Working Model Report

Titled as

"Material Balance Simulator"

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Dhanbad-826004

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Certificate

This is to certify that **Brindaa G (24MT0111)**, **Shobhita G (24MT0165), Sathish Kumar M (24MT0398),** are the students from Master of Technology (Petroleum Engineering), Department of Petroleum Engineering, Indian Institute of Technology (Indian School of Mines), Dhanbad has worked under my supervision and completed their working model titled **"Material Balance Simulator"**

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Assistant Professor

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Date: 10/04/2025

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We extend our wholehearted gratitude to our mentor, **Prof. Neetish Kumar Maurya,** for his valuable advice, excellent guidance, patience, support, and good wishes. Without his undisputable support, this work would not have been true in the light of daylight.

We would like to extend our wholehearted gratitude towards our fellow students who were there by my side and helped me to make this project a grand success.

Sincerely,

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Abstract

The material balance is a fundamental reservoir engineering method that relates reservoir pressure, production data, and fluid properties to estimate hydrocarbons in place and assess reservoir performance over time. This project presents the development of a comprehensive material balance simulator using Python for the evaluation of both oil and gas reservoirs. The simulator applies the general material balance equation to calculate the original oil and gas in place (OOIP and OGIP), integrating fluid properties through empirical correlations such as Standing and McCain to improve the accuracy of reservoir behavior modeling. A water influx model has also been integrated to account for improving analysis in water-drive reservoirs. Graphical techniques, including Campbell and Cole plots, are implemented to identify dominant reservoir drive mechanisms and interpret pressure-production trends. In addition to historical analysis, the simulator includes a forecasting module that estimates future production based on extrapolated trends and reservoir parameters. The tool features automated plotting, future production forecasting, and a user-friendly web interface, allowing interactive input and result visualization. The integration of these functionalities within an open-source Python environment offers a cost-effective, user-friendly alternative to commercial reservoir simulation tools, making it suitable for academic and research purposes.

1. Introduction

In the field of petroleum engineering, the ability to model and predict reservoir performance is crucial for effective resource management and decision-making. One of the most fundamental tools in reservoir engineering is the material balance equation, which allows engineers to estimate the amount of hydrocarbons present in a reservoir and predict its future performance. This equation is based on the principle of conservation of mass, which states that the amount of material entering, leaving, or accumulating within a system must be accounted for.

However, solving material balance equations analytically can often be complex and time-consuming, especially for reservoirs with intricate geological and operational conditions. To address this challenge, the development of a Material Balance Simulator using Python aims to provide an efficient, user-friendly tool that can model different reservoir scenarios, simulate fluid behavior, and estimate key parameters such as pressure, production rate, and remaining reserves. This simulator will use numerical methods to solve the material balance equations, allowing for more accurate and flexible analyses of various reservoir conditions.

The objective of this project is to design and implement a simulator that can handle different types of reservoirs, fluid properties, and production strategies, while providing users with an intuitive interface and reliable results. By automating and streamlining the material balance process, this tool will help engineers make more informed decisions about reservoir management and optimization, ultimately improving the efficiency and sustainability of petroleum production.

1.1 Material Balance Equation (MBE)

The Material Balance Equation (MBE) is a fundamental tool in reservoir engineering used to estimate hydrocarbon reserves and predict reservoir performance. It is based on the principle of conservation of mass, ensuring that the original hydrocarbon volume is balanced with the produced fluids and the remaining hydrocarbons.

Material Balance Equation for Oil Reservoirs

For a volumetric oil reservoir (without significant water influx or gas cap expansion), the basic material balance equation is:

$$N = \frac{N_P B_o + N_P (R_{Si} - R_S) B_g + W_P B_w}{(B_o - B_{oi})}$$

The general form of the material balance equation for an undersaturated oil reservoir (considering different drive mechanisms) is:

$$N_P\left[B_o + (R_P + R_S)B_g\right] = N\left[(B_o - B_{oi}) + (R_{Si} - R_S)B_g\right] + NmB_{oi}\left[\frac{B_g}{B_{gi}} - 1\right] + \frac{N(1+m)B_{oi}(C_w S_w + C_f)\Delta P}{(1 - S_{wi})} + W_e + W_P B_w$$

Where:

N = Original Oil in Place (OOIP) (STB)

N_P = Cumulative oil produced (STB)

B_o= Oil formation volume factor (RB/STB)

B_{oi} = Initial oil formation volume factor (RB/STB)

B_g= Gas formation volume factor (Ft^3/SCF)

R_S = Solution gas-oil ratio (SCF/STB)

R_P = Produced gas-oil ratio (SCF/STB)

R_{Si} = Initial Solution gas-oil ratio (SCF/STB)

W_e = Water influx (bbl)

W_P = Cumulative water production (bbl)

B_w= Water formation volume factor (RB/STB)

Campbell plot

The Campbell plot is a graphical technique used in material balance analysis to evaluate the influence of water influx in a reservoir. It plots withdrawal against the withdrawal over total expansion (F/E_T) while neglecting the water influx term.

- Without water influx, the data forms a horizontal line, indicating that reservoir withdrawal is balanced purely by fluid expansion.
- With water influx, the withdrawal over total expansion term increases proportionally to the water influx over total expansion, reflecting the contribution of the aquifer.
- A weak aquifer exhibits an unusual trend where the curve decreases over time, which can be counter-intuitive.

The Campbell plot is particularly useful for assessing the strength of the aquifer, as it can highlight subtle variations in water influx more effectively than other material balance methods. However, this approach considers only total expansion (ET) and neglects the compressibility effects of water and formation compaction.

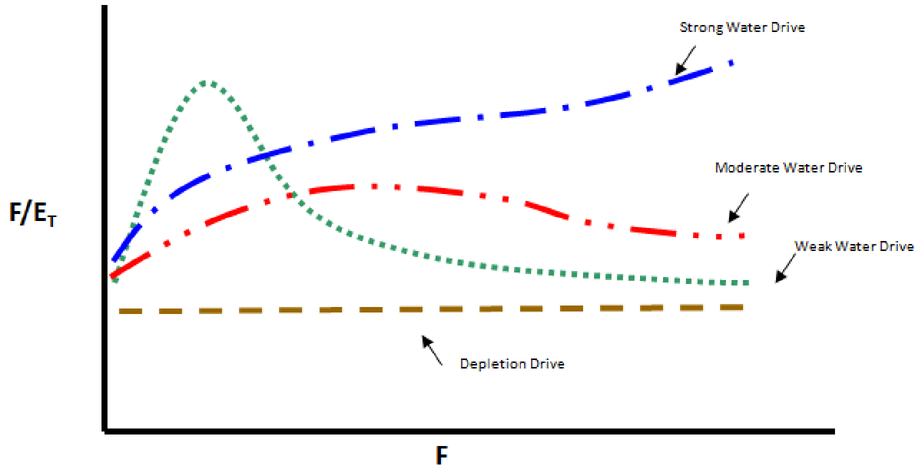


Figure.1 Campbell Plot

Material Balance Equation for Gas Reservoirs

For a **volumetric** gas reservoir (without water influx), the basic material balance equation is:

$$G = \frac{G_p B_g}{B_g - B_{gi}}$$

The general form of the material balance equation for a gas reservoir (considering water drive mechanism) is:

$$G_p B_g + W_p B_w = G\left(B_g - B_{gi}\right) + G B_{gi}\left[\frac{C_w S_{wi} + C_f}{1 - S_{wi}}\right] \Delta P + W_e$$

Where:

G = Original Gas in Place (OGIP) (SCF)

G_p = Cumulative gas produced (SCF)

W_e = Water influx (bbl)

W_p = Cumulative water production (bbl)

B_g = Gas formation volume factor (Ft^3/SCF)

B_{gi}= Initial Gas formation volume factor (Ft^3/SCF)

B_w= Water formation volume factor (RB/STB)

Cole Plot

The Cole plot is a graphical approach used in material balance analysis to assess the behavior of gas reservoirs, particularly in relation to water influx and depletion. It plots withdrawal against the ratio of withdrawal to total expansion (W/ET), providing insights into the reservoir's production characteristics.

- For a depletion-drive gas reservoir (without significant water influx), the data points typically form a horizontal trend, indicating that gas expansion is the dominant drive mechanism.
- For a gas reservoir with water influx, the withdrawal over total expansion term increases proportionally to the water influx over total expansion, reflecting aquifer support.
- A weak aquifer may show a declining trend over time, revealing its limited ability to sustain reservoir pressure.

The Cole plot is particularly useful for distinguishing between pure depletion drive and water-influx-supported gas reservoirs. However, like the Campbell plot, it considers only total expansion (ET) and does not account for formation compressibility or compaction effects.

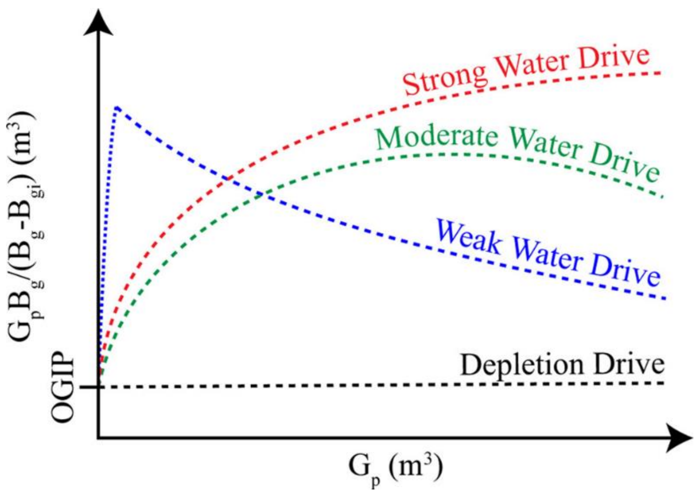


Figure.2 Cole Plot

1.2 Reservoir Drive Mechanisms

Reservoir drive mechanisms are the natural energy sources responsible for pushing hydrocarbons from the reservoir toward the wellbore. These mechanisms determine the reservoir's production behavior, pressure maintenance, and ultimate recovery efficiency. Understanding the different drive mechanisms is crucial for optimizing production strategies and improving hydrocarbon recovery.

Solution Gas Drive (Depletion Drive)

Solution gas drive, also known as depletion drive, occurs in undersaturated oil reservoirs where oil initially contains dissolved gas under high pressure. As production begins, the reservoir pressure decreases, and once it drops below the bubble point pressure, gas comes out of solution, expanding and pushing the oil toward the production wells. The expansion of this liberated gas provides the primary driving force for oil movement. However, solution gas drive reservoirs experience rapid pressure decline, leading to poor oil recovery, typically ranging between 5% and 30%. The gas-oil ratio (GOR) increases significantly over time as more gas is produced along with the oil. Due to inefficient pressure support, these reservoirs often require secondary recovery methods, such as water or gas injection, to enhance production.

Gas Cap Expansion Drive

Gas cap expansion drive occurs in reservoirs that have a free gas cap above the oil zone. When oil is produced, the reduction in pressure causes the gas cap to expand, exerting pressure on the oil column and driving it toward the production wells. This drive mechanism helps to maintain pressure more effectively than solution gas drive, resulting in a more moderate pressure decline. Oil recovery in gas cap drive reservoirs typically ranges from 20% to 40%. However, as production progresses, the GOR gradually increases due to an increasing contribution from the expanding gas cap. Proper well placement is crucial in gas cap reservoirs to prevent excessive gas production and to maximize oil recovery.

Water Drive (Aquifer Support)

Water drive is one of the most efficient natural drive mechanisms, occurring when a connected aquifer provides pressure support by pushing water into the reservoir as oil is produced. The continuous water influx replaces the void space left by produced fluids, helping to maintain reservoir pressure. This results in a slower and more controlled pressure decline compared to other drive mechanisms. Water drive reservoirs generally exhibit high oil recovery, typically ranging between 35% and 70%. They also tend to have a low gas-oil ratio, as most gas remains dissolved in the oil. However, as water encroachment increases, water production rises over time, potentially leading to high water cuts and production challenges.

Gravity Drainage Drive

Gravity drainage occurs when gravity causes the denser oil to move downward while the lighter gas migrates upward within the reservoir. This drive mechanism is highly effective in reservoirs with good vertical permeability and large thickness. Gravity drainage is particularly significant in naturally fractured reservoirs, where fluids can easily flow through fractures. Unlike solution gas or water drive reservoirs, gravity drainage results in a slow and steady pressure decline. Oil recovery from gravity drainage reservoirs can range from 50% to 70%, making it one of the most effective natural drive mechanisms. When combined with water influx, this drive provides excellent pressure maintenance and stable production rates.

Combination Drive

Many reservoirs exhibit a combination of multiple drive mechanisms, where two or more energy sources contribute to production. For example, a reservoir may initially be dominated by solution gas drive, but as pressure declines, water influx from an aquifer may start to support production. Similarly, a gas cap expansion drive can be complemented by gravity drainage, enhancing recovery. The efficiency of a combination drive reservoir depends on the dominant mechanism. In most cases, reservoirs with water influx or strong gravity drainage tend to have better pressure maintenance and higher ultimate recovery compared to those relying solely on solution gas expansion.

The performance and recovery efficiency of a reservoir largely depend on its dominant drive mechanism. Water drive and gravity drainage generally lead to higher recovery due to better pressure maintenance, while solution gas drive results in lower recovery due to rapid pressure depletion. Identifying the primary drive mechanism in a reservoir helps in selecting the most suitable production strategies and enhanced oil recovery (EOR) techniques to maximize hydrocarbon extraction.

1.3 Python in the Material Balance Simulator

Python is the core programming language used to develop a Material Balance Simulator that estimates the Original Oil in Place (OOIP) based on reservoir properties, fluid behavior, and production data. The script takes user inputs, performs calculations using various correlations, and visualizes the results through plots. Several Python libraries are used to handle numerical computations, data visualization, and interpolation.

Numerical Computations with NumPy

NumPy is used extensively in this project to perform mathematical operations and handle large arrays of data. It allows efficient storage and manipulation of numerical values, making it ideal for modeling reservoir conditions at varying pressure levels. The simulator generates a pressure range and applies fluid property correlations to compute key parameters like Solution Gas-Oil Ratio (Rs), Oil Formation Volume Factor (Bo), and Gas Formation Volume Factor (Bg). NumPy's ability to perform fast element-wise operations ensures that these calculations are both precise and computationally efficient.

Visualization with Matplotlib

Data visualization is a crucial part of reservoir analysis, and Matplotlib is used to generate plots that illustrate how fluid properties change with pressure depletion. The simulator produces multiple graphs, including:

- Solution Gas-Oil Ratio vs. Pressure to observe gas dissolution behavior.
- Oil Formation Volume Factor vs. Pressure to track oil shrinkage with depletion.
- Material Balance Plots to estimate OOIP using regression techniques.

Data Interpolation and Regression using SciPy

To improve accuracy, SciPy's interpolation functions are used to estimate fluid property values for pressure points that are not explicitly calculated. This ensures that fluid behavior transitions smoothly across different pressure levels, avoiding abrupt changes in the data. Additionally, linear regression from SciPy is applied to solve the Material Balance Equation. By plotting the expansion term (E) against the production term (F), a straight-line fit is generated, and the slope of this line provides an estimate of Original Oil in Place (OOIP). This statistical approach enhances the reliability of the simulator's results.

Simulation of Production Data

To test the model under realistic conditions, synthetic production data is generated using Python's random module. The simulator creates a dataset for cumulative oil, gas, and water production over time, which is then used to analyze pressure depletion trends. This feature makes the simulator adaptable for different reservoir conditions, ensuring that the analysis remains relevant across various field scenarios.

Integration with Streamlit for Web Interface

A key future enhancement of this project is its integration with Streamlit, a Python library designed for building interactive web applications. Instead of requiring users to manually enter input values through a console, Streamlit will provide an intuitive user interface with sliders, text boxes, and buttons. This web-based approach will allow users to:

- Input reservoir parameters easily.
- View real-time updates of graphs and calculations without running scripts manually.
- Interact with different reservoir scenarios and analyze results dynamically.

This integration will transform the simulator into a user-friendly and accessible tool for petroleum engineers, enabling them to perform reservoir evaluations efficiently.

2.Literature Review

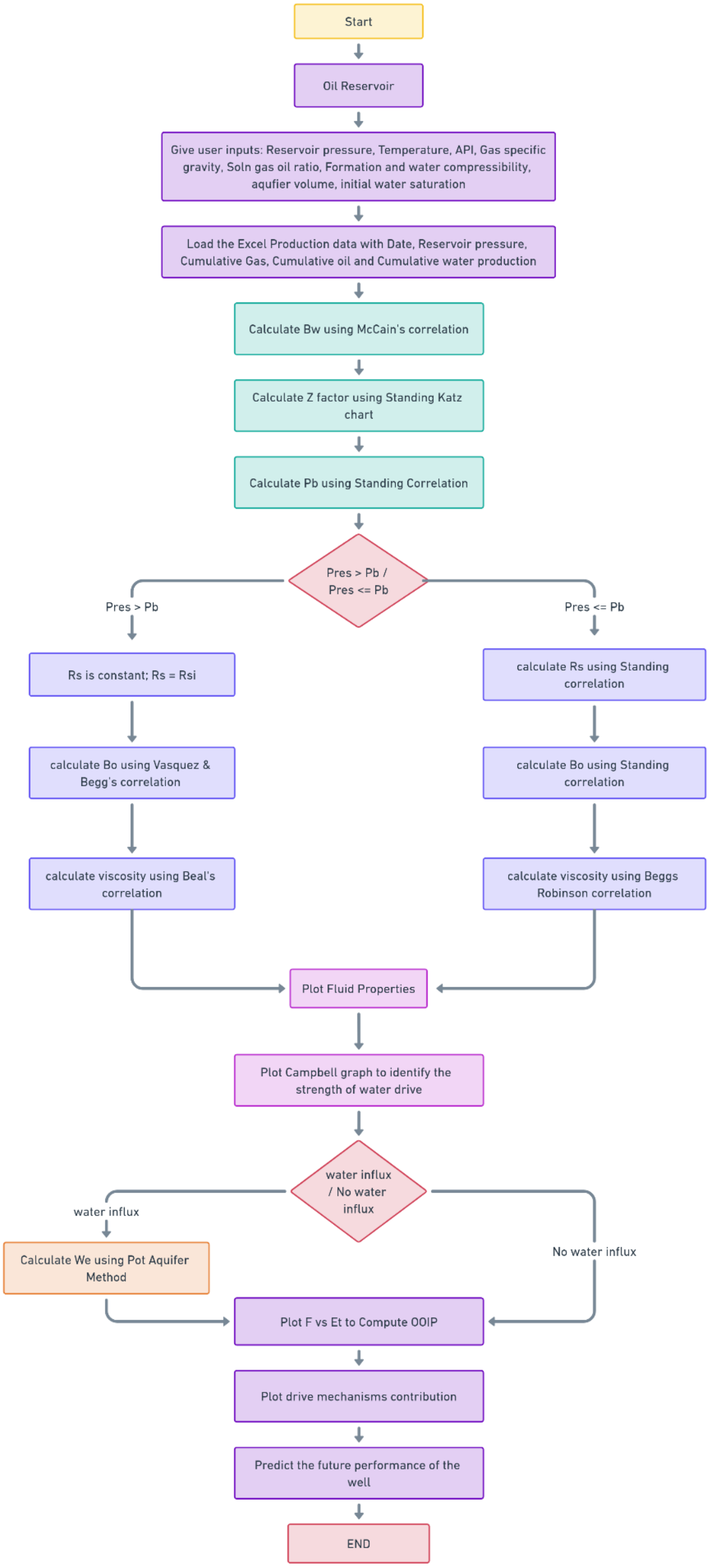
Title	Year and Author	Inference
Reservoir Engineering Manual	1983 Frank W Cole	• All the fundamental concepts of reservoir engineering were covered, including rock and fluid properties. Additionally, various drive mechanisms in oil and gas reservoirs were discussed, along with their impact on reservoir performance, recovery factors, and future production forecasting. • Cole emphasized the importance of the Material Balance Equation (MBE) in reservoir engineering, particularly for estimating the Original Hydrocarbons in Place (OHIP). To analyze reservoir performance, graphical methods such as the Campbell plot and Havlena-Odeh plots were explored.
Applied Multiphase Flow in Pipes and Flow Assurance	2017 Eissa M. AI-Safran and James P. Brill	• The fundamentals and practical applications of multiphase flow in pipelines were discussed, with a focus on oil and gas production. Key topics included flow assurance challenges and transient multiphase flow behavior. • Fluid properties relevant to the black oil model were examined, along with the empirical correlations used to calculate various parameters.
Development of Machine Learning-Based Production Forecasting for	2024 Junhyeok Hyoung,	• Reservoir flow analysis model was established by combining MBE and

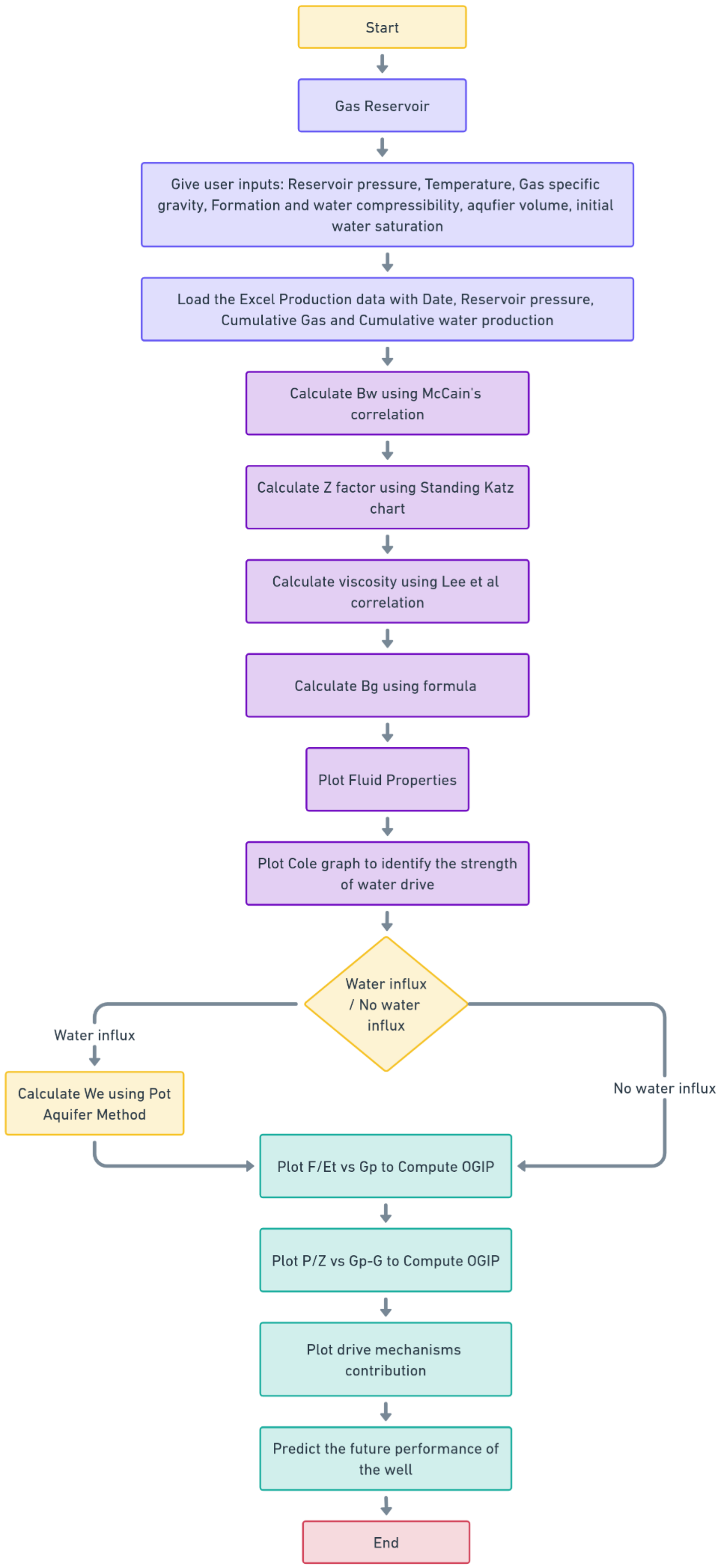
Offshore Gas Fields Using a Dynamic Material Balance Equation	Youngsoo Lee and Sunlee Han	IPR and developed a model to predict BHP by using machine learning. • The model had not fully captured the complexities of flow dynamics particularly for heterogeneous reservoirs. The dynamic parameters like fluid compositions and temperature variations were not incorporated.
Analytical Estimation of hydrogen Storage Capacity in Depleted Gas Reservoirs: A Comprehensive Material Balance Approach	2024 Deema Albadan, Mojdeh delshad, Bruno Ramon Batista Fernandes, Esmail Eltahan and Kamy Sepehrnoori	• The hydrogen storage capacity was estimated in both volumetric drive and water drive gas reservoirs by using mass conservation and validated the results. • The analytical model had not fully captured the dynamic interactions and complexities present in the reservoir leading to discrepancies between two methods.
Improvements to Reservoir Material Balance Methods	2002 J.L. Pletcher	• The presence of weak water drive was diagnosed by Cole and Campbell plot as the failure to account for weak water drive resulted in significant material balance errors. • The Cole plot was modified to account for formation compressibility. • Pot aquifer models were studied to analyse the significant effects on material balance.

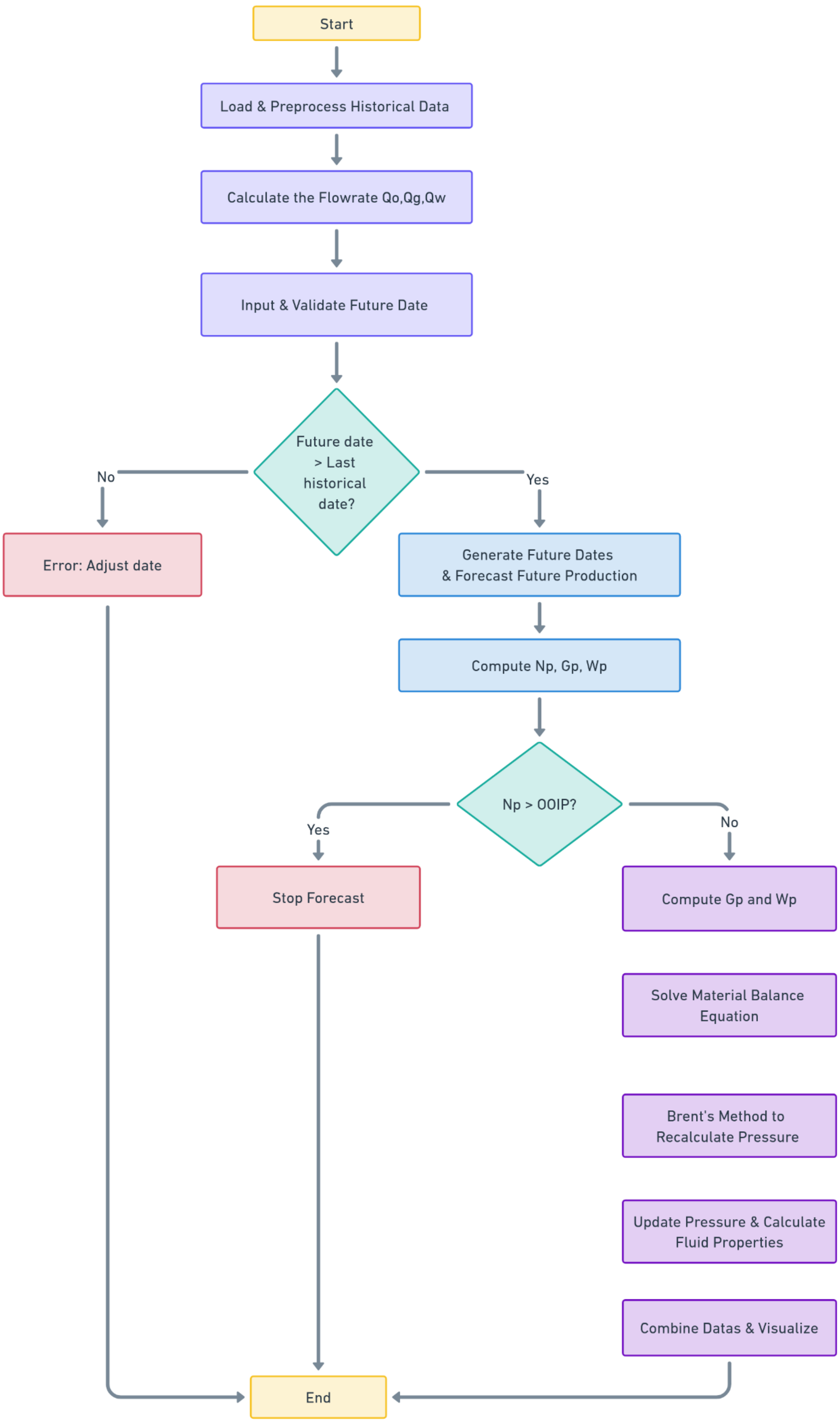
Table 1. Literature review

3.Methodology

Algorithm




Start
Gas Reservoir
Give user inputs: Reservoir pressure, Temperature, Gas specific gravity, Formation and water compressibility, aqufier volume, initial water saturation
Load the Excel Production data with Date, Reservoir pressure, Cumulative Gas and Cumulative water production
Calculate Bw using McCain's correlation
Calculate Z factor using Standing Katz chart
Calculate viscosity using Lee et al correlation
Calculate Bg using formula
Plot Fluid Properties
Plot Cole graph to identify the strength of water drive
Water influx / No water influx
Water influx
Calculate We using Pot Aquifer Method
No water influx
Plot F/Et vs Gp to Compute OGIP
Plot P/Z vs Gp-G to Compute OGIP
Plot drive mechanisms contribution
Predict the future performance of the well
End



Start
Load & Preprocess Historical Data
Calculate the Flowrate Qo,Qg,Qw
Input & Validate Future Date
Future date > Last historical date?
No
Yes
Error: Adjust date
Generate Future Dates & Forecast Future Production
Compute Np, Gp, Wp
Np > OOIP?
Yes
No
Stop Forecast
Compute Gp and Wp
Solve Material Balance Equation
Brent's Method to Recalculate Pressure
Update Pressure & Calculate Fluid Properties
Combine Datas & Visualize
End

Oil Reservoir

Calculation of Fluid Properties

Fluid properties in reservoir engineering are essential for understanding and predicting the behaviour of hydrocarbons in the reservoir and during production. These properties influence reservoir performance, well design, and production strategies.

Fluid properties are estimated at different reservoir pressures using industry-standard correlations.

Water Formation Volume Factor (B_w)

Water Formation Volume Factor (B_w) is the ratio of the volume of water at reservoir conditions to its volume at standard conditions. It is expressed in reservoir barrels per stock tank barrel (rb/stb).

B_w slightly decreases with increasing pressure due to water compressibility and slightly increases with increasing temperature due to thermal expansion.

The water formation volume factor (B_w) is calculated using Mc Cain's Correlation:

$$B_w = (1 + \Delta V_{wP})(1 + \Delta V_{wT})$$

Where:

$$\Delta V_{wP} = -1.95301(10^{-9})PT - 1.72834(10^{-13})P^2T - 3.58922(10^{-7})P - 2.25341(10^{-10})P^2$$

$$\Delta V_{wT} = -1.0001(10^{-2}) + 1.33391(10^{-4})T + 5.50654(10^{-7})T^2$$

```
# ---------------------------------------------------
# Function: Calculate Bw using McCain's correlation
# ---------------------------------------------------
def calculate_Bw(res_p, t):
    delta_VwP = (-1.95301e-9 * res_p * t
                 - 1.72834e-13 * (res_p**2) * t
                 - 3.58922e-7 * res_p
                 - 2.25341e-10 * (res_p**2))
    delta_VwT = (-1.0001e-2
                 + 1.33391e-4 * t
                 + 5.50654e-7 * (t**2))
    Bw = (1 + delta_VwP) * (1 + delta_VwT)
    return Bw
```

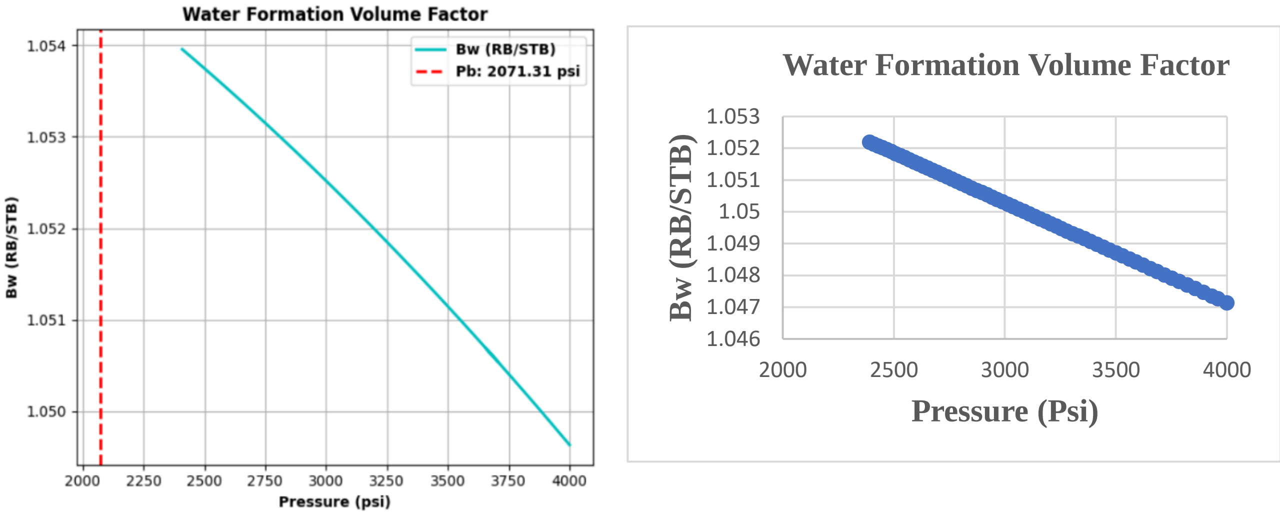


Figure3. Water Formation Volume Factor plot from code and MBAL

Compressibility Factor (Z)

The Compressibility Factor (Z) is a dimensionless value that measures how much a real gas deviates from ideal gas behavior. It is essential for calculating gas volumes at reservoir and surface conditions. It is used in material balance equations, gas reserves estimation, and PVT calculations.It is used to correct the ideal gas law for real gas conditions.

PV=ZnRT

The pseudocritical temperature and pseudocritical pressure are calculated by using a set of empirical equations proposed by Sutton:

$$T_{pc} = 120.1 + 425sg_g - 62.9sg_g^2$$

$$P_{pc} = 671.1 + 14sg_g - 34.3sg_g^2$$

The compressibility factor (Z) can be estimated using pseudo-reduced pressure and pseudo-reduced temperature, especially for natural gas systems:

$$T_{pr} = \frac{T}{T_{pc}}$$

$$P_{pr} = \frac{P}{P_{pc}}$$

$$\rho_r = \frac{0.27P_{pr}}{ZT_{pr}}$$

The compressibility factor is calculated by using the Dranchuk and Abu-Kassem correlation that represents the Standing and Katz Z-factor chart. The below equation is implicit in Z and solved by some iterative method, such as Newton-Raphson iteration technique.

$$Z = \left(A_1 + \frac{A_2}{T_{pr}} + \frac{A_3}{T_{pr}^3} + \frac{A_4}{T_{pr}^4} + \frac{A_5}{T_{pr}^5}\right)\rho_r + \left(A_6 + \frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right)\rho_r^2 - A_9\left(\frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right)\rho_r^5$$
$$+ A_{10}(1 + A_{11}\rho_r^2)\left(\frac{\rho_r^2}{T_{pr}^3}\right)\exp(-A_{11}\rho_r^2) + 1.0$$

Where:

A_1= 0.3265 A_2= -1.0700 A_3= -0.5339 A_4= 0.01569 A_5= -0.05165

A_6= 0.5475 A_7= -0.7361 A_8= 0.1844 A_9= 0.1056 A_{10}= 0.6134

A_{11}= 0.7210

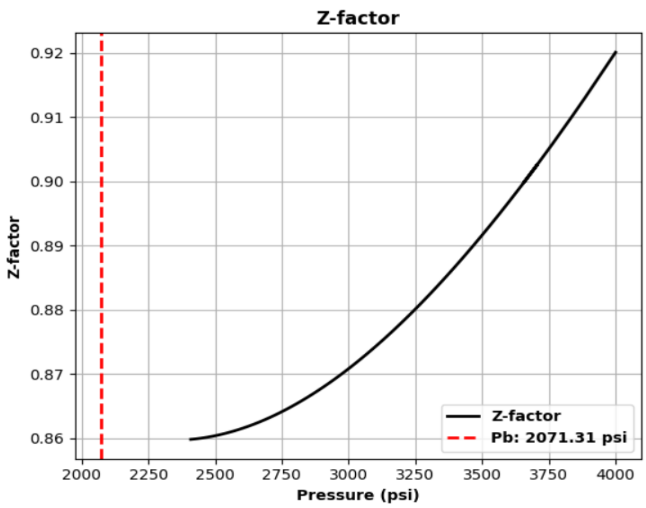


Figure 4. Compressibility factor plot from code

Bubble Point Pressure (Pb)

Bubble point pressure is the pressure at which the first bubble of gas comes out of solution from the oil when the pressure of a reservoir fluid is reduced at a constant temperature.

Above Bubble Point Pressure: The oil remains undersaturated, meaning all the gas is dissolved in the oil.

At Bubble Point Pressure: The oil is saturated with the maximum amount of dissolved gas.

Below Bubble Point Pressure: Free gas starts to form, affecting reservoir performance and fluid flow.

The bubble point pressure (Pb) is calculated using Standing's Correlation:

$$P_b = 18.2\left[\left(\frac{R_s}{sg_g}\right)0.83 \times 10^{(0.00091T-0.0125API)} - 1.4\right]$$

```
# Bubble Point Pressure (Pb) using Standing's Correlation
p_b = 18.2 * (((r_s_input / sg_g) ** 0.83) * (10 ** (0.00091 * t - (0.0125 * api))) - 1.4)
print(f"Calculated Bubble Point Pressure (Pb): {p_b:.2f} psi")
```

Solution Gas-Oil Ratio (Rs):

Solution Gas-Oil Ratio (GOR) is the amount of natural gas dissolved in crude oil at a given pressure and temperature. It is expressed in standard cubic feet of gas per stock tank barrel of oil (scf/stb).

Above Bubble Point Pressure: All gas remains dissolved in the oil, and R_S remains constant.

At Bubble Point Pressure: The oil holds the maximum amount of dissolved gas.

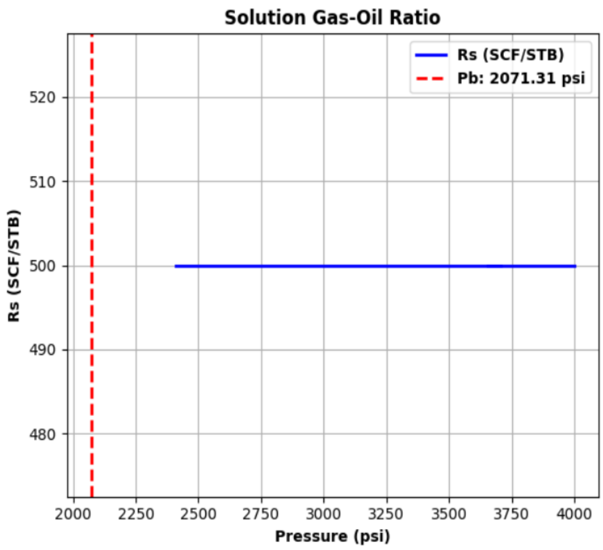
Below Bubble Point Pressure: Gas starts to come out of solution, reducing R_S as free gas forms.

For pressures below Pb, the solution gas-oil ratio is calculated by using Standing's correlation:

$$R_s = sg_g\left(\frac{P \times 10^{(0.0125API)}}{18 \times 10^{(0.00091T)}}\right)^{1.2048}$$

```
# Compute Rs (solution GOR) at each production pressure
Rs_data = np.zeros(n_points)
for i in range(n_points):
    if pressure_data[i] > p_b:
        Rs_data[i] = r_s_input
    else:
        Rs_data[i] = sg_g * (((pressure_data[i]+14.7) * (10 ** (0.0125 * api))) /(18 * (10 ** (0.00091 * t)))) ** 1.2048
```

For pressures above Pb, Rs is constant at Rs at Pb.



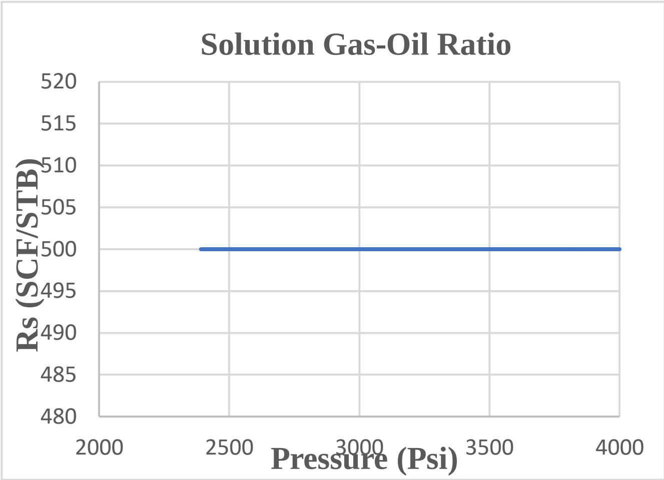


Figure 5. Solution Gas-Oil Ratio plot from code and MBAL

Oil Formation Volume Factor (B_o)

Oil Formation Volume Factor (B_o) is the ratio of the volume of oil at reservoir conditions to its volume at standard surface conditions. It is expressed in reservoir barrels per stock tank barrel (rb/stb).

Above Bubble Point Pressure: B_o decreases as pressure decreases due to oil compression.

For pressures above Pb, oil formation volume factor is calculated by exponential relation:

$$B_o = B_o(atP_b) \times e^{-co(P-P_b)}$$

At Bubble Point Pressure: B_o is at its maximum due to dissolved gas expansion.

Below Bubble Point Pressure: B_o decreases as gas comes out of solution, shrinking the oil volume.

For pressures below Pb, oil formation volume factor is calculated by using Standing's correlation:

$$B_o = 0.9759 + 0.00012\left(\left(R_s \times \sqrt{\frac{sg_g}{sg_o}}\right) + 1.25T\right)^{1.2}$$

```
# Calculate Oil Formation Volume Factor (Bo)
sg_o = 141.5 / (api + 131.5)
rs_bp = sg_g * ((p_b * (10 ** (0.0125 * api))) /(18 * (10 ** (0.00091 * t)))) ** 1.2048
bo_b = 0.9759 + 0.00012 * (((rs_bp * (sg_g / sg_o) ** 0.5) + (1.25 * t)) ** 1.2)
```

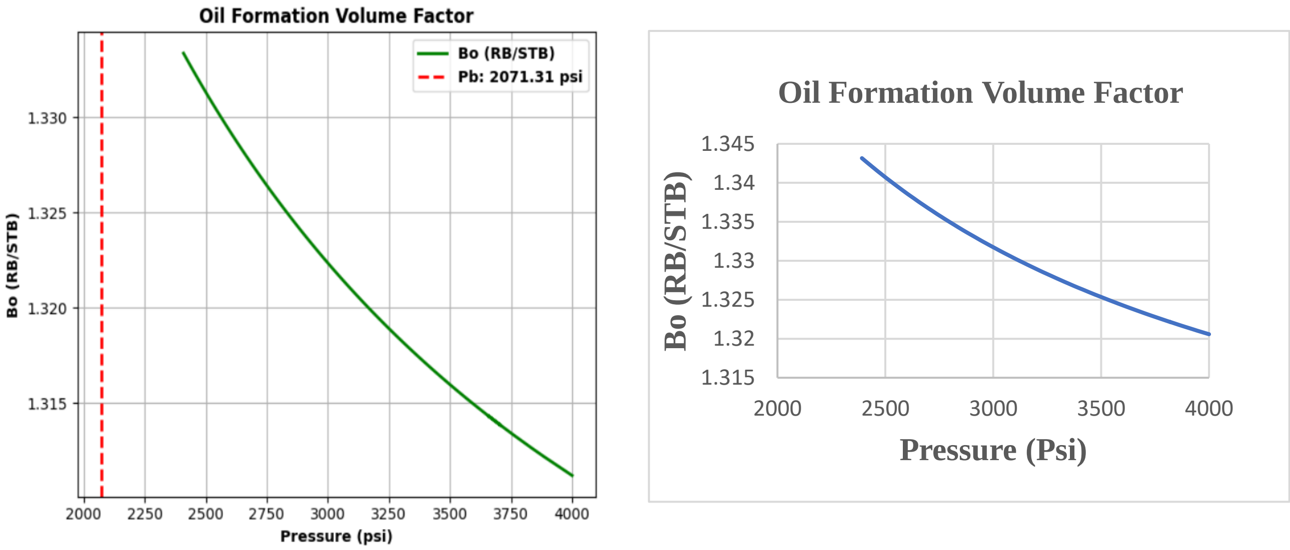


Figure 6. Oil Formation Volume Factor (B_o) plot from code and MBAL

Oil Compressibility (C_o)

Oil compressibility (C_o) is the fractional change in oil volume per unit change in pressure, at constant temperature. It is expressed in psi^{-1} or bar^{-1}.

For pressures above Pb, oil compressibility is calculated by using Vasquez-Beggs correlation:

$$C_o = \frac{5R_{sb} + 17.2T - 1180sg_g + 12.61sg_o - 1433}{P(10)^5}$$

```
# Estimate oil compressibility (c_o)
c_o_data = np.zeros(n_points)
for i in range(n_points):
    c_o_data[i] = ((5 * rs_bp) + (17.2 * t) - (1180 * sg_g) + (12.61 * api) - 1433) / ((pressure_data[i]+14.7) * 100000)
```

Gas Formation Volume Factor (B_g)

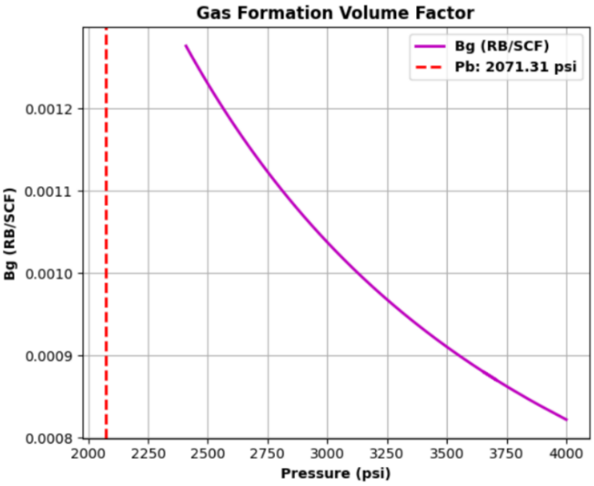
Gas Formation Volume Factor (B_g) is the ratio of the volume of gas at reservoir conditions to its volume at standard conditions. It is expressed in reservoir cubic feet per standard cubic foot (rcf/scf).

B_g decreases as reservoir pressure increases and increases as pressure decreases (gas expands during production).

The gas formation volume factor is calculated by the below formula:

$$B_g = 0.005035 \times \frac{Z \times (T + 460)}{P}$$

```
# Compute Z Factor and Gas Formation Volume Factor (Bg)
Z_prod = np.array([compute_z(sg_g, p_val, t) for p_val in pressure_data])
Bg_data = 0.005035 * Z_prod * (t + 460) / pressure_data
```



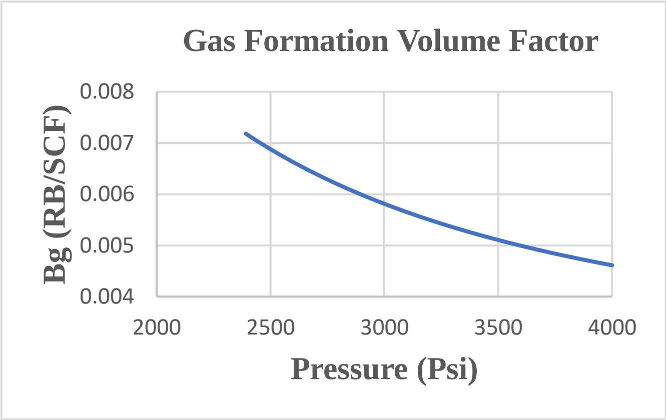


Figure 7. Gas Formation Volume Factor (B_g) plot from python and MBAL

Oil Viscosity

Oil viscosity (μ_o) is a measure of the oil's resistance to flow under shear stress. It is expressed in centipoise (cp) and depends on temperature, pressure, and composition of the oil.

Above Bubble Point Pressure: Viscosity decreases slightly with decreasing pressure.

For pressures above Pb the oil viscosity is calculated using Beal's correlation:

$$\mu_o = (10.715(R_s + 100)^{-0.515}) \times v_o^{(5.44(Rs+150)^{-0.338})}$$

Where, v_0 is the viscosity of the dead oil

$$v_o = 10^X - 1$$

Where:

X= Y$(T - 460)^{-1.163}$

Y= 10^Z

Z= 3.0324-0.02023 ^{o}API

At Bubble Point Pressure: Viscosity starts increasing as gas begins to separate.

Below Bubble Point Pressure: Viscosity increases significantly as more gas evolves and oil becomes heavier.

For pressures below Pb the oil viscosity is calculated using Beggs-Robinson correlation:

$$\mu_o = \mu_o(atP_b) + 0.001(P - P_b) \times (0.024{\mu_o}^{1.6} + 0.038{\mu_o}^{0.56})$$

```
# Viscosity Calculation
v_od = 10 ** (10 ** (3.0324 - 0.02023 * api) * t ** (-1.163)) - 1
Viscosity_data = np.zeros(n_points)
for i in range(n_points):
    if pressure_data[i] <= p_b:
        Viscosity_data[i] = (10.715 * (Rs_data[i] + 100) ** (-0.515)) * v_od ** (5.44 * (Rs_data[i] + 150) ** (-0.338))
    else:
        v_o_sat = (10.715 * (rs_bp + 100) ** (-0.515)) * v_od ** (5.44 * (r_s_input + 150) ** (-0.338))
        Viscosity_data[i] = v_o_sat + 0.001 * (pressure_data[i] - p_b) * ((0.024 * v_o_sat ** 1.6) + (0.038 * v_o_sat ** 0.56))
```

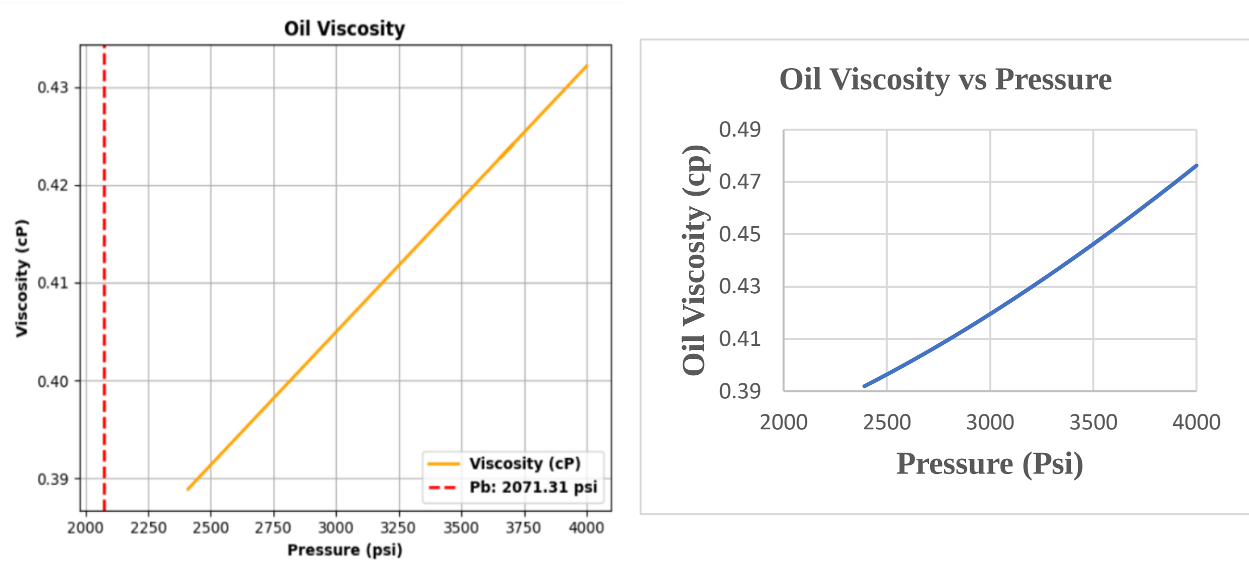


Figure 8. Oil viscosity plot from code and MBAL

Water Influx Calculations

Water influx is the volume of water that enters the reservoir from the surrounding aquifer (water-bearing formation) as a result of pressure decline during oil or gas production. It acts as a support mechanism that maintains reservoir pressure and slows down decline in production.

The water influx is calculated by using small pot aquifer model

$$W_e = W_i(C_w + C_f)\Delta P$$

Campbell Plot

Campbell plot is plotted between withdrawal(F) versus the withdrawal over total expansion (F/E_T) while neglecting the water influx term. It is used to evaluate the influence of water influx in a reservoir.

Material Balance Calculations

Material balance analysis is performed using graphical methods.

Production Terms (F)

$$F = N_p \times B_o + (G_p - N_p \times R_s) \times B_g + W_p \times B_w$$

Expansion Terms (E)

Total expansion term

$$E = (B_o - B_{oi}) + (R_s - R_{si})B_g + B_{oi}\, c_e (P_i - \mathrm{P})$$

where:

$$c_e = \frac{c_w S_{wc} + c_f}{1 - S_{wc}}$$

Graphical Method for OOIP Estimation

A linear regression fit between F and E determines Original Oil in Place (OOIP)

$$\mathrm{N} = \frac{\sum EF}{\sum E^2}$$

```python
# -----------------------------------------------------
# Material Balance Plot for N Estimation (Graphical Method)
# -----------------------------------------------------
if not influx_present:
    num = np.sum(E_t_data * F_data)
    denom = np.sum(E_t_data**2)
    if denom == 0:
        raise ValueError("Zero variance in E_t_data")
    N_intercept = num / denom
    plt.figure(figsize=(8, 6))
    plt.plot(E_t_data, F_data, 'bo', linewidth=2, label='F vs E_t')
    plt.plot(E_t_data, N_intercept * E_t_data, 'r-', linewidth=2, label=f'Fit: N = {N_intercept * 1e6:.2f} STB')
    plt.xlabel('Total Expansion Term (E_t, RB/STB)', fontweight='bold')
    plt.ylabel('Production Term (F)', fontweight='bold')
    plt.title('Material Balance Plot (No Influx)', fontweight='bold')
    plt.legend(prop={'weight':'bold'})
    plt.grid()
    plt.show()
    print(f"Estimated Original Oil in Place (Graphical, No Influx): {N_intercept * 1e6:.2f} STB")
else:
    num = np.sum(E_t_data * (F_data - We_data / 1e6))
    denom = np.sum(E_t_data**2)
    if denom == 0:
        raise ValueError("Zero variance in E_t_data")
    N_intercept = num / denom
    F_minus_We = F_data - We_data / 1e6
```

Drive Mechanism Analysis

Stacked area plots are used to visualize the dominant drive mechanism.

Gas Reservoir

Water Formation Volume Factor (B_w)

Water Formation Volume Factor (B_w) is the ratio of the volume of water at reservoir conditions to its volume at standard conditions. It is expressed in reservoir barrels per stock tank barrel (rb/stb).

B_w slightly decreases with increasing pressure due to water compressibility and slightly increases with increasing temperature due to thermal expansion.

The water formation volume factor (B_w) is calculated using Mc Cain's Correlation:

$$B_w = (1 + \Delta V_{wP})(1 + \Delta V_{wT})$$

Where:

$$\Delta V_{wP} = -1.95301(10^{-9})PT - 1.72834(10^{-13})P^2T - 3.58922(10^{-7})P - 2.25341(10^{-10})P^2$$

$$\Delta V_{wT} = -1.0001(10^{-2}) + 1.33391(10^{-4})T + 5.50654(10^{-7})T^2$$

Compressibility Factor (Z)

The Compressibility Factor (Z) is a dimensionless value that measures how much a real gas deviates from ideal gas behavior. It is essential for calculating gas volumes at reservoir and surface conditions. It is used in material balance equations, gas reserves estimation, and PVT calculations.It is used to correct the ideal gas law for real gas conditions.

PV=ZnRT

The pseudocritical temperature and pseudocritical pressure are calculated by using a set of empirical equations proposed by Sutton:

$$T_{pc} = 120.1 + 425sg_g - 62.9sg_g^2$$

$$P_{pc} = 671.1 + 14sg_g - 34.3sg_g^2$$

The compressibility factor (Z) can be estimated using pseudo-reduced pressure and pseudo-reduced temperature, especially for natural gas systems:

$$T_{pr} = \frac{T}{T_{pc}}$$

$$P_{pr} = \frac{P}{P_{pc}}$$

$$\rho_r = \frac{0.27 P_{pr}}{Z T_{pr}}$$

The compressibility factor is calculated by using the Dranchuk and Abu-Kassem correlation that represents the Standing and Katz Z-factor chart. The below equation is implicit in Z and solved by some iterative method, such as Newton-Raphson iteration technique.

$$Z = \left(A_1 + \frac{A_2}{T_{pr}} + \frac{A_3}{T_{pr}^3} + \frac{A_4}{T_{pr}^4} + \frac{A_5}{T_{pr}^5}\right)\rho_r + \left(A_6 + \frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right)\rho_r^2 - A_9\left(\frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right)\rho_r^5$$
$$+ A_{10}(1 + A_{11}\rho_r^2)\left(\frac{\rho_r^2}{T_{pr}^3}\right)\exp(-A_{11}\rho_r^2) + 1.0$$

Where:

A_1= 0.3265 A_2= -1.0700 A_3= -0.5339 A_4= 0.01569 A_5= -0.05165

A_6= 0.5475 A_7= -0.7361 A_8= 0.1844 A_9= 0.1056 A_{10}= 0.6134

A_{11}= 0.7210

Gas Formation Volume Factor (B_g)

Gas Formation Volume Factor (B_g) is the ratio of the volume of gas at reservoir conditions to its volume at standard conditions. It is expressed in reservoir cubic feet per standard cubic foot (rcf/scf).

B_g decreases as reservoir pressure increases and increases as pressure decreases (gas expands during production).

The gas formation volume factor is calculated by the below formula:

$$B_g = 0.005035 \times \frac{Z \times (T + 460)}{P}$$

Gas Viscosity

Gas viscosity is a measure of a gas's resistance to flow or shear deformation. It is typically expressed in centipoise (cP) and is much lower than oil or water viscosity.

Gas viscosity is calculated by using Lee et al correlation

$$M_a = sg_g \times 28.96$$

$$u_g = 10^{-4} Kexp[X(\frac{sg_g}{62.4})^Y$$

Where:

$$K = \frac{(9.4 + 0.02M_a)(T + 460)^{1.5}}{669 + 19M_a + T}$$

$$X = 3.5 + \frac{986}{(T + 460)} + 0.01M_a$$

$$Y = 2.4 - 0.2X$$

```
# ----------------------------------------------------
# Function: Calculate Gas Viscosity using Lee et al.
# ----------------------------------------------------
def calculate_gas_viscosity(p, t, sg_g, Z):
    M = 28.97 * sg_g
    rho_g = (28.97 * sg_g * p) / (Z * 10.73 * (t + 460))
    K = ((9.4 + 0.02 * M) * ((t + 460)**1.5)) / (209 + 19 * M + t + 460)
    X = 3.5 + (986 / (t + 460)) + 0.01 * M
    Y = 2.4 - 0.2 * X
    viscosity = 1e-4 * K * np.exp(X * ((rho_g / 62.4)**Y))
    return viscosity
```

Water Influx Calculations

Water influx is the volume of water that enters the reservoir from the surrounding aquifer (water-bearing formation) as a result of pressure decline during oil or gas production. It acts as a support mechanism that maintains reservoir pressure and slows down decline in production.

The water influx is calculated by using small pot aquifer model

$$W_e = W_i(C_w + C_f)\Delta P$$

Cole Plot

Cole plot is plotted between $\frac{G_p B_g}{B_g - B_{gi}}$ versus the cumulative gas production G_p, it is used to evaluate the influence of water influx in a reservoir.

Material Balance Calculations

Material balance analysis is performed using graphical methods.

Production Terms (F)

$$F = G_p B_g + W_p B_w$$

Expansion Terms (E)

Total expansion term

$$E = G(B_g - B_{gi}) + G B_{gi} c_e \Delta P + W_e$$

where:

$$c_e = \frac{c_w S_{wc} + c_f}{1 - S_{wc}}$$

Graphical Method for OGIP Estimation

A linear regression fit between $\frac{F}{E_t}$ and G_p determines Original Gas in Place (OGIP) and

A linear regression fit between $\frac{P}{Z}$ and G_p-G_i determines Original Gas in Place (OGIP).

```
# -----------------------------------------------------
# Material Balance Plot for OGIP Estimation (Graphical Method)
# -----------------------------------------------------
F_data = Gp_data * Bg_data + Wp_data * Bw_data
c = (c_f + c_w * S_wc) / (1 - S_wc)
E_t_data = (Bg_data - B_gi) + B_gi * c * (res_p - pressure_data)
numerator = np.sum(E_t_data * F_data)
denom = np.sum(E_t_data**2)
if denom == 0:
    raise ValueError("Zero variance in expansion term.")
G_intercept = numerator / denom

if not influx_present:
    ratio = F_data / E_t_data
```

```
# -------------------------------------------------------
# Modified p/Z Plot for OGIP Estimation
# -------------------------------------------------------
from sklearn.linear_model import LinearRegression
G_initial = Gp_data[0]
x_modified = Gp_data - G_initial
y_modified = pressure_data / Z_prod
model = LinearRegression()
model.fit(x_modified.reshape(-1, 1), y_modified)
slope_val = model.coef_[0]
intercept_val = model.intercept_
OGIP_estimated = intercept_val / -slope_val
```

Drive Mechanism Analysis

Stacked area plots are used to visualize the dominant drive mechanism.

```
# ------------------------------------------------------
# Drive Mechanism Analysis
# ------------------------------------------------------
E_g_drive = Bg_data - B_gi
C_val = (c_f + c_w * S_wc) / (1 - S_wc)
E_fw_drive = B_gi * C_val * (res_p - pressure_data)
We_term_drive = We_data / (G_intercept * 1e3) if G_intercept != 0 else np.zeros_like(We_data)
total_expansion_drive = E_g_drive + E_fw_drive + We_term_drive
gas_exp_pct = np.nan_to_num((E_g_drive / total_expansion_drive) * 100)
rock_water_pct = np.nan_to_num((E_fw_drive / total_expansion_drive) * 100)
water_influx_pct = np.nan_to_num((We_term_drive / total_expansion_drive) * 100)
```

4.Results and Discussions

Oil Reservoir

The following are the results for an oil reservoir (dataset 1) .The reservoir is undersaturated with the reservoir pressure above the bubble point pressure.

Campbell Plot Results

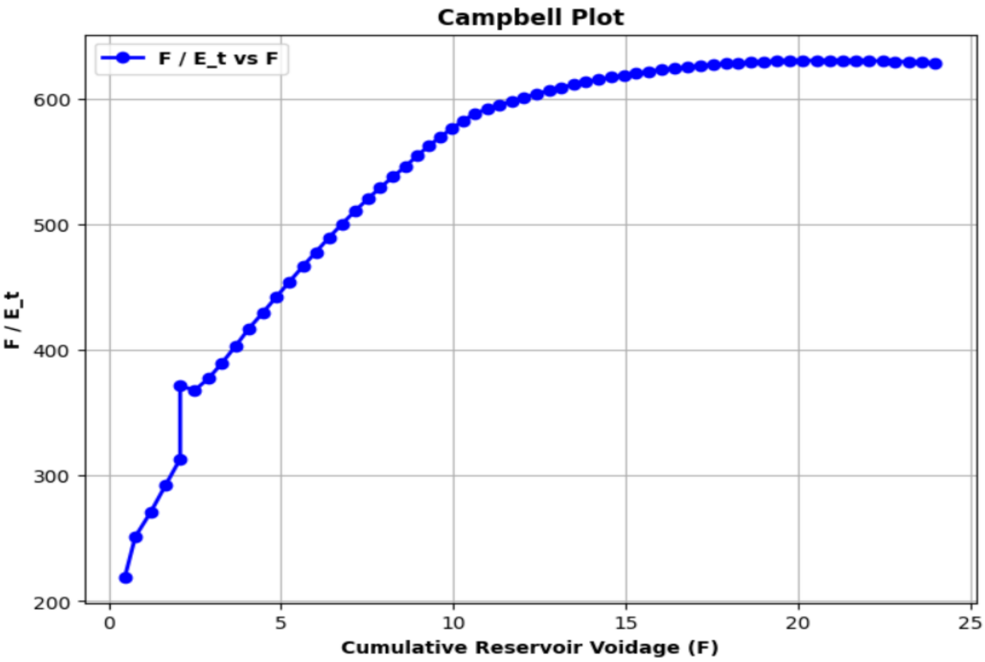


Figure 9. Campbell plot from code

The Campbell plot analysis indicates that the oil reservoir is supported by a moderate water drive and validated from the MBAL software.

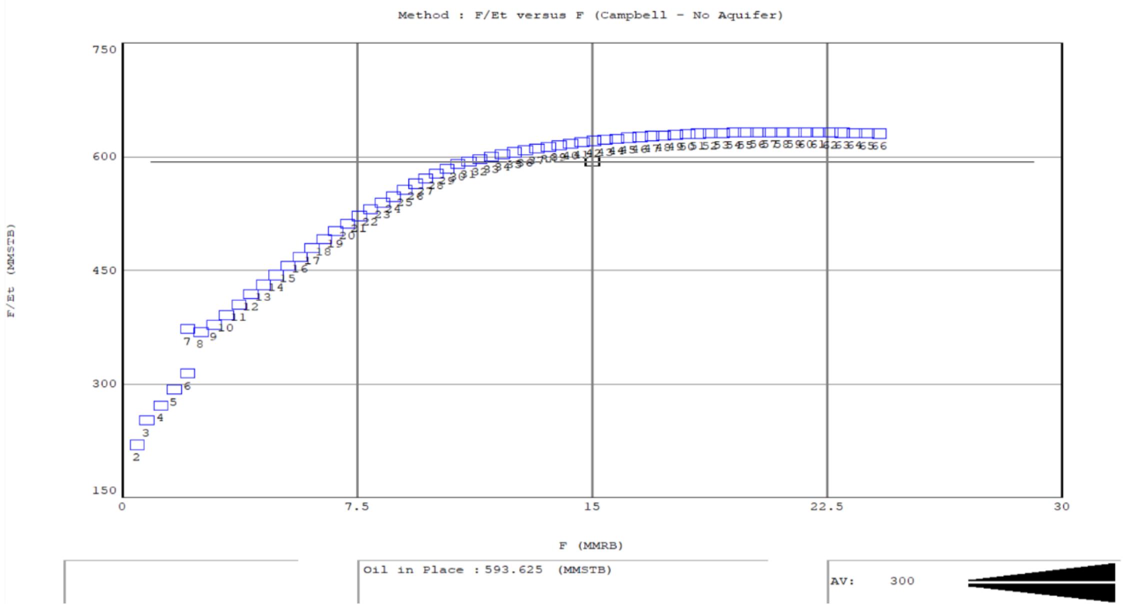


Figure 10. Campbell plot from MBAL

Fluid Properties

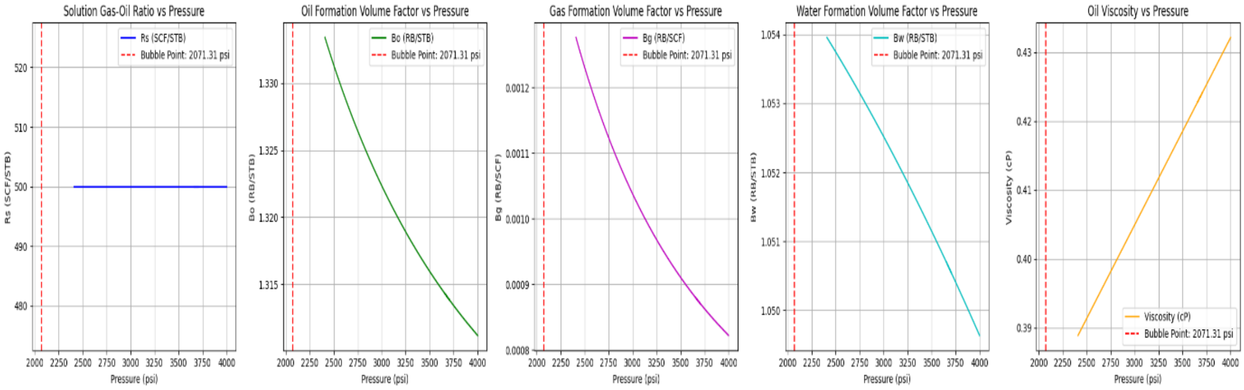


Figure 11. Fluid properties plots from Code

All the fluid properties followed the expected trends.

- The solution gas–oil ratio (Rs) remained constant above the bubble point pressure.
- The oil formation volume factor (Bo) increased as pressure decreased from the initial reservoir pressure.
- The gas formation volume factor (Bg) decreased with increasing pressure above the bubble point.
- The water formation volume factor (Bw) followed a nearly linear trend with pressure.
- Oil viscosity decreased as pressure decreased from the initial reservoir pressure.

Cumulative Production

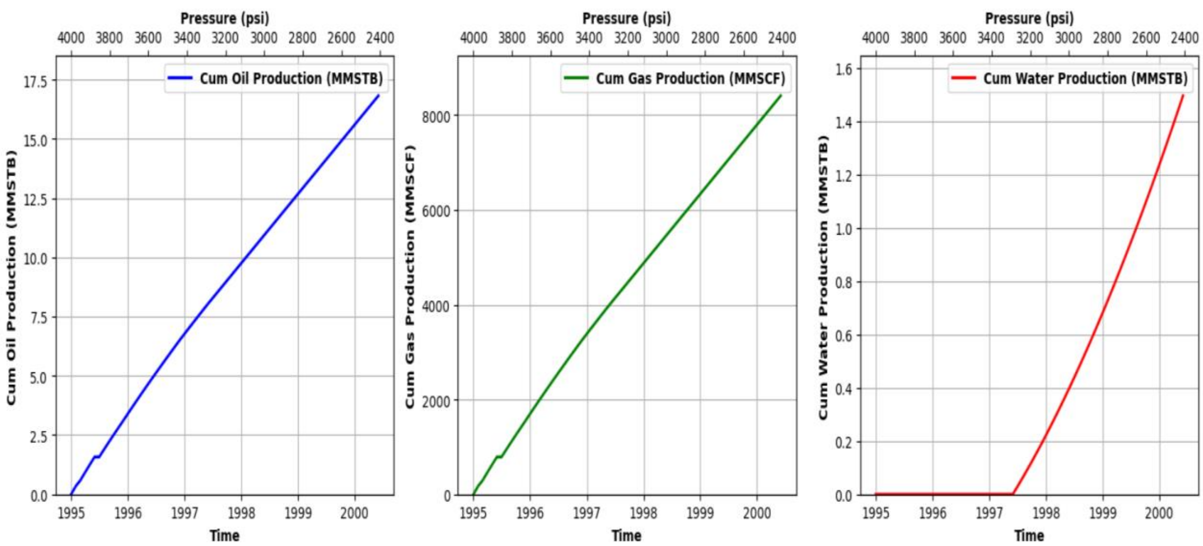


Figure 12. Cumulative oil, gas and water production plots from Code

Plot for OOIP estimation

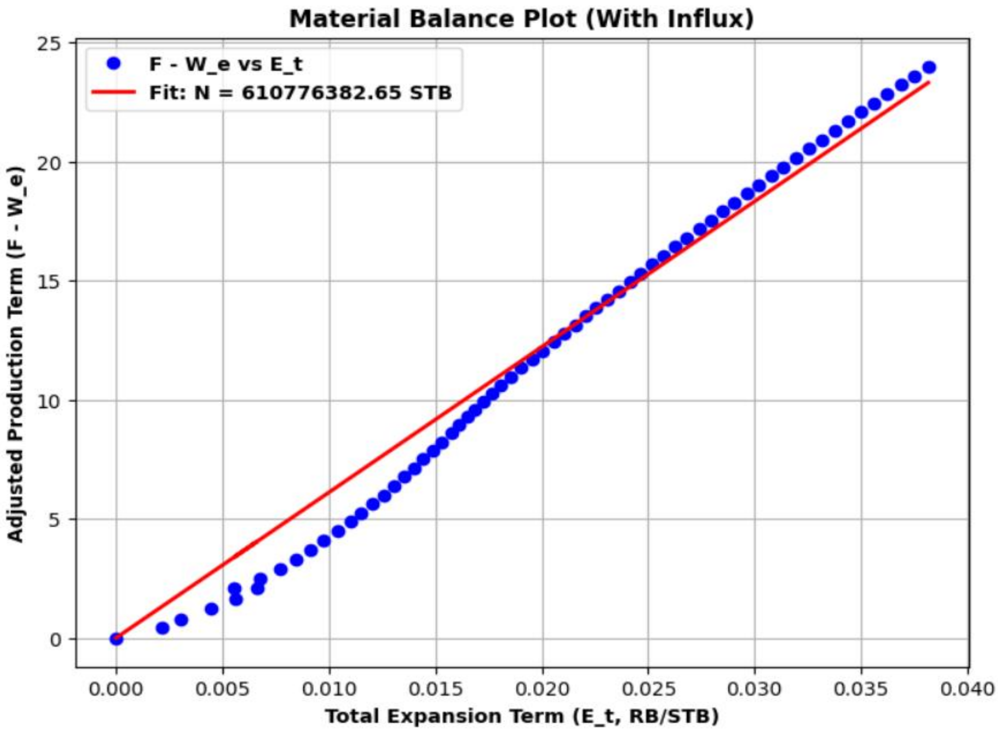


Figure 13. OOIP estimation from Code

From the plot, the original oil in place was estimated to be approximately 610 million STB.

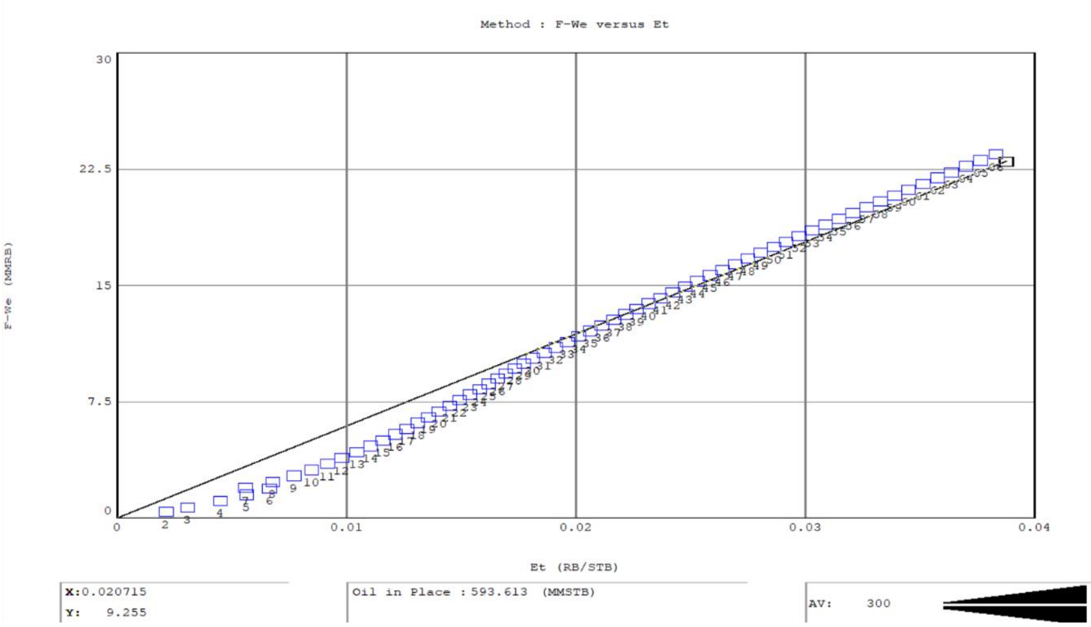


Figure 14. OOIP estimation from MBAL

From the plot, the original oil in place was estimated to be approximately 593 million STB.

Energy plot

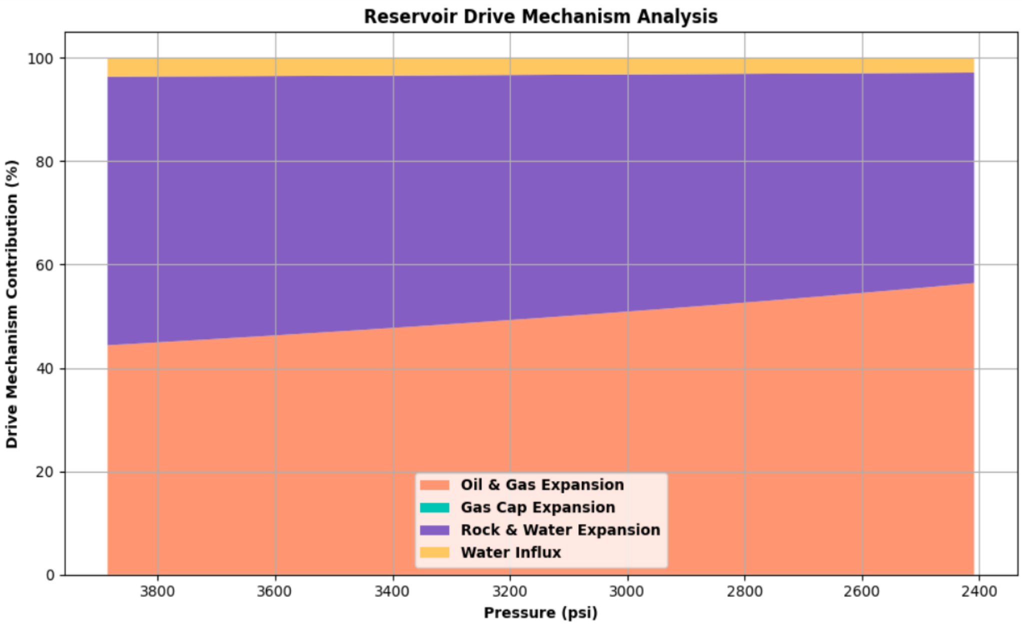


Figure 15. Energy plot from code

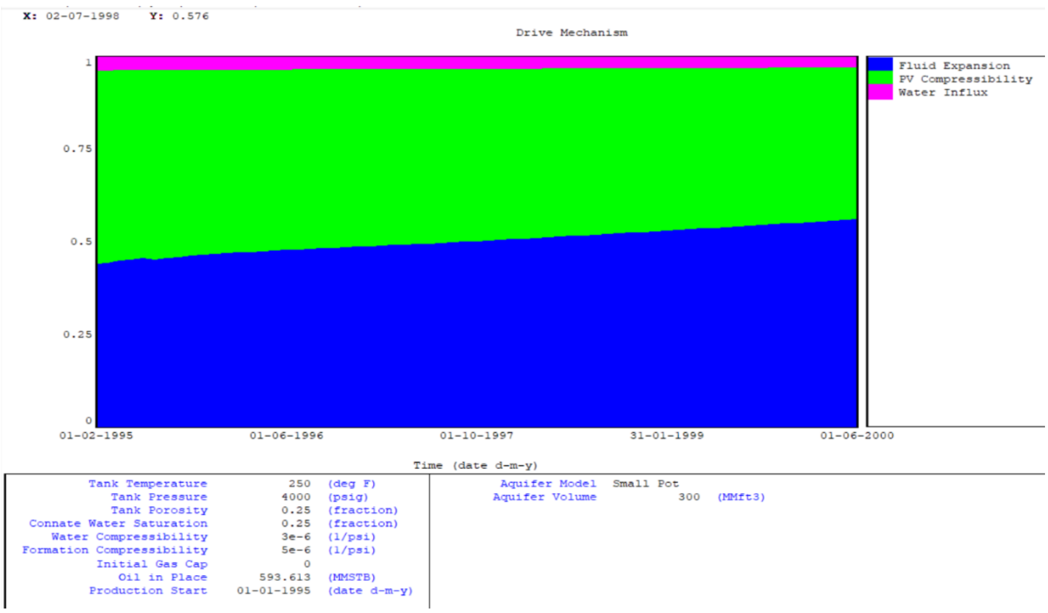


Figure 16. Energy plot from MBAL

The energy plot generated using code closely follows the trend observed in the MBAL plot.

Future Prediction

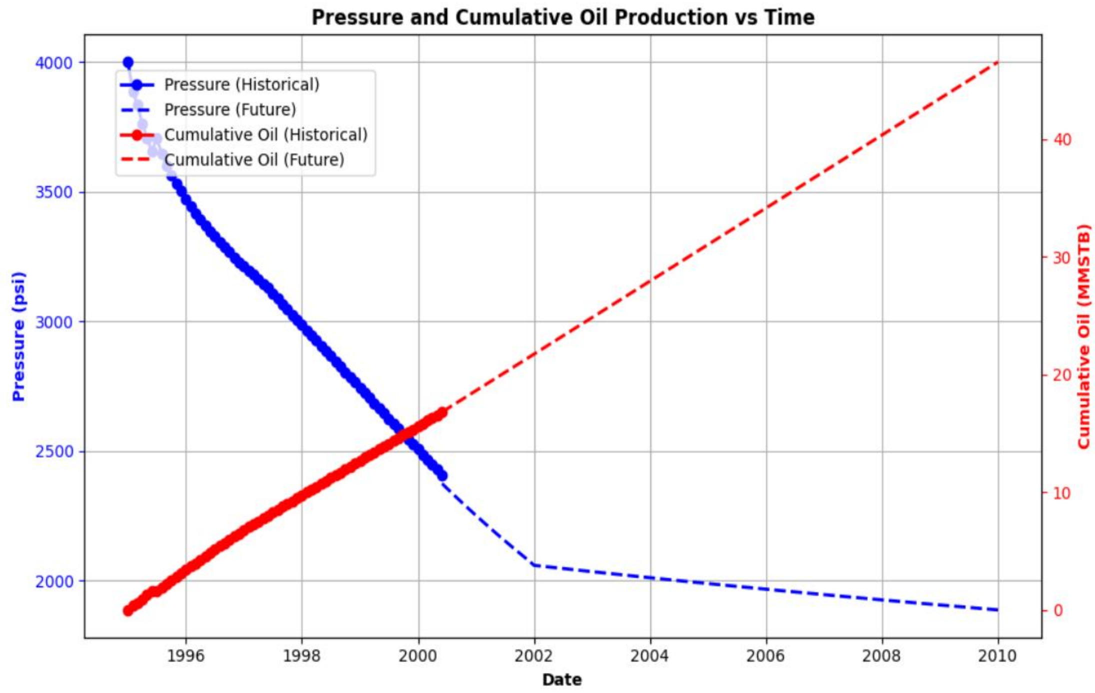


Figure 17. Cumulative Oil Production and Pressure plots from code

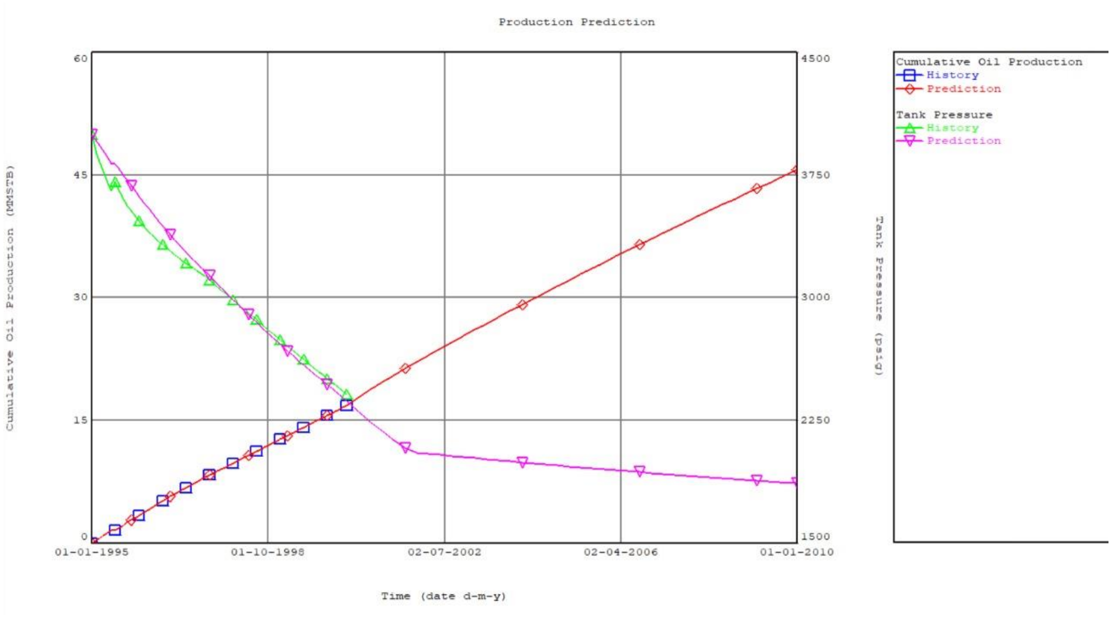


Figure 18. Cumulative Oil Production and Pressure plots from MBAL

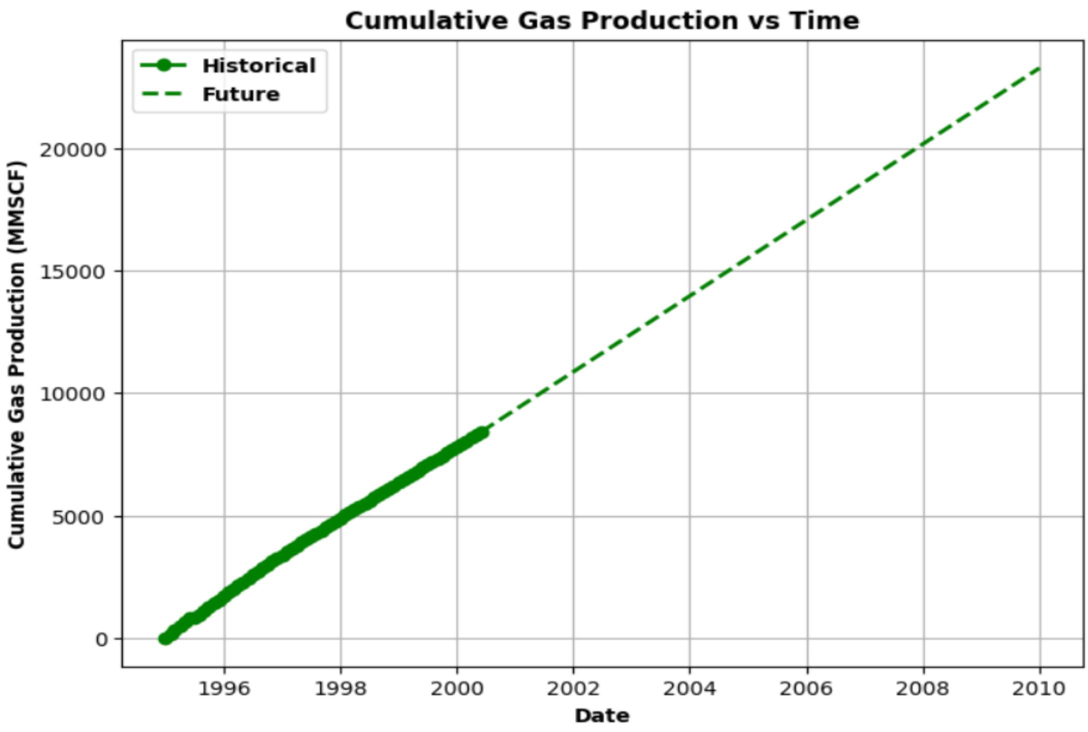


Figure 19.Cumulative Gas Production vs Time from code

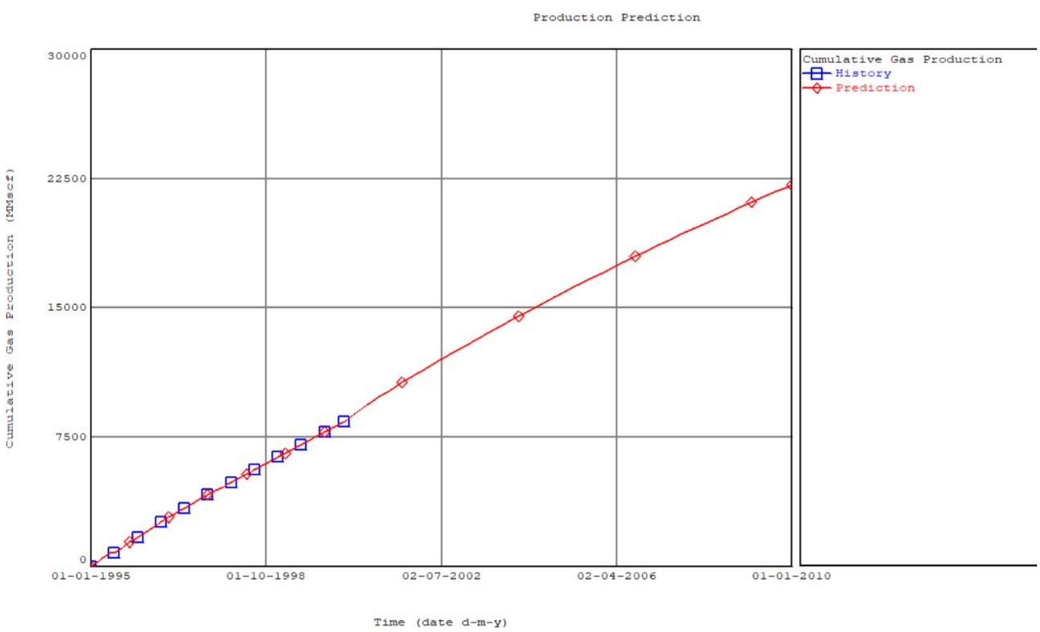


Figure 20.Cumulative Gas Production vs Time from MBAL

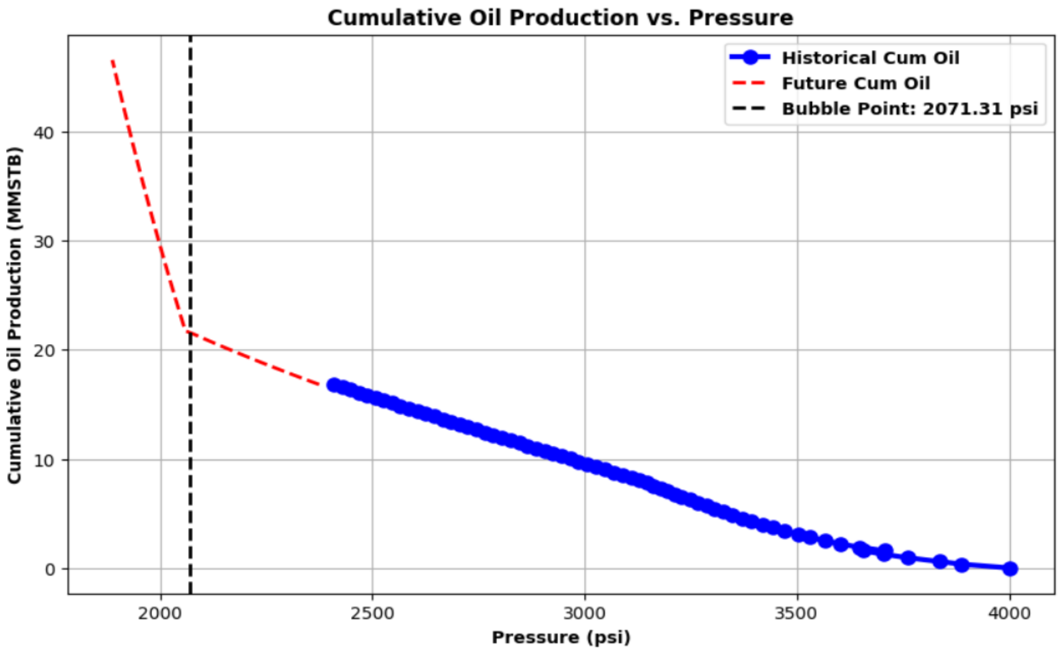


Figure 21.Cumulative Oil Production vs Pressure plot from code

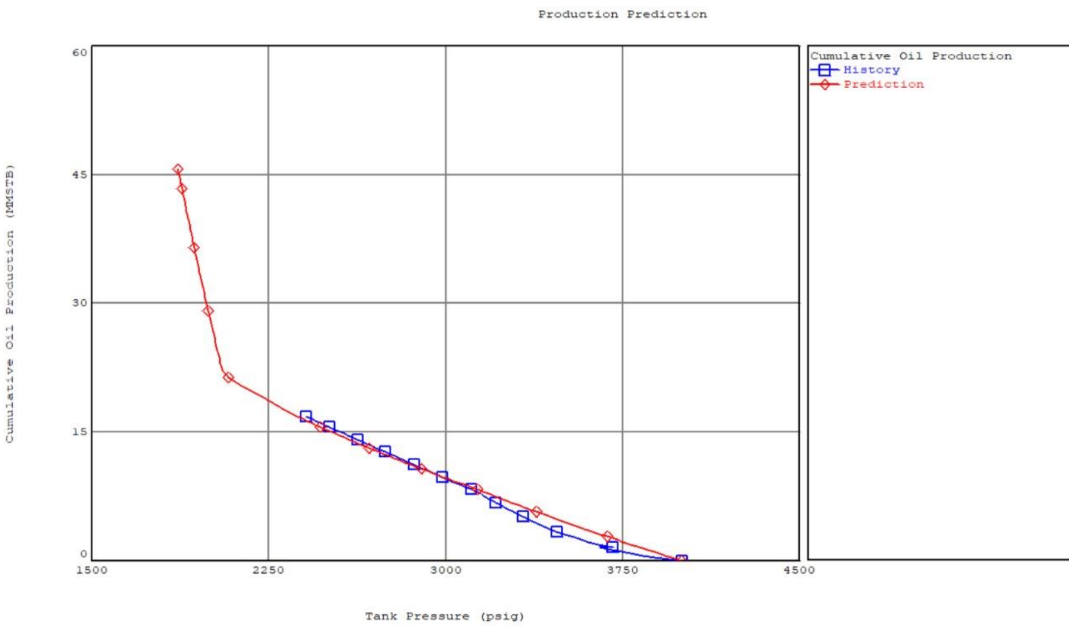


Figure 22.Cumulative Oil Production vs Pressure plot from MBAL

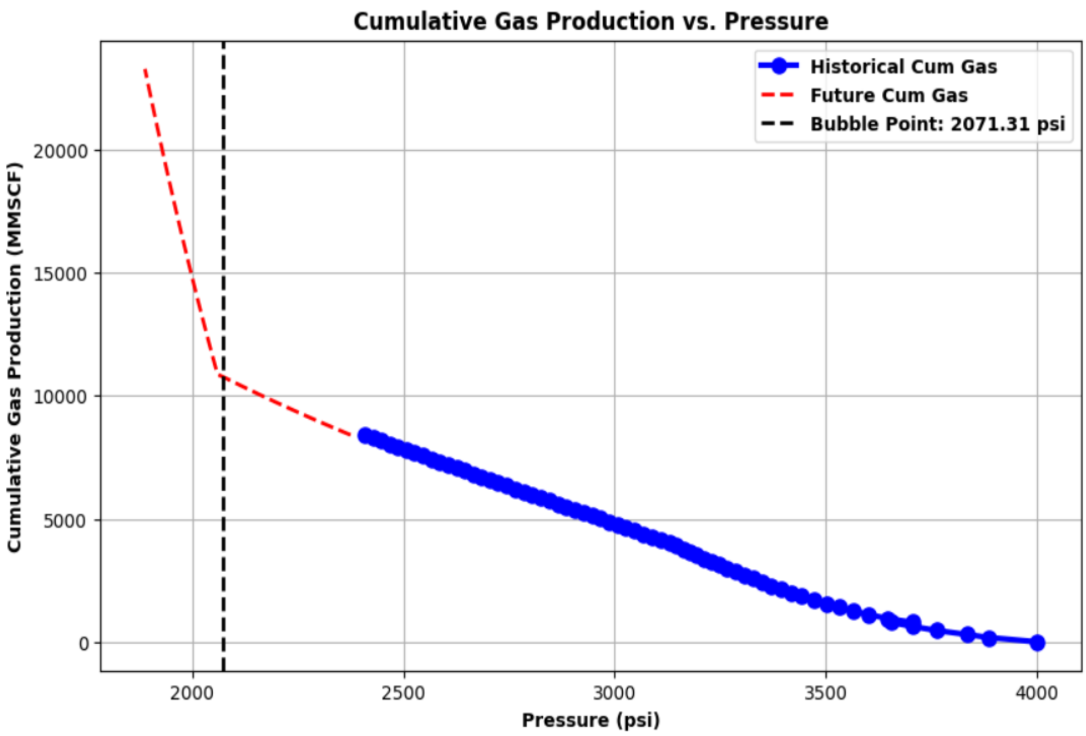


Figure 23.Cumulative Gas Production vs Pressure from code

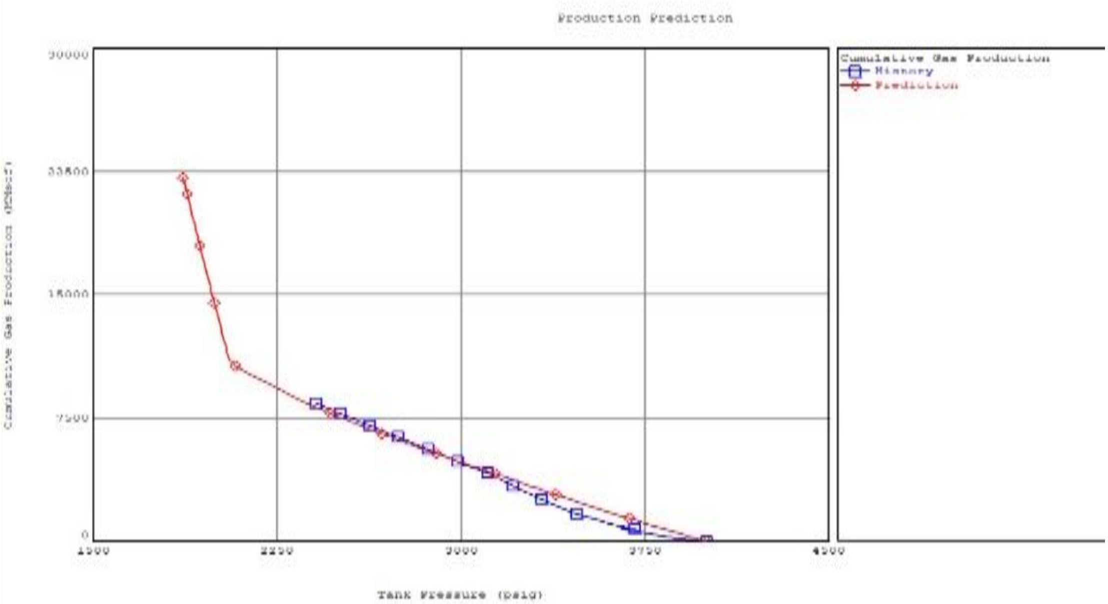


Figure 24.Cumulative Gas Production vs Pressure from MBAL

Future trends of fluid properties

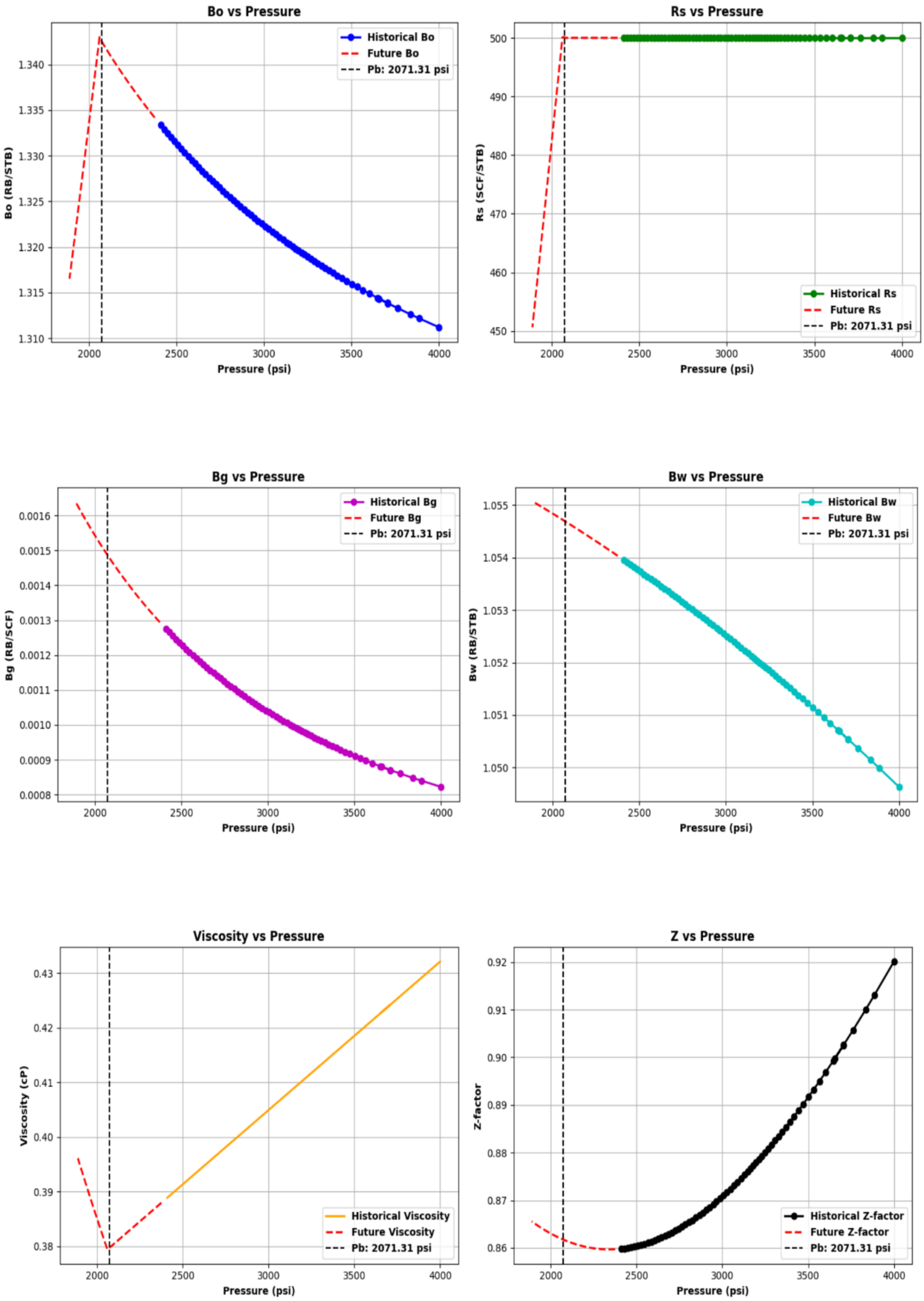


Figure 25.Future tends of fluid properties plots from code

Oil Reservoir-2

The following are the results for an oil reservoir (dataset 2) .The reservoir is saturated with the reservoir pressure below the bubble point pressure.

Campbell Plot Results

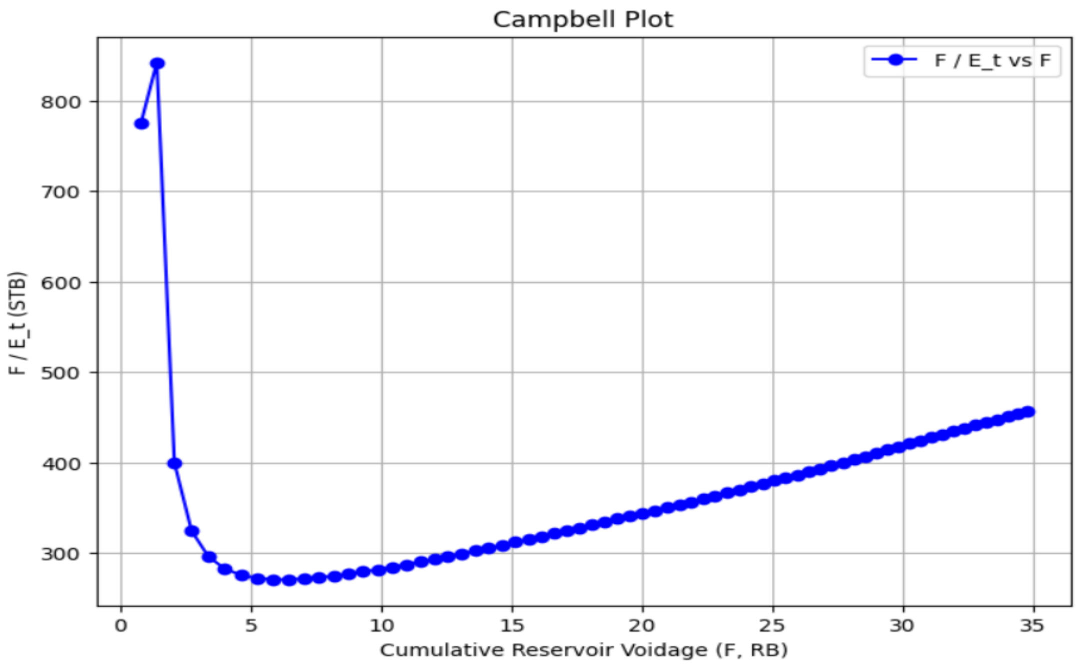


Figure 26. Campbell plot from code

The Campbell plot analysis indicates that the oil reservoir is supported by a moderate water drive and validated from the MBAL software.

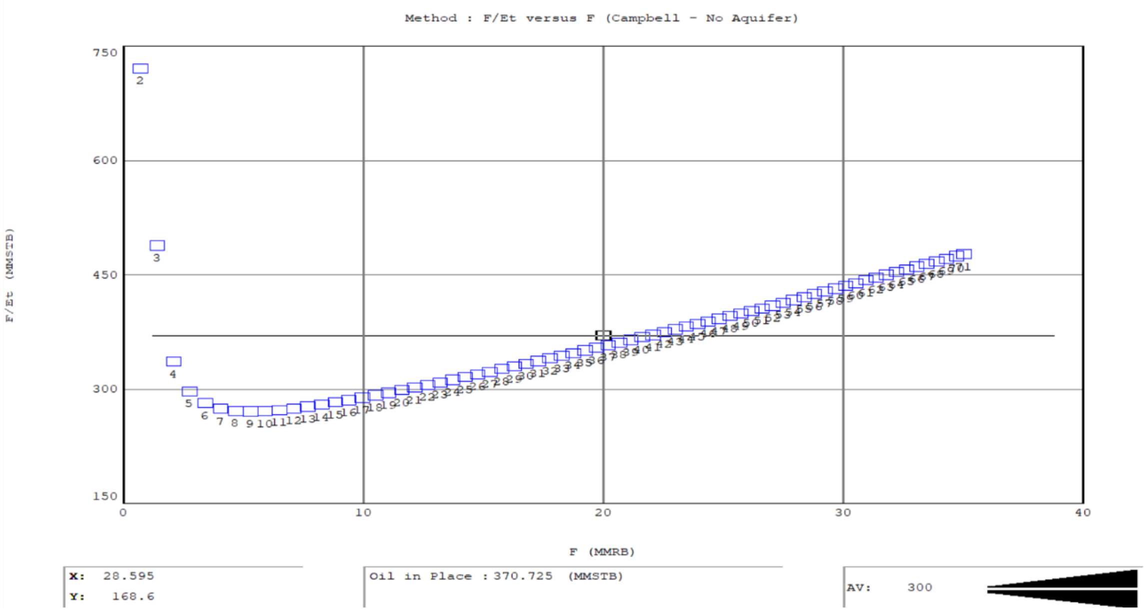


Figure 27. Campbell plot from code

Fluid Properties

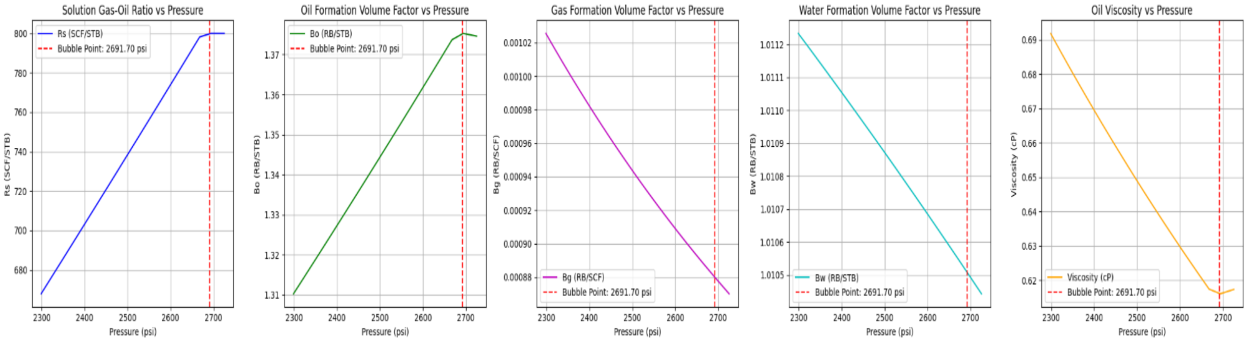


Figure 28. Fluid properties plots from Code

All the fluid properties followed the expected trends.

- The solution gas–oil ratio (Rs) decreased below the bubble point pressure.
- The oil formation volume factor (Bo) decreased as pressure decreased from the bubble point pressure.
- The gas formation volume factor (Bg) decreased with increasing pressure.
- The water formation volume factor (Bw) followed a nearly linear trend with pressure.
- Oil viscosity increased as pressure decreased from the bubble point pressure.

Cumulative Production and Water Influx

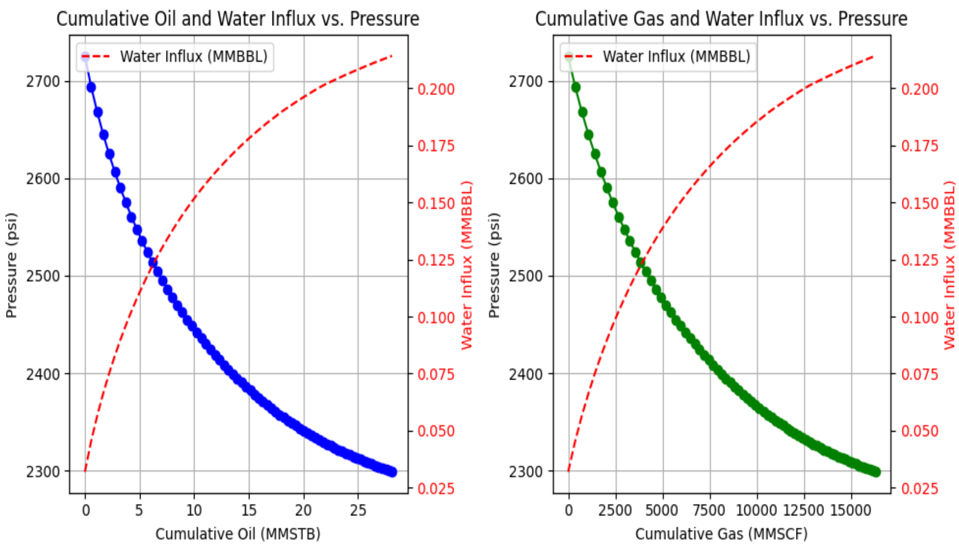


Figure 29. Cumulative oil and gas production and water influx plots from Code

OOIP estimation

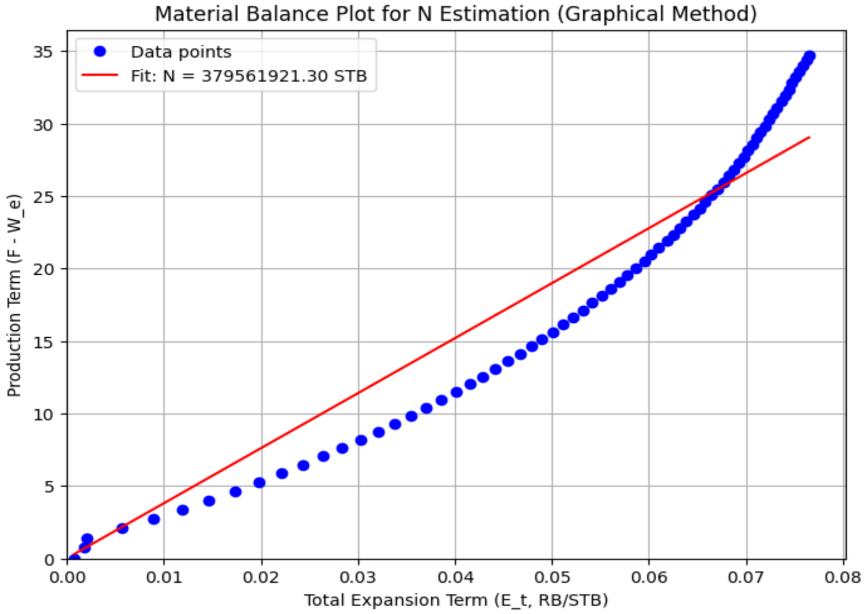


Figure 30. OOIP estimation from Code

From the plot, the original oil in place was estimated to be approximately 379 million STB.

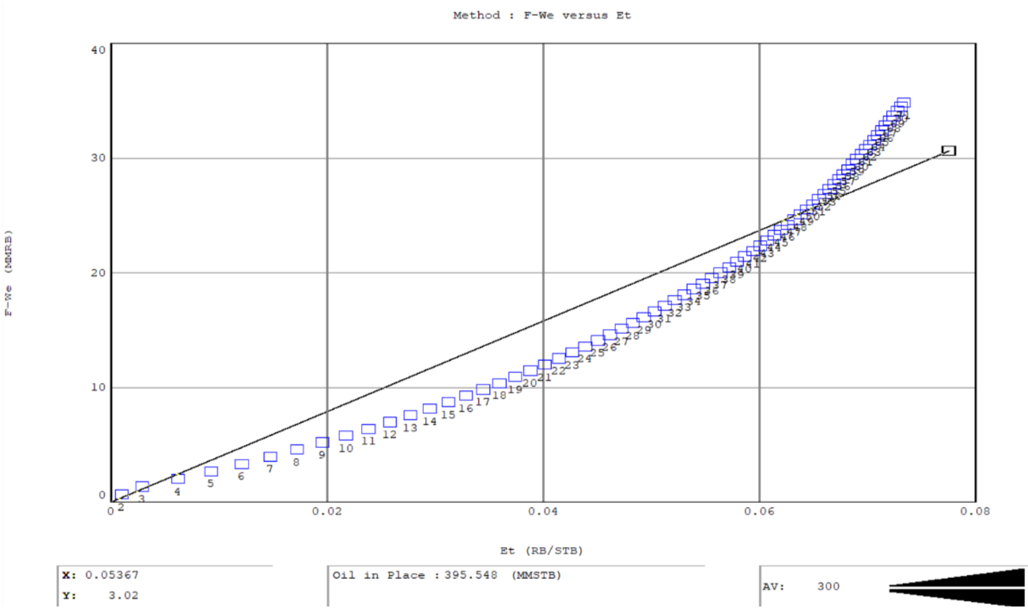


Figure 31. OOIP estimation from MBAL

From the plot, the original oil in place was estimated to be approximately 395 million STB.

Energy plot

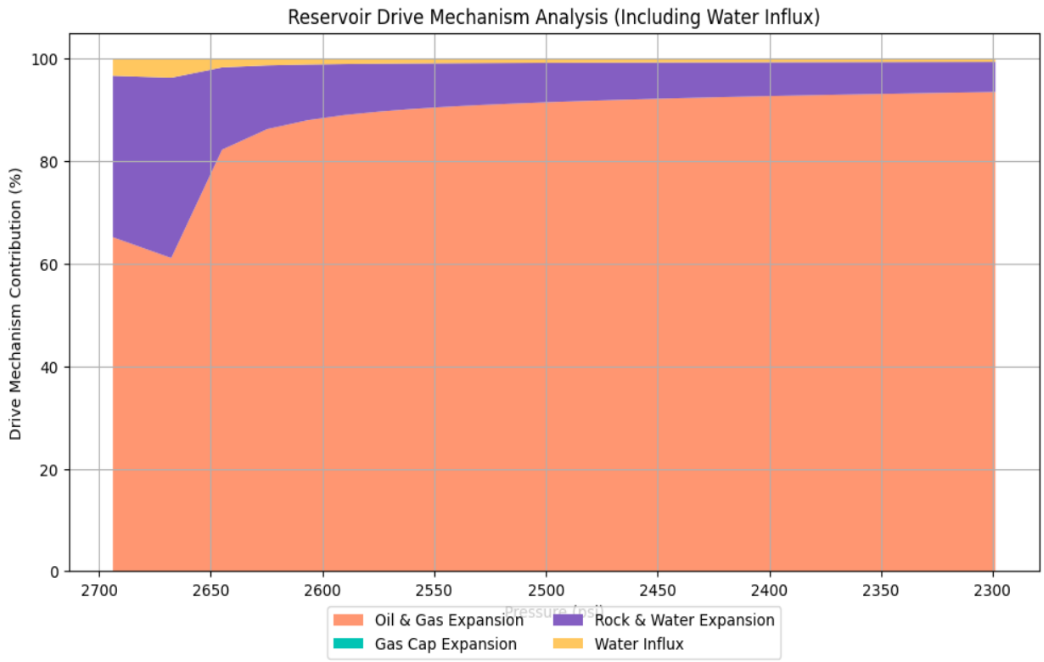


Figure 32. Energy plot from code

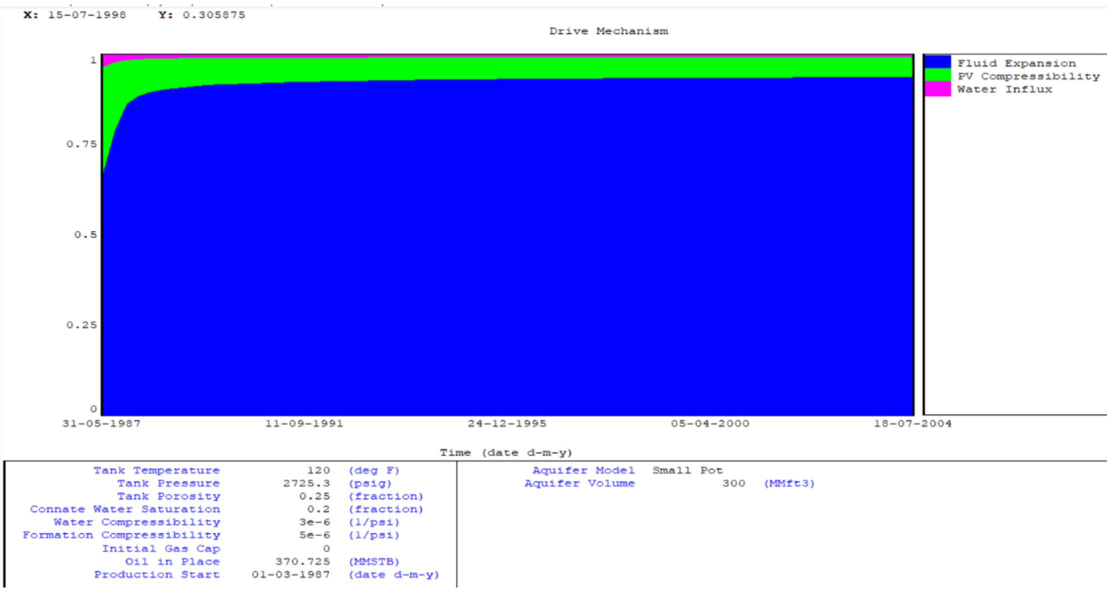


Figure 33. Energy plot from MBAL

The energy plot generated using Python code closely follows the trend observed in the MBAL plot.

Gas Reservoir

Cole Plot

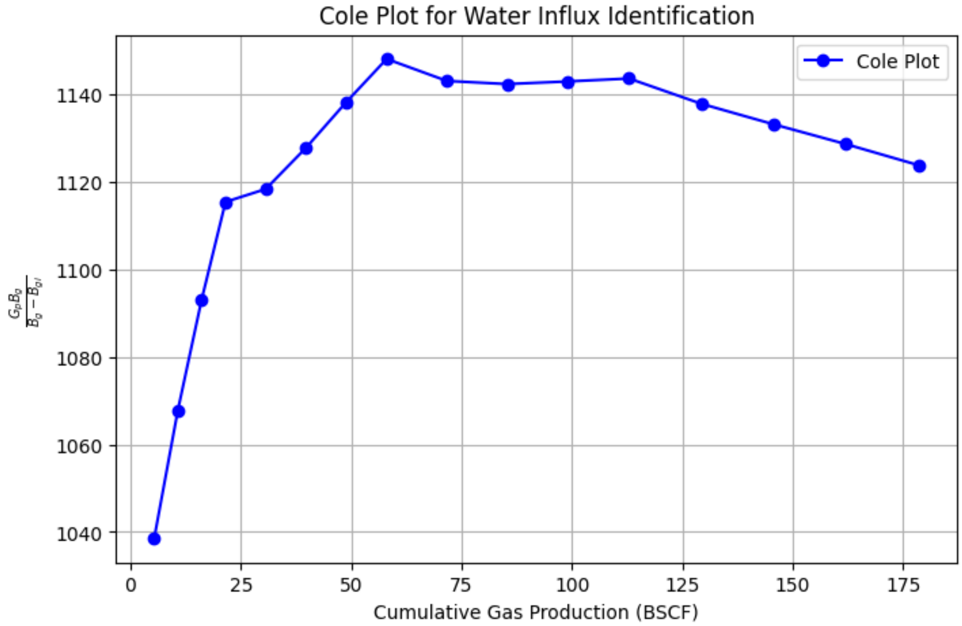


Figure 34. Cole plot from code

The Cole plot analysis indicates that the gas reservoir is supported by a moderate water drive and validated from the MBAL software.

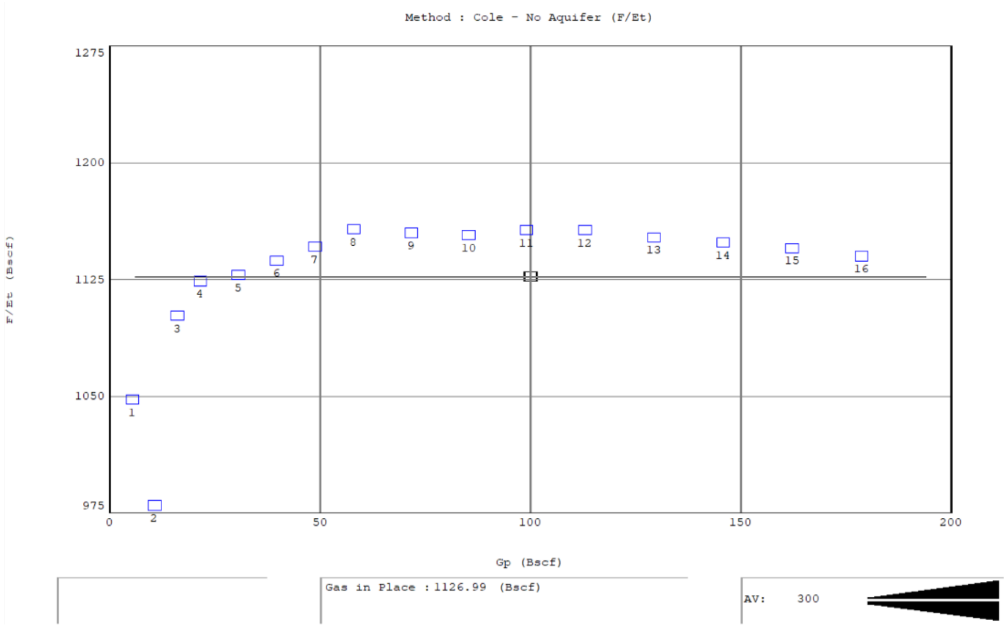


Figure 35. Cole plot from MBAL

Fluid properties

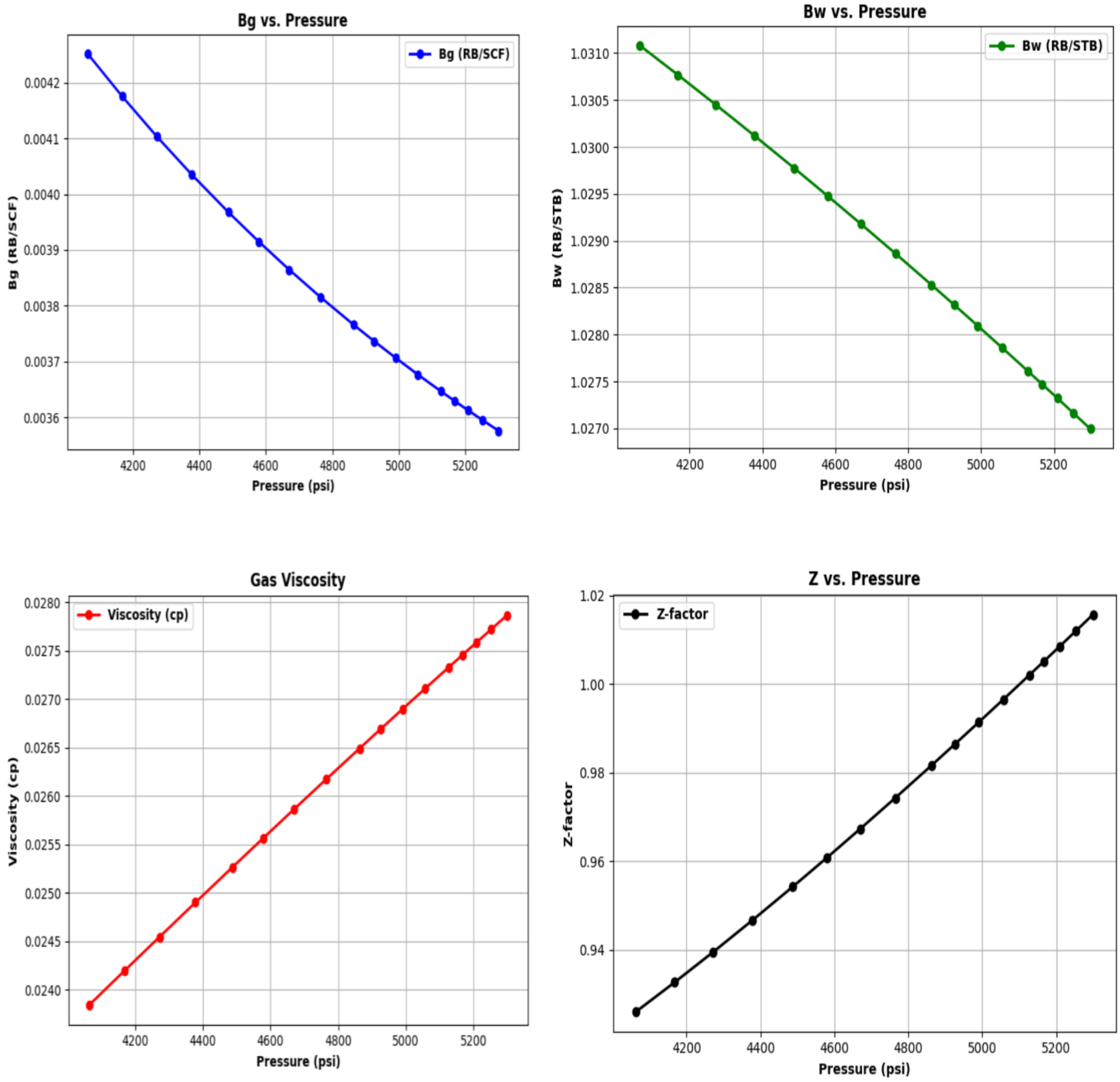


Figure 36.Fluid properties plots from code

All the fluid properties followed the expected trends.

Cumulative Production

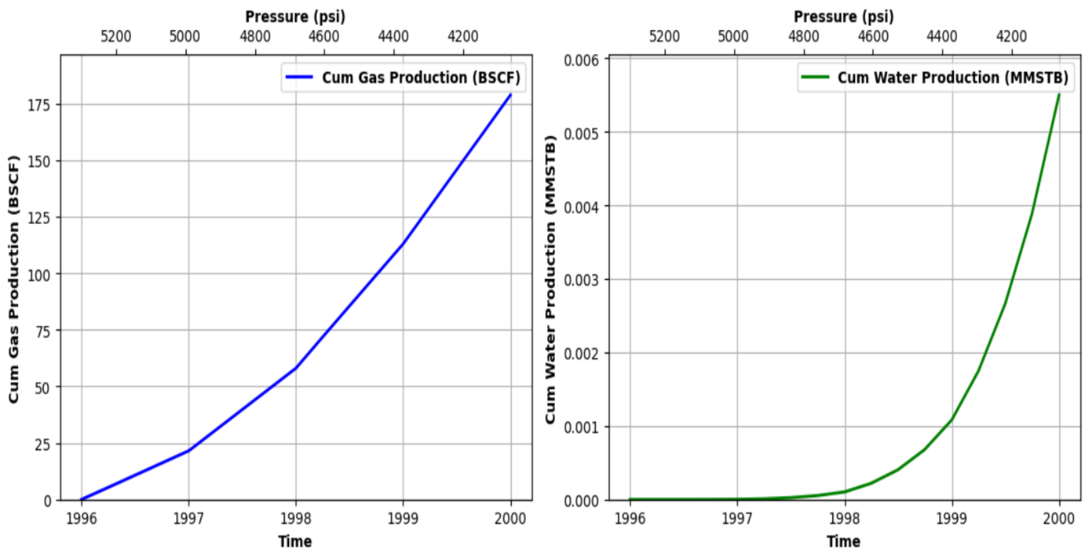


Figure 37. Cumulative gas and water production plots from Code

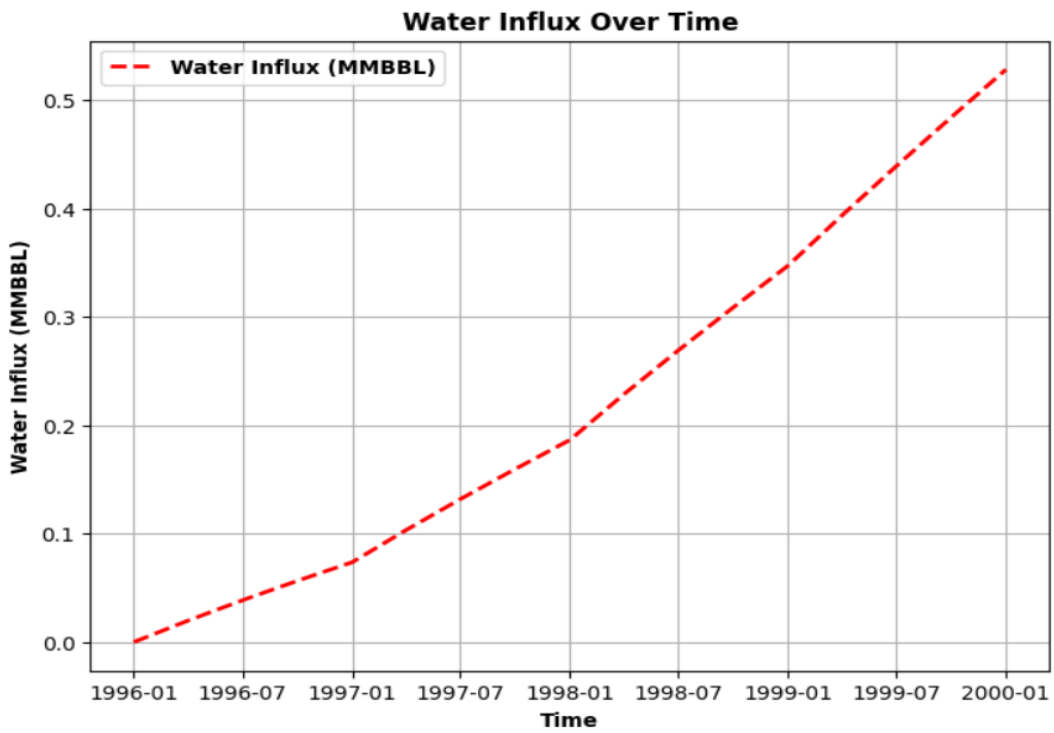


Figure 38.water influx plot from code

Energy Plots

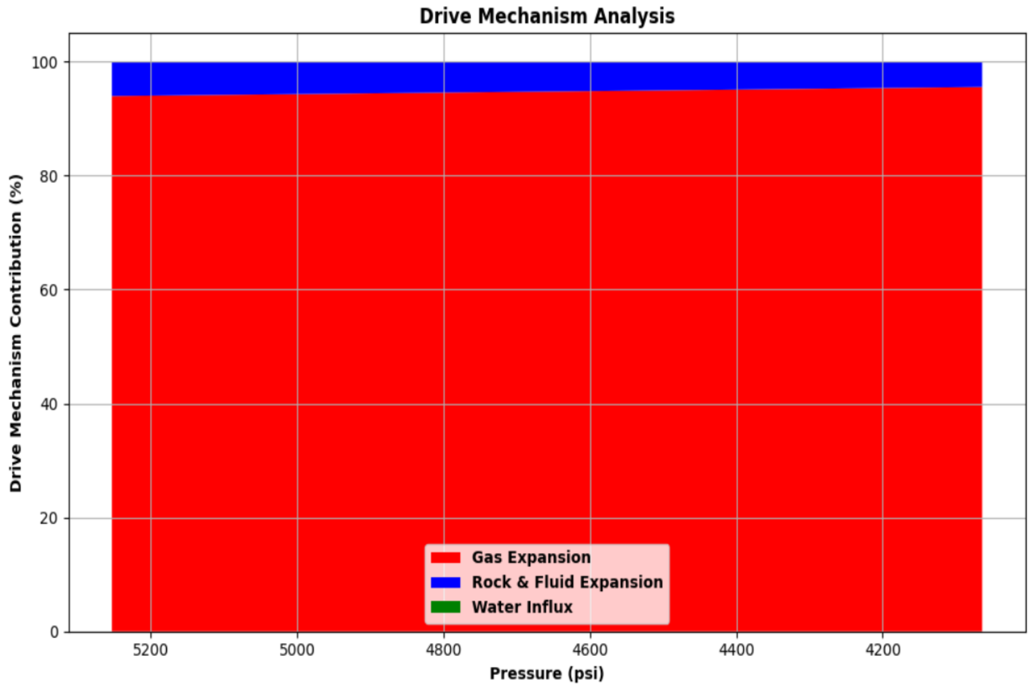


Figure 39. Energy plot from code

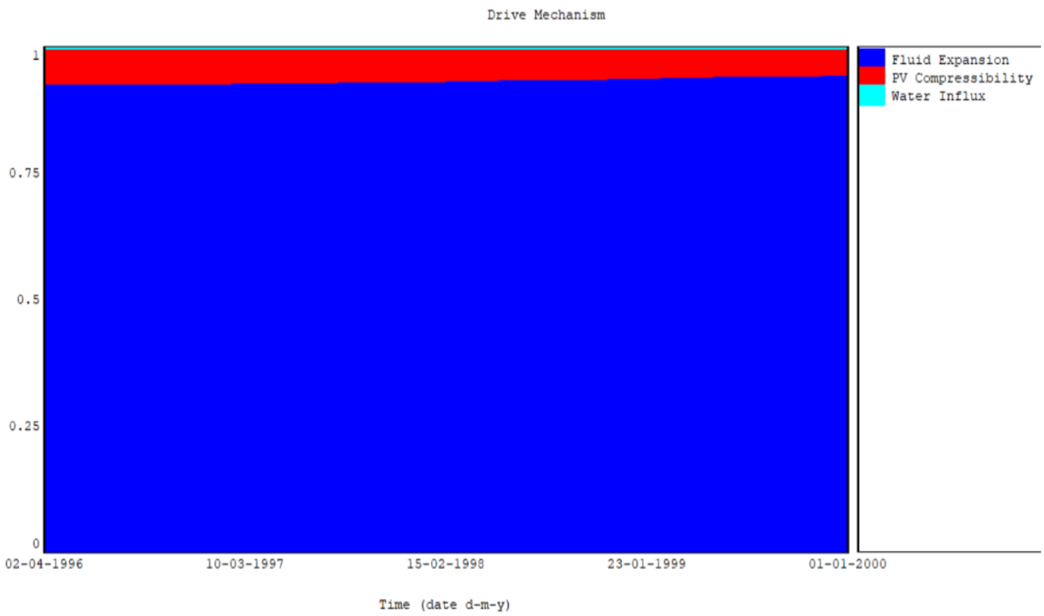


Figure 40. Energy plot from MBAL

The energy plot generated using Python code closely follows the trend observed in the MBAL plot.

OGIP Estimation

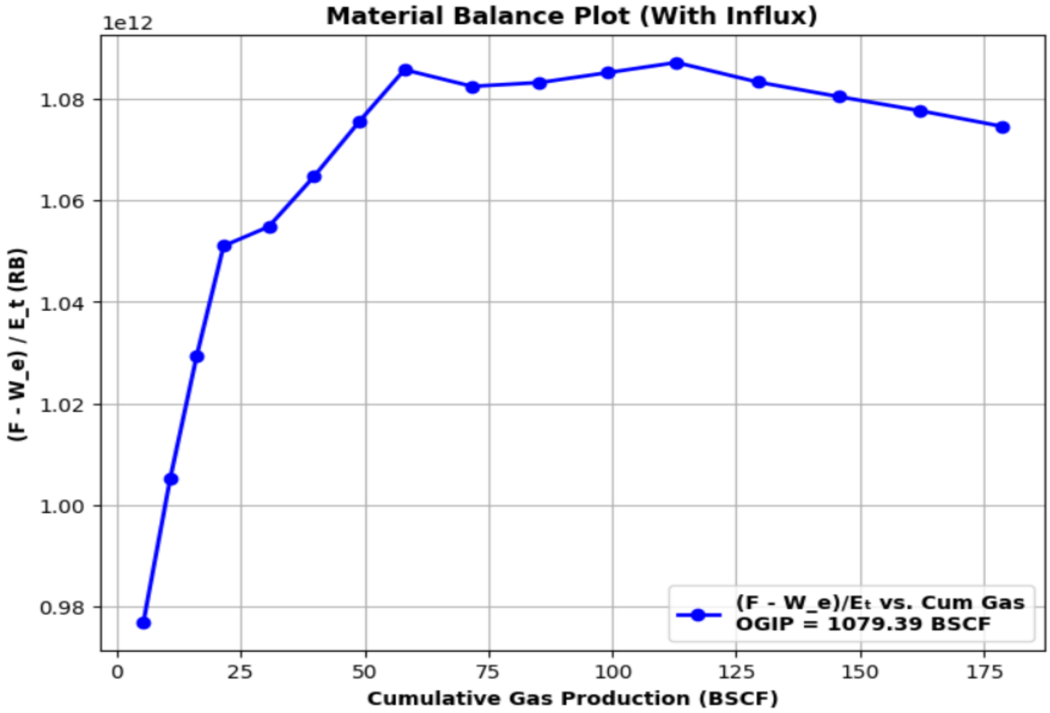


Figure 41. OGIP estimation plot from code

From the plot, the original gas in place was estimated to be approximately 1079 BSCF.

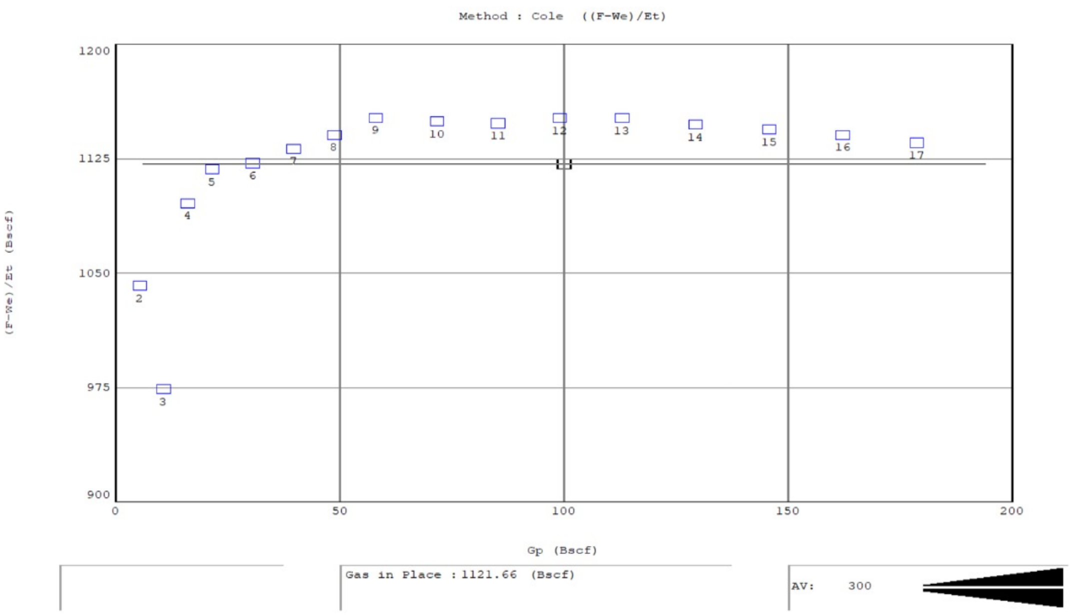


Figure 41. OGIP estimation plot from MBAL

From the plot, the original gas in place was estimated to be approximately 1121 BSCF.

OOGIP Estimation

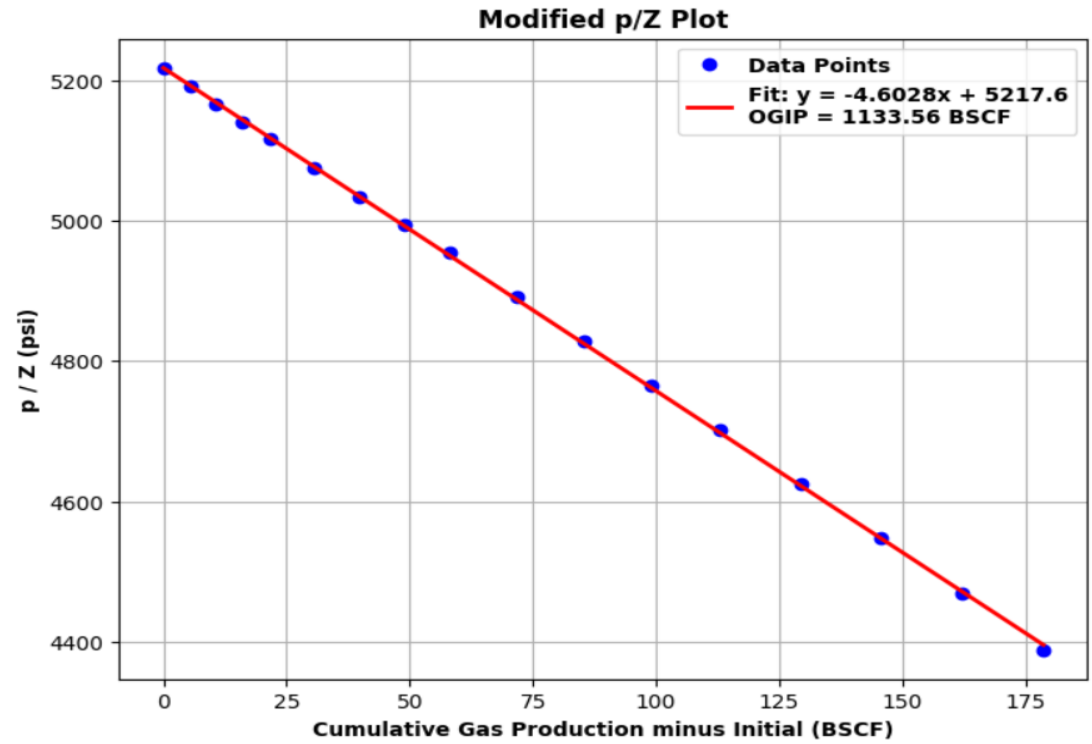


Figure 43. OGIP estimation using P/Z plot from code

From the plot, the original gas in place was estimated to be approximately 1133 BSCF.

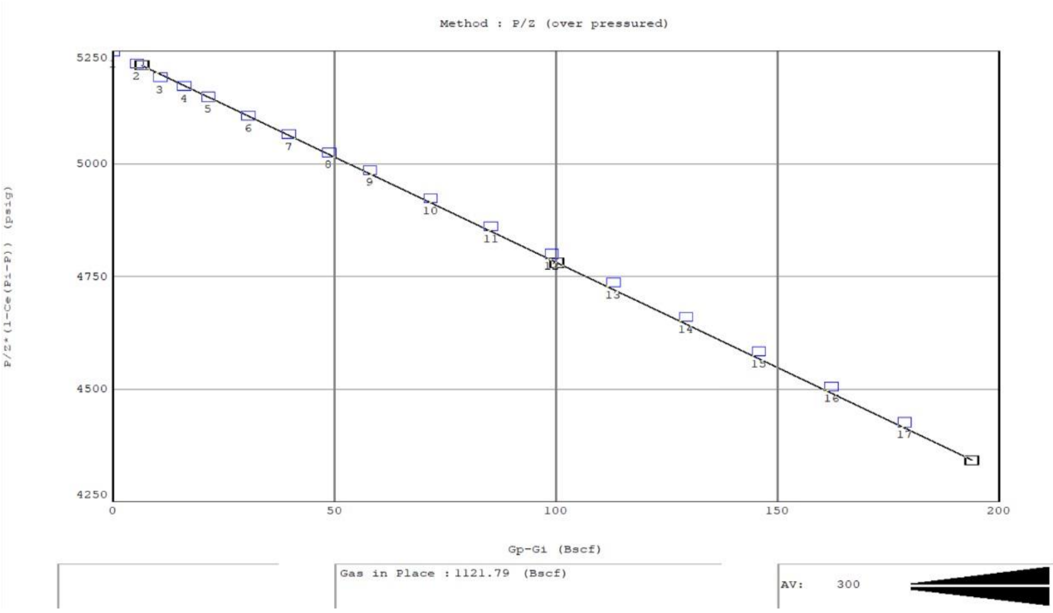


Figure 44. OGIP estimation using P/Z plot from MBAL

From the plot, the original gas in place was estimated to be approximately 1121 BSCF.

Future Prediction

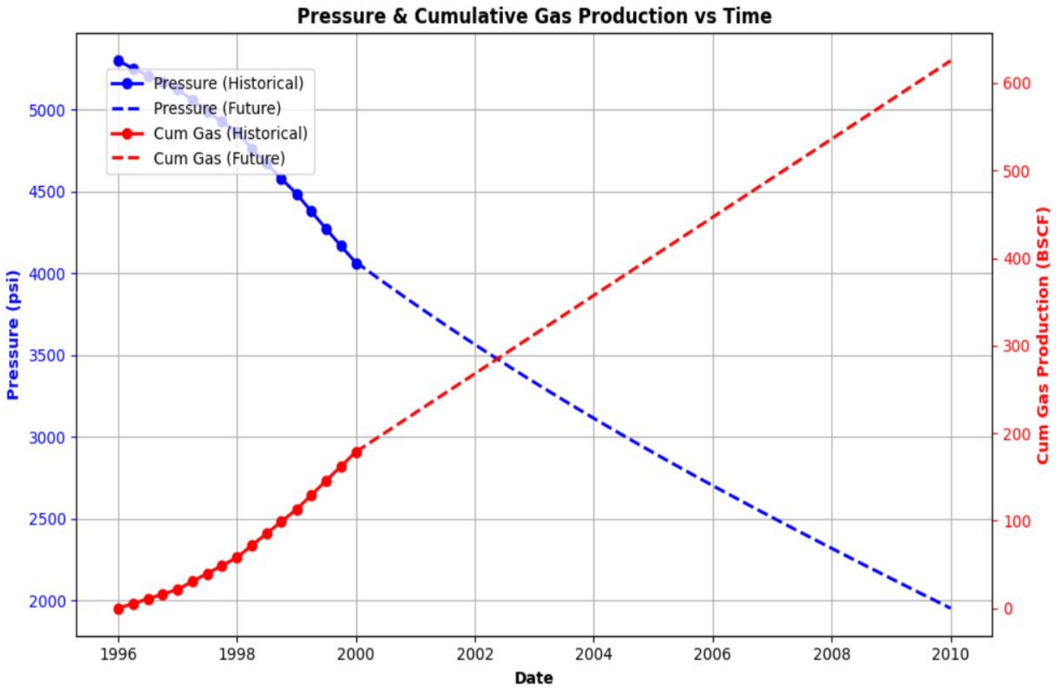


Figure 45. Cumulative Gas Production and Pressure plots from code

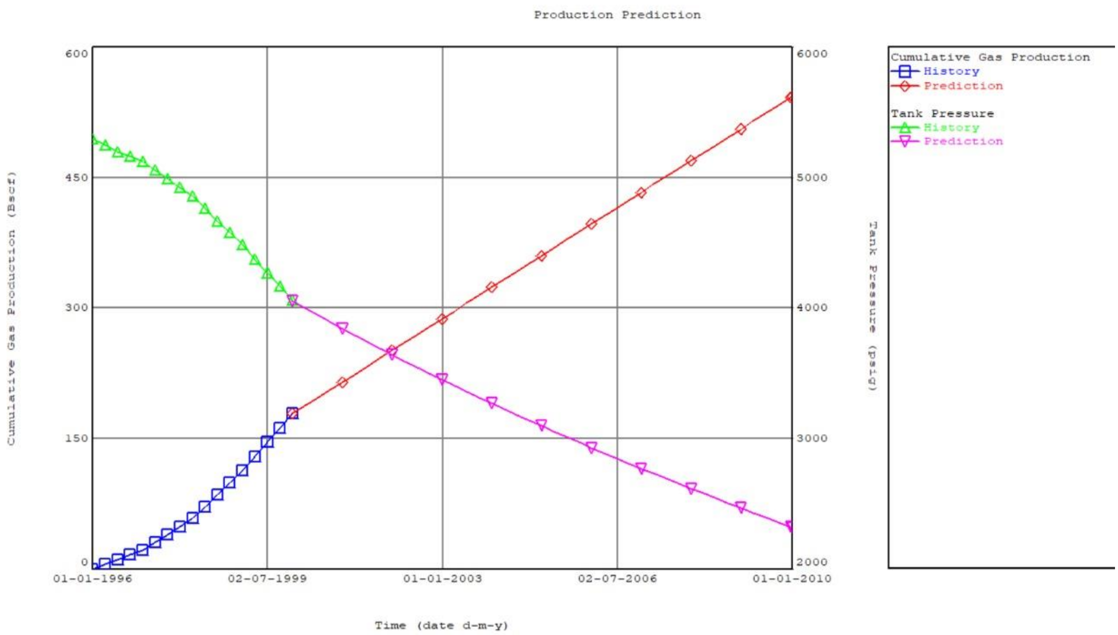


Figure 46. Cumulative Gas Production and Pressure plots from MBAL

P/Z Plot

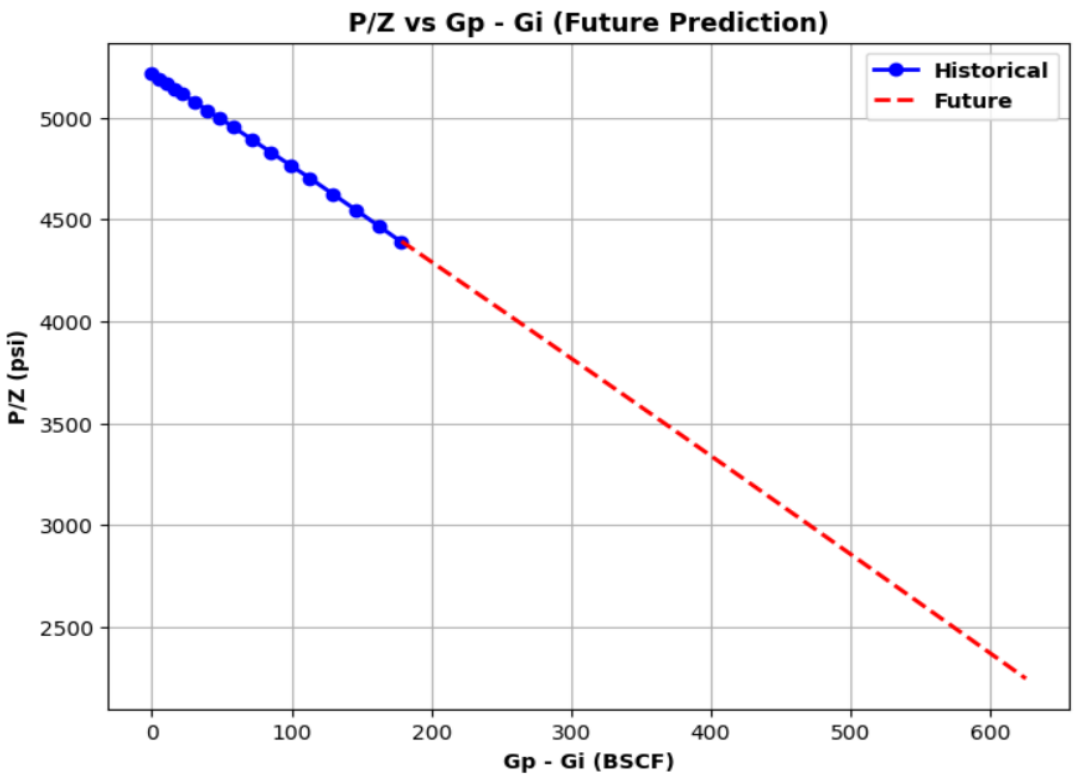


Figure 47.Future prediction of P/Z Plot from code

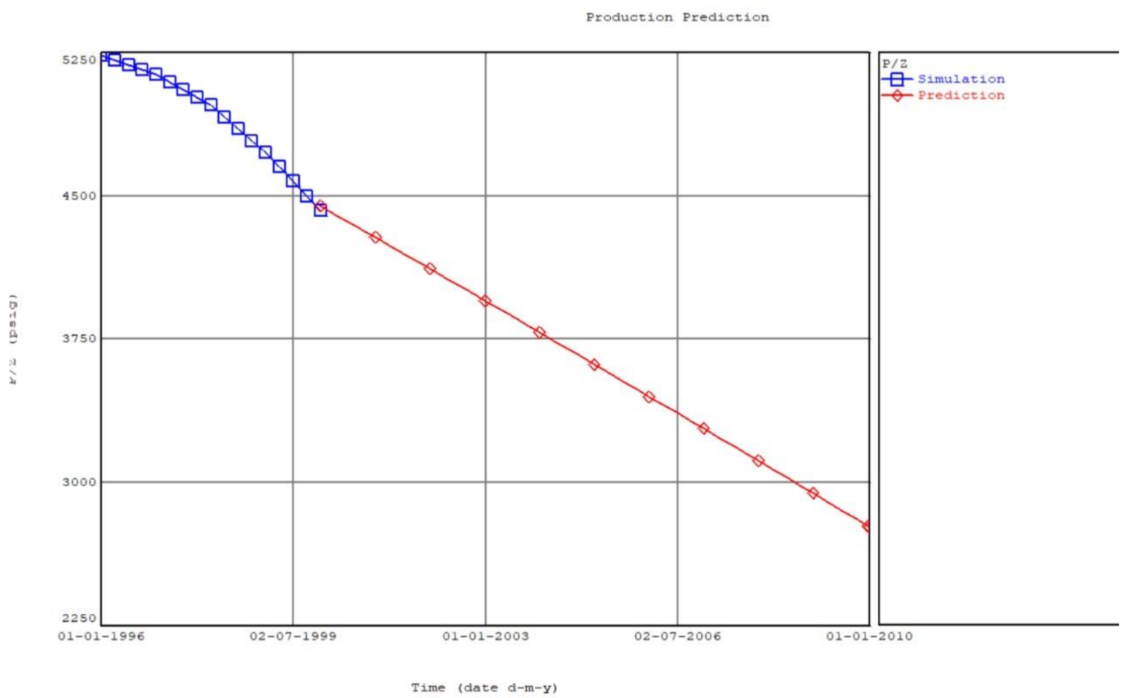


Figure 48. Future prediction of P/Z Plot from MBAL

Future trends of fluid properties

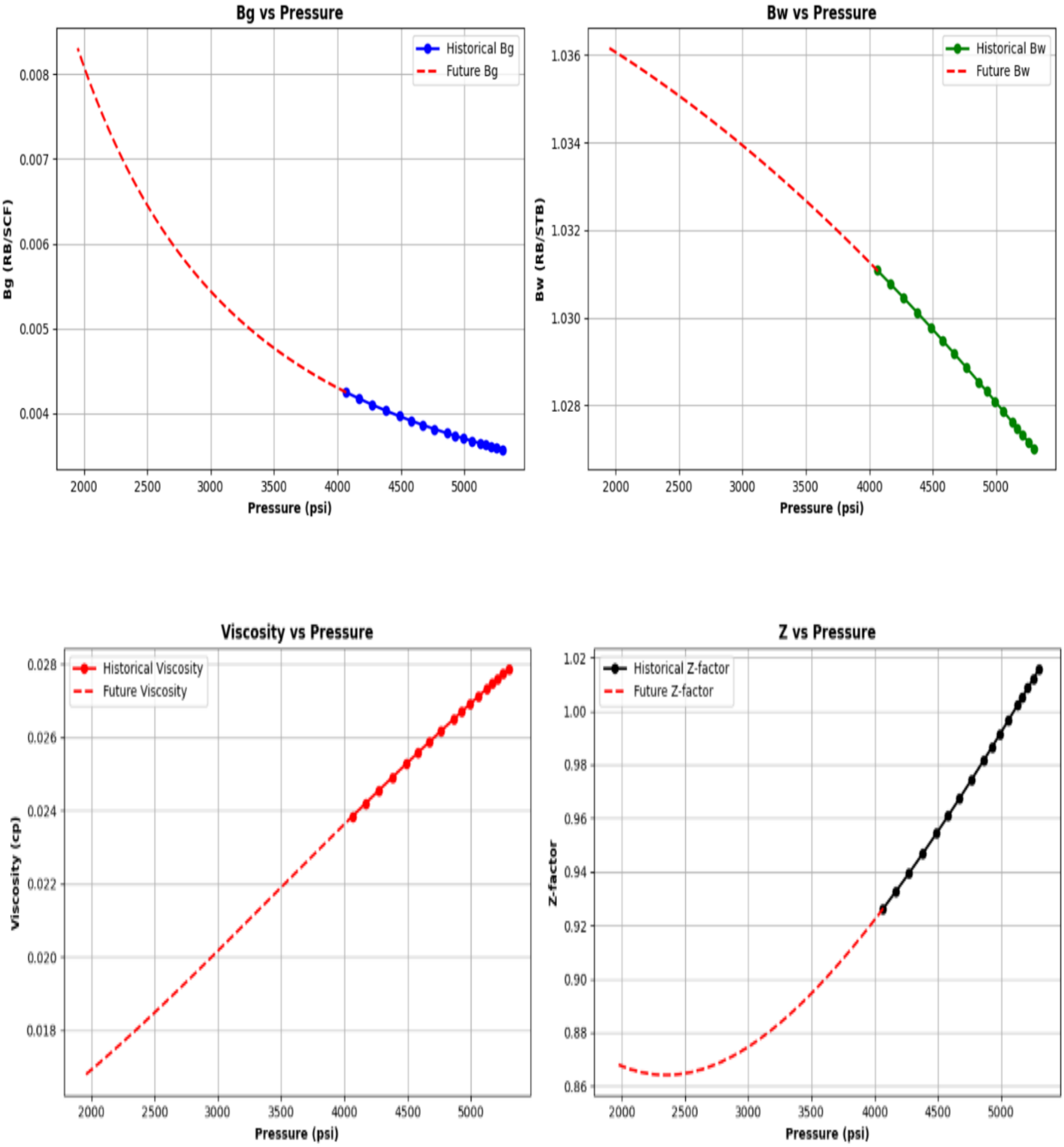


Figure 49.Future tends of fluid properties plots from code

Conclusions

The material balance simulator developed in this project successfully demonstrates the practical application of reservoir engineering principles using Python. By incorporating the general material balance equation, fluid property correlations, and water influx modeling, the tool effectively estimates original oil and gas in place (OOIP and OGIP) and provides insights into reservoir drive mechanisms. The inclusion of Campbell and Cole plots enhances diagnostic capabilities, particularly in identifying water drive systems. The addition of a water influx model enables the accuracy of analysis for reservoirs influenced by aquifers, allowing for better prediction of pressure behavior over time. The development of a web-based interface significantly enhances user experience by providing an interactive platform for data input, visualization, and analysis without requiring advanced programming knowledge. The simulator also includes forecasting functionality, allowing users to predict future production trends based on historical performance. Overall, the project offers a reliable, open-source, and interactive solution for early-stage reservoir evaluation.

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