Research Article

1D Basin Modeling of Kra Buri-1, W9-E-1 and Thalang-1 Wells, Mergui Basin, Andaman Sea, Thailand

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Abstract

Exploration in the Mergui Basin, located in the Andaman Sea offshore southern Thailand, has so far been unsuccessful. There were no commercial hydrocarbons found in this basin. Previous study has focused on structure and trap. It was deemed necessary to study basin modeling to better understand the petroleum system of this basin. Basin modeling was constructed using PetroMod 1D (Version11) program. Input parameters can be divided into 3 groups. (1) Stratigraphic and source rock properties data were extracted from previous study reports. (2) Boundary conditions, the surface water interface temperature (SWIT) values are based on a publication by Wygrala (1989). Other boundary conditions, the paleo water depths (PWD) used in this study are estimated based on the deposition environments of each unit. (3) Calibration is based on vitrinite reflectance and bottom hole temperature (BHT) data to adapted models by varying heat flow (HF). The basin modeling of Kra Buri-1, W9-E-1 and Thalang-1 wells shows depth of petroleum generation at about 9,500-10,000 feet since 7 Ma at 9,800 feet in Kra Buri-1 well and 17 Ma at 12,500 feet in W9-E-1 well.

Keywords: Basin modeling, Mergui Basin, Andaman Sea

1. Introduction

The Mergui Basin is located in the Andaman Sea, southern part of Thailand. It is approximately 50,000 square kilometers where offshore petroleum concession blocks A4/48, A5/48 and A6/48 (PTTEP Siam Ltd.) are located. These blocks lie in water ranging in depth from 650 feet to over 7,500 feet (Figure 1).

Mergui Basin exploration has so far been unsuccessful. There were no commercial hydrocarbons found, except minor gas and oil shows in six of nineteen exploration wells. The Mergui Basin extends southwards into the North Sumatra Basin where large oil and gas fields have been found. It is therefore important to determine the reasons for the lack of successful exploration within the Mergui Basin. Previous study has focused on structure and trap. It was deemed necessary to study basin modeling to better understand the petroleum system of this basin. Basin modeling, which are the burial histories, maturity models, and predict petroleum generative window, are generated aiming to estimate time and depth of petroleum generation.

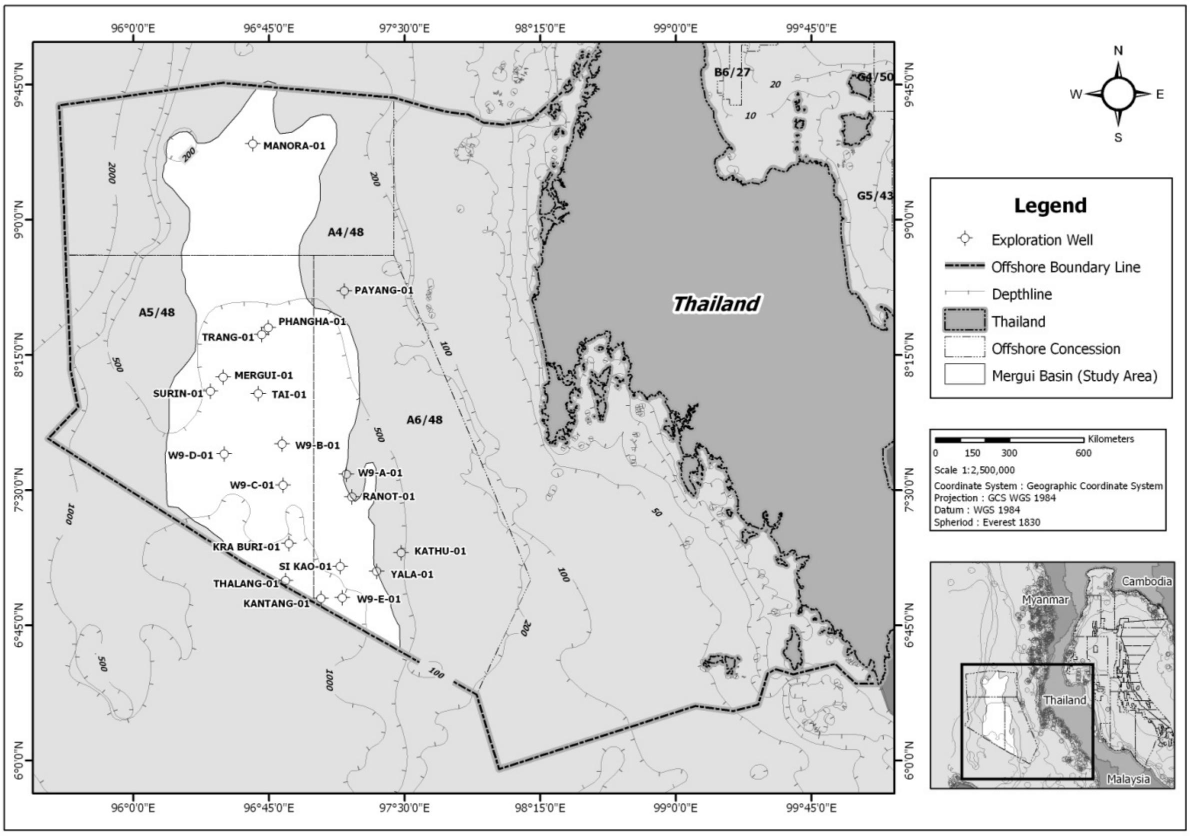

Figure 1. Location of the study area.

2. Geology of Mergui Basin

The Mergui Basin is a transitional back arc basin that is continuous with the North Sumatra Basin to the south. The basin overlies continental crust at the western edge of Sundaland, where the Indian Oceanic plate is subducting obliquely beneath the south-east Asian plate. The basin developed rapidly during the late Oligocene as a series of N-S trending half-grabens, and rifting developed progressively northward (Polachan, 1988). These syn-sedimentary faults are a result of the transitional dextral shear along the NW-SE trend.

The basin is divisible into three main sub-basins (the Western Mergui sub-basin, Eastern Mergui sub-basin and Ranong Trough) separated by the Central High and the Ranong Ridge (Figure 2) (Polachan, 1988). The Eastern Mergui sub-basin is wider than the Western Mergui sub-basin. The sediment is thicker in the west and south of the Eastern Mergui sub-basin. Moreover, in the east of the basin there are small basin; Ranong Trough which is separated by the Ranong Ridge (Prasit and Kevin, 2000). Faults in Mergui Basin are strike-slip faults and normal faults. The main strike-slip faults have two trends, NW-SE Mergui Fault Zone and NE-SW Ranong and Klong Marui Fault Zone, N-S and NNE- SSW are normal faults trend (Srigulwong, 1986).

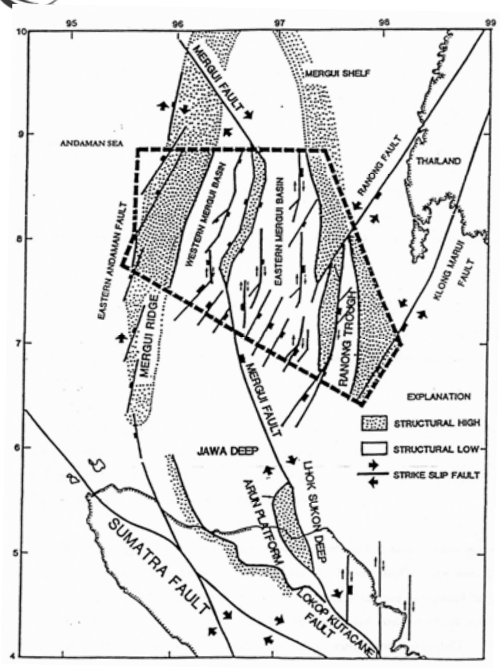

Figure 2. Structural map of the Mergui Basin (Polachan, 1988).

Polachan and Racey (1994) studied stratigraphy of the Mergui Basin and correlated them with that of the Sumatra Basin (Figure 3). They named stratigraphic section studied as Mergui Group and divided Tertiary sediments into 9 formations. Sediments in the basin are deep sea deposit (Yala, Kantang, Trang, Thalang and Takua Pa Formations), shallow marine clastic (Ranong, Payang and Surin Formations) and carbonate reef buildup (Tai Formation). The basement of the basin comprises igneous rocks; granite, volcanic rocks, and Late Cretaceous to Late Miocene low-grade metamorphic rocks.

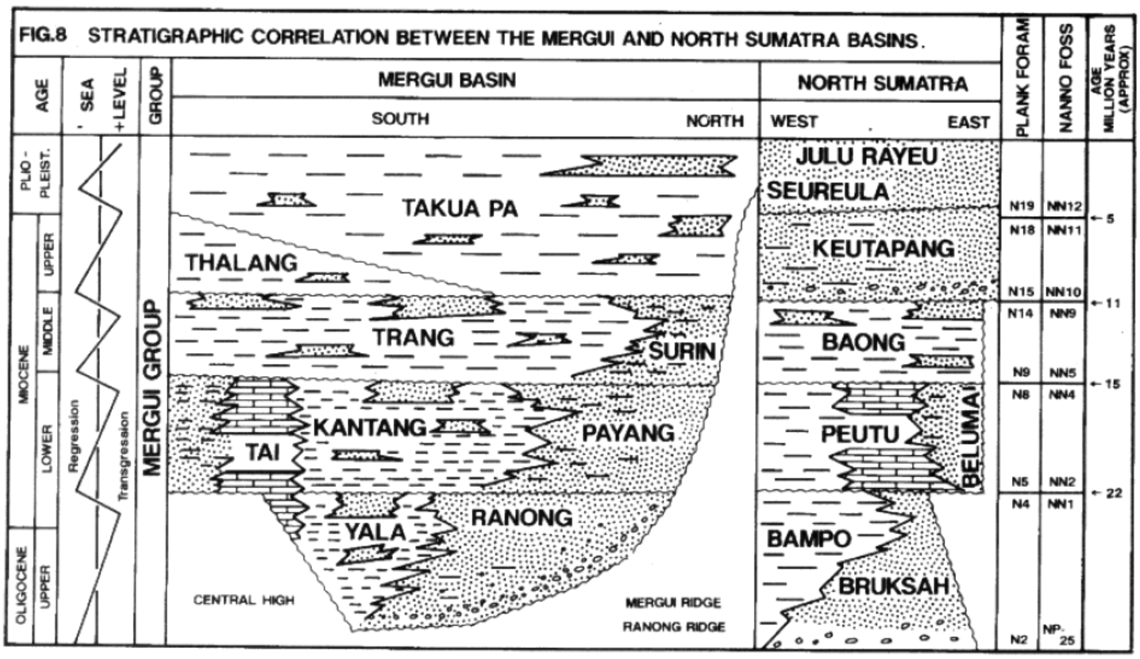

Figure 3. Stratigraphic correlations between the Mergui Basin and the North Sumatra Basin (Polachan and Racey, 1994).

3. Petroleum system of the Mergui Basin

Source rock: Possible source rocks units are the Thalang, Trang, Kantang and Yala Formations. However, the Thalang, Trang and Kantang Formations are thermally immature relative to petroleum generation, while the Yala Formation is mature only in the W9-C-1 and W9-E-1 Wells. Source rocks potential are poor to fair and generally comprise Type III gas-prone kerogen, and Type III and Type II gas-oil prone kerogen.

Reservoir rock: The main reservoirs of the Mergui Basin comprise two types of rocks, limestones and sandstone. The limestone (Tai Formation) of carbonate buildups were prime targets of exploration. Carbonate buildups occur in the basement high of the Ranot Trough and Ranong Ridge. Depositional setting of these carbonate buildups is reef. Porosity varies from 13-25% in Late Oligocene reef and 13-22% in Miocene reef. These values are of good quality of reservoirs (Khursida, 2002).

Sandstones of the fluviatile-deltaic shallow marine depositional environment are other main targets of exploration. These sandstones are found at the deeper part of the half-graben basin. These sandstones are of Ranong Formation deposited in Late Oligocene. The porosity of sandstone varies from 9-20% indicating a fair quality reservoir potential.

Seal:. The effective hydrocarbon seals of Mergui Basin are marine shale or claystone unit (Yala, Kantang, Trang and Thalang Formations) which mostly deposited throughout the basin from Late Oligocene to Recent.

Trap: The majority of the traps in the study area are structural and stratigraphic traps (Atop, 2006). Potential structural traps are along the N-S trending normal faults. The reefs located on the isolate basement high have potential to be both structural and stratigraphic traps due to the reefs were drown and being buried in the bathyal shale.

Migration: The hydrocarbons may have migrated up from deeper in the basin along the fault planes into shallower sections or seeped away (Khursida, 2002).

4. Methodology

Basin modeling of selected wells was constructed using PetroMod 1D (Version11) program. Input parameters in the model can be divided into 3 groups.

Stratigraphic and source rock properties data: Sequence stratigraphy, lithology and age of each layer were extracted from previous study reports are summarized in Tables 1-3. Geochemical data such as source rock quality, percentage of TOC and HI were from previous study reports.

Table 1. Summary of the input data for Kra Buri-1 well basin modeling.

Formation	Top (ft)	Base (ft)	Thick (ft)	Depo to (Ma)	Depo from (Ma)	Lithology	PSE	TOC (%)	HI (mgHC/gTOC)
Takua Pa Fm.	3,185	4,050	865	5.3	1.2	Shale	Overburden rock	1.09	224.00
Thalang Fm.	4,050	5,012	962	11.6	5.3	Shale	Source rock	2.43	209.50
Trang Fm.	5,012	5,350	338	16.0	11.6	Shale	Source rock	1.33	168.25
Kantang Fm.	5,350	7,080	1,730	20.4	16.0	Shale	Source rock	1.90	80.84
Yala Fm.	7,080	8,106	1,026	31.0	20.4	Shale	Source rock	1.22	112.47
Ranong Fm.	8,106	10,342	2,236	38.0	31.0	Sandstone	Reservoir rock	1.04	121.05

Table 2. Summary of the input data for W9-E-1 well basin modeling.

Formation	Top (ft)	Base (ft)	Thick (ft)	Depo to (Ma)	Depo from (Ma)	Lithology	PSE	TOC (%)	HI (mgHC/gTOC)
Takua Pa Fm.	3,416	4,750	1,334	5.3.00	1.20	Shale	Overburden rock	1.09	227.00
Thalang Fm.	4,750	5,200	450	11.60	5.30	Shale	Source rock	0.86	75.50
Trang Fm.	5,200	6,000	800	16.00	11.60	Shale	Source rock	0.82	101.40
Kantang Fm.	6,000	7,050	1,050	20.40	16.00	Shale	Source rock	0.72	91.83
Yala Fm.	7,050	14,036	6,986	38.00	20.40	Shale	Source rock	0.63	103.99

Table 3. Summary of the input data for Thalang-1 well basin modeling.

Formation	Top (ft)	Base (ft)	Thick (ft)	Depo to (Ma)	Depo from (Ma)	Lithology	PSE	TOC (%)	HI (mgHC/gTOC)
Takua Pa Fm.	3,416	5,380	1,964	5.30	1.20	Shale	Overburden rock	2.48	169.00
Thalang Fm.	5,380	6,048	668	11.60	5.30	Shale	Source rock	2.43	261.25
Trang Fm.	6,048	6,620	572	16.00	11.60	Shale	Source rock	1.33	366.00
Kantang Fm.	6,620	7,204	584	20.40	16.00	Shale	Source rock	1.07	200.88
Yala Fm.	7,204	8,500	1,296	31.00	20.40	Shale	Source rock	0.76	136.44

Boundary conditions: The surface water interface temperature (SWIT), the position of the plate through geologic time and the water column is automatically defined by PetroMod software. The settings are for southeastern Asia, northern hemisphere, 7 degrees latitude. The data for plate position through geologic time and paleo-temperatures are stored in a data base of the 1D PetroMod. The values are based on a publication by Wygrala (1989).

Paleo water depths used in this study are estimated based on the deposition environments of each unit as interpreted from biostratigraphic and paleontologic reports. Takau Pa, Thalang and Yala Formations are of lower bathyal environment, estimated water depth used in the model is 5,000 feet (1500 m). Trang Formation was deposited in a bathyal environment, estimated water depth used in the model is 2,600 feet (800 m). Environment of deposition of Kantang Formation is an upper bathyal, estimated water depth used in the model is 1,300 feet (400 m). Ranong Formation is interpreted to be deposited in a fluviatile-deltaic environments, estimated water depth used is 650 feet (200 m).

Calibration data: Calibration data (Ro, BHT) are created in the Well Editor, the software within PetroMod 1D package. Calibration data are then loading from Well Editor to PetroMod for model verification. Figures 4A, 16A and 18A show temperature maturity model with vitrinite reflectance data used as calibration data. Calibration is a process of adapting model to the thermal maturity data which record temperature history in the samples, by varying heat flow (HF) of the basin through time. In case that the built temperature model is not matched with vitrinite reflectance data, model can be adapted manually by modifying HF values to find a better fit (Figures 4B, 6B and 8B).

5. Results and Interpretation

Basin modeling is constructed for 3 wells including Kra Buri-1, W9-E-1 and Thalang-1 wells as required data for basin modeling are relatively more complete in these wells. Geochemical data used in basin modeling of these wells are from previous studies. The selected wells were drilled through Yala Formation, a mature section and main source rock formation of the Mergui Basin. Total depth of W9-E-1 well was the deepest amongst the wells studied and contain thick Yala Formation.

Kra Buri-1 well: Kra Buri-1 well was drilled through main formations deposited in the Mergui Basin, including Yala Formation which contains deep marine shale source rock layers and Ranong Formation of shallow marine sandstone layers. Yala Formation, the deepest marine shale source rock layer has average TOC of 1.22 %wt. Kra Buri-1 well has TOC value of Yala Formation higher than other wells (0.67 %wt). Maturity model generated from software shows higher trend in maturity than those of calibration data (Figure 4A). Heat flow values were changed from default values to values show in Table 4 to fit modeled maturity trend with observed data (Figure 4B).

Output of basin modeling consists of burial history curve and maturity model. Burial history curve overlay with vitrinite reflectance maturity of Kra Buri-1 well is shown in Figure 5. From this figure it is noticeable that sedimentation rate is generally constant, although in Early Miocene (20-24 Ma) there was a rapid subsidence of the basin. From the figure, depth of petroleum generation (early mature) is at about 9,800 feet in lower Ranong Formation about 7 Ma ago. At the present time, depth of petroleum generation is about 9,500 feet.

Table 4. Summary of the boundary conditions data for Kra Buri-1 well.

Age (Ma)	PWD (ft.)
3.25	5000.00
8.45	5000.00
13.80	2600.00
18.20	1300.00
25.70	5000.00
34.50	650.00

Age (Ma)	SWIT (ºC)
3.25	5.00
8.45	5.00
13.80	5.00
18.20	12.98
25.70	7.50
34.50	21.85

Age (Ma)	HF (mW/m^2)
3.25	65.00
8.45	70.00
13.80	75.00
18.20	80.00
25.70	85.00
34.50	85.00

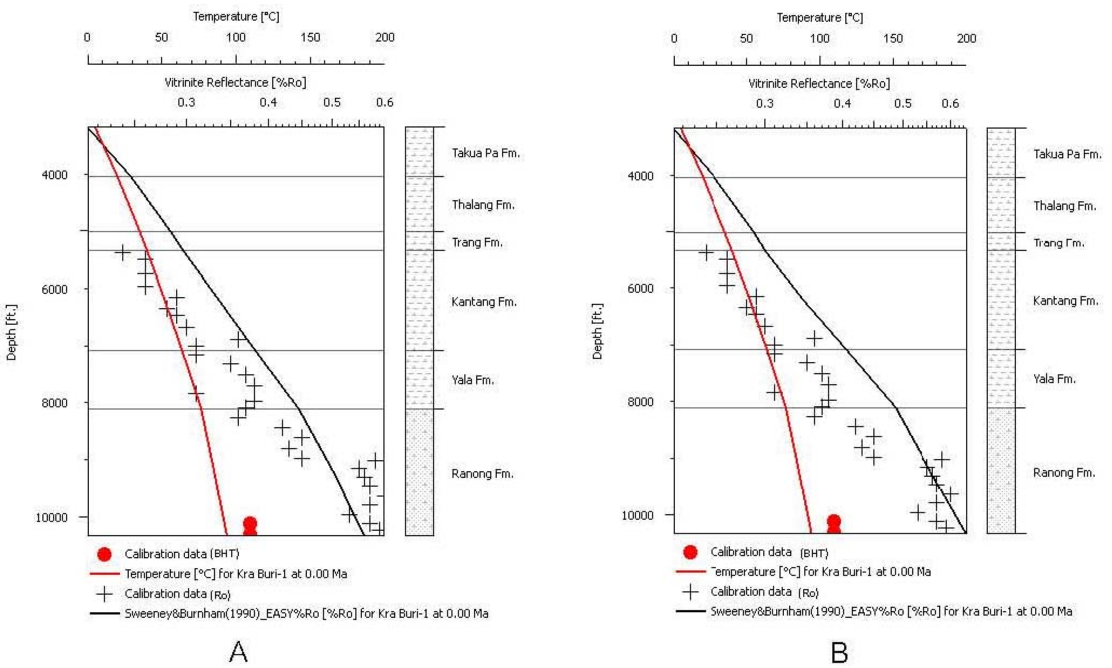

Figure 4. Comparison of maturity model of Kra Buri-1 well between before (A) and after calibration (B).

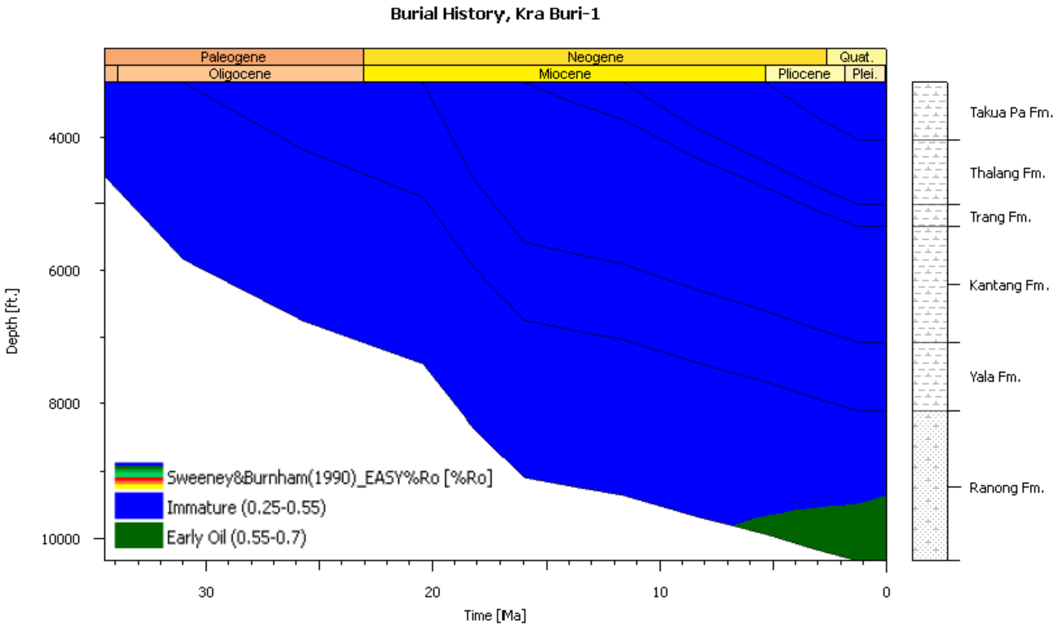

Figure 5. Burial history curve of Kra Buri-1 well overlay with petroleum generative window deduce from vitrinite reflectance maturity data.

W9-E-1 well: W9-E-1 well is the deepest well drilled in the Mergui Basin (14,036 feet) and contains thick Yala Formation. Yala Formation in this well may have deposited in the deep part of a sub basin. Average TOC of Yala Formation in this well is 0.63 %. Lithology of Yala Formation in this well is mostly fine-grained sediments of deep marine shale or claystone. This well also contains other possible source rock layers with Takua Pa Formation act as an overburden layer but has no potential reservoir layer. Maturity model of W9-E-1 well generated from the software was calibrated with vitrinite reflectance data (Figure 6A). Calibration was done by adapting heat flow to values listed in Table 5 to fit modeled maturity trend with vitrinite reflectance data (Figure 6B).

Burial history curve of W9-E-1 well (Figure 7) shows that the sedimentation rate is generally constant, but rather low. Burial history curve does not show evidence of break in deposition, but during Pliocene (2 – 4 Ma) sedimentation rate is slightly higher than other times. Trace of gas show was reported in this well. The model shows that petroleum generation in W9-E-1 well started at 12,500 feet around 17 Ma. At present time depth of petroleum generation is at 10,000 feet. This well has thick mature section to generate early oil (0.55-0.7 %Ro) and main oil (0.7-1.0 %Ro) in the lower Yala Formation.

Table 5. Summary of the boundary conditions data for W9-E-1 well.

Age (Ma)	PWD (ft.)
3.95	5000.00
8.45	5000.00
13.80	2600.00
18.20	1300.00
24.40	5000.00

Age (Ma)	SWIT (ºC)
3.95	5.00
8.45	5.00
13.80	5.00
18.20	12.98
24.40	7.12

Age (Ma)	HF (mW/m^2)
3.95	70.00
8.45	70.00
13.80	75.00
18.20	75.00
24.40	80.00

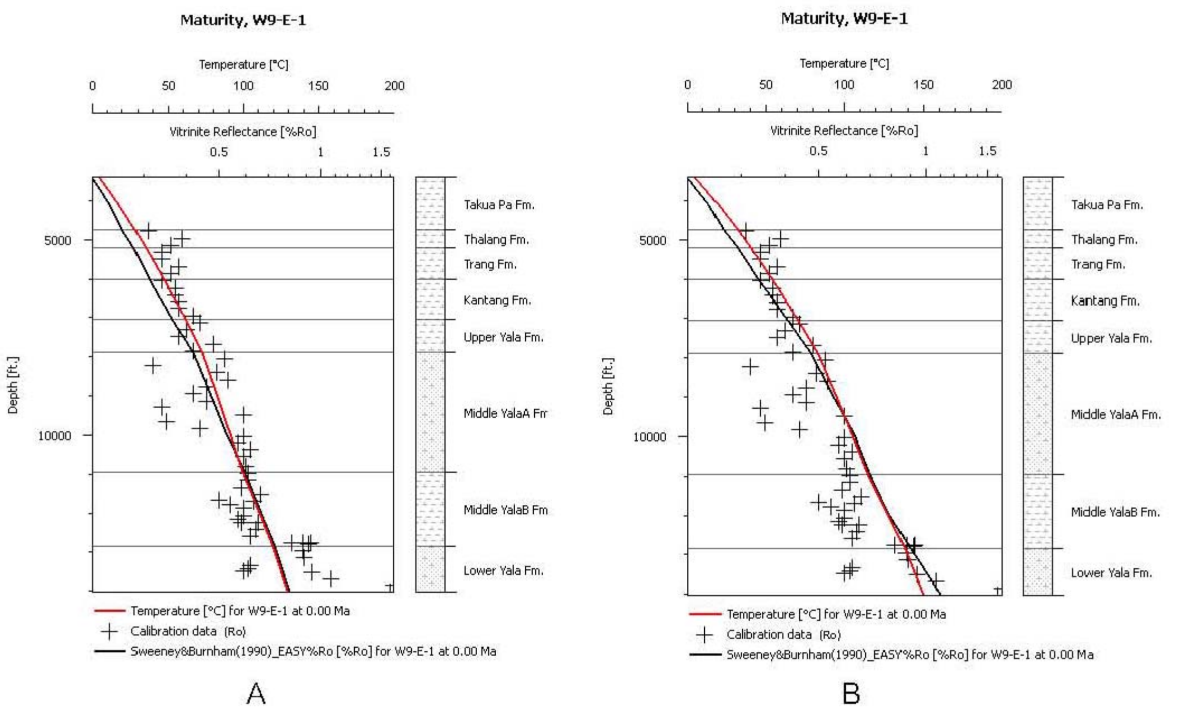

Figure 6. Comparison of maturity model of W9-E-1 well between before (A) and after calibration (B).

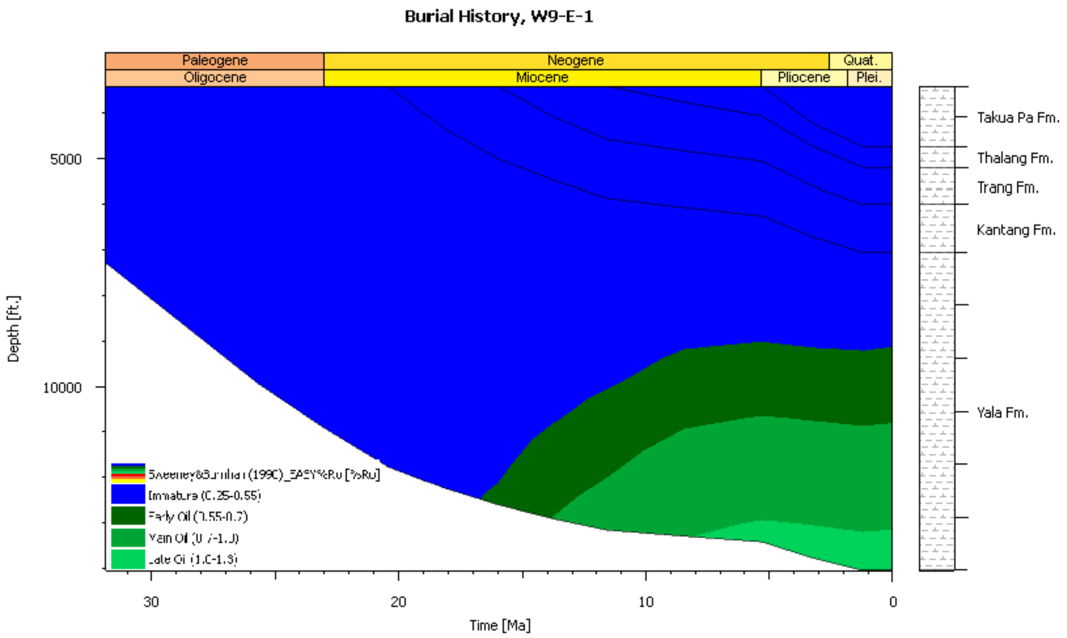

Figure 7. Burial history curve of W9-E-1 well overlay with petroleum generative window deduce from vitrinite reflectance maturity data.

Thalang-1 well: Thalang-1 well was drilled to total depth of 8,518 feet but the result was dry. Sediments layers in the well are similar to those in W9-E-1 well, which has only deep marine shale source rock layer. Thickness is high in Takua Pa Formation, overburden section, and Yala Formation, a mature source rock section. This well drilled through about 1,269 feet of Yala Formation. Average TOC in Yala Formation is 0.76 %wt. Maturity model generated from the software is generally lower than maturity input data, vitrinite reflectance (Figure 8A). Heat flow for each formation is listed in Table 6 and the model result is shown in Figure 8B.

Burial history curve of Thalang-1 (Figure 9) shows low sedimentation rate but higher than those of W9-E-1 well. High rate of sedimentation occurred in Pliocene (1-5 Ma), similar time interval as W9-E-1 well. Sedimentation rate was generally slower later in Pleistocene to recent (1-0 Ma). The entire section drilled is immature (Ro < 0.55 %).

6. Conclusions

Burial history curve of Kra Buri-1, W9-E-1 and Thalang-1 wells show sedimentation rate in general is low with depth of petroleum generation (early mature) at about 9,500-10,000 feet. Petroleum generation started since 7 Ma at 9,800 feet in Kra Buri-1 well and 17 Ma at 12,500 feet in W9-E-1 well.

Table 6. Summary of the boundary conditions data for Thalang-1 well.

Age (Ma)	PWD (ft.)
3.25	5000.00
8.45	5000.00
13.80	2600.00
18.20	1300.00
25.70	5000.00

Age (Ma)	SWIT (ºC)
3.25	5.00
8.45	5.00
13.80	5.00
18.20	12.98
25.70	7.50

Age (Ma)	HF (mW/m^2)
3.25	70.00
8.45	75.00
13.80	80.00
18.20	85.00
25.70	85.00

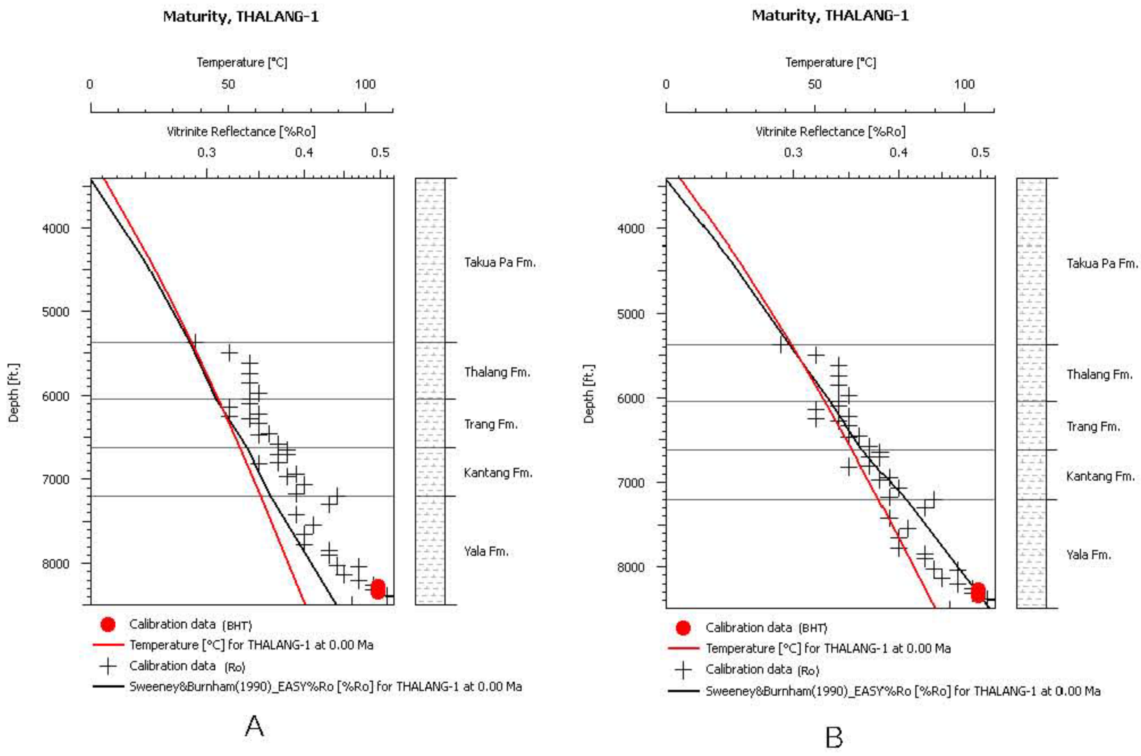

Figure 8. Comparison of maturity model of Thalang-1 well between before (A) and after calibration (B).

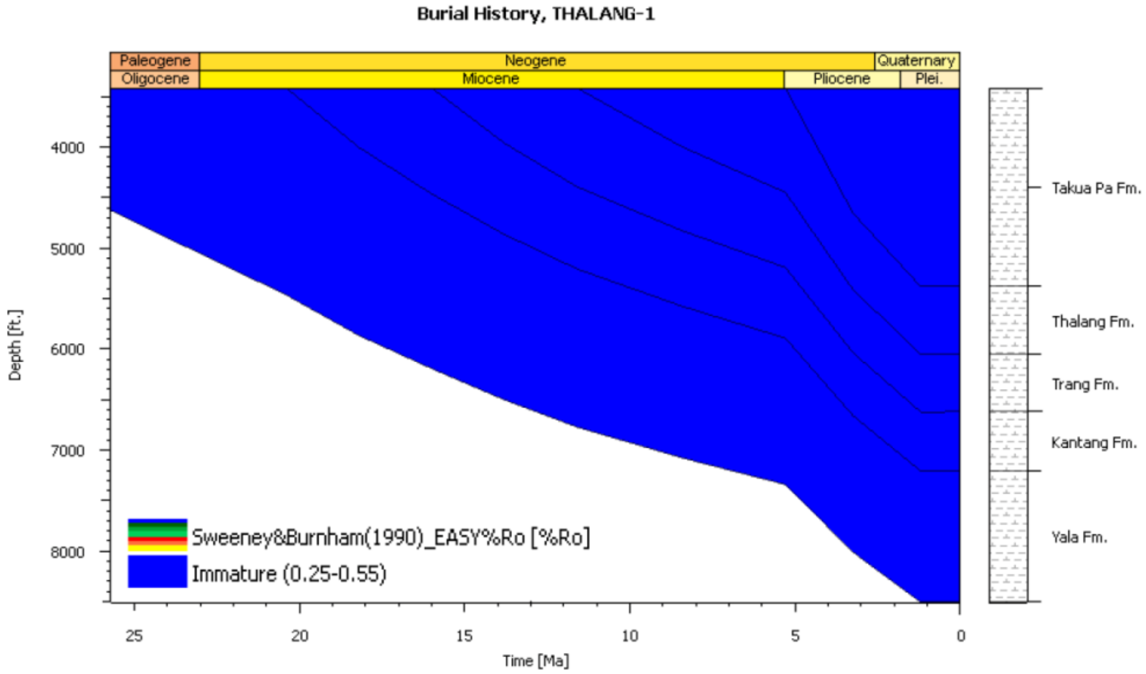

Figure 9. Burial history curve of Thalang-1 well overlay with petroleum generative window deduce from vitrinite reflectance maturity data.

7. Acknowledgements

This study is a part of Master thesis in Geology Department, Chulalongkorn University. We would like to thank the Department of Mineral Fuels for allowing the useful data and the Graduate School, Chulalongkorn University for financial support.

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