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Research Paper

Hydrocarbon Generation Potentials of Cenozoic Lacustrine Source Rocks: Gulf of Thailand, Southeast Asia

Oladapo O. Akinlotan[1]*, Byami A. Jolly[2] and Okwudiri A. Anyiam[3]

Corresponding Author: **Oladapo O. Akinlotan ✉ dapo_akinlotan@yahoo.com*

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Several hydrocarbon-rich Cenozoic basins are scattered across Southeast Asia and they present excellent opportunity to examine these rich but under-explored basins. These near-shore basins have petroleum potentials that are associated with the Oligocene-Miocene fluvio-lacustrine multi-petroleum systems but are largely underexplored. This study evaluates the petroleum source potentials of some selected Cenozoic basins via maturation modelling analysis, burial and heat flow histories. ZetaWare's Genesis modelling software was used for the study with burial history and thermal history parameters (vitrinite, TOC and HI). The maximum transformation of kerogen to hydrocarbon for source rocks in these basins may be as high as 80-100%. Analyses showed that threshold maturity for maximum hydrocarbon expulsion is around 1.0% vitrinite reflectance (Ro). Thermal maturation is accentuated with depth-especially southward and offshore. Source rocks in the Western (central) and Hua Hin (north) Basins are the most prolific (with up to 400 mgHC/gtoc); least prolific sources are in the Western (north and south) Basin with 96-120 mgHC/gtoc and 40-50 mgHC/gtoc respectively. These sources have expelled only secondary amount of gas (11-80mg/gtoc) because they are oil prone sources. Oil to gas expulsion ratio of 7:1 is estimated. Hydrocarbon expulsion started in the Late Miocene *after* the emplacement of all necessary traps. Deeply buried sources show good prospects for possible residual hydrocarbon generation. Moreover, all the modelled wells displayed source rocks that expelled significant quantity of hydrocarbon. All these basins show strong correlation with Pattani Basin, the most prolific hydrocarbon-bearing basin in the Gulf of Thailand.

Keywords: Petroleum potentials, Lacustrine source rocks, Basin modelling, Cenozoic, Gulf of Thailand, Southeast Asia

Introduction

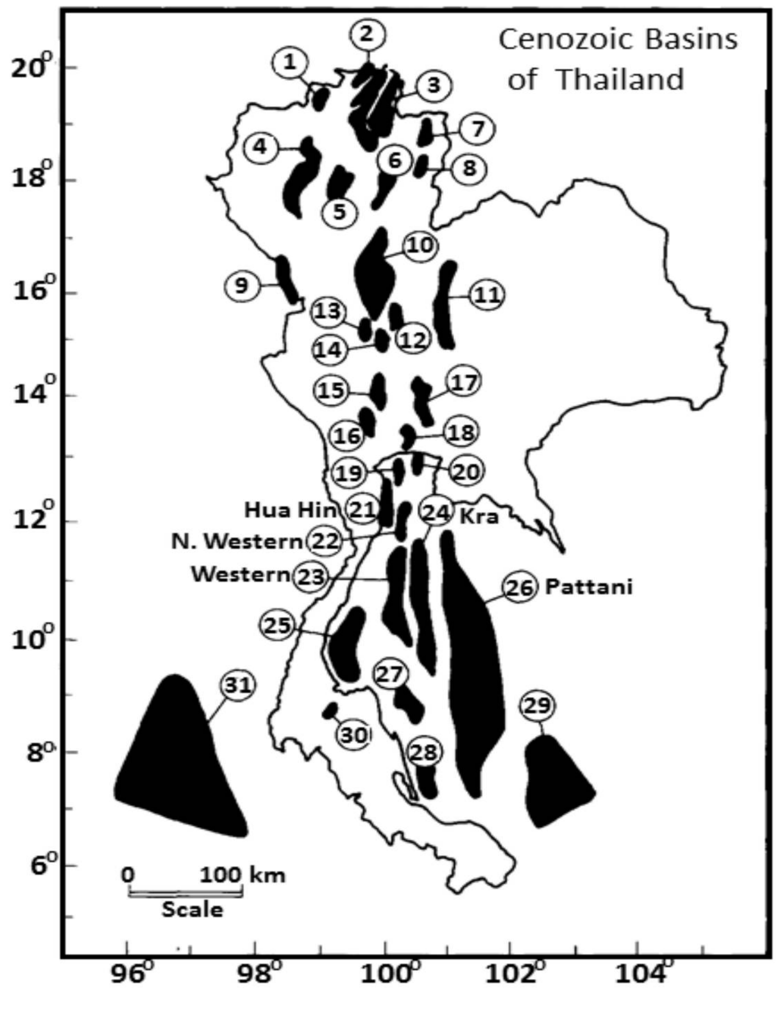
Several Cenozoic basins are scattered across the onshore and offshore areas of Southeast Asia (Polachan *et al.*, 1991). These basins are key

[1] Bader International Study Centre, Department of Geological Sciences and Geological Engineering, Queen's University, 36 Union Street, Kingston, Ontario, Canada, K7L 3N6
[2] Department of Geology, Ahmadu Bello University, Zaria, Nigeria.
[3] Department of Geology, University of Nigeria, Nsukka Road, 410001, Nsukka, Nigeria.

targets for petroleum exploration and production in this region because they are extremely rich in hydrocarbon. Thailand and the Gulf of Thailand present excellent opportunity to examine these Cenozoic basins (Figure 1) for their hydrocarbon potentials. In Thailand alone, over 60 basins are spread across onshore and offshore areas with 12 major basins in the Gulf of Thailand including Pattani, Malay, Hua Hin, Western and Kra. More than 30 of these basins have significant hydrocarbon generation potentials (Lawwongngam and Philp, 1993; Polachan *et al*., 1991).

All the Cenozoic basins of Southeast Asia have very close similarities in terms of the tectono-stratigraphy, structural style, sedimentary environments, burial history, and hydrocarbon evolution (e.g. Doust and Sumner, 2007, Lawwongngam and Philp, 1993 Polachan *et al*., 1991). The widely accepted tectonic model is 'Extrusive Tectonics' of Tapponnier *et al*., (1982). The formation of these basins commenced in the Early Cenozoic (Oligocene) as a result of the continental collision of India and Southern Asia (Eurasia) and linked to the movement of strike-

Figure 1: Cenozoic Basins in Thailand (Numbered 1 – 31). Redrawn After Polachan *et al*. (1991). The Labelled Basins (21, 22, 23, 24, and 26) Show the Locations of the Modelled Wells.



slip faults (e.g. Barber *et al*., 2011, Hall, 2009; Lee and Lawver, 1995; Morley 2013, Morley *et al*., 2011, Polachan *et al*., 1991, Searle and Morley 2011). This collision resulted in many fault-bounded rifted basins characterized by grabens and half-grabens. The development of sedimentary facies and petroleum systems have four distinctive episodes: early syn-rift and late syn-rift (Oligocene to Early Miocene) and early post-rift and late post-rift (Late Miocene to Recent time) (Doust and Sumner, 2007; Morley and Racey 2011, Petersen *et al*., 2006). In Thailand and Gulf of Thailand, these rift basins are mainly N-S trending grabens or half-grabens with the oldest sediments being of Late Oligocene age (Morley and Racey 2011, Polachan *et al*., 1991). These basins were initially filled with fault-controlled lacustrine sediments, followed by alluvial deposits and then by parallic facies in the large coastal areas including intermontane deposits in the onshore and marginal areas of the gulf (Lawwongngam and Philp, 1993). Continental facies such as fluvial and deltaic deposits are also present in these basins (Lawwongngam and Philp, 1993).

Lacustrine basins especially the algal-rich ones are extremely important sources of hydrocarbon as they generate more oil on a weight-for-weight basis when compared to marine sources (Curiale and Gibling, 1994). For example, in Southeast Asia, lacustrine mudstones and coals are important sources of oil in many Cenozoic basins (Andersen *et al*., 2005, Morley and Racey 2011). At the onshore Cenozoic basins, the sediments within Thailand and its gulf are mainly lacustrine and fluvial. In the Gulf of Thailand some marine strata are present in addition to the fluvio-lacustrine facies (Gibling *et al*., 1985). The huge petroleum potential of the lacustrine facies in Thailand is demonstrated by over eight basins with proven generation of significant quantities of petroleum. One of these is the Pattani Basin – the most prolific liquid hydrocarbon-bearing in the Gulf of Thailand (Bustin and Chonchawalit, 1997; Lawwongngam and Philp, 1993).

Basin modelling is a very useful tool useful in examining the petroleum potentials of hydrocarbon sources during hydrocarbon exploration (e.g. Andersen *et al*., 2005; Cukur *et al*., 2012, Hadad *et al*., 2017, Hakimi and Ahmed 2016, Hakimi *et al*., 2018). Therefore, basin modelling provides valuable information including but not limited to the thermal maturation, transformation of kerogen to hydrocarbon, hydrocarbon expulsion, and depth of mature source rocks in a hydrocarbon-rich basin (e.g. Andersen *et al*., 2005; Cukur *et al*., 2012, Hadad *et al*., 2017, Hakimi and Ahmed 2016, Hakimi *et al*., 2018). As important as basin modelling, this approach of hydrocarbon exploration is extremely scarce in the Gulf of Thailand.

Although exploration has been on for more than 50 years with a lot of acquired data in Thailand, less than one third of the basins with significant petroleum potential had been fully explored (Bustin and Chonchawalit, 1997; Polachan *et al*., 1991). Exploration has been restricted to Pattani, Malay, Chumpon, Mergui, Phitsannulak, Chiang-Mai, Fang, Phetchabun, Suphan Buri, Kamphaeng Saen, Songkhlas where significant hydrocarbon has been found. More than nine onshore basins of the Gulf of Thailand including Hua Hin and Western are largely underexplored albeit having similar hydrocarbon potentials to nearby prolific Pattani Basin. Consequently, this study is aimed at unraveling the petroleum potentials of the underexplored basins in the Gulf of Thailand through basin/maturity modelling. This is the first time this kind of analysis is applied in order to increase our understanding of the petroleum potentials of the basins in Thailand. Therefore, the main objectives of this study are to (1) assess the source rock potentials of Hua Hin and Western Basins via maturation modelling including burial and heat flow histories, potential maturation and generation of hydrocarbons, time and type of possible hydrocarbon expelled and (2) evaluate the petroleum systems of Gulf of Thailand to highlight future hydrocarbon prospects in these underexplored basins.

Geological Setting

Tectonic Framework

The major phases of the Tertiary rift basin development in the Thailand has been divided into early syn rift, late syn rift, early post rift and late post rift (Doust and Sumner, 2007; Polachan *et al*., 1991) and these are summarized in Table 1.

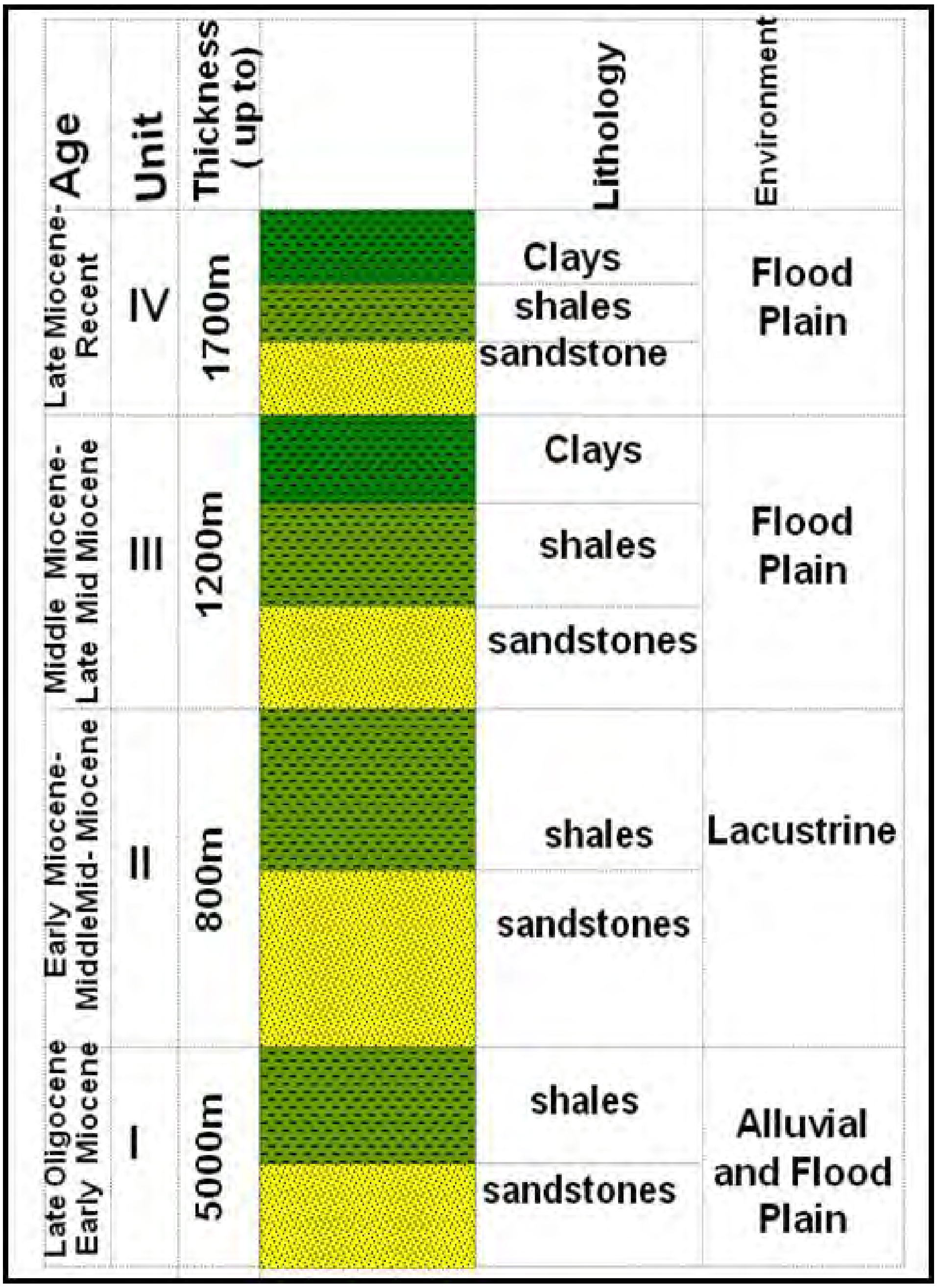
Stratigraphy

The stratigraphy of the various Cenozoic basins in Thailand has been documented (e.g. Doust and Sumner, 2007, Morley and Racey 2011, Polachan *et al*., 1991) and this is summarized in Figure 2. Cenozoic basins (grabens) in the Gulf of Thailand are separated into two main groups by the Ko Kra Ridge. The Western graben consists of ten basins namely Sakhon, Pakanam, Hua Hin, Prachuap, North Western, Western, Kra, Chumphon, Nkhon and Songkhla containing about 4000 m of sediments. The basinal area consists of two major basins: Pattani and Malay Basins - having up to 8000 m of sediments. No sedimentary rock older than Late Oligocene has been reported. Pre- Tertiary basements are sedimentary, meta-sediments, extrusive and

Table 1: Summary of the tectonic events in the Gulf of Thailand based on Doust and Sumner (2007), Polachan et al. (1991), Morley (2013), Searle and Morley (2011), Morley et al. (2011) and Racey (2011)

Mega Sequence	Time/Age	Tectonic Events	Sedimentary Facies	Petroleum System
1	Eocene-Lower Oligocene (45-39.5 to 32Ma)	Greatest tectonic activity. Basin initiation and start of syn-rift activity.	Alluvial and lacustrine to deltaic sediments.	Lacustrine source. Fluvio-lacustrine clastics and turbidites reservoirs. Non-marine shale seals.
2	Oligocene to? Lower Miocene(32-25.5 to 23Ma)	Start of South China Sea floor spreading. 'Break up' unconformity. Transtensional rifting slowed down.	Deltaic sandstones, alluvial/ fluvial plain sediments and marine shales.	Coals and coaly shales sources rocks. Fluvio-deltaic reservoirs.
3	Upper Oligocene to Lower Miocene(25.5 -23 to 16-15.5 Ma)	Major plate reorganisation. Unconformity.Regional post-rift. Thermalsubsidence. Widespread depression.	Deep marine shales Turbidite sandstones. Reefs.	Marine shale sequence source rocks. Marine carbonates and reefs reservoirs. Regional seal.
4	Middle Miocene to ?Upper Miocene(16-15.5 to 12-10Ma)	Change in tectonic and/ orclimatic conditions. End of South China Sea floor spreading. Widespread unconformity.	Alluvial/fluvial sediments.	Coals and coaly shales. source rocks. Fluvio-deltaic reservoirs.
5	Upper Miocene to ? Lower Miocene (12-10 to -5.5Ma)	Major plate reorganisation. Culmination of transpressional deformation. Regional compression caused inversion.	Coarse clastics.Deep marine shales.	Deep marine shales Source rocks. Clastics sandstones reservoirs.
6	Pliocene to Recent(circa 5.5- 5 Ma)	Change in deformation from dextral transpression to transtension. Pronounced unconformity. Regional compression.	Coarse clastics.Deep marine shales.	Deep marine shales Source rocks. Clastics sandstones reservoirs.

Figure 2: Simplified Stratigraphy of Cenozoic basins in the Gulf of Thailand, Modified After Polachan *et al*. (1991).



intrusive igneous rocks (Doust and Sumner, 2007, Morley and Racey 2011, Polachan *et al*., 1991).

Tertiary succession of the Gulf of Thailand was divided into three cycles of sedimentation by Polachan *et al*., (1991) which are well developed in Pattani and Malay Basins. More recent description was presented by Morley and Racey 2011. Cycle I and Cycle II are regressive in nature while Cycle III is transgressive. More recent and appropriate stratigraphic divisions of Tertiary

Pattani is 4 units (Polachan *et al*., 1991) which can also be identified in western area from seismic data and drilled wells. The sediments are generally nonmarine.

In essence, sedimentary facies development of the area have been described (e.g. Doust and Sumner, 2007, Polachan *et al*., 1991, Morley and Racey 2011). These authors demonstrated that the early syn rift witnesses the sequence of alluvial and lacustrine to deltaic sediments which became increasingly transgressive during the latest syn-rift (more marine and transgressive nature in more distal basins). Widespread regional transgression resulted in the deposition of open marine shales and carbonates in many of the rifts and adjacent intra–rift basement high blocks during the early post rift. During the late post rift: uplifts and inversion led to the development of active delta systems that prograded over the previous transgressive sequence especially in areas close to uplifted mountain belts.

Petroleum Systems and Heat Flows

The major controls on the petroleum development of Thailand and Southeast Asia are: geometry of the rift graben, the rate of subsidence and their palaeogeographical situation, the extent of early Miocene transgression and the impact and location of the various collisions and uplift events (e.g. Doust and Sumner, 2007, Polachan *et al*., 1991, Morley 2013, Morley and Racey 2011, Morley and Racey 2011, Ridd *et al*., 2011). The petroleum system in the Gulf of Thailand is closely linked to the phase of basin development (Figure 3) and this is well documented (Doust and Sumner, 2007, Racey 2011, Searle and Morley 2011). The early syn- rift lacustrine petroleum system is characterized by strongly oil prone, algal rich, organic-rich lacustrine and fluvio-lacustrine source rocks. The reservoirs are the fluvio-lacustrine clastics, lacustrine carbonates and volcani-clastics interbedded with laterally discontinuous non-marine shale seals. The late syn- rift lacustrine petroleum system has oil and gas prone source rocks: coals and coaly shales that are interbedded with fluvio-deltaic reservoirs and seals of excellent quality. In the early post- rift lacustrine petroleum system, the source rocks are mainly marine shale (gas prone) sequence. Petroleum charge originates from mainly transported terrestrial materials. The main reservoirs are the open marine carbonates including reefal build ups. Widespread regional seal is common (e.g. Doust and Sumner, 2007, Morley and Racey 2011, Polachan *et al*., 1991 Racey 2011). This petroleum system is similar in environment and characteristics to the late syn rift except that it is progradational rather than retrogradational. The source materials are typically terrestrial organic matter. Source rocks in the Gulf of Thailand are mainly Oligocene-Lower Miocene fluvio-lacustrine sediments (Curiale and Gibling, 1994).

The present day recorded heat flow within the basins in the Gulf of Thailand is variable and complex (Thienprasert and Raksaskulwong 1984). However, it is generally well above global averages (Figure 4). The Malay Basin has consistently high levels of heat flow (Thienprasert and Raksaskulwong, 1984). In Thailand, geothermal gradients of hydrocarbon-rich wells vary in the broad range of 21-95 mK/m. Heat flow value ranges from 17-320 mW/m^2 (Thienprasert and Raksaskulwong 1984). In Northern Thailand four regions have high heat flow of over (105mW/m^2) (Thienprasert and Raksaskulwong, 1984).

Figure 3: Four Main Petroleum System Types in Southeast Asia After Doust and Sumner (2007).

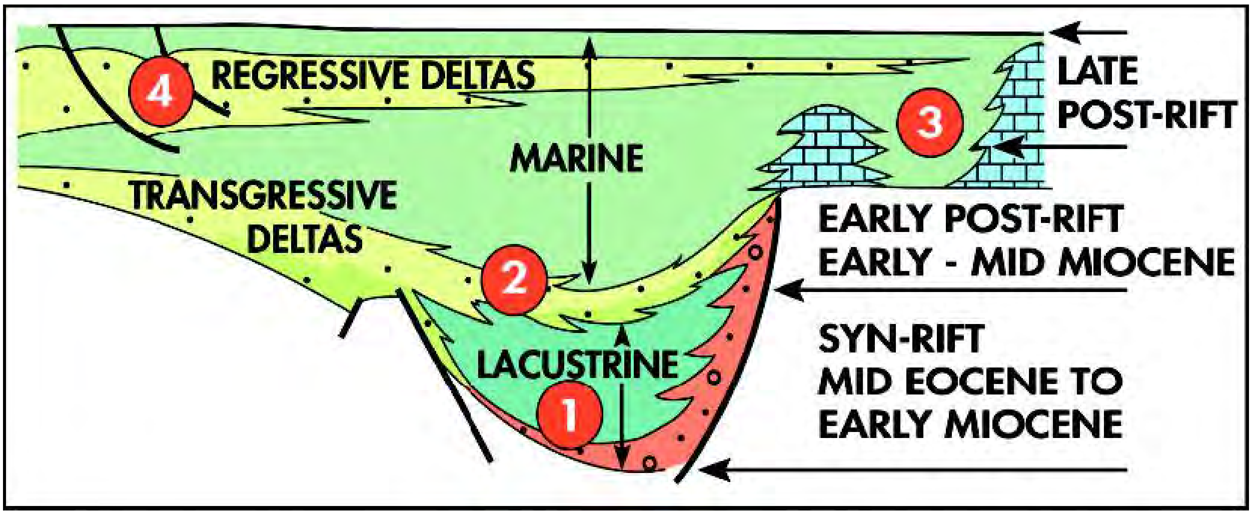
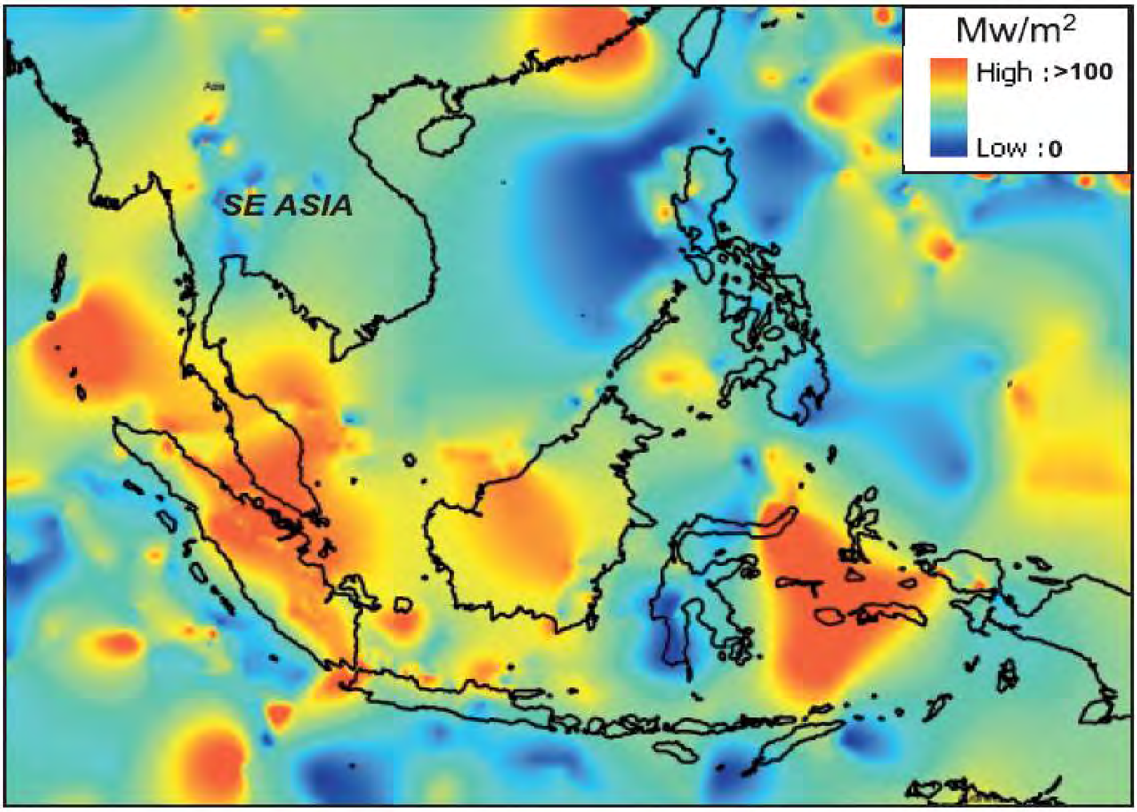


Figure 4: Measured Heat Flow from Southeast Asia Tertiary Rift Basins After Doust and Sumner (2007).



Dataset and Methodology

Data Inputs

The basin modelling analysis used in this study was carried out using ZetaWare's Genesis software. The software requires basic data inputs which are classified into three categories namely: burial history: thermal history and hydrocarbon generation. The data used for the burial history include the depths, thickness, age and lithologies of the modelled wells (Andersen *et al*., 2005, Bustin and Chonchawalit, 1997, Doust and Sumner, 2007, Petersen *et al*., 2001, Petersen *et al*., 2004, Petersen *et al*., 2014, Polachan *et al*., 1991, Racey 2011) and are presented in Tables 2-4. The present-day heat flow data have been documented in drilled wells in this area particularly from Pattani Basin (e.g. Thienprasert and Raksaskulwong, 1984). The palaeo-heat flow was reconstructed based on the review of the tectonic history of the study area while taking into consideration the present-day heat flow. The heat flow models were quality-controlled to achieve accurate correlation. This was done using vitrinite reflectance, a maturity data from wells in the study area. Vitrinite reflectance data was also used for model calibration (Table 3). Hydrocarbon Generation: The data used for the hydrocarbon generation were Kerogen type, initial TOC and initial Hydrogen Index (e.g. Andersen *et al*., 2005, Bustin and Chonchawalit, 1997, Curiale and Gibling, 1994, Petersen *et al*., 2001, Petersen *et al*., 2004, Petersen *et al*., 2014). All the data used in the construction of wells and pseudo wells which include depths, age, lithologies, palaeo and present heat flow, vitrinite reflectance, kerogen type, initial TOC and HI are based on relevant literature (e.g. Andersen *et al*., 2005, Bustin and Chonchawalit, 1997, Curiale and Gibling, 1994, Doust and Sumner, 2007, Petersen *et al*., 2001, Petersen *et al*., 2004, Petersen *et al*., 2014, Polachan *et al*., 1991, Racey 2011).

Methodology

A total number of 8 wells were used for this study and these are located in the near shore of the north-western Gulf of Thailand (Fig. 1). A geologic section which is representative of general sedimentation in Hua Hin, Western, Kra Basins was subjected to burial history modelling using ZetaWare's Genesis software. The lithologies, depths, thickness and vitrinite reflectance data used for the modelling are shown in (Tables 2-4).

Two source rocks (megasequences 1 and 2) have been identified in these wells. These sources are estimated to have effective thickness of 50 m each. The older megasequence 1 is composed primarily of oil-prone, lacustrine derived organic matter while the younger one is gas prone terrestrial organic matter (Doust and Sumner, 2007, Polachan *et al*., 1991). An initial Total Organic Content (TOC) of 5% and Initial hydrogen Index of 500 were assigned for megasequence 1, while TOC of 10% and initial Hydrogen Index of 300 were assigned for the younger megasequence 2 (Andersen *et al*., 2005, Bustin and Chonchawalit, 1997, Petersen *et al*. 2001, Petersen *et al*., 2004, Petersen *et al*., 2014). The same stratigraphy and set of vitrinite reflectance (with slight variation) were applied to each model (Tables 2 and 3).

A variable heat flow model was used. The measured present-day heat flow from wells in this area is approximately 84mWm^2 and 77mWm^2 in Western and Hua Hin Basins respectively (Thienprasert and Raksaskulwong, 1984). There is a degradation of heat flow which followed the initial rift interruption by a heat pulse in the Late Miocene. Little variations in the heat flow of different

Table 2: Input Parameters Used for Modelling of Wells in Hua Hin, Western and Kra Basins in this Study Based on Doust and Sumner (2007), Polachan *et al.* (1991) and Racey (2011).

Megasequences	Average Thickness (M)	Lithologies (%) SST-Sandstone SH -Shale LST- Limestone	Hua Hin North (M)	Hua Hin South (M)	Western North (M)	Western Central (M)	Western South (M)	Kra North (M)	Kra South (M)
6	798	SST 60, SH 40	1048	360	421	1579	592	869	720
5	683	SST 60, SH 40	801	432	664	631	194	1114	945
4	788	SST 100	673	1103	586	520	1415	704	518
3B Upper	135	SST 60, SH 30, LST 10	139	88	144	154	160	62	203
3 Source Rock	50	SH 100	50	50	50	50	50	50	50
3 A lower	135	SST 60, SH 40	139	88	144	154	160	62	203
2	734	SST 80, SH 20	800	1040	1183	560	560	591	459
1B Upper	331	SST 100	93	506	217	250	232	244	775
1 Source Rock	50	SH 100	50	50	50	50	50	50	50
1A Lower	208	SST 60, SH 40	93	145	217	250	232	244	275

Table 3: The Thickness of Megasequences is in Meters (M).

Depth (m)	900	1000	1100	1200	1300	2500	2600	2700	2800	3200	3300	3384
VR %Ro	0.277	0.275	0.284	0.295	0.306	0.585	0.627	0.684	0.710	0.900	0.935	0.985

Table 4: Summary of the Modelled Wells, Input Parameters are Based on Andersen *et al*. (2005), Bustin and Chonchawalit, (1997), Doust and Sumner, (2007), Petersen *et al*. (2001) Petersen *et al*. (2004), Petersen *et al*. (2014), Polachan *et al*., (1991) and Racey (2011)

	Hua Hin North	Hua Hin South	Western North	Western Central	Western South	Kra North	Kra South	Pattani North
Input Parameters								
Source Rock	Middle Eocene	Middle Eocene	Middle Eocene	Middle Eocene	Middle Eocene	Middle Eocene	Middle Eocene	Middle Eocene
Age (Ma)	42	42	42	42	42	42	42	42
Lithology	Shale	Shale	Shale	Shale	Shale	Shale	Shale	Shale
Thickness (meters)	50	50	50	50	50	50	50	50
Depth (approx in meters)	3888	4332	3888	4332	4332	3888	4332	3888
Initial Hydrogen Index (mg/g/TOC)	500	500	500	500	500	500	500	500

Table 4 (Cont.)

	Hua Hin North	Hua Hin South	Western North	Western Central	Western South	Kra North	Kra South	Pattani North
Initial TOC (%)	5	5	5	5	5	5	5	5
Kerogen Lithofacies	Deep Lacustrine shales (oil prone)	Deep Lacustrine shales (oil prone)	Deep Lacustrine shales (oil prone)	Deep Lacustrine shales (oil prone)	Deep Lacustrine shales (oil prone)	Deep Lacustrine shales (oil prone)	Deep Lacustrine shales (oil prone)	Deep Lacustrine shales (oil prone)
Results								
Maturity (Megasequence 1)	Late Mature	Late Mature	Oil Window	Late Mature	Oil Window	Oil Window	Mature-Late Mature	Oil Window
Maximum Kerogen Transformation HC (%)	80-100	80-100	20-25	80-100	20-25	60-80	80-100	80-100
Time of Maximum Kerogen Trans-formation (Ma)	2.84	8.84	0.19	1.87	0.84	1.1	0.19	13.48
Maximum Oil Expelled (mg/gtoc)	320-400	280-350	96-120	320-400	40-50	240-300	280-350	320-400
Maximum Gas Expelled (mg/gtoc)	40-50	32-40	11-14	64-80	20-25	20-40	32-40	80-100
Rate of Expulsion (mg/gtoc/my)	172	101	70.25	290	70	74.18	75.93	500
Time of Maximum	2.24	8.84	0.06	2.71	0.26	2.12	2.24	13
Expulsion (Ma)								
Depth of Maximum Expulsion (meters)	3459	3400	3416	3514	3368	3741	3869	5642

basins are reflected by slight variation observed in the different wells. Models from all 8 wells show an excellent correlation with the observed vitrinite reflectance data and therefore are able to justify present day observations in terms of vitrinite reflectance and heat flow (Figure 5).

RESULTS

Hua Hin (North) Basin

In Hua Hin (north) well the megasequence 1 source rock is late mature (Figure 6A). The megasequence 2 is early mature and did not expel any significant hydrocarbon. Although kerogen transformation was initiated since the Middle Eocene, significant transformation did not occur until Middle Miocene (2.77 Ma) and at a depth of 3406 m. Kerogen transformation reached the maximum in the Late Pliocene and continued till the Recent (Figure 6B). Significant hydrocarbon expulsion occurred in the Middle Miocene (4.06 Ma) in the deeper source reaching the maximum at 2.24 Ma. Significant amount of oil and little amount of gas were expelled at depths of 3474 m and 3459 m respectively (Figure 6). Hua Hin

Figure 5: Excellent Correlation with the Observed Vitrinite Reflectance from Hua Hin (North) Basin.

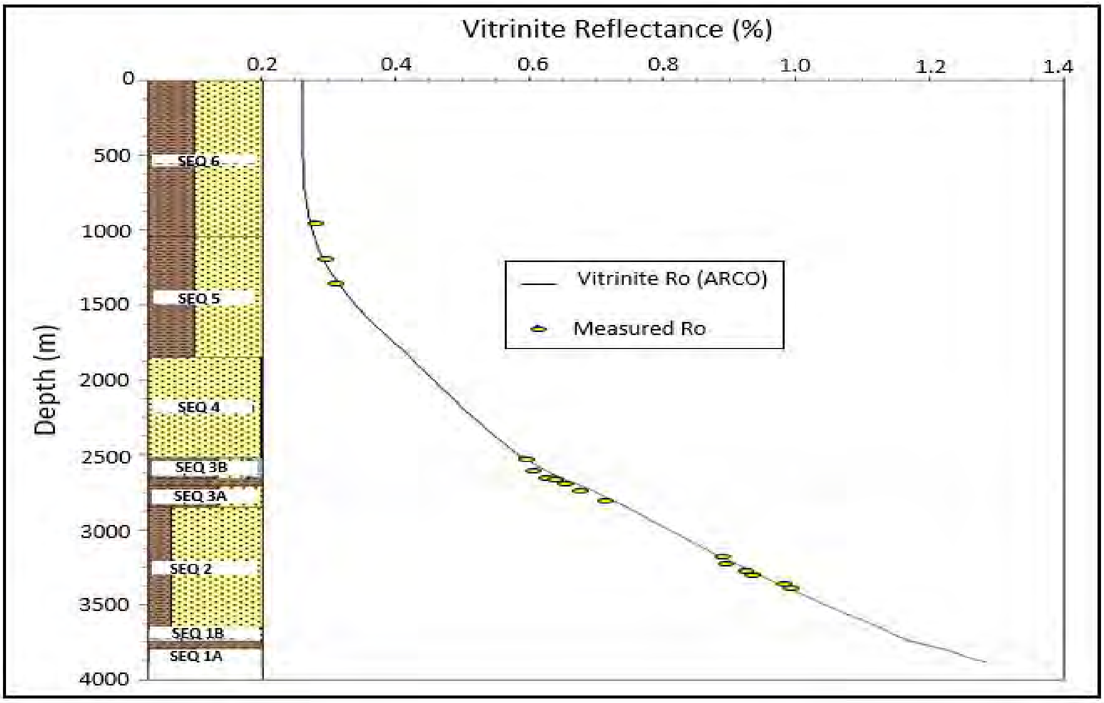


Figure 6: (A) Thermal Maturity in Hua Hin (North) Basin, (B) Quantity and Time of Expelled Oil in Hua Hin (South) Basin, SEQ: Sequence; Fm: Formation; Plio: Pliocene; Qua: Quaternary.

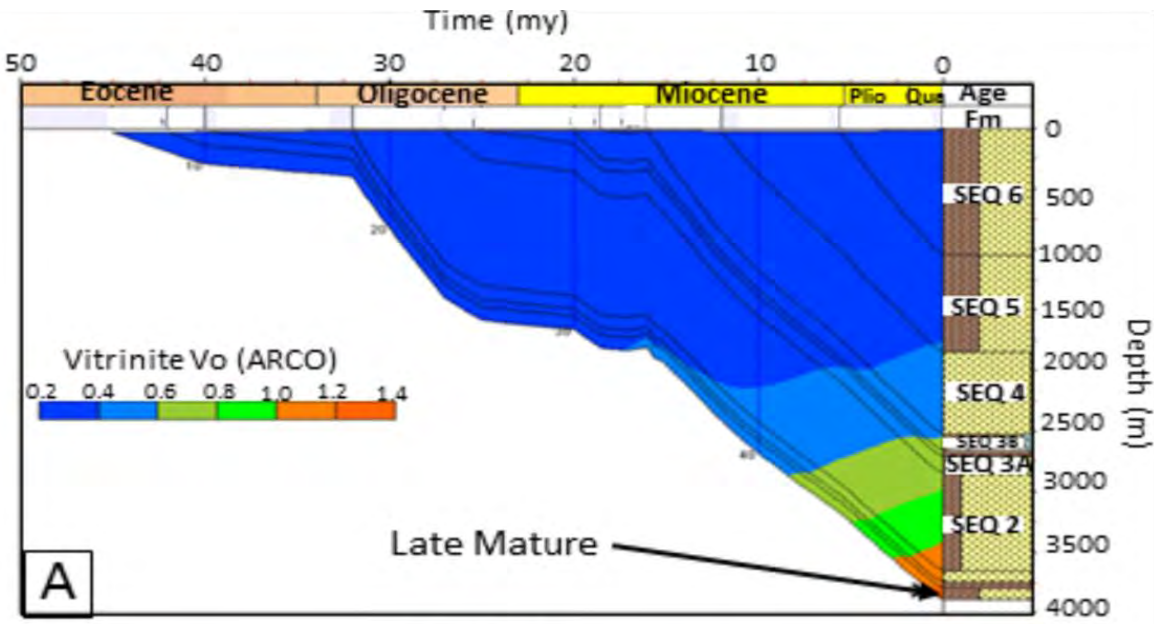
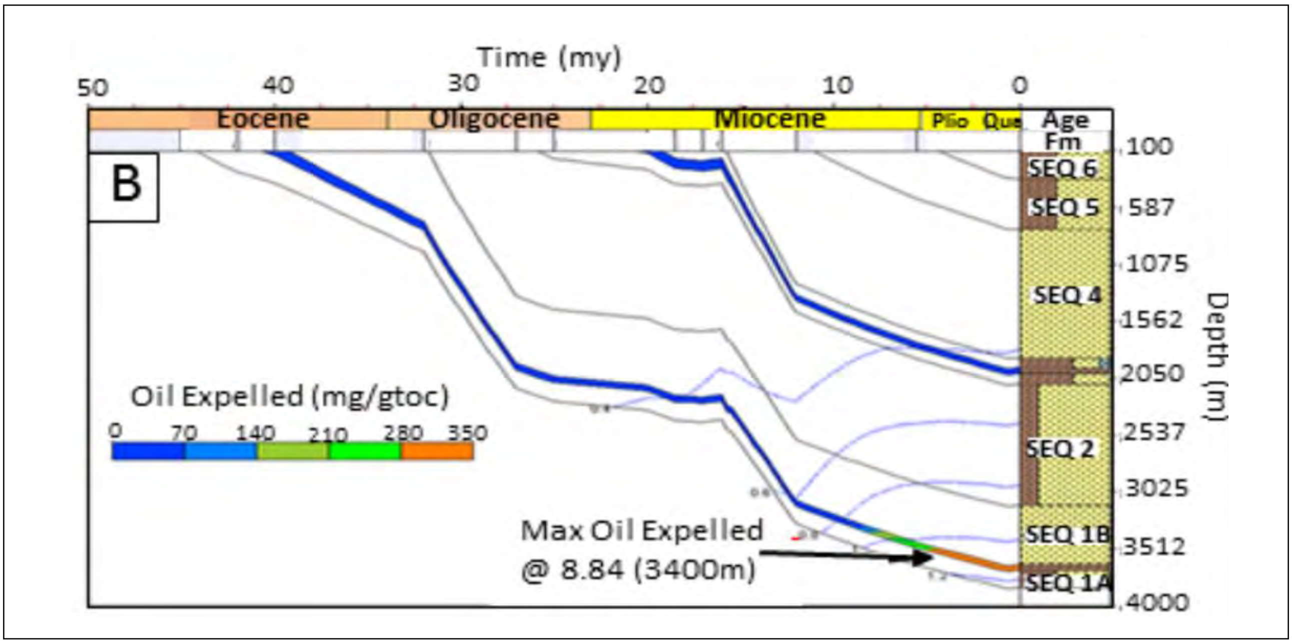


Figure 6 (Cont.)



(north) well with source rock at depth of 2795 m did not expel any hydrocarbon. The depth of the well was further extended by 1000 m deeper until the source rock at 3795 m attained hydrocarbon expulsion.

Hua Hin (South) Basin

The megasequence 1 source rock is in the oil window. The shallower source rock did not attain maturity. Significant kerogen transformation did not occur until the Late Miocene (9.03 Ma) and at a depth of 3254 m. Kerogen transformation reached the peak in the Late Miocene and continued till the present. Significant hydrocarbon expulsion occurred in the Late Miocene (6.77 Ma). Oil (significant amount) and gas were expelled at depths of 3460 m and 3400 m respectively (Fig. 6B). Like the Hua Hin (south) well, Hua Hin (north) well with source rock at depth of 2795 m did not expel any significant hydrocarbon. The well was further extended by 500 m deeper until the source rock (3734 m) attained hydrocarbon expulsion and also showed residual hydrocarbon.

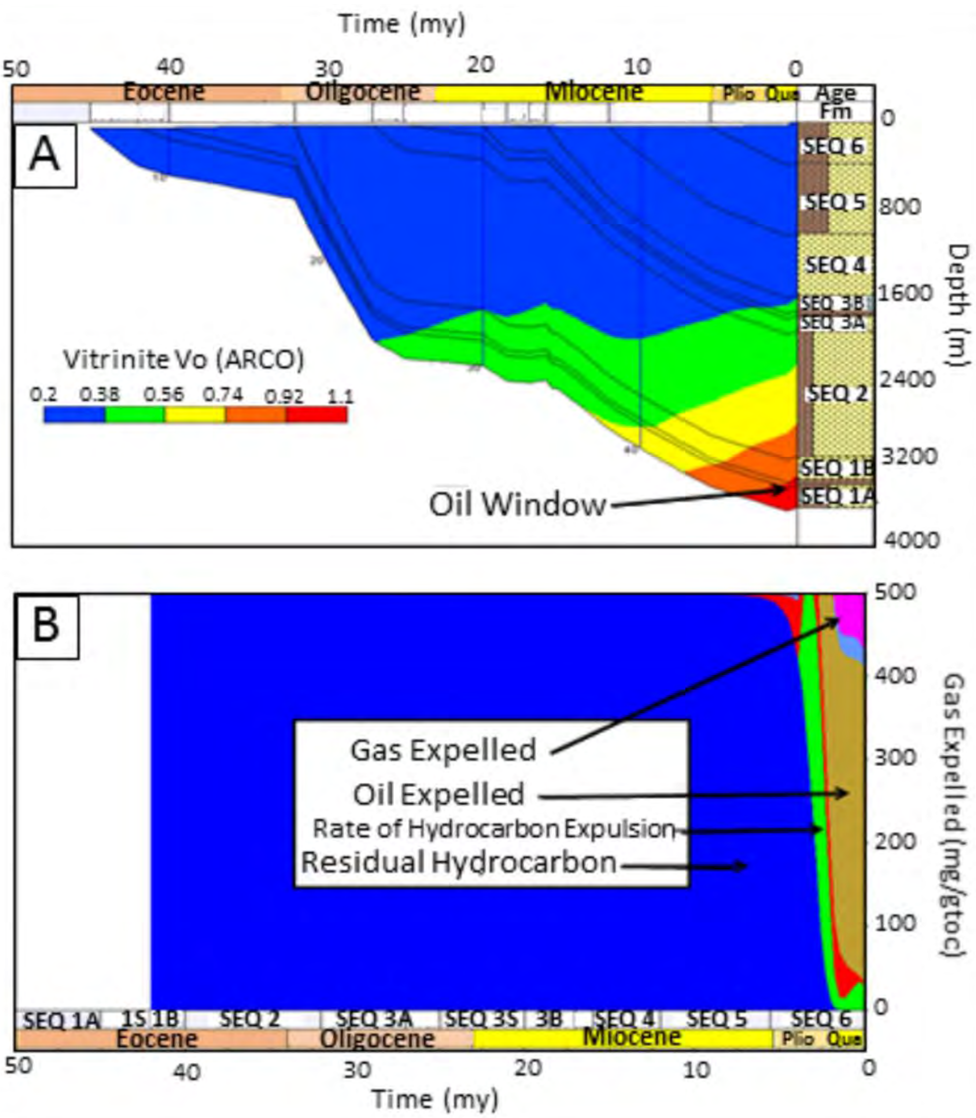
Western (North) Basin

The deeper oil prone source (megasequence 1) is mature and is in the oil window (Figure 7A). The shallow source rock is immature for hydrocarbon generation and expulsion. Unlike all other wells, the Western (north), with source rock at depth of 3460 m did expel hydrocarbon without any downward extension (Table 4). Significant kerogen transformation did not occur until the Late Pliocene (2.26 Ma) and at a depth of 3374 m. It reached its peak in the Late Pleistocene (0.19 Ma) and continued till the present (Table 4). Significant hydrocarbon expulsion occurred in the Late Pliocene (0.15 Ma) reaching its peak at 0.06 Ma. Gas and oil were significantly expelled at depth of 3426 m.

Western (South) Basin

In the Western (south) well the shallow source rock is immature to early mature while the deeper oil prone (megasequence 1) is in oil window (Table 4). Although significant kerogen transformation did occur in the Late Pliocene

Figure 7(A): Thermal Maturity in Western (North) Basin, (B): Expelled and Residual Hydrocarbon in Western (Central) Basin, SEQ: Sequence; Fm: Formation; Plio: Pliocene; Qua: Quaternary.



(2.58 Ma), maximum kerogen transformation was not achieved until Pleistocene (0.84 Ma) and continued till the Recent. Significant hydrocarbon expulsion occurred in the Late Pliocene (0.52 Ma) in the deeper source reaching the maximum at (0.26 Ma) (Table 4). The shallow source (megasequence 2) had little or no expulsion. Gas and oil were significantly expelled at depths of 3398 m and 3468 m respectively. Originally Western (south) well with source rock at depth of 2645 m did not expel any hydrocarbon. The well was further extended by 500 m deeper until the source rock at 3369 m expelled hydrocarbon.

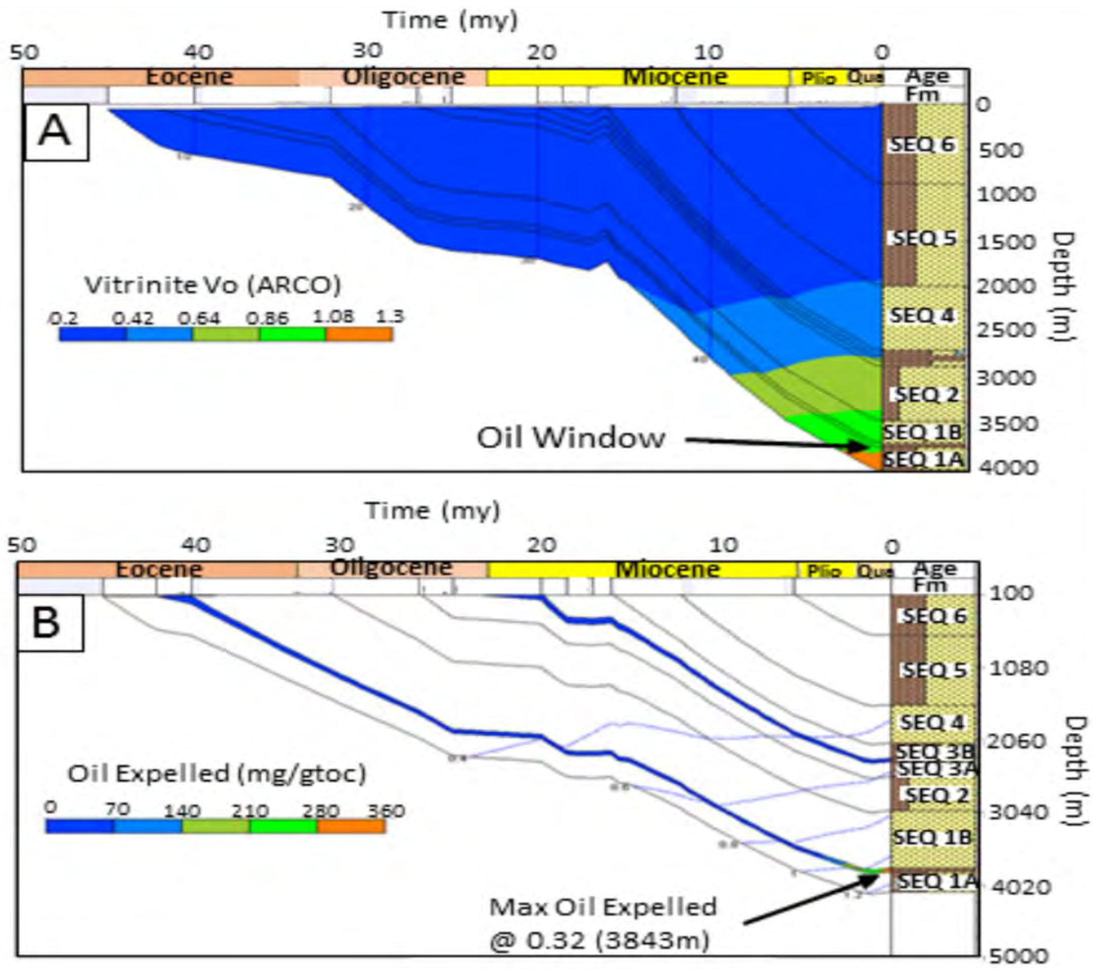
Western (Central) Basin

The megasequence 2 source rock in the Western central did not attain maturity and did not expel any significant hydrocarbon while the megasequence 2 source is late mature (Fig. 7B). Significant kerogen transformation did not occur until late Pliocene (2.71 Ma) and at a depth of 3314 m reaching its peak in the Late Pliocene and continued till the present (Table 4). Gas and oil were significantly expelled at depths of 3933 m and 3514 m respectively. Significant hydrocarbon expulsion occurred in the Late Pliocene (2.13 Ma) reaching its peak of 290 mg/gtoc/my at (0.32 Ma) and (1.87 Ma) for gas and oil respectively (Table 4). Like the south well, Western (central) well with source rock at depth of about 2897 m did not expel any hydrocarbon until it was further extended deeper by 1000 m and expelled hydrocarbon at (3897 m).

Kra (North) Basin

In Kra (north) Basin, the shallow source rock is early mature and had little or no expulsion while the (megasequence 1) source is in oil window and expelled hydrocarbon (Figure 5.7 and Table 4). Significant kerogen transformation did occur in the Middle Pliocene (3.87 Ma) and maximum kerogen transformation was achieved shortly in the Late Pliocene (1.1 Ma) and continued till the Recent (Figure 8A). Significant hydrocarbon

Figure 8(A): Thermal Maturity in Kra (North) Basin, (B): Quantity and Time of Expelled Oil in Kra (South) Basin, SEQ: Sequence; Fm: Formation; Plio: Pliocene; Qua: Quaternary.



expulsion was initiated in the Early Pliocene (4.29 Ma) in the deeper source reaching the maximum at (2.12 Ma). Significant expulsion continued to the present. Unlike in some basins, only oil was significantly expelled at depths of 3421 m reaching the peak at 3742 m. Originally, Kra (north) well with source rock at a depth of 3246 m did not expel any hydrocarbon. The well was further extended deeper by 500 m until the source rock at depth (3746 m) expelled significant hydrocarbon.

Kra (South) Basin

The shallow source rock in Kra (south) well is immature to early mature and did not expel any significant hydrocarbon. The deeper source (megasequence 1) is mature to late mature (Table 4). Significant kerogen transformation did not occur until the Early Pliocene (4.77 Ma) and at a depth of 3549 m and then reached the peak in the Pleistocene at depth of 3857 m and continued till the present (Figure 8B). Significant hydrocarbon expulsion (57.75 mg/gtoc/my) occurred in the Middle Eocene (42 Ma) reaching its peak of 75.93 mg/gtoc/my in Late Pliocene (Table 4). Gas and oil were significantly expelled at depths of 3880 m and 3869 m respectively although the quantity of oil expelled is more than seven times that of gas (Table 4). Kra (north) well showed significant residual hydrocarbon (Table 4). Like the Kra (north) well, Kra (south) well with source rock at depth of 2923 m did not expel any significant hydrocarbon. The well was further extended by 1000 m until the source rock at (3923 m) achieved hydrocarbon expulsion.

Pattani (North) Basin

Unlike in all other basins the shallow source rock (megasequence 2) in Pattani well attained maturity and expelled hydrocarbon in oil window while the deeper source (megasequence 1) is over mature and did not expel. Significant kerogen transformation did occur in the Middle Miocene (14.84 Ma) and at a depth of 3733m. Maximum kerogen transformation occurred shortly thereafter at 13.48 Ma and continued till the present (Table 4). Significant hydrocarbon expulsion occurred in the Middle Miocene (13.23 Ma) reaching its at 10 Ma (Table 4). Gas and oil were significantly expelled at depths of 4602 m and 4069 m respectively (Table 4).

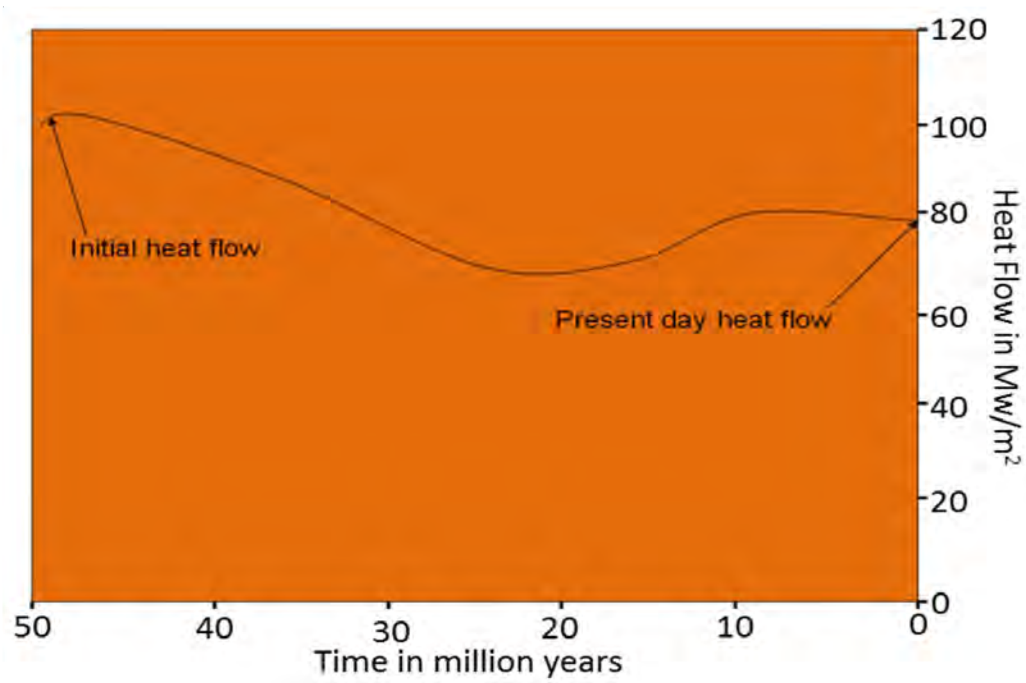
Discussion

Heat Flow and Thermal Maturity

Western Basin has a slightly higher heat flow than Hua Hin Basin. Present day heat flow derived from maturation modelling averages approximately 84 mWm^2 and $77mWm^2$ in Western and Hua Hin Basins respectively (Figure 9). This supports previous studies (e.g. Thienprasert and Raksaskulwong, 1984) that heat flow increases southward in the Gulf of Thailand. The heat flow in Kra Basin may be similar to that of the Western Basin or slightly higher in the southern part of Kra Basin. The variation in heat flow across the Gulf of Thailand accounts for the variation in the thermal maturation of source rocks and this led to increase in source maturity southwards in the Gulf of Thailand. The variation in heat flow was linked to fluctuations in the tectonic and sedimentation history of this area.

The source rock (megasequence 1) in these basins show good thermal maturity. Hua Hin (north and south) Basins are late mature and they did expel significant amount of hydrocarbon at the maturity level that is greater than the threshold maturity of 0.8-1.0% Ro for oil prone source. Western (north and south) Basins are in the oil window but expelled little or no significant amount

Figure 9: Inferred Heat Flow in North Western Gulf of Thailand Based on Maturation Modelling.



of hydrocarbon (Table 4). Western central is over mature and expelled good quantity of hydrocarbon at 1.48% Ro. Kra (north and south) Basins are in oil window and mature-late mature also expelled significant amount of hydrocarbon between 0.8-1.0% Ro. The relationship between source maturity and hydrocarbon expulsion in these basins clearly indicates that the threshold maturity for maximum hydrocarbon expulsion is a minimum of 1.0% Ro which is greater than the threshold maturity for oil-prone source rocks. Hua Hin (north), Hua Hin (south), Kra (north) and Western (central) Basins have source maturity greater than 1.0% Ro and expelled huge quantities of hydrocarbon (Table 4). The thermal maturation in excess of 1.0% Ro in these basins may suggest slow burial of source rocks with a relatively longer period of time to attain maturity. This is further stressed by the higher depth of burial in the late mature source rocks than those in oil window (Table 4). Maturation modelling from this study reveals that the thermal maturation increases with depth in these basins. It is also important to note that mature source rocks are buried deeper southwards and thermal maturity also increases southward locally. In Pattani Basin, which is southward of Hua Hin, Kra and Western Basins (see Figure 1), mature source rock at depth of 5642 m is an evidence to support deeper depth of mature source rocks southward in Gulf of Thailand (Table 4).

Based on the results of this study, minimum depths for mature source rocks in these basins are as follows: Hua Hin (3459 m), Western (3514 m) Kra (3741 m) and Pattani (4169 m) suggesting that depth of mature source rocks increases southward and offshore in the Gulf of Thailand (Table 4). Likewise, based on the different depths of hydrocarbon expulsion observed in the maturation modelling carried out in this work, specific depths (ranging from 3400 to 4200 m) are proposed as the minimum depths for locating mature source rocks in these basins. The strong correlation in depths of mature source rocks with that of Kra Basin (3741 m) and Pattani Basin (4069 m) further suggests increased maturation southward.

Hydrocarbon Expulsion and Potentials

Western (central), Hua Hin (north and south) and Kra (south) Basins expelled significant amount of oil in that order. This ranges between 300-400 mg/gtoc (Table 4). All these sources expelled very little amount of gas (secondary expulsion) between 11-80 mg/gtoc. This low gas expulsion confirms the oil-prone nature of the sources in these basins. Generally, the ratio of oil to gas expulsion is 7:1 in these basins (Table 4).

Maximum hydrocarbon expulsion in this area was first initiated in the Late Miocene (8.84 Ma) in Hua Hin (south) Basin, then in Pleistocene (2.24 Ma) in Kra south and then (1.87 Ma) in Western (central) Basin and in (0.19 Ma) in Western (north) Basin (Figure 7). It is important to stress the right timing of hydrocarbon expulsion in these basins. This is because, all series of expulsion occurred *after* the emplacements of all the necessary structural elements for hydrocarbon trapping - probably in the early Late Miocene; while hydrocarbon expulsion started from Late Miocene to Recent.

Western (central), Kra (south), Hua Hin (north), Hua Hin (south) and Kra (south) (in that order) present excellent hydrocarbon potentials in terms of timing and ratio of kerogen transformation, maximum oil expelled, rate and timing of hydrocarbon expulsion (Table 4). All the modelled wells in Hua Hin, Western and Kra Basins did expel significant quantity of hydrocarbon at some specific (extended) depths other than the depths derived from seismic lines. However, the certainty that these source rocks actually exist at these extended and proposed depths is the main risk involved in these basins. More detailed work will be required to verify the actual presence and nature of these source rocks at these proposed depths.

Based on the assessment of thermal maturity, maximum kerogen transformation, quantity of oil expelled, rate of expulsion, depth of maximum expulsion and time of maximum expulsion of the modelled wells, they can be classified into low-risk (Hua Hin north and south, Western central), moderate-risk (Kra north) and high-risk (Western south and north) basins. Additionally, Hua Hin, Western and Kra Basins show good prospects for possible residual hydrocarbon at deeper depths (Table 4). Western (north and south) are of particular interests as regards to possible residual hydrocarbons. At depths of 3416 m and 3368 m for north and south respectively, little amount of hydrocarbon was expelled compared to Western central at 3514 m. Although, these basins expelled less than considerable amount of hydrocarbon at these depths, they have huge potentials for hydrocarbons at deeper depth (Table 4).

In essence, Hua Hin, Western and Kra Basins show strong and well-established correlation with Pattani Basin – the most prolific liquid hydrocarbon-bearing basin in the Gulf of Thailand. In terms of source rock maturity, maximum kerogen transformation, quantity of maximum oil expelled, and hydrocarbon generation, these basins show strong similarity and correlation with Pattani Basin (Table 4). The results of this maturation modelling supports previous opinion (e.g., Bustin and Chonchawalit, 1997; Doust and Sumner, 2007) that points to similar origin of organic matter for all the basins in the Gulf of Thailand. The only difference is the expected higher heat flow and deeper source (which has been described earlier to increase southward and basinward), and earlier hydrocarbon expulsion (about 13 my) in Pattani Basin.

Significance and Wider Implications

The results presented in this paper have wider significance and implications beyond Thailand and the Gulf of Thailand. For example, the basin modelling method used here has provided vital information on the thermal maturation, transformation of kerogen to hydrocarbon, hydrocarbon expulsion, and depth of mature source rocks in these hydrocarbon-rich basins. This kind of modelling can be applied elsewhere as it is a cost-effective means of assessing hydrocarbon potentials (e.g. Andersen *et al*., 2005; Cukur *et al*., 2012, Hadad *et al*., 2017, Hakimi and Ahmed 2016, Hakimi *et al*., 2018, Mustapha and Abdullah, 2013). Specifically, this work has presented valuable information on the petroleum potentials of Cenozoic basins in the Gulf of Thailand. Our findings can be effectively applied to understand the petroleum potentials of similar Cenozoic basins in Southeast Asia (e.g. Hall 2009, Jiang and Zhang, 2015, Mathur, 2014, Petersen *et al* 2006). The results presented in this research will also be useful for understanding the petroleum systems of similar rifted basins (e.g. Doust and Sumner 2007, Petersen *et al*., 2006). The petroleum potentials of lacustrine source rocks from the Gulf of Thailand will be extremely useful for other petroleum systems with lacustrine sources (e.g. Ding *et al*., 2015, Wei *et al*., 2017). The knowledge gained from this kind of analysis of hydrocarbon potentials of multi-petroleum systems will serve as a guide in exploring sedimentary basins with more than one petroleum systems. In summary, the basins described from the Gulf of Thailand have the potential to be useful analogues for similar Cenozoic basins in Southeast Asia and/or elsewhere and also for similar rifted basins and basins with multi-petroleum systems.

Summary and Conclusion

Petroleum geochemical modelling using ZetaWare Genesis software has enabled the evaluation of source rocks potentials in the onshore basins of Gulf of Thailand. Throughout the Gulf of Thailand, Eocene/Oligocene source rocks are typically lacustrine facies and have potentials for large scale accumulations of highly oil-prone organic matter. Present day heat flow in Hua Hin (north and south) Basins range between approximately 70 mW/m^2 and 84 mW/m^2 averaging around 77 mW/m^2. In the Western (north, central and southern) Basins, it ranges from 80 mW/m^2 to 89 mW/m^2 (with an average of 84 mW/m^2) and this may be similar to that of Kra Basin. The higher heat flow in the Western Basins (which are southward extension of Hua Hin Basin) is consistent with previous work that heat flow increases southward in Gulf of Thailand.

Eocene/Oligocene source rocks in the Hua Hin (north and south), Western (central) and Kra (south) Basins potentially expelled hydrocarbon at maturity level greater than 0.8% Ro which is the threshold maturity level for oil-prone sources. Expulsion may attain a peak nearer to 1.0% Ro. Hydrocarbon generation with expulsion has occurred since the Late Miocene (8.7 Ma) in Hua

Hin (south) Basin. Expulsion did not occur in Western (central) Basin until Pleistocene (1.9 Ma), then in 2.24 Ma in Kra south and lately at 0.2 Ma in the Western (north) Basin. The timing of expulsion in these basins presents good prospects for hydrocarbon discoveries. This is because hydrocarbon expulsion did not occur until after the structural elements needed for trapping have been formed in pre-Late Miocene times. Within the three basins there is a good correlation to that of Pattani Basin in terms of source rock maturation history and kerogen transformation. There is need to verify the depths of mature sources in order to reduce the risk involved in these basins.

The basins analyzed in this study have the potential to be useful analogues for similar Cenozoic basins in Southeast Asia and/or elsewhere and also for similar rifted basins and basins with multi-petroleum systems. This work therefore recommends detailed exploration work to unravel the full hydrocarbon potentials of these modelled basins and other promising yet underexplored basins in the Gulf of Thailand.

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