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Original article

Estimation of Oil Recovery Factor for the Bouri Field in Libya

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Abstract
Accurately estimating Recovery is pivotal to optimizing production strategies and maximizing economic returns in mature fields such as the Bouri Field. This study employs three methodologies: Volumetric, Material Balance Equation (MBE) utilizing MBAL software, and Decline Curve Analysis (DCA) to evaluate Recovery Factor with minimized estimation errors. Each method offers unique insights into reservoir characteristics, production history, and fluid dynamics, contributing to a comprehensive assessment of potential enhancements in oil recovery. By integrating these approaches, this study aims to identify the most effective strategy for predicting future production profiles and optimizing field development. Comparative analysis of results and evaluation of the uncertainties associated with each method will provide robust recommendations for achieving maximum oil-recovery efficiency at Bouri Field.
Keywords. Recovery Factor, Oil Reserve, Initial Oil in Place, Decline Curve Analysis.

Introduction

The recovery factor (RF) stands as a pivotal parameter within the petroleum industry, crucial for evaluating the economic feasibility of reservoir development [1]. It is computed by comparing the expected ultimate recovery (EUR) with the original oil-in-place (OOIP) [2]. However, the accuracy of OOIP estimates often faces challenges due to uncertainties regarding reservoir drainage areas [3]. These uncertainties are particularly pronounced in unconventional reservoirs, where complexities arise from factors such as intricate fracture networks, varying reservoir pressures, heterogeneous pore volumes, and diverse in-situ hydrocarbon properties [4].

To address these challenges, the material balance equation (MBE) approach is employed [5], enabling both deterministic (single value) and probabilistic (distribution-based) assessments of RF [6]. This method incorporates a sensitivity analysis to gauge the impact of input parameters on RF determination [7]. Additionally, EUR estimation relies on decline curve analysis (DCA), utilizing historical well production data and abandonment rate information [8]. DCA serves as a forecasting model to predict EUR and remaining reserves over time [9].

Once RF and EUR are established, the calculation of OOIP becomes feasible [10], derived as the quotient of EUR and RF. This approach not only provides a quantitative measure of recoverable reserves but also informs strategic decisions regarding reservoir management and resource utilization [9].

Study objectives

The main objectives and aims of the present study can be listed in the following points: understand the concept of water influx or encroachment into a reservoir, understand the various types of aquifer models, learn about MBAL software to have practical knowledge on how to use it, calculate (OOIP) from volumetric method based geological and petrophysical data, calculate (OOIP) from material balance equation (MBE) based on PVT and production data by using MBAL Software, compare the results obtained; identify possible reasons for variance, determination the type of natural forces of the reservoir, determine the most likely aquifer model and evaluate the strength of aquifer, perform different scenarios of reservoir performance predictions and finally apply DCA to know a type of decline period then Calculate Np to obtain RF.

Scope and limitations

While the material balance equation (MBE), volumetric analysis, and decline curve analysis (DCA) are widely used methodologies for estimating recovery factor, they face challenges in accurately capturing the complexities of modern reservoir dynamics:

Integration of Uncertain Parameters: One significant limitation lies in the integration of uncertain parameters across these methodologies. MBE relies on assumptions of reservoir homogeneity and steady-state conditions, which may not hold true for complex reservoirs with varying permeabilities, heterogeneous lithology, and fluid behavior. Volumetric analysis similarly assumes uniform reservoir characteristics and can be sensitive to uncertainties in parameters such as porosity and saturation, leading to potential inaccuracies in estimated original oil-in-place (OOIP) [11].

Sensitivity to Assumptions in DCA: DCA, based on historical production data, assumes that past production trends will continue. This approach may overlook changes in reservoir conditions, such as unexpected compartmentalization, water influx, or technological advancements affecting recovery rates [12]. Variability in abandonment rate data and the assumptions made about decline curve shapes can also introduce

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uncertainties in estimating the expected ultimate recovery (EUR) [12], which directly impacts recovery factor calculations [13].

Complexity of Probabilistic Approaches: While probabilistic methods enhance the robustness of recovery factor estimation by accounting for uncertainty through distribution-based analysis, they require comprehensive datasets and advanced modeling techniques [14]. Incorporating probabilistic elements adds complexity in interpreting results and may necessitate extensive computational resources and expertise to manage uncertainty effectively.

Literature review

Recovery factor definition

Recovery factor or fractional recovery efficiency is a fraction representing the portion of the original oil in place that is recovered. Mathematically, the recovery factor is computed by dividing the change in oil content in the reservoir by the original oil content. Considering one barrel of reservoir pore volume, the recovery factor is the estimated proportion of hydrocarbon that geologic data and engineering calculations demonstrate with a high degree of certainty to be recoverable from the reservoir, under the existing economic conditions and the available engineering technology, of the primary hydrocarbon in the reservoir [15].

$$RF = \frac{Np}{OIIP}$$

The Recovery Factor is defined as the fraction of the initial oil in place (OIIP) that will probably be recovered in (STB) from a certain reservoir.

The Reserves defined as the total amount of hydrocarbon that can be recovered from a certain reservoir using the known technical practices.

The oil in place is calculated by the volumetric method or by material balance.

Methods of calculating the recovery factor

Many methods could be used as follows:

Comparative method (data bank)

Using (K, ¢, Pi, Swi, Rsi) by compared with other fields, in case of no information, usually every country has its own (data bank).

Material balance method

The convention of material balance calculations is applied to the production history of the reservoir, which is treated as a single unit to achieve one or more of the following objectives [6].

• Evaluate the HIIP.

•To forecast the recovery as a function of pressure drop.

•To identify and quantify the driving mechanism.

Production decline method

When production starts to decline, the decline curve analysis can be used to calculate the recovery factor [9].

Empirical correlations

These are simplified analogs (based on analysis and statistics of hundreds of depleted fields) in which the recovery factor is correlated as a function of some reservoir average rock and fluid properties, namely, porosity, oil saturation, thickness, and mobility ratio. The use of this tool should be restricted to the period before production. Consequently, it is used as a first estimate during the exploration and appraisal phases [2].

Methodology

Methods of; Volumetric, material balance equation, and decline curve analysis were performed on the reservoir data from fields in the Bouri field. The initial oil in place and recoverable oil amounts are determined by those three respective methods as follows:

Volumetric method (estimation OOIP)

The initial oil in place (OOIP) was determined using data generated from geological and petrophysical evaluation (areal extent, formation sand thickness, porosity, and saturation, etc.) and computing the initial oil in place from the general formula [16]. The governing equation for the volumetric estimation of oil in place is given as follows:

$$\mathbf{OOIP = N = \frac{7758 \times A \times h \times \emptyset \times (1 - S_{wi})}{B_{oi}}} \quad \text{................................ Equation 1}$$

The estimate using the volumetric method is done with a Microsoft Excel spreadsheet.

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Material balance method (estimation OOIP)

The data required for material balance analysis to estimate the initial oil in place include:
- PVT Data
- Initial Reservoir Pressure
- Reservoir Average Pressure History
- Production History
- All available Reservoir and Aquifer Parameters

Material balance calculations

PVT matching

PVT matching is used to build a unique PVT for the tank by measuring the quality of the plot from which red from PVT match calculations [17]. While the matching process is verified by comparing the data entered in match tables with the correlations that are used (in this study, the black oil PVT was modified with correlations present to get minimum standard deviation (accurate results) [18].

History-matching

History matching involves a trial-and-error approach to provide a best-fit comparison between the observed data and the calculated data on a zero-dimensional level. It comprises the functions of the graphical method, the analytical method, simulation tests, and pseudo-relative permeability matching techniques [19]. History matching is used to determine and identify sources of reservoir energy and their magnitude, the value of OOIP, OGIP, aquifer type and strength, etc. History matching in MBE is the most effective way to determine the aquifer model that best fits the observed data.

Analytical method

The analytical method allows for regression on all reservoir model parameters. Regression is used to adjust the reservoir model to minimize the difference between the observed/measured and the model production. It is used to assess the effects of varying parameters, such as formation compressibility, that cannot easily be assessed using graphical methods. The quality of the regression match is expressed as the standard deviation between model and measured values. The analytical plot was regressed to compute the oil in place, the encroachment angle, the aquifer permeability, inner and outer radius.

Graphical method

The first step taken was to plot $(F / We)\ Et$ versus F (i.e. the withdrawal) known as Campbell's plot, with no aquifer defined initially [20].

Energy plot

The plot describes the prevalent energy system present in the reservoir: water influx and pore volume compressibility. Fluid expansion, ingestions e.t.c. It describes the fractional contributions of these energy systems present in the reservoir and the most prominent at various dates [19].

Applying material balance through the MBAL 10.5 software used in this study

The MBAL 10.5 software package was developed by Petroleum experts depending on the material balance method principle. MBAL 10.5 is a software application made up of various tools designed to help the reservoir engineer gain a better understanding of the reservoir behavior. The tool to be used here is the Material Balance one [21].

The MBAL Tool consists of the input section, the history matching, and the production prediction sections. The input section enables the analyst to key in the data that describes the reservoir properties, Known and estimated reservoir parameters, Known or estimated aquifer type and properties, Pore volume fractions vs. depth (optional), Relative permeability curves, Transmissibility parameters (optional), Production and injection history on a well-to-well basis or total tank production (Figure 1).

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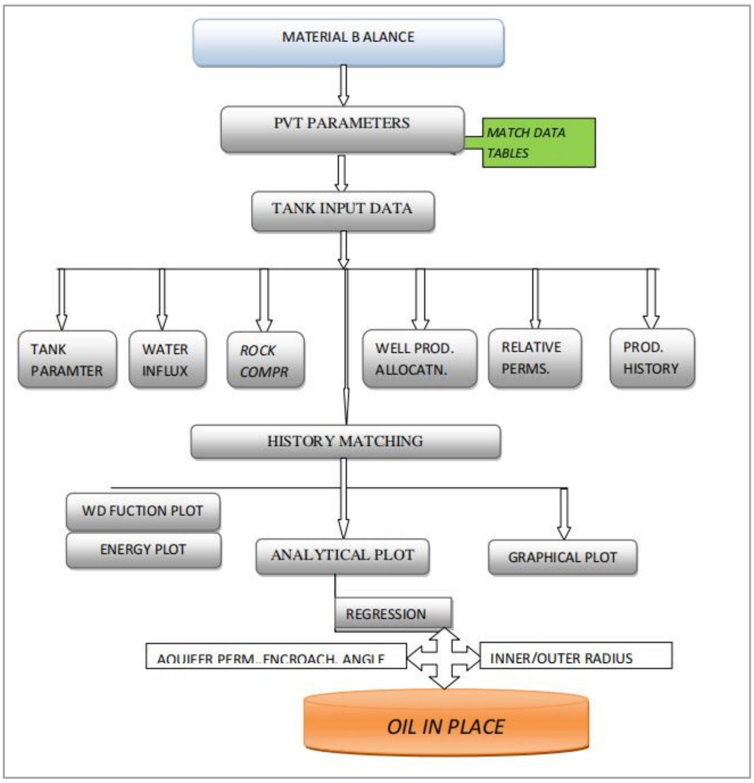

Figure* 1. *Flow Diagram of the MBAL TM workflow

MBAL workflow procedure

In the analytical reservoir engineering tool kit, MBAL software is a progressive option for running a simulation based on historical data, which should be matched with an analytical model. MBAL provides substantial matching facilities and aquifer modelling, which advances research about pressure support response and forecasting. There were certain steps followed during this research study to forecast the performance of the selected reservoir [22]:

1. PVT, cumulative oil Production and pressure depletion data were entered while considering a tank model.
2. The matching amenities available in MBAL were used to adjust the empirical fluid property correlations to fit PVT laboratory data. To foremost fit the measured data, correlations were modified using non-linear regression techniques, then selected for use in the model.
3. Vazquez-Beggs was selected for bubble point pressure, Gas-oil ratio, and Formation volume factor; and Betrosky et al-correlation selected for viscosity.
4. Tank data included for further reservoir model development, like Initial pressure, porosity, Reservoir Temperature, Initial hydrocarbon in place, connate water saturation, and production start date data. Initial hydrocarbon in place calculated based on petrophysical & Geological data (Volumetric Method). History matching requires past production data along with pressure decline.
5. After matching, three graphical plots were developed, which were used to determine reservoir and aquifer parameters. The energy plot was used to observe the driving mechanism, and the Campbell plot was a diagnostic tool to identify the reservoir type based on the sign of pressure and production behavior. The analytical method shows the variation between the model and historical data, which indicates the unaccounted energy.
6. Non-linear regression method was employed to evaluate the unknown aquifer potential and reservoir parameter, and then tuned the data related to pressure and production. Various aquifer models are chosen, and the best-fit matched aquifer model is selected.
7. After selecting the optimum water influx model that gives the best match, we can estimate OIIP, and then we can run the prediction performance of the reservoir and pressure performance for some years coming from the life of the reservoir.
8. The model's precision was verified through the utilization of historical data, such as pressure measurements and cumulative oil and gas production data.

Results and discussion

Approach discussion

In this work, MBAL and Microsoft Excel were used to carry out Material Balance, decline curve calculations, and aquifer modeling. The results obtained from the volumetric method calculations by using Excel software and simulations by using MBAL software are presented and discussed in this section.

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Volumetric method

The first method used in this study to determine the original oil in place (OOIP) of the Bouri reservoir is the volumetric method. Based on the accurate and average reservoir properties of the following parameters: Area, Porosity, water saturation, Boi, the Equations (2,3) are integrated in Excel software following by the available data. (2) shows the results obtained.

General form:

$$\boldsymbol{Ni} = \frac{\boldsymbol{7758\, A\, h\, \emptyset\, (1-swi)}}{\boldsymbol{\beta oi}} \text{...Equation 2}$$

$$RF = \frac{N_p}{Ni} \times 100 \text{ ....Equation 3}$$

Table** 1**. Volumetric method calculations on Excel software.

Petrophysical Data	**Value**	**Units**
Thickness	260	Ft
Oil FVF	1.3765	Rb\stb
Water Saturation	0.30	Frac.
Porosity	0.415	Frac.
Area	40800	Acre
OOIP	6068	MMSTB
Rf	12	%

2

Material balance method by mbal software

The results show that the history matching processing assumes two reservoir models. The first model was building a tank model (without an aquifer), which is the first assumption used to distinguish if the reservoir is in contact with aquifer influx or the reservoir layer is isolated. The second assumption is associated with reservoir models and aquifer models to evaluate the original oil in place, and accomplish the matching between reservoir pressure and simulation pressure. The final model will be a real case to understand the reservoir performance, as well as analyze the drive mechanisms, and then run a reservoir model simulation result (Aquifer influx volumes, recovery factor, etc.).

Option summary

To begin setting up the system options, make the following selections:

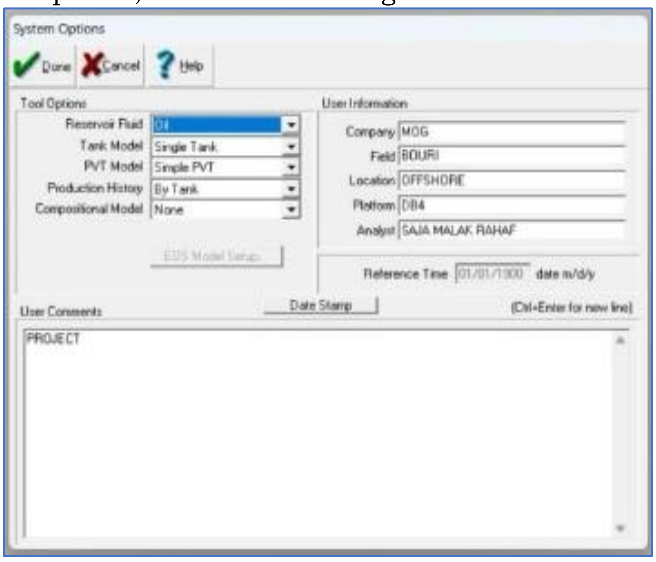

Figure** 2**. System option

PVT data

The MBAL software will need an initial set of data on fluid properties parameters, as shown in the figure below**:**

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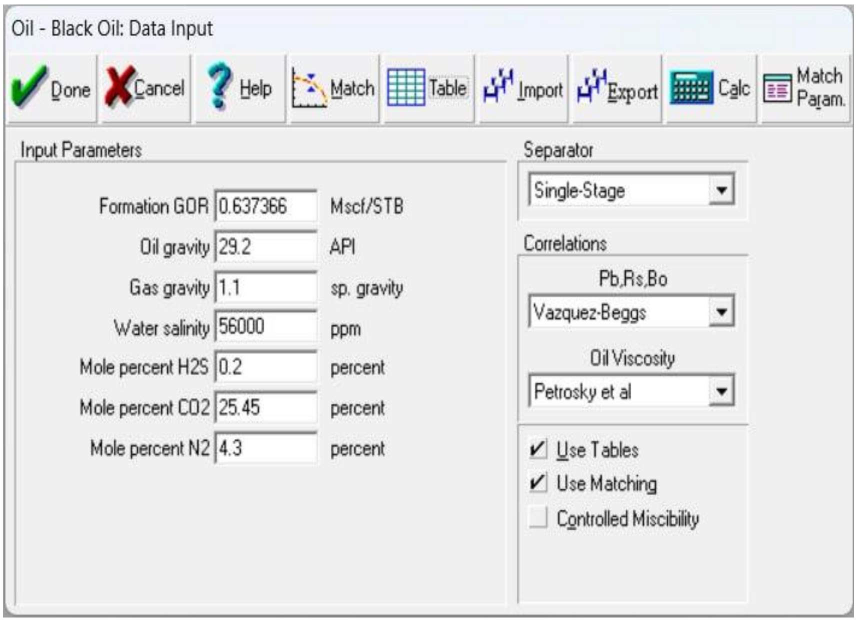

Figure* 3. *Fluid properties input data

By clicking on the "match button," the software provides a table, as shown in (Figure 4) that allows the entry of the PVT data.

	Pressure (psig)	Gas Oil Ratio (Mscf/STB)	Oil FVF (RB/STB)	Oil Viscosity (centipoise)	Gas FVF (RB/Mscf)	Gas Viscosity (centipoise)
1	4281.5	0.637366	1.3765	0.83		
2	3926.1	0.637366	1.3828	0.79		
3	3683.9	0.637366	1.3873	0.76		
4	3507.4	0.637366	1.3904	0.75		
5	3144.4	0.559064	1.356	0.82	1.0201	0.0265
6	2716.5	0.472392	1.318	0.91	1.1689	0.0243
7	2148	0.36475	1.271	1.06	1.4723	0.0216
8	1579.4	0.263842	1.226	1.23	2.0196	0.0195
9	868.8	0.141771	1.169	1.49	3.7918	0.0176
10	298.8	0.038457	1.117	1.73	11.5477	0.0162
11						
12						
13						

Figure* 4. *Fluid properties input data

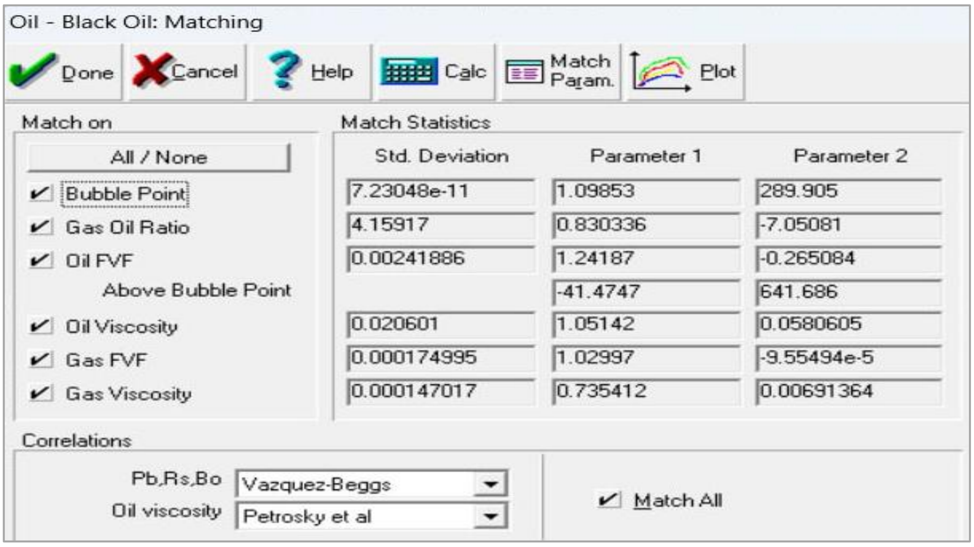

Figure* 5. *Fluid PVT matching with correlations

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In this case study, the results showed that:

- For the (oil viscosity), the Petrosky correlation [25] is the best match.
- For the (bubble point, gas oil ratio, oil FVF), the Vazquez-Beggs correlation is the best match.

(Figure 6) illustrates the quality of the match, the plot of FVF versus pressure, Gas Oil Ratio versus pressure, oil viscosity versus pressure, and bubble point versus pressure.

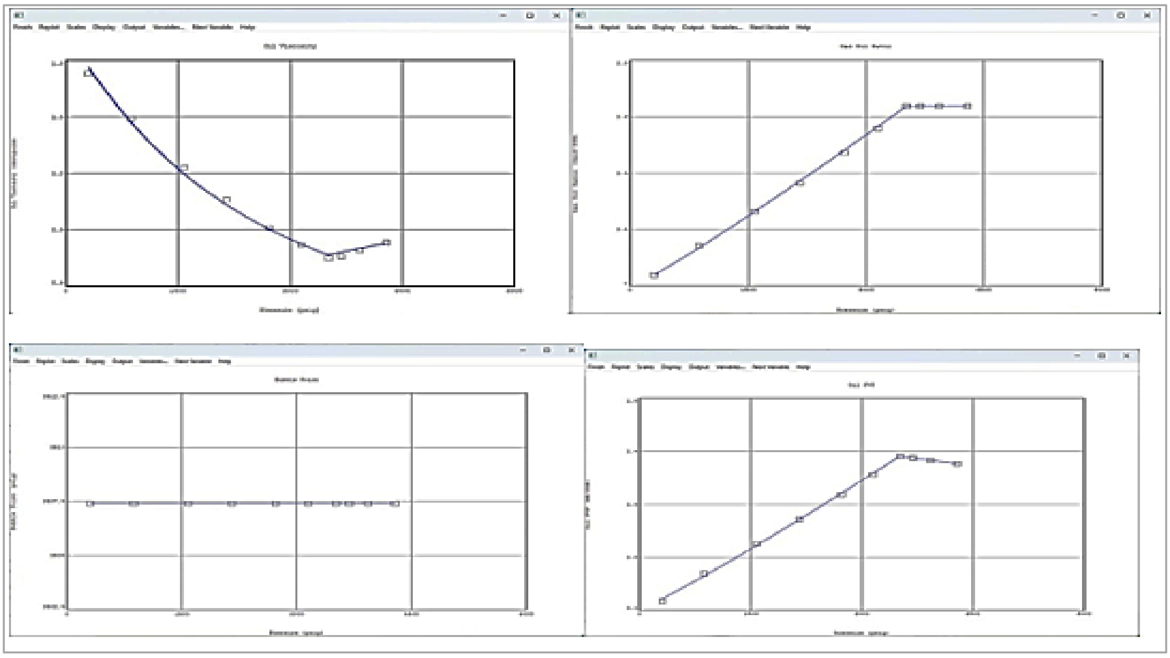

Figure* 6. *Mbal plots of (μo, rs, βo, pb) versus pressure

Input data

The software will need a set of data for the tank. This data is the building block for the model. Each of these building blocks are discuss as follows:

Tank parameter

In this section, all reservoir parameters that are used to calculate should be entered as seen in the figure below:

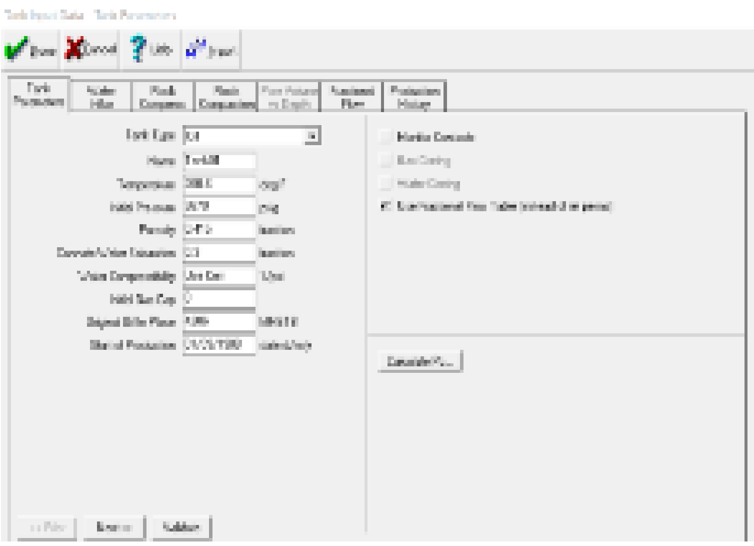

Figure* 7 *Tank Input Data

Water influx

This section is used to define the type and properties of an aquifer. The particular input variable depends on the model, as shown in (Figure 8).

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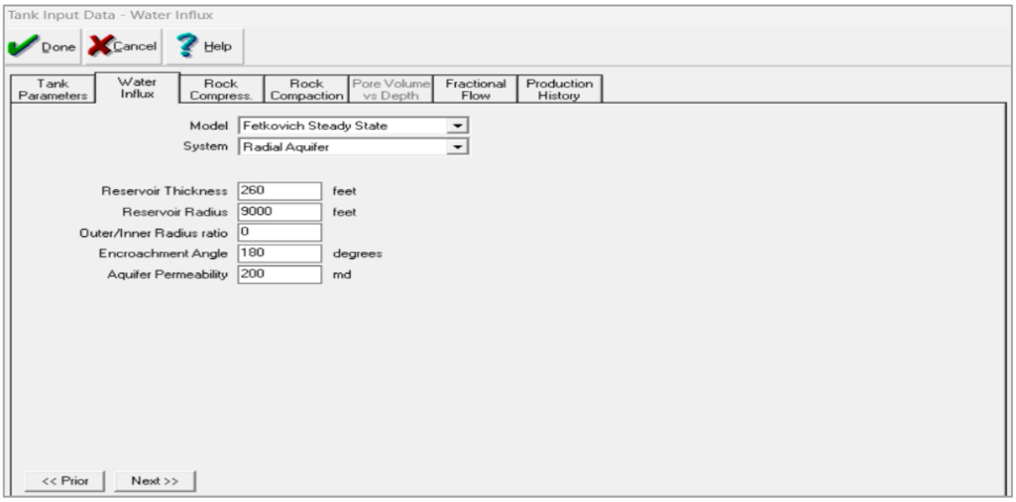

***Figure** 8. **Water influx input data**.*

Rock compressibility

The rock compressibility should be provided; if there is no value given for the rock compressibility, the correlations option used in this study.

Frictional flow

This method allows the user to import friction flow information, as in (Figure 9).

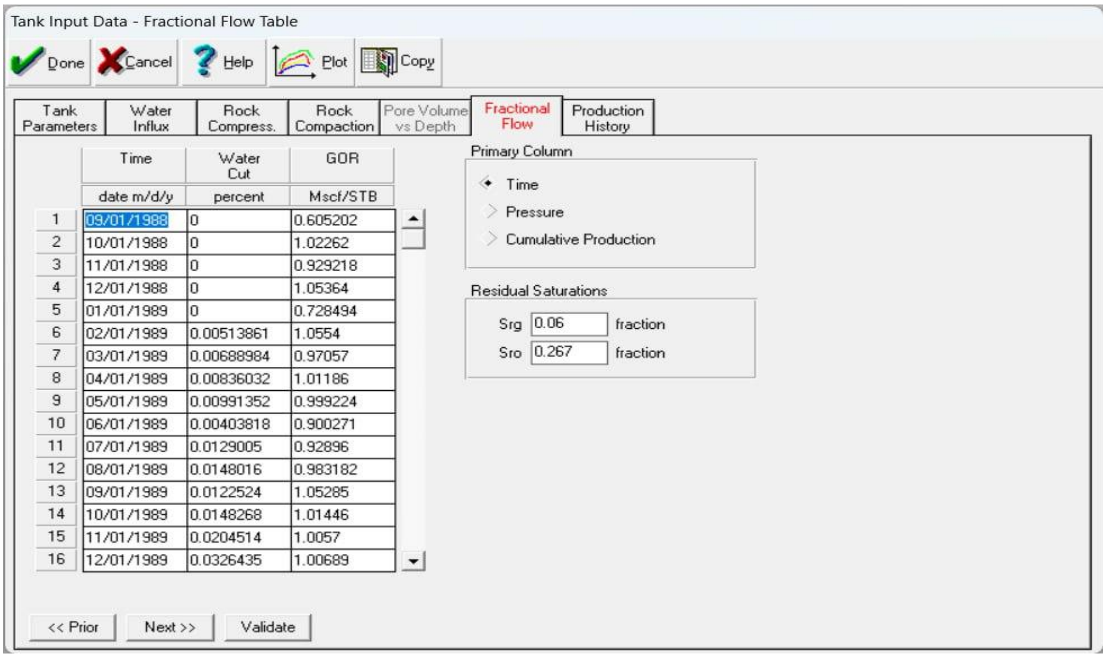

Figure** 9. **Frictional flow input data

Production history

This tab is used to enter the pressure and cumulative production injection history data of the tank. Which is the critical data used on the model, and it's the building block reservoir match and production prediction making in this study, where the time, reservoir pressure, cumulative (oil, gas, water) production, and cumulative water injection are entered (Figure 10).

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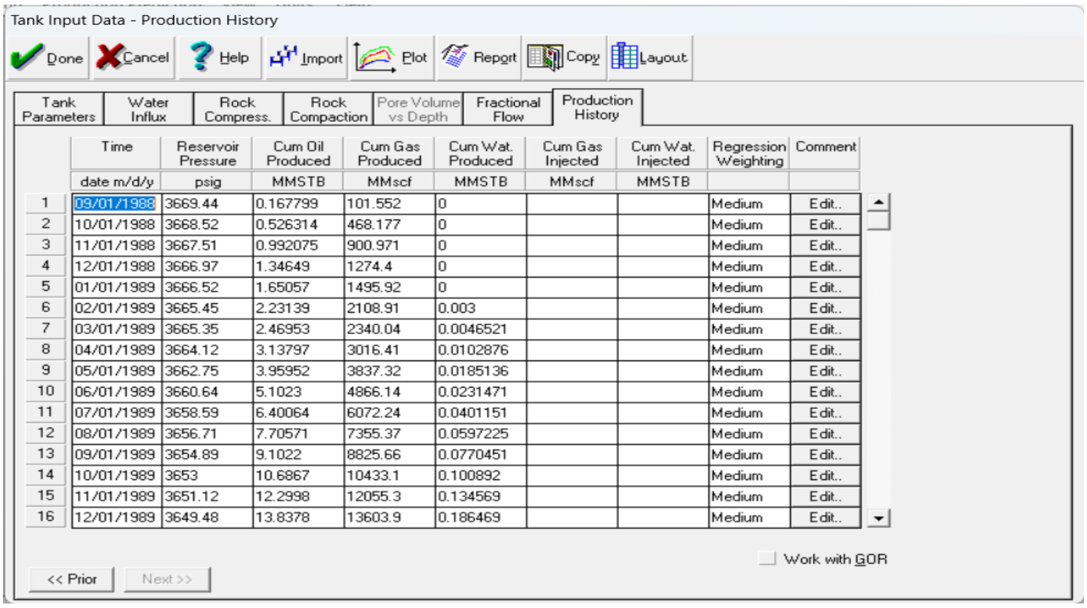

	Time	Reservoir Pressure	Cum Oil Produced	Cum Gas Produced	Cum Wat. Produced	Cum Gas Injected	Cum Wat. Injected	Regression Weighting	Comment
	date m/d/y	psig	MMSTB	MMscf	MMSTB	MMscf	MMSTB		
1	09/01/1988	3669.44	0.167799	101.552	0			Medium	Edit..
2	10/01/1988	3668.52	0.526314	468.177	0			Medium	Edit..
3	11/01/1988	3667.51	0.992075	900.971	0			Medium	Edit..
4	12/01/1988	3666.97	1.34649	1274.4	0			Medium	Edit..
5	01/01/1989	3666.52	1.65057	1495.92	0			Medium	Edit..
6	02/01/1989	3665.45	2.23139	2108.91	0.003			Medium	Edit..
7	03/01/1989	3665.35	2.46953	2340.04	0.0046521			Medium	Edit..
8	04/01/1989	3664.12	3.13797	3016.41	0.0102876			Medium	Edit..
9	05/01/1989	3662.75	3.95952	3837.32	0.0185136			Medium	Edit..
10	06/01/1989	3660.64	5.1023	4866.14	0.0231471			Medium	Edit..
11	07/01/1989	3658.59	6.40064	6072.24	0.0401151			Medium	Edit..
12	08/01/1989	3656.71	7.70571	7355.37	0.0597225			Medium	Edit..
13	09/01/1989	3654.89	9.1022	8825.66	0.0770451			Medium	Edit..
14	10/01/1989	3653	10.6867	10433.1	0.100892			Medium	Edit..
15	11/01/1989	3651.12	12.2998	12055.3	0.134569			Medium	Edit..
16	12/01/1989	3649.48	13.8378	13603.9	0.186469			Medium	Edit..

Figure 10 ***Production history input data form***

History matching result

The essential step to generating a reservoir model process is the History Matching. The analytical matching between observed reservoir pressure data and the simulation must be proved. Then, the original oil in place value will be determined. Two assumptions are made in this study, the first one is that no aquifer influx is attached to the Bouri-reservoir tank model, and the second is aquifer model is involved with the model.

Analytical method (without aquifer)

Based on the first assumption, build a tank reservoir model without an aquifer model. In MBAL Software, there is a section of History matching that uses a non-linear regression method to improve history matching. (Figure 11) illustrates the analytical plot of the Bouri oil field versus cumulative oil production before regression, where the match points observed data (Points) and the blue line represent the reservoir model without the presence of an aquifer.

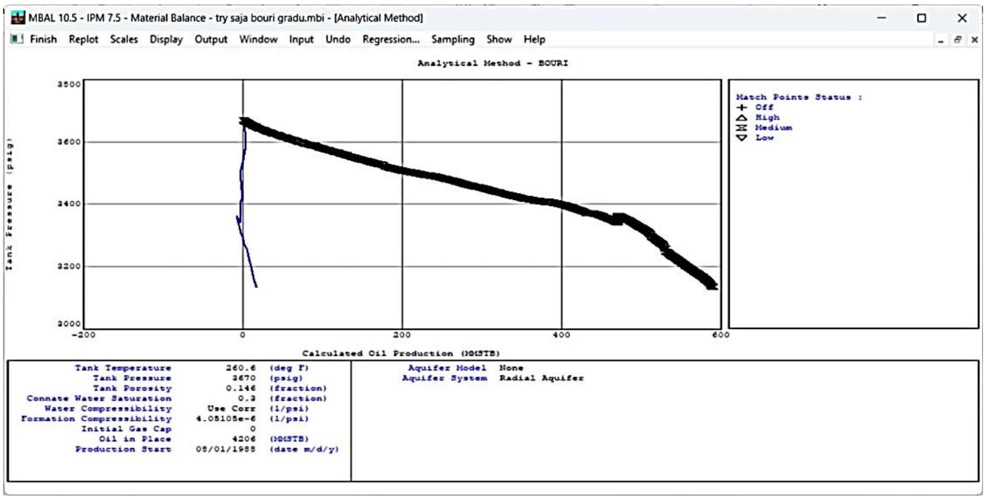

Figure 11. ***Analytical plot before regression***

Regression Option helps to improve the Analytical Method with a good match by eliminating the deviation between the simulated model and historical behavior in terms of production and pressure data (Figure 12). illustrates the analytical plot after regression.

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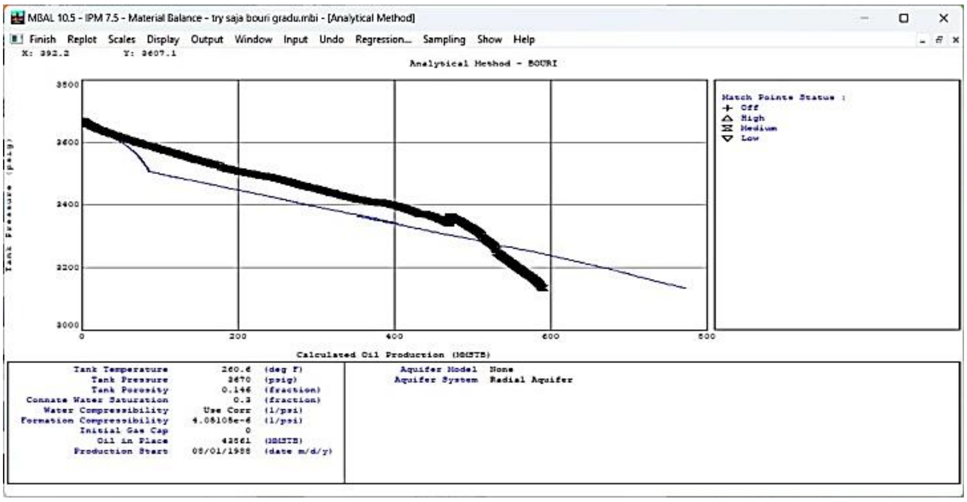

Figure 12***. Analytical plot after regression***

We can see that the analytical model, constructed based on this assumption, is not precise due to the large standard deviation between the actual data and the simulated data. The second assumption must be applied to validate the analytical model with an aquifer influx attached to the reservoir.

Analytical method (with aquifer)

As seen from the result of the first assumption, the presence of an aquifer was likely. Therefore, in the second assumption of this study, different aquifer models are tested to select the suitable water influx model for the studied reservoir by using a sensitivity analysis. After performing different water influx models, the results showed that the optimum water influx model, based on the standard deviation and agreement between the OIIP value estimated by the MBE method, is a Fetkovich steady state model [23] With standard deviation 34.0576, outer/inner radius 6.07093, reservoir radius about 12279.5 feet, encroachment angle about 359.302 degrees, reservoir thickness about 1114.46 feet, and aquifer permeability about 174.387 md, the results are shown in (Figure 13).

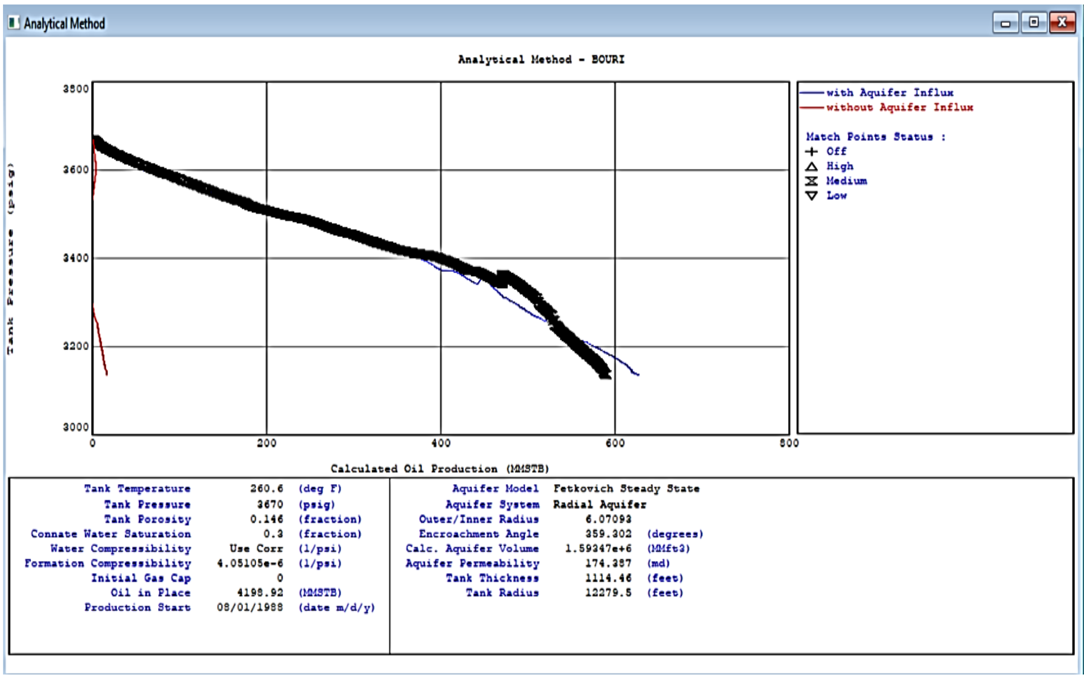

Figure 13 ***Analytical match with (Fetkovich steady state)***

Graphical method

The graphical method comprises different plots for an oil reservoir, which are;

a) Havlena and Odeh
b) F/E, versus We/Et
c) F-We versus Et
d) (F-We)/E, versus F (Campbell)

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In this study, the graphical method was used to evaluate model results of the Bouri Field, which is F-We VS Et to estimate the value of the oil initially in place, which turned out to be an acceptable result and a good straight line as seen in the figure below:

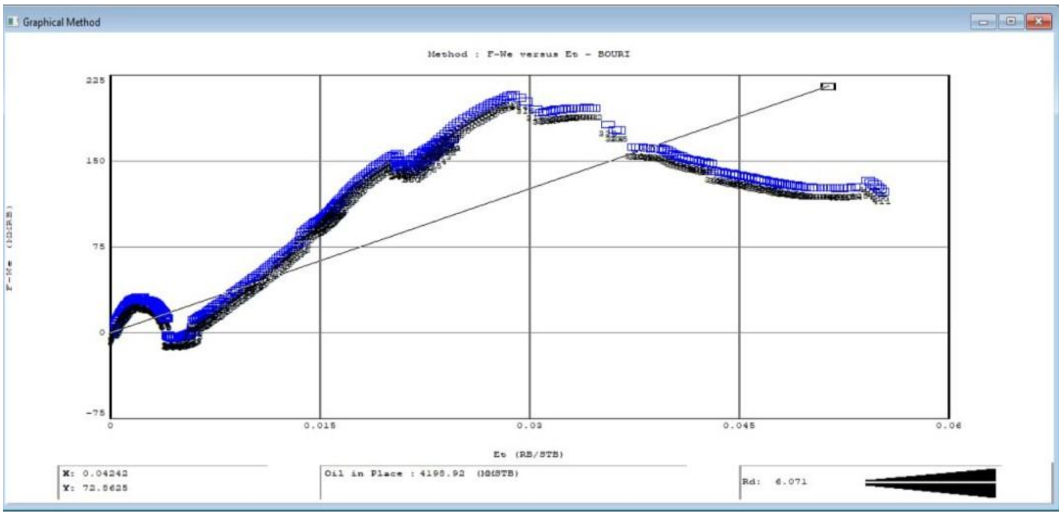

Figure* 14. *Graphical method- Fetkovich steady state

Energy source of the system

Different driving mechanism plays a role into reservoir for providing enough energy for the system. After running history matching, it was necessary to select the aquifer, and for better history matching, we selected a suitable aquifer. The relative contributions of the different driving mechanism energy, and the aquifer system to the recovery from the reservoir were discovered with certainty. From the energy plot (Figure 15), it can be seen that three drives are affecting the recovery of oil, which are: Pore Volume Compressibility (represented in green), fluid Expansion (in blue sections), and aquifer (in red sections), with the aquifer being the dominant drive.

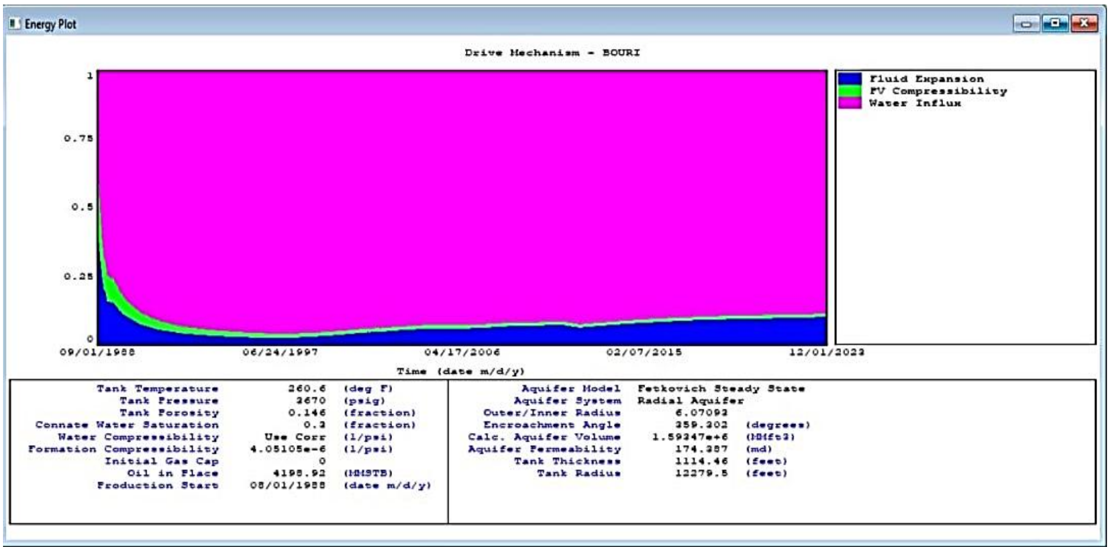

Figure* 15. *Energy plot

Reservoir simulation

Reservoir simulation is considered a tool for overall field development planning and is used to perform reverse calculations [24]. Simulation study in (Figure 16) revealed that if the simulated model has been properly history matched, there should be no variance between predicted reservoir pressure as a function of time from the simulation result and the historical measured pressure result. After the result in this case, the simulated and historical data were matched together.

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Figure* 16. *Tank Pressure vs Time Reservoir Simulation

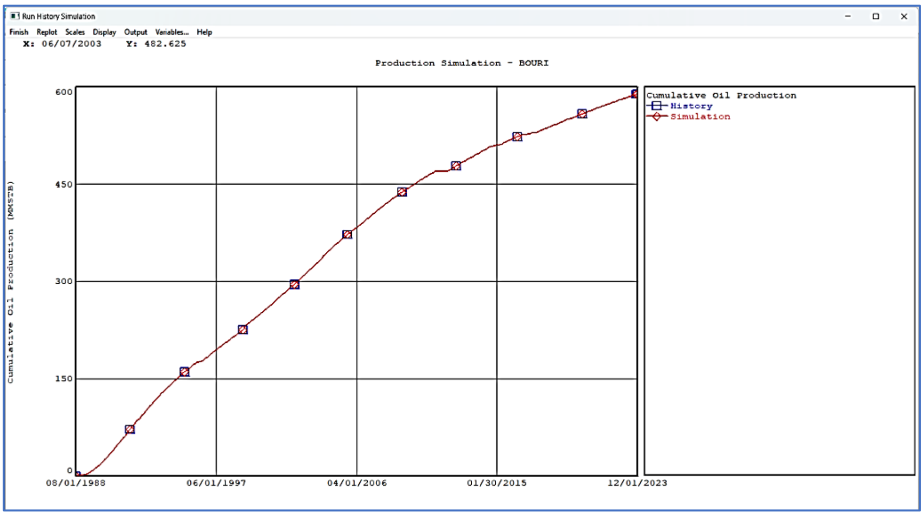

Figure* 17 *Cumulative oil production vs Time Reservoir Simulation

Running the prediction performance/forecasting
Using MBAL software

After obtaining a history match, as seen, we found that the Fetkovich steady state is the optimum water influx model match with the Bouri Field. The prediction of the future performance in the studied reservoir is the final step on the MBAL software; the discussion of steps and results is shown as follows:

Predicting setup

This is the first prediction dialogue box. It defines the types of prediction to be performed, the start and end of the prediction. In this study, we start prediction from the end of production history, and we predict the performance of the field for ten years (Figure 18).

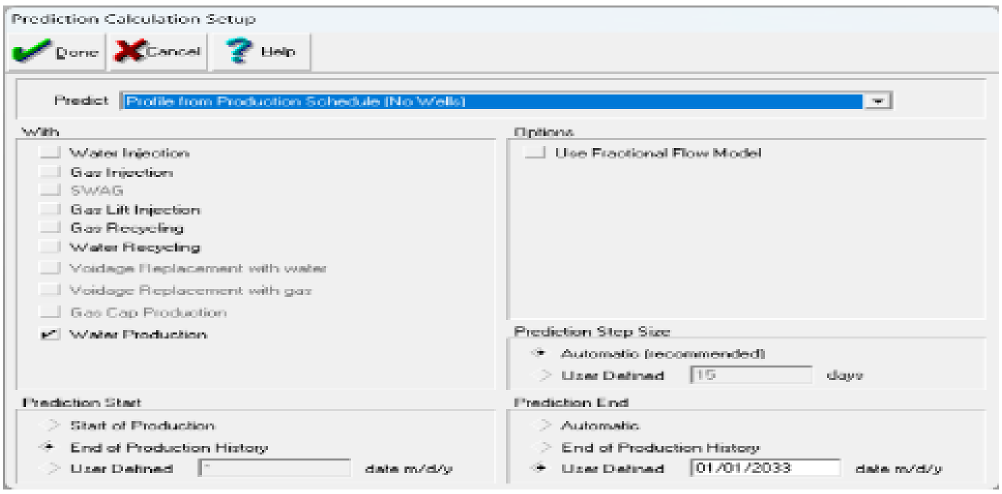

Figure 18. Prediction setup dialog

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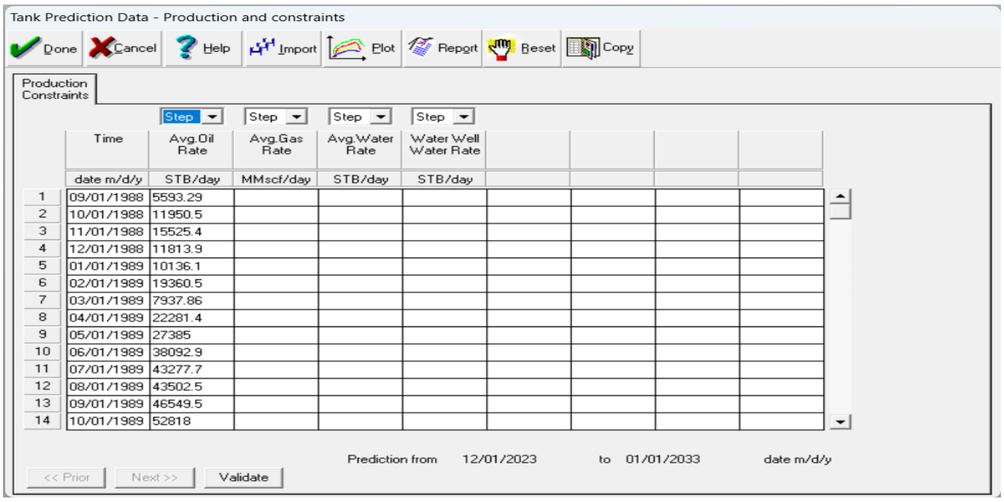
Production and constraint
After the previous step, we have to fill in the production history field data that is required to continue the prediction process, as appears in (Figure 19).



	Time	Avg.Oil Rate	Avg.Gas Rate	Avg.Water Rate	Water Well Water Rate
	date m/d/y	STB/day	MMscf/day	STB/day	STB/day
1	09/01/1988	5593.29			
2	10/01/1988	11950.5			
3	11/01/1988	15525.4			
4	12/01/1988	11813.9			
5	01/01/1989	10136.1			
6	02/01/1989	19360.5			
7	03/01/1989	7937.86			
8	04/01/1989	22281.4			
9	05/01/1989	27385			
10	06/01/1989	38092.9			
11	07/01/1989	43277.7			
12	08/01/1989	43502.5			
13	09/01/1989	46549.5			
14	10/01/1989	52818			

Figure 19***. Production and constraints***

Prediction results
After acceptable history matched obtained, prediction of cumulative oil production, oil recovery factor, water production, and reservoir pressure decline is carried out (Figure 20).

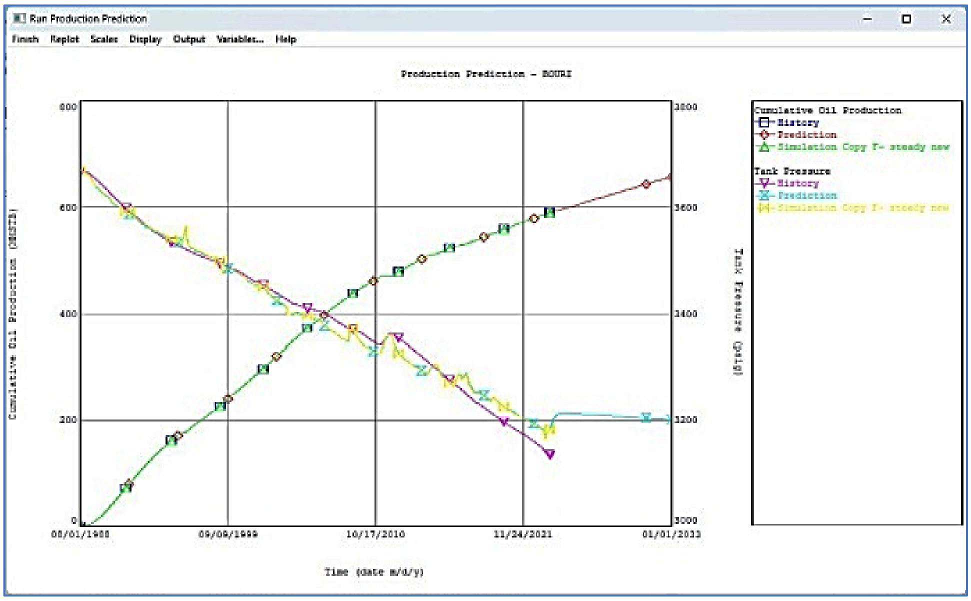


Figure 20***. Performance prediction of the reservoir and History match data plotted***

(Figure 21) shows that from the beginning of the production in 01/08/1988 to the continuous decline of the production in the plot till 01/01/2033. As we can clearly see that history model, the simulated model, and performance prediction fall in the same line. Further cumulative oil production after 01/12/2023 will follow according to the performance prediction plot.

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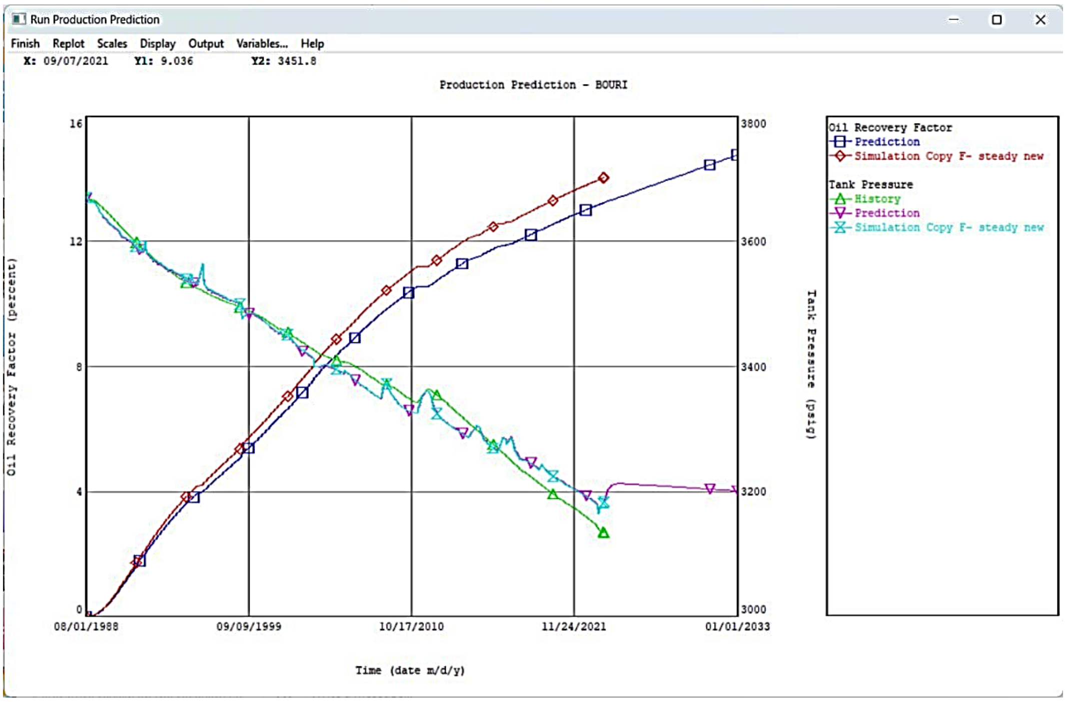

Figure* 21. *Oil recovery factor and tank pressure prediction

Assessment of water influx volumes

The cumulative water influx into the Bouri reservoir (Figure 22) is considered by the steady state model. Shows the cumulative water influx versus time and the total volume of water influx invaded into the reservoir (prediction results).

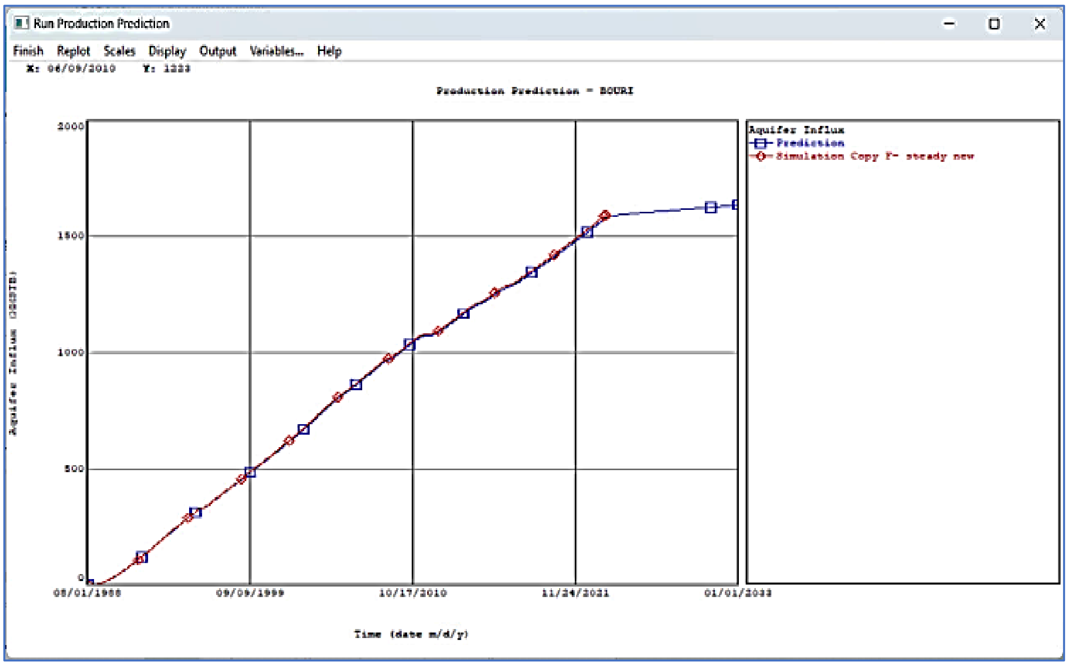

Figure* 22. *Aquifer influx Vs. Time

Recovery factor prediction

The OOIP results are summarized by using material balance in (**Error! Reference source not found.**):

Table* 3. *OOIP Results from MBE Methods

Type	OOIP (MMSTB)
Fetkovich steady state	4198.92
Fetkovich semi steady state	3856.87
Hurst-van Everdingen-odeh	4027.17

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Decline curve method

Here, after we input the production history into Excel software to obtain Decline period that we could analysis the period to get the type which give us a less value of sum Error as shown in (Figure 23), we noticed the type of Decline is Exponential that mean b=0, then we selected a type of decline into MBAL software as shown in (Figure 24) to get a prediction oil recovery until 2033 as shown in (Figure 25).

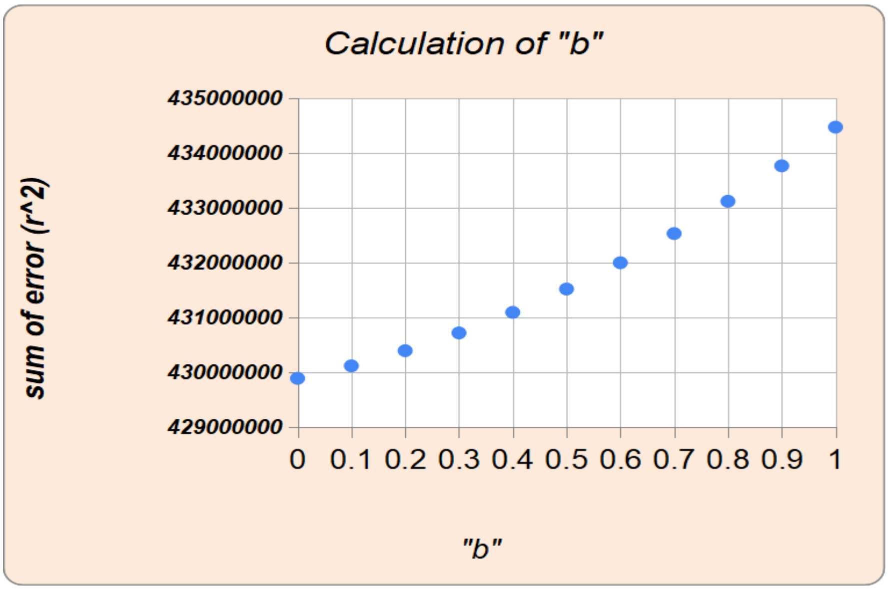

Figure* 23. *Sum of Error VS values of b

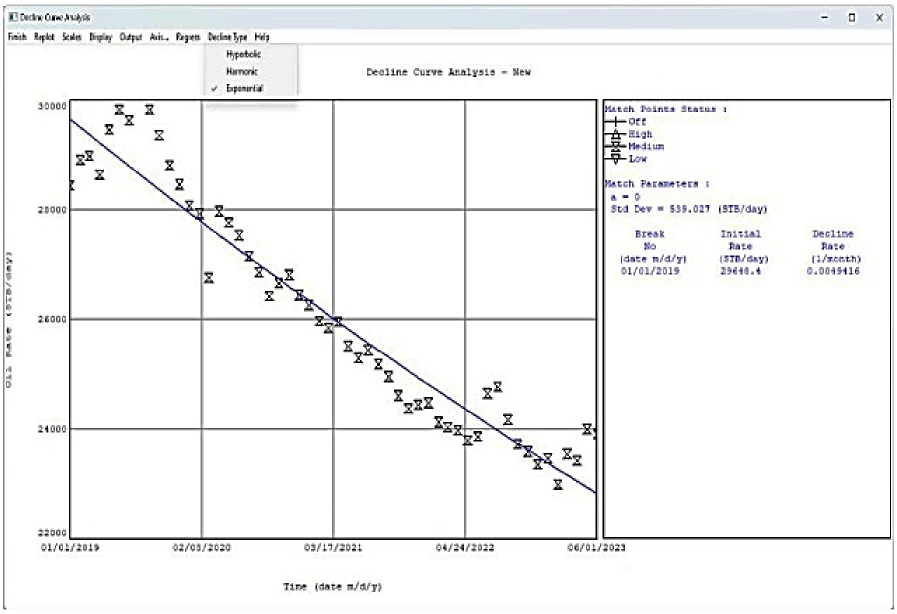

Figure* 24. *Matched a type with field data into the MBAL Software

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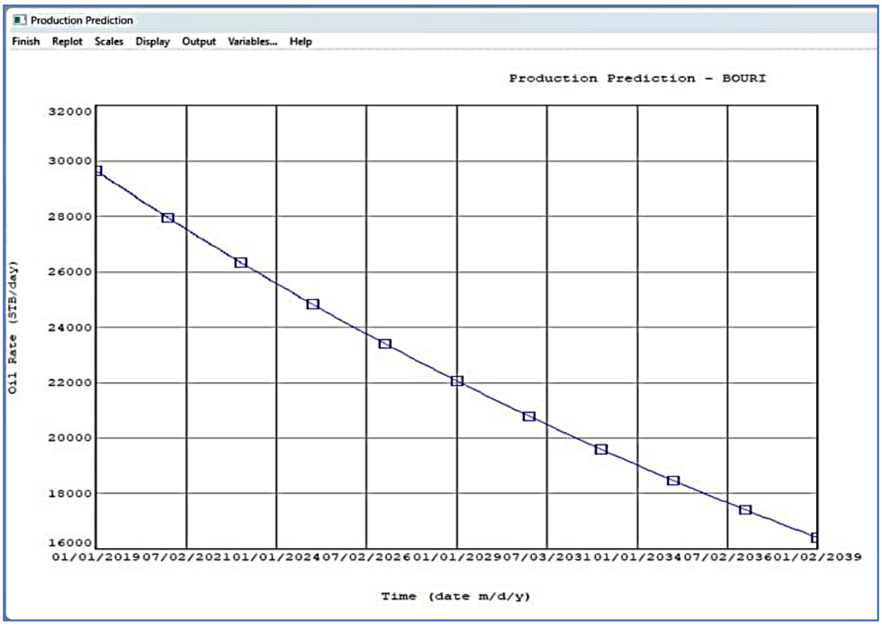

Figure 25. Prediction of oil production

Determine the error in each method

In this table, we noticed that the MBE method includes most parameters that made the RF almost as accurate as one.

Table 4. Determine the error in each method

Method	RF %	Error %
Volumetric	12	25
Material Balance	14.042	12.237
DCA	14.03	12.312

Conclusion

Volumetric Analysis: This method estimates recoverable reserves based on the initial oil-in-place (OIIP) volume and assumes an average recovery factor. It provides a quick assessment but often yields conservative recovery estimates due to simplified assumptions about reservoir behavior and recovery mechanisms as we see in this case, RF=12%. Material Balance: Material balance equations integrate reservoir pressure and fluid pressure to calculate remaining reserves and predict recovery. In this case, this method offers a detailed understanding of reservoir dynamics. It can adjust recovery factor estimates nearly to 14.042% based on actual field data using MBAL software, making it robust for mature fields with extensive production history, so this method gives a lower error value of RF based on the original RF of the Bouri field. Decline Curve Analysis: DCA forecasts future production by fitting empirical decline curves to historical production data. It extrapolates decline trends to estimate ultimate recovery, considering factors like well depletion and production efficiency. DCA is effective for early-stage reserves assessment but requires accurate production data and assumes consistent future performance. In this case DCA method is used to obtain a type of decline that runs into the MBAL software, then the RF is here at nearly 14.03%.

Recommendations

Based on the findings of this study, several key recommendations have been established regarding reservoir analysis and data management. It is essential to carefully screen and evaluate basic engineering data when utilizing software to ensure the Material Balance Equation (MBE) is accurately applied to the reservoir. To verify the validity of results obtained from MBAL, integrated software solutions like Petrel and Eclipse should be employed for cross-referencing. In instances where a significant variance exists between volumetric estimates and MBAL estimates, a dynamic model such as Eclipse™ is recommended to conduct a more detailed reservoir analysis. Furthermore, the uncertainties inherent in petrophysical data can be mitigated through the acquisition of additional data, which facilitates a more precise delineation of reservoir contacts and net thickness.

Conflict of interest. Nil

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