From Seabed to Source: Improving Petroleum System Models in the MSGBC through MB&SS and Geophysical Calibration

Introduction

Several source rock intervals have been proven across the MSGBC offshore basins, when considering exploration boreholes, DSDP wells, seafloor cores and coastline seeps. Most of them are particularly close to the palaeo-shelf edge where bypass systems connect proximal plays with the deeper basin domain.

Methods such as satellite seep detection provide strong evidence for an active petroleum system, while basin modelling based solely on structural interpretation can offer a reasonable first-order assessment of thermal evolution. Operators with access to exploration well data, specifically temperature and fluid measurements, also benefit from critical calibration points that strengthen these models.

The real advantage of multibeam and seafloor sampling campaigns (MB&SS), however, lies in the targeted acquisition of hydrocarbon samples directly from live or palaeo seeps, often far from existing exploration wells. The resulting 3D temperature, burial-history, and maturation model is therefore calibrated using measured geochemical and heat flow data, elevating the model far beyond a hypothetical reconstruction. Because heat flow measurements at the present-day seabed, together with borehole temperature profiles, must align with model predictions, the integrated MB&SS and seismic approach yields a near–real-time representation of subsurface maturity conditions. These models are therefore driven by measured geophysical data rather than purely conceptual rift-history assumptions, as this study will show case.

Furthermore, geochemical characteristics of oil and gas families, biomarker characteristics, and maturation ages provide an additional suite of constraints. These data must reconcile with the stratigraphic framework, burial history, and predicted source rock maturity through time. Minimum migration timing from reservoir to seabed also imposes strict temporal limits. Collectively, these constraints narrow the range of viable charge scenarios and allow elimination of options that do not satisfy the observations from the full geophysical and geochemical dataset. As a result, predictions of which source rocks (and their modelled timing of expulsion) may have contributed to specific discoveries become non-unique but tightly bounded, even in the absence of exploration wells.

Achieving this level of confidence, however, depends on acquiring a sufficiently large number of high-quality geochemical samples to enable robust biomarker and kerogen analyses. These measurements are factual and non-negotiable; any mismatch with the model forces a return to the interpretation workflow.

Method and Results

The modern MB&SS survey campaigns are having an increased success rate compared to legacy campaigns. Hydrocarbon samples recovered in seafloor cores offshore Nigeria deepwater, for example, have been collected during a vintage campaign before multibeam was used and another round during a 2020 MB&SS campaign with multibeam and geophysical target ranking (TDI) before coring. When comparing diagrams of gas chromatography

Unresolved Complex Mixture (UCM) values versus Total Scanned Fluorescents (TSF) of both of those campaigns (Geomark, 2020), focussing on samples viable for biomarker analysis, the comparison shows that the new technology, which was also deployed for the MSGBC MB&SS campaign, clearly has a higher ratio of live hydrocarbon samples in the seafloor cores, recognised by higher TSF and UCM values and more sample clustering at this higher value threshold. In the past, high-resolution bathymetry helped ranking possible core target locations mostly by structural considerations, such as escarpments and pockmarks, and was possibly guided by some subsurface seismic mapping. The modern survey combines high-resolution bathymetry with the backscatter measurements that provide 3 additional parameters for target location ranking in real-time during the campaign: 1) gas clouds in form of disruptions in the recorded reflection; 2) ground hardness at locations where bi-halves feed from organic material, and; 3) total fluorescence levels compared to the seabed muds.

In the wake of this MB&SS campaign over (M)SGBC, a grid-based 3-D basin and petroleum system modelling (BPSM) has been built utilising regional depth surfaces compiled by TGS, and the thermal-burial history constrained using 1-D and 2-D basin modelling (TechMod, 2025; Figure 1), during which a thermo-tectono-stratigraphic basin reconstruction modelling technique was applied (Rüpke, 2008). Based on the modelling results and sparse availability of data on source rock geochemistry along the margin, we included unproven but anticipated source rocks from the older rift sections which will give indications of maturation history relative to the proven younger source rocks.

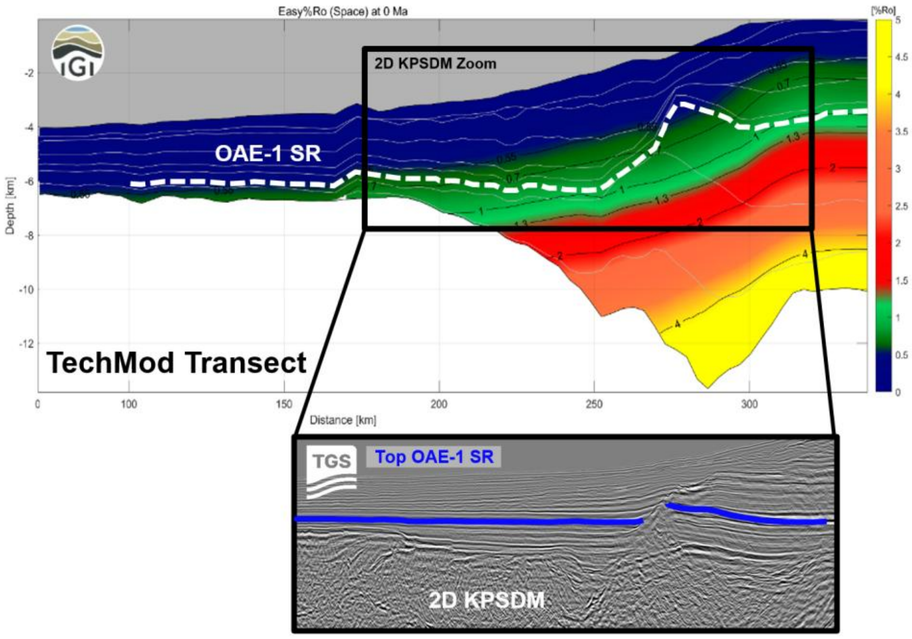

Figure 1 *Regional transect 2D TechMod model indication the same source rock horizon as shown in the transformation ratio map in Figure 2c. The petroleum system model provides vitrinite reflectance predictions over time of burial history as shown here, as well as temperatures and basal heatflow at the transect location. The inset seismic depth section indicates regional data quality that was available for the regional interpretation input to the models.*

Calibrated to temperature, surface heat flow and vitrinite reflectance data, where available from exploration wells and publications, the updated calibration now includes surface heat flow from the 2020 regional measured grid during the MB&SS campaign. The 3D thermal and burial history reconstruction results demonstrate the likely widespread maturity of early to mid-

Cretaceous source rocks across the platform, but also in the deep basin oceanward of the shelf break. This suggests oil and gas charge is not limited to just the platform, but deepwater prospects are also likely to contain oil from mature kitchens.

For example, Figure 2 shows reported in-place volumes of reported discoveries, compared to the predicted volumes from the model, based on one source rock, considering only the recent 30Myrs of expulsion.

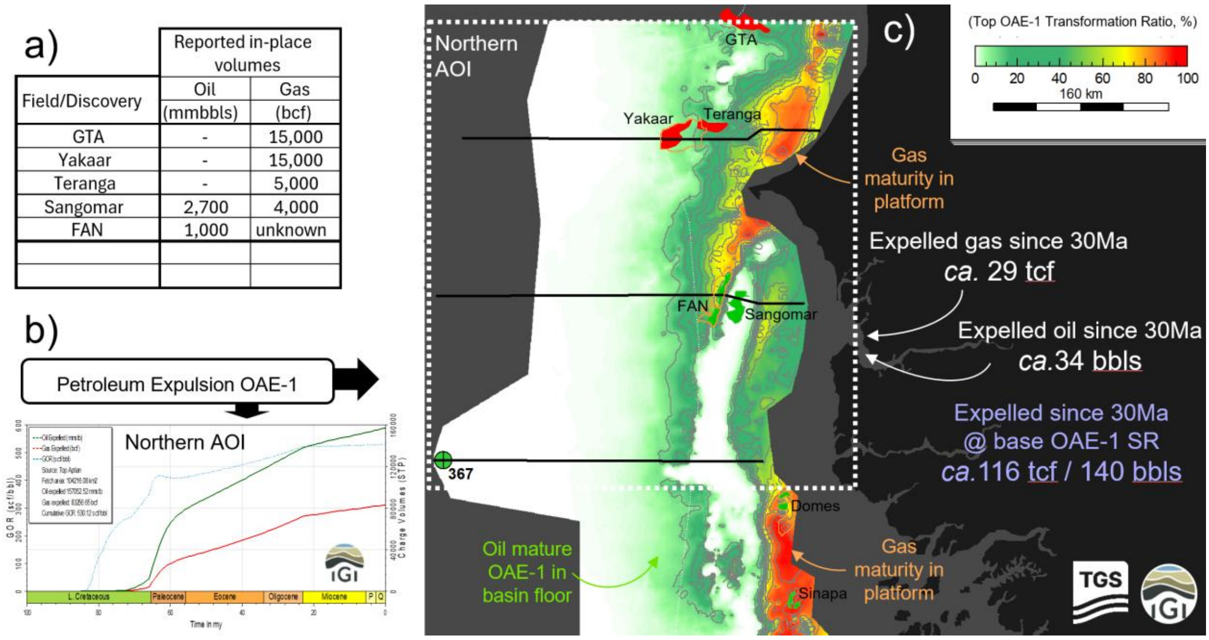

Figure 2 *Comparison of reported in-place volumes of discoveries in the northern AOI of the study area (a) with estimates from predicted petroleum expulsion for the same AOI, limited to volumes expelled since 30Ma (b). The predicted volumes are based on one oceanic anoxic event (OAE-1) marine shale, one of several source rocks (SR) mapped regionally across the study area, assuming a net 100m SR thickness.*

Discussion

Seabed sampling of sediments containing mobile hydrocarbons can act as a Direct Hydrocarbon Indicator (DHI), proving at least one active source rock. Moreover, in order to seep to the surface this likely indicates a prolific source capable of saturating the carrier bed and filling intermediate traps, strongly indicating charge at depth along the migration path.

The potential oil micro-seep locations are distributed along the entire MSGBC margin, with clusters found in distinct "sub-areas" from north to south, often where regional top seals are thin or absent, providing a window to the subsurface which is usually sealed. Furthermore, oil shows in multiple boreholes along the margin, not classed as commercial discovery still provide crucial indication of source rock presence and maturity, which the objective is to map, and therefore these are included in the 3D calibration of the margin.

For example, Figure 3 shows a core location tied with seismic 3D fault mapping, in the vicinity of recently drilled targets, which yielded the technical success of oil staining.

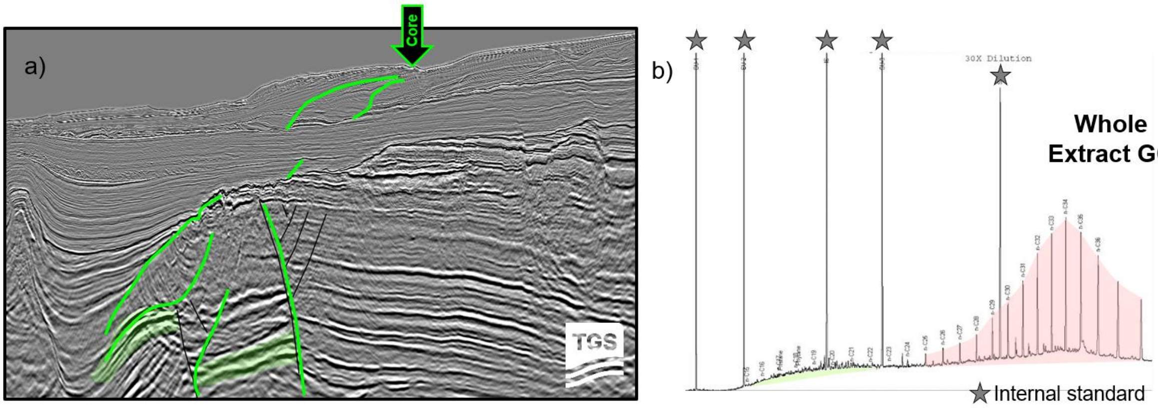

Figure 3 *(a) Seafloor core sample location on seismic depth section over a prospect in the vicinity of a recent 2025 exploration well. The interpretation showcases possible migration routes from reservoir to seafloor where the live hydrocarbon sample has been recovered. (b) Whole extract GC of a seafloor coring sample recovered with the 2020 campaign, showing migrated hydrocarbons (red shaded area), which has been analysed and integrated in this study.*

Conclusions

Our study presents selected examples from the MSGBC basin, illustrating predicted source maturation scenarios from the 3D BPSM in the context of recent production and undrilled prospects from 3D seismic mapping within what remains a frontier region.

Seabed samples confirming the presence of source rocks that have never been penetrated by drilling, calibrated with 3D predictive models constrained by temperature and heat flow, yield a data-driven indicator map for the likely distribution and timing of effective source rock maturation. When integrated with seismic stratigraphy and facies mapping, this workflow enables a reliable reconstruction of the kitchen areas and their charge potential.

Acknowledgements

We thank our partners for the data available to this study, TGS, GeoPartners, Petrosen, PC Gambia, Agence de Gestion et de Cooperation entre Le Sénégal et la Guinée Bissau, Republic of Guinea and TDI Brooks.

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