

# We are IntechOpen, the world's leading publisher of Open Access books Built by scientists, for scientists

6,900

Open access books available

186,000

International authors and editors

200M

Downloads

Our authors are among the

154

Countries delivered to

TOP 1%

most cited scientists

12.2%

Contributors from top 500 universities



WEB OF SCIENCE™

Selection of our books indexed in the Book Citation Index  
in Web of Science™ Core Collection (BKCI)

Interested in publishing with us?  
Contact [book.department@intechopen.com](mailto:book.department@intechopen.com)

Numbers displayed above are based on latest data collected.  
For more information visit [www.intechopen.com](http://www.intechopen.com)



---

# Unconventional Resources of Shale Hydrocarbon in Sumatra Basin, Indonesia

---

Abdul Haris, Agus Riyanto, Bayu Seno,  
Husein Agil Almunawar, Martogu Benedict Marbun,  
Iskandarsyah Mahmudin and Prima Erfido Manaf

Additional information is available at the end of the chapter

<http://dx.doi.org/10.5772/intechopen.75600>

---

## Abstract

Sumatra Basin is the largest hydrocarbon producer in Indonesia, which was produced from North Sumatra, Central Sumatra and South Sumatra Basins. Looking at the large accumulation of hydrocarbons that have been produced from Sumatra Basin, it opens the possibility of hydrocarbon potential, which is trapped in shale source rock. The integrated study, which includes geochemical, geomechanical, petrophysical and geophysical analysis, was performed to assess shale reservoir in Sumatra Basin. The geochemical assessment of the Baong formation of North Sumatra Basin show that the total organic content (TOC) ranges from 2 to 3.5 wt.% and is categorized into fair to very good. The geophysical and geomechanical assessment shows the shale layer is indicated by an acoustic impedance, which is higher than 2490 ft/s\*g/cc, with rock strength of 3000 Psi and the brittleness index of 0.48. In Central Sumatra Basin, we assessed Brownshale of Pematang formation. The geochemical analysis shows that the Brownshale has TOC ranges from 0.15 to 2.71 wt.%, which can be categorized into poor to very good. In South Sumatra Basin, we focused on Talang Akar formation (TAF). The geochemical result shows that the TOC ranged from 0.35 to 3.66 wt.% and is categorized into poor to very good.

**Keywords:** hydrocarbon shale, integrated geochemical, geomechanical, petrophysical and geophysical, Sumatra basin

---

## 1. Introduction

Sumatera is the most productive island for oil and gas production coming from three major basins, that is, North, Central and South Sumatra Basin. However, today's production of oil

---

and gas has been depleted because many fields have been reaching the maximum of recovery factor. Exploration activities are intensified to increase the potential of new oil and gas. The potential of oil and gas originating from the unconventional reservoir is potentially observed. The geological agency report showed the total potential of shale gas reserves in Sumatra Island reached 233 trillion cubic feet (TCF) [1]. This enormous resource has yet to be developed.

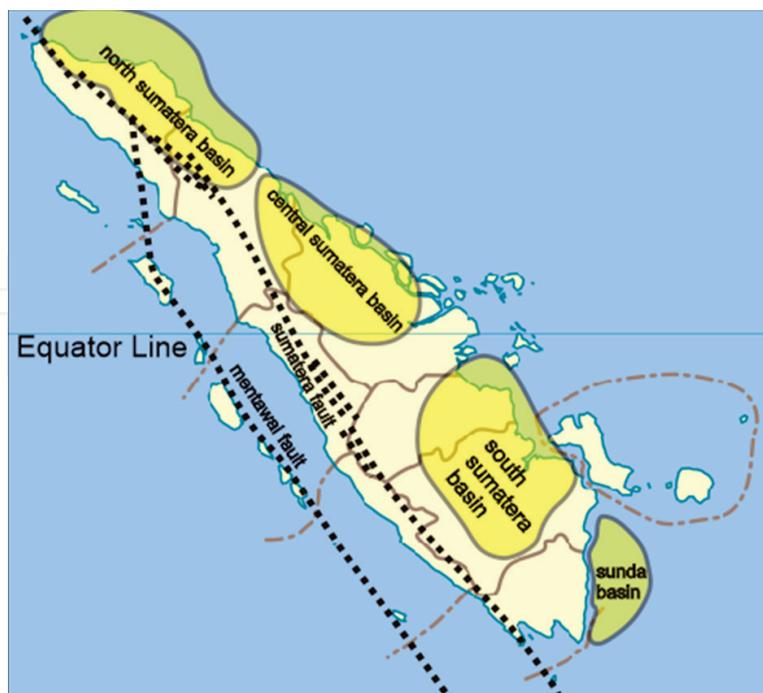
Understanding the characteristics of the shale hydrocarbons is very important, particularly the characteristic that is related to in situ parameters of the shale hydrocarbons. The organic richness of shale layer is represented by total organic carbon (TOC). The potential shale gas is commonly presented by TOC > 2 wt% [1], while for shale oil is indicated by TOC > 1 wt% [2]. The shale maturity is represented by vitrinite reflectance (Ro), which commonly ranges from 1.1 to 1.4% for shale gas [1] and from 0.6 to 1.1% for shale oil [2].

The productivity of shale hydrocarbon is influenced by shale layer thickness, which is related to the technical strategy in producing hydrocarbon. The shale layer thickness of shale gas should be higher than 30 meters [1], while shale oil's must be higher than 15 meters [3]. The last parameter that should be considered is the depth of shale reservoir, which is related to overpressure conditions. The potential depth is in the depth range of 1000–5000 m [1]. In addition, **Table 1** shows a comparison of the prospect criteria for shale oil and shale gas for US cases, and shale gas for Indonesian cases [1].

Until now, shale hydrocarbon reservoir has never been developed in Indonesia. To reduce the risk of failure in the exploration, various studies are required to minimize the level of uncertainty.

Criteria	Data range shale oil US	Data range shale gas US	Data range shale gas
TOC	>1% [2]	2–5% [6] and 3–10% (Marcellus shale)	> 2 wt% [1]
Thermal maturity (Ro)	0.6–1.1% for oil window, but sometimes can reach 1.4% [2]	> 1.4 for dry gas and 1.1–1.4 for wet gas [5], Tmax >450	> 1.1–1.4%, 1–1.3% for wet gas and > 1.3% for dry gas
Kerogen type	The ideal condition is type I, II or IIs. [2] HI > 250, 250–800 mg/g	Type II or III	Type II
Shale thickness	> 15 m [3], > 50 m [2]	Minimum 15–20 m [6], 32 m [7], 20–100 m (Haynesville Shale)	> 30 m
Depth	> 1500 m [3], > 1000 m [8]	200 m (antrim shale), 1300 m (marcellus shale)	1000–5000 m
Mineralogy (clay content)	Clay (low) < 35% Silica (significant) > 30% Less carbonate [2]	Clay <40%	Clay <10%

**Table 1.** Comparison of the prospect criteria for shale oil and shale gas for US cases [5] and shale gas for Indonesian cases [1].



**Figure 1.** Sumatra Island that includes three main basins (north, central and South Sumatra basin).

In this chapter, we describe the mathematical application, geological and geophysical methods for studying shale hydrocarbons in the North, Central and South Sumatra basin. The study area is shown in **Figure 1**. We applied the advanced data processing technique that includes multi-linear regression, linear least square, seismic inversion and geostatistical modeling.

## 2. Geochemical assessment

The hydrocarbon that was generated in the shale reservoir started with the oil formation that had undergone various stages of chemical reaction caused by temperature and pressure on organic material of the shale. The organic material in the first stage underwent diagenesis and made up a kerogen (temperature  $< 1000^{\circ}\text{C}$ ). In the next stage kerogen changes to become a bitumen, and finally they form hydrocarbons through mutagenesis (oil at temperatures  $1000\text{--}1500^{\circ}\text{C}$  and gas at temperatures  $1500\text{--}2300^{\circ}\text{C}$ ). The organic material that becomes hydrocarbon is only a few percent and the remaining is still in the form of kerogen. This condition that makes the geochemical assessment is important [4].

Geochemical assessment is the critical step for shale hydrocarbon exploration. The main purpose of the geochemical assessment is to assess the quantity, quality and maturity of the shale reservoir. Hydrocarbon content of shale reservoir is a complex function of TOC,  $R_o$ , porosity, pressure and temperature. There are several parameters that must be acquired for geochemical assessment. The most accurate parameter is the parameter that is obtained from

laboratory measurements, by using such methods as Leco, Rock-Eval Pyrolysis, to quantify TOC, kerogen type and maturity level. TOC is the amount of organic carbon expressed as weight percent of the dry rock [9]. There is a minimum TOC value to classify that shale reservoir is potential to becoming a source rock [10]. The next parameter is kerogen type, which is determined by using a cross plot between hydrogen index and oxygen index (Van

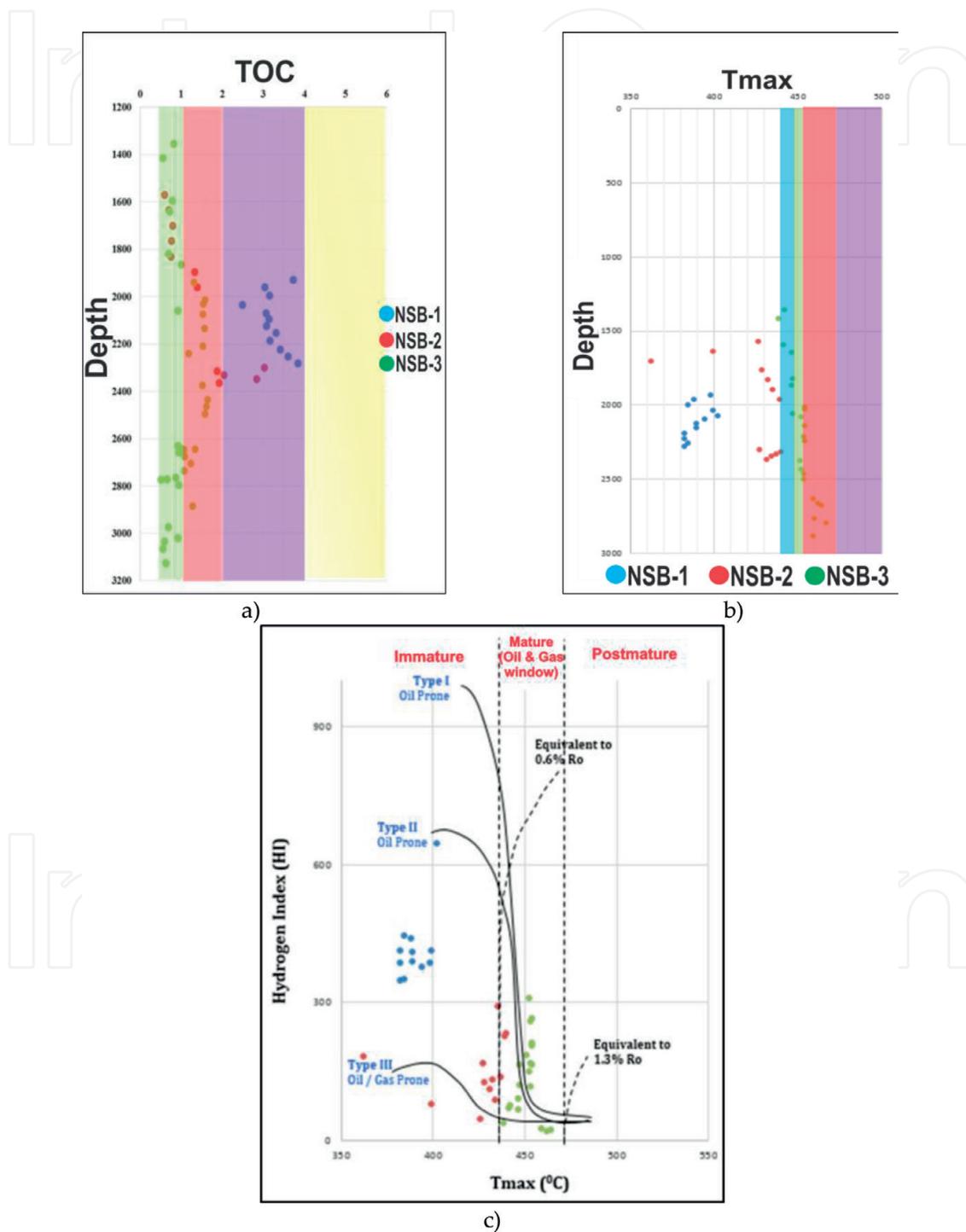


Figure 2. Geochemical assessment of shale hydrocarbon of Baong shale formation in North Sumatra basin, where (a) TOC, (b) Tmax as a function of depth and (c) the relationship between Tmax and HI [11].

Krevelen diagram) and comparison between the hydrogen index and Tmax. The maturity level of organic matters is determined by vitrinite reflectance (Ro) and Tmax. Hydrocarbons can be produced from organic-rich shale with TOC > 1 wt%, Ro from 0.6–1.1% and HI of >200 mg H/g [10].

The study area of North Sumatra Basin is located in Telaga Said and Pantai Pakam area. The conventional reservoir comes from the sand of Ketapang formation, limestone of Belumai formation and source rock of Baong shale formation. In shale hydrocarbon exploration, Baong shale formation plays as a source rock and reservoir as well. The geochemical assessment of Baong shale formation was taken from three well log data (i.e., NSB-1, NSB-2 and NSB-3). The TOC measurement of a core sample from three well log data, which is shown in **Figure 2a**, ranges from 0.5 to 4 wt %. These TOC values are classified as fair to very good. In addition, Tmax ranges from 350–500°C as shown in **Figure 2b**. Referring to Tmax, the Baong shale formation is classified in the category from immature to early mature. **Figure 2c** shows the Krevelen diagram of a core sample of three well log data that indicated the kerogen type of Baong shale formation. The diagram shows that Baong shale formation is categorized into the type II with the maturity level in oil window so that has potential to produce oil.

Geochemical assessment of the Central Sumatra basin was carried out based on our previous studies. A core sample of Pematang Brown shale formation was taken from CSB-1 well. Geochemical assessment on CSB-1 well is shown in **Table 2** [12]. TOC ranges from 0.04 to 4.74 wt%, which is categorized as poor to excellent. This category corresponds to the result of S1 + S2 analysis that shows the potential value from low to moderate. In addition, kerogen type of Pematang Brown Shale is classified as kerogen type III, which has potential to produce gas. In terms of maturity level, we found that Ro ranges from 0.5 to 0.8% with Tmax from 435 to 445°C, which shows maturity level early mature to mature.

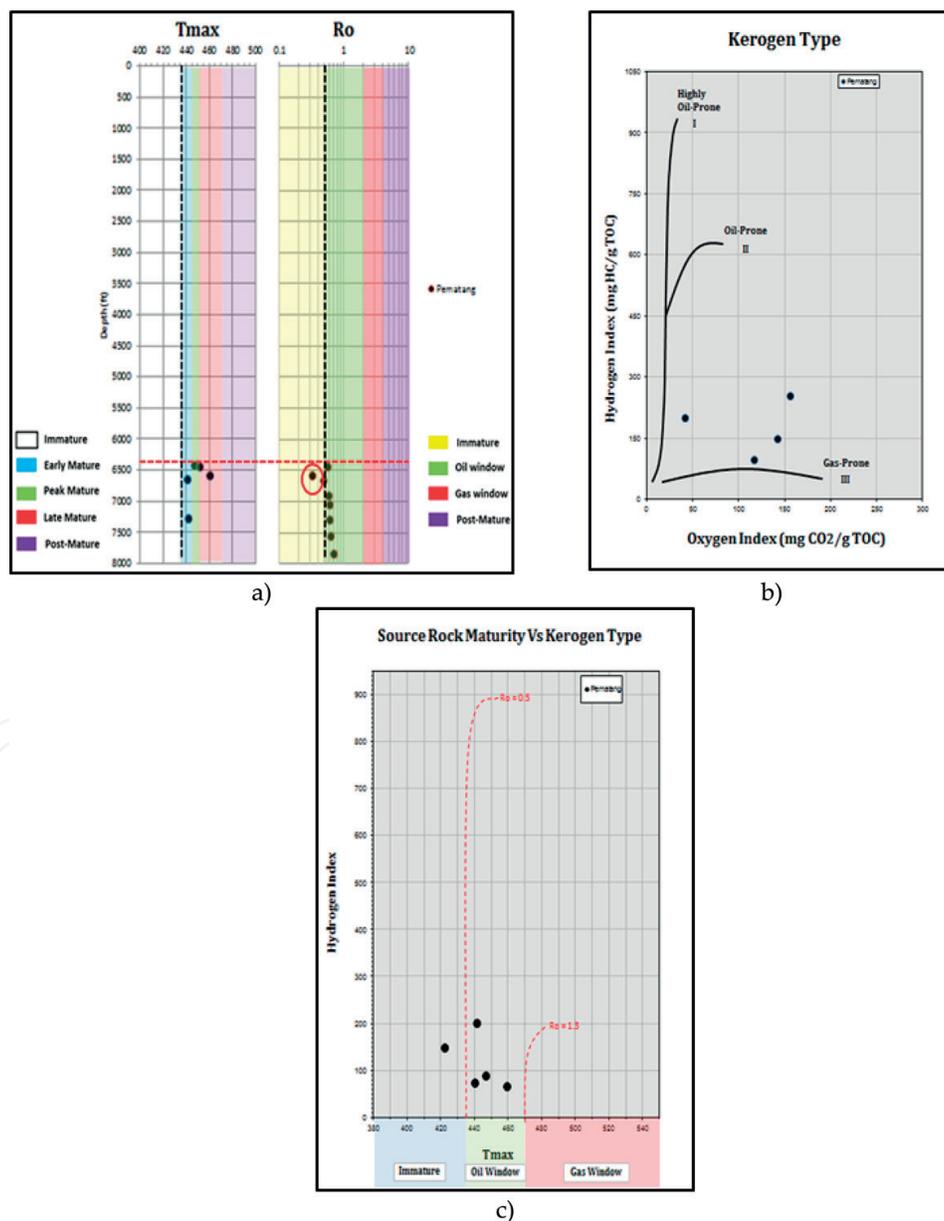
Further geochemical assessment based on a core sample from the next two wells (i.e., CSB-2 and CSB-3 well) shows that Pematang Brown Shale formation of Central Sumatra is classified into early mature phase with Tmax 435°C and Ro 0.55% at depth of 6400 ft as shown in **Figure 3a**. In terms of organic richness, this formation is indicated by organic richness varying from

Depth (ft)	Organic richness (wt%)	HC potential (S1 + S2) mgHC/g rock	Hydrogen index (HI)
6000–6190	Fair (0.98–1.03)	Low (1.91)	Low (159)
6200–6850	Poor (0.26–0.44)	Low (0.07–1.00)	Low (22–186)
7350–8350	Very good (2.01–4.74)	Moderate (2.78–7.65)	Low (189)
8400–8910	Fair (0.74–1.70)	Moderate (2.01)	Low (136–199)
8940–9190	Good (2.09–2.66)	Moderate (2.61–4.35)	Low (136–199)
9240–9710	Fair (0.54–1.57)	High (4.04–8.11)	Moderate (206–350)

**Table 2.** The geochemical properties of shale rock of CSB-1 well in Pematang Brown shale formation.

0.49 to 1 wt% that is categorized as fair quality. The classification of kerogen type, Pematang Brown Shale formation, is classified into kerogen type III, which is shown in **Figure 3b** and **c**. This means that Pematang Brown Shale formation has the capability to produce gas.

Geochemical assessment of shale hydrocarbon in the South Sumatra basin was focused on Talang Akar formation, which was derived from SSB well. **Figure 4** shows the geochemical assessment of shale hydrocarbon of Talang Akar formation in South Sumatra basin. The shale hydrocarbon reveals that organic richness varies from 0.35 to 3.66 wt% that is categorized as poor to very good. In addition, the hydrogen index ranges from 107 to 278, which shows the potential to produce oil and gas. This potential is confirmed by maturity level, which ranges from 0.54 to 1.3%. This maturity level is classified as the early mature phase.



**Figure 3.** Geochemical assessment of Pematang formation of Central Sumatra basin based on CSB-2 and CSB-3 well. Maturity level is indicated by (a) Tmax (left) and (b) Ro as a function of depth (right). Kerogen type is indicated by (a) van Krevelen diagram and (b) the relationship between HI and Tmax [13].

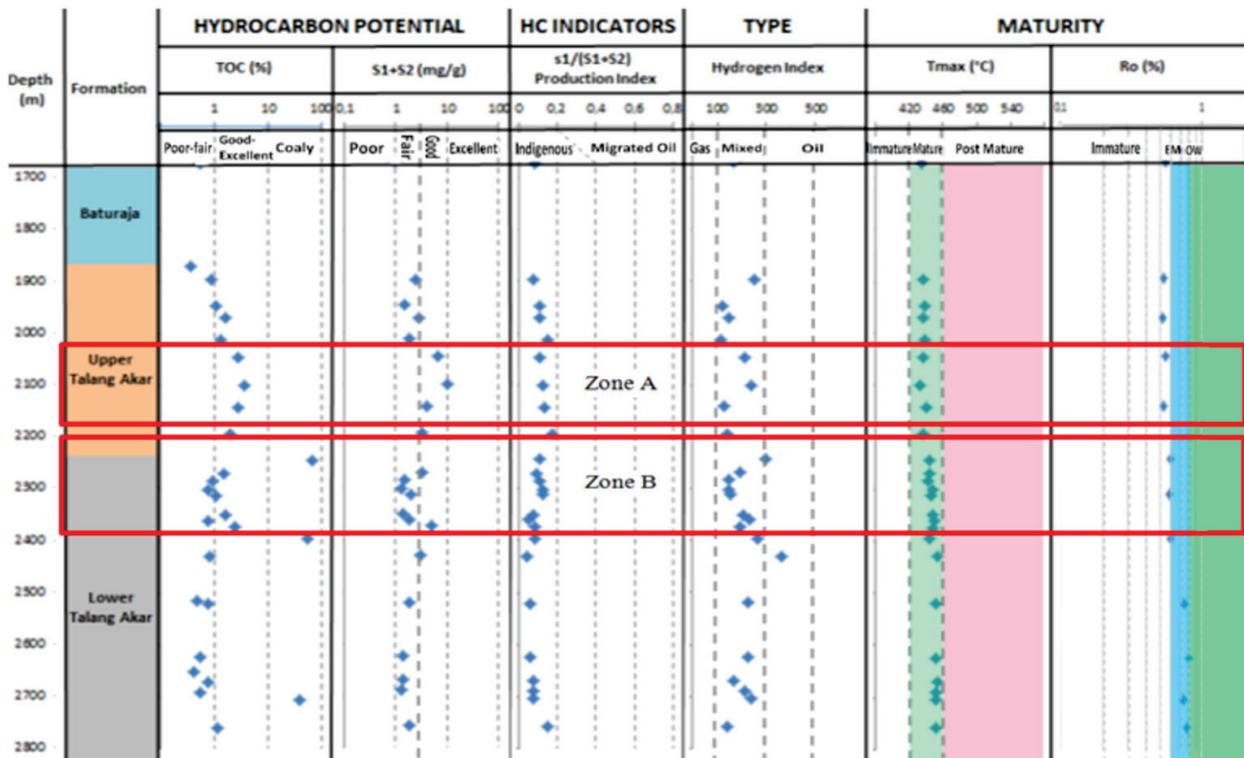


Figure 4. Geochemical assessment of shale hydrocarbon of Talang Akar formation in South Sumatra basin, which was derived from SSB well [14].

### 3. Geomechanical assessment

To achieve a great success in shale hydrocarbons exploration, the integrated assessment by implementing the geomechanical assessment should be applied to complement the previous geochemical assessment [15]. The natural character of the shale layer is indicated by very low permeability; therefore, we need hydraulic fracturing to increase shale permeability [16]. The key success in hydraulic fracturing is related to the geomechanical understanding of the shale layer such as the brittleness index and the rock strength.

There are some criteria of the mechanical properties for shale reservoir to be able to be fractured; the shale reservoir must have a low rock's strength and Poisson ratio and high Young's modulus [17]. The mechanical properties of shale reservoir are also influenced by the mineral composition contained in shale reservoir. Rock strength is dependent on porosity, quartz-dolomite and kerogen fraction. This means the rock strength decreases when shale porosity increases [17] and the quartz-dolomite and kerogen fraction of shale increases as well [18]. The increasing kerogen fraction in the shale will increase horizontal shear stress and in contrast will decrease the shear wave velocity. As a consequence the Poisson ratio of the shale decreases with decreasing shear wave velocity. In addition, the increasing quartz-dolomite fraction will decrease the vertical shear strain and as a consequence the Young's modulus of the shale increases.

The change of diagenetic to silica-rich shale is caused by the transformation from smectite to illite. This change may increase brittleness [7]. The presence of smectite makes the density of the shale decrease and the shear wave velocity of the shale will increase; thus, the shale kerogen fraction decreases. In particular, brittleness increases with decreasing TOC. However, brittleness may decrease as pressure and temperature increase.

According to Wang and Gale [7] brittleness index is a function of mineral composition and diagenesis. The modified equation of Jarvie et al. is shown in Eq. 1 [17].

$$BI = \frac{Q + Dol}{(Q + Dol + Lm + Cl + TOC)} \quad (1)$$

where  $BI$  presents the brittleness index,  $Q$  states the percentage of quartz mineral,  $Dol$  corresponds to the percentage of dolomite,  $Cl$  presents the total clay, and  $Lm$  presents limestone mineral. The increasing dolomite may increase brittleness since dolomite is more brittle than limestone. As a consequence, increasing TOC may increase ductility [8]. In addition, the brittleness is a function of diagenesis caused by changes in temperature and fluid composition associated with the tectonic system and burial history. This means that the most prospect reservoir for shale hydrocarbon is brittle reservoir, which is indicated by high Young's modulus and low Poisson ratio [19]. Further, the brittleness index might be determined by normalizing Young's modulus and Poisson ratio [19]. The relationship of Young's modulus and Poisson ratio is presented in Eqs. (2)–(4).

$$YM_{Brittleness} = \left[ \frac{YM - YM_{min}}{YM_{max} - YM_{min}} \right] \times 100 \quad (2)$$

$$PR_{Brittleness} = \left[ \frac{PR - PR_{max}}{PR_{min} - PR_{max}} \right] \times 100 \quad (3)$$

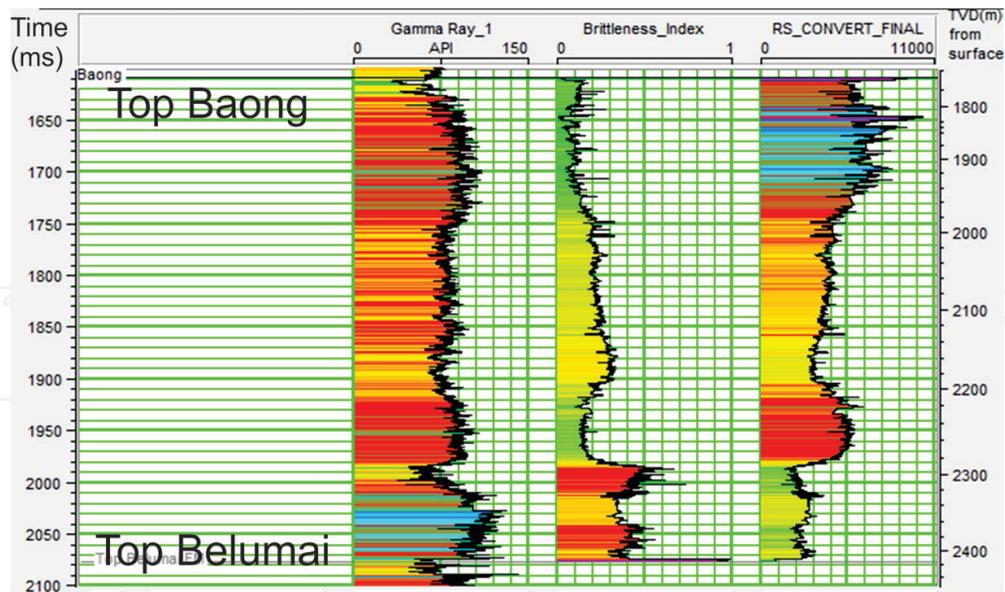
$$BI_{Average} = \frac{YM_{Brittleness} + PR_{Brittleness}}{2} \quad (4)$$

where  $YM$  represents Young's modulus,  $YM_{min}$  is the minimum Young's modulus for a certain interval and  $YM_{max}$  is the maximum Young's Modulus. While  $PR$  represents Poisson ratio,  $PR_{min}$  is the minimum Poisson ratio and  $PR_{max}$  is the maximum Poisson ratio.

In this study, the geomechanical assessment is only carried out in the North Sumatra and Central Sumatra basin due to the limitation of mineralogy data. In term of mineralogy analysis, the brittleness index (BI) was calculated by using Jarvie et al. equation, which was modified by Wang and Gale as shown in Eq. 1 [2, 7]. The equation was modified by incorporating dolomite content that caused the increase of BI.

The presence of mineral fraction in BI calculation is significant. On the other hand, Eq. 1 does not consider plagioclase mineral. However, the result of mineralogy identification shows that the presence of plagioclase mineral is quite significant, which is indicated by the fraction of 2–6%. Thereby, we incorporate the plagioclase mineral into Eq. 1 in calculating BI. The calculated BI using Jarvie and Wang shows a good agreement of BI, which is shown in a similar trend.

**Figure 5** illustrates that BI is strongly connected to rock strength, in which the rock strength decreases with increasing brittleness index for the Baong formation of North Sumatra basin. In this case, the Baong formation of North Sumatra basin is identified by TOC ranging from 2 to 3.5 wt%. In terms of geomechanical, this formation is indicated by brittleness index of 0.48 and rock strength of 3000 Psi. Theoretically the potential shale reservoir is indicated by high



**Figure 5.** Geomechanical assessment of Baong shale formation of North Sumatra Basin, which was derived from NSB well. The left panel is gamma ray log, the mid-panel is BI and the right panel is rock strength [11].

TOC, high BI and low rock strength; therefore, the Baong formation of North Sumatra basin can be classified into fair or moderate quality that has potential to be developed.

In addition, the geomechanical assessment was carried out in the Pematang Brown Shale formation of Central Sumatra basin that is based on the mineralogy content. **Table 3** presents X-Ray Diffraction (XRD) analysis of the sample data of CSB-2 well. The result of X-Ray Diffraction (XRD) analysis is then used to determine the BI. Our calculation shows that the Pematang Brown Shale formation is indicated by high BI, which is greater than 0.48. This calculated BI has a good agreement with the calculated BI in North Sumatra basin.

#### 4. Predicting total organic content using multilinear regression

The previous TOC calculation is only related to the core sample for certain depth. To derive the TOC data that cover the whole depth of well log data, we performed TOC prediction by using multilinear regression approach. This TOC prediction was applied to all available well log data (i.e., NSB-1, CSB-1 to CSB-5, and SSB-1 well) from North, Central and South Sumatra basin.

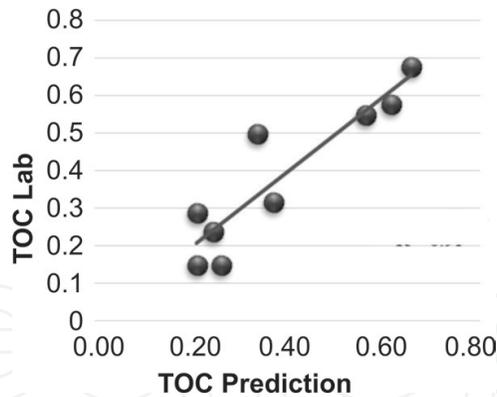
Our approach by using multilinear regression for Baong shale formation of North Sumatra Basin shows the relationship between TOC and available log data as presented in Eq. 5 [11].

$$\text{TOC} = 1.8994 - 0.0488 \times \text{GR} + 1.0176 \times \text{Density} + 20.893 \times \text{Neutron} - 0.0488 \times \text{Sonic} + 0.321 \times \text{Resistivity} \quad (5)$$

Eq. 5 is then used to predict the TOC log of NSB-1 well. The same approach is continuously applied from the CSB-1 to CSB-5 well for Pematang Brown Shale formation. The relationship

No	Litho	Clay minerals (%)				Carbonate minerals (%)			Other minerals (%)				Total (%)		
		Smectite	Illite	Kaolinite	Chlorite	Calcite	Dolomite	Siderite	Quartz	K-Feldspar	Plagioclase	Pyrite	Clay	Carbonate	Other
1	Sand	—	3	10	—	—	—	87	—	—	—	13	—	87	
2	Shale	—	30	45	—	—	—	25	—	—	—	75	—	25	
3	Sand	—	3	24	—	—	1	72	—	—	—	27	1	72	
4	Sand	—	7	14	5	—	—	74	—	—	—	26	—	74	
5	Sand	—	4	7	—	—	—	89	—	—	—	11	—	89	
6	Sand	—	2	3	—	—	—	95	—	—	—	5	—	95	

**Table 3.** The X-ray diffraction analysis for CSB-2 well.



**Figure 6.** The relationship between predicted and measured TOC from the lab.

between organic richness and available log data for Pematang Brown Shale formation of Central Sumatra basin is presented in Eq. 6 [13].

$$\text{TOC} = -14.8534 + (-0.0168 \times \text{GR}) + (3.9498 \times \text{Density}) + (4.7925 \times \text{Neutron}) + (0.0751 \times \text{Sonic}) + (0.0651 \times \text{Resistivity}) \quad (6)$$

**Figure 6** shows the relationship between predicted and measured TOC from the lab. The result shows a good agreement among them.

The relationship between TOC and available log data for Talang Akar formation of South Sumatra basin is presented in Eq. 7 [14].

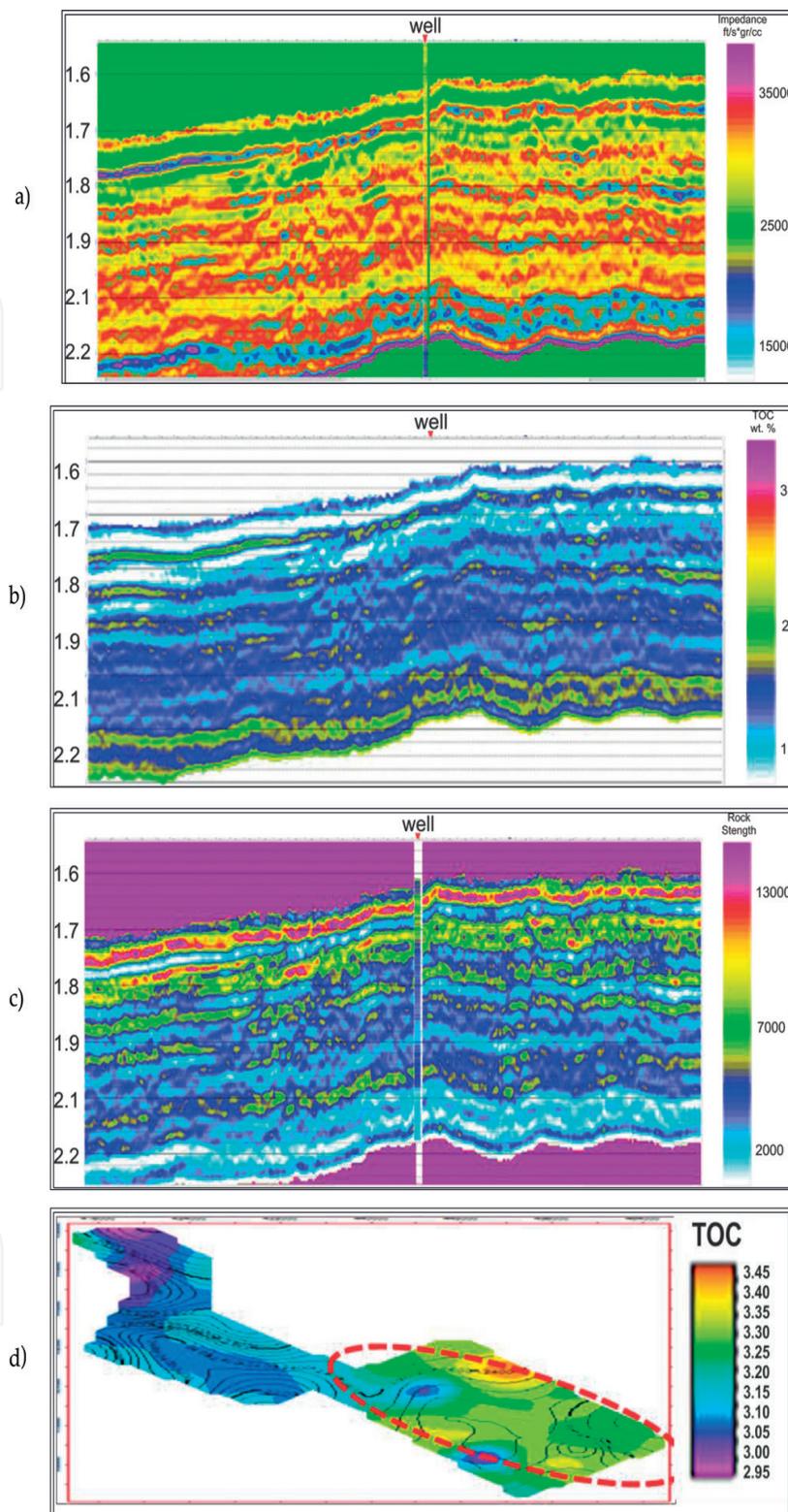
$$\text{TOC} = -1.74 + 0.00038 \times \text{GR} + 1.023 \times \text{Density} - 0.0058 \times \text{Neutron} + 0.0062 \times \text{Sonic} \quad (7)$$

These relationships were successfully applied to all well log data (i.e., NSB-1, CSB-1 to CSB-5, and SSB-1 well) from North, Central and South Sumatra basin.

## 5. Sweet spot of shale hydrocarbon distribution

Understanding the prospect reservoir for shale hydrocarbon exploration is significantly controlled by mapping the geochemical and geomechanical properties. The previous section has discussed geochemical and geomechanical analysis for one dimension of the well location, which does not cover the spatial distribution. Seismic data that have spatial coverages are then used to spatially distribute the geochemical and geomechanical properties [20, 21].

The relationship between seismic and geochemical and geomechanical properties may be approached with acoustic impedance properties [22]. Thereby, transforming the seismic into acoustic impedance (AI), which is produced by applying seismic inversion, is required [23]. This approach can be understood because AI has a strong correlation to the geochemical and geomechanical properties that are possible for mapping the TOC and rock strength distribution. Obviously, the sweet spot of shale hydrocarbon distribution could be identified based on the geochemical and geomechanical properties.



**Figure 7.** The spatial distribution in term of section and map, where (a) acoustic impedance, (b) organic richness, (c) rock strength, and (d) the organic richness of Baong shale formation of North Sumatra basin. The dashed line is the sweet spot of shale hydrocarbon distribution [11].

## 6. Sweet spot of Baong Shale formation of North Sumatra Basin

**Figure 7** shows the spatial distribution in terms of the seismic section, where AI section was transformed into a section of TOC and rock strength section and TOC map of Baong Shale formation of North Sumatra basin. The zone, which is surrounded by dashed-line, is the sweet spot of potential shale hydrocarbon [11]. **Figure 7a** is acoustic impedance section, which was derived from seismic data. **Figure 7b** and **c** illustrate the TOC and rock strength section, respectively, which were derived from acoustic impedance section.

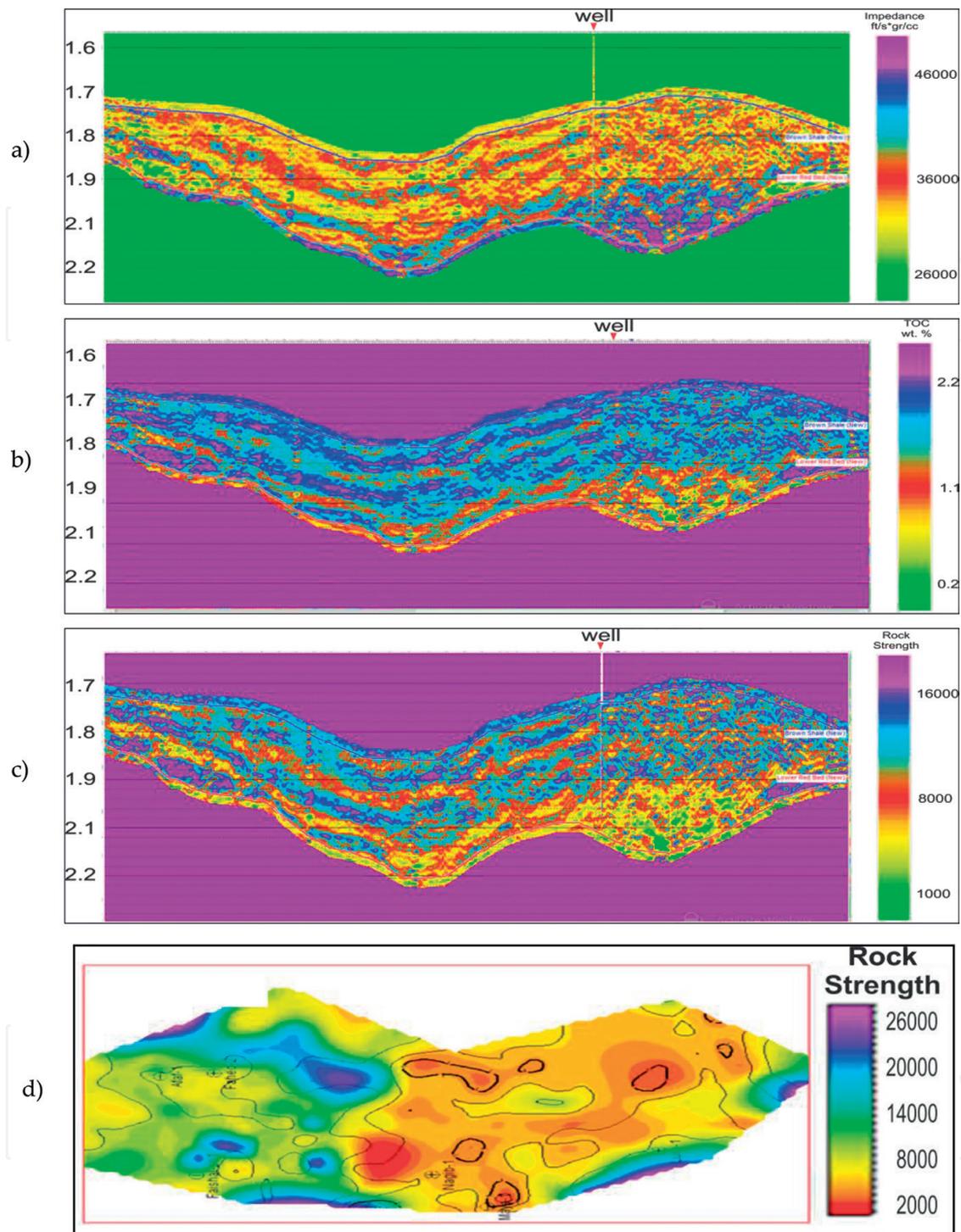
Baong Shale formation is located in the lower part of the section as shown by the white ellipse. The prospect layers were indicated by the low AI (blue), high TOC (green) and low rock strength (light blue). To see the spatial distribution of the sweet spot for the shale hydrocarbon development, we extracted TOC and rock strength along the top Baong shale horizon to map TOC and rock strength. The sweet spot of shale hydrocarbon distribution may be easily mapped by observing **Figure 7d**, which overlaid the rock strength (contour) and TOC map (color legend). The sweet spot of shale hydrocarbon distribution was identified in the southeastern part of the map.

## 7. Pematang Brown Shale, Central Sumatra Basin

The same procedure was performed to Pematang Brown shale formation of Central Sumatra basin. Seismic inversion was conducted to derive the acoustic impedance section, which is shown in **Figure 8a**. The AI section was then transformed to the TOC as shown in **Figure 8b** and rock strength as shown in **Figure 8c**. Pematang Brown Shale formation is located on the bottom of the basin area indicated by the low AI (purple), high TOC (green to yellow) and low rock strength (green to yellow). The sweet spot of shale hydrocarbon is illustrated in **Figure 8d**, which is the integrated map between TOC (contour) and rock strength (color legend). The sweet spot is indicated by the white tight boundary with rock strength of 10,000 psi and TOC of 1 wt%. In terms of structural geology, the sweet spot area might be identified as a basin where the sediment was deposited [24]. The diagenesis transformed sediment turns into the mature phase by sedimentation in high temperature.

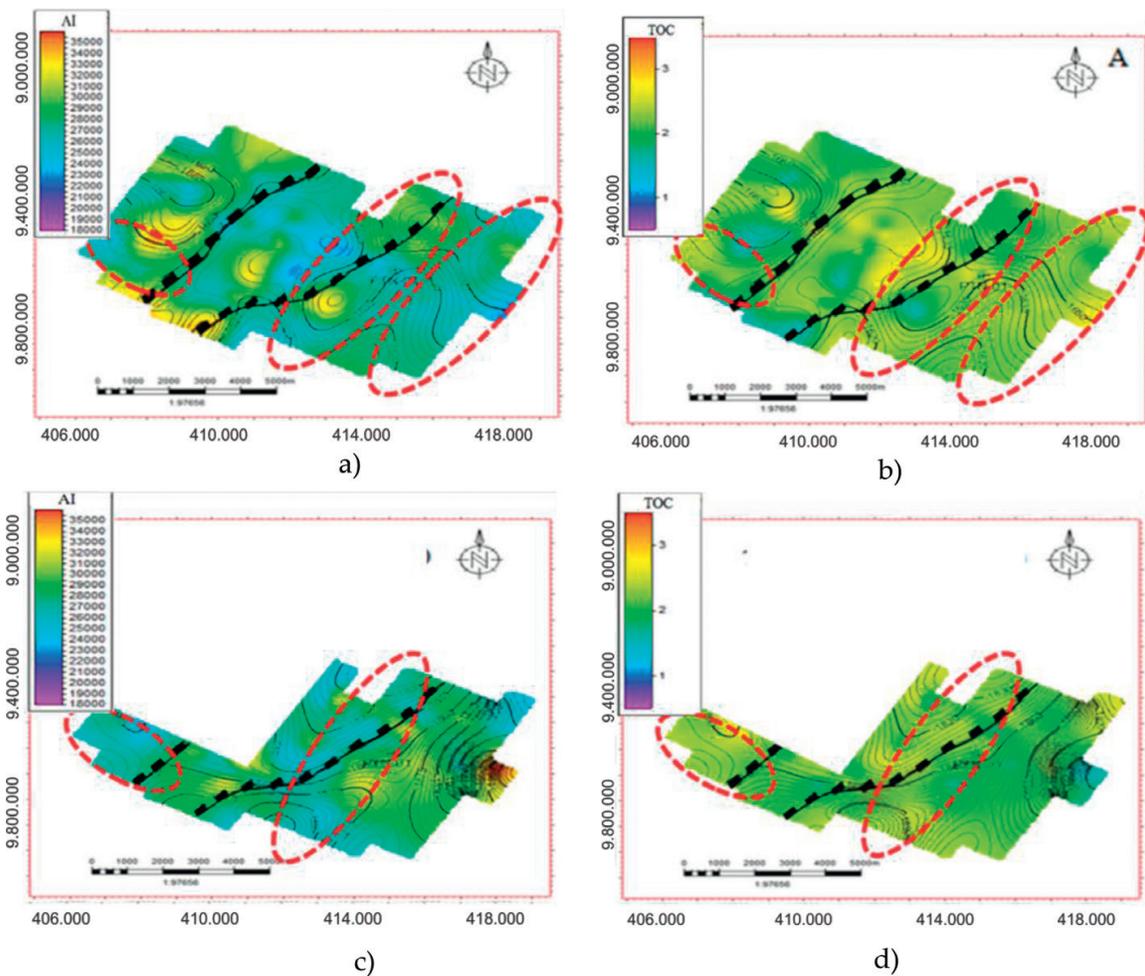
## 8. Talang Akar formation, South Sumatra Basin

The sweet spot identification on Talang Akar formation was performed by dividing the formation into upper Talang Akar and Lower Talang Akar. A different approach was carried out due to the lack of geomechanical data, where only TOC map was produced. **Figure 9** shows the sweet spot distribution of shale hydrocarbon of Talang Akar formation of South Sumatra basin. **Figure 9a** and **b** illustrate the AI and TOC map for upper Talang Akar formation, respectively, while **Figure 9c** and **d** present the AI and TOC map for lower Talang Akar



**Figure 8.** The spatial distribution in term of section and map (a) acoustic impedance, (b) organic richness, (c) rock strength and (d) rock strength map that is overlaid with TOC contour for identifying sweet spot potential of shale hydrocarbon of Pematang Brown shale Central Sumatra Basin [13].

formation, respectively [14]. The sweet spot of shale hydrocarbon is illustrated by red dashed line, which is indicated by low acoustic impedance (less than 27,500 ft/s\*gr/cc) and relatively high TOC (greater than 2%). This sweet spot of shale hydrocarbon is classified as good quality.

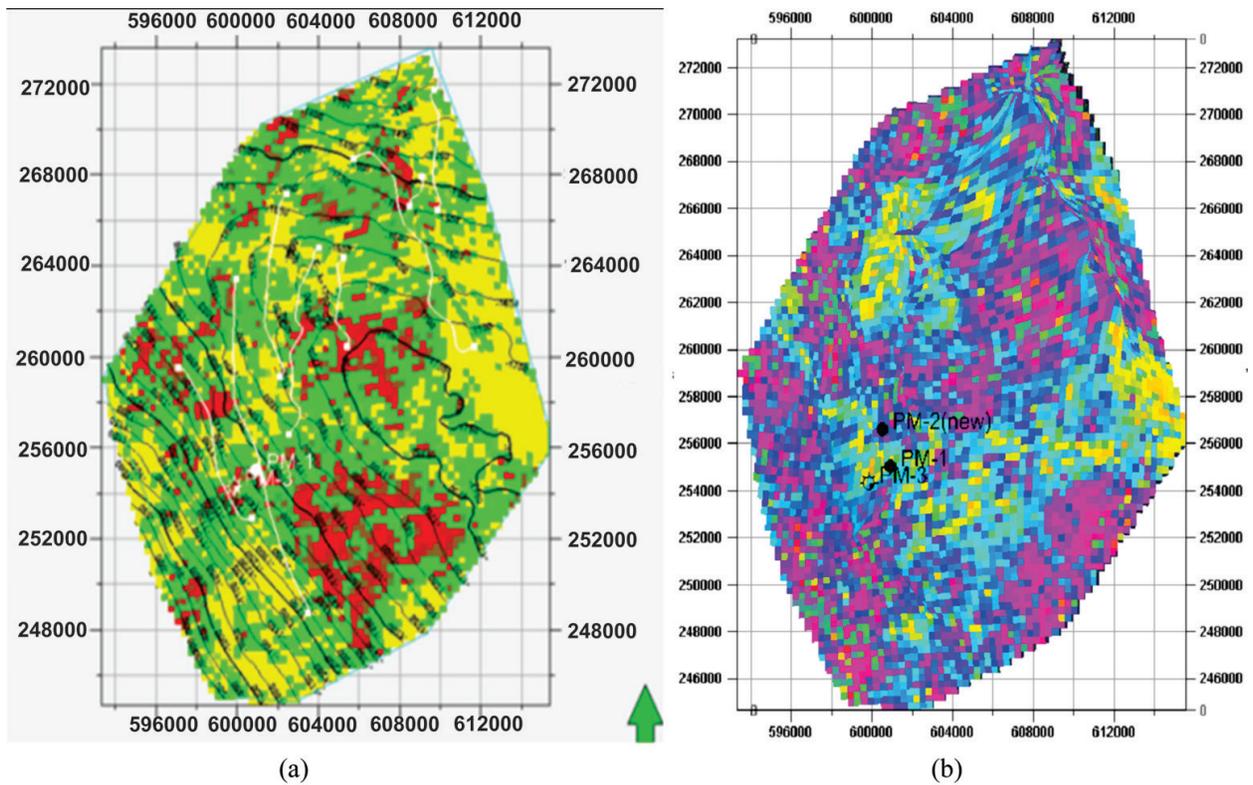


**Figure 9.** Sweet spot distribution of shale hydrocarbon, which is indicated by red dashed line, for upper Talang Akar formation in AI map (a) TOC map, (b) the lower Talang Akar formation is illustrated in AI map (c) TOC map, (d) sweet spot zone indicated with relatively low AI and high TOC [14].

## 9. Reservoir modeling approach for shale hydrocarbon

Reservoir modeling approach was carried to assess shale hydrocarbon in terms of the three-dimensional framework. This three-dimensional framework was performed based on sequential Gaussian simulation of geostatistical approach, which was focused on Pematang Brown Shale formation of Central Sumatra basin. The three-dimensional framework was then filled up by TOC and Brittleness Index.

**Figure 10** shows the modeled shale hydrocarbon reservoir, which is represented by brittleness index and TOC. The illustrated model in the two-dimensional map is shown in **Figure 10a** for brittleness index and **Figure 10b** for TOC. We identify that sweet spot distribution is associated with the brittle area, which is indicated in red. The brittle area means that reservoir might be easily fractured for exploration purposes. In terms of brittleness index, the sweet spot is dominantly distributed in the southern part of the field, which is confirmed by TOC map.



**Figure 10.** The modeled shale hydrocarbon reservoir, which is represented by brittleness index (a) and TOC (b), which is approached by geostatistical modeling [12, 25].

## 10. Conclusions

In terms of geochemical and geomechanical methods, the shale of Baong formation of North Sumatra basin is supposed to be developed for shale hydrocarbon. This conclusion is confirmed by potential level from TOC was classified from fair to very good, with kerogen type was classified into type II that associated with gas prone. The sweet spot identification was successfully performed by combining geochemical and geomechanical assessment, where the sweet spot was focused in the southeastern part of the field. The geochemical assessment shows that shale reservoir is indicated by TOC ranging from 2 up to 3.5 wt% and brittleness index of 0.48, while geomechanical assessment shows the rock strength is less than 3000 Psi.

Pematang Brown Shale Formation of Central Sumatra basin is identified as fair to excellent based on prospect level. This formation is categorized into a mature phase that has potential to produce oil. This conclusion is confirmed by mud log data at CSB-2 well that shows oil indicator at the depth of 8500 ft. The sweet spot is identified based on the intersection between geochemical and geomechanical assessment, where shale hydrocarbon distribution was indicated by TOC ranging from fair to good and deposited in the thickness of up to 50 ft. In terms of geomechanical assessment, the brittleness index is identified as greater than 0.48 and rock strength is less than 10,000 Psi.

The geochemical and geomechanical assessment of Talang Akar formation of South Sumatra Basin illustrates that two interest zones in the depth interval of 2030–2182 m, called as Upper Talang Akar formation, and 2204–2396 m, called as Lower Talang Akar formation, are considered as a potential zone for shale hydrocarbon exploration. These two prospect zones are classified as good to excellent quality in terms of organic richness criteria and fulfill sufficient maturity levels.

## Conflict of interest

The authors declare that there is no conflict of interest.

## Author details

Abdul Haris\*, Agus Riyanto, Bayu Seno, Husein Agil Almunawar, Martogu Benedict Marbun, Iskandarsyah Mahmudin and Prima Erfido Manaf

\*Address all correspondence to: [abdulharis@sci.ui.ac.id](mailto:abdulharis@sci.ui.ac.id)

Geology and Geophysics Study Program, FMIPA Universitas Indonesia, Depok, Jawa Barat, Indonesia

## References

- [1] Sukhyar R, Fakhruddin R. Unconventional Oil and Gas Potential in Indonesia with Special Attention to Shale Gas and Coal Bed Methane. Jakarta: Badan Geologi KESDM; 2013
- [2] Jarvie DM. Shale resource system for oil and gas: Part 1-shale gas resources system. In: Breyer JA, editor. Shale Reservoirs – Giant Resources for the 21st Century. AAPG Memoir. 2012a;97:69-87
- [3] Charpentier RR, Cook TA. USGS Methodology for Assessing Continuous Petroleum Resources. U. S. Geological Survey Open-File Report. 2011. Vol. 1167. pp. 1-73
- [4] Waples DW. Geochemistry in Petroleum Exploration. Dordrecht, Netherlands: Springer Science & Business Media; 2013. pp. 55-180
- [5] Andrews IJ. The Jurassic Shales of the Weald Basin: Geology and Shale Oil and Shale Gas Resource Estimation. London, UK: British Geological Survey for Department of Energy and Climate Change; 2014
- [6] dan Baker Hughes GCA. Shale Gas Workshop Houston. Houston: Gaffney Cline and Associates; 2011

- [7] Wang Fred P, dan Gale Julia FW. Screening Criteria for Shale Gas Systems: Gulf Coast Association of Geological Societies Transactions. 2009;**59**:779-793
- [8] U.S. Energy Information Administration (USEIA). Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formation in 41 Countries Outside the United States. Report; 2013
- [9] Verma S, Marfurt K. A Way of TOC Characterization on Barnett and Woodford Shale. Search and Discovery Article #80429. Norman, OK: University of Oklahoma; 2014
- [10] Peters Kenneth E, dan Cassa Mary R. Applied source rock geochemistry. AAPG Memoir. 1994:60
- [11] Haris A, Seno B, Riyanto A, Bachtiar A. Integrated approach for characterizing unconventional reservoir shale hydrocarbon: Case study of North Sumatra Basin. In IOP Conference Series: Earth and Environmental Science. Bristol, UK: IOP Publishing; 2017 April;**62**(1):012023
- [12] Haris A, Marbun MB, Bachtiar A, Riyanto A. Geochemical analysis of shale gas reservoir based on well log and 3D seismic data in Pematang formation, central Sumatera Basin. In: AIP Conference Proceedings. New York, USA: AIP Publishing; 2017 July;**1862**(1):030176
- [13] Haris A, Almunawwar HA, Riyanto A, Bachtiar A. Shale hydrocarbon potential of brown Shale, Central Sumatera Basin based on seismic and well data analysis. In: IOP Conference Series: Earth and Environmental Science. 2017, April;**62**(1):012018. IOP Publishing
- [14] Manaf PE, Suparno S, Haris A, Usman A, Riyanto A. Organic shale analysis using geochemical data and seismic attributes: Case study of Talang Akar formation, south Sumatera Basin. In: AIP Conference Proceedings. 2017, July;**1862**(1):030178. AIP Publishing
- [15] Rickman R, Mullen MJ, Petre JE, Grieser WV, Kundert D. A Practical use of shale petrophysics for stimulation design optimization: all shale plays are not clones of the Barnett Shale. In: SPE Annual Technical Conference and Exhibition; 2008, January. Society of Petroleum Engineers
- [16] Mair R, Bickle M, Goodman D, Koppelman B, Roberts J, Selley R, Younger P. Shale Gas Extraction in the UK: A Review of Hydraulic Fracturing; 2012
- [17] Dradjat, Anggoro S. 2013. Dasar-Dasar Explorasi dan Eksploitasi Gas Shale. IAGI. 2013
- [18] Hui J, Sonnenberg Stephen A, Fredrick SJ. Source Rock Evaluation for the Bakken Petroleum System in the Williston Basin, North Dakota, and Montana; 2012. AAPG #20156
- [19] Grieser, dan Bray JM. Identification of production potential in unconventional reservoir. SPE 106623, SPE Production and Operator Symposium held in Oklahoma City, Oklahoma, USA, 31 March – 3 April; 2007
- [20] Sharma Ritesh Kumar, dan Chopra Satinder. New attribute for determination of lithology and brittleness. AAPG Article #41368; 2014

- [21] Løseth H, Wensaas L, Gading M, Duffaut K, Springer M. Can hydrocarbon source rocks be identified on seismic data? *Geology*. 2011;**39**(12):1167-1170
- [22] Perbawa A, Kusuma B, Winardhi S. Integration of Seismic Inversion, Pore Pressure Prediction, and TOC Prediction in Preliminary Study of Shale Gas Exploration. In 37th HAGI Annual Convention & Exhibition; 2012
- [23] Prasad M. Rock physic of unconventional. *The Leading Edge*. 2009;**28**(1):34-38
- [24] Williams HH, Eubank RT. Hydrocarbon habitat in the rift graben of the Central Sumatra Basin, Indonesia. In: Lambiase JJ, editor. *Hydrocarbon Habitat in Rift Basins*. London, UK: Geological Society Special Publication; 1995;**80**:331-337
- [25] Iskandarsyah HA, Riyanto A. Brittleness modelling of shale gas reservoir: Case study of Pematang formation, Central Sumatera basin. In: *AIP Conference Proceedings*. New York, USA: AIP Publishing; 2017 July;**1862**(1):030165

