Geochemical characteristics and depositional environments of the Narimba Formation source rock, Bass Basin, Australia

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Abstract

This research aims to conduct source rock characterization on the Narimba Formation in the Bass Basin, Australia, which is made of mostly sandstone, shale and coal. The geochemical characteristics and depositional environments have been investigated through a variety of data such as rock–eval pyrolysis, TOC, organic petrography and biomarkers. Total organic carbon (TOC) values indicated good to excellent organic richness with values ranging from 1.1 to 79.2%. Kerogen typing of the examined samples from the Narimba Formation indicates that the formation contains organic matter capable of generating kerogen Type-III, Type-II-III and Type-II which is gas prone, oil–gas prone and oil prone, respectively. Pyrolysis maturity parameters (T_{max} , PI), in combination with vitrinite reflectance and some biomarkers, all confirm that all samples are at early mature to mature and are in the oil and wet gas windows. The biomarkers data (the isoprenoids (Pr/Ph), CPI, isoprenoids/n-alkanes distribution (Pr/nC₁₇ and Ph/nC₁₈), in addition to the regular sterane biomarkers (C₂₇, C₂₈ and C₂₉) are mainly used to evaluate the paleodepositional environment, maturity and biodegradation. It has been interpreted that the Narimba Formation was found to be deposited in non-marine (oxygen-rich) depositional environment with a dominance of terrestrial plant sources. All the analyzed samples show clear indication to be considered at the early mature to mature oil window with some indication of biodegradation.

Keywords Narimba Formation · Source rock characterization · Petroleum system · Bass Basin

Introduction

The Bass Basin is located to the southeast of Australia. It is a rift basin underlying the Bass Strait which runs between Victoria and Tasmania (Fig. 1). It had been formed during the Early Cretaceous to recent, trending northwest–southeast (Blevin et al. 2003; Boreham et al. 2003). It is dominantly offshore and has a total extent of 42,000 km², bounded to the west by the King Island High and northwest and by Flinders Island and the Bassian Rise to the northeast (Fig. 1) (Blevin, et al. 2003; Boreham et al. 2003; Cummings et al. 2004). The basin is divided into the Cape Wickham and Durroon sub-basins (Fig. 1). The Bass Basin is a portion of the larger Southern Rift System that separated Australia

and Antarctica from the Late Jurassic to Early Cretaceous (Etheridge et al. 1985a, 1985b; Boreham et al. 2003).

Several geochemical analyses had shown that the hydrocarbon in the Bass Basin is mainly originated from land-plant material with little to no indication of marine origin (Edwards et al. 1999). It has been suggested that liquid hydrocarbons are produced from organic matter disseminated in carbonaceous claystones, while natural gas originated mostly from coaly facies (Nicholas et al. 1981; Miyazaki 1995). However, Blevin et al. (2003) and Boreham et al. (2003) had found that tertiary coals (aged Middle to Early Eocene) were responsible for generating the liquid hydrocarbons. The pattern of hydrocarbon distribution suggests that hydrocarbons had been generated and accumulated in the Cormorant, Yolla and Pelican troughs in Bass Basin. The generated hydrocarbons migrated to traps within the troughs or adjacent structures. More than 30 wells had been drilled since 1965 with a drilling density of approximately one well per 1320 km² (Blevin et al. 2003). Previous exploration had discovered hydrocarbons

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Fig. 1 Map showing the extent of the Bass Basin, highlighting the studied wells (modified after Boreham et al. 2003)

at the fields named Pelican, Cormorant, Yolla, Trefoil and White Ibis (Blevin et al. 2003; Arian 2010).

The interbedded coals and fluvio-deltaic as well as lacustrine shales are considered the dominant source rocks in the basin (Partridge 2002) where the Bass Basin contains significant amounts of these source rocks (Partridge 2002). The Narimba Formation is being part of the Middle Eastern View Group. It is comprised of interbedded coals, thin shale beds and sandstone (Blevin et al. 2005). This formation has strong criteria to play the role of source rock.

The main objectives of this study are to characterize and evaluate the source rock characteristics of the Narimba Formation in the study area. The Narimba Formation is assessed for its oil generation potential by means of organic geochemical analyses which include the determination of the total organic carbon (TOC) content, rock–eval pyrolysis, maceral composition and vitrinite reflectance measurements and geochemical biomarkers. This research is also to provide clues for the stage of the paleodepositional environments and thermal maturity to assess the hydrocarbon generation potential of the source rock in the Narimba Formation.

Fig. 2 Regional map showing the location of tectonic elements and generalized basement fault trends in the Bass Basin (Blevin et al. 2003). Cormorant (CT), Yolla (YT), White Ibis (WIT), Pelican troughs (PT) and the Chat Accommodation Zone (CAZ)

Geological background

Structural setting

The Bass Basin has been described as a system of multiple northwest-trending, inter-linked half graben dipping northeast and southwest (Etheridge et al. 1985a, b; Lennon et al. 1999; Boreham et al. 2003; Arian 2010). The basin is part of the much larger Southern Rift System, which was initiated during lithospheric extension in the Late Jurassic–Early Cretaceous (Etheridge et al. 1985a, b; Boreham et al. 2003). The Bass Basin underlies the Bass Strait region between Tasmania and Victoria (Fig. 2) in offshore southern Australia (Boreham et al. 2003). It is detached from the Otway Basin by the King Island High to the west and northwest. Bass Basin is also separated from the Gippsland Basin to the northeast by Flinders Island and the Bassian Rise (Fig. 2) (Boreham et al. 2003).

The Bass Basin underwent three phases of extension, based on previous seismic mapping and well log interpretation studies by Etheridge et al. (1985a, b), Lennon et al. (1999), Blevin et al. (2003), Cummings et al. (2004) and

Arian 2010). Later, the basin underwent several periods of compression and reactivation. In the Middle Eocene, minor contractional events took place (Blevin et al. 2003). This is followed by reactivation in the form of right-lateral wrench compression along with the localized extensional structures created by the inversion of Cretaceous–Middle Eocene (Cummings et al. 2004). The fact that the Bass Basin is underlain by basement of differing fabric has also influenced the different structural styles observed within the overlying Mesozoic rift basin (Blevin et al. 2003). The integration of basement geology and mapping of the depocenters has helped to clarify the nature of structural elements within the basin (Blevin et al. 2003).

The Bass Basin is separated into two sub-basins; the Cape Wickham Sub-basin to the west and the Durroon Sub-basin to the east (Fig. 2) (Baillie and Pickering 1991; Boreham et al. 2003; Arian 2010). The Chat Accommodation Zone (CAZ) (Fig. 2) marks the boundary between the Cape Wickham and Durroon sub-basins (Baillie and Pickering 1991). The location of the main Cretaceous half graben in the Cape Wickham Sub-basin (Fig. 2) is shown by the Cormorant (CT), Yolla (YT), White Ibis (WIT) and Pelican troughs

Fig. 3 Lithostratigraphic column of Bass Basin, highlighting the Late Paleocene-Early Eocene Narimba Formation (modified after Cummings et al. 2004)

(PT) (Blevin et al. 2003). These two depocenters differ in age and structure due to distinct tectonic influences. The easternmost Durroon Sub-basin (Baillie and Pickering 1991) is separated from the western depocenters by a northeast-trending structural accommodation zone (Fig. 2). The extension in the Durroon Sub-basin ceased by Santonian-Campanian time, while tectonic activity in the Otway-Sorell region continued to influence and enhance accommodation in the western Cape Wickham depocenters until the Early–Middle Eocene (Boreham et al. 2003). The Durroon Sub-Basin is affected by extension which is terminated between the Santonian and Campanian, while accommodation zones kept developing in the Cape Wickham Sub-basin (Boreham et al. 2003).

Stratigraphy

The simplified stratigraphic columnar section of Bass Basin is illustrated in Fig. 3. The most significant coal-bearing section extends from Late Cretaceous to Eocene, encompassing the Eastern View Group and the Demons Bluff Formation (Fig. 3) (Partridge 2002; Arian 2010). Coal deposition had been associated with the availability of deep lakes distributed in the central and northwestern Bass Basin (Partridge 2002). Fluvio-deltaic and lacustrine shales are also potential source rocks, whereas reservoir rock types are generally silty, fluvial channel and delta sands with very little marine influence (Arian 2010). Meandering fluvial channel belts and distributary channels had been identified as the most potential reservoirs (Arian 2010). In addition to the requirement of medium to coarse-grained sands, resistance to compaction (to preserve intergranular porosity) and presence of fractures and secondary porosity also play roles in making a good reservoir. The Middle Eastern View Group (Fig. 3) had been found to bear thick sand zones with excellent lateral continuity (Arian 2010).

The Demons Bluff Formation, which is a regional sealing facies, overlies the Eastern View Group (Fig. 3), and it is made up of fine-grained sediments. This formation also exhibits good lateral extent as well as thickness (100–395 m) (Blevin et al. 2003). Therefore, the reservoirs in the Middle Eastern View Group could potentially be sealed by fining-upward cycles within the unit (Arian 2010). The Lower Eastern View Group is made up of the Durroon Megasequence (Fig. 3). It was deposited as a result of the Tasman Rifting, which was the second rift phase underwent by the basin from the Cenomanian to Campanian (Late Cretaceous) (Cummings et al. 2004; Arian 2010). The basaltic basement is overlain by lithologic variation consisting of shale, siltstone and sandstone (Blevin et al. 2005) (Fig. 3).

The Middle Eastern View Group is comprised of the Bass Megasequence which was deposited during the third rift phase (Late Cretaceous-Cenozoic) (Arian 2010). This

megasequence is further divided into three formations (Fig. 3), namely the Furneaux, Tilana and Narimba Formations (Blevin et al. 2005). The Furneaux Formation is well imaged on seismic data in the central and western basin, around the Poonboon-1, Tilana-1 and Tarook-1, and Koorkah-1 and Toolka-1A wells (Blevin et al. 2003). Seismic interpretation suggests that the Furneaux Formation was deposited as a syn-rift succession as a result of reactivation of older Early Cretaceous extensional faults (Blevin et al. 2003). Furneaux Formation (Fig. 3) ranges from interbedded fluvio-deltaic sandstones and freshwater lacustrine shales to fluvio-deltaic sandstones and thin interbedded overbank or delta plain shales and coals. The upper sequence boundary is marked by an angular unconformity (Blevin et al. 2005).

Blevin et al. 2003 concluded that the Tilana Formation (Fig. 3) encompasses the latest Maastrichtian to latest Paleocene succession. Seismic correlations suggest that deposition of the Tilana was controlled by a combination of reactivation of underlying Early Cretaceous faults, tectonic subsidence, sediment loading and compaction (Blevin et al. 2003). Some areas of the basin appear to have been unaffected by increased subsidence during this time (Poonboon-1), suggesting that rates of accommodation varied significantly between the different rift segments. This variation in accommodation is clearly shown in the thickness and range of facies types deposited (Blevin et al. 2003).

The latest Late Paleocene to late Early Eocene Narimba Formation (Fig. 3) is the youngest sequence within the Bass Megasequence (Blevin et al. 2003). The Narimba Formation was deposited across most of the Bass Basin as a result of the reactivation of select Early Cretaceous rift faults (Blevin et al. 2003). The Narimba Formation, which is the main focus of this study (Fig. 3), also has a complex composition of sandstones, thin shale beds and coals which are of lacustrine lower delta plain and peat mire origin (Blevin et al. 2005). A combination of high rates of accommodation and a steady supply of sandy sediment feeding down the flanks of the rift from northern Tasmania accounts for the

Table 1 Tops, bottoms and thicknesses of the Narimba Formation as encountered by studied wells, i.e., Pelican-1, Pelican-2, Pelican-3, Pelican-4, Pelican-5, Narimba-1 and Tilana-1

Well name	Top depth (m)	Bottom depth (m)	Thick (m)
Plican-1	2499	3168	669
Plican-2	2661	3068	407
Plican-3	2661	3068	407
Plican-4	2528	3050	522
Plican-5	2560	3110	550
Narimba-1	2580	3354	774
Tilana-1	2490	2990	500

Table 2 Rock–eval pyrolysis results for the Narimba Formation in wells Pelican-1 to 5 and Narimba-1

Well name	Depth(m)	Lithology	S1	S2	S3	TOC	OI	HI	PI	PY	T _{max}
Pelican-1	2825	Non-coal	0.61	3.62	2.02	2.24	90	161	0.14	4.23	435
Pelican-2	2878	Coal	18	255	–	76.35	–	334	0.07	273.00	446
	2912	Coal	20.1	223	–	61.43	–	363	0.08	243.10	448
Pelican-3	2861	Non-coal	0.46	2.42	4.12	2.86	144	84	0.16	2.88	434
Pelican-4	2816	Non-coal	0.51	16	–	10.06	–	159	0.03	16.51	442
Pelican-5	2557	Non-coal	0.77	7.45	1.57	2.85	55	261	0.09	8.22	428
	2565	Non-coal	1.86	9.19	0.72	3.02	23	304	0.17	11.05	424
	2583	Non-coal	5.14	25.5	0.63	8.45	7	301	0.17	30.64	432
	2619	Non-coal	1.32	9.25	0.75	2.84	26	325	0.12	10.57	425
	2637	Non-coal	0.92	12.4	0.33	11.10	2	111	0.07	13.32	434
	2655	Non-coal	0.82	5.37	1.18	2.52	46	213	0.13	6.19	426
	2709	Non-coal	1.02	11.49	0.49	3.46	14	332	0.08	12.51	434
	2727	Non-coal	1.27	11.01	0.74	3.68	20	299	0.1	12.28	433
	2745	Non-coal	0.7	5.37	0.82	2.46	33	218	0.12	6.07	431
	2763	Non-coal	1.52	14.24	0.71	4.50	16	316	0.1	15.76	434
	2790	Coal	3.2	18.76	0.38	39.40	1	48	0.15	21.96	435
	2794	Coal	27.01	338.76	4.43	79.20	6	428	0.07	365.77	441
	2808	Non-coal	0.75	3.89	0.94	2.04	50	191	0.16	4.64	435
	2844	Non-coal	2.3	13.09	0.89	3.64	24	360	0.15	15.39	431
	2862	Coal	2.47	15.22	0.71	18.60	4	82	0.14	17.69	428
	2898	Non-coal	0.69	4.01	0.94	1.76	53	228	0.15	4.70	433
	2916	Non-coal	1.21	16.08	0.85	4.20	20	383	0.07	17.29	433
	2937	Non-coal	0.82	2.52	1.61	1.10	146	229	0.25	3.34	436
	2970	Coal	1.84	14.76	0.3	17.80	2	83	0.11	16.60	440
	2970	Coal	23.37	235.34	4.06	72.40	6	325	0.09	258.71	442
	2978	Non-coal	1.06	3.85	1.17	1.56	75	247	0.22	4.91	440
	2988	Coal	0.62	6.7	0.22	20.60	1	33	0.08	7.32	437
	2991	Non-coal	0.72	3.86	2.23	2.00	111	193	0.16	4.58	442
	3006	Non-coal	1.63	9.66	1.04	6.25	17	155	0.14	11.29	439
	3042	Non-coal	0.52	2.38	0.94	2.00	47	119	0.18	2.90	441
	3060	Non-coal	1.87	9.49	0.46	4.50	2	36	0.16	11.36	439
Narimba-1	2759	Coal	10.7	200		43.96		455	0.05	210.70	438
	2835	Coal	26.5	65.7		23.13		284	0.29	92.20	434
	2878	Non-coal	0.18	1.6		3.14		51	0.1	1.80	430
	3198	Non-coal	0.75	22.22		11.95		186	0.03	22.90	445

unusually high rate of sedimentation in the Pelican Trough (Blevin et al. 2003).

The Upper Eastern View Group contains the Aroo Formation (Fig. 3). It was formed during thermal subsidence at a rift transition period, likely to be the transition between the second and third rift phases (Boreham et al. 2003). The Aroo Formation is considered as intercalations of sandstones, siltstones, carbonaceous shales and coal seams (Meszoly et al. 1985). Due to a decrease in rate of deposition, the coal successions have higher frequencies and thicknesses (Blevin et al. 2005; Arian 2010).

Data and methodology

Geochemical dataset is retrieved from the *Government of Western Australia, Department of Mines, Industry Regulation and Safety*. Source rock characterization has been performed using geochemical analyses data applied on different samples collected from different wells. The geochemical datasets utilized in this source rock evaluation include total organic carbon (TOC) content, rock–eval pyrolysis, vitrinite reflectance, maceral composition and the biomarkers (Tables 2, 3, 4, 5). These methods gave insights on the quantity, quality and thermal maturity of the source rocks. Biomarker data facilitate the definition of the thermal maturity, hydrocarbon potentiality and paleodepositional

Table 3 Vitrinite reflectance data for the Narimba Formation within the wells Pelican-1 to 5, Narimba-1 and Tilana-1

Well name	Depth (m)	Mean %Ro
Pelican-1	2497	0.69
	3060	0.86
	3062	0.81
Pelican-2	2875	0.8
	2882	0.81
	2913	0.82
	2915	0.81
Pelican-3	2802	0.67
	2810	0.71
Pelican-4	2815	0.75
	2815	0.73
Pelican-5	2646	0.77
	2691	0.7
	2691	0.73
	2838	0.69
	2862	0.82
	3024	0.88
Narimba-1	2747	0.67
	2825	0.62
	2885	0.56
	3051	0.71
	3176	0.78
	3196	0.79
Tilana-1	3204	0.78
	2687	0.62
	2697	0.62
	2805	0.6
	2895	0.83
	2978	0.75

environment of the formation of interest. The subsequent classifications of quality, quantity and thermal maturity were done in accordance with Tissot and Welte (1978), Peters (1986), Peters and Cassa (1994).

Rock eval and total organic carbon (TOC) were determined using a Rock Eval 6 instrument. Vitrinite reflectance and fluorescence measurements were taken using the procedures described in Newman (1997) and Newman et al. (2000). Gas chromatography–mass spectrometry of the saturated hydrocarbons using selected ion monitoring (GCMS-SIR) and compound-specific carbon isotopic analysis of the n-alkanes by gas chromatography–combustion-isotope ratio mass spectrometry (GC-C-IRMS) were conducted according to Boreham and Summons (1999).

A total of 35 source rock samples have been collected from 7 wells, namely Pelican-1, Pelican-2, Pelican-3, Pelican-4, Pelican-5, Narimba-1 and Tilana-1 in the Bass Basin (Fig. 1). Top and bottom depths of the Narimba Formation, together with thicknesses as encountered by the studied wells, are presented in Table 1, illustrating values that range from 2490 to 2661 m, 2990 to 3354 m and 407 to 774 m, respectively.

Rock–eval pyrolysis data have been performed on 35 samples as follows: Pelican-1 (one sample), Pelican-2 (two samples), Pelican-3 (one sample), Pelican-4 (one sample), Pelican-5 (26 samples), Narimba-1 (4 samples) (Table 2): the volume of volatile hydrocarbon (bitumen) already available in the source rock (S1); volume of hydrocarbon generated during pyrolysis (S2); amount of carbon dioxide emitted (S3); maximum pyrolysis temperature (Tmax); and measurement of the total organic carbon (TOC). Hydrogen index (HI) and oxygen index (OI) and some other parameters have been calculated by using rock–eval parameters (Espitalié et al. 1977; Peters 1986).

Vitrinite reflectance is the measurement of the degree with which light will be reflected for vitrinite polished surface which varies according to the level of thermal maturity (Mukhopadhyay and Hatcher 1993; Law 1999; Wilkins and George 2002). Vitrinite reflectance data for 29 samples collected from the wells Pelican-1, 2, 3, 4, 5, Narimba-1 and

Table 4 Biomarker data and parameters calculated from n-alkanes and isoprenoids for Pelican-1, Pelican-3, Pelican-5 and Tilana-1

Well name	Depth (m)	Pr/Ph	Pr/nC17	Ph/nC18	CPI	nC27	nC28	nC29
Pelican-1	2825	8.36	5.17	0.87	1.13	5.8	5.3	6.6
Pelican-3	2861	7.02	4.76	0.85	1.2	5.7	4.7	5.2
Pelican-5	2788	–	–	–	–	29	19	52
	2790	4.7	0.84	0.15	–	12	44	44
	2961	4.9	0.87	0.17	–			
	2169	9.8	4.8	0.6	–			
	2691	5.5	0.86	0.12	–			
	2691	7.5	2.5	0.25	–			
Tilana-1	2800.9	8.44	7.28	1.00	1.22	8.5	6.6	8.9

Table 5 Biomarker parameters calculated from steranes, hopanes and terpanes

Well name	Depth (m)	nC19	nC23	C29/(C29 + C27)	C19/ (C19 + C23)	C27/C29	C27/(C27 + C29)
Pelican-1	2825	2.4	3.1	0.532	0.436	0.879	0.468
Plican-3	2861	2.3	3.3	0.477	0.411	1.096	0.523
Plican-5	2788	–	–	0.642	–	0.558	0.358
	2790	–	–	0.786	–	0.273	0.214
Tilana-1	2800	1.7	4.1	0.511	0.293	0.955	0.489

Table 6 Maceral composition (vitrinite, inertinite and liptinite) data for the Narimba Formation in Pelican-5 well

Depth (m)	Vitrinite (%)	Inertinite (%)	Liptinite (%)
<i>Pelican-5 well</i>			
2592–2601	70	5	25
2745–2754	80	5	15
	45	30	25
2790	45	5	50
2790–2799	65	5	30
2937	55	40	5
2961–2970	70	10	20

Tilana-1 were utilized in this study as indicators of thermal maturity (Table 3). The maceral composition for 7 samples from Plican-5 well has been provided by the *Government of Western Australia, Department of Mines, Industry Regulation and Safety* (Table 6).

The biomarker data (9 samples) from the wells Pelican-1 (one sample), Pelican-3 (one sample), Pelican-5 (6 samples) and Tilana-1 (one sample) have been used to identify paleodepositional environment of the Narimba Formation source rocks (Tables 4, 5).

Biomarkers are ‘molecular fossils’ which retain most of the original carbon skeleton of their original form (Philp and Lewis 1987; Simoneit 2002).

Biomarkers are a group of degradation-resistant compounds which are primarily hydrocarbons and can be found in oil, rocks, sediments and soil extracts (Philp and Lewis 1987; Simoneit 2002). These ‘molecular fossils’ are distinguishable from other compounds as they retain most of the original carbon structure of the original material, such as previous living organisms (Mobarakabad et al. 2011). They are present predominantly and globally and, hence, are very useful in indicating organic source material, paleodepositional environment, thermal maturity and source rock quality (Moustafa and Morsi 2012).

The interpretations of the biomarker data and its derivatives such as the pristane/phytane ratio, isoprenoid/n-alkanes ratio, hopanes, terpanes, concentration of regular steranes (C_{27} , C_{28} and C_{29}) and carbon preference index (CPI) have been performed following the research done by Philp and Lewis (1987), Peters and Moldowan (1993), Peters and Cassa (1994), Simoneit, (2002), Peters et al. (2005), Rodriguez and Philp (2015), Ayinla et al. (2017), Jumat et al. 2018, Osli et al. 2018, 2019 and Shalaby et al. 2019b). The organic petrographical data used are the maceral analysis and vitrinite reflectance measurements on samples collected from Pelican-5 Well. The volumetric

Fig. 4 A cross-plot of S1 versus TOC indicating the origin of the hydrocarbon within the Narimba Formation (Fakhri et al. 2013)

Fig. 5 PY versus TOC cross-plot indicating hydrocarbon generating potential

maceral composition of the proportions of vitrinite, liptinite and inertinite has been provided by *Government of Western Australia, Department of Mines, Industry Regulation and Safety*.

Results and discussion

The geochemical analyses and organic richness

The geochemical analyses for the total of 35 samples from the studied wells have been interpreted. Table 2 shows these rock–eval pyrolysis results and other associated parameters in detail. Out of the total number of samples, 28.6% was coal and the remaining 71.4% have been interpreted as non-coal (shale and mudstones). The free volatile hydrocarbon, S1 values, ranged from 0.18 to 27.01mgHC/gm rock. The

pyrolyzed hydrocarbon, S2 values, ranged from 1.60 to 338.76mgHC/gm rock, and the total CO₂, S3 values ranged from 0.22 to 4.43mgCO₂/gm rock. The maturity parameter, Tmax, is the maximum temperature at which the peak hydrocarbon generation from cracking the kerogen is recorded to range from 424 to 448 °C. Total organic carbon (TOC) content indicates the quantity of organic richness, and it is found to range from 1.1 to 79.2 wt. %. Subsequently, the source rock potentiality represented by hydrogen index (HI) and oxygen index (OI) values produced ranges of 33 to 455 mg HC/g TOC and 1 to 146 mg CO₂/g TOC, respectively. Additional parameters attained were production yield (PY) values which gave a value range of 1.80 to 365.77 and production index (PI) can also use to reflect the maturity and it ranges from 0.03 to 0.29.

Vitrinite reflectance (%Ro) is an optical parameter describing the degree of coalification and, hence, the

Fig. 6 S2 versus TOC cross-plot for quality and quantity of organic matter (Espitalié et al. 1985)

Fig. 7 S_2 versus TOC cross-plot to identify kerogen typing of organic matter (Langford and Blanc-Valleron 1990)

degree of organic matter thermal maturity in source rocks (Mukhopadhyay 1994; Mukhopadhyay and Hatcher 1993; Wilkins and George 2002). As thermal evolution causes alteration in chemical composition of vitrinite, the reflectance values also change. Generally, vitrinite reflectance values of 0.2–0.6% correspond to immature organic matter, 0.6–1.35% is mature, and > 1.35% is postmature (Peters and Cassa 1994). The summary of vitrinite reflectance (R_o %) data relative to depth for the Narimba Formation within the studied wells shows the minimum and maximum values have been recorded in Pelican-5 well as 0.37 and 1.41, respectively (Table 3).

The biomarkers data (CPI, the isoprenoids (Pr/Ph), isoprenoids/n-alkanes distribution (Pr/ nC_{17} and Ph/ nC_{18}), in addition to the regular sterane biomarkers (C_{27} , C_{28} and C_{29}) utilized in this study are presented in Tables 4, 5. The percentages of vitrinite, liptinite and inertinite available for samples from Pelican-5 are listed in Table 6. The average percentages of vitrinite, inertinite and liptinite compositions were 60.9%, 16.6% and 23.1%, respectively. Maceral composition data can be utilized to further evaluate the type,

potentiality and thermal maturity of organic matter within the source rock.

The source rock generated hydrocarbon from the Narimba Formation can be evaluated by the use of the cross-plot relationship of S_1 versus TOC shown in Fig. 4, applied according to Fakhri et al. (2013). It indicates that the Narimba source rock hydrocarbon was originally generated within the source rocks themselves and not affected by any contamination or migration from elsewhere.

Pyrolysis results can be utilized to identify the types of organic matter in terms of quantity and quality. Quantity of organic matter refers to the amount of organic matter available in which higher amounts are more favorable to generate hydrocarbon. Organic matter quality refers to whether the organic matter is suitable to produce either oil, gas or both. The TOC measurements shown in Table 2 which show a range from 1.1 to 79.2 wt% indicate that the Narimba Formation is a promising potential source rock with good to excellent quantity of organic matter, based on the TOC classification introduced by Peters and Cassa (1994).

Fig. 8 Modified Van Krevelen diagram (HI versus OI) for determining the type of kerogen present in the source rock (Espitalié et al. 1985)

Type of kerogen and source rock potential

Hydrocarbon generation potential can be demonstrated by cross-plotting production yield (PY) versus TOC as shown in Fig. 5 (Shalaby et al. 2011, 2012a, b, c and Qadri et al. 2016). Production yield (PY), obtained by summing up S_1 and S_2 , aims to measure the total quantity of hydrocarbon that can be generated from the source rock. The plot shows that majority of the studied samples show good to excellent generation potential, while only a few non-coal samples can display poor to fair potential.

Figure 6 shows the relationship of S_2 and TOC, which represent quality and quantity, respectively (Espitalié et al. 1985). Results are wide-ranged, encompassing good to excellent organic matter quantity based on TOC and dominantly fair to excellent hydrocarbon quality based on S_2 . Plotting of S_2 vs TOC can also give further indication of the quality or kerogen types in Fig. 7 (Langford and Blanc-Valleron 1990). It illustrates how coal samples can be

interpreted as Kerogen Type-II, Type-II/III and Type-III which is oil prone, oil–gas prone and gas prone, respectively. The result shows that samples from Pelican-5 are mostly Type-II (oil) and Type-II/III (mixed). Minorly, Narimba-1 samples are Type-II (oil) and Type-III (gas prone).

The relationship between HI (S_2 /TOC) and OI (S_3 /TOC), demonstrated by the modified Van Krevelen diagram in Fig. 8, can also give indication of the quality of organic matter (Tissot and Welte 1978; Espitalié et al. 1985; Waples 1985; Peters and Cassa 1994). According to the plot, the available data show the abundance of kerogen Type-II, Type-II-III and Type-III which are oil, mixed and gas prone, respectively (Peters 1986; Peters and Cassa 1994) which is in good agreement with results from Fig. 7.

Figure 9 demonstrates the correlation of concentrations of macerals composition (vitrinite, liptinite and inertinite) for samples collected from the well Pelican-5 in a ternary diagram. The data are collected from 7 samples covering the interval of the Narimba Formation (2592–2970 m) in Pelican-5 well to characterize the quality of organic matter

Fig. 9 Ternary diagram correlating concentrations of vitrinite, Liptinite and inertinite to identify organic matter quality

in the Narimba source rocks. The data indicate that samples are of Type-II/III and Type-III, meaning that they are oil–gas prone and gas prone, respectively. This further affirms the results obtained from Figs. 7 and 8.

Thermal maturity

Thermal maturity is another important factor for source rock evaluation in addition to organic richness and quality. The parameters which can be used to determine thermal maturity are T_{max} , vitrinite reflectance ($R_o\%$) and production index (PI) (Barker 1974; Peters and Cassa 1994; Shalaby et al. 2011, 2012a, b, c). The maturity parameters (T_{max} and $R_o\%$) were under investigations and evaluation by Shalaby et al. (2019a, 2020). The study explains the prediction of these parameters in case of absence of geochemical analyses. In this study, T_{max} is the temperature reached at maximum kerogen generation, i.e., the peak of S_2 (Espitalié et al. 1985) and increases proportionally with level of thermal maturity (Barker 1974; Espitalié et al. 1977). According to Peters and Cassa (1994), the T_{max} values shown in Table 2, which range from 424 to 448 °C, indicate a wide range of thermal maturity throughout the source rocks in the formation, i.e., immature to peak mature.

To further evaluate the maturity level of organic matter, a cross-plot of HI versus T_{max} can be implemented. This is illustrated in Fig. 10 which indicates that samples are majorly Type-II/III and Type-III and are within the mature

oil window. These results correspond to the results from Figs. 7 and 8.

PI was obtained by using the formulae $PI = S_1 / (S_1 + S_2)$. The parameter represents the proportion of free hydrocarbons already generated (bitumen) to the total amount of hydrocarbon that can be generated (bitumen plus kerogen) (Tissot and Welte 1978; Peters and Cassa 1994). Table 2 shows the PI values (ranging from 0.03 to 0.29) indicating that the source rocks range from immature to peak mature (Peters 1986; Peters and Cassa 1994). Figure 11 shows a cross-plot between T_{max} and production index (PI) showing that samples are mostly immature to mature.

A cross-plot demonstrating the distribution of T_{max} and vitrinite reflectance ($R_o\%$) with increasing depth is shown in Fig. 12 (Shalaby et al. 2012c). The plot reflects that most of samples are located within the mature oil window and show increase in maturity with depth. This provides further confirmation to affirm that source rock samples became more mature and its maturity increases with increasing depth. Hence, the majority of the samples are in agreement with the results of Figs. 9, 10, 11.

With regard to biomarkers, carbon preference index (CPI) can be used as a thermal maturity indicator. Carbon preference index (CPI) of organic matter is defined as the ratio between the sum of odd-numbered carbon alkanes to the sum of even-numbered carbon alkanes. CPI values which are either significantly high or less than 1 relate to thermally immature source rocks (Peters et al. 2005). From this parameter, thermal maturity of the source rock and the source of the organic matter can be defined (Tissot and

Fig. 10 Cross-plotting HI versus T_{max} to indicate source rock thermal maturity

Fig. 11 T_{max} versus PI for further indication of thermal maturity

Fig. 12 T_{max} and vitrinite reflectance versus depth showing the trend of maturity levels with depth

Welte 1978). CPI values for samples from the wells Pelican-1, Pelican-3 and Tilana-1 in Table 4 range from 1.11 to 1.85. This indicates that the samples vary from being mature to immature. CPI values are observed to become closer to 1 with increasing depth.

The gas chromatograms (Fig. 13) are also useful for thermal maturity interpretations where a lack of higher molecular weight compounds would mean a higher degree of maturity. This is due to the tendency of longer atom chains to be broken down into shorter chains as a sample matures. In Fig. 13a, b, d, the abundance of higher molecular weight compounds suggests that thermal maturation has not reached the level where longer atom chains are broken down into shorter chains. Thus, we can interpret

the maturity level to be early mature (oil window to oil/gas window). In contrast, Fig. 13c shows there is a lower concentration of higher molecular weight compounds, suggesting a higher level of maturity than observed in Fig. 13a, b, d possibly in the oil/gas window. These observations correlate well with those from Figs. 9, 10, 11, 12.

Paleodepositional environment

N-alkanes distribution can help to identify the depositional environment of source rock samples. Figure 13 shows the GC results for samples from the Pelican-1, 3 and 5 wells. Bimodal n-alkane distributions with predominance of both lower and higher molecular weight compounds are clearly

Fig. 13 Gas chromatograms of extracted saturates of samples from the Narimba Formation

Fig. 14 Cross-plot of Pr/nC_{17} versus Ph/nC_{18} showing depositional environment and maturity level (modified from Peters et al. 2005)

Fig. 15 Ternary diagram of the regular steranes C_{27} , C_{28} and C_{29} for paleodepositional environment of the Narimba Formation (modified from Huang and Meinschein 1979)

Fig. 16 Paleodepositional environment by plotting $C_{27}/(C_{27} + C_{29})$ sterane versus Pr/Ph (modified from Hossain et al. 2009)

observed in Fig. 13a, b. The modes are around nC_{13} , nC_{17} and nC_{27} for both figures. Meanwhile, the n -alkane distributions of chromatograms in Fig. 13c, d are unimodal, with modes at nC_{17} and nC_{25} , respectively. The presence of lower and higher molecular weight compounds from all the chromatograms, especially in Fig. 13a, b, suggests the contribution of both algal (marine) and terrigenous organic matter, respectively. In Fig. 13c, there is dominance of intermediate molecular weight compounds indicating a higher

algal influence. Contrastingly, Fig. 13d shows a dominance of higher molecular weight compounds and, hence, indicates a stronger influence of terrestrial environment. Such conclusions of the depositional environment are consistent with results observed in Figs. 14, 15, 16, 17.

Pr/Ph which is the ratio between the two biomarker isoprenoids pristane (2, 6, 10, 14-tetramethyl pentadecane) and phytane (2, 6, 10, 14-tetra-methyl hexadecane) can be utilized to evaluate the conditions of a source rock's

Fig. 17 Further support for paleodepositional environment by plot of C_{27}/C_{29} regular sterane versus Pr/Ph

depositional environment (Peters et al. 2005; Moustafa and Morsi 2012). Pr/Ph ratios in addition to the isoprenoids/n-alkanes ratios can indicate the paleodepositional environments subjected to the source rock at the time of deposition (Powell and McKirdy 1973; Didyk 1978). According to the data displayed in Table 4, the isoprenoids/n-alkanes ratios used in this study are the Pr/nC₁₇ and Ph/nC₁₈ ratios (Table 4). These two parameters indicate biodegradation, maturation and diagenetic state of a source rock (Peters et al. 2005; Jumat et al. 2018; Osli et al. 2019). Correlation of the two ratios by cross-plot can define the paleodepositional environment of the Narimba Formation (Peters et al. 2005). This is shown in Fig. 14 which indicates the dominance of non-marine organic matter (oxidizing environment). This has been confirmed later when evaluating the Pr/Ph values among the analyzed samples from different wells. It has been found that Pr/Ph values range from 1.30 to 10.18 which are much higher than 1 and also suggest an oxygen-rich depositional environment with a dominance of terrestrial plant sources. This is in good agreement with interpretation made previously by isoprenoids/n-alkanes. Significant biodegradation is also evident in the plots (Fig. 14) of samples from Pelican-1, Pelican-3 and Tilana-1.

The regular sterane biomarkers C₂₇, C₂₈ and C₂₉ (Table 5) were also used in this study to indicate the environmental origin of the organic matter making up the hydrocarbon. Generally, a dominance in the concentration of C₂₇ steranes would signify marine origin, dominance of C₂₈ points to lacustrine environment particularly algal, and dominance of C₂₉ indicates terrestrial origin. These parameters can be used in correlation by using a ternary diagram as shown in Fig. 15 (Huang and Meinschein 1979). The figure shows that the C₂₉ sterane has the strongest influence. However, data points suggest that the paleodepositional environment is marginal between terrestrial and marine with Pelican-5 having most dominant terrestrial origin.

In Fig. 16, a plot of $C_{27}/(C_{27} + C_{29})$ sterane versus the isoprenoids Pr/Ph had been used to further describe paleodepositional environment (Hossain et al. 2009). In the figure, all samples show oxic environment origins where Pelican-1, Pelican-3 and Tilana-1 samples are intermediate between terrestrial and marine origin and the Pelican-5 sample is terrestrial. There are also indications of strong biodegradation according to Pelican-1, Pelican-3 and Tilana-1 samples. This is in good compliance with Figs. 13 and 14. Deductions are further supported in Fig. 17 where the cross-plot of C_{27}/C_{29} versus Pr/Ph shows oxic depositional conditions with the influence of both land and marine environments. Pelican-5 is also again shown to have the highest terrestrial influence. Biodegradation signatures apparent in the gas chromatograms (Fig. 13) provide added confidence in the interpretations of levels of biodegradation in Figs. 14 and 16. Biodegradation removes n-alkanes (lower members) first since they are more easily destroyed by bacteria. This can be observed in Fig. 13a, b and d where the absence of lower-member n-alkanes produces an irregular pattern at the base of the sample signatures.

Conclusions

The geochemical analysis and source rock characteristics of the Narimba Formation within the Bass Basin possess excellent potential as a promising source rock. Based on pyrolysis data, high TOC values indicated good to excellent organic richness. According to pyrolysis parameters (S₂ and HI), maceral compositions and gas chromatograms, the source rocks have fair to excellent quality, primarily and most abundance, consisting of Type III, Type II/III and Type II (gas, mixed and oil-prone, respectively). The source rocks are thermally mature, dominantly in the oil and oil/gas window, as indicated by T_{max} and vitrinite reflectance values as well as gas chromatograms. Biomarker data and derivatives indicated that the

paleodepositional environment of the Narimba Formation is dominantly marginal between terrestrial and marine. Pelican-5 samples, particularly, showed the strongest terrestrial influence compared to samples from other wells. Furthermore, the rock samples did not show signs of significant migration of hydrocarbons as longer-chained atoms are still majorly unbroken according to the gas chromatograms.

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Compliance with ethical standards

Conflict of interest On behalf of all the co-authors, the corresponding author states that there is no conflict of interest.

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