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DEPARTMENT OF PETROLEUM ENGINEERING.

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MASTER THESIS

TITLE: A MODERN ECONOMIC AND EFFICIENT ESTIMATION OF CONTEMPORARY ENHANCED OIL RECOVERY.

STUDENT: DARKO MENSAH ISAAC

SUPERVISOR PROF: GASHAM ZEYNALOV

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REFERAT

Recovery efficiencies of 70 to 80% of the original oil in place (OOIP) are possible in some water drive reservoirs. Recoveries are low, on the order of 10 to 30% of the OOIP. In the reservoir recovery is low because the gas is more mobile than the oil phase. Therefore the recovery factors for gas cap drives are between 90% to 95% while for water drive reservoir varies from 50 % to 80%. Gravity drainage has a high rate of EOR find outted ultimate recovery factor of about 99% of the oil in set (IOIP) in perspective that ultimate oil recovery of 94% of 1OIP of the world's oil and gas reserves and this has contributed almost 35 40%.

This thesis is centering on critical issues a modern economic and efficient approximation of contemporary enhanced oil recovery with systematic approaches to new facilities and engineering adopted in oil industry. The major areas that this thesis covers are entry, five chapters, conclusion and references.

In entry, the main subject, the object of the thesis, ways of figure outing mitigation's and brief description of various chapters were foregrounded.

This thesis concentrates on the second approach and assesses the potentiality for increasing production from such known reservoirs with various engineering and methods. In developing offshore, onshore oil new technologies are widely used, with new setup oil production increasing is directly associated.

Increasing of modern economic and efficient contemporary estimate of EOR in oil industry is used in many oil field productions. However, the main methods of enhanced oil recovery operations are miscible shift (carbon dioxide carbonic acid gas injection or hydrocarbon injection).

Thermal recovery (steam deluge, and chemical deluging (alkaline deluging or mi basement polymer flooding) or thermal recovery (steam inundate). Despite the above techniques, chemical mechanisms of H2O injection, thermal processes under it are steam drives, and others are espoused to facilitate reservoir performance.

Gas exploration and production over two decades with a vigorous development in well systems and advancement of modern engineering and there has been a significant transformation of oil industry. With an accurate precision, drilling and completion engineering has made feasible new well shapes that have increased the performance of oil production.

The master thesis embraces of five chapters.

The first chapter deals with the general reexamine of H2O deluging or associated with enhancement of oil recovery deluging, chemical mechanisms. In developing offshore these methods are predominantly used.

The second chapter deals with different displacement efficiency of fluids which promotes EOR.

While the third chapter does deals with water deluging. All the various contrive methods which necessitate the EOR efficiency are analyzed so as to find out optimal performance which is suitable for the venture.

Chapter four centering on thermal methods of recoveries. Simulation treatments or thermal recovery processes also can be classed as thermal drives. There are processes of thermal recovery methods which are used today. The one in which hot liquid are infused into the reservoir and those in which heat is generated within the reservoir itself.

Evaluation of reservoirs recoveries parametric quantities for enhancing recoveries performances are discoursed in chapter five. These are screening criteria, screening guidelines, preferred standards and selection criteria. And also the schemes which adopted for worldwide statistical distribution and market schemes for crude oil production and economic efficiency which facilitate EOR.

Lastly, decision, recommendation and future directions are foregrounded in the last chapter of the thesis.

XÜLASƏ

Bəzi su-itələyici mexanizmli yataqlarda yerdəki orijinal neftin verim effectivliyinin 70 – 80%-ə qədər olması mümkündür. Aşağı effektivlik yerdəki orijinal neftin verimliliyi 10 – 30% arasında olur. Verimliliyin aşağı olmasının səbəblərindən biri yataqdakı qazın neftə nisbətən daha mobildir. Buna görə qaz-papağı mexanizmli yataqlarda verimlilik 90 – 95% arası dəyişdiyi halda, su-itələyici mexanizmli yataqlarda bu 50 – 80% arası dəyişir. Ağırlıq Drenaj mexanizmli yataqlarda əsas verimlilik faktoru olduqca yüksəkdi. Beləki, yerdəki ilkin neftin verimliliyi əsasən 94% olduğu halda, Ağırlıq Drenaj mexanizmli yataqlarda bu 99%-ə qədər yüksəlir. Bu xassə dünyanın 35 – 40% nef və qaz yataqlarına yardım etmişdir.

Bu tezis iqtisadi və səmərəli uyğunlaşdırılmanın günümüzün inkişaf etmiş neft hasilatına sistematik yanaşma ilə yeni obyektlərin və mühəndəsliyin neft sənayesinə qəbul olunması haqdadır. Bu tesiz quruluş baxımından giriş, beş fəsil, nəticə və mənbələrdən ibarətdir.

Giriş tezisin əsas mövzusunu, onun obyektini və fəsillərin ümumi məzmununun izahını əhatə edir.

Tezisin əsaə diqqət obyekti əlavə yanaşma və müxtəlif mühəndislik metodlarını qiymətləndirərək məlum potensiallı yataqların hasilatı artırmaqdır. Neft hasilatının arması birbaşa yeni texnologiyalardan və alətlərdən asılıdır. Yeni texnologiyalar həm quruda həm dənizdə geniş tətbiq olunur.İqtisadi və səmərəli uyğunlaşdırılmanın günümüzün inkişaf etmiş neft hasilatına sistematik yanaşma bir çox neft yataqlarının işlənməsi və hasilatında istifadə olunur.

Buna baxmayaraq neft hasilatının gücləndirilməsində(EOR) istifadə olunan əsas metod qarışdırıla bilən qazlarla əvəzolunma(karbon dioksid CO_2 və ya digər karbohidrogenlərin inyeksiyası), termal çıxarma (buxar doldurulması, buxar və digər kimyəvi qarışıqların(alkinlərin və polimerlərin) yeridilməsidir. Hərçənd, yuxarıda sadalananlara nisbətən H_2O-nun kimyəvi inyeksiyası, bunun təsiri nəticəsində yataqda baş verən termal proseslər yataqın işlənməsini asanlaşdırmışdır.

Son iki onillik ərzində quyu sistemləri təkmilləşdirilməsi və müasir mühəndisliyin inkişafı neft və qaz kəşfiyyatı və hasilatında əhəmiyyətli çevrilişə səbəb olmuşdur. Dəqiq hesablamar, qazma və tamamlama mühəndisliyi mümkün yeni quyu formalaşmasını təmin etmişdir ki, bu da öz növbəsində neft istehsal fəaliyyətini artmışdır.

Magister tezisi beş fəsildən ibarətdir.

Birinci fəsil H_2O-nun güclü təzyiqlə yeridilməsini ümumi olaraq gözdən keçirərək kimyəvi mexanizmlərin EOR ilə əlaqələndirir.

Bu metodlar əsasən dənizdəki yataqların işlənməsində istifadə olunur.

İkinci fəsil EOR təşviq edən müxtəlif mayelərlə əvəzolunma barədədir.

Üçüncü fəsil kimyəvi qarışıqlarla suyun daşqın şəklində inyeksiya olunmasını əhatə edir. Bütün bu metodlar EOR-in effektivliyinin artırılmasında vacib olduğundan müəssisə üçün uyğun olan müəyyən optimal performans üçün təhlil olunur.

Dördüncü fəsilin diqqət mərkəzində termal bərpa metodlarla hasilatın gücləndirilməsidir. Termal bərpa metodları öz növbəsində termal itələmə və stimulasiyaya ayrılır. Hal hazırda termal berpanın əsas iki üsulundan istifadə olunur. Bunlardan biri yatağın öz istiliyi hesabına meydana gəlir ki, ikincisi kenardan qaynar mayenin yataga yeridilməsi prinsipinə əsaslanır.

Beşincə fəsilin müzakirə obyekti Yatağın bərpa parametrlərinin hasilatın gücləndirilməsi əsasında qiymətləndirilməsidir. Bura seçim kriteriyaları, seçim kitabçası, üstünlük verilən seçimlər daxildir. Həmçinin, bura dünya üzrə böluüdürülmüş və qəbul edilmiş sxemlər və hasilatın asanlaşdırılması ilə xam neftin hasilatı və iqtisadiyyatını effectivləşdirliməsinin sxemi daxildir. Və nəhayət, son fəsildə gələcək istiqamətlərimç nəticə və tövsiyələrim ön mövqedədir.

TABLE OF CONTENT

PAGES

CHAPTER I

CHAPTER II

CHAPTER III

List of Tables.

Page

List of Figures

Page

Abbreviations

EOR - Enhanced Oil Recovery.

E&P – Exploration and production

RDP - Reservoir Development Plans

B/D – Barrels per Day

m^3/d – Meters Cubic per Day

OOIP - Original Oil - In Place

GOR's – Gas Oil Ratios

PVT – Pressure Volume Temperature

IOIP - Initial Oil - In Place

E_D – Microscopic Displacement Efficiency

E_R – Waterflood Recovery, fraction OOIP

FVF – Formation Volume Factor

m^2 – Meters Square

bbl – Barrel

STB – Stock Tank Barrel

Ev – Volumetric Sweep Efficiency fraction

Btu – *British thermal unit*

Lbm – Lattice Boltzmann methods.

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Dedication

This Thesis is dedicated to my late parents to whom I owe every success that I achieved.

INTRODUCTION.

The theme: The human beings imbalance between demand and furnish for oil and gas is growing significantly Pointed out in this thesis from various organizations that watch the E&P industry the be adrift. However, some surveys presents that the decline charge per unit of existing oilfields is increasing tremendously over time, more so, additional production is becoming progressively more important to countervail the demand and however, some studies demonstrate that the decline charge per unit of existing oilfields is increasing tremendously over time, more so, additional production is becoming progressively more important to countervail the demand. For the past decades of the twentieth century, there is not and will not be an economical, abundant substitute for crude oil in the economic systems of industrial countries.

To propel these economic systems necessitates developing additional crude reserves keeping the furnish. Drilling which could sustained by applying enhanced oil recovery EOR and in some ways, this additional development will be in descriptor of exploration.

A large graduated table application of EOR is not an easy project. It will need a large number of people and a higher degree of engineering to bring about substantial EOR production.

This thesis explains schemes for appraising reservoir development plans (RDPs) back enhanced oil recovery (EOR).It concentrates on the conclusion doing that leads to commencement EOR projects, in this sense. Any scheme that ultimately increases oil and gas recovery is under consideration for EOR conclusions. Oil and gas production increasing is contingent upon bringing into development new offshore oil and gas Fields. However, the second, main and not less important in oil and gas production significant role plays application of new facilities and engineering in oil and gas industry.

Of successful enhanced oil recovery methods elements and underlying conceptions are discoursed to aid as background materials for readers who are unfamiliar with modern EOR engineering.

The oil market in decades has triggered a momentous increase in property evaluation. In this thesis is directed toward significantly ameliorating modeling approaches in the five main areas discoursed above. This project targets the development of general reexamine of water flooding, specifically. Specifically, this project targets the development of

- General Review of Water flooding
- Displacement Efficiency of Fluids.

- Water flooding Design
- Thermal Recovery Methods.
- Evaluation of Reservoirs for Recoveries and Economic Indicators of Enhanced Oil Recovery.

The object of the Thesis.

Modern application of EOR and to ascertain optimal economic efficiency.

Mitigation approaches.

1. Mathematical statistically processing and adequate field data acquisition, systematization.
2. The approximation economic efficiency of modern techniques and engineering application by economical statistical methods.

Matter of Thesis.

The thesis comprises: referat, introduction, five chapters, conclusion and references.

Brief descriptions of each chapter are stated and entry comprises the subject, object, mitigation approaches.

Chapter One. Critically centering on EOR method used to recover more oil from a reservoir by primary recovery. Brief descriptions of each chapter are stated and entry comprises the subject, object, mitigation approaches. In primary production, oil is displaced to the production well by natural reservoir energy. Rock enlargement, solution gas drive, gravitation drain, and the inflow of H2O from aquifers and sources of natural reservoir energy are fluid.

Chapter Two. Ascertains displacement efficiency of any materials such as oil, accents on the displacement efficiency of fluids also evaluation of all the various methods used to in reservoir determination such as immiscible displacement. Determination of material balance, repose facial latent hostility, contact angle measure, stability are discoursed.

Chapter Three, Water flooding design, the contrive of a H2O deluge involves both technical. These estimates may be rough or complex depending on the requirements of a particular project and the doctrine of the operator.

This section centering on methods of estimating H2O deluge performance for economic analyses. Gas recovery factors overall the human beings oil and gas Fields investigated and foreboded and oil. When it is 40% on the secondary production, oil recovery factor on the primary production is estimated about 30%.

Chapter Four. Two processes of thermal recovery methods which are used today, thermal recovery methods. In which hot fluid is injected into the reservoir. Thermal recovery is outlined as a means in which heat is introduced deliberately into a subsurface accretion of organic chemical compounds for the aim of recovering fuels through high gravity wells. This definition covers, to the best of my cognition, all practiced this definition covers and proposed methods for recovering oil and combustible gases from the subsurface by thermal means. Thousands of papers and articles have been published since 1865 on the entry of heat into subsurface reservoirs to accelerate oil recovery.

This literature reflects the great variety in which thermal energy has been and is being used, or considered to figure out or ameliorate many different types of problems associated with the production of oil. In preference to other recovery methods for a number of reasons thermal recovery is used. Which is the case of most current interest, in the case of viscous oil, heat is used to ameliorate the displacement, and others known as in-stu processes in which in-stu combustion or fire flooding.

In- stu coevals of heat have been tested but currently are not widely practiced to some extent and the processes combining injection. Stimulation treatments or thermal recovery processes also can be classed as thermal drives. On thermal drives however, this thesis concentration and the focusing was on steam drives, EOR and each parameter that characterizes.

Chapter Five. Economic index numbers of enhanced oil recovery and evaluation of reservoirs for recoveries.

Stresses on a number of criteria are which are used to appraise the reservoir recoveries. Selection criteria and these are screening criteria, screening guidelines, preferred criteria. However, each criteria, may be affected by the current and local economic climate.

A systematic control index number of the various economic indexes with cost evaluation performance on EOR is critically analyzed. Conical furnish of worldwide crude oil trend, efficient control chemical mechanism to increase the end product and the human beings are poised to have an effective. Optimal method of steam drives is adopted for EOR because of its imaginary cost, with its environmental mitigation and efficiency couple.

The final result of the thesis could be used in organizing of oil and gas fields’ development, gas fields' recoverable reserves and in deciding crude production engineering problems and calculation of oil. Oil production increase is directly correlated with contemporary technologies in all branches of oil and gas industry. In developing offshore, onshore oil gas fields’ ultramodern technologies are widely used.

Hot H_2O injection and increasing economic efficiency in oil industry there are many methods which may be adopted for ordinary water injections. It is premised that an understanding of the various chemical mechanisms come abouting during a thermal displacement process, however, its fluids, is important in the selection, contrive, operation, and as well as of the properties of the reservoir, surveillance, and interpretation of that process, and other economic index numbers which are used to appraise EOR.

CHAPTER I

1.1. Waterflooding Review

By any means used to regenerate more oil from a source is recognized as enhanced oil recovery (EOR). Of oil recovery processes this encompasses all methods and agents of oil recoveries. The definition does not curtail EOR to a certain phase that is primary, secondary and Tertiary of the producing life of a reservoir. Oil is forced out of the production well by natural reservoir energy in primary chemical mechanism. And the sources of natural reservoir energy are fluid, the influx of H_2O from aquifers and, gravitation drainage, rock enlargement, and solution gas drive. H_2O deluging is the most widely applied EOR process and is the subject of this chapter. For a future volume other EOR processes are planned, to define the initial condition of the reservoir at the time H_2O deluging operations are being considered, then primary production and chemical mechanisms are reexamined.

1.2. Development of Waterflooding

The discovery of crude oil by Edwin L. Drake at Titus-ville, PA, on Aug. 27, 1859, marked the beginning of the petroleum era [59]. Within 2 years other Wells were drilled that flowed 1000s of barrels per day, although the first oil well produced about 10 b/ d [1 6 m^3 d]. From these shallow Keystone State reservoirs declined rapidly as reservoir energy was depleted. Recovery was a small percentage of the amount of oil estimated to be initially in place.

Carll (1880) raised the possibility that, oil recovery might be increased by the injection of H_2O into the reservoir to displace oil to producing wells, as early as 1880s. When operators realized that water come inning the productive formation was imitating production, perhaps as early as 1890, H_2O injection began. The practice of water injection had an appreciable impact on oil production from the Bradford field, of injecting H_2O into a well until encircling producing wells watered out termed a circle flooding the first flooding pattern started [13].

To injection to create an expanding "circular" waterfront the watered out production wells were converted. A keystone state law requiring plugging of abandoned H. G. Wells, and holes to foreclose water from come inning oil and gas sand was construed as prohibiting H_2O flooding, so H_2O deluging was done secretly. In 1921, in which H_2O injection expanded rapidly after 1921 the practice, the keystone state law makers legalized the injection of H_2O into the Bradford litoral.

Wells were keeled on both sides of an equally spaced row the circle inundate method was replaced by a "line" deluge, in which two rows of producing.

By 1928, the line deluge was replaced by a new method termed the "five spot" because of the resemblance of the pattern to the five floaters on die. In the Bradford field H_2O deluging was quite successful [13]. The life of the production history of the Bradford field for more than 100 years of production, on production from this field had apparent effects on H_2O deluging.

Spread slowly throughout the oil producing provinces, called secondary recovery because the process yielded a second batch of oil after a field was depleted by primary production, H_2O deluging. H_2O injection operations were reported in 1931, in Kansas in 1935, and in Lone Star state in 1936.

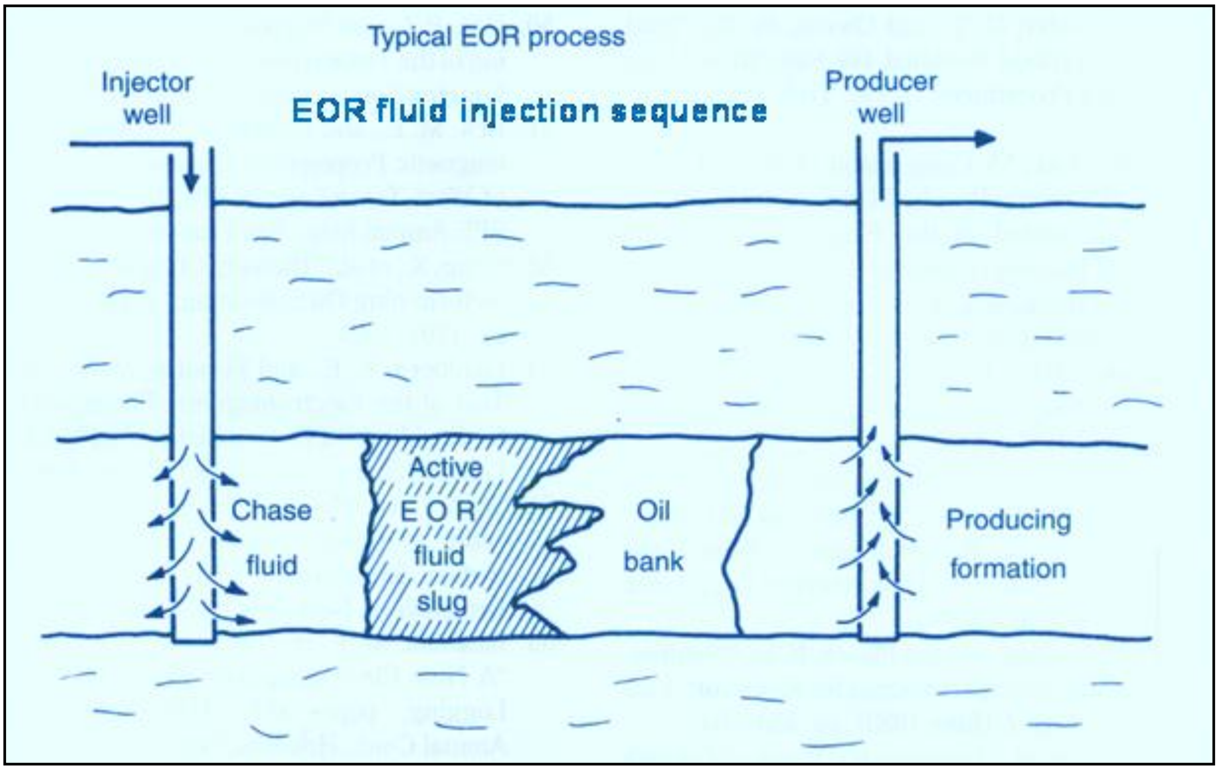


Figure.1.1. Common EOR fluid injection sequence [35]

“The slow growing of H_2O injection was caused by several factors. H_2O deluging was understood poorly, in the early days. Gas injection developed about the same time as H_2O deluging, in 1930's led to peroration in several states and major discoveries of crude oil in the

United Sates in the 1920's. Oil production was much greater than market demand capability. Large furnishes of low cost imported oil also prolonged the primary life of reservoirs; consequently, primary depletion of many reservoirs was controlled by market demand".

Early 1950's as reservoirs approached economic limits and operators sought to increase reserves and interest in H_2O deluging developed in the late 1940's. By 1955, water flooding was estimated to contribute more than 750,000 B/D [119 200 m^3/d] out of a total production rate of 6.6 million B/D [106 m^3/d] in the U.S. [59], throughout the world H_2O deluging is practiced expensively.

1.3. Primary Production

"The magnitude of oil that can be displaced by the natural reservoir energy allied with a reservoir varies, with reservoir type" [54]. According Thomas, C. E (1989) pointed out the number of factors to be considered during H_2O deluging that are suitableness of a campaigner reservoir for H_2O deluging, reservoir characteristics must be considered the following;

- ✓ Inclination of the source
- ✓ Mobility in place
- ✓ Depth of the sources
- ✓ Petrology and rock in place
- ✓ Impregnations of the liquid
- ✓ Uniformity of the source and make up flow
- ✓ Primary source driving mechanisms

Hayes (1976) noted that, on the efficiency of H_2O injection in a particular reservoir lithology has a profound influence. Rock properties that affect deluge ability and success are;

- ❖ reservoir lithology
- ❖ Clay content
- ❖ Porosity
- ❖ Thickness of the grid
- ❖ Permeability

Reservoirs with thin net thickness or tight [4] (low permeability) reservoirs possess H_2O injection problems in footing of the desired H_2O injection charge per unit or force per unit area.

Where

$$P_{inj} \propto \frac{i_w}{hk}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots .. 1.1$$

P_{inj} = water-injection pressure

i_w = water-injection rate

h = thickness of the grid

k = absolute permeability

There are wild ranges of reservoirs classifications supported by basis of the energy of the reservoir. These are; gravity drainage, solution gas drive, fluid expansion, gas-cap drive, and water drive,

1.3.1. Water Drive

Reservoirs that are classed as strong H_2O drive reservoirs are not usually considered to be good candidates for H_2O deluging because of the natural ongoing H_2O inflow. In some instances a natural H_2O drive could be supplemented by water injection in order to;

- Support a higher withdrawal rate
- Better distribute the water volume to different areas of the field to achieve more uniform areal coverage
- Better balance voidage and influx volumes

"Between the reservoirs a water drive reservoir has a hydraulic connection and porous, H_2O saturated rock called an aquifer" [29]. The aquifer may underlie all or part of the reservoir.

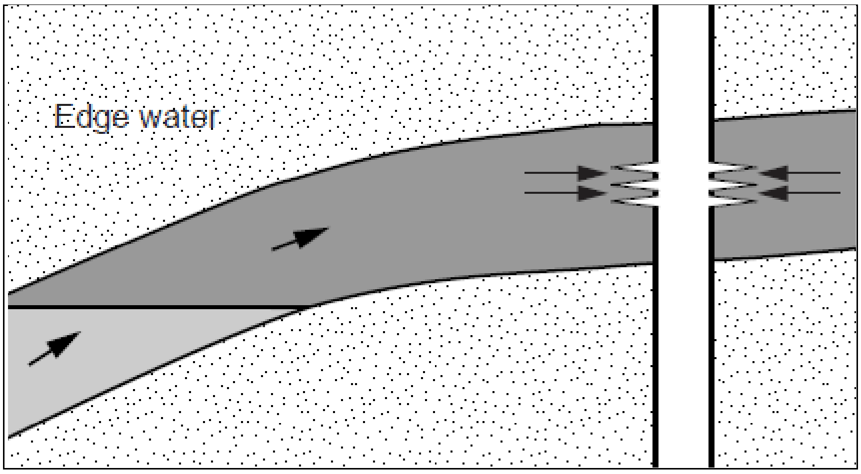


Figure. 1.1. *Edge Water Drive Reservoir* [3]

The water in an aquifer is pressed tightly together. As reservoir pressure is decreased by oil production, the water expands, creating a natural waterflood at the reservoir/aquifer boundary. The H2O expands, creating a natural H2O flooding at the reservoir aquifer boundary, as reservoir pressure is decreased by oil production. By compressibility of the rock in the aquifer reservoir energy is also supplied. When the aquifer is large and may be "water flooded" by proper management of fluid withdrawal rates contains sufficient energy of the entire reservoir.

Recovery efficiencies of 70 to 80% of the original oil in place (OOIP) are possible in some H_2O drive reservoirs. Structural positions are important variables affecting recovery effectiveness and reservoir geology, heterogeneity. Meanwhile, all over the world strong reservoirs H_2O drive has found worldwide.

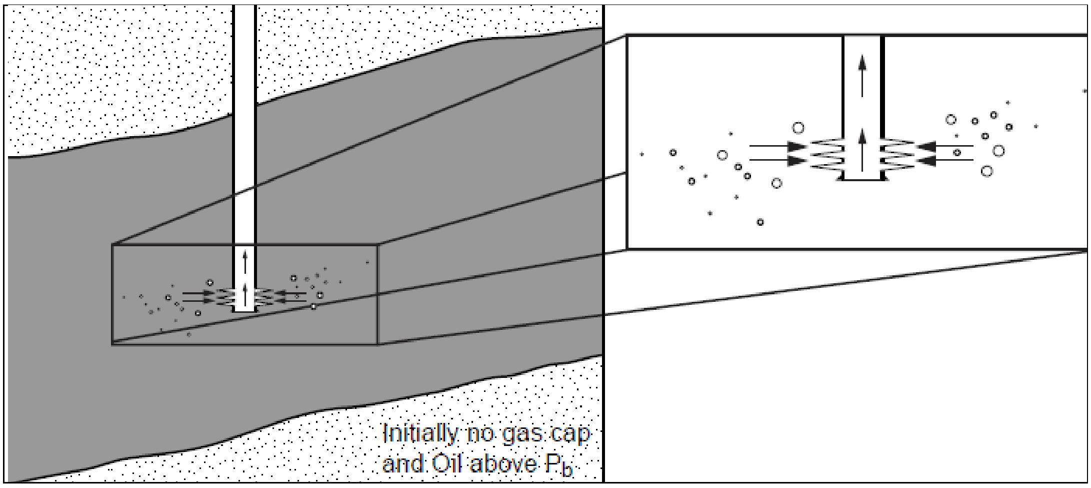
Reservoirs are connected to aquifers that have limited amounts of energy H_2O drive. Unless there is extensive geological information about the aquifer from drilling or other records, its capability to furnish reservoir energy is not known until well into the primary production period and the extent of the aquifer.

Reservoir force per unit area is monitored with fluid withdrawal, usually, H_2O inflow can be calculated. Of H_2O drive capability the leveling of reservoir force per unit area at a withdrawal charge per unit is measured. Sufficient energy to encounter desired fluid withdrawal rates while keeping reservoir force per unit area if the aquifer cannot furnish. Natural reservoir energy an edge H_2O injection program may be used to supplement.

The program, called force per unit area maintenance is a H_2O flooding, that reservoirs with strong aquifers are seldom H_2O deluge candidates to its follows, reservoir heterogeneity may limit the consequence of a natural H_2O drive to a component part of the reservoir.

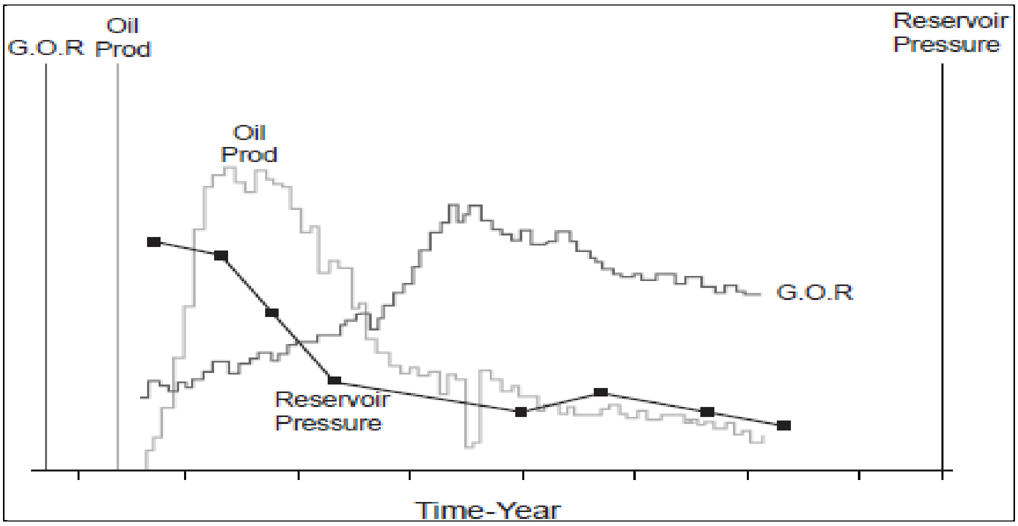
1.3.2. Solution Gas Drive

Under a high pressure, crude oil might accommodate considerable measures of diffused gas. This occurs when the pressure from the source is decreased as the mobile liquids are withdrawn, the gas expels out of the solution which dislodges the oil from the source to the bearing wells, as shown in Fig. 1.2a.



$Figure. 1.2a. Solution\ Gas\ Drive\ Reservoir$ [3]

The effectiveness of this method relies upon by the size of the gas in emulsion, the rock and oil characteristics, and the reservoir architecture.



$Figure. 1.2b. Production\ for\ Solution\ Gas\ Drive$ [30].

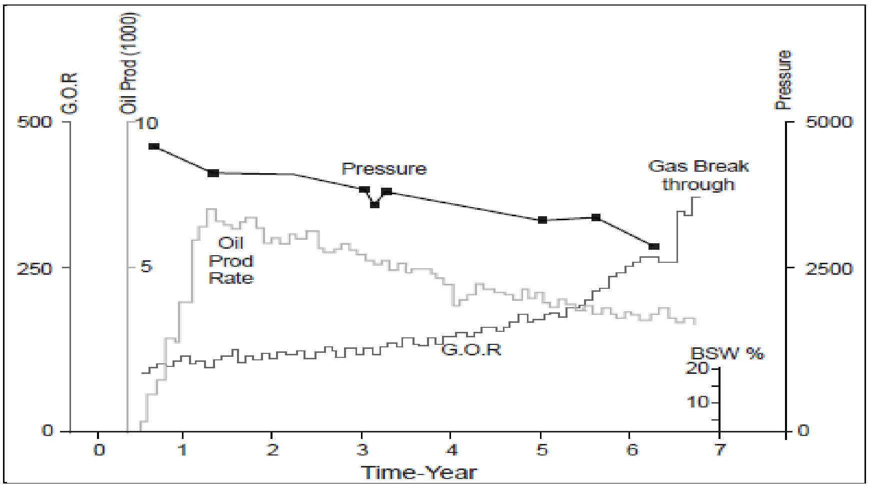
There are minimal recoveries varies from 10 to 30% of the OOIP, due to the large amount of gas influx than oil phase from the source. This leads to the declining of the pressure, as gas moves at a faster rate than mobile oil, consequently, leading to sudden depletion of energy of the source, which ascertained by the increasing gas / oil ratio (GOR's) in the domain. This process is a unique candidate for water-flooding applications.

1.3.3. Undersaturated Reservoir

A crude oil which bears low gas than is needed to saturate the oil at force and head of the source is termed under-saturated. Considering the fact that, oil is vastly under-saturated, a great deal of source energy is accumulated in the way of fluid and sponginess of the rock. Meanwhile, precipitately declines of the pressure expels the fluids from an under-saturated formation in advance of bubble point is attained. Furthermore, the solution gas drive leads to the source of energy for dislodged fluid. Analysis from the reservoir characterization reviewed that, both PVT and formation pressure information show an under-saturated reservoir. Hence, high reservoir pressure yields large amount of recoveries which make it good candidates for water injection.

1.3.4. Gas –Cap Drive.

Considering the fact that a reservoir with a vast gas cap as shown in Fig.1.4, predominately considerable energy accumulated in the order to squeezed gas. Meanwhile, as the cap gas enlarges, liquids are expels from the configuration, leaving only the oil through a gas drive aided via gravity drainage.



$Figure.1.3. Reservoir\ Performance\ Gas - Cap\ Drive$ [30]

The development of the gas cap is subdued by the intended level of the pressure in the formation and through the gas output subsequently, the gas enters into formation wells.

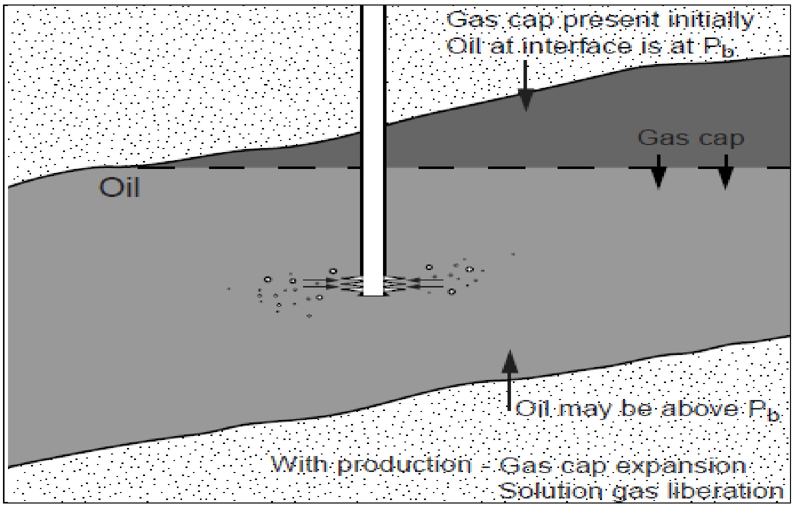


Figure. 1.4. *Gas Cap Drive Reservoir* [3]

Sometimes, formations with a considerable amount of gas cap are usually not acceptable candidates for water-flooding. It is crucial to maintain pressure in these formation whenever injecting gas into the gas cap. Reservoir that have a concealed pay zone may have fused both gas and water injection pattern.

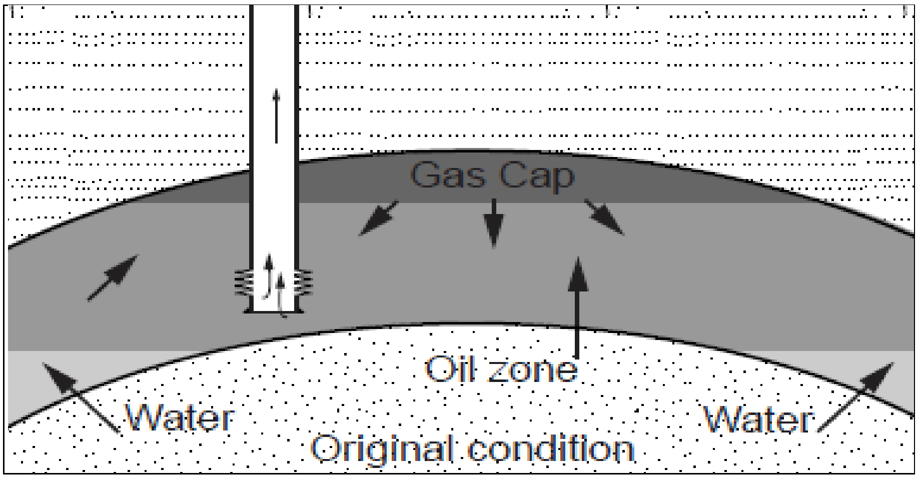


Figure. 1.5. *Combiation of Water and Gas Cap Drive Reservoir*[3]

Circumspection is necessary whenever fusing both water and gas injection development is planned. Uncertainty is that oil will be superseded towards the gas –cap area and will linger cornered at the completion of the program.

1.3.5. Gravity Drainage

The primary aim of gravity drainage is when the existing producing technique highly substantial formations that have excellent vertical connection or in abrupt inclining source. It delays because gas need to move upward stream or at the apex of the configuration to inflate the aperture preciously engrossed through oil.

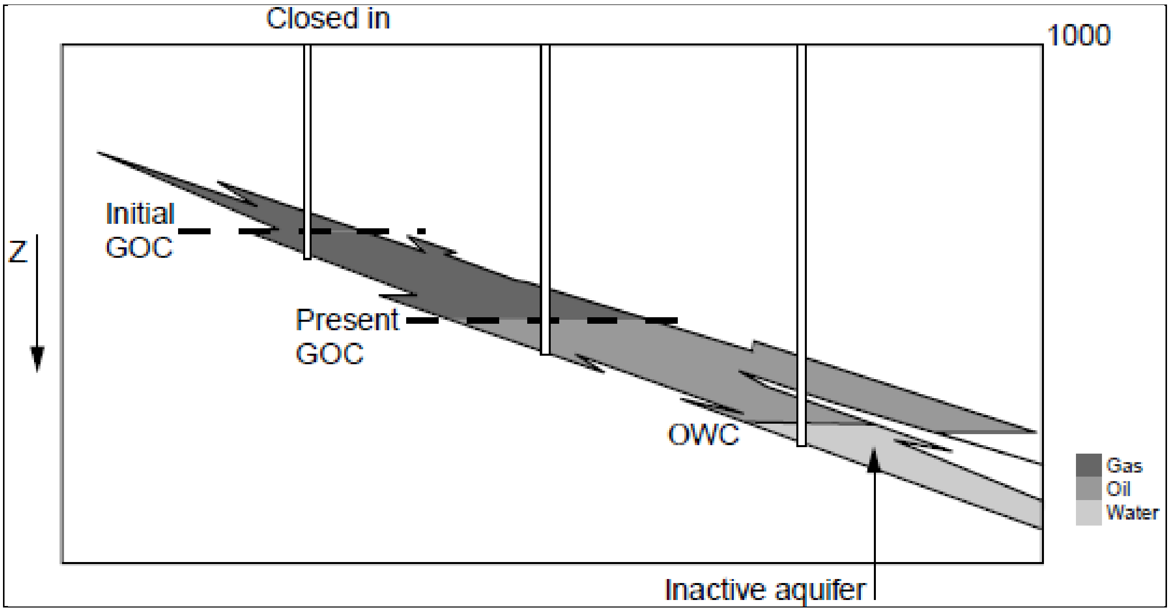


Figure. 1.6. *Gravity Drive [3]*

Gravity Drainage has a high rate of EOR according to [32], ascertained "ultimate recovery factor of about 99% of the initial oil in place (IOIP) by his experiment" [20]. Da Sle and Guo (1990) are on the view that ultimate oil recovery of 94% of IOIP. And this has contributed almost 35-40% of the world's oil and gas reserves. Gas movement is swift comparative towards oil drainage such that velocities of the oil are managed by the magnitude of oil seepage [24]. In formation where wells are stressed throughout to ambient pressure, air may get into the reservoir at the apex of the bearing intermission if the whole intermission is open.

Mechanism	Characteristics	
Combination drive typically blend	Reservoir pressure	comparatively fast pressure deceases
	Gas oil ratio GOR	Manager to retain small GOR
	Water invention	sluggish raise of water production
	Well conduct	Structurally small wells prove low GOR. Structurally high wells illustrate growing GOR.
	Oil recovery	Normally advanced than depletion drive reservoirs but less than recovery as of water drive or gas cap reservoirs. Final recovery depends lying on the amount to which it is potential to decrease the magnitude of recovery through depletion drive.
Gas cap drive	Reservoir pressure	deceases gradually and incessantly
	GOR	Swells constantly and as the intensifying gas cap attains the generating

		intervals, the GOR raises sharply and at last falls.
	Water Production	missing or unconstructive
	Well activities	Drifts to course longer than depletion drive recoveries
	Oil recovery	Varies from 20% to 40%, by an average of 25%
Gravity drainage drive	Reservoir pressure	Swift decline of pressure
	GOR	usually little GOS'
	Water Production	slight or nix water invention
	Well conduct	Structurally small wells illustrate small GOR. Structurally soaring wells illustrate growing GOR.
	Oil recovery	Changes mostly but typically soaring oil recoveries are practicalized Recoveries up to 80% have been reported.
Water drive. virtually resourceful reservoir dynamic force	Reservoir pressure	Relics high
	GOR	Rest little
	Water invention	Begins untimely and raises to substantial amount
	Well activities	Runs pending water production gets extreme
	Oil recovery	Varies commencing 30% to 80%
Depletion drive: Solution gas drive Dissolved gas drive Internal gas drive	Reservoir pressure	Deceases swiftly and incessantly
	GOR	raises to a highest and then deceases
	Water invention	small or no water invention
	Well activities	involves pumping at early phase
	Oil recovery	Incredibly ineffective driving mechanism. Oil recovery effectiveness differs from fewer than 5%, to beyond 30% with a typical of 16%
Rocks and Liquid expansion drive	Recovery pressure	Exceeding bubble point fast and constant pressure deceases in anticipation of bubble point is accomplished.
	GOR	exceeding bubble point: GOR relics small and constant
	Water invention	small or no water invention
	Well activities	necessitates pumping at early period
	Oil recovery	Slightest efficient driving mechanism. Oil recovery effectiveness usually ranges from 1% to 5%, by an average of 3%

Table1. Primary Recovery Mechanisms Performance. [5], [49].

CHAPTER II

2.1. Displacement Efficiency of Fluids

To ascertain displacement efficiency of any materials such as oil, assume that density of oil is constant; then, the displacement efficiency for oil becomes [34];

$$D_E = \frac{Quantity\ of\ oil\ dislodged}{Quantity\ of\ oil\ contacted\ by\ displacing\ agent} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 2.0a$$

This is given as;

$$D_E = \frac{\frac{\overline{S_{0l}}}{B_{0l}} - \frac{\overline{S_0}}{B_0}}{\frac{\overline{S_{ol}}}{B_{0l}}}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots .2.0\ b$$

Where

$\overline{S_{0l}}$ = volumetric middling oil infiltration at the beginning of the waterflood, where the average pressure oil saturation is P_l, fraction,

$\overline{S_o}$ = volumetric middling oil infiltration at a particular during the waterflood,

B_{ol} = oil FVF at pressure P_l, bbl/Stb [m^3/stock-tank m^3], and

B_0 = oil FVF at a particular point during the waterflood, bbl /Stb [m^3/stock-tank m^3].

When the oil saturation in the PV swept by water is reduced to the residual saturation (S_{or}),

D_E is bounded between 0 and 1. The rate at which D_E erectile dysfunction draw nears 1 is strongly affected by the initial conditions, the displacing agent, and the amount of displacing agent. Other factors which affect the displacing agent are fluids, rock, and fluid – rock properties. "If the movement is such that the displacing agent comes in contact with oil originally present in the avenue, the volumetric sweep efficiency will be integrity", then D_E becomes the recovery efficiency E_R then;

$$D_E = 1 - \left(\frac{S_{or}}{\overline{S_{0l}}}\right)\left(\frac{B_{ol}}{B_0}\right), \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots .2.1$$

which becomes,

$$D_E = 1 - \left(\frac{S_{or}}{S_{0l}}\right), \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots .. 2.2$$

For an incompressible, single –component oil phase flowing in an incompressible permeable medium. Equation 3.1. D_E is proportional to the middling oil infiltration in the medium.

2.2. Immiscible Displacement

EOR displacement begins with understanding of the displacement of one fluid by an immiscible second fluid [14]. According to Buckley and Leverett (1942), water displacing oil was first solved (water / oil, gas/oil, gas /water or gas/water and oil) in reservoir rocks alters the capacity of a rock to transmit fluids. In two immiscible, incompressible phases in a one dimensional permeable medium is given by the mass conservation equation H_2O and owing to the isothermal flux of oil [59].

$$\left\{\begin{matrix} Mass\ of\ oil\ entering \\ the\ differential \\ element\ in\ the\ time\ increment\ \Delta t \end{matrix}\right\} - \left\{\begin{matrix} Mass\ of\ oil\ leaving \\ the\ differential \\ element\ in\ the\ time\ incerement\ \Delta t \end{matrix}\right\}$$

$$= \left\{\begin{matrix} Mass\ of\ oil\ that\ accumulates \\ within\ the\ differential\ element\ in\ the\ time \\ increment\ \Delta t \end{matrix}\right\}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots .2.3$$

Water and oil are immiscible under nearly all reservoir and surface conditions because the mutual solubilities of water in oil and oil in water are respectively small. At equilibrium where a crude oil and a gas, the crude oil contains the entire component of the gas in proportions is determined by the equilibrium distribution coefficients. Sometimes, these systems are partially miscible because substantial amounts of gas which may be dissolved in oil depending on pressure, temperature, and the composition.

2.3. Interfacial Tension

The interface connecting two junctures is a zone of limited solubility which is at most a few molecules thick. Abrams (1975) stressed that, stereotype as stage parameters that occur because the attractive forces binding the molecules in the same zone are much larger than those that occur among molecules in separate zones.

Interfacial tension σ has units of force/length, and can be visualized in terms of the force that acts along any line in the plane of the surface, [1] as shown in figure 2.1

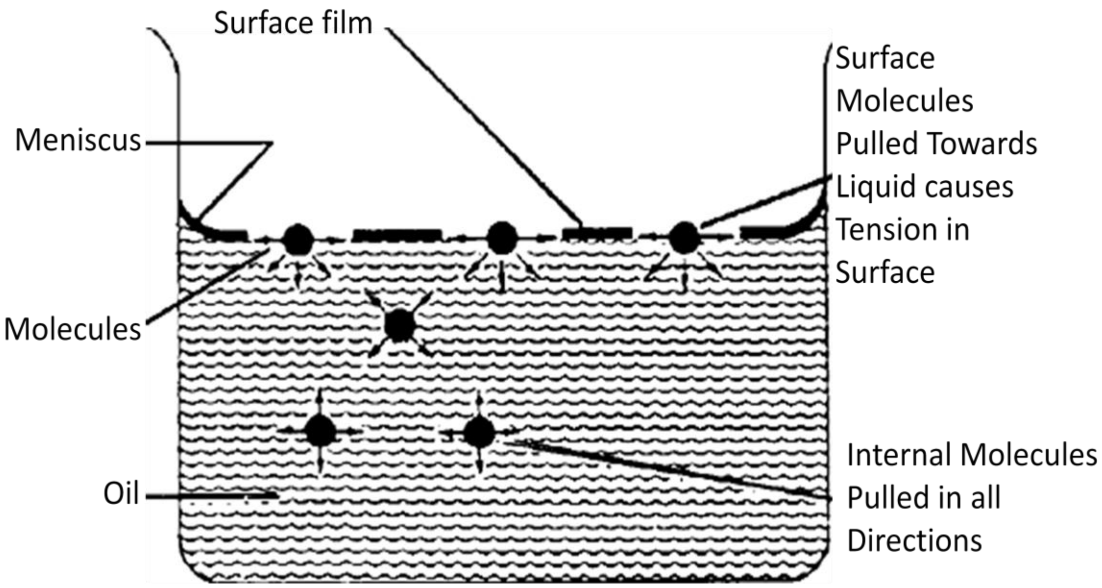


Figure 2.1: Interfacial tension force at an interface between two fluids [5].

If we consider the equilibrium of the spherical cap of an interface between two fluids, as shown in Figure 2.2.

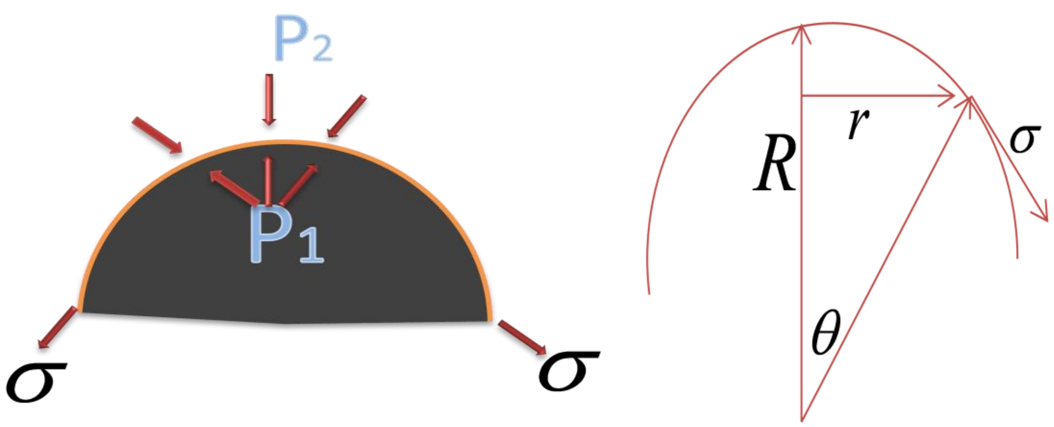


Figure 2.2: Spherical cap of an interface between two fluids.

If we consider a force balance on the cap, the differences in pressure on both inside (fluid 1) and outside (fluid 2) with the force along the edge of the cap due to interfacial tension,

One can assumes that,

$[P_1 - P_2]\pi r^2 = \sigma \sin\theta \times 2\pi r$, ……………………………………………………..2.4

Rearranging equation 2.4, then equation 2.5 becomes

$$[P_1 - P_2] = \frac{2\sigma \sin\theta}{r}, \ldots \ldots \ldots \ldots 2.5$$

Therefore,

$$[P_1 - P_2] = \frac{2\sigma}{R}, \ldots \ldots \ldots \ldots 2.6$$

For a spherical cap since r=R sinθ.

By considering a nonspherical cap with two differences in radii of curvatures R_1 and R_2, the balance forces are,

$$[P_1 - P_2] = \sigma\left[\frac{1}{R_1} + \frac{1}{R_2}\right], \ldots \ldots \ldots \ldots 2.7$$

Where, R_1 and R_2 are the main radii of the curvature, therefore, the quantity $\frac{1}{R_1} + \frac{1}{R_2}$ is an invariant for some pair of an orthogonal line surfaces, hence, the mean radius of curvature r_m is given by

$$\frac{1}{r_m} = \frac{1}{2}\left[\frac{1}{R_1} + \frac{1}{R_2}\right], then\ [P_1 - P_2] = \frac{2\sigma}{r_m}, \ldots \ldots \ldots \ldots 2.8$$

This equation is known as Laplace equation which might be use to influence some interfacial tension of a medium.

2.4. Wettability

Wettability is the fundamental interaction joining the surface of the reservoir rock and the fluid stages confined in the pore space steer fluid propagation in rocks as well as flow properties. One of the zones is usually captivated to the surface more strongly than other zone, considering that two immiscible liquids are set to link with a solid surface" [59]. This zone is demonstrated as the wetting zone while the unrelated is the non-wetting zone.

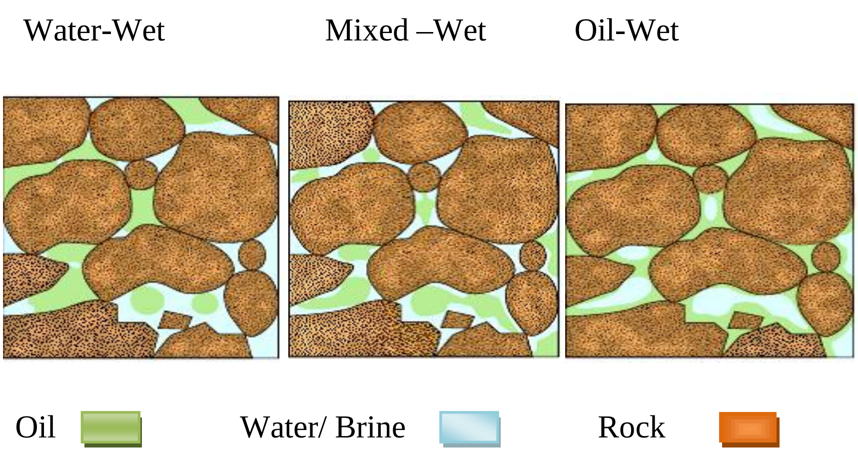


Figure 2.3: Shows drenching in orifices the three settings shown have similar saturations of water and oil [50].

In a water-wet case (left), oil remains in the center of the pores. The reverse condition valid if all skins are oil-wet (right). In the mixed-wet case, oil has expels water from some of the skins, but is still in the middle of water-wet pores (middle) [50].

Wettability is technique which illustrated quantitatively by exploring the compelling balances amidst two immiscible liquids at the approach line among the two liquids (water and oil) and the solid. The momentums that are associated with the line are outlined by [61] equation, constituting the moment in the direction parallel to the rock surface.

$$\sigma_{os} - \sigma_{ws} = \sigma_{ow} \cos\theta \text{ , } \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{ 2.9}$$

Where,

σ_{os} = interfacial force among oil and solid, dyne/cm;
σ_{ws} = interfacial force involving water and solid, dyne/cm;
σ_{ow} = interfacial force, or interfacial tension, involving oil and water, dyne/cm;
θ = contact angle at oil-water-solid interface measured through the water phase, deg.

At equilibrium, the summation of the forces characterizing along the liaison line must be zero.

On extrication the bodies apart, one boundary, bodies L and S relevantly vanishes and two novel edges, bodies L and S ambient, occur. Therefore, the overall power alter in such a development, per unit skin region, is given by equation 2.10.

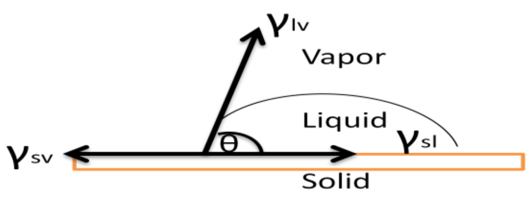


Figure.2. 4. Shows the linking perspective and interfacial pressure of the three planes at the three-segment periphery.

By examining Duper's equations.

Duper by Cerro (2010) contributed to the field of surface investigation, according to this equation, exertion of bond W_{adh} between a solid (s) and a liquid (l) can be articulated as,

$$W_{adh} = \gamma_l + \gamma_s - \gamma_{ls}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 2.10$$

However, if the body L is a liquid drop, even as S is a solid substrate, [17] then the contact angle, θ, revealed by the liquid drop at the surface of the substrate is resolute by the Young equation,

$$\cos\theta = \frac{\gamma_s - \gamma_{ls}}{\gamma_l}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 2.11$$

By integrating equation 2.10 and 2.11,

$$W_{adh} = \gamma_l + \gamma_s - \gamma_{ls} = \gamma_l(1 + \cos\theta), \ldots\ldots\ldots\ldots\ldots\ldots\ldots 2.12$$

The above equation is called Young-Duper by [17] equation which may perhaps be used for the understanding of all contact angle statistics.

The contact-angle scheme is footed on the assertion that wettability of formation rocks is administered by the existence or deficiency of polar or film-forming composites in crude oil that adsorb or leave on the mineral exterior. Wettability is dogged by appraising the contact perspective after the untainted reservoir crude oil and replicated brine are uncovered to the prevailing mineral near the reservoir rock [17]. This is frequently quartz, in lieu of the principal mineral of sandstone reservoirs, or calcite, representing limestone reservoir rock.

Two contact angles be capable of been calculated at the oil/brine/mineral interface on the immobile crystal. However, only the water-proceeding contact angle considered. The water-proceeding contact angle alterations with the era of the oil/mineral/brine interface. As the water proceeds over a formerly oil-contacted plane, the polar or film-forming composites that adsorbed or placed on the plane may be dislodged by water or desorbed.

At the same time, a velocity-dependent adsorption or deposition progression may arise involving the solid exterior and the crude oil at positions away from the oil/brine/mineral contact point. In some illustrations, a great duration of time is required prior to an equilibrium contact direction is achieved, and large transformations can occur involving the initial contact plane and the final dimension.

2.5. Capillary Pressure

The perceptions of capillary as a distinctive of a porous rock progress from the illustration of capillary trend in capillary tubes.

An oil / water edge or an air/ water boundary in a huge tube is horizontal because the wetting energies at the walls of the tube have been circulated above a large boundary and do not infiltrate into the core to several broaden [40]. However, the pressures of the fluids at the edge are equal. Due to the diminutive diameter of the capillary tube, pores in reservoir rocks suit equivalent. When the diameter is miniature, plane forces stimulates by the restricted wetting of the solid by one of the solution extend over the entire boundary, as a result, causing measureable pressure differences connecting the two zones transversely the edges.

Figure. 2.5. *The interface among the water plane and oil plane in a parallel saturated duct cylinder*

At static equilibrium, water is stoutly wet the glass exterior with a contact perspective impending zero. The susceptible pressure gauges were accompanied to each end of the capillary tube to assess the water-segment pressure and the oil-segment pressure [33]. We could discern that oil-segment pressure is constantly larger than water-segment pressure despite the length of the tube. Lake (2010) anticipated at least three tests frequently used to appraise permeable media wettability. These are;

- In the Amott test wettability is dogged by the quantity of oil or water instinctively imbibes in a core sample contrasted to the same valves when flooded [6]. Amott wettability valves sort from +1 for comprehensive water wetting to – 1 for complete oil wetting.
- In the United States Bureau of Mines test, "wettability index W is the logarithm of the ratio of the areas under centrifuge-measured capillary pressure curves in both wetting phase saturation increasing and decreasing directions" [23]. W can range from -∞ (oil wet) to + ∞ (water wet) but are characteristically between -1.5 and +1.0 [23].

- In a third test, contact angles can be measured directly on polished silica or calcite surfaces [58].

As a way of approximating wettability in porous media, none of these tests is entirely adequate. The Amott index and the W index can be taken in authentic permeable media; nevertheless, their communication to capillary pressure is not direct. But both of these tests are procedures to aggregate relatively than local wettability.

Let us examine Amott Wettability Tests procedures.

Amott WettabilityTest.

Preliminary situation of core: entirely inundated with water and kerosene at lingering kerosene dissemination [6].

- ✓ Test 1: determine volume of water that is spontaneously displaced from the core when it is immersed in kerosene for 20 hours.
- ✓ Test 2: determine additional volume of water that is displaced from the core when the core from Test 1 is centrifuged under kerosene until water production ceases.
- ✓ Test 3: immerse core from Test 2 under water for 20 hours and determine the volume of oil spontaneously displaced by water.
- ✓ Test 4: centrifuge core from Test 3 under water and determine the volume of oil displaced when oil saturation is reduced to a residual level, [6].

Two wettability indexes *(A_w and A_0)* can be defined from the data and are presented as follows:

1) **Water wetting inclination:**

A_w = volume of water instinctively absorbed (Test 3) separated by volume of water at lingering oil infiltration (Test 4).

2) **Oil wetting predilection:**

A_0 = volume of oil instinctively absorbed (Test 1) separated by volume of oil at lingering water infiltration (Test 2).

Each indicator calibrates the portion of the supersedeable volume that can be replaced unexpectedly in 20 hours.

Thus A_w = *1* and A_o = *0* for a robustly water-wet rock.

While A_w=*0* and A_o = *1* for a robustly oil-wet rock.

A modified method using reservoir crude oil and formation water by [12], with a relative displacement index I_{rd} which express wettability with a single numerical valve as

$$I_{rd} = A_w - A_o \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots .. 2.13$$

Commencing this indicator transitional wettability would be indicated by I_{rd} near nought.

However, Amott method has a great compensations because is relatively quick, with analysis times of a few days compared to months for contact direction quantity.

Reservoirs that are entrants for EOR developments usually encompass saturations that are with a reduction of the preliminary oil saturation.

	Recovery Efficiency			
Reservoir position	Primary % OOIP	Type of Secondary Recovery	Secondary %OOIP	Oil Remaining % OOIP
California Sandstones	26.5	Pattern Waterfloods	8.8	64.7
Louisiana Sandstones	36.5		14.7	48.8
Oklahoma Sandstones	17.0		10.6	72.4
Texas Sandstones	25.6		12.8	61.6
Wyoming Sandstones	23.6		21.1	55.3
Texas Carbonates	15.5		16.3	68.2
Louisiana Sandstones	41.3	Edge Water Injection	13.8	44.9
Texas Carbonates	34.0		21.6	44.4
California Sandstones	29.4	Gas Injection Into Cap	14.2	56.4
Texas Sandstones	35.3		8.0	56.7

$Table\ 2.1. Illustrates\ \%\ of\ OOIP\ oil\ recovery\ efficiencies\ of\ primary\ and\ secondary$ [35]

As table 2 shows after primary and secondary oil recovery, a significant amount of oil is left behind in the reservoir [48]. "The global basis demonstrates reviewed that, the typical recovery efficiency is approximately one-quarter of the original oil in place" or little, is recovered by traditional primary and secondary methods [31]. Oil recovery schemes could be enhanced during the effectiveness of traditional primary and secondary by realization of oilfield campaigns such utilize of horizontal and infill drilling jointly with other ameliorated oil recovery procedures.

Thus, the initial condition of the reservoir will be on one of the displacement paths. If the EOR practice mobilizes oil, creating an oil bank or region of increased oil saturation, the saturation path must change from imbibitions to drainage or vice versa. When the direction of saturation change is altered, it is necessary to obtain relative permeability curves that represent both paths.

Hysteresis was observed for other fluid pairs when the contact angle measured through the wetting phase was equal to or, transcended 73° proposing that contact angle is an important factor. Other possible contributors to hysteresis of relative permeability curves include surface roughness and hysteresis of the contact angle. This attributed reduction of imbibitions permeabilities in water-wet systems to gradual trapping of the residual oil saturation [47]. Developed a model of two-phase flow based on the percolation theory that qualitatively produces hysteresis in relative permeability curves [34].

2.6. **Principles of Multiphase Flow in Porous Media**

To assess shift of oil from a permeable material by water there are a variety of parameters which could be used or gas deals with the concurrent flowing of several immiscible phases. Fluid flowing patterns during multiphase flow through porous media 1950's identify and the conceptions of multiphase flow in porous media is the consequence of various studies in late 1940's [59].

The transmission channel of flowing differs from each media, the boundaries of the channels varied from solid and liquid interfaces to liquid and liquid interfaces [59]. Dispersed phase flow comes about at speeds that are higher than those found in crude oil reservoirs. Water and oil flowed heterogeneously through the porous media as globules [52]. Transported through the media by the continuous phase are large, when flow is dispersed, one phase becomes discontinuous.

2.6.1. **Permeability in Multiphase Flow and Extension of Darcy's Law**

Application of permeabilities of several phases flowing in the course of a porous rock can be calculated from exploratory figures by presumptuous Darcy's law applies to each phase. Arithmetical demonstration of multiphase flow in permeable medium when feed stream prevail is based on supposition of Darcy's law applies to each phase is given by equation 2.14 [59].

$$\mu_{ox} = -\frac{k_{ox}\rho_o}{\mu_o}\ \frac{\partial \Phi_o}{\partial x}, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots .2.14$$

$$\mu_{wx} = -\frac{k_{wx}\rho_w}{\mu_w}\ \frac{\partial \Phi_w}{\partial x}, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 2.15$$

And

$$\mu_{gx} = -\frac{k_{gx}\rho_g}{\mu_g}\ \frac{\partial \Phi_g}{\partial x}, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots . \dots . . . 2.16$$

Where k_{ox} ,k_{wx}, and k_{gx} are the active permeabilities of the oil, water and gas developments in the x direction. WhileΦ_o,Φ_w, and $\Phi_g$are the potential conditions for each media.

For oil condition

$$\Phi_o = g(Z - Z_d) + \int_{p_{od}}^{p_o} \frac{dp_o}{\rho_o} \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots . \dots \dots 2.17$$

Where;

Z is the height above a parallel datum,

Z_d is the height of the orientation datum'

p_{od} is the oil development pressure at the orientation datum.

When x is the parallel plane direction,

$$\frac{\partial \Phi_o}{\partial x} = \frac{1}{\rho_o}\ \frac{dp_o}{\partial_x}, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots . . 2.18$$

with equation 3.2 becomes

$$\mu_{ox} = -\frac{k_{ox}}{\mu_o} \frac{\partial p_o}{\partial x}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 2.19$$

Likewise,

$$\mu_{wx} = -\frac{k_{wx}}{\mu_w} \frac{\partial p_w}{\partial x}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 2.20$$

also

$$\mu_{gx} = -\frac{k_{gx}}{\mu_g} \frac{\partial p_g}{\partial x}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 2.21$$

At this point it is obligatory to accent the importance of relative permeability and the hysteresis of the relative permeability curves. "The effective permeability is defined as the ratio of the effective permeability of a media to a base permeability". The three main base of permeability are;

- The absolute air permeability
- The absolute water permeability
- The effective permeability to oil residual wetting –phase saturation.

These permeabilities do not have the same valves; however, it is necessary to know which base permeability that is used for a particular set of data. Relative permeability curves and their associated parameters are virtually relevant petrophysical relations for EOR. By Darcy's law of steady state flow, that is the saturation of all the phase s does not vary with time and position is given by [46],

$$U_j = -\frac{\lambda \Delta \Phi_j}{\Delta \chi}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 2.22$$

Where;

λ is the mobility of phase j. The mobility is the constant of proportionality between the flux of phase U_j and the potential difference

$$\Delta \Phi_j = \Delta\left(P_j - \rho_j D_Z\right) \times \lambda_j, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 2.23$$

Can be decomposed into a rock property, the absolute permeability k, a fluid property, the phase j viscosityμ_j, and a rock-fluid property, the relative permeability k_{rj}.

$$\lambda_j = k\left(\frac{k_{rj}}{\mu_j}\right), \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 2.24$$

Therefore, mobility and relative permeability are the given by these equations

Relative mobility λ_{rj}

$$\lambda_{rj} = \frac{k_{rj}}{\mu_j}, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 2.25$$

And the phase permeability k_j

$$k_j = k\, k_{rj}, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 2.26$$

k_j is the tensorial property in three dimensions. To clearly define these four definitions (mobility, relative mobility, phase permeability and relative permeability). The relative permeability depends on the course at which each saturations follows, the trail dependence, the variation of capillary pressure with the direction of saturation alteration.

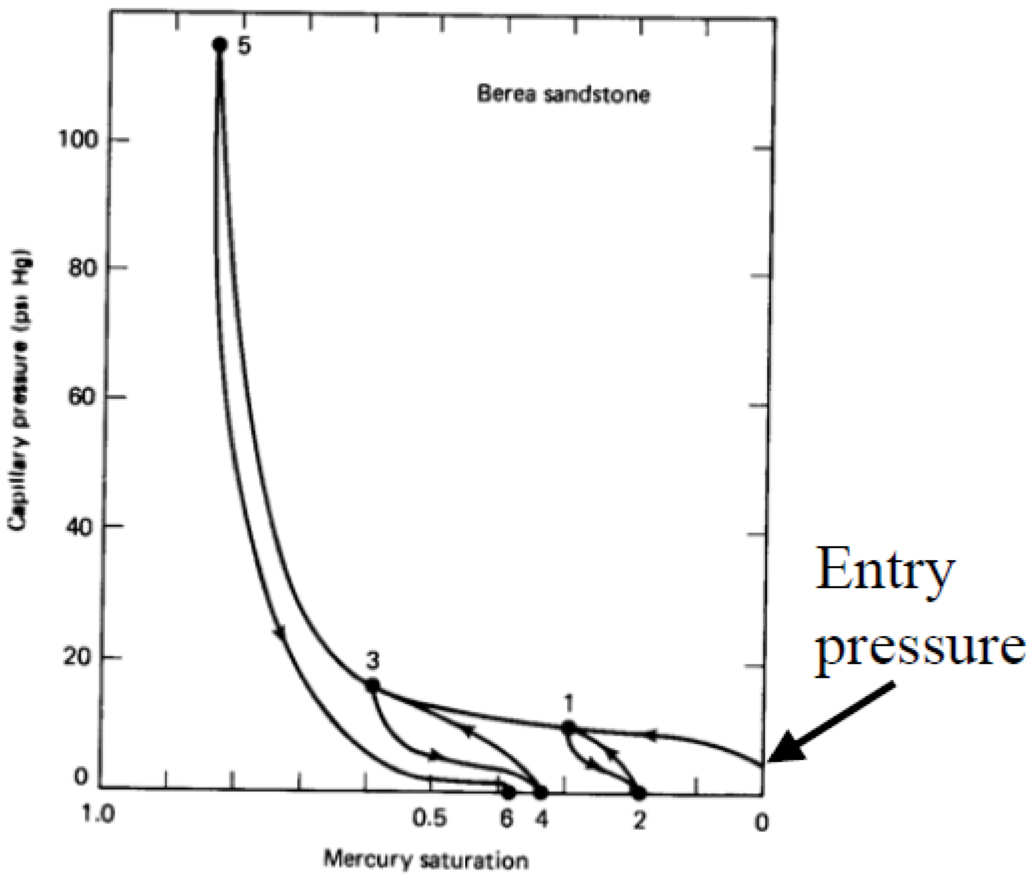


Figure.2. 6. Capillary pressure saturation sequence [33]

Meanwhile, viscosity ratio plays a vital role in immiscible phases in a porous media. Many authors consider the relative permeability curvatures to be independent of viscosities of the displaced and the displacing fluids. Others view it as irregular flow patterns in visual cells as well as modifications in relative permeability figures that have been attributed to viscosity ratio effects.

2.6.2. Residual Oil Saturation

The oil saturation that remains trapped in a reservoir rock after a dislodgment development is dependent on many variables. These include wettability, pore size distribution, microscopic heterogeneity of the rock, and properties of the displacing fluid.

By studying the characteristics of H_2O wet systems in which oil has been displaced by water to a residual saturation. It is assumed that the displacement process occurs without bypassing, which has been attributed to viscous fingering or rock heterogeneities.

The significance of the lingering oil saturation is imperative for two grounds. Foremost, it establishes the utmost efficiency intended for the dislodgment of oil by water on a infinitesimal level. Secondly, it is the initial saturation for EOR practices in areas of a reservoir formerly swept by a waterflood.

The Pore Doublet Model by assumes well developed Poiseuille flow occurs in each path of Doublet, and the presence of the interface does not affect flow. The assumptions valid if the accurate length of the doublet were much larger than the largest path radius and the flow were very slow [40].

The volumetric flow rate in either path is given by [51],

$$q = \frac{\pi R^4}{8\mu} \; \frac{\Delta P}{L_t}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 2.27$$

Therefore, the total volumetric flow rate through the doublet is

$$q = \; q_1 - q_2 = \frac{\pi}{\mu 8 L_t} \; (R_1^4 \Delta P_1 + R_2^4 \Delta P_2), \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 2.28$$

And, because the paths are parallel, the driving force across each path must be equal:

$$\Delta P_1 - P_{c1} = \; \Delta P_2 - P_{c2} \,, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 2.29$$

By rewriting the volumetric flow rate in either course in term of the total flow rate, the doublet geometry, and the interfacial tension-contact angle product from equation 3.27

$$q_1 = \frac{q - \frac{\pi R_2^4 \sigma \cos\theta}{\mu 4 L_t}\left(\frac{1}{R_2} - \frac{1}{R_1}\right)}{1 + (R_2/R_1)^4} \quad , \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots . \ldots 2.30$$

$$q_2 = \frac{q\left(\frac{R_2}{R_1}\right)^4 + \frac{\pi R_2^4 \sigma \cos\theta}{\mu 4 L_t}\left(\frac{1}{R_2} - \frac{1}{R_1}\right)}{1 + (R_2/R_1)^4}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 2.31$$

By investigating the trapping behavior of doublet, we form the ratio of the average velocities in the paths

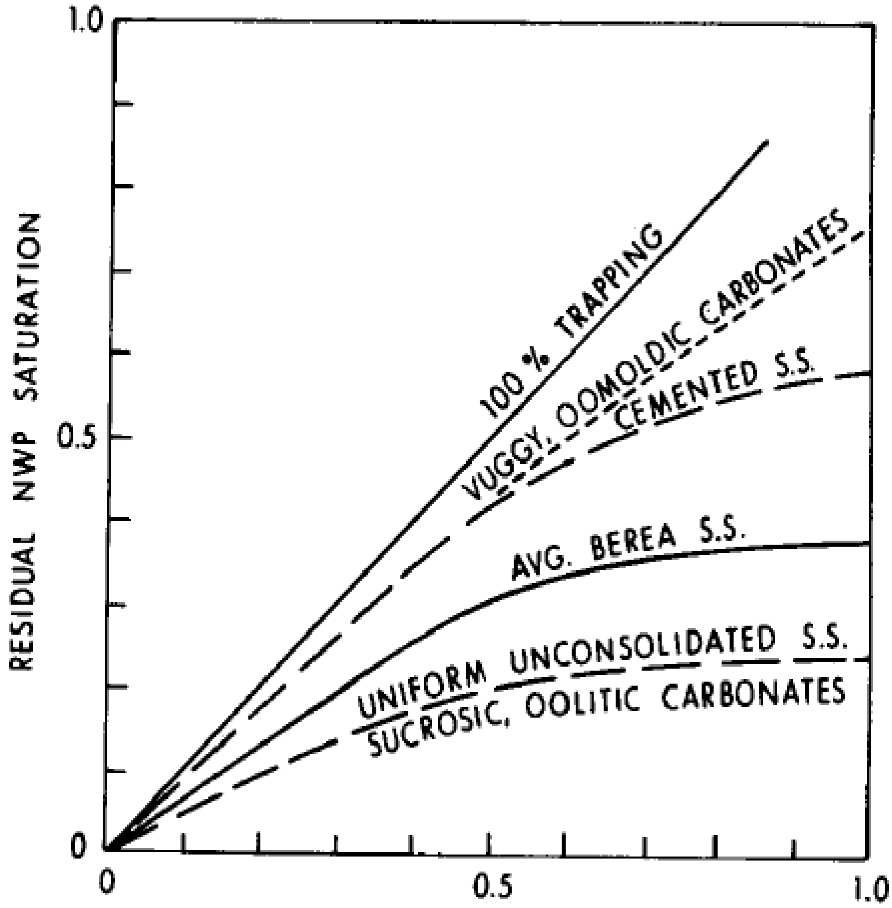
$$\frac{v_2}{v_1} = \frac{4N_\infty + \left(\frac{1}{\beta} - 1\right)}{\frac{4N_\infty}{\beta^2} - \beta^2\left(\frac{1}{\beta} - 1\right)}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 2.32$$

Where $\beta = R_2/R_1$ is a heterogeneity factor, and

$$N_\infty = \left(\frac{\mu L_t q}{\pi R_1^3 \sigma \cos\theta}\right), \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 2.33$$

is dimensionless ratio of viscous to capillary forces which we henceforth call the local capillary number. The trapping behavior of the pore doublet follows from eq.2.33 and the capillary number definition [51].

Though the extreme of negligible viscous forces is hard to visualize, it is easy to imagine an intermediate case where viscous forces are small, but not negligible, compared to capillary forces. The nonwetting phase is trapped in large-radius corridor shown bellow.



Initial nonwetting phase saturation (S_{NWP})

Figure.2. 7. Typical IR nonwetting phase saturation curves [33].

CHAPTER III

3.1. Waterflood Design

The contrive of a water deluge involves both technical and economic factors. Water deluge efficiency is as a result of evaluation of economic estimates [7]. These evaluations might be circuitous or rough depending on the factors of a specific project and the doctrine of the operator. This part deals with methods of analyzing water deluge efficacy for economic evaluation.

3.2. Factors Constituting a Design

There are five basic steps in designing of water deluge systems. These necessities are.

I. Estimation of the reservoir, inclusive of main production efficiency.
II. Choosing of possible deluging plans.
III. Production rates and approximation of injection.
IV. Blueprint forecasts of oil recovery exceeding the anticipated life of the scheme for each deluging.
V. Classification of variables that may result to precariousness in the technical examination.

3.3. Reservoir Description

To attain this, it is needed to make out the reservoir depiction in water deluge design. These are;

- Perpendicular lengthens of the reservoir and describing the areal.
- Defining quantitatively the discrepancy in rock features such as permeability and porosity within the tank.
- To ascertain the most important manufacture chemical mechanism, as well as estimates of the oil left over to be produced under main process.
- Approximating the allotment of the oil reserve in the tank.
- To appraise fluid properties necessary for foreboding water deluge efficiency.

Data is usually accessible from a reservoir explanation are:

a) Reservoir Characteristics;

- Perpendicular expand of producing structure and areal.

- Dispatch maps of gross and net sand.
- Additional zones and connection of layers.

b) **The Properties of the Reservoir Rock;**

  - Inclusive of directional trend resulting from geographical exposition, areal disparity of regular permeability.
  - Porousness of areal regularity.
  - Zone and reservoir heterogeneity predominantly the dissimilarity of permeability with thickness.

c) **Properties of Reservoir Fluid**;

  - Severity, FVF, and viscosity as a purpose of tank force.

d) Method of Prime Producing;

  - ✓ Classification of produce chemical methods such as a liquefied extension, result gas drive or water drive.
  - ✓ Being of gas cap or aquifers.
  - ✓ Approximation of oil left over to be formed under principal operation.
  - ✓ Force per unit area delivery in the tank.

e) Distribution of Oil Resources in Reservoir at Beginning of Water flood;

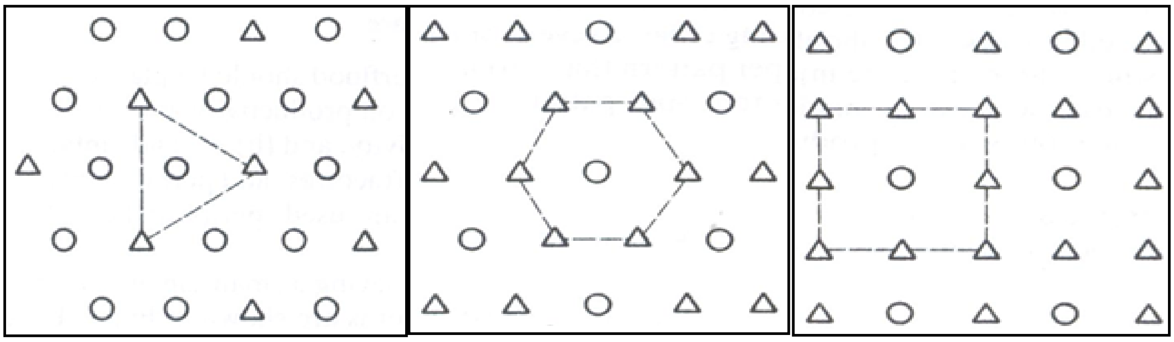
  - ❖ Ensnared gas diffusion from elucidation "gas drive.
  - ❖ Perpendicular deviation of saturation as a consequence of gravitation separation.
  - ❖ Water existence of movable connotes.
  - ❖ By nature water drive regions previously water deluged.

f) Properties of the Liquid and Rock;

  - ➢ Virtual permeability information for the tank rock.

3.4 Potential Flooding Patterns

There are diverse descriptors of deluging patterns which may perhaps be used in formation development. These are two, three, standard four spot, twisted four spot, five spot, seven spot, reversed seven spot, ordinary nine spot, upturned nine spot, straight line drive and spread out line drive.



(a). Four-Spot Pattern (b). Seven-Spot Pattern (c). Nine-Spot Pattern

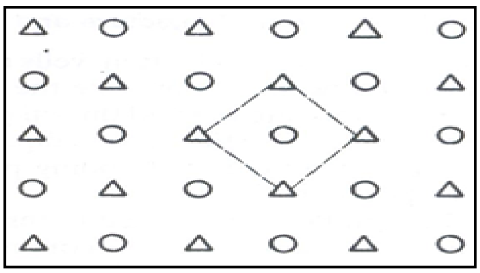
$Figure. 3.1. Showing\ some\ of\ the\ different\ \ Flooding\ Patterns\ above$ [20]

In fusion of the water deluging illustration is governed by a number of considerations that are often exclusive to each composition. In some cases in reservoir, the water deluge could be done with edge wells to form a peripheral deluge. It's called pressure continuance when water injection augment decreasing reservoir energy from solution-gas drive or an aquifer of restricted expand [20].

Pressure safeguarding usually commence while the reservoir is still under key process to preserve highest manufacture rates. Pattern deluging, an option to force per unit area maintenance, may be chosen, for the reason that reservoir properties will not countenance water deluging all the way through boundary Well at preferred injection rates may be chosen. Withdrawal rates depend on well spacing as well as reservoir properties and model size variable that are considered in economic analyses and injection. The choice of probable water deluging patterns depends on existing wells that usually must be used because of economic science. It is forced by the position of production wells.

3.5. Displacement in a Five-Spot Pattern

A standard five-spot pattern in Fig. 3.2 includes of a manufacture well enclosed by four insertion wells.



$Figure. 3.2. Shows\ Five - Spot\ Flooding\ Patterns$ [20]

Whilst each pattern is recurring in a big reservoir, the ratio of insertion wells to production wells move towards 1.0. Consequently, models of displacement efficacy refer to an idyllic five-spot pattern, as in Fig. 3.2, wherever there are four injection wells and one production well. It is supposed that the insertion rates are comparable to the production rates.

In the region of each injection well with 0 25 of the injection charge per unit from each well restricted to the pattern that flow circulates. The broken lines linking injection wells in Fig. 3.2 symbolize the boundaries of the pattern area [20]. Production rates are the same; the dashed precincts also correspond to no flow borders and in a harmonized reservoir. Consequently, examination of a five place model in a reservoir can be simplified by analyzing the actions of a solitary five place pattern.

The forms for five –spot with two sections of a circle that have radii r_{ep} and r_{ei}, correspondingly [59]. When $r_{ei} = r_{ep} = r_e$, then $r_e = d/\sqrt{\pi}$ the dotted areas are incorporated in both injection and production segments, while cross-hatched areas are ruled out. The place of the flood-front saturation, r_f, can be calculated with material balanced. Disregarding the radius of the wellbore,

$$W_i = (\pi r^2 \emptyset h)\left(S_{wf} - S_{iw}\right), \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \quad 3.1$$

Thus,

$$r_f = \sqrt{\frac{W_i}{\pi \emptyset h (S_{wf} - S_{iw})}}, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 3.2$$

for $r_f < r_e$, when the displacement is piston-like,

$r_{wf} = 1 - r_{foi}$. Then,

$$r_f = \sqrt{\frac{W_i}{\pi \emptyset h (S_{oi} - S_{or})}}, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 3.3$$

When $S_{iw} = 1 - S_{oi}$

For steady- state radial flow in a porous rock with radii r_1 and r_2,

$$p_1 - p_2 = \frac{i \ln \frac{r^2}{r_1}}{\left(\frac{k}{\mu}\right) 2\pi h}, \ldots 3.4$$

Thus

$$p_w - p_p = (p_w - p_f) + (p_f - p_e) + (p_e - p_p), \ldots 3.5$$

Or

$$p_1 - p_2 = \frac{i \ln \frac{r_f}{r_w}}{\left(\frac{k_w}{\mu_w}\right)_{s_{or}} 2\pi h} + \frac{i \ln \frac{r_e}{r_f}}{\left(\frac{k_o}{\mu_o}\right)_{s_{iw}} 2\pi h} + \frac{i \ln \frac{r_e}{r_{wp}}}{\left(\frac{k_o}{\mu_o}\right)_{s_{iw}} 2\pi h} \ldots 3.6$$

Solving for the injection rate,

$$i = \frac{2\pi h (p_w - p_p)}{\frac{\ln \frac{r_f}{r_w}}{\lambda_w} + \frac{\ln \frac{r_e}{r_f}}{\lambda_o} + \frac{\ln \frac{r_e}{r_{wp}}}{\lambda_o}}, \ldots 3.7$$

and

$$i = \frac{2\pi \lambda_o h (p_w - p_p)}{\frac{1}{M} \ln \frac{r_f}{r_w} + \ln \frac{r_e}{r_f} + \ln \frac{r_e}{r_{wp}}}, \ldots 3.8$$

If M=1 to check the effects of the assumptions used in developing the model. M = 1 and r_w = r_p Eq.3.9 becomes

$$i = \frac{2\pi \lambda_o (p_w - p_p)}{\ln \frac{r_e^2}{r_w^2}}, \ldots 3.9$$

Because

$$r_e = \frac{d}{\sqrt{\pi}}, \ldots 3.10$$

Therefore, Eq.3.10 may be written in terms of d as in Eq.3.11

$$i = \frac{\pi\lambda_o\left(p_w - p_p\right)}{\ln\left(\frac{d}{r_w}\right) - 0.572}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots .3.11$$

To express it in oilfield units (pounds per square inch, centipoises, days, feet, barrels per day, Darcies) Eq.3.12 becomes,

$$i = \frac{3.541\pi\Delta\lambda_o}{\ln\left(\frac{d}{r_w}\right) - 0.572}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.12$$

To assess and compute exhausted reservoirs water deluge are regularly commenced after some of the oil has been formed by solution –gas drive. The mobile-gas saturation is near when water injection starts.

Eq.3.13 describes the injection rate during fill-up to the interference point for a five-spot when the flow resistance is,

$$i = \frac{2\pi\lambda_o(p_{wi} - p_{wp})}{\frac{1}{M}\ln\left(\frac{r_f}{r_w}\right) + \ln\left(\frac{r_{ob}}{r_f}\right)}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.13$$

Where,

r_{ob} = radius of the bank, $r_w \leq r_{ob} \leq d\sqrt{2}$, and

r_f = radius of the flood-front saturation

r_f and r_{ob} may be defined by a material balance on the injected water.

$$W_i = \pi\left(r_f^2 - r_w^2\right)(s_w - s_{iw})h\emptyset\ , \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.14$$

To solve for r_f,

$$r_f = \sqrt{\frac{W_i}{\pi\emptyset h(S_w - S_{iw})}} + r_w^2, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots . \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3.15$$

To compute the quantity of water injected to fill-up is equivalent to the volume of gas relocated by the bank oil as the initial gas saturation, S_{gi}, is decreased to the trapped –gas saturation, g_t.

By material balance Eq.3.16 becomes,

$$r_{ob} = \sqrt{\frac{W_i}{\pi\emptyset h(S_{gi} - S_{gt})} + r_w^2}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \ldots\ldots\ldots\ldots\ldots\ldots..3.16$$

If the radius of the wellbore is neglected, and injection rate is constant, then W_i can be computed.

$$W_{ii} = \frac{\pi d^2}{2}\phi h\left(S_{gi} - S_{gt}\right), \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots..\ldots 3.17$$

Therefore, the volume of water injected at fill-up is given by Eq.3.18

$$W_{if} = 2d^2\phi h S_{gi}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots.\ldots 3.18$$

When the trapped gas is redissolved in the oil with neglecting change in volume is given by substituting Eq. 3.18 into 3.15 to obtain

$$r_f = \sqrt{\frac{2d^2 S_{gi}}{\pi(S_w - S_{iw})} + r_w^2}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots..3.19$$

3.5.1. Evaluation and Analysis of Five-Spot Pattern

Presumptuous an assessment of injection rate in a 5-acre (20 -235-m^2) five spot wherever the initial gas saturation is 0.10 and the trapped- gas saturation is nothing.

Data

Pattern area, acres	5
Thickness, ft	16
Radius of injection & production wells, ft	0.5
S_{iw}	0.26
S_{or}	0.31
Porosity	0.15

Permeability to liquid, Darcies	0.203
K_{ro} at S_{iw}	0.6
K_{rw} at S_{or}	0.14
Viscosity of oil, cp	2.0
Viscosity of water, cp	1.0

An approximation of the injection rate is wanted for a water deluge in a 5-acre (20 235-m^2) five –spot pattern. Pretentious, the reservoir is been used up by solution-gas drive and has a preliminary gas saturation of 0.10.

Solutions to the evaluated data;

In view of the fact that injection rates can be evaluated with the fairly accurate model pending interference,$r_w \leq r_{ob} \leq d\sqrt{2}$, where d is the distance among the injection well and production well.

The distance among the injection well and the production well is computed as follows.

$$d = \sqrt{\frac{(5 - acres)\left(43{,}560\ sq\,\frac{ft}{acre}\right)}{2}} = 330\ ft$$

The interference occurs when

$r_{ob} = d\sqrt{2}$ = 330/$\sqrt{2}$ = 233.35 ft or (71.12 m)

From Eq. 3.17, the volume of water injected at interference.

$$W_{ii} = \frac{\pi}{2}\ (330\ ft)^2(0.15)(16\ ft)(0.10)$$

= 41,054cu ft

= 7,312 bbl

From Eq.3.15 is to compute the injection rate for$0 \leq w_i \leq 7312\ bbl\ (1163m^3)$, assume S_w = 1.0, S_{or} = 0.7.

From Eq. 3.17.

$$r_f = \sqrt{\frac{(7312)(5.615)}{\pi(0.15)(16.0)(0.60-0.26)} + (0.5)^2}$$

= 126.6 ft

To convert into oilfield units (Darcies, centipoises, feet, pounds per square inch, and barrels per day), Eq.3.15 is

$$i = \frac{7.082k_b\left(\frac{k_{ro}}{\mu_o}\right)(p_{wi}-p_{wp})}{\frac{1}{M}\ln\left(\frac{r_f}{r_w}\right) + \ln\left(\frac{r_{ob}}{r_f}\right)}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 3.20$$

The mobility ratio M is computed.

$$M = \frac{\left(\frac{k_{rw}}{\mu_o}\right)_{s_{or}}}{\left(\frac{k_{ro}}{\mu_o}\right)_{s_{iw}}} = \frac{\left(\frac{0.14}{1.0}\right)}{\left(\frac{0.6}{2.0}\right)}$$

$$= 0.47$$

By substituting into Eq.3.20 gives i at interference:

$$i = \frac{(7.082)(0.203)\left(\frac{0.60}{2.0}\right)(16)(330)}{\frac{1}{0.47}\ln\left(\frac{126.6}{0.5}\right) + \ln\left(\frac{233.35}{126.6}\right)}$$

$$= \left(\frac{2{,}277}{12.39}\right)$$

$$= 183.8\ B/D$$

Given that injection rates at the starting of introduction to interference can be designed easily.

However, nonstop introduction of water leads to fill-up of the gas space. The degree of water injected to fill-up obtained from Eq. 3.17

$$W_{if} = \frac{(2)(330)^2((0.15)(16)(0.10)}{5.615}$$

$$= 9{,}309 \ \ bbl.$$

At fill –up, radius of water bank is given by Eq.3.15

$$r_f = \sqrt{\frac{(9{,}309)(5.615)}{\pi(0.15)(16.0)(0.60 - 0.26)} + (0.5)^2}$$

$$= 142.8 \ \ ft.$$

Assume that the entire pattern is 100% liquid – saturation so that Eq. 3.15 now describes the injection rate fill-up to the radius where the assumptions made in developing Eq.3.15 are not valid i.e $r_f = d/\sqrt{2}$ is maximum valve of r_f where Eq.3.15 is valid.

Thus

$$r_f = 330/\sqrt{\pi}$$

$$= 186.2 \, ft$$

Solving for w_i with Eq. 3.16 gives

$$W_i = \frac{\pi(186.2)^2(0.60 - 0.26)(16)(0.15)}{5.615}$$

$$= \ 15{,}829 \, bbl$$

However, the injection rate for 9,039 $\leq \ w_i \leq 15{,}829$ may be estimated from Eq.3.15.

By applying Eq.3.15 with r_e = 186.2 (56.8 m) and r_f = 127.0 ft (39 m) give the injection rate at the instant fill –up occurs.

Thus,

$$i_f = \frac{(7.082)(330)(0.203)(0.35)(16)}{\frac{1}{0.47}\ln\left(\frac{127.0}{0.5}\right) + \ln\left(\frac{186.2}{127.0}\right) + \ln\left(\frac{186.2}{0.5}\right)}$$

$$= \frac{2{,}656.769}{18.084}$$

$= 146.9\ B/D$

Initiation the exceeding computation one perhaps resolved to become aware of the intervention and fill-up, the introduction rate reduced from **183.8 to 146.9 B/D (29.2 to 23.4 m^3 /d)** as w_i changed from **7,312 to $\mathbf{9,309}$ bbl [1163 to 1480 m^3].**

The time among interference and fill-up correspond to the injection of $\mathbf{1,997}$ **[318 m^3]** of water at a decreasing rate. Meanwhile, a little error would accrue if an average rate for this interval equal to **(183.8 +146.9)/2 or 165.35 B/D [26.3 m^3 /d]** were assumed.

Table 3.1. Evaluation of an Injection Rate Variation.

W_i (bbl)	R_f (ft)	R_{ob} (ft)	I (B/D)	Time (days)
0.1	0.66	1.02	2,298.4	0.00
686.4	20.87	73.79	230.7	0.54
1,828.79	56.80	104.36	214.3	3.59
2,513.19	70.54	127.81	205.7	5.81
3,198.69	81.85	147.58	200.0	10.81
3,884.09	91.38	166.00	195.8	13.57
4,569.59	99.78	180.75	193.5	17.06
5,253.99	107.38	196.23	189.8	20.60
5,939.49	114.36	208.71	187.5	24.18
6,624.99	120.86	221.37	185.6	27.81
7,311.49	126.63	233.35	183.8	34.21

From the previous calculation, the approximate model for the liquid fill-up system applies for $r_f \le d/\sqrt{\pi}$. At$r_f = d/\sqrt{\pi}$,

$$i = \frac{(7.082)(0.203)\left(\frac{0.60}{2.0}\right)(16)(330)}{\frac{1}{0.47}\ln\left(\frac{126.6}{0.5}\right) + \ln\left(\frac{233.35}{126.6}\right)}$$

$$= \left(\frac{2,277}{12.39}\right)$$

$$= 183.8\ B/D$$

Beginning the calculation above, injection rate remains invariable amid fill-up and W_i = **$15,829\ bbl$ B/D [2517 m^3/d].** However, the injection rate reduce in the untimely stages of injection is caused by two reasons.

- The elevated mobility of the gas phase.
- The injected water has a low mobility compared with oil (M=0.47).

The injection rate would deteriorate rapidly from the beginning of injection for the basis that the oil bank is displaced by water, which has a minor mobility. As a consequence of dominate fluid flow within the area of the well bore the alteration in injection charge per unit would be significant. Distinctive displacement performances of five-spot deluges are shown in Fig. 3.4 for four dissimilar oil/water viscosity ratios. These facts were gotten in lab sand packs imitating a quadrant of a five place pattern.

3.6. Injection Rates

There is oil recovery correlates with the cumulative degree of water injected. The injection tempo is a major economic indicator in the assessment of waterflood. When a waterflood is carried out in a conventional area, there may perhaps data or correlations based on operating experience. However, injection rates are allied in terms of injectivities as barrels per day per acre foot, barrels per day per net food of sand, or barrels per day per net foot per pounds per square inch. Specific valves are dependent on reservoir rock properties, fluid and rock interaction, spacing, and available pressure drop.

3.7. Economic Estimation of Water flood Performance

To estimates of waterflood recovery, production rates and production time curves can be achieved in a relatively short time with simple models of displacement process. Estimation of waterflood recovery by material balance with core data and estimates of the sweep efficiency. This can be done in two ways the volume swept by the waterflood and unswept volume.
The amount of oil moved from the pool is given by Eq. 3.21.

$$N_d = \frac{E_V}{B_O}(\Delta S_o)V_p, \ldots \ldots \ldots 3.21$$

Where,
E_V = fraction of the reservoir volume that is swept by the injected water when the economic limit is attained.

ΔS_o = alteration in a typical oil infiltration contained by the swept volume, and

N_d = oil dislodged from the volume swept by the water deluge.

The part of the oil put out of place is not convalesced. Eq.3.22 gives the oil left behind in the formation when the unswept pore space is resaturated to the initial oil saturation.

$$N_r = \frac{E_v S_{or} V_p}{B_o} + \frac{(1 - E_v) S_{oi} V_p}{B_o}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 3.22$$

Where the initial term represents the oil left behind the swept volume and the second term is the oil remaining in the unswept zone.

The oil recovered by water deluging (N_{pw}) is computed with Eq.3.23

$$N_{\rho\omega} = [S_{ol-} E_v S_{or} - (1 - E_v) S_{oi}] \frac{V_\rho}{B_o}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots .3.23$$

Where S_{oi} is the oil saturation at the beginning of the water deluging

In Eq.3.24 expresses the water deluging recovery in terms of the original- oil -in place (OOIP) and the oil produced during principal operations.

$$N_{\rho\omega} = (N - N_\rho) - N \frac{B_{oi}}{B_o} \left[1 + E_v \left(\frac{S_{or}}{S_{oi}} - 1\right)\right], \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 3.24$$

Where,

$N_{\rho\omega}$ = oil potentially recoverable by water deluge, STB,

N = primary oil in place, STB,

N_ρ = oil produced during major operation, STB, and

B_{oi} = preliminary FVF

"Consequently, there are three techniques of ascertaining volumetric sweep performance. Being of an analogous reservoir or of which two are experimental and depend on the accessibility of water deluge efficacy From Eq. 3.24 Ev from the efficiency of accomplished water deluges is computed. This approach is broadly used to attain prelude approximations of water deluge recovery. The second method evaluates of perpendicular and areal sweep efficacies can be obtained from understanding of core analyses, well logs, fluid and rock properties [59]".

Hence, volumetric sweep effectiveness is the product of the areal sweep efficacy (E_A) and the perpendicular sweep efficacy (E_L) as in Eq.3.25.

$E_V = E_A E_L$ …………………………………………………………...3.25

Where,

E_L = division of the reservoir cross section that has been relocated by injected water, and

E_A = division of the reservoir region within the perpendicular segment of the reservoir that has been swept to remaining oil saturation.

The engineers ought to put to mind that all approximation must convince the material balance equation for reasonable series of residual saturations and sweep efficiencies.

At this position it is essential to approximates production rates as a function of time. The production rate / time relationship is found empirically. The oil rate, $q_o(t)$, is required to produce the estimated waterflood reserves ($N_{\rho\omega}$) in the estimated flood life (t_l) [15].

Mathematically,

$$N_{\rho\omega} = \int_0^{t_l} \frac{q_o(t)dt}{B_o} , \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 3.26$$

Where $q_o(t)$ is obtained from operating experience of similar floods.

Cumulative oil production equation during a particular time interval can obtain by integrating the resultant rate equation as in Eqs.3.26 through 3.27

$$N_{\rho\omega}(t_2) - N_{\rho\omega}(t_1) = \int_{t_l}^{t_2} \frac{q_o(t)dt}{B_o} , \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots .3.27$$

For the period of declining rate with $B_o = 1.o,$

$$\Delta N_{\rho\omega} = \frac{q_o\rho}{B_o} \int_{t_\rho}^{t_l} e^{-D(t-t_\rho)dt} , \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots ..3.28$$

$$\Delta N_{\rho\omega} = \frac{q_o\rho}{DB_o} \left[1 - e^{-D(t-t_\rho)}\right], \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots .3.29$$

and

$$\Delta N_{\rho\omega} = \frac{1}{DB_o} \left[q_{o\rho} - q_{ol}\right] , \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots . \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots . \ldots \ldots 3.30$$

Consequently, all pragmatic models must satisfy the material balance i.e, if the water flood reserves includes (primary) are estimated to be $N_{\rho\omega}$, then

$$N_{\rho\omega} = \int_o^{t_f} \frac{q_o dt}{B_o} + \int_{t_l}^{t_\rho} \frac{q_o dt}{B_o} + \int_{t_\rho}^{t_l} \frac{q_o dt}{B_o} , \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 3.31$$

Where the first integral represents fill-up, the second integral incline, and the third integral decline. Assumed that t_f, t_ρ and t_l can be estimated from working know-how for a precise variety of reservoir. The correlation shows an average condition in sandstone reservoirs [15].

Injection rates will be estimated by assuming an injectivity of L_{AF} (barrels per day per acre-foot) sand. Thus

$$t_l = I_{AF}Ah, \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots 3.32$$

$$t_l = (7{,}758A\emptyset h)(1.25/B\,D/acre - ft), \qquad = \frac{9{,}698\emptyset}{Ah}\ days.$$

The flood life is calculated from Eq.2.32 assumes that the average injection rate is q_w throughout the project.

If exponential incline and declines are assumed, the rate/time curve after fill-up is found by solving Eq.3.33 for q_{op}.

$$\Delta N_{\rho\omega} = \frac{(q_{o\rho} - q_{oi})(t_\rho - t_f)}{B_o \ln\left(\frac{q_{o\rho}}{q_{oi}}\right)} + \frac{\left(q_{o\rho} - q_{ol}\right)(t_l - t_\rho)}{B_o \ln\left(\frac{q_{o\rho}}{q_{ol}}\right)}, \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots 3.33$$

Where,

$N_{\rho\omega}$ = estimated oil production for $\left(t_f \to t_l\right)$, and

q_{oi} = oil rate at beginning of the incline, B/D.

The oil rate at flood-out is determined by the economic limit.Eq.3.33 can be solved for $q_{o\rho}$ by trial and error or by Newton's method.

CHAPTER IV

4.1. Thermal Recovery Methods

Thermal recovery methods employ thermal intensity in which the reservoir temperature increase and whereby decrease the oil viscosity, which causes the possibility of displacement of oil close to the producing wells. These recovery methods are worldwide the most modern EOR processes are classified in three major categories [27].

- Stem Drive
- Cyclic Steam Injection
- In-situ Combustion or Fire flooding

According to [18] if the distance flanked by the viscous fingers that are most likely to form decreases with increasing crude viscosity and the fingers are likely to be formed at relatively low flow rates.

What can be done to improve the recovery from reservoirs containing viscous crudes? Let us investigate some of the dimensionless groups that affect flow mechanisms in the reservoir. There are essentially three independent proportionless parameters that affect the flow rate of crude:

$$\frac{Lg\Delta\rho\cos\Theta}{\Delta p}, \frac{\sigma\cos\theta_c}{\sqrt{k}\Delta p}, and\ \frac{k\Delta p}{\mu Lu}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \quad 4.1$$

Where in these ratios,

K = permeability of the reservoir,

Δp = pressure drop between injectors and producers,

μ = crude viscosity

L = Distance between injection and production wells,

u = volumetric flow velocity, and known as the Darcy velocity and volumetric flux,

σ = interfacial tension between crude and water,

θ_c = wetting contact angle,

g = acceleration constant due to gravity,

Δp = density difference between water and crude and,

Θ = formation dip.

4.2. In-situ Combustion or Fire Flooding

In-situ combustion or fire flooding is a method in which oxygen accommodating gas is infused into the reservoir where it proceed with the oil held within the pore space to bring about a high temperature maintaining combustion front that is proliferated through the reservoir. Inflammation may be produces through electrical or gas fuels of may be impromptus if the crude oil has enough reactivity [46]. However, the injected gas is air and inflame consumed by the inflammation is a residues produced by a compounded process of coking, cracking and steam purification that occur ahead of the inflammation front. "The heat generated from burning thins out of the oil around it, results gas to vaporize from it, hence, vaporizes the water in the reservoir to steam" [39]. All these methods, hot water, steam and gas acts to force oil in front of the fire to production wells. This process is applicable if the crude oil and rock combines to produce enough feed to sustain the inflammation front. A field tests has been conducted in reservoir having API gravities from 9 to 40^{c} API [27], [55].

"As early stated thermal recovery methods are the most modern EOR process and attributed significantly to daily amounts of oil production [25]. Cyclic and steam drive contributed hugely to most of thermal production worldwide. Both in-situ combustion and steam flooding has become the latest methods in which has been proposed for the early phases of evaluation and expected to have a significant impact on oil production as a future prospects [37]".

4.3. Cyclic Steam Injection

Cyclic steam injection, only one well acted as either injection and as well as production well. In this case steam is injected into the reservoir for a various days or weeks for the oil to heat up. The injection process is stopped and the well is closed in to pave way for the reservoir to soak for many days, [35]. Within the reservoir, there is condensation of the steam, and an area of hot water and little viscous oil sorts. Thereafter, the well is caused into production and both hot water and thinned oil run out. This process repeated several times until oil recovery stops [55].

It is notorious to contribute to the dissipation of oil within the neighborhood downstream in cooperation with steam drives and combustion drives. Thus, many elements of the discussion on hot-water drives presented in this chapter are applicable to appropriate regions in other processes. “Hot-water flooding is said to be almost as old as conventional waterflooding, although early operations have not been documented adequately”. In this process, the water is filtered, treated to control corrosion and scale, heated, and if necessary, treated to minimize the swelling of clays in the reservoir [2] .The primary role of the heated water is to reduce the oil viscosity and, thereby, improve the displacing efficiency over that obtainable from a conventional waterflood [57]. The design and operation of hot-water drives have many elements in common with conventional waterflooding these are:

- The first is that gases dissolved in the crudes, even heavy crudes, tend to come out of solution as the temperature increases.
- The second effect, that of a trapped residual gas phase on hot-water flood recovery, is thought to be analogous to that found in waterflooding.
- The third effect is that the displaced oil tends to fill the space initially occupied by gas, which delays significant oil production.

The principal frame of the injected hot water loses heat accordingly as it quickly reaches the initial reservoir temperature. Thus, at the principal frame of the dislodgment front, the oil mobility is that of the unheated oil; furthermore, the viscosity of the infused hot water is less significant than in habitual or conventional waterfloods.

4.3.1. Mechanisms of Displacement

The investigational work of [60], shows that the improvement in recovery of viscous crudes by means of hot-water floods relative to normal (unheated) waterfloods is primarily due to;

(1) The improved oil mobility resulting from the reduction in the oil viscosity and

(2) The reduction in residual oil at high temperatures.

For convenience, the reduction in residual oil with increasing temperature is discussed first. Thermal expansion of the crude obviously contributes to the diminution in residual oil at soaring temperatures [45]. Thermal expansion of the crude obviously contributes to the diminution in residual oil at high temperatures.

$$S_{or}[1+\beta_o(T-T_{ir})], \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 4.2$$

Where

S_{or} = residual oil saturation at the initial reservoir temperature T_{ir} occupies a volume at an elevated temperature *T*. β_o is the volumetric thermal expansion coefficient of the oil.

Let us say that the residual saturation measured at any temperature is constant. When the formation is allowed to return to its initial temperature T_{ir} , the oil volume will decrease. If the same thermal expansion coefficient applies during the cooling as during the heating cycle, if the oil has not been altered, the apparent residual saturation would have been reduced by an amount

$$S_{or}[\beta_o(T - T_{ir})], \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots ..4.3$$

However conclusion could be drawn about hot-water flooding, these may contributes to the efficacy of the evaluation of the pool crude. These attributes are;

- There are two recognizable displacement fronts,
- the leading front is at the initial temperature of the reservoir,
- the hot-water front substantially lags the cold-water front,
- large volumes of injected hot water may be required to ring the oil saturation to its residual value even near n injection well,
- oil is displaced throughout the entire zone swept by the injected water, and
- The effect of instabilities appears o be quite important even in homogeneous formations.

For performance prediction of hot-water drives, there are three essentially different approaches to estimating the performance of a hot-water drive.

The first approach, proposed by Van Heiningen and Schwarz (1955), makes use of the effect of oil viscosity on the isothermal recoveries as reflected, the method calls for shifting from me viscosity ratio curve to another of lower value in a manner subsequent to the alters in the regular temperature of the reservoir [56].

The second approach also is borrowed from waterflood technology and is based on the isothermal displacement equation [14]. It was modified for application to hot-water drives. It is simple way of estimating the recovery performance of hot-water drives in linear and radial systems [60].

For linear or radial flows, the rate of growth of the saturation fronts, at a temperature T_j, is given by

$$\frac{dA}{dt} = [1.289 \times 10^{-4}\ acre - ft/bbl] \times \frac{1}{\phi h_n} q(T_j) \frac{\partial f_w(S, T_j)}{\partial S}, \dots\dots\dots\dots\dots\dots\dots .4.4$$

Where

$\frac{dA}{dt}$ = rate of growth of the area encompassed by the saturation front having a water saturation *S*, acres/D, *(f>* = porosity.

h_n = net sand thickness, ft,

ϕ = porosity,

f_w = fractional flow of water, which in hot-water floods depends on both saturation and

temperature,

q = flow rate at ambient reservoir temperature and pressure, B/D and

Tj = is the temperature level of the jth zone, °F.

The third approach to estimating the performance o a hot-water drive is to use thermal statistical simulators. The simulators are capable of calculating more accurate recovery performances than can be achieved by the two simpler methods.

However, in conventional waterfloods where the reservoir temperature is not constant with time, equation 4.4 can be deduced to;

$$\frac{dA}{dt} = [1.289 \times 10^{-4}\ acre - ft/bbl] \times \frac{i}{\phi h_n} f_w'(S), \dots\dots\dots\dots\dots\dots\dots\dots\dots .4.5$$

$$f_w'(S) = \frac{\partial f_w(S, T_i)}{\partial S}, \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots .4.6$$

T_i is being the original reservoir temperature.

This is the form of the, displacement equation that describes the rate of advance of a saturation front [14]. Since the Buckley-Leverett equation is not linear, its results cannot be superimposed. Inherent in any application of the displacement equation is the requirement that the fluids be of constant density-i.e., no thermal expansion or change of density is allowed [14]. In thermal applications, this condition is applied within each constant-temperature zone, but the densities are allowed to differ from zone to zone.

For constant-density fluids and for insignificant gravity and capillary effects, the fractional water flow is given by

$$f_w(S, T_{ir}) = \frac{1}{1 + [M(S,T)]^{-1}} \text{ , ………………………………………………………………………..4.7}$$

Where

M(S,T), the mobility ratio of the co -flowing fluids, is given by

$$M(S,T) = \frac{k_{rw}}{\mu_w} \; \frac{\mu_o}{k_{ro}} \text{ , …………………………………………………………………………….4.8}$$

The viscosity ratio of oil to water has a strong dependence on temperature, especially for viscous crudes. The relative permeability ratio, for convenience, usually is taken to be a function only of saturation. Calculation of the area swept by the saturation fronts from Eq. 4.1 requires information about df_w / dS over a saturation range at each temperature *Tj*. Generally these slopes are determined graphically by generating initial reservoir temperature by means of the relations

$$f_w(S,T) = \frac{f_w(S)}{f_w\,(S) + F_\mu |1 - f_w(S)|} \text{ , ……………………………………………………………….4.9}$$

And

$$\frac{\partial f_w(S,T)}{\partial S} = \frac{f_w(S)}{\{f_w\,(S) + F_\mu |1 - f_w(S)|\}^2} \text{ , ……………………………………………………… 4.10}$$

Where

$$F_\mu = \left(\frac{\mu_O}{\mu_w}\right)_{T_i} \Big/ \left(\frac{\mu_o}{\mu_w}\right)_T \text{ , ……………………………………………………………………… 4.11}$$

4.4. Steam Drives

“In steam drive or steam injection as known, it involves producing steam of about 80% conditions on the surface and driving this steam down the injection wells and then keen on the reservoir. “When the steam reaches the reservoir, it energies builds up the oil therefore reduces its viscosity”. However, the steam moves via the reservoir, which cools down and condenses. As such, the energy from the steam and hot water vaporizes lighter hydrocarbons, or reduce them into gases [55]. Consequently, these gases push ahead of the steam, and then cool down, hence, condense back into liquids which flux in the oil. As result both gases and steam aids in additional gas drive. The thinned oil is moved by the hot water to produced wells where water and oil are produced [55].

Table 4.2. Domestic EOR Production in United States of America.

	Production (bbl / day or 0.159 m^3 / day)					
	1980	1982	1984	1986	1988	1990
Thermal Methods						
Steam	243,477	288,396	358,115	468,692	455,484	444,137
In situ combustion	12,133	10,228	6,455	10,272	6,525	6,090
Hot water	-	-	-	705	2,896	3,985
Total thermal	**255,610**	**298,624**	**364,560**	**479,669**	**464,905**	**454,212**
Chemical						
Micellar polymer	930	902	2,832	1,403	1,509	637
Polymer	924	2,587	10,232	15,313	20,992	11,219
Alkaline	550	580	334	185	-	0
Total chemical	**2,404**	**4,069**	**13,398**	**16,901**	**22,501**	**11,856**
Solvent						
Hydrocarbon miscible	-	-	14,439	33,767	25,935	55,386
Co_2 miscible	21,532	21,953	31,300	28,440	64,192	95,591
Co_2 immiscible	-	-	702	1,349	420	95
Nitrogen	-	-	7,170	18,510	19,050	22,260
Fuel gas	-	-	29,400	26,150	40,450	17,300
Total solvent	**74,807***	**71,915***	**83,011**	**108,216**	**150,047**	**190,632**
Grand total	**332,821**	**374,608**	**460,969**	**604,786**	**637,453**	**656,700**

Source: *By process type from oil and gas journal biennial surveys* [43]

Where the steam condenses, the condensable hydrocarbon components do the same, whereby reducing the viscosity of the crude at the condensation front in which the condensing steam infuses the displacement process supplementary proficient and improves the sweep efficiency. There by making the net effect is that recovery from steam drives is significantly higher than from hot-water drives.

4.4.1. Displacement Mechanisms

Work by Willman at al (1961) shows that both hot-water drives and steam;

- Improve oil mobility by dropping viscosity
- Reduced residual oil at soaring temperatures.

They were able to achieve these because, those effects to such a degree that recovery of viscous crude is better than could be attained by waterflooding. The effect of temperature will affect surface forces but the magnitudes may be different as a result of the vapor phase. Whilst in hot-water drives the displacement process is affected by the changes in surface forces resulting from temperature effects [60].

Willman (1961) however stressed that, additional phenomenon affecting displacement in steam drives is the steam distillation of relatively light fractions in the crude. This distillation causes the vapor phase to be composed not only of steam but also of condensable hydrocarbon vapors [60]. The condensation of the hydrocarbon vapors along with the steam whereby mixing with the original crude and increasing the quantity of moderately radiance parts of the lingering oil trapped by the advancing condensate water ahead of the front.

The distillation by the light fractions causes some of the trapped oil to be displaced by the condensed water while the rest is tripped by the steam of all the remaining light ends, therefore, leaving less but heavier residue [60]. "The lighter components stripped from the bypassed oil, assist to regenerate and maintain a solvent bank just downstream of the condensate front". Willman noted that, the produced crude did not change in composition until the steam zone was relatively near at which point the volatile content increased rapidly [60].

Table 4.3. Showing Active Domestic EOR Projects.

	1971	1974	1976	1978	1980	1982	1984	1986	1988	1990
Thermal Methods										
Steam	53	64	85	99	133	118	133	181	133	137
In situ combustiom	38	19	21	16	17	21	18	17	9	8
Hot water	-	-	-	-	-	-	-	3	10	9
Total thermal	**91**	**83**	**106**	**115**	**150**	**139**	**151**	**201**	**152**	**154**
Chemical										
Micellar polymer	5	7	13	22	14	20	21	20	9	6
Polymer	14	9	14	21	22	47	106	178	111	42
Alkaline	-	2	1	3	6	18	11	8	4	2
Total chemical	**19**	**18**	**28**	**46**	**42**	**85**	**138**	**206**	**124**	**50**
Solvent										
Hydrocarbon M.	21	12	15	15	9	12	30	26	22	23
Co_2 miscible	1	6	9	14	17	28	40	38	49	52
Co_2 immiscible	-	-	-	-	-	-	18	28	8	4
Nitrogen	-	-	-	-	-	-	7	9	9	9
Fuel gas	-	-	-	-	8	10	3	3	2	3
Total solvent	**22**	**18**	**24**	**29**	**34**	**50**	**98**	**104**	**90**	**91**
Other										
Carbonated waterflood	-	-	-	-	-	-	-	1	-	-
Grand total	132	119	158	190	226	274	387	512	366	295

(*Sources*: *From Oil and Gas Journal Biennial Surveys*) [43]

4.4.2. Stability of Steam Fronts

The displacement of steam is a stable process the one not favorable to the formation and growth of viscous fingers. However, if small steam is fingers are formed, tend to lose heat at relatively high rates, eventually resulting in condensation and disappearance of the steam, hence, the fingers.

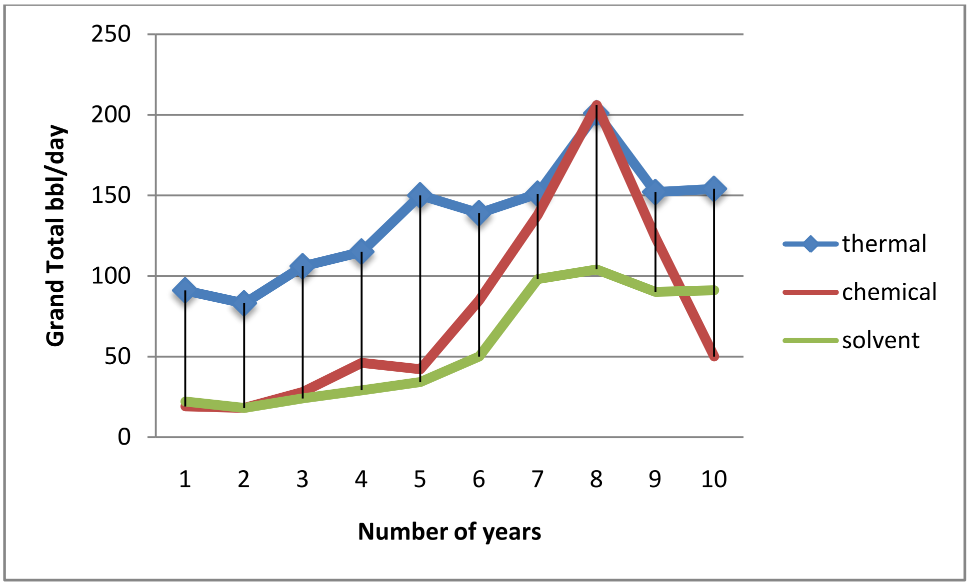


Figure. 3.1. Shows the Variation of EOR for Active Domestic Projects.

Miller (1975), first provided an insight by geometric support in which displacing water was used. The stability of a displacement front in the absence of capillary and gravity forces is the ratio of the pressure gradient $\partial p/\partial n$ normal to and on the downstream side of the displacement front to that on the upstream side [39].

From Darcy's law, the pressure gradient ratio is given as

$$\frac{\left(\frac{\partial p}{\partial n}\right)\Big|_d}{\left(\frac{\partial p}{\partial n}\right)\Big|_u} = \frac{\left(\frac{u}{\lambda}\right)_d}{\left(\frac{u}{\lambda}\right)_u}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 4.12$$

Where,

$(u/\lambda)_d$ = is the volumetric flux, U normal to the front divided by the mobility λ of flowing phase present at the downstream side of the displacement front, the same to upstream side.

Meanwhile, Muskat (1949) deduced the pressure gradient assuming that, water flows upstream of the displacement front and only oil downstream, $u_d = u_u$ then equation 4.12 becomes [41].

$$\frac{\left(\frac{\partial p}{\partial n}\right)\Big|_d}{\left(\frac{\partial p}{\partial n}\right)\Big|_u} = \frac{\lambda_u}{\lambda_d}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 4.13$$

The ratio of the pressure gradients then is given by the statistical control device of the ratio of the mobility of the only fluid flowing in the swept zone to that the only fluid flowing in unswept zone (oil). Therefore, mobility ratio M

$$M = \frac{\lambda_u}{\lambda_d} = \frac{(k_r/\mu)_u}{(k_r/\mu)_d}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots .. 4.14$$

We all knew that mobility ratio controls the steadiness dissipation, conversely, actually the pressure gradient ratio which controls the conduct of dissipation abut. “A very large value of the mobility ratio is realized as a result of low viscosity of the steam vapor”. Consequently, the pressure gradient ratio is given by

$$M_{eq} = \frac{\left.\left(\frac{\partial p}{\partial n}\right)\right|_d}{\left.\left(\frac{\partial p}{\partial n}\right)\right|_u}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots . 4.15$$

$$= (u_w \mu_w / k_{rd})_d \, (k_{rs}/u_s \, \mu_s)_u, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots 4.16$$

$$= \frac{(w_u \rho_w)_d}{(u_s \rho_s)_u} \, \frac{v_w, d}{v_s} \, \frac{k_{rs}}{k_{rw}, d}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots . 4.17$$

Where v is the kinematic viscosity,

$$v = \frac{\mu}{\rho}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots . 4.18$$

μ = the fluid viscosity

k_r = the relative permeability

The subscripts s and w categorize properties related to steam and water and d is used to indicate that a property is evaluated at the downstream plane of the dislodgment and condensation front.

Meanwhile, Hagoort (1976) and Combarnous (1971), evaluated equivalent mobility ratio by considering the effect of a moving oil phase in the presence of residual oil saturation is given by

$$\frac{u_s \mu_s}{u_w \mu_w} = \frac{k_{rs}}{k_{rw}} \, \frac{1}{M_{eq}}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots .. 4.19$$

Combarnous (1971) however, evaluated the magnitude intended for piston like dislodgment of water by introduction of

- boiled water (at the steam saturation temperature equivalent to the ambient strain)
- Steam of 100% value, and
- Superheated steam

These computations are hinged on a mass stability for the entire water content across an accelerating the displacement front [19]. Each hot or steam water is well thought-out to exist at the upstream zone despite the fact that liquid water only exists at the downstream of the front.

Therefore, the performance predictions of oil saturations in the steam swept zones are low and effective mobility correlations are constructive and uncomplicated to undertake structures of predicting oil recovery.

If v_s is the gross volume of the steam zone, to determine the volume of zone and the amount of oil superseded from it, the amount of oil produced is

$$N_p = \left\{7{,}758 \frac{bbl}{acre-ft}\right\} \phi \frac{h_n}{h_t} (S_{oi} - S_{or}) E_c V_s, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 4.20$$

Where

h_n = the net reservoir thickness

h_t = the gross reservoir thickness

S_{oi} = the initial oil saturation

S_{or} = the residual oil saturation

E_c = the produced fraction of the oil displaced from the steam zone.

Marx and Langenheim (1959) stressed that, critical time concept is vital for heat in the reservoir, based on these three assumptions:

- There is no gravity supersede of the steam phase,
- All points on the condensation front advance at the same rate, and
- The heat injection rate is constant

Meanwhile, Myhill (1978) adopted the modification of steam zone volumes calculated by such that the steam zone volume would disappear when no steam vapor is injected. Consequently, the volume of the steam related to the fraction of the heat injected that present in the steam zone, $E_{h,s}$ given by [36],

$$v_s = (acre - ft/43{,}560)\frac{Q_i E_{h,s}}{M_R \Delta T}, \ldots\ldots\ldots\ldots\ldots 4{,}21$$

Where

M_R = the total hest content of the steam zone per unit volume

Q_i = the cumulative heat injected

Hence the heat injection rate Q_i could be calculated as

$$Q_i = w_i(C_w \Delta T + \square_{sdh} L_{vdh}), \ldots\ldots\ldots\ldots\ldots 4.22$$

Where

W_i = the mass rate of injection into the reservoir

ΔT = the temperature rise of the steam zone above the initial reservoir temperature

$f_{sdh\ and}\ L_{vdh}$ = are the steam quality and the latent heat of vaporization at both downhole conditions respectively

C_w = the average specific heat over the temperature range corresponding to ΔT

$E_{h,s}$ = the thermal efficiency of the steam zone and disappears when no steam vapor is injected.

At a constant rate heat injection,

$$E_{h,s} = \frac{1}{t_d}\left\{G(t_d) + (1 - f_{hv})\frac{U(t_D - t_{cD})}{\sqrt{\pi}} . \left[\begin{array}{c} \sqrt[2]{t_D} - 2(1 - f_{hv})\sqrt{t_D - t_{cD}} \\ - \int_0^{t_{cD}} \frac{e^x erfc\sqrt{xdx}}{\sqrt{t_D - x}} - \sqrt{\pi}\, G(t_D) \end{array}\right]\right\}, \ldots 4.23$$

The dimensionless time t_D is given by

$$t_D = 4\left(\frac{M_S}{M_R}\right)^2 \frac{\alpha_S}{h_t^2} t, \ldots\ldots\ldots\ldots\ldots 4.24$$

The function G (t_D) is given by

$$G = \sqrt[2]{\frac{t_D}{\pi}} - 1 + e^{t_D} erfc\sqrt{t_D} \text{ , } \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \; 4.25$$

However, the dimensionless critical time is given by

$$e^{t_{cD}}\, erfc\, \sqrt{t_{cD}} \;\equiv 1 - \; f_{hv}, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots . . 4.26$$

f_{hv} , is the fraction of the heat injected in latent form is given by

$$f_{hv} = \left(\frac{1 + C_w \Delta T}{f_{sdh}\, L_{vdh}}\right)^{-1} \text{ , } \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots . . 4.27$$

And the unit function U(x) is zero for x $<$ 0 and one for x $>$ 0 .

To know the quantity changes slowly during steam drive time projected, the ratio of the equivalent volume of steam injected per unit volume of oil produced. Therefore, the quantity of steam /oil ratio is given by

$$F_{so} = \frac{W_{s,eq}}{N_p} \text{ , } \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \quad \dots . . . 4.28$$

Where,

$W_{s,eq}$ = is a measure of the steam used, expressed as equivalent volumes of water. These include the steam injected, the steam generated, the feed water passed through the generator and the equivalent energy content.

F_{SO} = the steam / oil ratio.

Myhill (1978) however, converted the enthalpy of the steam at the generator outlet to the equivalent volume of injected steam $W_{s,eq}$ based on a reference enthalpy of 10^3 Btu/ lbm it expressed in the relation of heat injected Q_i becomes [42]

$$W_{s,eq} = \left(2.853 \;\times 10^{-6} \frac{bbl}{Btu}\right) . \left[\frac{C_w(T_{sb} - T_A) + f_{sb} L_{vb}}{C_w(T_{idh} - T_i) + f_{sb} L_{vb}}\right] Q_i, \dots \dots \dots \dots \dots \dots \dots \dots \; 4.29$$

Where,

T_A = the ambient temperature of the boiler feedwater, b and dh represent boiler outlet and down hole conditions respectively.

It is important to note that the equivalent volume of steam injected is measure of the thermal energy injected into the reservoir, might not change to zero even when the steam quality is zero. Actually, constant rates of heat injection are unattainable, so that in principle,

- The cumulative steam injected necessity based on the ordinary steam injection rate
- The cumulative equivalent dimensions of steam injected furthermore must consider variations in temperature at the cistern inlet and outlet and at the bottom of the injection well
- The thermal effectiveness of the steam region should be obtained by superposition or equivalent measures.

The circulation of the steam contained by the reservoir is vital for the following [25];

- ✓ Appraising injectivity
- ✓ Heat and steam breakthrough which may have an impact on well spacing, project life, and post steam breakthrough production performance
- ✓ The general recovery effectiveness.

It is also very important to know the location of the steam zone within the vertical extent of the reservoir. Both field and laboratory studies show that steam rises to the top of the injection interval where necessary vertical information is present. The rise occurs as a result of the effect of buoyant forces, and the degree of the gravity override would be expected to be correlated with ratio of the gravity forces to the horizontal viscous forces is expressed by [11].

$$\frac{Lg\Delta\rho}{\Delta P g_c} = \frac{Ak\rho g\Delta\rho}{\mu w_i g_c}, \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \; 4.30$$

$g\Delta\boldsymbol{\rho}/ g_c$ = buoyant force gradient between two fluids having a density difference $\boldsymbol{\rho}$,

Δp /L = the pressure gradient

w_i / A = the mass injection rate w_i per cross-sectional area A,

$\boldsymbol{\rho}$ and k/$\boldsymbol{\mu}$ are the density and the mobility of the injection fluid.

Hence, the vertical sweep efficiency at a time is given by

$$\frac{\alpha t}{h^2} = 0.08\ , \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ 4.31$$

Where,

α = the thermal diffusivity of the water- saturated sand

h = the sand thickness

t = time

have been calculated versus relative values of the ratio of gravity forces to viscous defined by equation 4.26 from the results reported by [11].

Neuman (1975) proposed that, if the given area is increasing linearly with the square root of the steam injection time when the net heat injection rate is constant, and the thickness of the steam zone at any distance from the injection well is given as proportional to the square root of the elapsed time since the leading edge of the front reached the point. By Neuman's equation, comparison between observed steam zone thicknesses and those evaluated by [44], is given as

$$\Delta z_s = \frac{4(M\sqrt{\alpha}\,)_S C_w \Delta T}{L_v M_{Rse}} \sqrt{\Delta t/\pi}\ , \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots .4.32$$

$(M\sqrt{\alpha}\,)_S$ = an average value of the properties in the overburden and in the reservoir beneath the steam zone,

M_{Rse} = the volumetric heat capacity of the steam zone neglecting all contributions due to the steam itself,

ΔT = the elapsed time since steam first arrived where the steam zone thickness Δz_s is to be calculated.

Neuman (1985) however reported that, half as much oil is shift from the region below the steam zone as from the condensation region itself.

4.5. Economic Evaluation of Steam Drives

Evaluation of the recoverable oil by steam drives mechanisms with the subsequent reservoir parameters specified below.

Gross thickness, ft	40.0
Net thickness, ft	33.0
Porosity	0.17
Average oil saturation	0.65
Residual oil saturation	0.16
Reservoir temperature, ^oF	92
Volumetric heat capacity of heated reservoir, Btu/cu ft-^oF	38.0
Volumetric heat capacity of adjacent formations, Btu/cu ft-^oF	41.7
Thermal diffusivity of adjacent formations, sq ft/D	0.6
Injection temperature, ^oF	564
Latent heat of condensation, Btu/bm	615.3
Steam quality	0.72
Specific heat of water, Btu/bm ^oF	1.07
Density of water, ibm/cu ft	45.0

To proceed for evaluating, it is crucial to know effective volumetric heat capacity of the reservoir formation from this equation 4.33 to estimate the amount of heat capacity Q required to increase the temperature of a bulk volume of formation V_R by an amountΔT, and at constant pressure, is

$$Q = \left(43{,}560\frac{cu}{ft}acre - ft\right)V_R M_R \Delta T\ , \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots .4.33$$

Where,

M_R = the isobaric volume heat capacity of the bulk, fluid -filled reservoir, therefore, M_R is the amount of heat required to raise a unit bulk volume by one degree of temperature and is equal to the product of the effective density and the scope isobaric heat of the bulk formation. Hence, M_R is specified by [46]

$$M_R = (1-\emptyset)M_\sigma + \emptyset S_O M_O + \emptyset S_W M_W + \emptyset S_G \,.\left[f\ M_G + (1-f)\left(\frac{\rho_s L_v}{\Delta T} + \rho_s C_w\right)\right] \text{, ... 4.34}$$

Where,

f = is the volumetric fraction of non-condensable gas in the vapor phase;

M_σ, M_o, M_w, and M_g are isobaric volumetric heat capacities of solid, oil , water and gas phases, respectively;

S_O, S_w, and S_g are the saturation of fluid phases;

L_V = is the latent of vaporization of water;

ρ_s = is the steam density,

C_w = is the isobaric heat capacity of water per unit mass.

From the data above, if the feed water rate into a steam generator is 1,000 /D at temperature of 60 °F , the inlet feed water average temperature 80 °F, and the output temperature and the steam quality average 564 °F and 0.77. The quality of the steam entering the reservoir is 0.72, and the buttonhole temperature is also 564 °F .

A. Estimation the general recovery accounted owing to the steam injection by [42], method the segment of heat infused in suppressed form

$$f_{h\,v} = \left(1 + \frac{(C_w \Delta T)}{f_{sdh}\, L_{vdh}}\right)^{-1} = \left(1 + \frac{\left(1.07\,\frac{Btu}{lbm}\,°\mathrm{F}\right)(564-92)°\mathrm{F}}{(0.72)\left(15.3\,\frac{Btu}{lbm}\right)}\right)^{-1}$$

$$= 0.44$$

B. The valve of dimensionless critical time

$$e^{t_{cD}}\, erfc\,\sqrt{t_{cD}} \equiv 1 - f_{h\,v,} \Rrightarrow 0.56$$

$$e^{t_{cD}}\, erfc\,\sqrt{t_{cD}} = 0.56$$

$$t_D = t_{cD} = 0.75$$

C. The correlation involving real and dimensionless time

$$t = \frac{(38.0\frac{Btu}{cu}\ ft\ °F)^2(40.0\ ft)^2 t_D}{(4)\left(0.60\ sq\frac{ft}{D}\right)\left(41.7\frac{Btu}{cu\ ft}\ °F\right)^2}$$

t (in days) = 415 t_D

t (in years) = 1.50 t_D

D. Estimation of rate of injection by heat into the reservoir, Q_i

$$Q_i = \left(1{,}000\frac{B}{D}\right)\left(62.3\frac{lbm}{cu}ft\right)\left(5.614\frac{cu\ ft}{bbl}\right).[(1.07\frac{Btu}{lbm})(564-92)°F + (0.72)(615.3\frac{Btu}{D})]$$

$$= 3.31\ \times 10^8\ Btu/D$$

E. Volume of the steam zone evaluation as a function of time

$$V_s = [\left(3.31\ \times 10^8\frac{Btu}{D}\right) t\ E_{h.s}\ ] \div \left[\left(43{,}560\ cu\frac{ft}{acre - ft}\right) \times \left(38.0\frac{Btu}{cu}ft\ °F\right)(564-92)°F\right]$$

$$= 0.424\ t\ E_{h.s}$$

F. Approximation of areal enlargement of the stream zone is given as

$A(in\ acres) = V_s/(40.0\ ft)$

G. Cumulative oil production which is comparatively to the steam zone volume is calculated as

$$N_p = \left(\frac{7{,}758bbl}{acre} - ft\right)(0.17)\left(\frac{33.0\ ft}{40.0\ \ ft}\right) \times (0.65-0.16)V_s$$

$N_p(in\ bbl) = 533V_s$

H. Cumulative steam oil fraction is evaluated from the cumulative production and cumulative corresponding to steam injected is specified as

$$W_{s,sq}\left(2.853 \times \frac{10^{-6}Btu}{D}\right).\left[\left(1.07\frac{Btu}{lbm} - °F\right)(564-70)°F + (0.77)(\frac{615.3\ Btu}{lbm})\right] \div \left[\left(1.07\frac{Btu}{lbm} - °F\right)(564-92) + (0.72)(615.3\frac{Btu}{lbm})\right]$$

$= 3.016 \times 10^{-6}Q_i$ bbl

CHAPTER V

5.1. Evaluation of Reservoirs for Recoveries and Economic Indicators of Enhanced Oil Recovery

There are a number of bench marks which are used to evaluate the reservoir recoveries. These are screening criteria, screening guidelines, preferred criteria and selection criteria. However, each bench marks may be affected by the current and local economic climate. The effect of economic considerations in the technical variables such as

- The ability to generate heat within or injected into an oil containing reservoir at efficient rates.
- The ability to displace the oil.
- The ability to recover the oil all in a control manner.

There are some limitations of properties ranges which may be applicable to a thermal process. Let as consider steam drives, the gravity of the crude plays no role in technical considerations just mentioned except as it might affect plugging, hence, the ability to maintain adequate communication between wells in reservoir containing relatively heavy crudes. “Gravity however is override of the steam reduces the tendency of the formation plug”. Hydraulic fracturing also controls of the injection temperature, and cyclic steam injections have been used successfully in thermal operations to avoid or minimize plugging.

Another case is by considering injectivity. A systematic reduction in ability to inject fluids is a factor affecting the economics of all enhanced recovery processes, those requiring the injection of heated fluids. When the injection rate is reduced, the project life must be longer and more of the heat entering is lost to the adjacent zones. As results to reduce the oil displacement and production rates, which in turn reduces the economic attractiveness. Meanwhile, what may be an acceptable level of injectivity in one project could be economically catastrophic to another.

5.2. Economic Indicators of EOR

There are many techniques for measuring the economic desirability of production schemes. It is however necessary to evaluate the net present value.

Table 5.1. Showing World Crude Oil Production including Condensate 1997- 2010.

Year	Algeria	Angola	Azerbaijan	Egypt	China	Iran	Iraq	Kuwait	Libya	Nigeria	Norway	Oman	Qatar	Russia	Saudi R.	US	Venezuela
1997 Average	1,277	714	173	856	3,200	3,664	1,155	2,007	1,446	2,132	3,142	904	550	5,920	8,362	6,452	3,280
1998 Average	1,246	735	230	834	3,198	3,634	2,150	2,085	1,390	2,153	3,011	900	696	5,854	8,389	6,252	3,167
1999 Average	1,202	745	276	852	3,195	3,557	2,508	1,898	1,319	2,130	3,019	910	665	6,079	7,833	5,881	2,826
2000 Average	1,254	746	280	768	3,249	3,696	2,571	2,079	1,410	2,165	3,222	970	737	6,479	8,404	5,822	3,155
2001 Average	1,310	742	657	720	3,300	3,724	2,390	1,998	1,367	2,256	3,226	913	714	6,917	8,031	5,746	3,010
2002 Average	1,306	896	310	715	3,390	3,444	2,023	1,894	1,319	2,118	3,131	897	679	7,408	7,634	5,811	2,604
2003 Average	1,611	903	320	713	3,409	3,743	1,308	2,136	1,421	2,275	3,042	819	715	8,132	8,775	5,681	2,335
2004 Average	1,677	1,052	433	658	3,609	4,001	2,011	2,376	1,515	2,329	2,954	751	783	8,805	9,101	5,419	2,557
2005 Average	1,797	1,250	433	658	3,609	4,139	1,878	2,529	1,633	2,627	2,698	774	835	9,043	9,550	5,178	2,565
2006 Average	1,814	1,413	640	633	3,673	4,028	1,996	2,535	1,681	2,440	2,491	738	850	9,247	9,152	5,102	2,511
2007 Average	1,834	1,744	842	637	3,729	3,912	2,086	2,464	1,702	2,350	2,270	710	851	9,437	8,722	5,064	2,433
2008 Average	1,825	1,981	870	581	3,790	4,050	2,375	2,586	1,736	2,165	2,182	757	924	9,357	9,261	4,950	2,394
2009 Average	1,782	1,907	1,006	539	3,799	4,037	2,391	2,350	1,650	2,208	2,067	813	927	9,495	8,250	5,361	2,239
2010 10-Month Average	1,809	1,968	1,033	523	4,053	4,084	2,389	2,350	1,650	2,446	1,868	861	1,105	9,689	8,442	5,492	2,127

Source: U.S. Energy Information Administration Annual Energy [8]

It is assumed, as customary, that a single discount rate i is applicable to all cash flows. For a net cash inflow after taxes, P_j, in the jth year after an initial investment of magnitude $P_i = P_0$, the net present value of an operation lasting n_y years is given as

$$Ppv = \sum_{j=0}^{n_y} Pje^{-ij} , \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots 5.1$$

P_j are positive when the net cash flow after taxes for the year is positive and negative for an out flow of cash. Note that initial investment is also negative.

The yearly after tax cash inflow P_j is composed of four parameters.

$$P_j = (V_j - O_j - C_j)f_{n,j}, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots ..5.2$$

Where,

V_j = is the annual gross revenue after royalties and wellhead taxes.

O_j = is the annual operating cost

C_j= is the annual capital outlay

$f_{n,j}$, = is the net fraction of yearly cash inflow remaining after all taxes have been paid.

The operating cash income is given by

$I_j = V_j - O_j, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots$ ..5.3

The annual gross revenue after royalties and wellhead taxes is proportional to the annual production:

$V_j = V_{u,j} \Delta N_{p,j}, \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots$ 5.4

Where,

$V_{u,j}$ = is the average unit crude price after royalties and wellhead taxes.

$\Delta N_{p,j}$= is the annual oil production.

Since any field project involves risk, the rate of return should be higher than that obtainable in comparatively low risk investments. The discounted cash flow rate return is represented by I_r , is the value of the discount rate i

5.2.1. Importance of Cash Flow

It is important to note that, in most instances the cumulative recovery or revenue is higher in steam drives than waterflooding injection processes. As a whole, the present value of a scheme depends not only on the process but also on many reservoir and fluid properties and operating conditions.

Another condition is such that, the process to be used is the average amount of oil in place at the start of the scheme, whether existing producing wells must be used, and whether only new injection wells are to be drilled and also may be considered to be known by the operator.

5.2.2. Estimating Gross Income History from Performance Prediction Models

The purpose is to demonstrate how the gross income history may be estimated from the prediction models and to identify an operational variable and how the gross income history is responsive to it.

Table 5.2. Total Energy Supply, Disposition, and Price Summary (Quadrillion Btu per year, unless otherwise).

Supply, Disposition, and Prices	Reference Case							Annual growth 2010-2035 present
	2009	2010	2015	2020	2025	2030	2035	
PRODUCTION								
Crude oil and condensate	11.35	11.59	13.23	14.40	13.77	13.71	12.89	0.4%
Natural gas plant liquids .	2.57	2.78	3.33	3.79	3.93	3.98	3.94	1.4%
Dry natural gas	21.09	22.10	24.22	25.69	26.91	27.58	28.60	1.0%
Imports								
Crude oil	19.70	20.14	18.87	16.00	16.23	16.04	16.90	-0.70%
Liquid fuels and other petroleum6	5.40	5.02	4.32	4.03	4.08	4.04	4.14	-0.80%
Natural gas7	3.85	3.81	3.73	3.49	2.75	3.00	2.84	-1.20%
Exports								
Liquid fuels and other petroleum9	4.20	4.81	5.00	4.39	4.46	4.67	4.95	0.1%
Natural gas10	1.08	1.15	1.93	3.09	3.51	3.86	4.17	5.3%
Liquid fuels and other petroleum12	36.50	37.25	36.72	36.38	36.58	36.99	37.70	0.00%
Natural gas	23.43	24.71	26.00	26.07	26.14	26.72	27.26	0.4%
Prices (2010 dollars per unit)								
Low sulfur light crude oil	62.37	79.39	116.91	126.68	132.56	138.49	144.98	2.4%
Imported crude oil16	59.72	75.87	113.97	115.74	121.21	126.51	132.95	2.3%
Natural gas (dollars per million Btu) at Henry hub	4.00	4.39	4.29	4.58	5.63	6.29	7.37	2.1%
at the wellhead17	3.75	4.06	3.84	4.10	5.00	5.56	6.48	1.9%
Natural gas (dollars per thousand cubic feet) at the wellhead17	3.85	4.16	3.94	4.19	5.12	5.69	6.64	1.9%
Coal (dollars per ton) at the minemouth18	33.62	35.61	42.08	40.96	44.05	47.28	50.52	1.4%

Source: U.S. Energy Information Administration Annual Energy Outlook 2012.[8]

To make a sensitivity analysis on the level of the injection pressure, one must be able to estimate how operating and capital cost and revenues will be affected by the injection pressure. By model of [38],

$$\Delta N_{p,j} = \frac{0.25F_O F_{\Delta h} i_S h_t^2 \Delta G_j}{\alpha_S}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 5.5$$

Where the steam injection rate in equivalent barrels of water per day is estimated by

$$I_s = \frac{3.54 \times 10^{-3}(p_{inj} - p_p)\Im_{as}}{\ln\left(\sqrt{43{,}560\,A}\ /r_w\right) - 0.964}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 5.6$$

$$F_O = (S_{Oi} - S_{or})\phi h_n \,/\, h_t\,, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 5.7$$

Is the fractional volume of oil per unit bulk volume of reservoir

$$F_{\Delta h} = \frac{\rho_w \left(\frac{C_w \Delta T + f_s}{L_v}\right)}{M_R \Delta T}, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 5.8$$

Is the dimensionless ratio of the effective volumetric heat capacity of the injected steam to that of the reservoir steam zone.

$$\Im_{as} = (k_s h_n/\mu_s)_a, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 5.9$$

Is the effective apparent transmissivity of the reservoir to the injected steam in md-ft/cp

$$\Delta G_j = G(jt_{D1}) - G[(j-1)t_{D1}], \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 5.10$$

The volume of the reservoir steam zone

$$\Delta G_O \equiv O, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 5.11$$

$$t_{D1} = 1{,}460\ \alpha_s/\ h_t^2, \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 5.12$$

Is the value of the dimensionless time at 1 year.

Where,

i_s = steam injection rate per injection well, B/D

h_t = gross reservoir thickness, ft

α_s= diffusivity of the surrounding formations, sq ft/D,

$(p_{inj} - p_p)$= the pressure difference between injection and production wells, psi

A = spacing per injection well, acres,

r_w = wellbore radius, ft,

$(S_{Oi} - S_{or})$ = the difference between initial and residual saturation,

ϕ = porosity, fraction,

h_n = net reservoir thickness, ft,

ΔT = the difference between the injected steam and initial reservoir temperature, °F,

f_s= the steam quality, fraction,

L_v = latent heat of condensation of steam, Btu /lbm,

K= reservoir permeability, md, and

μ= fluid viscosity, cp

5.3. Recoverable Oil.

The recoverable oil per unit bulk volume of reservoir is given as

$\emptyset(S_{Oi} - S_{or})h_n h_t$.

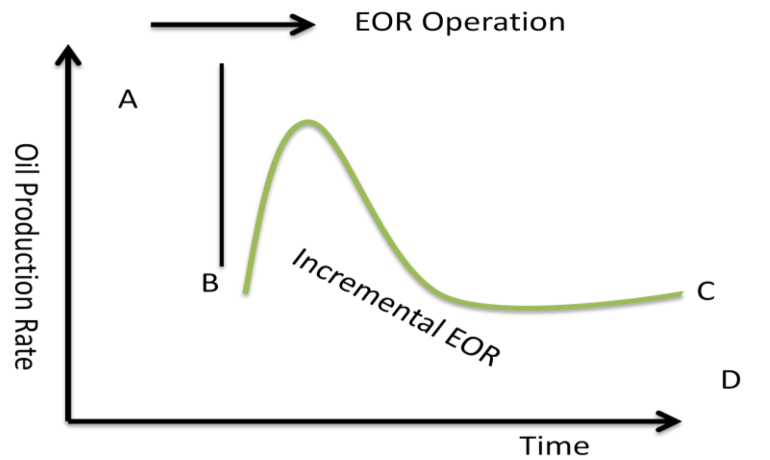


Figure. 5.1. *Incremental oil recovery from a typical EOR response.*

The minimum acceptable values of quantity estimated from the requirement that the fuel value of the oil displaced and recovered from a unit volume of the reservoir must be larger than the energy required to displace it. Therefore, steam displacement is given by

$(0.77)\emptyset(S_{Oi} - S_{or})h_n /h_t > \frac{M_R(T_s - T_i)}{\rho_o \Delta h_F E_{h,s} E_c}$,…………………………………..12.12

Where,

$\emptyset$= porosity, fraction,

S_{Oi}= initial oil saturation, fraction,

S_{or} = residual oil saturation, fraction,

h_n= net sand thickness, ft,

h_t= gross sand thickness, ft,

M_R = effective volumetric heat capacity of the steam zone, Btu /cu ft-°F,

T_s = steam injection temperature,°F,

T_i = original reservoir temperature,°F,

ρ_o = oil density, lbm /cu ft,

Δh_F = fuel value of the oil per unit mass, Btu/lbm,

$E_{h,s}$ = fraction of the cumulative heat injected into the reservoir present in the steam zone at the end of the project.

E_c = fraction of the displaced oil that is produced at the end of the project.

Table 5.2. Showing World Wide Projected Variations of Imported Crude Oil.

Imported Liquids by Source, Reference case
(million barrels per day)

Sources	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Growth Rate (2009-2035)
Crude Oil																													
Canada	1.96	1.95	2.01	2.02	2.05	2.05	2.05	2.09	2.1	2.13	2.14	2.15	2.15	2.16	2.14	2.11	2.1	2.09	2.1	2.12	2.13	2.14	2.15	2.14	2.14	2.14	2.14	2.17	0.40%
Mexico	1.19	1.09	1.12	1.11	1.11	1.07	1.07	1.07	1.07	1.07	1.07	1.06	1.06	1.05	1.03	1.01	0.99	0.98	0.98	0.97	0.97	0.97	0.97	0.95	0.95	0.95	0.94	0.95	-0.50%
North Sea	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06	-2.00%
OPEC	5.4	4.36	4.69	4.66	4.5	4.52	4.38	4.27	4.14	3.94	3.86	3.84	3.82	3.86	3.79	3.83	3.88	3.95	4	3.97	3.91	3.89	3.9	3.88	3.79	3.77	3.79	3.9	-0.40%
Latin America	1.25	1.13	1.28	1.26	1.23	1.22	1.19	1.19	1.16	1.14	1.13	1.11	1.1	1.11	1.09	1.09	1.09	1.09	1.09	1.09	1.08	1.08	1.08	1.07	1.06	1.05	1.04	1.06	-0.20%
North Africa	0.38	0.34	0.37	0.37	0.37	0.36	0.36	0.36	0.36	0.36	0.36	0.35	0.35	0.35	0.34	0.33	0.32	0.32	0.31	0.31	0.31	0.31	0.3	0.3	0.3	0.29	0.29	0.32	-0.30%
West Africa	1.43	1.22	1.25	1.28	1.29	1.27	1.26	1.27	1.26	1.25	1.26	1.24	1.23	1.23	1.21	1.18	1.16	1.14	1.14	1.13	1.13	1.13	1.12	1.1	1.09	1.09	1.07	1.07	-0.50%
Persian Gulf	2.34	1.66	1.79	1.74	1.61	1.67	1.56	1.45	1.37	1.2	1.12	1.14	1.14	1.17	1.14	1.24	1.31	1.41	1.46	1.44	1.38	1.37	1.39	1.41	1.35	1.34	1.38	1.45	-0.50%
Other Middle East	0.02	0.05	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.30%
Other Latin America	0.49	0.65	0.55	0.54	0.54	0.54	0.55	0.57	0.58	0.61	0.63	0.64	0.67	0.68	0.7	0.69	0.69	0.69	0.71	0.72	0.74	0.75	0.77	0.78	0.8	0.81	0.84	0.86	1.10%
Other Africa	0.33	0.37	0.33	0.32	0.3	0.28	0.26	0.25	0.24	0.23	0.22	0.19	0.19	0.19	0.19	0.18	0.18	0.18	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.14	0.14	-3.70%
Other Asia	0.28	0.44	0.38	0.39	0.37	0.37	0.35	0.35	0.33	0.33	0.33	0.31	0.31	0.31	0.29	0.28	0.28	0.28	0.26	0.25	0.23	0.2	0.18	0.16	0.16	0.15	0.15	0.15	-4.10%
Total Crude Oil	9.78	9.01	9.21	9.17	9	8.96	8.79	8.74	8.6	8.46	8.38	8.33	8.34	8.39	8.27	8.24	8.24	8.28	8.32	8.3	8.26	8.23	8.24	8.18	8.1	8.08	8.11	8.28	-0.30%
Light Refined Products 1/																													
Canada	0.41	0.41	0.27	0.25	0.31	0.32	0.31	0.31	0.31	0.31	0.3	0.3	0.29	0.28	0.29	0.29	0.29	0.29	0.3	0.29	0.3	0.3	0.3	0.3	0.3	0.31	0.3	0.3	-1.20%
Northern Europe	0.29	0.28	0.19	0.17	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.2	0.2	0.2	0.2	0.2	0.21	0.2	0.21	0.21	0.21	0.21	0.21	0.22	0.21	0.21	-1.20%
Southern Europe	0.1	0.1	0.07	0.06	0.08	0.09	0.09	0.08	0.09	0.09	0.09	0.09	0.1	0.09	0.1	0.09	0.09	0.09	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.11	0.1	0.1	0.10%
OPEC	0.32	0.32	0.22	0.22	0.29	0.29	0.3	0.31	0.33	0.32	0.33	0.34	0.36	0.34	0.37	0.35	0.35	0.36	0.37	0.39	0.38	0.39	0.39	0.4	0.39	0.4	0.39	0.39	0.80%
Latin America	0.15	0.14	0.1	0.1	0.12	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.15	0.14	0.15	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.40%
North Africa	0.03	0.04	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.40%
West Africa	0.06	0.06	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	-0.20%
Persian Gulf	0.06	0.06	0.04	0.05	0.07	0.07	0.07	0.07	0.08	0.08	0.09	0.09	0.1	0.1	0.1	0.1	0.1	0.1	0.11	0.12	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12	2.70%
Caribbean Basin	0.33	0.32	0.21	0.2	0.25	0.25	0.25	0.25	0.26	0.26	0.25	0.25	0.25	0.24	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.26	0.26	0.26	0.26	0.25	-0.90%
Asian Exporters	0.13	0.13	0.09	0.09	0.12	0.12	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	-0.10%
Other	0.16	0.17	0.12	0.11	0.14	0.14	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.14	-0.60%
Total Light Refined Products	1.75	1.72	1.16	1.14	1.4	1.42	1.43	1.44	1.46	1.45	1.46	1.46	1.47	1.41	1.47	1.44	1.45	1.47	1.49	1.51	1.5	1.51	1.54	1.55	1.55	1.57	1.55	1.52	-0.50%
Heavy Refined Products 2/																													
Canada	0.09	0.06	0.05	0.05	0.06	0.06	0.06	0.07	0.07	0.08	0.07	0.08	0.08	0.08	0.07	0.08	0.07	0.07	0.07	0.06	0.07	0.07	0.06	0.06	0.06	0.07	0.07	0.07	0.40%
Northern Europe	0.24	0.15	0.12	0.12	0.15	0.15	0.15	0.14	0.15	0.13	0.14	0.14	0.13	0.14	0.13	0.14	0.13	0.13	0.14	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	-0.40%
Southern Europe	0.03	0.02	0.01	0.02	0.01	0.03	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00%
OPEC	0.46	0.36	0.31	0.34	0.38	0.39	0.41	0.42	0.43	0.42	0.42	0.42	0.42	0.41	0.39	0.4	0.4	0.41	0.4	0.4	0.4	0.41	0.4	0.4	0.41	0.41	0.41	0.42	0.50%
Latin America	0.11	0.08	0.07	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.08	0.09	0.08	0.09	0.08	0.09	0.09	0.09	0.09	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.11	1.20%
North Africa	0.27	0.2	0.17	0.18	0.21	0.21	0.21	0.21	0.23	0.21	0.21	0.21	0.21	0.2	0.2	0.2	0.2	0.2	0.19	0.18	0.18	0.18	0.17	0.17	0.17	0.18	0.18	0.18	-0.40%
West Africa	0.03	0.03	0.02	0.02	0.02	0.03	0.04	0.04	0.04	0.04	0.04	0.03	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.40%
Persian Gulf	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.06	0.06	0.07	0.06	0.06	0.06	0.06	0.05	0.06	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	4.20%
Caribbean Basin	0.29	0.2	0.17	0.19	0.22	0.21	0.2	0.19	0.19	0.17	0.17	0.16	0.16	0.16	0.16	0.15	0.15	0.15	0.16	0.16	0.16	0.15	0.15	0.15	0.16	0.16	0.16	0.16	-0.80%
Asian Exporters	0.11	0.08	0.08	0.09	0.11	0.1	0.1	0.1	0.1	0.11	0.1	0.1	0.1	0.1	0.1	0.09	0.09	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.60%
Other	0.21	0.15	0.12	0.12	0.14	0.15	0.15	0.14	0.14	0.15	0.15	0.15	0.15	0.14	0.14	0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	-1.00%
Total Heavy Refined Products	1.43	1	0.87	0.92	1.05	1.09	1.09	1.08	1.08	1.08	1.07	1.07	1.06	1.04	1.01	1	0.98	0.98	0.97	0.97	0.97	0.96	0.97	0.97	0.98	0.98	0.99	1	0.00%

National Energy Modeling System [43].

CONCLUSION AND RECOMMENDATION

Conclusion.

The research reviewed that, the interest on development of EOR processes and associated oilfield performance would pave away for targeting vital volumes of oil build-up that have been remaining behind in evolve reservoirs after primary and secondary oil recovery procedures.

The capability for EOR is factual and attainable. However, systematic improvements of the viable performance and economical improvement of EOR schemes in the prospect would depend upon the application of a cooperative approach between EOR processes, cleared reservoir description, assessment formation, reservoir representation and modeling, reservoir operation, well engineering, modern and revolutionary observation approaches, production mechanisms, and surface appliances.

1. Recovery efficiencies of 70 to 80% of the original oil in place (OOIP) are possible in some water-drive reservoirs. Recoveries are low, on the order of 10 to 30% of the OOIP. Recovery is relatively low because the gas is more mobile than the oil phase in the reservoir. Therefore the ultimate recovery factors for gas-cap drives are between 90% to 95% whilst for water drive reservoir varies from 50 % to 80%. Gravity Drainage has a high rate of EOR ascertained ultimate recovery factor of about 99% of the initial oil in place (IOIP) in view that ultimate oil recovery of 94% of IOIP. And this has contributed almost 35-40% of the world's oil and gas reserves.
2. The interference and fill-up, the injection rate decreased from 186.9 to 129.9 B/D (29.7 to 20.6 m^3 /d) as w_i changed from 6,855 t0 8,728 bbl [1090 to 1388 m^3]. The time between interference and fill-up corresponds to the injection of 1,873 bbl [298 m^3] of water at a declining rate. Meanwhile, a little error would accrue if an average rate for this interval equal to (186.9 +129.9)/2 or 158.4 B/D [25.2 m^3 /d]**.**
3. Statistics shows that, the total production increase due to thermal recovery are based on the incremental production rate of 199,000 B/D amounted to 20% of the total production.

RECOMMENDATION.

a) Forecasting these processes in a highly volatile economic scene is risky at best. Nevertheless, a prediction EOR trend does some give idea of current thing. From the predicted market trends from Annual growth 2009-2035 of crude oil and condensate supply and disposition and prices shows that, by the end of 2035, the supply of crude oil with condensate would have been increased by 0.4% worldwide.

b) It is however, predicted that, by the end of 2035, the prices of low sulfur light crude oil would have been increased by 2.4% whilst natural gas also would have had an increased of about 2.1% million Btu. Well head cost in dollars per thousand cubic feet has been quoted an increased by 1.9%.

c) Analytical review showed that consumptions of natural gas increased by the 0.4% , from this analysis one could inferred that world wild consumption would be steady despite a heavy demand of energy from both China and India by the end of 2035.

d) Shell Canada Resources Ltd. and Shell Explorer Ltd. Announced plan to use a modified steam drive / pressure cycle process to produce bitumen from Peace River in commercial quantities, this quantifies the future is brighter for thermal recoveries because with this development heavy crudes could be exploits and extracts.

e) The synergistic adopted is in accordance with the SFC, at the same time called as Intelligent Field, or Digital Field, i-Field, invented by Shell International Exploration and Production that incorporates an integrated technique, which comprises of data possession, simulation, collective decision capabilities, coupling with operational field management, each with an extraordinary level of integration and computerization.

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