Exploring a 19th Century Basin in the 21st Century: Seeing the North Sumatra Basin with New Eyes*

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Abstract

The offshore North Sumatra Basin (NSB) is a relatively immature exploration province with super-giant potential. It has strong parallels to the mature, onshore part of the NSB, which has been a major hydrocarbon province for more than a century.

In the first century of exploration, a number of significant discoveries accounted for 6 BBOE of hydrocarbon reserves, mostly gas, in an area approximately the size of the Texas and Louisiana Gulf Coast and continental shelf combined. Approximately 500 wildcat wells were drilled in the onshore portion of the basin.

In contrast, in the offshore portion of the basin, which comprises more than 75% of the area, only 42 wells were drilled. These wells, drilled in shallow water in the 1970s, resulted in minimal new reserves additions (again mostly gas). In the past 30 years, less than 0.5 BBOE have been discovered, and in the past decade, only 4 offshore wells were drilled.

On the basis of these negative results, the United States Geological Survey estimated that there were only 0.3 BBOE yet to find in the basin (USGS, 2010). Most of these unproven reserves were assumed to be gas, based on the exploration track record. As a result, the region has been considered effectively creamed by all conventional metrics.

And thus ends, for practical purposes, the story of exploration in the North Sumatra Basin.

Or does it? To quote Sir Francis Bacon, "They are ill discoverers that think there is no land, when they can see nothing but sea." In 2009,

3715 km^2 of 3D marine seismic data were acquired by Zaratex in the Lhokseumawe PSC, the first 3D survey in the North Sumatra Basin and the largest 3D survey in Indonesia. These data show that all of the prolific trends in the onshore part of the basin extend into the offshore, and that the undrilled potential of these plays may exceed the discovered volumes to date. Moreover, previously untested plays have been identified, and there is a strong likelihood of oil as well as gas charge, both of which add a component of true greenfield exploration to this supposedly mature, but massively underexplored, province.

This article reviews the fascinating exploration history of the region from the dawn of petroleum exploration to the advent of modern technology, characterizes its petroleum systems with specific reference to the new and the historic data, and demonstrates its yet-unrealized super-giant potential. The key play is stratigraphic traps in Miocene carbonate build-ups (Peutu Formation) on Oligo-Miocene syn-rift horst blocks. Gas, oil, and condensate are interpreted to have migrated from deep basinal kitchens located adjacent to structural highs. Source rocks are generally accepted to be highly prolific, but low richness terrestrial and marine shales (Parapat and Bampo formations). Seal is provided by thick regional marine shales that flooded over the carbonates (Baong and Keutapang formations).

Introduction

In 1970, the great explorer, Michel Halbouty, wrote that "The very thought of a giant petroleum field, to most explorationists, is an exciting dream; relatively few giants have been found, so few of us ever have been associated with one, yet many more are needed to keep the world's petroleum industry alive and healthy." (Halbouty, 1970) (Slide 2). Early days of "Discovery Thinking" are illustrated in Slides 3, 4, and 5; interest in Indonesian geology began before the first significant discovery in Asia in 1885 (Slides 6 and 7).

Since 1970, vast resources have been discovered across the globe, and there are now 173 basins globally with giant petroleum fields. The fortunes of many countries, especially in developing regions, have depended on these discoveries. Deepwater exploration has been instrumental in this period, opening provinces that were simply not prospective four and a half decades ago. Despite this phenomenal success, though, Halbouty's prescient comments have perhaps even more resonance today than they did at the time he made them.

For instance, across the Asia-Pacific region, reserves replacement has been diminishing steadily since 2003, despite fairly consistent exploration success rates (Findingpetroleum.com, February 2012). In Indonesia, the fourth-most populous country in the world, this situation has led to a remarkable reversal of fate. Indonesia joined OPEC in 1962, but by late 2008, production had stagnated, particularly in northern Sumatra, and it was unable to find significant new reserves (news.BBC.co.uk, 28 May 2008). It became a net oil importer and left OPEC in 2009.

Thus, as the country continues to grow, there is unquestionably a need for substantial discoveries, both to meet domestic demand and to re-ignite the E&P industry. Comments by senior Indonesian governmental officials indicate the current state of play (Petromindo.com, 2012;

Slide 8):

- “Indonesia, particularly the Aceh [North Sumatra] region, currently requires gas supply, as gas fields nearby, such as Exxon‟s Arun, have continued to decline.” *(Widhyawan Prawiraatmadja, Deputy for Planning at BPMIGAS)*
- “The government [of Indonesia] will push for massive development of gas infrastructure facilities in the country, in a bid to increase natural gas production, to compensate for the declining trend in crude oil output.” *(Jero Wacik, Minister of Energy and Mineral Resources)*

Much recent exploration activity in Indonesia has focused on frontier areas such as the eastern deepwater Makassar Straits (offshore Sulawesi) and the Papuan offshore. However, success to date has been modest in those areas, and there is renewed interest in revisiting the heartlands of Indonesian exploration, using modern technology to seek previously unidentified resources.

One of the Indonesian heartlands, the North Sumatra Basin (NSB), is a world-class petroleum province. It is one of 173 basins worldwide with giant fields, and is approximately the same geographic size as, for example, the following basins (Slide 9): the Northern North Sea; Ghadames; Sirte; Niger Delta & Deepwater; offshore Angola; South Caspian; Amu Dar‟ya; Sichuan; Luconia, Sarawak, and offshore Brunei; North Carnarvon; North Slope, Alaska; California; Permian; Louisiana Gulf Coast + Shelf + Deepwater; Maracaibo; East Venezuela; Campos; and Santos.

The NSB is the third-largest province in Indonesia, with 25 trillion cubic feet (TCF) of discovered gas reserves (= 4.5 billion barrels of oil equivalent, BBOE) and ~1.5 BBOE of oil and condensate reserves. The total discovered resource in the NSB is ~6.0 BBOE. The NSB is one of 13 basins in the Asia-Pacific region with reserves > 5 (BBOE) (Slide 10).

Of the 13 major Asia-Pacific basins, nine are in Southeast Asia, accounting for two-thirds of the discovered reserves (Slide 10). The SE Asian basins all occur on the Sunda Platform, which represents the submerged limits of the Miocene continental shelf (Slide 11). Sundaland, as this region is called, is defined to the S, SW, and NE by a volcanic arc (the western extension of the "Ring of Fire"); its SE limit is defined by the famous "Wallace Line," a major plate-tectonic boundary first described by Alfred Russel Wallace (1863); and its other boundaries, to the NW and N, are defined at the margins of recently-formed oceanic basins: the Andaman Sea and the South China Sea, respectively.

The large-scale geology of Sundaland is remarkably similar, such that only four petroleum systems (early syn-rift lacustrine, late syn-rift transgressive deltaic, early post-rift marine, and late post-rift regressive deltaic) are responsible for virtually all of the significant discovered volumes (Doust and Sumner, 2007). The early post-rift marine petroleum system, which is best known for gas discoveries in Miocene carbonate build-ups, is the most successful of these systems, accounting for nearly twice as many resources (on a BOE basis) as the second-largest system (Doust and Sumner, 2007). In the NSB, the carbonate play accounts for approximately 75% of the discovered volumes to date.

Exploration History of the North Sumatra Basin

The first hydrocarbon discovery in the NSB was made in 1885 at the Telaga Said field (Slide 12). Telaga Said was the first significant oil discovery in Asia, and was the foundation asset in Royal Dutch Shell's global portfolio (cf. Shell.com website). Other major discoveries followed, such as the giant Rantau oil field in 1929 (Slide 13), which established the NSB as one of the world's early super-basins. These early discoveries, in shallow anticlinal structures, established the late post-rift regressive deltaic petroleum system (*sensu* Doust and Sumner, 2007) as the early candidate for "favored child" status within the basin, a status that continued until 1969, when a milestone in discovery thinking occurred.

That milestone was the publication of a seminal paper (Koesoemadinata, 1969), in which the author stated that "... the greatest oil potential in western Indonesia Tertiary basins is in reservoir beds of the transgressive facies, especially in basinal areas where extensive exploration has not been conducted (e.g., NE Sumatra, ...). In the northern Sumatra basin the transgressive facies has been found to be devoid of oil, and only the regressive facies is productive.... [I]t can be concluded that to find oil in the lower transgressive facies, one should look toward the hinge belt at the edge of the Sunda shelf, i.e., offshore." His assertion was based on his analysis of the regional hydrocarbon geology of the west Indonesian basins of Sundaland, which showed that the "transgressive" sequence (comprising the two syn-rift petroleum systems of Doust and Sumner, 2007) was much more prolific than the "regressive" (or post-rift) sequence, on a regional basis (Slide 14).

Within a decade, Koesoemadinata's hypothesis was proven largely correct. Enormous volumes were indeed discovered in the transgressive sequence in basinal positions; however, they were gas, not oil, and discoveries were onshore, rather than offshore.

The real gamechanger in NSB exploration was Mobil's discovery of the super-giant Arun Field (14-15 TCFG) in a large, post-rift carbonate build-up (Peutu Formation) in 1971 (Slide 15). Not only did Arun demonstrate that the transgressive facies was incredibly prolific, it also changed the playing field for hydrocarbon exploration in SE Asia and globally: it was one the largest gas fields in the world at the time of its discovery (Slide 16), and became the first liquefied natural gas (LNG) development in Asia, establishing the global viability of LNG export as a commercial activity and eventually becoming the "...most lucrative LNG operation in the 20th century" (von der Mehden and Lewis, 2006). Furthermore, the prices established in Arun LNG contracts governed the historical price for gas in SE Asia until very recently (von der Mehden and Lewis, 2004).

The Arun discovery was followed by the giant NSO A and Lhok Sukon A gas discoveries in 1972 in similar carbonate reservoirs. These discoveries shifted the balance of attention from the post-rift, regressive sequence to the syn-rift, transgressive sequence. Exploration activity chasing this new trend exploded through the 1970s and 1980s (Slide 17). By 1985, the end of the first century of NSB exploration, approximately 330 exploration wells had been drilled, resulting in ~5.5 BBOE of hydrocarbon reserves (or an average of ~17 MMBOE/exploration well).

However, volatile geopolitical and geological conditions in Aceh led to a steep decline in overall drilling activity after 1985, and a coinciding flattening of the "creaming curve" for the basin (Slide 17). Only ~0.5 BBOE have been discovered since 1985, and only 8 wildcat wells have been drilled in the NSB in the last decade (Slide 17). Some will see these statistics as a problem; others will see the potential underlying the statistics. Of particular note, Arun is near the end of its field life (Slide 17), leaving a void in export gas supply and un-utilized LNG infrastructure; demand in SE Asia for hydrocarbons (including gas) has increased dramatically since 1985, and northern Sumatra itself has an enormous domestic demand for gas and oil.

The potential for renewed exploration in north Sumatra is tantalizing: the vast majority of the reserves occur in a few large fields located in the onshore portion of the basin, while the offshore portion of the basin is much less mature as an exploration province (Slides 18 and 19). Early attempts to extend the prolific onshore plays into the offshore portion of the basin, which makes up more than 75% of the total NSB, were largely unsuccessful. These failures led to a mentality that the basin was "creamed." Moreover, with a few notable exceptions, such as NSO A, discoveries made in the offshore were relatively small and gas-prone, which made them difficult to monetize unless they could be tied back to Arun. [Ironically, the Arun LNG contracts kept gas prices low and reduced the economics of smaller gas projects significantly.]

As a result of these numerous disparate factors, the offshore NSB, long recognized as an obvious continuation of the onshore NSB with significant "greenfield" exploration potential, has remained relatively under-explored (Meckel et al., 2012). Less than 40 wells have been drilled in more than 100 m water depth (Slide 19). A lack of modern 3D seismic data to define prospects and slow adoption of deepwater drilling technologies have only made the problem more acute in the past two decades (Slide 19).

These factors should excite any explorationist with more than a cursory knowledge of the history of offshore and deepwater exploration, where frontier basins outboard of established onshore basins have proven to be extremely prolific (e.g., NW Borneo, Gulf of Mexico, W Africa). Specifically, consider how few global exploration provinces have the following characteristics (Slide 20):

- Offshore continuation of prolific, proven, hyper-mature onshore trend;
- All play elements are demonstrated to be „world class" (reserves > 6.0 BBOE) in immediately adjacent areas;
- Fewer than 10 exploration wells drilled in WD > 300 m (2% of all exploration wells);
- Only 8 offshore wells in any water depth in last decade (16 in last 20 years);
- Large-scale 3D seismic coverage only in last five years;
- Key prospects located 15-50 km from existing infrastructure (with near-term and long-term ullage);
- Robust domestic and regional gas markets, with strong sales prices and high demand;
- Oil upside in perceived gas-prone province;
- Reserves potential on the order of several billion BOEs.

As stated by Meckel et al. (2012), "Many areas globally have seen proven, prolific onshore trends extended with great success into the offshore. To date, the offshore North Sumatra Basin has been an exception, despite its proximity to proven, world-class fields and discoveries. Only one significant field (NSO-A) has been found. However, it is important to realize that the offshore NSB is still massively under-explored with respect to comparably sized basins. Limited success in early exploration wells presumably tempered enthusiasm, and very few wells have been drilled since the advent of 3D seismic and modern deepwater drilling technologies."

Of specific significance, the highly successful onshore Peutu carbonate build-up trend can be mapped with confidence into deepwater on the new 3D seismic data (Slide 21). Previous shallow-water wells, such as NSO-A1, Peusangan-B1, B2, C1, D1, and E1, established that the Peutu Formation is present and can be effective as a reservoir in the offshore; however, successful prospectivity in the deepwater NSB was limited until recently by sparse, low-quality 2D seismic grids.

Tectonic Evolution and Stratigraphy of the Offshore North Sumatra Basin

The NSB was subject to three episodes of tectono-stratigraphic activity in the Tertiary: extension and rifting from the Oligocene (Eocene?) - early Miocene, middle Miocene quiescence and post-rift subsidence, and middle Miocene to Pleistocene dextral wrenching and compression. [The timing of cessation of late-stage rifting versus post-rift thermal subsidence is vague. For instance, Meckel et al. (2012) introduced a 4-stage tectonic evolution which placed the cessation of rifting and onset of post-rift subsidence in the late Oligocene. More detailed analysis of seismic data (beyond the scope of this article) would ascertain when the rift faults ceased to be active. However, for the purposes of this article, the 3-stage evolution proposal by Doust and Sumner (2007), which is consistent with the "transgressive" and "regressive" cycles of Koesoemadinata (1969), is preferred.] These basic regimes are known across much of SE Asia, and the large-scale stratigraphic succession (first-order transgressive, flooding, and regressive cycles) is common to many geographic areas within the region (Koesoemadinata, 1969; Daly et al., 1991; Doust and Sumner, 2007; Hall, 2009).

In the NSB, W-E to NW-SE oriented, plate-scale extensional forces from the Eocene or early Oligocene through the early Miocene created a series of N-S oriented horsts and grabens and NW-SE oriented shear zones (Davies, 1984; Andreason et al., 1997; Curray, 2005; Banukarso, 2013). In the onshore part of the NSB, and extending offshore into the Lhokseumawe PSC, the local horst-and-graben architecture follows a NW-stepping trend, bounded to the north by the Lhokseumawe shear zone (Meckel et al., 2012) and to the south by the Sumatran shear zone (Slide 21).

The horsts and grabens exerted a significant influence on the depositional patterns of the "transgressive" sedimentary succession (*sensu* Koesoemadinata, 1969): alluvial and fluvial clastic sediments of the continental Parapat Formation and deep marine shales and turbidite sands of the overlying Bampo Formation were deposited in intra-basinal lows (Meckel, 2013; Banukarso et al, 2013). Further flooding allowed carbonate build-ups of the Peutu Formation to localize on N-plunging intra-basinal highs (Slides 21 and 22) (Collins et al., 1996), while laterally equivalent, carbonate-rich mudstones of the Belumai Formation were deposited on the flanks of the Peutu build-ups and in the deeper marine basins. Subsequent flooding during the post-rift quiescent phase resulted in deposition of blanketing regional marine shales (Baong Formation) that erased much of the syn-rift paleo-bathymetry (Slide 22).

Changes in plate-tectonic stresses in the late Miocene led to regional N-S compression and dextral transpression on the shear zones. Large-scale, tectonically induced collapse of the continental margin created a shallow fold-and-thrust belt in the offshore NSB (Scardina, 2006). The interbedded sand and shale deposits of the Keutapang and Seurula formations were deposited at this time.

Miocene Carbonate Build-Up Play

On a discovered resources (BOE) basis, the most successful play in the NSB is stratigraphic-structural traps in Miocene carbonate build-up reservoirs on rift-related paleo-topographic highs, sealed by Baong shales and charged from ultra-prolific kitchens in basinal lows, where syn-rift clastic source rocks (Bampo marine shales or Parapat lacustrine shales) are mature for gas and possibly oil (Slides 22 and 23). Twenty-one fields with more that 5 MMBOE UR have been discovered, and the UR of all the discovered fields is ~4600 MMBOE. The P50 field size at a minimum cutoff of 5 MMBOE is ~20 MMBOE, with a significant upside if fields are above the P50 value.

The carbonate play is equally significant throughout SE Asia; these reservoirs accounted for more than 10% of Indonesian daily production by the late 1970s (Nayoan et al., 1981), and slightly more than 18 BBOE have been discovered in the play so far across SE Asia (Slide 24). Furthermore, on a regional basis, the play shows little indication - 45 years after the first discovery - of having matured yet (Slide 24). Rather, the "creaming curve" is characterized by a more or less consistent background rate of discovery (~75 MMBOE/year), punctuated by 1-3 year-long periods of major discovery (1000-2000 MMBOE/year) that occur about once a decade (Slide 24). The last such period of major discovery occurred in the period 2000-2001.

The play was first explored in 1965, when the use of modern floating rigs opened the Central Luconia province (offshore Malaysia). In 1967, modern digital seismic allowed 2D surveys to be acquired and processed relatively inexpensively. Early exploration blossomed following these two technological advances. From 1968-1975, major discoveries in the offshore Central Luconia province, such as F-06 (1969), K-05 (1970), and F-23 (1973), established the emergence of an important new play.

However, it was the discovery of Arun (1971) in onshore North Sumatra (Slide 15), and its benchmark LNG contract, that confirmed the world-class nature of the carbonate play. Central Luconia and North Sumatra were explored actively through the early 1980s, resulting in many smaller, but still significant discoveries.

In the 1990s, 3D seismic data, acquired with long cables and processed with pre-stack algorithms, became standard for the industry. A new wave of major discoveries followed its implementation, including Malampaya (NW Palawan), Jintan (Central Luconia), and numerous, smaller discoveries in East Java and South Sumatra.

In the offshore NSB, where the undrilled potential of the play may exceed the discovered volumes onshore, the carbonate play is clearly mappable on 3D seismic datasets acquired in 2009, in which multiple episodes of carbonate reef-building, spanning the latest Eocene to late Miocene (Tampur, Cunda, and Peutu formations), are visible on the Bireun High. The offshore continuation of the carbonate play was previously tested and proven in the NSB by wells in the Lhokseumawe PSC and on the Malacca Shelf by the Peusangan-B discovery and the NSB and NSO field clusters (Insets, Slides 25 and 26).

The only discovery to date outside of the NSO and NSB cluster has been the underfilled Peusangan-B gas accumulation, NNW of Arun on the distal edge of the N-plunging Arun High (Slide 25). Four wells have been drilled on the Peusangan-B structure:

- *ONS L-1X* (1972) was a blow-out. It flowed salt water and a small amount of gas from the Peutu Formation.
- *ONS L-1BX* (1972) was a dry hole downdip of ONS L-1X. It tested 208 m of good Peutu limestone with no hydrocarbon shows. A drill stem test (DST) in the Peutu Formation recovered 288 BW/D. The well is below the GWC established in Peusangan-B1.
- *Peusangan-B1* (1985), drilled updip of ONS L-1X, tested 154 m of Peutu Limestone. Average porosity is 35%. Gas was encountered only in the uppermost 8 m of reservoir, indicating the structure is underfilled with respect to its spillpoint, as mapped on 2009 vintage 3D seismic. Average water saturation (Sw) in the gas zone was 28%. The gas zone flowed 10.3 MMCFG/D and 877 BC/D on a 0.5" choke.
- *Peusangan-B2* (1986) was drilled updip of Peusangan-B1. It penetrated 158 m of water-bearing Peutu near-reef and lagoonal facies. The cause of failure is unknown.

Following the success of Arun and Peusangan-B, three exploration wells were drilled on the Bireun High, to test the highly successful carbonate play on the next horst block to the west of Arun (Slide 26).

- *Peusangan-C1* (1987) was a dry hole in a faulted dip closure on the western flank of a structural high. It encountered 148 m of good quality porous limestone (13-29% porosity) and 56 m of tight dolomite (average porosity 3%) within the Peutu Formation. Maximum permeabilities in the limestone range from 25-535 mD. A DST recovered 2.7 MMCFG/D and 1215 BW/D. The gas contained 20% CO_2. The cause of failure is interpreted to be a thin and faulted top seal. Potential reservoirs beneath the Peutu Formation were water-bearing, although deep dolomites had traces of oil.
- *Peusangan-D1* (1988) was a dry hole drilled on the flank of a small 4-way dip closure. It encountered several lagoonal shaly limestones <1 m thick, in which gas shows were recorded. Cause of failure is interpreted to be lack of effective reservoir and insufficient limestone thickness.
- *Peusangan-E1* (1989) was a dry hole. It was drilled on a structural high, but encountered 20 m of shelfal carbonate mudstone at the objective level. A slight oil show was recorded in primary porosity, and gas is interpreted, based on neutron-density crossover,

suggesting that the cause of failure was a lack of a substantial amount of secondary porosity.

Reservoir

Miocene carbonates are known to be spectacular reservoirs throughout SE Asia (Nayoan et al., 1981; Sun and Esteban, 1994; Wilson and Hall, 2010; Gutteridge et al., 2011) and also in the NSB (Graves and Weegar, 1973; Houpt and Kersting, 1976; McArthur and Helm, 1982; Abdullah and Jordam, 1987; Jordan and Abdullah, 1992; Caughey and Wahyudi, 1993; Barliana et al., 1999; Widarmayana, 2007), where good quality carbonate reservoirs are the rule, rather than the exception (Slide 23).

Caughey amd Wahyudi (1993) report two dominant carbonate lithofacies in Peutu outcrop studies:

1. A clean, skeletal limestone facies (wackestones and packstones to grainstones) that is up to 300-500 m thick. This facies has a diverse shallow water faunal assemblage (inner sublittoral to outer neritic or deeper), and consists predominantly of shoal-water banks or mounds of *Lepidocyclina* and other large benthonic foraminifera. Intraskeletal and vuggy, intergranular solution porosity is common.

2. An argillaceous limestone facies, from 30-200 m thick, is characterized by thin, interbedded limestones and calcareous shales (net-to-gross 5-30%). This facies is dominated by planktonic foraminifera with an outer neritic to upper bathyal faunal assemblage. Since these rocks occur in close proximity to shoal water skeletal limestones, they probably accumulated in quiet lows, rather than in true bathyal environments. Porosity is poor (5-10%) and probably ineffective. Microcrystalline calcite thoroughly fills intergranular pore spaces and cements the rock, resulting in only minor intraparticle (incompletely-filled foram chambers) and solution porosity. Permeability is ~1 mD.

True coral reef boundstones are not reported in outcrop.

In the subsurface NSB, reefal boundstone (cf. Jordan and Abdullah, 1992) and mounded packstone carbonate build-ups and wackestone shoals occur on all basement highs (Slides 21 and 22). Major discoveries have been made onshore on the Arun, Lhok Sukon, Alur Siwah, Pergidatit, Ibu, Telaga Said, and Kuala Langsa highs (Slide 21). Nevertheless, Caughey and Wahyudi (1993) caution that significant reservoir risk remains: "Deep structures abound in the North Sumatra Basin, and features of various shapes and sizes have been drilled at different depths and pressure regimes. Nevertheless, Peutu build-ups have remained elusive. Exploratory failures resulted from structures that were too high and bald, others not high enough and choked by terrigenous clastics, and even ones that look just right - but still did not develop reefs."

Seismic evidence of carbonate build-ups includes (Caughey and Wahyudi, 1993):

1. Divergent or thickening seismic packages within the Peutu interval
2. Character changes in the Peutu from high amplitude, parallel reflections (thin platform limestones) to discontinuous, undulating, lower amplitude packages (carbonate build-ups)
3. Prominent thinning and/or onlap in the overlying lower Baong stratigraphy.

On the Bireun High, the most prominent horst block in the offshore NSB (Slide 21), at least 12 mounded build-ups with the requisite seismic characteristics can be mapped on the new 3D seismic data (Slide 27). The build-ups appear to back-step to the south, following a series of fault blocks that transect the Bireun High (Slide 27). Sun and Esteban (1994) provide a generic model for this type of carbonate facies development in SE Asia (Slide 27). The build-ups look very similar to successful carbonate build-ups in the onshore NSB, such as Alur Siwah Field (Slide 28). They meet the seismic recognition criteria of Caughey and Wahyudi (1993), and are considered to be highly prospective.

Prospect Cucur (build-up #4 in Slide 27) occurs in 1000 m water depth, and is representative of the offshore carbonate play on the Bireun High. Zaratex N.V. drilled the Jayarani-1 well in late 2012 to test Prospect Cucur. The well encountered gas-bearing Peutu carbonates, as expected, indicating that the key elements of the petroleum system (reservoir presence, trap, charge, and seal) were all working. However, porosity is very low due to diagenetic alteration and recrystallization, and the reservoir quality of the accumulation was deemed uncommercial by deepwater standards. Zaratex plans follow-up drilling on the Bireun High and elsewhere to test other prospects in the play.

Prospect Cucur is a well-defined, broadly circular build-up in map view that occurs on the NE margin of a faulted basement high (Slides 29 and 30). Two stages of carbonate growth are clearly visible on 3D seismic (Slides 29, 30, and 31): an early stage of aggradational growth that is best-developed at the outer edges of the build-up, and a later stage of less pronounced growth that drapes the high. The two stages are separated by an acoustically "hard" reflectivity peak, which represents the top of massive, recrystallized limestone in the well (the skeletal limestone facies of Caughey and Wahyudi, 1993). The later stage is characterized by thin limestones interbedded with outer neritic to upper bathyal calcareous shales (the argillaceous limestone facies of Caughey and Wahyudi, 1993).

The earlier stage of growth has a concave-up cross-sectional geometry and is characterized by low-frequency, low-amplitude internal reflectivity. Vague internal seismic character can be invoked (Slide 31), but it requires an "eye of faith" to ascribe depositional significance to this character. This stage is interpreted as the primary growth phase, probably occurring during relative sea level transgression. The later stage of growth has a more uniform thickness, and less internal seismic character, which is not that of a classical carbonate build-up. This stage is interpreted as drowning phase deposition that occurred as relative sea floor deepened beyond the healthy photic zone for carbonates (highstand shedding), and the zone of active carbonate growth shifted landward. Bright amplitudes within the mapped trap may be associated with small amounts of gas.

The geological model based on interpretation of well, seismic, and outcrop data is that the syn-rift horsts formed a series of rimmed carbonate platforms where isolated, mounded, reef-like build-ups grew, typically on the windward, or eastern, side (Gutteridge et al., 2011; Slide 32). The build-ups can have spectacular, atoll-like geometries, as seen in an isopach map of the early stage build-up at Prospect Cucur (Slide 33). Porosities in the build-ups typically range from 5-20%, with typical permeabilities ranging from 1-1000 mD (Slide 32). However, primary porosity is typically low (<5%); so secondary (diagenetic) porosity and/or connected fracture networks are required for high-performance reservoirs, even in gas accumulations.

Trap

Traps in the Miocene carbonate build-up play are predominantly stratigraphic, but they may have a structural component. As is typical in many carbonate environments, depositional topographic relief of the build-ups (reefal or otherwise) is onlapped and draped by impermeable deep marine shales. The higher pressure encasing shales form a natural closure, creating a classic stratigraphic trap (Caughey and Wahyudi, 1993).

However, in the NSB, the stratigraphic component is frequently enhanced structurally by differential compaction, fault-related juxtaposition, and/or late-stage compression. For instance, at Prospect Cucur, the top Peutu seismic event has ~125 m of "pure" structural closure, but total stratigraphic closure is in excess of 400 m (Slide 33).

Seal

A period of significant marine flooding drowned the carbonate factory in the NSB and led to deposition of fine-grained, deep marine, highstand shales of the Baong, Keutapang, and Seurula formations above the Peutu limestones (Meckel et al. (2012). The shales are regionally extensive and can be hundreds to thousands of meters thick (Slide 34). Overpressures in the Baong and Lower Keutapang shales ensure that they act as very effective seals.

The degree of fill in traps is variable and appears to be related to top-seal competency, which may be compromised where shales are thin or where faults in the topseal provide paths for leakage. Of particular note, late Miocene to Pliocene basin-directed decollement of the overburden affects top-seal integrity in inboard areas, such as at the Peusangan-C1 well location.

Source Rock, Charge, and Migration

Lacustrine shales of the Parapat are considered to be a probable source rock for oils and condensates in the North Sumatra Basin (Ellis et al., 1991; Caughey and Wahyudi, 1993; Machette-Down et al., 1993). In the NSB, the Parapat Formation consists predominantly of alluvial, fluvial and lacustrine clastics that grade up into shallow marine clastics. In the Peusangan-C1 well, shales within this succession had fair source rock characteristics, capable of generating hydrocarbons. Mixed oil- and gas-prone source rocks (Type-II/III) are recorded in the BJM-1 and BLD-1 wells (Banukarso et al., 2013). Proprietary thermal modeling indicates that hypothetical Parapat sources rocks in the Bireun Deep (Slide 35) may have been in the charge window (10-90% conversion) from ~23-2 Ma.

Gas, by far the more prevalent phase in the NSB, is typically typed to Bampo source rocks (e.g., Buck and McCulloh, 1994), although Parapat, Belumai, or Baong shales may also contribute (Caughey and Wahyudi, 1993). Bampo shales in the Bireun-1 and BJM-1 wells are oil-prone (Type-II) and oil-gas prone (Type-II/III) (Banukarso et al., 2013). Proprietary thermal modeling indicates that hypothetical Bampo sources rocks in the Bireun Deep (Slide 35) may have been in the charge window (>10% conversion) since ~4.5 Ma.

A seismically-derived structural map at the Top Bampo stratigraphic level (Slide 35) shows major basinal lows were prevalent throughout the offshore part of the NSB. These kitchens are gas mature at present day and have easily defined migration pathways to major accumulations and other highs in the NSB (Slide 35), including the prospective Bireun High, where gas chimneys are seen in association with prospects, such as Cucur (Slide 36).

Subsurface discoveries and hydrocarbon seeps tend to be clustered in close proximity to the likely kitchens (Slide 37), providing compelling evidence that source rocks are present and effective and have migrated hydrocarbons more or less ubiquitously throughout the area. Overall, the kitchens are more likely to be more gas-prone in the east, where they are more deeply buried, than in the west, where they are shallower and more likely to be liquid-prone (Slide 35).

Summary: Critical Moment

All elements of the petroleum system were working by ~15 Ma (Slide 38).

- Bampo and Parapat shales, which are the primary source rocks, were deposited from 35-21 Ma, during rifting and early post-rift quiescence.
- Peutu carbonates, the primary reservoirs, were deposited from 21-15 Ma, during post-rift quiescence.
- Belumai, Baong, and Keutapang shales, the primary sealing units, were deposited from 20-8 Ma, during post-rift quiescence and early compression.
- Stratigraphic traps, requiring reservoir and seal, were in place by 15 Ma. Compressional tectonics (13.5-0 Ma) and differential compaction associated with burial (10-0 Ma) may have enhanced the structural component of the traps.
- Source rocks were mature and capable of generating hydrocarbons from 23 Ma to present. In the Bireun Deep kitchen, the Parapat is modeled to have reached 50% conversion at ~18.5 Ma, while the Bampo is modeled to have reached 50% conversion at ~1.5 Ma.

Risk of Carbon Dioxide

Throughout SE Asia, there is a recognized risk that high amounts of carbon dioxide (CO_2) may occur in carbonate reservoirs. If CO_2 exceeds about 20-25% of the gas by volume, disposal becomes problematic and increased costs may render even large hydrocarbon accumulations uneconomic. In discoveries such as Natuna D-Alpha (Natuna Sea) and Kuala Langsa (North Sumatra), many trillions of cubic feet of discovered hydrocarbon gas are unable to be produced because of the enormous amounts of associated CO_2.

The generally accepted source of the CO_2 in the NSB is thermal alteration (decarbonation) of deeply buried carbonates (Caughey and Wahyudi, 1993; Reaves and Sulaeman, 1994; Ryacadu and Sjahbuddin, 1994; Cooper et al., 1997; Gutteridge et al., 2011; Brown, 2012). To date, however, there is no published model that conclusively explains the high degree of variability observed. In the absence of a predictable model, the risk of CO_2 contamination cannot be discounted.

In the NSB, Peutu reservoirs are known to be slightly sour and contain widely varying amounts of CO_2. The mean CO_2 percentage is ~21% (all values) and P50 CO_2 is ~17% (Slide 39). Statistically,

- ~20% of reported values (n=5/29) have $CO_2 < 5\%$;
- 45% of reported values (n=12/29) have $CO_2 < 15\%$;
- 60% of reported values (n=17/29) have $CO_2 < 20\%$;
- 75% of reported values (n=22/29) have $CO_2 < 30\%$;
- ~95% of reported values (n=27/29) have $CO_2 < 50\%$.

In most of the offshore NSB, the risk of $CO_2 > 20\%$ is relatively low, as seen on a map of regional distribution of CO_2 (Slide 39). This empirical observation is consistent with more rigorous methodology presented in unpublished industry reports (Brown, 2012). The highest CO_2 concentrations (20-30%) occur in discoveries centered around the Lhok Sukon (LS) deep. In contrast, the mean CO_2 percentage is ~17.5% within a 100-km radius of the Bireun (B) deep, and only slightly higher within a 250-km radius (Slide 39).

Analogues

The known discoveries and undrilled carbonate leads mapped on 3D in the North Sumatra Basin are similar in size to the prolific build-ups of Central Luconia (offshore Sarawak) and the Golden Lane, Mexico (Viniegra and Castillo-Tejero, 1970) and have similarities with the modern carbonate islands of the Pulau Seribu, offshore west Java (Jordan, 1998a, 1998b) (Slide 40). Within the NSB, the mapped leads on the Bireun High bear a striking similarity to the Arun and NSO-A gas fields (Slide 41) and the Alur Siwah Field (Barliana et al., 1999).

The closest analogue to North Sumatra in terms of discovered commercial volumes in carbonate reservoirs is Central Luconia (Slide 42). Although the other significant carbonate provinces of SE Asia have similar "stepped" or punctuated discovery patterns, they are not nearly as prolific as the NSB and Central Luconia (Slide 42). To be sure, the NSB creaming curve is dominated by Arun; if Arun is removed, then the NSB would look more similar to South Sumatra, West Java, East Java, and NW Palawan. However, even if Arun were excluded, North Sumatra differs from all the other basins insofar as there have been far fewer total carbonate discoveries, and no discoveries since 1999 (Slide 42). In fact, the NSB is the second-richest carbonate basin in SE Asia (after Central Luconia) on a per field volumetric basis.

Conclusions

The NSB is a world class petroleum province. It is the birthplace of the SE Asian petroleum industry and was instrumental in establishing the global LNG market. Discovered resources through 2012 are in excess of 6 BBOE.

Significant fields have been discovered on every syn-rift horst block in the NSB except the Bireun High, where the under-explored offshore continuation of the highly successful Miocene carbonate build-up play can be mapped on 3D seismic data. The carbonate play, which is mature in the onshore NSB, has the following key elements (Slide 43):

- *Reservoir*: Reef build-ups > 150m thick are proven to exist on every high. The reservoirs have been penetrated by numerous wells in the onshore NSB. Offshore drilling to date has been less extensive than in the onshore NSB, but carbonate reservoirs have been tested and are proven.
- *Trap*: Large carbonate build-ups, analogous to discoveries elsewhere in the NSB and in SE Asia, can be mapped unambiguously on modern 3D seismic in the Lhokseumawe PSC. The traps are stratigraphic in nature, but many have a degree of structural closure.
- *Seal*: Thick regional shales are ubiquitous throughout the NSB. These intervals act as outstanding seals, capable of holding substantial columns.
- *Source*: Prolific source rocks are known to generate hydrocarbons from multiple kitchens. Gas is ubiquitous in the system. Oil is present in smaller amounts, but thermal models indicate that more shallowly buried kitchens in the western part of the NSB may be more oil-prone.

At least 12 potential carbonate build-ups can be mapped on 3D seismic data. These data represent an enormous step forward in exploration of the offshore NSB, an area ripe for renewed and re-invigorated exploration using a "discovery thinking" mindset (Slide 44).

1. Understand the regional context – Speculate *prudently*, based on mature analogues The Miocene carbonate play is probably not creamed yet. Discovery histories of analogous carbonate basins are stepped, and there has not been a discovery in the NSB carbonate trend since 2001.

2. Understand the basin – See the potential. Acknowledge the problems. The NSB has a relatively simple petroleum systems story: Build-ups with thick topseal work; off-reef prospects with thin/breached topseal don't.

   - Poor seismic and immature facies models led to sub-optimal prospect definition and well location.
   - Trap, seal, charge, and magration are relatively low risk.
   - CO_2 is a manageable, if not fully predictable, risk.
   - What are the implications? There are lots of space to explore, and the possibility of oil in the western part of the basin is exciting.

3. Utilize integrated subsurface analysis to characterize the portfolio.

4. Define prospect(s) to test the key risk(s).

As an example, Prospect Cucur was drilled in 2012 by the Jayarani-1 well to test two key risks, charge and reservoir presence. The well succeeded in de-risking both aspects of the offshore play. Reservoir quality remains a key risk. Subsequent wells targeting this trend will address this latter risk. The reward is substantial - estimated undiscovered volumes in the trend are in excess of several TCFG.

In closing, we return to the words of Michel Halbouty (1970), who framed the challenge thus (Slide 45): "Giant fields keep nations in business, and it is toward such fields that we must direct our major efforts, because the day of economic production of petroleum from tar sand is only just arriving; the day of economic production of coal and oil shale is not here, and a suitable technological 'breakthrough' for economic production of such energy sources has not been developed. Petroleum still is 'king"'. Technologies have advanced in the intervening 43 years, such that unconventional resources are now attractive opportunities in many basins. However, for the foreseeable future in SE Asia, petroleum is still king, and areas such as the North Sumatran Basin merit the attention of innovative 21st century explorationists.

Acknowledgements (Slide 46)

The author would like to thank Charles Sternbach and AAPG for the generous invitation to make this presentation at the first international AAPG Discovery Thinking Forum. The management of Zaratex N.V. and BPMIGAS kindly granted permission to prepare and make the presentation.

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American Association of Petroleum Geologists

International Conference & Exhibition

16-19 September 2012

Exploring a 19th Century Basin in the 21st Century: Seeing the North Sumatra Basin with New Eyes

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With contributions from

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ZARATEX N.V.

18 September 2012

Discovery Thinking - Prelude

"The very thought of a giant petroleum field, to most explorationists, is an exciting dream; relatively few giants have been found, so few of us ever have been associated with one, yet *many more are needed to keep the world's petroleum industry alive and healthy*."

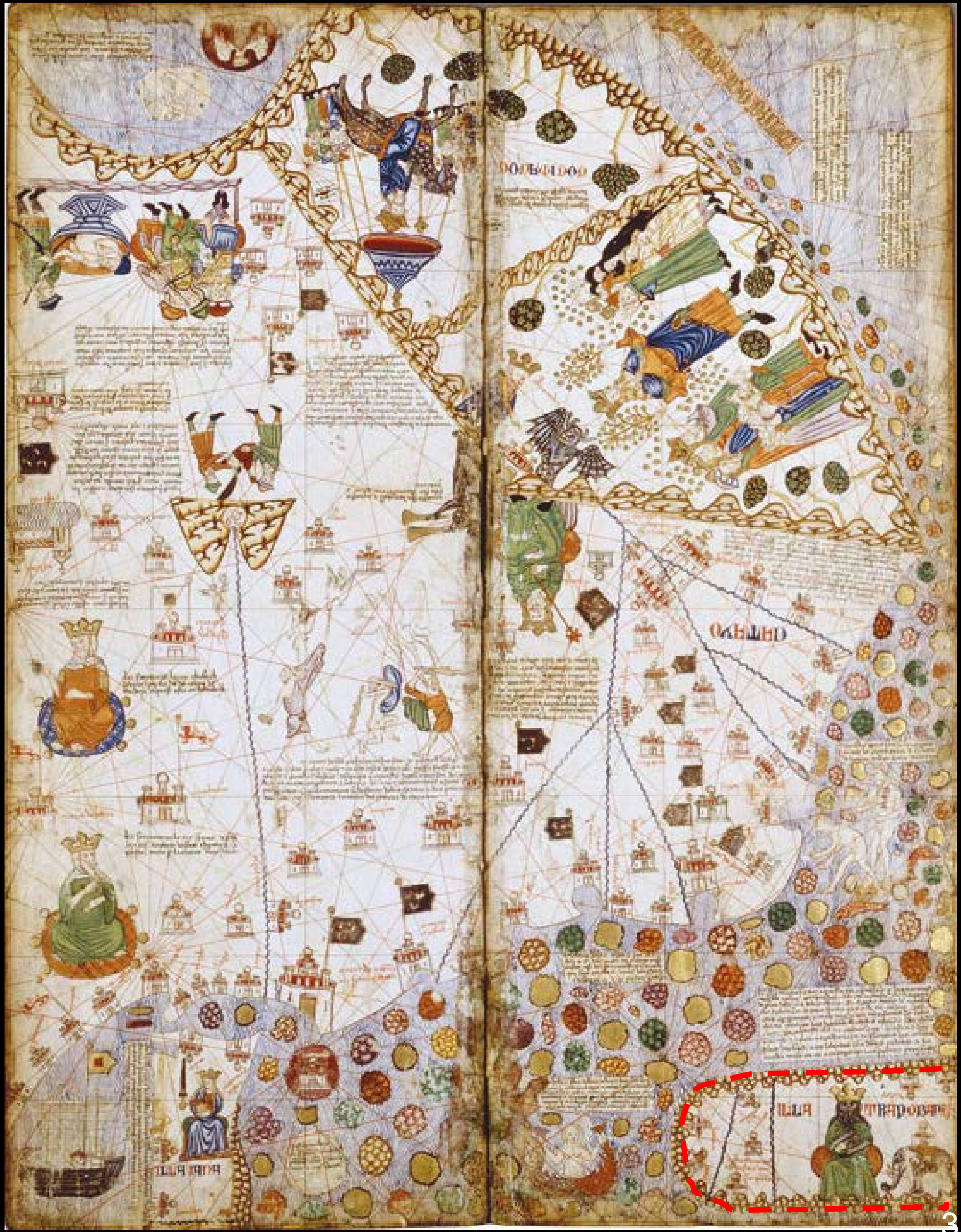
Michel Halbouty (1970)

The Early Days of “Discovery Thinking”

First Oil

Ptolemy (ca.150 AD) – 15th Century Reproduction

Marco Polo (1292), from the Catalan Atlas (1375)



Still Early Days...

The Hunt for Elephants Is On!

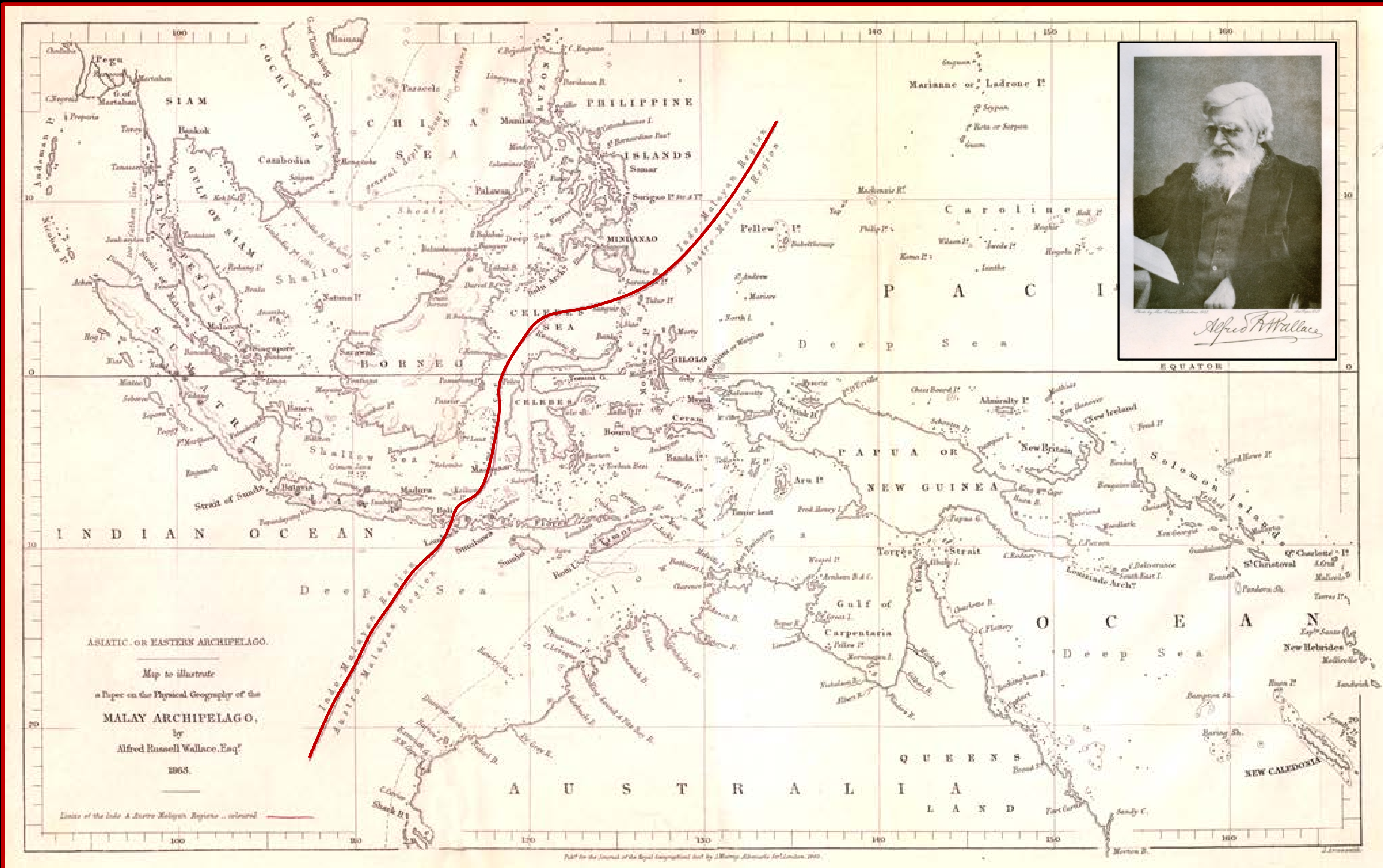
Petri (1588)

A Different Type of Discovery Thinking:
Dutch East India Company (1602-1796)

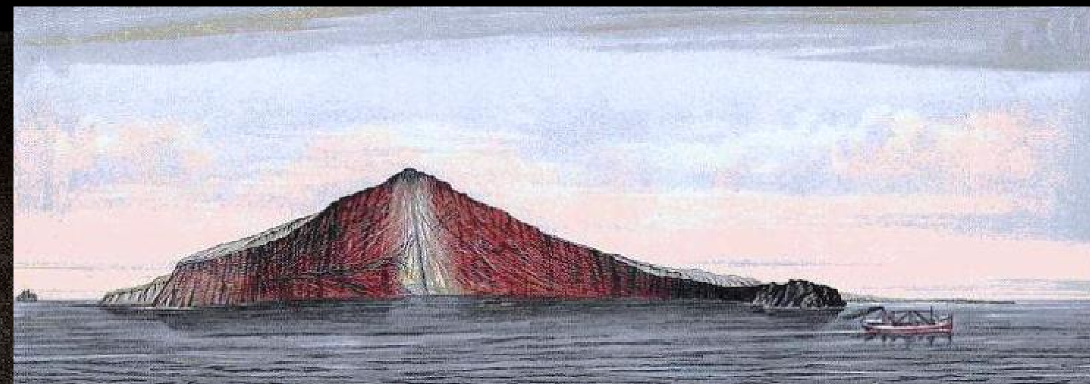
What Got Certain People Excited About Indonesian Geology Before 1885

"On the Physical Geography of the Malay Archipelago"

Alfred Russel Wallace, Royal Geographical Society (1863)



What Got a Lot of People *Really* Excited About Indonesian Geology Before 1885: *Krakatau (1883)*



Verbeek 1885

Tocht naar Krakatau (1883).

Staande van l. naar r.: Stuurman v. d. Hopperbarge; Dr. M. Treub, Dir. Plantentuin; J. W. de Bruijn Kops, Ir. B.O.W. Busenbender, Fotograaf; J. F. de Corte; Dr. R. D. M. Verbeek; R. Fennema; Dr. Bauer, Dir Krankz.gesticht te Buitenzorg; J. A. Havelaar, Ir. B.O.W.; een globetrotter, naam onbekend.

Petromindo.Com

Indonesia Oil, Mining & Energy News

30 August 2012

- "Indonesia, particularly the Aceh [North Sumatra] region, currently requires gas supply, as gas fields nearby, such as Exxon's Arun, have continued to decline."

(Widhyawan Prawiraatmadja, Deputy for Planning at BPMIGAS)

- "The government [of Indonesia] will push for massive development of gas infrastructure facilities in the country, in a bid to increase natural gas production, to compensate for the declining trend in crude oil output."

(Jero Wacik, Minister of Energy and Mineral Resources)

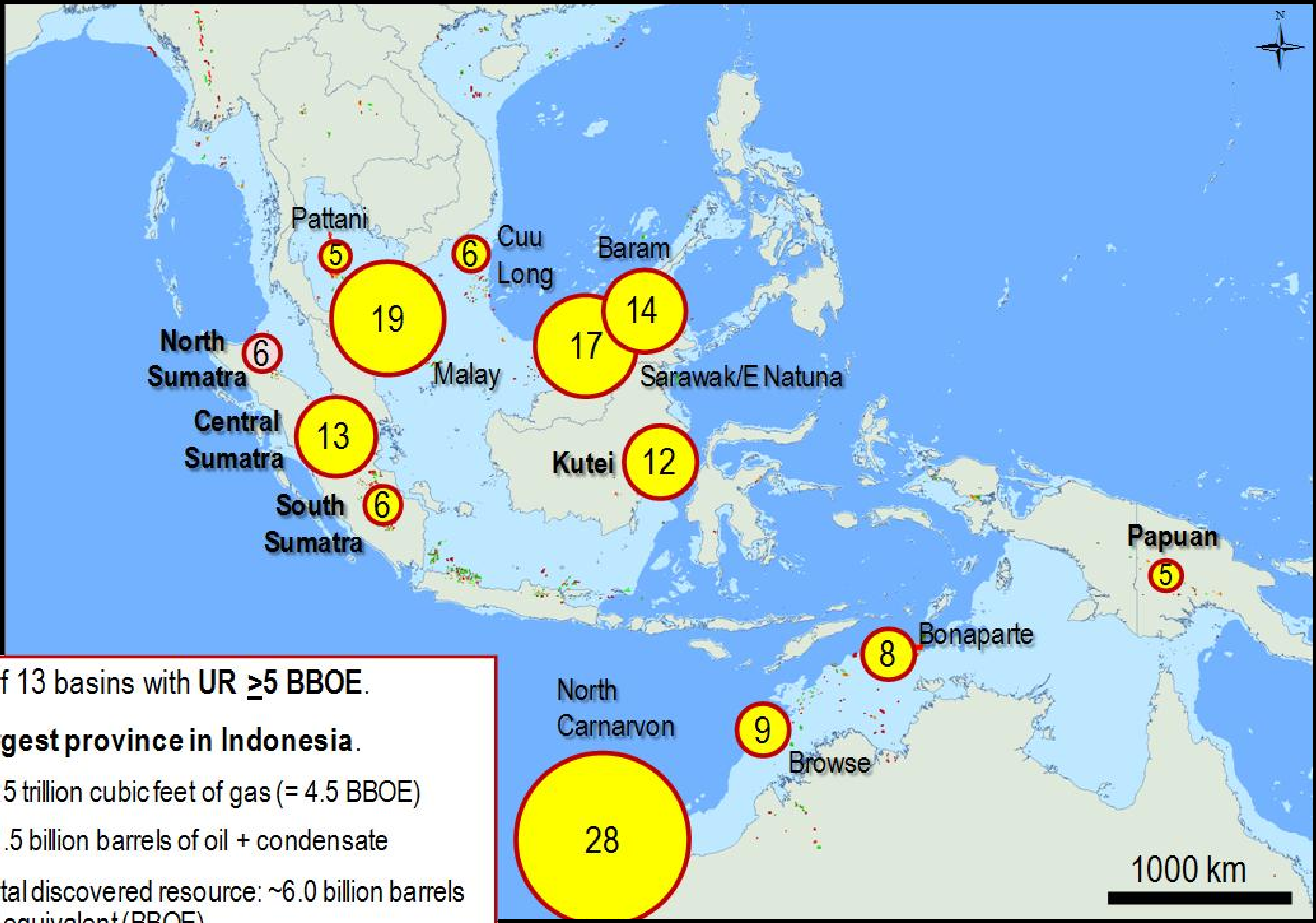
North Sumatra Basin

Indonesia, SE Asia

One of 173 basins globally with giant fields

Approximately the same size as (for example): Northern North Sea; Ghadames; Sirte; Niger Delta & Deepwater; offshore Angola; South Caspian; Amu Dar'ya; Sichuan; Luconia & Sarawak; North Carnarvon; North Slope, Alaska; California; Permian; LA Gulf Coast & Shelf & Deepwater; Maracaibo; East Venezuela; Campos; and Santos basins

SE Asia & NW Australia



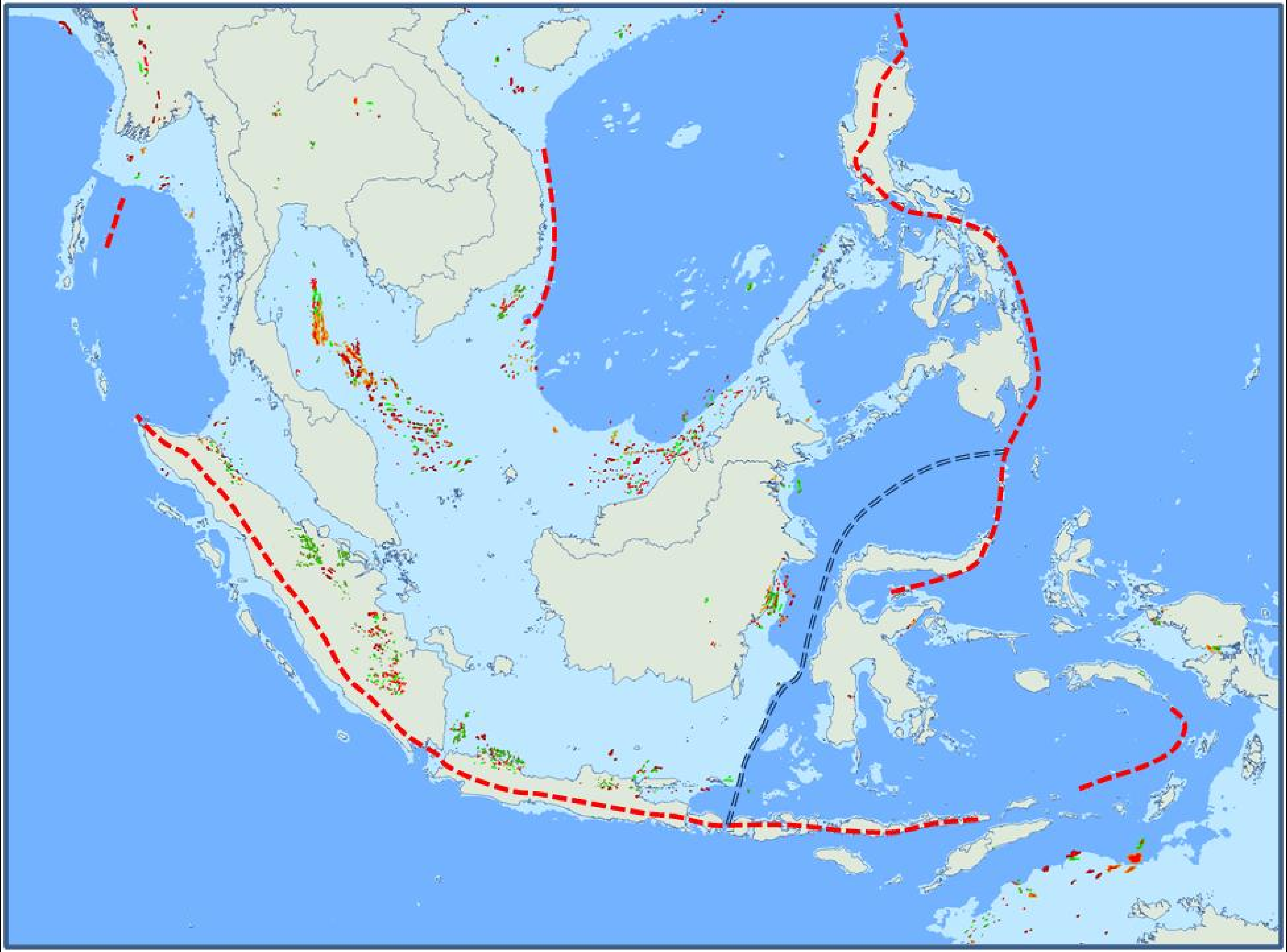
One of 13 basins with **UR ≥5 BBOE**.

3rd largest province in Indonesia.

- >25 trillion cubic feet of gas (= 4.5 BBOE)
- ~1.5 billion barrels of oil + condensate
- Total discovered resource: ~6.0 billion barrels oil equivalent (BBOE)

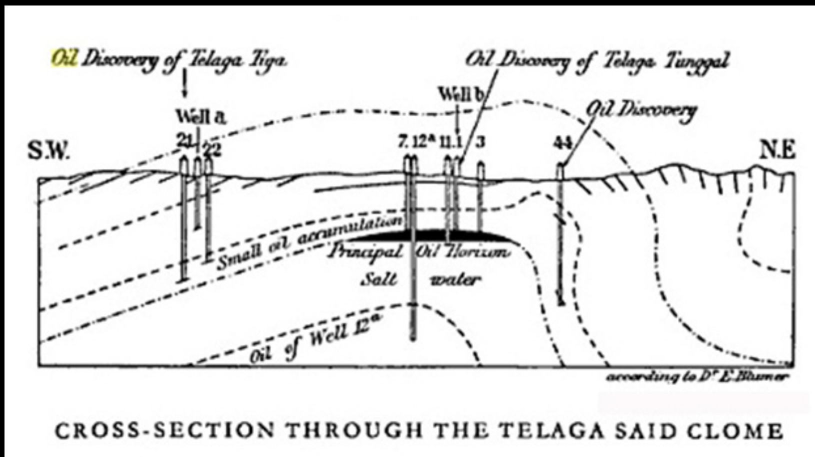
Plate Tectonics – Bringing It All Together

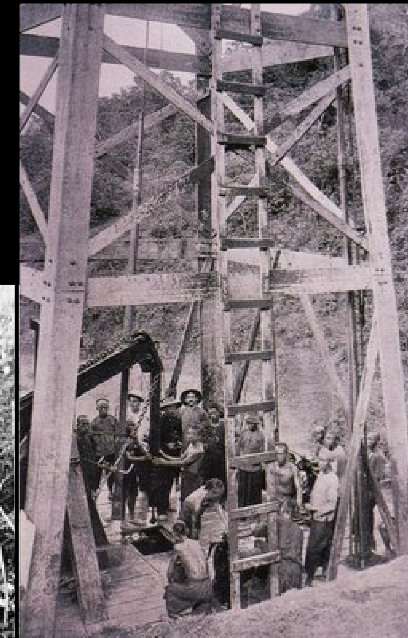
The Wallace Line, the "Ring of Fire" and the Sunda Platform

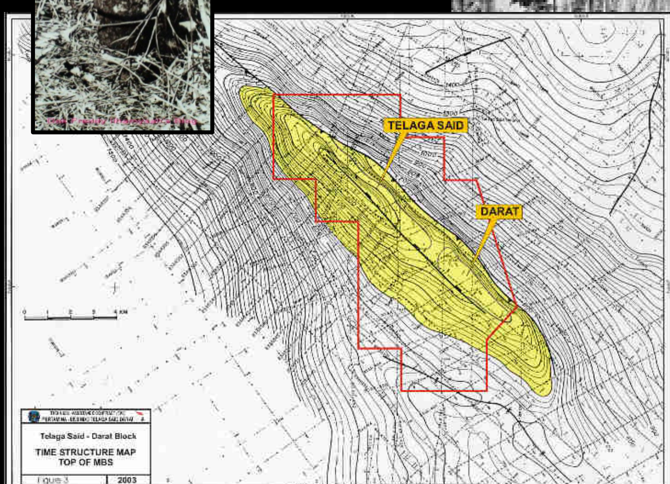


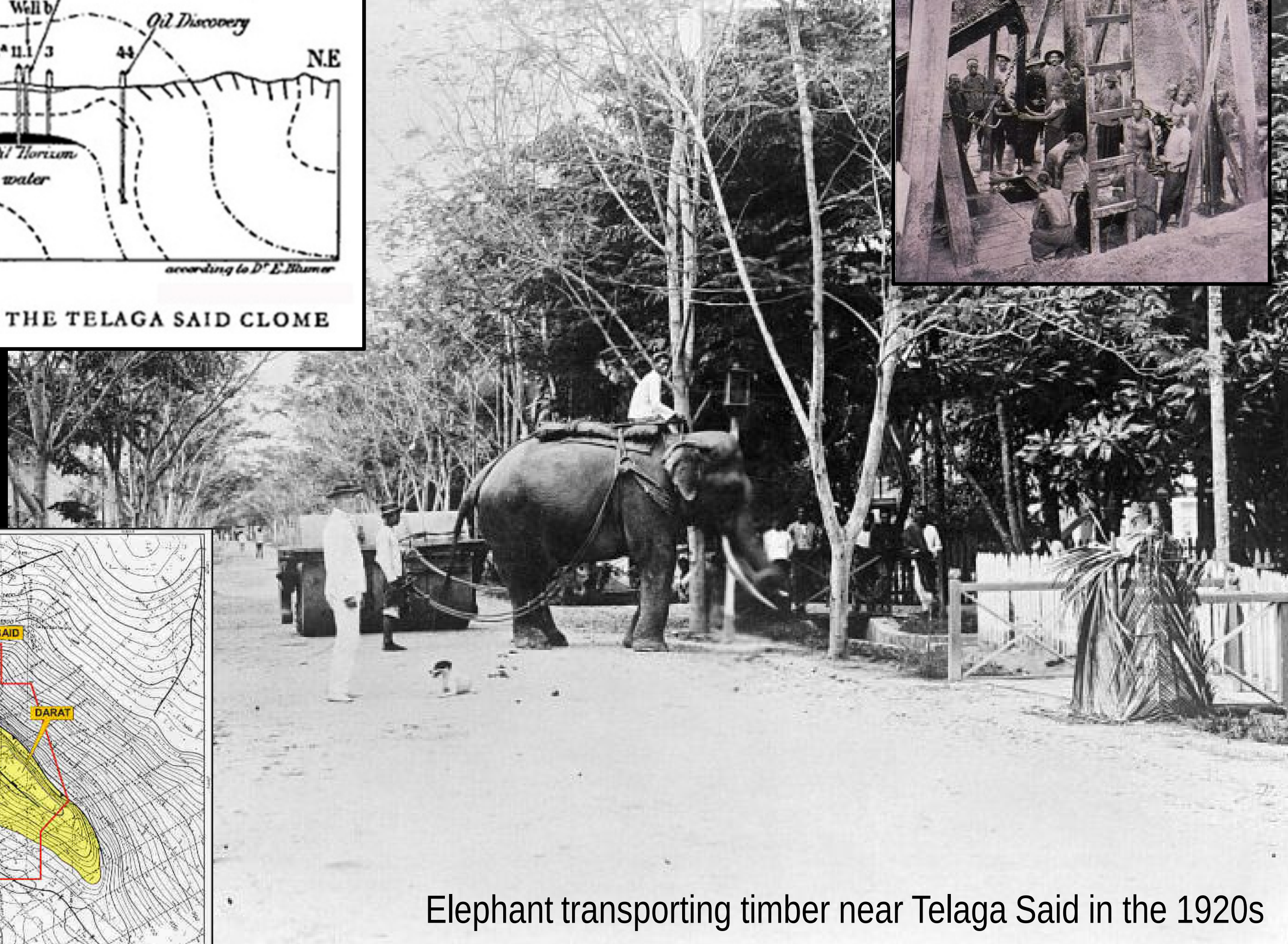
What *Should* Have Gotten People Excited About Indonesian Geology, 600 Years After Marco Polo

Telaga Said (1885)



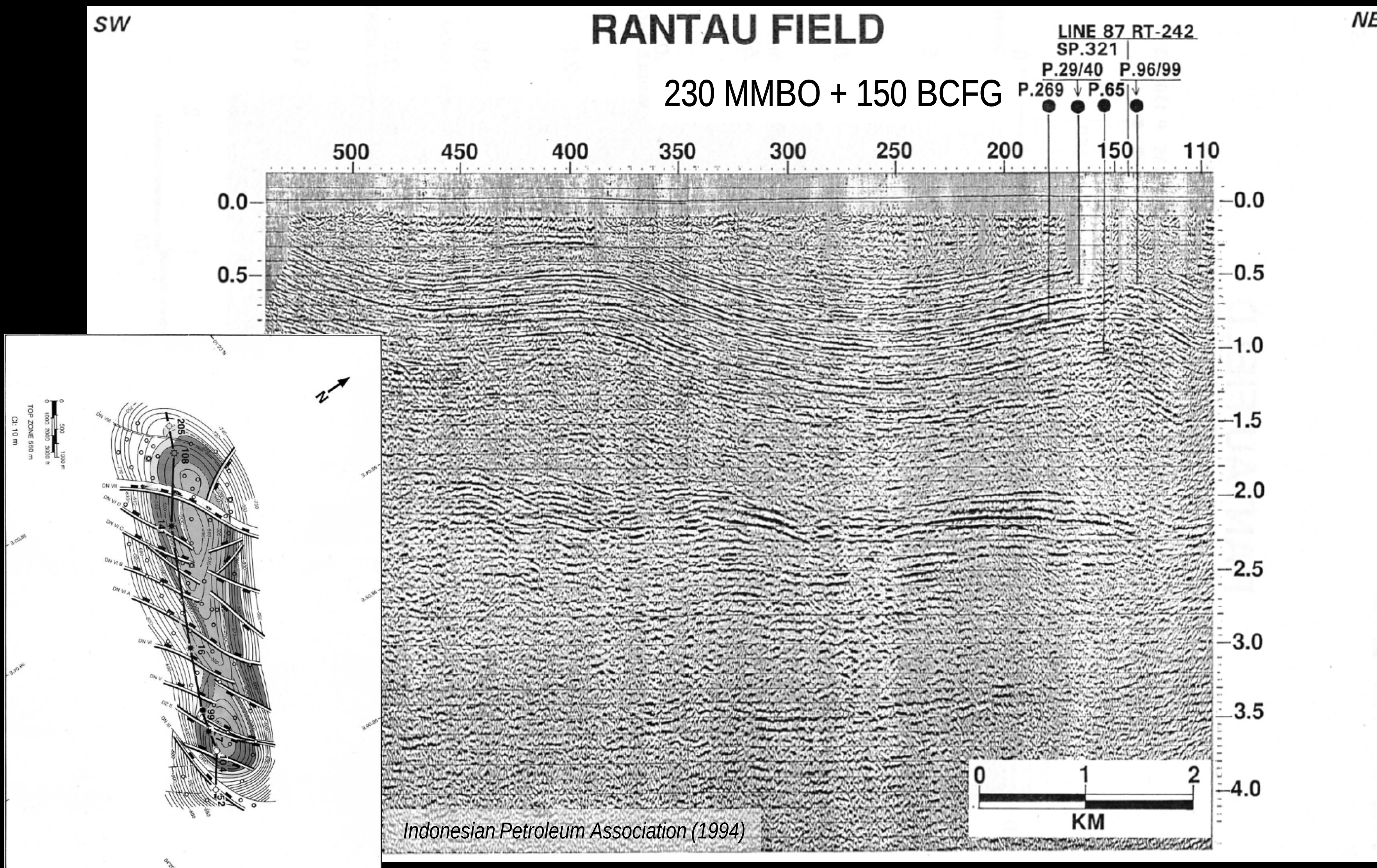






Elephant transporting timber near Telaga Said in the 1920s

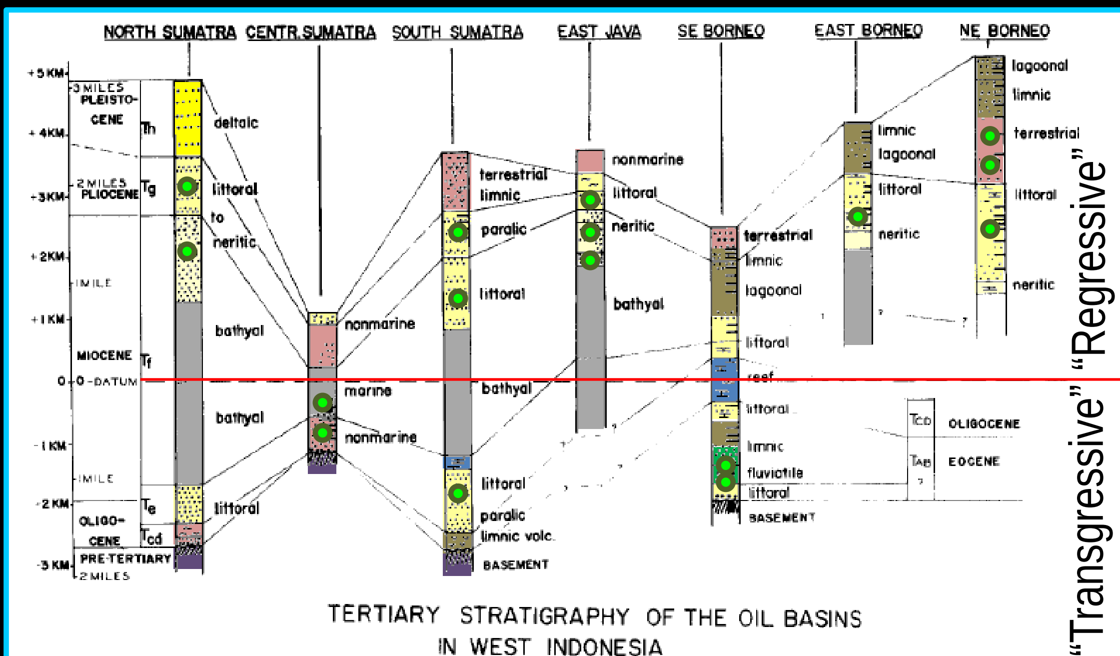
Between the Wars:
A North Sumatran Elephant (Finally!)
Rantau (1929)



Indonesian Petroleum Association (1994)

A Man on the Moon and a Milestone in “Discovery Thinking”

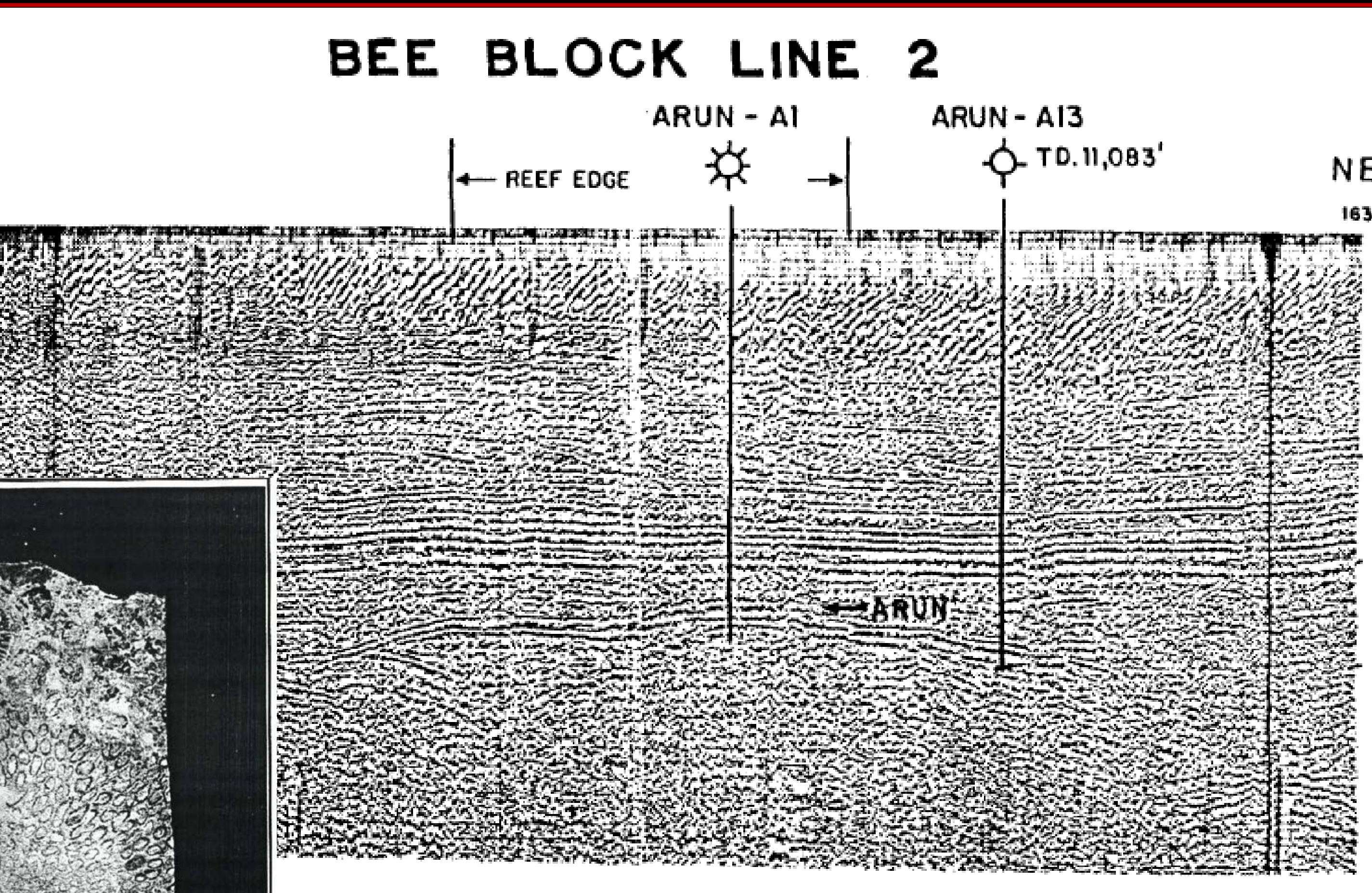
“Outline of the Geologic Occurrence of Oil in Tertiary Basins of West Indonesia” (R.P. Koesoemadinata, AAPG Bulletin, 1969)

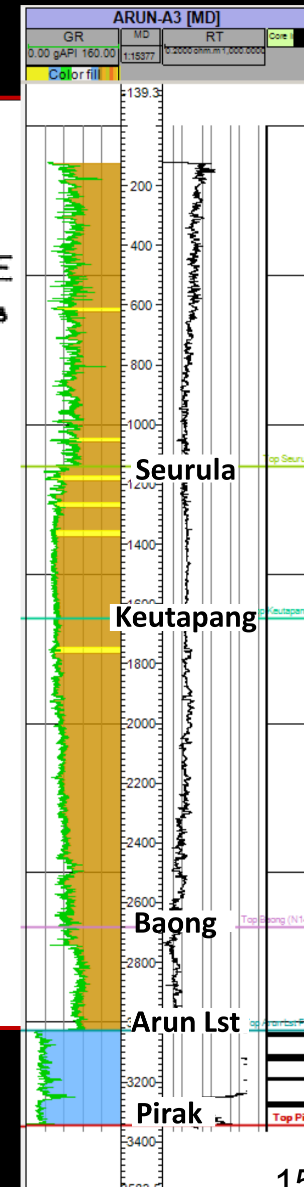


Cumulative Production to June 1968		
Basin	“Transgressive Sequence” (MMBO)	“Regressive Sequence” (MMBO)
North Sumatra	None	194
Central Sumatra	1237	None
South Sumatra	926	302
Northwest Java	0.294	None
Northeast Java	None	168
Kalimantan	69	529
W INDONESIA	2232	1194

“I believe that the greatest oil potential in western Indonesia Tertiary basins is in reservoir beds of the transgressive facies, especially in basinal areas where extensive exploration has not been conducted (e.g., NE Sumatra, ...)”

Spot One of the Top 200 Fields in the World
Arun (1971)*





*1971 was a *great* year for gas: 14 discoveries with ~1250 TCFG reserves. [~200 TCFG without North Field.]
Arun (14-17 TCFG) was only the <u>5th largest gas discovery that year</u>!

Arun: A Real Watershed

1. Proved Koesoemadinata's 1969 hypothesis (in spades)!

2. Globally…
   - 112th largest petroleum discovery (35th largest gas field) through 1971
   - 184th largest discovery (73rd largest gas field) ever

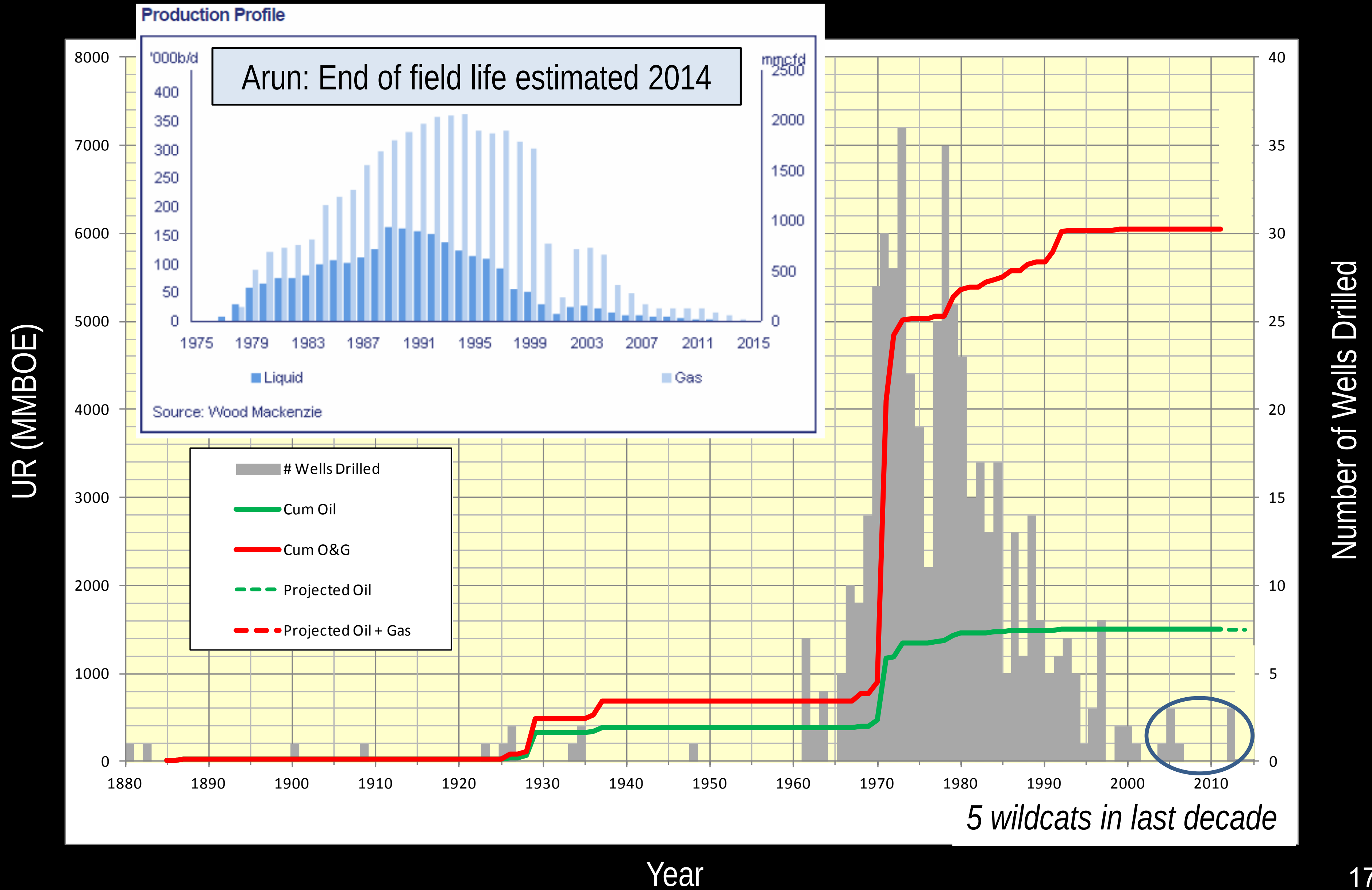
3. Excl. Middle East & Former Soviet Union…
   - 31st largest discovery (10th largest gas field) through 1971
   - 60th largest discovery (21st largest gas field) ever

4. Asia/Oceania…
   - 7th largest petroleum discovery (3rd largest gas field) through 1971
   - 13th largest discovery (9th largest gas field) ever

5. SE Asia…
   - 2nd largest petroleum discovery (2nd largest gas field) through 1971
   - 4th largest discovery (4th largest gas field) ever

6. "The most lucrative LNG operation in the 20th century" (von der Mehden & Lewis, 2004)

Exploration & Production History

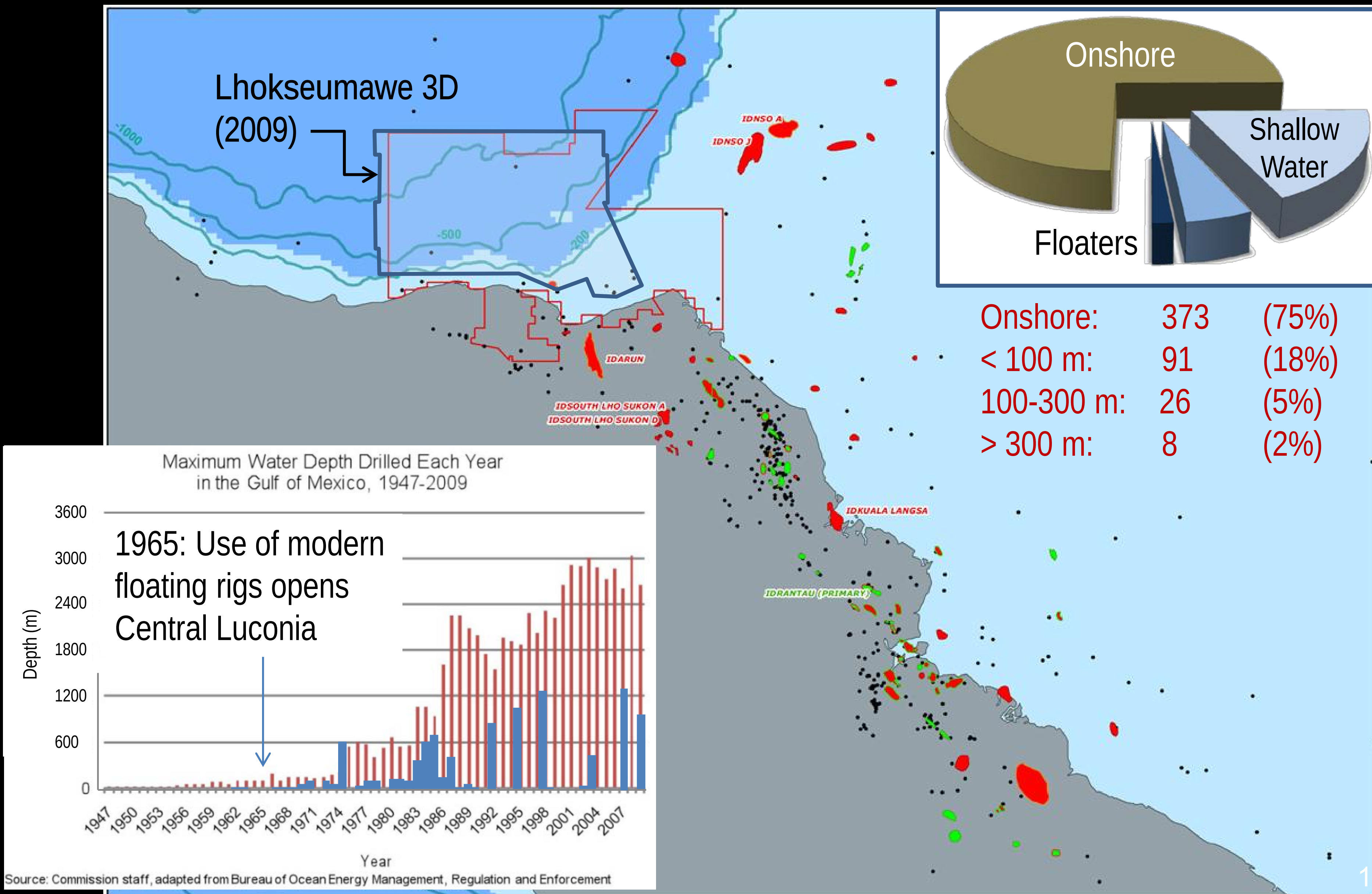


Why?

Despite substantial early success, a combination of factors has resulted in relatively few offshore exploration wells to extend the proven trend into deep water.

- Volatile geopolitical and geological conditions in Aceh over much of the past 3 decades
- Perception that the basin is gas-prone
- Low historical gas prices (ironically, driven by Arun)
- Early offshore exploration failure (1970s, 1980s)
  - "basin is creamed" mentality
- Lack of modern 3D seismic data to define prospects
- Slow adoption of deepwater drilling technologies

"They are ill discoverers that think there is no land, when they can see nothing but sea."



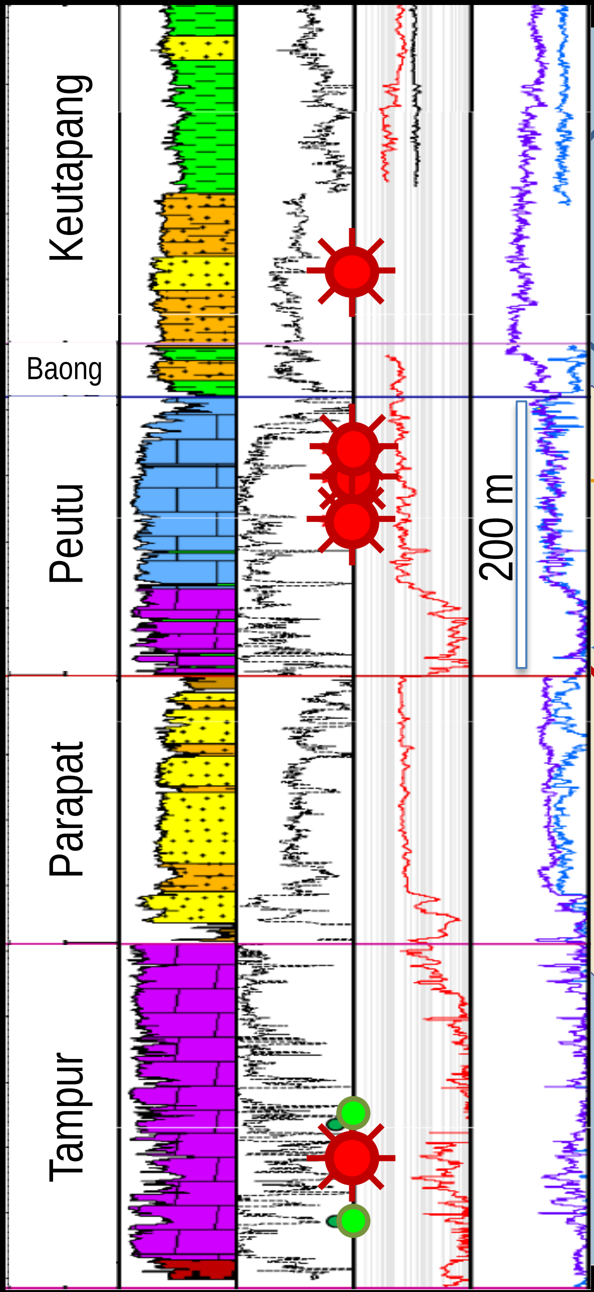
Onshore:	373	(75%)
< 100 m:	91	(18%)
100-300 m:	26	(5%)
> 300 m:	8	(2%)

Intermezzo: Discovery Thinking

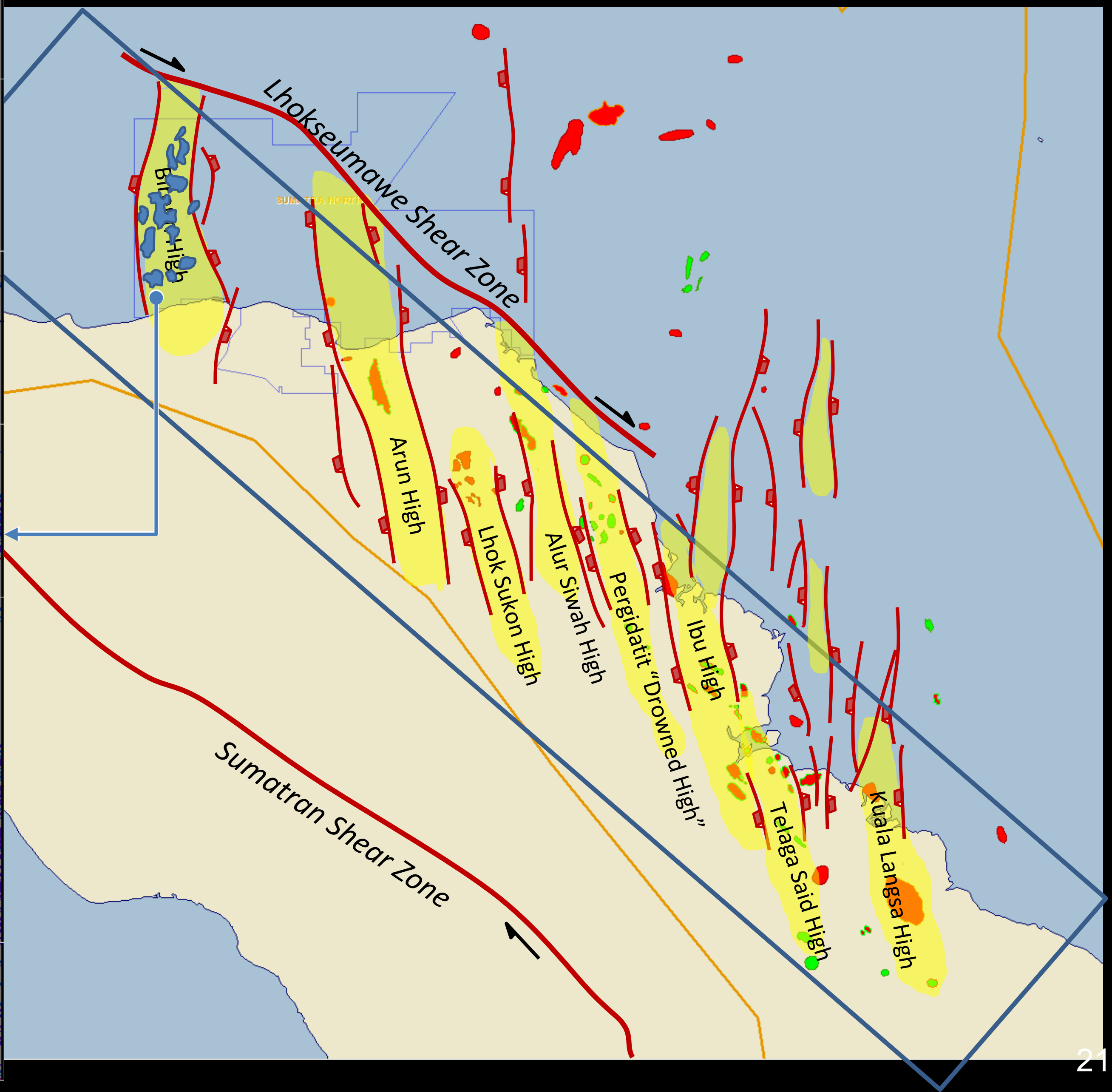
How many global exploration provinces have the following characteristics?

- Offshore continuation of prolific, proven, hyper-mature onshore trend
- All play elements demonstrated to be ‘world class’ (reserves > 5.0 BBOE) in immediately adjacent areas
- 10 exploration wells total drilled in WD > 200 m (2% of all exploration wells)
- Only 8 offshore wells in last decade (16 in last 20 years)
- No large-scale 3D coverage until 2009
- Key prospects 15-50 km from existing infrastructure
- Robust domestic and regional gas markets with strong sales prices & high demand
- Oil upside
- Reserves potential on the order of several billion BOEs

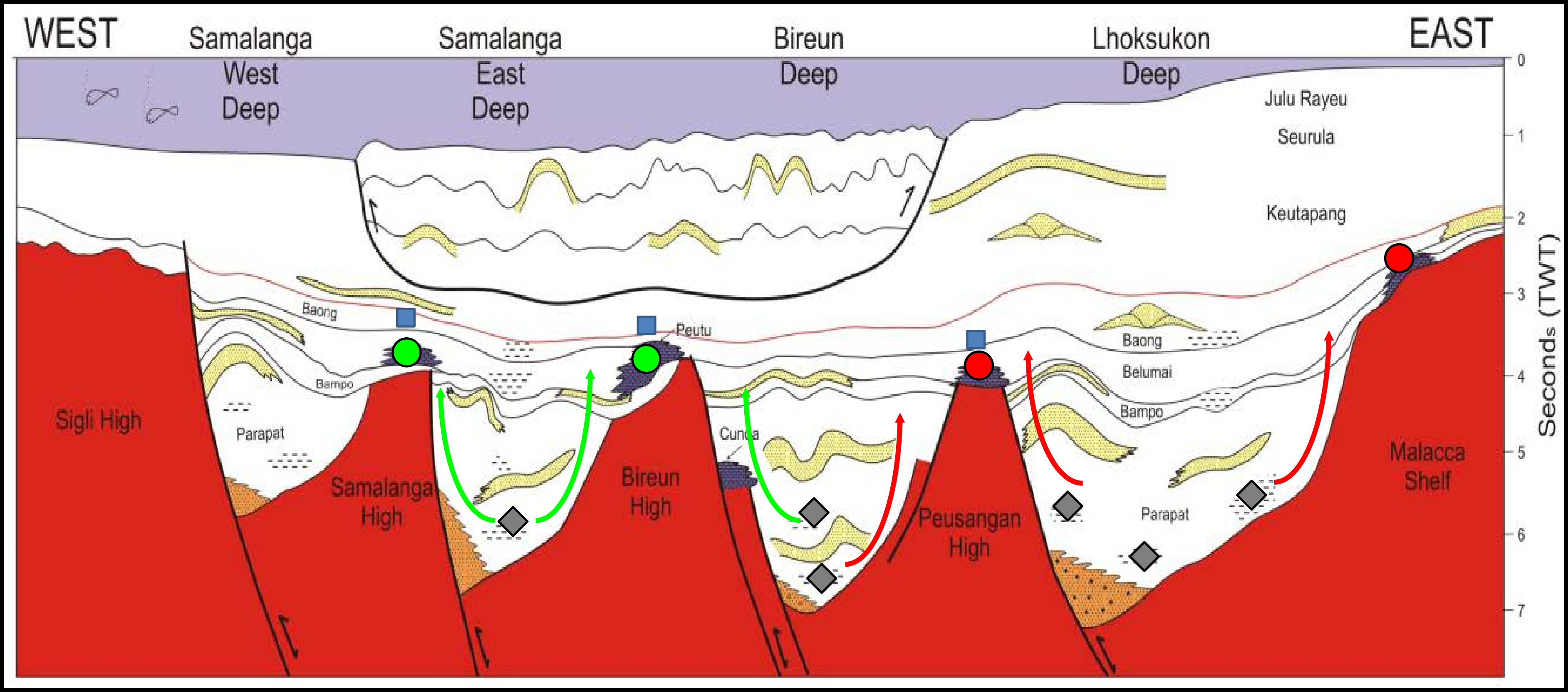
PEU C-1



Basement Structures



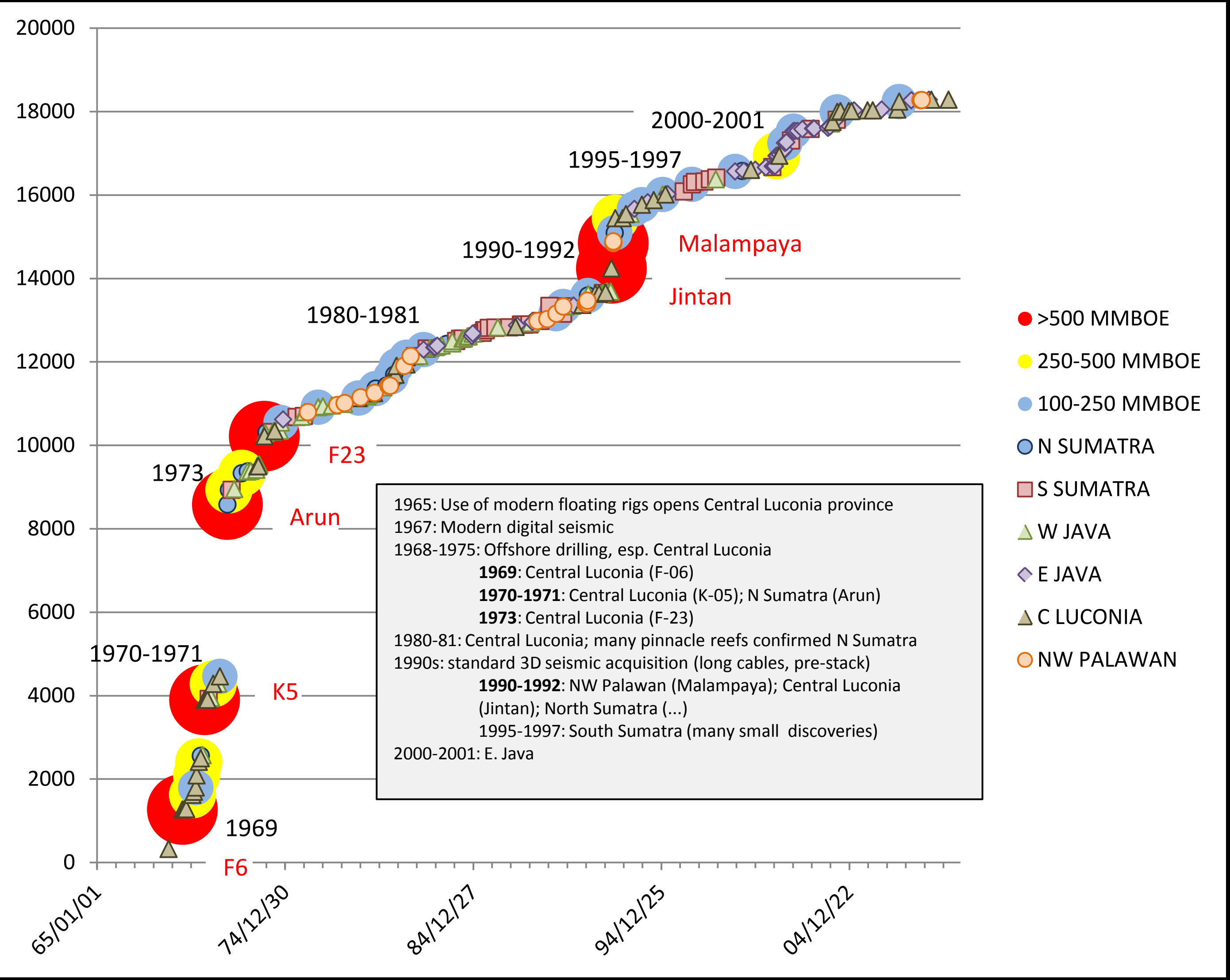
Plays in the Offshore North Sumatra Basin



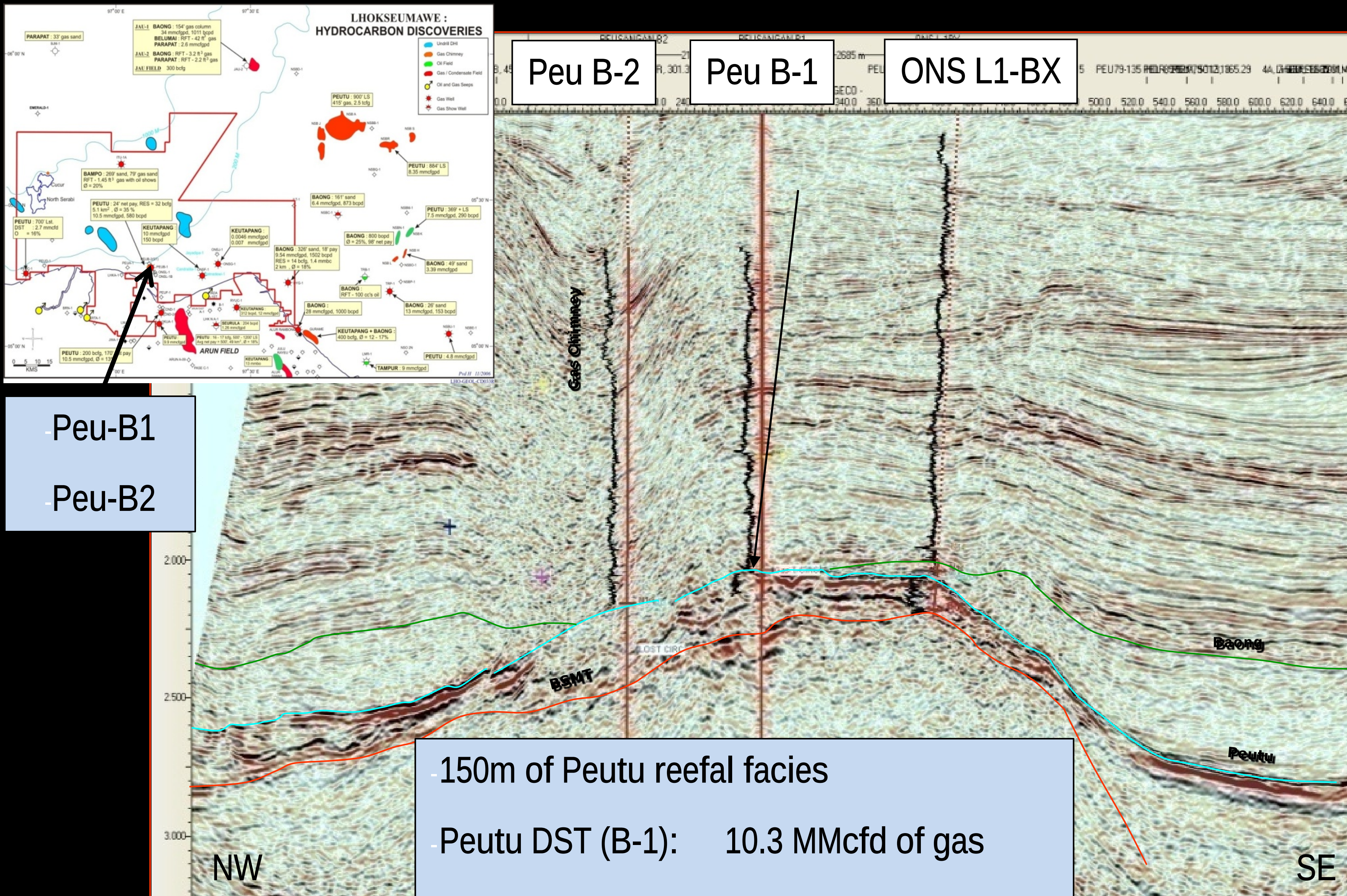
Carbonate Play

- Good quality carbonate reservoirs are the rule, rather than the exception, in the NSB
  - Reefs and build-ups occur on all basement highs
  - Secondary porosity enhances the likelihood of effective reservoir
- Most prolific play in North Sumatran Basin
  - 21 fields > 5 MMBOE UR
  - UR ~4600 MMBOE
  - P50 field size distribution (@ 5 MMBOE cutoff) ~20 MMBOE
  - Significant upside if minimum field size > P50 (large fields are very large)
- Clearly mappable on 3D seismic datasets
  - Multiple episodes of carbonate reef-building on the Bireun High, spanning the latest Eocene to late Miocene (Tampur, Cunda, Peutu)

Creaming Curve
SE Asia Carbonate Play



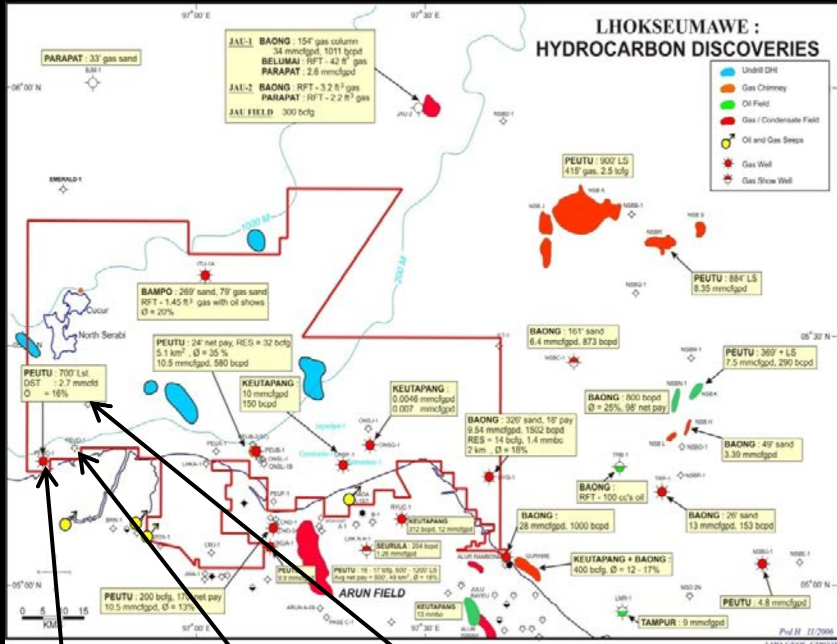
Offset Wells: Peusangan B Reef



- Peu-B1
- Peu-B2

- 150m of Peutu reefal facies
- Peutu DST (B-1): 10.3 MMcfd of gas
- 877 bpd of condensate

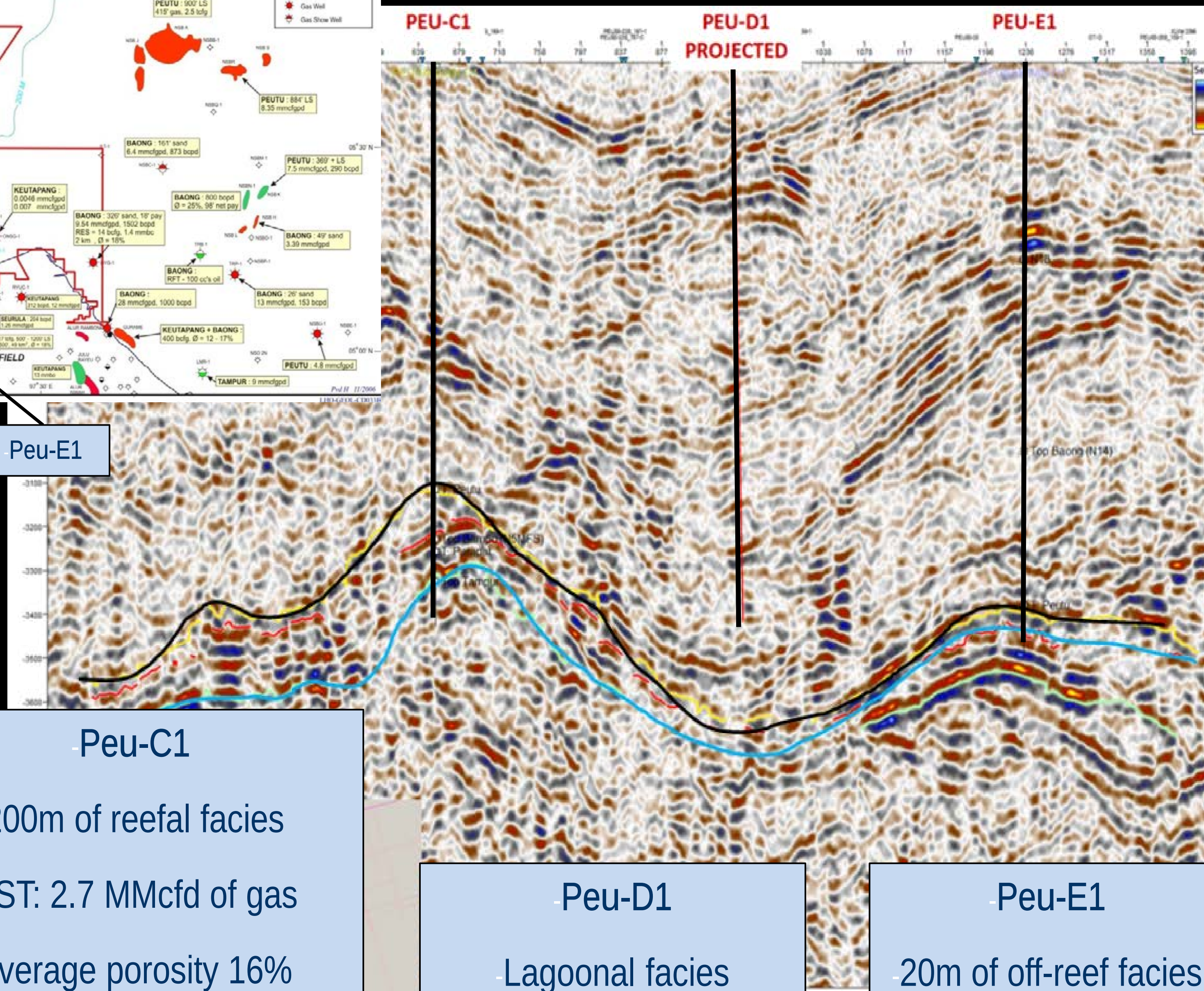
Offset Wells on Bireun Horst



Peu-C1

Peu-D1

Peu-E1



Peu-C1

200m of reefal facies

DST: 2.7 MMcfd of gas

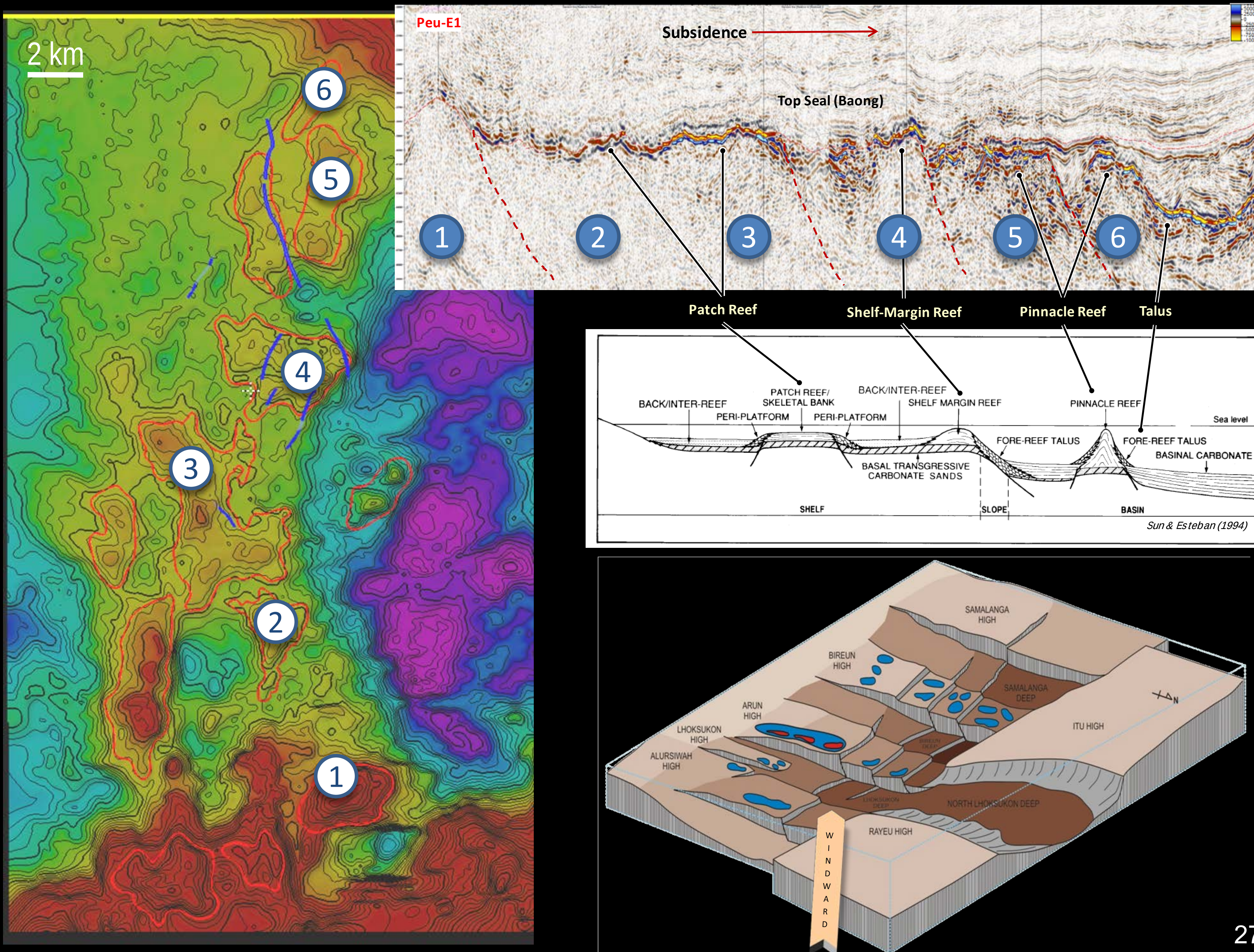
Average porosity 16%

Peu-D1

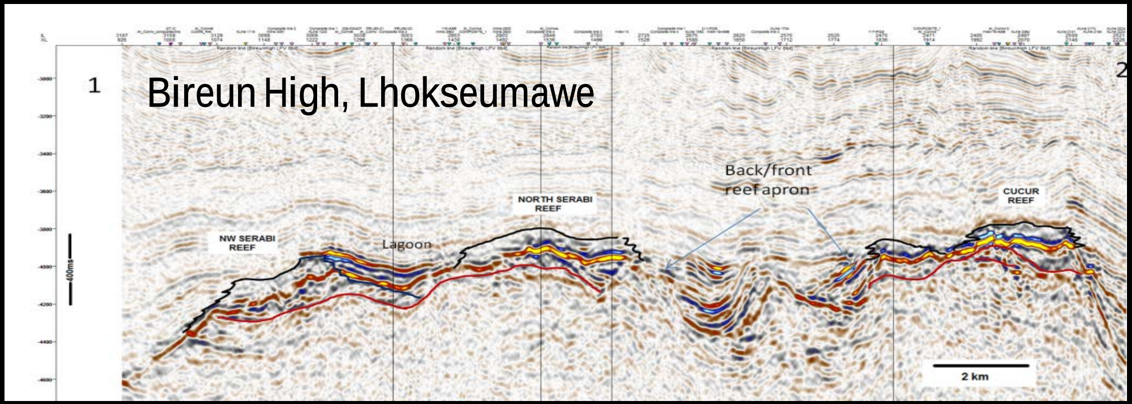
Lagoonal facies

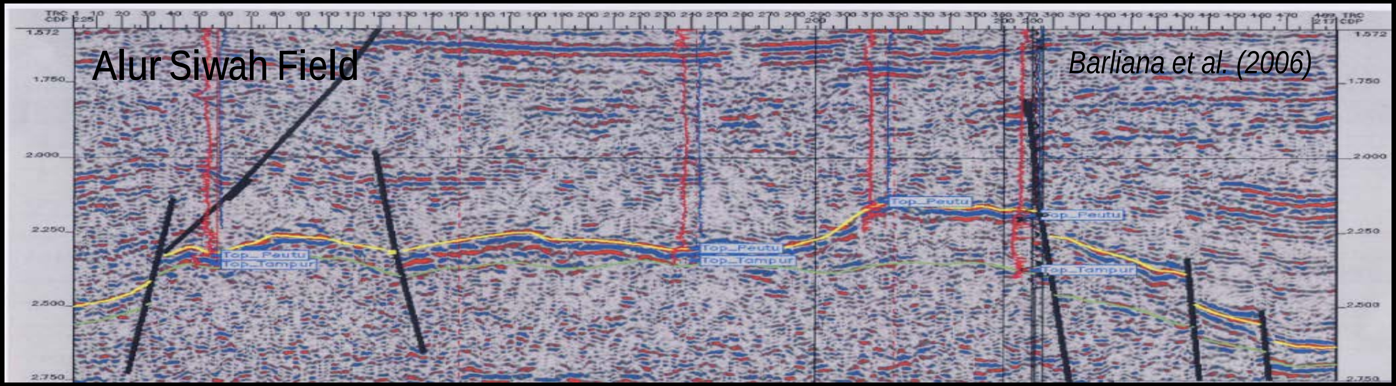
Peu-E1

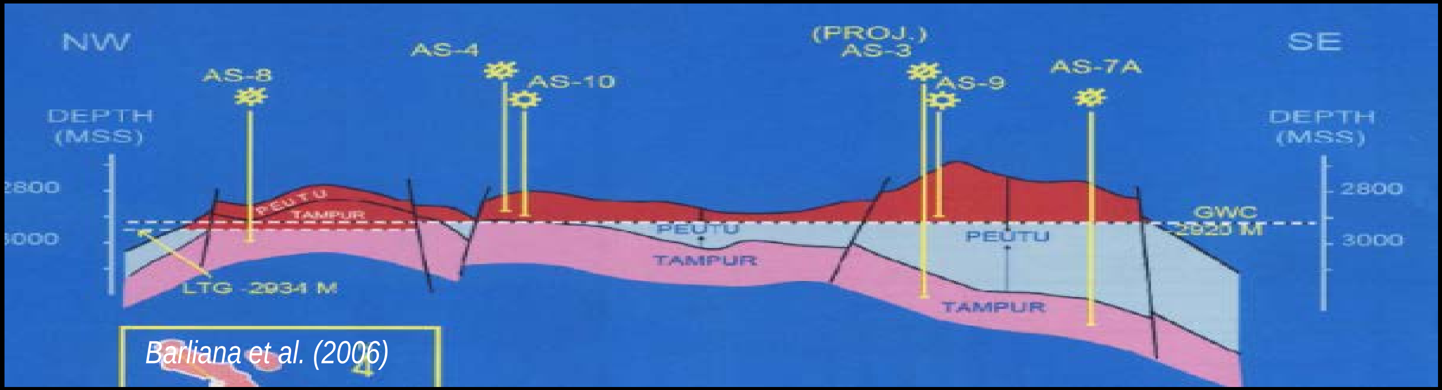
20m of off-reef facies

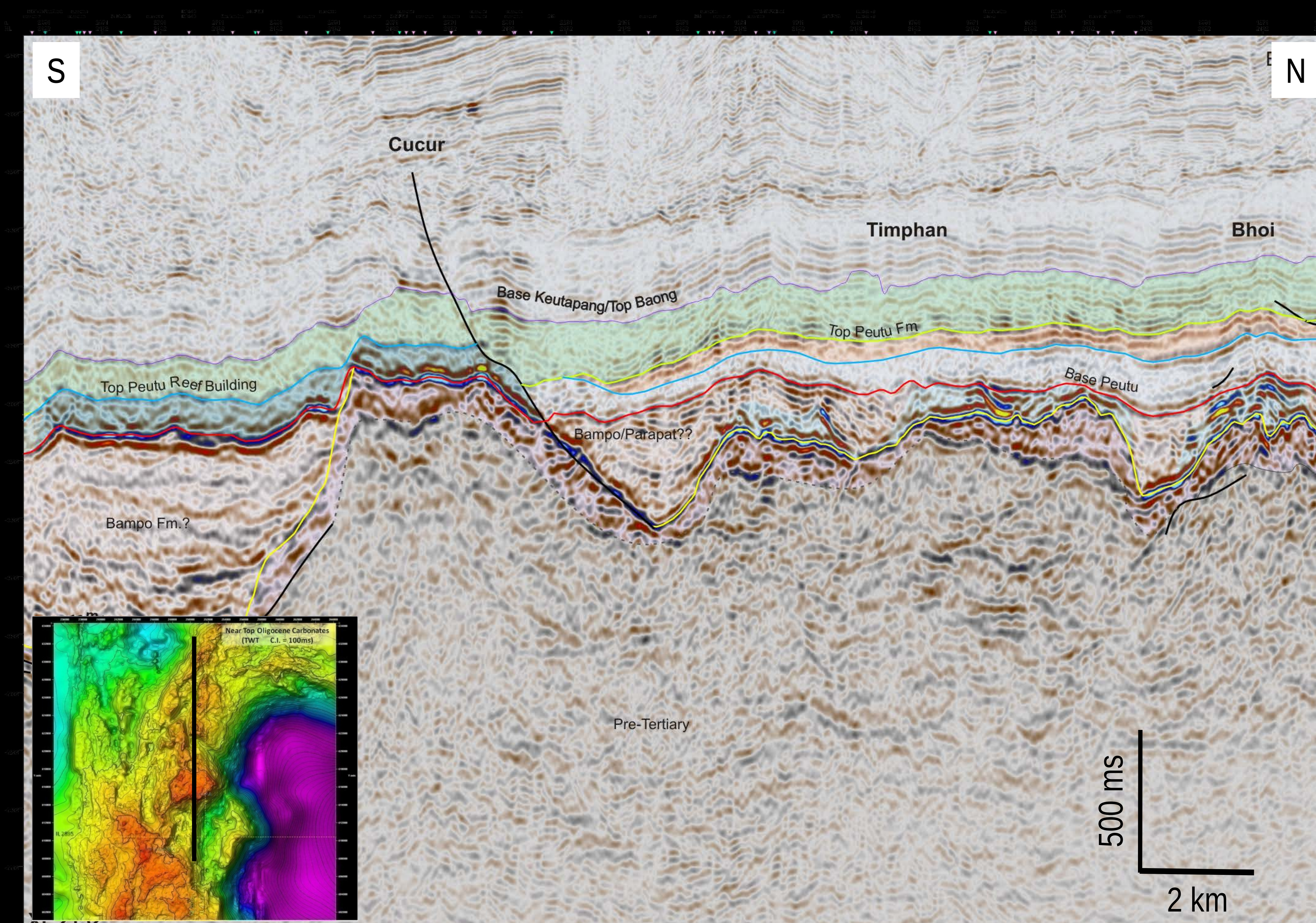

2 km
1
2
3
4
5
6
Peu-E1
Subsidence
Top Seal (Baong)
Patch Reef
Shelf-Margin Reef
Pinnacle Reef
Talus
BACK/INTER-REEF
PATCH REEF/
SKELETAL BANK
PERI-PLATFORM
PERI-PLATFORM
BACK/INTER-REEF
SHELF MARGIN REEF
PINNACLE REEF
Sea level
FORE-REEF TALUS
FORE-REEF TALUS
BASINAL CARBONATE
BASAL TRANSGRESSIVE
CARBONATE SANDS
SHELF
SLOPE
BASIN
Sun & Esteban (1994)
SAMALANGA
HIGH
BIREUN
HIGH
SAMALANGA
DEEP
ARUN
HIGH
LHOKSUKON
HIGH
ALURSIWAH
HIGH
ITU HIGH
NORTH LHOKSUKON DEEP
RAYEU HIGH
WINDWARD
N

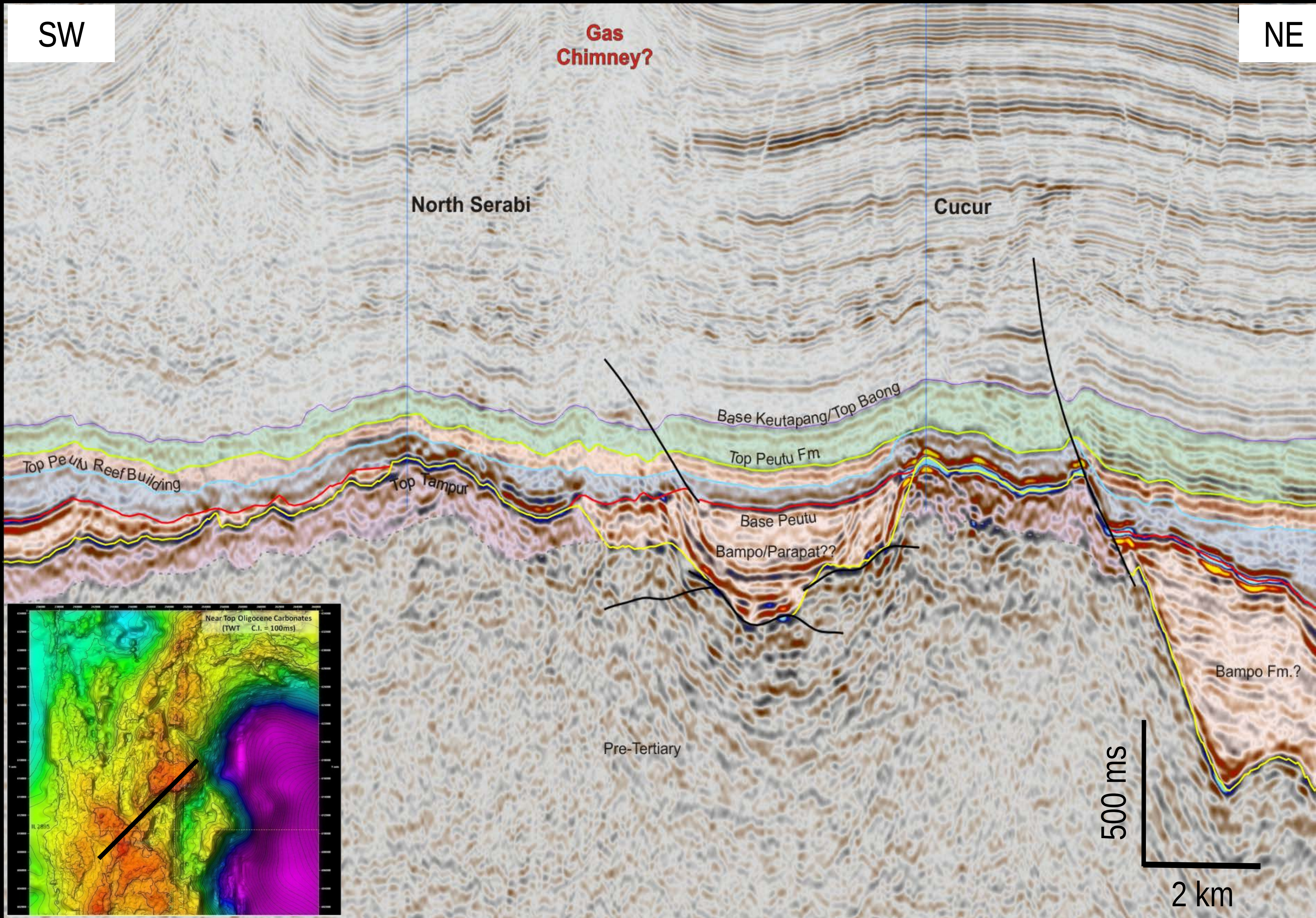
Alur Siwah Field Analogue





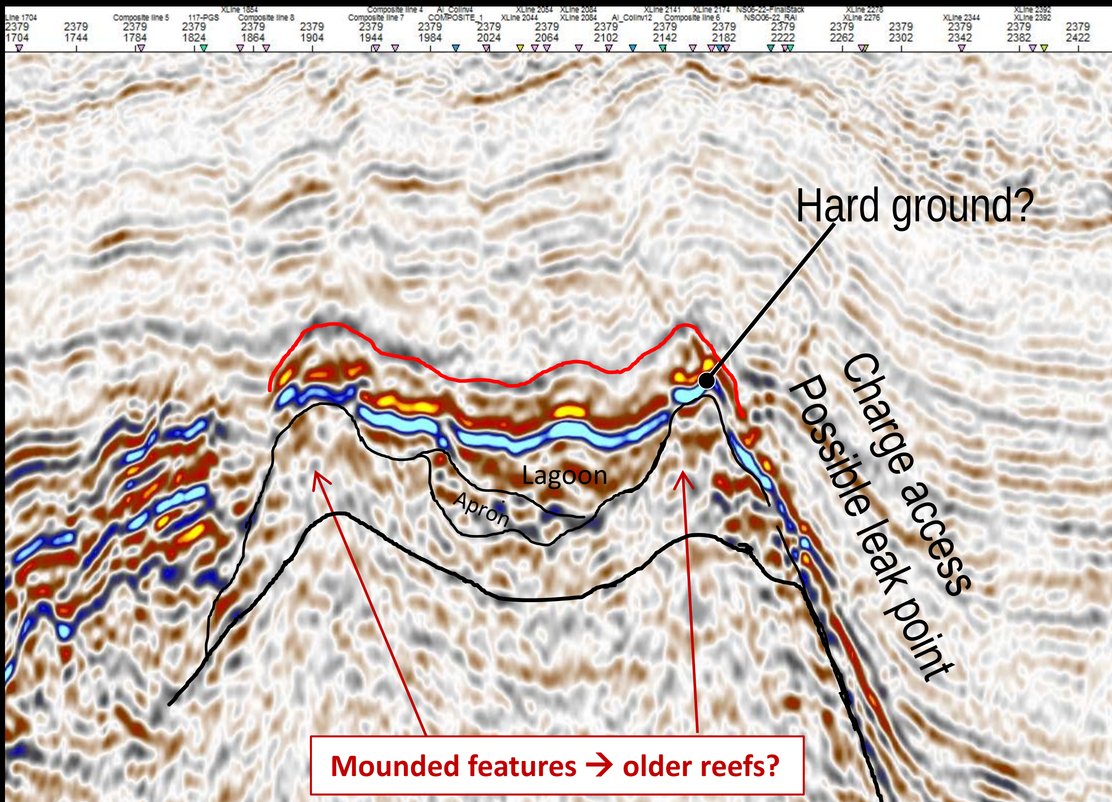


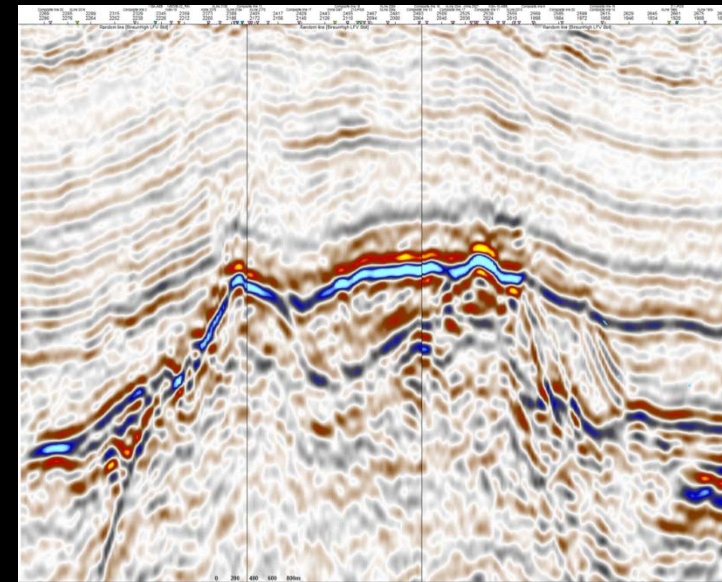

S
N
Cucur
Timphan
Bhoi
Base Keutapang/Top Baong
Top Peutu Fm
Top Peutu Reef Building
Base Peutu
Bampo/Parapat??
Bampo Fm.?
Pre-Tertiary
Near Top Oligocene Carbonates
(TWT C.I. = 100ms)
500 ms
2 km

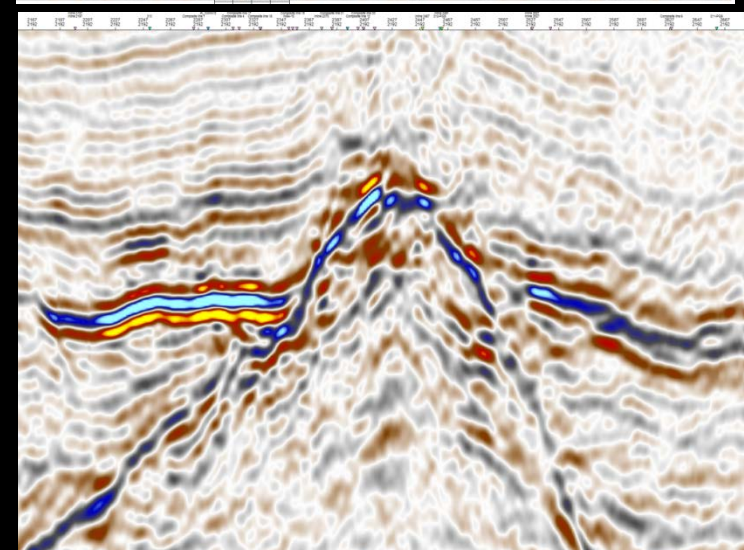


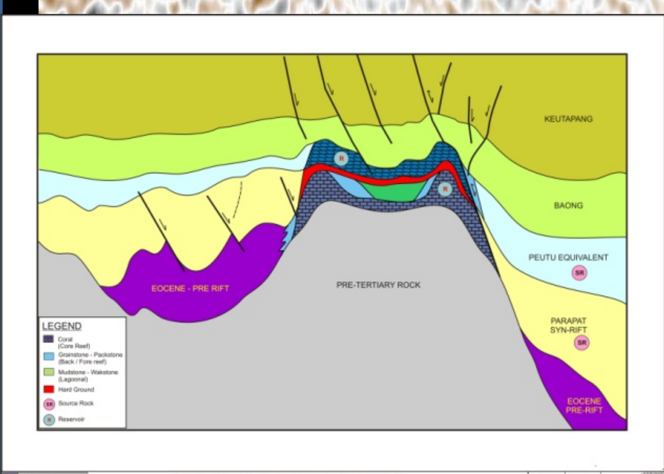
SW
NE
Gas Chimney?
North Serabi
Cucur
Base Keutapang/Top Baong
Top Peutu Fm
Top Peutu Reef Building
Top Tampur
Base Peutu
Bampo/Parapat??
Bampo Fm.?
Pre-Tertiary
500 ms
2 km
Near Top Oligocene Carbonates
(TWT C.I. = 100ms)

Cucur (Jayarani-1)







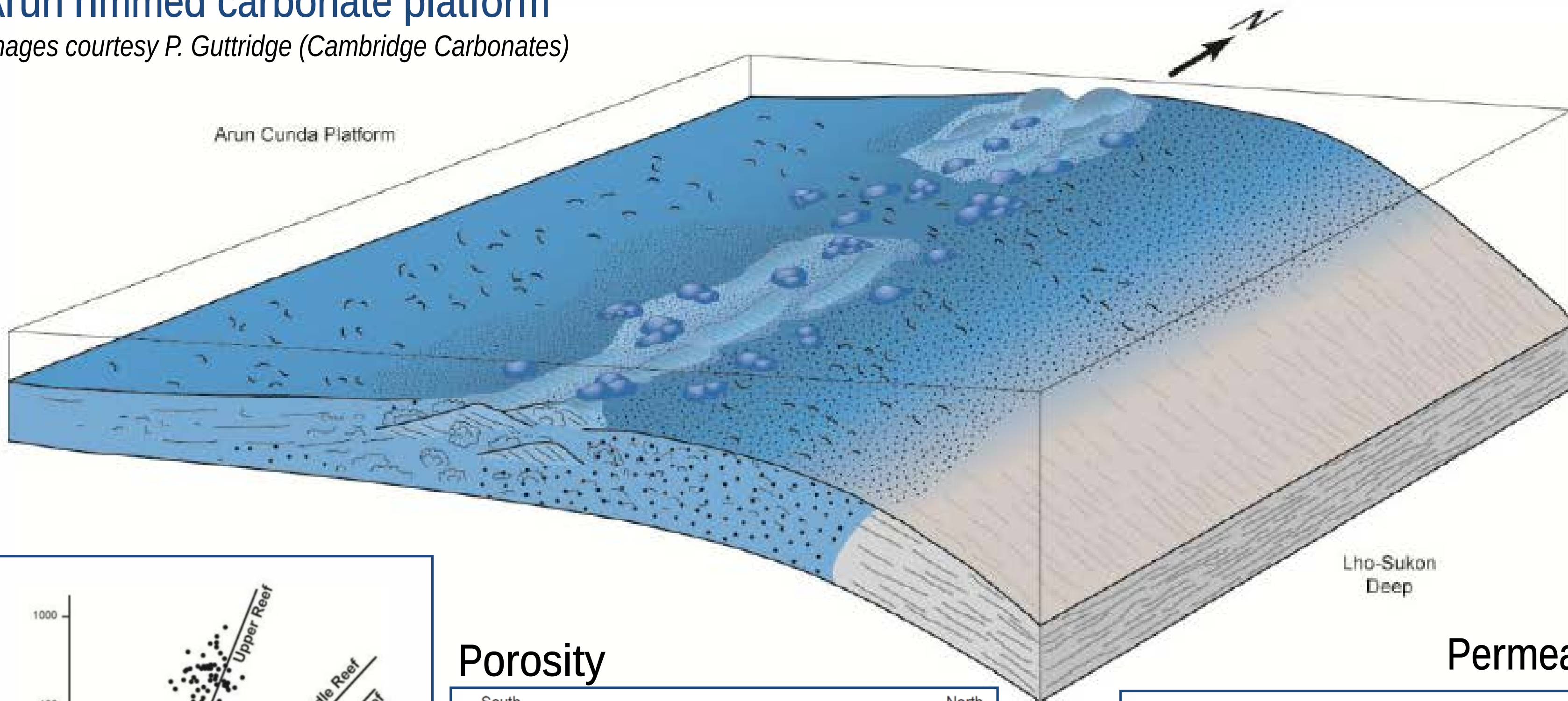


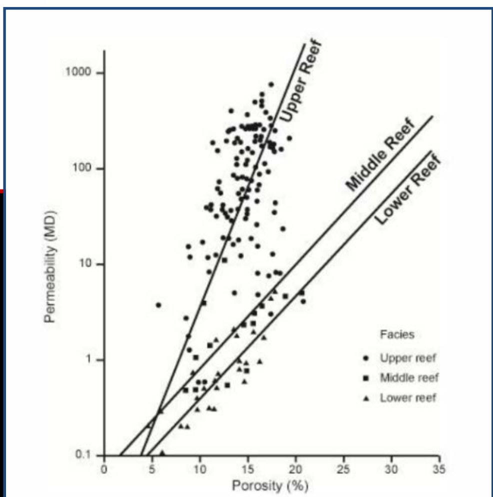
Mounded features with chaotic/blank reflectivity interpreted as carbonate reefs.
Parallel and subparallel reflections interpreted as lagoon and apron facies.
The bright blue indicates hard ground

Arun – Reservoir Characteristics

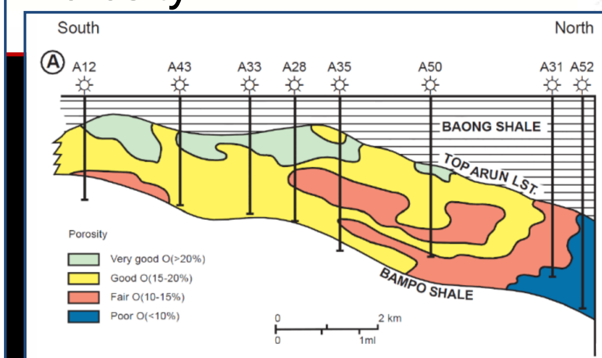
Arun rimmed carbonate platform

Images courtesy P. Guttridge (Cambridge Carbonates)

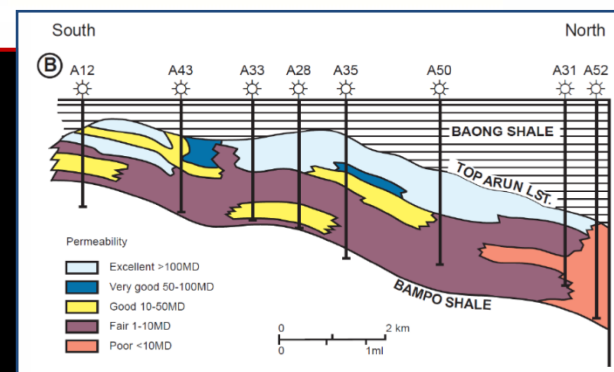




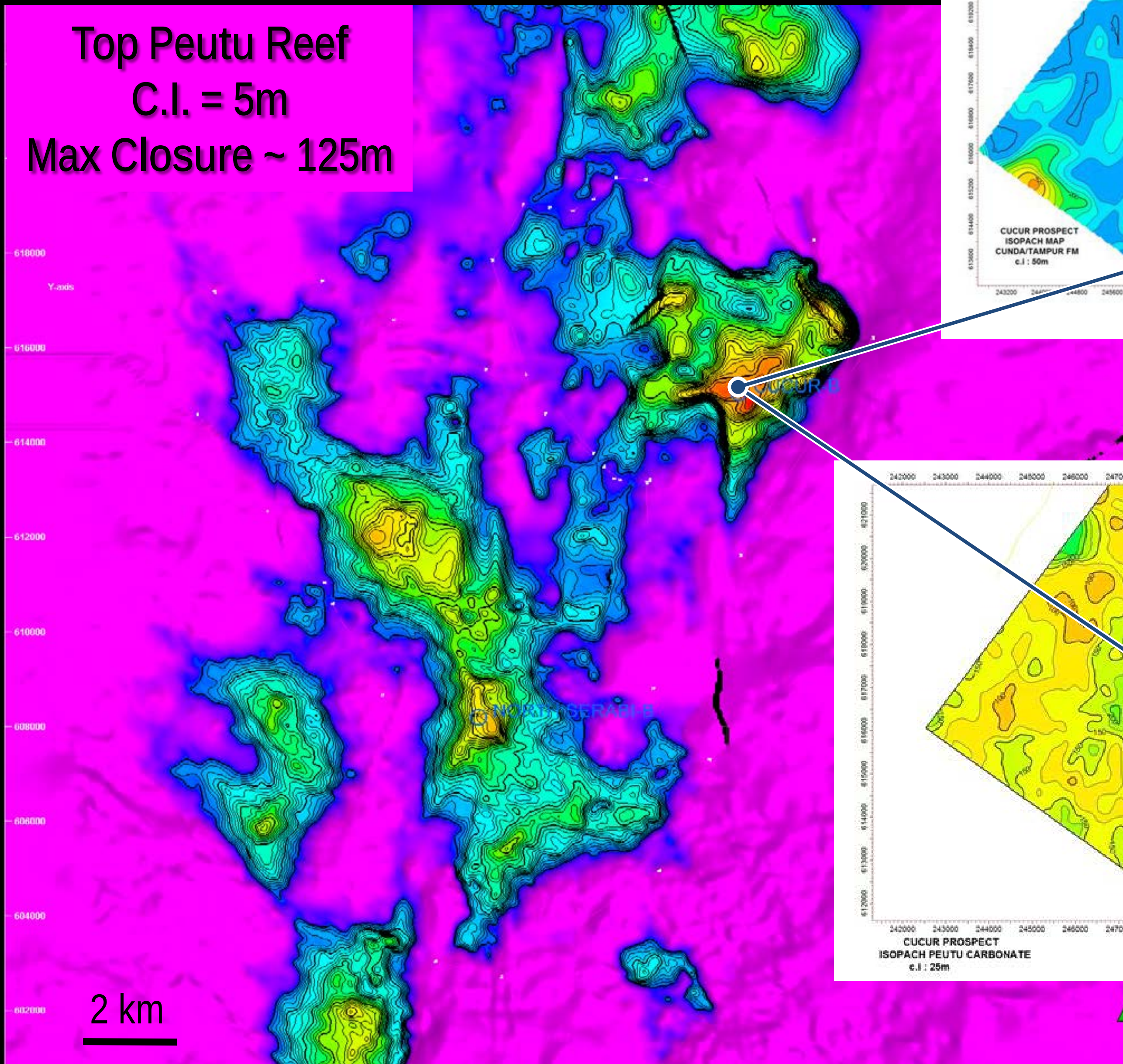
Porosity

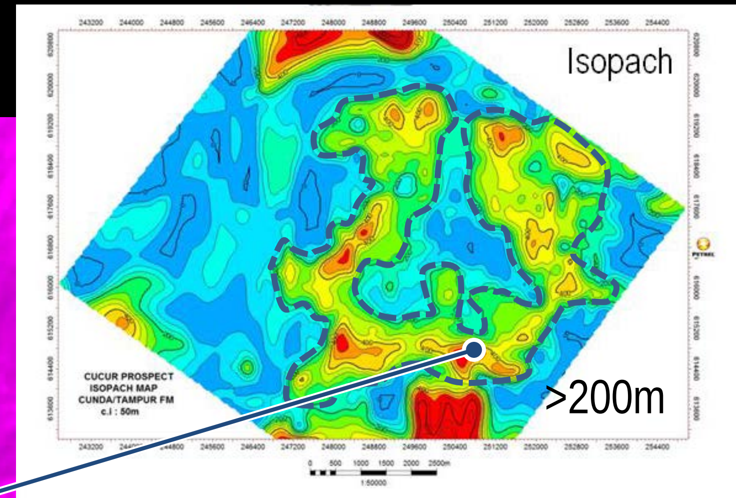


Permeability

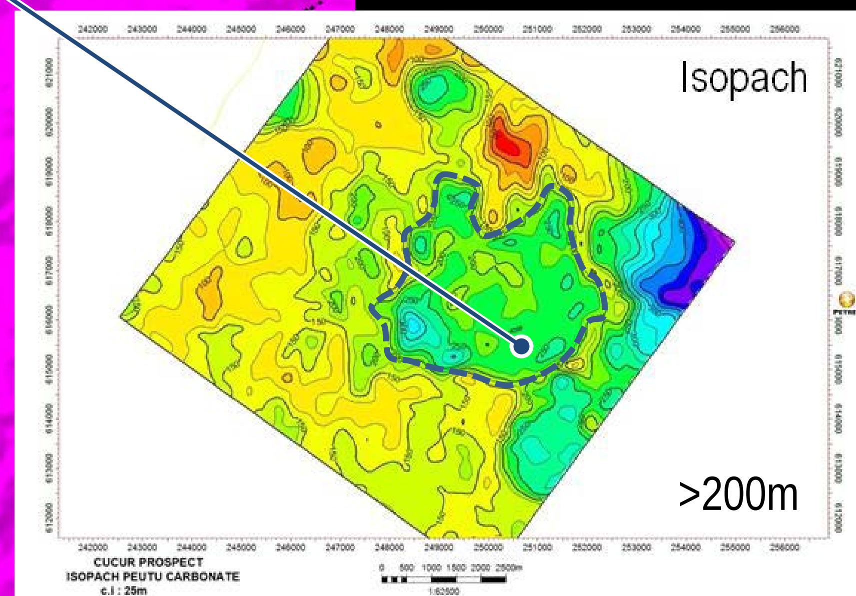


Structure and Thickness



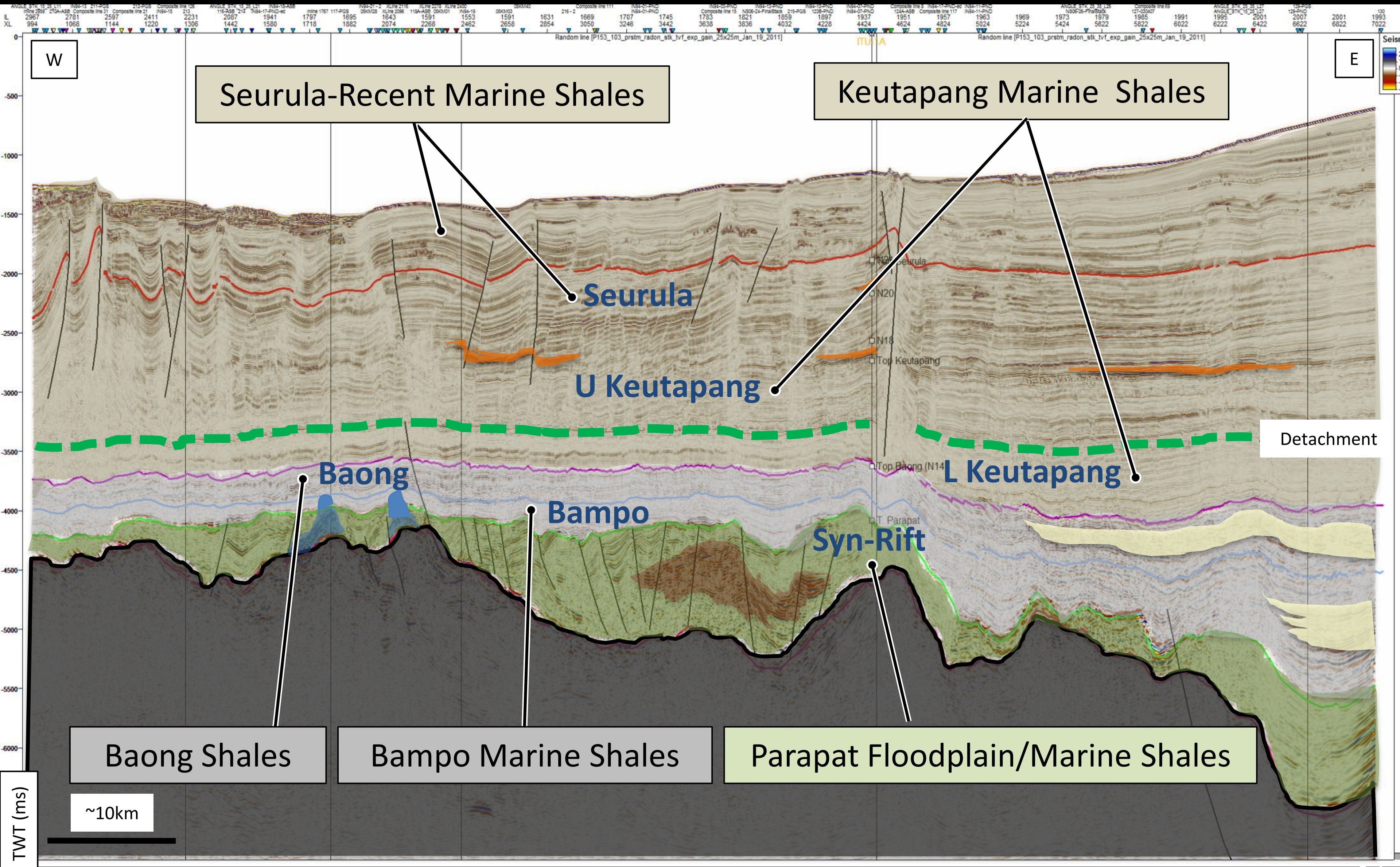


Isopach of Early Stage Build-Up

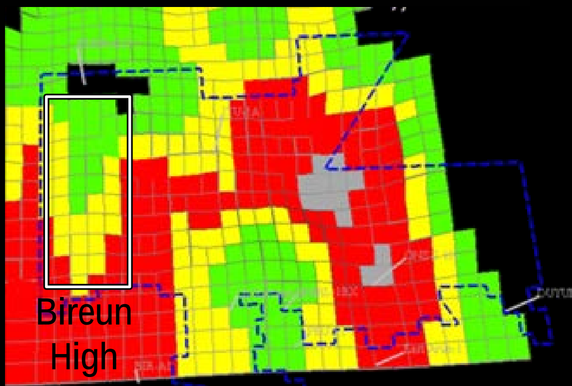


Isopach of Late stage Build-Up

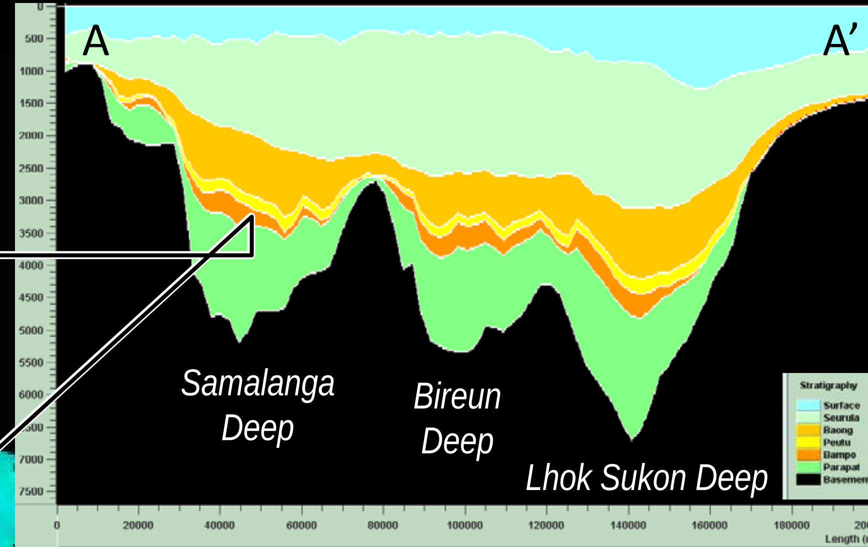
Sealing Stratigraphy in the Offshore NSB



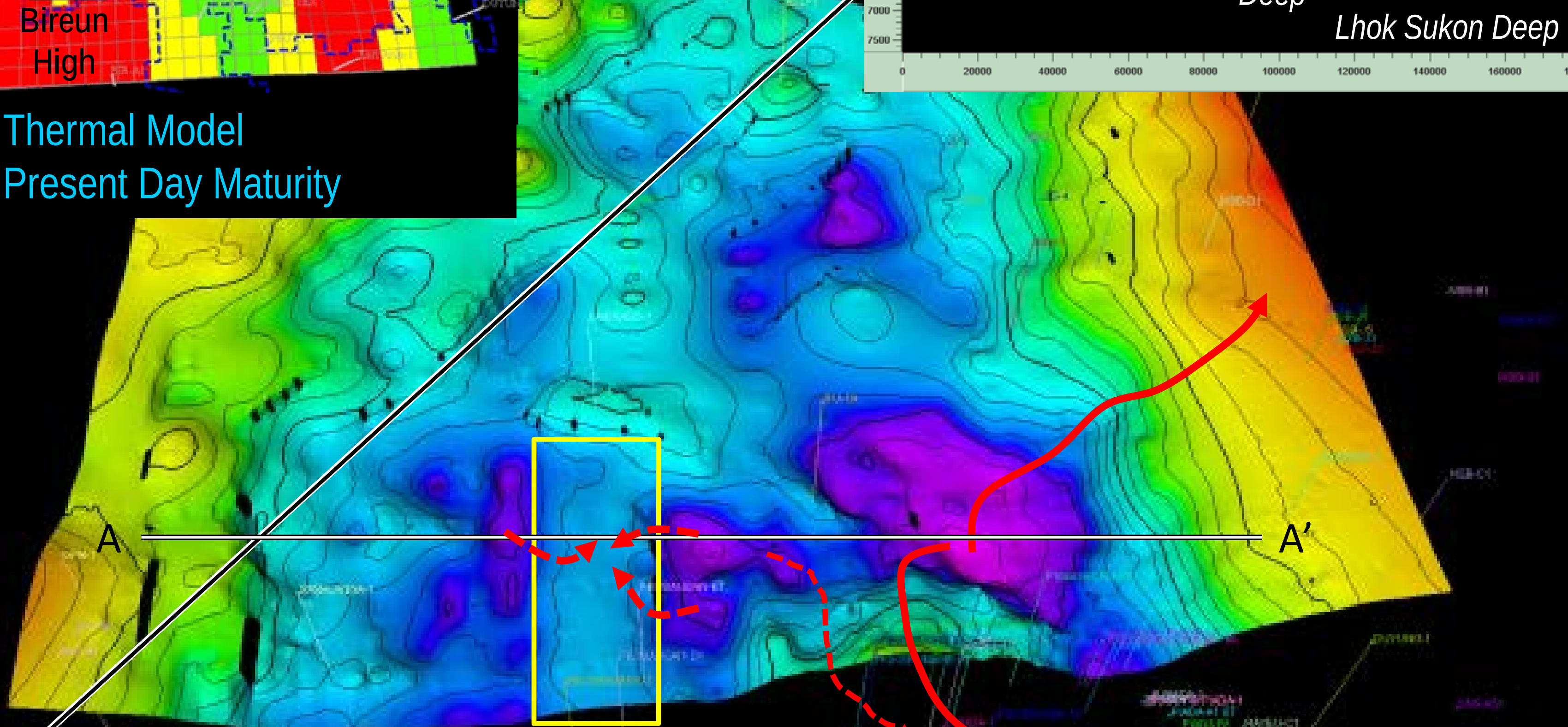
Source Rock and Migration



Thermal Model
Present Day Maturity

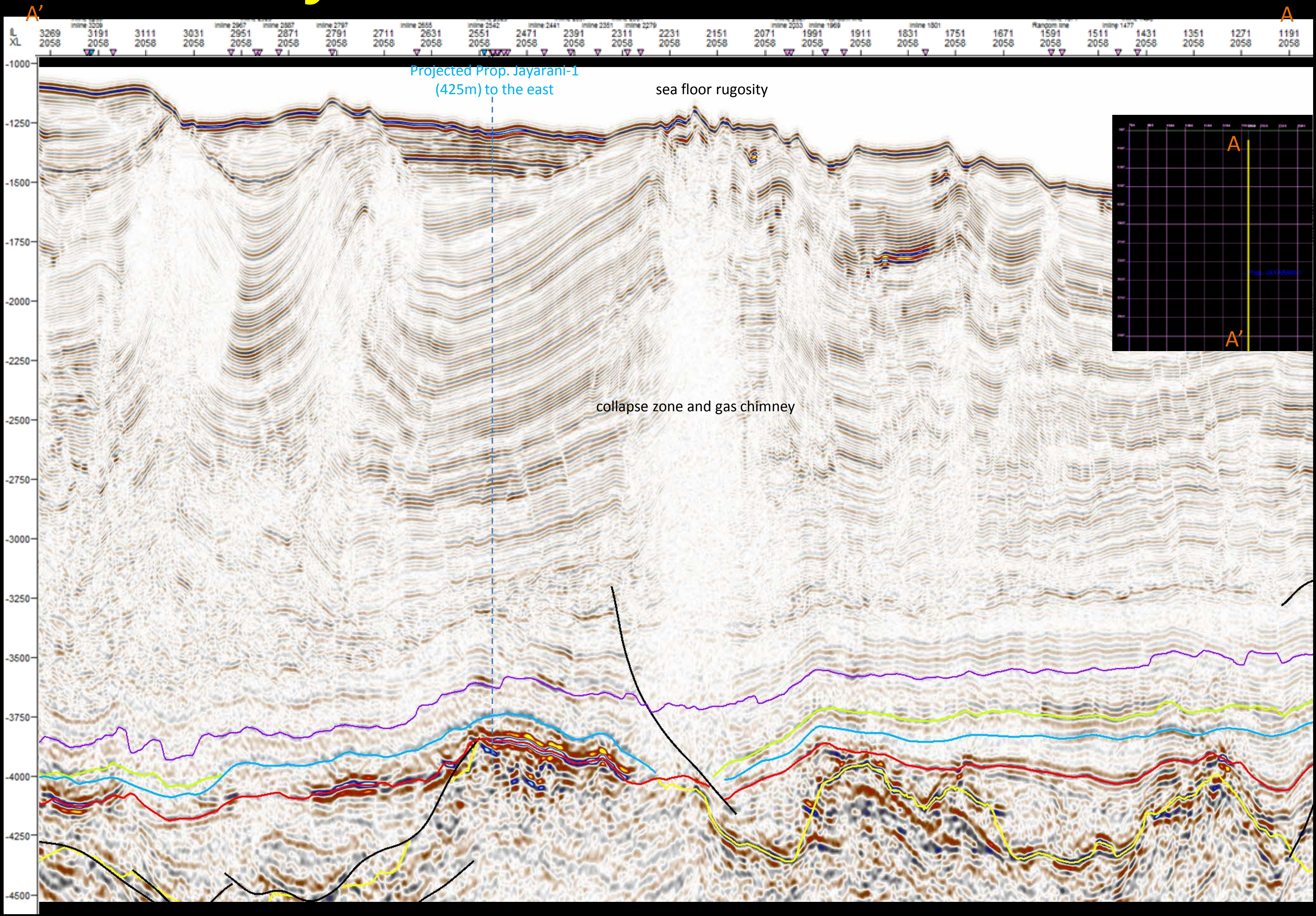


Top Bampo Horizon

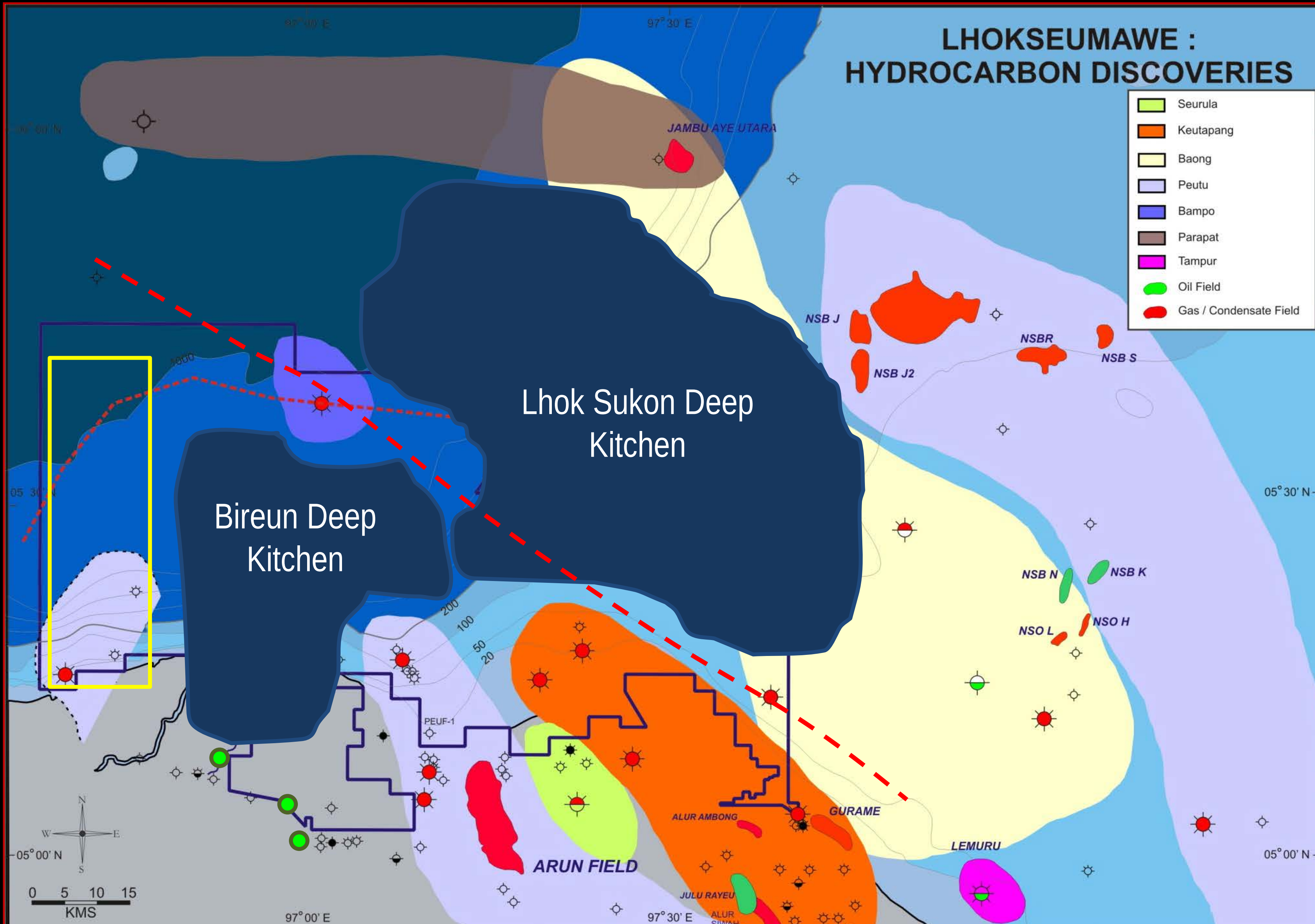


Bireun High

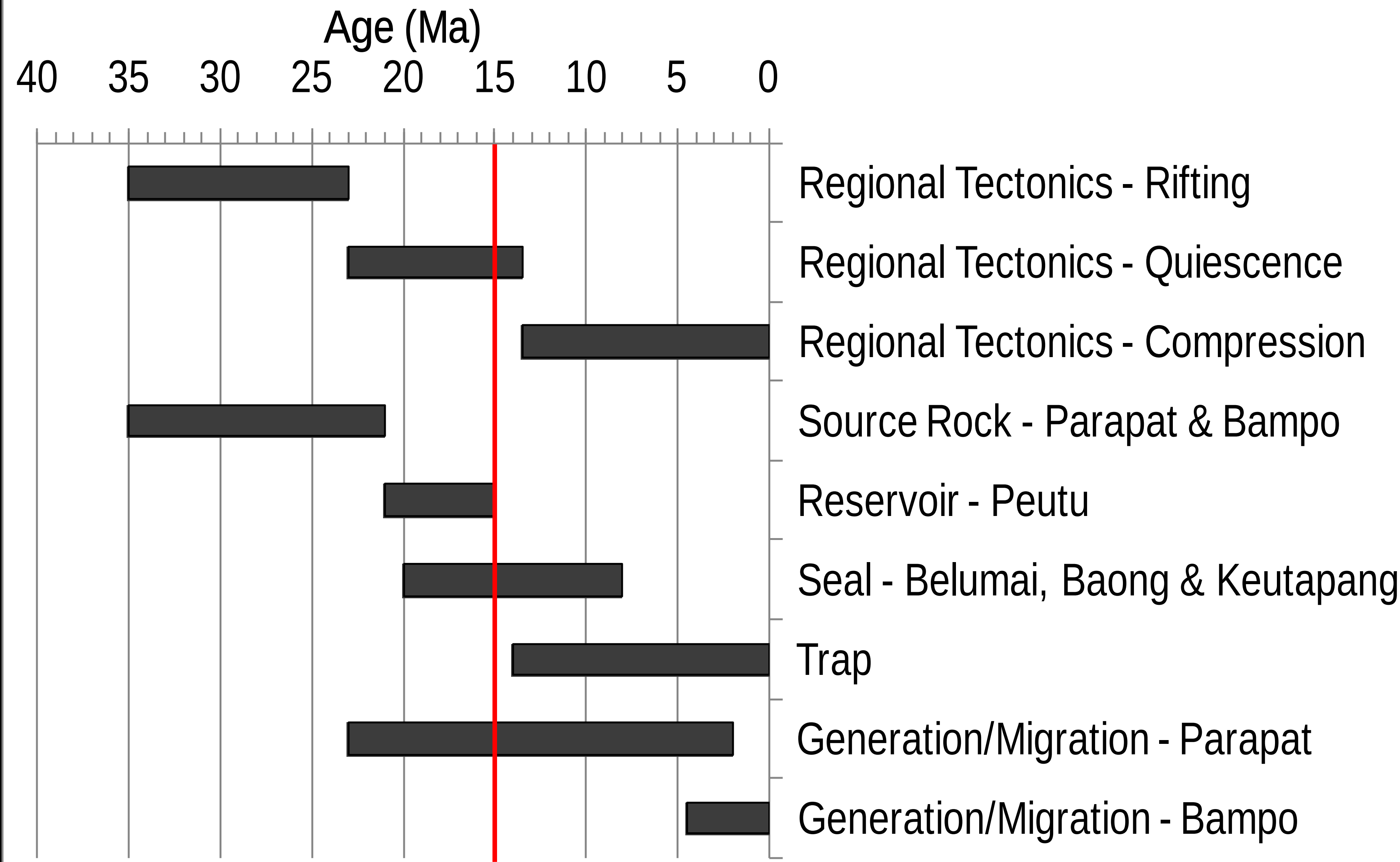
Hydrocarbon Indications



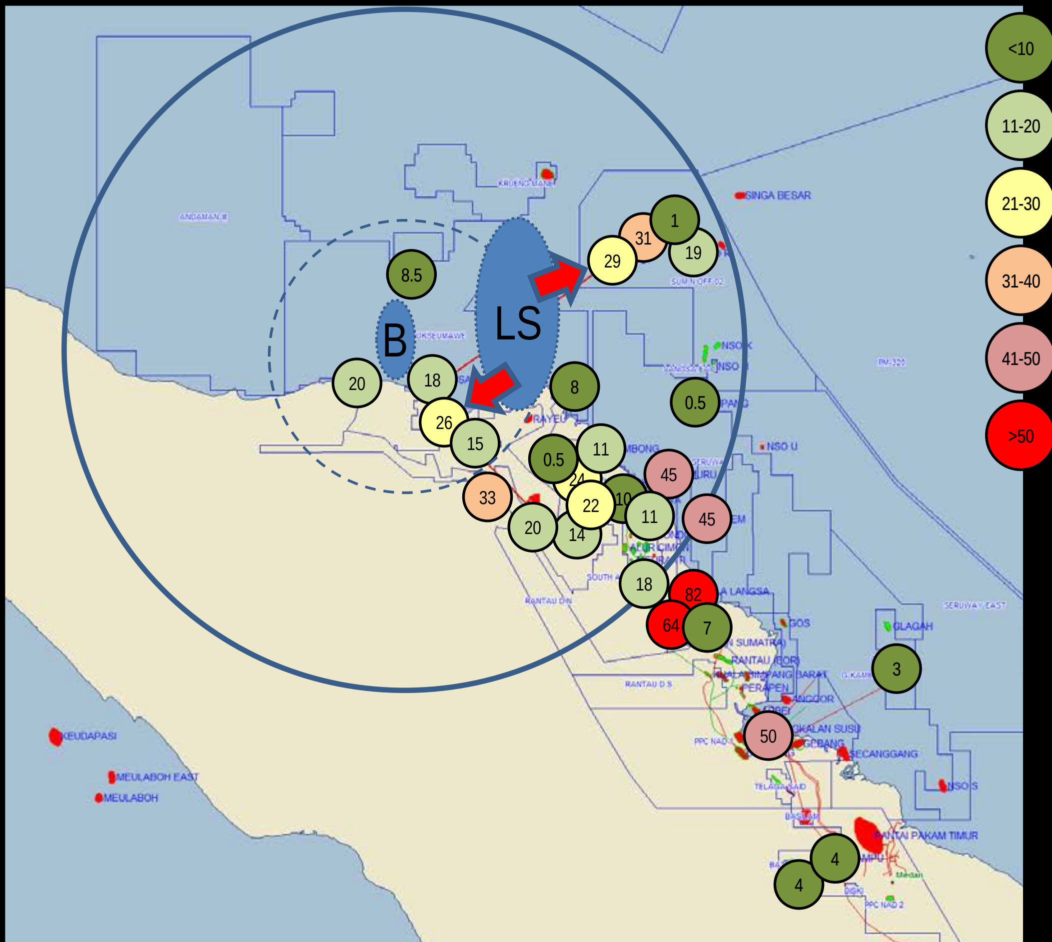
Evidence for Active Petroleum Systems



Critical Moment

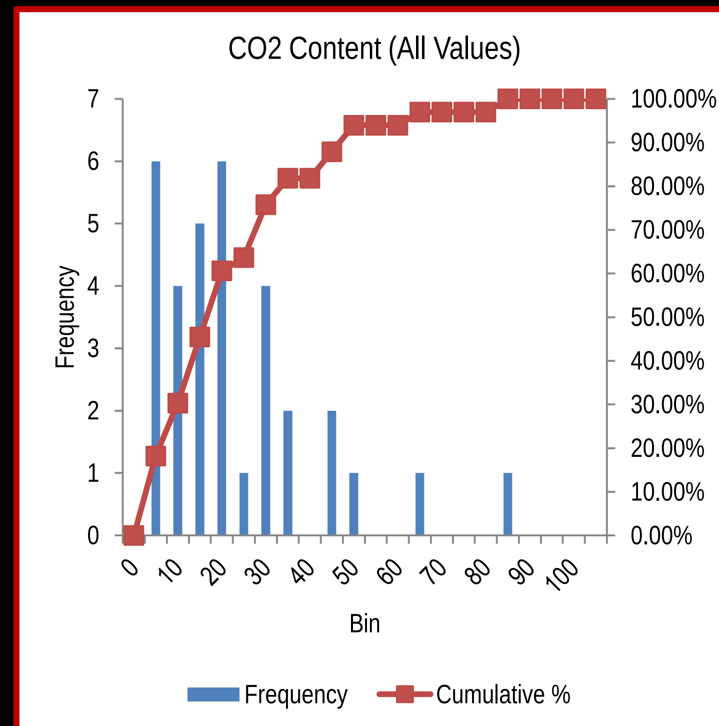


CO_2 Distribution, North Sumatra



Mean CO_2 within 100 km ~ 17.5%
Mean CO_2 within 250 km ~ 19%

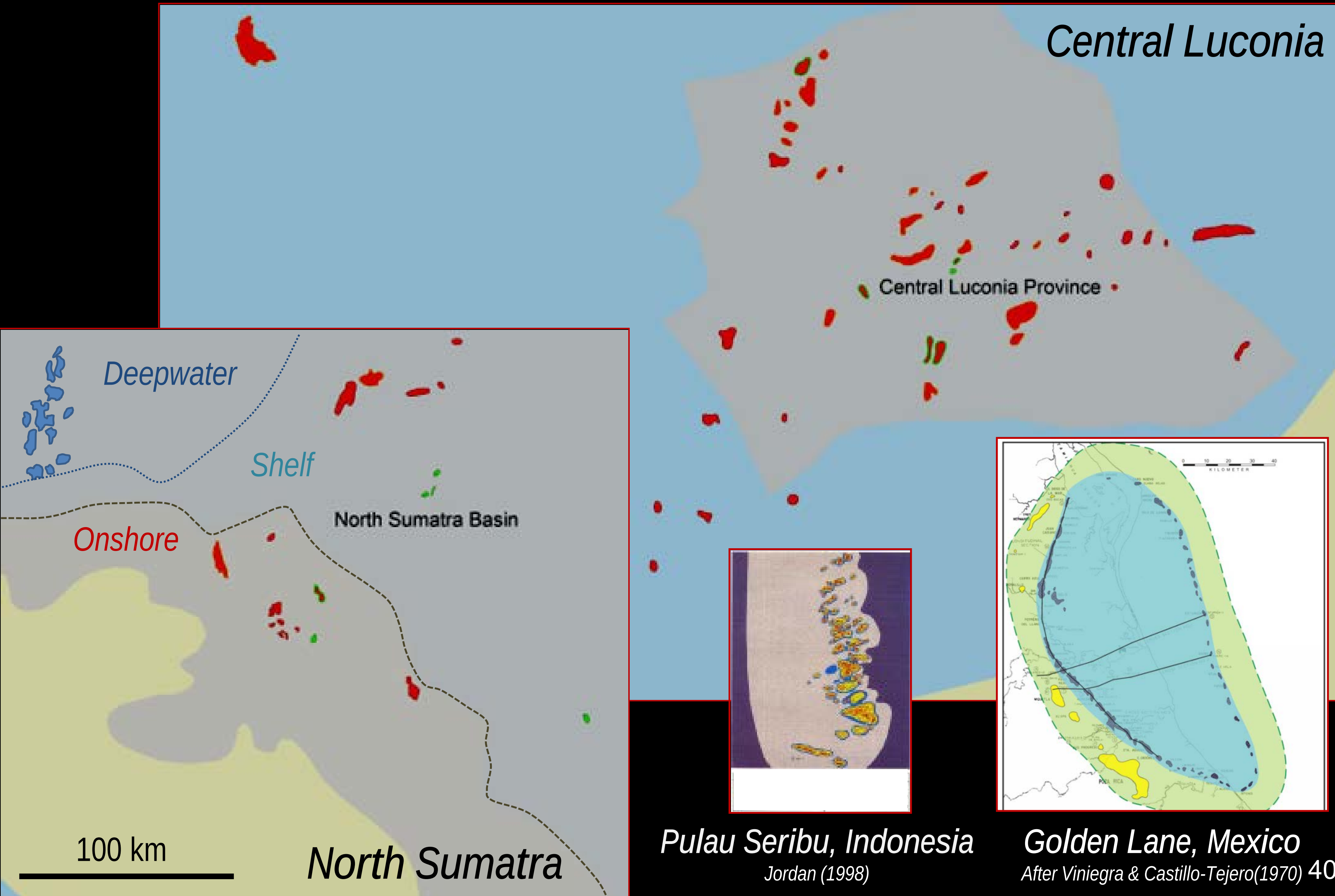
Risk of CO_2>20% is low in NSB
and exceedingly low in Lhokseumawe



All values: Mean CO_2 ~ 21% | P50 CO_2 ~ 17%

- ~20% of reported values (n=5/29) have CO_2 < 5%
- 45% of reported values (n=12/29) have CO_2 < 15%
- 60% of reported values (n=17/29) have CO_2 < 20%
- 75% of reported values (n=22/29) have CO_2 < 30%
- ~95% of reported values (n=27/29) have CO_2 < 50%

Analogues

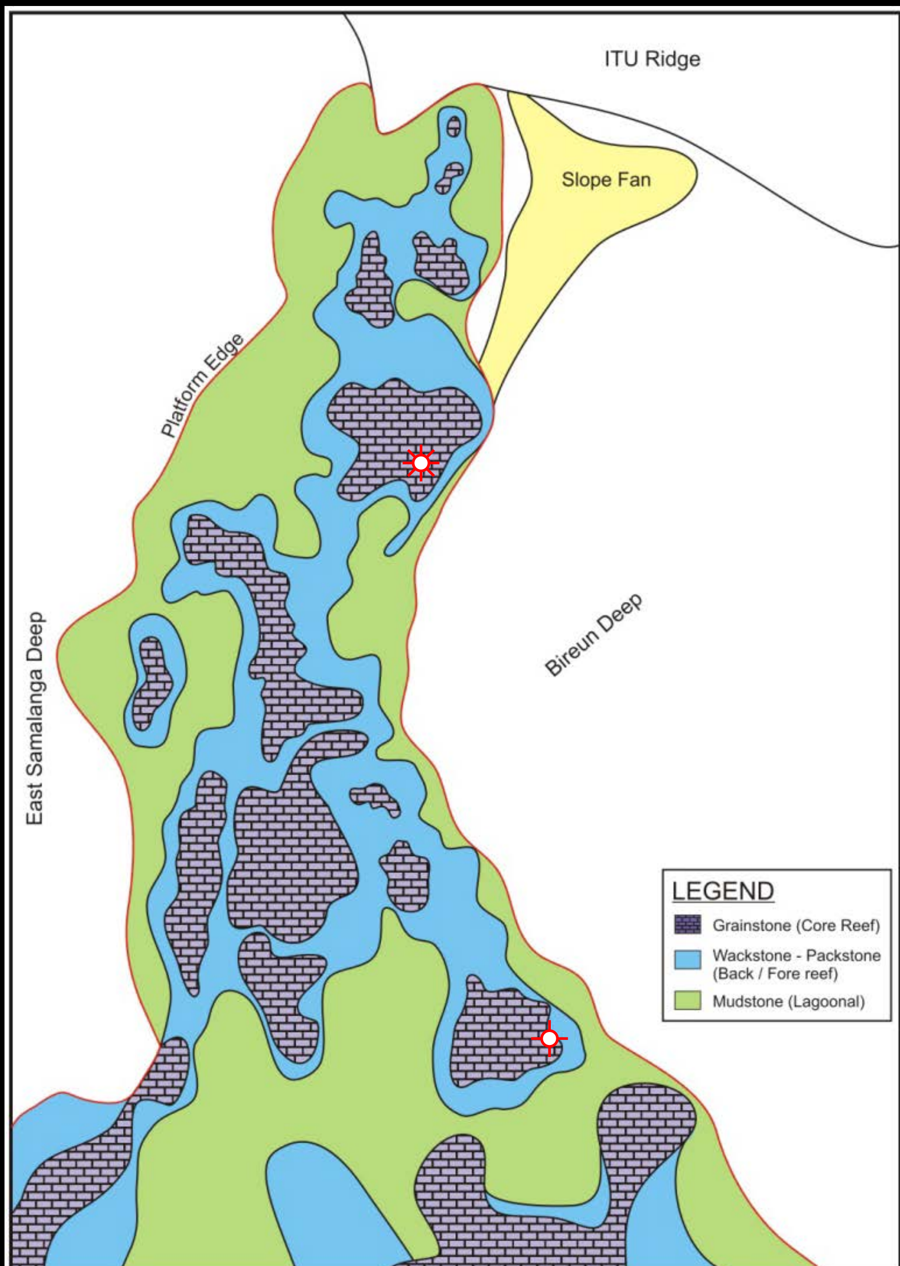


Pulau Seribu, Indonesia
Jordan (1998)

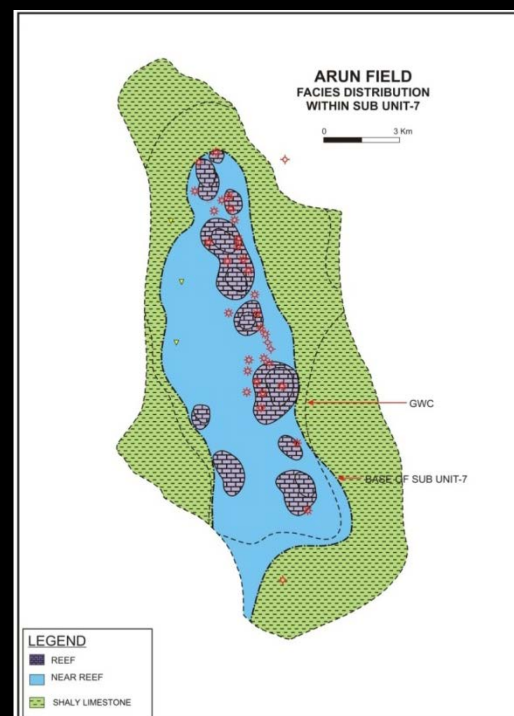
Golden Lane, Mexico
After Viniegra & Castillo-Tejero(1970)

North Sumatran Basin Analogues
Same Scale

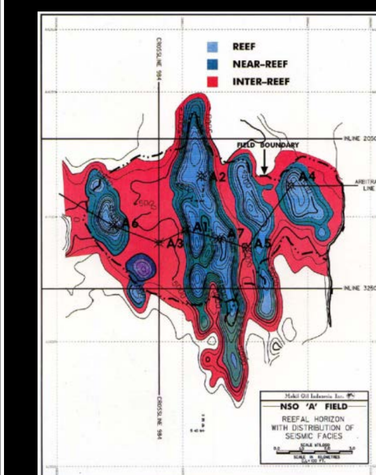
Bireun High



Arun Field
UR ~ 4 BBOE

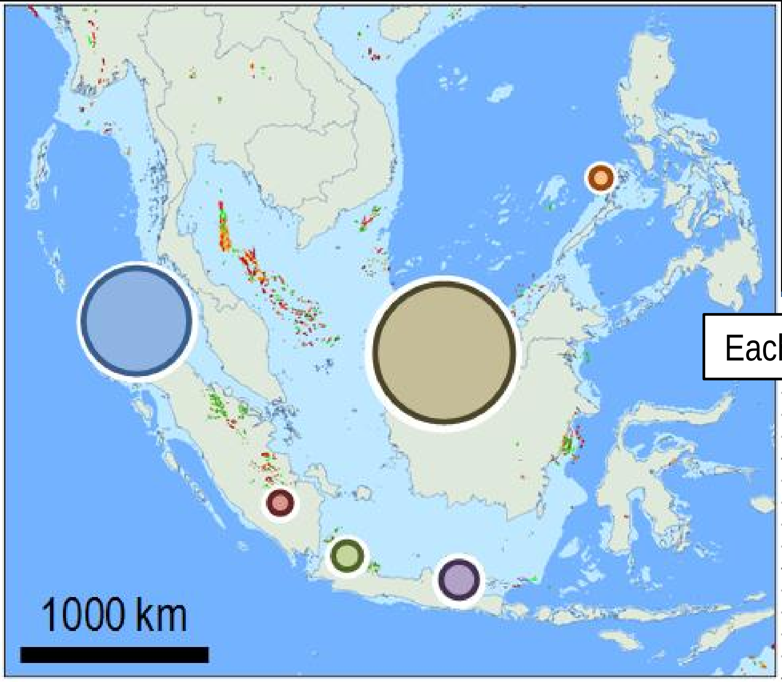


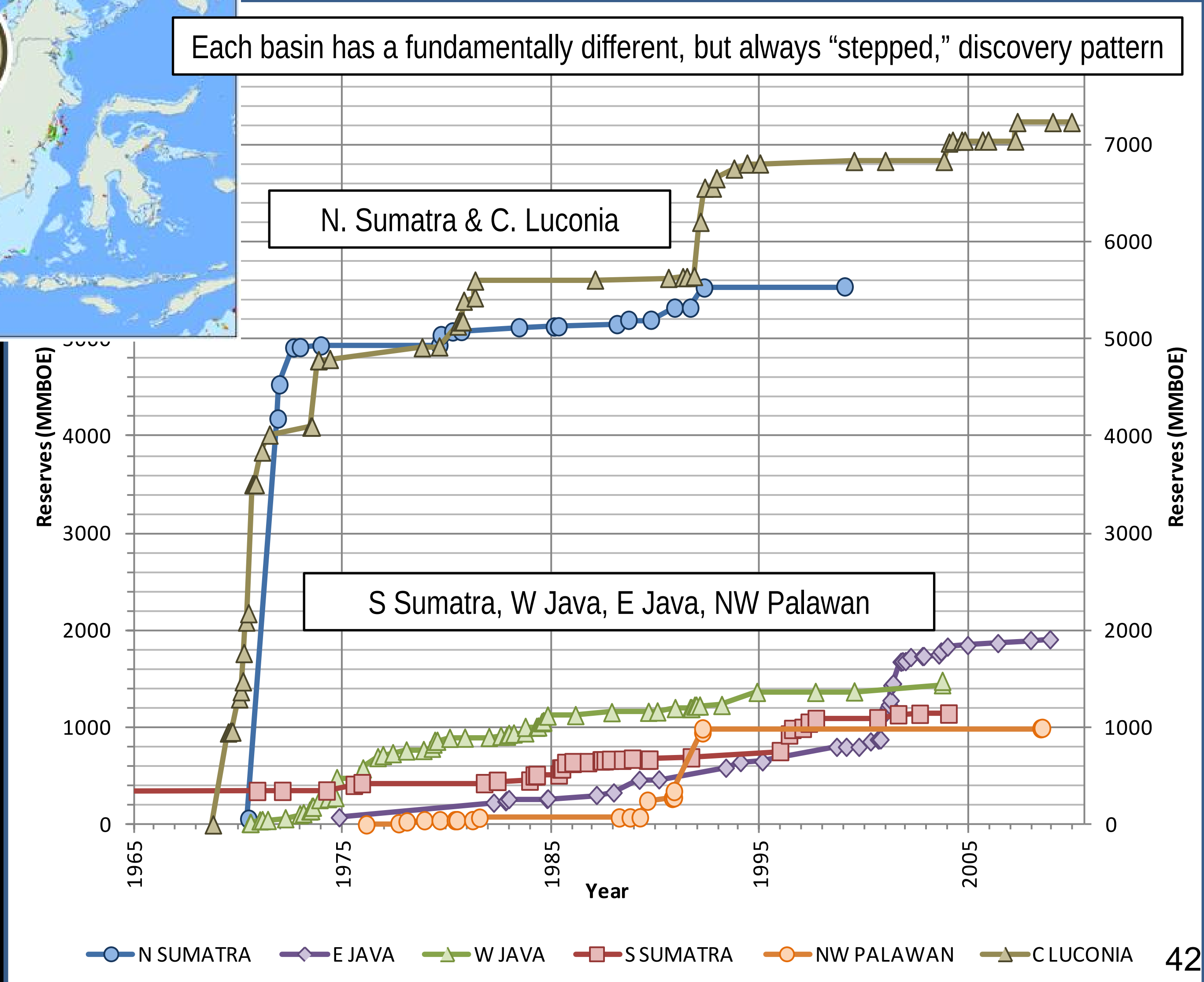
NSO-A Field
UR ~ 350 MMBOE



5 km

Creaming Curves by Basin
SE Asia Carbonate Play





Carbonates in the North Sumatran Basin

World class petroleum province, with giant fields on (almost) every horst block

- **Reservoir**: Reef buildups $\geq$ 150m proven to exist on every high
  - Established in onshore NSB; proven in offshore (Peu B, C; NSO)
- **Source**: Prolific source rocks known generate hydrocarbons
  - Multiple kitchens (possibly generating oil!)
- **Seal**: Thick regional shales are ubiquitous
- **Trap**: Mapped unambiguously on modern 3D seismic

Discovery Thinking - Conclusions

1. Understand the regional context
   - Speculate *prudently*, based on mature analogues
     - Regional carbonate play not creamed yet
     - Discovery histories of major carbonate basins are stepped
2. Understand the basin
   - See the potential. Acknowledge the problems.
     - Simple story
     - What worked? (Buildups with thick topseal)
     - What didn't? (Off-reef; thin/breached topseal; CO_2)
     - Why? (Poor seismic; immature facies models)
     - What are the implications? (Lots of space to explore; possibility of oil)
3. Utilize integrated subsurface analysis to characterize the portfolio
4. Define a prospect to test the key risk(s)

Discovery Thinking - Coda

“Giant fields keep nations in business, and it is toward such fields that we must direct our major efforts, because the day of economic production of petroleum from tar sand is only just arriving; the day of economic production of coal and oil shale is not here, and a suitable technological “breakthrough” for economic production of such energy sources has not been developed. Petroleum still is ‘king.’”

Michel Halbouty (1970)

Acknowledgements

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Niko Resources Ltd.

BPMIGAS

AAPG