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Presented By:

Belhocine Mohamed rami

-THEME-

**FLUID CHARACTERIZATION OF OIL FIELD RESERVOIR USING BLACK OIL
MODEL CASE STUDY RNS FIELD**

Thesis defended on 08 June 2026

Before the review board

Jury:

President :	Mr. DOUAK MOHAMED	M.C.A	Univ. Ouargla
Examiner	MAHSSOUL AMMAR	M.C.A	Univ. Ouargla
Supervisor	DJEBASS FAYCEL	M.C.A	Univ. Ouargla

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وَكَانَ فَضْلُ اللَّهِ عَلَيْكَ عَظِيمًا

Dedication

I humbly dedicate this work

To my beloved parents _may God protect and preserve them.

To my dear sister, for her constant presence.

To all my friends, for their unwavering support.



Résumé :

En résumé, ce travail vise à caractériser les fluides de réservoir du gisement TAGS de Rhourde Nouss Central (RNC) à l'aide du modèle Black Oil et des données PVT de laboratoire. L'étude a porté sur l'analyse des propriétés des fluides de réservoir, l'examen du comportement de phase et des concepts de modélisation Black Oil, ainsi que sur le calage des données des essais de Libération Différentielle (DL) à l'aide du logiciel PVTP. Le modèle développé a été ajusté avec succès aux mesures de laboratoire, montrant une bonne concordance pour les paramètres clés tels que le rapport gaz dissous/huile (R_s), le facteur volumique de formation de l'huile (Bo), le facteur volumique de formation du gaz (B_g) et les viscosités des fluides. Les résultats ont confirmé la nature riche en condensats du réservoir et ont démontré la capacité du modèle Black Oil modifié à reproduire avec précision le comportement des fluides de réservoir en fonction de la pression. Ces résultats soulignent l'importance d'une caractérisation PVT précise pour la gestion des réservoirs, la prévision de la production et l'optimisation de la récupération des hydrocarbures.

Mots-clés : Modèle Black Oil, Données PVT, Fluides de réservoir, Réservoir TAGS, Calage PVTP, Comportement de phase.

Abstract:

In summary, this work aims to characterize the reservoir fluids of the Rhourde Nouss Central (RNC) TAGS reservoir using the Black Oil Model and laboratory PVT data. The study involved analyzing reservoir fluid properties, reviewing phase behavior and Black Oil modeling concepts, and calibrating Differential Liberation (DL) test data using PVTP software. The developed model was successfully matched with laboratory measurements, showing good agreement for key parameters such as the solution gas–oil ratio (R_s), oil formation volume factor (Bo), gas formation volume factor (B_g), and fluid viscosities. The results confirmed the condensate-rich nature of the reservoir and demonstrated the ability of the Modified Black Oil Model to accurately reproduce the pressure-dependent behavior of reservoir fluids. These findings highlight the importance of accurate PVT characterization for reservoir management, production forecasting, and hydrocarbon recovery optimization.

Keywords: Black Oil Model, PVT Data, Reservoir Fluids, TAGS Reservoir, PVTP Calibration, Phase Behavior.

ملخص

يهدف هذا العمل إلى توصيف موائع المكنم في مكنم TAGS بحقل Rhourde Nouss Central (RNC) باستخدام نموذج النفط الأسود (Black Oil Model) وبيانات PVT المخبرية. شملت الدراسة تحليل خصائص موائع المكنم، ومراجعة مفاهيم السلوك الطوري ونمذجة النفط الأسود، ومعايرة بيانات اختبار التحرر التفاضلي (DL - Differential Liberation) باستخدام برنامج PVTP. وقد تمت مطابقة النموذج المطور بنجاح مع القياسات المخبرية، حيث أظهر توافقاً جيداً مع المعلومات الأساسية مثل نسبة الغاز المذاب إلى النفط (R_s)، ومعامل حجم تكوين النفط (Bo)، ومعامل حجم تكوين الغاز (B_g)، ولزوجة الموائع. وأكدت النتائج الطبيعية الغنية بالمكثفات للمكنم، كما أظهرت قدرة نموذج النفط الأسود المعدل على تمثيل سلوك موائع المكنم المعتمد على الضغط بدقة عالية. وتبرز هذه النتائج أهمية التوصيف الدقيق لبيانات PVT في إدارة المكنم، والتنقيب بالإنتاج، وتحسين استخلاص المحروقات.

الكلمات المفتاحية: نموذج النفط الأسود، بيانات PVT، موائع المكنم، مكنم TAGS، معايرة PVTP، السلوك الطوري

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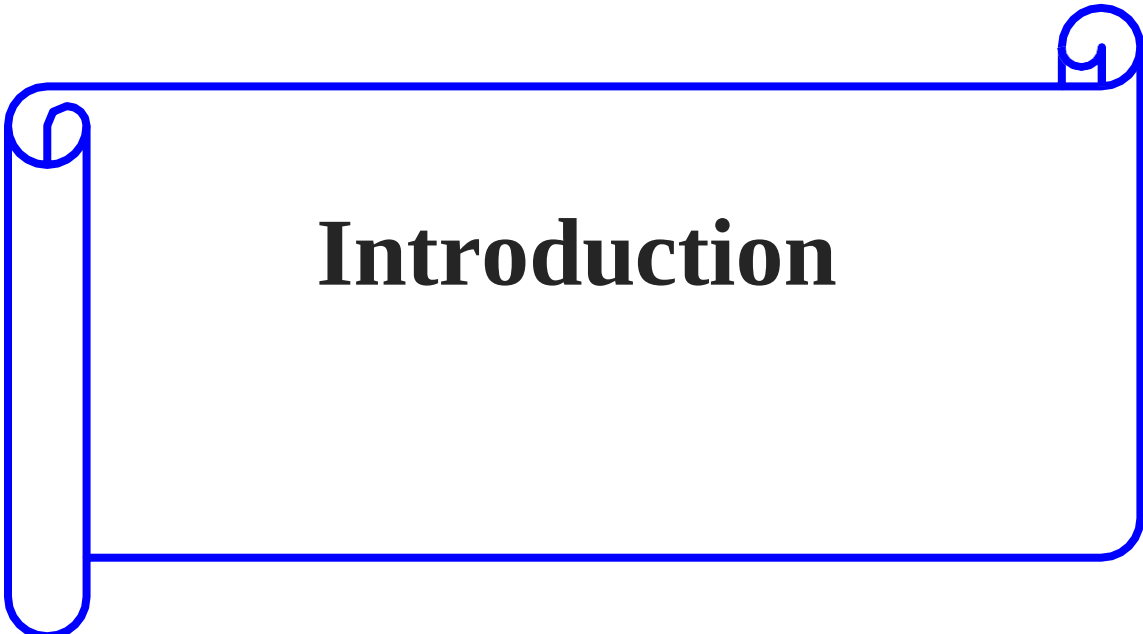
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List of Abbreviations

List of Abbreviations

Abbreviation	Meaning	Typical Units
API	API Gravity	°API
B_g	Gas Formation Volume Factor	RB/scf or m ³ /Sm ³
B_o	Oil Formation Volume Factor	RB/STB or m ³ /m ³
CCE	Constant Composition Expansion	No units (laboratory test)
CVD	Constant Volume Depletion	No units (laboratory test)
DL	Differential Liberation	No units (laboratory test)
GOR	Gas–Oil Ratio	scf/STB or Sm ³ /Sm ³
P_b	Bubble Point Pressure	psi, psia, bar, MPa
PVT	Pressure, Volume, Temperature	Pressure: psia/bar; Temperature: °F/°C; Volume: RB, STB, ft ³ , m ³
RNC	Rhourde Nouss Central	No units (field name)
R_s	Solution Gas–Oil Ratio	scf/STB or Sm ³ /Sm ³
R_v	Vaporized Oil–Gas Ratio	STB/MMscf or m ³ /Sm ³
TAGS	Triassic Clays and Sandstones	No units (formation name)
Z	Gas Compressibility Factor	Dimensionless



Introduction

Introduction:

The efficient development and management of hydrocarbon reservoirs require a thorough understanding of reservoir fluid behavior under changing pressure and temperature conditions. As production progresses, reservoir fluids undergo significant physical and thermodynamic transformations that directly influence recovery efficiency, production forecasting, reserve estimation, and field development strategies. Consequently, accurate characterization of fluid properties has become a fundamental aspect of modern reservoir engineering.

Pressure–Volume–Temperature (PVT) analysis provides the essential information needed to describe reservoir fluids and predict their behavior throughout the production life of a field. Parameters such as bubble point pressure, solution gas–oil ratio, formation volume factors, viscosity, density, and gas compressibility factor are critical inputs for reservoir simulation and production optimization studies. The reliability of these studies depends strongly on the quality of the fluid characterization process.

Among the various fluid modeling approaches used in the petroleum industry, the Black Oil Model remains one of the most practical and widely applied techniques. By representing reservoir fluids through simplified oil, gas, and water phases, it offers an effective balance between computational efficiency and engineering accuracy. Furthermore, the Modified Black Oil formulation extends the model’s applicability to more complex systems such as volatile oils and gas-condensate reservoirs.

The Rhourde Nouss Central (RNC) TAGS reservoir is one of Algeria’s important gas-condensate reservoirs, characterized by complex phase behavior and significant pressure depletion effects. Understanding the evolution of its fluid properties is essential for improving reservoir management and optimizing hydrocarbon recovery.

The main objective of this work is to characterize the reservoir fluids of the Rhourde Nouss Central field using laboratory PVT data and the Black Oil Model technique. More specifically, this study aims to:

- Analyze the thermodynamic behavior and classification of reservoir fluids.

- Evaluate the principal PVT properties governing reservoir performance.

- Generate and calibrate Black Oil PVT tables using PVTP software and laboratory data from well RN4.

INTRODUCTION

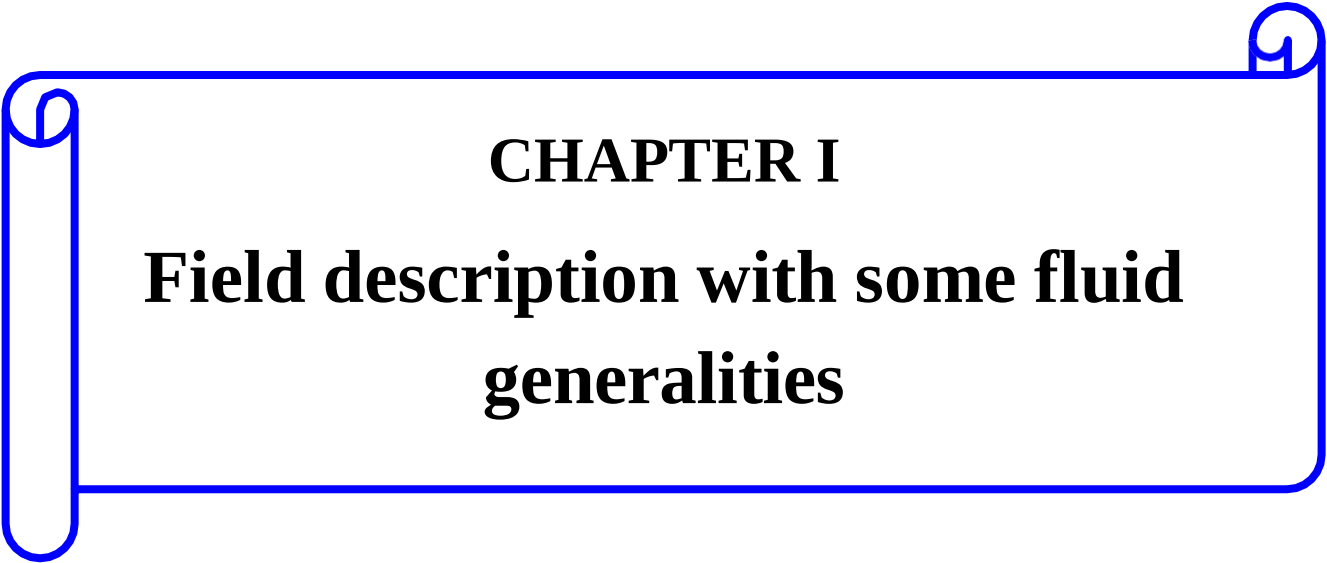
Assess the ability of the Black Oil Model to reproduce the observed behavior of the RNC reservoir fluids.

Compare simulated results with measured laboratory data to validate the developed model.

To achieve these objectives, this work combines theoretical and practical approaches. Theoretical concepts related to reservoir fluid properties, phase behavior, and Black Oil modeling are first reviewed. Subsequently, laboratory PVT data are analyzed and calibrated to construct a representative fluid model capable of describing the behavior of the reservoir under different pressure conditions.

This dissertation is organized into four chapters. The first chapter presents the fundamental properties of reservoir fluids and the importance of PVT analysis. The second chapter discusses hydrocarbon phase behavior and the classification of reservoir fluids. The third chapter introduces the Black Oil Model, its assumptions, governing equations, empirical correlations, and application domain. Finally, the fourth chapter presents the case study of the Rhourde Nouss Central TAGS reservoir, including PVT data calibration, Black Oil model construction, and analysis of the obtained results.

Through this work, the importance of accurate fluid characterization and Black Oil modeling in reservoir management, production forecasting, and hydrocarbon recovery optimization is demonstrated.



CHAPTER I

**Field description with some fluid
generalities**

1.1 Introduction

The study of reservoir behavior comes with the knowledge of the physical and chemical properties of the reservoir fluid. These fluid properties are usually determined by laboratory experiments performed on reservoir fluid samples. In the absence of experimentally measured properties, it is necessary to determine the properties from empirically derived correlations.

The nature of these fluids (gas or liquid) implies the introduction of thermodynamics for the determination of these properties such as : density, fluid composition, and petroleum fractions as well as PVT parameters.

The aim of this chapter is to present well-established correlations of physical properties for reservoir fluids.

1.2 Geographical Situation [4]

The RhourdeNouss region is located within the Illizi province, approximately 280 km southeast of Hassi Messaoud and about 1,000 km from Algiers. It is situated between:

- 29°16' and 30° parallels
- 06°24' and 07° meridian

Access is via a 30 km paved road that connects the region to National Route No. 3 (Ouargla-Illizi). The area is bordered to the north by the Gassi-Touil region, to the south by the regions of Hamra and TIN-FOUYE TABANKORT (TFT).

Rhourde Nouss is characterized by a dry desert climate with very low humidity with significant temperature variations between winter and summer (-5°C to 55°C). It experiences very low annual rainfall (2 to 4 mm) and frequent sandstorms. The average altitude is approximately 275 meters above sea level.

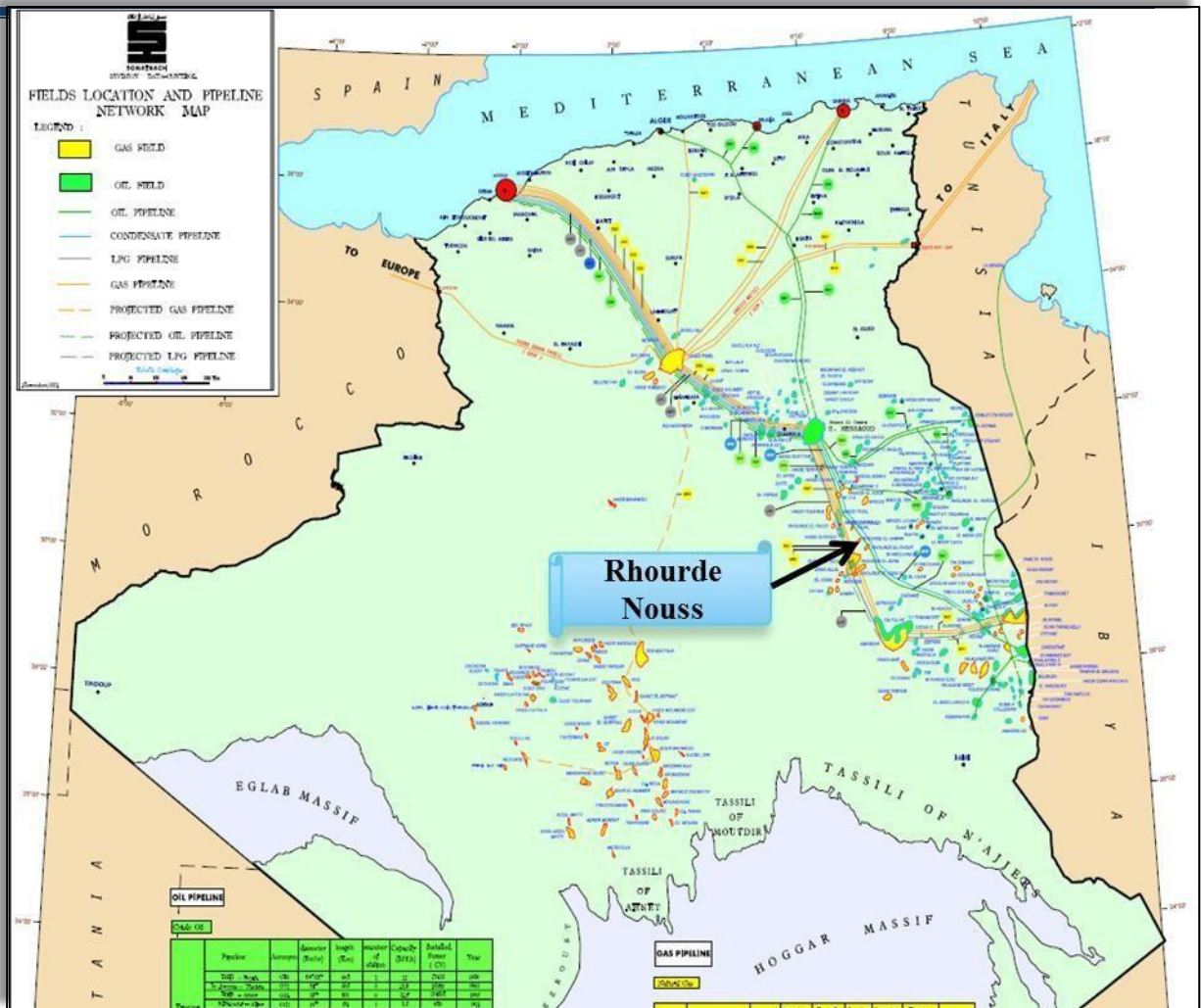


Figure I.1: geographical location of the Rhourde Nouss region

1.3 Geological Boundaries

The Rhourde-Nouss region is situated along the southern edge of the Triassic basin. It is bounded by:

- To the west, by the Amguid-ElBiod massif
- To the southeast, by the Illizi basin (western part of the Ahara massif)
- To the northeast, by the Ghadames basin

The RhourdeNouss area was the first unit within SONATRACH to install a DCS system at Hamra in 1995, enabling real-time data transmission.

1.4 Description of the Rhourde-Nouss Field

The main fields under exploitation are:

- Rhourde-Nouss Central
- Rhourde-Nouss Northeast
- Rhourde-Nouss Southeast
- Rhourde-Nouss Southwest
- Rhourde-Chouff
- Rhourde-Adra
- Rhourde-Hamra
- Hamra

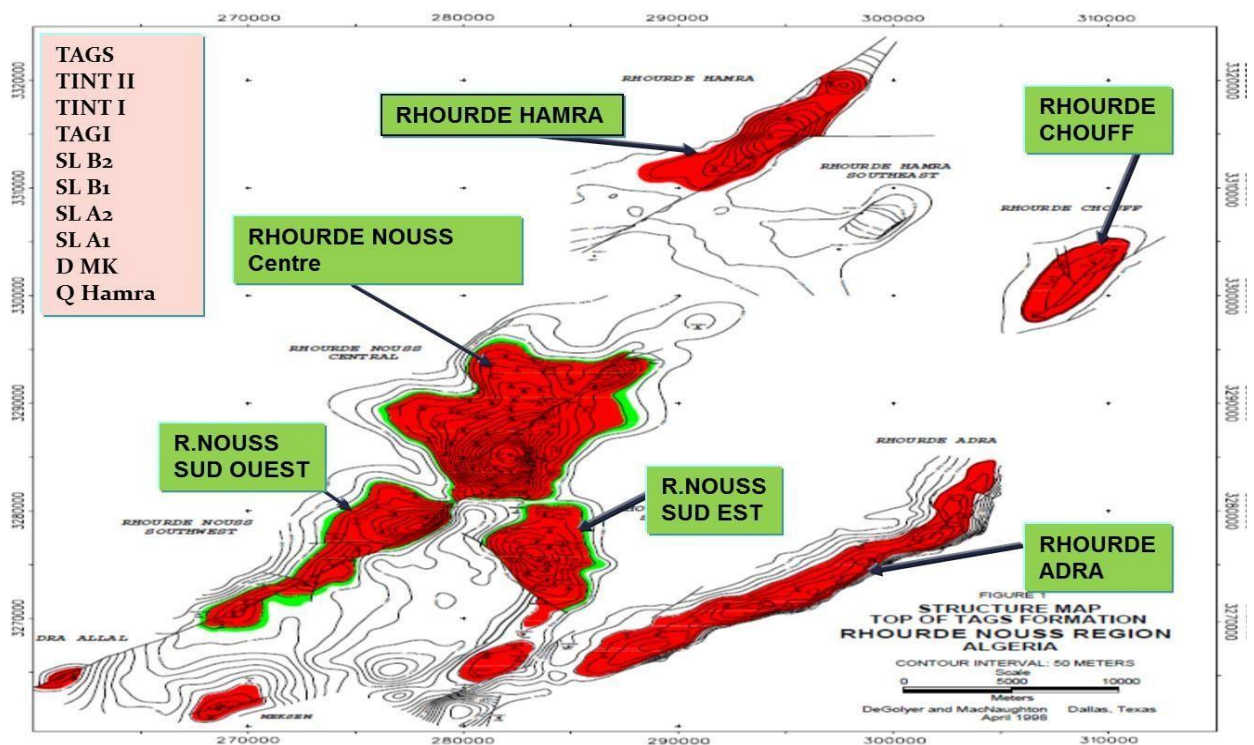
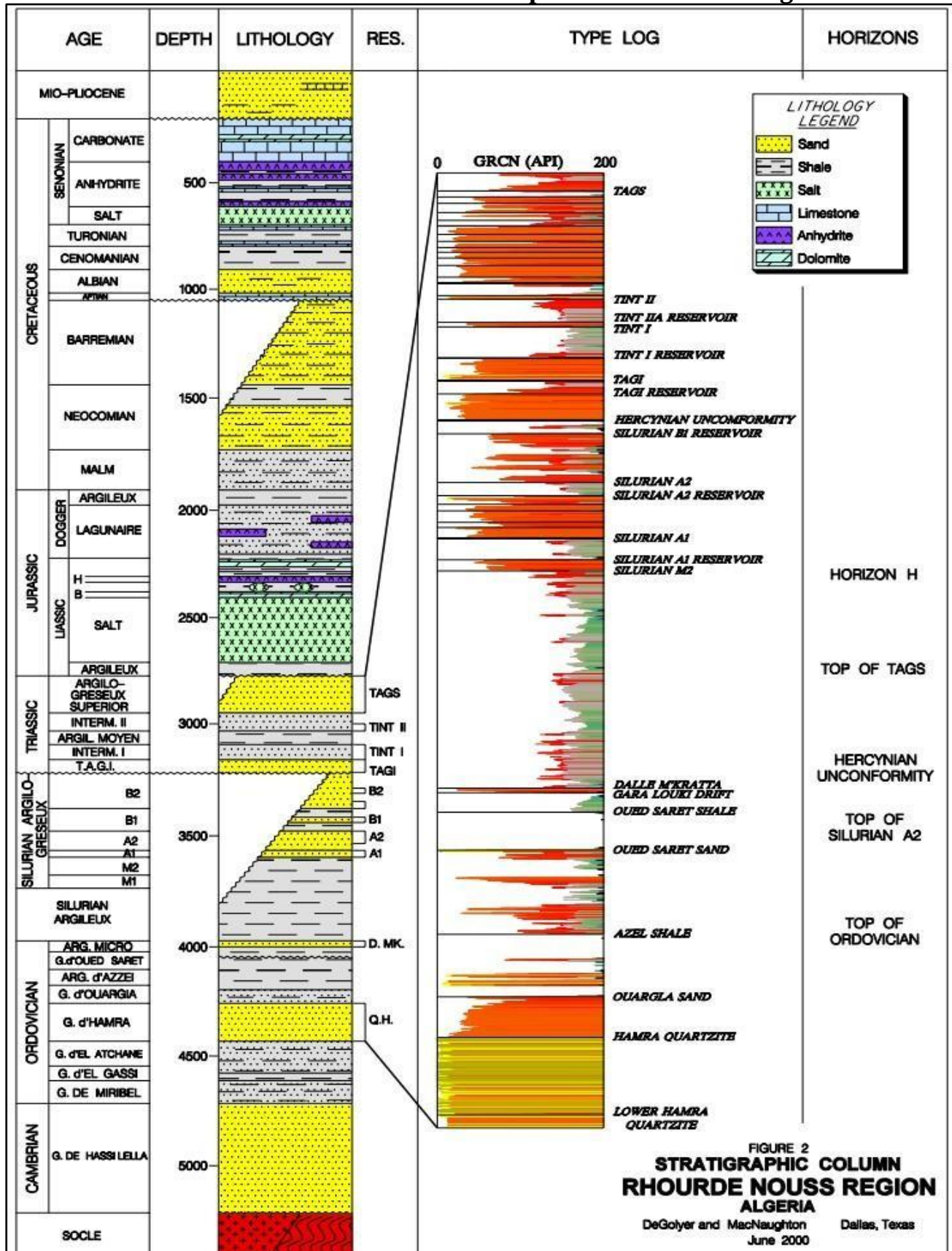


Figure I.2: The main Fields of RhourdeNouss

CHAPTER I:

Field description with some fluid generalities



FigureI.3: Stratigraphic columns of the RhourdeNouss region

1.5 General Overview of the Rhourde Nouss Central Structure

The Rhourde Nouss structure was brought into production in 1988 with the drilling of 23 production wells, averaging a flow rate of 18 million standard cubic meters per day (Mscm/d), and 12 injection wells with an injection capacity exceeding 8 million standard cubic meters per day (Mscm/d). The exploited reservoir is the Triassic Clays and Sandstones (TAGS).

1.5.1 Analysis of the Production History of the Rhourde Nouss Field

The RhourdeNouss field was put into production in February 1988, with an initial average flow rate of approximately 18 Mscm/d. Based on the production history; three distinct periods can be identified:

1.5.1.1 Period from 1988 to the end of 1994:

Initially, there were disturbances during the field startup, followed by stabilization of the flow rate at around 18 Mscm/d. A notable decline in production occurred during 1993/1994 due to work-over operations (changing completion, replacing carbon steel tubing with 13% Cr high-grade steel).

1.5.1.2 Period from late 1995 to late 1999

An increase in production flow rate to about 20 Mscm/d was observed, compensating for the shortfall in RhourdeAdra's production after the closure of three producers from that structure.

1.5.1.3 Period from late 1999 to early 2002

The production rate increased further to approximately 22 Mscm/d following the plugging of certain wells.

Comparison with the simulation conducted by DMN indicates that actual field production exceeds the projected figures.

1.5.2 Condensate Richness in the RhourdeNouss Central Area

Currently, three classes of condensate richness are recognized:

❖ First Class

This class includes wells located on the southwestern periphery, which have a condensate richness of 130 g/m³. This part of the structure has maintained pressure effectively, resulting in good sweep efficiency.

❖ Second Class

This class includes wells located at the top of the structure (RN01, RN26, RN47, RN28)

as well as wells near faults. These wells exhibit lower condensate richness compared to the field's average, with values ranging from 40 to 70 g/m³. These lower figures are attributed either to the wells' positioning at the summit of the structure, where gas accumulations are poor in condensable products, or to the arrival of injected dry gas transported via faults.

❖ Third Class

This class comprises wells that are distant from the injection lines, with a more or less average condensate richness of approximately 90 to 105 g/m³. The pressure drop follows a normal distribution depending on the production regime

Very low rainfall (2 to 4 mm/year) and strong sand wind occurrences. The average altitude is approximately 275 meters above sea level.

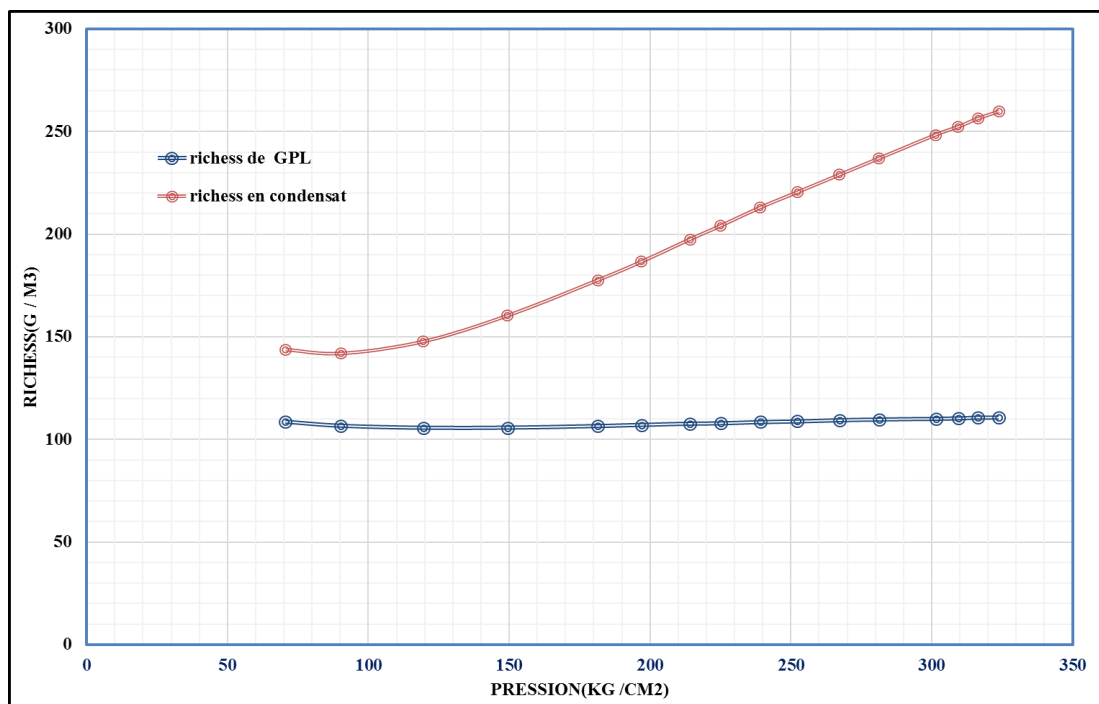


Figure I.4: The richness in condensate and GPL

1.5.3 Characteristics of the Reservoir Fluids

a) Oil

Evaluation of the reservoir fluid properties was conducted using synthetic core analysis (Evaluation carried out in February 1977 by CORE LAB) on samples collected from wells RN4 and RN6. Among all laboratory studies performed during this evaluation, this was the most comprehensive.

Another sample was obtained by a representative from Core Laboratories from well RN15 on October 19, 1977, during its drilling. During this PVT study, the bubble point pressure was found to be 276 kg/cm², compared to the initial pressure of 297 kg/cm². The cumulative oil production to date was approximately 2 million stock tank cubic meters (MM STB), with associated gas production around 4.5 million stock tank cubic meters (MMM m³).

b) Gas Cap

Two PVT studies of the TAGS gas cap were conducted, based on two samples taken from wells RN2 and RN3. The PVT study of RN2 is the most representative. The dew point pressure observed was 283.0 kg/cm², quite close to the initial formation pressure of 297.6 kg/cm². The flowing pressure was 281.8 kg/cm².

Regarding the RN3 study, the well was flowing at 215.4 kg/cm² during sampling, which likely caused retrograde condensation around the wellbore.

Therefore, the data from this study should not be considered representative.

Table I.1 : Fluid characteristics of RNS central

Composition	Molar Fraction (%)	Molar Mass (g/mole)	Density (g/cm³)
N₂	0,63	28,016	0,808
CO₂	0,77	44,01	0,827
C₁	78,92	16,042	0,300
C₂	7,93	30,068	0,377
C₃	3,54	44,074	0,508
iC₄	1,11	58,12	0,563
nC₄	1,52	58,12	0,584
iC₅	0,7	72,146	0,625
nC₅	0,69	72,146	0,631
C₆	0,92	86,172	0,664
C₇₊	3,27	133	0,688

c) Reservoir Fluid Composition

Table I.2: Characteristics Of The Central Reservoir Fluids

Type de Fluide	Densité	GOR (m3/m3)	Prosée (Bar)	Bg(m3/m3)
Gaz a condensat	0.74	4650	300	0,004

d) Reservoir Water Characteristics

Two analyses of the reservoir water are available from well RN4. These samples were collected during formation testing at a depth of 2728 meters.

The properties of the water at 300 kg/cm² and 105°C are:

- Density: 1.124 g/cm³
- Viscosity: 0.284 cP
- Compressibility: 4.6×10^{-5} L/Kg/cm²
- Gas-Water Ratio: 0.516 m³/STB
- Formation Volume Factor: 1.038 m³/STB

1.5.4 Geology

The reservoir consists of two layers forming the TAGS reservoir: the basal sand layer ("Basal Sand") and the main reservoir layer ("Main Reservoir"). The first layer has a thickness of approximately 10 to 15 meters, while the second layer ranges from 100 to 200 meters in thickness.

1.5.5 Petro physics

The main reservoir layer has a thickness of 100 to 200 meters and exhibits good petro physical characteristics. Porosity varies between 15% and 20%, permeability reaches values on the order of a Darcy, and the irreducible water saturation (S_{wi}) is around 20%.

1.6 The importance of a PVT analysis

Oil companies are very interested in PVT analyses. Exploration companies, in particular. These analyses determine the characteristics and behavior of reservoir fluids under different conditions of pressure, volume, and temperature. The main objective of such a study is to:

- Estimate the volume of oil and gas in the tank.
- Study the thermodynamic behavior of reservoir fluids.
- Property requirements for reservoir engineering calculations.
- Provide information on reservoir pressure decay as a function of time.
- Calculate the flow properties of the reservoir fluid.
- Optimize liquid recovery.
- Define the type of reservoir fluid.
- Calculation and optimization of surface installations (production column, pipe, separators, etc.).
- Establish a development plan and a production method that maximizes profit.
- Study the deposition mechanisms of organic deposits (asphaltenes, kerosenes) and their prevention.
- Creation of a PVT model.

1.7 General information on oil and gas properties

Crude oil and natural gas are the most common forms of hydrocarbon mixtures extracted from the subsoil.

These hydrocarbon mixtures can exist in solid, liquid, or gaseous form, depending on the pressure and temperature conditions in the reservoirs or the production equipment through which they pass.

The liquid and gaseous phases under which hydrocarbon mixtures are most often exploited are usually associated. For example, the production of crude oil is almost usually accompanied by the production of gas, and conversely, the exploitation of a gas deposit very often leads to the production of liquids.

The most important properties for oil production are:

- Saturation pressure at reservoir temperature
- Apparent molecular weight, M_a
- Gas solubility in reservoir oil
- Compressibility factor, z
- Density,
- Formation volume factor
- Viscosity
- Solution gas density.
- Isothermal coefficient of compressibility

- Chemical compositions.

Data on most of these fluid properties are usually determined by laboratory experiments on reservoir fluid samples.

In the absence of experimentally measured properties of crude oils, the petroleum engineer must determine the properties from empirically derived correlations.

1.8 Petroleum fluid composition

1.8.1 Gases

These are complex mixtures of hydrocarbons, essentially containing the first elements of the paraffinic series, namely:

Table 1.3 : TABLE OF GAS COMPONENTS

• Méthane C_1H_4	<i>Ou</i>	C_1
• Ethane C_2H_6	<i>Ou</i>	C_2
• Propane C_3H_8	<i>Ou</i>	C_3
• Butane C_4H_{10}	<i>Ou</i>	C_4

A. Dry gases, wet gases, and gases with retrograde condensate

As pressure drops during production, some of the dissolved gas re-gasifies, and the gas bubbles carry the oil with them toward the outlet.

When the gas has almost completely escaped or if the oil contains very little gas in its natural state the well ceases to be eruptive or may not be eruptive at all.

Sometimes, a cap of free gas (called a gas cap) overlies the oil-saturated layer, which itself is saturated with dissolved gas.

When they reach the surface, some natural gases remain in a gaseous state. These gases, mainly composed of C_1 (methane), C_2 (ethane), C_3 (propane), N_2 (nitrogen), and H_2 (hydrogen), are referred to as dry gases. Other gases deposit some of their components known as gasoline and are referred to as wet gases or retrograde condensate gases.

When the pressure of such a gas is reduced (at constant temperature), a drop of liquid forms (known as retrograde dew point pressure). As the pressure continues to decrease:

The amount of condensate increases,
Reaches a maximum,
Then decreases again.

Eventually, the condensate disappears entirely at a second pressure value (also called the dew point pressure).

$$T_c < T_g < T_{cc}.$$

Therefore, we can distinguish two classes of gas:

The first class includes hydrocarbons that are still in a gaseous state in the reservoir ($T_g > T_{cc}$): these are wet gases.

2. The second class includes gases which, when expanded to reservoir temperature (isothermal expansion), can deposit condensate in the reservoir. These are known as retrograde condensate gases [11].

B. Oils

Crude oils are mixtures of heavy hydrocarbons. They are mainly made up of:

Table 1.4 TABLE OF OIL COMPONENTS

<i>C5</i>
<i>C6</i>
<i>C7</i>
C8 PLUS

Under pressure, under reservoir conditions crude oil also contains lighter elements (C_1 , C_2 , C_3 , C_4 , H_2S , CO_2 , etc.), which begin to degas when the pressure is lowered to the saturation or bubble point pressure.

In other words, crude oil can release a significant proportion of its volatile components both within the reservoir during its productive life and during production, as it moves from the reservoir to surface storage.

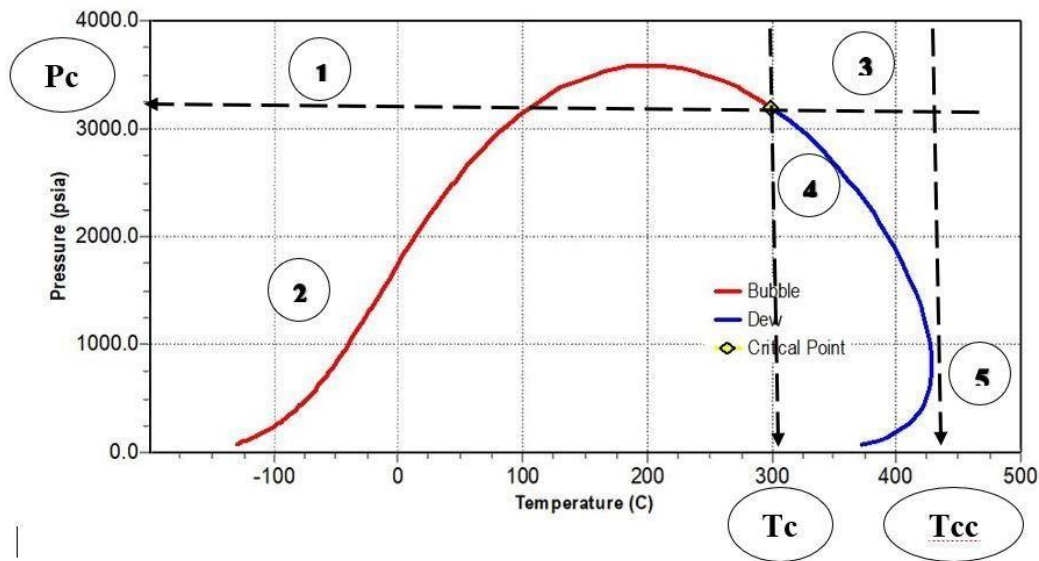


Figure I.5: phase diagram (Pressure-temperature) of a wet gas

The P–T diagram (pressure–temperature diagram) illustrates the classification of reservoirs according to thermodynamic criteria (Figure).

(Figure: Pressure-temperature diagram)

- Point 1: Single-phase liquid zone, under-saturated oil.
- Point 2: Two-phase vaporization zone.
- Point 3: Single-phase gas zone, with condensate.
- Point 4: Biphasic zone of retrograde condensation.
- Point 5: Single-phase gas zone [12].

1.9 Natural gas properties

A gas is defined as a homogeneous fluid of low viscosity and density that has no fixed volume but expands to completely fill the container in which it is placed.

Typically, natural gas is a mixture of hydrocarbon and non-hydrocarbon gases. The hydrocarbons commonly found in natural gas include methane, ethane, propane, butane, pentane, and small quantities of hexane.

Non-hydrocarbon gases (impurities) include carbon dioxide, hydrogen sulfide, and nitrogen [13].

1.9.1 Molecular mass

One of the main properties of gases that often interests engineers is the apparent molecular weight.

If y_i represents the mole fraction of component i in a gas mixture, the apparent molecular

weight is mathematically defined by the following equation (1):

$$M_g = \sum_{i=1}^n y_i M_i \dots \dots \dots (I.1)$$

With:

- (y_i) : Mole fraction of component i
- (M_i) : Molecular weight of the component
- (M_g) : Apparent molecular mass of a gas mixture [12]

1.9.2 Density

Gas density is the mass of gas contained in a unit volume

$$\rho_g = \frac{M_g}{V} \dots \dots \dots (I.2)$$

With:

- (M_g) : Molecular mass of the gas
- 28.966: The molar mass of air [13]

1.9.3 Gas formation volume factor (B_g) :

The gas formation volume factor is used to relate the volume of gas measured under reservoir conditions to the volume of gas measured under standard conditions.

This gas property is defined as the actual volume occupied by a given quantity of gas at a specified pressure and temperature, divided by the volume occupied by the same quantity of gas under standard conditions, as expressed by the following equation (3):

$$B_g = \frac{v(P, T)}{v(P_{sc}, T_{sc})} \dots \dots \dots (I.3)$$

With:

- (B_g) : Gas formation volume factor, ft³/scf.
- $(V(p, T))$: Volume of gas at pressure P (psi) and temperature T (K).
- (V_{sc}) : Volume of gas at standard conditions, scf.

It can also be expressed according to the following equation (4):

$$B_g = \frac{T}{T_{sc}} Z \frac{P_{sc}}{P} \dots \dots \dots (I.4)$$

With:

- (Z) : Compressibility factor [11].

1.9.4 The compressibility factor (Z)

To describe the behavior of gas mixtures, the petroleum industry has introduced the dimensionless coefficient (Z) , called the compressibility factor.

Using standard notation, the equation of state for natural gases is given by the following equation (5):

$$PV = ZnRT \quad \dots \dots \dots (I.5)$$

$$P_{pr} = \frac{P}{P_{pc}} \quad avec : \quad P_{pc} = \sum_{i=1} y_i P_{ci} \quad \dots \dots \dots (I.6)$$

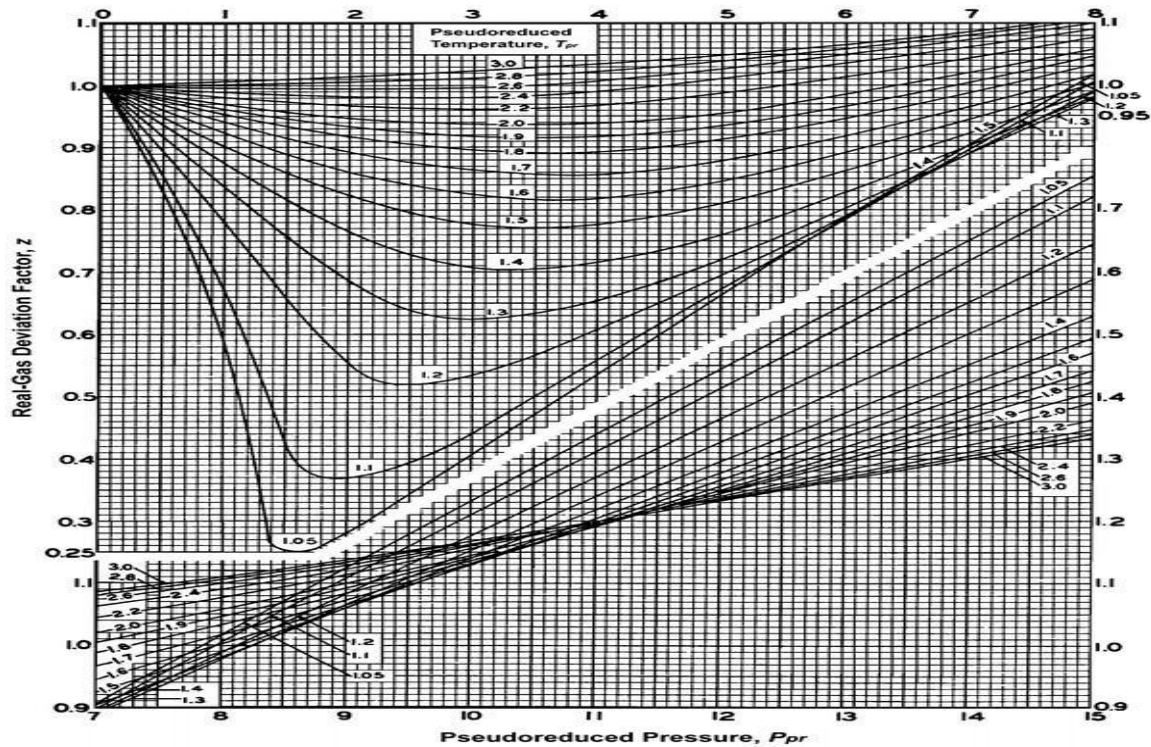
$$T_{pr} = \frac{T}{T_{pc}} \quad avec : \quad T_{pc} = \sum_{i=1} y_i T_{ci} \quad \dots \dots \dots (I.7)$$

- P_{pr} pseudo-reduced pressure of the mixture
- T_{pr} pseudo-reduced mixture temperature
- P_{ci} critical pressure of component i
- T_{ci} critical temperature of component i
- P_{pc} pseudo-critical pressure of the mixture
- T_{pc} pseudo-critical temperature of the mixture

The compressibility factor depends on gas compressibility, pressure, and temperature.

As pressure tends toward 0, molecular interactions diminish; the behavior of the gas tends toward that of a perfect gas, and (Z) tends toward 1.

The compressibility factor can be determined by pseudo-reduced pressure and pseudo-reduced temperature, using the Standing and Katz diagram (Figure I.2).



(Figure I.6: Diagram of compressibility factors (Z) by Standing and Katz)

This diagram is generally reliable for natural gas with a minor amount of non-hydrocarbons. It is one of the most widely accepted correlations in the oil and gas industry [14].

1.9.5 Gas viscosity

Lee, Gonzalez, and Eakin (1966) presented a semi-empirical relationship for calculating the viscosity of natural gases. Their proposed equation is given by the following (6):

$$\mu_g = 10^{-4} K \exp \left[x \left(\frac{P_r}{62.4} \right) \right] \dots \dots \dots (1.8)$$

With:

- (T) : Reservoir temperature, °R

- (M_a) : Molecular mass of the gas mixture [13].

1.10 Properties of Crude Oil

An accurate description of the physical properties of crude oil is of considerable importance in applied and theoretical science, particularly in solving petroleum reservoir engineering problems. Physical properties of primary interest in petroleum engineering studies include:

1.10.1 Bubble Point Pressure

The bubble point pressure (P_b) of a hydrocarbon is defined as the highest pressure at which a gas bubble first releases from oil. This important property can be measured experimentally for a crude oil system by performing a constant composition expansion test [10].

1.10.2 Density

The density of a liquid is the ratio of its density to that of water. Each is measured at a given temperature. In the petroleum industry, the standard temperature of 15°C is accepted for both water and oil under these conditions. The density of crude oil varies from 0.700 for light condensates to values somewhat greater than unity for bitumen's, according to the following equation [7]:

$$d_0 = \frac{\rho_o}{\rho_w} \dots \dots \dots (I.9)$$

Where:

- (ρ_o) = density of crude oil
- (ρ) = density of oil
- (ρ_w) = water density

The American industry uses API gravity to measure crude oil density.

$$API = \frac{141.5}{d_0} - 131.5 \dots \dots \dots (I.10)$$

1.10.3 Gas-to-Oil Ratio (GOR)

The GOR is defined as the ratio of the volume of gas released to the volume of separator liquid measured under standard conditions. It represents the quantity of gas dissolved in the reservoir oil and is given by equation [13].

$$GOR = \frac{\text{volume gaz (cs)}}{\text{volume huile (cs)}} \dots \dots \dots (I.11)$$

1.10.4 Solution Gas-Oil Ratio (R_s)

The solution gas-oil ratio (R_s) is defined as the standard volume of gas that will dissolve in a barrel of crude oil at a given pressure and temperature. The solubility of natural gas in crude oil is highly dependent on gas pressure, temperature, API gravity, and density. It is called the GOR solution.

1.10.5 Oil Formation Volume Factor (B_o)

The oil formation volume factor (B_o) is defined as the ratio between the volume of oil (plus gas in solution) at reservoir temperature and pressure, and the volume of oil under standard conditions. (B_o) is always greater than or equal to unity. The volume factor for oil formation is given by equation [11]:

$$B_o = \frac{V_o(p, t)}{V_{sc}(p_{atm}, 15^\circ\text{C})} \dots \dots \dots (I. 12)$$

Where:

- ($V(p)$): volume of oil at pressure (P) and temperature (T) of the tank
- (V_{sc}): volume of oil measured under standard conditions

1.10.6 Contraction Factor (F_c) or Shrinkage (Sh)

The difference between the initial volume (pressure and temperature) and the volume at the storage tank represents the liquid contraction. This contraction is due to both the release of dissolved gas caused by the drop in pressure and the drop in temperature. It is given by equation [12].

$$SF = \frac{V_{ST}}{V_{SZ}} \dots \dots \dots (I. 13)$$

1.10.7 Oil Compressibility

Compressibility is a characteristic of a material that defines its relative change in volume under the effect of applied pressure. It is very high for gases, low for liquids, and very low for common solids. It is defined by equation [13]:

$$C_o = -\left(\frac{1}{V}\right) \left(\frac{\partial V}{\partial P}\right)_T \dots \dots \dots (I. 14)$$

Where:

- (C_o) = oil compressibility

- (V) = volume

- $(\frac{\partial V}{\partial P})$ = volume change with respect to pressure

1.10.8 Oil viscosity

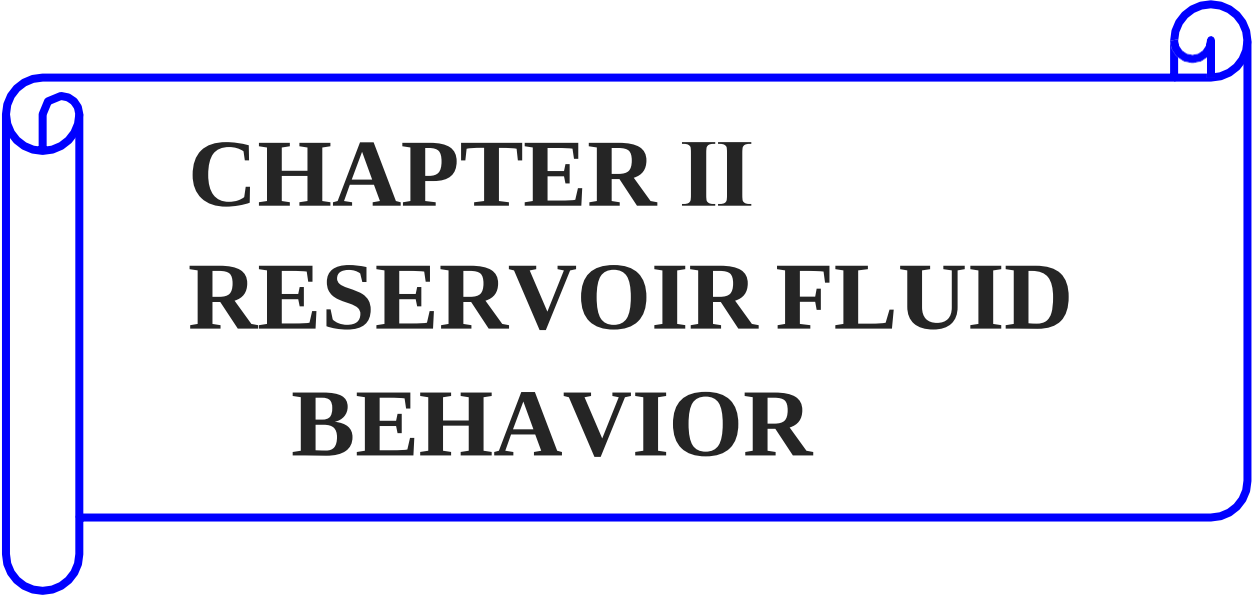
The viscosity of crude oil is an important physical property that controls and influences the flow of oil through porous media, production pipes, and at the surface. Viscosity, in general, is defined as the fluid's internal resistance to flow.

Conclusion

The characterization of fluid properties is very important in the oil industry. Knowledge of key thermodynamic parameters such as fluid pressure and temperature, gas-oil ratio (GOR), formation volume factor, compressibility factor, and density, among others, helps reservoir engineers assess reservoir behavior and the volumetric performance of fluids at different pressure levels.

Moreover, obtaining these properties can also help solve many production-related problems. For this reason, by studying and analyzing PVT (Pressure-Volume-Temperature) data through specific tests on representative samples taken from the tank in a laboratory, we are able to collect these properties.

In the following chapter, we will explain these tests and the experimental procedures.



CHAPTER II RESERVOIR FLUID BEHAVIOR

2.1 Introduction

Crude oils and natural gas are the most common forms of hydrocarbon mixtures extracted from the subsurface. These mixtures can exist in solid, liquid, or gaseous states, depending on the pressure (p) and temperature (T) conditions under which they are found. The liquid and gaseous phases in which hydrocarbon mixtures are most often exploited are usually associated: the production of crude oil is often accompanied by the production of gas, and vice versa.

For crude oil, it is practically impossible to determine its complete composition due to the complexity of its constituents. Therefore, we rely on certain physical properties (e.g., color, odor, density, viscosity, refractive index) to differentiate between produced oils.

As for natural gas, at the final stage of exploitation, it is essentially characterized by three properties: density, calorific value, and chemical composition (nature of compounds and their molar or volumetric fractions).

2.2 Constituents of Reservoir Fluids

Petroleum reservoir fluids are multi-component mixtures primarily composed of hydrocarbons. Methane (CH_4) is the simplest and most common hydrocarbon. Hydrocarbons with seven or more carbon atoms are referred to as C7+ components, and this group is collectively known as the C7+ fraction [2]. A given component in this fraction can fall under one of the following categories:

2.2.1 Paraffins

Paraffinic compounds are made of hydrocarbon segments such as C, CH, CH_2 , or CH_3 , with carbon atoms connected by single bonds. Paraffins are categorized as normal paraffins (n-paraffins) when their carbon atoms form straight chains, and as iso-paraffins (i-paraffins) when they include side chains. Paraffins are also known as alkanes.

2.2.2 Naphthenic

These compounds are similar to paraffins in structure but include one or more cyclic rings. The cyclic segments (e.g., CH_2) are also connected by single bonds. Most naphthenic rings contain six carbon atoms, though five- or seven-membered rings are also common in reservoir fluids.

2.2.3 Aromatics

Aromatic compounds also contain cyclic structures, but unlike naphthenic, the carbon atoms are connected by alternating double bonds known as aromatic bonds. Benzene (C_6H_6) is the simplest aromatic compound. More complex structures such as polycyclic aromatics—, which contain two or more aromatic rings—are also found in petroleum fluids.

2.2.4 Olefins

In organic chemistry, olefins (or alkenes) are hydrocarbons that contain at least one carbon–carbon double bond. This bond may be terminal or internal. Terminal alkenes are also referred to as α -olefins.

The proportions of paraffinic (P), naphthenic (N), aromatic (A), and olefinic (O) compounds in a reservoir fluid are often referred to as the PONA distribution.

Reservoir fluids may also contain inorganic compounds, the most common of which are nitrogen (N_2), carbon dioxide (CO_2), and hydrogen sulfide (H_2S). Water (H_2O) is another important component, but due to its limited miscibility with hydrocarbons, it is generally found in a separate layer below the oil and gas zones.

2.3 Behavior of Hydrocarbon Phases

A phase is a physically distinct and homogeneous part of a system, separated from other phases by clearly defined boundaries. Although the phase of a substance depends on both pressure and temperature, changing either can cause a phase transition—a phenomenon known as phase behavior [1, 3].

Hydrocarbon systems in petroleum reservoirs exhibit multiphase behavior over a wide range of pressure and temperature conditions. The most relevant phases in the oil and gas industry are:

- Liquid phase, such as crude oil and condensate
- Gaseous phase, such as natural gas

Understanding the conditions under which these phases exist is critical. These conditions are often represented graphically using phase diagrams, which help describe and predict the volumetric behavior of fluids. This chapter aims to present the fundamental principles of phase behavior and demonstrate the use of phase diagrams in characterizing both single- and multi-component systems.

2.3.1 Single-Component Systems

The simplest hydrocarbon system consists of a single component, composed of identical molecules.

1. a Pressure–Temperature (P–T) Diagram

If we plot the bubble and dew points in terms of pressure (p) and temperature (T), we find that they coincide for each temperature in a single-component system. Hence, the saturation curve, which represents the two-phase region, ends at the critical point (P_c , T_c), as illustrated in Figure

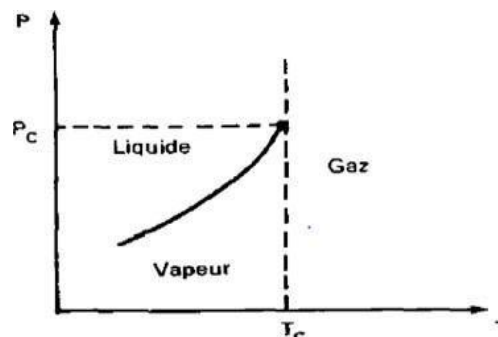


Figure II.1: Pressure-temperature diagram for a pure substance

In the Clapeyron diagram, the behavior of a pure substance under varying pressure and volume conditions can be described in the following sequence:

- A rapid decrease in pressure is observed as long as the pure substance remains in the liquid phase, due to the fact that liquids are not highly compressible.
- The appearance of a vapor phase occurs at the bubble point (point B in Figure I.2), where the first gas bubbles begin to form within the liquid.
- As vapor formation increases and the liquid phase decreases, pressure remains constant, even though the volume continues to expand.
- At the dew point (point R in the figure), the last drop of liquid disappears, and the substance becomes entirely vapor.
- Beyond this point, a relatively slow decrease in pressure is observed as the gas expands, reflecting the fact that vapors are compressible.

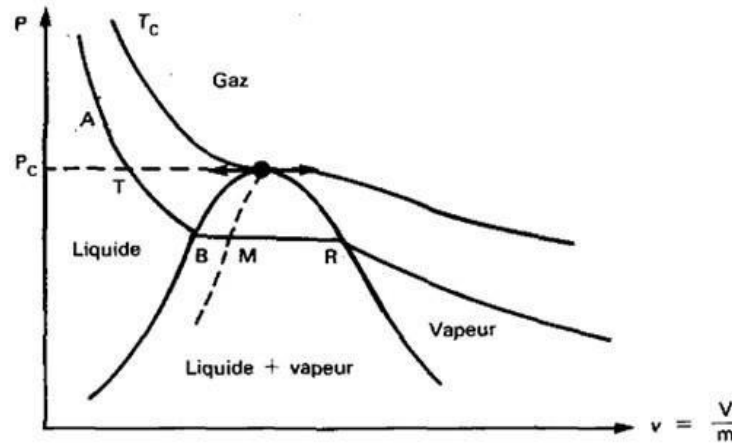


Figure II.2: Pressure–volume diagram for a pure substance (Clapeyron diagram)

We can repeat the experiment. The experiment can be repeated at temperatures both lower and higher than T , up to a temperature T_n , the critical temperature, above which the pure substance exists only in a single phase, regardless of the applied pressure.

The collection of bubble points at different temperatures forms the bubble curve, while the collection of dew points forms the dew curve. Together, these two curves are referred to as the saturation curve.

2.3.2 Multi-component Systems (Mixtures)

a. Pressure–Temperature Diagram

The saturation curve of a multi-component mixture is plotted in the form of a closed envelope, consisting of two branches:

- The bubble curve, and
- The dew curve.

The critical point of the mixture is located either to the left or to right of the maximum point on the saturation envelope.

The temperature and pressure at the critical point are generally different from the maximum values at which the two phases coexist. This behavior is illustrated in Figure.

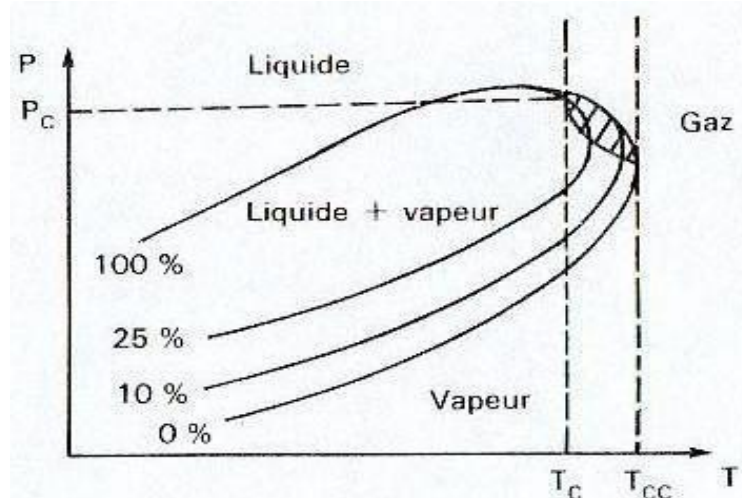


Figure II.3: Pressure–temperature diagram for two bodies and the mixture.

b. Pressure–Volume Diagram

We successively observe on the diagram in Figure

- A rapid decrease in pressure in the liquid phase.
- The appearance of a vapor phase at point B_1 ; bubble point.
- The increase in the vapor phase and the decrease in the liquid phase; the pressure decreases, but less rapidly than in the liquid phase alone.
- The disappearance of the last drop of liquid at the dew point R_1 .

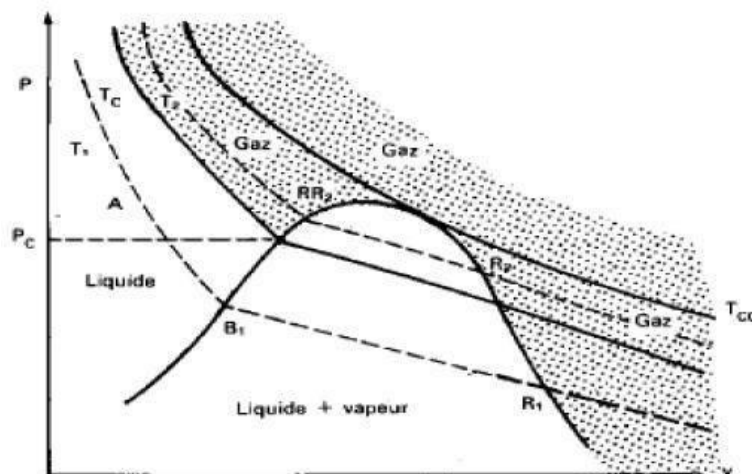


Figure II.4: pressure –volume diagram for two bodies and the mixture

2.4 Classification of Reservoir Fluids

To distinguish natural hydrocarbon mixtures, a common classification is based on basic physical properties. The mixture is typically referred to as either oil or gas.

However, in most cases, the exploitation of oil results in the production of gas, and conversely, the exploitation of gas often results in the production of some liquid hydrocarbons.

The main challenge, therefore, lies in determining the origin of the liquid production—that is, identifying the state in which it exists in the reservoir and its subsurface characteristics.

Hydrocarbon mixtures can be classified based on the following:

- Production data
- Effluent composition
- Pressure–temperature (P–T) diagrams

2.4.1 Classification Based on Production Data

The nature of the hydrocarbon mixture can be determined from production measurements taken during the initial well testing.

Density (API gravity)

This parameter helps distinguish between oil and condensate.

If the density is greater than 0.8 (i.e., API gravity < 45), the liquid is usually colored and is classified as oil.

Otherwise, the liquid is often colorless, indicating that it originates from the retrograde condensation of gas.

Gas-to-liquid ratio (GLR)

This ratio represents the volume of gas (measured under standard conditions) produced per unit volume of liquid.

It serves as a key indicator in distinguishing between oil reservoirs and gas condensate reservoirs.

Table summarizes the classification of different petroleum fluids:

Table II.1: Classification based on production data

Reservoir fluid Types	GOR [scf/stb]	D	API	<i>Rs</i> [scf/STB]	<i>Bo</i> [bbl/STB]	Color
Black oil (Fig.I.7)	100-2500	0,83- 0,88	15-40	200 - 700		Brown to dark green
Volatile oil (Fig.I.8)	3000	0,78- 0,83	<35	<200	<1,2	Black or deeply colored
Gas– Condensate (Fig.I.10)	5-100	0,7- 0,78	50<	8000 - 70.000	-	pale white or slightly colored
Wet gas (Fig.I.11)	100	0,7- 0,78	60<	60000 - 100000	-	pale white
Dry gases (Fig.I.12)	-	-	-	>100000	-	-

2.4.2 Classification Based on the Composition of the Effluent

The chemical composition of the effluent can also provide valuable insight into the type of fluid in equilibrium within the reservoir.

Hydrocarbon molecules vary greatly in size:

- Smaller molecules (e.g., methane, ethane, propane) typically exist in the gaseous phase under atmospheric pressure and temperature conditions.
- Larger molecules (e.g., hexane and heavier) are generally found in the liquid phase.

Thus, analyzing the relative presence of light versus heavy hydrocarbons in the effluent helps infer whether the reservoir fluid is predominantly gaseous or liquid under subsurface conditions.

2.4.3 Classification Using the P–T Diagram

While production data, density, gas–liquid ratio, chemical composition, and effluent color offer useful information regarding the nature of the produced fluid, they are not sufficient to fully characterize the fluid behavior.

These parameters do not account for reservoir conditions that control phase transitions within the system.

Therefore, reservoir fluids are more accurately classified by analyzing the location of the pressure–temperature point (P, T) that represents:

- The initial reservoir conditions, and
- The surface production conditions,

In relation to the saturation envelope (bubble point and dew point curves) of the hydrocarbon mixture.

This classification helps determine whether:

- The fluid behaves as under saturated oil (gas dissolved in oil only), or
- Free gas exists in the reservoir (i.e., the fluid is above the bubble point).

It is common practice to categorize reservoir fluids into five types, depending on their location on the P–T diagram and phase behavior:

- Black Oil (rich in heavy components)
- Volatile Oil
- Gas Condensate
- Wet Gas
- Dry Gas

These types are illustrated in Figure I.5.

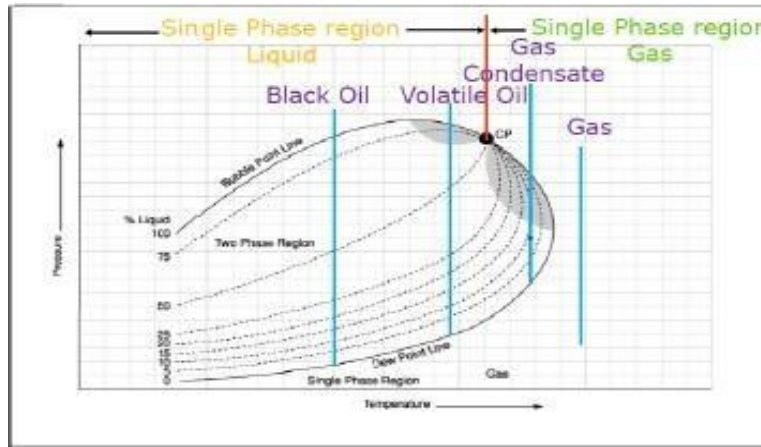


Figure II.5: The different types of reservoir fluids.

a. Black oil

Black oil contains a relatively small amount of gas in solution and is rich in heavy hydrocarbon components.

As a result, its critical temperature is relatively high, and its critical point is generally located to the right of the cricondenbar (Pct) on the pressure–temperature diagram.

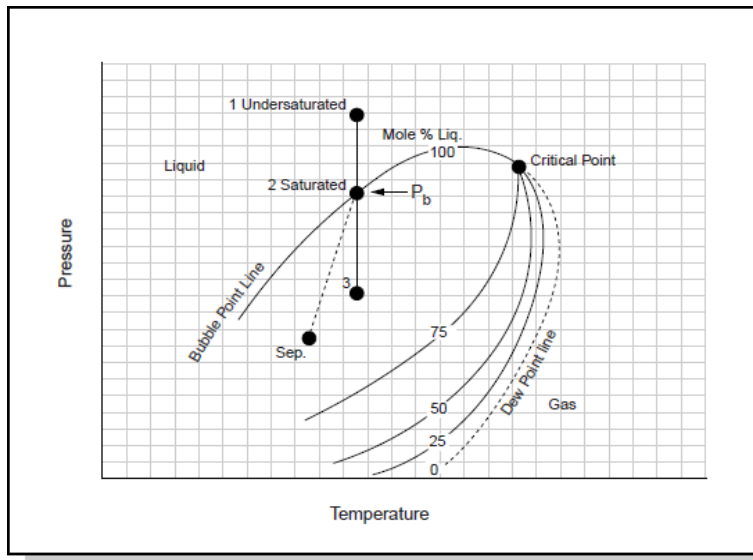


Figure II.6: Phase diagram for Black Oil.

b. Volatile oil

This oil contains more gas in solution than the previous case. It is therefore richer in volatile constituents (hence, T_c is lower and thus closer to T_r). The iso-volume lines in the phase diagram (Fig. I.8) are very close together near the bubble curve but very spaced out elsewhere (for

low pressures).

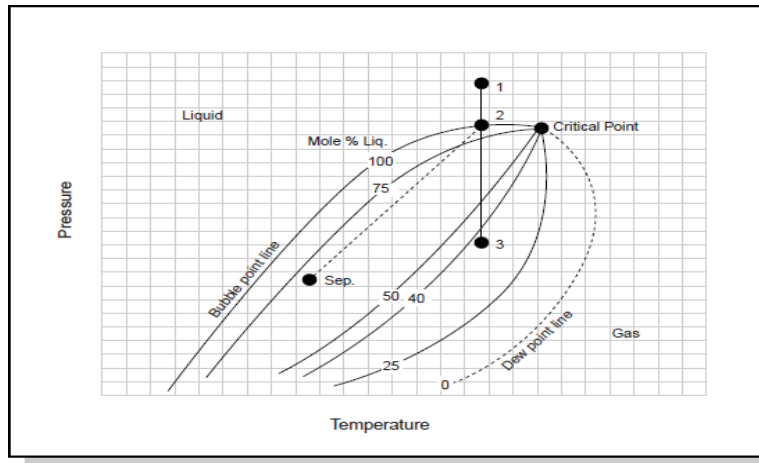


Figure II.7: Phase diagram for volatile oils.

c. Gas condensate reservoir

The hatched region in Figure II.8 represents the retrograde condensation zone, where a liquid phase is formed by depressurizing (i.e., reducing the pressure) a gas mixture.

When the reservoir pressure (P_r) is reduced at a constant temperature ($T_r = \text{constant}$), the first drop of liquid appears at point 2, corresponding to the intersection with the dew point curve.

As pressure continues to decrease, the liquid fraction increases, reaching a maximum value (30% in this example).

Beyond this point, which marks the end of the retrograde condensation, region further pressure reduction results in the gradual vaporization of the liquid phase. Eventually, the system crosses the dew point curve again, and the mixture becomes entirely gaseous once more.

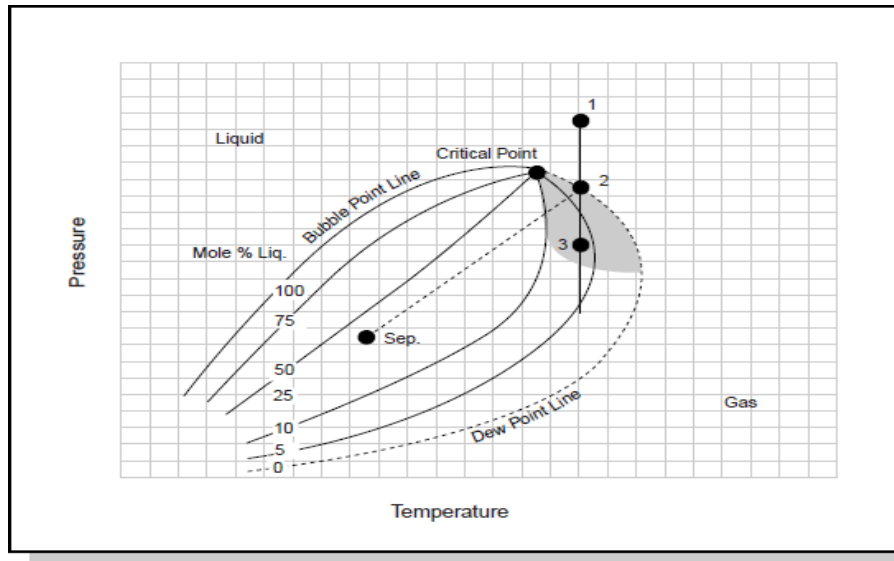


Figure II.8: Phase diagram for condensate gas.

For retrograde condensation to occur, the reservoir temperature (T_r) must lie between the critical temperature (T_c) of the gas mixture and its maximum condensation temperature (T_{ct}); that is, $T_c < T_r < T_{ct}$.

Under such conditions, the reservoir pressure (p_r) is typically close to the dew point pressure (Point 2), which causes hydrocarbon condensation to begin rapidly as soon as the reservoir is brought into production.

d. Wet Gas

A gas is classified as wet if liquid hydrocarbons are produced at the surface, but no retrograde condensation occurs in the reservoir (see Fig.).

In this case, the reservoir temperature (T_r) is greater than the maximum condensation temperature (T_{ct}), meaning that the two-phase region is not intersected, and no liquid phase forms in the reservoir during pressure depletion.

However, a liquid phase forms at the surface, where the conditions (T_s , p_s) fall within the liquid–vapor domain.

From a compositional standpoint, wet gas contains fewer heavy hydrocarbons than condensate gas; as a result, its critical temperature is lower, and the two-phase envelope is less pronounced.

Importantly, if surface conditions (temperature and pressure) remain fixed during reservoir depletion, the amount of surface liquid produced remains constant, and the composition of the

produced gas does not vary over time.

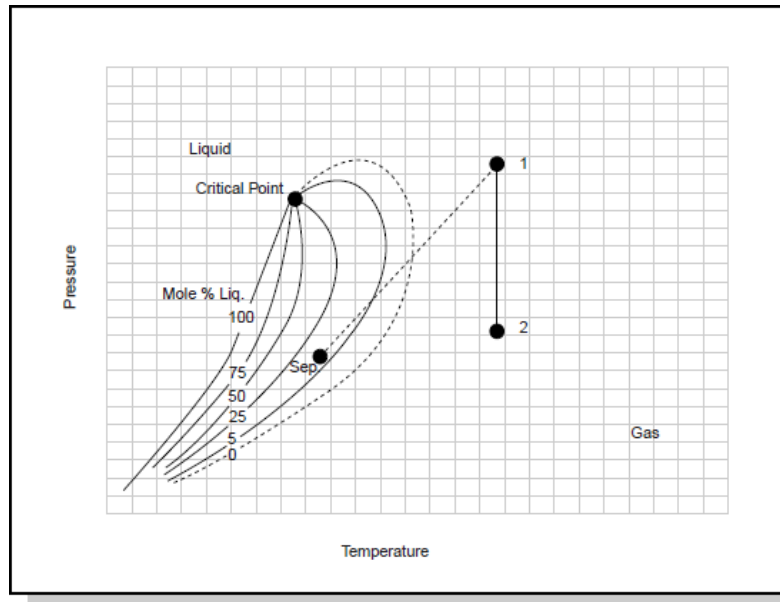


Figure II.9 Phase diagram for wet gas.

e. Dry gas

A dry gas does not produce liquid either under surface or reservoir conditions. The isotherm corresponding to the reservoir temperature T_r and the point representing surface production conditions T_s are, therefore, both located outside the gas saturation curve (hydrocarbon mixture) (Fig.).

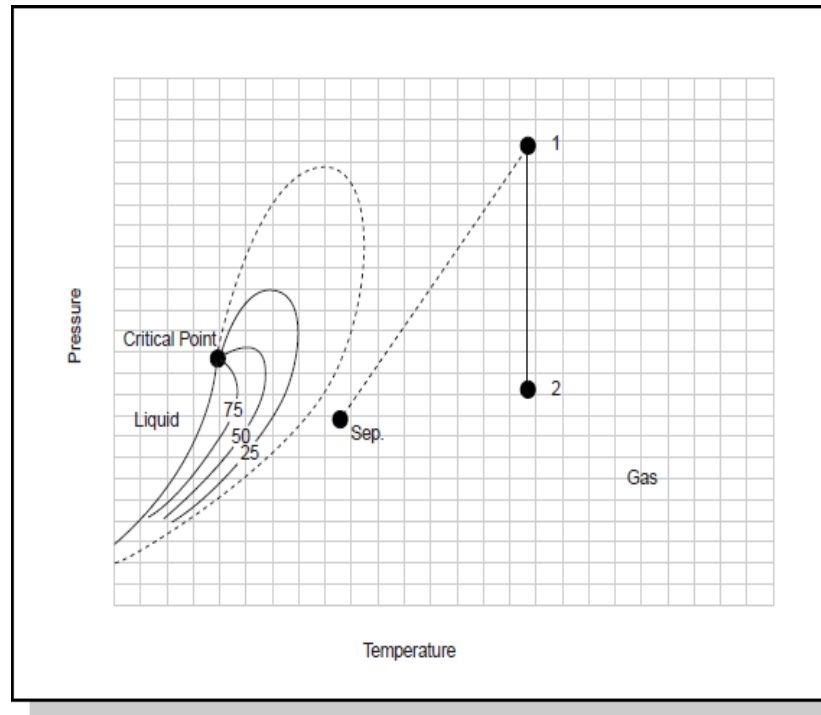
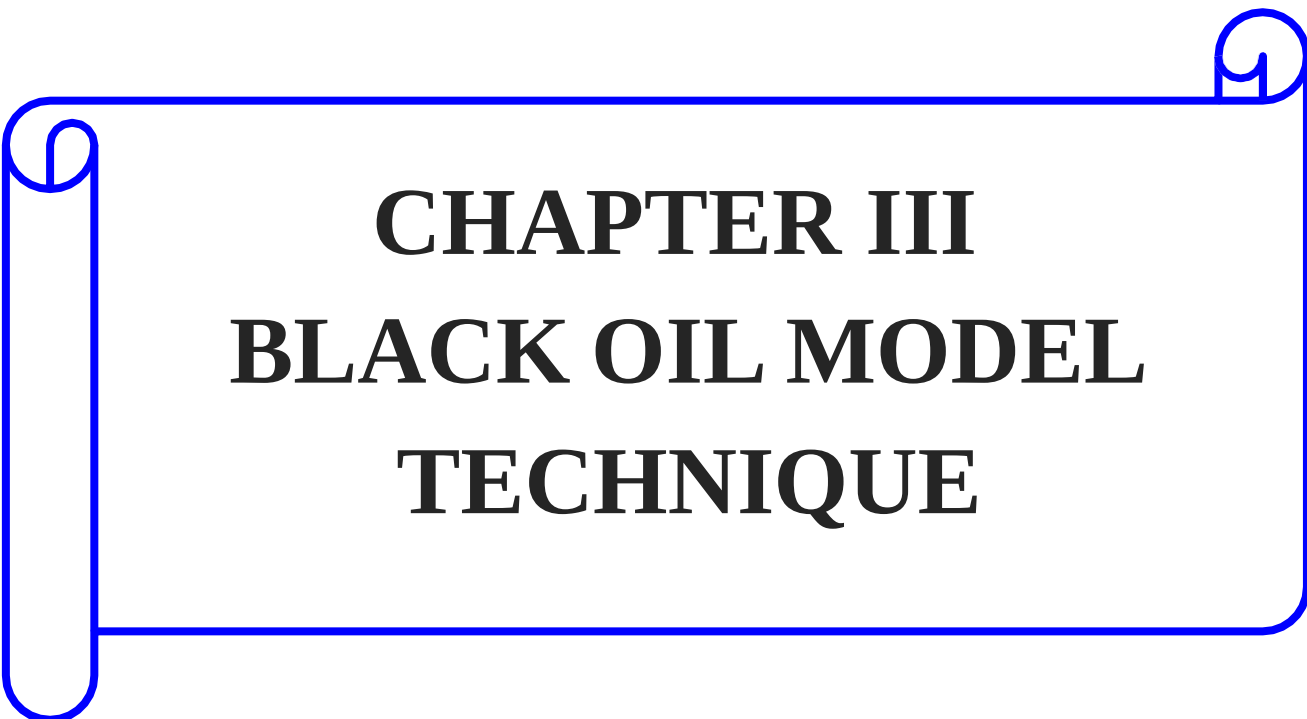


Figure II.10: Phase diagram for dry gas.

Conclusion

Reservoir fluids are classified into two categories based on whether their critical temperature is higher or lower than the reservoir temperature. In the first case, we deal with oils with dissolved gas, and in the second case, we deal with gases.

Gases, in turn, are further subdivided into three groups based on their critical temperature and the presence of liquid production under surface conditions. These groups are : condensate gas, wet gas, and dry gas.



CHAPTER III

BLACK OIL MODEL

TECHNIQUE

3.1 Introduction

Black-Oil Models in Petroleum Reservoir Engineering

Black-oil simulators are widely used in petroleum reservoir engineering for predicting the dynamics of oil production, particularly during the initial stages of oil-field exploitation. These simulators also play a key role in guiding pressure maintenance strategies for long-term reservoir management. The main assumption underlying the black-oil approach (in contrast to compositional flow models) is the classification of all reservoir species into two primary categories based on their physical state under surface conditions:

- A mixture of heavy hydrocarbon (H/C) components, containing all species that exist in a liquid phase at surface conditions (denoted as “o”).
- A mixture of volatile hydrocarbon components, containing all species that exist in a gaseous phase under surface conditions (denoted as “g”).

Additionally, the aqueous phase (“w”) is considered the third phase, which is abundant in petroleum reservoirs.

What is a Black Oil Model?

The black-oil PVT (Pressure-Volume-Temperature) model is a simplified fluid model that uses only two components surface gas and oil as compared to more complex compositional models such as the cubic equation of state (EOS) models (e.g., Peng-Robinson and Soave-Redlich-Kwong).

The properties that define the black-oil table are divided into volumetric properties (such as formation volume factors and surface volume ratios) and viscosity for each phase. The volumetric properties are represented by the oil formation volume factor (B_o) and gas formation volume factor (B_g), as well as the gas-oil ratio (R_s) and/or the oil-gas ratio (r_s or R_v).¹

3.2 Assumptions of the Black Oil Model

The main assumptions of the black-oil models are as follows:

- Three components (under standard conditions):
Water, oil, and gas.

¹ Brulé, C. H. (2000). *Phase Behavior*. Texas.

The composition of oil and gas is assumed constant over time, and the densities of water, oil, and gas are assumed to remain constant throughout the reservoir's life .and compositions are represented through PVT relationships R_s , B_o , B_g , etc.

- Three phases (under reservoir conditions):

Oil is a mixture of the oil and gas components.

Gas corresponds to the gas component.

Water corresponds to the water component.

- Three flow equations:

Oil Equation: Describes the flow of the oil component contained in the oil phase.

Gas Equation: Describes the flow of the gas component in both the oil and gas phases.

Water Equation: Describes the flow of the water component in the water phase.

3.2.1 Black-Oil Equations

The black-oil equations are a set of partial differential equations that describe the flow of fluids in an oil reservoir. These equations are essential for understanding the movement of oil, gas, and water through the reservoir during production.

$$\frac{\partial}{\partial t} \left(\frac{S_g}{B_g} + \frac{R_{so} S_o}{B_o} \right) + \nabla \cdot \left(\frac{1}{B_o} \frac{R_{so}}{B_o} u_g \right) = q_g \dots \dots \dots (III. 15)$$

$$\frac{\partial}{\partial t} \left(\frac{S_o}{B_o} \right) + \nabla \cdot \left(\frac{1}{B_o} u_o \right) = q_o \dots \dots \dots (III. 16)$$

$$\frac{\partial}{\partial t} \left(\frac{S_w}{B_w} \right) + \nabla \cdot \left(\frac{1}{B_w} u_w \right) = q_w \dots \dots \dots (III. 17)$$

Where the volumetric phase velocity is given by

$$u_\alpha = - \frac{K_{r\alpha}}{\mu_\alpha} K (\nabla p_\alpha - \rho_\alpha g) ; \alpha = g, o, w \dots \dots \dots (III. 18)$$

The black-oil model is based on the coupled solution of mass conservation equations for the water (w), oil (o), and gas (g) phases (mixtures), subject to appropriate boundary and initial conditions. Additionally, it accounts for mass transfer of dissolved species between the oil and gas phases.

The basic partial differential equations² governing the black-oil model in a porous medium, expressed as conservation of mass for volatile species, heavy species, and water, are as follows:

Here, ϕ and K denote the porosity and intrinsic permeability tensor of the porous medium. The variables S_α , μ_α , ρ_α , p_α , u_α , B_α , $k_{r\alpha}$, and q_α represent the saturation, viscosity, density, pressure, volumetric velocity, formation volume factor, relative permeability, and external source term, respectively, for phase α .

R_{so} represents the gas solubility in the oil phase, and g is the acceleration due to gravity.

The system is closed by the local constraints. The three phases together fill the void space, satisfying the relationship:

$$S_g + S_o + S_w = 1 \dots\dots\dots (III.19)$$

Where S_g , S_o , and S_w are the saturations of gas, oil, and water phases, respectively.

Additionally, the pressures of the phases— p_g , p_o , and p_w —are related to one another through the gas-oil and oil-water capillary pressures, respectively:

$$-p_{cgo} = p_g - p_o, \dots\dots\dots (III.20)$$

$$-p_{cow} = p_o - p_w \dots\dots\dots (III.21)$$

It is assumed that the porous medium is fully saturated, but the phases are separated at the pore scale. The porous matrix and fluids are considered slightly compressible, and diffusion is neglected for all phases. Furthermore, the entire system is assumed to be in local thermodynamic equilibrium.

² Bell, J. A. (1989). *SIAM journal on Applied Mathematics*. Récupéré sur SIAM Publications Library: <https://doi.org/10.1137/0149044>

This formulation provides a clear description of the underlying assumptions and equations governing the black-oil model in reservoir simulation.

3.3 Black-oil Model Application Domain

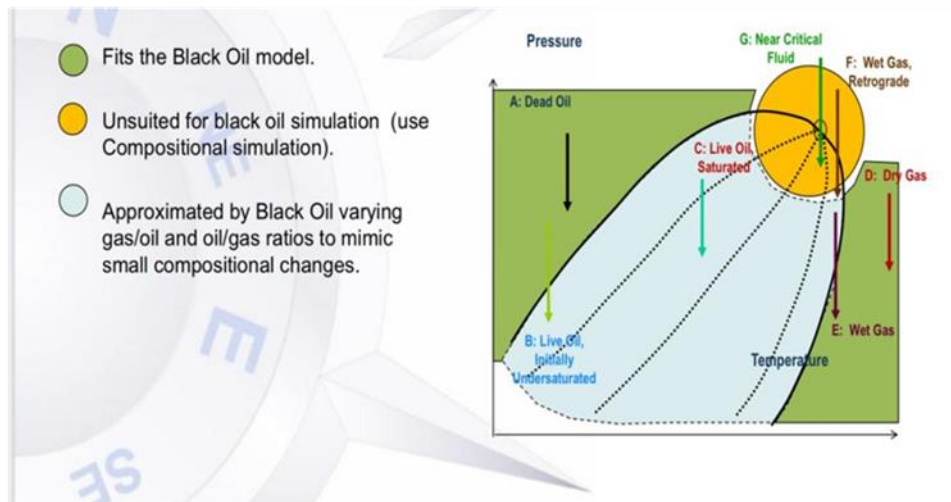


Figure III.1: Black-oil Model Application Domain

³ Ali, H. M. (2022). *PVT Analysis And EoS Modeling*. Récupéré sur <https://kh.aquaenergyexpo.com/wp-content/uploads/2022/12/PVT-Analysis-EoS-Modeling.pdf>

3.4 Traditional formulation vs. modified formulation

Traditional Black Oil (TBO) vs. Modified Black Oil (MBO) Models:

Traditional Black Oil (TBO) and Modified Black Oil (MBO) are simplified reservoir simulation models used to describe hydrocarbon phase behavior. These models differ in complexity and applicability:

3.4.1 Traditional Black Oil (TBO)

The TBO model treats oil and gas as two pseudo-components, assuming that gas dissolves in oil (via the solution gas-oil ratio, R_s), but oil cannot vaporize into the gas phase. This unidirectional mass transfer works well for under saturated oils in conventional reservoirs, where gas evolves from oil only when the pressure drops below the bubble point. However, the TBO model cannot account for scenarios where oil vaporizes into the gas phase or retrograde condensation occurs, limiting its use to simple systems, such as water flooding or low-volatility oil reservoirs.

3.4.2 Modified Black Oil (MBO)

In contrast, the MBO model introduces two-way mass transfer by tracking both R_s and R_v (gas dissolving in oil and oil vaporizing into gas). This enhancement allows MBO to handle volatile oils and gas condensates, where significant oil vaporization or liquid dropout in gas phases occurs. For example, MBO can model reservoirs where the gas phase contains substantial

condensate or where pressure changes cause oil to vaporize. This makes the MBO model more versatile for complex phase behavior but increases the need for detailed PVT data, as it requires additional inputs like R_v and gas-phase properties.

- Computational Differences:

Computationally, TBO is simpler and faster due to its limited interactions between phases, while MBO requires more resources to track bidirectional mass transfer. Surface volume calculations also differ: TBO assumes that all gas separates from oil at surface conditions, ignoring any vaporized oil in the gas phase. In contrast, MBO accounts for this vaporization, improving accuracy in systems like gas condensates with rich surface liquids.

- Applications:

- TBO is ideal for straightforward, low-volatility reservoirs, where phase behavior is relatively simple.
- MBO bridges the gap between TBO and fully compositional models, offering a practical balance for volatile oils and gas condensates, making it suitable for more complex phase behaviors.
- However, both models are less accurate than full compositional simulations, particularly in highly complex fluids (e.g., miscible gas floods or CO_2 injection).

- Summary:

- TBO: Best suited for simple systems with low volatility.
 - MBO: Handles moderate complexity and volatile oils or gas condensates.
- Compositional models: Necessary for advanced scenarios with highly complex fluids

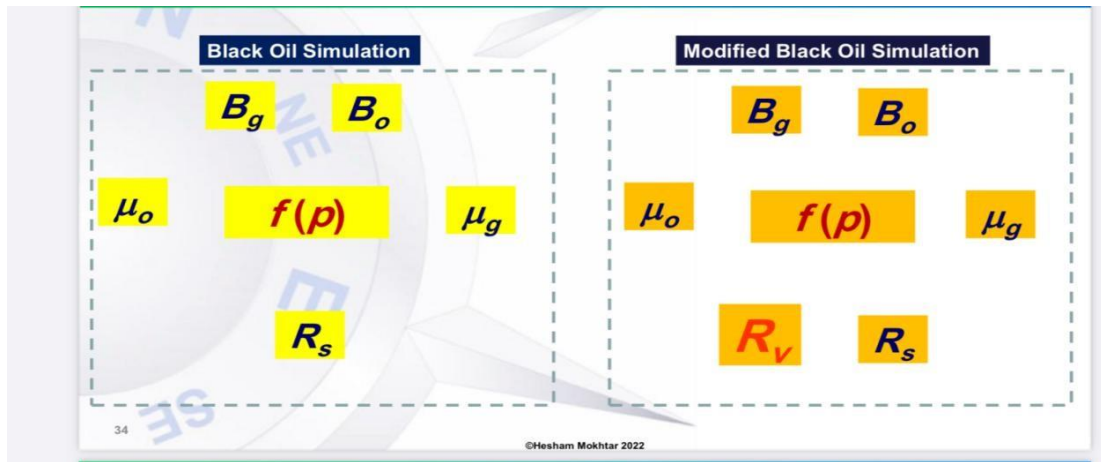


Figure III.2 TBO vs MBO

4

Empirical Correlations for Prediction of Reservoir Fluid Properties:

⁴ Ali, H. M. (2022). *PVT Analysis And EoS Modeling*. Récupéré sur <https://kh.aquaenergyexpo.com/wp-content/uploads/2022/12/PVT-Analysis-EoS-Modeling.pdf>

Oil Formation Volume Factor

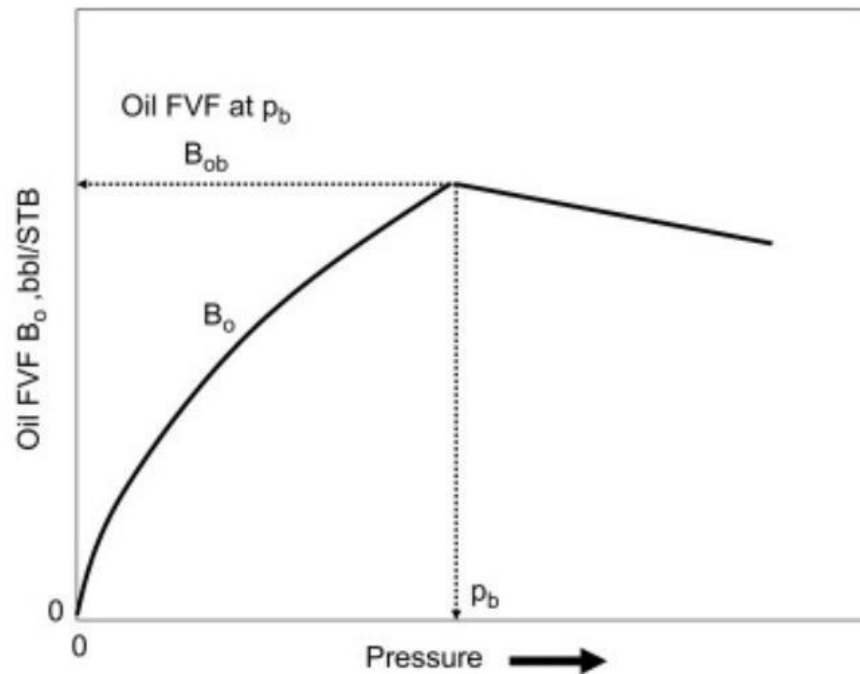


Figure III.3 : Bo trend

Five different methods of predicting the oil formation volume factor are presented below:

- Standing's correlation

$$B_o = 0.9759 + 0.000120 \left[R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.5} + 1.25(T - 460) \right]^{1.2} \dots\dots (III.22)$$

- The Vasquez-Beggs correlation

$$B = 1.0 + C R + (T - 520) \left(\frac{API}{100} \right) [C + C R] \dots\dots (III.23)$$

Where:

R = gas solubility scf/STB

T= temperature, °R

Y_{gs} = gas specific gravity as defined by equation 2-72, I.e.:

$$\gamma_{gs} = \gamma_g \left[1 + 5.912(10^{-5})(API)(T_{sep} - 460) \log \left(\frac{p_{sep}}{114.7} \right) \right] \dots\dots (III.24)$$

values for the coefficients C₁ et C₂ and C₃ are given below:

Coefficients	API ≤ 30	API > 30
C ₁	4.677×10^{-4}	4.670×10^{-4}
C ₂	1.751×10^{-2}	1.100×10^{-5}
C ₃	-1.811×10^{-8}	1.337×10^{-9}

- Glaso's correlation

$$B_o = 1.0 + 10^A \dots \dots \dots (III. 25)$$

Where

$$A = +6.58511 + 2.91329 \log B^*_{ob} - 0.27683 (\log B^*_{ob}) \dots (26)$$

B^*_{ob} is correlating number and is defined by the following equation:

$$B^*_{ob} = R_s \left(\frac{\gamma_g}{\gamma_o} \right)^{0.526} + 0.968 (T - 460) \dots (III. 27)$$

- T = temperature, °R
- γ_o = specific gravity of the stock tank oil

- Marhoun's correlation

$$B_o = 1.0113 + 7.204(10^{-5}) \dots \dots \dots (III.28)$$

$$\left[R_s^{0.3738} \left(\frac{\gamma_g^{0.2914}}{\gamma_o^{0.6265}} \right) + 0.24626(T - 460)^{0.5371} \right]^{3.0936} \dots \dots (III. 29)$$

Where

- T = temperature, °R
- γ_o = specific gravity of the stock tank oil

- The Petrosky-Farshad correlation

$$B_o = 0.497069 + 0.862963 \times 10^{-3}T + 0.182594 \times 10^{-2}F$$

$$+ 0.318099 \times 10^{-5} F^2 \dots (III.30)$$

With the correlating parameter F as defined by the following equation:

$$F = R_s^a \gamma_g^b \gamma_o^c \dots \dots \dots (III.31)$$

The coefficients a,b and c have the following values

- a=0.742390
- b=0.323294
- c=-1.202040

CHAPTER III:

Black Oil Model Technique

Table III.1: Bubble Point Pressure Correlations for Black PVT Tables: ⁵

Correlation	Application Limits	Domain of Use	Comment
Standing (1947)	- API Gravity: 15 - 45° - Solution Gas-Oil Ratio (R_s): 100 - 1,250 scf/STB - Reservoir Temperature: 60 - 290°F - Gas Gravity (γ_g): 0.6 - 1.2	- California crude oils - Conventional onshore reservoirs - Moderate pressure & temperature fields	An arithmetic average error of 1.17% was reported
Vazquez-Beggs (1980)	- API Gravity: 16 - 58° - R_s: 20 - 2,070 scf/STB - Temperature: 75 - 340°F - γ_g: 0.6 - 1.68	- Gulf of Mexico offshore & onshore - Light to medium crude oils - Higher GOR reservoirs	A correlation was developed for Bo at and below Pb.Pb. A correlation with two different set of coefficients was developed because of the wide variations in the volatility of the crude samples. The two groups were for $\gamma_{API} \leq 30$ and $\gamma_{API} > 30$.
Glasø (1980)	- API Gravity: 22 - 46° - R_s: 50 - 1,500 scf/STB - Temperature: 100 - 260°F - γ_g: 0.7 - 1.5	- North Sea offshore reservoirs - Deep, high-pressure reservoirs - Moderate to high API oils	Corrections for the effect of non-Hydrocarbon component in the crude oil were incorporated in the correlation.
Marhoun (1988)	- API Gravity: 10 - 40° - R_s: 10 - 2,000 scf/STB - Temperature: 75 - 290°F - γ_g: 0.55 - 1.35	- Middle Eastern crude oils - Heavy/medium crude oils - Lower GOR reservoirs	R^2 for the developed correlations is 0.997 with AAPRE of 3.66%. This was compared with some previous correlations, Standing (1947) [$R = 0.979$, AAPRE = 12.08%] and Glasø (1980) [$R^2 = 0.891$, AAPRE = 25.22%].
Petrosky-Farshad (1993)	- API Gravity: 16 - 52° - R_s: 20 - 1,750 scf/STB - Temperature: 90 - 320°F - γ_g: 0.85 - 1.4	- Gulf of Mexico offshore - Moderate temperature reservoirs - Light to medium crude oils	AAPRE = 0.64%

⁵ Oloso, M. A. (2018, June). *PREDICTION OF RESERVOIR FLUID PROPERTIES USING MACHINE LEARNING*. University of Portsmouth.

Table III.2: Bubble Point Pressure Correlations for Black PVT ⁶

Authors	γAPI	Equation	Comments
Standing (1947)	16.5-63.8	$Pb = 18.2 \times [(Rs/\gamma g)^{0.83} \cdot 10^{a-1.4}]$ Where: $a = 0.00091T - 0.0125\gamma API =$ Bubble point pressure (psia) = Solution gas/oil ratio (scf/STB) = Gas gravity = Reservoir temperature (°F) γAPI = API gravity of oil	105 experimentally determined Pb values from 22 different crude oil mixtures were used for the study. An arithmetic average error of 4.8% was reported.
Al-Marhoun (1988)	19.40-44.6	$Pb = 5.38088 \times 10^{-3} * Rs^{0.715082} * \gamma g^{-1.87784} * \gamma o^{3.1437} * T^{1.32657}$ Where: = Solution gas/oil ratio (scf/STB) γg = Gas gravity = Oil gravity = Reservoir temperature (°F)	PVT analyses of 69 different Middle East oil/gas mixtures were used for this study. R2 for the developed correlations is 0.997 with AAPRE of 3.66%. This was compared with some previous correlations, Standing (1947) [R2 = 0.979, APPRE = 12.08%] and Glasø (1980) [R2 = 0.891, APPRE = 25.22%].
Vazquez & Beggs (1980)		$Pb = [A(Rs/\gamma gc)^{10^a}]^c$ where: A = Constant based on empirical data a = Coefficient based on API and temperature = $\gamma g[1 + (0.5912 \times 10^{-4} * Tsp/114.7)]$ Tsp = Separator temperature (°F) γAPI = API gravity of oil	This correlation is based on the reported Rs correlation a new correlation for bubble point pressure based on mathematical rearrangement of their solution gas oil ratio correlation which was developed using 5008 data point taken from 600 laboratory
Jarrahian et al. (2015)	14.08-51.7 to 9	$Pb = P_o * \gamma_o * P_1 * R_s * P_2 * T * P_3 * \gamma_g * P_4 * \exp(P_5 * (\gamma g / \gamma_o))$ Where: $P_o = 2.995555554962301E-2$	Two different correlations were developed: compositional and non-

⁶ Oloso, M. A. (2018, June). *PREDICTION OF RESERVOIR FLUID PROPERTIES USING MACHINE LEARNING*. University of Portsmouth.

		$P1 = 3.32023121093229$ $P2 = 8.2470515729579E-1$ $P3 = 1.07473639420694$ $P4 = -4.48067373662815E-1$ $P5 = -5.4244629566970E-1$ γ_g = Gas gravity γ_o = Oil gravity R_s = Solution gas/oil ratio (scf/STB) T = Reservoir temperature (°F)	compositional models. The non-compositional model was 10 tested on another 1840 data sets from the literature with AAPRE of 15.555%. The compositional correlation was tested against 171 data set from the literature with AAPRE = 7.7%..
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Oil Viscosity Correlations for Black Oil PVT Tables

Table III.3: Oil Viscosity Correlations for Black Oil PVT ⁷

Correlation	Application	Best Use Case	Mathematical Correlation	Physical basis	Best use case
Beggs & Robinson (1975)	Works for saturated & under saturated oils	Light to medium crude oils (API 16-58°) Temperature : 60 F to 250 F	Dead Oil Viscosity: $\mu_o = 10^{(A-B^*)/API}$ $A = 10^{(0.43+8.33/API)},$ $B = (0.00076 - 0.000021 \cdot API) \cdot T$ Saturated Oil Viscosity: $\mu_{os} = \mu_{od} \cdot (Rs + 1)^{-0.246}$ Under saturated Oil Viscosity: $\mu_o = \mu_{os} \cdot (P/P_b)^{(2.6)^*} (P/P_b) - 1.187$	Take into consideration The gas dissolution That reduces viscosity	Moderate temperature range (~100–300°F)
Vasquez & Beggs (1980)	Best for low GOR and heavy oils	Heavy oils (API 10-40°), low GOR reservoirs	Same as Beggs & Robinson for Dead Oil Saturated Oil Viscosity: $\mu_{os} = \mu_{od} \cdot (Rs + 1)^{-0.246}$ Under saturated Oil Viscosity: $\mu_o = \mu_{os} \cdot (P/P_b)^{(2.6)^*} (P/P_b) - 1.187$	Heavy oil correction for better accuracy in low GOR oils	Pressure above P_b

⁷ Oloso, M. A. (2018, June). *PREDICTION OF RESERVOIR FLUID PROPERTIES USING MACHINE LEARNING*. University of Portsmouth.

CHAPTER III:

Black Oil Model Technique

Chew & Connally (1959)	Used for saturated oil viscosity	Moderate GOR, API 20-45°	Saturated Oil Viscosity: μ_{os} $= \mu_{od} * 10^{(-3.9*10^{-3} * R_s)}$	Simplified approach based on gas saturation effect	
Beal (1946)	Simpler method for dead oil viscosity	Heavy & medium Crude oils (API 10-40°)	Dead Oil Viscosity: $\mu_o = 10^{(A-B)*API}$ $A = 10^{(0.43 + 8.33/API)}$, $B = (0.00076 - 0.000021 * API) * T$	Estimates dead oil viscosity only ignoring gas effects	Low temperature
Glasso (1980)	Used in high-pressure, deep reservoirs	Deep offshore reservoirs, high-pressure oils	Saturated Oil Viscosity : μ_{os} $= \mu_{od} * 10^{(-3.9*10^{-3} * R_s)}$	Adjusted for high pressure high temperature oils	• North Sea oils • More complex fluids

Solution Gas–Oil Ratio (Rs) Correlations for Black Oil PVT Tables:

Table III.4: Solution Gas–Oil Ratio (Rs) Correlations for Black Oil PVT ⁸

Correlation	Application	Best Use Case	Mathematical Correlation	Comments
Standing (1947)	Very widely used Works best for California-type oils	Light oils (API 15–45°), onshore reservoirs	$R_s = \gamma_g \times (P/10^{(0.0125 \times API - 0.00091 \times T)^{1.204}})$	Too simple for the significant changes in gas solubility behavior near pb
Vasquez & Beggs (1980)	Used for saturated and under Saturated oils	/	$R_s = C_1 \gamma_g P^{C_2} \exp(C_3 API/T)$	A correlation with two different set of coefficients was developed by dividing the data set into two based on $\gamma API \leq 30$ and $\gamma API > 30$. More flexible
Glaser (1980)	More accurate for North Sea oils	Mostly mid-range oils (~16–58 API, but biased dataset)	$R_s = 10^{((C_1 + C_2 \times API)/T) \times P^{C_3}}$	Nonlinear relationship for reservoirs with complex gas solubility behavior especially near bubble point

Marhoun (1988)	Designed for heavy and medium crude oils	Heavy oils (API 10-40°), Middle East reservoirs	$R_s = \gamma_g - (P^{1.0937-0.00538088} - 10^{(0.71508210^{-3}API T+1)})$	Developed for Middle East crude oils and provides improved accuracy for that region
Petrosky & Farshad (1998)	Best for moderate temperature reservoirs	Light to medium oils (API 16-45°), Gulf of Mexico	$R_s = \gamma_g \times (P/10^{(0.00091 \times T + 0.0125 \times API)})^{1.24}$	The correlation was developed for saturated R_s . AAPRE = 3.8%.

Gas Viscosity Correlations for Black Oil PVT Tables:

Table III.5: Gas Viscosity Correlations for Black Oil PVT

Correlation	Application	Best Use Case	Mathematical Correlation
Lee, Gonzalez & Eakin (1966)	More accurate at high pressure / high density	Lee works great for normal reservoir gases	$\mu_g = K \exp(X \rho_g Y)$ $K = (9.379 + 0.01607M)$ $T^{1.5/209.2 + 19.26M + T}$ $X = 3.448 + 986.4/T + 0.01009M$ $Y = 2.447 - 0.2224X$
Carr, Kobayashi & Burrows (1954)	• Less accurate at : High pressure High density • Older method • More approximate	Low-pressure gas systems Dry gas systems	$\mu_g = \mu_g^* \times F$ • μ_g^* = viscosity at atmospheric pressure • F = correction factor based on: ○ Reduced pressure P_r ○ Reduced temperature T_r

Gaz Formation Volume Factor:

This is the **primary and most accurate method**:

$$BG=0.02827ZT/P$$

For field units: T in °R, P in psia

Since Z is not directly known, it is calculated using correlations:

a) Standing–Katz Chart (Graphical)

- Uses :
 - Reduced pressure P_r
 - Reduced temperature T_r

Then read Z from chart

b) Dranchuk & Abou-Kassem Correlation (Analytical)

A widely used equation to compute Z numerically:

$$Z=1+\text{function of } p_r, T_r Z$$

(Complex equation solved iteratively in simulators)

c) Hall–Yarborough Correlation

Another analytical method for Z, especially for:

- High pressure gas systems

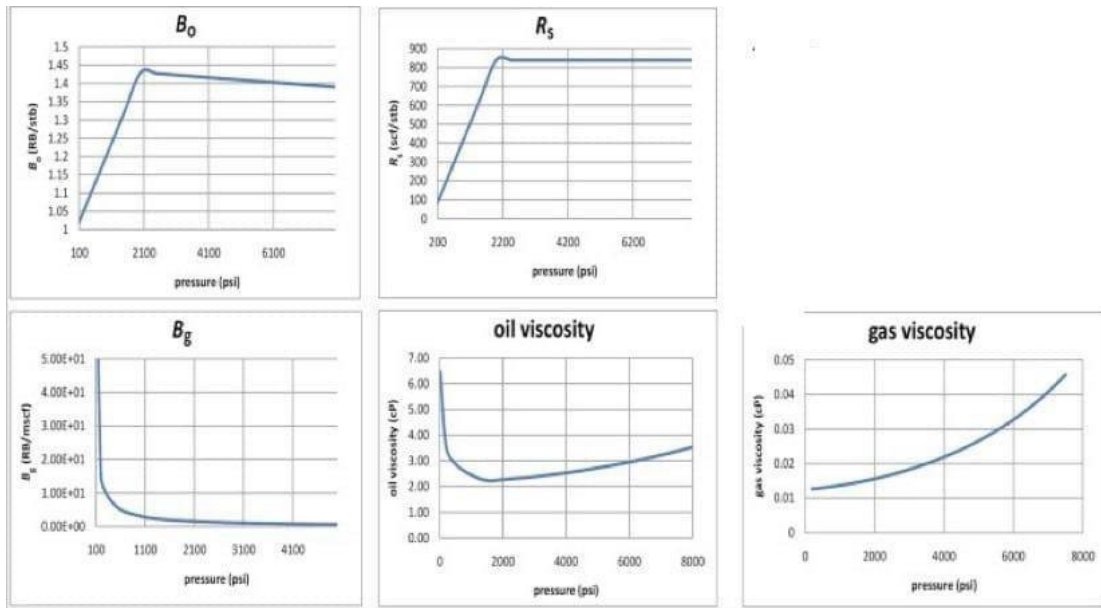


Figure III.4 General properties trends

Types of Laboratory Tests:

Accurate laboratory studies of PVT and phase-equilibrium behavior of reservoir fluids are necessary for characterizing these fluids and evaluating their volumetric performance at various pressure levels. There are many laboratory analyses that can be performed on a reservoir fluid sample. The amount of data desired determines the number of tests performed in the laboratory. In general, there are three types of laboratory tests used to measure hydrocarbon reservoir samples:

1. Primary tests (simple, routine field/on-site tests):

- Measurements of the specific gravity and gas-oil ratio of produced hydrocarbon fluids.

2. Routine laboratory tests:

- Laboratory tests routinely conducted to characterize the reservoir hydrocarbon fluid:
- Composition Analysis
- Constant-Composition Expansion (CCE)
- Differential Liberation (DL)
- Separator Tests
- Constant-Volume Depletion (CVD)

3. Special laboratory PVT tests:

- Performed for very specific applications, such as depletion under miscible gas injection or gas cycling schemes:
- Slim-tube test
- Swelling test

Laboratory Tests Needed for Black Oil Model

- Constant-composition expansion experiments (CCE):

Conducted on gas condensates or crude oil to simulate the pressure-volume relations of these hydrocarbons.

The test aims to determine:

- Saturation pressure (bubble point or dew point pressure)
- Isothermal compressibility coefficients of the single-phase fluid above saturation pressure
- Compressibility factors of the gas phase
- Total hydrocarbon volume as a function of pressure

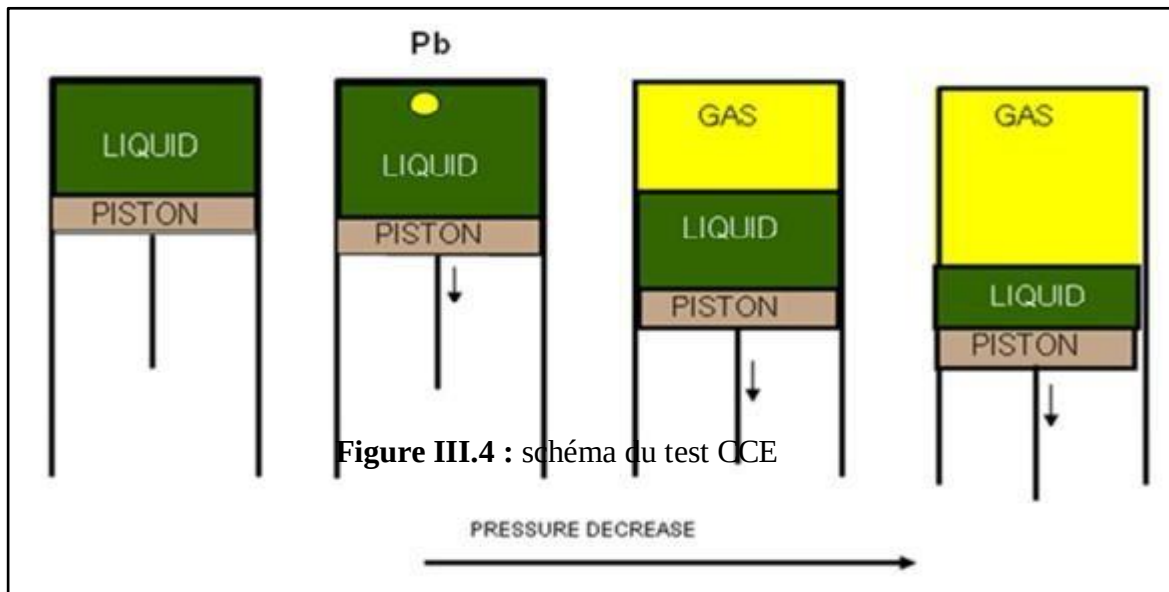


Figure III.4 : schéma du test CCE

FigureIII.5: CCE

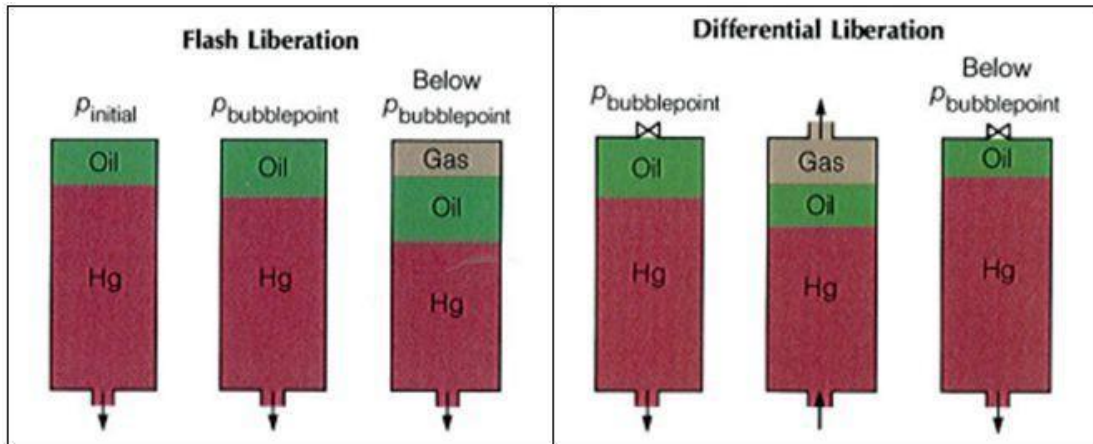
- Separator Tests (or Differential Liberation):

The primary objective is to provide essential laboratory information for determining the optimum surface separation conditions.

Starting point: the bubble point pressure.

- Tests performed at various temperature and pressure pairs.
- Conditions: T = reservoir temperature.

- Properties determined:
- Oil formation volume factor (B_o)
- Solution gas-oil ratio (R_s)
- Separator and stock tank gas gravity (γ_g)
- Stock tank oil gravity (γ_o)



FigureIII.6: DL

Workflow for Black Oil PVT Table Generation Using Python and PyResToolbox

Accurate characterization of reservoir fluids is essential for reliable reservoir simulation studies. The Black Oil Model (BOM) is one of the most widely used fluid models in reservoir engineering due to its simplicity and computational efficiency. In this approach, the reservoir fluid is represented by two pseudo-components: oil and gas. The thermodynamic behavior of these components is described through pressure-dependent properties such as the solution gas-oil ratio (R_s), vaporized oil-gas ratio (R_v), oil formation volume factor (B_o), gas formation volume factor (B_g), viscosity, and compressibility.

Importation of Laboratory PVT Data:

The workflow begins with the acquisition of laboratory PVT data obtained from Constant Composition Expansion (CCE), Differential Liberation (DL), and Separator Tests. These measurements constitute the reference dataset used for model calibration and validation.

Data Preprocessing Using Python:

The laboratory data are imported into Python where preprocessing operations are performed, including file reading, unit verification, data cleaning, organization of datasets, and preparation of pressure grids. Pandas and NumPy are commonly used for these operations.

Fluid Characterization:

The fluid is classified based on API gravity, gas gravity, reservoir temperature, initial gas-oil ratio, and bubble point pressure. This step determines whether the fluid can be adequately represented using the Black Oil Model.

PVT Property Calculations Using PyResToolbox:

PyResToolbox is used to calculate the main pressure-dependent properties including R_s , R_v , B_o , B_g , oil viscosity, gas viscosity, oil compressibility, gas compressibility, and gas compressibility factor (Z). Industry-standard correlations such as Standing, Glaso, Vasquez-Beggs, Hall-Yarborough, and Dranchuk-Abou-Kassem may be employed.

Generation of Black Oil Tables:

The calculated properties are organized into simulator-ready Black Oil tables including PVTO, PVTG, and DENSITY tables. These tables describe the fluid behavior over the reservoir pressure range.

Interpolation of Fluid Properties:

Interpolation techniques are applied to generate intermediate property values between measured pressure points, ensuring smooth and continuous fluid-property curves.

Validation of Generated Results:

Calculated properties are compared with laboratory measurements through graphical and numerical analyses. If discrepancies exceed acceptable limits, alternative correlations may be selected and recalibrated.

Statistical Analysis:

Model performance is quantified using Average Absolute Relative Error (AARE), Root Mean Square Error (RMSE), and the coefficient of determination (R^2). These indicators provide an objective assessment of model accuracy.

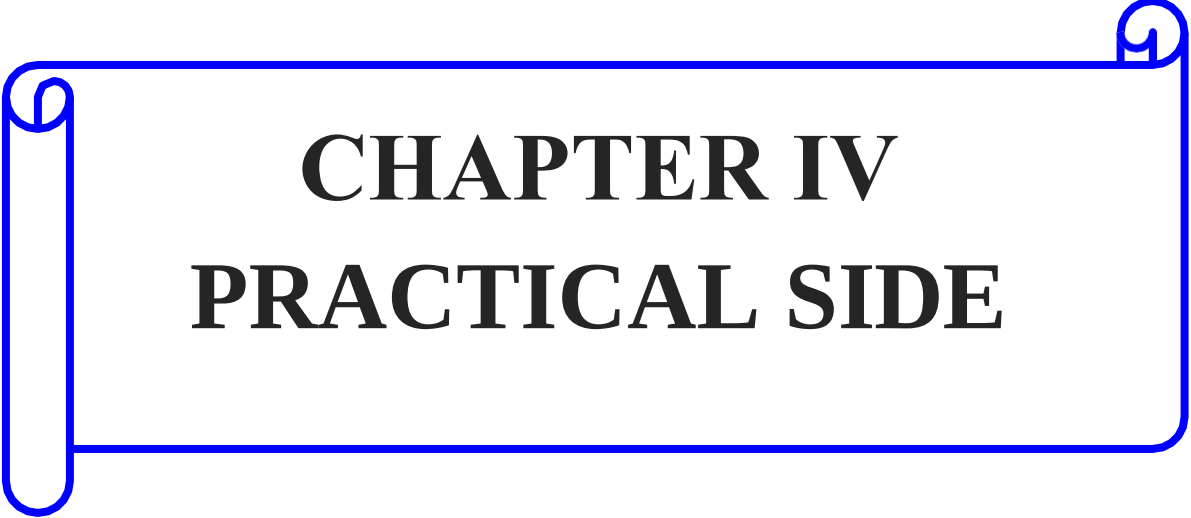
Exportation and Application in Reservoir Simulation:

The validated PVT tables are exported in formats compatible with Eclipse, CMG, and other reservoir simulators. The generated tables are then used for reservoir performance forecasting and production studies.

Conclusion

The black oil model is based on simple interpolation of PVT (Pressure-Volume-Temperature) properties as a function of pressure. Key characteristics of the model include:

- Water phase modeling: Water is explicitly modeled alongside two hydrocarbon components (oil and gas phases).
- Hydrocarbon components: At standard P/T conditions, hydrocarbons are divided into a gas component and an oil component in the stock tank.
- No mass transfer occurs between water and hydrocarbons: No mass transfer occurs between the water phase and the oil/gas phases.



CHAPTER IV

PRACTICAL SIDE

4.1 Generalities on the Central RhourdeNouss Structure [4]

The RhourdeNouss structure was brought into production in 1988 through the opening of 23 producer wells with an average flow rate of 18 M standard m³/day, and 12 injector wells with an injection rate of more than 8 M standard m³/day. The exploited reservoir is the Triassic Clayey-Quartz Sandstone (TAGS).

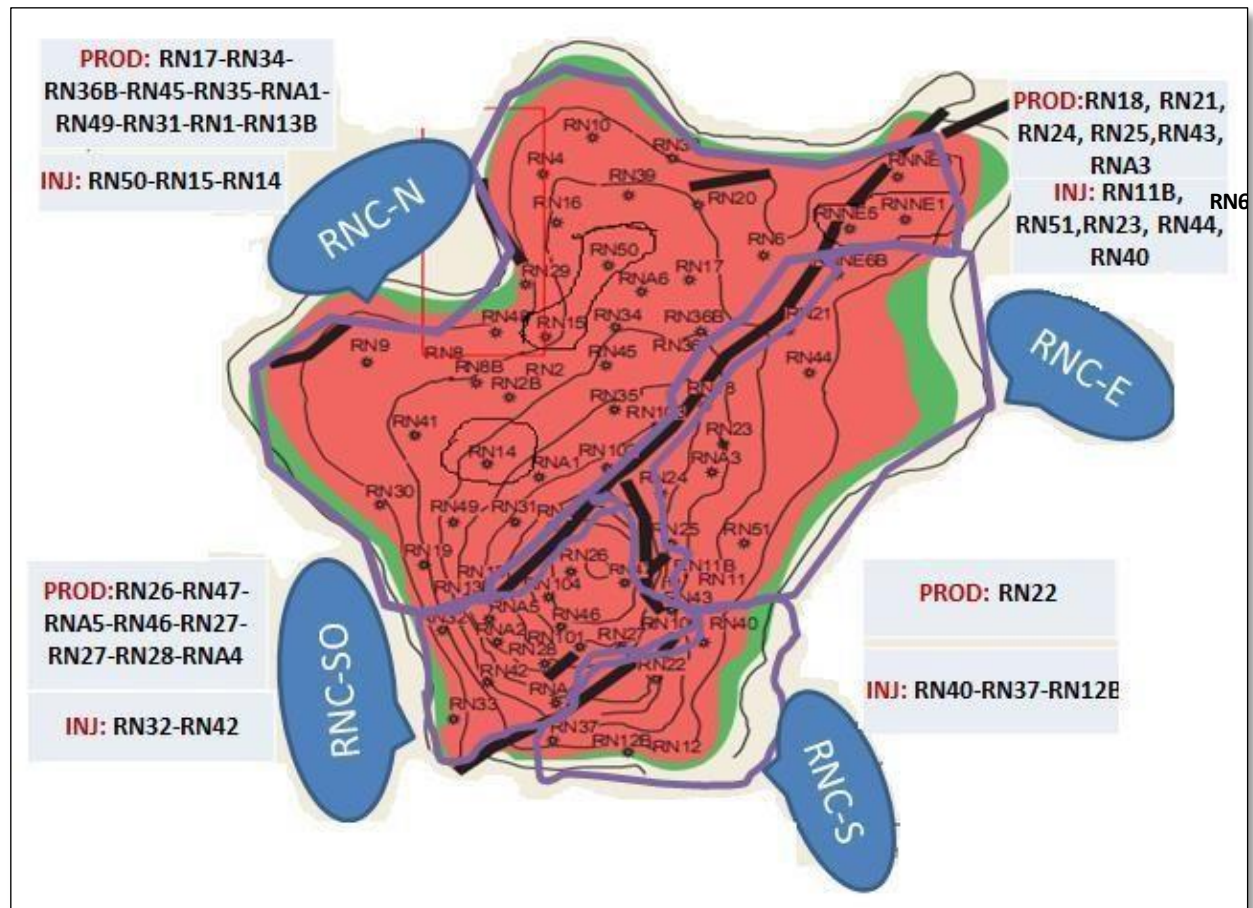


Figure IV.1: The isobath map at the top of the TAGS reservoir of RNC

4.2 COMPARTMENTS OF THE CENTRAL ZONE

Perimeter	Number of PPG Wells	Number of PIG Wells
RhourdeNouss Central	25	14

PPG: Gas producer well

PIG: Gas injector well

4.2.1 Generalities on the wells**Tableau IV.1 wells type**

Pattern	Puits	Date de mise en exploitation	Etat initial	Conversion
RNC NORTH	RN6	30/05/1992	Injector	
	RN34	14/10/1992	Producer	
	RN36B	12/03/1991	Producer	
	RN45	16/04/1992	Producer	
	RN35	01/03/1992	Producer	
	RN10	18/02/1992	Producer	
	RN49	08/10/1992	Producer	
	RN31	03/10/1992	Producer	
	RN1	15/04/1992	Producer	
	RN13B	06/05/1992	Producer	
	RN50	14/11/1992	Producer	2004-injecter
	RN15	24/08/1992	Injector	
	RN4	11/05/1992	Producer	2002-Injecter
RNC SOUTH	RN22	10/10/1992	Producer	
	RN40	30/08/1992	Injector	
	RN37	24/07/1994	Injector	
	RN12B	27/03/1992	Injector	
	RN18	22/08/1990	Producer	
	RN21	17/07/1994	Producer	
	RN24	06/10/1992	Producer	
	RN25	07/05/1992	Producer	
	RN43	18/05/1992	Producer	

RNC EAST	RNA3	14/05/2014	Producer	
	RN11B	03/01/1996	Injector	
	RN51	16/11/1991	Injector	
	RN23	05/04/1985	Injector	
	RN44	11/02/1992	Injector	
	RN40	30/08/1992	Injector	
RNC S O	RN26	23/04/1989	Producer	
	RN47	04/11/1993	Producer	
	RNA5	08/05/1992	Producer	
	RN46	11/10/1993	Producer	
	RN27	23/05/1992	Producer	
	RN28	06/04/1989	Producer	
	RNA4	05/10/1992	Producer	
	RN32	27/09/1993	Injector	
	RN42	31/07/1992	Injector	

Tableau IV.2 sections patterns

PATTERNS	Gaz Contribution « % »	Condensat contribution « % »	GPL Contribution « % »	Reinjection Rate « % »
RNC-SW	17,8	15,6	18,2	33,7
RNC-SUD	2,1	0,8	3,2	144,2
RNC-Nord	21,4	24,6	20,9	29,2
RNC-EST	10,0	8,6	10,1	95,2

4.2.1 Initial Characteristics of the Effluent

Two types of effluents characterize the TAGS reservoir of RhourdeNouss Central: gas with condensate, with the presence of an oil ring.

- Initial pressure: 300 kg/cm²
- Initial richness: 360 g/m³

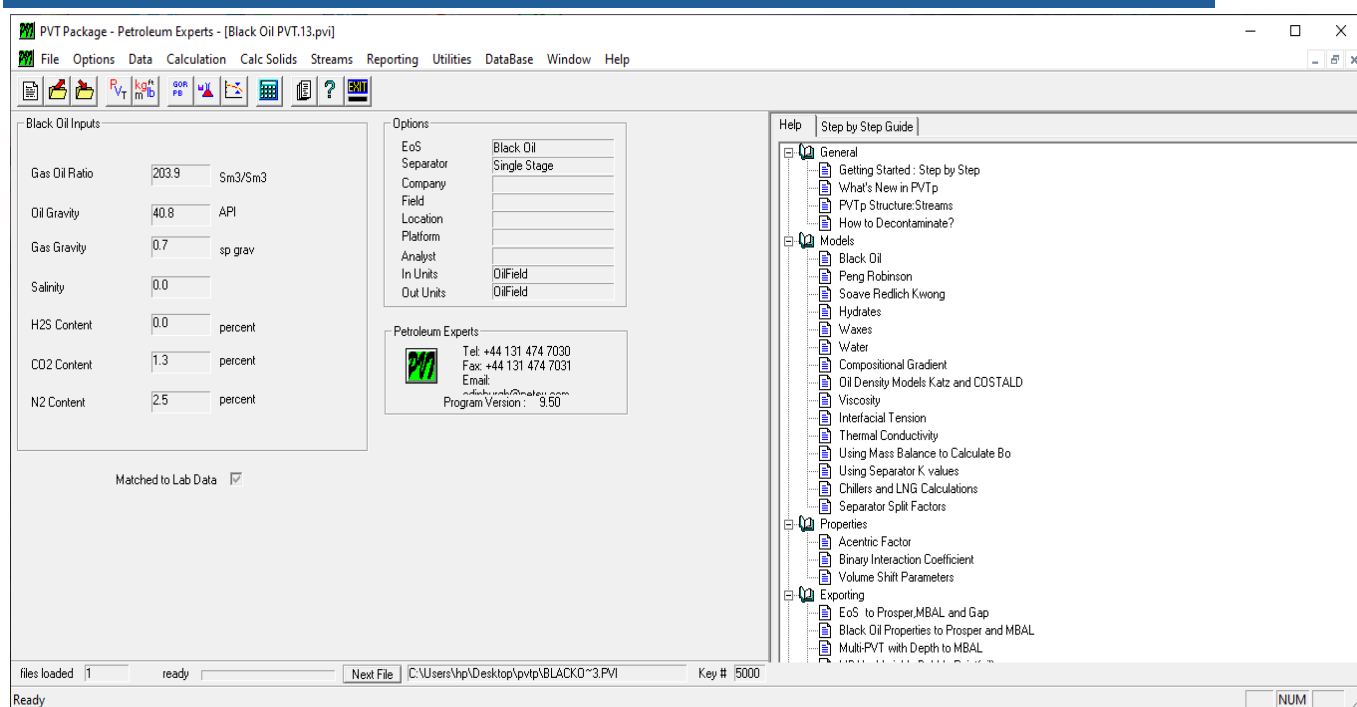
- Temperature: 102°C

4.3 PVT Data Calibration using PVTP software:

The PVTP program was used to study and determine the fluid behavior by the black oil model technique. For this purpose, we used the results of the Oil PVT Study (Black Oil Laboratory Study) RN4.

4.3.1 PVTP:

The IPM suite of applications was created to allow integrated systems to be constructed; therefore eliminating artificial boundary conditions that engineer would have to impose on models of individual parts of any production or injection system. The basis of any integrated model is a solid and consistent 32 PVT definition, which respects the behaviour of any fluid when it flows in the reservoir, in wells, in pipes and beyond. Traditional approaches of modelling each part of the system in isolation relied on PVT models that were bespoke and created for a single specific use. Integrated Models present challenges of not only ensuring that the same description is valid for any part of the system, but also in a vendor neutral environment, ensuring that different software from different vendors communicate dynamically and receive or pass PVT information that works for their own domain. An integrated model with reservoir simulation, facilities and process models from three or more vendors needs to ensure that the limited number of components or black oil models used in the reservoir simulator are translated into full-blown compositions of large component numbers used in process models. PVTP was created with the objective of not only creating thermodynamically consistent and precise Equation of State models for fluids, but also to deliver these models in ways that can satisfy the vendor neutral principles of integrated modelling. Unique lumping/delumping algorithms have been embedded into the program, which satisfy this role and enable engineers to create integrated systems in a straightforward manner and with confidence that consistency in fluid thermodynamics is achieved.



4.3.2 matching and black oil input data:

4.3.2.1 black oil input data:

Property	VALUE
PRODUCED GOR	203.9 SM3/SM3
OIL GRAVITY	40.8API
GAS GRAVITY	0.71
CO2 %	1.269 MOLE
N2%	2.513 MOLE

4.3.2.2. MATCHING DATA :

Pression kg/cm2	GOR Dissous SM3/SM3	Bo	Viscosity cp
400		1.589	0.286
380		1.596	0.281
360		1.603	0.276
340		1.610	0.271
320		1.619	0.266
300		1.631	0.261
297.6	203.9	1.633	0.260
280	187.2	1.585	0.283
260	169.8	1.534	0.315
240	153.7	1.488	0.346
220	138.7	1.446	0.383
200	124.6	1.408	0.418
180	111.4	1.374	0.456
160	98.8	1.341	0.494
140	86.9	1.311	0.534
120	75.4	1.283	0.574
100	64.3	1.257	0.615
80	53.5	1.231	0.656
60	42.9	1.206	0.697
40	32.2	1.18	0.739
20	20.8	1.151	0.785
1	0	1.069	0.922

4.3.3 Collage «matching »de test Differential Liberation:

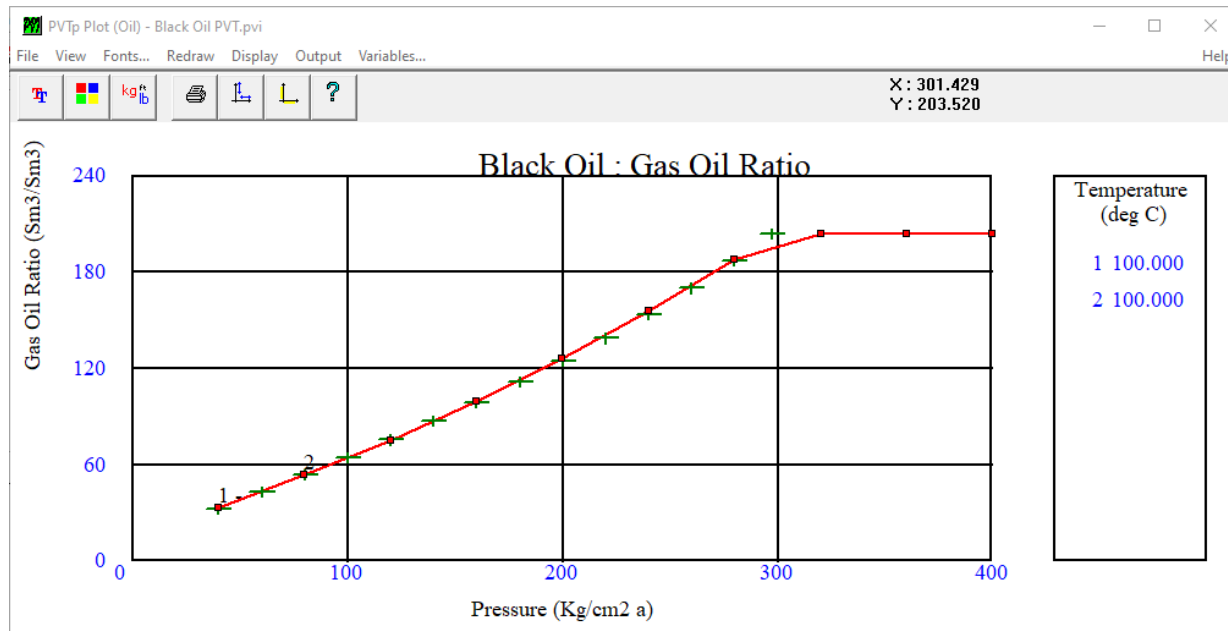
For the matching, we used data from the DL experiment with the separator conditions, after sample validation.

After running the regression on the DL experiment with the separator conditions, and after sample validation, the simulator provided the differences between the measured and calculated data for each parameter. The results are illustrated in the curves in the figures below.

We use the DL test results to calibrate the following parameters: solution Gas oil ratio, oil formation volume factor; gas viscosity, gas formation volume factor and viscosity of the oil

Using the PVTP tool, several simulations were run to measure the properties of

reservoir fluids and compare the measured data to field data. And showed similar behavior for all measured fluid properties, so we'll present and discuss the results of the (RN4) well in this section; the results are shown in figures below , the first Figure illustrates the variance of Gas Rs instantaneous solubility with pressure p for RN4, both for the origin and measured effects. It can be shown that the Rs increases as the pressure rises because the gas is forced to solve This behavior continues until the pressure exceeds 297.6 kg/cm², at which point the approximated remains constant. The following scenarios are created as a result of the pressure drop from reservoir to surface conditions: The oil weight decreased as a result of the loss of dissolved gas caused by the pressure drop; the oil volume decreased slightly as a result of the temperature drop; however, the oil slightly expanded as a result of the pressure drop. Temperature and pressure induced volume contraction and expansion normally balance each other out, resulting in no major changes. The increase in Bo above bubble point pressure corresponds to an increase in oil volume at P & T and, as a result, an increase in Bo. Oil shrinkage due to gas evolution appears to resolve its expansion below the bubble limit, resulting in pressure reduction, consequently Bo declines steeply.



First step in matching Rs data

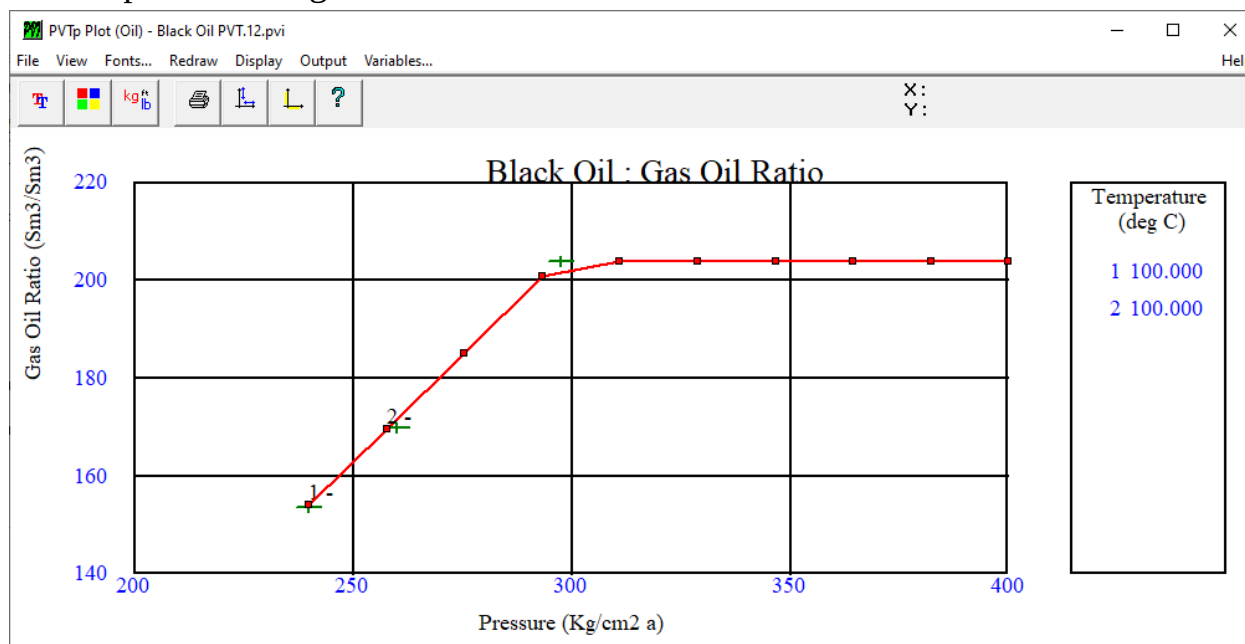
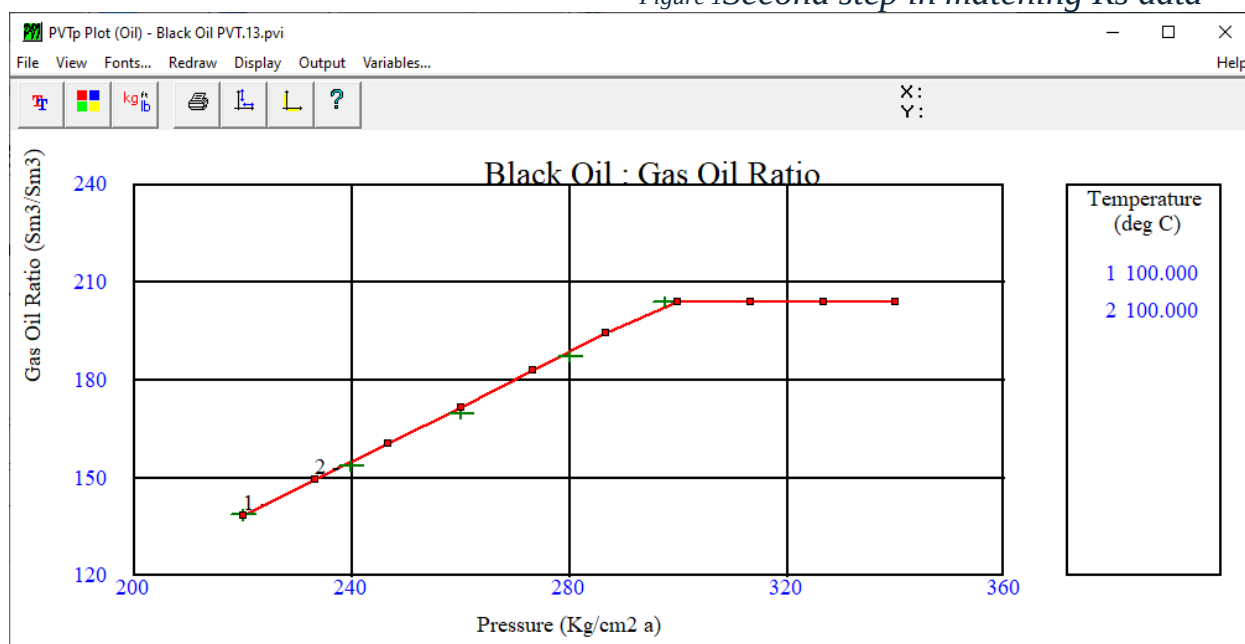
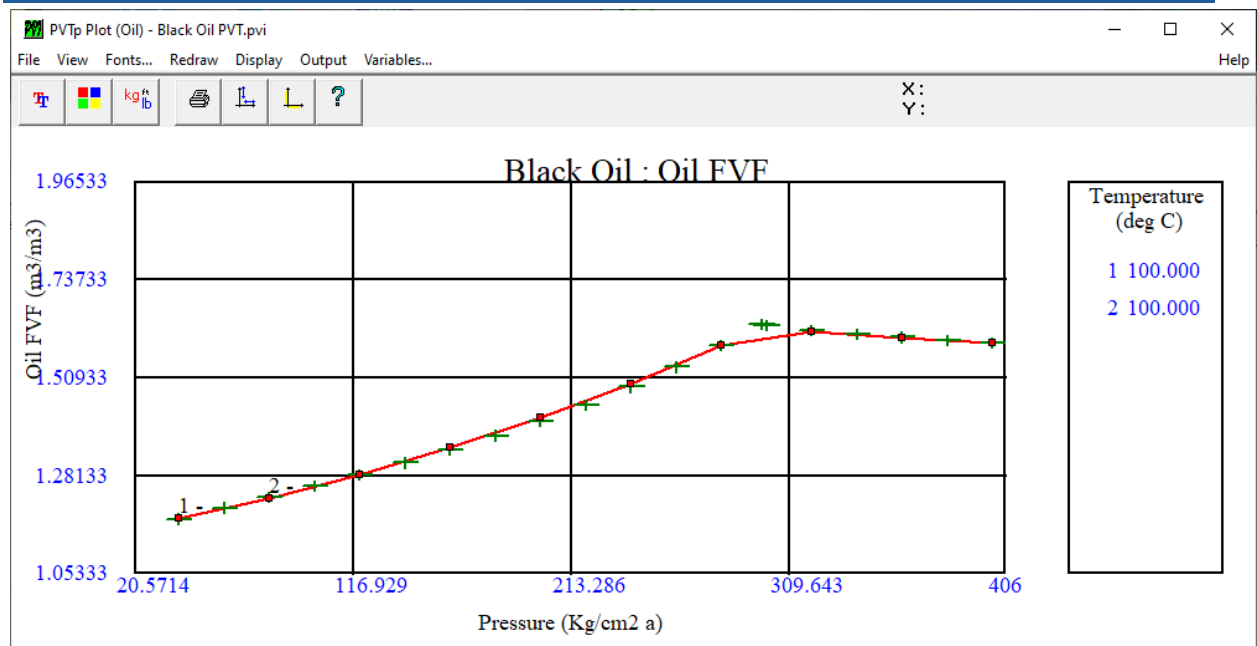


Figure 1 Second step in matching Rs data

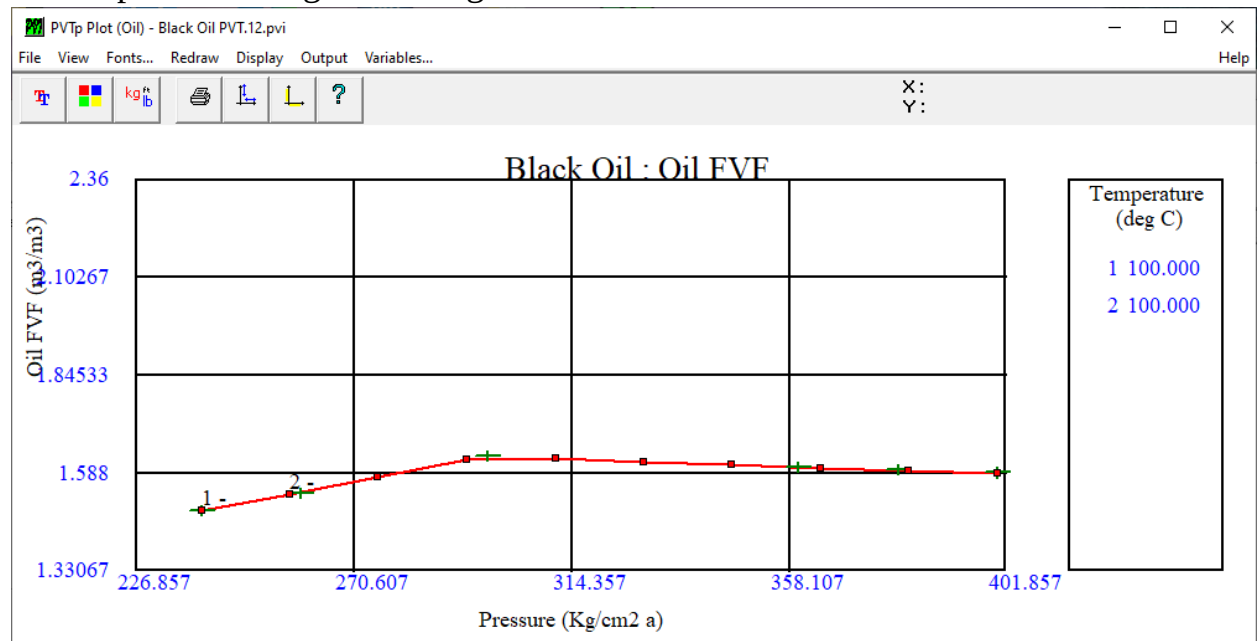


matched data on the regression for the Rs

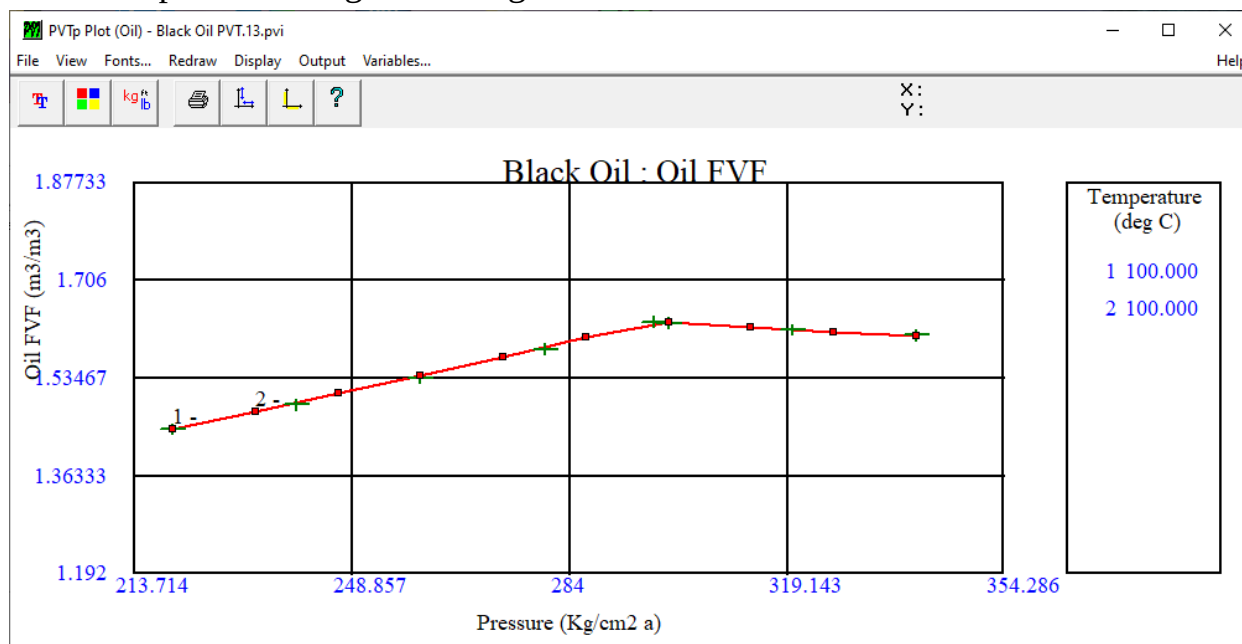
Variation in the ratio of oil formation, as well as the origin and measured effects. Since pressure causes the oil to become more compact and the particles to become closer together, the Bo increases with pressure. This behavior continues until the pressure reaches 297.6 kg/cm², after which it decreases due to changes in the structure and properties of hydrocarbons at these pressures.



first step in matching the Bo regression to the data

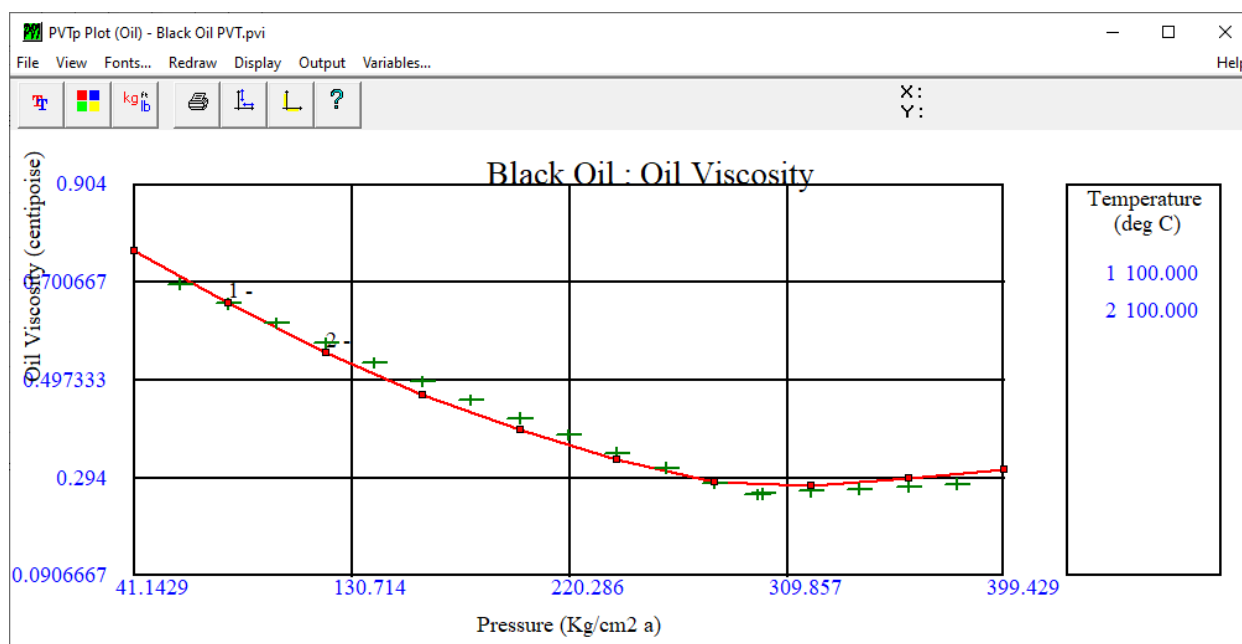


second step in matching the Bo regression to the data

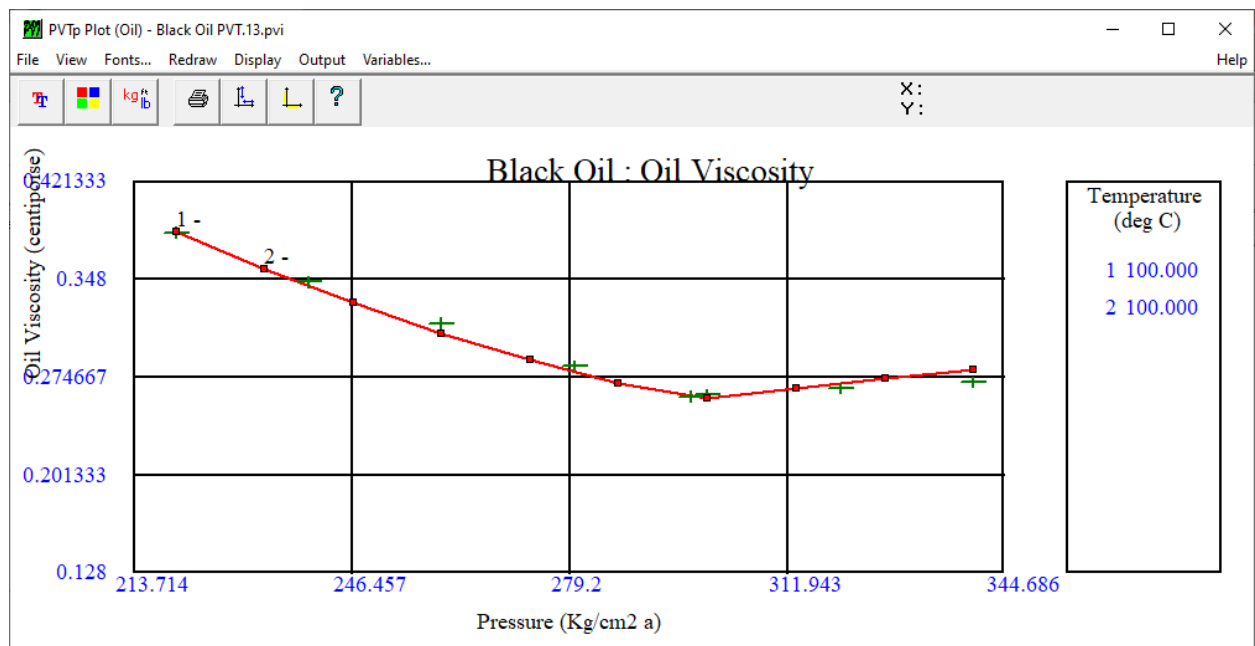


matched data for the Bo

The viscosity of oil decreases as the pressure rises, as the temperature rises, weakening the particle bonds and lowering the viscosity. Oil viscosity often decreases with decreasing pressure due to decreased friction between fluid layers, and reaches its lowest point at saturation pressure. If pressure is reduced more, more gas escapes from the oil, causing the oil to become denser and more viscous due to the lack of lighter components.



first step in matching oil viscosity data



matched viscosity data

table IV.3 results suymmary

Temperature	Pressure	Bubble Point	Gas Oil Ratio	Oil FVF	Oil Viscosity	Z Factor	Gas FVF	Gas Viscosity
(deg C)	(Kg/cm2 a)	(Kg/cm2 a)	(Sm3/Sm3)	(m3/m3)	(centpoise)		(ft3/scf)	(centpoise)
100	40	297.6	33.3674	1.18132	0.769027	0.953074	0.031845	0
100	80	297.6	53.4352	1.22832	0.656135	0.915748	0.0152989	0
100	120	297.6	75.3599	1.28278	0.555307	0.89199	0.00993467	0
100	160	297.6	99.5192	1.34528	0.467348	0.884102	0.00738512	0
100	200	297.6	126.157	1.41609	0.392931	0.891422	0.00595701	0
100	240	297.6	155.5	1.49544	0.332222	0.911137	0.00507396	0
100	280	297.6	187.791	1.58352	0.285118	0.940017	0.00448696	0
100	320	297.6	203.9	1.61719	0.277123			
100	360	297.6	203.9	1.60199	0.293746			
100	400	297.6	203.9	1.58994	0.310368			

4.4 PVT Data Calibration using python library:

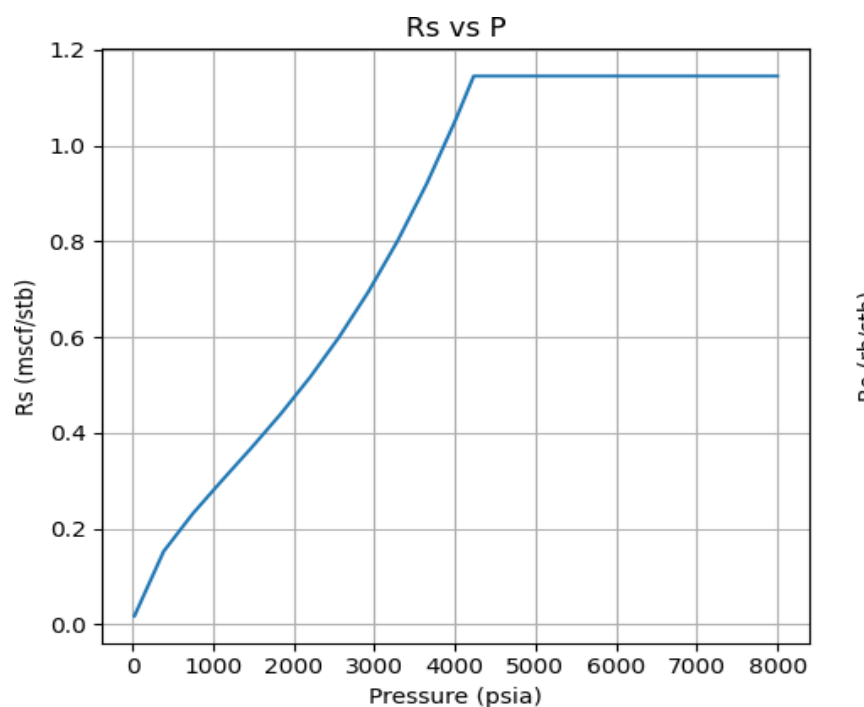
Pyres Toolbox library is a collection of Reservoir Engineering Utilities

This library consists of a collection of commonly used utility functions that support the development of programming solutions. The author has frequently reused these functions across multiple projects, often through copying and modifying earlier versions. As a result, several slightly different implementations of similar functionality accumulated over time.

To address this inconsistency, the current library has been designed with an emphasis on **generality, flexibility, and reusability**. The functions have been refined and standardized so that they can be applied across a wide range of use cases without requiring further modification.

For beginners, this means that the library provides **ready-to-use building blocks** that simplify common programming tasks. Instead of rewriting code from scratch or adapting older versions, users can rely on this consistent and well-structured set of functions to improve efficiency and reduce errors.

Creating black oil table information for oil using this library led to the following results:



FigureIV.2 : solution gas-oil ratio vs pressure

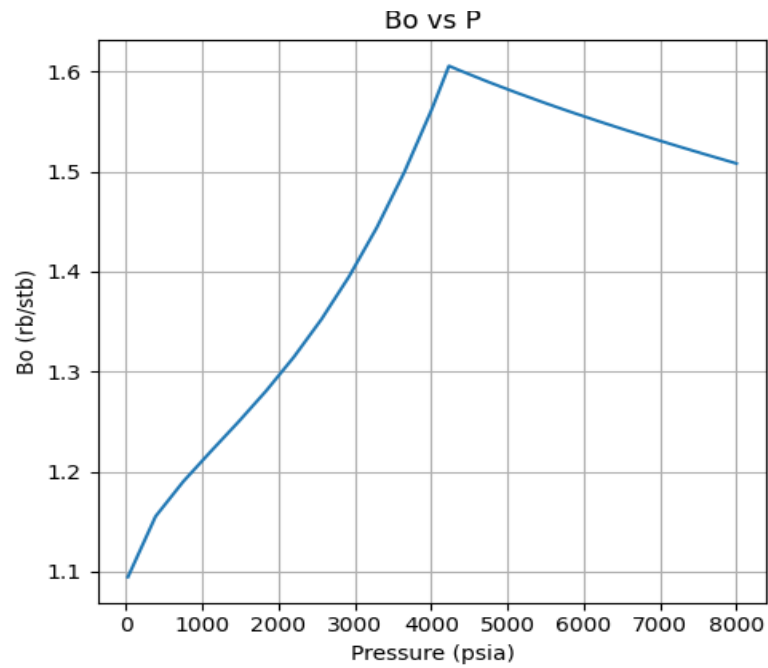


Figure IV.3 : oil formation volume factor vs pressure

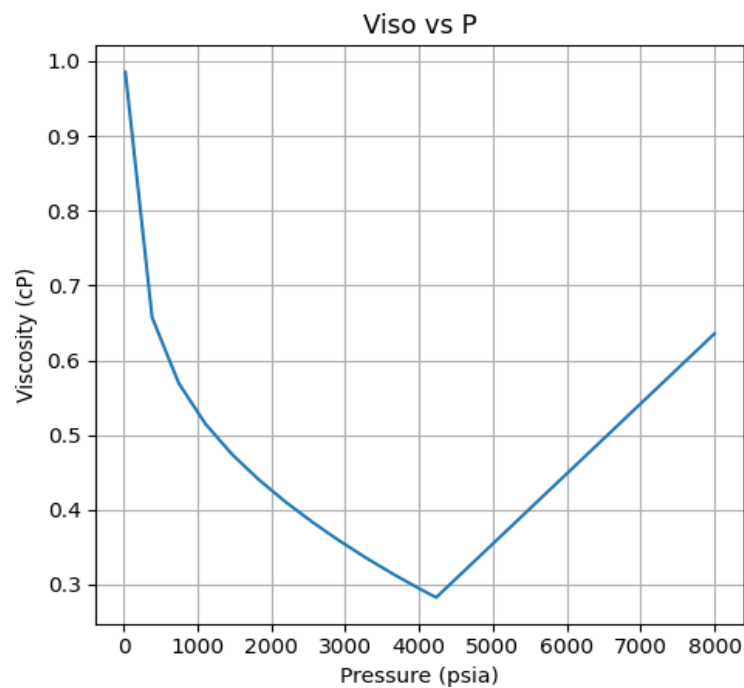


Figure IV.4: Oil viscosity vs pressure

	Pressure (barsa)	Rs (sm ³ /sm ³)	Bo (rm ³ /sm ³)	uo (cP)	Gas (v/v)	Z	Bg (rm ³ /sm ³)	ug (cP)
0	25.000000	25.351160	1.150447	0.672267	0.971207		9.061516	0.013571
1	40.000000	34.050137	1.171959	0.609786	0.955394		5.571240	0.013877
2	69.272727	48.563883	1.207490	0.534930	0.928597		3.126756	0.014637
3	113.545455	69.390849	1.258345	0.462884	0.901031		1.850970	0.016163
4	157.818182	92.433534	1.315345	0.408861	0.891893		1.318211	0.018072
5	202.090909	120.106486	1.385227	0.363220	0.900787		1.039692	0.020240
6	246.363636	154.245812	1.473323	0.323204	0.924329		0.875144	0.022533
7	290.636364	196.435395	1.584357	0.287926	0.958518		0.769271	0.024846
8	297.600000	203.900000	1.604195	0.282780	0.964637		0.756066	0.025207
9	334.909091	203.900000	1.587595	0.333467	1.000089		0.696532	0.027113
10	379.181818	203.900000	1.569536	0.393614	1.046718		0.643889	0.029301
11	423.454545	203.900000	1.552805	0.453762	1.096805		0.604160	0.031394
12	467.727273	203.900000	1.537090	0.513909	1.149259		0.573131	0.033390
13	512.000000	203.900000	1.522176	0.574056	1.203325		0.548204	0.035292
14	556.272727	203.900000	1.507913	0.634204	1.258480		0.527701	0.037106
15	600.545455	203.900000	1.494193	0.694351	1.314354		0.510500	0.038839
16	644.818182	203.900000	1.480930	0.754499	1.370686		0.495827	0.040499
17	689.090909	203.900000	1.468064	0.814646	1.427287		0.483130	0.042091
18	733.363636	203.900000	1.455542	0.874794	1.484023		0.472009	0.043624
19	777.636364	203.900000	1.443325	0.934941	1.540793		0.462165	0.045102

4. 5 Results Comparison:

Rs, Bo, and Z show strong agreement between the two tables. Uo is moderately different at low to mid pressure but converges near bubble point. Ug cannot be compared because the PVTP file contains only zeros in the gas-viscosity column. Bg becomes consistent after converting the PVTP values to the same numerical convention used in the library table; the mean absolute Bg error after conversion is about 1.87%

4.5.1 Method used for the comparison:

Pressure values from pvtp.xlsx were converted from kg/cm² (a) to bar (a), then interpolated onto the pressure grid of python librairie.xlsx over the common overlap range. For Rs, Bo, Uo, and Z, values were compared directly after interpolation. For Bg, the raw PVTP values were first converted to the same numerical convention used in the library table before comparison. The resulting empirical conversion factor was 177.51, which aligns the two Bg series closely.

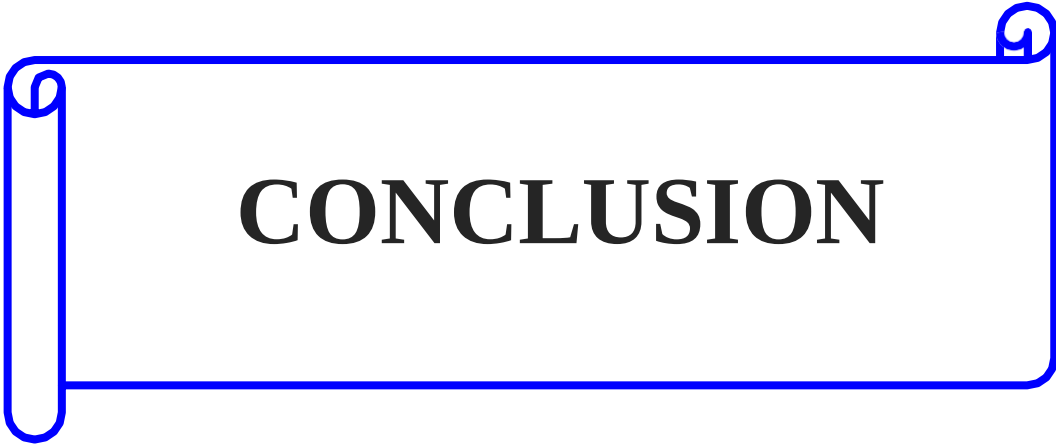
Full comparison :**Table IV.5:** Full comparison

Press ure	Rs lib	Rs PVTP	Bo lib	Bo PV TP	Uo lib	Uo PV TP	Z lib	Z PV TP	Bg lib	Bg PV TP con v.	Ug lib	Ug PV TP
40.00 00	34.05 01	33.76 31	1.17 20	1.18 22	0.60 98	0.76 68	0.95 54	0.95 23	5.57 12	5.59 49	0.01 39	0.00 00
69.30 00	48.56 39	48.73 86	1.20 75	1.21 73	0.53 49	0.68 26	0.92 86	0.92 45	3.12 68	3.40 31	0.01 46	0.00 00
113.5 000	69.39 08	73.04 91	1.25 83	1.27 70	0.46 29	0.56 59	0.90 10	0.89 45	1.85 10	1.86 39	0.01 62	0.00 00
157.8 000	92.43 35	100.1 384	1.31 53	1.34 69	0.40 89	0.46 56	0.89 19	0.88 43	1.31 82	1.30 50	0.01 81	0.00 00
202.1 000	120.1 065	130.6 137	1.38 52	1.42 81	0.36 32	0.38 37	0.90 08	0.89 44	1.03 97	1.03 36	0.02 02	0.00 00
246.4 000	154.2 458	164.5 584	1.47 33	1.52 01	0.32 32	0.31 90	0.92 43	0.91 92	0.87 51	0.87 15	0.02 25	0.00 00
297.6 000	203.9 000	197.2 420	1.60 42	1.60 33	0.28 28	0.28 04	0.96 46	-	0.75 61	-	0.02 52	-

Error summary**Table IV.6:** Error summary

Property	Average absolute error	Interpretation
Rs	3.27%	Good agreement
Bo	1.53%	Very good agreement
Uo	12.79%	Moderate difference
Z	0.60%	Excellent agreement
Bg (after correction)	1.87%	Good agreement after conversion
Ug	Not comparable	PVTP Ug values are zeros

Final conclusion: the two tables are strongly consistent for Rs, Bo, Z, and corrected Bg. Oil viscosity is reasonably consistent but shows larger differences than the other oil properties. Gas viscosity cannot be compared because the PVTP file contains only zeros for Ug.



CONCLUSION

Conclusion

This work focused on the study of reservoir fluid properties and their behavior through the application of the Black Oil Model to the RhourdeNouss Central (RNC) TAGS reservoir. The study highlighted the essential role of PVT analysis in reservoir engineering and production optimization. Understanding the thermodynamic and physical properties of reservoir fluids such as pressure, temperature, density, viscosity, gas–oil ratio (GOR), formation volume factors, and compressibility is fundamental for predicting reservoir performance and ensuring efficient hydrocarbon recovery.

The theoretical part presented the main concepts related to reservoir fluid characterization, phase behavior, and fluid classification. Particular attention was given to gas condensate systems and the importance of pressure–temperature relationships in determining fluid behavior inside the reservoir and at surface conditions. Different empirical correlations used for estimating PVT properties were also reviewed, including correlations for bubble point pressure, solution gas–oil ratio, oil formation volume factor, gas formation volume factor, and viscosities. These correlations remain essential tools when laboratory measurements are limited or unavailable.

The study also demonstrated the importance of the Black Oil Model as a practical and efficient approach for reservoir simulation. Although simplified compared to compositional models, the Black Oil approach provides reliable predictions for many reservoir engineering applications while requiring less computational effort. The comparison between Traditional Black Oil (TBO) and Modified Black Oil (MBO) models showed that the modified formulation offers better representation of volatile oils and gas-condensate systems due to its ability to account for two-way mass transfer between oil and gas phases.

In the practical section, the RhourdeNouss Central TAGS reservoir was analyzed using PVTP software and laboratory PVT data from well RN4. The matching and calibration of Differential Liberation (DL) test data allowed the determination of important reservoir fluid properties and confirmed the consistency between experimental and simulated results. The obtained trends for R_s , B_o , viscosity, and other fluid properties

showed realistic reservoir fluid behavior under varying pressure conditions. The analysis confirmed the condensate-rich nature of the reservoir and demonstrated the

CONCLUSION

significant influence of pressure depletion on fluid properties and phase behavior.

Finally, this study confirms that accurate fluid characterization and proper PVT modeling are indispensable for reservoir management, production forecasting, and optimization of recovery processes. The integration of laboratory analyses, empirical correlations, and simulation tools provides reservoir engineers with reliable methods for understanding reservoir performance and supporting field development strategies.



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