Cambridge Carbonates Ltd

Expertise in carbonate and evaporite systems

CONFIDENTIAL

Multiclient report purchased by:

"CAMBRIDGE CARBONATES LTD"

Peter Gutteridge, Joanna Garland, Benoit Vincent, Sarah Thompson, Julia Morgan, Jack Turney, Dougal Jerram

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

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 of 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.

- 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.

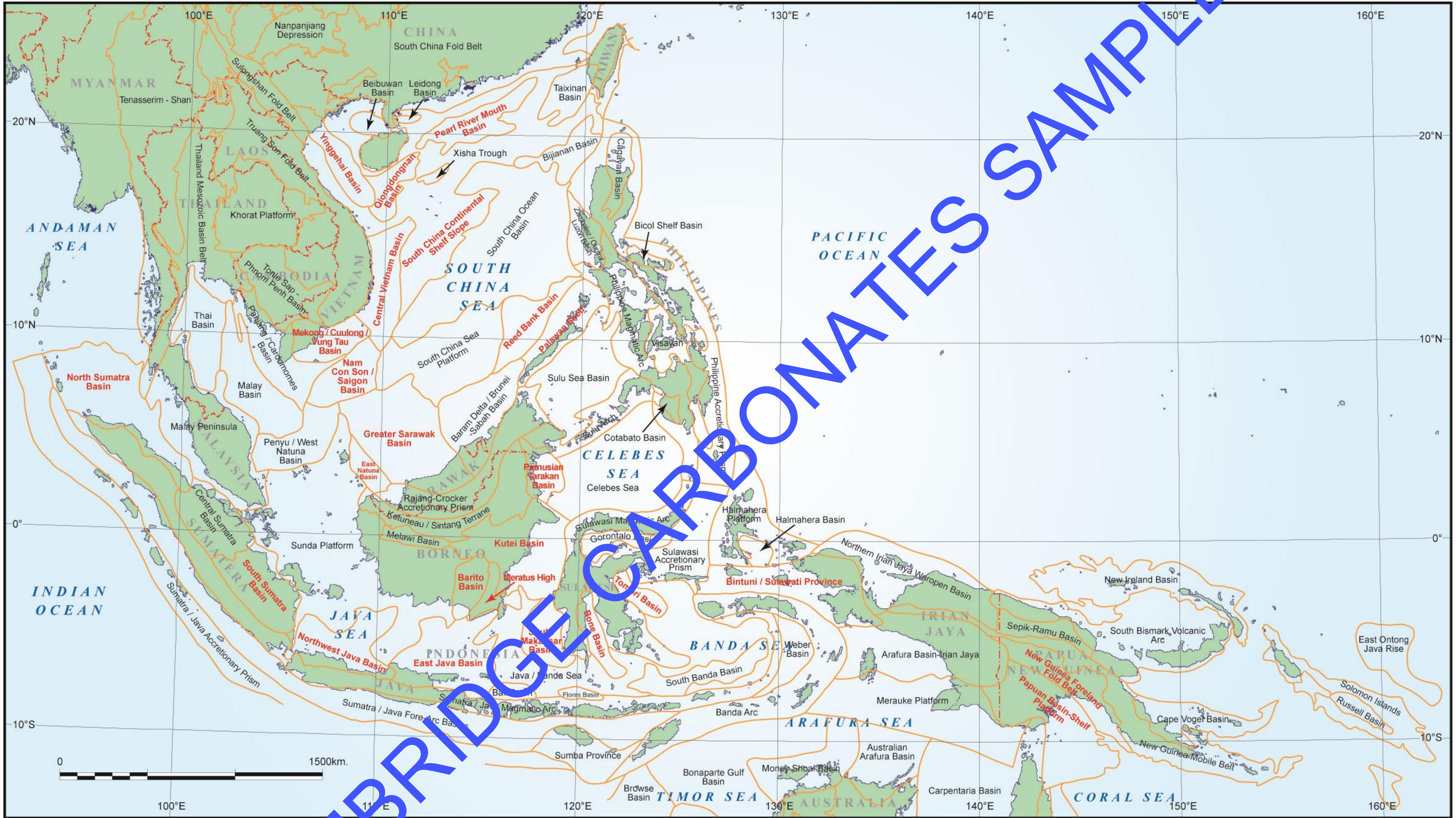


Figure 1 Location map and basins in SE Asia. Note that the basins with important carbonate reservoirs are marked in red, and have been reviewed in detail in this report. Modified from Steinshouer et al. (2000).

Eocene and Oligocene: the end of the Paleocene marked a diversification of benthic foraminifera and a switch from rimmed carbonate shelves to carbonate ramps. Shallow ramp lagoonal environments are characterised by miliolids and alveolinids; mid carbonate ramp settings including carbonate shoals are characterised by nummulites, assilinids and discocyclinids. Deep carbonate ramp environments are characterised by resedimented nummulites, discocyclinids and red algae. Planktonic foraminifera become predominant in outer carbonate ramp settings. The best reservoir quality is found in mid ramp carbonate shoal and associated up-dip storm wash over and down-dip resedimented facies.

Late Oligocene and Miocene shallow carbonate ramp back barrier and restricted lagoonal environments are characterised by victoriellids and soritids. Mid carbonate ramp carbonate shoal environments are characterised by amphisteginids, lepidocyclinids and red algal rhodoids. Red algae and corals may form patch reefs in the mid carbonate ramp setting. Mid to deep carbonate ramp environments are characterised by *Cycloclypeus, Miogypsina,* encrusting red algae, resedimented *Amphistegina*, red algal rhodoids, patch reefs and some encrusted hard grounds. The best reservoir quality tends to occur in mid ramp carbonate shoals; red algal patch reefs tend to have poorer reservoir quality because they have a high component of low porosity encrusting organisms.

Plio-Pleistocene The importance of carbonate ramp systems declined and many carbonate systems reverted to rimmed carbonate shelves with fringing reefs formed by scleractinian corals, green algae and molluscs. Benthic bioclasts include benthic foraminifera, *Halimeda* and scattered coral patch reefs. Nearshore platform interior facies often consist of muddy mixed siliciclastic-carbonate systems strongly affected by local run-off. The majority of Plio-Pleistocene reefs in SE Asia are limited to fringing continental areas and islands away from areas of siliciclastic input; however, the Natuna carbonate platform (NW Borneo) forms part of a carbonate system that was initiated in the Early Miocene and is still extant today (Wilson, 2002).

Productive Pliocene petroleum systems with good reservoir quality occur in pelagic and contourite carbonates dominated by planktonic foraminifera (globigerinids) in

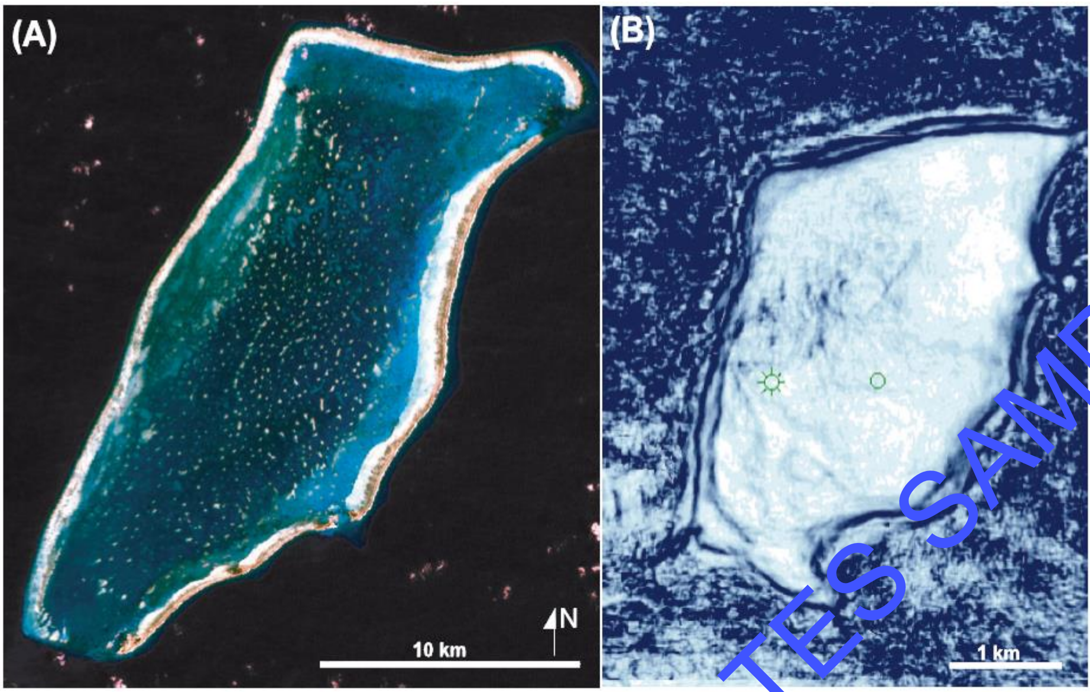


Figure 10 Comparison of the Glovers reef, offshore Belize (A) (this is a mixed carbonate-clastic setting) and a 3D semblance volume of a Luconia Middle Miocene buildup (B). In the Glovers reef, it is possible to determine the reef rim, white back-reef carbonate sands, and a lagoon with numerous small patch reefs. On the semblance slice high semblance values (dark blue) correspond with the reef seismic facies, intermediate semblance in the adjacent back-reef deposits, low semblance values of the lagoonal seismic facies. Note that the seismic image is capable of recording the breaks in the reef rim. From Eberli et al. (2004), reprinted by permission of the AAPG whose permission is required for further use.

Interaction between carbonates and regional siliciclastic systems

In many basins, such as the North Sumatra, offshore Vietnam, South China Sea, offshore NW Borneo and the North and South Makassar Basins, local carbonate systems develop over intra-basinal highs. Carbonate sedimentation over these highs is brought to an end during the Mid- to Late Miocene by the progradation of regional siliciclastic systems. The development of carbonate systems on these intra-basinal highs depends on:

- The elevation of the intra-basinal high, ideally the elevation should be such that it is within the zone of maximum carbonate production during the local stratigraphic 'carbonate window'.

- Depositional pore systems may also be modified during diagenesis such that the original depositional facies and sequence stratigraphic layering have been over printed.

- Dolomitisation takes place at various stages of diagenesis and affects the distribution and amount of porosity. However, porosity and permeability may be reduced as well as enhanced by dolomitisation. Fracture-associated and burial dolomites represent an additional play type in some basins referred to in Section 2.3.2.

- The presence of CO_2 in carbonate reservoirs in SE Asia is linked to diagenetic processes such as dolomitisation, maturation and high heat flow. This is discussed in 2.4.

2.3.2. Diagenesis and porosity evolution in Cenozoic carbonate reservoirs

Some reservoirs contain pore systems that are mainly depositional such as the Poleng field, a shelfal coral reef complex at the northern margin of the East Java-Madura Shelf Edge in which diagenesis is facies-dependant (Kenyon, 1977). In South Sumatra, carbonate pore systems in reservoirs appear to reflect more closely the original depositional porosity. Early marine cementation appears to have been responsible for only minor porosity reduction during early diagenesis. Muddy facies are typically neomorphosed leading to a re-arrangement of the micropore system that increases the pore-throat size in the original micrite improving permeability and increasing the storage capacity of reservoirs (Longman et al., 1993).

This process is also known from the Parigi reservoirs in NW Java (Yaman et al., 1991), and in the Kutei Basin (Saller and Vijaya, 2002). The reservoir quality in limestones with low initial depositional porosity and permeability in North Sumatra have been improved by early dissolution that created mouldic and vuggy pores in reefal facies. Secondary porosity is also present in the associated coral-debris facies and foraminifera-algal facies, though locally pores have been filled by late-stage cement. Secondary pore creation is not present in the algal or deep-water shelf facies, and visible porosity is poor.

Field/well	Formation	Substrate	Depth m	CO_2 %	Comments
Alur Siwah	Peutu	Tampur	2900	30	Field average; well site analyses vary from 6.5-81.5%, also 2000ppm H_2S
Arun	Peutu	Bampo	3050	15	Field average with traces of H_2S and Hg
Arun				13.8	Satyana *et al.* (2007)
Arun A1	Peutu	Bampo	2895	15	
Arun A2	Peutu	Bampo	2890	17	
Arun A3	Peutu	Bampo	3080	14	
Arun A5	Peutu	Bampo	3100	13	
Arun A6	Peutu	Bampo	3060	14	
Arun A-8	Peutu	Tampur	3078	25	Off main structure
Bata-1	Peutu	Belumai	2065	14	24ppm H_2S
Bata-1	Belumai	Tampur	2089	18	
Cunda	Peutu	Phyllite	3755	26	Field average
Cunda A2	Peutu	Phyllite	3050	25	
Iee Tabeue-50	Peutu	Unknown	2386	18	
Jeuku-1	Bampo	Unknown	3300	36	Reported up to 75%
Langsa TAC	Peutu	Metasediments	1680	35	Field average
Kuala Langsa-1	Peutu	Metasediments	3370	82	
Kuala Muku-1A	Peutu	Bampo	3220	7	
Lhok Sukon S A	Peutu	Tampur	2590	24	
Salem	Peutu	Unknown		45	
Teripang	Peutu	Unknown		9	
NSB-A	Peutu	Unknown	1533	31	
NSB-A				31.1	Satyana *et al.* (2007)
NSB-H	Peutu	Unknown		15	
NSB-J1	Peutu	Unknown	1488	28	
NSB-J1				28.3	Satyana *et al.* (2007)
NSB-J2	Peutu	Unknown	1493	29	
NSB-R	Peutu	Unknown	1320	19	
Pase-C1	Peutu	Unknown		33	
Pergidatit-AB1	Belumai	Pre-Cenozoic	2397	11	
Peudawa Rayeu	Belumai	Unknown	2979	10	
Peulalu-3	Peutu	Bampo	2311	22	
Peutouw-1	Peutu	Tampur	2764	64	Also 3000ppm H_2S
Rantau				0.9	Satyana et al. (2007)
Batum Andi				4.2	Satyana et al. (2007)
Kuala Simpang				1.27	Satyana et al. (2007)
Paluh Tabuhan Timur				0.8	Satyana et al. (2007)
Paluh Tabuhan Barat				1.14	Satyana et al. (2007)

Table 3 Gas composition in N Sumatra, data from Caughey and Wahyudi (1993), Reaves and Sulaeman (1994), Cooper et al. (1997), Carnell and Wilson (2004) **and** Murachi et al. (2005).

Field/well	C_1 % normalised	C_{3+} % normalised	H_2S %	CO_2 %	$\delta^{13}C$ CO_2
Arar	95.14	4.86			
Terembu	99.75	0.75			
Walio	78-93.48	6.5-22	1.33	4.31	
Salawati N	93.72	6.28		0.78	
Wir	97.1	2.9		20	
Lao-Lao	81.67	18.33	0.05		
Maniwar	81.33	18.67		0.28	
TBC	80	20			
Mogoi Deep	99.5	0.5		4.97-7.54	
Vorowata	88.4-96.7	3.3-11.6		0.26-11.9	-10.04 to -0.94
Wiriagar Deep	87-97	3-13		5.26-13.42	-7.07 to -2.7

Table 10 Gas composition in Papuan basins, data from Satyana et al. (2007).

In the Salawati Basin, hydrocarbon gas sourced from the Klasafet source contains the highest associated CO_2 (up to 20%). The CO_2 was sourced from thermal degradation of the Kais carbonate that has entered the over-mature window in the northern part of the basin.

Gas fields in the North Papuan Basin contain no appreciable CO_2 (Satyana et al., 2007).

2.4.11. Occurrence of CO_2 in western Sarawak and the Natuna basins

Many gas discoveries in western Sarawak contain high amounts of non-hydrocarbon gasses, mainly CO_2 (up to 88%) and N_2 (up to 39%). In the Tatau Province, the CO_2 appears to follow fault trends suggesting that these form deep seated migration pathways. High concentrations of N_2 are mainly found in the Tatau Province while it is relatively low in the remainder of the western Sarawak Shelf. The isotopic composition of the CO_2 suggests that it is predominantly inorganic in origin. There is a correlation between CO_2 content and thermal maturity suggesting that it was derived from a more deeply buried source (Madon & Hassan 1999). In the J32.1 discovery, high CO_2 content can be linked to a local source of carbonate dissolution by acidic pore fluid (Idris, 1991). The source of N_2 is less well understood but may come from deep crustal sources.

Field/well	C_1 % normalised	C_{3+} % normalised	H_2S %	CO_2 %	$\delta^{13}C$ CO_2
Tembang	98.06	1.04		0.85	
Udang	86.5	13.5		2.77	
Belut	73.3-99.2	0.8-26.7		0.17-0.62	

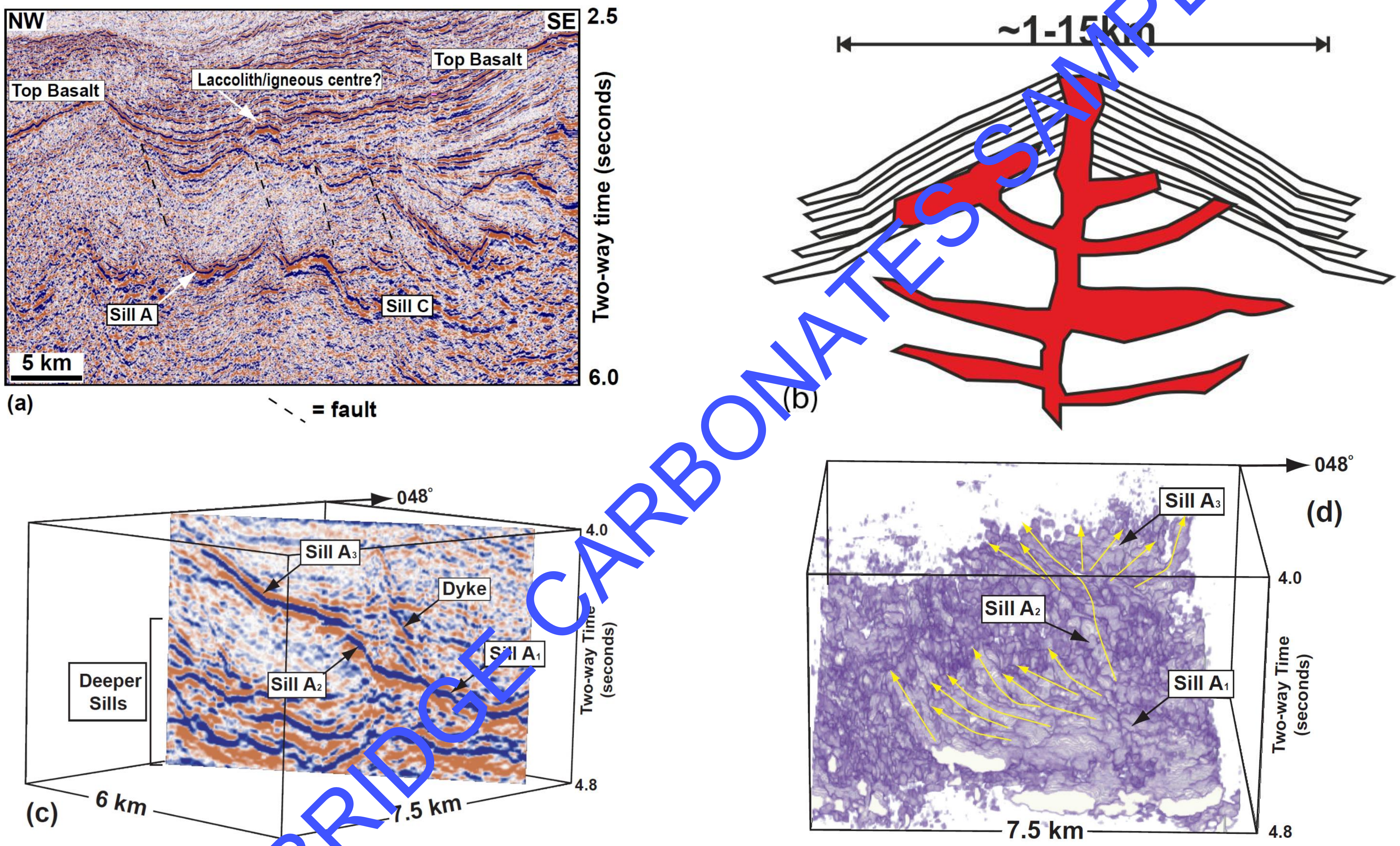


Figure 22 a) Key seismic facies can be observed in volcanic strata imaged in offshore settings such as basalt layering, sill feeders, volcanic centres and hyaloclastites (from Thompson and Schofield, 2008). b) Within the volcanic structure, igneous centres will contain a feeder system that contains high velocity bodies such as sills, dykes and small solidified magma chambers. The lavas on the flanks of the volcano will be a mixture of high and low velocity layers such as those in Figure 21. c) and d) Opacity rendering of the 3D seismic allows the structures within the volcanics to be examined (Thompson and Schofield, 2008). Such techniques may identify differences between carbonates and volcanics based on their preserved structures. Figures reproduced with permission.

Thomson, K. and Schofield, N., 2008, Lithological and structural controls on the emplacement and morphology of sills in sedimentary basins, Structure and Emplacement of High-Level Magmatic Systems, Geol. Soc. London, Special Publication, 302, p. 31-44..

Tonkin, P.C., Temansja, A., Park, R.K., 1992. Reef complex lithofacies and Reservoir, Rama Field, Sunda Basin, Southwest Sumatra, Indonesia. In: Siemers, C.T., Longman, M.W., Park, J.G., Kaldi, J.G. (Eds.), Carbonate rocks and reservoirs of Indonesia, Indonesian Petroleum Association Core Workshop Notes 1, Chap. 7.

Vahrenkamp, V.C., David, F., Duijndam, P., Newall, M. and Crevallo, P. 2004. Growth architecture, faulting, and karstification of a middle Miocene carbonate platform, Luconia Province, offshore Sarawak, Malaysia, in Seismic imaging of carbonate reservoirs and systems: AAPG Memoir 81, p. 329– 350.

Vincent, E. and Berger, W.H. 1985. Carbon dioxide and polar cooling in the Miocene: the Monterery hypothesis. In: Sundquist, E.T. & Broecker, W.S. (eds). The carbon cycle and atmospheric CO_2 – natural variations, Archaen to present. American Geophysical Union Monograph, 32, 455-468.

Wight, A.W.R., Hardian, D., 1982. Importance of diagenesis in carbonate exploration and production, Lower Batu Raja Carbonates, Krisna Field, Java Sea. Indonesian Petroleum Association, Proceedings 11th Annual Convention, 211– 236.

Wilgus, C.K., Hastings, B.S., Kendall, C.G.St.C., Posamentier, H.W., Ross, C.A. & van Wagoner, J.C. 1988. Sea level changes – an integrated approach. Special Publication of the SEPM No,42.

Wilson, M.E.J. 1996. Evolution and hydrocarbon potential of the Tonasa Limestone; Sulawesi. Proceedings of the Indonesian Petroleum Association, Annual Convention 1996 1.1-54 227-240.

Wilson, M.E.J. 2002. Cenozoic carbonates in South East Asia: implications for equatorial carbonate development. Sedimentary Geology, 147, 295-428.

Wilson, M.E.J. 2011. SE Asian carbonates: tools for evaluating environmental and climatic change in equatorial tropics over the last 50 million years. In: Hall, R., Cottam, M.A. & Wilson, M.E.J. (editors). The SE Asian Gateway: history and tectonics of the Australia-Asia collision. Geological Society Special Publication No.355 p347-372.

Wilson, M.E.J., and Evans, M.J. 2002. Sedimentology and diagenesis of Tertiary carbonates on the Mangkalihat Peninsula, Borneo: implications for subsurface reservoir quality. Marine and Petroleum Geology 19 (2002) 873–900

Wilson, M.E.J. & Hall, R. 2010. Tectonic influences on SE Asian carbonate systems and their reservoir development. In: Morgan, W.A., George, A.D., Harris, P.M., Kupecz, J.A. & Sarg, R. (editors). Cenozoic Carbonate Systems of Australasia. SEPM Special Publication No.95 p13-40

Yaman, F., Ambismar, T. and Bukhari, T. 1991. Gas exploration in Parigi and pre-Parigi carbonate build-ups, NW Java Sea. Proceedings of the Indonesian Petroleum Association, 20th Annual Convention, 319—346.

Zhang, T., Zhang, M., Bai, B., Wang, X. and Li, L. 2008. Origin and accumulation of carbon dioxide in the Huanghua depression, Bohai Bay Basin, China. Bulletin of the American Association of Petroleum Geologists. v. 92, p341-358.

Zheng, L. P., S. J. Wang, Y. S. Liao, and Z. J. Feng, 2001, CO_2 gas pools in Jiyang sag, China: Applied Geochemistry, v. 16, p. 1033– 1039.

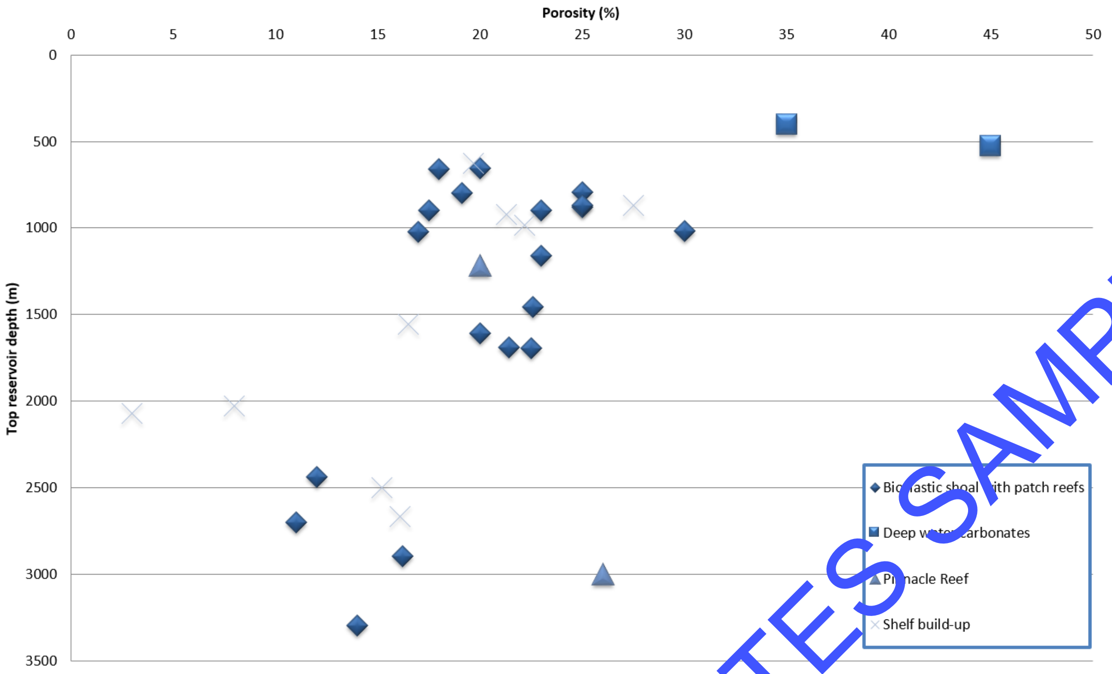


Figure 33 Average porosity vs depth as a function of reservoir type for carbonate reservoir examples in SE Asia

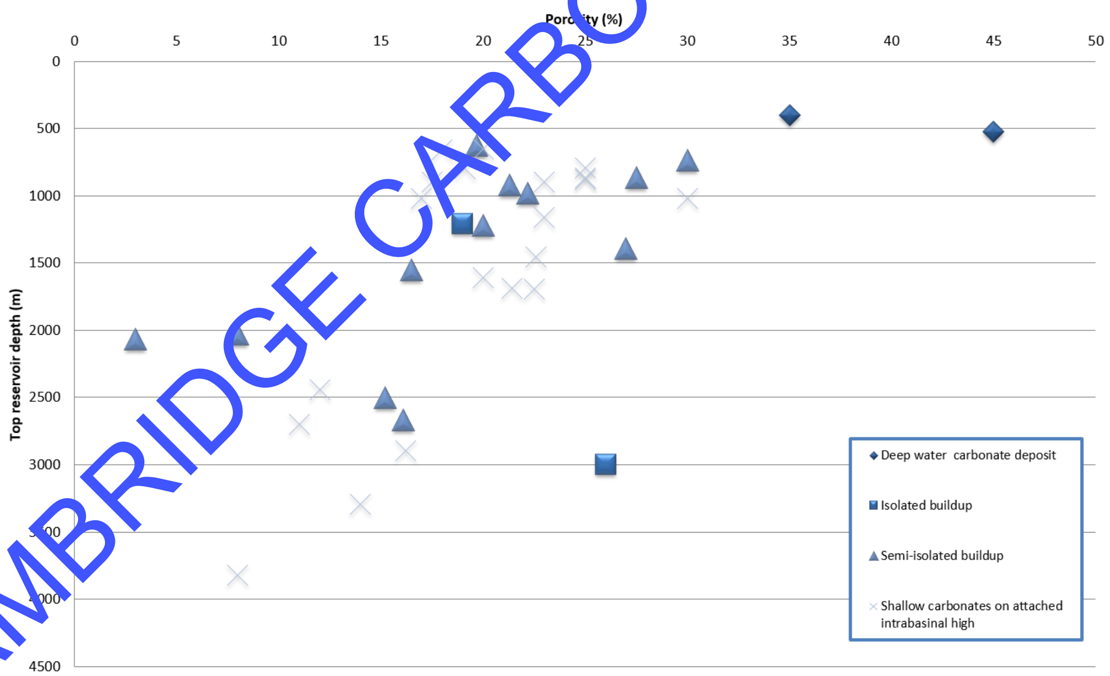


Figure 34 Average porosity vs depth as a function of depositional setting, for carbonate reservoir examples in SE Asia

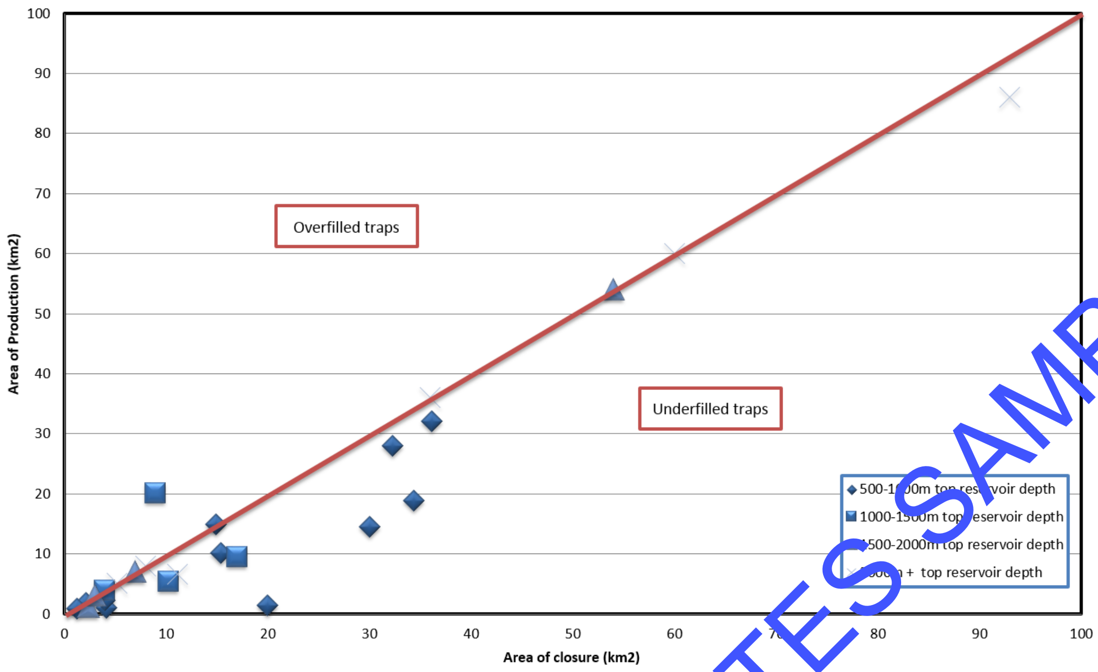


Figure 44 Area of closure vs area of production as a function of top reservoir depth, for carbonate reservoir examples in SE Asia

3.2.5. Reservoir thickness

Net:gross, net pay and gross pay can be plotted as a function of various attributes to try and determine trends. Reservoir formation appears to have a clear influence on net:gross and net pay (Figure 46). Although the Baturaja reservoirs tend to have some of the best reservoir quality in terms of porosity and permeability (see sections 3.2.1 and 3.2.2), they also appear to have some of the thinnest reservoirs (<40m net pay) with a low net:gross. Kais Formation reservoirs generally have thicker net pay (60-90m) with a wider ranging net:gross. Whilst Cibulakan reservoirs typically have a high net:gross, but a resultant wide ranging net pay. The Peutu and Mendi-Puri-Darai Formation examples (Arun Field and Elk-Antelope field respectively) stand out as having the thickest net pay, exceeding 150m in thickness. Although data points are fewer, similar relationships can be seen between gross pay and net:gross as a function of reservoir formation (Figure 48).

Net:gross can also be plotted versus top reservoir depth (Figure 47), but there are no apparent trends/relationships in this dataset.

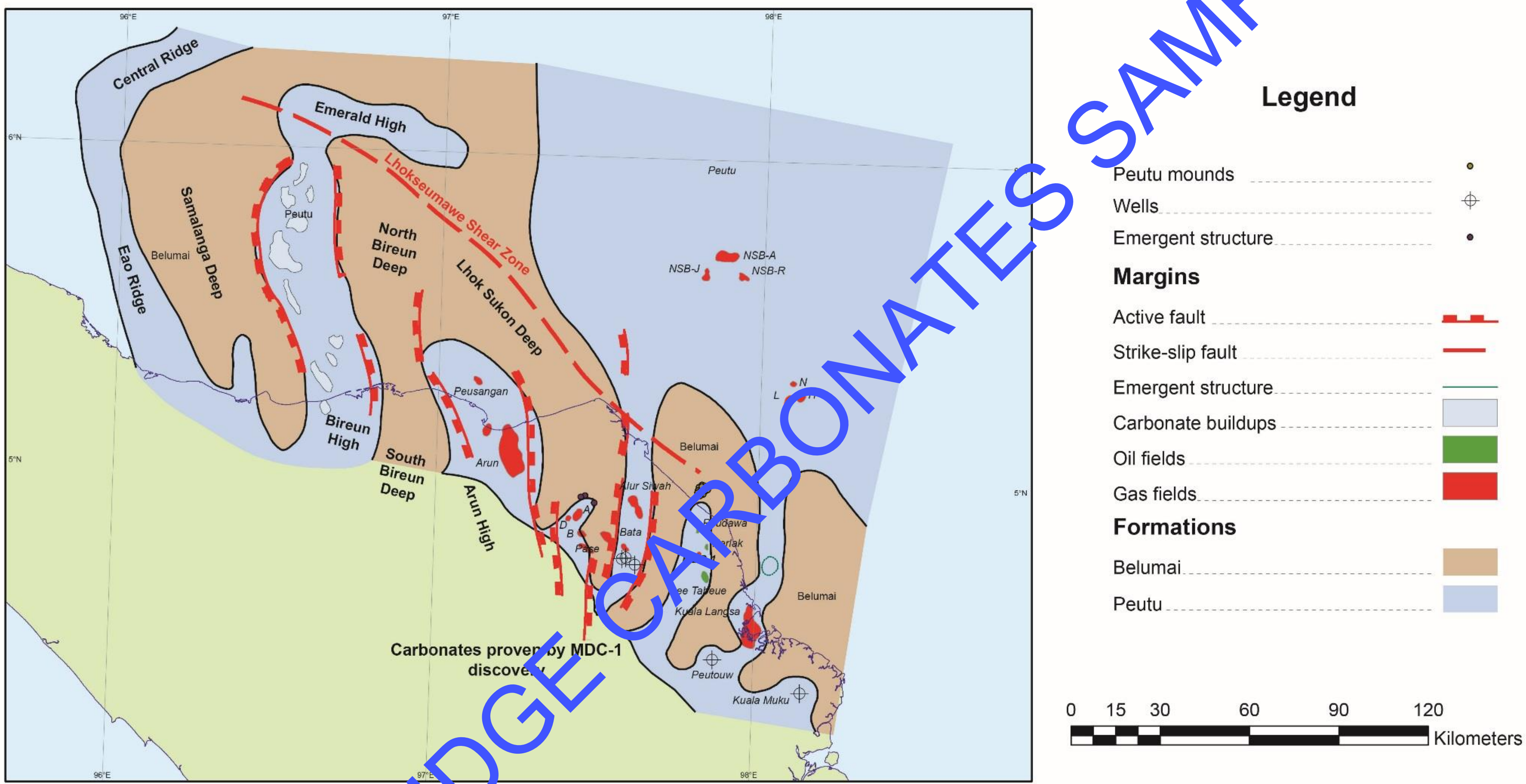


Figure 50 Early Miocene palaeogeography of the North Sumatra Basin. Modified from Caughey and Wahyudi (1993).

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
Lhok 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 5[illegible] m dolomite	13-2[illegible]% (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

Abdullah and Jordan (1987) and Jordan and Abdullah (1988) extrapolated their facies scheme to non-cored wells using resistivity logs and derived mixed lithology-porosity logs. They interpreted the Arun field as a mid-shelf reef located behind the rimmed eastern margin of the Arun-Cunda Platform recognising three phases of sedimentation (Figure 58):

- Lower 'patch-reef' complex formed on the shale-covered basement high.
- The northern patch reefs drowned during a rapid rise in sea level during the Mid-Miocene with the deposition of a large area of lagoonal sediment over the reef area.
- A lowstand during the end Middle Miocene caused establishment of reefs on the northern side of the field. Further sea level drop caused exposure to meteoric diagenesis.

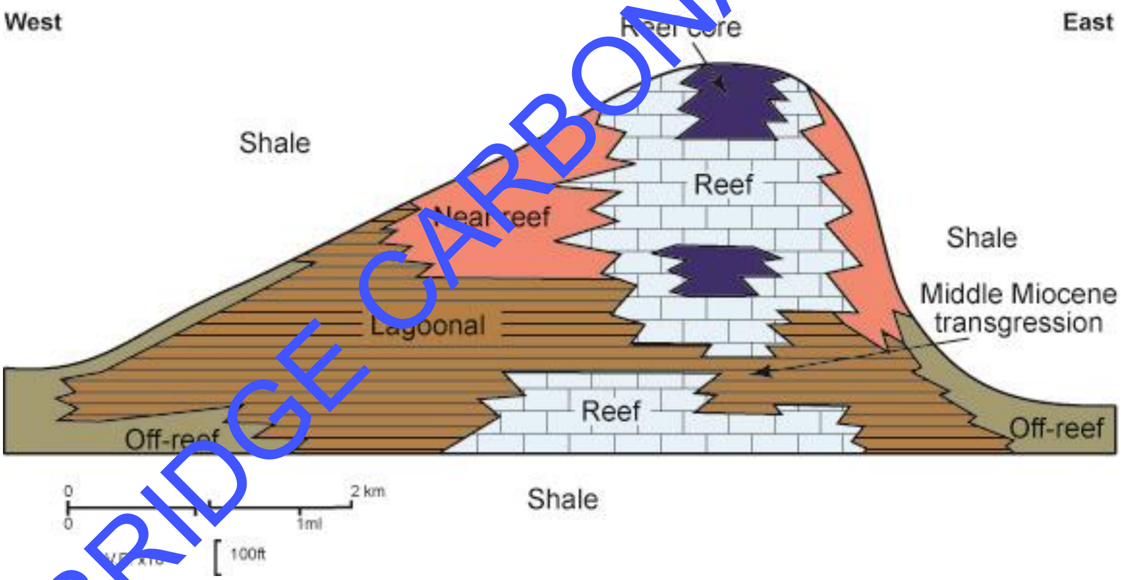


Figure 58 Reefal depositional model of the Arun reservoir (redrafted from Abdullah and Jordan, 1987; Jordan and Abdullah, 1988).

However, a review of data from Arun and other fields suggest that this reefal model may need to be re-assessed as follows:

- The presence of planktonic foraminifera in shelf interior facies suggests that it was part of a carbonate ramp or non-rimmed shelf system. The presence of a

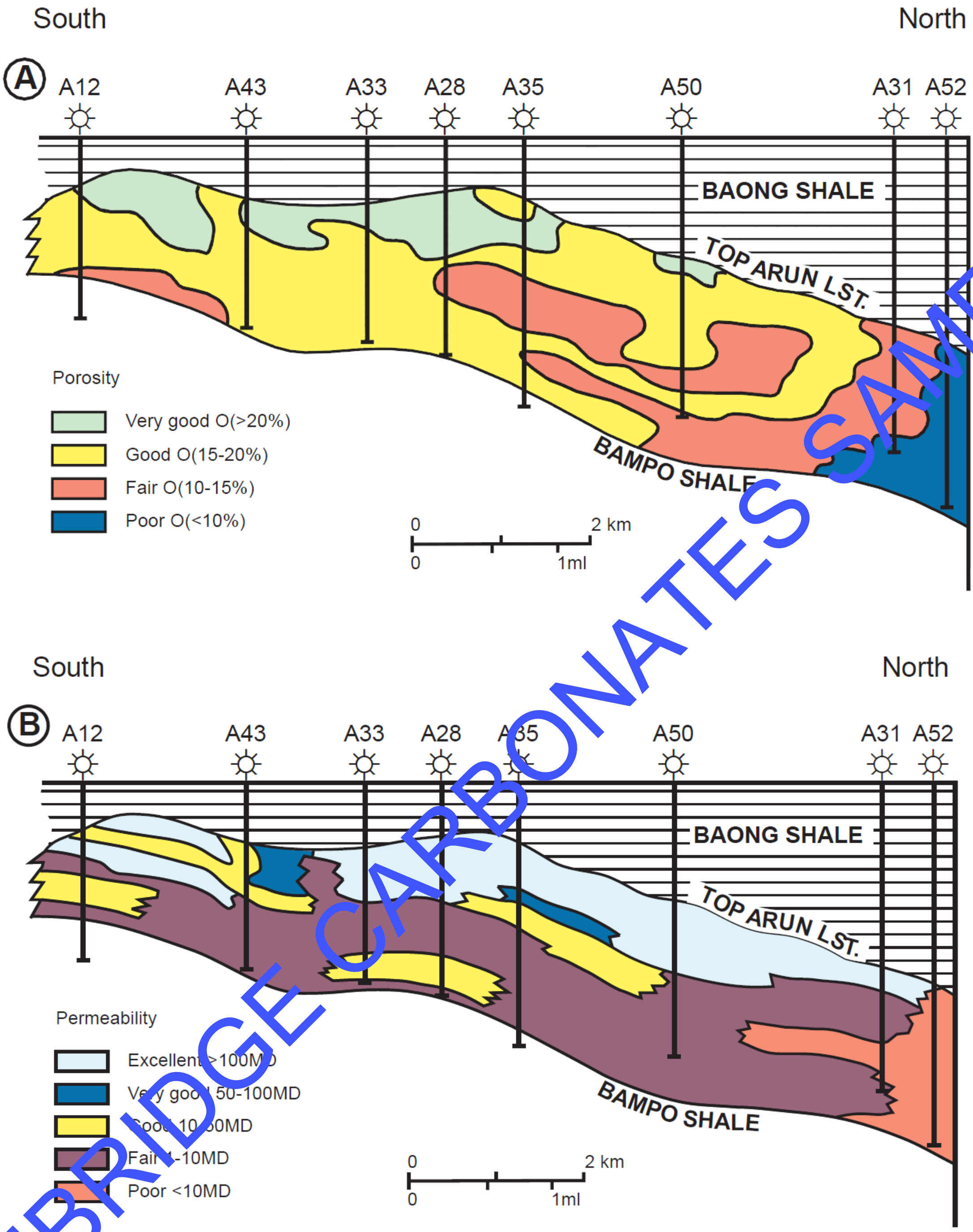


Figure 68 Distribution of (a) porosity and (b) permeability through the Arun reservoir (redrafted from Abdullah and Jordan, 1987; Jordan and Abdullah, 1988).

Cunda field	*Basin:* North Sumatra Basin	*Block:* Aceh B Block
Operator: ExxonMobil Oil Indonesia Inc		
No' wells on structure: 4		
Discovered: 1984, well A2a		
Produced since: N/A		
Current status: appraising gas discovery		
Geological setting: Back arc basin		
Top reservoir depth: 3637m		
Lithology: Limestone		
Reservoir type: Bioclastic shoal with patch reefs		
Reservoir age: Early Miocene		
Formation: Peutu Formation		
Depositional setting: Shallow carbonates on attached intrabasinal high	*Structure and trap type:* structural and stratigraphic	
Migration and Seal: Baong Formation marine shale seal	*Fill history:* Generation started Early Miocene continuing to present; peak generation Late Miocene.	*Source:* Oligo-Miocene deltaic marine Bampo Shale
Net pay: 102m	*Structural closure*: N/A	*Area of closure*: N/A *Productive area*: N/A
Net/Gross: N/A	*Gross pay*: 119m	*Reservoir depth*: 3637m
Pore system		
Matrix pore system: N/A	*Matrix porosity:* 13%	*Macroporosity:* N/A
Macropore system: N/A	*Matrix permeability:* N/A	*Macro-permeability:* N/A
Layering: N/A	*Bit drops:* N/A	*Mud losses*: N/A
Well performance		

Fontaine, H. Salih, A.M. and Hassan, S.S. 1992. Pre-Tertiary sediments founf at the bottom of wells drilled in the Melacca Straits. Unpublished PRSS report, no PRI/RP5/92-01

Fuse, A., Tsukada, K., Kato, W., Honda, H., Sulaeman, A., Troyer, S., Wamsteeker, L., Abdullah, M., Davies, R.C. and Lunt, P. 1996. Hydrocarbon kitchen and migration assessment of North Aceh offshore basin, North Sumatra, Indonesia from views on sequence stratigraphic and organic geochemisty. Proceedings of the Indonesian Petroleum Association, 25th Annual Convention, October 1996. IPA-1.0-016. 15-28.

Graves, R.R., Weegar, A.A., 1973. Geology of the Arun gas field (North Sumatra). Indonesian Petroleum Association, Proceedings 2nd Annual Convention, 53-72.

Hakim, F., Gunarto, M., Sompie, M. & Raharjo, S. 2014. Bireun High Complex, a rejuvenated carbonate province in offshore North Sumatra Basin. Proceedings, Indonesian Petroleum Association. 38th Annual Convention and Exhibition, May 2014. IPA14-G-177.

Hall, R. 1997. Cenozoic plate tectonic reconstructions of SE Asia. In: Fraser, A.J., Matthews, S.J. and Murphy, R.W. (eds). Petroleum Geology of South East Asia. Geological Society Special Publication No. No.126, 21-23.

Hatch, C.S. 1987. Technical evaluation and project summary for PM-1 Block, Straits of Malacca, Malaysia. Sun Malaysia Petroleum Company, Unpublished report ER:SUN:1:87-01

Hinton, L.B., Atmadja, W.S. and Suryo Suwito, P. 1987. Peusangan-C1 reef interpretation with top reef transparent to seismic. Proceedings of the Indonesian Petroleum Association, 16th Annual Convention, October 1987. IPA87-12/04. 339-361.

Houpt, J.R. and Kersting, C.C. 1976. Arun reef, Bee block. North Sumatra. Proceedings of carbonate seminar, IPA. 42-60

Jordan, C.F. Jr., and Abdullah, M., 1988, Lithofacies analysis of the Arun reservoir, North Sumatra, Indonesia. In: SEPM core workshop no. 12 (Houston, 19-20 03/1 988) Proc (Giant oil and gas fields) v1, pp89-117.

Kirby, G.A., Morley, R.J., Humphreys, B., Matchette-Downes, C.J., Sarginson, M.J., Lott, G.K., Nicholson, R.A., Yulihanto, B., Widiastuti, R., Karmajaya, Sundoro, Fitris, F., Sofyan, S. and Wijaya, Sri. 1993. A re-evaluation of the regional geology and hydrocarbon prospectivity of the onshore central North Sumatran Basin. Proceedings of the Indonesian Petroleum Association, 22nd Annual Convention, October 1993. IPA-1.008. 243-264.

Liew, K.K. 1994. Timing of Cenozoic basin formation in northern Sundaland, Southeast Asia. AAPG International Conference and Exhibition, Kuala Lumpur, Malaysia, 21-24 August 1994. Bulletin of the Geological Society of Malaysia, 37, 231-251

Madon, M.B.Hj., Ahmad, M.B. 1999. Chapter 10: Basins in the Straits of Melaka. In: The Petroleum Geology and Regional Resources of Malaysia. Petronas. 237-249

Maliki, M.A. and Sonowari, S. 1991. South Lho Sukon-D1 discovery, north Sumatra. Proceedings of the Indonesian Petroleum Association, No. 20, v1. 235-254.

Maridhona, H., Gumelar, Ricardo, M. & Miftahurochman. 2014. A new gas discovery in the early Miocene carbonate, North Sumatra Basin, Indonesia. Proceedings, Indonesian Petroleum Association. 38th Annual Convention and Exhibition, May 2014. IPA14-G-077.

McArthur, A.C. & Helm, R.B. 1982. Miocene carbonate buildups, offshore North Sumatra. Proceedings, Indonesian Petroleum Association. 11th Annual Convention and Exhibition, June 1982. p127-146.

Meckel, L.D. 2012. Exploring a 19th Century Basin in the 21st Century: Seeing the North Sumatra Basin with New Eyes. Search and Discovery Article #10464 (2012)

Meckel, L.D., Gidding, M, Sompie, M., Banukarso, M., Setoputri, A., Gunarto, M., Citajaya, N., Abimanyu, A. & Sim, D. 2012. Hydrocarbon systems of the offshore North Sumatra

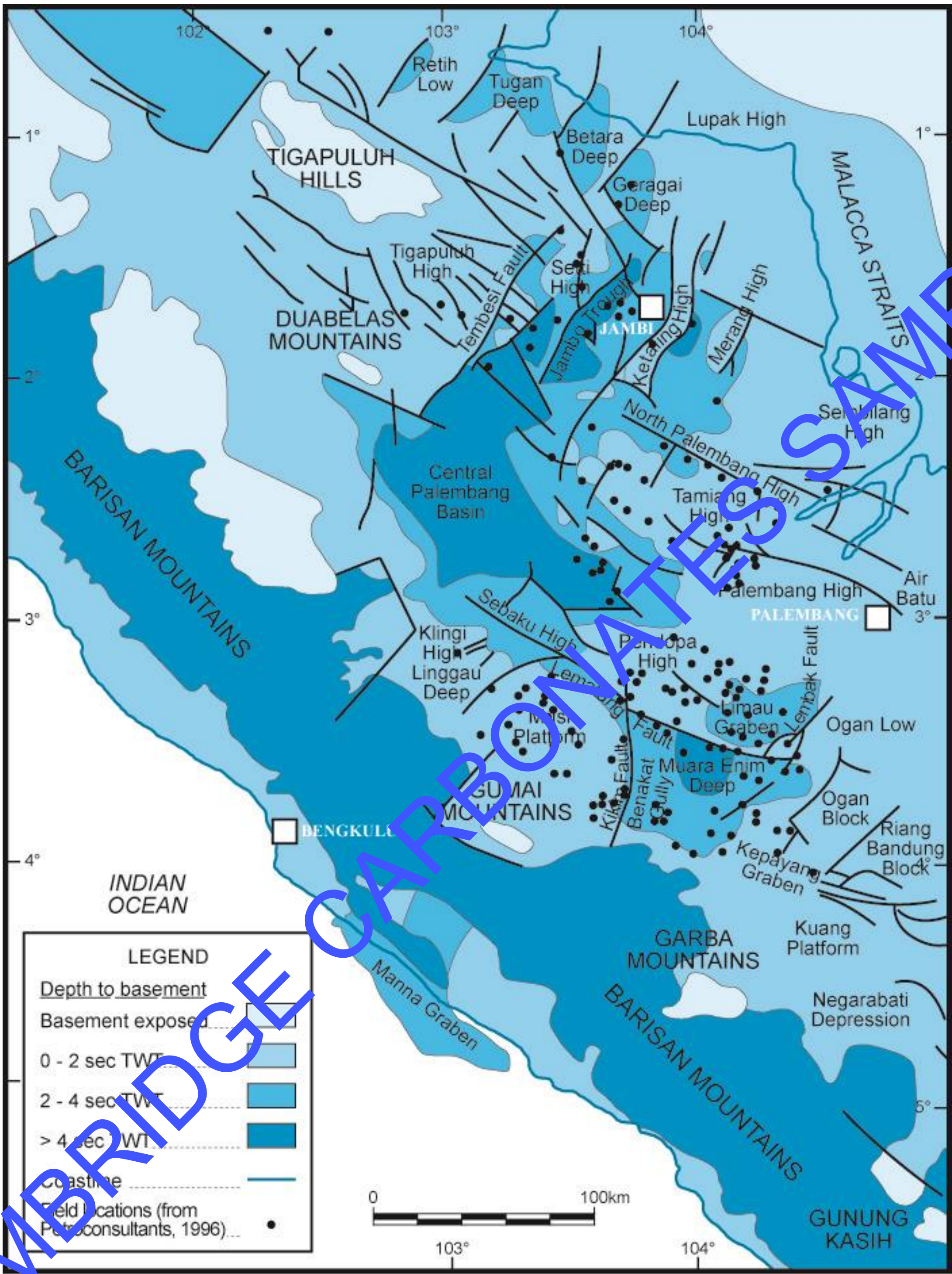
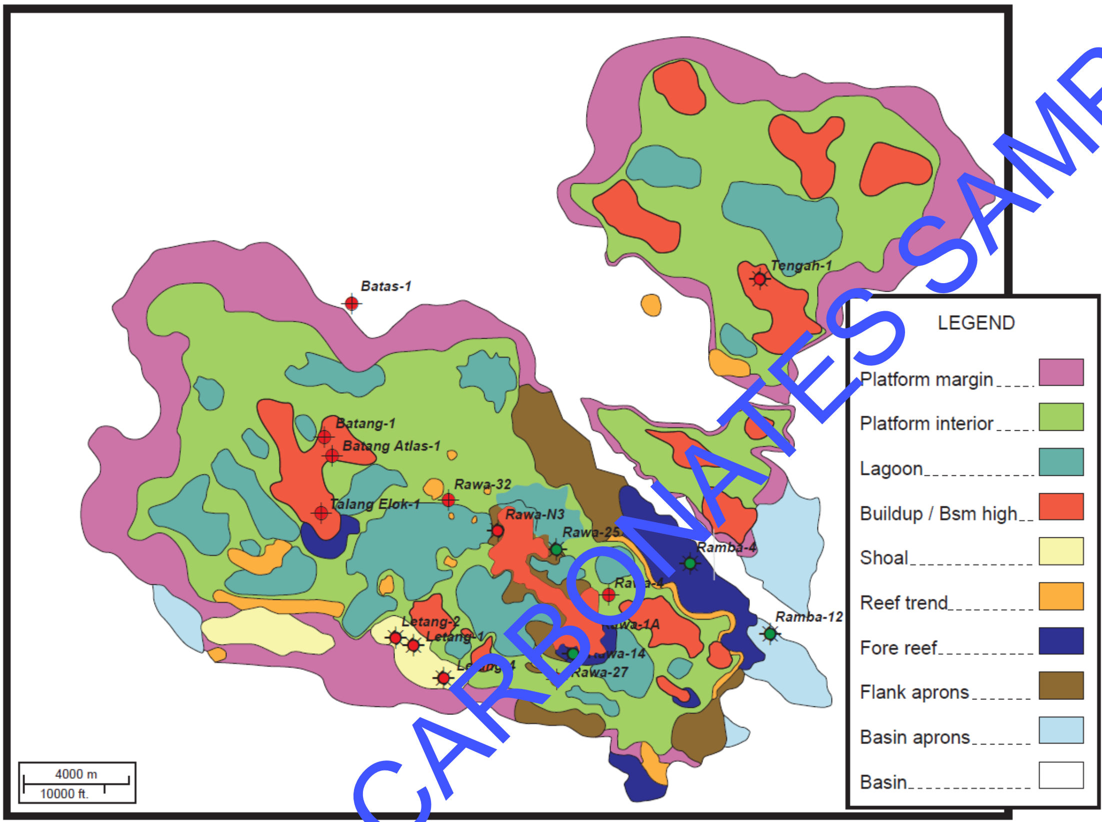


Figure 72 South Sumatra Basin basement structure (adapted from Barber and Crow, 2005).

outboard of these fields (Figure 77) – the limit of the platform margins are associated with regional faults. However, with no well penetrations in the interpreted platform margin facies, and only limited quality 2D seismic data to support this, the model is still open to scrutiny.



Facies	Description
Buildup/ reef	Argillaceous massive coral floatstones grading upwards to coral boundstone facies. May be represented by multiple cycles.
Forereef/ flank	Reworked skeletal packstones and wackestones, with interbeds of clastics, which coarsen upwards to coral floatstones or rudstone facies. Coral packstones locally occur at the top of the successions.
Shoal	Skeletal packstones/grainstones and peloidal grainstones which locally has components of coral and bryozoan boundstones and wackestones. Occurs predominantly on the leeward side of platforms.
Sand/Mud aprons	Skeletal packstones and wackestones with interbedded clastics. Typically capped by burrowed wackestones, packstones or floatstones.
Platform Interior	Very heterogeneous. Skeletal packstones and wackestones and common restricted lagoonal wackestone facies.
Lagoon	Argillaceous, bioturbated wackestones (degree of bioturbation dependant on restriction of the lagoon).
Basin	Skeletal packstones and wackestones interbedded with mudstones and clastic facies.

Figure 77 Depositional model and facies types for the Upper Baturaja Formation carbonates in the Ramba-Rawa-Tengah fields. Modified from Sanchez and Danudjaja (2013).

also been observed in core in the Ramba and Rawa fields, and is likely to be related to karst processes (Amir et al., 2011). Given the sequence stratigraphic framework described in Section 5.4.4, it would seem likely that there are several exposure surfaces within the Baturaja that could have resulted in meteoric diagenesis (Figure 76).

Chalky microporosity is also present near the top of the Baturaja in the Ramba field and is considered to represent transgressive micritic facies. It is unclear if the micrites already possessed this microporosity, or if it was created through diagenesis (Sitompul et al., 1992). If created through diagenesis, it seems unlikely that it would have been related to exposure, since this is interpreted as a transgressive facies that were presumably deposited after exposure (Figure 76). However, Amir et al. (2011) suggest that the chalky micrite is a product of meteoric diagenesis at the nearby Tengah field. Sitompul et al. (1992) conclude that gas migration and entrapment may have played a role in forming this porosity. Microporosity is common in many Cenozoic carbonate reservoirs of SE Asia, and is commonly considered to be created by flushing of organic acids in a deep burial setting.

Interestingly, Longman et al. (1992) play down the role of early meteoric diagenesis in the Air Serdang and Mandala fields (located on the Kedaton Platform). Although dissolution of aragonitic grains is present, they note that there are little other supporting data indicating freshwater diagenesis (i.e. no meniscus or pendant cements, no caliche or soil horizons, no speleothems). Longman et al. (1992) also note that some of the vugs and moulds in Air Serdang field are associated with stylolite horizons, and indicate that the same burial fluids responsible for the stylolites also created some of the mouldic and vuggy pores. Sudewo et al. (1987) note in several fields in South Sumatra, whilst an early leaching event is apparent, a later leaching event could be equally as important in preserving reservoir quality. Sudewo et al. (1987) suggest that CO_2-rich pore waters derived from thermal maturation of organic matter dispersed through the carbonate interval could be responsible for this late, secondary porosity.

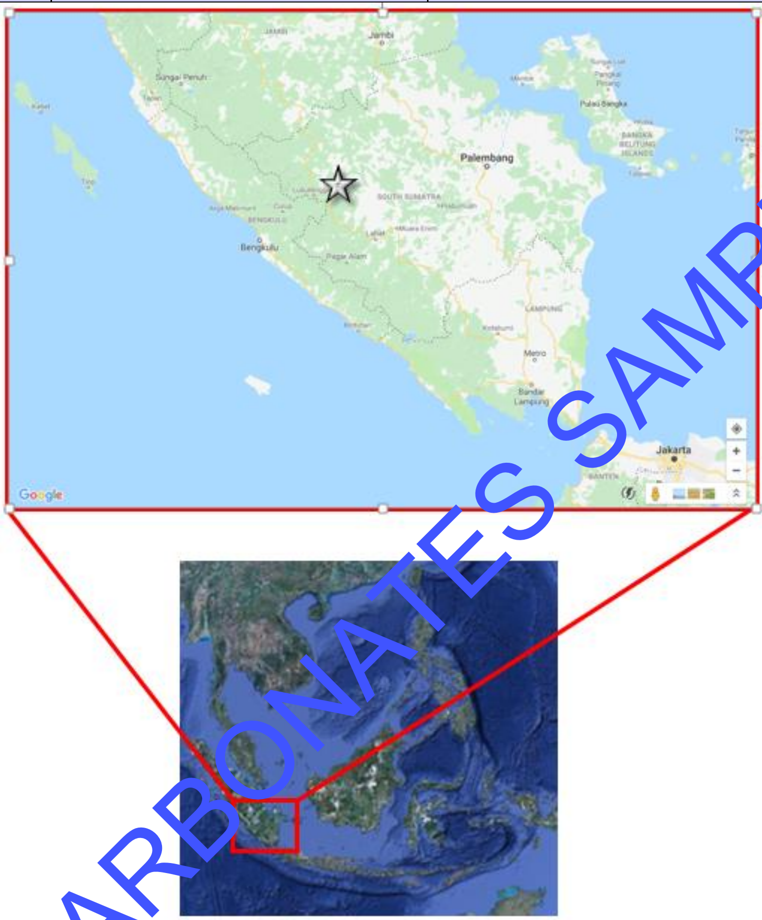
5.6. Field descriptions

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

Musi field	*Basin:* South Sumatra Basin	*Block:* Palembang
Operator: PT Pertamina EP		
No' wells on structure: 25		
Discovered: late 1938 (Musi-1)		
Produced since: N/A		
Current status: producing oil (1994)		
Geological setting: Back arc basin		
Top reservoir depth: 654mss		
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 and stratigraphic trap on basement high.	
Migration and Seal: N/A	*Fill history:* N/A	*Source:* N/A
Net pay: 150m (gas), 5m (oil)	*Structural closure:* 250m	*Area of closure:* 32.23 km^2 *Productive area:* 28 km^2
Net/Gross: 0.85	*Gross pay:* 183m	*Reservoir depth:* top 654mss base pay 837mss
Pore system		
Matrix pore system: N/A	*Matrix porosity:* 20%	*Macroporosity:* N/A
Macropore system: vugs	*Matrix permeability:* 3802mD	*Macro-permeability:* N/A
Layering: N/A	*Bit drops:* N/A	*Mud losses:* N/A
Well performance		

Well performance		
Initial rate: N/A	*Typical single well rate:* N/A	*Initial pressure:*
Well tests: 30.7 mmscfd gas from a 79m interval. Singa-3: high porosity carbonate (horizontal well).	*Test permeability:* N/A	*Average well rate:* N/A
Reservoir drive: N/A	*Decline:* N/A	*EOR:* N/A
Productivity index: N/A	*Performance:*	
Reserves		
Recoverable: N/A	*Initially in place:* N/A	*Recovery factor:* N/A
Cumulative production: N/A		
Field history: N/A		
Hydrocarbon type and formation fluid		
Hydrocarbon type: gas and condensate	*API:* N/A	*GOR:* N/A
S content: N/A	*Wax content:* N/A	*Pour point:* N/A
N_2: N/A	*CO_2:* 30%	*Other:* 110ppm H_2S
Methane: N/A	*Ethane:* N/A	*Propane:* N/A
IsoButane: N/A	*Gas cap:* N/A	*Biodegradation:* N/A
Formation volume factor: N/A	*Reservoir Temp:* N/A	*Reservoir pressure:* N/A
S_w: N/A	*R_w:* N/A	*Formation water salinity:* N/A
OWC: N/A	*GWC:* N/A	*GOC:* N/A
Water cut: N/A		*Recovery method:* N/A
Comments		
References		

Yanto, Y., Iswachyono, T., Arief MMZ, M., and Wood, J.J. 2011. Reservoir quality and porosity prediction in carbonate using seismic inversion and attributes case study: Singa field, South Sumatra Basin. IPA conference proceedings, IPA11-G-033.

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).

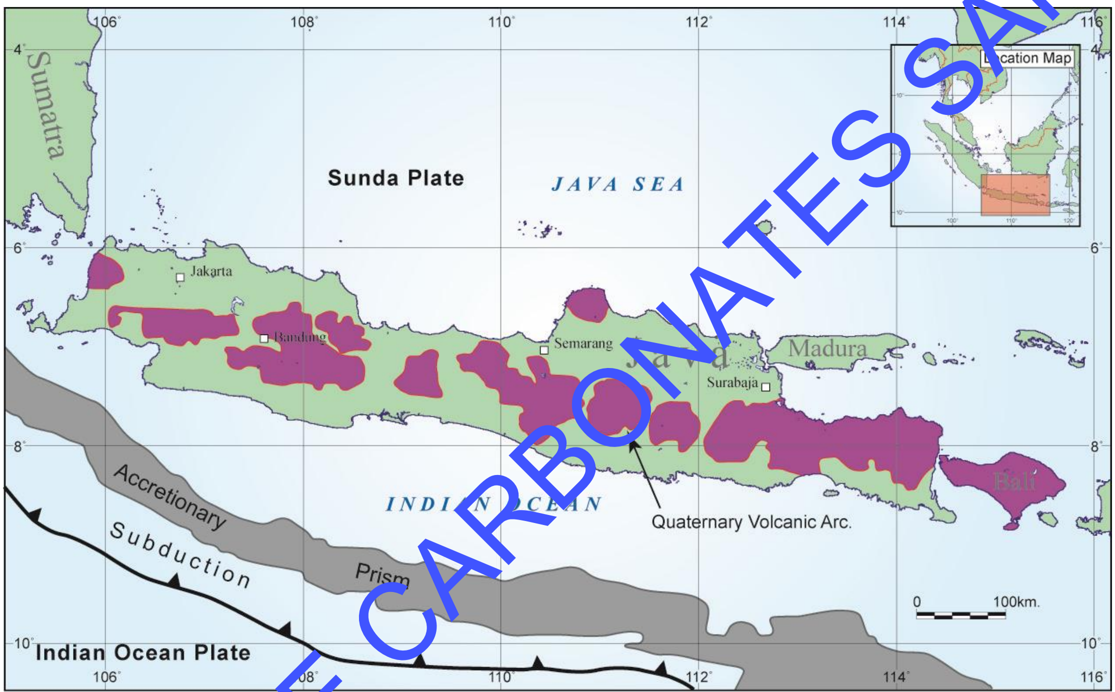


Figure 89 Geological setting of Java. An elongate volcanic arc is situated in the centre of Java, which in turn lies north of the subduction trench where the Indian Ocean plate is being subducted below Java. Modified from Wight et al. (1997).

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

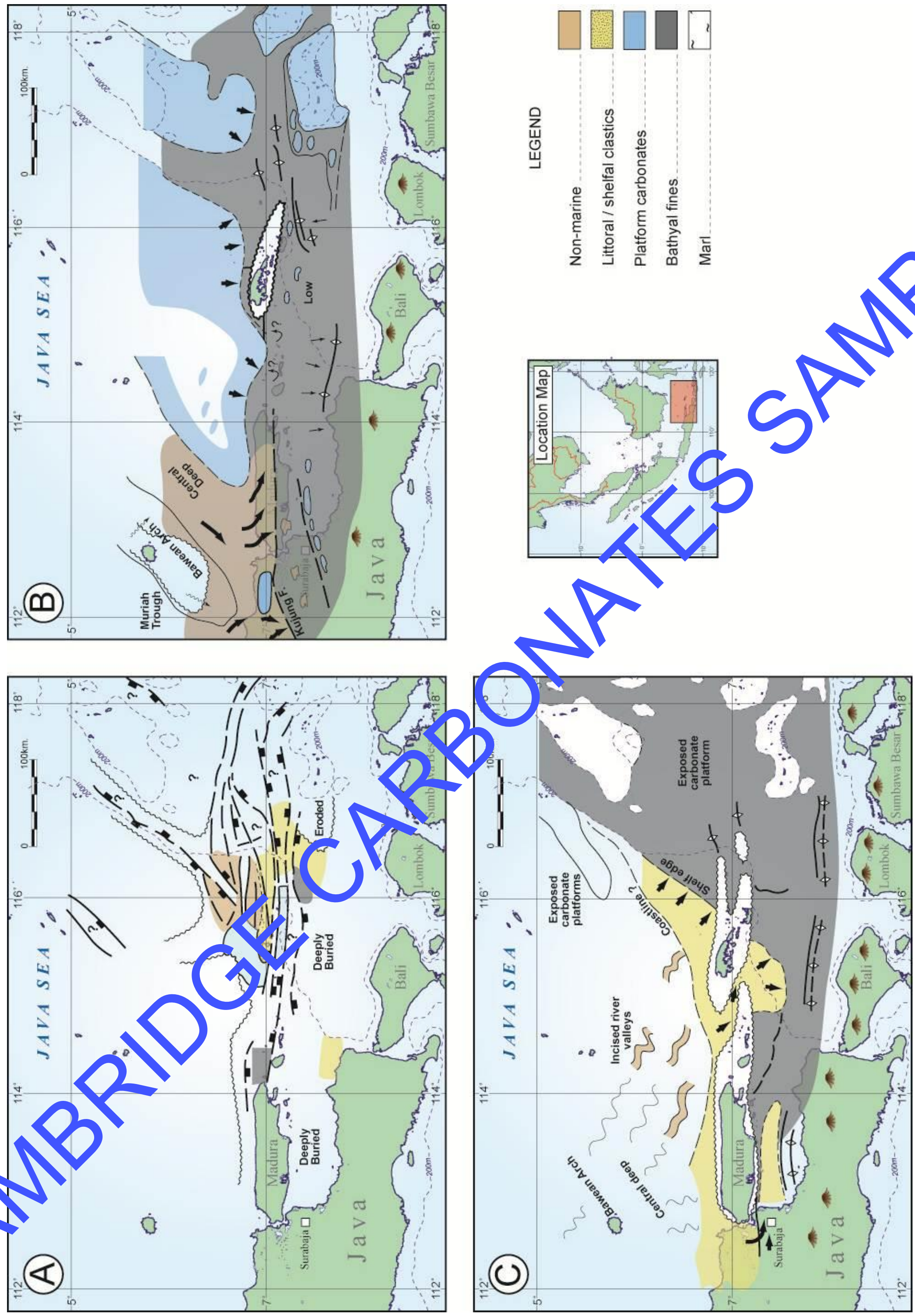
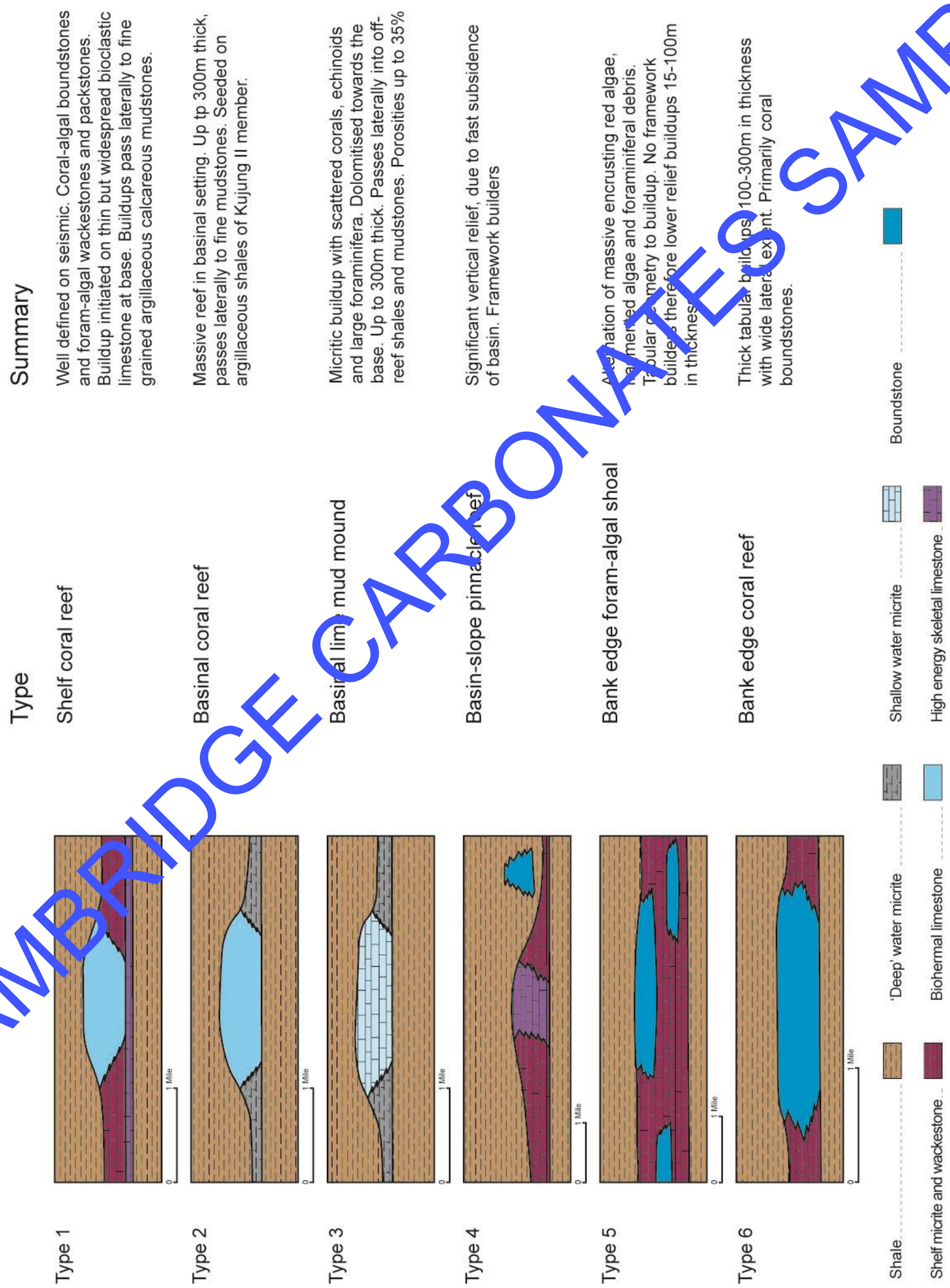


Figure 93 (a) Eocene palaeofacies, intra-Ngimbang Formation (b) Early Miocene palaeofacies (c) Early Pliocene palaeofacies. Adapted from Bransden and Matthews (1992).

which Zeiza et al. (2012) suggest a link bentween subsidence rate, stratigraphic age and reservoir quality in shallow isolated carbonate buildups. Subsidence plays a role because it controls the exposure to meteoric water and karstification. So carbonate buildups with high subsidence rates, identified by sediment thickness, tend to have poor reservoir quality.



EXAMPLE: BANYU URIP FIELD

Development drilling on the Banyu Urip field commenced in 2012. The field is a certified 1 BBO in place, making it the largest onshore discovery in Indonesia. The reservoir is an isolated carbonate buildup with an oil column of 939ft rising some 3000ft from the surrounding carbonate platform. The reservoir is highly layered with repeated 150ft thick cycles of shallow water carbonate that have undergone meteoric leaching to form high quality reservoir rock with an average porosity of 27% and 100mD permeability (Zeiza et al., 2016). The large ratio of column height to aerial foot print (1000ft tall to 1500 acres), the wells were drilled with a relatively close spacing of 50 acres per well. Water injection will take place in the water leg to maximise drainage. Karst-related macropore systems and associated mud losses are common with the majority of exploration and development wells experiencing bit drops or losses, sometimes up to as 20,000bbls (Ahdyar et al., 2019). The heights of karst featuresr averaged 1.5m and they are concentrated near sequence boundaries. Some karst features are resolvable on seismic suggesting that there is a higher probability of intersectiong karst features around palaeotopographic highs.

The Banyu Urip field is an isolated carbonate buildup in the East Java Basin developed in the late Middle Eocene to Early Miocene age Kujung Carbonate the comprises three main stratigraphic zones (Figure 104):

- Lower Aggrading Phase
- Aggrading Phase
- Drowning Phase

This consists of cyclic succession of shallow water carbonate facies including wackestone/packstone and coral-rich boundstone. Both the aggrading phases have a tight 'rind', referring to the platform margin facies cemented in the marine environment (Stephens et al. 2013). The drowing facies are dominated by deeper water platy coral and platy red algae interbedded with shallower water wackestone.

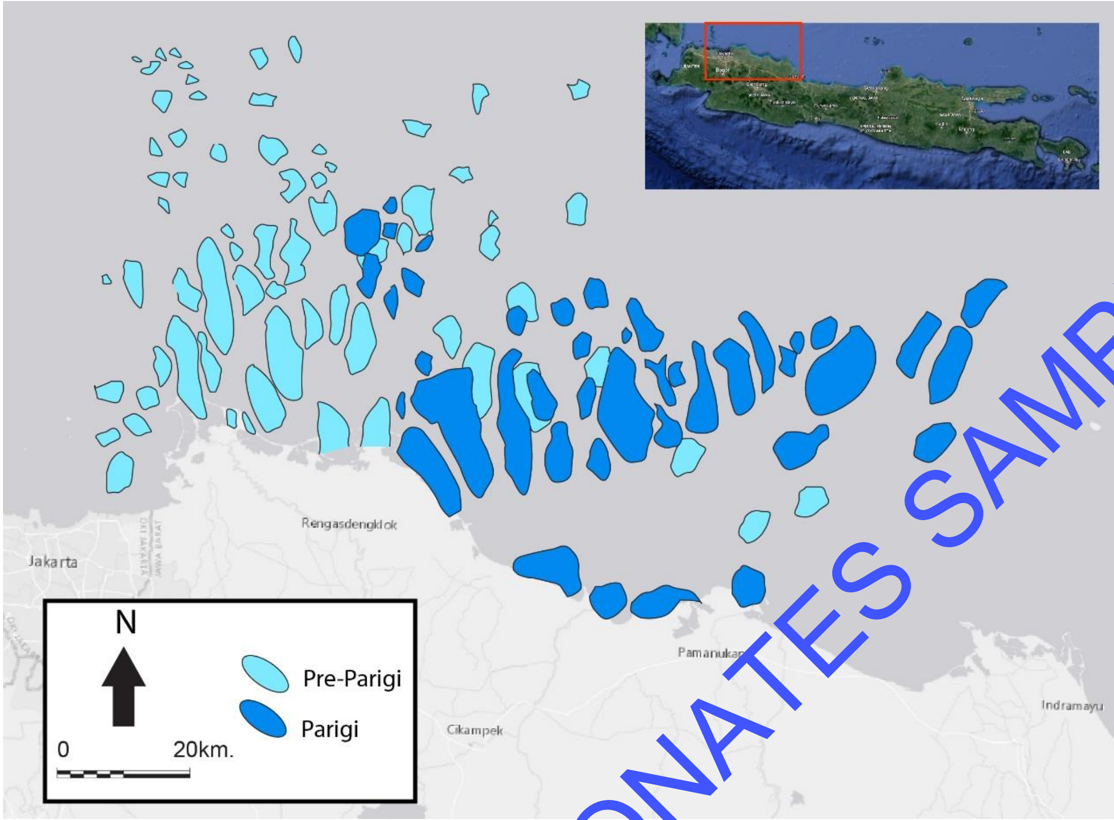


Figure 108 Location of the Pre-Parigi and Parigi buildups, Ardjuna sub-basin. Redrawn from Carter and Hutabarat (1994).

Internally, these complexes have three seismic facies (Carter and Hutabarat, 1994):

1. A low amplitude facies, with discontinuous lenses, high frequency and poor reflection continuity. It is thought that this seismic facies may represent localised organic buildups within the carbonate complex. Wells on the margins of these facies consist pebble sized clasts of red algae indicating potential organic buildups close by.
2. A layered facies which has moderate amplitude continuous reflections that are subparallel to the base and top of the complex. These represent a stack of low-relief sheet like units, which may represent reworked carbonate sediments surrounding the core of the complex.
3. A low-angle clinoform facies occurring along the margin of the complex. The clinoforms are approximately 600m in length and have a dip less than 5°.

Fisher and Suffendy (1998) reviewed the seismic character of known hydrocarbon accumulations in the south Arjuna Basin, and revealed a relationship between relative decreases in amplitude (dim spots) and presence of gas in post-stack 2D seismic. The

Parigi reservoir, porosity averages 30%, with permeabilities up to 2 darcies (Yaman et al., 1991; Bishop, 2000). Vuggy porosity is an important component, and lost-circulation is a common drilling problem in the most porous intervals (Suherman and Syahbuddin, 1986). Dolomites are locally present in some reservoirs, occurring as fine crystalline replacement dolomite and a later ferroan dolomite.

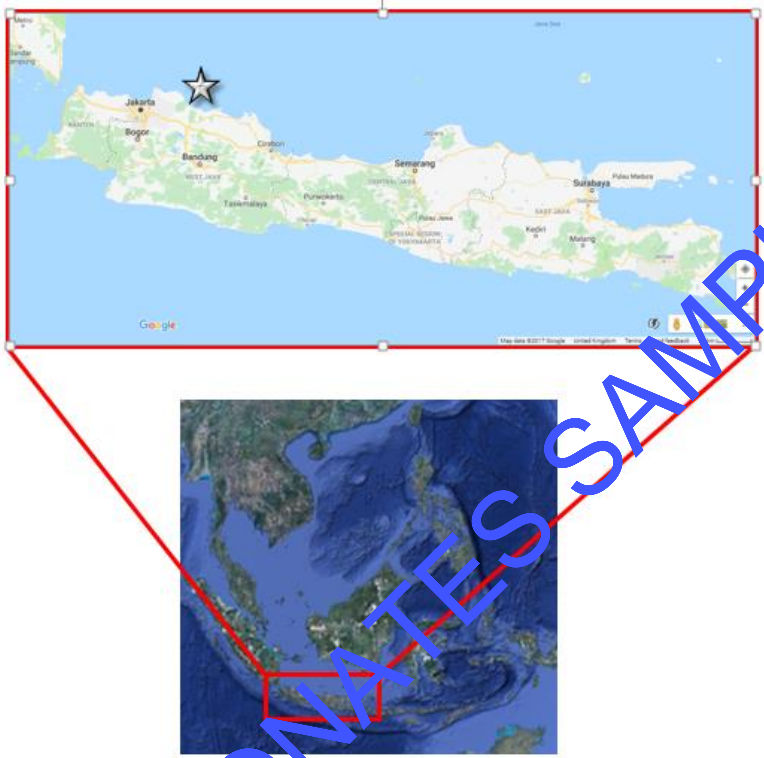
Reservoir quality in the Parigi reservoirs ranges from tight to good, with facies variably affected by cementation and creation of secondary porosity (Yaman et al., 1991). As with the Pre-Parigi, porosities can reach as high as 30%, with permeabilities up to 2 darcies. Porosity is mostly microporosity (intergranular and intercrystalline chalky) with additional secondary vuggy and mouldic porosity improving connectivity and permeability. Early dolomitisation is common to abundant, and generates intercrystalline porosity (Bukhari and Yaman, 1992). Calcite cements partially infill pore space.

Reservoir quality for a suite a lithofacies was documented in the Parigi buildups by Bukhari et al. (1992).

1. **Bioclastic peloidal packstone to grainstones.** Cementation is common, and infills interparticle and vuggy pores. Leaching pre-dated cementation, and is characterised by formation of moulds through aragonite dissolution. Some moulds remained uncemented, giving this lithofacies a porosity range between 12-38%. Mouldic macropores are up to 30%, vuggy pores up to 10%, and the remainder is matrix or intercrystalline pores.

2. **Bioclastic wackestone to packstone.** Cementation is not as prolific as in lithofacies 1, due to the more muddy nature of the lithofacies. Replacement by dolomite is locally present. Late diagenetic dissolution results in porosities ranging from 12-35%. Microporosity is the main contributor. Up to 15% mouldic or vuggy macropores are present.

3. ***Amphistegina* wackestone to packstone.** Porosities range from 6-40%, with the majority represented as microporosity. Leaching provides macropores which can contribute up to 10% of porosity. Late dissolution created additional mouldic and vuggy porosity.

Arjuna BZZ field	*Basin:* NW Java Basin	*Block:* N/A
Operator: PT Pertamina Hulu Energi ONWJ Ltd		
No' wells on structure: 23		
Discovered: 1994 (BZZ-1)		
Produced since: N/A		
Current status: 1995: producing oil and gas		
Geological setting: Back arc basin		
Top reservoir depth: 1692.1mss		
Lithology: Limestone and sandstone		
Reservoir type: Bioclastic shoal with patch reefs		
Reservoir age: Early Miocene		
Formation: Baturaja and Talang Akar		
Depositional setting: Shallow carbonates on attached intrabasinal high	*Structure and trap type:* Structural and stratigraphic	
Migration and Seal: N/A	*Fill history:* N/A	*Source:* N/A
Net pay: 76.5m	*Structural closure*: N/A	*Area of closure*: N/A *Productive area*: N/A
Net/Gross: 0.75	*Gross pay*: N/A	*Reservoir depth*: top 1692.1mss base pay 2256.1mss
Pore system		
Matrix pore system: N/A	*Matrix porosity:* 20-25%	*Macroporosity:* N/A
Macropore system: vugs	*Matrix permeability:* 700mD	*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:* 3180 psia at 2240.9m

Hydrocarbon type: N/A	*API:* 36°	*GOR:* N/A
S content: 0.1%	*Wax content:* 4.9%	*Pour point:* N/A
N_2*:* N/A	CO_2*:* 0.1%	*Other:* Specific gravity (gas): 0.85; H_2S: none
Methane: 1.5%	*Ethane:* N/A	*Propane:* N/A
IsoButane: N/A	*Gas cap:* N/A	*Biodegradation:* N/A
Formation volume factor: N/A	*Reservoir Temp:* 170 °F (Bottom hole temp. in Camar-1)	*Reservoir pressure:* N/A
$S_{w:}$ N/A	$R_{w:}$ 0.2 Ωm at 100 °F	*Formation water salinity:* N/A
OWC: Multiple OWCs in complex layered reservoir.	*GWC:* N/A	*GOC:* N/A
Water cut: N/A		*Recovery method:* N/A

Comments

After being shut down since late 2004, the Camar field in the Bawean block, East Java, resumed production in Q2 2007 starting at 1,000 BOPD

References

Caughey, C.A., Dyer, J.N.J., Kohar, A., Lestarini, H., Lodwick, W.R., Prijosoesilo, P., Wight, A.W.R. and Wilson, J.N. (editors) 1996. Seismic Atlas of Indonesian oil and gas fields, Volume 2: Java, Kalimantan, Natuna and Irian Jaya. Indonesian Petroleum Association.

Carter, D.C, Mandhiri, D., Park, R.K., Asjhari, I, Basyuni, S., Birdus, S., Bardfield, J.P., Iriawan, A, Nasfiah, M and Nugroho, M.A.A. 2005. Interpretation methods in the exploration of Oligocene-Miocene carbonate reservoirs, offshore Northwest Madura, Indonesia: IPA 30th Convention proceeding, 179-215

Satyana, 2005. Oligo-Miocene carbonates of Java, Indonesia: Tectonic-volcanic setting and petroleum implications. IPA05-G-031, 217-249.

S content: Upper Baturaja 0.07% Lower Baturaja 0.13%	*Wax content:* Upper Baturaja 20.69% Lower Baturaja 18.26%	*Pour point:* Upper Baturaja 35 °C Lower Baturaja 36 °C
N_2: Upper Baturaja 0.93vol % Lower Baturaja 1.16 vol %	*CO_2:* Upper Baturaja 2.59 vol % Lower Baturaja 5.22 vol %	*Other:* Oil viscosity: Upper Baturaja 2.7cp at 1810 psig 99 °C Lower Baturaja 2.22cp at 2064 psig 108 °C; Specific gravity (gas): Upper Baturaja 0.7617 Lower Baturaja 0.7494; Calorific value: Upper Baturaja 1249 BTU/cuft Lower Baturaja 1160 BTU/cuft
Methane: Upper Baturaja 76.44 vol % Lower Baturaja 77.29 vol %	*Ethane:* Upper Baturaja 9.00 vol % Lower Baturaja 7.56 vol %	*Propane:* N/A
IsoButane: N/A	*Gas cap:* N/A	*Biodegradation:* N/A
Formation volume factor: N/A	*Reservoir Temp:* Upper and Lower Baturaja: 99 °C	*Reservoir pressure:*
S_w: N/A	*R_w:* Upper Baturaja 0.1 Ωm at 99 °C Lower Baturaja 0.11 Ωm at 99 °C	*Formation water salinity:* N/A
OWC: Lowest known oil: 1378m ss	*GWC:* N/A	*GOC:* N/A
Water cut: N/A		*Recovery method:* N/A

Comments

The seismic response to variations in lithology is complex and non-unique in the Krisna-Yvonne fields. Consequently seismic attributes, in isolation, have no unique interpretation. Welker-Haddock, 1996.

Using a stochastic methodology it was possible to show that rock type distribution in the skeletal mound facies association controlled porosity and permeability distribution. The study determined that rock type, porosity, and permeability distribution are the main factors controlling heterogenity and connectivity in the UBR reservoir. The study results will be used as the main input to a dynamic simulation for water injection and further development planning in Krisna Field. Ageng et al, 2014.

References

Ageng, C., Hairunnisa, Hidayat, D., Nurgroho, D., Indro Basuki, N., Facies Analysis, Rock Type, and Property Distribution in Upper Interval of Baturaja Formation, Krisna Field, Sunda Basin. Proceedings Indonesian Petroleum Association. Twenty Eigth Annual Convention, May 2014. IPA14-G-055

Ardila, L.E., (1983) The Krisna High: Its Geologic Setting and Related Hydrocarbon Accumulations. SEAPEX Proceedings, Volume 6, 1983, p 10-23.

Formation, Offshore Northwest Java. Indonesian Petroleum Association, Proceedings of the International Symposium on Sequence Stratigraphy in SE Asia. 311-325

Carter, D., and Hutabarat, M., 1994, The geometry and seismic character of mid-Late Miocene carbonate sequences, SS area, offshore northwest Java: Proceedings of the Twenty Third Annual Convention Indonesian Petroleum Association, v.1, p. 323-338.

Carter, D.C, Mandhiri, D., Park, R.K., Asjhari, I, Basyuni, S., Birdus, S., Bardfield, J.P., Iriawan, A, Nasfiah, M and Nugroho, M.A.A. 2005. Interpretation methods in the exploration of Oligocene-Miocene carbonate reservoirs, offshore Northwest Madura, Indonesia: IPA 30th Convention proceeding, 179-215

Caughey, C., Dyer, J.N.J., Kohar, A., Lestarini, H., Lorentz, R.A., Lodwick, W.R., R., Prijosoesilo, P., Wight, A.W.R. & Wilson, J.N. 1995. Seismic atlas of Indonesian oil and gas fields, volume 2: Java, Kalimantan, Natuna and Irian Jaya. Indonesian Petroleum Association, Jakarta.

Cavalin, D., Ismail, N., Paten, T., Agbebi, K. and Lim, D. Application of fill waveform inversion to resolve and eroded shallow carbonate platform, North Madura, East Java, Indonesia. Proceedings of the Indonesia Petroleum Association 43rd Annual Conference 2019

Chaoyang, Z., Pengxiao, S., Xiaohong, S., Shuliang, W., Donglin, Y. and Liqun, H. 2013. Case study: can we use angle gathers to detect fracture distribution of carbonate reservoir in Rama field? Indonesian Petroleum Association Proceedings, IPA13-G-102

Clements, B., Hall, R., Smyth, H.R., Cottam, M.A. 2009. Thrusting of a volcanic arc: a new structural model for Java. Petroleum Geoscience, v15, 159-174

Courteney, S., Cockcroft, P., Miller, R., Phoa, R. S. K., and Wight, A. W. R., eds., 1989, Indonesia Oil and Gas Fields Atlas Volume IV: Java: IPA Professional Division Oil and Gas Fields Atlas Sub-Committee, 249 pp

Crumb, R.E. 1989. Petrophysical properties of the Bima Batu Raja carbonate reservoir, offshore NW Java. Proceedings Indonesian Petroleum Association. IPA 89-22.06 p161-208

Darmawan, F.H., Ardana, I.W., Shen, L.C. and Wijaya, A.K. 2016. Unravel the Olig-Miocene depositional architectures in the North Madura Platform using stratal volume. Proceedings of the Indonesia Petroleum Association, Fortieth Annual Convention and Exhibition, May 2016. IPA-16-629-G.

Darmanwan, F.H., Mustafa, S.B., Wijaya, A.K., Juliansyah, M.N., Kaeng, G. and Probawanto, D.B. 2019. Facies and strigraphic controls on velocity anomalies in the North Madura Platform, offshore East Java Basin. Proceedings of the Indonesia Petroleum Association 43rd Annual Conference 2019.

Doust, H. and Noble R.A. 2008. Petroleum systems of Indonesia. Marine and Petroleum Geology, 25, 103-129.

Doust, H. And Sumner, H.S. 2007. Petroleum systems in rift basins – a collective approach in Southeast Asian basins. Petroleum Geoscience, 13, 127-144.

Elicia, R., Yunita, A., Rahmandani, U., Hutama, R.D. and Widodo, B.T. 2019. Oil Seepages from Thrusted Anticlines; Carbonates of Wonocolo and Bulu Formations, East Java Basin. Proceedings, Indonesian Petroleum Association, 43rd Convention, 2019.

Fikri, R., Aulia, F., Natawijaya, M., A., Ditya, A. and Prakasa, Y. 2020. Successful Geological strategy for setting casing prior to approaching Kujung Carbonate in Jambaran field, Cepu Block. Proceedings, Indonesian Petroleum Association, Digital Technical Conference, 14-17 September 2020.

Firdani, A.I., Affandi, A.K., Irawan, E.W., Kamal, Haider, M.W. and Yulisasongko, M.F. 2015. Uncertainty anlysis for top Tuban carbonate prerdiction using velocity modelling

- Late Pliocene N19/21[d?-e] – the Selorejo Fm. This may be influenced by global lowstand at 2.4 or 3.0 myrs when both storm and normal wave bases were lowered causing enhanced winnowing of deep water sediment (Schiller et al., 1994; Musliki and Suratman, 1996). Bransden and Matthews (1992) interpret winnowed globigerinid sands as early transgressive deposits when deep water currents would also be amplified causing winnowing in deep water. They gave a Late Miocene to Pliocene age (N15/20) for these globigerinid sands in the Selorejo Formation. However, the difference in dating of the same deposits by Bransden and Matthews (1992) and Schiller et al. (1994) may be the result of differing interpretations of the sequence stratigraphic context of the globigerinid sands.

Tectonism also plays a role in contourite deposition by re-configuring the basin such that causing deep marine currents are amplified or diverted so that winnowing and transportation of pelagic sediments by traction is increased. Similarly, lowering of sea level stands causes the lowering of normal and storm wave bases with the possibility of much deeper wave and storm reworking than during highstands.

7.3. Hydrocarbon Geology

7.3.1. Exploration History

Hydrocarbons have been discovered and produced in Pliocene deep water deposits since the late 1800s, with many of these onshore fields now abandoned (Table 17). The largest field was the Lidah Field with some 16.2MMBO of cumulative production, which is quite impressive given the outdated drilling and development practices of the time (Schiller et al., 1994). In the 1930s, discoveries were made in the Cepu area, notably the Balun field, which produced gas and condensate.

Discoveries were later made in the offshore settings of the Madura Straits in the 1980s. MDA-1, MDA-2/2ST, MDB-1 and KE-11A all encountered porous globigerinid facies that were hydrocarbon bearing (Schiller et al., 1994). Since 1980, 25 exploration

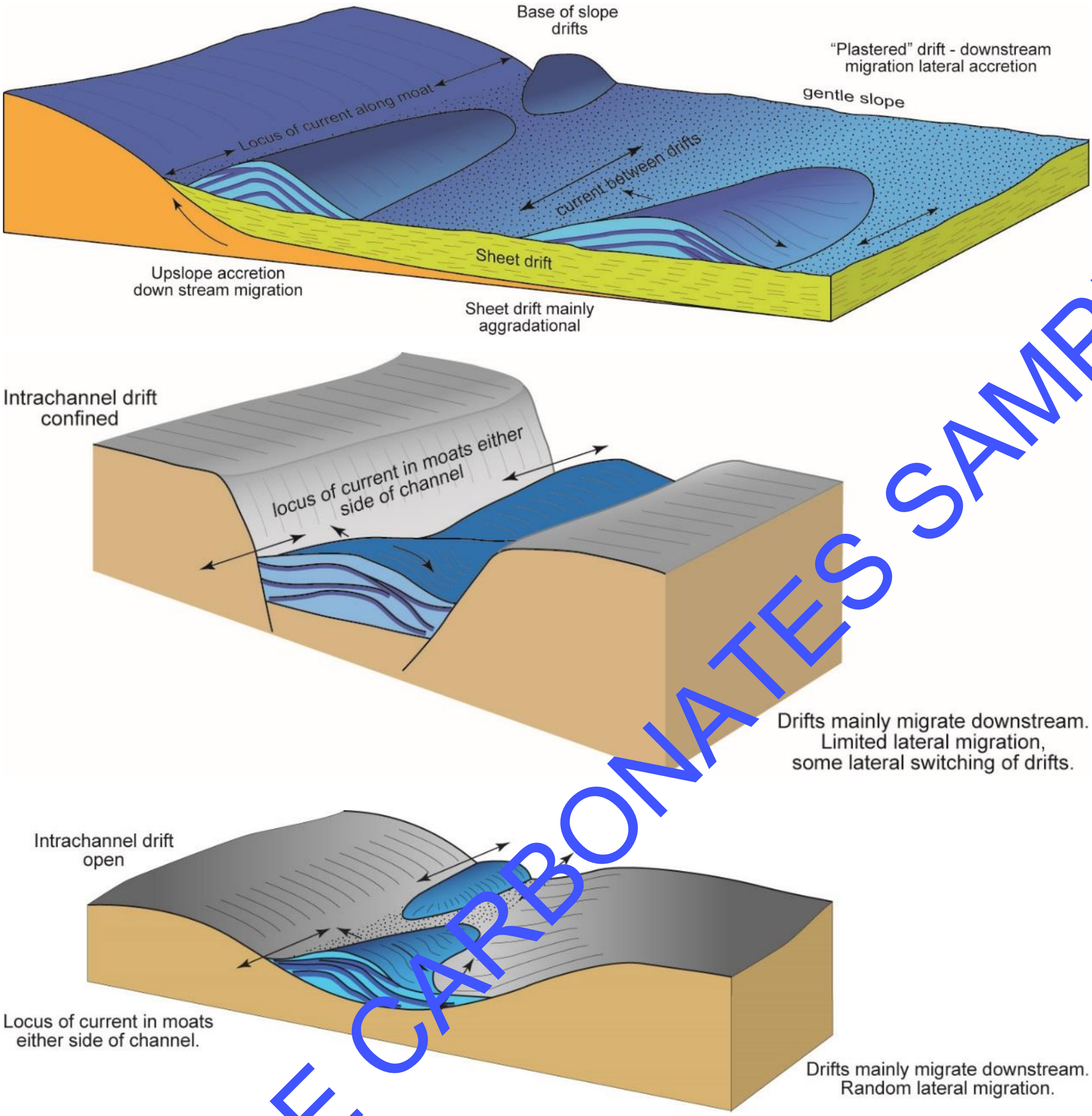


Figure 120 Geometry and depositional setting of contourite drifts modified from Faugères et al. (1999). a) Top; Sheet and 'plastered' drifts on continental rise and mounded drift at base of slope. b) Middle; Mounded drifts in confined channel. c) Bottom; mounded drifts in more open channel.

Comparison of contourites and turbidites

The key differences between contourites and turbidites are listed below and illustrated by outcrop and sub-surface examples from Java (Figure 121) detailed descriptions of the lithology and sedimentary structures of these sections are given in Table 19:

- Carbonate turbidites are generally deposited in submarine channels and fans with erosional bases. Whereas contourite deposits often have gradational bases.

7.6. Field descriptions

Madura MDA field	*Basin:* East Java Basin	*Block:* Madura Straits
Operator: Husky-CNOOC Madura Ltd		
No' wells on structure: 3		
Discovered: 1984		
Produced since: not yet in production		
Current status: discovery		
Geological setting: Back arc basin		
Top reservoir depth: 915m		
Lithology: Globigerinid limestone		
Reservoir type: Deep water carbonates: contourite		
Reservoir age: Pliocene		
Formation: Madura Limestones		
Depositional setting: Deep water carbonate deposit	*Structure and trap type:* Anticlinal trap.	
Migration and Seal: Pliocene deep water shale seal	*Fill history:* N/A	*Source:* Paleogene fluvio-deltaic mudstone.
Net pay: N/A	*Structural closure*: N/A	*Area of closure*: N/A *Productive area*: N/A
Net/Gross: N/A	*Gross pay*: 190m	*Reservoir depth*: 915m
Pore system		
Matrix pore system: inter- and intraparticle	*Matrix porosity:* MDA-1 35-48%; MDA-3 10-40%	*Macroporosity:* N/A
Macropore system: N/A	*Matrix permeability:* MDA-1 10-2000mD; MDA-3 0.1-20mD	*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

8.2. Stratigraphy

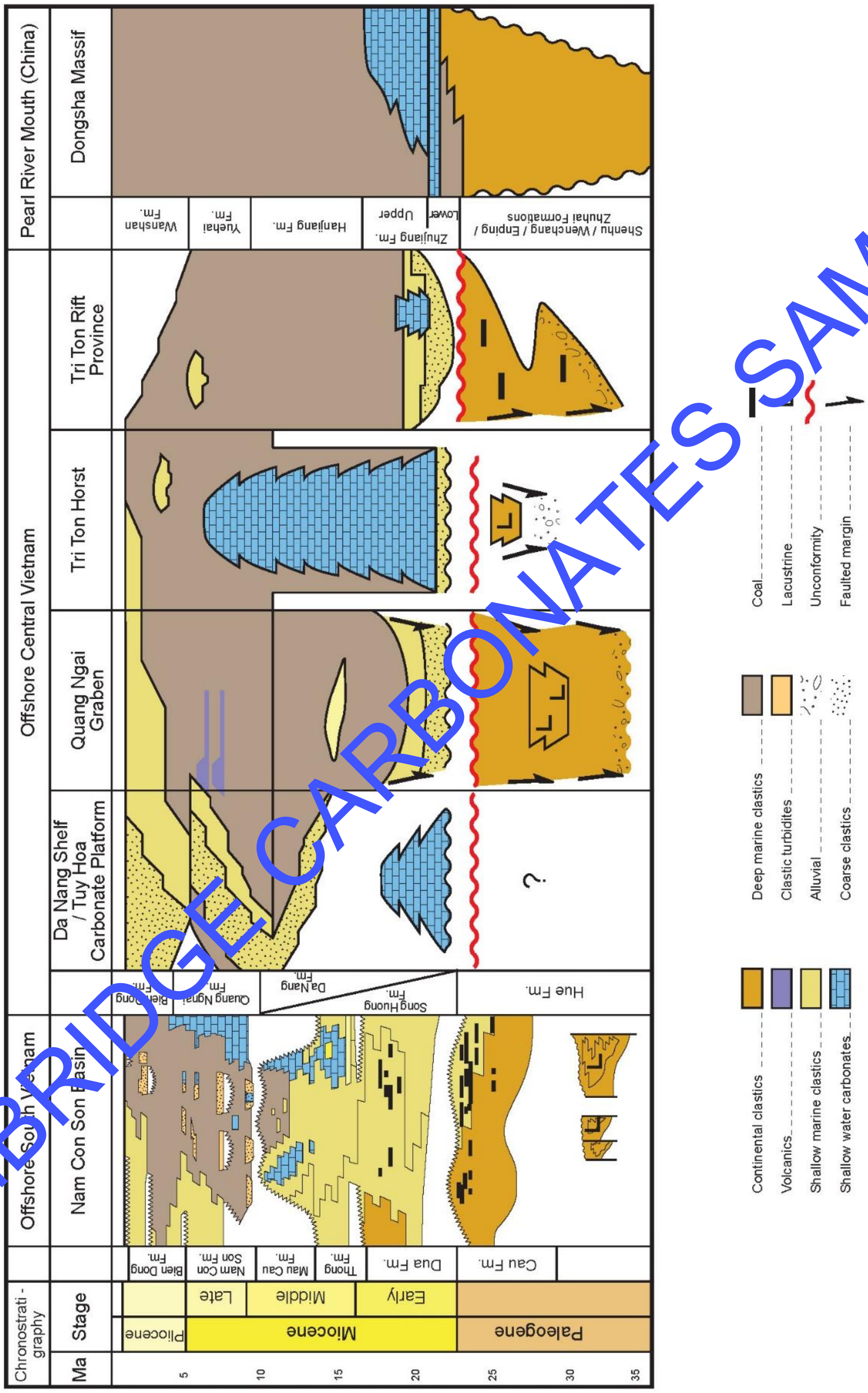


Figure 128 Stratigraphic column for the Nam Con Son Basin, offshore Central Vietnam and Pearl River Mouth, Offshore South China. Modified from Dang and Sladen (1997), Sattler et al. (2004), Fyhn et al. (2013) and Matthews et al. (1997).

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. Ding et al., (2018, 2021) described fluid inclusion gases in quartz from wells in the Baiyun Depression and Panyu lower uplift that were generated from oil prone Wenchang Formation of high thermal maturity (R_o between 1.7-3.1%; mostly between 2.1-2.7%). 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.

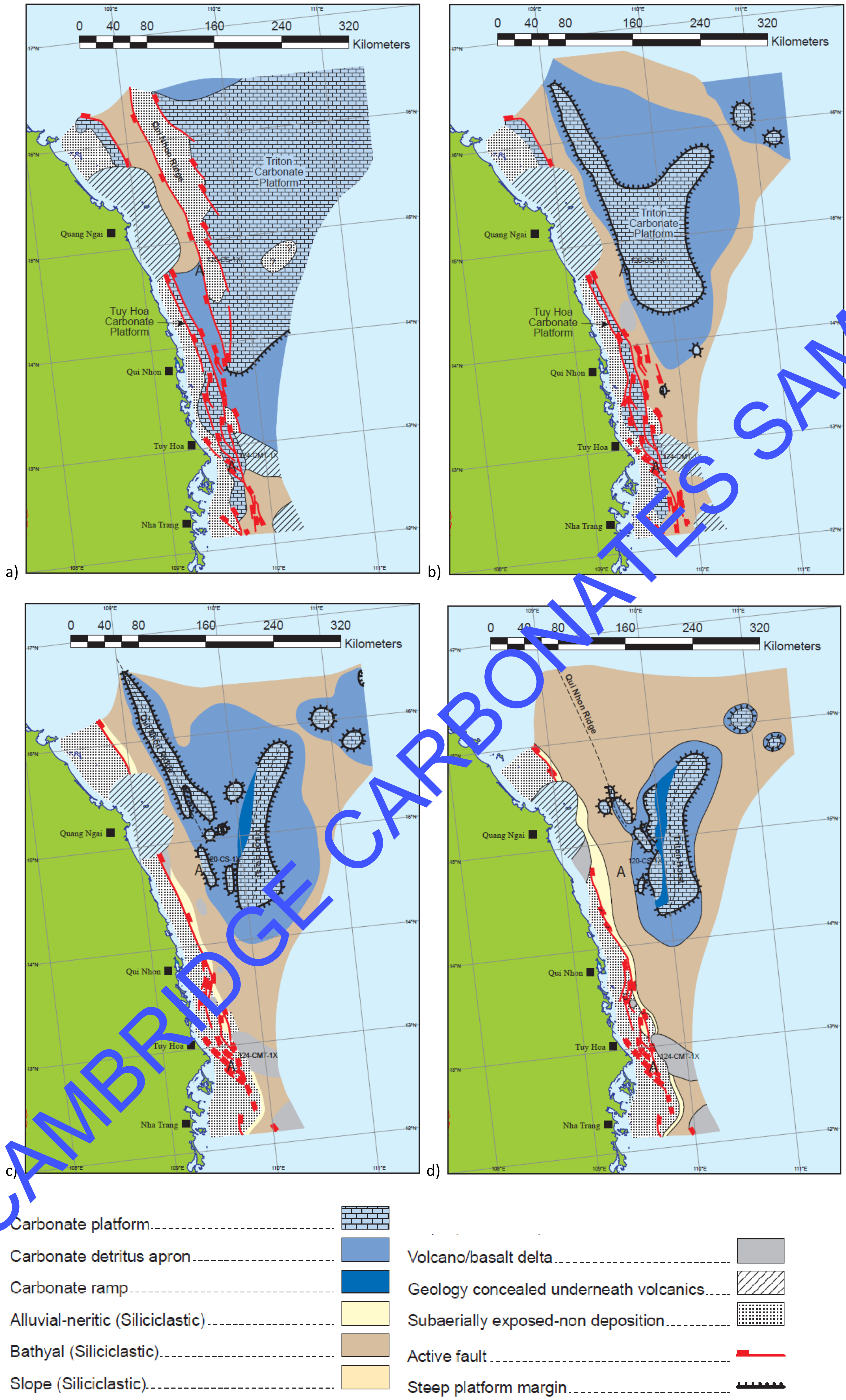


Figure 138 palaeogeographic maps showing the evolution of the Tri Ton and Tuy Hoa Carbonate Platforms from their initiation in the (a) Early Miocene (b) Early-Middle Miocene, (c) Middle Miocene and (d) Late Middle Miocene. Redrawn from Fyhn et al. (2013).

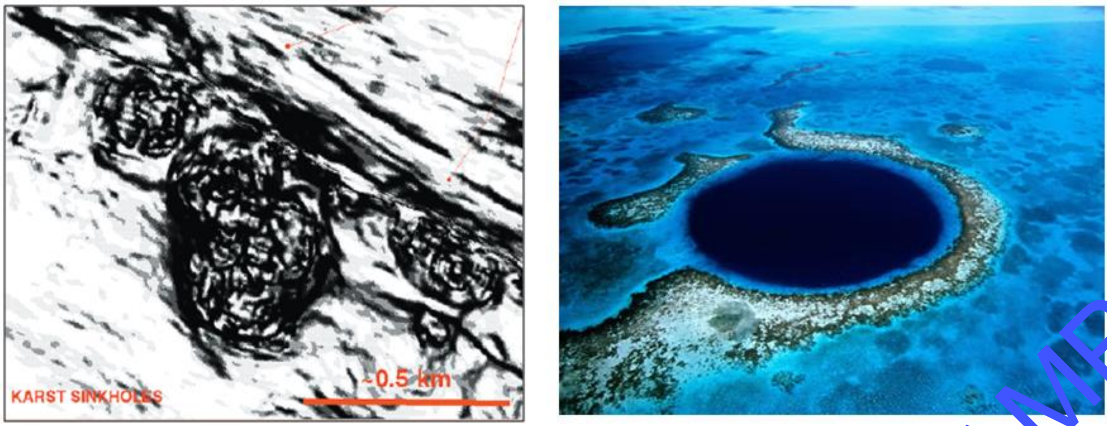


Figure 143 Coherency image of karst sinkholes across the southern margin of the Liuhua 11-1 field, and example of a modern karst from offshore Belize. From Story (2003), reprinted by permission of the AAPG whose permission is required for further use.

Processes that have produced low-porosity zones in the reservoir are both chemically and mechanically driven (Figure 142a). Of particular importance is a major phase of cementation that occurred during repeated exposure of the carbonate platform during the Early Miocene. Subaerial exposure caused leaching of metastable grains above the water table, but also caused widespread cementation of sediments at and below the water-table (phreatic zone). These cements are characterised by distinctive low $\delta^{13}C$ and $\delta^{18}O$ signatures which are present in this zone (Sattler et al., 2004). These cemented zones can be considered to represent the palaeo-water table and as such form an important time line which can be used for correlation purposes. These low-porosity zones are sufficiently continuous, thick, or well-cemented to affect fluid flow through the reservoir (Heubeck et al., 2004). However, they have a double effect on well productivity as they protect the wellbore from early water breakthrough and reduce pressure support from the strong bottom-water drive (Heubeck et al., 2004).

Reservoir zonation in the Liuhua field is a function of both primary sedimentary and diagenetic processes. Eight zones have been recognised (Heubeck et al, 2004; Figure 142b):

1. ***Zone A.*** Primary sedimentary reservoir zone. Dominantly interparticle porosity formed by rhodolith-foraminiferal packstones. Average porosity is 13%

8.6. Field descriptions

<table>
<tr><th>Lan Tay/Lan Do fields</th><th>Basin: Nam Con Son</th><th>Block: 06.1</th></tr>
<tr><td>Operator: Rosneft Vietnam</td><td colspan="2" rowspan="12">
</td></tr>
<tr><td>No' wells on structure: 7 (5 on Lan Tay, 2 on Lan Do)</td></tr>
<tr><td>Discovered: 1992/3</td></tr>
<tr><td>Produced since: N/A</td></tr>
<tr><td>Current status: producing gas and condensate</td></tr>
<tr><td>Geological setting: N/A</td></tr>
<tr><td>Top reservoir depth: N/A</td></tr>
<tr><td>Lithology: Limestone</td></tr>
<tr><td>Reservoir type: N/A</td></tr>
<tr><td>Reservoir age: Miocene</td></tr>
<tr><td>Formation: N/A</td></tr>
<tr><td></td></tr>
<tr><td>Depositional setting: Isolated buildup</td><td colspan="2">Structure and trap type: N/A</td></tr>
<tr><td>Migration and Seal: N/A</td><td>Fill history: N/A</td><td>Source: N/A</td></tr>
<tr><td>Net pay: N/A</td><td>Structural closure: N/A</td><td>Area of closure: N/A</td></tr>
</table>

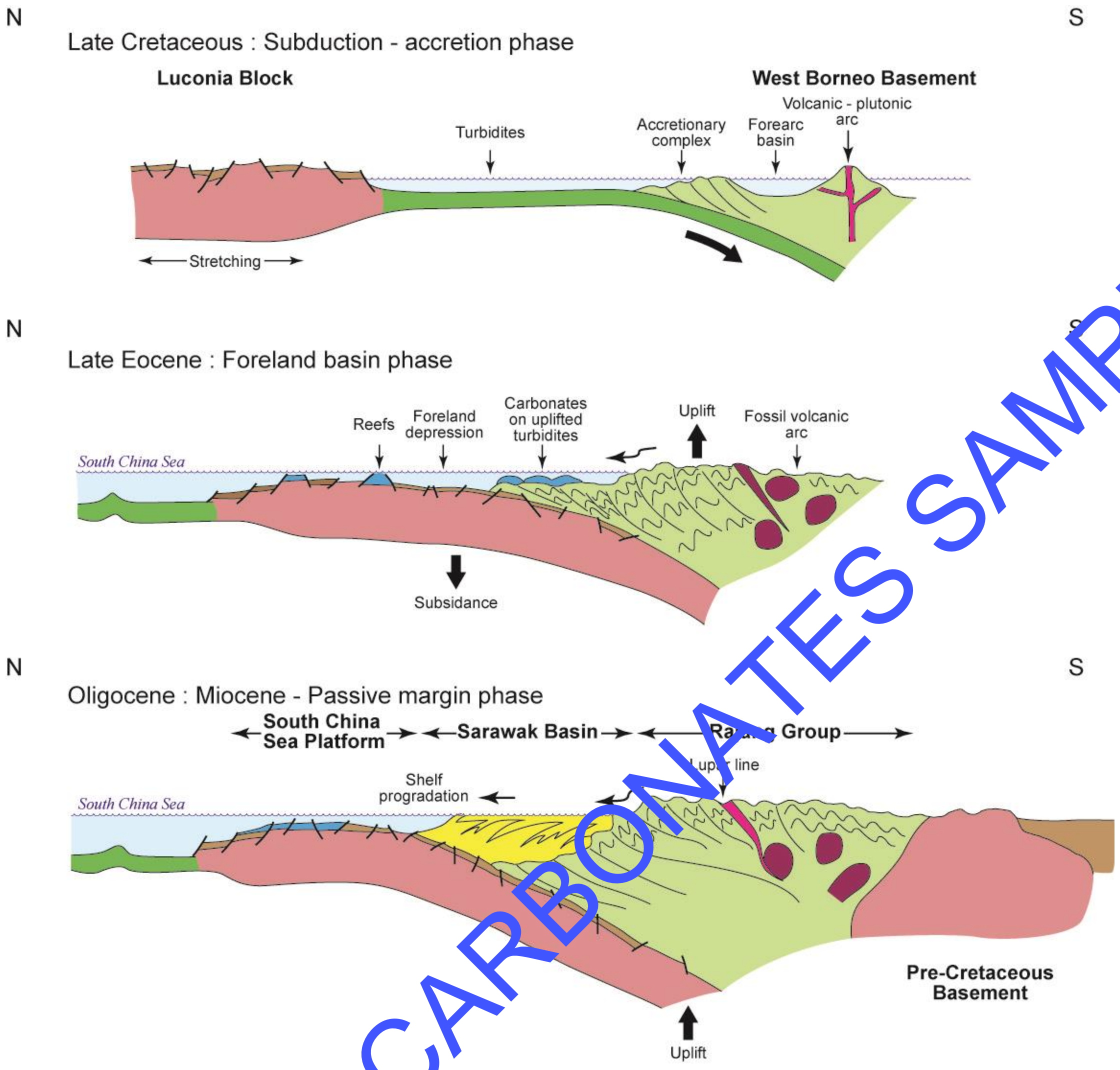


Figure 147 Structural evolution of the Sarawak Basin from Late Cretaceous to Recent. Modified from Madon (1999a).

The East Natuna Basin had a similar geological history. The basin itself is bounded on the west by the N-S trending Natuna Arch, and the carbonate shelf is a N-S trending high which was fragmented by Cenozoic extensional tectonics into a mosaic of normal fault blocks (Dunn et al., 1996; Figure 148). To the east the basin opens to Sarawak Basin. The south part is bounded by Sunda Shelf and the northern part by Vietnam Basin. Hutchison (1989) divided the East Natuna Basin into Sokang Sub Basin and North East Natuna Basin. They are separated by the Paus-Ranai Ridge, a feature parallel to the eastern side of Natuna Arch, which also forms the north-eastern boundary of Sokang Sub Basin.

coarse clastics into the basin (Sales et al., 1997). The Esperanza Sand Unit is also locally developed.

9.2.6. Late Miocene

East Natuna Basin

The Muda Formation is a series of stacked prograding mud-rich wedges that were initiated in the Late Miocene (Rudolph and Lehmann, 1989). However, it was not until the Pliocene that these shales draped structurally high carbonates of the Upper Terumbu Formation. The lowermost parts of the Muda Formation consist prodelta to basinal shales which were considered to be deposited in waters around 900m deep (Rudolph and Lehmann, 1989).

Sarawak Basin

Deposition of deltaic siliciclastics became more dominant during the Late Miocene (Cycle V). These were sourced from both the Baram and West Luconia deltas, and resulted in coastal progradation and filling up of pre-existing bathymetric lows. The West Luconia delta prograded in a northward direction towards the North Luconia Province (Madon, 1999b), whilst the Baram delta prograded in a more westerly direction.

At the end of the Late Miocene, there was a period of significant uplift which resulted in an extensive unconformity (Madon, 1999b).

Palawan Shelf

A major period of collisional tectonics occurred at the end of the Middle Miocene, resulting in an unconformity at the top of the Pagasa Formation (Figure 151). The Late Miocene to Early Pliocene Matinloc Formation is a product of this renewed uplift, and is characterised by polymict conglomerates. The base of the Matinloc Formation is often represented as relatively thin (7m) sandstone, which is overlain by pebble- to granule-grade conglomerates showing an admixture of lithotypes including quartz, siltstones and dark green rock fragments. The base of the conglomeratic package typically has an argillaceous nature to the matrix, but there is no visible matrix at the top of the succession (Sales et al., 1997).

Field	API°	Sulphur wt %	Viscosity cp	Pour point °F	GOR (scf/bbl)
Nido-1	37	0.54	3.46	20	504
Cadlao	47.7	0.66	0.90	20	600
Matinloc	42.9	0.58	1.48	20	600
Pandan	42.9	0.49	1.65	35	20
Tara	38.4	0.77	1.30		22.1
Libro	43.6	0.64	5.18	35	14

Table 21 Table of oil characteristics for selected fields with carbonate reservoirs. Data from Saldivar et al. (1981b)

9.3.3. Reservoirs

East Natuna Basin

The Terumbu Formation carbonates are the primary reservoir in the East Natuna Basin, and are discussed in more detail in Section 9.4.

Sarawak Basin

In the Sarawak Basin, oil and gas is producing from both clastic and carbonate reservoirs.

In the West Baram Delta Province (Figure 149) the main reservoirs are deltaic and shallow marine clastics of the Cycles V/VI Formation (Mahmud and Saleh, 1999). These include major oil producing fields such as Baram, Baronia, Bokor, W Lutong and Takau. In the Balingian Province, clastic reservoirs are slightly older, from lower coastal plain clastics. Fields in the Balingian province tend to be small, being trapped in more complex structural traps (Mahmud and Saleh, 1999). In the Sabah Basin, shallow marine to coastal clastic reservoirs also dominate, and are predominantly Miocene to Pliocene in age. The only carbonate platform in the basin is the Khudat Platform to the north. Two wells tested the Upper Miocene reservoir, encountering good porosities (15-28% in Kalutan-1 and Balambangan-1), but the reservoirs were not hydrocarbon-bearing.

Carbonate reservoirs produce from the Central Luconia Province in the Sarawak Basin. This is known as the gas province of Sarawak, with more than 40TSCF gas in place and 30TSCF ultimately recoverable (Ali and Abolins, 1999). The main carbonate reservoir is the Miocene Cycle IV/V reservoir, which forms small transgressive buildups through to large carbonate platforms. Up to 1999, approximately 200 carbonate buildups have core analysis (Dunn et al., 1996; Rudolph and Lehmann, 1989), a powerful and detailed dataset is available.

Seismic surveys over Natuna and Segitiga Platforms are both 2D surveys. However, appropriate reprocessing and integration with wells allows a very detailed picture to emerge of platform initiation, growth and demise. Seismic facies on the Segitiga Platform are distinctive (Bachtel et al., 2004; Figure 162):

- **Mounded facies**: characterised by bidirectional downlap of reflectors. Internal geometries are convex-up. The sequence locally thickens where mounded facies are present. They are interpreted to represent **shelf-margin or platform reefs** and grainshoals.
- **Progradational facies:** reflectors either have a steep oblique geometry or lower relief sigmoidal geometry. Packages downlap onto a thin MFS, and toplap against an upper sequence boundary. They are interpreted to represent **grain-dominated lithofacies** associated with the platform margin deposited during the highstand systems tract.
- **Chaotic facies:** internally disrupted reflectors which can occur as linear bodies at the basin margin or isolated bodies in the platform interior. This seismic facies may represent several types of depositional feature. It may represent shelf-margin or platform patch reefs, similar to the mounded facies. It may also represent areas of dissolution and karst formation, or an intensely faulted area.
- **Parallel facies in the platform:** parallel internal seismic reflectors, locally wavy, but continuous to semi-continuous. These facies occur in the platform interior and could represent a range of lithofacies from mud-dominated to grain-dominated.
- **Inclined facies on the slope:** located basinward of the platform margin, and landward of the toe of slope. Typically gently inclined reflectors that lack toplap and downlap geometries. This is interpreted to represent the slope

- Main build-out phase. The carbonate platform is seeded and starts to grow. Progradational geometries develop as the reef margins build out over more distal facies. The thickness of this depositional phase reaches 180m in the EX-2 well, and is characterised by wackestones with platy corals and platform-derived breccias at the base, and heavily dolomitised grainstones and boundstones near the top. This is interpreted to represent the late highstand systems tract.

- Platform exposure. Major fall in relative sea level leads to exposure of the carbonate platform and meteoric diagenesis. This phase is interpreted to represent the sequence boundary and lowstand systems tract. Interestingly, there appears to be only minor insitu carbonate production during the lowstand systems tract – exposure and diagenetic processes are dominant.

- Submerged bank stage. Platform drowning due to a rapid rise in relative sea level. Slowing of carbonate production and increased proportion of clays. In well EX-2, this is characterised by a 20m thick succession of argillaceous mudstones with common rhodoliths, which overlies an erosion surface. Represents the transgressive systems tract and maximum flooding surface.

- Main buildup stage. The main buildup stage displays aggradational geometries where carbonate production is able to pace the rise in relative sea level. This succession consists of 130m of coral-boundstones interbedded with foraminiferal packstones and grainstones in well EX-2. This stage is interpreted to represent the early highstand systems tract.

- Build-in stage. The build-in stage occurs when carbonate production cannot keep pace with relative sea level rise. The actively growing reefs move inwards to topographically elevated areas. The cored interval is 60m thick in EX-3 and is represented by foraminifera-rich packstones interbedded with boundstones. The succession is estimated to reach 250m in thickness elsewhere on the buildup based on seismic. This is interpreted to represent the transgressive systems tract.

Code	Sedimentary facies	Dominant allochems	Depositional setting
LATE EOCENE			
E1	Quartz-rich bryozoan foraminiferal algal packstone	Bryozoans; benthic foraminifera (*Discocyclina*, *Nummulites*, miliolids); *Halimeda*; coralline algae	Shallow-open shelf
R1a	Rhodolithic floatstone/ rudstone	coralline algae (rhodoliths); *Halimeda*; benthic foraminifera (miliolids, alveolinids, *Nummulites*, encrusting forms); echinoderms	Inner shelf slope
EARLY OLIGOCENE			
R1b1	Mud-rich foraminiferal *Halimeda* floatstone	Benthic foraminifera (miliolids, soritids, amphestiginids, *Nummulites*, local heterosteginids); *Halimeda*; coralline algae; corals; bryozoans	Shallow inner shelf
R1b2	Mud-poor *Halimeda* floatstone	*Halimeda*; benthic foraminifera (*Peneroplis*, miliolids, amphestiginids, *Nummulites*, heterosteginids); coralline algae; corals; bryozoans	Inner shelf sand shoal
R1c	Coral algal floatstone	Corals; coralline algae, benthic foraminifera (*Heterostegina*; *Cycloclypeus*, flat *Nummulites*, *Amphistegina*, occasional miliolids and arenaceous foraminifera	Reef slope
R2	Coral foraminiferal coralline algal floatstone/rudstone	Corals, benthic foraminifera (miliolids, *Amphestigina*, alveolinids, soritids, arenaceous foraminifera); coralline algae, echinoderms, rare *Halimeda* and bryozoans	Near reef zone
R3a	Coral foraminiferal coralline algal grainstone/ floatstone	Large scleractinian corals; benthic foraminifera (miliolids, alveolinids, thick-walled amphestiginids, rotaliids); coralline algae	Sand shoal in back reef setting
R3b	Coralline algal–foraminiferal packstone	Coralline algae; benthic foraminifera (miliolids, alveolinids, amphestiginids, arenaceous foraminifera); echinoderms, coral fragments	Shallow inner shelf
R3c	Echinoderm coralline algal packstone	Echinoderms, encrusting coralline algae, benthic foraminifera (miliolids, alveolinids, *Nummulites*, arenaceous foraminifera); rare corals and bryozoans	Relatively deep and protected inner shelf
LATE OLIGOCENE			
C1a	Coralline algal wackestone/packstone	Encrusting coralline algae; foraminifera (arenaceous foraminifera, miliolids, amphestiginids, rare alveolinids)	Deep inner shelf
C1b	Coralline algal echinoderm wackestone/packstone	Encrusting coralline algae; echinoderms (mainly echinoids); foraminifera (amphestiginids, rotaliids, arenaceous foraminifera, miliolids, alveolinids, rare planktonics)	Deep protected inner shelf
C2	Coral coralline algal foraminiferal grainstone	Small coral debris, encrusting and geniculate coralline algae, benthic foraminifera (*Borealis pygmaeus*, *Sphaerogypsina*, rotaliids, amphestiginids, *Austrotrillina*, other miliolids, *Heterostegina borneesis*, broken soritids and arenaceous foraminifera)	Inner shelf shoal
C3	Coral coralline algal foraminiferal packstone/floatstone	Large coral debris, encrusting and geniculate coralline algae, benthic foraminifera (rotaliids, *Heterostegina borneensis*, amphisteginids, miliolids, alveolinids, soritids, lepidocyclinids)	Shallow protected inner shelf with sea grass meadows and patch reefs
C4a	Coralline algal foraminiferal packstone	Coralline algae (algal balls), benthic foraminifera (Heterosteginids, *Spiroclypeus*, rotaliids, lepidocyclinids), echinoderms	Slope
C4b	Coralline algal foraminiferal grainstone	Coralline algae (algal balls), benthic foraminifera (Heterosteginids, lepidocyclinids, rotaliids, thick tested *Amphistegina*, miliolids, local *Spiroclypeus*), corals	Proximal reef slope
C5a	Lepidocyclinid rhodolithic rudstone	Large benthic foraminifera (large lepidocyclinids, *Operculina*, *Heterostegina*, *Cycloclypeus*, *Spiroclypeus*, rare miliolids and amphisteginids); coralline algae (rhodoliths); *Halimeda*; bryozoans; echinoderms	Flank
C5b	*Halimeda* rudstone	*Halimeda*; coralline algae; large benthic foraminifera (large lepidocyclinids, *Operculina*, *Heterostegina*, *Cycloclypeus*, rare miliolids and amphisteginids); bryozoans	Flank
EARLY MIOCENE			
M0	Planktonic foraminiferal wackestone/packstone	Planktonic foraminifera; fragments of benthic foraminifera (heterosteginids, miogypsinids, encrusting foraminifera); coralline algae; echinoderms	Drowned platform
M1	Echinoderm coralline algal wackestone/packstone	Echinoderms (orphiuroids and echinoids); coralline algae; benthic foraminifera (*Bolivina*, discorbids, *Miogypsinoides*, lepidocyclinids, amphisteginids and heterosteginids); planktonic foraminifera	Deep open shelf
M2a	Coralline algal foraminiferal echinoderm packstone	Coralline algae; benthic foraminifera (arenaceous foraminifera, miliolids, *Bolivina*, discorbids, rare lepidocyclinids); planktonic foraminifera; echinoderms (mainly echinoids)	Deep protected inner shelf
M2b	Echinoderm coralline algal foraminiferal packstone	Echinoderms (orphiuroids and echinoids); coralline algae; benthic foraminifera (arenaceous foraminifera, miliolids, lepidocyclinids); planktonic foraminifera	Moderately deep and open shelf
M3	Coral coralline algal foraminiferal packstone/ floatstone	Large coral debris, encrusting and geniculate coralline algae; benthic foraminifera (soritids, miliolids, arenaceous foraminifera, amphestiginids, miogypsinids, lepidocyclinids)	Shallow protected inner shelf with sea grass meadows and patch reefs
M3g1	Foraminiferal coralline Algal grainstone	Benthic foraminifera (soritids, miliolids, alveolinids, miogypsinids, encrusting foraminifera); encrusting and geniculate coralline algae; occasional echinoderms and *Halimeda* plates	Inner shelf sand shoal
M3g2	Foraminiferal coralline algal grainstone	Miogypsinids, miliolids, soritids, arenaceous foraminifera; occasional echinoderms	Shelf margin sand shoal
M3h	Coralline algal green algal foraminiferal packstone	Coralline algae; *Halimeda*; benthic foraminifera (miliolids, soritids, lepidocyclinids, occasional amphestiginids and miogypsinids); occasional echinoderms and molluscs	Shallow water protected inner shelf
M4	Coral foraminiferal floatstone/ rudstone	Corals (mainly *Alveopora*); benthic foraminifera (lepidocyclinids, Miogypsinoides; *Amphestigina*; miliolids, soritids); coralline algae; *Halimeda*; occasional bryozoans; echinoderms, dasycladaceans	Reef flat

Table 26 Depositional facies identified in the Malampaya field. From Fournier et al. (2005)

5. Mouldic sucrosic dolomite

6. Overdolomite (i.e. occlusion of all remaining pore space by dolomite cementation). Poor reservoir properties.

Despite the strong diagenetic modification, distribution of reservoir quality is still strongly linked to primary depositional characteristics (Ramli and Fui, 1982). In the Jintan buildup in the northern Central Luconia Province, the best reservoirs qualities are associated with facies deposited during the highstand systems tract, whilst the poorest reservoir qualities are associated with flooding surfaces and the transgressive systems tracts (Vahrenkamp et al., 2004; Figure 177). However, the overall low permeabilities of these plugs, with grain sizes predominantly more than 100µm is related to the microporosity of the matrix, which connects the larger biomouldic vugs.

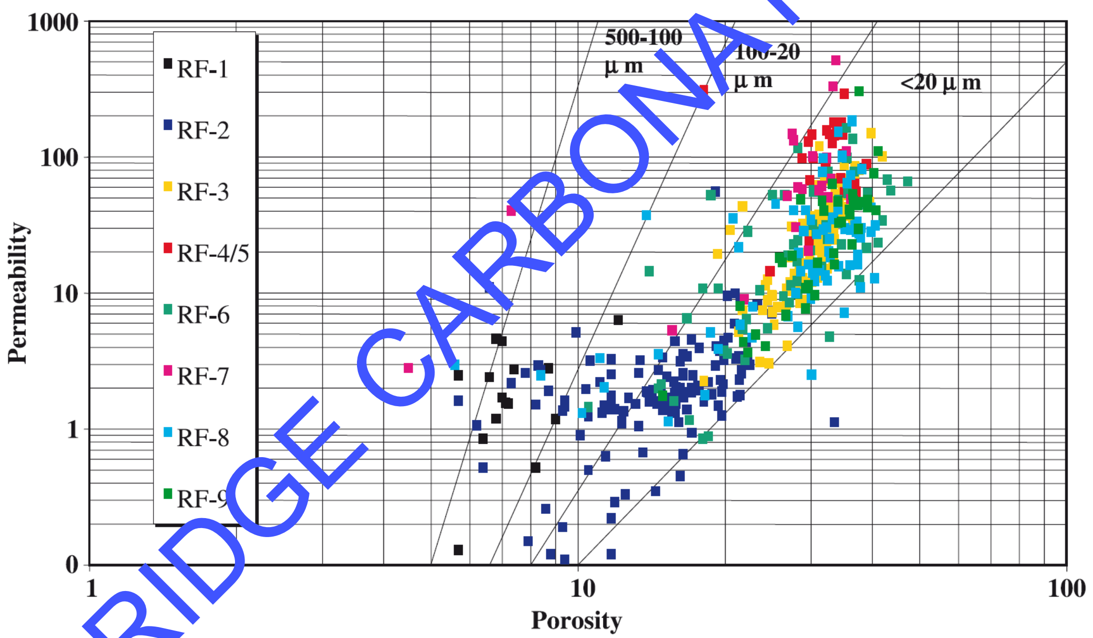


Figure 177 Plug data from the Jintan-3 well, plotted on log-log axes, with the Lucia (1995) petrophysical classes noted. From Vahrenkamp et al. (2004), reprinted by permission of the AAPG whose permission is required for further use.

clastic-sourced oils are present, and are likely to be in the condensate window for maturity.

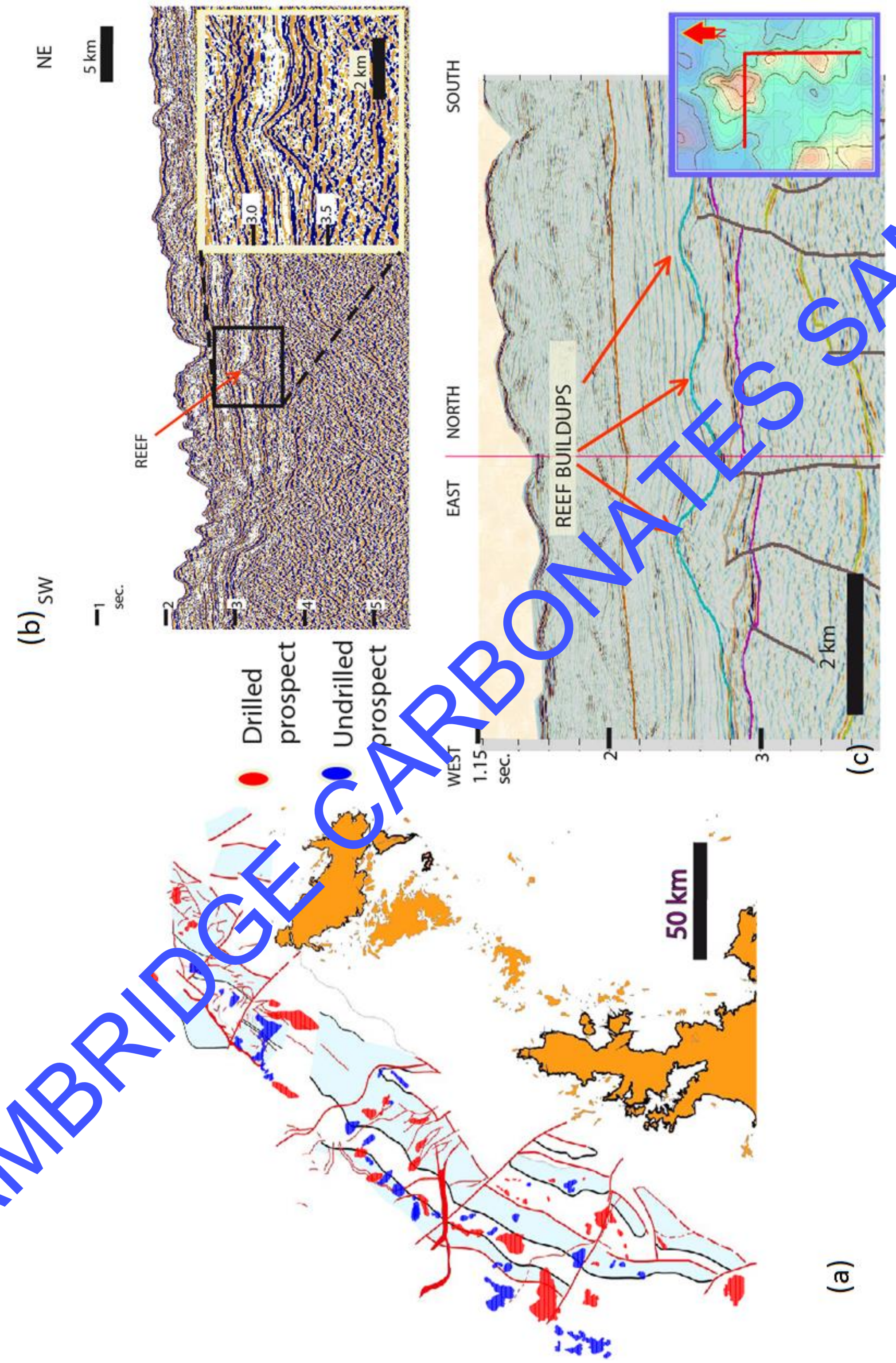
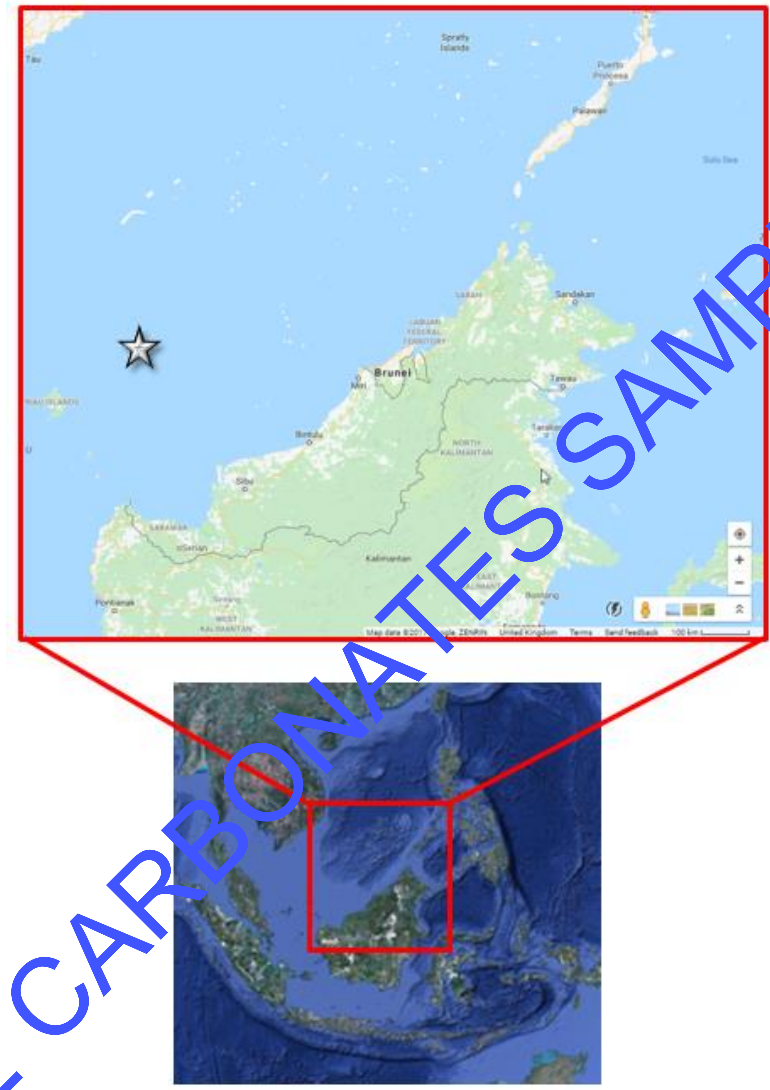


Figure 182 (a) Drilled and undrilled closures on the Palawan Shelf (b) example of undrilled reefal buildups in the NW Palawan Basin and (c) examples of undrilled reefal buildups in the SW Palawan Basin. From the Philippine Department of Energy (2003).

Natuna-L discovery	*Basin:* East Natuna Basin	*Block:* Natuna-D Alpha
Operator: PT Pertamina		
No' wells on structure: N/A		
Discovered: 1973		
Produced since: N/A		
Current status: gas discovery		
Geological setting: N/A		
Top reservoir depth: 2640m		
Lithology: Limestones		
Reservoir type: reefal		
Reservoir age: Middle and Upper Miocene		
Formation: Terumbu Limestone Formation		



Depositional setting: Isolated buildup	*Structure and trap type:* Stratigraphic	
Migration and Seal: Muda Shale	*Fill history:* N/A	*Source:* deltaic Arang Formation shales. Type III.
Net pay: 1524m	*Structural closure:* 1638m	*Area of closure:* 310km^2 basal closure *Productive area:* N/A
Net/Gross: N/A	*Gross pay:* 1638m	*Reservoir depth:* 2640m
Pore system		
Matrix pore system: interparticle	*Matrix porosity:* up to 30%	*Macroporosity:* N/A
Macropore system: mouldic, vuggy, cavernous	*Matrix permeability:* N/A	*Macro-permeability:* N/A

Nelson, R.A. 2001. Geologic Analysis of naturally fractured reservoirs. Butterworth-Heinemann, pp332

Neuhaus, D., Borgomano, J., Jauffred, J-C., Mercadier, C., Olotu, S. and Grötsch, J. 2004. Quantitative seismic reservoir characterisation of an Oligo-Miocene carbonate buildup, Malampaya, Philippines. In: Eberli, G.P., Masafero, J.L. and Sarg, R.J.F. (eds) Memoir of the American Association of Petroleum Geologists, 81, p169-183.

Nido Petroleum, 2006. www.doe.gov.ph/ER/archives/nidopetroleum.pdf

Offshore Technology 2010. http://www.offshore-technology.com/projects/natuna/

Otto Energy, 2009. Appraisal and Development Opportunity, Calauit Oil Fields, offshore Palawan, Philippines. www.ottoenergy.com

Prabowo, K., Cherdasa, J.R., Syihab, Z. and Ariadji, T., 2019, Reservoir characterisation and storage capacity evaluation for Carbon Captur and Storage: a case history from East Natuna. Proceedings Indonesian Petroleum Association 43rd Annual Convention, 2019.

Philippines DOE, 2003. PETROLEUM POTENTIAL OF OFFSHORE WEST PALAWAN BASINS. www.doe.gov.ph/.../pdf%20West%20Palawan%20petroleum%20potential.pdf

Ramli, M.N., and Ho, Kiam Fui, 1982, Depositional environments and diagenesis of the F6 reef complex, central Luconia province, offshore Sarawak, Malaysia: Joint ASCOPE/CCOP Workshop on Hydrocarbon Occurrence in Carbonate Formation, Surabaya, Indonesia, 35 p.

Rudolph, K.W., and Lehmann, P.J., 1989, Platform evolution and sequence stratigraphy of the Natuna Platform, South China Sea, in Crevello, P.D., Wilson, J.L., Sarg, J.F., and Read, J.F., eds., Controls on Carbonate Platform and Basin Development: SEPM Special Publication, no. 44, p. 353-361.

Saldivar-Sali, A., Oesterle, H. G., and Brownlee, D. N., 1981a. The geology of offshore northwest Palawan, Philippines – 1. Oil and Gas Journal, November 30 1981. P119-127

Saldivar-Sali, A., Oesterle, H. G., and Brownlee, D. N., 1 a 981. The geology of offshore northwest Palawan, Philippines – 3. Oil and Gas Journal, December 14 1981. P196-199

Sales, A.O., Jacobsen, E.C., Morado Jr., A.A., Benavidez, J.J., Navarro, F.A., and Lim, A.E., 1997, The petroleum potential of northwest Palawan block GSEC 66: Journal of Asian Earth Sciences, v. 15, nos. 2-3, p.217-240

Steinshouer, DW., Qiang J., McCabe, PJ. and Ryder, RT. 2000. Maps showing geology, oil and gas field and geologic provinces of the Asia Pacific region. USGS Open-File Report 97-470F.

Steuer, S., Franke, D., Meresse, F., Savva, D., Pubellier, M., Auxietre, J-L and Aurelio, M. 2013. Time constraints on the evolution of southern Palawan Island, Philippines from onshore and offshore correlation of Miocene limestones. Journal of Asian Earth Sciences 76 (2013) 412–427

Steuer, S., Franke, D., Meresse, F., Savva, D., Pubellier, M., and Auxietre, J-L. 2014. Oligocene-Miocene carbonates and their role for constraining the rifting and collision history of the Dangerous Grounds, South China Sea. Marine and Petroleum Geology 58 (2014) 644e657

Taberner, C., Mateu, E., Warrlich, G., Asyee, W., Ferrero, M., Cassidy, P. 2008. Early versus late diagenesis as main controls for porosity distribution in Malampaya Field, Philippines. AAPG 2006 Abstract (15) p104

Taylor, G., Powell, C., Newall, M. and Ngau, A. 1997. Petronas and Sarawak Shell Berhad Joint Regional Study of the Pre-Cretaceous clastics, Central Luconia Province, Offshore Sarawak. Unpublished Internal Report. EXP.R.50793

10.2.2. Oligocene

Tarakan Basin

During the Oligocene, shallow water carbonates were deposited (Seilor Formation) and continued into the Early Miocene as the Mangkabua Shales and the reefal Tabalar Limestone.

Kutei Basin

Late Oligocene transgression and deposition of platform carbonates (the Upper Berai Formation equivalent) over the Barito Shelf and on basement highs in the Kutei Basin (van de Weerd et al., 1987). At the same time carbonate slope and marine shales were deposited in the basin centres (the Bongan Formation).

Shallow-water carbonates occurred as isolated buildups and more extensive platform carbonates, particularly in the southwest of the basin, bordering the Barito Shelf. The facies are characterised by coralline-algal grainstone shoals, coral- foraminifera-algal rudstones and nodular bedded, platform interior coral floatstones. Relatively steep shelf-margin edges have been mapped on seismic, alongside reefal features (van de Weerd et al., 1987). Platform carbonates can reach up to 1000m in thickness. The Kerendan Field is in a large stratigraphic trap in the upper Berai limestone which formed on an Oligocene carbonate platform seeded on basement high.

The Bongan Formation is characterised by slope and basinal facies. Slope facies are represented by hemipelagic claystones, interbedded with mega-breccias, conglomerates and volcaniclastic turbidites. Olistoliths and syndepositional deformational features are also common. In-situ accumulations of benthic foraminiferal packstones to mudstones also locally occur in slope settings (van de Weerd et al., 1987) – in our view, these may represent development of lowstand deposits. Basinal facies of the Bongan Formation are characterised by claystones and rare turbidites.

In the central and eastern parts of the Kutei Basin, the Oligocene is characterised mainly by basinal clastics of the Atan Beds (Figure 188). Again, carbonates are locally developed on basement highs.

carbonate and siliciclastic clasts into adjacent outer neritic or upper bathyal settings.

- Early to Middle Miocene: Complex platform margin at the far eastern margin of the peninsula with high energy, reef-rimmed margin and steep and possibly faulted platform margin shedding massive clast-supported limestone breccias. Shallow water bioclasts, including massive corals, and lithified carbonate and siliciclastic clasts were reworked from the platform margin. Extensive shallow water, moderate to low energy carbonate platforms along the NE margin of the peninsula.
- Middle Miocene to earliest Pliocene: Probable continuation of moderate to low energy, shallow water carbonate platform sedimentation along NE margin of peninsula. A complex, moderate energy shelfal area with patch reef development, some tidal influence and deeper water embayments or channels lay at the far east of the peninsula.
- Late Pliocene to Quaternary: Moderate to high energy mixed carbonate-siliciclastic shelf deposits containing abundant coral debris deposited at the south-eastern end of the Mangkalihat Peninsula. These deposits unconformably overlie Early Miocene lithoclastic facies and have been uplifted to 30–40 m above sea level.

Based on 2D seismic offshore from the Mangkalihat Peninsula, several large and small scale carbonate highs have been imaged. These range from kms to several 10s km in size (Wilson and Evans, 2002). Based on outcrop observations, the best reservoir quality is likely to be related to packstones and grainstones located interior to the platform margin, where there is minimal micritic matrix, and pores have not been early cemented. Koeshidayatullah et al. (2013) describe four facies types from the Middle Miocene carbonates at outcrop:

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 196). Kerendan-2 well also exhibits a similar facies association, although the argillaceous clastic content is higher (Figure 196, Figure 197). It is suggested that this well may be in a more proximal setting, closer to a deltaic and/or volcanic source in the south. For both wells, deposition is considered to be shallow (<5m water depth; Subekti et al., 2015). Slightly deeper environments are interpreted in the Kerendan-3 area. The reservoir is characterised by clean carbonate dominated by platy corals – these commonly indicate environments with deeper photic depths (i.e. deeper part of the fore-reef or deeper platform; Subekti et al., 2015; Figure 197). Earlier work by Saller and Vijaya (2002) suggested a platform rim was encountered in Kerendan-3 well, and that basinward of this well, steeply dipping seismic reflectors indicated the shelf margin. Subekti et al. (2015) revisited the seismic in this area, and interpret these reflectors to be a result of later folder and fault reactivation, and are not a true representation of depositional morphologies. The West Kerendan-1 well encountered a complex mosaic of shallow-platform carbonate facies, dominated by bioclastic packstones and grainstones/rudstones, rudstones and boundstones, and also bioclastic wackestone textures. Subekti et al. (2015) interpret these as representing shallow reefal flats (Figure 196).

(C) In the middle Late Oligocene, deepening of the platform enabled open marine, locally shaly, coral-rich limestones to be deposited over the entire platform.

(D) The final stage relates to the demise of the platform, with prograding deltaic shales covering the platform during the latest Oligocene to Early Miocene. These provided the top and lateral seal to the buildup reservoir facies. The drowning of the platform does not coincide with regional or global sea level

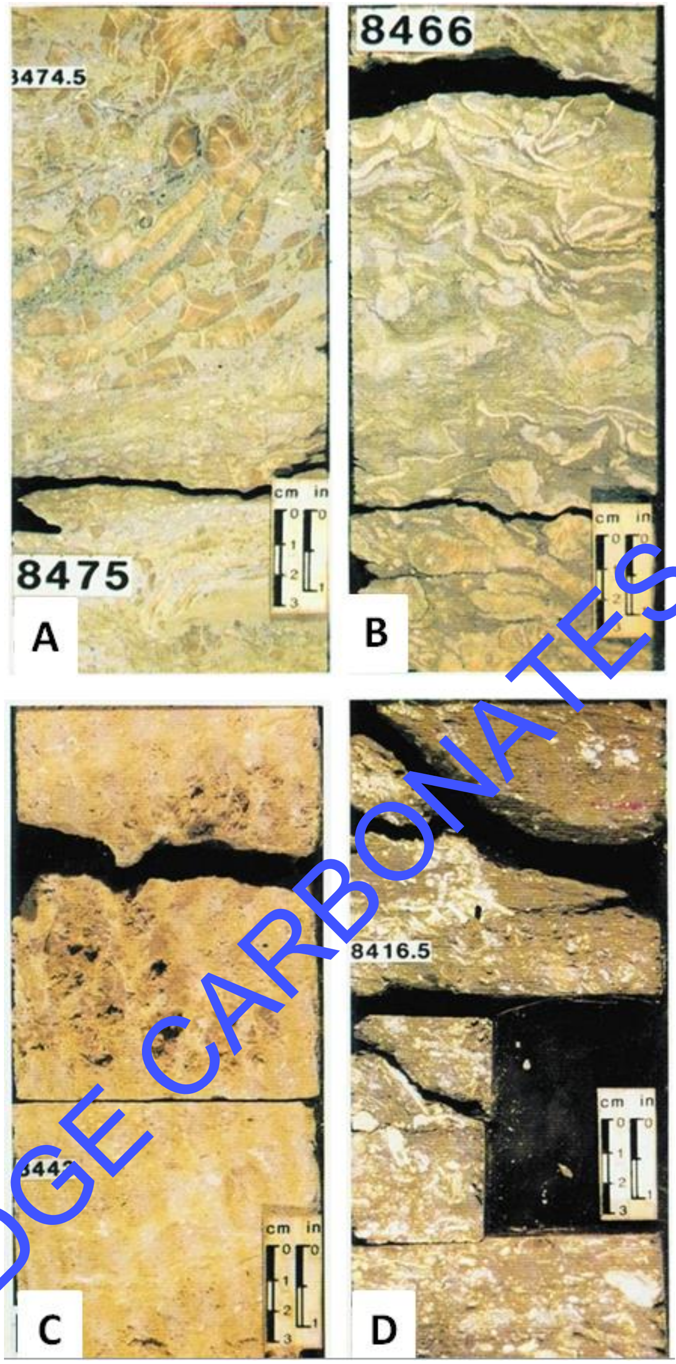


Figure 201 Lithofacies of the 80-6 carbonate unit in the Sedang Field. (a) Lower Reef Buildup, finger like branching coral fragments within a slightly silty and argillaceous carbonate mud matrix. Porosity averages 3.2%, permeability is less than 0.1md due to the muddy nature of the matrix and recrystallization of the corals. (b) Lower, deep water part of the Upper Reef Buildup. Abundant irregular platy corals at the top of the core piece and finger-like branching corals (lower part of core piece) in a sandy argillaceous carbonate mud matrix. Porosity averages 4%, permeability 0.5md. (c) Reef core of the Upper Reef Buildup. Coral-mouldic porosity within the coral reef core lithofacies. Porosity averages 21.5%, permeability in the range of 20-85md. (d) Shelly shale bed that overlies the carbonate buildups. Skeletal fragments include corals, bivalves, larger foraminifera and minor Halimeda flakes. Benthonic and planktonic foraminifera are also present. Matrix has a high clay and silt content, along with traces of glauconite and plant fragments. Selected core photos from Siemers et al. (1992), with permission.

Barito Basin

The Barito Basin has undergone compressional tectonics since the Late Miocene. This pulsed inversion has led to the breaching of early formed traps, and created new traps during, for example, the Pliocene. Understanding the tectonic history including trap formation, migration and seals, is therefore critical (Satyana et al., 1999).

To date there has been no published production from carbonate reservoirs in the Barito Basin. It is possible that this is due to the extensive shelfal carbonates to the north of the basin not being strongly structured. As Satyana et al. (1999) note, the carbonates, where they form a suitable trap, should have good reservoir quality, particularly if they are fractured. It would appear that isolated platforms, so common in the Kutei, Tarakan and possibly South Makassar Basins did not form in the Barito Basin, due to the very different palaeogeographic setting and having only a very narrow inlet to the open ocean.

Kutei Basin

It is clear from the wells and discoveries made to date that both primary depositional facies and diagenesis have an impact on reservoir quality. Reservoir quality is best in reef core and reef margin positions, where detrital clays are limited due to increased winnowing, and where diagenetic processes such as dissolution and creation of vugs have the best chance of occurring.

Many undrilled carbonate buildups exist in the Kutei Basin, particularly those associated with transgressions near the Mahakam delta, and further north. Subekti et al. (2015) also note the presence of numerous undrilled "buildups" in the Kerendan area. Critical factors for well placement will be the identifying the optimal location for the best reservoir facies (i.e. away from the argillaceous facies tracts), and also assessing the potential for late diagenetic processes such as shale decompaction improving reservoir quality.

11. CARBONATE RESERVOIRS OF SOUTH SULAWESI AND SOUTH MAKASSAR BASIN

11.1. Geological setting

The southern arm of Sulawesi is characterised by both sedimentary basins and volcanics. The sedimentary basins of interest include the East Sengkang Basin, where limestones of the Tacipi Member form reservoirs, and the eastern margins of the South Makassar Basin where the Tonasa Formation is prospective (Figure 205). Offshore, the South Makassar Basin extends westwards and southwards towards the Java Sea (Figure 184).

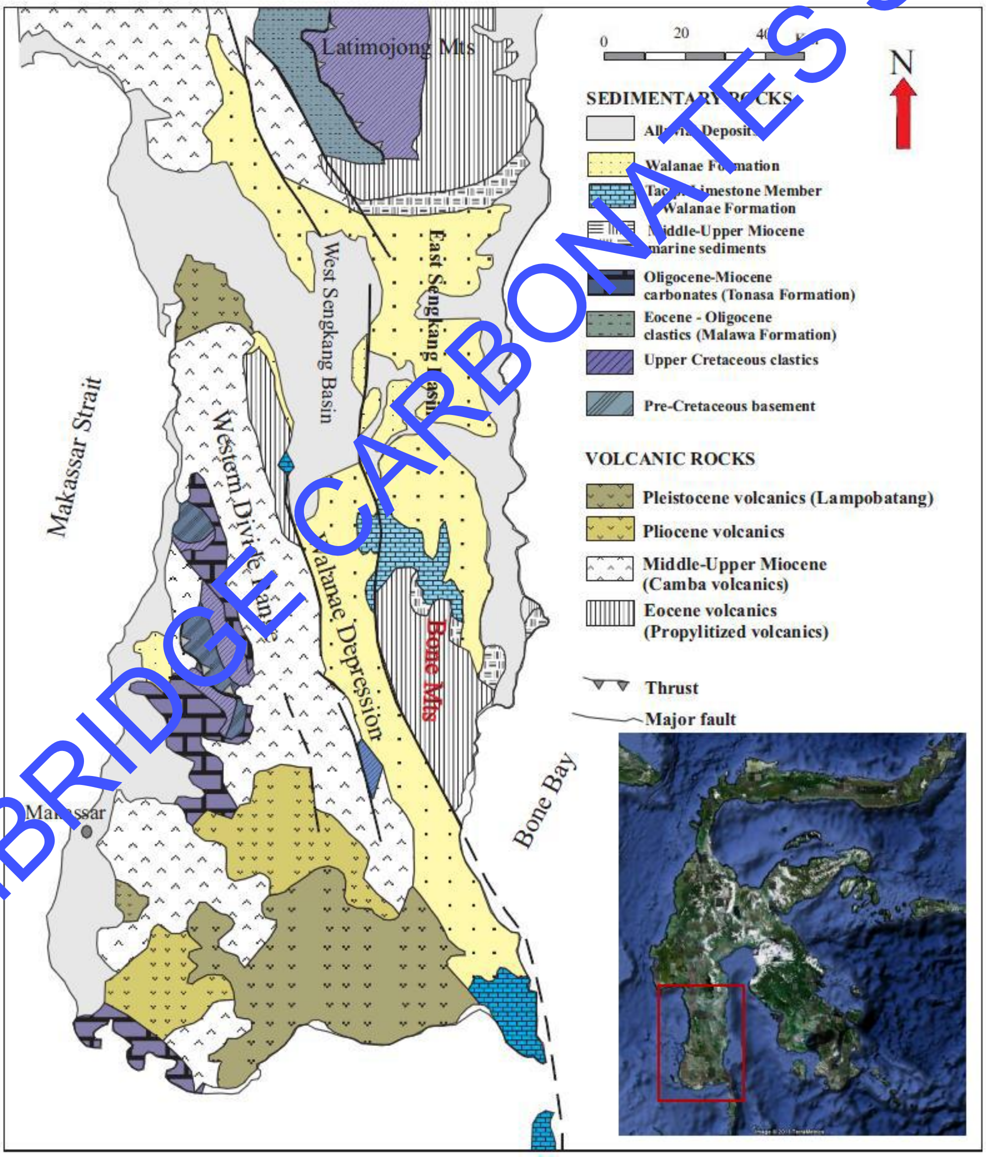


Figure 205 Geological map of southern Sulawesi. Modified from Suyono and Kusnama (2010).

Field	Reservoir	Facies	Depth m	Poroperm data	Discovered	Status	Reserves
South Sulawesi							
Kampung Baru	Tacipi Fm	Reefal	735m	30% average porosity; 13-313mD perm	1976	Producing gas	415bcfg (384bcf already produced)
Walanga	Tacipi Fm	Reefal			1976	Discovery	142bcfg
Sampi Sampi	Tacipi Fm	Reefal			1980	Discovery	36bcfg
Bonge	Tacipi Fm	Reefal				Discovery	13bcfg
Sallo Bullo	Tacipi Fm	Reefal				Discovery	32bcfg
South Makassar Basin							
Sultan-1	Eocene to Oligocene ?Tonasa equivalent		3100 m	10-12%	2009	Discovery	50 bcf gas
Kris-1	Eocene to Oligocene ?Tonasa equivalent		3650 m	13-14%	2010	Dry	

Table 28 Reservoir characteristics of selected fields/discoveries in carbonate reservoirs of South Sulawesi and South Makassar Basin.

11.3.4. Seals

In South Sulawesi, the upper part of the Tonasa Formation mainly formed as a deep water carbonate, and can therefore also act as potential seal. The Tacipi Limestone reservoir is effectively sealed by tight clays and silts of the Walanae Formation, often rich in volcaniclastic components (Sinameta, 2009).

Miocene marine shales and hemipelagic mudstones are the expected sealing facies for the Oligocene carbonate reservoirs in the South Makassar Basin (Courel et al., 2011). The petroleum systems summary, as presented by Courel et al. (2011).

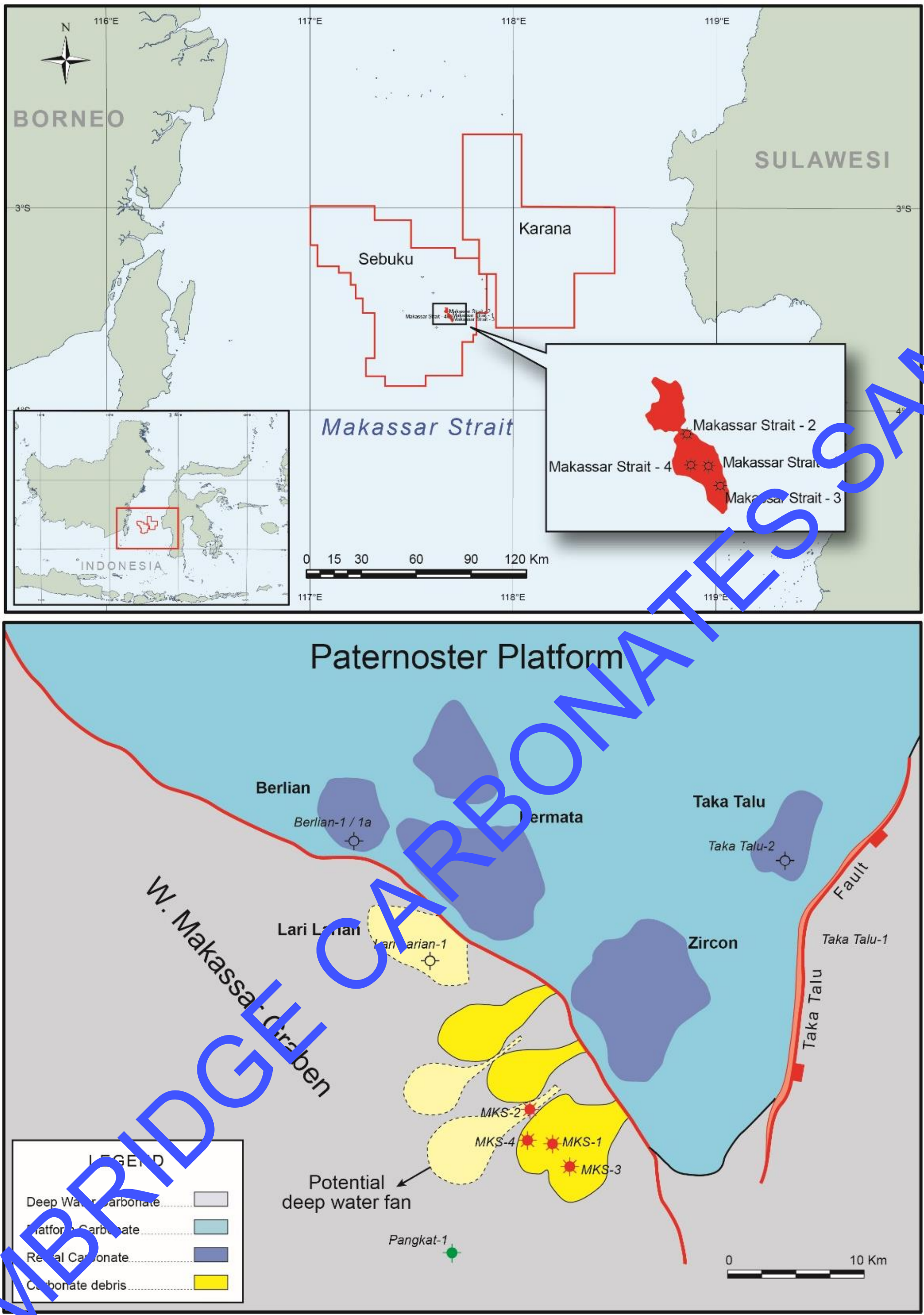


Figure 216 Location of the Ruby field (wells MKS-1, 3 and 4) and depositional model of the Berai limestone in the Ruby field. Redrafted from Pireno et al. (2009).

OWC: N/A	*GWC:* N/A	*GOC:* N/A
Water cut: N/A		*Recovery method:* N/A

Comments

Reconnaissance seismic data from 1971-72 demonstrated the presence of reefal bodies that nucleated on fault block highs.
Success rate of exploration drilling was 4 gas discoveries in 15 wells (1 in 4).
Tacipi formation: the lower ubiquitous interval consisting of interbedded limestones and calcareous mudstones, informally called unit B, and an upper reef limestone interval that is restricted to areas of buildup, called unit C. Grainge and Davies, 1985)

References

Grainge, A.M. and Davies, K.G. 1985. Reef exploration in the East Sengkang Basin, Sulawesi, Indonesia. Marine and Petroleum Geology, May 1985 Vol 2, 142-155.

Katili, J.A. 1978. Past and present geotectonic position of Sulawesi, Indonesia. Tectonophysics 45: 289-322.

Mayall, M.J. and Cox, M. 1988. Deposition and diagenesis of Miocene limestones, Senkang Basin, Sulawesi, Indonesia. Sedimentary Geology, Vol 59, Issue 1-2, pp77-92.

Energy World Corp (2008)

Yulihanto, B. 2004. Hydrocarbon play analysis of the Bone Basin, South Sulawesi. Proceedings, Deepwater and Frontier Exploration in Asia and Australasia Symposium, Dec 2004. DFE04-OR-003.

12.3. Hydrocarbon Geology

12.3.1. Exploration History

Oil and gas exploration in eastern Indonesia has been less successful than western Indonesia, with complex geological terrains being present (Hasanusi et al., 2004). Geological expeditions were reported since the early 20th century in the Sulawesi Island, during which several oil and gas seeps have been located in the east and north coasts, one being located 15km west of Tiaka field. Union Texas Petroleum (UTP) started the contemporaneous exploration in 1980 with extensive field geological and geophysical surveys carried out on the eastern coast of central Sulawesi. At the same time, geochemical analyses were performed on oil seep samples. Most of the first seismic surveys in the former Tomori PSC were marine (Hasanusi et al., 2004).

Between 1980 to 1996, UTP drilled 11 wells (9 offshore and 2 onshore) in the Tomori PSC. The first well, Mantawa-1, has been drilled in 1983 and encountered small amounts of gas in a Miocene reef buildup. Later in the same period, UTP discovered the offshore Tiaka oilfield and the onshore Minahaki and Matindok gas fields (Hasanusi et al., 2004).

In 1997, The Senoro-Toili JOB-PSC (a portion of the former Tomori PSC), was awarded by UTP in contract with Pertamina. One year later, ARCO drilled Senoro-1, discovering gas and condensate in the Mantawa Member. In 2000, ARCO sold out their interest to PT. Medco Energi Internasional.

Since that time, the Senoro-2 and Senoro-3 appraisal wells were drilled respectively in 2001 and 2002, and additional 2D seismic data were acquired over the Senoro area, which confirmed the high potential of the Senoro field (Hasanusi et al., 2004).

The total resource of the Tomori basin is estimated between 10-1000MMBOE according to Doust and Noble (2008). The main fields are: the Tiaka oil field where estimated reserves are 12.8MMBO plus 4MMBC, and the Senoro gas field with reserves of 3.24TCF plus 52MMBC and 6.4MMBO. Several other gas fields are present in the Tomori basin, all with reserves below 500BCF: Maleo Raja (204BCF), Matindok (408BCF), Sukamaju (36BCF plus 5MMBC), Minahaki (108BCF plus 1MMBC), Donggi

(420Bcf plus 7MMBC), Anoa Besar (440BCF), Mantawa (146BCF), and Dongkala (50BCF).

12.3.2. Source rocks

Three main potential source rocks are present in the Tomori basin (Hasanusi et al., 2004):

- the Late Jurassic to Early Cretaceous shales which crop out on the Peleng Island,
- the shales, carbonaceous limestones and coals of the Tomori Formation,
- the shales and coals from the Matindok Formation.

However, the analyses of the various potential source rocks and of hydrocarbons from the reservoirs indicate that the latter are most likely genetically related to the second source rock, i.e. intra-Tomori Formation, with minor contribution from the Matindok, and no apparent contribution from the Jurassic (Davies, 1990; Hasanusi et al., 2004). Davies (1990) particularly reports the correspondence between the high organic sulphur content of the coal of the Tomori Formation and (1) high sulphur contents of the oil in Minahaki-1, Tiaka-1, and Dongkala-1, and (2) the abundant H_2S in the gases of Minahaki-1 and Matindok-1.

The Table 29 presents some characteristics of the main source rocks analysed in the Tomori basin (Davies, 1990; Hasanusi et al., 2004).

The kitchen of the system is identified in the deeply buried Miocene area in the western part of the basin, and also beneath the imbricate thrust sheets in the thrust belt (Figure 219b). The rapid burial by the Pliocene sediments in the foreland basin drove quickly Miocene source rocks into gas generation window as soon as the late Early Pliocene (Figure 223). Then the primary migration occurred along the thrust and wrench faults during the late stage of compression in the Mid Pliocene; remigration/dismigration also probably took place later, during the uplift of the belt in the Pleistocene. In most of the reservoirs, the gas also displays a biogenic origin. The biogenic gas charge is an early event, occurring probably shortly after the pinnacle reefs growth (Hasanusi et al., 2004).

Tiaka field	*Basin:* Tomori Basin	*Block:* Tomori PSC
Operator: JOB Pertamina-Medco E&P Tomori Sulawesi		
No' wells on structure: 10		
Discovered: 1985		
Produced since: June 2003		
Current status: producing oil		
Geological setting: imbricate thrust slices		
Top reservoir depth:		
Lithology: Limestone		
Reservoir type: Shallow shelf		
Reservoir age: Early Miocene		
Formation: Tomori Limestone		
Depositional setting:	*Structure and trap type:* Thrusted anticline	
Migration and Seal: Generation started early/mid Pliocene by loading by thrusts.	*Fill history:* Possible re-migration during Pleistocene	*Source:* Shale and coal in the early to mid-Miocene Tomori Formation. Gas is biogenic.
Net pay:	*Structural closure:*	*Area of closure:* *Productive area:*
Net/Gross:	*Gross pay:*	*Reservoir depth:* 6800-8700 ft TVDSS

Pore system		
Matrix pore system:	*Matrix porosity:* 7 to 12%	*Macroporosity:*
Macropore system:	*Matrix permeability:* 5 to 8md	*Macro-permeability:*
Layering: N/A	*Bit drops:* N/A	*Mud losses:* N/A

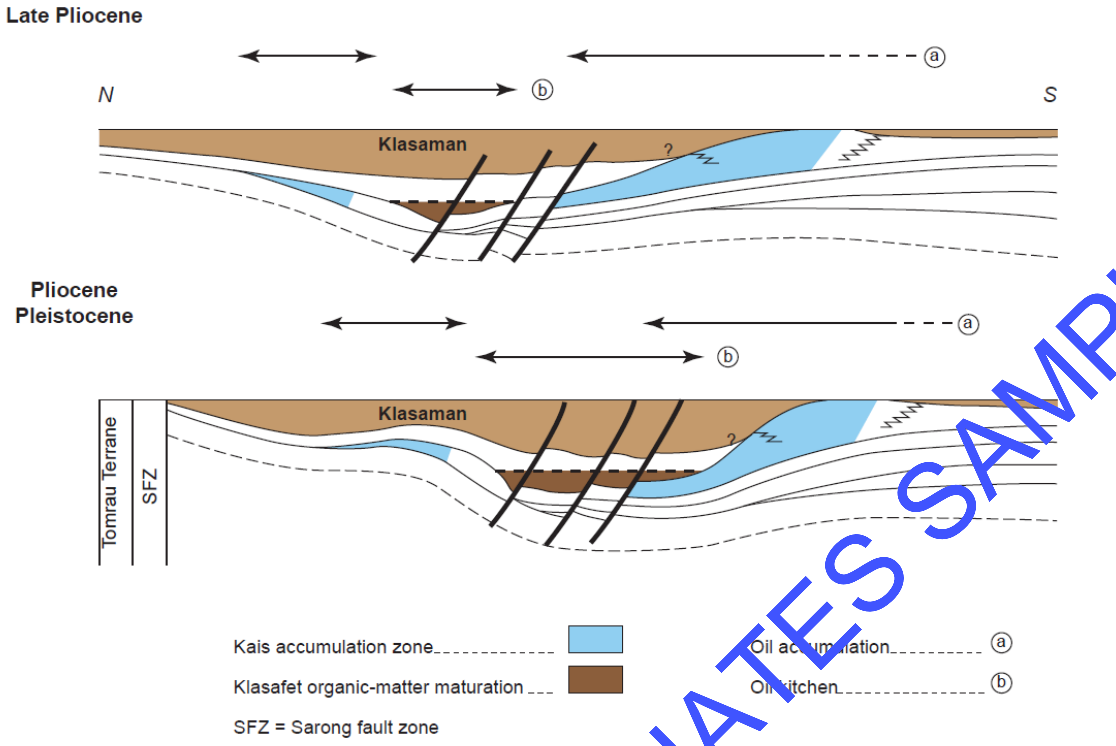


Figure 231 : Schematic N-S cross-sections through the Eastern part of the Salawati Basin between the Late Pliocene and Pleistocene and the development of the oil kitchen. Noteworthy is that the patch-reefs over the Anan high may have been the earliest charged reservoirs. Adapted from Satyana (2003).

Field	Setting	Discovered	Tested BOPD	Tested MMCFGPD
Matoa	Lagoonal reef	1991	1825	2.08
SWO	Lagoonal reef	1995	3564	12.49
Matoa-20	Lagoonal reef	1996	601	
Amuk	Lagoonal reef	1998	1667	0.4
Koi-1	Patch reef over Walio bank	2000	898	2.89

Table 30 Reservoir characteristics of selected fields/discoveries in carbonate reservoirs of West Papua

13.3.3. Seals

The Klasafet Formation, which is the key source rock, also may act locally as a seal. But the main seal is the Klasaman Formation (Figure 228) which includes thick piles of fine grained deep marine clastics. However, the latter formation also includes some sandstone and conglomerates and this sedimentary heterogeneity may locally hamper the efficiency of the seal, especially in the northern part of the basin, close to the clastic sources, i.e. the rising exposed landmass. Fractures may also alter and/or have

Net/Gross: N/A	*Gross pay*: N/A	*Reservoir depth*: N/A
Pore system		
Matrix pore system: N/A	*Matrix porosity:* 22.2%	*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
Well performance		
Initial rate: 23610 (9/76) with 3 wells flow/pump	*Typical single well rate:* N/A	*Initial pressure:* 1480 psi at 1036m
Well tests: Cendrawasih-01; 1036-1103m 20451BOPD + 218BWPD with 2" choke size; 28°API	*Test permeability:* N/A	*Average well rate:* N/A
Reservoir drive: N/A	*Decline:* N/A	*EOR:* N/A
Productivity index: N/A	*Performance:* N/A	
Reserves		
Recoverable: N/A	*Initially in place:* N/A	*Recovery factor:* N/A
Cumulative production: N/A		
Field history:		
Hydrocarbon type and formation fluid		
Hydrocarbon type: Oil	*API:* 28.1°	*GOR:* N/A
S content: 1.05%	*Wax content:* 7.87	*Pour point:* 0°
N_2: N/A	*CO_2:* N/A	*Other:* N/A
Methane: N/A	*Ethane:* N/A	*Propane:* N/A
IsoButane: N/A	*Gas cap:* N/A	*Biodegradation:* N/A
Formation volume factor: N/A	*Reservoir Temp:* 91 °C (1976)	*Reservoir pressure:* N/A
S_w: N/A	*R_w:* 0.77 Ωm at 27 °C	*Formation water salinity:* N/A
OWC: N/A	*GWC:* N/A	*GOC:* N/A
Water cut: N/A		*Recovery method:* N/A

Macropore system: vugs	*Matrix permeability:* 6.00mD	*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
Well tests: (well not specified): 2539-2548m 8.56 mmcuftd, 455 bcpd no water cut through 32/64" 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:* N/A	
Reserves		
Recoverable: N/A	*Initially in place:* N/A	*Recovery factor:* N/A
Cumulative production: 23.488 BCF at Feb 1995		
Field history: **Condensate production rates:** Initial production March 1987 327 BCPD from 1 well by flow. Maximum production Oct 1994 1477 BCPD from 5 wells by flow. Feb 1995 1387 BCPD from 5 wells by flow. **Gas production rates:** Initial production March 1987 3.2 mmscftpd from 1 well by flow. Maximum production Oct 1994 28.8 mmscuftpd from 5 wells by flow. Feb 1995 26.6 mmscuftpd from 5 wells by flow.		
Hydrocarbon type and formation fluid		
Hydrocarbon type: gas and condensate	*API:* 43.5 °	*GOR:* 1198 scf/bbl
S content: N/A	*Wax content:* N/A	*Pour point:* N/A
N_2: 0.89 vol %	*CO_2:* 2.76 vol %	*Other:* Oil viscosity: 0.4734cp; Specific gravity (gas): 0.765; Calorific value: 1269 BTU
Methane: 77.98 vol %	*Ethane:* .85 vol %	*Propane:* N/A
IsoButane: N/A	*Gas cap:* N/A	*Biodegradation:* N/A
Formation volume factor: N/A	*Reservoir Temp:* 157 °C	*Reservoir pressure:* N/A

13.7. References

Ajam, S.O., Henzell. L.A., Wang, J., Syarif, A.M. and Soerdirdja. 1982. Wellsite evaluation of the Miocene carbonates in Salwati Basin. Proceedings Indonesian Petroleum Association. 357-377

Birt C., Boyd B., & Nugraha A., 2015. Evolution and karstification of the Eocene-Miocene carbonates overlying the Tangguh gas fields in Western Papua – Observations from 3D seismic and impact in drilling operations. Proceedings of the 39th Annual IPA Convention and Exhibition.

Caughey, C., Dyer, J.N.J, Kohar, A., Lesttarini, H., Lodwick, W.R., Prijosoesilo, P., Wight, A.W.R. and Wilson, J.N. 1995. Seismic atlas of Indonesian oil and gas fields volume II: Java, Kalimantan, Natuna and Irian Jaya. Indonesian Petroleum Association.

Chevallier B., and Bordenave M.L., 1986. Contribution of geochemistry to the exploration in the Bintuni Basin, Irian Jaya. Proceedings of the 15th Annual IPA Convention and Exhibition.

Dolan P.J. and Hermany, 1988. The geology of the Wiriagar field, Bintuni Basin, Irian Jaya. Proceedings of the 17th Annual IPA Convention and Exhibition.

Eloni R., Husni Sahidu M.R., Panggeleng I., Birt C. & Manning T., 2016. From chaos tto caves – An evolution of seismic karst interpretation at the Vorwata field. Proceedings of the 40th Annual IPA Convention and Exhibition.

Gibson-Robinson, C. and Soedirdja, H. 1986. Transgressive development of Miocene reefs, Salawati Basin, Irian Jaya. Proceedings of the Indonesia Petroleum Association 15th Annual Convention and Exhibition, 377-403.

Gibson-Robinson, C., Henry, N.M., Thompson, S.J., and Raharjo, H.T., 1990, Kasim and Walio Fields - Indonesia, Salawati Basin, Irian Jaya, in Beaumont, E.A., and Foster, N.H., eds., Stratigraphic Traps I: AAPG Treatise of Petroleum Geology, Atlas of Oil and Gas Fields, p. 257-295.

Gilang, A., Gunawan, A., Putrazony, S., Prasetyadi, C. and Prasetyo, A.C. 2019. Tectono-stratigraphic framework within 2D palinspastc reconstruction of Salawati Basin, Bird's Head West Papua. Proceedings of the Indonesia Petroleum Association 43rd Annual Convention, 2019.

Gold, D.P., Baillard, F., Rathore, R,. Zhang, Z. and Arbi, S. 2020. An integrated biostratigraphic, seismic reservoir characterisation and numerical stratigraphic forward modelling approach to imaging drowned carbonate platforms: a case study from eastern Indonesia. Geological Society, London, Special Publications, 509,

Halbouty, M.T. 2001. Giant oil and gas fields of the decade 1990-2000: an introduction. Search and Discovery Article, 20005, Online Version of the Presentation at the APPG Convention, Denver, CO, June 5, 2001.

Hendardjo, K.S. and Netherwood, R.E. 1986. Palaeoenvironmental and diagenetic history of the Kais Formation, KBSA, Irian Jaya. Proceedings Indonesian Petroleum Association, 423-438

Hinschberger, F., Malod, JA., Réhault, JP., Villeneuve, M., Royer, JY. and Burhanuddin, S. 2005. Late Cenozoic geodynamic evolution of Eastern Indonesia. Tectonophysics, 404, 91-118.

IPA 2008 newsletter

Livingstone, H.J., Sincock, B.W., Syarief, A.M., Sriwidadi, and Wilson, J.N. 1992. Comparison of Walio and Kasim Reefs, Salawati Basin, Western Irian Jaya, Indonesia. IPA: Carbonate Rocks and Reservoirs of Indonesia, a core workshop.

Lundin, 2010. www.lundin-petroleum.com/eng/operation_indonesia.php

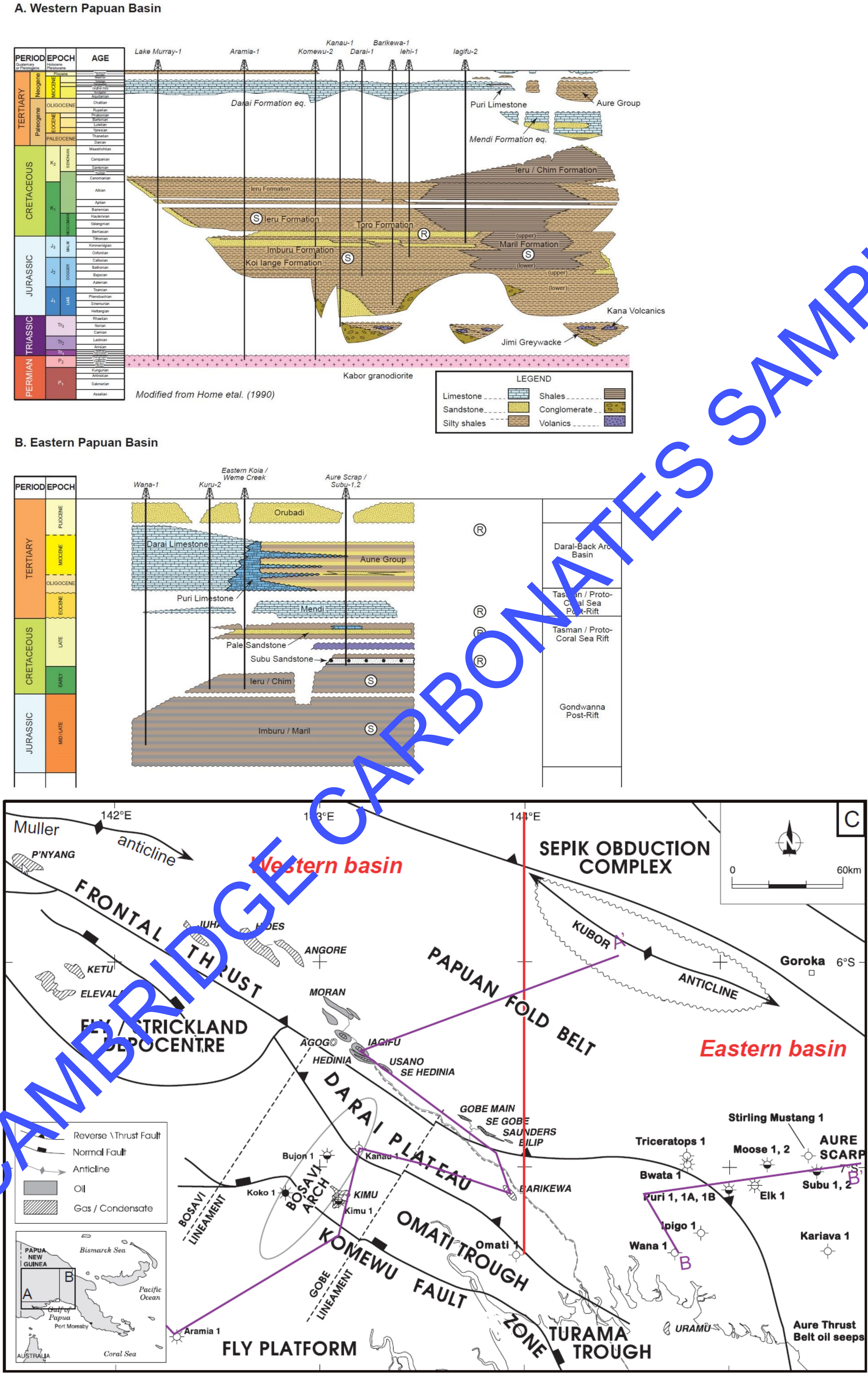


Figure 238 Lithostratigraphic schemes of the Western Basin and the foreland (A) and the Eastern Basin (B; InterOil, 2009). (C) Geological map of Western and Eastern basins, positioning of wells, and location of transects from (A) and (B). Modified from (A) Home et al. (1990) (B) from InterOil (C) Allan et al. (2006)

Several sandstone levels interbedded in the Koi Iange, Imburu, and Ieru shales are also productive, but the regionally extended Toro Formation, i.e. an allocyclic stratigraphic event, is an easier target. The shallow marine carbonates of the Darai Formation are not considered as interesting targets as they are most often not buried deep enough in this zone and are not overlain by a seal. Producing fields (Hides, Angore, Juha, Kutubu, Agogo, Moran and Gobe) are currently only reservoired in Toro sandstone. Details on reserves are shown in Table 32.

.

LICENCE / FIELD	OIL SEARCH INTEREST %	TOTAL OIL AND CONDENSATE MMBBL	TOTAL GAS BCF	TOTAL OIL AND CONDENSATE MMBBL	TOTAL GAS BCF
Reserves		Proved (1P)		Proved & Probable (2P)	
PDL 2 - Kutubu	60.00	12.1	-	16.7	-
PDL 2/5/6 - Moran Unit	49.50	7	-	10.6	-
PDL 4 - Gobe	10.00	0	-	0.1	-
PDL 3/4 - SE Gobe5	22.30	0.2	10.7	0.3	14.2
PDL 1 – Hides GTE6	16.70	-	3.2	-	5
Oil fields and Hides GTE reserves		19.3	13.9	27.7	19.2
PNG LNG Project reserves5	29.00	43.1	2,136.80	48	2,405.60
Subtotal reserves		62.3	2,150.70	75.7	2,424.90
Contingent resources		1C		2C	
PNG LNG Project gas, oil and condensate		-	-	1.6	60
Other PNG gas, oil and condensate7		-	-	46.7	3,649.30
Middle East gas, oil and condensate7		-	-	-	-
Subtotal resources		-	-	48.3	3,709.20
Total reserves and resources		62.3	2,150.70	124	6,134.10

Table 32 Reserves and resources in fields that produce from the Toro sandstone in the Western Basin (Oil Search, 2017)

14.3.4. Seals

The seal to the carbonate reservoirs is formed by the thick Mio-Pliocene clastic succession resulting from the erosion of the rising belt to the N and NE (Aure group, Orubadi Formation). In the Eastern Basin, this succession is quite thick (more than 1000m), and begins locally with deep marine *Orbulina*-rich marls. The risk in this basin is the possible upward remigration through faults. In the Gulf of Papua, the seal is similar in nature, but its integrity is potentially better due to the absence of significant late tectonic movements. The thickness of the seal may be a problem since the source of clastics is farther to the N-NE.

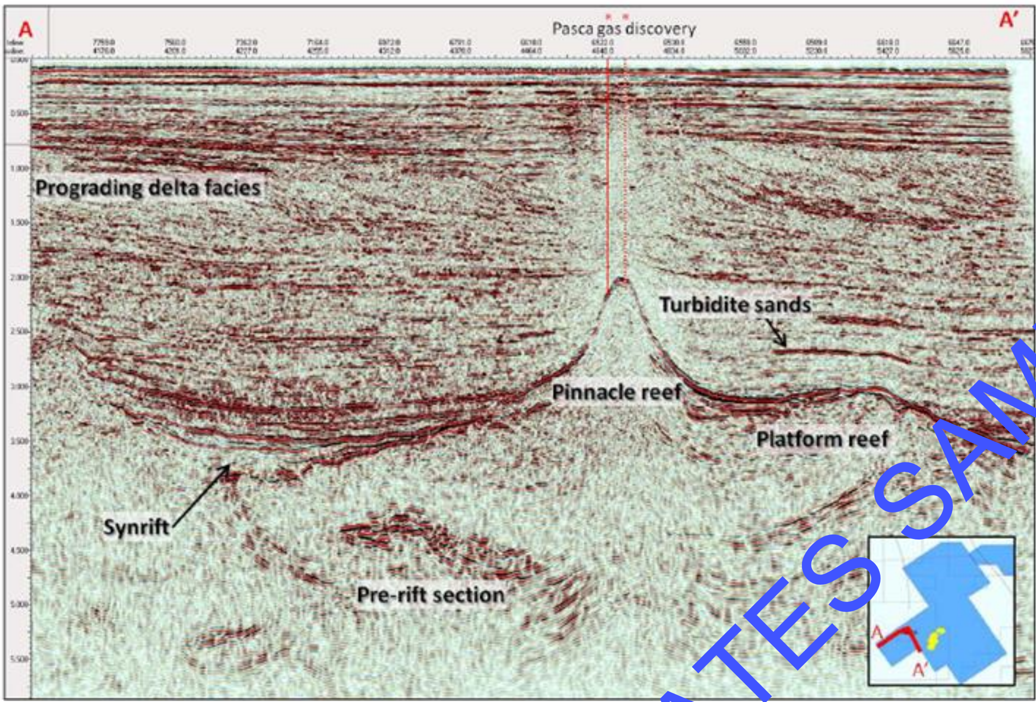


Figure 251 Seismic cross-section showing main play elements in the Gulf of Papua including the Pasca pinnacle reef. From Davies et al. (2012).

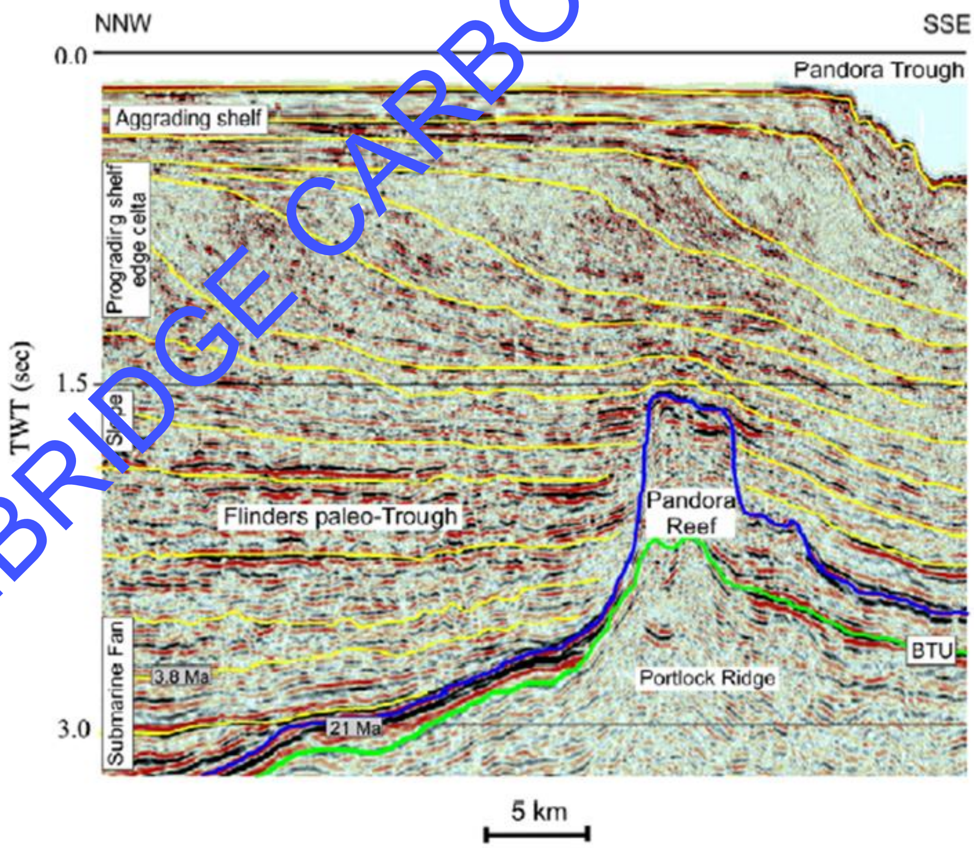


Figure 252 Interpreted seismic section showing the drowned Early Miocene Pandora Reef. From Tcherepanaov et al. (2008b) with permission

benthic foraminifera such as *Lepidocyclina*, encrusting organisms like encrusting bryozoans and encrusting foraminifera, and coralline red algae including rhodoliths (FB). Over the bank crest/shoal (BA), textures vary from bioclastic packstones, bioclastic grainstones and coral framestones. Biota includes *Porites*, coral spicules, Scleractinian coral, coralline red algae, encrusting sponge, indeterminate aragonitic fragments, and green algae. Bioclastic wackestones and packstones containing biota such as gastropods, molluscs and miliolids are found in the lagoon (LA).

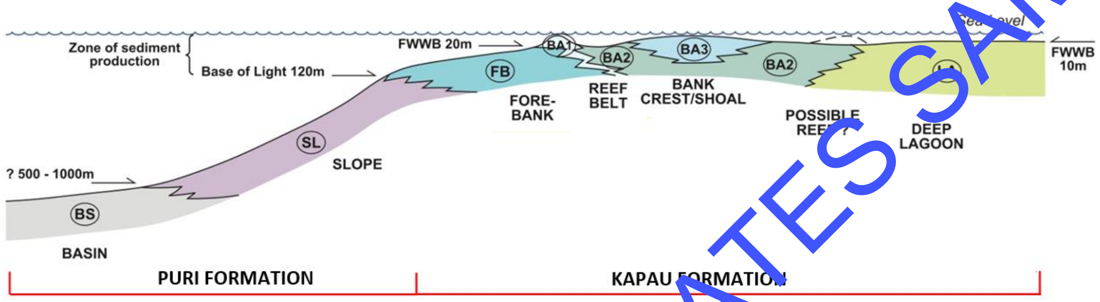


Figure 260 Schematic transect showing interpreted depositional setting of Puri and Darai Formation carbonates from basin to lagoon. Cambridge Carbonates in house work.

14.4.2. Diagenesis and reservoir quality

1. Fractured Mendi and Puri Formations:

Reservoir quality has been enhanced in the Mendi and Puri Formations by fracturing, which is likely to have developed during folding and thrusting in Papua New Guinea. Folding and thrusting mostly occurred in the Late Miocene-Holocene, after arc-continent collision in the Late Oligocene-Miocene, between the Australian plate and the Melanesian arc (Hill 1991 and Hill and Hall 2003 in Baldwin et al., 2012). Results from surface studies indicate a primary bimodal ENE and NW- trending fracture distribution (Leech et al., 2006). Dolomitisation has further enhanced reservoir quality; core data has identified increased porosity and permeability in zones of dolomitisation (Leech et al., 2006).

Evidence of fracturing in the Mendi Formation comes from Eocene platform carbonates at Wana-1 which flowed 18,000 barrels of water per day in a DST (Durkee et al., 1986). Further evidence comes from the Elk Field. The target reservoir in Elk-1 was the Puri Formation, however Elk-2 intercepted both Puri and Mendi limestone frontier areas dominated by carbonate reservoirs in the Eastern Basin, including offshore areas in the Gulf of Papua. Prospective targets include:

- Further exploration of the Eocene Mendi and Oligo-Miocene Puri and Darai Formations (see elaboration below) (e.g. Kina Petroleum Limited, 2017)
- Mid and Upper Miocene reefs (e.g. Kina Petroleum Limited, 2016)
- Plio-Pleistocene carbonates: the presence of hydrocarbons in Plio-Pleistocene carbonates is supported by gas shows in Plio-Pleistocene Wedge Hill Limestone at Black Bass (Kina Petroleum Limited, 2017).

<u>Darai Formation</u>

Oligo-Miocene carbonates have been grouped into six basic play types by Leamon and Parsons (1986), including:

1) Pinnacle Reefs (Figure 248)
2) Thrust faulted anticlines,
3) Barrier Reef (Borabi Reef Trend) (Figure 248)
4) Intra-carbonate Barrier Reef (Ru Reef Trend),
5) Prograding Detrital shelf
6) Algal Banks (Figure 248)

Pinnacle reefs and thrust faulted anticlines have been the subject of exploration and gas from these play types is soon to be commercialised. Little exploration has however been undertaken on the remaining play types (3-6), which could be the subject of future potential:

Barrier Reef (Borabi reef trend)

The Borabi Reef Trend was a major Miocene barrier reef development that has been mapped for approximately 250km from the mouth of the Turama River in the north to the eastern edge of the northern Great Barrier Reef in the south (Figure 269) (Leamon and Parsons, 1986). The Borabi reef trend marks the eastern perimeter of an extensive Miocene carbonates shelf (Leamon and Parson, 1986). The central part of the reef

Macropore system: N/A	*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:* 4500 psi (A-3 Durkee, 1990) *Initial temperature:* 115.5˚C
Well tests: 7.2 mmcfg/d with 101 BC/hr (A-3, Durkee, 1990). In Pasca A-2, ten drill stem tests were carried out, four of these flow gas and condensate at rates of up to 17.05 mmcfg/d with a gas/liquid ratio of 16.75 mcf/bbl (Durkee, 1990).	*Test permeability:* N/A	*Average well rate:* N/A
Reservoir drive: N/A	*Decline:* N/A	*EOR:* N/A
Productivity index: N/A	*Performance:* N/A	
Reserves		
Recoverable: N/A	*Initially in place:* (BCF) 260 (Phillips, 1978-1982), 458 (Superior 1982-1986), 410 (RRA, 1982), 172-342 (GSPNG, 1986), 312 (ERC, 1986) in Durkee (1990) * 435 (InterOil, 2008b)	*Recovery factor:* N/A
Cumulative production: N/A		
Field history: N/A		
Hydrocarbon type and formation fluid		
Hydrocarbon type:	*API:* N/A	*GOR:* N/A
S content: N/A	*Wax content:* N/A	*Pour point:* N/A
N_2: N/A	CO_2: N/A	*Other:* N/A
Methane: N/A	*Ethane:* N/A	*Propane:* N/A
IsoButane: N/A	*Gas cap:* N/A	*Biodegradation:* N/A

RPS, 2010. Independent Geologisy's Report PPL 326, Eastern Papuan Basin, Papua New Guinea, prepared for Newport Energy Limited (unpublished report).

Sarg, J.F., Markello, J.R., Weber, L.J., Thomson, J.M., Kmeck, J.J., Christal, M.E., Southwell, J.K., and Tanaka, Y. 1996. Carbonate Sequence Stratigraphy – A Summary and Perspective with Case History, Neogene, Papua New Guinea, in: Proceedings of the International Symposium on Sequence Stratigraphy in S.E. Asia, pp 137-179, Indonesian Pet. Assoc., Jakarta.

Schofield, S. 2000. The Bosavi Arch and the Komewu fault zone: their control on basin architecture and the prospectivity of the Papuan foreland. In PG. Buchanan, AM. Grainge and RCN. Thornton (Eds): "Papua New Guinea's petroleum industry in the 21st Century", Proceeding of the Fourth PNG Petroleum Convention, Port Moresby, 101-122.

SEAPEX Press, 2016. No. 83, v. 19, issue 1, Q1.

SEAPEX Press, 2016b. No. 84, v. 19, issue 2, Q2.

SEAPEX Press, 2017. No. 87, v. 20, issue 1, Q1.

Steinshouer, DW., Qiang, J., McCabe, PJ. and Ryder, RT. 2000. Maps showing geology, oil and gas field and geologic provinces of the Asia Pacific region. USGS Open-File Report 97-470F.

Storey, J., Holland, D.J., Sarma, S. and Sioni, S. 2007. Seismic acquisition and analysis of the Elk carbonate reservoir, Papua New Guinea. ASEG 2007, Perth, Western Australia.

Symonds, P., Davies, P.J., Feary, D.A. and Pigram, C.J. 1988. Geology of the Northeastern Australian Margin Basins. PESA.

Tcherepanov, E.N., Droxler, A.W., Lapointe, P. and Mohn, K. 2008. Carbonate seismic stratigraphy of the Gulf of Papua mixed depositional system: Neogene stratigraphic signature and eustatic control. Basin Research, 20, 185-209.

Tcherepanov, E.N., Droxler, A.W., Lapointe, P., Dickens, G.R., Bentley, S.J., Beaufort, L., Peterson, L.C., Daniell, J. and Opdyke, B.N. 2008b. Neogene evolution of the mixed carbonate-siliciclastic system in the Gulf of Papua, Papua New Guinea. J. Geophy. Res., 13, F01S2, doi:10.1029/2006JF000684.

Twinza Oil, 2017. http://www.twinzaoil.com/home

USGS, 2012. Assessment of Undiscovered Oil and Gas Resources of Papua New Guinea, Eastern Indonesia and East Timor, 2011. U.S. Geological Survey Fact Sheet 2012-3029.

Waples, D.W. and Wulff, K.J. 1996. Genetic classification and exploration significance of oils and seeps of the Papuan Basin. In PG. Buchanan (Ed):"Petroleum exploration, developments and production in Papua New Guinea", 417-430.

Wilson, M.E.J., Lewis, D., Yogi, O., Holland, D., Hombo, L. and Goldberg, A. 2013. Development of a Papua New Guinean Onshore Carbonate Reservoir: A Comparative Borehole Image (FMI) and Petrographic Evaluation. Marine and Petroleum Geology, v. 44, pp. 164-195

Zachos, J.C., Opdyke, B.N., Quinn, T.M., Jones, C.E. and Halliday, A.N. 1999. Early cenozoic glaciation, antartic weathering and seawater 87Sr/86Sr: is there a link?. Chemical Geology, 161, 165-180.

Zachos, J.C., Pagani, M., Sloan, L., Thomas, E. and Billups, K. 2001. Trends rhythms, and aberrations in global climate 65Ma to present. Science, 292, 686-693.