FORECASTING THE PRESENCE OF HYDROCARBON IN MOC TINH TAY PROSPECT, BLOCK 05-3, NAM CON SON BASIN BY 3D PETROLEUM SYSTEM MODELLING

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Summary

Moc Tinh Tay is located to the west of the Moc Tinh discovery, Block 05-3, Nam Con Son basin. Results of exploration wells and production wells clarified the petroleum potential of Block 05-3, especially Moc Tinh area, including Moc Tinh Tay structure.

The purpose of this paper is to understand, by 3D basin modelling, the generation, migration and accumulation histories of oil and gas from source rock; and evaluate the presence of hydrocarbons in Moc Tinh Tay prospect to minimise the risk of oil and gas exploration in the study area.

In this study, Lower Miocene and Oligocene source rocks are fair to very good source richness and essentially contain kerogen type III and a mix of type III and type II and has fair to good gas generation potential. Oligocene source rock has generated hydrocarbon since 24Ma. It is in oil window at 13Ma, and reached dry gas phase at 10Ma to the present time. The Lower Miocene source rock has generated hydrocarbon since 12Ma. It is in oil window from 5.5Ma and in gas phase in almost the entire area at the present.

Key words: *Petroleum system modelling, Moc Tinh Tay, Petromod software, hydrocarbon potential, Nam Con Son basin.*

1. Introduction

The Moc Tinh Tay prospect is located to the west of Moc Tinh discovery, Block 05-3, central part of Nam Con Son basin. It consists of two segments, West and East. The West segment is a faulted three-way dip closure against a large-throw, N-S trending fault. The East segment is a two-way dip closure against a large throw, NE-SW trending fault and another small N-S trending fault at T30 level (Figure 1).

The potential of Moc Tinh Tay structure is proved by the results from the exploration well in Block 05-3. The expected reservoir section is fluvio-deltaic Late Oligocene to Early - Middle Miocene deltaic/shallow marine sandstones and turbidite sandstone in the upper syn-rift.

The principal aims of this study are to evaluate the petroleum system and estimate the volume of hydrocarbon accumulations in Upper Miocene turbidite, Lower Miocene and Oligocene plays on Moc Tinh Tay structure by 3D basin modelling.

The Tertiary structural history of the Nam Con Son basin, and Block 05-3 in particular, can be divided into distinct episodes of tectonic activities, namely first rift phase (Eocene - Early Oligocene), intra rift phase (Late Oligocene - Early Miocene), second extensional phase (Middle Miocene), and post rift phase (Late Miocene - Pliocene). The Middle Miocene faulting related to rifting created intensive faulted blocks and a major structural depression through Block 05-3 and the adjacent areas [2]. The chrono-stratigraphy chart summarising the history of the Nam Con Son basin is shown in Figure 2.

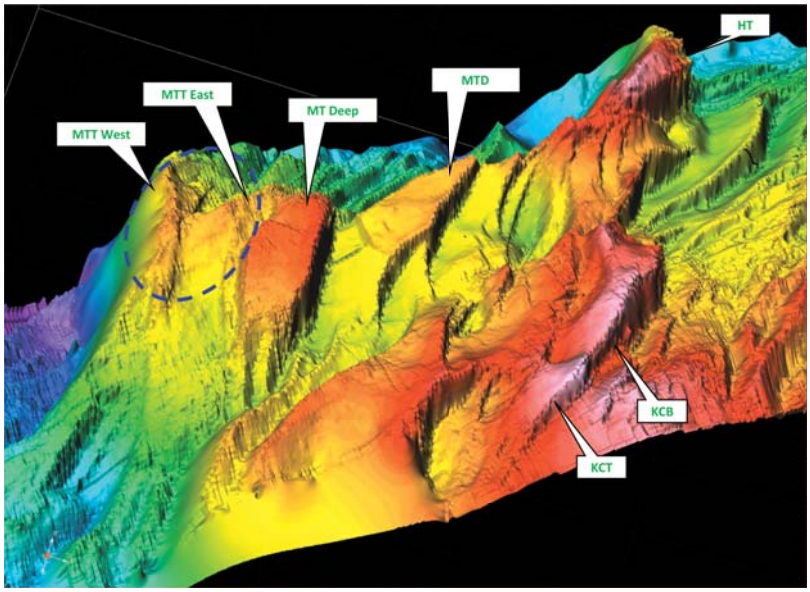


Figure 1. *Moc Tinh Tay location*

2. Model building

2.1. Geometry

To begin with, the present geometry for 3D Petroleum System Modelling is based on the input structural model in Petromod, covering an area in Block 05-3. Geometry (faults and horizons) modelling for the 3D model incorporates data from a range of disciplines including regional geological frame-work, seismic interpretation as well as wireline, environment and source rock characteristics. The structural model is built from simple grid and faults which are converted to depth domain from seismic interpretation results correlated with well markers. The horizontal grid increment is defined by 200 x 200 metre grid (I increment and J increment) due to a large study area. The fault model is built from forty-three (43) interpreted faults, in which fault stick is provided from seismic interpretation (Figure 3). Moreover, the properties of fault are assigned into the model that faults opened during the active time and closed when they became inactive (Figure 4).

The horizon modelling is the creation of main stratigraphic horizons based on seismic interpretation and subdivision of structural model (Figure 3). The sub-horizons between the main horizons are conformably followed base which are constrained by well correlations.

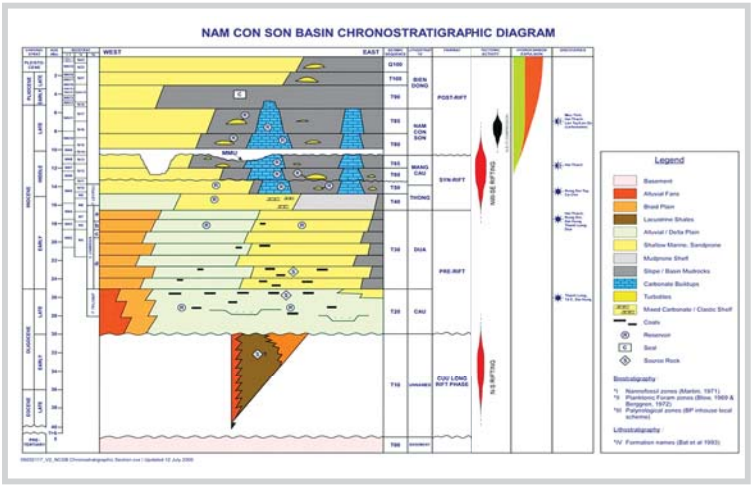


Figure 2. *Nam Con Son basin chrono-stratigraphic chart*

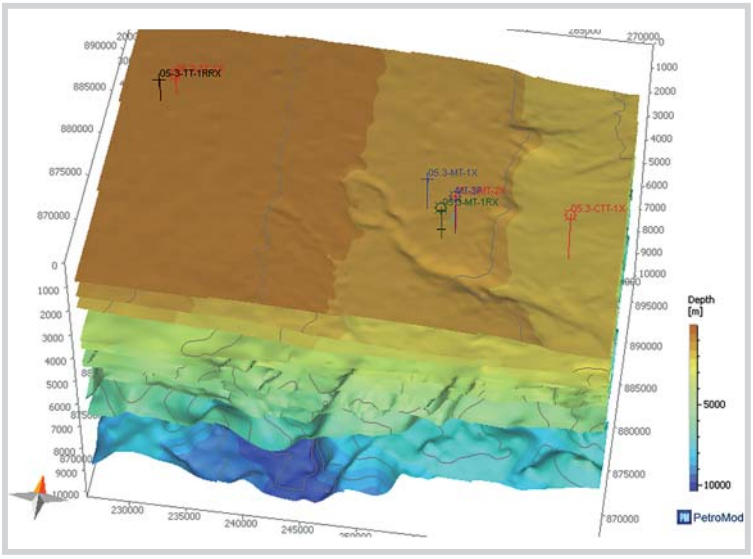
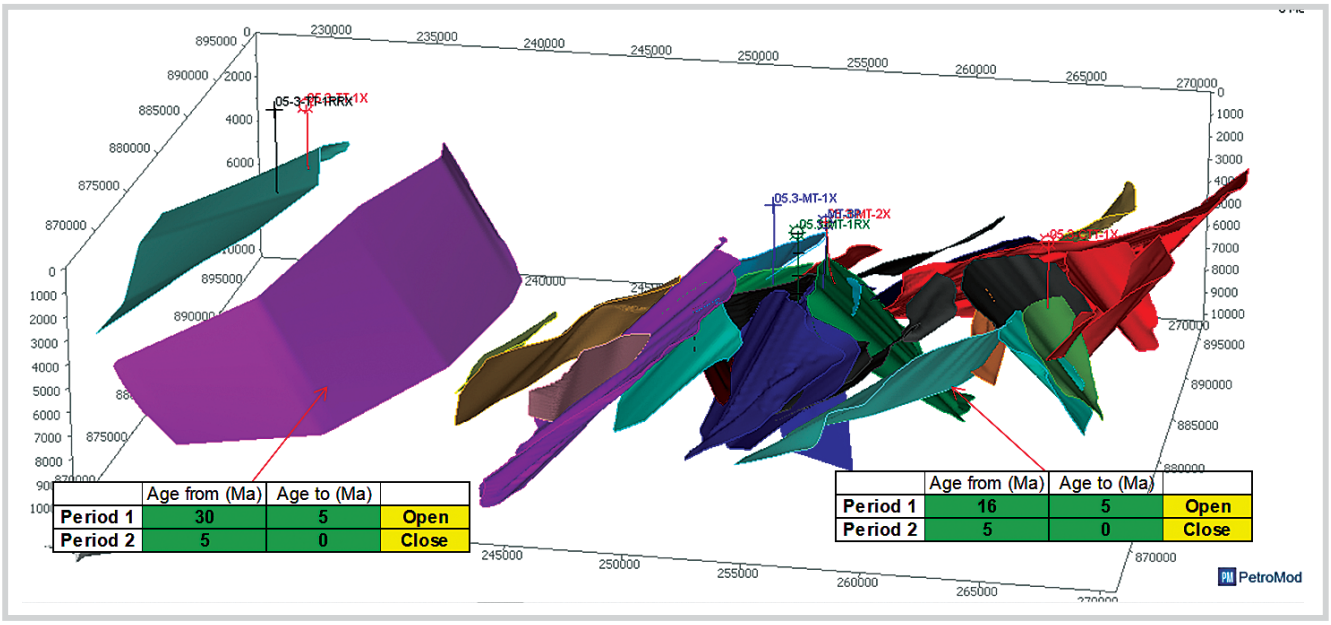


Figure 3. *The 3D view of grids of 10 main horizons derived from seismic interpretations*



	Age from (Ma)	Age to (Ma)	
Period 1	30	5	Open
Period 2	5	0	Close

	Age from (Ma)	Age to (Ma)	
Period 1	16	5	Open
Period 2	5	0	Close

Figure 4. *43 key faults were selected for building the fault model*

2.2. Lithology and facies distribution

2.2.1. Stratigraphy/age assignment

Cenozoic stratigraphy in the basin was subdivided into four major mega-sequences based on tectonic stages of basin evolution: syn-rift 1, intra-rift, syn-rift 2 and post-rift (RN/EPC Joint Study 2012). These mega-sequences were subdivided into thinner zones equivalent to vertical resolution of the models. Ages of mega-sequences were derived from the available biostratigraphic data of Vietnam Petroleum Institute and other analyses from different oil/gas companies (Table 1).

2.2.2. Lithologies/facies definitions

Lithologies used in 3D models were generated by mixing fundamental lithologies in the Petromod library e.g. sandstone, shale, and coal, etc. For sandstone, previous studies suggested that it is mainly arkoses to lithic arkoses in Folk (1974) [6] classification. The basement mainly contains granitic intrusive such as granite, granodiorite with extrusive and metamorphic rocks in places, so in the Petromod models basement was simply assigned to be granite (150Ma old).

2.2.3. Facies maps

Facies map for the area covered by 3D models have been constructed based on the integration of key information including the well-log interpretation, the isopach maps and the depositional frame-work of the Nam Con Son basin.

2.3. Boundary Condition

2.3.1. Paleo-water depth

The PWD was inferred from the interpreted facies maps by the following relationships: Delta front-shore face (0 - 30m); shallower marine (> 30 - 200m) and deep marine (> 200m). Figure 5 shows the estimated PWD maps for 3D modelling areas of key events.

2.3.2. Sedimentary water interface temperature (SWIT)

Sedimentary water interface temperature or Paleo-water interface temperature in this modelling was extrapolated from pseudo trends created by assigning the location at latitude 8°, South East Asia to Petromod software (Figure 6).

2.3.3. Heat flow (1D modelling)

The Nam Con Son basin is a rifting basin, the heat

Table 1. *List of interpreted horizons and assigned ages*

Horizons	Nano	Foram	Age	Ma
WB			Holocene	0.0
T100	NN3 - NN4	N19 - N20	Pliocene	1.7
T90			Intra Pliocene	2.5
T80	NN10 - NN11	N15 - N18	Late Miocene	5.5
T65	NN5 - NN9	N9 - N14	Middle Miocene	10.5
T30	NN2 - NN4	N6 - N8	Early Miocene	16
T20	? - NP24		Late Oligocene	24.5
T10	?		? - Early Oligocene	30.0
T00				40.00

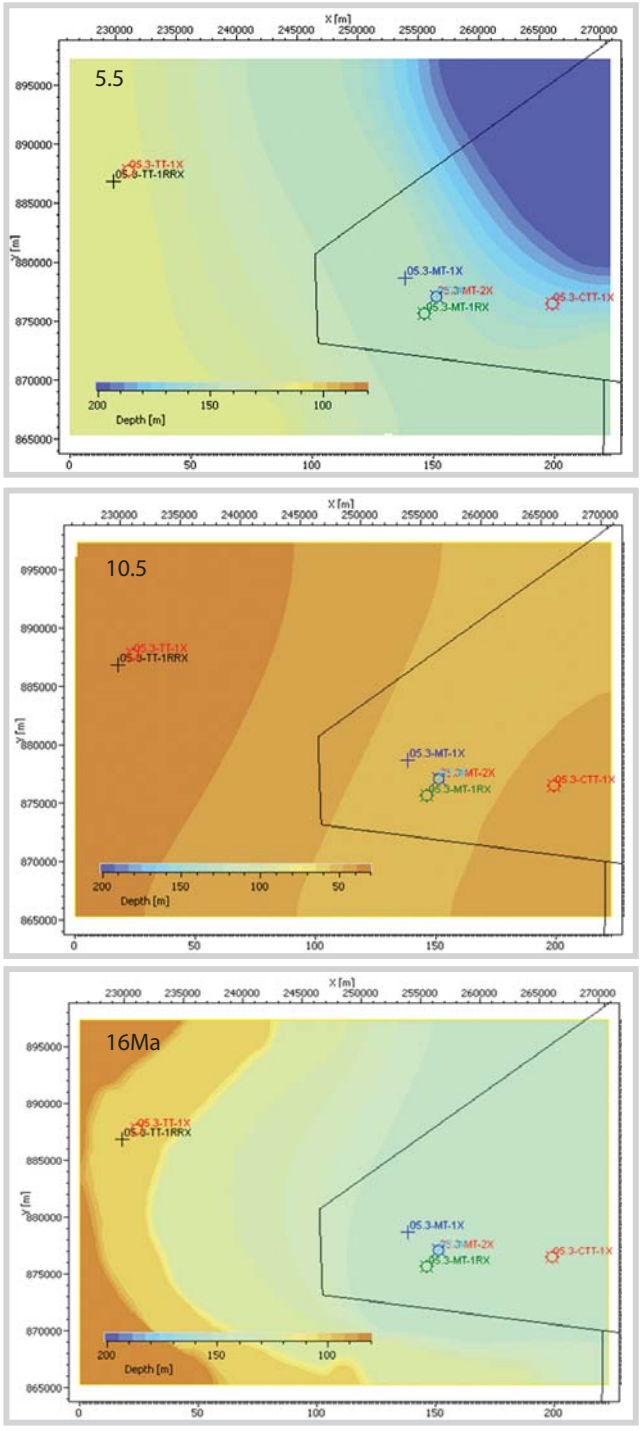


Figure 5. *Paleo water depth (PWD) maps at key events*

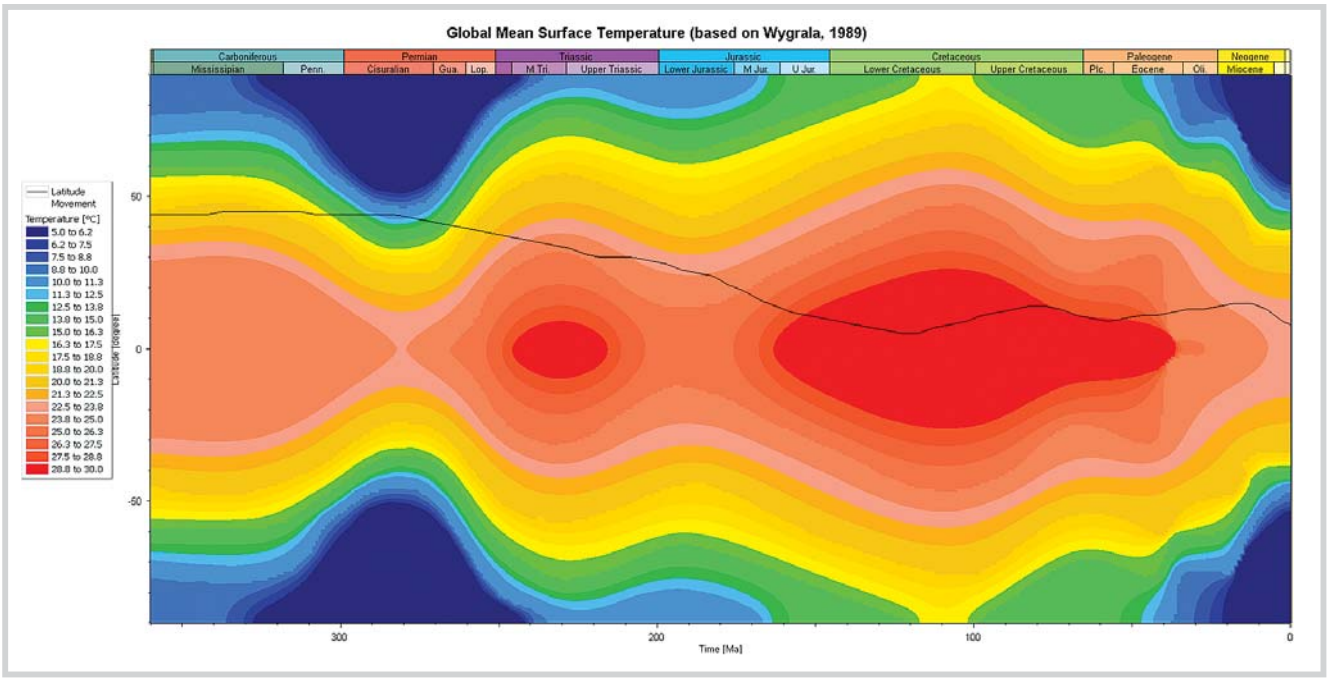


Figure 6. *Sedimentary Water Interface Temperature (SWIT) at latitude 8°, South East Asia*

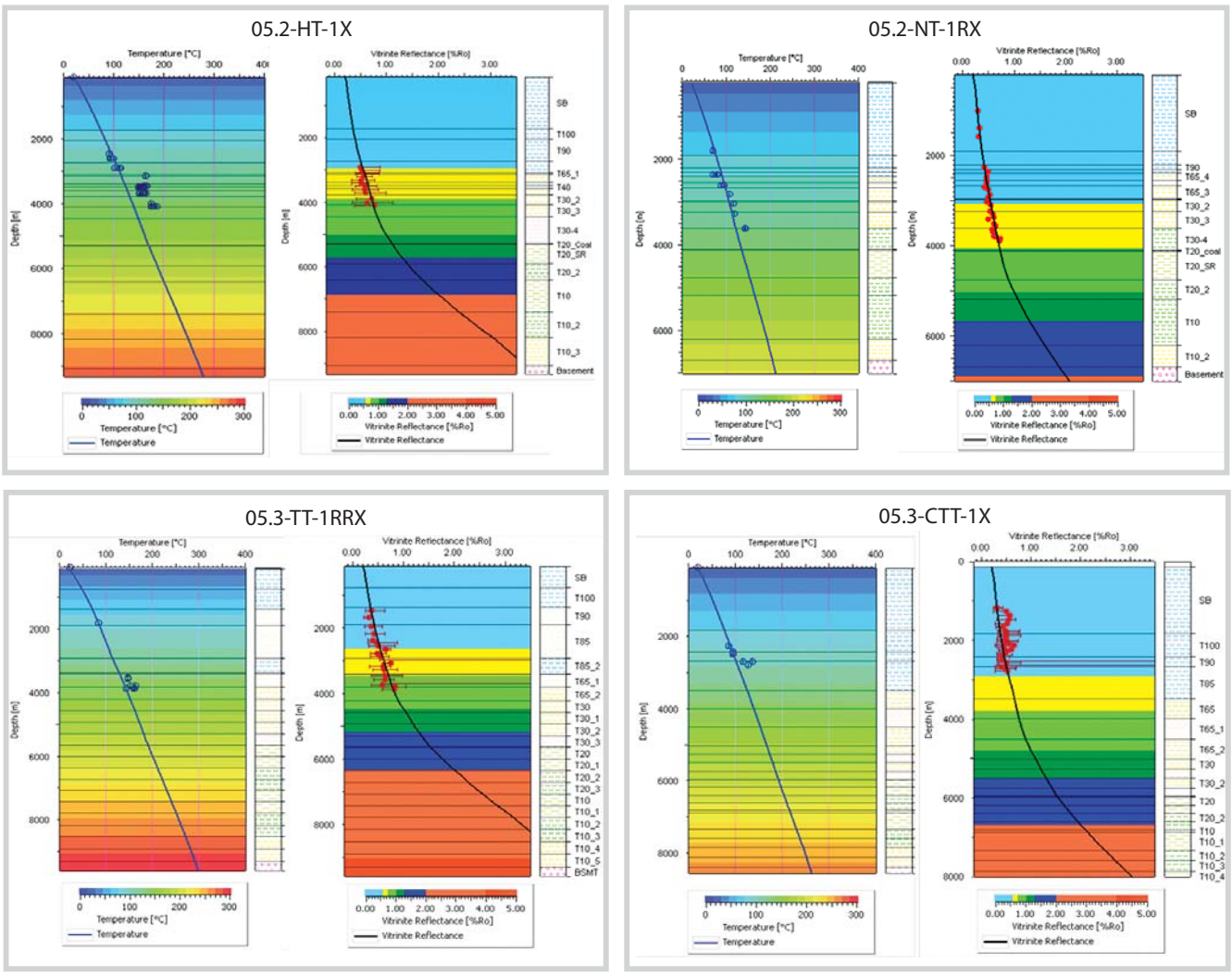


Figure 7. *Vitrinite calibration of key wells in Blocks 05-2 & 05-3*

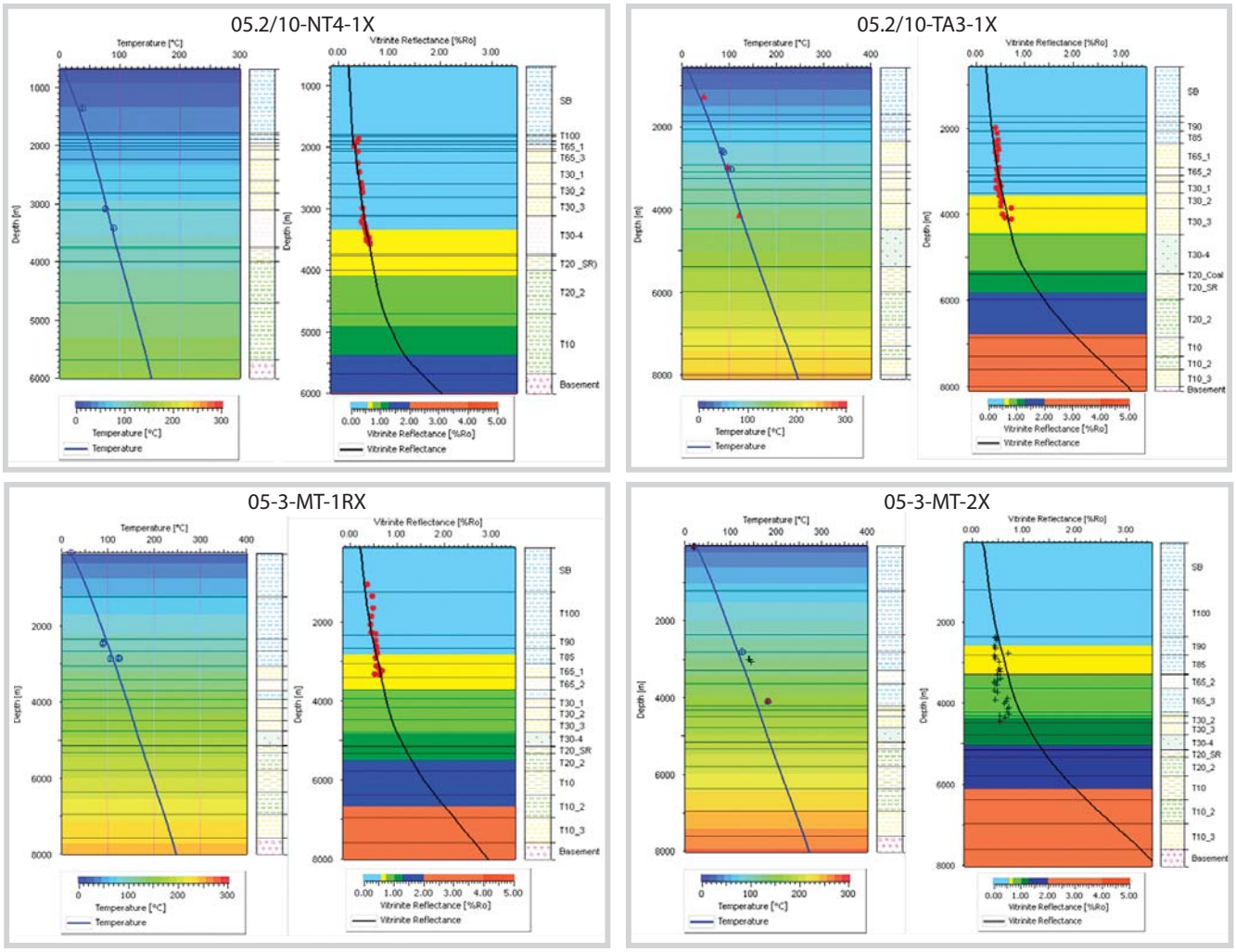


Figure 8. *Vitrinite calibration of key wells in Blocks 05-2 & 05-3*

flow model is a modification of the classic McKenzie model (McKenzie, 1978) [1]. The heat flow profiles have been well calibrated with measured vitrinite reflectance and temperature values from wells (Figure 7, 8). It can be observed that heat flow exhibit profiles 2 peaks at 30Ma and 10.5Ma which are consistent with reliable rifting phases in the Nam Con Son basin (Figure 9). The recent uprising in heat flow observed from the 1D modelling is consistent for all modelled wells in the Nam Con Son basin.

The heat flow trends of 1D models were used to interpolate the heat flow maps in 3D models.

2.4. Kerogen type and source rock kinetic

For 3D models, main source rocks are swamping shale in the Oligocene - Lower Miocene sequences, and some lacustrine source was assumed existing in deep grabens. The input TOC and in 2D models were determined from the highest frequency of analysed samples for each source rock formation. Oligocene swamping deposit is the primary source rock for Nam Con Son basin with most-likely TOC of 2% and HI of 400mgHC/gTOC.

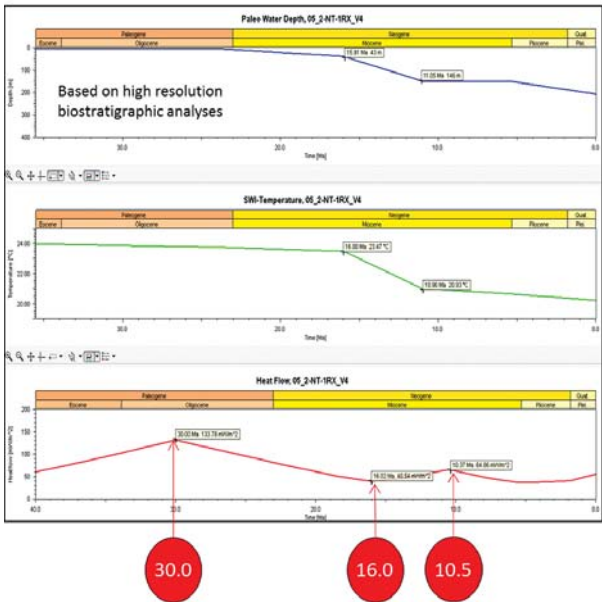


Figure 9. *Boundary conditions used to calibrate temperature and vitrinite*

Based on the study of the depositional environment, the lacustrine source rock may be limited. In addition, coal was encountered at near top T20 sequence such

as in LD-1X, NT4-1X wells with the total thickness up to 20m. The averaged TOC (av. 53.84%) and HI (av. 224) were used for the coal layers. The organic richness of T30 shale seems to be poor with most-likely TOC of about 1% and HI of 300mgHC/g TOC.

With the organofacies concept of Oligocene and Early Miocene mentioned above, it can be seen that the source rocks in the study area mainly consist of type III kerogen and minor type II/III deposited in the swamping environment. For that reason, compositional kinetic models named Handil_Mahakam Delta; IES_TIII_Tertiary_Coal_4C were selected for Oligocene - Lower Miocene shale and coal.

3. Modelling results

3.1. Maturity of source rock

In basin analysis studies, vitrinite is used to calibrate the burial and thermal history models as well as hydrocarbon generation. The approach to determination of vitrinite-reflectance value is using temperature and measured Ro of key wells to calibrate modelled maturity.

The 3D modelling results show the detailed maturity level of all potential source rocks in Block 05-3. Modelled Ro maps indicate that the Oligocene (T20 sequence) section is mature for generation and expulsion of wet to dry gas in the study areas (Figure 10). In fact, the maturity maps point out the T20 source rock located at the central area completely entered the dry gas phase (red colour), while due to burial depth source rock at Moc Tinh and Tho Tinh well is now wet gas (blue colour) in top T20.

At shallower stratigraphy levels T30 - Lower Miocene source rocks entered the oil window to the dry gas phase over most of Block 05-3. The T30 sequence was split into 4 subzones named T30-4; T30-3; T30-2 and T30-1 (Top T30) in the 3D Petromod models. Due to the influence of the depositional environment (shore - face sand and shallow marine) in upper parts T30, the lowermost part of the sequence T30-4 was considered as Lower Miocene source rock (Figure 11).

3.2. Timing of hydrocarbon generation and expulsion

Based on extracted 1D models combined with the cumulative generation curve (Figure 12), it can be clearly seen that T30 source rock has generated HC since 12Ma in the central area while T20 SR has generated HC since 24Ma in the central area and migration phase was widespread from 15Ma to 8Ma. In fact, the increase in maturity level of Oligocene source rock is not stable; it is commonly

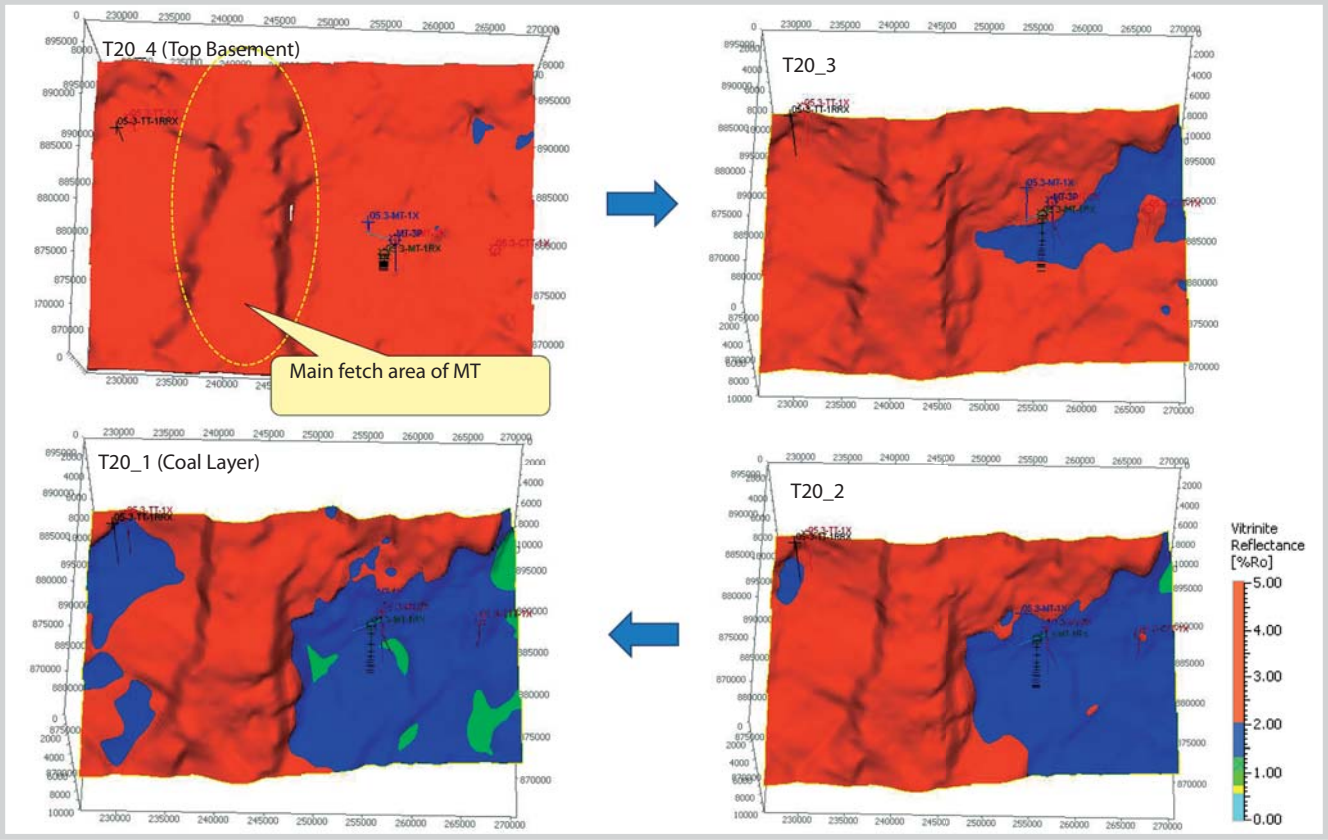


Figure 10. *Modelled vitrinite reflectance for T20 source rock*

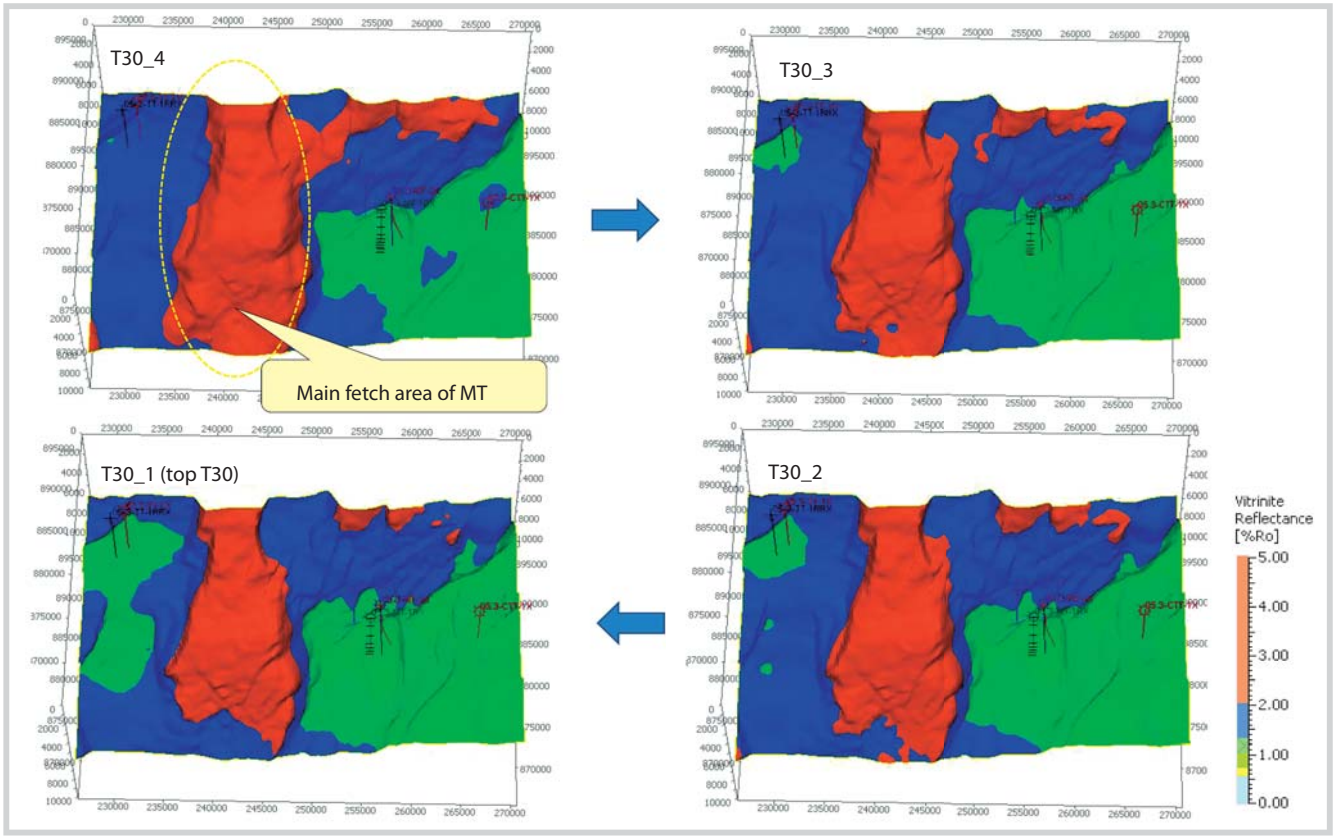


Figure 11. *Modelled vitrinite reflectance for T30 source rock*

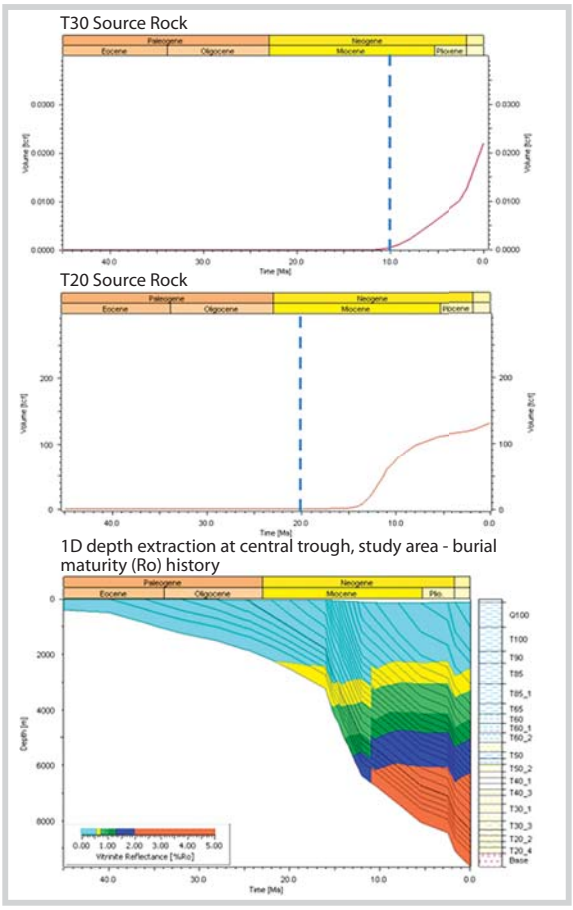


Figure 12. *Cumulative generation and expulsion of source rock layers in Block 05-3*

speeded up during rifting phases or high heat flow phases. This explains why during the Early Miocene the generation was not much changed, but it significantly increased during the Middle Miocene (16 - 10.5Ma).

Moreover, Lower Miocene source rock started to generate hydrocarbon since 12Ma. At that time, this source rock was in the early mature stage. The main oil generation time of this source rock is from 5.5Ma to present.

3.3. Hydrocarbon migration and accumulation

Together with the source rock potential and maturity, the effectiveness of migration is a key factor deciding the exploratory success or failure [5].

3D Model accumulation volume or fluid composition outputs can be compared with the information at discovery wells of Block 05-3 and the model can be adjusted to improve the match. Figure 13 shows that flow path lines for all levels, all accumulations, with Oligocene TR map underneath; fault (gray colour) provides a preferential migration pathway.

Firstly, the accuracy of simulation was proven by matching at discovery wells (the wells in Moc Tinh fields). Most Oligocene source rock is in gas prone at present, so it is reasonable to explain why the accumulations in Moc Tinh discovery are condensate and dry gas (CH_4).

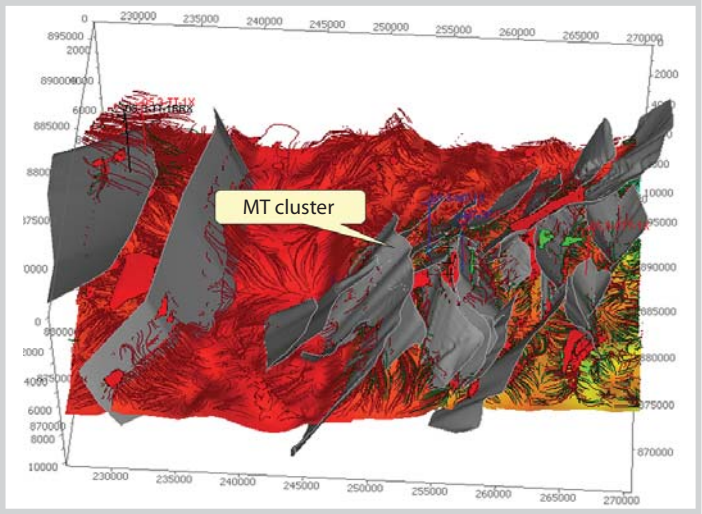


Figure 13. *Flow path lines for all levels, all accumulation in study area*

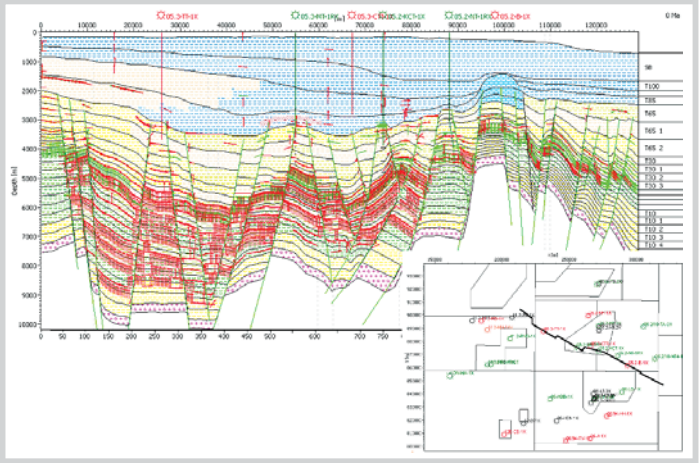


Figure 14. *Hydrocarbon migration and accumulation in Moc Tinh and Tho Tinh prospect-2D basin modelling*

To increase the accuracy of basin modelling, the 2D migration and accumulation model is simulated. Based on 2D modelling results, the charge system in the central part of the Nam Con Son basin is dominated by vertical migration through faults and imperfect intra formation seals. Moreover, Moc Tinh and Moc Tinh Tay structures can be charged with higher column height of gas and condensate (Figure 14).

The modelling results of 3D petroleum system modelling show possible significant accumulations in T50, and T85 reservoir levels in the Moc Tinh Tay structure. Besides, it is predicted that the parts of T30 sequence on the Moc Tinh Tay structure have been charged by minor amount of oil and gas.

4. Conclusions and recommendations

In this study, detailed 1D, 2D, and 3D modelling of petroleum system in Block 05-3 has been carried out. The inputs for the modelling have been integrated from various investigations on structural development, paleo-depositional environment, heat-flow calibration, top seal calibration, source rock properties and the aspects of in-fault migration. The results show that:

- The Oligocene, Lower Miocene sedimentary layer contains mainly kerogen type III and a mix of kerogen type III and I. The Oligocene, Lower Miocene source rocks have got enough organic matter richness for HC generating.

- Hydrocarbon generation potential: Main source rock (Oligocene & Lower Miocene) is mainly located in the centre trough and in gas prone at present.

- Migration and charge: Hydrocarbon was expelled since 24Ma from Oligocene T20 SR which widely migrated from 15 to 8Ma.

- Main accumulation in prospect Moc Tinh Tay is in T50 and T30 layers. No accumulation in Oligocene sandstones due to low porosity.

- Uncertainties of model: the presence and amount of HC accumulations depend on time-depth conversion; sample grid; and fault properties.

In general, the findings from basin modelling reveal that Moc Tinh Tay prospect can be charged from source rock in surrounding areas with significant amount. To reduce investment risk in oil and gas exploration in Block 05-3, further studies including verification of facies and lithology distribution at Moc Tinh Tay prospect by seismic inversion are recommended.

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