ABSTRACTS

Day 1: 27th June 2018

Session 1: Context

Chair: Andy Butler – SundaGas

9:00	What the Future Holds for SE Asia's Exploration and Production Industry: An Independent's Perspective	Richard Lorenz	CKR Resources
9:25	Context for the Opportunities in Asia Pacific	Dylan Mair	IHS Markit
9:50	Animated, High Resolution Plate Tectonic Reconstructions of SE Asia Based on the Geognostics Earth Model (GEM) – a New Base for Paleogeographic Mapping	Jon Teasdale	Geognostics
10:15	Montane Pollen Indicates Character of Mid Cenozoic Uplands Across Sunda Shelf	Bob Morley	Palynova

PESGB SEAPEX Asia Pacific E&P Conference
Olympia Exhibition Centre, London
27th – 28th June 2018

ORAL PRESENTATION

What the Future Holds for SE Asia's Exploration and Production Industry: An Independent's Perspective

Richard Lorentz[1]

[1]CKR, Singapore

richard.lorentz@ckr.com.sg

Southeast Asia remains among the fastest growing areas, in economic terms, in the world. Indeed, growth is set to accelerate over at least the next three decades according to sources such as the World Bank and IMF. The same sources and the IEA, show that energy demand will increase in line with this growth, most of which will require the consumption of fossil fuels, especially oil and gas. At the same time production in Southeast Asia is set to decline over the near term, with some countries already well into post-peak production.

The major oil companies are beginning to withdraw from the region to focus on much larger targets elsewhere, while even larger independents are moving out of Southeast Asia as part of portfolio rationalisation; so where will the required production come from? Although regional government-owned entities are taking over operations of the bigger fields, smaller operated and non-operated fields are certain to come onto the market in the near term as is already happening. Various estimates by authoritative third parties also suggest that 15 Bboe remain to be found in Southeast Asia; who is going to explore for these resources? This is an enormous opportunity for independent oil and gas companies, with long experience of building exploration and production portfolios in the region, to capitalise on this evolving set of circumstances.

ORAL PRESENTATION

Context for the Opportunities in Asia Pacific

Dylan Mair[1], Antonio Dimabuyu[1]

[1]IHS Markit, Singapore

dylan.mair@ihsmarkit.com

Demand for hydrocarbons in Southeast Asia continues to outpace domestic supply, providing excellent opportunities for the 50 companies who have added to their Asia Pacific acreage in the last two years, and for the 40 new country entrants in the region. As LNG trains move forward by the biggest operators in Australia and Papua New Guinea the opportunities for companies of every size are being realized. At oil prices over US$ 70 per barrel the competition for these opportunities will only get more intense.

158 conventional exploration wells were drilled in the study area between Bangladesh and New Zealand during 2017, an increase of 16% over the year before. The majority of these exploration wells of the last two years were drilled onshore by Beach Energy, Santos, PTTEP and Pertamina. Petronas and Quadrant also completed 13 to16 offshore wells each including deepwater. In total there were around 60 operators of exploration wells. Despite the increased activity, discovered volumes were down, lacking contributions from Australia where an offshore exploration hiatus has been supported by extensions from the government.

The strategy of each Asia Pacific explorer today is a singular combination that meets ongoing investor expectations, leverages and de-risks monetization schedules, aligns with national goals, and builds on the company's expertise and track record as well as that of its partners. Exploration remains a core strategy for most new entrants and many existing players – while well counts are 40% of the 2013 peak, many companies still see exploration as critical to generating value. A lot of effort goes into de-risking the highest value targets for these smaller drilling campaigns. Recent successes by Woodside, Total, Pertamina and their partners illustrate the potential value of Asia Pacific frontiers and older plays.

This presentation dives into the exploration and broader upstream strategies of Asia Pacific players and looks at the opportunities – bid rounds, contract expirations, fiscal changes and high impact wells – coming up in the year ahead for this truly dynamic region.

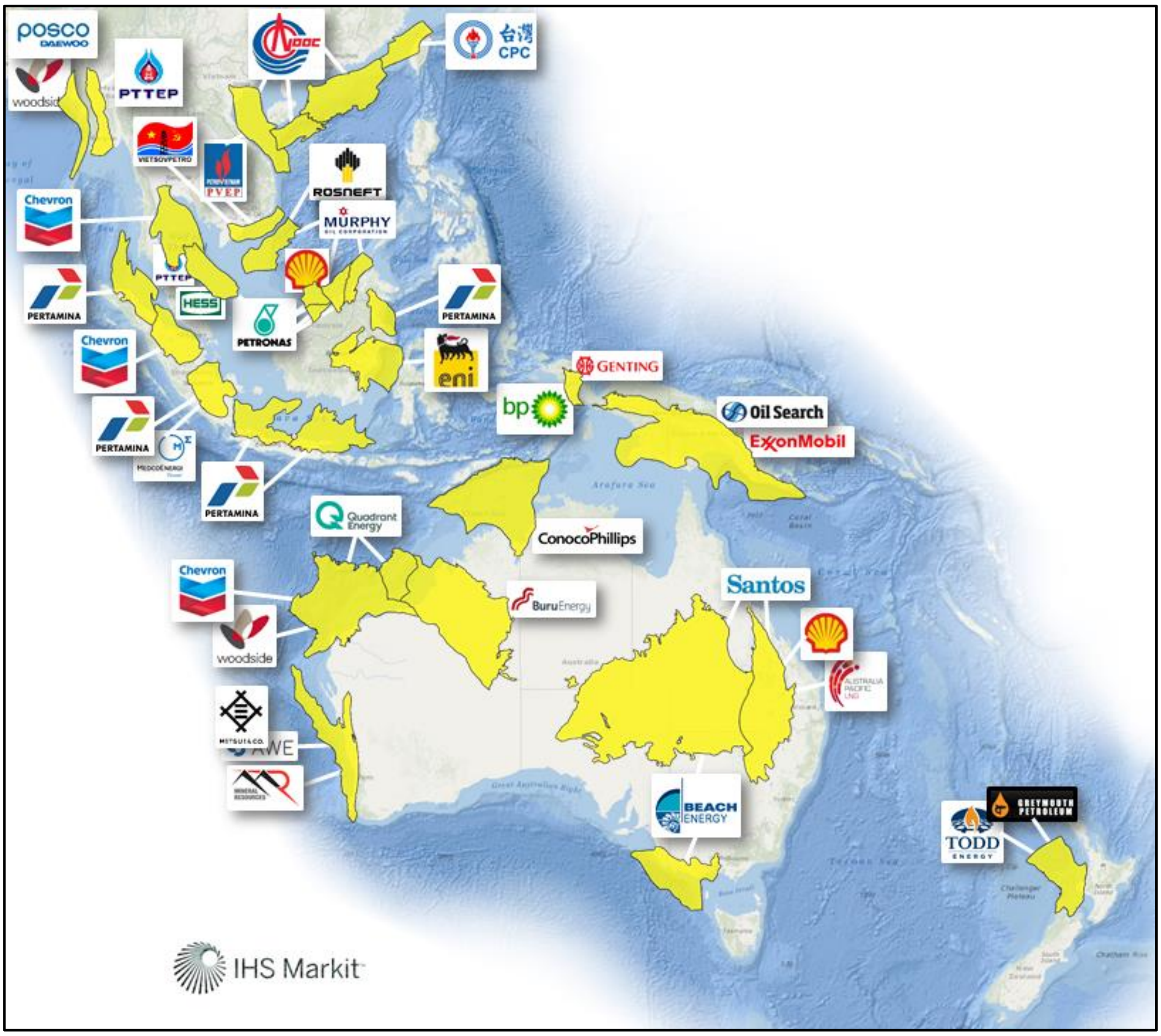


Figure 1. Basin Masters. Companies with a major stake in key basins of Asia Pacific are shown. Most basin masters are growing these key positions although some (notably Chevron and Shell in Southeast Asia) have sought to focus expenditure elsewhere.

ORAL PRESENTATION

Animated, High Resolution Plate Tectonic Reconstructions of SE Asia Based on the Geognostics Earth Model (GEM) – a New Base for Paleogeographic Mapping

Jon Teasdale[1], Jan Bon[2]

[1]*Geognostics, UK*

[2]*GeoConsultants, Netherlands*

jon.teasdale@geognostics.com

INTRODUCTION

SE Asia is the most geologically complex region on Earth due to the three-way convergence of the Indo-Australian, Eurasian and Pacific plates. Many attempts have been made to unravel its tectonic history with varying levels of success, but most are limited by the lack of integration of offshore geological data, hence their utility as basin exploration tools is limited.

We have gone back to first-principals, by interpreting basement terranes and major structures across the region, both onshore and offshore, to provide a spatially consistent and continuous view of its geological fabric. We then worked back in time to undo deformation patterns on major shear zones, basins and subduction zones. A detailed understanding of the basins of the region helped us to unravel this history.

The resulting animated plate model provides a kinematically and geologically constrained view of the tectonic evolution of SE Asia. It is consistent with the evolution of basins and petroleum systems across the region and can be used as a predictive tool for hydrocarbon exploration.

MODEL BOUNDARY CONDITIONS

The starting point of our model is a spatially consistent interpretation of the present-day crustal framework of SE Asia, comprising basement terranes and major structures. Plate tectonic analysis is somewhat futile without a good definition of these building blocks, both onshore and offshore. We used published geological maps, digital elevation data, gravity, magnetics and seismic to map basement terranes and structures focussing on spatial continuity, especially offshore.

The complex collage of basement terranes in SE Asia comprises three broad terrane groupings:

1. Precambrian 'Cratons' including Greater India, Australia and South China-Indochina. At a first approximation these continents have behaved rigidly since the early Palaeozoic.
2. Proterozoic-Palaeozoic, Gondwana-derived continental terranes that crossed the Tethyan oceans and progressively amalgamated with Eurasia in the Mesozoic.
3. Mesozoic-Tertiary arc-related terranes that have amalgamated to SE Asia or formed in situ at its margins since the Cretaceous.

We have interpreted the regional structures that bound and deform these basement terranes, from subduction zones and orogenic thrusts, to strike-slip faults and basin-bounding normal faults. These structures have been attributed by age and plate code so that they appear and disappear appropriately when reconstructed.

In order to understand the temporal evolution of the geology of SE Asia, a detailed tectonostratigraphic event chart was constructed by analyzing more than 300 publications for relevant observations. These data were divided by basement terrane and basin, and then used to define a series of key events and corresponding basin phases. Stratigraphy and petroleum systems have been characterized in this 4D framework, and most SE Asian megasequences coincide with these time steps.

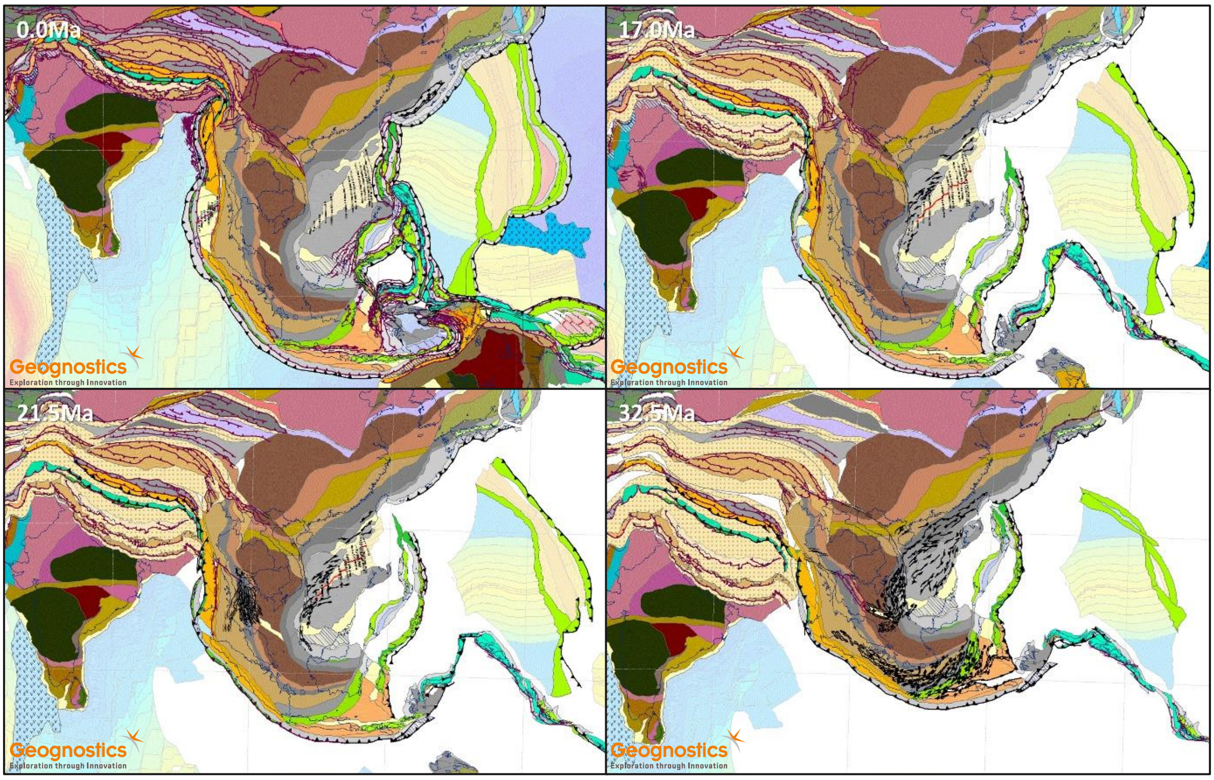
PLATE RECONSTRUCTION METHODOLOGY

Our plate modelling was undertaken using Rothwell's PaleoGIS software in ArcGIS. Starting in the present-day, we worked back in time to undo deformation patterns on major shear zones, basins and subduction zones, using the time steps outlined above. The resulting plate model was animated in Microsoft PowerPoint to enable controlled viewing both forwards and backwards in time. Animation is a key step in plate modelling as it highlights inconsistencies in plate rotation poles. Many published plate models do not animate well.

MODEL HIGHLIGHTS

Some significant outcomes of our plate model include:

- The recognition that SW Borneo and Peninsular Malaysia are part of the same rigid Sundaland basement terrane linked by mappable basement structures and compositional domains, discounting independent rotation of Borneo.
- 'Progressive rotational extrusion' of Sundaland, then Indochina was accommodated by a series of major strike-slip bounding shear zones that follow small circles, indicating block rotation. Firstly, the greater Wing Chao Shear Zones in Southern Thailand caused transpression in the Gulf of Thailand, opened the Malay Basin pull-apart, and 'horse-tailed' into the South China Sea opening the Penyu, Cuu Long and other rifts in the Late Eocene-Early Oligocene. As India moved northward, a second phase of extrusion occurred in the Mid-Late Oligocene, via sinistral strike-slip on the greater Red River Shear Zone in SW China and Northern Vietnam, opening a series of new syn-extrusion, strike-slip basins, most spectacularly in the Gulf of Thailand and the Nam Con Son Basin. These events caused clockwise rotation of Sundaland plus Borneo in two phases in the Late Eocene and Oligocene, consistent with observed basin evolution.
- The opening of the South China Sea is a logical consequence of our rotational extrusion model, which is consistent with the latest published data on the timing and kinematics of sea floor spreading, as well as rift ages for extension on its margins.
- A detailed analysis of the 'train wreck' of terranes in East Indonesia, consistent with the onshore geology, basin evolution, paleogeography and petroleum systems. This domain is dominated by westward movement of the Pacific Plate coupled with northward movement of Australia. We have analysed the complex counter-clockwise rotation of the Bird's Head in this context, explaining its surrounding basins and fold belts.
- A series of NW-trending sinistral strike slip shear zones linked the 'salami-slicer' tectonics of East Indonesia with NW Borneo, driving the Sabah Orogeny in the Mid Miocene. Unravelling these shear zones clarifies the geology of Northern Indonesia and the Philippines, and a series of linear island arcs and back-arc basins emerge that significantly simplify the geology of this highly complex region.



ORAL PRESENTATION

Montane Pollen Indicates Character of Mid Cenozoic Uplands Across Sunda Shelf

Robert J. Morley[1 2], Harsanti P Morley[1]

[1]*Palynova, UK*

[2]*Department of Earth Sciences, Royal Holloway, University of London, UK*

bobmorley100@gmail.com

Many aspects of the Cenozoic palaeogeography of Sundaland remain poorly understood, especially with respect to the past distribution of uplands. Montane pollen is a common element of palynomorph assemblages across the region and provides an insight into the palaeoaltitude and palaeoclimate of lowlands and uplands from the Paleocene to the Pliocene.

Using a dataset derived from the palynological analysis of more than 250 petroleum exploration wells, maps have been constructed showing the occurrence through time of pollen of temperate or montane taxa across the region, including hickory (*Carya*), walnut (*Juglans*), alder (*Alnus*), wingnuts (*Pterocarya*), Pere David's pine (*Keteleeria*), hemlock (*Tsuga*) and spruce (*Picea*). These taxa are essentially restricted to temperate Asia today, although a few occur locally on mountains in northern Vietnam and Thailand, Myanmar and Laos.

Taking into account issues of pollen transportation and provenance, the former vegetation of uplands can be proposed in the areas of the submerged Sunda Shelf as well as for the Malay Peninsula, Indochina and Borneo, and from this, palaeoaltitudes over time can be suggested for each upland area based on the occurrence of pollen of temperate climate plants.

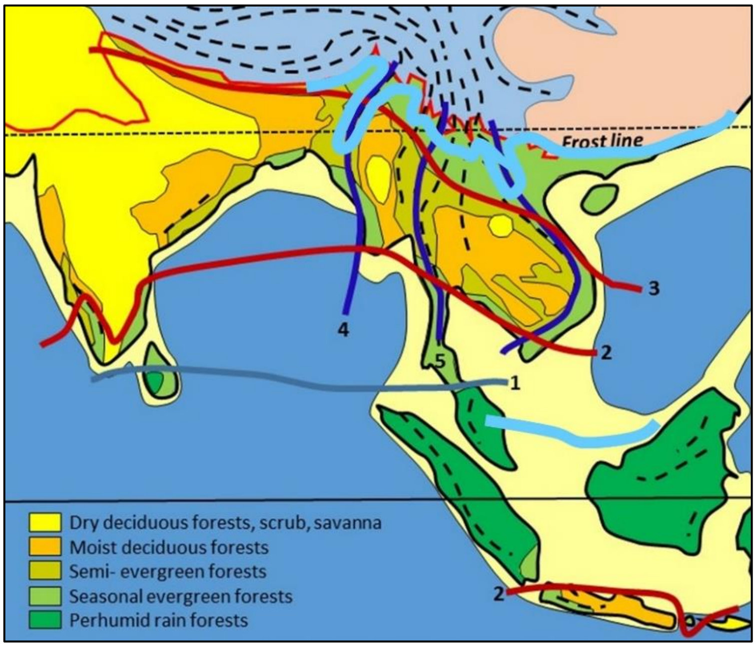


Figure 1. Present day vegetation belts in the South and Southeast Asian region (Ashton 2014, Morley in press), 1) Kangar-Pattani Line, marking the northern boundary of the perhumid tropics, 2) equatorward limit of seasonally dry climates, which control the distribution of semi-evergreen and deciduous forests and align with the Kra Isthmus; 3) northern limit of seasonally dry lowland climates. 4-6) N-S mountain ranges providing trackways for temperate plants to disperse equatorwards. Northern light blue line, southern limit of temperate deciduous trees, southern light blue line, southern limit of pollen of temperate trees in the Oligocene.

The distribution of Southeast Asian lowland vegetation is strongly controlled by latitude (Figure 1) with perhumid mixed Dipterocarp forests essentially occurring within 8° of the equator, and seasonally dry vegetation roughly from 12° to 20°N, then with seasonal evergreen forests occurring up to the frost line, which roughly coincides with the tropic of Cancer. The composition of montane vegetation on the other hand is controlled mainly by mean annual temperature, which changes with altitude, and seasonality (Fig 2). Pollen generated by lowland and montane vegetation is transported mostly by rivers and is widely preserved in marine sediments. A pollen assemblage from a marine deposit will probably contain pollen from lowland and montane vegetation occurring within an individual catchment, and once provenance is understood, the pollen record can be used to construct former lowland and montane vegetation on a regional scale. The former distribution of lowland vegetation based on fossil pollen will therefore provide an independent proxy for palaeolatitude, whereas pollen from montane plants provides a proxy for palaeoaltitude.

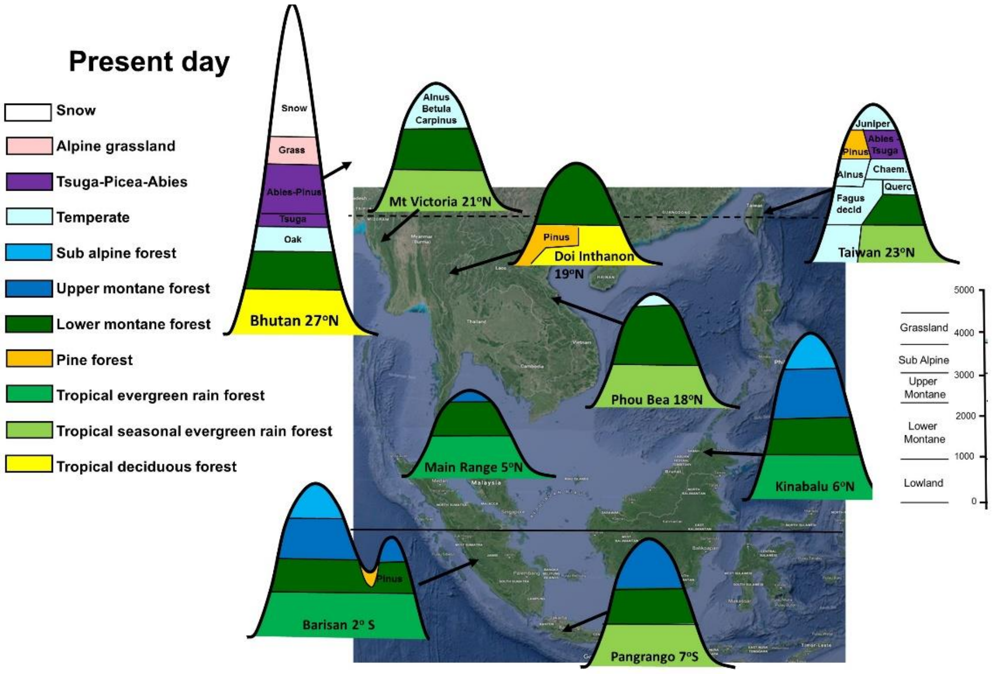


Figure 2. Present day mountain vegetation. In the perhumid tropics, montane vegetation consists of Lower Montane, Upper Montane and Sub-alpine formations. In the seasonal tropics, Upper Montane vegetation is missing and Lower Montane forests give way to temperate forests at 2000 m at 23°N and 2600 m at 18°N. There are no tall mountains between Mt Victoria in Myanmar and Kinabalu in Borneo.

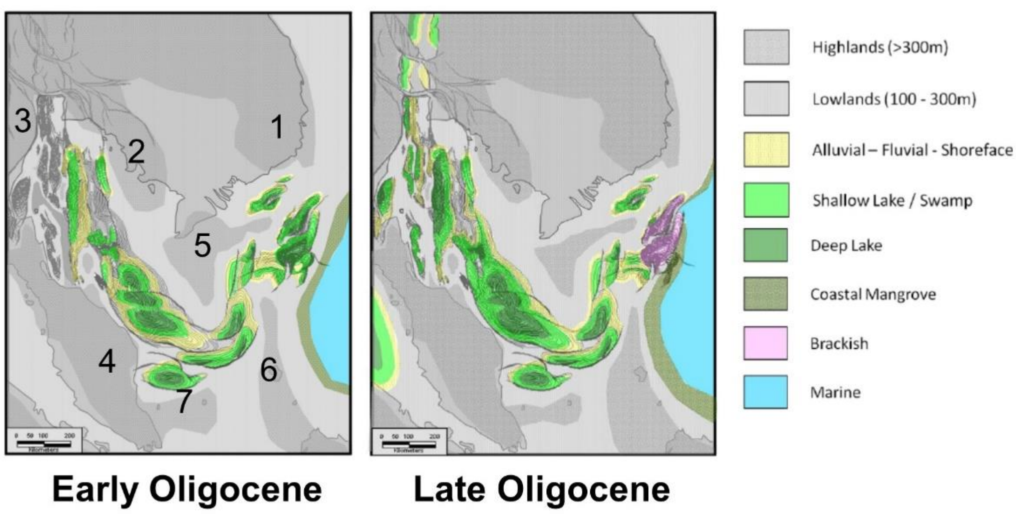


Figure 3. Areas which may include highlands during the Oligocene; 1, Ammanite Range in Vietnam; 2, Cardomoms in Cambodia; 3, Kra Isthmus; 4, Main Range, Malay Peninsula; 5, Con Son Swell; 6, Natuna Arch; 7, Singapore Rise.

In the Sunda region, areas which may have yielded uplands of sufficient altitude to support montane vegetation during the mid-Cenozoic are shown in Figure 3 (from Shoup et al 2012). As well as current upland areas such as the Ammanites, Cardomoms and Main Range, the Kra Isthmus, Con Son Swell and Natuna Arch were likely to have been of sufficient altitude during the Oligocene to bear a diverse montane palaeoflora.

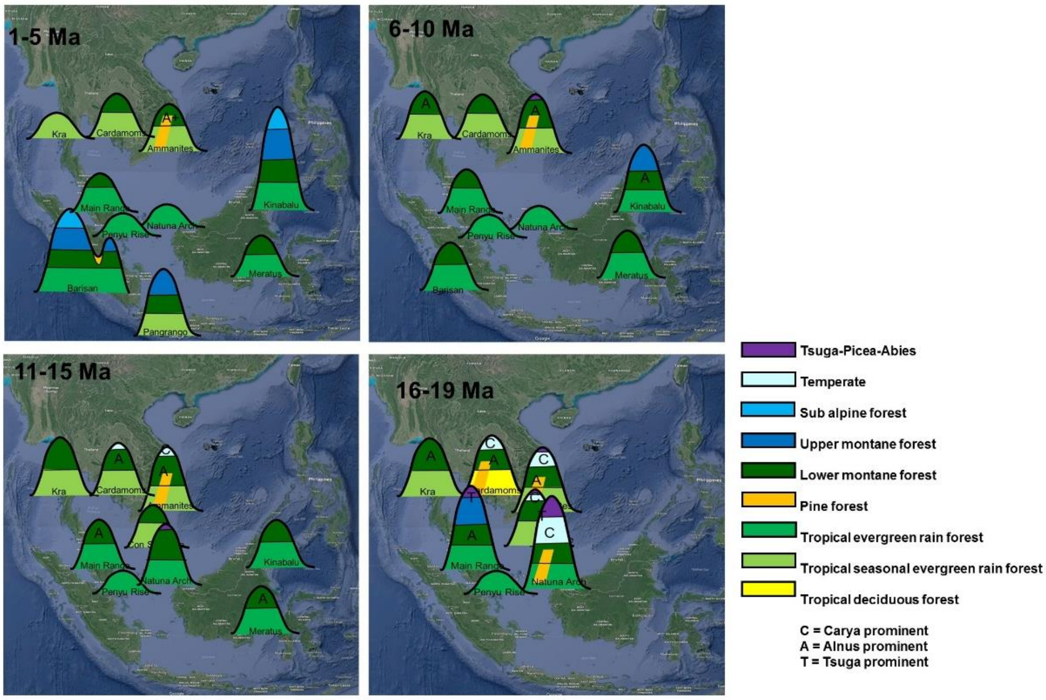


Figure 4a. Schematic altitudes of upland areas based on montane pollen occurrences, for time slices 1-5 Ma, 6-10 Ma, 11-15 Ma and 16 – 19 Ma

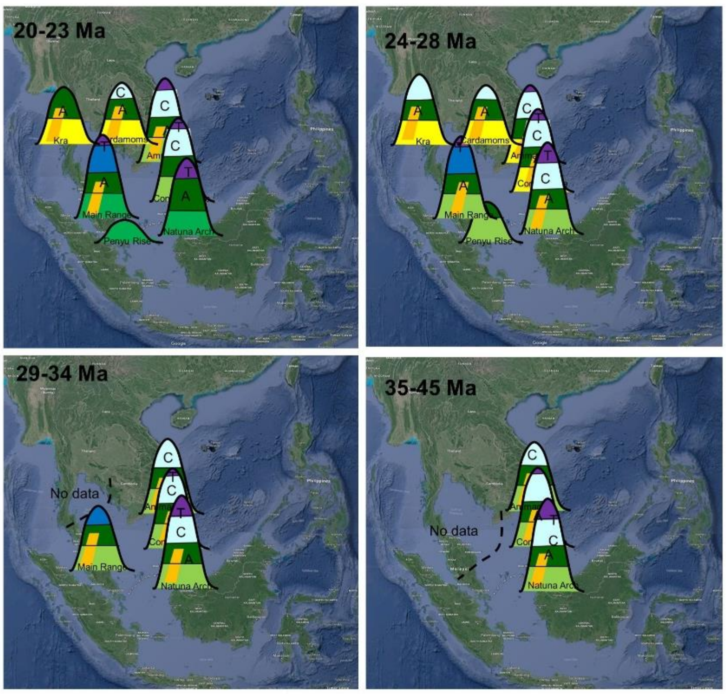


Figure 4b. Schematic altitudes of upland areas based on montane pollen occurrences, for time slices 20-23 Ma, 24-28 Ma, 29-34 Ma and 35-45 Ma

During the Late Eocene and Oligocene, the Natuna Arch, Con Son Swell and Ammanite Ranges were likely to have been of sufficient altitude to support temperate broadleaf and cool temperate conifer forests at their summits, with altitudes in the order of 2500m or more (Figure 4b). Highest altitudes were probably reached during the Late Oligocene. During the Miocene (Figure 4a), all of these areas variously eroded or subsided. Some further uplift may have occurred but the elevations of the Oligocene were not reached. The Late Miocene and Pliocene were characterised by uplift in Borneo, culminating in the Pliocene formation of Kinabalu (Cottam et al 2010, Merckx et al 2015), with the Barisan Range exhibiting uplift since the Late Miocene and the volcanoes of Java forming during the Pleistocene (Morley 2018).

The latitudinal distribution of vegetation over time is also discussed in relation to different plate tectonic models, with the transition from seasonal tropical to perhumid tropical climates initially taking place in southern Kalimantan and South Sumatra during the Late Oligocene and in the Natuna Arch and Malay Peninsula during the Early Miocene. The history of the regional shift from a seasonal tropical to a perhumid tropical climate during the Late Oligocene and Early Miocene is consistent with tectonic models that involve the clockwise rotation of Borneo into the equatorial zone, rather than models that keep Borneo in an equatorial position throughout the Cenozoic.

References

Ashton, P.S. 2014, *On the forests of Tropical Asia. Lest the memory fade*. Kew Publishing, Royal Botanic Gardens Kew, and Arnold Arboretum, Harvard University. 670pp

Cottam, M.A, Hall, R., Sperber, C. & Armstrong, R. 2010, Pulsed emplacement of the Mount Kinabalu Granite, North Borneo. *Journal of the Geological Society of London* 167, 49-60

Merckx, V.S.F.T, Hendriks, K.P., Beentjes, K.K. et al. 2015, Evolution of endemism on a young tropical mountain. *Nature* 524, 347–350.

Morley 2018, The complex history of mountain building and the establishment of mountain biota in Southeast Asia and Eastern Indonesia Chapter 31 in Hoorn, C., Perrigo, A and Antonelli, A., (eds) *Mountains, climate and diversity*. Wiley in press

Shoup, R.C, Morley, R.J, Swiecicki, T. and Clark, S. 2012, Tectono-stratigraphic Framework and Tertiary Paleogeography of Southeast Asia: Gulf of Thailand to South Vietnam Shelf. *Search and Discovery* Article #30246 Posted September 24

Day 1: 27th June 2018

Session 2: Myanmar

Chair: Keith Maynard – Woodside

11:15	Exploring the "Undeformed" Bengal Fan and What Lies Below	Romain Courel	Ophir Energy
11:40	Physics and Biology of Biogenic Gas Plays: Implications for SE Asia	Duncan MacGregor	MacGeology
12:05	Exploration in the Central Burma Depression, Onshore Myanmar	Andy Racey	Andy Racey Geoscience

ORAL PRESENTATION

Exploring the "Undeformed" Bengal Fan and What Lies Below: Deepwater Rakhine Basin

R. Courel[1], W. Parsons[1], E. Pettinotti[1], D. Harger[1], N. Bianchi[2], J. Teasdale[3], K. Bale[4]

[1]*Ophir Energy, UK*

[2]*LR Senergy, Indonesia*

[3]*Geognostics, UK*

[43]*Chevron, Thailand*

romain.courel@ophir-energy.com

Ophir Energy and partner Parami Energy signed the deepwater Myanmar AD-3 PSC in December 2014 and quickly covered the whole block with 10,000 km^2 of broadband 3D seismic data.

Processing centres provided the team with high quality time-processed products, which brought great improvement and deepening of the imaging available in this part of the deepwater basin: the "undeformed" Bengal Fan, located west of the Rakhine deformation front.

This permitted the joint venture partners to consider drilling an exploration well ahead of their PSC commitments; however, plans had to change when it became evident that some of the best prospectivity was located in areas where shallow gas and Mass Transport Complexes were inducing large structural anomalies on the time structure of the data and attenuating important amplitude information, hindering the exploration task.

As the exact causes of the image degradation were not clear, a subset PreSDM was run, before Ophir asked contractors for feasibility studies to investigate possible solutions such as Q tomography and Q migration. A full-block depth processing project was finally designed from these learnings and regional processing experience.

This talk will present the geology of the block, the exploration challenges and discuss how the various 3D datasets have provided new insights into the understanding of the basin. Having deep, good quality seismic available over a large area helped us develop a consistent geological model at the scale of this tectonically active margin. New imaging of the basement brought a few unexpected surprises regarding the nature of the crust and its early history, well before it was hidden in Neogene times below a thick deepwater sediment fan sourced from the Bengal Delta with large-scale channel systems.

The complete dataset now available to Ophir shows conditions prone to the establishment of a prolific biogenic gas charge as well as potential for a deeper thermogenic petroleum system. Volcanic basement highs are large enough to induce differential compaction of the fan sediments deposited on top of them which provides migration focus and structural components to the traps.

Ophir Energy managed to maintain a workflow able to ensure operational readiness, involving simultaneous progress of interpretation and well design work: for example, geohazards, pore pressure and fracture gradient studies were conducted early on a block scale to anticipate the contingencies needed.

ORAL PRESENTATION

Physics and Biology of Biogenic Gas Plays: Implications for SE Asia

Duncan Macgregor[1]

[1]*MacGeology Ltd, UK*

duncan@macgeology.co.uk

This century has seen a surge in biogenic gas discoveries worldwide, particularly in deepwater settings, with fields being found of much larger scale than previously. This trend is represented in Southeast Asia by the Rakhine Basin discoveries, while other global examples include the Levantine and Zohr discoveries in the Eastern Mediterranean. Many such discoveries lie deeper than previous biogenic gas finds and at temperatures exceeding that of the biogenic window (Figure 1).

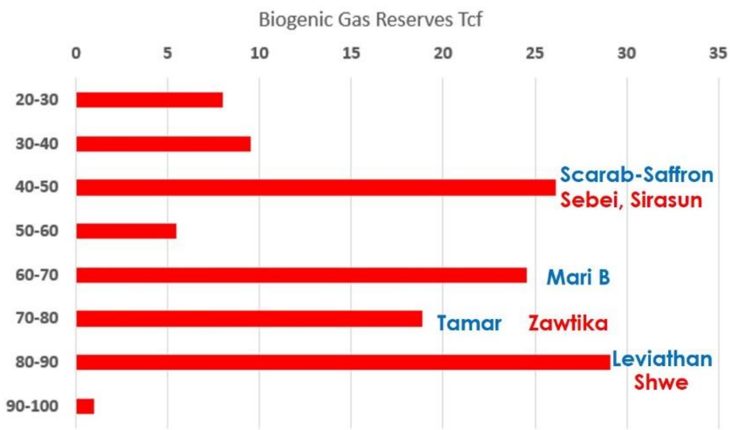


Figure 1. Global Biogenic Gas reserves, (excluding mixed systems in West Siberia, Caspian and GOM, plotted by reservoir temperature (deg C). SE Asia fields labelled in red, Eastern Mediterranean in blue

Biogenic gas plays in SE Asia (Figure 2) had previously attracted relatively little attention, with the region often viewed as generally unfavourable for their development due to high surface temperatures and high geothermal gradients. Study of the few small to moderate sized biogenic gas occurrences previously found in the region appear to confirm such a view for most onshore and shallow marine settings, including provinces in East Java, Indonesia and Qaidam, China. PVT data from these provinces illustrate constraints that confine the biogenic window to shallow intervals where the gas expansion factor is low and seals are often under-compacted.

It is shown here, with reference to the Rakhine Basin of Myanmar and the Eastern Mediterranean, that the evolution of PVT (Pressure-Volume-Temperature) conditions in deep water (both at the time of sediment deposition and at present day) are considerably more favourable to the development of multi-Tcf biogenic gas fields. This results not only from the lower seabed temperatures and geothermal gradients that characterize these regimes, but also from the effects of the increased pressure imposed by a water column. A key constraint to date on shallow water biogenic plays has been that generation is shut off at around 60-70^{o} C, below which the volume of gas can be expected to shrink with increased pressure. The proportional rate of shrinkage however declines with increased pressure, so this is far less of a concern in deep marine settings. This can be illustrated with reference to the PVT History of the deepest pools of the Shwe Field (Figure 3).

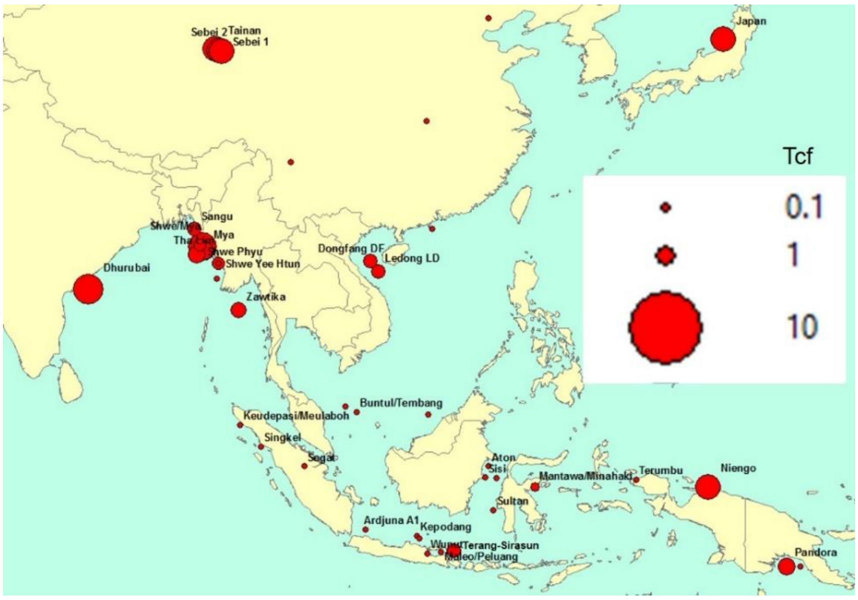


Figure 2. Biogenic or mixed biogenic-thermogenic gas fields of the Asia-Pacific region

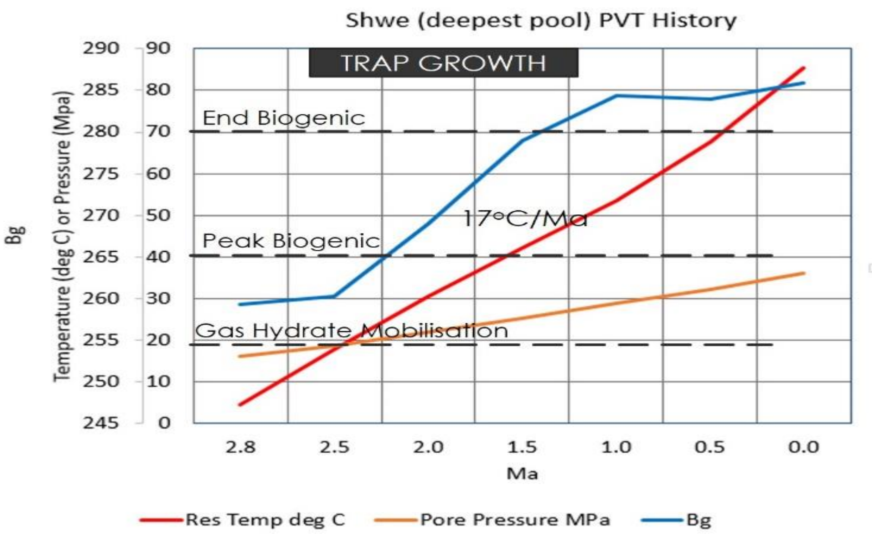


Figure 3. Interpreted PVT and petroleum system history of the deepest pool of the Shwe field. Bg = gas expansion factor, controlling compression of the gas pool after generation has ceased.

A matrix is developed here from study of the working analogues for evaluating the potential for undiscovered biogenic gas systems in SE Asia, which will be demonstrated for some of the generally colder basins of eastern Indonesia and Papua New Guinea. Key factors include:

a. The occurrence of thick series of type iii kerogen bearing sediments, e.g. in a prodelta.
b. Development of anoxia and/or heating rates of 3-25 °C/Ma.
c. Under-compaction of sediments with pore spaces large enough to accommodate bacteria.
d. Low surface / seabed temperature (as in deepwater) and/or geothermal gradients under 25 ° C/km.
e. Deposition in a highly pressured deep marine setting.
f. Development of traps at a very early stage after deposition, particularly syn-sedimentary compressional anticlines, associated pinchouts and carbonate build-ups.
g. Development of a reasonably compacted seal soon after deposition.

ORAL PRESENTATION

Exploration in the Central Burma Depression, Onshore Myanmar

Andy Racey[1]

[1]*Andy Racey Geoscience, UK*

andy@andyracey.com

The Central Burma Depression comprises several basins (Figure 1), for which the exploration results of the main four basins are described below and summarised in Table 1.

CHINDWIN BASIN

The most northerly basin, the Chindwin Basin covers 35,185 km^2 and is the least explored of the main basins. Oil and gas seeps are recorded in the Western Outcrops and Eastern Thrust Belt whilst 28-35^o api paraffinic oil has been produced from hand dug wells. Exploration to date has resulted in gas discoveries in the Eocene of the Yenan and Patolon fields and oil in the Miocene of the Indaw Field, whilst several large structures remain to be tested. Uyu is the largest mapped structure but has only been tested by one well drilled by Amoco which was dry.

SALIN BASIN

The most explored basin is the Salin Basin where the TD ages are mainly Eocene and Oligocene. Most of the major onshore fields are located in this basin and these include 20 of the 28 known onshore oil discoveries. The main oil-bearing reservoirs are in the Oligocene and to a lesser extent in the Lower to Middle Miocene and Upper Eocene. Source rocks occur throughout the Lower Eocene to Upper Oligocene, although the main source intervals are believed to be the Upper Eocene and Lower Oligocene.

PYAY BASIN

The Pyay Basin covers approximately 24,484 km^2 and contains 12 oil and gas fields with many other wells having significant hydrocarbon shows, although exploration to date has mainly focussed on the area around the main discoveries. Most of these wells targeted the Miocene and to a lesser extent the Oligocene. Eocene and Oligocene formations, although oil bearing in Letpando and Kyaukkwet Fields in the Salin Basin to the north, have not been tested in central and southern parts of basin. The discoveries to date are small with traps comprising long narrow anticlines cross-cut by strike-slip faults. The Pyay Field was discovered in Miocene carbonates below mud volcanoes associated with gas seeps and was the first carbonate discovery in Myanmar. Sub-thrust plays in Eocene and Oligocene sandstones are mainly untested yet are proven to be oil-bearing to the north.

AYEYARWADY BASIN

Most of the wells in this basin have targeted the Miocene, resulting in mainly gas discoveries with minor condensate (65^o api) in Upper and Middle Miocene deltaic sandstones and Pliocene fluvial sandstones. Discoveries include Apyauk, Nyaungdon, Maubin and Payagone. The main discovery is Aypauk, with an EUR of 100-450 Bcf plus associated condensate. Subthrust plays are only moderately explored whilst Eocene and Oligocene sandstones are mainly untested.

PETROLEUM SYSTEMS OBSERVATIONS AND COMMENTS

Many of the drilled structures are tectonically active at present day and thus carry a significant leakage risk. The geochemistry of the oils commonly indicates minimal biodegradation and could indicate direct "plumbing" into a mature source kitchen at depth. Some of the oils are fractionated rather than cracked. This may indicate the presence of a deeper liquid play (possibly Eocene) in the central and southern parts of the Central Burma Depression.

There is a general change from heavier oil in north to lighter oil (condensate) and then gas in the south.

Despite high levels of activity only four fields with greater than 100 MMbo EUR have been discovered to date. To what extent has this been due to limited access to technology due to sanctions?

Why has such a large area (Central Myanmar Depression) with a large sediment thickness yielded so little oil? Many of the structures appear to be under-filled whilst hydrocarbon migration is mainly vertical and over short distances. Trap breaching due to recent tectonism may limit hydrocarbon charge to these structures.

Sandstones often have poor reservoir quality and/or are markedly compartmentalised by faults. Both factors may limit hydrocarbon migration into these sandstones.

Overpressure is commonly encountered in many of the wells drilled and has often led to the suspension of such wells. However, reservoir quality sandstones may be present below such over-pressured zones and this idea has yet to be adequately tested.

Seismic imaging is often difficult and has resulted in most wells (and therefore discoveries) being drilled on the more gently dipping limbs of the main anticlinal structures. Improved imaging techniques may in the future allow the more steeply dipping limbs of such structures to be tested.

Basin	No. Expl. Wells	Well Result (percentage of total wells by basin)								
		Dry	Oil Discovery	Oil shows	Gas & Condensate	Gas Discovery	Gas Shows	Oil & Gas Discovery	Oil & Gas Shows	Unknown
Chindwin	23	22	1	13	0	3	9	9	43	0
Salin	273	30	20	7	1	17	9	5	7	4
Pyay	115	37	7	5	5	17	12	5	5	7
Ayeyarwady	88	38	1	5	15	18	17	3	2	1

Table 1. Summary of exploration results in the four main basins of the Central Burma Depression, Myanmar

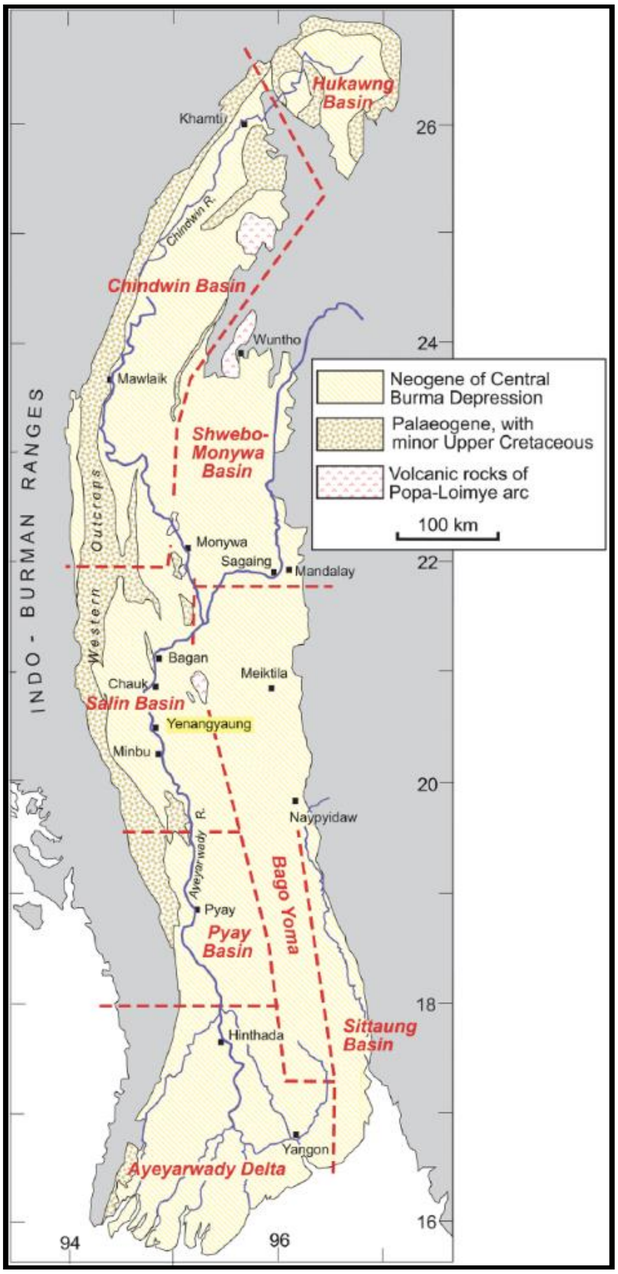


Figure 1. Basin Map of the Central Burma Depression, after Racey & Ridd, 2015

Day 1: 27th June 2018

Session 3: Papua New Guinea

Chair: Sam Algar – Oil Search

13:30	Forward Modeling and Mechanical Behaviors of a Carbonate Platform Involved in Fold-and-Thrust Belt. The Case of Antelope Field and Surrounding Prospectivity	Charlie Kergaravat	TOTAL
13:55	Pasca-A Gas Condensate Field, a 50-year-old Field brought to Life	Huw Evans	Twinza Oil
14:20	New Insights into the Tectonic Architecture and Evolution of the Offshore Papuan Plateau, PNG	Alaister Shakerley	TOTAL
14:45	New Regional Data and Advances in Understanding of the Stratigraphy, Tectonics, Structure and Prospectivity of the Gulf of Papua (Papua New Guinea)	Andrew Weller	Searcher Seismic

ORAL PRESENTATION

Forward Modeling and Mechanical Behaviors of a Carbonate Platform Involved in Fold-and-Thrust Belt. The Case of Antelope Field and Surrounding Prospectivity

C. Kergaravat[1,4], W. Vetel[2], P. Souloumiac[3], P. Jousselin[2], W. Gordon-Canning[2], A. Shakerley[2], A. Pichon[2], F. Gisquet[1], J-C. Ringenbach[1]

[1]*TOTAL E&P, CSTJF, Pau, France*

[2]*TOTAL E&P, Singapore*

[3]*Université de Cergy-Pontoise, Laboratoire GEC, France*

[4]*Université de Pau et des Pays de l'Adour, France*

charlie.kergaravat@total.com

The Elk-Antelope multi-Tcf gas field (operated by Total 40.13% and partners: Exxon 37.04%, OilSearch 22.84%) located within PRL15 in western Papua New Guinea represents a singular example of a Tertiary isolated carbonate build-up located within the foothills at the junction of two major Fold Belt (FB) systems, the Papuan and the Aure Fold Belts.

The reservoirs of Antelope are associated with the Early-Mid Miocene Darai Formation, dominated by shallow-water carbonate deposits passing laterally to the Puri mud-prone deep-water carbonates and resedimented shallow water carbonates, then overlapped by Orbulina Marls. A thick overburden is composed of the shale-rich Orubadi and sand-rich Era foreland mega sequence. In that sense, the influence of mechanical stratigraphy plays an overwhelming role in the location of thrusts and final thrust sheet geometries driven by subsequent decollement levels both in the Mesozoic underlying sediments (Ieru and potentially Barikewa Fm.) and in the Orubadi Fm. The contrasted rheology of the implied series led to a strong decoupling between surface deformation and carbonate sub-thrust at depth, ie. large syncline development on top of carbonate thrust sheets.

In this way, the prospectivity of peri-Antelope and potential shallow or deep carbonates relies directly on the understanding of the structural model and the reconstruction of the pre-deformed framework to understand the palaeo-environnement and target more accurately areas of high reservoir quality as seismic imagery is very poor in this FB environment and does not allow direct de-risking.

For that purpose, a multiple approach integration is proposed using:

1. 3D constrained model and 2D forward modelling approach (Move™ software),
2. mechanical approach (Op+Um G2 software) based on final element, and
3. uplift quantification based on river profile analysis.

Two major structural hypotheses have been tested with forward modelling:

- Pure thin-skinned deformation with low angle thrusts using a shallow decollement level below the carbonate: the well-known Cretaceous Ieru detachment. This model implies large displacement (cumulated shortening up to 15km) along thrusts and a stacking of flat thrust sheets.
- Deeper decollement activation within the Barikewa Fm (cumulated shortening up to 7km) and / or involving pre-existing normal faults.

These two models can fit the surface and sub-surface observations. Consequently, in order to discriminate between alternative hypotheses a mechanical approach has been used integrating the influence of a stiff carbonate platform in between two incompetent layers (Orubadi and Ieru) on the onset and location of thrusts.

Finally, our multiple data integration approach refined:

- The timing of the deformation and the location of recent uplift.
- The most likely activation of deeper decollement levels.
- The location of thrusts in relation to the presence of carbonate lateral thickness variations in case of mechanical stratigraphy architecture dominated by two incompetent layers encompassing a stiffer layer.

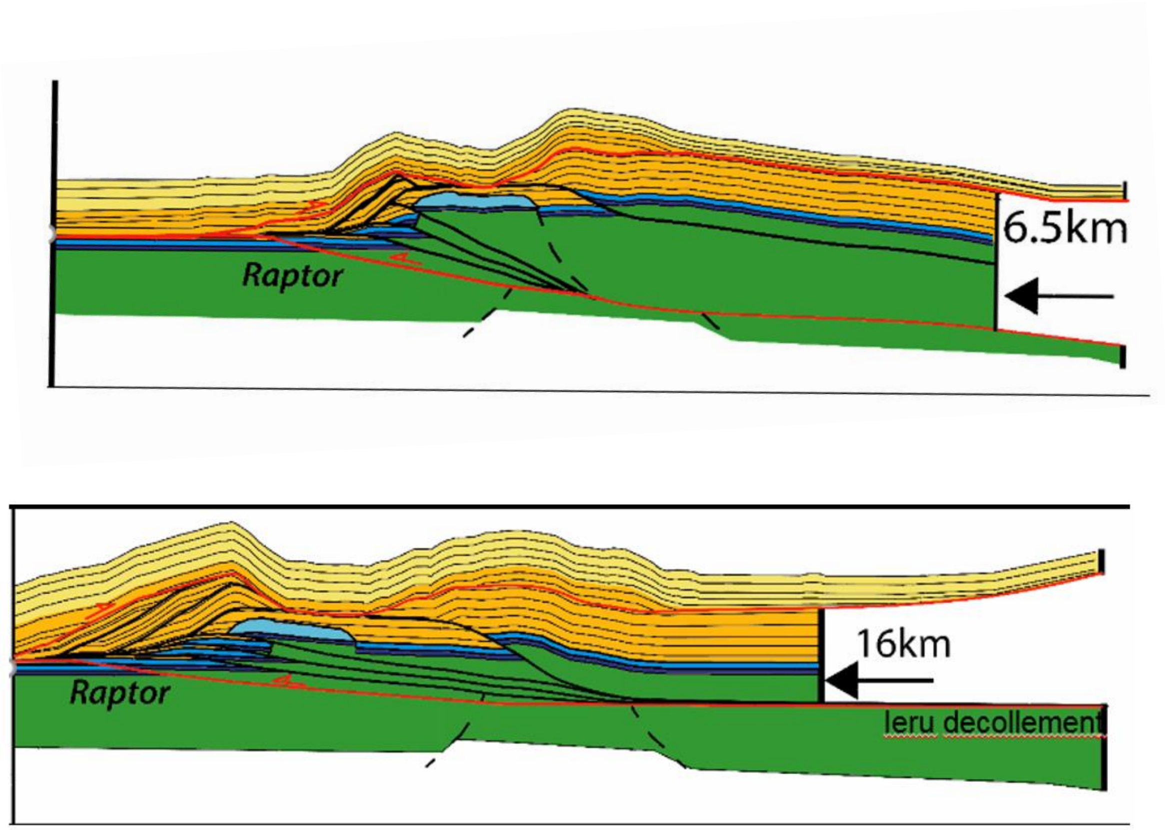


Figure 1. Two hypotheses of forward modelling testing the activation of a shallow versus deep decollement level on final geometry (amount of uplift, overburden erosion, …)

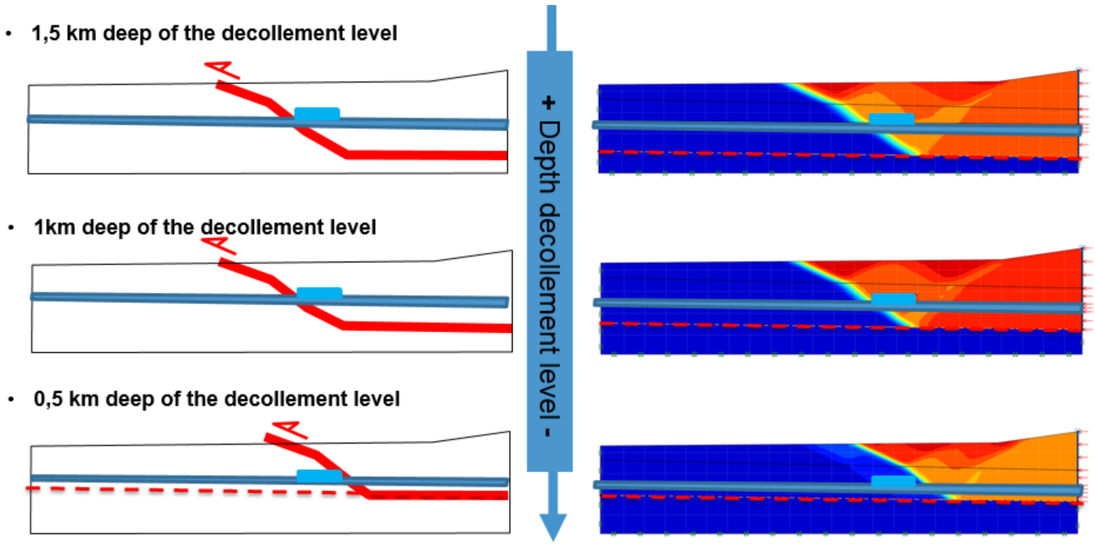


Figure 2. Mechanical modelling using Op+Um G2 software showing the influence of the depth of decollement level on the thrust onset at the front or at the back of a simulated rigid carbonate platform

ORAL PRESENTATION

Pasca-A Gas Condensate Field, a 50-year-old Field brought to Life

Huw Evans[1]

[1]*Twinza Oil, Singapore*

huwevans@twinzaoil.com

The Pasca A gas condensate field was discovered in offshore Papua New Guinea by Phillips Petroleum in 1968 in a classic reefal build-up which proved to be over-pressured and prolific. Significant challenges were presented during evaluation and drilling, with the wells being drilled with total losses using a hazardous mud-cap technique. In 1983 Superior Oil lost control of the Pasca A3 well and the poor public record keeping resulted in the event becoming part of PNG folklore.

In 2011 Twinza licenced the Pasca A field and late last year successfully drilled and tested the Pasca A4 well using modern managed-pressure drilling techniques. On test the well achieved an equipment constrained rate of approximately 53 MMcfd with a very high natural-gas liquid yield of condensate and LPG. The Pasca A field now has independently assessed proven liquid reserves for the first time since discovery.

The presentation will summarize how Twinza challenged the widespread scepticism of the PNG regulator and Industry and overcame considerable technical, drilling and engineering challenges leading to the development of the country's first offshore field. The Pasca A field is currently entering the final approval stages with the PNG regulators and will lead to Papua New Guinea's first offshore production and the country's first offshore production infrastructure.

ORAL PRESENTATION

New Insights into the Tectonic Architecture and Evolution of the Offshore Papuan Plateau, PNG

A. Shakerleyl[1], C. Kergaravat[1], V Bailly[1], W. Vetel[1], W. Gordon-Canning[1], A. Kusuma[1], M. Dixon[1], J-C. Ringenbach[2]

[1]*TOTAL E&P, Singapore*

[2]*TOTAL E&P, CSTJF, Pau, France*

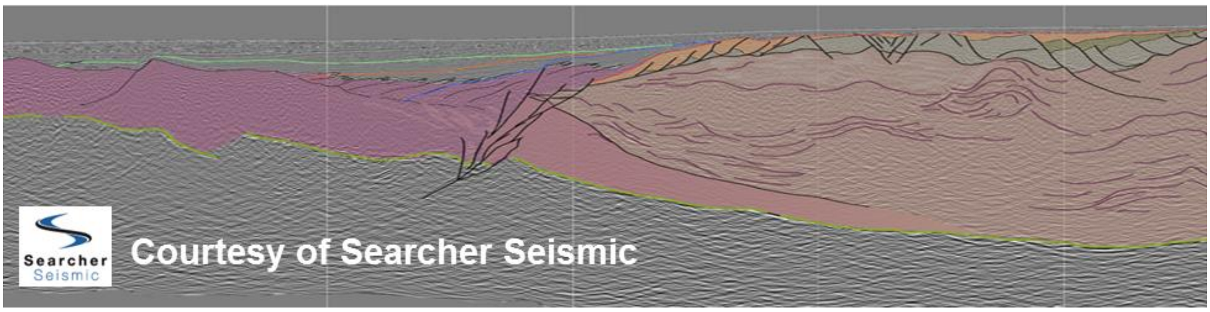
alaister.shakerley@total.com

The tectonic architecture and evolution of the Offshore Papuan Plateau (OPP) has remained enigmatic until recent years due to the sparsity of marine seismic reflection data.

Following new data acquisition in 2016-2017 by Searcher Seismic, remarkable imaging to 14 seconds TWT provides a window into the mechanics and rheology of the lithosphere. Light is shed on possible, multiple 'Cretaceous' rifting events and the consequent transition from rift to drift that led to the formation of the Coral Sea in the Early Tertiary. The style of rifting and resulting structural architecture varies, depending on the tectonic origin of the extension and the thermo-mechanical state of the lithosphere. The earlier rifting event(s) affecting the OPP are associated with extension generated in a back-arc setting. The resulting architecture is typified by low angle normal faults, multiple detachments and crustal core complexes. The later rift event which concluded with the formation of the Coral Sea was formed in a westward propagating rift propagator setting. Higher angle normal faults rooting into deeper detachments, that point to a contrast in rheological behaviour of the OPP crust and the influence of inherited fabric, can be observed between the early and late rift events.

The transition from rift to drift of the Coral Sea is interesting, as neither the presence of mantle exhumation or typical packages of seaward dipping reflectors (SDR) are recorded. Despite the absence of voluminous flood basalts, the continent to ocean transition (COT) displays many geometries normally associated with magmatic margins. Seaward dipping flows (SDF) are observed underlain by landward dipping normal faults detaching within a shallow brittle to ductile transition. However, the packages containing the SDF appear to be primarily composed of sediments and are significantly thinner than their counterparts from volcanic margins. A large reservoir of highly ductile lower crust and normal faulting processes associated with formation of core complexes is interpreted to facilitate the transition from rift to drift and the rise and increasing role of melt. We propose that final break-up and the formation of oceanic crust occurs when the supply of mobile ductile material to the transition zone is restricted by crustal welds; and once the remaining crust at the point of breakup is thinned to a critical thickness.

This aim of this presentation is to show with new, high quality seismic reflection data the tectonic architecture and evolution of the OPP and new insights into the transition from continental rifting to seafloor spreading in a rift propagator setting.



ORAL PRESENTATION

New Regional Data and Advances in Understanding of the Stratigraphy, Tectonics, Structure and Prospectivity of the Gulf of Papua (Papua New Guinea)

Andrew Weller[1], Said Amiribesheli[2], Dariusz Jablonski[2]

[1]Searcher Seismic, Australia

[2]Discover Geoscience, Australia

a.weller@searcherseismic.com

Between 2015 and 2017, Searcher Seismic acquired approximately 32,500 km of long-offset PSDM 2D seismic data and reprocessed approximately an additional 13,000 km of previously acquired 2D data in the Gulf of Papua, Papua New Guinea (PNG). The new data has resulted in a significant improvement in subsurface imaging and areal coverage, providing the foundation for a new integrated analysis of the region. In addition, a regional drop core geochemistry and heat flow survey provides important clues regarding the existence of working petroleum systems in the area. The evaluation of these new datasets has improved the current understanding of the stratigraphy, plate tectonics, local structure and petroleum prospectivity of the Gulf of Papua.

New seismic allowed identification of several depositional packages that are often bounded by regional unconformities related to the tectonic development of the area. Seismic and shipborne gravity/magnetics analyses allowed a confident identification of the following events/packages:

1. Moho event, allowing estimation of the crustal thickness and differentiation between oceanic and continental crust and calibration of the heat flow measurements.
2. Palaeozoic, severely folded succession, analogous to eastern Australia accretionary terrains.
3. Permian, analogous to the Bowen Basin in Queensland, Australia.
4. Triassic to Jurassic succession, supported by the existence of the Jurassic seep identified by the Davaria geochemical survey.
5. Presence of previously unidentified block faulted highs with Miocene reefs and carbonate platform build-ups.
6. Pliocene and younger sandstone basin floor fans.
7. Extension of the compressional front into the deep-water Gulf of Papua.

These observations have been integrated into an updated plate tectonic model that predicts widespread deposition of the Permian and Triassic to Tertiary source rocks estimated to be often within the hydrocarbon generative window.

Day 1: 27th June 2018

Session 4: Indonesia

Chair: Nicola Adams – BP

15:45	Creative Exploration in a Mature Basin: Jangkrik and Merakes Discoveries (Kutei Basin, Indonesia)	Lorenzo Meciani	ENI
16:10	Shallow Gas Play Takes Off in West Natuna Sea, Indonesia	Amir Mahmud	Conrad Petroleum
16:35	The Greater Tarakan Basin Area - New Plans and New Opportunities	Allan Scardina	VGS and Associates
17:00	Regional Review of Statoil's Indonesian Exploration Portfolio and Upside	Toril Karlberg Dyreng	Equinor

PESGB SEAPEX Asia Pacific E&P Conference
Olympia Exhibition Centre, London
27th – 28th June 2018

ORAL PRESENTATION

Creative Exploration in a Mature Basin: Jangkrik and Merakes Discoveries (Kutei Basin, Indonesia)

Lorenzo Meciani[1], Marco Orsi[1]

[1]Eni Spa, Italy

lorenzo.meciani@eni.com

The Kutei Basin is located on the east coast of Kalimantan Island, in central Indonesia. The prospective sequence is Eocene to Recent in age and is predominantly composed of Mahakam River derived fluvio-deltaic to deep water sediments, deformed by regional compressional tectonic movements.

The Kutei Basin is one of the longest-explored petroleum basins in the world, with 125 years of onshore and offshore hydrocarbon exploration and exploitation and more than 850 exploration wells drilled. It can definitely be considered as an historical, mature basin. From the initial discovery of Sanga Sanga oil field, made in 1896, more than 13 Bboe of recoverable oil and gas resources have been discovered.

Eni (re)entered Indonesia and the Kutei basin in 2000 as a result of the acquisition of Lasmo, who at the time held several assets in the country, including in the Kutei Basin. Eni reinforced its position in the basin with the award of additional blocks, including Muara Bakau PSC in 2002 (Eni operator, presently with ENGIE E&P International SA and Saka Energy Indonesia as partners), where the Jangkrik and Jangkrik NE discoveries were made in 2009-11, and East Sepinggan PSC in 2012 (Eni operator, with Pertamina as partner), where Merakes was discovered in 2014.

The two discoveries are located in the southern part of the Makaham delta, in water depths of 450 m (Jangkrik) and 1350 m (Merakes).

Both discoveries are characterized by creative and innovative exploration thinking associated with the use of state of the art technology.

In the Kutei basin, exploration both in shallow and deep water was historically aimed at Miocene targets, but the Jangkrik gas discovery pursued an innovative exploration play composed of Pliocene slope channels. Jangkrik NE proved a significant extension of this play, confirming the validity of the approach. The Jangkrik complex today comprises Jangkrik Main and Jangkrik NE, cumulatively exceeding 2.5 Tcf GIIP, and is composed of many separated channels, mainly not juxtaposed. The size of each individual channel is relatively modest and even the largest pool would not be able to be individually economically produced. The project's commerciality was generated by a delineation campaign with a 100% drilling Rate of Success, supported by seismic amplitude indications.

The limited lateral extent of each individual channel has required the acquisition of a new dedicated 3D survey and the optimization of drilling trajectories. A multidisciplinary, integrated team effort was essential for the success of the entire project, from the delineation to the development drilling.

The production from the Jangkrik field started in May 2017, three and a half years from sanctioning of the development project. The gas is processed at a dedicated Floating Production Unit, then flows to shore via a 79 km dedicated pipeline to the East Kalimantan Transportation System, finally reaching the Bontang gas liquefaction plant.

The Merakes gas discovery is also within the previously neglected Pliocene sequence, but located in a more basinal environment, where the Pliocene turbidites form a large fan lobe at the base of the slope. Remarkably, the well Gambah-1, drilled by the previous operator in 1999, missed the Merakes fan by few hundred meters. The well, aimed at a deeper Miocene target, was dry and therefore the area was later relinquished. Merakes pre-drill assessment identified that Gambah-1 had drilled a large canyon filled with a mixture of re-sedimented carbonate and shale that had cross-cut and eroded the previously deposited Merakes Fan. Merakes-1 successfully verified this hypothesis, finding a significant gas accumulation with estimated 2 Tcf GIIP.

Merakes-2, drilled in 2017 to test the part of Merakes lobe on the opposite side of the Gambah mud-filled channel, successfully found gas hydraulically separated from Merakes-1, confirming the quality of the discovery and the model.

The Joint Venture is currently evaluating options for an accelerated development of Merakes discovery.

In summary, Merakes and Jangkrik have again proved that in a mature basin creative ideas and exploration approaches can still lead to discoveries. More than 4.5 Tcf GIIP in excellent quality reservoir sands have been discovered by pursuing a previously neglected sequence (the Pliocene) with innovative ideas (clustering many small channels, pursuing previously drilled areas).

These creative exploration ideas would not have generated the Jangkrik and Merakes successes without the fundamental support and integration of top-class contributions from many disciplines such as sedimentology, geophysics (DHI identification, seismic acquisition and processing), drilling, reservoir modelling and others, and an effective project coordination and management.

The authors are grateful to the Indonesian authorities and to the Joint Ventures' partners for having granted permission to present this paper.

ORAL PRESENTATION

Shallow Gas Play Takes Off in West Natuna Sea, Indonesia

Amir Mahmud[1], Miltos Xynogalas[1], Radian Z Hartama[1]

[1]*Conrad Petroleum Ltd, Indonesia*

amir@conradpetro.com

The West Natuna Basin is located between the basement highs of the Sunda Shelf to the south, the Natuna Arch to the east and the Khorat Swell to the north, in the West Natuna Sea, Indonesia. The basin has had a complex structural history comprising microplate collision, intrusion, extension, inversion and wrenching. The basin can be viewed as the south-eastern extension of the Malay Graben and was initially formed as a series of separate half grabens, that with increasing post-rift subsidence eventually formed the overall basin.

Until recently, shallow biogenic gas in the West Natuna Basin was deemed to be a shallow drilling hazard. With a strong demand for natural gas, the shallow accumulations have been reconsidered as exploration targets. West Natuna Exploration limited (WNEL) the operator of Duyung PSC, recently proved the presence of a large resource of biogenic gas within the sands of the Muda Formation in the eastern portion of the PSC. The structure is a flat-topped anticline, with an extent of approximately 490 km^2, located above the inverted Anambus Graben in the centre of the West Natuna Basin.

The Muda Formation is of Pliocene age and is the youngest formation in the basin. Intra Muda Sands are unconsolidated and are encountered at around 1250 ft TVDSS. This paper will present some interesting subsurface findings pertaining to the understanding of the shallow gas play of the Muda Formation.

PESGB SEAPEX Asia Pacific E&P Conference
Olympia Exhibition Centre, London
27th – 28th June 2018

ORAL PRESENTATION

The Greater Tarakan Basin Area - New Plays and New Opportunities

Allan Scardina[1], Jon Teasdale[2], Herman Darman[3]

[1]*VGS and Associates Pty Ltd, Australia*

[2]*Geognostics, United Kingdom*

[3]*Indogeo Social Enterprise, Indonesia*

allan.scardina@vgsandassociates.com

The greater Tarakan Basin area, including the Tidung, Berau and Muara sub-basins, has long been seen as a second-tier hydrocarbon province when compared to both the Kutei Basin / Mahakam Delta area to the south and the basins of Northwest Borneo: the Luconia and Baram-Balabac Basins. While it is unlikely that the Tarakan Basin area resources will ever eclipse those two large hydrocarbon provinces, a continuing string of modest discoveries does suggest that the Tarakan Basin area has more potential than previously believed. The focus of this presentation will be on highlighting the potential of a possible new play in the Tarakan Basin using plate tectonic models, regional geology, and global analogs.

The greater Tarakan Basin area is thought to have formed in the Early Eocene in response to back-arc extension driven by Pacific slab rollback [1]. This same tectonic event also caused the opening of the Makassar Straits / proto-Sulu Sea and the formation of the Kutei Basin. However, compared to the largely orthogonal extension associated with the Kutei Basin formation, current plate models along with supporting regional geologic data suggest a slightly oblique or transtensional opening of the greater Tarakan Basin Area.

Basins that form through pure transtensional extension typically have dip profiles with abrupt changes in beta factor and associated narrow shelves with steep slopes. The narrow shelf with limited extension provides for only minor accommodation space for post-rift sediments. This geometry lends itself to the formation of thick turbidite deposits on the mid and lower parts of the paleo-slope if sufficient clastic supply is present. The steep slope can result in turbidite sands becoming detached from their (subsequently) mud-filled feeder systems, leading to more effective traps. While the Tarakan Basin does not appear to have a purely transtensional origin, similar depositional patterns can be expected from basins with more oblique opening styles.

The historic play-type for the Tarakan Basin has been oil and gas reservoired in topset fluvio-deltaic sands belonging to the Late Miocene Tabul and Plio-Pleistocene Tarakan formations [2], sealed by interbedded deltaic shales in a variety of largely structural traps, often where growth faults are heavily modified by later wrench-induced uplift and inversion [3]. Hydrocarbon charge has been linked to Middle to Late Miocene age paralic coals and mudstones with some lacustrine influence [4]. The more recently opened deepwater play in the Tarakan basin has (so far) been focused on turbidite reservoir equivalents of the shelf play, targeting foldbelt traps with reservoirs in either pre / syn-kinematic or onlapping post-kinematic deposits. Hydrocarbon charge in the deepwater play is thought to be similar to the historic shelf play, though calibration is lacking.

Outside of the Muara sub-basin, the pre-Late Miocene section beneath the shelf and slope of greater Tarakan Basin is generally poorly imaged on seismic and has almost no well penetrations. However, using plate models and well data from the inner shelf and onshore, a history of the area can be described. The post-rift phase from Middle Eocene through to approximately Early Miocene was a period of relative quiescence dominated by carbonate formation and deposition on the shelf and minor shale and marl deposition on the slope and abyssal plain. The tectonics of the region changed in the early Middle Miocene with the onset of collision of the northern extension of Australia with Sundaland and the uplift and inversion of Borneo, including the Sabah Orogeny [5]. This tectonic activity is illustrated in the Tarakan Basin by a Middle Miocene clastic pulse (Meliat / Latih Formations) and the development of at least one, if not multiple unconformities. Whilst not constrained by the limited well data for the Middle Miocene, it is reasonable to assume that as in other narrow shelf basins, the Middle Miocene and subsequent clastic pulses would have delivered turbidite sands onto the paleo-slope. Hydrocarbon charge for these speculative turbidites could come from redeposited time-equivalent coals documented updip in the Berau Basin [6].

Later tectonic activity in the greater basinal area, especially the onset of collision of the Sulu-Zamboanga Arc with Borneo (Semporna and Dent Peninsulas) beginning in the Late Miocene, could be a positive for the pre-Late Miocene turbidite play by creating structural traps on what may have been a largely unstructured paleo-slope. However, excessive tectonic activity could result in trap breach or highly faulted highs, at least in certain locations. Historic earthquake data highlights the ongoing tectonics in the greater Basin area and suggest that trap integrity will need to be reviewed carefully.

Reservoir quality will also be an area that needs careful and localized (space and time) review as the provenance of Tarakan Basin clastics varied with changes in onshore tectonics. Work on outcrops of the Middle Miocene Latih Formation sandstones in the Berau sub-Basin [7] indicates that these potential updip equivalents of outboard turbidites are predominately litharenites with moderate to low porosity.

While the area where this new (paleo-)slope structured onlap turbidite play may be present is not large, global analogs suggest that If all play elements are present then significant volumes may still be waiting to be found. As part of this play could exist in present-day shelf water depths, the economics for future development of any discoveries would be favorable.

REFERENCES

[1] Teasdale, Jon, 2018, SE Asia Plate Tectonic Animations Based on the Geognostics Earth Model (GEM™). 612 slides. Available from: http://geognostics.com

[2] Doust, Harry and Noble, Ron A., 2008, Petroleum Systems of Indonesia. Marine and Petroleum Geology Vol 25 pp.103–129.

[3] Sudarmono, A. Direza, H. B. Maulin, A. Wicaksons, 2017, Some New Insights to Tectonics and Stratigraphic Evolution of the Tarakan Sub-Basin, North East Kalimantan, Indonesia. Proceedings Indonesian Petroleum Association 41st Annual Convention and Exhibition. IPA17-722-G., 22 pp

[4] Rosary, D, A.B. Nicaksana, J.K. Wilkinson, 2014, A Correlation of Climate Stratigraphy with Biostratigraphy to Confirm Stratigraphic Units in the Sebatik Area. Proceedings Indonesian Petroleum Association 38th Annual Convention and Exhibition. IPA14-G-258., 17 pp

[5] Cullen, Andrew B., 2010, Transverse segmentation of the Baram-Balabac Basin, NW Borneo: refining the model of Borneo's tectonic evolution. Petroleum Geoscience, Vol. 16 2010, pp. 3–29.

[6] Suwarna, Nana and Bambang Hermanto, 2007, Berau coal in East Kalimantan; Its petrographicscharacteristics and depositional environment. Jurnal Geologi Indonesia, Vol. 2 No. 4 Desember 2007: pp. 191-206

[7] Maryanto, S., 2012, Diagenesis and Provenance of Lati Sandstones in the Berau Area, East Kalimantan Province, based on Petrography Data. Indonesian Journal of Geology, Vol. 7 No. 3 September 2012: pp.145-156

ORAL PRESENTATION

Regional Review of Statoil's Indonesian Exploration Portfolio and Upside

Toril Karlberg Dyreng[1]

[1]*Equinor, Norway*

tkd@equinor.com

Equinor (previously Statoil) established a Jakarta office in 2007 to focus on the exploration of the Indonesian offshore. Since then the company has drilled seven wells, of which three were operated, and participated in the acquisition and processing of several 2D & 3D seismic surveys.

Currently Equinor's exploration activities are focused on the Aru Basin, part of what is often referred to as the West Papua Area, offshore Eastern Indonesia, where we are active in three licenses: West Papua IV and Aru PSC's as a partner and Aru Trough I PSC as operator. These licenses cover 14,000 km^2 of deep water (>1000 m) frontier exploration acreage.

Pre-2007 the initial exploration activities offshore West Papua were based on 2D data of variable quality and focused on the shallow water areas and the well results were disappointing. Based on the few poor oil and gas shows encountered in these wells at several stratigraphic levels, the presence of an active hydrocarbon system was most uncertain.

In 2007/8 piston cores acquired in combination with a multibeam seabed survey covering the Aru Basin encountered convincing oil seeps in the deep-water area. Typing of the oil indicated a Tertiary marine origin and the Klasafet Formation was identified as the most likely source. All observations indicated the presence of an active, oil prone, hydrocarbon system in this deep-water frontier exploration area.

The acquisition of state-of-the-art 2D seismic identified a number of promising Miocene New Guinea Limestone leads comprising large horst blocks surrounded by Klasafet source. The acquisition of additional 2D in this structurally complex area was considered to be of limited value and the first 3D survey was acquired (1700 km^2) in 2010 followed in 2013 by the first deep water exploration well in the Aru Basin, Cikar-1, targeting a sizable New Guinea Limestone closure.

Due to operational difficulties, it was not possible to evaluate the hydrocarbon content of the New Guinea limestone. However, promising oil indications were encountered just before entering the reservoir and in addition, this well confirmed the source properties and excellent sealing quality of the overlying Klasafet. Furthermore, the temperature data from this well necessitated a revision of the basin model resulting in a more oil prone Klasafet source.

Encouraged by the well results, an additional 4300 km^2 broadband 3D seismic was acquired in order to further mature the Aru Basin prospect portfolio and identify the most optimal target for the next exploration well.

Day 2: 28th June 2018

Session 5: South China Sea

Chair: Nick Comrie-Smith – Premier Oil

9:00	South China Sea: The Problem of Politics	Bill Haydon	Chatham House
9:25	Rewards and Challenges of Exploration on the South China Margin - a Review of BP Heritage Exploration	Woody Wilson	BP
9:50	Reservoir Characterization of the Middle Miocene Isolated Ca Voi Xanh Carbonate Platform	Christian J. Strohmenger	ExxonMobil
10:15	Unlocking Hidden Plays in and Around Sarawak with FTG Gravity Data	Colm Murphy	Bell Geospace / Petronas

ORAL PRESENTATION

South China Sea: The Problem of Politics

Bill Hayton[1]

[1]*Chatham House, UK*

bill@billhayton.com

All around the southern fringe of the South China Sea, governments and oil companies are coming under pressure from China. This presentation will explain what's going on and why. Even though China comprehensively lost an international arbitration case brought by the Philippines, it continues to block several major oil and gas developments off other countries' coasts by diplomatic and other forms of pressure. Recent seismic surveys and drilling have confirmed the presence of sizeable hydrocarbon prospects in disputed waters around the southern South China Sea. By any mainstream interpretation of the Law of the Sea, these are located within the Exclusive Economic Zones of Vietnam, Indonesia, Malaysia, Brunei and the Philippines. China uses more idiosyncratic arguments to claim that it has the rights to the same resources. This presentation will outline what these arguments are and how they have changed since the 2016 arbitration decision.

ORAL PRESENTATION

Rewards and Challenges of Exploration on the South China Margin – a Review of BP Heritage Exploration

R W Wilson[1], G. Molinero[1], T. Love[1], W. Matthews[1], S. Matthews[1,2], N. Kusznir[3], G. Mohn[4]

[1] *BP Exploration, UK*

[2] *Frontier Structure, UK*

[3]*Badley Geosciences, UK*

[4]*Université de Cergy-Pontoise, France*

woody.wilson@uk.bp.com

BP has a long history of exploration on the South China margin (SCM). Due to its proximity to one of the world's biggest energy markets, the region offers a huge prize for those successful explorers. To date greater than 5 Bboe of oil and gas have been discovered along the margin. BP (and its heritage companies Amoco and Arco) has been an active explorer on the SCM over the past 4 decades, discovering the Yacheng 13-1 and Liuhua 11-1 fields. Alongside these discoveries, there have also been a number of dry wells which reflect various subsurface challenges along the margin. We shall present various insights from BP's exploration campaigns on the margin and integrate these with learnings from crustal and basin modelling.

In recent years exploration focus has stepped out into deep water provinces which bring both new opportunities and new challenges. Understanding crustal structure and its implications on both palaeobathymetry and heatflow in distal margin domains is a key focus for many explorers and researchers. These factors are both fundamental to predicting source rock presence and deposition, and subsequent maturity; both of which are critical for future exploration success on the SCM. Using various margin modelling tool kits and insights from past exploration campaigns we will discuss the opportunities and risks associated with exploration along the margin.

PESGB SEAPEX Asia Pacific E&P Conference
Olympia Exhibition Centre, London
27th – 28th June 2018

ORAL PRESENTATION

Reservoir Characterization of the Middle Miocene Isolated Ca Voi Xanh Carbonate Platform

Christian J. Strohmenger[1,3], Lori Meyer[2], Donald Lyons[1], Mazlina Md Yusoff[1], David Walley[1], Jacqueline Sutton[1], Matthew R. Bourke[1], Beata von Schnurbein[3], Phong Nguyen Xuan[4]

[1]Esso Australia Pty. Ltd., Melbourne, Australia

[2]ExxonMobil Exploration & Production Vietnam Ltd., Hanoi, Vietnam

[3]ExxonMobil Production Germany GmbH, Hannover, Germany

[4]PetroVietnam Exploration Production Corporation Ltd., Hanoi, Vietnam

christian.j.strohmenger@exxonmobil.com

The Ca Voi Xanh (CVX) field is located offshore Vietnam in the Song Hong Basin. Tertiary carbonates of Middle Miocene (Langhian and Serravallian) age form an isolated carbonate platform along the Triton Horst structural high. Shallow water corals and large benthic foraminifera (LBF) are the main constituents of the older Langhian carbonates, whereas the overlying Serravallian carbonates are dominated by deeper water coralline red algae (rhodolith) and LBFs.

The Langhian carbonates can be described by one lithofacies: coral-LBF grainstone / rudstone. Depending on the presence of mud in the samples, two lithofacies types are characteristic for the Serravallian: LBF-rhodolith packstone to mud-lean packstone and rhodolith-LBF grainstone to mud-lean packstone.

Two well-developed exposure surfaces can be identified on top of the Langhian (*Ser1_SB*) and on top of the Serravallian (*Tor1_SB*). Serravallian carbonates show an overall shallowing-upward trend from more horizontally-oriented rhodoliths (encrusted and bored pavements / hardgrounds) at the lower part of the section to large, roundish, irregular rhodoliths towards the upper part of the section. Petrographic thin section, stable isotope (oxygen and carbon), and fluid inclusion analyses confirm a freshwater (vadose and phreatic) diagenetic overprint of the carbonates below the exposure surfaces (sequence boundaries).

Sequence stratigraphic interpretation is based on detailed sedimentolological core description tied to well-log character. A sequence stratigraphic framework was established for the Serravallian carbonates, displaying three third-order depositional sequences (Ser1, Ser2, and Ser3).

A reproducible reservoir rock type (RRT) scheme was developed for the described carbonates, using a combination of depositional environment, diagenetic overprint, and reservoir parameters (porosity and permeability). The Serravallian RRTs are separated into dominantly packstone (RRT1) and dominantly grainstone textures (RRT2 - RRT6). The grainstone RRTs show varying degrees of cementation (RRT2 and RRT3), dolomitization (RRT4), and dissolution (RRT5 and RRT6). The Langhian is characterized by two RRTs, depending on the degree of cementation (RRT3L) and dissolution (RRT5L).

The vertical and lateral distribution of RRTs, supported by seismically derived paleo-reconstruction of the carbonate platform, adequately describes the reservoir. Sequence stratigraphy-keyed RRTs were used as input to the geological (static) model, providing a more detailed reservoir description to the dynamic model.

PESGB SEAPEX Asia Pacific E&P Conference
Olympia Exhibition Centre, London
27th – 28th June 2018

ORAL PRESENTATION

Unlocking Hidden Plays in and Around Sarawak with FTG Gravity Data

Colm Murphy[1], Mohd Idrus Ismail[2], Hamdan Mohamad[2]

[1]*Bell Geospace, UK*

[2]*Petronas, Malaysia*

cmurphy@bellgeo.com

High resolution airborne Full Tensor Gravity Gradiometry (FTG) data acquired across the Sarawak Basin area, from Tatau in the west to Balingian and Tinjar in the east and Luconia in the north, facilitate the regional mapping perspective of the primary geological trends influencing the location and prospectivity of both known producing structures and the presence of others.

The Luconia carbonates reveal a clear definitive response in FTG data facilitating direct mapping of presence and assessment of compositional complexity. Intermediate and longer wavelength anomalies point to a variable sub-carbonate geological complexity, from the presence of basins to a shallowing basement. Balingian carbonates are less expressive and the FTG signal changes to the southeast, pointing to the presence of deeper kitchen areas where source rocks potentially reside. Fault patterns are evident in the data and lead to an increased understanding of the direction of migration for hydrocarbons from deeper source rocks to their carbonate build-up hosts. FTG data facilitates clear imagery associated with sub-carbonate geology, locating Top Basement and overlying basins.

The Tinjar and East Balingian areas offer an additional but equally exciting set of plays in the form of closed anticlinal structures. FTG identifies these with a characteristic anomaly pattern making it a must-have technology for the exploration tool kit. Known oil fields in the offshore have an associated FTG response that is used to calibrate potential for new plays in the onshore Tinjar area. Supporting geochemical, seismic and resistivity data facilitate a ranking mechanism when prioritising targets.

This paper will show and describe FTG's imaging of key structures and potential for new leads across the Sarawak area.

Day 2: 28th June 2018

Session 6: Cambodia and Regional Aspects

Chair: Alasdair Duncan – Mandala Energy

11:15	Cambodia's Hydrocarbon Prospectivity - An Insight from Block A	Katherine Kho	Kris Energy
11:40	Volcanic Reservoirs in SE Asia	Andy Racey	Andy Racey Geoscience
12:05	Sediment Provenance Studies in SE Asia	Robert Hall	Royal Holloway

ORAL PRESENTATION

Cambodia's Hydrocarbon Prospectivity - An Insight from Block A

Katherine Y.J. Kho[1], Dr John M. Jacques [1,2]

[1]*KrisEnergy Ltd*

[2]*JMJ Petroleum Pte Ltd*

katherine.kho@krisenergy.com

The Gulf of Thailand is one of the most prolific areas for oil, gas and condensate production in Southeast Asia. Formed by the collision of the Indian Plate and the Eurasian Plate in the Eocene, the Gulf of Thailand is made up of asymmetrical grabens filled with non-marine to marginal marine Tertiary sediments in several structurally complex transtensional basins. One of these basins, the Khmer Trough, is the subject of this paper; with Block A, operated by KrisEnergy, providing an invaluable insight into the untapped hydrocarbon potential of offshore Cambodia. The Block itself is close to several large producing oil and gas fields in the Central and Northern Pattani basins and contains the Apsara oil field - Cambodia's only confirmed discovery.

The exploration potential of the pre-, syn- and post-rift sections of the Khmer Trough have been evaluated by synthesising the tectonic, structural and depositional history of the basin in order to summarise proven and potential plays and identify new play concepts. In turn, the in-depth evaluation of Block A has been constrained by seismic, well, gravity, geochemical, heat flow and other complimentary datasets.

In the Gulf of Thailand, the sediments are deposited from an initial period of alluvial-fluvial to a progressively mid-phase fluvial-lacustrine, fluvial-dominated setting and ending with an increasingly marine environment from the Mid Miocene. Lacustrine shales present in the Oligocene syn-rift sequences are sources for the oil and gas accumulations. Hydrocarbon-bearing reservoirs within the Khmer Trough consist of Early Miocene syn- to post-rift, fluvial sandstones. Intra-formational fluvial shales from paleosols are the main top seals of hydrocarbon bearing reservoirs in the Khmer Trough. Fault seals are accomplished by sand-shale juxtaposition and gouge smear.

Prospective trends in Block A have been identified with 3D seismic interpretation and exploratory drilling. These plays are situated within 3-way dip structural closures of north-south trending fault blocks, with multiple stacked reservoirs throughout the Oligo-Miocene section. There is also substantial potential for other fault bounded complexes and stratigraphic traps.

This talk highlights some of the technical work undertaken by KrisEnergy for the first phase of Apsara oil development in Cambodia Block A. KrisEnergy, as operator, and the various government authorities have agreed on the terms for development and steps are underway, aiming for first oil approximately 24 months after the final investment decision was declared in October, 2017.

ORAL PRESENTATION

Volcanic Reservoirs of SE Asia

Andy Racey[1]

[1]*Andy Racey Geoscience, UK*

andy@andyracey.com

Around 60% of the world's conventional hydrocarbon resources are in sandstones, 40% in carbonates and less than1% in volcanics and other types of "basement". However, extrusive volcanic rocks are present in most geological settings, occur over the entire geological column, often cover large areas and can form a large proportion of a basin's fill.

To date there are over 300 global records of hydrocarbon discoveries and significant shows in volcanic rocks of which around 170 have proven reserves. Most producing volcanic reservoirs occur onshore and at a broad range of depths from a few hundred to 5000 m. Fields are often located close to a mature source and are more common in rifts and back-arc basins, where volcanic rocks and mature source rocks are commonly juxtaposed. Since volcanic rocks are less affected by compactional porosity loss during burial, due to their greater mechanical strength, they can retain their porosity in the deeper parts of basins where more conventional reservoirs are unproductive.

Within SE Asia, producing volcanic reservoirs include: Upper Carboniferous, Lower Cretaceous and Palaeogene in the Songliao, Junggar, Erlian, Sichuan, Santanghu and Bohai Bay basins of China; Miocene-Pliocene in the Nigata and Akita basins of Japan; Miocene in the Petchabun Basin of Thailand and Moattama Basin of Myanmar; and the Eocene-Oligocene of onshore NW Java, Indonesia. Amongst these, the recent Aung Sinkha discovery in Myanmar represents the only offshore discovery.

Japan has a long history of producing hydrocarbons from volcanic rocks with the first significant discoveries being in 1958. Japan is a major importer of oil and gas with only 0.3% of total oil and 3.3% of total gas requirement being provided by indigenous resources, of which around 75% are from volcanic rocks. Production is from onshore and is mainly from Lower-Middle Miocene rhyolites (the "Green Tuff") of the Niigata and Akita Basins. These submarine volcanics were erupted in a back-arc basin setting during the opening of the Sea of Japan. The total basin fill is greater than 7 km thick and includes deep-marine source rocks and thick mudstone sealing units. The largest field discovered to date is Minami-Nagaoka with an estimated recoverable resource of 1 Tcf and 33 MMbbls of condensate from reservoirs at between 3800 m and 5000 m depth.

By contrast, exploration in volcanic rocks in China's onshore basins has been a more recent development. In China such rocks cover around 2.1 million km^2 with "potential" volcanic reservoirs occupying around 20% of this area. Since 2005, volcanic reservoirs have become primary exploration targets with major gas discoveries in the Songliao Basin. To date 13 onshore basins have produced hydrocarbons from volcanic rocks of which nine have produced oil, two gas and two oil and gas, with a further three basins having hydrocarbon shows. This has resulted in the discovery of over 40 fields. Several of these rift basins (Junggar, Tarim, Songliao and Bohai) are classified as deep in having a total fill of between 4500 m and 7000 m. The total resource potential for China's volcanic rocks is estimated at between1.9 and 2.6 Bbbls of liquids and around 148 Tcf of gas onshore, with a proven resource in 2014 of 365 MMbbls of oil and 14 Tcf of gas. Hydrocarbons are recovered from a broad range of depths (1000 m to 5000 m) with the deepest well to date being to 7000 m.

Discoveries in Thailand and Myanmar are within fractured Miocene volcanics and include the Na Sanun and Bo Rang fields onshore Thailand and the Aung Sinkha Field offshore Myanmar. In the case of the Thailand examples there is also additional production from associated Miocene sandstones.

Many volcanic sequences in sedimentary basins are either unexplored or underexplored and the presence of volcanic rocks in a region should not always condemn an area from hydrocarbon exploration. However, exploring in such areas does require a different exploration mindset and methods.

ORAL PRESENTATION

Sediment Provenance Studies in SE Asia

Robert Hall[1]

[1]*Southeast Asia Research Group, Department of Earth Sciences, Royal Holloway, University of London, UK*

Robert.Hall@rhul.ac.uk

The clastic sediments in SE Asian basins contain a record of significance for the hydrocarbon industry. Attention is commonly focused on physical properties of sandstones and their important practical implications. However, provenance studies can provide other valuable insights into basin development, sediment sources and pathways, as well as contributing to regional tectonic understanding. We have now undertaken many such studies across this large region and the accumulated results permit recognition of important patterns.

The widely used ternary plots of light mineral modes used to assess provenance have limited value and often mislead. They tend to reflect tropical processes in SE Asia, including weathering and diagenesis, and in many areas overlook a volcanic quartz contribution. Heavy mineral studies can also be influenced by tropical processes and may include a bias towards continental and granitic rocks, but commonly give better insights into sources. Among the heavy minerals, detrital zircons are especially useful and U-Pb dating may provide depositional ages in regions with contemporaneous magmatism and identify sediment source types and regions. The combination of heavy mineral assemblages and detrital zircon ages can be very useful and it is possible to identify distinct source regions such as continental Australia, Bird's Head of New Guinea, Borneo, Sumatra, Sundaland, Indochina and South China and see temporal changes in sources. Most of our studies have so far been undertaken on land and the value of this work would be significantly enhanced if offshore sediments could be included.

Day 2: 28th June 2018

Session 7: NW Borneo

Chair: Mark Jones – Consultant

13:30	Heartlands in Transition: Brunei and Malaysia	Graeme Smith	Shell
13:55	A New Direction for Asian Stratigraphy	Peter Lunt	Universiti Teknologi Petronas
14:20	Reservoir Characterization of Deep Marine Sediments, Northern Borneo	Melissa Johansson	Geode Energy
14:45	Frontier Sabah Malaysia – New Exploration Opportunities Unveiled by Latest Regional 3D Seismic	Tad Choi	PGS

ORAL PRESENTATION

Heartlands in Transition: Brunei and Malaysia

Graeme Smith[1]

[1]*Shell Exploration Asia, Malaysia*

Shell has been exploring in the Asia Pacific region for over one hundred years and has significant experience doing so specifically in two of our heartlands, Brunei and Malaysia.
We've learned over the years that despite what we think we know about the geology (e.g. Sarawak carbonates), there's always more to learn.
Mother nature continues to give us surprises, both ups and downs, so humility and the ability to adapt and innovate are critical to ongoing success.
Technological advances have enabled an improved understanding of the subsurface and we are learning that the petroleum systems are more complex than we once thought.
New and improving seismic is providing greater insights into what lies beneath our feet, uncovering valuable oil and gas in old heartlands, busting paradigms and enabling smarter wells to be drilled.
In Brunei and in Malaysia we find ourselves confronting those dogmas and re-imagining the future of exploration, as we've seen in other old basins (North Sea, GOM, Egypt, Norway etc.).
This is good not only for Shell, but for the world, because while the energy transition is certainly underway, this transition will be measured in decades and we will continue to need new Oil and Gas discoveries to meet global demand and to keep our business going.

ORAL PRESENTATION

A New Direction for Asian Stratigraphy

Peter Lunt[1], Professor Hadi Rahman[1]

[1]*Universiti Teknologi Petronas, Malaysia*

plunt@mac.com

Southeast Asia has a long history of stratigraphic studies, not well represented in global literature, a "peripheral isolate" of specialist techniques, such as the Letter Stages that were East Tethyan replacements for European Ages. From this often-overlooked area, characterised by highly variable Cenozoic tropical sediments, in tectonically active basins, might come ideas to assist stratigraphic studies in other, less dynamic areas.

In spite of this promising history, this is mostly an account of a revolution delayed. The development of a reliable geomagnetic polarity time scale [GPTS] during the 1980's (especially Berggren et al., 1985a,b) should have invigorated local studies with an accurate dimension of time, to monitor fluctuating rates of sedimentation, accurately correlate and map out the varying magnitudes of unconformities. However, two factors prevented the modernisation of evidence-based stratigraphic techniques. The first was the adoption of strictly eustatic seismic stratigraphy methods, an effect described in Miall and Miall (2002), imported almost as a package with modern quality seismic acquisition in the Asian region. Secondly was a rapid decline in motivation and innovation from geological service companies, as a result of the commoditisation of professional services; an economic condition known as a Nash Equilibrium. This concept, from game theory, is that every participant adopts a strategy optimised to their best short-term benefit, but in many cases a stable equilibrium is reached where decisions that are good for the individuals can be detrimental for the group; or in this case integrated geological sciences.

The adherence to a strictly eustatic sequence stratigraphic model has faded in most Southeast Asian basin studies in the past few years, simply because it does not fit, and does not predict. However seismic horizons are still given eustatic sequence boundary names, and terms like "3rd Order Cycles" are frequently mentioned in literature. Some passive areas such as the Mahakam Delta can still be force-fitted into a simple fluctuating proximal-distal model that may have some eustatic influences (caveat Miall 1992, 2010), but many basins have simply failed to match geological observations with these model-driven ideas. Most Southeast Asian basins are stratigraphically distinct due to local tectonic influences, and the unique characters of a basin can often affect petroleum systems elements. However, many exploration inputs and riskings are based on over-simple, long-standing assumptions that do not withstand modern tests. Unfortunately, due to retirement and lack of training in specialist skills, the Southeast Asian industry has nearly lost the ability to both apply these tests, and subsequently develop new petroleum systems models.

Several examples are given, selected from areas with long exploration and production histories (East Java and North Sumatra), of such modern tests and the subsequent new stratigraphic frameworks. These have direct impact on risking and ranking of plays, yet-to-find estimates, and may even indicate new plays. Such exploration, off the old creaming curves, is a fiscal requirement for most medium to large operators in the region.

A third example is given from current work by Universiti Teknologi Petronas on Sarawak where a 1980's evidence-based model was abandoned by nearly the whole industry but is now being revived as the methodically tested, evidence-based sequence stratigraphy for not only the Northwest Borneo region, but a keystone for the whole South China Sea. The study area has a dense well data set, good seismic, and is positioned close to tectonic features that leave a stratigraphic record of nearly all the events affecting the South China Sea since the onset of sea-floor spreading near the Oligo-Miocene boundary. This, plus the good age and facies control from the Neogene micropalaeontology, is leading to a detailed stratigraphic model, tested through Walther's Law and tied to plate tectonics. The University is building on the old evidence-based model, neglected in the 1990's, bringing it up to date, developing new work flows, and identifying three and four dimensional stratigraphic characters that had been forced into a 2D sequence model for nearly 30 years.

References

Berggren, W.A., D.V. Kent, and J.J. Flynn. 1985a. Jurassic to Paleogene: Part 2. Palaeogene geochronology and chronostratigraphy. in The Chronology of the Geological Record (Memoir 10), ed. N.J. Snelling, 141-186. London: Geological Society of London.

Berggren, W.A., D.V. Kent, and J.A. van Couvering. 1985b. Neogene geochronology and chronostratigraphy. in The Chronology of the Geological Record (Memoir 10), ed. N.J. Snelling, 211-260. London: Geological Society of London.

Miall, A.D. 1992. Exxon global cycle chart: An event for every occasion. Geology 20, 787-790.

Miall, C.E., and A.D. Miall. 2002. The Exxon factor: The Roles of Corporate and Academic Science in the Emergence and Legitimation of a New Global Model of Sequence stratigraphy. The Sociological Quarterly 43, no. 2: 307-334.

Miall, A.D. 2010. The geology of stratigraphic sequences (Second Edition). Berlin: Springer-Verlag.

ORAL PRESENTATION

Reservoir Characterization of Deep Marine Sediments, Northern Borneo

M. Johansson[1]

[1]*Geode-Energy, UK*

mjohansson@geode-energy.com

The Northwest Borneo margin and the NW Borneo Trough are related to the opening of the South China Sea. The proto-South China Sea was subducted beneath the Sunda Shelf from Late Cretaceous times. The cessation of subduction occurred in the Miocene, where large blocks of continental shelf blocked the Subduction trench. Subsequently collision occurred between the leading edge of the South China Sea continental realm and the Crocker-Rajang accretionary margin of Northwest Borneo. The uplift and erosion of this accretionary margin provided abundant sediment supply to form the Baram Delta. Both modern day and ancient sediments deposited in deep-marine settings, offshore Brunei, are characterized by large scale submarine landslides, which have been well documented in the literature. The deposits of the landslides are known as Mass Transport Complexes (MTC's) or Mass Transport Deposits (MTD's) and provide valuable information on sediment dispersal patterns, palaeoslope and reservoir development. They are particularly significant when reservoir sands are devoid of any indication of paleocurrent direction and seismic data quality is poor.

The modern-day shelf is 50 to 70 km wide and characterized by the Baram river and delta system connected via a canyon to the NW Borneo Trough. A steep sided escarpment rises 1km from the basin floor, separating the shelf margin from the trough. The seafloor morphology is defined by elongate mini basins parallel to the coastline, separated by shale-cored ridges. Observed on the modern basin floor are giant submarine landslides. The size of these slides (volume of 1200km^3, covering an area of 5300 km^2, with a thickness of approximately 240 m) are some of the largest ever observed. These features are commonly observed in the subsurface and are thought to be a result of the tectonically active margin and the large sediment supply from the Baram Delta.

Miocene sediments appear dominated by quiescent sedimentation, with medium thick bodies of conformable sediments with consistent structural dip, interspersed with sheet sands and sporadic debris flows, forming the majority of the sediment. However, interspersed in this uniform sedimentary environment, is massive structural failure, initially slides, slumps and debris flows, followed by post depositional creep, similar to the modern-day seabed. Related to these deposits are thick, massive sands, probably deposited as canyon–fill, suggesting that these slope failures are sea-level driven, with failure initiated by sea-level fall and the sand reaching the outer slope during a sea-level low-stand.

ORAL PRESENTATION

Frontier Sabah Malaysia – New Exploration Opportunities Unveiled by Latest Regional 3D Seismic

Dr Tad Choi[1], Jo McArdle[1]

[1]PGS, Malaysia

tad.choi@pgs.com

INTRODUCTION

The NW Sabah Basin also referred to as the Baram-Balabac basin, Sabah, or NW Borneo Basin, covers an area of approximately 43,000 km^2 with marine Tertiary beds typically more than 8 km thick. It receives its major sediment input from the Baram Delta, which is a prolific hydrocarbon province extending from Brunei to NW Sabah, as well as from the Champion and Meligan deltas. Gravity loading and thin-skinned deformation has resulted in a fold and thrust belt in the inboard area. This initiated near the shelf in the Mid Miocene, which then propagated north-westward in the Pleistocene. This fold and thrust belt, which hosts turbidite reservoirs within anticlinal structures, has been the major focus and most successful play area in the basin to date.

Further outboard of the fold and thrust belt, beyond the Sabah Trough, lies the NW Sabah Platform, also known as the Dangerous Grounds. It consists of rifted continental fault blocks that split during the opening of South China Sea. Eocene-Oligocene syn-rift packages that were deposited during this extensional phase potentially host source rocks that could be mature at present-day to charge the overlying mid-Miocene carbonates. This is a play type that is typically targeted and successful in SE Asia. Due to the lack of any seismic data in the Dangerous Grounds, it remains as a frontier area which has had limited exploration activities, that is until now.

EXPLORATION OPPORTUNITIES UNVEILED

18,000 km^2 of regional multiclient 3D data acquired between 2014 and 2017 show incredible high-quality images of the fascinating and complex geological frontier province of the Sabah Basin. This is the first ever regional scale seismic dataset that provides the explorationist with the ultimate tool to better understand the sub-surface geology and fairway systems of offshore Sabah. The measured broadband seismic data's high-fidelity imaging was enabled through advanced acquisition technology solutions, coupled with high end processing techniques, to provide the imaging solution that was necessary to better illuminate and image the complex structural geometries of the fold and thrust belt of the Sabah Province.

This paper will showcase contiguous regional geological correlations from the petroleum play types of the inboard fold and thrust belt of Sabah, out past the Sabah Trough and outboard to the older rift systems of the Dangerous Grounds. Regional key horizons such as MMU (Mid-Miocene Unconformity), which has historically been difficult to track below the fold and thrust belt, can now be confidently interpreted across the entire basin.

New geological understanding and exploration opportunities will also be presented based on the interpretation of the latest regional 3D data. It is evident that a series of sub-basins exist in the outboard Dangerous Grounds. These sub-basins may host potential source rocks that are buried deep enough to be present-day mature. Pre-rift and syn-rift packages can be observed within these sub-basins, which would have been deposited during the extensional phase of the opening of the South China Sea. Several direct hydrocarbon indicators (DHI's) provide strong evidence of a working petroleum system in the Dangerous Grounds.

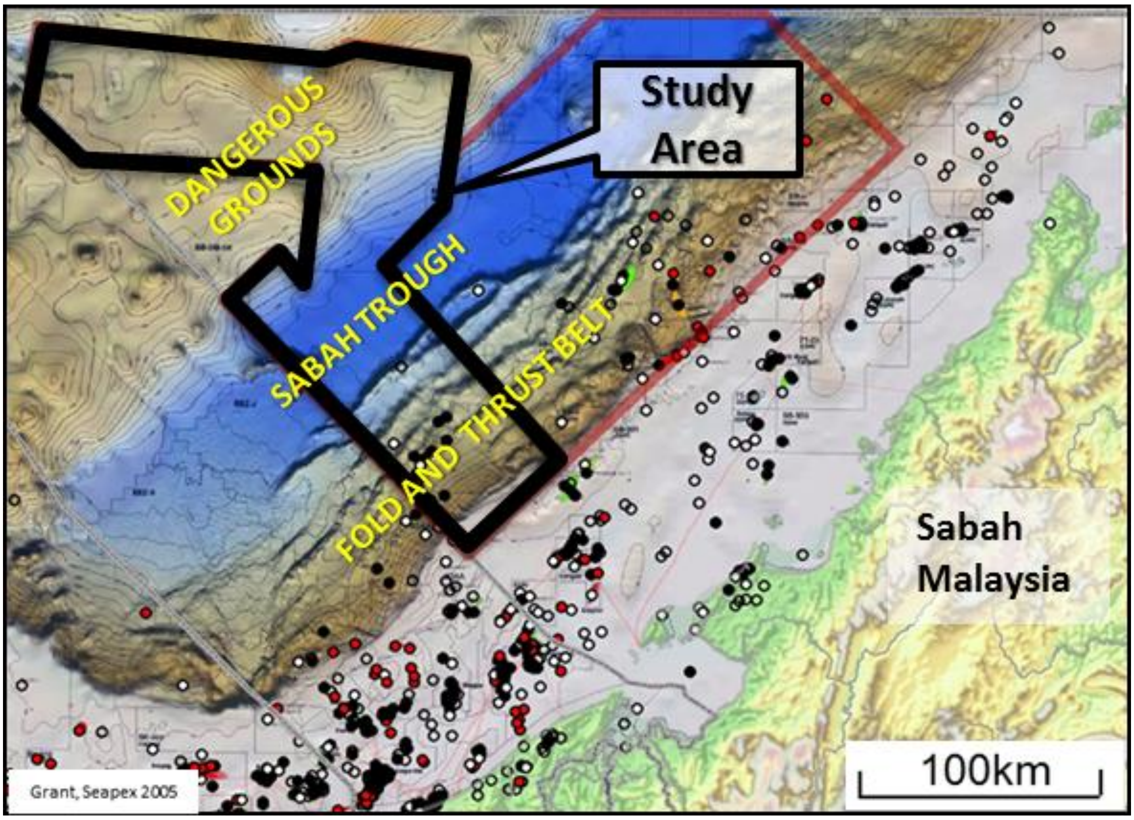


Figure 1. Location map of NW Sabah highlighting the study area. The map also illustrates the various geological terranes.

Day 2: 28th June 2018

Session 8: Australia and Timor-Leste

Chair: Ian Longley – Gis-Pax

15:45	TIMOR GAP's Onshore Block: A Preliminary Assessment of Prospectivity in Onshore Timor-Leste	Tim Charlton	TIMOR GAP
16:10	Mesozoic Stratigraphic Evolution of the North Carnarvon Basin Unlocked Using Olympus 3D	Stacey Mansfield	BP
16:35	Xanadu Oil Discovery, Northern Perth Basin, Western Australia	Shelley Robertson	Norwest
17:00	Asia-Pacific Unconventional Opportunities at $50 Oil: The Differences and Challenges Between North American Proven Unconventional Systems and Recognised Unconventional Opportunities in Australia and SE Asia	Ian Cockerill	RISC

PESGB SEAPEX Asia Pacific E&P Conference
Olympia Exhibition Centre, London
27th – 28th June 2018

ORAL PRESENTATION

TIMOR GAP's Onshore Block: A Preliminary Assessment of Prospectivity in Onshore Timor-Leste

Tim Charlton[1], Dino Gandara[1], Debora Freitas[1], Maria Guterres[1], Norberta da Costa Noronha[1]

[1]*TIMOR GAP E.P., Timor-Leste*

tim.charlton@timorgap.com

1. ONSHORE BLOCK HISTORY

TIMOR GAP, E.P., the national oil company of Timor-Leste, was awarded the exclusive hydrocarbon exploration rights to the Onshore Block (Figure 1) by Government Resolution 44/2017 in December 2015. Subsequently the Onshore Block was divided into 3 sub-blocks (A, B & C, Figure 1), each with an area of approximately 1000km^2. In April 2017 Blocks A & C were gazetted as full PSC exploration areas (PSCs TL-OT17-08 and TL-OT-17-09 respectively) in 50:50 partnership with Australian company Timor Resources (a subsidiary of the Nepean Group), with Timor Resources assuming operatorship. In early 2018 talks are advanced on turning Block B into a third PSC licence area in partnership with a separate company, with TIMOR GAP taking operatorship.

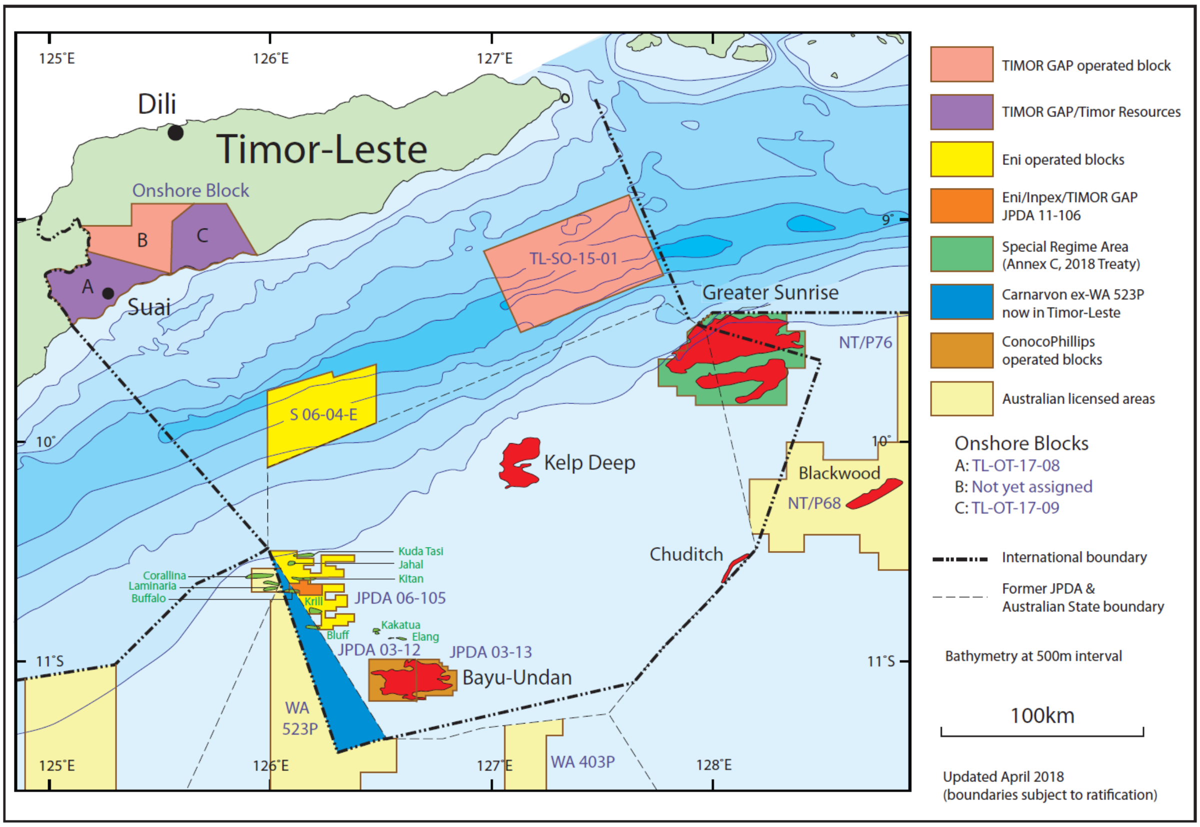


Figure 1. Timor-Leste current PSC licence areas, with offshore international boundaries following the 2018 treaty with Australia (subject to ratification). Oil fields are shown in green, gas fields in red. JPDA is the former Timor-Leste – Australia Joint Petroleum Development Area, annulled by the 2018 Timor-Leste – Australia maritime boundary treaty (subject to ratification).

Earlier exploration for hydrocarbons in onshore Timor-Leste was carried out particularly by Australian company Timor Oil between 1957 and 1975. The company drilled 18 exploration wells in the Onshore Block area (16 in Block A, 2 in Block C), with hydrocarbons encountered in 9 wells in Block A, and 1 well in Block C. Of these, two wells in Block A tested significant oil flows: Matai-1A at an unsustained rate of 110 bbl/day, and Cota Taçi-1 at 216 bbl/day.

In 1968 Timor Oil acquired 248 km of 2D seismic along the south coast of East Timor, and in 1969 and 1970 shot further seismic (248km and ~30km respectively) in what is now Block A. In 1994 Pertamina, the national oil company of Indonesia, acquired 314 km of 2D seismic across the southern parts of Blocks A, B & C. The 1994 seismic data has recently been reprocessed by Timor Resources. Timor Oil also acquired an extensive onshore gravity database particularly across the southern parts of Blocks A & C. We are currently awaiting the results of an airborne gravity-magnetic survey carried out across the entirety of Timor-Leste, acquired through Government funding in 2017.

During 2017 TIMOR GAP focused on reconnaissance geological mapping in Blocks A (Figure 3) and C (Figure 6). An updated lithostratigraphy has been developed as a framework for this mapping, as summarised in Figure 2.

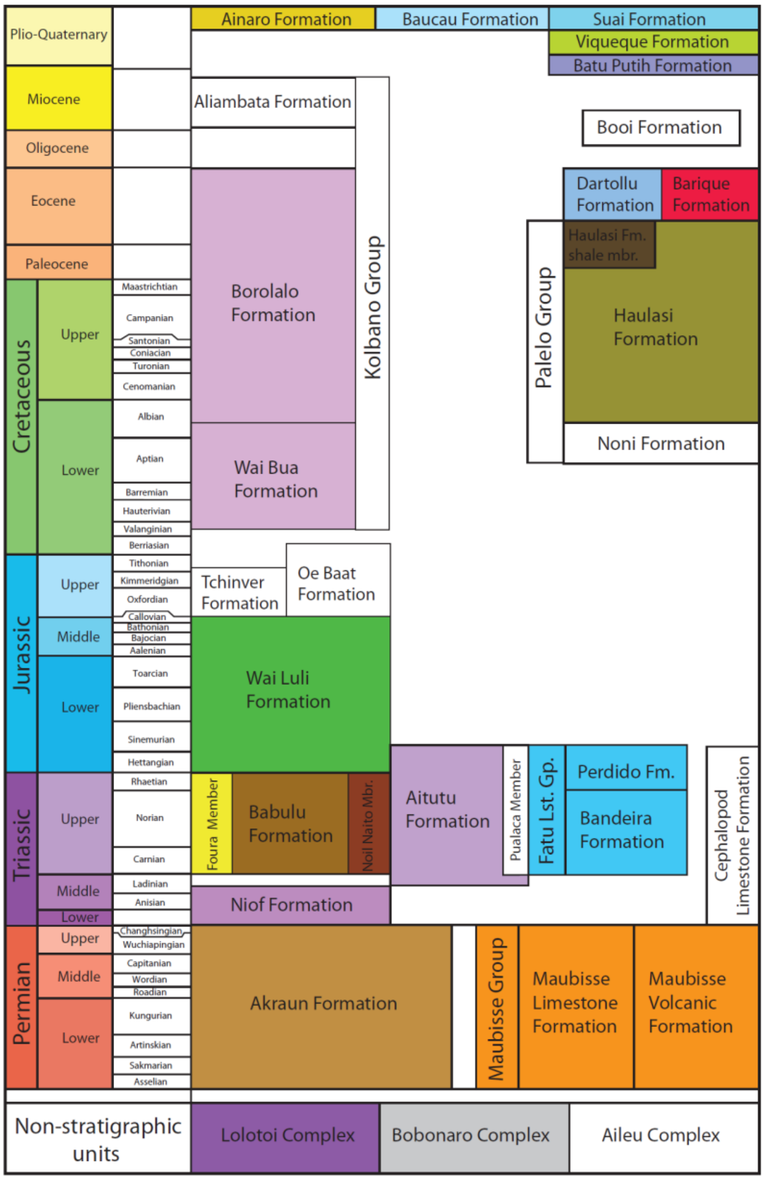


Figure 2: TIMOR GAP preliminary revised lithostratigraphy for Timor-Leste. The colour scheme is that for the reconnaissance geological mapping (Figures 3 & 6). Units left blank have not yet been encountered in the Onshore Block mapping areas. Note that the Permian Akraun Formation is a new name suggested equivalent to the Atahoc and Cribas formations of Audley-Charles [1].

2. HYDROCARBON INDICATIONS

More than 70 natural or drilling-induced hydrocarbon seeps or shows are now documented from across Timor-Leste, with more than 30 in Block A, about 20 in Block B and at least 6 in Block C. Across the territory oils are described as greenish and brown to black in colour, sweet, with gravities ranging from 14.5-44.6°API (heavier oils biodegraded), and with sulphur contents of 0.06-1.36% (a report of 4% sulphur [2] is apparently a typographical error for 0.4%). Higher sulphur values are associated with heavier, more biodegraded oils. Based on published and unpublished geochemical studies [5, 6, 8] and Timor Oil unpublished reports, the oils appear to derive from a common Triassic-Jurassic suboxic, somewhat restricted marine shale source containing mixed Type II/III kerogen, including a high proportion of land plant detritus.

3. BLOCK A (SUAI AREA)

The Suai area was the primary focus for Timor Oil's exploration between 1959-1972. Figure 3 shows the core region of the Suai Basin, a synorogenic basin of late Miocene to Recent age developed unconformably on top of the Timor fold and thrust belt. Timor Oil's wells primarily targeted reservoir in the Suai Basin succession (Viqueque Formation sandstone reservoir target), but as Figure 4 shows, most of the hydrocarbon shows were encountered in the sub-basinal thrustbelt, or even in the underlying Lolotoi metamorphic complex. Figure 5 is a cross-sectional interpretation of the Suai area, highlighting the primary exploration plays that TIMOR GAP recognise in the block. Based on our fieldwork, we interpret the Lolotoi Complex as basement to the fold and thrust belt cover sequences, both originating on the Australian continental margin. However, Timor Resources are also investigating the alternative interpretation of the Lolotoi Complex as allochthonous (obducted forearc), opening up the possibility of subthrust plays beneath outcropping Lolotoi Complex.

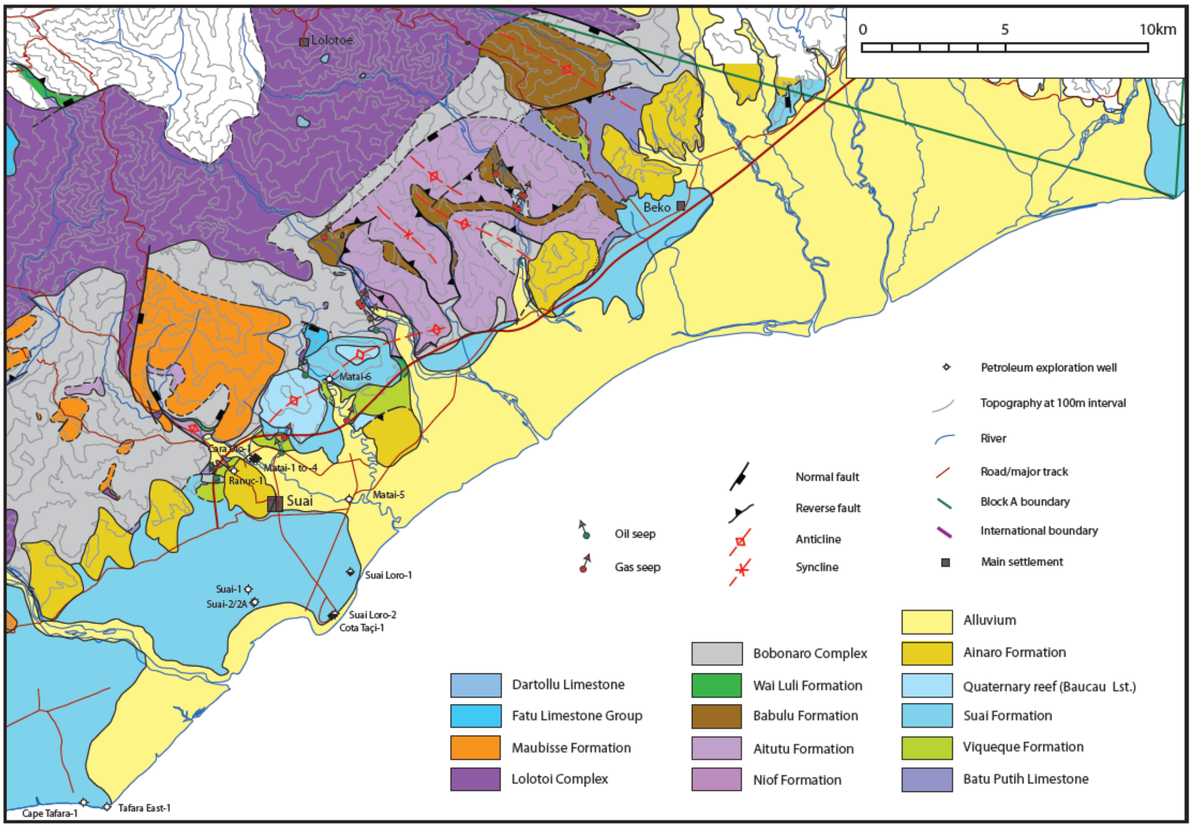


Figure 3: Suai Basin geology, Block A.

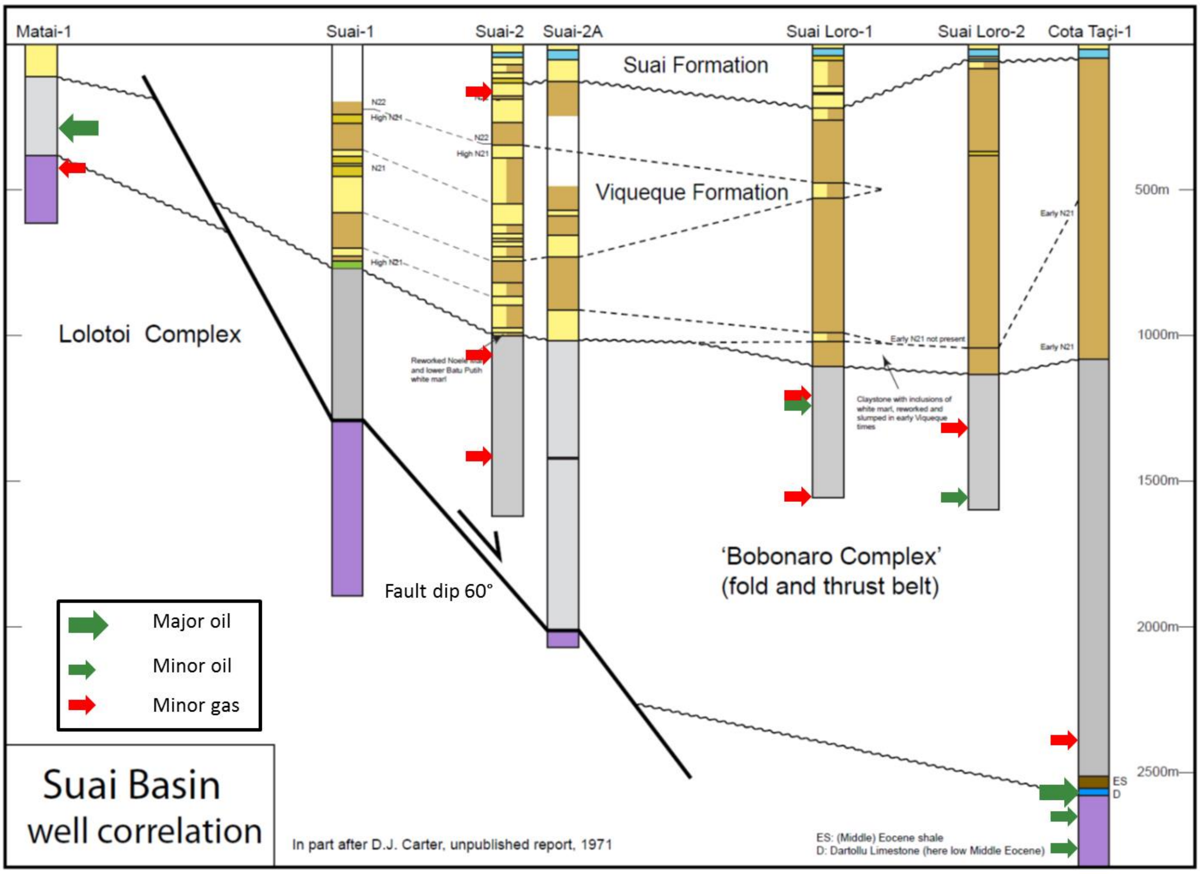


Figure 4: Suai Basin well correlation and hydrocarbon shows. See Figure 3 for well locations.

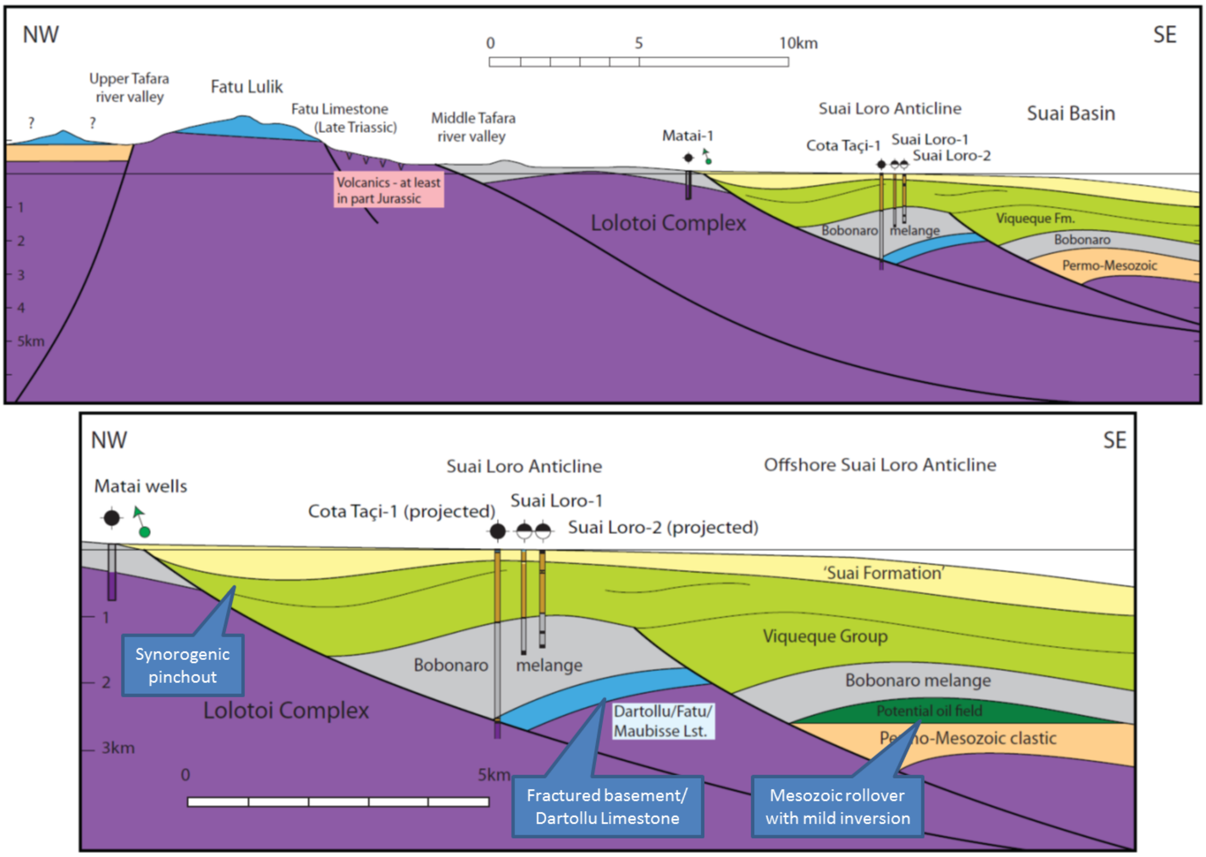


Figure 5: Suai Basin cross-section and exploration plays. See Figure 3 for well locations.

4. BLOCK C (BETANO-SAMÉ AREA)

The Block C area has received relatively little geological investigation since the reconnaissance mapping of Audley-Charles (1968) [1]. Figure 6 shows our new reconnaissance geological map for this area based on our 2017 fieldwork. In our pre-fieldwork interpretation [4] we had identified three main foldbelt exploration leads in Block C, with two additional (Lolotoi) basement highs as secondary leads. Our fieldwork has strengthened the case for a potential subthrust domal culmination beneath the Central Betano structure (Figures 6 & 7) and identified a small but potentially prospective new anticline 5km south of Samé. However, the case for a western prospect was weakened by the discovery of extensive Permian outcrop in an area previously interpreted (based on mapping [1] and remote sensing data) as an antiformal culmination in Mesozoic cover sequences. Timor Resources are, however, considering the possibility of a subthrust play in this area based on the reprocessed 1994 seismic data. The third, eastern, prospect has little surface expression, and will require seismic and/or shallow drilling to more fully delineate. One of the two basement-high leads was probably also invalidated by our fieldwork, as Lolotoi Complex was found outcropping on the crest of the high, so that any previously sealed basement structure in this area is probably breached.

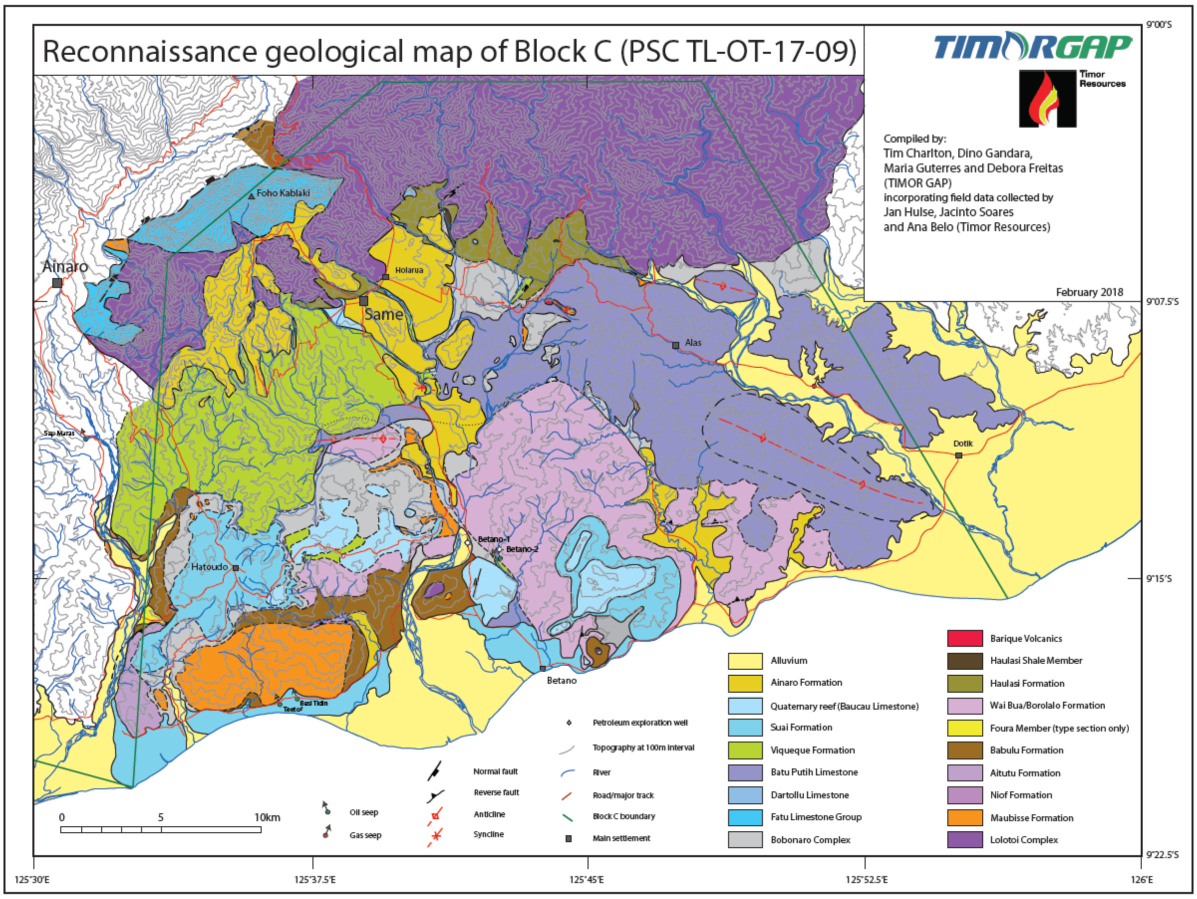


Figure 6: Reconnaissance geological map of Block C.

In addition to the petroleum exploration aspects of the new mapping in Block C, there are also several aspects of more academic significance:

i. The widespread outcrop of the Permian Maubisse Formation in the southern half of the area. No Maubisse Formation was indicated in this area on Audley-Charles's map [1].

ii. The separation of the deep marine carbonate Batu Putih Formation (primarily in the east) from the siliciclastic Viqueque Formation in the synorogenic Colitie Syncline [1] running E-W through the centre of Block C.

iii. The extensive development of the Haulasi Formation on the southern margin of the Lolotoi Complex north of the Colitie Syncline (as previously identified by [3] and [7]). Preliminary age determinations for the Haulasi Formation (MGPalaeo report to Timor Resources, December 2017) indicates Late and ?Late Cretaceous ages, and marine shelf environments of deposition. The list of six genera and one species of dinoflagellates recorded in the report (*Exochosphaeridium*, *Florentinia*, *Heterosphaeridium*, *Odontochitina*, *Palaeohystrichophora infusorioides*, *Spiniferites*, *Subtilisphaera*) have also been identified in full in 7 wells drilled on the Australian continental margin to the south of Timor (Bayu-1, Fohn-1, Lynedoch-2, Mistral-1, Mount Ashmore-1, Sikatan-1 and Wallaroo-1 wells; other wells from this area list some or most of these genera [10]). All 7 genera/species occur in the late Albian-early Cenomanian interval in the Mount Ashmore-1 well. This may suggest an Australian rather than Asian palaeogeographic affinity for the Haulasi Formation, which previously has been considered an allocthonous forearc succession obducted during collision, e.g. [7]. The Haulasi Formation outcropping in the north of Block C is significantly less deformed than the partly contemporaneous Wai Bua and Borolalo formations in the south of the block. The Wai Bua/Borolalo formations represent Australian continental margin deepwater facies but are located to the south of (inboard of) the apparently more proximal marine Haulasi Formation. These data are consistent with the Wai Bua/Borolalo formations being overthrust from the northern pre-collisional continental margin of Australia, while the more proximal Haulasi Formation unconformably overlying the Lolotoi Complex may have attained its present position through late-stage basement uplift (Figure 7). If any geological unit in Timor could be described as structurally allochthononous, it might be the Wai Bua-Borolalo succession rather than the Haulasi-Lolotoi grouping.

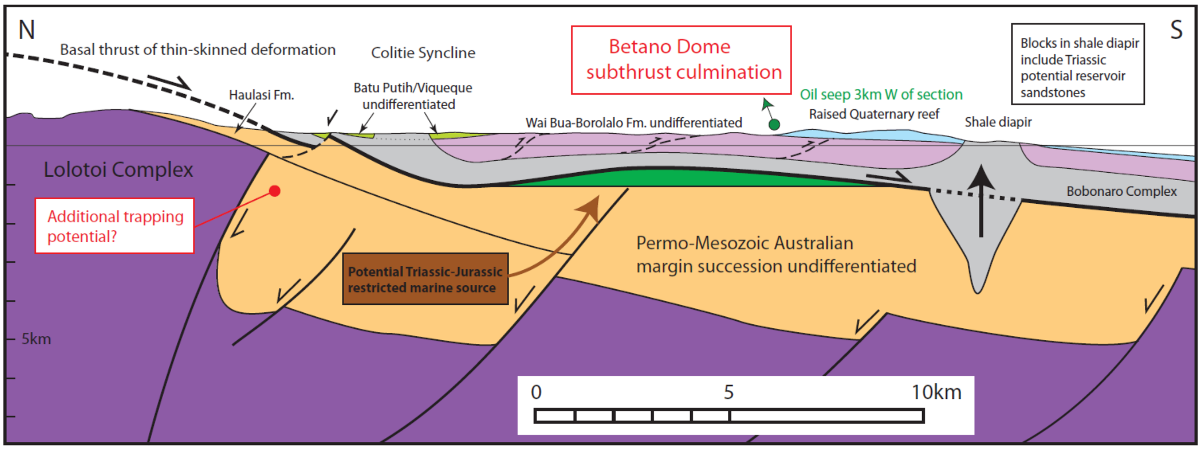


Figure 7: Cross-section N-S through central Block C. Deeper structure additionally constrained by electromagnetic Profile B of [9]. A possible subthrust graben in the north of the section (based on the electromagnetic profile) could form a potential kitchen for restricted marine Triassic-Jurassic source rocks.

5. BLOCK B

Block B occupies the more interior parts of the Onshore Block area, including mountains up to nearly 3000m elevation. There are, however, also abundant surface hydrocarbon indications in this area, particularly associated with the Bazol Anticline, and to a lesser extent the Aitutu Anticline (Timor Oil unpublished reports; Audley-Charles [1]; Figure 8).

Little new geological work has yet been carried out in Block B, although it is a primary target for investigation in the 2018 field season. What work has been undertaken so far, however, suggests a rather different relationship between the Bazol Anticline and associated gas seeps compared to earlier interpretations. Whereas Audley-Charles [1] showed a Permian-cored Bazol Anticline with a WSW-ENE trend and the gas seeps occurring primarily along the northern flank of the anticline, our reconnaissance studies suggest that the anticline trends NW-SE with the gas seeps primarily along the southern flank of the anticline, and rocks only as old as Triassic exposed in the anticlinal core. This suggests the possibility that the gas seeps might originate from a Permian gas-charged anticlinal core. Similar potential prospectivity at the Permian level may be associated with the larger Aituto Anticline to the NE of the Bazol Anticline, as also recognised (and nearly drilled) by Timor Oil in the 1960s. The Aituto Anticline is comparable in size and in its collision-zone structural setting (but not in stratigraphy) to the giant Hides gas field of Papua New Guinea (Figure 8).

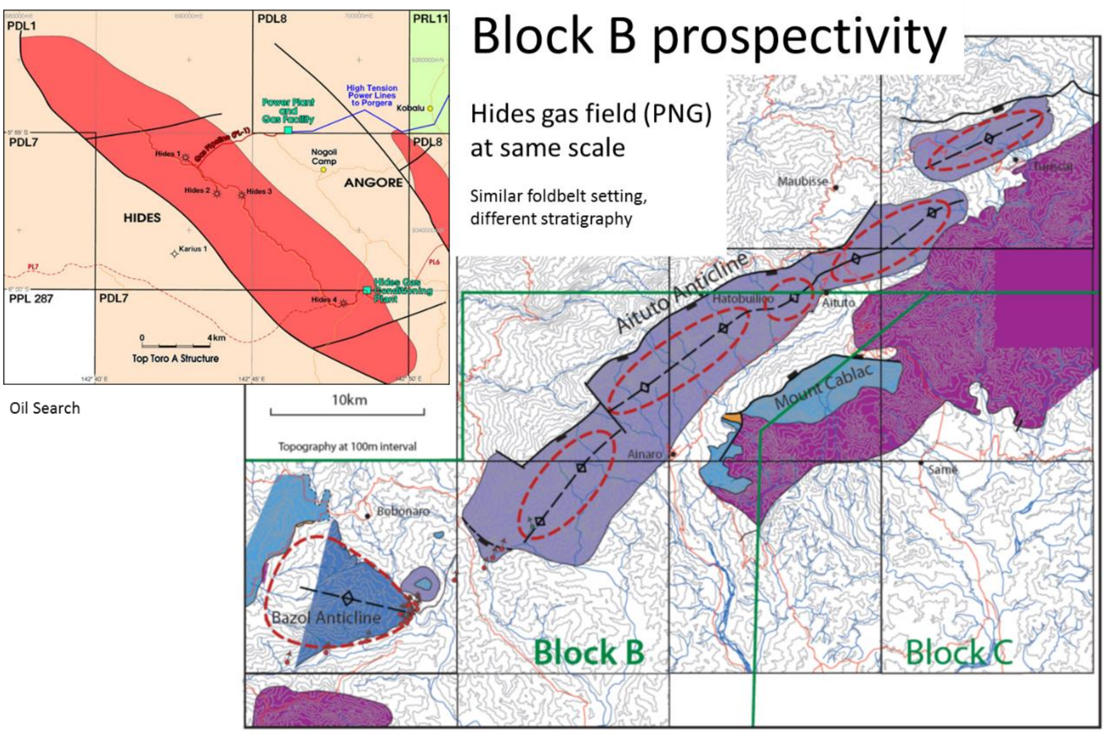


Figure 8: The Bazol and Aituto anticlines in the north of Block B, with the giant Hides gas field (Papua New Guinea) shown at the same scale for comparison. Only reconnaissance fieldwork has so far been carried out in Block B, but it is a primary target for work during 2018.

6. WIDER TIMOR-LESTE ONSHORE PROSPECTIVITY

The Onshore Blocks in the SW of Timor-Leste are currently the only onshore areas licensed by the Timor-Leste Government as PSCs. Considerable exploration potential also exists, however, in the eastern half of the country. Particularly strong natural oil and gas seeps occur at Pualaca in the central mountains, while both natural and drilling-induced strong surface seeps are found at Aliambata on the south coast. These areas attracted significant exploration interest from the end of the nineteenth century until the early stages of Timor Oil's investigation in the late 1950s, but have been largely neglected since that time. Elsewhere, potentially large subsurface anticlines may be indicated by domal folding of Quaternary reef terraces along the north coast of the island, and despite a widespread perception that these internal parts of the Timor fold and thrust belt 'should' be too structurally complex to be prospective, this is not borne out by the relatively simple fold/thrust belt structural style seen at outcrop in these areas.

ACKNOWLEDGMENTS

We are grateful to our exploration partners Timor Resources and particularly their exploration team including Jan Hulse, Mike Bucknill, Jacinto Soares and Ana Belo for their excellent and productive collaboration, and to TIMOR GAP, E.P. for permission to publish this study. The interpretations are, however, those of the authors, and are not necessarily those of either TIMOR GAP or particularly Timor Resources.

REFERENCES

[1] M.G. Audley-Charles, The geology of Portuguese Timor, Geological Society of London Memoir, no. 4, 1968.

[2] N. Boutakoff. Oil prospects of Timor and the outer Banda Arc, S.E. Asia, Australasia Oil & Gas Review, v. 14, pp. 44-55, 1968.

[3] D.J. Carter, M.G. Audley-Charles and A.J. Barber, Stratigraphical analysis of an island arc-continental margin collision zone in eastern Indonesia, Journal of the Geological Society of London, v. 132, pp. 179-198, 1976.

[4] T.R. Charlton, D. Gandara and N. da Costa Noronha, TIMOR GAP's Onshore Block: a preliminary assessment of prospectivity in onshore Timor-Leste, SEAPEX SEC Conference, Singapore, May 2017.

[5] K.E. Peters, T.H. Fraser, W. Amris, B. Rustanto and E. Hermanto, Geochemistry of crude oils from eastern Indonesia, Bulletin of the American Association of Petroleum Geologists, v. 83, pp. 1927-1942, 1999.

[6] Robertson/Patra Nusa Data, Timor Sea: Mesozoic Source Rock Distribution and Palaeoenvironments, unpublished, 1998.

[7] C.E. Standley and R.E. Harris, Tectonic evolution of forearc nappes of the active Banda arc-continent collision: origin, age, metamorphic history and structure of the Lolotoi Complex, East Timor, Tectonophysics, v. 479(1-2), pp. 66-94, 2009.

[8] P. Ware & L.O. Ichram, The role of mud volcanoes in petroleum systems: examples from Timor, the south Caspian and the Caribbean, In: Petroleum Systems of SE Asia and Australasia, pp. 955-970, Indonesian Petroleum Association, 1997.

[9] Wei Yan, Yang Zhanjun, Meng Cuixan, Li Dechun, Luo Weifeng and Wang Tianping, Geological report of gravity, magnetic and CEMP survey in the Democratic Republic of Timor-Leste, Petrochina (unpublished), 2004.

[10] Well completion reports held in the Geoscience Australia library, Canberra.

ORAL PRESENTATION

Mesozoic Stratigraphic Evolution of the North Carnarvon Basin Unlocked Using Olympus 3D

Stacey Mansfield[1], Daniel Bishop[2], Megan Halbert[2], Vincent Dykmans[2], Simon Price[2]

[1]*BP Plc, UK*

[2]*BP Developments Australia Pty Ltd*

stacey.mansfield@bp.com

Interpretation of the Olympus 3D dataset has for the first time allowed interpreters to provide a detailed description of Mesozoic stratigraphy in the North Carnarvon Basin on a high quality and continuous dataset. The dataset, which BP licensed from Spectrum in 2016, covers almost 20,000 km^2, combines 19 3D surveys and is broadband processed from field tapes to create a unified PSDM volume. BP has described Triassic depositional environments using various seismic attributes and extraction techniques, which show good contrast between low-stand and high-stand fluvial channel complexes and marginal marine clastic systems. Enhanced PSDM processing allows for better seal and reservoir thickness and net to gross assessments, which can now be tied back to well and field data on a continuous survey.

ORAL PRESENTATION

Xanadu Oil Discovery, northern Perth Basin, Western Australia

Shelley Robertson[1]

[1]*Norwest Energy NL, Australia*

shelley.robertson@norwestenergy.com.au

The Xanadu Prospect is located in state waters in exploration permit TP/15, situated approximately 300 km north of Perth, Western Australia. The Xanadu Prospect targets Permo-Triassic sands from a depth of approximately 800 m, located in very shallow water immediately adjacent to the coast. Structuring took place during the Early Cretaceous, creating a very prominent horst, fault-bounded on all four sides.

The seismic lines in the vicinity of the Xanadu Prospect have been acquired over the past 50 years with greatly varying orientations due to the restrictions imposed by the shallow water and the many reefs in the area. A Full Tensor Gravity survey confirmed the presence of a strong positive gravity anomaly coincident with the seismically mapped structural high.

The Xanadu-1 exploration well spudded in September 2017 to test the hydrocarbon potential of the Xanadu Prospect.

The well was technically challenging, drilled as a deviated s-shaped well from an onshore surface location to an offshore target. Xanadu-1 was declared a discovery in late September 2017, when it intersected hydrocarbon-bearing reservoirs, evidenced by elevated gas readings, oil shows and fluorescence while drilling. Wireline logging including pressure testing and fluid sampling validated these results. Xanadu is the first oil discovery in the Perth Basin for over 15 years.

Subsequent integration of the petrophysical analysis, MDT data, fluid recoveries and seismic interpretation now indicate that Xanadu-1 did not intersect the crest of the culmination, and that the structural high is likely to be located to the north, beyond the northernmost 2D seismic line currently available.

The logical next step in this program is the acquisition of 3D seismic, and a 40 km^2 survey is currently planned. Assuming this seismic validates the assumption that the structure rises to the north, the plan is to re-enter the suspended Xanadu-1 well and drill a side-track to a northern up-dip location.

With positive results from this side-track well, the development could be fast-tracked, given the proximity of the Arrowsmith oil production facility supporting the Cliff Head oil field.

Permian sands beneath the Kockatea Shale regional seal have provided the reservoir for four oilfield discoveries in the vicinity since 2001, namely Cliff Head, Jingemia, Hovea and Eremia.

ORAL PRESENTATION

Asia-Pacific Unconventional Opportunities at $50 Oil: The Differences and Challenges Between North American Proven Unconventional Systems and Recognised Unconventional Opportunities in Australia and SE Asia

Ian Cockerill[1]

[1]*RISC Advisory, Australia*

ian.cockerill@riscadvisory.com

2017 saw a flourishing unconventional sector in North America. A resurgence in drilling and asset transaction activity led to a significant rebound in investor sentiment in North American unconventional exploration and development. Why haven't we seen a similar rebound in unconventional exploration sentiment in Australia and South East Asia? What are the challenges facing unconventional plays in the Asia-Pacific region versus the more established plays in North America? How 'good' are the North American plays versus those recognised in the Asia-Pacific region? This paper will address key unconventional petroleum systems of North America and look at how the heterogeneity of these plays develop commercial 'sweet-spots'. Understanding play heterogeneity and the identification of 'sweet-spots' is critically important, particularly in challenging price environments. Reporting an impressively high hydrocarbon in-place number in your prospective unconventional play is the easy part. The estimation of ultimate recovery potential is significantly more difficult. RISC has developed spatial analysis techniques and methodologies to identify unconventional sweet-spots and quantify recovery potential in pervasive unconventional systems.