Integrated Petroleum System Modeling to Evaluate Frontier Basins and Resource Plays*

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Search and Discovery Article #41438 (2014)
Posted September 22, 2014

*Adapted from extended abstract prepared in conjunction with oral presentation given at AAPG Asia Pacific Region AAPG/MGS Conference, Yangon, Myanmar, August 14-15, 2014, AAPG©2014

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Abstract

Integrated petroleum system modeling provides a conceptual framework to evaluate both conventional and unconventional resources by combining all the available data with geological interpretation of basin evolution to evaluate exploration potential. Petroleum system modeling has the potential to guide future exploration in Myanmar by leveraging information on known petroleum systems to different parts of the basins. Three case studies will illustrate how this has been accomplished in three analogous situations elsewhere in the world.

An integrated evaluation of the exploration potential of the offshore Potiguar and Ceará basins of Brazil was undertaken leveraging calibration of petroleum systems in the onshore and shallow shelf to make predictions on petroleum occurrence in the deep water portions of these basins. Seismic data that covers the deeper parts of the basins has been tied to wells in the shallower parts of the basins. Well data enabled depth conversion and interpretation of the seismic data. Geochemical data and the geological model were combined to build a 3D petroleum systems model of the area that predicts the location of yet-to-be discovered hydrocarbon accumulations. This model was used to select areas for controlled source electromagnetic (CSEM) surveys. 3D resistivity anomalies inverted from the CSEM surveys, and accumulations predicted by petroleum systems modeling, were imported into the 3D geological model to allow an integrated evaluation of the prospectivity of the basins.

In compressive settings, such as the inboard area of the offshore Rakhine Basin and onshore Central Myanmar Basin, structural restoration, rather than simple decompaction, is required to model the evolution of the basin structure. An example from the Monagas fold and thrust belt of Venezuela shows how combined structural restoration and petroleum system modeling can be used to evaluate prospectivity in strongly deformed structural settings.

Recent interest in exploration for shale oil and gas in onshore Myanmar requires evaluation of source rocks as potential unconventional reservoirs. An example from onshore Alaska shows how petroleum system modeling of conventional accumulations may be used to calibrate models that are useful in assessing unconventional resources hosted in source rocks. This example also serves to illustrate how risk and resource assessment tools that are widely used in evaluation of conventional plays may also be used to assess economically recoverable resources in unconventional plays.

Introduction

Exploration in frontier basins relies heavily on geological interpretation but also leveraging what information is available. This presentation will illustrate how petroleum system modeling can serve as a framework to integrate existing geological information with geological interpretations to make forward predictions on the prospectivity of basins. In each case we will see how information from one part of the petroleum system may be used to calibrate exploration models of the unexplored parts of the basin.

In the Brazilian example we will show how seismic and CSEM data were combined with information from the onshore part of the basin to make predictions on the unexplored deep water part of the basin. In the Venezuelan example we will show how geomechanically constrained structural restoration has been coupled with petroleum system modeling to better understand exploration risk in a complex compressional setting. In the Alaskan example we will see how a petroleum system model, calibrated for conventional oil and gas accumulations, has been used to evaluate shale oil and gas potential. In shale resource plays exploration risk is not only related to the chance of finding hydrocarbons but also to the feasibility of economically exploiting those hydrocarbons. We show how the geological elements of subsurface risk may be combined with engineering data from an analog formation to evaluate the chance of finding economically recoverable hydrocarbons in mature shales.

Potiguar and Ceará Basins, Brazil

As exploration in Myanmar moves into deep water there is an opportunity to leverage what is known about the onshore and shallow offshore portions of the basins to constrain models of petroleum systems in the deep water. A similar situation occurred in 2009 when multipurpose 3D geological models were built to enable an integrated evaluation of the exploration potential of the offshore portions of the Potiguar and Ceará basins of Brazil ahead of the Brazilian 11th licensing round. Prestack depth-migrated 2D seismic data that covered the deeper parts of the basins were tied to released well data in the shallower part of the basins. The well data enabled depth conversion of the seismic data and interpretation of eight horizons. Geochemical data and the geological model were combined to build a 3D basin and petroleum systems model of the area that predicted the amount and location of yet-to-be discovered hydrocarbon accumulations. The 3D geological model was used to select five areas for controlled source electromagnetic (CSEM) 3D surveys. The model was used to design the CSEM acquisition parameters tuned to optimize acquisition and maximize the probability of illuminating targets. Three-dimensional resistivity anomalies inverted from the CSEM surveys, as well as accumulations predicted by petroleum systems modeling, were imported into the 3D geological model to allow an integrated evaluation of the prospectivity of the basins.

In 1999, 14,000 km of 2D multi-client seismic data was acquired from the shallow nearshore to deeper-water portions of the Potiguar and Ceará basins off the northern coast of Brazil (Figure 1). During 2008, these data were reprocessed using pre-stack depth migration with improved noise suppression and removal of multiples (Lovatini et al., 2010). Seven wells from the shallow shelf were tied to the seismic to enable depth conversion and interpretation of eight key horizons to build a 3D geological model of both basins. This geological model of the offshore portions of the basins was combined with geochemical data and heat flux data to build a 3D petroleum systems model (Bender et al., 2010). The depth converted horizons were exported to the petroleum systems modeling application. Interpolation between the mapped horizons was used to generate a 28-layer model. Interpretation of the sparse well log data, together with published geological studies, enabled assignment of appropriate rock properties to the basin-fill, even in the deep water parts of the basin where no exploration wells had been drilled at that time (Figure 2).

Basin and petroleum system modeling requires reconstruction of the geological history of the basin to evaluate the maturation, migration, entrapment and preservation of hydrocarbons through geological time. In this extensional basin, simple burial was modeled following compaction trends. Multiple source rocks occur in both basins, with the main source rocks occurring in the Early Cretaceous rift-filling sequences. The petroleum systems modeling indicated over 1,700 billion barrels of oil have been generated from the multiple source rocks present in these basins. Although, the Potiguar and Ceará basins contain effective seals, they lack the thick salt deposits that characterize the Atlantic-margin basins further to the south (Bryant et al., 2012), and so trapping efficiency is much lower than in these southern basins. Our models suggested that less than 40 billion barrels remains in known and yet-to-be discovered accumulations (Bryant et al., 2010).

Multiple model runs were made to assess ranges of uncertainty in the resource volumes generated (Bender et al., 2010). Each run of the model resulted in generation of a number of modeled accumulations that evolve through geological time (Figure 3). Some of these accumulations corresponded to known oil fields that are producing in the shallower parts of the basins. The close correspondence between the predicted API gravity of the oils in these forward modeled accumulations to oil gravity measured in the produced oils enhanced our confidence in the model predictions.

By examination of the seismic data, and consideration of surface oil slicks interpreted from satellite imagery, five areas were selected for CSEM surveys that might detect resistivity anomalies in the basin-fills. We built a resistivity model of each of the major sequences between the mapped horizons in the basin. By assigning a single laterally homogenous resistivity for each of these intervals, we were able to evaluate the detectability of resistive bodies embedded in this stratigraphy and also to tune acquisition parameters to obtain optimal illumination whilst minimizing acquisition costs (Lovatini et al., 2010). The five surveys were collected in June 2009. Model-based inversions were displayed in the reference Earth model (Figure 4).

The subsurface resistivity anomalies detected by the CSEM in the basin-fill could be hydrocarbon accumulations or igneous rocks. To help distinguish between these alternatives, the results from resistivity inversion and petroleum systems modeling were brought into the reference earth model (Figure 5). The forward modeled hydrocarbon accumulation (green) is collocated with a resistivity anomaly (yellow) detected by inversion of a CSEM survey at a point where three surface oil slicks (black dots) had been interpreted from satellite data. In August, 2012 Petrobras and BP announced a significant oil discovery in the Paracuru Formation by the Pecem well, proving the model predictions in the BM-CE-2 concession in the Ceará Basin.

Monagas Fold and Thrust Belt, Venezuela

In the foregoing case study simple vertical translation of points through geological time was a sufficiently good approximation to model the evolution of basin geometry through geological time. Large parts of Myanmar have been affected by compressional tectonics where structural restoration is required in order to adequately model the evolution of the petroleum systems. An example from the Monagas fold and thrust belt serves to illustrate how this may be achieved.

The area considered is located south of Maturin in Venezuela (Figure 6). We have used an assumption of linear elasticity to geomechanically constrain structural restoration through geological time (Figure 7) (Maerten and Maerten, 2006; Neumaier et al., 2014). At each successive time step we are able to incorporate the restored geometries into the petroleum system simulation to evaluate maturation migration and accumulation of hydrocarbons (Figure 8).

North Slope of Alaska

As Myanmar begins to examine the potential for onshore source rocks to be exploited as unconventional reservoirs of shale oil and gas, there is an opportunity to use calibration of the conventional elements of the petroleum system to make predictions on the reservoir potential of the source rocks themselves. An example from Alaska serves to illustrate a methodology to evaluate both resource and recoverable resource potential of shales.

Together with the USGS we have constructed a petroleum system model of the North Slope of Alaska (Schenk et al., 2012). The model covers approximately 275,000 km^2 and incorporates interpretation of over 400 wells and seismic data, also taking account of the complex tectonic history of the North Slope including varying rates of subsidence, uplift, and erosion through geological time (Schenk et al., 2012) (Figure 9a). The model has been calibrated for known hydrocarbons that have migrated to conventional traps. However, the model can also be used to predict the potential of source rocks to be viable shale resource plays. The petroleum system model not only predicts the API gravity of the hydrocarbons in conventional accumulations but also that of the hydrocarbons retained in the source rocks (Figure 9b).

Petroleum system modeling can be used to make predictions of the type, quantity and pressure of hydrocarbons remaining in the shale as well as the amount of organic porosity created by the maturation process. While this approach captures the spatial variation of many parameters to define the distribution of reservoir quality and volumes in place, it does not provide a means to assess the economic viability of each area. In reality, decisions have to be made to acquire one license block versus another or to select one location for a pilot well to assess the viability of the play over an alternative location. To do this it is necessary to capture the spatial variations of the play and combine them with engineering data in order to make informed investment decisions.

Unlike conventional accumulations, unconventional resource play assets cannot be counted and analyzed as discrete entities that are delineated by down-dip water contacts. Rather, these large continuous volumes of rock are both the source and reservoir. In order to evaluate the economic viability of different areas of the shale play it is necessary to subdivide the play into assessment units. These assessment units are generated by stacking common risk segment (CRS) maps and common volume segments (CVS) that delineate parts of the play with similar geological characteristics, in-place fluid properties, and similar drilling and completion costs (Bryant, Stabell, and Neumaier, 2013).

At the end of the process we have the full set of assessment inputs for each assessment unit (Figure 10). These inputs capture the geological variation in the various elements of the resource play, both from the output of petroleum system modeling and the mapping of other relevant elements of play risk. They are then used by the stochastic simulation engine to produce estimates of success case volumes and chance of success for each ASU.

Risk for success case volumes are then input to a full-cycle economic valuation that generates stochastic estimates of production over time and net present value (NPV). The valuation is based on a model of the activities involved in exploring and exploiting each assessment unit.

The simulation produces estimates of recoverable reserves and production profiles. As shown in Figure 11, reported success case profiles contain both mean estimates and stochastic estimates for each year. Browsing of individual trials can be used to identify representative profiles for P90- P50-P10 success case NPV outcomes.

Conclusions

As Myanmar seeks to explore in the deeper water of known petroliferous basins and to evaluate resource potential of shales, there is an opportunity to use methodologies that have proven successful in similar situations elsewhere. We have shown, by means of three case studies, how petroleum system models may be used to integrate data and interpretations developed in one part of a basin in order to constrain new evaluation of plays in different parts of the basin.

In the Brazilian example we showed how knowledge of the onshore part of the petroleum system could be used to evaluate offshore deep water frontier plays and leads. In the Venezuelan example we saw how reconstruction of basin-scale tectonics could be used to evaluate the prospectivity of leads identified on 2D models. Finally, in the Alaskan example we saw how calibration of petroleum system models for conventional accumulations could be used to infer prospectivity for unconventional resource plays in oil-prone source rocks. By combining information for an appropriate analog these unconventional resources could be assessed in terms of economically recoverable resources in various parts of the play rather than in place volumes.

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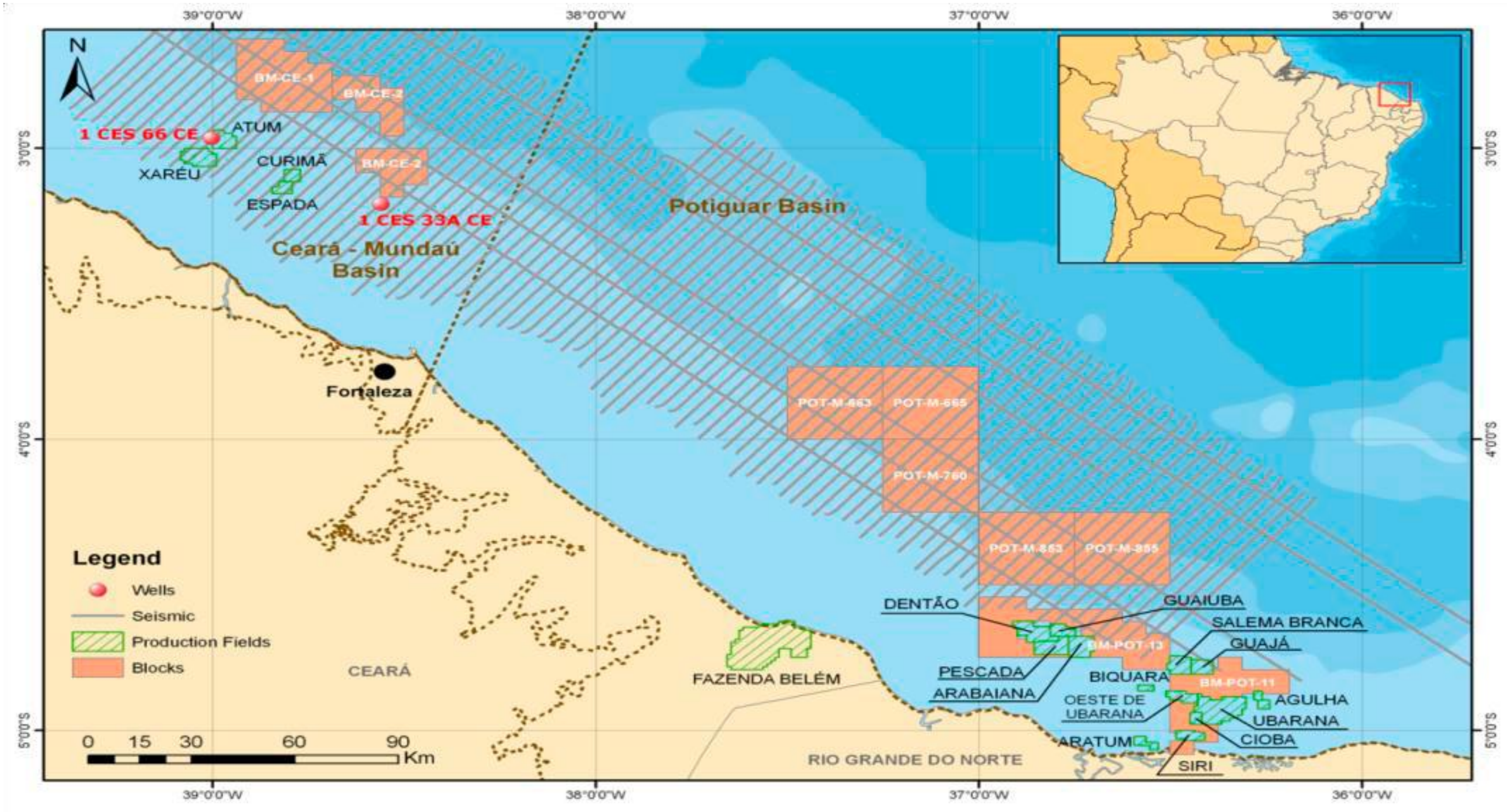


Figure 1. Location map of the seismic lines used to build the 3D geological model. Also shown are the locations of leased acreage, producing fields, and key wells. The red box in the inset shows the location of the Potiguar and Ceará basins off the northern coast of Brazil.

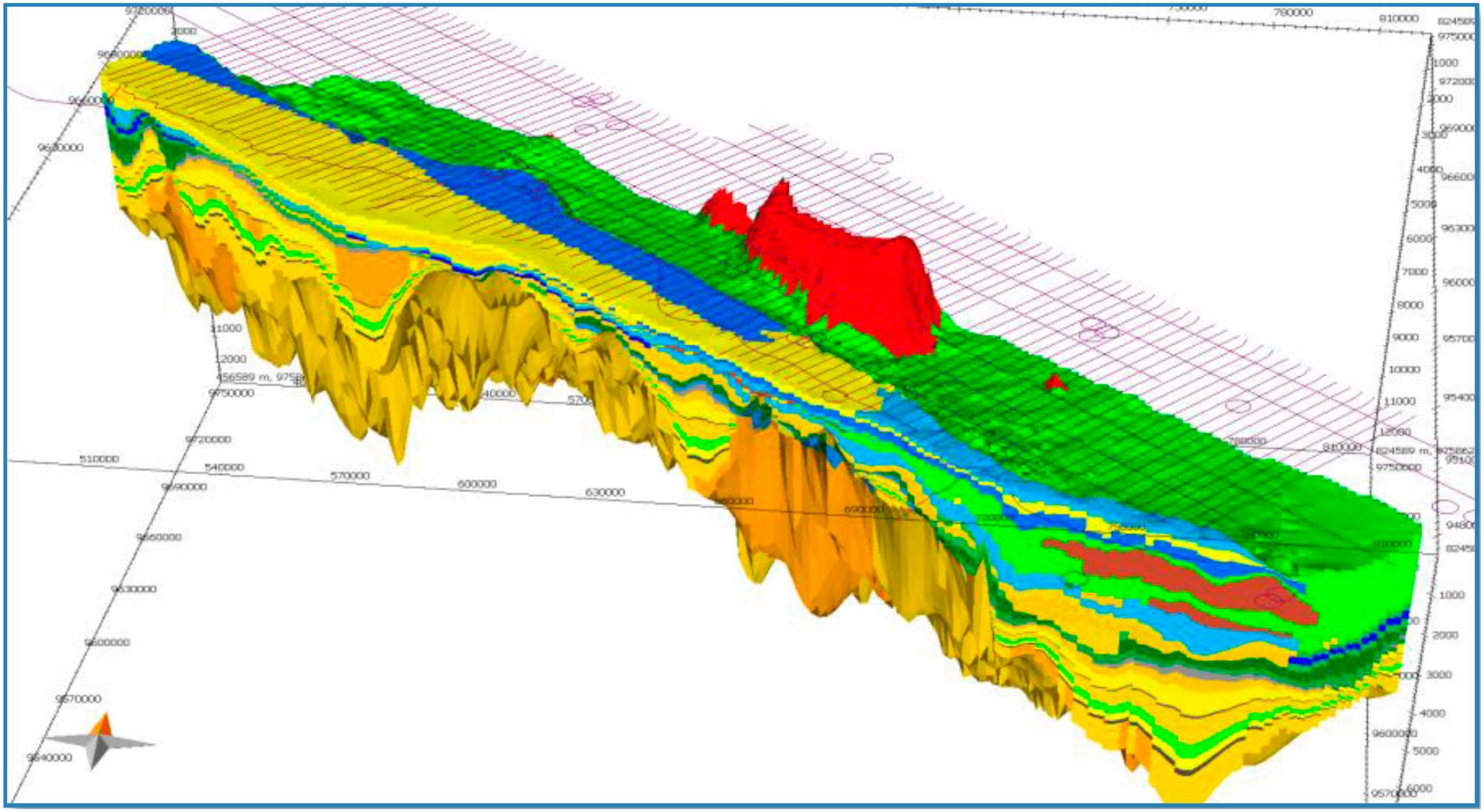


Figure 2. Three-dimensional petroleum systems model. Colors indicate various sedimentary lithologies in the basin-fill. Red indicates igneous intrusions. The locations of 2D seismic lines are also indicated.

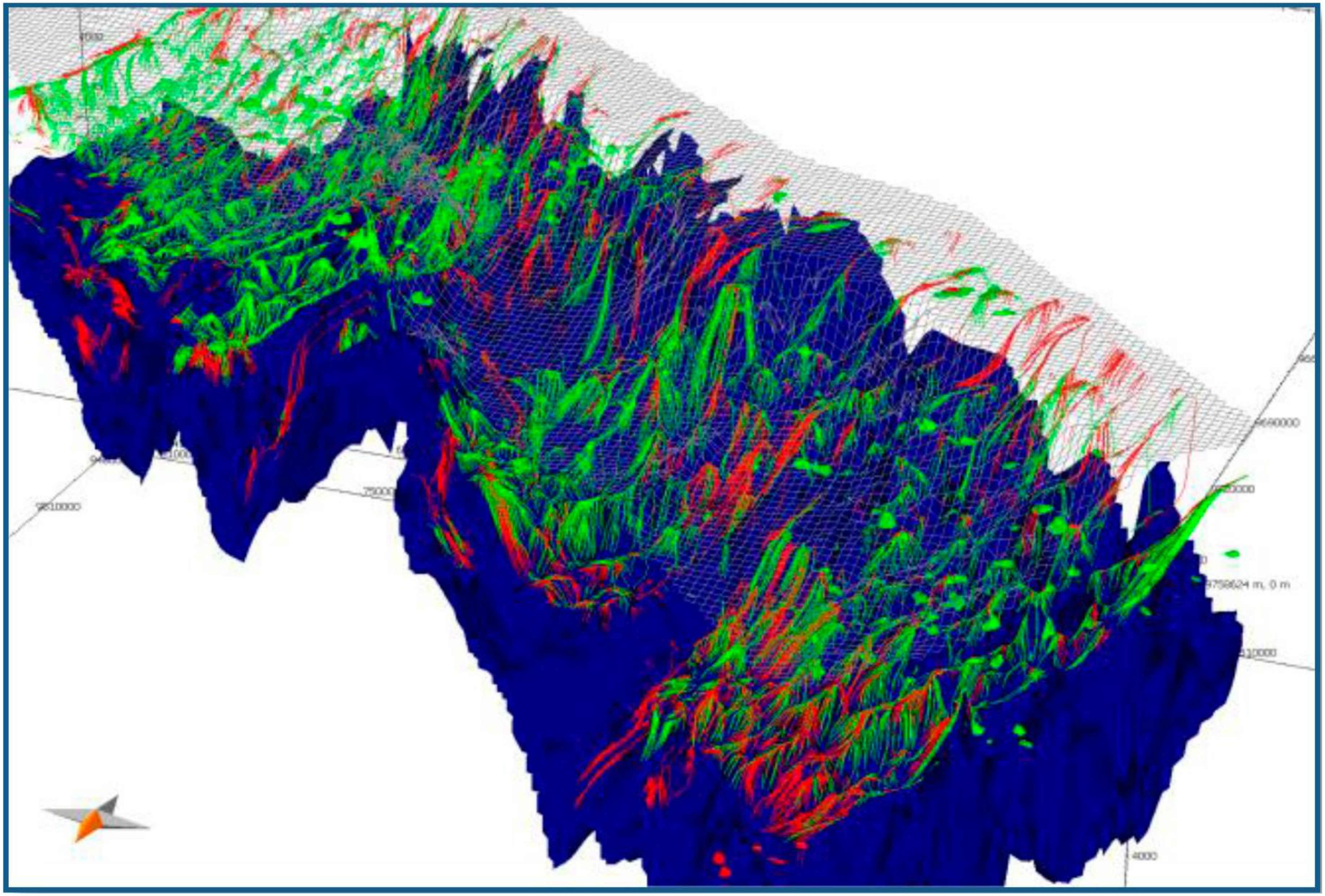


Figure 3. Prediction of hydrocarbon accumulations 20 million years before present in green. Modeled migration pathways of oil and gas are shown by green and red lines.

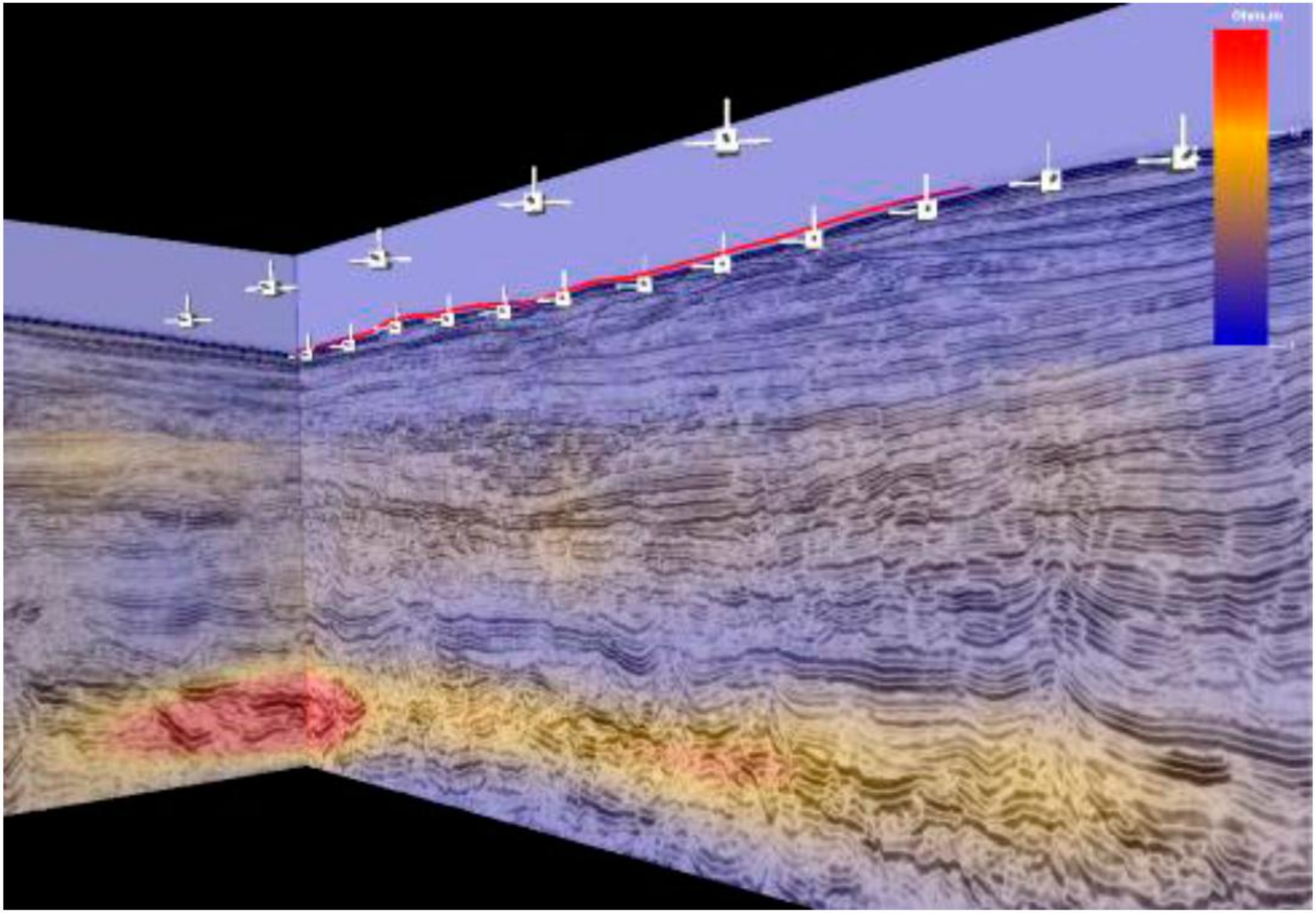


Figure 4. Vertical resistivity volume co-rendered with seismic sections (white symbols indicate receivers and the red line the source path) from 3D CSEM anisotropic inversion. Hotter colours are more resistive.

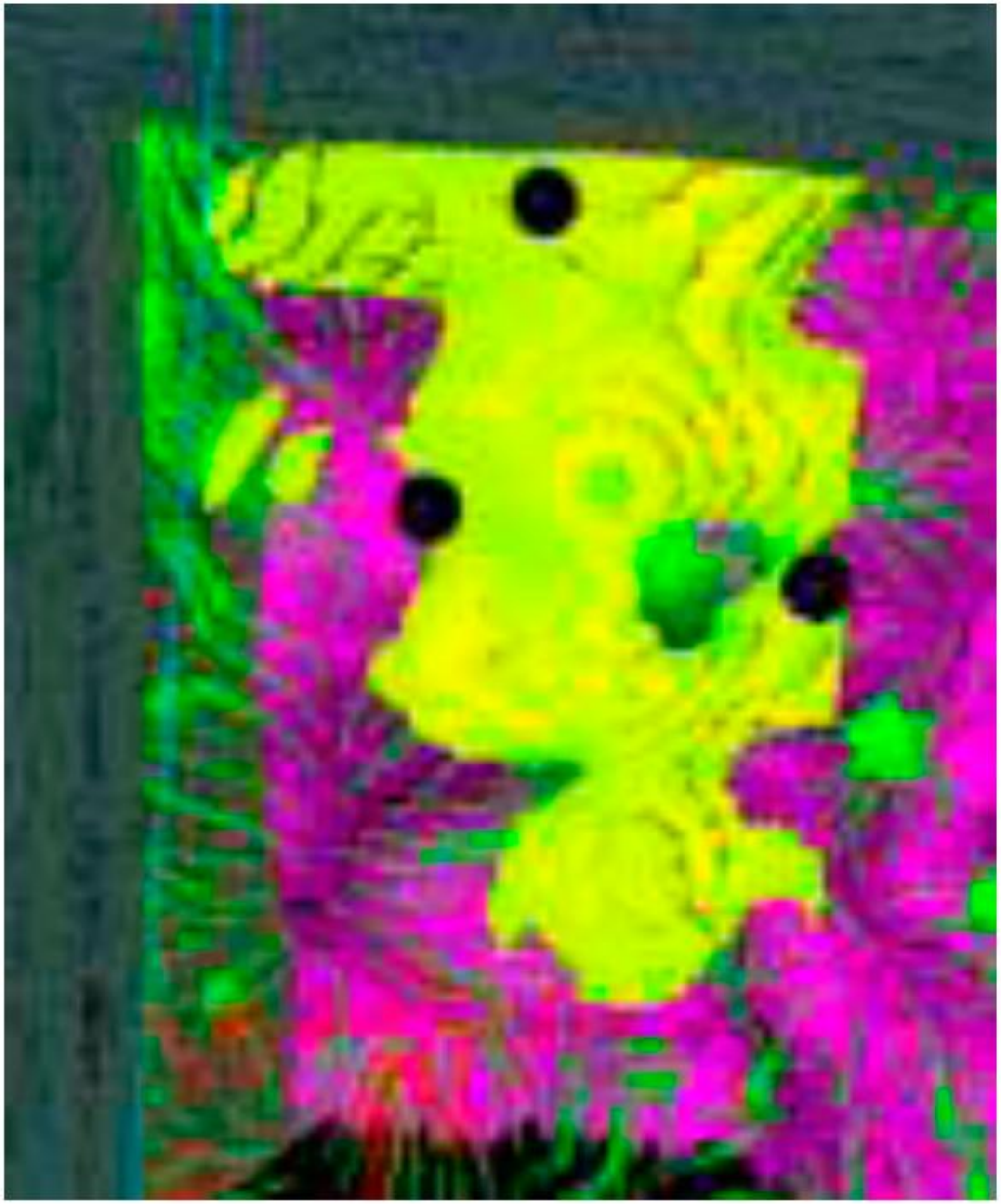


Figure 5. View of reference Earth model from above showing coincidence of resistivity anomaly (yellow), modeled oil accumulation (green) and surface oil slicks (black dots).

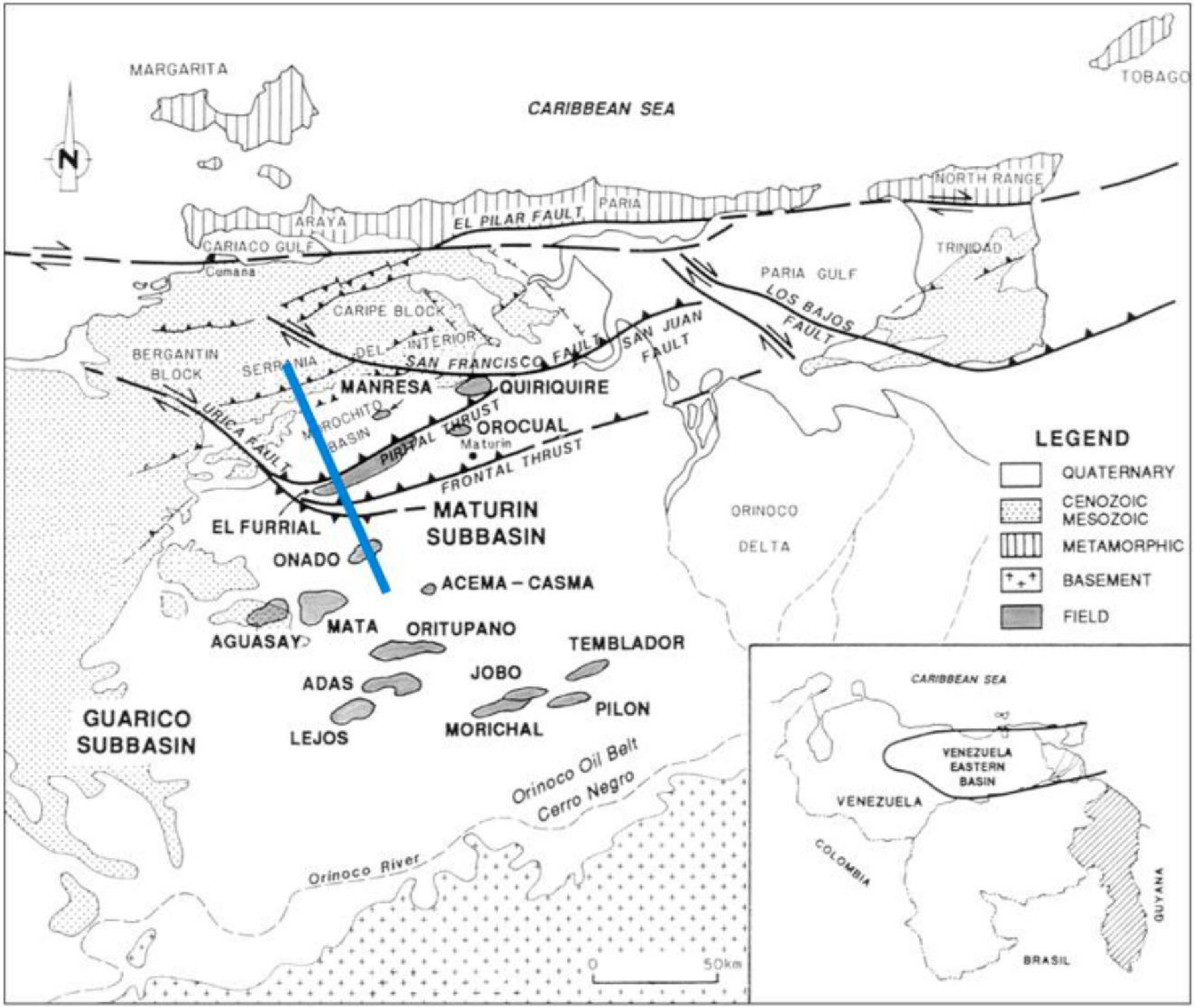


Figure 6. Location of the study area in the Monagas fold and thrust belt. Blue line is line of section for Figure 7 and Figure 8. (Modified from Parnaud et al., 1995).

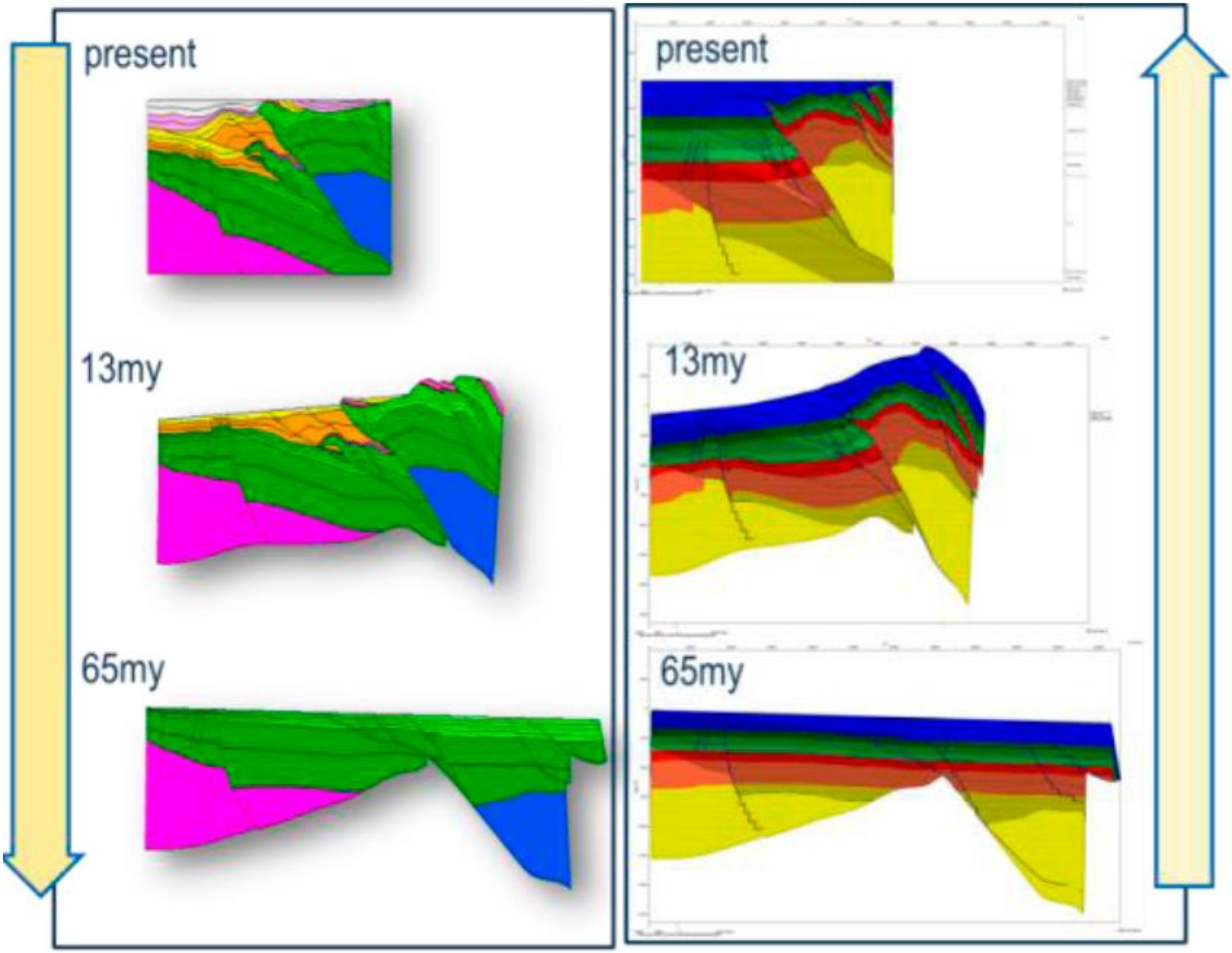


Figure 7. Structural restoration backwards through geological time is shown on the left. Maturation (blue - immature; green - oil window; red - gas window) is forward modeled through geological time as shown on the right.

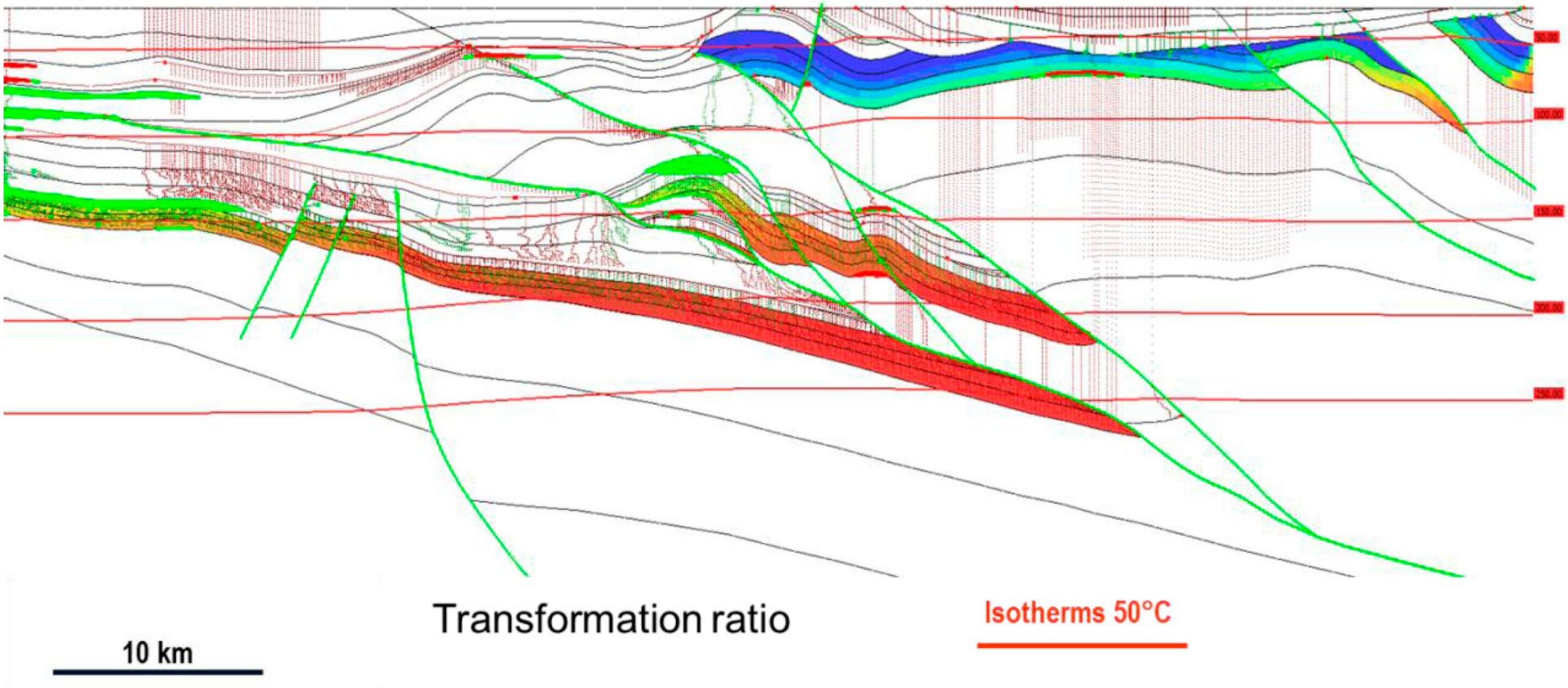


Figure 8. Modeled liquid hydrocarbon accumulations shown in green; vapor accumulations in red with migration vectors shown as green and red lines. Maturity of source rocks follows same color scheme as Figure 7.

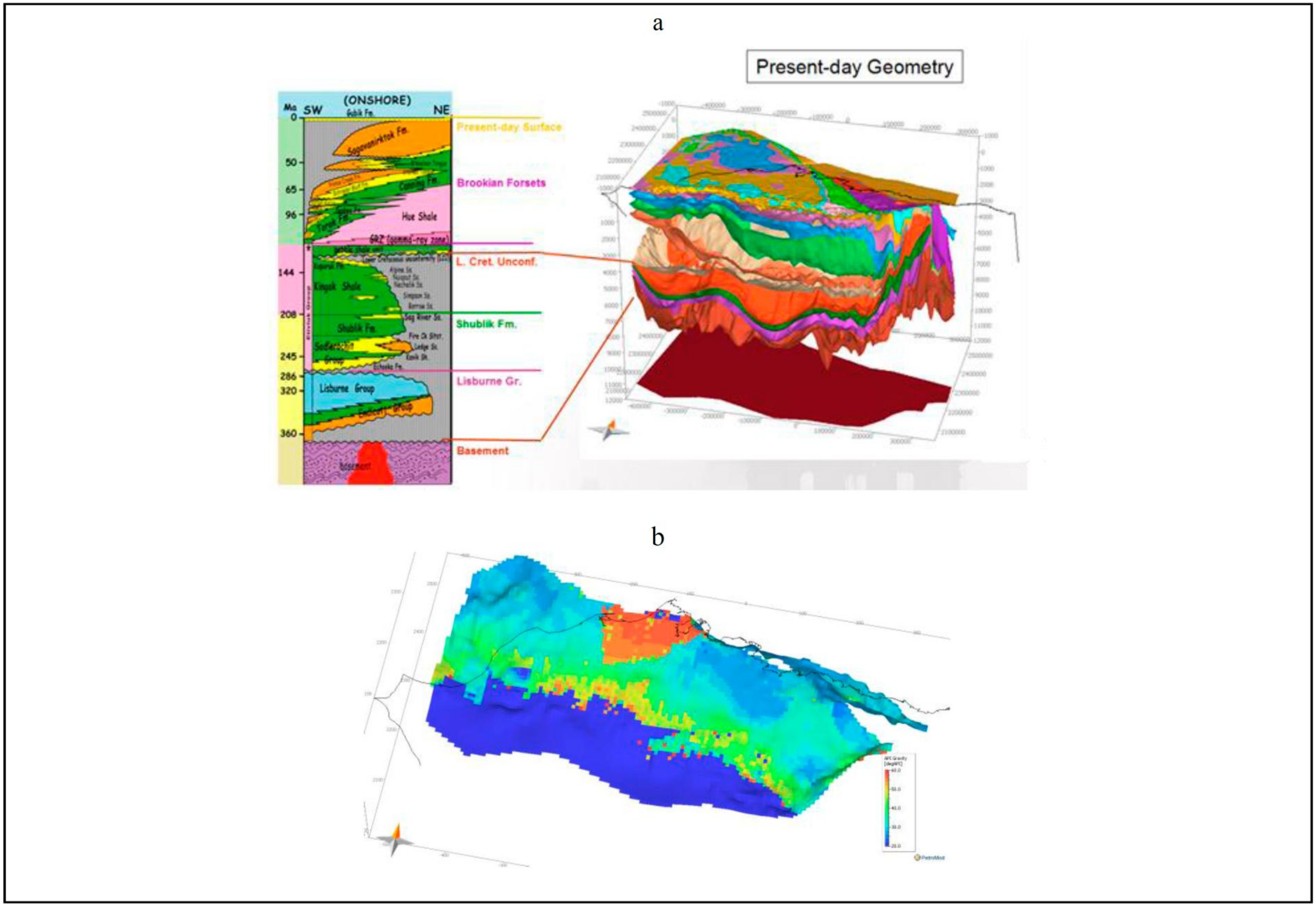
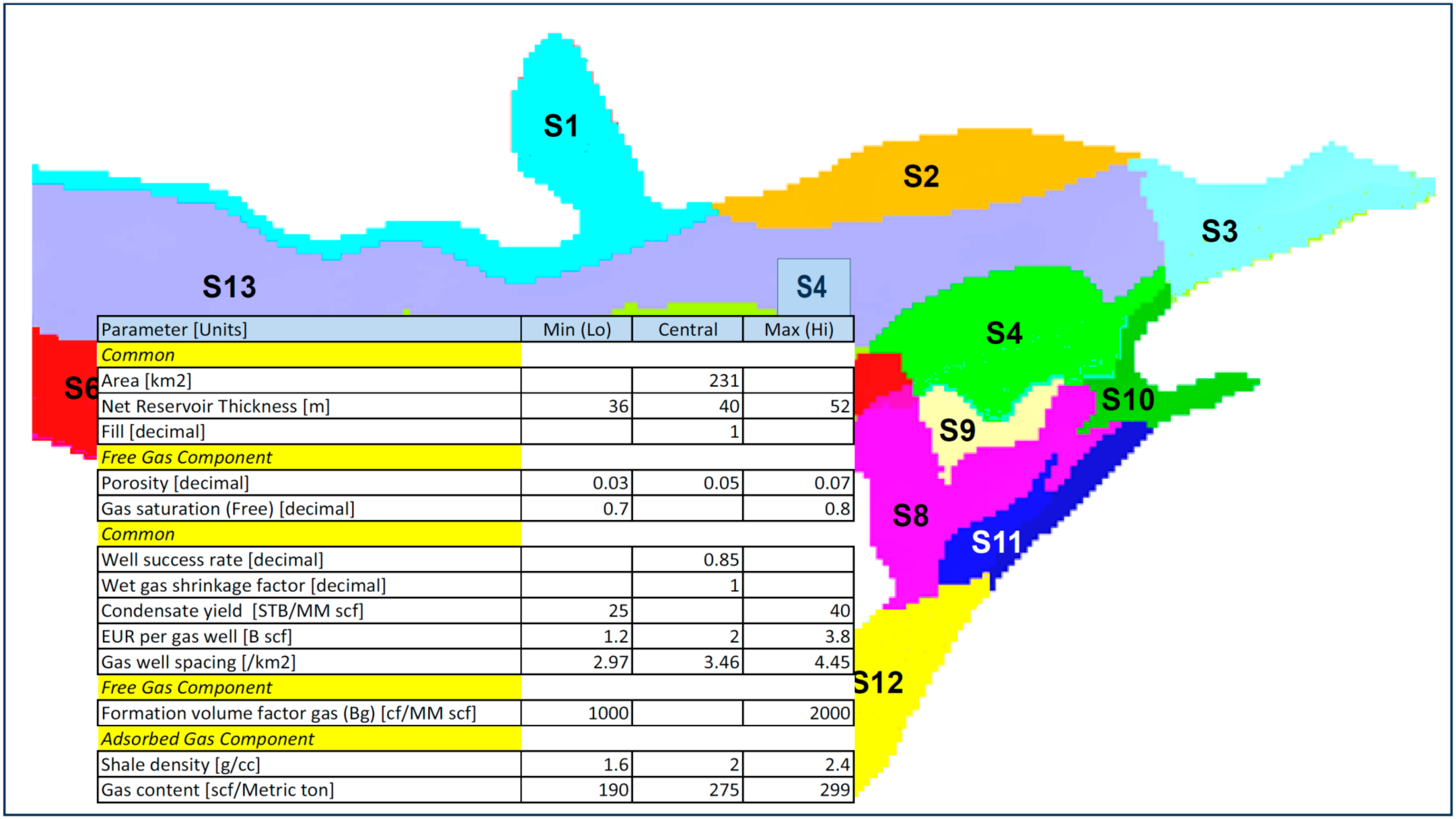


Figure 9. (a) A petroleum system model of the North Slope of Alaska. (b) Colors denote variations in the predicted API gravity of the oil retained within one of the source rocks in the area in one of several sensitivity runs.



Parameter [Units]	Min (Lo)	Central	Max (Hi)
Common			
Area [km2]		231	
Net Reservoir Thickness [m]	36	40	52
Fill [decimal]		1	
Free Gas Component			
Porosity [decimal]	0.03	0.05	0.07
Gas saturation (Free) [decimal]	0.7		0.8
Common			
Well success rate [decimal]		0.85	
Wet gas shrinkage factor [decimal]		1	
Condensate yield [STB/MM scf]	25		40
EUR per gas well [B scf]	1.2	2	3.8
Gas well spacing [/km2]	2.97	3.46	4.45
Free Gas Component			
Formation volume factor gas (Bg) [cf/MM scf]	1000		2000
Adsorbed Gas Component			
Shale density [g/cc]	1.6	2	2.4
Gas content [scf/Metric ton]	190	275	299

Figure 10. An illustrative set of 13 assessment units in an area of interest generated through stacking of CRS maps in an Alaskan North Slope shale play. The table shows the CVS inputs for one area.

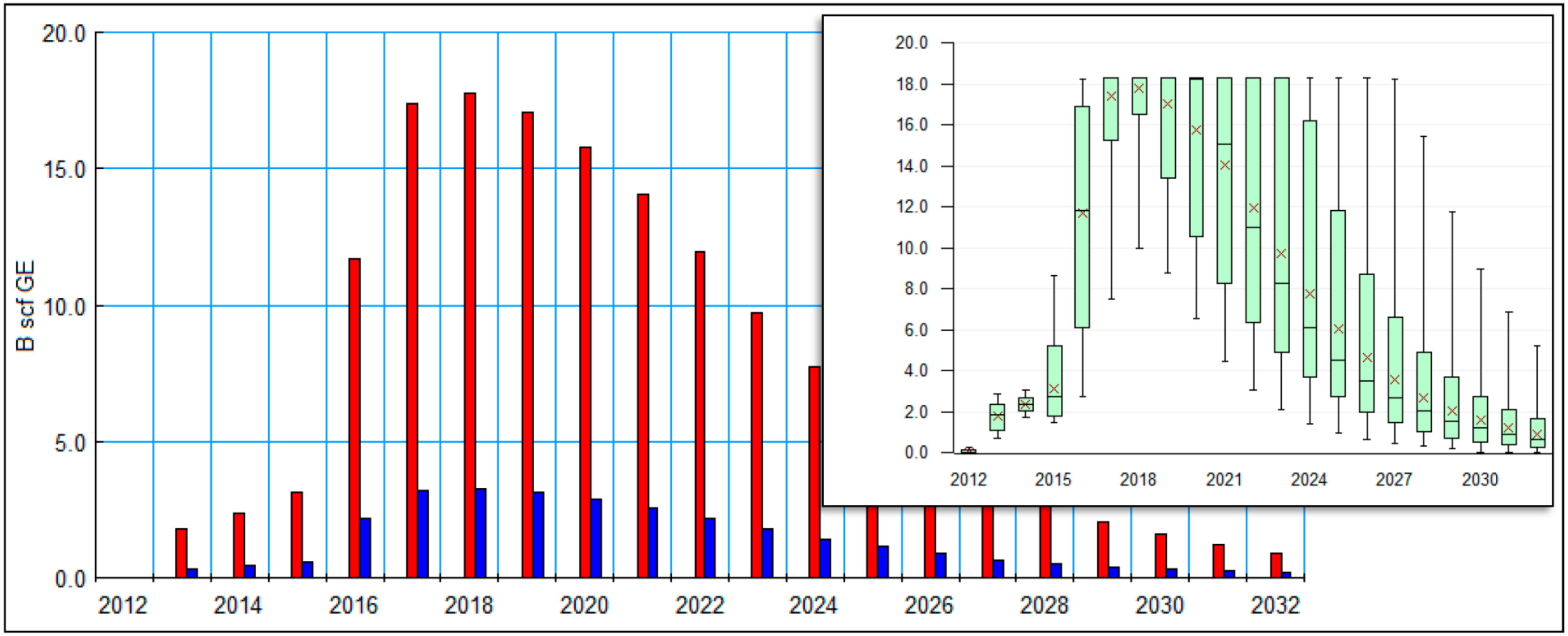


Figure 11. Mean and stochastic success case production profiles. The box plot shows year-by-year stochastic variation (P100-P90-P50-P10-P0) in production volumes.