Due to the improved time-depth calibration of the subsurface, 2 contingent resource (CR) gas reservoirs were identified in the Adi field, which addresses the business drive to provide incremental volumes to the gas plant and enhance NING supply security.

In conclusion, the integration and understanding of geological and geophysical controls is critical for time-depth conversion, multi-discipline data integration and robust subsurface evaluation. Applying the right scaled methodology and understanding the impact of the chosen approach is critical to achieving business value.

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Stochastic vs Seismic-Driven Reservoir Modeling in a Mature Deepwater Field: Insights from Production Field Studies of a Deepwater Niger Delta Oil Field

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ABSTRACT

This work was carried out in a mature field in deep-water Nigeria with over 16 years of production from 11 oil producers and 8 water injectors. Declining field production and a depleting opportunity inventory necessitated a comprehensive field study. The production field study involved the integration of all available static and dynamic data including reprocessed high quality broadband seismic data, two 4D monitor surveys together with well logs, flow rates, MDTs and bottomhole pressures from more than 20 wells to characterize the field. Results from the field study will form the basis for production optimization, reservoir management, and infill drilling. This will be done by leveraging the integrated Reservoir Models for drill-well and workover opportunity generation/maturation, water injection optimization and other valued-added field depletion optimization strategies. A dual approach was adopted for the reservoir modeling: one approach involved detailed conventional methods using Object-based Modeling (OBM) and qualitative seismic-conditioning; the other used Inversion-based modeling (IBRC) with stronger seismic influence. Both reservoir models were completed and taken through model initialization and history-matching. The distinct history-matched model scenarios will be instrumental in generating production forecasts for field management and for infill and workover opportunity generation/maturation. The dual approach enabled comparison of the pros and cons of both modeling methods especially with regards to matching existing data, reservoir characterization cycle time and achievement of field study objectives. This paper outlines key learnings from the application of these two methods in a mature field and considerations for their application in mature and green fields.

Keywords: Stochastic, 4D Monitor, Object-Based Modeling, Inverson-Based Modeling, History-Matching Models

INTRODUCTION

GEOLOGIC FRAMEWORK

This study was carried out on deepwater slope confined channel complexes located in the Niger Delta Basin offshore Africa (Fig. 1) at about 1200m water depth. It is a brown field asset with over 16 years of production from 11 oil producers and 8 water injectors. The field is set-up by large regional detachment fold at the transition between an extensional – contractional system (Fig. 2).

The Niger Delta basin is primarily a linked extensional - compressional tectonic system with distinct structural provinces (Corredor *et al.* 2005). Updip, extension at the shelf margin is composed of landward dipping growth faults and basinward dipping normal faults. Downdip and along slope, is dominantly compressional, composed of large mobile shale cored folds, followed by smaller scale buckle folds, and finally ends in belts of low relief toe-thrusts. This system is driven by gravitational collapse of a prograding deltaic sediment wedge that prograded along with the sediment wedge (Corredor et al., 2005; Obi et al., 2018). The geologic column in the Tertiary Niger Delta is subdivided into three lithostratigraphic formations namely the marine Akata Formation, paralic Agbada and continental Benin Formation (Avbovbo, 1978). Deepwater reservoirs in this area are primarily in the Agbada formation.

In terms of stratigraphic framework, the field consist of deepwater confined to weakly confined channels divided into four complexes: 1CC, 2CC, 3CC & 4CC (Fig. 3). The

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fairway featured periodic changes in depocenter location as the main control for repeated switch in position of the individual channel complexes for the first set of erosionally confined complexes (1CC – 4CC) with lateral migration from north to south (Fig. 3). Each time there is a new surge of sediment supply, the new deposits take advantage of adjacent available depositional low (considering the depositional inner bank and erosive outer bank of the preceding cycle), eroding parts of the pre-existing underlying channel complex and placing its sediments in the new location (Oomkens 1967, 1974). The process continues and is repeated when the current depocenter builds elevation there by creating an adjacent depositional low for the new cycle of deposits to occupy. According to Obi and Mode (2011), gradual reduction in the overall depositional energy with increased accommodation results in smaller, higher sinuosity, levee confined complexes such as CC3 – CC4 with more preserved internal and external margin facies (Fig. 3).

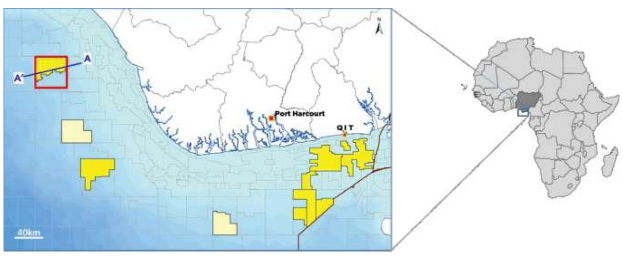

Figure 1: Acreages in the Niger Delta Basin showing study location in Red box.

Objectives and Characterization Workflows

The key driver for this work was to improve reservoir management and production optimization to deplete the remaining significant reserves in the deepwater field. This was accomplished by the integration of a suite of static and dynamic data for improved reservoir characterization to support future workover and infill drilling opportunities. A dual approach of using the conventional Object-Based Modeling (OBM) and Inversion-Based Reservoir Characterization (IBRC) with stronger seismic influence (Fig. 4) was adopted. The OBM and seismic (IBRC) modeling reservoir characterization approach allowed the

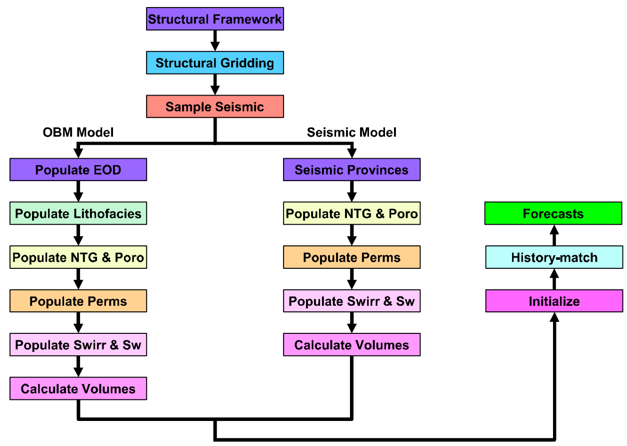

Figure 4: Workflow showing the OBM and seismic model approach to reservoir characterization including the dynamic model integration.

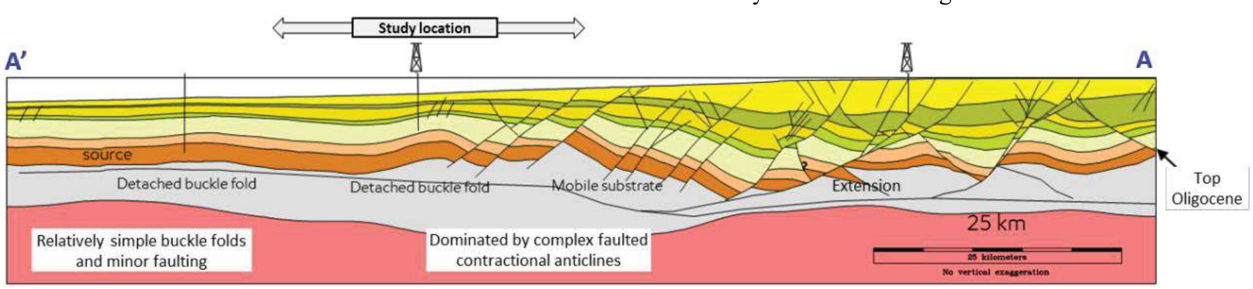

Figure 2: Sub-regional transect showing structural provinces (coupled extensional – compressional system). Study location sits on a detachment fold in central portion of asset (Courtesy ExxonMobil Deepwater Collaborative 1999).

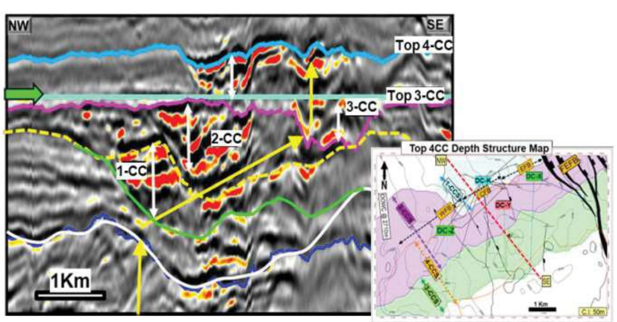

Figure 3: Stratigraphic framework and depositional sequence of study area.

team to maximize the availability of good broadband seismic data with excellent derivate volumes. This approach also allowed for independent subsurface realizations of plausible reservoir architecture that were progressed through history match and forecasts to constrain the range of uncertainty around assessment of the remaining recoverable volumes.

Object-Based Modeling (OBM) Workflow

The conventional modeling workflow involved the use of Environment of Deposition (EOD) maps to generate EOD property that captures lateral and vertical facies boundaries. The EOD OBM approach was used to introduce channel objects within inter-channel background. This approach helped to capture finer scale heterogeneity and facies distribution within each sub-EOD body (Fig. 5). This workflow essentially allows for robust integration of observed seismic extraction, well logs and finer-scale objects which are important to flow. Five lithofacies assemblages (LA) were interpreted from well core and well data and modeled using depth trends generated from the OBM within channel objects, with variograms oriented along EOD directions. Modeled lithofacies fractions were checked against target lithofacies from the wells for consistency.

The workflow Net-to-Gross (NTG) modeling was based on the Volume of Shale (Vsh) distribution for each Las. The calculated total porosity from the wells was populated within the model and constrained based on the LA distribution. The NTG and porosity models were further conditioned by seismic inversion Vsand and porosity volumes respectively. The NTG and porosity map patterns were checked against the interpreted EOD fairway trends for consistency.

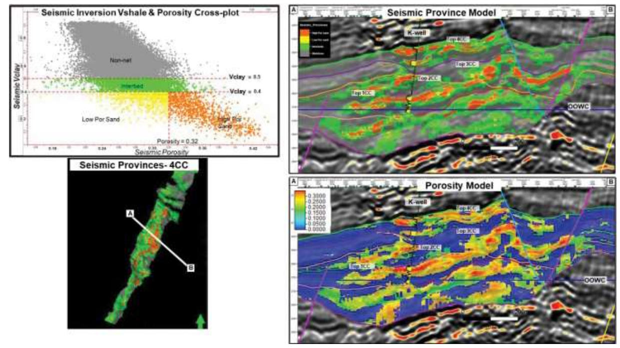

Figure 6: showing the seismic model workflow with the seismic inversion cross-plot, the corresponding seismic provinces and the porosity model cross-sections.

province and conditioned with seismic porosity derivate volume (Fig. 6).

RESULTS AND DISCUSSION

Model Comparison- Matching Static Data (NTG)

Results from both model approaches show similarities

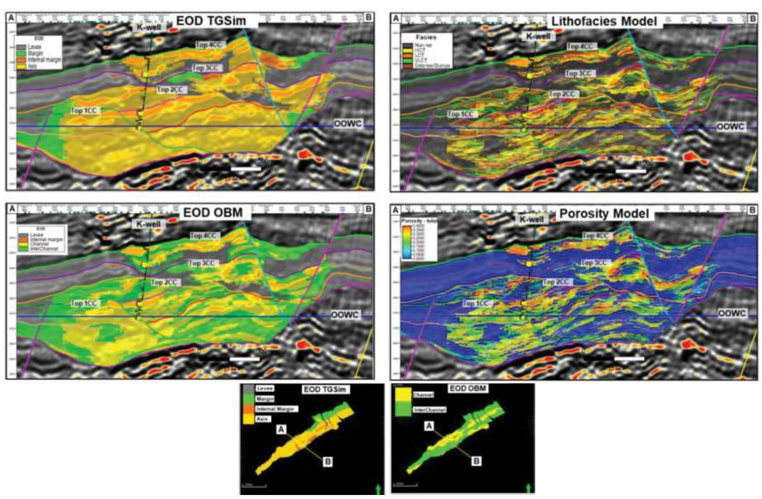

Figure 5: Showing the conventional model workflow with EOD, Lithofacies and Porosity model cross-sections

Seismic-Based Modeling Workflow

The seismic model approach was implemented with the use of cross-plot of the seismic inversion (Vclay and porosity) volumes to discriminate between varying rock facies and correlate it to reservoir quality. Areas with similar reservoir properties were classified as seismic provinces. Four seismic provinces (High Por sand, Low Por sand, Interbed and Non-net) were defined based on the set cross-plot cutoffs values (Fig. 6). Net-to-Gross was calculated from Vsh log and modeled using distribution curves generated for each seismic facies (province) and conditioned by Vsand derivative volume (collocated co-krigging). Porosity distribution curves was generated for each seismic facies which was modeled for each seismic

and differences in certain aspects with significant trade-offs in match between the conventional and seismic models with the key static data. While the seismic-based model matches the seismic data and most well data, it is limited in areas with poor correlation between seismic amplitude strength and sand development (Fig. 7, B-well). The conventional model closely matches all the well data and is generally consistent with the seismic data and EOD interpretation (Fig. 7).

Model Comparison- Matching Static Data (Porosity)

Results from the porosity modeling show that the seismic-based model matches closely with input seismic data and well data, except in areas with poor correlation between

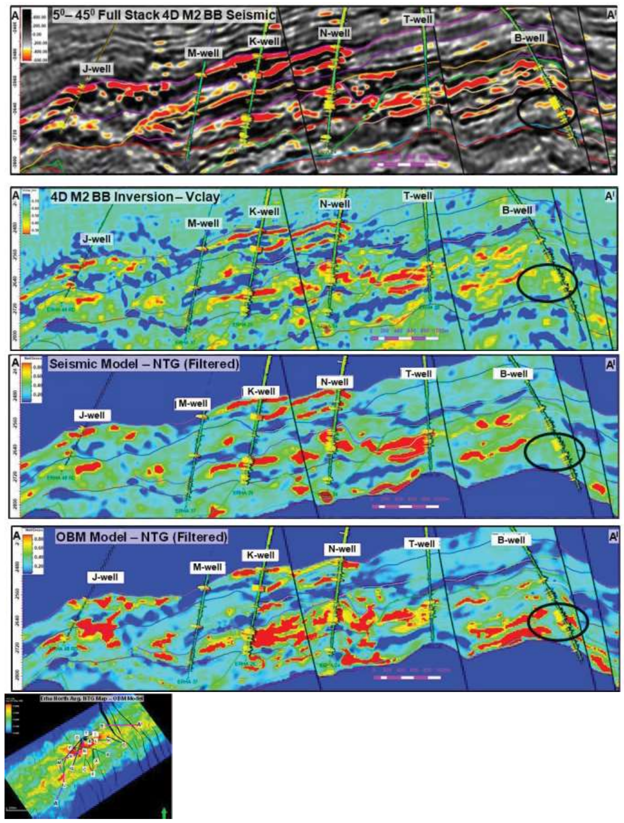

Figure 7: Comparison of NTG model results from the conventional (OBM) and seismic methods.

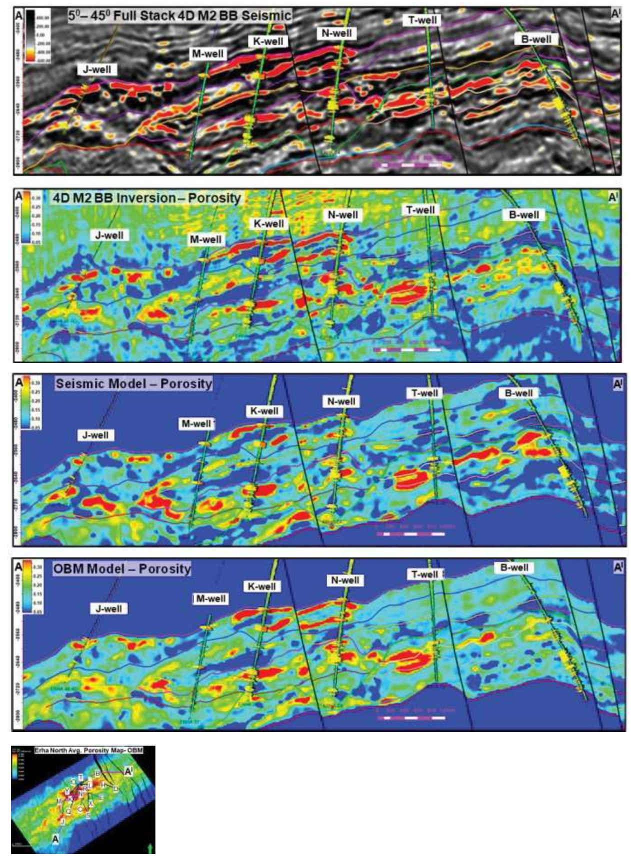

Figure 8: Comparison of porosity model results from the conventional (OBM) and seismic methods.

seismic amplitude strength and sand development (Fig. 8, B-well). The seismically conditioned conventional object-based model closely matches all the well data and is generally consistent with the seismic data and EOD interpretation. These differences in model results around areas with seismic quality issues and poor calibration of model properties at well locations is critical to achieving a good history-match.

In-Place Volumes Comparison

In-place volumes estimated from both model scenarios show comparable total volumes with about 6% difference. While both models show comparable total volumes, the distribution of volumes show markedly differences within some of the individual channel complexes (Fig. 9 & 10).

Model Scenario	Bulk volume [*10^9 m3]	Avg. NTG [Frac]	Avg. Sw [Frac]	STOIIP [GBO]
Seismic	10	0.17	0.23	1.3
OBM	10	0.19	0.18	1.4

Figure 9: Table showing the in-place total volumes from conventional (OBM) and seismic methods.

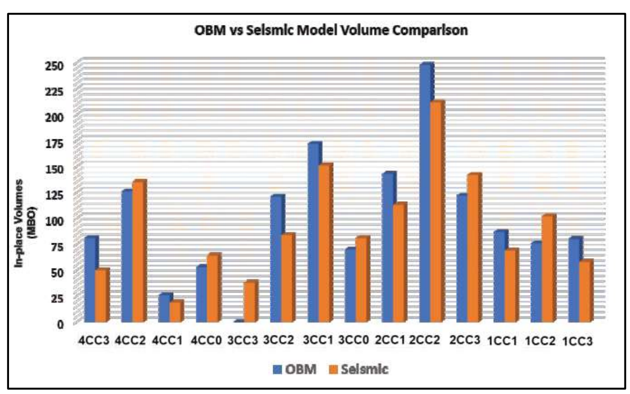

Figure 10: Comparison of distribution of in-place volumes within individual channel complexes.

Dynamic Insights

Initial OBM and seismic model results show a good match with historical data and represents a good starting point for history match. The seismic model generally showed a lower pressure and lower water production compared to historical data (Fig. 11). The gas breakthrough was observed to be late in the model compared to the lower gas production in the historical data after 2019. The result from the initial OBM showed a good starting point for history match (Fig. 12). The OBM shows lower pressure and early water breakthrough in the model compared to historical data.

Good history-match (flow rate and cumulative production) was achieved for both model scenarios after adjustments to some of the static and dynamic assumptions with lower pressures observed in the seismic based compared to the object-based model (Fig. 13 & 14). The two model approaches show differences in the changes required to achieve history match at the well level.

The B-producer seismic model history-match required direct poro-perm multiplication in the dynamic model (hand-over approach), which sometimes involve geologic compromises due to the limitations of using seismic inversion volumes as reservoir facies quality calibration (Fig. 15).

The B-producer HM in the object-based model was achieved by an integrated approach which involved modifying rock distributions (due to flexibility offered by the EOD objects) in the geologic model and applying those changes in the dynamic model such that the changes are consistent with geologic assumptions (Figure 16). The object based history match was completed much faster

Initial Model Field Result- Seismic

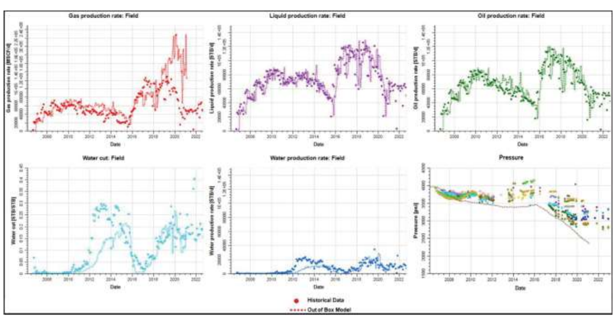

Figure 11: Initial (out of the box) seismic model field match.

Initial Model Field Result- OBM

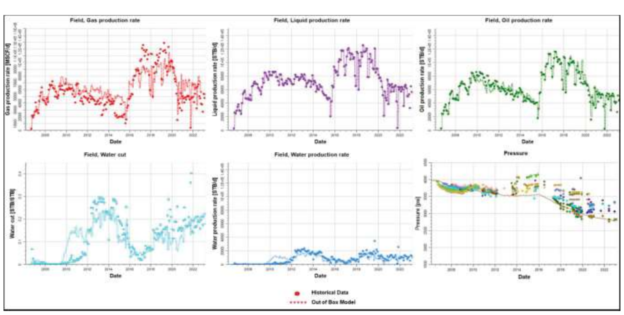

Figure 12: Initial (out of the box) object-based model field match.

Model Field Level History-Match- Seismic

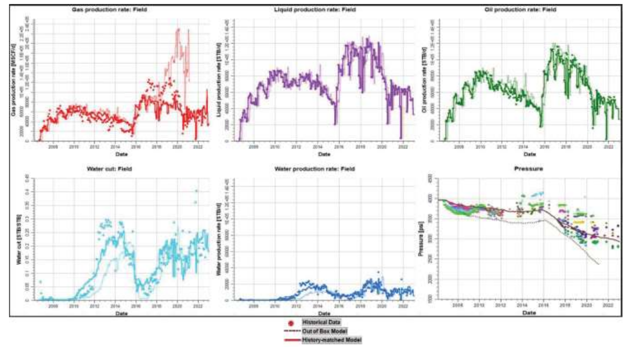

Figure 13: History matched seismic-based model field match.

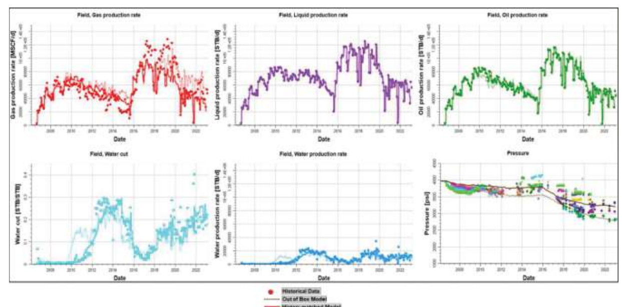

Figure 14: History matched object-based model field match.

Well Level History-Match (B-producer Example)

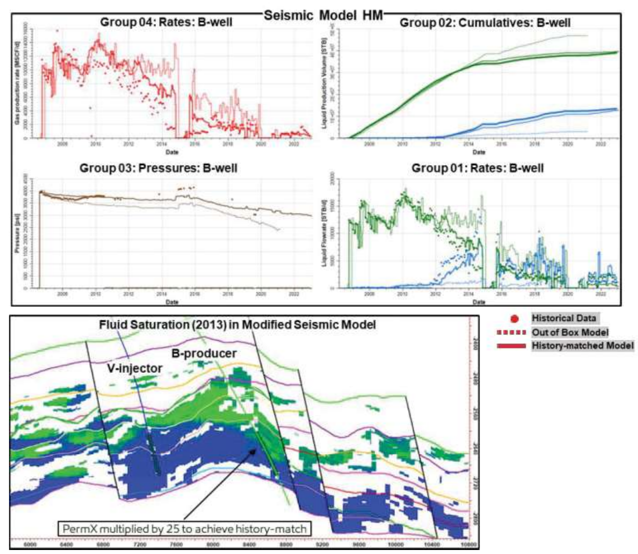

Figure 15: Well level (B-producer) history matched example in the seismic-based model.

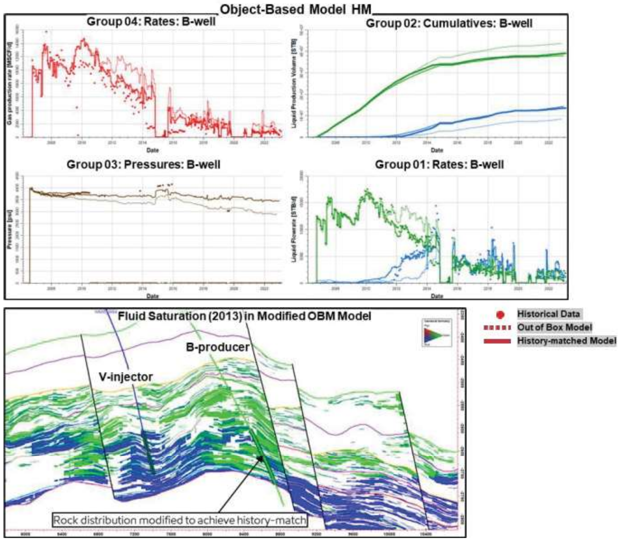

Figure 16: Well level (B-producer) history matched example in the object-based model.

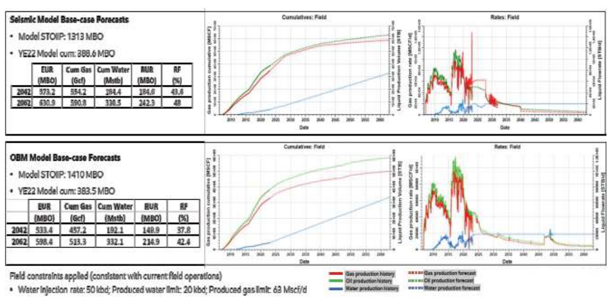

Figure 17: Production forecast results for both model scenarios.

Consideration	Seismic	OBM	Comments
Static model cycle time	green	yellow	• 2 weeks for Seismic model vs 1 month for OBM model • Additional 1 month for EOD maps, rock types etc. for OBM model
Matching seismic data	green	yellow/green	• Qualitative seismic-conditioning applied throughout conventional modeling workflow: framework, EODs, property distribution
Matching static well data	yellow/green	green	• Match of Seismic model to well data is highly dependent on quality of seismic data and inversion
Dynamic model cycle time	yellow	green	• History-match: 4 months for Seismic model vs 2 months for OBM
Matching dynamic data	yellow/green	green	• Better match to late pressures in OBM vs Seismic model
Forecasts	green	green	• Both models provide alternative scenarios which are very useful for reservoir management, production optimization, opp. gen.

Figure 18: Summary of observations from the object-based and seismic-based modeling.

(~2 months) compared to longer duration (~4 months) required to achieve similar HM in the seismic based model Base-case forecasts from both models show similar model STOIIP and YE 22 cumulative production after appropriate field constraints were applied (Fig. 17). Higher recovery factor (RF) and lower water production was observed in the seismic model compared to the object-based model (Fig. 17). Both model scenarios show significant uplift with sensitivities around infill drilling, increased injection, and increased water handling.

In general, both the model scenarios find usefulness in varying situations and should be used based on business needs (Fig. 18)

SUMMARY AND CONCLUSION

In this work, we implemented an Object-Based Modeling (OBM) algorithm which is a method of using conceptual channel objects to capture finer-scale heterogeneity and facies distribution. This approach adopted a stochastic distribution of architectural elements (such as channels) represented as distinct objects to provide additional controls on the rock facies distribution. Lithofacies interpreted from core and well log analysis were distributed within the architectural elements and petrophysical properties of net-to-gross, porosity etc. were stochastically populated within the Lithofacies.

The seismic-driven approach on the other hand was based on facies-based seismic inversion products. The seismic inversion products were analyzed and used to generate regions of similar seismic responses as seismic provinces which were used as a proxy for rock facies. Petrophysical properties were subsequently populated within these seismic provinces using the same seismic inversion products as secondary variables in a co-located co-kriging algorithm. The seismic-driven methodology is fast and relatively easy to execute and can be applied to support urgent business decisions. However, this method shows significant limitation in areas with seismic imaging challenges and in reservoirs with poor correlation of rock physics (seismic amplitude) and lithology response.

Seismic-based models are excellent tools for production forecasts especially during right concept selection and early production phase. Conventional models (conditioned to seismic) are recommended for producing fields that have more wells and longer production history because they tend to have better match at well locations and offers more flexibility for faster history match

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