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A View for Prospective EOR Projects in Iraqi Oil Fields

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Abstract
Exploitation of the enormous untapped energy source is the greatest challenge ever faced by the oil industry. Over the past four decades, the petroleum industry has been engaged in the research and development of various enhanced oil recovery (EOR) processes needed to produce the oil left behind (may reach more than 50% of OOIP) by conventional methods. Several techniques have been used all over the world for different types of formations. The main goal of the EOR process is to mobilize the "residual" oil throughout the entire reservoir. This is achieved by enhancing microscopic oil displacement and volumetric sweep efficiencies. There is no a single technique that can be considered a "cure all" for recovering additional oil from every reservoir. Each process has its specific application. Before initiating an EOR process, reservoir rock and fluid properties and past production history should be analyzed. It is also important to review the preceding secondary recovery process in order to determine the principal reasons why the residual oil was left in that reservoir. EOR techniques including process descriptions, production mechanisms, limitations, problems, and technical screening guides will be presented in this paper. It shows that gas injection process comes in the first rank of applications while thermal recovery process takes the second position. Chemical flooding is third EOR techniques that has been used for both sandstone and carbonate reservoirs. It shows also that more than 40% of gas injection processes have been used in carbonate reservoirs while 10% of thermal recovery techniques have been used in carbonate reservoirs. The current paper focuses on Iraqi oil fields that are previously or currently in stream. It shows a classification for these oil field based on zone, structure, surface area, reservoir, geological age, reservoir lithology, depth, net pay thickness, porosity, permeability, API gravity. This classification is used for the screening criteria for the prospective EOR projects in Iraq. The paper emphasize the fact that the great percentage of Iraqi oil fields is produced either naturally or by improved oil recovery, however, reasonable attentions have to be considered in the prospective future for serious need to use EOR techniques in several Iraqi oil fields to increase the ultimate recovery and extend reservoirs life.

Key Word and Phrases
Reservoir Engineering, Improved Oil & Gas Recovery, Secondary Oil & Gas Recovery, Enhanced Oil & Gas Recovery.

1. Introduction

Typically, the use of the natural stored reservoir energy may not produce more than 40% of the original oil in place by the primary mechanisms. As these energies are exhausted, programs of waterflooding or gas injection may then be applied to the reservoirs during the secondary recovery phase in order to maintain the energy of the reservoirs.

Fundamentally, waterflood involves pumping water through a well (injector) into the reservoir. The water is forced through the pore spaces to sweep the oil towards the producing wells (producers). The percentage of water in the produced fluids steadily increases until the cost of removing and disposing of water exceeds the income from oil production. After this point, it becomes uneconomical to continue the operation and the waterflooding is stopped. Some wells remain economically feasible at a watercut of up to 99%2. Other secondary recovery methods include CO2 flooding and hydrocarbon gas injection, which requires a nearby source of inexpensive gas in sufficient volume. As the secondary recovery techniques come to the point of uneconomical operation, the tertiary recovery or what has been called enhanced oil recovery (EOR) becomes the next strategy techniques for oil and gas reserve production.

EOR implementation depends on the characteristics of the oil. For light oils, EOR refers to the techniques after primary and secondary recovery that include surfactant flood, polymer flood, miscible drive and even thermal methods. For heavy oils, EOR implies techniques after primary recovery which include steam injection and in-situ combustion. The application of enhanced oil recovery techniques allows the economic value of existing hydrocarbon resources fields to be maximized, through increasing oil recovery and field life extension. Identifying appropriate projects in any field can be a difficult task because of the large number of EOR techniques and reservoir combinations that need to be considered.

Since the production of oil by EOR process is rather difficult, risky, and need huge capital cost, the proper selection of the EOR method for a certain reservoir is important to attaining a successful and profitable project. The most difficult problem that faces reservoir engineers and experts is how to select the most appropriate method to enhance the oil production based on technical and economical factors. To achieve this mission, many reservoir factors must be studied carefully such as reservoir depth, reservoir area, reservoir temperature, porosity, permeability, oil gravity and oil viscosity, and also how these factors may affect each other.

Different EOR techniques have been used in the last two decades. Gas injection (CO_2, N_2, and Hydrocarbon gases) is the most widely used all over the world with more than 51% of EOR projects. Thermal recovery comes in the second place with more than 41% of the EOR projects. Chemical flooding ranks as the third technique with more than 8% of EOR projects due to the high investment required by this process . Fig. 1 shows the percentage of EOR projects.

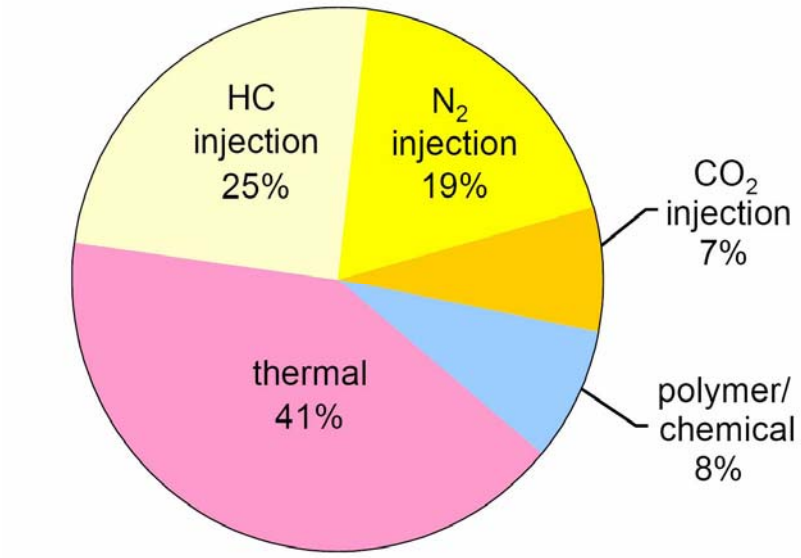

Fig. 1 EOR projects percentages (Alvarado and Manrique 2010)

2. Enhanced Oil Recovery in Sandstone Reservoirs

The great percentage of EOR projects (78%) have been applied in sandstone reservoirs in the last couple decades. Fig..2 shows the distribution of EOR projects all over the world based on lithology. It can be seen that thermal recovery and chemical flooding techniques are the most frequently used in sandstone reservoirs. Gas injection techniques have the same opportunities in both carbonate and sandstone reservoirs. Manrique et al [5] stated that sandstone reservoirs show the highest potential for the enhanced oil recovery process. Most EOR technologies have been experienced in this type of lithology either in pilot scale or in the field or industrial scale. Moreover, several oil fields have been subjected to EOR techniques in pilot plant scale and showed successful results. Two examples for the successful applications of the EOR techniques are the Carmopolis heavy oil (22 API) field in Brazil and the Karazhanbas heavy oil (19 API) field in Kazakhstan. These two sandstone reservoirs have undergone different types of EOR processes such as in-situ combustion, steam flooding, polymer injection and microbial flooding.

3. Enhanced Oil Recovery in Carbonate Reservoirs:

A considerable portion of the world's hydrocarbon exists in carbonate reservoirs. Carbonate reservoirs may exhibit low porosity and may be fractured. When enhanced oil recovery (EOR) strategies are pursued, the injected fluids will likely flow through the fracture network, bypassing oil in the rock matrix (Manrique et al [5]). Early breakthrough of the injected fluid is certainly predicted for type-1 naturally fractured carbonate reservoirs where the fracture network provides all the reservoir storage capacity and permeability and the matrix exhibits low equivalent porous volume. Therefore, several option have been used to mitigate the early breakthrough and increase oil recovery. One of them is the infill drilling programs and well conformance strategies. In the case of porous carbonate rocks, type-2 naturally fractured carbonate reservoirs such as Iraqi oil fields in Kirkuk and type-3 naturally fractured carbonate reservoirs, fracture networks can still cause uneven sweeping of the reservoir leading to early breakthrough of injected fluids in the producing wells, resulting in low recovery factors.

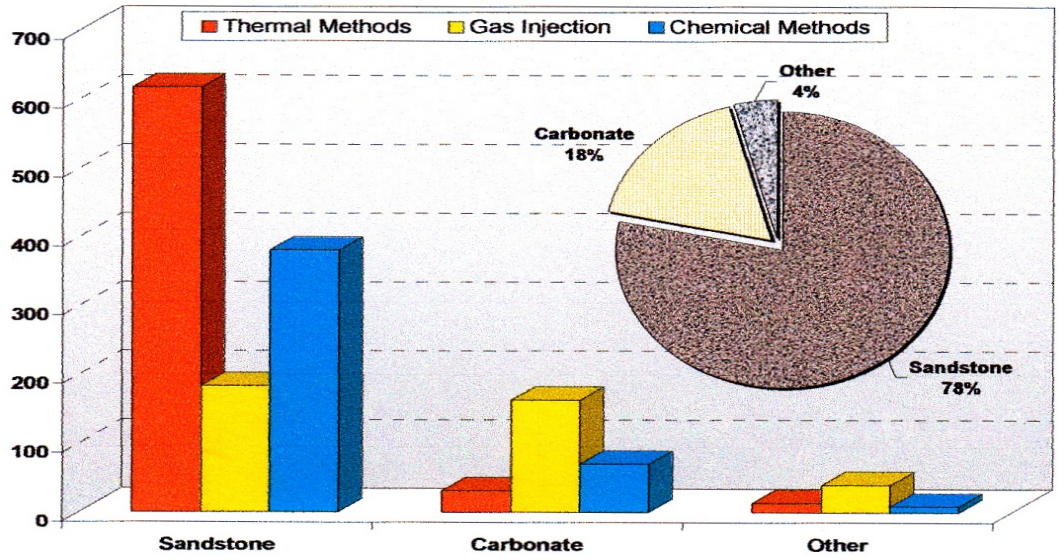

Fig. 2 Lithology distribution for EOR projects (Alvarado and Manrique 2010)

Due to the abundance of carbonate reservoirs, numerous studies have been focused on attempts to characterize the heterogeneities of carbonate reservoirs, classify the different types or classes of fractured reservoirs and determine how rock and fluid properties of carbonate reservoirs impact ultimate recovery. In addition, large number of EOR field projects in carbonate reservoirs have been reported in the literature since the early 70's. These field projects showed the technological capability to increase oil recovery. This increase in oil recovery would directly result in additional reserves extending the productive life of the different formations. However, the technical results were not matched by their economic viability. In some cases high upfront investments created insurmountable barriers for the technology's application. In other cases, the high marginal costs eliminated all benefits from the increased recovery. The latter is especially true for EOR processes based on chemical and thermal methods. Over the last three decades, many improvements have reduced the cost per incremental barrel (Alvarado and Manrique et al [2]).

Recently, CO_2 flooding is the most common recovery process in carbonate reservoirs while air injection, nitrogen injection, steam injection and surfactant stimulation are the remaining active EOR projects in carbonate reservoirs. This fact is resulted from the cheap CO_2 sources and the ability to transport and store CO_2.

4. EOR Concepts

The overall flooding recovery efficiency is given:

$$E_R = E_D \times E_V \quad (1)$$

where:

E_R overall recovery efficiency, fraction or percent.

E_D displacement efficiency within the volume swept by injected fluid, fraction, or percent.

E_V volumetric swept efficiency, fraction or percent of the reservoir volume actually swept by injected fluid.

E_D Displacement efficiency is influenced by rock and fluid properties and throughput (pore volumes injected). It can be determined by:

(1) Laboratory core floods:

Laboratory core floods, ideally using representative formation cores and actual reservoir fluids, are the preferred method for obtaining of S_{or} and E_D:

$$E_D = \frac{\frac{S_{oi}}{B_{oi}} - \frac{S_{or}}{B_{or}}}{\frac{S_{oi}}{B_{oi}}} = 1 - \frac{S_{or}}{S_{oi}}\frac{B_{oi}}{B_{or}} \approx 1 - \frac{S_{or}}{S_{oi}} \quad (2)$$

(2) Frontal advance theory, (assuming $B_{oi} = B_{or}$):

Fractional flow theory can be used to estimate Sor and E_D, but it requires measured water-oil relative permeability curves.

$$E_D = \frac{\bar{S_w}_{BT} - S_{wi}}{1 - S_{wi}} \quad (3)$$

(3) Empirical correlations.

E_V Volumetric swept efficiency is defined by:

$$E_V = E_A \times E_I \quad (4)$$

where:

E_A = areal swept efficiency-fraction of the pattern area or intended flood area that is swept by the displacing fluid.

E_I = vertical or invasion swept efficiency-fraction of the pattern thickness or intended thickness that is swept by the displacing fluid.

There are basically three physical factors that lead to high residual oil saturation after primary and secondary recovery:

1. High oil viscosity.
2. Interfacial forces.
3. Reservoir heterogeneity.

The goal of EOR processes is to mobilize the "residual" oil throughout the entire reservoir. This is achieved by enhancing microscopic oil displacement and volumetric swept efficiencies. Oil displacement efficiency is increased by decreasing oil viscosity (e.g., thermal floods) or by reducing capillary forces or interfacial tension (e.g., chemical floods). Volumetric swept efficiency is improved by decreasing the drive water mobility (e.g., polymer floods).

If mobility (permeability/viscosity) of the displacing phase is greater than the phase being displaced, the mobility ratio is unfavorable (i.e. M>1).

$$M = \frac{\lambda_w \ \ in\ the\ water\ contated\ portion}{\lambda_o \ \ in\ the\ oil\ bank} = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o} \quad (5)$$

M can be made smaller by lowering the viscosity of oil, increasing the viscosity of the displacing phase, increasing the oil permeability, or decreasing the displacing phase permeability. Another parameter that plays a very important role in EOR is the "capillary number" which is a dimensionless group expressing the ratio of viscous to interfacial forces:

$$N_C = \frac{\mu_w v}{\sigma \cos(\theta)} \quad (6)$$

Abrams [1], included the effect of a water-wet core by modifying this group to:

$$N_C = \frac{\mu_w v}{\sigma \cos(\theta)} \left(\frac{\mu_w}{\mu_o}\right)^{0.4} \quad (7)$$

As N_c is increased, the residual oil saturation decreases. An increase in N_c is obtained by increasing pressure gradient, lowering oil viscosity, or decreasing interfacial tension. For miscible displacement, the interfacial tension approaches zero, and the oil displacement efficiency on the microscopic scale is very good.

5. EOR Techniques

There is no a single technique that can be considered a "cure all" for recovering additional oil from every reservoir. Each process has its specific application. Before initiating an EOR process, reservoir rock and fluid properties and past production history should be analyzed. It is also important to review the preceding secondary recovery process in order to determine the principal reasons why the residual oil was left in that reservoir. Factors that strongly affect the success of a waterflood will usually also affect the success of a subsequent tertiary project.

The following methods are discussed including process description, production mechanisms, limitations, problems, and technical screening guides:

5.1 Thermal Recovery

Many reservoirs contain highly viscous crude oil refers to us as "heavy oil reservoirs". Attempts to produce such oil by primary recovery or with waterflooding will yield very poor recoveries. Often this oil is too viscous to flow, or it requires pressures high enough to fracture the reservoir. Even if the oil is movable by waterflooding, the resultant fingering caused by the unfavorable viscosity ratio provides poor recovery. Application of heat is often the only feasible solution to such reservoirs. Thermal methods are primarily used for heavy viscous oil (10-20 API) and tar sands. About 60% of all EOR oil production was due to thermal recovery. Two types of thermal recovery are used to produce heavy oil formations: steam injection and in-situ combustion. Steam injection is a process where the heat is given to the formation using steam stream. This process has three different techniques: 1) Steam stimulation 2) Steam flooding, and 3) Steam assisted gravity drainage (SAGD). The three techniques have been used all over the world to recover heavy to extra heavy oil from sandstone reservoirs. Canada and Russia are the two places where thermal recovery is concentrated.

In-situ combustion (ISC) is the oldest thermal recovery method. It has been used since 1920's with many successes and failures. Although several projects have been reported economically attractive, this recovery method is considered as a high-risk process. Air injection in heavy and light crude oil reservoirs is known as ISC but is also termed as high pressure air injection (HPAI)

when is used in deep light crude oil reservoirs. Air injection has proven to be an effective recovery method in a variety of reservoir types and conditions and recently has received considerable attention for onshore and offshore applications based several successful projects in light crude oil reservoirs (Manrique et al [5]).

5.1.1 Steam Stimulation

Steam stimulation, also known as "steam soak," "cyclic steam injection," or "huff-and-puff' is the most successful thermal recovery process. It involves a single well, until communication between wells develops. Steam is injected into the well at a high rate for a short period of time (a few weeks); next the steam is allowed to soak in for a few days, then the well is allowed to flow back and pumped. Fig. 3 shows the steam stimulation process.

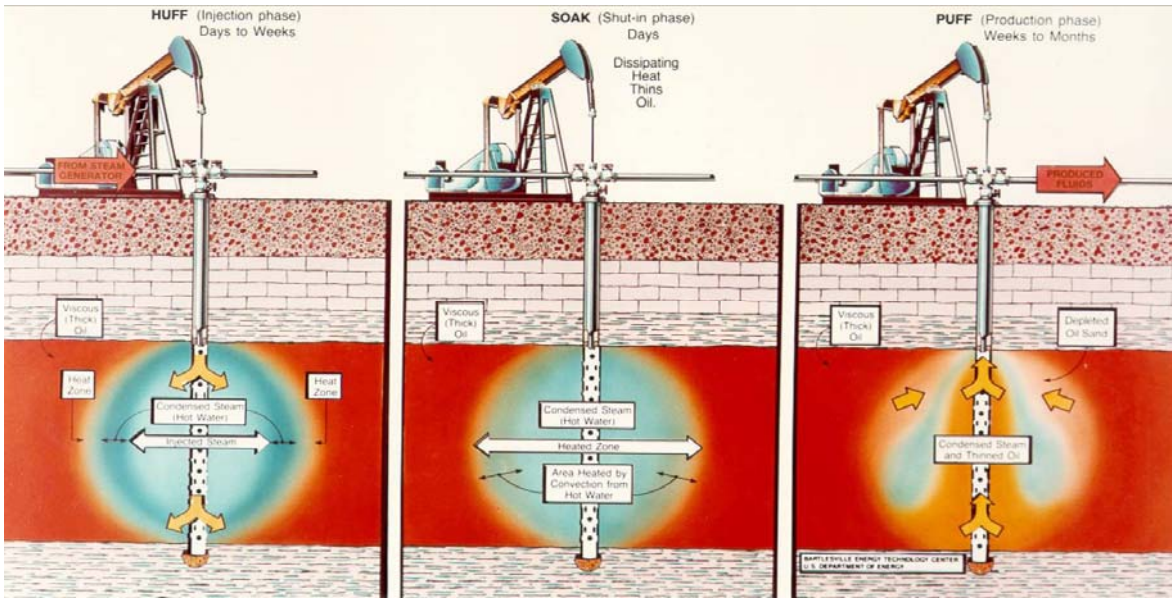

Fig. 3 Steam stimulation process.

The oil rate increases initially, then drops off. When the rate becomes low, the entire process is repeated. This process is repeated many times until the well becomes uneconomic; or in some cases, it is converted from steam stimulation to steam flooding. In the stimulation process, the steam fingers through the oil around the well bore and heats the oil. The soak period permits the oil to be heated even further. During the production cycle, the mobilized oil flows into the wellbore, as a result of pressure drop, gravity, and other mechanisms. This process is most effective in highly viscous oils with a good reservoir permeability. The performance of this method drops as more and more cycles are carried out. Oil recovery is generally very small in this process because only a fraction of the formation is affected.

5.1.2 Steam Flooding

In the steam flooding process shown in Fig. 4, steam is continuously introduced into injection wells to reduce the oil viscosity and to mobilize oil towards the producing wells.

The injected steam forms a steam zone that advances slowly. The injected steam at the surface may contain about 80% steam and 20% water (i.e., 80% steam quality). When steam is injected into the reservoir, heat is transferred to the oil-bearing formation, the reservoir fluids, and some of the adjacent cap and base rock. Due to this heat loss, some of the steam condenses to yield a mixture of steam and hot water. Ahead of the steam zone, an oil bank forms and moves towards the producing well. In many cases, the injected steam overrides the oil due to gravity. This behavior can render this process less efficient. When steam breakthrough occurs, the steam injection rate is reduced by recompletion of wells or shutting off steam producing intervals. Steam reduces the oil saturation in

the steam zone to very low values (about 10±%). Some oil is transported by steam distillation. Normal steam flooding practice is to precede and accompany the steam drive by a cyclic steam stimulation of the producing wells.

For both steam stimulation and steam flooding, steam recovers crude oil by heating the crude oil and reducing its viscosity and supplying pressure to drive oil to the producing well. However, the process has several limitations:

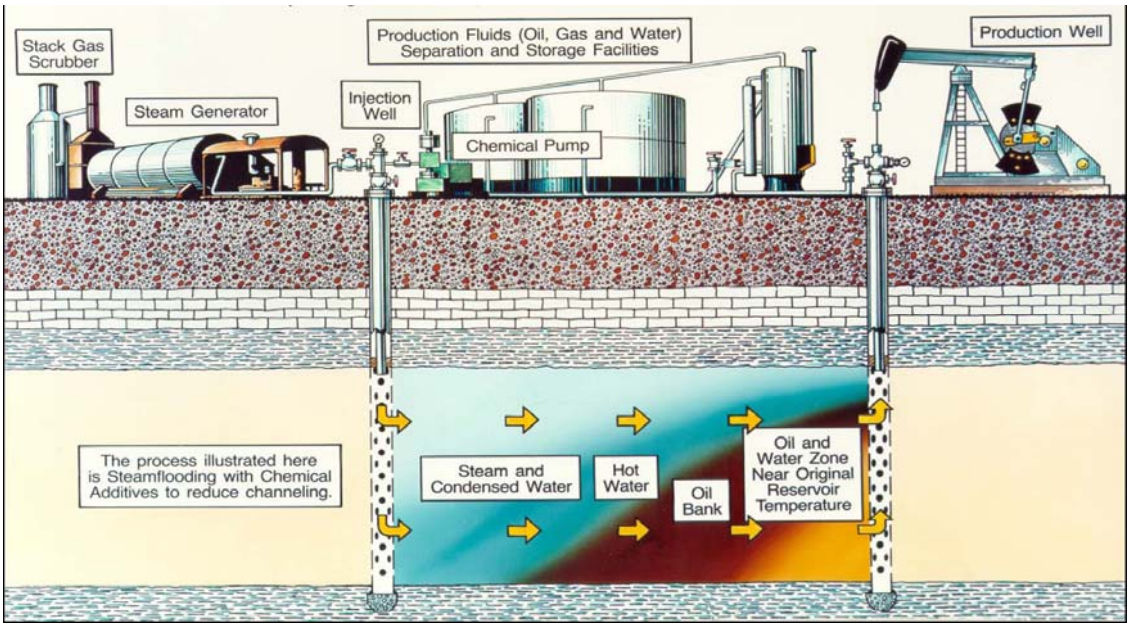

Fig. 4 Steam Flooding process.

- Oil saturations must be quite high, and the pay zones should be more than 20 feet thick to minimize heat losses to adjacent formations.
- Lighter, less viscous crude oils can be steam flooded, but normally they will not be if the reservoir will respond to an ordinary waterflood.
- Steam flooding is primarily applicable to viscous oils in massive, high permeability sandstones or unconsolidated sands.
- Because of excessive heat losses in the wellbore, steam flooded reservoirs should be as shallow as possible as long as pressure for sufficient injection rates can be maintained.
- Steam flooding is not normally used in carbonate reservoirs.
- Since about one-third of the additional oil recovered is consumed to generate the required steam, the cost per incremental barrel of oil is high.
- A low percentage of water-sensitive clays is desired for good injectivity.

The technical screening guides for steam flooding are as follows:

Crude Oil

Gravity	< 25^o API (normal range is 10-25^o API)
Viscosity	> 20 cp (normal range is 100-5,000 cp)
Composition	Not critical but some light ends will help steam distillation

Reservoir

Oil Saturation	> 500 bbl/acre-ft (or> 40-50% PV)
Type of Formation	Sand or sandstone with high porosity and permeability preferred
Net Thickness	> 20 feet
Average Permeability	> 200 md
Transmissibility	> 100 md ft/ cp

Depth	300-5,000 ft
Temperature	Not critical

5.1.3 In-Situ Combustion

In-situ combustion or fire-flooding involves starting a fire in the reservoir and injecting air to sustain the burning of some of the crude oil. The most common technique is forward combustion shown in Fig. 5. One of the variations of this technique is a combination of forward combustion and waterflooding (COFCAW), and a second technique is reverse combustion. In this process, which uses air and water, which are the world's cheapest and most plentiful fluids for injection, a significant amount of crude oil is burned (about 10% of the OOIP) to generate heat. The lighter ends of the oil are carried forward ahead of the burned zone upgrading the crude oil, whereas the heavy ends of the crude oil are burned. Heat is generated within a combustion zone at a very high temperature, about 6000 ^{o}C. As a result of burning the crude oil, large volumes of flue gas are produced. Thus corrosion is a major problem in this process. Over 100 firefloods have been conducted in the world; however, there have not been many successes.

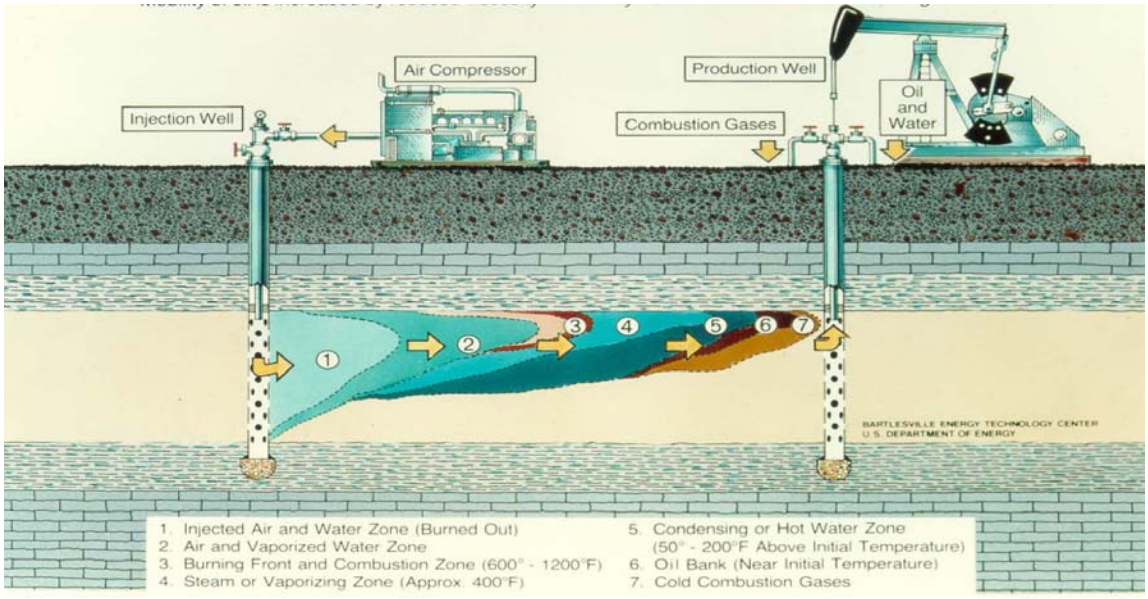

Fig. 5 In-situ combustion.

In-Situ combustion or fire flooding involves starting a fire in the reservoir and injecting air to sustain the burning of some of the crude oil. The most common technique is forward combustion in which the reservoir is ignited in an injection well, and air is injected to propagate the combustion front away from the well. One of the variations of this technique is combination of forward combustion and waterflooding (COFCAW). A second technique is reverse combustion in which a fire is started in a well that will eventua1ly become a producing well, and air injection is then switched to adjacent wells. However, no successful field trials have been completed for reverse combustion.

In-situ combustion recovers crude oil by different mechanisms: 1) The application of heat that is transferred downstream by conduction and convection, thus lowering the viscosity of the crude, 2) The products of steam distillation and thermal cracking that are carried forward to mix with and upgrade the crude, 3) Burning coke that is produced from the heavy ends of the crude oil, and 4) The pressure supplied to the reservoir by the injected air.

The technical screening guides for the in-situ combustion are shown in Table 1. The limitation of this process are:

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

- If excessive coke is deposited, the rate of advance of the combustion zone will be slow, and the quantity of air required to sustain combustion will be high.
- Oil saturation and porosity must be high to minimize heat loss to rock.
- Process tends to sweep through upper part of reservoir so that sweep efficiency is poor in thick formations.

Crude Oil

Gravity	< 40° API (Normally 10-25°)
Viscosity	< 1000 cp
Composition	Some asphaltic components to aid coke deposition

Reservoir

Oil Saturation	> 500 bbl/acre-ft (or < 40-50% pv)
Type of Formation	Sand or sandstone with high porosity
Net Thickness	> 10 ft
Average Permeability	> 100 md
Transmissibility	> 20 md ft/ cp
Depth	> 500 ft
Temperature	> 150°F preferred

5.2 Gas Injection

Gas injection process is used for enhanced recovery from light, condensate, and volatile reservoirs. Gas flooding either miscible or immiscible involves injecting a gas to the formations . As a result, the interfacial tension between the two fluids (oil and gas) is very low, and a very efficient microscopic displacement efficiency takes place. The displacing fluid may be hydrocarbon gas that mixes with oil at first contact. For LPG slug or solvent flooding, enriched (condensing) gas drive and high pressure (vaporizing) gas drive, miscibility is achieved at different pressures. Displacement of oil by propane or LPG is miscible at first contact in all proportions. With a high pressure gas (e.g., CO2 or nitrogen), displacement of oil usually takes place by multiple contacts. In recent years the emphasis has been shifting to less valuable non-hydrocarbon gases such as CO2, nitrogen, and flue gases. Although nitrogen and flue gases do not recover oil as well as the hydrocarbon gases (or liquids), the overall economics may be somewhat more favorable. After thermal recovery, miscible flooding contributes the most among various EOR methods. About 40% of the total EOR production is by gas miscible/immiscible flooding.

5.2.1 Hydrocarbon Gas Flooding

As one of the oldest EOR methods, hydrocarbon injection was practiced for years before the (Multiple Miscible Contact) MMP concept was well understood. When a surplus of a low-molecular-weight hydrocarbon existed in some fields, they were often injected to improve oil recovery. In terms of the pressure required for efficient miscible displacement, the hydrocarbon gases were ranked between the very high pressures required for nitrogen and the more modest range of pressures for CO_2. This ranking is correct for methane. However, if a shallower reservoir depth requires a lower pressure, it can be achieved by adding more enriching hydrocarbons (usually C_2-C_4 if the economics permits).

Hydrocarbon miscible flooding consists of injecting light hydrocarbons through the reservoir to form a miscible flood. Three different methods are used :

1- Sometimes in the first LPG Slug Method, water is injected with the chase gas in a WAG (alternating water and gas) mode to improve mobility ratio between the solvent slug and the chase gas.
2- In the second Enriched (Condensing) Gas Drive method, the enriching components are transferred from the gas to the oil. A miscible zone is formed between the injected gas and the reservoir oil, and this zone displaces the oil ahead.
3- In the third High Pressure (Vaporizing) Gas Drive method, components from the crude oil being displaced result in multiple contact miscibility.

Hydrocarbon miscible flooding consists of injecting light hydrocarbons through the reservoir to form a miscible flood. Three different methods are used. One method uses about 5% PV slug of

liquified petroleum gas (LPG) such as propane, followed by natural gas or gas and water. A second method, called Enriched (Condensing) Gas Drive, consists of injecting a 10-20% PV slug of natural gas that is enriched with ethane through hexane (C2 to C6), followed by lean gas (dry, mostly methane) and possibly water. The enriching components are transferred from the gas to the oil. The third method, called High Pressure (Vaporizing) Gas Drive, consists of injecting lean gas at high pressure to vaporize C2 - C6 components from the crude oil being displaced.

The mechanisms for the hydrocarbon gas flooding are represented by Generating miscibility (in the condensing and vaporizing gas drive), Increasing the oil volume (swelling), and Decreasing the viscosity of the oil. The limitations of this process are:

- The minimum depth is set by the pressure needed to maintain the generated miscibility. The required pressure ranges from about 1,200 psi for the LPG process to 3,000-5,000 psi for the High Pressure Gas Drive, depending on the oil.
- A steeply dipping formation is very desirable to permit some gravity stabilization of the displacement that normally has an unfavorable mobility ratio.

The technical screening guides for the hydrocarbon gases injection are as follows:

Crude Oil

Gravity	> 35° API
Viscosity	< 10 cp
Composition	High percentage of light hydrocarbons (C2- C7)

Reservoir

Oil Saturation	> 30% PV
Type of Formation	Sandstone or carbonate with a minimum of fractures and high permeability streaks
Net Thickness	Relatively thin unless formation is steeply dipping
Permeability	Not critical if uniform
Depth	> 2,000 ft (LPG) to > 5,000 ft (High Pressure Gas)
Temperature	Not critical

5.2.2 Carbon Dioxide Flooding

In the CO_2 miscible flooding process, a volume of a relatively pure CO_2 is injected to mobilize and displace residual oil. Through multiple contacts between the CO_2 and the oil phase, intermediate and higher molecular weight hydrocarbons are extracted into the CO_2 rich phase. Under proper conditions, this CO_2 – rich phase will reach a composition that is miscible with the original reservoir oil. From that point, miscible or near miscible conditions exist at the displacing front interface. Under ideal conditions, this miscibility conditions will be reached very quickly in the reservoir and the distance required to establish the multiple-contact miscibility initially is negligible compared with the distance between wells.

Carbon dioxide flooding is carried out by injecting large quantities of CO_2 (15% or more of the hydrocarbon PV) into the reservoir as shown in Fig. 6. Miscible displacement by carbon dioxide is similar to vaporizing gas drive. The only difference is a wider range of components; C2 to C30 are extracted. As a result, CO2 flood process is applicable to a wider range of reservoirs at lower miscibility pressures than those for the vaporizing gas drive. CO2 is generally soluble in crude oils at reservoir pressures and temperatures. It swells the net volume of oil and reduces its viscosity even before miscibility is achieved by vaporizing gas drive mechanism. As miscibility is approached as a result of multiple contacts, both the oil phase and the CO2 phase (containing intermediate oil components) can flow together because of the low interfacial tension. One of the requirements of the development of miscibility between the oil and CO2 is the reservoir pressure.

CO2 flooding should be used in moderately light-oil reservoirs (API gravity> 25), and the reservoir should be deep enough to have high enough pressure to achieve miscibility. CO2 can dissolve in water; thus, it can lower the interfacial tension between oil and water. However, this process can also lead to more corrosion problems. In this process, about 20-50% of the CO2 slug is followed by chase water. Water is generally injected with CO2 in a WAG mode to improve mobility

ratio between the displacing phase and the oil. CO2 flooding is the fastest growing EOR method in the United States, and field projects continue to show good incremental oil recovery in response to CO2 injection. The CO2 flooding method works well as either a secondary or tertiary operation, but most large CO2 floods are tertiary projects in mature reservoirs that have been waterflooded for many years.

Although CO2 is not truly miscible with the crude oil, the CO2 extracts the light-to-intermediate components from the oil, and, if the pressure is high enough, develops miscibility to displace the crude oil from the reservoir. The mechanisms for oil recovery by CO_2 are performed by generation of miscibility, swelling the crude oil, lowering the viscosity of the oil, and Lowering the interfacial tension between oil and the CO2- oil phase in the near-miscible regions. The limitation for this process are:

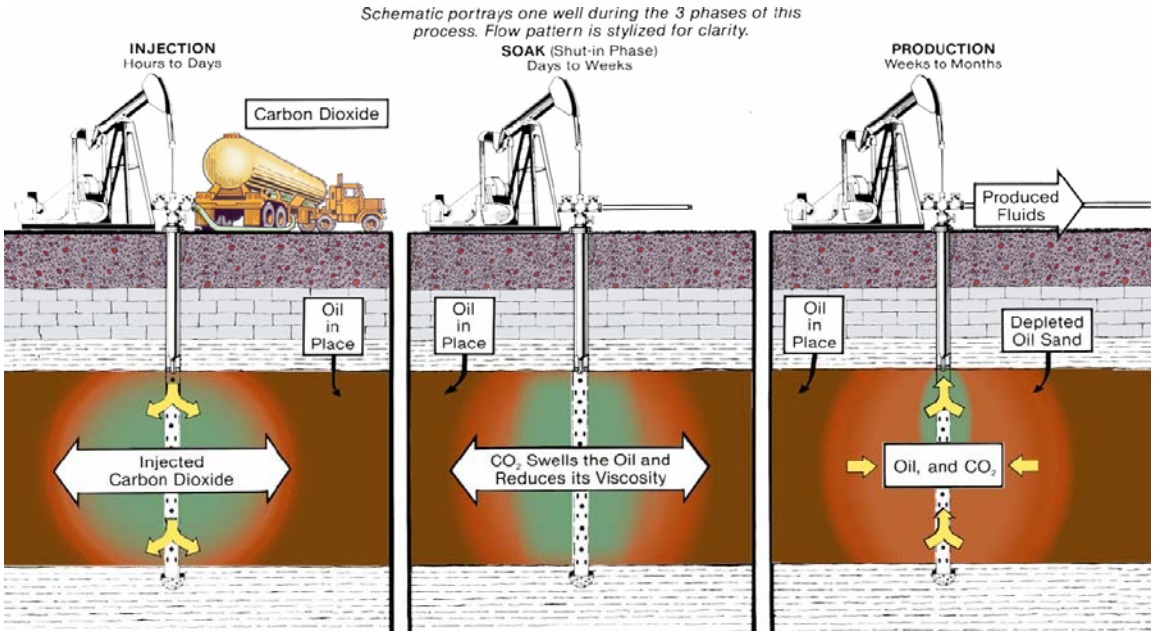

Fig. 6 CO_2 Flooding

- Very low viscosity of CO2 results in poor mobility control.
- Availability of CO2.
- Early breakthrough of CO2 causes several problems.
- Corrosion in the producing wells.
- The necessity of separating CO2 from saleable hydrocarbons.

The screening criteria foe the CO2 injection are as follows:

Crude Oil

Gravity	> 26° API (preferably> 30)
Viscosity	15 cp (preferably < 10 cp)
Composition	High % of intermediate hydrocarbons (C5 - C20), especially C5-C12

Reservoir

Oil Saturation	> 30% PV
Type of Formation	Sandstone or carbonate with a minimum of fractures and high permeability streaks
Net Thickness	Relatively thin unless formation is steeply dipping
Permeability	Not critical if sufficient injection rates can be maintained
Depth	Deep enough to allow high enough pressure (>about 2,000 ft.), pressure required for optimum production (sometimes called minimum miscibility pressure) ranges from about 1,200 psi for a high gravity (> 30°API) crude

	at low temperatures to over 4,500 psi for heavy crudes at higher temperatures.
Temperature	Not critical but pressure required increases with temperature

5.2.3 Nitrogen and Flue Gas Flooding

Nitrogen and flue gas flooding are oil recovery methods that may be either miscible or immiscible depending on the pressure and oil composition. Both nitrogen or flue gas are inferior to hydrocarbon gases (and much inferior to CO2) from an oil recovery point of view. Nitrogen has a lower viscosity, has poor solubility in oil, and requires a much higher pressure to generate or develop miscibility. The increase in the required pressure is significant compared to methane and very large (4-5 times) when compared to CO2. Therefore, nitrogen will not reduce the displacement efficiency too much when used as a chase gas for methane, But it can cause a significant drop in the effectiveness of a CO2 flood if the reservoir pressures are geared to the miscibility requirements for CO2 displacements. Indeed, even methane counts as a desirable "light end" or "intermediate" in nitrogen flooding, but methane is not favorable to the achievement of miscibility in CO2 flooding at low pressures. Fig. 7 shows the N_2 flooding.

Nitrogen and flue gas flooding recover oil by vaporizing the lighter components of the crude oil and generating miscibility if the pressure is high enough and providing a gas drive where a significant portion of the reservoir volume is filled with low-cost gases. The limitation for this process are:

- Developed miscibility can only be achieved with light oils and at high pressures; therefore, deep reservoirs are needed .
- A steeply dipping reservoir is desired to permit gravity stabilization ofthe displacement, which has a very unfavorable mobility ratio.
- Viscous fingering results in poor vertical and horizontal sweep efficiency.
- Corrosion can cause problems in the flue gas method.
- The non-hydrocarbon gases must be separated from the saleable produced gas.

The screening guides for the nitrogen and flue gas injection are as follows:

Crude Oil	
Gravity	> 240 API (> 35 for nitrogen)
Viscosity	< 10 cp
Composition	High % of light hydrocarbons (C1 - C7)
Reservoir	
Oil Saturation Type	> 30% PV
Type of Formation	Sandstone or carbonate with few fractures and high permeability streaks
Net Thickness	Relatively thin unless formation is dipping
Average Permeability	Not critical
Depth.	> 4,500 ft
Temperature	Not critical

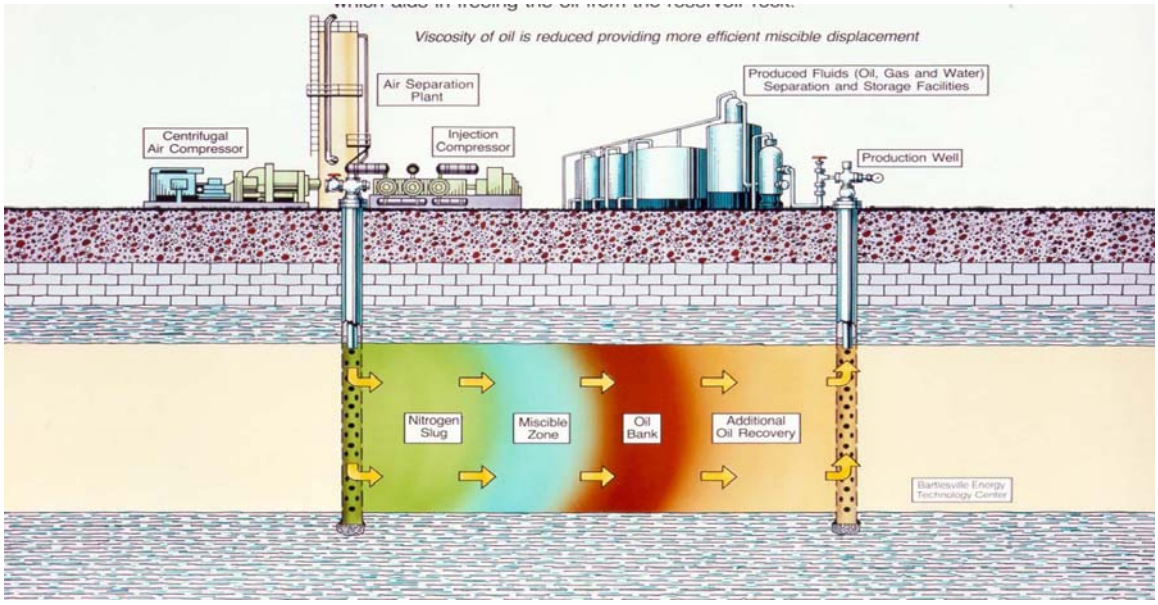

Fig. 7 N_2 injection process

5.3 Chemical Flooding

Chemical flooding processes comes in the second rank of all EOR projects all over the world. It has been used for both carbonate and sandstone formations. The 1980s was considered as the best time (peak) for the oil recovery by chemical flooding. These processes require conditions favorable to water injection because they are modifications of waterflooding. Chemical flooding is applicable to oils that are more viscous than oils suitable for gas injection, but less viscous than oils that can be recovered by thermal methods. Reservoirs with moderate permeability are desirable. The presence of a gas cap is not desirable, since there is the potential of re-saturating the cap. Formations with high clay contents are undesirable, since the clays increase the adsorption of the injected chemicals.

Three type of chemicals have been used in the chemical flooding. Polymers group is the mostly used type for different formation where there is serous need to improve the swept efficiency. Surfactants group is the second type of chemical that has been used in the formations where there is serous need to reduce the interfacial tension between oil and water. Mixed polymer and surfactant (SP) solutions, also known as micellar flooding or micro-emulsion flooding, are commonly used. Caustic solutions group, also known as alkaline solutions group, is the third type of chemical flooding. A combination of polymer-surfactant-alkaline (ASP) may be used.

5.3.1 Polymer Flooding

The objective of polymer flooding is to provide better displacement and volumetric sweep efficiencies during a waterflood. The mechanisms for oil recovery improvement by polymer are increasing the viscosity of water, decreasing the mobility of water, contacting a larger volume of the reservoir, and reducing the injected fluid mobility to improve areal and vertical sweep efficiencies.

It should be noted that polymer does not lower the residual oil saturation. Because polymer flooding inhibits fingering, the oil displacement is more efficient in the early stages as compared to a conventional waterflood. As a result, more oil will be produced in the early life of the flood. This is the primary economic advantage because it is generally accepted that ultimate recovery will be the same for polymer flooding as for waterflooding.

Many factors affect polymer flooding. These include polymer degradation due to salinity, temperatures, time, shear rates, and the presence of divalent ions. Some polymers, like polysaccharides, are more resistant; however, they suffer from bacterial degradation problems and cause wellbore plugging. Also, polymers may be lost in the formation due to adsorption. Polymers

may be ineffective in a mature waterflood because of low mobile oil saturation. They show some promise in a reservoir with high vertical heterogeneity where the oil saturation may still be high and the vertical conformance poor.
Some operators have been successful in treating injection wells (near-well treatment) with polymers to modify vertical profiles.

Polymer augmented waterflooding consists of adding water soluble polymers to the water before it is injected into the reservoir. Low concentrations (often 250-2,000 mg/L) of certain synthetic or biopolymers are used; properly sized treatments may require 15 - 25% reservoir PV. Fig. 8 shows polymer flooding.
The limitations of the polymer flooding process are:

- If oil viscosities are high, a higher polymer concentration is needed to achieve the desired mobility control.
- Results are normally better if the polymer flood is started before the water-oil ratio becomes excessively high.
- Clays increase polymer adsorption.
- Some heterogeneity is acceptable but for conventional polymer flooding, reservoirs with extensive fractures should be avoided. If fractures are present, the cross-linked or gelled polymer techniques may be applicable.
- Lower injectivity than with water can adversely affect oil production rate in the early stages of the polymer flood.
- Acrylamide-type polymers lose viscosity due to sheer degradation, or it increases in salinity and divalent ions.
- Xanthan gum polymers cost more, are subject to microbial degradation, and have a greater potential for wellbore plugging.

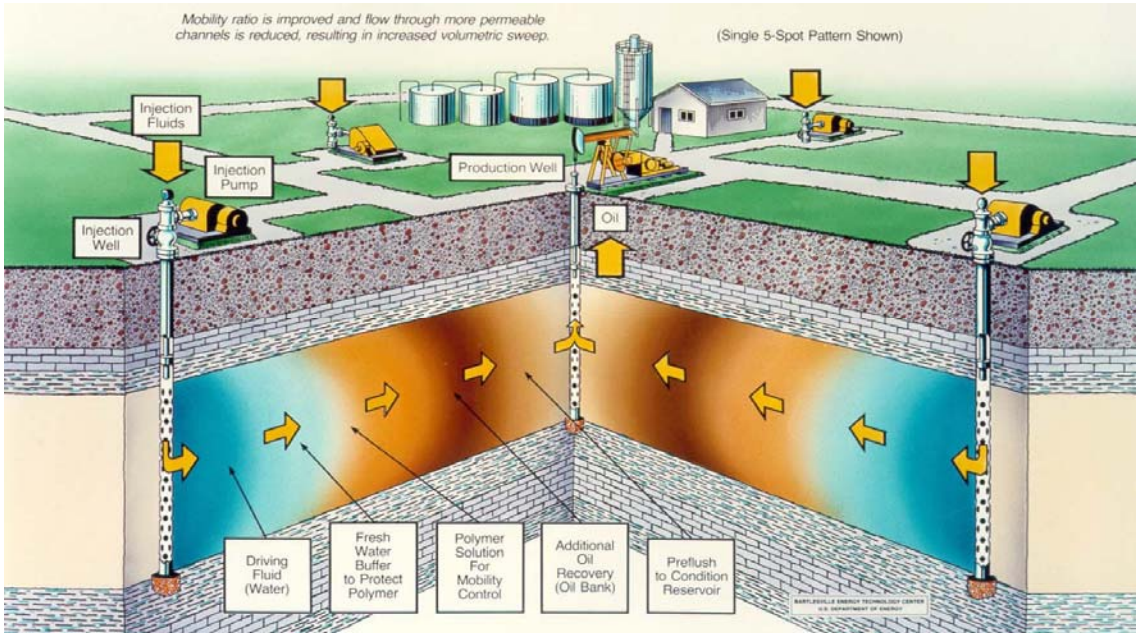

Fig. 8 Polymer Flooding.

The technical guides for the screening process of the polymer flooding are as follows:

Crude oil

Gravity	> 25° API
Viscosity	< 150 cp (preferably < 100)
Composition	Not critical

Reservoir

Oil Saturation	> 10% PV mobile oil

Type of Formation	Sandstone preferred but can be used in carbonate
Net Thickness	Not critical
Permeability	>10 md (as low as 3 md in some cases)
Depth	< about 9000 ft (see Temperature)
Temperature	< 200°F to minimize degradation

5.3.2 Surfactant Flooding

Surfactant/polymer flooding, also called "micellar/polymer" or "micro-emulsion flooding" consists of injecting a slug that contains water, surfactant, electrolyte (salt), usually a cosolvent (alcohol), and possibly a hydrocarbon (oil) . Fig.(9) shows surfactant flooding.

The size of the slug is often 5-15% PV for a high surfactant concentration system and 15-50% PV for low concentrations. The surfactant slug is followed by polymer-thickened water. Concentrations of the polymer often ranges from 500-2,000 sg/L. The volume of polymer solution injected may be 50% PV, more or less, depending on the process design. The mechanisms for oil recover by surfactant/polymer flooding are lowering the interfacial tension between oil and water, solubilization of oil, emulsification of oil and water, and mobility enhancement. The limitations for this process are:

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

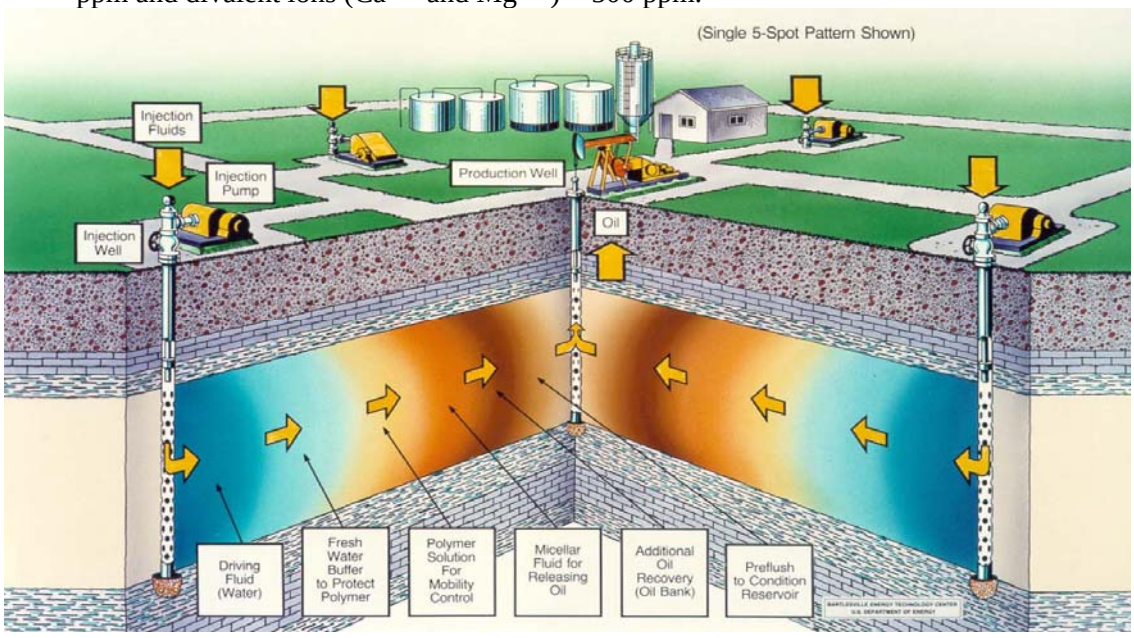

Fig. 9 Surfactant flooding

The screening criteria for the surfactant flooding are as follows:

Crude Oil

Gravity	> 25° API
Viscosity	< 30 cp
Composition	Light to intermediates are desirable

Reservoir

Oil Saturation	> 30% PV
Type of Formation	Sandstone preferred
Net Thickness	> 10 ft

Average Permeability	> 20 md
Depth	< about 8,000 ft
Temperature	< 175°F

5.3.3 Caustic Flooding

Caustic or alkaline flooding involves the injection of chemicals such as sodium hydroxide, sodium silicate, or sodium carbonate. Oils in the API gravity range of 13 – 35^{o} are normally the target for alkaline flooding. One of the desirable properties for the oils is to have enough organic acids so that they can react with the alkaline solution. Another desirable property is moderate oil gravity so that mobility control is not a problem.

Sandstone reservoirs are generally preferred for this process, since carbonate formations often contain anhydride or gypsum which consume a large amount of alkaline chemicals. The alkali is also consumed by clays, minerals, or silica. In addition, the consumption is high at elevated temperatures. Another problem with caustic flooding is the scale formation in the producing wells.

Alkaline solutions react With organic petroleum acids in certain crudes to create surfactants in situ. They also react With reservoir rocks to change wettability. The concentration of the alkaline agent is normally 0.2 to 5%; slug size is often 10 to 50% PV, although one successful flood only used 2% PV, (but this project also included polymers for mobility control). Polymers may be added to the alkaline mixture, and polymer-thickened water can be used following the caustic slug. Oil is recovered by alkaline solution throughout different mechanisms. These mechanisms are a reduction of interfacial tension resulting from the produced surfactants, changing wettability from oil-wet to water-wet, changing wettability from water-wet to oil-wet, emulsification and entrainment of oil, emulsification and entrapment of oil to aid in mobility control, and solubilization of rigid oil films at oil-water interfaces. However, not all mechanisms are operative in each reservoir.

The limitations for alkaline flooding process are:

- Best results are obtained if the alkaline material reacts With the crude oil; the oil should have an acid number of more than 0.2 mg KOH/g of oil.
- The interfacial tension between the alkaline solution and the crude oil should be less than 0.01 dyne/cm.
- At high temperatures and in some chemical environments, excessive amounts of alkaline chemicals may be consumed by reaction With clays, minerals, or silica in the sandstone reservoir.
- Carbonates are usually avoided because they often contain anhydrite or gypsum, which interact adversely With the caustic chemical.

The screening guides for the chemical flooding techniques are as follows:

Crude Oil

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

Reservoir

Oil Saturation	Above waterflood residual
Type of Formation	Sandstones preferred
Net Thickness	Not critical
Average Permeability	> 20 md
Depth .	< about 9,000 ft (see Temperature)
Temperature	< 200°F preferred

5.4 Special EOR techniques

5.4.1 Water-Alternative-Gas Injection (WAG)

WAG is one of the most important techniques used in low dip reservoirs. This process involves injecting alternating cycles of gas and water. The underlying principle is based on the experimental fact that the total mobility of a two-phase system is less than single-phase mobility by proper choice of ratio of the volumes injected. An ideal situation can be created where the displacing

mixture of gas and water has the lowest mobility, which works better than even water injection. In practical, gravity segregation and reservoir heterogeneity tend to limit the development of such uniform displacements. The WAG technique may result in high oil recovery in horizontal reservoirs. One of the advantages of the WAG technique is that it allows maximizing the contacted volume for a given volume of gas available. This could be important in situations where we have limited supply of gas, where the only gas available is the gas produced from the field with no external supply.

Important factors affecting water-alternating gas injection are reservoir and fluid properties, miscibility conditions, injection technique and WAG parameters, screening of WAG injection is based on accounting of specific reservoir conditions, particular reservoir and fluid properties. Oil recovery by the injection of water alternately with gas (WAG flooding) is often limited by gravity segregation, which causes the injected gas to rise to the top of the formation and water to migrate to the bottom. This segregation results in a miscible flood in only a thin layer at the top of the formation, whereas the remainder is waterflooded. However, vertical conformance in a WAG flood can be greatly improved by use of injection rates that are high relative to well spacing. The degree of improvement and, hence, the resultant oil recovery is primarily a function of a single dimensionless parameters, which is one form of the viscous-gravity ratio.

Optimum conditions of oil displacement by WAG would be achieved if the gas and water travel in the reservoir at equal velocity. The effect may occur for a short time in the water-gas mixture zone but has a limited extent in the reservoir because of difference in viscous and gravity forces. Therefore portioning of water/gas banks and cycling are required to tune the injection scheme for particular reservoir conditions. The decrease of gas bank volume injected in altered cycles with water into high permeability layer increases the trapped volume of gas in the layer. This limits the amount of segregated gas that can be injected to the upper layer, thus the increase of WAG ratio and of WAG cycles give improved oil recovery from the low permeability layer at the expend of recovery from the low permeability top layer. Fig. 10 shows the water-alternative-gas injection process (WAG).

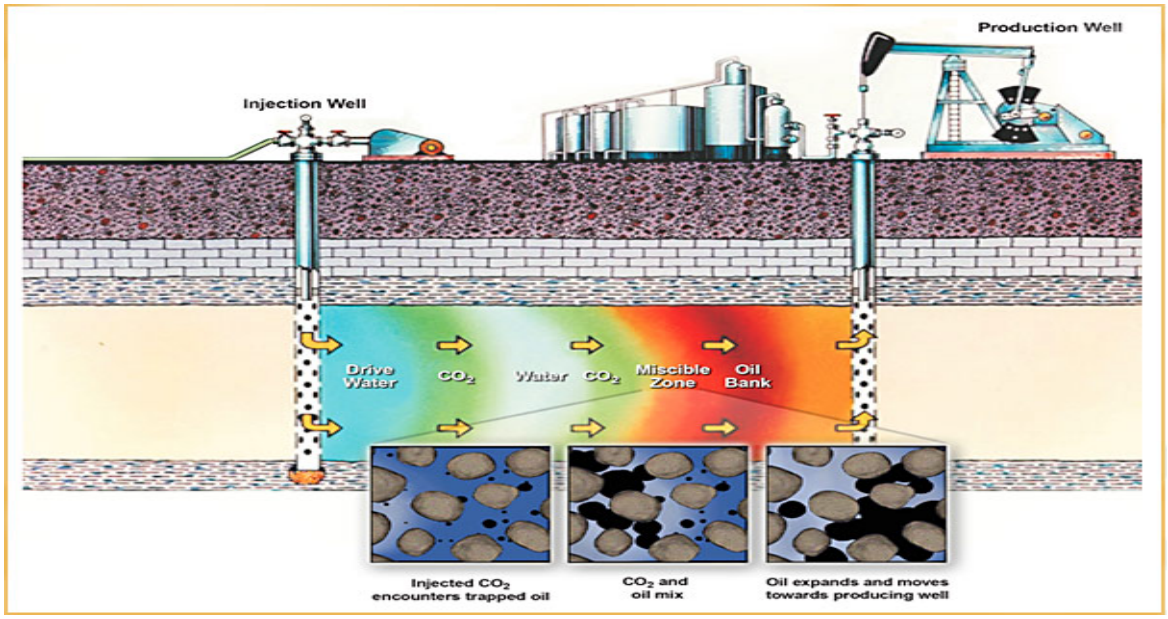

Fig. 10 WAG Flooding process

5.4.2 Steam Assisted Gravity Drainage (SAGD)

Steam assisted gravity drainage (SAGD) is an effective method of producing heavy oil and bitumen. In a typical SAGD approach, steam is injected into a horizontal well located directly above a horizontal producer. A steam chamber grows around the injection well and helps displace heated oil toward the production well, as shown in Fig. 11. SAGD maximize the role of gravity

forces during steam flooding of heavy oils. Heat is transferred by conduction, convection, and latent heat of the steam. By injecting steam, a steam chamber forms directly above the production well. At the steam chamber boundary, steam condenses to water as heat is transferred to the oil. Condensed water and hot oil flow along the steam chamber to the production well.

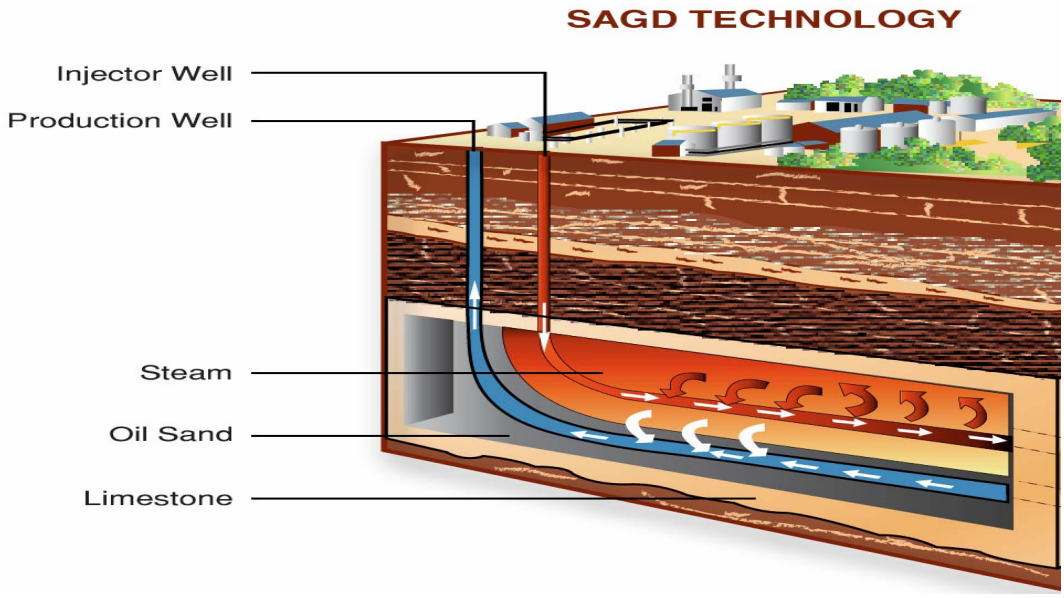

Fig. 11 Steam Assisted Gravity drainage (SAGD) process

5.4.3 Microbial Flooding (MEOR)

Microbial enhanced oil recovery (MEOR) is one of the EOR techniques where bacteria and their by-products are utilized for oil mobilization in a reservoir (Marshal [6]). In principle, MEOR is a process that increases oil recovery through inoculation of microorganisms in a reservoir, aiming that bacteria and their by-products cause some beneficial effects such as the formation of stable oil-water emulsions, mobilization of residual oil as a result of reduced interfacial tension, and diverting of injection fluids through upswept areas of the reservoir by clogging high permeable zones. Microbial technologies are becoming accepted worldwide as cost- effective and environmentally friendly approaches to improve oil production.

In this method, nutrients and suitable bacteria, which can grow under the anaerobic reservoir conditions, are injected into the reservoir. The microbial metabolic products that include biosurfactants, biopolymers, acids, solvents, gases, and also enzymes modify the properties of the oil and the interactions between oil, water, and the porous media, which increase the mobility of the oil and consequently the recovery of oil especially from depleted and marginal reservoirs; thus extending the producing life of the wells. In MEOR process, different kinds of nutrients are injected to the reservoirs. In some processes, a fermentable carbohydrate including molasses is utilized as nutrient.

Some other reservoirs require inorganic nutrients as substrates for cellular growth or as alternative electron acceptors instead of oxygen. In another method, water containing a source of vitamins, phosphates, and electron acceptors such as nitrate, is injected into the reservoir, so that anaerobic bacteria can grow by using oil as the main carbon source. The microorganisms used in MEOR methods are mostly anaerobic extremophiles, including halophiles, barophiles, and thermophiles for their better adaptation to the oil reservoir conditions. These bacteria are usually hydrocarbon-utilizing, non-pathogenic, and are naturally occurring in petroleum reservoirs (Rashidi et al 2012). Fig. 12 shows the microbial flooding.

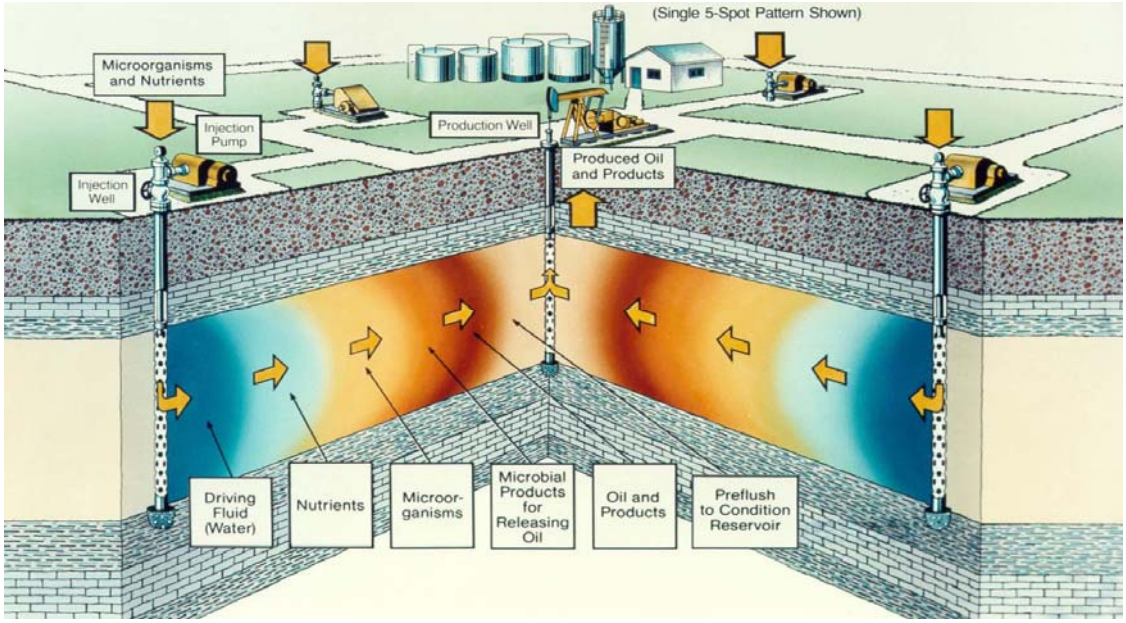

Fig. 12 Microbial flooding pocess

Several publications state that oil recovery through microbial action takes place due to several mechanisms as follows (Jackson et al [3] and Nielson et al [7]):

1- Reduction of oil/water interfacial tension and modification of porous media wettability by surfactant production and bacterial action.
2- Selective plugging of porous media by microorganisms and their metabolites.
3- Oil viscosity reduction caused by gas solution in the oil due to bacterial gas production or degradation of long-chain saturated hydrocarbons.
4- Production of acids that dissolve rock improving porous media permeability.

5.4.4 Nanofluid injection

New type of fluids usually called “smart fluids” has become more accessible for the oil and gas industry. The nanofluids are created by the addition of nanoparticles to fluids for intensification and improvement of some properties at low volume concentrations of the dispersing medium. Then the main feature of nanofluids is that their properties greatly depend on the dimensions of nanoparticles. Suspensions of nanodimensional particles have the following advantages; increase in sedimentation stability because surface forces easily counterbalance the force of gravity; thermal, optical, stress–strain, electrical, rheological and magnetic properties that strongly depend on size and shape of the nanoparticles can be created during production. It is for this reason that nanofluid properties often exceed the properties of conventional fluids. The researches have shown how dispersed nanoparticles in an aqueous phase can modify the interfacial properties of the liquid/liquid systems if their surface is modified by the presence of an ionic surfactant. Mixed particle/surfactant interfacial layers have been characterized through measurements of the effective interfacial tension and wettability (Onyekonwu et al [9]).

Presence of nanoparticles changes rheological properties and increase effect of surfactant solution on oil recovery processes. First of all it changes interfacial tension value of surfactant/oil interface more effectively. Observed reduction of interfacial tension is the result of nanoparticles presence at the interfacial layers. In lower concentration of nanoparticle, they are attached to the liquid surface and due to absorption process decrease surface tension. However in concentration larger than 0.4 wt.%, the nanoparticles nearly completely remove the surfactant from the bulk aqueous phase and there is no free surfactant available in the bulk. Thus, for nanoparticles concentrations below 0.4 wt.%, the interfacial tension of the dispersion is determined by a mixed layer composed by attached nanoparticles and surfactant adsorbed at the liquid interface (Ogolo et al [8]).

Haroun et al [4] explained that the nanotechnology EOR has the following advantages over the other techniques:

- Low viscosity oil
- High salinity
- Large well spacing
- High clay content
- Extensive thermal fracture

6. Iraqi oil Fields

It is well known that the majority of Iraqi oil fields are having carbonate lithology. However, sandstone formations are existed also in several Iraqi oil fields. Iraqi oil is considered as moderate to light oil in which the API gravity covers the range (20-35). Very few Iraqi oils are classified as heavy oil like the oil produced from Qaiyarah structure (Jeribe reservoir 15.3 API, Euphrates reservoir 15.3 API, and Hartha reservoir 17.3 API). At the same time, very few oils are considered light oil with API gravity around 40 such as the oils from Ajeel structure (Fatha reservoir 41 API, Gotnia 37 API, and Sargelu 38 API).

Based on the lithology type, both gas injection techniques and chemical flooding processes are good candidates for the enhanced oil recovery treatment in Iraqi oil fields. The consideration should be taken for the permeability rang and the viscosity of the oil. The permeability of most Iraqi oil fields is in the range of several milidarcies to almost one Darcy. Naturally fractured carbonate reservoirs is the second consideration for the screening criteria of the enhanced oil recovery process in the Iraqi oil fields. Appendix-A shows classification for Iraqi oil fields based on structure, length, width, reservoir, lithology, depth, net pay thickness, porosity, permeability, API, sulfur content, and the produced fluid. This classification might be used for screening criteria of the prospective EOR projects. Three technical selection criteria have to be considered. Lithology is the first selection criterion for the EOR projects where thermal flooding is the dominant technique for sandstone reservoirs while gas injection is the best candidate for the carbonate reservoirs. The second criterion is the reservoir fluid properties in which the API gravity and the viscosity are the two parameters that typical taken into account. The third one is the formation properties in which the porosity and permeability ranges are the main factors for the selection of the EOR projects. Reservoir depth also has some impacts on the selection criteria as the pressure and temperature gradient depend on the depth.

Nomenclatures

B_{oi} *intial oil formation volume factor*
B_{or} *residual oil formation volume factor*
k_{rw} *relative water permeability, md*
k_{ro} *relative oil permeability, md*
S_{oi} *intial oil saturatio*
S_{or} *residuall oil saturation*
S_{wi} *intial water saturation*
$\bar{S}_{wBT}$ *water saturation at break through*
v *linear velocity, cm/sec*
μ_w *water viscosity, cp*
μ_o *oil viscosity, cp*
σ *interfacial tension, dyne/cm*
θ *contact angle*

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Appendix

Structure	Length Km	Width Km	Reservoir	Age	Reservoir lithology	Depth m	Net Pay m	Por (%)	Perm Md	API	S%	Shows	Date completed or on stream	Expected EOR Technique
Abtakh		2	Fatha Jeribe Shir./hartha Mushorah Mus Butmah Kurra chine	Miocene Miocene Camp_Maast Turonian Liassic Liassic U Triassic	Carb. Carb. Carb. Carb. Carb. Carb. Carb.	956 1407 2401 2656 3298 3509 3574	---- ---- ---- ---- ---- ---- ---	---- ---- ---- ---- ---- ---- ---	---- ---- ---- ---- ---- ---- ----	---- ---- ---- ---- ---- ---- ----	---- ---- ---- ---- ---- ---- ---	Oil & Gas	1978	
Abu Ghirab N	8	2	Kirkuk Group Mishrif Mauddud	Oligocene Cen-Tru Albian	Carb. Carb. Carb.	3014 3797 4258	__ __ __	18 12 13	400 93 5.6	24 24.9 26	3.93 3.6			Polymer flooding
Abu Ghirab S	19	4	Jer.\Eu ph.	Miocene	Carb.	2887	__	20	500	21	3.23		1971 on stream	CO2 injection
Adaiyah			Shiranish Butamah Kurra chine	Camp-Maast L Triassic U Triassic	Marl Carb. Carb.	326 1226	__ __ __	__ __ __	__ __ __	15 31 __	__ __ __	Heavy	1938	
Ain Ghazal	14	4	Jeribe Euphrat	Miocene Miocene	Carb. Carb.	1084 1386	__ __	__ __	__ __	__ __	__ __	Oil &Gas	1983	
Ain zalah	15	4	Shiranish Mushorah Mauddud	Camp-maast Senonian Albian	Carb. Carb. Carb.	1607 2231 3438	90 ------ 223	3 18 18	Fr.re __	31.5 31.4 31.4	2.6 2.7 2.7		1951 on stream	Polymer flooding
Ajeel	20	6	Fatha Jer/dhiban Euphrates Chia gara Gotnia Sargelu	Miocene Miocene Miocene Tithonian U Jurassic M Jurassic	Carb. Carb. Carb. Carb. Carb. Carb.	644 944 989 2924 3175 3243	__ __ __ __ __ __	__ __ __ __ __ __	__ __ __ __ __ __	41 34 30 27 38 42	__ __ __ __ __ __	Oil &Gas	1998 on stream	
Alan	28	4	Sargelu Kurra chine Kurra chine	M Jurassic U triassic U triassic	Carb. Carb. Carb.	1247 2320 __	17.4 50.3 __	__ __ __	__ __ __	13.3 34.1 29.1	2.5 1 1.57	Heavy	1937&1955	
Ashtan	30	3	Sargelu Mus/Adaiyah	M Jurassic Liassic	Carb Carb	951 1273	---- ----	---- ----	---- ----	34.2 34	1.8 1.9	Heavy	1954	

Structure	Length Km	Width Km	Reservoir	Age	Reservoir lithology	Depth m	Net Pay m	Por (%)	Perm Md	API	S%	Shows	Date Completed or on Stream	Expected EOR TEchnique
			Butmah Kurra chine Geli khana	Liassic U Triassic M triassic	Carb. Carb. Carb.	1381 1991 2539	__ __ __	__ __ __	__ __ __	34 __ __	1.5 __ __			
Avanah_ kirkuk	27	--	Kirkuk Group Shiranish Kometan	Oligocene Camp-maast turonian	Carb. Marl Marl	666 1448 1670	472 __ __	25 __ __	200 __ __	36.1 33 33	1.95 __ __		1933 on stream	Chemical flooding+ Gas injection
Baba-Kirkuk	50	3	Kirkuk Group Shiranish Kometan Mauddud Shuaiba	Oligocene Camp-maast Turonlan Albian Aptian	Carb. Carb. Marl Carb. Carb.	363 925 1150 1275 1571	747 __ __ __ __	25 __ __ __ __	+250 __ __ __ __	36.7 33 33 38 29	2.05 __ __ __ __		1934 on stream	Chemical flooding+Gas Injection
Bai hassn	22	3	Jeribe Kirkuk Group Jaddala Aaliji Shiranish L kometan Mauddud shuaiba	Miocene Oligocene Eocene Pal-Eoc Camp-maast Turonlan Albian Aptian	Carb. Carb. Chalk Marl Marl Marl Carb. Carb.	788 801 1036 1152 1188 1480 1549 1822	-- 378 -- -- -- -- -- --	-- 20 -- -- -- -- -- --	-- 30-200 -- -- -- -- -- --	-- 34 28 28 31.5 11 22 26.5	-- 2.6 -- -- -- -- -- 3.7		1930 on stream	Gas injection+ Chemical flooding Thermal Reco.
Bohaira	-	5	Kurra chine	U Triassic	Carb.	--	--	--	--	--	--		1998	
Butmah East	8	1.6	Shiranish Kurra chine	Camp-maast U Triassic	Carb. Carb.	1277 2981	152 --	3	Fr.re --	29.3 36.2	2.6 1.08		1954 1954	Polymer flooding
Butmah west	8	3	Kurra chine Geli khana	U Triassic M triassic	Carb. Carb.	2790 3775	-- --	-- --	-- --	35 34	1.2 0.04		1986 on stream	Chemical flooding
Chemechemal	74		Pila spi Shiranish Sadi kometan	Eocene Camp-maast Senonian Turonlan	Carb. Marl Carb. Marl	508.4 1825 -- --	-- -- -- --	-- -- -- --	-- -- -- --	43 63.1 Gas Gas	0.14 0.14 -- --		1930&1960	
Chia surkh	6.5		Fatha Jeribe	Miocene Miocene	Carb. Carb.	1010 1720	-- --	20 18	-- --	41 43	0.58 0.67		1954	Gas Injection
Demir dagh	10		Gercus Shiranish Pilsener/Har.	M Eocene Camp-maast Senonian	Carb. Carb. Carb.	1017 1567 ?	-- -- --	-- -- --	-- -- --	14.9 22 14.9	4.9 3.9 --		1980	Thermal recovery

Structure	Length Km	Width Km	Reservoir	Age	Reservoir lithology	Depth m	Net Pay m	Por (%)	Perm Md	API	S%	Shows	Date Completed or on Stream	Expected EOR TEchnique
Jumber	15	5	Jeribe Euph/serik Shiranish	Miocene Miocene Camp-masat	Carb. Carb. Marl	1554 1586 2082	102 64 __	20 30 __	4 40 __	40.5 40.6 __	1.2 1.3 __		1995 on stream	Gas Injection
Jaria pika	15	5	Jeribe Dhiban Euphrates serikagni	Miocene Miocene Miocene Miocene	Carb. Carb. Carb. Carb.	1457 1509 1626 1651	__ __ __ __	__ __ __ __	__ __ __ __	48 52 52 52	2.2 0.1 0.1 0.1	Gas	1976	Gas injection
Jawan	16	5	Jeribe Euphrates Hartha	Miocene Miocene Camp-masat	Carb. Carb. Carb.	175 254 693	150 50 200	__ __ __	__ __ __	15 19 20	7 6.8 5.8		1936	Thermal recovery
Judaida	5	1	Jeribe Dhiban Euphrates Kirkuk groub kometan	Miocene Miocene Miocene Oligocene turonian	Carb. Carb. Carb. Carb. marl	2236 2286 2385 2445 3247	__ __ __ __ __	17.4 16.9 18.5 17.8 8.9	0.29 21.1 7.8 36.5 0.04	26 25 24.9 25 18	2.9 __ __ 4.18 __	Oil &Gas		Gas injection
Kand	33	5	nd	--	Carb.	--	--	--	--	--	--		1983	
khabaz	15	4	Jeribe Kirkuk groub Mauddud shuaiba	Miocene Oligocene Albian Aptian	Carb. Carb. Carb. Carb.	2063 2111 2753 3045	-- -- -- --	20 15 12 8	146 740 25 83	37 37 29 39	2.08 1.5 2.05 2		1994 on stream	Gas injection
khanuaqah	33	3	Jeribe	Miocene	Carb.	265	--	--	--	--	--	Gas	1929	
Khashim Ahmar	11	3	Fatha Jeribe Dhiban	Miocene Miocene Miocene	Carb. Carb. Carb.	955 1338 1393	-- -- --	15 21 15	-- -- --	-- -- --	-- -- 1.17	Gas	1928&1980	
khurmala	24	5	Kirkuk groub Mauddud shuaiba	Oligocene Albian Aptian	Carb. Carb. Carb.	815 1771 2031	300 -- --	-- -- --	150 -- --	34 38 29	1.95 -- --			Chemical flooding

Structure	Length Km	Width Km	Reservoir	Age	Reservoir lithology	Depth m	Net Pay m	Por (%)	Perm Md	API	S%	Shows	Date Completed or on Stream	Expected EOR TEchnique
East Anah	215	8	Hartha	Camp-maast	Carb.	2338	—	—	—	—	—	Heavy	1939	
			Mushorah	Turonian	Carb.	2412	—	—	—	—	—		1959	
			Alan	Liassic	Carb.	2698	—	—	—	—	—			
			Adaiyah/Mus	Liassic	Carb.	2732	—	—	—	—	—			
			Butamah	Liassic	Carb.	2885	—	—	—	—	—			
Khleisia	20	20	Khabour	Ordovician	Clast	2544	—	—	—	—	—	Oil &Gas	1959	
West Anah	215	8	—	—	—	—	—	—	—	—	—			
Afaq	4	2	Aaliji	Pal-Eoc	Marl	1195	—	—	—	—	—	Oil &Gas	1961	
	2	5	Hartha	Camp-Maast	Carb.	1690	—	—	—	—	—			
			Ahmadi	Cenomanian	Carb.	2457	—	—	—	—	—			
			Mauddud	Albian	Carb.	2519	—	—	—	—	—			
			Zubair	L Cretaceous	Carb.	2873	—	—	—	—	—			
Ahdab North	10	2	Tanuma	Senonian	Carb.	2542	—	23	—	25	—	Oil &Gas	1982	Polymer flooding
			Khasib	Turonian	Carb.	2595	—	22.5	80	25	—			
			Mishrif	Cenomanian	Carb.	2700	—	14.8	63	25	—			
			Rumaila	Cenomanian	Carb.	2806	—	19.2	63	24	—			
			Mauddud	Albian	Carb.	3080	—	16.7	0.7	22	—			
			Nahr Umr	Albian	Carb.	3385	—	—	—	22	—			
			Shuaiba	Aptian	Carb.	3482	—	—	—	22	—			
Ahdab Suuth	7	3	Hartha	Camp-maast	Carb.	2263	—	22.5	—	25	—	Oil &Gas	1982	
Amara			Khasib	Turonian	Carb.	2801	—	—	—	21	—	Oil &Gas	1985	
			Mishrif	Cenomanian	Carb.	2880	—	—	—	23	—			
			Mauddud	Albian	Carb.	3308	—	—	—	12	—			
			Nahr Umr	Albian	Carb.	3673				30				

Structure	Length Km	Width Km	Reservoir	Age	Reservoir lithology	Depth m	Net Pay m	Por (%)	Perm Md	API	S%	Shows	Date Completed or on Stream	Expected EOR TEchniq
Buzurgan	18	7	Jeribe	Miocene	Carb.	2850	__	20	15	31	__	Oil &gas	1976 on stream	Chemical
Buzurgan south	27	5	Kirkuk groub mishrif	Oligocene Cenomanian	Carb. Carb.	2864 3733	__ __	24 16	20 47	25 23	__ 3.9	Oil &gas	1980	Polymer
Dhufriya S.	10	3	zubair	L cretaceous	Clast.	4107	__	15	__	23.6	__	Oil &gas	1984	
Dibdiba	8	3	Mauddud Nahr umr Yamama sulaiy	Albian Albian L cretaceous Tith-Berr	Carb. Clast. Carb. Carb.	2810 2917 4051 4282	__ __ __ __	__ __ __ __	__ __ __ __	__ __ __ __	__ __ __ __	Oil &gas	1984	
Dujaila	9	3	Mishrif	Cenomanian	Carb.	2839	__	__	__	14	__	Oil &gas		
East Baghdad (EB)	100	6	Hartha	Camp-maast	Carb.	1874	_	24	_	19	5.18	Oil &gas	1989 on stream	
EB Diyala	30	7	khasib Mishrif Nahr umr zubair	Turonian Cenomanian Albian L cretaceous	Carb. Carb. Clast. Clast.	2432 2590 3213 3408	__ __ __ __	30 15 20 20	__ __ __ __	21 19 32 27	3.81 3.76 1.3 1.5	Oil &gas		Chemical flooding
EB NE	40	7	Sadi	senionian	Carb.	2192	__	15	__	20	33.95	Oil &gas		
EB Rashidiya	30	5	tanuma	senoinan	Carb.	2316	__	20	__	22	3.6	Oil &gas		
Ekhaidher	12	7	Hartha Nahr umr zubair	Camp-maast Albian L Cretaceous	Carb. Clast. Clast.	563 1387 1533	__ __ __	__ __ __	__ __ __	__ __ __	__ __ __	Oil &gas		
Ekhaidher 1	8	3	Hartha Nahr umr zubair	Camp-masa Albian L Cretaceous	Carb. Clast. Clast.	468 1264 1417	__ __ __	__ __ __	__ __ __	__ __ __	__ __ __	Oil &gas		

Structure	Length Km	Width Km	Reservoir	Age	Reservoir lithology	Depth m	Net Pay m	Por (%)	Perm Md	API	S%	Shows	Date Completed or on Stream	Expected EOR TEchnique
Halfaya	25 10	7 2	Jeribe Euphrates Kirkuk Group Sadi Tanuma Khasib Mishrif Nahar Umr Yamama	Miocene Miocene Oligocene Senonian Senonian Turonian Cenomanian Albian L Cretaceous	Carb. Carb. Carb. Carb. Carb. Carb. Carb. Carb. Carb.	1902 -- 1913 2608 2733 2748 2833 3505 4369*	__ __ __ __ __ __ __ __ __	18 20 24 18 16 16 17 18 9	__ __ __ __ __ __ __ __ __	22 22 22 26 26 21 20 31 27	__ __ __ __ __ __ 4.7 2.12 __	Oil& Gas	1978	Chemical flooding
Huwaiza	15	5	Hartha Sadi Khasib Mishrif Nahr Umr Zubair Yamama __	Camp-maast Senonian Turonian Cenomanian Albian L Cretaceous L Cretaceous __	Carb. Carb. Carb. Carb. Clast. Clast. Carb. __	2912 2966 3078 3145 3721 4095 __ __	__ __ __ __ __ __ __ __	__ __ __ __ __ __ __ __	__ __ __ __ __ __ __ __	26 26 20 20 20 __ __ __	__ __ __ __ __ __ __ __	Oil& Gas		Polymer flooding
Jabel Sanam	5	5	Shiranish Mushorah Mauddud	Cenomanian Cenomanian Albian L cretaceous	Carb. Carb. Clast. Clast.	2552 2771 3041 3412	__ __ __ __	__ __ __ __	__ __ __ __	__ __ __ __	__ __ __ __	Oil& Gas	1978	
Jraishan	8	5	Khasib Mishrif Mauddud Shuaiba Nahar Umr Ratawi /Yam. Sulaiy	Turonian Cenomanian Albian Aptian Aptian L Cretaceous Tith - berr	Carb. Carb. Carb. Carb. Clast. Carb. Carb.	__ __ __ __ 2750 ____	__ __ __ __ __ ___	__ __ __ __ 18 ___	__ __ __ __ 532 ____	__ __ __ __ 30 32.7	__ __ __ __ ____ 1.73	Oil& Gas	1976	

Khidr	10	2.5	Nahr Umr Zubair Ratawi Yamama Najmah	Albian L Cretaceous L Cretaceous L Cretaceous U Jurassic	Clast Clast Carb. Carb. Carb.	2582 2948 2526 3703 4783	___ ___ ___ ___ ___	___ ___ ___ ___ 30	___ ___ ___ ___ ___	___ ___ ___ ___ ___	___ ___ ___ ___ ___	Heavy	1983	
kifl	13	7	Didibba Fatha Aaliji Hartha Nahr Umr Zubair Yamama Gotnia Najmah Sargelu	Miocene Miocene Pal-Eoc Camp-maast Albian L Cretaceous L Cretaceous U Jurassic U Jurassic M Jurassic	Clast Carb. Marl. Carb. Clast Clast Carb. Carb. Carb. Carb.	65 84 507 845 1787 2001 2488 2951 3026 3177	___ ___ ___ ___ ___ ___ ___ ___ ___ ___	___ ___ ___ ___ 20 23 ___ ___ ___ ___	___ ___ ___ ___ ___ ___ ___ ___ ___ ___	___ ___ ___ ___ 26 20 14 ___ ___ ___	___ ___ ___ ___ ___ ___ ___ ___ ___ ___	Oil & Gas	1960	
Kumait	15	3	Mishrif Nahr Umr	Cenomanian Albian	Carb. Carb.	3049 3645	___ ___	11.3 18.5	___ ___	23 30	3.92 2.9	Oil & Gas	1983	Chemical flooding
Luhais	24	10	Nahr Umr Zubair	Albian L Cretaceous	Carb. Clast	2482 2776	___ ___	20 20	___ ___	32 33	___ ___	Oil & Gas	1978 On stream	Chemical flooding
Majnoon	48	10	Fatha Ghar Shiranisb Hartha Sadi Khasib Mishrif Ahmadi Nahr Umr Shuaiba Zubair Yamama	Miocene Miocene Camp-Maast Camp-Maast Senonian Turonian Cenomanian Cenomanian Albian Aptian L Cretaceou L Cretaceous	Carb. Carb. Carb. Carb. Carb. Carb. Carb. Carb. Clast Carb. Clast Carb.	962 1255 1992 2109 2210 2343 2385 2622 2955 3129 3279 3818	___ 35 40 ___ ___ ___ 140 70 25 50 25 150	20 20 15 21 18 15 13 25 16 15 20 10	___ 200 143.5 76 10 4 330 268 515 150 254 180	----- 24 20.4 30 19.5 25 21 21 30 30 27.5 35	___ 3.45 ___ 3.08 4.64 ___ 3.9 4.21 2.29 ___ 2.18 0.98	Oil & Gas	1977	Chemical flooding+ Gas injection

Structure	Length Km	Width Km	Reservoir	Age	Reservoir lithology	Depth m	Net Pay M	Por (%)	Perm Md	API	S%	Shows	Date Completed or on Stream	Expected EOR TEchnique
Nasiriya	26	10	Mishrif Nahr Umr Ratawi Yamama	Cenomanian Albian L Cretaceous L Cretaceous	Carb Clast Carb Carb	1943 2321 3101 3178	----- ----- ----- -----	22 22 10 9.2	500 ----- ----- ----	24 35 37 37	3.62 ----- ------- 2.2	Oil & Gas	1979	Gas injection + Chemical flooding
Noor	20	8	Mishrif Nahr Umr	Cenomanian Albian	Carb Clast	3308 3947	----- -----	14 22	----- 120	23 25	----- -----	Oil & Gas	1978	Chemical flloding
Rachl	16	5	Nahr Umr Zubair Yamama	Albian L Cretaceous L Cretaceous	Clast Clast Carb	2614 2938 3855	----- ----- -----	----- ----- 14	----- ----- 1	28 32 39	------ ------ ------	Oil & Gas	1957	
Rafidin	28	4	Mishrif Nahr Umr Zubair Ratawi Yamama	Cenomanian Albian L Cretaceous L Cretaceous L Cretaceous	Carb Clast Clast Carb Carb	2432 3045 3294 3703 3836	----- ----- ----- ----- -----	15 23 24 20 10	----- ----- ----- ----- -----	26 25 39 37 34	----- ----- ----- ----- -----	Oll & Gas	1981	
Rafidin E	-----	12	Mishrif Ratawi Yamama	Cenomanian L Cretaceous L Cretaceous	Crab Crab Carb	2677 3923 4073	----- ----- -----	---- ---- ----	----- ----- -----	24 30 30		Oil	1979	
Ratawi	25	13	Mishrif Ahmadi Mauddud Nahr Umr Yamama	Cenomanian Cenomanian Albian Albian L cretaceous	Carb Carb Carb Carb Carb	2094 2324 2458 2574 2533	----- ----- ----- ----- -----	18 23 18 20 13	44 9.2 10.2 152 17.2	26 15 15 25 42	----- ----- ----- ----- 1.24	Oil & Gas	1950	Chemical Thermal Thermal Chemical Chemical
Rumaila S	34	7	Fatha Mishrif Nahr Umr Zubair	Mipcene Cenomanian Albian L Cretaceous	Carb Carb Clast Clast	152 2228 2685 3025	----- ----- ----- 29	---- ---- ---- 20	----- ----- ----- 2500	----- 25 30 35.4	------ ------ ----- 2	Oll & Gas	1954 on stream	Chemical + Gas injection