New Exploration Play Concepts in the North Sumatra Basin, Indonesia: Subsurface Insights from around Timpan-1

Mark A. Reynald[1], Joseph Jennings[1], Christopher Gravestock[1], Thomas Jewell[1]

[1]Halliburton

Extended abstract

Introduction

Half of Indonesia’s energy consumption is currently supplied by oil and gas (EIA, 2021). However, Indonesia’s proven natural gas reserves totaled 49.7 trillion cubic feet (TCF) in 2021, down more than 50% from 100.4 TCF in 2019. Population growth and improving regional economics have been driving a rapid increase in energy usage and energy imports. This has led to a renewed search for local energy sources over the last few years. There has been a redoubling of exploration efforts in the region, especially for advantaged hydrocarbons, e.g. for gas, while also supporting the longer-term energy transition with increasing usage of geothermal and other renewables for electricity generation (EIA, 2021).

Much of Indonesia’s recent hydrocarbon exploration has been focused on frontier deep-water areas, such as the North Sumatra Basin. Active drilling and evaluations are currently underway in the deep-water Andaman II block (Figure 1), awarded in 2018 (Harbour 40%, BP 30% and Mubadala 30%). In 2022, the play opening Timpan-1 gas discovery was made in Oligocene sandstones, which introduced potential new exploration opportunities for stratigraphically deeper clastic plays within the deeper water areas. This new play has since been extended into the South Andaman block by the Layaran-1 discovery in 2023 (awarded in 2019 to Mubadala 80%, Harbour 20%) (Enverus, 2024). This article assesses the potential to extend this new Oligocene sandstone play into the wider North Sumatra Basin, by discussing the presence, distribution, and effectiveness of the individual play elements within this fairway and implications for the wider region.

Exploration Context

Early hydrocarbon exploration in the North Sumatra Basin began during the 1880s, primarily targeting stratigraphically shallow reservoirs in the onshore areas. The first oil was encountered within Middle Miocene sandstones in the Tunggal-1 well, Telaga Said Field, in 1885. Throughout the early 20th century further discoveries were made onshore within Neogene siliciclastic reservoirs, predominantly in structural 4-way dip closures. In 1971, a new play opening discovery was made onshore in an Early to Middle Miocene carbonate reefal build-up, at the super giant Arun gas field, with reserves of 15 TCF gas (Alexander and Nellia, 1993; Merkle, 2012). Subsequent exploration throughout the next few decades predominantly focused on extending these plays onshore and into the shallow-water areas over the Malacca Platform (Figure 1).

Renewed interest in the basin has recently driven exploration further offshore into the more frontier deep-water areas. In July 2022, the first deep water well Rencong-1X well, was spudded (Figure 1), targeting Late Eocene– Early Oligocene reefal carbonates on footwall highs in the Andaman III block. However, by December 2022, it was declared a dry hole (Enverus, 2024). Exploration continued to move into the deep-water looking for additional, as well as different play types away from the carbonates, as seen with the success of the Timpan-1 well, which reported up to 12 TCF of gas in Oligocene sandstones. In December 2023, the Layaran-1 well made a significant gas discovery within a similar Oligocene sandstone play as the Timpan-1 discovery, with the ongoing Gayo-1 well likely to have similar results (Craig, 2023). Further drilling plans for 2024, include the Halwa-1 and Timpan-2 wells (Craig, 2023).

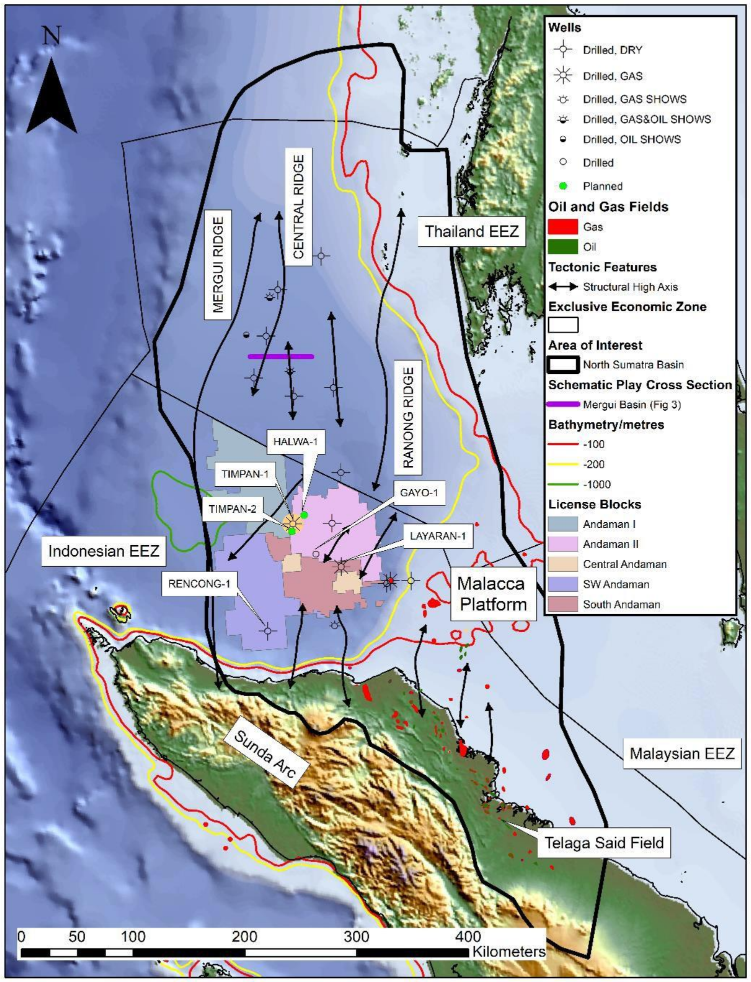

Figure 1: Location map of license blocks and recently drilled and planned wells in the North Sumatra Basin.

Despite the North Sumatra Basin's extensive history of oil and gas exploration, because of the newly established Timpan-1 fairway extent, there could possibly be substantially more untapped hydrocarbon potential in the deeper offshore areas of the basin as well as within older stratigraphic units, which remain relatively underexplored in the wider region.

Deep-water Play Opener: Insights from Timpan-1

The Timpan-1 discovery was made 50 km offshore Aceh Province in a water depth of 1,294 meters with total vertical depth of 4,211 meters subsea. The target was Oligocene Sandstones (4-way closure) and encountered a 118.9 meter gas column within a fine-grained sandstone reservoir, with permeabilities ranging from 1-10 mD (millidarcey). The well flowed on test at 27 mmscfd (million standard cubic feet per day) of gas and 1,884 bopd (barrels of oil per day) of associated condensate (Harbour Energy plc, 2022).

The play for the Timpan-1 discovery involves Oligocene turbidite sandstones in anticline inverted structures charged by Eocene to Oligocene organic-rich lacustrine sediments of the Lower Parapat Formation and Late Oligocene organic-rich deep-marine shales of the Bampo Formation. These reservoir sandstones represent the Late Oligocene Upper Parapat Formation (Bampo Formation equivalent, North Sumatra Basin and the Yala Formation equivalent, Mergui Basin) (Polachan and Racey, 1994; Banukarso et al., 2013; Figure 2).

All exploration comes with risks, but can risks be identified, understood, and then managed effectively? Continued success in this frontier petroleum province can be assisted by a play-based exploration approach building upon an integrated geological framework. Bringing all the data together within a robust geological context can help, for example, in identifying where the petroleum system elements (source rocks, reservoirs, and seals) are proven or likely to be present, where source rocks are mature, reservoir quality is retained, and seal integrity is preserved.

Tectonostratigraphic Framework: Understanding Basin Evolution

To gain a comprehensive understanding of the North Sumatra Basin's geological evolution and hydrocarbon potential, it is crucial to examine the tectonostratigraphic history, which is split into four main phases starting from the Eocene: Syn-rift I (Lutetian to Priabonian), Syn-rift II (Rupelian to Chattian), Post-rift (Aquitanian to Serravallian), and Foreland Basin (Tortonian to Present) (Figure 2 and 3).

The syn-rift I phase is driven by subduction of the Indo-Australian Plate beneath the western margin of the Eurasian Plate, which led to the formation of the Sunda Arc and the back-arc basin where there was deposition of syn-rift siliciclastics and shallow marine carbonates. The syn-rift II phase began with the deposition of the Parapat Formation consisting of a lower continental member with potential lacustrine source rocks and an upper marine member (including the Bampo Formation equivalent) containing proven reservoirs of the Late Oligocene sands of the Timpan-1 discovery (Ariyanto and Syarifuddin, 2018; Nirsal et al., 2021). The latter parts of the syn- rift II phase consist of the Bampo Formation deep-marine shales, which could contain potential source rocks in the deeper parts of the North Sumatra Basin (Nirsal et al., 2021).

The Aquitanian to Serravallian post-rift phase is dominated by many of the first hydrocarbon discoveries made in the basin (onshore and shallow water offshore), including shallow-marine carbonate reservoirs of the Mallaca and Peutu limestones. The Tortonian to present foreland basin phase holds secondary petroleum elements including the Middle Baong reservoirs and the Upper Baong organic-rich shales, with the Baong shales being the primary seal for many of the plays in the basin. The main phase of trap formation, for the play types in this basin, occurred during the Tortonian to present compressional foreland phase, during which many of the syn-rift structures were inverted to form 4-way dip closures, including that of the Late Oligocene plays discussed.

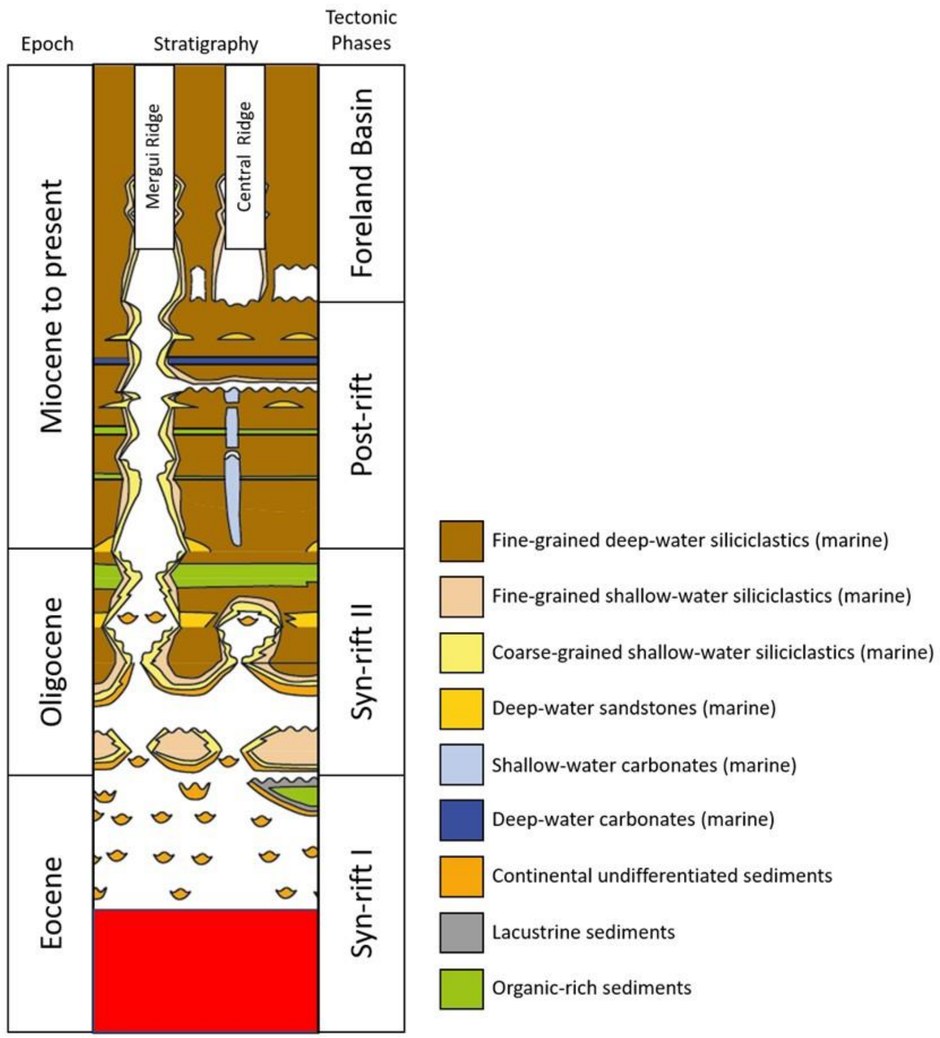

Figure 2: A simplified chronostratigraphic chart showing the stratigraphic evolution of a portion of the North Sumatra basin from the Middle Eocene to present, highlighting some of the key petroleum elements.

Extension of the Timpan-1 Fairway

Building upon the insights gained from the Timpan-1 well and the tectonostratigraphic framework of the North Sumatra Basin, other plays within the fairway can be formulated (Figure 2), possibly offering additional opportunities for future hydrocarbon exploration. By mapping the extent of the syn-rift structures in the basin, the presence of potential reservoir facies of the Late Oligocene deep-marine sandstones and the presence of mature source rock including the syn-rift lacustrine organic-rich facies and the deep-marine organic-rich siliciclastics, other potential play types of the same fairway can be potentially outlined, and geological risks identified (Figure 4).

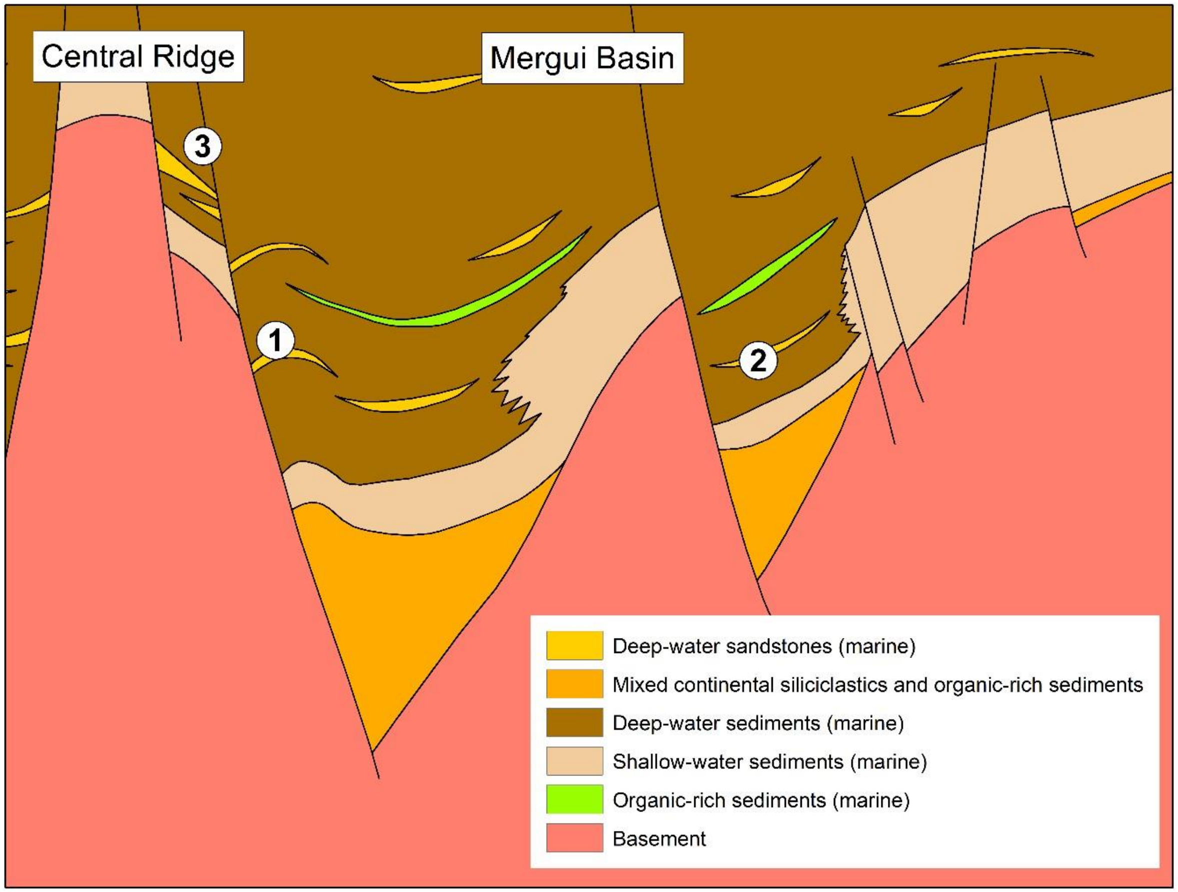

Figure 3: A schematic cross section through the Mergui Basin, Thailand (northern part of the larger North Sumatra Basin) derived from CCOP (2009) showing the current Timpan-1 play. Potential play types: 1 = Deep marine basin floor sands in anticline inverted structures 2 = Deep marine basin floor sands in up-dip pinch-outs, 3 = Deep marine basin floor sands in footwall wall blocks.

Play-Fairway Mapping: Identifying Exploration Risks

Based on the recent success and new data from the Timpan-1 and Layaran-1 exploration wells coupled with published well, seismic and paleogeographic data, all brought together within an integrated tectonostratigraphic framework, Neftex®, allows for the different petroleum system elements to be mapped, evaluated and potential geological risks identified (Figure 4). The presence of Late Oligocene sandstone reservoirs is one of the key petroleum system openers for this new play-fairway. Therefore, understanding their distribution and potential quality (or changes in quality across the region) is key.

The geological history of the North Sumatra Basin has a complex interplay of tectonic and depositional processes. Understanding the burial history of the Late Oligocene sandstone reservoirs reveals two significant phases (i) a syn-rift depositional phase and (ii) a foreland post-depositional phase – burying the reservoir to its present-day depth. Mapping the reservoir presence and distribution requires integrating Late Oligocene gross depositional environment maps with an understanding of the active Oligocene tectonic elements to delineate structural features like grabens and horsts. Building such a framework, not only enhances reservoir presence and distribution predictions, but is also critical in assessing reservoir effectiveness due to variations of porosity with depth.

To better understand reservoir quality and potential presence, regional source to sink relationships offer a holistic way to understand the region and make better predictions on an effective reservoir. For example, the contrasting difference of hinterland composition and erosion rates between Thailand vs. Sumatra at the time of deposition and the impact on clastic quality delivered to the basin can be assessed.

The mature hinterland provenances in Thailand underwent uplift and exhumation caused by a thermal anomaly during the Oligocene (Sautter et al., 2017), this likely supplied good quality quartz-rich Late Oligocene sands into the basin. In contrast, the immature and active Sunda volcanic arc, in Sumatra, is likely to have supplied poorer quality sands (e.g. feldspar and lithics) into the basin throughout the Oligocene. A combined prediction of (i) reservoir presence based on the gross depositional environments and sequence stratigraphic principles, (ii) reservoir effectiveness based on depth modelling and (iii) reservoir quality based on source to sink relationships, highlights that potentially, reservoir may not necessarily be the main risk in all areas of the basin (Figure 4A).

However, care should be taken in the source to sink nature of the dispersed clastic materials.

Assessing source rock presence and maturity is potentially the most important component of play-based hydrocarbon play-fairway mapping. The presence and maturity of the two main predicted source rocks: an Eocene-Oligocene lacustrine source rock and a Late Oligocene marine source rock, are potentially the main regional risks associated with any future extension of this Late Oligocene play-fairway.

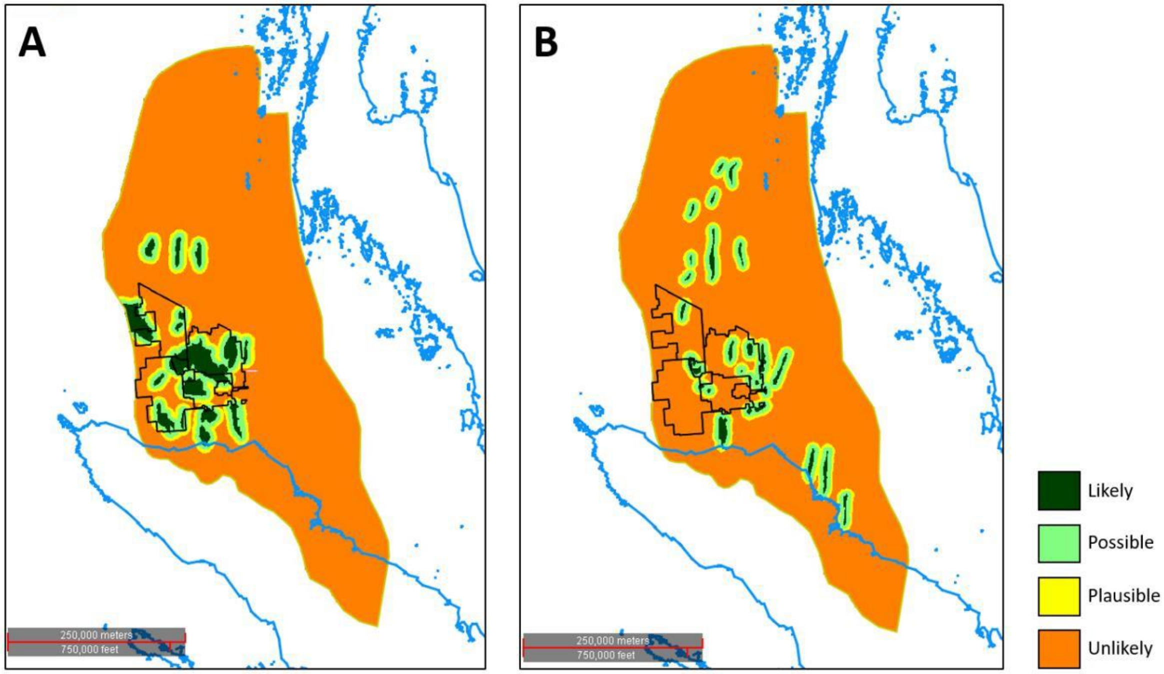

Figure 4: A selection of play fairway Chance Maps showing: (A) Late Oligocene deep-marine sandstone reservoir chance map, (B) Eocene to Oligocene lacustrine source rock presence chance map. The Indonesian deep-water license blocks are shown in black.

The geothermal gradient is likely to have been high in an active back-arc basin such as the North Sumatra Basin, therefore increasing the chance of generating gas. Due to the nature of the stratigraphy, the marine organic-rich sources are unlikely to directly charge the Late Oligocene reservoirs, as this source rock is younger stratigraphically than the reservoir. For these sandstones to be charged by the marine organic-rich sources, there needs to be a significant juxtaposition of the reservoir and the source rock (e.g. Play 3 Figure 3). With the dominant hydrocarbon phase being gas in the basin, as found in Timpan-1 with minor condensate (light oil), the Eocene-Early Oligocene lacustrine organic-rich sediments are predicted to be the likely main source rock contributors (Banukarso et al., 2013).

Combining the predictions of (i) source rock presence based on gross depositional environments and time- attributed active tectonic elements (Figure 4B) and (ii) source rock maturity based on depth to source rock modelling and geothermal gradient variations in an active back-arc basin, the likely chance of a source rock kitchen in a complex geological region can be mapped out and predicted.

While only discussing a small proportion of a larger workflow in this article, the combination of all relevant data within a robust tectonostratigraphic and depth framework has allowed for efficient predictions of potential likely source rock kitchens as well as reservoir presence and quality across the region. Taken all together, this helps to frame wider regional exploration pathways.

Towards Future Exploration Success

The recent gas discoveries in the North Sumatra Basin are a significant milestone in the region's hydrocarbon exploration journey. These discoveries, coupled with advancements in subsurface understanding and exploration methodologies, pave the way for further future exploration success in the basin. By leveraging insights from Timpan-1, within a standardized geological framework, such as the Neftex solution, allows for a better understanding of the basin's tectonostratigraphic framework, and adopting of an integrated play-based mapping approach. This can help conceptualize geological risks and unlock the full hydrocarbon potential of the North Sumatra Basin. As exploration efforts continue to expand into other parts of Indonesia and the wider Southeast Asian region, geological context, subsurface characterization, and fairway mapping innovations will be key drivers of success in the quest for new advantaged hydrocarbon resources and maximizing asset value.

References

Alexander, W.L. and M.R. Nellia 1993. 3D seismic facies analysis of a reefal buildup: NSO 'A' Field, offshore North Sumatra. Proceedings Twenty Second Annual Convention. IPA Annual Convention Proceedings no. 1, p. 137- 168.

Ariyanto, P. and I.Y. Syarifuddin 2018. New Insights into the Structural Development of the Block A Area, North Sumatra Basin: Constraints from Subsidence Analysis and Palinspatic Reconstruction. 41st Annual Convention of the Indonesian Petroleum Association 2017: Accelerating Reform to Re-Attract Investment to Meet the Economic Growth Target. Proceedings of the Indonesian Petroleum Association Annual Convention & Exhibition no. 42, p.
1-22.

Banukarso, M., L.D.T. Meckel, N. Citajaya and S. Raharjo 2013. An inverted syn-rift play in the offshore North Sumatra Basin. Thirty-Seventh Annual Convention & Exhibition, May 2013. IPA Annual Convention Proceedings, p. 1-17.

Clark, S., J. Teasdale, A. Jervis and D. Rudd 2021. Regional tectonic & structural framework of offshore Aceh's Andaman sub-basin, Northern Sumatra, Indonesia. Proceedings of the Indonesian Petroleum Association Annual Convention & Exhibition, v. 45, p. 1042-1055.

CCOP 2009. Petroleum geology and exploration history of the Mergui Basin, Thailand. EPPM (1) Project -12th May 2009. Presentation. Coordinating Committee for Geoscience Programmes in East and Southeast Asia (CCOP) AKA CCOP Technical Secretariat

Craig, J. 2023. Major drilling campaign planned for the new mega-gas trend in Indonesia. The Power of Paleogeography. GEO ExPro no. 20, p. 98-99.

Enverus, 2024. *Enverus*, accessed 3 May 2024, https:/ /ww w.enverus.co m/ .

Harbour Energy plc 2022. Timpan exploration well result, Harbour Energy, 1 p.

Nirsal, N., S. Clark, A. Jervis and D. Rudd 2021. New perspectives on the stratigraphy of the Andaman Trough, offshore North Sumatra, Indonesia. Utilising modern quantitative biostratigraphical analysis, integrated with newly acquired 3D multi-client seismic data, v. 45, p. 1-10.

Polachan, S. and A. Racey 1994. Stratigraphy of the Mergui Basin, Andaman Sea: implications for petroleum exploration. Journal of Petroleum Geology, v. 17, p. 373-406.

Sautter, B., M. Pubellier, P. Jousselin, P. Dattilo and Y. Kerdraon 2017. Late Paleogene rifting along the Malay Peninsula thickened crust. Tectonophysics, v. 710-711, p. 205-224.

Waples, D.W. 1985. Migration. In: Geochemistry in Petroleum Exploration. Geological Sciences Series. Springer, Dordrecht.

U.S. Energy Information Administration 2021. Country Analysis Executive Summary: Indonesia. In Energy Information Administration. Energy Information Administration (EIA).