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RE-EVALUATION OF ORIGINAL OIL IN PLACE AND PROPOSING A
FIELD DEVELOPMENT PLAN USING MBAL SOFTWARE: CASE STUDY
ZONE 12 HMD FIELD

Supported on 09/06/2026

Before the jury:

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Thanks

We first thank God, who gave us the strength and power to complete this modest work.

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Finally, we would like to thank all those who directly or indirectly; contributed to the completion of this work.

Dedication

I dedicate this modest work to:

My dearest mother

My beloved father

My friend Moussa

My brother Fayçal

My sisters

My friends and all those who are dear to me

*Mr. HORIMEK & MOUMEN reservoir engineers
at SONATRACH for their support and data.*

Riad

Dedication

I dedicate this modest work to:

My dearest mother

My beloved father

My friends

My brothers

My sisters

My friends and all those who are dear to me

.

Ikram

Dedication

I dedicate this modest work to:

My dearest mother

My beloved father

My friend Taha

My brother Obaida

My sisters

My friends and all those who are dear to me

*Mr. HORIMEK & MOUMEN reservoir
engineers at SONATRACH for their support
and data.*

Chouaib

ملخص :

استعمال المكامن النفطية يعتبر من المشاريع الهامة المحفوفة بالمخاطر الاقتصادية، إن لم يتم تقدير أرباح المشروع والمصاريف ورأس المال الابتدائي للمشروع بشكل جيد. ولهذا فإن تقدير المخزون يحظى بأهمية كبيرة ويقع هذا الواجب على عاتق قسم الهندسة البترولية، بفضل التكنولوجيات الحديثة والمتطورة اليوم يتم تقدير المخزون بطرق مختلفة من أجل ضبط التوقعات وتحقيق التقدير المثالي للمخزون في هذه المذكرة قدرنا مخزون المنطقة 12 من حقل حاسي مسعود باستعمال طريقة موازنة المادة ب 122 مليون متر³ وقمنا بمقارنتها مع الحسابات الحجمية التقليدية للمخزون التي قدرت ب 114 مليون متر³ واقتراح مخطط لتحسين معامل الاسترداد والمحافظة على ضغط المكامن.

الكلمات المفتاحية: مخزون، الحسابات الحجمية، طريقة موازنة المادة، معامل الاسترداد.

Abstract:

The exploitation of oil reservoirs is considered an important investment project that could involve a significant economic risk. If the project's revenue is not properly forecast, taking into account expenditures and the initial capital investment, substantial losses may occur; hence, the importance of reserve estimation. Reservoir estimation is the responsibility of a reservoir engineer. Reserves are estimated using various methods to align predictions with the actual reservoir model and achieve an optimum estimate. Owing to today's technological advancements, these methods have become increasingly accurate. In this humble effort, we estimate the reserves of Zone 12 HMD using the Material Balance Method at **122 million Sm³** and compare the result with that obtained from the Volumetric Method (**114 million Sm³**). We also propose a development plan based on water injection to improve the recovery factor and provide pressure support.

Key words: reserves, volumetric method, Material Balance method, Recovery factor.

Résumé :

L'exploitation des réservoirs pétroliers est considérée comme un projet d'investissement majeur pouvant présenter un risque économique important. Si les revenus du projet ne sont pas correctement estimés, en tenant compte des dépenses et du capital initial investi, des pertes considérables peuvent en résulter ; d'où l'importance de l'estimation des réserves. Cette tâche relève de la responsabilité de l'ingénieur réservoir, qui utilise différentes méthodes d'évaluation afin d'adapter les prévisions au comportement réel du réservoir et d'obtenir une estimation optimale. Grâce aux avancées technologiques actuelles, ces méthodes sont devenues de plus en plus précises. Dans ce modeste travail, nous avons estimé les réserves de la zone 12 HMD par la méthode du bilan matière à 122 millions de Sm³ et comparé ce résultat à celui obtenu par la méthode volumétrique, qui est de 114 millions de Sm³. Nous proposons également un plan de développement basé sur l'injection d'eau afin d'améliorer le facteur de récupération et d'assurer le maintien de la pression du réservoir.

Les Mots-clés : Réserves, la méthode volumétrique, la méthode du bilan matière, le facteur de récupération.

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List of abbreviations

API: American Petroleum Institute.
 Bo: Bottom Volumetric factor of the oil [Rm^3/STm^3].
 Bw: Bottom Volumetric factor of the water [Rm^3/STm^3].
 Bg: Bottom Volumetric factor of the gas [Rm^3/STm^3].
 Co: Oil compressibility [bar^{-1}].
 Cr: Compressibility of the rock [bar^{-1}].
 Cw: Isothermal compressibility of water [bar^{-1}].
 F: Racking.
 Et: Total expansion.
 GOR: Gas Oil Ratio.
 Gp: Cumulative gas production [STm^3].

Hu: Average useful height.

Ht: Total height.

IP: Productivity informant.

K: Permeability [md].

Kro: Relative oil permeability.

Krw: Relative water permeability.

m: Ratio of the initial cap gas volume to the initial oil volume.

N: Initial oil volume in place [STm^3].

Np: Cumulative oil production in [STm^3].

OGIP: Original gas in place.

OOIP: Original oil in place.

P: Pressure [Psia].

Pb: Bubble pressure [Psia].

Pr: Tank pressure [Psia].

Rp: Production GOR [m^3 / m^3].

Rs: Dissolution GOR [m^3 / m^3].

Sw: Water saturation.

T: Tank temperature [$^{\circ}\text{F}$].

We: Cumulative water inlet [STm^3].

Wp: Cumulative water production [STm^3].

Winj: Quantity of water injected [STm^3].

WDI: Water Drive Index.

Vo: Volume of the oil.

Vr: Volume of impregnated rock.

Z: Compressibility factor.

μ_o : Density of oil.

$\emptyset$: Porosity [Fraction]

General Introduction

Accurate hydrocarbon reserve estimation is a fundamental aspect of reservoir engineering, as it provides the basis for field development planning, production forecasting, and economic evaluation. Because oil reservoirs are complex geological systems, reserve estimation is subject to uncertainties related to reservoir properties, fluid characteristics, production history, and reservoir drive mechanisms. Consequently, reliable engineering methods are required to reduce these uncertainties and support efficient reservoir management.

Among the available reserve estimation techniques, the material balance method is one of the most widely used due to its simplicity and practical application. Based on the principle of mass conservation, the material balance equation relates reservoir fluid expansion and external energy support to the production of oil, gas, and water. The method provides valuable information about reservoir performance, dominant drive mechanisms, and hydrocarbons initially in place. However, its accuracy depends on the availability of reliable pressure and production data, as well as a proper understanding of reservoir behavior.

The Hassi Messaoud field is one of the largest and most important oil fields in Algeria and has undergone different production stages since its development. Initially produced under natural depletion, the field was later supported by secondary recovery operations through water injection to maintain reservoir pressure and improve hydrocarbon recovery. Understanding the effects of these production mechanisms is essential for optimizing reservoir management and planning future field development.

The present study focuses on the application of the material balance method to Zone 12 of the Hassi Messaoud field. The main objectives are to analyze reservoir behavior, identify the dominant drive mechanisms, evaluate reservoir performance, and investigate the role of water injection in pressure maintenance and improved oil recovery. Material balance analysis, supported by MBAL software, provides an effective approach for integrating production and pressure data to better understand reservoir dynamics and support engineering decisions.

This thesis is organized into four chapters. Chapter I presents the geological and reservoir characteristics of the Hassi Messaoud field and Zone 12. Chapter II reviews the theoretical background of reservoir engineering and the main petrophysical and PVT properties required for reservoir evaluation. Chapter III describes the principles of the material balance method and the MBAL software used for reservoir analysis. Finally, Chapter IV presents the application of the material balance method to Zone 12, including reservoir performance evaluation and a development plan proposal based on water injection to enhance pressure support and improve recovery [7].

CHAPTER I

Geological situation of Hassi Messaoud Field

1.Field History

The Hassi Messaoud Oil Field was discovered by two distinct operators: **Compagnie Française des Pétroles Algérie (CFPA)** in the northern sector (OM, ON blocks), and **Société Nationale de Recherche et d'Exploitation des Pétroles en Algérie (SN Répal)** in the southern sector.

Exploration activities initiated by SN Répal in 1946 across the Algerian Sahara were followed, in 1949, by the acquisition of regional geophysical data, notably through gravimetric surveys aimed at delineating large-scale subsurface structures.

In 1951, the first seismic acquisition campaign (seismic shooting) was conducted in the Ouargla region. This early-stage reconnaissance of the Saharan basin margins enabled SN Répal, in association with CFPA, to formalize and submit the initial exploration permit applications.

The discovery of the Hassi Messaoud field was confirmed on January 16, 1956, by SN Répal, following the drilling of the exploration well MD1. The well was spudded and positioned based on interpretations derived from a seismic refraction survey. The MD1 well intersected hydrocarbon-bearing Cambrian sandstone reservoirs at a depth of 3,338 m MD, confirming the presence of a significant oil accumulation.

Subsequently, in May 1957, CFPA validated the field extension by drilling the OM1 well, located approximately 7 km northwest of MD1, thereby confirming reservoir continuity and lateral extension.

During the development phase between 1959 and 1964, a total of 153 wells were drilled and brought on stream, marking the transition to large-scale field exploitation. Following the Nationalization of Algerian hydrocarbons on February 24, 1971, drilling activity intensified significantly, reaching an average drilling rate of 34 wells per year by 1977.

Field development strategy initially focused on conventional vertical drilling targeting primary production zones until the year 2000. Starting from 1997, advanced development approaches were implemented, including the exploitation of structurally complex zones and reservoirs characterized by low matrix permeability (notably the Upper R2 reservoir unit), through the deployment of non-conventional drilling techniques such as directional and horizontal wells.

Production performance has been constrained by several flow assurance and reservoir management challenges, including inorganic scale deposition (salts), organic deposition (asphaltenes), as well as gas breakthrough and water breakthrough resulting from reservoir pressure support via water injection.

Surface facilities are composed of two major processing complexes designed to handle the full stream of produced hydrocarbons (oil, associated gas, and produced water), in addition to managing injection fluids required for secondary recovery operations [1].

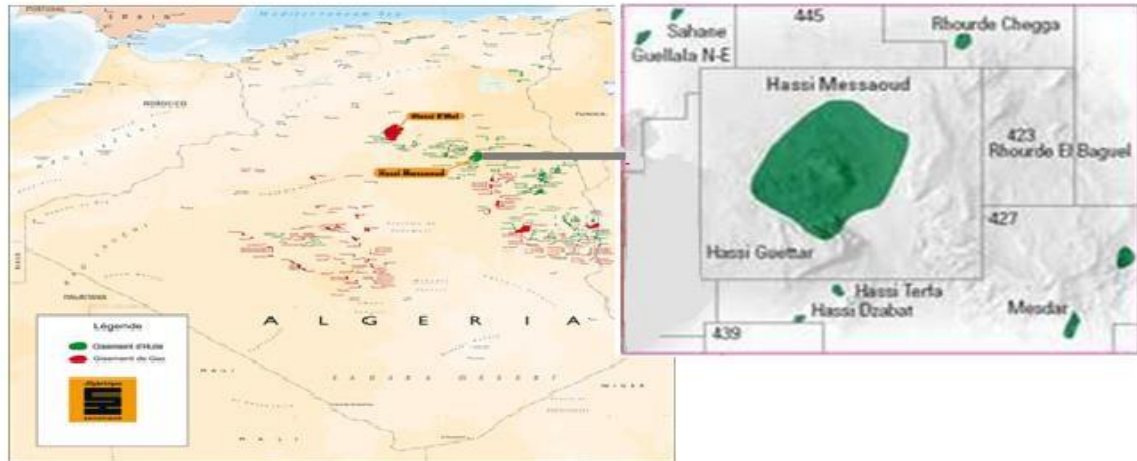


Figure I.1 : Field description [1]

2.Geographic location

The Hassi Messaoud Oil Field is located approximately 650 km south-southeast of Algiers and about 350 km from the Tunisia border. The field covers an approximate surface area of 2,500 km² [1].

Location Coordinates:

In the Lambert South Algeria coordinate system, the field is defined as follows:

X = [790,000 – 840,000] East

Y = [110,000 – 150,000] North

In geographical coordinates, the field boundaries are:

Northern limit: Latitude 32°15' N

Southern limit: Latitude 31°30' N

Western limit: Longitude 5°40' E

Eastern limit: Longitude 6°35' E



Figure I.2: Location of the Hassi Messaoud Basin [2]

3.Geological situation :

The Hassi Messaoud field is located in the central part of the Algerian Sahara, along the margin of the Great Eastern Erg.

In relation to surrounding oil and gas fields, Hassi Messaoud is bounded as follows :

- To the Northwest, it is bordered by the Ouargla fields (Guellala, Ben Kahla, and Haoud Berkaoui).
- To the Southwest, it is limited by the El Gassi, Zotti, and El Agreb fields.
- To the Southeast, it is adjacent to the Rhourde El Baguel and Mesdar fields.

From a regional geological standpoint, the field is structurally constrained by major tectonic and sedimentary features :

- To the West, the Oued Mya depression.
- To the South, the Amguid El Biod structural high (mole).
- To the North, the Djammâa–Tougourt structural trend.
- To the East, the Dahar highs, the Rhourde El Baguel area, and the Ghadames Basin depression [1].

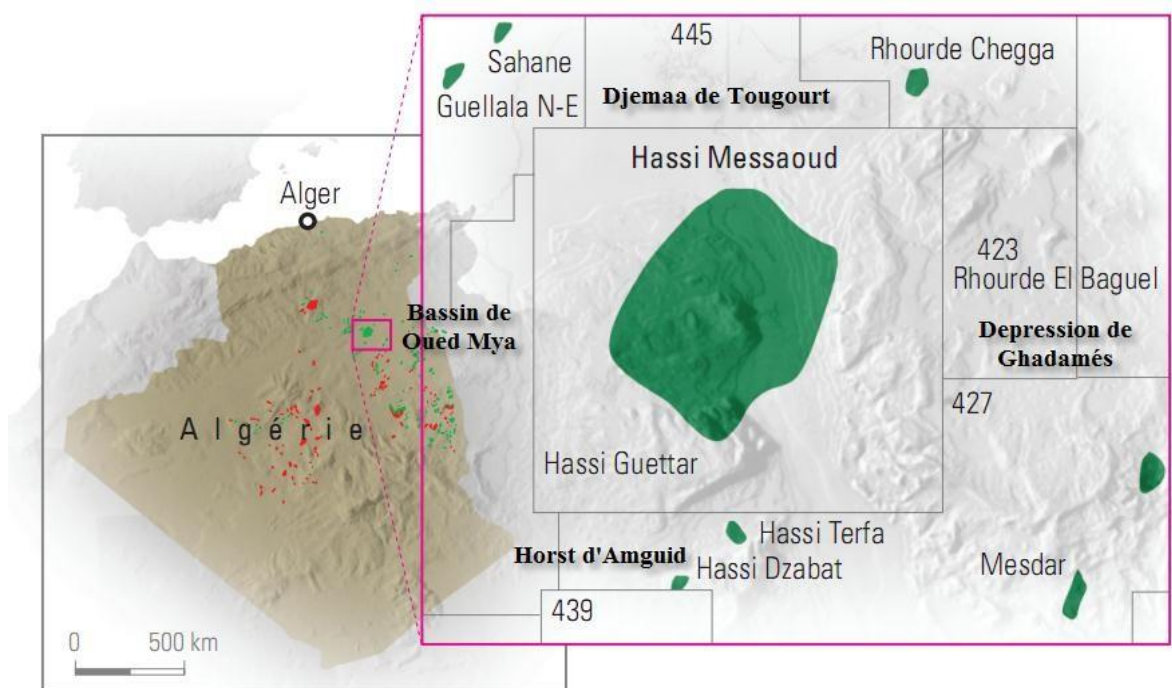


Figure I.3: Geological situation of Hassi Messaoud field (2007) [2]

4. Reservoir Description :

The reservoir is subdivided into four main units (lithozones), designated from bottom to top as R3, R2, Ra, and Ri.

The Ra interval extends from 3257 m to 3348 m, with a thickness of 91 m. It represents the main reservoir unit in its upper part. This interval is composed predominantly of quartzitic sandstones with medium anisometric grain size, irregularly interbedded.

The R2 interval extends from 3348 m to 3430 m, with a thickness of 82 m. It consists of quartzitic sandstones and locally micaceous quartzites, with a relatively abundant clay-rich cement.

4.1. Reservoir Characteristics:

The Hassi Messaoud field is characterized by a Cambro-Ordovician reservoir formation, located at depths ranging from 3361 m to 3473 m.

The crude oil is light, with an API gravity of 54.5°, and the reservoir exhibits a high initial pressure of approximately 482 kg/cm². The bubble point pressure ranges between 140 and 200 kg/cm².

4.2. Zones and Well Numbering:

At present, the field is divided into 25 production zones (see figure below). These zones are relatively independent and correspond to groups of wells that are in hydraulic communication and exhibit similar reservoir pressure behavior [1].

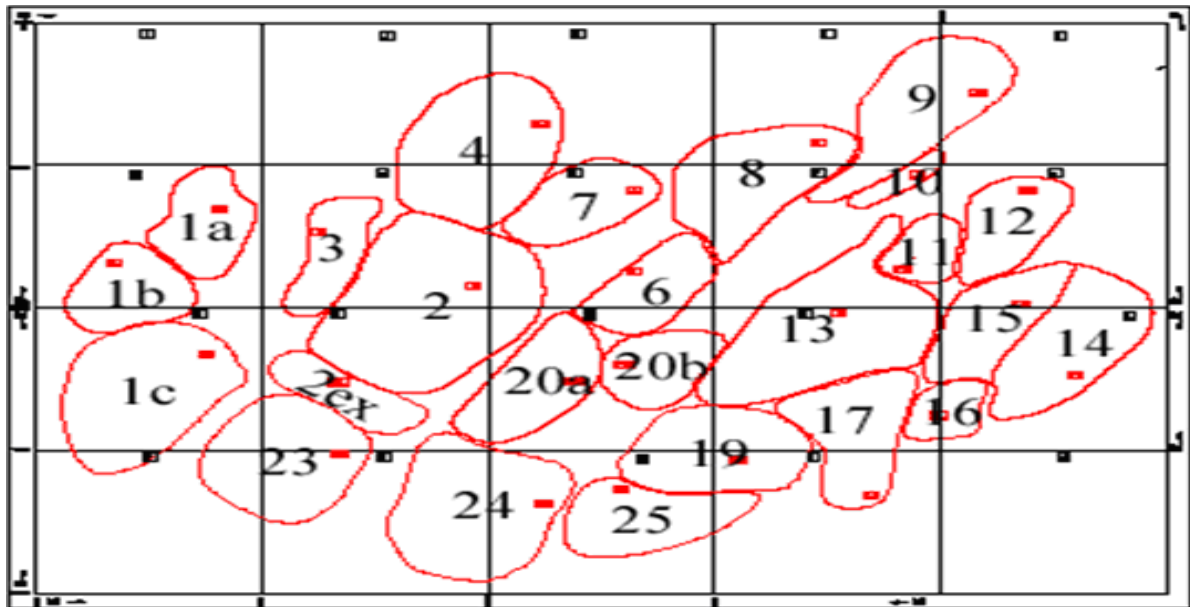


Figure I.4: Subdivision of Hassi Messaoud field [1]

5.Stratigraphy of the Hassi Messaoud Field:

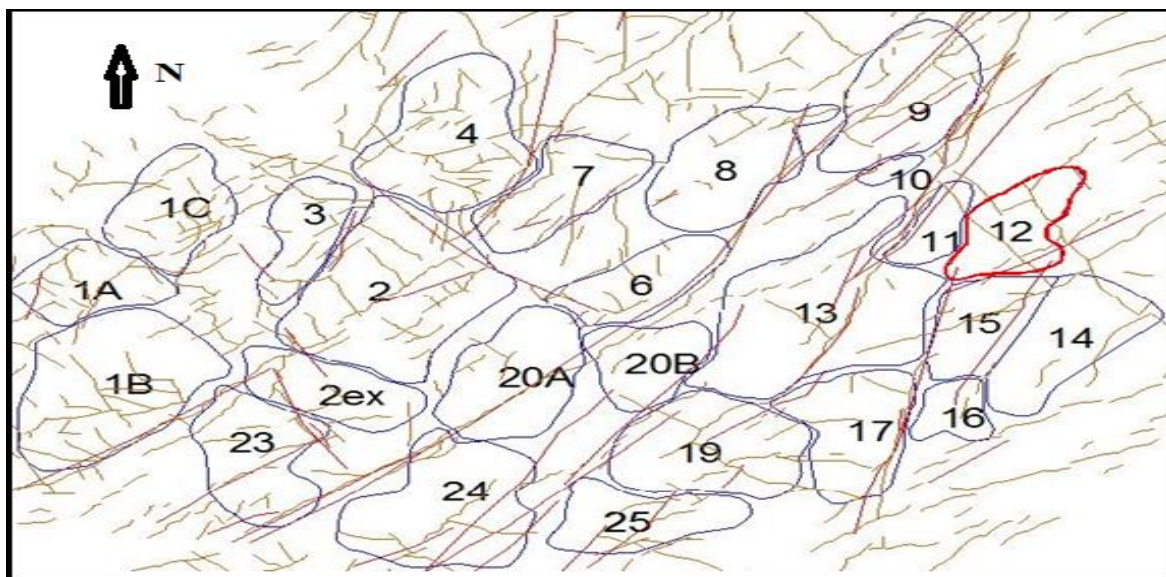
The stratigraphy of the Hassi Messaoud field is summarized in the following table:

ERE	SYST	ETAGES		Ep moy	DESCRIPTION	
CENO-ZOIQUE	NEOGENE	MIO-PLIOCENE discordance alpine		240	Sable, calcaire, marne sableuse	
		EOCENE		120	Sable, calcaire à silex	
MESOZOIQUE	CRETACE	SENONIEN	CARBONATE	107	Calcaire, dolomie, anhydrite	
			ANHYDRITIQUE	219	Anhydrite, marne, dolomie	
			SALIFERE	140	Sel massif et traces d'anhydrite	
		TURONIEN		90	Calcaire crayeux avec quelques niveaux argileux	
		CE NOMANIEN		145	Anhydrite, marne, dolomie	
		ALBIEN		350	Grés, sable avec intercalations d'argile silteuse	
		APTIEN		25	Dolomie cristalline avec niveau argileux, calcaire	
		BARREMIEN		280	Argile, grés, dolomie	
		NEOCOMIEN		180	Argile, marne, dolomie, grés	
		JURASSIQUE	MALM		225	Argile, marne, calcaire, grés et traces d'anhydrite
	DOGGER		ARGILEUX	105	Argile silteuse, marne dolomitique avec fines passées de grés	
			LAGUNAIRE	210	Anhydrite, marne dolomitique, marne grise	
	L I A S		L.D 1	65	Dolomie, anhydrite, argile	
			L.S 1	90	Alternances sel, anhydrite et argile	
			L.D 2	55	Anhydrite et dolomie cristalline	
			L.S 2	60	Alternances sel et argile	
			L.D 3	30	Alternances de dolomie et de marne	
	T R I A S		SALIFERE	TS 1	46	Alternances de sel, d'anhydrite et de dolomie
				TS 2	189	Sel massif à intercalations d'anhydrite et argile gypsifère
		TS 3		202	Sel massif et traces d'argile	
		ARGILEUX		113	Argile rouge dolomitique ou silteuse injectée de sel et d'anhydrite	
		GRESEUX		35	Grés, argile	
		ERUPTIF discordance hercynienne		0.92	Andésites altérées	
		PALEOZOIQUE	ORDOVICIEN	QUARTZITES D'EL HAMRA		75
	GRES D'EL ATCHANE			25	Grés fins à ciment argileux, bitumineux	
ARGILES D'EL GASSI				50	Argiles schisteuses, vertes ou noires, glauconieuses à graptolithes	
ZONE DES ALTERNANCES				20	Alternance de grés et argile. Présence de tigillites	
CAMBRIEN	Ri		50	Grés isométriques, fins, silteux		
	Ra		120	Grés à grés quartzitiques anisométriques à niveaux de silts		
	R2		100	Grés moyens à grossiers à ciment argileux illitique		
	R3		300	Grés grossier à ciment argileux, argile silteuse		
INFRA-CAMBRIEN			45	Grés argileux rouges		
S O C L E				Granite porphyroïde rose		

Table I.1: Stratigraphy of the Hassi Messaoud Field [1]

6.Presentation of Zone 12:

Zone 12 is located in the northeastern part of the Hassi Messaoud field. Its development began in 1959 with the drilling of well ONM13.



FigureI.5: Zone 12 location in The HMD field [9]

6.1.Structural setting :

Zone 12 exhibits a gentle dip toward the east. It is bounded to the south and east by two major faults.

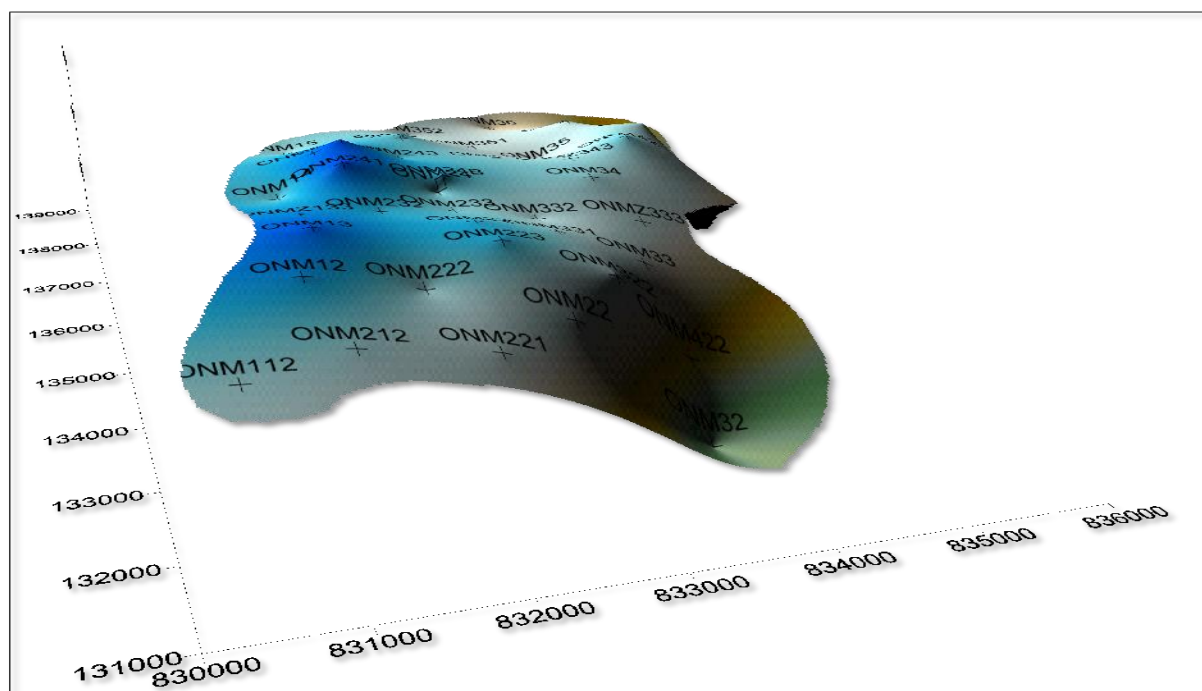


Figure I.6: Structural aspect of Zone 12 [9]

6.2. Reservoir Description :

D5, D4, and D3: Completely eroded.

D2: Strongly eroded; it remains only in the northeastern (NE) and southeastern (SE) parts of the zone.

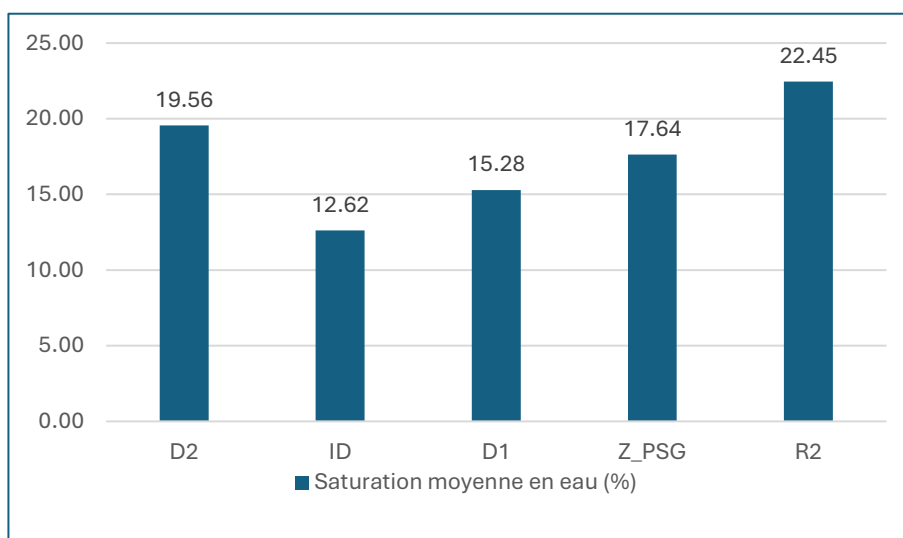
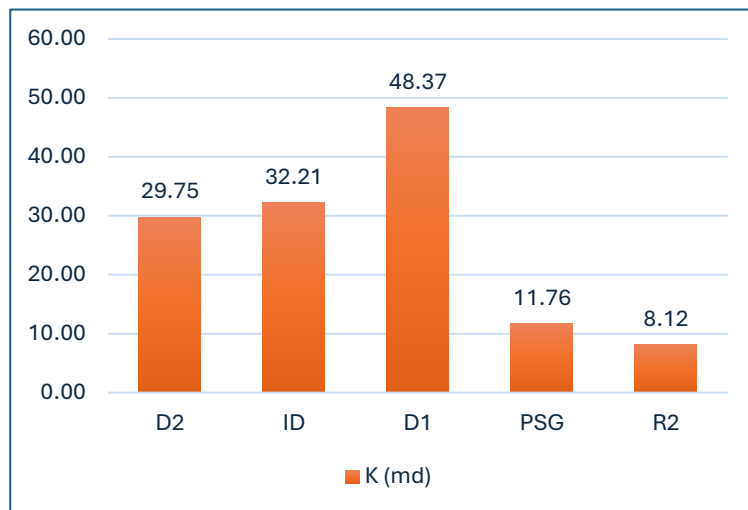
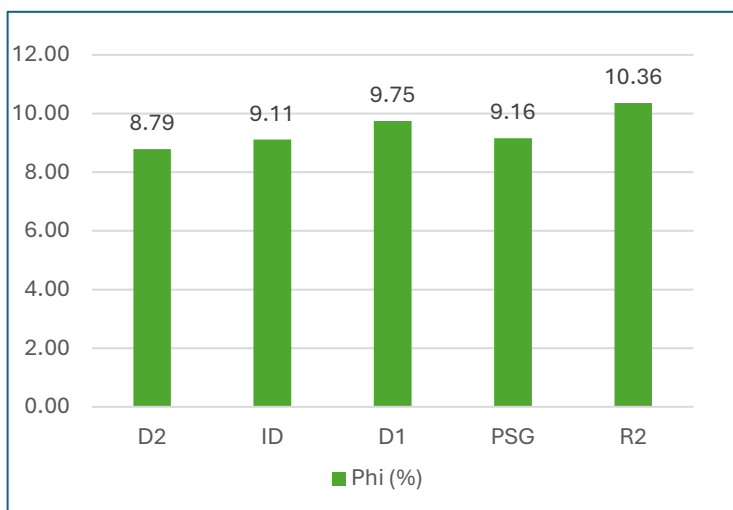
ID: Present across the entire zone, with thickness decreasing westward.

D1: The most significant producing interval in terms of reserves, with a considerable thickness ranging from 27 to 33 m.

Transition zone between Ra and R2: Approximately 6 m thick on average.

R2: Partially penetrated by numerous wells in the area, with an average thickness of about 80 m [9].

6.3. Petrophysical characteristics :



6.4. Production, Injection and Pressure History of Zone 12:

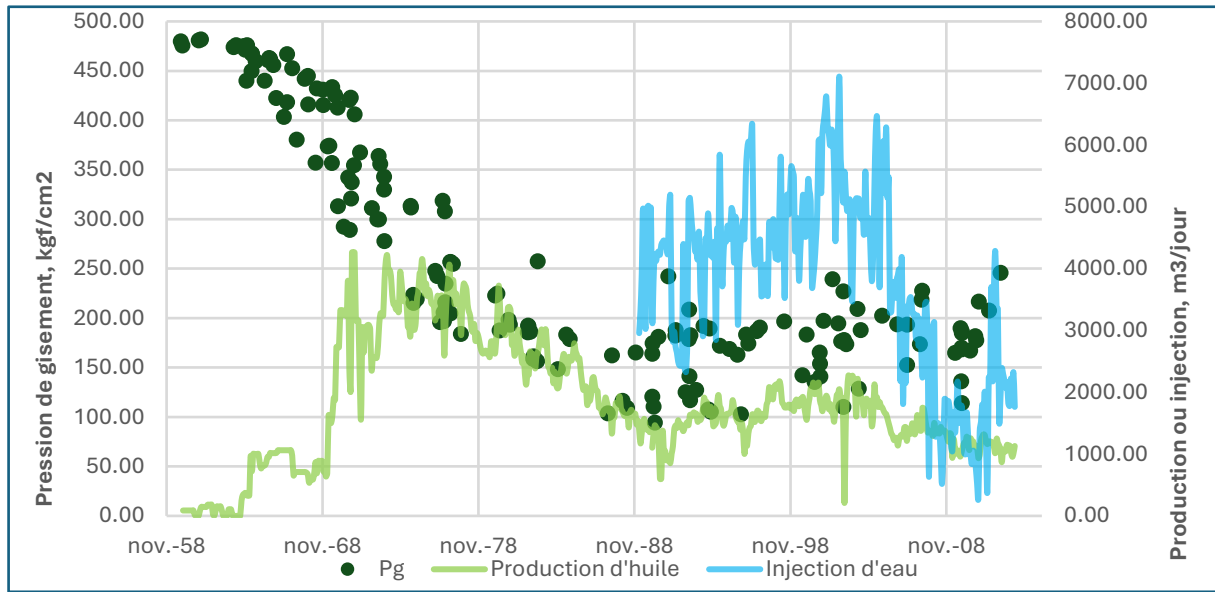


Figure I.7: Production, Injection and Pressure History of Zone 12 [9]

6.5. Zone 12 Composition:

a) Wells

- Oil Producing Wells (OP): **35 wells.**
- Abandoned wells: **5 wells.**
- Dry wells: **3 wells.**
- Water Injector Wells (WI): **14 wells.**
- Gas Injector Wells (GI): **0 wells.**

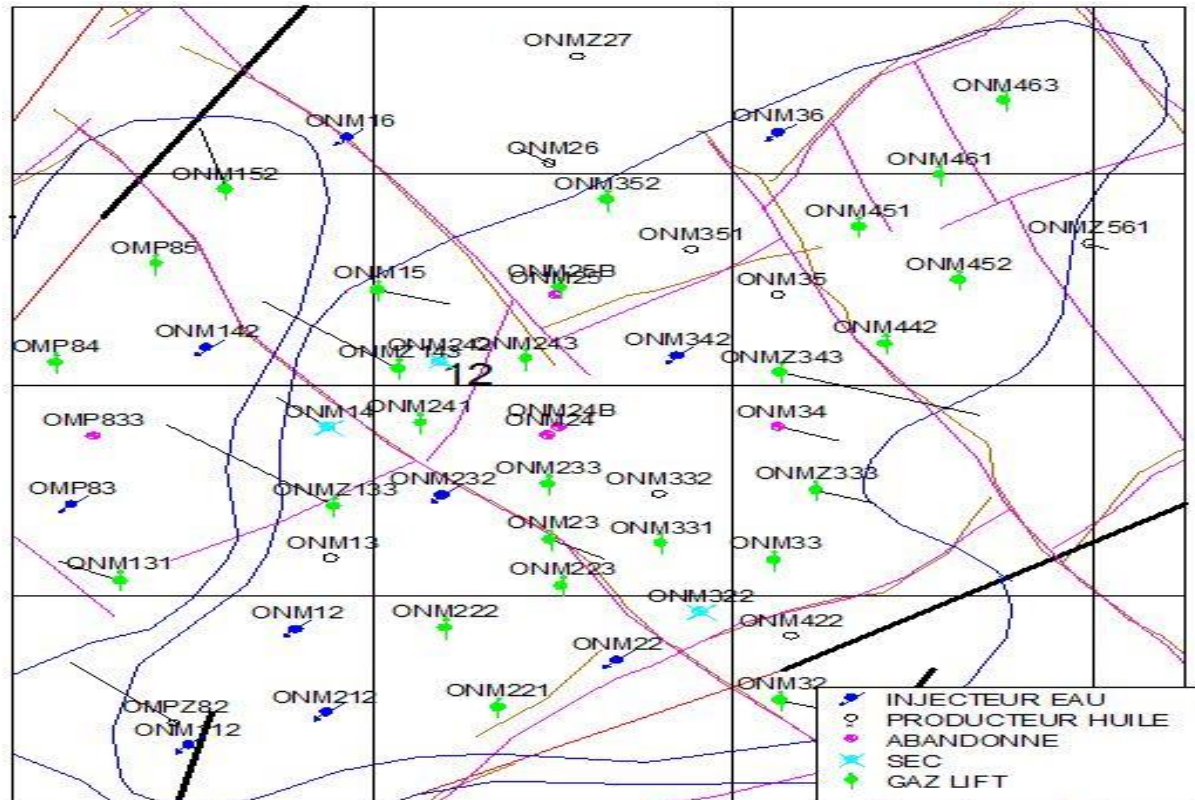


Figure I.8: Well Location and Geological Structure within Zone 12 [9]

CHAPTER II

Reserves Estimation Methods

1. Introduction:

The categories of **proved**, **probable**, and **possible** have for some time provided a basis for differentiating estimates of **reserves** to reflect the probability of recovery considered appropriate by the estimator. Stated in another way, the assignment of the estimate of reserves to the three categories has provided a qualitative measure of the probability that a particular estimate of reserves will, in fact, be realized. However, for some time there has been discussion as to whether a more rigorous approach should be adopted to describe the degree of probability associated with the specific reserves categories. Some observers view the use of terms such as "high degree of certainty" to describe reserves classification categories as too subjective, and believe a definitive statistical probability of recovery would give users more confidence in utilizing the estimates of reserves provided for each of the categories. For this reason, consideration has been given to a means to further quantify the degree of probability associated with each of the categories.

The probability ranges adopted by the Standing Committee on Reserves Definitions for the definitions of proved, probable, and possible reserves are intended to more explicitly quantify the probability of recovery associated with each of the reserves categories, both on an absolute and on a relative basis. The ranges provide an assessment that is more quantitative in nature than some prior definitions.

The estimation of initial in-place resources involves contributions from several disciplines, primarily geology, geophysics, petrophysics, and engineering, but contributions in varying degrees may also be required from specialists in chemistry, physics, economics, and other geological-engineering disciplines.

It is important that the size, or at least the range in size, of a potential resource be determined using consistent approaches and considering the interrelationships of the parameters used to make the estimate. The size of the resource forms the basis for the determination of how much oil, gas, and related products may ultimately be produced for society's use, and for the formulation of operation plans and the necessary business decisions.

Volumes of these discovered resources may be estimated by either a **volumetric** or a **material balance method** of calculation. These methods are described in chapter [7].

2. Reserves and Resources

The terms "reserve" and "resource" have specific meaning in petroleum qualification and therefore distinguishing between them is essential. Every reserve is indeed a resource, but not every resource is a reserve.

Resources are including quantities that are potentially recoverable but not yet marketable or discovered. Reserves are defined as the quantities recoverable from known deposits, under current economic and technical conditions.

Two requirements determine whether a resource becomes a reserve.

- The first is the degree of certainty that it exists.
- The second criterion relates to the economic feasibility of accessing and extracting the resource.

Whilst the original source of this concept — the American geologist Vincent McKelvey — visualized it as a static box, this transition between resources and reserve classifications is dynamic.

As we discover previously unknown resources and develop improved extraction technologies for economic recovery, this reserve box can grow with time. It can also shrink if we consume them at a faster rate than they're discovered.

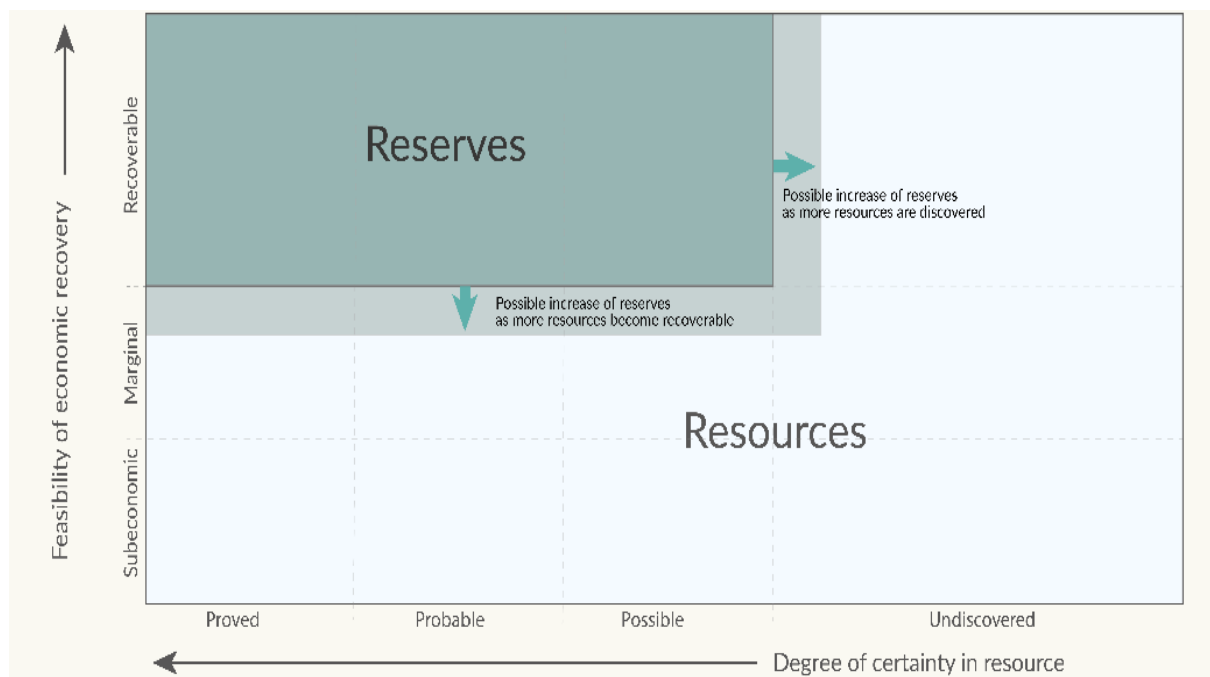


Figure II.1: Turns resources into reserves [3]

2.1. Resources classification:

Two subcategories:

2.1.1. Contingent :

Known deposits, but not yet mature enough for exploitation (e.g., technology under development, unviable market)

2.1.2. Prospective :

Undiscovered deposits, requiring future projects.

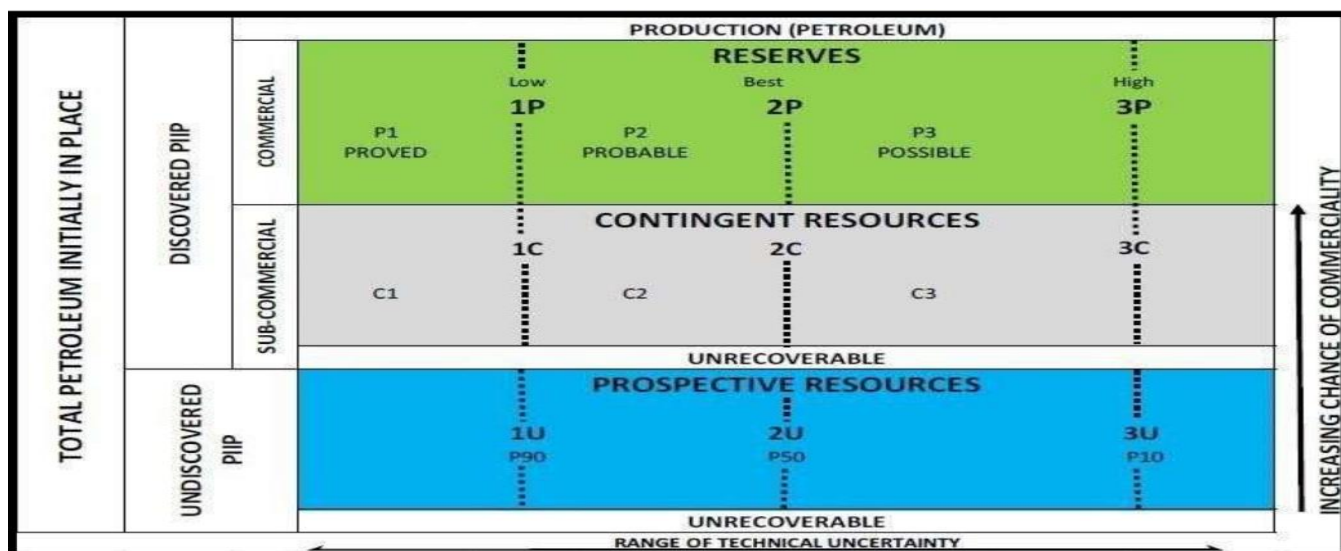


Figure II.2 : Resources Classification system Framework [3]

2.2. Reserves classification:

1. Proved (1P/P90): 90% probability.
2. Probable (2P/P50) : 50% probability.
3. Possible (3P/P10) : 10% probability.

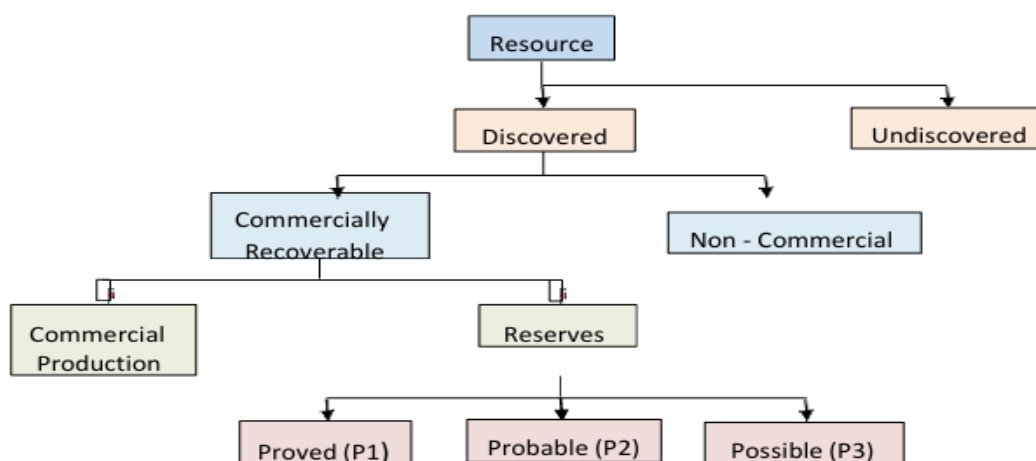


Figure II.3: Classification of resources and reserves [3]

3. Reserves Estimation Methods:

Reserves estimation can be categorized relating to pre- and post- production stages i.e. (static and dynamic). The static methods indicate the analogy and volumetric calculation that are used before production process in the reservoir and generally use geologic and engineering data; while dynamic methods involve performance techniques applied after production started in the field and typically need production data and pressure of the wells

3.1. Volumetric method:

The volumetric method is based on the assumption that the tank is a closed system, meaning that no fluid enters or leaves the tank. The method uses the following formula to estimate the original oil in place , It assimilates the deposit as a homogeneous block with isotopic petrophysical parameters. These parameters are measured by two methods: logging and coring. [3]

OIL

$$N = V_r * (H_u / H_t) * \phi_{moy} * (1 - S_{wmoy}) / B_o$$

N: Reserves in place (m3).

H_u: Average usable height of the rock (m).

H_t: Total average height of the rock (m).

V_r: Volume of rock containing hydrocarbons (m3).

Ø_{moy}: Average porosity of the rock (fraction).

S_{wmoy}: Average water saturation (fraction).

B_o: Oil volumetric factor (rb/stb).

The average values of the parameters H_u, S_w, and Ø are calculated for each well by the weighted average method as follow:

$$S_{wmoy} = \frac{\sum_{i=1}^n S_{wi} \cdot H_{ui} \cdot \phi_i}{\sum_{i=1}^n H_{ui} \cdot \phi_i}$$

$$\phi_{moy} = \frac{\sum_{i=1}^n H_{ui} \cdot \phi_i}{\sum_{i=1}^n H_{ui}}$$

$$H_{umoy} = \frac{\sum_{i=1}^n H_{ui} \cdot H_{ti}}{\sum_{i=1}^n H_{ti}}$$

❖ In Imperial units, the equation is as follows:

$$N = V_r * 7758 * \Phi * \frac{1}{B_o} * (1 - S_w)$$

Where N= oil in place (bbl) (1 acre foot = 7758 stb)

V_r = rock volume (acre feet) = $A \times h$

A = drainage area (acres)

h = average net pay thickness (ft)

Φ = porosity (fraction of rock volume)

B_o = formation volume factor (rb/stb)

S_w = water saturation (fraction)

NATURAL GAS

The in-place volume of natural gas is adjusted for temperature and pressure in order to measure volumes at standard surface conditions. The compressibility factor adjusts for the compressibility characteristics for different mixtures of natural gas components in changing from reservoir to surface conditions to account for the variance from the Ideal Gas Law [7].

Natural gas resources may be classified as follows:

- Solution gas
- Associated gas (gas cap)
- Non associated gas

Solution gas is the gas liberated from oil produced from a reservoir. The rate of production of solution gas depends on the rate of oil production, the relative flow characteristics of the reservoir fluids, and the state of depletion of the reservoir.

For calculation of initial solution gas in place, G_s , the following equation is used:

$$G_s = N * R_{si}$$

Where G_s = solution gas in place (m3)

N = oil in place (m3)

R_{si} = gas in solution at P_i (m3/m3) / P_i = original reservoir pressure (kPa)

In imperial units: G_s (scf) / N (stb) / R_{si} (scf/stb) / P_i (psia)

Associated gas is the gas associated with an oil reservoir as a gas cap. Most, if not all, of the energy in the gas cap is required for maximum oil recovery, so associated gas reserves usually remain shut in until most of the oil reserves have been produced [7].

Non associated gas is gas that is not associated with an oil reservoir. Production is limited only by market availability and contract terms.

For the calculation of non-associated and gas cap in-place volumes, the following equation is used:

$$G = Vr * \Phi * (1 - Swi) * \frac{Tsc}{Psc * Tf} * \frac{Pi}{Zi}$$

Where G = raw gas in place (m3)

Vr = rock volume (m3) = $10^4 * A * h$

A = drainage area (ha) (1ha = 10^4 m^2)

h = average net pay thickness (m)

Φ = porosity (fraction of pore volume)

Sw = water saturation

Tsc = standard base temperature (°K)

Psc = standard base pressure (kPa)

Tf = formation temperature (°K)

Pi = original reservoir pressure (kPa)

Zi = gas compressibility factor at Pi and Tf

In Imperial units, the equation is as follows:

$$G = Vr * 43,560 * \Phi * (1 - Swi) * \frac{Tsc}{Psc * Tf} * \frac{Pi}{Zi}$$

Where: G (scf) / Vr (acre feet) / Tsc, Tf (°Rankine) / Psc, Pi (psia)

3.1.1. Petrophysical parameters

3.1.1.1. Porosity:

It is the fraction of the volume of voids in relation to the total volume of the rock [12].

$$\emptyset = \text{volume of voids} / \text{volume of the rock}$$

$$\emptyset = V_p / V_t = (V_t - V_s) / V_t = (1 - V_s) / V_t$$

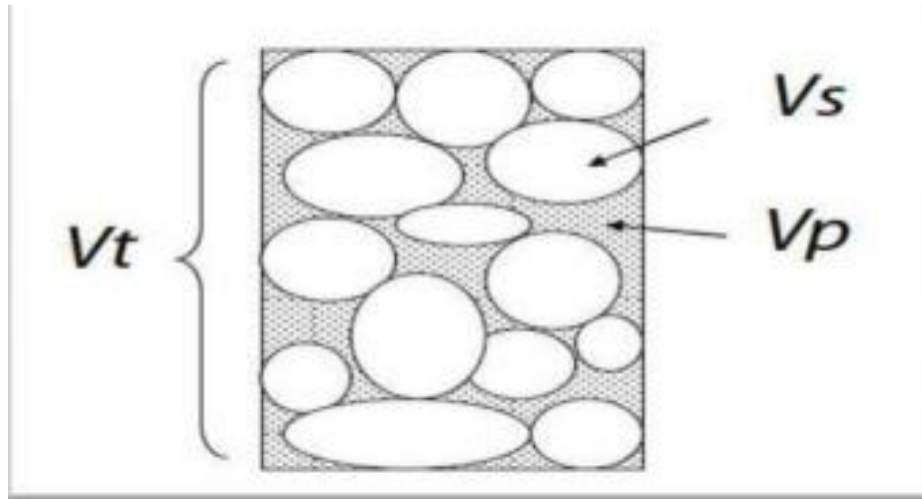


Figure II.4: The different volumes in the rock [11]

3.1.1.2. Types of porosity:

3.1.1.2.1. Effective porosity:

Designates the volume of interconnected pores allowing the circulation of fluids (oil, gas, water)

3.1.1.2.2. Residual porosity:

Corresponds to isolated pores without connection to the main pore network

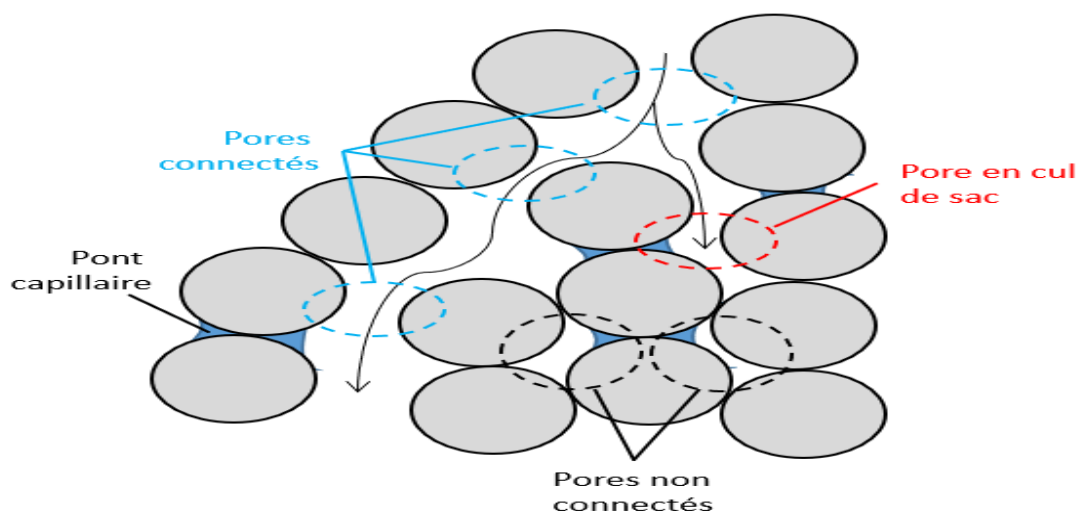


Figure II.5: Types of porosity [11]

3.1.1.3. Measurement methods:

For porosity measurement there are two methods coring or logging:

3.1.1.3.1. Coring:

Coring involves taking rock or soil samples from a vertical borehole in the soil or rock. These samples provide information about the geological composition, structure, texture, porosity, and permeability of geological formations [12].



Figure II.6: Coring [10]

3.1.1.3.2. Logging:

Logs are recorded during a shutdown or at the end of drilling, and the measured parameters are only accessible after a certain delay in the drilling execution, hence the name delayed logging [12].

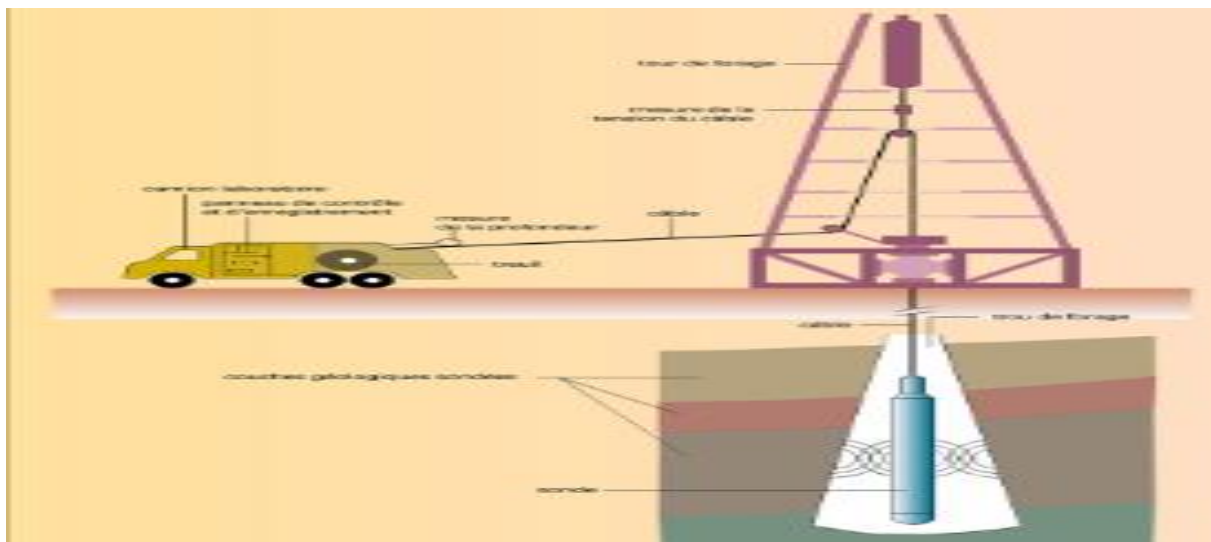


Figure II.7: Logging

3.1.1.4. A comparison between coring and logging:

Method	Coring	Logging
Principle	Extraction of a rock sample for laboratory analysis	In-situ measurement of the physical properties of the rock using probes
Measure	Direct	Indirect
Precision	Very high	Medium to high, depends on tool and calibrations
Measurement conditions	Controlled conditions	Natural conditions
Type of tools used	Corers, laboratory analyzers (porosimeters, permeameters)	Nuclear, acoustic, neutron, gamma, electrical logging tools
Main use	Detailed studies and calibration of logs	Global reservoir mapping and assessment

Table II.1: Measurement of porosity [12]**3.1.1.5. Saturation:**

The saturation of a fluid in a reservoir rock is expressed by the volume fraction of the fluid relative to the total porosity [13].

$$S = V_f / V_p$$

V_f : fluid volume

V_p : pore volume

The oil, water and gas saturations are:

Oil saturation = oil volume / pore volume

Gas saturation = gas volume / pore volume

Water saturation = water volume / pore volume

3.1.1.6. Measurement methods:

By the coring or logging:

Method	Coring	Logging
Principal	Extraction and analysis of fluids by physical or chemical methods	Indirect estimation by measurement of electrical or nuclear properties
Saturation measured	Saturation of water (S_w), oil (S_o), gas (S_g)	Saturation mainly in water (S_w) and estimation of S_o , S_g
Precision	Very high	Medium
Effect of salinity	No impact	Strong impact on resistivity logs
Main use	Detailed studies and calibration of logs	Reduced accuracy in complex environments

Table II.2: Measurement of saturation [12]

3.2. Material Balance method:**3.2.1. Concept of material balance:**

The material balance equation is one of the fundamental equations a reservoir engineer for :

- ❖ Determining the initial hydrocarbon in place.
- ❖ Predicting an overall recovery factor.
- ❖ Determining reservoir drive mechanism.

Material balance simply compares the original volumes at initial reservoir pressure to the current volumes at a lower pressure. It is zero dimensional, meaning that it compares the initial state to the current state and nothing else. The concept of material balance is easy to understand if viewed as an expanding piston. A conceptual view of material balance is presented in the figure below [3]:

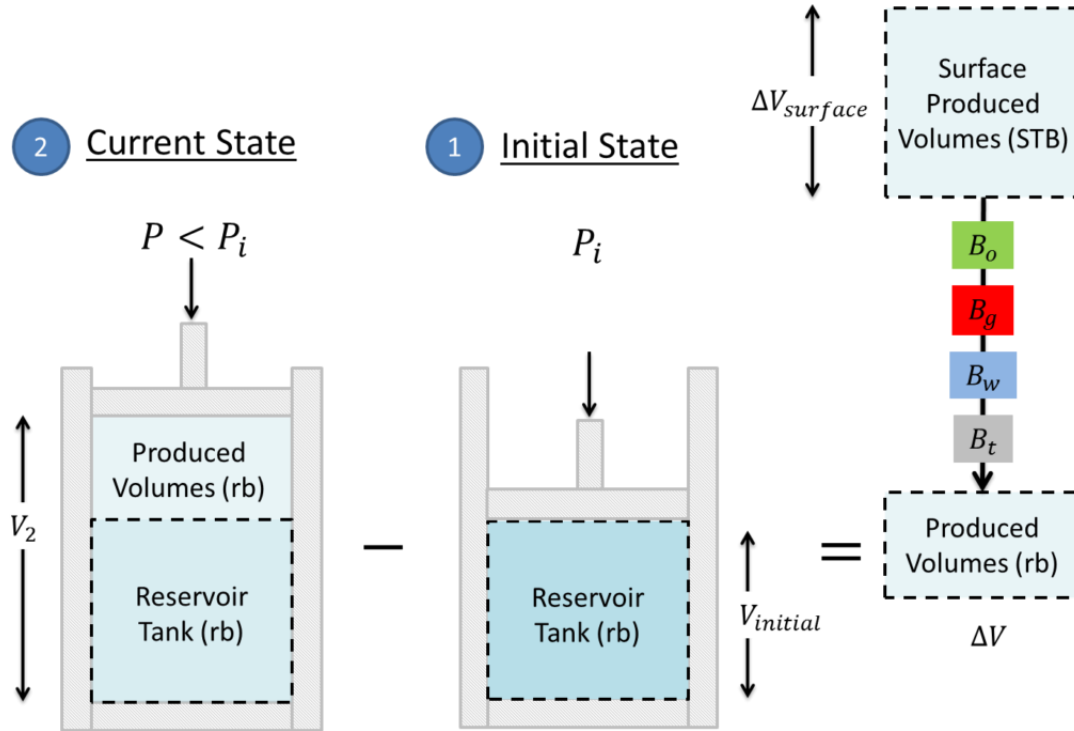


Figure II.8: The concept of material balance equation [3]

3.2.2. The derivation of the Material Balance Equation:

Before starting for driving material balance equation (MBE) it is necessary to identify some expressions:

- Defining the ratio m as:

$$m = \frac{\text{Initial volume of gas cap}}{\text{Volume of oil initially in place}} = \frac{G B_{gi}}{N B_{oi}}$$

- Solving the volume of the gas cap gives:

$$\text{Initial volume of the gas cap} = G B_{gi} = m N B_{oi}$$

- The total volume of the hydrocarbon system is then given by:

$$\text{Initial oil volume} + \text{initial gas cap volume} = N B_{oi} + G B_{gi} = PV (1 - S_{wi})$$

Then, the general form of MBE can be written as follows:

$$N B_{oi} + m N B_{oi} = PV (1 - S_{wi}) \quad \text{or} \quad PV = \frac{N B_{oi} (1+m)}{1-S_{wi}} \quad (2-1)$$

$$\begin{aligned}
 & \left(\begin{array}{c} \text{Pore volume} \\ \text{occupied} \\ \text{by the} \\ \text{initial oil in place} \\ \text{at initial } p \end{array} \right) + \left(\begin{array}{c} \text{Pore volume} \\ \text{occupied} \\ \text{by the gas} \\ \text{in the gas cap} \\ \text{at initial } p \end{array} \right) = \left(\begin{array}{c} \text{Pore volume} \\ \text{occupied} \\ \text{by the} \\ \text{remaining} \\ \text{oil at } p \end{array} \right) + \left(\begin{array}{c} \text{Pore volume} \\ \text{occupied} \\ \text{by the gas} \\ \text{in the gas cap} \\ \text{at } p \end{array} \right) + \\
 & \left(\begin{array}{c} \text{Pore volume} \\ \text{occupied by} \\ \text{the evolved} \\ \text{solution gas} \\ \text{at } p \end{array} \right) + \left(\begin{array}{c} \text{Pore volume} \\ \text{occupied by} \\ \text{the net water} \\ \text{influx} \\ \text{at } p \end{array} \right) + \left(\begin{array}{c} \text{Reduction} \\ \text{in pore volume} \\ \text{due to connate} \\ \text{water expansion} \\ \text{and rock expansion} \end{array} \right) + \\
 & \left(\begin{array}{c} \text{Pore volume} \\ \text{occupied by} \\ \text{the injected gas} \\ \text{at } p \end{array} \right) + \left(\begin{array}{c} \text{Pore volume} \\ \text{occupied by} \\ \text{the injected water} \\ \text{at } p \end{array} \right).
 \end{aligned}$$

Figure II.9: The total volume of the hydrocarbon system [3]

The above terms formulate the MBE as follows:

♦ **Pore volume occupied by the Initial oil in place:**

$$\text{Volume occupied by initial oil in place} = N B_{oi} \quad (2-2)$$

♦ **volume occupied by the Initial Gas in the Gas Cap:**

$$\text{Volume of gas cap} = m N B_{oi} \quad (2-3)$$

♦ **Pore volume occupied by the remaining oil:**

$$\text{Volume of the remaining oil} = (N - N_p) B_o \quad (2-4)$$

♦ **Pore volume occupied by the gas in the gas cap at P:**

As the reservoir pressure (p_i) decreases to a lower pressure (p) because of the production, the gas in the gas cap enlarges and fills a large space. Assuming no gas produced from the gas cap during the pressure drop from p_i to p , then the gas cap volume can be calculated as:

[3]

$$V_{g \text{ at } p} = \left[\frac{m N B_{oi}}{B_{gi}} \right] B_g \quad (2-5)$$

♦ **Pore Volume occupied by the Evolved Solution Gas at P:**

This term can be calculated by using the material balance on the solution gas:

$$\begin{aligned} & \text{volume of} & \text{volume of gas} & \text{volume of} & \text{volume of} \\ & (\text{The evolved solution gas}) = & (\text{initially in solution}) - & (\text{gas produced}) - & (\text{gas remained}) \\ & \text{Volume of the evolved solution gas} = [NR_{si} - N_p R_p - (N - N_p) R_s] B_g \end{aligned} \quad (2.6)$$

♦ **Volume occupied by the Net Water Influx:**

$$\text{Net water influx} = W_e - W_p B_w \quad (2.7)$$

♦ **Reduction in Pore Volume due to Initial Water and Rock Expansion:**

The components describing the change in hydrocarbon pore volume (HCPV) due to the expansion of initial water and reservoir matrix are the water compressibility (C_w) and rock compressibility (C_f) which of the same significance as the compressibility of oil.

The compressibility coefficient c , which identify the change in the volume of the reservoir fluid or formation matrix with changing pressure is based on the general expression of law isothermal compressibility: [4]

$$c = \frac{-1}{V} \left(\frac{\partial V}{\partial P} \right)_T$$

$$\text{Connate water expansion} = [(pore\ volume) S_{wi}] C_w \Delta p$$

Then, by substitute in pore volume PV equation (2-2) gives:

$$\text{Expansion of connate water} = \frac{N B_{oi} (1+m)}{1-S_{wi}} \cdot S_{wi} \cdot C_w \cdot \Delta P \quad (2-8)$$

Similarly, the reduction in the pore volume due to the expansion of the reservoir rock is given by:

$$\text{Change in pore volume} = \frac{N B_{oi} (1+m)}{1-S_{wi}} \cdot C_f \cdot \Delta P \quad (2-9)$$

Where C_f = Formation compressibility coefficient, psi^{-1}

By combining the connate water and the formation rock in equation (2.8) and (2-9) it gives:

$$\text{Total Changes in pore volume} = N B_{oi} (1 + m) \left(\frac{S_{wi} \cdot C_w + C_f}{1-S_{wi}} \right) \cdot \Delta P \quad (2-10)$$

♦ **Pore Volume occupied by the Injection Gas and Water:**

Assuming that G_{inj} and W_{inj} are the volume of gas and water respectively, that have been injected for pressure problems, then the total pore volume occupied by the two fluids is given by: [4]

$$\text{Total volume} = G_{inj} B_{ginj} + W_{inj} B_w \quad (2-11)$$

Linking equations from (2-4) to (2-11) and solving for N after rearranging them

$$N = \frac{N_p B_o + (G_p - N_p R_s) B_g - (W_e - W_p B_w) - G_{inj} B_{inj} - W_{inj} B_w}{(B_o - B_{oi}) + (R_{si} - R_s) B_g + m B_{oi} \left[\frac{B_g}{B_{gi}} - 1 \right] + B_{oi} (1 + m) \left[\frac{S_{wi} C_w + C_f}{1 - S_{wi}} \right] \Delta p} \quad (2.12)$$

This expression is known as the Material Balance Equation (MBE).

A more convenient form of the MBE can be determined by introducing the concept of the total (two-phase) formation volume factor B_t into the equation.

This oil PVT property is defined as:

$$B_t = B_o + (R_{si} - R_s) B_g$$

Introducing B_t into equation (2.12) and assuming, for the sake of simplicity, no water or gas injection gives: [4]

$$N = \frac{N_p [B_t + (R_p - R_{si}) B_g] - (W_e - W_p B_w)}{(B_t - B_{ti}) + m B_{ti} \left[\frac{B_g}{B_{gi}} - 1 \right] + B_{ti} (1 + m) + \left[\frac{S_{wi} C_w + C_f}{1 - S_{wi}} \right] \Delta p} \quad (2.13)$$

3.2.3. Material Balance Expressed as an Equation of Straight line:

Havelena and Odeh (1963, 1964) presented two publications described the theory of material balance as an equation of straight line. The first paper interpreting the theory of material balance as an equation of straight line; while, the second paper illustrates the consistent material balance equation with six reservoir scenarios.

They established a linear formula by assuming terms to the different components of the volume change of balance equation. [5]

The straight-line equation begins with the Oil Material Balance Equation (OMBE) expression written as:

$$\begin{aligned} N_p[B_o + (R_p - R_s) B_g] + W_p B_w = N[(B_o - B_{oi}) + (R_{si} - R_s)B_g] + m N B_{oi} \left[\frac{B_g}{B_{gi}} - 1 \right] + \\ N B_{oi} (1 + m) \left[\frac{S_{wi} C_w + C_f}{1 - S_{wi}} \right] \Delta p + W_e + G_{inj} B_{ginj} + W_{inj} B_w \end{aligned} \quad (2-14)$$

Havelena and Odeh expressed Equation (2-14) in straight line equation form as: [5]

$$F = N [E_o + m E_g + E_{f,w}] + (W_e + W_{inj} B_w + G_{inj} B_{ginj}) \quad (2-15)$$

The terms F , E_o , E_g and $E_{f,w}$, are identified by the following relationships illustrated below:

F expresses the underground withdrawal (production term).

$$F = N_p [B_o + (R_p - R_s) B_g] + W_p B \quad (2-16)$$

E_o is the term which represent the expansion of oil and its originally dissolved gas and it is defined in terms of oil formation volume factor.

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s) B_g \quad (2-17)$$

E_g is the term defined the expansion of the gas – cap gas and is expressed in the following equation:

$$E_g = B_{oi} \left[\frac{B_g}{B_{gi}} - 1 \right] \quad (2.18)$$

$E_{f,w}$ identify the expansion of the initial water and change in the pore volume as given below:

$$E_{f,w} = B_{oi} (1 + m) \left[\frac{S_{wi} C_w + C_f}{1 - S_{wi}} \right] \Delta P \quad (2.19)$$

CHAPTER III

Different solutions of MBAL Equation

1. Oil Material Balance:

As seen in the general material balance equation there are many unknowns, and as a result finding an exact or unique solution can be difficult. However, using other techniques to help determine some variables (for example, m or original gas-in-place from volumetric or seismic), the equation can be simplified to yield a more useful answer. Various plots are available to conduct an oil material balance rather than calculating an answer from individual measurements of reservoir pressure.

1.1. History Matching

1.1.1. Graphical method

❖ Havlena-Odeh (All Reservoir Types)

Similar to the interpretation of gas material balance, oil material balance uses plotting techniques. However, unlike the equation for single-phase gas expansion, the standard form of the material balance equation for oil reservoirs does not easily yield a linear relationship. The equation can be organized to show linear behavior. Based on the rearrangement below, the large combinations of terms are used as x and y while G is the slope and N is the intercept. This of course implies that water influx term for each data point is a known value, or the simpler scenario that there is no water influx. Additionally, if the water influx is neglected in calculating the terms the result will be non-linear behavior on the plot. This can be a diagnostic to determine the presence of water drive. In practice, the scatter in the data may be great enough and the signature of water drive subtle enough that deviation from linear behavior on the Havlena-Odeh plot may go unnoticed [6].

$$\frac{F - W_e B_w}{E_o + B_{oi} E_{fw}} = N + G \left(\frac{E_g + B_{gi} E_{fw}}{E_o + B_{oi} E_{fw}} \right) \quad (3.1)$$

An example of the plot is shown below. The scatter shown in the data points demonstrates the difficulty in determining trends in the reservoir behavior.

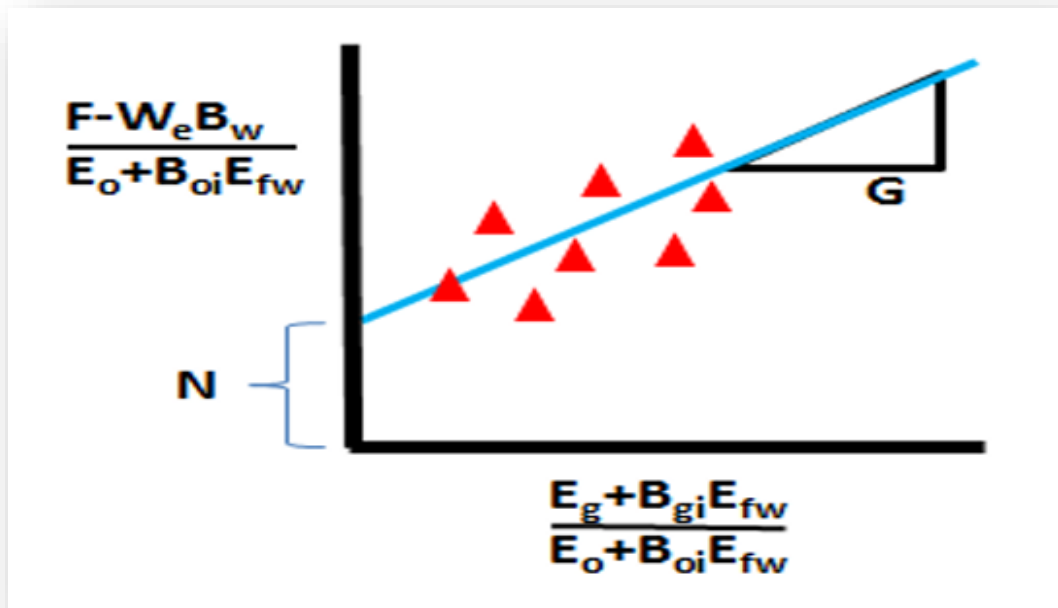


Figure III.1: Havlena-Odeh (All reservoir types) [6]

❖ $F - We$ vs. Et (No Initial Gas Cap)

If the reservoir to be analyzed has no initial free gas, the free gas terms of the equation can be eliminated. This equation is now much simpler to linearize. In the equation shown below, the total expansion term is split into the oil and water / formation expansion terms. Once again, the inclusion of water influx is such that it is assumed to be known.

$$F - WeB_w = N(E_o + B_{oi}E_{f,w}) \quad (3.2)$$

In this form of the equation, N is the slope on a plot of expansion terms versus withdrawal and influx terms. There is no intercept so the analysis line is typically forced through zero. Similar to the Havlena-Odeh plot that includes gas terms, if water influx is neglected and a non-linear trend results, this can be a diagnostic for observing water drive effects. An example of the plot is shown below.

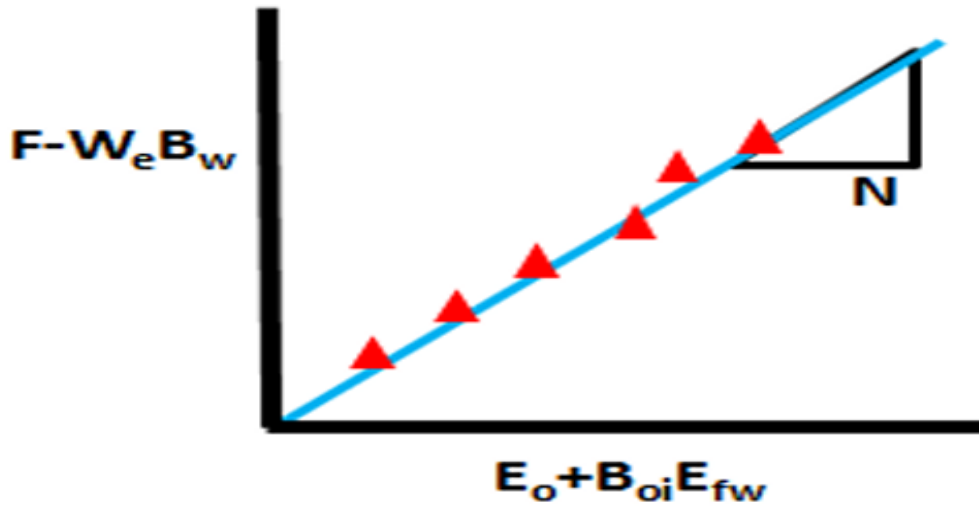


Figure III.2: Havlena-Odeh (No initial Gas Cap) [6]

❖ F/Et vs We/Et - Havlena-Odeh (water Drive)

This method is used in MBAL to estimate the Original Oil in Place (OOIP) when a reservoir has a significant water drive (aquifer influence) [5].

It comes from the rearranged material balance equation for an oil reservoir with an aquifer:

$$F = N.Et + We$$

Dividing both sides by Et :

$$\frac{F}{Et} = N + \frac{We}{Et} \quad (3-3)$$

So when you plot $\frac{F}{Et}$ vs $\frac{We}{Et}$, you get a straight line:

- Slope = 1
- Y-intercept = N (OOIP)

The Y-intercept on the graph is used to estimate the amount of oil originally in place.

Application :

1. **Check aquifer influence:** If the data align linearly, it confirms that your **aquifer model is appropriate**.
2. **Estimate OOIP:** The intercept of the best-fit line gives you the estimated OOIP.
3. **Validate model in MBAL:** A good linear match means your aquifer and PVT data are consistent with observed production.

❖ Havlena-Odeh (Material Balance Equation - Graphical Form)

The Havlena–Odeh method is a graphical technique used in petroleum engineering to analyze reservoir performance and estimate Original Oil In Place (OOIP). It is based on rearranging the general material balance equation for different reservoir drive mechanisms [5].

What the graph shows :

- **Y-axis (vertical):** $\frac{F}{Et}$
→ The ratio of total cumulative production energy (F) to total expansion energy (Et).
- **X-axis (horizontal):** $\sum \left[\frac{dP \cdot Q(t_D)}{Et} \right]$
This is a **summation of pressure drops weighted by production rate over time**, normalized by expansion.

This plot is typically used when a reservoir has a **strong aquifer drive** or a **complex drive mechanism**.

The Havlena–Odeh approach generalizes the material balance equation into a linear form like:

$$\frac{F}{Et} = N + C \cdot \sum \left[\frac{dP \cdot Q(t_D)}{Et} \right]$$

Where:

(3-4)

F: cumulative production (energy term)

Et: total expansion term

N: **OOIP** (intercept of the graph)

C: slope of the line, often related to aquifer characteristics or compressibility

Q: production rate as a function of time.

Application :

1. **Graphical fitting:** The method provides a **line fit** to validate production data against drive mechanisms.
2. **OOIP estimation:** The **intercept of the fitted line** represents the original oil in place.
3. **Model calibration:** A good fit indicates that the reservoir and aquifer models are consistent with historical production data.

❖ (F - We) / Et vs F – Campbell Method

The **(F - We) / Et vs F graph**, also known as the **Campbell method**, is a graphical approach used in reservoir engineering to analyze field performance by applying the material balance equation.

The general material balance equation can be rearranged as follows [5]:

$$\frac{F - W_e}{E_t} = f(F) \quad (3.3)$$

where **(F - We) / Et** is plotted as a function of **F**.

This graphical method is used to **identify the primary reservoir energy drive mechanism** (expansion, aquifer influx, etc.).

The shape and slope of the curve indicate whether the **aquifer influx is significant or not**.

Graph interpretation

- **If the curve is linear with a constant slope**, this indicates **uniform fluid and rock expansion** without significant water influx.
- **If the curve deviates from a straight line**, it suggests that the aquifer is contributing to the reservoir's energy.
- **A decreasing slope** indicates an **increase in aquifer support**.

❖ F/Et vs F – Campbell Method (Without Aquifer Influence)

When applied **without aquifer influence**, it assumes that the reservoir energy comes only from **fluid and rock expansion**, without additional water influx [5].

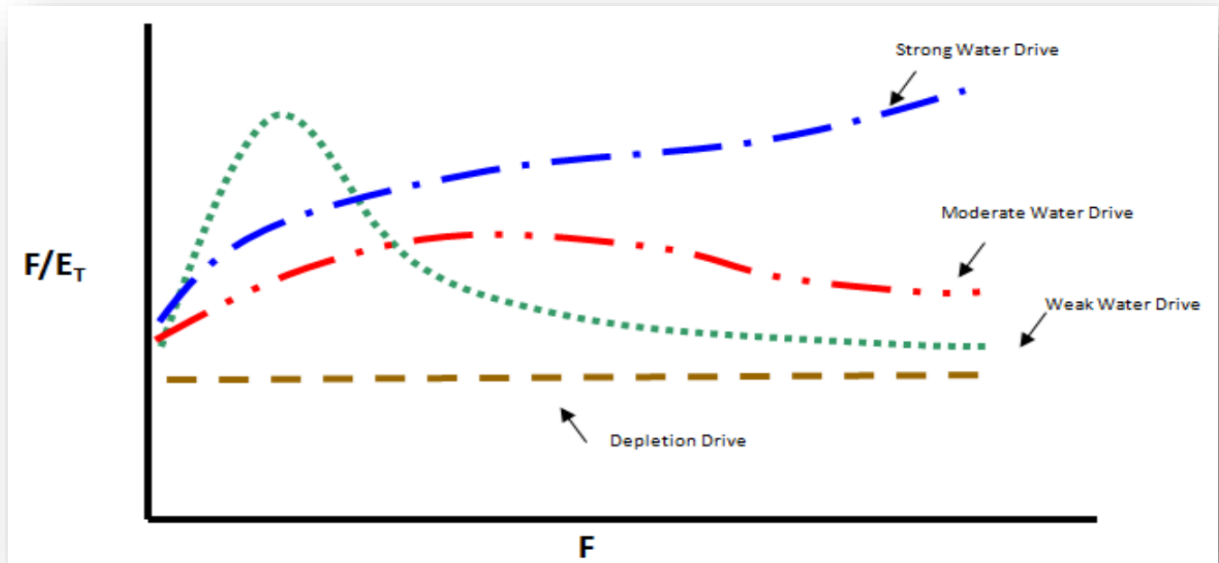


Figure III.3: Campbell plot [6]

1.1.2. Analytical method

Analytical method is used to assess the regression match between observed/measured data used to construct this model. The value of this match is represented by the standard deviation between model obtained by MBAL software and measured used data. Figure (III-3) illustrates Analytical approach for X oil field; the red line clarifies the simulator running without aquifer influx while the blue line represents the simulator running with water influx support it is matches about 100%.

From Analytical plot, it could be understanding the water influx the main reservoir energy supporting.

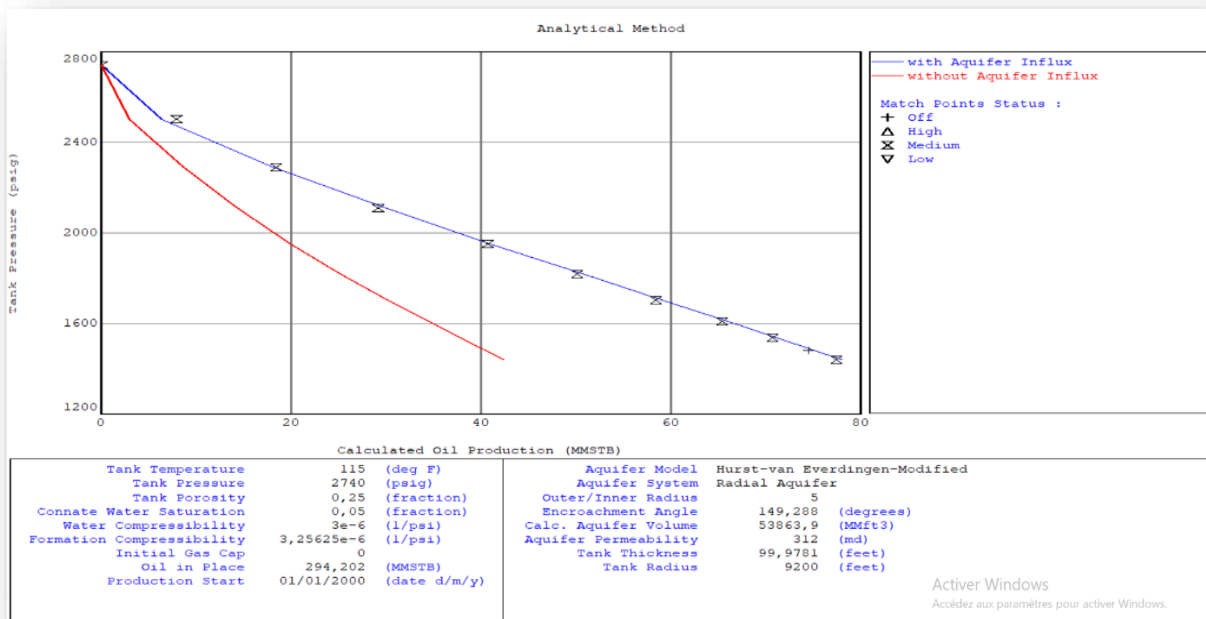


Figure III.4: Analytical Plot for an X field

1.2. Energy plot

1.2.1. Drive Indices

Drive indices for oil reservoirs indicate the relative magnitude of the various energy sources acting in the reservoir. A simple description of a drive index is the ratio of a particular expansion term to the net withdrawal (hydrocarbon voidage). These drive indices are cumulative and will change as the reservoir is produced. A plot of drive indices and the details of specific drive indices are shown below [6].

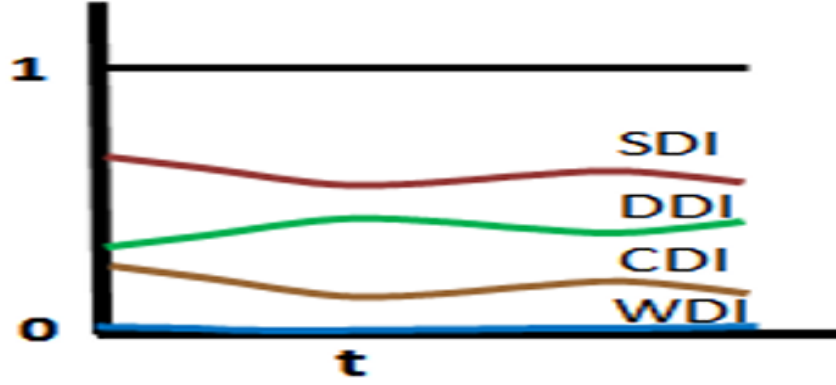


Figure III.5: Drive indices [6]

1.2.2. Summary of Drive Indices

Drive Index	Description
$DDI = \frac{N E_o}{F}$	Depletion Drive Index
$SDI = \frac{N m E_g \left(\frac{B_{oi}}{B_{gi}} \right)}{F}$	Segregation (Gas cap) Drive Index
$WDI = \frac{W_e B_w - W_p B_w}{F}$	Water Drive Index
$CDI = \frac{N (1 + m) E_{fw} B_{oi}}{F}$	Formation and Connate Water Compressibility Index

Table III.1: Equations of drive indices [6]

Figure (III.5) describes the fractional contributions of drive mechanisms of the recovery of an X oil field. From this plot, it can be noticed that there are three energy sources are affecting the recovery of oil which are water influx illustrated in pink color section, pore volume compressibility represented in green color section and the impact of fluid expansion clarified in blue color section.

We can see that the water influx expansion is the prominent energy source in the reservoir. In addition, it is corresponding with the water influx simulator running approach.

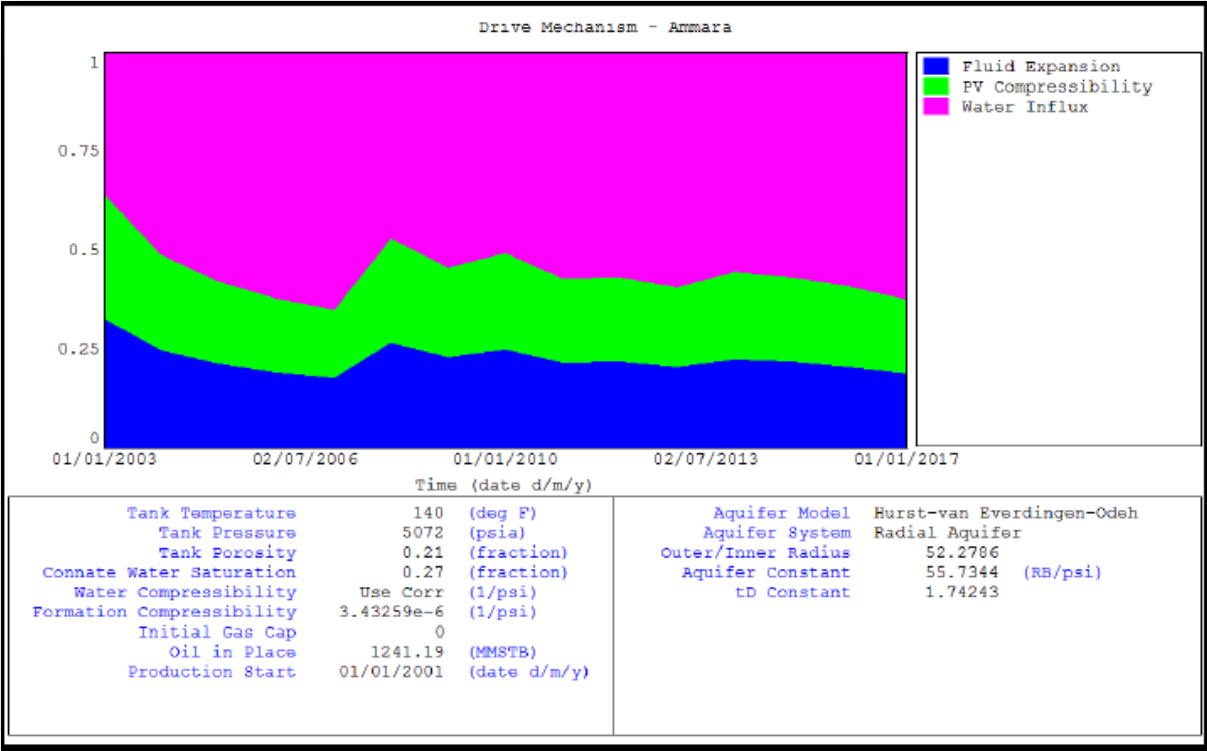


Figure III.6: Energy Plot of an X field [3]

1.3. WD Function plot

The **WD Function Plot** is used in reservoir engineering to analyze the **water influx behavior** in a petroleum reservoir supported by an **aquifer**. It is based on the **aquifer models** and helps engineers determine the strength of an aquifer’s contribution to reservoir energy [13], [14].

- **X-Axis : Dimensionless time (tD)** (logarithmic scale)

This shows how long the reservoir has been producing. (Higher values indicate later production times).

- **Y-Axis : Q (tD) – Water Influx Function**

Represents the **cumulative water influx** normalized by reservoir parameters. (Higher values mean stronger aquifer support).

Figure (III.7) describes the water influx behavior for an X field:

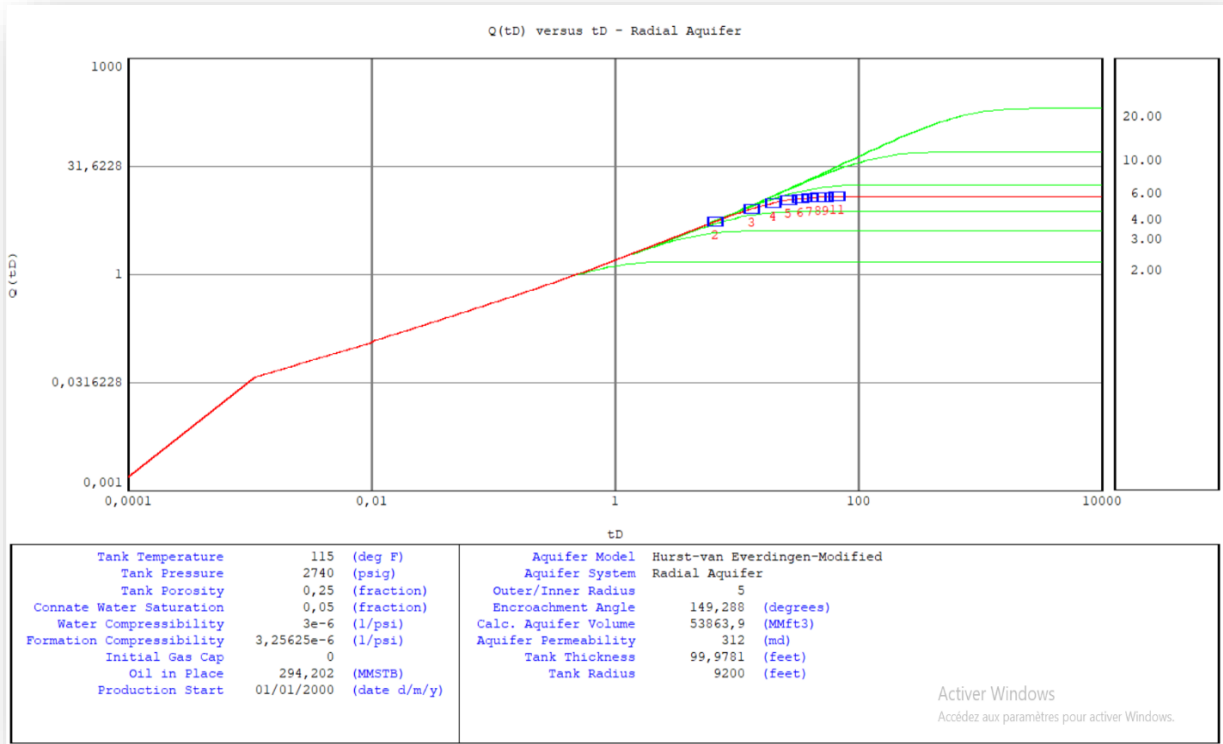


Figure III.7: WD Function Plot of an X field

CHAPTER IV

OOIP Estimation for Zone12 using MBAL Software

MBAL allows non dimensional reservoir analysis to be conducted throughout the life of the field, this is in early field life when limited data is available, or even in mature fields where more certainty is such, this straightforward but powerful reservoir toolkit can be applied throughout the life of the field, and is often used in conjunction with numerical simulators as a quality check of history matching, as a proxy model for fast calculations. Using limited data (PVT and cumulative production) the MBAL is well equipped to find the amount of oil in place, and any associated drive mechanisms. Unlike material balance theory, MBAL can be used to describe any hydrocarbon fluid (Oil, Gas or condensate) using PVT data or compositional descriptions in scenarios where variations in PVT with depth occur (e.g. compositional gradient are important in high relief reservoirs). Moreover, compartmentalized reservoirs (e.g. partially sealing faults, or pressure activated faults) can be modelled and history matched by creating compartmentalized models with transmissibilities. This evolution of the material balance concept is another development from PE Limited, and extends the range of applicability to full field life [8].

Based on reservoir engineering analysis, supported by geological and production data, the wells in Zone 12 of the Hassi Messaoud region were grouped into four development patterns as follows:



3. MBAL software simulation of Zone 12 :

3.1.Material balance:

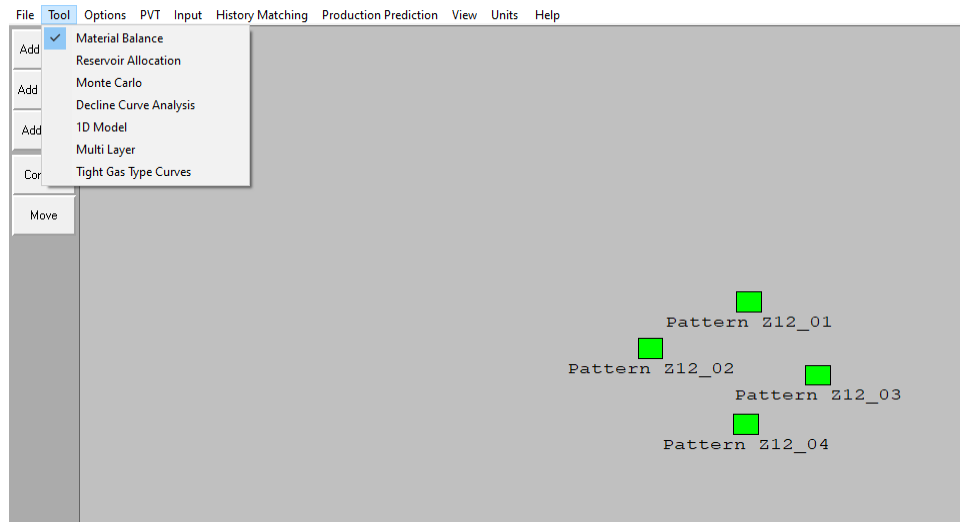


Figure IV.2: Mbal software tools

3.2.PVT Data and Black oil matching:

The best match of correlations is:

- Glaso for R_s and B_o
- Beal et al for μ_o

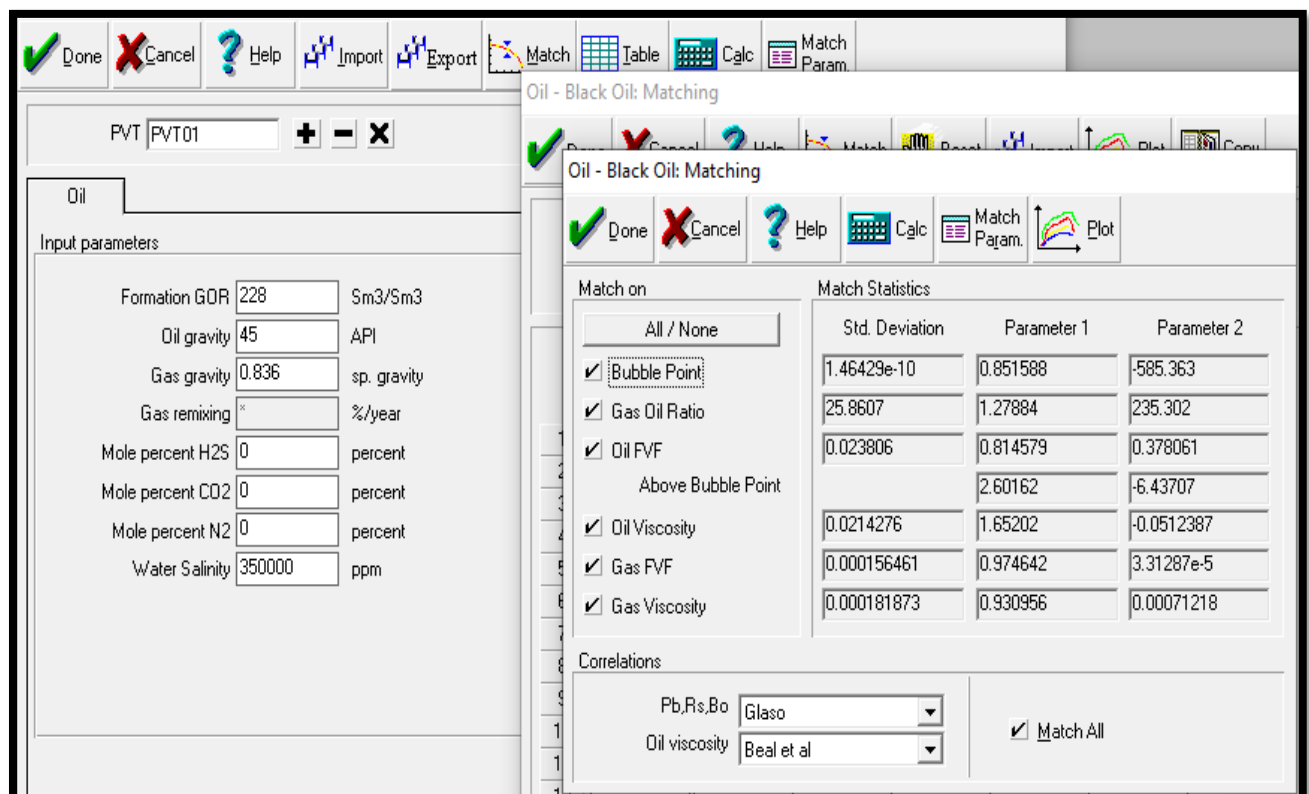


Figure IV.3: PVT data and black oil matching

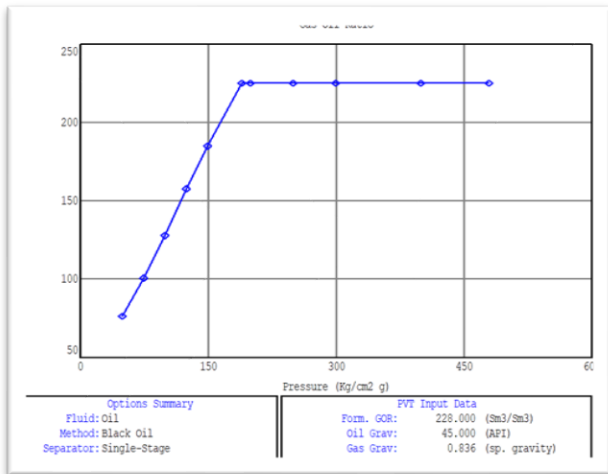


Figure IV.4: Gas Oil Ratio

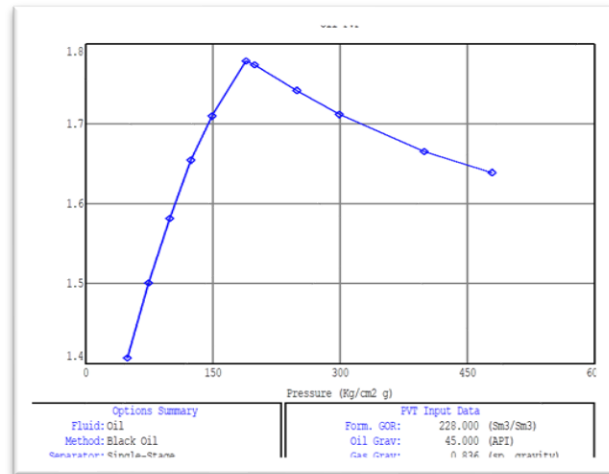


Figure IV.5: Oil FVF

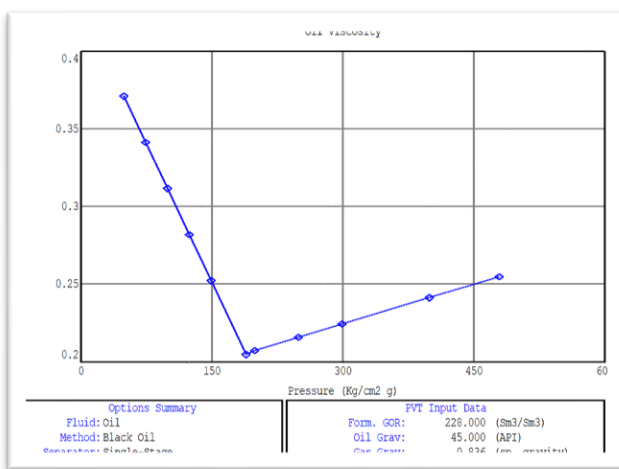


Figure IV.6: Oil viscosity

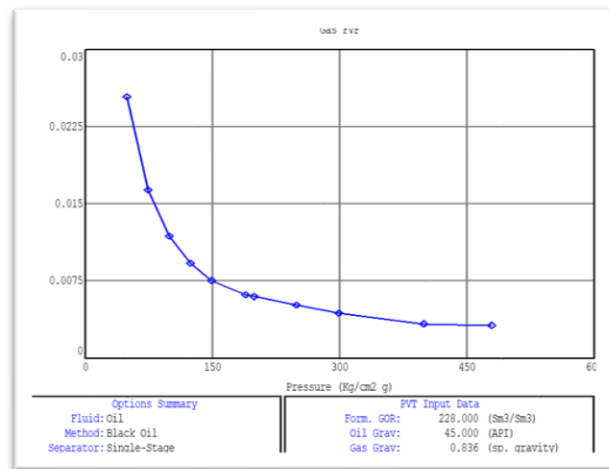


Figure IV.7: Gas FVF

3.3. Petrophysical Data:

$$\Phi_{\text{moy}} = 9,6\%$$

$$S_{\text{wi}} = 16,3\%$$

$$C_{\text{wi}} = 3 \times 10^{-5} \text{ 1/(kgf/cm}^2\text{)}$$

$$C_{\text{f}} = 1,149 \times 10^{-5} \text{ 1/(kgf/cm}^2\text{)}$$

No Gas cap No water drive

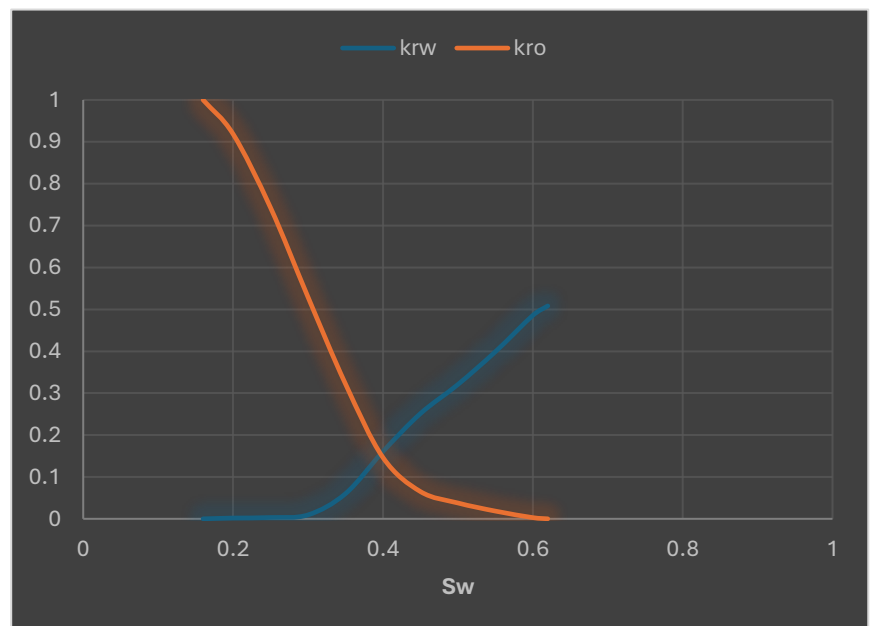
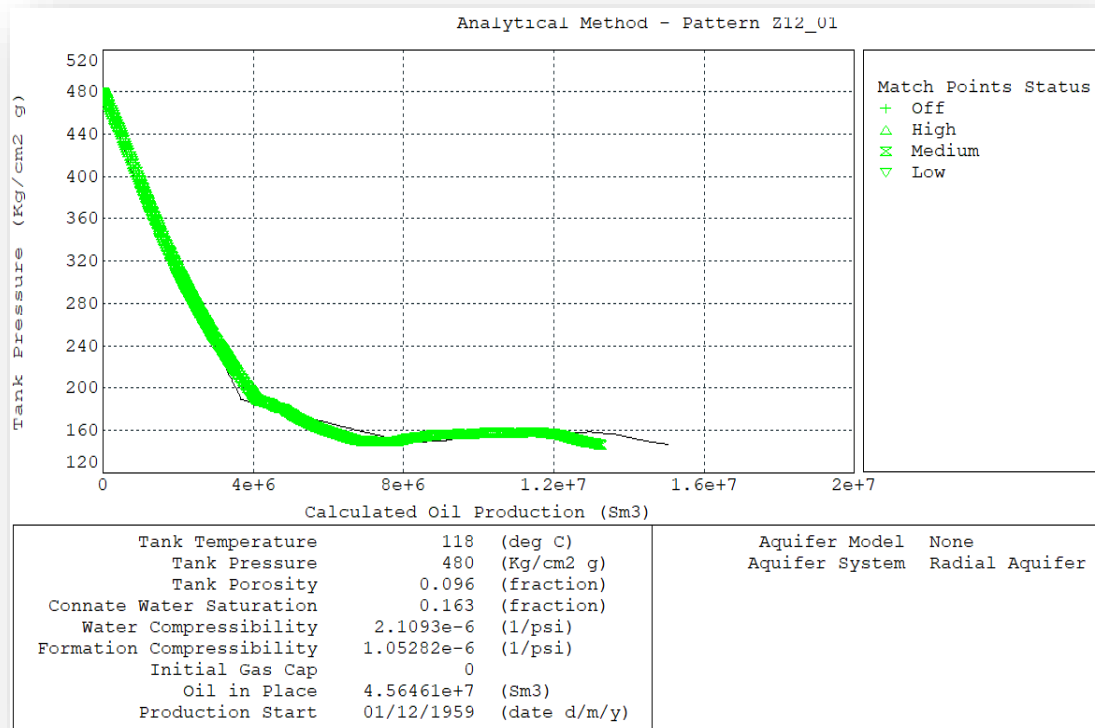
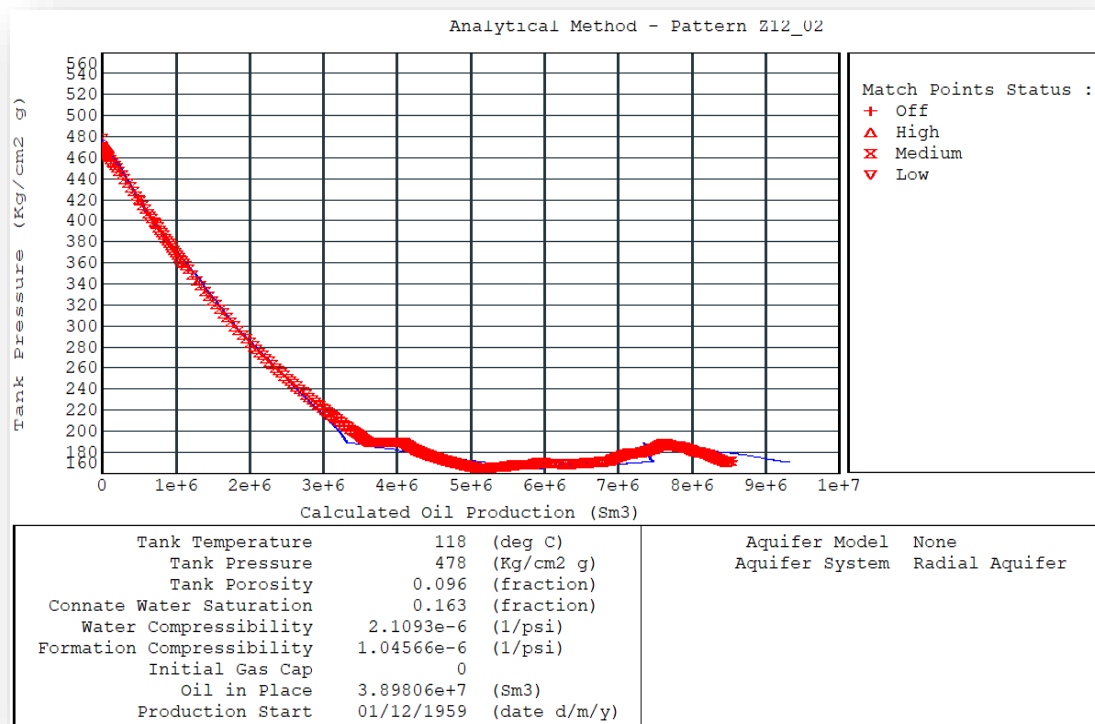


Figure IV.4: Relative permeability plot

3.4.History Matching (Analytical method):

From 01.12.1959 To 01.04.2013

***Figure IV.5.1. Analytical method for Pattern 01 – Z12******Figure IV.5.2. Analytical method for Pattern 02 – Z12***

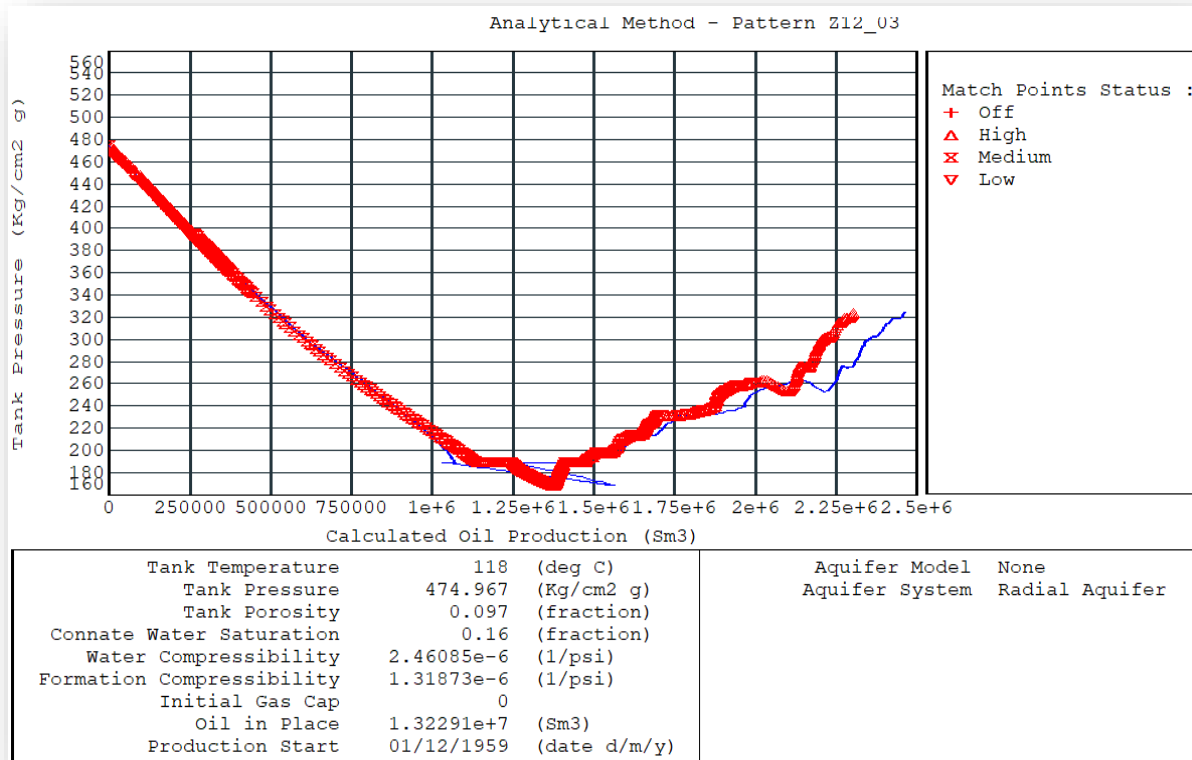


Figure IV.5.3. Analytical method for Pattern 03 – Z12

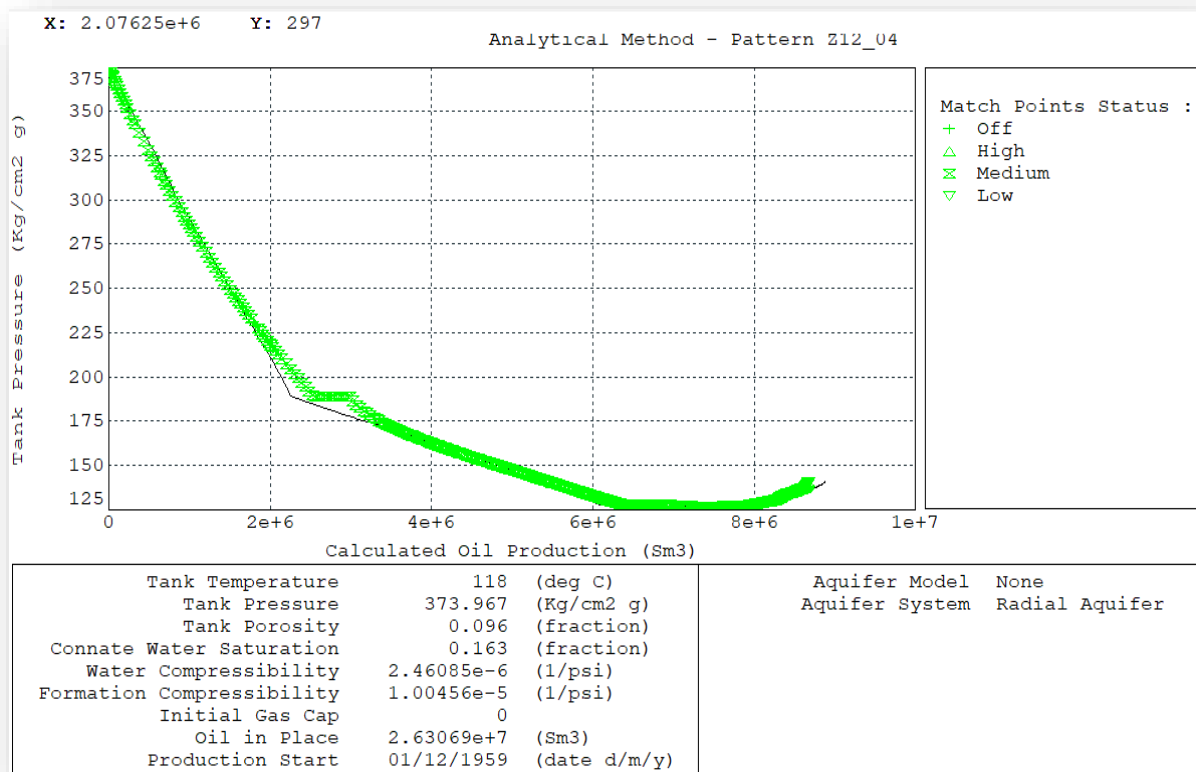


Figure IV.5.4. Analytical method for Pattern 04 – Z12

The calculated data are not matched 100% with measured data from **01/03/1980** to **01/04/2013**, We can distinguish two periods:

□ **1959-1989 (primary depletion):** There is a close agreement between measured and calculated values, In spite of the data uncertainties because of:

- PVT inaccuracies.
- Pressure data quality.
- Possible weak aquifer (often overlooked).

□ **Post-1989 (water injection phase):** There is a noticeable mismatch between measured and calculated reservoir pressures because of:

- Uncertainties in injection data are considered one of the main causes of the observed mismatch.
- Sweep inefficiency / heterogeneity.
- Incorrect voidage replacement assumptions.

❖ **History matching 1959–1988 (Natural depletion):**

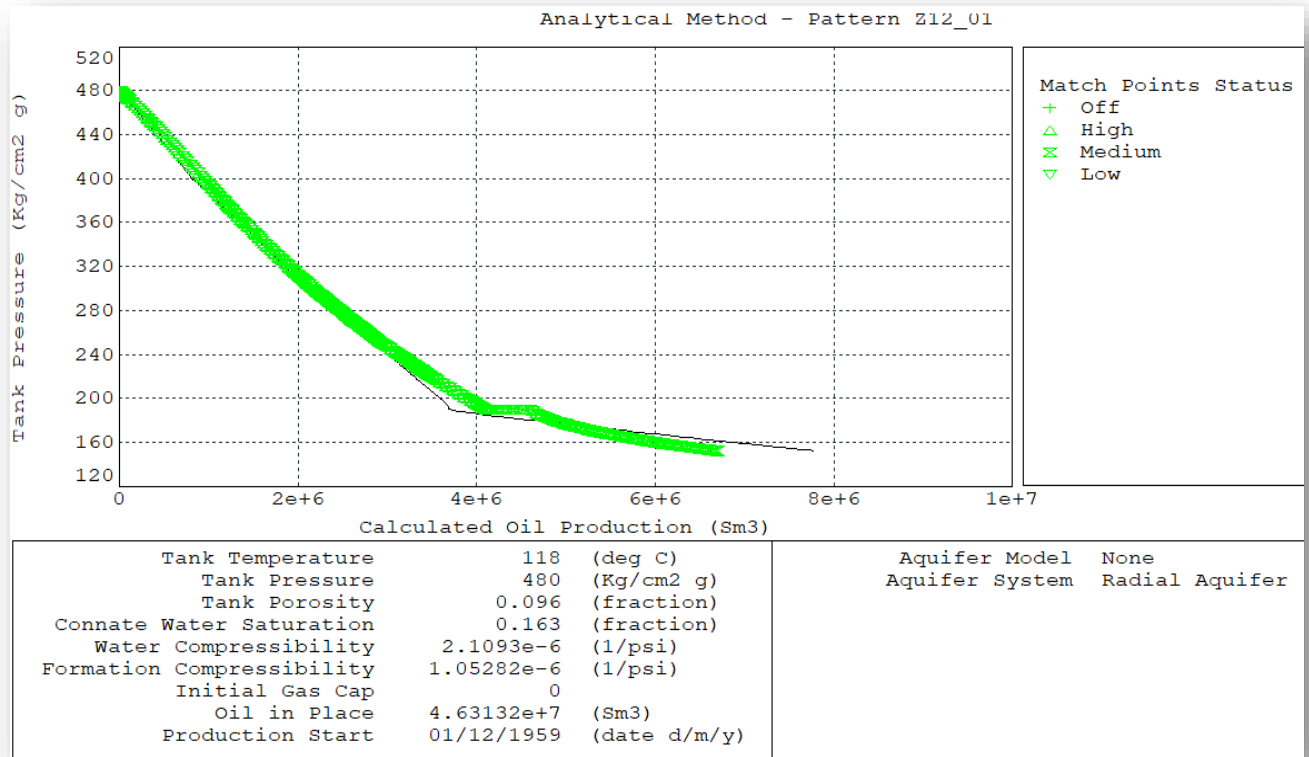


Figure IV.6. History matching 1959–1988 (Natural depletion) for Pattern 01 – Z12

- There is a good history match for all patterns of zone 12 between 01/12/1959 and 01/12/1988

$$OOIP \text{ of pattern 01} = 4,63132 \cdot 10^7 \text{ Sm}^3$$

3.5. History matching (Graphical method): Method F-We versus Et

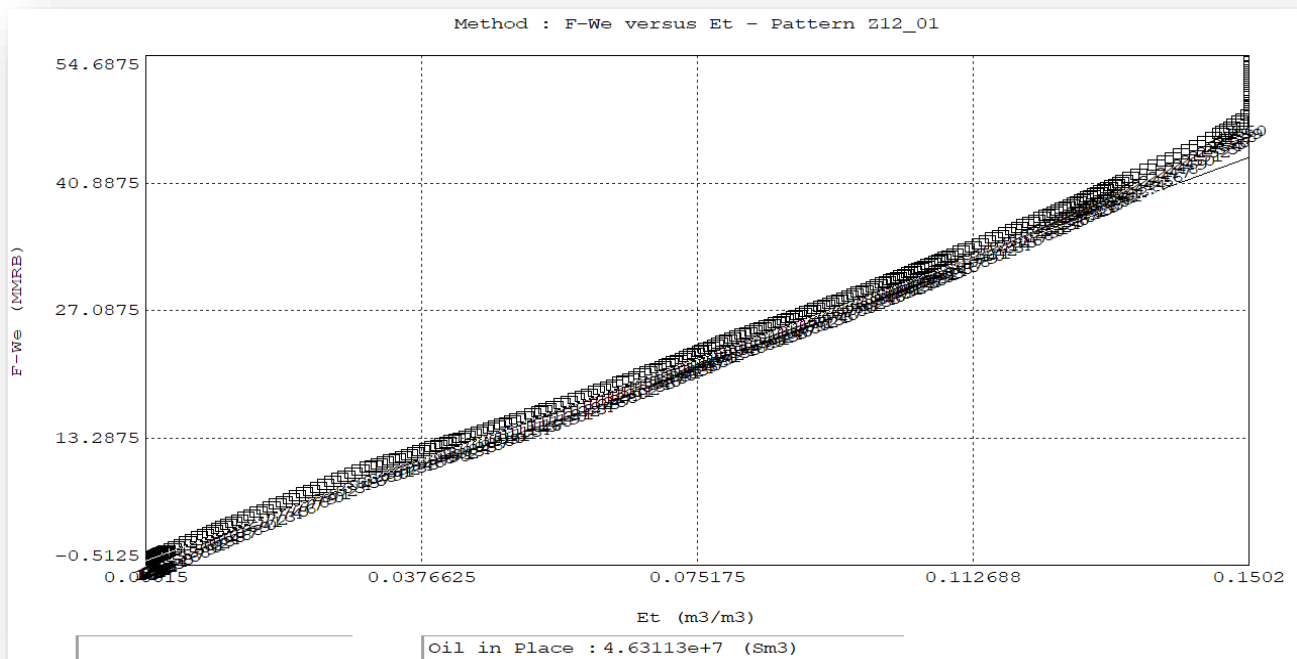


Figure IV.7. History matching (Graphical method): Method F-We versus Et

There is a perfect match in graphical method on this period (1959 – 1988)

3.6. Energy Plot (Drive mechanism):

Natural depletion period:

- Fluid expansion: 90%
- PV compressibility: 10%

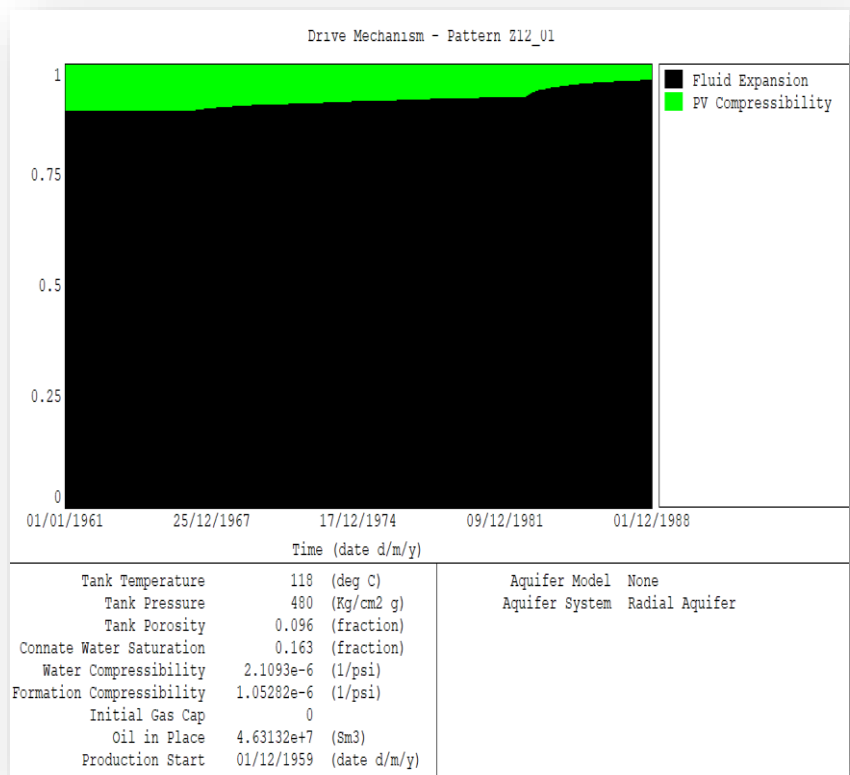


Figure IV.8. Drive Mechanism (Natural depletion) for Pattern 01 – Z12

3.7. History matching of all patterns:

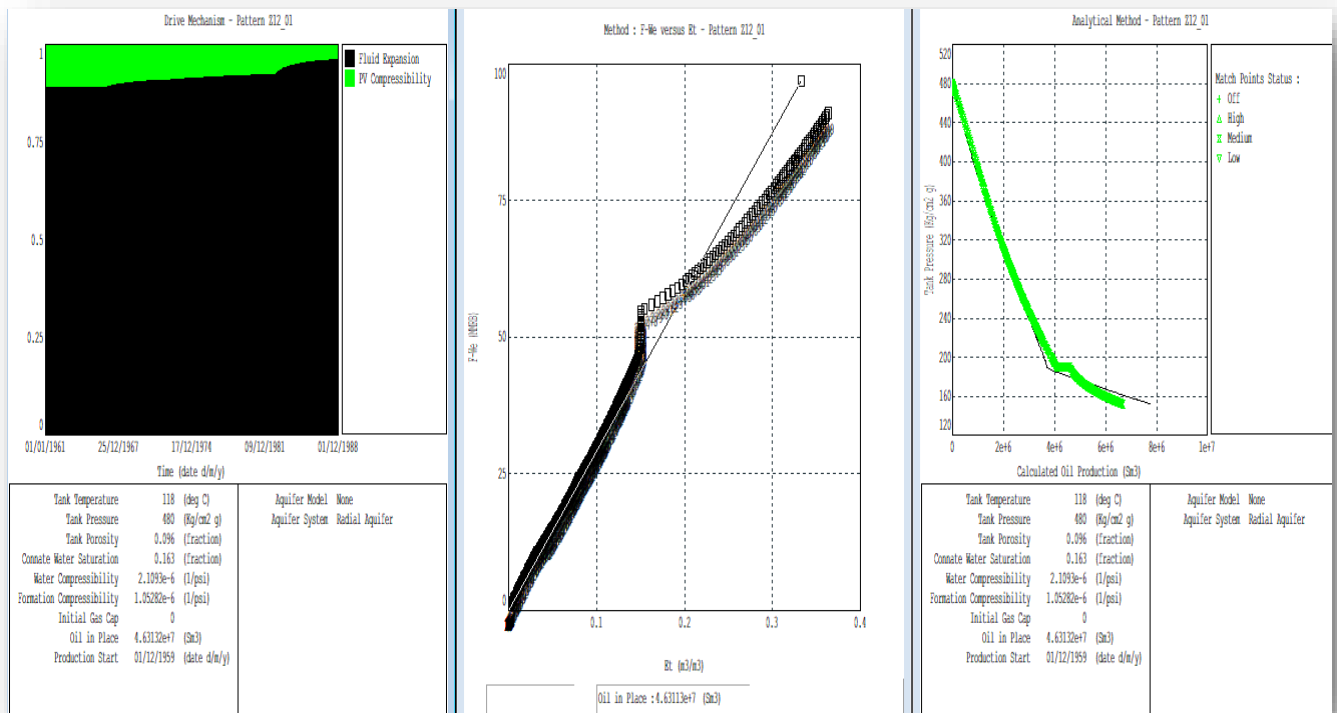


Figure IV.9.1. All plots for Pattern 01-Z12

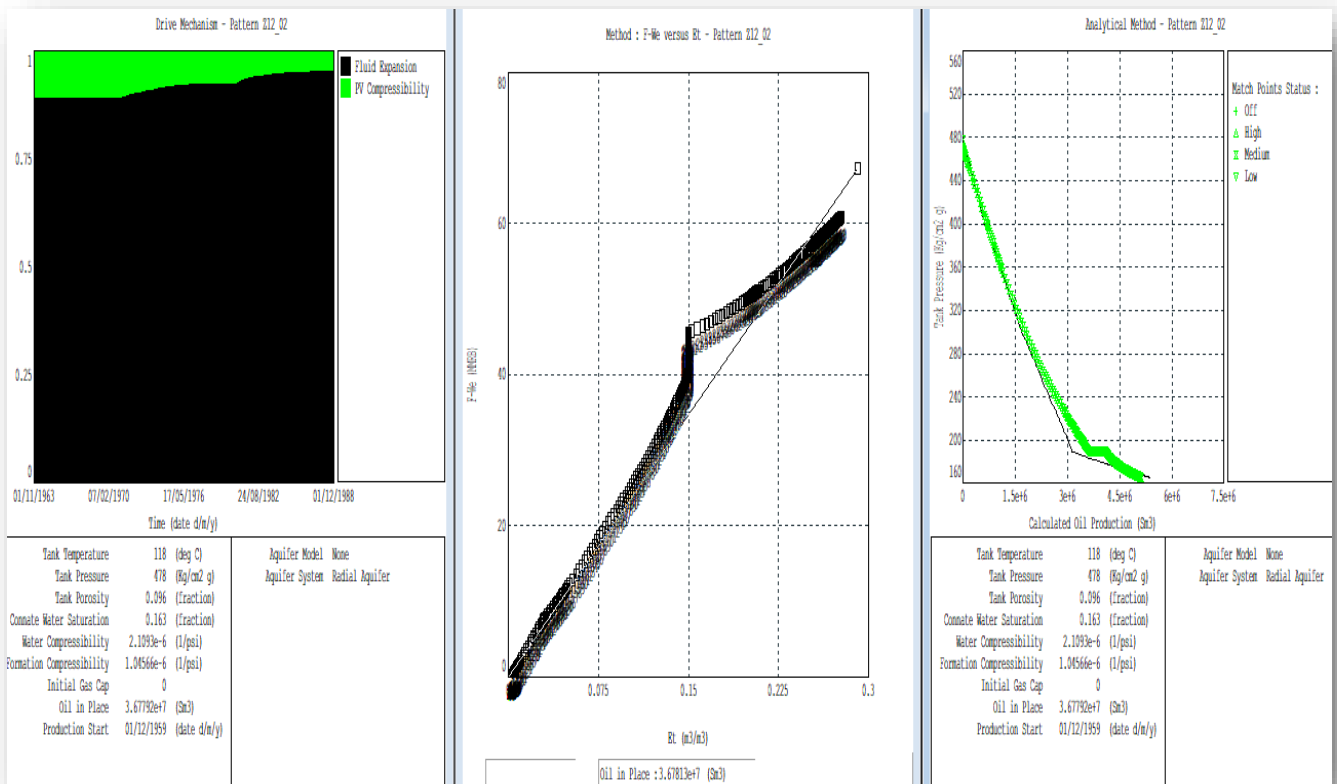


Figure IV.9.2. All plots for Pattern 02-Z12

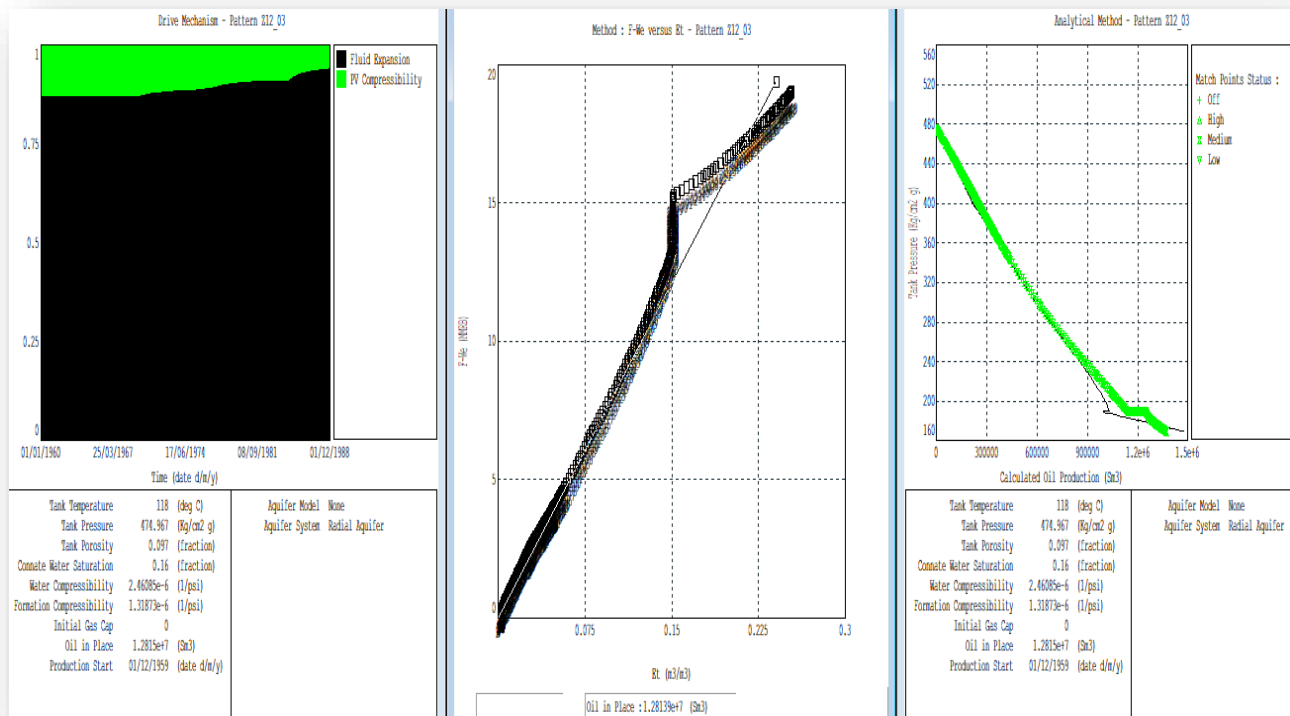


Figure IV.9.3. All plots for Pattern 03-Z12

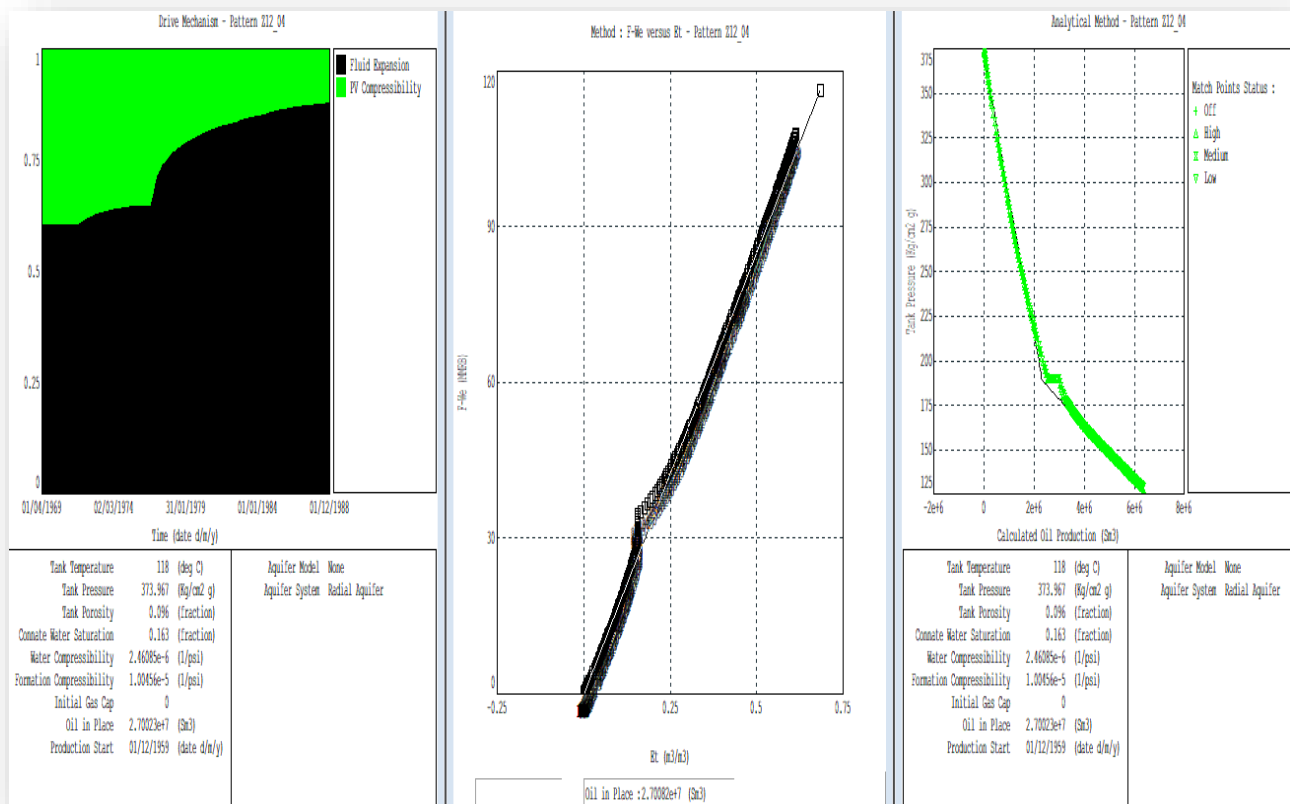


Figure IV.9.4. All plots for Pattern 04-Z12

$$OOIP = 4,63132 \cdot 10^7 + 3,67792 \cdot 10^7 + 1,2815 \cdot 10^7 + 2,70023 \cdot 10^7$$

$$OOIP \text{ Zone12} = 122.29097 \text{ MSm}^3$$

4. Comparison between volumetric method and Mbal software results:

Reserves	Pattern 1	Pattern 2	Pattern 3	Pattern 4	Zone 12
volumetric method, Sm^3 .	50 665 678	28 112 065	16 387 645	19 566 838	114 732 227
Material Balance method, Sm^3 .	46 313 200	36 779 200	12 815 000	27 002 300	122 290 970
Difference (Sm^3)	4 352 478	-8 667 135	3 572 645	-7 435 462	- 7 558 743

Table IV.1: volumetric method and Mbal software results

The MBAL results are slightly higher than the volumetric estimates, suggesting that Zone 12 may not behave as a completely isolated reservoir compartment.

5. Production Prediction & Oil recovery factor:

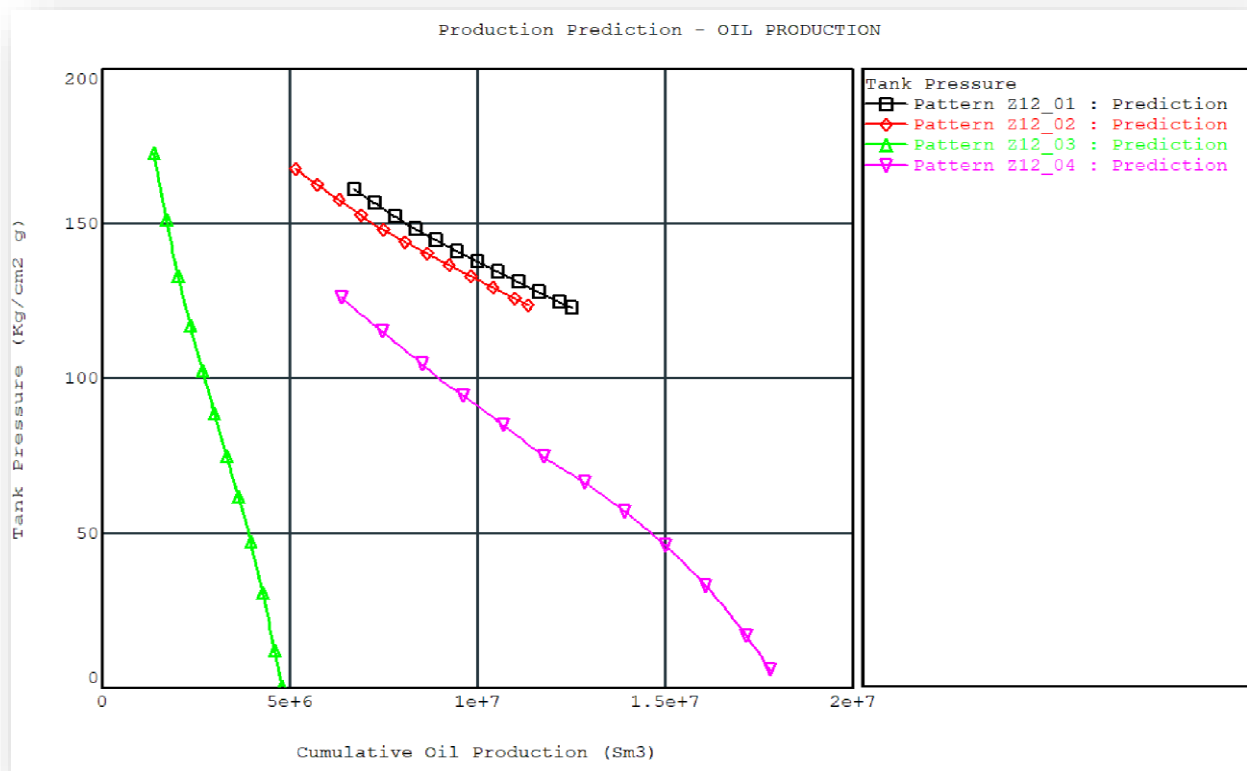


Figure IV.10.1. Production prediction – Tank pressure vs cumulative oil production

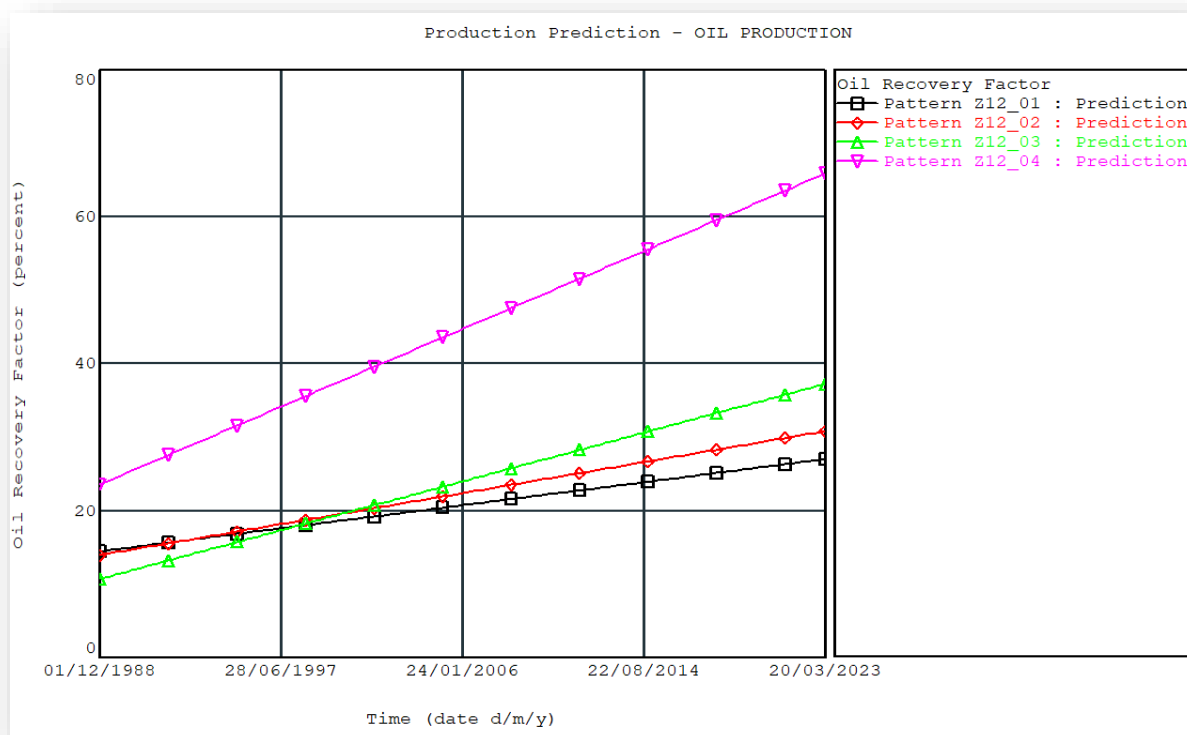


Figure IV.10.2. Natural depletion - Oil recovery factor vs Time

6. Development Plan Proposal (Water Injection):

Considering the rapid pressure depletion observed across all patterns in Zone 12, reservoir engineers have proposed a field development plan based on water injection as a secondary recovery method. Water injection is preferred over gas injection due to several technical and economic advantages. Firstly, the reservoir lacks an initial gas cap and does not exhibit strong gas-drive mechanisms, making gas injection less effective for pressure maintenance. In contrast, water injection provides efficient pressure support by maintaining reservoir energy and improving sweep efficiency, especially in mature fields with long production histories. Additionally, water is more readily available, cost-effective, and easier to handle operationally compared to gas, which may require compression, recycling, or importation. Furthermore, water injection helps displace oil toward production wells more uniformly, reducing bypassed zones and enhancing overall recovery. Therefore, under the given reservoir conditions, water injection represents a more reliable and economically viable strategy for sustaining production and optimizing recovery in Zone 12.

6.1. History matching post-1989 (water injection phase):

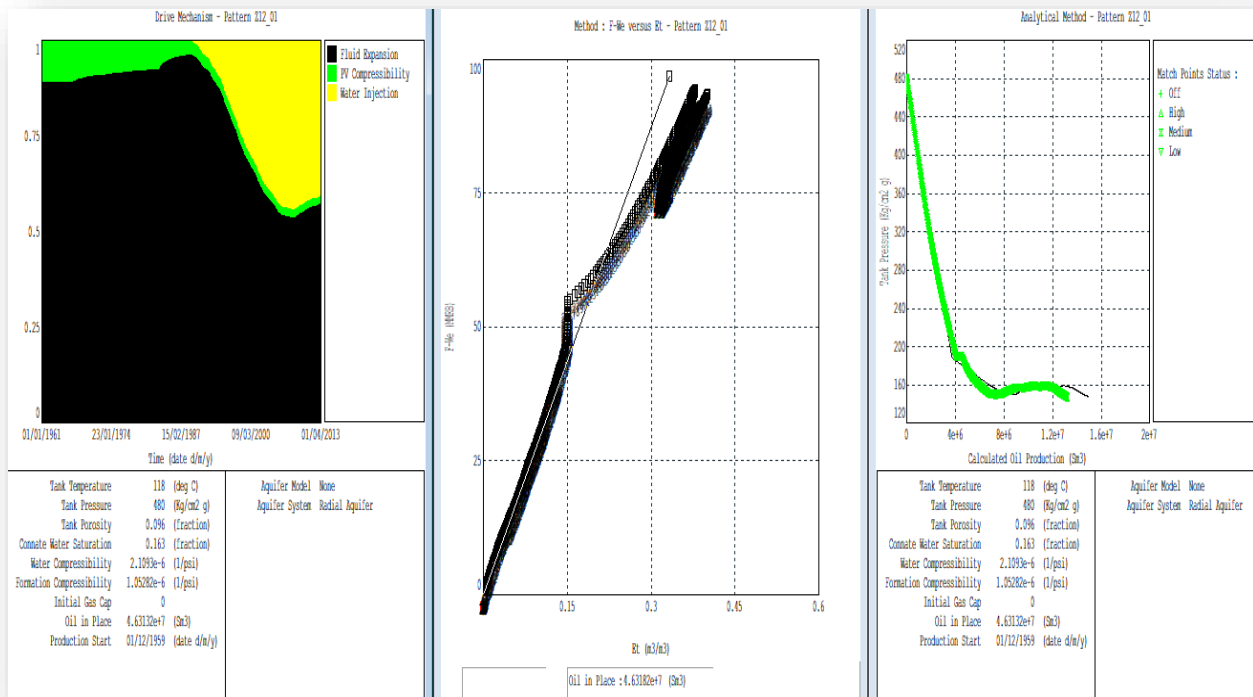


Figure IV.11.1. Water injection phase for Pattern 01 – Z12

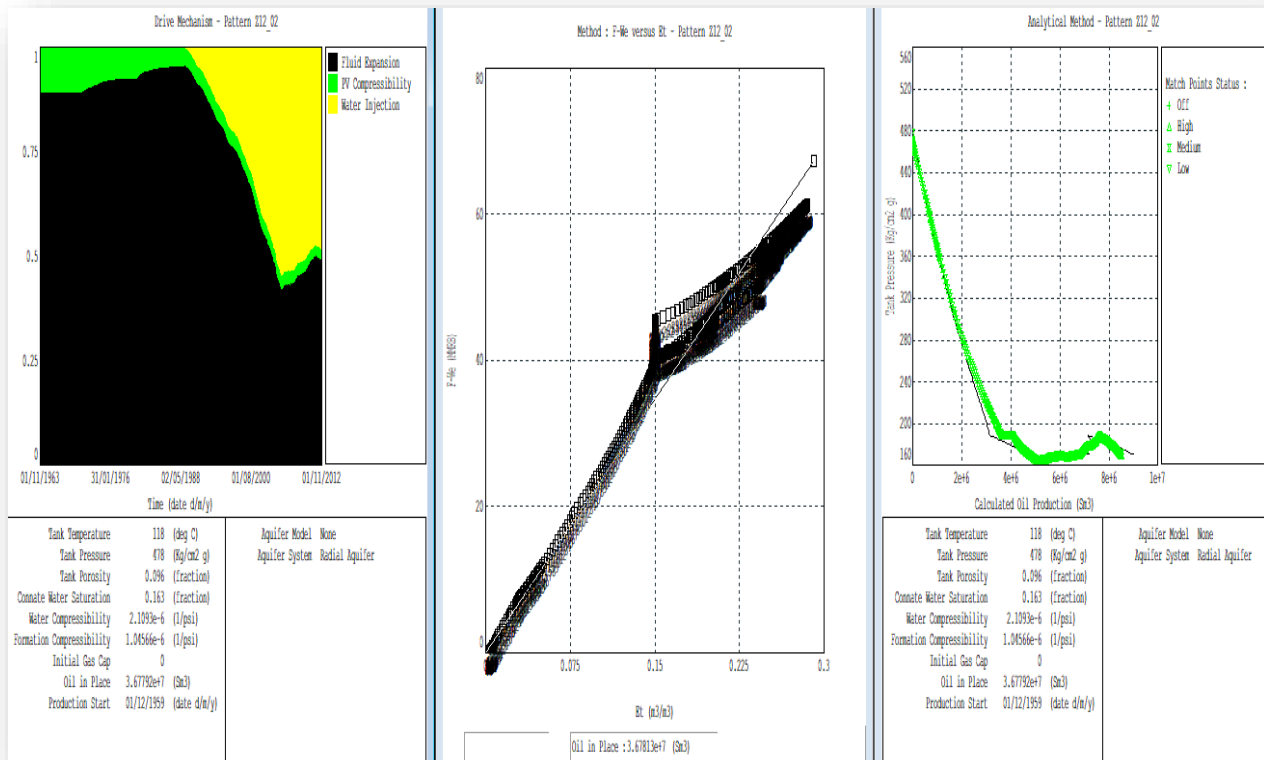


Figure IV.11.2. Water injection phase for Pattern 02 – Z12

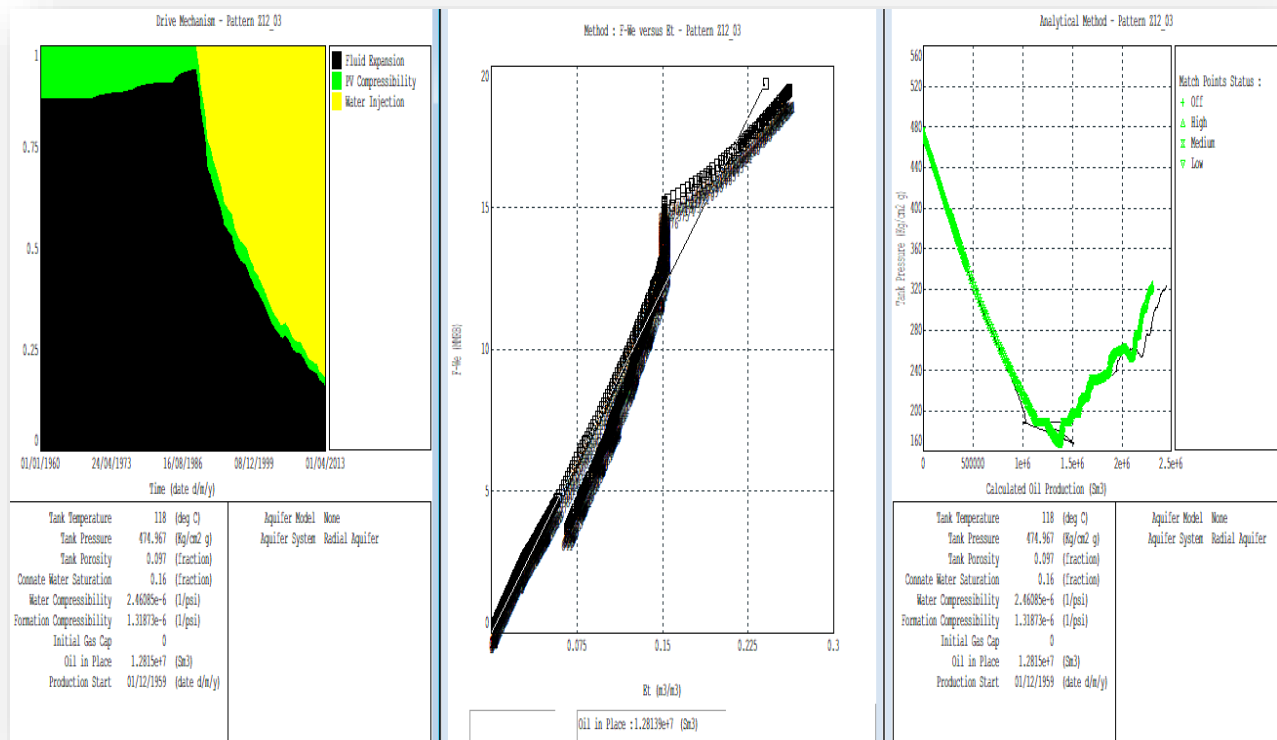


Figure IV.11.3. Water injection phase for Pattern 03 – Z12

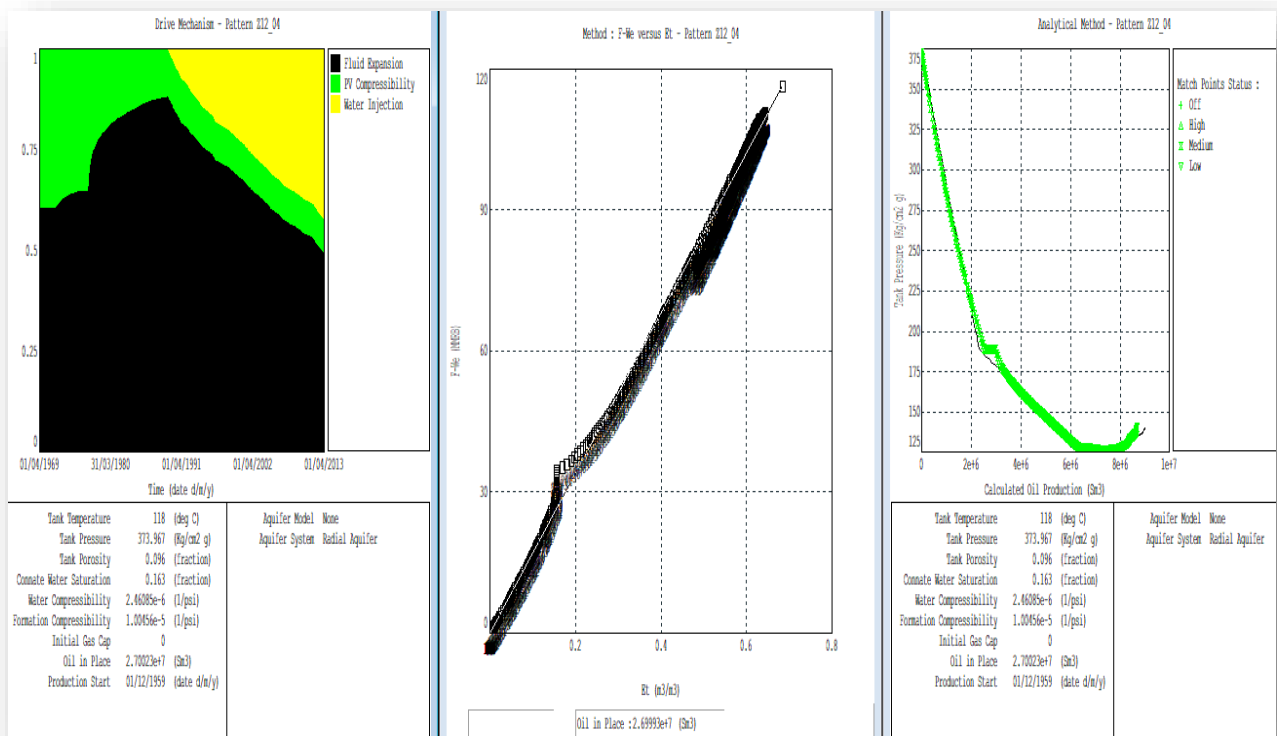


Figure IV.11.4. Water injection phase for Pattern 04 – Z12

6.2. Water injection - Production prediction:

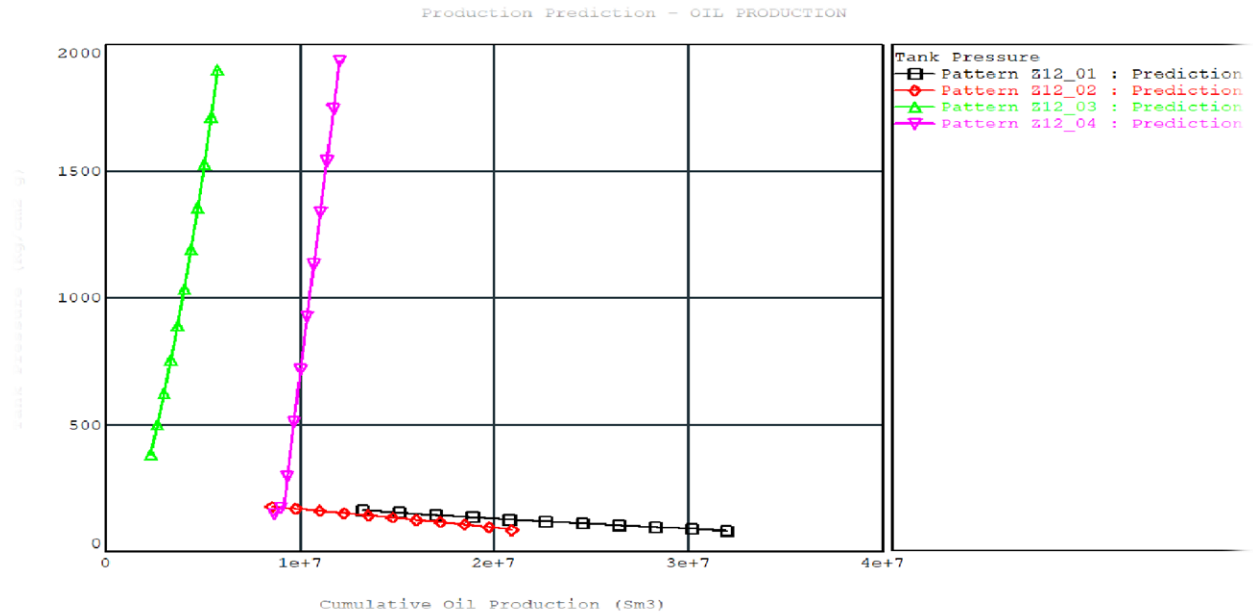


Figure IV.12. Production prediction – Tank pressure vs cumulative oil production

➤ Pressure maintenance through injection significantly improved cumulative oil production (increased from approximately 4.8–18 million Sm^3 under natural depletion to about 6–32 million Sm^3 with water injection support), delayed reservoir depletion, and extended the productive life of the field (Expected production period under water injection: approximately 2040–2050).

6.3. Water injection - Oil recovery factor prediction:

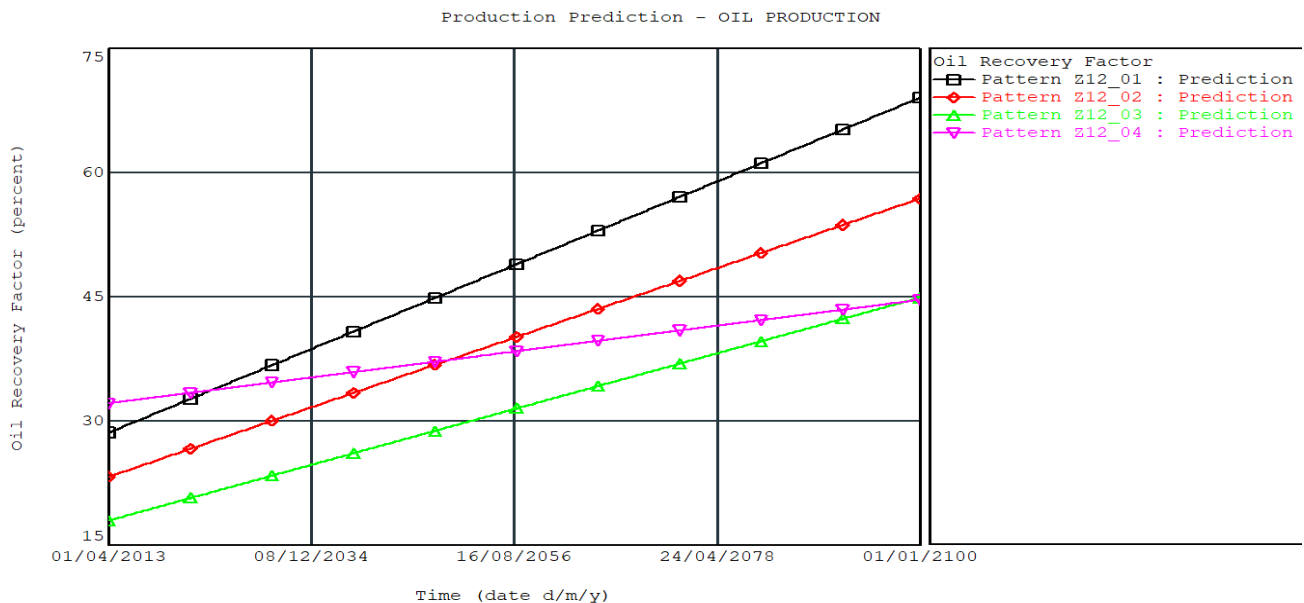


Figure IV.13. Production prediction – Oil recovery factor vs Time

➤ *Water injection significantly enhances oil recovery in Zone 12 by maintaining reservoir pressure and improving displacement efficiency. The predicted results demonstrate substantial increases in recovery factor—ranging from approximately +13% to +38% depending on the pattern—leading to ultimate recovery values as high as 57%. This confirms that water injection is an effective and reliable secondary recovery strategy for maximizing reserves and extending the productive life of the field.*

7. Comments:

- The accuracy of MBAL history matching is highly dependent on the **quality, consistency, and representativity** of reservoir input data.
- Uncertainties in production data (oil, gas, and water rates and cumulates) directly impact material balance calculations and fluid withdrawal estimates.
- **Poor pressure data quality** (non-stabilized build-up tests, gauge drift, limited pressure surveys) reduces confidence in reservoir pressure trends and energy diagnostics.
- **Gas lift injection** introduces recycled gas into the production stream, which—if not corrected—leads to inflated produced gas volumes and distorted GOR behavior.
- **Water injection** provides artificial pressure maintenance, which can be misinterpreted as aquifer support if injector performance and volumes are not properly modelled.
- Incomplete or inconsistent production and injection history leads to uncertainty in cumulative voidage replacement and reservoir balance calculations.

Conclusion

This study, devoted to the application of the material balance equation to the Hassi Messaoud reservoir, has provided a better understanding of the dynamic behavior of an oil reservoir initially produced under a depletion-drive mechanism, in the absence of a gas cap and significant aquifer support. During the initial production phase, which began in 1959, the observed reservoir pressure decline was mainly attributed to the expansion of reservoir fluids and rock, confirming that the dominant production mechanism was depletion drive.

The implementation of water injection in 1989 marked the transition to a pressure-maintenance mechanism, aimed at compensating for the reservoir energy depletion and improving the ultimate recovery factor. Material balance analysis, performed using MBAL software, enabled the reconstruction of the reservoir production history and the estimation of the original oil in place (OOIP). Furthermore, the study highlighted the positive impact of water injection on pressure support and overall reservoir performance.

As expected in reservoir engineering studies, a certain degree of deviation between measured data and calculated results was observed. Such differences are generally considered reasonable and can be attributed to several factors, including uncertainties in PVT data, the quality of pressure measurements, errors in produced and injected volumes, as well as reservoir heterogeneity and the limited sweep efficiency of the injected water.

In conclusion, the material balance method remains an essential tool for evaluating reservoir performance and estimating hydrocarbons initially in place. However, its reliability depends largely on the quality of the available production and pressure data, as well as on the validity of the assumptions adopted during the analysis. When integrated with detailed geological and petrophysical studies, together with numerical reservoir simulation, the material balance method provides a more realistic representation of reservoir behavior. This integrated approach improves the understanding of reservoir dynamics, reduces uncertainties in reserve estimation, and supports the optimization of future reservoir management and field development strategies.

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