



Future Performance Prediction of a Naturally Producing Oil Reservoir Using History-Matched ECLIPSE Simulation: Development Implications

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التنبؤ بالأداء المستقبلي لمكمن نفطي منتج طبيعياً باستخدام نموذج محاكاة **ECLIPSE** المطابق تاريخياً: استراتيجيات تطوير حقل

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Abstract:

In this study, reservoir simulated-model history matching, trial and error technique, is undertaken to improve understanding of BB oilfield reservoir dynamic behavior and provide a robust basis for production forecasting that informs development implications. The work steps started with; building Eclipse dynamic simulated-model through generating static model using Petrel software, and followed by upscaling of fine grid model, representation of the reservoir rock properties, characterization of the fluid properties and rock-fluid physical data, well modeling, production history validation. The next step is calibration of observed production data for simulated-model history matching, followed by reservoir performance prediction, evaluation, and development implications. The studied BB reservoir formation primarily consists of medium-to coarse-grained sandstones interbedded with shale layers. In addition, BB oilfield consists of three vertical oil wells, BB-1, BB-3, BB-4, and it produced 9 MMSTB in cumulative through approximately 31 years. The BB Field simulated-model prediction estimated that the field cumulative natural oil will be 12.48 MMSTB in 2034. Moreover, the field natural production rates are expected to range 143-400 STB/D, associated with very high GOR (4-8.1 MSCF/STB), small water cut (less than 4%), and relatively moderate bottom-hole pressures (3800-4200 psi). The most likely reason behind the extreme GOR is the heavy depletion-driven gas liberation, due to reservoir gas saturation passes the critical gas saturation (S_{gc}), eliminating oil production as pressure drops. The study recommended some measures to manage field GOR and improve oil recovery including; GOR control, drilling infill horizontal wells, and pressure maintenance.

Keywords: Reservoir Simulation, History Matching, Solution Gas Drive, Natural Depletion, Performance Prediction, Development Strategy.

الملخص:

أجرت الدراسة مطابقة تاريخية لنموذج المحاكاة الديناميكية للمكمن باستخدام أسلوب التجربة والخطأ، بهدف فهم السلوك الديناميكي لمكمن حقل BB النفطي، وتوفير أساس موثوق للتنبؤ بالإنتاج، بما يدعم تقييم الآثار المترتبة على تطوير الحقل.

بدأت الدراسة ببناء نموذج المحاكاة الديناميكية باستخدام ECLIPSE وذلك من خلال إنشاء النموذج الساكن باستخدام Petrel تلاه إجراء عملية تكبير حجم الشبكة (Upscaling) للنموذج، وتمثيل خصائص صخور المكن، وتوصيف خصائص المواع والبيانات الفيزيائية للصخر-المانع، بالإضافة إلى نمذجة الآبار والتحقق من صحة بيانات الإنتاج. ثم جرت معايرة بيانات الإنتاج الفعلية بهدف تحقيق المطابقة التاريخية لنموذج المحاكاة، أعقبها التنبؤ بأداء المكن وتقييمه، ومن ثم تحديد الانعكاسات التطويرية. يتكون التكوين المكني المدروس بصورة رئيسية من أحجار رملية متوسطة إلى خشنة الحبيبات، تتخللها طبقات من الطفل الصفحي. كما يضم حقل BB ثلاث آبار رأسية، هي BB-1 وBB-3 وBB-4 وقد بلغ إجمالي إنتاج الحقل التراكمي نحو (9MMSTB) لما يقارب 31 عامًا. أظهرت النتائج أن الإنتاج التراكمي الطبيعي المتوقع للنفط سيبلغ نحو (12.48 MMSTB) بحلول عام 2034. أما توقع معدلات الإنتاج الطبيعي للحقل تتراوح بين 143 و400 (STB/D)، مصحوبة بنسبة غاز (GOR) تتراوح بين 4 و8.1 MSCF/STB، ونسبة مياه مصاحبة ضئيلة تقل عن 4%، مع بقاء متوسط ضغط قاع الآبار عند مستويات متوسطة نسبيًا، تتراوح بين 3800 و4200 psi. ويُعزى هذا السلوك الإنتاجي إلى زيادة الغاز المتحرر نتيجة لارتفاع ضغط تشبع الغاز عن ضغط التشبع الحرج مسببة إنتاج مفرط للغاز، مما يحد من إنتاج النفط وإعاقة استرداده. لذلك يوصى باتخاذ إجراءات تطويرية للتحكم في GOR، وحفر آبار إنتاجية أفقية، وكذلك تطبيق اليات المحافظة على ضغط المكن بهدف تحسين أدائه.

الكلمات المفتاحية: محاكاة المكامن، المطابقة التاريخية، الدفع بالغاز المذاب، الاستنزاف الطبيعي، التنبؤ بالأداء، الانعكاسات على تطوير الحقل.

Introduction:

Reservoir simulation is a cornerstone of modern petroleum engineering, providing essential tools for predicting hydrocarbon recovery, optimizing production strategies, and evaluating enhanced oil recovery (EOR) methods. One of the critical procedures of reservoir simulation is history matching that enhances the accuracy and reliability. Studies have shown that without proper history matching, simulation forecasts can be highly inaccurate and potentially leading to suboptimal development decisions [0]. History matching process depends on calibration of key parameters including permeability and porosity distributions, relative permeability and capillary pressure curves, well productivity indices, skin factors, and aquifer support.

The non-uniqueness of history-matched solutions is a well-documented challenge; multiple parameter sets can produce similar matches to historical data, highlighting the importance of geologically realistic constraint [2]. Recently, automated history matching techniques proved efficiency such as Ensemble Kalman Filter (EnKF), genetic algorithms, and gradient-based optimization approaches. For instance, applied smoother iterative set methods for assisted history matching in the Norne field, achieving efficient calibration while reducing computational costs [3]. History matched reservoir simulation is applied for evaluation of multiple production strategies, including primary depletion, water flooding, gas injection, or chemical enhanced oil recovery, under realistic operational constraints [4,5].

In general, reservoir performance prediction is essential for field development planning and economic evaluation. Traditional prediction methods, such as decline curve analysis and material balance analysis, remain widely used due to their simplicity [6]. Decline curve methods assume the continuation of historical trends, whereas material balance employs mass conservation to estimate ultimate recovery. These both approaches are limited in heterogeneous or complex reservoirs. Nevertheless, Numerical reservoir simulation has emerged as the most reliable method for reservoir performance forecasting, particularly, when it is integrated with history-matched models. Generally, numerous studies have demonstrated the effectiveness of reservoir simulation in both conventional and complex reservoirs. Some commercial simulators, particularly Eclipse, have been widely adopted due to their capability to handle black-oil, compositional, thermal, and chemical flooding scenarios. In addition, Case studies emphasised Eclipse's effectiveness in forecasting production in mature fields for instance; research on North Sea fields and Middle Eastern sandstone reservoirs illustrated how history matching and subsequent forecasting inform decisions on infill drilling, waterflood optimization, and production scheduling [0].

Moreover, Studies exhibited that simulation-informed decisions can improve recovery factors by up to 10–15% compared to conventional planning methods [6]. In this study, ECLIPSE-based simulation is applied to a natural depletion BB Oil Field to predict and analyse future reservoir performance and inform development decisions. The BB Oilfield has relatively long-term historical production period of around 31 years. The field production started in December 1994 and produced around 9 MMSTB, in cumulative, up to March 2025. The field consists of 3 oil wells, opened to flow, and the observed production data is utilized in history matching and refining the Eclipse BB field simulated-model. Finally, the precise simulated-model predicted the future BB reservoir performance to analyse production constraints and development implications.

Material and methods:

The study work steps shown in **خطأ! لم يتم العثور على مصدر المرجع.** are; static model built in Petrel and imported to Eclipse as the basis for the dynamic simulation model, upscaling of fine grid model, representation of the reservoir rock properties, characterization of the fluid properties and rock-fluid physical data, well modelling, production history validation, integrated history matching for model input data calibration, and reservoir performance prediction and analysis of constraints for development implications.

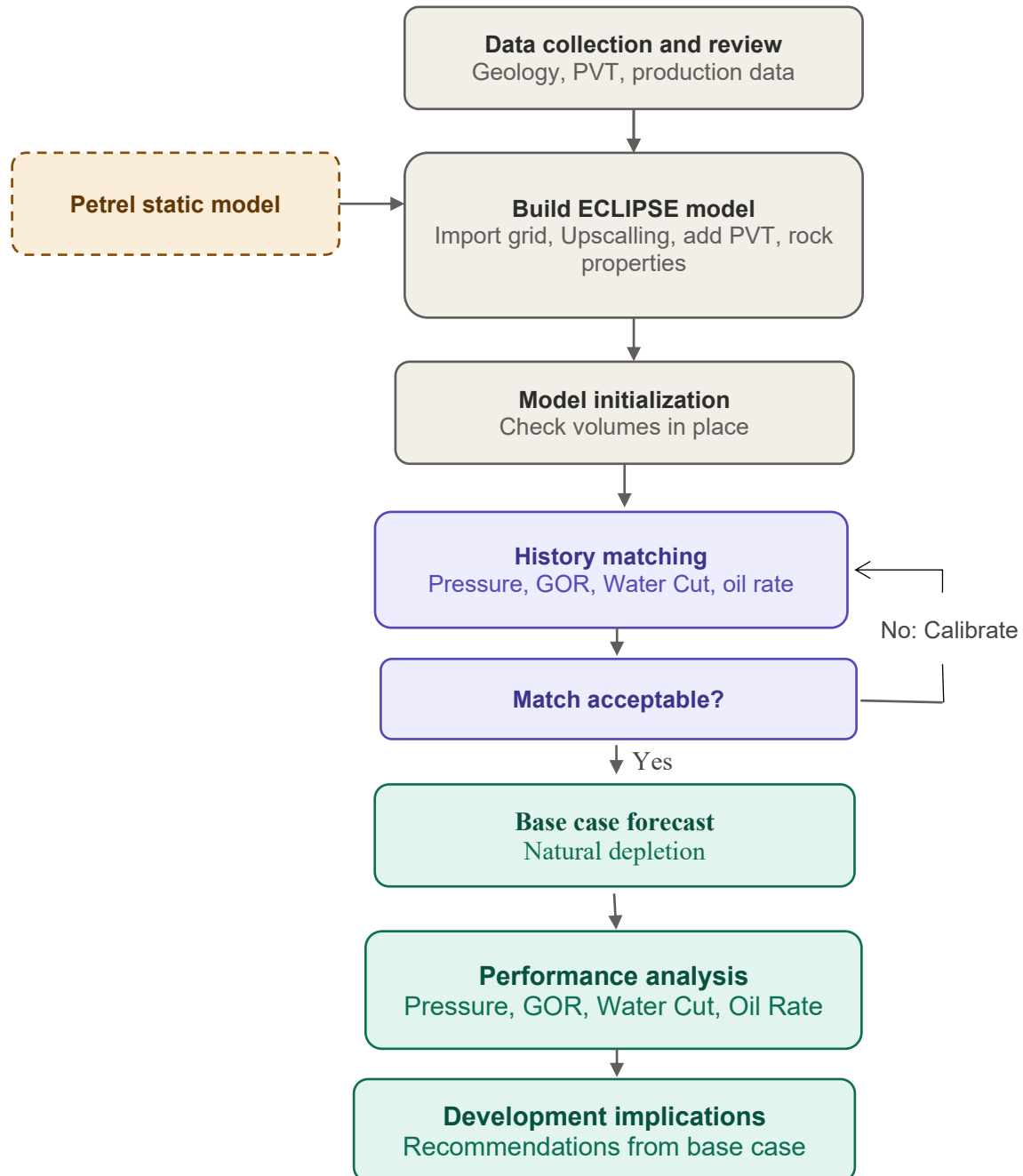


Figure (1): Methodology flowchart for reservoir simulation, history matching, and base case forecasting.

Data Collection and Preparation:

Data collection and preparation is a fundamental step in reservoir simulation study that is directly linked to the completeness and reliability of model matching [8]. At this stage, all relevant datasets are compiled and validated to provide a solid foundation for subsequent Modeling work. The datasets include:

- Geological descriptions, defining the structural framework and stratigraphy.
- Petrophysical properties, such as porosity, relative permeabilities, water saturation, and capillary pressure.
- Fluid characterization data, including PVT analyses.
- Historical production and pressure records.

Static and Dynamic Simulation Model:

The development of the base case simulation model begins with the construction of a static geological model using Petrel software, which captures the structural architecture, stratigraphy, heterogeneity, and fluid connectivity within the reservoir. Using well log data, seismic interpretations, and geological correlations, the static model defines the spatial distribution of rock properties such as porosity, permeability, and facies boundaries [7]. Accurate representation of reservoir architecture and heterogeneity ensures that the static model preserves the essential geological framework [8]. Once the static model is established, it is converted into a dynamic simulation model, suitable for implementation in Eclipse, and the properties are upscaled from fine-scale geological grids to coarser simulation grids ($50 \times 50 \times 10$ cells). The simulation grid, comprised of 12096 active cells, are structured to align with fault geometry and stratigraphic layering, and the cell dimensions are $64 \text{ m} \times 21 \text{ m} \times 9 \text{ m}$. Porosity and permeability are assigned from upscaled property models. Relative permeability (k_r) is derived from core flood experiments using Corey-type functions for oil-water and gas-oil systems. Capillary pressure (P_c) was modeled using Leverett J-function. And then, Eclipse black-oil input format was used to define oil, gas, and water phase properties, based on laboratory-measured PVT data. Figure (1) shows BB field simulated-model of oil, gas, water saturations map. also, productivity indices were calculated from well test data. Finally, Carter-Tracy aquifer model was implemented to represent water influx from adjacent aquifers, with initial parameters estimated from material balance analysis.

The created dynamic model incorporates key petrophysical properties and fluid flow parameters required for numerical simulation, including PVT data, relative permeability and capillary pressure functions, and saturation-dependent flow properties. Additionally, the dynamic model integrates well configurations such as well trajectories, completions, production or injection schedules, as well as operational constraints like bottom-hole pressure limits, production rates, and injection schedules.

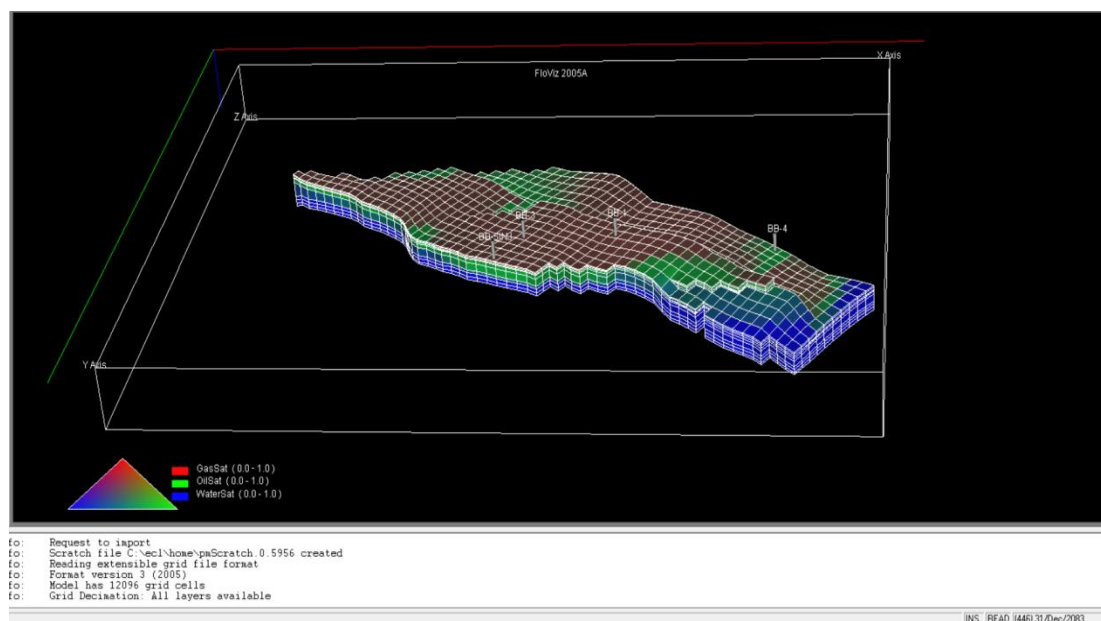


Figure (1): BB Field Fluid Saturation Map.

History Matching and Reservoir Future Performance Prediction:

The dynamic model allows the simulator to replicate reservoir fluid flow behavior under different development scenarios. Thus, the base simulation model serves as the foundation for history matching and production forecasting. Its quality directly impacts the accuracy of subsequent analyses, making the precise construction and validation of both the static and dynamic components essential for the overall success of the study. By developing a reliably history-matched model of the BB Field, this study aims to improve understanding of reservoir dynamic behavior and provide a robust basis for production forecasting that support development strategies decision making.

BB Field information:

The geological framework of the BB Field, discovered in 15th of December 1994, is defined by an anticlinal trap. BB reservoir formation primarily consists of medium-to coarse-grained sandstones interbedded with shale layers. The reservoir porosity ranges from 15 to 20%, while permeability exhibits significant variability due to lithological heterogeneity and compartmentalization associated with faulting. This variability complicates reservoir characterization, making fluid flow prediction and optimization of recovery strategies more challenging. There are three producing wells, BB-1, BB-3, and BB-4 located in a separate block, producing in the field. The BB reservoir drive mechanism is solution gas drive and the bubble-point pressure (P_b) is 6,187 psi. In March 2025, well BB-4 bottom-hole pressure was around 5985 psi, whereas wells BB-1 and BB-3 pressures were 3712 psi and 4769 psi respectively. The BB oilfield has a production period of approximately 31 years, through which it produced around 9 MMSTB in cumulative.

Results and Discussion:

Well Bottom-hole Pressure Prediction:

خطأ! لم يتم العثور على مصدر المرجع. shows well BB-1 bottom-hole pressure, observed and predicted trends, as it is noticed that it was 3850 psi in March 2025, and it is expected to slightly drop to reach 3800 psi in 2031. Similarly, Well BB-3 bottom-hole pressure, presented in خطأ! لم يتم العثور على مصدر المرجع. was about 4200 psi in March 2025, and it is expected to slightly fall to reach around 4100 psi in 2026. Finally, خطأ! لم يتم العثور على مصدر المرجع. represents Well BB-4 bottom-hole pressure trends representing 4950 psi in March 2025 and it will slowly decrease to reach 4200 psi in 2034. In general, the BB field wells bottom-hole pressures are expected to be 3800-4200 psi, roughly 2370 psi below the bubble-point pressure (P_b), 6170 psi, at the predicted end of the natural flow period.

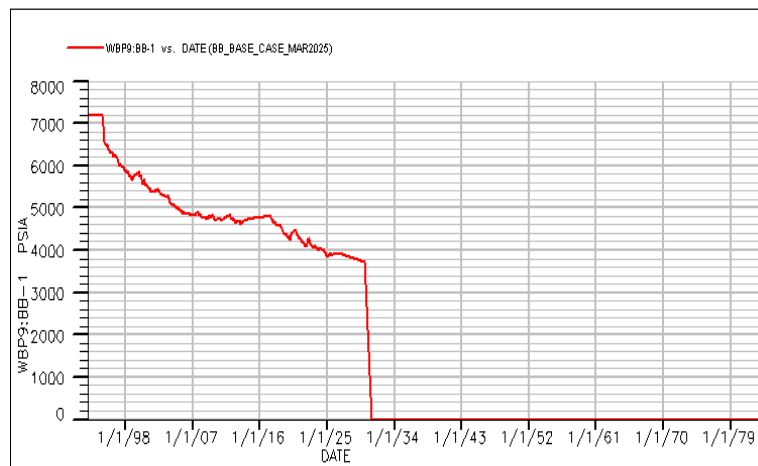


Figure (3): Well BB-1 Bottom-Hole Pressure History Matching and Prediction.

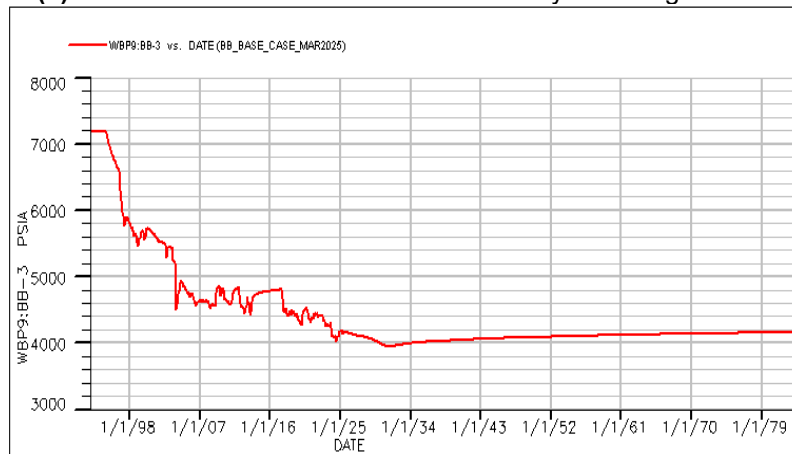


Figure (2): Well BB-3 Bottom-Hole Pressure History Matching and Prediction.

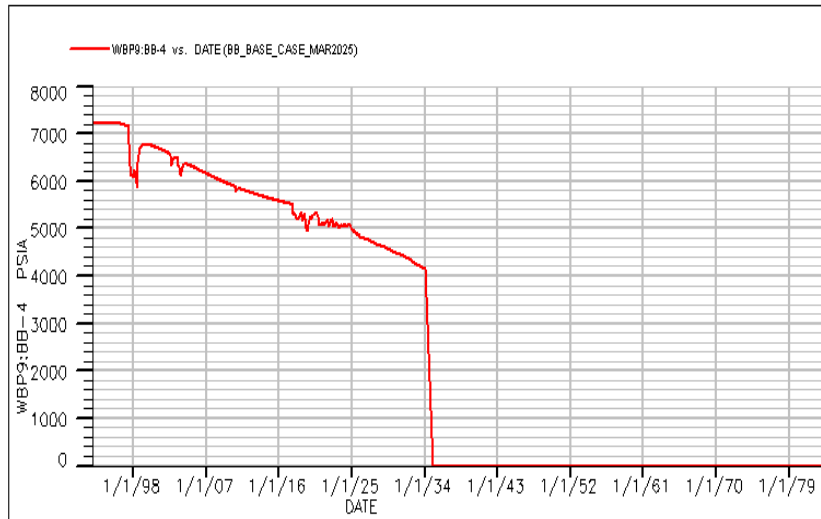


Figure (3): Well BB-4 Bottom Hole Pressure History Matching and Prediction.

Gas Oil Ratio Prediction:

خطأ! لم يتم العثور على مصدر المرجع. shows BB-1 Well matched and predicted GOR trends. The well GOR was observed to be 8 MSCF/STB in March 2025. It is expected that the well GOR will start at 4.1 MSCF/STB in March 2025, as the production restarted, then it will rise steeply to reach the maximum GOR of 8.1 MSCF/STB in 2031. Also, Well BB-3 GOR, presented in خطأ! لم يتم العثور على مصدر المرجع., is expected that it will start at 5 MSCF/STB in March 2025, and increase significantly to reach maximum 7.8 MSCF/STB in January 2026. Moreover, خطأ! لم يتم العثور على مصدر المرجع. represents Well BB-4 GOR trends, well matched GOR is about 1.95 MSCF/STB in March 2025, and then it will slowly rise to reach 4 MSCF/STB, maximum, in 2034. In general, the BB field GOR is very high and it is expected to continuously rise to be 4-8.1 MSCF/STB as production proceeds.

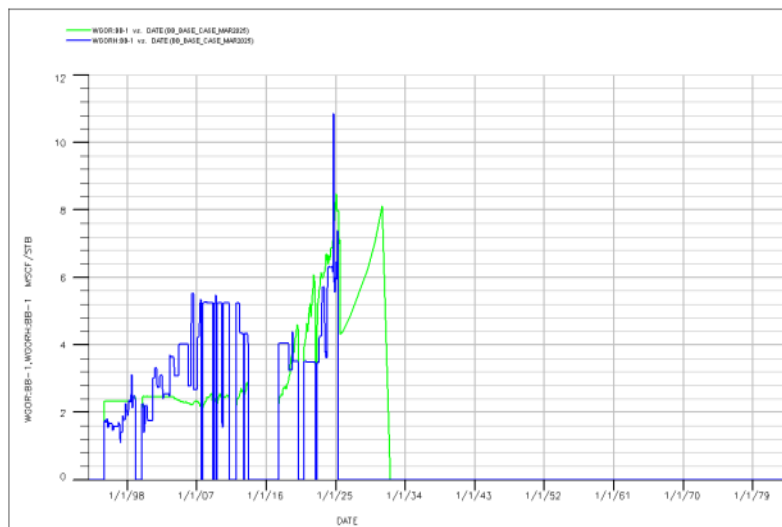


Figure (4): Well BB-1 Gas Oil Ratio History Matching and Prediction Trends.

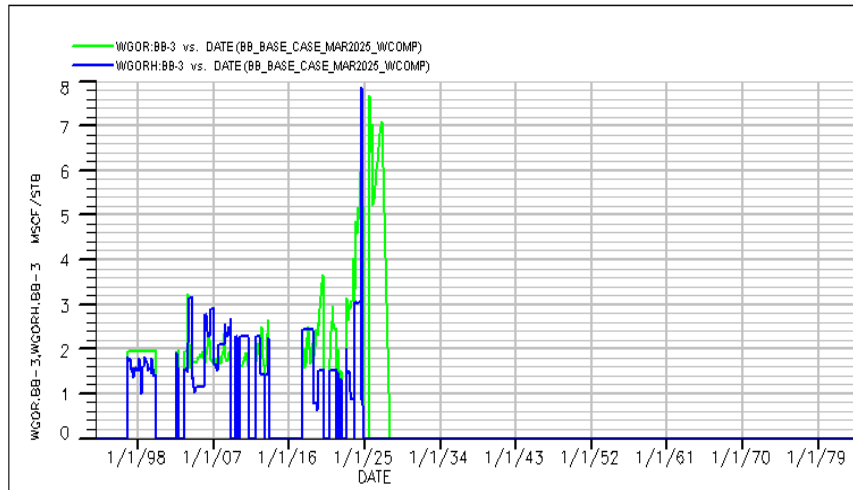


Figure (5): Well BB-3 Gas Oil Ratio History Matching and Prediction Trends.

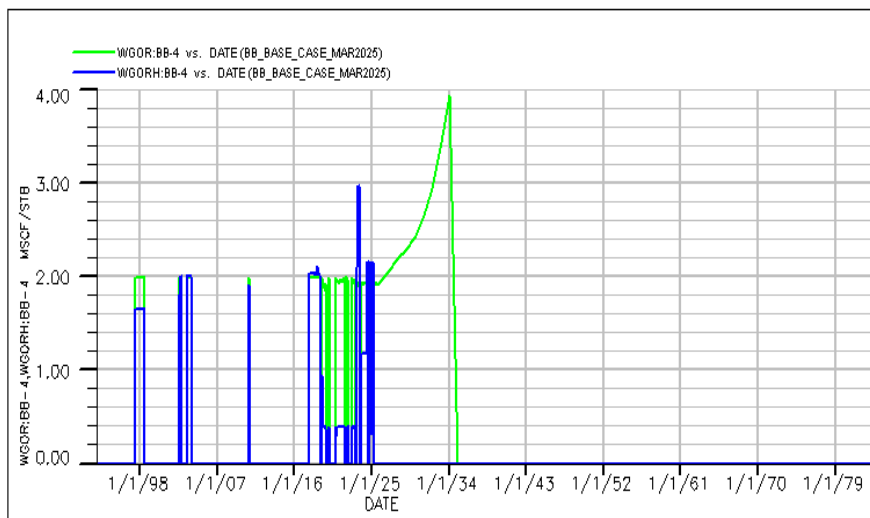


Figure (6): Well BB-4 Gas Oil Ratio History Matching and Prediction Trends.

Water Cut Prediction:

Well BB-1 produced water cut, presented in خطأ! لم يتم العثور على مصدر المرجع, was about 0.5% in March 2025. The simulated model predicted that water cut will slightly rise to reach 0.62% in 2031, which it is considered negligible. Also, خطأ! لم يتم العثور على مصدر المرجع represents Well BB-3 water cut that was approximately 3% in March 2025, and it will rise slowly to reach about 4% in January 2026. Finally, خطأ! لم يتم العثور على مصدر المرجع represents Well BB-4 water cut trends, observed and history matched, as it was 0.1% in March 2025, and it will slightly grow to be around 0.3% in 2034. In general, BB oilfield has small water cut, 4% maximum, throughout the predicted natural production period.

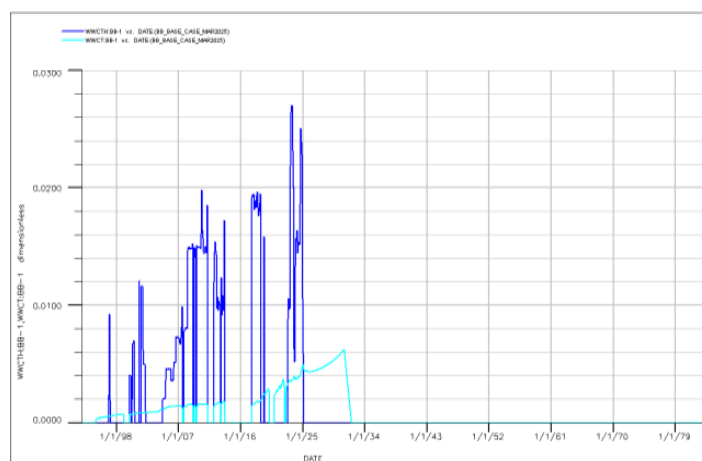


Figure (7): Well BB-1 Water Cut History Matching and Prediction Trends.

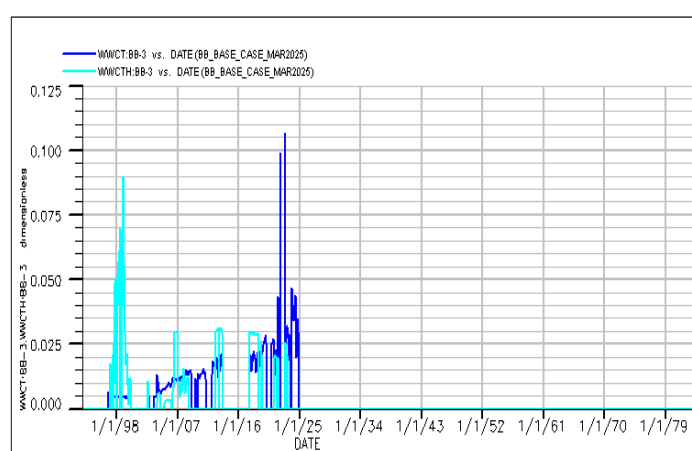


Figure (8): Well BB-3 Water Cut History Matching and Prediction Trends.

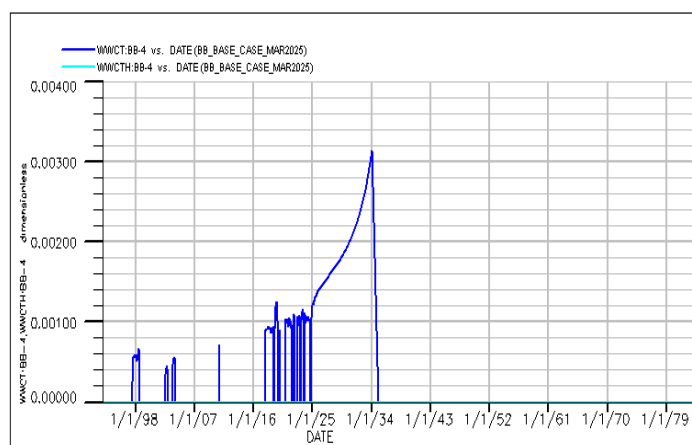


Figure (9): Well BB-4 Water Cut History Matching and Prediction Trends.

Oil Production Prediction:

The BB oil field wells production rates are predicted based on the history matched simulated-model. Firstly, the well BB-1 oil production rate, shown in **خطأ! لم يتم العثور على مصدر المرجع.**, was 390 STB/D in March 2025, and it is predicted to continue in approximately the same rate until 2030, when the production rate will sharply decrease to reach the uneconomic limit, about 100 STB/D, in 2031. Secondly, the well BB-3 production rate, **خطأ! لم يتم العثور على مصدر المرجع.**, was gradually declined to very low level, below the economic limit, around 63 STB/D in October 2024, and it was shut down. The simulation predicts that the well production rate will peak at maximum rate of 400 STB/D if the well was reopened to flow in March 2025, the start of the prediction period, for around a month, then production trend exhibited steep fall to reach 200 STB/D in July 2025. Afterwards, this well production rate will

continue decreasing sharply to reach the economic limit in January of 2026. Noticeably, the well production spike trend is a resultant of well storage effect as the well bottom-hole pressure builds during the shutdown period, from October 2024 to March 2025. Finally, the well BB-4 observed production rate, presented in. خطأ! لم يتم العثور على مصدر المرجع. is 143 STB/D in March 2025. It is expected that the well will continue producing at constant rate, 143 bbl/d till January 2034, when it will drop steeply to reach the economic limit. All in all, the BB field wells rates are expected to be low, range from 143-400 STB/D. The production fast drop is attributed to the reservoir drive signature, solution gas drive, and therefore artificial lift should be considered in well development strategy in addition to GOR control measures.

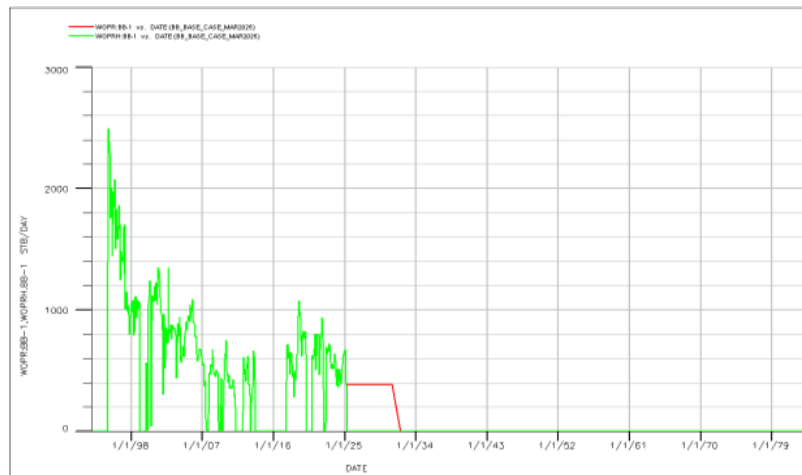


Figure (10): Well BB-1 Oil Production History Matching and Prediction Trends.

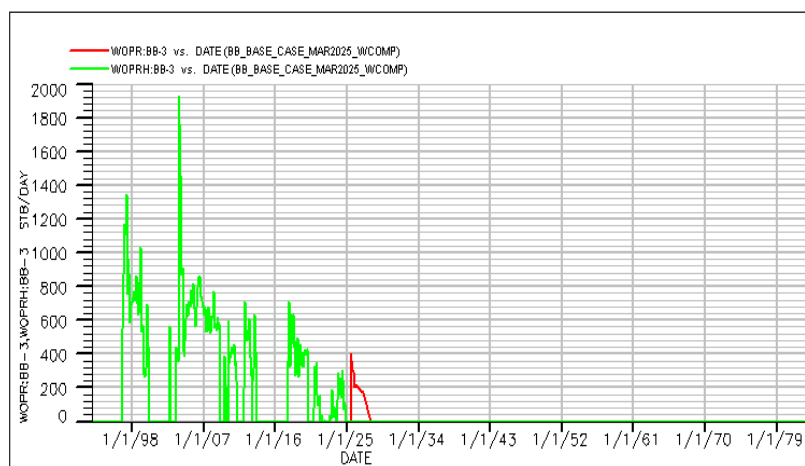


Figure 11: Well BB-3 Oil Production History matching and Prediction Trends.

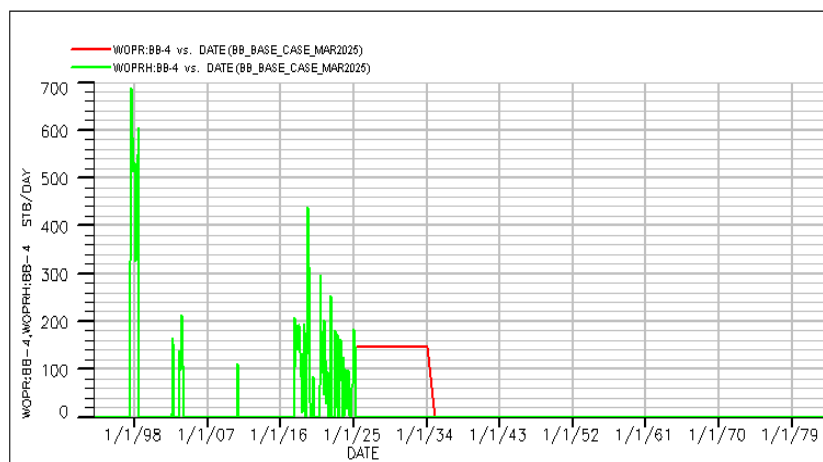


Figure (12): Well BB-4 Oil Production History Matching and Prediction Trends.

BB oilfield Production Constraints and Development implications:

Based on the analysis, the BB Field wells cumulative oil natural production prediction are; BB-1 (8.12 MMSTB), well BB-3 (3.34 MMSTB), BB-4 (1.02 MMSTB). Moreover, the BB field cumulative natural oil production is expected to be around 12.48 MMSTB in 2034. More importantly, the field will produce at a noticeably decreased oil production rate associated with very high GOR, and small water cut. In addition, the BB field wells bottom-hole pressure is expected drop slightly to be 3800-4200 psi, roughly 2370 psi below the bubble-point pressure (P_b), 6170 psi, at the predicted end of the natural depletion period. The overall reservoir performance show increasingly high depletion driven GOR. This is due heavy gas liberation, Oil shrinkage as gas liberate, gas saturation passes critical gas saturation (S_{gc}) and free gas flows. Moreover, gas mobility rises at low pressure as its viscosity decrease leading to increase in GOR and oil mobility drops. Oil shrinkage as gas liberated. However, the field water cut is small and it is most likely classified as connate water. Based on the analysis, the some development implications are drawn; reducing drawdown by holding bottom hole pressure and setting a GOR limit to slow gas liberation near the wells, introducing pressure maintenance such as; re-injecting produced gas at the crest, drilling infill horizontal wells, use autonomous inflow control devices to choke gas, shutting off high-GOR intervals with plugs or cement squeezes, Use gas-tolerant artificial lift such as gas separators on ESP, and finally use proper surface gas handling to not capping oil rate.

Conclusion:

To sum up, History matched simulated-model supports precise future reservoir performance prediction to inform development strategies. The overall Field cumulative natural oil production is predicted to be about 12.48 MMSTB in 2034. The field three vertical oil wells, BB-1, BB-2, BB-3, natural depletion rates are expected to be low, range 143-400 STB/D. The predicted natural depletion decrease is attributed to the reservoir drive mechanism, solution gas drive. The field is expected to produce at a noticeably high depletion-driven GOR (4-8.1 MSCF/STB), resulted from heavy gas liberation as pressure drops and consequently gas saturation exceeded the critical gas saturation (S_{gc}), small water cut (less than 4%), and relatively moderate bottomhole pressures (3800-4200 psi). finally, the drawn development options includes; reduce drawdown by holding bottom hole pressure and set a GOR limit to slow gas liberation near the wells, use autonomous inflow control devices to choke gas, perforate low in the oil column and shut off high-GOR intervals with plugs or cement squeezes, introduce gas-tolerant artificial lift such as gas separators on ESP, insure proper surface gas handling to not capping oil rate, initiate pressure maintenance such as reinjecting produced gas at the crest, drill infill horizontal wells.

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