Understanding Complex Fluid Contact Distribution in a Brown Carbonate Field-Mumbai High*

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Abstract

This paper presents a case study of an integrated and efficient methodology for establishment of complex fluid contacts in a large, heterogeneous, multi-layered carbonate brown field. The main producing reservoirs in this field exhibit unique behaviour in terms of fluid distribution. Whereas the gas-oil contacts appears to be consistent, the oil-water contacts encountered in different wells are found to be variable, in a stair-case pattern where it seems to be inclined down the structure. The case study focuses on the verification of fluid levels identified in different wells in the field with special emphasis on understanding the geological factors responsible for the variation of fluid levels. The study incorporates multi-scaled data analyzed and reviewed together to build a conceptual 'hydrocarbon accumulation model'. The study establishes that the hydrocarbon accumulation in this field is mainly controlled by the quality of the reservoir rock both vertically and laterally across the field and capillary forces above free water level, building the basis for a new saturation model. The good quality reservoir rock is characterized by the presence of secondary porosities in terms of vugs, moldic porosity etc., which is the result of intensive dissolution caused by freshwater meteoric invasion as suggested by core study results. This is also validated by the spatial distribution of reservoir quality from seismic inversion and fieldwise production distribution. The proposed conceptual model demonstrates the evolution of secondary porosity as a subtle interplay between sea level fluctuations and relief on the carbonate bank environment and how these, at a later stage, were filled with hydrocarbon. It explains the accumulation conditions within the framework of lithology, rock parameters, structure and fluid migration and is supported by reservoir data of the field.

Introduction

The Mumbai high field located in western coast of India was discovered in 1974 and was put on production in 1976. It is a giant, multi-layered carbonate reservoir covering an area of about 1,700 km^2 with approximately 1,750 wells including vertical, deviated and horizontal-lateral wells. Structurally, the field is divided into North and South, separated by a structural low. The oil and gas production is mainly contributed by L-II and L-III reservoirs of Miocene age. The LII and L-III reservoirs comprise of a number of sub-layers, separated by regionally extensive thin shales. L-II and L-III reservoir heterogeneity is controlled mainly by diagenesis along with depositional processes, which has a significant role in distribution of fluid in the field.

Defining fluid contacts (Gas Water Contact/Oil Water Contact/Gas Oil Contact) is one of the major variables for estimating the initial hydrocarbons in place as well as in planning redevelopment strategies. Mumbai High field exhibits a unique behaviour in terms of fluid contacts. Mumbai High North and South structures are believed to be in two different reservoir hydro-dynamic and fluid contact systems. Whereas the gas-oil-contact levels are found to be consistent within the individual north and south structures, oil-water-contacts are encountered at spatially varying depths both in North and South. The oil-water-contacts seems to occur in a step-like distribution, with contact shallowest in the lowermost layer and deepest in the uppermost layer, the reason of such a variation in fluid contacts is not properly understood. Various hypotheses have been proposed during previous studies. It was explained initially by a concept of 'Tilted oil water contact' due to hydrodynamics or difference in permeability. Another hypothesis suggesting late migration of gas displacing oil down the flanks is also proposed (Mandal and Sengupta, 1998). The effect of faults on hydrocarbon distribution in the field seems to be minimal owing to fact that faults don't have a significant throw. The existing reservoir model of Mumbai High considers different fluid contacts for different sub-layers where the intervening shales are assumed acting as vertical barriers.

Methodology

The integrated approach adopted for this study allows incorporating all available information in this field and enables to build a fluid contact model. In order to facilitate this, the well data base of ~1,750 wells is prepared, ~ 30,000 markers are edited / picked to define stratigraphic model. Then the pre-production (exploratory) and early-production wells are studied first to estimate the fluid contacts in original condition on the basis of petrophysical logs and validated against perforation results. This is followed by identification of fluid contacts in each individual well. Different cross-sections along and across the dip direction of the field are prepared and analysed, displaying wells with interpreted fluid contacts, in order to understand the field-wide pattern of hydrocarbon distribution. Different geological features identified in the core descriptions, SEM (Scanning Electron Microscopy) photographs and thin sections are studied to understand the depositional and diagenetic controls in the reservoir rock distribution. Probability cubes of elastic domain response for different reservoir facies are generated using seismic inversion data (Acoustic Impedance) which provide a gross estimation of reservoir rock distribution across the field and the distribution are validated by production data.

Identification of Fluid Contacts

Petrophysical logs are the main basis for identifying fluid contacts at well level. This exercise starts with the identification of reservoir zones from non-reservoir zones. A non-reservoir zone here refers to shales (indicated by high gamma, neutron-density separation or high Vclay) and tight carbonates (intervals against which effective porosity is low). Fluid contacts are then marked on the basis of SUWI log, wherever available or by resistivity logs in reservoir zones and gas column is differentiated from oil column on the basis of neutron-density cross-over. Fluid contacts are defined as OWC (Oil Water Contact) if a clear contact between oil and water is observed within a clean reservoir section or GOC (Gas Oil Contact) when a clear contact between gas and oil can be observed. However, most of the cases, gas column or oil column is vertically constrained by shale or tight rock facies, in which case it is defined as GDT (Gas Down To), or ODT (Oil Down To) respectively. Where a high saturation of water is clearly observed, upper limits of water column is marked as WUT (Water Up To).

Results and Observations

Cross-sections prepared along dip and strike of the field, provide a good understand of the fieldwise distribution of hydrocarbon. Figure 1 shows an example of a vertical profile along a well located in the crestal part of the field. The figure depicts that hydrocarbon column is limited by the vertical distribution of good and medium quality reservoir rocks. A good reservoir rock type is characterised by the abundance of secondary porosity as also observed in thin sections of core (Satynarayana et al. 1999) shown in Figure 1 whereas a comparatively tight carbonate facies are characterised by primary porosity only or with secondary porosities later being plugged by recementation.

The cross-sections reveal that the gas cap in both the LII and LIII reservoirs occurs down to consistent depths, whereas ODTs are identified at variable levels. Dip sections (Figure 2) show that the total stratigraphic thickness is consistent across the field but, the base of the hydrocarbon column which is formed by the ODT levels in individual wells is actually not restricted to these stratigraphic layers and cuts through the formations from the deeper units into the shallower units towards the flank and so, in the crestal area the hydrocarbon column is the thickest. If the dip sections are flattened at reservoir top, it gives a very clear picture of the distribution of hydrocarbon column, the base of which is defined by the presence of poorly developed rock facies that is thickest at the crestal part and wedging out towards flank of the structure (Figure 6A).

In the LIII southern block, the total hydrocarbon accumulation is situated much deeper than the northern block. This phenomenon can be explained by structural reasons which have caused the southern block to be in a deeper position.

Integration of Core Study Results

A detailed core analysis enables to refine the depositional environment interpretation and its bearing on the reservoir heterogeneity of Mumbai High field. The study suggests that the Mumbai High carbonate bank formed mainly as low relief carbonate sand bars. The bank formed an irregular, anastamozing pattern in map view of emergent carbonate bars and shallow-water swales (Figure 3).

During periods of bank growth, swales between bar crests were filled with calcareous terrigenous mudstones. When the entire bank was flooded by rising sea level, off-bank sediments were deposited everywhere, including over the crest of the bank creating extensive shale layers across the field (Figure 3).

During lowstand periods, topographic highs were intensely leached producing discontinuous karst regions and allowing meteoric water to enter the rock system, which resulted in the formation of vuggy porosity in carbonates. Calcareous and non-calcareous terrigenous muds also accumulated essentially at sea level within marshes that typically bordered onto the karsted paleotopographic highs (Figure 3).

Integration of Seismic Inversion and Production Data

A gross estimation of reservoir quality is derived from seismic inversion data (Acoustic Impedance). Probability density function associated with different lithology is estimated from inversion data which provides a good understanding of the distribution of reservoir quality rock in the field (Figure 4). Probability maps generated from PDFs show that good and medium quality rock types are mostly distributed in the crestal part of the structure, whereas the tight, poor quality carbonates are present in the flank.

A production bubble map displaying contours and interpreted rock type fractions at wells shows a good agreement with results of seismic inversion where most of the good reservoir rock types derived from petrophysical logs lie in the same crestal area of the field from where the major production is coming from (Figure 5).

The Integrated Fluid Contact Model

The analysis and integration of multi-scale of data enable to build a conceptual geological model, which explains the evolution of good reservoir quality rock as a subtle interplay between sea level fluctuations and structuration and how these, at a later stage, were filled with hydrocarbon. The conceptual model (Figure 6) suggests that a gentle slope of the structure is accountable for the crestal part of the Mumbai High structure to get affected by more intensive leaching and secondary porosity formation during the low stand periods whereas the flank part was exposed to a very limited extent to fresh water invasion (Figure 6B). Because of the relief, the crestal part has a thicker zone of good reservoir quality rock developed compared to the flank side and at the base of this zone; re-cementation caused by the precipitation of $CaCO_3$ saturated water in the pore spaces plugged the previously formed vugs transferring it into tight, poor quality rocks. Post-diagenesis tectonic disturbances resulted in dividing North and South into separate structural blocks and gave rise to the present structural configuration of Mumbai High field (Figure 6C). Hydrocarbons moved to this structure at a later stage, when the structure was in place suitable for entrapment and filled up the areas of good quality reservoir rock, governed by capillary forces above the free water level. (Figure 6D)

Conclusions

In summary, the rock quality and capillary pressure are the governing factors that control the distribution of hydrocarbon in the LII and LIII reservoirs. The container of oil is bounded by the GOC at the top and a varying base at the bottom, dominated by a poor quality rock type.

This study introduces a much simplified (and more consistent) fluid contact model, with only one FWL per reservoir. The conceptual model is a basic input for the static reservoir modeling. It provides a clear understanding of hydrocarbon distribution in the field for better history matching and predictions.

Statement from Authors

Views expressed in the paper are those of authors only and can be different from the official version of Oil and Natural Gas Corporation Ltd. Data utilized and referred for the paper will not affect ONGC's business interest in any way.

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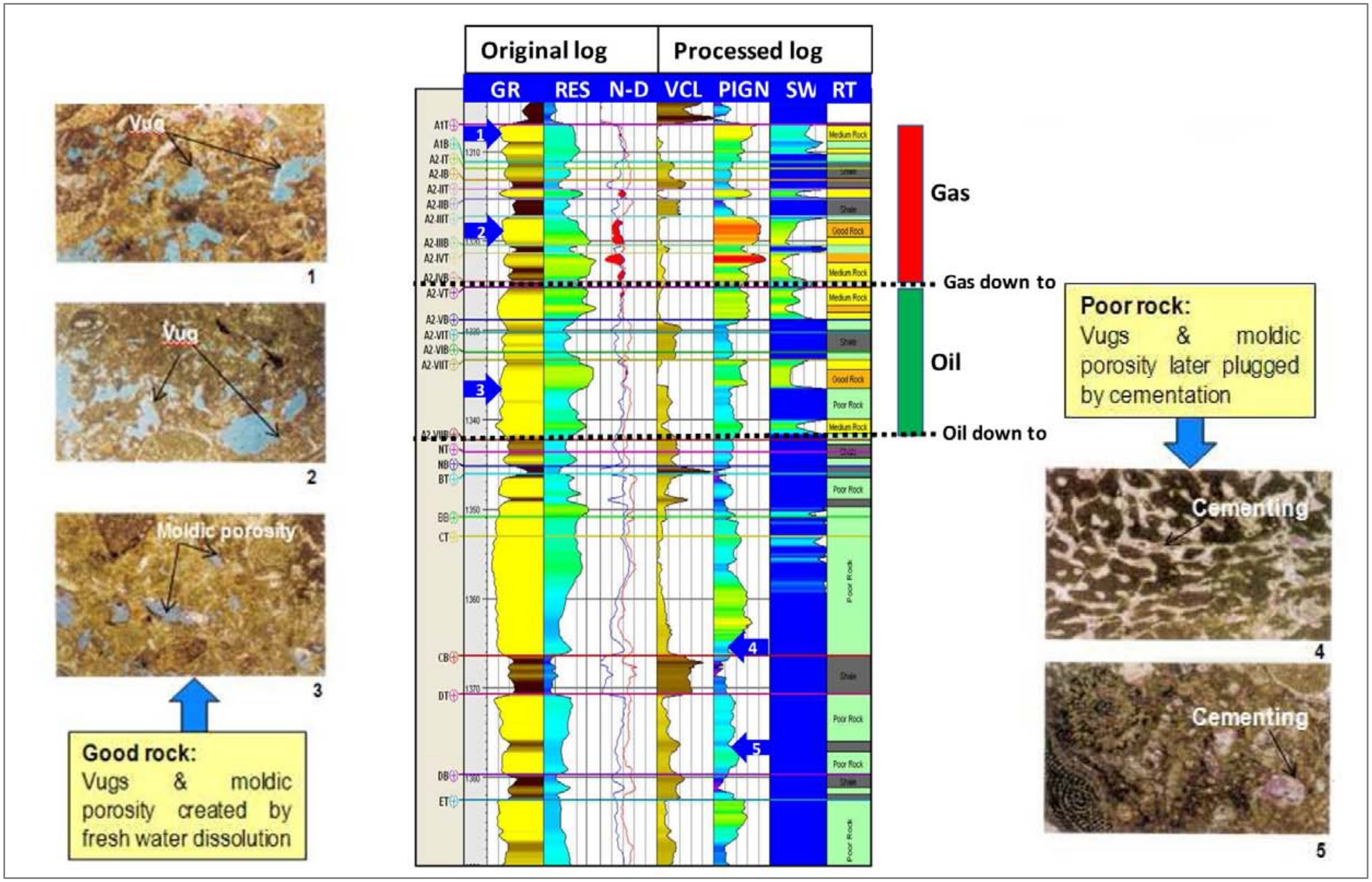

Figure 1. Well section depicting vertical distribution of hydrocarbon, thin sections are dyed, blue colours represent pore spaces (XN, scale bar=0.38mm).

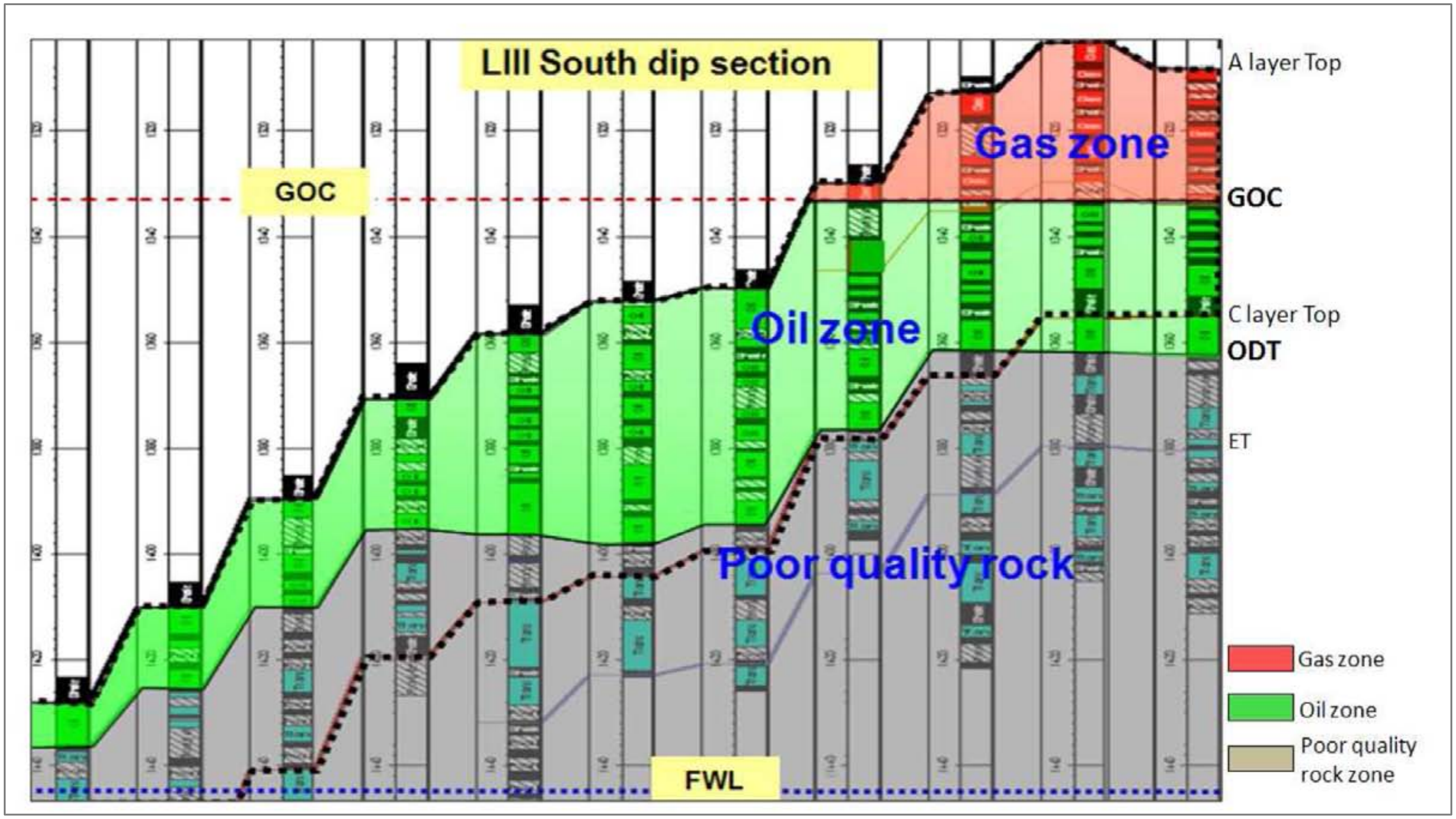

Figure 2. A dip-section of Mumbai High South structure depicting the hydrocarbon distribution across the field.

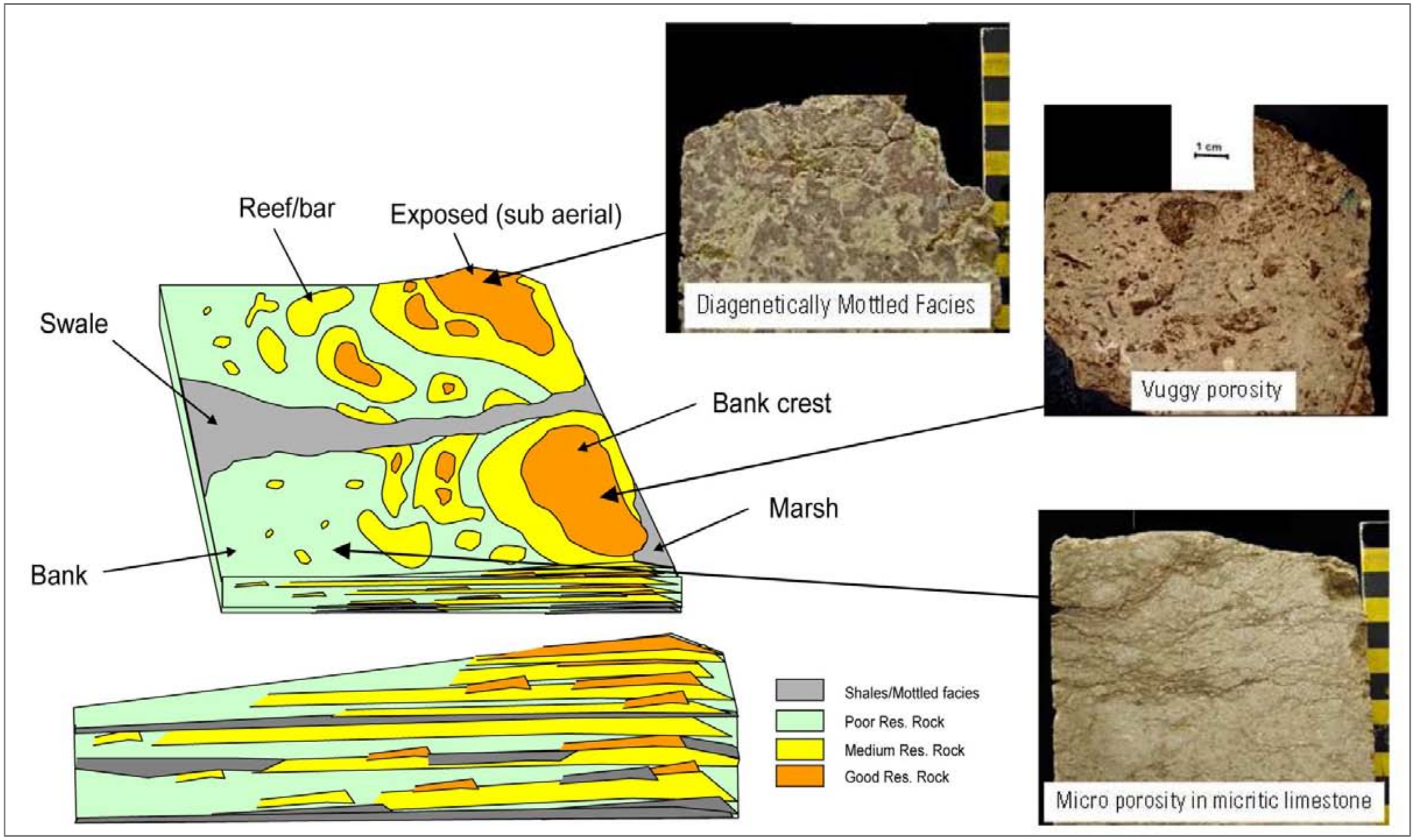

Figure 3. Depositional model of Mumbai High carbonates as suggested by core study results and diagenetic features identified in cores.

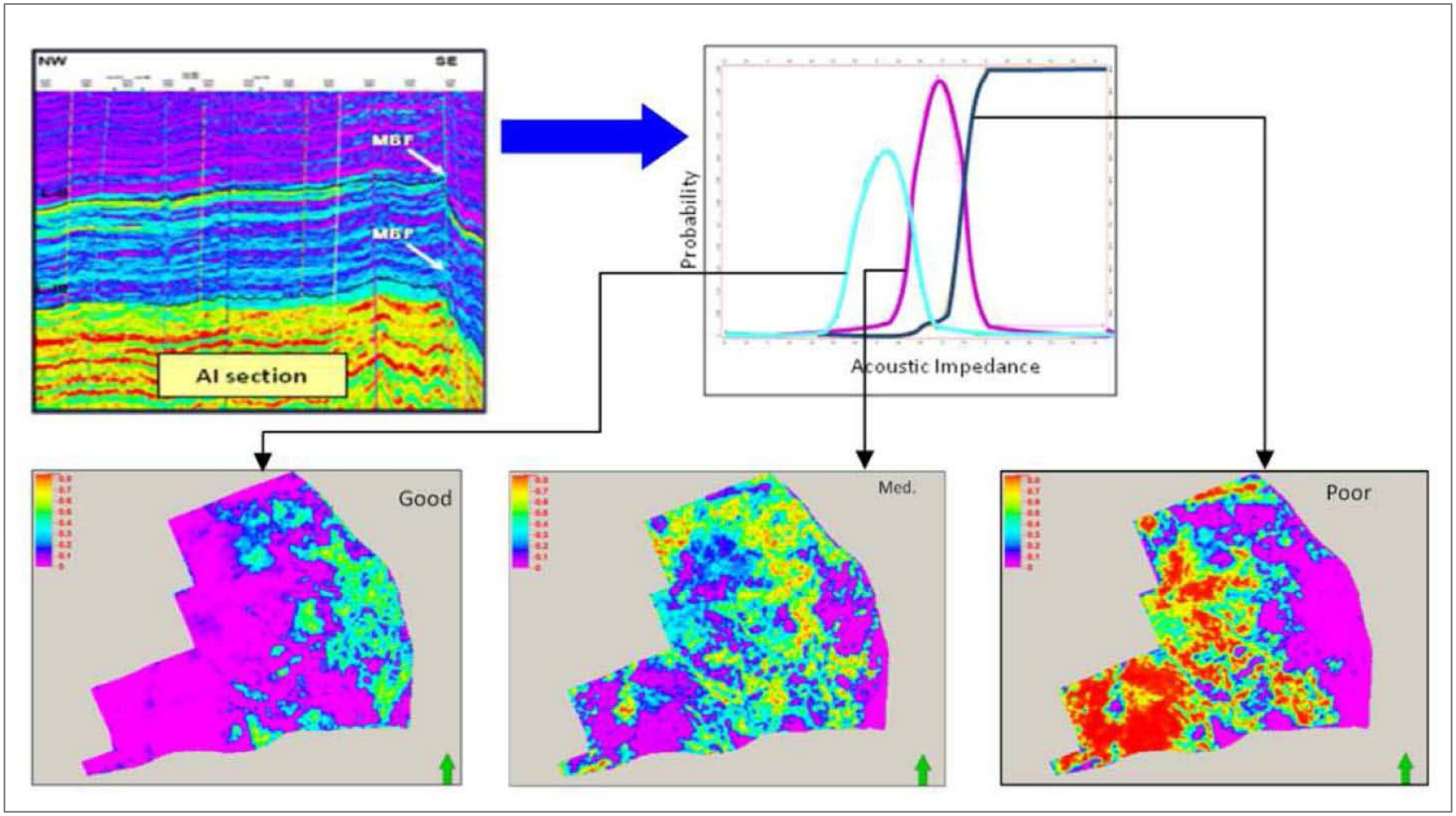

Figure 4. Rock type distribution probability map generated from Seismic Inversion data.

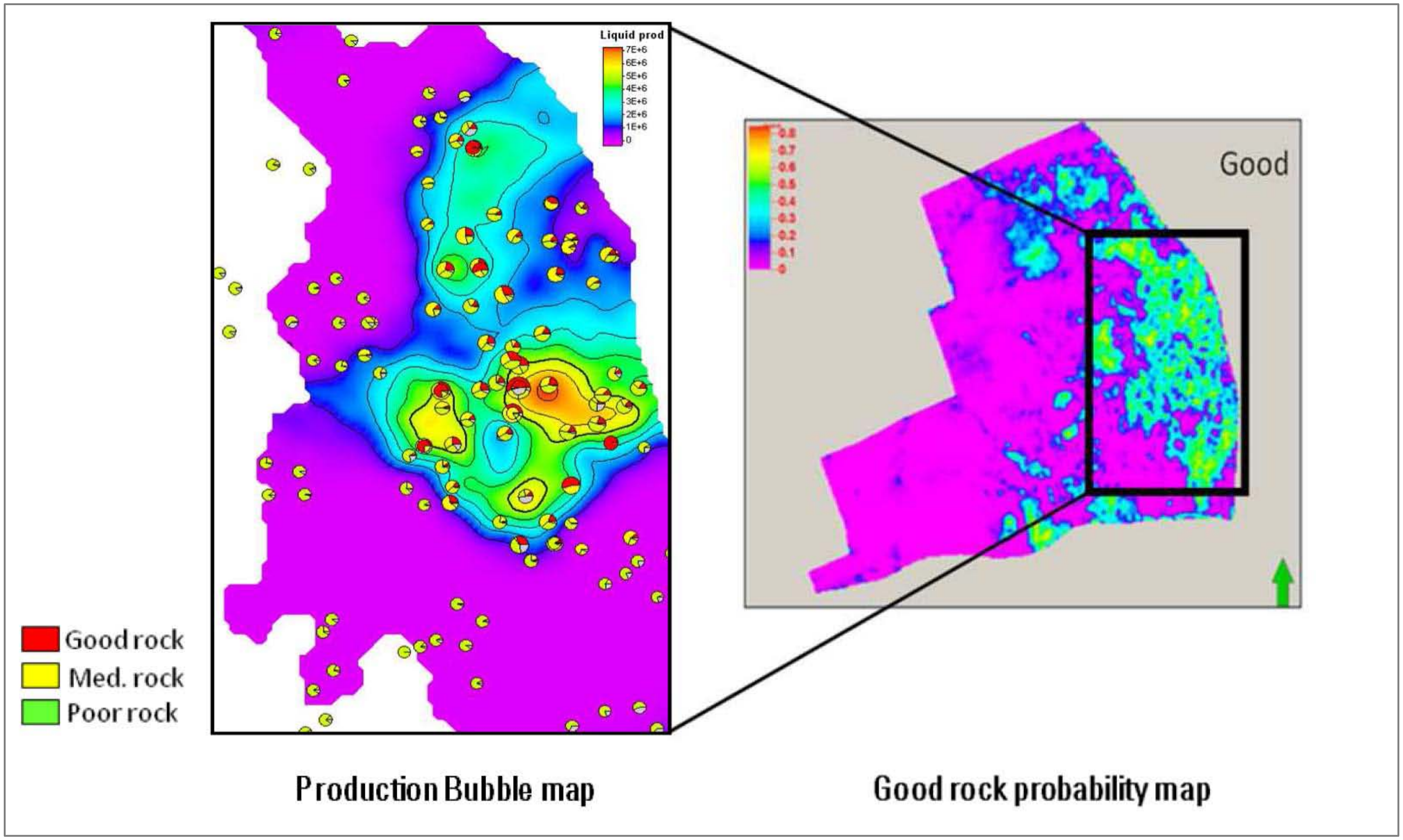

Figure 5. Production bubble map supports seismic probability map.

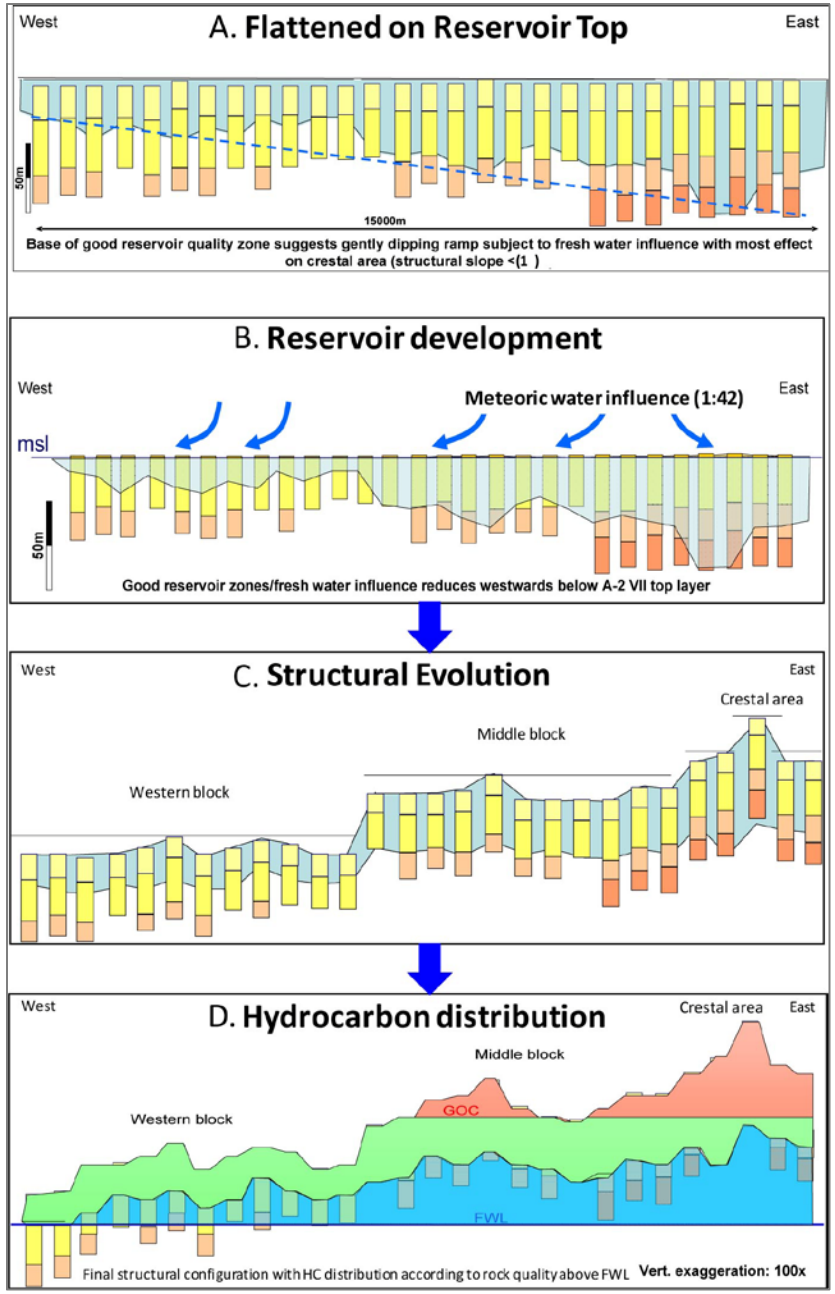

Figure 6. The conceptual Hydrocarbon accumulation model explaining reservoir development, structural evolution and hydrocarbon distribution.