Structural style of the North Sumatra basin, offshore Aceh

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Abstract. The Offshore North Sumatra Basin is an underexplored basin. Only a limited amount of exploration has occurred in the past resulting in the discovery of one economic field that is currently producing, a number of uneconomic discoveries and some unsuccessful wells. This is reflected in limited geological studies of the area. This paper demonstrates the importance of N-S trending faults associated with Basin formation in the Oligocene, continued fault activity in the late Oligocene and both compressional and extensional reactivation in the Miocene.

1. Introduction
The North Sumatra Basin (NSB) is located in the western part of Indonesia, part of Aceh and offshore North Sumatra. The basin is bordered by Mergui Ridge to the west and Malacca Platform to the east. To the south, it is bounded by the Barisan Mountains. To the north, it extends into Thailand offshore, where it is known as the Mergui Basin (Figure1).

Exploration in offshore Aceh began in the 1970s. Most wells drilled targets on the crest of horst structures. So far, only one field is in operation [1]. Other fields have not been developed because of economic issues. Some wells did not encounter hydrocarbon.

The offshore NSB needs to be further studied to understand its petroleum potential. This paper aims to introduce and discuss the structural evolution of the offshore area of Aceh Province, where fewer structures have been drilled than in the onshore area.

2. Regional Geology

2.1. Tectonic Setting
The North Sumatra Basin is a Paleogene-Neogene basin with a complex tectonic history located in a back-arc setting relative to the India-Sumatra subduction trench [2]. The initiation of the India-Sumatra subduction began in Cretaceous [3]. The rate of subduction in Sumatra is between 6 to 7 cm/year [4]. The activity of the plates is indicated by the myriad of seismic shocks that occur along the trench.

The Barisan Mountains separate the North Sumatra Basin from the India-Sumatra trench. They are cut by the Sumatra Fault System (SFS). The dextral Sumatra dextral strike-slip Fault is associated with the oblique subduction of the Indian oceanic plate beneath Sumatra. Several authors stated that the initiation of the Sumatra Fault System and spreading in the Andaman Sea occurred at the same time during the mid-Miocene [5]. Uplift of the Barisan Mountains occurred in the Pliocene [6].
illustrates the importance of understanding the interaction between extension, compression and strike-slip tectonics in the evolution of the North Sumatra Basin.

Figure 1. Location of North Sumatra Basin and its regional geology

2.2 Regional Stratigraphy

The North Sumatra Basin contains sedimentary rocks from late Eocene to Recent age. However, most exploration wells only penetrated the crest of horst blocks and found Oligocene rocks deposited in the basement. Thus, the age of the sedimentary sequences that filled the graben is less well constrained. A summary of the stratigraphy of NSB is shown by figure 2 and is described as the following section.

The bottom part is the basement. Most of the wells drilled into basement rock in the NSB encountered metamorphic rocks of Cretaceous age. According to Cameron et al. (1980) and Barber (2000), the Cretaceous basement is categorized as the Woyla Group which outcrops along the western margin of the Barisan Mountains. Then followed by Meucampli/Tampur Formation (Late Eocene). Tampur Formation primarily consists of carbonate sediment and dolomites with cherts nodules. The Tampur Formation was deposited under sub-littoral to marine conditions (7), in the eastern part of basin high near the Asahan arch. Meanwhile, the Meucampli Formation consists of clastic sediments that outcrop in the Northwest of Aceh. Next is Parapat Formation (Early Oligocene). The Parapat Formation consists of conglomerate and sandstone. The sands came from local contributions from the horst blocks. The sediments were deposited during the transgression and deepening of the graben. The Bampo Formation is the primary source rock that generated gas and is reported to be the source for the giant onshore Arun field. In addition, this formation could be a candidate for unconventional gas plays in the future. The Bampo Formation is followed by Belumai/Peutu Formation (Early Miocene). Sandstones are dominant in the Peutu Formation. Cameron et al. (1980) defined the sediments as the Belumai Formation, consisting of fine- to medium-grained sandstones. Carbonate reefs of the Peutu
Formation are major producers of condensates and host the Arun field (Mobil). Then, Baong Formation is deposited in Middle Miocene. The Baong Formation (Middle Miocene) primarily contains massive dark grey, variably calcareous shale, rich in foraminifera, which indicates a neritic marine depositional environment. Then, it is followed by Keutapang Formation (Late Miocene). The Keutapang Formation comprises of fine-grain sandstones and shales with a thin layer of limestones [9]. Seurula Formation is on top of Keutapang Formation. The Seurula Formation contains coarse-grained sandstone and shales [9]. Finally, Julu Rayeuk Formation is on top of Seurula Formation. This formation is dominated by sandstone sedimentary rocks which vary from fine to coarser grain from the base to the top of the sequence [9].

![Figure 2](image.png)

**Figure 2.** Left is the general Stratigraphy chart of the North Sumatra Basin [10]. Right is top formations from the Bayu Laut Dalam well which are tied to the seismic.

3. **Data Set**

More than 60 lines of 2D seismic data from offshore NSB are used to build a structure map. The length of the line varies from 50 km to 180 km. The spacing line is 10kms. The record length of each seismic line varies from 4000 milliseconds to 6000 milliseconds (ms) two-way time (TWT). Most lines are oriented East-West and North-South. NE-SW and NW-SE oriented lines are also present. The resolution of the image varies from poor to moderate. The seismic amplitudes are heterogeneous varying between different surveys. The stratigraphy and geological structures of the offshore NSB were interpreted and mapped using Petrel. There is one well, Bayu Laut Dalam (BLD) which tied into the seismic and controlled the stratigraphic interpretation (figure 2). The well was spudded on a basement high (horst) and contained recent to pre-Paleogene sediment. Eight horizons were interpreted from the pre-Paleogene basement to younger sediments of Pliocene to recent. They are; Basement, Parapat, Bampoo, Belumai, Baong, Lower Keutapang, Keutapang and Pliocene to younger.
4. Major Sequences
The interpreted horizons are categorized as pre-rift, early syn-rift, late syn-rift, and post-rift, syn-inversion and post inversion (see Figure 3 & 4). Sedimentary rocks that filled at each stage represent the dominant environmental and the basin setting at that time.

4.1 Pre-rift (Basement)
The basement is characterized by a chaotic and dimmed reflector. There are several major faults that cut through the basement. First, extensional faults that shape horst and grabens (Figure 4). The displacement varies from 900 to 1450 meters. Dip angles are variable.

4.2 Early and Late Syn-Rift, Early to Late Oligocene (Parapat and Bampoo Formation)
This unit is characterized by parallel and continuous reflectors. In the upper part, it shows a high amplitude, but the lower part shows medium to low amplitude. Early syn-rift is marked by thicker Parapat sediments toward the major faults within the grabens than on the horst. The late syn-rift is shown by the thicker Bampoo unit toward the major faults.

4.3 Post-Rift, Early to Middle Miocene (Belumai and Bampoo Formation)
This unit is characterized by moderate to high amplitude, continuous, and parallel reflectors. During the deposition of this unit, there is less evidence of the deformation. The thickness of this sequence varies from thinning at the edges and thicker in the depocenter.
4.4 Syn-Inversion, Late Miocene (Keutapang)

The syn-compressional sequence is described by a thinning sequence deposited on to the anticline (very symmetrical) crest. Within the Keutapang, there are onlap features cutting the anticline indicating the beginning of compression. The seismic is characterized by parallel and continuous reflectors. Populations of minor faults are present within this sequence.

4.5 Post-Inversion (Late Miocene to Recent)

The seismic characteristic of this unit is high amplitude, continuous and parallel reflectors. However, in the lower slope area at the east, chaotic and transparent reflectors are identified. There are few faults, although one major fault reactivated old structures during the Pliocene. It is located in the eastern area of the Basin margin.

5. Structural style and timing

North-South trending faults define a series of elongated horsts and grabens. Faults show variable dip and angle both to be East and West. Then, several minor faults are present within the graben that terminate at the top of Oligocene time. Those, plus the syn-rift characteristics of Parapat formation show that extension occurred during Oligocene. The fact that the timing of the extension is unclear as the older sediments within the grabens have not been penetrated. During the late Oligocene, the basin experienced extension for the second time, which caused some Major faults reactivated. It is shown by the thickening of Bampoo formation within the grabens towards the faults. During this time, the fault may increase the angle of rotation. It recreates the large displacement between the upthrown and downthrown blocks. In some parts, the vertical displacement may exceed 1400 meters. The magnitude of the grabens varies from 35 km to 10 km wide. The length also ranged from 70 km to 80 km. Inversion structure present in the west part. This structure is defined by a symmetrical anticline above the footwall. This structure formed during the late Miocene that we indicated by the thinning sequence within the Keutapang Formation. Some minor faults also present during this age. During Pliocene, older structures were reactivated by major normal faults. The reactivation is defined by different thicknesses of the unit in the lower and upper parts that cut by the fault. The fault terminates within the Pliocene sediment unit.

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**Figure 5.** Map of the basement high and low of Aceh offshore. This map shows major deformations that occurred during Paleogene-Neogene. This map was done by Arc-Map software, whereas the input from interpreted seismic horizons using Petrel.
6. Conclusion
The interpretation of 2D seismic lines has revealed the major structures in the offshore Aceh of North Sumatra Basin. Mostly, those structures have oblique N-S orientation. These major faults controlled the horsts and grabens development during early and late Oligocene under the extensional regime. Then, fault activity continued both compressional and extensional reactivation in the Miocene and the Pliocene. Offshore Aceh still attracts many companies to explore for oil and gas. As a result, the data of this basin will increase and hopefully can be opened to academia in Aceh. By doing so, it is expected that this work can be updated with details and more precise.

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