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Southeast Asian carbonate systems and reservoir development: an up-to-date synthesis, 2017

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1. EXECUTIVE SUMMARY

1.1. Summary of contents

This report provides an update to Cambridge Carbonates previous 2011 report on carbonate reservoirs of SE Asia. The report includes data on new discoveries and concepts, and integrates data from more than 120 additional publications in the area plus Cambridge Carbonates in-house experience. The 2017 updated edition of the report also contains over 80 new or updated figures.

New for the 2017 updated version is an associated GIS project. The GIS project contains georeferenced map figures and also a geodatabase of reservoir parameters.

This report aims to:

- Review the existing and future hydrocarbon potential Cenozoic carbonate systems of SE Asia.
- It emphasises future hydrocarbon potential by examining the possibility of making further discoveries and adding reserves to existing fields in different basins.
- It presents an up to date review of the sedimentological and sequence stratigraphy of Cenozoic carbonate reservoirs in light of recent research in SE Asia and on evolving concepts of carbonate sedimentology in general.

The report starts with an introduction followed by a discussion of the geology, carbonate systems, reservoirs and future hydrocarbon potential region by region. Topics covered by the introduction include:

- The general depositional controls of Cenozoic carbonate systems in SE Asia including a classification of carbonate buildups and depositional systems.
- Evolving conditions of global sea level, palaeoclimate, oceanography and carbonate producing communities through the Cenozoic and how these impact on reservoir distribution, type and quality.

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- Sequence stratigraphic control on reservoir layering and architecture of Cenozoic carbonate systems and the implications for the development of potential of reservoir facies in differing basins.
- Interaction between carbonate and siliciclastic sedimentation highlighting the potential for developing carbonate systems within siliciclastic settings and the seismic geometries that can be used to identify carbonate systems in these settings.
- The recognition of karsted and drowned carbonate platforms and their contrasting significance for reservoir development.
- The use of high resolution sequence stratigraphy studies of core as a means of integrating core and log data.
- Diagenesis of Cenozoic carbonates.
- The origin and prediction of sub-surface CO_2.
- Distinguishing volcanic structures from carbonate systems using seismic data.
- A compilation of carbonate reservoir parameters including porosity vs. depth, porosity and permeability vs. reservoir type, depositional facies and hydrocarbon type, trap type and size and net:gross.

The study area has been broken down into the following areas, each of which has its separate treatment (Figure 1):

- North and South Sumatra and adjacent offshore areas.
- Java and adjacent offshore areas. Including a separate chapter on finds in Pliocene carbonate contourites.
- Offshore south and east Vietnam and the South China Sea.
- Offshore Sarawak, Philippines and Natuna Seas.
- East Kalimantan, Sulawesi and adjacent offshore areas.
- West Papua and Papua New Guinea.

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Figure 1 Location map and basins in SE Asia. Note that the basins with important carbonate reservoirs are marked in red, and have been reviewed in detail in this report. Modified from Steinshouer et al. (2000).

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Each area is treated as follows:

- Geological setting describing the main geological elements, tectonic regime and basin evolution.
- Stratigraphy with the depositional environments of the main stratigraphic units, highlighting their source and reservoir potential.
- Hydrocarbon geology including the exploration history of the basin or basins, the main source rocks and burial histories.
- Carbonate reservoirs covering the main carbonate systems, concentrating on the main controls on reservoir quality including the depositional facies, sequence stratigraphic context, diagenesis, porosity-permeability properties and seismic expression.
- Future potential of the basins that highlights any additional plays, the key uncertainties and any new concepts or methodologies that may lead to making further discoveries or adding reserves to existing fields.
- A dataset of reservoir properties and other parameters from fields in each area.

1.2. Future potential in SE Asia

This review suggests that the future potential of SE Asian carbonate systems can be unlocked by addressing a number of key uncertainties, concepts and methodologies. These factors may differ from basin to basin because of varying exploration maturity; for example, offshore east Vietnam, and Natuna East Basins are considered to be relative frontier areas because they have proven hydrocarbon systems with large projected undiscovered reserves. Other basins such as the Nam Con Son Basin may be a relatively mature basin with respect to gas reserves, but is immature in respect of oil reserves.

The key geological issues common to many basins include:

- A detailed knowledge of the regional palaeogeography will help to predict the occurrence of additional reservoirs, particularly by mapping carbonate

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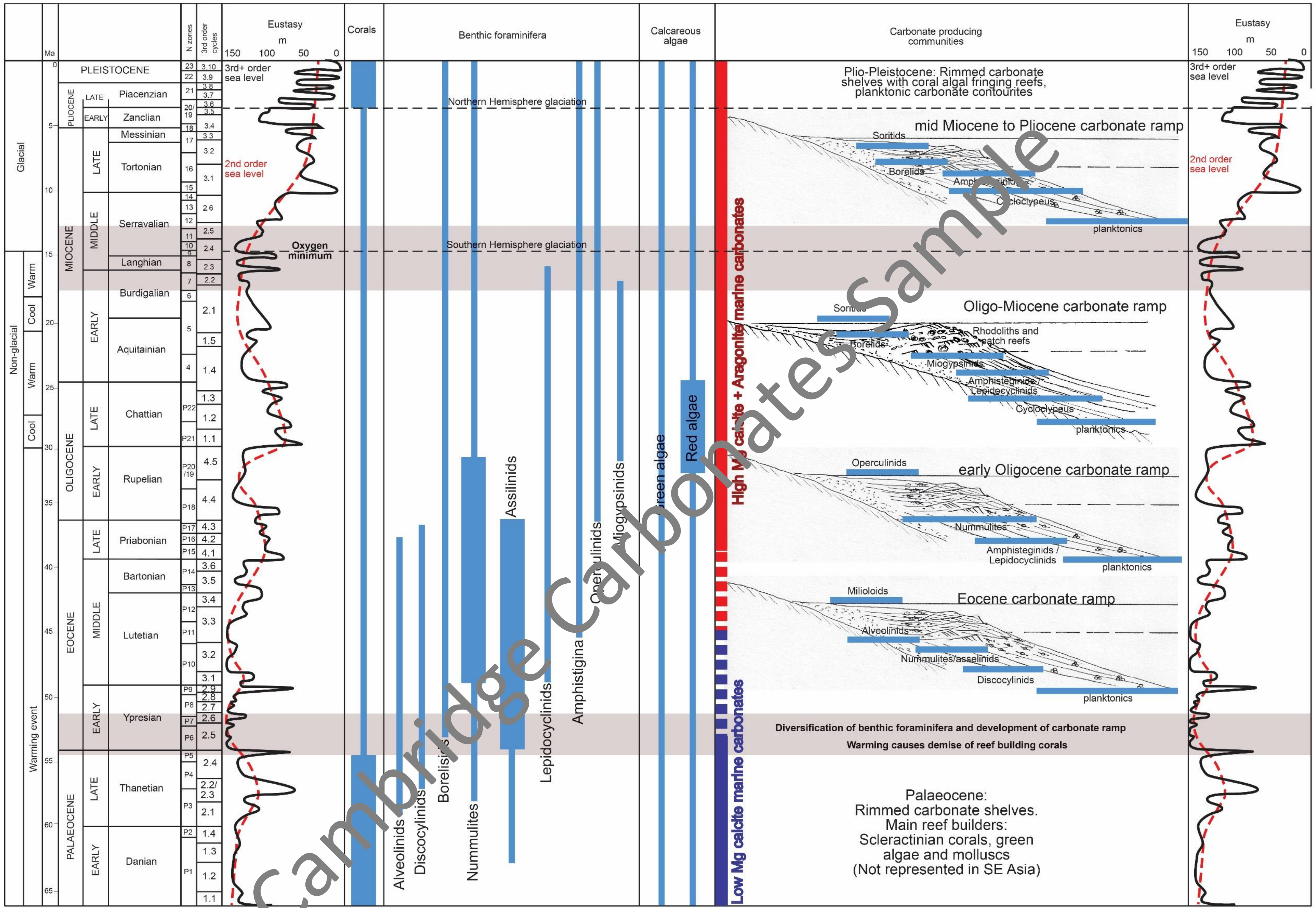

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Figure 4 Evolution of Cenozoic carbonate producing communities. Based on Babic and Zupanic (1981), Lutherbacher (1984), Reiss and Hottinger (1984), Al-Hashimi and Amer (1985), Sartorio and Venturini (1988), Buxton and Pedley (1989), Stanley and Hardie (1998), Wilson (2002, 2011) **and** Flugel (2004).

During periods of transgression and highstand in mixed carbonate-siliciclastic system, however, carbonate sedimentation more typically prevails, since the siliciclastic source is pushed landward, and the shelf is covered by shallow carbonate-producing seas. This concept is well demonstrated in the Cenozoic history of the Great Barrier Reef in NE Australia (Figure 8).

Coeval deposition

In settings where siliciclastics dominate, carbonate production occurs in areas of starvation by siliciclastic deposition, predicting the distribution of carbonates is more subtle. Typically in these settings, carbonates develop during sea level rise (transgressive systems tract), since siliciclastic sediments are "locked" into a more proximal setting. Carbonate buildups occur in an outer shelf location, away from the clastic sediment source. Figure 6 shows how in the Mahakam delta, during periods of sea-level fall and lowstand, incision of the former shelf occurs, leading to the development and fill of incised channels by fluvial clastics. Carbonate bioherms establish themselves on the distal parts of the system which are sediment-starved during the subsequent transgression. Significant progradation of deltaic facies over the underlying carbonates takes place during highstands.

In these types of settings though, particularly where there are high clastic sedimentation rates, the importance of syn-depositional tectonics for initiating carbonate development should not be ignored. Netherwood and Wight (1992) note how in the Tarakan Basin, Pliocene-aged carbonate buildups have developed on subtle highs which have been created due to rollover anticlines forming as a result of a large basinward growth-fault system.

Seismic sequence geometries are an exploration tool to identifying carbonate reservoir potential in mixed carbonate-siliciclastic sequences. Indicators of carbonate sequence geometry within siliciclastic systems are as follows:

- Mounded seismic facies at the outer shelf; particularly if associated with clinoforms dipping towards the shelf interior (such as Figure 7 and Figure 9)

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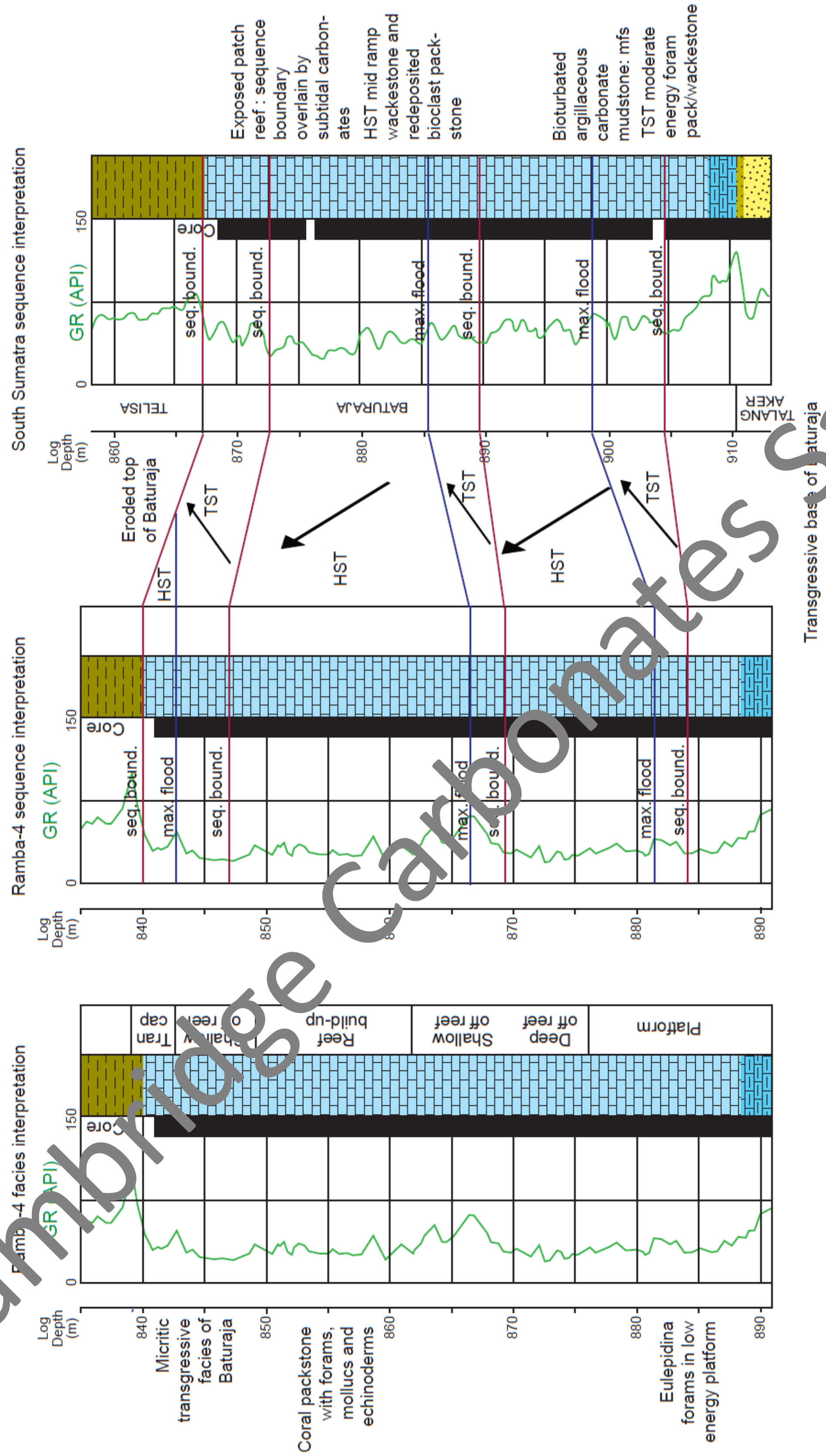

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Figure 12 Example of an integrated core and wireline log sequence stratigraphic interpretation from the Baturaja Limestone of Sumatra. Facies interpretation of Ramba-4 is from Situmeang et al. (1992).

- Precipitation of carbonate minerals removes CO_2 from solution. This may take place on mixing with meteoric pore fluid near the surface and also occurs during migration through siliciclastic reservoirs. In contrast, the CO_2 content of the pore fluid remains in equilibrium with the host rock as it passes through carbonate reservoirs, which thus tend to contain higher levels of CO_2 than clastic reservoirs.
- CO_2 may be diluted by mixing with other gases. If CO_2 was generated from a hydrocarbon source, it will be diluted by hydrocarbon gases generated from the same source rock. For example, in northern Sumatra, variations in CO_2 content can be explained by differing contributions of CO_2 from the Tampur Formation and hydrocarbon gases from the overlying Bampo Formation. Alternatively, CO_2 may mix with other gases from a different source during migration. For example, gas in the Baturaja Formation in Pamanukan-2 well of offshore NW Java comprises 90% CO_2. The $^3He/^4He$ isotope ratio of 4.002 indicates a contribution from the mantle mixed with another source or sources.
- Formation of methane by reduction of CO_2. This can be identified by the hydrogen isotopic signature of the methane such that $\delta D_{CH4} > -200‰$ (Satyana, 2007).

These principles of interpreting the origin and prediction of the distribution of CO_2 in the subsurface are illustrated by a number of case histories from the area.

2.4.3. Gas composition in Bohai Bay Basin, China

An example of distinguishing between shallow Cenozoic and mantle-derived CO_2 was described from the Bohai Bay Basin in NE China (Figure 13). The CO_2 content of reservoir gases varies from 0.003-99.6%, which is derived from a combination of mantle degassing, the decomposition of Ordovician carbonates and low temperature decomposition of organic matter in Carboniferous to Cenozoic coal-bearing clastics (Zhang et al., 2008).

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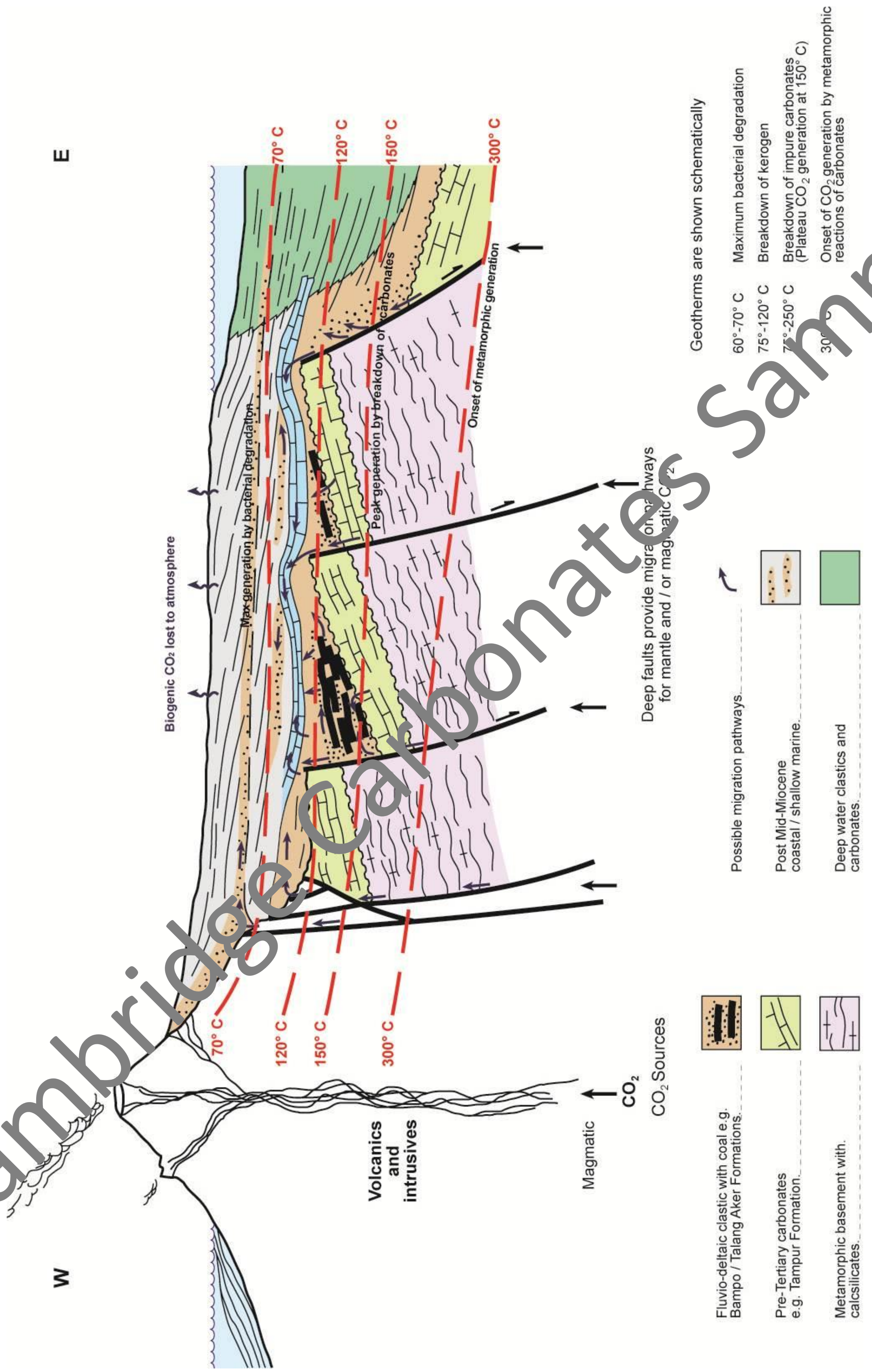

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Figure 16 Schematic model for the origins of sub-surface CO_2 in northern Sumatra.

2.5. Distinguishing volcanic structures from carbonate buildups using seismic data (contribution from Dougal A. Jerram)

The study of volcanic margins and associated facies associations is increasingly becoming an important area for petroleum exploration (e.g. Jerram, 2015; Senger et al., 2017; Planke et al., 2017). Building conceptual volcanic evolution models in conjunction with seismic observations from volcanic basins helps us to be better informed on what volcanic rocks look like in the subsurface (here 'volcanic' is used to cover both the extrusive and intrusive parts of the system). For example, an evolving volcanic system will have a number of associations that can be recognised within the resultant rocks that are preserved (Figure 19). These in turn have characteristic seismic expressions that can be helpful to determine their internal structure and origin (e.g. Planke et al., 2005; Jerram et al., 2009). The use of 3D seismic, for example, is becoming increasingly useful to determine volcanic features (e.g. Thompson and Schofield, 2008; Sun et al., 2014; Planke et al., 2017). An example of an RMS amplitude image made from a detailed 'top basalt' pick in a 3D dataset offshore Norway, highlights the important seismic geomorphological features that can be preserved to help interpret the modes of emplacement of the volcanics (Figure 20). Such features include lava flow morphologies, lava deltas and debris flows (Planke et al., 2017). Clearly such rendering will rely on good datasets, but as exploration efforts increase, such data becomes more readily available and if interpreted with some experience of volcanic margin studies a more successful interpretation can be realised.

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WRZ ¼ weak reflection zone; TPF ¼ top of polygonal fault tier; location in (a); (d) Representative seismic profile through DSA38 and DSA39. (For detail of the specific DSAs numbered please refer to Sun et al., 2014). Reproduced with permission.

The assessment of whether volcanic rocks within a basin are a hindrance or a help is also a question worth evaluating, even when you have successfully identified volcanics (e.g. Jerram, 2015; Senger et al., 2017). As indicated above, intrusions can form trap structures in the sediment overburden. The volcanic units themselves can also be important reservoirs. Significant volcanic reservoirs have been identified in onshore China for example (e.g. Jiang et al., 2017), igneous induced hydrothermal alteration and modification of carbonates can provide favourable secondary permeability characteristics, and the associations of carbonates and volcanics within significant discoveries (e.g. the Libra discovery on the Brazilian Margin) highlight the many possibilities that need consideration where volcanics are present. Further details regarding the role of volcanism in petroleum systems can be gained through the Volcanic Margin Petroleum Prospectivity (VMAPP) multiclient project produced by VBPR/DougalEARTH/TGS[3].

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[3] http://vbpr.no/products/special-products/vmapp-volcanic-margin-petroleum-prospectivity/

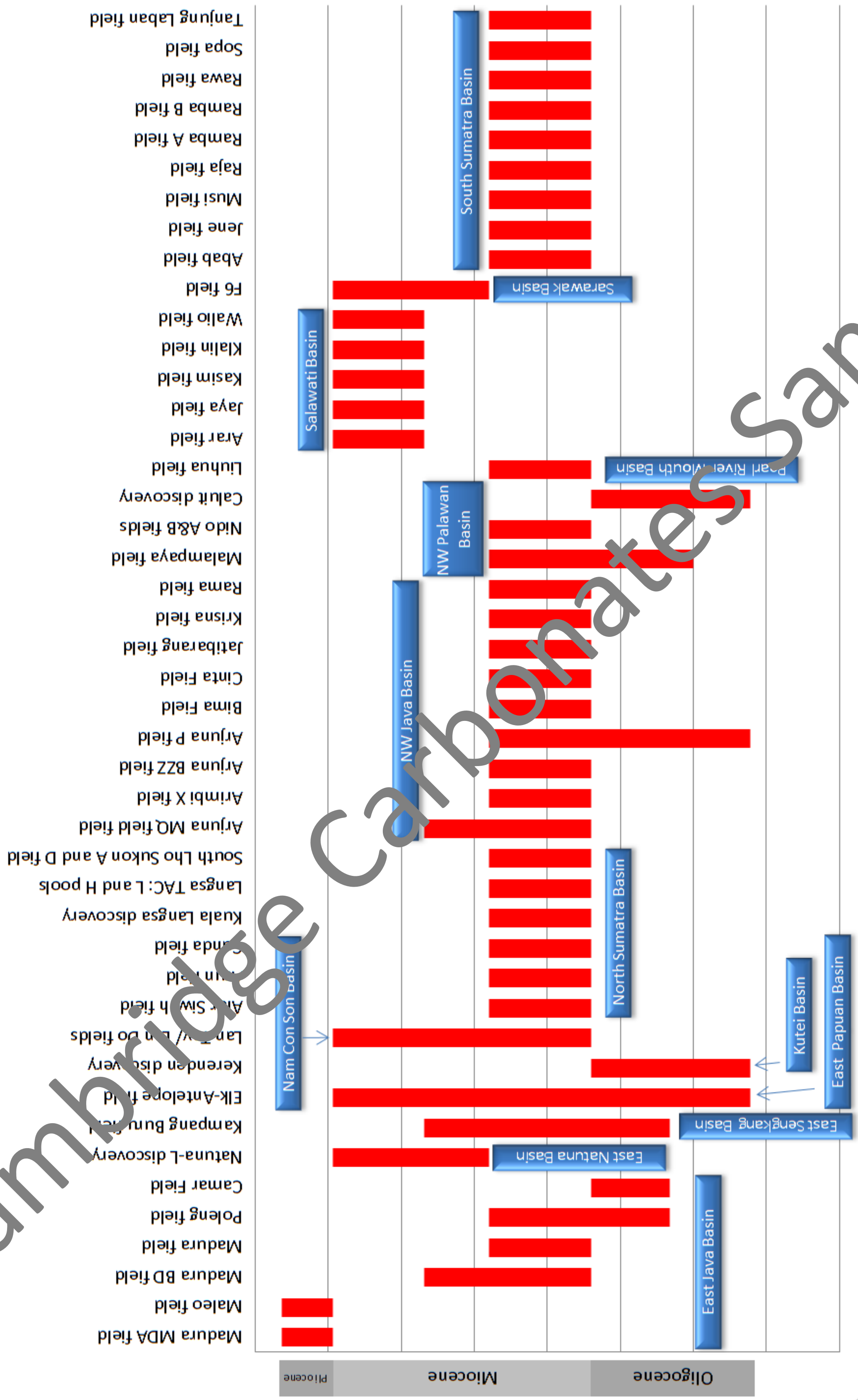

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Figure 29 Reservoir Age of selected carbonate reservoir examples in SE Asia database, grouped by location (basin).

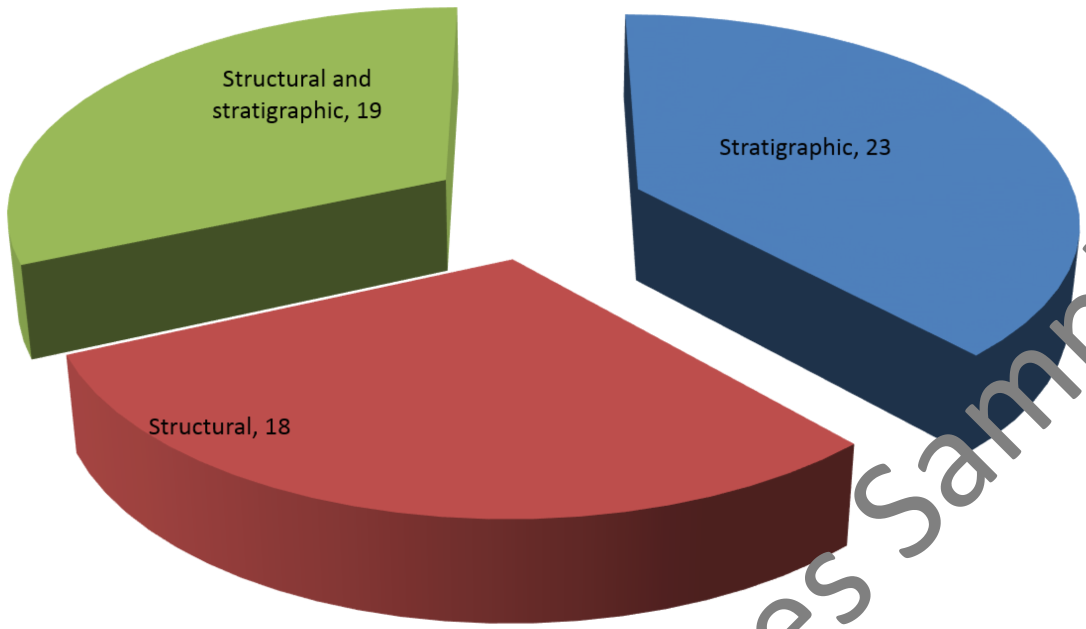

Figure 41 Trap types characterisation for the carbonate reservoir examples in SE Asia

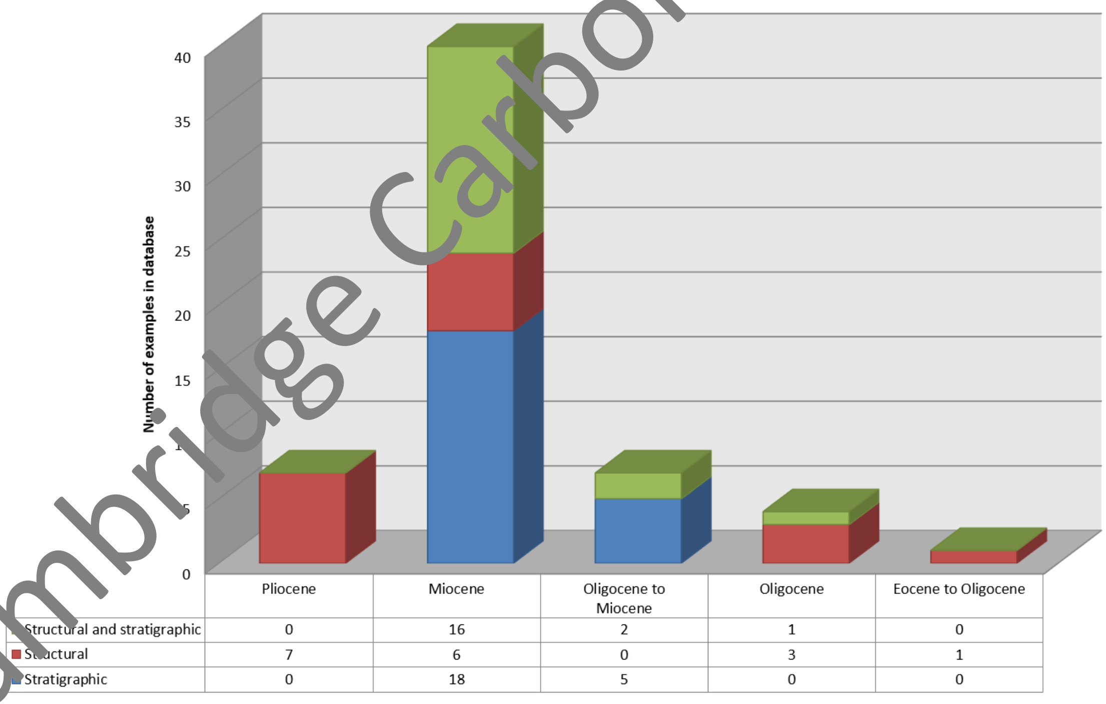

Figure 42 Column chart showing trap type as a function of top reservoir age, for carbonate reservoir examples in SE Asia

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with the inferred P22/N4 low stand. However, low stands are difficult to recognise during this period of overall subsidence. These are sealed laterally by shales and traps are formed by Middle Miocene to Pleistocene compression; no discoveries have been made in this play (Meckel et al., 2012). Carbonates, known as the Jeuku Limestone, were deposited over siliciclastic-starved highs, particularly in the southern part of the basin away from the main siliciclastic source. These typically consist of shallow water foraminiferal packstone and wackestone with minor corals that represent bioclastic shoals. Carbonate buildups in the Jeuku Limestone are not necessarily associated with the carbonate buildups in the overlying Peutu Limestone. Some carbonate buildups in the Jeuku Limestones have also been eroded at the syn/post-rift unconformity; these carbonate buildups are not thought to represent significant reservoir targets (Meckel et al., 2012).

4.2.3. *Early Miocene*

The Peutu and Belumai Formations both form part of the Early Miocene post-rift sequence (Figure 51). The Peutu Formation is a shallow water carbonate facies that was deposited over structural highs present in both offshore and onshore parts of the basin and the Belumai Formation is a laterally equivalent deep water facies deposited in basinal areas between the highs (Soeparjadi, 1983, Meckel et al. 2012, Hakim et al. 2014). The reservoirs of the Arun and Alur Siwah fields, the largest gas reservoirs in northern Sumatra, are in carbonate systems developed over depositional highs in the Peutu Limestone (Figure 50). The Peutu Formation is also referred to as the Peutu Limestone/Peutu Limestone Member; names for time equivalent carbonate facies on other structural highs include: Arun Limestone, Cunda Limestone, Malacca Limestone Member (in the Malacca Straits), Western High Limestone and the Peusangan Limestone. Where the term 'Member' is used, it refers to a member of the Belumai Formation (Wilson, 2002).

The Peutu Formation was deposited during the Late Oligocene to Early Miocene as a mixed carbonate siliciclastic ramp system that onlapped a series of N-S trending basement-cored horsts extending from the Barisan Mountains (Wilson 2002; Figure

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Field	Reservoir	Facies	Reservoir depth m	Reservoir thickness/pay m	Poroperm data	Discovered	Status	Reserves/rate
Arun	Peutu Fm	Foraminiferal bioclastic shoals with patch reefs.	2896mss		7-35% average 16.2%; 0.01-1466mD, mainly 2-500mD	1971	Producing gas	Reserves: 14.1 TCF gas plus 700 MMB condensate
Lho Sukon South A and B	Peutu Fm	Bioclastic limestone with patch reefs surrounded by deeper water facies.	2440m			1972	Producing gas and condensate	Reserves: 300 BCFG and 3 mmbc
Paseh	Peutu Fm							
Alur Siwah	Peutu Fm	Foraminiferal shoal with coral patch reefs.	500m		Average porosity 11% (10-15%); 0.1-5.0md permeability. Super k zones in vuggy facies.	1972	Producing gas	Reserves (ultimate): 385 BCFG and 10 MMBO
NSO-A	Malacca Mbr of Belumai Fm	'Reefal' limestone	1160mss	152.4m	Karsted reef with zones of lost circulation; 27-32% vuggy porosity Inter-reef: 23-27% Dolomitised interval at base: 12-17% Typically ranges from 100-300mD k	1972		
NSO-H&L fields	Peutu Fm				6-11%		Oil	Reserves (ultimate): 7 BCFG; oil rate 2000-4000 BO/D
Kuala Langsa	Peutu Fm	Foraminiferal shoal with coral patch reefs.	3296m		Average 14% (6-23%):	1992	Gas discovery	
Langsa TAC: L and H pools	Malacca Limestone	Karsted and dolomitised limestone			Layer 1: 6.4% Layer 2: 7.8% Layer 3: 10.7%	1980	Oil producer	Reserves: 13 MMBO proven; 33.5 MMBO proven and probable
Peusangan A-1 (Arun High)	Peutu Fm			Few m		1980	No shows, water bearing limestone	
Peusangan B-1 (Arun High)	Peutu Fm	Near reef/lagoonal		152m	Average 35%	1985	Gas and condensate	Gas rate 10.3 MMSCF/D; condensate rate 877 BC/D
Peusangan B-2 (Arun High)	Peutu Fm	Near reef/lagoonal				1986		Inconclusive test owing to mechanical problems
Peusangan C-1 (Bireun High)	Peutu Fm	Limestone with dolomite		148m porous limestone 56 m dolomite	13-29% (limestone) Average 3% (dolomite)	1986	Non-commercial, probably seal failure	Gas rate 2.7 MMSCF/D; water rate 1215 BW/D
Peusangan D-1 (Bireun High)	Peutu Fm	Argillaceous limestone		<1m		1988	Gas shows, non-commercial	
Peusangan E-1 (Bireun High)	Peutu Fm			40m gross; 24m net pay	Average 15%	1989	Dry hole, but petrophysical appraisal suggests gas column	
Peusangan F-1 (Bireun High)		Carbonates absent				1990	Dry hole	
Peutouw	Peutu Fm				7% average (4-10%)		Discovery	
Cunda	Peutu Fm			52m pay	13 %	1984	Discovery	Reserves (ultimate): 20 BCFG; gas rate 10.5 MMSCF/D
Jau-1	Peutu Fm						Gas discovery	Gas rate 10.5 MMSCF/D
JKUA-1	Peutu Fm						Gas discovery	Gas rate 9.9 MMSCF/D
NSB-A field	Peutu Fm			Reservoir 274m thick			Gas	Reserves (ultimate): 2000 BCFG and 2 MMBO

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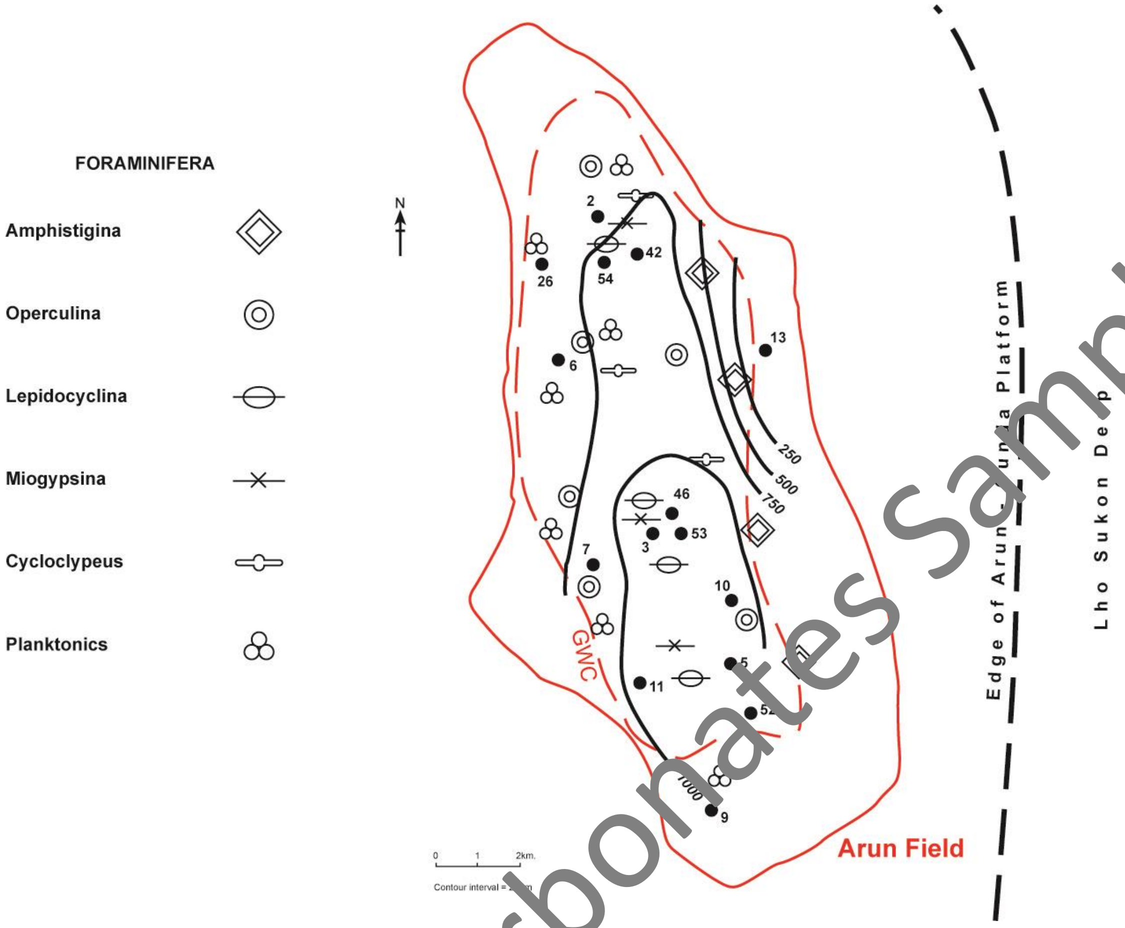

Figure 59 Distribution of benthic and planktonic foraminifera across the Arun reservoir (data from Abdullah and Jordan (1987), Jordan and Abdullah (1988)).

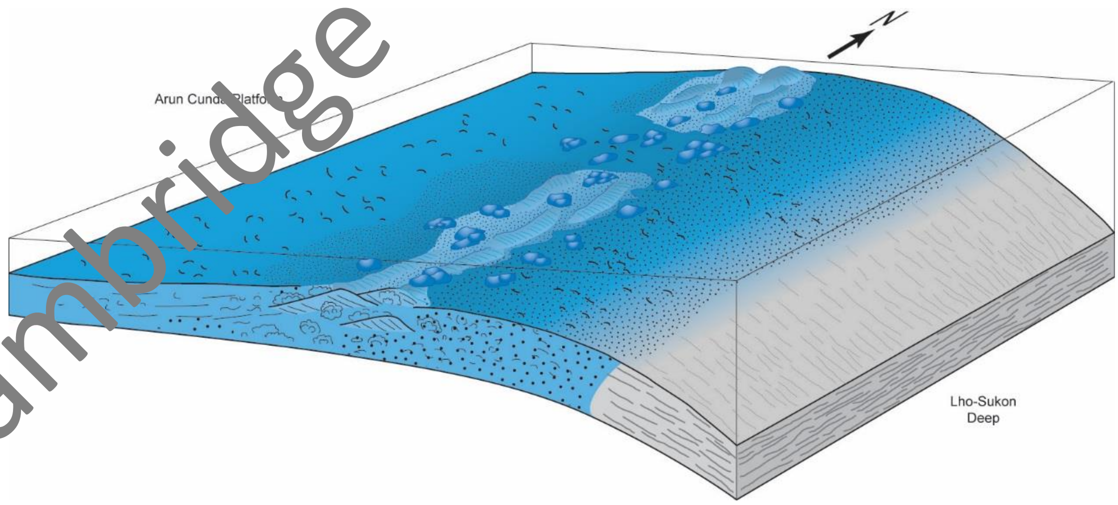

Figure 60 Revised sedimentological setting of a carbonate ramp, or non-rimmed shelf for the Arun-Cunda platform.

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Porosity is distributed through the Arun reservoir in four layers (Figure 67; Figure 68; Abdullah and Jordan, 1987; Jordan and Abdullah, 1988):

- Layer D (Upper Reef) contains 10-20% porosity with a high permeability area in the west and central part of the field. This zone is absent on the east flank where reasonable reservoir quality is found.
- Layer C (Middle Reef) contains moderate porosity. Permeability is generally low to moderate but is very variable with both low and high permeability streaks. Layer C extends over the whole reservoir and forms a barrier to vertical flow.
- Layer B (Lower Reef) contains low porosity (7-13%) and generally low permeability but there is a high permeability streak at the base of layer B.
- Layer A (Base) is a dolomite with very low matrix porosity, but contains fractures that allow a strong water drive to the reservoir.

The pattern of dolomitisation is best documented from the Arun field; the distribution of dolomite within other carbonate buildups in the Peutu Formation appears to follow a similar pattern (Carnell and Wilson, 2004). A tight (1-2% porosity) dolomite 3m thick is present at the base of the reservoir in the Peutu Formation fields. Fracturing of this unit may increase its matrix permeability by some tens of mD. Higher in the reservoir, dolomite with up to 30% porosity occurs in layers 1-3m thick that replaces foraminiferal wackestone and packstone in the middle shelf facies. In the Arun field, dolomite is best developed in the north and along the flanks of the reservoir. The mechanism of the dolomite formation is not proven, but isotopic composition suggests a low temperature, mixing zone origin; however dolomites from areas of known meteoric diagenesis have not been studied within these fields.

The NSO-A field has a diagenetically-controlled three-layered porosity structure; from the top downwards (Alexander & Nellia, 1993; Sunaryo, 1994):

- Zone 1: this has the highest porosity in the field but appears to be absent in the eastern part. It is a vuggy pore system with 27-32%; permeability has been estimated using transforms.

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5. CARBONATE RESERVOIRS OF THE SOUTH SUMATRA BASIN

5.1. Geological setting

The South Sumatra Basin is the southern most of the three rift-sag back-arc basins located along the southwest side of the Sundaland craton in Sumatra (Figure 69). There is a major dextral strike-slip system through the Barisan Mountains associated with the western margin of Sumatra.

Oblique subduction of the Indian oceanic plate under the SW margin of the Sundaland Craton commenced during the Late Cretaceous. A period of Late Cretaceous to Early Cenozoic convergence was followed by a period of back arc rifting during the latest Eocene and Early Oligocene that caused the sub-division of the margin into three basins; the northern, central and south Sumatra basins, separated by structural highs. Each of these basins contains sub-basins and sub-highs controlled by the local basement structure.

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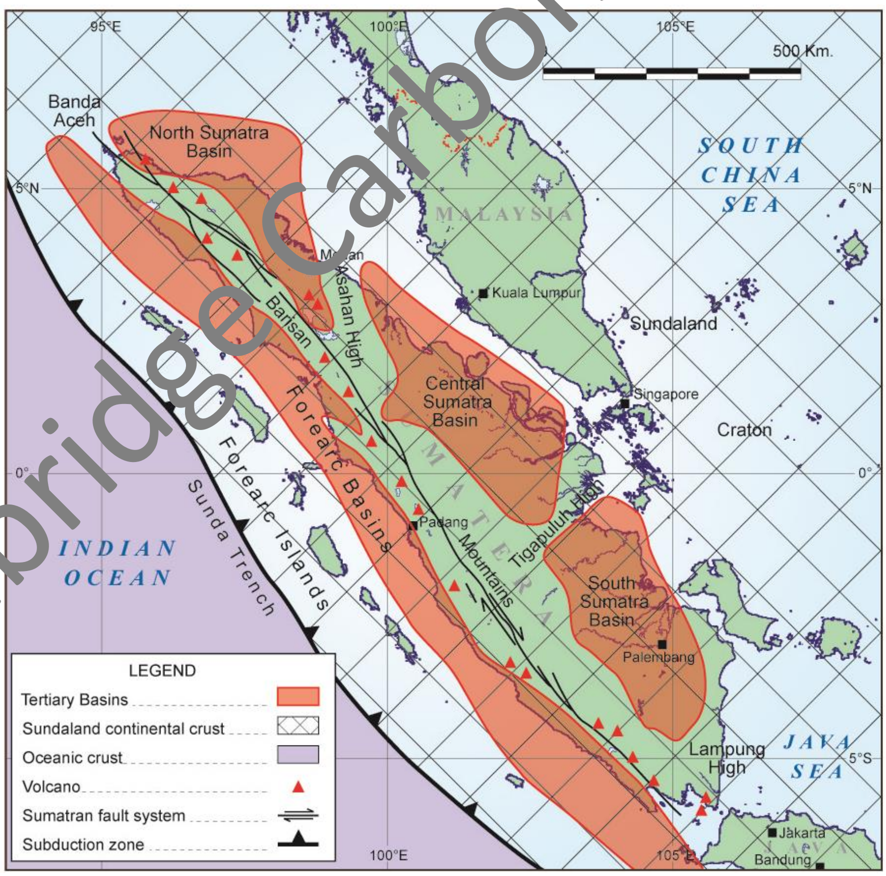

Figure 69 Present day tectonic setting of hydrocarbon-bearing basins in Sumatra. Adapted from Hall (1997) and Barber et al. (2005).

5.3.5. Geopressure

Lost circulation in the Baturaja Formation is known from several fields. This causes problems, particularly where the overlying Gumai Formation shales are overpressured, leading to potential for blow-outs.

5.4. Carbonate reservoirs

5.4.1. Baturaja Formation Petroleum System

The Baturaja petroleum system has a long exploration history stretching back to the 1930s. Despite this, it is a relatively immature play, probably because a lot of initial discoveries that were gas-bearing were of no economic interest at the time of discovery. Recent discoveries are the result of improved seismic acquisition and processing, and the Singa discovery, in the main depocentre of the Lematang Trough, encountered gas some 900m deeper than any other previous discovery (Ebdale et al., 2000; Yanto et al., 2011). The discovery well encountered porous reefal carbonates and tested gas at 30.7MMSCFD from a 79m interval.

5.4.2. Palaeogeography and sedimentology

The proven area of the Baturaja Formation play lies in the south and east of the South Sumatra Basin, primarily associated with the Palembang High, Musi Platform and Kedaton Platform (Figure 73). The key factors influencing their distribution are:

- Reservoir presence and effectiveness – high porosity carbonate reservoirs are present in the east and south of the basin away from siliciclastic input.
- Association with palaeohighs in the Early Miocene.
- There is little exposure and enhancement of porosity in the west of the basin.
- Limit of the Gumai Formation seal – this fails on the extreme eastern side of the basin.

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et al., 1987). There is often, therefore, a polarity reversal of the pick, going from porous gas-filled reservoir to tight reservoir (as seen in North Lembak field; Sudewo et al., 1987; Chacko, 1986). If the Baturaja reservoir sits directly upon basement, it can be difficult to pick the boundary on conventional seismic, since there is typically a low reflectivity contrast between them (Feriyanto et al., 2005).

If the reservoir is relatively thin (i.e <50m), tuning effects from the Baturaja and Basement reflections makes the reservoir difficult to distinguish (Martandinata, 1998). Feriyanto et al. (2005) suggest that instantaneous frequency is the most suitable method for determining tuning effect of seismic data (the Baturaja generally has lower instantaneous frequency compared to basement).

An issue with even 3D seismic is that there is still low vertical resolution, as many of the reservoirs are very deep. The Singa field is at 3650m depth (ss), and as a consequence, the dominant frequency is 15Hz, and subsequent seismic resolution is approximately 55m (given an average velocity of the Baturaja Formation of 3400m/s) (Yanto et al., 2011) . However, because the Singa buildup has 275m vertical relief, it can clearly be recognised on seismic: a demonstrable, mounded, buildup feature with steep flanks, and onlapping reflectors representing deep water sediments of the Gumai Formation (Yanto et al., 2011).

5.4.4. Sequence stratigraphy

Long term changes in accommodation space, as a response to tectonism, had an enormous influence on the reservoir-source-seal distribution. The rift phase during the Late Oligocene to Early Miocene enabled deep lacustrine basins to develop; source rocks deposited in these (Talang Akar Formation; Figure 71; Figure 83). Slow rates of accommodation development in the early transgression of the sag phase saw the initial flooding of basement highs which allowed shallow-water conditions to prevail, consequently resulting in deposition of the shallow-marine carbonate reservoirs (Baturaja Formation; Figure 71; Figure 82; Figure 83). Then a major increase in accommodation development meant that deep-water environments very quickly became established, resulting in shale deposition that provided a perfect seal for the

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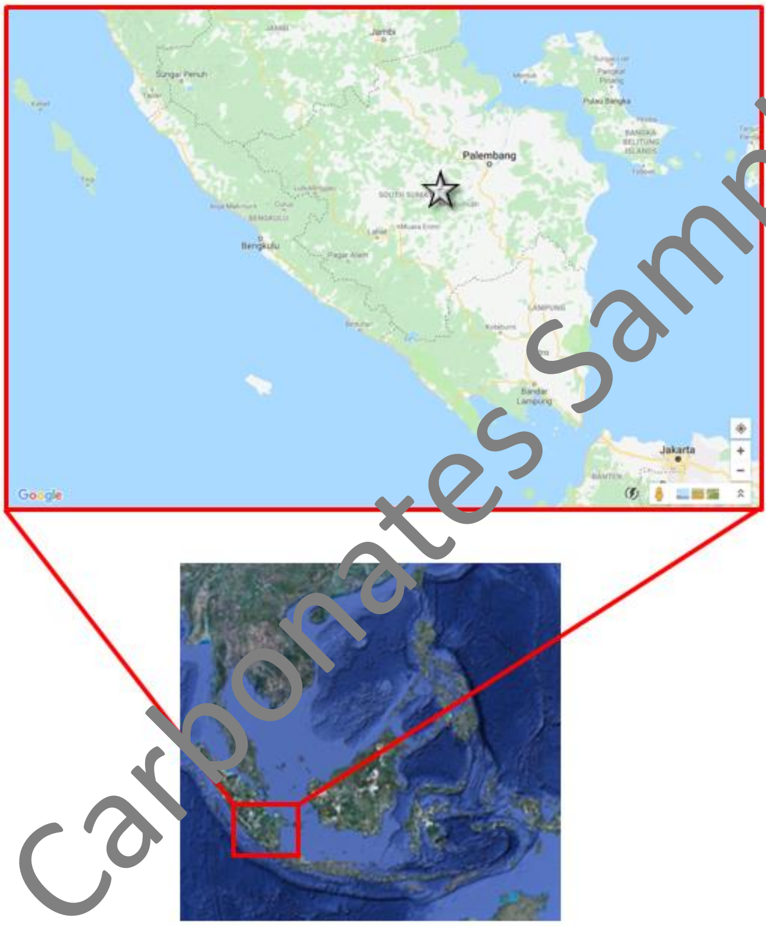
5.6. Field descriptions

Abab field	*Basin:* South Sumatra Basin	*Block:* Palembang

Operator: PT Pertamina EP	
No' wells on structure: 137 (both reservoirs)	
Discovered: late 1951 (Abab-2)	
Produced since: N/A	
Current status: producing oil (1994)	
Geological setting: Back arc basin	
Top reservoir depth: 1457mss	
Lithology: Limestone	
Reservoir type: Bioclastic shoal with patch reefs.	
Reservoir age: Early Miocene	
Formation: Baturaja Fm	
Depositional setting: Shallow carbonates on attached intrabasinal high.	*Structure and trap type:* Structural and stratigraphic trap on basement high.

Migration and Seal: N/A	*Fill history:* N/A	*Source:* N/A
Net pay: 7.77m	*Structural closure*: N/A	*Area of closure*: 3.94 km^2 *Productive area*: 3.94 km^2
Net/Gross: 0.39	*Gross pay*: 20m	*Reservoir depth*: top 1457mss base pay 1599mss

Pore system		
Matrix pore system: N/A	*Matrix porosity:* 22.6% (oil) 26.1% (gas)	*Macroporosity:* N/A
Macropore system: vugs	*Matrix permeability:* N/A	*Macro-permeability:* N/A
Layering: N/A	*Bit drops:* N/A	*Mud losses*: N/A

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Pore system		
Matrix pore system: N/A	*Matrix porosity:* 16%, up to 25%, average 19.1%	*Macroporosity:* N/A
Macropore system: vugs	*Matrix permeability:* up to 3600mD, average 750md	*Macro-permeability:* N/A
Layering: N/A	*Bit drops:* N/A	*Mud losses*: N/A
Well performance		
Initial rate: N/A	*Typical single well rate:* N/A	*Initial pressure:* 1232 psig at 855m
Well tests: (pool not specified): 857-920m 1050 bblsopd 37.3 API° oil through 3/8" choke by flow. 865-878m 191 bblsopd 38.3 API° oil through 3/8" choke by flow. Ramba-1 had a 17m net oil pay and 3.5m net gas pay with the former showing 37.3 degrees API at a rate of 900 BOPD on 3/8 inch choke	*Test permeability:* N/A	*Average well rate:* N/A
Reservoir drive: N/A	*Decline:* N/A	*EOR:* N/A
Productivity index: N/A	*Performance:* **Total oil production rates:** April 1983, 5600 bblsopd from 8 wells, by flow. Maximum production Dec 1986, 33,000 bblsopd from 55 wells by flow. March 1992, 9722 bblsopd from 62 wells by flow, gas lift and rotary pump. **Total gas production rates:** Maximum production: Nov 1991 58 mmscfd March 1992, 51 mmscfd.	

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6. OLIGO-MIOCENE CARBONATE RESERVOIRS OF JAVA

6.1. Geological Setting

Java is part of a volcanic island arc situated in the Indonesian archipelago at the southern margin of the Sunda Plate (Figure 89). Java has a relatively simple structure. In the north there is the margin of the Sunda shelf, and to the south Cenozoic (Quaternary) volcanic arc rocks were produced by episodes of subduction-related volcanism (Clements et al., 2009).

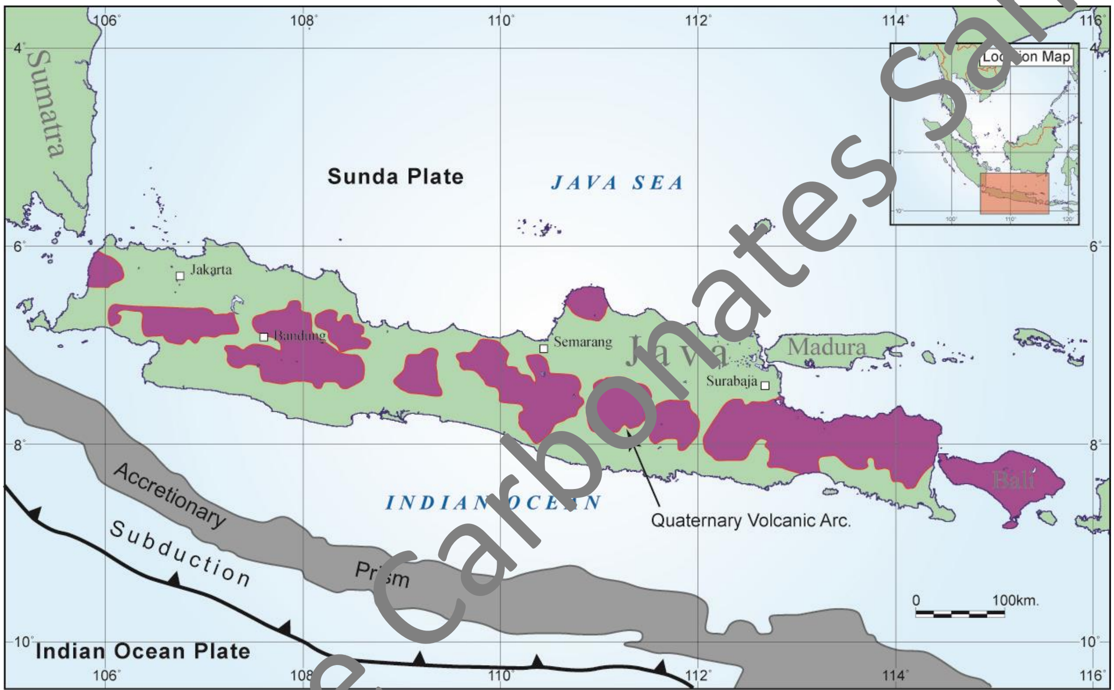

Figure 89 Geological setting of Java. An elongate volcanic arc is situated in the centre of Java, which in turn lies north of the subduction trench where the Indian Ocean plate is being subducted below Java. Modified from Wright et al. (1997).

During the Late Cretaceous, a relatively stable tectonic core, known as the Sundaland craton, existed over much of present day Indochina, western Indonesia and Thailand (Doust and Sumner, 2007). During the Cenozoic, active subduction occurred along the margins of this "core". The character and development of the consequent rift basins on the margins of Sundaland depended very much on the interaction of these subduction zones (in the case of Java, the Eocene-aged India collisional zone in the NW and Miocene-Recent aged collisional zone to the south and southeast; Figure 90). The youngest subducted rocks in Java are radiolarian cherts in accreted deep-marine

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6.2.5. Late Miocene to Early Pliocene

East Java Basin

The Late Miocene is represented by generally monotonous mudstones and limestones (Figure 93c). The Wonocolo Formation contains thin sandstones which are not laterally extensive. There are indications of structural growth during this period (Bransden and Matthews, 1992). Reefal carbonates with some sandstones and shale were deposited during the Late Miocene-Early Pliocene. A north-south compressional event caused uplift and inversion along basin bounding faults. Inverted highs were eroded; however, the resulting sediment source was mostly mud prone. Inversion has continued, leading to the formation of the present-day island chain.

Northwest Java Basin

The Late Miocene saw deposition of the Parigi Formation carbonates in the Arjuna sub-basin. These buildups have variable geometries, with some pinnacles having significant relief. The Parigi Formation developed on structurally stable shallow marine platforms as bioherms associated with palaeohighs, but not necessarily basement highs. From east of Jakarta to north of Cirebon, Parigi carbonate buildups occur, offset to the east of the Pre-Parigi buildups, over a large area both onshore and offshore (Carter and Hutabarat, 1994; Yaman et al., 1991; Bishop, 2000). In offshore areas, the NE-SW trending buildups are controlled by currents and wind direction – typically they have tidal channels separating the buildups. The Parigi Formation is widespread, being distributed onshore and offshore across an area overlapping the eastern portion of Pre-Parigi distribution and continuing to the east (Yaman et al., 1991; Bishop, 2000). Offshore, north- to south-oriented Parigi bioherms are more than 120 m thick (Yaman et al., 1991; Pertamina, 1996, Bishop. 2000). Separated from this trend, to the south in both onshore and offshore areas, are northeast- to southwest-oriented Parigi bioherms that are as much as 450m thick (Yaman et al., 1991; Pertamina, 1996; Bishop, 2000). The orientation of the bioherms is interpreted to be the result of a combination of palaeogeographic features and palaeocurrent directions; the separation of the two trends may have been caused by a deeper water re-entrant from the east (Yaman et al., 1991; Bishop, 2000). Bioherms in the northern trend are

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Figure 98 Classification of Oligo-Miocene buildups in the East Java Sea. Redrafted from Kenyon (1977).

EXAMPLE: NORTH MADURA PLATFORM CD CARBONATES

Wijaya et al. (2016) described the depositional evolution and diagenesis of the late Eocene/Early Oligocene CD carbonates (part of Njimbang Formation) in block P on the North Madura Platform (Figure 99).

- Stage 1: initiation – early Oligocene transgressive event; an early carbonate bank developed in the south of the area, with open marine area to south and lagoonal area between platform and emergent area in north.
- Stage 2: keep-up: progressive northward onlap and thickening to south due to rapid sea level rise causing aggradational shelf margin. Minor patch reefs and grainstone shoals are deposited behind the shelf margin.
- Stage 3: keep-up and amalgamation; the sea level inundated all the emergent areas forming a large amalgamated rimmed carbonate platform. Clastic influx was trapped in inshore areas.
- Stage 4: demise of the carbonate platform; rapid sea level rise during late Oligocene produces drowing unconformity and replacement of carbonates by deeper water, muddier facies and onlap by siliciclastic sediment.

Carbonate lithofacies and depositional environments include:

Shelf margin reefs: rare in situ framework organisms and is dominated by red algae, corals and benthic foraminifera with packstone, grainstone and floatstone textures dominated. These were deposited in high energy conditions associated with the shelf margin and can be mapped as a narrow facies belt associated with the E-W-trending shelf margin by seismic character and attribute analysis.

Restricted lagoon: Mud-supported carbonates, mainly foraminiferal wackestone/packstone with some lagoonward-shedding of bioclastic sediment from the shelf margin.

Shoal: this consists of a back-barrier/shelf margin spread of grainier microfacies including foraminiferal red algal packstone/grainstone.

Foreslope: Basinward of the shelf margin comprising reworked carbonates including intraclasts rudstone and coral floatstone – reworking of cemented shelf margin microfacies.

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is characterised by a diverse faunal assemblage including corals, bivalves, echinoderms, foraminifera, red and green algae, sponges and gastropods. Seaward of these accumulations the facies become more argillaceous in nature with pelagic foraminifera more abundant (Park et al., 1995).

The Baturaja Formation is, at a large scale, transgressive in nature. However, there is evidence for lowstands within the Baturaja Formation which led to exposure of platforms and subsequent subaerial exposure and dissolution. These relative sea level lowstands are responsible for much of the secondary porosity present in the Lower Baturaja reservoirs. Tonkin et al. (1992) interpret a major 3rd order sea level lowstand within the Lower Baturaja, but more recent work by Park et al. (1995) suggest multiple higher order falls in relative sea level are responsible for exposure of the platform and subsequent meteoric diagenesis. Transgression eventually outpaced carbonate production, and the Baturaja Formation was finally overlain by deep water sediments of the Gumai Formation. These mudstones form an excellent seal to the carbonate reservoirs.

Sugiharto (1984) note that for the Baturaja Formation, interval velocities for tight (non-reservoir) limestones range between 14000 to 15000 ft/sec. In the producing zones, however, the interval velocities are 13000-13800 ft/second. These relatively slower interval velocities result from the higher porosity in the upper part of the reservoir.

In the Arjuna sub-basin, reefal buildups also occur along fault-controlled basement highs and around basement highs (Bishop, 2000). The reefs vary in thickness from 30-45m.

In the Jatibarang sub-basin, the Baturaja Formation is more marly/shaley, though still produces hydrocarbons from interbedded limestones. These hydrocarbons have a high CO_2 content, either due to deep crustal faults or volcanic cross-cutting the carbonates (Bishop, 2000; Adnan et al., 1991).

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particularly in the upper parts of the succession, though locally pores have been filled by a late-stage cementation event. Secondary pore creation is not present in the algal or deep-water shelf facies, and visible porosity is poor. Muddy facies are typically neomorphosed.

Although it is not the case in the Poleng field, there is evidence that some deeper-water Kujung sediments have been subjected to subaerial exposure, with the formation of a macropore system at the top of the Kujung I succession. Karstic fractures, cavities and brecciated intervals are all present in core, and are interpreted to have formed shortly after deposition.

As discussed in Section 6.4.1, exposure surfaces have been identified on seismic in many examples. Typically they are characterised by a rugose nature and show circular features interpreted as karst sink holes and other collapse features.

In the Banyu Urip Field, the reservoir quality is strongly controlled by diagenesis that over-prints the sedimentary facies:

- Early diagenesis is characterised by early marine cements and also vadose and phreatic processes associated with times of sea level low stand.
- Later diagenesis comprises porosity reduction by isopachous blocky cement followed by pore-filling calcite cement, sometimes in the form of syntaxial overgrowths on echinoderms.
- There is some dissolution of aragonite bioclasts associated with meteoric leaching.
- Later burial diagenesis includes enlargement of fractures and vugs; some of thevugs cross-cut sytloolites. Some are partly infilled by high temperature phases including saddle dolomite and kaolinite; it does not follow that these are hydrothermal phases.

The best reservoir quality is in the platform interior platform aggrading stage with 15-35% porosity and 100mD permeability; this is related to leaching in meteoric lenses that pervaded the platform during low stands. The reservoir quality in the drowning phase is poorer with low depositional porosity and permeabilty.

Zeiza et al. (2016) also suggest that pervasive hydrothermal dissolution have improved reservoir performance in the Banyu Urip field by the enlargement of fractures and vugs that cross-cut styoloites seen in image logs and core. These late diagenetic

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6.6. Field descriptions

Arimbi X field	*Basin:* NW Java Basin	*Block:* N/A
Operator: PT Pertamina *No' wells on structure:* 34 *Discovered:* 1972 (X-1) *Produced since:* N/A *Current status:* producing oil and gas (1995) *Geological setting:* Back arc basin *Top reservoir depth:* 1019.2mss *Lithology:* Limestone *Reservoir type:* Bioclastic shoal with patch reefs *Reservoir age:* Early Miocene *Formation:* Baturaja		
Depositional setting: Shallow carbonates on attached intrabasinal high	*Structure and trap type:* structural	
Migration and Seal: N/A	*Fill history:* N/A	*Source:* N/A
Net pay: (Baturaja) 37.5m, (Upper Cibulakan) 10.1m	*Structural closure*: (Baturaja) 77.7m, (Upper Cibulakan) 45.7m	*Area of closure*: (Baturaja) 8.92 km^2, (Upper Cibulakan) 5.59 km^2 *Productive area*: (Baturaja) 20.17 km^2, (Upper Cibulakan) 5.59 km^2
Net/Gross: (Baturaja) 0.79, (Upper Cibulakan) 0.26	*Gross pay*: N/A	*Reservoir depth*: (Baturaja): top 1019.2mss; base pay 1088.1mss (Upper Cibulakan): top 766.2mss base pay 983.2mss
Pore system		
Matrix pore system: N/A	*Matrix porosity:* (Baturaja) 30%, (Upper Cibulakan) 36%	*Macroporosity:* N/A

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<table>
<tr><th>Cinta field</th><th>Basin: NW Java Basin</th><th>Block:</th></tr>
<tr><td>Operator: CNOOC Southeast Sumatra BV</td><td colspan="2" rowspan="11"></td></tr>
<tr><td>No' wells on structure: 69</td></tr>
<tr><td>Discovered: 1970 (Cinta-1)</td></tr>
<tr><td>Produced since: N/A</td></tr>
<tr><td>Current status: 1995: producing oil</td></tr>
<tr><td>Geological setting: Back arc basin</td></tr>
<tr><td>Top reservoir depth: 792.5mss Baturaja</td></tr>
<tr><td>Lithology: Limestone and sandstone</td></tr>
<tr><td>Reservoir type: Bioclastic shoal with patch reefs</td></tr>
<tr><td>Reservoir age: Early Miocene</td></tr>
<tr><td>Formation: Baturaja and Talang Akar</td></tr>
<tr><td>Depositional setting: Shallow carbonates on attached intrabasinal high</td><td colspan="2">Structure and trap type: Structural and stratigraphic</td></tr>
<tr><td>Migration and Seal: Virtually all the source and migration systems serve the Cinta-Rama arch and Selatan horst</td><td>Fill history: N/A</td><td>Source: N/A</td></tr>
<tr><td>Net pay: Talang Akar 19.8m
Baturaja 8.6m</td><td>Structural closure: 213.4m</td><td>Area of closure: Talang Akar 20.6 km^2
Baturaja 14.9 km^2
Productive area: Talang Akar 20.6 km^2
Baturaja 14.9 km^2</td></tr>
<tr><td>Net/Gross: Talang Akar 0.13
Baturaja 0.04</td><td>Gross pay: N/A</td><td>Reservoir depth: Talang Akar: top 914.4mss base pay 1127.8mss
Baturaja: top 792.5mss base pay 1005.8mss</td></tr>
<tr><td colspan="3">Pore system</td></tr>
</table>

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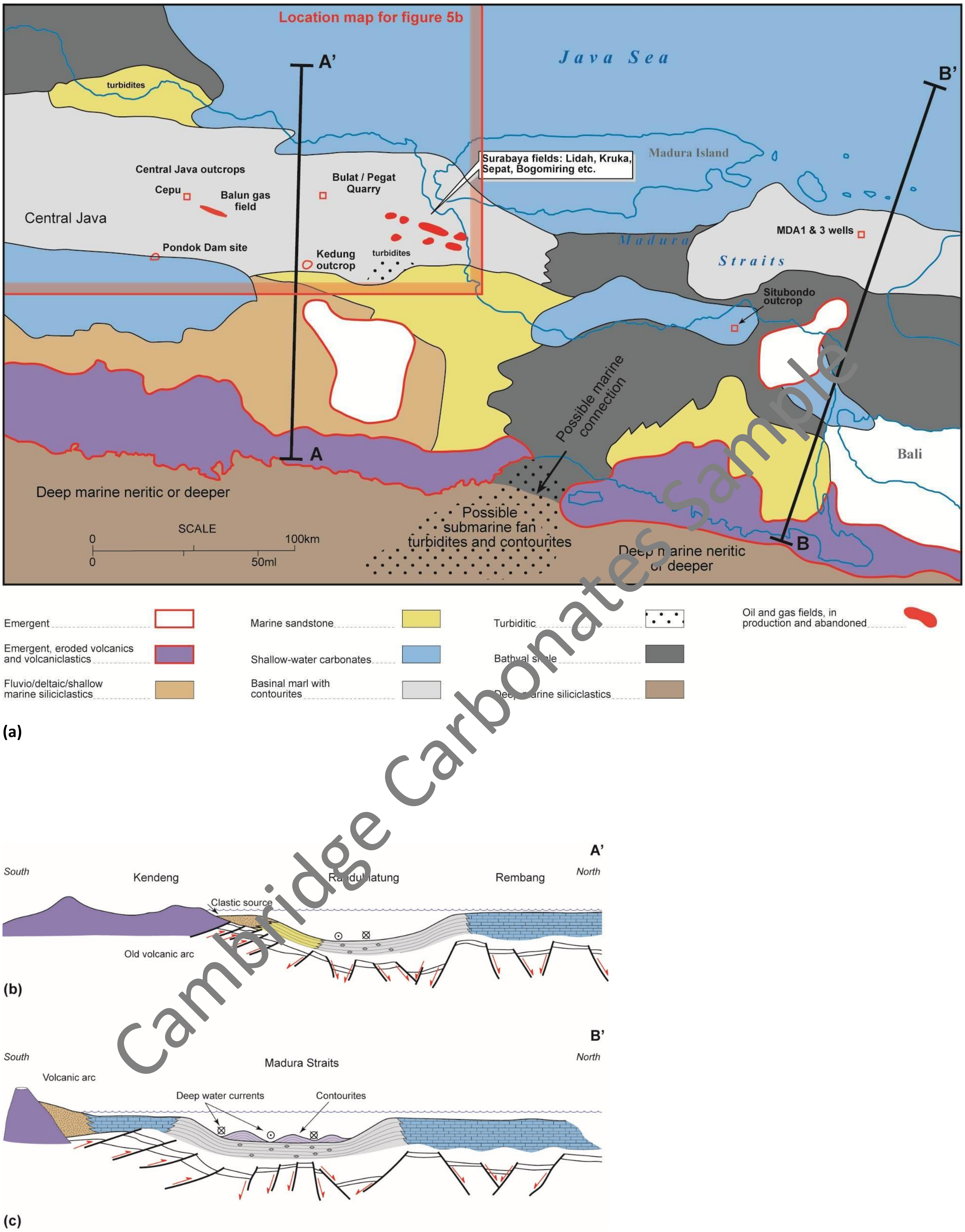

Figure 112 (a) Pliocene palaeogeography of the NE Java Basin showing outcrop and sub-surface occurrences of Pliocene carbonate reservoir facies (modified from Schiller et al., 1994). Refer Figure 116 for key. Red outline indicates area of map in Figure 114 (b) A-A' South-North cross section through Kendeng, Randublatung and Rembang zones highlighting Pre-Pliocene structure and Pliocene palaeogeographies. Note the section is approximately 180km in length (c) B-B' SSE-NNW cross section across the Madura Straits. Note the section is approximately 220km in length.

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scale laminations, scours, slumps and occasional cross bedding at various scales. Some *Skolithos* type burrowing may be present at horizons. At outcrop, porosity in the form of intergranular and internal pores in the globigerinids may be as much as 70% but nodular and pervasive carbonate cementation may also be present. These lithological descriptions are taken from Musliki and Suratman (1996), Schiller et al. (1994), Lund et al. (2000) and Wilson (2002).

The average depositional rate of modern pelagic carbonates is about 30mm per 1000 years (Scholle et al., 1983). In contrast, depositional rates of the globigerinid limestone facies were estimated at 100-400mm per 1000 years by Schiller et al. (1994). The increased sedimentation rate of contourites is caused by the concentration of pelagic carbonates by deep water currents or by input of resedimented pelagic carbonates (Scholle et al., 1983). Depositional processes of globigerinid limestone facies include concentration by deep water currents and winnowing over topographic highs. Sand-sized planktonic foraminifera have hydrodynamic properties equivalent to silt-sized quartz and so it is possible for these foraminifera to be entrained by currents as slow as 0.8-1.0cm sec^{-1}. The globigerinid limestone facies occur as turbidite as well as contourite deposits and some have been modified by later reworking (Figure 118).

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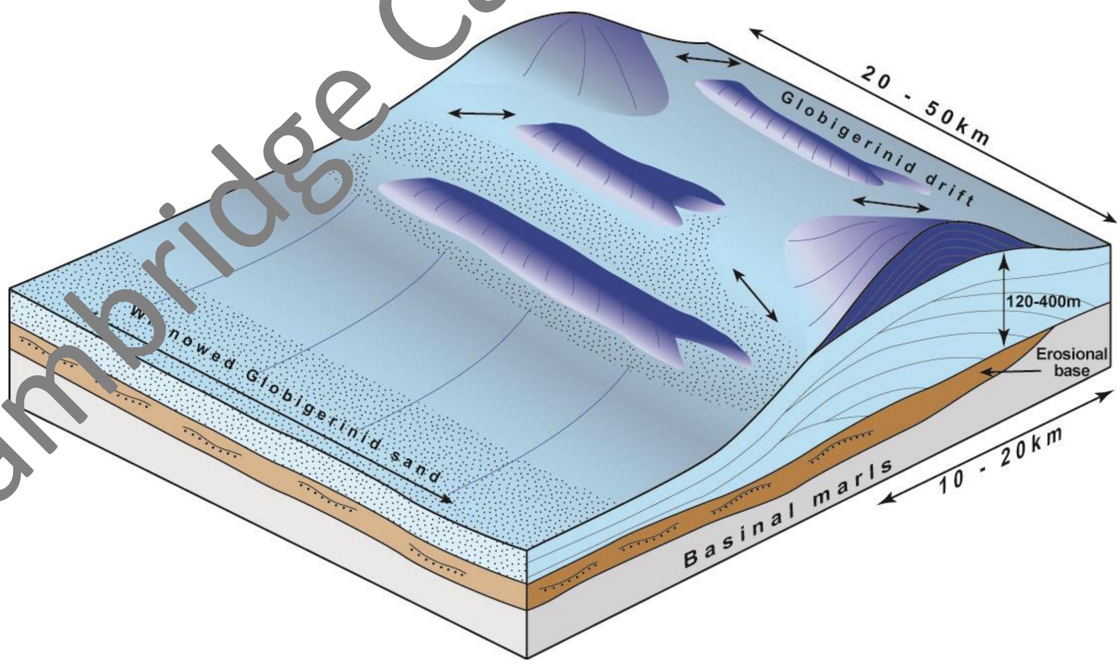

Figure 118 Depositional model for Pliocene carbonate contourites (redrafted from Schiller et al., 1994).

elsewhere but at different stratigraphic levels such as in the Miocene of Southern Sumatra.

- Contourites form during periods when deep water currents become restricted such as during glacio-eustatic lowstands and during periods of active tectonism. This suggests that globigerinid contourites may be present along much of the southern margin of the archipelago.
- Capillary pressure curves suggest that globigerinid contourites are more suitable as gas and condensate reservoirs than oil; but this facies has produced oil in onshore Java.
- The amount of detrital matrix is a critical control on permeability with a slight increase in matrix producing a large decrease in permeability. Other controls on porosity and permeability include cementation.

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8.2. Stratigraphy

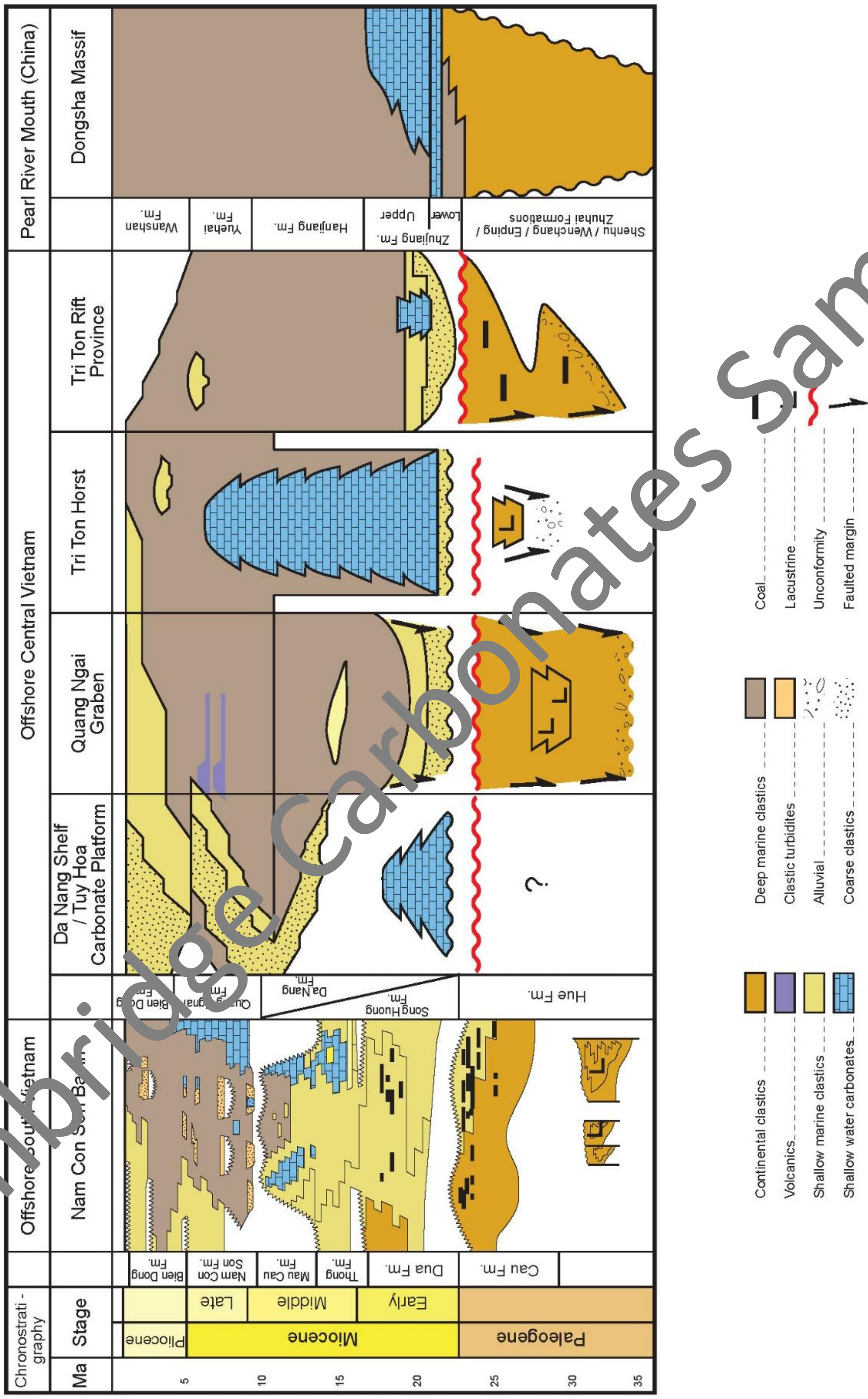

Figure 128 Stratigraphic column for the Nam Con Son Basin, offshore Central Vietnam and Pearl River Mouth, Offshore South China. Modified from Dang and Sladen (1997), Sattler et al. (2004), Fyhn et al. (2013) and Matthews et al. (1997).

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Offshore East Vietnam

Stable C isotope analyses of hydrocarbons suggest that the gas is thermogenic and was probably derived from cracking of an oil prone source rock. Biomarker data suggest it is a marine source. The most likely source is Early Miocene marine shale deposited in the Quang Ngai Graben and possibly also in the Tri Ton Graben. Zhang and Zang (1991) describe a Middle Miocene marine source rock encountered in the Ledong 30-1-1A well to the north in the Quang Ngai Graben. An alternative source is non-marine lacustrine mudrocks that underlie the carbonates over the Tri Ton Horst, these may also have been deposited in a marine environment in the Quang Ngai Graben and the Tri Ton Graben.

At least two culminations on the Tri Ton Platform are shown to be gas-bearing with at least 5 TCF hydrocarbon gas discovered in the play to 1997 (Dang and Sladen, 1997). The amount of CO_2 is significant but variable, being present in some discoveries, but not others. Meyer et al. (2017) suggest a decreasing CO_2 content from north to south along The Tri Ton Horst. The origin and distribution of CO_2 in this area may be related to mantle degassing and associated with deep seated faults.

South China

Shales of the Paleogene Wenchang are the main source rocks in the Pearl River Mouth Basin (Quan, 2016). They have an average TOC of 2.23%, and are Type II kerogen. The Enping Formation shales are also rich, with a TOC of 1.78% and are a mix of Type II and Type II kerogens. The clastics at the base of the Zhujiang Formation are thought to be carrier bed to the overlying carbonate reservoirs (Turner and Hu, 1991). Robison et al. (1998) suggest the following scenario:

- The depocentre in the Huizhou sag in the Zhu 1 basin may contain lacustrine source facies.
- Organic-rich source rocks in such a setting would generate a high-wax crude oil upon becoming thermally mature.
- The oil would be expelled from the source into a massive sandstone carrier system that is sealed by a widespread, tight limestone.

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in house data). These facies distributions are typical of shallow platform-interior and platform margin settings (Figure 138).

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Figure 137 (a) Bioclastic packstones are a common component of Late Miocene carbonates in the Nam Con Son Basin. (b) Bioclastic grainstone, with coarse sand to small granule grade fragments of bioclastic material that is now largely present as mouldic porosity. The cream-coloured allochems are

Offshore East Vietnam

The lowermost part of the Tri Ton carbonate platform exhibits massive dolomitisation, whilst the upper main reservoir is significantly karstified due to repeated exposure of the platform during the Middle Miocene. This led to the development of channel, vugs and cavernous porosity (Cambridge Carbonates in house data). Wells drilled on the Tri Ton horst demonstrate the presence of excellent quality reservoirs with high net/gross, high permeability (up to 1150md) and average porosity of between 18-24.5% (Dang and Sladen, 1997).

Collapse features have been recognised on seismic across the Tri Ton Horst. These are depressions, a few km wide, on the upper surface, which sit above chaotic reflections below. Commonly these are associated with significant faults. Whilst karstification is common-place in the Early Miocene, these collapse features occur within the Middle to Upper Miocene carbonates, which are not as extensively karstified. Fyhn et al. (2013) propose the following explanations for these phenomenon:

- Hydrothermal circulation and venting guided by pre-existing faults associated with e.g. deeper seated intrusions. This would then result in carbonate dissolution.
- Carbonate dissolution associated with flow of CO_2-rich fluids along faults.
- Acidification and carbonate dissolution associated with biodegradation of hydrocarbons seeping along pre-existing faults.

South China

The Liuhua 11-1 field is a world-class example of a diagenetically-modified reservoir. Subaerial exposure during the Early Miocene led to significant modification of primary stratification of the carbonate facies, and also fundamental modification of the primary pore-types and connectivity. However, later burial-related diagenesis had a major impact as well.

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Liuhua field	*Basin:* Pearl River Mouth Basin	*Block:* N/A
Operator: CNOOC Shenzhen *No' wells on structure:* Initial production from 25 horizontal wells *Discovered:* Jan 1987 *Produced since:* March 1996 *Current status:* Oil producer *Geological setting:* N/A *Top reservoir depth:* 1197.5m (1505.5mSS) *Lithology:* Limestone *Reservoir type:* Cyclic carbonate platform with karst zones *Reservoir age:* Early Miocene *Formation:* Zhujiang		
Depositional setting: Isolated buildup	*Structure and trap type:* Combined depositional drape over carbonate platform developed on structural high.	
Migration and Seal: Sealed by Late Miocene to Holocene Hanjiang Shale.	*Fill history:* N/A	*Source:* Wenchang and Enping Fms. Lacustrine.

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and consequent complex basement morphology, exerted a strong control on this carbonate platform (Grötsch and Mercadier, 1999). A major "break-up" unconformity occurred at the end of the Early Oligocene, and represents the onset of sea floor spreading (Figure 151b).

The Late Oligocene is represented by focussed carbonate development, mostly along the margins of fault block crests. Deep-water sedimentation characterised the off-crest areas. This was associated with a major transgression which continued through to the late Early Miocene: carbonate production was focussed areally, forming a series of pinnacle reefs. These were drowned at different times in the late Early Miocene.

Sea floor spreading was accommodated by subduction in a SE direction along the Palawan Trench (Williams, 1997). Continental collision occurred in the Middle Miocene where the North Palawan Block collided with the Philippine archipelago; this resulted in the uplift and formation of Palawan Island (Branson et al., 1997; Williams, 1997; Figure 151c). Middle to Late Miocene subsidence resulted in deposition of a siliciclastic wedge on the NW margin of the Palawan Block. Active continental collision continued to the Early Pliocene.

The result of this collision is that the time-equivalent Oligocene-Miocene carbonate reservoirs are now exposed on Palawan Island, whilst they are downwarped and buried more deeply in the offshore area.

From the Early Pliocene to Recent, the NW Palawan Basin has been tectonically quiescent, and a site of carbonate deposition on highs, with flanking deep water sediments in bathymetric lows (Figure 151d).

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9.3. Hydrocarbon geology

9.3.1. Exploration history

East Natuna Basin

The Natuna concession lies in Indonesian waters, 225km NE of Natuna Island. By the early 1970s exploration in the area was established, and in 1973 AGIP discovered the Natuna-L Gas discovery with well AL-1X (Dunn et al., 1996). Esso took over operatorship of the Natuna D-Alpha block in 1980 and appraised the Natuna-L discovery. The field has an estimated 222TCF gas reserves, but 70% of this is CO_2, leaving 45TCF of methane recoverable. The discovery remains undeveloped so far. Further gas discoveries in the area were made (Sokiang-1, AV-1X, Bantenal-1) but were considered non-commercial. Non-commercial oil and gas was also discovered with the Bursa-1 well.

East Natuna has been little explored over the last 15 years, mainly due to political disruption, its remoteness, and because discoveries such as Natuna-L have proved uneconomic to develop (Offshore Technology, 2010).

Sarawak Basin

First oil was officially encountered onshore Sarawak in 1882, but it was not until 1910 that the first commercial oil field, Miri, was discovered (Kin, 1999). Production peaked from the Miri field in 1929, and the field was finally shut-in in 1972 having produced 80MMBO (Kin, 1972). After the Miri discovery, exploration was mostly unsuccessful, until the 1960s, when attention turned to the offshore basins. During the 1960s concessions were granted, and significant discoveries were made, with international companies playing an important role. The first discovery in carbonates was by Shell in the Central Luconia Province in 1969 (F6 gas field). By the early 1970s the petroleum industry was recognised as the most important hydrocarbon resource in Malaysia (Kin, 1999). In 1974 the Government set up the National Petroleum Corporation, PETRONAS. PETRONAS initially started as a regulator of the upstream sector, but then progressed to taking an active role in exploration and production. Production Sharing

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Field	Reservoir	Facies	Depth m	Poroperm data	Discovered	Status	Test results	Reserves
EAST NATUNA BASIN								
Natuna-L	Terumbu	Isolated buildup	2640m	Up to 30% porosity	1973	Gas discovery		45tcf methane gas
PALAWAN BASIN								
Nido	Nido Fm	Shelfal buildup	2070m	1-9% plug porosity; 138-1138md plug perm; Fractures	1979	Oil producer	A-1 well: 7340BOPD; B-1 well 9800 BOPD	18 MMBO
Matinloc	Nido Fm	Shelfal buildup	2030m	8% av porosity; 3-17% range; 250-600md perm DST; 5.4md plug	1979	Oil producer	7500 BCPD	11 MMBO
Cadlao	Nido Fm	Shelfal buildup		10-22% porosity; 103md DST		Oil producer	3630 BCPD	
Tara	Nido Fm	Shelfal buildup	1300m	22% av porosity, range 10-24%; 178md DST perm; 0.1-9md plug perm		Oil producer	3468 and 4350 BOPD	
Pandan	Nido Fm	Shelfal buildup		6-13% porosity; 4.9md plug perm		Oil producer	6350 BCPD	
Libro	Nido Fm	Shelfal buildup	1250m	15% av porosity, 9-19% range; 14md plug perm, 120md DST perm.		Oil producer	1600 BCPD	
Malampaya	Nido Fm	Pinnacle reef	3000m	Up to 36% porosity	1989	Gas producer		Malampaya-Camago (together): 4.1 TCF (GIIP) 700 MMBO (STOOIP)
Camago	Nido Fm	Pinnacle reef			1989	Gas and condensate producer		
Destacado	Nido Fm	Pinnacle reef			1982	Oil and gas shows		
San Martin	Nido Fm	Pinnacle reef			1982	Gas discovery	20 MMSCFGD	
Bantac	Nido Fm	Pinnacle reed						35 MMBO
Calauit	Linapacan Fm	Fractured deep-water carbonates			1991	Oil discovery	3300 BOPD, 7000BOPD and 3286BOPD	10-70mmbo in place.
South Calauit	Linapacan Fm	Fractured deep-water carbonates			1991	Oil discovery		
Linapacan	Linapacan Fm	Fractured deep-water carbonates				Gas discovery	4.57 MMSCFGD and 190 BOPD	
West Linapacan A and B pools	Linapacan Fm	Fractured deep-water carbonates			1990	A structure shut-in in 1996. B structure not yet producing	10.9 MMSCFGD and 2860 BOPD.	20 MMBO.
SARAWAK BASIN								
Jintan	Cycle IV/V	Platform			1992	Producing gas		
M1	Cycle IV/V	Pinnacle reef		10-40% porosity; 800-1500mD perm		Producing gas Field has an oil rim.		
Serai	Cycle IV/V	Pinnacle reef			1993	Producing gas		
F6	Cycle IV/V	Platform	~1060m	Up to 40% porosity, up to 4D perm	1969	Producing gas		3.4TCF, 24MMBC recoverable
M3	Cycle IV/V	Pinnacle reef		15-32% porosity, 200-480mD perm		Producing gas		

Table 22 Example fields and discoveries in the East Natuna, Palawan and Sarawak basins with carbonate reservoirs. Data from various sources in text.

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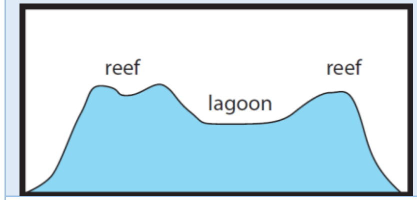
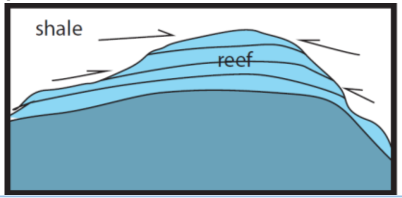
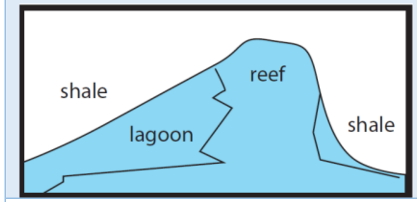
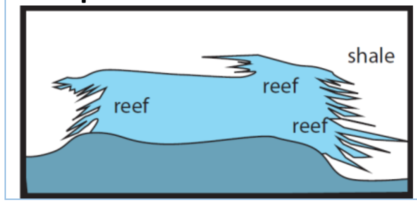
Platform category	Characteristics	Examples
Rimmed Platforms 	Platforms have well-developed reefal margins, and an interior lagoon. Asymmetry may reflect windward and leeward sides.	F9 platform
Backstepping "wedding cake" platforms 	Symmetrical or asymmetrical geometries. Asymmetry tends to indicate lateral input of nutrients and/or clastics from prograding deltas. Landwards margins of the platform retreat. Often the oceanic margins have an aggradational character.	Mega Platform (Jintan; M1) F6
Pinnacles 	Of critical importance is that the buildup core rather than the flank is reefal; there is no well-developed lagoon. Low energy facies are therefore located on the flanks/downdip.	E11 Cili Padi
Composite Platforms 	Late amalgamation of platforms	E14 F4, F6, F9, F10, F12

Table 23 Carbonate platform types in Central Luconia.

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suggesting that rather than siliciclastics drowning the carbonate platforms and causing their demise, it was actually prolonged exposure which lead to their demise. This is in contrast to the buildups to the south of the Central Luconia Province (Vahrenkamp et al., 2004).

Seismic geomorphology of carbonate buildups

Koša et al. (2015) describe in great detail the seismic geomorphological characteristics of Miocene buildups in the Central Luconia Province. Whilst their categories, as determined from seismic, are broadly the same as those described in Table 23, they have considerably more subcategories (Table 25). The different geometries are a complex interplay between siliciclastic and carbonate sedimentation (and thus, a function of relative sea level oscillations), but Koša et al. (2015) clearly make the point that these buildups are a function of both the carbonates and clastics interacting coevally. Whilst, on seismic, a pinnacle reef may appear to have had 1.5km relief, these pinnacles are in fact composed of aggradational bodies, with coeval "wings" into clastic sediments. Both "open wings" and "closed wings" are noted. Carbonate buildups extending into the surrounding siliciclastics via layers conformable to both intracarbonate and onlapping siliciclastic bedding are said to be flanked by open wings (Koša et al., 2015). Carbonate deposits that drape the walls of the buildups and are thus unconformable with respect to both intracarbonate and siliciclastic bedding and termed "closed wings" (Koša et al., 2015). These closed wings have up to 500 m of depositional relief and steep present-day angles of up to 40° (Koša et al., 2015). Buildups are considered to reside in onshelf or offshelf settings, depending on their relationship with deltaic topsets (Koša et al., 2015).

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in the porosity logs (Figure 174). The Terumbu Limestone Formation has been variably dolomitised, as shown in Figure 174. However, little has been published on the dolomitisation processes, models, or how they affect reservoir quality.

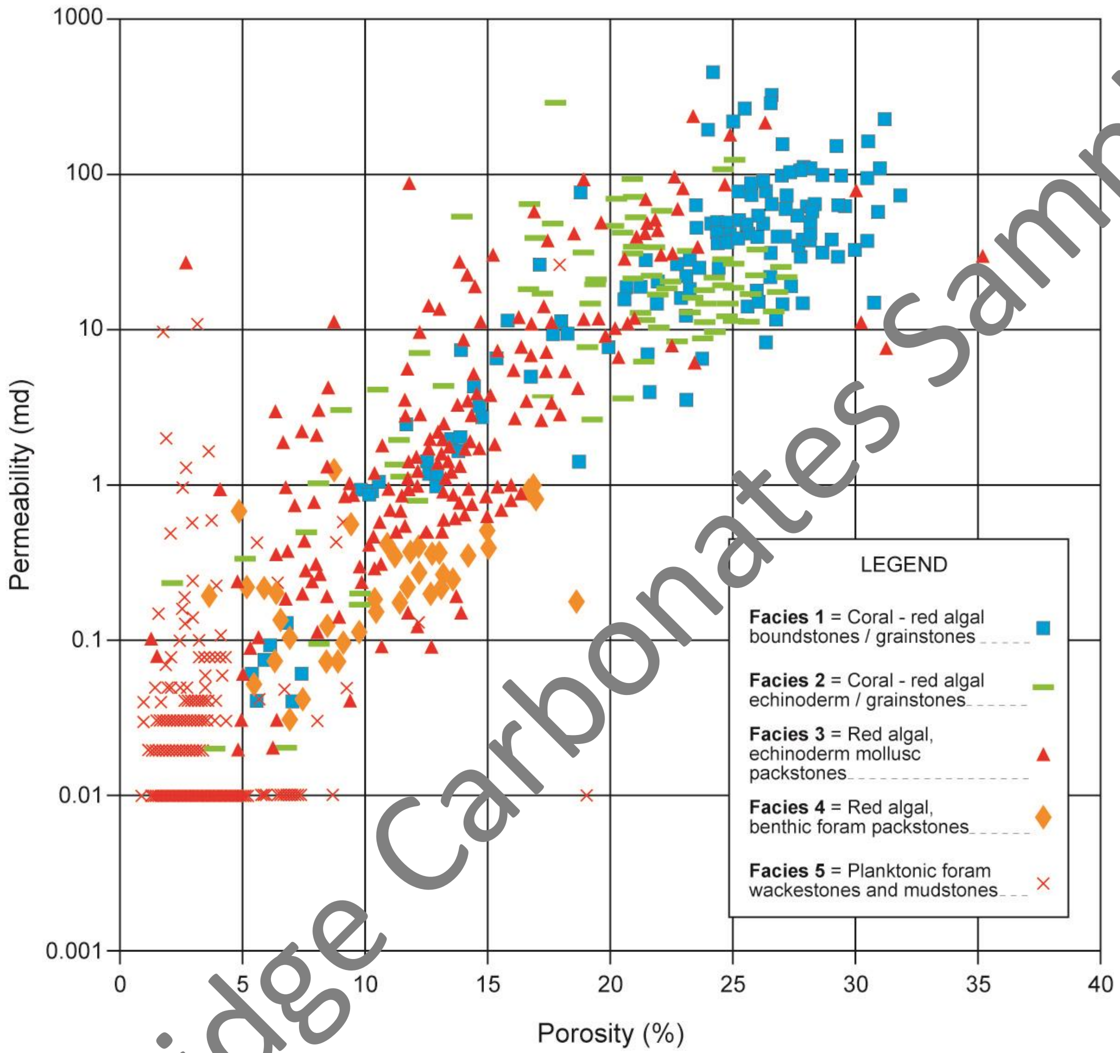

Figure 173 Core plug porosity vs permeability for Natuna Field lithofacies. Redrafted from Dunn et al. (1996)

Grabowski et al. (1985) also recognise that late burial dissolution also played an important role in porosity creation. Fluids derived from the underlying granitic basement selectively leached grains in the deeply buried Terumbu Limestone Formation, improving reservoir characteristics. CO_2 within the reservoir itself is thought to be derived from dissolved Terumbu Limestone (Grabowski et al., 1985).

The correlation between lithofacies and reservoir quality is likely related to the aragonitic nature of the corals in lithofacies 1 and 2. These were leached during meteoric diagenesis and thus improved the reservoir quality (Dunn et al., 1996).

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Deep water fractured reservoirs

Microfracturing is typical in the deep-water limestone reservoirs of the Palawan Shelf, and is required in order produce sufficiently high quantities of hydrocarbon. Two sets of fracture swarms are recognised in the Calcuit and Calcuit South fields: a dominate fracture direction of 150/330°, and a conjugate set at 20/200° (Otto Energy, 2010). High extended well test production rates of 5,000-15,000 BOPD support that fractures are significantly contributing to production. Fracture swarms can be mapped on seismic, leading to improved well placement and higher rates of oil recovery (Otto Energy, 2010). Interestingly, Otto Energy (2010) suggest that the fractures in the Calcuit fields are of a "type 1" (c.f. Nelson, 2001) whereby fractures provide essential reservoir porosity and permeability, with only a minor contribution to recoverable volumes expected from the rock matrix. Issues associated with type 1 fracture reservoirs include rapid decline curves, early water encroachment, and the necessity for a high fracture intensity.

The Linapacan limestones in the West Linapacan and Linapacan fields are also micofractured, although intraparticle porosity, micro-intercrystalline porosity and mouldic porosity also contribute to production. Average matrix porosity is 14% (Walston and Oesterle, 1992). Fractures were identified in wells by erratic ROP's, and this was also confirmed by micro-resistivity logs. DST's through fracture zones had stabilised rates of 6800BOPD and 4500BOPD, with a peak of 9350BOPD.

9.5. Future potential

East Natuna Basin

Natuna-L is the largest gas discovery in Indonesia, yet still remains undeveloped as it remains uneconomic to do so with such high CO_2 content, the field's remoteness, and the area's political instability. The value of the area is increasing lately though, with the advent of the West Natuna Gas Project.

Geologically the area is proven to be hydrocarbon-bearing, and if the issues of bringing the gas to market are resolved, then exploration in the area is likely to pick up again. There are several undeveloped discoveries in the basin, and several buildups that are

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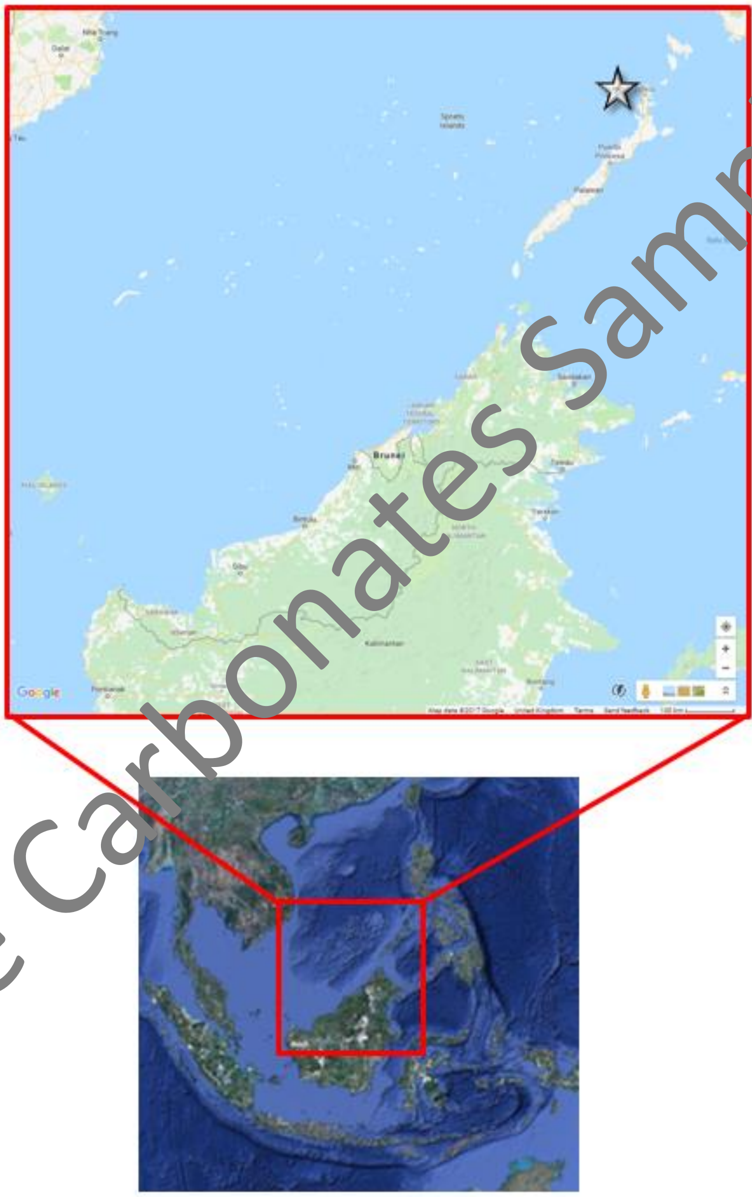
Nido A and B fields	*Basin:* NW Palawan	*Block:* Block A, Service Contract 14
Operator: The Philodrill Corporation *No' wells on structure:* 5 *Discovered:* 1977 (A-1 well) *Produced since:* 1979 *Current status:* Oil producer *Geological setting:* N/A *Top reservoir depth:* 2070m *Lithology:* Limestone *Reservoir type:* Shelf build-up *Reservoir age:* Lower Miocene *Formation:* Nido		
Depositional setting: Semi-isolated buildup	*Structure and trap type:* Combined depositional drape over carbonate platform developed on structural high.	
Migration and Seal: Migration tended to be towards the SSE but due to uplift and erosion, present day migration is enhanced to the ESE	*Fill history:* Fill and spill	*Source:* N/A
Net pay: N/A	*Structural closure*: N/A	*Area of closure*: 1.5 x 1km *Productive area*: N/A

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Net/Gross: N/A	*Gross pay*: 200m	*Reservoir depth*: 2070m
Pore system		
Matrix pore system: N/A	*Matrix porosity:* 1-9%, average 3% (from core plugs)	*Macroporosity:* N/A
Macropore system: Fracture, mouldic, vuggy	*Matrix permeability:* 0.01-3.3md, 1md average (from core plugs)	*Macro-permeability:* N/A
Layering: N/A	*Bit drops:* N/A	*Mud losses*: N/A
Well performance		
Initial rate: 40,000BOPD from 5 wells	*Typical single well rate:* N/A	*Initial pressure:* N/A
Well tests: A-1 well: 7340BOPD; B-1 well 9800 BOPD	*Test permeability:* N/A	*Average well rate:* Each of the 3 producing wells at Nido B have rates in excess of 7000 BOPD
Reservoir drive: Bottom water	*Decline:* N/A	*EOR:* N/A
Productivity index: N/A	*Performance:* N/A	
Reserves		
Recoverable: 20 MMbbls oil	*Initially in place:* N/A	*Recovery factor:* N/A
Cumulative production: >18.5MMBO (through 1979)		
Field history: Both fields were brought into production in February 1979 with production peaking in mid to late 1979 at over 13,000 bopd and 29,000 bopd for Nido-A and Nido-B, respectively. Both fields were switched to a cyclic production regime in mid 1984. Total oil production from both fields has passed 18.5 million barrels of oil. Production rates were initially high, and it is thought that this was primarily from fractures. Water encroached into the oil column preferentially flooding the fractures. Decline in production flattened in 1980, whereby matrix flow was the main contributor		
Hydrocarbon type and formation fluid		
Hydrocarbon type: N/A	*API:* 27°	*GOR:* 7-10 scf
S content: N/A	*Wax content:* N/A	*Pour point:* N/A
N_2: N/A	*CO_2:* N/A	*Other:* 2% H_2S
Methane: N/A	*Ethane:* N/A	*Propane:* N/A

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Kalimantan including the Kutei, Tarakan and Barito Basins (Alam et al., 1999; Laya et al., 2013). Basin sag followed rifting in the Late Eocene to Late Oligocene, with high subsidence rates.

In the Kutei Basin, the Oligo-Miocene was the main period of carbonate deposition, and predominantly occurred on the structurally stable basin margins, away from the main axis of siliciclastic input. In the basin centres, shelfal, slope and bathyal conditions existed, with thick deltaic sequences being deposited. Deltas prograded and aggraded in response to relative sea level fluctuations, which were mostly tectonically driven (relating to inversion and uplift of the Kucing High; Alam et al., 1999; Laya et al., 2013). A similar situation existed in the South Makassar Basin, where rifting started in the Middle Eocene (Noeradi et al., 2007; Figure 187). The Late Eocene to Oligocene was a transitional sag phase which caused regional subsidence controlled by NW-SE extensional tectonic regime. Faulting had mostly ceased by this point, with only major NE-SW faults being active. The Late Oligocene was a period of carbonate deposition, with platforms and isolated build-ups developing on highs (Noeradi et al., 2007). Siliciclastic turbidites characterised slope and basinal settings.

The Middle Miocene saw a major uplift episode of the Kalimantan hinterland, which in turn triggered a massive influx of turbidites in the deep-water areas of the Kalimantan basins (Kaj et al., 2000). Volcanics were also extruded in the Middle Miocene in the Tarakan Basin as a result of the Sulu Sea being subducted below the accreted continental crust of North Kalimantan.

In the Barito Basin, basin inversion was recorded in the Late Miocene, in association with the Meratus Uplift, to produce an asymmetric basin; the Barito Basin, dipping gently in the NW, towards the Barito Platform, and steeply in the SE against the Meratus Uplift. Restored modelling for the Barito tectonics and petroleum generation has shown that inversion of the basin resulted from compressional tectonism (Satyana and Silitonga, 1994; Satyana, 1995; Satyana and Idris, 1996). Uplift of the Meratus Mountains was continuous during the Late Miocene, through the Pliocene.

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migration is of greatest importance. Hydrocarbon migration probably started in the Late Miocene and continued through to the Pliocene (Laya et al., 2013).

Gas is the dominant hydrocarbon type in the basin (Paterson et al., 1997). It is considered to be a product of oil to gas catagenesis rather than kerogen to gas metagenesis. Oil is only found above the oil to gas cracking threshold (approx. 3km, or where Ro=0.6). Both waxy crudes and light oils (heavier components cracked off) have been discovered (Paterson et al., 1997).

The Eocene deltaic deposits are also possible source rocks, having a TOC range from 1-3% for shales, and 20-70% for coaly shales (Laya et al., 2013). The Hydrogen Indices range from 50-300. However, the maturity of Eocene source rock ranges from late mature to over mature, with vitrinite reflectance in the range of 0.9 to 1.8. Generation from the Eocene source rocks probably started in the Late Oligocene, but stopped by the late Early Miocene (Laya et al., 2013).

Barito Basin

Hydrocarbons of the Barito Basin were generated in, and migrated from, Eocene coals and carbonaceous shales of the Tanjung Formation, and also the Middle Miocene Warukin carbonaceous shales (Satyana et al., 1999). The main hydrocarbon kitchen is in the centre of the Barito Basin. The middle Early Miocene saw the onset of generation, migration and entrapment of hydrocarbons due to basin inversion and subsidence (Satyana et al., 1999). Tanjung source rocks in the depocentre of the Barito Basin were mature by the Late Miocene. Graben-fill sequences were actively inverted and hydrocarbons generated from the basin depocentre were expelled to fill these structural traps (i.e. the Tanjung Field; Satyana et al., 1999). The Tanjung Formation shales and coals have TOC's ranging from 1 to 20 wt.% and a HI of 200-400 mgHC/gTOC (Argakoesoemah, 2017).

Satyana et al. (1999) suggest that by the Early Pliocene the Tanjung source rocks had exhausted their liquid hydrocarbon generating capability and at this stage gas was generated and migrated to fill the existing traps. However, the Warukin Shales in the basin depocentre reached the depth of the oil window at this time (Satyana et al., 1999). Plio – Pleistocene tectonism caused strong inversion of the Barito Basin, and

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(West Kerendan-1) which was drilled in 2014 (Subekti et al., 2015). In the absence of appraisal wells, and new 2D seismic (shot in 2006), Saller and Vijaya (2002) originally interpreted the Kerendan buildup as an isolated "atoll", separated from the main Barito Platform, with a rimmed margin and an interior lagoon (Figure 195). However, the more recent drilling and seismic reprocessing has shed new light on the development of the carbonates in the Kerendan field. Subekti et al. (2015) integrated all new and old data, and concluded that the Kerendan field is in fact attached to the main Barito Platform, and the shelf margin is a more complex arrangement of semi enclosed marine embayments (Figure 193). The Kerendan carbonates are interpreted as a complex of open platform carbonates with local reefal buildups and carbonate sand aprons (Subekti et al., 2015).

The evolution of Upper Berai Formation platform carbonates in the Kerendan area can be characterised by four key stages of development (Saller and Vijaya, 2002; Subekti et al., 2015):

(A) Lower to Middle Eocene sands shales and coals deposited during the rift phase. Upper Eocene carbonates seeded on structurally elevated area and formed the base of the isolated buildup. These had an interbedded limestone, sandstone, shale nature, and the margins had a gentle depositional dip. Carbonates continued to be deposited to the Early Oligocene and were characterised by shallow-water platform limestones, but a period of relative sea level rise resulted in deeper water mudstones being deposited over the platform.

(B) After deposition of the dark mudstones, shallow-water conditions returned and shallow-platform carbonates were deposited. This is the main reservoir interval. Floatstones and rudstones are common components, particularly in the vicinity of the Kerendan-1 well. These are composed of larger benthic forams, branching corals and bryozoan/sponges. Although Subekti et al. (2015) acknowledge that these could represent reef-margin facies, they in fact interpret these as localised, relatively low-energy, coral-reefs in an open platform setting (Figure 197). Kerendan-2 well also exhibits a similar facies association, although the argillaceous clastic content is higher (Figure 197;

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Kutei Basin

Discoveries have been made in both south and the north Kutei Basins. The Kerendan field is by far the largest discovery in carbonate facies, and is located in the very south of the basin. Eight wells have been drilled, and core description and petrography has established a diagenetic history for the buildup, along with how diagenesis impacts on reservoir quality.

Saller and Vijaya (2002) and Subekti et al. (2015) both conclude that diagenesis has had a significant impact on reservoir quality in the Kerendan field, since most porosity is secondary relating to the development of microporosity or vuggy porosity. Throughout carbonate deposition there is, however, no evidence for subaerial exposure. Regarding reservoir quality, the important diagenetic processes include (Saller and Vijaya, 2002):

- Transition of high-Mg calcite to low-Mg calcite. Microporosity is very important in the grain-support facies of the Kerendan field, and a possible process creating this microporosity is related to the transition of original high-Mg calcite to the more stable low-Mg calcite. This is an early diagenetic process. Saller and Vijaya (2002) also note that later diagenetic dissolution could in part be responsible as well.
- Aragonite dissolution. Most moulds of corals and molluscs have been subsequently cemented by calcite cements, but locally moulds remain open. Since there is little sedimentological evidence for subaerial exposure, it seems unlikely that dissolution was related to meteoric processes. Dissolution related to burial fluids in moderate to deeper burial, or indeed on the seafloor seems more likely.
- Calcite cementation. Moulds, vugs and intergranular pores have variably been cemented by calcite. The cements postdate dissolution and to some extent compaction, and is therefore considered to be a later burial process.
- Compaction. Pressure solution occurred before significant cementation, thus reducing porosity. This takes the form of both grain-to-grain contacts and the

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10.7. References

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reservoirs and Oligocene to Miocene carbonate reef buildups of the Tonasa Formation.

11.3.2. Source rocks

In South Sulawesi the source rocks are thought to be Eocene carbonaceous shales or coals of the Malawa Formation; however, no wells have penetrated these (Inameta, 2009; Wilson et al., 1999). Surface samples of mature oil collected from the eastern onshore area of the basin, combined with seismic studies has allowed synthetic well geochemical modelling, suggesting the Malawa Formation is the most likely source (Inameta, 2009; Wilson et al., 1999; Argakoesoemah, 2017). Average TOC values for the black shales are 11%. Coals have 33% TOC and contain predominantly type III vitrinitic kerogen. HI values range from 158 to 578 (Wilson et al., 1999). Eocene deltaic sands are thought to be one of the primary migration routes for hydrocarbons (Wilson et al., 1999). Hydrocarbon gas in eastern South Sulawesi is of thermogenic origin (Wilson et al., 1999).

In eastern South Sulawesi, maturation modelling based on the deepest well (Sallo Bullo-1) with 3650m sediment, indicates that the early hydrocarbon generation for the East Sengkang sub-basin is approximately 1500m depth and the mid mature area could be below 2400m depth (Inameta, 2009). Hydrocarbon migration started in the Late Miocene (ca. 2.5 Ma).

Although a gas discovery has been made in the South Makassar Basin (Sultan-1, possible biogenic gas; Satyana et al., 2012), the source rocks have not been typed. Satyana et al. (2012) comment that isotopic evidence for the origin of the gas is inconclusive at present with possible mixing between thermogenic and biogenic sources but the presence of biogenic gas may indicate a lack of maturity. Subroto et al. (2007) and Noeradi et al. (2007) suggest Eocene, Oligocene and Miocene shales are the likely source rocks for the basin. They contain mainly Type III and locally Type II kerogens. Geochemical analyses from more shelfal wells indicates that most of the samples have not reached the oil window (Subroto et al., 2007). 2D and 1D basin modelling, based on this data, indicates that Eocene sediments in the deeper basin range from mature up to the dry gas window to peak of oil generation, whilst Miocene

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repeated subaerial exposure. Carbonate platform demise is attributed to a rise in sea level (Grainge and Davies, 1985).

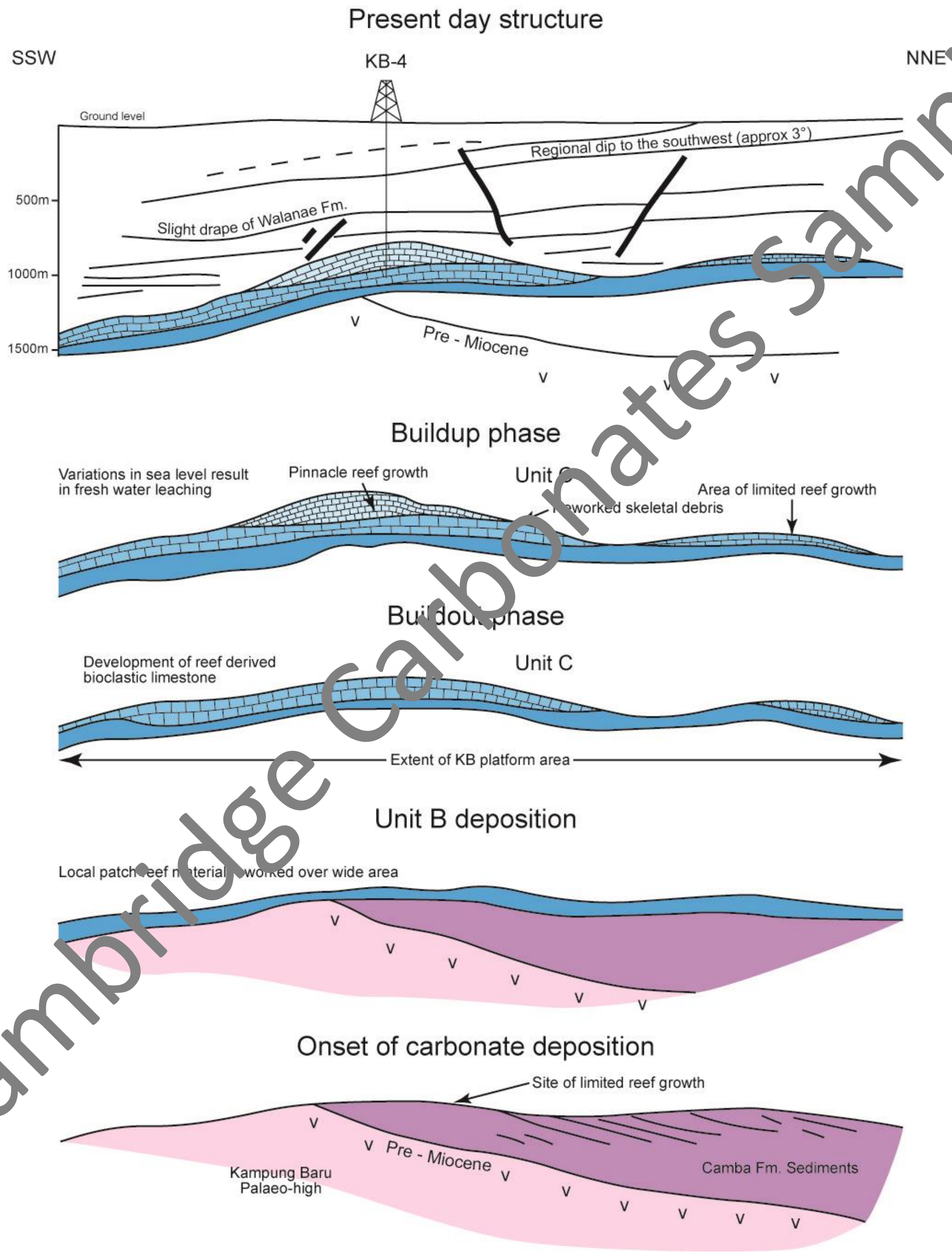

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Figure 214 Development of the Tacipi Limestone Formation in the Kampung Baru area. Redrafted from Grainge and Davies (1985)

detail regarding dolomitising processes, but it does not appear to have impacted significantly on reservoir quality, since porosities are similar to that in Sultan-1 well. In the Kris-1 well, the average porosity for the carbonate interval is 13%, with that value increasing to 14% deeper in the section. In total, 59% of the carbonate interval that was drilled had average porosities over 11% (Bacheller III et al., 2011).

For the redeposited carbonate debris flow reservoirs which are sourced from the Paternoster Platform (Ruby Field) the pore system, which is enhanced by open fractures, is developed in both the clasts and the matrix of the resedimented carbonates. Mouldic and vuggy pores are the most common pore type. They are related to the early dissolution of skeletal aragonite of corals and molluscs in the freshwater-phreatic environment and precipitation of early marine cements. These carbonates were subsequently redeposited as talus in the slope setting, whereby clasts were locally cemented by fibrous calcite (Pireno et al., 2009). During burial, a dissolution phase occurred, possibly related to early stages of hydrocarbon generation and acidification of formation fluids, mainly leaching foraminifera and red algae. During the mid-Middle Miocene the reservoir unit was folded (forming the trap) and a set of subhorizontal fractures developed. Finally, very fine crystalline dolomite precipitated along open pores, fractures and stylolites. The resulting average porosities of the MKS-1, 3, and 4 wells lies between 15 and 17%. The mouldic and vuggy pores resulting from the dissolution of foraminifera and red algae are believed to be of crucial importance for the well-connected pore system of the Ruby field due the abundance of these skeletal allochems in both the matrix and clasts of the resedimented carbonates (Pireno et al., 2009).

Of interest, after the successful discovery and appraisal of the Ruby field, a nearby exploration target was also drilled, but was unexpectedly dry (Tanos et al., 2013). The NW Ruby-1 well had tested a valid structure, with suitable seal, but diagenetic studies indicated that the reservoir had not experienced the late-stage dissolution that the neighbouring debris lobes of the Ruby structure had. In fact, it would appear that the NW Ruby-1 debris lobe was surrounded by shales laterally – precluding migration of both late stage dissolution fluids and hydrocarbon charge (Tanos et al., 2013). The NW

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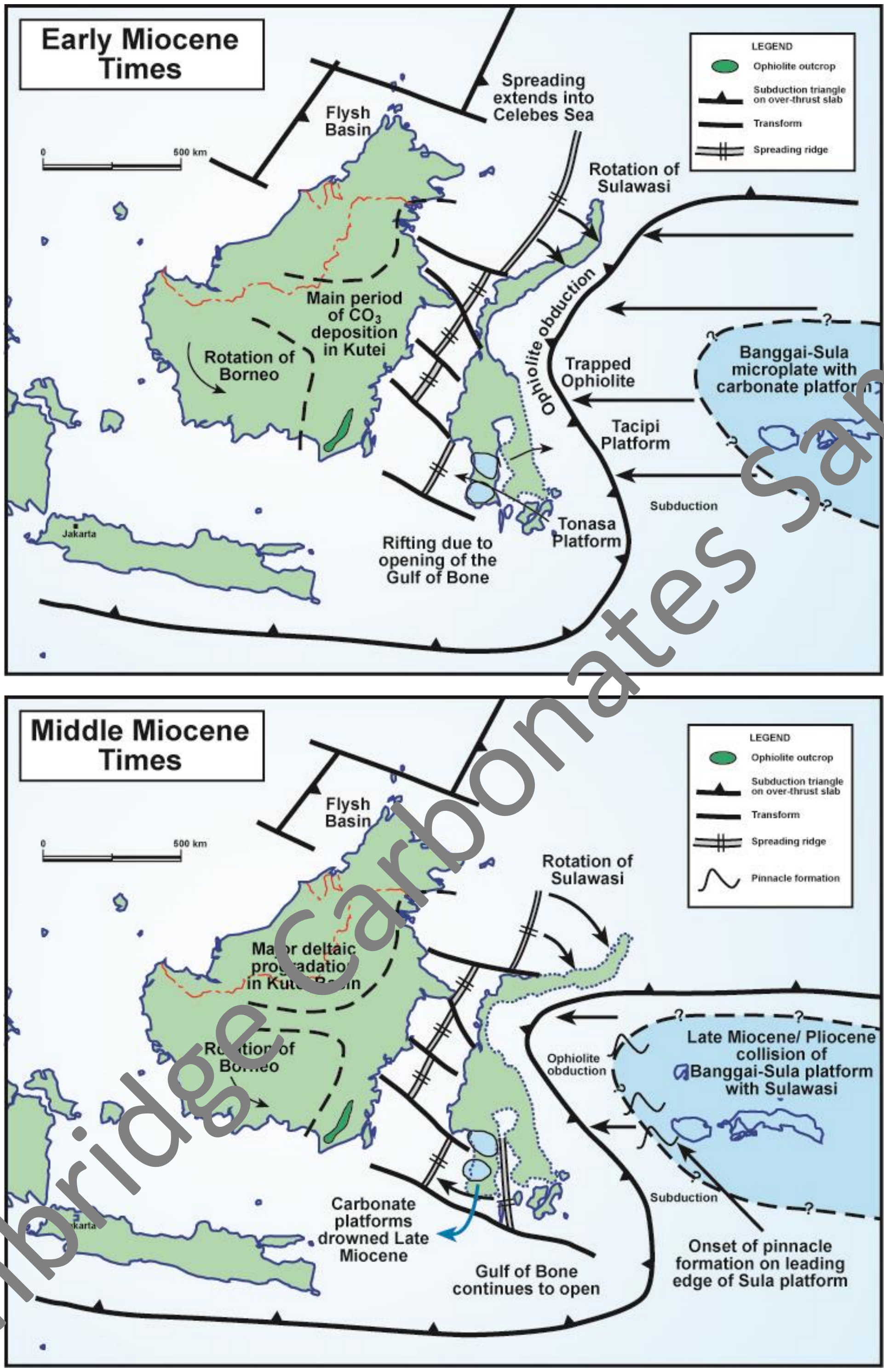

Figure 222 Structural sketches illustrating the evolution of the Sulawesi and Borneo area at the (A) Early Cretaceous, (B) Paleocene-Miocene transition, (C) Early Miocene, and (D) Middle Miocene. The Tomori Basin is younger than the rift-related Kutei basin. Adapted from Davies (1990).

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skeletal packstone are probably more abundant in the north (Senoro field; Hasanusi et al., 2004), but the depositional setting is almost the same, i.e. a low energy shallow platform interior. The platform margin was probably oriented SSW-NNE with shallow water facies to the ESE and basinal environments to the WNW (Figure 225), the latter being now over-ridden by thrust sheets.

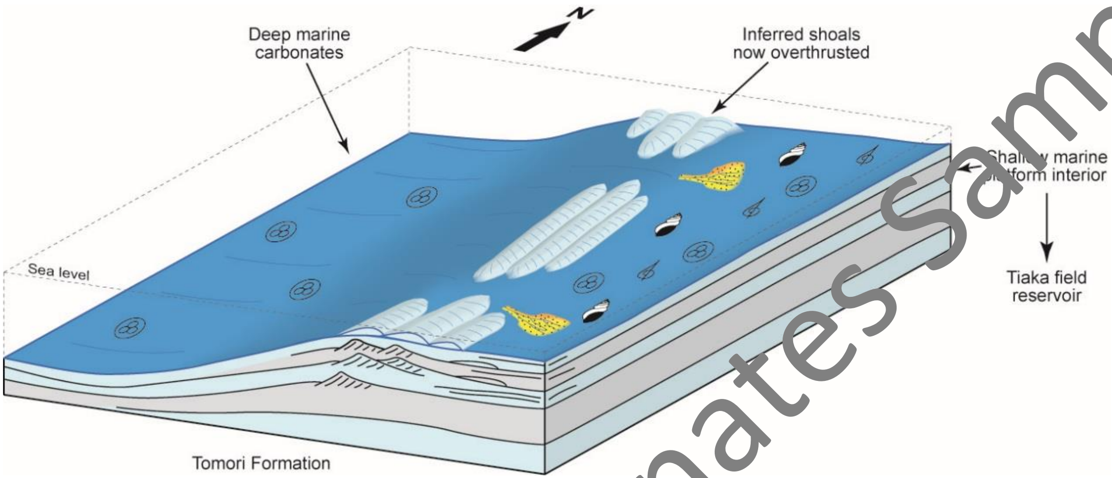

Figure 225 Palaeogeographic sketch during the deposition of the Tomori Formation. Passive margin of the Banggai-Sula microcontinent prior to collision. The shallow marine platform interior deposits form the reservoir of the Tiaka oil field.

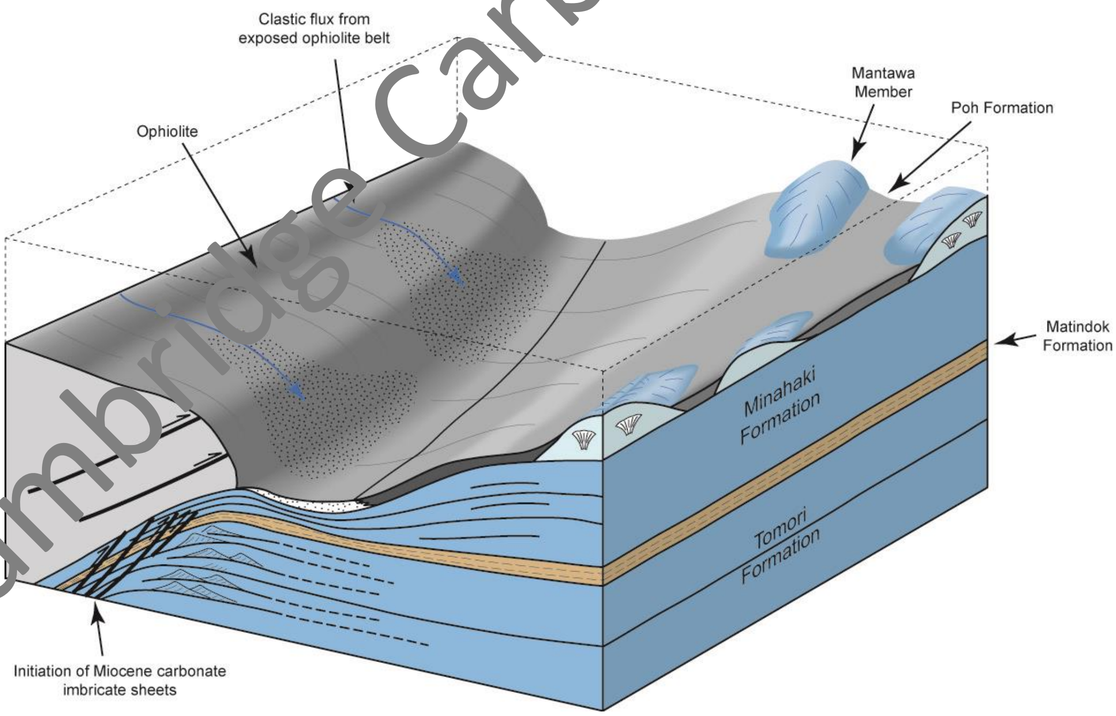

Figure 226 Palaeogeographic sketch during the deposition of the Poh Formation and Mantawa Member. Mantawa carbonate pinnacles form in response to increased subsidence caused by foreland loading and clastic influx. The pinnacles of the Mantawa member form the reservoirs of the Senoro gas field.

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13. CARBONATE RESERVOIRS OF WEST PAPUA

13.1. Geological Setting

Two main petroleum provinces are recognised in the West Papua province (former Irian Jaya): the Bintuni/Salawati Province (*sensu* Steinshouer et al., 2000), located in the Bird's Head or Doberai peninsula, and the Arafura basin (*sensu* Steinshouer et al., 2000; named *pro-parte* Akimeugah Basin by McChonachie et al., 2002). The petroleum system of the latter is almost identical to the system of the Papua New Guinea fold belt western basin (McChonachie et al., 2000), with potential plays in the Early Cretaceous Toro (and equivalent) sandstones, and it will not be described here.

Consequently, this section focuses on the petroleum system of the Bintuni/Salawati province, which encompasses the Salawati strike-slip or transform margin basin and the Bintuni transform margin to foreland basin. The latter basin will be briefly described since the main producing fields are not in the Cenozoic formations.

13.1.1. Salawati Basin

The Salawati Basin is an E-W-trending asymmetric basin located on the northern margin of the Indo-Australian plate (Figure 228). It developed during the Late Oligocene over various terranes accreted during the Paleocene (Caughey et al., 1995). The basin is bounded to the north by the left-lateral ENE-WSW Sorong fault that has been active since the Late Miocene or late Early Pliocene, depending on references. Movement along the Sorong Fault has caused (1) the creation of NE-SW en echelon folds and synthetic left-lateral faults through the Salawati Island, and (2) the re-activation of older NW-SE normal faults that originated during Late Palaeozoic-Mesozoic rifting (Satyana et al., 2002; Figure 228). To the south and east the Salawati Basin is bounded by the Misool-Onin Geanticline in front of the Seram thrust-related trough, and the Ayamaru Platform respectively (Figure 228).

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Lagoonal mud-mounds and reefs

The Central Salawati lagoon, or intrashelf basin, is the broadest facies belt. The western part display mud-mounds and reefs whereas the eastern part is deeper and only displays few buildups. The eastern part started as a shallow water subtidal carbonate which deepened with the deposition of pelagic carbonates. The limestone is generally micritic or argillaceous carbonate mudstone/wackestone deposited in a low energy environment. Jeflio-1, Nurmana-1 and Klamogun-1 wells typify this facies. Carbonate buildups grew in the western part of the Salawati lagoon, probably as a response to subsidence and tilting relative to the eastern part of the basin. These are generally low relief buildups (e.g. Matoa-20) consisting largely of carbonate mud cores with some grainstone and packstone. Skeletal components include planktonic and benthic foraminifera and some coral fragments. The Matoa field is an example of a field within the "lagoonal" facies.

Reefs over the Salawati ridge(s)

Some igneous palaeo-ridges are present in the Salawati Basin, these may be areas of shallower water inside the lagoon with the patchy growth of isolated coral heads (also with *Amphistegina* and coralline red algae). Examples include Salawati K-1X, WIR-1, WIR-1A, Salawati N-1X and Salawati O-1X.

Lagoonal pinnacle reefs

An E-W belt of carbonate buildups is present on the lagoon or intrashelf basin side of the Walio bank. These buildups, from west to east include: TBA, TBC, TBM, Salawati C, Salawati E, Salawati F, Salawati D, Kasim complex, Jaya, Cenderawasih and Moi. The pinnacle reefs of TBA, TBC and TBM were more open marine whereas the Salawati C through Moi were true lagoonal pinnacle reefs. Carbonate fabrics include skeletal wackestone and packstone, carbonate mudstone and boundstone. The limestone is often strongly dolomitised. Bioclasts include corals and red algae with minor echinoderms and large benthic foraminifera.

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Salawati A field	*Basin:* Salawati Basin	*Block:* Teluk Berau
Operator: PT Pertamina EP		
No' wells on structure: 7		
Discovered: 1975		
Produced since: N/A		
Current status: N/A		
Geological setting: strike-slip		
Top reservoir depth: 1554m		
Lithology: Limestone, dolomite		
Reservoir type: Shelf build-up		
Reservoir age: Late Miocene		
Formation: Kais		
Depositional setting: Semi-isolated buildup.	*Structure and trap type:* Structural and stratigraphic	
Migration and Seal: Pliocene fine clastics of the Klasaman Formation	*Fill history:* Plio-Pleistocene migration from Cenozoic source	*Source:* Type II kerogen was probably expelled from Miocene Klasafet organic matter-rich fine limestone laterally equivalent to carbonate build-ups
Net pay: 141m	*Structural closure*: 226m	*Area of closure*: 2.37 km^2 *Productive area*: 1.2 km^2
Net/Gross: N/A	*Gross pay*: N/A	*Reservoir depth*: N/A
Pore system		
Matrix pore system: N/A	*Matrix porosity:* 16.5%	*Macroporosity:* N/A
Macropore system:	*Matrix permeability:* N/A	*Macro-permeability:* N/A

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14.2.4. Late Cretaceous-Paleocene

Coral Sea syn-rift Megasequence: The onset of the Coral Sea rifting to the southeast of Papua New Guinea in the Cenomanian marked the end of the passive margin setting. The rifting resulted in reactivation of pre-existing extensional faults and only in the formation of minor new faults. The depositional setting is that of marine shelf/slope, and according to Home et al. (1990) shallow and deep fine clastic sediments are dominant (Figure 237). The Fly Platform was still in a proximal shallower domain but was probably entirely submerged. Because of the Coral Sea rifting, the deeper zones were the east and southeast of the Gulf of Papua, and the northeast Papuan Basin. The Kubor Anticline remained a high zone, and the occurrence of volcanogenic material in this area suggests a northerly sediment source, such as an island-arc. However, the recent exploration by InterOil in the Eastern Basin (Barclay et al., 2003; George et al., 2007) revealed an entire Turonian to Campanian sequence including from base to top (1) deep marine turbidites (Subu Formation), (2) volcanic rocks, and (3) shallow marine (shoreface) clean quartz-rich sandstone (Pale Formation; Figure 239B). This clearly changes the simple palaeogeographic view of Home et al. (1990), and more work is required to better understand this whole stratigraphic interval, which seems to be prospective (George et al., 2007).

In the latest Cretaceous, a thermal uplift occurred in the southeast of Papua New Guinea which exposed the Gulf of Papua and the Fly Platform. Up to 2km of sediments were eroded in these areas, where this main unconformity, called the Base Tertiary Unconformity (BTU; Home et al., 1990; Gordon et al,. 2000; Tcherepanov et al., 2008), locally reached down into the Jurassic formations (Figure 238). The crystalline basement is even re-exhumed on the Pasca ridge (Figure 238) but the amount of erosion quickly decreases to the north and northwest where the syn-rift series are preserved.

14.2.5. Late Cretaceous-Eocene

Coral Sea post-rift Megasequence: Whilst most of the Fly Platform remained exposed until the Late Oligocene, marine conditions resume during the Eocene in the central Gulf of Papua through thermal subsidence which progressively migrated to the east of

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14.4. Carbonate Reservoirs

14.4.1. Palaeogeography and sedimentology

Seismic surveys, airborne gravity and magnetic surveys (e.g. by InterOil 2004-2005 in Goldberg and Holland, 2008; Margins Panash 2004 in Tcherepanov et al 2008b; Fugro 2006 in PESA News, 2006; and by the U.S. Geological Survey 2011 in USGS, 2012) in the Eastern Basin and in the Gulf of Papua, have allowed an interpretation of the structural template, on which sedimentology takes places. Outcrop and thin section studies have aided interpretation. In the Eastern Basin and in the Gulf of Papua carbonates were deposited in the Eocene, Oligocene and Miocene.

1. Eocene fractured shallow marine Mendi Formation:

Widespread deposition of shallow marine Mendi Formation carbonates occurred in the Eastern Basin and in the Gulf of Papua, due to thermal subsidence post Coral Sea rifting (Gordan et al., 2000). A relatively thick Paleocene-Eocene section was deposited south of the Kubor Anticline (Figure 244) and in the Aure Thrust Belt (Carmen, 1989 in Carmen, 1990). The distribution of Eocene strata relates to two broad environments of deposition; neritic and bathyal (Carman, 1990). The Fly Platform (Figure 235) received no deposition or only thin deposition and subsequent erosion, whereas to the east of the Fly Platform, Eocene carbonates thicken to over 300m, interrupted only by sporadic structural highs such as the Borabi, Pasca, and Pandora areas (Figure 251; Figure 252) (Carman, 1990). The thickness of the Mendi limestone is reported to vary from 40m at Puri to 900m at the Aure Scarp (InterOil, 2003). At Puri-1, the formation shows a maximum thickness of 232m (Carman, 1990), and at Elk-2, the true stratigraphic thickness of the Formation is 292m (InterOil, 2007b).

To the east of the Fly Platform, Eocene carbonates (Figure 244) are shallow shelfal, and shoal facies (Carman, 1990). Microfacies are mostly packstones characterised by abundant echinoderm debris, bivalves, larger benthic foraminifera and bryozoans (Durkee, 1990). Eocene shelf facies are observed in the upper part of well Puri-1; microfacies include grainstones with abundant echinoderm debris, planktonic and benthic foraminifera, fragments of coralline algae, fragments of bryozoans, and algal foraminiferal (larger benthic and planktonic) packstones (Carman, 1990). In the lower

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Puri Formation consists of slope deposits such as breccias, and deep water pelagic sediments, i.e. planktonic foraminiferal limestones. The Puri Formation ranges from 300-900m in thickness (InterOil, 2008b) and is contiguous with the platform carbonates of the Darai Limestone (Leech et al., 2006). Puri carbonates are observed, for example, at Elk, and Triceratops.

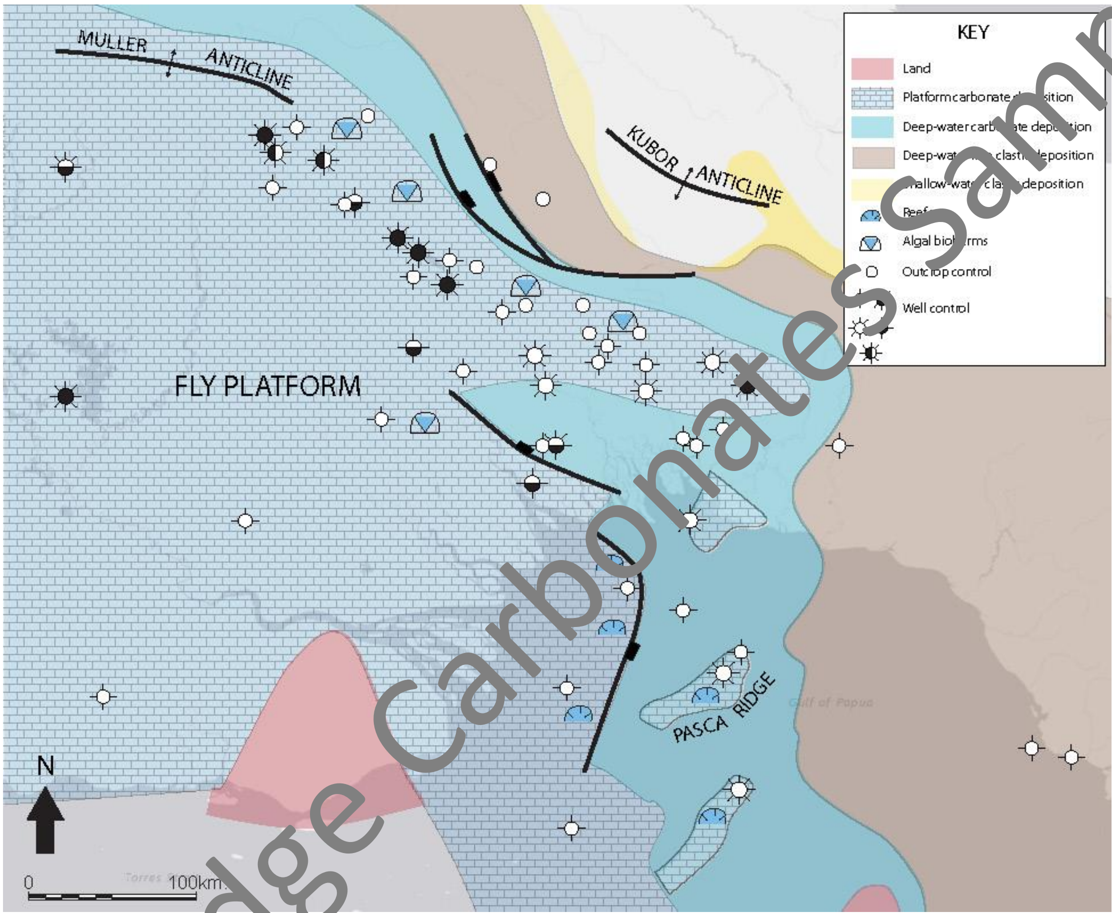

Figure 245 Palaeogeography at 20Ma (end Aquitanian) within the Darai Back-Arc Megasequence showing carbonate development over the Fly Platform passing distally into pelagic carbonates of the Puri Formation (redrafted after Home et al., 1990)

Elk

The Elk-1 discovery well was drilled by InterOil in 2006. The Puri Formation at Elk-1 and Elk-2 can be defined generally by: 1) planktonic foraminiferal wacke-packstones, 2) planktonic foraminiferal wacke-packstones with probable coral/bioclastic rud-packstones, and 3) carbonate lithoclastic pack-rudstones/breccias with planktonic foraminifera, larger benthic foraminifera and corals (Wilson et al., 2013). Wells Elk-1 and Elk-2 are interpreted to pass through slope and basinal facies with a general

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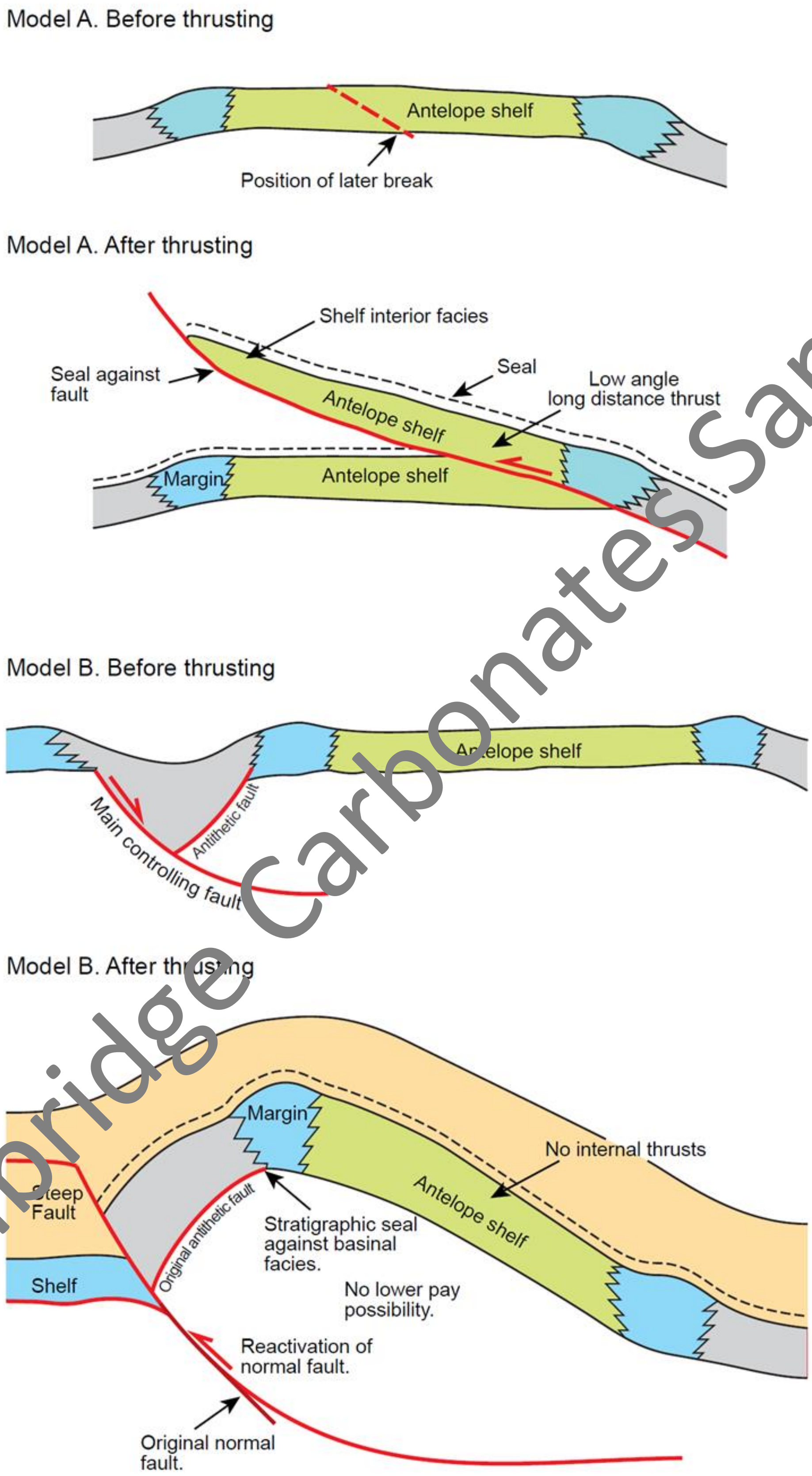

Figure 256 Alternative models for the structure of the Antelope Field. Model A) showing low angle long distance thrust fault. Model B) showing reactivation of normal fault giving steep thrust fault. Cambridge Carbonates in-house model.

Cambridge Carbonates Sample

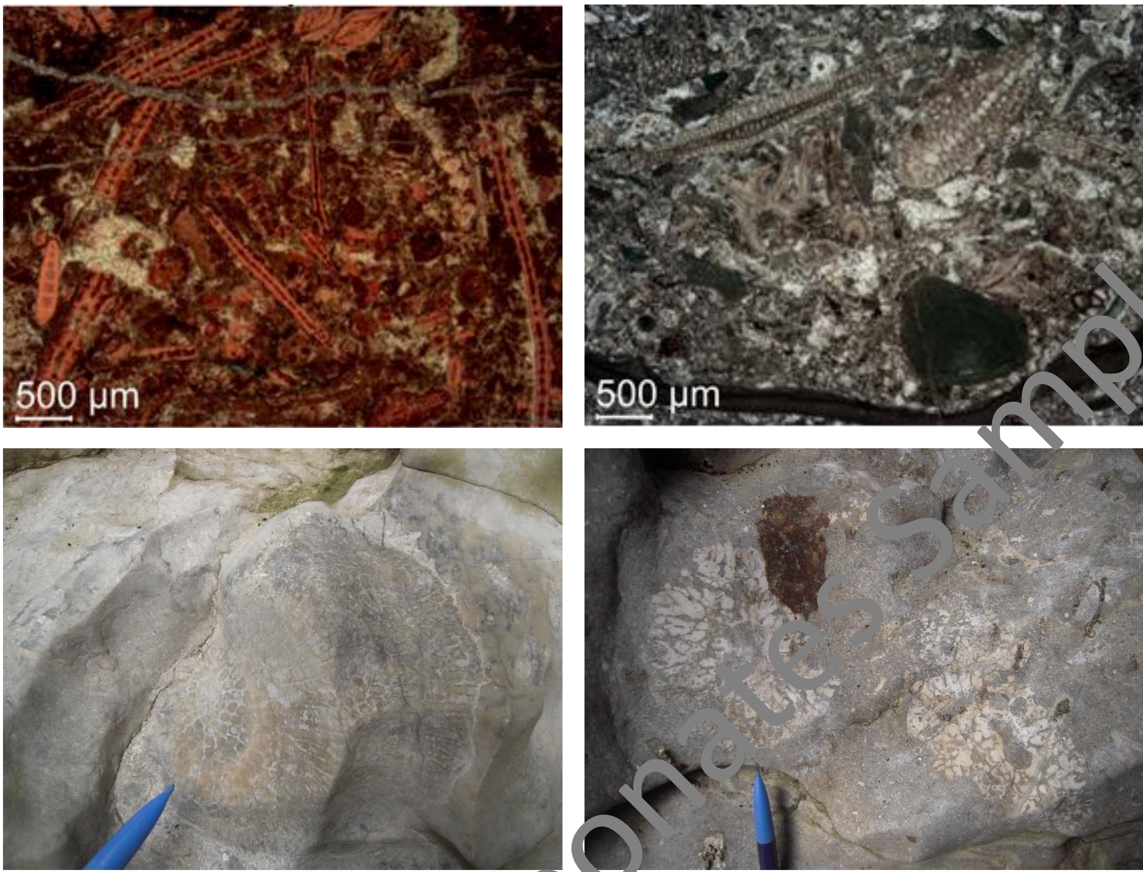

Figure 260 Thin section photomicrographs of Darai Formation fore-bank carbonates showing: (TL) Bioclastic packstone with abundant *Lepidocyclina* and also *Amphistegina,* (TR) Bioclastic packstone with *Lepidocyclina*, *Miogypsina* and coralline red algae, (BL) Outcrop sample showing Scleractinian coral, (BR) Outcrop sample showing *Porites* coral. Cambridge Carbonates in-house work.

Lagoon: The lagoonal setting is identified by micritic facies, which has a distinct colour mottling, and a bioassemblage rich in green algae, gastropods and *Acropora* finger coral. Various larger benthic foraminifera including *Lepidocyclina, Miogypsina* and *Sorites* are also present.

Darai-Puri Formation Summary:

Figure 261 summarises the relationship between the Darai and the Puri Formations. Darai carbonates grew on palaeohighs such as the Pasca and Pandora reefs, whereas, the Puri Formation was deposited on the slopes and in the basins of the highs. Planktonic foraminiferal wacke-packstones characterise the basin (BS), reworked shelf shelfal material is observed on the slopes (SL), the fore-bank is typified by larger

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Analysis of Darai Formation carbonates by Cambridge Carbonates has identified two karst surfaces. Fluid inclusion analysis showed that meteoric fluids reached significant depths. Percolation of meteoric fluids led to the development of fractures, cavities and widespread dissolution of aragonitic allochems creating mouldic porosity (Figure 269 L). Post-karstification, as normal marine conditions returned, sea water circulated through the limestone precipitating finely crystalline dolomite; dolomitisation is confined to the upper “layer” of the Darai Formation carbonates. Dolomitisation resulted in enhanced reservoir quality with open, probably well connected, but small pores present in between the small euhedral dolomite crystals. Compactional collapse after burial of karst and associated dolomitised textures also enhanced porosity, forming crackle fractures (Figure 269 R), particularly in the dolomitised layer. Late burial cements, such calcite (Figure 269 R) and dolomite, however then reduced porosity, including fractures associated with karstification and cavities created due to compactional collapse. Stratigraphically, the best samples are located in the middle part of the Early Miocene stratigraphic cycles; this is most likely due to the early meteoric diagenesis associated with the exposure surface capping the cycles.

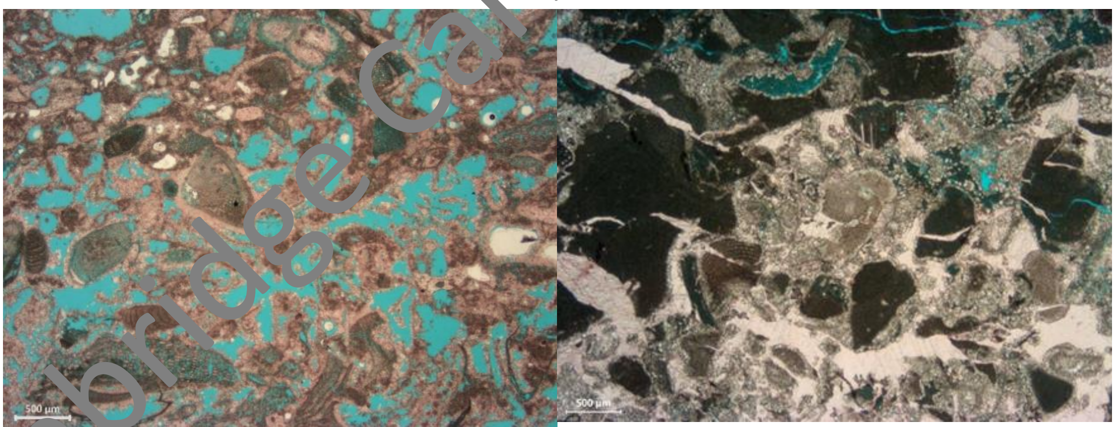

Figure 269 Thin section petrography of Darai Formation carbonates showing L) Development of mouldic porosity after dissolution of aragonitic allochems, R) Crackle microfractures occluded by late calcite cement. Cambridge Carbonates in-house work.

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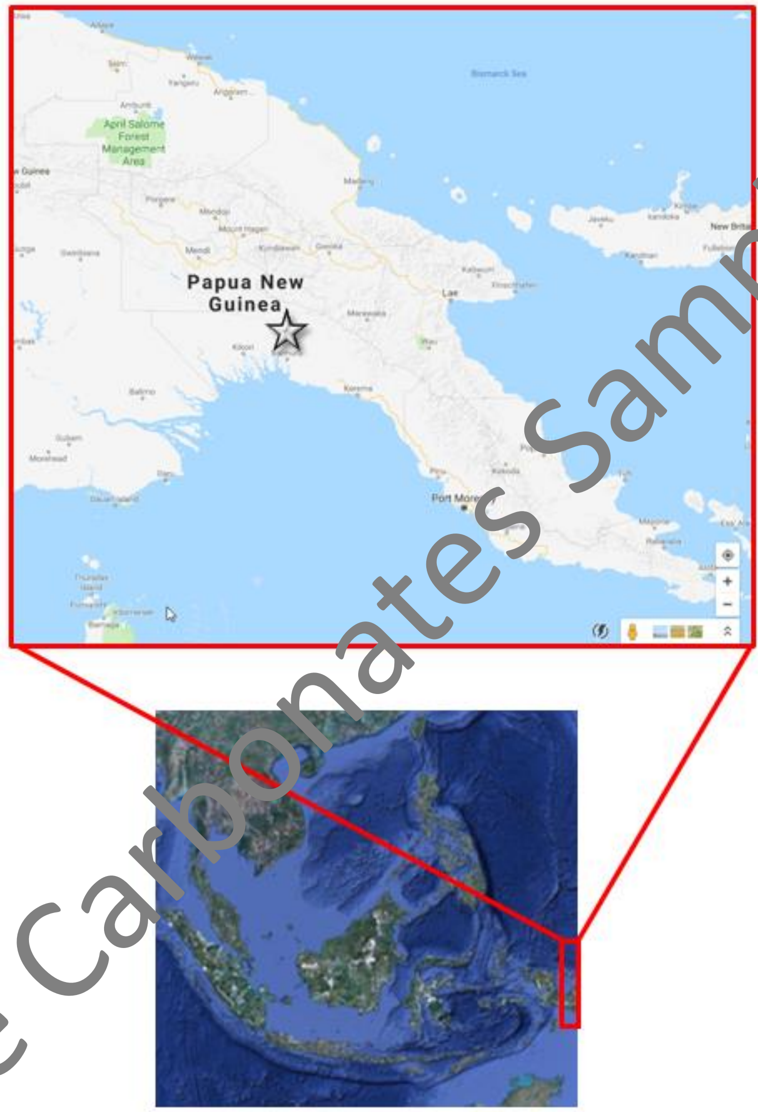
14.5. Future potential

Eastern Basin

Following the Elk-Antelope gas discovery, there has been a shift in exploration away from the Toro sandstone reservoirs in the fold and thrust belt in the Western Basin to

Antelope field	*Basin:* Eastern Basin	*Block:* N/A

Operator: ExxonMobil	
No' wells on structure: 7	
Discovered: 2009	
Produced since: N/A	
Current status: gas and condensate discovery	
Geological setting: Fold and Thrust Belt	
Top reservoir depth: 2264m mD	
Lithology: Limestone and dolomite	
Reservoir type: Reefal	
Reservoir age: Oligo-Miocene	
Formation: Darai (or Kapau)	

Depositional setting: Semi-isolated buildup	*Structure and trap type:* structural stratigraphic trap (reef)	
Migration and Seal: N/A	*Fill history:* N/A	*Source:* N/A
Net pay: N/A	*Structural closure*: N/A	*Area of closure*: N/A *Productive area*: N/A
Net/Gross: N/A	*Gross pay*: N/A	*Reservoir depth*: N/A
Pore system		
Matrix pore system: N/A	*Matrix porosity:* 8.4 to 20% Antelope-1 reef	*Macroporosity:* N/A
Macropore system:	*Matrix permeability:* N/A	*Macro-permeability:* N/A
Layering: N/A	*Bit drops:* N/A	*Mud losses*: N/A
Well performance		
Initial rate: N/A	*Typical single well rate:* N/A	*Initial pressure:* N/A

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