الاستهلال

بسم الله الرحمن الرحيم

يقول الله تعالى في محكم تنزيله: (***إِقْرَأْ بِاسْمِ رَبِّكَ الَّذِي خَلَقَ (1) خَلَقَ الإِنسَانَ مِنْ عَلَقٍ (2) اقْرَأْ وَرَبُّكَ الأَكْرَمُ (3) الَّذِي عَلَّمَ بِالْقَلَمِ (4) عَلَّمَ الإِنسَانَ مَا لَمْ يَعْلَمْ(5)*** ﴾

صـــدق الله العظيـم

سـورة العلق (1-5)

Dedication

To our fathers and mothers who taught us great lessons about life, guiding, motivate and support us along life's level, reached us for this educational level without them I would not become the person who I am today.

To our brothers and sisters who stand with us, allow us to use their purpose when we need it to complete this research.

For future generations that hold future of the oil industry in Sudan.

We are honor to offer this modest work and we hope that helping to guide and understand some principle of an oil industry process.

Thanks all for giving us a chance to prove and improve our self through all levels of university life.

Acknowledgment

Undertaking a project of this size requires the support, direction and advice. We are deeply indebted to our supervisor Assistante. Proff. Eng. Satti Marghani Mohammed Ahmed For his technical directions, Motivation and moral support throughout this research.

Our profound gratitude goes to engineer Khalid Abdelbaset for taking time out of his busy schedule to guide us through this project.

We also wish to express our sincere appreciation for Abubaker Omer Mohammed Hussein, for his efforts and time, that he sacrificed it for us to complete this research.

We also wish to express our appreciation and sincere thanks to Department of Petroleum Engineering and Technology for information, advices and guidance that had given to us throughout five years. Finally, we would like to extend our gratitude to people who worked with us.

Abstract

In this research an EOR screening software has been designed by using visual basic studio based on recent EOR projects and the advanced technologies and used it with SPE format and EORgui software to apply screening criteria for Greater Neem field which is partially depleted. It's current condition requires implementing EOR techniques in order to maximize oil recovery and field life as much as possible. After that, the results have been obtained and compared between the three applications. It has been concluded that carbon dioxide injection and polymer flooding are the most viable options for Greater Neem field.

Key words:

Enhanced Oil Recovery, Screening Criteria, EORgui ,SPE Format.

التجريد

في هذا البحث تم تطوير برنامج باستخدام لغة (Visual Basic) يستخدم معايير تحليلية محدثة لطرق الاستخلاص المحسن. وأستخدم هذا البرنامج، بالإضافة الي صيغ جمعية مهندسي النفط، وبرنامج (EORgui) لإختيار الطريقة الأمثل لحقل (Greater Neem) الذي استنزف جزئيا والظروف الحالية للحقل تحتاج للدراسة، لتطبيق إحدى طرق الإستخلاص المحسن لزيادة استخلاصه. تمت مقارنة النتائج المتحصل عليها باستخدام الطرق الثلاثة بما فيها البرنامج الذي تم تطويره. أظهرت نتائج البحث أن طريقة حقن ثاني أكسيد الكربون وطريقة البوليمير هما الأمثل لهذا الحقل.

كلمات دلالية:

الاستخلاص المحسن للنفط ،المعيار التحليلي ،صيغ جمعية مهندسي النفط ،برنامج(EORgui)

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Nomenclature:

BOPD	:	Barrel Oil per Day
CSS	:	Cyclic Steam Stimulation
EOR	:	Enhanced Oil Recovery
G&G	:	Geological and geophysics
GNPOC	:	Greater Nile Petroleum Operating Company
IFT	:	Interfacial Tension
IOR	:	Improved Oil Recovery
ISC	:	In Situ Combustion
MEOR	:	Microbial Enhanced Oil Recovery
MMP	:	Minimum Miscibility Pressure
OEPA	:	Oil Exploration and Production Authority
OOIP	:	Original Oil in Place
PPM	:	Part Per Million
PV	:	Pore Volume
RF	:	Recovery Factor
SAGD	:	Steam Assisted Gravity Drainage
SOR	:	Steam Oil Ratio
SPE	:	Society Of Petroleum Engineering
WAG	:	Water alternating Gas
WNPOC	:	White Nile Petroleum Operating Company
S	:	Saturation, fraction
S_o	:	Oil saturation, fraction
S_w	:	Water saturation, fraction
S_g	:	Gas saturation, fraction
S_{oc}	:	Critical oil saturation, fraction
S_{or}	:	Residual oil saturation, fraction
M	:	Mobility ratio, general ($\lambda_{displacing} / \lambda_{displaced}$)
λ	:	Mobility (k/μ),md/cp
P_c	:	Capillary pressure.psi
C_a	:	Capillary number
E_V	:	Volumetric efficiency
E_A	:	Areal efficiency

E_I	:	Vertical efficiency
q	:	Production rate or flow rate, bbl/day
k	:	Absolute permeability, md
k_i	:	Effective permeability to phase(i), md
k_{ri}	:	Relative permeability to phase(i),
σ	:	Surface tension, interfacial, lb_m/s^2
θ	:	Contact angle
g	:	Acceleration of gravity, ft/s^2
ρ	:	Density, lb_m/ft^3
γ_o	:	Oil specific gravity
μ_o	:	Oil viscosity, cp
Ø	:	Porosity
h	:	Thickness (general and individual bed), ft.
D	:	Depth, ft.
T	:	Temperature, ^oF
CO_2	:	Carbon Dioxide
N_2	:	Nitrogen Gas

Chapter 1

Introduction

1.1. EOR background

The potential for enhanced recovery by advanced injection techniques has been known for many decades, but unstable economic climate and the complex nature of the reservoir processes often involved in enhanced recovery have hindered implementation of many projects. Due to improved drilling methods, better production technologies, improved reservoir knowledge, and higher oil prices, these methods are more attractive today (Green, D. and Willhite, G.P., 1998).

Enhanced oil recovery (EOR) definition is “the recovery of oil by injection of a fluid that is not native to the reservoir” and it is a method of extending the production life of depleted oil filed according to Green, D. and Willhite, G.P. EOR used to recover oil by using two different wells including water flooding, it is usually applied after primary, and secondary recovery processes have been exhausted. EOR cannot be applied in all reservoirs. Effective screening practice must be employed to identify suitable candidates. As a part of projections discount cash-flow are performed to assess profitability.

The general mechanism of oil recovery is movement of hydrocarbons to production wells due to a pressure difference between the reservoir and the production wells. The recovery of oil reserves is divided into three main categories worldwide.

1- **Primary recovery techniques**: This implies the initial production stage, resulted from the displacement energy naturally existing in a reservoir.
2- **Secondary recovery techniques**: Normally utilized when the primary production declines. Traditionally these techniques are water flooding and gas injection. The recovery factor can rise up to 50% by using them.
3- **Tertiary recovery techniques**: These techniques refer to the ones used after the implementation of the secondary recovery method. Usually these processes use miscible gases, chemicals, and/or thermal energy to displace additional oil after the secondary recovery process has become uneconomical. The recovery factor may arise up to 12% additionally to the RF obtained with the secondary recovery method.

Selection of EOR method:

There are many methods for enhanced oil recovery and each has differences that make it more useful based on specific reservoir challenges and other parameters. Selecting the suitable EOR method by screening the reservoir and fluid properties can ultimately reduce the risk by eliminating inefficiencies.

The criteria for selecting particular EOR process are complex because of the large number of petro-physical, chemical, geological, environmental and fluid properties (density & viscosity which are dependent on temperature) that must be considered for each individual case. The common methods used for the selection of EOR method include SPE Format and EORgui. These will be discussed individually**.**

1.2. Problem statement

Greater Neem field has a low recovery (OEPA, 2014) because of the decrease in the production that is why it needs to enhanced the recovery by EOR methods. EOR methods are quite complex and the selecting of suitable method for each field requires prescreening of rock, fluid and field characteristics in details. Before implementing any of these methods, they should undergo a careful and detailed screening process, then come up with the most suitable and compatible method.

This study examines the Greater Neem field though screening criteria using SPE format, EORgui software and a new software (EOR analysis) built by project team and IT engineer to compare and select the suitable EOR method to increase recovery factor.

1.4. Objectives

The main objectives of this research are:

1. To diagnose Greater Neem field and determine its problems which is low recovery.
2. Study rock and fluid properties that affect the selecting of EOR methods
3. To develop a new software based on updated screening criteria
4. Apply Greater Neem field data on EORgui to obtain results and compare it with the results from a new software.

1.5. Methodology

1. Determine the geological description and data required for the Neem field.
2. Implement screening process for this field by using: SPE format (manual), EORgui and new software.

3. Compare between obtained results to select the suitable method/s.

1.6. Greater Neem Overview:

The Greater Nile Petroleum Operating Company (GNPOC) operates greater Neem oil field in Block 4. It is in South Kordofan state.

Block 4 is divided into four grouping/cluster: Greater Diffra, Greater Neem, Azraq area and Canar area. The first commercial discovery in Block 4 was in 2002. The geological survey shows a multiple structures, multi-reservoirs & highly faulted features. The depth of reservoirs varies from 1400 to 3500 m. This reservoir is characterized by a high GOR and the porosity ranges from 16-30%. Abu Gabra is the main reservoir with Bentiu and Aradeiba sand representing the minor reservoirs. Figure 1-1 shows location map of block 4.

Well productivity is found to be good from DST. The produced oil is mainly light except NEN, NENA, NEW, HLE and HLNE. Diffra FPF,NeemFPF and Canar FPF are the three processing facilities in this block. CO_2 is found in Neem East Bentiu/Intra-Bentiu.

Greater Neem field consists of five reservoirs: Neem Main, Neem K, Neem F, Neem East,and Neem North.The first commercial discovery was in 2003. The geological survey shows multiple structures, multi-reservoirs & highly faulted features. The depth of reservoirs varies from 3000 to 3500m. This reservoir is characterized by a high GOR. AG is main reservoir consist of alternations of Sand & Shale.

Well Productivity is found to be good from DST. The produced oil is mainly light except Neem North and Neem West. CO_2 is found in Neem East Bentiu/Intra-Bentiu.

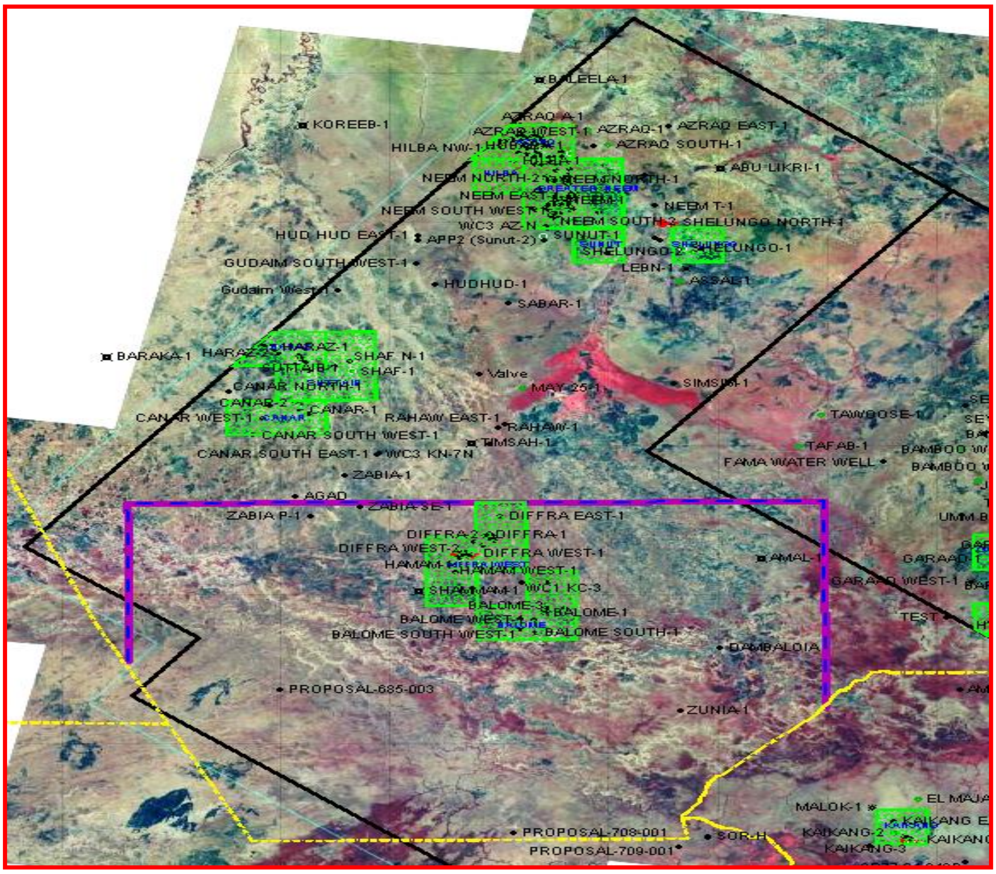

Fig. 1.1: Location Map of Block4 (OEPA, 2014)

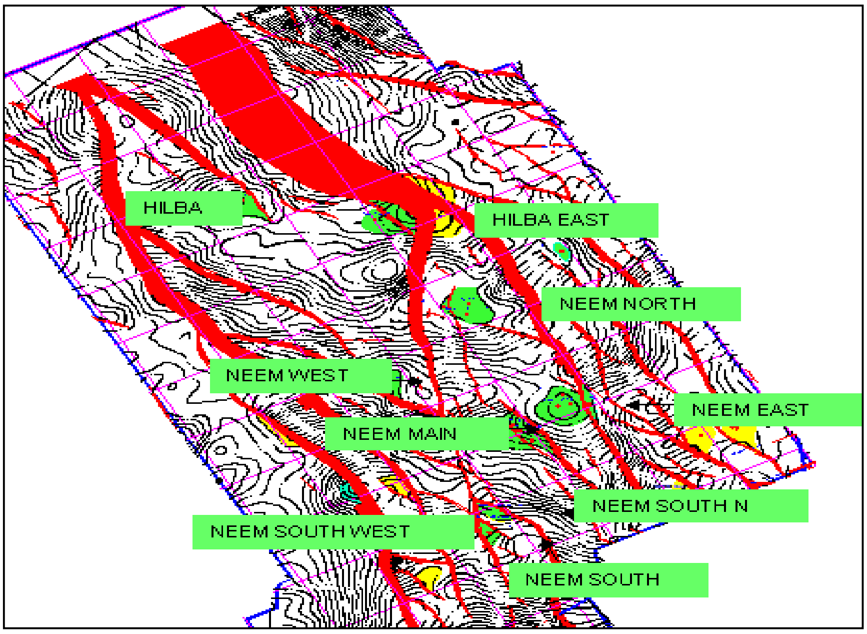

Fig.1.2: Location Map of Greater Neem Oil field (OEPA, 2014)

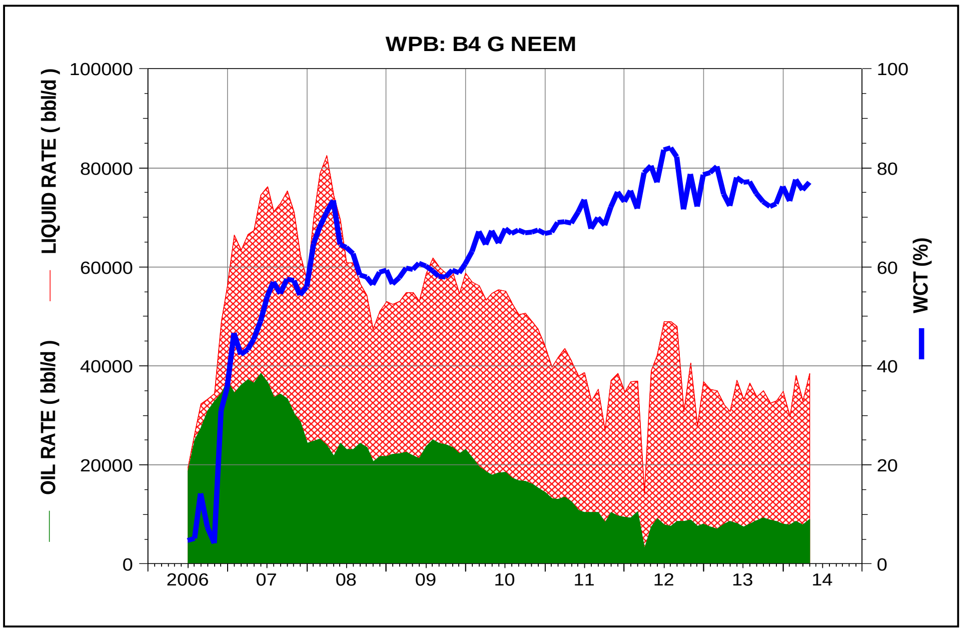

Fig.1.3: Production Status as of 31st May 2014(OEPA,2014)

In Greater Neem, the main producing sands are Abu Gabra and Bentiu .Water drive is the main driving mechanism in this field. Field development plan conducted in 2005 and updated in 2008 and new G&G study plan is set to start in 2014.

Table 1.1: Performance Summary for Greater Neem (OEPA, 2014)

Liquid flow rate	38.5 Mbbl/d
Oil flow rate	9 Mbbl/d
Water cut	77%
Cumulative oil production	52.87 MMstb
Number of wells	73wells (48 active)

Chapter 2

Literature Review and Theoretical background

2.1. Literature Review

Once primary and secondary oil recovery processes have been exhausted about two thirds of original oil in place (OOIP) is left behind and the role of enhanced oil recovery methods (EOR) is to recover that remaining oil. Selecting the suitable EOR method according to reservoir characteristics screening must be done.

Taber et.al in 1996 developed EOR criteria in (EOR screening criteria revisited part1) paper. The criteria are based on oil displacement mechanisms, the results of EOR field projects application reported in oil and gas journal, and at various SPE, conferences and they mentioned that: The depth oil gravity and oil production from hundreds of projects are displayed in graph to show the wide distribution and relative importance of the methods. Steam flooding continues to be dominant method but hydrocarbon injection and CO_2 flooding are increasing and if only oil gravity is considered, the results show that there is a wide choice of effective methods that range from miscible recovery of the lightest oil by nitrogen injection to steam flooding and surface mining for heavy oil and tar sands. However, there is often a wide overlap in choice with low oil prices, there is less chemical flooding of the intermediate-gravity oils that are normally waterflooding polymer flooding continues to show promise especially if projects are started at high oil saturation.

In 1996, Taber.et.al also have published EOR screening criteria revisited part 2. They have found that: The CO_2 screening criteria were used to estimate the capacity of the world's oil reservoir for the storage/disposal of CO_2 and the impact of oil prices on EOR production in the U.S was considered by comparing the recent EOR production to that predicted by the NPC reports for various oil prices

Ahmed Aladasani and Baojun Bai in 2010 reviews recent development in enhanced oil recovery (EOR) techniques published in SPE conference proceedings for 2007 to 2009. It also updates the EOR criteria developed by Taber et al.

Galal Eldin Yousif in 2010 has studied all Sudanese fields through screening criteria based on only five properties, which are permeability, oil viscosity, depth, pressure and API gravity by using SPE format, to select the suitable EOR method for each block to increase the recovery factor. He reviewed economic analysis for methods that applied in Sudanese fields also; he made road maps and wide picture for EOR in Sudan

Abd-Alrhman Salih Ali et al in 2010 had proposed screening criteria for all enhance oil recovery methods based on geological description and reservoir properties from previous oil field experience besides economic evaluation and ranking of IOR/EOR opportunities. Data from AB field had been examined and the optimum. They had noted reservoir characteristics for successful field enhancing performance.

Based on these studies a new software will be designed using updated screening criteria and compare the results with SPE format and EORgui.

2.2. History of Oil in Sudan

Exploration activities in the Sudan began at the end of the 1950s in the coastal waters of the Red Sea and the Sudanese continental shelf by the Italian company (AGIP) at mid of 1970s to 1980s exploration activities were very active and shifted to the interior basins of the Sudan. Chevron drilled the first well in AbuGabra area in 1977 and Baraka-1 in 1978 providing the presence of source rock and made its first discovery of unity-1. Sudan has been producing its petroleum resource commercially since 1999 when Block 1/2/4 started production of reserve. This was the major achievement by its operator GNPOC when they commercialize and export crude to foreign buyers via 1500 km new pipeline to Port Sudan. Since then, its daily production has increase to maximum of 300 KBOPD in 2006 (before it started declining rapidly with increasing water production). Three more operators: Petro-Energy, PDOC and WNPOC started their oil production in 2006 (Galal Eldin, 2010)

Total Sudan oil in place as of 1st January, 2009 was estimated to be 15.9 billion barrels, 39% of which (6.2 billion barrels) is in Block 3/7 operated by PDOC which contributes about 37% of total Sudan estimated ultimate oil recovery. GNPOC holds second biggest oil in place, which is about 5.5 billion barrels but the highest recoverable oil of 1.6 billion barrels, contributing about 45% of the national reserve. The remaining is possessed by WNPOC and Petro-Energy (Galal Eldin, 2010).

The average recovery factor for Sudan is estimated at 23%, which is relatively low on international standard, and GNPOC's average recovery factor is the highest at 26%, followed by PDOC, Petro-Energy and WNPOC at 21.5%, 23% and 11.9% respectively according to (Sudapet, 2009). This is low recovery factor is attributed to amongst other qualities of the oil and also non-favorable reservoir properties, GNPOC's API is the highest at 33 API, followed by PDOC at 25 API, WNPOC at 21 API and Petro-Energy at 18 API. With declining production and the fact that 77% of the oil will remain in the ground at the end of field producing life, there is an urgent need to adopt new approach in order to enhance oil recovery to arrest the declining production. Most oil fields production are on natural depletion and assisted by artificial lift pumps. Only Unity and Talih fields in GNPOC is on water injection to provide pressure maintenance, while a pilot test was being implemented in PDOC. In the low API oil and viscous crude production environment, water injection is usually not favorable for application due to the poor mobility ratio which susceptible to water fingering. Early high water-cut and low oil production rate are expected in heavy oil production. Beside infill drilling, well stimulation and horizontal well drilling to produce the "low hanging fruits" a major step forward is needed to improve oil recovery. Suitable and cost effective enhanced oil recovery technique should be selected for implementation.

According to U.S Energy Information Administration report at September 2013, Sudan and South Sudan have 5 billion barrels of proved crude oil reserves of January 1, 2013. Approximately 1.5 billion barrels are in Sudan and 3.5 billion barrels in South Sudan. Currently, oil produced from Blocks 2, 4, 6 and 17 counted as Sudan's production, while oil from Blocks 1, 3 and 7 belongs to South Sudan. Total oil production in Sudan and South Sudan reached its peak of 486,000 bbl/d in 2010, but it declined to 453,000 bbl/d in 2011.

After the secession of the South (85% of total oil production come from it) Sudan’s, oil production declined to 120,000 bbl/d. At the end of 2012, Sudan brought two new fields: the Hadida field in Block 6 and al-Barasaya in Block 17. Sudan hope to increase production in the future by ramping up new fields and increasing oil recovery rates in existing fields from 23 % to 47 % (eia, 2012). The production forecast for Sudan and South Sudan and average recovery factor shown at figures (2.1 and 2.2).

There are many reasons for selecting EOR to increase the recovery factor in Sudan fields including low recovery factor, high water cut and high amount of remaining oil reserves. Availability of technology and good oil price also are important reasons for implementing EOR processes.

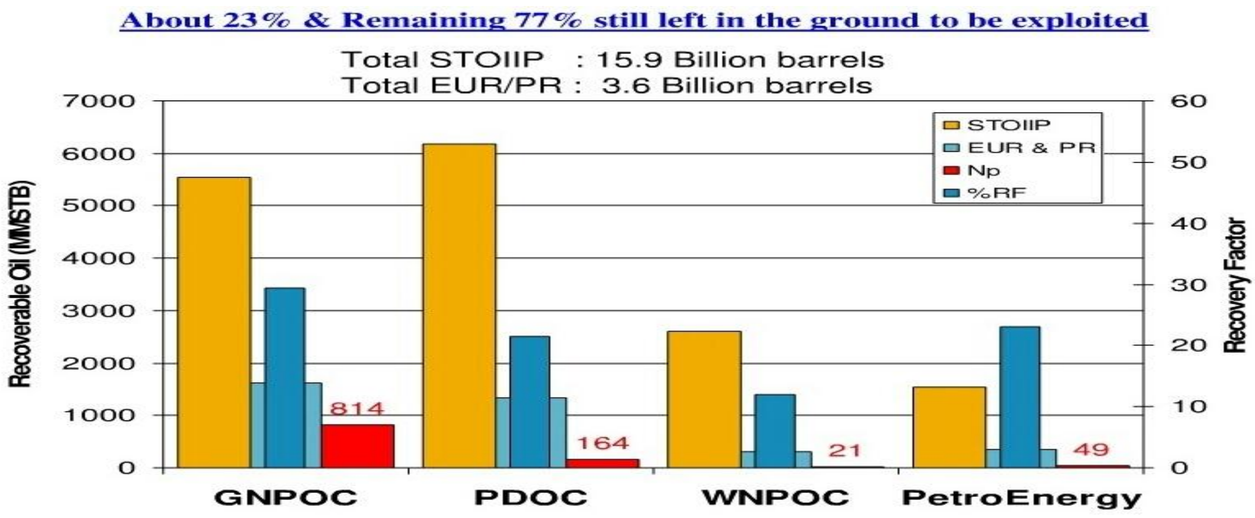

Fig. 2.1: Production Forecast for Sudan & South Sudan (Sudapet, 2009)

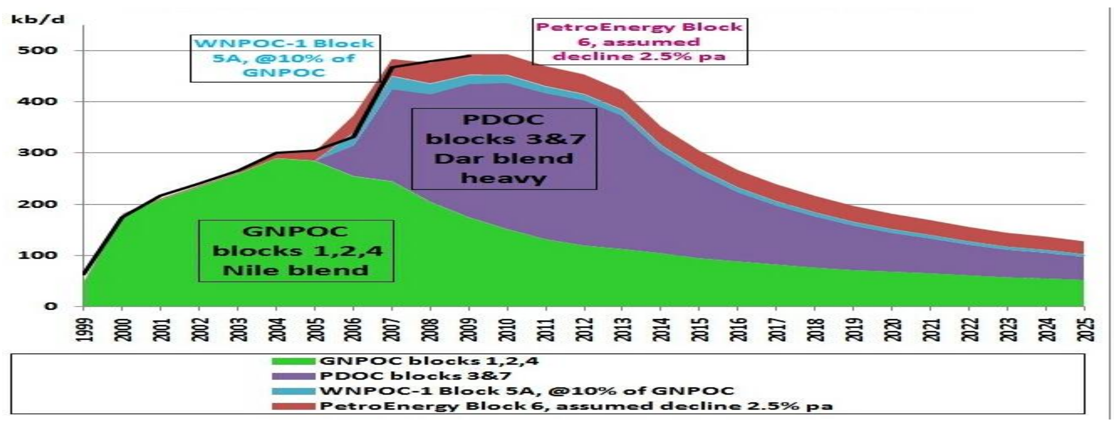

Fig. 2.2: Average RF for Sudan & South (Sudapet, 2009)

EOR projects in Sudan are few; examples of these projects are chemical injection and (CSS) in Bamboo field and thermal EOR project (CSS and steam flooding) in FNE Block in Fula field.

Oil Recovery Processes

The recovery of oil reserves divided into three main categories as shown in figure 2.3.

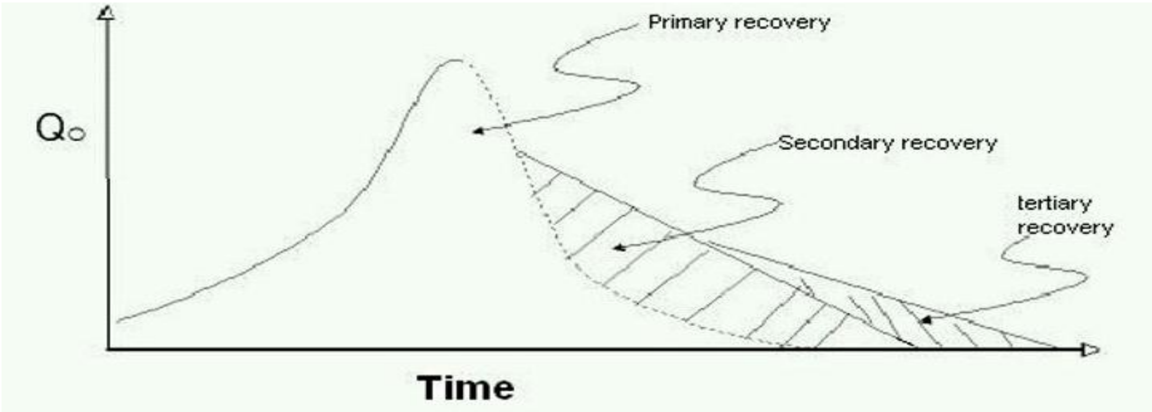

Fig. 2.3: Recovery Stages of a Hydrocarbon Reservoir Through Time (Sultan Pwage et al, 2010)

Primary oil recovery use natural reservoir energy to drive the oil through the complex pore network to producing wells. That means it depends mainly on existing natural pressure in the reservoir. Primary recovery efficiency is generally low and range from 5% - 20% OOIP according to (Teknica, 2001).The driving energy may consist of expanding force of natural gas, gravitational force, Influx of natural water, gravitational force and gas that released from solution out of the oil. Secondary recovery purposes are pressure maintenance and pressure restoration. It has involved the introduction of energy into a reservoir by injecting external fluid such as gas or water (Teknica, 2001). The secondary oil recovery employed to increase the pressure required to drive the oil to production wells when oil production declines because of hydrocarbon production. Processes of secondary recovery include: water injection, which refers to water, injected in the aquifer through several injection wells to support pressure or improve sweep/displacement oil from the reservoir and the. Selection of water injection method depends upon mobility ratio. Corrosion of surface and sub-surface equipment and formation damage are the main disadvantages of water injection process.

Gas injection, which used for the purpose of maintaining reservoir pressure and restoring oil well productivity. The primary problem with gas injection is the high mobility of it and the benefits of gas injection depend upon horizontal and vertical sweep efficiency of the injected gas. Using of gas injection is limited because of it is low oil displacement and also the need of gas supplies in market.

Limitations of primary and secondary recovery processes

1- Leads to low oil production rates and oil recovery (5-10) % of original oil in place OOIP (Teknica, 2001).
2- Secondary recovery does not yield a good recovery due to: water and gas coning problems, low sweep efficiency and Unsuitable mobility ratio

Tertiary Oil recovery also known as enhanced oil recovery processes .it is refer to processes in porous medium that recover oil not produced by the conventional methods. Ronald .E (2001) states that" It is characterized by injection of special fluids such as: chemicals, miscible gases and /or the injection of thermal energy".

2.3. Fluid and rock properties

To understand the basic principles of EOR some reservoir engineering parameters should been known. Mobility Ratio, Relative Permeability, Wettability and IFT are the most important reservoir engineering parameters.

2.3.1. Saturation

Saturation is defined as" that fraction, or percent, of the pore volume occupied by a particular fluid (oil, gas, or water) "(Tarek Ahmed, 2010). This property expressed mathematically by the following relationship

All saturation values based on pore volume and not on the gross reservoir volume. The saturation range between (0-100) %. By definition, the sum of the saturations is 100%, therefore for the oil phase to flow, the saturation of the oil must exceed a certain value, which is termed critical oil saturation (S_{oc}). At this particular saturation, the oil remains in the pores and, for all practical purposes, will not flow. During the displacing process of the crude oil system from the porous media by water or gas injection (or encroachment), there will be some remaining oil left that is quantitatively characterized by a saturation value that is larger than the critical oil saturation. This saturation value is called the residual oil saturation (S_{or}) .The term residual saturation is usually associated with the non-wetting phase when it is being displaced by a wetting phase.

2.3.2. Mobility Ratio

Tarek Ahmed (2010) states that “The mobility is defined as the ratio of permeability to the viscosity and the mobility ratio is defined as the mobility of displacing phase (water) to the mobility of the displaced phase (oil)".

$M_p = K_p/\mu_p M_{W.o} = M_w/M_o$ **(2-1)**

Mobility control processes injected a low mobility-displacing agent to increase volumetric and displacement sweep efficiency. This process includes polymer flooding and foam flooding.

2.3.3. Capillary Pressure

The capillary forces in a petroleum reservoir are the result of the combined effect of the surface and interfacial tensions of the rock and fluids, the pore size and geometry, and the wetting characteristics of the system.

Any curved surface between two immiscible fluids has the tendency to contract into the smallest possible area per unit volume. When two immiscible fluids are in contact, a discontinuity in pressure exists between the two fluids, which depend upon the curvature of the interface separating the fluids we call this pressure difference the capillary pressure (p_c). The displacement of one fluid by another in the pores of a porous medium is either aided or opposed by the surface forces of capillary pressure.

It is necessary to maintain the pressure of the non-wetting fluid at a value greater than that in the wetting fluid to maintain a porous medium partially saturated with non-wetting fluid and while the medium is also exposed to wetting fluid. The capillary pressure can be expressed as:

Capillary pressure = (pressure of the non-wetting phase) - (pressure of the wetting phase)

$\mathbf{p_c = p_{nw} - p_w}$ **(2-2)**

There are three types of capillary pressure: Water-oil capillary pressure (denoted as $\mathbf{P_{cwo}}$), Gas-oil capillary pressure (denoted as $\mathbf{P_{cgo}}$) and Gas-water capillary pressure (denoted as $\mathbf{P_{cgw}}$)

2.3.4. Wettability

Fluid distribution in porous media affected by the forces at fluid/fluid interfaces, and by forces at fluid/solid interfaces. Wettability Defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. Fluid distribution in porous media depends on fluid-fluid forces and fluid-solid forces. When two immiscible fluids are in contact with a solid surface, one fluid usually attracted more strongly than the other fluid (wetting phase). Wettability can be determined when checking for the contact angle The solid considered water-wet, if the contact angle α is smaller than 90°. At contact angles α larger than 90°, the fluid is referred to as oil-wet. Intermediate wettability occurs, when the contact angle α is close to 90° (Figure 2.4)

Fig. 2.4: Illustration of Wettability (Tarek Ahmed, 2010)

By convention, contact angles measured through the water phase. Water-wet is that the entire rock surface of both large and small pores coated with water. Oil-wet is that the oil completely coats the rock surface. Intermediate wettability tends for both oil and water to wet the rock surface. In case of wetting fluid, the contact angle is smaller than 90°. At contact angles larger than 90°, the fluid referred to non-wetting. In oil/water phase, water is wetting fluid, and oil is non-wetting fluid.

2.3.5. Capillary number

In fluid dynamics, the **capillary number** (**Ca**) represents the relative effect of viscous forces versus surface tension acting across an interface between a liquid and a gas, or between two immiscible liquids. For example, an air bubble in a liquid flow tends to be deform by the friction of the liquid flow due to viscosity effects, but the surface/interfacial tension forces tend to minimize the surface. The capillary number defined as:

$$Ca = \frac{\mu V}{\gamma} \qquad \textbf{(2-3)}$$

Where **μ** is the shear viscosity of the liquid, **V** is a characteristic velocity and **γ** is the surface or interfacial tension between the two fluid phases. The capillary number is a dimensionless quantity, hence its value does not depend on the system of units. For low capillary numbers (a rule of thumb says less than 10^{-5}), flow in porous media is dominated by capillary forces whereas for high capillary number the capillary forces are negligible compared to the surface force.

2.3.6. Volumetric Sweep efficiency

It represents the overall fraction of the flood pattern that contacted by the injected fluid. If the displacing fluid will contact all the oil initially present in reservoir, the volumetric sweep efficiency will be unity.

$$\mathbf{E_v} = \frac{\textbf{Volume of oil contacted by displacing fluid}}{\textbf{Total amount of oil in place}} \qquad \textbf{(2-4)}$$

E_v can decompose into two parts, (areal sweep efficiency) and (vertical sweep efficiency).

$$\mathbf{E_v = E_A \times EI} \qquad \textbf{(2-5)}$$

$$\mathbf{E_A} = \frac{\textbf{Area contacted by displacing fluid}}{\textbf{Total area}} \qquad \textbf{(2-6)}$$

$$\mathbf{E_I} = \frac{\textbf{Cross} - \textbf{sectional area contacted by displacing fluid}}{\textbf{Total cross – sectional area}} \qquad \textbf{(2-7)}$$

2.3.7. Relative Permeability

A measurement of the ability of two or more fluid phases to pass through a formation matrix. The relative permeability reflects the ability of a specific formation to produce a combination of oil, water or gas more accurately than the absolute permeability of a formation sample, that is measured with a single-phase fluid, usually water.

The relative permeability of one phase in multiphase flow in porous media is a dimensionless measure of the effective permeability of that phase. It is the ratio of the effective permeability of that phase to the absolute permeability. It can been viewed as an adaptation of Darcy's law to multiphase flow.

For two-phase flow in porous media given steady-state conditions, we can write

$$q_i = \frac{K_i}{\mu_i}\,\Delta Pi \qquad \text{for } i = 1,2,.. \qquad \textbf{(2-8)}$$

Where q_i the flux, ΔP_i is the pressure drop, μ_i is the viscosity. The subscript i indicates that the parameters are for phase i.

K_i is here the phase permeability (i.e., the effective permeability of phase i), as observed through the equation above. Relative permeability, K_{ri}, for phase i defined from

$K_i = K_{ri} \times K$, as $K_{ri} = \frac{\mathbf{Ki}}{\mathbf{K}}$ **(2-9)**

Where is the permeability of the porous medium in single-phase flow, i.e., the absolute permeability K Relative permeability must be between zero and one. In applications, relative permeability is often represented as a function of water saturation.

2.3.8. Surface/Interfacial Tension

The surface tension is defined as the force exerted on the boundary layer between a vapor phase and liquid phase per unit length, (Tarek Ahmed, 2010) which is caused by differences between the molecular forces in the vapor phase and those in the liquid phase, and also by the imbalance of these forces at the interface. The surface tension can been measured in the laboratory and is unusually expressed in dynes per centimeter and it is an important property in reservoir engineering calculations and designing enhanced oil recovery projects.

Sugden suggested a relationship the correlating parameters of the proposed relationship are molecular weight M of the pure component, the densities of both phases, and a newly introduced temperature independent parameter P_{ch} The relationship expressed mathematically in the following form:

$$\sigma = \left[\frac{Pch(Pl - Pv)}{M}\right]^4 \quad \textbf{(2-10)}$$

Where σ is the surface tension and P_{ch} is a temperature independent parameter and is called the parachor.

When the interface is between two liquids, the acting forces are called **Interfacial Tension.** If a glass capillary tube is placed in a large open vessel containing water, the combination of surface tension and wettability of tube to water will cause water to rise in the tube above the water level in the container outside the tube as shown in Figure 2.5.

The water will rise in the tube until the total force acting to pull the liquid upward is balanced by the weight of the column of liquid being supported in the tube.

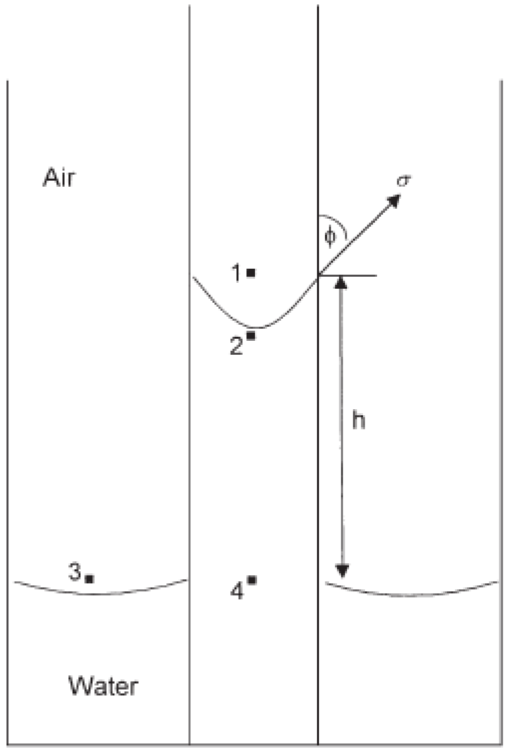

Fig. 2.5 :Pressure Relation in Capillary Tube (Tarek Ahmed, 2010)

Assuming the radius of the capillary tube is r, the total upward force F_{up}, which holds the liquid up, is equal to the force per unit length of surface times the total length of surface, or

$F_{up} = (2\pi r)\ (\sigma_{gw})\ (\cos\theta)$ **(2-11)**

Where:

σ_{gw} = surface tension between air (gas) and water (oil), dynes/cm

θ = contact angle

r = radius, cm.

The upward force is counteracted by the weight of the water, which is equivalent to a downward force of mass times acceleration, or

$F_{down} = \pi r2\ h\ (\rho w - \rho air)\ g$ **(2-12)**

Where:

h = height to which the liquid is held, cm

g = acceleration due to gravity, cm/sec2

ρw = density of water, gm/cm3

ρ_{air} = density of gas, gm/cm3

Because the density of air is negligible in comparison with the density of water, Equation (2.12) is reduced to:

$$F_{down} = \pi\ r2\ \rho wg \qquad \textbf{(2-13)}$$

Equating Equation (2-11) with (2-13) and solving for the surface tension gives:

$$\sigma_{gw} = \frac{rh\rho wg}{2\cos\theta} \qquad \textbf{(2-14)}$$

The generality of Equations (2-11) through (2-14) will not be lost by applying them to the behavior of two liquids, i.e., water and oil. Because the density of oil is not negligible, Equation (2-144) becomes:

$$\sigma_{ow} = \frac{r\ h\ g\ (\rho w - \rho o)}{2\cos\theta} \qquad \textbf{(2-15)}$$

Where:

ρo = density of oil, gm/cm3

σ_{ow} = interfacial tension between the oil and the water, dynes/cm

2.4. Enhanced Oil Recovery

Teknica (2001) states that "EOR Refers to any method used to recover more oil from a reservoir than would not be obtained by primary recovery" .The goal of EOR is to recover at least apart of remaining oil in place.

EOR improve sweep efficiency by reducing the mobility ratio between injected and in place fluid or eliminate/ reduce the capillary and interfacial forces thus improve displacement efficiency sometimes EOR act on both phenomena simultaneously. A common procedure for determining (Ronlad E, 2001) has showed the optimum time to start EOR process after water flooding includes:

1- Expected oil recovery

2- Fluid production rates

3- Monetary investment

4- Costs of water treatment, pumping equipment, maintenance and operation of the water facilities

5- Costs of drilling new injection wells or converting existing production wells into injectors.

Improved Oil Recovery

Improve oil recovery reveres to any reservoir processes to improve oil recovery including production enhancement by fraction acidizing or sand management for example, drilling new wells (infill drilling),work overs and enhanced oil recovery.

Table 2.1: Methods of Enhanced Recovery (Teknica, 2001)

Method	Method Used for	Basic principle
Chemical Methods	1- mobility control processes (Polymer-augmented water flooding /CO2-augmented water flooding /immiscible CO2 displacement). 2- low IFT process (e.g. surfactant flooding /alkaline flooding)	Improve of : - sweep efficiency. - displacement efficiency
Miscible Methods	Miscible fluid displacement using: CO_2, N_2, alcohol, LPG, dry gas, rich gas.	-Improve of displacement efficiency
Thermal Methods	Cyclic steam injection, steam drive, in situ combustion	-improve of both sweep and displacement efficiency

2.5. Processes of EOR methods

2.5.1. Miscible Methods

Definition: "the processes where the effectiveness of the displacement result primarily from miscibility between the oil in place and the injected fluid" (Sultan Pwaga, et al., 2010). Examples of displacement fluid includes CO_2, hydrocarbon solvents, nitrogen and H_2.

Immiscible displacement processes: means the displacing fluid is immiscible with the displaced fluid or two fluids do not mix in all proportion to form a single phase. For example, water flooding in it the micro displacement efficiency E_d less than one because part of crude oil in place is trapped as isolated drops; rings…etc. depending on the wettability and that reduce the relative permeability of the oil and then oil recovery.

Solvents are more expensive than water or dry gas, for economic reasons the injected solvent must be small and maybe followed by less expensive fluid (water).

2.5.1.1. CO_2 Flooding

CO_2 flooding is a process whereby carbon dioxide is injected into an oil reservoir in order to increase output (Sultan Pwaga, et al., 2010). It was discovered since 1985.

Processes of CO_2 flooding:

CO_2 recovers crude oil by injecting CO_2 into the reservoir, the viscosity of any hydrocarbon will be reduced also density. Oil will be easier to flow because the mobility improved. As we see at figure below. The conditions for CO_2 flooding shown at table 2.3

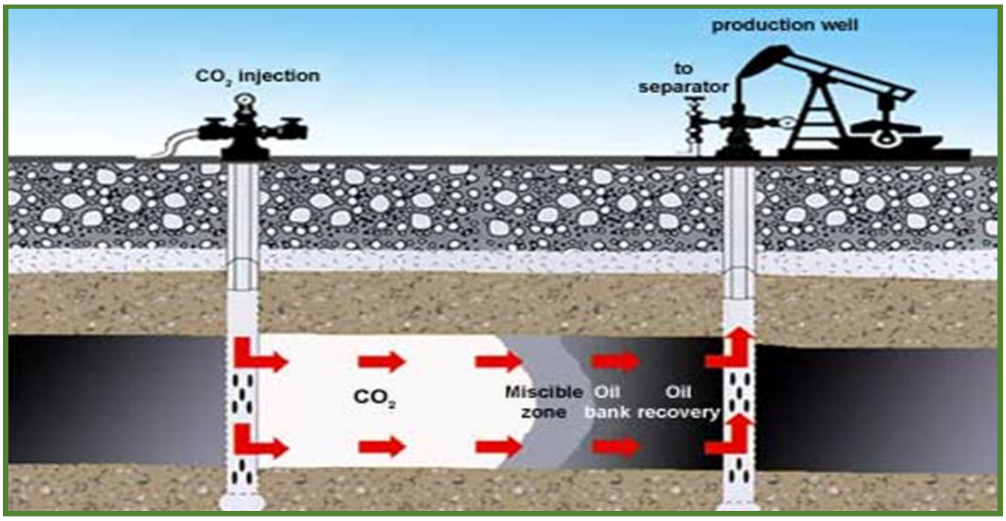

Fig. 2.6: CO_2 Flooding (Barrufet, M.A, 2001)

We must restore pressure within reservoir to a suitable pressure for CO2 flooding by injecting water.CO_2 flooding is second most tertiary recovery technique. The Advantages of CO2 flooding including reduce the residual oil saturation (S_{or}), extract heavier component, when CO_2 mixing with oil cause a reduction in oil viscosity and density. The displacement of oil become more effective as a result of reduction in IFT

High mobility and Availability of carbon dioxide considered main disadvantage of carbon dioxide flooding. Taber et al (1997) have shown that "Corrosion can cause problems especially if there is early breakthrough of CO_2 in producing wells".

2.5.1.2. Nitrogen and flue gas Injection

Nitrogen and flue gases can enhance the recovery of oil by miscible displacement (require high pressure in deep reservoir and light oil) or pressure maintenance and the processes sown at figure 2.7.

According to Taber et al (1997), there are two process of nitrogen injection including vaporizing the lighter components of the crude oil and generating miscibility if pressure is high enough. The other process is providing a gas drive and enhancing gravity drainage in dipping reservoirs. Shown at figure below.

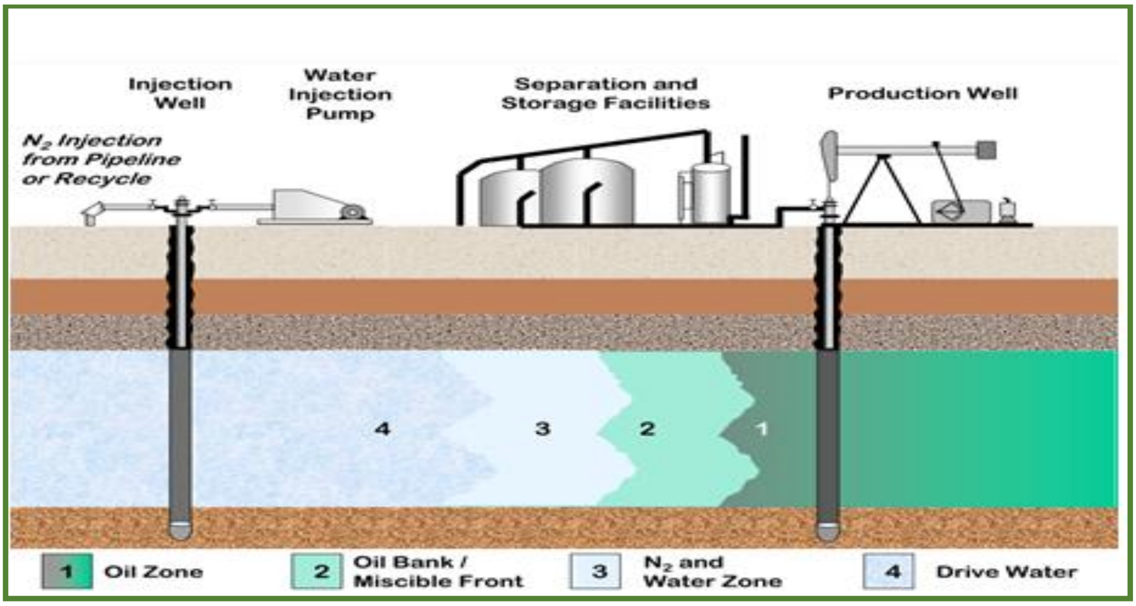

Fig. 2.7: N_2 Injection (Barrufet, M.A, 2001)

The Advantages of nitrogen injection including reduce the residual oil saturation (S_{or}). Moreover, increasing oil production and recovery. When N_2 mixing with oil cause a reduction in oil viscosity. Thus, the displacement of oil will be more effective because of reducing mobility ratio, and when using N_2 the cost will be less than using CO_2.

Some difficulties associated with nitrogen injection are the need a high pressure in deep reservoirs. The difference between mobility's will cause fingering.

Limitation:

1- A steeply dipping reservoir is desired to permit gravity stabilization of the displacement.
2- Developed miscibility can only be achieved with light oils and at very high pressure, (deep reservoirs are needed).

Main problem is viscous fingering results in poor vertical and horizontal sweep efficiency. The conditions for N_2 flooding shown at table 2.3

2.5.1.3. Hydrocarbon Injection

Hydrocarbon Injection process consist of inject light hydrocarbons through reservoirs to form miscible flood. It needs high pressure to enhanced oil movement by increasing the oil volume (swelling) and that vaporizing the heavy oil components and decreasing the oil viscosity. Immiscible gas displacement can made by hydrocarbon injection ($P_{reservoir}$ < MMP), the conditions for hydrocarbon injection shown at table 2.3

The Advantages of hydrocarbon injection including reduce the residual oil saturation (S_{or}) and reduction of oil viscosity. Moreover, vaporize the heavy oil component. Hydrocarbon injection needs high pressure in deep reservoir but it consider as less effectiveness method because of it is high cost.

2.5.1.4. Hydrogen Injection

Like hydrocarbon injection, its increase the oil volume (swelling) if pressure is high enough to achieve miscibility and vaporize heavy component (Abdulbasit, 2013). The conditions for hydrogen injection shown at table 2.3

The Advantages of hydrogen injection including reduction of oil viscosity and reduce the residual oil saturation (S_{or}). Moreover, vaporize the heavy oil component, but hydrogen injection failed many times because it is difficult to be controlled and also needs high pressure.

2.5.1.5. Problems in Applying Miscible Methods

Because of differences in density and viscosity between the injected fluid and the reservoir fluid(s), the miscible process often suffers from: : poor mobility and viscous fingering.

Injection of a miscible agent and brine was suggested to solve the problem but it was not good enough because the miscible agent and brine tended to separate due to density differences.

Several techniques are suggested and they typically involve the injection of a miscible agent followed by brine (miscible agent–brine injection). The latter variation have been named the WAG (water alternate gas) process and has become the most popular.

2.5.2. Chemical Flooding

2.5.2.1. Polymer flooding:

Polymer flooding is the process of adding small amount of polymer to thicken brine (water) to reduce water mobility. In which a large macromolecule is used to increase the displacing fluid viscosity, this leads to improve sweep efficiency in the reservoir.

There are many types of polymer but the two basic types of polymers, which are widely used in field recovery projects, are XC-biopolymer and Polyacrylamides**.**

Polymer flooding processes:

Firstly low-salinity brine (freshwater) slug injected to the reservoir followed by injection of a slug of 0.3 or higher PV of polymer solution. The polymer slug followed by another freshwater and then followed by continuous drive water injection. The schematic cross-section view of polymer injection illustrated in figure 2.8.

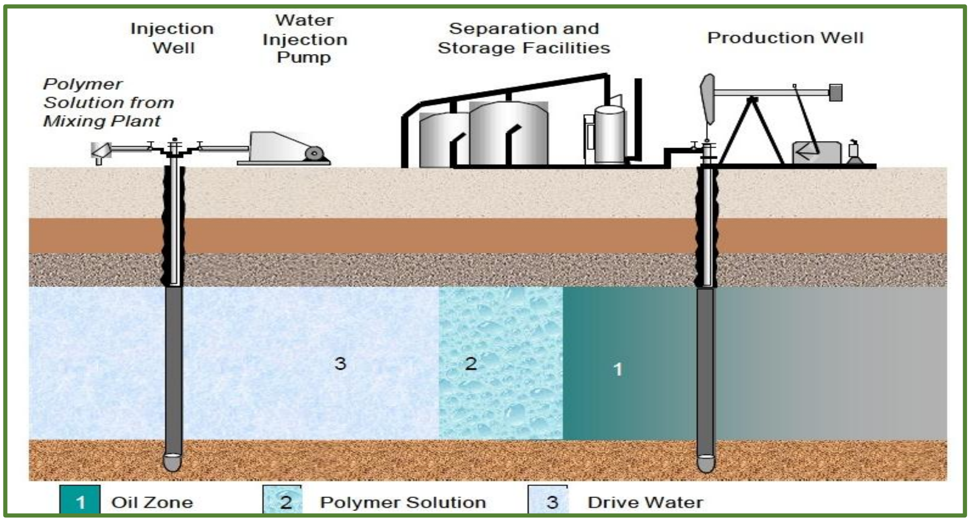

Fig. 2.8: Polymer Process(Barrufet, M.A, 2001)

Polymers usually added to water in concentrations ranging from 250 to 2000 parts per million (PPM).The conditions for polymer flooding shown at table 2.3

Limitations:

High oil viscosities require higher polymer concentration, which results in high cost. Results from polymer flooding can be better if the process started before the water-oil ratio becomes excessively high. Some heterogeneity is acceptable, but the extensive fractures must be avoided also clays increase polymer adsorption.

2.5.2.2. Surfactant flooding:

The aim of surfactant flooding is to recover the capillary-trapped residual oil after waterflooding. By means of surfactant solutions, the residual oil can been mobilized through a strong reduction in the interfacial tensions between oil and water. By the possibility to inject the surfactant before the reservoir is completely waterflooding, it is likely to improve the process economy by earlier production of the extra oil, restricting us to a time window for the application of surfactant flooding (Sultan Pwaga,et al.,2010).

A surfactant is a surface-active agent that contains a hydrophobic (“dislikes” water) part to the molecule and a hydrophilic (“likes” water) part. The surfactant migrates to the interface between the oil and water phases and helps make the two phases more miscible. As the interfacial tension between an oil phase and a water phase is reduced, the capacity of the aqueous phase to displace the trapped oil phase from the pores of the rock matrix increases..

Surfactant flooding processes:

After the surfactant solution injected into the formation, targeting the surface between oil-water to break the attractive forces between them (IFT) by producing soaps at the contact: reducing residual oil saturation. In addition to wettability change from oil wet to water wet, followed by polymer injection to enhance the sweep efficiency and control the mobility as well as to stabilize the flow pattern. The conditions of surfactant flooding shown at table2.3 the following figure 2.9 shows the surfactant flooding mechanism:

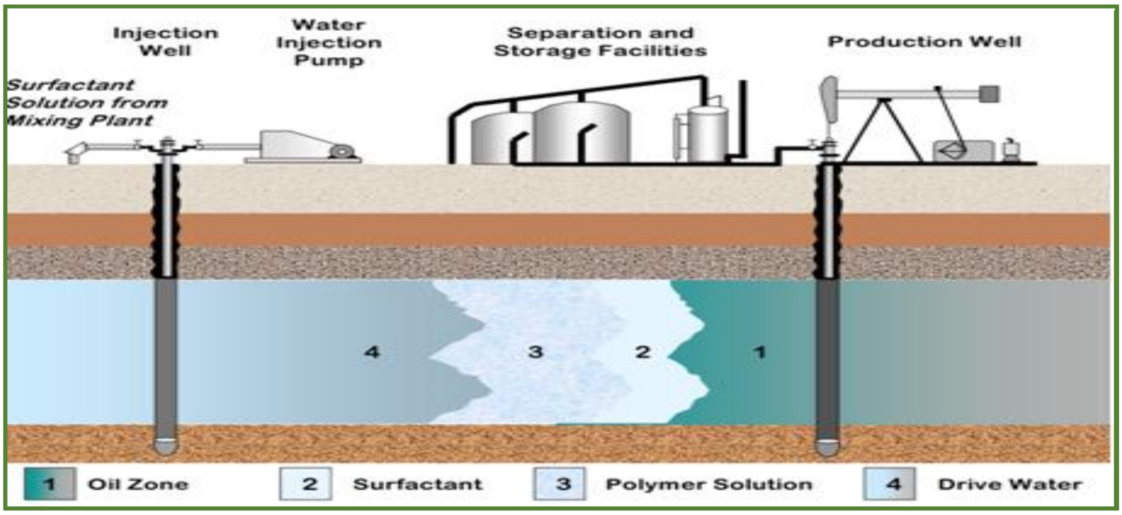

Fig. 2.9: Surfactant Flooding Mechanism (Barrufet, M.A, 2001)

By designing and selecting a series of specialty surfactants to lower the interfacial tension to the range of 10-3 dynes/cm, a recovery of 10-20 % of the original oil in place, when not producible by other technologies, is technically and economically feasible by surfactant flooding (Akzonobe, 2006).

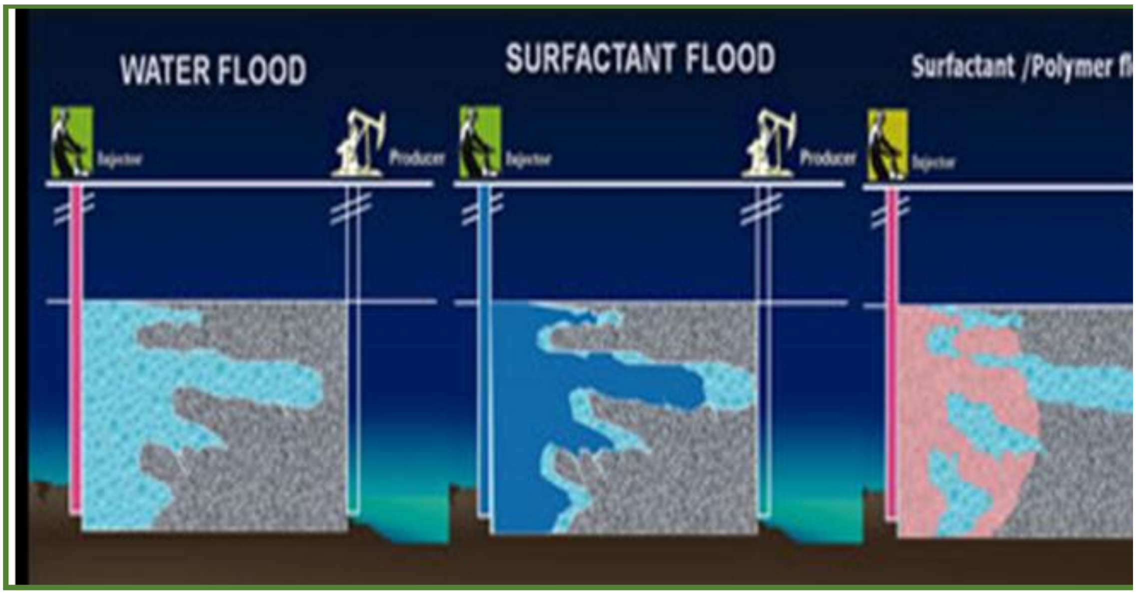

Fig. 2.10: Surfactant Flooding Fingering (Akzonobe, 2006).

There are many factors should considered to performing a successful surfactant flooding EOR these factors including Formulations**,** Cost of surfactants**,** Availability of chemicals**,** Environmental impacts and oil price. The advantages of surfactant flooding are reduce IFT and work as emulsifier between oil and water, S_{or} reduction to a very minimum value, which immediately leads to increase in the recovery factor, wettability change from oil to water wet, trapped (bypassed) oil is produced and injection of polymer leads to pattern flow stabilization and mobility control. While the disadvantages are considered a complex process, expensive compared to alkaline and polymer, incompatibility between surfactant-polymer in case of no co-solvent is used, degradation of surfactant and polymer in case of high reservoir temperature and strong aquifer leads to both surfactant and polymer adsorption.

2.5.2.3. Alkaline Flooding

Alkaline or caustic flooding is also method used to improve displacement efficiency. It is explained that alkaline agents such as sodium hydroxide can react naturally with organic acids in crude oils to produce soaps at water –oil interface. Then surfactant molecules are formed in situ and reduce the IFT. The effect produced in the reservoir appears to be similar to that of micellar solutions. But the difference is that alkaline flooding reduces the interfacial tensions (IFT) with surfactant generated in situ and thus increases the microscopic sweep efficiency and thereby increases oil recovery (Ronald E, 2001).

Ronald E (2001) has shown that "Alkaline substances have been used include sodium hydroxide, sodium orthosilicate, sodium metasilicate, sodium carbonate, ammonia ammonium hydroxide". The most popular one is sodium hydroxide. Sodium orthosilicate has some advantages in brines with high divalent ion content.

Displacement Mechanisms:

The displacement mechanisms of alkaline flooding consist of: lowering the interfacial tension between oil and water, mobility enhancement and wettability alteration. Moreover, the solubilization of oil in some micellar system aid the displacement and figure 2.11 represents alkaline flood injection.

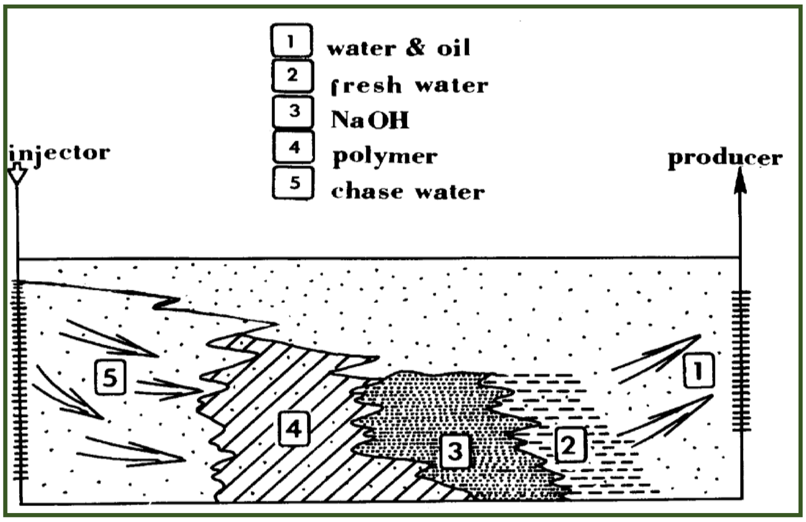

Fig. 2.11: Schematic of Alkaline Flood Injection (Teknica,2001)

Alkaline processes:

The basis of alkaline flooding process starts with injecting a softened water pre-flush injection followed by alkaline solution injection of about 10 to 30 percent PV and then followed by continuous injection of drive water. This process can be changed slightly according the reservoir condition. To improve sweep efficiency and control mobility, polymer slug should be injected behind the alkaline solution. Because of complexity of mineralogy and lithology of petroleum reservoir, a big consideration should be given to the possible reactions between rock-alkaline solution, saline water and oil in existing conditions of pressure and temperature. This explains the importance of efforts put into laboratory alkaline flooding tests and field trials in order to design properly the best design system for specific conditions for certain reservoir.

In designing an alkaline process, the principal goal is to achieve a minimum IFT in the reservoir. The corresponding alkali concentration is considered the optimum concentration. In the laboratory, this concentration is very low. However, in the field, it discovered that this concentration does not survive far from the wellbore because of the reaction with rock and consumption.

Earliest laboratory experiments have shown that salinity plays important role in determining optimum alkali concentration. For instance, minimum IFT could be achieved with distilled water and a wide range of NaOH concentrations, between 0.1 and 0.8 wt %. Adding alkali to increase concentration and then to keep the effect of alkaline concentration as far as possible from the injection wellbore increased the salinity of the system and the IFT value (figure 2.12).

Recent laboratory work has done for trying to adjust higher alkali levels without losing the acceptable low IFT values. Experiments on core samples showed that the injection of combination of alkali-surfactant-polymer behind water flooding is the most efficient one comparing with polymer and alkali polymer (Table2.2). Moreover, it can reduce the IFT to the lowest level. The displacement efficiency of adding low amount of surfactant to alkali-polymer system is the same as in the micellar-polymer system, but at lower chemical cost.

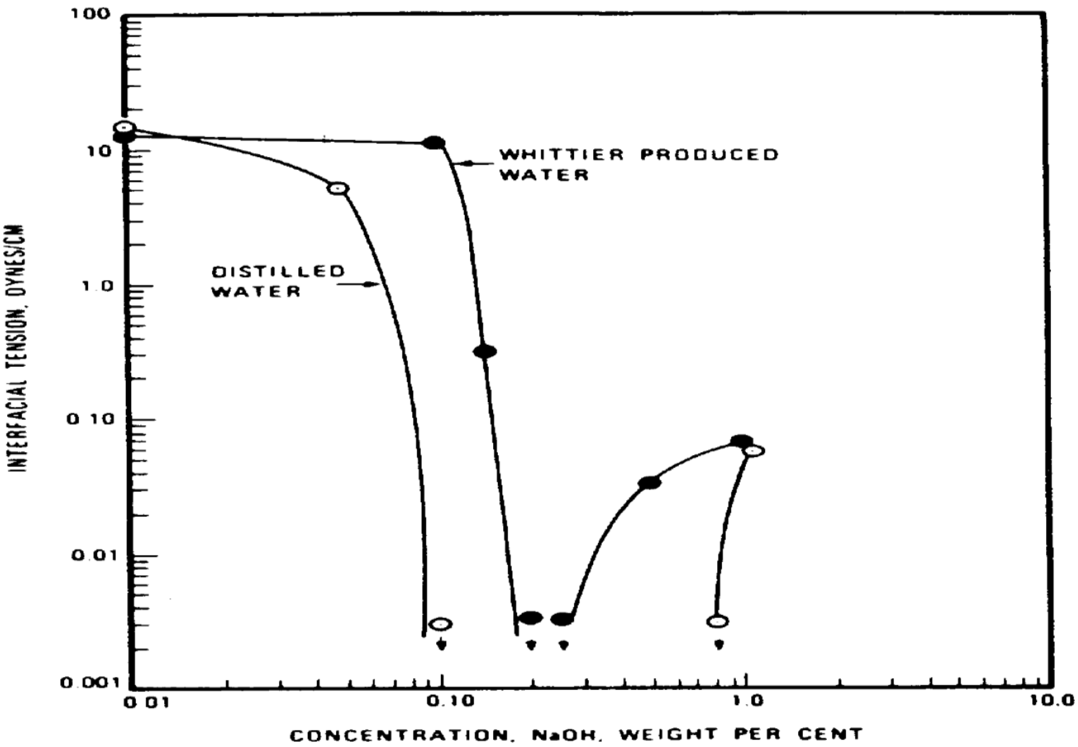

Fig. 2.12: IFT of Murphy-Whittier Second and Third Zones Crude (Graue and Johnson, 1974)

Although the laboratory tests and studies reported good results, the process will have to be proven by an increasing number of field pilots and by commercial development.

Table 2.2: Tertiary Oil Recovery-Alberta Systems (Teknica, 2001)

System	Final S_o (PV)
Polymer	**0.388**
Alkali-Polymer	**0.251**
Alkali-Surfactant-Polymer (0.1 wt %)	**0.115**

2.5.3. Microbial Enhanced Oil Recovery (MEOR)

Microbial Enhanced Oil Recovery is potentially cost-effective method, particularly for recovering additional oil from striper wells. Microorganisms are injected to the reservoir so these organisms multiply and their metabolic products such as polymers, surfactants, gases and acids improve oil recovery. The microbial mechanisms that supported in the work of Ahmed Aladasani and Baojun Bai (2010) are:

1. Increasing in the reservoir pressure by generated gas.
2. Reduction in oil viscosity.
3. Permeability modification because of acidic dissolution or plugging.
4. Reduction in IFT by the generation of bio surfactant

Microbial Processes:

It is so difficult and complex to determine reservoir limitations on this technique. In many cases, simple compatibility studies between reservoir fluids and microorganisms are enough to predict whether microorganism applied successfully or not. According to Asimon and Schuster Company Englewood Cliffs, 1992, compatibility tests are usually test tube experiments in which various microbial formulations are grown in the presence of reservoir fluids and sometimes reservoir rock. The growth and metabolite production of the microorganisms are measure to determine the optimal condition.

Microbial Treatments

The most practiced MEOR technique includes cyclic treatments of producing wells. There are generally two types of well-stimulation treatments: firstly, treatments designed to improve injectivity by cleaning out the well bore. Secondly, those are designed to improve crude oil mobilization in the near well bore region by removing paraffinic or asphaltic deposits. These treatments are considered more important, because there is a potential for improved residual oil mobilization. Well stimulation treatments also can decrease the cost of maintenance and operation of a well by improving injectivity.

In microbial-enhanced waterflood, the micro-organisms should be able to move through reservoir and produce chemical products to mobilize crude oil. Micro-organisms can produce surfactants which can decrease the IFT and may change relative permeability. Also micro-organisms can produce gases such as Co_2, N_2, H_2, and CH_4 that can increase reservoir pressure and decrease oil viscosity and both of them result in increasing oil recovery.

Fluid diversion is another application for micro-organisms in water flood. Because polymers can be produced by many types of micro-organisms, it has been suggested that some micro-organisms could be used in situ to plug high-permeability zones in reservoirs and thus improve sweep efficiency. Injected micro-organisms remain in the water phase and may act to increase relative permeability to oil and decrease relative permeability to water. Ahmed Aladasani and Baojun Bai (2010) have both shown reservoir conditions for MEOR at table 2.3.

Limitations and challenges

Most successful MEOR projects are applied to reservoirs with temperature less than 55°C. Low production rate and high water cut reservoirs are more suitable for MEOR projects. In addition, the adsorption of surfactant to the reservoir rock and biodegradation impact MEOR performance adversely.

2.5.4. Thermal methods

Thermal methods have been tested since 1950's, primary and secondary production from reservoirs containing heavy, low-gravity crude oils is usually a small fraction of the initial oil in place. This is due of the fact that these types of oils are very thick and viscous and as a result does not migrate readily to producing wells. Figure 2.13 shows a typical relationship between the viscosity of a heavy, viscous crude oil and temperature. As can be seen, for certain crude oils, viscosities decrease by orders of magnitude with an increase in temperature of 100–200◦F.

This suggests that if the temperature of a crude oil in the reservoir can be raised by 100–200◦F over the normal reservoir temperature, the oil viscosity will be reduced significantly and will flow much more easily to a producing well. The temperature of a reservoir can be raised by injecting a hot fluid or by generating thermal energy in-situ by combusting the oil (Ronald E, 2001).

Most of the oil that has been produced by EOR methods to date has been as a result of thermal processes. There is a practical reason for this, as well as several technical reasons. In order to produce more than 1–2% of the initial oil in place from a heavy-oil reservoir, operators had to employ thermal methods. Thermal processes are most effective when a petroleum reservoir contains a low-gravity (less than 20° API), high-viscosity oil and have a high porosity. The injection of steam reduces the oil viscosity which causes an increase in the oil mobility. Depending on the way in which the heat is generated in the reservoir. To do thermal injection in EOR, new wells have to be drilled for injection except in Cyclic Steam Stimulation (CSS) (Sultan Pwaga, et al.,2010).

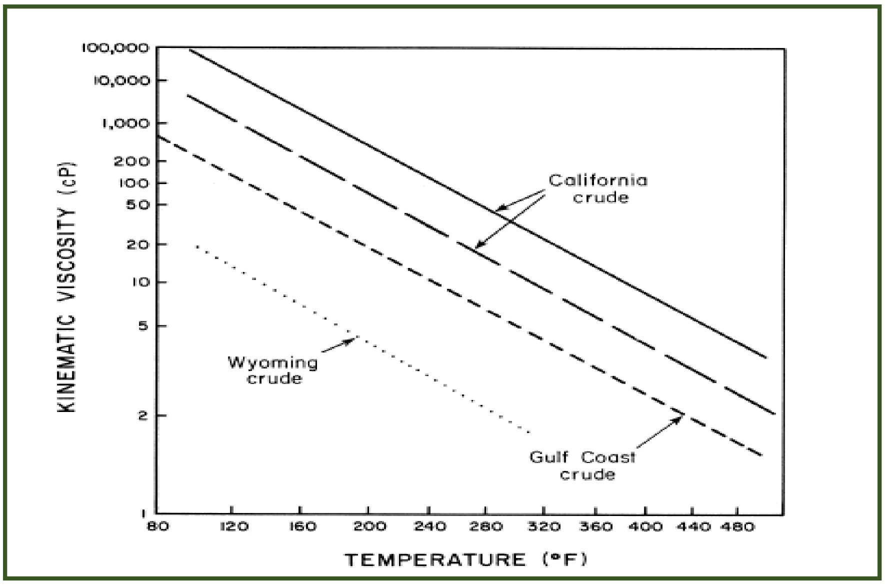

Fig. 2.13: Typical Viscosity–Temperature Relationships for Several Crude Oils (Ronald E, 2001)

Types of thermal EOR:

There are many types of thermal enhanced oil recovery including steam injection, cyclic steam stimulation (CSS), in-situ combustion (ISC) and steam assisted gravity Drainage (SAGD).

2.5.4.1. Steam injection

The steam drive process (figure 2.14) is much like a conventional water flood. Once a pattern arrangement is established, steam is injected into several injection wells while the oil is produced from other wells. This is different from the steam stimulation process, whereby the oil is produced from the same well into which the steam is injected. As the steam is injected into the formation, the thermal energy is used to heat the reservoir oil. Unfortunately, the energy also heats the entire environment such as formation rock and water. Some energy is also lost to the under burden and overburden. Once the oil viscosity is reduced by the increased temperature, the oil can flow more readily to the producing wells. The steam moves through the reservoir and comes in contact with cold oil, rock, and water. As the steam comes in contact by the cold environment, it condenses and a hot water bank is formed. This hot water bank acts as a water flood and pushes additional oil to the producing wells.

Several mechanisms have been identified that are responsible for the production of oil from a steam drive. These include thermal expansion of the crude oil, viscosity reduction of the crude oil, changes in surface forces as the reservoir temperature increases, and steam distillation of the lighter portions of the crude oil.

Steam applications have been limited to shallow reservoirs because as the steam is injected it loses heat energy in the well bore. If the well is very deep, all the steam will be converted to liquid water. Recently, interest has been shown in downhole steam generation; research to develop an economical system is continuing in this area.

Steam drives have been applied in many pilot and field scale projects with very good success. Oil recoveries have ranged from 0.3 to 0.6 bbl of oil per barrel of steam injected.

The advantages of steam injection are reduces remaining oil thus increases recovery factor and reduces oil viscosity resulting in mobility ratio reduction and wettability change. Steam oil ratio is controlled by steam injection and good performance can obtain due to continuous steam injection. While the disadvantages are in deep reservoirs steam injection loss its effectiveness due to reduction of quality . If the depth is excessive, high the process cannot be applied. Heat losses occurred in case of strong or excessive water drive.

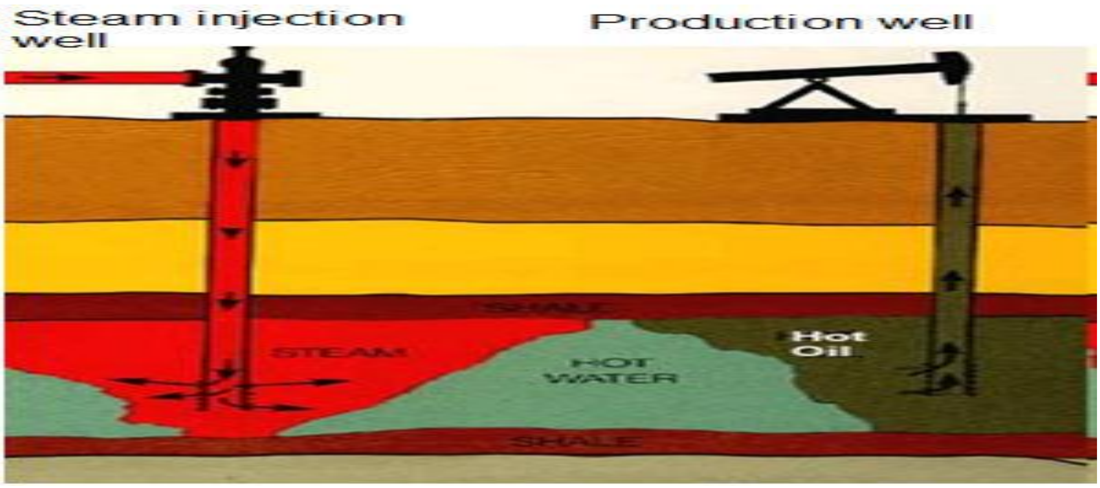

Fig. 2.14: Steam Injection Process (Sultan Pwaga, et al.,2010)

2.5.4.2. Cyclic Steam Stimulation

The steam stimulation process was discovered by accident in the Mine Grande Tar Sands, Venezuela, in 1959. During a steam injection trial, it was decided to relieve the pressure from the injection well by back flowing the well. When this was done, a very high oil production rate was observed. Since this discovery, many fields have been placed on steam stimulation. The steam stimulation process, also known as the steam huff and puff, steam soak, or cyclic steam injection, begins with the injection of 5000–15,000 bbl of high-quality steam.

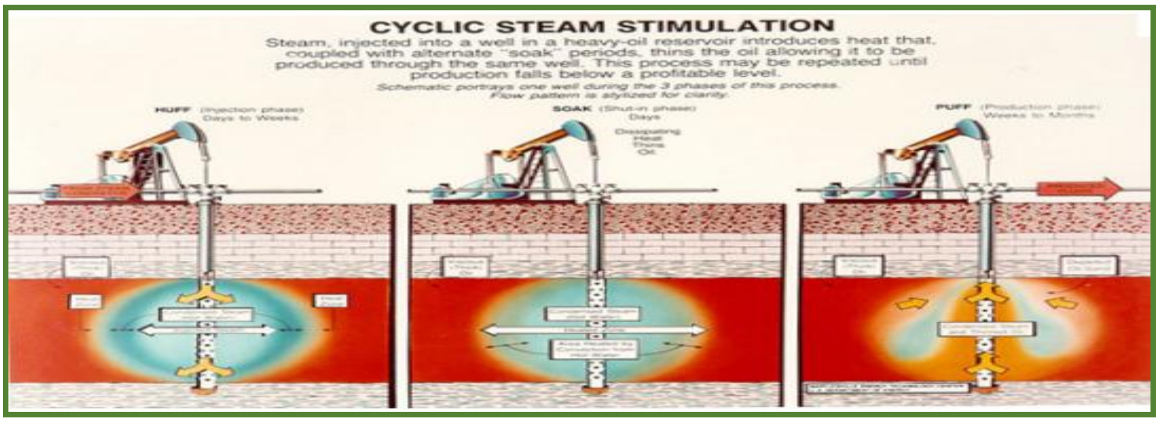

Fig. 2.15: CSS Process (Sultan Pwaga, et al., 2010).

This can take a period of days to weeks to accomplish. The well is then shut in, and the steam is allowed to soak the area around the injection well. This soak period is fairly short, usually from 1 to 5 days. The injection well is then placed on production. The length of the production period is dictated by the oil production rate but can last from several months to a year or more. The cycle is repeated as many times as is economically feasible. The oil production will decrease with each new cycle (Sultan Pwaga, et al., 2010).

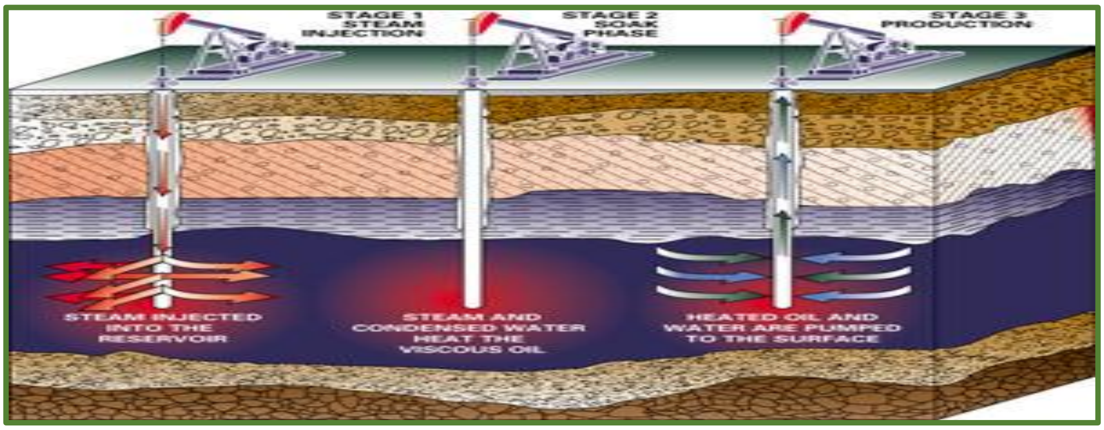

Fig. 2.16: CSS Stages (Sultan Pwaga, et al., 2010)

The advantages of CSS including prepares the field for future steam flooding by heating a part of the reservoir. Heating causes reduction in oil viscosity and thereby change the wettability around the well bore from oil to water wet in addition to mobility ratio reduction. Another advantage is the quick increment in oil rate once the production phase is started.While the disadvantages of CSS are difficult to be applied in case of low current reservoir pressure and affected by strong water aquifer drive.

2.5.4.3. In-Situ Combustion

The crude oil was ignited down hole in in-situ combustion process, and then a stream of air or oxygen-enriched air was injected in the well where the combustion was originated. The flame front was then propagated through the reservoir. Large portions of heat energy were lost to the overburden and under burden with this process. To reduce the heat losses, researchers devised a reverse combustion process. In reverse combustion, the oil is ignited as in forward combustion but the airstream is injected in a different well. The air is then “pushed” through the flame front as the flame front moves in the opposite direction. Researchers found the process to work in the laboratory, but when it was tried in the field on a pilot scale, it was never successful. What they found was that the flame would be shut off because there was no oxygen supply and that where the oxygen was being injected, the oil would self-ignite. The whole process would then revert to a forward combustion process (Ronald E,2001).

When the reverse combustion process failed, a new technique called the forward wet combustion process was introduced. This process begins as a forward dry combustion does, but once the flame front is established, the oxygen stream is replaced by water .As the water comes in contact with the hot zone left by the combustion front, it flashes to steam, using energy that otherwise would have been wasted. The steam moves through the reservoir and aids the displacement of oil. The wet combustion process has become the primary method of conducting combustion projects. Not all crude oils are amenable to the combustion process.

For the combustion process to function properly, the crude oil has to have enough heavy components to serve as the fuel source for the combustion. Usually this requires an oil of low API gravity. As the heavy components in the oil are combusted, lighter components as well as flue gases are formed. These gases are produced with the oil and raise the effective API gravity of the produced oil.

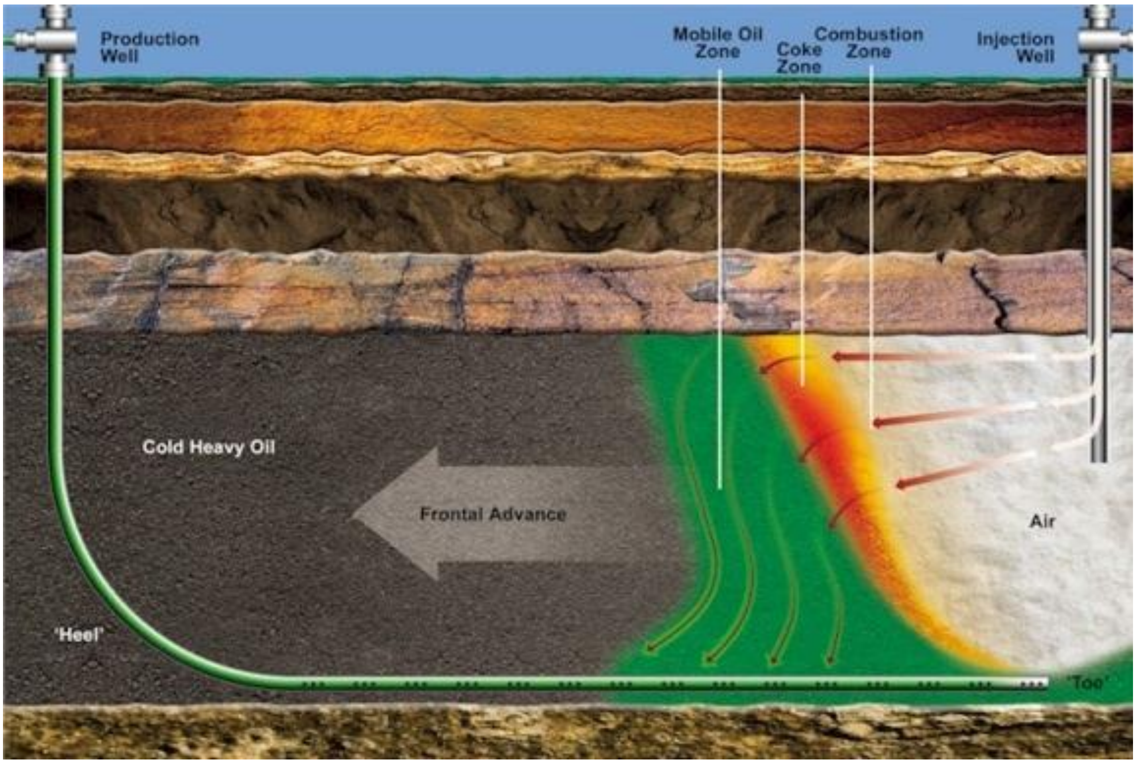

Fig. 2.17: In situ Combustion Process (Sultan Pwaga, et al.,2010)

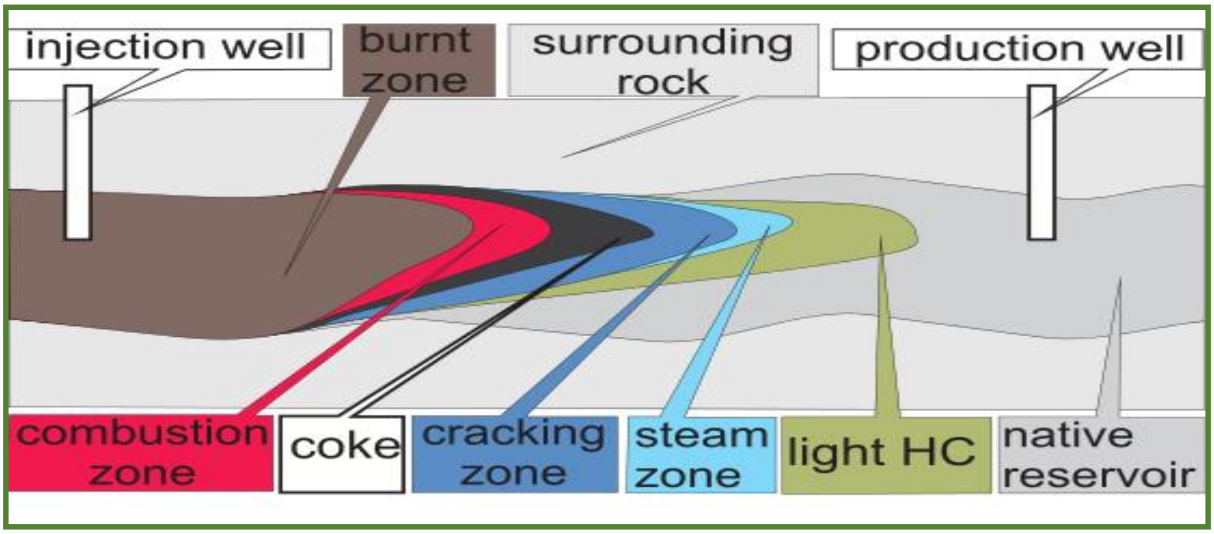

Fig. 2.18: Simplified Combustion Process (Sultan Pwaga, et al., 2010)

***There are three types of in-situ combustion processes as described below*:**

1. **Dry in-situ combustion**

It is the normal in-situ combustion process, both injection of air and burning front are created at the injector and it is not followed by injection of water and the process is kept dry, in this process the propagation of the burning front and the combustion front are from the injector to the producer.

2. **Wet in-situ combustion:**

In this process, water is injected into the reservoir, after the air is being injected to it. The reason of water injection is to cool the reservoir to protect the well from damage due to the very high temperature, which is created of the burning process.

3. **Reverse in-situ combustion**

In reverse in-situ combustion injection of air is in the injector and the ignition is created in the producer, it is called reverse due to the direction of the combustion front is in the opposite direction of the injection, then by the continuous air injection burning front is travelled in the reservoir towards the producer.

The advantages of in-situ combustion are cheaper process and causes reduction in oil viscosity thereby change the wettability around the well bore from oil to water wet in addition to mobility ratio reduction. Incremental in recovery factor is another advantage. While the disadvantages of in-situ combustion are a complex process and causes reservoir damage where any other EOR methods cannot be applied after that. A part of OIIP is burned during ignition and burning in the reservoir as well as providing fuel to the process. Also, Carbon dioxide is formed during the process which it affects the surface facilities if it is being produced. Another disadvantage is unfavorable gas-oil mobility during the injection and burning front processes.

2.5.4.4. Problems in Applying Thermal Processes:

The main technical problems associated with thermal techniques are poor sweep efficiencies, loss of heat energy to unproductive zones underground and poor injectivity of steam or air. Poor sweep efficiencies are due to the density differences between the injected fluids and the reservoir crude oils. The lighter steam or air tends to rise to the top of the formation and bypass large portions of crude oil. Research is being conducted on methods of reducing the tendency for the injected fluids to override the reservoir oil. Techniques involving foams are being employed.

Large heat losses continue to be associated with thermal processes. The wet combustion process has lowered these losses for the higher-temperature combustion techniques, but the losses are severe enough in many applications to prohibit the combustion process. The losses are not as large with the steam processes because they involve smaller temperatures. The development of a feasible downhole generator will significantly reduce the losses associated with steam injection processes.

The poor injectivity found in thermal processes is largely a result of the nature of the reservoir crudes. Operators have applied fracture technology in connection with the injection of fluids in thermal processes. This has helped in many reservoirs.

Operational problems include the following: the formation of emulsions, the corrosion of injection and production tubing and facilities, and the creation of adverse effects on the environment. When emulsions are formed with heavy crude oil, they are very difficult to break. Operators need to be prepared for this. In the high-temperature environments created in the combustion processes and when water and stack gases mix in the production wells and facilities, corrosion becomes a serious problem. Special well liners are often required. Stack gases also pose environmental concerns in both steam and combustion applications.

Stack gases are formed when steam is generated by either coal- or oil-fired generators and, of course, during the combustion process as the crude is burned (Sultan Pwaga, et al., 2010).

2.6. Screening Concept

A large number of variables are associated with a given oil reservoir for instance, pressure, temperature, crude oil type and viscosity and the nature of the rock matrix and connate water Because of these variables not every type of EOR process can be applied to every reservoir. An initial screening procedure would quickly eliminate some EOR processes from consideration in particular reservoir application .table 2.5 contains the screening criteria for different EOR methods. In summary factors used in the screening are:

1- Reservoir conditions- temperature and pressure.
2- Reservoir fluid properties-oil viscosity and density and formation water salinity.
3- Reservoir geology-rock type and depth and permeability and porosity(Teknica, 2001)

In general screening has two sides: Technical screening & Commercial screening

Table 2.3: Oil Properties and Reservoir Characteristics for EOR Methods (Ahmed Aladasani and Baojun Bai, 2010)

Oil properties					Reservoir Characteristics						
SN	**EOR Method**	**# Projects**	**Gravity (°API)**	**Viscosity (cp)**	**Porosity (%)**	**Oil Saturation (%PV)**	**Formation Type**	**Permeability (md)**	**Net Thickness**	**Depth (ft)**	**Temperature (°F)**
Miscible Gas Injection											
1	CO_2	139	28[22]-45 Avg. 37	35-0 Avg. 2.1	3-37 Avg. 14.8	15-89 Avg. 46	Sandstone or Carbonate	1.5-4500 Avg. 201.1	[Wide Range]	1500[a]-13365 Avg. 6171.2	82-250 Avg. 136.3
2	Hydrocarbon	70	23-57 Avg. 38.3	18000-0.04 Avg. 286.1	4.25-45 Avg. 14.5	30-98 Avg. 71	Sandstone or Carbonate	0.1-5000 Avg. 726.2	[Thin unless dipping]	4040[4000]-15900 Avg. 8343.6	85-329 Avg. 202.2
3	WAG	3	33-39 Avg. 35.6	0.3-0 Avg. 0.06	11-24 Avg. 18.3		Sandstone	130-1000 Avg. 1043.3	[NC]	7545-8887 Avg. 8216.8	194-253 Avg. 229.4
4	Nitrogen	3	38[35]-54 Avg. 47.6	0.2-0 Avg. 0.07	7.5-14 Avg. 11.2	0.76[0.4]-0.8 Avg. 0.78	Sandstone or Carbonate	0.2-35 Avg. 15	[Thin unless dipping]	10000[6000]-18500 Avg. 14633.3	190-325 Avg. 266.6
Immiscible Gas Injection											

5	Nitrogen	8	16-54 Avg. 34.6	18000-0 Avg. 2256.8	11-28 Avg. 19.46	47-98.5 Avg. 71	Sandstone	3-2800 Avg. 1041.7		1700- 18500 Avg. 7914.2	82-325 Avg. 173.1
6	CO_2	16	11-35 Avg. 22.6	592-0.6 Avg. 65.5	17-32 Avg. 26.3	42-78 Avg. 56	Sandstone or Carbonate	30-1000 Avg. 217		1150- 18500 Avg. 3385	82-198 Avg. 124
7	Hydrocarbon	2	22-48 Avg. 35	4-0.25 Avg. 2.1	5-22 Avg. 13.5	75-83 Avg. 79	Sandstone	40-1000 Avg. 520		6000- 7000 Avg. 6500	170-180 Avg. 175
8	Hydrocarbon +WAG	14	9.3-41 Avg. 31	16000- 0.17 Avg. 3948.2	18-31.9 Avg. 25.09	Avg. 88	Sandstone or Carbonate	100-6600 Avg. 2392		2650- 9199 Avg. 7218.71	131-267 Avg. 198.7
(Enhanced) Waterflooding											
9	Polymer	53	13-42.5 Avg. 26.5	4000[b]-0.4 Avg. 123.2	10.4-33 Avg. 22.5	34-82 Avg. 64	Sandstone	1.8[e]-5500 Avg. 834.1	[NC]	700-9460 Avg. 4221.9	74-237.2 Avg. 167
10	Alkaline Surfactant Polymer (ASP)	13	23[20]- 34[35] Avg. 32.6	6500[c]-11 Avg. 875.8	26-32 Avg. 26.6	68[35]-74.8 Avg. 73.7	Sandstone	596[10]- 1520	[NC]	2723- 3900[900 0] Avg. 2984.5	118[80]- 158[200] Avg. 121.6

11	Surfactant + P/A	3	22-39 Avg. 31	15.6-3 Avg. 9.3	16-16.8 Avg. 16.4	43.5-53 Avg. 48	Sandstone	50-60 Avg. 55	[NC]	625-5300 Avg. 2941.6	122-155 Avg. 138.5
Thermal/Mechanical											
12	Combustion	27	10-38 Avg. 23.6	2770-1.44 Avg. 504.8	14-35 Avg. 23.3	50-94 Avg. 67	Sandstone or Carbonate [Preferably Carbonate]	10-15000 Avg. 1981.5	[> 10]	400-11300 Avg. 5569.6	64.4-230 Avg. 175.5
13	Steam	271	8-30 Avg. 14.5	5E6-3[d] Avg. 32971.3	12-65 Avg. 32.2	35-90 Avg. 66	Sandstone	1[e]-15000 Avg. 2605.7	[> 20]	200-9000 Avg. 1643.6	10-350 Avg. 105.8
14	Hot Water	10	12-25 Avg. 18.6	8000-170 Avg. 2002	25-37 Avg. 31.2	15-85 Avg. 58.5	Sandstone	900-6000 Avg. 3346		500-2950 Avg. 1942	75-135 Avg. 98.5
15	[Surface Mining]	-	[7]-[11]	[Zero could flow]	[NC]	[> 8 wt% sand]	[Mineable tar sand]	[NC]	[> 10]	[> 3:1 overburden to sand ratio]	[NC]
Microbial											
16	Microbial	4	12-33 Avg. 26.6	8900-1.7 Avg. 2977.5	12-26 Avg. 19	55-65 Avg. 60	Sandstone	180-200 Avg. 190		1572-3464 Avg. 2445.3	86-90 Avg. 88

The following reported EOR reservoir characteristics have extreme values that impact the respective average and range in Table 2.3

a- Minimum CO_2 miscible flooding depth reported in Salt Creek Field, U.S.A.

b- Maximum polymer flooding viscosity reported in Pelican Lake, Canada

c- Maximum ASP flooding viscosity reported in Logomar, Venezuela

d- Maximum steam injection viscosity reported in Athabasca Oil Sand, Canada

e- Maximum steam injection permeability reported in North Midway-Sunset, U.S.A

2.7. Glance about economic view

The enhanced oil recovery projects are affected by a lot of economic factors, these include change in oil price, adjustment in taxes, political situations, and the constancy of the oil industry of productive countries.

Getting started with this type of projects, it requires providing the capital share with the proper management of investors, to make them agree to bear all the risk factors associated with technical changes that may arise on recovery method, especially that the enhanced recovery project do not always give immediate result. Generally the related cost for this type of project is so high especially capitalism (OPEX), but having a high cost is not constant rule.

Most of studies ensure that delaying this type of project to late time from field age, mean in most times losing huge amount of oil, there for losing a lot of profit could be gained. That's why companies shouldn't be looking after proved reserves, but concerning and pay more attention to the employment of typical technology of the proper enhanced oil recovery during the production interval.

Figure (2.19) show the relative cost of moderation different techniques used in enhanced oil recovery. Although the oil prices that prevailed in doing this figure estimation is relatively old, but any change in oil price was accompanied by a relative change in capital and operational cost. The cost make this estimation reflects an approximation for the area of the cost of each method, or at least shows the cost of each technique for the rest of the techniques.

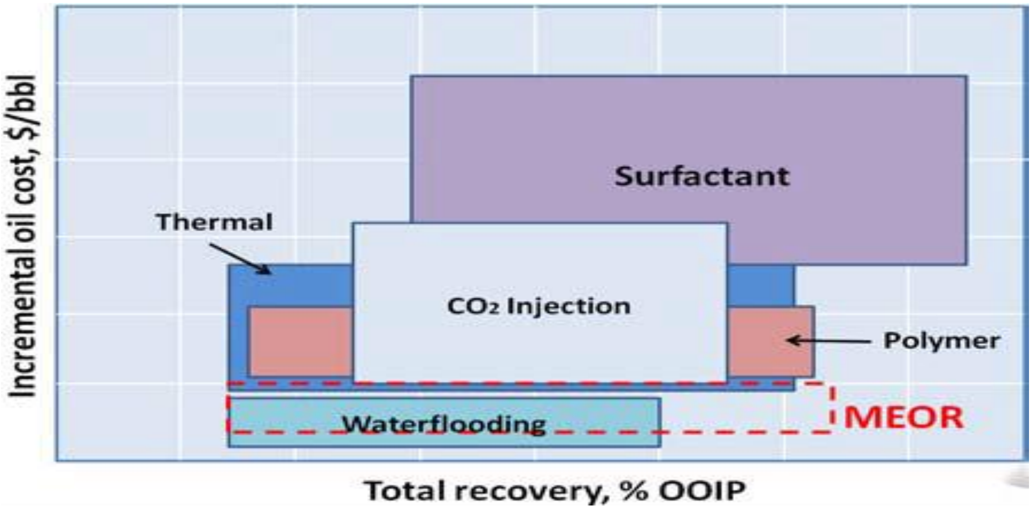

Fig. 2.19: The Cost of the Different Techniques Used in Enhanced Oil Recovery (OPEC, 2009)

Chapter 3
Methodology

This chapter will review some of common methods to select the most technically applicable EOR processes, which they are: Manual method using SPE format, EORgui allows to apply EOR screening criteria of nine methods to any field and a new designed software (EOR analysis) allows to apply EOR screening criteria of fifteen methods to any field.

3.1. Screening using SPE format:

SPE (Society of Petroleum Engineers) has established technical EOR screening concepts using certain format. This format is based on field experience, project implementation around the world and this method was the start point of all the EOR screening software's .The objective is to select the suitable EOR method to be implemented in the future. The procedure contains five plots:

3.1.1. Permeability plot

Permeability is one of the important factors in EOR screening, due to injection of the fluids into the formation. It is important as well for the mobility ratio; all EOR methods require high and enough permeability. Figure 3.1 presented permeability screening for EOR methods.

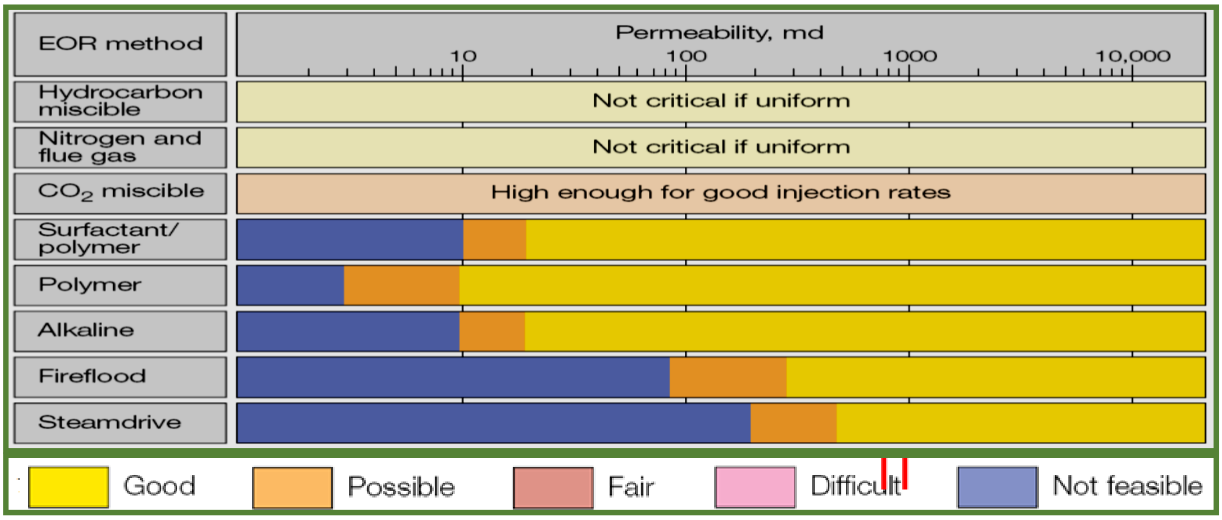

Fig 3.1: Permeability Screening for EOR Methods (David, 2009)

3.1.2. Viscosity plot:

Viscosity is important factor in EOR screening too, due to injection of both thermal and miscible gas react with oil viscosity. It is important as well for the mobility ratio; all EOR methods need viscosity data as in figure 3.2.

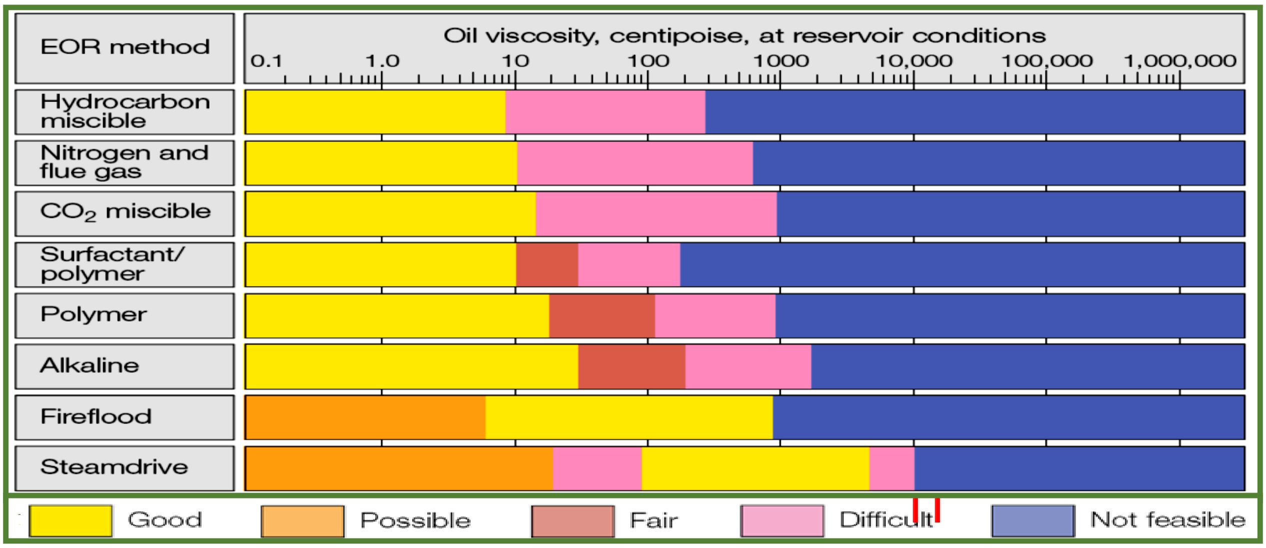

Fig. 3.2: Viscosity Screening for EOR Methods (David, 2009)

3.1.3. Depth plot:

Depth is one of the important factor in EOR screening too, due to injection of thermal requires shallow formations because of steam quality and heat losses, and miscible gas injection requires deep formations (Abdulbasit, 2013)as in figure 3.3 .

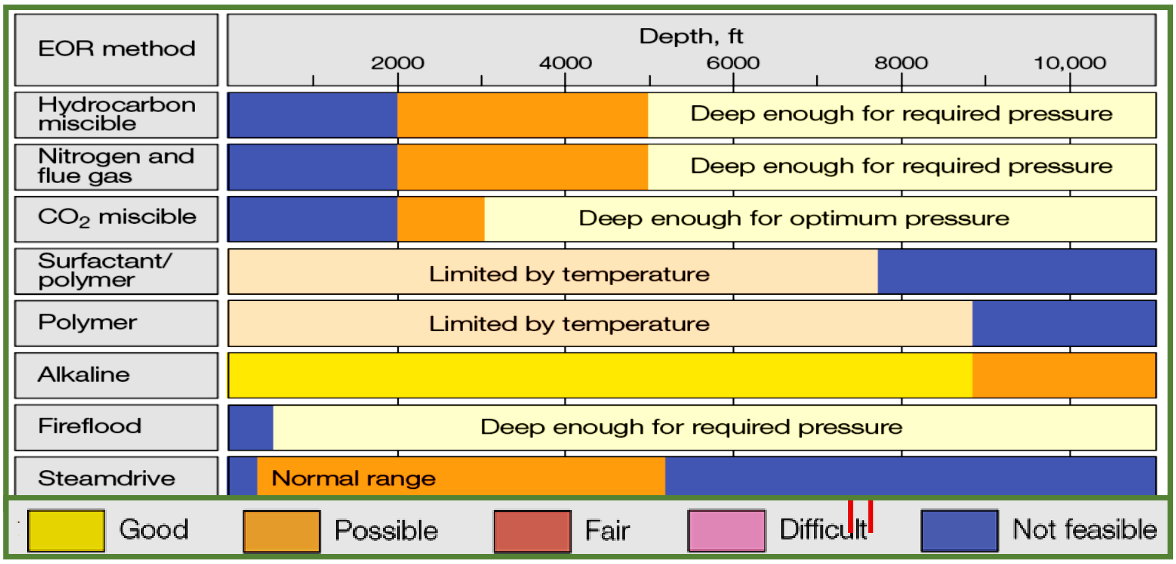

Fig. 3.3: Depth Screening for EOR Methods (David, 2009)

3.1.4. Reservoir Pressure vs. Oil Viscosity:

Pressure Vs viscosity also important plot to define the suitable EOR method (consists of two main factors): Viscosity in X- axis and pressure in Y-axis, the location in the plot is used to define the suitable method. Single value or range is used in the plot as in figure 4.4.

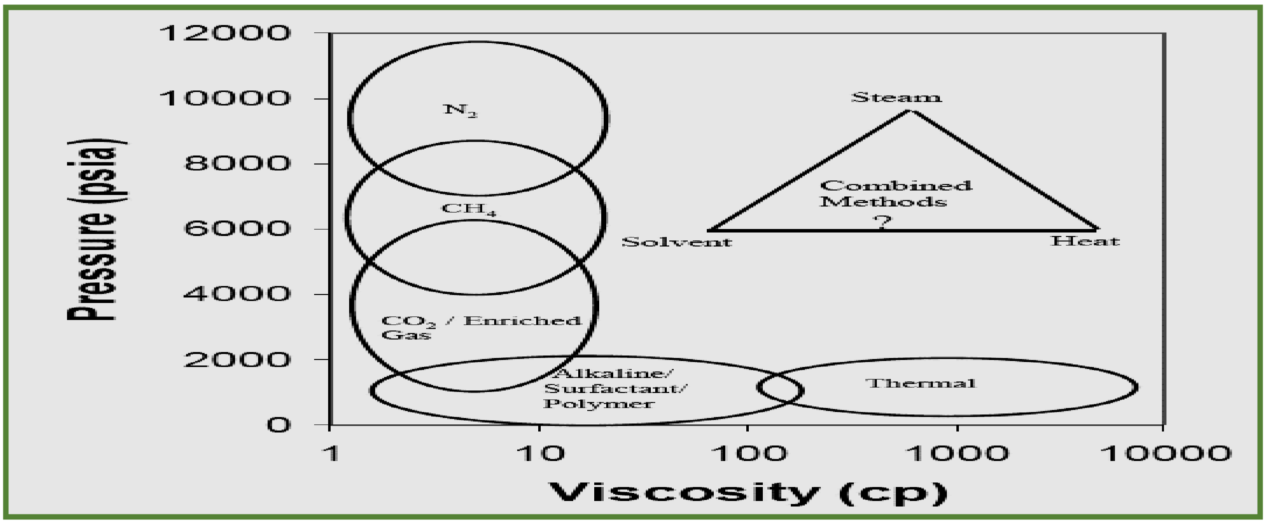

Fig. 3.4: Pressure & Viscosity Screening for EOR Methods (David, 2009)

3.1.5. Reservoir Depth vs. Viscosity:

It consists of two main factors: Depth in X- axis and viscosity in Y-axis, the location in the plot is used to define the suitable method as in figure 3.5. The final screening result based on the combination between the five plots.

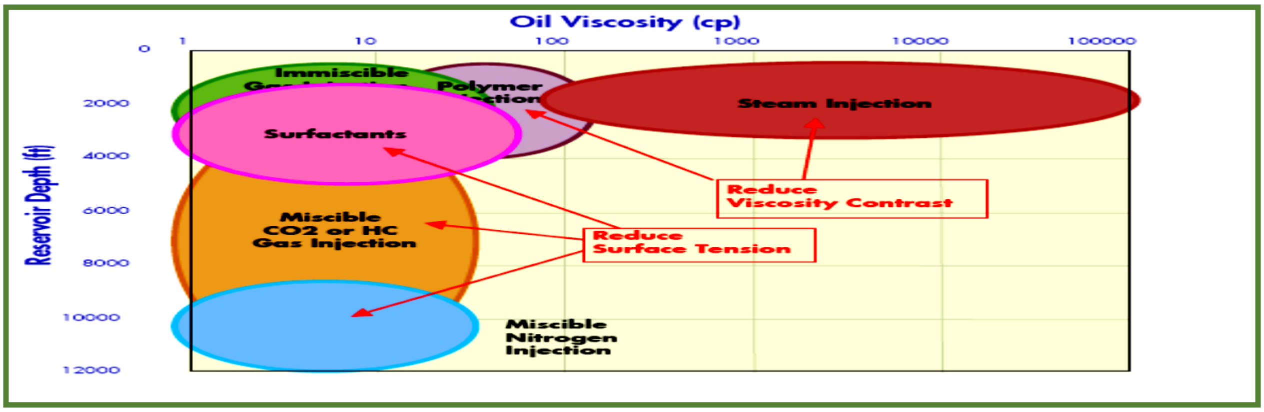

Fig. 3.5: Reservoir Depth & Viscosity Screening for EOR Methods (David, 2009)

3.1.6. Oil gravity:

Oil gravity range for different methods of EOR shown at figure 3.6:

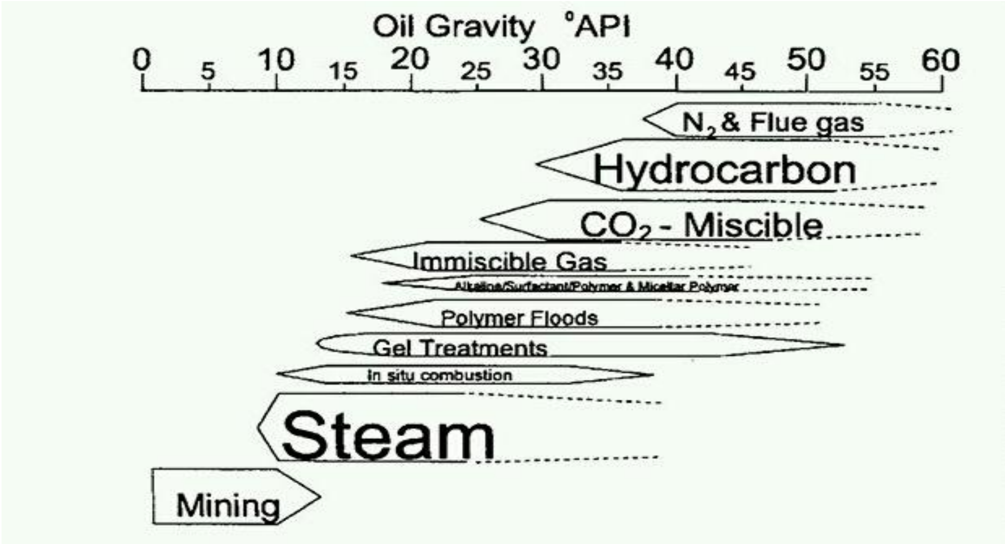

Fig. 3.6: Oil Gravity Range for EOR Methods (Taber et al, 1997)

3.2. Screening using EORgui:

3.2.1 EORgui Description:

EORgui is a Graphical User Interface (figure 3.7) for the United States of America, Department of Energy, National Energy Technology Laboratory, Publically Available EOR Software.

With this software the user can quickly screen oil fields and quantify incremental production for potentially applicable EOR techniques (Petroleum Solutions, 2010)

3.2.2. Applications of EORgui:

1. Quickly screen and rank appropriate EOR methods for a given set of summary reservoir and fluid properties.
2. Prepares the input files required for the technical analysis portion of the publically available Fortran application.
3. The GUI runs the Fortran applications and import the result back into the application.
4. The results are input into convent data tables, and plotted in charts for export into other applications.

3.2.3. EORgui sections:

1- Quick Screening
2- CO_2 Miscible Flooding Predictive Model
3- Chemical Flood Predictive Model
4- Polymer Predictive Model
5- In-situ Combustion Predictive Model
6- Steam flood Predictive Model
7- Infill Drilling Predictive Model

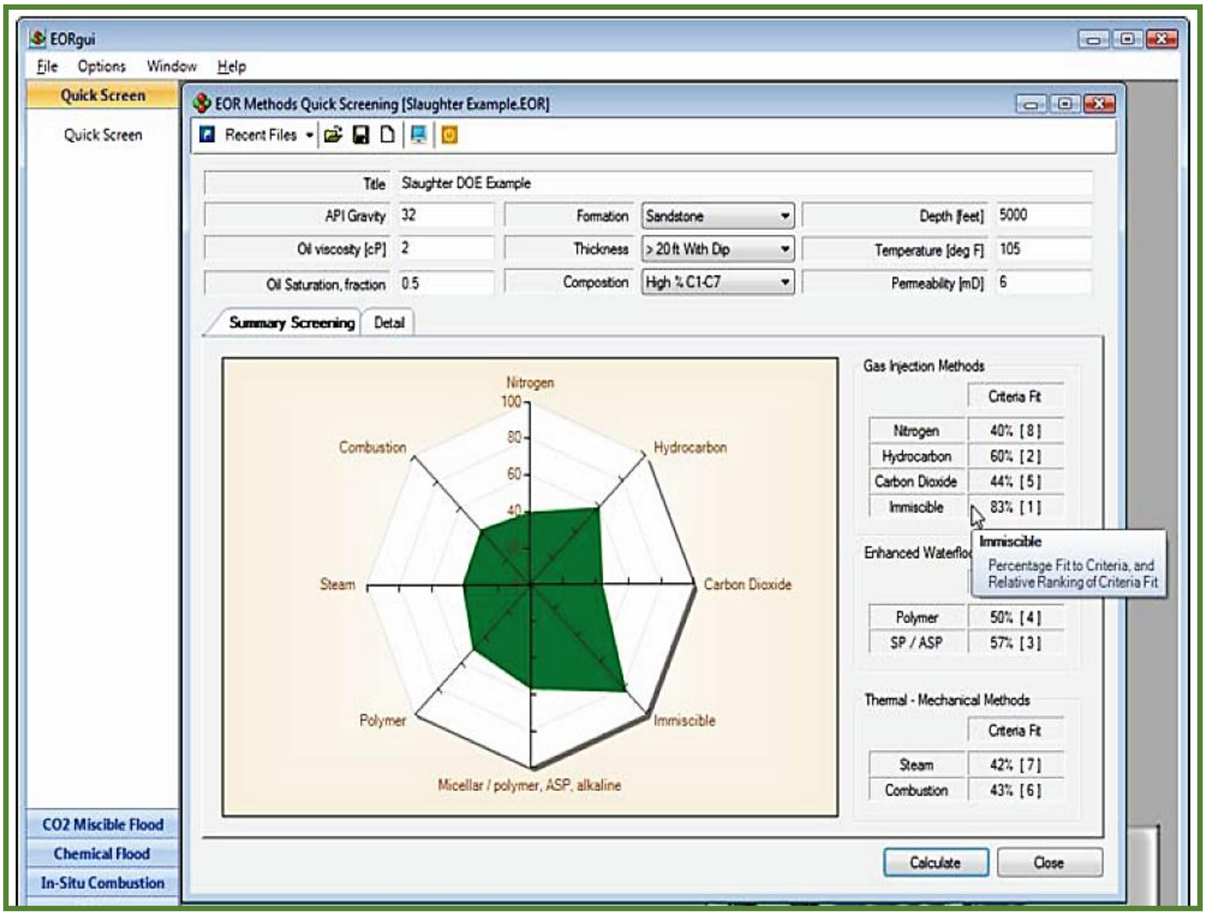

Fig. 3.7: EORgui Enhanced Oil Recovery Software (Petroleum Solutions, 2010)

3.2.4. EOR Method Quick Screening (figure 3.8):

This routine based on the 1996 Society of Petroleum Engineers Paper entitled "EOR Screening Criteria Revisited" by Taber, Martin, and Seright.

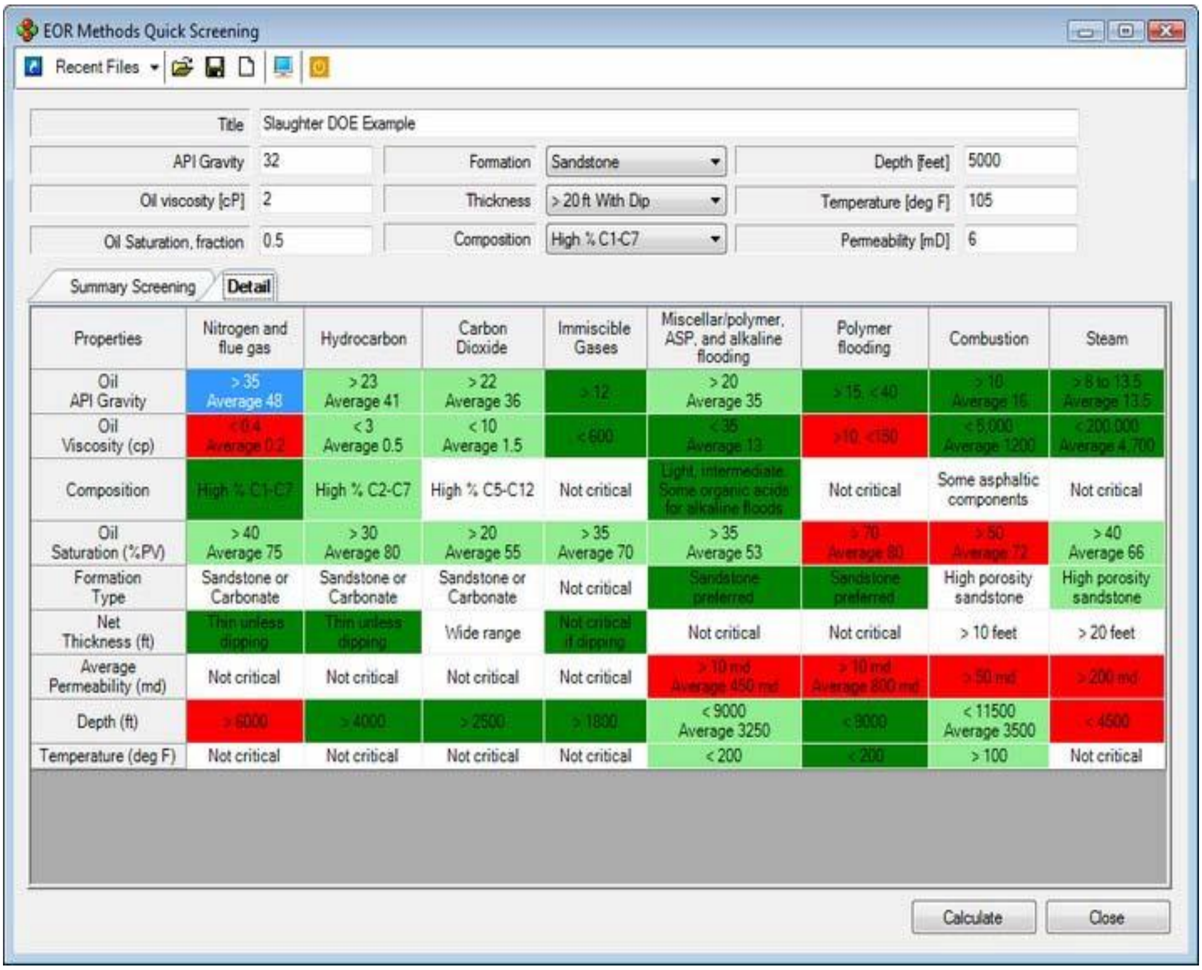

Fig. 3.8: EOR Method Quick Screening (Petroleum Solutions, 2010)

3.3. Screening using EOR analysis:

EOR analysis is a software built by project team and IT engineer, using visual basic environment. The routine is based on 2010 society of petroleum engineer's paper entitled "Recent Developments and Updated Screening Criteria of Enhanced Oil Recovery Techniques" by Ahmad Aladasani and Baojun Bai. With this program, the user can quickly screen oil field to determine the suitable EOR method/s. Fifteen methods of enhanced oil recovery are available using nine properties: (API, Gravity, Porosity, and Oil saturation, Formation, Thickness, Permeability, Depth and Temperature). EOR analysis software is designed to make the selection of enhanced oil recovery method, easier and quicker. The flow chart of the software illustrated in figure 3.9.

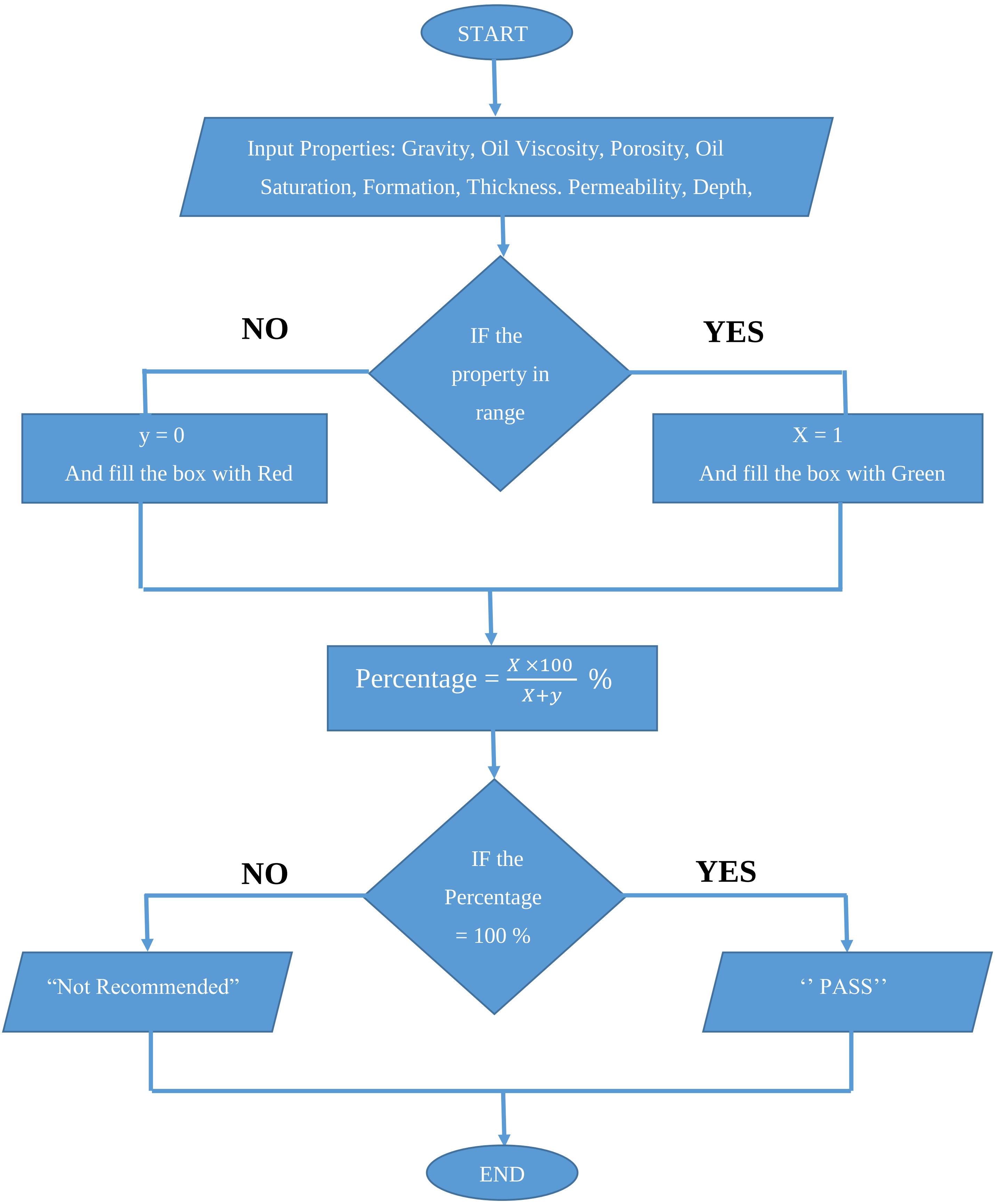

Fig. 3.9: EOR Analysis Flow Chart

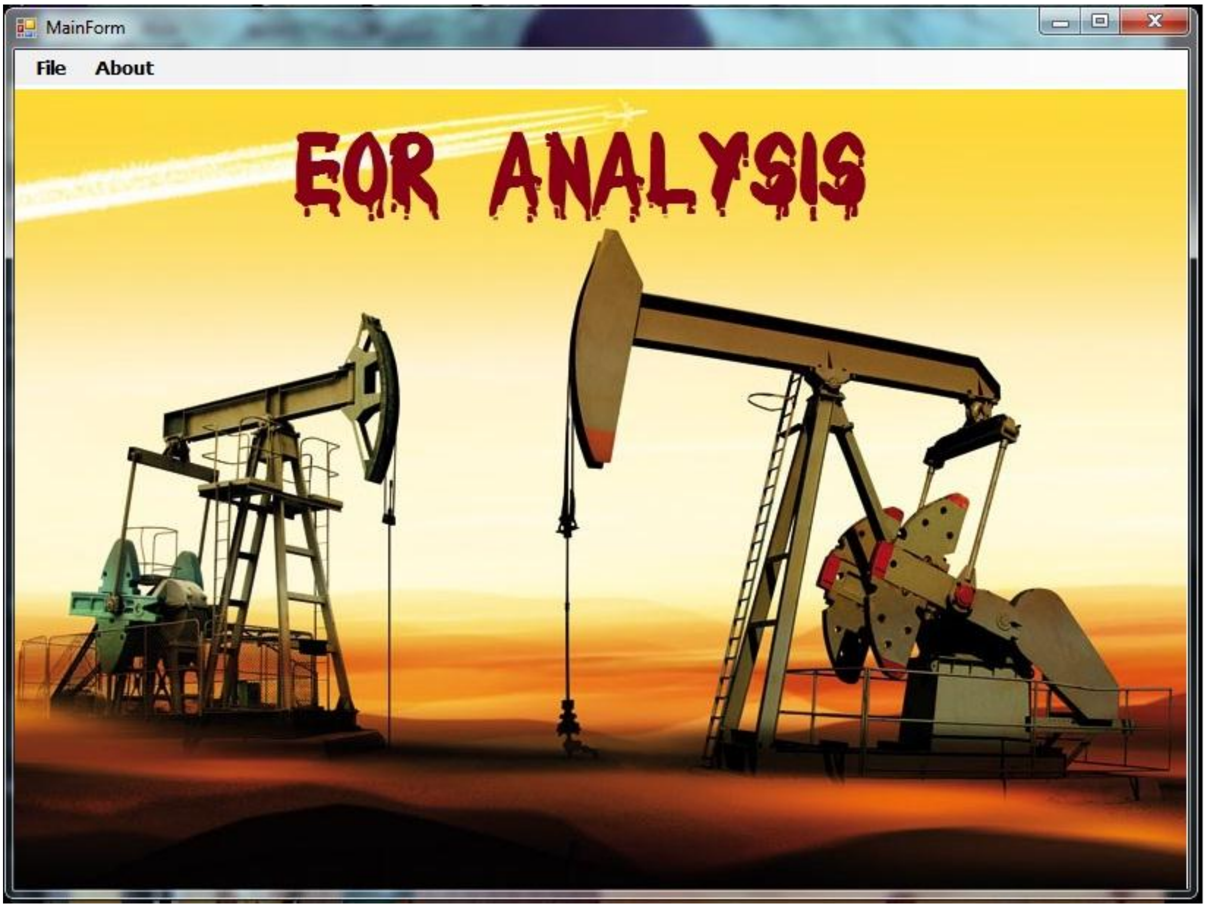

Fig. 3.10: EOR Analysis Program

3.3.1. Microsoft Visual Studio:

Microsoft Visual Studio is an integrated development environment (IDE) from Microsoft. It is used to develop computer programs for Microsoft Windows, as well as websites, web applications and web services. Visual Studio uses Microsoft software development platforms such as Windows API, Windows Forms, Windows Presentation Foundation, Windows Store, and Microsoft Silverlight. It can produce both native code and managed code.

Visual Studio support different programming language and allows the code editor. Visual Studio features including code editor, debugger, designer and other tools

3.3.2. Applications of the program:

1- Quickly screen suitable EOR methods for each reservoir based on its properties
2- The program runs the visual basic applications and imports the results back into the application
3- Technical screening can made by this program not economical screening.

4- The program divided EOR methods into success or not recommended and shows the percent for each one of them.

3.3.3. Sections of the program:

3.3.3.1. Screening Result:

The routine is based on 2010 society of petroleum engineer's paper entitled "Recent Developments and Updated Screening Criteria of Enhanced Oil Recovery Techniques" by Ahmad Aladasani and Baojun Bai.

Input data: oil properties and reservoir characteristics shows at figure 3.11

Once the user has input all necessary data then click on Analysis button to calculate results shown as "success" for the method/s has achieved all properties and "not recommended" for the method/s has not achieved all properties figure 3.11

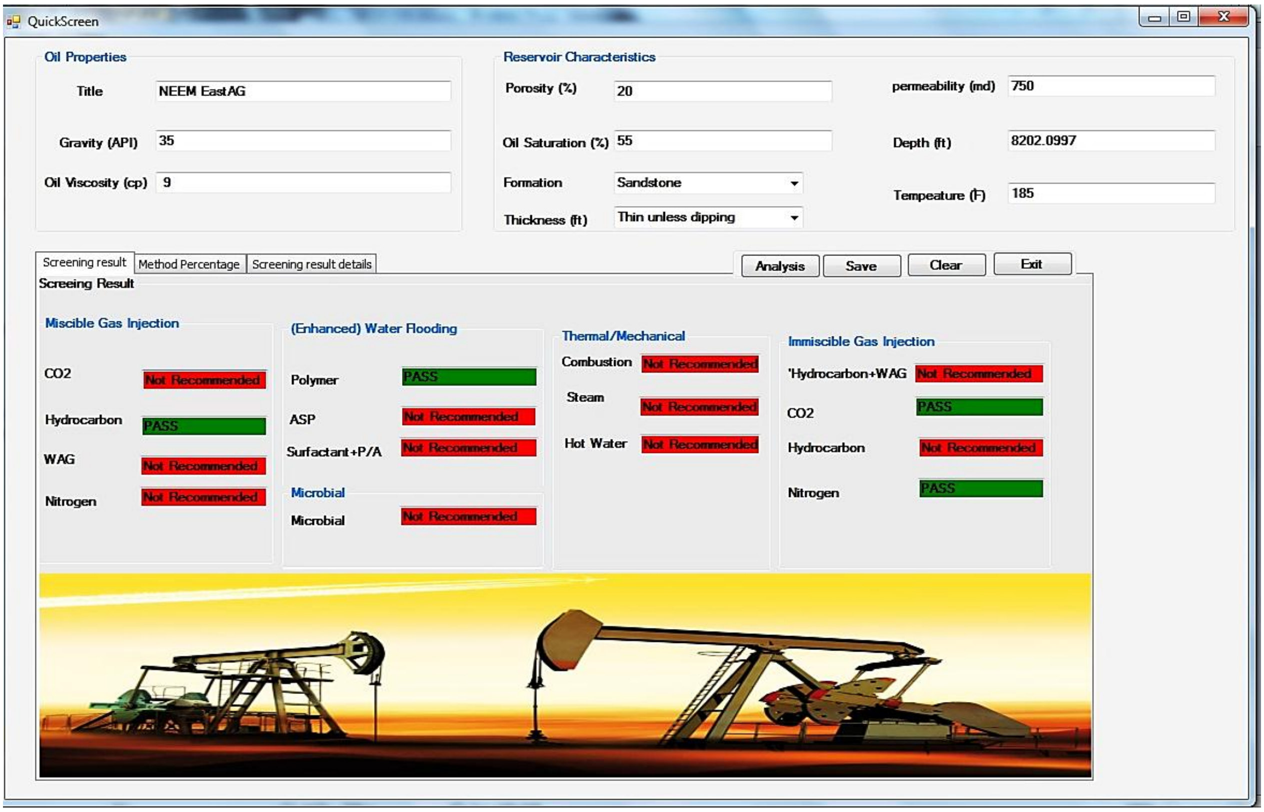

Fig. 3.11: EOR Analysis Screening Results

3.3.3.2 Screening result details:

This screen shows each properties successes and each of them failed for all methods to answer the question "why some methods are not recommended and which method should be selected in more details"

If a cell is colored red then this criteria is not met, whereas if a cell is colored green then the criteria is met, whereas if the cell is colored white then the criteria is not critical as shown in figure (3.12).

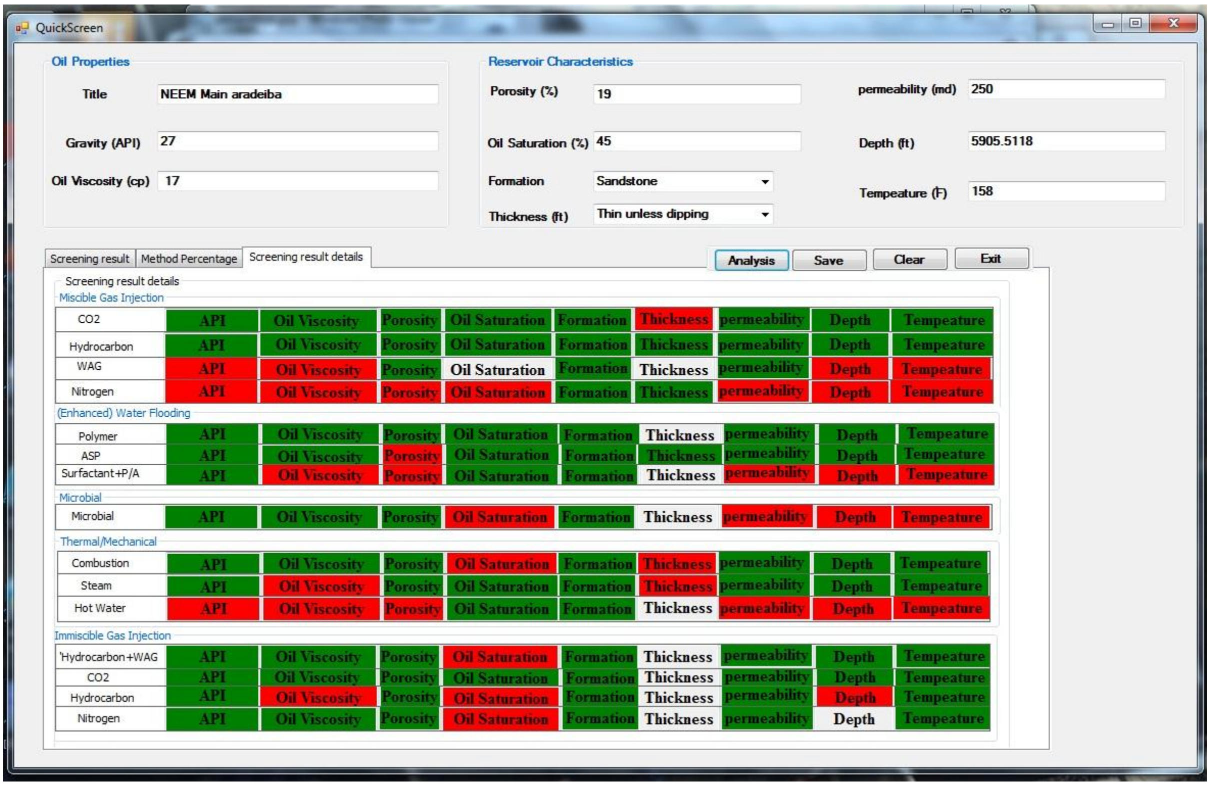

Fig. 3.12: EOR Analysis Screening Results Details

3.3.3.3. Methods Percentage:

This screen shows (figure 3.13) the percent of each method based on the properties have been achieved by it, for example if only four properties have been achieved from the nine properties thus the percent is calculated as follows:

$$\text{Percentage} = \frac{4}{9} \times 100\ \% = 44\%$$

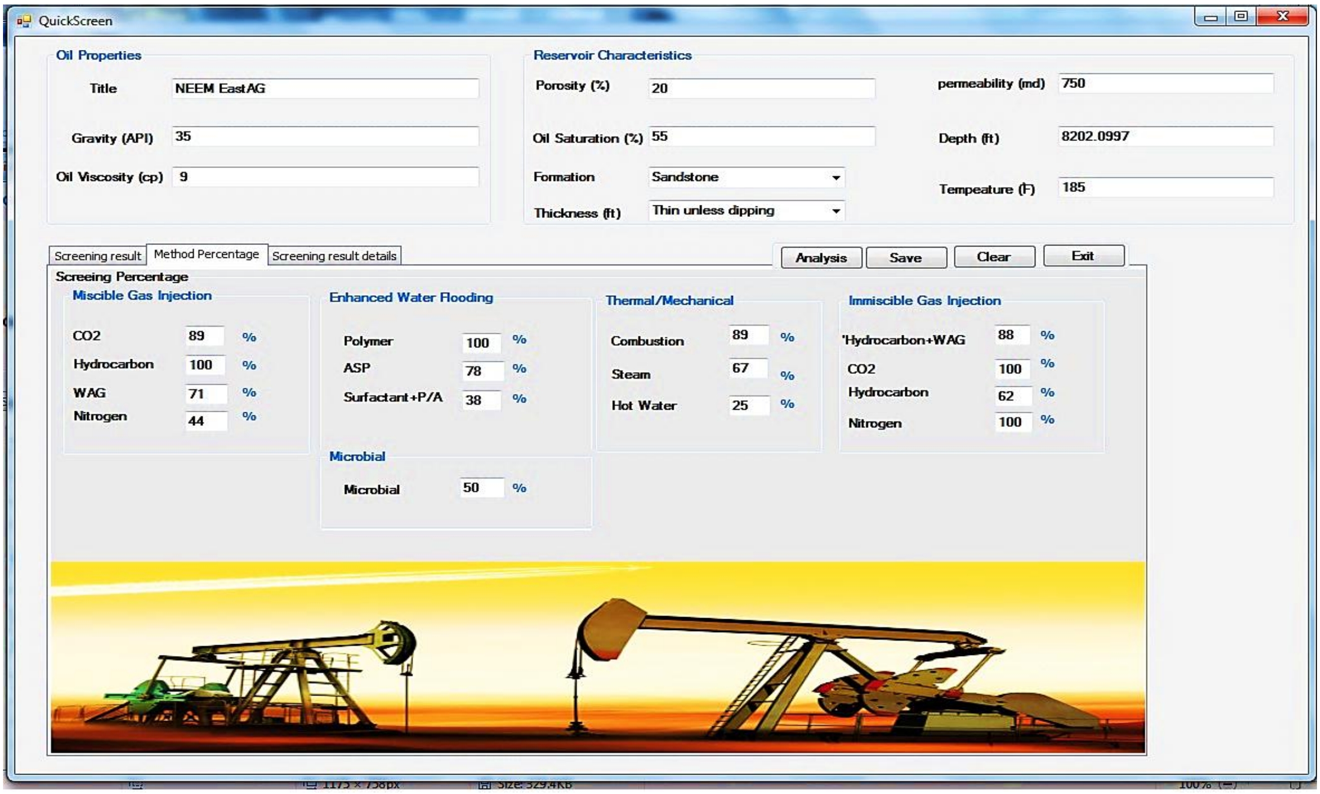

Fig. 3.13: EOR Analysis Screening Percentage

The final screening result based on the combination between the three methods

Chapter 4

Results and Discussion

In this chapter, data illustrated in table (4.1) was processed by using the three methods that discussed in previous chapter.

In addition, the results, which were obtained from the technical screening, have been summarized in table (4.2) and these results have been discussed individually for each method.

Table 4.1: DATA of Greater Neem Field

parameter	NEEM Main			NEEM K		NEEM F	NEEM East			NEEM North	
Reservoir	Aradeiba	Bantiu	AG	Amal	AG	AG	Aradieba	Bantiu	AG	Bantiu	AG
Depth (mKB)	1800	2000	2400	750	2550	3100	1800	2100	2500	1800	2100
Initial pressure, (psi)	2300	2600	3300	1800	3200	4100	2565	2700	3200	2400	2900
Current pressure, (psi)	1850	1900	2500	1200	2440	2900	2000	1980	2350	1758	2
Temperature. degC	70	75	88	53	91	102	71	78	85	76	86
Porosity, friction	0.19	0.23	0.18	0.31	0.19	0.15	0.19	0.23	0.20	0.26	0.20
Permeability, mD	200-300	1500-2000	300-600	1000-1300	300-600	600-1000	200-300	1000-1500	600-900	4000-6000	400-900
Oil gravity, Deg API	27	32	40-44	15	38	41	25	33	35	28	21
Viscosity, CP	17	2.2-4	2-6	10	1-3	3-5	18	2-7	9	12	15
Oil FVF, rb/STB	1.03	1.04	1.08-1.6	1.01	1.08	1.1	1.03	1.05	1.2	1.05	1.08
Net pay, m	5-6	6-9	4-8	12	7-9	6-8	4-5	5-10	3-8	5.5-9	4-9
Oil saturation, friction	0.45	0.56	0.59	0.69	0.60	0.58	0.49	0.56	0.55	0.67	0.66

4.1. Neem Main

4.1.1. Neem Main-AG

1- Screening using SPE format:

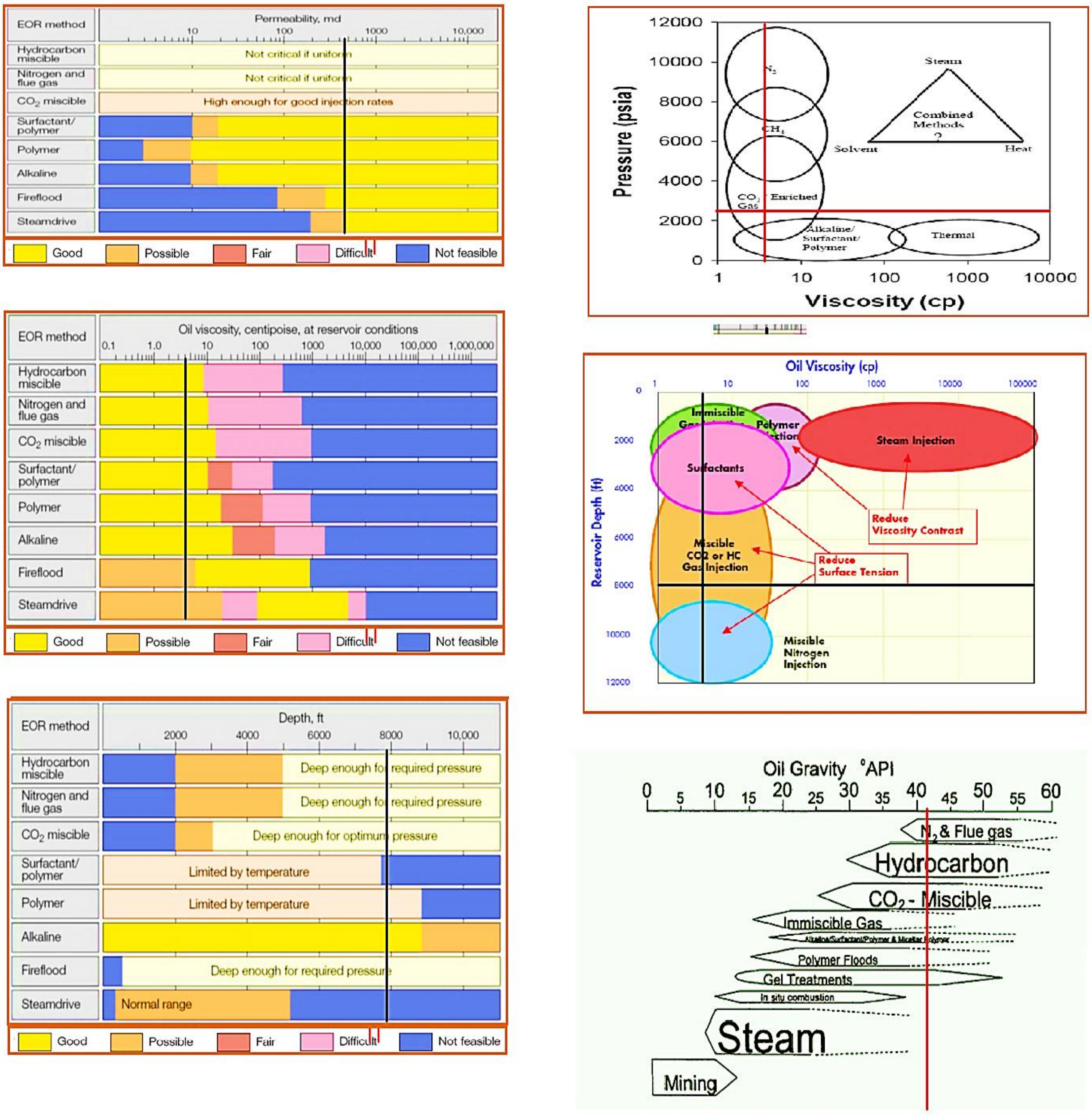

Fig. 4.1: Screening Using SPE Format for Neem Main-Ag

Suitable EOR methods are :

1-Miscible CO_2

2-Miscible HC

3-Polymer

2- Screening using EORgui:

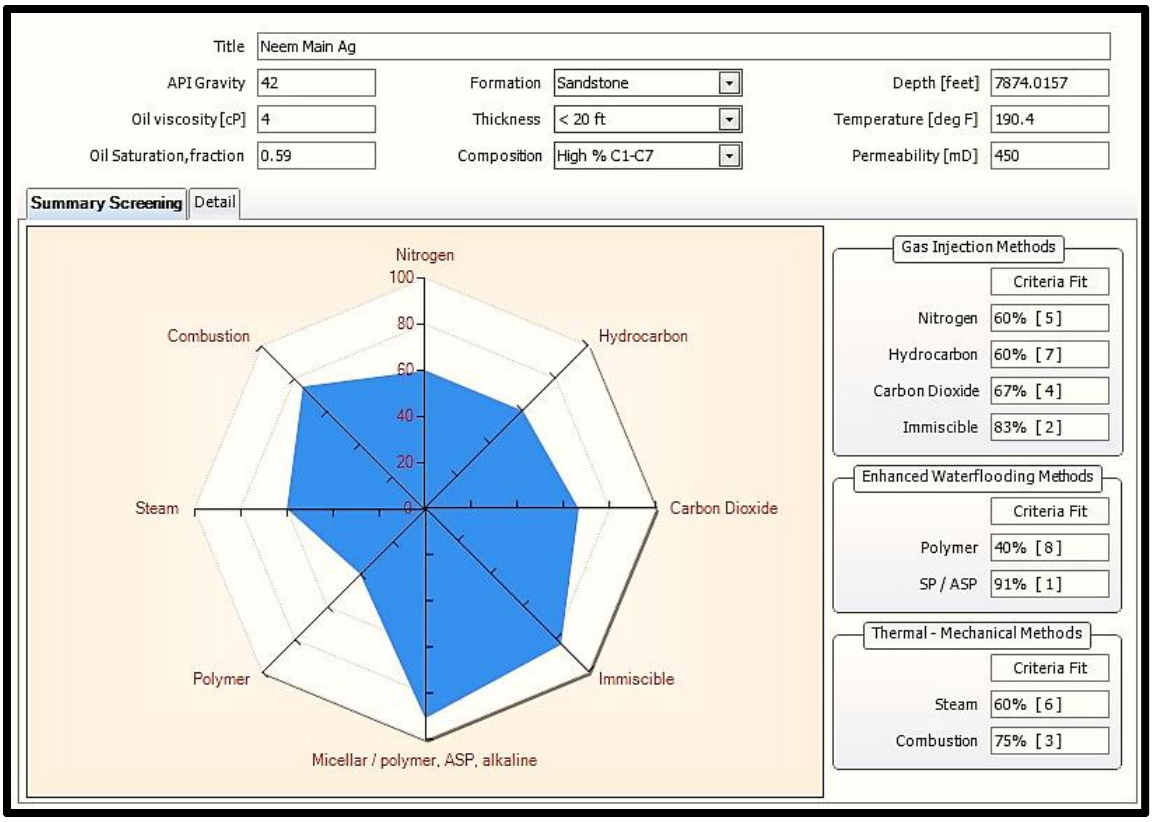

Fig. 4.2: Screening Using EORgui for Neem Main-Ag

Suitable EOR methods are:

1- Chemical methods group(Micellar/Polymer,ASP,Alkaline) has a higher percentage with (91%)

2- Immisible method in second order with (83%)

3- Combustion in third order with (75%)

4- Carbon dioxide in forth order with (60%)

3- Screening Using EOR Analysis:

Fig. 4.3: Screening Using EOR Analysis for Neem Main-Ag

Suitable EOR methods are: (Miscible HC, Immiscible N_2, and Polymer), Miscible CO_2, Immiscible CO_2.

4.1.2. Neem Main-Aradeiba

1- Screening Using SPE Format:

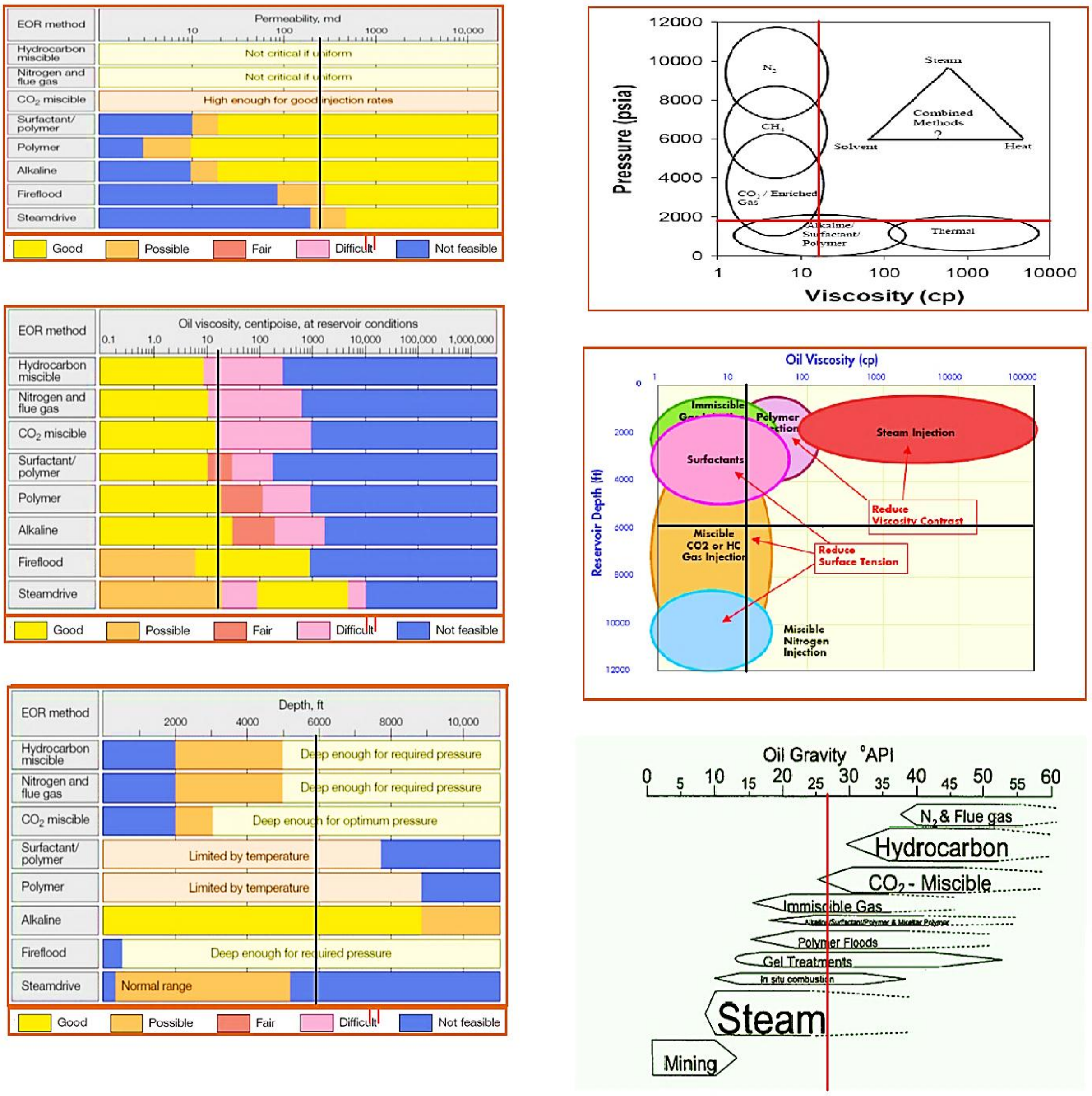

Fig. 4.4: Screening Using SPE Format for Neem Main-Aradeiba

Suitable EOR methods are:

1-Miscible CO_2

2-Chemical (Alkaline, Polymer)

2- Screening using EORgui:

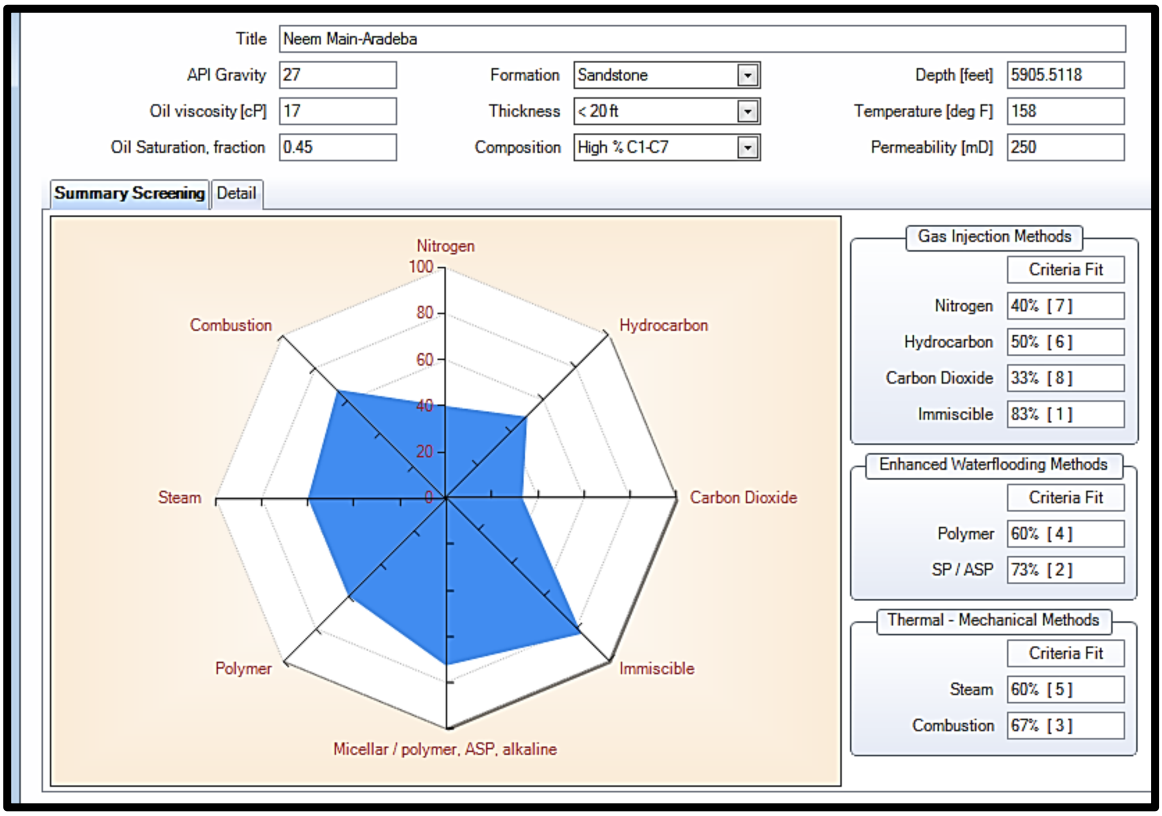

Fig. 4.5: Screening Using EORgui for Neem Main-Aradeiba

Suitable EOR methods are:

1-Immisible method has a higher percentage (83%)

2- Chemical methods group(Micellar/Polymer,ASP,Alkaline) in second order with (73%)

3- Combustion in third order with (67%)

3- Screening Using EOR analysis:

Fig. 4.6: Screening Using EOR Analysis for Neem Main-Aradeiba

Suitable EOR methods are: (Immiscible CO_2, Miscible HC, and Polymer), (Miscible CO_2, ASP)

4.1.3. Neem Main-Bantiu

1- Screening Using SPE Format:

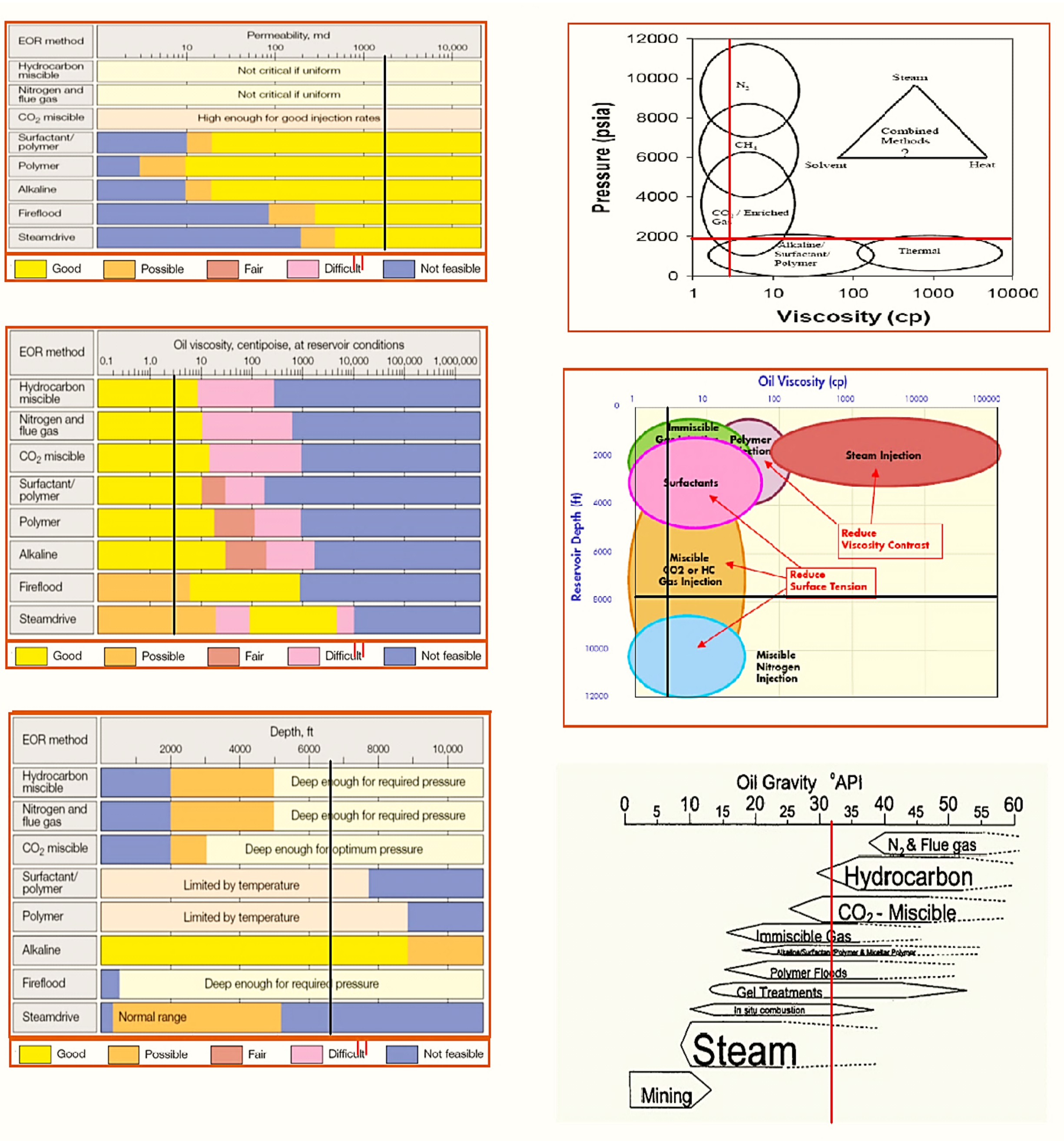

Fig. 4.7: Screening Using SPE Format for Neem Main-Bentiu

Suitable EOR methods are:

1-Miscible CO_2

2-Chemical (Alkaline, Polymer)

3-Miscible HC

2- Screening Using EORgui:

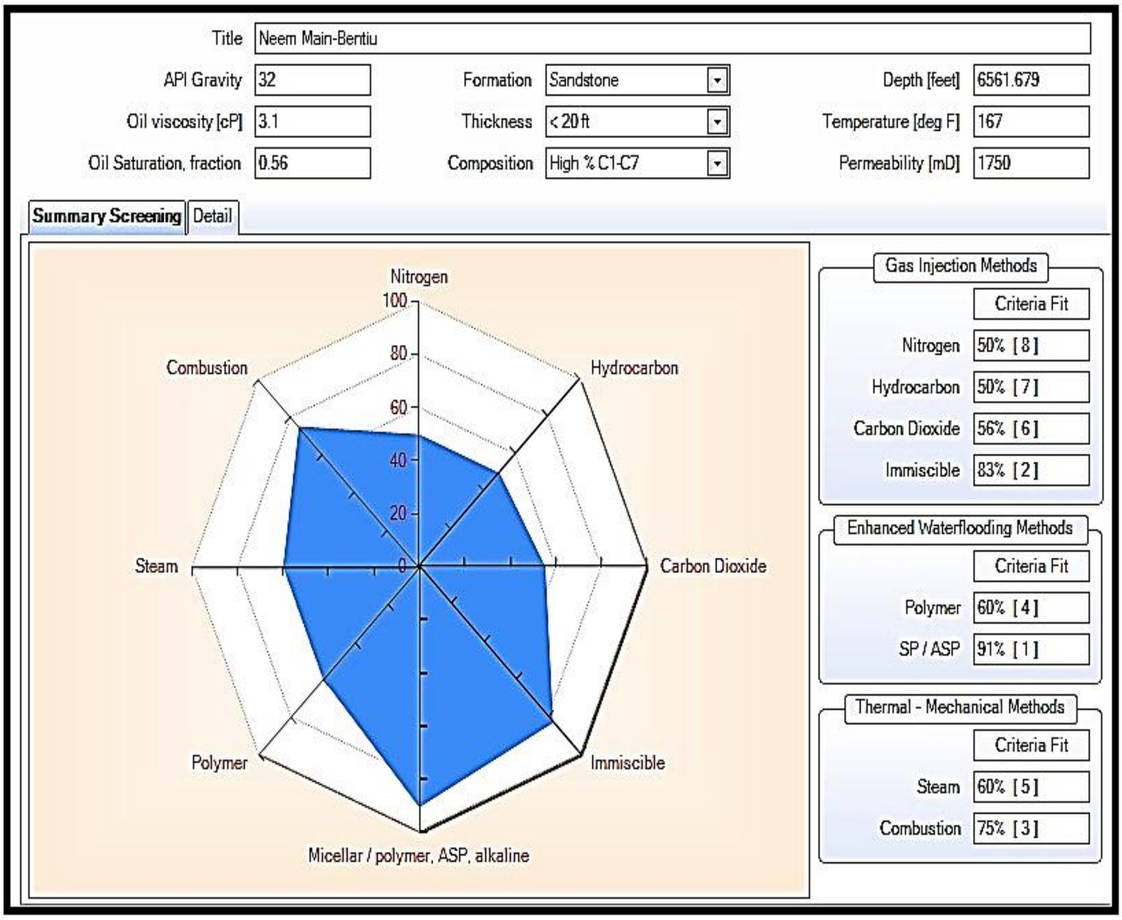

Fig. 4.8: Screening Using EORgui for Neem Main-Bentiu

Suitable EOR methods are:

1- Chemical methods group(Micellar/Polymer,ASP,Alkaline) has a higher percentage with (91%)

2- Immisible method in second order with (83%)

3- Combustion in third order with (75%)

4- Polymer and Steam in forth order with (60%)

3- Screening Using EOR Analysis:

Fig. 4.9: Screening Using EOR Analysis for Neem Main-Bentiu

Suitable EOR methods are: (Miscible HC, Immiscible N_2, Polymer),(Miscible CO_2 , Combustion), Immiscible CO_2.

4.2. Neem East

4.2.1. Neem East-AG

1- Screening using SPE format:

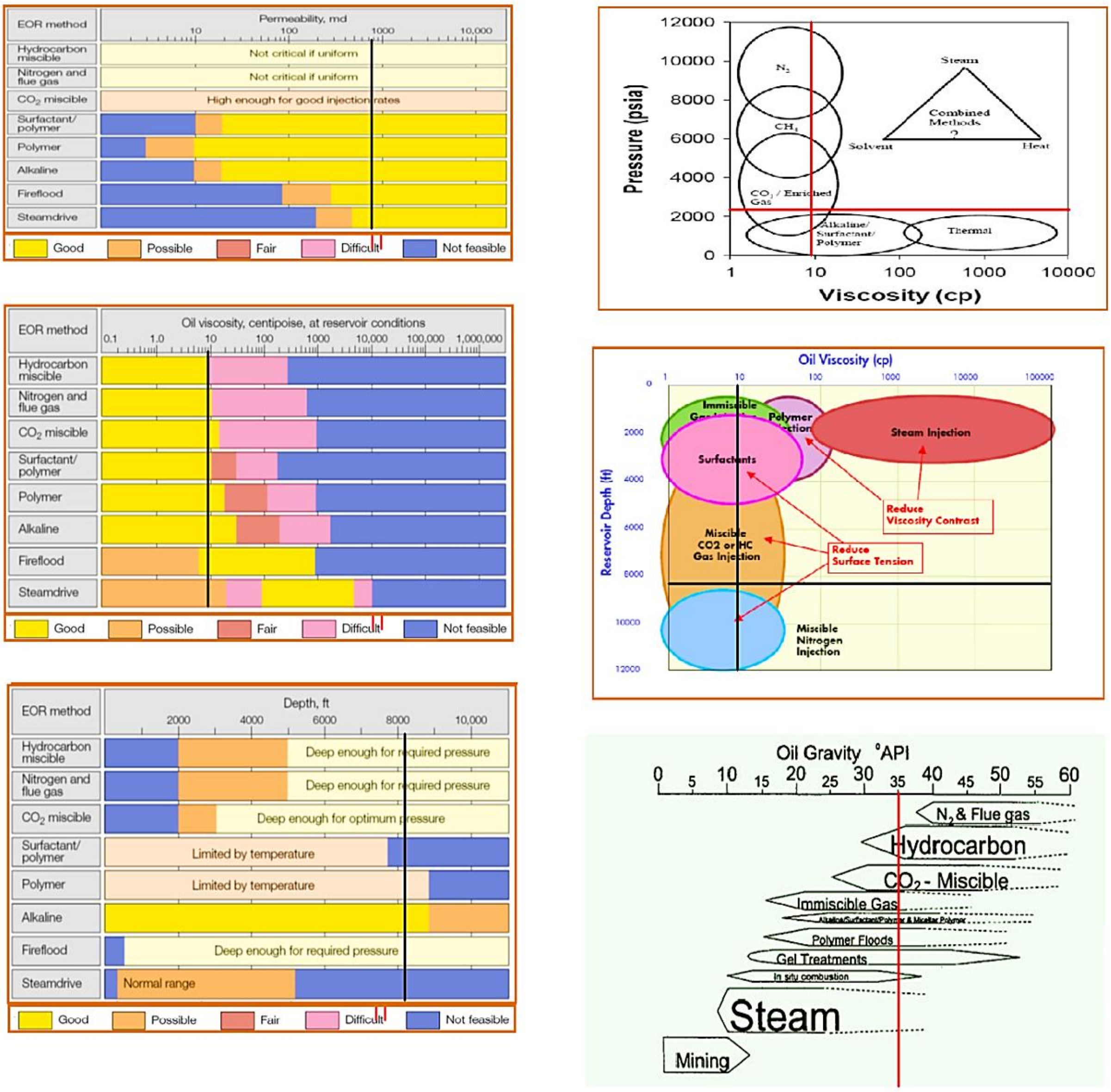

Fig. 4.10: Screening Using SPE Format for Neem East –Ag

Suitable EOR methods are:

1-Miscible CO_2

2-Chemical (Alkaline, Polymer)

3-Miscible HC

2- **Screening Using EORgui:**

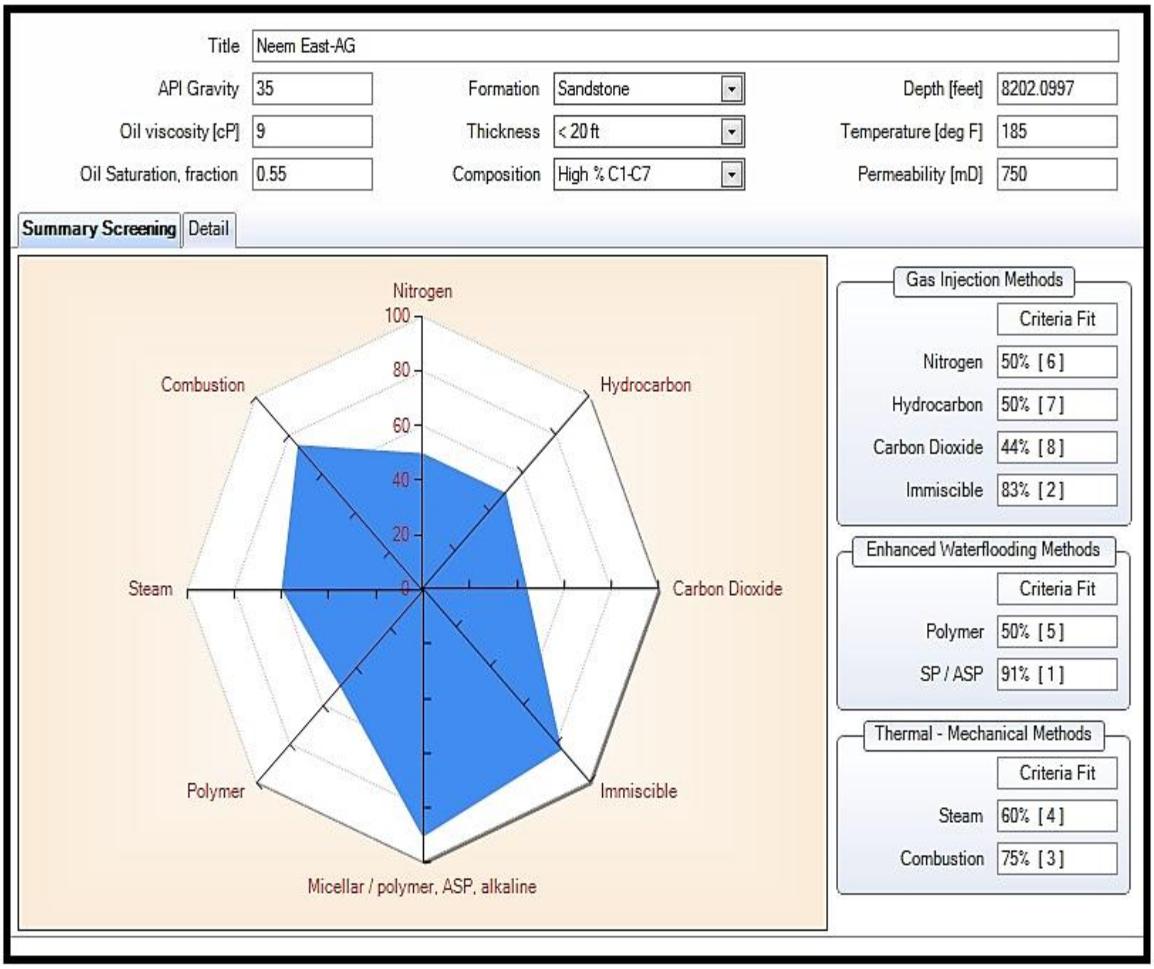

Fig. 4.11: Screening Using EORgui for Neem East-Ag

Suitable EOR methods are:

1- Chemical methods group (Micellar/Polymer,ASP,Alkaline) has a higher percentage with (91%)

2- Immisible method in second order with (83%)

3- Combustion in third order with (75%)

4- Steam in forth order with (60%)

3- Screening Using EOR analysis:

Fig. 4.12: Screening Using EOR Analysis for Neem East - Ag

Suitable EOR methods are: (Miscible HC, Immiscible N_2, Polymer, and Immiscible CO_2), (Combustion, Miscible CO_2)

4.2.2. Neem East Arardeiba

1- Screening using SPE Format:

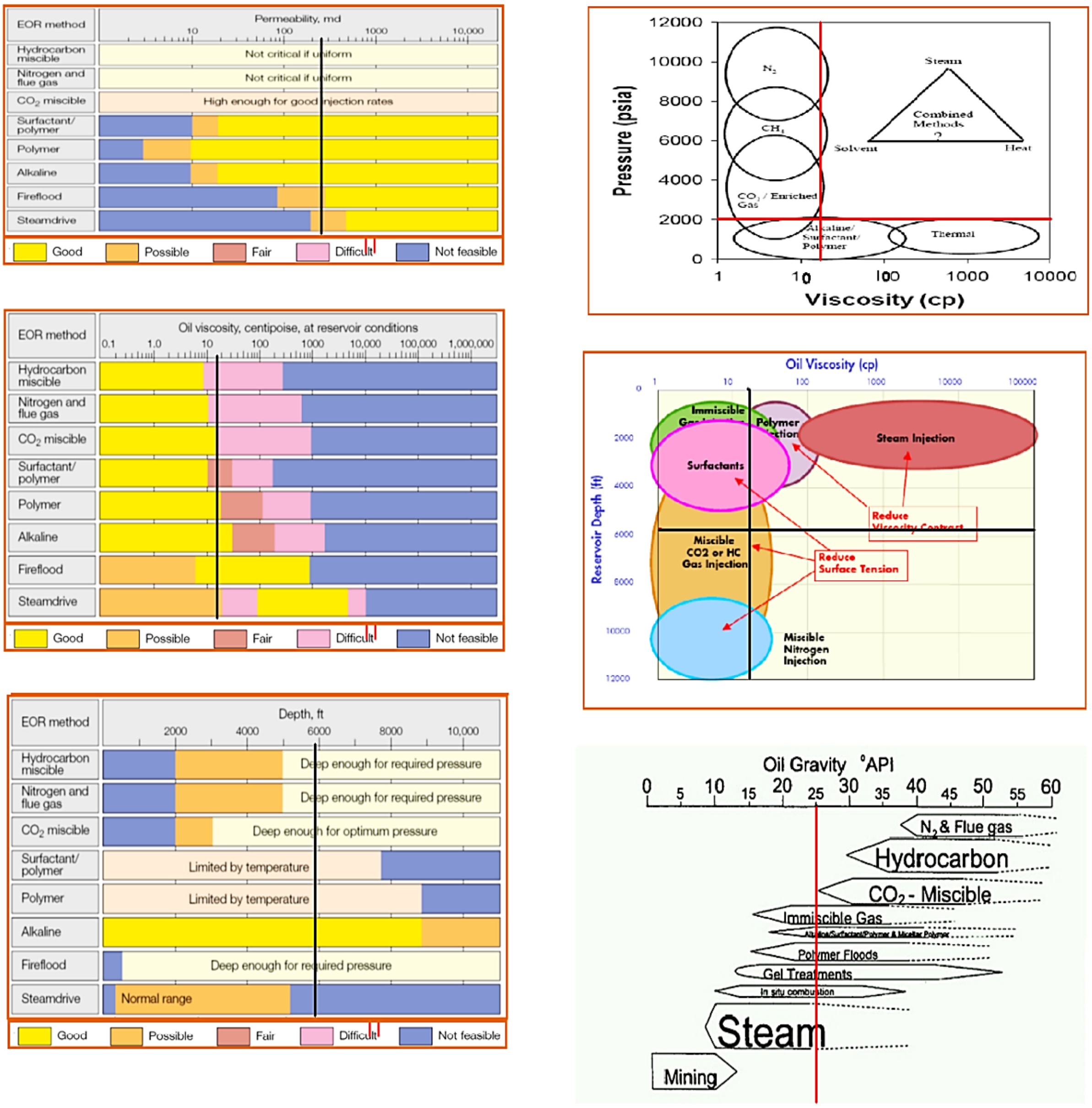

Fig. 4.13: Screening Using SPE Format for Neem East Aradeiba

***Suitable EOR methods are*:**

1-Chemical (Alkaline, Polymer)

2- Miscible CO_2

2- Screening using EORgui:

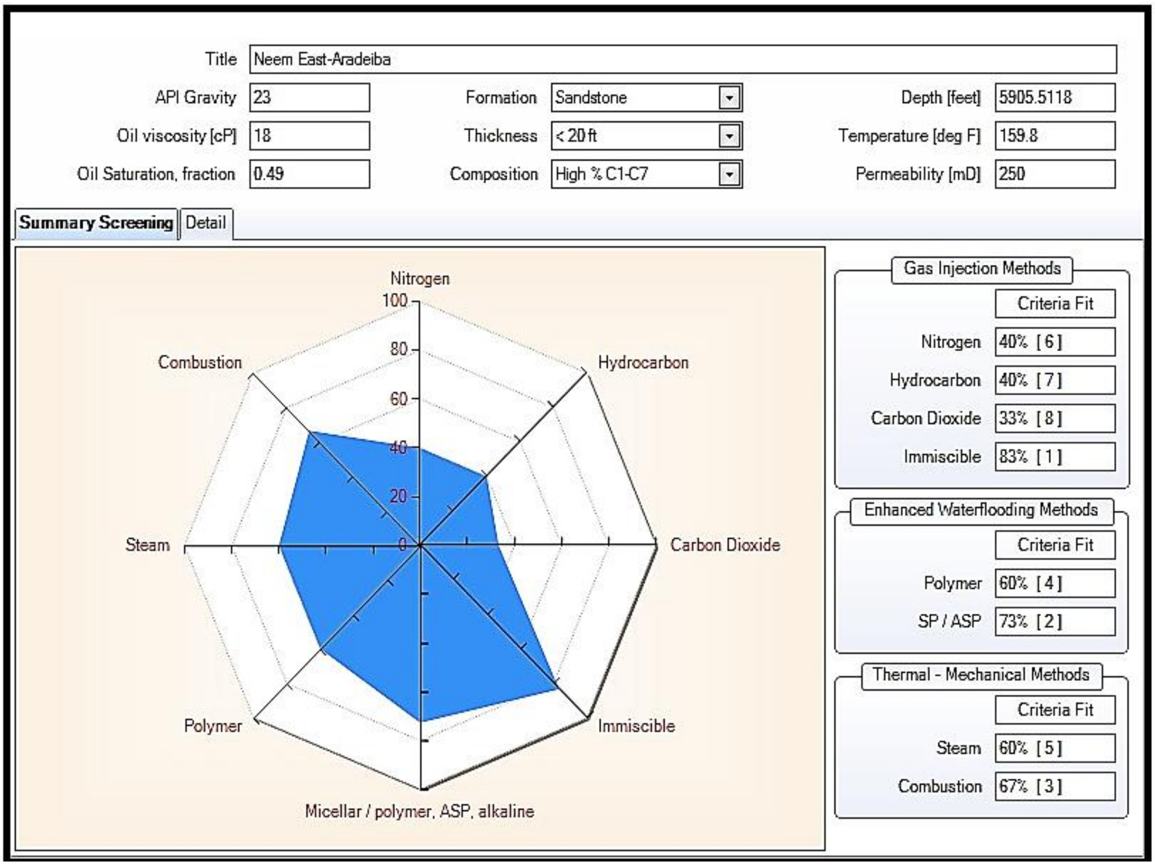

Fig. 4.14: Screening Using EORgui for Neem East Aradeiba

Suitable EOR methods are:

1-Immisible method has a higher percentage (83%)

2- Chemical methods group(Micellar/Polymer,ASP,Alkaline) in second order with (73%)

3- Combustion in third order with (67%)

4- Polymer and Steam in forth order with (60%)

3- Screening using EOR Analysis

Fig. 4.15: Screening Using EOR Analysis for Neem East- Aradeiba

Suitable EOR methods are: (Miscible HC, Immiscible N_2, Polymer, and Immiscible CO_2), (ASP, Miscible CO_2), (Combustion, Steam)

4.2.3. Neem East- Bantiu

1- Screening using SPE Format:

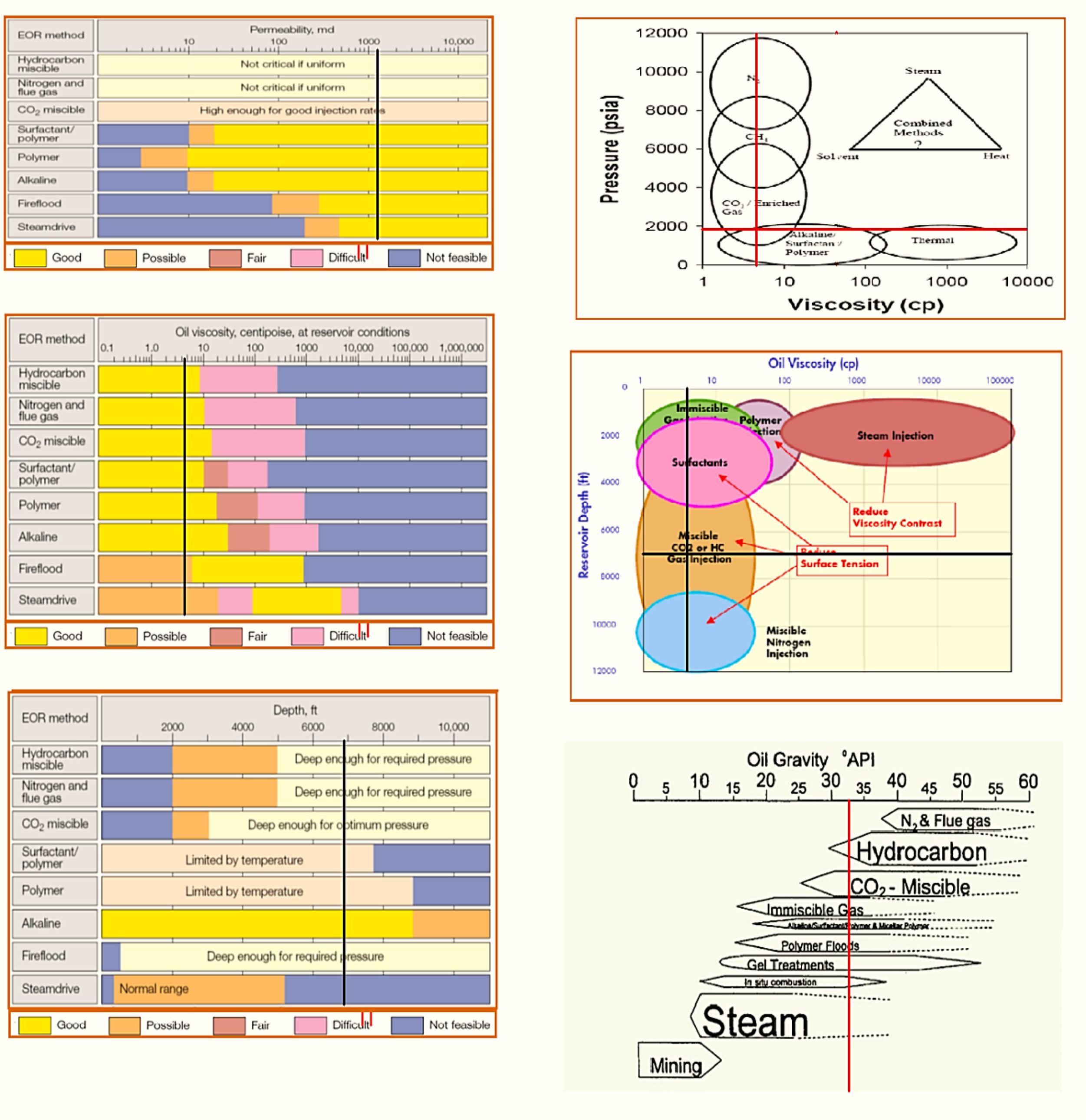

Fig. 4.16: Screening Using SPE Format for Neem East-Bentiu

***Suitable EOR methods are*:**

1-Miscible CO_2

2-Chemical (ASP, Alkaline)

3-Miscible HC

2- Screening Using EORgui:

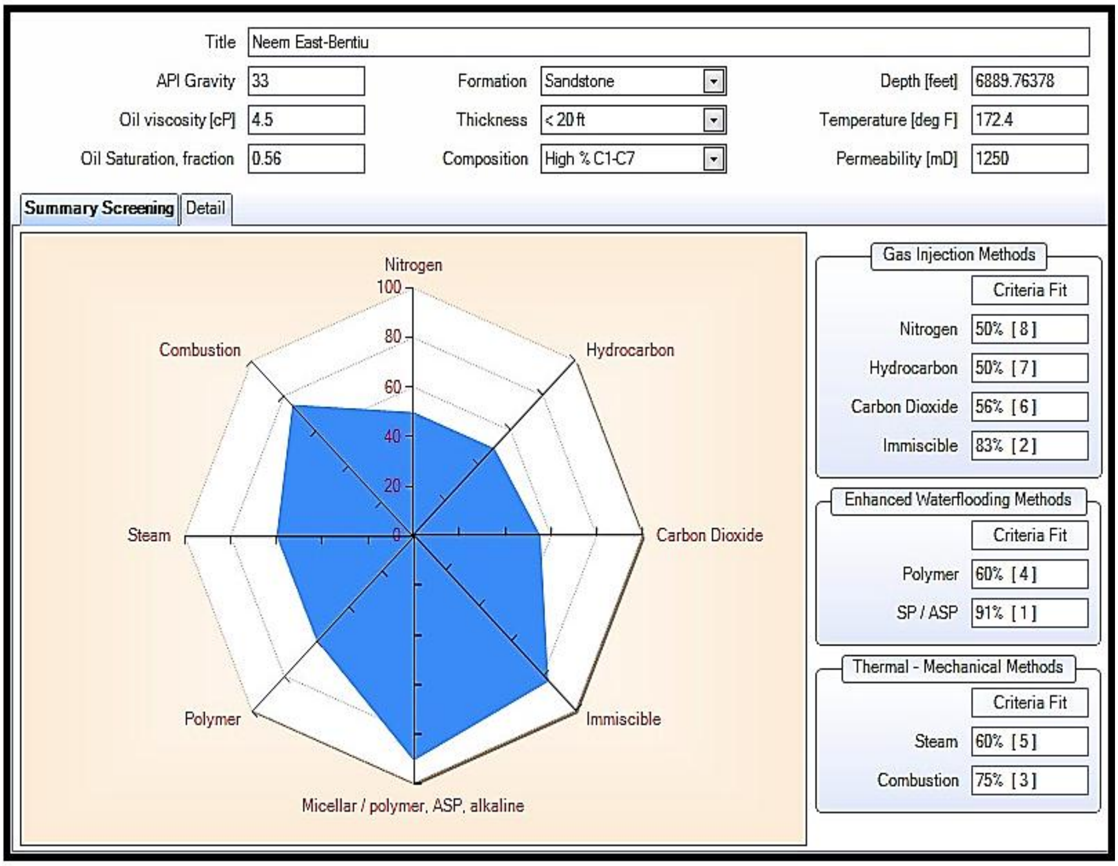

Fig. 4.17: Screening Using EORgui for Neem East- Bentiu

Suitable EOR methods are:

1- Chemical methods group(Micellar/Polymer,ASP,Alkaline) has a higher percentage with (91%)

2- Immisible method in second order with (83%)

3- Combustion in third order with (75%)

4- Steam and Polymer in forth order with (60%)

3- Screening Using EOR Analysis:

Fig. 4.18: Screening Using EOR Analysis for Neem East- Bentiu

Suitable EOR methods are: (Miscible HC, Immiscible N_2, and Polymer), Miscible CO_2, Combustion, and Immiscible CO_2

4.3. NEEM K

4.3.1. NEEM K- AG

1- Screening using SPE format:

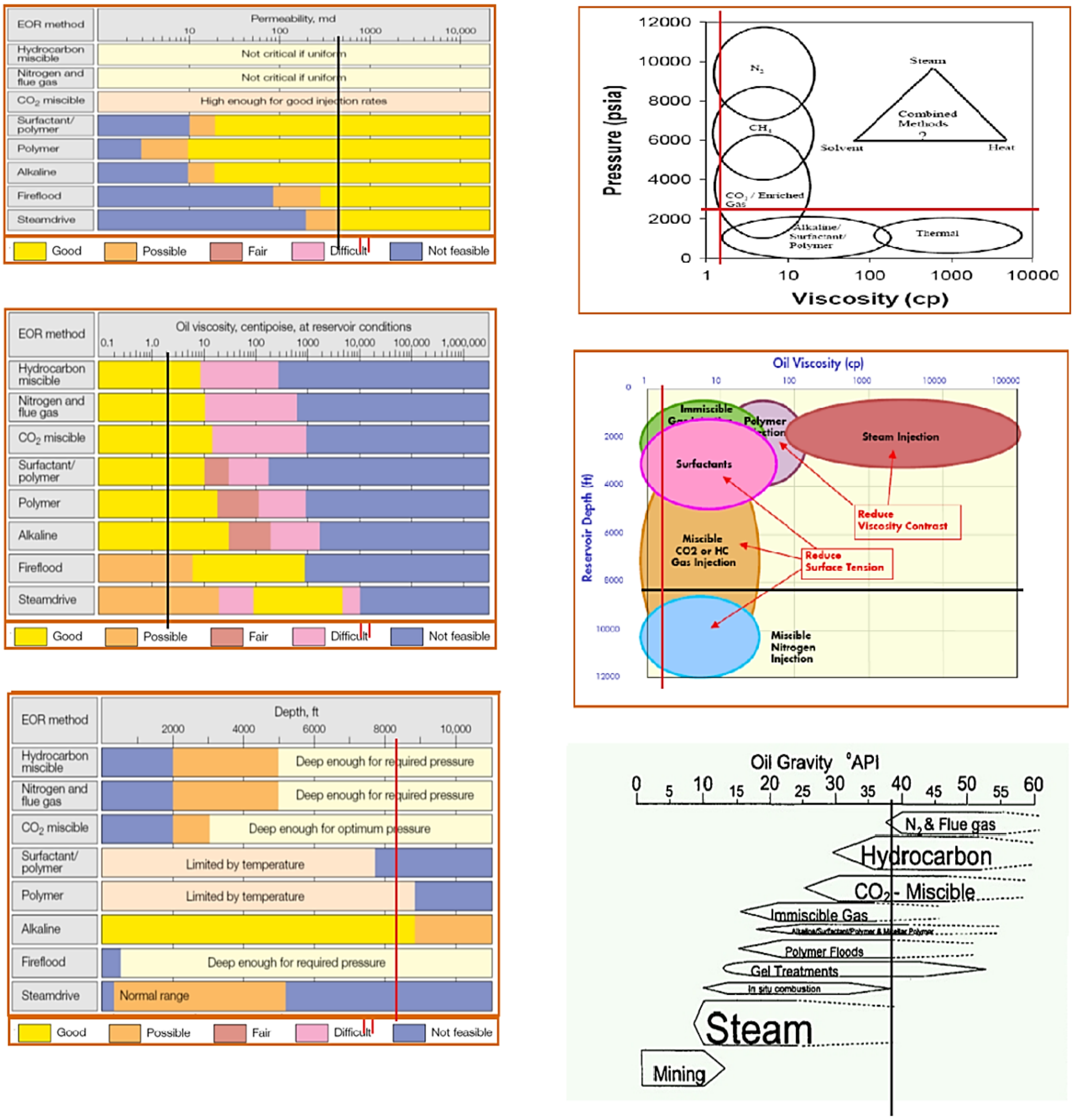

Fig. 4.19: Screening Using SPE Format for Neem K-Ag

***Suitable EOR methods are*:**

1-Miscible CO_2

2- Miscible HC

3-Alkaline

2- Screening using EORgui:

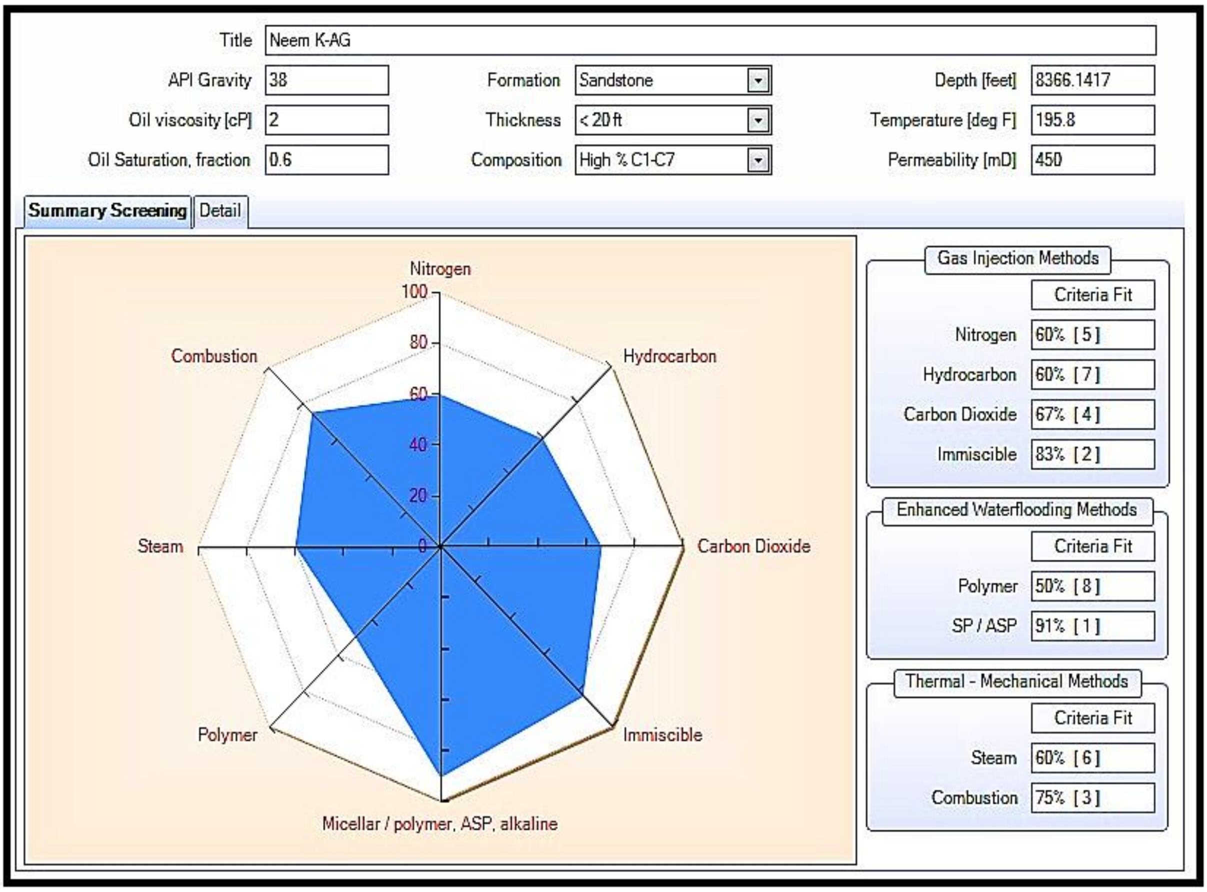

Fig. 4.20: Screening Using EORgui for Neem K-Ag

Suitable EOR methods are:

1- Chemical methods group(Micellar/Polymer,ASP,Alkaline) has a higher percentage with (91%)

2- Immisible method in second order with (83%)

3- Combustion in third order with (75%)

4- Carbon dioxide in forth order with (67%)

3- Screening using EOR analysis:

Fig. 4.21: Screening Using EOR Analysis for Neem K-Ag

Suitable EOR methods are: (Miscible HC, Immiscible N_2, and Polymer), (Miscible CO_2, Combustion), Immiscible CO_2

4.3.2. Neem K-Amal

1- Screening using SPE Format:

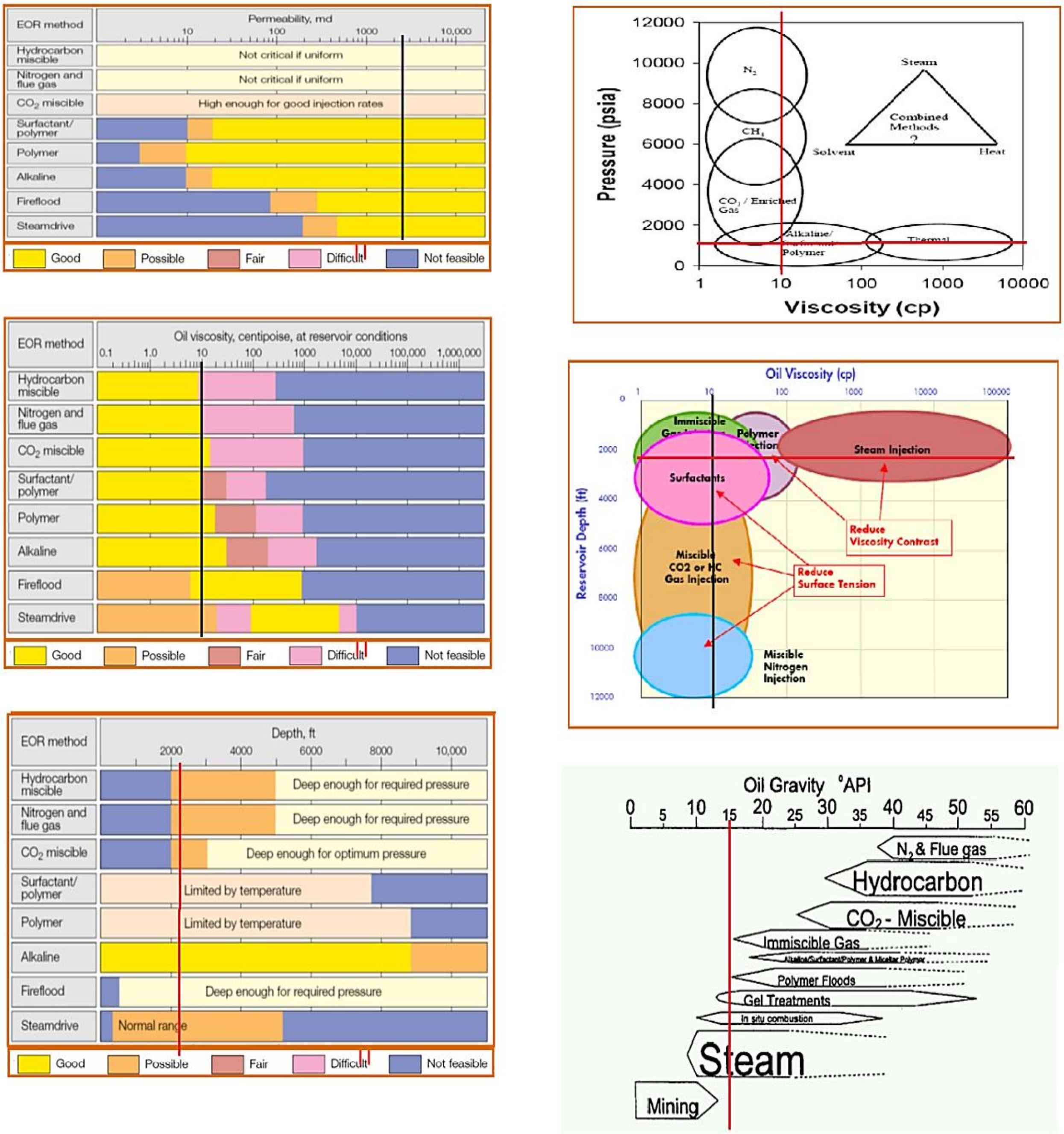

Fig. 4.22: Screening Using SPE Format for Neem K-Amal

Suitable EOR methods are **chemical** (Alkaline, Polymer)

2- Screening using EORgui:

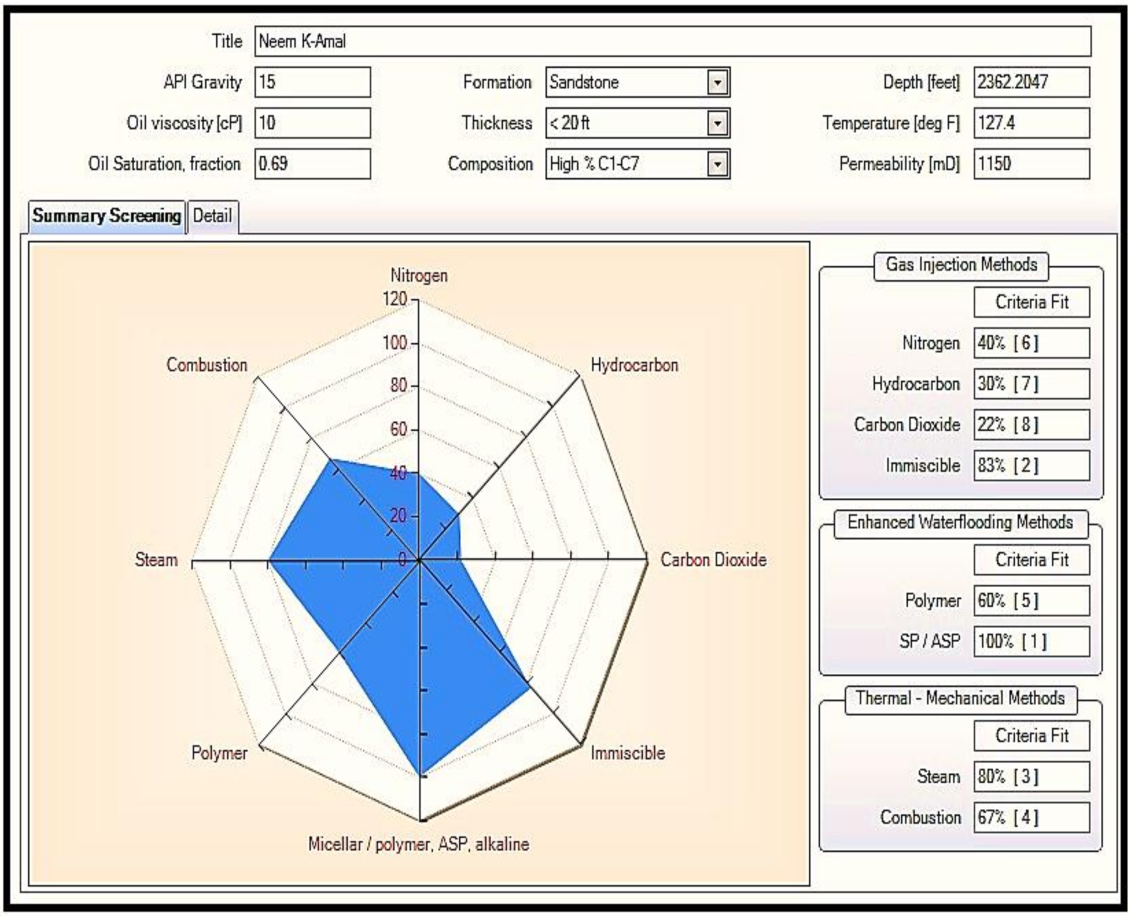

Fig. 4.23: Screening Using EORgui for Neem K-Amal

Suitable EOR methods are:

1- Chemical methods group(Micellar/Polymer,ASP,Alkaline) has a higher percentage with (100%)

2- Immisible method in second order with (83%)

3- Steam in third order with (80%)

4- Combustion in forth order with (67%)

3- Screening using EOR analysis:

Fig. 4.24: Screening Using EORAnalysis for Neem K-Amal

***Suitable EOR methods are*:** Polymer, Combustion, Immiscible CO_2, and Steam

4.4. Neem F:

4.4.1. Neem F-AG:

1- Screening using SPE format:

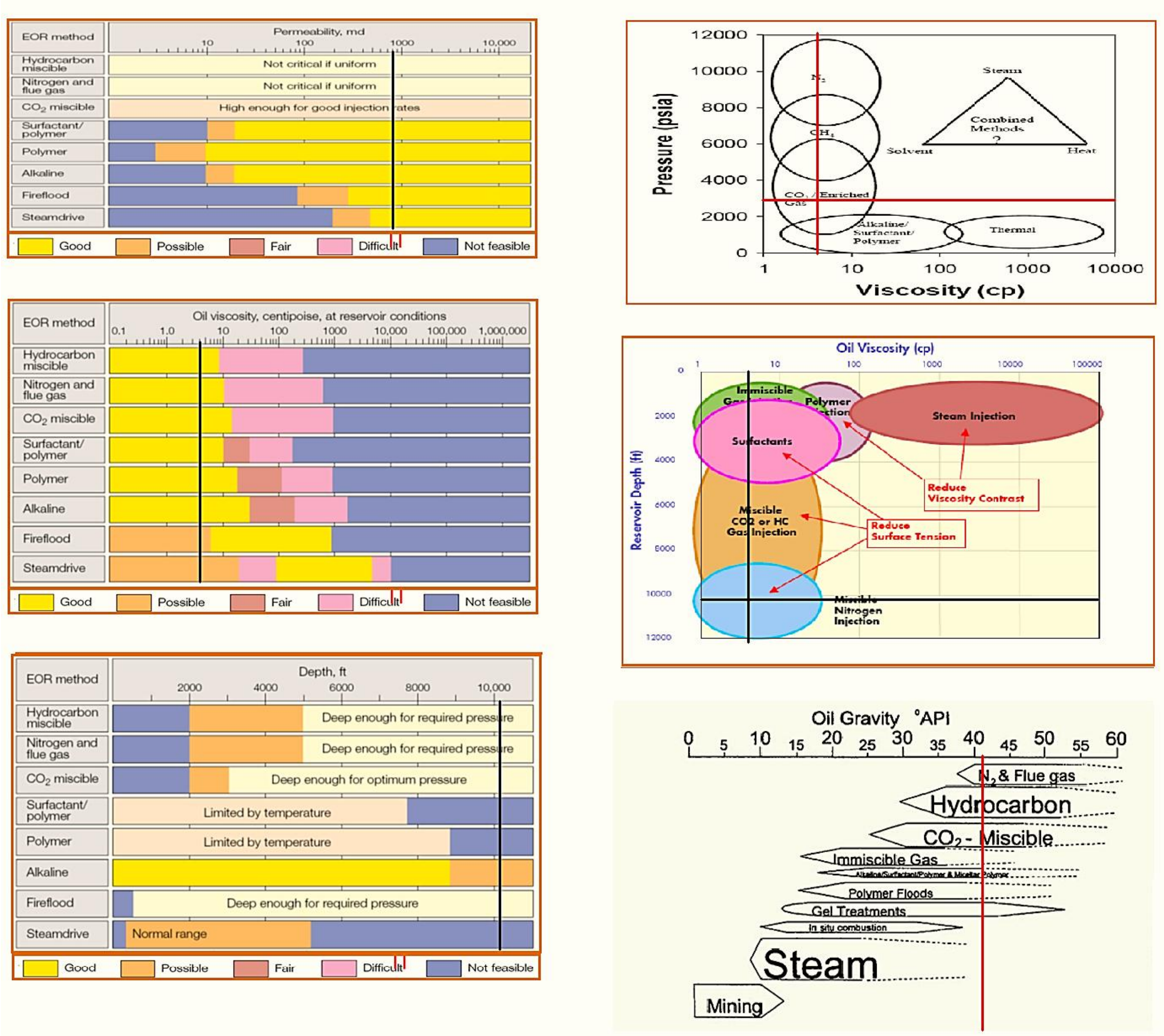

Fig. 4.25: Screening Using SPE Format for Neem F-Ag

Suitable EOR methods are:

1-Miscible CO_2

2-Miscible HC

3-Alkaline

2- Screening using EORgui format:

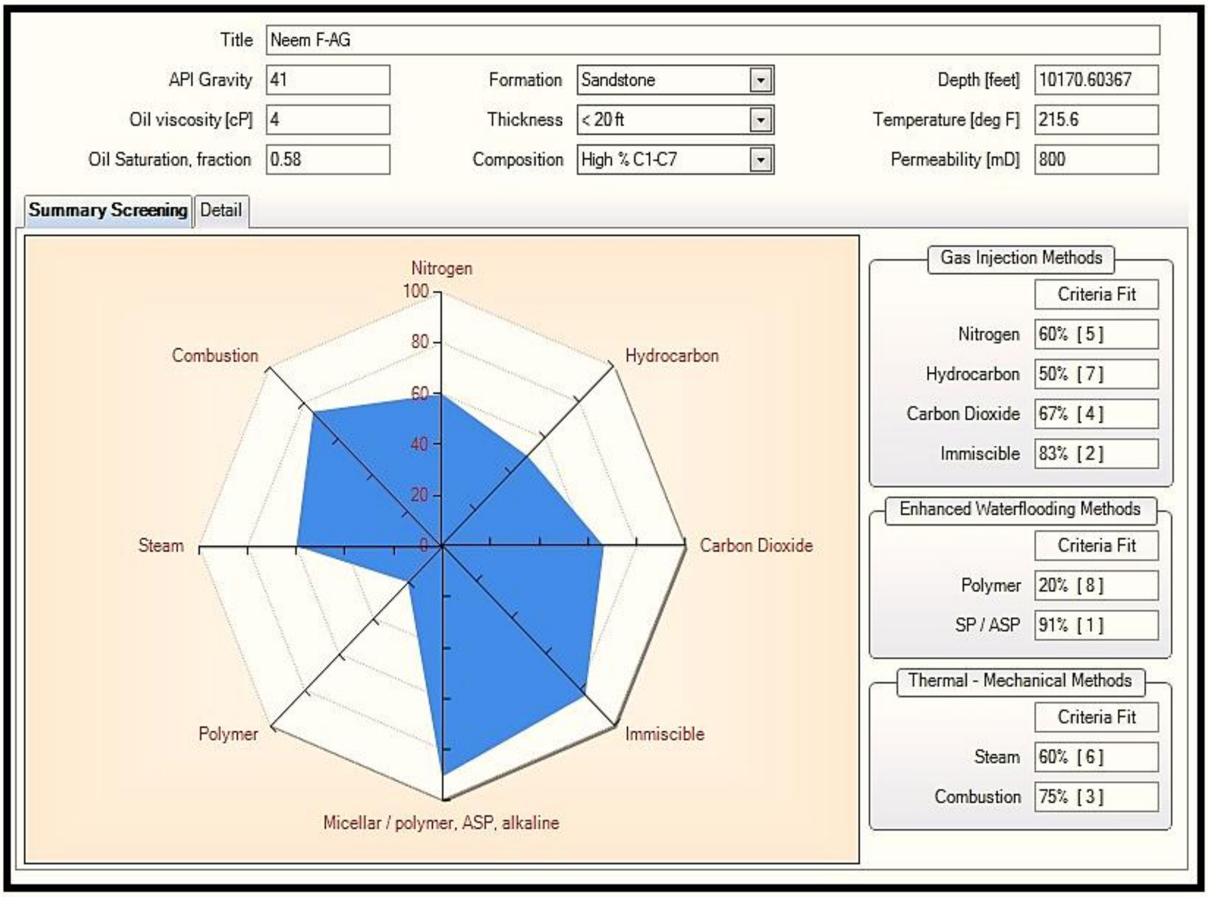

Fig. 4.26: Screening Using EORgui for Neem Main F-Ag

Suitable EOR methods:

1- Chemical methods group(Micellar/Polymer,ASP,Alkaline) has a higher percentage with (91%)

2- Immisible method in second order with (83%)

3- Combustion in third order with (75%)

4- Carbon dioxid in forth order with (60%)

3- Screening using EOR analysis:

Fig. 4.27: Screening Using EOR Analysis for Neem Main F-Ag

Suitable EOR methods are**:** **(**Miscible HC, Immiscible N_2), Miscible CO_2, Polymer, and Combustion

4.5. Neem North:

4.5.1. Neem North -AG

1- Screening using SPE format:

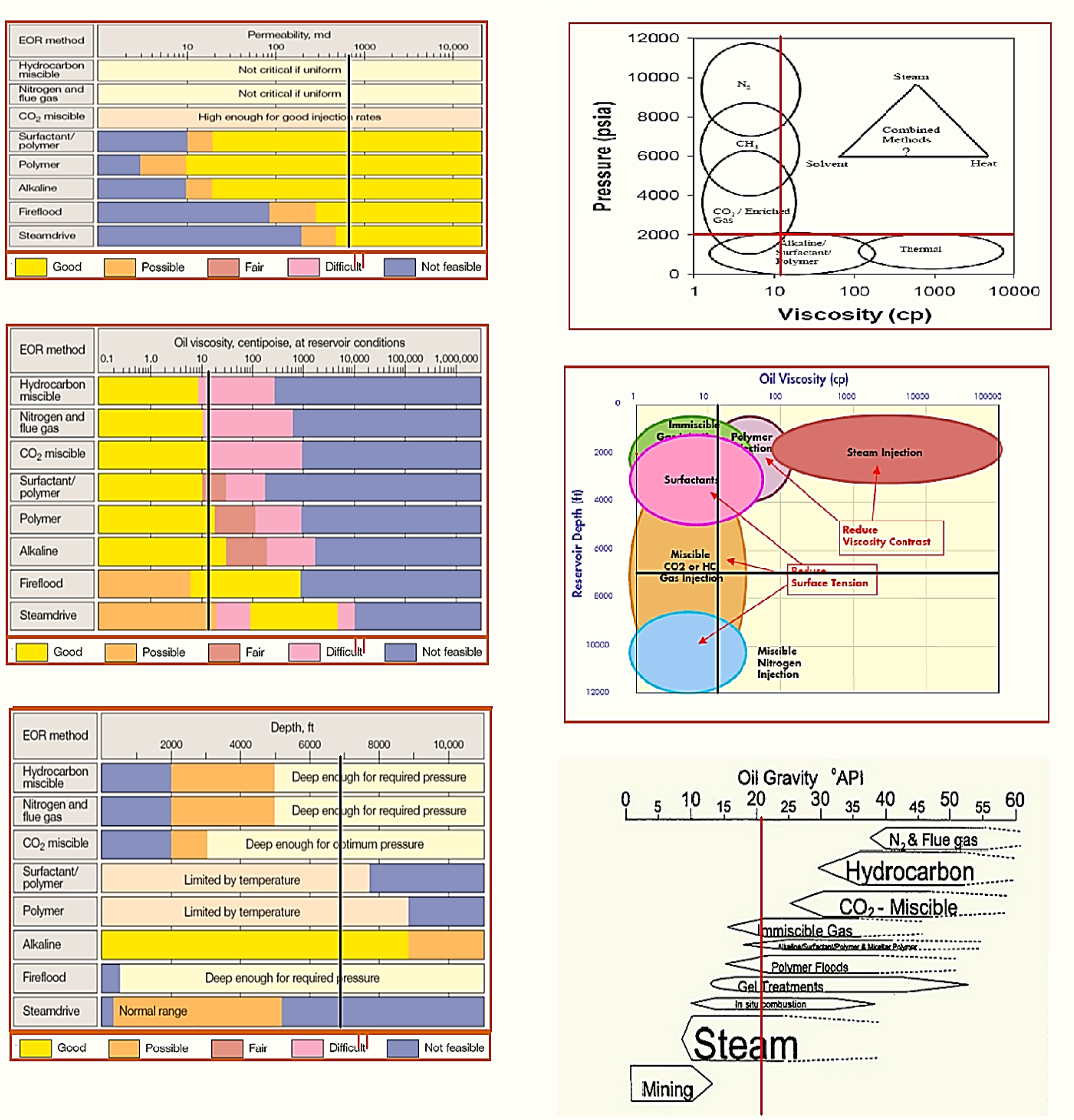

Fig. 4.28: Screening Using SPE Format for Neem North-Ag

Suitable EOR methods are:

1-Chemical (Alkaline, Polymer)

2-Miscible (CO_2, HC)

2- Screening using EORgui:

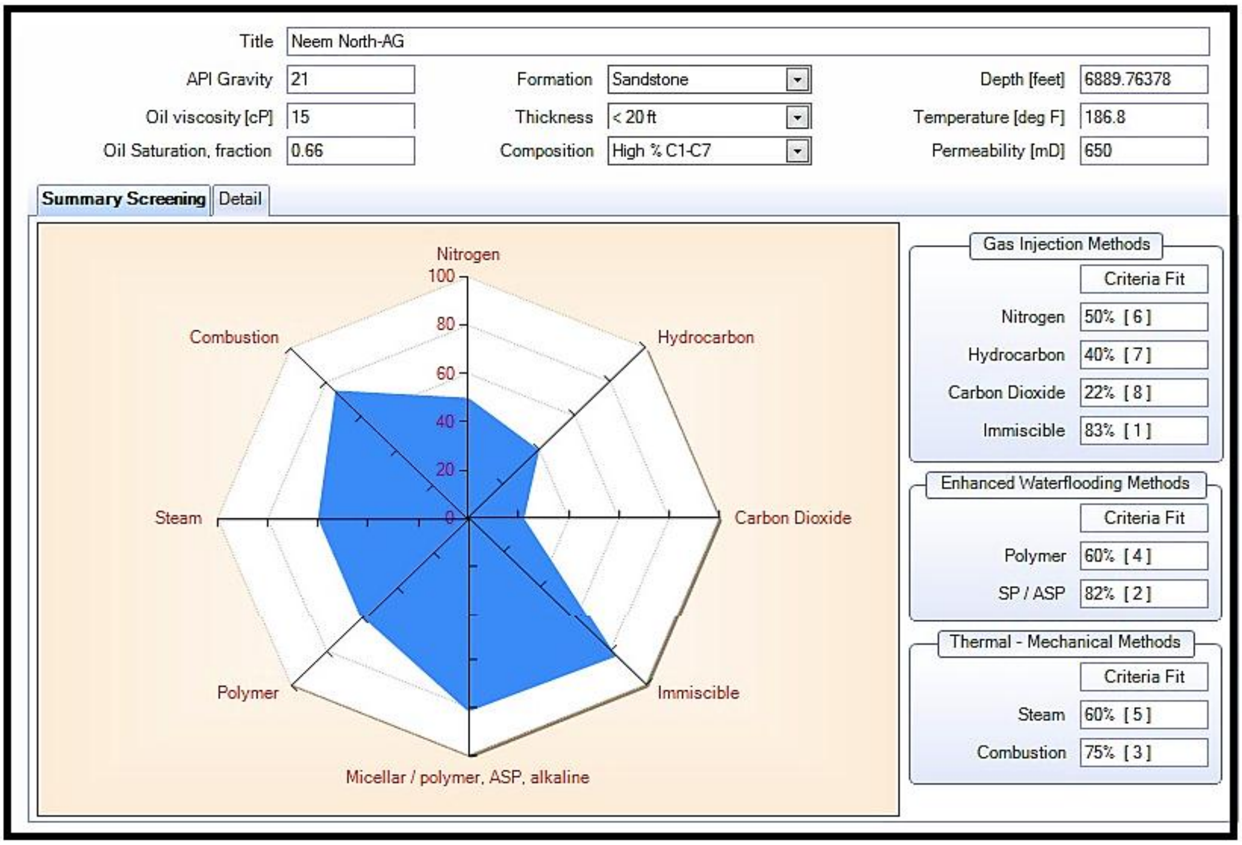

Fig. 4.29: Screening Using EORgui for Neem North-Ag

Suitable EOR methods are:

1-Immisible method has a higher percentage (83%)

2- Chemical methods group(Micellar/Polymer,ASP,Alkaline) in second order with (82%)

3- Combustion in third order with (75%)

4- Polymer and Steam in forth order with (60%)

3- Screening using EOR analysis:

Fig. 4.30: Screening Using EOR Analysis for Neem North-Ag

***Suitable EOR methods are*:** Polymer, (Immiscible CO_2, Immiscible N_2), (Miscible HC, ASP, Combustion)

4.5.2. Neem North Bentui

1- Screening using SPE format:

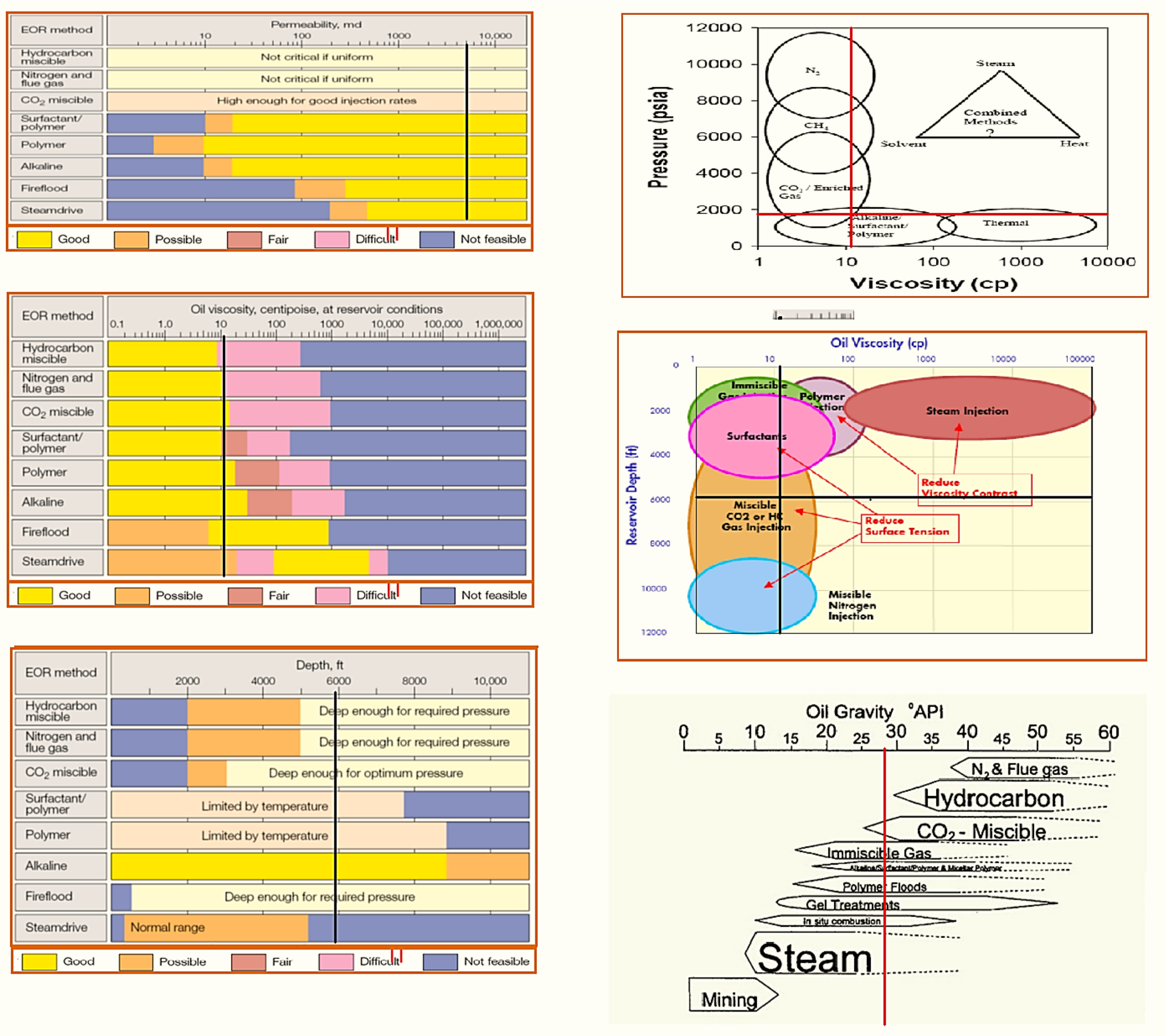

Fig 4.31: Screening Using SPE format for Neem North Bentui

***Suitable EOR methods are*:**

1- Alkaline

2- Polymer, Miscible CO_2

2- Screening using EORgui:

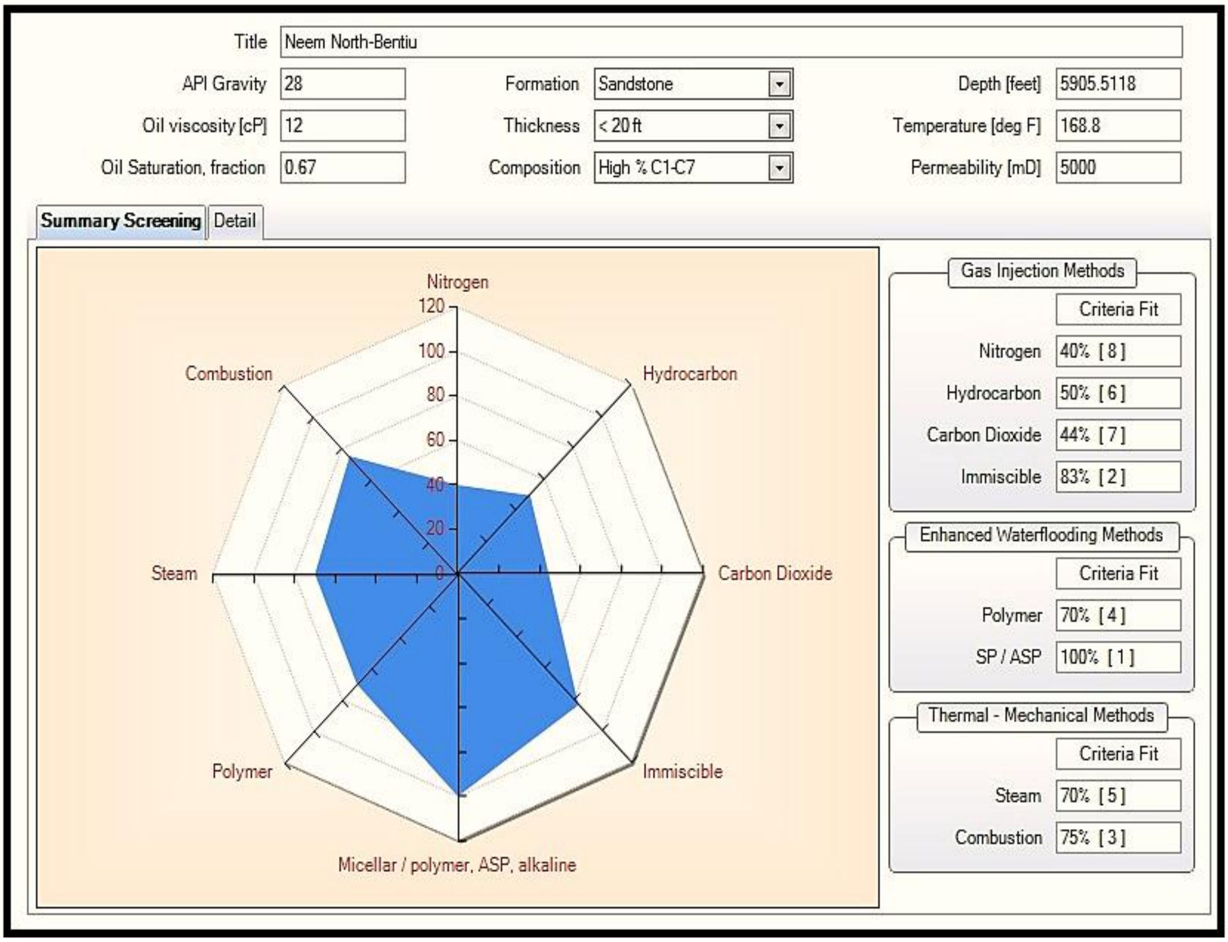

Fig. 4.32: Screening Using EORgui for Neem North-Bentui

Suitable EOR methods are:

1- Chemical methods group(Micellar/Polymer,ASP,Alkaline) has a higher percentage with (100%)

2- Immisible method in second order with (83%)

3- Combustion in third order with (75%)

4- Steam and Polymert in forth order with (67%).

3. Screening using EOR analysis:

Fig. 4.33: Screening Using EOR Analysis for Neem North-Bentui

Suitable EOR methods are (Miscible HC, Polymer), ASP, Combustion, Immiscible CO_2, Miscible CO_2

Table 4.2: Results Obtained From SPE Format, EORgui and EOR Analysis

Field Name	Formation	SPE Format	EORgui	EOR Analysis
Neem Main	**AG**	1-Miscible CO_2 2-Miscible HC 3-Polymer	1-Chemical (Micellar/polymer, ASP, Alkaline) 2-Immiscible 3-Combustion 4- Miscible CO_2	1-(Miscible HC, Immiscible N_2, Polymer) 2-Miscible CO_2 3-Immiscible CO_2
	Aradeiba	1-Miscible CO_2 2-Chemical (Alkaline, Polymer)	1-Immiscible 2-chemical (Micellar/polymer, ASP, Alkaline) 3-Combustion 4- Polymer & Steam	1-(Immiscible CO_2, Miscible HC, Polymer) 2-(Miscible CO_2, ASP)
	Bentiu	1-Miscible CO_2 2-Chemical (Alkaline, Polymer) 3-Miscible HC	1-chemical (Micellar/polymer, ASP, Alkaline) 2-Immiscible 3-Combustion 4-Polymer & Steam	1-(Miscible HC, Immiscible N_2, Polymer) 2-(Miscible CO_2 , Combustion) 3-Immiscible CO_2
Neem K	**AG**	1-Miscible CO_2 2- Miscible HC 3-Alkaline	1-Chemical (Micellar/polymer, ASP, Alkaline) 2-Immiscible 3-Combustion 4-Miscible CO_2	1-(Miscible HC, Immiscible N_2, Polymer) 2-(Miscible CO_2 , Combustion) 3-Immiscible CO_2
	Amal	Chemical (Alkaline, Polymer)	1-chemical (Micellar/polymer, ASP, Alkaline) 2-Immiscible 3-Steam 4-Combustion	1-Polymer 2-Combustion 3-Immiscible CO_2 4-Steam

Neem F	**AG**	1-Miscible CO_2 2-Miscible HC 3-Alkaline	1-chemical (Micellar/polymer, ASP, Alkaline) 2-Immiscible 3-Combustion 4-Miscible CO_2	1-(Miscible HC, Immiscible N_2) 2-Miscible CO_2 3-Polymer 4-Combustion
Neem East	**AG**	1-Miscible CO_2 2-Chemical (Alkaline, Polymer) 3-Miscible HC	1-chemical (Micellar/polymer, ASP, Alkaline) 2-Immiscible 3-Combustion 4-Steam	1-(Miscible HC, Immiscible N_2, Polymer, Immiscible CO_2) 2-(Combustion, Miscible CO_2)
	Aradeiba	1-Chemical (Alkaline, Polymer) 2- Miscible CO_2	1-Immiscible 2-chemical (Micellar/polymer, ASP, Alkaline), 3-Combustion 4-Polymer & Steam	1-(Miscible HC 2-Immiscible N_2, Polymer, Immiscible CO_2) 3-(ASP, Miscible CO_2) 4-(Combustion, Steam)
	Bentiu	1-Miscible CO_2 2-Chemical (ASP, Alkaline) 3-Miscible HC	1-chemical (Micellar/polymer, ASP, Alkaline) 2-Immiscible 3-Combustion 4-Steam & Polymer	1-(Miscible HC, Immiscible N_2, Polymer) 2-Miscible CO_2 3-Combustion 4-Immiscible CO_2
Neem North	**AG**	1-Chemical (Alkaline, Polymer) 2-Miscible (CO_2, HC)	1-Immiscible 2-chemical (Micellar/polymer, ASP, Alkaline) 3-Combustion, Polymer & Steam	1-Polymer 2-(Immiscible CO_2, Immiscible N_2) 3-(Miscible HC, ASP, Combustion)
	Bentiu	1-Alkaline 2-Polymer, Miscible CO_2	1-chemical (Micellar/polymer, ASP, Alkaline) 2-Immiscible 3-Combustion, Polymer & Steam	1-(Miscible HC, Polymer) 2-ASP 3-Combustion 4-Immiscible CO_2 5-Miscible CO_2

Discussion:

1. A steep dipping reservoir is preferred to permit some stabilization of displacing front in gas methods.
2. Generally, miscible methods give good results at low viscosity and high permeability.
3. Depth must be high enough to required pressure in case of miscible methods to form MMP.
4. For good CO_2 injection rate the permeability should be high enough.
5. Relatively homogenous formation is preferred in chemical methods.
6. Chemical methods except alkaline limited by temperature and depth (Degradation of surfactant and polymer at high temperature).
7. To apply thermal methods porosity must be high to minimize heat losses in the rock matrix.
8. Thermal methods used for heavy oil.
9. Steam injection limited to shallow reservoir to limit heat loss.
10. HC injection needs uniform reservoirs and low viscosi

Chapter 5

Conclusion and Recommendation

5.1. Conclusion:

The suitable EOR methods for Greater Neem Field based on the combination of results obtained by EORgui, EOR analysis and manual method by using SPE format curves shown at table 5.1.

Table 5.1. Suitable EOR Methods for Greater Neem

		EOR method
Neem Main	AG	Immiscible N_2, Miscible CO_2, Polymer
	Aradeiba	Immiscible CO_2, Miscible CO_2, Polymer
	Bentiu	Miscible CO_2, Immiscible (CO_2, N_2), Polymer
Neem K	AG	Miscible CO_2, Immiscible (CO_2, N_2), Polymer
	Amal	Polymer, Immiscible CO_2, Combustion & Steam
Neem F	AG	Miscible CO_2, Polymer, Immiscible N_2
Neem East	AG	Immiscible (CO_2, N_2), Polymer, Combustion
	Aradeiba	Immiscible (CO_2, N_2), Polymer, Miscible CO_2 & Combustion
	Bentiu	Immiscible (CO_2, N_2), Polymer, Combustion, Miscible CO_2
Neem North	AG	Polymer, Miscible CO_2, Immiscible (CO_2, N_2)
	Bentiu	Polymer, Immiscible CO_2 , Combustion,

From table (5.1) The suitable EOR methods for Greater Neem reservoirs are: polymer, CO_2 injection (Immiscible or miscible). CO_2 injection (Immiscible or miscible) are effective in term of cost because the availability of CO_2 in Neem field.

MMP calculated based on reservoir temperature from (Ahmed, T., 2007) as:

$$MMP = 15.988 \times T \times (0.7744206 + 0.0011038 \times MW_{C5+})$$

Where:

T : Temperature in ^oF

MW_{C5+} : Molecular weight of pentanes and heavier fractions of the oil

5.2. Recommendations:

1. Through the results and discussion obtained in this research, the following recommendations have been signed:
2. The following step after the technical screening is economical screening process to come up with the most cost effective method. This process should include; availability of injected fluid, cost of equipment, remaining oil and recovery factor by the method…etc.
3. It is recommended to conduct lab analysis for the selected EOR process.
4. The final step required is implementing pilot test to achieve high verification in order to apply the method in the whole field.
5. In case of the MMP is greater than formation break down pressure (P_{bd}), reservoir pressure should be supported by using water flooding to avoid formation fracture.
6. water flooding can be done by using one injection well or more and there are many factors must be studied carefully before selecting well/s location including: reservoir uniformity and pay continuity, reservoir geometry and depth, fluid properties and saturations, lithology and rock properties and reservoir driving mechanisms
7. The program can be improved by adding other functions to it for example: Draw curves related any method with its percentage, Alter screening criteria to update the program with most recent criteria because it is based on field application that does not stop.
8. It is recommended to permit more cooperation between university and petroleum companies to provide the actual field data needed.

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