
Modelling hydrocarbon generation and migration in tertiary source rocks of deepwater, Phu Khanh Basin, offshore Vietnam

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Abstract: This study modelled a petroleum system to analyse the history of basin evolution, maturity, and hydrocarbon generation in the deepwater of the Phu Khanh Basin, offshore Vietnam. The paleo-heat flow, surface-water interface temperatures, and paleo water-depth were modelled using existing wells occurring in shallow to deep marine environments. Based on the geochemical analysis, the Oligocene and Lower-Middle Miocene source rocks are predominantly a mixture of type II and type III kerogens, with differences in distribution and maturation level. In the Phu Khanh Basin, hydrocarbon generation started during the Early Miocene. Petroleum migrated to a trap and accumulated in an uplift structure in the sandstone and carbonate reservoirs of the Lower Miocene formation. The results of this study can assist in defining the distribution of reservoir locations for future field development planning in the Phu Khanh Basin. [Received: March 28, 2020; Accepted: August 7, 2020]

Keywords: Phu Khanh Basin; hydrocarbon generation; migration; heat flow; source rock; Vietnam.

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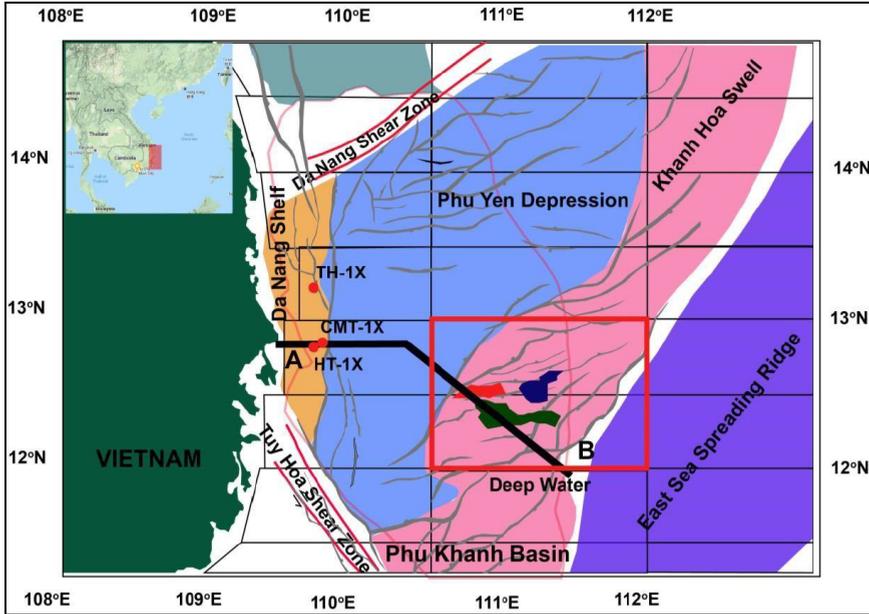
1 Introduction

Seismic survey and drilling activities remain challenging in deepwater regions, especially at depths greater than 1,000 m below sea level (Weimer et al., 2006). The Phu Khanh Basin is considered a deepwater sedimentary basin located on the continental shelf of Central Vietnam. Its boundary spans approximately 250 km, from 11°N to 14°N, and 50–75 km, from 109°20'E to 111°E (Bojesen-Koefoed et al., 2005; Nguyen et al., 2012).

The Phu Khanh Basin lies adjacent to the southern part of the Song Hong Basin, northeast of the Cuu Long (CL) and Nam Con Son (NCS) basins, and next to the Da Nang and Phan Rang shelves toward the western shore of the basin. The shallow marine region of the western section of the basin is less than 300 m in depth. The depth increases gradually from 300 m to 4,000 m below sea level toward the east. The basin is surrounded by N-S (meridian fault 110°) and NW-SE fault systems [along the spreading axis of the South China Sea (SCS)], which are separated by different structural segments (Savva et al., 2013). The most significant tectonic structures have been

classified into five units: Da Nang Shelf, Phan Rang Shelf, Phu Yen Depression, Tuy Hoa Shear Zone, and Khanh Hoa Swell (Nguyen, 2007; Tran et al., 2019) (Figure 1). The Phu Khanh Basin is considered as one of the last remaining frontier basins in Southeast Asia (Savva et al., 2013).

Figure 1 Location and major tectonic structures of the Phu Khanh Basin (see online version for colours)



The history of oil and gas in the Phu Khanh Basin remains sparse and inconsistent. The first gravity survey was performed on the western wing of the Phu Khanh Basin in the 1970s. Along with a series of magnetic-gravity surveys, seismic exploration in the deepwater was conducted in 2008 using a multi-client two-dimensional (2D) seismic program by GeoStreamerTM, which the length of the seismic survey covered a stretch of 14,500 km (Maingarm et al., 2011). The evidence of algae-rich sapropel layers in the oil seeps of the Dam Thi Nai Lagoon has generated interest regarding the origin of the oil in the area (Bojesen-Koefoed et al., 2005; Fyhn et al., 2009).

The latest seismic and well data have been used for a detailed structural interpretation and horizon geometries. The data were obtained from wells TH-1X and CMT-1X in 2009, and HT-1X in 2011, which were drilled into the uplift blocks in the shallow-water basin. Checkshot surveys and depth markers were used to investigate CMT-1X and the biostratigraphy and geological records were apparent in TH-1X, CMT-1X, and HT-1X. The only oil and gas recorded were in CMT-1X in the Lower Miocene carbonate reservoir (Nguyen et al., 2012), which has been regarded as the first evidence of hydrocarbon potential in the Phu Khanh Basin. However, no well explorations have yet been undertaken deeper than 1,000 m sea level.

The tectonic mechanism and petroleum potential of the Phu Khanh Basin have attracted the attention of researchers. These studies have typically included seismic stratigraphic and structural analyses of the northwest Phu Khanh Basin (Lee and Watkins,

1998; Fyhn et al., 2009; Maingarm et al., 2011), hydrocarbon generation potential and its implications (Bojesen-Koefoed et al., 2005; Fyhn et al., 2009; Maingarm et al., 2011; Nguyen et al., 2012; Vu et al., 2017), tectonic history of the SCS (Briais et al., 1993; Cullen et al., 2010; Franke et al., 2014), in Southeast Asia (Morley, 2002), and the Phu Khanh Basin evolution (Savva et al., 2013; Hoang et al., 2013; Vu et al., 2017; Tran et al., 2019).

Nguyen et al. (2012) used Sigma-2D software to model the generation, migration, and accumulation of petroleum in the shallow marine region of the Phu Khanh Basin. The results showed that there are two types of source rocks. Oligocene source rock generated oil window since the Middle Miocene and in the gas phase of the whole basin at present. The Lower Miocene source rock reached the oil window in the Late Miocene and is presently in the gas phase in the centre of the basin. Using a database for the CS-1X and CMT-1X wells, however, Nguyen et al. (2012) conducted basin simulations assuming heat flow (HF) values in the range of 1.3–1.5 heat flow unit (HFU) on the measured temperature of the wells, which created uncertainties in predicting the hydrocarbon generation time. Therefore, the effects of paleo-HF on the process of oil and gas generation in the Phu Khanh Basin is significant.

This study reconstructs the history of hydrocarbon generation based on seismic interpretations at a high resolution, with a grid of 1 km × 1 km. The geological cross-section of the 2D model was selected to cover the entire topography of the Phu Khanh Basin, from the shallow marine to deepwater environments. In addition, the characteristics of the source rock in the deepwater area were described using existing wells in adjacent regions. The paleo-HF, paleo water depth (PWD), and paleo sediment water interface temperature (SWIT) were reconstructed as ancient climatic conditions to facilitate hydrocarbon production. This model revealed an initial picture of the basin evolution, the maturity of source rock, hydrocarbon generation, and migration path in the deepwater regions of this basin in Vietnam.

2 Geological setting

The tectonic development of the Phu Khanh Basin is tied to the rifting and spreading history of the SCS through a substantial multi-phase process of regional extension, compression, wrenching, and inversion (Cullen et al., 2010; Savva et al., 2013). Toward the southeast, there was a great attenuation of the continental crust beneath the NW Borneo Trough and Baram-Balabac Foreland Basin (Morley, 2002; Cullen et al., 2010). The earliest phase of rifting in the SCS began in the Late Cretaceous to Early Paleocene with the extension of a Mesozoic convergent margin. After approximately 30 Ma of rifting, the major eastern sub-basin of the SCS began to break up during the Early Oligocene (Franke et al., 2014). Rifting continued and the subsequent breakup of the southwest sub-basin occurred during the Late Oligocene (Fyhn et al., 2009; Vu et al., 2017).

The Phu Khanh Basin developed as a typical rift-margin basin, which has been identified to have undergone two rift phases, a Paleogene-Eocene synrift and an Early Miocene-Late Miocene post-rift, separated by the late Oligocene breakup unconformity (Lee and Watkins, 1998; Fyhn et al., 2009). The two rift phases of the evolutionary history comprised the first rifting phase from the Paleocene to Eocene as an expansion period, and the second phase included a regional extension from

the Late Eocene to Early Miocene (Fyhn et al., 2009). Thermal subsidence created a substantial sinkhole in the post-rift phase after the Middle Miocene (Lee and Watkins, 1998; Fyhn et al., 2009). This subsidence is the primary factor affecting the sediments that had filled the Phu Khanh Basin, where the various sediments had originated from shallow water and settled in the deepwater to ultra-deepwater regions. Furthermore, large geothermal energy sources had migrated up the faulting system, potentially heating the source rocks to generate oil and gas.

By updating the latest seismic interpretation, the tectonic evolution of the deepwater Phu Khanh Basin was recognised to have undergone three phases:

- *Eocene-Early Miocene (56–15.97 Ma)*: a rifting phase caused a substantial continental crustal extension (up to 36 Ma) that was determined by strike-slip faults and horizontal movement accompanied with thermal anomalies (Savva et al., 2013). During the Late Eocene, the sediments were deposited within a continental environment with possible alluvial fans and conglomeratic reservoirs (Fyhn et al., 2009). During the Oligocene, as the basins created more space, a more fluvial-lacustrine-deltaic environment dominated. The deposition sediments contained coal and shale, producing the primary source rocks in the basin. Fluvio-deltaic sheet-like sands and sand bars belonging to the synrift sequence could be the potential petroleum reservoirs.
- *Early-Late Miocene (15.97–5.33 Ma)*: the seafloor spreading of the SCS ceased at the end of the Early Miocene (–15 Ma) (Briais et al., 1993; Fyhn et al., 2009), and subsequently, a considerable portion of the inferred oceanic crust had been subducted at the Manila Trench in the east. The continental crust gradually cooled and shrunk after the Middle Miocene. The basin was then pulled apart by strong tectonic reactivity along the 110° meridian fault (Hoang et al., 2013; Tran et al., 2019), storing heat magma in thermal anomalies.

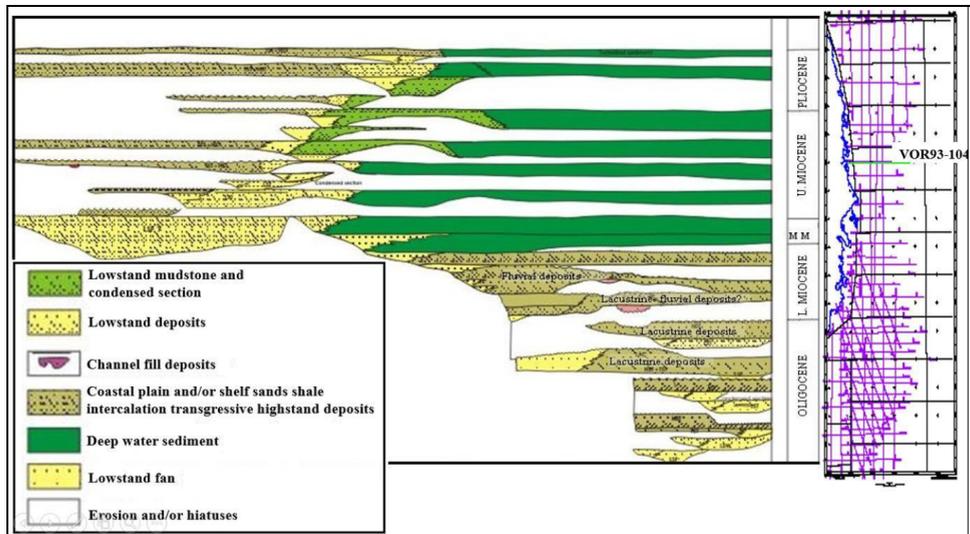
Consequently, during the marine transgression in the Late Oligocene, a widespread build-up of carbonates on the shelf and basin peaks occurred during the Early and Middle Miocene. A terrigenous influx due to the inversion in the Upper Oligocene formation resulted in the deposition of both shallow marine siliciclastics and turbidities to the east of the continental shelf. The top of the Middle Miocene formation is characterised by a regional unconformity (Savva et al., 2013; Tran et al., 2019), which exhibited considerable amounts of erosion in both the Song Hong and NCS Basins simultaneously. This areal unconformity is associated with a eustatic sea-level fall linked to the termination of seafloor spreading in the SCS.

After the Late Miocene, there was an eastward tilting of the region due to increased volcanism in onshore Vietnam, maintaining increased sediment accumulation rates, water depths, and transgression in the Phu Khanh Basin. West of the basin, there was a rapid progradation of deltaic sediments toward the shelf edge, which drowned and buried the platform carbonates and reefs. A series of large Late Miocene submarine slope fan complexes were deposited immediately above the Middle Miocene unconformity toward the eastern slope. The Pliocene and Pleistocene shelf sediments are characterised by prograded deltaic clinoforms, which, through time, had migrated toward the shelf break further east. The sedimentary sections observed east of the shelf were mainly comprised of deepwater shales with discrete intercalated turbidite bodies.

- *Pliocene and Pleistocene (5.33 Ma–present)*: in a recent study, hot venting on axial volcanic seamounts on the seabed was reported (Tran et al., 2019). This is indicative of the quick cooling and shrinkage that led to rapid thermal subsidence since the Pliocene and Pleistocene epochs.

Sediment accumulation has been distributed in the grabens with horizontal lithofacies and specific vertical stratigraphic columnar sections; the process is closely related to global sea level change and regional tectonic activities. The lithofacies and deposition environments have been interpreted from the well-log data on the VOR93-104 seismic section, as shown in Figure 2 (Mai et al., 2003).

Figure 2 Lithofacies distribution from the shallow to the deepwater marine through VOR93-104 seismic route (see online version for colours)



The synrift phase was characterised by lacustrine and alluvial sediments during the Oligocene. Carbonate deposits developed and became predominant in the early phase of the transgression from the Early to Middle Miocene. Terrigenous sediments were deposited during the inverse phase at the top of the Oligocene formation, where siliciclastics were formed in the shallow areas and turbidites located in a low slope extending from the eastern slope of the basin.

A rapid progradation of deltaic sediments toward the shelf edge was initiated at the end of early Miocene in the western part of the basin; this was also the period for sinking and burial of deep carbonate deposits and reefs. Submarine slope fan complexes of the Upper Miocene formation overlaid the Middle Miocene unconformity that had spread into the eastern slope. The Pliocene and Pleistocene shelf sediments accumulated as predominately prograded deltaic clinoforms, which characterised the facies transition zone from shelf to deepwater.

3 Methodology

The mechanisms of oil and gas generation vary from basin to basin depending on the key elements of sedimentary facies, burial history, tectonics, and other geologic processes that were simulated based on the input of the initial basin model. A thermal maturity history was defined on the paleo-geothermal regime that related to the burial depth of the source rocks within the basin. A multi-dimensional basin model was generated to clarify the history of the generation, migration, and accumulation of hydrocarbons. As shown in Figure 3, the workflow for hydrocarbon generation history is described as follows:

Step 1 Geology and geophysics interpretation

- Re-interpreting 2D seismic routes with a grid resolution of 1×1 km and time-depth conversion for a typical seismic section.
- Building of a litho-stratigraphic model, including layer thickness and lithological properties of the main formation, which also includes faults and their properties.

Step 2 Source rock parameters

- Defining source rock properties to evaluate the intensity of hydrocarbon generation using geochemical indices, such as total organic carbon (TOC) content, hydrogen index (HI), and kerogen type. The dynamic kinetics describing the generation and transformation of the organic matter is also defined.

Step 3 Boundary conditions

- Defining the three primary boundary conditions (paleo-HF, PWD, and paleo SWIT) to reconstruct an evolution history of the thermal gradient in various stages in the geological region. This step also helps to calculate the burial history of the various layers within the basin. The paleo-HF can be modelled considering the tectonic events and evolution of the basin.

Step 4 Hydrocarbon generation history

- The output of the model was calibrated to match the practical measured data. The model parameters were correspondingly modified, and the simulation was repeated until a reasonable result with acceptable errors was obtained.

3.1 *Geology and geophysics interpretation*

3.1.1 *Seismic re-interpretation*

It was necessary to implement a conversion between the time domain in the well-log data and the depth domain in seismic data through a time-depth correlation based on the checkshot data. The well tops were converted from the depth to time domain to match the formation tops in the seismic data, and the main horizons were chosen (Figure 4). The data were converted largely using the stacking velocity that was generated during the original processing of the multi-channel reflection data. Numerous small-scale faults were encountered in the seismic data; therefore, for simplicity, only major faults governing the structural and petroleum system are shown in the interpretation results to depict the general geological structures of the study area.

Figure 3 Workflow for basin modelling (see online version for colours)

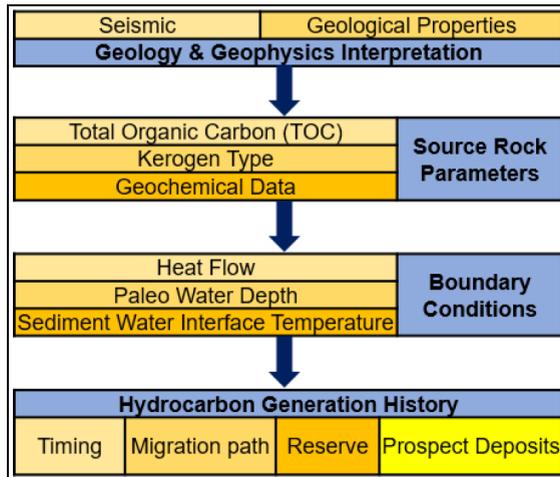
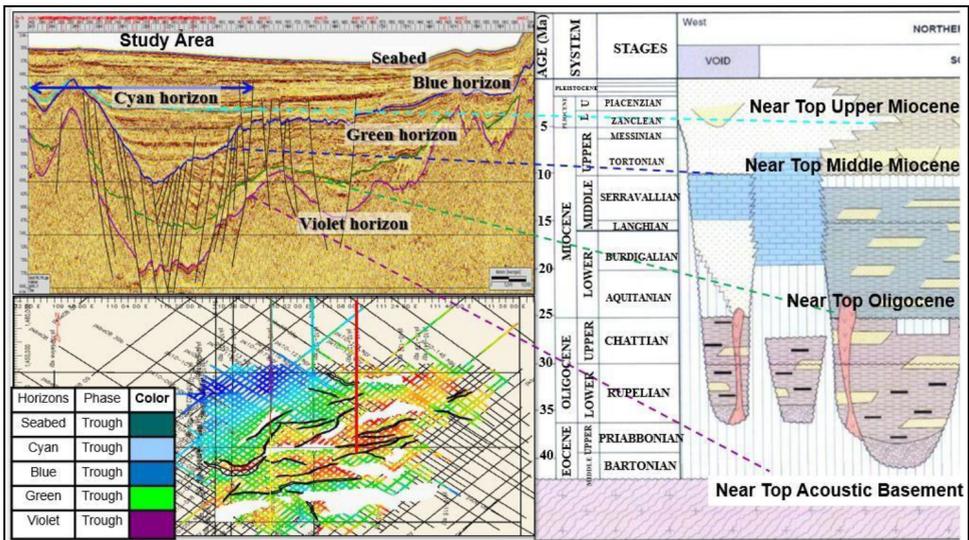


Figure 4 Stratigraphic and seismic interpretation along meridian direction (see online version for colours)



The 2D seismic sections were interpreted to have six main horizons: seabed, near top Pliocene, near top Upper Miocene, Mid Miocene unconformity, near top Oligocene, and near top basement. The 1×1 km grid was redistributed for better resolution than the original map (Figure 5). A selected geological section of the AB route was crossed for special structural elements marked as structural uplift/anticline, wings, the epicentre of the Phu Yen depression and Khanh Hoa swell, structural/stratigraphic traps formed in a four-way-closure trap for oil and gas accumulation, and prospect structures (Figure 6).

Figure 5 Comparison of seabed time map between original seismic data and newly updated seismic data (see online version for colours)

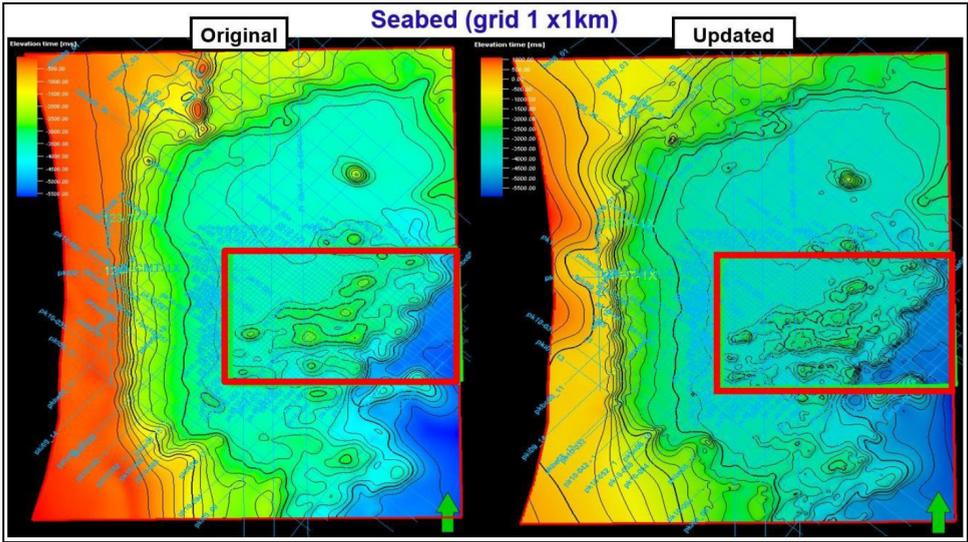
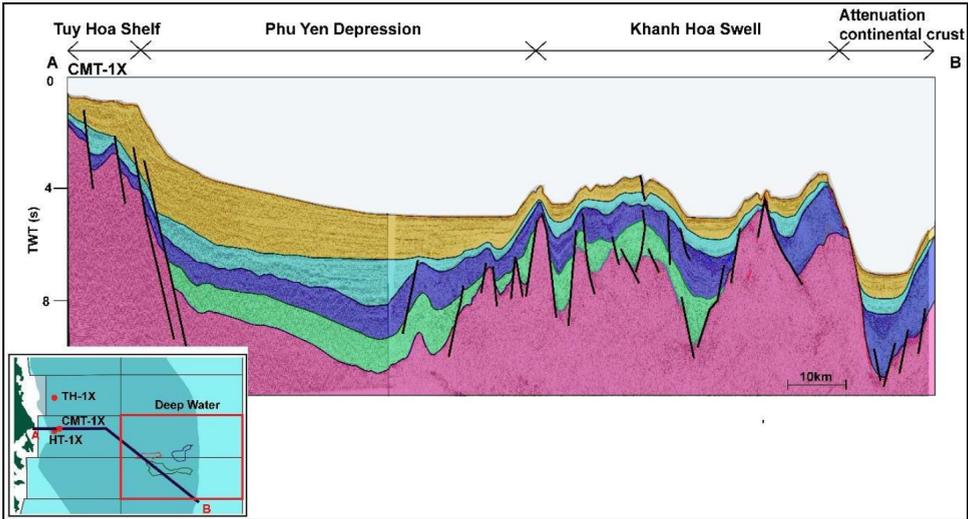


Figure 6 Seismic section surveyed along the AB route (see online version for colours)

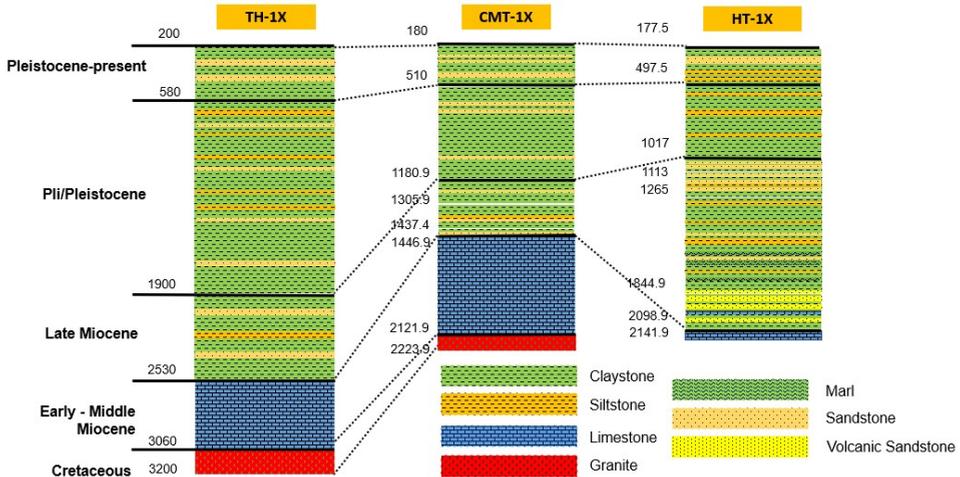


Faults play an important role as channel paths for oil and gas occurring in reservoirs. The faults were assigned attributes, including age and property, such as the shale gouge ratio (SGR) or fault capillary pressure (FCP), which indicated the degree of sealing/openness of the fault. These properties determine the times and degrees to which the faults influenced hydrocarbon migration and accumulation. Most major faults stopped during the Middle Miocene and few minor faults opened in the Late Pliocene during thermal subsidence. Fault properties in 2D were defined by the duration of faulting and the width and permeability of the faults.

3.1.2 Geological properties

Each set of well data was used to establish a relationship between the seismic facies and lithofacies. The correlation between the lithological components of the TH-1X, CMT-1X, and HT-1X wells and the interpreted seismic sections were divided into six facies: siltstone, claystone, volcanic sandstone, limestone, sandstone, and granite (Table 1). The correlations of the lithological facies of the three wells are illustrated in Figure 7.

Figure 7 Well correlation between TH-1X, CMT-1X, and HT-1X (see online version for colours)



3.2 Source rock parameters

Two approaches, an experimental approach and another approach similar to the experimental approach, were implemented to determinate the geochemical parameters; these are described as follows:

- Rock-Eval pyrolysis is an experimental method to identify the type and maturity of organic matter and to detect petroleum potential in sediments based on core sample data collected from existing wells in shallow areas.
- A similar approach is to match the kerogen type based on the Cenozoic sedimentary basins and adjacent regions, where the formation mechanisms of the CL, NCS, and Phu Khanh Basins are similar. Therefore, source rock properties have the same origin.

Based on the geochemical database of the TH-1X, CMT-1X, and CVX-1X wells, TOC and HI were selected in value range between the minimum and maximum (Table 2). According to Weimer et al. (2006), Neogene source rocks in the deep sea of Borneo (Indonesia) and Malaysia have considerably high TOC/HI values of more than 2–20%. The Middle Miocene-Neogene deep marine clay sediments in the Phu Khanh Basin have incredibly high TOC/HI values. These values from regions adjacent to the CVX-1X well (northern part of the Phu Khanh Basin), such as the NCS and CL basins, could be applied to Oligocene source rock.

Table 1 Interpreted horizons, geological age, and lithology

<i>Interpreted horizon</i>	<i>Layer</i>	<i>Age (Ma)</i>	<i>Lithology (facies)</i>
Near top seabed	Seabed	0	Claystone + minor interbedded sandstone
Near top Pliocene	Plio-Pleistocene	2.58	Claystone 75–95%; sandstone 5–25%
Near top Upper Miocene	Upper Miocene	5.33	Claystone/shale with occasional thinly interbedded sandstone and siltstone
Near top Middle Miocene	Middle Miocene	11.63	Claystone 90–100%, sandstone 0–10%; Siltstone 5%
Near Lower Miocene	Lower Miocene	21	Predominantly limestone with dolomitic zones and thin shale interbeds
Near top Oligocene	Eocene-Oligocene	23.03	75% shale, 25% sand
Near top basement	Basement	120	Basement

Table 2 The source rock characteristics in deepwater Phu Khanh basin from the well data of shallow marine and adjacent basins

<i>Source rock</i>	<i>TOC (% wt.)</i>	<i>HI (HCmg/g)</i>	<i>Kerogen</i>	<i>Location</i>
Neogene	2–20	300–700	II/III	Deepwater
Lower Miocene	1.25–2.03	131–269	III	TH-1X
	0.41–1.01	83–380	III/II	CMT-1X
	1–2	150	II/III	05-1C, 06D NCS basin
Eocene-Oligocene	5	400–700	II/III	Enreca-1 (Santos's Report, 2010)
	6	440	III/II	CVX-1X
	0.6–4.0	298–346	III/II	NCS and CL basins
<i>Phu Khanh Basin</i>				
Upper/Middle Miocene	2.5	280	II/I	Deepwater
Lower Miocene	2.0	250	III/II	Deepwater
Eocene-Oligocene	1.8	320	III/II	Deepwater

The maturity modelling was based on the Sweeney and Burnham (1990) kinetic model. The calculations of the transformation ratios for the assigned source rock intervals were based on the Tissot and Welte (1984) TII and TIII hydrocarbon generation kinetics, and the implemented generation kinetics depended on the facies assigned.

3.3 Boundary conditions

The initial boundary conditions, HF, PWD, and SWIT, play a significant role in building an evolutionary history of the basin (Schlumberger, 2012) and significantly affect the thermal maturity of the source rock that is generating petroleum.

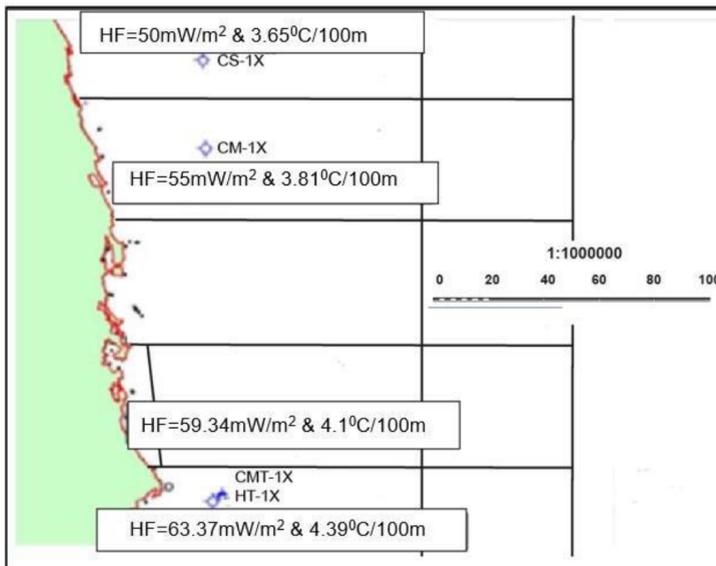
3.3.1 Heat Flow

Geothermal data provide critical constraints for models of global accretion, core-mantle segregation, and crustal evolution. The temperature history is a controlling factor in the maturation of organic compounds into fossil fuels. HF (Q) can be calculated as a function of the thermal gradient and thermal conductivity as follows:

$$Q = -\lambda \frac{\partial T}{\partial z'}$$

where λ is the thermal conductivity ($\text{Wm}^{-1}\text{K}^{-1}$), $\frac{\partial T}{\partial z}$ is the thermal gradient ($^{\circ}\text{C}/\text{km}$), and the negative sign indicates the direction of HF from high to low temperature. Note that $Q < 0$ indicates the direction of increasing temperatures and $Q > 0$ indicates the direction of decreasing temperatures.

Figure 8 The average HF and geothermal gradient in the Phu Khanh Basin (see online version for colours)



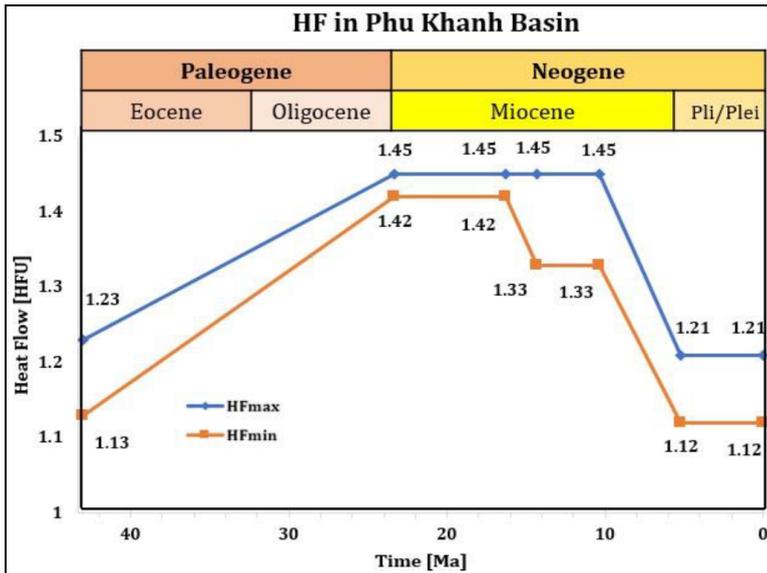
The age and thickness of the continental crust affect the surface HF mostly through their effects on crustal heat generation. In general, radiogenic elements in older crust are depleted through natural decay, and as a direct consequence, older crust typically exhibits lower surface HFs (Sass and Lachenbruch, 1979; Teichmuller and Teichmuller, 1986) and thermal gradients. Similarly, the volume of the heat-producing material is directly proportional to the thickness of the crust. Therefore, a thicker crust contributes more heat than a thinner crust of the same age.

HF accumulation in uplifted structures is often higher than in grabens or troughs. The HFs of the CS-1X and CMT-1X wells in the Phu Khanh Basin were measured as approximately $50 \text{ mW}/\text{m}^2$ ($3.65^{\circ}\text{C}/100 \text{ m}$) and $55 \text{ mW}/\text{m}^2$ ($3.81^{\circ}\text{C}/100 \text{ m}$), respectively (Santos's Report, 2010). In the TH-1X well, the geothermal gradient was approximately

4.1°C/100 m. The seabed temperature of the CMT-1X well was approximately 17°C at 193 m below the sea level. The static bottom-hole temperature (BHT) at 3,200 m (true vertical depth sub-sea) was measured as approximately 142°C, and the geothermal gradient was calculated to be 4.39°C/100 m using the Horner correction diagram. Therefore, the static BHT was extrapolated as 106.5°C. The geothermal profiles of the wells showed that HF increased toward the western part in the shallow marine areas, but decreased gradually toward the east in the deep marine region, with the lowest HF of 1.12 HFU (conversion 1 HFU = 41.86 mW/m²) positioned in the central part of the Phu Yen depression. The geothermal gradients and HF measured in the existing wells are shown in Figure 8.

The 110° meridian fault was significantly reactivated during the Early Middle to Late Miocene period due to the spreading seafloor of the SCS, leading to the formation of sub-basins filled by Oligocene-Lower Miocene sediments. In addition, the heat plume moved upward into the seabed leading volcanic activities appearing during the Pleistocene. The value of the HF has been dropping rapidly since the Middle Miocene and is currently at the lowest value. This result is due to rapid crustal cooling and shrinkage accompanied by the thermal subsidence stage. Therefore, the average values of HF in deep water could have been in the range of 47.26–63.9 mW/m² (1.12–1.45 HFU) during this time. The paleo-HF could be modelled by considering the tectonic events and evolution of the basin (Figure 9).

Figure 9 Heat flow (see online version for colours)



3.3.2 Paleo water depth

In previous research, it has been reported that the resulting PWDs fluctuated within the range of 50 m and 200 m during the Oligocene-Early Miocene (Miller et al., 2004) with lacustrine-derived sediment accumulating in the sub-basins (Figure 10). The reactivation of the 110° meridian strike-slip fault in terms of movement and stretching during the

Middle-Late Miocene caused the sea level to drop by more than 2,000 m. Volcanic activities and thermal subsidence continued during the Pliocene-Pleistocene, resulting in a sea level reduction of more than 4,000 m. The estimated PWD values, from minimum to maximum, for the Phu Khanh Basin are illustrated in Figure 11.

Figure 10 Paleo bathymetric on the global research (see online version for colours)

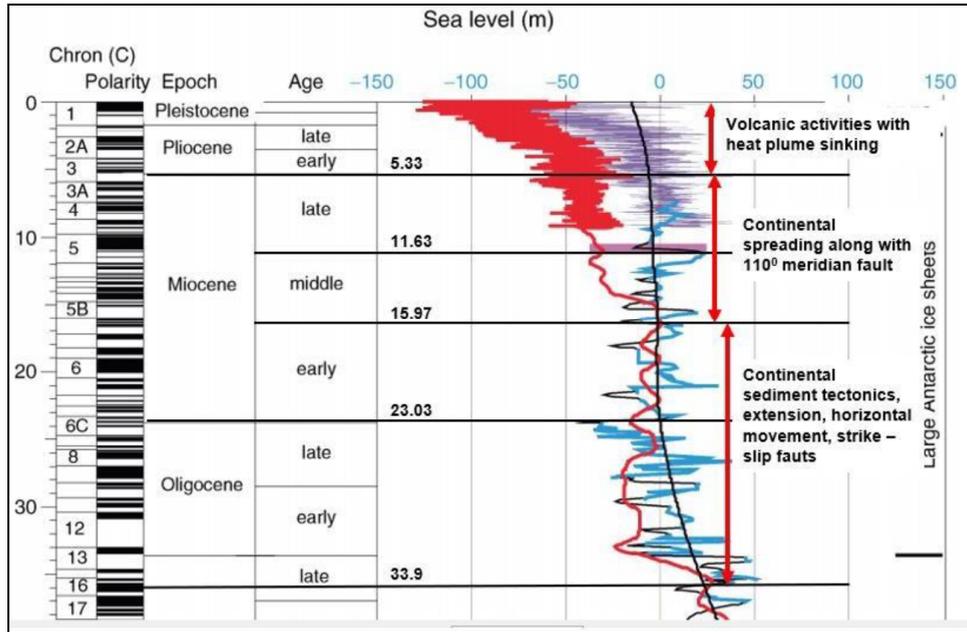


Table 3 The change of SWIT change with sea level depth

Depth (m)	SWIT (°C)
20–100	20–25
100–200	15–19
400–500	8.5–10
800–3,500	5–10
>3,500	<2.5

3.3.3 Sediment water interface temperature

The SWIT depends on the change in the sea level depth. However, the temperature decreases rapidly as sea level rises. An oceanography process study regarding the Phu Khanh Basin is summarised in Table 3 (Bui, 2003). Because of the complex changes in the depth of the paleo-sea level during the Middle Miocene-Pleistocene, the SWIT value also changed accordingly. When the sea water depth dropped below 3,500 m, the SWIT was reduced to less than 2.5°C. Figure 12 displays the changes in temperature based on its relationship with the PWD and corresponding tectonic activities.

Figure 11 Paleo water depth (see online version for colours)

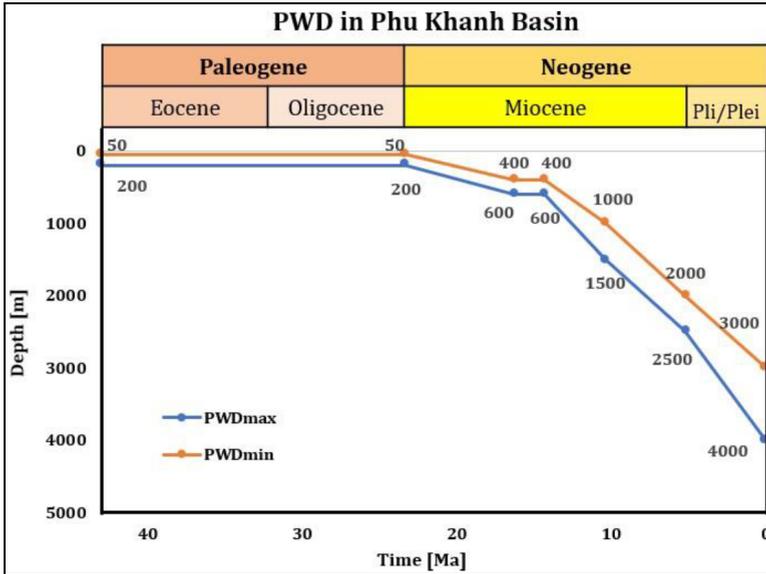
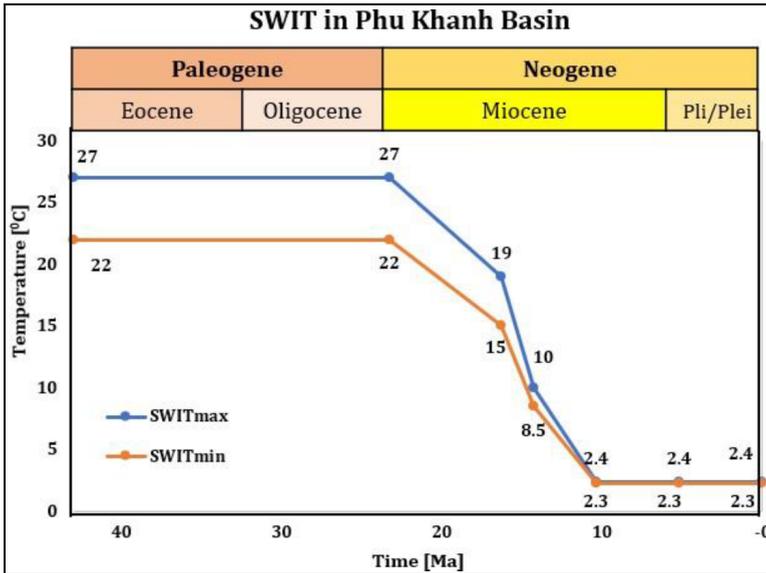


Figure 12 Sediment water interface temperature (see online version for colours)



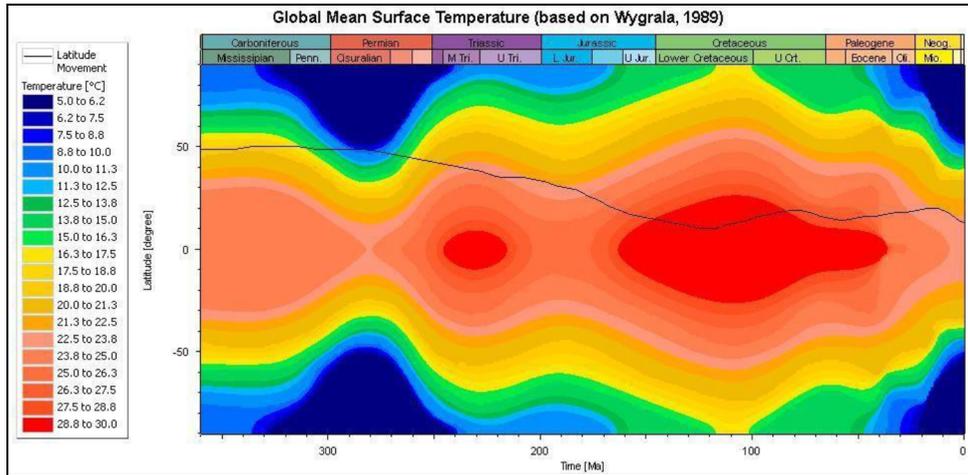
Wygrala (1989) developed a method to determine the average air surface temperature change for different latitudes and proposed a model for the linear interpolation of sediment surface temperature values based on the following three fixed points as an approximation function for adjusting the SWIT according to the bathymetry:

$$T_{swi}(0\text{ m}) = T_s, T_{swi}(200\text{ m}) = T_s - 3^\circ\text{C}, T_{swi}(600\text{ m}) = T_n$$

where T_{swi} is the surface temperature of sediment ($^{\circ}\text{C}$), T_s is the surface temperature ($^{\circ}\text{C}$), and T_n is the coldest arctic water temperature ($^{\circ}\text{C}$).

A distribution function of time-temperature for the Phu Khanh Basin at 11°N – 14°N latitude is presented in Figure 13.

Figure 13 Paleo surface temperatures at 13°N latitude in Southeast Asia (see online version for colours)



4 Results and discussion

4.1 Burial history

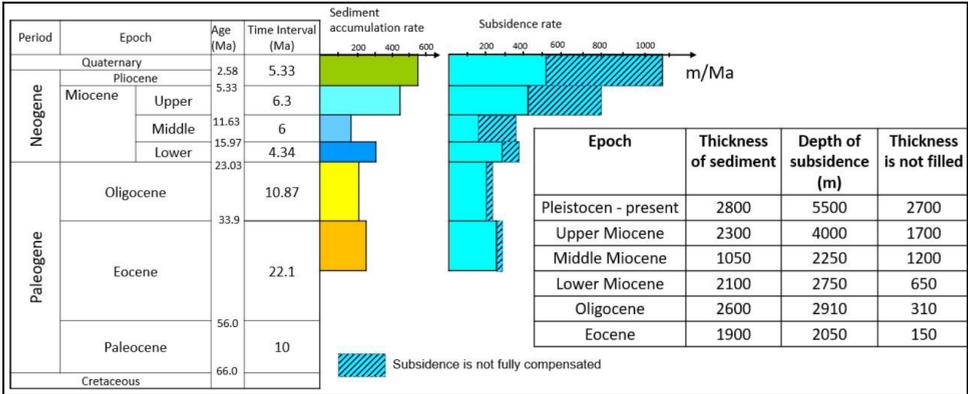
The burial history was based on the pseudo-well at the epicentre of the Phu Yen depression, where the subsidence depth was estimated to have been approximately 2,600 m during the Paleocene-Oligocene. The subsidence rate had increased gradually after the Late Oligocene-Early Miocene because the seafloor of the SCS had begun to spread. The geological record indicated that uplifts, grabens, and erosions had existed during that time. Since the Middle Miocene, the basin has been experiencing high subsidence rates, reaching its present-day burial depth of approximately 10,000 m. However, the fast subsidence rates since the Late Miocene prevented sufficient sediment accumulation to fill the gap created by the subsidence. It is presumed that a large amount of sediments had been compensated within the basin (Figure 14).

4.2 Maturity and petroleum generation history

The most important source rocks, the Oligocene rifting lacustrine shale and the Lower-Middle Miocene marine transgressive claystone, were chosen to illustrate the hydrocarbon generation process in space and time. The uplift structures were sealed regionally by the overlying Pliocene transgressive marine claystone. The timing of hydrocarbon generation is extremely critical, and the migration and trapping of hydrocarbon should have occurred after the Upper Miocene unconformity was deeply

truncated and enclosed by a sufficiently thick and sealing layer of the Pliocene claystone sequence. The subsidence rate of the northeastern part has been quite slow since the Late Oligocene. The precise timing of hydrocarbon generation depends on significant paleo-HF and the richness of organic matter during tectonic events.

Figure 14 Subsidence rates and amount of accumulated sediment in Phu Yen depression (see online version for colours)



In the deepest part of the Central Phu Yen depression, the onset of hydrocarbon generation in the Oligocene source rocks had begun approximately 21.63 Ma (Early Miocene); however, peak oil generation had predominately occurred approximately 16.41 Ma (Middle Miocene) and the oil window ceased during the Pliocene (0.25 Ma). The upper part of the Oligocene source rocks had matured to the wet gas phase since 12.46 Ma, and the lower part has been releasing dry gas from 5.81 Ma until the present day (Figure 15 and Table 4).

Figure 15 Burial curve with maturity overlays for pseudo well in Phu Yen depression (see online version for colours)

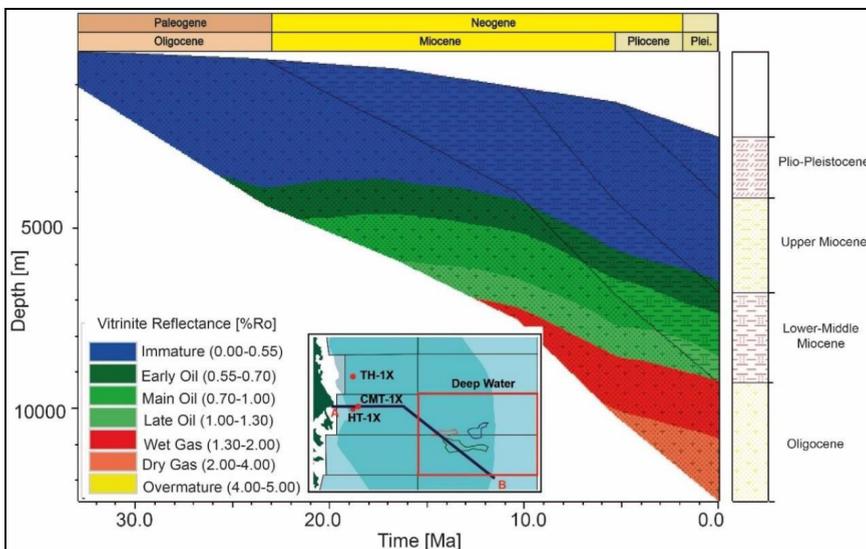
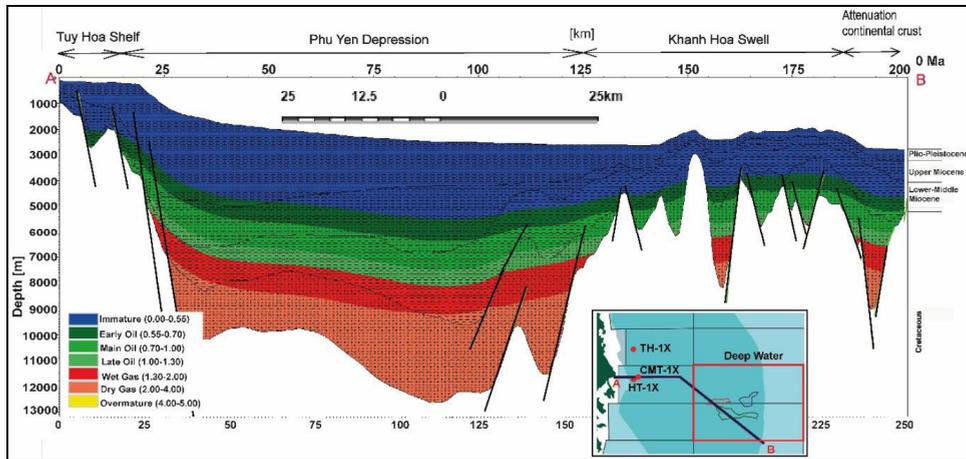


Table 4 Detailed results of hydrocarbon generation zones in the Phu Khanh Basin

Source rock	Time (Ma)	Depth (m)	Zone
Oligocene	21.63 (Early Miocene) – 0.25	4,760	Main oil
	16.41 (Middle Miocene) – 0.25	5,928	
	12.46–0.25	6,951	Wet gas
	5.81 – present	9,893	Dry gas
Lower-Mid Miocene	6.85 – present	5,991	Main oil
	3.15 – present	7,869	

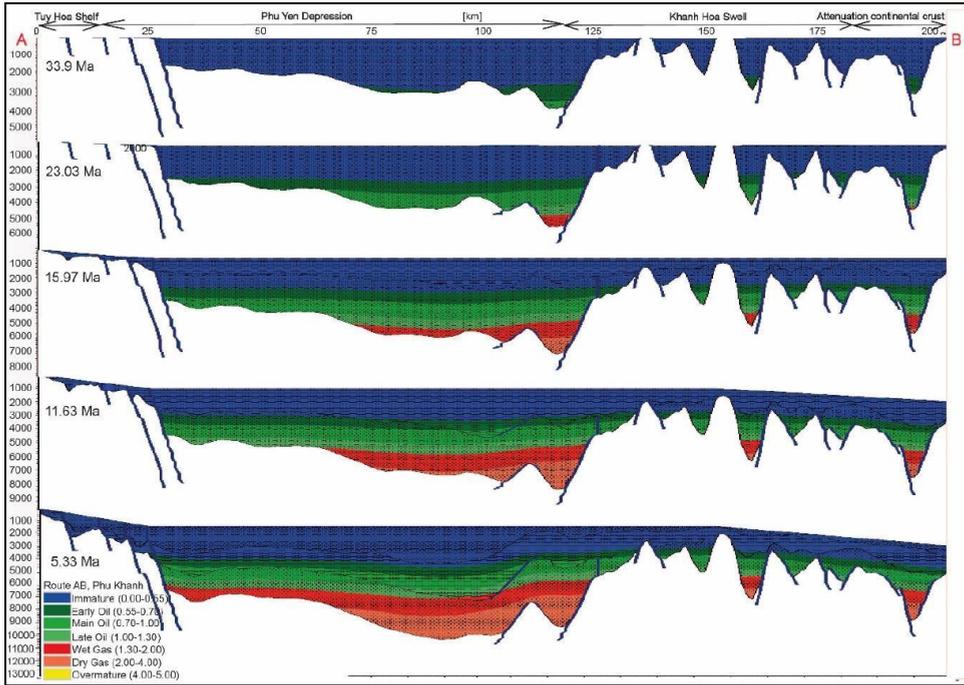
Figure 16 Thermal maturity modelling (see online version for colours)


The onset of oil and gas generation of the Lower Miocene source rocks mostly began during the Late Miocene (6.85 Ma) in the deepest part of the Central Phu Yen depression (Figure 15 and Table 4). On the edge of the Phu Yen depression, the hydrocarbon generation process began later, with the oil and gas generated being released and migrating into stratigraphic traps from the Pliocene (3.15 Ma) until the present.

The thermal maturity index of the Oligocene source rocks increased gradually with depth towards the Central Phu Yen depression. The Oligocene source rock had reached the dry gas phase (Figure 16). However, the principal oil-prone phase of the Lower Miocene source rocks started in deep troughs and narrow grabens near the dome structures.

For the geological section studied, the back-stripping method (Roberts et al., 1998) was used to reconstruct the evolution of the hydrocarbon generation process in each stage (Figure 17). Abundant oil and gas were generated and had migrated during the Early Miocene (23.03 Ma) in the deepest part of the Phu Yen depression. The Oligocene source rocks passed the main oil phase, whereas the bottom sections have been releasing dry gas.

Figure 17 Hydrocarbon generation history in AB route (see online version for colours)

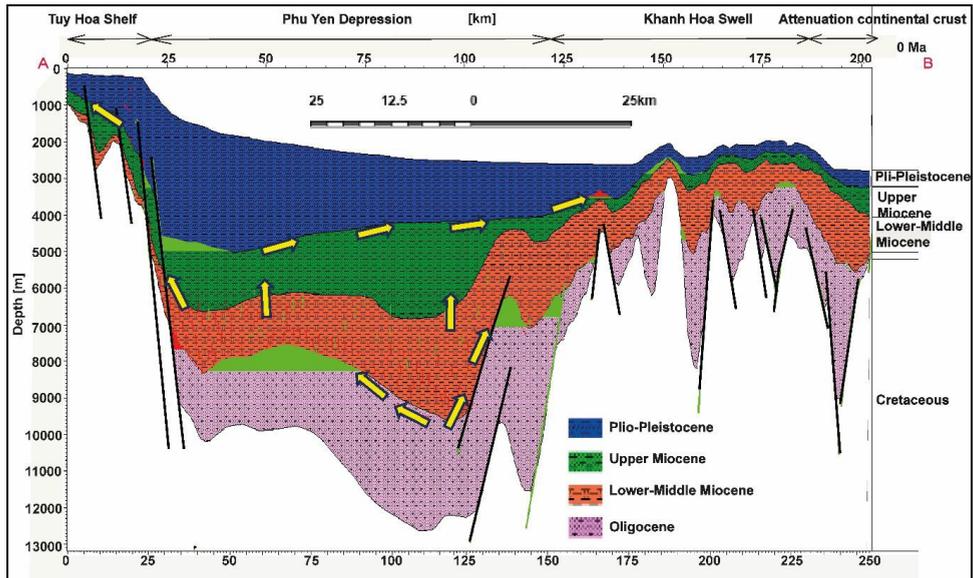


4.3 Migration

Hydrocarbon migration mechanisms were modelled two ways: migration directly from the source rocks into permeable carrier beds or an unconformity and through a hydrodynamic pressure gradient. The generated oil and gas had migrated horizontally along with the interbedded sandstones in the Oligocene and Lower Miocene reservoirs and vertically through major faults and were trapped in these horizons. Oil and gas deposits accumulated in the turbidity fans that developed during the Middle to Lower Miocene in the deep marine environment (Figure 18).

In addition, hydrocarbon generation had occurred contemporaneously with the formation of traps within the Upper Miocene-Lower Pliocene mud-draped submarine fans and basin floor turbidites. The migration model presented that the hydrocarbons had moved vertically, being trapped in shallower depths along the basin margin. The concentration level of the migration vectors of the Oligocene formation is much larger than for the Lower Miocene formation, as demonstrated by a substantial volume of hydrocarbons expelled from the latter.

In summary, most of the known traps had formed during pre-tertiary times, and the critical moment for the hydrocarbon generation processes had commenced since the Early Miocene. The timing of peak hydrocarbon generation varied spatially and had begun after trap formation. The migration direction of the hydrocarbons was predominately in the vertical distance, from areas of high pressure toward low-pressure regions, until the hydrocarbons had accumulated in the Miocene porous sandstones and fractured basement reservoirs.

Figure 18 Migration pathways and accumulation prospects (see online version for colours)

5 Conclusions

This study analysed that the Phu Khanh Basin consists of two main source rock units: the Oligocene and Lower-Middle Miocene source rocks. The Oligocene source rocks were derived from clastics and lacustrine environments. The organic matter dominated a mixture of type II–III kerogen, which mostly produced oil and gas. The Oligocene source rock had undergone from mature to overmature under the influence of varying of paleo-HF. The primary oil-producing phase occurred from the Early Miocene to the Pliocene, and rapid subsidence of Phu Khanh Basin could be attributed to seafloor spreading in SCS. At present, these source rocks still generate dry gas in the Central Phu Yen depression.

Our investigation revealed the following: while the Lower Miocene fluvial-deltaic source rock has generally entered the main oil window from the Late Miocene to the present, intense peak oil generation has occurred since the Early Pliocene. Vertical migration processes through the Oligocene barrier, unconformity, and faults moved predominately into sandstone and porous carbonate reservoir of the Miocene formation. Uplift and dome structures were found in the deepwater region. Further, petroleum reservoirs were found to be distributed in sandstones, submarine fans, turbidites, and slumps in this region. It is expected that these findings will assist in defining the distribution of reservoirs for field development planning of the Phu Khanh Basin in the future.

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