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Technically Recoverable Shale Oil and Shale Gas Resources:

Indonesia

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Introduction

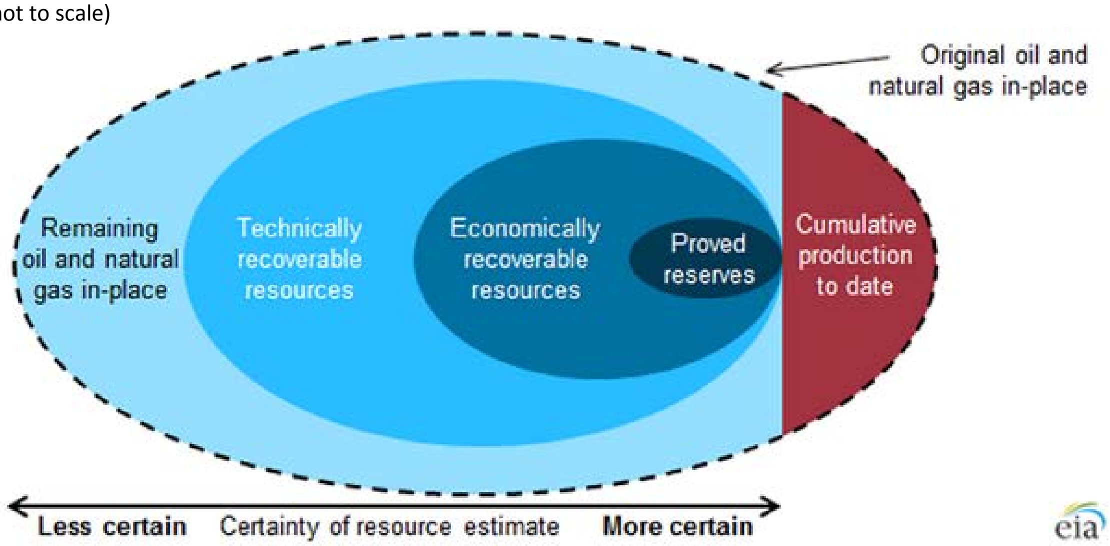
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically recoverable oil and natural gas resources. This chapter is from the 2013 EIA world shale report Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States.

Resource categories

When considering the market implications of abundant shale resources, it is important to distinguish between a technically recoverable resource, which is the focus of this supplement as in the 2013 report, and an economically recoverable resource. Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Economically recoverable resources are resources that can be profitably produced under current market conditions. The economic recoverability of oil and gas resources depends on three factors: the costs of drilling and completing wells, the amount of oil or natural gas produced from an average well over its lifetime, and the prices received for oil and gas production. Recent experience with shale gas and tight oil in the United States and other countries suggests that economic recoverability can be significantly influenced by above-the-ground factors as well as by geology. Key positive above-the-ground advantages in the United States and Canada that may not apply in other locations include private ownership of subsurface rights that provide a strong incentive for development; availability of many independent operators and supporting contractors with critical expertise and suitable drilling rigs and, preexisting gathering and pipeline infrastructure; and the availability of water resources for use in hydraulic fracturing. See Figure 1.

Figure 1. Stylized representation of oil and natural gas resource categorizations

(not to scale)



Source: U.S. Energy Information Administration
Note: Resource categories are not drawn to scale relative to the actual size of each resource category. The graphic shown above is applicable only to oil and natural gas resources.

Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

For many purposes, oil and natural gas resources are usefully classified into four categories:

- Remaining oil and gas in-place (original oil and gas in-place minus cumulative production at a specific date)
- Technically recoverable resources
- Economically recoverable resources
- Proved reserves

The oil and natural gas volumes reported for each resource category are estimates based on a combination of facts and assumptions regarding the geophysical characteristics of the rocks, the fluids trapped within those rocks, the capability of extraction technologies, and the prices received and costs paid to produce oil and natural gas. The uncertainty in estimated volumes declines across the resource categories (see figure above) based on the relative mix of facts and assumptions used to create these resource estimates. Oil and gas in-place estimates are based on fewer facts and more assumptions, while proved reserves are based mostly on facts and fewer assumptions.

Remaining oil and natural gas in-place (original oil and gas in-place minus cumulative production). The volume of oil and natural gas within a formation before the start of production is the original oil and gas in-place. As oil and natural gas are produced, the volumes that remain trapped within the rocks are the remaining oil and gas in-place, which has the largest volume and is the most uncertain of the four resource categories.

Technically recoverable resources. The next largest volume resource category is technically recoverable resources, which includes all the oil and gas that can be produced based on current technology, industry practice, and geologic knowledge. As technology develops, as industry practices improve, and as the understanding of the geology increases, the estimated volumes of technically recoverable resources also expand.

The geophysical characteristics of the rock (e.g., resistance to fluid flow) and the physical properties of the hydrocarbons (e.g., viscosity) prevent oil and gas extraction technology from producing 100% of the original oil and gas in-place.

Economically recoverable resources. The portion of technically recoverable resources that can be profitably produced is called economically recoverable oil and gas resources. The volume of economically recoverable resources is determined by both oil and natural gas prices and by the capital and operating costs that would be incurred during production. As oil and gas prices increase or decrease, the volume of the economically recoverable resources increases or decreases, respectively. Similarly, increasing or decreasing capital and operating costs result in economically recoverable resource volumes shrinking or growing.

U.S. government agencies, including EIA, report estimates of technically recoverable resources (rather than economically recoverable resources) because any particular estimate of economically recoverable resources is tied to a specific set of prices and costs. This makes it difficult to compare estimates made by other parties using different price and cost assumptions. Also, because prices and costs can change over relatively short periods, an estimate of economically recoverable resources that is based on the prevailing prices and costs at a particular time can quickly become obsolete.

Proved reserves. The most certain oil and gas resource category, but with the smallest volume, is proved oil and gas reserves. Proved reserves are volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves generally increase when new production wells are drilled and decrease when existing wells are produced. Like economically recoverable resources, proved reserves shrink or grow as prices and costs change. The U.S. Securities and Exchange Commission regulates the reporting of company financial assets, including those proved oil and gas reserve assets reported by public oil and gas companies.

Each year EIA updates its report of proved U.S. oil and natural gas reserves and its estimates of unproved technically recoverable resources for shale gas, tight gas, and tight oil resources. These reserve and resource estimates are used in developing EIA's Annual Energy Outlook projections for oil and natural gas production.

- Proved oil and gas reserves are reported in EIA's U.S. Crude Oil and Natural Gas Proved Reserves.
- Unproved technically recoverable oil and gas resource estimates are reported in EIA's Assumptions report of the Annual Energy Outlook. Unproved technically recoverable oil and gas resources equal total technically recoverable resources minus the proved oil and gas reserves.

Over time, oil and natural gas resource volumes are reclassified, going from one resource category into another category, as production technology develops and markets evolve.

Additional information regarding oil and natural gas resource categorization is available from the Society of Petroleum Engineers and the United Nations.

Methodology

The shale formations assessed in this supplement as in the previous report were selected for a combination of factors that included the availability of data, country-level natural gas import dependence, observed large shale formations, and observations of activities by companies and governments directed at shale resource development. Shale formations were excluded from the analysis if one of the following conditions is true: (1) the geophysical characteristics of the shale formation are unknown; (2) the average total carbon content is less than 2 percent; (3) the vertical depth is less than 1,000 meters (3,300 feet) or greater than 5,000 meters (16,500 feet), or (4) relatively large undeveloped oil or natural gas resources.

The consultant relied on publicly available data from technical literature and studies on each of the selected international shale gas formations to first provide an estimate of the "risked oil and natural gas in-place," and then to estimate the unproved technically recoverable oil and natural gas resource for that shale formation. This methodology is intended to make the best use of sometimes scant data in order to perform initial assessments of this type.

The risked oil and natural gas in-place estimates are derived by first estimating the volume of in-place resources for a prospective formation within a basin, and then factoring in the formation's success factor and recovery factor. The success factor represents the probability that a portion of the formation is expected to have attractive oil and natural gas flow rates. The recovery factor takes into consideration the capability of current technology to produce oil and natural gas from formations with similar geophysical characteristics. Foreign shale oil recovery rates are developed by matching a shale formation's geophysical characteristics to U.S. shale oil analogs. The resulting estimate is referred to as both the risked oil and natural gas in-place and the technically recoverable resource. The specific tasks carried out to implement the assessment include:

1. Conduct a preliminary review of the basin and select the shale formations to be assessed.

2. Determine the areal extent of the shale formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the prospective area deemed likely to be suitable for development based on depth, rock quality, and application of expert judgment.
4. Estimate the natural gas in-place as a combination of *free gas*[1] and *adsorbed gas*[2] that is contained within the prospective area. Estimate the oil in-place based on pore space oil volumes.
5. Establish and apply a composite success factor made up of two parts. The first part is a formation success probability factor that takes into account the results from current shale oil and shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a prospective area success factor that takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the prospective area from development.
6. For shale oil, identify those U.S. shales that best match the geophysical characteristics of the foreign shale oil formation to estimate the oil in-place recovery factor.[3] For shale gas, determine the recovery factor based on geologic complexity, pore size, formation pressure, and clay content, the latter of which determines a formation's ability to be hydraulically fractured. The gas phase of each formation includes dry natural gas, associated natural gas, or wet natural gas. Therefore, estimates of shale gas resources in this report implicitly include the light wet hydrocarbons that are typically coproduced with natural gas.
7. Technically recoverable resources[4] represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor.

Based on U.S. shale production experience, the recovery factors used in this supplement as in the previous report for shale gas generally ranged from 20 percent to 30 percent, with values as low as 15 percent and as high as 35 percent being applied in exceptional cases. Because of oil's viscosity and capillary forces, oil does not flow through rock fractures as easily as natural gas. Consequently, the recovery factors for shale oil are typically lower than they are for shale gas, ranging from 3 percent to 7 percent of the oil in-place with exceptional cases being as high as 10 percent or as low as 1 percent. The consultant selected the recovery factor based on U.S. shale production recovery rates, given a range of factors including mineralogy, geologic complexity, and a number of other factors that affect the response of the geologic formation to the application of best practice shale gas recovery technology. Because most shale oil and shale gas wells are only a few years old, there is still considerable uncertainty as to the expected life of U.S. shale wells and their ultimate recovery. The recovery rates used in this analysis are based on an extrapolation of shale well production over 30 years. Because a shale's geophysical characteristics vary significantly throughout the formation and analog matching is never exact, a shale formation's resource potential cannot be fully determined until extensive well production tests are conducted across the formation.

Key exclusions

In addition to the key distinction between technically recoverable resources and economically recoverable resources that has been already discussed at some length, there are a number of additional factors outside of the scope of this report that must be considered in using its findings as a basis for projections of future

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[1] Free gas is natural gas that is trapped in the pore spaces of the shale. Free gas can be the dominant source of natural gas for the deeper shales.

[2] Adsorbed gas is natural gas that adheres to the surface of the shale, primarily the organic matter of the shale, due to the forces of the chemical bonds in both the substrate and the natural gas that cause them to attract. Adsorbed gas can be the dominant source of natural gas for the shallower and higher organically rich shales.

[3] The recovery factor pertains to percent of the original oil or natural gas in-place that is produced over the life of a production well.

[4] Referred to as risked recoverable resources in the consultant report.

production. In addition, several other exclusions were made for this supplement as in the previous report to simplify how the assessments were made and to keep the work to a level consistent with the available funding.

Some of the key exclusions for this supplement as in the previous report include:

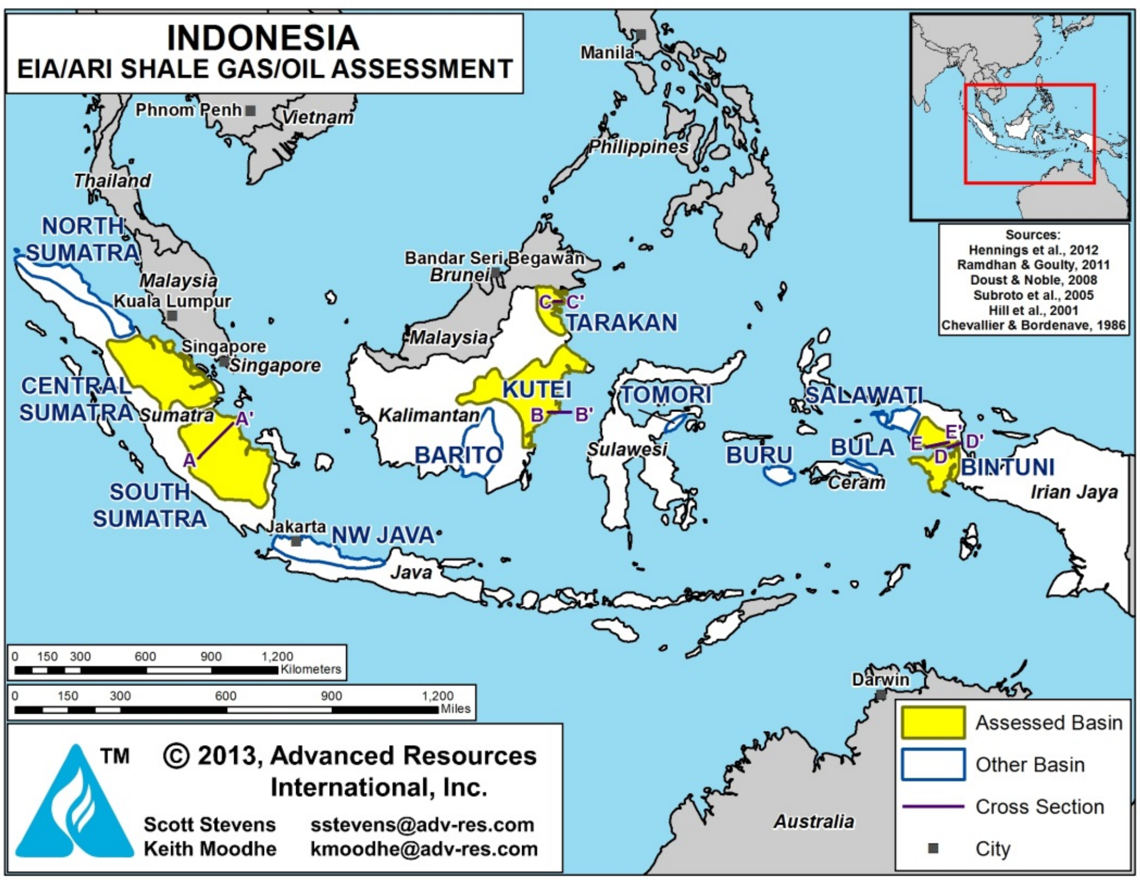
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas resources that may exist within these countries were also excluded from the assessment.
3. **Assessed formations without a resource estimate**, which resulted when data were judged to be inadequate to provide a useful estimate. Including additional shale formations would likely increase the estimated resource.
4. **Countries outside the scope of the report**, the inclusion of which would likely add to estimated resources in shale formations. It is acknowledged that potentially productive shales exist in most of the countries in the Middle East and the Caspian region, including those holding substantial non-shale oil and natural gas resources.
5. **Offshore portions of assessed shale oil** and shale gas formations were excluded, as were shale oil and shale gas formations situated entirely offshore.

XXIII. INDONESIA

SUMMARY

Indonesia has shale gas and shale oil potential within selected marine-deposited formations, as well as more extensive shale resources within non-marine and often coaly shale deposits, Figure XXIII-1. The best overall potential appears to be mostly oil-prone, lacustrine-deposited shales within the Central and South Sumatra basins, which sourced the prolific nearby conventional oil and gas fields. Kalimantan's Kutei and Tarakan basins also have thick lacustrine source rock shales with oil and gas potential.

Figure XXIII-1. Shale Basins of Indonesia



Source: ARI, 2013

Indonesia has an estimated 46 Tcf and 7.9 billion barrels of risked, technically recoverable shale gas and shale oil resources out of 303 Tcf and 234 billion barrels of risked shale gas and shale oil in-place, Tables XXIII-1 and XXIII-2. Several companies (AWE, Bukit, NuEnergy) have reported early-stage evaluations of shale gas potential in Sumatra, but no PSC's have been awarded nor has shale-related drilling activity been reported.

Table XXIII-1. Shale Gas Reservoir Properties and Resources of Indonesia.

Basic Data	Basin/Gross Area		C. Sumatra (36,860 mi^2)	S. Sumatra (45,170 mi^2)	Kutei (35,840 mi^2)	Tarakan (7,510 mi^2)			Bintuni (15,200 mi^2)
	Shale Formation		Brown Shale	Talang Akar	Balikpapan	Naintupo	Meliat	Tabul	Aifam Group
	Geologic Age		Paleogene	Eocene-Oligocene	Mid.-U. Miocene	L. Miocene	Mid. Miocene	U. Miocene	Permian
	Depositional Environment		Lacustrine	Lacustrine	Lacustrine	Lacustrine	Lacustrine	Lacustrine	Marine
Physical Extent	Prospective Area (mi^2)		4,700	15,490	1,630	1,010	880	510	3,340
	Thickness (ft)	Organically Rich	295	918	900	750	1,000	1,500	1,000
		Net	266	367	450	375	400	600	500
	Depth (ft)	Interval	6,560 - 10,496	3,300 - 8,000	3,300 - 15,000	6,600 - 16,000	3,300 - 13,120	3,300 - 6,600	5,000 - 15,000
		Average	8,530	7,000	9,000	11,500	10,000	5,000	9,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Highly Overpress.	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		6.0%	5.0%	4.0%	5.0%	3.0%	3.0%	1.5%
	Thermal Maturity (% Ro)		0.80%	0.70%	0.70%	1.50%	1.15%	0.70%	1.50%
	Clay Content		Medium	High	High	High	High	High	Low
Resource	Gas Phase		Assoc. Gas	Assoc. Gas	Assoc. Gas	Dry Gas	Wet Gas	Assoc. Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		19.6	25.0	62.1	170.7	142.3	37.3	213.8
	Risked GIP (Tcf)		41.5	67.8	16.2	34.5	25.1	3.8	114.3
	Risked Recoverable (Tcf)		3.3	4.1	1.3	5.2	3.8	0.2	28.6

Table XXIII-2. Shale Oil Reservoir Properties and Resources of Indonesia.

Basic Data	Basin/Gross Area		C. Sumatra (36,860 mi^2)	S. Sumatra (45,170 mi^2)	Kutei (35,840 mi^2)	Tarakan (7,510 mi^2)	
	Shale Formation		Brown Shale	Talang Akar	Balikpapan	Meliat	Tabul
	Geologic Age		Paleogene	Eocene-Oligocene	Mid.-U. Miocene	Mid. Miocene	U. Miocene
	Depositional Environment		Lacustrine	Lacustrine	Lacustrine	Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi^2)		4,700	15,490	1,630	880	510
	Thickness (ft)	Organically Rich	295	918	900	1,000	1,500
		Net	266	367	450	400	600
	Depth (ft)	Interval	6,560 - 10,496	3,300 - 8,000	3,300 - 15,000	3,300 - 13,120	3,300 - 6,600
		Average	8,530	7,000	9,000	10,000	5,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Highly Overpress.	Normal	Normal
	Average TOC (wt. %)		6.0%	5.0%	4.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.80%	0.70%	0.70%	1.15%	0.70%
	Clay Content		Medium	High	High	High	High
Resource	Oil Phase		Oil	Oil	Oil	Condensate	Oil
	OIP Concentration (MMbbl/mi^2)		32.8	50.2	64.7	7.1	103.7
	Risked OIP (B bbl)		69.4	136.2	16.9	1.3	10.6
	Risked Recoverable (B bbl)		2.77	4.09	0.68	0.04	0.32

In general, western Indonesia has comparatively simple structure but is dominated by the non-marine shale types, whereas eastern Indonesia has abundant marine shale deposits but is structurally more complex. Eastern Indonesia (Sulawesi, Seram, Buru, Irian Jaya) is tectonically more complex but has excellent marine-deposited shale source rocks.

INTRODUCTION

Indonesia is the world's fourth most populous country (250 million) and a major producer of coal, oil, and natural gas. Formerly an oil exporter and OPEC member, Indonesia's declining oil production and increasing domestic consumption have made the country a net oil importer since 2004. In 2011 Indonesia produced an average 2.5 million bbl/day of crude oil from 4.0 billion barrels of proved reserves, while consuming 3.1 million bbl/day. Indonesia remains a major exporter of LNG and pipeline-conveyed natural gas, producing an average 7.4 Bcfd during 2011 while exporting 3.7 Bcfd.[1] However, Indonesia's domestic gas consumption is rising faster than its output. Gas prices have risen significantly in recent years and new LNG import terminals are being constructed in Java, Indonesia's most densely populated island.

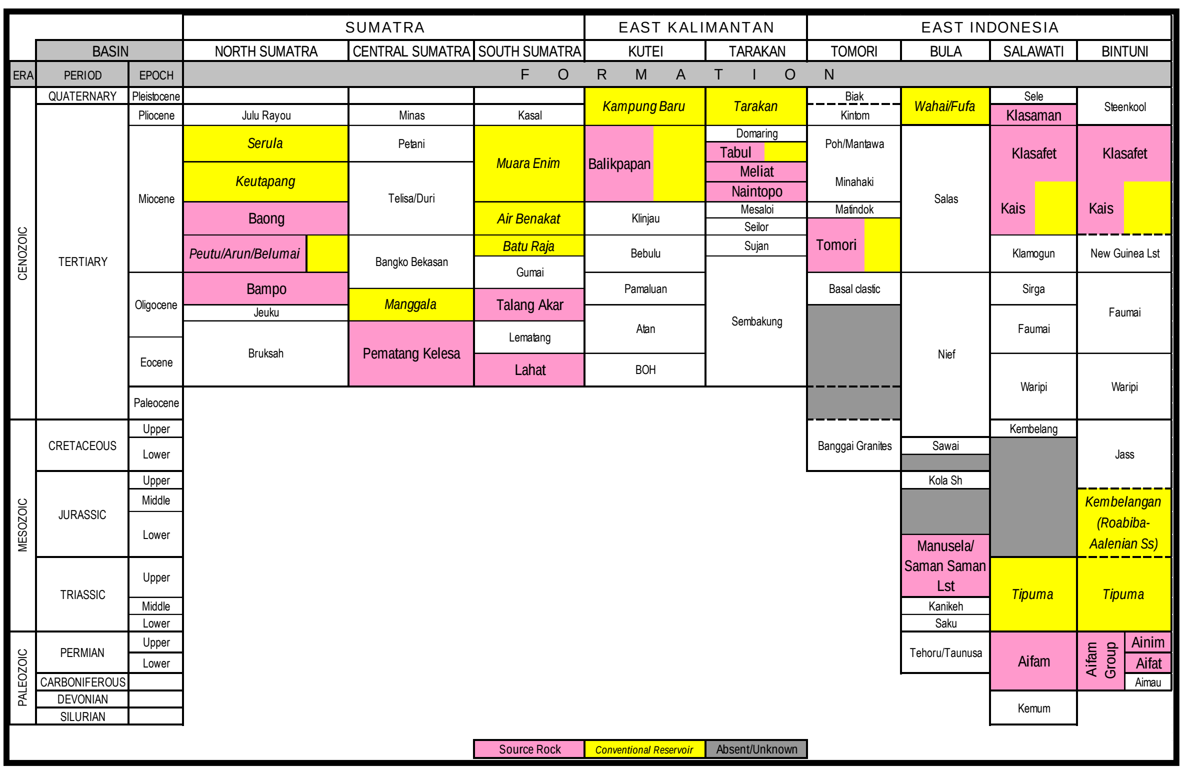
Indonesia's Ministry of Energy and Mineral Resources (MIGAS) administers upstream investment policy and awards exploration and production licenses in the country's oil and gas industry. A separate organization BPMIGAS administers the implementation of these licenses and work programs. However, a recent (November 2012) judicial decision by Indonesia's highest court unexpectedly dissolved BPMIGAS, directing MIGAS to implement oil and gas investment. Indonesia's 2001 Oil and Gas Law is expected to be revised during 2013 to clarify these significant changes and clear up the current regulatory uncertainty.

Domestic and foreign companies are active in Indonesia's oil and gas sector, with foreign companies operating the bulk of production. Pertamina, Indonesia's wholly state-owned oil company, plans to eventually transition into a listed company with significant private ownership. PGN (Perusahaan Gas Negara), the dominant natural gas pipeline operator that is partly state- and publicly owned, is gradually moving into the upstream business as well, including pursuing unconventional gas development. Foreign companies active in Indonesia include Chevron, Total, ConocoPhillips, ExxonMobil, and BP, as well as numerous smaller Indonesian and foreign operators.

ARI's review of published geologic literature indicates that Indonesia has a number of onshore sedimentary basins which may have shale gas/oil potential. These include the Central and South Sumatra basins on Sumatra Island; the Kutei and Tarakan basins in Kalimantan; and smaller, structurally complex basins in eastern Indonesia (Salawati, Bintuni, Tomori). Other basins in Indonesia appear to be less prospective due to low TOC, high clay and CO_2 contents, and/or excessive structural complexity.

The petroleum source rocks in onshore Indonesian basins are relatively young, mostly Eocene to Pliocene, with older Permian source rocks present in the east, Figure XXIII-2. Their depositional setting ranges from deepwater marine in eastern Indonesia to mostly lacustrine and deltaic environments in central and western Indonesia. Many of Indonesia's organic-rich shales are non-marine coaly deposits that may not be brittle enough for shale development. MIGAS, the upstream oil and gas regulator in Indonesia, has estimated the country's shale gas resources at 574 Tcf. However, neither the methodology nor the basis of this estimate has been reported.

Figure XXIII-2. Stratigraphy of Source Rocks and Conventional Petroleum Reservoirs in Indonesia.



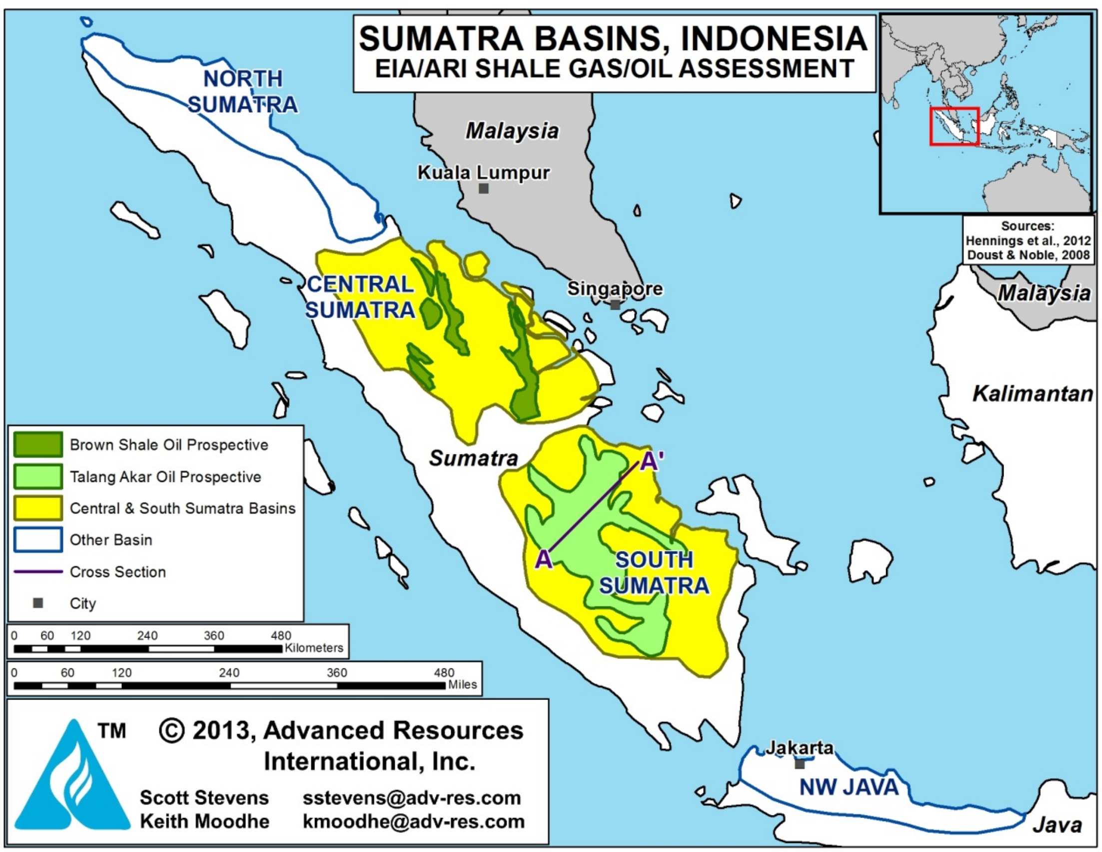
Advanced Resources International, Inc.

1 NORTH, CENTRAL, AND SOUTH SUMATRA BASINS

1.1 Introduction and Geologic Setting

Sumatra has shale oil and gas potential in three deep basin complexes: the North, Central, and South Sumatra basins, Figure XXIII-3. The North Sumatra Basin produces mainly conventional gas both onshore and offshore. However, gas production has declined sharply in this basin and the Arun LNG export facility is being converted to handle LNG imports. The Central Sumatra Basin produces mainly oil onshore, notably 300,000 bbl/day from the Duri thermal EOR field, and is a major consumer of natural gas for steam fuel. The South Sumatra Basin produces both oil and increasing volumes of gas from onshore fields. Major coal and coalbed methane deposits also occur in South and Central Sumatra, while North Sumatra is largely barren of coal. All three basins are back-arc tectonic settings containing young, rapidly deposited and poorly lithified sedimentary rocks. Heat flow and CO_2 content often are elevated.

Figure XXIII-3. Prospective Shale Areas in the Central and South Sumatra Basins, Indonesia.



Source: ARI, 2013

North Sumatra Basin. A series of north–south trending ridges and grabens, formed during the Early Oligocene, became filled with predominantly marine deposits. These include deep marine claystones, shales and shallow water limestones on structural highs, while shallow water deltaic facies formed in the southeast. The main source rocks are the Middle Miocene Lower Baong shale and the Early Miocene Belumai calcareous shale. The Late Oligocene Bampo black shale, which formed in localized thick and euxinic deposits, is another potential source rock.[2] The Bampo contains thick, deep marine claystones, mudstones and dark shales and is the main source rock for gas fields in the northern part of the North Sumatra Basin.

Thermal maturity of the Baong, Belumai, and Bampo shales is gas-prone but TOC is low, seldom exceeding 1% (Type III) while clay is abundant (mostly smectite). CO_2 and H_2S contamination are fairly common: output from the Arun gas field averages about 20% CO_2, while the Peutu carbonate reservoir contains 82% CO_2. Overall, these source rocks appear to be too low in TOC and possibly ductile due to their shallow depth, rapid burial, high clay content, and young age. There have been no reports of shale exploration activity in the North Sumatra Basin and we do not consider it to be prospective for shale gas/oil development.

Central Sumatra Basin. Sumatra's most important oil-producing region, the Central Sumatra Basin is a trans-tensional pull-apart basin bounded by major strike-slip faults to the north and south. It developed during the Late Cretaceous to Early Tertiary in a back-arc setting as a result of the Indian Ocean plate subducting at an oblique angle beneath Southeast Asia. The basin comprises a series of north-south trending fault-bounded troughs that are separated by uplifted horst blocks. The troughs became filled with non-marine clastic, lacustrine, and marine sediments. Sedimentation began with deposition of continental sediments followed by a transgressive/regressive marine cycle that started in Late Oligocene or Early Miocene. The Paleogene Pematang Group, Lower Miocene Sihapas Group, and Middle Miocene/ Pliocene Petani Group are the main Tertiary units.

The Brown Shale Formation within the Pematang Group is considered the most important oil-generating formation in the South Sumatra Basin, having generated an estimated 60 billion barrels and sourced the giant Duri and Minas oil fields.[3,4] The overlying marine Menggala sandstones are the main conventional petroleum reservoirs in Central Sumatra, consisting of well-sorted quartzose to subarkosic sandstones with average >20% porosity and 1,500 mD of permeability.

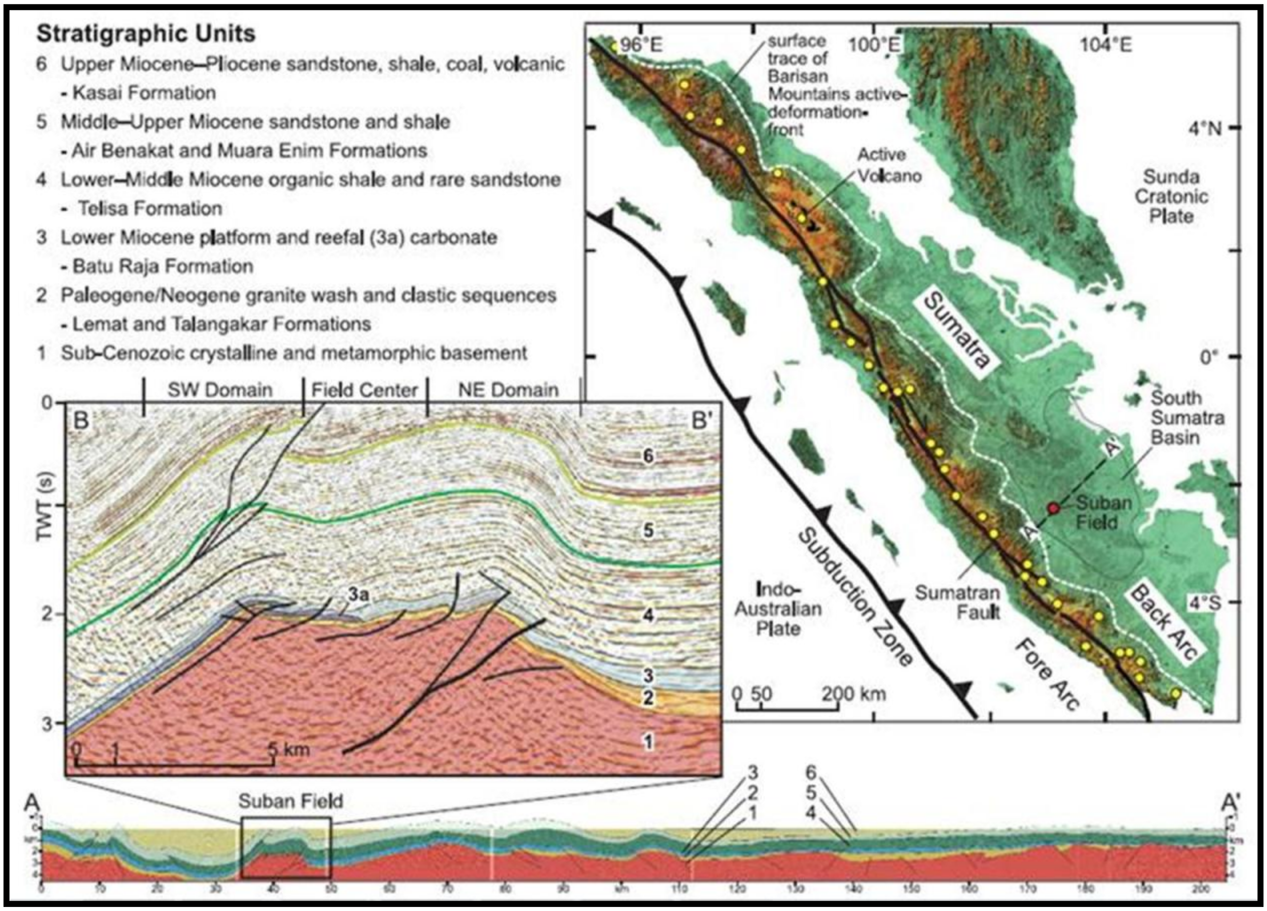
The Brown Shale is a lacustrine-formed unit, deposited in a freshwater to brackish lake system with anoxic bottom conditions. Variation in oil composition within the basin is attributed to local facies changes which reflect the distribution of productivity and paleoclimate conditions during source rock deposition that resulted in varying proportions of algal and terrigenous organic matter. The organic-rich portion of the Brown Shale is about 295 ft thick and is 6600 to 10,500 ft deep in the troughs (average depth 8,500 ft). Mean TOC for this unit throughout the basin is approximately 3.7%, reaching 7.3% at the well-exposed Karbindo coal mine, with mean 25.3 mg HC/g rock petroleum generation capacity.[5]

Two organic-rich facies occur within the Brown Shale Formation. The deep lacustrine facies consist of dark brown to black, well laminated, non-calcareous shales, containing 1 to 15% TOC that consists of Types I and II kerogen. The shallow lacustrine facies consists of red-brown laminated carbonate and terrigenous mudstones with occasional coal stringers. This unit contains average 3.4% TOC, derived from algae that resulted in oil-prone Type I kerogen.[6]

The Keruh, Kiliran, Sangkarewang, Lakat, and Kelesa Formations also can be organic rich, but these are relatively immature thermally and may not be brittle. The U. Miocene to L. Pliocene Binio Formation, part of the Petani Group, contains a sequence of medium- to light grey claystones and minor sandstones that are charged with low-CO_2 and isotopically light biogenic gas. The Binio Fm is overlain by the Late Pliocene Korinci Formation, a regressive sequence of claystones, siltstones, sandstones, and minor coal deposited under a fluvial environment.[7] The Binio and Korinci formations are not considered to be prospective for shale gas/oil development.

South Sumatra Basin. This basin is a significant conventional oil and gas producing area as well as a focus of coalbed methane exploration. The basin contains late Eocene to early Oligocene deposits of clastic sediments in transpressional pull-apart depressions. Thermal subsidence followed rifting in the late Oligocene to the early Miocene, enabling marine incursions to deposit fine-grained marine sequences in lows and reefal buildups on high-standing blocks. Continued subsidence drowned the carbonate system and caused deposition of organic-rich deep-water shales and marls that later became gas-prone hydrocarbon source rocks. Northeast-directed compression and tectonic inversion began in the mid-Miocene, Figure XXIII-4. An estimated 50-90% of the faults in the basin are potentially active and may be at risk of being triggered during large-scale hydraulic fracturing.[8]

Figure XXIII-4. Regional and Detailed Cross Sections of the South Sumatra Basin, Indonesia.



Source: Hennings et al., 2012

Petroleum source rock shales in the South Sumatra Basin include alluvial, lacustrine, and brackish-water sediments in the Lahat Formation and coals and coaly shales in the Talang Akar Formation.[9] These units reach a gross thickness of approximately 1 km. Mid-late Eocene to early Oligocene in age, the Lahat can be oil- or gas-prone depending on location.

Because of limited data, the Lahat Formation was not quantitatively assessed. The Talang Akar Formation is up to over 1 km thick in the South Palembang sub-basin, averaging 1,300 ft thick. TOC ranges from 1.7% to 8.5%, locally reaching 16%. Thermal maturity is low (R_o 0.5%) down to about 6,000 ft depth, increasing to about 0.9% R_o at a depth of 8,000 ft, averaging about 0.7% R_o at 7,000 ft.

The Miocene Muara Enim Formation of the South Sumatra Basin contains important coal and coalbed methane resources that were deposited in a coastal plain environment during an overall regressive cycle, resulting in a thick sequence of mainly clastic sandstone, siltstone, coal, and coaly shale.[10] Thermal maturity is quite low, reaching only about 0.4% to 0.45% R_o within troughs up to 4,000 ft deep. Overall, the Muara Enim Fm is a coaly and probably non-brittle non-marine deposit, too shallow and thermally immature to be favorable for shale development.

1.2 Reservoir Properties (Prospective Area)

The general location of the prospective deep troughs in the Central and South Sumatra basins is well constrained by public data but, unfortunately, not the detailed depth distribution of the shale formations.[11] However, proprietary maps developed by ARI for coalbed methane exploration in these basins provided improved control on depth and thermal maturity, indicating that about 5% of the total basin area could be depth- and thermal-prospective for shale oil. The North Sumatra Basin is not considered prospective.

Central Sumatra. The high-graded prospective area for the Brown Shale Formation in the Central Sumatra Basin is estimated at 4,700-mi^2 based on the extent of the deep troughs. Within this prospective area the Brown Shale averages 266 ft thick (net) with an average depth of 8,530 ft. Average TOC is estimated at 6.0% and is in the oil window (R_o of 0.8%). Pressure gradient is normal and the clay content is considered medium.

South Sumatra Basin. The Eocene to Oligocene Talang Akar Formation is prospective within a large 15,490-mi^2 area and estimated to have a 367-ft thick high-graded zone with average 5% TOC and 0.7% R_o. The pressure gradient is normal and the clay content is considered high.

1.3 Resource Assessment

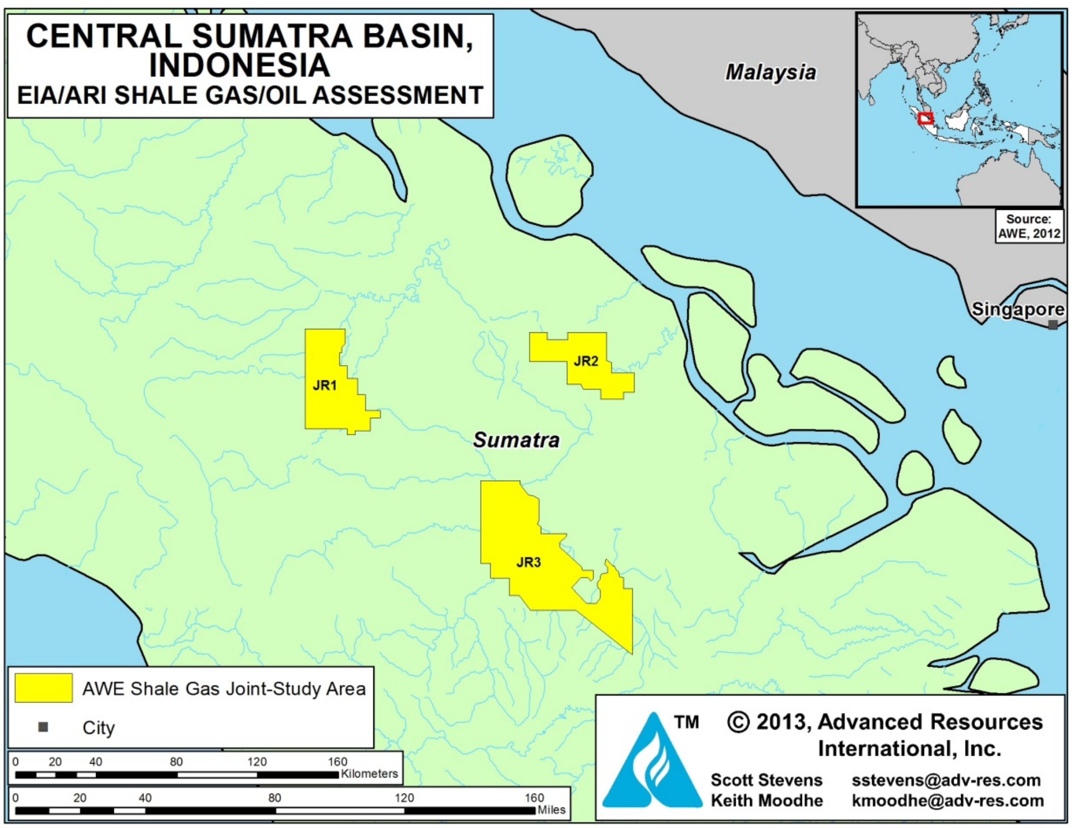
Central Sumatra Basin. Risked, technically recoverable resources from the Brown Shale are estimated at 3.3 Tcf of associated gas and 2.8 billion barrels of shale oil out of 42 Tcf and 69 billion barrels of shale gas and shale oil in-place (all figures risked). ARI considers the shale oil resource in the Central Sumatra Basin to be the most prospective shale potential in Indonesia, particularly given the extensive drilling and transportation infrastructure already present in what is the country's most important oil-producing region.

South Sumatra Basin. The Talang Akar Formation has an estimated 4.1 Tcf and 4.1 billion barrels of technically recoverable shale gas and shale oil resources, out of 68 Tcf and 136 billion barrels of shale gas and oil in-place (all figures are risked). While larger than the estimated Brown Shale oil resource in Central Sumatra, there is much less public data available on the Talang Akar.

1.4 Shale Leasing and Exploration Activity

Four shale gas joint studies totaling 5,000 km^2 in the Central Sumatra Basin were initiated by MIGAS in March 2012, Figure XXIII-5. (Note that although classified as shale gas studies, the main source rocks here actually are in the oil window.) Four companies are evaluating these blocks, including Bukit Energy Inc., AWE Limited, and New Zealand Oil & Gas (NZOG).[12] Although Indonesia does not yet have formal shale licensing regulations, these joint studies eventually could lead to Indonesia's first shale gas PSCs.

Figure XXIII-5. Location of Several Approved Shale Gas Joint-Study Areas in The Central Sumatra Basin.



Source: Modified from AWE Limited, April 2012

Calgary-based Bukit is a small private oil and gas E&P company that operates or participates in several conventional petroleum licenses in the Central and North Sumatra basins. Bukit also has applied for unconventional shale gas/oil exploration blocks in Sumatra and anticipates an award during 2013.

Earlier this year Australia-based AWE announced that they planned to make a decision about their study during Q3 2012, but to date no decision has been released.[13] New Zealand based NZOG holds conventional petroleum PSC's in the Central (Kisaran) and Northern (Bohorok) Sumatra basins, partnering with Bukit in each block, and also reports it is evaluating shale gas opportunities nearby. No shale-related drilling has been disclosed in Sumatra or anywhere in Indonesia.

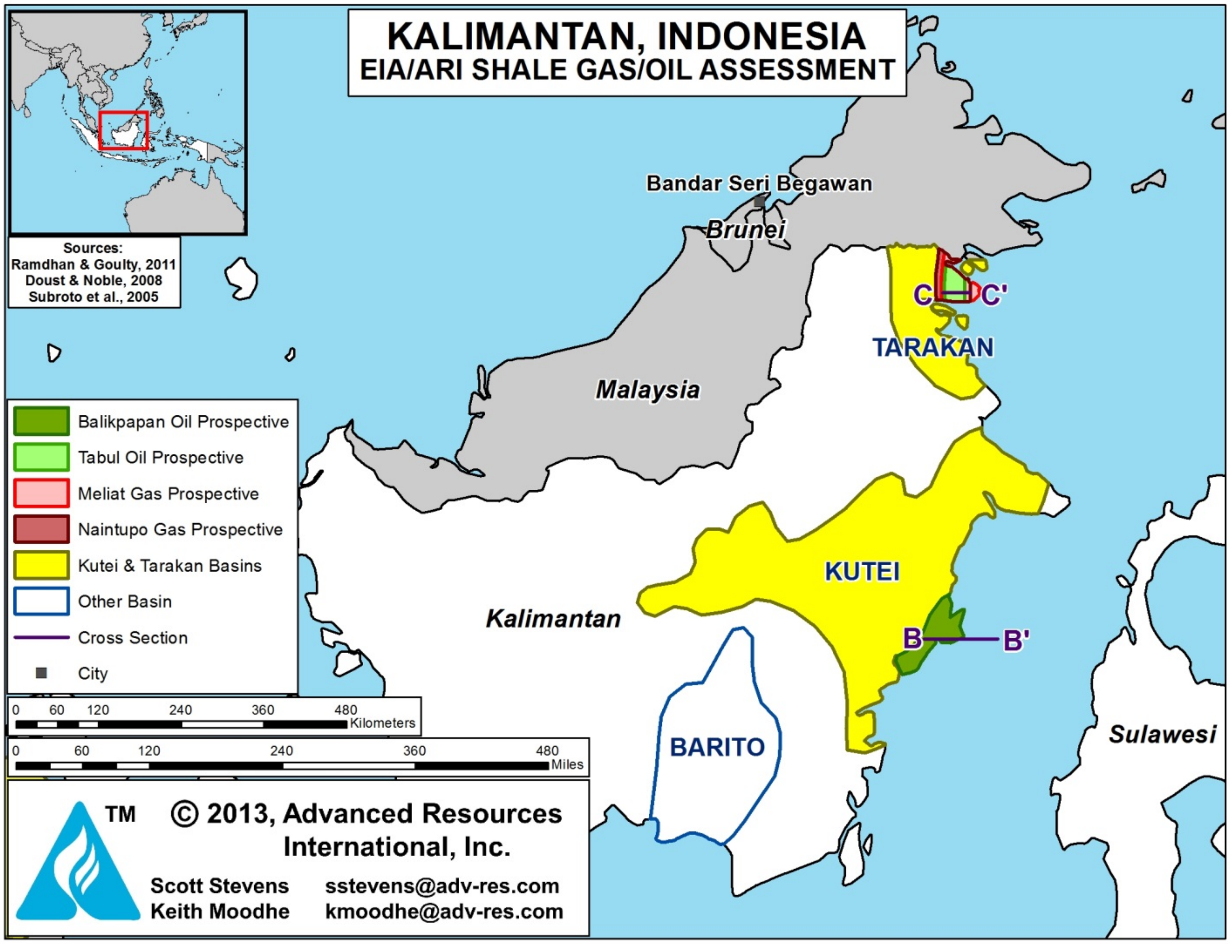
2 KUTEI AND TARAKAN BASINS

2.1 Introduction and Geologic Setting

The Kutei (or Kutai) is Indonesia's largest sedimentary basin, its 36,000-mi^2 onshore portion centered around the Mahakam Delta in eastern Kalimantan, Figure XXIII-6. The Kutei is the second largest oil and gas producing region in Indonesia after Central Sumatra as well as Indonesia's largest gas producer. The Bontang LNG export facility on the coast is the main gas market within this lightly populated region, with a capacity of 22.5 million t/yr. However, Bontang has been operating at about 16 million t/yr due to declining conventional gas production in East Kalimantan.

The 7,510-mi^2 Tarakan Basin, located north up the coast in northeast Kalimantan, contains a similar sedimentary sequence as the Kutei Basin. Fluvio-deltaic to shallow marine shales of Late Eocene age are overlain by Oligocene to Early Miocene open marine carbonate platforms. Finally Mid-Miocene to Quaternary fluvio-deltaic sandstone, shales, and coals were deposited. The entire sequence has been gently deformed with NE-SW trending folds. The main source rocks are Mid-Late Miocene coals and coaly shales of the Tabul Formation, while fluvial-deltaic sandstones of the Tabul and Plio-Pleistocene Tarakan Formation are the main conventional reservoirs.

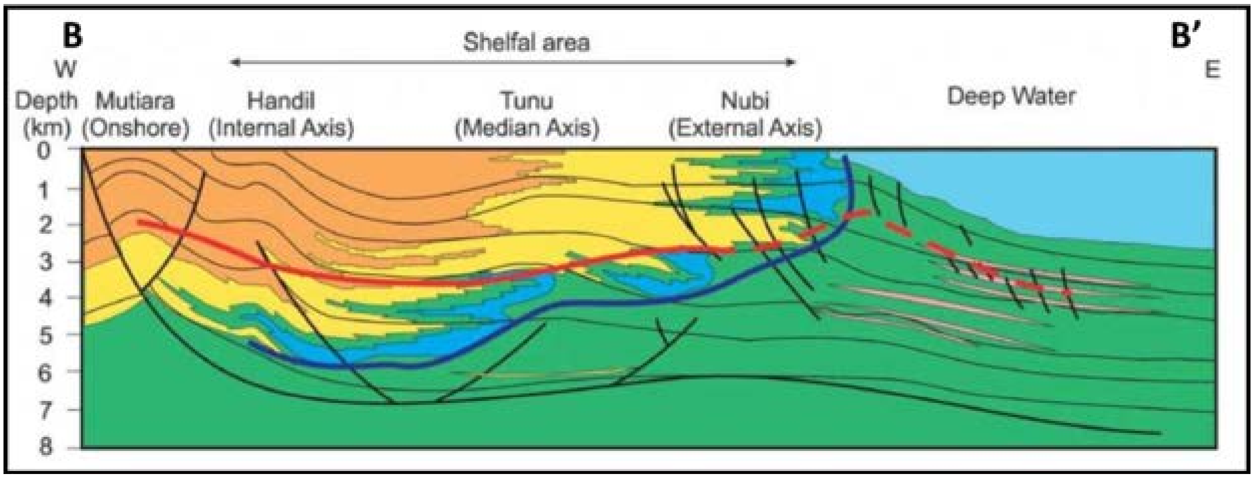
Figure XXIII-6. Prospective Shale Areas in the Kutei and Tarakan Basins, Eastern Kalimantan.



Source: ARI, 2013

The Kutei Basin is bounded by the Mangkaliat Platform on the north, the Kuching High on the west, and the Paternoster High on the south. It developed by rifting and syn-rift deposition during the mid-late Eocene. Deep marine sediments were deposited in the basin center during the late Eocene to late Oligocene, with a carbonate platform developed along the basin edge. Figure XXIII-7 shows the general structure of the Kutei Basin and illustrates that these marine mudrocks are mostly deeper than 5 km in the onshore basin extent.

Figure XXIII-7. Generalized East-West Trending Structural Cross-Section Across the Kutei Basin, Showing Marine Mudrocks Mostly Deeper than 5 Km in the Onshore Areas.



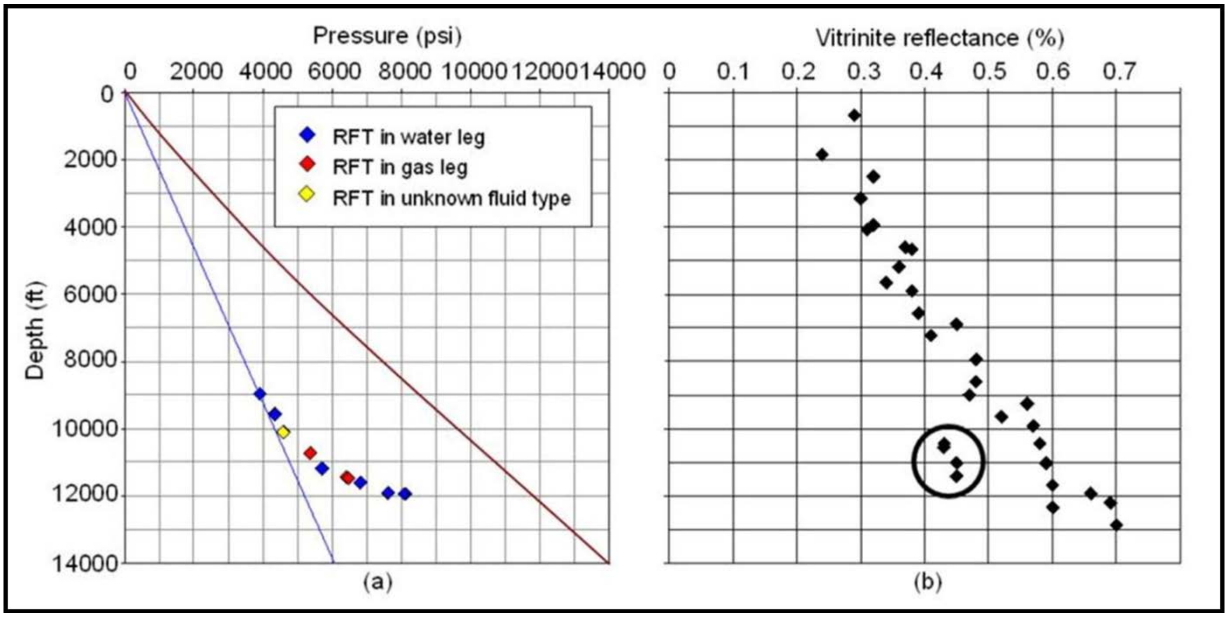
Source: Ramdhan and Gouty, 2011

The main source rocks recognized in the Kutei Basin are Mid-Late Miocene mudstones and carbonaceous shales, with essentially all of the conventional oil and gas production sourced from these shallower Neogene fluvio-deltaic deposits. These source rocks also are the principal shale gas/oil exploration targets in the basin. Prograding deposition during the early Miocene formed deltaic sediments, which are rich in Type III organic matter in coal seams and coaly mudstones. Thermal maturity of this sequence in the deeper troughs is oil-prone, ranging from 0.6% to 0.9% R_o.[14]

The mostly deltaic Miocene shales of the Balikpapan Group in the Kutei Basin are characterized by a depositional environment rich in land-plant material and containing Type III kerogen.[15] TOC ranges from 2% to 6% (average 4%) but some intervals have over 20% TOC. The interbedded shale, sand, and coal sequence is over 3,000 feet thick in many areas. Depth to the top of the oil generative zone (0.7% R_o) averages 9,000 feet in the onshore Kutei Basin, while Miocene rocks become overmature for gas below 19,000 ft depth. Shale oil potential appears to be largely confined to the eastern Kalimantan coast and productive Mahakam Delta.

Structural deformation started during the middle Miocene, forming steep north-south trending anticlines with more gentle synclines. Rapid deposition followed by basin unloading during the Neogene resulted in significant overpressure, caused by gas generation and water being trapped in lithifying sandstones due to interbedded mudstone seals. Overpressuring, ranging up to more than twice hydrostatic levels (1.0 psi/ft), is present throughout the coastal portion of the Kutei Basin starting below a depth of about 7,000 ft and accelerating markedly below about 12,000 ft, Figure XXIII-8.[16] The average surface temperature in the Kutei Basin is 30°C and the average geothermal gradient is about 30°C/km.

Figure XXIII-8. Pressure Gradients in the Kutei Basin Can Reach 1.0 psi/ft Below Depths of About 12,000 ft. Thermal Maturity is Oil-Prone to Immature, with a Very Low Ro/Depth Gradient.



Source: Ramdhan and Gouty, 2011

Further north in the Tarakan Basin, the basin contains Eocene to Miocene deep marine deposits overlain by mostly non-marine clastic sediments of Miocene and younger age that were deposited under deltaic conditions. The principal source rock is the Late Miocene Tabul Formation, along with the Early Miocene Naintupo and Middle Miocene Meliat formations.[17] Unfortunately, these three source rocks are coal-rich deltaic deposits that are considered less prospective for shale gas exploration.

The Naintupo contains deltaic sequences of shale with fair to good organic carbon content, ranging from 1.6% to 12.1% (average 5%). Kerogen is mainly Type III along with some Type II. Well penetrations indicate the Naintupo Fm is 1,000 to 1,500 feet thick (average 1,250 ft thick). Depth ranges from 6,000 ft to over 16,000 feet (average 11,500 ft). Well data and burial history modeling indicate the Naintupo Fm is in the dry gas window (R_o 1.3% to 2.0%, averaging 1.5%). Local structural uplifts may elevate the Naintupo to shallower and thermally less mature levels, where it could be oil prone.

The overlying Middle Miocene Meliat Formation includes shales and claystones along with sandstone, coal, and dolomite layers. Total organic carbon of the deltaic clays ranges from 0.7% to 6.5% (average 3% TOC), mainly Type III kerogen. The Meliat Formation ranges from 3,300 to 6,600 ft thick (average 5,000). Depth varies from 3,300 feet on basin highs to over 13,000 feet in the troughs (average depth 10,000 ft). Thermal history analysis indicates the Meliat has wet gas maturity (1.0 to 1.3% R_o).

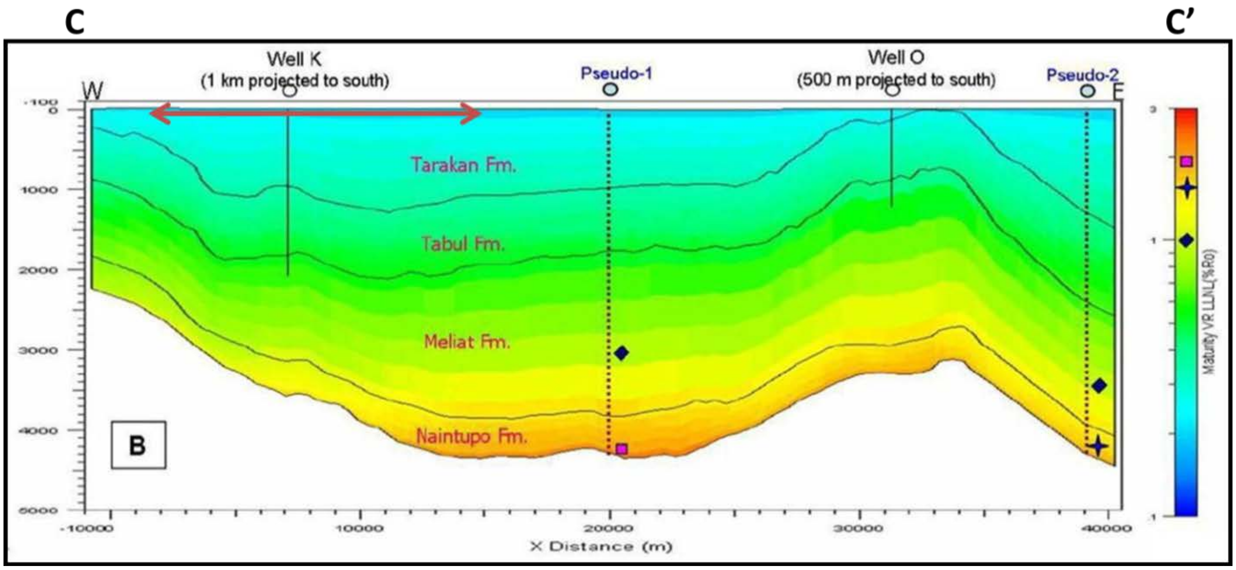
The predominant source rocks of the Tarakan Basin are shales of the Late Miocene Tabul Formation, again a non-marine, deltaic sequence. TOC ranges from 0.5% to 4%, higher in coal-rich sequences. Both lithologies contain mixtures of Type II and III kerogen. The Tabul Formation averages about 3,300 feet thick, of which approximately 1,500 feet is organic-rich, while depth ranges from 3,300 feet to 6,600 feet. Well data and modeling indicate vitrinite reflectance averages 0.7%, in the oil window.

2.2 Reservoir Properties (Prospective Area)

Kutei Basin. Lacustrine mudstones and carbonaceous shales in the Mid-Late Miocene Balikpapan Fm are estimated to be prospective within a 1,630-mi^2 area near the Mahakam Delta, based on limited cross-section data and augmented by ARI-proprietary coalbed methane mapping. These shales are oil-prone (R_o 0.7%) even at average 9,000 ft depth within this thermally immature basin. Net thickness is estimated at 450 ft, with average 4.0% TOC. Reservoir pressure is elevated above hydrostatic.

Tarakan Basin. Three shale-bearing targets are present at varying thermal maturity (oil- to gas-prone). Depth was estimated based on limited cross-section data and proprietary coalbed methane maps developed by ARI. Figure XXIII-9 is a west-east trending structural cross-section across the onshore north-central Tarakan Basin, showing generally simple structural conditions. The L. Miocene Tabul Fm averages 600 ft thick (net) and 5,000 ft deep within its 510-mi^2 prospective area, and has 3.0% average TOC that is in the oil window (0.7% R_o). The Meliat Formation occurs at 10,000-ft average depth and is mostly in the wet gas window (R_o 1.15%), while the Naintupo Formation averages 11,500 ft deep and is dry-gas-prone (R_o 1.5%).

Figure XXIII-9. West-East Trending Structural Cross-section Across the Onshore North-Central Tarakan Basin, Showing Generally Simple Structural Conditions. Source Rocks of the Tabul Formation Occur at Prospective Depths of 1 to 2 Km with Oil-prone R_o of 0.6% to 0.7%. Vertical Exaggeration = 3x.



Source: Subroto et al., 2005

2.3 Resource Assessment

Kutei Basin. Based on the geologic conditions described above, the Balikpapan Fm in the Kutei Basin has an estimated 1.3 Tcf and 0.7 billion barrels of risked, technically recoverable shale gas and shale oil resources, out of risked shale gas and oil in-place of 16 Tcf and 17 billion barrels. Note that this unit is coaly and may not be brittle.

Tarakan Basin. The oil-prone Tabul Formation has an estimated 0.2 Tcf and 0.3 billion barrels of technically recoverable shale gas and shale oil resources, out of 3.8 Tcf and 10.6 billion barrels of shale gas and shale oil in-place (risked). The gas-prone Naintupo and Meliat formations have an estimated 5 and 4 Tcf of risked, technically recoverable shale gas resources out of 35 and 25 Tcf of risked shale gas in-place, respectively. In addition, the Meliat Fm has a small volume (0.04 billion barrels) of technically recoverable condensate from shale.

2.4 Activity

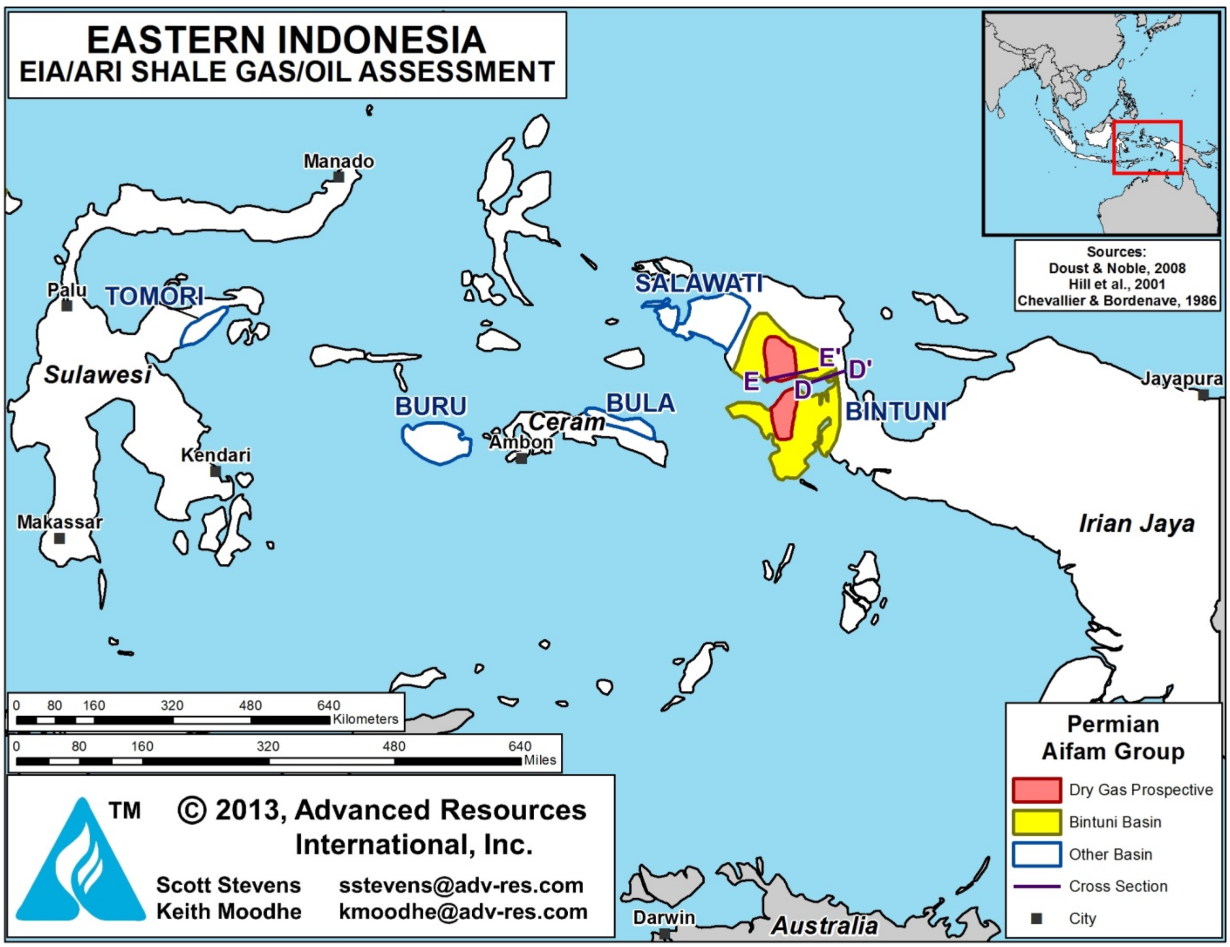
No shale gas/oil leasing or exploration activity has been reported in the Kutei or Tarakan basins.

3 EASTERN INDONESIA BASINS

3.1 Introduction and Geologic Settings

Eastern Indonesian sedimentary basins are markedly different from those in western Indonesia, with significantly older deposits generally reflecting a more marine character.[18] Sulawesi and the islands of eastern Indonesia have some of the country's only marine-deposited (non-lacustrine) shale. Thermal maturity is higher too, predominately in the dry gas window. These basins tend to be small and tectonically complex, thus we group them into a single Eastern Indonesian region for analysis, Figure XXIII-10.

Figure XXIII-10. Prospective Shale Areas in Eastern Indonesia.



Source: ARI, 2013

The Salawati and Bintuni basins in the Bird's Head region of western West Papua contain thick source rocks of Permian age that are rich in Type III coals with some contribution from overmature Jurassic marine shales containing Types II/III kerogen. However, the main source rock is Late Miocene marine shales and marlstones of the Kais and Klasafet formations, which contain Types II/III kerogen. The Klasafet is overlain by thick regressive shales and sandstones of the Plio-Pleistocene Klasaman Formation.[19] Marine marlstones and shales of the Klasaman and Kais/Klasafet formations are potential shale oil targets. They contain mainly Type II/III kerogen, albeit with relatively low TOC of 0.3% to 1.1%.[20] The Klasafet is 1,000 to over 2,000 feet thick in deep troughs, with depth ranging from 5,000 ft in the east to over 12,000 ft in the Sele Strait and Salawati Island to the north and west. Thermal maturity reaches wet gas levels (1.0% R_o) at a depth of 10,000 feet.[21]

The Klasaman Formation contains organic-rich shales with average 1.7% TOC (range 0.6% to 2.3%), mainly Type II and III kerogen. It ranges from 3,000 to 5,000 ft thick in the Salawati Basin, about 15 to 20% of which contains elevated TOC above 1%. Depth ranges from less than 3,000 ft to more than 10,000 ft. Biomarker data indicate the Klasaman sourced oil seeps in the north, where calculated vitrinite reflectance values approach 0.7% R_o and up to 1.0% in deeper parts of the Salawati Basin.

Bintuni Basin. The Bintuni Basin, located in the eastern side of the Bird's Head region, appears to have the simplest structural conditions and best shale prospectivity in the eastern Indonesia region. The Bintuni Basin is bordered to the east by the Lengguru Fold/Thrust Belt. The stratigraphic section resembles that of the Salawati Basin, with preserved Paleozoic, Mesozoic, and Tertiary units. Basement consists of Silurian and Devonian metamorphic rocks. These are unconformably overlain by Carboniferous and Upper Permian clastic sediments and shales of shallow marine origin (Aifam Group). Next are interbedded fluvial shales and sandstones of the Triassic-Jurassic Tipuma Formation and Cretaceous deltaic shales of the Kembelangen Formation.

Limited oil production from New Guinea Group limestones (Kais/Klasafet equivalent) occurred during the 1930's. In the 1990's ARCO Indonesia discovered the Wiriagar Deep gas field, which produces from Middle Jurassic "Roabiba" and "Aalenian" sandstone reservoirs and is exported via the Tangguh LNG facility.[22] Some source rock studies discount the Klasafet shales, since they are typically immature and low in organic content, mostly under 1% TOC.[23]

More important are the Permian and Jurassic sediments, analyzed below for shale oil potential. The Aifat and Ainim formations are the respective lower and upper members of the Permian Aifam Group and considered to be the main hydrocarbon generating rocks in the Bintuni. The older Aifat consists of black marine calcareous shales. Limited data show relatively modest TOC of 1.0% to 1.8%, averaging 1.5%. Gross thickness can exceed 3,500 feet, while depth can exceed 12,000 ft in the Bintuni Basin.

The overlying Ainim Formation also contains calcareous shales, although deposited in a more deltaic setting. Source rock thickness is approximately 2,400 feet. Depth averages about 10,000 feet. This unit contains adequate organic matter with abundant coal seams. Hydrogen index is over 300 mg HC/g. Vitrinite reflectance is sharply lower (0.66% R_o) in the overlying Ainim compared with the older Aifat, indicating an unconformity within the Permian.

In addition to the Permian, the Jurassic Tipuma Formation may be a potential hydrocarbon source. The Tipuma contains sandstones and carbonaceous shales. Analyses of the shallow marine shales indicate maximum TOC of 4.5 and 7.6%, mainly humic kerogen. The Tipuma ranges from 4,000 to nearly 8,000 feet deep. Near the Bintuni Basin's western limit, the Jurassic shales are in the immature-mature oil window, at about 0.6% R_o.

The Tomori Basin of eastern Sulawesi shares many similarities with the Salawati/Bintuni basins, from which it was transported along strike-slip faults. The Tomori is a foreland basin within the greater Banggai-Sula micro-continent, a fold-thrust system that developed following Pliocene collision and thrusting of continental crust over ophiolitic material. Oil and gas exploration began during the 1980's, resulting in the discovery of the Senoro "giant" gas field in 2001.[24] Oil and gas are produced from fractured limestones of the Lower Miocene, sourced by shales within the contemporaneous Tomori Formation, which is similar to the Klasafet Fm.

The Lower Miocene Tomori Fm, ranging from 500 to 1,000 ft thick, also is a potential target for shale exploration. It comprises marine and carbonaceous shale along with some limestone and coal, with the upper section typically more deltaic in origin. TOC is fairly high, averaging 2 to 4% and consisting of Type II/III kerogen. The lower marine section contains higher Type II kerogen but TOC generally is less than 1%. The Tomori Fm attains 0.5% R_o at a depth of 7,200 ft, becoming gas prone (> 1.0% R_o) below a depth of about 11,300 ft.[25]

Finally, the Bula Basin in northeast Seram island contains Mesozoic to Mid-Tertiary open marine pelagic and oceanic deposits, including clays, limestones, and thin sandstones. This assemblage later collided with Irian Jaya and the Australian continental shelf.26 Conventional oil, sourced from Triassic-Jurassic marine carbonate Type II mudstone source rocks, is produced from fractured Jurassic limestone as well as from Plio-Pleistocene marginal marine sandstones and limestones.[27]

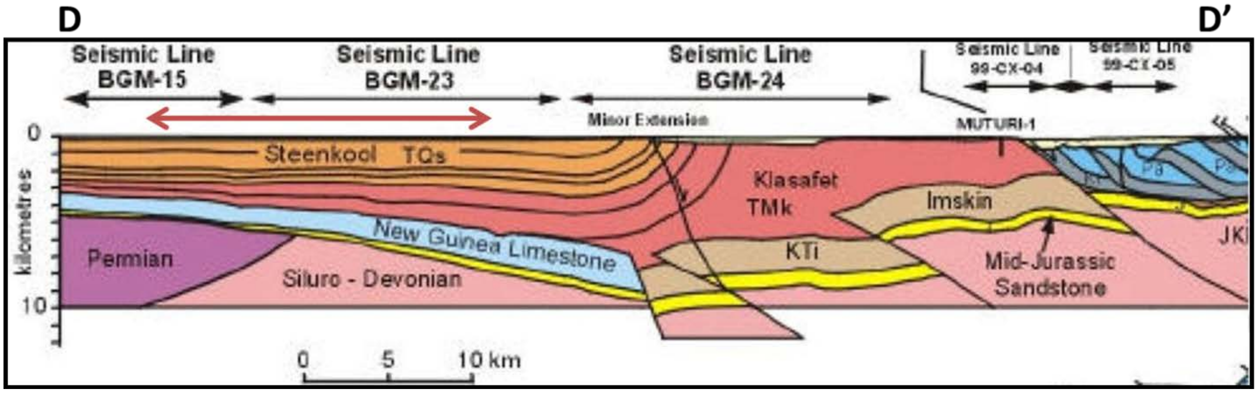
3.2 Reservoir Properties (Prospective Area)

Only the Bintuni Basin had sufficient data to evaluate shale gas/oil reservoir properties and resources, while the other areas (Salawati, Tomori, Bula) lacked adequate data for detailed analysis.

Bintuni Basin. Figure XXIII-1 shows a WSW-ENE trending structural cross-section across the east-central Bintuni Basin.[28] According to this interpretation, the Permian shales here are too deep but marine shales within the Klasafet Fm dip gently to the east and are at prospective depths of 2.5 to 5 km, although as noted above these appear to have low TOC. Further east this unit is structurally deformed by thrusting and not considered prospective. The prospective Klasafet shale area is inferred to be a north-south elongated rectangle just west of the Lengguru Fold and Thrust belt, but this unit was not assessed due to its low TOC (<1%).

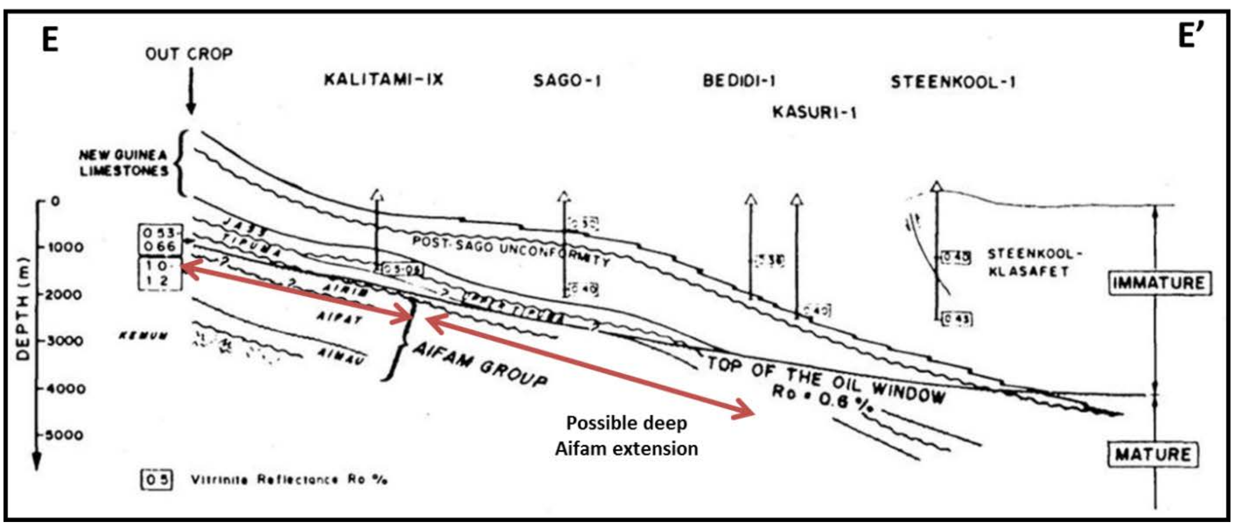
Figure XXIII-12 shows a west-east trending structural cross-section across the west-central Bintuni Basin. Here the organic-rich and prospective Permian Aifam Group (Aifat and Ainim formations) is about 1.0 to 3.5 km deep (possibly deeper further to the east), structurally simple, and within the volatile oil to wet gas windows (R_o of 1.0% to 1.2%). The prospective Aifam Group shale region is assumed to be a north-south elongated rectangle in the west-central Bintuni Basin.

Figure XXIII-11. Generalized WSW-ENE Trending Structural Cross-section Across the Bintuni Basin, Showing Marine Shales in the Klasafet Fm Dipping Gently to the East at Prospective Depths of 2.5 to 5 Km. Further East this Unit is Structurally Deformed and Not Prospective.



Source: Hill et al., 2001

Figure XXIII-12. West-east Structural Cross-section Across West-central Bintuni Basin. Here the Organic-rich and Prospective Permian Aifam Group (Aifat and Ainim formations) is about 1.0 to 3.5 Km Deep, Structurally Simple, and Within the Volatile Oil to Wet Gas Windows (R_o of 1.0% to 1.2%).



Source: Chevalier et al., 1986

3.3 Resource Assessment

Bintuni Basin. The prospective areas of the Permian Aifam Group has an estimated 29 Tcf of technically recoverable shale gas resources out of 114 Tcf of gas in-place (both risked), as defined by the R_o contours of 1.2% to 1.8%. This marine-deposited unit could be the best shale gas target in Indonesia, although its location is relatively remote from market and services.

3.4 Shale Leasing and Exploration Activity

No shale gas/oil leasing or exploration activity has been reported in eastern Indonesia.

4 OTHER BASINS

Indonesia's other onshore sedimentary basins appear to have limited potential for shale gas/oil development. These areas contain mainly non-marine sequences of sandstone, siltstone, coal, and coaly shale that are not considered stable and brittle enough for horizontal frac shale well completions.

- Bengkulu Basin**.** Located in southwest Sumatra across the Barisan Mountains from the South Sumatra Basin, this relatively small and structurally deformed fore-arc basin contains predominantly non-marine clastic and sedimentary rocks of Eocene through Pleistocene age. Geochemical analyses have identified the Mid-Late Miocene Lemau Formation as a potential source rock. This unit consists of mudstone, calcareous mudstone, coal seams, sandstone, and conglomerate deposited in a mainly shallow marine environment that transitioned into mangrove and freshwater environments.[29] Intense faulting, steep structural dips, low thermal maturity (R_o averages 0.40%), and coaly non-brittle lithology all appear to make the Bengkulu Basin unsuitable for shale gas/oil development.

- Ombilin Basin**.** This small non-producing basin is located in west-central Sumatra along the eastern side of the Barisan Mountains. It is a transpressional pull-apart basin that developed during the Eocene to Middle Oligocene and was later deformed into tightly spaced folds trending northwest-southeast. The basal Eocene Brani and Oligocene Sangkarewang formations were deposited in lacustrine rift settings. This later evolved into fluvial deposits of the Late Oligocene Sawahtambang Formation, followed by the marine Miocene Ombilin Formation which resulted from a global sea level rise and transgression.

  Several shallow coal mines are in operation along the edge of the Ombilin Basin, but only a few conventional oil & gas exploration wells have been drilled. These encountered conventional sandstone reservoirs containing natural gas with high levels of

CO_2 (50-90%). Geochemical analyses indicate that shales within the Sangkarewang, Sawahlunto, and Ombilin formations are the best source rocks in the basin. These units contain Type III kerogen that mostly has reached the oil window (T_{max} 435-447° C).[30] Overall, the complex structure, high CO_2 content, and non-brittle nature of the Ombilin Basin shales appears to make them poorly suited for shale gas/oil development.

- The Northwest Java Basin northeast of Jakarta is one of the larger of the small graben structures on Java Island. The Jatibarang sub-basin, the onshore extension of the larger Northwest Java Basin, formed by rifting during the Eocene when volcaniclastics, tuffs and interbedded lacustrine shales were deposited.[31] Subsidence continued into the Late Oligocene and Early Miocene, forming a sequence of shale, coal, and sandstones deposited in fluvio-deltaic, coastal, and shallow marine environments. Deposition evolved to mainly carbonate during the Middle Miocene. By Late Miocene to Quaternary time subsidence diminished, with deposition of regressive clastics and platform carbonates.

  Miocene sandstone is the primary conventional oil and gas reservoir in the Jatibarang Basin, sourced mainly by carbonaceous shale and coal of the Late Oligocene Upper Talang Akar Formation. Organic material consists mainly of Type II and III kerogen. Total organic carbon (TOC) reaches 40-70% in coal, while the shales also can be fairly organic-rich (0.5 to 9%).[32] The inter-bedded shale-clastic sequence can be over 1,000 ft thick, comprising coal seams, limestone, and sandstone. Depth to the Talang Akar is about 7,500 to 11,500 ft. These non-marine to marginal marine source rocks can be oil and gas prone, becoming increasingly more mature offshore. Shales in the Jatibarang Basin are coaly and unlikely to be brittle enough for hydraulic fracturing in horizontal wells.

- The Barito Basin in southern Kalimantan is a large (70,000 km^2 onshore extent), structurally simple basin containing up to 6 km of Eocene and younger sedimentary rocks which unconformably overlie the igneous and metamorphic basement. Minor conventional oil production (of 30-40° API gravity) occurs in the northern Barito, but most of the basin is non-productive. Recent coalbed methane exploration is underway in the southern Barito.

  The Middle Eocene to late Early Oligocene Tanjung Formation is the most important petroleum source rock, consisting of fluvial and marginal marine clastic strata, including thin coal deposits.[33] The formation is over 3,300 ft thick in Tanjung Field in the north.[34] High-TOC shale and marl is concentrated in its upper section, which reaches 2,400 ft thick in the deep southern Barito Basin.[35] Depth to the Tanjung ranges from 3,000 to 12,000 ft, averaging about 6,000 ft deep in the shallow conventional anticlinal fields. TOC is uncertain. The Tanjung has entered the oil window throughout much of the basin, reaching dry gas maturity in the deepest regions. However, the shales within the Tanjung Fm are coaly and probably not brittle.

Overlying the Tanjung Fm are shallow carbonate rocks of the Late Oligocene to Early Miocene Berai Formation, which record a regional marine transgression. Above these, the overlying Plio-Pleistocene Warukin Formation contains marginal marine to fluvial-deltaic sedimentary rocks, including thick, low-rank, sub-bituminous coal deposits. The lack of significant conventional oil and gas production in the Barito Basin, apart from its northernmost edge, is considered a negative factor and makes this basin unattractive for shale gas/oil exploration.

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