Acta Geochim (2023) 42(1):38–49
https://doi.org/10.1007/s11631-022-00569-4

ORIGINAL ARTICLE

Source rock potential assessment of the Huai Hin Lat Formation, Sap Phlu Basin, Nakhon Ratchasima Province, northeastern Thailand

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Received: 19 April 2022 / Revised: 31 August 2022 / Accepted: 9 September 2022 / Published online: 29 September 2022

Abstract The Huai Hin Lat Formation has a high-potential resource, and the Ban Nong Sai part was researched and sampled. To achieve this goal, petrographic analysis (kerogen types), geochemical analysis (total organic carbon content, TOC), vitrinite reflectance (R_o), and Rock–Eval (RE) pyrolysis were carried out in this study. According to the findings, types II, III, and IV were identified using a modified Van-Krevelen diagram because the higher mature source rock showing hydrogen index (HI) and oxygen index (OI) are continuously depleted and raised. However, microscopic observation describes macerals as primarily sapropelic amorphinite, therefore, type I is important. The TOC was determined to be between 1.90% and 7.06%, which is considered very good to excellent. The original total organic carbon (TOC_o) was decided to use its maceral components to determine how to convert extremely mature TOC to TOC_o. It varies between 5.13% and 10.74% and reaches a maximum of 57.21% which is comparable to TOC. At 0.82%–1.04%, 443–451 °C, 0.50%–38.10%, and 69.00%–99.59% are the vitrinite reflectance (R_o), maximum temperature (T_{max}), production index (PI), and transformation ratio (TR), respectively. Late peak maturity refers to a mixture of oil and gas, whereas most TR ratios refer to the main gas phase. Similarly, the petroleum residual shows no indication of gas trapped at a volume of 6309.50 mcf/ac-ft. In summary, source rock potential was assessed within a suitable risk range defined by T_{max} (445.70 °C), R_o (0.91%), TR (90.63%), TOC (8.15%), shale thickness (46 m), and kerogen type (type I).

Keywords TOC · Shale gas · Maturity · Geochemistry · Kerogen type · Pyrolysis

1 Introduction

Thailand's energy demands have been increasing steadily throughout the development era. The responsible government sector is constantly on the lookout for ways to provide considerably more energy to all sections of Thailand. Alternatively, the government implemented the plan by importing electricity from Laos and petroleum from other hydrocarbon-rich countries. Additionally, the government can investigate other locations with more significant potential and even extend contracts for existing fields. Although various basins dispersed over Thailand have been examined however, some remain undiscovered yet.

According to the Khorat Plateau, it is approximately 200,000 km^2 in area and encompasses northeastern Thailand. It is home for a thousand Thai residents and some industrial estates. It is comprised of several distinct basins that are expected to yield a significant amount of petroleum for conventional and unconventional evaluation. As previously anticipated, the gas resources discovered by three gas fields have been produced on the Permian carbonate platform. Additionally, the other is focused on Mesozoic rocks, particularly the Huai Hin Lat Formation, which is highly anticipated to be the source rock (Khositchaisri 2012; DMF 2021) and in-situ reservoir (USEIA 2015)

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based on conventional and unconventional assessments respectively. It is composed of 9 basins which were not focused on the distinct basins. Previously, explorationists were usually emphasized on an exposed formation of the Na Pho Song Basin in Petchabun Province but another outcrop of the Sap Phlu Basin in Nakhon Ratchasima Province became less intense as a new area. Additionally, the volume of created hydrocarbons must be comprehensive, yet it is deficient.

Initially, a seismic profile was processed across the Sap Phlu Basin to ascertain the characteristics of basin and overlying formation. Then, TOC and depositional environment parameters such as palaeoproductivity and palaeoredox were offered. Then, the Sap Phlu Basin source rock data is incredibly informative regarding the quality and quantitative mean of macerals, kerogen types, present-day total organic carbon (TOC_{pd}), original total organic carbon (TOC_o), free hydrocarbon volume, and actual stage of maturation. For more understanding, they will be studied and evaluated for the source rock potential as well as the generated hydrocarbon yield. Therefore, this study is innovative and successful in exploration assessment.

1.1 Tectonic setting and stratigraphy of the Sap Phlu basin

In the southwest of Pak Chong District, Nakhon Ratchasima Province, rocks cropping out of the Sap Phlu Basin have been exposed significantly. They were titled Ban Nong Sai depth profile by Arsairai et al. (2016) and are located at 14°38′11.4″ N and 101°38′56.2″ E. It is located along Highway No. 2048 (Pak Chong-Wang Nam Khiao Districts) between the villages of Nong Sai and Khlong Muang (Fig. 1). It was formed by the collision and fusion of Sibumasu (Chonglakmani 2011) and Indochina (Chonglakmani 2011) in the west and Indochina (Chonglakmani 2011) in the east. It was most likely transformed in response to the strongest unconformity or the Indosinian I event in northern Thailand (Booth and Sattayarak 2011). Following regional uplifting and conjugated shear faulting, the Late Triassic brought narrow and elongated as a half-graben. This half-graben gradually transformed into a fluvio-lacustrine basin, irregularly resting on Permian and earlier rocks. The Huai Hin Lat Formation was discovered and mapped before in the Sap Phlu village as the topic of a lithostratigraphic study. However, it has not been examined earlier in geochemistry despite a few source rock quality data. According to the Ban Nong Sai depth profile (Fig. 1), it is approximately 14 m thick and is divided into three lithostratigraphic units: (1) light grey to black calcareous shale; (2) light grey to grey marl or muddy limestone; and (3) greenish grey to black calcareous mudstones and light grey to black calcareous shale.

2 Methodology

The Ban Nong Sai depth profile and sedimentologic characteristics were described based on rocks cropping out by Arsairai et al. (2016). The unweathered organic-rich fine-grained rocks were analyzed to determine the petroleum source rock potential. Geochemical analysis (total organic carbon, TOC), vitrinite reflectance (R_o), and Rock–Eval (RE) pyrolysis) are addressed and used as proxies as is petrographic examination.

2.1 Geochemical analysis

The total organic carbon content (TOC) of fine-grained rock was determined using the Liqui TOC equipment (1% error) of Elementar UK Ltd who is a market-leading supplier of elemental analysis as well as total organic carbon (TOC). It was carried out at the State Key Laboratory of Biogeology and Environmental Geology, Ministry of Education, China University of Geosciences (Wuhan). The dried samples were mixed with water and HCL for removing the inorganic matter. The mixed samples were heated and centrifuged. While pouring out the upper part, the remaining sediments were heated, dried, and pulverized to powder. The powder samples were taken to the combustion furnance with temperarure about 960–970 °C (the most organic matter will combust between 450 and 500 °C). Then the signal values (S total value of the signal, K_C detector sensitivity coefficient, W_1 amount of the acid-treated sample, C percentage content of carbonate in the sample, and W_{H2O} dried sample moisture content) of each sample were measured and calculated to its organic carbon content as follows.

$$W_{oc} = \frac{S}{K_c \frac{W_1}{1-C}(1 - W_{H_2O})} \times 100\% \quad (1)$$

The R_o technique is the most precise way to determine thermal maturity. The complement is a technique that uses a reflectance microscope to optically monitor changes in kerogens. The fraction of incident light reflected from the polished surfaces of woody fragments (vitrinite) was identified by using a Leica MSP200 Light Microscope at the Petroleum Geologic Test Center, Petroleum Exploration and Development Research Institute of Jianghan Oilfield Company (SINOPEC).

The Rock–Eval (RE) pyrolysis technique is the only approach that has been widely utilized to rapidly assess the quality of probable petroleum source rocks including their thermal maturity (Espitalié et al. 1977, 1984; Clementz et al. 1979; Stanley et al. 1992). Initially, around 50–70 mg of each sample placed in a platinum crucible and heated at 300 °C to liberate the free hydrocarbons beneath the S_1

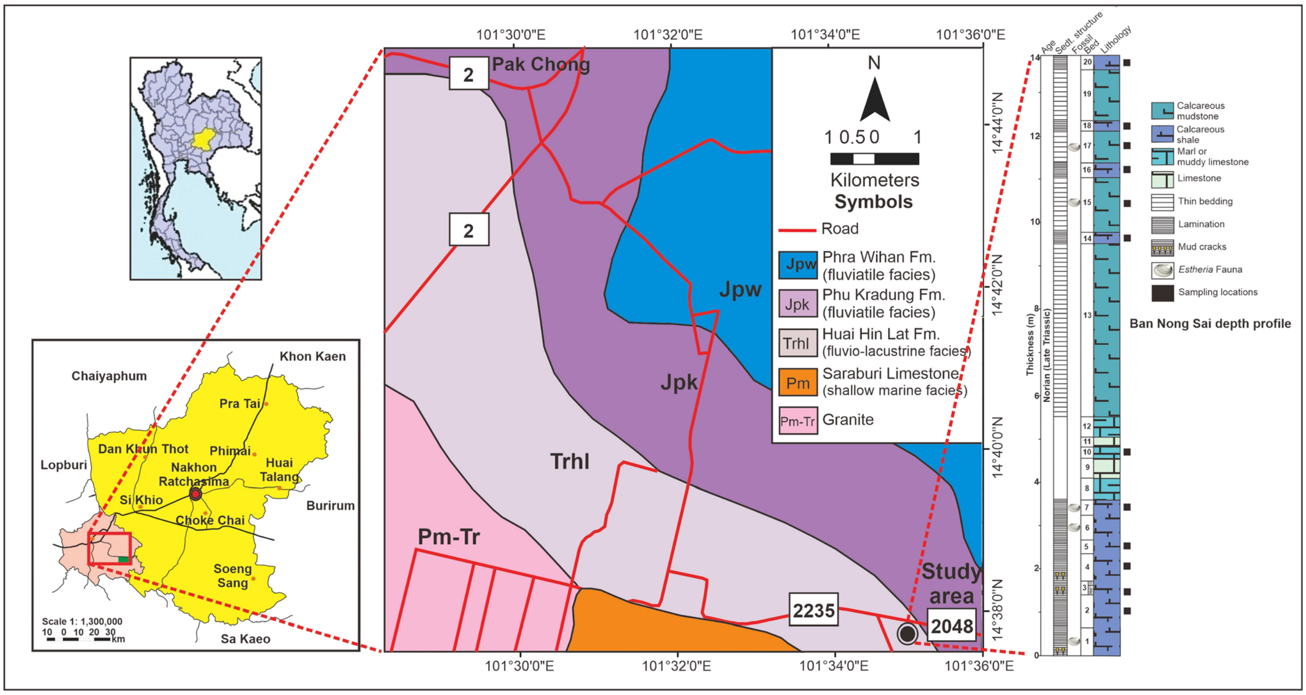

Fig. 1 A geologic map of the study area and the lithostratigraphy of the Ban Nong Sai depth profile (after Arsairai et al. 2016)

peak. The samples are then heated at a rate of 25 °C per minute from 300 to 650 °C using programmed pyrolysis (Espitalié et al. 1977; Lafargue et al. 1998; Behar et al. 2001; Vinci Technologies 2003; Hazra et al. 2019). The hydrocarbons produced during kerogen cracking are represented by the S_2 peak, whereas the temperature measured at the top of the S_2 peak represents the maximum temperature (T_{max}) (Lafargue et al. 1998). The S_3 peak indicates CO_2 from oxygenated compounds following the pyrolysis stage (Espitalié et al. 1977; Lafargue et al. 1998; Behar et al. 2001; Vinci Technologies 2003; Hazra et al. 2019; Hazra et al. 2020). All samples were identified by using a Rock–Eval 6 pyrolysis at the Petroleum Geologic Test Center, Petroleum Exploration and Development Research Institute of Jianghan Oilfield Company (SINOPEC).

2.2 Petrographic analysis for the determination of kerogen types

A kerogen analysis serves as a foundation for identifying organic materials that were intact in the formation throughout the deposition. Their abundance enables us to deduce the categories based on their palaeoenvironment. According to this analysis, the kerogen type will be separated from the rock matrix. The kerogen compositions will be identified using a microscope and reported as a contribution percentage. These specific types were performed and identified in the laboratory of the Petroleum Geological Test Center, Petroleum Exploration and Development Research, Institute of Jianghan Oilfield Company (SINOPEC).

3 Results

The hydrocarbon was generated and supplied by the organic-rich shale accumulated in the micropores. The amount of organic materials and hydrocarbon is a key for determining the source rock potential using microscopic and geochemical methods.

3.1 Petrographic analysis

The proportion of maceral identification based on Ban Nong Sai samples is shown in Table 1. It is predominantly constituted of sapropelic, vitrinite, and inertinite, which are conditionally less abundant than liptinite. The sapropelic reveals a range from 80.70% to 90.30% which is extremely relevant to the sapropelic amorphinite and sapropelic vitrodetrinite excluding alginite (Table 1). The percentages of sapropelic amorphinite and sapropelic vitrodetrinite varied between 57.70% and 73.00% (average value increased by 65.60%) and 16.00%–24.00% (average value increased by 20.20%) respectively. The vitrinite content is modest (9.70%–19.00%), while defining, densinite, gelovitrinite, and texto-ulminite contents range between 5.00%–8.70%, 4.30%–11.00%, and 0.30% respectively. The inertinite

Table 1 Identification of maceral types through petrographic analysis of the Ban Nong Sai depth profile

Beds	Sapropelic						Humic												
	SA	SV	Alginite			Total (%)	Liptinie/exinite					Total (%)	Vitrinite			Total (%)	Inertinite		Total (%)
			AL	GA	AC		RE	SP	SE	CT	BI		TE	DE	GE		FU	SC	
20	66.30	16.00	–	–	–	82.30	–	–	–	–	–	0.00	0.30	6.00	11.00	17.30	0.30	-	0.30
18	59.70	24.00	–	–	–	86.70	–	–	–	–	–	0.00	0.30	7.70	8.30	16.30	–	–	–
16	62.70	21.30	–	–	–	84.00	–	–	–	–	–	0.00	0.30	8.70	7.00	16.00	–	–	–
14	67.30	18.70	–	–	–	86.00	–	–	–	–	–	0.00	0.30	6.00	7.70	14.00	–	–	–
10	57.70	23.00	–	–	-	80.70	–	–	–	–	–	0.00	0.30	8.00	10.70	19.00	0.30	-	0.30
7	64.70	21.70	–	–	-	86.30	–	–	–	–	–	0.00	0.30	6.00	7.00	13.30	0.30	-	0.30
5	68.00	21.00	–	–	-	89.00	–	–	–	–	–	0.00	-	5.00	6.00	11.00	–	–	–
3A	70.70	19.00	–	–	-	89.70	–	–	–	–	–	0.00	-	5.70	4.70	10.30	–	–	–
2	73.00	17.30	–	–	-	90.30	–	–	–	–	–	0.00	-	5.30	4.30	9.70	–	–	–

Remarks; *SA* sapropelic amorphinite, *SV* sapropelic vitrodetrinite, *AL* algae, *GA* green algae; *AC* acritarch, *RE* resinite, *SP* sporinite, *SE* suberinite, *CT* cutinite, *BI* bituminite, *TE* texto-ulminite, *DE* densinite, *GE* gelovitrinite, *FU* fusinite, *SC* sclerotinite

content is the lowest, at 0.30% fusinite, with no sclerotinite. They are consistent with petrographic result of Arsairai et al. (2016). Although the processing conditions were slightly different however, both results are predominantly constituted of sapropelic amorphinite (AOM and acritarch) and vitrinite (phytoclast). Finally, mixed oil and gas can be produced from all of the maceral measured in the Ban Nong Sai depth profile. The following section will determine and discuss additional details on kerogen type.

3.2 Geochemical analysis

Geochemical examination of hydrocarbons is required to estimate its hydrocarbon source potential more accurately. This analysis is separated into three sections: TOC, R_o, and RE pyrolysis.

3.3 Total organic carbon content (TOC)

Previously, organic matter or carbon was critical for understanding how hydrocarbons become entrapped and saturated in rock. Organic matter is quantified in its total organic carbon content (TOC) (Stanley et al. 1992). Interestingly, this is the initial screening criterion for estimating the petroleum generation potential (Khositchaisri 2012).

As mentioned previously, the samples were analyzed and sought to acquire a high level of organic matter or TOC values as shown in Table 2. As a result, the TOC varies between 3.67% and 6.93% (average value by 5.18%). The samples may include a more incredible amount of organic materials. The maximum TOC is found in the lower section, particularly in Bed 3 (6.93%) and gradually decreases to the upper section. However, the lowest result of 3.67%, on the other hand, is indicated in Bed 14 of the middle section.

3.4 Vitrinite reflectance (R_o)

The R_o analysis is a frequently used technique in the oil and gas industry (Fowler et al. 2005; Peters et al. 2005; Fraser et al. 2012). The amount of light reflected by vitrinite maceral is critical for determining its thermal maturity and level (McCarthy et al. 2011).

According to the findings, the selected samples from the Ban Nong Sai depth profile represent no further fluctuation in the list. That twelve samples were evaluated but most of them failed to locate a good location for measurement except for the samples from Beds 14, 15, and 17 (Table 2). Finally, their values for Beds 14, 15, and 17 are 0.82%, 1.04%, and 0.86% respectively. These values indicating that their vitrinites or formations were heated in the earth during burial. As the result of deeper subsidence, condensation of aromatic (carbon-ring) structures in the coal matrix gradually increases (Bustin 1985; Mukhopadhyay and Hatcher 1993; Stach et al. 1982) and higher values of vitrinite reflectances will be measured.

3.5 Rock–Eval (RE) pyrolysis

RE pyrolysis is a widely utilized process, particularly in the petroleum industry. It immediately assesses the quality, thermal maturity (Espitalié et al. 1977, 1984; Clementz et al. 1979; Stanley et al. 1992), and organic matter type of prospective petroleum source rocks (McCarthy et al. 2011). As a result, Table 2 will also depict the programmed pyrolysis between S_1, S_2, S_3, and T_{max}.

Table 2 Average values of TOC, RE, and R_o of the Ban Nong Sai depth profile, the Sap Phlu Basin

Beds	TOC (%))	Measured R_o (%)	Pyrolysis (mg HC/g rock)			T_{max} (°C)	HI	OI	Gas in rock from S_1 (mcf/ac-ft)	Generation potential from S_2 (mcf/ac-ft)
			S_1	S_2	S_3					
20	5.33	–	0.03	3.51	0.77	444	66	15	3.94	461.00
18	5.39	–	0.04	7.12	0.53	443	132	10	5.25	935.14
17	5.07	0.86	–	–	–	–	–	–	–	–
16	4.07	-	0.04	2.65	0.57	443	65	14	5.25	348.05
15	4.95	1.04	–	–	–	–	–	–	–	–
14	3.67	0.82	0.18	7.94	0.30	447	216	8	23.64	1042.84
10	4.51	–	0.16	0.26	0.21	445	6	5	21.01	34.15
7	5.56	–	0.03	0.33	0.44	444	6	8	3.94	43.34
5	5.27	–	0.05	7.26	0.36	447	138	7	6.57	953.53
4	5.31	–	0.13	14.34	0.23	451	270	4	17.07	1883.42
3A	6.93	–	0.12	23.91	0.74	448	345	11	15.76	3140.34
2	6.15	–	0.03	3.63	0.90	445	59	15	3.94	476.76
Avg	5.18	0.91	0.08	7.10	0.51	445.70	130	10	10.64	931.86

Remark; HI = $(S_2/TOC) \times 100$ (mg HC/g TOC), OI = $(S_3/TOC) \times 100$ (mg HC/g TOC), Oil in rock from S_1 (mcf/ac-ft) = $S_1 \times 131.34$, Generation potential from S_2 (mcf/ac-ft) = $S_2 \times 131.34$, and calculated R_o (from T_{max}) = $(0.018 \times T_{max}) - 7.16$

The ten samples were analyzed, and the S_1 was measured at concentrations ranging from 0.03–0.18 mg HC/g rock, with an average of 0.08 mg HC/g rock. The majority of numbers are close to zero, indicating that free gas has been maintained slightly. Additionally, the S_2 was analyzed, revealing a range of 0.26–23.91 mg HC/g rock, with an average of 7.10 mg HC/g rock. Although, lower values of 23.91 and 14.34 mg HC/g rock were found in the list of Beds 3 and 4 however, they were indicated that are more significant than the others. The S_3 value is lower, ranging from 0.21 to 0.90 mg HC/g rock with an average of 0.51 mg HC/g rock. Then T_{max} denotes the temperature at which the highest rate of kerogen cracking proceeds. It fluctuates from 443 to 451 °C with an average of 445.70 °C. As a result of the findings, these numbers indicate that carbon, hydrogen, and other elements have been processed and converted to hydrocarbons. However, as the given overlapped, it is not precise to promote to the mature stage as the given overlapped.

In general, the S_1 and S_2 can be converted to gas volume using a conversion factor of 131.34 mcf/ac-ft, assuming that the source rock is over peak maturity. Then S_1 refers to the free gas that has been trapped recently at a rate of approximately 10.64 mcf/ac-ft. It is reported as slightly low, which could be due to a minor loss of free hydrocarbon or the presence of a higher gas potential (S_2) in the source rock. However, the generated potential gas is not excessively high (931.86 mcf/ac-ft) resulting from increased mauturity stage and near-complete loss. The lost free gas is proportional to the difference between the initial and present potential gases (S_{2o}) and represents potential gas (S_2). Thus, the abrupt transition from S_{2o} to S_2 is intended to be carefully manufactured and most likely migrated.

4 Discussion

The assessment of source rocks in unconventional and conventional reservoirs is comparable. They used to conduct analyses based on the organic matter quality of the kerogen types, the quantity and quality of organic matter, the thermal maturity stage, the volume of generated hydrocarbons, and risk assessment based on a favourable development.

4.1 Kerogen types

By comparing the hydrogen index (HI) to the oxygen index (OI), the RE pyrolysis technique is typically used to determine the kerogen types (organic matter types). All data are shown on a modified Van-Krevelen diagram (Fig. 2a) in which type II and type III areas are invisible. On the other hand, some data are located in the lower-left portion of the diagram which is helpful in the event of a problematic kerogen type interpretation. Figure 2b illustrates the relationship between the HI and T_{max} values which correspond to kerogen types II–III but the others are

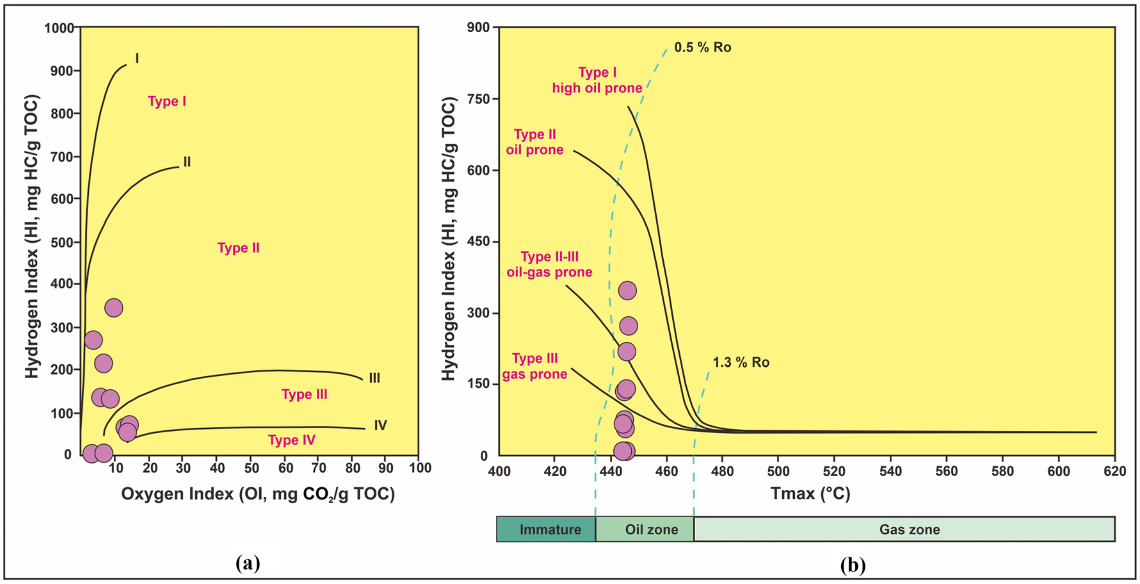

Fig. 2 Classification of kerogen types using a modified Van-Krevelen diagram (**a**) and hydrogen index vs T_{max} (**b**)

unidentified. These complex data points to a decrease in HI due to increased hydrocarbon expelled while organic matter subsiding into higher temperature. Hydrocarbons with increasing thermal maturity are expelled from the system resulting in a decrease in hydrogen indices (Behar et al. 1992; Singh et al. 2021). Peters and Cassa (1994) describtively suggested that more hydrocarbon products caused the kerogen becoming in hydrogen and relatively enriched in carbon. Conformably, the HI/OI ratios of mature or over-mature source rocks converge toward the origin resulting in type III (Tissot and Welte 1984). Still, type IV does not reflect the initial kerogen quality. Additionally, the original kerogen type I can exhibit toward HI is more significant than 400 mg HC/g TOC for oil-rich sources (Core Laboratories 1993). The HI of the examined samples, on the other hand, is slightly less than 400 mg HC/g TOC, which is likely due to the higher temperature and is more associated with type I.

Consistent with the petrographic analysis, the macerals were constituted primarily of sapropelic amorphinite or amorphous organic matter (AOM) at 65.57% resulting in a highly amorphous groundmass. Pashin (2008a, b) has published that the numerous types of AOM can be derived from biological degradation including resinite, suberinite, bituminite, and exsudatinite. Regrettably, these macerals do not preserve in all samples because they have most likely been derived. Additionally, it is not essential to analyze the proportions of sapropelic amorphinite using fluorescence. Since they must exhibit golden yellow fluorescence during the immaturity stage, non-fluorescent cells will be present throughout the post-maturity stage (Mukhopadhyay et al. 2013). Thus, all macerals were examined to confirm that they were kerogen type I.

4.2 Organic matter quantity and quality

Organic matter can be quantified in terms of present-day total organic carbon (TOC_{pd} or TOC), which can be converted to original total organic carbon (TOC_o). The TOC is used to determine the volume of hydrocarbons ejected from sedimentation to the present day concerning the potential of the source rock.

4.3 Present-day total organic carbon

Source rock is a geological phrase that refers to a rock unit that contains sufficient organic materials to generate the expelled hydrocarbons via thermal processes (Miles 1994). Although it is irrespective of maturity or immaturity, however, the volume of expelled hydrocarbons is strictly regulated during the maturity stage. Additionally, the abundance of organic matter will be related to the anoxic conditions under which they were preserved during deposition (Arsairai et al. 2016). The dominating AOM (algal) and minor vitrinite can be previously described and identified using C27 and C29 sterols of liquid chromatography and gas chromatography/mass spectrometry, respectively (Volkman 1986; Ammar et al. 2020). Both are available, although the petrographic method is more restricted.

The higher amount of organic matter represents the more potential to be a good source rock. Peters and Cassa (1994) divided the TOC content of shale into five categories: poor (< 0.50%), fair (0.50%–1.00%), good

(1.00%–2.00%), very good (2.00%–4.00%), and excellent (> 4.00%). Additionally, Gehman (1962) asserted that the organic matter content of shale is four times that of limestone. TOC can be classified into five categories: < 0.12%, 0.12%–0.25%, 0.25%–0.50%, 0.50%–1.00%, and > 1.00%, which correspond to poor, fair, good, very good, and excellent respectively. Thus, only Beds 14 has been determined to be very good, whereas the others have been determined to be excellent in the majority of samples (Fig. 3).

4.4 Original total organic carbon

The original total organic carbon content (TOC_o) of the source rock is a key parameter for determining the total hydrocarbon volume of the source rock. The TOC_o is composed of the first original hydrogen index (HI_o) that may be calculated using kerogen measurements of microscopic observation (type I-IV) following the argument of Jarvie et al. (2007) as follows:

$$HI_o = \left(\frac{\%type\ I}{100} \times 750\right) + \left(\frac{\%type\ II}{100} \times 450\right) + \left(\frac{\%type\ III}{100} \times 125\right) + \left(\frac{\%type\ IV}{100} \times 50\right) \quad (2)$$

This equation requires the input of kerogen-type percentages of the source rock as shown in Table 3. For example, Bed 2 has an HI_o of 689 mg HC/g TOC. It is composed of 90.30% type I, 0.00% type II, 9.70% type III, and 0.10% type IV respectively. As a result, the HI_o of the Ban Nong Sai depth profile ranges from 629 to 689 mg HC/g TOC (Table 3). Initially, the HI_o can be as high as 750 mg HC/g TOC on high thermal maturity of 100% type I whereas the rest is close to zero.

According to Claypool's equation, the transformation or fractional ratio (TR) is determined from the change in the HIo to be HI (Espitalié et al. 1984; Pelet 1985; Peters et al. 2006; Jarvie et al. 2007; Kuchinskiy et al. 2012) is as follow:

$$TR_{HI} = 1 - \left[\frac{HI_{pd}(1200 - HI_o(1 - PI_o))}{HI_o(1200 - HI_{pd}(1 - PI_{pd}))}\right] \quad (3)$$

This equation is consistent with the formula of Pelet's (1985) in which the constant 1200 represents the maximum quantity of hydrocarbon that forms at 83.33% of the typical carbon content in hydrocarbons. The original production index (PI_o) is 0.02 to the present-day value (Peters et al. 2006) therefore, the transformation ratio is determined by the maceral components (TR_{HI}) of the studied section which ranges from 69.00% to 99.59% (Table 3). As a result, the TR_{HI} is exceedingly high indicating a significant degree of kerogen modification and thermal maturation.

To summarize, the HI_o and TR_{HI} can be computed previously and the TOC_o can be obtained by following the equation from low to high mature values.

$$TOC_o = \frac{(HI_{pd})\left(\frac{TOC_{pd}}{1+k}\right)(83.33)}{\left[(HI_o)(1 - TR_{HI})\left(83.33 - \left(\frac{TOC_{pd}}{1+k}\right)\right)\right] - \left[HI_{pd}\left(\frac{TOC_{pd}}{1+k}\right)\right]} \quad (4)$$

k ($TR_{HI} \times C_R$) is a correction factor based on residual organic carbon being enriched in carbon over original values at high maturity (Burnham 1989; Jarvie et al. 2007). C_R is going to increase in residual carbon depending on

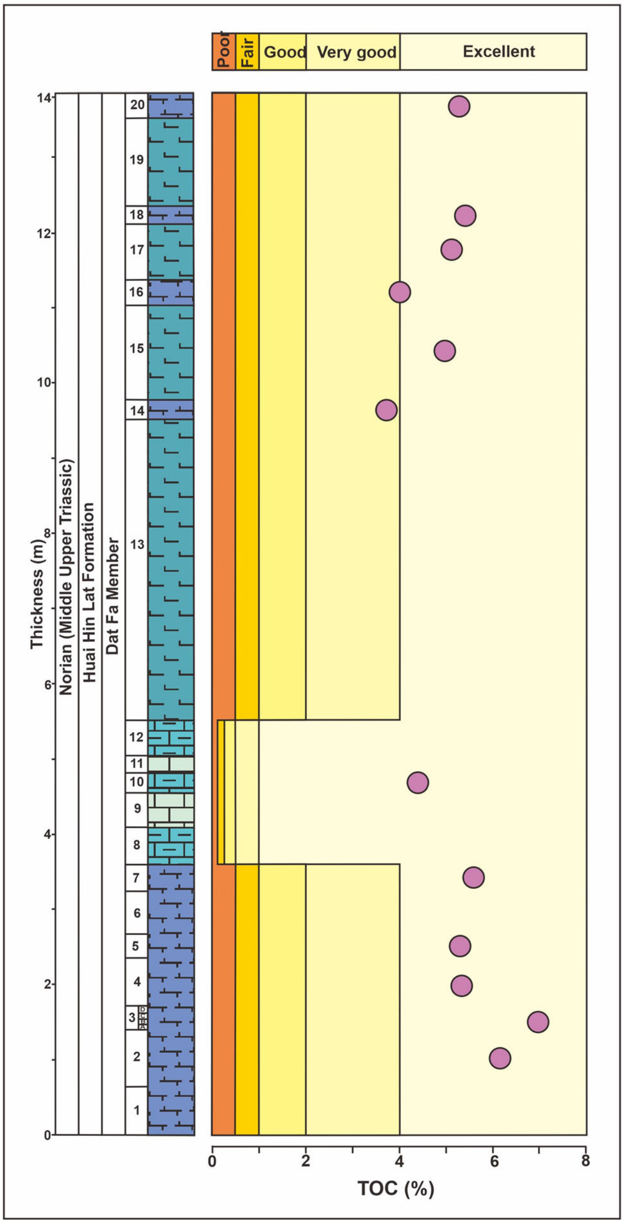

Fig. 3 Classification of source rock potential for the Ban Nong Sai depth profile according to their total organic carbon content (TOC)

Table 3 Original source rock characteristics and hydrocarbon yield of the Ban Nong Sai depth profile, the Sap Phlu Basin

Beds	Kerogen assessment				Calculated R_o (%)	HI_o	PI_o	PI $S_1/(S_1+S_2)$	TR	k ($TR_{HI} \times C_R$)	TOC_o (%)	S_{2o}	Generated hydrocarbons	Hydrocarbon yields (mcf/ac-ft)
	Type I	Type II	Type III	Type IV	(T_{max})							(mg HC/g rock)		
20	82.30	0.00	17.30	0.30	0.83	639	0.02	0.85	94.79	47.39	8.21	52.46	48.95	6429.67
18	86.70	0.00	16.30	0.00	0.81	671	0.02	0.56	90.00	45.00	8.44	56.60	49.48	6498.86
17	–	–	–	–	–	–	–	–	–	–	–	–	–	–
16	84.00	0.00	16.00	0.00	0.81	650	0.02	1.49	95.03	47.52	6.18	40.17	37.52	4927.88
15	–	–	–	–	–	–	–	–	–	–	–	–	–	–
14	86.00	0.00	14.00	0.00	0.89	663	0.02	2.22	81.82	40.91	5.13	33.99	26.05	3420.91
10	80.70	0.00	19.00	0.30	0.85	629	0.02	38.10	99.55	49.78	6.93	43.60	43.34	5692.29
7	86.30	0.00	13.30	0.30	0.83	664	0.02	8.33	99.59	49.79	9.41	62.49	62.16	8163.47
5	89.00	0.00	11.00	0.00	0.89	681	0.02	0.68	89.86	44.93	8.34	56.82	49.56	6508.72
4	–	–	–	–	0.96	–	–	0.50	–	–	–	–	–	–
3A	89.70	0.00	10.30	0.00	0.90	686	0.02	0.50	69.00	34.50	9.98	68.43	44.52	5846.71
2	90.30	0.00	9.70	0.00	0.85	689	0.02	0.82	96.07	48.03	10.74	74.04	70.41	9247.57
Avg	86.10	0.00	14.10	0.10	0.86	664	0.02	5.95	90.63	45.32	8.15	54.08	47.79	6309.51

Remark; $_o$ original, $_{pd}$ present day, PI_o 0.02, k the correction factor, C_R an increase in residual carbon that depend on type I, type II, and type III of 50%, 15%, and 0%, respectively

kerogen type, which type I, type II, and type III are at 50%, 15%, and 0%, respectively. In summary, the TOC_o ranges from 5.13% to 10.74% and the average value of 8.15% (Table 3). They rise by around 57.21% that comparing with the TOC_{pd}. They evolved into the TOC as a result of carbons combining with hydrogen and then being expelled due to the high thermal maturity.

4.5 Thermal maturity stage

The thermal maturity stage can be determined by the maximum temperature at which turning gas has been expelled. This temperature is used as a key parameter for determining the hydrocarbon potential (Jarvie et al. 2004, 2007). The potential is evaluated on the difference between the original and present-day potential of the TOC and HI. The TOC and HI of organic matter could have recently changed depending on the kerogen type. They indicate that kerogen conversion to hydrocarbons occurs at different maturities (Behar and Vandenbroucke, 1987; Behar et al. 1992; Hazra et al. 2015). Furthermore, typing kerogens based on HI values can be deceptive (Hazra et al. 2015), as demonstrated before by another petrographic analysis. Thus, it is critical to illustrate the thermal maturity of the section by using the R_o, T_{max}, PI, and TR to substantiate its temperature-related effects.

4.6 Vitrinite reflectance (R_o)

The R_o is now utilized to assist geochemists in determining the kerogen maturation rate as a function of temperature. Petrographically, type I alginites and type II sporinites are more prone to conversion (higher f) than type III vitrinites or type IV inertinites. Hence, the oil will be expelled (Hazra et al. 2015) corresponding to the mature stage. However, at elevated temperatures, complex hydrocarbons of types I-II will decompose into simple gaseous molecules.

According to Peters and Cassa (1994), and Espitalié and Bordenave (1993), the thermal maturity stage is categorized according to their R_o values. The R_o values of $<$ 0.60%, 0.60%–0.65%, 0.65%–0.90%, and 0.90%–1.35% are classified as immaturity, early maturity, peak maturity, and late maturity respectively. A higher R_o of 1.35% denotes the post-maturity stage. Thus, most samples, excluding the overlapping Bed 15 are classed as peak maturity (Fig. 4a).

Additionally, the T_{max} has been associated with thermal maturation implying a stronger association with R_o. As a result, Jarvie et al. (2001) presented the following relationship between T_{max} and R_o.

$$R_o(eq) = 0.0180(T_{max}) - 7.16 \quad (5)$$

According to the preceding calculation, T_{max} range from 443 to 451 °C and the calculated R_o is between 0.81% and 0.96%, with an average value of 0.86% (Table 3). The calculated R_o (0.89%) and measured R_o (0.82%) of Bed 14 were examined in terms of their slight resemblance and similar development stage. Similarly, the other calculated R_o is identical to the measured R_o indicating predominantly late peak maturity. As a result, liquid and a small number of gaseous hydrocarbons were generated.

4.7 Maximum temperature (T_{max})

The maximum temperature (T_{max}) is a function of the thermal maturity of the organic matter. The T_{max} associates with kerogen type towards a lower value that is relative to simple molecules of type I–II. On the other hand, a more significant value is the result of type III–IV or complex residual carbon structures.

Peters and Cassa (1994), and Espitalié and Bordenave (1993) established the T_{max} classification, which includes < 435 °C, 435–445 °C, 445–450 °C, and 450–470 °C. They indicate immaturity, early maturity, peak maturity, and late maturity. The gas window allows for the evaluation of temperatures greater than 470 °C. According to the present findings, most values correspond to the late peak maturity stage, except for four values that correspond to early maturity (Fig. 4b). However, these T_{max} values can be calculated to R_o and still be presented in late peak maturity as well. Thus, the majority of samples can be evaluated as late peak maturity.

4.8 Production index (PI)

Espitalié and Bordenave (1993), and Peters and Cassa (1994) discussed thermal maturity stages using production index values, $PI = S_1/(S_1 + S_2)$. They range from 0.50 to 38.10 (Table 3) with most data indicating the immaturity stage (Fig. 4c). For example, the PI revealing at < 10.00%, 10.00%–25.00%, 25.00%–40.00%, and > 40.00% is considered immature, early mature, peak mature, and late mature, respectively. It is low compared to other proxies for the immaturity stage since generating hydrocarbon (S_1) is lost during measurement. It has most likely been expelled and moved from most samples, leaving just trace levels of free hydrocarbon in the pores. On the other hand, Bed 10 includes a more significant amount of free gas and a minor concentration of potential gas. It is possible to denote that the mature temperature has already been attained as a result of the pyrolytic effect. As a result of the data from Bed 10, it is established that the PI of all samples was probably also associated with the late peak maturity stage.

4.9 Kerogen transformation ratio (TR)

The kerogen transformation ratio (TR) is a measure of the conversion of organic matter from the immature to the mature stages. The TR can be computed using Claypool's equation in conjunction with the previously described and presented TOC_o technique.

Jarvie et al. (2005, 2007) defined the thermal maturity stage of TR that < 50.0%, 50%–80%, 80%–90%, and > 90% referring to the primary oil stage, the mixed oil and gas stage, the earliest gas window, and the dry gas stage, respectively. Beds 5 and 18 are identical to the others in that they represent overlapping the dry gas window stage (Fig. 4d). Indeed, Beds 3 and 14 have been assessed and determined to be inside the mixed oil and gas and wet gas windows respectively. As a result, most values can be applied to wet and dry gases after the late peak maturity stage following R_o, T_{max}, and PI.

To summarize, R_o, T_{max}, PI, and TR are created to be the optimal critical palaeotemperatures. Although they cannot accurately describe the thermal maturity stage, however, the majority of proxies (R_o, T_{max}, and PI) point to late peak maturity. Finally, they suggest the presence of a mixture of liquid and gaseous hydrocarbons comprising wet and dry phases (TR) that have been expelled from source rocks.

4.10 Volume of generated gas in source rocks

A stage of late peak maturity is found inside the Ban Nong Sai depth profile using selected thermal maturity proxies. There is with relation to oil and gas mixtures. On the contrary, most significant utility of the TR is in the wet and dry gas phases, when they are most likely confined due to the lack of indication of leftover oil. If both gases have been expelled, the volume of each gas may be determined using Schmoker's equation (1994). It is connected to the present-day (remaining) S_2 and the original potential (S_{2o}). The S_2 can be determined directly from the pyrolysis (Table 2), but the S_{2o} must be computed backwards using the TOC_o and HI_o formulas (Jarvie et al. 2007; Peters et al. 2005). This equation allows for the backward calculation of S_{2o} obtaining as the following:

$$S_{2o} = \left(\frac{HI_o \times TOC_o}{100} \right) \tag{6}$$

The TOC_o and HI_o values in the equation above range from 5.13 to 10.74 °C and 629–689 mgHC/gTOC respectively. It produces S_{2o} with a concentration of 33.99–74.04 mg HC/g rock (Table 3). Finally, the volume of produced gas can be calculated by subtracting S_{2o} from S_2. The following equation is obtained for the generated gas:

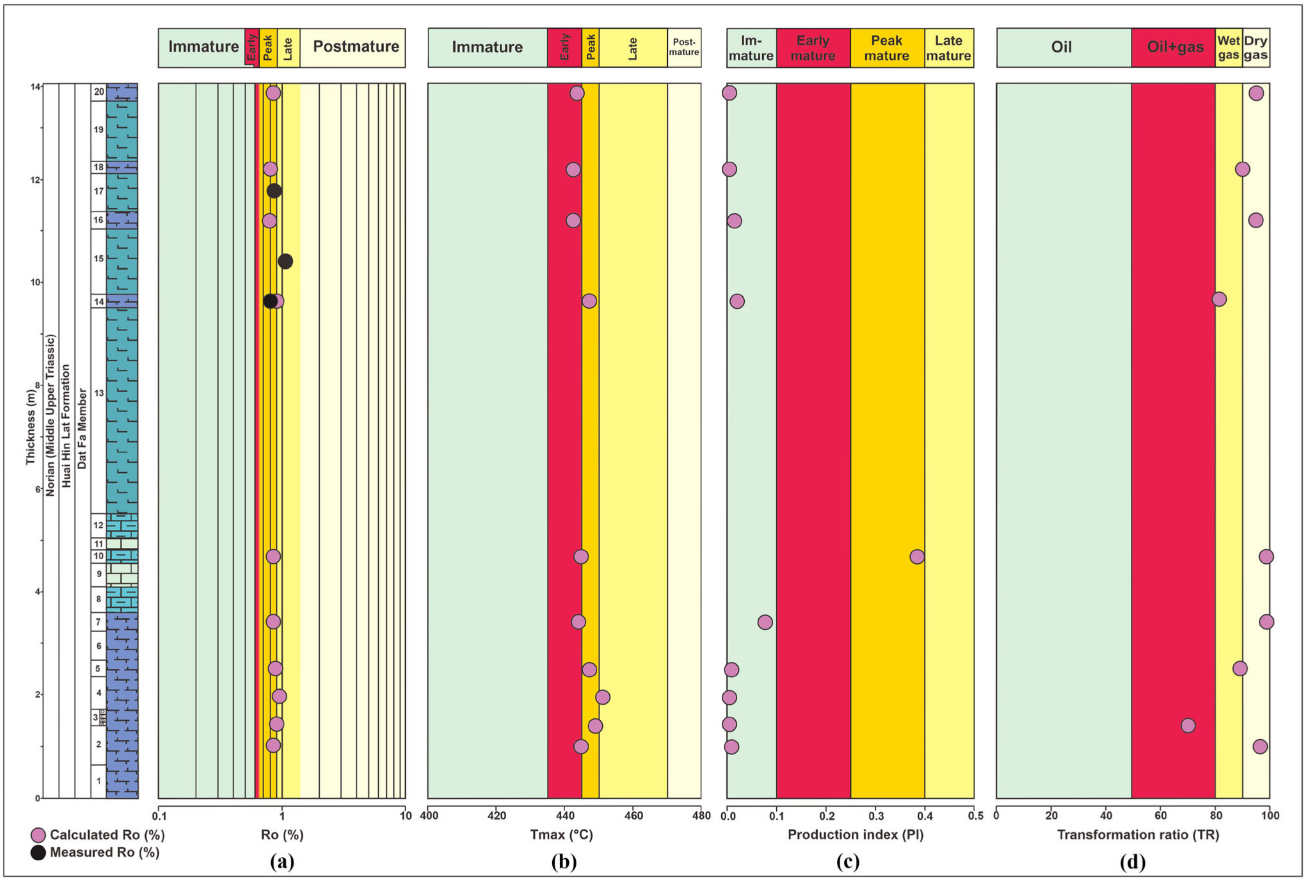

Fig. 4 Thermal maturity stages of source rocks from the Ban Nong Sai depth profile, Sap Phlu Basin as defined by **a** R_o of visual analysis (purple) and calculation from T_{max} (black), **b** T_{max} (°C), **c** PI, and **d** TR

$$Generated \cdot hydrocarbon = S_{2o} - S_2 \tag{7}$$

As a result, the Ban Nong Sai samples generated gas with an average value of 47.79 mg HC/g rock ranging from 26.05 to 70.41 mg HC/g rock. The generated gas can be converted to gas yield using a conversion factor of 131.34 mcf/ac-ft. Therefore, an average gas yield of 6309.51 mcf/ac-ft (Table 3) was expelled previously.

4.11 Risk assessment of source rock potential

The source rock evaluation indicates a good risk is modified by Jarvie et al. (2005). It is a straight forward method for comparing numerous criteria, and its use provides an initial economic assessment in the following manner.

The term good risk refers to the lowest possible value for each parameter at which that stage of hydrocarbon is generated. The source rock potential threshold data has been established using TR (50.00%), TOC (2.00%), shale thickness (50 ft) (Jarvie et al. 2005, 2007), T_{max} (435 °C), R_o (0.60%), and kerogen type (type III). A yellow hatched area (Fig. 5a) was primarily created using threshold data suggesting a low chance of development. Otherwise, the enclosed area (Fig. 5b) was created using data from the Ban Nong Sai, including T_{max} (445.70 °C), R_o (0.91%), TR (90.63%), TOC (8.15%), shale thickness (46 ft), and kerogen type (type I). It was more than double the size of the unproductive area. As a result, it can be determined that most source rock parameters are either in good condition or have a high potential.

The excellent source rock was expected which large gas volumes of 6309.51 mcf/ac-ft have been expelled since the late peak maturity stage. These expelled gases respect the bulk volume of fine-grained rock over 14 m thick and a large area covering the Sap Phlu Basin. In findings, these source rock parameters could be evaluated to pretty good reservoirs as unclearly. For more understanding, the excellent reservoir rock is expected to be further studied that porosity, brittle mineral, clay mineral, and thickness will become > 4.00%, > 50.00%, < 50.00%, and > 50 m respectively. Lastly, extended area and micropores will be studied to describe how hydrocarbon exists.

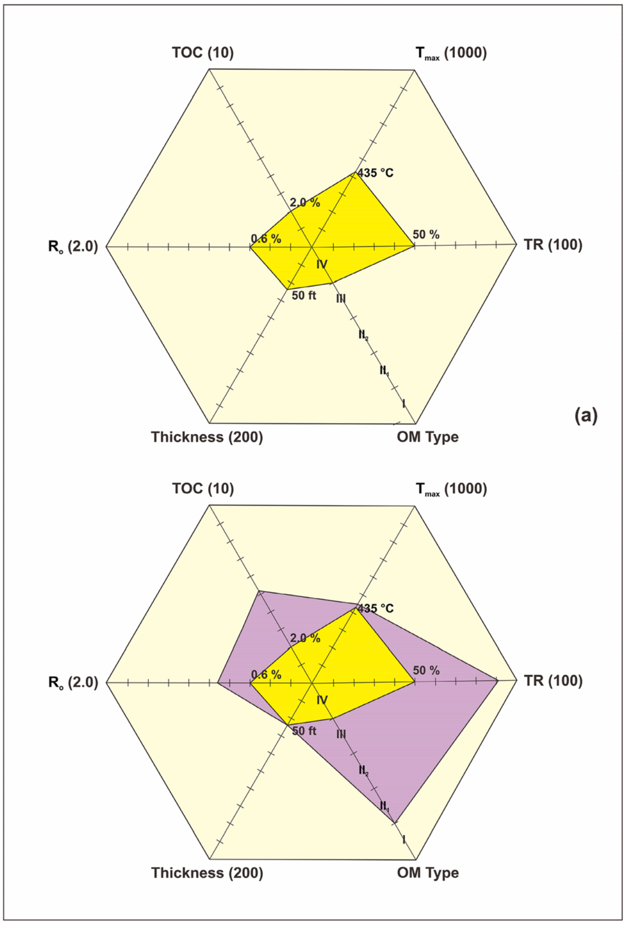

Fig. 5 Polar shale-gas risk plot with multiple visual and chemical assessments; **a** sufficient conditions for comprehensive evaluation (yellow); **b** polar good risk plot

5 Conclusions

The organic matter of the Ban Nong Sai depth profile is primarily constituted of amorphous sapropelic particles, a type I oil-prone kerogen. The TOC and TOC_o are outstanding at 1.90%–7.10% and 5.10%–10.70% respectively. The majority of thermal maturation proxies (R_o, T_{max}, and PI) are in the late peak stage of maturity. It can be inferred that it is a mixture of oil and gas, even though most TR values are in the wet and dry gas phases and there is no evidence of remaining oil maintained. As a result, most gas is likely trapped with an expulsion volume of 6309.50 mcf/ac-ft. Similarly, the excellent risk metric obtained from the T_{max}, R_o, TR, TOC, shale thickness, and kerogen type of 445.70 °C, 0.91%, 5.95%, 90.63%, 8.15%, and 46 ft respectively, is judged as having a good or high source rock potential.

Acknowledgements The present study is fully supported by The Commission on Higher Education, Ministry of Education of Thailand and the Royal Golden Jubilee Program of the Thailand Research Fund (RGJ-TRF), the NSFC (Project No. 41172202), China Geological Survey Program (No. 1212011121256), and granted special funding from the State Key Laboratory of Geological Processes and Mineral Resources. Many special thanks are conveyed to the officials at the State Key Laboratory of Geological Processes and Mineral Resources and State Key Laboratory of Biology and Environmental Geology, China University of Geosciences, Wuhan.

Declarations

Conflict of interest The authors state that they have no conflicting interests.

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