; Satter et al., 2008)

2.2.1 Water Injection

In the process of water injection, water is discharged to the aquifer through a few injection wells around the production well. The reservoir oil is pushed upwards by the driving force of water from the bottom. The injected water can not only maintain the reservoir pressure, but also push the reservoir oil to the production well. However, water flooding has also some disadvantages, such as formation damage due to reaction between injected water and formation water, and equipments corrosion.

2.2.2 Gas Injection

The first idea of utilizing gas injection for the sake of maintaining reservoir pressure was proposed as early as 1864, only a few years after the drilling of Drake Well in Pennsylvania, United States. It is one of the oldest fluid injection methods. In the past, the gas injection were usually applied to maintain reservoir pressure. However, in recent years this injection method has been used as a strategy for enhanced oil recovery. A primary problem for gas injection is the high mobility of the injected fluid, requiring great control over the injection process.(Donaldson et al., 1989)

The oil recovery efficiency of gas injection is usually lower than that of water flooding. Nevertheless, the gas injection is sometimes a better choice for oil recovery in some situations, such as oil formations with quite low permeability like shales, and reservoir rock with swelling clays, and thin formations where solution-gas drive is the primary driving mechanism.(Lyons et al., 2005)

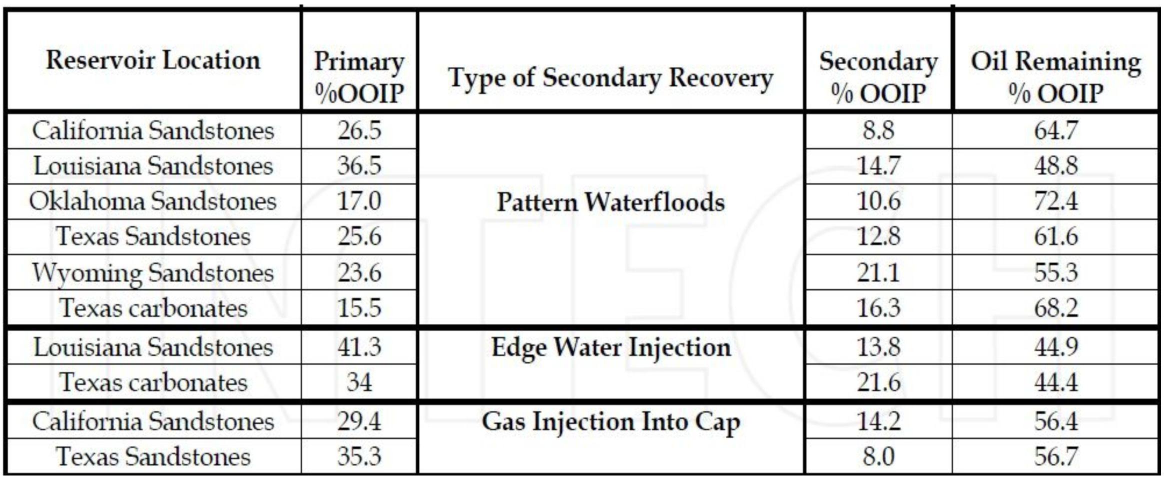
2.2.3 Limitations of Primary and Secondary Recovery

One limitation of primary recovery and secondary recovery is the rapid decrease of reservoir pressure leading to low oil recovery. The causes of low oil recovery efficiency in the secondary recovery primarily cover reservoir heterogeneity, undesirable mobility ratio between oil and water, water and gas coning, and low sweep efficiency.

After the secondary recovery, the amount of recovered reservoir oil can achieve 40%. Therefore, after the primary and secondary phase, about 60% of oil still remains in the petroleum reservoir, which means that there exist lots of oil recovery potential.(Tunio et al., 2011)

Some practical examples with recovery efficiencies and percentages of remaining oil are demonstrated in Table 2-1.(Lyons et al., 2005)

Table 2-1: Oil recovery efficiencies of OOIP from primary & secondary recovery.



Reservoir Location	Primary %OOIP	Type of Secondary Recovery	Secondary % OOIP	Oil Remaining % OOIP
California Sandstones	26.5	**Pattern Waterfloods**	8.8	64.7
Louisiana Sandstones	36.5		14.7	48.8
Oklahoma Sandstones	17.0		10.6	72.4
Texas Sandstones	25.6		12.8	61.6
Wyoming Sandstones	23.6		21.1	55.3
Texas carbonates	15.5		16.3	68.2
Louisiana Sandstones	41.3	**Edge Water Injection**	13.8	44.9
Texas carbonates	34		21.6	44.4
California Sandstones	29.4	**Gas Injection Into Cap**	14.2	56.4
Texas Sandstones	35.3		8.0	56.7

2.3 Enhanced Oil Recovery

To further improve oil production, Enhanced Oil Recovery(EOR) is applied in the tertiary recovery phase.(James, 2010) The optimal time to start Enhanced Oil Recovery project is determined based on several factors, such as fluid production rates, anticipated oil recovery, monetary investment, costs of water treatment, costs of maintenance and operation, and other relevant costs.(Jelmert, 2010) According to Donaldson etc., feasible methods for Enhanced Oil Recovery can be classified into three major types, which are thermal processes, chemical processes, and miscible displacement processes, and are shown in details in Figure 2-1.(Donaldson et al., 1989)

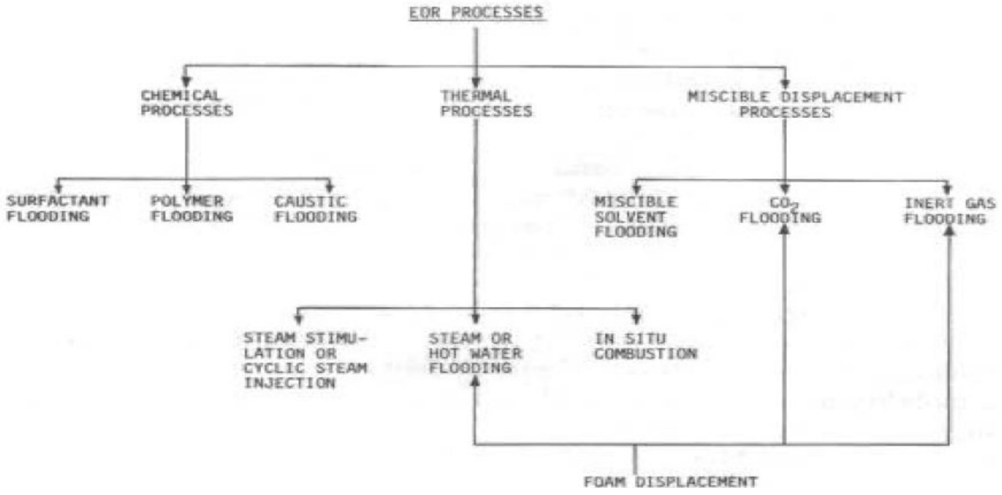


Figure 2-1: Different EOR methods.

However, the Oil and Gas Journal has a different classification of EOR methods, which are divided into four types: thermal methods, gas methods, chemical methods and other methods. The detailed classification is shown briefly below.(Lake et al., 2008)

Thermal EOR processes:

Steam flooding

Cyclic steam stimulation
In-situ combustion
Hot waterflooding
Steam-assisted gravity drainage
Gas EOR processes:
Hydrocarbon miscible/immiscible
CO_2 miscible
CO_2 immiscible
Nitrogen
Flue gas (miscible and immiscible)
Gravity drainage
Chemical EOR processes:

Micellar-polymer flooding

Polymer flooding

Caustic/alkaline flooding

Alkaline/surfactant flooding

Other EOR processes:

Carbonated waterflood

Microbial EOR

Electromagnetic heating

2.3.1 Thermal EOR Processes

Thermal EOR projects have been concentrated mostly in Canada, Former Soviet Union (FSU), U.S. and Venezuela, and Brazil and China to a lesser extent.

Thermal methods improve the reservoir oil recovery by usually using steams in the steam flooding. Other thermal methods include cyclic steam injection (Huff & Puff) method, and Steam-Assisted Gravity Drainage (SAGD). These thermal methods are widely used in the recovery of heavy oil in sandstone reservoirs. EOR projects utilizing thermal methods are found mostly in Canada, Former Soviet Union (FSU), U.S. and Venezuela. There are also some thermal EOR projects in Brazil and China.(Alvarado et al., 2010)

2.3.1.1 Cyclic Steam Injection

Cyclic Steam Injection(CSI) method is also known as Cyclic Steam Stimulation(CSS) or Huff & Puff method, which is an effective thermal EOR method. It improves oil recovery by reducing the viscosity, alternating wettability, and expanding gas. The first application of CSI was in the Mene Grande field by Shell Oil Company in Venezuela in the late 1950s. Since then, CSI has been used widely to not only light oil reservoirs, but also heavy oil reservoirs around the world.(Alvarez et al., 2013)

In the cyclic steam injection process, firstly steam is injected into a single well with high flow rate and high pressure to supply heat to the oil reservoir for a period usually from 10 days to a month, which is known as the injection stage. The period of this stage depends on the quantity of steam injected and the capacity of the equipment used. Then in the soaking stage, the well is shut down to allow for the heat distribution in the reservoir for around six months to twelve months. In the final stage, namely the production stage, large amount of hot water that generated from the condensation of injected steam in the reservoir come out of the production well, which is the same well as the injection well in the injection stage. Then the production rate of water decreases little by little, while the oil out flow rate increases gradually. The response of a specific oil reservoir using cyclic steam injection relies mainly on the existing permeability of the reservoir, the radius heated, the viscosity of the oil, the initial reservoir pressure and heat losses. The performance of cyclic steam injection is also influenced by several operation factors: the amount of steam injected, the net sand thickness of the producing interval, the surface injection pressure, the rate at which energy is removed from the formation through production, the number of preceding cycles, steam properties, and the state of the primary depletion.(Rodríguez et al., 2008)

The average recovery factor using conventional Cyclic Steam Injection was only 15% in the 1980s. However, after applying the modern technologies, such application of hydraulic fracturing, adding chemical to steam, and application of horizontal wells, the average recovery factor increased to around 40%. The advantage of CSI is its high success rate of pay out as a result of its abundant experience. Nevertheless, the ultimate recovery factor of CSI is relatively low when compared to that of other thermal EOR methods. For instance, the ultimate recovery factor of steam flooding is from 50% to 60%, and OOIP of Steam-Assisted Gravity Drainage(SAGD) is from 60% to 70% .(Alvarez et al., 2013)

But CSI is still the most widely used steam injection method. In the CSI process, steam is injected into a well bore, and the heated radius could be a few tens of meters. After a period of time, the original injection well becomes production well, where the productions like steam, hot water, and oil come out.(Lake et al., 2008)

2.3.1.2 Steam Flooding

Steam flooding, also known as steam drive or steam displacement, is another major thermal EOR method and an important method for heavy oil recovery. The main mechanisms of steam flooding are the reduction of oil viscosity and the thermal expansion. In the steam flooding process, the injection wells and production wells are separate, while the injection well and production well are the same well. The steam injected heats the area around the injection well, and a steam zone forms and grows as the injection of steam continues. The injected steam can reduce the oil viscosity and also the oil saturation in the steam zone, and can push the oil out of the steam zone. As the steam injection goes on, the heat zone grows and the displaced oil is driven out of the steam zone, and accumulates and forms a oil bank ahead of the steam front. A steam flood project usually is made up of four steps of development: reservoir screening, pilot tests, field implementation and reservoir management.(Mandl et al., 1969)

2.3.1.3 Steam-Assisted Gravity Drainage

Steam-Assisted Gravity Drainage(SAGD) is effective in the recovery of heavy oil and bitumen. Butler and his former colleagues of Imperial Oil first proposed the idea of SAGD for the recovery of bitumen in the late 1970s.(Butler et al., 1981)

The steam is typically injected into the horizontal well which is located above a horizontal production well. The two horizontal wells are close to the bottom of a formation and have a short vertical distance which is about 4 to 10 meters. The steam chamber around the injection well displaces heated oil and drives it towards the production well. In this process, the driving forces also include gravity, which enhances the oil production as well. In the heavy oil reservoirs, the driving force of gravity is more obvious, and helps to recover more oil. Heat is transferred by convection, conduction and latent heat of steam. At the boundary of steam chamber, the heat of steam is transferred to reservoir oil, then steam condenses to water because of its heat loss. Afterwards, the heated reservoir oil flows together with the condensed water to the production well.(Elliott et al., 1999)

The mechanisms of SAGD mainly cover the reduction of viscosity, thermal expansion and steam distillation.(Willman et al., 1961)

SAGD has many advantages over other thermal EOR methods and can reach a high oil recovery factor. When compared to the conventional steam flooding methods, the SAGD technology solves the steam override problem, as its driving mechanism is only gravity, which makes the displacement stable and improves oil recovery efficiency. What’s more, in the conventional steam flooding method, the displaced oil from the steam chamber is cooled and it is difficult for the cooled oil to move towards the production well. While in the SAGD process, the oil is still hot and movable, which helps it to move towards the producer.(Butler, 1998, Butler, 2001)

2.3.1.4 In-situ combustion

In-situ combustion(ISC), also known as fire flooding, is the oldest thermal recovery method and has many economically successful cases. It can be used as an effective thermal method for deep oil reservoirs with low permeability and high temperature, where other enhanced oil recovery methods are limited. Oxidizing gas, such as air or oxygen enriched, is injected into the oil reservoir, then the reservoir oil is ignited by a special heater. The burning of oil generates heat, which leads to hydrocarbon cracking, deposition of heavy hydrocarbons, and the vaporization of light hydrocarbons and water in the reservoir. The fire grows and expands, and the burning front drives the mixture of combustion gases, steam and hot water. In this way, the viscosity of reservoir oil is decreased, and the oil is displaced and pushed towards the production well. In addition, in front of the burning front, the light hydrocarbons and steam condense to liquids because of heat loss to reservoir oil. This phenomenon can create miscible displacement and hot waterflooding, which improves the recovery efficiency of reservoir oil as well.(Chu, 1982)

Depending on the movement direction of the fire front, the in-situ combustion process can be divided into two processes. One process is the forward combustion, where the fire front moves in the same direction as the air flow. The other is the reverse combustion, where the combustion front advances against the air flow.

In practice, only forward combustion is applied, and can be further divided into two categories, dry forward combustion and wet forward combustion, based on whether water is added to the injected gas or not. As to the reverse combustion, it has been studied in laboratory scale extensively and also been tried in the field. Reverse combustion is supposed to be quite useful in the recovery of very heavy oil with high viscosity. However, it is not as successful as forward combustion for two reasons. The first reason is the high cost of operation since the reverse combustion needs more oxygen. The other reason is that at some time the remaining coke will burn and revert to forward combustion, where large amount of heat is generated, but little reservoir oil is produced.(Cadelle et al., 1981, Joseph et al., 1980)

To sum up, this thermal recovery technique enhances oil recovery by a set of complicated reactions and procedures, such as oxidation, hydrocarbon cracking, fire front displacement, distillation, miscible and immiscible gas flooding gravity drainage and hot water flooding.(Bousaid et al., 1968)

2.3.2 Chemical EOR Processes

Chemical EOR methods were most widely used in the 1980s. The majority of chemical injection methods were utilized in sandstone reservoirs.For the chemical injection, polymers or detergent-like surfactants are injected into the reservoir to improve the oil recovery. The chemical processes can be classified mainly into three categories, polymer flooding, surfactant flooding and caustic flooding(alkaline flooding). (Needham, 1987)

2.3.2.1 Polymer flooding

Polymer flooding, also known as polymer augmented waterflooding, is assumed as the simplest and most extensively used chemical methods to control the mobility. Water-soluble polymer, usually hydrolyzed polyacrylamides (HPAM) and biopolymer Xanthan, is added to water before its injection into the reservoir. (Pope, 2011)

The first application of polymer flooding was from Pye and Sandiford who added small amounts of soluble water polymer to reduce the mobility of water in 1964. Then a large number of experiments were carried out to explore and improve the performance of this new method.(Chang, 1978)

Polymer flooding improves oil recovery by increasing the viscosity of water, thus the mobility and permeability of water is decreased. Another mechanism of polymer flooding is that a large volume of reservoir can be contacted by the injected fluid. The application of conventional polymer flooding to reservoir with excessive fractures should be avoided. However, if in the case of high oil viscosity, a higher concentration of polymer is needed to control the water mobility well. Therefore, polymer flooding is suitable for oil reservoirs with low oil viscosity. Polymer flooding performs better if the polymer is injected before the water-oil ratio becomes quite high. The performance of polymer flooding is also influenced by temperature. The most appropriate reservoir temperature of reservoir is less than 93 degrees Celsius. One disadvantage of polymer flooding is that at the early stage of the flooding, the oil production rate can be affected by the injectivity of polymer flooding which is lower than that of water flooding.(Lyons, 2005)

2.3.2.2 Micellar-polymer flooding

The increase of oil production due to micellar-polymer floodingis much like the dish-washing detergent which makes it easy for the grease to be washed away from the used dishes by the flowing water. In the micellar-polymer flooding process, micelle solutions are injected into the oil reservoir through injection wells to reduce the interfacial tension and capillary forces between oil and water, which results in an increase in oil production. The first procedure of micellar-polymer flooding is a pre-flush by low salinity water. Then chemical solutions like micellar or alkaline are injected into the oil reservoir in order to decrease the interaction forces between oil and water, and then mobility buffer is injected to control the mobility. At last, driving fluid such as water is pumped into the reservoir to displace chemicals and push the oil bank towards the production wells. Since the interfacial tension and capillary forces are changed by micellar-polymer flooding, the reservoir fluids become miscible, making the oil production less difficult. By the use of alkaline(Sodium Carbonate), almost 100 percent of oil can be recovered in theory. However, the non-uniformity of reservoir rock has an negative effect on the oil recover, and the oil recovery efficiency is reduced.(Carcoana, 1992, Gogtirty, 1976)

Micellar solution is also called as microemulsion in some literatures.(Willhite, 1980)

Usually the weight percent of surfactant is 20%-25% to produce microemulsion solution. While the cost of surfactant is not low. So the optimum weight percent of surfactant when making microemulsion solution is about 5%-10% to reduce the total cost of an EOR project.(Shinoda, 1973)

2.3.2.3 Surfactant flooding

Surfactant flooding is often used after waterflooding and is especially effective for the recovery of conventional oil with 25 API or higher. The oil left after waterflooding could be as much as 60% of the original oil in place.(Thomas, 2001)

Surfactant flooding can improve the recovery of capillary-trapped residual oil after water flooding by reducing the interfacial tensions between oil and water and also altering the wettability of the reservoir rock. The large reduction in interfacial tension(IFT) can make the residual oil more mobile and easier to be recovered. In addition, the surfactant can prevent the mobile oil from being trapped again. What’s more, the dispersion of oil in water is increased, and the oil bulbs can change their shape and pass the pore throats more easily. Then the residual oil saturation is reduced and the relative permeability curves of oil move up and shift towards right. The endpoints of water phase is also increased.(Kleppe, 1992, Yin, 2008)

The efficiency of surfactant flooding is influenced by different variables, for example, the oil in place at the beginning of surfactant flooding, the reservoir sweep efficiency, and microscopic displacement efficiency.(Fathaddin, 2010)

2.3.2.4 Caustic flooding

Caustic flooding, also called alkaline flooding, is mostly applied in light oil reservoirs. However, it has great potential in heavy oil recovery, especially for the heavy oil reservoirs where thermal methods are not suitable. The mechanisms of caustic flooding primarily include the reduction of interfacial tension, reversal of rock wettability, and emulsification of reservoir oil.(Peia, 2013)

The origin of caustic flooding can date back to as early as 1927 when H. Atkinson got a patent for his idea to add sodium hydroxide to waterflooding. But since then three were no successful application of this method to oil field production. Emery et al. proved that caustic flooding could make wettability reversal possible and enhance the oil recovery in laboratory experiments in the Singleton Field in 1970.(Jennings, 1974)

2.3.3 Gas EOR methods

In miscible displacement methods, several displacement fluids can be used, such as CO_2, nitrogen, hydrocarbon solvent, and flue gas. These displacement fluids are usually more expensive than fluids that are immiscible with crude oil, like water. Therefore, to lower the cost, the injected miscible fluid slug is relatively small. Then large volume of less expensive fluids, such as water and lean gas, follow after the primary slug. Miscible displacement methods can eliminate the interfacial tension(IFT) between displacing fluid and displaced fluid, leading to incremental oil production.

CO_2 flooding is suitable for oil reservoirs deeper than 2,000 feet. The API gravity of reservoir oil should be larger than 22^o–25^o ,and remaining oil saturations bigger than 20%, if CO_2-EOR is to be utilized.(Jelmert et al., 2010)

Taber’s study shows that CO_2 injection might be able to be applied in approximately

80% of reservoirs in the world, if only well depth and oil gravity are considered. (Taber, 1997)

2.3.3.1 N2 flooding

Nitrogen flooding can enhance oil recovery by pressure maintenance, immiscible displacement and miscible placement. High reservoir pressure and light oils are needed to reach miscible conditions, which are the limitations of nitrogen flooding. However, nitrogen flooding has also its advantages. The major advantages of nitrogen flooding is its low cost and easy accessibility. Other outstanding features include preventing the oil encroachment into the gas cap, higher recovery efficiency than waterflooding in low permeability reservoirs, and its supply reliability.(Jelmert et al., 2010) Besides, nitrogen flooding has no corrosion to the facilities and equipments. (Anada, 1980)

2.3.3.2 CO_2 Enhanced Oil Recovery

The CO_2-EOR technology will be discussed in details later.

2.3.4 Other EOR Methods

2.3.4.1 Microbic EOR

Microbic EOR, also know as MEOR, utilizes bacteria and their by-products by the inoculation of microorganisms in a reservoir in order to mobile oil in the reservoirs, which can improve oil recovery efficiency. The favorable effects caused by the injected bacteria and their by-products mainly include the reduced interfacial tension between oil and water, the formation of stable oil-water emulsions, transferring of injection fluids to the reservoir's upswept areas as a result of clogging high permeable zones.(Ghadimi et al., 2006)

Other mechanisms of Micorbic EOR include alteration of wettability by surfactant production and bacterial presence, the reduction of oil viscosity caused by gas production or by degradation of long-chain saturated hydrocarbons, production of acids that dissolves minerals from the reservoir rock and improves absolute permeability, and selective plugging by the microorganisms and their metabolites. The main two mechanisms with the greatest effects on oil recovery are the decreased interfacial tension between oil and water, and the alteration of wettability.(Nielsen et al., 2010)

The MEOR processes are becoming more and more popular in the world because it is cost-effective and quite environmental friendly.(Sarkar et al., 1994) The first idea of using microorganisms to release oil from porous media and improve oil recovery efficiency came from Beckman in 1926.(Lazar, 2007) Later ZoBell and his research partners made a series of systematic laboratory investigations on applying microbiology to oil recovery. In the microbic EOR(MEOR) process, the viscosity of oil is decreased by the gases produced by bacteria. The bacteria can also produce some materials that can act as surface-active substances or wetting agents, which helps to improve the oil recovery. Other mechanisms of microbic EOR processes include dissolution of inorganic carbonates caused by metabolites produced from bacterial. Also the bacteria can replace and push away the oil films on the rocks because of its high affinity for rocks.(ZoBell, 1947)

A complete microbic EOR system should cover four main components, that is, reservoir, bacterial system, nutrients, and protocol of well injection.(Lazar, 1998)

MEOR is attractive because the cost of injected bacteria is low, and it is not difficult to obtain and handle the bacteria in the oil field. And the cost of the injected fluids does not depend on oil prices. The implementation of MEOR is not complicated. The only procedure is to just make some minor modifications to the existing field facilities. Therefore MEOR cost less to install and are less difficult to be applied than the other EOR methods. Another advantage of MEOR is that the effects from activity of bacteria increase with time because of their growth whole, while the effects of the additives decrease as time goes on in other EOR processes. Other EOR methods, especially the chemical EOR methods, have an negative impact on the environment, but the MEOR processes are very environmental friendly, since the products from MEOR are all biodegradable and are unable to be accumulated in the reservoir or its surrounding environment. In addition, the MEOR methods are quite suitable for carbonate oil reservoirs, where other EOR processes are not able to recovery reservoir in a good efficiency. MEOR is also a good choice for the marginal wells before abandoning them.(Lazar, 2007)

Though MEOR has many advantages over other EOR methods, it also has some disadvantages. Jack suggested some common problems that MEOR system has to face.(Jack, 1993) The first problem is the lose of injectivity caused by the wellbore plugging. The wellbore plugging can be avoided if filtration is done before injection. The non production of biopolymers when solution is injected can also help to decrease the wellbore pugging. Secondly, the use of MEOR has some requirements for the reservoir properties. Reservoirs with low permeability(less than 50-75mD) are not suitable for the application of MEOR. Thirdly, in the MEOR process, factors like PH, temperature, salinity, and pressure in the reservoir limit the promotion of the desired metabolic activity in situ. Finally, there are some undesirable secondary activities, such as the sulfate-reducing bacteria(SRB), that can also be a problem for the EMOR process. Nitrate can be injected into the reservoir together with the nutrient support, since nitrate at low concentration can reduce the production of hydrogen sulfide.(Knapp, 1990)

3 CO_2 Enhanced Oil Recovery

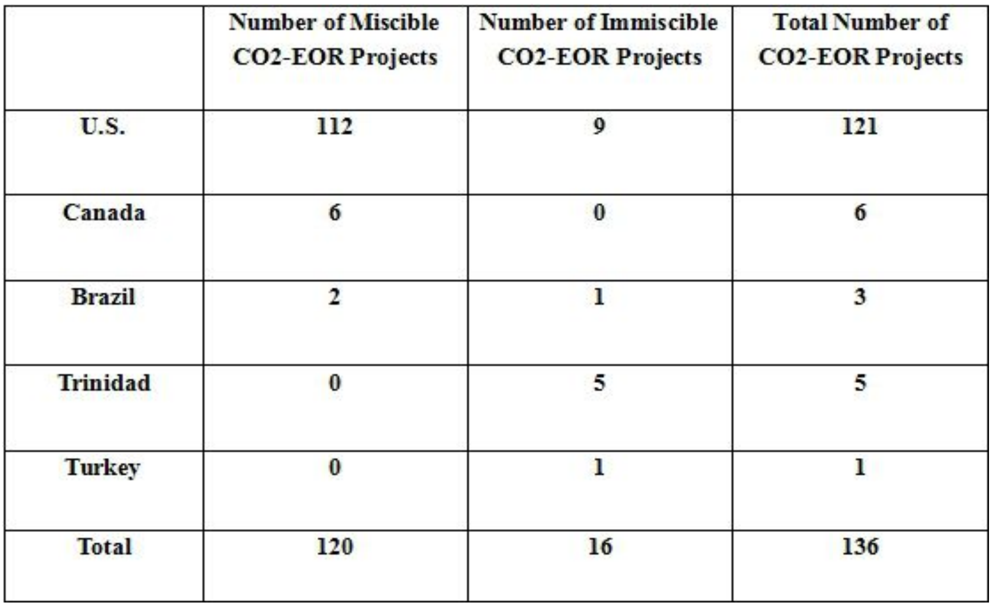
3.1 History

Enhanced Oil Recovery by the application of carbon dioxide injection has a history of more than 60 years. The first idea came from Whorton Brownscombe, who got the patent for CO_2 Enhanced Oil Recovery in 1952.(Whorton, 1952) Afterwards, CO_2 was injected into the reservoir in a pilot project at the Mead Strawn Field in 1964, which proved that injection of CO_2 did help the improvement of oil production. (Holm, 1971) In 1972, the first commercial CO_2 Enhanced Oil Recovery project started at the Kelly-Snyder Field in United States.(Langston et al., 1988) Since this first commercial CO_2-EOR project at the Kelly-Snyder Field, the number of CO_2-EOR projects have been growing in the world. According to the worldwide EOR survey by Koottungal in 2012, the total number of CO_2-EOR projects on earth reached 136.(Koottungal, 2012)

3.2 Global Distribution

According to the latest data from worldwide EOR survey by Koottungal, Table 3-1 was made to show the distribution of CO_2-EOR projects in the world in deatails. (Koottungal, 2012)

Table 3- 1: Distribution of CO_2-EOR projects worldwide until 2012.



	Number of Miscible CO2-EOR Projects	Number of Immiscible CO2-EOR Projects	Total Number of CO2-EOR Projects
U.S.	112	9	121
Canada	6	0	6
Brazil	2	1	3
Trinidad	0	5	5
Turkey	0	1	1
Total	120	16	136

The survey indicates that most of the global CO_2-EOR projects are in the North

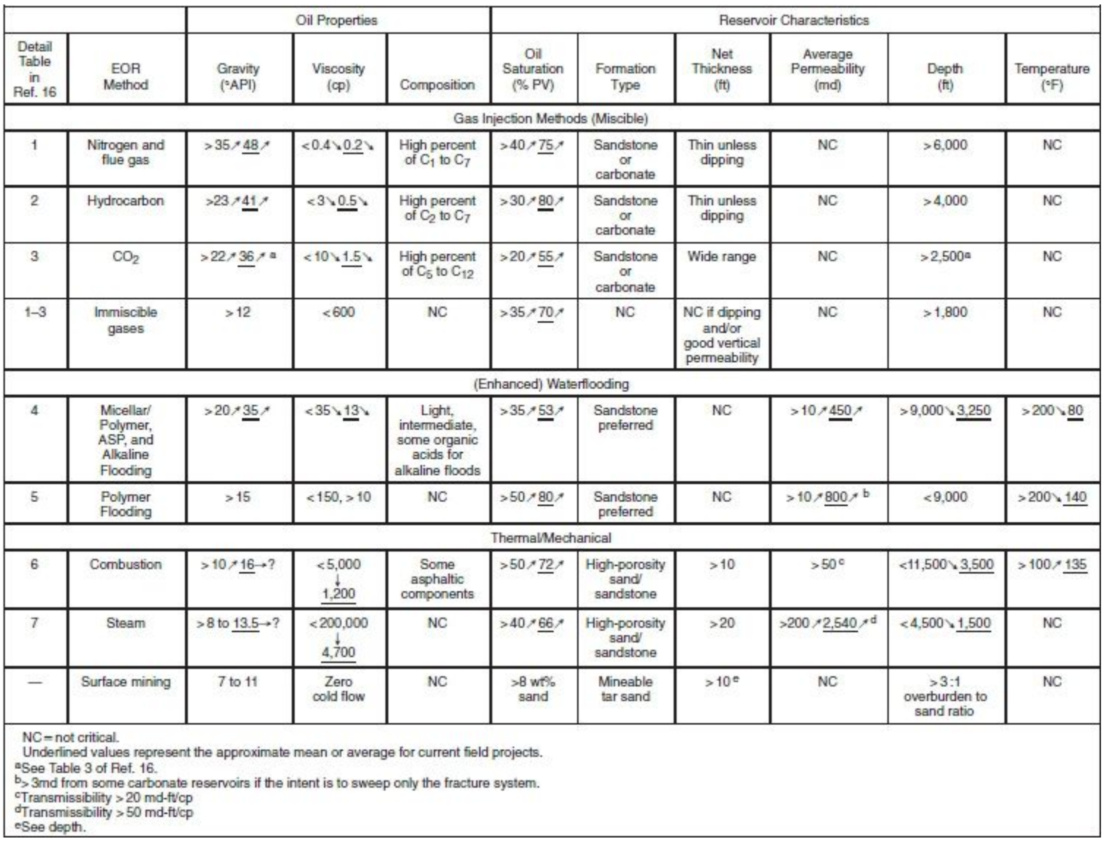
America, mainly in United States. Until 2012, the number of CO_2-EOR projects in United States is 121, while there are totally 136 CO_2-EOR projects all around the world. Canada owns the second largest number of CO_2-EOR projects in the world, which is, however, only 6. The other CO_2-EOR projects are located sporadically in three different continents, namely 5 in Trinidad, 3 in Brazil, and 1 in Turkey. It can also be concluded that miscible CO_2-EOR process is much more popular than immiscible CO_2-EOR process. However, the six planned CO_2-EOR projects in the survey are all CO_2 immiscible, and are all to be constructed in the United States with starting date between 2012 and 2014.(Koottungal, 2012) One main reason why United States and Canada is leading the CO_2-EOR application is because of their sufficient natural sources of CO_2.(Sohrabi et al., 2009) The main barrier of CO_2-EOR is not technical issue, but the high cost of CO_2 supply.(Gozalpour, 2005)

3.3 Screening Criteria

3.3.1 EOR

Different enhaced oil recovery methods have different screening criteria, which are shown in details in Table 3-2.(Taber et al., 1997)

Table 3- 2: Screening criteria for different EOR methods.



		Oil Properties			Reservoir Characteristics					
Detail Table in Ref. 16	EOR Method	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods (Miscible)										
1	Nitrogen and flue gas	>35↗48↗	<0.4↘0.2↘	High percent of C_1 to C_7	>40↗75↗	Sandstone or carbonate	Thin unless dipping	NC	>6,000	NC
2	Hydrocarbon	>23↗41↗	<3↘0.5↘	High percent of C_2 to C_7	>30↗80↗	Sandstone or carbonate	Thin unless dipping	NC	>4,000	NC
3	CO_2	>22↗36↗ [a]	<10↘1.5↘	High percent of C_5 to C_{12}	>20↗55↗	Sandstone or carbonate	Wide range	NC	>2,500[a]	NC
1–3	Immiscible gases	>12	<600	NC	>35↗70↗	NC	NC if dipping and/or good vertical permeability	NC	>1,800	NC
(Enhanced) Waterflooding										
4	Micellar/ Polymer, ASP, and Alkaline Flooding	>20↗35↗	<35↘13↘	Light, intermediate, some organic acids for alkaline floods	>35↗53↗	Sandstone preferred	NC	>10↗450↗	>9,000↘3,250	>200↘80
5	Polymer Flooding	>15	<150, >10	NC	>50↗80↗	Sandstone preferred	NC	>10↗800↗ [b]	<9,000	>200↘140
Thermal/Mechanical										
6	Combustion	>10↗16→?	<5,000 ↓ 1,200	Some asphaltic components	>50↗72↗	High-porosity sand/ sandstone	>10	>50 [c]	<11,500↘3,500	>100↗135
7	Steam	>8 to 13.5→?	<200,000 ↓ 4,700	NC	>40↗66↗	High-porosity sand/ sandstone	>20	>200↗2,540↗ [d]	<4,500↘1,500	NC
—	Surface mining	7 to 11	Zero cold flow	NC	>8 wt% sand	Mineable tar sand	>10 [e]	NC	>3:1 overburden to sand ratio	NC

NC = not critical.

Underlined values represent the approximate mean or average for current field projects.

[a] See Table 3 of Ref. 16.

[b] > 3md from some carbonate reservoirs if the intent is to sweep only the fracture system.

[c] Transmissibility > 20 md-ft/cp

[d] Transmissibility > 50 md-ft/cp

[e] See depth.

3.3.2 CO_2-EOR

The application of CO_2-EOR and storage is not suitable for all kinds of oil reservoirs because of technical and economic reasons. Before considering other economic criteria, Shaw et al. suggested some preliminary technical evaluations for choosing oil reservoir for CO_2-EOR and storage. At first, screening for CO_2-EOR and storage suitability should be done. Then comes the technical ranking of suitable reservoir. At last, CO_2-EOR and CO_2 storage capacity should be predicted. Shaw also proposed the screening criteria for application of CO_2-EOR by various authors, which are based on the optimization of the performance of CO_2-EOR.(Table 3-3)(Shaw et al., 2002)

Table 3- 3: Screening criteria for application of CO_2-EOR by various authors.

Reservoir Parameter	**Geffen (1973)**	**Lewin et al. (1976)**	**NPC (1976)**	**McRee (1977)**	**Jyoho (1978)**	**OTA (1978)**	**Carcoana (1982)**	**Taber&Martin (1983)**	**Taber et al. (1997a)**
Depth(ft.)		> 3,000	> 2,300	> 2,000	> 2,500	i) > 7,200 ii) > 5,500 iii) > 2,500	< 9,800	> 2,000	i) > 4,000 ii) > 3,300 iii) > 2,800 iv) > 2,500
Temperature (℉)		NC	< 250				< 195	NC	
Original pressure(psia)	> 1,100	> 1,500					> 1200		
Permeability (mD)		NC		> 5	> 10		> 1	NC	
Oil gravity (^{0}API)	> 30	> 30	> 27	> 35	30-45	i) < 27 ii) 27-30 iii) > 30	> 40	> 26	i) 22-27.9 ii) 28-31.9 iii) 32-39.9 iv) > 40
Viscosity(cP)	< 3	< 12	< 10	< 5	< 10	< 12	< 2	< 15	< 10
Fraction of oil remaining	> 0.25	> 0.25		> 0.25	> 0.25		> 0.30	> 0.30	> 0.20

These criteria do not necessarily need to be all met, as some of them can be ignored which are affected by other factors. For example reservoir depth and oil viscosity can be ignored as the are related to other parameters like oil gravity and reservoir temperature. The utilization of these screening criteria helps to evaluate and decide rapidly whether CO_2-EOR is a good choice for a specific oil reservoir depending on the general properties of reservoir and oil.(Shaw et al., 2002)

Rivas et al. studied how the reservoir parameters influence the performances of CO_2-EOR, and their results show that there exist a set of optimum values for the properties of reservoir and oil which can grantee the best performance of CO_2-EOR. These optimum values are shown in Table 3-4. The relative performance(the weighting factor) is given also in Table3-4. When analyzing and evaluating the properties of a oil reservoir, the parameter value that varies farthest from the optimum value is called as the worst value. It is fine to exist to worst values in the evaluation, however, one worst value should be above the optimum value, the other should be be lower than the optimum value.(Rivas et al., 1992)

Table 3- 4: Optimum reservoir parameters for CO_2-EOR screening.

Reservoir parameters	**Optimum values**	**Parametric weight**
API Gravity(°API)	37	0.24
Remaining oil saturation	60%	0.20
Pressure over MMP(MPa)	1.4	0.19
Temperature(°C)	71	0.14
Net oil thickness(m)	15	0.11
Permeability(mD)	300	0.07
Reservoir dip	20	0.03
Porosity	20%	0.02

At last, the performance of a specific oil reservoir is considered mainly by three performance parameters, namely, OOIP, CO_2-EOR recovery factor and CO_2 storage capacity, which are really critical. However, the final decision should also take other extrinsic conditions into account, such as surface facilities, availability and cost of CO_2 and other economic factors.(Rivas et al., 1992)

3.4 CO_2 Properties

To improve CO_2-EOR performance, it is necessary and important to study and understand the properties, especially the physical properties of carbon dioxide. A phase diagram for CO_2 is shown is Figure 3-1 to demonstrate the CO_2 properties in a simple and clear way.(Picha, 2007)

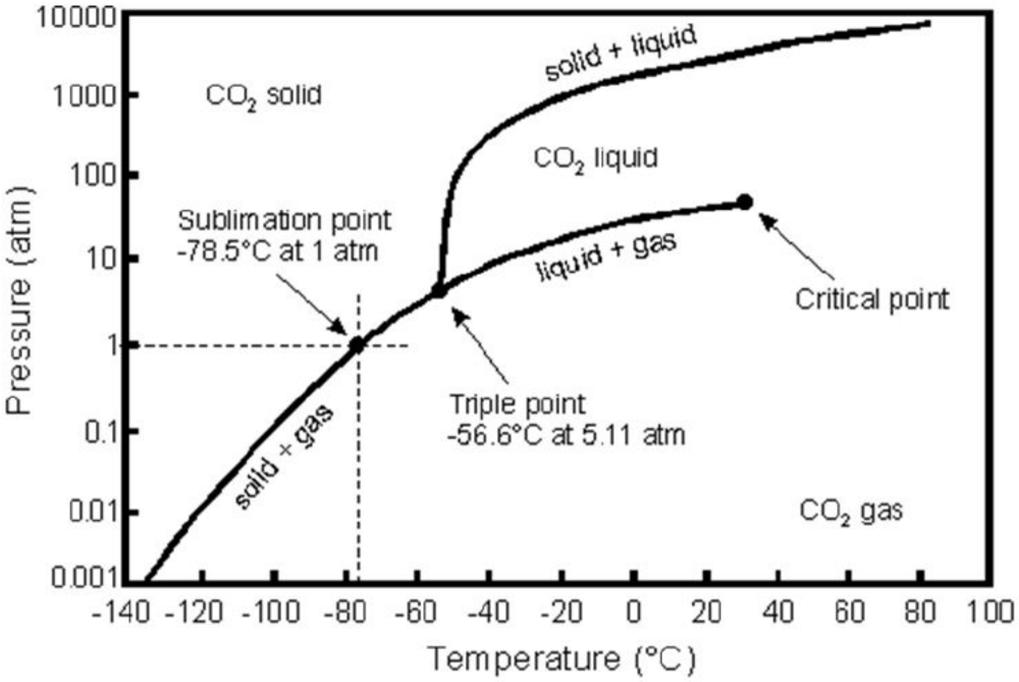


Figure 3- 1: Phase diagram of CO_2.

The critical temperature is about 30℃, and the critical pressure is around 70 bar. These two values are of interest, because the area with temperature above critical temperature and with pressure larger than the critical pressure is the supercritical zone, where CO_2 is under supercritical conditions.

According to the data from Sage, the precise critical temperature of CO_2 is 31℃, and the critical pressure is 73.825 bar(72.3485 atm). The critical density of CO_2 is 464 kg/m^3. The triple point of CO_2 is an important point as well. The triple point temperature is -56.6 °C, and the triple point pressure is 5.185 bar. The molecular weight of CO_2 is 44.01 g/mol and specific gravity is 1.521 with temperature at 15 °C and pressure at 1.013 bar. The density is 1.87 kg/m3(1.013 bar and 15 °C), and the compressibility factor(Z) is 0.9942(1.013 bar and 15 °C).(Sage, 1955)

The density of CO_2 at many reservoir conditions is similar to that of reservoir oil. Sometimes the density of CO_2 is larger than that of oil, sometimes the density of CO_2 is less than the oil density. The degree of the similarity between the densities of CO_2 and oil depends on reservoir temperature, reservoir pressure, and reservoir oil composition.

The compressibility of CO_2 is also of interest as it is quite related to the transportation and supply of CO_2. The relationship between compressibility and pressure and temperature is shown in Figure 3-2 below.

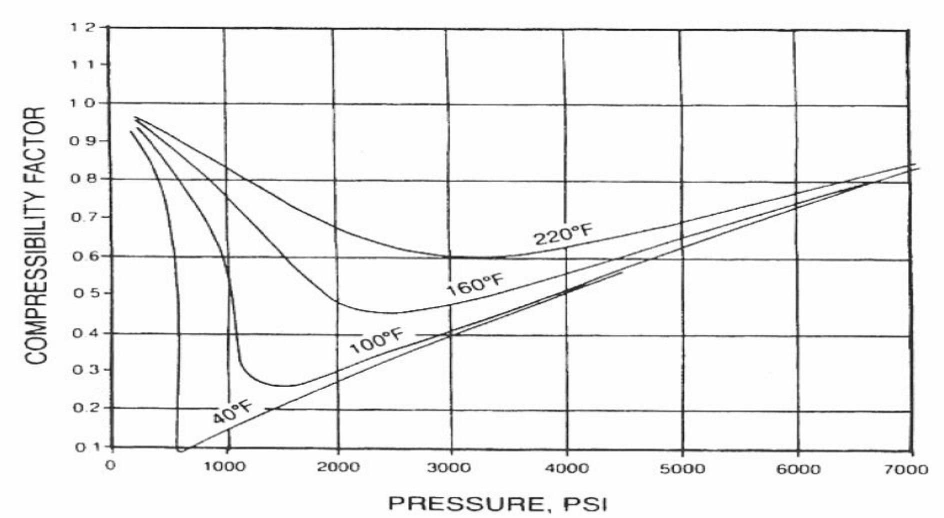


Figure 3- 2: Compressibility factors for CO_2.

As can be observed from the figure above, the compressibility of CO_2 increases as the pressure of CO_2 increases. However, the relationship between compressibility of CO_2 and its temperature is more complicated than that of compressibility of CO_2 and its pressure. In general, the carbon dioxide compressibility first decreases as its temperature increases, while when the CO_2 temperature increases above the temperature of the turning point, which is the lowest point of the compressibility curve, the CO_2 compressibility starts to grow with the increase of CO_2 temperature.(Sage, 1955)

3.5 Mechanisms

CO_2-EOR achieves incremental oil recovery with different mechanisms, which are concluded as below.(Haynes et al., 1990; Tzimas et al., 2005; Gozalpour et al., 2005; Andrei et al., 2010; Advanced Resources International, Inc, 2010)

(1) oil swelling

After injected into the reservoir, CO_2 dissolves in crude oil, which expands the volume of the reservoir oil. This swelling effect improves the mobility of oil, and makes it easier for the oil to flow from the reservoir to the production well. The larger the oil expansion is, the less amount of the residual oil remains.

(2) viscosity reduction in oil

When the injected CO_2 is saturated in crude oil, it can greatly reduce the viscosity of oil. The change in viscosity makes the oil more mobile and therefore improves oil production. Normally, more percentage of viscosity is reduced if the viscosity of crude oil is high. That is to say, the percentage of oil viscosity decrease due to CO_2 dissolution in heavy crude oil is much bigger than that in light crude oil. That is why it is thought that CO_2 can be a good choice in the recovery of heavy crude oil. Under the formation condition, the higher the pressure is, the more CO_2 dissolves in crude oil and the more significant reduction of the oil viscosity is achieved.

(3) reduction of the mobility ratio

After CO_2 dissolves in water, the water viscosity improves, and thus the water mobility improves. At the same time the mobility of crude oil ratio decreases. Thus the mobility ratio between oil and water decreases and the stability of fluid flow is improved, which increases the volumetric sweep efficiency.

(4) reduction of the interfacial tension between oil and water

The interfacial tension of oil and water is reduced after the CO_2 injection. This decrease in interfacial tension enables the reservoir oil to flow more easily and achieves incremental oil production.

(5) extraction and vaporization of light oil component

The light hydrocarbon has great intersolubility with CO_2. When the pressure is above a certain value, which is related to the properties and temperature of crude oil, CO_2 can extract and vaporize the light oil component from the reservoir oil. This phenomenon is especially prominent to light oil recovery. CO_2 enables the extraction and vaporization of the light hydrocarbon in crude oil which is one of the main mechanisms of using CO_2 injection to increase oil.

(6) effect of weak acid

The mixture of CO_2 and water forms carbonic acid and can react with carbonate in the reservoir rocks. The reaction leads to the corrosion of reservoir rocks, which improves the permeability of the reservoir. Additionally, the product of carbon dioxide and water mixture can to some extent clear the inorganic scale obstruction and unchoke the oil flow passage, thus improving the oil production.

(7) solution gas drive

During the injection process, with the increasing injection pressure, more and more CO_2 dissolves in the reservoir oil. After the cease of CO_2 injection, the pressure in oil reservoir will decline as the oil production continues. Then the CO_2 dissolved in the crude oil before will separate from the oil and forms solution gas drive, which provides energy for the oil flow and is quite similar to the natural solution gas drive. Besides, CO_2 occupies the pore space of oil after oil displacement, which promotes oil production as well.

Different mechanisms are dominant in different types of reservoir oil. For example, the recovery of light crude oil is enhanced by the effect of oil swelling and the carbon dioxide's extraction of hydrocarbon. While in the heavy oil recovery, it is the reduction of oil due to the dissolution of CO_2 in oil that mainly improves oil recovery. (Abedini et al., 2014)

3.6 Advantages and disadvantages

CO_2-EOR technology has a few advantages in recovering oil. For example, after injected into the reservoir, CO_2 can change the property of oil towards a favorable direction of improved oil recovery by helping the swelling of oil, reducing the oil viscosity, decreasing the surface tension of oil and increasing oil density. CO_2 can dissolve in water and reduce the surface tension of water. It can also reduce the density of water, thus reducing gravity segregation by decreasing the density difference between oil and water. When compared to other gases, CO_2 is more likely to become supercritical fluid at common reservoir conditions since the minimum miscible pressure required by CO_2 is low. CO_2 is also special as it can extract heavier components up to C_{30}.

However, it also has some disadvantages. The high mobility of CO_2 is one of the main problems, which leads to the poor sweep efficiency and early CO_2 breakthrough.(Mathiassen, 2003) The causes of poor CO_2-EOR performances in the past have been investigated by Vello Kuuskraac and Robert Ferguson. For instance, the volume of injected CO_2 was limited previously because of the high cost of CO_2 and relatively low oil prices. Also, it was difficult to control the CO_2 flow in the reservoir. As a result, the volume of injected CO_2 was not enough to achieve optimized oil recovery. In addition, some phenomenons such as gravity override, viscous fingering and channeling of CO_2 can lead to poor contact between injected

CO_2 and thus cause low sweep efficiency. What's more, the miscibility between injected CO_2 and reservoir oil is insufficient as a result of unexpected pressure decreases in parts of reservoir and limited well operating pressures. Some other factors causes the poor performances of CO_2-EOR as well, such as the difficulty to inject CO_2 into the right reservoir strata with high residual oil, and lack of CO_2 management and control.(Kuuskraa et al., 2010)

Odd Magne Mathiassen suggested several ways to reduce the negative effects, such as shutting in production wells to regulate flow, applying alternating water gas(WAG), adding foaming solutions together with CO_2 injection and installing well packers and applying perforating techniques.(Mathiassen, 2003) Mehran Sohrabi mentioned about the use of carbonated water injection or gravity stable to solve the problem caused by the high mobility of CO_2. (Sohrabi et al., 2009)

3.7 Miscible And Immiscible CO_2-EOR

There mainly exist two types of CO_2-EOR processes, namely miscible and immiscible CO_2-EOR processes, which are classified depending on whether the injected CO_2 completely dissolve in the reservoir oil. Reservoir pressure, reservoir temperature, injected gas composition and oil components determine whether miscible or immiscible process is achieved after the injection of CO_2 into the reservoir. The mechanisms of these two CO_2-EOR processes differ from each other. (Haynes et al., 1990)

3.7.1 Miscible CO_2-EOR Process

Miscible CO_2-EOR occurs when the reservoir pressure is higher than MMP (Minimum Miscible Pressure) which depends on reservoir temperature and oil composition. In this situation, CO_2 is supercritical and can mix with oil in all parts, leading to the formation of one single-phase liquid. Primarily, at first contact, CO_2 does not immediately dissolve in the reservoir oil completely. However, after the multiple contact process where the light components of oil vaporize into the CO_2 phase and CO_2 also dissolves in the reservoir oil, the injected CO_2 are totally miscible with the reservoir oil, and forms a miscible zone between the injected CO_2 and the original oil. The new mixture of CO_2 and reservoir oil has low viscosity and low interfacial force. In this way, reservoir oil become much more mobile and then oil recovery is improved. However, the injected CO_2 can not be utilized efficiently as a result of its high mobility. To improve the efficiency of this process and decrease the amount of CO_2 used, water is injected in addition to CO_2, which is known as water alternating gas(WAG). (Haynes et al., 1990; Tzimas et al., 2005) F. Gozalpour referred to the lack of capillary effect promotes the oil recovery in the miscible process as well.(Gozalpour et al., 2005) The miscible CO_2-EOR process is demonstrated in Figure 3-3.(Advanced Resources International, Inc., 2006)

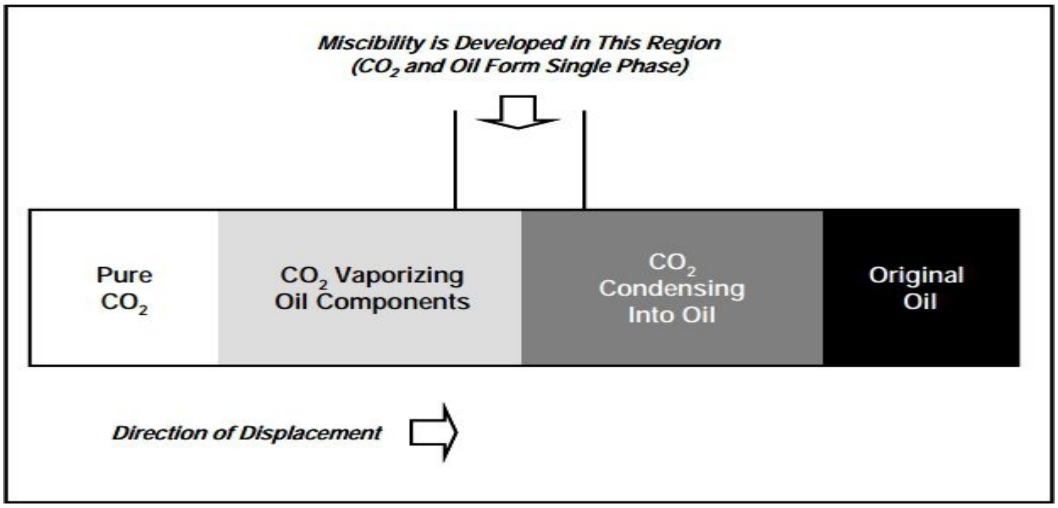


Figure 3- 3: Miscible CO_2-EOR process in one dimension.

3.7.2 Immiscible CO_2-EOR Process

When the reservoir pressure is not enough to reach the MMP, only part of the injected CO_2 dissolve in the reservoir oil and the other CO_2 is in gas phase. This process is defined as immiscible CO_2-EOR process. In the immiscible process, the injected CO_2 can lead to oil swelling because the oil is saturated with CO_2, and the viscosity of the swollen mixture of oil and CO_2 is reduced. The injected CO_2 also increases oil recovery by raising and maintaining the pressure in the reservoir, just like the role of water in the water flooding. CO_2 acts as artificial gas cap, driving the reservoir oil towards the production wells at the rim of the reservoir. Moreover, CO_2 can extract light oil components. The extraction of light oil components reduces the density of oil and decreases the oil viscosity, which helps the oil recovery as well. Usually, gravity stable gas injection (GSGI) is utilized to inject CO_2 slowly to the crest of the reservoir. However, the water alternating gas is also an option for CO_2 injection for immiscible CO_2-EOR displacement. The process of immiscible CO_2-EOR process is displayed in Figure 3-4.(Advanced Resources International, Inc, 2011; Tzimas et al., 2005)

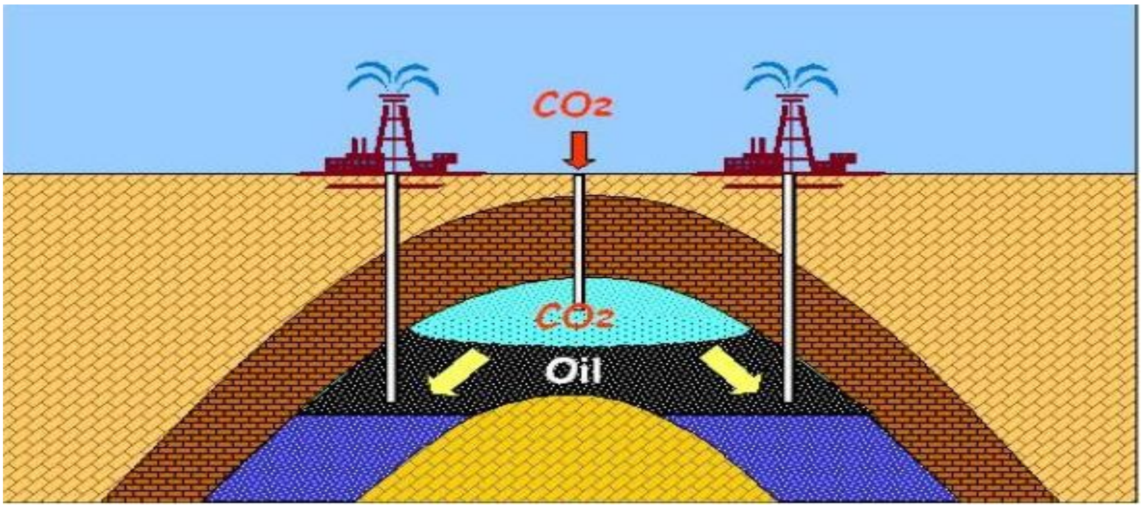
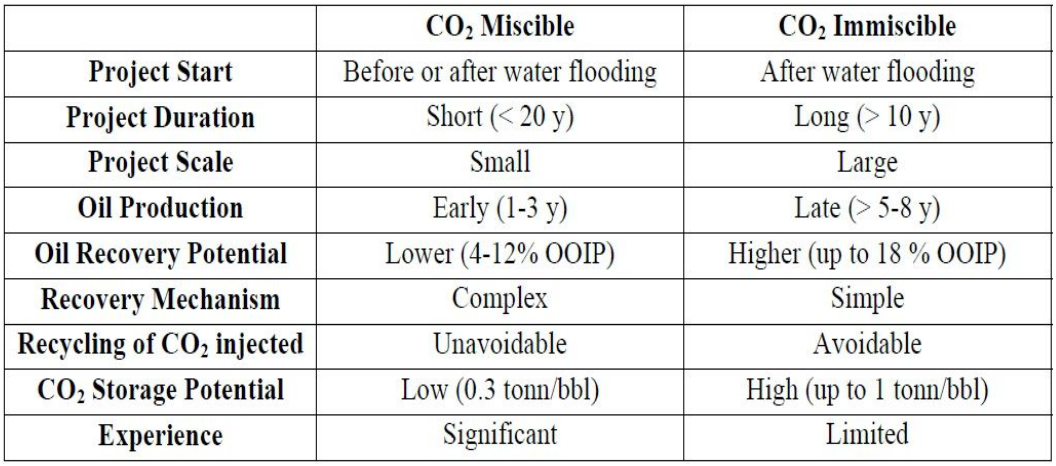


Figure 3- 4: Immiscible CO_2-EOR process.

The immiscible CO_2-EOR process can be used as well if the density of reservoir oil is high, and can be a potential method for heavy oil reservoir. (Bagci, 2006)

The comparison of features of miscible and immiscible processes are shown in Table 3-5. As can be seen from the table, immiscible process project takes longer and is larger in scale than miscible process. In terms of CO_2 sequestration, immiscible CO_2 process has a higher potential than miscible process, and can become more important if large scale of CO_2 storage are carried out.(Andrei et al., 2010)

Table 3- 5: Comparison between miscible and immiscible CO_2-EOR techniques.



	CO_2 Miscible	**CO_2 Immiscible**
Project Start	Before or after water flooding	After water flooding
Project Duration	Short (< 20 y)	Long (> 10 y)
Project Scale	Small	Large
Oil Production	Early (1-3 y)	Late (> 5-8 y)
Oil Recovery Potential	Lower (4-12% OOIP)	Higher (up to 18 % OOIP)
Recovery Mechanism	Complex	Simple
Recycling of CO_2 injected	Unavoidable	Avoidable
CO_2 Storage Potential	Low (0.3 tonn/bbl)	High (up to 1 tonn/bbl)
Experience	Significant	Limited

According to the data of miscible and immiscible projects constructed between 1986 and 2012 from 2012 EOR worldwide survey, Figure 3-5 was made. As shown in the figure, miscible CO_2-EOR projects are increasing as a whole during this period, while immiscible has decreased if the number of immiscible projects in 2012 is compared to that of immiscible projects in 1986. It is obvious in figure1 that miscible CO_2-EOR are used more widely than immiscible CO_2-EOR.

The 31 CO_2-EOR projects belonging to Occidental Petroleum Corporation, a company that owns the largest number of CO_2-EOR projects in the world, are all miscible. Debury Resources has the second largest number of CO_2-EOR projects, among which 16 projects are miscible and the other 6 projects are immiscible. (Koottungal, 2012)

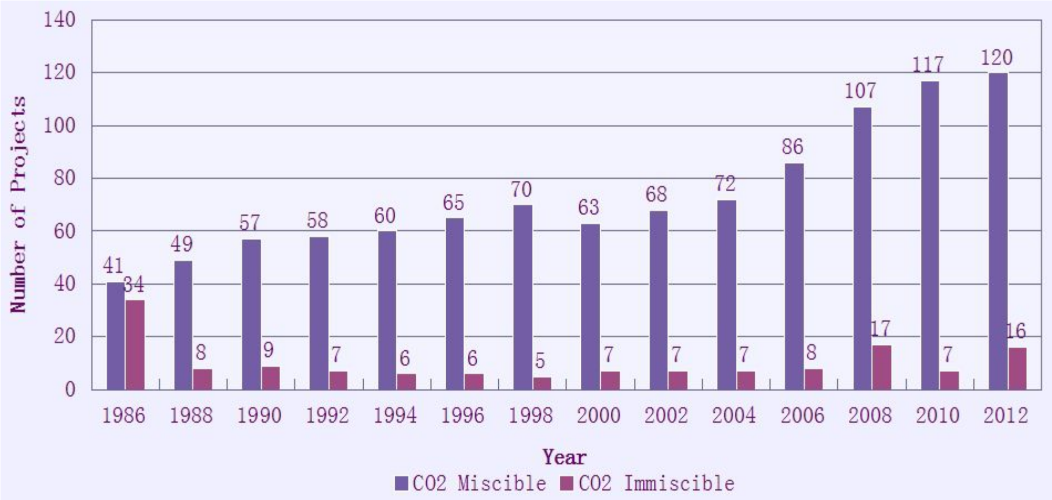


Figure 3- 5: Number of miscible & immiscible CO_2-EOR projects from 1986 to 2012.

3.7.3 Near Miscible CO_2-EOR Process

Zick proposed a new drive mechanism, combining condensing-gas drive and vaporizing-gas drive in 1986. This is when the first idea of near miscible process occurred. (Zick, 1986)

Near miscible CO_2-EOR process appears, when the reservoir pressure is below and near the minimum miscible pressure. The advantage of near miscible displacement lies in its lower pressure requirement than miscible process, which saves the cost of compression and makes the operation easier. In fact, many miscible processes are actually a mix of miscible process and near miscible process, due to the pressure decline in the reservoir caused by viscous figuring and reservoir heterogeneity.

Shyeh-Yung listed several incentives for developing the near miscible process. For instance, the efficiency of near miscible displacements can nearly be the same as miscible displacements.(Shyeh-Yung, 1991)

3.8 Cyclic CO_2 Injection Process

The cyclic CO_2 injection process, also called CO_2 huff-n-puff process, is one of the injection strategies to improve oil recovery using carbon dioxide. The cyclic CO_2 injection is based on the cyclic steam injection process, which was first applied in heavy oil reservoirs in the late 1950s and then was used in both light and heavy oil reservoirs widely around the world.(Alvarez et al., 2013)

The whole process of cyclic steam injection(Figure 3-6) is quite similar to that of CO_2 huff-n-puff, which mainly consist of three phases, namely huff(injection phase), soak(shut-in phase), and puff(production phase).(Thomas et al., 1990)

The combination of these two injection methods are studied by Luo etc. They analyzed the feasibility of cyclic CO_2 injection after cyclic steam injection.(Luo et al., 2005)

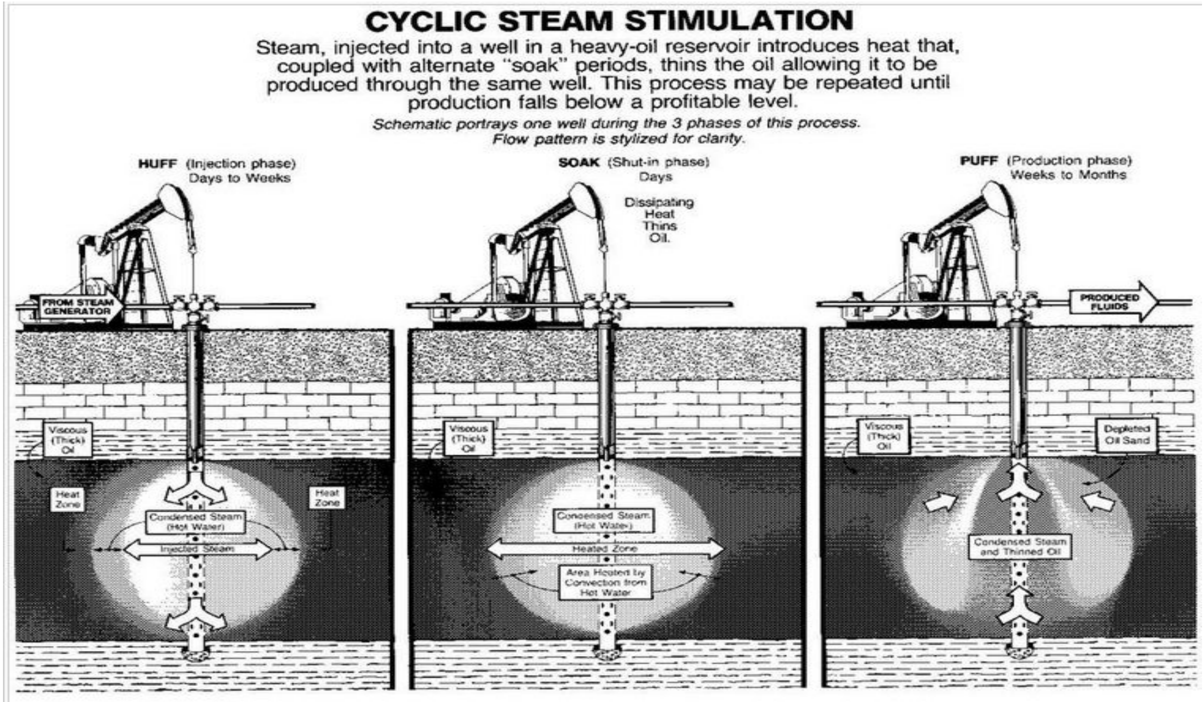


Figure 3- 6: Cyclic Steam Injection Process.

(from United States Department of Energy)

In the first place, CO_2 is injected into the oil zone in one single well for some time(huff), and then the well is shut in for a period of time(soaking period). After this period, the previous injection well becomes a production well(puff), and oil is produced out of the well until the production decreases to a certain value. This whole process is known as a complete injection cycle. This injection cycle is repeated for several times until few amount of oil is produced.(Thomas et al., 1991)

The cyclic CO_2 injection process was first investigated by means of numerical simulation in a light oil filed by Hsu and Brugman in 1986. They studied the effects of the number of cycles. Besides, they investigated the influences of timing of the three main operations(injection, soaking period and production), and how the quantity and composition of the injected solvent affect the oil recovery. The study concluded that the difference in incremental oil recovery between the first and second cycle is significant, and a third cycle may not be attractive. As to the soaking period, they claimed the oil recovery does not have a big change when the soaking time varies between 5 and 40 days. The most important factor affecting the oil recovery, according to their study, is the amount of CO_2 injected. The oil recovery efficiency is not obviously influenced if pure CO_2 is contaminated by by nitrogen and methane within 20% mole fraction.(Hsu et al., 1986)

The mechanisms of cyclic CO_2 injection mainly include the oil swelling, the decrease of oil viscosity and interfacial tension after the dissolution of injected carbon dioxide in oil, solution gas drive, and vaporization of lighter oil components.(Abedini et al., 2014) In addition, the corrosion effect of carbonic acids, produced by the reaction of CO_2 and water, can enhance the dissolution of reservoir rock, and hence increase the reservoir's permeability.(Wolcott et al., 1995) What's more, the hysteresis effect during the production period reduces the relative permeabilities to water and CO_2. Therefore, the relative permeability for oil is increased and thus oil recovery is improved.(Menzie et al., 1963)

The performance of cyclic CO_2 injection process are influenced by several factors. Some studies showed that gravity the formation of segregation, gas cap, higher residual oil saturation, long soaking period, large CO_2 slug size can help the oil production in cyclic CO_2 injection process. Based on the results from experiments and simulation, Torabi, F etc. claimed that fractured and heterogeneous reservoirs are suitable for cyclic CO_2 injection method, since gas has more contact area with oil in such kinds of reservoirs. In their experiment, it was found that the oil recovery in cyclic CO_2 process is improved if higher pressure is applied.(Torabi et al., 2010)

Primarily, cyclic CO_2 injection process was designed for heavy crude oil recovery. However, it is also possible to apply this strategy in the recovery of light oil. Another advantage of this injection strategy is that the risk in implementation of cyclic CO_2 is less than that of other enhanced oil recovery methods.(Monger et al., 1988)

3.9 Carbonated water injection(CWI)

Carbonated water injection(CWI) can make up for a few shortcomings of conventional CO_2 injection. For example, the mobility ratio between carbonated water and reservoir oil is more ideal than that between CO_2 gas and oil. Also, when applying carbonated water injection, CO_2 distributed in the reservoir more equally. These two advantages mentioned above could improve the sweep efficiency and thus improve oil recovery. In addition, CWI can make the CO_2 storage safer, since the denser carbonated water stays below the native brine, which reduces the cost of monitoring stored CO_2 as well. As the high efficiency of utilizing CO_2, carbonated water injection is suitable for oil reservoirs where CO_2 sources are insufficient, such as offshore reservoirs. In the coreflooding test conducted by Mehran Sohrabi et al., the results show that mixed-wet core, light oil and low salinity carbonated brine can improve the oil production performance.(Sohrabi et al., 2012)

A case study of CO_2 storage by using carbonated water injection in an Iranian oil reservoir has been conducted, which also included experimental and simulation study. The study concluded that carbonated water injection can improve oil recovery up to 20% in comparison with water injection, and up to 71% when compared to natural reservoir depletion. The simulation results also show that about 75% of injected CO_2 can be stored safely by the application of carbonated water injection. The report also mentioned about another mechanism of how CWI can enhance oil recovery. Carbonic acid which formed from carbonated water can react with rocks. This phenomenon improves permeability of oil reservoir and therefore enhances oil recovery. (Hasanvand et al., 2013)

3.10 Water Alternating Gas(WAG)

Andrei M believes water-alternating-gas(WAG) injection is the most commonly used in CO_2-EOR flooding.(Andrei et al., 2010) The first reported water-alternating-gas injection case was in Canada in 1957.(Caudle et al., 1958) At first, the WAG injection was applied to increase the sweep of injected gas, where water was used to control the mobility and to make the front more stable. Gas injection can do a better job in microscopic displacement of oil than oil. However, the macroscopic sweep of gas injection is not as good as water injection. As the WAG injection is a combination of water injection and gas injection, it combines the advantages of these two kinds of injections. The WAG processes can be classified into two types, miscible WAG injection and immiscible injection. Christensen, J. R made a review of around 60 field cases applying WAG injection and found that almost all the these cases had been successful in utilizing this strategy. The incremental oil recovery of several fields had increased up to 20%. The major problem of WAG injection is corrosion of injection facility and production equipment. It is also proved that the tapering WAG injection is an efficient tool in oil recovery in this review.(Christensen et al., 1998)

Simultaneous water and gas injection (SWAG) is another kind of WAG injection, where water and gas are injected at the same time. K. Akbari Aghdam concluded that SWAG injection had higher oil recovery than WAG injection. However, the cost of WAG injection is smaller than SWAG injection.(Aghdam et al., 2013) Algharaib et al. reported that the water phase and gas phase can be separated when moving through porous media because of the different density when SWAG is applied.(Algharaib et al., 2007) The first reported field with full application of SWAG injection in the North Sea is Siri Field. Different injection strategies had been evaluated, and SWAG had been proved to be the optimum scheme as a result of its improved sweep efficiency, oil swelling and residual oil saturation reduction.(Quale et al., 2000)

P. Heidari et al. made a comparison between WAG and SWAG injection with experimental and simulation studies, and concluded that in immiscible, near miscible and miscible modes of injection, SWAG can accelerate oil production in comparison with WAG injection.(Heidaria et al., 2013)

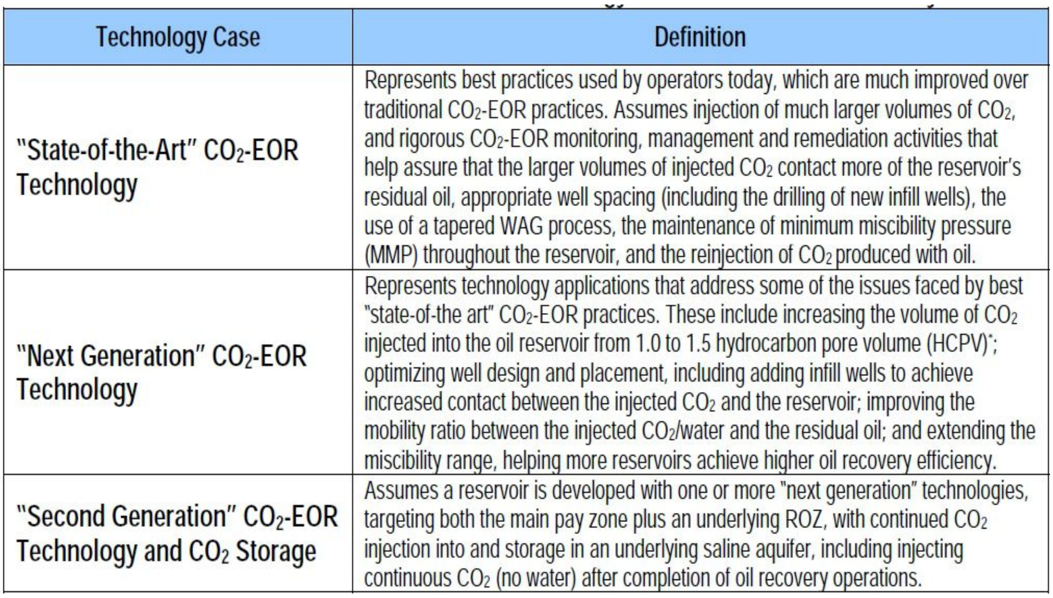
3.11 “Next generation” CO_2-EOR technology

Advanced Resources International, Inc. studied about the potential approaches optimizing CO_2-EOR with CO_2 storage, such as “next generation” CO_2-EOR technologies, applying CO_2-EOR technology to the immobile residual oil zones (ROZs), applying CO_2 injection earlier and so on.

Since CO_2-EOR technology was first introduced, several remarkable changes have occurred, such as injecting much more CO_2, combining tapered WAG and other methods, and applying advanced well drilling and completion strategies. These changes greatly have improved “state-of-the-art” CO_2-EOR technology and resulted in higher oil recovery efficiency. However, “state-of-the-art” CO_2-EOR technology still can meet some problems, which can be solved by the application of “next generation” CO_2-EOR technology. “Next generation” CO_2-EOR technology mainly include four strategies: (1)injecting more CO_2 into the oil reservoir; (2)optimizing well design and placement(including adding infill wells), to increase the contact between reservoir oil and injected CO_2; (3)improving the mobility ratio between the injected CO_2/water and the residual oil, and extending the miscibility range, to help more reservoirs reach higher oil recovery efficiency.

The definitions of alternative technology cases studied in Advanced Resources International, Inc., namely “State-of-the-Art” CO_2-EOR Technology, “Next Generation” CO_2-EOR Technology, and “Second Generation” CO_2-EOR Technology and CO_2 Storage, are displayed and compared in Table 3-6.(Advanced Resources International, Inc., 2010)

Table 3-6: Definitions of alternative technology cases.



Technology Case	Definition
"State-of-the-Art" CO_2-EOR Technology	Represents best practices used by operators today, which are much improved over traditional CO_2-EOR practices. Assumes injection of much larger volumes of CO_2, and rigorous CO_2-EOR monitoring, management and remediation activities that help assure that the larger volumes of injected CO_2 contact more of the reservoir's residual oil, appropriate well spacing (including the drilling of new infill wells), the use of a tapered WAG process, the maintenance of minimum miscibility pressure (MMP) throughout the reservoir, and the reinjection of CO_2 produced with oil.
"Next Generation" CO_2-EOR Technology	Represents technology applications that address some of the issues faced by best "state-of-the art" CO_2-EOR practices. These include increasing the volume of CO_2 injected into the oil reservoir from 1.0 to 1.5 hydrocarbon pore volume (HCPV)*; optimizing well design and placement, including adding infill wells to achieve increased contact between the injected CO_2 and the reservoir; improving the mobility ratio between the injected CO_2/water and the residual oil; and extending the miscibility range, helping more reservoirs achieve higher oil recovery efficiency.
"Second Generation" CO_2-EOR Technology and CO_2 Storage	Assumes a reservoir is developed with one or more "next generation" technologies, targeting both the main pay zone plus an underlying ROZ, with continued CO_2 injection into and storage in an underlying saline aquifer, including injecting continuous CO_2 (no water) after completion of oil recovery operations.

Vello Kuuskraa and Robert Ferguson concluded that “next generation” CO_2-EOR technology could improve CO_2-EOR and CO_2 storage greatly if applied. They also summarized three major benefits from using “next generation” CO_2-EOR. The first benefit of implementing “next generation” CO_2-EOR is to increase the oil production by 40% when compared to the current “best practices” for CO_2-EOR. Secondly, “next generation” CO_2-EOR could create large demand for CO_2 sources, about 9 to 13 gigatons, according to their study. At last, the produced oil by injecting captured CO_2 is 50% to 80% “carbon-free” with the application of “next generation” CO_2-EOR.(Kuuskraa et al., 2010)

3.12 Global Potential

In order to study the global potential for CO_2-EOR, a research was conducted by Advanced Resources International and IEA Greenhouse Gas R&D Programme.The largest 54 oil basin was studied to test their potential for CO_2-EOR.(IEA Greenhouse Gas R&D Programme, 2009) The methodology for this assessment was developed based on the related experience of United States.(U.S. Department of Energy/National Energy Technology Laboratory, 2010)

The results show that 50 out of the 54 largest oil basins are possible to apply miscible CO_2-EOR. These oil basins could produce 470 billion barrels of additional oil and store 140 billion metric tons of CO_2 by using “state-of-the-art” CO_2-EOR technology.If smaller oil fields in the world are also amenable to CO_2-EOR, over 1 trillion additional barrels of oil could be extracted and 320 billion metri tons of CO_2 could be stored by the application of “state-of-the-art”CO_2-EOR Technology all over the world.(Advanced Resources International, Inc., 2011)

3.13 CO_2 Capture and Storage

CO_2 capture and storage(CCS), also called carbon capture and sequestration, is an important process that can help to reduce the immission of waste CO_2 from large point sources, for example fossil fuel power plants, to the atmosphere and mitigate the Green House Effect and the ocean acidification as well. (CSIRO et al., 2013) First of all, CO_2 is separated from the industrial and energy-related sources. Then the separated CO_2 is transported to a storage location, usually an underground geological formation, where CO_2 can be isolated from the atmosphere for a long term so that this greenhouse gas concentrations in the atmosphere can be reduced.

Large point sources of CO_2 can be installed with the equipments and facilities for CO_2 capture. Capturing CO_2 at point sources, like large fossil fuel and biomass energy facilities, is perhaps most effective. Extraction of CO_2 from air is a possible method, but it is not quite practical. There exist three categories of scrubbing technologies: post-combustion, pre-combustion, and oxy-fuel combustion. In the post-combustion process, CO_2 is separated from other products after combustion of fossil fuel. This process best suits fossil-fuel burning power plants, and is well understood and utilized in other industrial applications. The pre-combustion technology oxidizes part of the fossil fuel in a gasifier. Then the products mainly include CO_2 and H2. CO_2 can be extracted from a relatively pure exhaust stream before combustion occurs, which makes this step easier. H2 can be utilized as fuel also. The pre-combustion technology is widely used in fertilizer, chemical, gaseous fuel, and power production. When compared to the conventional post-combustion technology, this new pre-combustion technology has its own advantages, but has also some disadvantages. In the oxy-fuel combustion, the fuel is not burned in air any more, but in oxygen. Cooled flue gas is recirculated and injected into the combustion chamber in order to limit the temperatures of the resulting flame. The flue gas includes carbon dioxide and also water vapour. The final stream is almost pure CO_2, since the water vapour can be separated by just condensing through cooling, and can be directly sent to the storage sites. This oxy-fuel combustion process is sometimes referred to as “zero emission” cycles, because all the final flue gas, which is almost pure CO_2, are transported to the sequestration sites. The oxy-fuel combustion has a bright future, however, this technology also costs lots of energy at the initial air separation step.

After the capture of CO_2, the captured gas needs to be transport to the storge sites, which typically utilizes pipeline because it has the lowest cost. Pipeline plays an important role especially in the long distance movement of large quantities of carbon dioxide. Usually in the pipeline, large volumes of natural gas, oil, condensate and water are carried over distances of thousands of kilometers. Pipelines are laid on lands, like in deserts, mountain rages, farmland, and also in the seas and oceans up to 2200 meters deep. In the pipeline, CO_2 is transported in three states: gas, liquid, and solid. In the commercial-scale transport system, tanks, pipelines and ships are used for gaseous and liquid carbon dioxide.

For the sequestration of the captured CO_2, different forms can be utilized, which include ecological formations, the ocean, mineral carbonates, or industrial processes. The geological storage is also known as geo-sequestration, which is done by the injection of CO_2 in supercritical form directly into the underground geological formations. The injection of CO_2 into geological formations have a history of several decades for different purposes, for example enhanced oil recovery. However, the concept of long term storage of CO_2 is relatively new. The first application of this concept was Weyburn in 2000.

The suggested storage sites of geological storage could be oil and gas fields, saline formations, un-mineable coal seams, saline-filled basalt formations. As to the ocean storage, it was recommended in the past as a storage site of carbon dioxide. However, nowadays it is not a wise option, because it would contribute to ocean acidification. Ocean storage has even been made illegal under specific regulations and is not taken into consideration any more. In the mineral storage process, CO_2 reacts with metal oxides, producing stable carbonates. The mineral storage process takes place naturally over many years and lead to the great amount of surface limestone. Professor Schuiling suggested using olivine in the mineral storage process. Higher temperatures and pressures, or pretreatment of the minerals, can make the reaction rate faster, but more additional energy is required.(Rubin et al., 2006)

The most promising storage or sequestration site are currently the geological formations. But the long term predictions about submarine or underground storage security are very difficult and uncertain, because the risk of CO_2 leakage still exists.(Metz et al., 2005)

Three main components of the carbon capture and storage system, namely capture, transport and storge, are shown in Figure 3-7. All these three components can be found in the industrial operations today, but most of them are not for the purpose of CO_2 storage.In the capture process, CO_2 is separated from other gaseous products.This separation step can be done either after combustion, or be done by decarbonizing the fuel before combustion.In the second component, the captured CO_2 may have to be transported for a long distance between the CO_2 source and the storage site. The captured CO_2 is often compressed to a high density at the capture facility to make it easier to be transported and stored.At the last process, CO_2 can be sequestrated by injecting it into underground geological formations and into the deep ocean,or can be used in industrial fixation in inorganic carbonates. Captured CO_2 can also be stored in some manufactured products in some industrial processes.(Metz et al., 2005)

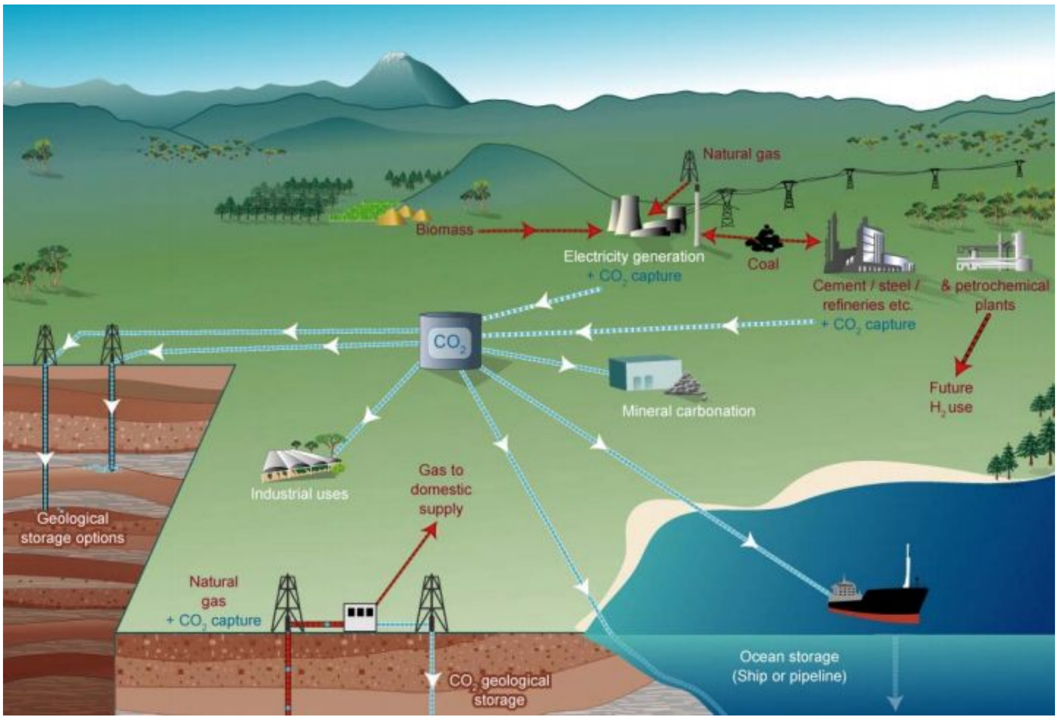
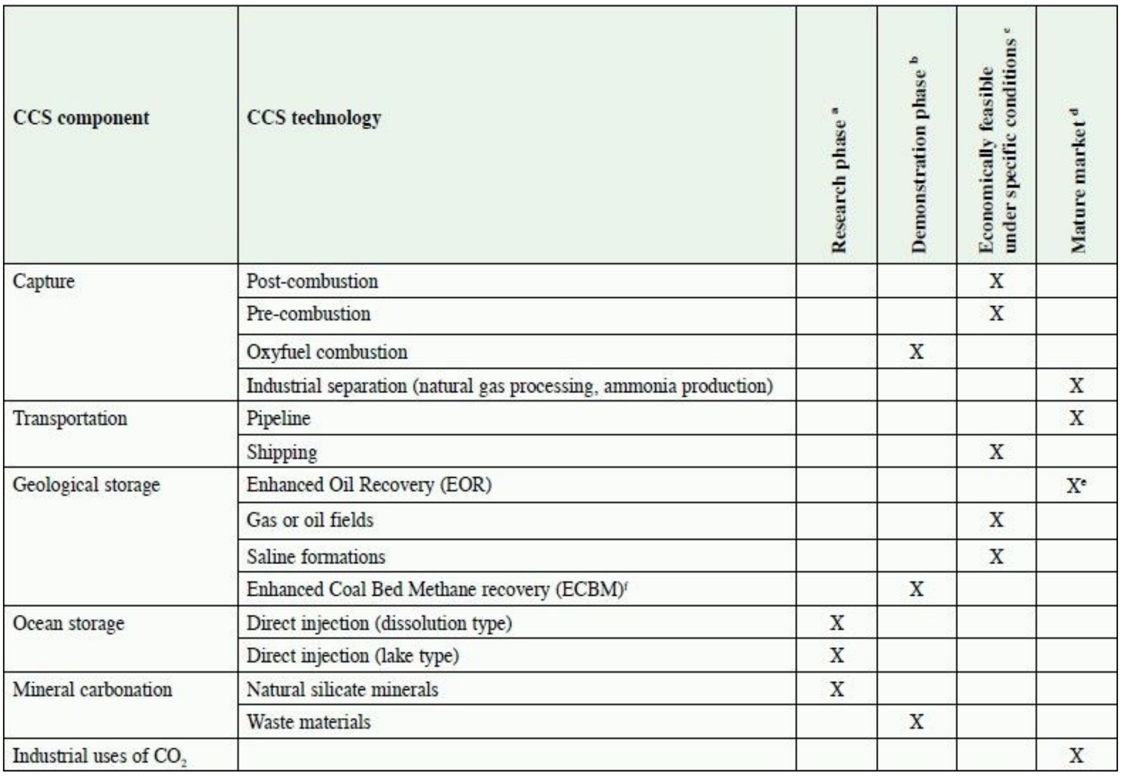


Figure 3- 7: Schematic diagram of possible CCS systems.

The technical maturity of different components in the carbon capture and storage system is various. Some CCS technologies are widely deployed in the mature markets, mainly in the oil and gas industry first.But other CCS technologies are still in the demonstration phase or development phase.The current status of all carbon capture and storage components are demonstrated briefly in Table 3-7.There have been several commercial projects that links CO_2 capture and geological storage, mainly in the oil and gas industry, for example, the offshore Sleipner natural gas processing project in Norway and the Weyburn Enhanced Oil Recovery project in Canada. However, the CCS has not yet been applied to large fossil-fuel power plant, and the maturity of the overall system may be lower than that of its components.(Metz et al., 2005)

Table 3- 7: Current maturity of CCS system components.



CCS component	CCS technology	Research phase [a]	Demonstration phase [b]	Economically feasible under specific conditions [c]	Mature market [d]
Capture	Post-combustion			X	
	Pre-combustion			X	
	Oxyfuel combustion		X		
	Industrial separation (natural gas processing, ammonia production)				X
Transportation	Pipeline				X
	Shipping			X	
Geological storage	Enhanced Oil Recovery (EOR)				X[e]
	Gas or oil fields			X	
	Saline formations			X	
	Enhanced Coal Bed Methane recovery (ECBM)[f]		X		
Ocean storage	Direct injection (dissolution type)	X			
	Direct injection (lake type)	X			
Mineral carbonation	Natural silicate minerals	X			
	Waste materials		X		
Industrial uses of CO_2					X

An X indicates the highest level of maturity for each component. There are also less mature technologies for most components

The distance between the CO_2 sources and the storage sites are of great importance, as it affects the efficiency of the CCS processes. The distribution of large stationary sources of CO_2 in the world is shown in Figure 3-8. Figure 3-9 shows the possible storage sites for CO_2 around the world.(Metz et al., 2005)

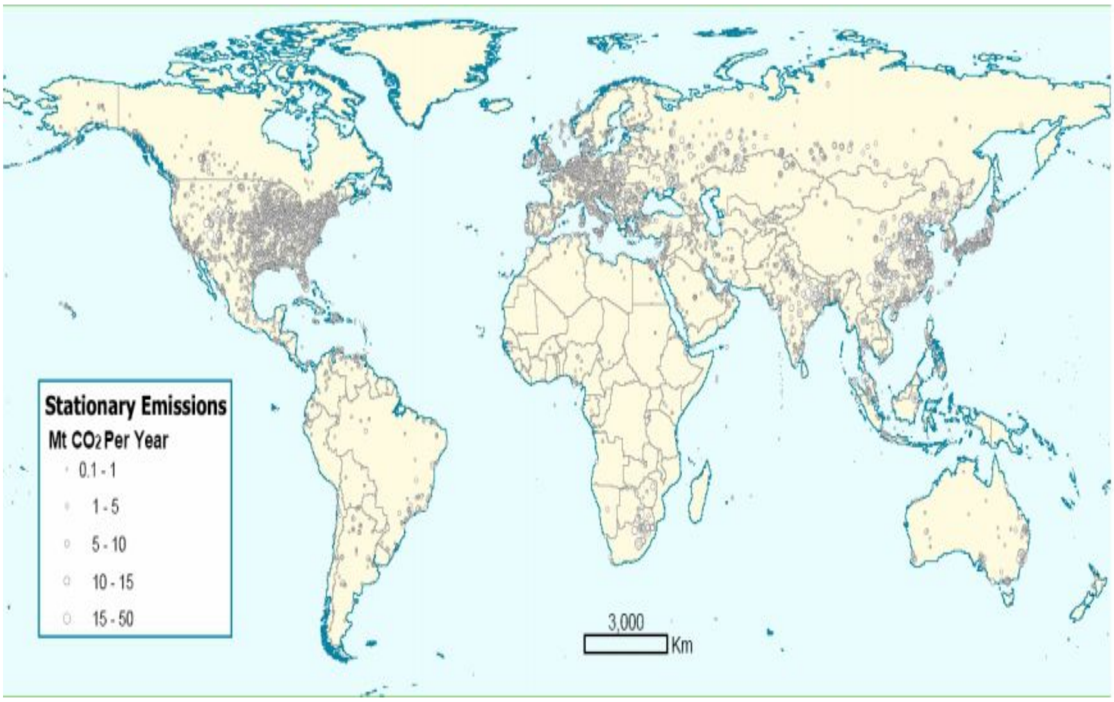


Figure 3- 8: Global distribution of large stationary sources of CO_2.

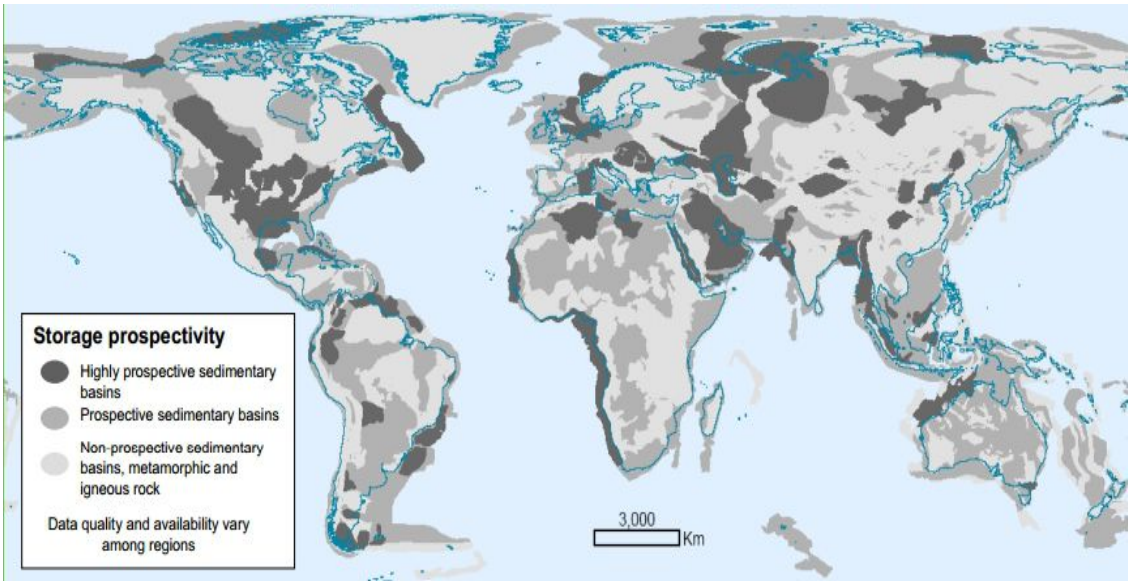


Figure 3- 9: Prospective areas in sedimentary basins where suitable saline formations, oil or gas fields, or coal beds may be found.

3.14 CCS and CO_2-EOR

The idea of combining carbon capture and storage(CCS) and enhance oil recovery(EOR) is a nice suggestion which can not only decrease the emission of carbon dioxide, but also increase oil production. CO_2-EOR helps to push the development of CCS and provide economic support for CCS, while CCS provides CO_2-EOR enough CO_2 sources to improve more oil production. A fundamental change is that now many CO_2-EOR project developers start to aim at the CCS as affordable and reliable sources of carbon dioxide. However, some think that CO_2-EOR is not able to decrease the emission of carbon dioxide effectively, because the potential storage capacity of CO_2-EOR is limited . In the conventional CO_2-EOR technique, the volume of CO_2 injected is limited to optimize the efficiency of oil production, as the cost of CO_2 is not cheap. So the amount of CO_2 used in the CO_2-EOR process is limited.

Nevertheless, some potential alternative approaches, such as "next generation" technology, can increase the oil production, and also improve the amount of CO_2 stored in the geological formation.

The sources of CO_2 is an important parameter in a CO_2-EOR project. The availability of reliable affordable supplies of CO_2 determines whether further growth in oil production is possible. Most of the CO_2 projects in the U.S. and Canada have access to natural CO_2 resources, which are of high purity and low cost. And studies show that anthropogenic sources of carbon dioxide are actually increasing all the time in the world, which is a good news to CCS. The studies at the Permian Basin found that there still exists huge potential for the improvement of utilizing CO_2-EOR as one CCS method. This potential comes from the residual oil zones(ROZs), where larger amount of crude oil remain unexploited. In addition to the main pay portion, the ROZs is the second target that has the potential to store huge amount of CO_2. It is proved by fields pilots that there are commercial values of applying CO_2-EOR to the ROZs, and this application can even make the storage capacity of CO_2 increase as much as twofold.

Other methods that can increase the amount of CO_2 storage include injection of CO_2 earlier and longer, injection of CO_2 instead of water, and injection of CO_2 into other geologic horizons.Basins with large potential for CO_2-EOR also has big potential for CO_2 storage, because the process of CO_2 storage can take advantage of the injection wells and surface infrastructures that have been used by CO_2-EOR.

The limiting factors that prevent the wide-scale deployment of CCS and CO_2-EOR are the lack of incentives provided under Clean Development Mechanism as part of Kyoto Protocol, the lack of standards and guidelines, and other regulatory and uncertainties need to be resolved. The wide combination of CCS and CO_2-EOR requires the government to ensure a policy, so that a regulatory and legal environment is created.(Advanced Resources International, Inc., 2010)

4 Simulation

4.1 Basic Theories

4.1.1 Mobility and Mobility Ratio

Mobility describes the ratio between the permeability of a porous media to a given fluid to the viscosity of that fluid.

$$\lambda = \frac{K}{\mu} \qquad (4\text{-}1)$$

Mobility ratio is the ratio of the mobility of the displacing phase to that of the displaced phase.

$$M = \frac{\lambda_{\text{displacing phase}}}{\lambda_{\text{displaced phase}}} \qquad (4\text{-}2)$$

4.1.2 Capillary Pressure

Capillary Pressure is the difference in the pressure across the interface between two immiscible fluids, namely the non-wetting phase and the wetting phase.

$$p_c = p_{\text{non-wetting phase}} - p_{\text{wetting phase}} = p_{nw} - p_w \qquad (4\text{-}3)$$

Water is often the wetting phase in an oil-water system, while in an oil-gas system, oil is the wetting phase.

The pressures difference of a hemispherical meniscus, can be calculated by Young-Laplace equation, which is shown below. In this equation, the pressure difference increases as the interfacial tension increases, and decreases as the effective radius of the interface reduces. In addition, it varies with the wetting angle of the liquid on the surface of the capillary.

$$p_c = \frac{2\gamma\cos\theta}{r} \qquad (4\text{-}4)$$

where p_c is the capillary pressure, γ is the interfacial tension, θ is the wetting angle of the liquid on the surface of the capillary, and r is the effective radius of the interface. For a cylindrical tube, the capillary pressure can be calculated in another equation.

$$p_c = \sigma_{nww}(\frac{1}{R_1} + \frac{1}{R_2}) \qquad (4\text{-}5)$$

where p_c is the capillary pressure, σ_{nww} is the interfacial tension between the non-wetting phase and the wetting phase, and R1 and R2 are the radii of the shared interface curvature.(Zolotukhin et al., 2000)

4.1.3 Capillary Number

Capillary number(N_c) is a dimensionless ratio of the viscous forces (VF) to local capillary forces (CF) . One of the ways that can define the capillary number is:

$$N_c = \frac{k\left|\nabla \vec{\phi}\right|}{\sigma_{nww} \cos \theta_c} = \frac{VF}{CF} \qquad (4\text{-}6)$$

where N_c is the capillary number, ϕ is the flow potential, σ_{nww} is the interfacial tension between the non-wetting phase and the wetting phase, and θ_c is the contact angle.(Zolotukhin et al., 2000)

Capillary number can also be calculated by another formula below:

$$C_a = \frac{\mu V}{\gamma} \qquad (4\text{-}7)$$

where Ca is the capillary number, μ is the dynamic viscosity of the liquid, V is a characteristic velocity and γ is the surface or interfacial tension between the two fluid phases.(Saylor et al., 2012)

4.1.4 Wettability

Wettability reflects the tendency of one fluid to adhere to a solid surface when another immiscible fluid is presented.(Craig, 1971)

It is an important parameter which affects the reservoir flow in various ways. Wettability can influence the waterflood behavior, relative permeabilities, capillary pressure, residual oil saturation, irreducible water saturation, and so on.(Anderson, 1987)

4.1.5 Fluid Saturations

In the oil and gas reservoir, the pore spaces of reservoir rocks are fully saturated with fluids all the time. Usually in the pores of oil and gas reservoirs, there mainly exist three types of fluids, namely crude oil and its impurities, natural gas and its impurities, and connate water or injected water. The oil saturation is the ratio between the reservoir oil volume and the pore volume in the rock, and is defined in formula below. The determination of the gas saturation and water saturation are also similar to that of oil saturation and are defined below.(Amyx et al., 1960)

$$\mathrm{S}_o = \frac{\text{oil volume}}{\text{pore volume}} = \frac{V_o}{V_p} \qquad (4\text{-}8)$$

$$\mathrm{S}_g = \frac{\text{gas volume}}{\text{pore volume}} = \frac{V_g}{V_p} \qquad (4\text{-}9)$$

$$\mathrm{S}_w = \frac{\text{water volume}}{\text{pore volume}} = \frac{V_w}{V_p} \qquad (4\text{-}10)$$

Assume the pore spaces of reservoir rock are only filled with oil, gas and water, so the total values of saturations of oil, gas and water always equal to one.

$$\mathrm{S}_o + \mathrm{S}_w + \mathrm{S}_g = 1 \qquad (4\text{-}11)$$

Reservoir fluid saturations reflect the contents in the pore space of reservoir rock, and is an important reservoir property as it is closely related to relative permeabilities of fluids in the reservoir. This relationship between saturations and relative permeability will be discussed in the relative permeability part.

Porosity

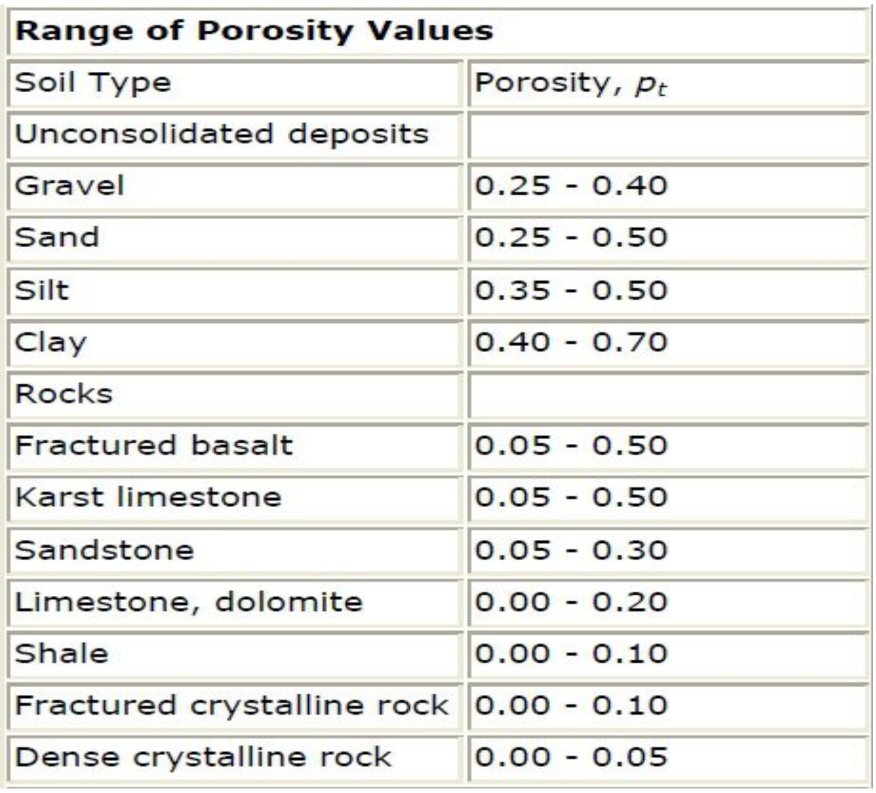
In the oil and gas reservoir, there are actually pore spaces between the reservoir rocks. Porosity is introduced to describe the volume of the reservoir that is not taken up by the framework of the reservoir, that is the volume fraction of pore space in the reservoir. The porosity can be calculated according to the formula below.

$$\phi = \frac{V_b - V_{gr}}{V_b} = \frac{V_p}{V_b} \qquad (4\text{-}12)$$

where ϕ refers to porosity, V_b is the bulk volume of reservoir rock, V_{gr} is the volume of grains, V_p is the pore volume.

There are two different kinds of porosity, namely total porosity and effective porosity. The total porosity is also called as absolute porosity. It represents the ratio between the whole volume of pore space and the bulk volume of reservoir. However, the effective porosity, known as kinematic porosity, considers only the pore spaces that are interconnected in the reservoir rocks. Different matierails have various porosity values, which are displayed in Table 4-1.(Tiab et al., 2012; Freeze, 1979)

Table 4- 1 :Range of Porosity of different materials.



Range of Porosity Values

Soil Type	Porosity, p_t
Unconsolidated deposits	
Gravel	0.25 - 0.40
Sand	0.25 - 0.50
Silt	0.35 - 0.50
Clay	0.40 - 0.70
Rocks	
Fractured basalt	0.05 - 0.50
Karst limestone	0.05 - 0.50
Sandstone	0.05 - 0.30
Limestone, dolomite	0.00 - 0.20
Shale	0.00 - 0.10
Fractured crystalline rock	0.00 - 0.10
Dense crystalline rock	0.00 - 0.05

4.1.6 Permeability

Permeability is an indication of the porous media’s ability to transmit the fluids. Permeability is an important property as it can determine the flow direction and flow rate of reservoir fluids in the reservoir. The permeability is affected by the reservoir pressure. It is easy for the fluids to flow through in reservoirs with high permeability. The reservoirs with low permeabilities are often fractured or acidized artificially to improve the permeability and create a flow. To study the permeability more accurately, Henry Darcy proposed the first equation by which permeability can be calculated in 1856. This fluid flow equation is called Darcy's Law, and has been used widely in petroleum engineering ever since. The unit of permeability is called darcy(D), named after Henry Darcy. The common values of permeability vary from tens of millidarcys to hundreds of milidarcys.

$$V = -\frac{K}{\mu}\frac{dP}{dL} \qquad (4\text{-}13)$$

where V is the superficial fluid flowing velocity, k refers to the permeability(proportionality constant) of a medium, μ is the dynamic viscosity of the flowing fluid, dP/dL is the pressure drop per unit length.

Permeability is an important property as it determines the flow characteristics of hydrocarbon in oil and gas reservoirs. To determine whether a hydrocarbon reservoir is exploitable without artificial stimulations or not, permeability is a good reference. Usually, hydrocarbon reservoirs with permeability greater than 100 millidarcys are exploitable. However, rocks with permeability lower than 100 millidarcys can also be utilized. They can behave as efficient seals.

4.1.7 Relative Permeability

Permeability is also known as absolute permeability. There are two other conceptions, effective permeability and relative permeability. Effective permeability measures the ability of one phase to flow through a porous media that has more than one phase. Relative permeability of one phase is the ratio of effective permeability at a given saturation of the phase to a reference or base permeability. The base permeability could be absolute permeability, air permeability, or effective permeability of non-wetting phase at irreducible wetting phase saturation, such as the relative permeability to oil at irreducible water saturation.

$$K_r = \frac{K_{eff}}{K_{ref}} \qquad (4\text{-}14)$$

Relative permeability can be expressed as a function of saturations of fluids in the porous media. Factors that influence relative permeability include fluid saturations, history of fluid saturation(whether drainage or imbibition), wettability, and geometry of the pore spaces and pore size distribution. The importance of relative permeability lies in that it can affect the flow characteristics of reservoir fluids, and influence the recovery efficiency of oil. Relative permeability can be used to calculate the multiphase flow in reservoir, and can be utilized in the reservoir simulation, and in the estimation of residual oil saturation.(Bear, 1972)

4.1.8 Relative Permeability Curves

As the relative permeability curves will be adjusted to simulate the CO_2-EOR process, it is necessary to study about them. First of all, a schematic of oil-water relative permeability curves in a water-wet reservoir is displayed in Figure 4-1. In the schematic, S_{wc} is the connate or irreducible water saturation. The water relative permeability at water saturations below S_{wc} is zero. S_{orw} is the residual oil saturation or critical oil saturation, which means that oil with saturation below this point is not able to move, and the oil realtive permeability is zero. Figure 4-2 shows the oil-water relative permeability curves in a oil-wet reservoir.(Craft et al., 1991)

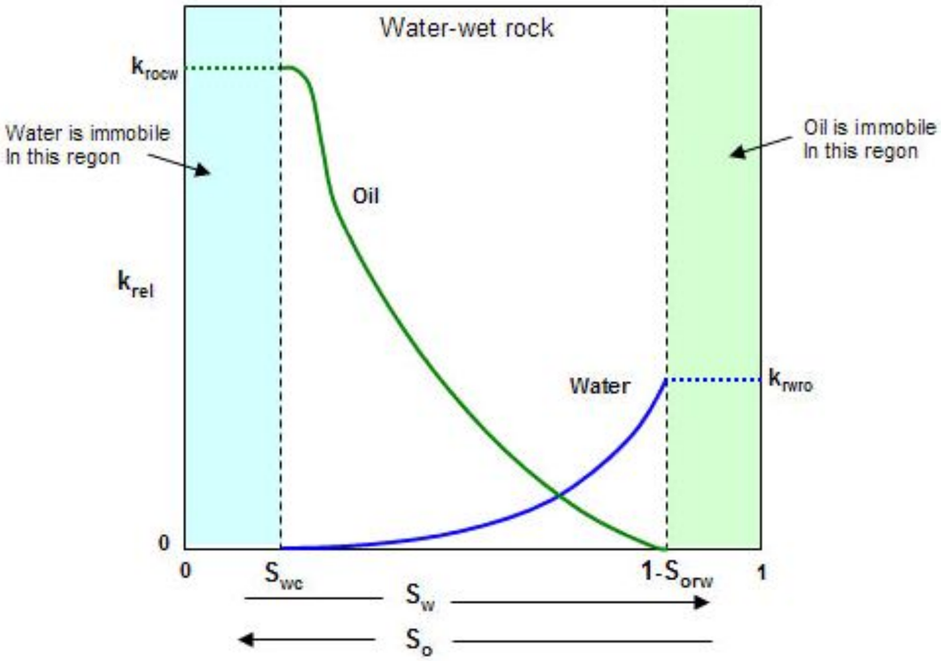


Figure 4-1: Water-wet relative permeability curves (oil and water).

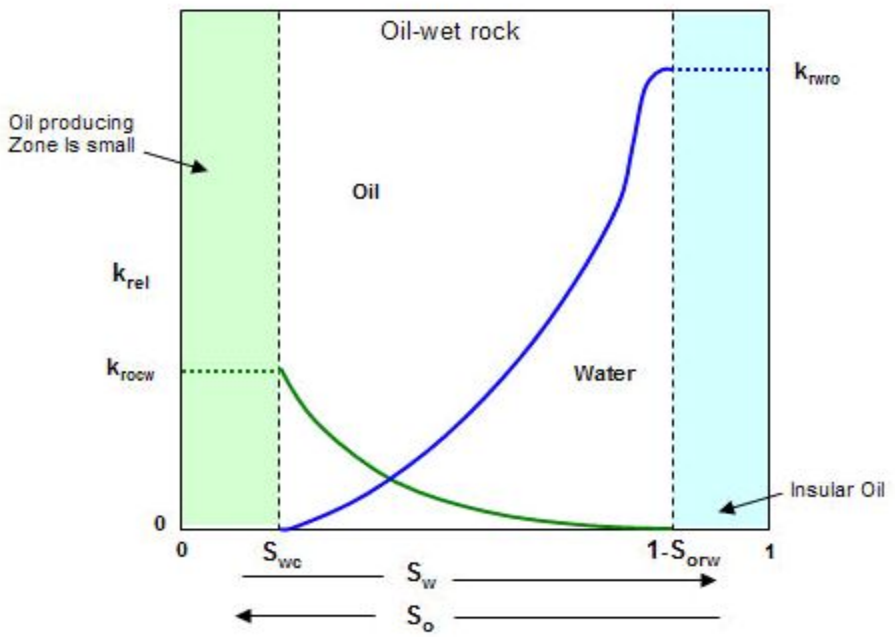


Figure 4-2: Oil-wet relative permeability curves (oil and water).

The schematic of gas-oil relative permeability curves is demonstrated in Figure 4-3.

S_{gc} is the critical gas saturation, which is the minimum saturation for gas to be able to move. S_{org} is the gas residual oil saturation, below which oil is immobile when gas is the displacing fluid. k_{rogc} is the oil relative permeability at the critical gas saturation. k_{rgc} is the gas relative permeability at the residual oil saturation.

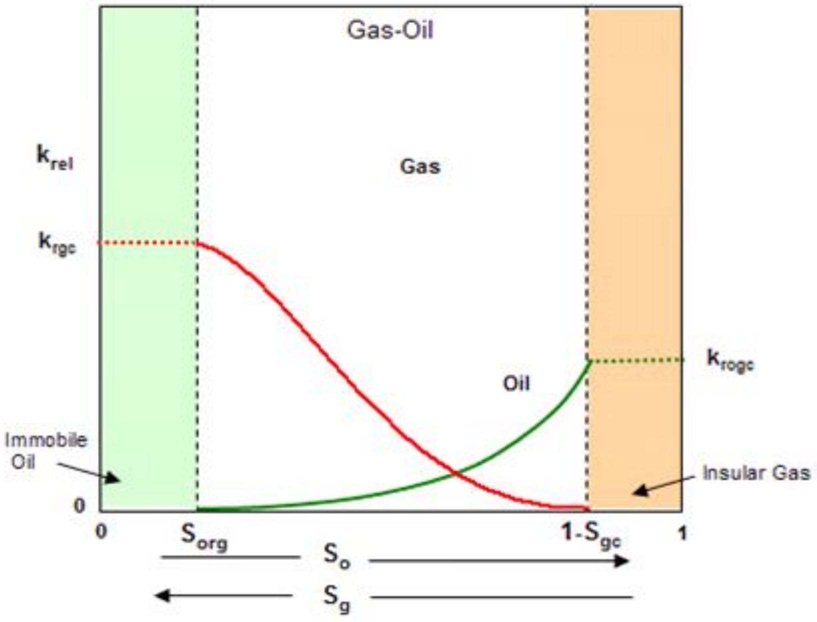


Figure 4-3: Gas-oil relative permeability curves.

4.2 Relative Permeability Model

4.2.1 Corey Model

In 1954, Corey believed that there existed a definite relationship between gas and oil relative permeabilities, and based on this relationship and Burdine's previous findings, he derived expressions of relative permeabilities for oil and gas two-phase conditions.(Burdine, 1953; Corey, 1954) Corey and Rathjens studied the effect of laminations on the oil and gas relative permeability, and made a model for heterogeneous rock. The expressions of oil and gas relative permeability are not the same if the flow direction is different, depending on whether the flow is perpendicular or parallel to the laminations.(Corey, 1956)

Based on Corey's equations derived in 1954, Brooks and Corey suggested improved expressions for wetting phase and non-wetting phase permeability by introducing the number λ to characterize the distribution of pore sizes in 1964, which are displayed below. In the expressions, S_e is called effective saturation by Corey.(Brooks, 1964)

$$K_{rw} = (S_e)^{\frac{2+3\lambda}{\lambda}} \qquad (4\text{-}15)$$

$$K_{rnw} = (1-S_e)^2(1-S_e^{\frac{2+\lambda}{\lambda}}) \qquad (4\text{-}16)$$

where Krw and Krnw are the relative permeabilities of wetting phase and non-wetting phase, S_e is called the effective saturation, and $S_e = \frac{S-S_r}{1-S_r}$

Another "power-law" relationships, also called as modified Brooks-Corey relations, describes the relative permeabilities to oil, water, and gas. And these relationships are quite similar to the Brooks-Corey expression.

$$K_{ro} = K_{ro,\max}\left(\frac{S_o - S_{or}}{1-S_{or}-S_{wc}-S_{gc}}\right)^{n_o} \qquad (4\text{-}17)$$

$$K_{rw} = K_{rw,\max}\left(\frac{S_w - S_{wc}}{1-S_{or}-S_{wc}-S_{gc}}\right)^{n_w} \qquad (4\text{-}18)$$

$$K_{rg} = K_{rg,\max}\left(\frac{S_g - S_{gc}}{1-S_{or}-S_{wc}-S_{gc}}\right)^{n_g} \qquad (4\text{-}19)$$

where n_o, n_w, n_g are the exponents ranging from 1 to 6, and $k_{ro,max}$, $k_{rw,max}$, and $k_{rg,max}$ represent the the maximum relative permeabilities to oil, water, and gas, ranging from 0 to1.

4.2.2 Chierici Model

Chierici model is made up of several exponential expressions for gas/oil drainage relative permeabilities and oil/water imbibition relative permeabilities, proposed by Chierici in 1984. The estimated results by this model are in better agreement with the curves of experimental data at and around the starting points and end points. Chierici put forward that these expressions are especially appropriate for the simulation of gas percolation in dissolved gas drive reservoirs.(Chierici, 1984)

The expressions of Chierici Model for oil and gas relative permeabilities are:

$$K_{ro} = \exp\left(-AS_{gN}{}^{L}\right) \qquad (4\text{-}20)$$

$$K_{rg} = \exp\left(-BS_{gN}{}^{-M}\right) \qquad (4\text{-}21)$$

$$S_{gN} = \frac{S_g - S_{gc}}{1 - S_{wi} - S_g} \qquad (4\text{-}22)$$

The expressions of Chierici Model for oil and water relative permeabilities are:

$$K_{ro} = K_{ro,\max} \exp\left(-AS_{wN}{}^{L}\right) \qquad (4\text{-}23)$$

$$K_{rw} = K_{rw,\max} \exp\left(-BS_{wN}{}^{-M}\right) \qquad (4\text{-}24)$$

$$S_{wN} = \frac{S_w - S_{wi}}{1 - S_{or} - S_w} \qquad (4\text{-}25)$$

where A and B are the parameters in Chierici model, S_{gN} is the normalized gas saturation, S_{wN} is the normalized water saturation, L and M are the parameters in Chierici model.

Alpak et al. presented a modified Carman-Kozeny expression to model two-phase relative permeabilities. In the modified expression, the relative permeabilities change with total surface area, interfacial areas, and tortuosity relationships, in addition to fluid saturations.(Alpak et al., 1999)

4.2.3 Stone I Model

In 1970, Stone proposed Stone I model for water-wet systems to predict three-phase relative permeabilities. In this model, Stone mentioned the idea of applying the data of two-phase relative permeability to calculating the three-phase relative permeabilities. In a water wet porous media, oil is assumed to be in the middle of gas and water, and thus it prevents the contact between gas and water. Then the oil-water displacements and oil-gas displacements can be regarded as two mutually independent activities. In this way, the three-phase water relative permeability is the same as that in oil/water displacements. Similarly, the gas relative permeability of three-phase and oil/gas displacements are also identical. The water relative permeability changes only with water saturation, and also the gas relative permeability depends on gas saturation alone. However, the oil relative permeability is more difficult and complicated to predict. The expression of Stone I model for three-phase oil relative permeability is shown in formula below.

$$K_{ro} = S_{onor} \beta_w \beta_g \qquad (4\text{-}26)$$

where S_{onor} is the normalized oil saturation, β_w is the factor to allow for oil blockage by water, and β_g is the factor to allow for oil blockage by gas.

Formula 4-27 can be used to calculate the normalized oil saturation.

$$S_{onor} = \frac{S_o - S_{om}}{1 - S_{wc} - S_{om}} \text{ (when } S_o \geq S_{om}\text{)} \qquad (4\text{-}27)$$

where S_o is saturation of oil, S_{or} is the residual saturation of oil for three-phase models, and S_{wi} is critical saturation of water.

β_w and β_g can be calculated according to formula 4-28 and 4-29.

$$\beta_w = \frac{K_{row}}{1 - S_{wnor}} \qquad (4\text{-}28)$$

$$\beta_g = \frac{K_{rog}}{1 - S_{gnor}} \qquad (4\text{-}29)$$

where k_{row} and k_{rog} are the relative permeabilities to oil in water-oil and gas-oil displacements respectively. The fact that the sum of the normalized saturations of water, oil and gas equals to 1 can also be utilized. Formula 4-28 was deduced based on the assumption of two-phase conditions where the normalized saturation of gas was zero and β_g was equal to 1. Formula 4-29 was deduced in a similar way.

S_{wnor} and S_{gnor} are the normalized saturation of water and gas respectively, and can be calculated based on two formulas similar to the formula for calculating S_{onor} (Stone, 1970):

$$S_{wnor} = \frac{S_w - S_{wc}}{1 - S_{wc} - S_{om}} \quad (\text{ when } S_w \geq S_{wc}) \qquad (4\text{-}30)$$

$$S_{gnor} = \frac{S_g}{1 - S_{wc} - S_{om}} \qquad (4\text{-}31)$$

4.2.4 Stone II Model

Later Stone presented another revised model based which is known as Stone II model in 1973. In both Stone I model and Stone II model, the three phase water and gas relative permeabilities are identical to those measured in two-phase displacements, and their results both agree with experimental data to some extent. However, the relative permeabilities estimated by Stone II model fit the previous experimental data better than Stone I model, particularly in the low oil saturation region. The expression of oil relative permeability in Stone II model takes advantage of two-phase relative permeabilities in water-oil and gas-oil displacements respectively, and is demonstrated below.

$$K_{ro} = (K_{row} + K_{rwo})(K_{rog} + K_{rgo}) - (K_{rwo} + K_{rgo}) \quad (4\text{-}32)$$

where K_{ro}, K_{rw}, and K_{rg} are the relative permeabilities to oil, water and gas respectively. K_{row} and K_{rwo} are relative permeabilities for oil and water in water-oil displacements. Similarly, K_{rog} and K_{rgo} are relative permeabilities in gas-oil displacements, to oil and gas respectively.

(Stone, 1973)

4.2.5 Aziz and Settari Model

In 1979, Aziz and Settari modified Stone's two models to improve their performances. In Stone I model, only when the relative permeabilities at the end-point were equal to 1, can the three-phase model be reduced to two-phase. The modified Stone I model is able to overcome this shortcoming by multiplying K_{romax} on the right hand side of the equation.

$$K_{ro} = K_{ro\max} S_{onor} \beta_w \beta_g \qquad (4\text{-}33)$$

β_w and β_g can be calculated according to:

$$\beta_w = \frac{K_{row}}{K_{ro\max}\left(1 - S_{wi}\right)} \qquad (4\text{-}34)$$

$$\beta_g = \frac{K_{rog}}{K_{ro\max}\left(1 - S_{gnor}\right)} \qquad (4\text{-}35)$$

K_{romax} is also used in the modified Stone II model by Aziz and Settari.(Aziz et al., 1979)

$$K_{ro} = K_{ro\max}\left[\left(\frac{K_{row}}{K_{ro\max}} + K_{rwo}\right)\left(\frac{K_{rog}}{K_{ro\max}} + K_{rgo}\right) - (K_{rwo} + K_{rgo}) \right] \qquad (4\text{-}36)$$

4.2.6 Hirasaki Model

Hirasaki took the reduction in the oil relative permeability as a result of the presence of a third phase into consideration, and his expression of oil relative permeability model is(Dietrich et al., 1976):

$$K_{ro} = K_{row}\left(S_w\right) + K_{rog}\left(S_w + S_o\right) - K_{row\max} + \left(S_w + S_o\right)\left[K_{row\max} - K_{row}\left(S_w\right)\right]\left[K_{row} - K_{rog}\left(S_w + S_o\right)\right] / K_{row\max}$$

(4-37)

4.2.7 Baker model

In 1988, Baker proposed two models respectively using saturation-weighted interpolation and true-linear interpolation between oil-water data and oil-gas data to predict three-phase relative permeabilities. He compared these two models with different previous models for three-phase relative permeabilities, such as Stone, Hirasaki, Corey et al., Land and so on. The results show that the models before which based on theories did not perform as well as the two models put forward by Baker in fitting the experimental data. He also concluded that the choice of model could significantly affect the simulation results. (Baker, 1988)

$$K_{ro,wog} = \frac{\left(S_w - S_{wr}\right)K_{ro,wo} + \left(S_g - S_{gr}\right)K_{ro,go}}{\left(S_w - S_{wr}\right) + \left(S_g - S_{gr}\right)} \qquad (4\text{-}38)$$

$$K_{rw,wog} = \frac{(S_o - S_{or})K_{rw,ow} + (S_g - S_{gr})K_{rw,gw}}{(S_o - S_{or}) + (S_g - S_{gr})} \quad (4\text{-}39)$$

$$K_{rg,wog} = \frac{(S_w - S_{wr})K_{rg,gw} + (S_o - S_{or})K_{rg,go}}{(S_w - S_{wr}) + (S_o - S_{or})} \quad (4\text{-}40)$$

In 1989, Kokal and Maini mentioned Stone's models were widely used for the studies of reservoir simulation to compensate for the lack of three-phase data, and claimed two limitations of the modified Stone's models by Aziz and Settari. According to their results, the prediction of Aziz and Settari's modified Stone's models did not fit well with the available three-phase data at that time. They suggested different modified Stone's models, and these models matched the six different sets of experimental data better than the original Stone's models did.(Kokal et al., 1990)

$$Kro = S_{onor} \frac{K_{row}}{K_{ro\max}(1 - S_{wnor})} \frac{K_{rog}}{K_{ro\max}(1 - S_{gnor})} \frac{K_{ro\max}S_{gnor} + K_{ro\max}S_{wnor}}{1 - S_{onor}} \quad (4\text{-}41)$$

4.2.8 Blunt Model

In 1999, Blunt introduced a three-phase relative permeability model based on saturation-weighted interpolation between oil-water phase and oil-gas phase relative permeabilities, which is similar to Baker's three-phase relative permeability model. He discussed about three major limitations of most three-phase relative permeability models. The first shortcoming was that most of the models are designed for water-wet media, but the majority of the reservoir rocks are oil-wet. In addition, these models were not able to explain the trapping of oil and gas. Finally, for oil with low saturation, the relative permeabilities calculated by these models failed to agree with the available experimental results. According to Blunt, his model could solve the three limitations above.(Blunt, 1999)

Fayers et al. proposed a method named Rescaled Interpolation Method(RIM) that can calculate three-phase relative permeabilities and the capillary pressures as well. This method could be applied in mixed-wet systems, and when the systems experiencing changing oil and gas compositions with hysteresis.(Fayers et al., 2000)

4.3 Case Definition

4.3.1 Reservoir Definition

The shape of the oil reservoir to be simulated is assumed to be cuboid, and the size of the reservoir is 49.6 meters long, 80 meters wide, and 20 meters high. The porosity of the reservoir is 30%. The oil reservoir is assumed to be homogeneous, and the reservoir permeability is 5000mD. The reservoir pressure is 30 bar. The connate water saturation in the reservoir is 0.4, and the residual gas saturation is 0.2. At first, the oil reservoir is assumed to be saturated with crude oil only. Gas specific gravity is 0.64, and oil specific gravity is 0.85. The reservoir oil viscosity is 100cp. There are two feeds when simulating the process of water flooding and CO_2-EOR process. One feed is almost pure oil, and the other feed mainly contains water.

4.3.2 Pipe Defination

There are two main pipes to transfer the reservoir oil to the production well, namely PIPELINE and FLOWPATH. Four near well sources, four leaks, and seven valves distribute evenly on the PIPELINE. These near well sources are linked with the oil reservoir to collect crude oil. Then the four leaks on the PIPELINE are connnected to the FLOWPATH so that the reservoir oil can be transferred further to the produciton well.

4.3.3 Basic Idea

As the process of CO_2-EOR is quite complicated, the process can be simulated in a less complicated way by adjusting the relative permeability curves and decreasing the viscosity of oil on the basis of waterflooding process in OLGA-Rocx. As discussed in the mechanism part before, CO_2-EOR improves the oil production by decreasing the oil viscosity and reducing the residual oil saturation. Therefore, decreasing the oil viscosity and reducing the residual oil saturation on the basis of waterflooding process can in a way simulate the process of CO_2-EOR.

4.4 Simulation Method

4.4.1 Simulation of Waterflooding and CO_2-EOR

At first, the processes of waterflooding and CO_2-EOR are simulated to see the difference in the amount of oil production. For the waterflooding process, the value of residual oil saturaiont is set to 0.4 in the K_c and P_c section, and the viscosity of reservoir oil is 100cp in the Fluid Properties section in the Rocx file.When simulating the CO_2-EOR process, the residual oil saturation is decreased to 0.05, and the oil viscosity is reduced to 10cp. Corey model and Stone II model are used as the relative permeability model to calculate the water relative permeability, gas relative permeability and oil relative permeability. Then the accumulated liquid oil flow(ACCOIQ) and accumulated liquid volume flow(ACCLIQ) of both waterflooding process and CO_2-EOR process are compared. The difference in water breakthrough time between these two processes is also studied.

4.4.2 Simulation Scale

The case previously defined is a small scale oil reservoir. However, there exist lots of reservoirs larger than that case. To explore the effect of reservoir scale on the CO_2-EOR process, a relatively large scale reservoir case is studied. The size is 992 meters long, 80 meters wide, and 20 meters high. Then the increase in the amount of oil production and accumulated liquid volume flow(ACCLIQ) is compared with the simulation results from the previous small scale oil reservoir case.

4.4.3 Simulation Period

The influence of simulation period on the final simulation result is also of interest. In another case to be studied, the simulation period extends to about two months(60 days). Then the difference in accumulated oil volume flow(ACCOIQ), accumulated liquid volume flow(ACCLIQ), and water breakthrough time between waterflooding process and CO_2-EOR process in the two months's case are studied and compared with the results of the previous case, where the simulation runs for 20 days.

4.4.4 Reservoir Pressure

As the pressures of reservoirs vary from each other, how the CO_2-EOR process influences the accumulated oil volume flow(ACCOIQ) and the accumulated liquid volume flow(ACCLIQ) in reservoirs with high reservoir pressure and low reservoir pressure is worthy of studying. In the first place, reservoirs with low reservoir pressure is studied. The reservoir pressure and well pressure are both set to 30bar in the Boundary Conditions in the Rocx file. The pressure in the Initial Conditions in the Rocx file is also 30bar. In the initial conditions of FLOWPATH in the OLGA file, the inpressure of outpressure are 20 bar, while the inpressure of outpressure in the initial conditions of PIPELINE are set to 21bar.

As to the reservoirs with high reservoir pressure, the reservoir pressure and well pressure are both increased to 100 bar in the Rocx file, so is the pressure in the initial conditions. The inpressure of outpressure are set to 100 bar in the initial conditions of FLOWPATH in the OLGA file, and the inpressure of outpressure in the initial conditions of PIPELINE are changed to 91bar.

4.4.5 Reservoir Porosity

The difference in the reservoir porosity can affect the performance of CO_2-EOR process. And how the CO_2-EOR technology behaves in reservoirs with differenct porosities is also interesting. Reservoir with relatively high porosity is studied first. The value of porosity is set to 0.3 in the Reservoir Properties in the Rocx file. Then the porosity is reduced to 0.1 to simulate oil reservoirs with relatively low porosity. At last, both the accumulated oil volume flow(ACCOIQ) and accumulated liquid volume flow(ACCLIQ) of both results from high porosity reservoir and low porosity reservoir are compared.

4.4.6 Reservoir Permeability

The permeability of reservoirs are different from each other. To explore how the CO_2-EOR performs in different types of reservoirs with different permeability, a case of oil reservoir with relatively high permeability is studied, so is a case of oil reservoir with low permeability. Oil reservoirs with relatively low permeability is explored and the value of permeability is set to 5000mD in the Reservoir Properties in the Rocx file. Then the value of permeability is increased to 4000mD to study oil reservoirs with relatively high permeability. Finally, the results of both cases are contrasted to see the role of permeability in affecting the CO_2-EOR performance.

4.4.7 Relative Permeability Model

As disccussed before, there exist several models to calculate relative permeability of oil, water, and gas. Some of the relative permeability models are chosen to study their influences on the accumulated oil volume flow(ACCOIQ) and accumulated liquid volume flow(ACCLIQ) after CO_2-EOR technology is utilized. Corey model, modified Brooks-Corey relations, Chierici model, Stone II model, Baker model, and so on are used and their simulation results are compared with each other.

4.4.8 Heterogeneous Reservoir

The cases studied previously are all based on the assumption that the oil reservoir is homogeneous. However, in practice most oil reservoirs are acturally heterogeneous. Therefore, the influence of reservoir heterogeneity will be studied in this section. In this case, the permeabilities of the oil reservoir differ from each other, so the peameability in Rocx are changed to ijk from constant. The permeability of nearly one third of the reservoir is set to 5000mD, the permeability of nearly one third is set to 7000mD, and the permeability of another one third of the oil reservoi is set to 8000mD. Then the simulation results are compared to those from the previous case where the peameability are constant to 5000mD.

5 Results

5.1 Results of Waterflooding and CO_2-EOR

The results of waterflooding process simulation and CO_2-EOR process simulation are demonstrated in Figure 5-1 and Figure 5-2. The data of accumulated oil volume flow(ACCOIQ) and accumulated liquid volume flow(ACCLIQ) after 20 days of both processes are also displayed and compared in Table 5-1.

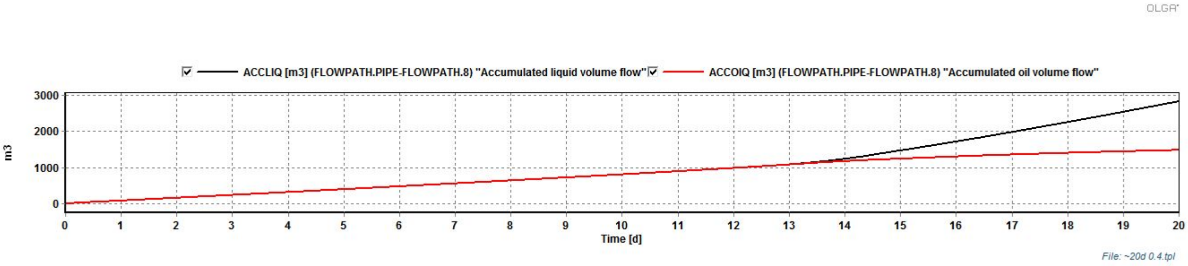


Figure 5-1: ACCOIQ and ACCLIQ of waterflooding process after 20 days..

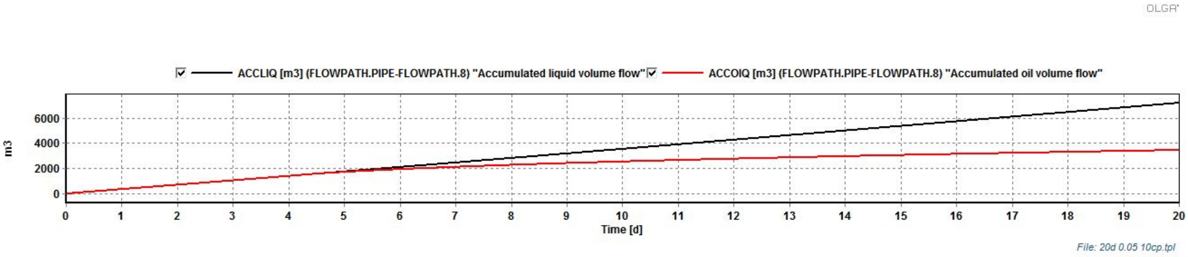


Figure 5-2: ACCOIQ and ACCLIQ of CO_2-EOR process after 20 days.

Table 5- 1: Simulation data of waterflooding and CO_2-EOR process after 20 days.

	ACCOIQ(m^3)	ACCLIQ(m^3)	Water Breakthrough	ACCOIQ Difference(m^3)
Waterflooding	1479	2823	Day 14	1977
CO_2-EOR	3456	7207	Day 6	

5.2 Results of Simulation Scale

The accumulated oil volume flow(ACCOIQ) and accumulated liquid volume flow(ACCLIQ) of both waterflooding and CO_2-EOR processes in the large scale oil reservoir case are shown in Figure 5-3 and Figure 5-4. The simulation data of both processes are demonstrated and compared in Table 5-2.

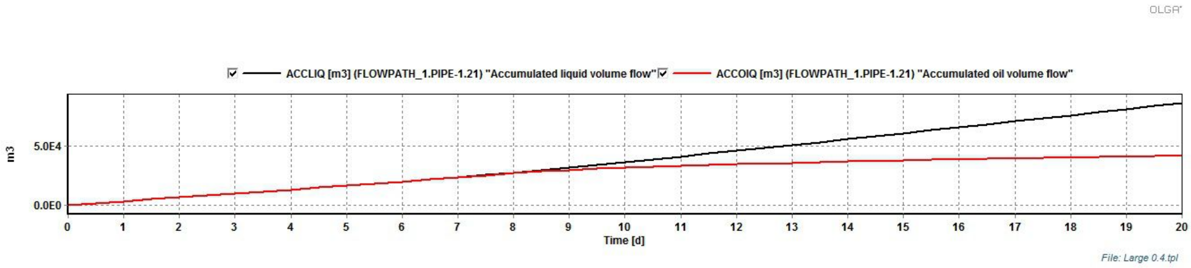


Figure 5-3: ACCOIQ and ACCLIQ of waterflooding in large reservoir after 20 days.

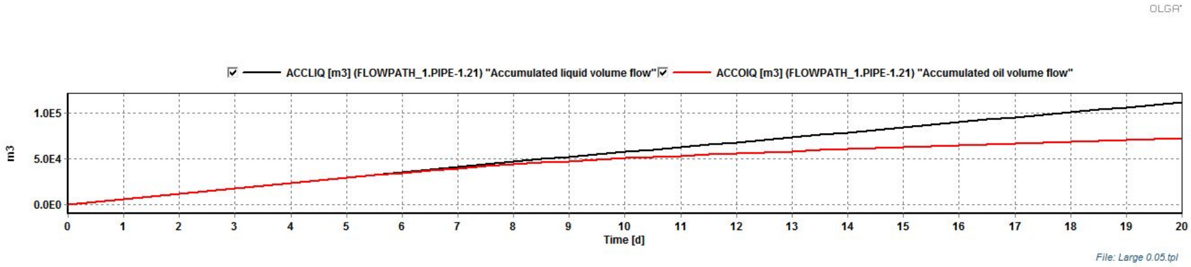


Figure 5-4: ACCOIQ and ACCLIQ of CO_2-EOR in large reservoir after 20 days.

Table 5- 2: Simulation data of waterflooding and CO_2-EOR in large reservoir after 20 days.

	ACCOIQ(m^3)	ACCLIQ(m^3)	Water Breakthrough	ACCOIQ Difference(m^3)
Waterflooding	41937	86307	Day 9	30342
CO_2-EOR	72279	111850	Day 8	

5.3 Results of Simulation Period

The accumulated oil volume flow(ACCOIQ) and accumulated liquid volume flow(ACCLIQ) of waterflooding process in the case with longer simulation period(60 days) are displayed in Figure 5-5, and the ACCOIQ and ACCLIQ of CO_2-EOR process are shown in Figure 5-6. And the simulation data of ACCOIQ and ACCLIQ of both processes are demonstrated and compared in Table 5-3.

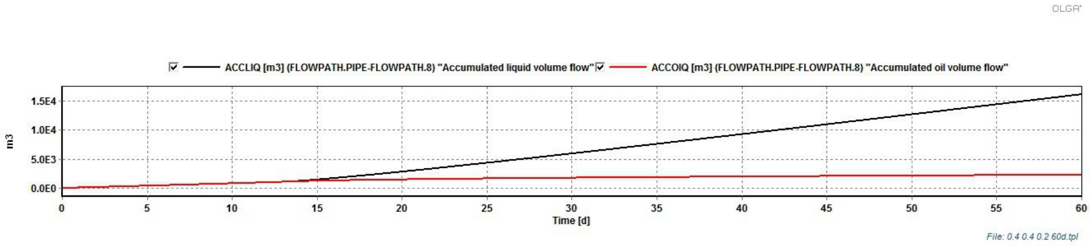


Figure 5-5: ACCOIQ and ACCLIQ of waterflooding process after 60 days.

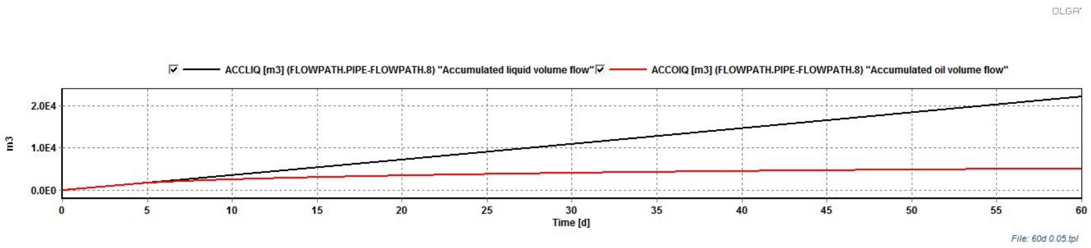


Figure 5-6: ACCOIQ and ACCLIQ of CO_2-EOR process after 60 days.

Table 5- 3: Simulation data of waterflooding and CO_2-EOR after 60 days.

	ACCOIQ(m^3)	ACCLIQ(m^3)	Water Breakthrough	ACCOIQ Difference(m^3)
Waterflooding	2287	16169	Day 14	2834
CO_2-EOR	5121	22093	Day 6	

5.4 Results of Reservoir Pressure

The accumulated oil volume flow(ACCOIQ) and accumulated liquid volume flow(ACCLIQ) of both waterflooding process and CO_2-EOR process in the higher reservoir pressure case(100bar) are displayed in Figure 5-7 and Figure 5-8. The simulation data of ACCOIQ and ACCLIQ etc. are shown and compared in Table 5-6.

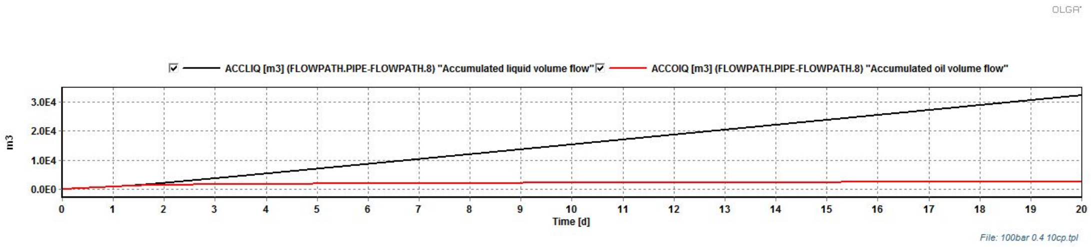


Figure 5-7: ACCOIQ and ACCLIQ of waterflooding in reservoir with high pressure after 20 days.

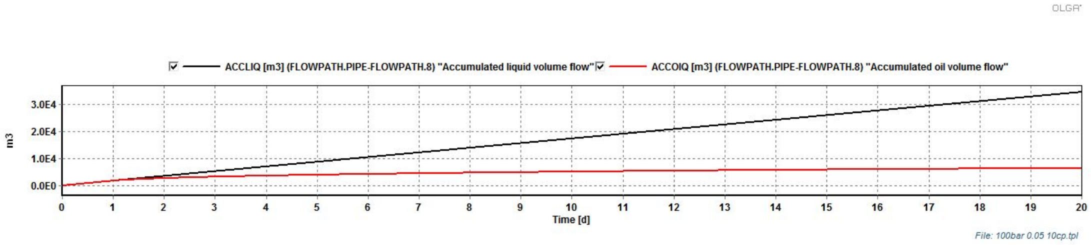


Figure 5-8: ACCOIQ and ACCLIQ of CO_2-EOR in reservoir with high pressure after 20 days.

Table 5- 4: Simulation data of waterflooding process and CO_2-EOR process in reservoir with high pressure after 20 days.

	ACCOIQ(m^3)	ACCLIQ(m^3)	Water Breakthrough	ACCOIQ Difference(m^3)
Waterflooding	2551	32128	Day 2	3918
CO_2-EOR	6469	34596	Day 2	

5.5 Results of Reservoir Porosity

The ACCOIQ and ACCLIQ of waterflooding process with porosity equal to 0.1 is shown in Figure 5-9, and the ACCOIQ and ACCLIQ of the CO_2-EOR process is displayed in Figure 5-10. The data of ACCOIQ and ACCLIQ of both processes are compared in Table 5-5.

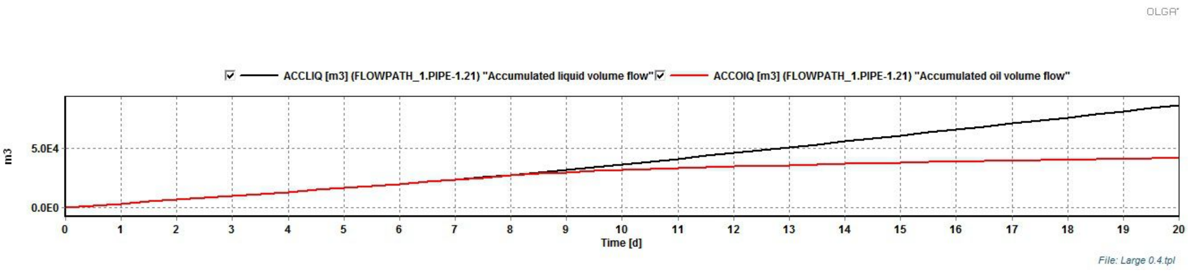


Figure 5-9: ACCOIQ and ACCLIQ of waterflooding with porosity equal to 0.1 after 20 days.

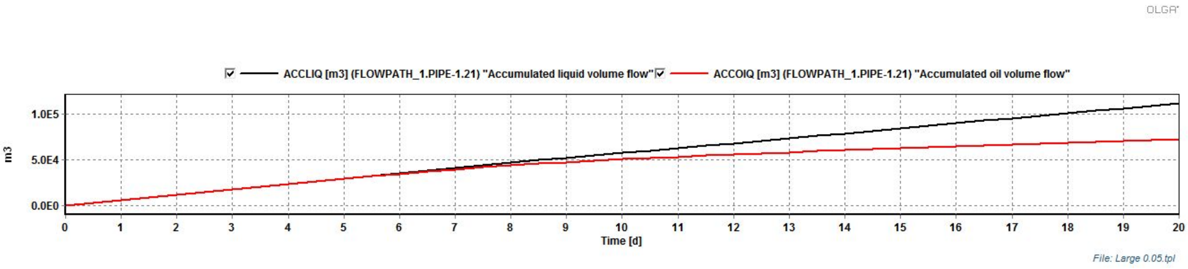


Figure 5-10: ACCOIQ and ACCLIQ of CO_2-EOR with porosity equal to 0.1 after 20 days.

Table 5- 5: Simulation data of waterflooding and CO_2-EOR with porosity equal to 0.1 after 20 days.

	ACCOIQ(m^3)	ACCLIQ(m^3)	Water Breakthrough	ACCOIQ Difference(m^3)
Waterflooding	794	5693	Day 8	916
CO_2-EOR	1710	7365	Day 7	

5.6 Results of Reservoir Permeability

The ACCOIQ and ACCLIQ of waterflooding process and CO_2-EOR process in the case with higher reservoir permeability(4000mD) are shown in Figure 5-11 and Figure 5-12. The data of ACCOIQ and ACCLIQ etc. of both cases are demonstrated and compared in Table 5-6.

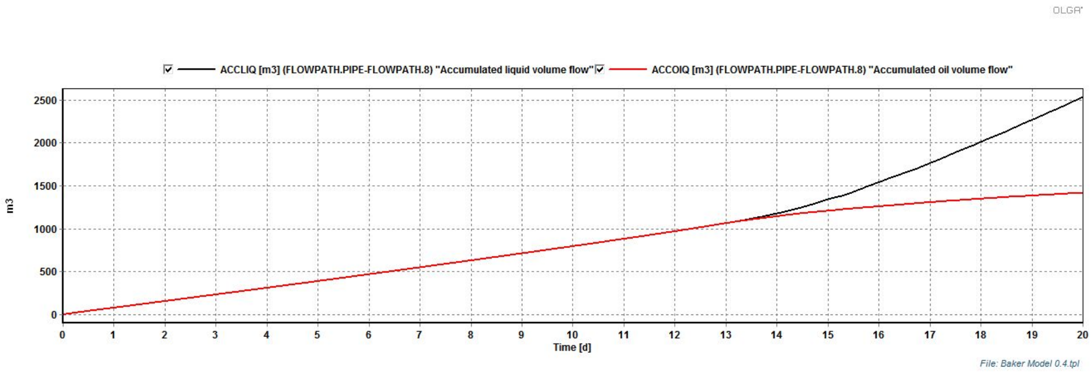


Figure 5-11: ACCOIQ and ACCLIQ of waterflooding with permaebility equal to 4000 mD after 20 days.

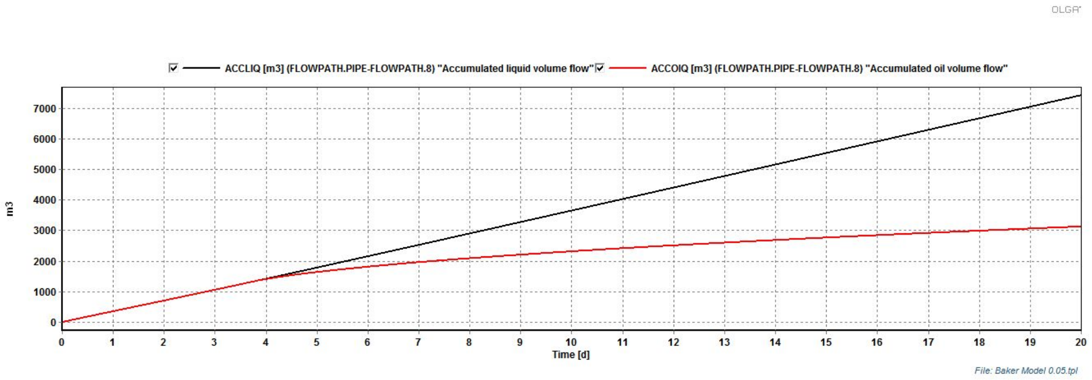


Figure 5-12: ACCOIQ and ACCLIQ of CO_2-EOR with permaebility equal to 4000 mD after 20 days.

Table 5- 6: Simulation data of waterflooding and CO_2-EOR with permaebility equal to 4000 mD after 20 days.

	ACCOIQ(m^3)	ACCLIQ(m^3)	Water Breakthrough	ACCOIQ Difference(m^3)
Waterflooding	1321	1810	Day 14	2064
CO_2-EOR	3385	6939	Day 4	

5.7 Results of Relative Permeability Model

5.7.1 Corey Model and Stone II Model

The simulation results using Corey model and Stone II model are demonstrated already earlier in Figure 5-1, Figure 5-2, and Table 5-1.

5.7.2 Modified Brooks-Corey Relations and Stone II model

The ACCOIQ and ACCLIQ of waterflooding process in the case using modified Brooks-Corey relations and Stone II model are shown in Figure 5-11, and the ACCOIQ and ACCLIQ of CO_2-EOR process are displayed in Figure 5-12. The simulation data of both cases are demonstrated and compared in Table 5-6.

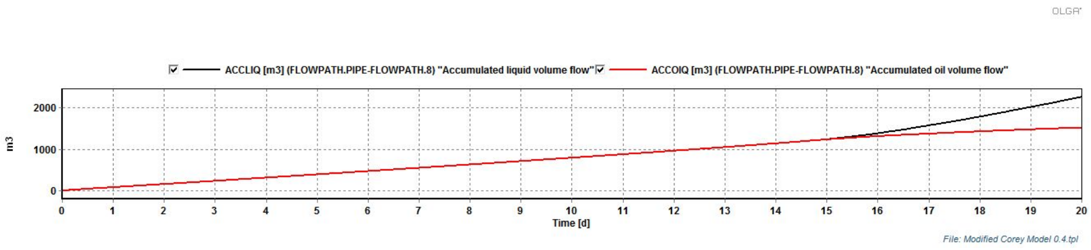


Figure 5-13: ACCOIQ and ACCLIQ of waterflooding using modified Brooks-Corey relations and Stone II Model after 20 days.

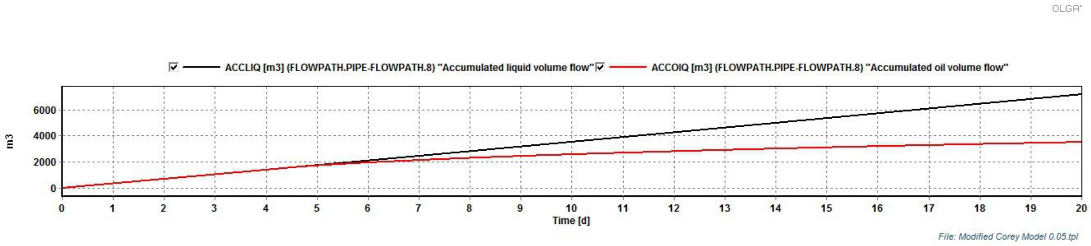


Figure 5-14: ACCOIQ and ACCLIQ of CO_2-EOR using modified Brooks-Corey relations and Stone II Model after 20 days.

Table 5- 7: Simulation data of waterflooding process and CO_2-EOR process using modified Brooks-Corey relations and Stone II Model after 20 days.

	ACCOIQ(m^3)	ACCLIQ(m^3)	Water Breakthrough	ACCOIQ Difference(m^3)
Waterflooding	1516	2261	Day 15	2002
CO_2-EOR	3518	7178	Day 6	

5.7.3 Chierici Model and Stone II Model

The ACCOIQ and ACCLIQ of waterflooding process and CO_2-EOR process in the case using Chierici model and Stone II model are shown in Figure 5-13 and Figure 5-14. The simulation data of both cases are demonstrated and compared in Table 5-7.

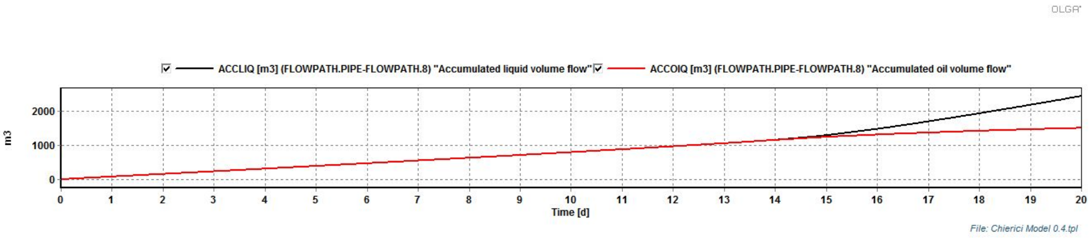


Figure 5-15: ACCOIQ and ACCLIQ of waterflooding using Chierici model and Stone II model after 20 days.

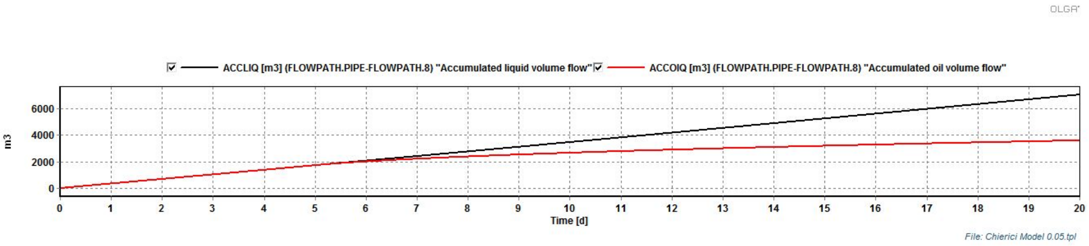


Figure 5-16: ACCOIQ and ACCLIQ of CO_2-EOR using Chierici model and Stone II model after 20 days.

Table 5- 8: Simulation data of waterflooding process and CO_2-EOR process using Chierici model and Stone II model after 20 days.

	ACCOIQ(m^3)	ACCLIQ(m^3)	Water Breakthrough	ACCOIQ Difference(m^3)
Waterflooding	1514	2453	Day 15	2091
CO_2-EOR	3605	7068	Day 6	

5.7.4 Baker Model

The ACCOIQ and ACCLIQ of waterflooding process and CO_2-EOR process in the case using Baker model are shown in Figure 5-15 and Figure 5-16. The simulation data of both cases are demonstrated and compared in Table 5-8.

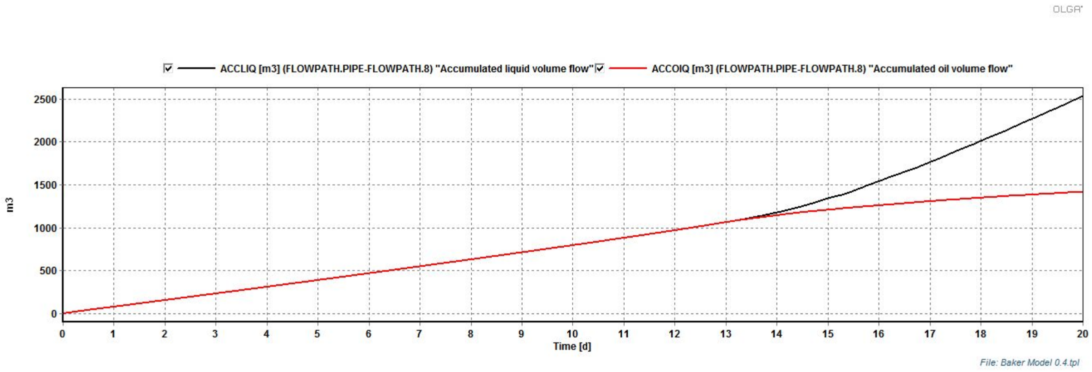


Figure 5-17: ACCOIQ and ACCLIQ of waterflooding using Baker model after 20 days.

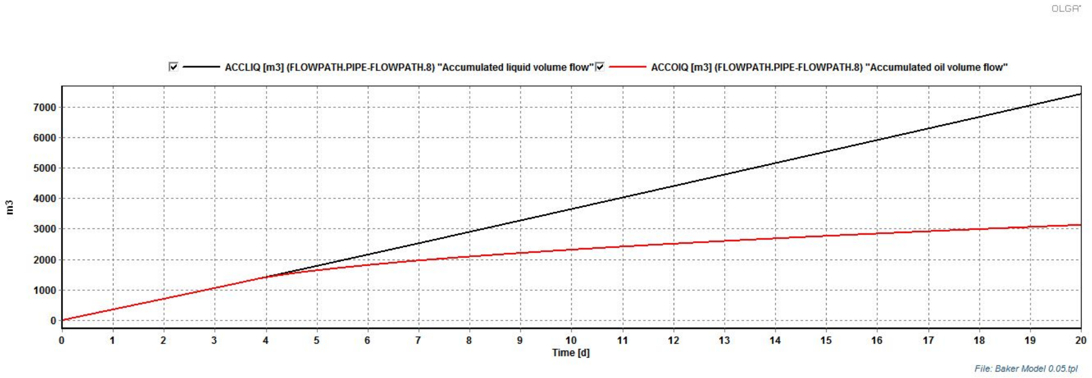


Figure 5-18: ACCOIQ and ACCLIQ of CO_2-EOR using Baker model after 20 days.

Table 5- 9: Simulation data of waterflooding and CO_2-EOR using Baker model after 20 days.

	ACCOIQ(m^3)	ACCLIQ(m^3)	Water Breakthrough	ACCOIQ Difference(m^3)
Waterflooding	1418	2536	Day 14	1704
CO_2-EOR	3122	7418	Day 5	

5.8 Results of Heterogeneous Reservoir

The ACCOIQ and ACCLIQ of waterflooding process in the case where the oil reservoir is heterogeneous are shown in Figure 5-19, and the ACCOIQ and ACCLIQ of CO_2-EOR process are demonstrated in Figure 5-20. The data of ACCOIQ and ACCLIQ etc. of both cases are demonstrated and compared in Table 5-10.

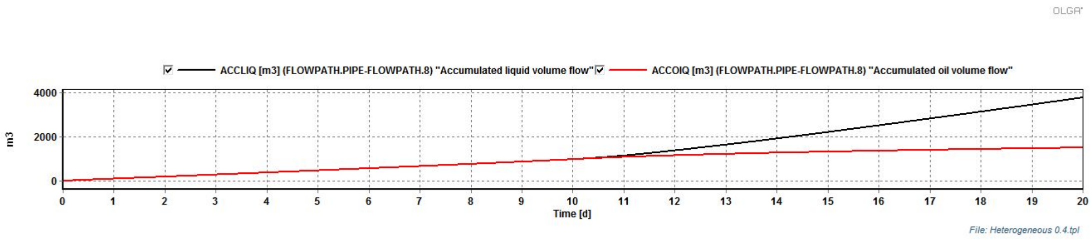


Figure 5-19: ACCOIQ and ACCLIQ of waterflooding in heterogeneous reservoir after 20 days.

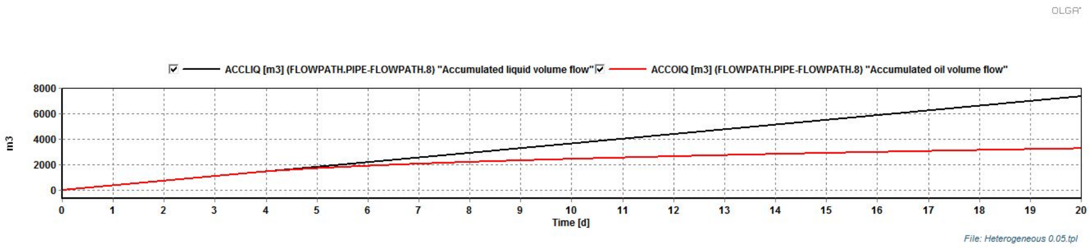


Figure 5-20: ACCOIQ and ACCLIQ of CO_2-EOR in heterogeneous reservoir after 20 days.

Table 5- 10: Simulation data of waterflooding and CO_2-EOR in heterogeneous reservoir after 20 days.

	ACCOIQ(m^3)	ACCLIQ(m^3)	Water Breakthrough	ACCOIQ Difference(m^3)
Waterflooding	1508	3784	Day 11	1768
CO_2-EOR	3276	7374	Day 5	

6 Discussion

6.1 Discussion of Waterflooding and CO_2-EOR

As can be seen from Table 5-1, the accumulated oil volume flow(ACCOIQ) of CO_2-EOR process is 3456 m^3 and the ACCOIQ of waterflooding process is 1479 m^3. Thus the CO_2-EOR process improves oil production by 1977 m^3, and the oil production increase percentage is about 137%, which proves that CO_2-EOR process does have potential in improving oil production.

The water breakthrough of the CO_2-EOR process takes 6 days only, while the water breakthrough time of the waterflooding process is more than 14 days. Therefore the water breakthrough occurs 8 days earlier in the CO_2-EOR process than that in the conventional waterflooding process.

6.2 Discussion of Simulation Scale

As shown from Table 5-2, in the large scale reservoir case, the accumulated oil volume flow(ACCOIQ) of CO_2-EOR process is 72279 m^3 and the ACCOIQ of waterflooding process is 41937 m^3. These data shows that the oil production is improved by 30342 m^3 when applying CO_2-EOR process to a large scale reservoir, which is 72% increase in oil production when compared to that of waterflooding. These results prove again that CO_2-EOR process can improve oil production efficiently. The oil increase in the previous small scale case is about 137%. Therefore, the oil production potential by using CO_2-EOR technology is more obvious in the small scale oil reservoirs than that in large scale reservoirs.

The water breakthrough of the CO_2-EOR process in the large scale reservoir case takes 8 days, while the water breakthrough time of the waterflooding process in the large reservoir is about 9 days. This indicates that the water breakthrough occurs only one day earlier in the CO_2-EOR process than the waterflooding process in the large scale reservoir case. In the small scale reservoir case, the diffenrence of waterflooding process and CO_2-EOR process in the waterbreakthrough time is around 8 days. This also indicates that the CO_2-EOR using in the small scale oil reservoirs brings water breakthrough forward more effectively than when applied to oil reservoirs with relatively large scale.

6.3 Discussion of Simulation Period

As the results in Table 5-3 show, in the longer simulation peroid case(60 days), the accumulated oil volume flow(ACCOIQ) of CO_2-EOR process is 5121 m^3 and the ACCOIQ of waterflooding process is 2287 m^3. These results show that the CO_2-EOR process in a longer simulation peroid case improves the oil production of waterflooding by 2834 m^3, which is around 124% increase in oil production when compared to that of waterflooding. The oil increase in the previous case with 20 days' simulation period is about 137%. The increase of oil production percentage in the longer simulation period case(60 days) is less than that of the case with shorter simulation period(20 days). This is due to the decrease in the total amount of crude oil and reservoir pressure etc. in the reservoir as the production goes on.

The water breakthrough of the CO_2-EOR process in the longer simulation peroid case takes 6 days only, and the water breakthrough time of the waterflooding process in the longer simulation peroid case is about 14 days. So the water breakthrough time of the case with longer simulation period is the same as that in the shorter simulation period case.

6.4 Discussion of Reservoir Pressure

As shown from the results in Table 5-4, in the higher reservoir pressure case, the accumulated oil volume flow(ACCOIQ) of CO_2-EOR process is 6469 m^3 and the ACCOIQ of waterflooding process is 2551 m^3. The CO_2-EOR process in a higher reservoir pressure case improves the oil production by 3918 m^3. The increase in oil production is 153% when compared to that of waterflooding. The oil increase in the previous case with lower pressure is about 137%. Therefore, the increse in oil production by using CO_2-EOR technology when applying to higher reservoir pressure case is more obvious than the oil increase in lower reservoir pressure case.

The water breakthrough of the CO_2-EOR process in the higher reservoir pressure case takes 2 days only, while the water breakthrough time of the waterflooding process in the higher reservoir pressure case is also about 2 days. This means that both the water breakthrough in the CO_2-EOR process and in the waterflooding process in the higher reservoir pressure case are the same. In the lower reservoir pressure case, the diffenrence of waterflooding process and CO_2-EOR process in the waterbreakthrough time is around 8 days. This indicates that when higher pressure is applied to the oil reservoir, the difference in water breakthrough time between CO_2-EOR process and waterflooding process is almost none, and is less than that in the case where lower pressure is applied.

6.5 Discussion of Reservoir Porosity

As can be seen from the results in Table 5-5, in the oil reservoir with porosity equal to 0.1, the accumulated oil volume flow(ACCOIQ) of CO_2-EOR process is 794 m^3, and the ACCOIQ of waterflooding process is 1710 m^3. The CO_2-EOR process in oil reservoir with relatively low porosity improves the oil production by 916 m^3. The increase in oil production is 115% when compared to that of waterflooding. While in the previous case where the porosity is relatively high(0.3), the oil increase percentage by utilizing CO_2-EOR technology is about 137%. These results indicate that the increse in oil production by using CO_2-EOR technology is more obvious when applying to oil reservoirs with high porosity than oil reservoirs with relatively low porosity. This is maybe because of the high porosity is benificial to the crude oil flow in the oil reservoir.

The water breakthrough of the CO_2-EOR process in the reservoir with relatively low porosity(0.1) takes 7 days, while the water breakthrough time of the waterflooding process in the reservoir with the same porostiy is about 8 days. This shows that the water breakthrough occurs 1 day earlier in the CO_2-EOR process than the waterflooding process in the reservoir with low porosity. In the reservoir case with relatively large porostiy, the diffenrence of waterflooding process and CO_2-EOR process in the waterbreakthrough time is about 8 days. This also indicates that the CO_2-EOR brings water breakthrough forward more efficiently in the high porosity oil reservoirs than in the relatively low porosity oil reservoirs.

6.6 Discussion of Reservoir Permeability

As the results show in Table 5-6, in the oil reservoir with permeability equal to 4000 mD, the accumulated oil volume flow(ACCOIQ) of CO_2-EOR process is 3385m^3 and the ACCOIQ of waterflooding process is 1321 m^3. These data mean that the CO_2-EOR process in oil reservoir with relatively low porosity improves the oil production by 2064 m^3, which is 156% increase in oil production when compared to that of waterflooding. While in the previous case with permeability equal to 5000 mD, the oil increase percentage by utilizing CO_2-EOR technology is about 137%. These results show that the increse in oil production in the oil reservoir with permeability equal to 4000 mD is more obvious than oil reservoirs with relatively low permeability.

The water breakthrough of the CO_2-EOR process in the reservoir with permeability equal to 4000 mD takes 4 days only, while the water breakthrough time of the waterflooding process in the reservoir is about 14 days. This means that the water breakthrough occurs 10 day earlier in the CO_2-EOR process than the waterflooding process in the reservoir with relatively low permeability(4000 mD). In the reservoir case with relatively high permeability(4000 mD), the diffenrence of waterflooding process and CO_2-EOR process in the waterbreakthrough time is about 8 days. This shows that the CO_2-EOR brings water breakthrough forward more efficiently in oil reservoirs with relatively low permeability than oil reservoirs with relatively high permeability.

6.7 Discussion of Relative Permeability Model

6.7.1 Modified Brooks-Corey Relations and Stone II model

As shown from the results in Table 5-7, the accumulated oil volume flow(ACCOIQ) of CO_2-EOR process where modified Brooks-Corey relations and Stone II model are used is 3518 m^3 and the ACCOIQ of waterflooding process 1516 m^3. These data indicate that the CO_2-EOR process where modified Brooks-Corey relations and Stone II model are used improves the oil production by 2002 m^3, which is 132% increase in oil production when compared to that of waterflooding. The oil increase in the previous case where Corey model and Stone II model are used is about 137%. Therefore, the increse in oil production by using CO_2-EOR technology when applying modified Brooks-Corey relations and Stone II model is a little bit less than that in the case where Corey Model and Stone II model are used.

In the case where modified Brooks-Corey relations and Stone II model are used, the water breakthrough of the CO_2-EOR process takes 6 days only, while the water breakthrough time of the waterflooding process is about 15 days. This indicates that the water breakthrough occurs 9 days earlier in the CO_2-EOR process than the waterflooding process. In the case where Corey Model and Stone II model are used , the diffenrence of waterflooding process and CO_2-EOR process in the water breakthrough time is around 8 days. This shows that the CO_2-EOR in the case where modified Brooks-Corey relations and Stone II model are used brings water breakthrough forward a little bit more obviously than the case where Corey model and Stone II model are applied.

6.7.2 Chierici Model and Stone II Model

As shown from the results in Table 5-8, the accumulated oil volume flow(ACCOIQ) of C_2-EOR process where Chierici model and Stone II model are used is 3605 m^3 and the ACCOIQ of waterflooding process is 1514 m^3. These data show that the CO_2-EOR process where Chierici model and Stone II model are used improves the oil production by 2091 m^3, which is 138% increase in oil production when compared to that of waterflooding. The oil increase in the previous case where Corey model and Stone II model are used is about 137%. Therefore, the increse in oil production by using Chierici model and Stone II model to simulate CO_2-EOR technology is almost the same as that in the case where Corey model and Stone II model are utilized.

The water breakthrough of the CO_2-EOR process in the case where Chierici model and Stone II model are used takes 6 days, while the water breakthrough time of the waterflooding process in the case where Chierici model and Stone II model are used is about 15 days. This means that the water breakthrough occurs 9 days earlier in the CO_2-EOR process than the waterflooding process. In the case where Corey Model and Stone II model are used , the diffenrence of waterflooding process and CO_2-EOR process in the waterbreakthrough time is around 8 days. These results indicate that the difference in water breakthrough time between waterflooding process and CO_2-EOR process in the case using Chierici model and Stone II model is almost the same as that in the case where Corey model and Stone II model are utilized.

6.7.3 Baker Model

As shown from the results in Table 5-9, the accumulated oil volume flow(ACCOIQ) of CO_2-EOR process where Baker model are used is 3122 m^3 and the ACCOIQ of waterflooding process where Chierici model and Stone II model are used is 1418 m^3. These data shows that the CO_2-EOR process where Chierici model and Stone II model are used improves the oil production by 1704 m^3, which is 120% increase in oil production when compared to that of waterflooding. The oil increase in the previous case where Corey model and Stone II model are used is about 137%. Therefore, the increse in oil production by using Baker model to simulate CO_2-EOR technology is not as much as that in the case where Corey model and Stone II model are utilized.

In the case where Baker model are used, the water breakthrough of the CO_2-EOR process takes 5 days, while the water breakthrough time of the waterflooding process is about 14 days. This means that the water breakthrough occurs 9 days earlier in the CO_2-EOR process than the waterflooding process. In the case where Corey Model and Stone II model are used , the diffenrence of waterflooding process and CO_2-EOR process in the waterbreakthrough time is around 8 days. This also shows that the difference in water breakthrough time between waterflooding process and CO_2-EOR process in the case using Baker model is more obvious than that in the case where Corey model and Stone II model are utilized.

6.8 Discussion of Heterogeneous Reservoir

As can be seen from the results in Table 5-10, in the heterogeneous oil reservoir, the accumulated oil volume flow(ACCOIQ) of CO_2-EOR process is 3276 m^3, and the ACCOIQ of waterflooding process is 1508 m^3. So the CO_2-EOR process in heterogeneous oil reservoir improves the oil production by 916 m^3. The increase in oil production is 117% when compared to that of waterflooding. While in the previous case where the oil reservoir is homogenious, the oil increase percentage by utilizing CO_2-EOR technology is about 137%. These results indicate that the oil production potential by using CO_2-EOR technology in homogenious oil reservoir is more than that in heterogeneous oil reservoir.

The water breakthrough of the CO_2-EOR process in heterogeneous oil reservoir takes 5 days, while the water breakthrough time of the waterflooding process is about 11 days. This shows that the water breakthrough takes place 6 day earlier in the CO_2-EOR process than the waterflooding process in the heterogeneous oil reservoir. In the homogenious reservoir case, the diffenrence of waterflooding process and CO_2-EOR process in the waterbreakthrough time is about 8 days. This indicates that the CO_2-EOR brings water breakthrough forward more efficiently in the homogenious oil reservoirs than in the heterogeneous oil reservoirs.

7 Conclusion

The simulation results indicate that CO_2-EOR technology, one type of tertiary oil recovery methods, can improve the oil production after waterflooding process which is one common secondary recovery method. And the water breakthrough time is also brought forward after applying CO_2-EOR process when compared to that of waterflooding process. The simulation results also show that the oil production potential by applying CO_2-EOR technology in an oil reservoir with smaller scale, higher reservoir pressure, higher reservoir porosity, and lower reservoir permeability is more than that in an oil reservoir with larger scale, lower reservoir pressure, lower reservoir porostiy, and higher reservoir permeability.

The difference in waterbreakthrough time between waterflooding process and CO_2-EOR process is more obvious in the oil reservoirs with smaller scale, lower reservoir pressure, higher reservoir porosity, and lower reservoir permeability than the oil reservoirs with larger scale, higher reservoir pressure, lower reservoir porosity, and higher reservoir permeability. In the case with longer simulation period, the percentage of increase in oil production by using CO_2-EOR technology is less than that in the case with shorter simulation period.

The simulation results in the relative permeabiliity model part of cases using different relative permeability models are different as well. The simulation results show that the percentage of oil increace when using modified Brooks-Corey relations and Stone II model to simulate CO_2-EOR process is less than that when using Corey model and Stone II model. However, the difference in water breakthrough time between waterflooding process and CO_2-EOR process is almost the same. The oil production potential and difference in water breakthrough time after appling CO_2-EOR technology when using Corey model and Stone II model are almost the same as that in the case using Chierici model and Stone II model. The simulation results also indicate that the percentage of oil production increace when using Baker model to simulate CO_2-EOR process is less than that when using Corey model and Stone II model. However, the difference in waterbreakthrough time between waterflooding process and CO_2-EOR process is a little bit more in the case when using Baker model than that in the case where Corey model and Stone II model are utilized.

Reservoir heterogeneity affects the performance of CO_2-EOR technology as wll. The oil production potential by utilizing CO_2-EOR technology after waterflooding in the homogenious oil reservoirs is more obvious than that in the heterogeneous oil reservoirs. The difference in water breakthrough time between waterflooding process and CO_2-EOR process in the homogenious oil reservoirs is less than that in the heterogeneous oil reservoirs, which indicates that the CO_2-EOR technology in the homogenious oil reservoirs brings forward the water breakthrough more obviously.

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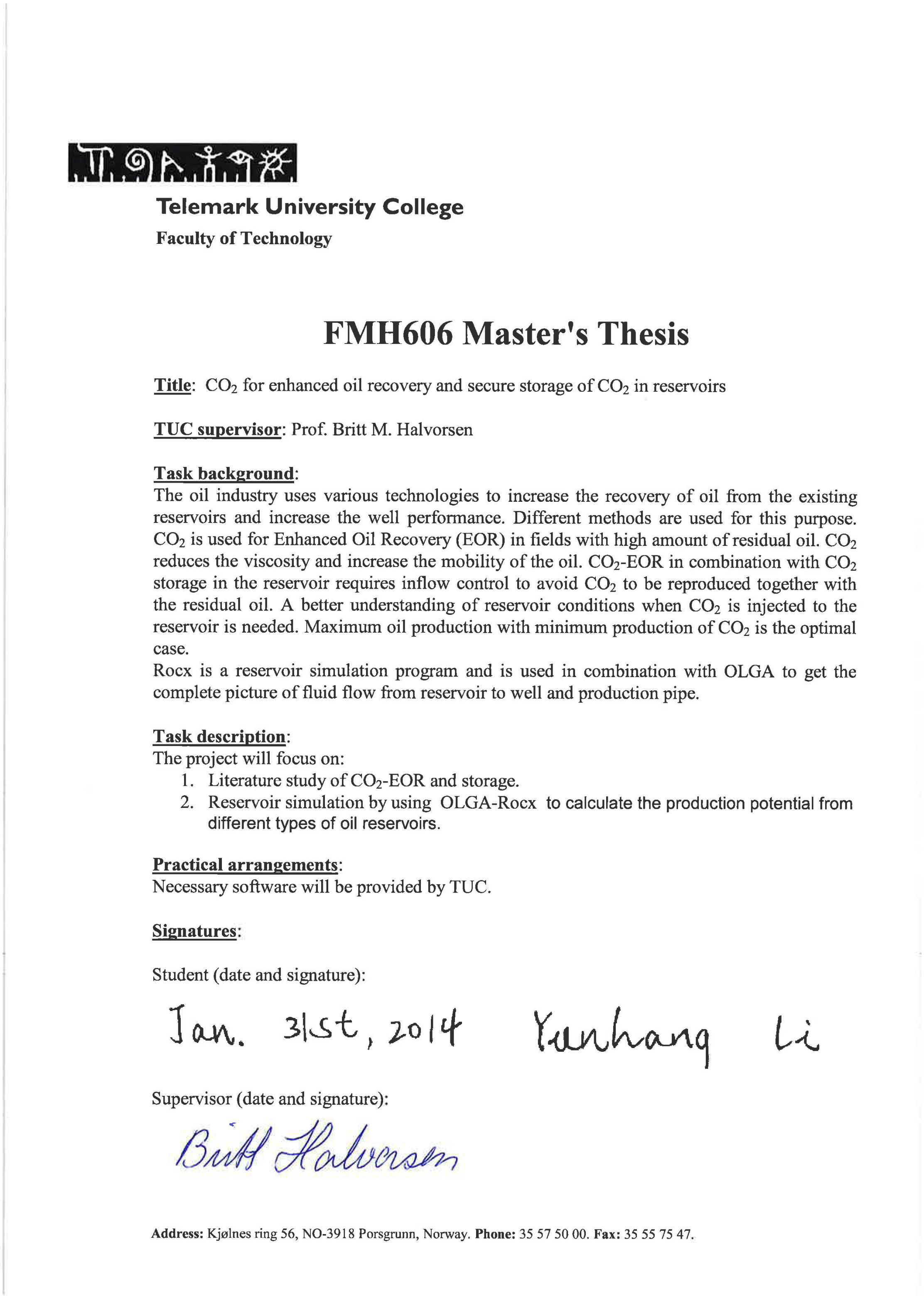
Appendices

Appendix 1: Task Description



Telemark University College
Faculty of Technology

FMH606 Master's Thesis

Title: CO_2 for enhanced oil recovery and secure storage of CO_2 in reservoirs

TUC supervisor: Prof. Britt M. Halvorsen

Task background:
The oil industry uses various technologies to increase the recovery of oil from the existing reservoirs and increase the well performance. Different methods are used for this purpose. CO_2 is used for Enhanced Oil Recovery (EOR) in fields with high amount of residual oil. CO_2 reduces the viscosity and increase the mobility of the oil. CO_2-EOR in combination with CO_2 storage in the reservoir requires inflow control to avoid CO_2 to be reproduced together with the residual oil. A better understanding of reservoir conditions when CO_2 is injected to the reservoir is needed. Maximum oil production with minimum production of CO_2 is the optimal case.
Rocx is a reservoir simulation program and is used in combination with OLGA to get the complete picture of fluid flow from reservoir to well and production pipe.

Task description:
The project will focus on:

1. Literature study of CO_2-EOR and storage.
2. Reservoir simulation by using OLGA-Rocx to calculate the production potential from different types of oil reservoirs.

Practical arrangements:
Necessary software will be provided by TUC.

Signatures:

Student (date and signature):

Jan. 31st, 2014 Yunhang Li

Supervisor (date and signature):

Britt Halvorsen

Address: Kjølnes ring 56, NO-3918 Porsgrunn, Norway. **Phone:** 35 57 50 00. **Fax:** 35 55 75 47.

Appendix 2: Input Data of Relative Permeabilities using Different Relative Permeability Models in the Simulation

A. Corey Model & Stone II Model

Residual Oil Saturation=0.4, Connate Water Saturation=0.4, Residual Gas Saturation=0.2

Corey Model for K_{rw} and K_{rg}

K_{rw}:

0	0
0.4	0
0.45	0.0625
0.5	0.25
0.55	0.5625
0.6	1
1	1

K_{rg}:

0	0
0.2	0
0.25	0.015625
0.3	0.0625
0.35	0.14063
0.4	0.25
0.45	0.39063
0.5	0.5625
0.55	0.76563
0.6	1
1	1

Stone II Model for K_{row} and K_{rog}

K_{row}:

0	1
0.4	1
0.45	0.5625
0.5	0.25
0.55	0.0625
0.6	0
1	0

K_{rog}:

0	1
0.05	0.5625
0.1	0.25
0.15	0.0625
0.2	0
1	0

Residual Oil Saturation=0.05, Connate Water Saturation=0.4, Residual Gas Saturation=0.2

Corey Model for K_{rw} and K_{rg}

K_{rw}:

0	0
0.4	0
0.45	0.0082645
0.5	0.033058
0.55	0.07438

0.6	0.13223
0.65	0.20661
0.7	0.29752
0.75	0.40496
0.8	0.52893
0.85	0.66942
0.9	0.82645
0.95	1
1	1

K_{rg}:

0	0
0.2	0
0.25	0.0044444
0.3	0.017778
0.35	0.04
0.4	0.071111
0.45	0.11111
0.5	0.16
0.55	0.21778
0.6	0.28444
0.65	0.36
0.7	0.44444
0.75	0.53778
0.8	0.64
0.85	0.75111
0.9	0.87111

0.95	1
1	1

Stone II Model for K_{row} and K_{rog}

K_{row}:

0	1
0.4	1
0.45	0.82645
0.5	0.66942
0.55	0.52893
0.6	0.40496
0.65	0.29752
0.7	0.20661
0.75	0.13223
0.8	0.07438
0.85	0.033058
0.9	0.0082645
0.95	0
1	0

K_{rog}:

0	1
0.05	0.82645
0.1	0.66942
0.15	0.52893
0.2	0.40496
0.25	0.29752
0.3	0.20661

0.35	0.13223
0.4	0.07438
0.45	0.033058
0.5	0.0082645
0.55	0
1	0

B. Modified Brooks-Corey Relations & Stone II Model

Residual Oil Saturation=0.4, Connate Water Saturation=0.4, Residual Gas Saturation=0.2

Modified Brooks-Corey Relations for K_{rw} and K_{rg}

K_{rw}:

0	0
0.4	0
0.45	0.037
0.5	0.150
0.55	0.337
0.6	1
1	1

K_{rg}:

0	0
0.2	0
0.25	0.037
0.3	0.156
0.35	0.338
0.4	0.679

0.45	0.937
0.5	0.985
0.55	0.996
0.6	1
1	1

Stone II Model for K_{row} and K_{rog}

K_{row}:

0	1
0.4	1
0.45	0.5625
0.5	0.25
0.55	0.0625
0.6	0
1	0

K_{rog}:

0	1
0.05	0.5625
0.1	0.25
0.15	0.0625
0.2	0
1	0

Residual Oil Saturation=0.05, Connate Water Saturation=0.4, Residual Gas Saturation=0.2

Modified Corey Model for K_{rw} and K_{rg}

K_{row}:

0	0
0.4	0
0.45	0.0074
0.5	0.0296
0.55	0.0666
0.6	0.1185
0.65	0.1852
0.7	0.2667
0.75	0.3631
0.8	0.4741
0.85	0.6
0.9	0.7407
0.95	1
1	1

K_{rg}:

0	0
0.2	0
0.25	0.0074
0.3	0.0296
0.35	0.0667
0.4	0.1185
0.45	0.1852
0.5	0.2667
0.55	0.363
0.6	0.4741
0.65	0.6

0.7	0.7407
0.75	0.8963
0.8	0.9325
0.85	0.9863
0.9	0.9987
0.95	1
1	1

Stone II Model for K_{row} and K_{rog}

K_{row}:

0	1
0.4	1
0.45	0.82645
0.5	0.66942
0.55	0.52893
0.6	0.40496
0.65	0.29752
0.7	0.20661
0.75	0.13223
0.8	0.07438
0.85	0.033058
0.9	0.0082645
0.95	0
1	0

K_{rog}:

0	1

0.05	0.82645
0.1	0.66942
0.15	0.52893
0.2	0.40496
0.25	0.29752
0.3	0.20661
0.35	0.13223
0.4	0.07438
0.45	0.033058
0.5	0.0082645
0.55	0
1	0

C. Chierici Model

Residual Oil Saturation=0.4, Connate Water Saturation=0.4, Residual Gas Saturation=0.2

Chierici Model for K_{rw} and K_{rg}

K_{rw}:

0	0
0.4	0
0.45	0.0181
0.5	0.1442
0.55	0.4867
0.6	1
1	1

K_{rg}:

0	0
0.2	0
0.25	0.0023
0.3	0.018
0.35	0.0608
0.4	0.1442
0.45	0.2817
0.5	0.4867
0.55	0.996
0.6	1
1	1

Stone II Model for K_{row} and K_{rog}

K_{row}:

0	1
0.4	1
0.45	0.5625
0.5	0.25
0.55	0.0625
0.6	0
1	0

K_{rog}:

0	1
0.05	0.5625
0.1	0.25
0.15	0.0625
0.2	0

1	0

Residual Oil Saturation=0.05, Connate Water Saturation=0.4, Residual Gas Saturation=0.2

Chierici Model for K_{rw} and K_{rg}

K_{rw}:

0	0
0.4	0
0.45	0.0009
0.5	0.0069
0.55	0.0234
0.6	0.0555
0.65	0.1852
0.7	0.1872
0.75	0.2973
0.8	0.4438
0.85	0.6319
0.9	0.8668
0.95	1
1	1

K_{rg}:

0	0
0.2	0
0.25	0.0004
0.3	0.0027
0.35	0.0092

0.4	0.0218
0.45	0.0427
0.5	0.0738
0.55	0.1173
0.6	0.175
0.65	0.2492
0.7	0.3418
0.75	0.455
0.8	0.5907
0.85	0.751
0.9	0.938
0.95	1
1	1

Stone II Model for K_{row} and K_{rog}

K_{row}:

0	1
0.4	1
0.45	0.82645
0.5	0.66942
0.55	0.52893
0.6	0.40496
0.65	0.29752
0.7	0.20661
0.75	0.13223
0.8	0.07438

0. 85	0. 033058
0. 9	0. 0082645
0. 95	0
1	0

K_{rog}:

0	1
0. 05	0. 82645
0. 1	0. 66942
0. 15	0. 52893
0. 2	0. 40496
0. 25	0. 29752
0. 3	0. 20661
0. 35	0. 13223
0. 4	0. 07438
0. 45	0. 033058
0. 5	0. 0082645
0. 55	0
1	0

D. Baker Model

Residual Oil Saturation=0.4, Connate Water Saturation=0.4, Residual Gas Saturation=0.2

K_{rw}:

Sw	krw, wog
0	0
0. 4	0

0.45	0.1958
0.5	0.4612
0.55	0.8891
0.6	1
1	1

K_{rg}:

Sg	krg,wog
0	0
0.2	0
0.25	0.0226
0.3	0.0852
0.35	0.1821
0.4	0.3546
0.45	0.4531
0.5	0.6213
0.55	0.8415
0.6	1
1	1

K_{ro}:

So	kro,wog
0	0
0.4	0
0.45	0.1192
0.5	0.2834
0.55	0.3174
0.6	0.5147

0.65	0.7871
0.7	0.8148
0.75	0.9524
0.8	1
1	1

Residual Oil Saturation=0.05, Connate Water Saturation=0.4, Residual Gas Saturation=0.2

K_{rw}:

Sw	Krw, wog
0	0
0.4	0
0.45	0.0145
0.5	0.0532
0.55	0.1564
0.6	0.2156
0.65	0.3564
0.7	0.4122
0.75	0.5124
0.8	0.6316
0.85	0.7416
0.9	0.9451
0.95	1
1	1

K_{rg}:

0	0
0.2	0

0.25	0.0091
0.3	0.0245
0.35	0.0515
0.4	0.0845
0.45	0.2147
0.5	0.2457
0.55	0.3454
0.6	0.3945
0.65	0.4713
0.7	0.5447
0.75	0.6134
0.8	0.7277
0.85	0.8412
0.9	0.9175
0.95	1
1	1

K_{ro}:

0	0
0.05	0
0.1	0.0241
0.15	0.1164
0.2	0.2382
0.25	0.2784
0.3	0.3747
0.35	0.4687
0.4	0.5251

0.45	0.6841
0.5	0.7234
0.55	0.8826
0.6	1
1	1