EMIRATES INTERNATIONAL UNIVERSITY
FACULTY OF ENGINEERING AND INFORMATION TECHNOLOGY
OIL AND GAS ENGINEERING DEPARTMENT

SELECTION OF THE PROPER ENHANCE METHOD FOR HEAVY OIL FIELDS IN BLOCK 14 (MASILA)

A PROJECT SUBMITTED IN PARTIAL FULFILLMENT
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ABSTRACT

Increase of oil consumption and price of the crude oil in the world has caused an increasing attention to heavy oil and extra-heavy oil production. As far as production from most of these reservoirs is not easy by conventional technologies and requires using more complicated technologies, thus, more recognition of oil recovery methods from heavy oil reservoirs and finding details of each method, especially the correct understanding of effective oil production mechanisms, are important in selection of suitable and economical technologies. Developing technologies for enhanced oil recovery (EOR) from existing oil fields would supply the world's energy needs for several decades. This alternative represents a valuable option considering the current and future outlook of world energy supplies and reserves.

Basically, screening concept in petroleum engineering is selection of the most appropriate EOR method with respect to rock and fluid properties, and consideration of existing facilities and economic policies. This concept clearly makes savings in time and cost, and reduces the final decision-making risk. An appropriate technical and economical screening can provide the context for modeling the project. Screening criteria have been proposed for all enhanced oil recovery methods. Data from EOR projects around the world have been examined and the optimum reservoir/oil characteristics for successful projects have been noted. The oil gravity ranges of the oils of current EOR methods have been compiled and the results are presented graphically. The proposed screening criteria are based on both field results and oil recovery mechanisms. Steam flooding and gas injection are still the dominant EOR methods.

Taber method was available, so it was proposed to select EOR method to increase the recovery of heavy oil existed in Hemiar, West Hemiar and South Hemiar fields. Taber has recommended steam injection as the proper thermal EOR method. Then a form of steam injection has been selected to suit the field conditions based on the available data sources, so the Injection of High Temperature Fluids has arisen as a New effective enhance method. S. Hemiar-10, S. Hemiar-12 and S. Hemiar-19 wells were suggested to perform a pilot test of the enhance method to examine its effectiveness. Some expected encouraging scenarios were documented for the performance after the application of the Injection of High Temperature Fluids.

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First of all, we owe our most sincere gratitude to Allah the almighty and the most powerful for offering us such a strength, endurance, willingness, and capability to accomplish this project.

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TABLE OF CONTENTS

TABLE OF FIGURES

LIST OF TABLES

CHAPTER ONE

1. INTRODUCTION

1.1. Introduction:

The rapid progressing of the industry, investment and projects all over the world demands extra energy sources. Currently, the crude oil plays a major role of the energy resources. The economic consideration is an essential parameter in taking decision of investment in oil production which, in the beginning of oil industry, make it more favorable to look for conventional (light) crude oil reservoir. However, recent researches have shown that the light hydrocarbons reservoir is being declined and the exploration processes have covered most of the light hydrocarbons basins which are expected to be depleted at the end of twentieth-first century.

On the other hand, the increased demand of mankind for energy source has forced the technology to look for new sources or reevaluate the unconventional sources such as heavy oil and finding new economically practical recovery methods. Each recovery method is proper to special reservoir characteristics and fluid properties. The successful application of such methods has declared that heavy oil production, which has not been economical in the past, is great beneficial by new technologies.

In this project, we will study the reservoir characteristics and the properties of the unconventional fluid contained in Hemiar, West Hemiar and south Hemiar fields in Block-14 (**Masila**) in Sayun-Masila Basin, in order to evaluate the optimum economic recovery method. Also, the project will specify application of the method only to south Hemiar filed.

1.2. Aim and Objectives

1.2.1. Aim of The Project:

The project aims to produce the unconventional oil in Block-14 using the optimum recovery method (techniques) associated with the economic considerations, and introduces a proposal for the best exploitation of the product.

1.2.2. The Project Objectives:

1. Studying the reservoir characteristics and the nature of fluid contained with its properties and define the main production restrictions.
2. Provide scientific selection criteria of EOR as a rule for selection of EOR method.
3. Define the new EOR methods and choose the appropriate one to apply it for our case study field.

1.3. Problem Statement

heavy oil production has many restrictions which make it invaluable to be produced. Most heavy oil reservoir couldn't introduce the fluid contained into the production well and then to the surface which is the first difficulty that must be solved by designing and selecting the appropriate recovery method. The nature of the heavy oil with its components are relatively complex in comparison with the conventional(light) oil, which is the second challenge in heavy oil production that we should recover by providing a special processing plant able to produce valuable products as much as possible from the crude oil. Actually, the real side of the project that will dominates also the previous two difficulties in heavy oil production is the cost effectiveness of the project. The economic side along with the commerciality of the reserve will determine the feasibility of the project. These issues will be our concern of the study about Block-14 (**Masila**) in this graduation project.

1.4. Research question

How we can exploit the heavy oil reserve in Hemiar, West Hemiar and south Hemiar fields in Block-14 (**Masila**) in the appropriate way?

1.5. Scope of the project

The target of our project is Hemiar, West Hemiar and south Hemiar fields Block-14 (**Masila**)

1.6. Significance of the project

The project significance is to improve the reserve of Hemiar, West Hemiar and south Hemiar fields in Block-14 (**Masila**), basically by introducing the appropriate Enhance Oil Recovery method.

1.7. Sayun-Masila Basin

Sayun-Masila basin is one of the onshore basins in Yemen and its located in the east part of Yemen. Sayun-Masila basin as its name implies, is divisible into two sectors. The western or Sayun sector is more rift-like in its configuration a subsidence manner than the eastern or Masila sector, where deposits have intertongued with an open marine condition, inception extends into the early cretaceous. Sayun-Masila basin is considered one of the most important petroleum basins in Yemen which has several oil fields with a great oil and gas reserve.

1.7.1. Geological setting

The geology of Yemen is diverse extending from Precambrian basement rocks to recent sediments. It includes metamorphic rocks, that formed during Archean Proterozoic time (**Fig. 1-1**). Yemen composes part of the Arabian Shield within the larger framework of the Arabian-Nubian Shield. The Precambrian Arabian Shield is in the western part of the country and an extensive and thick cover of Phanerozoic sub horizontal sediments to the east.

The India/Madagascar and Africa separation worked out in late Jurassic caused extensional tectonic in Yemen. It is remarkable to notice that there is no volcanic activity related to this event. But remarkable feature is generation of graben/horst structures that shaped new topographies for sediments accumulation especially in east and southeast of Yemen. Seismic images, well data, and field observations from the Mesozoic basins of Yemen indicate that the rifting started during early Kimmeridgian in the western part, during middle Kimmeridgian–Lower Tithonian in the central part, and shortly later in the eastern parts of Yemen. Subsequent northeastward separation of the Indian plate is reflected in the easterly and southerly propagation of basin subsidence and sediment fills in Yemen during Tithonian-Valanginian times. The geology of Yemen has influenced by a complex tectonic history in the first event. It is evident from the various terranes with various origin (continental and island arc). During the second event of tectonostratigraphic renewed tectonostratigraphic activity without related volcanisms activity produced various depositional environments. Transgression and regression have been the significant controlling factor for sedimentary and patterns.

Age			Group West	Group East	formation West	formation East	Lithology	
Cenozoic	quater nary	Holocene/ Pleistocene	Quaternary Deposits				Sands, gravel, loam, loess, clay, conglomerates, sabkha deposits, marine shell and reef deposits	
			Quaternary Basalts				Basalts, tuffs, agglomerates, trachy-andesite, pumice	
	Tertiary	Oligocene/ Miocene	Jezan group	Shihr group	Baid	Irqah	Shales, limestones,	Gravelly conglomerates
						Fuwwah		Conglom & fossiliferous limestone
		Miocene/ Eocene	Tertiary Intrusive				Granites	
			Yemen Volcanics				Basalts, trachy-ndesites, rhyolites, pyroclastic rocks	
		Eocene		Hadramawt group		Habshiya	Limestones, marls, shales, gypsum	
						Rus	Gypsum, anhydrite, dolomitic limestones	
						Jiza	Shales, fine-grained limestones	
		Paleocene				Umm-Er-Radhuma	Massive marly & dolomitic limestones.	
			Tawilah group		Medj-Zir		Hard argillites, cross-bedded bioclastic sandstones	
Mesozoic	cretaceous				Twailah sandstone	Sharwayn	Yellow sandstones (Kawkaban member), dark red sandstones (Shibam member), and white clayey sandstones (Thula member)	Sales, limestone, sandstones
						Mukalla		Fine/medium sandstones
						Fartaq		Calcarenites
						Harshiyat		Sandstones with conglomerate intercalations
						Qishn		Calcarenites, limestone
	Jurassic		Amran limestone		Ahjur		Bituminous marly and sandy mudstones	
					Nayfa		Limestones and dolomites	
					Madbi	Sabatayn	Marls and limestones	Evaporates and shales
					Shuqra		Limestones	
	Lower Jurassic		Kohlan group		Kohlan Sandstone		Sandstones with conglomerate intercalations	
Pale ozo	Permian				Akbra Shale		Laminated mudstones, siltstones, shales	
	Cmbo-ordovician		Wajid group		Wajid Sandstone		Cross-bedded sandstones and coarse siltstones	
Pc.	Precambrian		Precambrian basement				Igneous rocks, metamorphic rocks, metasediments	

Figure 1-1 The Stratigraphy of Yemen

One of the wide exposures of sedimentary basins in Yemen was in Mesozoic and Cenozoic units. Sayun-Masila basin is one of the Mesozoic basins in Yemen. It is formed as a result of a rift-basin like linked with the Mesozoic break up of Gondwanaland, and due to the evolution of the Indian ocean during the Jurassic and cretaceous. Sayun-Masila basin has several different interpretations due to its complex structural morphology. Common agreement is that Sayun-Masila basin has a western area with NW-SE orientation parallel with Sabatayn basin. Another extension to the north is the Sir basin. To the east the Sayun-Masila basin is oriented more (east-west) and is broadly symmetric with intrabasin high known as Masila terrace. Regionally in Yemen and locally in Sayun-Masila basin, the

Jurassic and lower cretaceous strata have reflected the breakup of Gondwanaland and basin creation formed by rifting during the early cretaceous and late Jurassic period, also rifting of Aden and red sea throughout tertiary age. Rifting caused series of NW-SE and E-W trending major faults basin bounding the Sayun-Masila basin (**Fig. 1-2**). This basin has been affected structurally by many normal faults, also folds (anticline and syncline) were present.

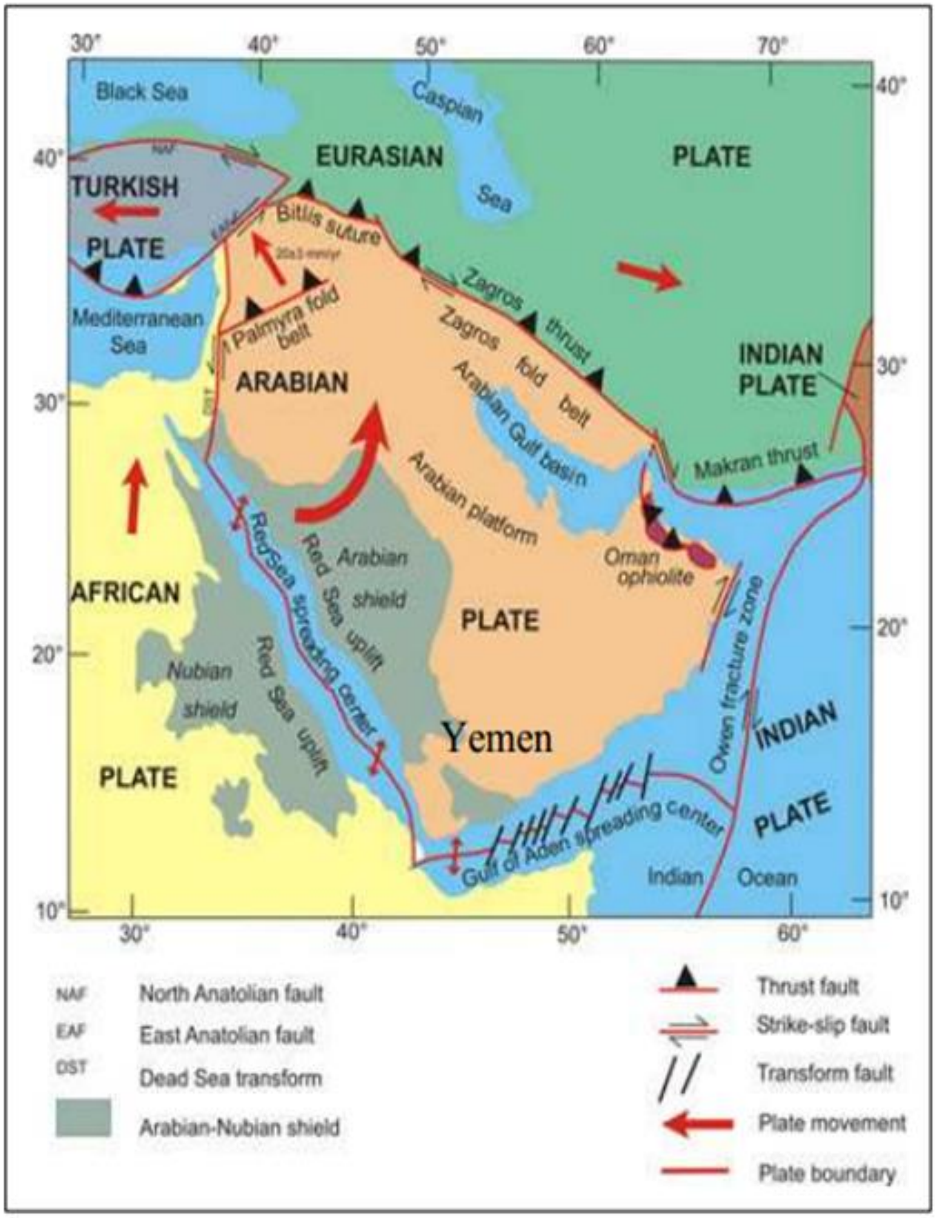

Figure 1-2 Tectonic setting of Arabian shield and Nubian shield

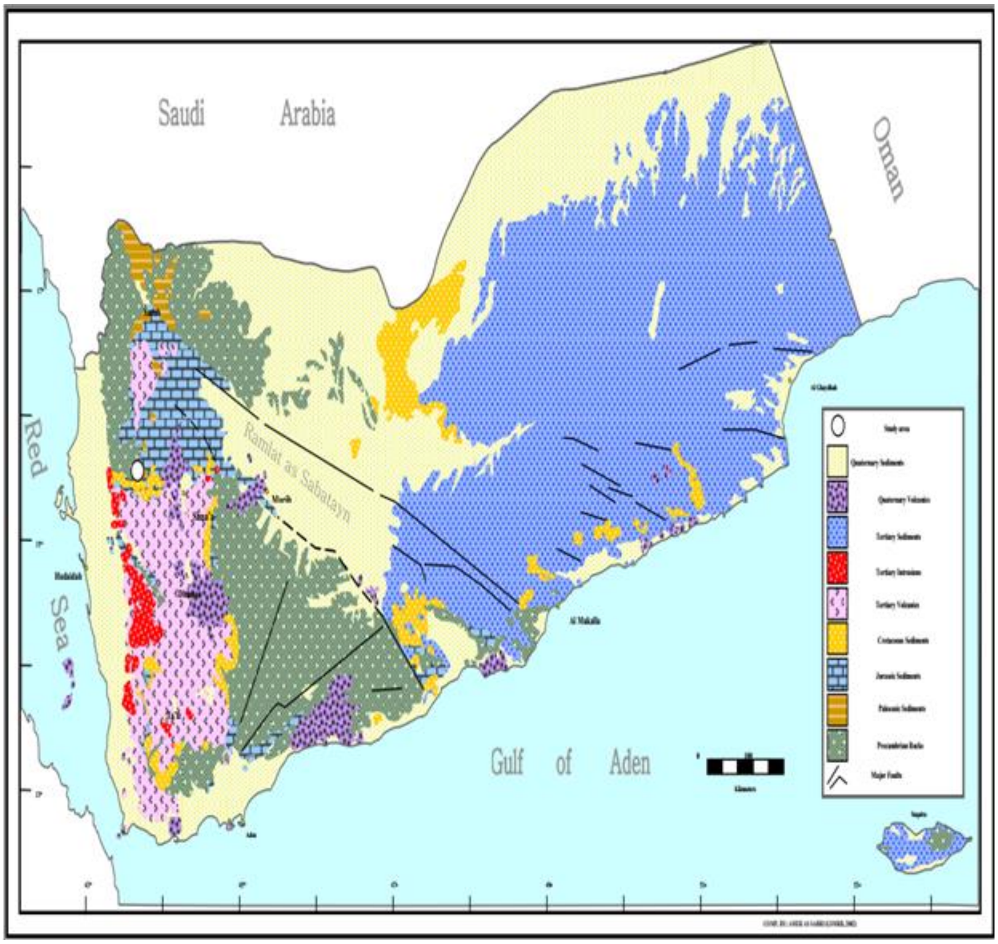

Figure 1-3 Simplified Geological map of Yemen

1.7.2. Stratigraphy of Sayun-Masila Basin

1. **The Basement**: Pre Cambrian rocks, consist of metamorphosed Pre-Cambrian sediments to lower Cambrian. Also, it contains granite and diorite rocks.
2. **Kuhlan Formation**: Jurassic sequence (middle-late). It is clastic with local basement topography. It includes fluviatile and arkosic red beds. It contains siltstone, sandstone, conglomerate and limestone.
3. **Shuqra Formation**: upper Jurassic age, it is neurotic limestone rich with fossiliferous marls. Also there exist lime-mudstone, wackestone and grain stone.

4. **Madbi Formation**: it is a syn rift sediments deposited in the late of the Jurassic age. The lithofacies reflects the marine environment. Madbi Formation consist of two members: -
    a. **The lower member**: is argillaceous limestone and sandstone and forms a good reservoir in some oil fields in Masila basin.
    b. **The upper member**: composed of laminated organic shale, mudstone and calcareous sandstone. This member is prolific source rock in Masila province.
5. **Naifa Formation**: this formation consists of silt and dolomitic limestone and lime-mudstone with wackestone
6. **SAAR Formation**: this formation has deposited during transgression in the early cretaceous time. It consists of limestone and dolomite with mudstone and sandstone intercalations.
7. **Qishn Formation**: Qishn formation ages between Barremian and Aptian.
    a. Qishn Formation Transition: Lower Aptian age. Shale, calcareous shales, and occasional sandstones constitute this interval. The unit directly overlies the Qishn Carbonate and forms the uppermost part of the hydrocarbon seal for the reservoir sandstones of the Qishn Clastics
    b. Qishn Formation Carbonate: Barremian to Lower Aptian age. Predominantly argillaceous limestones with interbedded calcareous shales. This unit is a regional hydrocarbon seal for the reservoir sandstones of the underlying Qishn Clastics.
    c. Upper Qishn Formation Clastics: Barremian age. The major hydrocarbon-bearing reservoir of **Masila block** with sandstone and claystone/siltstone interbeds. Thin coals, limestones and occasional anhydrite may be present. The sandstones are mainly well sorted, sub-angular to sub-rounded and generally poorly consolidated with scattered well-consolidated stringers. The loose grains indicate good porosity, and this unit is recognized to be the primary hydrocarbon objective. The upper Qishn sandstones of the Qishn Formation have been stratigraphically subdivided by petroleum geologists into three informal units: an upper S1, a middle S2, and a bottom S3. S1 refers to the first sandstone encountered below the Qishn Carbonates Member, followed by the S2 and S3. The S1 is subdivided into S1A,

S1B, and S1C, based on the presence or absence of non-reservoir (carbonate and shale) lithology's

d. **Lower Qishn Formation Clastics:** Barremian age, Finer grained than the Upper Qishn Clastics. Mainly siltstones and shales; interbedded sandstones are usually poorly sorted, and tight. There are some porous sands, though only locally does this unit constitute a reservoir. The Lower Qishn Formation is divided into two informal units: an upper LQ1 and lower LQ.

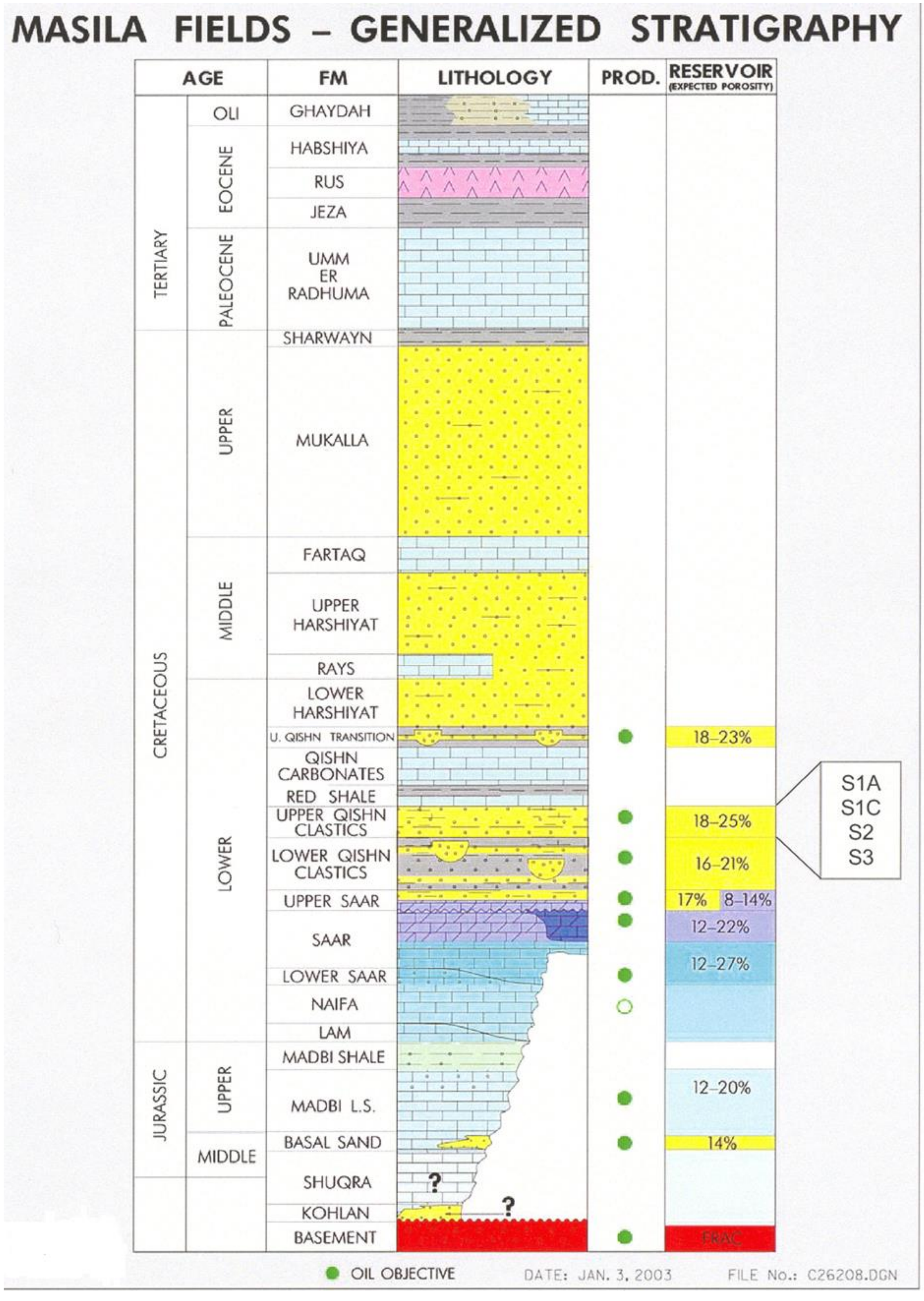

Figure 1-4 The Geological Column of Sayun-Masila Basin

1.8. Block 14 – Masila

The Masila Block is comprised of 20 producing Fields containing 56 pools within the Masila Block. The block was operated by Canadian Occidental Petroleum Yemen and then by Petro Masila.

It is located in the **Hadhramaut** region, in east-central Republic of Yemen.

Oil was first discovered on the Block in late1990 with Commerciality declared in late 1991. Commercial production commenced in 1993 and cumulative production from the Block is estimated to total 1073.50 MMbbls as of December 31, 2010. Production is forecast to continue to the end of the Production Sharing Agreement in December, 2011. probable and possible reserve estimates are in excess of one billion and a half barrels of recoverable oil.

Seismic acquisition in the Masila block has been difficult and expensive because of the remote location, rugged topography and rocky desert terrain. To date, four 3D seismic programs totaling 162 miles (414 km2), and 1,415 miles (2,264 km) of 2D data have been acquired.

The biggest production challenge in these fields is water handling. Much water is produced along with the oil, due to a combination of medium gravity (15-33 API) moderate viscosity oil, high reservoir permeability and a strong regional aquifer.

At end of December 1999, the daily production rate collectively for all fields was 210,000 STB/D, with 680,000 BWPD and 6.5 MMCF/D solution gas. Cumulative oil production is over 400 million STB

Produced oil and water volumes are processed at the Central Processing Facility (CPF) which has 250,000 b/d of oil processing capacity and 650,000 b/d of water processing capacity. Approximately 1,350,000 b/d of water is processed and disposed in-field through 10 hydro cyclones and 2 inclined free-water knock-outs. The CPF also generates diesel fuel (approximately 6,700 b/d) for usage on the Block. The processed oil is shipped through a 24-inch pipeline, 135 kilometers in length, to the Marine Terminal on the Gulf of Aden for tanker loading.

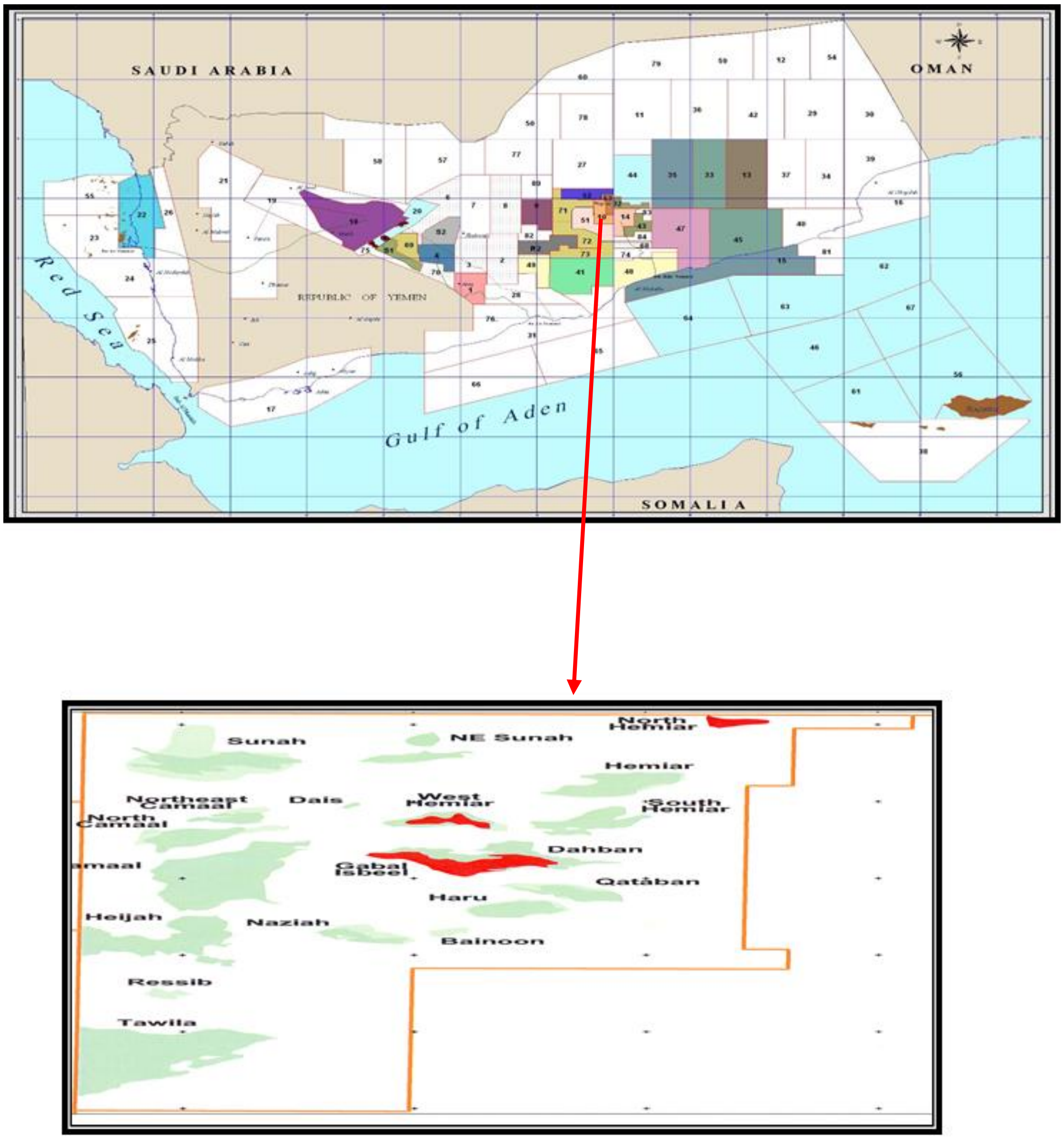

Figure 1-5 Concession Maps for Blocks in Yemen

1.9. Heavy oil Evolution

Oil, petroleum, Black gold and such other names or nick names are used by the public which indicate the crude oil found under the ground as a natural source of energy. Most people “specially those who aren’t involved in oil industry” think of oil as a single substance or homogenous product from similar environment or circumstances from the subsurface. Actually, crude oil is a subsurface product that is applied to so many variables in (origin, characteristics, properties, compounds, etc.) which make crude oil has more than one type. Simple classification of crude oil is:

Class A: These light oils can penetrate porous surfaces and are clear or almost clear. They have a strong odor and flammability. Since they are thin and highly fluid, they mix well with other liquids. Most high-quality light crude oils and refined petroleum products fit into this class.

Class B: These non-sticky oils are thicker than those in Class A and have a waxy feel. They adhere better to porous surfaces when in warm temperatures such as Paraffin.

Class C: With density near that of water, these oils do not usually penetrate porous surfaces, but they do sink in water. They are sticky, similar to tar, and usually black or brown. Medium and heavy crude oils including residual fuel oils fit into this class.

Class D: These oils are not fluid, so they do not penetrate porous surfaces and do not flow freely. They can become more fluid when heated and are usually made up of heavy crude oils or those with high paraffin content.

Another general classification of crude oil is:

1. Conventional oil: this type is the most common and most type consumed. It has more interest and great space in oil industry investments due to its ease of production, processing and transportation. Also, it has a good characteristic which plays a major role in its refinery products. Another important aspect is the economic side that has a high possibility of profit and a wide space to invest.
2. Un conventional oil: the second oil types which dominates the highest volume of reserve which exceeds the conventional oil. For some reasons, un conventional oil hasn't been developed as much as conventional oil. The little interest relates directly to the opposite variations it has against the conventional one such as production, processing, etc.

For better understanding of the previous types, classification parameters are required. The main parameter is distinguished here, but it is more detailed in chapter 2.

The weight is considered the main parameter that distinguishes between conventional and unconventional crude oil. This parameter provides them with better terms which are **Light oil** for (conventional oil) and **Heavy oil** for (unconventional oil). The American Petroleum Institute has represented this parameter as **API GRAVITY**.

Heavy oil (unconventional oil) performs 70% of the world reserve which exceeds 6 trillion barrels (**Fig. 1-6**), while 30% only is the share of light oil reserve. Despite the big difference between them in volume, the high market value and high production and development interest since the beginning of oil exploration were made for light oil. The availability of simple and technical methods of light oil production and processing was the main reason along with economic feasibility. In the other hand, heavy oil was much more difficult to recover from subsurface reservoir for many reasons specially its high weight (density). Another reason is that; heavy oil cannot be recovered in its normal state by current methods of typical production used for light oil. Also, the high flow resistance that affects the nature of flow. Furthermore, the refining of unconventional oil requires great specificity and produces lower proportions of high value products such as gasoline, kerosene and diesel.

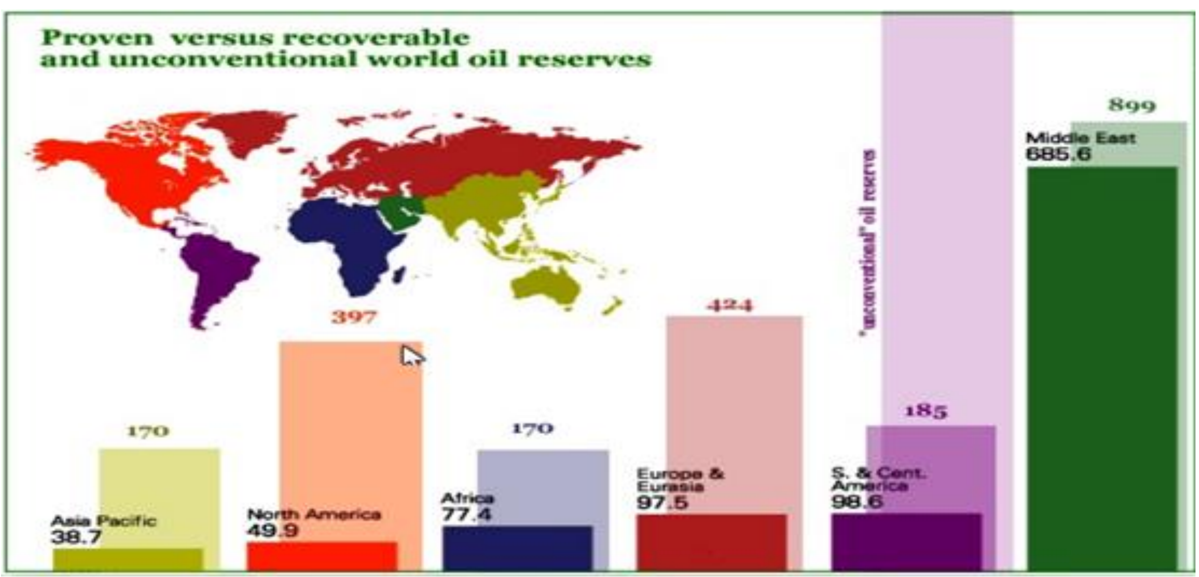

Figure 1-6 An Illustration of The Regional Distribution of Proven and Recoverable Reserves of Unconventional Oils.

Through the past two decades, the global economic growth increased on average by 3.73% resulted in increasing oil demand by 1.95%. According to a short analyzes, a minimum 0.5% increase in oil production is needed to boost the world economy by 1%. Based on this prediction, the world oil demand will increase from 28 to 38 MMBD in period between 1980-2030. Until recent years, heavy oil was rejected as an energy for the inconvenience and costs associated with its production, but today with the continuous increase in world energy demand by the economic development and dramatic population growth recorded in recent decades has caused the decline of availability of petroleum resources characterized by more efficient production and refining. The analysis of production capacity of oilfield has shown that the conventional oil reserves reached its maximum volume around the early 1960s. Since then, the reserves have followed a constant decline, so they will present a small portion of the total petroleum resources in the near future (**Fig. 1-7**). Currently, the new discoveries of conventional oil are scares and to meet the future increase in energy demand. The result is a wide gap worldwide energy supply global economic impact.

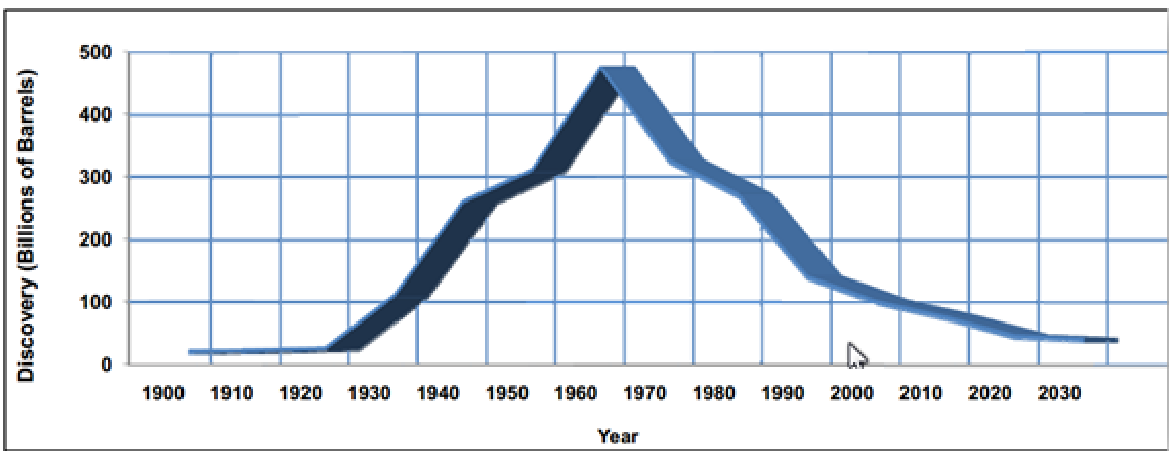

Figure 1-7 History and forecast of world discoveries of conventional oil.

At the same time, another issue is being raised which is the concern of environment that marks a new age in the energy industry as an attempt to move toward an alternative clean and renewable energy. Such energy sources have a considerable impact our dependence on hydrocarbon resources, nevertheless, this shift will not reverse the demand for oil. Along with these factors, heavy oil has attracted oil companies and encourage them to apply many investments in heavy oil production as an alternative energy resource.

Many countries in the world have heavy oil reservoirs. Canada and Venezuela in particular contain some of the largest heavy oil and bitumen resources in the world. The size of heavy oil deposits is enormous and it is likely to be one of the main future energy sources in coming years. Recently, the total volume of unconventional oil is to be similar to the total conventional oil reserves in the middle east. South America retains 61% of the recoverable heavy oil due to contributions from the Orinoco river in Venezuela. The International Energy Agency estimated that heavy oil and bitumen production from Canada and Venezuela will be 6MMBD in 2030. The low recovery factors relate to the necessity for technical developments in the recovery of the resource. About one-third of the global heavy oil reserve (specially in carbonates rocks) occur in the middle east. Owing to its vast light oil reserves, documentation in the public domain on middle eastern heavy oil accumulation is not complete but enough information is available to assemble a reasonable picture of the geological setting, reservoir, oil quality issues and the state of cold and EOR production in the region.

In addition, there is considerable focus and renewed efforts on adapting recovery techniques to the production of heavy oil. It is not surprising that there has been a growing interest and research in the potential to expand EOR methods to heavy oil reservoirs such as carbon dioxide injection, water flooding, polymer flooding, chemical treatment, and gas lift. In fact, during the past five decades, a variety of EOR methods have been developed and applied to mature and mostly depleted oil reservoirs. These methods improve the efficiency of oil recovery compared with primary (pressure depletion) and secondary (water flooding) oil methods. Overall, EOR development has expanded successfully into heavy oil recovery, and some projects offer additional benefits such as sites for disposing (sequestering) carbon dioxide at modest costs or even full-cycle profit.

CHAPTER TWO

2. LITERATURE REVIEW

2.1. Introduction

Heavy oil of all kinds plays an important role in the current and future energy markets, and the importance of this role within the global energy landscape, which is changing according to the fluctuation of oil and gas prices, which is linked in one way or another to the growing growth of the consumer market in various regions of the world.

Heavy oil is a type of petroleum that is viscous and contains a higher level of sulfur than conventional petroleum and occurs in similar locations where petroleum is obtained. The nature of heavy oil is a problem for recovery operations and for refining—the viscosity of the oil may be too high, thereby rendering recovery expense and/or the presence of sulfur content may be high which increases the expense of refining the oil.

Studies on heavy oil also confirm that the instability of energy markets causes investors to fear the risks of developing heavy oil fields, but the growth of medium and long-term demand will gradually increase the importance of heavy oil, especially in light of the decline in production rates of conventional oil due to the maturity of fields and diminished natural production, in addition to the remarkable economic growth in the Middle East.

2.2. Sources and reserves of heavy oil:

Heavy oil is typically found in supergiant, shallow deposits. As a result of this, a few nations hold most of the world's resources and production of heavy oil and bitumen. Saniere et al (2004) reported that 87% of the heavy oil is located in Western Canada, Venezuela and Former Soviet Union states in Eastern Europe. The U.S Society for Geological Survey estimates that the geological source of heavy oil around the world is about 3.4 trillion barrels and distribution in 127 basins worldwide.

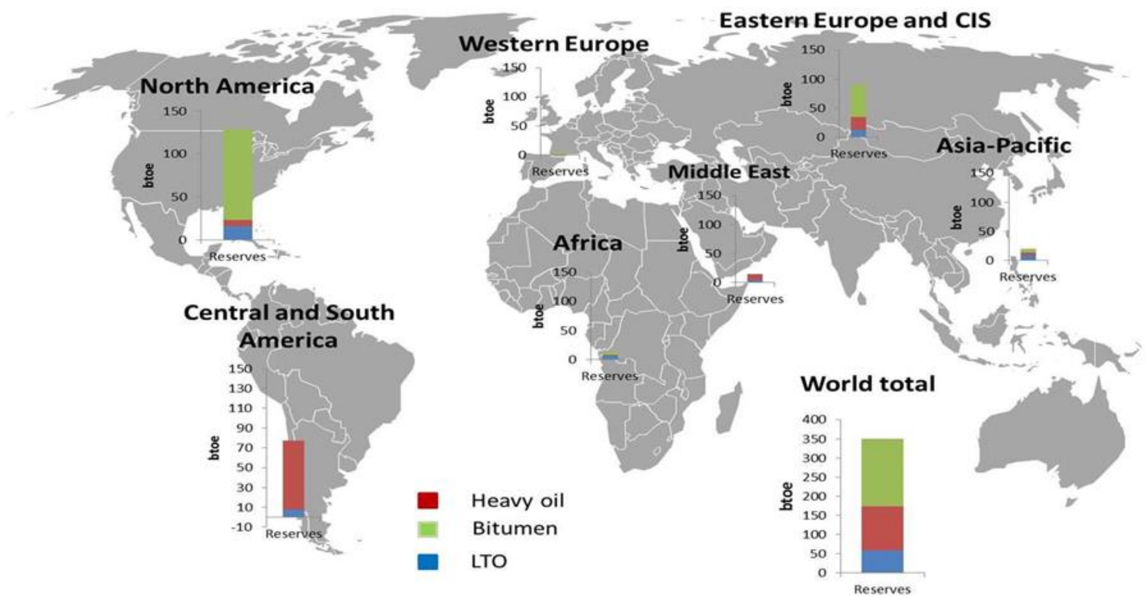

Figure 2-1 Geography of unconventional oil technically recoverable reserves (Source: IEA,2017).

Table 2-1 Geographical distribution of heavy oils and bitumen reserves (Adapted From U.S Geological Survey, 2003).

Region	Heavy oil		Bitumen	
	Recovery Factor	Reserve (BBO)[1]	Recovery Factor	Reserve (BBO)
North America	0.19	35.3	0.32	530.9
South America	0.13	265.7	0.09	0.1
Africa	0.18	7.2	0.10	43.0
Europe	0.15	4.9	0.14	0.2
Middle East	0.12	78.2	0.10	0.0
Asia	0.14	29.6	0.16	42.8
Russia	0.13	13.4	0.13	33.7
Total	-	434,3	-	650,7

2.2.1. Estimates of Heavy Oil Sources in Arab Countries:

The US Society for Geological Survey estimates the distribution of heavy oil sources in 15 basins within Middle East and North Africa:

Table 2-2 Heavy Oil Sources in Arab Countries

Location/ Basin	Billion barrels
Arab Basin	842
Zagros Basin	115
Gulf of Suez	24.7
Diyar Bakir (Syria - Turkey)	13.5
Sudan	0.71
Northern Egypt	0.667
Timimoun (Algeria)	0.55
Atlas (Tunisia, Algeria, Morocco)	0.45
Mukulla (Yemen)	0.38
Pelagian (Tunisia - Libya)	0.226
Gazi Antep (Syria-Turkey)	0.221
Sirte Basin (Libya)	0.17
Tarfaya (Morocco)	0.05
Nile Delta	0.02
Dead Sea (Jordan)	0.0002
Total	998.64

2.2.2. Sources of heavy oil in Yemen

1. Sabatayn Basin (Marib- Shabwa Alhujr)
2. Sayun-Masila Basin (Sayun)

Table 2-3 Sources of heavy oil in Yemen

Block	Field	Viscosity CP	API gravity	Date of exploration
Block (14) Masila	Hemiar	41.6	18	1991
	South Hemiar	41.6	17.5	1991
	West Hemiar	39.1	17.4	1994
Block (9) Malik	Alruwaydat	214.3	14.2	2004
Block (S1) Damis	Harmal	195.33	22	2004

According to Petroleum Exploration & Production Authority in Yemen the reserve of Hemiar, South Hemiar and West Hemiar fields are about 170.44 million barrels of oil and the proved reserve 37.86 million barrels. Also, reserve of Alruwaydat field about 44.6 and the proved reserve 8.92. In addition, Harmal field the reserve about 531.5 and the proved reserve 64.09, as in

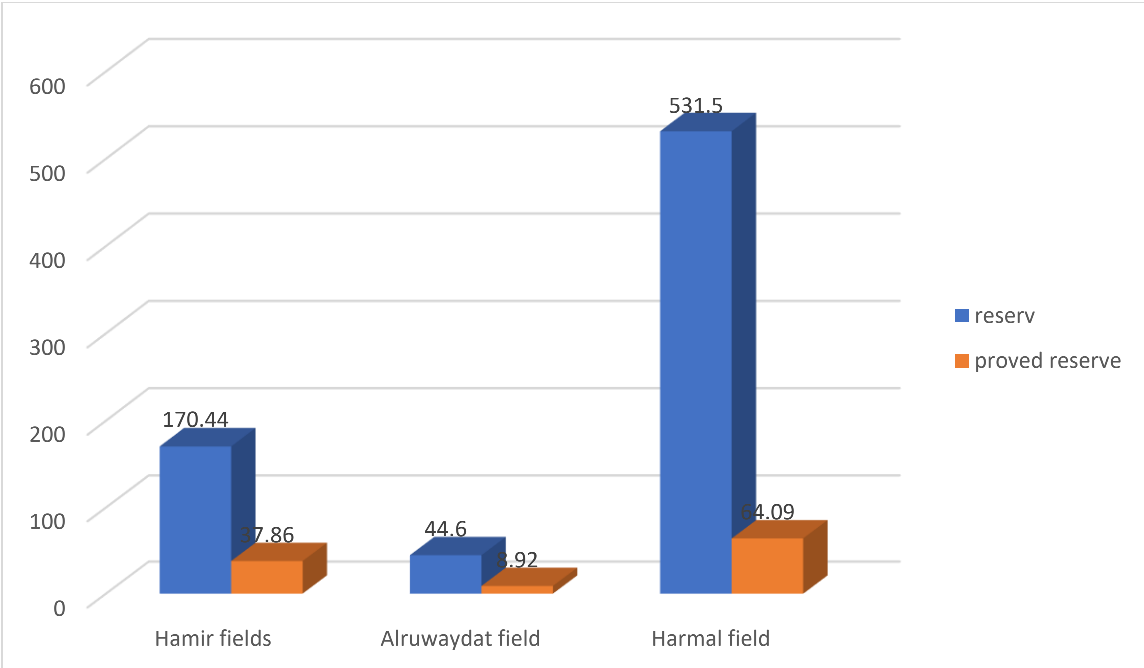

Figure 2-2 Heavy oil reserves in Yemen

2.3. Definition of Heavy Oil

The name heavy oil can often be misleading as it has also been used in reference to:

1) Fuel oil that contains residuum left over from distillation, i.e. Residual fuel oil,
2) Coal tar creosote, or
3) Viscous crude oil. For the purposes of this text the term is used to mean viscous crude oil.

Heavy crude oil is described as dead oil (gas-free oil) when its density is below 21°API and its viscosity is between 100 and 10,000 centipoise (cP) at original reservoir temperature. Dead oil was chosen because it is easily handled and because standardized analytical techniques were available to measure the properties.

Heavy oil is an oil resource that is characterized by high viscosities (i.e. resistance to flow) and high densities compared to conventional oil. Most heavy oil reservoirs originated as conventional oil that formed in deep formations but migrated to the surface region, where they were degraded by bacteria and by weathering and where the lightest hydrocarbons escaped.

Heavy oil accounts for more than double the resources of conventional oil in the world, and heavy oil offers the potential to satisfy current and future oil demand. Not surprisingly, heavy oil has become an important theme in the petroleum industry, with an increasing number of operators getting involved or expanding their plans in this market around the world.

Heavy oil is a type of crude oil characterized by an asphaltic, dense, viscous nature (similar to molasses), and its asphaltene (very large molecules incorporating roughly 90 percent of the sulfur and metals in the oil) content. It also contains impurities such as waxes and carbon residue. Hence, heavy oil requires additional processing (upgrading) to become a suitable refinery feedstock for a normal refinery.

Although variously defined, the upper limit for heavy oil is 22° API gravity with a viscosity of 100 cp (centipoise).

2.4. Petroleum, Heavy Oil, And Tar Sand Bitumen

2.4.1. Petroleum

The definitions of petroleum (crude oil) and heavy oil have been varied, unsystematic, diverse, and often archaic. In fact, there has been a tendency to define petroleum and heavy oil on the basis of a single property. While this may be suitable for a general understanding, it is by no means accurate and does not reflect the true nature of petroleum or heavy oil or the characterization of the material. Unfortunately, this form of identification or differentiation is a product of many years of growth and its long-established use, however general or inadequate it may be, is altered with difficulty, and a new term, however precise, is adopted only slowly.

Petroleum is a naturally occurring mixture of hydrocarbons, generally in a liquid state, which may also include compounds of sulfur, nitrogen, and oxygen metals and other elements. Thus, petroleum and its equivalent term crude oil cover a wide assortment of materials consisting of mixtures of hydrocarbons and other compounds containing variable amounts of sulfur, nitrogen, and oxygen, which may vary widely in specific gravity, API gravity, and the amount of residuum. Metal-containing constituents, notably those compounds that contain vanadium and nickel, usually occur in the more viscous crude oils in amounts up to several thousand parts per million and can have serious consequences during processing of these feedstocks. Because petroleum is a mixture of widely varying constituents and proportions, its physical properties also vary widely and the color varies from near colorless to black.

Because there is a wide variation in the properties of crude petroleum and heavy oil , the proportions in which the different constituents occur vary with the origin and the relative amounts of the source materials that form the initial proto petroleum as well as the maturation conditions. Thus, some crude oils have higher proportions of the lower boiling components, and others (such as heavy oil and bitumen) have higher proportions of higher boiling components (asphaltic components and residuum).

Petroleum is typically recovered from the reservoir by the application of primary and secondary recovery techniques whereas heavy oil, although under certain circumstances recoverable by primary and secondary recovery techniques, typically requires the application of tertiary recovery techniques for more efficient recovery of the oil.

2.4.2. Heavy Oil

Heavy oil is a type of petroleum that is different from conventional petroleum insofar as it is much more difficult to recover from the subsurface reservoir. These materials have a much higher viscosity (and lower API gravity) than conventional petroleum, and recovery of these petroleum types usually requires thermal stimulation of the reservoir.

However, heavy oil is more difficult to recover from the subsurface reservoir than conventional or light oil. A very general definition of heavy oils has been, and remains based on, the API gravity or viscosity, and the definition is quite arbitrary although there have been attempts to rationalize the definition based upon viscosity, API gravity, and density.

The term heavy oil has also been arbitrarily (but incorrectly) used to describe both the heavy oils that require thermal stimulation of recovery from the reservoir and the bitumen in bituminous sand (tar sand) formations from which the heavy bituminous material is recovered by a mining operation.

Table 2-4 Heavy Oil Properties

	API gravity	**Viscosity CP**
Heavy oil	< 21	< 1,000

2.4.3. Extra Heavy Oil

Extra heavy oil is a nondescript term (related to viscosity) of little scientific meaning. While this type of oil may resemble tar sand bitumen and does not flow easily, it is generally recognized as having mobility in the reservoir compared to tar sand bitumen, which is typically incapable of mobility (free flow) under reservoir conditions.

Table 2-5 Extra Heavy Oil Properties

	API gravity	Viscosity CP
Extra heavy oil	< 10	1,000 - 10,000

2.4.4. Tar Sand Bitumen

For reference and in order to clarify the terms petroleum (crude oil) and heavy oil, the term bitumen includes a wide variety of reddish brown to black materials of semisolid, viscous to brittle character that can exist in nature with no mineral impurity or with mineral matter contents that exceed 50% by weight.

Crude bitumen is an extremely viscous hydro carbonaceous material (it is not pure hydrocarbon in nature) that will not flow in the deposit unless heated or diluted with low boiling liquid hydrocarbons, such as naphtha. It is frequently found filling pores and crevices in sandstone, limestone, or argillaceous sediments, in which case the organic and associated mineral matrix is known as rock asphalt.

The expression tar sand is commonly used in the petroleum industry to describe sandstone reservoirs that are impregnated with a heavy, viscous black crude oil that cannot be retrieved through a well by conventional production techniques.

By inference, conventional petroleum and heavy oil are recoverable by well production methods (i.e., primary and secondary recovery methods) and by currently used enhanced oil recovery (EOR) techniques.

However, the term tar sand is actually a misnomer; more correctly, the name tar is usually applied to the heavy product remaining after the destructive distillation of coal or other organic matter.

Current recovery operations of bitumen in tar sand formations have been focused predominantly on a mining technique, but thermal in situ processes are now showing success.

Although the word tar is descriptive of the black, heavy bituminous material, it is best to avoid its use with respect to natural materials and to restrict the meaning to the volatile or near-volatile products produced in the destructive distillation of such organic substances as coal and biomass. In the simplest sense, pitch is the distillation residue (the nonvolatile constituents) of various types of tar.

Thus, alternative names, such as bituminous sand or oil sand, are gradually finding usage, with the former name (bituminous sands) more technically correct. The term oil sand is also used in the same way as the term tar sand, and these terms are used interchangeably throughout this text.

Bituminous rock and bituminous sand are those formations in which the bituminous material is found as a filling in veins and fissures in fractured rocks or impregnating relatively shallow sand, sandstone, and limestone strata. These terms are, in fact, the correct geological description of tar sand. The deposits contain as much as 20% bituminous material, and if the organic material in the rock matrix is bitumen, it is usual (although chemically incorrect) to refer to the deposit as rock asphalt to distinguish it from bitumen that is relatively mineral free.

Table 2-6 Tar Sand Bitumen Propreties

	API gravity	**Viscosity CP**
Bitumen	< 10	> 10,00

2.4.5. Validity of The Definitions

The validity of the definitions related to petroleum, heavy oil, and tar sand bitumen is subject to much scrutiny and, consequently, criticism.

Thus, although a single property number, such as API gravity or viscosity, is employed for some of the definitions, the validity of using a single property number is open to serious error since the number is subject to the experimental error or experimental differences of the analytical method by which the number was determined. Comparative properties, such as pour point and reservoir temperature, offer some logic for understanding the differences in behavior of heavy oil and tar sand bitumen.

For example, the generic term heavy oil is often applied to petroleum that has an API gravity of less than 20°and the term bitumen applied to those materials having less than 10° API. Following from this convenient generalization, there has also been an attempt to classify petroleum, heavy oil, and tar sand bitumen using viscosity scale, with 10,000 centipoise being the fine line of demarcation between heavy oil and tar sand bitumen. Use of such a system leads to confusion when having to differentiate between a material having a viscosity of 9,950 centipoise and one having a viscosity of 10,050 centipoise, taking into account the limits of accuracy of the method of viscosity determination. Whether the limits are the usual laboratory experimental difference (±3%) or more likely the limits of accuracy of the method (±5% to ±10%), there is the question of accuracy when tax credits for recovery of heavy oil and bitumen are awarded. In fact, the inaccuracies (i.e., the limits of experimental difference) of the method of measuring viscosity (or any single property) also increase the potential for misclassification using this single property for classification purposes.

Any attempt to classify petroleum, heavy oil, and bitumen on the basis of a single property is no longer sufficient to define the nature and properties of petroleum and petroleum-related materials. The general classification of petroleum into conventional petroleum, heavy oil, and extra heavy oil should involve not only an inspection of several properties but also some acknowledgment of the method of recovery.

Petroleum is referred to generically as a fossil energy resource and is further classified as a hydrocarbon resource; for illustrative (or comparative) purposes in this text, coal and oil shale kerogen have also been included in this classification. However, the inclusion of coal and oil shale under the broad classification of hydrocarbon resources has required (incorrectly) that the term hydrocarbon be expanded to include the high molecular weight (macromolecular) non-hydrocarbon heteroatomic species that constitute coal and oil shale kerogen. Heteroatomic species are those organic constituents that contain atoms other than carbon and hydrogen, e.g. nitrogen, oxygen, sulfur, and metals (nickel and vanadium), as an integral part of the molecular matrix.

Use of the term organic sediments is more correct and to be preferred (**Figure 2.3**). The inclusion of coal and oil shale kerogen in the category hydrocarbon resources is due to the fact that these two natural resources (coal and oil shale kerogen) will produce hydrocarbons on high-temperature processing (**Figure 2.4**). Therefore, if either coal and/or oil shale kerogen is to be included in the term hydrocarbon resources, it is more appropriate that they be classed as hydrocarbon producing resource sunder the general classification of organic sediments. Thus, fossil energy resources divide into two classes: (1) naturally occurring hydrocarbons (petroleum, natural gas, and natural waxes) and (2) hydrocarbon sources (oil shale and coal), which may be made to generate hydrocarbons by the application of conversion processes. Both classes may very aptly be described as organic sediments.

Whenever attempting to define or classify tar sand bitumen, it is always necessary to return to the definition as given by the United States Federal Energy Administration (FE-76-4) . By inference, petroleum and heavy oil are recoverable by well production methods and currently used enhanced recovery techniques. For convenience, it is assumed that before depletion of the reservoir energy, conventional crude oil is produced by primary and secondary techniques whereas heavy oil requires tertiary(enhanced) oil recovery (EOR) techniques. While this is an oversimplification, it may be used as a general guide.

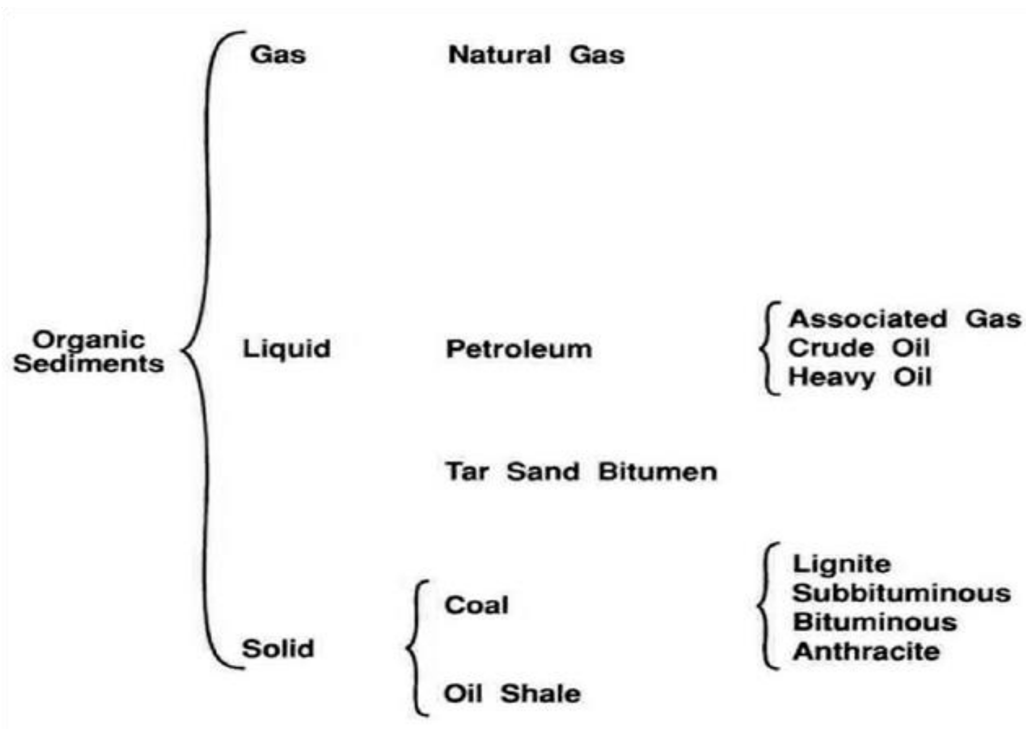

Figure 2-3 Classification of fossil fuel as organic sediments

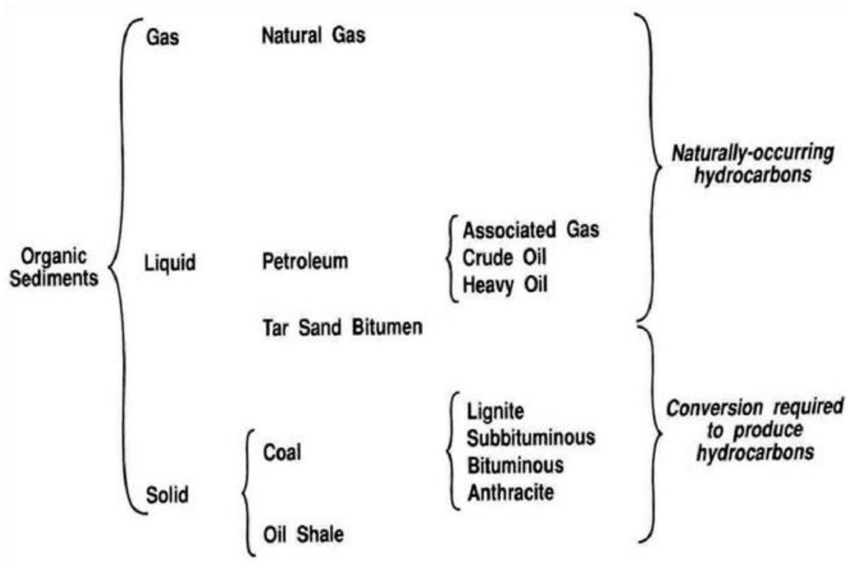

Figure 2-4 Classification of fossil fuels as hydrocarbon resources and hydrocarbon producing resources.

Generally, bitumen is solid or near solid at room temperature and is solid or near solid at reservoir temperature. In other words, tar sand bitumen is immobile in the reservoir and requires conversion or extreme stimulation for recovery.

Thus, by this definition tar sand bitumen is not crude oil, and it is set apart from conventional crude oil and heavy crude oil insofar as it cannot be recovered from a deposit by the use of conventional (including enhanced) oil recovery techniques as set forth in the June 1979 Federal Energy Regulations. To emphasize this point, bitumen has been recovered commercially by mining and the hot water process and is currently upgraded (converted to synthetic crude oil) by a thermal or hydrothermal process followed by product hydrotreating to produce a low sulfur hydrocarbon product known as synthetic crude oil.

Tar sand bitumen is a naturally occurring material that is immobile in the deposit and cannot be recovered by the application of enhanced oil recovery technologies, including steam-based technologies. On the other hand, heavy oil is mobile in the reservoir and can be recovered by the application of enhanced oil recovery technologies, including steam-based technologies.

Since the most significant property of tar sand bitumen is its immobility under the conditions of temperature and pressure in the deposit, the interrelated properties of API gravity and viscosity may present an indication (but only an indication) of the mobility of oil or immobility of bitumen. In reality, these properties only offer subjective descriptions of the oil in the reservoir. The most pertinent and objective representation of this oil or bitumen mobility is the pour point.

By definition, the pour point is the lowest temperature at which oil will move, pour, or flow when it is chilled without disturbance under definite conditions. In fact, the pour point of an oil when used in conjunction with the reservoir temperature gives a better indication of the condition of the oil in the reservoir than the viscosity. Thus, the pour point and reservoir temperature present a more accurate assessment of the condition of the oil in the reservoir, being indicators of the mobility of the oil in the reservoir. When used in conjunction with reservoir temperature, the pour point gives an indication of the liquidity of the heavy oil or bitumen and, therefore, the ability of the heavy oil or bitumen to flow under reservoir conditions. In summary, the pour point is an important consideration because, for efficient production, additional energy must be supplied to the reservoir by a thermal process to increase the reservoir temperature beyond the pour point.

A method that uses the pour point of the oil and the reservoir temperature (Figure 2.5) adds a specific qualification to the term extremely viscous as it occurs in the definition of tar sand. In fact, when used in conjunction with the recovery method (Figure 2.6), pour point offers more general applicability to the conditions of the oil in the reservoir or the bitumen in the deposit, and comparison of the two temperatures (pour point and reservoir temperatures) shows promise and may find more general use.

Heavy oil is mobile in the reservoir

Bitumen is immobile in the reservoir

Table 2-7 Simplified of the use of pour point to define heavy oil and bitumen.

Reservoir temperature is higher than oil pour point:	**Oil is Mobile**
Reservoir temperature is lower than oil pour point:	**Oil is Immobile**

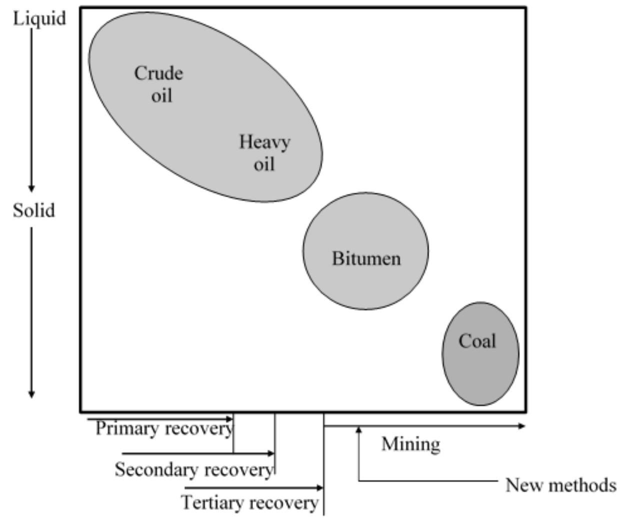

Figure 2-5 Schematic representation of the properties and recovery methods for crude oil, heavy oil, bitumen, and coal.

Heavy oil cannot be defined adequately or with any degree of accuracy using a single property. Likewise, tar sand bitumen cannot be defined using a single property. Both, however, can be redefined by the recovery method. By inference, heavy oil can also be defined using the same definition as tar sand bitumen. Heavy oil is usually mobile in the reservoir, whereas tar sand bitumen is immobile in the deposit.

Finally, it is essential to realize that in the current context of conventional petroleum and heavy oil, there are several parameters that can influence properties and recovery. These properties are usually site specific to the particular reservoir in which the crude oil or heavy oil is located (Figure 2.7).

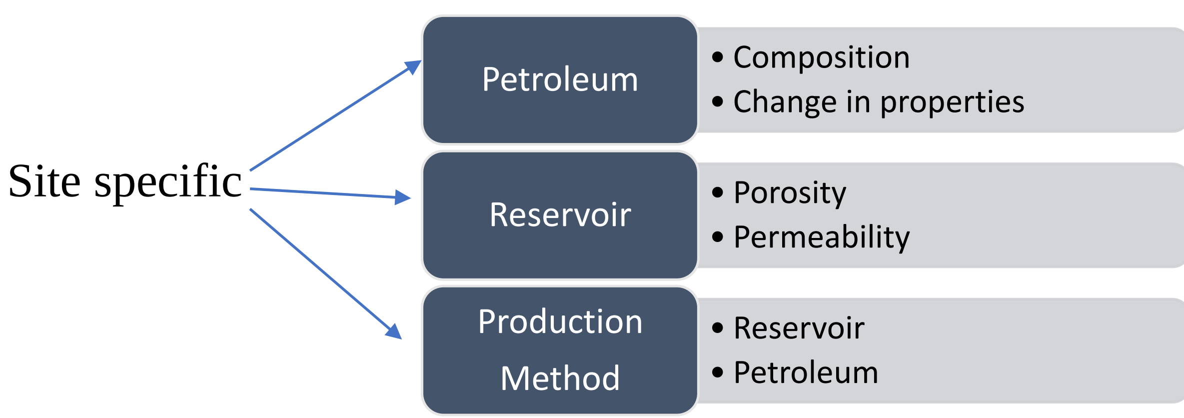

Figure 2-6 Representation of the changing parameters for crude oil and/or heavy oil.

2.5. Why we need heavy oil?

The gradual depletion of the world's lighter petroleum resources and the increasing prices for these commodities means a rising need to process alternative heavier feedstock. These alternatives include extra heavy oil, bitumen from oil sands, and residues from light and moderate crude oil refining. Upgrading oil sands and heavy oil is an essential part as it adds tremendous value to the raw resource and allows it to be further processed into fuels and lubricants at existing refineries, and used as feedstock in petrochemical plants. Petroleum upgrading represents a suite of physical and chemical processes whereby raw extra heavy oil and bitumen extracted from oil sands are transformed into synthetic crude oil to providing a safe and secure energy source to fill the widening gap between our future energy supply and demand requirements. Forecasts predict that a continuous expansion in world energy consumption must extend at least until 2035, as indicated by the U.S. Energy Information Administration (See Figure 2.8). For this reason, heavy oil reserves essential to supply the global energy.

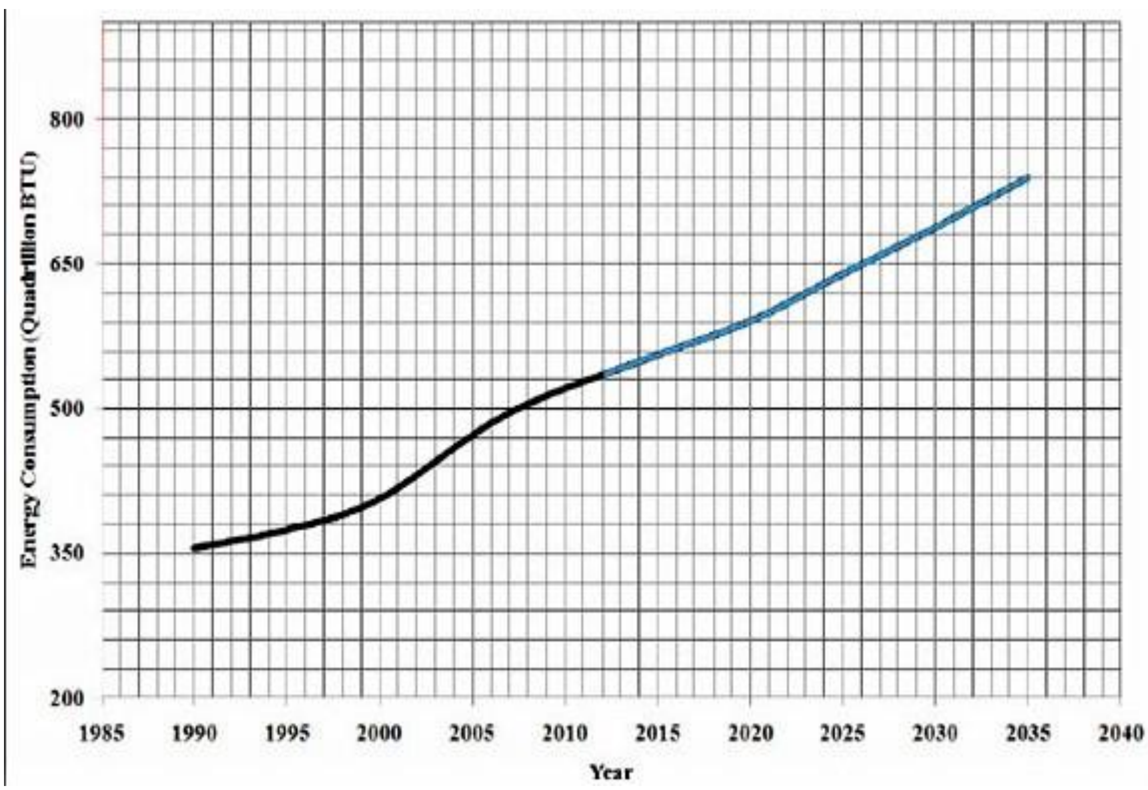

Figure 2-7 World market energy consumption – Forecast up 2035. Adapted from DOE/EIA 2010 International Energy Outlook, U.S. Energy Information Administration

Fig. 2-8: shows a chart of the world's total remaining oil reserves. The heavy, extra heavy oils and bitumen are expected to make up 70%. This number underlines the increasing importance of heavy oil production going forward, as conventional supplies are decreasing.

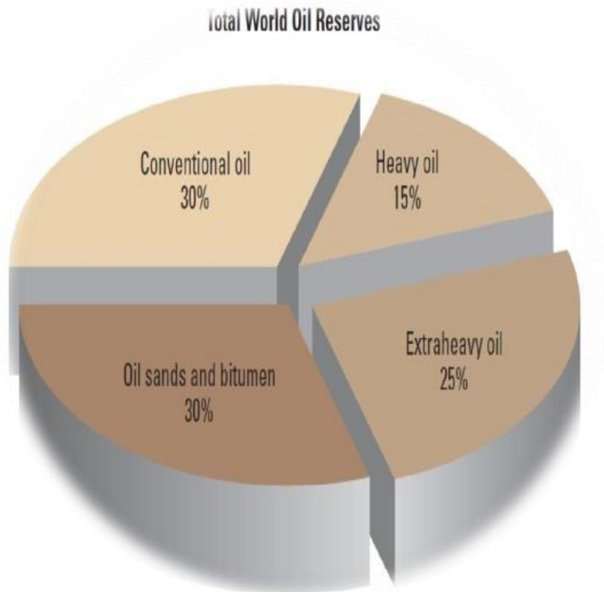

Figure 2-8 Distribution of Total World Oil Reserves by Classification Oilfield Review, (2006)

Data presented by Saniere et. al (2004). As **Fig. 2-9:** shows, heavy oil reserves are approximately the same amount as conventional reserves, but very little of the heavy oil has so far been produced compared to conventional resources.

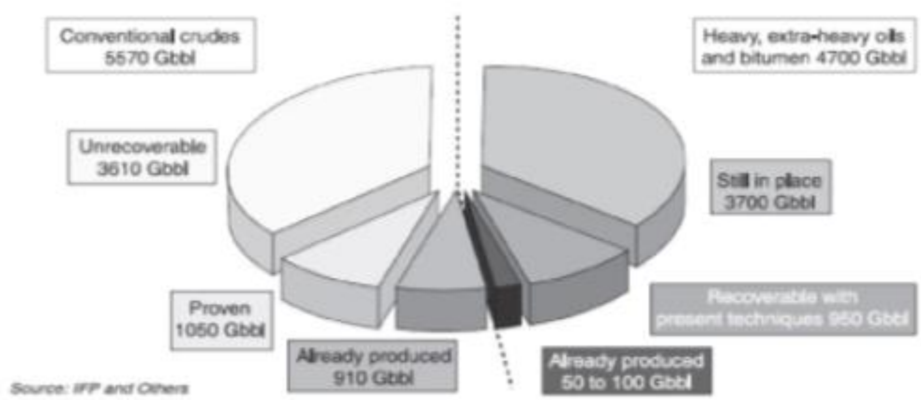

Figure 2-9 Total World Oil Resources Produced and In Place Saniere et.al, (2004)

2.6. Problems

Despite the importance of heavy oil and the existence of large reserves of oil in the ground, but the extraction from the ground and the physical and chemical treatments required to extract oil derivatives from it, may have environmental repercussions that require the adoption of preventive measures of a very high importance.

Heavy oils usually display a greater content of asphaltenes and resins than conventional oils (Speight, 1991), which directly impacts recovery, transport and refining processes. In many production fields and refineries, the content of asphaltene is one of the main criteria for process control. Table 5 shows the composition differences normally found in conventional oils, heavy oils and residues.

Sample	Typical composition range (Wt.%)		
	Asphaltene	Resin	Oil fraction [1]
Conventional oil	< 0.1 - 12	3 - 22	67 - 97
Heavy oil	11 - 45	14 - 39	24 - 64
Residue	11 - 29	29 - 39	< 39

n.d: Not determined
[1] Correspondent to the fraction composed of saturate and aromatic.

Figure 2-10 Composition for conventional oil, heavy oil and residue (Adapted from Speight, 1991).

In production process aspects related to its technological complexity and its high level of expertise and experience needed to successfully implement it in the oilfield should be taken into account to preserve the economic requirements. Piping of heavy oil is expensive due to the elevated resistance encountered in the flow of these oils.

2.7. Heavy Oil Reservoirs

2.7.1. Origin and Occurrence Heavy Oil

2.7.1.1. The Initial Formation of Heavy Oil

Heavy oil is formed from raw organic materials by the influence of temperature and pressure, which in turn relates to the sediment thickness that covers the rocks on the one hand and the development of sedimentary basins on the other, where the organic materials gradually turn into ordinary oil and then into light oil and gas, and that over a long period of time.

The presence of raw organic materials explains the presence of viscous oil concentrations that remained in the initial rocks and did not reach the stage of formation of light oil or that it migrated as a result of tectonic factors during the transformation phase and gathered in the nearby reservoirs.

The Secondary formation of heavy oil: There are secondary factors that may contribute to the process of forming heavy oil:

1. The impact of aerobic bacteria or sulfur: found in water source surface or groundwater, where allows aerobic bacteria active activity contributes to the conversion of light oil to heavy and that at temperatures below the required.
2. Effect of surface water moving water: As this water causes the washing of light materials commensurate with the degree of dissolution and that when filtered in the layer and contact with oil, which leads to a decrease in light materials and increase the proportion of asphalt and heavy materials in the reservoir and thus increase the viscosity of the residual oil and weight.
3. Natural separation of oil from its components: The natural migration of oil in different stratified rocks allows the passage of gas and light materials and leaves heavy materials sediments lead to a good closure prevents the continuation of oil migration.
4. Formation of asphalt: Asphalt deposition occurs during the migration of gas and light materials or during one of the stages of oil formation, and these sedimentary asphalts cannot be distinguished on the natural form of asphalt resulting from the transformation of organic materials

2.7.2. The Presence of Heavy Materials in Oil

The existence of such materials depends on many factors including: the properties of the oil produced, the thermodynamic properties of the layer, the hydrodynamic conditions of the layer, the geological and physical properties of the layer, the method of investment.

The most important of these factors is the specifications of the oil produced and the thermodynamic properties of the layer. During the change of the thermodynamic properties of the layer the asphalt and paraffin materials can accumulate at the bottom (leading to reduced permeability) Also in equipment that has downstream lines and stations, this sedimentation problem can appear in mechanical wells and on poor self and lead to a lower oil production rate. Below we show the specifications of both of these materials:

Paraffin materials

It consists of a crystalline form and its average partial weight (300_400) gr/mol And the degree of fusion (-50-60), They are characterized by good dissolution in aromatic hydrocarbons. (Kerosene, condensate) is practically insoluble in hydrocarbons.

Resin materials

The partial weight ranges (450-1500) gr/mol. And the density is close to the one and has rubber properties and is high viscosity, dark color.

And soluble in light and aromatic hydrocarbons.

And non-degradable in acids and alkali while heated in the air to (100-150 C) turn into asphalt.

Asphalt materials

The partial weight ranges (1500-10000) gr/mol. Not soluble in light hydrocarbon compounds but soluble in aromatic compounds.

The density is greater than one. While heated to a temperature higher than (300C) it does not melt but turns into coal. During heating, the presence of sulfuric acid hardens and transforms into carbon, not soluble even in aromatic compounds

2.8. Heavy Oil Properties

Petroleum is perhaps the most important substance consumed in modern society. It provides not only raw materials for the ubiquitous plastics and other products, but also fuel for energy, industry, heating, and transportation. From a chemical standpoint, petroleum is an extremely complex mixture of hydrocarbon compounds, with minor amounts of nitrogen-, oxygen-, and sulfur-containing compounds as well as trace amounts of metal-containing compounds.

The fuels that are derived from petroleum supply more than half of the world’s total supply of energy. Gasoline, kerosene, and diesel oil provide fuel for automobiles, tractors, trucks, aircraft, and ships. Fuel oil and natural gas are used to heat homes and commercial buildings, as well as to generate electricity. Petroleum products are the basic materials used for the manufacture of synthetic fibers for clothing and in plastics, paints, fertilizers, insecticides, soaps, and synthetic rubber. The uses of petroleum as a source of raw material in manufacturing are central to the functioning of modern industry. As petroleum resources are depleted, industry will rely more and more on heavy oil to satisfy the need for fuels, chemicals, and the other products currently derived from petroleum.**[1]**

Many types of heavy oil exist, and a variety of production processes are being used and developed to recover it. However, technologies and services used for conventional oil face limitations with heavy oil.

Heavy oil typically has relatively low proportions of volatile compounds with low molecular weights and quite high proportions of high molecular weight compounds. The high-molecular-weight fraction of heavy oils is composed of compounds (not necessarily paraffins or asphaltenes) with high melting points and high pour points that greatly contribute to the fluid properties of heavy oil and hence to reduced mobility compared to conventional petroleum. It is typically this poor mobility of the crude oil, as opposed to accumulations of paraffins or asphaltenes in formation rock pore throats or production lines, that is usually the cause of production problems.

Some, but not all, heavy oils do contain moderate-to-high levels of asphaltene constituents. However, the asphaltene constituents do not become a problem unless they drop out of solution (precipitate) and build up in the formation or production string.

In summary, the heaviness of heavy oil is primarily the result of an internal balance between a relatively high proportion of complex, high-molecular-weight, non-paraffinic compounds and a low proportion of volatile, lower-molecular-weight compounds. The problems of producing heavy oil from the reservoir are typically a result of disturbing the internal balance, which, in turn, influences the mobility of the oil and the deposition of asphaltene constituents. Success with heavy oil depends as much on understanding the fluid properties of the reservoir as it does on knowing the geology of the reservoir itself. The reason is that the chemical differences between heavy oil and conventional oil ultimately affect their viscosity.

Thermal recovery options in some reservoirs include the use of cyclical steam (huff 'n' puff), downhole heaters, or a relatively new commercial process called steam-assisted gravity drainage (SAGD). Other techniques, such as injecting slugs of water alternating with gas (WAG) are less efficient than thermal recovery but also less expensive. The use of steam influences the mobility of the oil, which influences recovery rates, but the enhanced oil recovery and artificial lift methods needed to produce changes to the already complex fluid characteristics of heavy oil.

Strategies for recovering heavy oil emphasize the difference in properties that influences the choice of methods for conversion to various products, and the availability of processes that can be employed to produce heavy oil from the reservoir has increased significantly in recent years. In order to determine the recoverability of heavy oil, a series of consistent and standardized characterization procedures are required. These procedures can be used with a wide variety of feedstocks to develop a general approach to predict behavior during recovery.

The recovery of heavy oil can be designed in an optimal manner by performing selected evaluations that lead to an understanding of the chemical and physical features of the oil.

The evaluation schemes do not need to be complex but must focus on key parameters that affect recovery. For example, the identification of the important features can be made with a saturates-aromatics-resins-asphaltene separation. Subsequent analysis of the fractions also provides further information about the intramolecular relationships of the oil. In this follow-on analysis, there is often emphasis on the asphaltene fraction since the solubility of asphaltene constituents and the thermal products has a dramatic effect on solids deposition during recovery. Further evaluation of the asphaltene constituents can lead to correlation of asphaltene properties with behavior. In addition, useful information can be gained from knowledge of elemental composition and molecular weight as well as size exclusion chromatography and high-performance liquid chromatography profiles.

2.8.1. Physical Properties

Heavy oil exhibits a wide range of physical properties, and several relationships can be made between various physical properties. Although the properties such as viscosity, density, and boiling range may vary widely, the ultimate or elemental analysis varies over a narrow range for a large number of samples. The carbon content is relatively constant, whereas the hydrogen and heteroatom contents are responsible for the major differences between heavy oils.

Initial inspection of the oil (conventional examination of the physical properties) is necessary. From this, it is possible to make deductions about the propensity for easy or difficult recovery. In fact, evaluation of heavy oil from physical property data to determine which recovery sequences should be employed for a particular crude oil is a predominant part of the initial examination of any heavy oil. Proper interpretation of the data resulting from the inspection of crude oil requires an understanding of their significance.

The chemical composition of heavy oil, however, is a much truer indicator of behavior than its physical properties. Whether the composition is represented in terms of compound types or (more likely) in terms of generic compound classes, it can assist in determining the nature of any potential interactions of the oil with the rock, for example, or with changes in pressure and temperature. Hence, chemical composition can play a large part in determining the nature of the products that arise from the recovery operations. It can also play a role in determining the means by which a particular feedstock should be processed. This becomes particularly important when partial upgrading in the reservoir is considered as a serious option for recovery.

2.8.1.1. Sampling

Because of the complexity of heavy oil, the importance of the correct sampling of heavy oil cannot be overstressed. Properties such as elemental analysis, metals content, density (specific gravity), and viscosity are affected by the homogeneity (or heterogeneity) of the sample. In addition, adequate records of the circumstances and conditions during sampling have to be made. For example, in sampling from oil-field separators, the temperatures and pressures of the separation plant and the atmospheric temperature would be noted. An accurate sample handling and storage log should be maintained and should include information such as:

1. The precise source of the sample, i.e., the exact geographic location or refinery locale from which the sample was obtained
2. A description of the means by which the sample was obtained
3. The protocols used to store the sample
4. Chemical analyses, such as elemental composition
5. Physical property analyses, such as API gravity, pour point, distillation profile, etc.
6. ASTM methods used to determine the properties in items 4 and 5
7. The number of times that the sample has been retrieved from storage to extract a portion, i.e. indications of exposure to the air or oxygen.

2.8.1.2. Elemental (Ultimate) Analysis

The analysis of heavy oil for the percentages of carbon, hydrogen, nitrogen, oxygen, and sulfur is perhaps the first method used to examine and evaluate the general nature of a feedstock. The atomic ratios of the various elements to carbon (i.e., H/C, N/C, O/C, and S/C) are frequently used for indications of the overall character of the heavy oil. It is also of value to determine the amounts of trace elements, such as vanadium and nickel, in a feedstock since these materials can have serious deleterious effects on catalyst performance during partial upgrading during recovery or even when using a partial upgrading process at the surface before transportation.

Of the data that are available, the proportions of the elements in heavy oil vary only slightly over narrow limits. Perhaps the more pertinent property in the present context is the sulfur content; sulfur content and API gravity represent the two properties that have the greatest influence on the value of heavy oil. The sulfur content varies from about 0.1% to about 5% by weight.

2.8.1.3. Metals Content

Metals (particularly vanadium and nickel) are found in most crude oils. Heavy oil contains relatively high proportions of metals, either in the form of salts or as organometallic constituents (such as the metalloporphyrin's), which are extremely difficult to remove from the feedstock. The metallic constituents may actually volatilize under thermal recovery operations and appear in the reservoir or in the production lines.

Determination of metals in whole feeds can be accomplished by combustion of the sample so that only inorganic ash remains. The ash can then be digested with an acid and the solution examined for metal species by atomic absorption (AA) spectroscopy or by inductively coupled argon plasma (ICAP) spectrometry.

2.8.1.4. Density and Specific Gravity

Density is the mass of a unit volume of material at a specified temperature; it has the dimensions of grams per cubic centimeter (a close approximation to grams per milliliter). Specific gravity is the ratio of the mass of a volume of the substance to the mass of the same volume of water and is dependent on two temperatures, those at which the masses of the sample and the water are measured. When the water temperature is 4°C (39°F), the specific gravity is equal to the density in the centimeter-gram-second (CGS) system since the volume of 1 gallon of water at that temperature is, by definition, 1 ml. Thus, the density of water, for example, varies with temperature, and its specific gravity at equal temperatures is always unity. The standard temperatures for a specific gravity in the petroleum industry in North America are 60/60°F (15.6/15.6°C).

Specific gravity is influenced by chemical composition, but quantitative correlation is difficult to establish. Nevertheless, it is generally recognized that increased amounts of aromatic compounds result in an increase in density, whereas an increase in saturated compounds results in a decrease in density. It is also possible to recognize certain preferred trends between the API gravity of crude oils and residua and one or more of the other physical parameters. For example, a correlation exists between the API gravity and sulfur content, Conradson carbon residue, and viscosity. However, the derived relationships between the density of heavy oil and its fractional composition are valid only when applied to a certain type of heavy oil and may lose their significance when applied to heavy oil from different sources.

The values for density (and specific gravity) cover an extremely narrow range, considering the differences in heavy oil behavior. In an attempt to delineate a more meaningful relationship between the physical properties and processability of the various crude oils, the American Petroleum Institute devised a measurement of gravity based upon the Baumé scale for industrial liquids. The Baumé scale for liquids lighter than water was used initially:

$$\text{Baumé} = 140/\text{sp gr @ } 60/60°\text{F} - 130$$

However, a considerable number of hydrometers calibrated according to the Baumé scale were found at an early period to be in error by a consistent amount, and this led to the adoption of the equation

$$\text{API} = 141.5/\text{sp gr @ } 60/60°\text{F} - 131.5$$

The specific gravity of conventional crude oil usually ranges from about 0.8 (45.3°API) for conventional crude oil to about 1.0 (10°API) for heavy oil. This is in keeping with the general trend that a lower atomic hydrogen/carbon ratio (increased aromaticity) leads to a decrease in API gravity (or, more correctly, an increase in specific gravity).

Density, specific gravity, or API gravity may be measured, depending upon the properties of the heavy oil sample, by means of a hydrometer (ASTM D287, ASTM D1298) or by means of a pycnometer (ASTMD941, ASTM D1217). The variation of density with temperature, effectively the coefficient of expansion, is a property of great technical importance since most crude oils are sold by volume, and specific gravity is usually determined at the prevailing temperature (21°C, 70°F) rather than at the standard temperature (60°F, 15.6°C). The tables of gravity corrections (ASTM D1555) are based on an assumption that the coefficient of expansion is a function (at fixed temperatures) of density only.

2.8.1.5. Viscosity

The viscosity of heavy oils is a critical property in predicting oil recovery. In fact, viscosity is often cited as the single most important fluid characteristic governing the motion of crude oil. It is actually a measure of the internal resistance to motion of a fluid by reason of the forces of cohesion between molecules or molecular groupings. It is unfortunate that oil-rock interactions and reservoir structure are often omitted when the focus is on oil viscosity.

Many types of instruments have been proposed for the determination of viscosity, but as in the determination of density, the choice of an instrument depends upon the properties of the oil.

Finally, heavy oil is high viscosity oil and does not flow easily—the term is a relative term compared to conventional (light) heavy oil and relates to specific technical issues of production, transportation, and refining. Properties that distinguish heavy oil from conventional (light) heavy oil must (at least) be parameters such as higher viscosity, higher specific gravity, method of production, as well as the presence of higher amount of high molecular weight and polar constituents. Extra heavy oil has a much higher viscosity and lower API gravity than heavy oil, but while tar sand bitumen is immobile in the deposit, extra heavy oil is mobile in the reservoir.

2.8.2. Thermal Properties

The thermal properties of heavy oil offer insights into its characteristics, and by measuring such properties, a set of basic characteristics can be obtained that can be correlated with behavior during thermal methods of recovery. For the purposes of this section, the tests that produce data relating to the various thermal properties of heavy oil, as they influence recovery, are described. These properties provide advance information relating to the movement of the heavy oil in the reservoir and up the wellbore.

2.8.2.1. Carbon Residue

The carbon residue of heavy oil is a property that can be correlated with several other properties of the oil and may be used to evaluate the carbonaceous depositing characteristics of heavy oil during thermal recovery.

There are two older well-used methods for determining the carbon residue the Conradson method (ASTM D189) and the Ramsbottom method (ASTM D524). Both are equally applicable to heavy oil but the metallic constituents will give erroneously high carbon residues. The metallic constituents must first be removed from the oil or they can be estimated as ash by complete burning of the coke after carbon residue determination. There is no exact correlation between the two methods but it is possible to interconnect the data.

Another method (ASTM D4530) requires smaller sample amounts and was originally developed as a thermogravimetric method. The carbon residue produced by this method is often referred to as themicrocarbon residue. Agreements between the data from the three methods are good, making it possible to interrelate all of the data from carbon residue tests.

2.8.2.2. Specific Heat

Specific heat is the quantity of heat required to raise a unit mass of material through one degree of temperature (ASTM D2766). It is an extremely important engineering quantity in practice and is used in all calculations on heating and cooling heavy oil. Many measurements have been made on various hydrocarbon materials, but the data for most purposes may be summarized by the general equation:

$$C = 1/d\ (0.388 + 0.00045t)$$

where Cis the specific heat at t °F of an oil whose specific gravity 60/60°F is d. Thus, specific heat increases with temperature and decreases with specific gravity.

2.8.2.3. Heat of Combustion

The gross heat of combustion of heavy oil is given with a reasonable degree of accuracy by the equation

$$Q = 12{,}400 - 2100d^2$$

where d is the 60/60°F specific gravity. Deviation is generally less than 1%, although highly aromatic heavy oil may show considerably higher values.

For thermodynamic calculation of equilibria, combustion data of extreme accuracy are required because the heats of formation of water and carbon dioxide are large in comparison with those of the hydrocarbons. Great accuracy is also required of the specific heat data for the calculation of free energy or entropy. Much care must be exercised in selecting values from the literature for these purposes since many of those available were determined before the development of modern calorimetric techniques.

2.8.2.4. Volatility

The volatility of a liquid or liquefied gas may be defined as its tendency to vaporize, that is, to change from the liquid to the vapor or gaseous state. Because one of the three essentials for combustion in a flame is that the fuel be in the gaseous state, volatility is a primary characteristic of liquid fuels. The distillation profile is also a measure of the relative amounts of these liquid fuels (albeit small and unrefined) in heavy oil.

Similarly, there must be some estimate of the ability of the constituents of heavy oil to distill, or steam distill, from the oil during thermal methods of enhanced oil recovery. However, before any volatility tests are carried out, it must be recognized that the presence of more then 0.5% water in test samples of heavy oil can cause several problems during distillation procedures. Water has a high heat of vaporization, necessitating the application of additional thermal energy to the distillation flask. Water is relatively easily superheated, and therefore excessive bumping can occur, leading to erroneous readings and the real potential for destruction of the glass equipment. In addition, steam formed during distillation can act as a carrier gas, and high-boiling-point components may end up in the distillate (often referred to as steam distillation).

Centrifugation can be used to remove water (and sediment) if the sample is not a tight emulsion. Other methods that are used to remove water include:

1. Heating in a pressure vessel to control loss of light ends
2. Addition of calcium chloride as recommended in ASTM D1160
3. Addition of an azeotroping agent such as iso-propanol or n-butanol
4. Removal of water in a preliminary low-efficiency or flash distillation followed by re blending of the hydrocarbon which co-distills with the water into the sample (see also IP 74)
5. Separation of the water from the hydrocarbon distillate by freezing

For some purposes, it is necessary to have information on the initial stage of vaporization and the potential hazards, even with heavy oil, that such a property can cause. To supply this need, flash-and-fire, vapor pressure, and evaporation methods are available. The data from the early stages of the several distillation methods are also useful. For other uses, it is important to know the tendency of a product to partially vaporize or to completely vaporize, and in some cases, to know if small quantities of high-boiling components are present. For such purposes, chief reliance is placed on the distillation methods.

The flash point of petroleum or a petroleum product is the temperature to which the product must be heated under specified conditions to give off sufficient vapor to form a mixture with air that can be ignited momentarily by a specified flame.

The flash point of heavy oil can also be used to detect contamination. A substantially lower flash point than expected for a product is a reliable indicator that a product has become contaminated with a more volatile product, such as gasoline. The flash point is also an aid in establishing the identity of a particular hydrocarbon contaminant.

A further aspect of volatility that receives considerable attention is the vapor pressure of heavy oil, which may be close to zero. The vapor pressure is the force exerted on the walls of a closed container by the vaporized portion of a liquid. Conversely, it is the force that must be exerted on the liquid to prevent it from vaporizing further. The vapor pressure increases with temperature. The temperature at which the vapor pressure of a liquid, either a pure compound or a mixture of many compounds, equals one atmosphere pressure (14.7 psi, absolute) is designated as the boiling point of the liquid.

2.8.2.5. Liquefaction and Solidification

The liquefaction and solidification of heavy oil seems to draw little attention in the standard petroleum science textbooks. Yet these properties are very important in the handling of heavy oil, both at the wellhead and in the refinery. In fact, since heavy oil can be a borderline liquid or near solid at ambient temperature, problems may arise from solidification during normal use or storage.

Recently, more emphasis has been placed on the pour point, which, in conjunction with the reservoir temperature, can give indications of the fluidity and mobility of the heavy oil in the reservoir. The pour point of a crude oil was originally applied to crude oil that had a high wax content. More recently, the pour point, like the viscosity, is determined principally for use in pumping arid pipeline design calculations.

2.8.2.6. Solubility

Although not truly a thermal property, the solubility parameter of heavy oil and its constituent fractions is of interest during thermal methods of recovery.

The solubility parameter of heavy oil fraction, especially the asphaltene fractions, has been the subject of study with some interesting results emerging. In fact, phase separation as can occur during thermal recovery of heavy oil can be explained by use of the solubility parameter, δ, for petroleum fractions and for the solvents. As an extension of this concept, there is sufficient data to draw a correlation between the atomic hydrogen/carbon ratio and the solubility parameter for hydrocarbons and the constituents of the lower boiling fractions of petroleum.

2.8.3. Metals Content

Heavy oils contain relatively high proportions of metals either in the form of salts or organometallic constituents (such as the metalloporphyrin's), which are extremely difficult to remove from the feedstock. Indeed, the nature of the process by which residua are produced virtually dictates that all the metals in the original crude oil are concentrated in the residuum (Speight, 2000). Those metallic constituents that may actually volatilize under the distillation conditions and appear in the higher-boiling distillates are the exceptions. The deleterious effect of metallic constituents on the catalyst is known particularly through their ability to modify the selectivity of Zeolite catalysts, thereby causing an increase in the formation of coke at the expense of the more desirable liquid products.

Thus, serious attempts have been made to develop catalysts that can tolerate a high concentration of metals without serious loss of catalyst activity or catalyst life. However, for the most part, the metals concentrate in the coke formed during thermal processes.

A number of the heavy metals such as nickel, vanadium, copper, and iron can also be effectively bound in large organic molecules characteristic of those found in the asphaltene fraction (the pentane- or heptane-insoluble portion of the feedstock) and resins. Nickel and vanadium porphyrins are commonly found and show high thermal stability, which allows them to pass through the extraction process into the upgrading process. Porphyrins are the major, but certainly not the only, organo-metallic complexes present. Metals may simply be entrapped or loosely bound in the very large molecules present in the asphaltenes and resins. Although ironis present as an organometallic compound, it occurs mostly in the form of process-accumulated rust or is scrounged from pipelines by the crude oil during shipping and pipelining. Thus, one should not worry about the geochemical significance of metal such as iron in crude oil. Without doubt, these heavy metals are present in recovered heavy oil. Since catalysts are used extensively in upgrading and are readily poisoned by such metals, it is important to know the amounts present.

2.9. General Methods for Oil Recovery

The initial production of crude oil from an underground reservoir is achieved by the use of the natural energy of the reservoir. As soon as the reservoir is opened, the natural energy comes into play and, whether through gas pressure or water pressure, forces the fluids to the surface facility (primary production). In the process, the actual sources of natural reservoir energy that lead to primary production include the swelling of reservoir fluids, the release of solution gas as the reservoir pressure declines, nearby communicating aquifers, and gravity.

When the natural reservoir energy has been depleted through production, it becomes necessary to supplement or even substitute the natural reservoir energy with energy from an external source. This is usually accomplished by the injection of fluids, such as natural gas or water (secondary recovery). The main purpose of either a natural gas injection process (gas flooding) or a water injection process (water flooding) is to depressurized the reservoir and then to maintain the reservoir at a high pressure. The term pressure maintenance is sometimes used to describe a secondary recovery process.

When gas is used as the pressure maintenance agent, it is usually injected into a zone of free gas (i.e., a gas cap) to maximize recovery by gravity drainage. The injected gas is usually natural gas produced from the reservoir in question which defers the sale of that gas until the gas flooding operation is completed and the gas can be recovered. On the other hand, other gases, such as nitrogen, can be injected to maintain reservoir pressure, which allows the natural gas to be sold as it is produced.

The situation is different for heavy oil and tar sand bitumen where the reservoirs of deposits have little to no reservoir energy in the form of the pressure exerted within the reservoir by the presence of or water. Heavy oil reservoir and tar sand deposits are found in the microscopic pores of sedimentary rocks such as sandstone and limestone. Not all of the pores in a reservoir rock or deposit will contain heavy oil or bitumen—some will be filled with water or brine—the latter is water that is saturated with minerals. Seismic surveys are used to try to predict where fields may be found but the only way of making certain is by drilling.

Production rates from reservoirs depend on a number of factors, such as reservoir geometry (primarily formation thickness and reservoir continuity), reservoir pressure, reservoir depth, rock type and permeability, fluid saturations and properties, extent of fracturing, number of wells and their locations, and the ratio of the permeability of the formation to the viscosity of the heavy oil or bitumen and what it will take to modify the viscosity to enable recovery methods to be effective. Operators can increase production over that which would naturally occur by such methods as fracturing the reservoir to open new channels for flow, injecting gas and water to increase the reservoir pressure, or lowering oil viscosity with heat or chemicals. These supplementary techniques are expensive, and the extent to which they are used depends on such external factors as the operator’s economic condition, sales prospects, and perceptions of future prices.

The extraordinary geological variability of different reservoirs means that production profiles differ from field to field. Heavy oil reservoirs can be developed to significant levels of production and maintained for a period of time by supplementing natural drive force, while gas reservoirs normally decline more rapidly.

2.9.1. Primary Recovery Methods

The initial stage in producing oil from a reservoir (primary recovery, primary production) is the stage in which oil is forced to the surface by such natural forces as: (1) expansion of oil; (2) expansion of the contained gas; (3) displacement by migration of naturally pressurized water from a communicating zone such as in natural water drive; and (4) drainage downward from a high elevation in a reservoir to wells penetrating lower elevations. The natural expulsive forces present in a given reservoir depend on rock and fluid properties, geologic structure and geometry of the reservoir, as well as on the rate of oil and gas production several of the forces may be present in a given reservoir. Recovery efficiency of conventional (light) crude oil varies in the primary stage from 10% to approximately 50% v/v of the oil in place. However, these numbers do not apply to heavy oil or to tar sand bitumen which are generally immune to recovery by primary methods.

Primary recovery occurs as wells produce because of natural energy from expansion of gas and water within the producing formation, which pushes fluids into the well bore and lifts them to the surface.

2.9.2. Secondary Recovery Methods

Secondary recovery processes are necessary because most of the crude oil in a reservoir remains in place after the natural energy pressurizing the reservoir has been dissipated. Several techniques are available for repressuring the reservoir by injecting fluids into the reservoir to augment the natural forces have been widely used for many years. Fluids, most commonly water (water flooding) and (although not truly a fluid but considered to be a reservoir fluid) natural gas (gas flooding) are injected into the reservoir through a series of wells (injection wells) to force the crude oil toward another series of wells (production wells). The pattern of injection and production wells most appropriate to a reservoir are a technical matter and depend upon the properties of the reservoir and the properties of the crude oil. Furthermore, it is frequently desirable to initiate such processes as soon as sufficient knowledge is available of the geology of the reservoir and the type of natural expulsive forces that are operative.

And there is no reason (in fact, it is often disadvantageous) to delay the fluid injection process until the natural energy in a reservoir is exhausted.

Most often, secondary recovery is accomplished by injecting gas or water into the reservoir to replace produced fluids and thus maintain or increase the reservoir pressure. When gas alone is injected, it is usually put into the top of the reservoir, where petroleum gases normally collect to form a gas cap. Gas injection can be a very effective recovery method in reservoirs where the oil is able to flow freely to the bottom by gravity. When this gravity segregation does not occur, however, other means must be sought.

Secondary recovery occurs as artificial energy is applied to inject fluids into the well bore and lift fluids to the surface. This may be accomplished by injecting gas down a hole, installing a subsurface pump, or injecting gas or water into the formation itself. Secondary recovery is done when well, reservoir, facility, and economic conditions permit.

2.9.3. Enhanced Oil Recovery Methods

Tertiary recovery (enhanced recovery) occurs when means of increasing fluid mobility within the reservoir are introduced in addition to secondary techniques. This may be accomplished by introducing additional heat into the formation to lower the viscosity (thin the oil) and improve its ability to flow to the well bore. Heat may be introduced by either injecting steam in a steam flood or injecting oxygen to enable the ignition and combustion of oil within the reservoir in a fire flood. Such methods are undertaken only in a few unique situations where technical, environmental, and economic conditions permit. Most gas reserves are produced during the primary recovery phase. Secondary recovery has significantly contributed to increasing oil recovery.

Describes the intent of EOR methods as follows:

1. To improve sweep efficiency by reducing the mobility ratio between injected and in-place fluids.
2. To eliminate or reduce capillary and interfacial forces and thus improve displacement efficiency.
3. To act on both phenomena simultaneously.

A decision must be made whether a tertiary recovery method may be used. The latter depends on reservoir complexity and reservoir conditions, field exploitation strategy is greatly affected by economics.

Improved Oil Recovery (IOR) methods encompass Enhanced Oil Recovery (EOR) methods as well as new drilling and well technologies, intelligent reservoir management and control, advanced reservoir monitoring techniques and the application of different enhancements of primary and secondary recovery processes. Secondary and tertiary recovery are together to as Improve oil recovery (IOR). **(Fig. 2-10)**

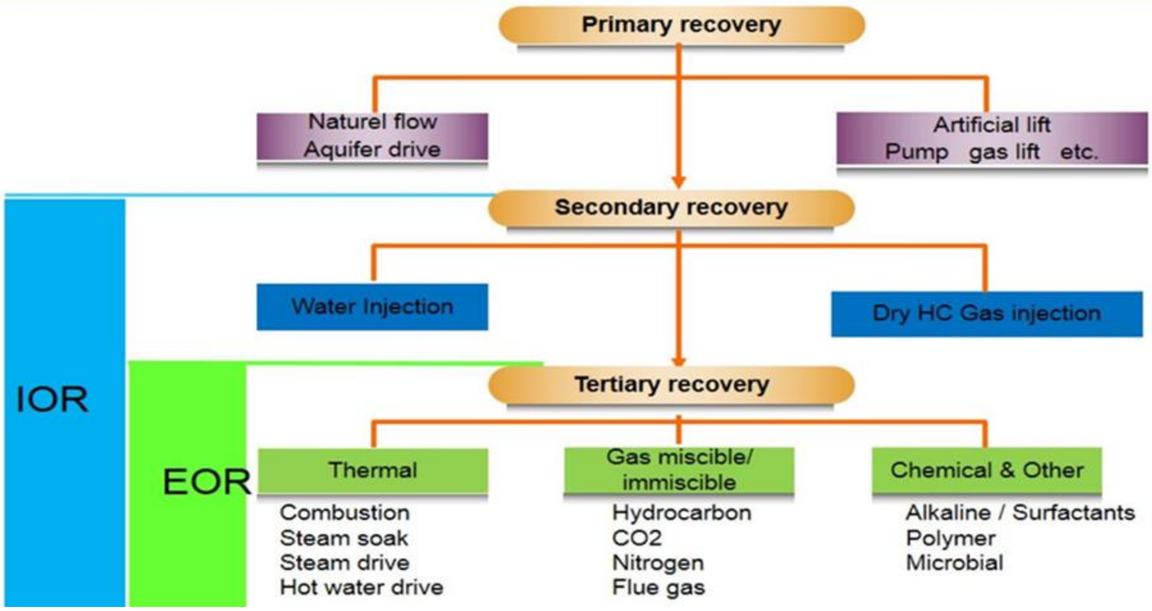

Figure 2-11 General Methods for Oil Recovery

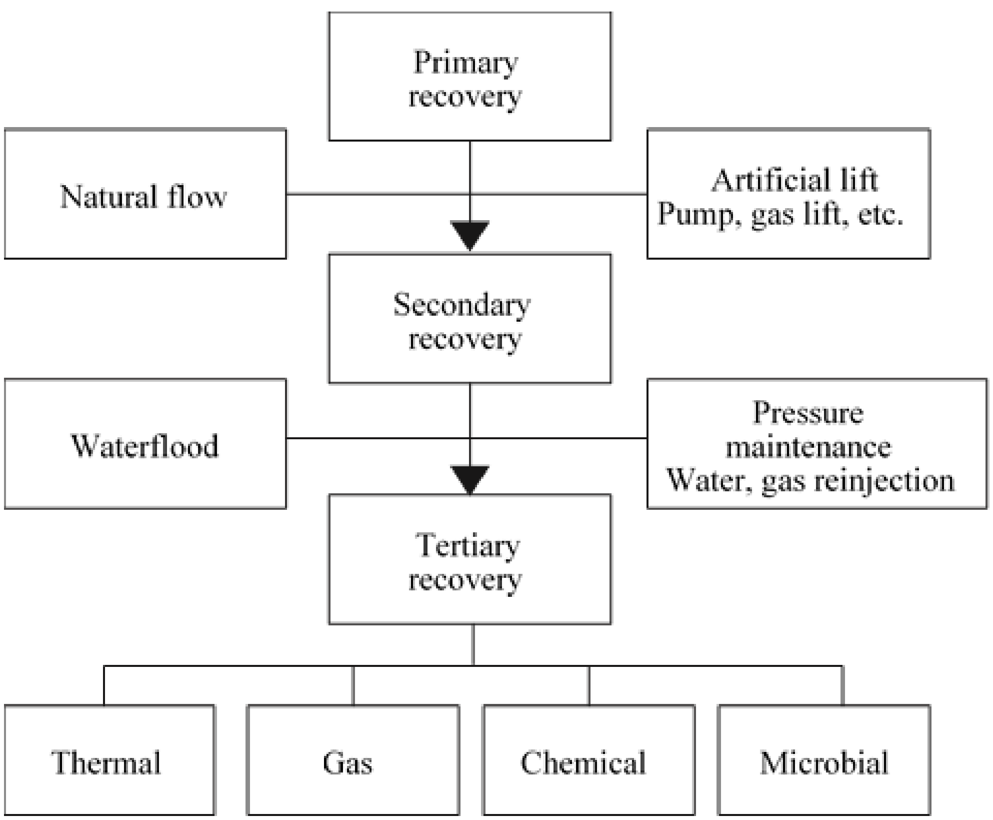

Figure 2-12 Methods for oil recovery

2.10. Enhanced Oil Recovery Methods

Enhanced oil recovery is one of the technologies needed to maintain reserves at an acceptable level. EOR methods used to improve reservoir recovery efficiency. Several enhanced oil recovery (EOR) techniques generally grouped together as tertiary production schemes have targeted this huge unexploited reserve (**Fig. 2-12**).

In the past, chemical, thermal, and miscible techniques have been used by the industry on a commercial scale. EOR techniques require the injection of chemical compounds dissolved in water, the injection of steam, or the injection of a gas that is miscible with the oil in place.

The amount of oil that can ultimately be recovered by existing EOR techniques is directly related to the price of crude oil. Important analysis before EOR projects begin: All EOR projects begin with an analysis of the nature, location, and causes of residual oil saturations (Sr) that remain after primary and/or secondary recovery operations.

Tertiary recovery includes all other methods used to increase the amount of oil recovered. The Efficiency of an Enhanced Recovery Method is a measure of its ability to provide greater. The optimal application of each type depends on reservoir temperature, pressure, depth, net pay, permeability remaining oil and water saturation, porosity and fluid properties such as oil API gravity and viscosity hydrocarbon recovery than by natural depletion, at an economically attractive production rate. These processes are summarized in the following:

1. Thermal methods: steam stimulation, steam flooding, hot water drive, and in-situ combustion
2. Chemical methods: Alkaline-surfactant-polymer processes (ASP), caustic and micellar/polymer flooding.
3. Miscible enhanced oil recovery OIEOR) methods including: hydrocarbon gas, C02, nitrogen, flue gas.
4. Microbial.

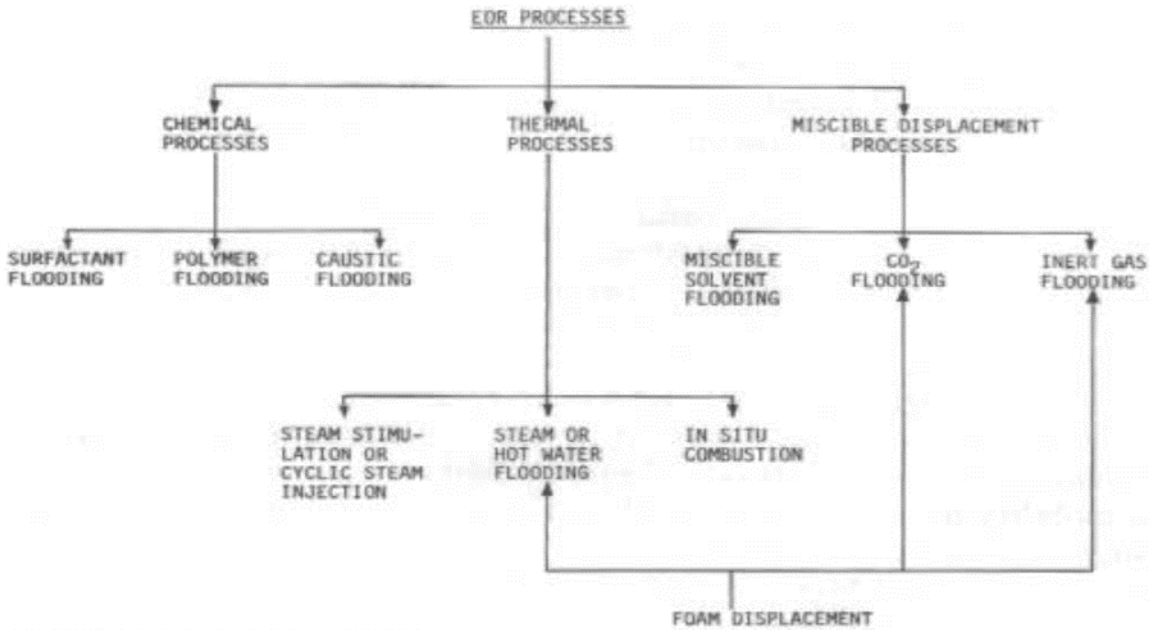

Figure 2-13 EOR process

2.10.1. Thermal Methods

Thermal methods raise the temperature of regions of the reservoir to heat the crude oil in the formation and reduce its viscosity and/or vaporize part of the oil and thereby decrease the mobility ratio. Thermal methods include the injection of hot water, steam or other gas, or by conducting combustion in situ of oil or gas.

The increase in heat reduces the surface tension and increases the permeability of the oil and improves the reservoir seepage conditions. The heated oil may also vaporise and then condense forming improved oil.

This approach however, requires substantial investment in special equipment. Both thermal recovery methods also severely damage the underground well structure, as well as pose safety risks in the larger production process. For these reasons, the methods are not generally used very often.

Primary production processes and secondary production processes from reservoirs containing heavy, low-gravity, viscous crude oils is usually a small fraction of the initial oil in place. This is due to the fact that these types of oils are very thick and viscous and as a result do not migrate readily to producing wells. However, the typical relationship between the viscosity of a heavy, viscous crude oil and temperature shows that viscosity decreases by orders of magnitude with an increase in temperature of 38°C to 95°C (100°F to 200°F) which, in the case of a heavy oil reservoir, will reduce the oil viscosity significantly and will flow much more easily to a producing well. The temperature of a reservoir can be raised by injecting a hot fluid (such as hot water or steam) or by generating thermal energy in situ by combusting the oil.

Viscosity, a measure of a liquid's ability to flow, varies widely among crude oils—some crudes flow easily (water-like) while others have more difficulty in flow properties. However, the viscosity of most crude oils dramatically decreases as temperature increases, and the purpose of all thermal oil recovery processes is to apply heat to the oil to enable flow under the impetus of injected fluids, which may be steam or hot water (steam injection), or air (combustion processes). Thus, thermal processes for oil recovery have found most use when the oil in the reservoir has a high viscosity.

Thermal EOR processes add heat to the reservoir to reduce oil viscosity and/or to vaporize the oil. In both instances, the oil is made more mobile so that it can be more effectively driven to producing wells. In addition to adding heat, these processes provide a driving force (pressure) to move oil to producing wells. The two main types of thermal recovery are:

2.10.1.1. Steam flooding

Steam flooding methods include: 1 steam drive - 2- cyclic steam injection.

Steam flooding introduces heat to the reservoir by pumping steam into the well in a pattern similar to that of water injection. Eventually the steam condenses to hot water. In the steam zone the oil evaporates and in the hot water zone the oil expands. As a result, the oil expands, the viscosity drops and the permeability increases. To ensure success, the process has to be cyclical. This is the principal enhanced oil recovery program in use today.

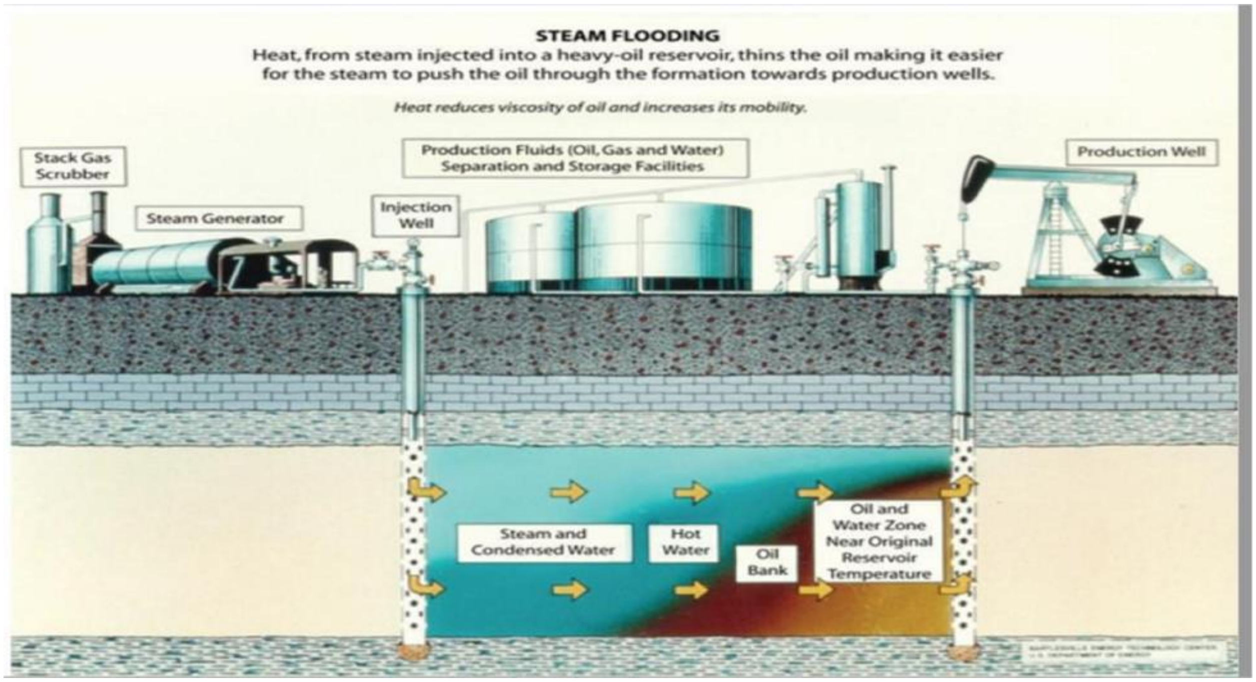

Figure 2-14 Steam flooding

Steam drive

The steam drive process (or processes) are considerably different in performance from hot-water drives due to the presence and effects of the steam which causes low molecular weight constituents in the oil to be distilled and carried along as hydrocarbon constituents in the gas phase. When and wherever the steam condenses, the condensable hydrocarbon components also condense and reduce the viscosity of the crude oil at the condensation front. Moreover, the condensing steam makes the displacement process more efficient and improves the sweep efficiency. Thus, the net effect is that recovery from steam drives is significantly higher than from hot water drives.

An important additional phenomenon affecting displacement in steam drives is the steam distillation of the relatively low-boiling fractions in the oil. Distillation causes the vapor phase to be composed not only of steam but also of condensable hydrocarbon vapors. Some hydrocarbon vapors will condense along with the steam, mixing with the original crude and increasing the amount of relatively light fractions in the residual oil trapped by the advancing condensate water ahead of the front. Dilution by the low-boiling constituents causes some of the trapped oil to be displaced by the condensed water. The remainder of the oil is stripped by the steam of all the remaining low boilers to leave the higher boiling residuum.

The lower-boiling constituents help to regenerate and maintain a solvent bank just downstream of the condensation front. During the process, the composition of the produced oil generally does not change until the steam zone is relatively near, at which point the volatile content increased markedly.

Steam drive injection (steam injection) has been commercially applied since the early 1960s. The process occurs in two steps: (1) steam stimulation of production wells, that is, direct steam stimulation; and (2) steam drive by steam injection to increase production from other wells (indirect steam stimulation). Steam drive differs considerably in performance from hot-water drive—the difference in performance is due to the presence and effects of the condensing vapor. The presence of the gas phase causes low-boiling constituents present in the crude oil to be distilled and carried along as hydrocarbon components in the gas phase. When the steam condenses, the condensable hydrocarbon constituents of the vapor also condense and reduce the viscosity of the crude oil at the condensation front. In addition, the condensing steam makes the displacement process more efficient and improves the sweep efficiency and the net effect of the steam drive is that crude oil recovery is significantly higher than the crude oil recovery from hot-water drives. (**Fig. 2-15**)

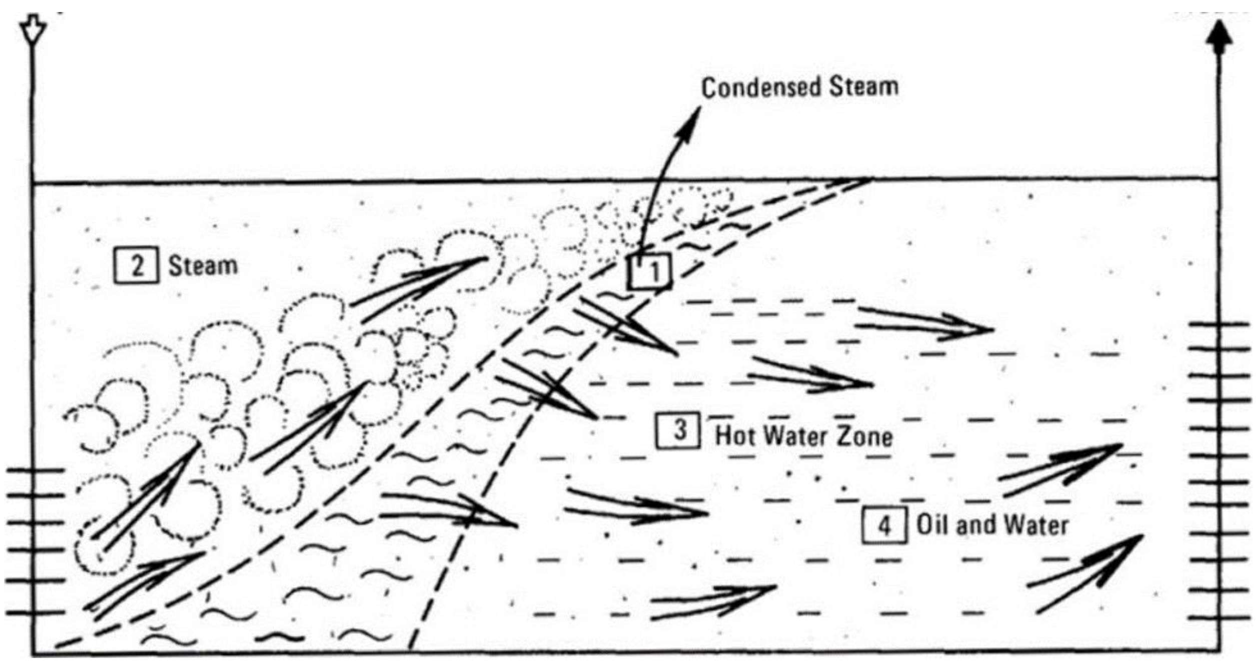

Figure 2-15 Steam Drive Process Scheme and Zones Formed in The Reservoir.

When there is some natural reservoir energy, steam stimulation normally precedes steam drive. In steam stimulation, heat is applied to the reservoir by the injection of high-quality steam into the produce well. This cyclic process, also called huff and puff or steam soak, uses the same well for both injection and production. The period of steam injection is followed by production of reduced viscosity oil and condensed steam (water). One mechanism that aids production of the oil is the flashing of hot water (originally condensed from steam injected under high pressure) back to steam as pressure is lowered when a well is put back on production.

cyclic steam injection

Cyclic steam injection is the alternating injection of steam and production of oil with condensed steam from the same well or wells. Thus, steam generated at surface is injected in a well and the same well is subsequently put back on production. A cyclic steam injection process includes three stages. The first stage is injection, during which a measured amount of steam is introduced into the reservoir. The second stage (the soak period) requires that the well be shut in for a period of time (usually several days) to allow uniform heat distribution to reduce the viscosity of the oil (alternatively, to raise the reservoir temperature above the pour point of the oil). Finally, during the third stage, the now-mobile oil is produced through the same well. The cycle is repeated until the flow of oil diminishes to a point of no returns. (**Fig. 2-16**)

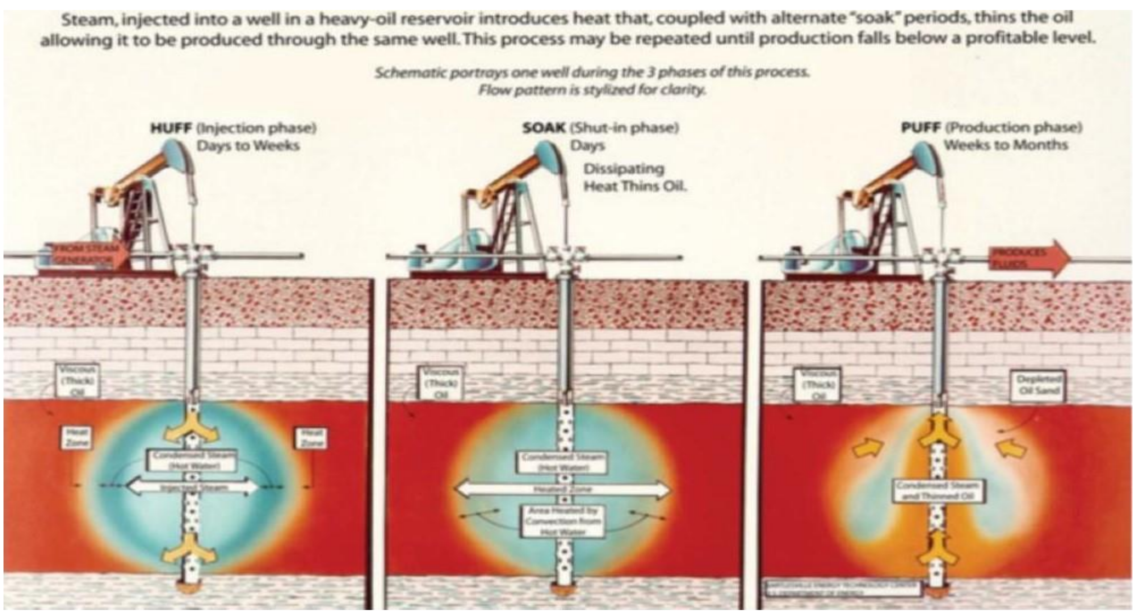

Figure 2-16 Cyclic steam process

Combustion to introduce heat to the reservoir.

In situ combustion of oil on site or fire flood, works best when the oil saturation and porosity are high. Combustion generates the heat within the reservoir itself. Continuous injection of air, or other gas mixture with high oxygen content, will maintain the flame front. As the fire burns, it moves through the reservoir towards the production wells. Heat from the fire reduces oil viscosity and helps to vaporize reservoir water to steam. The steam, hot water, combustion gas and a bank of distilled solvent all act to drive oil in front of the fire toward production wells (Figure2.17).

The performance of in situ combustion is predominantly determined by the four following factors: (1) the quantity of oil that initially resides in the rock to be burned; (2) the quantity of air required to burn the portion of the oil that fuels the process; (3) the distance to which vigorous combustion can be sustained against heat losses; and (4) the mobility of the air or combustion product gases.

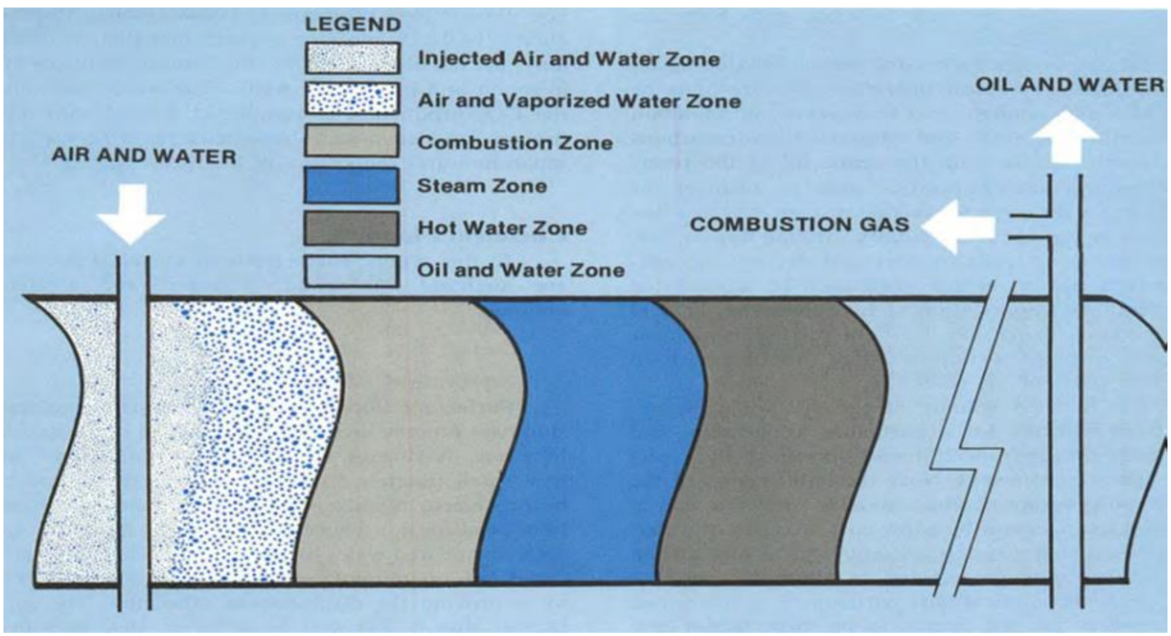

Figure 2-17 In-situ combustion process

There are three methods of combustion: Dry forward, reverse and wet combustion. The dry forward method uses an igniter to set fire to the oil. As the fire progresses, the oil is pushed away from the fire toward the producing well. In the reverse method, the air injection and the ignition occur from opposite directions. In the wet combustion method, water is injected just behind the front and turned into steam by the hot rock. This quenches the fire and spreads the heat more evenly.

2.10.2. Chemical Methods

Chemical flooding involves the addition of one or more chemical compounds to an injected fluid either to reduce the interfacial tension between the reservoir oil and the injected fluid or to improve the sweep efficiency of the injected fluid. There are three general methods in chemical flooding technology: (1) alkaline flooding; (2) polymer flooding; and (3) micellar-polymer flooding. Alkaline flooding and micellar-polymer flooding use chemicals that reduce the interfacial tension between an oil and a displacing fluid. Polymer flooding uses a macromolecule to increase the displacing fluid viscosity which leads to improved sweep efficiency in the reservoir.

Technical issues that have arisen with the use of chemical processes include: (1) screening chemicals to optimize the microscopic displacement efficiency; (2) making contact with the oil in the reservoir; and (3) maintaining good mobility in order to lessen the effects of viscous fingering. The requirements for screening of chemicals vary with the type of process and the chemicals must also be able to tolerate the environment in which they are used. Also, high temperature and salinity may limit the chemicals that could be used.

2.10.2.1. Alkaline Flooding

Alkaline flooding involves the use of aqueous solutions of certain chemicals, such as sodium hydroxide, sodium silicate, and sodium carbonate, that are strongly alkaline. These solutions will react with constituents present in some crude oils or present at the rock/crude oil interface to form detergent-like or surfactant-type materials which reduce the ability of the formation to retain the oil. These chemicals enhance oil recovery by one or more of the following mechanisms: interfacial tension reduction; spontaneous emulsification; or wettability alteration. These mechanisms rely on the in-situ formation of surfactants during the neutralization of petroleum acids in the crude oil by the alkaline chemicals in the displacing fluids. Alkaline substances that have been used include sodium hydroxide, sodium orthosilicate, sodium metasilicate, sodium carbonate, ammonia, and ammonium hydroxide. Sodium hydroxide has been the most popular.

When an alkaline solution is mixed with certain crude oils (high-acid crude oils are an example of such oils), surfactant molecules are formed formation of the surfactants in situ raised the possibility that the interfacial tension between the brine and oil phases could be reduced. The reduction of interfacial tension causes the microscopic displacement efficiency to increase, which thereby increases oil recovery. There are optimum concentrations of alkaline and salt and optimum pH where the interfacial tension values experience a minimum.

Several mechanisms have been identified that aid oil recovery in the alkaline process. These include the following: (1) lowering of the interfacial tension; (2) emulsification of the oil; and (3) wettability changes in the rock formation. All three mechanisms can affect the microscopic displacement efficiency, and emulsification can also affect the macroscopic displacement efficiency.

The addition of sodium hydroxide to injection water to aid recovery. It does this by lowering the surface tension, reversing the rock wettability, emulsifying the oil, mobilising the oil and helping to draw the oil out of the rock.

In areas with relatively poor physical properties and low permeability, there will still be a lot of residual oil left behind underground after using artificial water drive (e.g. generally heterogeneous sandstone reservoir results in ultimate oil recovery of only about 30 per cent).

2.10.2.2. Polymer Flooding

Polymer flooding is being adopted at an earlier stage in waterfloods because of its capability to control breakthrough and increase areal sweep efficiency.

Polymer flooding is one of the most widely used EOR methods to retrieve oil left behind after conventional recovery processes. It’s an augmented water flooding technique introduced in the 1960’s, mainly used for heterogeneous reservoirs, to retrieve oil after areas in the reservoir with high permeability have been highly water flooded.

The addition of polymers to an injected water can often increase the effectiveness of a conventional waterflood. Polymers are usually added to the water in concentrations ranging from 250 to 2000 parts per million (ppm) and a polymer solution is typically more viscous than a brine without polymer. In a flooding application, the increased viscosity changes the mobility ratio between the injected fluid and the reservoir oil leading to better vertical and areal sweep efficiencies and thus higher oil recoveries. Polymers have also been used to alter gross permeability variations in some reservoirs. In this application, polymers form a gel-like material by cross-linking with other chemical species and the polymer gel deposits in large permeability streaks and fractures diverting the flow of any injected fluid to a different location. Polymer flooding has seen success in moderately heterogeneous reservoirs and reservoirs containing oils with low viscosity (<100 cP).

The polymer flood process is:

1-Injection of polymer slug 0.3 or higher PV. 2-Injection of a low-salinity brine(freshwater) "pad" to protect the slug from brine / formation water. 3-Injection of brine / formation water chase fluid and by continuous drive water injection.

As explained by CNPC: “Polymer flooding is a tertiary recovery method by adding high-molecular-weight polyacrylamide into injected water, so as to increase the viscosity of fluid, improve volumetric sweep efficiency, and thereby further increase the oil recovery factor.

In the process, a polymer-thickened water solution process is introduced after the chemicals are injected to help obtain a more uniform movement (sweep) through the reservoir. Fresh water is then injected behind the polymer solution to prevent contamination from the final drive water which may be salty or otherwise incompatible with the chemicals. Alkaline flooding is usually more efficient if the acid content of the reservoir oil is relatively high. A new modification to the process is the addition of surfactant and polymer to the alkali, giving rise to an alkaline-surfactant-polymer enhanced oil recovery method. Although emulsification in alkaline flooding processes decreases injection fluid mobility to a certain degree, emulsification alone may not provide adequate sweep efficiency. Sometimes polymer is included as an ancillary mobility control chemical in an alkaline waterflood to augment any mobility ratio improvements due to alkaline-generated emulsions (**Fig. 2-18**).

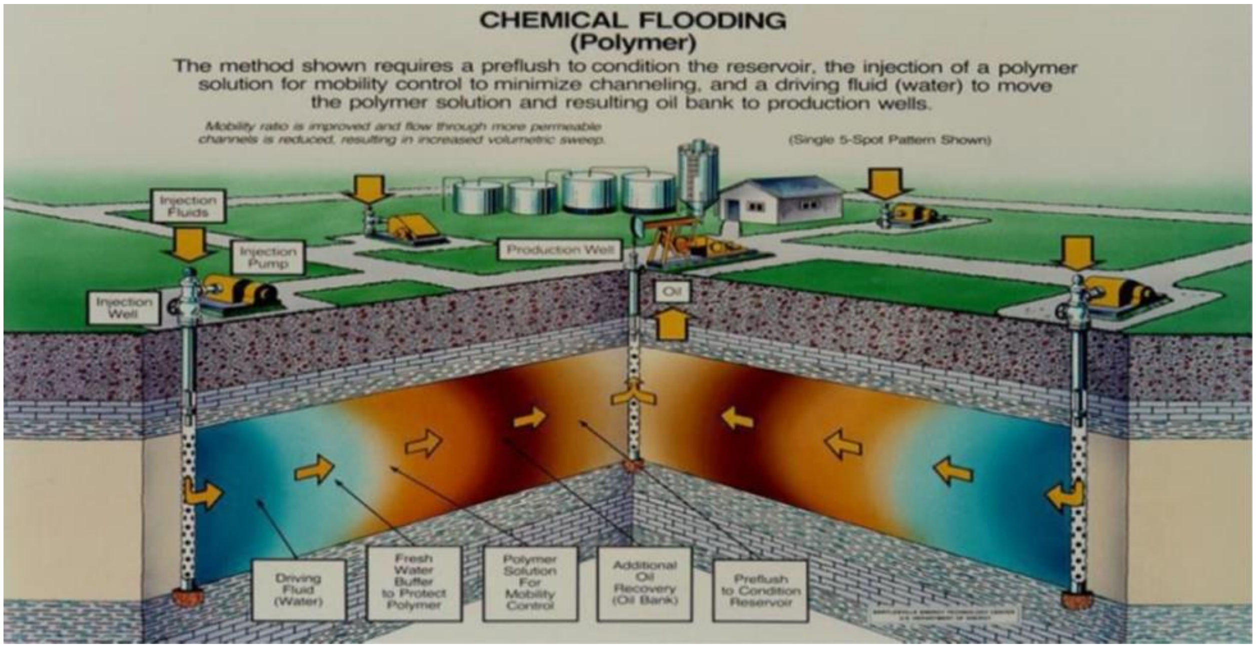

Figure 2-18 Chemical (Polymer Flooding)

Two general types of polymers have been used: (1) polyacrylamides; and (2) biologically produced polysaccharides. Polyacrylamides are long molecules with a small effective diameter and are susceptible to mechanical shear. High rates of flow through valves will sometimes break the polymer into smaller entities and reduce the viscosity of the solution, this can also occur as the polymer solution passes through the pore openings on the sand face of the injection well. However, polyacrylamides are also sensitive to salt (NaCl) and high concentrations of salt (in excess of 1% to 2% w/w) have an adverse effect on the viscosity-building effect of the polymers. On the other hand, polysaccharides are less susceptible to both mechanical shear and salt and, since they are produced biologically, care must be taken to prevent biological degradation in the reservoir. Typically, the use of polymers does not affect the microscopic displacement efficiency and the improvement in oil recovery is due to an improved sweep efficiency over what is obtained during a conventional water flood. Typical oil recoveries from polymer flooding applications are varied and are more likely to be successful if the process is initiated early in the producing life of the reservoir.

2.10.2.3. Micellar-Polymer Flooding

The micellar-polymer process uses a surfactant to lower the interfacial tension between the injected fluid and the reservoir oil. The surfactant migrates to the interface between the oil and water phases and helps make the two phases more miscible. Interfacial tensions can be reduced from approximately 30 dynes/cm, found in typical waterflooding applications, to 10−4 dynes/cm with the addition of as little as 0.1% to 5.0% w/w surfactant to water–oil systems.

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. The reduction of the interfacial tension results in a shifting of the relative permeability such that the oil will flow much more readily at lower oil saturations.

When surfactants are mixed above a critical saturation in a water-oil system, the result is a stable micellar solution which is made up of microemulsions that are homogeneous, transparent, and stable to phase separation. A microemulsion consists of external and internal phases sandwiched around one or more layers of surfactant molecules. The external phase can be either aqueous or hydrocarbon in nature, as can the internal phase. The microemulsions can exist in several shapes, which depend on the concentrations of surfactant, oil, water, and other constituents. Spherical microemulsions have a typical size ranging from 10−6 to 10−4mm.

There are, in general, two types of micellar–polymer processes: (1) one which uses a low-concentration surfactant solution (<2.5% w/w) but a large injected volume (up to 50% pore volume); and (2) another which involves use of a high-concentration surfactant solution (5% to 12% w/w) and a small injected volume (5% to 15% v/v of the pore volume). Either type of process has the potential of achieving low interfacial tensions with a wide variety of brine–crude oil systems. Whichever system is selected, the system is made up of several components. The multicomponent facet leads to an optimization problem, since many different combinations could be chosen. Because of this, a detailed laboratory screening procedure is necessary and typically involves three types of tests for: (1) phase behavior; (2) interfacial tension; and (3) oil displacement.

Phase behavior tests are typically conducted in small (up to 100 mL) vials in order to determine what type, if any, of microemulsion is formed with a given micellar– crude oil system. The salinity of the micellar solution is usually varied around the salt concentration of the field brine where the process will be applied. Besides the microemulsion type, other factors examined could be oil uptake into the microemulsion, ease with which the oil and aqueous phases mix, viscosity of the microemulsion, and phase stability of the microemulsion. Interfacial tension tests are conducted with various concentrations of micellar solution components to determine the optimal concentration ranges.

The oil displacement tests are usually conducted using two or more types of porous media. Often initial screening experiments are conducted in unconsolidated sand packs and then in Berea sandstone. The last step in the sequence is to conduct the oil displacement experiments in actual cored samples of reservoir rock. Frequently, core samples are placed end to end in order to obtain a core of reasonable length since the individual core samples may be only 5 to 7 inches long.

2.10.3. Miscible enhanced oil recovery (Gas Drive Oil)

Gas injection or miscible flooding is a general term for injection processes that introduce miscible gases into the reservoir. A miscible displacement process maintains reservoir pressure and improves oil displacement because the interfacial tension between oil and water is reduced. This refers to removing the interface between the two interacting fluids. This allows for total displacement efficiency.

Gases used in this process include CO_2, natural gas or nitrogen. The fluid most commonly used for miscible displacement is carbon dioxide because it reduces the oil viscosity and is less expensive than liquefied petroleum gas. Oil displacement by carbon dioxide injection relies on the phase behavior of the mixtures of that gas and the crude – these behaviors are strongly dependent on reservoir temperature, pressure and crude oil composition.

As oil and gas have a cognate symbiosis in the same structural trap, their physical and chemical properties are similar. As such, the Gas Drive Oil method has the potential to deliver better displacement process efficiency and higher recovery rates than other techniques. However, this theory is relevant only under specific reservoir conditions. If these specific conditions are present, then the volume expansion of the injected gas which acts to move the oil, takes precedent over the smaller chemical reactions from the gas drive process at the oil and gas interface.

2.10.3.1. Carbon Dioxide Flooding

When a reservoir's pressure is depleted through primary and secondary production, carbon dioxide flooding can be an ideal tertiary recovery method. It's particularly effective in reservoirs deeper than 2,000ft., where CO_2 will be in a supercritical state.

Carbon dioxide flooding works on the premise that by injecting CO2 into the reservoir, it dissolves in oil, the oil swells and the viscosity of any hydrocarbon will be reduced and hence, it will be easier to sweep to the production well.

If an existing well has been designated suitable for CO2 flooding, the pressure within the reservoir must first be restored to that of one suitable for production by injecting water (with the production well shut off) (**Fig. 2-19**).

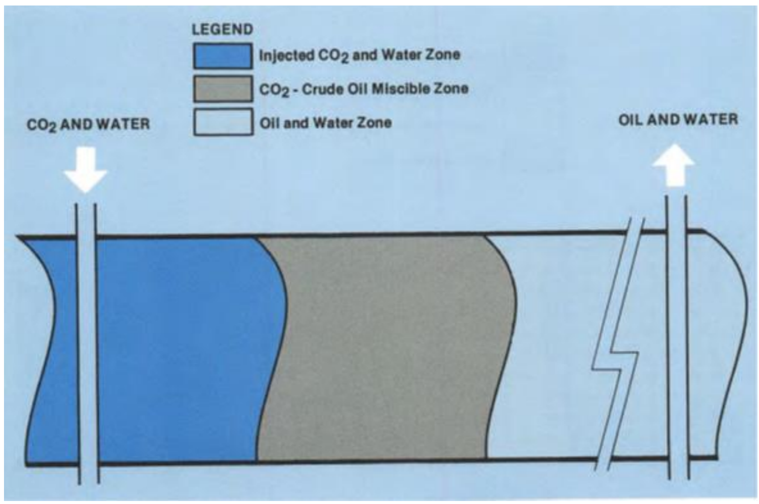

Figure 2-19 Carbon Dioxide Flooding process

Once the reservoir is at this pressure, liquid CO2 is injected into the same injection wells used to restore pressure to generate H2CO3, soluble Ca and Mg ionic components in the reservoir. The CO2 gas is forced into the reservoir and is required to come into contact with the oil.

This creates a miscible zone that can be moved more easily to the production well. Normally the CO2 injection is alternated with more water injection, with the water acting to sweep the oil towards the production zone.

In these applications, between one-half and two-thirds of the injected CO2 returns with the produced oil. This is then usually re-injected into the reservoir to minimise operating costs. The remainder is trapped in the oil reservoir by various means. Carbon dioxide as a solvent has the benefit of being more economical than other similarly miscible fluids such as propane and butane.

This type of technology can be good to enlarge volume and improve recovery efficiency, but unless natural CO2 exists in the neighborhood area, it's generally difficult to collect sufficient amounts of CO2 for industry use.

2.10.4. Microbial.

Microbial enhanced oil recovery (MEOR) processes involve the use of reservoir microorganisms or specially selected natural bacteria to produce specific metabolic events that lead to enhanced oil recovery. The processes that facilitate oil production are complex and may involve multiple biochemical processes. Microbial biomass or biopolymers may plug high-permeability zones and lead to a redirection of the water flood, may produce surfactants that lead to increased mobilization of residual oil, may increase gas pressure by the production of carbon dioxide, or may reduce the oil viscosity due to digestion of large molecules.

These days there is also a new biological theory which involves injecting bacteria into the oil reservoir to improve the recovery efficiency. Experimental results using a particular species in a reservoir have shown that through the metabolism of large population, large amounts of organic acids can be produced. These organic acids may act to restore vitality to an aging well, increase it From a microbiologist's perspective, microbial enhanced oil recovery

processes are somewhat akin to in situ bioremediation processes. Injected nutrients, together with indigenous or added microbes, promote in situ microbial growth and/or generation of products that mobilize additional oil and move it to producing wells through reservoir repressurization, interfacial tension/oil viscosity reduction, and selective plugging of the most permeable zones. Alternatively, the oil-mobilizing microbial products may be produced by fermentation and injected into the reservoir. productivity and thereby act to induce a substantial increase in oil recovery.

Three approaches have been used to achieve microbial injection. In the first approach, bacterial cultures mixed with a food source (a carbohydrate such as molasses is commonly used) are injected into the oil field.

In the second approach, used since 1985, nutrients are injected into the ground to nurture existing microbial bodies. These nutrients cause the bacteria to increase production of the natural surfactants they normally use to metabolise crude oil underground. After the injected nutrients are consumed, the microbes go into near-shutdown mode, their exteriors become hydrophilic, and they migrate to the oil-water interface area where they cause oil droplets to form from the larger oil mass. This then makes the oil droplets more likely to migrate to the wellhead.

The third approach is used to address the problem associated with the paraffin wax components of the crude oil, which tend to precipitate as the crude flows to the surface. Since the Earth's surface is considerably cooler than the petroleum deposits, a temperature drop of 9-10-14 °C per thousand feet of depth is usual.

Microbial injection is part of microbial enhanced oil recovery and is rarely used because of its higher cost and because the developments are not widely accepted. These microbes function either by partially digesting long hydrocarbon molecules and generating bio-surfactants, or by emitting carbon dioxide, which then functions as described in Gas Injection above.

One of the major attributes of microbial enhanced oil recovery is its low cost, but there must be recognition that it is a single process. Furthermore, reports on the deleterious activities of microorganisms in the oil field contribute to the skepticism of employing technologies using microorganisms. It is also clear that scientific knowledge of the fundamentals of microbiology must be coupled with an understanding of the geological and engineering aspects of oil production in order to develop microbial enhanced oil recovery technology. Finally, recent developments in upgrading of heavy oil and bitumen indicate that the near future could see a reduction of the differential cost of upgrading heavy oil. These processes are based on a better understanding of the issues of asphaltene solubility effects at high temperatures, incorporation of a catalyst that is chemically precipitated internally during the upgrading, and improvement of hydrogen addition or carbon rejection.

2.11. EOR Project Planning

Successful EOR project management depends on good planning – “prior proper planning prevents poor performance”, they say, and it’s especially true when EOR is involved. From the outset careful attention to economics and modeling at every step greatly improves the chances of success. We have all been involved in EOR developments where considerable time and effort was spent on projects that had no hope of achieving adequate profitability. Early screening studies would have clearly identified the problem and avoided a great deal of pointless engineering work.

Process selection begins with the identification of a target volume of hydrocarbons not accessible by primary or secondary means. This identification requires answers to the following questions:

1) What is the remaining hydrocarbon in-place after conventional methods?
2) Where is this resource located?
3) What is the reason it has not been recovered?

The determination and confirmation of the target volume and location is a critical first step in process selection. In order to answer these questions, a body of information about the characteristics of both the reservoir and the reservoir fluids is necessary. Geological analysis and dynamic modeling, addressed later herein, can help answer these questions, but should if possible be supported by field data: core analyses, fluid properties measurement, and detailed production history and pressure information.

Screening will result in a few candidate processes; selection requires that the specific target reservoir be matched to the specific process. This is not wholly a technical question; the economic viability of the project will depend on the matching process. For any EOR process: Can the process selected be used in the selected reservoir, given the reservoir rock and fluid environment in place? Can this process be implemented in such a way that it will result in an economically attractive project?

The answers to the above questions are critical in the final selection of a process, and must be carried out in conjunction with geological and laboratory investigations, as well as with project economic analysis and project design.

2.11.1. Geologic Studies

A good understanding of the reservoir geology is critical to the success of an EOR project. Because it is vital to contact remaining oil-in-place with the injecting, the geological understanding should be in sufficient detail to allow modeling of these complicated processes. In most cases, the reservoir will have sufficient production performance so that a history match can be obtained. This will not necessarily provide a sufficient geological description for EOR purposes. In EOR, movement of injecting through a thief zone, causing premature breakthrough, or loss of injecting out of zone, may result in failure of the project. Mineralogy of the reservoir, by determining the amount of adsorption of injecting (in the case of polymer and chemical methods), will dictate the amount of injecting necessary for success. A detailed geologic study should precede any EOR effort. This study should at a minimum revisit all logs, core and fluid data, as well as result in a detailed geologic model that provides a satisfactory history match to production performance.

In addition, reservoir fluid and core samples should be obtained and analyzed, and the data specific to the EOR method to be used for project design identified and gathered. If a pilot is intended, data should be gathered in the pilot area, and detailed geologic modeling carried out specific to the pilot.

2.11.2. Modeling

The modeling of EOR projects requires that the reservoir description used for conducting reservoir simulation studies be consistent with the geological model, and validated with pre- EOR reservoir performance, and requires much more data and time than scale-up techniques and waterflood secondary recovery project design studies. The modeling of EOR projects is basically a five-step procedure: (1) selection of an appropriate reservoir simulator for conducting the project design study, (2) collecting valid input data, (3) history matching past production-pressure performance of the reservoir, (4) predicting future EOR project performance, and (5) determining the optimum EOR project design, by conducting sensitivity studies.

The procedure for selecting an appropriate reservoir simulator for conducting an EOR project design study involves selecting a black oil or modified black oil/pseudo-compositional or fully compositional or thermal simulator that will accurate predict the performance of the reservoir under the EOR processes to be simulated. Since most producing companies these days use commercially available reservoir simulators, selection of a reservoir simulator involves not only comparing which of the commercially available simulators are known to be bug free, have the necessary and user-friendly pre- and post-processing interfaces, and run fast on the types of reservoirs and EOR processes to be simulated, but also the record/reputation of the software vendor in providing technical support whenever necessary to ensure that the reservoir simulation studies can move forward smoothly and the project can be completed in a timely manner.

2.11.3. Economics

For EOR projects, as in all E&P projects, the primary economic driver is project profitability, in most cases. Will the project meet the necessary economic criteria, and what are the conditions under which this will occur? In some cases, development of a reliable production stream, reserves additions, or employment related to project longevity might also be considerations. The economics of an EOR project are closely linked to the technical design of the process. Economic analysis should be carried out in tandem with the process screening and process selection steps, progressing from simple to progressively more complex analyses.

Once the target oil volume is determined, and process screening has resulted in the choice of a few options on a technical basis, economic screening should be done. At this stage, the critical parameters may be the slug size and cost of the EOR injecting. Using a range o During the screening step, it is essential that the range of uncertainty in both the reservoir parameters and the process parameters be recognized and considered. The process should be evaluated using optimistic assumptions for those parameters for which a range of uncertainty exists. At this stage, the effort should be to identify the critical technical factors that impact the project, so that subsequent efforts may be focused on those elements, which most impact the project viability. Included in this are assumptions regarding the timing and operation of the project; thus, simple process modeling using parameters of the field project in reservoir simulations will guide the economic analysis and the process selection path forward’s subsurface parameters, project economics can be estimated. Once the process has been selected, both the technical and economic effort will be focused on those aspects of the project, which have been identified as critical to success. This effort will use the results of laboratory investigations and field-testing, incorporated into more detailed reservoir geological and simulation models, to better characterize the project and its viability.

The economic analysis is critical to the success of an EOR project, by identifying the critical technical parameters that govern the project’s profitability and providing the justification to carry out the necessary work to confirm assumptions, modify the process, and optimize the results. It should be an integral part of the project design and development process.

2.11.4. Design Parameters

The specific EOR process to be implemented will determine the project design parameters that are critical. Design must be carried out on the micro scale, as well as the macro scale. On the micro scale, the parameters that determine an efficient displacement must be specified. In the case of a miscible project, for example, results from detailed laboratory tests of miscibility pressure and multiple contact experiments will be used to determine the optimum displacement of hydrocarbons.

In chemical processes, adsorption experiments will determine the rock-slug interaction, and phase behavior studies and surface tension measurements will allow design of the displacement process.

2.11.5. Pilots

There is a misconception that it is necessary, for technical reasons, to carry out a field pilot of any EOR process. This is not true. For example, if there is sufficient analogue experience, and the reservoir geology is understood, modern simulation methods may be reliable enough to make a pilot test unnecessary. A second misconception is that an “oil in the tank” pilot is sufficient to be able to predict performance on a field scale. Such pilots are almost always not sufficient to make a reliable extrapolation to a full-scale project.

The question should be: “what are the critical unknowns that may cause a material difference in the response of the project?” These critical parameters should be known from the sensitivity studies done in the process selection and design steps, and their accompanying economic analyses and reservoir modeling. If it is concluded that uncertainties in the key parameters are critical in determining the project’s viability, and that these uncertainties cannot be resolved in the laboratory or through modeling, then a pilot test should be considered to reduce those uncertainties. The pilot should then be designed to obtain the key information necessary. The pilot should be able to provide the quantitative information needed to calibrate models to predict commercial performance, and to reduce the project risk to acceptable levels. Pilot tests may range from a simple infectivity test to a full multipattern injection and production test. Pre- and post-test cores may be needed; logging and sampling observation wells and other data gathering methods may be necessary. A good understanding of the geology of the site, as well as dedicated production and injection wells, is critical to the success of a pilot.

Any pilot test should be specifically designed to obtain the key data required to better make a project decision. An appropriate test site, dedicated personnel, facilities, and wells are required, along with a commitment to use these resources to design, implement and carry the pilot to its conclusion. Thus, a pilot test must also be staffed with appropriate personnel, and have effective surveillance and post-test analysis carried out, in order to add value to the project.

2.11.6. Project Implementation

The project design will include in it recommendations for data gathering and surveillance activities, as well as operational guidelines and quality control specifications which will be essential to its success. Good installation and implementation of a project, following the guidelines and recommendations is likewise essential to its success. Prior to project startup, field personnel must be trained in the project's purpose and operations. An EOR project does not represent "business as usual" in the oil field. A detailed project management document should be developed, detailing both the project expectations and the surveillance activities to be carried out during the life of the project. Included should be scheduled well and project reviews on a regular basis.

Recommended surveillance may include taking of pressure or temperature data in observation wells, obtaining production fluid samples, carrying out quality control activities on injection fluid facilities, as well as the normal field operations activities. The use of a suite of reservoir simulation models which encompass the range of uncertainties in the process and project, as part of the normal reservoir management and surveillance process, will provide the ability to incorporate the data gathered and diagnose the behavior of the project. These models should be extensions of those used for project design, to provide a tie to the original project justification.

EOR is a technique, which can provide significant increases in recovery from a reservoir, but those increases depend on appropriate process selection, good project design, recognition and addressing of critical uncertainties, and attention to details in the implementation and management of the project.

2.12. Case Study 1: Oil Recovery from Thin Heavy-Oil Reservoirs: The Case of the Combined- Thermal-Drive Pilot in the Morgan Field

At 2013**, Dubert Gutie´rrez** wrote about the technique that improved the production of thin heavy oil at Morgan Field in Canada which applied for 10 years.

The Morgan field in Canada produces from the Lloydminster and Sparky sands, which are thin heavy-oil reservoirs. However, the area was essentially noncommercial after the 1986 oil-price collapse. In order to regain commerciality, the operators implemented progressing cavity pumps (PCPs) and horizontal drilling, which have proved to be a success. After applying these technologies only 10 % of the original oil in place (OOIP) had been estimated.**[2]**

Many projects had applied for this field. One of the EOR projects the combined-thermal-drive (CTD) pilot, which was carried out in one of the sections of the field for 10 years. The CTD had done in three stages:

- **Stage one**: Cyclic-steam stimulations **CSS**s were performed on individual wells.
- **Stage two**: In the next 4 years, air was added to the injection stream to perform cyclic air/steam stimulations on individual wells.
- **Stage three**: Pressure cycling in-situ combustion was performed for approximately 4 years.

2.12.1. Reservoir Properties

Table 2-8 Average Reservoir Properties in The Morgan Pilot Area

Reservoir Properties	Value or Type
Producing formation	Lloydminster “A”
Geologic age	Cretaceous
Description of pay	Sandstone
Depth (ft.)	1,900
Net pay thickness (ft.)	31
Porosity (%)	31
Permeability (md)	2,000
Oil saturation (%)	80
Original reservoir pressure (psi)	580
Bubble point pressure (psi)	580
Solution-gas/oil ratio (scf/STB)	53
Reservoir temperature (F)	70
Live-oil viscosity (cP)	6,800
Dead-oil viscosity (cP)	18,000
Oil gravity (API)	11–12
Initial oil formation volume factor (RB/STB)	1.025
Original oil in place (million STB)	25.3

2.12.2. Results and Conclusions

Historical production and injection records were gathered to perform a technical and economic analysis of the project. After approximately 20 years since the shutdown of the project, the data indicate that this pilot has outperformed all of the other operations carried out in other areas of the field. Not only has it produced the largest amount of incremental oil of all the sections of the field, but it also managed to sustain high production rates for 10 years, which is unparalleled in the area. On the economic side, the data indicate that the project was experiencing difficulty because of the 1986 oil-price collapse. However, an eco- nomic analysis under current oil prices and costs suggests that it would have been both a technical and an economic success. This air-injection case history represents a good opportunity for those operators facing the challenge to develop thin heavy-oil reservoirs.

The CTD project developed in the thin heavy-oil sands of the Morgan field was a technically successful pilot, which was unfortunately discontinued because of the unfavorable economic environment encountered during the 1980s. An analysis of the production data suggests that an incremental-recovery factor of approximately 15% was achieved after 10 years of operation, which is unparalleled in the area. An economic analysis under current oil prices and costs suggests that the fate of this project might have been different had the oil price been higher than USD 30/bbl., as it has been in recent years.[2]

2.13. Case Study 2: Steam flooding Heavy Oil in a Naturally Fractured Carbonate Reservoir in Sultanate of Oman.

This case study was applied to Khuff and Kahmah reservoirs in Mukhaizna Field by Oxy company. These reservoirs fluid was very viscous up to 10,000 cp which was a big challenge along with the lack of analogous fields that cause Oxy to be pioneer in new steam flooding methodology in Oman. The persistence in finding new ways to produce highly viscous oil from thin, heterogeneous limestone reservoir using steam injection has paid rich dividends. This would not be done without support from operation staff to a dedicated team.

The injection of large slugs of steam into low permeability reservoir at high pressure led to the development of SSI (sequential steam injection), this has helped in increasing injection rate of steam and thus approximately 10% of oil. Quick communication between wells during CSS and SSI was recovered by GCSS (Grouped cyclic steam stimulation) concept which has proven its effectiveness.

The central field area was thought to be producing high water cuts from the flanks , but actually simulation model with ADT Logs proved that the water was from the reservoir itself. After that modifications were applied to the development strategy and ESPs were used to reduce the reservoir pressure and increase steam injection.

For better steam distribution limited entry perforations were utilized. Beam pumps were raised up to 70^o in shallower depth to reduce run life. Cost saving was done by drilling slimmer wells and using flush tubing allowed the usage of bigger pumps.

Also, Downtime and OPEX were reduced by implementing steam bypass pump trials. This thing would do away the need for Hoist/RSR for converting production wells to injection wells and vice versa. Various number of small improvements in few years has resulted in excellent results with actual increase in oil production without additional drilling.

CHAPTER THREE

3. METHODOLOGY

3.1. Introduction

The main purpose of the project is to define the most proper EOR method to obtain the maximum oil recovery from Hemiar field. This chapter illustrates some types of screening criteria used to evaluate the optimum EOR method according to specific conditions and parameters for each method. Then, EOR is chosen to this case study depending on the availability of screening tool and data required.

3.2. Type of Data That Needed for The Project

Table 3-1 Data Needed for the Project

No.	Data Type
1	Alteration in the fluid properties in situ such as the comprise changes in phase behavior and PVT data.
2	**Rock properties** such as absolute permeability, porosity, rock compressibility, and the attendant changes in these properties on the injection.
3	**Properties related to fluid-rock interaction**. These include residual saturation (related in turn to wettability, interfacial tension, etc.), relative permeabilities, capillary pressure, and their dependence upon temperature.
4	**The reservoir environment:** net/gross ratio (presence of shale barriers, etc.), heterogeneity, properties of the overburden and underburden, the initial oil saturation, temperature, and pressure.
5	**Flood geometry:** pattern shape and spacing, producing-injecting interval (well completion) location and thickness.
6	**Thermal properties** of the formation and the contained fluids, such as specific heats, thermal conductivities, thermal expansion coefficient, and the changes induced in these.
7	**Parameters within the operator’s control**, such as steam injection rate, steam quality, injection pressure (temperature), cumulative amount of injection, etc.

Because of lack in data, this study was based on the quality and quantity of data available on hand, **Table. 3-2** shows the data that will be used in our study:

Table 3-2 Data Uses in This Project

NO.	Data Type
1	**Fluid properties (Oil):** PVT data just (API Gravity, Viscosity, Oil composition).
2	**Rock Properties (Reservoir)**: Formation Type, Pay thickness, Depth, Average permeability, Temperature, oil Saturation.

3.3. The nature and sources of data used in the EOR process

Through consideration, scrutiny and study of the reservoir properties and nature of oil located in the field to be conducted study, and knowledge of the most important characteristics to be studied for the process of selection of the appropriate EOR project. Therefore, it requires us to know from which report or source these characteristics were obtained and where they will be used based on the extent of the project. Therefore, the data used for this purpose can be divided from our point of view into two main parts:

3.3.1. Heavy oil properties

The most important properties of oil we have in the reservoir to be studied. There are several characteristics under this item, but the most important that we will need in this project are summarized as follows (API Gravity, Viscosity, Oil composition). We can get the data of these characteristics through several field reports have been working in the same field and the most important (PVT data).

3.3.2. Rock Properties (Reservoir)

Under this title, there are many characteristics of interest to many development projects, production improvement and others. We must identify the most important characteristics that concern us in this aspect, which requires us to achieve and identify the most important characteristics of the selection EOR process, (Depth, Temperature, Average permeability, Pay thickness, Formation Type, oil saturation). The values of these characteristics can be obtained from several specialized agencies, the most important of which are:

a. Formation Type, pay thickness and Depth can be obtained from wireline data or final drilling report.
b. Average permeability can be obtained from final test report. C- Temperature, oil saturation can be obtained from PVT data.

3.4. ANALYSIS APPROACH

There are several methods that are used in the examination process, through which the appropriate method is chosen from the EOR methods. It should be noted here that most of the methods used in this area is very complex depending on the basis on which each method and the conditions of implementation and analysis. It should also be noted that these methods range from the level of ease of use and some kind of available to the level of difficult to use and unavailable or rely on very complex analysis, which takes several years to use. We refer here to the most frequently used methods and will select the best available method from them.

3.4.1. TABER Method:

The choice of EOR methods to specific conditions is one of the most difficult tasks for a reservoir engineer. One of the methods, which offered technical screening, guides for EOR nowadays known as Taber's tables. It is one of the widely cited publications in petroleum engineering for EOR criteria. This method was introduced in 1996 by calibrating standards for several field experiments around the world to achieve success in the oil industry. These tables consisted of 12 EOR methods tabulated a giants 10 reservoir properties, which classified into oil properties and reservoir characteristic field. Both oil properties and reservoir characteristic are considering as a guideline for selection the suitable EOR method.

The EOR criteria published by Taber and colleagues (1996) was updated to include EOR survey reports submitted from 1998 through 2010, as shown in **Table. 3-3**. The updates to the EOR criteria include the addition of the entire range of oil and reservoir properties for all EOR methods, a reservoir fluid property, namely, porosity, and permeability and depth ranges for miscible and immiscible gas EOR methods because of their importance. New categories and subcategories of EOR methods also were added to the EOR criteria, including the categories of microbial EOR, miscible WAG, and hot water flooding, as well as the immiscible gas flooding subcategories of CO2, nitrogen and WAG. Furthermore, the new criteria include the number of EOR projects (the number of datasets) to provide an impression of the confidence level used for each EOR method to derive the EOR selection criteria. As a result, the number of EOR in Taber methods has been expanded from 12 to 16.

Table 3-3 Taber Tables

			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 (ºF)**
Miscible Gas Injection											
1	CO2	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)	1500-13365 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 0.6	11-24 Avg 18.3		sandstone	130-1000 Avg 1043.3	(NC)	7545-8887 Avg 8216.8	194-253 Avg 119.4
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 15.0	(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 61	sandstone	3-2800 Avg 1041.7		1700-18500 Avg 7914.2	82.325 Avg 173.1
6	CO2	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		1150-8500 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 15.09	Avg 88	sandstone or carbonate	100-6600 Avg 2392		2650-9199 Avg 7218.71	131-267 Avg 198.7

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 (ºF)**
Chemical Methods											
9	Polymer	53	13-42.5 Avg 26.5	4000-0.4 Avg 123.2	10.4-33 Avg 22.5	34-82 Avg 64	sandstone	1.8-5500 Avg 834.1	NC	700-9460 Avg 4221.9	74-327.2 Avg 167
10	Alkaline Surfactant Polymer (ASP)	13	23(20)- 34(35) Avg 32.6	6500-11 Avg 875.8	26-32 Avg 26.6	68(35)-74.8 Avg 73.7	sandstone	596 (10)- 1520	NC	2723-3900(9000) 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 Methods											
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 Avg32971.3	12-65 Avg 32.2	35-90 Avg 66	sandstone	1-15000 Avg 2605.7	(>20)	200-9000 Avg 1643.6	10-350 Avg 105.8
14	Hot Water	10				15-85 Avg 58.5	sandstone	900-6000 Avg 3346	-	500-2950 Avg 1942	75-135 Avg 98.5
Microbial											
15	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

3.4.1.1. Mechanism of Taber Method:

The mechanism is Done by matching data available with Taber tables in terms of data and parameters which each table has limitations. The EOR selection criteria categorize EOR methods into gas, chemical and thermal and are based on a range of reservoir properties listed for each of these methods. Also includes the limitations of each EOR method. The EOR selection criteria were based on a range of reservoir properties (table 3.4) without considering incremental recovery or the project's distribution scale. Despite the implementation of over 600 EOR projects since

1959 (The Oil and Gas Journal, (OandGJ), 1998-2008). The development and implementation of any recovery methodology, especially on a field-wide scale, requires confidence in its efficacy. Establishing such confidence requires an in-depth analysis of EOR projects that would provide updated and more concise EOR selection criteria.

Table 3-4 Reservoir properties used in Taber method

<table>
<tr><th>Oil properties</th><th rowspan="8"></th><th>Reservoir characteristics</th></tr>
<tr><td rowspan="4">Gravity (API)</td><td>Porosity</td></tr>
<tr><td>Oil saturation</td></tr>
<tr><td>Formation type</td></tr>
<tr><td>Permeability</td></tr>
<tr><td rowspan="3">Viscosity (cP)</td><td>Net thickness</td></tr>
<tr><td>Depth</td></tr>
<tr><td>Temperature</td></tr>
</table>

3.4.1.2. Success Rate and Failure of Taber Method:

Generally, rely on the economic (future oil price) and select of oil properties and reservoir characteristic are a guideline for selection the EOR method to achieve success.

3.4.2. Bayesian Network Analysis

The Bayes rule is the basis for updating process. Bayesian Network is a directed acyclic graph that nodes represent variables and edges show direct dependencies between the linked variables. Consider five measured variables (named a1to a6) that are supposed to be effective on another unknown variable, called b, and each of these seven parameters can admit four different states. Therefore, there are four powered seven (i.e. 16'384) possible states, and it is not only hard to compute and consider all these states, but also impossible in the case of lack of complete and comprehensive dataset of records. Now, suppose that dependency relationships between those previously mentioned seven variables can be represented as in **Fig. 3-1**.

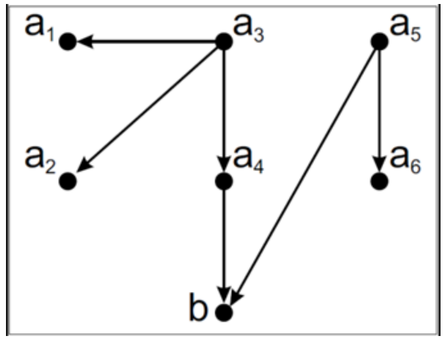

Figure 3-1 Example of an Acyclic Bayesian Network

3.4.2.1. The theory of Bayesian Belief Networks

The theory of Bayesian belief networks is based on the theory of probability that builds the most appropriate framework for evaluation in the areas associated with non-specificity. The Bayes network can behave like humans when faced with uncertainty and also provide a mathematical basis to predict the probability of a goal in future experiments, from certain incidents in previous experiments. The basic way to determine a situation with an uncertain outcome is to determine

its probability according to the Bayesian logic. This network consists of a series of variables and their relationships, each of which can be represented as a node in the network and has many instances that do not have shared domains. Each directional correlation between two nodes shows the direct influence of one (parent) on the other (continued). This effect is measured by a conditional probability distribution function that links the states of each node to those of its parents. The combination of variables and directional bonds forms a directional annular network (**Fig. 3-1**). There is a probability distribution accompanied by each sub node (conditional probability) which depends on the probability distribution related to its parents.

3.4.2.2. There Are Two Methodologies for Constructing BNs

1. Constraint-based methods: is used in cases that user is confident about the causal relationships between variables. In fact, constraint-based methods are judgmental methods that an expert is responsible for. In some cases, it is difficult or even impossible for a user to determine dependency relations between variables. In these cases, data- driven approaches are used to find the most probable state of dependency between each pair of variables.

2. Score based methods: In score-based methods, a calculated score is set as a criterion to find the dependency relation between two variables. For using score-based methods, two elements should be specified: search procedure and scoring metric. Scoring function should be associated with probability of a candidate directed acyclic graph, and search procedure is considered as an optimization problem. In this work, K2 algorithm is used in order to construct.

3.4.2.3. The most important advantages and disadvantages

Bayesian classification approach slightly differs from others. As a matter of fact, in the Bayesian approach, the joint probability distribution of the class and feature have to be estimated.

Advantages:

1. A key advantage of Bayesian networks is their synthesized representation of probabilistic relationships. In fact, it is necessary to consider only the known independencies among the variables in a domain, rather than specifying a complete joint probability distribution. The independencies declared at modeling time are then used to infer beliefs for all variables in the network.
2. In the case of the availability of the data necessary for the analysis and took the time to do so it will give very impressive results and reliable.

Disadvantages

1. The limitation of Bayesian method is its subjectivity, especially for the establishment of prior belief.
2. Difficulty calculating all these cases and considering them.
3. It is also impossible to perform an analysis in the absence of a complete and comprehensive data set of records.
4. Their analysis is very complex and requires a long period of time and detailed study in this manner.

3.4.3. Artificial Neural Network (ANN)

3.4.3.1. What is an Artificial Neural Network?

It is an intelligent computational system inspired by the Structure Processing Method Learning Ability of a biological brain. Artificial neural networks have been used for more than 50years. McCulloch and Pitts, introduced the first Neurode type, which is called perceptron, that computes the weighted input to a threshold value T, which is the minimum activity required for the

Neurode to generate a positive output. If the net input is greater than or equal to the threshold, the Neurode outputs +1; if not, it outputs –1. Now, neural network systems consist of a number of very simple and highly interconnected processors called Neurode. Each Neurode receives many signals over its incoming interconnections and produces an output signal. Most of these outgoing signals terminate at the incoming connection of some other Neurode in the network; others may terminate outside the network and generate control or response patterns.

3.4.3.2. Why Artificial Neural Networks?

Oil/gas exploration, drilling, production, and reservoir management are challenging these days since most oil and gas conventional sources are already discovered and have been producing for many years. That is why petroleum engineers are trying to use advanced tools such as artificial neural networks (ANNs) to help to make the decision to reduce non-productive time and cost.

3.4.3.3. The components of an ANN:

In general, the components of an ANN include:

1. Input layer.
2. Output layer
3. Hidden layer and their neurons.

The number of input and output layer neurons depends on the type of problem and the number of input and output variables. But the number of hidden layers and their neurons is selected based on the accuracy of the model.

3.4.3.4. Applications of ANN:

ANNs are used in a multitude of areas for scientific and pragmatic purposes. The use of ANNs significantly reduces the intensity of computationally demanding conventional methods. The concept of neural network is being widely used for data analysis nowadays. Neural network simulation often provides faster and more accurate predictions compared with other data analysis methods. Function approximation, time series forecasting and regression analysis can all be carried out with neural network software. The scope of possible applications of neural networks is virtually limitless: game-play forecasting, decision making, pattern recognition, automatic control systems and many others. Of course, neural networks play a significant role in data mining processes.

3.4.3.5. Applications of ANN in Oil Industry:

ANNs have been applied to many petroleum applications and have shown a reasonable accuracy. The availability of huge data sets in the petroleum industry gives the opportunity to use these

data to make better decisions and predict future outcomes. Petroleum engineering areas in which neural networks have been used include geology/ geophysics, drilling and completion, formation evaluation, production facilities, reservoir engineering, and business, economics and finance. One of the major important and useful applications is the proper selection and classification of EOR methods. The neural network part is based on exhaustive review and selection of successfully deployed literature case. It uses the rock, fluid and other reservoir parameters (figure…) to screen various EOR methods considering their technical-economical applicability. This artificial Intelligence approach utilizes data mining techniques in the form of hybrid system that makes use of neural network as screening tool and the genetic algorithm as an optimization tool to land into the optimum recommendation. The operational module enables to evaluate the implementation capability on the given field based on the specific requirements of the pre- selected EOR method and basic laboratory data among others.

The input layer is composed of the key reservoir parameters (reservoir depth, temperature, porosity, permeability, initial oil saturation, oil gravity, and in-situ oil viscosity) while the output layer is composed of the EOR methods to be evaluated.

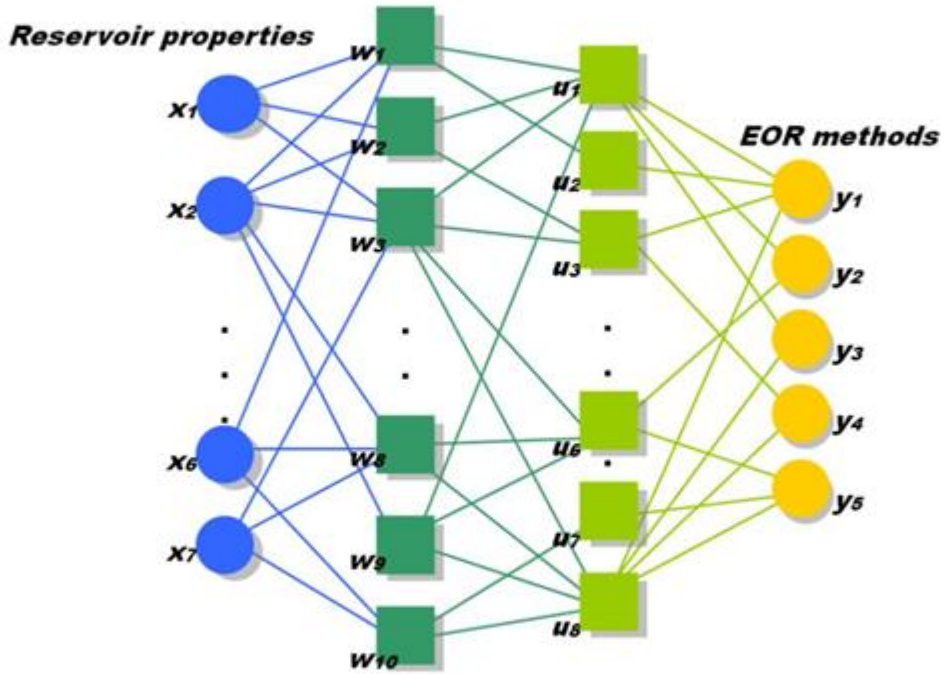

Figure 3-2 Structure of ANN Module

Disadvantages of this method

There were several obstacles that limit the use of this method, perhaps the most important:

1. Not available and we could not access it.
2. Difficulty in finding special data for this procedure and the lack of input data for that.
3. The difficulty of the practice required to apply this method and the short time for that.

Finally, for the case study of Hemiar field the screening tool used is **Taber Method** to define the enhance oil recovery applicable to the field conditions and reservoir properties.

The correlation developed between Hemiar reservoir parameters and Taber standard parameters has concluded that **Steam** enhance oil recovery is mostly matched to the reservoir properties. Steam injection has multi usage styles, so that care was taken to choose most effective steam injection way. After an extensive research on them, the **Injection of High Temperature Fluids** was suggested to be efficiently applicable and the most potential and compelling recovery technology to the current study.

3.5. EXPECTED RESULTS

Based on previous studies conducted using this method (Injection of High Temperature Fluids.) and based on matching reservoir properties of the formation and liquid of these studies with the characteristics of the target field to be studied and based on data available and environmental indicators we can say that in the case of the ideal application of this method in the S.Himiar fields in Block 14 Sayun-Masila Basin (Sayun), we can expect the following:

1. Decrease in the viscosity of oil and increase in the rate of oil production.

2. Decline of the water cut ratio in the production.

3. Rebuild the formation pressure and help drive mechanism in the reservoir.

4. Increase reservoir recovery and increase proved and probable reserves.

CHAPTER FOUR

4. INTRODUCING NEW EOR METHOD TO S. HEMIAR FIELDS

4.1. Introduction

This chapter explain the usage of the methodology for selecting the type of enhancement by the analysis and comparison process. Also, clarification for the **High Temperature Fluids Injection** method and its applications. In addition, it contains a detailed description of the way the study was conducted in the field of South Hemiar. Furthermore, the expected results are presented and evaluated and interpreted.

4.2. Selecting the EOR method based on Taber Method

As mentioned earlier, depending on the petrophysical properties of the reservoir and the liquid, there values have been taken from the available data described in chapter 3, for the study area in the fields of Hemiar, which contains heavy oil. These values were studied and the correlation process was done for them with the corresponding values in the Taber tables and the results were obtained.

- **Liquid Properties (Oil)** The liquid properties which are concerned in the process of selecting the appropriate method of EOR are summarized in **Table. 4-1**:

Table 4-1 Liquid Properties of Hemiar fields

	FIELDS		
Property	**Hemiar**	**S. Hemiar**	**W. Hemiar**
API Gravity	18	17.5	17.4
Viscosity (cP)	39.1	41	39

- **Rock Properties (Reservoir)**

The reservoir parameters which are required to correlate with **Taber tables** in the process of choosing the appropriate method for EOR are shown in **Table. 4-2**. Carefully these values were obtained in order to ensure the suitable decision to the enhance method.

Table 4-2 Rock Properties of Hemiar fields

Property	FIELDS		
	Hemiar	S. Hemiar	W. Hemiar
Porosity (%)	19	21	21
Oil Saturation (%)	58	71	70
Formation Type	Sandston	Sandston	Sandston
Permeability (md)	1500	500	500
Net Thickness (ft)	59	55	39
Depth (ft)	(5145-5204)	(5099-5154)	(5018-5057)
Temperature (ºF)	155	155	150

After comparing the previous values with those specified in TYPER tables, see chapter 3. It has been proven that the most suitable enhance methods for use in Hemiar fields in order to process heavy oil in the reservoir and increase production are the **Thermal Enhancement** methods. Through previous field studies conducted in reservoirs that are very similar to the properties present in this field, it was concluded that, the choice tends to use **Steam injection.**

Table 4-3 Thermal EOR Methods

EOR process	API Density	Viscosity (cp)	Porosity (%)	Oil saturation (%)	Formation type	Permeability (md)	Net thickness (ft)	Depth (ft)	Temp (F)
Combustion	10 - 38 Avg. 23.6	2770 -1.44 Avg. 504.8	10 - 35 Avg. 23.3	50 - 94 Avg. 67	Sandstone or Carbonate (Preferably Carbonate)	10 - 15000 Avg. 1981.1	> 10	400 - 11300 Avg. 5569.6	64.4 230 Avg. 175.5
Steam	8 - 33 Avg. 14.61	> 20	12 - 65 Avg. 32.2	35 - 90 Avg. 66	Sandstone	1 - 15000 Avg. 2669.70	> 20	200 - 9000 Avg. 1647	10 - 350 Avg. 105.91

- These are the final results of the comparison and selection process for the appropriate method of EOR summarized in the following table:

Table 4-4 Final Comparison

Parameters	Steam (TYPER method)	Hemiar	S. Hemiar	W. Hemiar
API Gravity	8-33 Avg.14.61	18	17.5	17.4
Viscosity (cp)	>20	39.1	41	39
Porosity (%)	12-65 Avg.32.2	19	21	21
Oil Saturation (%)	35-90 Avg. 66	58	71	70
Formation Type	Sandstone	Sandston	Sandston	Sandston
Permeability (md)	1-15000 Avg.2669.70	1500	500	500
Net Thickness (ft)	[>20]	59	55	39
Depth (ft)	200-9000 Avg. 1647.42	(5145-5204)	(5099-5154)	(5018-5057)
Temperature (^oF)	10-350 Avg. 105.91	155	155	150

Steam injection is multisystem method with different designs related to specific conditions of application for each type. Hence, in order to ensure the economic and technical quality and the exploitation of the reservoir in the required manner and to reach the recovery of a large amount of heavy oil, we have studied the steam injection methods to select the appropriate technical and economic method which is calibrated to the same standards as the steam method and has been succeeded in different stages with the lowest level of restrictions, this technique is called **Injection of High Temperature Fluids.** This technique is owned by **The China National Petroleum Corporation (CNPC)**.

4.3. Injecting of Hi-Temperature Fluids

4.3.1. Introduction:

Heating heavy oil, enhancing fluidity of formation oil by injecting high temperature and high-pressure steam into formation is an effective method to exploit heavy oil. It is also the primary method for heavy oil extraction. The Injecting hi-temperature fluids method is the most potential and compellent recovery technology for EOR. China National Petroleum

Corporation (CNPC) created this method. The technology was first applied to field in china in 1998 by joint team research. Until now, the technology has been matched and getting into all-round industrialized application stage. This kind of thermal technology is suitable for various types of reservoirs, such as, heavy oil reservoir, Light oil reservoir (including high condensating point reservoir) and other. Application modes can be Huff & Puff, continual gas driving and slug drive. Based on geologic study of the reservoir, Hi-temperature fluids will be injected into the formation with the optimized injection modes to enlarge the sweeping space for higher EOR. This new thermal method called multi-thermal fluid, which contains combustion of air, water and diesel for well stimulation to inject N_2, O_2 and CO_2 at the same time when injecting steam.

4.3.2. Formation of Hi-temperature Fluids and Related Equipment:

4.3.2.1. Formation of Hi-temperature Fluids:

Hi-pressure compressed air mixed with Hi-pressure atomized diesel in the thermal fluid generator, and the mixture is burning in the combustion chamber by electronic firing to produce Hi-pressure, Hi-temperature gas (3992 F). Cold water circulating outside the combustion chamber allows the system to keep stable work for long run. The Hi-temperature, Hi-pressure mixture continues to flow downward and mixes with the cold water from outside of the combustion chamber for conditioning the temperature of the effluents. Finally, the Hi temperature fluids (steam, N_2, CO_2, O_2), will be injected into the wells.

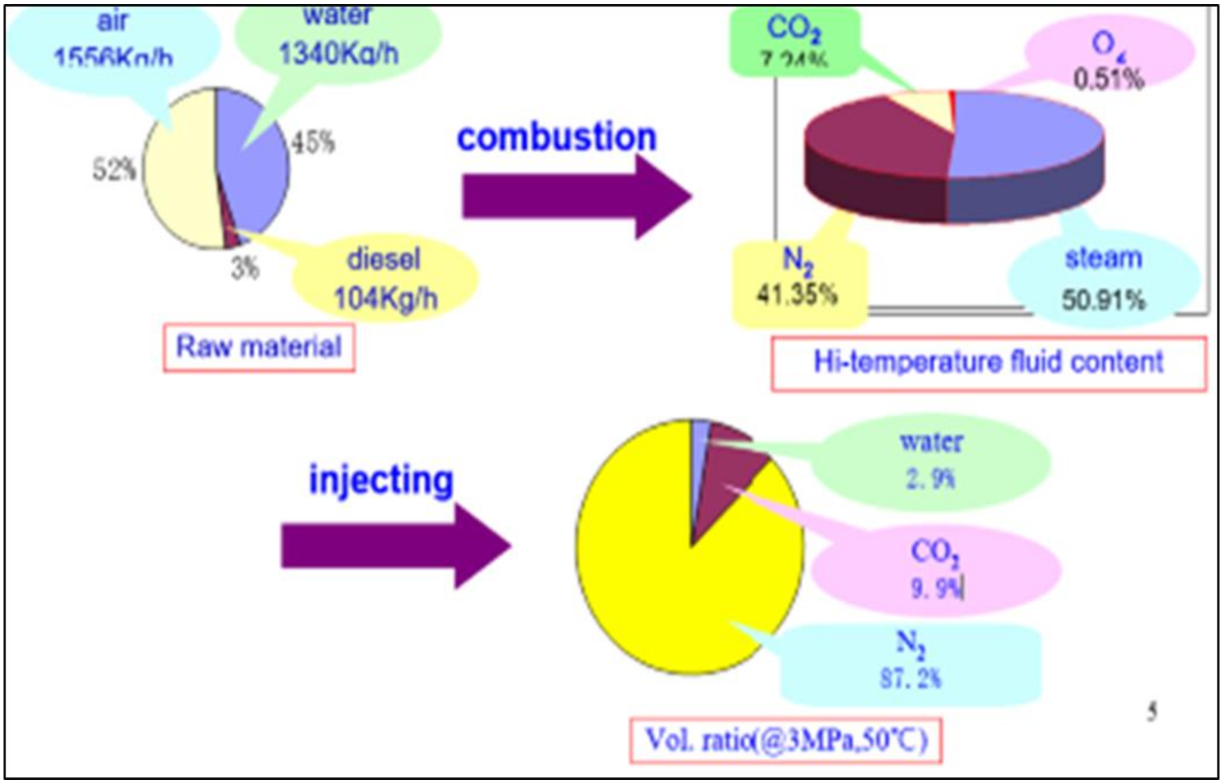

Figure 4-1 Substance changes in the process

4.3.2.2. Equipment system:

1. Hi-temperature fluid generator.
2. Air compressor.
3. Monitoring system.
4. Feed water system.
5. Feed diesel system.

Generator schematic:

Input to generator:

(1556 Kg/h of air, 1340 Kg/h of water, 104 Kg/h of diesel)

Output from generator:

(41.35% N2, 0.51% O2, 7.24% CO2, 50.91% steam)

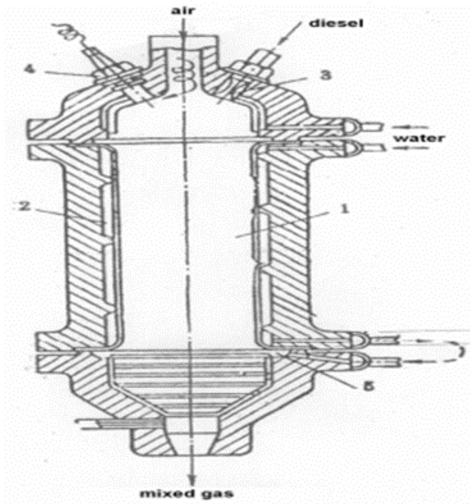

Figure 4-2 Generator schematic

This generator contains (1-combustion chamber. 2- preheating chamber.3- nozzle. 4- firing device)

Figure 4-3 Hi-temperature fluid generator

Figure 4-4 Flow lines for feed oil, water and air

Figure 4-5 Controllable convert-frequency feed oil and feed water system

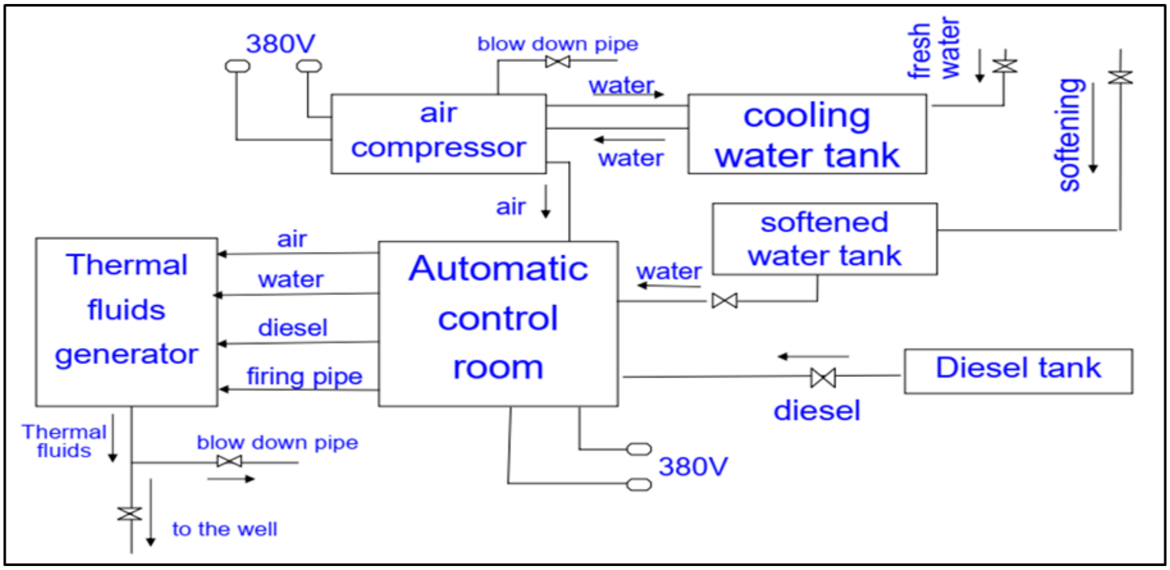

Figure 4-6 Procedure schematic of Hi-temperature Fluids.

Figure 4-7 Monitoring system panel

4.3.3. Thermal Recovery Mechanisms of Hi-Temperature Fluids.

4.3.3.1. Formation Pressure Build Up

The influenced space of gas pressure is much bigger than water injection with faster response because gas permeability is much greater than liquid permeability. Hi-pressure gas releases its energy to the formation by expansion, improving the displacement effect. There are lots of N_2 in the Hi-temperature fluids with greater compressibility coefficient (0.291). The max. Fluids injection rate can reach 28800Nm3/d, with equivalent volume in-situ of 960m3 (6038.22bbl). It will make formation pressure build up faster by 10 times than the conventional water injection. Therefore, it is an effective means to make the formation pressure build up fast. The thermal fluids will produce local gas caps and overlapping because of gravity segregation with function of gravity drive for oil, and controlling bottom water coning and edge water invasion to some extent, improving the displacement effect. Hi-temperature fluids can also prevent cold damage to the formation.

4.3.3.2. Oil Viscosity Reduction and Prevention of Wax Build Up.

Heave oil viscosity is very sensitive to temperature, the higher the temperature, the lower the oil viscosity. The steam existed in the thermal fluids (accounted for 50.91%) has got very greater enthalpy, particularly beneficial for viscosity reduction of heavy oil and prevention of wax buildup of high condensating point oil. In addition, there are lots of CO_2 existed in the thermal fluids with multifunction, such as forming carbonic acid to acidize with matrix, dissolved in oil to reduce the oil viscosity by more than 20%. In addition, CO_2 can increase the driving power of dissolved gas when the formation pressure is less than the bubble point.

4.3.3.3. Improving Displacement Effect.

1. The surfactants added in the thermal fluids can reduce the interfacial tension between driving medium and oil, improve surface wettability of the rock for higher driving efficiency.
2. The clay stabilizer added in the thermal fluids can prevent clay damage from swelling.

3. The foaming agent added in the thermal fluids can produce foam of N2, which can effectively plug the macrospore passage in the formation for enhancing the degree of producing reserves.
4. The CO2 dissolved in formation water becomes into carbonic acid, which removes some plugs to increase the reservoir permeability.

4.3.4. Different Application Modes.

4.3.4.1. Heavy Oil Reservoir

For the heavy oil reservoirs with steam Huff & Puff for quite a few cycles, oil/steam ratio (OSR) has been almost decreased to the critical point. In this case, Hi-temperature fluids can be injected for gas driving, or it mixes up with steam to be injected, or creating an alternate gas-steam slug driving, which are economic and effective development modes to improve the recovery factor in the last phase of steam Huff & Puff. Steam Huff & Puff surely produces lots of water existed in the near-wellbore zone, while injection of thermal fluids can both heat the reservoir for viscosity reduction and lots of Hi-pressure gas are helpful to remove the existed water flow back. For the heavy oil reservoirs with steam Huff & Puff, injection of Hi-temperature fluids is much more economic and effective than steam Huff & Puff, while the water amount required to produce the thermal fluids is greatly reduced by 90% compared to steam Huff & Puff (it's especially suitable for the districts with scarce water resources).

4.3.4.2. Light Oil Reservoir (Including High Condensating Point Reservoir)

For the exploited reservoirs with water flooding, water and the thermal fluids can be alternately injected into the formation to establish a kind of slug drive. We can optimize the slug size ratio to enlarge the sweeping space for higher recovery factor. For the local water blockage in the formation, the injected thermal fluids can effectively remove water blockage and make the water flow back from around the wellbore. For the reservoirs with gas cap (or no gas cap), edge water, bottom water, the Hi-temperature fluids can be injected at the top part of the structure both to supplement the formation energy and to control the water cut rise, also to enhance oil production. For the high wax content reservoirs (or high condensation point reservoirs), Hi-temperature fluids injected can dissolve and remove the wax deposition both in 5the wellbore and in the near wellbore zone.

4.3.4.3. Application Conditions for Hi-Temperature Fluids.

1. Heavy oil reservoirs with water flooding (CHOPS + cold-water injection + injection of Hi-temperature fluids or CHOPS + hot water injection + injection of HI-temperature fluids)
2. Heavy oil reservoirs with edge water or bottom water (CHOPS + injection of Hi-temperature fluids)
3. Light oil reservoir including high condensating point reservoir (conventional recovery + injection of Hi-temperature fluids)
4. Reservoir depth: less than 1500m.
5. Oil viscosity: from tens to a couple of 10000 cp.
6. Net pay: from several meters to tens of meters
7. Permeability: from tens to thousands of md
8. Reservoir pressure: less than 1450.4psi.

4.3.5. Lab Test.

4.3.5.1. Lab Test and Understanding.

For the high dip reservoirs, Hi-temperature fluids can be injected into the formation at the top part of the structure, keeping effectively the formation pressure for oil production (reasonable injection rate required to keep the GOC stable). In addition, there are lots of steam in the thermal fluids injected with greater steam quality downhole than that of the saturated steam in conventional Huff & Puff, with much more quantity of heat, and high-pressure gas has greater elastic energy by expansion. Therefore, it can sweep oil in much more space compared to steaming to get much high recovery factor. Injection of Hi-temperature fluids will sharply decrease the oil viscosity.

4.3.6. Evaluation on Oil Recovery Technology by the Hi-temperature Fluids.

1. The thermal fluids are mainly composed of steam, N2 and CO2. It is proved that the main function of the hot fluids is gas driving by its application in various kinds of reservoirs.
2. Thermal fluids injection is getting into gas driving mode by the Huff & Puff, while making a fast formation pressure build up.
3. With increase in Huff & Puff cycles of the thermal fluids, there are differences in oil increment and validity life, but it has better results in the early cycles.
4. The stimulation results are dependent on property of the reservoir fluids; the Hi-temperature fluids injection technology is especially suitable for heavy oil reservoirs.
5. Hi-temperature fluids has got a variety of stimulation mechanisms, suitable for different kinds of reservoirs (conventional heavy oil, high condensating point oil, edge water/bottom water reservoirs) with attractive results.

4.4. Preliminary Study on the New Oil Recovery Technology application in S. Hemiar Oilfield.

4.4.1. The Work Plan Forward

1. Well selection: to select a couple of well groups (about 3 wells) to open a pilot test area.
2. Review the geological features and data available to confirm the appropriate method of EOR.
3. The method used is Hi-temperature fluids injection technology.
4. Suitability study on the Hi-temperature fluids injection technology.
5. Review of production features and water cutting.
6. Review proved and probable reserves.
7. Preliminary economic analysis on the pilot test program.

4.4.1.1. Well Selection

Three wells have been selected for pilot test **(S. Hemiar-10, S. Hemiar-12, S. Hemiar-19**)

4.4.1.2. Geologic Features

- Shallow buried depth: main producing zones are the Cretaceous with depth of (5099 to 5154ft).
- Net pay: Cretaceous: 55ft.
- Good reservoir characteristics: porosity (21%) and medium permeability (500md) reservoirs.
- Greatly heterogeneous in reservoir property.
- Reservoir types: Cretaceous, clastic, Sandston (heavy oil).
- Fluid property: the reservoirs belongs to heavy oil with 17.5 API while the reservoir oil viscosity is 41cp.
- Formation pressure: 1300 psi.
- Formation temperature: 151.68F.

4.4.1.3. Production features

Table 4-5 Production features

Well name and type	**S. HEMIAR-12; HORZ WELL**	**S. HEMIAR-10; HORZ WELL**	**S. HEMIAR-19; HORZ WELL**
Production Rate (bopd)	1620	380	288
Productivity index (BIPD/psia)	5.9	0.320	0.5
Depth (ft)	MD (5619.9); TVD (5136.38)	MD (5385); TVD (5001)	MD (5616); TVD (5128.25)
Pressure (psia)	1304.72	1300	1280
Temperature (F)	156	147	137.31

Current pressure	Initial pressure	Number of wells drilled	Production start date	Date of discovery
1,183	1,424	22	January 1995	م1992 /July

Proved reserves(1P) in S. Hemiar field of year 2012 =

Remaining reserves (Million barrels)	Oil produced until May 2012 (Million barrels)	Recoverable oil (Million barrels)	Oil stock (Million barrels)
1.783	15.860	17.643	65.410

Proved + Potential + Possible reserves (3P) in S. Hemiar field of year 2012 =

Remaining reserves (Million barrels)	Oil produced until May 2012 (Million barrels)	Recoverable oil (Million barrels)	Oil stock (Million barrels)
4.208	15.860	20.068	69.592

4.4.1.4. Preliminary Economic Analysis on The Pilot Test Program

- Transformed Hi-temperature fluids generator & accessories

One set: 600000$

- Expenditure for lab tests and the pilot test program study and design

(Without tax): 200000 $

Total: 800000 $

4.5. Evaluate and Interpret Expected Results:

The essential mechanism of Injection of High Temperature Fluids is to exploit crude oil by the synergistic effect of gas and steam. This multi-thermal fluid could employ various mechanisms of each fluid, including reducing oil viscosity by heating and dissolving gas, increasing pressure by injecting gas, expanding heating range, reducing heat loss and gas assisting gravity drive.

4.5.1. Rebuild the Formation Pressure and Help Drive Mechanism in The Reservoir

Multi-thermal fluid has a significant influence on pressure maintenance. The order of pressure contributions is **N_2 > CO_2 > steam > water**. In the formation of high-pressure gas chamber, the average pressure of gas chamber is up to 0.2 ~ 2.0 MPa. Steam stimulation is depletion development, maintaining reservoir pressure is needed in the later stimulation. The pressure maintenance role of multi-thermal fluid can help to maintain reservoir pressure. The pressure maintenance effects of non-condensate gas mixed with steam injection is better than the type mixed with hot water.

Through previous experiments conducted on fields with the same characteristics and conditions where it appears that it is possible to increase the pressure of the reservoir in varying proportions perhaps the most prominent**, which we see from our point of view that it is expected that the pressure increment in South Hemiar field to be(0.3-0.9MPas) (44-130 psi).**

4.5.2. Reducing Oil Viscosity by Dissolving Gas

When the steam has a large degree of superheat, it may take a relatively long time to cool, during which time the steam is releasing high energy and transmitted long distances. In addition, do not forget that the ratio of steam in Hi-temperature fluids method is high up to 50.91%. Hi-temperature fluids stimulation in heavy oil reservoir pilot test results showed that the average daily oil production by Hi-temperature fluids stimulation was 2-4 times than that of saturated steam stimulation. Hi-temperature fluids is more effective to heat oil reservoir, so this factor is one of the most important factors in the process of reducing the viscosity of heavy oil and prevent the accumulation of wax in the corridors in the oil. Since one of the advantages of this method is that it can heat the reservoir to reduce viscosity, it also generates a high-pressure gas which removes the existing water.

Also, Because of the N2 and CO2 in the multi-thermal fluid, gas dissolving in crude oil under a higher pressure could reduce oil viscosity and increase expansion coefficient of oil.

According to the laboratory experiment of oil sample, gas dissolving in the multi-thermal fluid can reduce oil viscosity through dissolving in heavy oil, in which N2 leads to viscosity reduction of **approximate 15% and CO2 viscosity reduction of 20 %** fig 4.8 and fig4.9. Therefore**, the injection of high temperature fluids will lead to a sharp decrease in the viscosity of oil up to 70%; Of the total processes that will be performed by (steam, nitrogen N2, carbon dioxide CO2).**

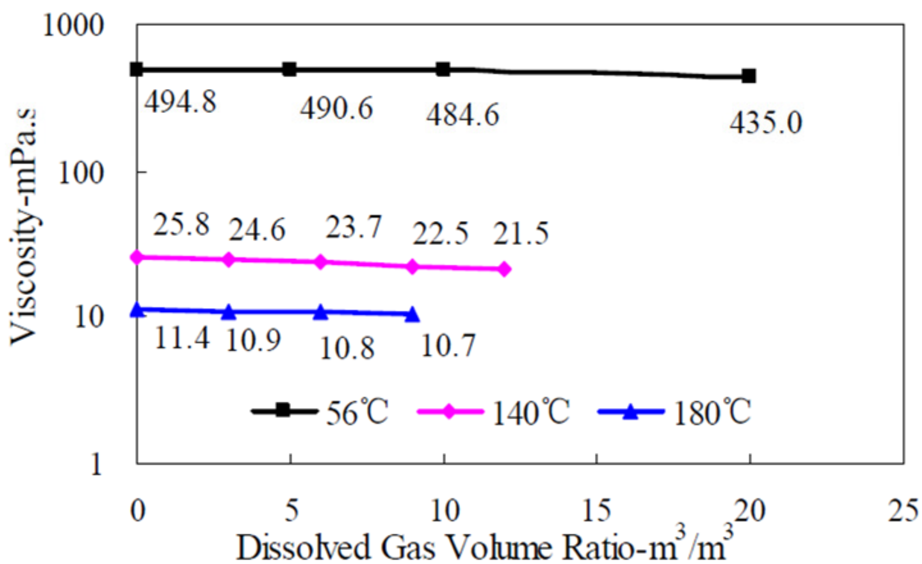

Figure 4-8 Relationships between Dissolved Gas-Oil Ratio and Viscosity of N2 - Heavy Oil Mixture.

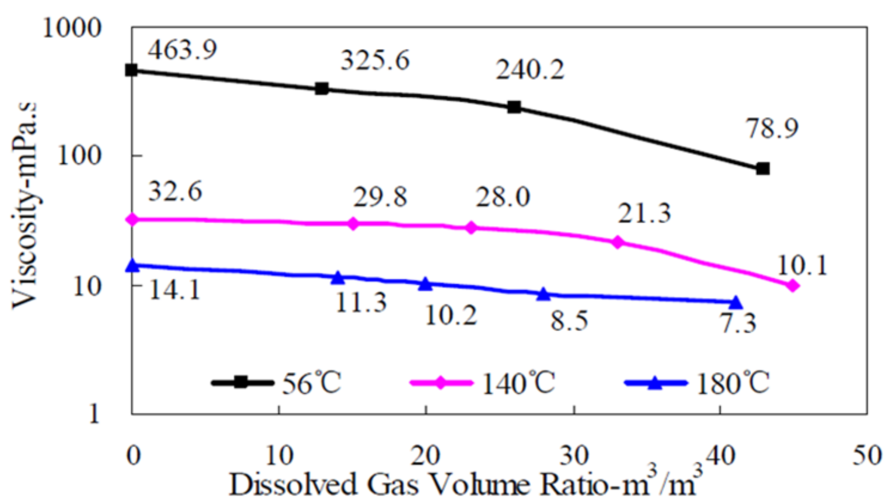

Figure 4-9 Relationships between Dissolved Gas-Oil Ratio and Viscosity of CO2 -Heavy Oil Mixture.

4.5.3. Reduce Interfacial Tension

The interfacial tension between the fluids or fluid and rock in reservoir directly affect the fluids distribution in the rock, capillary force and fluid flow. The interfacial tension between oil and gas is nearly 30% of the interfacial tension between oil and water Figure4.10, which thereby improved the displacement efficiency.

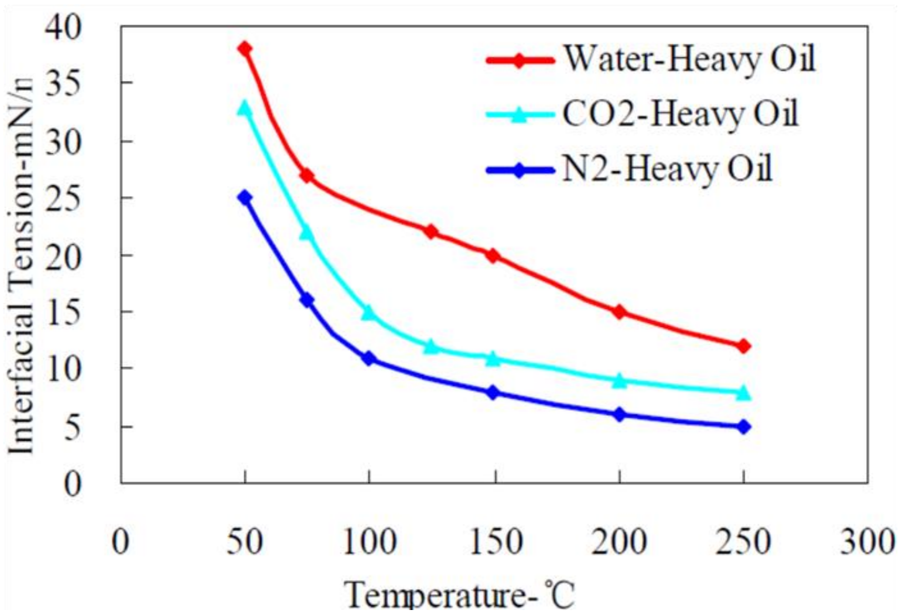

Figure 4-10 Interfacial tension of different temperature

4.5.4. Reduce Water Cut.

As the depletion development time increases, the reservoir pressure decreases further and the oil production rate declines with the water-cut going up. There are little or no economic benefits if continuing to develop by natural energy.

1. Fast oil production decreased.
2. Speedy water cut rise.

Percentage of water cut in the S. Hemiar field up to 50-90%. This percentage is considered to vary from one well to another, but it includes the diversity of water cut in this field. It is also known and traded and the results of several studies that include a high rate of cutting water, increased its chance to reduce the value of water cutting. So, it can say that given the reservoir properties and environmental conditions as well according to the previous study, where the characteristics of the reservoir and liquid correspond to this study, it is expected that the water cut decreases by up to 20 -50 %.

4.5.5. Increase Reservoir Recovery and Increase Proved and Probable Reserves.

Through the previous results and explanations and the operations that will be carried out by this method and mechanisms of implementation, which is in the interest of increasing production in general and increase the reserve in particular and for the following reasons:

1. Due to the reduced surface tension between water and oil which helps to push the oil towards the well, and also because of the decrease of water cut which will increase the permeability of the oil reservoir.
2. Due to the low viscosity and the removal of wax buildup, which may be a barrier to oil and hinder the movement of oil, therefore will result in extracting a large amount of oil, which was impossible to be extracted.
3. The foaming agent added in the thermal fluids can produce foam of N2 which can effectively plug the macro pore passage in the formation for enhancing the degree of producing reserves.

So, it can say here that the reserves will certainly increase; But the increasing value that cannot be determined because it must conduct further study and other procedures for determining reserves.

CHAPTER FIVE

5. CONCLUSION, RECOMMENDATIONS, AND LIMITATIONS

In this project, a review of the selecting criteria methods that are dependent on the process of selecting the appropriate method of EOR was researched. Then, study was applied to find a proper enhance method for recovery of heavy oil exist in Hemiar fields in Block 14 (Masila) using Taber tables. The **Injection of High Temperature Fluids method** was found to be the best choice as explained all in chapter - 4. Finally, the proposed enhance method was specifically suggested to perform a pilot test for three wells in S. Hemiar field.

5.1. Conclusion

5.1.1. Determine the EOR Screening Criteria

Choosing the type of EOR must be Based on scientific basis which is represented by screening criteria. Three of the widely screening criteria methods used were studied in chapter 3. They are 1-Taber Tables 2- Bayesian Network Analysis 3- Artificial Neural Network. They are varied between analytical, technical and comparison method. All of them have a common factor that they were created based on pervious experiments and analysis. Then, according to the limitations of Bayesian Network Analysis and Artificial Neural Network methods, the Taber Tables was performed as a screening criterion in order to contribute to EOR selection. Since the Taber method depends on the reservoir properties of the formation and liquid and after comparing the special properties in the Taber tables with the special properties in Hemiar fields, which was reached by the method of steam injection was used one of the forms of steam injection, which indicates that it is more feasible economic and technical and Its content was successfully use a method Injection of High Temperature Fluids in South Hemiar field.

5.1.2. Selecting the Enhance Method

Since the Taber method depends on specific reservoir parameters of the formation and liquid properties, values of them were taken from the available data of Hemiar fields and comparison was performed with the corresponding standards values in Taber Tables. The results have pointed toward the Thermal Recovery Enhancement as the most applicable methods with great matching with the steam injection type. Here, it was a must to choose the steam injection form with the highest level of accuracy based on its results from previous applications and experiments, so different Steam injection styles were researched and analyzed for their restriction and application conditions. The best matching of the conditions of Hemiar fields was with a new steam injection method known as The Injection of High Temperature Fluids. This method holds the Synergetic power of gas injection and steam injection. Both of them contribute by its features and Covers the defects of the other.

5.1.3. Injection of High Temperature Fluids in South Hemiar Field.

Injection of High Temperature Fluids assisted steam stimulation is a multi-function enhance method that can obviously improve recovery efficiency. It is an efficient way to enhance steam sweep zone and slow down the production decline for heavy oil. It has a several mechanisms such as reducing oil viscosity by heating and dissolving gas, increasing pressure by injecting gas, expanding the heating range, reducing heat loss and interfacial tension etc. The favorable geological conditions for Injection of High Temperature Fluids stimulation are high dip angle, high to medium reservoir permeability, high porosity layers, formation type and high oil viscosity. This method was explained in detail and preliminary study for S. Hemiar field was performed with the very positive and encouraging expected results which are explained in chapter 4. These results include rebuild the pressure, reducing viscosity, reducing water cut ratio and minimizing interfacial tension. This method was also explained and used in detail and the expected results of this method in the field of South Hemiar were very positive and encouraging results which are explained in chapter-4.

5.2. Recommendations

1. Perform a technical model by Artificial Neural Network simulation for Hemiar fields as a confirmation process for the suitability of High Temperature Fluids Injection Enhance method
2. Implementation of the pilot test proposed and then moving toward full implementation of this method on the ground geometrically in order to obtain greater economic return and increase the rate of production.

3. Study of steam generation by solar energy as an alternative energy as a power supplement for steam generators in order to reach better economic aspect
4. Study Harmal field in Block (S1) on the reality to exploit the optimal reserve available in this field. In addition, study the possibility of applying EOR methods in this field. We also suggest studying the Microbial enhanced oil recovery (MEOR).

5.3. LIMITATIONS

1. The lack of time required to implement this project and none of applied vision in the field.
2. The lack of the necessary data required for the complete study of this project in an engineering way from what led to the reduction of the objective of the nominal project to what it is.
3. Unavailability of special modern programs to determine EOR and to determine the sensitivity of the application of the method to control the performance.

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