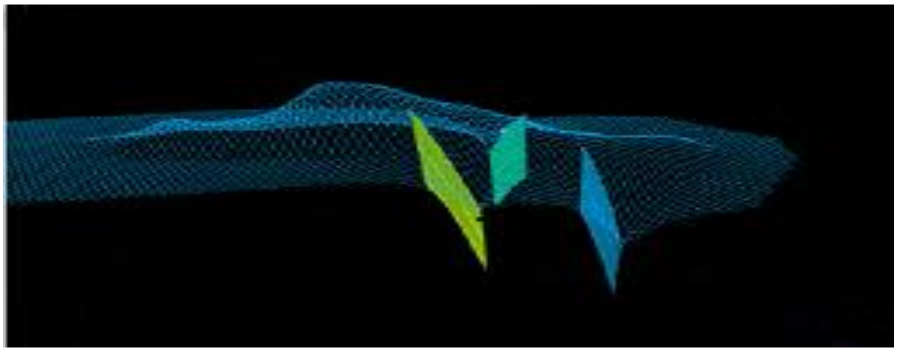

EOR Methods

Best Method for Enhanced Oil Recovery from Sarvak Reservoir and Analyse Sensitive Parameters

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Thesis to obtain the Master of Science Degree in

Petroleum Engineering

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Abstract

By increasing in the use of nonrenewable energy and decreasing in discovering hydrocarbon reservoirs, in near future the world will encounter with a new challenge in the field of energy, so increase in recovery factor of the existing oil reservoirs is necessary after the primary production. In one hand the existence of untouched heavy oil reservoirs in Iran and lack of producing from them and maturity of light oil reservoirs to 2^{nd} and 3^{rd} stage of their production age in other hand make the development and production of these heavy oil reservoirs necessary in Iran. The goal of this study is to survey common methods of producing oil reservoirs and emphasizing the advantages and limitations of these methods' appliance in heavy oil reservoirs of Iran especially in Kuh-e-Mund.

There are a lot of EOR methods and for choosing the best method we should consider factors such as the reservoir fluid and rock characteristics, availability of injection material, available equipments and other items. One way to choose an optimized method is the comparison of reservoirs' parameters in successful EOR projects with the considered reservoir. However, it should be consider that each reservoir has its especial characteristics and we cannot give certain idea about it. In the first section of this thesis, the processes of gas injection, water injection, chemical methods, water alternative gas injection, microbial ways, open recovery, condensed recovery, the set of thermal ways and other ways and new technologies and an introduction about oil recovery in fractured reservoirs are studied. The most common way for recovery of heavy oil reservoirs' is thermal ways which have the most usage in the recovery of the world's heavy oil and between these; steam injection in different ways with the most amount of oil production has terrific importance. Other thermal ways such as thermal combustion and electromagnetic and electric heat in practice, some studies and experiments have been doing in reservoirs. Now ways especially in heavy oil reservoirs in order to improve and increase oil recovery have been studied, for example we can point to horizontal wells technology. The gained results show that the best way for recovery heavy oil of Sarvak reservoir of Kuh-e-Mund is thermal way and especially steam injection (under optimum conditions of quality and steam nature and the model of production and injection wells paths). Steam modeling by activating gravity drainage drive process by using steam injection (SAGD) which is designed in a reservoir model in Sarvak reservoir of Kuh-e-Mund Mountain has been successful.

Keywords

EOR, SAGD, SARVAK reservoir, Kuh-e-Mund

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List of Abbreviation

Abbreviation	Stand for
API	American Petroleum Institute
ASP	Alkaline compound, Surfactant and Polymer
CHOPS	Cold Heavy Oil Production with Sand
CMG	CamputerModelling Group
CO2	Carbon Dioxide
CSS	Cyclic Steam Simulation
ES-SAGD	Expanding Solvent Steam Assisted Gravity Drainage
EOR	Enhanced Oil Recovery
GOR	Gas Oil Ratio
HCPV	Hydrocarbon Pore Volume
IFT	Interfacial Tension
MEOR	Microbial Enhanced oil Recovery
MMP	Minimum Miscibility Pressure
ISC	In-situ combustion
Md	MilliDarcy
PEDEC	Petroleum Engineering and Development Company
RF	Recovey Factor
SAGD	Steam Assisted Gravity Drainage
SP	Surfactant Polymer
SOR	Steam Oil Ratio
STOIIP	Stock tank oil initially in place
Vapex	Vapor Assisted Petroleum Extraction
PV	Pore volume
WASP	Water Alternative Steam Process

Chapter one

Introduction

1-1- Different kinds of reservoirs recovery

The first issues in definitions are about the way of enhanced oil recovery in the last of 19th century, and after sometimes and technology improvement, these definitions have been more universal. One of the theories about the definition of enhanced oil recovery ways which has a long time history classifies different kinds of recovery as follows:

1- Primary recovery
2- Secondary recovery
3- Tertiary recovery

Primary recovery in this classification is the only use of reservoir natural energy and second recovery is also each recovery which is done after the primary recovery in order to maintain reservoir pressure which usually includes water injection or gas injection.

Each mechanism which is done after the secondary recovery in order to produce the retained oil is called the tertiary recovery.

Today, advanced enhanced oil recovery methods are considered as the replace of 2nd and 3rd stages, based on the idea of many scientists. This classification is as follow:

1- Primary recovery : which is called as the use of all natural mechanisms in production from the reservoir and mechanisms which are formed in order to maintain the pressure in the reservoir;
2- Enhanced oil recovery in advanced ways (EOR): which are all the ways that have been done after primary recovery in order to production from the reservoirs?

1-2- Recovery parameters screening

The use of enhanced oil recovery, by considering oil production reduction, is necessary more than every other time. So choosing the best way to increase oil recovery has more important role. The screening of enhanced oil recovery parameters involves all of the enhanced oil recovery methods. In these methods, the information from all around the world projects has been gathered and the reservoir characteristics and oil properties which are involved in this successful action will be studied and surveyed.

Oil Recovery Factor in finished and / or running projects will be studied in this method and the results will be drawing such as curves. The goal of screening the recovery criteria at first is related to the results that are gained from the field and secondly recovery mechanisms. In this status, the way of using each recovery mechanism is studied in summary and the relation between them is described. Although the selection of injected material has been studied for a long time, oil engineers should still be careful in selecting the method which has the best oil production from the reservoir by considering the costs.

In recent years, computer had an important role in improving the use of recovery methods, although the value of using the computer applications depends on the accuracy of input information.

Here, our goal is to prepare a rational confine from the real parameters which can be used in field management by advancing new computer software.

In table 1-1 recovery parameters screening is shown shortly for common methods of EOR. The experiences have shown that the best methods in considered reservoir are those which have economic justification about the rate of their recovery. The best methods which have the best recovery factor in reasonable cost are 2 main methods of water injection (including thermal such as steam or chemical) or one of the low cost gases.

For some methods (such as polymer) the possibility of technical success is very much in detection but the success is low in economical point of view. If the oil price increases we can hope that most of the methods will be profitable. One of the ways of studying the enhanced oil recovery methods is to study them based on depth changes and API degree of oil. For this purpose, a great number of the world enhanced oil recovery projects are shown in figure 1-1, as it is clear from the figure, the process of method selection can changes from one project to another one by considering the depth of reservoirs and API degree of the heavy oil.

	Oil properties			Reservoir characteristic					
EOR method	Gravity (API)	Viscosity (cp)	composition	Oil saturation	Formation type	Net thickness (ft)	Average Permeability (md)	Depth (ft)	Temparature (f)
Gas Injection Method (miscible)									
Nitrogen And Flue Gas	>23-41	<0.4-0.2	High % of C1 to C7	>40-75	Sandstone Or Carbonate	Thin unless dipping	NC	>6000	NC
Hydrocarbon	>23-41	<3-0.5	High % of C2 to C7	>30-80	Sandstone Or Carbonate	Thin unless dipping	NC	>4000	NC
CO2	>22-36	<10-1.5	High % of C5 to C12	>20-55	Sandstone Or Carbonate	Wide range	NC	>2500	NC
Immiscible Gases	>12	<600	- NC	>35-70		Good vertical K	NC	>1800	NC
(Enhanced) waterflooding									
Polymer, Alkaline Flooding	>20-35	<35-13	Light Some organic Acids for Alkalina	>35-53	Sandstone Preferred	NC	>10-450	>9000 To 3250	>200-80
Polymer flooding	>15	<150 >10	NC	>50-80	Sandstone Preferred	NC	>10-800	<9000	>200-140
Thermal/Mechanical									
Combustion	>10-16	<5000 to 1200	Some asphaltic Components	>50-72	High porosity sand/sandston	>10	>50	>11500 To 3500	>100-135
Steam	>8-13	<200000 to 4700	NC	>40-56	High porosity sand/sandston	>20	>200-2540	>4500 to 1500	NC
Surface mining	>7-11	Zero Cold flow	NC	>	Tar sand	>10	NC	NC	NC

Table 1-1- recovery parameters for enhanced oil recovery methods (NIOC)

The amount of production oil in each method is shown generally in figure 1-2. The continue of oil production by using thermal methods (specially steam injection) in this figure is very clear, it should be noted that the greatest project of enhanced oil recovery in the world is steam injection that was running in Duri field in Indonesia and produces more than 245000 barrels daily.

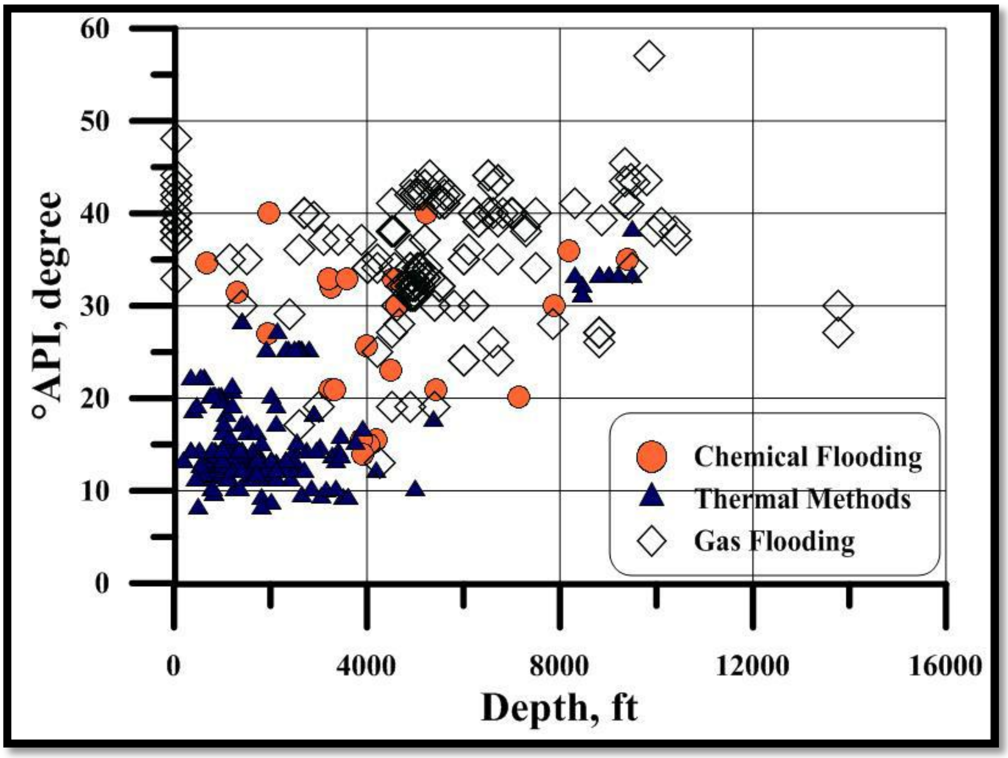


Figure 1-1- the study of enhanced oil recovery project, by considering depth and API (Halliburton)

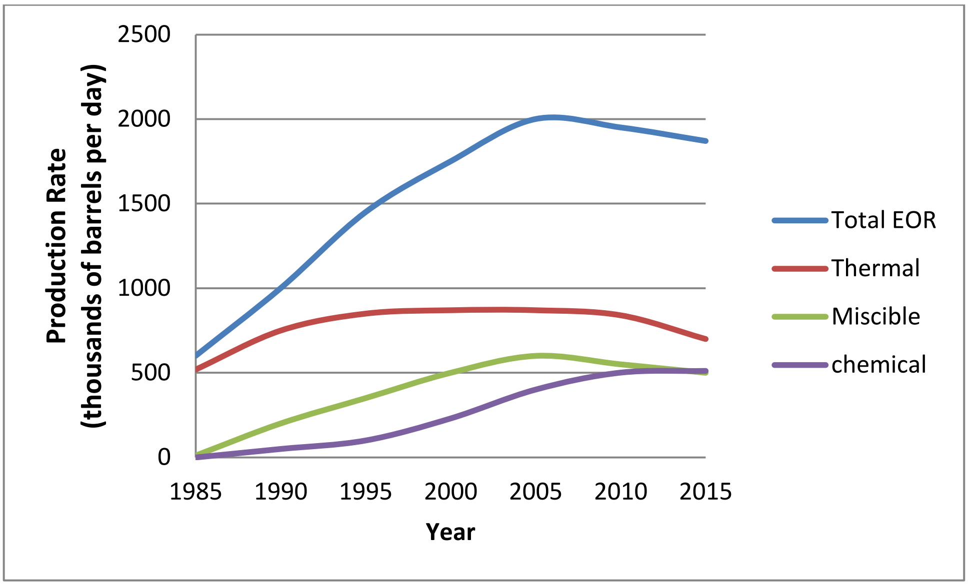


Figure 1-2- oil recovery rate in each method - National Iranian Oil company (NIOC)

In this thesis, by considering available information it is tried to specify the parameters of all methods, but it should be attended that each reservoir in the world has its especial characteristics and we cannot give a certain idea about it.

Chapter 2

Primary methods of production from the reservoir

2-1- natural mechanisms

During primary recovery the natural energy of the reservoir is used to transport hydrocarbons towards and out of the production wells. There are several different energy sources, and each gives rise to a drive mechanism. Early in the history of a reservoir the drive mechanism will not be known. It is determined by analysis of production data (reservoir pressure and fluid production ratios). The earliest possible determination of the drive mechanism is a primary goal in the early life of the reservoir, as its knowledge can greatly improve the management and recovery of reserves from the reservoir in its middle and later life. There are five important drive mechanisms (or combinations). These are:

1. Water drive
2. Gas cap drive
3. Solution gas drive
4. Gravity drainage
5. reservoir compaction
6. Combination or mixed drive

2-1-1- Water drive mechanism

Some reservoirs have communication with a water zone (aquifer) underneath. When reservoir pressure drops due to production, the compressed water in an aquifer expands into a reservoir and it helps pressure maintenance. This mechanism is called “water drive”. Water drive mechanism will be effective if an aquifer contacting reservoir is very large because water compressibility is very low. For example, an anticline structure with extensive water zone (aquifer) will have the most advantage from the use of a water drive mechanism. Water drive mechanism is a very good drive and reservoirs can produce oil over 50% recover factors in many cases.

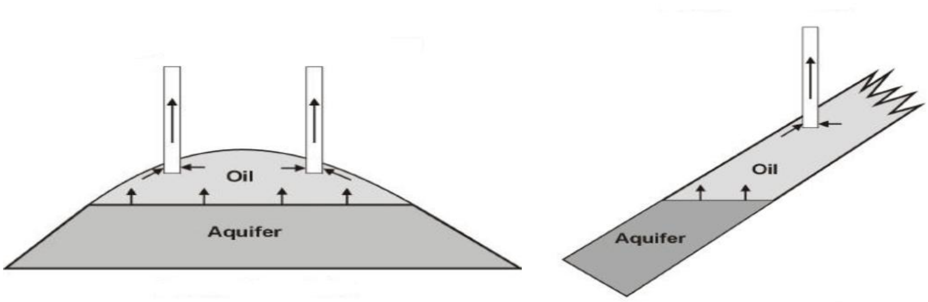


Figure 2-1- Bottom water Drive - Figure 2-2- Edge water Drive
(wiki.aapg.org/drive_mechanisms_and_recovery)

2-1-2- Gas cap drive mechanism

In hydrocarbon reservoirs with gas cap, the gas cap expansion applies a force to the oil column after production and reduction of reservoir pressure. This pressure is the main production mechanism which is called drive by gas cap. During production from this kind of reservoirs, reservoir pressure and oil production reduce with constant rate but the ratio of gas to oil (GOR) increases. This mechanism with recovery factor about 25% to 50%, in sand reservoirs has a weaker role than water drive mechanism.

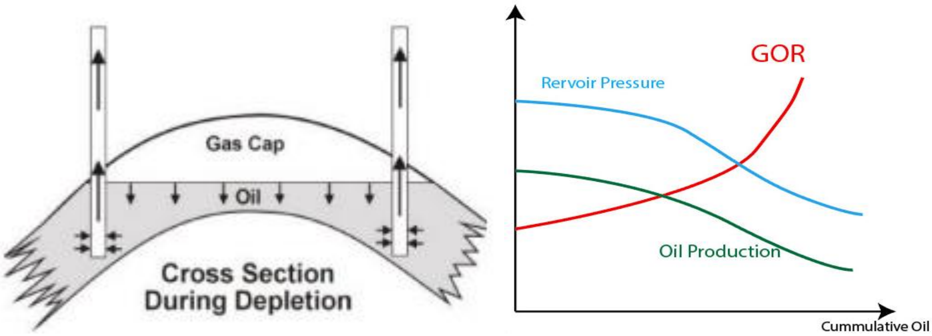


Figure 2-3- Gas cap Drive- (wiki.aapg.org/drive_mechanisms_and_recovery)

2-1-3- Solution gas drive

When reservoir pressure reaches a bubble point, oil becomes saturated and free gas will present in a reservoir. The expansion of gas is a main energy to produce reservoir fluid for the solution gas drive. At the beginning, the produced gas oil ratio will be slightly decline because free gas in a reservoir cannot move until it goes over the critical gas saturation. Then gas will begin to flow into a well. In some cases, where vertical permeability is high, gas may migrate up and become a secondary gas cap, which helps oil production. Typical recovery factor from the solution gas drive reservoir is about 5 – 30%.

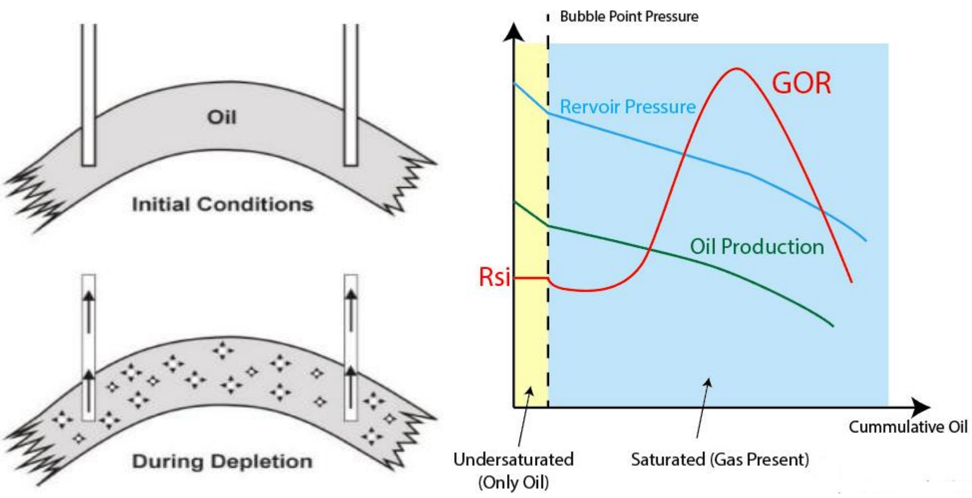


Figure 2-4- Solution gas Drive mechanism- (wiki.aapg.org/drive_mechanisms_and_recovery)

2-1-4- Gravity drainage drive

The density differences between oil and gas and water result in their natural segregation in the reservoir. This process can be used as a drive mechanism, but is relatively weak, and in practice is only used in combination with other drive mechanisms. Figure 2-5 shows production by gravity drainage. However, it is extremely efficient over long periods and can give rise to extremely high recoveries. Consequently, it is often used in addition to the other drive mechanisms.

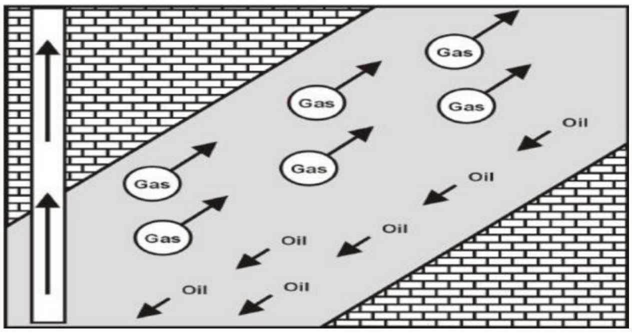


Figure 2-5: gravity drainage drive mechanism (wiki.aapg.org/drive_mechanisms_and_recovery)

2-1-5- Drive mechanism affected by reservoir compaction

The oil within the reservoir pore space is compressed by the weight of overlying sediments and the pressure of the fluids they contain. If fluid is withdrawn from the reservoir, then it is possible that the pressure depletion in the pore space attributable to the production of fluid can be compensated for by the overlying sediments compacting lower sediments such as those of the reservoir production zone. The impact of this is to create a reduction in porosity and thus a potential compression effect.

2-1-6- Combination drive mechanism

Most of the fields work with more than one mechanism. The most common combination of drives is solved gas drive (with or without gas free cap) with a weak water drive. When the free gas cap is combined with active water drive, combination drive has more efficiency.

Producing through theses mechanisms has been applied well in internal areas of northern America, Northern sea, Northern Africa and Indonesia.

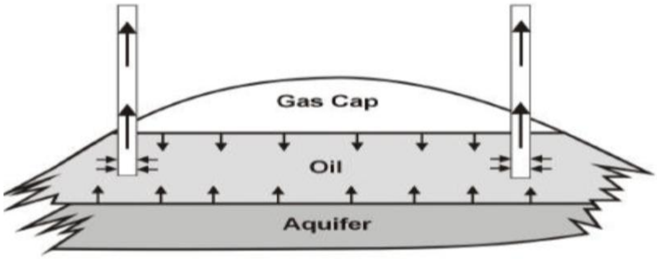


Figure 2-6-: combination drive (wiki.aapg.org/drive_mechanisms_and_recovery)

The reservoir pressure and GOR trends for each of the main (first) three drive mechanisms is shown as Figures 2-7 .Note particularly that water drive maintains has the reservoir pressure much higher than the gas drives, and has a uniformly low GOR.

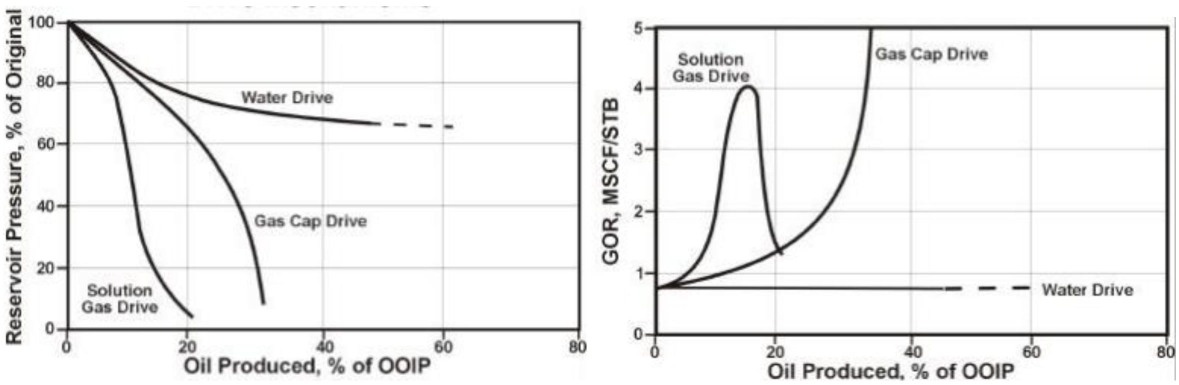


Figure 2-7-: Reservoir pressure and GOR trends for first three drive mechanism (NIOC)

2-2- Reservoir pressure maintenance mechanism

The second stage of Hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbon toward the wellbore. Two techniques are commonly used:

1. Water Injection
2. Gas Injection

2-2-1- Water injection in order to maintain pressure

In small oil fields which are shown in figure 2-8, pressure preserving by water injection in water layers at edge of reservoir is efficient, But in great field, injection should be done all over the water layer (figure 2-8), in this status water zones can be formed in reservoir and advancing of these zones in oil reservoir, help pressure increase and oil drive toward production wells.

Water injection has several advantages such as frequency in the ground surface, low price, easy to inject and having the characteristics of a reservoir natural fluid.

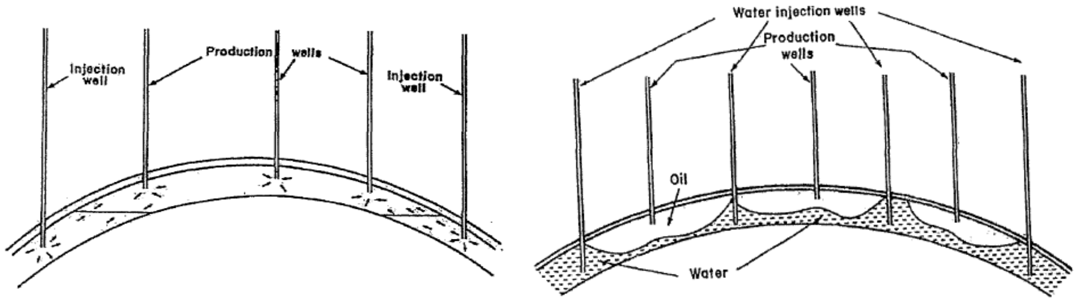


Figure 2-8-: water injection to reservoir in small fields (left) - water injection in large fields (Right) (NIOC)

2-2-2- Gas injection in order to maintain pressure

As you see in figure 2-9, gas injection is formed in gas cap center. In this kind of injection, the pressure of injective gas is relatively low and surface tension is fixed between phases. In large field, gas injection should be done in all over the reservoir, as what was said about water injection, it can create gas zones which result in pressure increase and oil drive toward the production well. It should be considered that gas injection is very effective, when the reservoir natural drive mechanism is gravity drainage mechanism. The injection of natural gas has been decreased in all over the world, because of using it as heat and fuel.

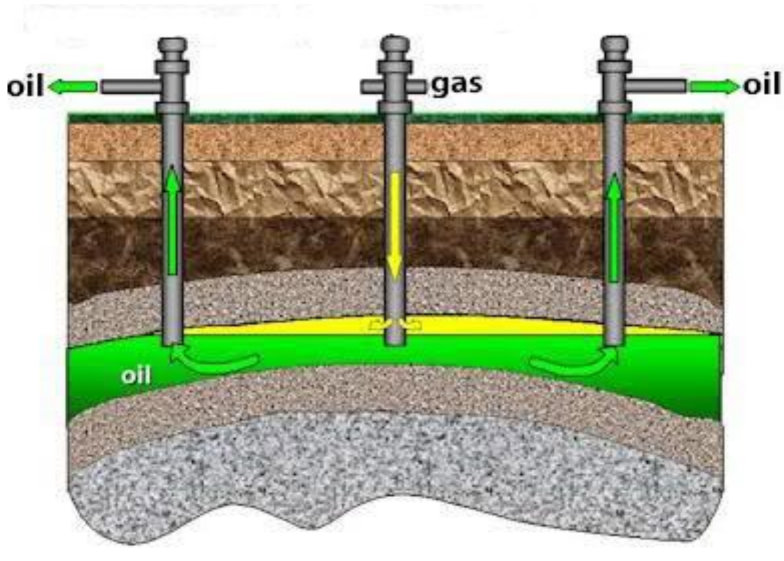


Figure 2-9-: Gas injection in gas cap *(Advanced CERT Canada Inc.)*

Chapter three

Methods of advanced enhanced oil recovery (EOR)

3-1- Gas injection in miscible way

Gas injection is the most widely applied EOR process for light oils. Oil recoveries for gas injection processes are usually greatest when the process is operated under conditions where the gas can become miscible with the reservoir oil. The primary objective of miscible gas injection is to improve local displacement efficiency and reduce residual oil saturation below the levels typically obtained by waterflooding. Examples of miscible gas injection are CO_2 or N_2 at sufficiently high pressure, dry gas enriched with sufficient quantities of LPG components, and sour or acid gases containing H_2S.

3-1-1- Nitrogen and flue gases

Compact air, nitrogen and produced gases are the cheapest gases. The combination of these gases also can be injected, because the minimum miscible pressure of these gases is close to each other so they can be used continually for oil recovery. Beside, corrosion was a problem resulted in better preference of nitrogen injection rather than other produced gases.

Parameter	Desirable	Parameter confine in running projects
Oil API degree	-	35-54
Oil viscosity	<0.4	0.07-0.3
Oil combination	High percentage of it, are formed from light hydrocarbons	
Oil saturation rate (%)	>40	59-80
Reservoir rock	Sand rock or carbonate rocks or low fracture with high permeability	
Reservoir Net Thickness(ft)	Relatively with low Net Thickness unless it is inclined	
Depth (ft)	>6000	10000-18500
Permeability (md)	It is not criterion	
Temperature (f^o)	It's not important, although there is high heat degree and pressure in those reservoirs which are located in high depths	

Table 3-1- suitable parameters in order to run flue gases and nitrogen gas injection projects (NIOC)

Beside, its low price and availability is another advantage toward other similar gases. Unfortunately, since minimum miscible pressure is high, the possibility of its injection is just in deep reservoirs.

Mechanisms

Mechanisms which occur in this method include:

1- Steaming of light ingredients of oil and creating miscibility in high and enough pressure
2- Creating gas drive in a place in which a large part of reservoir volume is full of gas
3- Increase of gravity drainage drive which occurs in inclined reservoir.

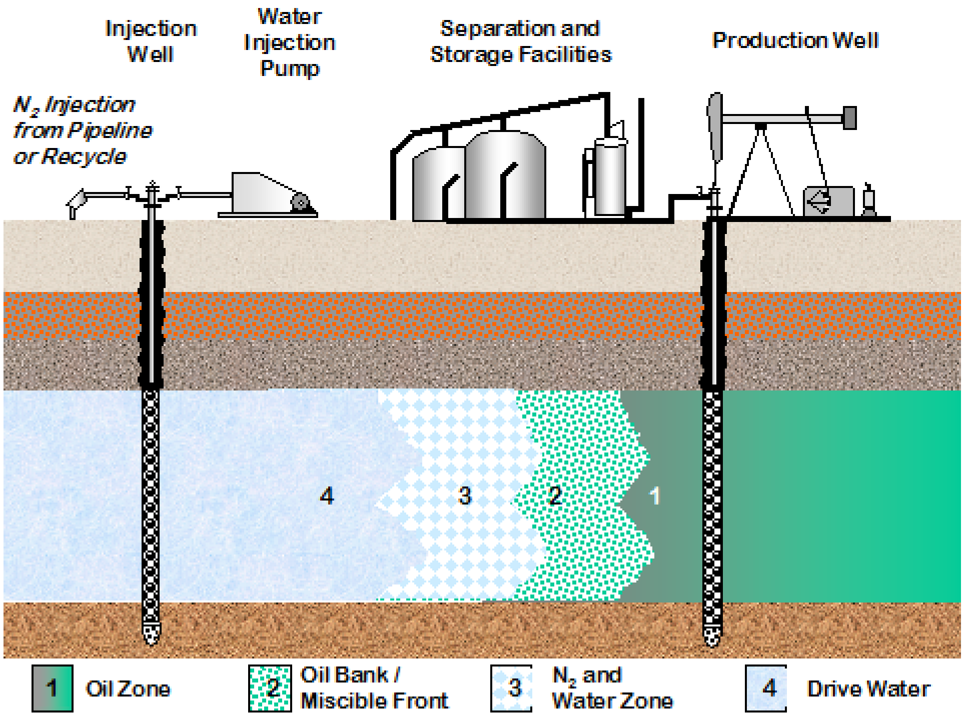


Figure 3-1- Nitrogen injection *(Advanced CERT Canada Inc.)*

Limitations and problems

Since proper miscible ability is formed with light oil and in high pressure, so this action is done in deep reservoirs. In inclined reservoirs, gravity drainage drive role can be determinant in low permeability. Corrosion makes problem in produced gas injection but at present time, in those projects which produced gas is used formally, nitrogen is used successfully.

3-1-2- hydrocarbon gas injection

Before introducing the concepts of minimum miscible pressure, hydrocarbon injection had been used for many years. In necessary pressure part, hydrocarbon located between nitrogen that needs high pressure and CO^2 that needs intermediate pressure for miscible replacement. In this case, methane is completely correct, anyway in a low depth reservoir which has low pressure it can be done by increase in the percentage of saturated hydrocarbons (C2 – C4). If it is reasonable economically, in those places in which CO^2 is not available (such as Canada) It is a good choice for EOR.

Mechanisms:

Different methods which are used in hydrocarbon gas injection include:

Enriched gas injection, lean gas injection, gas injection in high pressure, LPG injection

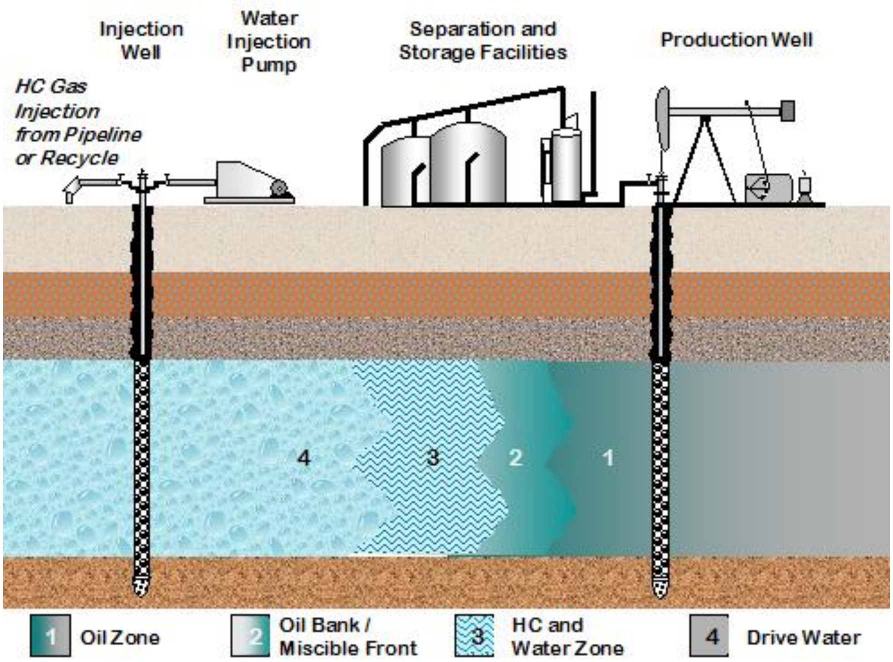


Figure 3-2- hydrocarbon gas injection *(Advanced CERT Canada Inc.)*

We can inject some other gases for EOR in miscible way like: Enriched gas, Lean gas injection and LPG (liquid petroleum gas).

3-1-3- CO^2 injection

The EOR technique that is attracting the most new market interest is CO_2-EOR. First tried in 1972 in Scurry County, Texas, CO_2 injection has been used successfully throughout the Permian Basin of West Texas and eastern New Mexico, and is now being pursued. Until recently, most of the CO_2 used for EOR has come from naturally-occurring reservoirs. But new technologies are being developed to produce CO_2 from industrial applications such as natural gas processing, fertilizer, ethanol, and hydrogen plants in locations where naturally occurring reservoirs are not available. When we inject CO2 into an oil reservoir, it becomes mutually soluble with the residual crude oil as light hydrocarbons from the oil dissolve in the CO2 and CO2 dissolves in the oil. When the injected CO2 and residual oil are miscible, the physical forces holding the two phases apart (interfacial tension) effectively disappears. This enables the CO2 to displace the oil from the rock pores, pushing it towards a producing well just as a cleaning solvent would remove oil from reservoir rocks.

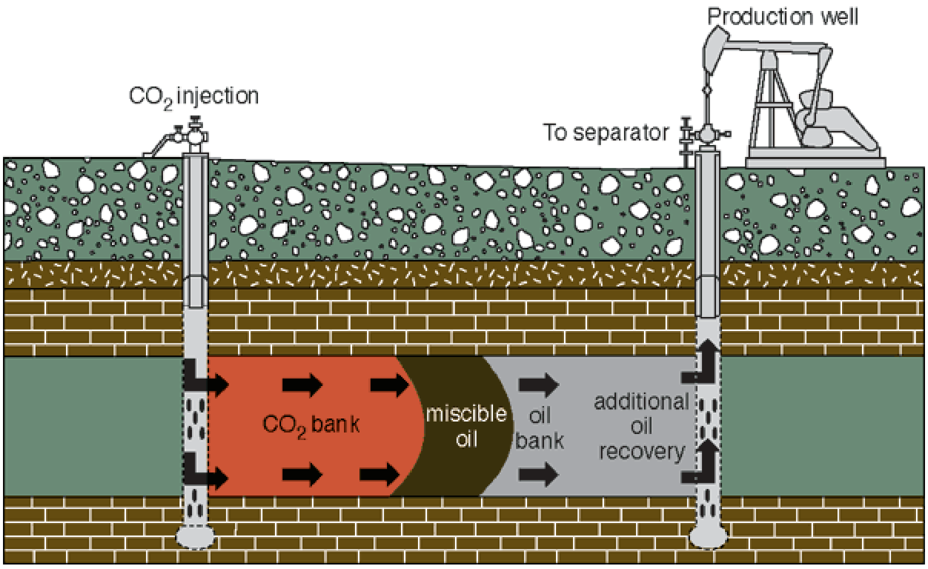


Figure 3-3- CO^2 injection *(Advanced CERT Canada Inc)*

Limitations and problems

We need a good and cheap source of CO^2; meanwhile, there are corrosion problems, especially if CO^2 is seen in production well.

Parameter	Desirable extent	Parameter confine in running projects
Oil API degree	>22	27-44
Oil viscosity	<10	0.3-6
Oil composition	High percentage of intermediates (C5 to C12)	
Oil saturation degree	>40	15-70
Reservoir rock type	Relatively thin sandstone or carbonate unless dipping	
Reservoir Net Thickness(ft)	It is not criterion but the injection rate should be sufficient and continuous	
Depth (ft) and temperature (f°)	For miscible displacement, depth must be great enough to allow injection pressures greater than the MMP, which increase with temperature and for heavier oils.	4040-15900

Table 3-2- proper parameters to apply CO^2 gas injection project in a miscible way (NIOC)

It should be considered that depth depends on oil gravity rate. So in table 3-4- this relation is studied in more detail.

Injection kind	Oil API degree	Desirable depth (major) ft
Miscible injection	More than 40	2500
	32-39.9	2800
	28-31.9	3300
	22-27.9	4000
	Less than 22	Mix is not possible
Immiscible injection	13-21.9	1800
	Less than 13	Injection fails in any depth

Table 3-3- the study of relation between depth and gravity to apply CO^2 gas injection project (NIOC)

3-2- gas/CO2 injection in immiscible way

When insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier), the injected carbon dioxide will not become miscible with the reservoir's oil. Then, another oil displacement mechanism, immiscible carbon dioxide flooding, occurs. The immiscible carbon dioxide flooding process has considerable potential for the recovery of moderately viscous oils, which are unsuited for the application of thermal recovery techniques. The main mechanisms involved in immiscible carbon dioxide flooding are: 1. Oil phase swelling which is as a result of oil saturation with carbon dioxide. 2. Viscosity reduction of the swollen oil and carbon dioxide mixture.

Parameter	Desirable extent
Oil API degree	>12
Oil viscosity	<600
Oil compound	Is not criterion
Oil saturation degree (%)	>35
Reservoir rock type	Is not criterion
Main Net Thickness(ft)	If the inclined is suitable and vertical relative permeability is good
Permeability (md)	Is not criterion
Depth (ft)	>1800
Temperature degree (f^o)	Is not criterion

Table 3-4- suitable parameters for immiscible transfer (NIOC)

3-3- water injection

One of the most common methods for increasing production from an oil reservoir is water injection to the reservoir; in this method water acts as a piston and drive oil forward. Since oil and water are immiscible so this transfer is called immiscible transfer, finally water bank receive to production wells and much water percentage is produced by reduction of oil percentage. If the production is not economical the injection should not be continued.

Usually sufficient water injection needs too much time, to fill reservoir pores and produce a great volume of oil. It is possible that several months pass from starting of a water injection process but we don’t have significant production increase. Usually in these projects, we will have maximum recovery after 2 to 5 years.

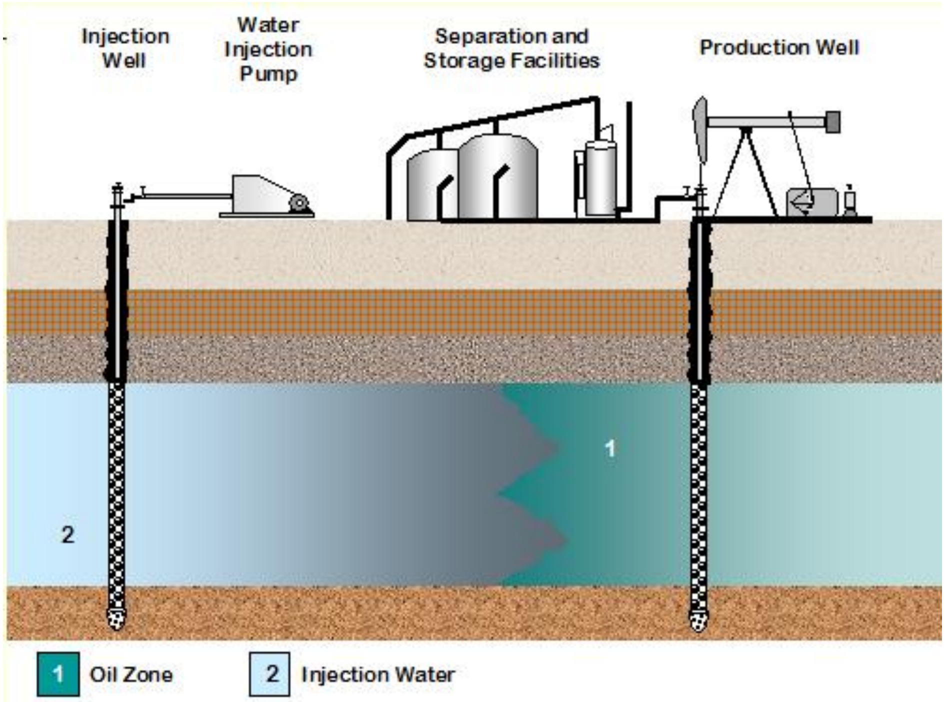


Figure 3-4- water injection (Advanced CERT Canada Inc)

The items which should be considered in applying water flooding project are as follows:

1- Water should be able to flow toward the reservoir in the same rate as oil and producing fluids from the reservoir, so the reservoir rock should have suitable permeability.
2- Every chemical material which has effect on rock and reservoir fluids and causes action like solved Oxygen, should be removed from the injective water in order to prevent any reaction.
3- The type of rock and reservoir characteristics should be surveyed completely, such as permeability.
4- The existence of high saturated gas and water areas that create canal should be studied.
5- The existence of the areas which have high or low permeability and cause insufficient injection should be studied.
6- Coning effect in water injection should be corrected and studied.

3-3-1- Waterflood Progression:

- Time 1- Early in life of waterflood. Producer making 100% oil.
- Time 2 - Still relatively early in life of waterflood. Water banks expanding, but producer still making 100% oil.
- Time 3 - Mid-life of the waterflood. Water has reached the producing well. Producer now makes oil and water.
- Time 4 - Late in the life of the waterflood. Producer now making large volume of water compared to the oil volume.

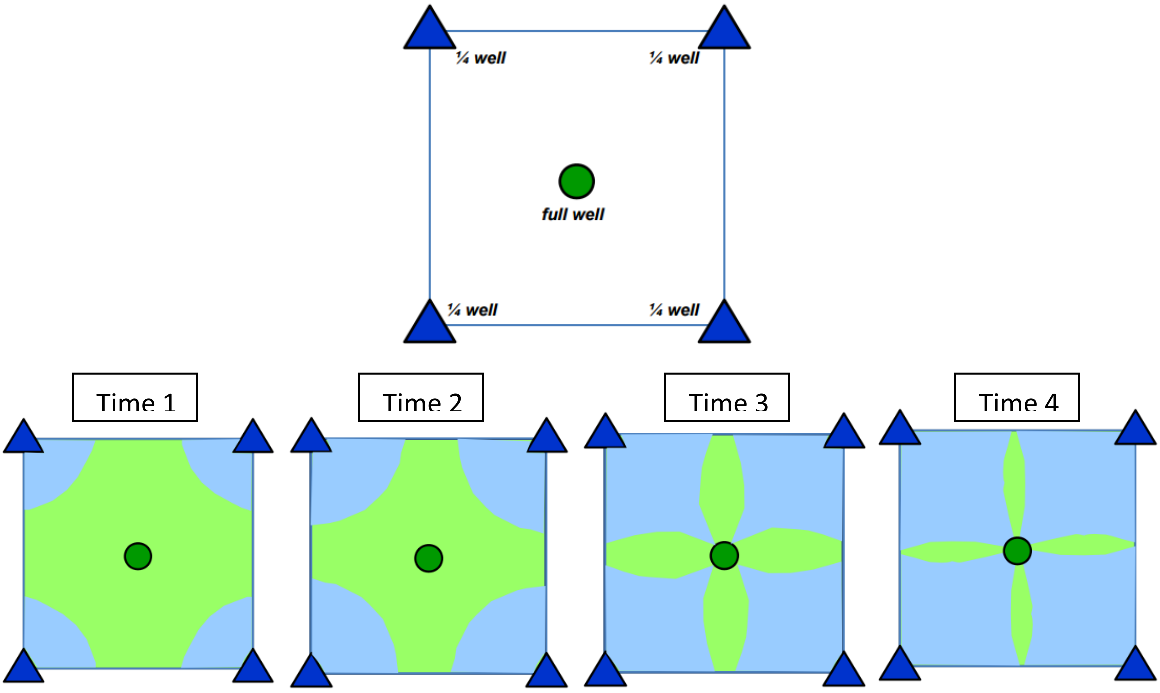


Figure 3-5- Waterflood progression (William M. Cobb & Associates, Inc.)

3-3-2- injection paths:

There are several basic well patterns that are commonly used waterfloods, as listed below (Fig3-6). Each pattern results in unique waterflood performance.

The items which should be considered in the selection of injection path:

1- Maximum rate of oil production
2- Optimizing the rate of injective water, in reaching the best oil recovery efficiency or, minimum rate of water injection and maximum rate of oil production.
3- Reservoir heterogeneousness in relation with permeability in different points, reservoir rock fracture, inclined and other items should be considered.

4- Having maximum consistency with available drilled wells and requiring fewer wells to drill.

5- Factors such as proper place for pitching injection facilities and other items in relation with injection operations should be consistent with injection path

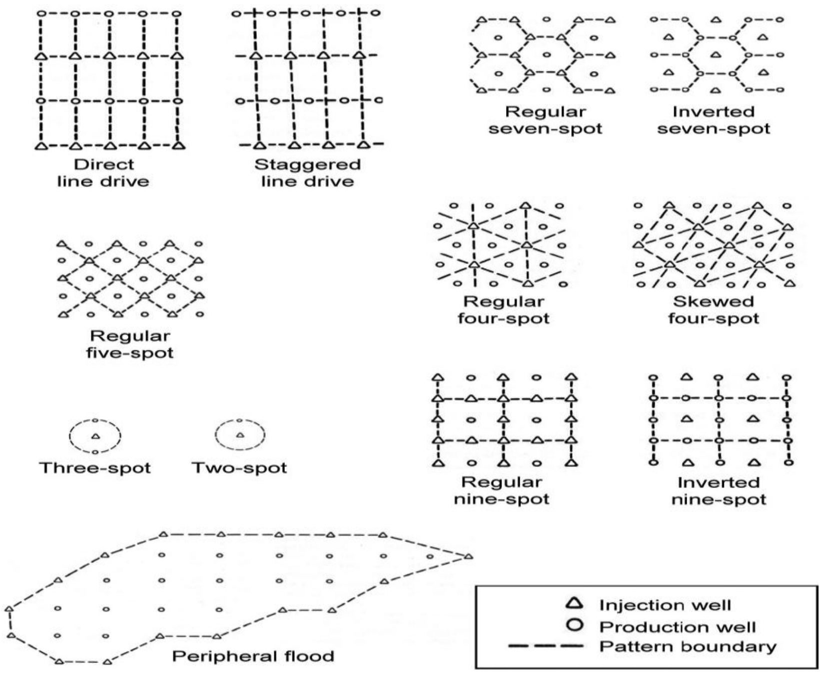


Figure 3-6- injection paths (NIOC)

Parameter	Suitable extent
Oil API degree	>25
Cp viscosity	<30
Oil compound	Is not criterion
The type of reservoir rock	Sand rock or carbonate
Reservoir Net Thickness(ft)	Is not criterion
Permeability (md)	Is not criterion
Transmissibility	Is not criterion
Depth	Is not criterion
Temperature (f^o)	Is not criterion

Table 3-5- proper parameters to apply water injection project (NIOC)

3-3-3- Permeability

Permeability, measured in milidarcy (md), is a measurement of a rock's ability to transmit fluid. Water injection rate will be a function of permeability. Most oil reservoirs have multiple layers with varying permeability values. We can see in Figure (3-7) if a layer has bigger permeability it has better result for water flooding process.

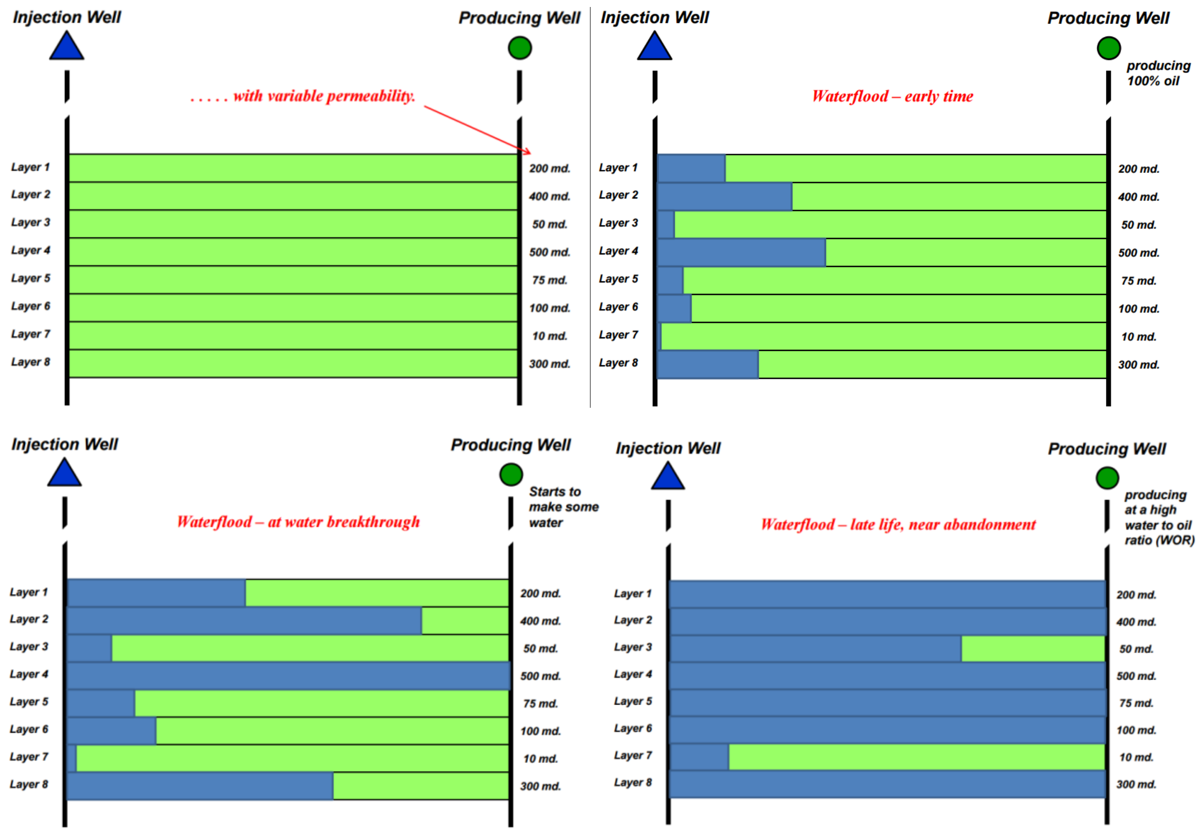


Figure 3-7- Permeability of different lyre (William M. Cobb & Associates, Inc)

3-4- injection of chemical materials

Chemical injection EOR helps to free trapped oil within the reservoir. This method introduces long-chained molecules called polymers into the reservoir to increase the efficiency of water flooding or to boost the effectiveness of surfactants, which are cleansers that help lower surface tension that inhibits the flow of oil through the reservoir. Less than 1% of all EOR methods presently utilized in the US consist of chemical injections. Polymer injection projects are used more than other chemical methods at present time (especially in America).

There are four types of chemical EOR:

- Polymer flooding where the injection-water is made more viscous in order to push the crude from the injection- to the producing well. This type of EOR is mostly used with crude that have a higher viscosity. We will study more about this type.
- Surfactant flooding where a “soap” is pushed through the reservoir to get remaining oil droplets out of the pores by reducing the surface tension of the droplets. This creates a micro-emulsion which increases the mobility of the crude. The soap can be the surfactant or created as petroleum soap by alkali. The chemical cocktail is stabilized by polymer hence the name Alkali Surfactant Polymer (ASP) flooding.

- Surfactant Polymer (SP) flooding is where no alkali is used. This is applicable in reservoirs with more saline formation water. Alkali and saline water produces scale and will clog up the producing wells.
- Low Salinity flooding where a reservoir with higher salinity formation water is flooded by fresh water. The fresh water releases the clay bound oil droplets in the reservoir.

3-4-1- Polymer injection

Polymer flooding is a tertiary recovery method by adding high-molecular-weight Polyacrylamide into injected water, so as to increase the viscosity of fluid, improve volumetric sweep efficiency, and thereby further increase the oil recovery factor. It should be considered that in polymer and gel injection, injective solution should enter all layers at the same time, but its rate depends on the permeability rate of the zones.

When oil is displaced by water, the oil/water mobility ratio is so high that the injected water fingers through the reservoirs. By injecting polymer solution into reservoirs, the oil/water mobility ratio can be much reduced, and the displacement front advances evenly to sweep a larger volume. The viscoelasticity of polymer solution can help displace oil remaining in micro pores that cannot be otherwise displaced by water flooding.

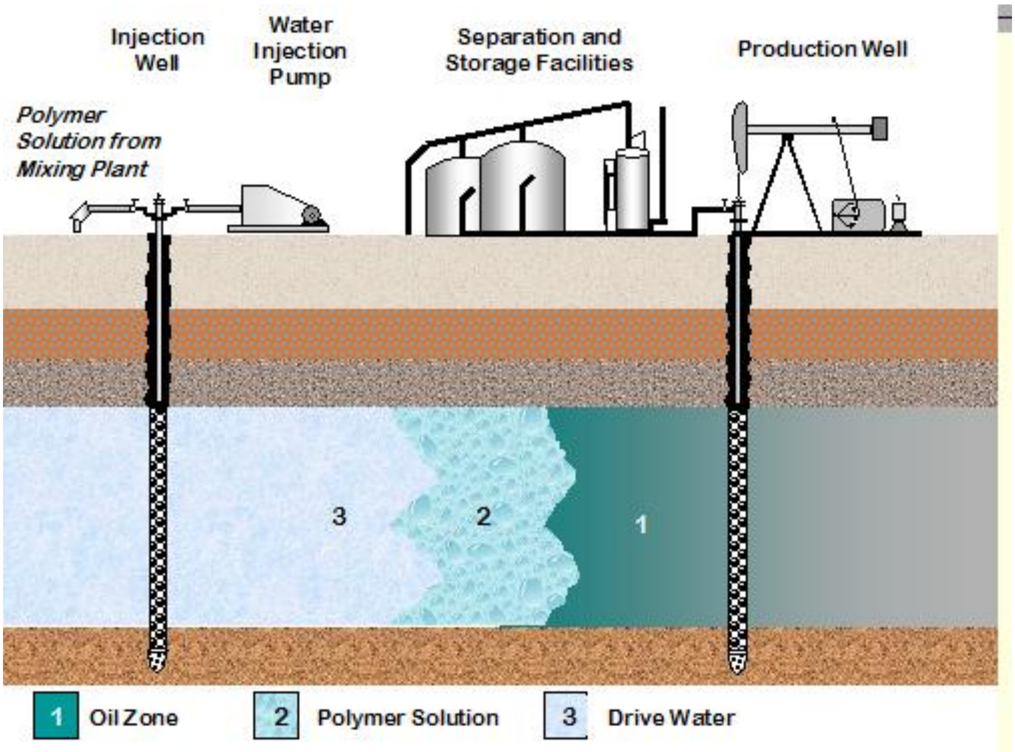


Figure 3-8- Polymer injection (Advanced CERT Canada Inc.)

Technical description:

Polymer flooding has been used for more than 40 years to effectively recover the remaining oil from the reservoir, up to 30% of the original oil in place. Due to decreased water production and enhanced oil production, the total cost of using the polymer flooding technique is less than that of water flooding. The polymer flooding efficiency ranges from 0.7 to 1.75 lb of polymer per barrel of incremental oil production. Polymers added to water increase its viscosity and reduce water permeability due to mechanical entrapment, thus decreasing its mobility. The process usually starts with pumping water containing surfactants to reduce the interfacial tension between the oil and water phases and to alter the wettability of the reservoir rock to improve the oil recovery. Polymer is then mixed with water and injected continuously for an extended period of time (can take several years). When about 30% to 50% of the reservoir pore volume in the project area has been injected, the addition of polymer stops and the drive water is pumped into the injection well to drive the polymer slug and the oil bank in front of it toward the production wells**.**

Criteria	Suggestion	Advancing projects
Oil API degree	>25	14-43
Oil viscosity (CP)	<150 (rather between 10-100)	1-80
Oil compound	Is not criterion	
Oil saturation degree	>50	50-92
Reservoir rock type	Sand rock reservoirs are preferred but it is also possible in carbonate reservoirs	
Reservoir main diameter	Is not criterion	
Mid permeability	>10 Everywhere that permeability is less than 50, polymer may cause the swept of just a part of reservoir unless the polymer molecule weight is sufficiently low	10-15000
Depth (ft)	<9000	1300-9600
Temperature (F^o)	<200	80-185

Table 3-6- proper parameters to apply polymer injection projects (NIOC)

Mobility Ratio

After the second phase (water or gas injection) there is still considerable amount of oil remaining, since it was not swept completely from the reservoir. One of the reasons for that phenomenon, outlined by Glatz, is the unfavorable mobility ratio. Mobility ratio is defined as the ratio of mobility (λ) of the displacing fluid (water) to the mobility of the displaced fluid (oil), where mobility is permeability (κ) divided by viscosity (μ):

$$M = \frac{\lambda_{water}}{\lambda_{oil}} = \frac{\kappa_{water} / \mu_{water}}{\kappa_{oil} / \mu_{oil}}$$

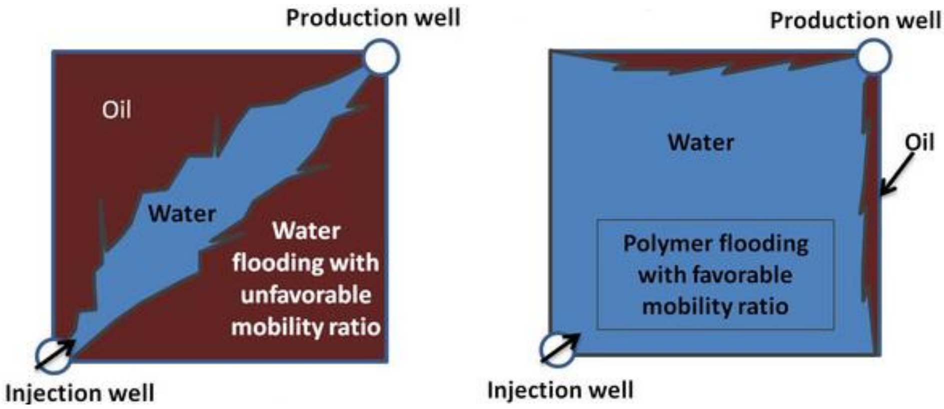


Figure 3-9- Fingering effect promoted by the unfavorable mobility ratio (top), and good oil recovery facilitated by the use of polymer flooding (bottom). (Source: G. Zerkalov)

Thus, there is an inverse relation between the volumetric sweep efficiency and the mobility ratio. The value of M greater than unity is unfavorable, since this will cause the instability of the displacement process and so called "viscous fingering" effect. Under the condition of a large viscosity difference between the displacing (water, lower viscosity) and displaced (oil, higher viscosity) fluid, the mobility ratio will become larger than one and, thus, poor recovery will be reached. The fingering effect is highly undesirable as it promotes itself more and more and sharply reduces the production as soon as the finger reaches the production well site. In an endeavor to decrease the mobility ratio below one, the approach of using viscous fluid (polymer) to increase the viscosity of displacing fluid has been developed. This helps to promote the displacing fluid in a stable, uniform manner and decrease the chance of fingering effect thus increasing the efficiency of oil recovery

3-5- water and gas alternative injection (WAG)

Mobile degree is not suitable between injective gas and reservoir oil in CO^2 injection or other miscible gas drives and this is for lower viscosity injective phase rather than reservoir oil that cause reduction of sweeping efficiency. The method which is improved in order to conquest on this problem is the injection of a specific deal of water and gas alternatively. Alternative injection of these two fluids causes reduction in their mobility as, the compounding of these two phases mobility be less than one of the fluids which is injected lonely. Caudle and Dyes in 1958 posed this method for the first time. The experiences show that alternative injection of water and gas has better efficiency.

Often, CO_2 floods involve the injection of volumes of CO_2 alternated with volumes of water; water alternating gas or WAG floods. This approach helps to mitigate the tendency for the lower viscosity CO_2 to finger its way ahead of the displaced oil. Once the injected CO_2 breaks through to the producing well, any gas injected afterwards will follow that path, reducing the overall efficiency of the injected fluids to sweep the oil from the reservoir rock.

Recently, WAG process has been studied and examined in some of heavy oil reservoirs. For example it has been examined in the Kozluka field in Turkey in which reservoir rocks are carbonate and its API is 12.6. In this project, water and CO^2 injection process causes that recovery rate increases about 9% rather than CO^2 injection.

Mechanism and process:

Oil recovery increases for viscosity reduction, petroleum inflation and restriction in petroleum steaming. If the reservoir conditions are suitable for gas injection, so the miscibility increases. Injective water results in oil drive toward production wells and prevents from more mobility and distribution of gas than oil. in this method, usually CO^2 and hydrocarbon gases are used.

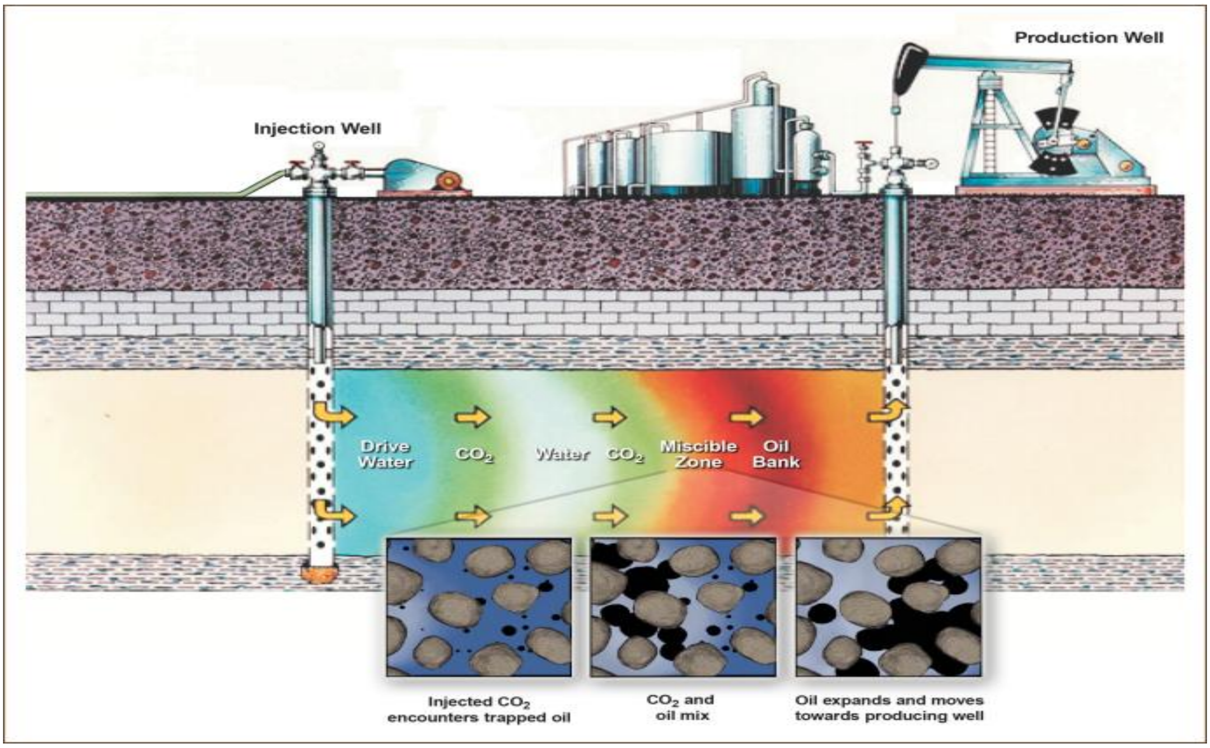


Figure 3-10- water and gas alternative injection (Advanced CERT Canada Inc)

Parameter	Suitable extent
Oil API degree	>38
Oil viscosity (cp)	<6
Oil compound	Its major part is C_2 to C_7
Oil saturation degree (%)	>30
Main reservoir Net Thickness(m)	Is not criterion
Porosity	Is not criterion
Permeability (md)	<2560
Depth (ft)	<9000 (by considering the heat degree)
Temperature (C^o)	Is not criterion

Table 3-7- proper parameters to apply WAG project (NIOC)

3-6- Microbial EOR Methods

Another tertiary method of oil recovery is microbial enhanced oil recovery, commonly known as MEOR, which nowadays is becoming an important and a rapidly developed tertiary production technology, which uses microorganisms or their metabolites to enhance the recovery of residual oil (Banat, 1995; Xu et al., 2009).

Microbial Enhanced Oil Recovery Mechanisms

Improvement of oil recovery through microbial actions can be performed through several mechanisms such as reduction of oil-water interfacial tension and alteration of wettability by surfactant production and bacterial presence, selective plugging by microorganisms and their metabolites, oil viscosity reduction by gas production or degradation of long-chain saturated hydrocarbons, and production of acids which improves absolute permeability by dissolving minerals in the rock, however, the two first mechanisms are believed to have the greatest impact on oil recovery. So that, microorganisms can produce many of the same types of compounds that are used in conventional EOR processes to mobilize oil trapped in reservoirs and the only difference between EOR and some of the MEOR methods probably is the means by which the substances are introduced into the reservoir. Table 3-8 summarizes different microbial consortia, their related metabolites and applications in MEOR.

Microbial product	Example microbes	Application in MEOR
Biomass	Biomass Bacillus, Leuconostoc, Xanthomonas	Selective plugging and wettability alteration
Surfactants	Acinetobacter, Arthrobacter, Bacillus, Pseudomonas	Emulsification and de-emulsification through reduction of IFT
Polymers	Bacillus, Brevibacterium, Leuconostoc, Xanthomonas	Injectivity profile and viscosity modification, selective plugging
Solvents	Clostridium, Zymomonas, Klebsiella	Rock dissolution for better permeability, oil viscosity reduction
Acids	Clostridium, Enterobacter, Mixed acidogens	Permeability increase, emulsification
Gases	Clostridium,Enterobacter Methanobacterium	Increased pressure, oil swelling, IFT and viscosity reduction

Table 3-8- Microorganism, their metabolites and applications in MEOR

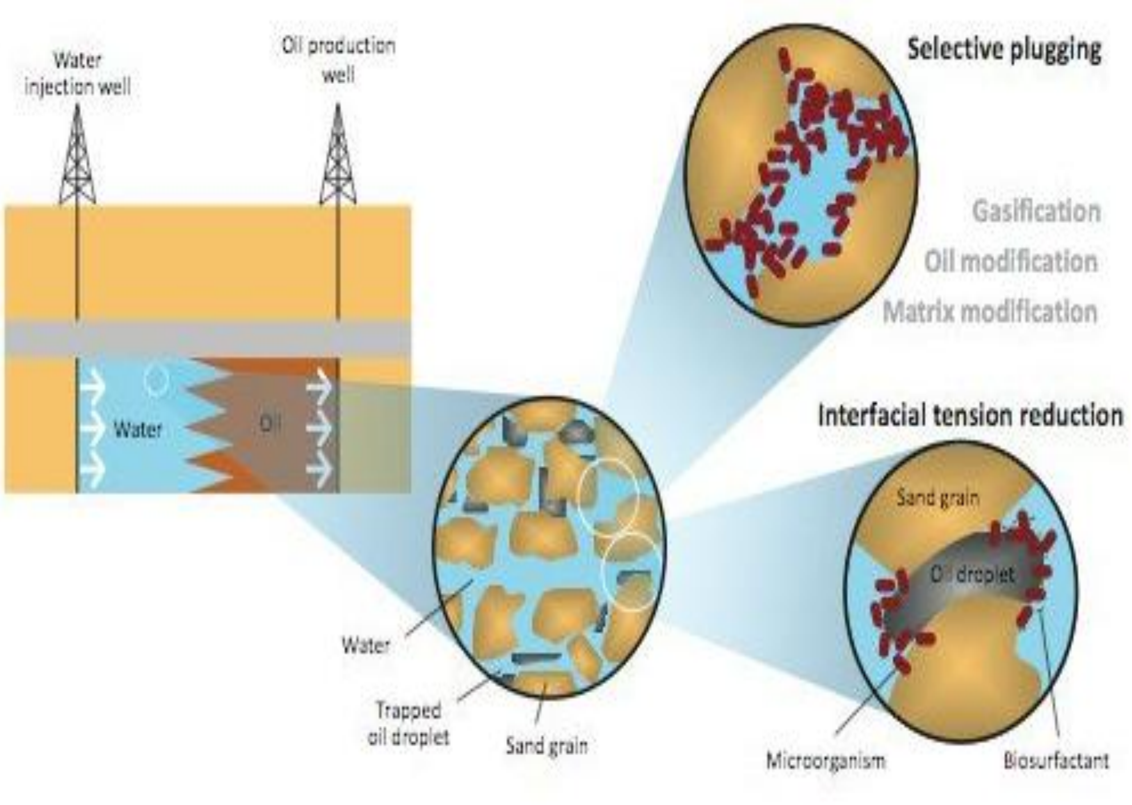


Figure 3-11- microbial injection (BGR Report of the Federal Institute for Geosciences and Natural Resources)

MEOR advantages

The most outstanding advantages of MEOR over other EOR technologies are listed below

1. The injected bacteria and nutrient are inexpensive and easy to obtain and handle in the field.

2. MEOR processes are economically attractive for marginally producing oil fields and are suitable alternatives before the abandonment of marginal wells.

3. Microbial cell factories need little input of energy to produce the MEOR agents.

4. Compared to other EOR technologies, less modification of the existing field characteristics are required to implement the recovery process by MEOR technologies, which are more cost-effective to install and more easily applied.

5. Since the injected fluids are not petrochemicals, their costs are not dependent on the global crude oil price.

6. MEOR processes are particularly suited for carbonate oil reservoirs where some EOR technologies cannot be applied efficiently.

7. The effects of bacterial activity within the reservoir are improved by their growth with time, while in EOR technologies the effects of the additives tend to decrease with time and distance from the injection well.

8. MEOR products are all biodegradable and will not be accumulated in the environment, therefore are environmentally compatible.

9. As the substances used in chemical EOR methods are petrochemicals obtained from petroleum feedstock after downstream processing, MEOR methods in comparison with conventional chemical EOR methods, in which finished commercial products are utilized for the recovery of raw materials, are more economically attractive.

MEOR disadvantages

1. The oxygen deployed in aerobic MEOR can act as corrosive agent on non-resistant topside equipment and down-hole piping

2. Anaerobic MEOR requires large amounts of sugar limiting its applicability in offshore platforms due to logistical problems

3. Exogenous microbes require facilities for their cultivation.

4. Indigenous microbes need a standardized framework for evaluating microbial activity, e.g. specialized coring and sampling techniques.

5. Microbial growth is favored when: layer permeability is greater than 50 md; reservoir temperature is inferior to 80 ^{0}C, salinity is below 150 g/L and reservoir depth is less than 2400m.

Parameter	Suitable extent
Salinity rate (Nacl) (%)	<15
Temperature (f^o)	<180
Depth (ft)	<1800
Tracer elements (Hg, Ni, Se, As)(ppm)	<10-15
Permeability (md)	>50
Oil API degree	>15
Oil saturation (%)	>15

Table 3-9- Proper parameters to apply microbial project (NIOC)

3-7- Recovery in fractured reservoirs

In relation with oil recovery, these reservoirs are affected by reservoir natural characteristics and fluid characteristics and also proper management strategy selection for field improvement in relation with optimizing and how to produce and selection of the best method for enhanced oil recovery.

Fractured reservoirs are divided to four classes:

1- Fractured reservoir with very low porosity and permeability of matrix, that in these reservoirs, the fractures create the capacity of saving and fluid flow.
2- Fractured reservoir with slightly low porosity and permeability of matrix that in these reservoirs, the matrix creates the capacity of fluid saving and fractures are the reservoir fluid flow path.
3- Fractured reservoir with good porosity and low permeability matrix that in this status, like the second kind of matrix, the matrix creates of capacity of fluid saving and fractures are the reservoir fluid flow path.
4- Fractured reservoir with high porosity and permeability matrix that in this status, the matrix creates saving capacity and fluid flow and the fractures are effective in permeability improvement.

Fractured reservoirs as lower recovery factor than other reservoirs. These oil reservoirs have average about 26% recovery factor. In figure 3- 12 final recovery rate of 64 reservoirs is shown. 8 gas reservoirs have mean recovery of 61%, and low recovery of two gas reservoirs is because of water entrance to swept fractures.

By attending to this point that, most of world fractured reservoirs are from 2^{nd} and 3^{rd} type, the performed researches are more in relation with these two types, it should be mentioned that most of the fractured reservoirs of Iran are from the 2^{nd} type.

3-7-1- Fractured reservoirs of 2nd type

The reservoir rocks of fractured reservoirs type 2 are brittle, such as Dolomite, hard lime, hard sand rock. In these reservoirs, recovery factor more depends on the condition of fractures network rather than factors such as reservoir fluid and matrix characteristics and the reason is that by considering widespread fractures of the reservoir rock, these reservoirs generally are in relation with underground water layers.

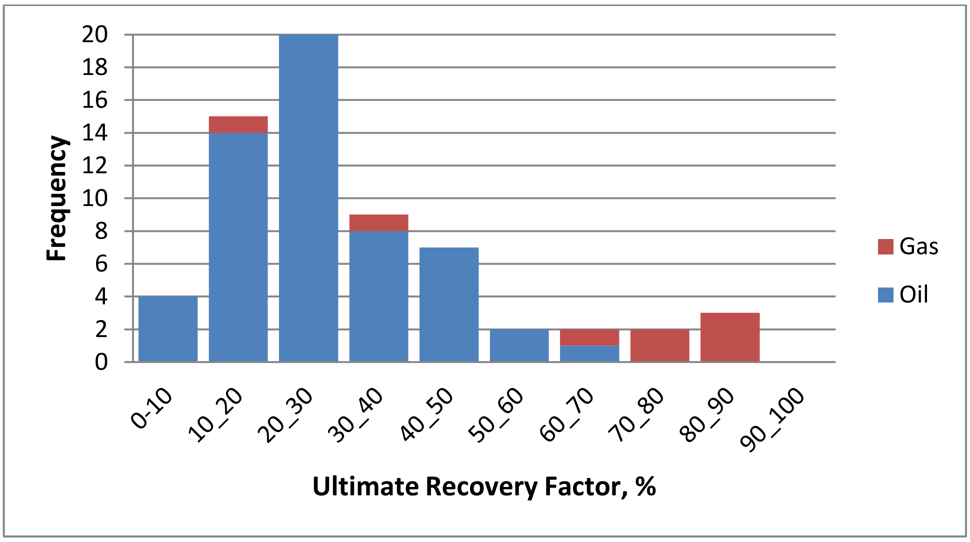


Figure 3-12- final recovery rate in studied fractured reservoirs (NIOC)

In this study, it was specified that recovery factor in this kind of reservoir generally depends on water drive rate from water layer. These reservoirs are too damageable in irregular production rate and if they be managed correctly, some of them will have a good recovery factor even without using secondary enhanced oil recovery and EOR. Oil recovery rate in these reservoirs which are in relation with an active water layer is more than reservoirs which have drive mechanism with weak water layer and other mechanisms and use secondary recovery methods and EOR.

For example we can point to Yanling field in China and Casablanca field in Spain. In Yanling field production was done in the first two years with a great Rate and this result in preventing more entrance of matrix oil into the fractures for sever pressure reduction and even a water injection project failed because of incursion problem and the final recovery rate became less than 20%.

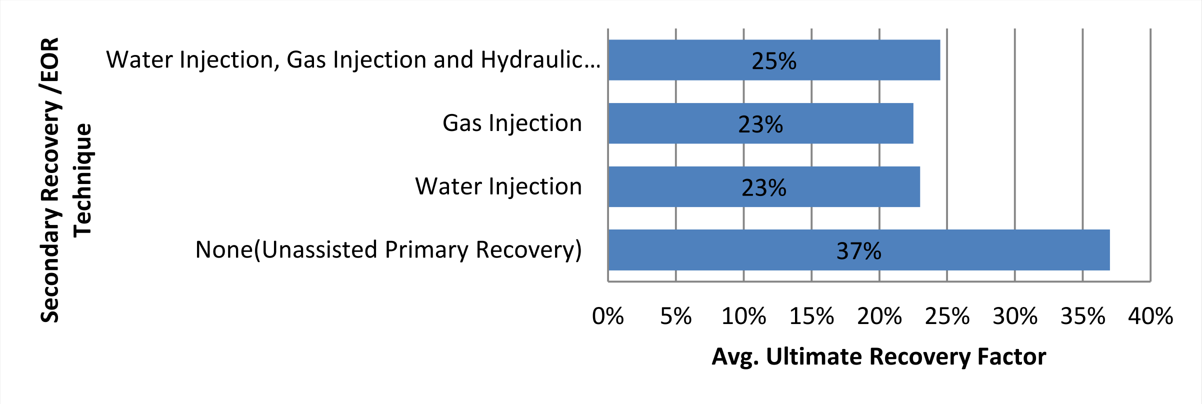


Figure 3-13- final recovery rate in fractured reservoirs type 2 after using enhanced oil recovery methods (NIOC)

But in Casablanca field which was similar to Yanling field, the production rate was controlled extremely and when the water cut rate reached an especial measure (2%), the production rate reduced. this simple control which was a combination of care on the production rate and water cut rate, resulted in increase of producing from this reservoir to more than 45%.

Field	Country	Basin	HC Type	Reservoir Lithology	Drive Mechanism	Secondary/EOR Technique	Ultimate Recovery Factor (%)
Altamont	Usa	Uinta	Light oil	Sand rock	Solution Gas	Microbial Injection	-
Amposta Marino	Spain	Gulf of Valencia	Heavy oil	Lime rock	Strong Bottom Water	Unassisted Primary Recovery	56 %
Bibi Hakimeh	Iran	Zagros	Medium oil	Lime rock Dolomite	Water/Gas cap expansion	Gas Injection	15 %
Casablanca	Spain	Gulf of Valencia	Light oil	Lime rock dolomite	Strong Bottom Water	Unassisted Primary Recovery	47.5 %
Dineh-Bi-Keyah	USA	Colorado Plateau	Light oil	Volcanic	Solution Gas	None	-
Gachsaran	Iran	Zagros	Light oil	Lime rock Dolomite	Water/Solution Gas	Gas Injection	26.6 %
Gela	Italy	Cakanisetta	Heavy oil	dolomite	Strong Bottom Water	Unassisted Primary Recovery	11 %
Haft Kel	Iran	Zagros	Light oil	Lime rock Dolomite	Water/Solution Gas	Gas Injection	27 %
La Paz	Venezuela	Maracaibo	Light oil	Lime rock	Solution Gas	Water injection	-
Lama	Venezuela	Maracaibo	Light oil	Lime rock	Water/Gas cap expansion	No data	23.5 %
Liubei	China	Bohai	Light oil	dolomite	Water	Water Injection	20 %
Maozhou	China	Bohai	Light oil	dolomite	Water	Water Injection	27.5 %
Maxi	China	Bohai	Light oil	Sandrock	Water/Solution Gas	Water Injection/Hydraulic Fracturing	40 %
Nido	Philippines	Northwest Palawan	Medium Oil Lime rock	Lime rock	Strong Bottom water	Unassisted Primary Recovery	35 %
Pars	Iran	Zagros	Light oil	Lime rock Dolomite	Water/Gas cap Expansion	Gas Injection	24 %

Ragusa	Italy	Iblean Plateau	Heavy Oil	Dolomite	Water	No data	30 %
Samgori	Georgia	Kura	Light oil	Volcanics	Water	No data	-
Tirrawarra	Australia	Cooper	Light oil	Sand rock	Solution Gas	Gas Injection/Hydraulic fracturing	25 %
Vega	Italy	Ragusaa	Heavy oil	Lime rock dolomite	Water	No data	15 %
Yanling	Chaina	Bohai	Medium oil	Dolomite	Water	Water Injection/Gas (N2) injection	18.5 %
Yihbezhuang	China	Bohai	Light oil	Lime stone dolomite	Weak Water	Water Injection	22.5 %

Table 3-10- A number of reservoir type 2 in the world (NIOC)

3-7-2- Fractured reservoirs type 3

The rock of fractured reservoir type 3 is almost such a chalk and silica shills. Unlike type 2 the characteristics of reservoir fluid and rock have a significant role in specifying the final recovery. These reservoirs are more in relation with gas drive, gravity drainage drive, and other compound drives mechanisms. Here, the use of secondary methods and EOR in order to optimizing the recovery degree of the reservoir is necessary. The recovery factor depends on the characteristics such as wettability, matrix, API degree and mobility degree.

Field	**Country**	**Basin**	**HC Type**	**Reservoir Lithology**	**Drive Mechanism**	**Secondary/EOR Technique**	**Ultimate Recovery Factor (%)**
Dan	Denmark	North sea Central Graben	Light oil	Primary Chalk	Solution Gas/ Gas cap Expansion	Horizontal Drilling/Hydraulic fracturing	11 %
Eldfisk	Norway	North sea Central Graben	Light oil	Primary Chalk	Solution Gas	Water Injection/Gas Injection	35 %
Eldfisk	Norway	North sea Central Graben	Light oil	Primary Chalk	Solution Gas	Hydraulic fracturing	23.5 %
Fahud	Oman	Oman Foredeep	Light oil	Chalky lime rock	Gravity drainage	Water Injection/Gas Injection	18 %
Gidding	USA	Gulf of Mexico	Medium &light oil	Primary Chalk	Solution Gas	Horizontal Drilling/Hydraulic fracturing	-
Idd El Shargi	Qatar	Persian Gulf	Medium oil	Chalky lime rock	Gravity drainage	Horizontal Drilling	-
Libsurne	USA	North inclined	Medium oil	Lime rock/dolomite	Solution Gas/ Gas cap Expansion	Horizontal Drilling/Hydraulic fracturing	7.6 %

Lost Hills	USA	San Joaquin	Heavy & Medium oil	Chert/ Dolomite	Solution Gas	Hydraulic fracturing/Water Injection	17 %
Midale	Canada	Williston	Light oil	Dolomite	Solution Gas	Horizontal Drilling/Water Injection	31 %
Natih	Oman	Oman Foredeep	Light oil	Chalky Lime rock	Gravity drainage	Water Injection/Gas Injection	22 %
Norman Wells	Canada	Western CanadaPearsall	Light oil	Chalky lime rock	Solution Gas	Horizontal Drilling/Water Injection	37 %
Pearsall	USA	Gulf of Mexico	Medium oil	Primary Chalk	Solution Gas	Horizontal Drilling/Hydraulic fracturing	12 %
Salym	Russia	Western Siberia	Light oil	Chert/Shale	Solution Gas	Hydraulic fracturing/Water Injection	-
Skjold	Denmark	North sea Central Garben	Light oil	Primary Chalk	Solution Gas/water	Water Injection	30 %
South Belridge	USA	San Joaquin	Heavy & light oil	Chert/ Dolomite	Solution Gas	Hydraulic fracturing/Water Injection	15 %
Valhall	Norway	North sea Central Garben	Light oil	Primary Chalk	Solution Gas	Horizontal Drilling/Hydraulic fracturing/water Weyburninjection	29 %
Weyburn	Canada	Williston	Light oil	Dolomite	Solution Gas/water	Horizontal Drilling/water injection	30 %
Yibal-A	Oman	South Oman	Light oil	Primary Chalk		Water Injection	44 %

Table 3-11- number of reservoirs type 3 in the world (NIOC)

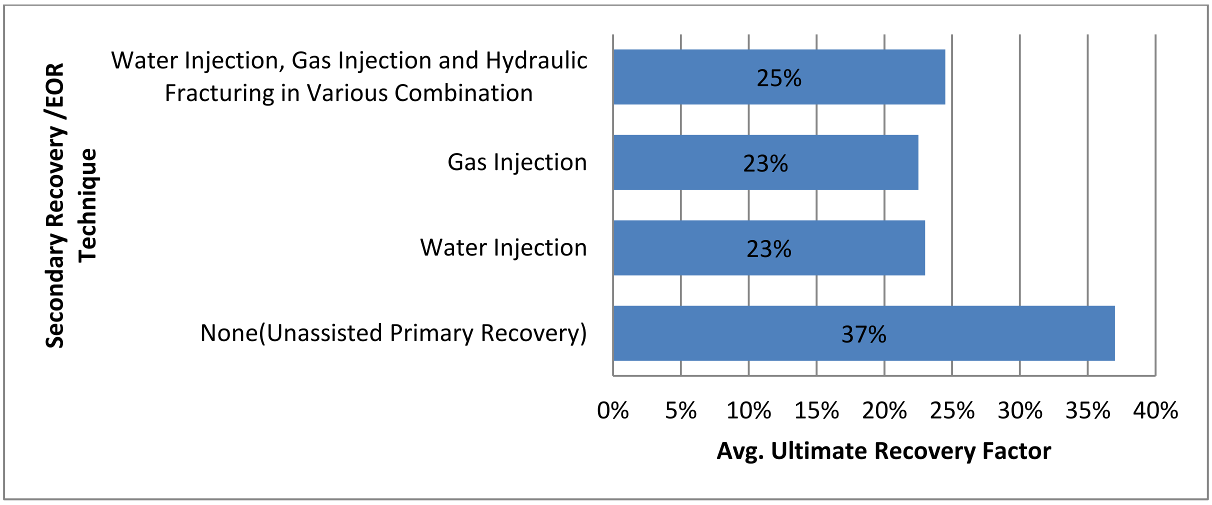


Figure 3-14- final recovery rate in fractured reservoir type 3 after using enhanced oil recovery methods (NIOC)

Chapter four

Heavy oil reservoir recovery methods

4-1- Heavy oil definition

Heavy oil and bitumen are defined as crude oil with high viscosity and low API degree. In general, crude oil with a viscosity (μ) ≥ 1 kg/m.s or oAPI ≤ 20 is classified as heavy oil, and crude oil with μ ≥10 kg/m.s and oAPI ≤10 is classified as bitumen. As the world's reserves for sweet crude oil decline rapidly and demands for petroleum resources continue to increase, the role of heavy oil and bitumen is crucial to the future of the world's petroleum supply.

Oil type	Viscosity (cp)	Density (kg/m^3)(15.6^{o}c)	API degree 15.6^{o}c)
Heavy	100-1000	394-1000	10-20
Ultra heavy/Bitumen	>10000	>1000	<10

Table 4-1- heavy oil definition (International Energy Agency)

4-2- heavy oil in the world

The world's proven reserves for non-conventional oil are approximately 8 trillion barrels, approximately 3 times larger than the world's reserves of conventional oil (Dusseault, 2006). As techniques in heavy oil recovery improve over time, the world's proven reserves for non conventional oil are expected to increase as well. Out of the total 8 trillion barrels of non USA 500 billion bbl Russia 600 billion bbl Middle East 530 billion bbl Venezuela 2 trillion bbl Canada 3 trillion bbl 2 conventional oil reserves, Canada and Venezuela possess 3 trillion and 2 trillion barrels respectively. Even though Canada has most of the heavy oil reserves in the world, the high in-situ viscosity and the low API makes their recovery a challenge.

Country	The rate of in-situ oil (10^9 bbl)	Country	The rate of in-situ oil (10^9 bbl)
Canada	1860	Syria	14
Venezuela	1200	China	10
Russia and prior Soviet republics	1200	Ecuador	7
America	55	Trinidad & tobacco	5
Iran	50	Colombia	3
Iraq	34		

Table 4-2- Known resources of heavy oils in the world (NIOC)

4-3- heavy oil in Iran

The first discovery of HO in Iran goes back to early 1931 when wells drilled for gas reservoir evaluation purposes in the southwest of Iran encountered a large Heavy oil occurrence. Systematic Heavy oil exploration in Iran started in 1982; in 1994 the Petroleum Engineering and Development Company (PEDEC) was established within the National Iranian Oil Company (NIOC) to manage national Heavy oil and Xtra heavy oil assets. According to the latest studies, Iran has over 50×10^9 bbl of heavy oil, mostly occurring in naturally fractured carbonate rocks (limestone and dolomite) and comprising >40% of Iran's proven oil reserves. Significant Heavy oil discoveries in the south and southwest of Iran, combined with high oil prices and difficulties in sustaining conventional oil production rates, have led to a greater interest in their development since 2000. But now Projects are stopped due to low oil price.

Row	**Field name**	**Structure**	**Field dimensions (km*km)**	**Rock type**	**API**
1	**Mund Mountain**	Jahrom	16*90	Dolomite	8-10
		Sarvak		Lime	12-14
2	**Zaghe**	Pabdeh	15*4	Lime and polmeh rock	15
3	**Ferdous**	Fahalyan		Lime	16
		Godone	20*13	lime	16
		Daryan		Lime	16
4	**Paydar**	Asemary	28*8	Dolomite and sand lime	17-18
5	**West Paydar**	Asemary and Sarvak		Lime and sand	17
6	**Sousangerd**	Asemary	25*6	Dolomite, lime and sand	14-19
		Sarvak		Lime	Not specified
7	**Ramshir**	Pabedeh-Goorpey	35*5	Lime – marl	15.1
8	**Soroush**	Kazhdomi		Sand rock	14-19
9	**Northern Pars**	Sarvak		Dolomite	10
		Khami		Lime	10

Table 4-3- Known resources of heavy oils (NIOC)

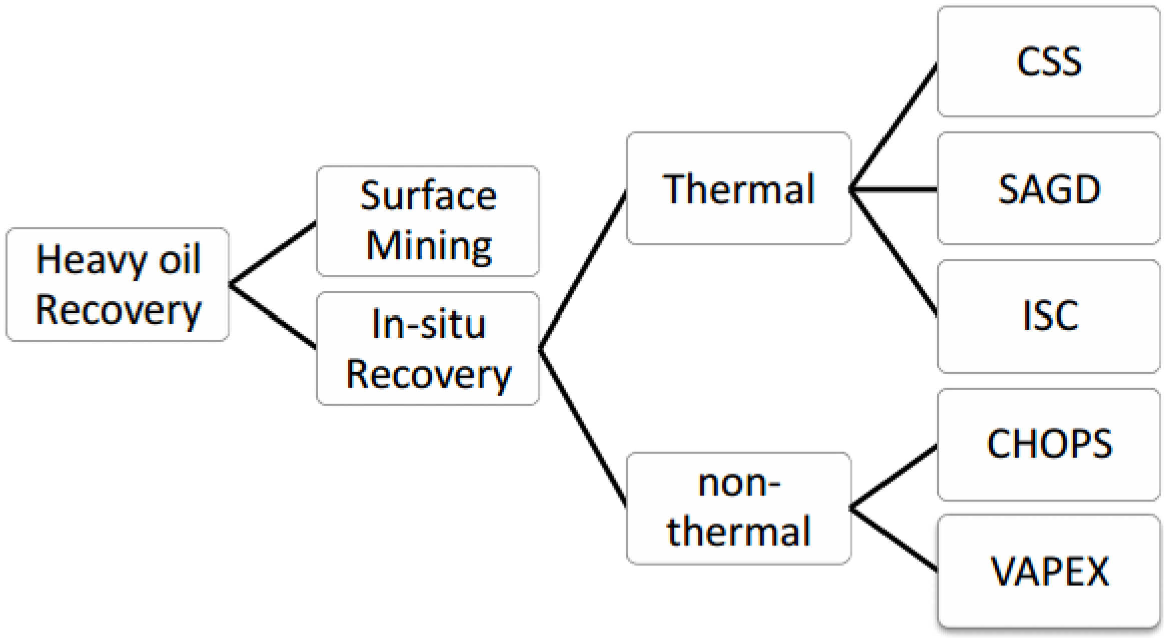
Main reservoirs of heavy oil of Iran are located in the fields such as Kuh-e-Mund, Zagheh, Paydar, Western Paydar, Sousangerd, Ramshir and Ferdous (in Persian Gulf). Reservoir rocks of these sources are formed from Dolomite and carbonate.

Row	Field name	Structure	Field dimensions (km*km)	Rock type	API heaviness degree
1	**Shadegan**	Asemary	27*4	Lime	28
		Sarvak			17.7-22
2	**Cheshmeh Khosh**	Pabdeh	28.5*4.5	Lime	17.8
		Goorpey		Marl	
3	**Shakhe**	Pabedeh	16*5.5	Lime	16-20
		Goorpay		Marl	
		Sarvak		Lime	13-24
4	**Boushehr**	Jahrom	28*8	Dolomite lime	
		Daryan		lime	
		Godone		Dolomite lime	
5	**Mansouri**	Bottom Sarvak	40*5	Lime	Not specified
6	**Ahwaz**	Bottom Sarvak	68*6	Lime	10-14
7	**Zireh**	Daryan	40*16	Lime	
		Godone			
		Fahalyan			
8	**Khoramshahr**	Kazhdomi		Shil and sand	
9	**Golshan**	Jahrom	26*9	Dolomite lime	
		Sarvak		Lime	

Table 4-4- Observed resources of heavy oil in South-West zones of Iran (NIOC)

4-4- Recovery of Heavy Oil

The world's reserves of non-conventional oil are approximately 3 times that of conventional oil, but only 13% of the world's crude oil production is non-conventional oil. The high capital investment and high operation cost in heavy oil recovery are the reasons. In Canada, in order to sustain an economical heavy oil production operation, the price of crude oil must remain well above $25 per barrel (Dusseault, 2006).



4-4-1- Cold Heavy Oil Production with Sand (CHOPS)

CHOPS is a technique applied to both tertiary recovery of conventional oil as well as to "quasi primary" production of oil sands and oil shale. CHOPS is really nothing more than the idea that if sand filters are removed from pumping equipment and sand is produced with oil, then the two can be separated above ground. The technique has the advantage that removing sand from the well can also result in enough space being created for oil to form small liquid pockets that are easily produced. The system is called "cold" because not heat is injected to help liquefy the petroleum, thereby saving on energy investment and improving ERO.

The CHOPS method allows sand into the wellbore with the oil to improve well productivity. Wells that formerly produced only 20 barrels/day have been observed to produce more than 200 barrels/day, according to Canada's Centre for Energy, with free movement of sand into the wellbore. This technology was pioneered in Canada.

CHOPS only recovers 5 -6% of the oil in a given reservoir, but it is cheap to implement. Disposal of the sand, which is contaminated with petroleum, is a serious drawback to this method. Some locations use oily sand in road construction, but this poses problems as well. Currently, most sand is disposed of in underground salt caverns.

Parameter	Desirable extent
Depth (ft)	1300-2500
Oil saturation degree (%)	67-87
Porosity (%)	30-34
Net Thickness(ft)	13-80
Permeability (md)	500-10000
Oil API degree	11-14
Reservoir pressure (psi)	400-848
Reservoir temperature (f^o)	61-70
Viscosity (CP)	160-600
Relation of gas to oil (GOR)	0-56

Table 4-5- proper parameter to apply cold production project (NIOC)

Limitations

As production process steadily continues the salt layered well also need to grow in order to have space for sand accumulation. At the same time it always has to facilitate the separation process but the structural integrity has to be maintained.
It has been found that the initial investment can be a little high for the super sump process but once established, the running cost is not that high.

4-4-2-Surface mining

Because of the existence of great sources of tar sand in the world, surface mining is on the list of EOR methods with the goal of criteria screening. This method is used just when no other method can be used and of course this is for its higher cost than thermal methods, so the saturation degree of natural tar in tar sand should be very high and the reservoir depth should be very low. However, some efforts are doing for oil production from this reservoir through methods such as SAGD.

Parameter	Desirable extent
Oil API degree	7-11
Viscosity (CP)	Zero cold flow (less possible of mobility)
Oil compounding	It is not criterion
Oil saturation degree (PV %)	>8
Reservoir stone type	Have the ability of mining
Net diameter (ft)	>10
Permeability (md)	It is not criterion
Depth (ft)	The rate of overburden/san should be larger than 3
Temperature (f^o)	It is not criterion

Table 4-6- proper parameter to apply mining and production project

4-4-3-Thermal methods

During the thermal recovery the reservoir is heated to reduce oil viscosity. Thermal EOR is the most popular method accounting for more than 50% of the overall EOR market. Steam injection is the most common method used in thermal EOR. Other methods include in-situ combustion, where the reservoir is heated and an injected high-oxygen gas mixture burns to create a combustion front. Steam injection is mostly used in shallow reservoirs that contain high viscosity (usually heavy) crude oil. These include reservoirs in the San Joaquin Valley of California or those that comprise the oil sands of Alberta, Canada. Steam injection is a very well understood EOR method, used commercially since the 1960s. The injection of steam lets heat the crude oil in the formation thus lowering its viscosity and vaporizing some of the oil to increase its mobility. The decreased viscosity helps reduce the surface tension, increase the permeability of oil and improve the reservoir seepage conditions. Oil vaporization allows oil to flow more freely through the reservoir and to form better oil once it has condensed.

4-4-4- In-situ combustion

In-situ combustion (ISC) is an enhanced oil recovery method in which the air is injected into the reservoir burning the heaviest crude oil components generating heat and combustion gases that enhance recovery by reducing oil viscosity and pressurizing the system, respectively. In this process, highly exothermic reactions occur in the porous medium resulting in significant increases in the temperature. For heavy oils, a 300-400 °C increase in temperature is not uncommon. Large temperature differences signify heat transfer and also will result in the phase change. ISC involves many phenomena, making modeling complex. So the engineering of the process is more difficult than any other method of crude oil recovery, but the advantages of in-situ combustion motivate researchers to investigate on it.

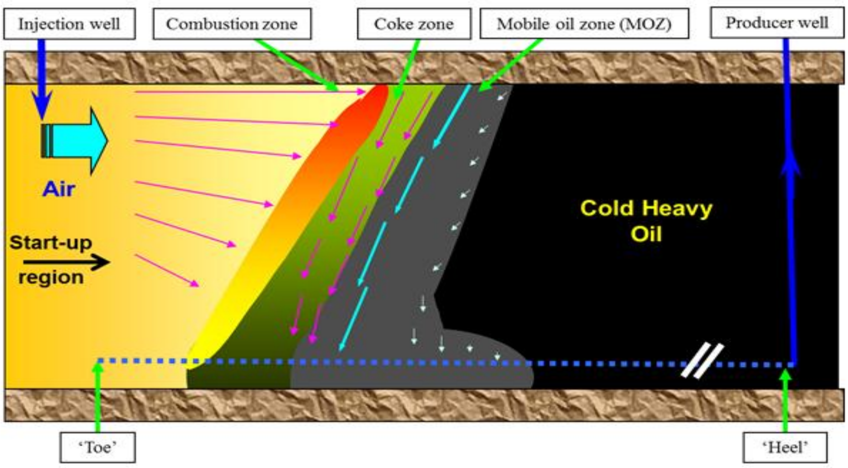


Figure 4-1- Thermal in situ combustion *(*Oliveros 2013)

Technical description

In this method the air is injected to the crude oil reservoir. After ignition the generated heat by combustion keeps the combustion front moving toward the producer well. Combustion front burns all the fuel in its way. Usually 5 to 10 percent of the crude oil is used as a fuel and the rest is going to be produced in the production well. The heat of reaction vaporizes initial water and also the light components of the oil in front of the combustion front. The steam is condensed while distancing from the hot region.

Restrictions and problems:

Several aspects of operating in-situ combustion projects must be considered:

1. The large compression ratio and associated costs required to inject air into the formation
2. The planning and design requirements for a combustion project, which are more difficult than for steam injection
3. Extensive laboratory work to assess fuel availability, air requirements, and burning characteristics of the crude that are required before designing in-situ combustion projects
4. The high degree of technical sophistication and the careful monitoring needed to ensure proper operation of a project
5. The limitation of numerical simulation and other techniques that makes predictions of recovery more difficult than most other enhanced oil recovery methods

Parameter	Desirable extent	Parameter confine in running projects
Oil API degree	10-27	10-40
Viscosity (CP)	<5000	6-5000
Oil compound	A deal of asphalting is needed for coke sediment	
Oil saturation degree (pv%)	>50	62-94
Reservoir type	Sand or sand rock with high porosity	
Net Thickness(ft)	>10	
Average permeability degree (md)	>50	85-4000
Depth (ft)	<11500	400-11300
Temperature (f^o)	>100	22-100

Table 4-7- proper parameters to apply thermal combustion parameters (NIOC)

4-4-5- steam injection

During the thermal recovery the reservoir is heated to reduce oil viscosity. Thermal EOR is the most popular method accounting for more than 50% of the overall EOR market. Steam injection is the most common method used in thermal EOR. Other methods include in-situ combustion, where the reservoir is heated and an injected high-oxygen gas mixture burns to create a combustion front. Steam injection is mostly used in shallow reservoirs that contain high viscosity (usually heavy) crude oil. Steam injection is a very well understood EOR method, used commercially since the 1960s. The injection of steam lets heat the crude oil in the formation thus lowering its viscosity and vaporizing some of the oil to increase its mobility. The decreased viscosity helps reduce the surface tension, increase the permeability of oil and improve the reservoir seepage conditions. Oil vaporization allows oil to flow more freely through the reservoir and to form better oil once it has condensed. Steam injection is the most common method used in thermal EOR. It helps produce up to 30% of original oil in place. Steam injection does not pose as many environmental risks as other EOR methods might have. This helps implement this technology in different countries, even with strict regulations. Economy is the main factor that determines if this technology should be implemented in one field or the other.

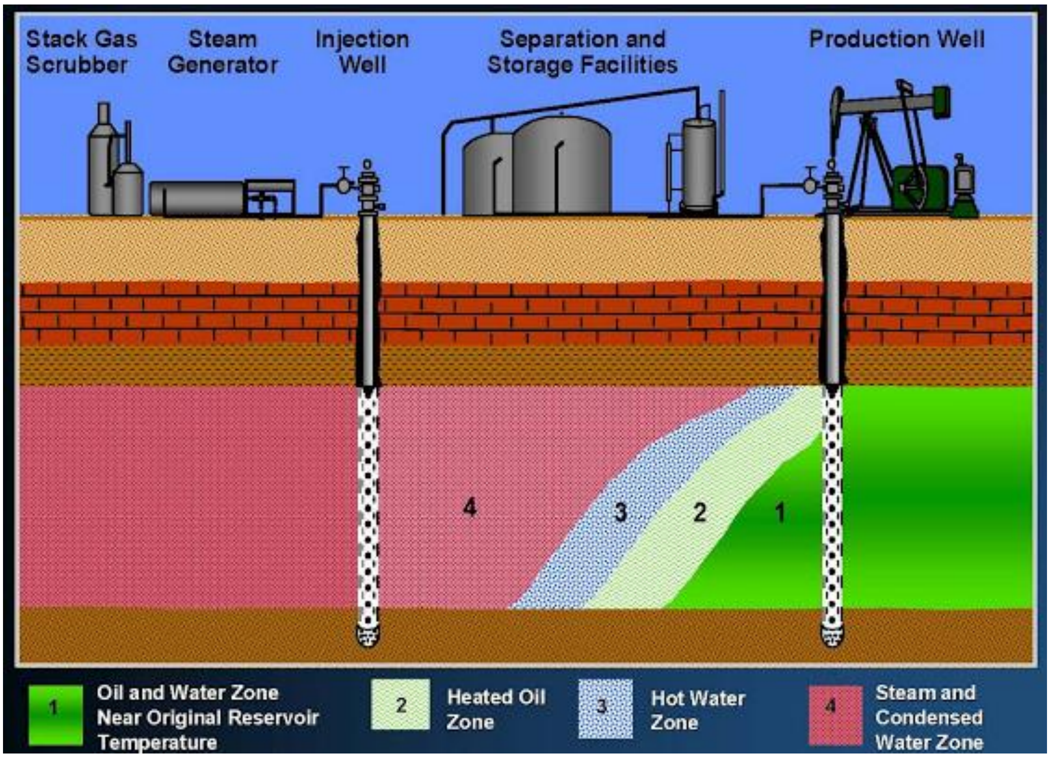


Figure 4-2- Steam injection (NIOC)

Parameter	Desirable extent	Parameter confine in running projects
Oil API degree	8-25	8-27
Viscosity (CP)	<100000	100-5000
Oil compound	Not critical but some light ends for steam distillation will help	
Oil saturation degree (pv %)	>40	35-90
Reservoir rock type	Sand or sand rock with high porosity and permeability is preferred but it is possible in carbonate reservoirs	
Net Thickness(ft)	>20	
Permeability degree (md)	>200	200-10000
Transmissibility md-ft/cp	>100	
Depth (ft)	<5000	300-5000
Temperature (f^o)	It is not criterion	60-280

Table 4-8- proper parameters to apply steam injection project (NIOC)

Steam injection methods:

The most important methods which are used in steam injection are:

- Cyclic Steam Simulation/Injection (CSS)
- Water flooding by steam
- Hot water injection
- Steam Assisted Gravity Drainage (SAGD)
- Water Alternative Steam Process (WASP)

4-4-6- Cyclic Steam Simulation/Injection, Steam Soaked, Huff and Puff:

In cyclic steam stimulation the same well is used for steam injection and oil production. At first, steam is injected for a period from couple of weeks to a couple of months. The introduced steam allows heat up the oil immediately surrounding the injection well through convective heating thus lowering its viscosity (Fig4-3-left).

After the target viscosity is reached, steam injection stops to allow heat to redistribute evenly in the formation. This helps maximize the amount of oil recovered after this stage. The well can then be produced until the temperature in the well drops and the viscosity of oil increases again (Fig. 4-3-right). This cycle is repeated until the response becomes insignificant and economical limits are reached. Obviously, most of the oil is produced in the first few cycles.

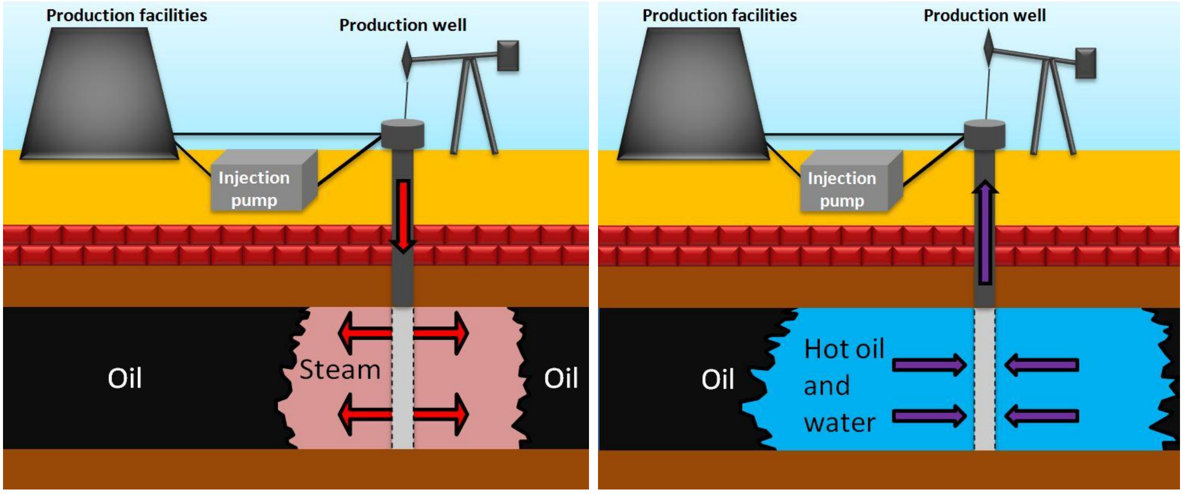


Figure 4-3- Cyclic steam stimulation. Left: Steam injection. Right: Production. (G. Zerkalov)

Parameter	Desirable extent	Parameter confine in running projects
Oil API degree	10-27	8-27
Viscosity (CP)	<50000	500-1000
Oil compound	Some asphaltic components to aid coke deposition	
Oil saturation degree (pv %)	>60	55-90
Reservoir rock type	Sand or Sandstone with high porosity but it is possible in carbonate reservoirs	
Net Thickness(ft)	>10	
Permeability degree (md)	>100	63-10000
Transmissibility md-ft/cp	>20	
Depth (ft)	>500	1000-4500
Temperature (f^{o})	>150	60-280

Table 4-9- proper parameters to apply cycle system simulation project (NIOC)

Limitations:

The major limitation of cyclic steam injection is that it leaves considerable amounts of oil in the reservoir that can only be recovered by drive processes and it is observed that less than 30% (usually less than 20%) of the initial oil in place can be recovered. One more limitation of this process is that it is preferred production on heavy oil reservoirs that can contain high-pressure steam without fracturing the overburden.

4-4-7- Water flooding by steam:

This method can be used in normal and fractured reservoirs. Steam water flooding is a process such as water flooding in which steam injection is formed continuously. In this method, oil is swept by steam and send toward the production well. Usually for steam injection methods in the reservoir, first of all, Cyclic Steam Injection is done and then when it is uneconomical steam water flooding will be used.

4-4-8- Hot water injection:

In this method sand is produced aggressively along with the heavy oil without applying heat. The oil production is improved substantially through the regions of increased permeability wormholes. The basis of this process is the oil production and recovery when sand production occurs naturally. The production of the unconsolidated un-cemented reservoir sand results in significantly higher oil production. In order to make it cost effective, the choice of fluid can be made according to the availability of fluid and its production response of the crude oil. For example, seawater may be injected in the undersea reservoir, which can save the cost of delivery of water to the reservoir. Also the mineralogy of the reservoir should be considered; for example, steam or hot water should not be injected without first considering their effects on the reservoirs containing swelling clays.

Using new technologies in heavy oil recovery

4-4-9- SAGD process:

This method involves drilling of two parallel horizontal wells (shown in figure-4-4), one above the other, along the reservoir itself. Hot steam is introduced from the top well which reduces the viscosity of the heavy oil (like all other thermal methods). The reduction in viscosity of the heavy oil separates it from the sand and it is drained into the lower well by means of gravity. The key to this method is the two parallel and horizontal wells, and this has only become possible due to the directional drilling technology.

The heat of the steam reduces the viscosity of the heavy oil and separates it from the sand. It is drained into the lower well by means of gravity. Even though the injection and the production wells can be close (5-7m), the mechanism causes the steam saturated zone, known as the steam chamber, to rise on the top of the reservoir, expand gradually sideways, and eventually allow the drainage. The distance between the pair of horizontal wells vertically separated by each other is 15-20 feet. These wells are drilled at the bottom of a thick unconsolidated sand stone reservoir. The injected steam reduces the oil viscosity to values as low as 1 -10 cp, depending upon the temperatures and the initial conditions and develops a steam chamber that grows vertically and laterally. The steam and gases rise, the lower well receives oil and condensates due to the density difference. The products are methane, carbon dioxide, and some traces of hydrogen sulfide. The non condensable gases act as a partial insulation blanket by filling up the void space, which helps to reduce the vertical heat losses. Injection pressures are much lower than the fracture gradient, which reduces the chances of breaking into thief zone.

The SAGD process, like all gravity driven processes, is extremely stable because the process zone progresses by means of gravity segregation, and there are no pressure driven instabilities such as conning, fracturing, or channeling. It is vital to maintain a volume balance; it means that each unit volume injected is replaced by each unit volume withdrawn or reduced. If bottom water influx develops, this indicates that the pressure in the water is higher than the pressure in the steam chamber, so this pressure should be balanced. It is obvious that the pressure in the water zone cannot be reduced, so the pressure in the steam chamber and production well must be increased. This increase in pressure is achieved by increasing the operating pressure of the steam chamber through the injection rate of steam or by reducing the production rate from the lower well.

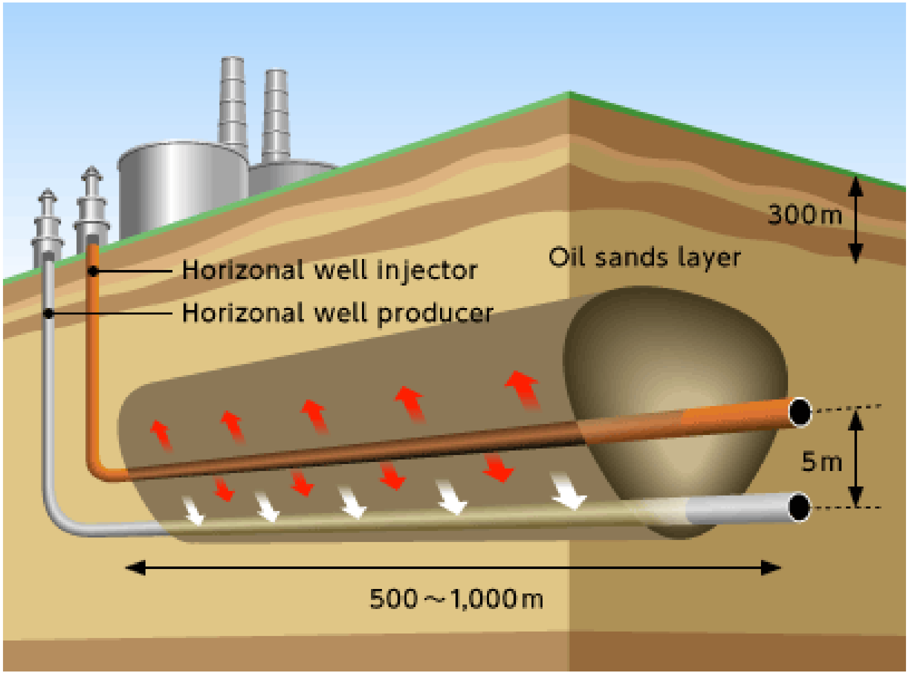


Figure 4-4- A perspective of SAGD project by using two horizontal wells

(SPECIAL REPORT: EOR/HEAVY OIL SURVEY: 2010 WORLDWIDE EOR SURVEY)

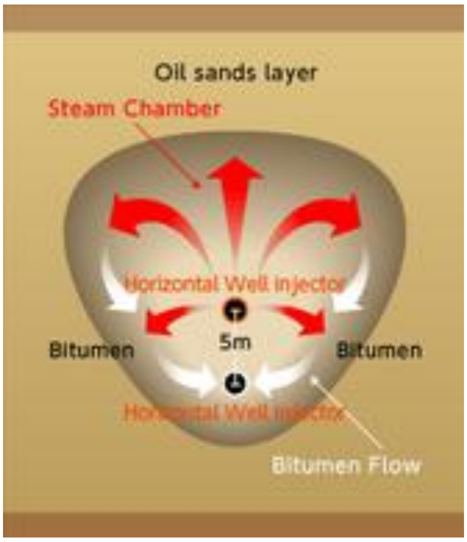


Figure 4-5- Mechanism in SAGD process

*(*SPECIAL REPORT: EOR/HEAVY OIL SURVEY: 2010 WORLDWIDE EOR SURVEY)

Parameter	Desirable extent
Net Thickness(ft)	The main Net Thicknesses more than 35 foot
Depth (ft)	<4500
Pressure (psi)	150
Permeability (md)	>1000
Vertical permeability (md)	>100
Oil viscosity (cp)	>2000
Transmissibility m.md/cp	>5
Porosity (5)	>20
Other positive characteristics	no gas cap and swelling clays

Table 4-10- proper parameters to apply SAGD project (NIOC)

Environmental Impact

The process of SAGD is non-cyclic, meaning that steam has to be constantly produced by the consumption of natural gas and injected into the system. This is costly in economic and environmental terms. This is the most dominant adverse consequence of SAGD. SAGD also negatively affects the environment in its large consumption of water. A large amount of fresh water is needed for steam generation, and then the resulting effluent water of the process must be treated and deposited. However, water recycling can be done to minimize this impact, and is in many cases. As well, some formation damage can occur due to clay swelling.

4-4-10- VAPEX process

The VAPEX method of recovery in conventional, non-fractured heavy oil, sandstone reservoirs (like those in the Canadian) is a method that oil and gas companies use to recover resources with a high viscosity. This method is very similar to the SAGD method but uses hydrocarbon solvents to dilute the bitumen or heavy oil to allow for a more environmentally efficient and cost effective recovery process.

Like the SAGD method, two horizontal wells need to be drilled in order for the VAPEX recovery process to commence. One well is drilled down to the bottom of the formation (production well), while the other well is drilled about 5 meters above the first well (injection well). The hydrocarbon solvent is injected into the injection well. The solvent dilutes the heavy oil and bitumen which begins to flow down to the bottom of the formation. The production well is then used to extract the resources from the reservoir. Figure 4-6 shows the simplified process, emphasizing on the need for horizontal wells and illustrating that you can use more than one injection well to improve the results.

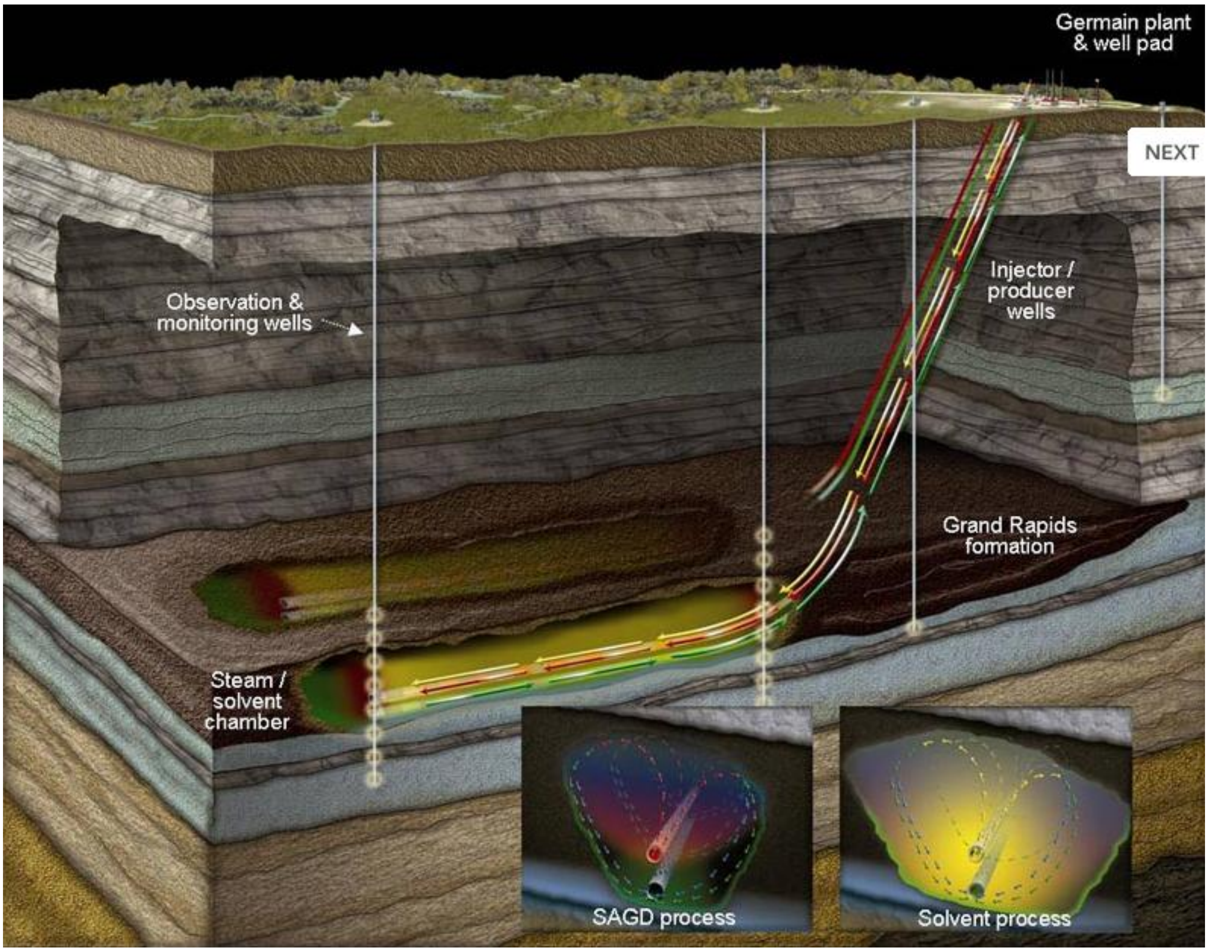


Figure 4-6- A perspective of VAPEX mechanism (**Germain sub-surface plan**)

An important step in this process is the recycling of the hydrocarbon solvent. After injecting the reservoir with the solvent, a vapor chamber is formed between the two wells. The solvent evaporates from the diluted oil and rises against the flow of water and oil through the porous reservoir, which simultaneously heats the passing water. The vapor moves to the top far reaches of the chamber where it is dissolved in cold, undiluted oil and the process can begin again. The recycling of the solvent extends the solvent-oil interface created by the chamber in the lateral direction. This allows for more and more oil to be extracted (until gravity stabilizes the boundary) as the solvent continues to dissolve, evaporate, condense and dissolve again.

This process also calls for hot water to be injected with the solvent. This was not mentioned before because the energy required (and hence cost) to heat up the water is vastly small in comparison with the energy costs for heating steam to be injected. The hot water has two major purposes in the process:

1. To help decrease the viscosity of the reservoir oil.
2. To increase the reservoir temperature so that the solvent can evaporate and hence be recycled.

Parameter	Desirable extent
Net Thickness(ft)	>35
Gas cap Net Thickness(m)	<1(less than 20 meters also may be Commodus economically
Permeability (d)	>1
The rate of mobile oil (bbl/acre-ft)	>500

Table 4-11- Proper parameters to apply VAPEX project (NIOC)

Environmental Advantages

The VAPEX process is more environmentally friendly compared to other in situ methods. Since VAPEX process is a non-thermal production method with a lower energy requirement; the following result as major environmental advantages:

- Approximately 93% less natural gas is required in VAPEX compared to other steam processes. Steam is only used to recover the VAPEX gas for solvent recycling.
- Also, almost 93% less fresh water is used in VAPEX compared to other steam processes.

With VAPEX, partial upgrading of the oil occurs in situ; this makes the process more environmentally viable due to:

- Reduction in hydrogen usage
- Reduction in emissions and hence, less greenhouse gas emissions into the atmosphere

Economical Advantages

Not only does VAPEX provide greener alternatives, but it also can be more economically practical. The costs for running the VAPEX process are appealing since:

- Facilities used are simple
- Energy costs required for operation are low
- No spending required for steam generation, oil-water separators, and water conditioning
- The VAPEX solvent stands for a small slice of the costs (the majority of it is recycled for reuse)

Comparison with SAGD

Table 4-12 below represents the environmental and economic advantages when using the VAPEX process compared to the SAGD method for heavy oil extraction. The numbers shown are on a basis of 4,000 cubic meters oil production per day.

Process	Natural Gas (m^3/day)	Fresh Water (m^3/day)
SAGD	1,150,000	85,000
VAPEX	1,700	110

Table 4-12- Natural Gas and Fresh Water Consumption in VAPEX and SAGD (NIOC)

The similar characteristics of SAGD and VAPEX:

1- Both of them are used to produce oil with high viscosity.
2- The main drive in both mechanisms is the gravity drainage drive.
3- Use of horizontal well is suggested in both methods.

Chapter five

The process of oil recovery from Mund field

5-1- Geological setting of Kuh-e-Mund oil field

Kuh-e-Mond is the largest on shore heavy oil (HO) field in Iran, found in a giant anticline with a NW-SE trend, parallel to the Zagros orogenic belt. Kuh-e- Mond was discovered in 1931 and systematic exploration began in 1984. This relatively symmetrical anticline is 90 km long and 16 km wide with an estimated minimum HO resource base of 6 Bb OOIP, found in three separate reservoirs with depths ranging from 400–1200 meters and oil viscosities of 570–1160 cSt *in situ*. A large number of faults cut the axial plane of the structure causing some strata displacements around the central and plunging parts of the structure. The average dip of the southwest and northeast flanks of the anticline is 17° and 15°, respectively.

Figure 5-1- A perspective of Kuh-e-Mund field earth zone (Google earth)

The Asmari Formation is considered to be a single reservoir. The Jahrum Formation of Eocene age mainly consists of highly fractured light brown medium-grained crystalline dolomite (Type I/III) with intercrystalline vuggy and fracture porosity. The lower Jahrum is mainly white detrital dolomite and partly anhydritic and cherty limestone (Type I/III). This reservoir has a maximum gross thickness of 450 m. Original minimum OOIP has been estimated at about 3.6×10^9 bbl.

The Cenomanian Sarvak Formation is mainly composed of highly fractured marly neritic and pelagic limestone with interbedded shale layers. This formation is divided into three main units, the upper, middle and lower Sarvak. The upper unit is clean limestone with some slightly argillaceous zones and comprises the Sarvak HO reservoir with a gross thickness of 100 meters. In the middle Sarvak, shale and marls dominate, and the lower Sarvak is mainly marly limestone with some shale bed intercalations. Heavy mud losses in drilling indicated a highly-fractured formation. The Sarvak HO reservoir contains an estimated OOIP of 3.6×10^9 bbl.

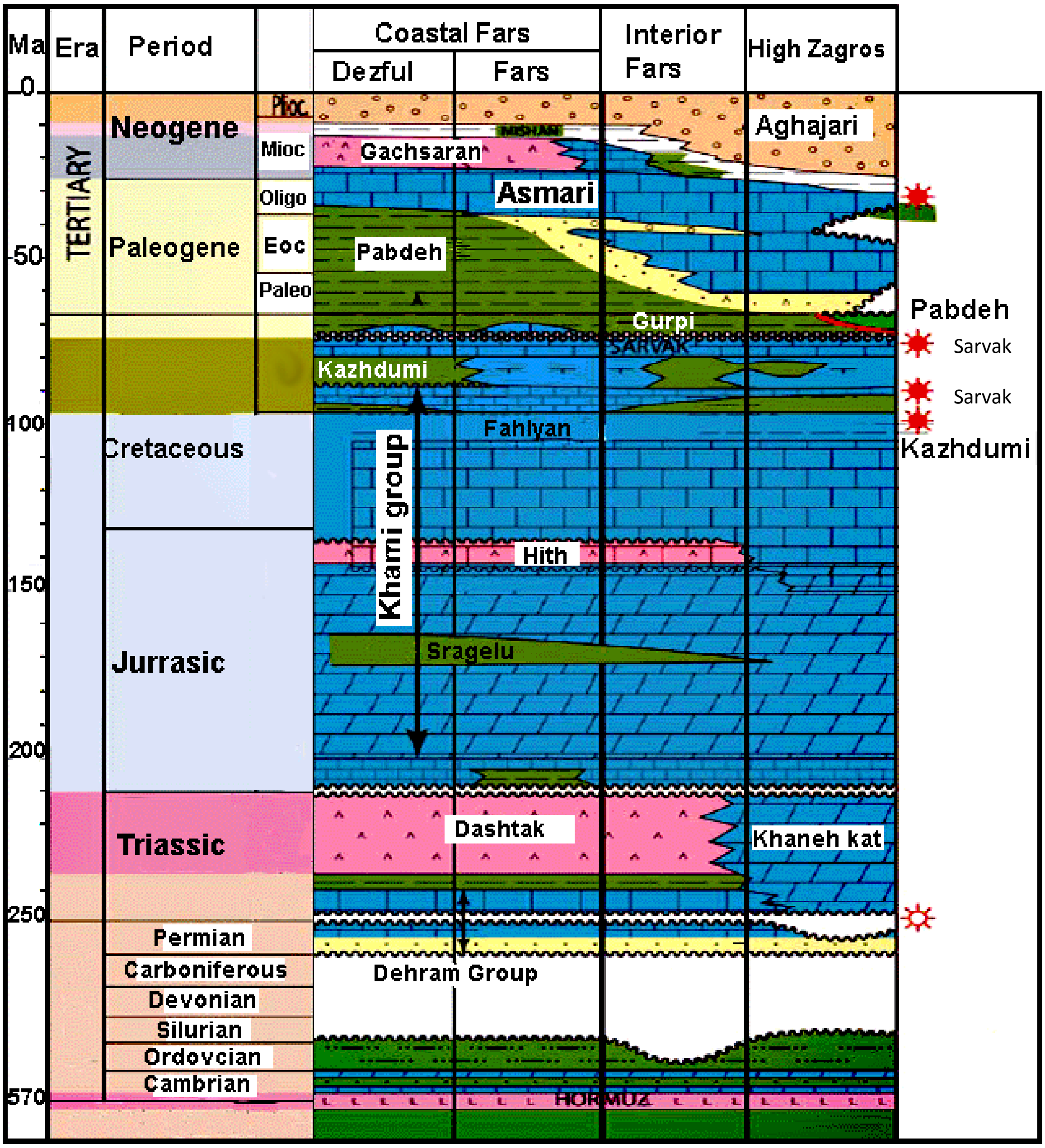


Figure 5-2- Lithostratigraphic column of the reservoirs at the Kuhe-e-Mond HO field (Modified from Morgenstern, N.R. 1962)

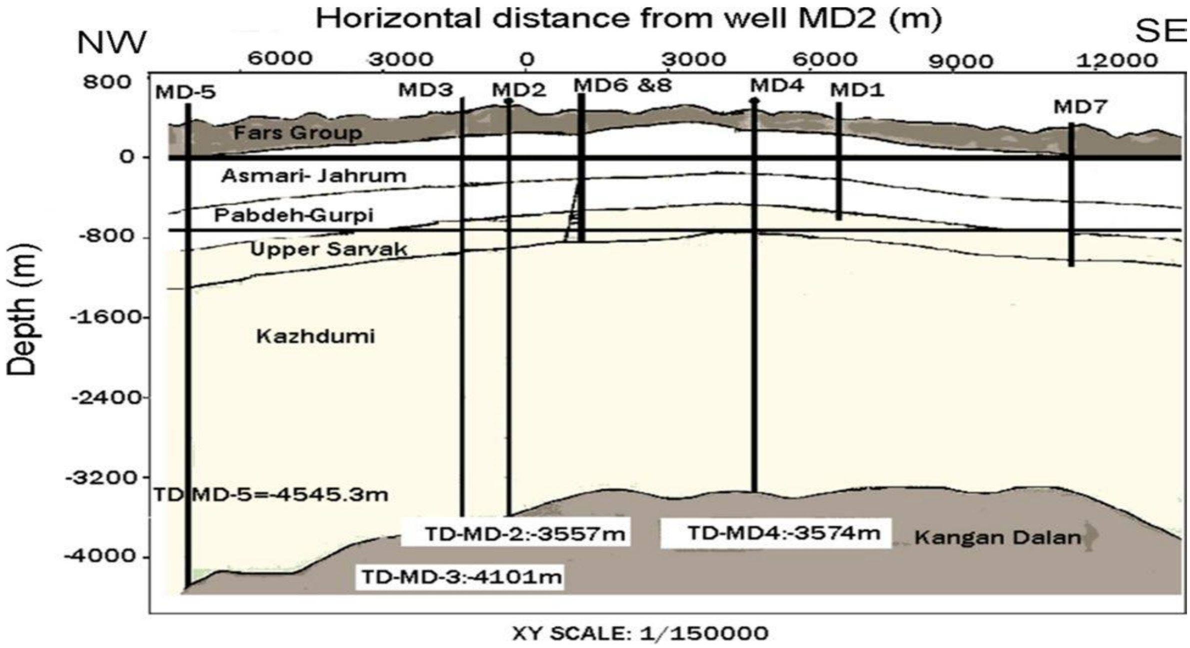


Figure 5-3- Geological cross-section of the Kuh-e-Mond anticline (NIOC)

5-2- Reservoir and Fluid Properties of the Kuh-e Mond

A representative screening parameter database is vital in production technology screening and recoverable reserves evaluation of a family of HO reservoirs to decide which are the best reservoirs deserving of most attention. As the first part of a production technology selection program, lithostratigraphic information and fluid properties for the HO reservoirs at the Kuh-e Mond HO field in SW Iran were collected, reviewed and are summarized in Table 5-1 This database was constructed using drilling and geophysical log data, as well as field and laboratory tests conducted in the reservoir (i.e. well tests) or on samples taken from exploration wells. Average reservoir and fluid properties for each selected reservoir was estimated from the available data. This database will serve as input for a production technology screening program.

The number of drilled wells	7
The volume of oil and gases in situ	4 billion barrels
The reservoir present pressure (psi)	1400
The type of reservoir rock	Fractures carbonate
porosity %	19%
Oil API degree	13-15
Oil Sulfur range	5% of weight
Oil saturation (%)	78
Temperature (F)	140

Table 5-1- A summary of Kuh-e-Mund field (NIOC)

5-3- STOIIP

In table 5-13 you can see the report of volume calculated of the Sarvak reservoir. We can see that the OIIP in Sarvak reservoir is 547 [×10ˆ6 m3]. The most volume of oil is located in first zone of Sarvak (Sarvak top) which has 20 m thickness.

$$\text{STOIIP} = V_b \times \frac{N}{G} \times \phi \times (1 - S_w) \times \frac{1}{B_o}$$

V_b	= bulk volume of the reservoir rock. bbl	$V_b = A \times h$
N/G	= net/gross ratio of formation thickness, fraction	
ϕ	=porosity, fraction	
S_w	= water saturation, fraction	
B_o	= oil formation volume factor, bbl/STB	A = area of the reservoir, ft
STOIIP	= stock-tank oil initially in place. STB	h = thickness of the reservoir. ft

Case	Bulk volume [×10ˆ6 m3]	Net volume [×10ˆ6 m3]	Pore volume [×10ˆ6 rm3]	HCPV oil [×10ˆ6 rm3]	STOIIP [×10ˆ6 sm3]
Sarvak Case	12276	9036	1049	601	547
Zones					
Sub Sarvak top	2296	2099	321	210	191
Sub Sarvak 1	999	30	4	2	2
Sub Sarvak 2	2222	1909	180	97	88
Sub Sarvak 3	2411	2015	308	184	167
Sub Sarvak 4	1718	1359	111	52	48
Sub Sarvak 5	1425	1011	76	33	30
Sub Sarvak 6	1205	613	49	23	21

Table 5-2- Volume calculation report of Sarvak formation zones (NIOC)

5-4- Petrophysical Modeling

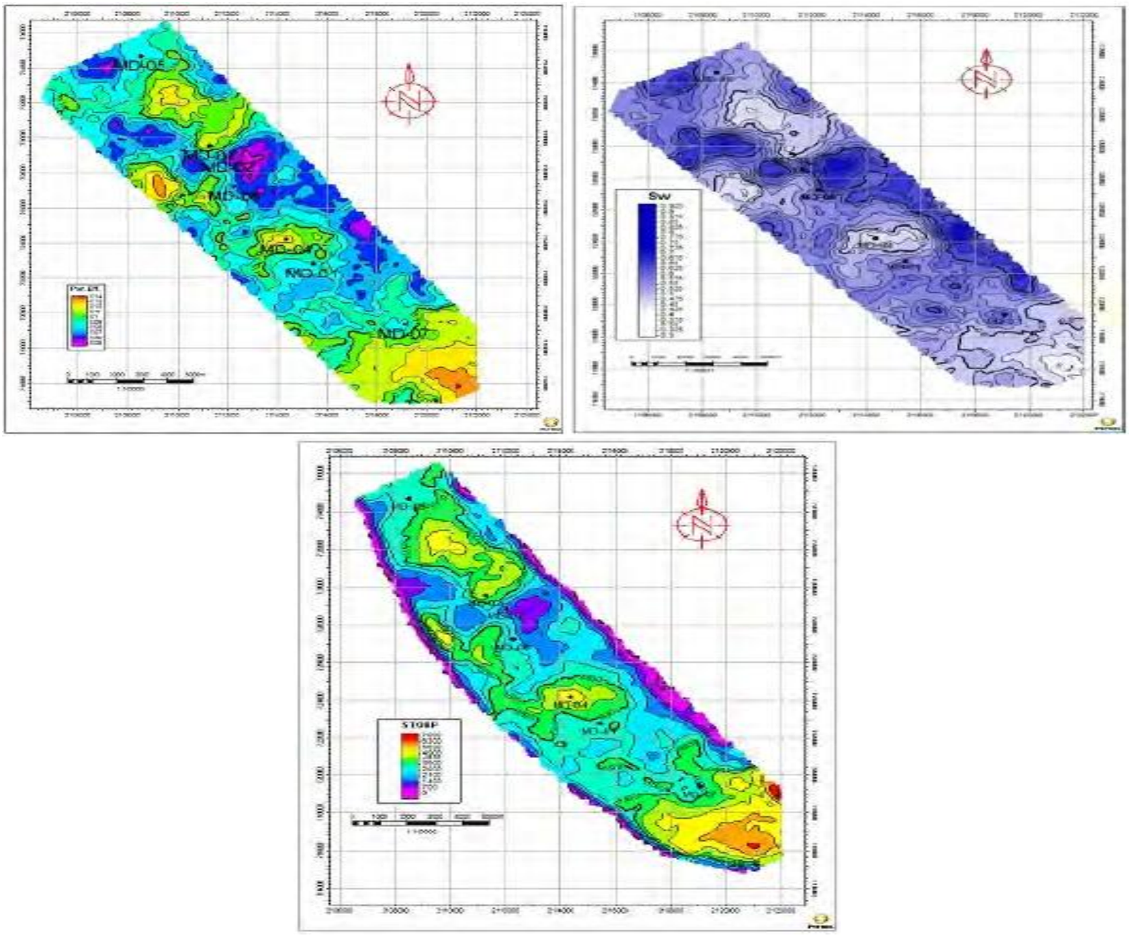


Figure 5-4- **map of average Reservoir properties, effective porosity (left), Water saturation (right) and oil in situ (bottom) (NIOC)**

From Petrophysical model we can understand some properties of reservoir like Permeability and porosity distribution or water saturation.

- The effective porosity map, shows the high porosity areas are in center and southeast of the field.
- The estimated oil in-situ of Sarvak Reservoir is 547.10^6 (m3), which are located in center of reservoir (under Sub sarvak top zone) and south of reservoir (Under Sub Sarvak 3 zone).

5-5- Best enhanced oil recovery method for Kuh-e-Mund field of Sarvak reservoir

The characteristics of Sarvak reservoir was evaluated with the desirable extent of each EOR methods, and the resulted was gained as follow:

1- Miscible injection of nitrogen and flue gas

   By attending to this point that for nitrogen and flue gas injection, oil API degree of the reservoir should be more than 35 and the oil should be light, so this method is not recommended.

2- Miscible injection of hydrocarbon gas

   Because the API degree of Sarvak reservoir is low, so hydrocarbon gas injection is not recommended.

3- Miscible injection of CO^2 gas

   It seems inappropriate because API degree of Sarvak reservoir is low, and oil viscosity is high in this reservoir, but by attending to new studies which were done recently especially in Willmigtone reservoir in California or Bati Roman in Turkey, that their API degree is in the range of Sarvak, these studies were successful, so more surveys should be done in this field.

4- Gas injection immiscibly

   This reservoir has appropriate parameters for immiscible injection, and can be used before steam injection project. The studies have shown that nitrogen gas is more appropriate than other gases for heavy oils reservoirs. Generally this method is recommended for heavy oil reservoirs, in which there are no possibility to use thermal methods.

5- Water injection

   Water injection is not appropriate because the viscosity of reservoir oil is very high. It should be considered that one of the reasons of water injection project failure in heavy oil reservoirs, is that this process results in reduction of reservoir temperature and then increase of oil viscosity.

6- Injection of Micellar and polymer solution compound, ASP, alkali materials, gel, polymer

   Generally chemical methods response better in sand rock reservoirs and also the oil viscosity of reservoir should be very low, and the reservoir oil API should be more than 20, so this method is not appropriate, meanwhile these methods usually are used in order to improve water flooding methods.

7- WAG injection

8- This method seems inappropriate for high viscosity and low reservoir oil gravity but by considering the researches which recently have been done, especially in Turkey reservoirs that are similar to Iran reservoirs, this item should be surveyed.

9- Microbial method

From the reservoir rock point of view, there are required characteristics to do this project but the oil API is lower than desirable extent, also in relation with the reservoir fluid characteristics more information is needed to conclude more accurate.

10- Open recovery

This method is impossible because of high depth of the reservoir.

11- Combustion in situ

This method is more effective in sand rocks with high porosity. Regardless of the reservoir type, other parameters are desirable for this process implementation.

12- Steam injection

The reservoir has all of the required characteristics for performing this process.

13- Cold production

Depth, porosity and pressure of the reservoir are not appropriate for this process.

14- SAGD, EA_SAGD, SAGP

Sarvak reservoir has the needed characteristics for these processes, but some researches should be done in relation with the fractures conditions.

15- VAPEX

Its mechanism is such as SAGD, and its use seems suitable in this scope.

Miscible Injection of Nitrogen	inappropriate
Miscible Injection of HC Gas	inappropriate
Miscible Injection of CO2	more surveys
Gas Injection(immiscibly way)	inappropriate
Water Injection	inappropriate
Polymer, Alkaline or Gel	inappropriate
WAG Injection	more surveys
Microbial	inappropriate
Surface mining/open recovery	inappropriate
Combustion in situ	inappropriate
Steam Injection	**PASS**
Cold Production	inappropriate
SAGD, EA-SAGD	**PASS**
VAPEX	**PASS**

Table 5-3- Heavy Oil Production Technologies and Technical Screening Criteria

5-6- Steam injection simulation with SAGD method in Kuh-e-mund field

As it was said in previous chapters, SAGD is an effective method in production of heavy oil and bitumen. Clearly, in a SAGD project, steam is injected to a horizontal well which is located on the top of another horizontal well (which is used as a production well).

This project can be applied by using several injection and production horizontal wells in different points of the reservoir.

5-6-1- Thermodynamic properties of oil and steam

Here is the one I used to understand the issue myself. It is a plot of enthalpy, that is the energy in the water (or steam), versus pressure. Pressure is measured in bars and is on a log scale. There are also a number of isotherms plotted in red, isotherms are lines of constant temperature. So for water at a particular pressure with a certain amount of energy we can use this chart to read off both the state of the water (gas or liquid) and the temperature.

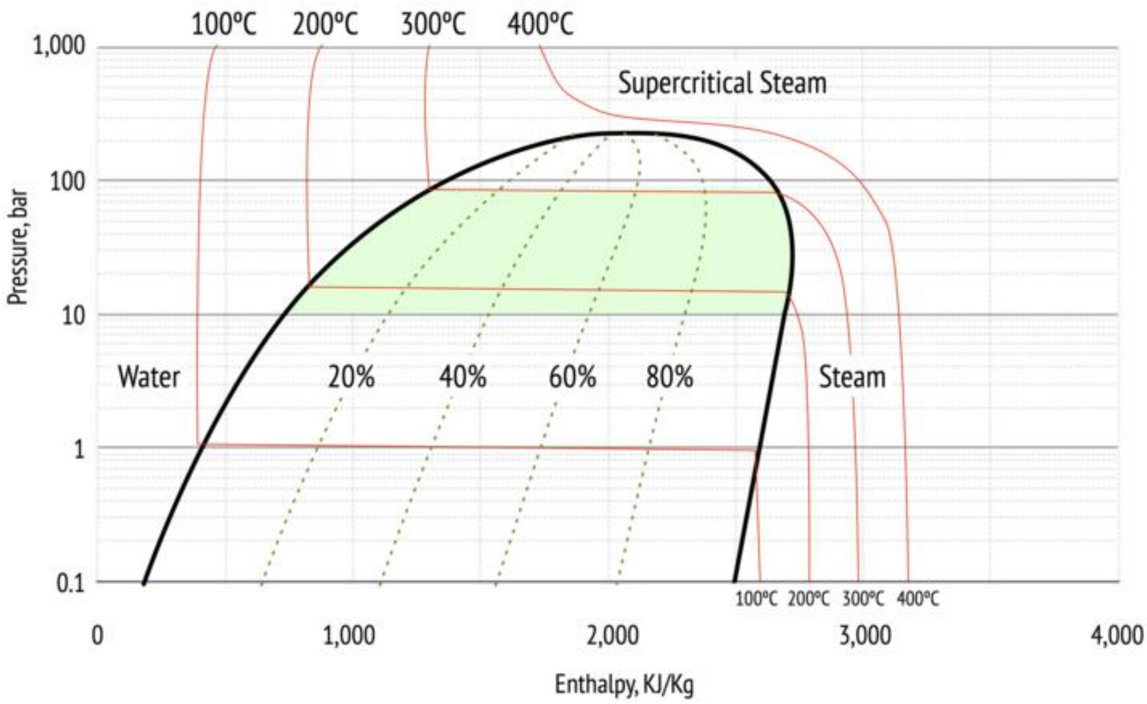


Figure 5-5- Pressure vs. Enthalpy for water, showing phase, steam quality and temperatures as isotherms (NIOC)

The thick black line is the phase envelope; to the left of the phase envelope water is liquid, to the right it is steam. To get our eye in on the chart let's go along the horizontal line at one bar of pressure and imagine boiling a kettle. At first the water is cold, as we add energy, the kettle warms and the temperature rises, soon we reach the left hand side of the phase envelope where the kettle begins to boil – you can see the 100ºC isotherm turns at right angles just here – as we add more and more energy the temperature doesn't change, but all the water turns into steam. Inside the phase envelope the dotted lines tell you the proportion of steam, or steam quality. When we are at the right hand side of the phase envelope we have 100% steam and the kettle has boiled dry. You can see it does take an awful lot of energy to turn water into steam. But once it is steam, if we keep adding heat, taking the temperature from 100ºC to 200ºC doesn't increase the energy in the steam by very much.

And that is the whole point of steam flooding. We inject steam to heat up the oil and to do that we have to heat the whole reservoir, all the oil in it and to some extent the rocks above and below as well. So we need a mechanism that delivers an awful lot of energy into the reservoir. It is the energy released as steam condenses and turns back into water which does that work.

As the pressure increases the enthalpy of condensation (illustrated on the chart by the distance between the two dark lines) reduces until, at about 200bar, there is no difference between steam and water and no enthalpy of condensation at all. So at 200bar steam is not as efficient at transferring energy and heat into the reservoir. In fact at 200 bar steam that has as much energy in it as steam at 1 bar and 100ºC, has a temperature of almost 400ºC.

The conventional limit for steam flooding is considered to be 3,000' which for a normally pressured reservoir is about 90bar, just around the top of the green zone on the chart. At that pressure the steam temperature is about 300ºC (600ºF). Most conventional downhole components have a temperature limit of 150ºC (300ºF), it takes specially designed equipment to work at such high temperatures, and there are few components rated for much more than 300ºC. So, in the end, it is really the temperature of steam at reservoir pressure that is the main reason why steam flooding has a practical depth limitation of about 3,000'

5-6-2- Steam quality

By attending to this point that boilers which are used for steam injection usually produce some moister (wet) steam than dry steam, the quality of the produced steam should be specified. Steam quality is calculated through following equation:

$$x = \frac{M_v}{M_v + M_L} = \frac{V_{vf}}{V_{vf} + V_{If}}$$

m_v = mass of vapor phase

m_l = mass of liquid phase

V_{vF} = cold water equivalent (CWE) of vapor phase

V_{lF} = cold water equivalent (CWE) of liquid phase

For two-phase steam (moist steam), its quality, temperature and pressure should be specific to determine its other thermodynamic properties. Two properties of these thermodynamic properties which are important in steam injection processes are specific volume and enthalpy.

Specific volume:

The steam specific volume is calculated through the follow equation:

$$v = v_f(1 - x) + v_g x$$

$v_f = \ ft^3/lbm$	Volume of saturation liquid
$v_g = \ ft^3/lbm$	Volume of Saturation Gas

When the pressure is increased in the reservoir, the steam volume decreases significantly, in a steam injection process to the reservoir with average pressure 200psia, the steam will have a volume four times more than the steam volume in a reservoir with the pressure of 800psia. By increase in occupied volume by steam, the steam is more in relation with the reservoir internal areas and the sweeping action will be performed well. Steam injection in lower pressure results increase of oil recovery, economically.

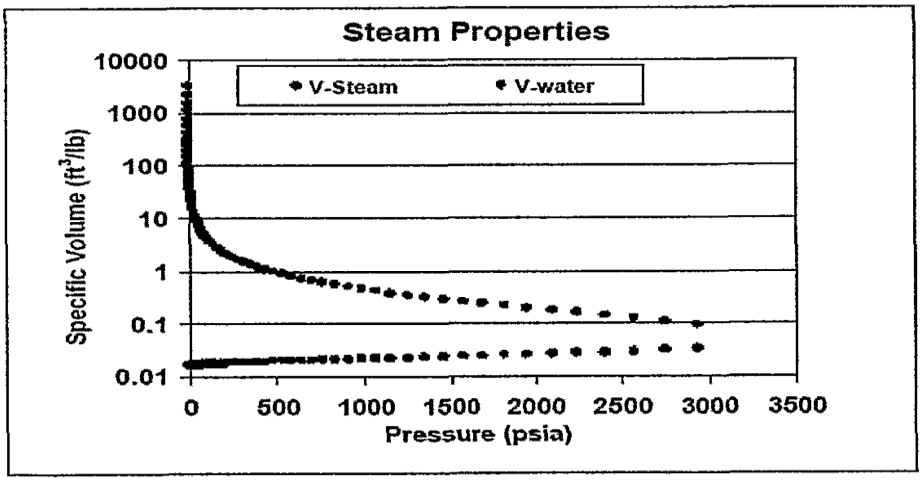


Figure 5-6- the steam specific volume to saturation pressure (NIOC)

Also the volume of a steam barrel (CWE 350lbm) and the different steam qualities can be gained through steam tables.

$$V = m\upsilon$$

where:

V = volume of steam, ft^3

m = weight of one barrel of water = 350 lbm

υ = specific volume of steam, ft^3/lbm (obtained from Equation (30))

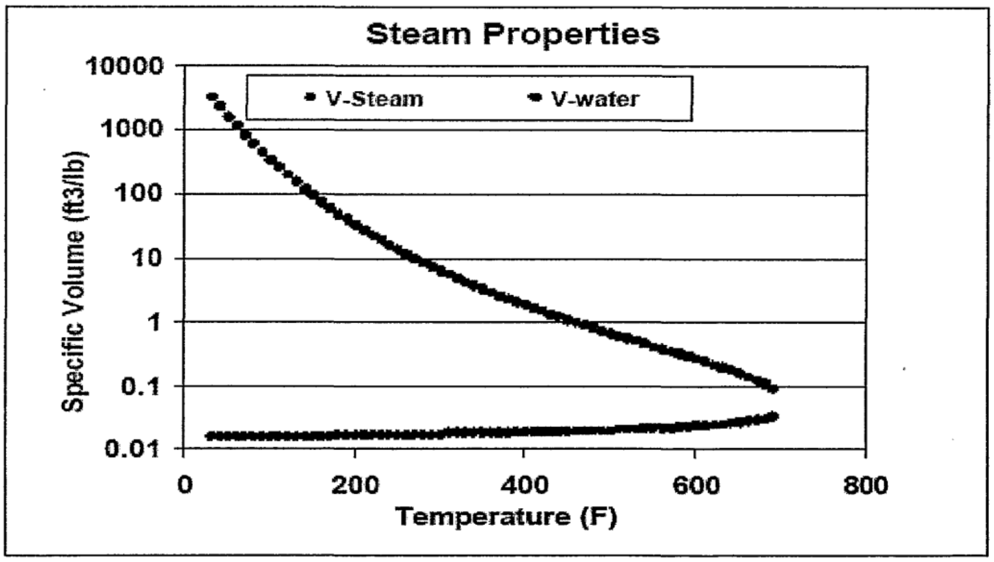


Figure 5-7- the steam specific volume to saturation temperature (NIOC)

5-7- Research method

Simulation is done for reservoirs with steam injection by SAGD method, and by considering natural fractures and dual permeability system and model selection of the characteristics of networking system and blocks dimensions in three points of coordinate axis.

In this study, the characteristics of the reservoir rock such as the fractures distance from each other, fractures and matrix porosity, fractures and matrix permeability in three dimensions, matrix and fractures thermal characteristics such as heat conduction of rock, reservoir fluid characteristics involves the water in the fractures and their heavy oil and gas and their compressibility, thermal reduction of the reservoir top and bottom rocks and fluid characteristics (water and oil with no solvent gas), heavy oil and water molecular weight and their compressibility and oil thermal expansion, critical temperature and pressure of water and oil viscosity value at temperature and relative permeability values of oil – water and the reservoir primary conditions as crack and matrix saturation and crack and matrix temperature and producing information involves data related to injection and production well as the pressure of the bottom of the well in the beginning and its maximum for injection well and its minimum for production well and the value of injective steam are the factors which have been considered and during different scenarios of steam injection and its economic optimizing condition, have been surveyed.

5-7-1- The model description

In this work, the employed simulator was CMG-STARS 93.00. Due to high run time because of large area of Kuh-e Mond, a rectangular sector of the field with dimension of 900 × 600 × 300 ft was selected as base case model. To exclude grid sensitivity of the results, the grid sensitivity analysis has been done and 15 × 10 × 15 cells in ***i***, ***j***, ***k*** coordinate were selected as reservoir grid numbers (figure 5-8). Average porosity, permeability and irreducible water saturation of water-wet matrix were set to 13%, 50 md and 20%, respectively. Formation thermal conductivity and rock heat capacity of matrix were set to 24 Btu/ft3. °F and 32 Btu/Day.ft.°F. The Matrix properties are summarized in Table 5-1.We considered two horizon well one producer and an Injector. The considered time for this study is 10 years. Modeling the fracture networks is one of the challenges faced by reservoir engineers and geoscientists when study naturally fractured reservoirs. Therefore, to simulate naturally fractured reservoirs, the dual permeability model has been employed in this study. The dual permeability models, allows one matrix porosity and one fracture porosity per grid block, where the matrix is connected to the fracture in the same grid block. Fracture porosities are connected to neighboring fracture porosities, and the same holds true for neighboring matrix porosities. The fractures with permeability of 2000 md made a network fracture with porosity of 0.05 and 80 % oil saturation. The oil thermal conductivity in the fractures was set to 16 Btu/ft3. °F.

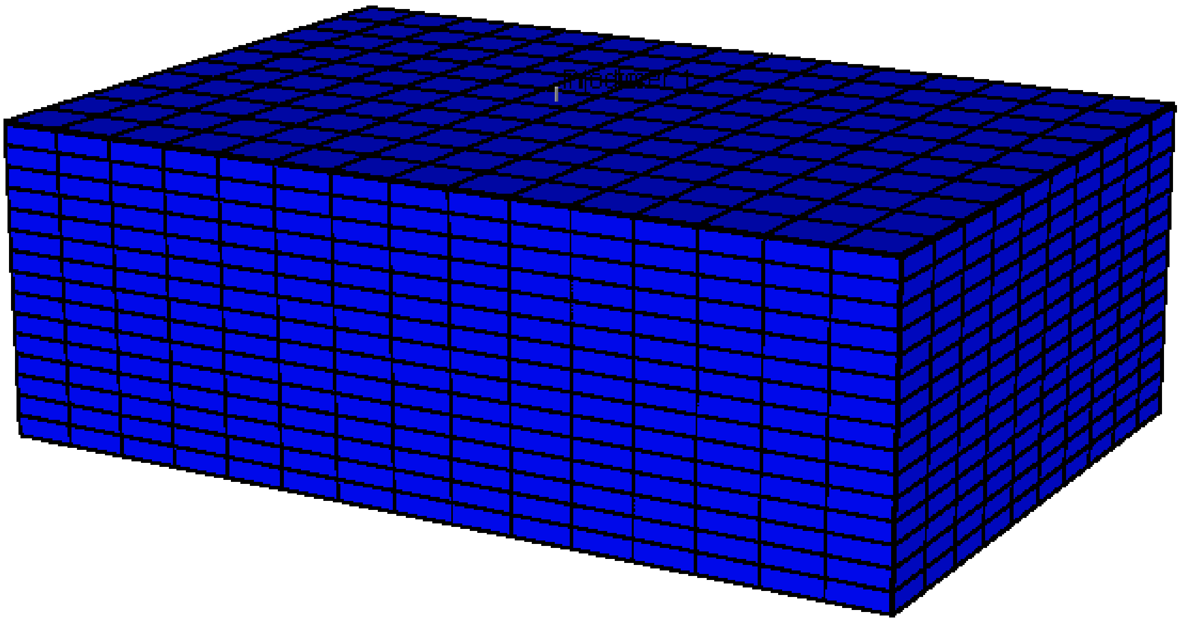


Figure 5-8- Reservoir simulation model

5-7-2 The model network

The model network is considered Cartesian with 2250 blocks (15 block in the x axis, 10 block in y axis and 15 block in z axis), the properties of the designed model is shown in table 5-1.

The block number	2250
Dimension in x axis	900 (Ft)
Dimension in y axis	600 (Ft)
Dimension in z axis	300 (Ft)

Table 5-4- the reservoir dimensions

5-7-3- Properties of the reservoir rocks and fluid

Properties of the reservoir rock and the related viscosity tables which are used in the simulation (Base Case) are shown in the follows:

The reservoir primary pressure (psi)	1400
Primary temperature (F^O)	150
Water primary saturation degree Matrix (%)	20
Oil primary saturation degree (%)	80

Porosity matrix (%)	12
Porosity fracture (%)	5
Kh fracture (md)	2000
Kh matrix (md)	50
Rock Heat Capacity (Btu/ft3. °F)	32
Steam quality	0.9
Steam Injection Rate (bbl/day)	20
Formation thermal conductivity (Btu/ft3)	24

Table 5-5- Properties of the reservoir rock and fluid

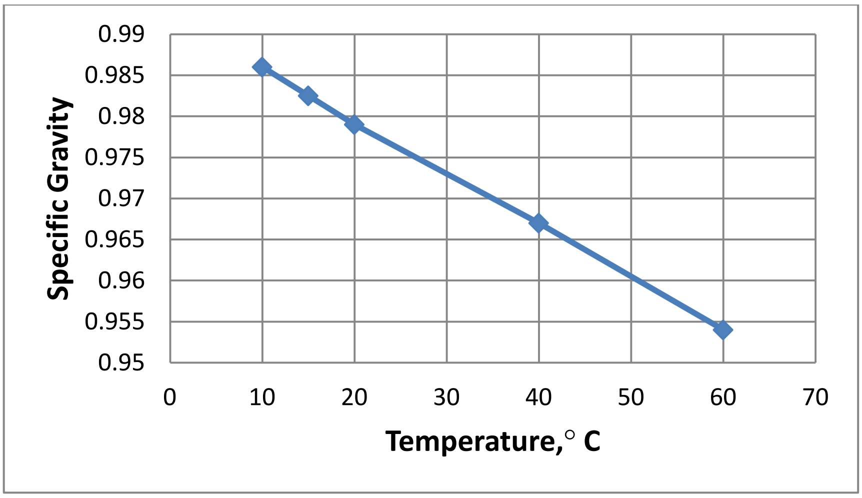


Figure 5-9- The range of oil specific gravity changes at temperature in the reservoir

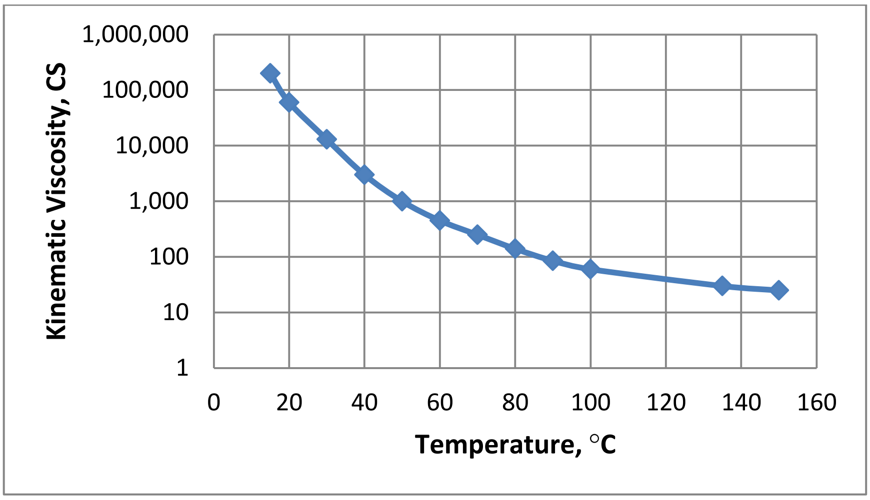


Figure 5-10- The range of viscosity changes at temperature

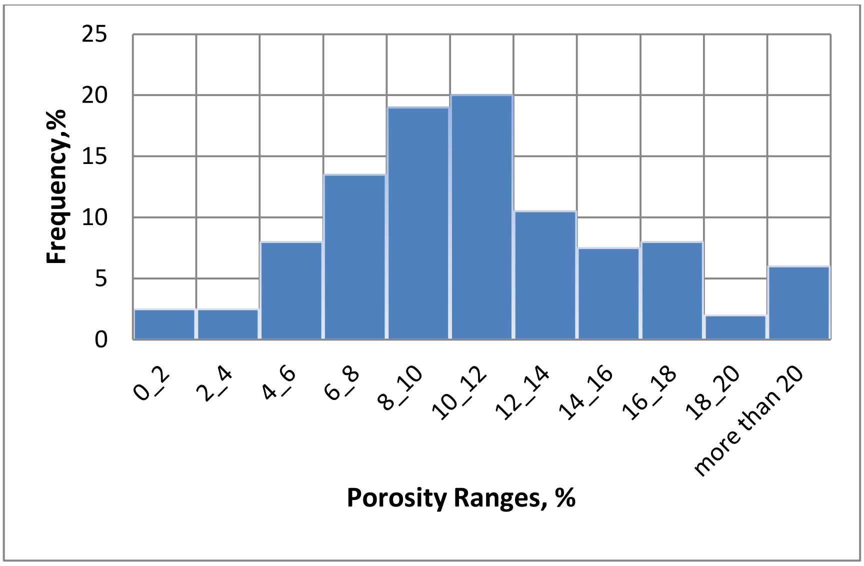


Figure 5-11- Porosity distribution in the reservoir

5-8- RESULTS AND DISCUSSION

This simulation is done by considering two wells, one injection well and the other production well. After running the model, for economic optimizing of the process, a desirable result has been gained about the injective steam properties, its rate, the distance between the wells and the wells position. The most effective factor in this process is the rate of injection fluid. The sensitivity of the model was tested for the following parameters:

1. Steam Injection Rate
2. Cost Analysis
3. Well distance
4. Well position
5. Porosity
6. Permeability

5-8-1- Base Case Analysis

Results show that Steam-Assisted Gravity Drainage (SAGD) process was efficient and has a reasonable recovery factor. Cumulative production oil was around 1263800 (bbl) and recovery factor of 32 (%). The production was started approximately 200 days after start of the process.

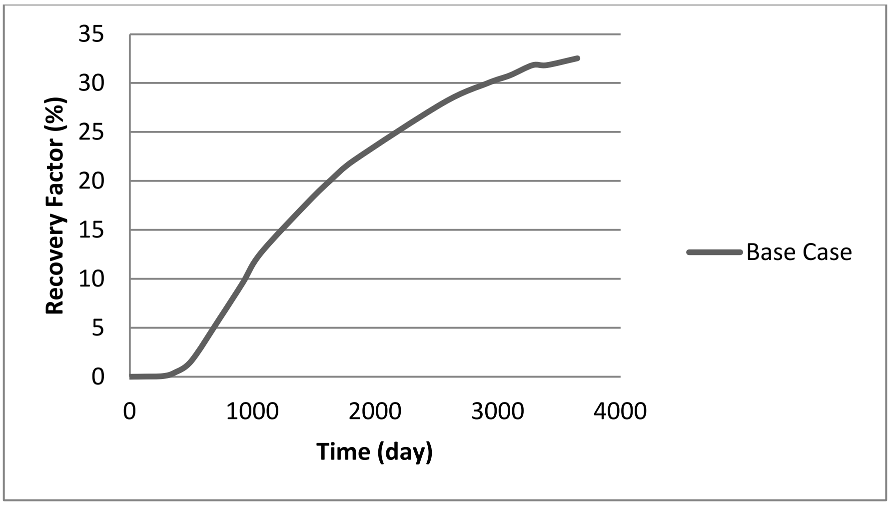


Figure 5-12- Recovery factor of base case in 10 year

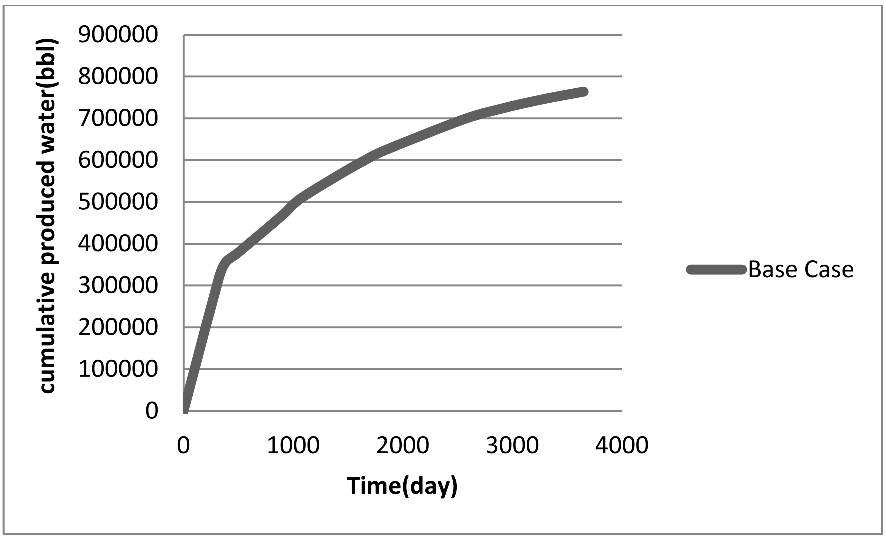


Figure 5-13- total produced water of base case in 10 years

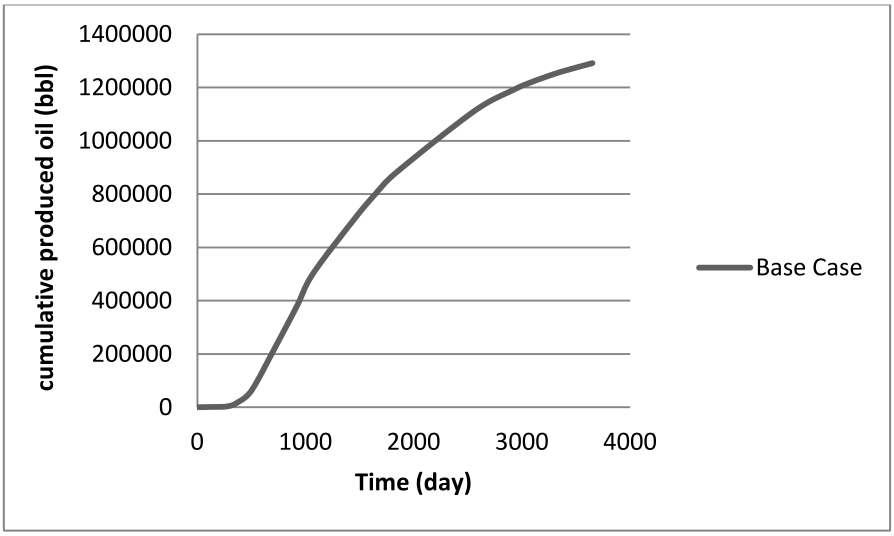


Figure 5-14- cumulative produced oil of base case in 10 years

5-8-2- Steam Injection rate

In figure 5-15 the oil recovery rate is shown for different Rate of injection. This graph shows that the most rate of oil production is related to injection fluid Rate equal to 35 barrels per day and the least is related to Rate equal to 5, but from Rate 20 to 35 barrels per day, the difference in oil recovery is very low and it can be concluded that 20 barrels per day is optimized for the rate of steam injection.

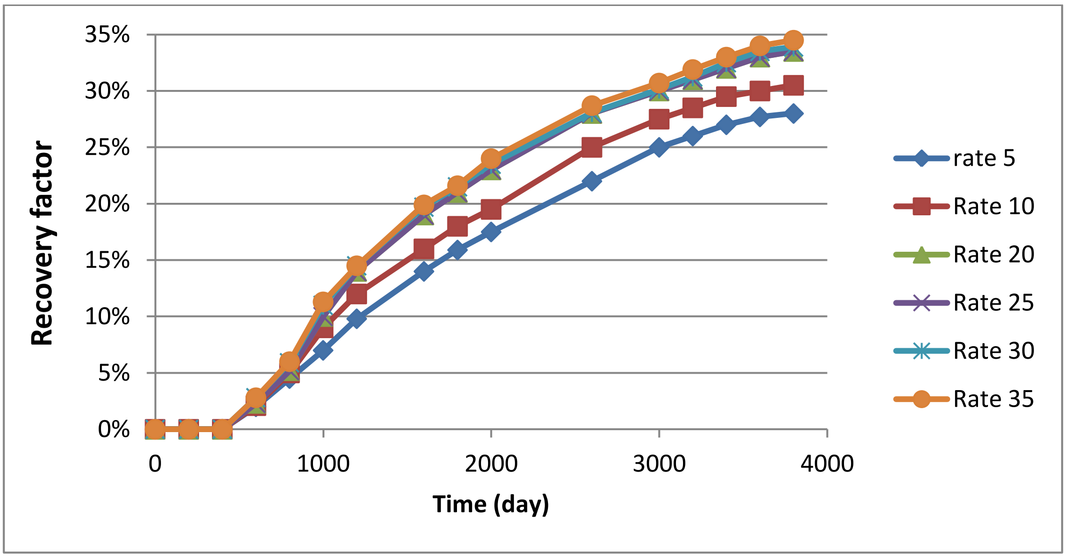


Figure 5-15- Oil recovery rate in 10 years

In figure 5-16 the recovery factor after one year is specified. As it is shown, in short time interval from injection beginning, we cannot see good recovery in different Rates, because oil was not warm in primary times to reduce viscosity and flow oil to production well. Then by reservoir warming and viscosity reduction and the role of gravity drive force, production increased. For getting better results and fast reaching to oil recovery, it is necessary to heat the neighbor environments of well in order to oil viscosity reduction and have better gravity drive.

The researches show that steam alternative injection will be very effective before applying of SAGD process in order to fast reach to oil production in the beginning of the project.

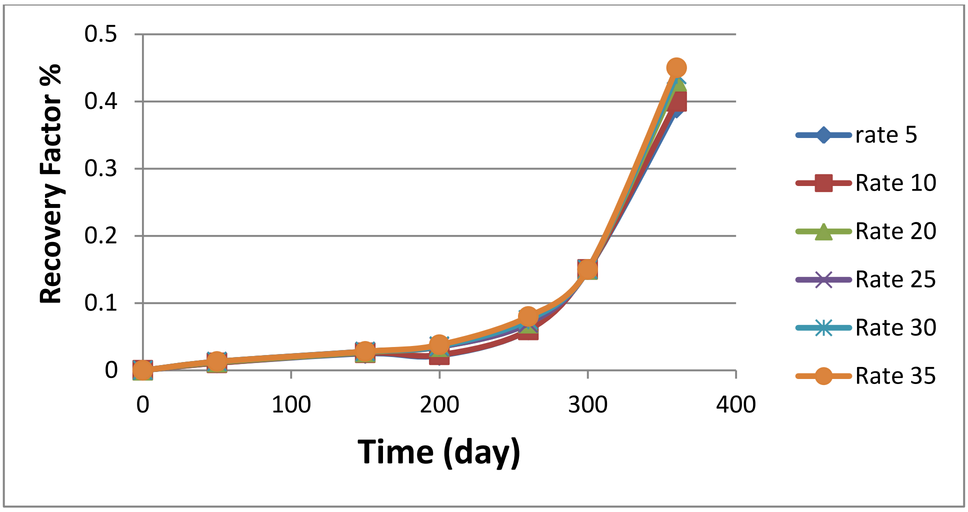


Figure 5-16- Oil recovery rate in 1 year

In figure 5-17 the cumulative produced oil with different injection Rate is shown. As it is specified as the graph related to recovery, here the most rate of oil production is for Rate with 35 barrels per day but its difference with Rate 20 barrels per day is low.

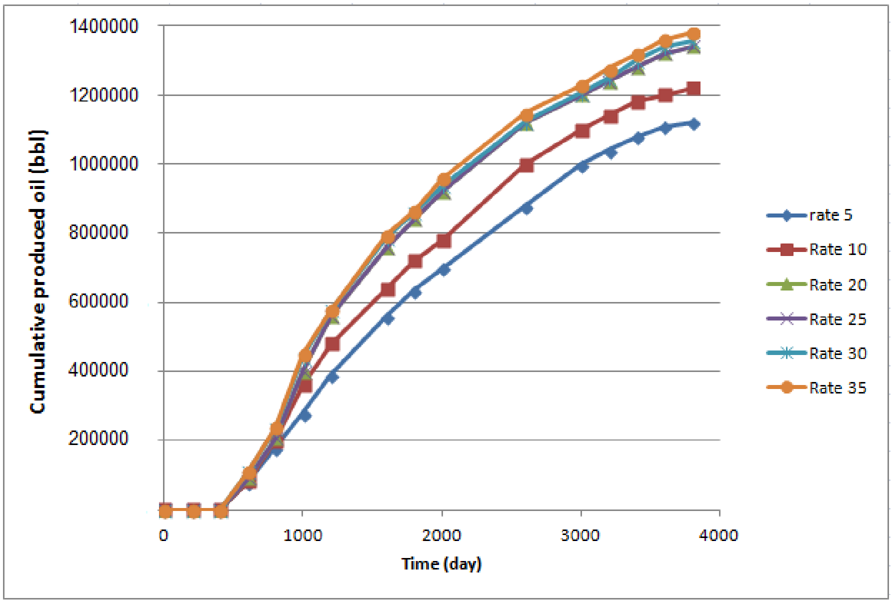


Figure 5-17- The total rate of produced oil in ten years at different injection Rate

In figure 5-18 total rate of produced oil at different injection Rate in different times is shown.

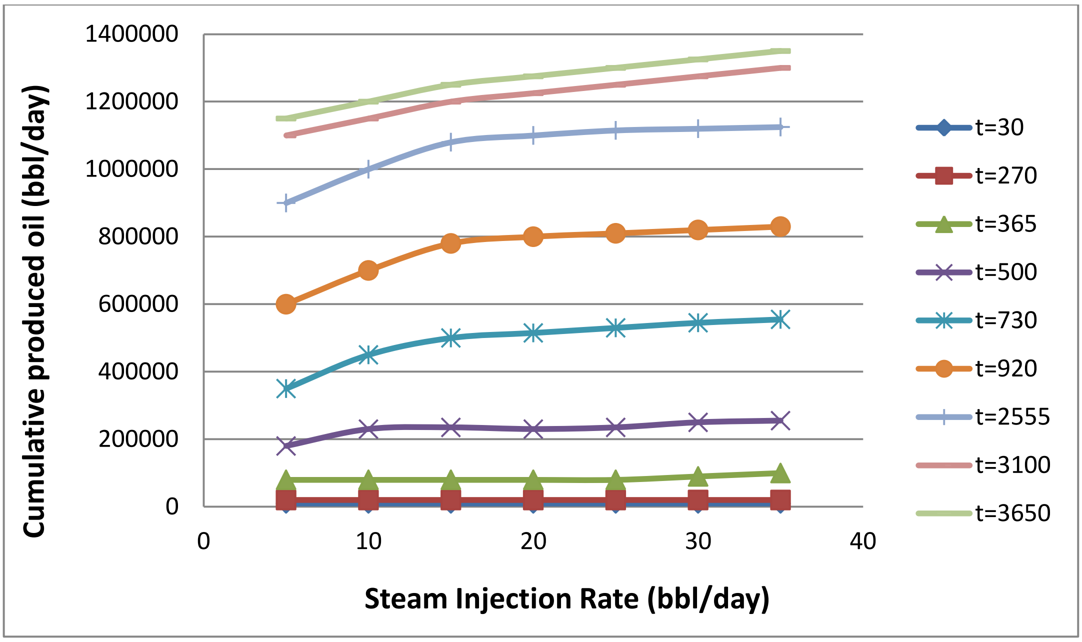


Figure 5-18- total rate of produced oil at different injection Rate in different times

In figure 5-19 the rate of produced oil in each injective Rate is specified to total water cut. As it is clarify in this graph, the range of water cut is constant till Rate equal to 15, but more than this rate has great increase in Rate of water cut. We can conclude that the Rate equal to 20 is optimized.

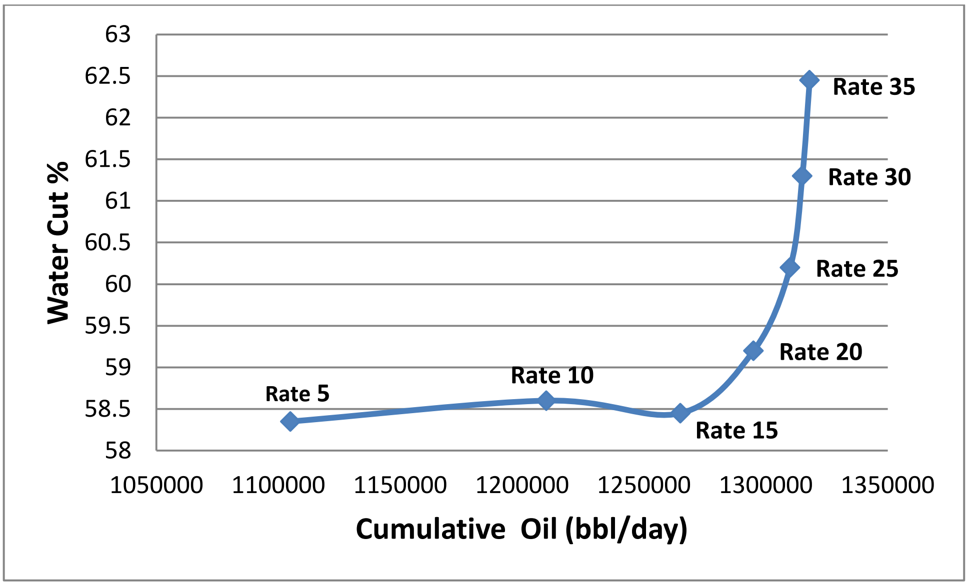


Figure 5-19- total range of produced oil in ten years at water cut

By attending to this point that the results of Rate 15 and 20 are similar, the range of water cut of these two Rate is shown at time, but as it is observed in figure 5-20, the results are very similar.

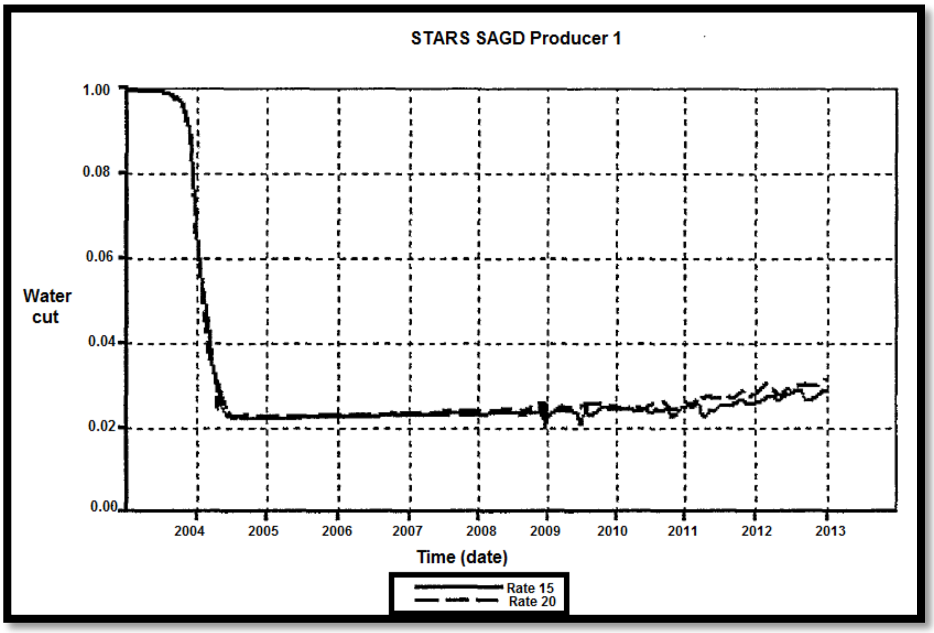


Figure 5-20- The comparison of water cut between Rate 15 and 20 barrels for everyday

5-8-3- Cost Analysis

In figure 5-21 the cost is drawn at different Rates. It can be concluded from this graph that, the cost of produced oil is not so increased by lower Rates of 20 barrels per day, but more than 20, the injection cost has significant increase, so it is concluded from this graph that Rate equal to 20 is optimized.

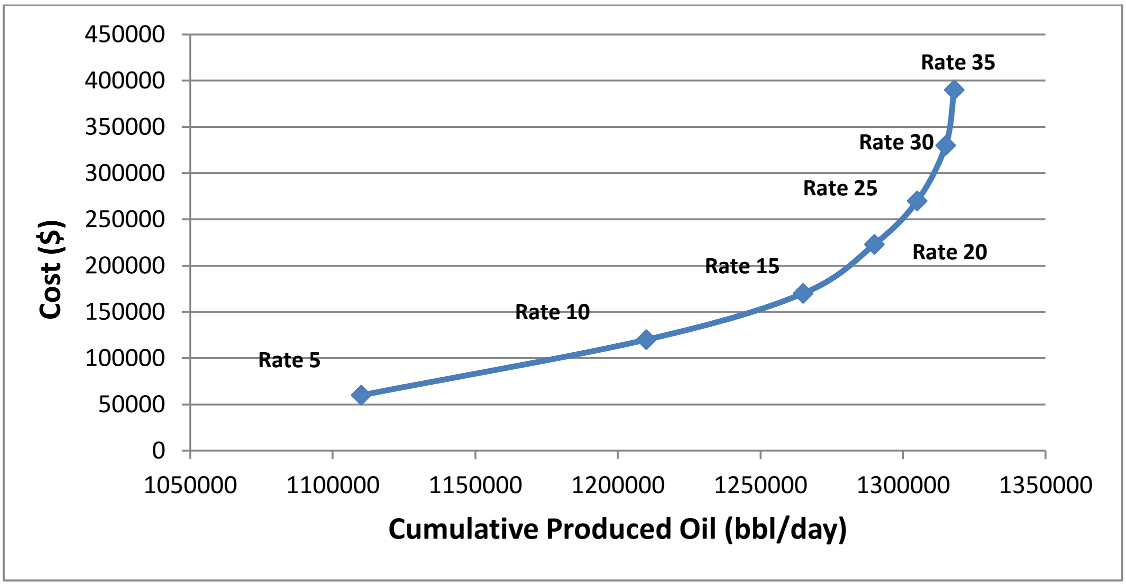


Figure 5-21- The cost range at total produced oil in each injection Rate

Injection cost (Dollar)	The rate of produced oil in 10 years (bbl)	Total injection in ten years (bbl)	Steam injection Rate (bbl/day)
54750	1105700	18250	5
109500	1208900	36500	10
164250	1265300	54750	15
219000	1291300	73000	20
273750	1305000	91250	25
328500	1313700	109500	30
383250	1317500	127750	35

Table 5-6- The steam cost for different injection Rate

In table 5-6 the total rate of produced oil and steam injection cost, at each injection Rate, are calculated 3 $ for each barrel. Also in figure 5-22 the relative cost of each Rate to the lower rates is calculated and shown that like figure 5-21 that 20 barrels per day is optimized.

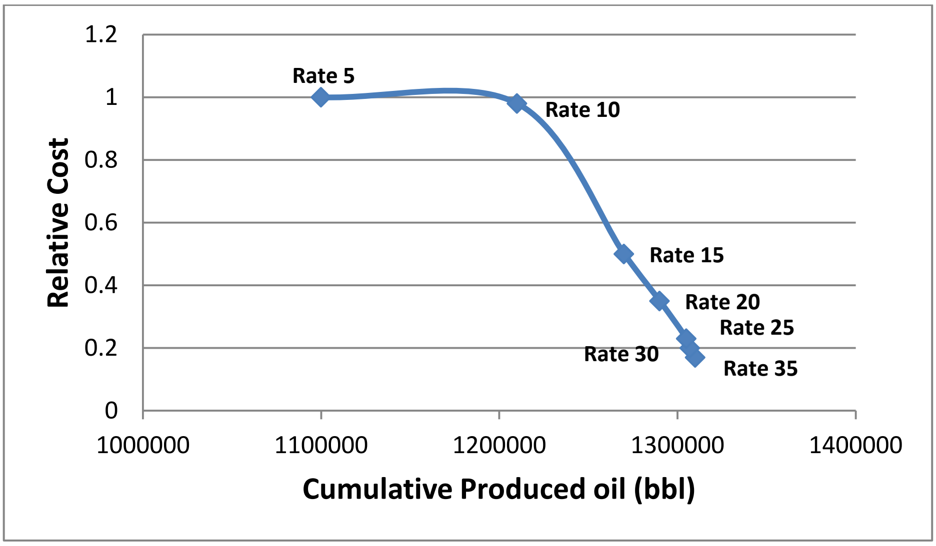


Figure 5-22- Economic analysis of total range of produced oil in relation with cost increase toward injection Rate increase.

Totally, it is concluded from the graphs that our production rate is optimized when our injection rate is between 15 and 20 (bbl/day), and it is economically profitable.

The injection Rate as the most important factor and cost for oil production has been surveyed and analyzed, but other factors were surveyed in this experiment and following results have been gained:

5-8-4- The position of injection and production wells in the reservoir

It seems that the well location is one of the important and effective factors in SAGD oil production, because parameters such as, enough extension of steam area, blocks heating and movement of heated oil under gravity drainage toward production well, depend on the position of injection and production well. So in discussed model, the places of the wells are changed in several forms:

A- Both wells should be located in the center and the production well should be in the bottom of injection well.

B- Both wells should be located in the corner and the production well should be in the bottom of injection well.

C- Both wells should be located in the corner and the injection well should be in the bottom of production well.

And the results were as follows:

In figure 5-23, the recovery factor has significant difference for the three statuses. It means that the well location has an effective role in recovery factor. In (c) status, the least value of recovery factor is seen, and it is in maximum in (A) status. Because in (A) status, by locating the wells in the center, steam area will be formed well, be extended similarly and all of the blocks will be under the effect of steam area. Heavy oil viscosity reduction will be done well in all of the blocks and oil gravity drainage will be gained with the most value, and then the recovery factor will be maximized. So we can conclude that the well location has a significant effect on recovery factor.

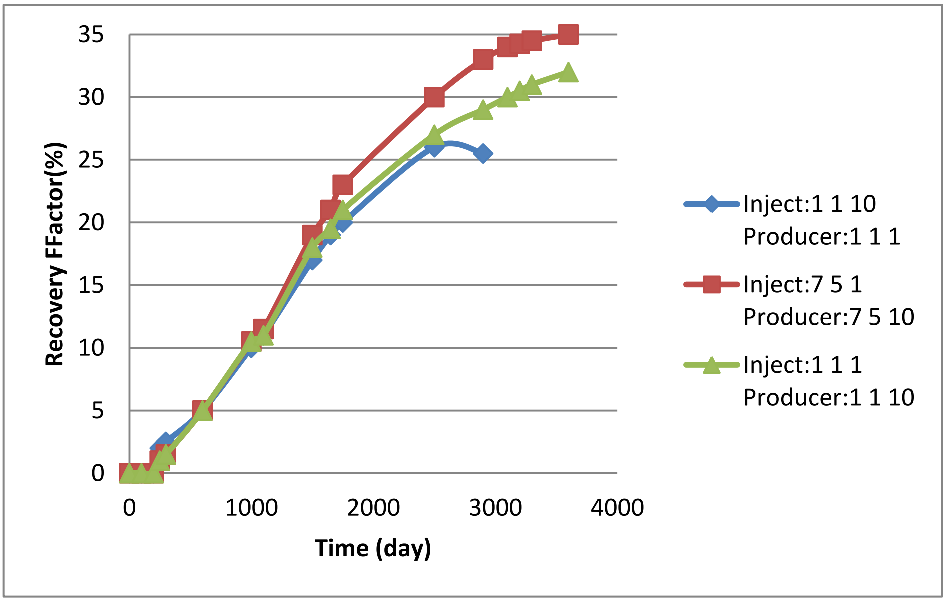


Figure 5-23- The rate of oil recovery by attending to the location of injection and production wells

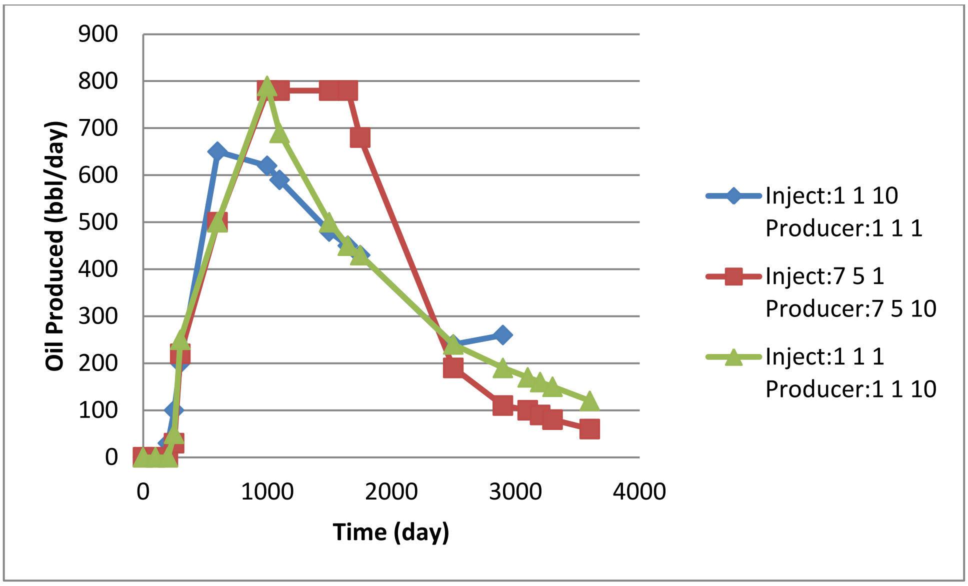


Figure 5-24- The range of daily production oil by attending to the location of injection and production wells

In figure 5-24, the produced oil has difference for the three statuses. It is concluded that well location is important parameters to analyze. For (A) status it has the most value and in (C) it has the least value.

In figure 5-25, the cumulative produced oil has significant difference for the three statuses. The difference is low for (A) and (B) status. In (c) status, the least oil will be produced, because a portion of oil will remain at the bottom and won't be produced.

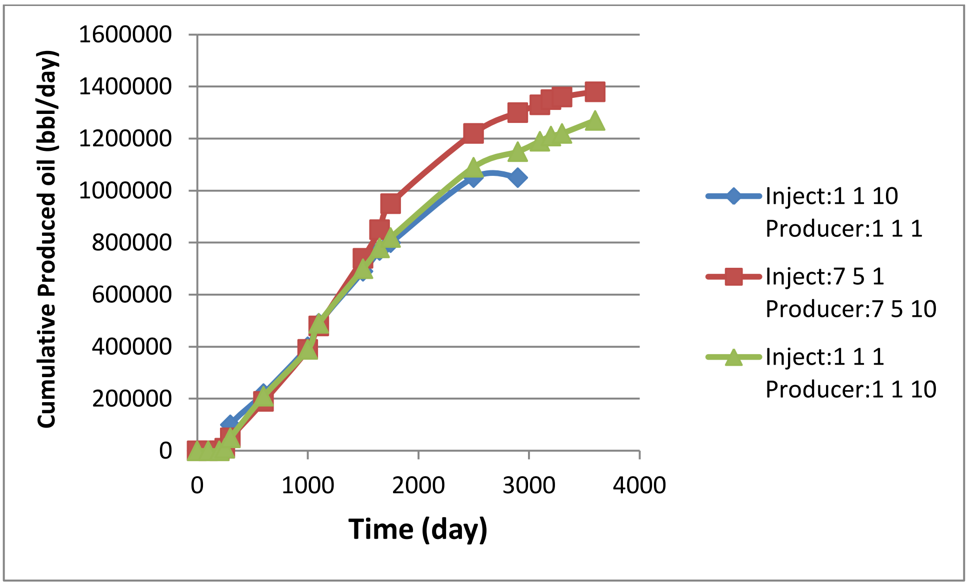


Figure 5-25- The total range of produced oil by considering the location of production and injection wells

In figure 5-26, much difference is seen between statuses (A), (B) and (C). So the location of wells is effective in water production. Difference is low for (A) and (B) status. In (c) status, the least water will be produced, it can happen because of soon mid-breaking.

Finally, it can be concluded that if the wells are located in the center and the production well is under the injection well, we have the best location for the wells, so we can maximize recovery and oil production.

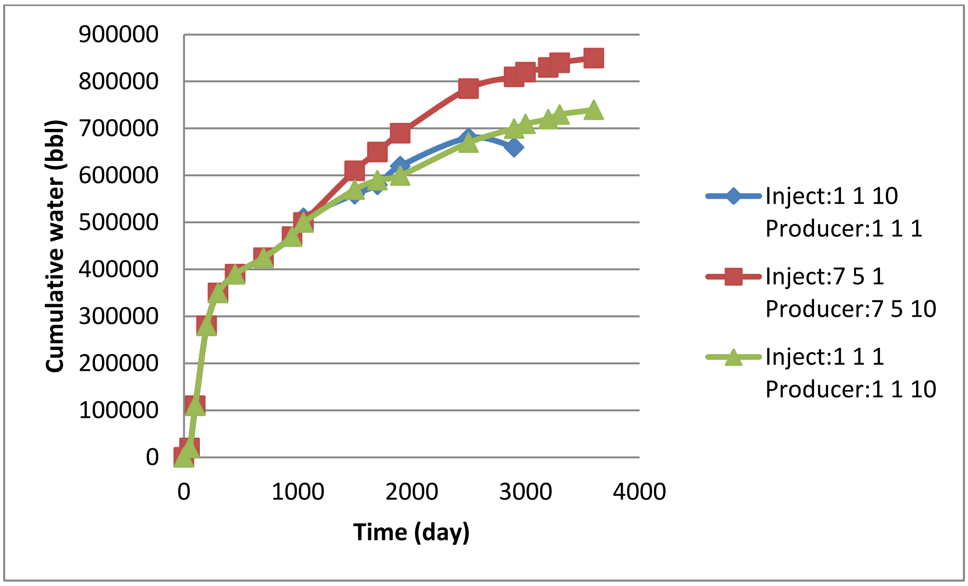


Figure 5-26- The total range of produced water by considering the location of production and injection wells

5-8-5- Surveying the distance between injection and production wells (Vertical)

One of the parameters which has effective role in oil production in SAGD method, is the distance between injection and production wells. Because it effects in heat wasting through reservoir bottom rocks and water production value, because of fingering. So in the discussed model we change the distance between production and injection wells in three statuses.

A- Injection well be three blocks upper than production well
B- Injection well be six blocks upper than production well
C- Injection well be nine blocks upper than production well

And the results are as follows:

In figure 5-27, the difference is observable in three statuses. Recovery factor is diferrenet for each status, so the distance between the wells has role in recovery factor. The difference is very low in statuses (B) and (C), and in (A) status, the minimum recovery factor is gained. Because in this status since production well is located three blocks lower than injection well, an amount of steam heat is transformed to bottom rocks and it is wasted, or we can have steam in production well before it can help to reduce oil viscosity. So the range of oil viscosity and its gravity drive is low, and then recovery factor is minimized.

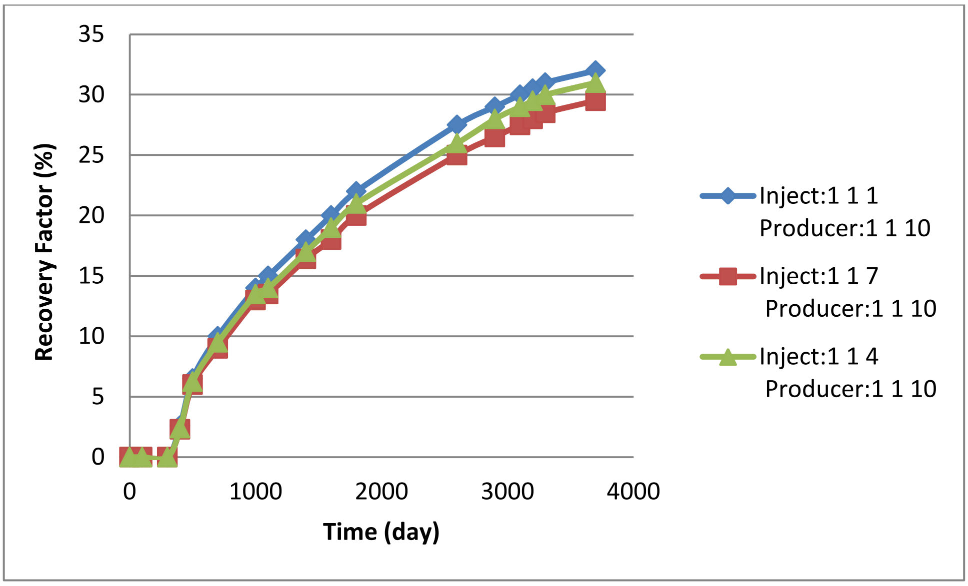


Figure 5-27- The range of oil recovery factor by considering vertical distance of production and injection wells

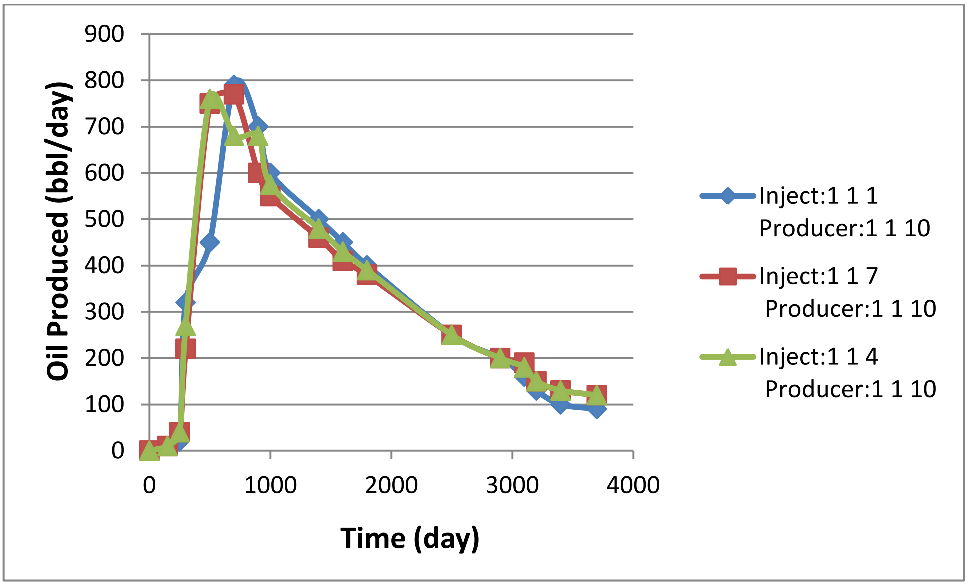


Figure 5-28- The range of daily oil production by considering vertical distance of production and injection wells

In figure 5-28 produced oil Rate has different values for the three statuses and oil Rate is minimized in (A) status. The reason was said in previous part. So it is concluded that the wells' distance are effective in produced oil Rate.

In figure 5-29 as it is seen, there is low difference between the three statuses, (A) status has the least value which was described in previous part. In figure 5-30, the range of produced water is similar for three statuses, so the wells distance has little effect on the water production.

By attending to the issues of this part, it can be concluded that (C) status, is the best status for well locating. Because recovery factor and the oil production is more than the two other statuses and the rate of produced water is lower than the two other statuses.

Typically 5 m vertical spacing is considered between the horizontal injection well and the horizontal production well in the field conditions.

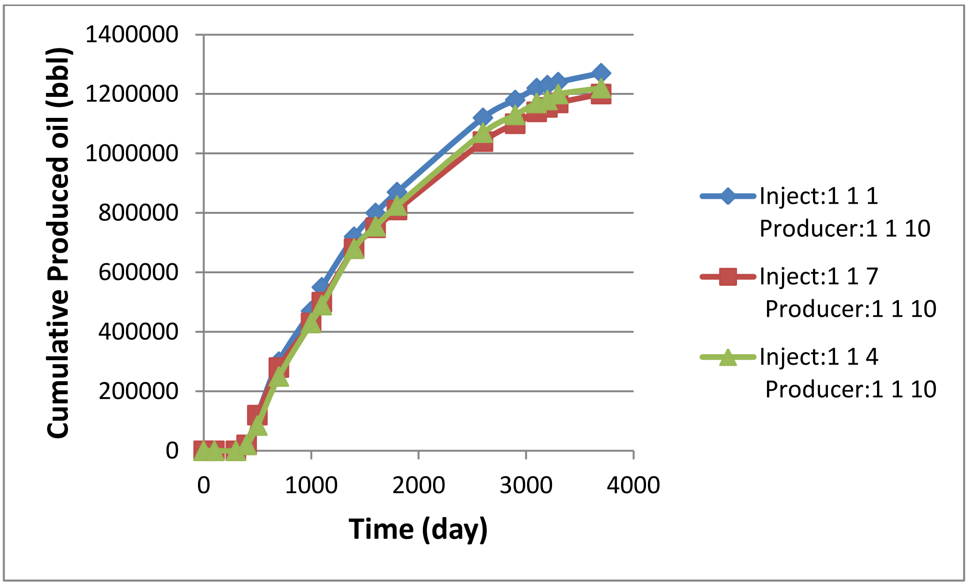


Figure 5-29- The total range of produced oil by considering vertical distance of production and injection wells

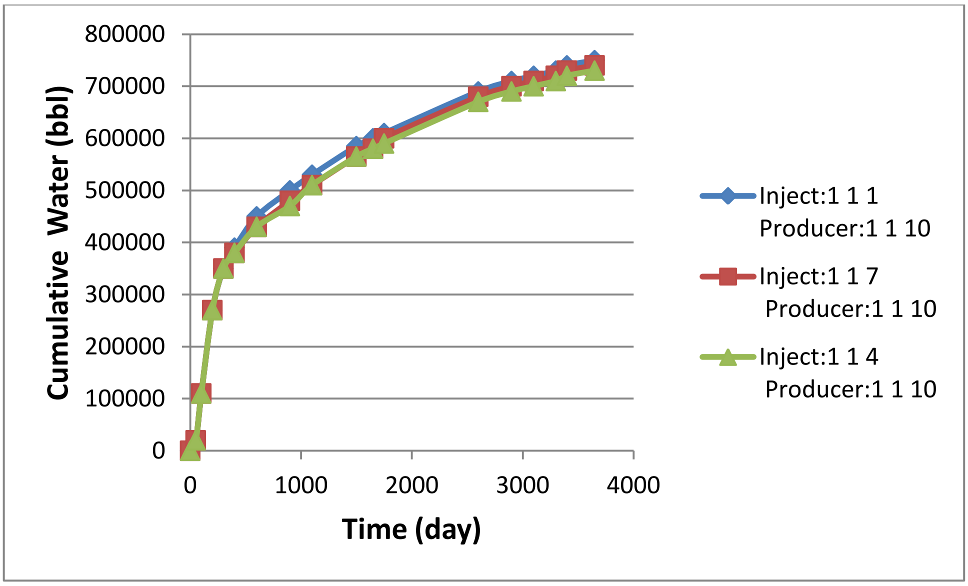


Figure 5-30- The total range of produced water by considering vertical distance of production and injection wells

5-8-6- The survey of matrix porosity

The rate of matrix porosity is one of the important parameter in oil production with SAGD method, because it states the range of pore volume and oil in situ. So it has an important role in production oil rate. In discussed model, the matrix porosity has been surveyed for 0.1, 0.13 and 0.15 values, and the results are as follows:

In figure 5-31, there is a significant difference for recovery factor between different statuses of matrix porosity. The lowest recovery factor value is seen for porosity 0.15, and the highest value is seen for porosity 0.1. Three different porosity values were selected to verify the effect of porosity on SAGD process, note that permeability values were kept fixed. Results illustrate that lower porosity causes a higher recovery factor while the amount of SOR is tremendously higher. The reason is that for a reservoir with lower porosity the initial oil in place is lower so lower amount of heat and energy is needed to heat up the reservoir. Therefore, the process in a lower porosity reservoir with a same steam injection rate and same period of injection becomes mature sooner but due to this lower porosity most of the injected heat will be lost due to the conduction to the reservoir rock. In general, reservoirs with higher porosity have better quality for SAGD process considering commercial and economic issues like SOR.

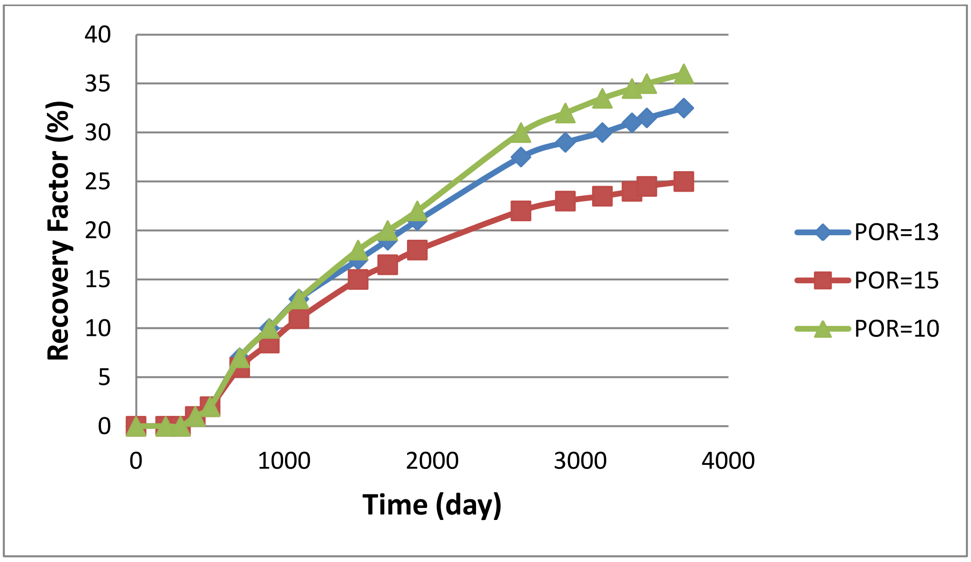


Figure 5-31- The range of oil recovery at porosity changes

In figure 5-28 it is seen that the oil produced Rate is different for different statuses of porosity, which is minimized for porosity 0.1 and maximized for porosity 0.15. So porosity is effective in produced oil Rate.

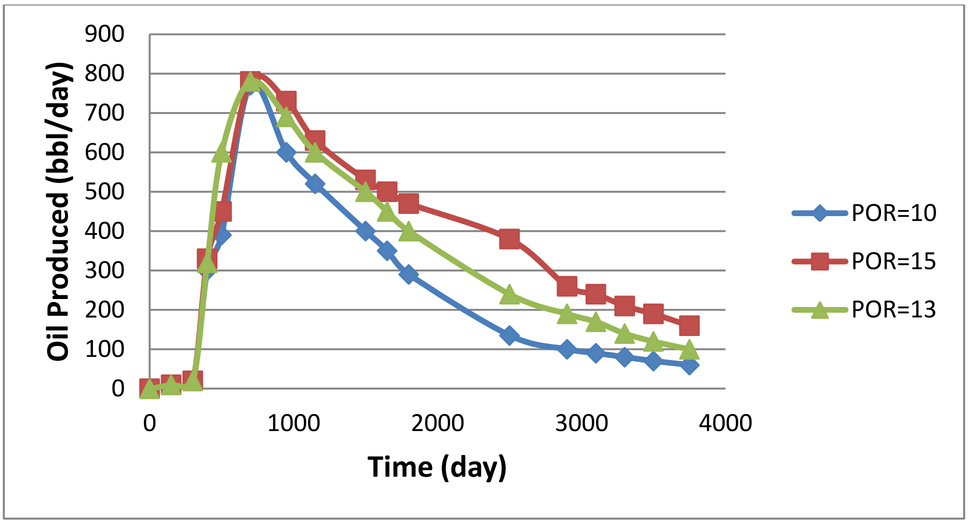


Figure 5-32- The range of daily oil production at porosity changes

In figure 5-32, it is observed that the cumulative produced oil, is different for different statuses, which is minimized for porosity 0.1 and maximized for porosity 0.15, and its reason was mentioned in the beginning.

In figure 5-33, cumulative produced water in different statuses is observable. Because, in fix initial saturation of water, the pore space is more in high porosity and for this status, there is more water value than in low porosity, so the oil of upper blocks will fall to downer blocks (because of viscosity reduction by heating of steam), in one moment, the downer matrix block is completely saturated by oil and the water of block exists from the block, which results in more water production in high porosity status. So porosity is effective on the value of produced water.

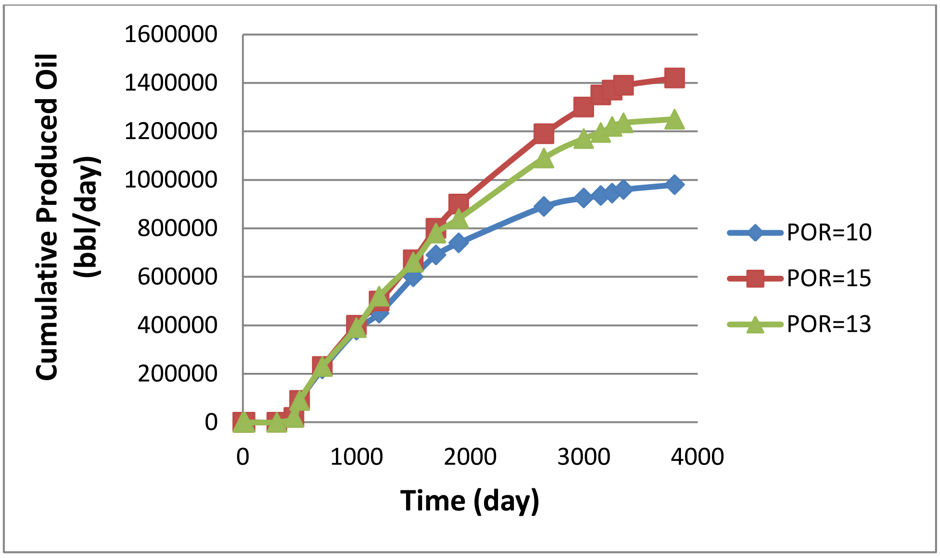


Figure 5-33- The total range of produced oil at porosity differences

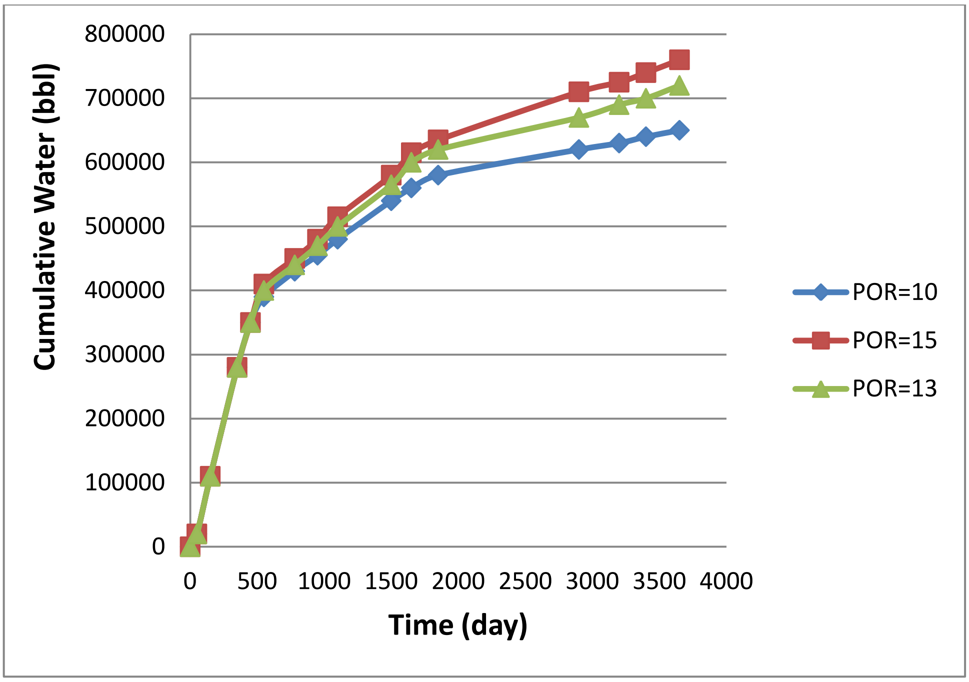


Figure 5-34- The total range of produced water at porosity differences

In general, reservoirs with higher porosity have better quality for SAGD process considering commercial and economic issues like SOR.

5-8-7- The survey of matrix permeability

Naturally fractured reservoirs are usually modeled using two permeability properties due to matrix system and fracture network. In this part, matrix permeability effects are evaluated. For this purpose permeability of matrix system was increased from 50 to 100 and 500 (mD). Figure 5-35 shows that higher matrix permeability has significant effect on recovery factor. In fact, higher matrix permeability resulted in faster and higher drainage of oil from matrixes to the fractures and therefore improvement in oil recovery eventually the economy of the process.

In figure 5-35, recovery factor for 500 millidarcy (mD) is maximized and for 5 mD is minimized, because as it was mentioned by increase in permeability, passing and flowing of oil and gravity drainage of hot oil will be more and faster, so the value of cumulative recovery factor related to 500 mD will be maximized.

In figure 5-36, amount of Produced oil will be more for 500 mD and it is maximized, compare to 50 and 100 mD.

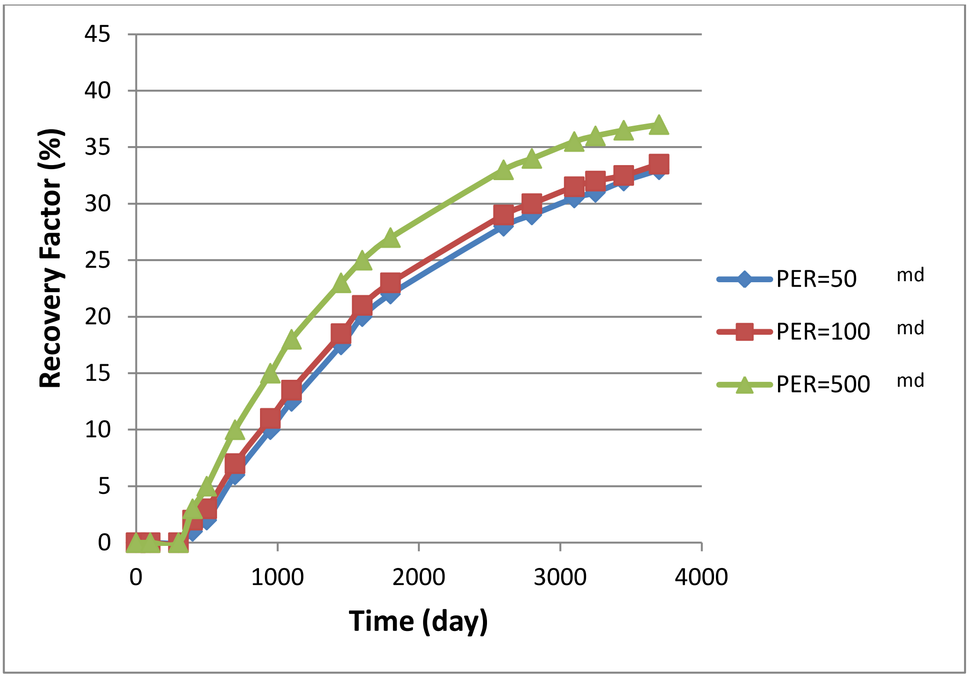


Figure 5-35- The rate of oil recovery at permeability changes

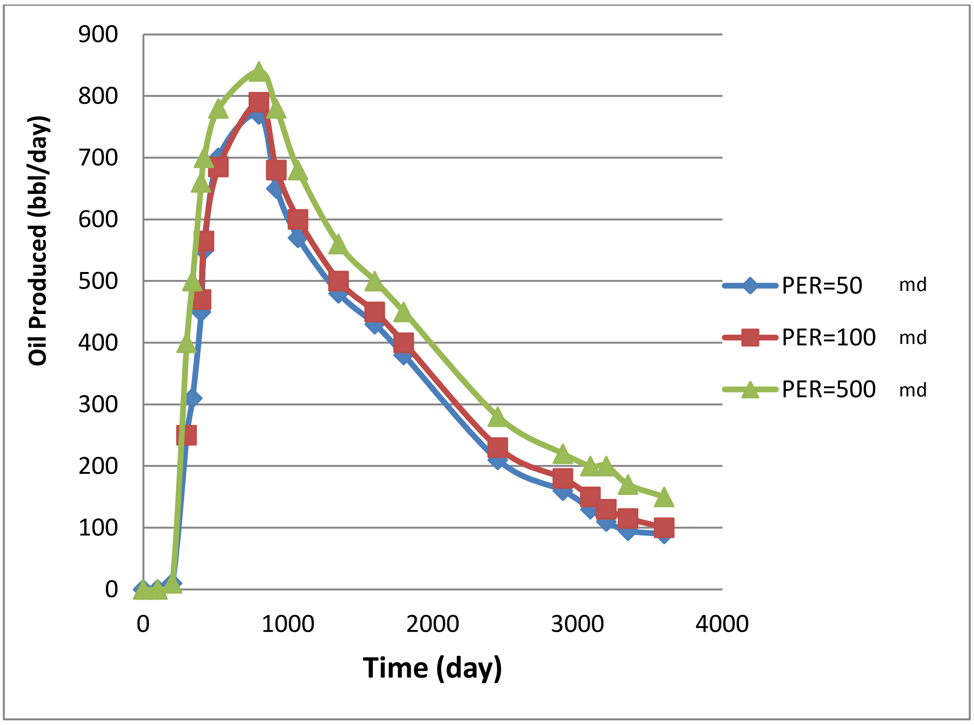


Figure 5-36- The rate of daily oil production at permeability changes

In figure 5-37, it is observed that scenario of Permeability=500 will have the most cumulative produced oil compare to other scenarios.

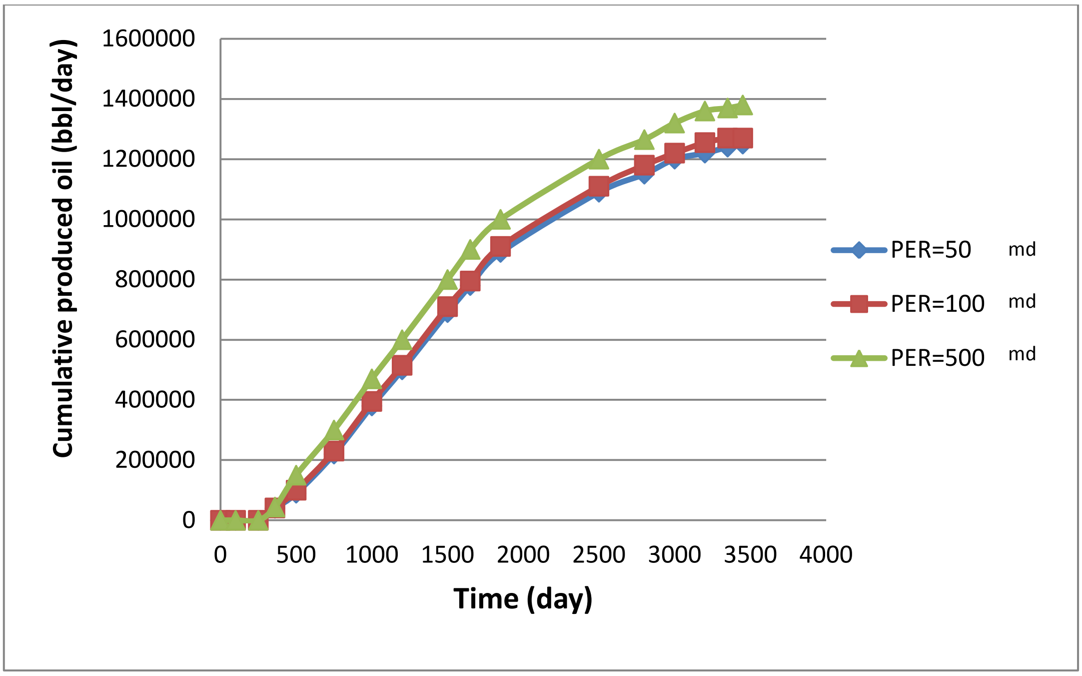


Figure 5-37- The total range of oil production at permeability changes

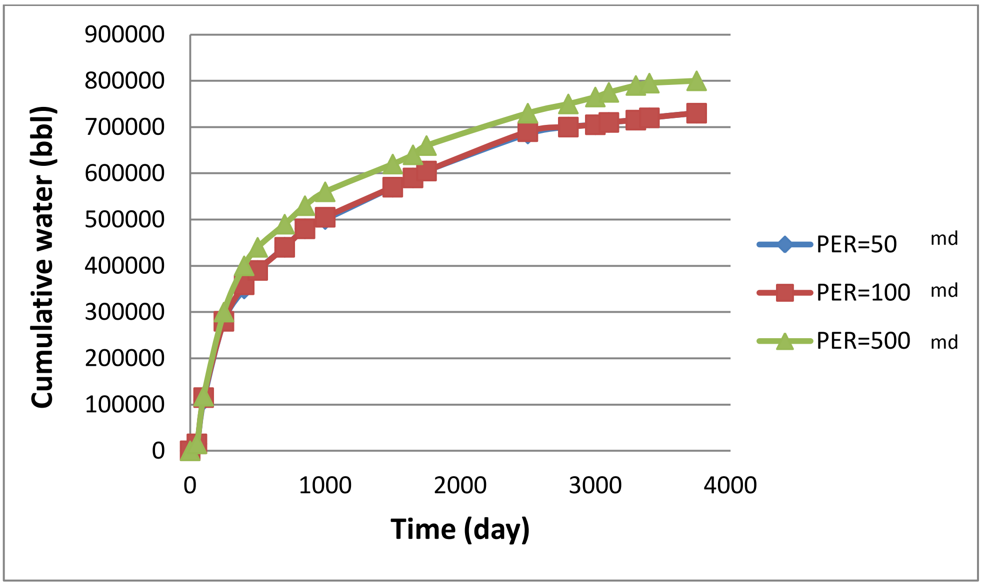


Figure 5-38- The total range of water production at permeability changes

In figure 5-38 it is seen that the produced water rate in different statuses had been affected. So we can see the most produced water is from scenario which has Permeabity =500 and the least is for permeability equal to 50 md.

Chapter six

Conclusion and recommendations

6-1- Conclusion

1- Producing heavy oil reservoirs can have proper recovery based on engineering principles.
2- By considering the reduction of new resources of hydrocarbon, increase of recovery from the reservoirs is necessary after the primary production. The existence of heavy oil reservoirs in Iran and lack of producing from them, is crucial.
3- In selection of the best production methods from heavy oil reservoirs, some factors such as reservoir fluid and rock properties, can be very useful in this action.
4- The most effective methods to increase recovery from heavy oil reservoirs are thermal methods. Before selection of the best method for heavy oil recovery, the use of technical knowledge and the performed researches in the advanced countries of the world such as Canada, is very useful.
5- Sarvak reservoir of Kuh-e-Mund field is from carbonate and fractured type and by attending to this point that most of the world reservoirs are from sandstone, in relation to this reservoir (fracture carbonate reservoir involving heavy oil), basic researches should be done.
6- By considering the recovery parameters screening and the results of simulation, the best options for the heavy oil of Sarvak reservoir of Kuh-e-Mund field is steam injection methods, such as VAPEX, WASP, SAGD and EA-SAGD and immiscible gas injection.
7- The simulation which was done on the Sarvak reservoir of Kuh-e-Mond field just involves a part of the reservoir as an indicator (sector model) and is distributable for all reservoirs.
8- In the study of the performed simulation, the rate of injective Rate is experimented as the most important controllable factor of oil recovery, and by surveying of different injective Rate it was resulted that, for the designed Rate model, the optimized injective steam is between 15 and 20 barrels per day (equal to water).
9- By using newer software in the future, identification of total reservoir information and designing the reservoir real model, the real result will be gained.

6-2- Recommendations

In order to reach a general conclusion about enhanced oil recovery of Iran reservoirs and also quantitative results about Sarvak reservoir of Kuh-e-Mund field, it is recommended that the following titles be studied and considered.

1- The study of Kuh-e-Mund field reservoir simulation as sector model and consideration of other variables of the reservoir and increase of considered changing scope in this study (P_C,K_C, K,P, …)
2- The general study of Sarvak reservoir (a full field study) to specify the gained qualitative results in a quantitative form under different production scenarios to make a better selection for recovery.
3- The repetition of the study method of Kuh-e-Mund field for other heavy oil reservoirs, as simulation study (sector model) and then the reservoir general study.
4- The study about using gas injection process to horizontal wells and the path for locating the injection and production wells together, to specify the optimized conditions for non thermal recovery and its comparison with steam injection.
5- Performing the experimental studies in fire pipe in order to provide primary data for those heavy oil reservoirs with appropriate parameters in using combustion in situ.

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Appendix 2

Raw data of simulation

Rate 5

time(day)	water(bbl/day)	oil(bbl/day)	cumulative water(bbl)	cumulative 0il(bbl)	SOR	RF	WOR
0.004	994.4	5.58	3.978	0.0223	0.896057	5.6195E-07	178.3857
30	994	5.973	29821	179	0.8371	0.00451075	166.5978
120	992.9	7.137	119240	763.6	0.700574	0.0192425	156.1551
270	982.4	17.52	267630	2363	0.285388	0.05954691	113.2586
365	654.7	318.4	346140	17850	0.015704	0.44981478	19.3916
500	117	328.5	371890	60590	0.015221	1.52685029	6.137812
730	150.3	547.2	402965	171980	0.009137	4.33384573	2.343092
920	142	515.9	430680	272770	0.009692	6.87372426	1.578913
1096	127	462.8	453750	356390	0.010804	8.98092382	1.273184
1460	110	397.5	495940	508710	0.012579	12.8193433	0.974897
1642	104.4	375.3	515210	578000	0.013323	14.565431	0.891367
1825	98.88	354.5	533550	643820	0.014104	16.2240758	0.828725
2555	77.96	276	597030	869920	0.018116	21.9217297	0.686304
2920	67.6	237	623170	961950	0.021097	24.2408588	0.64782
3100	62.56	218.2	634680	1002200	0.022915	25.255147	0.633287
3285	57.67	199.7	645620	1040100	0.025038	26.210216	0.620729
3400	54.76	188.9	651980	1062100	0.026469	26.7646095	0.613859
3650	48.95	167.1	644730	1105700	0.029922	27.8633168	0.583097

Rate 10

time(day)	water(bbl/day)	oil(bbl/day)	cumulative water(bbl)	cumulative 0il(bbl)	SOR	RF	WOR
0.004	994.4	5.58	3.978	0.023	1.792115	5.79593E-07	172.9565
30	994	5.97	29821	178.9	1.675042	0.004508228	166.6909
120	992.9	7.109	119240	761.3	1.406668	0.019184537	156.6268
270	979.9	20.1	267560	2426	0.497512	0.061134491	110.2885
365	648.2	324.9	346780	17382	0.030779	0.438021319	19.95052
500	159.5	458.2	376400	68900	0.021825	1.736259859	5.46299
730	198.4	708.5	422970	234050	0.014114	5.897991583	1.807178
920	168.9	598.6	456490	353100	0.016706	8.898016783	1.292807
1096	151.4	533.3	483810	449470	0.018751	11.32651261	1.076401
1460	131.1	457.3	534060	625370	0.021867	15.75914119	0.85399
1642	122.2	424.2	556830	704530	0.023574	17.75395005	0.790357
1825	114.2	394	578090	778020	0.025381	19.60587657	0.743027
2555	76.59	253	648690	1017500	0.039526	25.64070257	0.637533
2920	56.33	190.3	672530	1096300	0.052549	27.62643953	0.613454
3100	54.01	169.1	682600	1128300	0.059137	28.43283018	0.604981
3285	49.3	154.6	691770	1158300	0.064683	29.18882141	0.597229
3400	48.72	142.8	697250	1175300	0.070028	29.61721644	0.593253
3650	41.7	128.6	707970	1208900	0.07776	30.46392662	0.585632

Rate 15

time(day)	water(bbl/day)	oil(bbl/day)	cumulative water(bbl)	cumulative 0il(bbl)	SOR	RF	WOR
0.004	994.4	5.58	3.978	0.0223	2.688172	5.61953E-07	178.3857
30	994	5.964	29821	178.8	2.515091	0.004505708	166.7841
120	992.9	7.097	119230	762	2.113569	0.019202177	156.4698
270	976.1	23.28	267340	2636	0.64433	0.066426429	101.4188
365	591.1	323.4	347330	16396	0.046382	0.413174407	21.18383
500	156	451.9	3777730	64243	0.033193	1.618904821	58.80376
730	222.1	779.9	427070	236510	0.019233	5.959982864	1.805716
920	198.1	689.1	466900	375580	0.021768	9.464506212	1.243144
1096	175.2	603.6	498600	485050	0.024851	12.22311821	1.027935
1460	147	498.3	555670	679780	0.030102	17.13025729	0.817426
1642	135	453.3	580970	765050	0.033091	19.27903636	0.759388
1825	122.9	409.3	604430	843320	0.036648	21.25141748	0.716727
2555	76.76	238.5	676130	1077100	0.062893	27.14260515	0.627732
2920	65.68	195.1	701850	1158300	0.076884	29.18882141	0.605931
3100	58.38	169.6	712500	1190700	0.088443	30.00529194	0.598388
3285	49.83	144	722310	1219000	0.104167	30.71844367	0.592543
3400	47.01	131.1	728090	1234600	0.114416	31.11155911	0.589738
3650	43.72	107.7	739420	1263800	0.139276	31.84739057	0.585077

Rate 20

time(day)	water(bbl/day)	oil(bbl/day)	cumulative water(bbl)	cumulative 0il(bbl)	SOR	RF	WOR
0.004	994.4	5.58	3.978	0.0232	3.584229	5.84633E-07	171.4655
30	994	5.95	29821	178.7	3.361345	0.004503188	166.8774
120	993	6.95	119240	757.9	2.877698	0.019098858	157.3295
270	972.1	27.49	267220	2751	0.727537	0.069324396	97.13559
365	589.1	319.7	347640	16497	0.062559	0.415719578	21.07292
500	163.8	439.1	379180	62785	0.045548	1.582163647	6.039341
730	226	774	429820	233910	0.02584	5.894463624	1.837544
920	225	770.7	472710	380084	0.02595	9.578005695	1.243699
1096	194.6	657.8	508400	501970	0.030404	12.64949727	1.01281
1460	157.3	522.8	571190	711360	0.038256	17.92606406	0.802955
1642	141.9	461.9	598030	799050	0.043299	20.13582642	0.748426
1825	128.2	409.6	622300	876640	0.048828	22.09107174	0.70987
2555	83.15	250.1	697580	1110400	0.079968	27.98175541	0.628224
2920	69.15	191.8	724380	1190900	0.104275	30.01033188	0.608263
3100	59.75	160.9	735630	1222100	0.124301	30.79656276	0.601939
3285	52.64	135.6	745940	1249000	0.147493	31.4744349	0.59723
3400	46.67	122	751930	1263500	0.163934	31.83983066	0.595117
3650	47.97	102.8	763870	1291300	0.194553	32.54038253	0.591551

Rate 25

time(day)	water(bbl/day)	oil(bbl/day)	cumulative water(bbl)	cumulative 0il(bbl)	SOR	RF	WOR
0.004	994.4	5.58	3.978	0.0223	4.480287	5.61953E-07	178.3857
30	994	5.95	29821	178.6	4.201681	0.004500668	166.9709
120	993	6.995	119240	755.4	3.573981	0.019035859	157.8501
270	972.5	27.33	267160	2828	0.914746	0.071264773	94.46959
365	585.6	320.5	348200	16104	0.078003	0.405816093	21.62196
500	179.1	549.4	382650	65381	0.045504	1.647582088	5.852618
730	230	770	435300	241100	0.032468	6.075649522	1.805475
920	229.9	770.1	478990	387410	0.032463	9.762618754	1.23639
1096	207.4	687	517130	514410	0.03639	12.96298163	1.005288
1460	164.1	524	583060	728750	0.04771	18.36428697	0.800082
1642	146.4	458.9	610640	815610	0.054478	20.55313358	0.748691
1825	131.4	403.9	635710	893210	0.061897	22.5086309	0.711714
2555	84.69	252.7	713190	1123800	0.098932	28.31943149	0.634624
2920	73.34	185.9	741860	1204200	0.134481	30.34548799	0.61606
3100	66.61	161.9	754060	1235400	0.154416	31.13171887	0.610377
3285	57.99	136.8	765450	1262300	0.182749	31.80959101	0.606393
3400	56.17	126.2	771870	1277400	0.198098	32.19010659	0.604251
3650	46.39	104.6	785130	1305000	0.239006	32.88561853	0.601632

Rate 30

time(day)	water(bbl/day)	oil(bbl/day)	cumulative water(bbl)	cumulative 0il(bbl)	SOR	RF	WOR
0.004	994.4	5.58	3.978	0.0233	5.376344	5.87153E-07	170.7296
30	994.1	5.944	29822	178.4	5.047106	0.004495628	167.1637
120	993	6.98	119250	753.7	4.297994	0.01899302	158.2195
270	968.3	31.65	267090	2900	0.947867	0.073079152	92.1
365	621	327	348340	16259	0.091743	0.409722047	21.42444
500	243.9	756.1	389160	80355	0.039677	2.024922511	4.843009
730	233.6	766.4	443060	256450	0.039144	6.462465035	1.727666
920	233.8	766.2	487470	402040	0.039154	10.13129048	1.212491
1096	211.4	682.7	526740	530190	0.043943	13.36063302	0.993493
1460	166.4	515.5	593740	741400	0.058196	18.68306328	0.800836
1642	150.2	452.4	622070	827820	0.066313	20.86082201	0.751456
1825	134.8	397.1	647800	904190	0.075548	22.78532369	0.716442
2555	89.59	250.5	727600	1131700	0.11976	28.51850919	0.642927
2920	78.64	189.8	758100	1211900	0.158061	30.53952574	0.625547
3100	71.18	162.8	771380	1243900	0.184275	31.34591639	0.62013
3285	64.25	140.2	783310	1271400	0.21398	32.03890835	0.6161
3400	61.67	120.4	791020	1286000	0.249169	32.40682408	0.615101
3650	51.29	104.5	805050	1313700	0.287081	33.10485598	0.612811

Rate 35

time(day)	water(bbl/day)	oil(bbl/day)	cumulative water(bbl)	cumulative 0il(bbl)	SOR	RF	WOR
0.004	994.4	5.58	3.987	0.0223	6.272401	5.61953E-07	178.7892
30	994.1	5.936	29822	178.2	5.896226	0.004490588	167.3513
120	993.1	6.927	119250	752.2	5.052692	0.01895522	158.535
270	968.3	31.66	266970	3017	1.105496	0.076027518	88.48856
365	639.5	329.2	348840	16044	0.106318	0.40430411	21.74271
500	249	751	394390	90047	0.046605	2.269158078	4.379824
730	236.9	763.1	449140	265300	0.045866	6.685482448	1.692951
920	237.3	762.7	494280	410170	0.04589	10.3361641	1.205061
1096	215.3	677.1	534390	537830	0.051691	13.55315878	0.993604
1460	170.8	512.2	602810	747720	0.068333	18.84232543	0.806198
1642	153.6	449.6	631830	833400	0.077847	21.00143638	0.758135
1825	131	363.9	657550	906470	0.09618	22.84277902	0.725396
2555	98.56	261.9	738210	1125800	0.133639	28.36983091	0.65572
2920	80.32	207.7	771510	1209300	0.168512	30.4740065	0.637981
3100	69.85	176.1	786120	1243000	0.198751	31.32323665	0.632438
3285	64.4	143.2	799670	1272200	0.244413	32.05906811	0.628573
3400	71.28	128.7	807510	1287700	0.27195	32.44966358	0.627095
3650	60	110.4	822940	1317500	0.317029	33.20061487	0.624622

Appendix 2

Simulation code

```
**    The problem is a gravity drainage horizontal well, with water and
**   a dead oil.

**   Features:

**

**       Distinct permeability layering.

**       Black-oil type treatment of fluids. Oil density has
**       been increased by lLee to make heavier than water.

**       Oil viscosity has been modified to heavy oil/bitumen.  Sharp
**       changes occur at the steam front (33500 cp at 100 F to 4.23 cp
**       at 450 F).

**       Automatic initial vertical equilibrium calculation.

**       Multi-layer well with additional injection and production
**       operating constraints.


** ==============  INPUT/OUTPUT CONTROL  =====================

filename output index-out main-results-out   ** Use default file names

title1 'STARS SAGD '
title2 'Simple Gravity Drainage Process'
title3 'Natural Fractures Modelled with the Dual Permeability Option'

inunit field

outprn grid all
outprn well all   outprn iter tss
wprn grid 400  wprn iter 400
outprn res all
wrst 300
prntorien 2 0


** ==============  GRID AND RESERVOIR DEFINITION  =================

grid cart 15 10 15        **                             cartesian grid

di con 60
dj con 60
dk con 20

dualperm             ** Fracture spacing mimics Lee's sigma=3 value
difrac con 1.633     ** Reservoir has vertical fractures only
djfrac equalsi

por matrix    con 0.13
por fracture  con 0.05

permi matrix   con 050
permi fracture con 2000
permj matrix   con 050
permj fracture con 2000
permk matrix   con 050
permk facture  con 2000

rocktype 1                 **  Fracture heat properties

thype fracture con 1
rockcp 0 thcnr 0          **  Fracture does not contain rock
thconw 16  thcono 16  thcong 16
hlosprop overbur 33 23 underbur 33 23
```

```
rocktype 2 copy 1            ** Matrix heat properities

ttype matrix con 2
cpor 5e-4  rockcp 32
thconr 24  thconw 24  thcono 24  thcong 24


**   ==============  FLUID DEFINITIONS  ======================

model 2 2 2    ** Components are water and dead oil.  Most water
               ** properties are defaulted (=0).  Dead oil K values
               ** are zero, and no gas properties are needed.

compname          'Water'     'OIL'
**                -----       --------
cmm               18.02       575
molden            0           0.1075
cp                0           5e-6
ct1               0           8.8e-4
pcrit             3200        0
tcrit             700         0
cpl1              0           300

visctable

**      Temp
        60            0        160000
        70            0        60000
        85            0        13000
       105            0        3228
       122            0        1060
       140            0        451
       158            0        210
       176            0        122.5
       212            0        58.7
       275            0        25.09
       302            0        20.12


** Reference conditions
prsr 14.7 temr 60 psurf 14.7 tsurf 60

**   ==============  ROCK-FLUID PROPERTIES  ======================

rockfluid

rpt 1     **  -----------  MATRIX  ------------

swt    **  Water-oil relative permeabilities

**    Sw          Krw          Krow
**    ----        --------     --------
      0.2         0.0          1
      0.25        0.045        0.5
      0.3         0.085        0.385
      0.35        0.120        0.30
      0.4         0.170        0.235
      0.45        0.220        0.15
      0.5         0.275        0.10
      0.55        0.30         0.075
      0.6         0.35         0.05
      0.65        0.395        0.035
      0.7         0.435        0.01
      0.75        0.475        0.0
      0.8         0.50         0.0

slt    **  Liquid-gas relative permeabilities

**    Sl          Krg          Krog
**    ----        --------     --------
```

```
        0.2           0.16          0.14
        0.25          0.10          0.183
        0.3           0.075         0.250
        0.35          0.05          0.340
        0.4           0.025         0.420
        0.45          0.01          0.525
        0.5           0.0           0.625
        0.55          0.0           0.730
        0.6           0.0           0.835
        0.65          0.0           0.970
        0.7           0.0           1
        0.75          0.0           1
        0.8           0.0           1
        0.85          0.0           1

rpt 2     **  -----------  FRACTURE  ------------

swt    **  Water-oil relative permeabilities

**    Sw            Krw           Krow
**    ----          ------        ------
      0.0           0.0            1.0
      0.1           0.1            0.9
      0.2           0.2            0.8
      0.3           0.3            0.7
      0.4           0.4            0.6
      0.5           0.5            0.5
      0.6           0.6            0.4
      0.7           0.7            0.3
      0.8           0.8            0.2
      0.9           0.9            0.1
      1.0           1.0            0.0

slt    **  Liquid-gas relative permeabilities

**    sl            Krg           Krog
**    ----          ------        ------
      0.0           1.0             0.0
      0.1           0.9             0.1
      0.2           0.8             0.2
      0.3           0.7             0.3
      0.4           0.6             0.4
      0.5           0.5             0.5
      0.6           0.4             0.6
      0.7           0.3             0.7
      0.8           0.2             0.8
      0.9           0.1             0.9
      1.0           1.0             1.0

**   Assign rel perm sets

krtype matrix con 1
krtype fracture con 2

**  ==============  INITIAL CONDITIONS  =====================

initial

** Fractures in layer 5 will have initial pressure of 150 psi
** Presure in other layers (matrix and fracture) will be adjusted
** according to gravity
vertical on pstep 3 refpres 1400 refblock 1 1 5
pres mtrix con 1400
sw matrix   con 0.2
sw fracture con 0.2
pres frcture con 1400
tep matrix   con 150
temp fracture con 150

**  ==============  NUMERICAL CONTROL  =====================

numerical    ** All these can be defaulted.  The definitions
             ** here match the previous data.
```

```
maxsteps 400  north 8  newtoncyc 10  itermax
unrelax -1 sdegree 1  sorder rcmrb
dtmax 90  upstream klevel


norm      press 00  satur  .2   temp 180  y .2   x .2
rangecheck off
conerge  press .5   satur  .02  temp 2    y .02  x .02
rangechek on
run


**  ==============  RECURRENT DATA  =====================


date 2003 1 1.1  dtwell .004

   well 1 'Injector 1'      ** Horizontal well in J direction
   well 2 'Producer 1'      **

   injector mobweight 1
   operate     bhp   1500   ** Start on BHP
   operate max water 15  ** Maximum water rate
   operate max bhp   1500    ** Maximum BHP
   tijw 3650  qual 0.90
   perf 1 ** i j k wi = 0.007082 *k * h / ln(0.5 * re / rw)
            1 1 10 41.62

   producer 2
   operate     bhp    147   ** Start on BHP
   operte max liquid 1000  ** Maximum liquid rate
   operate min bhp    147   ** Minimum BHP
   operate max steam  5e-5  ** maximum steam rate
   geometry j .3 .5 1 0  ** rw cc ff ss
   pef geo 2 ** i j k
                 1 1 1

  time 30  time 120  time 270  time 365  time 500 time 730 time 920 time 1096 time 1460
time 1642 time 1825
  time 2555 time 2920 time 3100 time 3285 time 3400 time 3650  stop
```