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MODELLING OF HYDROCARBON GENERATION, MIGRATION AND ACCUMULATION IN THE NORTHERN PART OF THE MANNAR BASIN, OFFSHORE SRI LANKA

UPUL PREMARATHNE[1,*], NORIYUKI SUZUKI[1, 2] AND NALIN PRASSANNA RATNAYAKE[3]

[1]*Division of Earth and Planetary System Sciences, Graduate School of Science, Hokkaido University, N10 W8, Kita-Ku, Sapporo 060-0810, Japan*

[2]*Research Division of JAPEX Earth Energy Frontier, Creative Research Institution (CRIS), Hokkaido University, N21W10, Kita-ku, Sapporo 001-0021, Japan*

[3]*Department of Earth Resources Engineering, University of Moratuwa, Katubadha, Sri Lanka*

[*]*Coorresponding Author: e-mail: premarat@yahoo.com*

ABSTRACT

The Gulf of Mannar, a Mesozoic rift basin evolved during Gondwana beak up, extends in 10-3000 m water depths between India and Sri Lanka. It has evolved due to crustal extension between the Indo-Lanka landmasses. The rifting period might have lasted for about 55 Ma from the latter part of the Aptian to the end of the Cretaceous. The Sri Lankan sector of the Gulf of Mannar is commonly referred to as the Mannar Basin. The northern part of the basin has present to probably Late Jurassic or older sediments. The stratigraphic thickness ranges from 4 km in shallow water depths to more than 6 km in deep water depths towards the south. The occurrence of an active petroleum system in the basin was confirmed for the first time by the discovery of natural gas from two exploration wells in 2011. However, the petroleum system of the Mannar Basin is poorly understood. In this study, an integrated two dimensional modelling of hydrocarbon generation, expulsion, migration and accumulation was performed along a stratigraphic section in the northern part of the Mannar Basin by using the SIGMA-2D basin modelling software. The exploration wells drilled in the basin to date have not penetrated the Early Cretaceous and older sediments, which could be the potential source rocks in the northern part of the Mannar Basin. As a result, the source character of the potential source rocks is uncertain. Therefore, scenario modelling was performed on the source character of the Early Cretaceous and older potential source rocks.

The results of the basin and petroleum system modelling show if the Santonian to Cenomanian stratigraphic interval has a good hydrocarbon source potential they could have generated and expelled a smaller quantity of oil and natural gas. The productivity of this stratigraphic interval as a hydrocarbon source may increase towards the southern tip of the Mannar Basin. If the Early Cretaceous and older claystones have a good hydrocarbon source potential they would have expelled oil and natural gas mainly during the late Cretaceous. A couple of minor expulsion phases could be seen in the same stratigraphic sections in the Palaeogene and Neogene. Even if the Early Cretaceous and older potential source rocks have a relatively poor source potential (TOC ~0.5% and 100% Type III kerogen), they could still give rise to economically feasible natural gas deposits. Thermal cracking of oil generated in the Early Cretaceous and older source rocks increases towards the southern tip of the basin giving rise to a higher gas potential in the southern part of the Mannar Basin. The time lag between the oil generation and expulsion is around 5 Ma. Oil cracking starts at 120-140 ^{o}C. The potential source rocks in the Mannar Basin could be expected to have an average TOC content of at least 1% and 10-15% contribution from Type II kerogen. In this case, economically feasible oil and gas deposits could occur mainly in Cretaceous sandstone in the Mannar Basin.

Key words: *Mannar Basin, Gulf of Mannar, Pearl-1, Dorado-North, generation*

INTRODUCTION

The Gulf of Mannar Basin is located immediately south of *Rama Setu* between the northwest of Sri Lanka and the southeast of India (Fig. 1). The Sri Lankan sector of the basin is usually referred to as the Mannar Basin. It is a poorly studied exploration frontier extending in an area of approximately 45000 km^2. About 3000 km^2 of this area to the north lies in shallow water depths (< 400m).

Hydrocarbon exploration in Sri Lanka took place in the 1970s and in the early 1980s. During this period seven wells were drilled in the Sri Lankan sector of the Cauvery and Mannar Basins (Fig 1). The Pesalai-1, 2 & 3, Palk Bay-1, Delft-1, Pedro-1 wells in the Cauvery Basin (Location: Fig. 1) drilled up to a total depths of 2554, 2628, 2874, 2012, 1734, 1417 m, respectively (Cantwell *et al*., 1978). The Pearl-1 well located in the Mannar Basin was drilled up to a total depth of 2923 m. These wells, excluding Pearl-1, encountered crystalline basement. From 1984 to 2000, a little further hydrocarbon exploration took place in Sri Lanka. In 2001, Tomlinson Geophysical Services Inc. (TGS) delineated the Mannar Basin with 1050 km of 2D seismic data. Interpretation of the seismic data showed the basin to have rift structure and more than 6 km of present to probably Late Jurassic or earlier sedimentary rocks (Fig. 2). In 2008, Cairn Lanka Private Limited (CLPL) received an exploration license from the Sri Lankan Government for a block in the northern part of the Mannar Basin. CLPL drilled three exploration wells in the block during August-December 2011. Two of these wells, CLPL-Dorado-91H/1z (Dorado) and CLPL-Barracuda-1G/1 (Barracuda) encountered natural gas bearing sandstones. CLPL-Dorado-North-1-82K/1 (Dorado-North) located about 2.5 km north of the Dorado well was dry. Dorado was the first exploration well drilled in Sri Lanka in nearly 30 years and the first to discover hydrocarbons in Sri Lanka and in the Gulf of Mannar (Premarathne *et al*., 2013).

The discovery of natural gas in the Mannar Basin established the existence of an active petroleum system in the Gulf of Mannar (Mohapatra *et al*., 2012; Premarathne *et al*., 2013). However, the petroleum system of the Mannar Basin is poorly understood. The objective of this study is to perform an integrated two dimensional (2D) modelling of hydrocarbon generation, migration, and accumulation in the northern part of Mannar Basin to understand its petroleum system. Interpretation of seismic data and analysis of drill cuttings from the wells were used in this study.

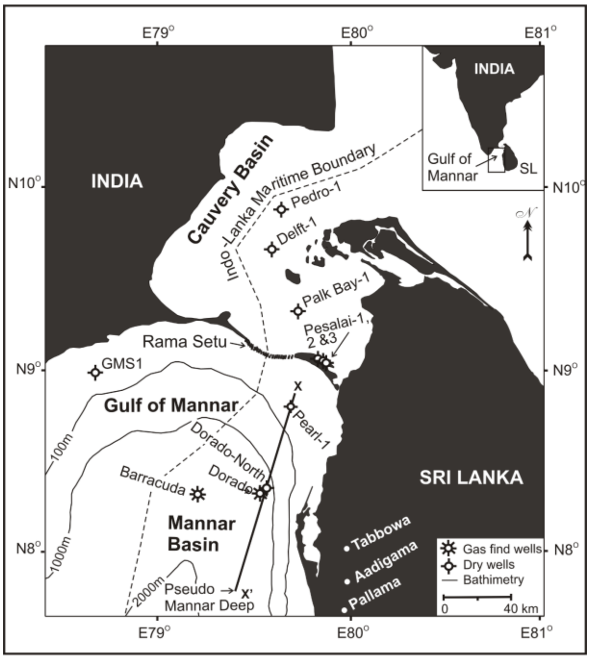

Fig. 1 Map showing the northern Mannar Basin and exploration wells drilled in Sri Lanka. A geological cross section along X–X′ line, which is a part of the SL-01-4 seismic line of the 2001 seismic survey, is shown in Fig. 2

MANNAR BASIN

The Gulf of Mannar, which has formed due to multiphase breakup of the Gondwana supercontinent (Baillie *et al*., 2003) is a failed rift (Curray, 1984). It has evolved during at least two phases of rifting triggered by the onset of separation of Antarctica and Madagascar from India (Baillie *et al*., 2003). The separation of Antarctica and Sri Lanka from India is thought to have initiated around 130 Ma (Lal *et al*., 2009). Some palaeomagnetic measurements from the Pesalai-1 well (Fig. 1) confirm Sri Lanka’s latitudinal shift from 16º S in the Paleogene to 8º N at present (Cantwell *et al*., 1978). This observation is roughly agreeable with the paleogeographic reconstructions carried out by Torsvik *et al*. (2002). During rifting, Sri Lanka has rotated a counter clockwise direction with respect to India (Yoshida *et al*., 1992). This has given rise to the Cretaceous marine entry into the Gulf of Mannar before similar events in

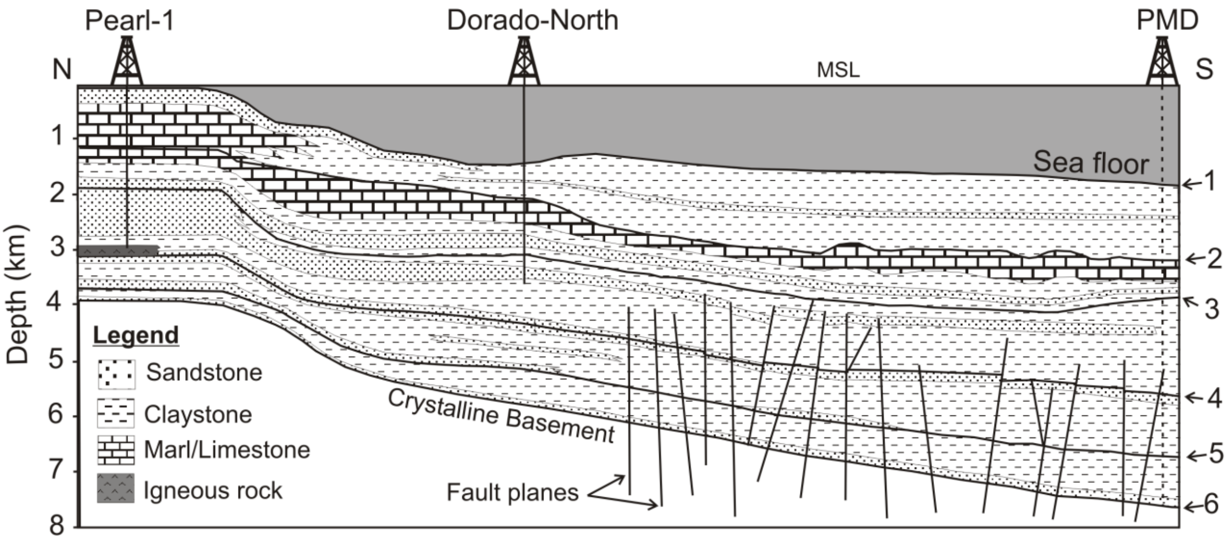

Fig. 2 Generalised stratigraphic section across northern Mannar Basin (X-X' in Fig. 1; After Premarathne et al. 2016) Trajectories of the Pearl-1 and Dorado-North wells and a pseudo well named Pseudo-Mannar-Deep (PMD) are shown. Nos. 1 to 5 show tops of Palaeogene, Late Cretaceous, Early Cretaceous, Jurassic and crystalline basement, respectively. MSL = mean sea level

the northwest offshore areas in Sri Lanka (Cantwell *et al*., 1978). The termination of faults close to the Cretaceous top (Fig. 2) indicates the cessation of rifting between the Indo-Lanka landmasses at the end of the Cretaceous. The igneous rocks found in an about 800 m thick stratigraphic interval of the Barracuda well are interbedded with the Maastrichtian sediments (Fig. 3). Premarathne *et al.* (2013) inferred these igneous rocks to have formed due to multiphase basaltic lava flows. In this case, the lava flows should have occurred during the Maastrichtian.

The seismic data suggest that the stratigraphic thickness in the Mannar Basin ranges from around 4 km in the shallow water depth to more than 6 km in the deep water depths towards the southern part of the basin (Fig. 2). No well drilled in the Mannar Basin has encountered the Early Cretaceous or older sediments. The oldest sediment deposited on crystalline basement could be probably Late Jurassic or earlier. Clues to the occurrence of Jurassic sediments come from the Tabbowa, Aadigama and Pallama grabbers in Sri Lanka (Locations: Fig. 1). These grabens accommodate Jurassic sediments (Wayland, 1920; Daraniyagala, 1939; Sitholey, 1942; 1944; Money and Cooray, 1966) having 1-1.2 km stratigraphic thickness (Tantrigoda and Geekiyanage, 1991). In addition, the occurrence of Jurassic sediments has been reported in the southeastern coast of India (Sastri *et al*., 1981). The GMS1 well located in the Indian shallow waters of the Gulf of Mannar penetrated Albian shale between the depths of 3283 and 3500 m (Rao *et al*., 2010). In addition, the Pesalai wells located in the Sri Lankan sector of the Cauvery Basin (Location; Fig. 1) penetrated Albian sediments on crystalline basement. The Pearl-1 well terminated in Late Turonian (?) sediment, the Dorado and Barracuda wells terminated in Campanian sediment, and the Dorado-North well terminated in Santonian sediment (Fig. 3). The Palaeogene and Neogene sections in the Mannar Basin are characterised by interbedded marl/limestones, claystones, and sandstones. All wells drilled in the Mannar and Cauvery Basins encountered a thick succession of Miocene marl/limestone (Figs. 2 & 3), which is >900 m thick in the Pearl-1 well. A Thick Miocene limestone sequence is exposed in the northern, northwest and northeast onshore areas of Sri Lanka. A detailed discussion on the stratigraphy of the Mannar Basin is available in Ratnayake *et al.* (2014); Premarathne *et al*., 2016.

SAMPLES AND METHODS

In total, 635 drill cutting samples from the Dorado, Dorado-North, and Barracuda wells starting from the depths of 2150 m, 2200 m and 2140 m, respectively to the total depth (T.D.) of the wells were collected from Sri Lanka's Petroleum Resources Development Secretariat (PRDS). Each sample contained around 35g of drill cuttings obtained over a depth interval of 10 m. Unpublished well completion report for the Pearl-1 well and the 2D marine seismic data acquired in 2001 by TGS were also used.

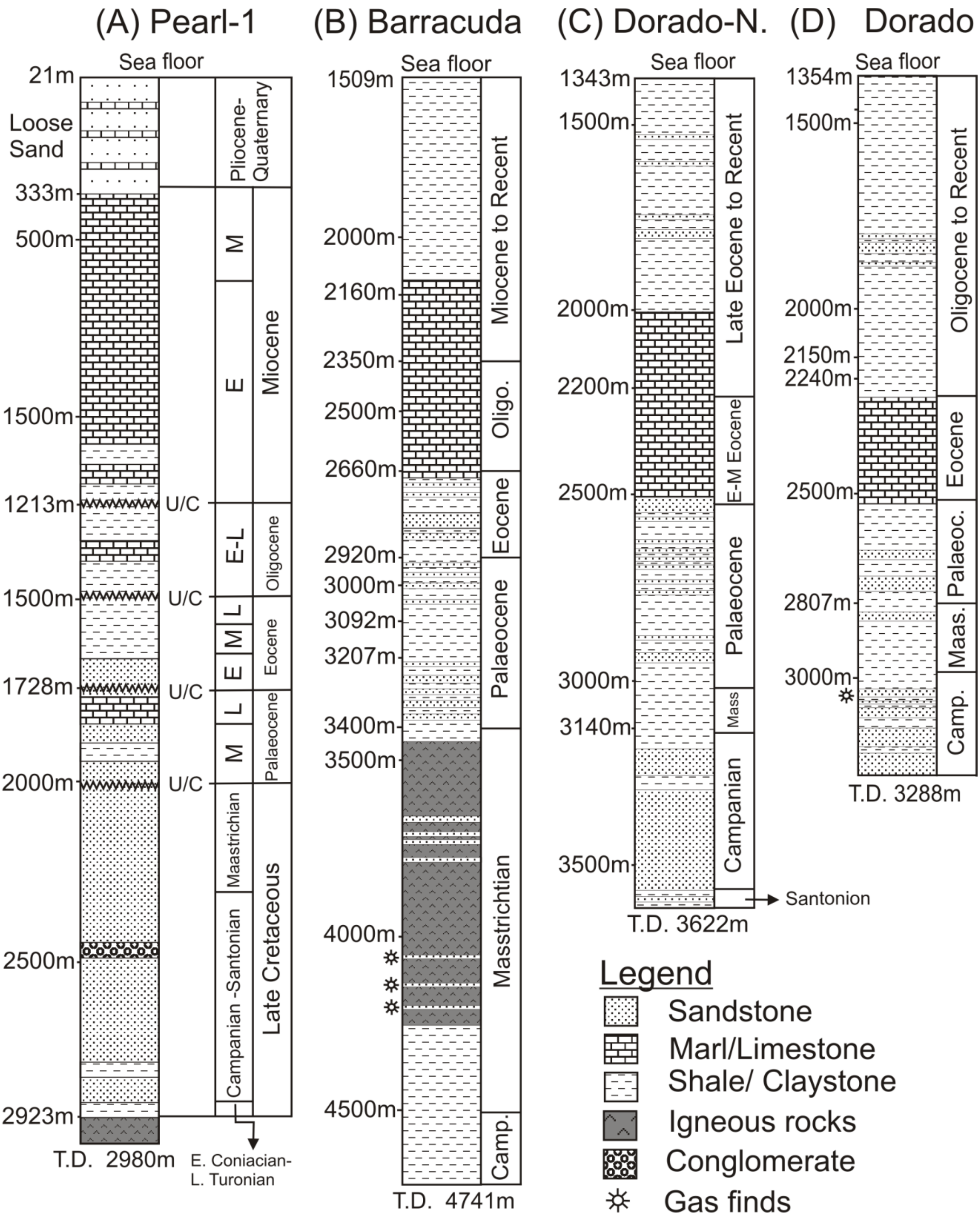

Fig. 3 Generalised stratigraphic sections for wells (A) Pearl-1, (B) Barracuda (C) Dorado-North and (D) Dorado (After Premarathne et al., 2016). Palaeoc. = Palaeocene, Maas. = Maastrichtian, Camp. = Campanian, E. = Early, M = Middle, L = Late, U/C = unconformity and T.D. = total depth

ELEMENTAL ANALYSIS

This study focused on the analysis of selected sediment samples from the Dorado well and calcareous claystone between the depths of 4260 to 4741 m in the Barracuda well. Each sample was freeze dried for 20 hours before pulverising them using an agate mortar. Our initial geochemical analysis of the cutting samples from the Dorado, Dorado-North, and Barracuda wells show that they had been contaminated with drilling oil of diesel composition. To minimize drilling oil, each pulverised cutting sample (5 g) was washed in a 15 ml mixture of methanol and dichloromethane in 1:1 and 0:1 volume ratios in an ultrasonic bath for 15 minutes each time. 3.7-4.3 mg of each dried sample was weighed into an Ag capsule, to which a few drops of 1N HCl was added and kept at a temperature of 160 ^{o}C over night to remove inorganic carbon. Then, 6 mg of vanadium (V) oxide (V_2O_5) powder was placed in the Ag capsule. It was then enclosed in a Sn capsule before moulding it into a tiny cube. The sample was analysed using Euro EA 3000 CHNS-elemental analyser. The combustion temperature inside the furnace was around 1020 ºC. L-cystine was used as the standard. The regression analysis was employed for quantitative analysis. The elemental concentrations was determined on a dry-weight basis. The error of analysis was ±3% for TOC. Washing of pulverised cutting samples in methanol and dichloromethane in an ultra-sonication bath could remove a significant quantity of bitumen (Bit), which is extractable using the organic solvents. The bitumen to total organic carbon ratio (Bit/TOC) varies from zero in shallow sediments to ~0.25 at the peak oil generation (Peters *et al*., 2007). Miles (1994) on the other hand inferred that greater than 0.2 Bit/TOC ratios for oil-prone sediments suggest a contamination. The Bit/TOC ratio for sediments in the oil window decreases with further burial due to conversion of bitumen to volatile hydrocarbons (Peters *et al*., 2007). Therefore, it is generally assumed that the removal of the bitumen fraction in sediments does not significantly affect the measured total organic carbon (TOC) content of a sample excluding oil-prone sediments in the oil window.

MACERAL COMPOSITION

Concentrated HF was used for standard method of acid maceration for kerogen separation on 20–30 g of cutting samples from the Dorado, Dorado-North, and Barracuda wells. Only fine-grained sediments with an organic carbon content of ~1.0 wt. % or higher were selected. Coaly fragments in the acid-macerated sediments were separated using a zinc bromide ($ZnBr_2$) solution having a density of 1.55 g/cm^3. The Maceral composition analysis and fluorescence microscopy were undertaken on bulk kerogen. Kerogen fluorescence was examined under white and ultraviolet (UV) light using a Nikon Optiphot-2 microscope with Hg lamp and white and UV light filters.

BASIN MODELLING

Basin and petroleum system modelling (BPSM), could be used to make valuable inferences on exploration frontiers such as the Mannar Basin. The SIGMA-2D basin modelling software (version 6) of Japanese Oil, Gas and Metals National Cooperation (JOGMEC) was used in this study.

The software could simulate the hydrocarbon generation, migration and accumulation along a two-dimensional (2D) cross section. The numerical simulation in BPSM takes place in three basic steps, the geological, generation and migration modelling. Under the geological modelling, the software reconstructs the burial and thermal history of the 2D cross section by using its lithology distribution, rock physical properties and boundary conditions such as ocean bottom temperature, present and palaeo heat flows and depositional water depths and sea level changes. The software use SIMPLE-R_o (Suzuki *et al*., 1993) to calculate the vitrinite reflectance (VR). The computed maturity data together with TOC, kerogen composition and kinetic models for different types of kerogen converting into hydrocarbons are used to simulate the hydrocarbon generation under the generation modelling. Finally under the migration and accumulation modelling, the software simulates the hydrocarbon expulsion, migration and accumulation. The relative permeability of oil, water and gas in shale is used to determine the hydrocarbon expulsion threshold. The migration of hydrocarbons is also based on the relative permeability of oil, water and gas in sandstone and in carbonate rocks. The relative permeability is an extension of the Darcy's law on multiphase fluid (water, oil and gas) flow. The software also takes into account hydro fracturing and phase behaviour of fluids such as the dissolution of gas in oil. More facts on the SIGMA-2D software performing BPSM is available in Okui *et al.* (1996); Okui (1998).

MODELING PARAMETERS

LITHOLOGY DISTRIBUTION AND SIMULA-TION CONDITIONS

The focus of this study was on a stratigraphic section covering the northern part of the Mannar Basin (X-X' in Fig. 1). This section is a fragment of the SL-01-04 seismic line acquired

Table 1 Boundary conditions used for modelling in this study (After Premarathne et al., 2016). "Shallow", "deep" stand for shallow and deep water depths, respectively, while OBT, DN and PMD stand for ocean bottom temperature and Dorado-North and Pseudo Mannar Deep wells, respectively. T= temperature. Heat flow in PMD was assumed the same as that in DN. Sea level is based on Pitman (1978)

Age	OBT (^oC)		Depositional Water Depth (m)			Heat flow (mW/m^2)			Sea level
(Ma)	Shallow	Deep	Pearl-1	DN	PMD	Pearl-1	DN	PMD	(m)
0	26	5	20	1343	1800	39.75	30.00	30.00	0
5.3	25	5	150	1310	1650	41.00	35.06	35.06	20
12	24	5	340	1250	1550	42.43	41.71	41.71	48
23	23	5	550	1150	1400	46.53	50.21	50.21	92
33.9	22	5	530	1060	1250	51.55	57.74	57.74	154
54	20.7	9	510	800	900	63.76	69.04	69.04	254
64	20	11	500	700	760	68.20	71.13	71.13	308
66	19.8	12	500	730	730	68.20	71.13	71.13	321
72	19.5	13	500	620	620	67.36	71.13	71.13	324
75	19.2	14	500	590	570	66.65	70.50	70.50	327
78	19.1	15	500	570	570	66.11	69.45	69.45	330
81	19	16	500	530	530	65.40	68.20	68.20	334
84	18.5	16.7	500	500	500	64.31	66.94	66.94	339
86.3	18.5	17	480	480	480	63.39	65.69	65.69	332
89.8	18	17	460	460	460	62.13	63.60	63.60	303
94	18	17	460	440	440	60.71	61.09	61.09	283
97	17.5	17	420	420	420	58.91	59.12	59.12	270
100	17	17	400	400	400	57.11	57.86	57.86	246
102	17	17	380	380	380	55.69	56.40	56.40	233
105	17	17	370	370	370	53.89	54.39	54.39	208
113	17	17	310	310	310	50.21	50.21	50.21	164
119	17	17	270	270	270	50.21	50.21	50.21	137
126	17	17	230	230	230	50.21	50.21	50.21	106
134	17	17	200	200	200	50.21	50.21	50.21	87
142	17	17	130	130	130	50.21	50.21	50.21	68
152	17	17	80	80	80	50.21	50.21	50.21	45
174	17	17	20	20	20	50.21	50.21	50.21	12

by TGS as part of the 2001 seismic survey. Figure 3 shows the interpretation of the generalized lithology distribution along the X-X' section. The section was divided into 27 formations (see Table 1 for age of formation boundaries). The Pearl-1 and Dorado-North wells fall on the section (Figs. 1 & 3). In addition, a pseudo well named "Pseudo-Mannar-Deep" (PMD; Fig.3), located at the southern tip of the X-X' section in around 1800 m water depth, was assumed to discuss the hydrocarbon generation and expulsion in a stratigraphic column at this location.

The boundary conditions that include present and paleo heat flows, ocean bottom temperature and depositional water depths and sea levels used for this study is shown in Table 1. Paleo heat flows at the Pearl-1 and Dorado-North well locations were optimized against the vitrinite reflectance (VR) data measured by Premarathne *et al.* (2016). Since the Mannar Basin has a rift structure (Fig. 3), the typical pattern of heat flow

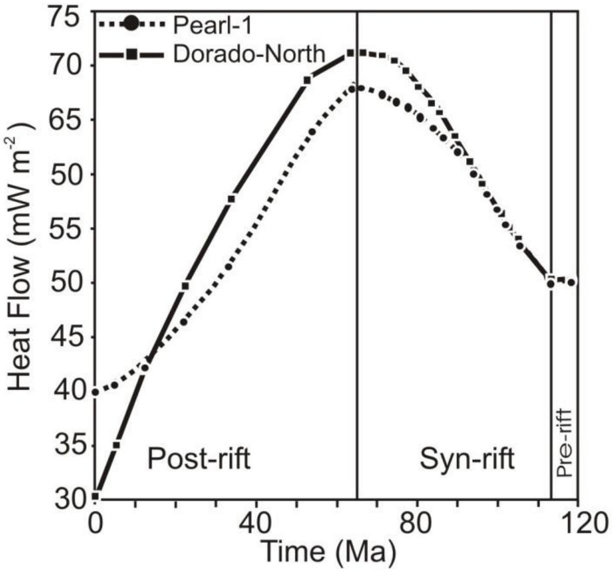

Fig. 4 Optimised heat flow change in stratigraphic columns at Pearl-1 and Dorado-North well locations. Values at time zero indicate the present-day heat flows

proposed by Parsons and Sclater (1977) for rift basins was adopted during the optimization of heat flow history of the Mannar Basin (Fig. 4). Since the Mannar Basin had a multiphase rifting (Baillie *et al.*, 2003), the McKenzie model (McKenzie, 1978) cannot be directly applied to estimate its heat flow history. The pre-rift heat flow have a minimum importance in petroleum system modeling. A plausible pattern of heat flow is a critical factor in the petroleum system modeling because it controls, among other factors, the timing of hydrocarbon generation and expulsion. Since measured VR data is not available for the Pseudo Mannar Deep well, the same present day and paleo heat flows optimized for the Dorado-North well were used for the deep water depths in the Mannar Basin (Table 1). More information about the VR data, rock physical properties, boundary conditions and tectonic history (erosional thicknesses) used for modeling in this study is available in Premarathne *et al.* (2016).

TOC AND KEROGEN COMPOSITION

Most of the sediments from the Pearl-1 well have around 0.5% TOC (Fig. 5A). Claystones penetrated by the Dorado well and calcareous claystones between the depths of 4260 to 4741 m in the Barracuda have relatively higher TOC content (1.0-2.5%; Figs. 5B & 5C, respectively). Rao *et al*. (2010) reported that Albian sediments penetrated by the GMS1 well in Indian shallow waters (location: Fig. 1) have a low TOC content (~0.5%) and a higher contribution from Type III kerogen. Plot of the hydrogen index (HI) against the oxygen index (OI) show that sediments penetrated by the Pearl-1 well are rich in Types III and IV kerogen (Fig. 6). The maceral composition analysis shows that the sediments from the Dorado, Dorado-North and Barracuda wells are also rich in Types III kerogen. Particularly, the calcareous claystone between the depths of 4260 to 4741 m in the Barracuda well is rich in fusinite but poor in petroleum generative kerogen.

Recent to Albian sediments in shallow water depths in the Mannar Basin could have poor hydrocarbon source potential. Though, Campanian and younger claystones penetrated by the Dorado well have higher TOC content, neither the Dorado well nor the Dorado-North well have entered the oil window (pink coloured iso VR lines in Fig. 13). On the contrary, the Pearl-1 and Barracuda wells have penetrated sediments, which have entered the oil window (VR = 0.6- 1.3 %R_o; Peters and Cassa, 1994; Petersen, 2002) at the depths of 3500 and 4260 m, respectively. However, thermally matured sediments penetrated by the Pearl-1 well is mostly sandstone, while thermally matured calcareous claystone in the Barracuda well have poor hydrocarbon source character. Therefore, the wells drilled in the Mannar Basin may not have penetrated potential source rocks.

Chandra *et al*. (1991) reported that Albian and earlier sediments in the Indian sector of the Cauvery Basin have a TOC content ranging 0.34-2.49% and around 20% contribution from Type II kerogen and remainder being Type III kerogen. Cantwell *et al*. (1978) reported that Albian mudstone penetrated by the Pesalai-1 well (Location: Fig. 1) have a TOC content ranging 2.8-6.9% and a significant contribution (~25%) from Type II kerogen. Ratnayake and Sampei (2015) reported that brown to black coloured Jurassic mudstone in the Aadigama graben (Location: Fig. 1) has relatively a higher TOC content (3.05- 5.10%). Based on these observations, it was thought that Early Cretaceous and older sediments could be the most significant hydrocarbon source in the Mannar Basin. Due to no well penetration, the exact source character of these sediments is not known. Therefore, different scenario modelling was performed on the hydrocarbon source character of potential source rocks in the Mannar Basin. A 0.5% of TOC and 100%

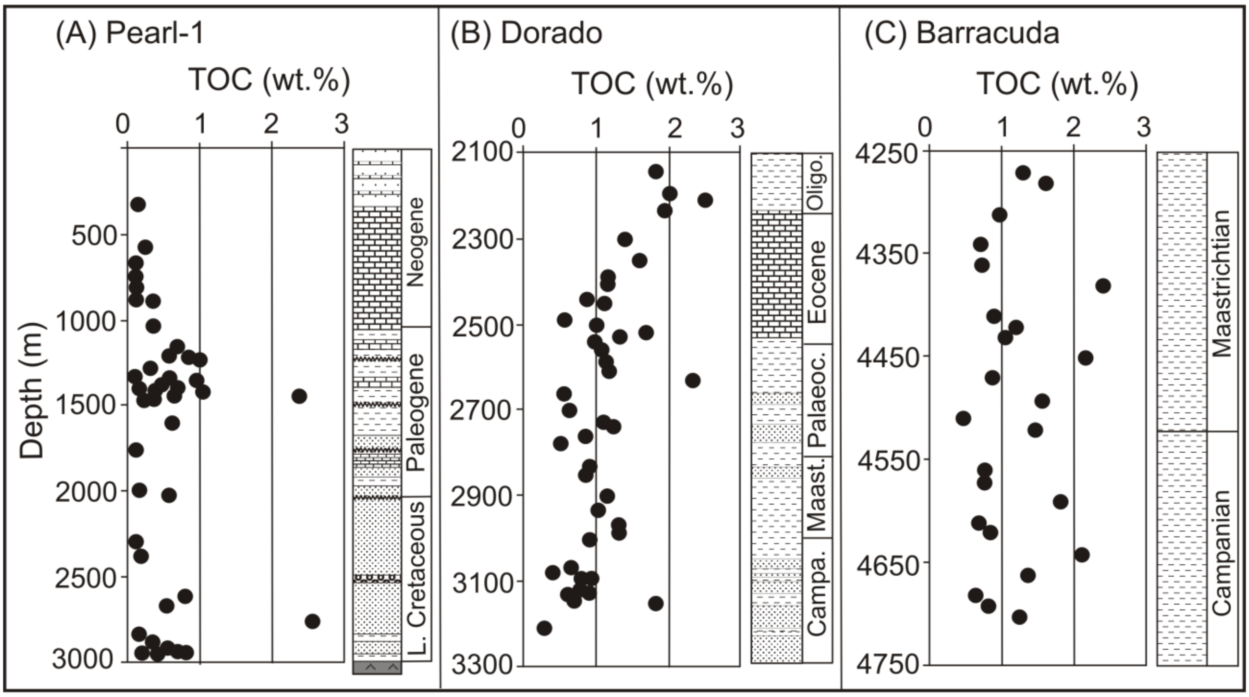

Fig. 5 Total organic carbon (TOC) of sediments from (A) Pearl-1, (B) Dorado and (C) Barracuda wells. Data for the Pearl-1 well is from unpublished reports held at PRDS

contribution from Type III kerogen were assumed as the pessimistic source character scenario, while 2.5% of TOC and 50% contribution from Types II kerogen (remainder being III kerogen) were assumed as the optimistic source character scenario. In addition, a moderate source character scenario of 1.5% of

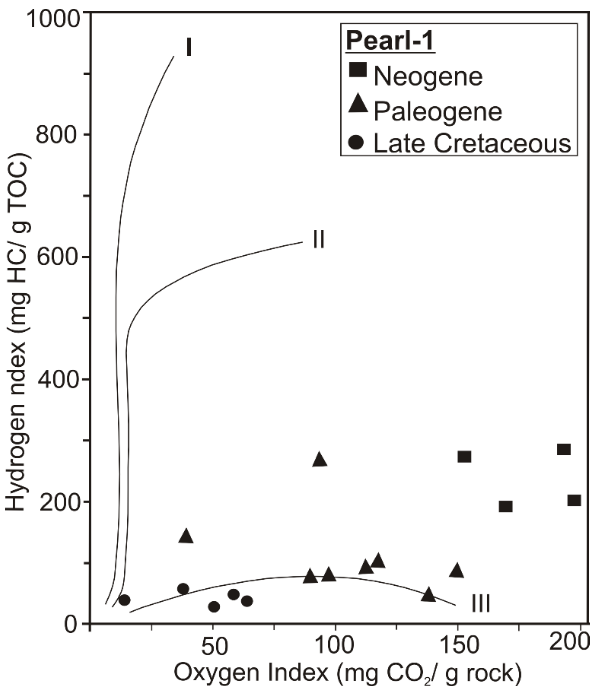

Fig. 6 Plot of the hydrogen index against the oxygen index for sediments from the Pearl-1 well. The organic maturation pathways (curves) of Type I, II, and III kerogens are based on Espitalié et al. (1977)

TOC and 20% contribution from Type II kerogen (remainder being Type III kerogen) was modelled.

KINETIC MODEL FOR HYDROCARBON GENERATION

Like in the case of source character, kinetic models for kerogen conversion into hydrocarbons are not available for Early Cretaceous and older sediments in the Mannar Basin. Nevertheless, many kinetic models, which are based on laboratory pyrolysis of sediment from petroliferous basins in various parts of the world, are available in the public domain (eg. Tissot *et al*., 1987; Burnham, 1989; Suzuki and Matsubayashi, 1995; Pepper and Corvi, 1995a). Two most commonly used kinetic models are those derived by French Petroleum Institute (eg. Tissot *et al*., 1987) and Laurence Livermore National Laboratory (eg. Burnham, 1989). They described Types I, II and III kerogen in shales from the Green River in the US, the Paris Basin in France and the Mahakam Delta in Malaysia. Waples (1994) compared the two models and found that the kinetic model of French Petroleum Institute (IFP) proposed by Tissot *et al*. (1987) does not produce natural gas directly from kerogen. Pepper and Corvi (1995a) proposed an alternative approach to select a kinetic model especially for basins with limited knowledge such as the Mannar Basin. This approach is based on the depositional

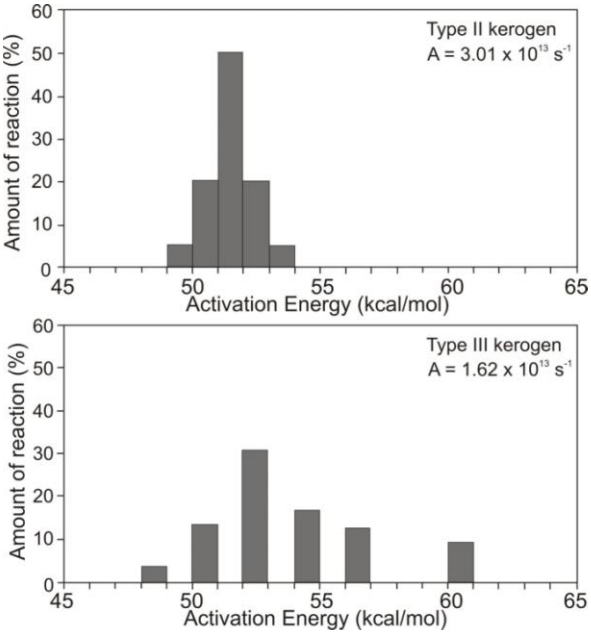

Fig. 7 LLNL kinetic model for Types II and III kerogen (after Burnham, 1989). A = frequency factor

environment of potential source rocks, which is thought to determine the oreganofacies in sedimentary rocks. The kinetic model proposed by Pepper and Corvi (1995a) for marine silisiclastic rocks, which is the possible lithofacies of potential source rocks in the Mannar Basin, agrees well with the Laurence Livermore National Laboratory (LLNL; Burnham, 1989) kinetic model. Therefore, the LLNL kinetic model for types II and III kerogen was used for this study (Fig. 7). In addition, the kinetics for oil and coke cracking into natural gas were adopted from the same model.

HYDROCARBON EXPULSION THRESHOLD

Fluid flow in a sedimentary rock is controlled by buoyancy, capillary attraction and the wettability of fluid (England and Fleet, 1991). The concept of relative permeability, which is an adoption of the Darcy's law, is used to explain multiphase fluid flow in a non-mixing mixture. It is the ratio between the effective permeability of a phase of the mixture to the absolute permeability of the phase in a rock. The SIGMA 2D software simulates the hydrocarbon expulsion threshold based on the relative permeability of fluids (oil, gas and water) in shale.

Discussions on the relative permeability of mudstones are uncommon compared to those on sandstones (Aplin and Larter, 2005). However, Ungerer *et al.* (1987); Pepper (1991); Okui and Waples (1993); Pepper and Corvi (1995b) discussed the relative permeability of the oil-water system in mudstones. The relative permeability is an experimentally derived property lacking profound theoretical foundation (Ungerer *et al.*, 1984). Pepper and Corvi (1995b) thought that laboratory measurement of the relative permeability in compacted fine grained rocks is difficult, and therefore a simple analogy has to be guessed, assumed with reservoir rocks or extrapolate from other data sets. Okui and Waples (1993) estimated the relative permeability of oil-water system in shale source rocks based on a computer simulation (Fig. 8A).

According to this model, the irreducible water saturation in mudstones is relatively high (~80%). The crossover point, beyond which the oil relative permeability exceeds the water relative permeability, achieves at a relatively low oil saturation. As a result, the oil expulsion readily takes place at low oil situations. The model proposed by Okui and Waples (1993) for the oil-water system in shale was used in this study for shale source rocks. Discussions on the relative permeability of the gas-water and gas-oil systems are also rare. Pepper and Corvi (1995b) reported the relative permeability of the gas-water system in fractured coal. According to this model, gas is readily movable at low saturations. Based on the discussions of the relative permeability in Ungerer *et al.* (1987); Pepper (1991); Okui and Waples (1993); Pepper and Corvi (1995b), the relative permeability of the gas-oil and gas-water systems in shale in this study were assumed as shown in Figs. 8B & C.

RESULTS AND DISCUSSION

MODELLED HYDROCARBON GENERATION AND EXPULSION TIMING

The timing of hydrocarbon generation and expulsion in three stratigraphic columns located at the Pearl-1, Dorado-North and Pseudo Mannar-Deep well locations are discussed below. Though the Pearl-1 and Dorado-North wells penetrated only a part of the total stratigraphic column, their names in the discussion below refer to the total stratigraphic column at respective locations. Table 3 summaries the duration of peak oil generation and cracking and the amount of oil generation in kilogram per unit volume of rock (kg/m^3) under the optimistic scenario.

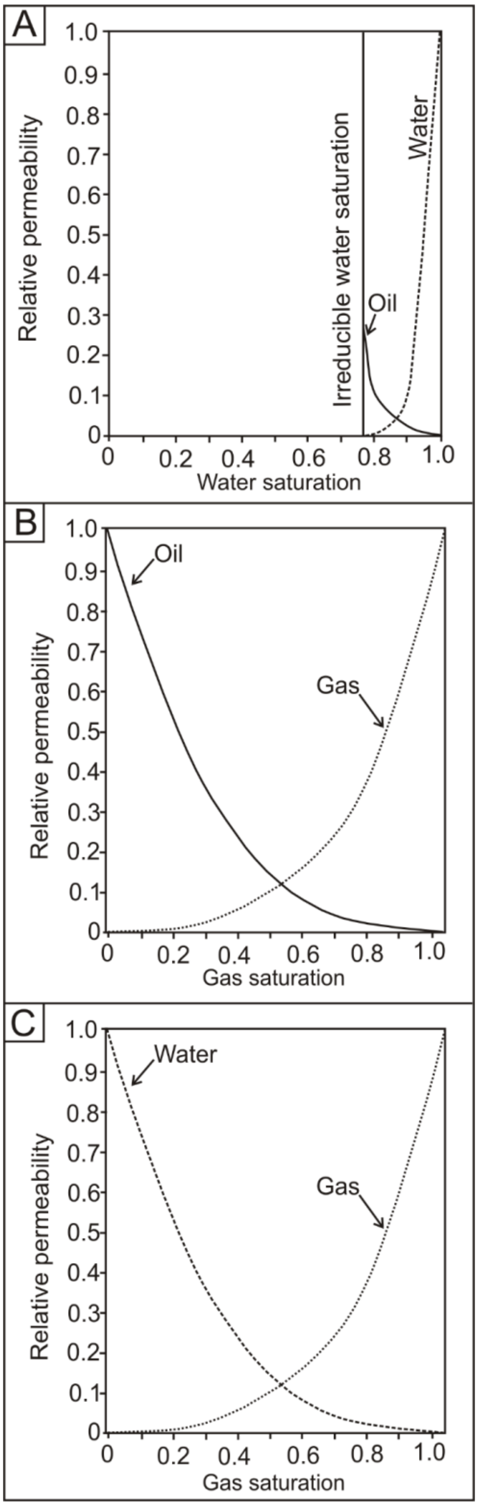

Fig. 8 Relative permeability curves for typical shale source rock used as hydrocarbon expulsion threshold in this study for (A) Oil-water system (after Okui and Waples, 1993) and (B) & (C) oil-gas and gas-water systems, respectively

PEARL-1 WELL

Peak hydrocarbon generation in the Berriasian and older sediments under the optimistic scenario (TOC = 2.5% and Type II kerogen = 50%) takes place during the Campanian to Eocene (78-35 Ma). Peak oil generation in the Aptian, Turonian and Santonian sediments take place during 60-10 Ma, 45-5 Ma and 30-5 Ma, respectively. No hydrocarbons are generated in the sediments younger than the Santonian. The amount of hydrocarbon generated in the Santonian and Turonian sediments is less than that in the sediments older than the Turonian. The timing of hydrocarbon generation under the both optimistic and pessimistic scenarios is more or less the same, though the quantity widely differs in two scenarios. Under the pessimistic source character scenario, the maximum oil generation in the Bathonian to Kimmeridgian sediments is less than 1 kg/m^3, which is a much lesser quantity compared to 15 kg/m^3 observed in the same section under the optimistic scenario (Figs. 9 & 10). The sediments younger than the Kimmeridgian produce even a lesser amount of hydrocarbon under the pessimistic scenario.

Under the optimistic scenario, the peak hydrocarbon expulsion from the Late Jurassic sediments takes place from the middle Campanian to Oligocene. However, there is a minor gas expulsion phase in this section during the Neogene (see Fig. 11). Peak hydrocarbon expulsion from the Valanginian to Berriasian and Aptian sediments takes place from the Maastrichtian to Pliocene and from the middle Palaeocene to Pliocene, respectively. The hydrocarbon expulsion from these stratigraphic intervals during the Neogene seems to be a second expulsion phase. A smaller phase of hydrocarbon expulsion could be seen in the Turonian and Santonian sediments during the Neogene. The timing of hydrocarbon expulsion from a particular stratigraphic interval, both under the optimistic and pessimistic scenarios, is roughly the same. However, the amount of hydrocarbon expulsion under the pessimistic scenario is more than 100 time lesser that under the optimistic scenario.

The accuracy of modelling is confirmed by the fact that the production index of the Coniacian to Turonian (?) sediments at the depths of 2920 m in the Pearl-1 well yields 0.43 (Table 2). The oil generation at this depth agrees well with the source maturity suggested by the Rock Eval T_{max}, which become greater than 435 ^oC from the depths of 2740 m (Table 2). The reason for not generating hydrocarbon in some stratigraphic intervals in the Pearl-1 well, such as the Albian, Hauterivian, Barremian and Tithonian is due to the assumption of 100% sandstone and zero percent TOC content in these stratigraphic intervals. It is possible to have thin layers of claystone interspersed with the sandstone. However, it is difficult to distinguish such interbeddings in the seismic profiles due to the limitations on seismic resolution. In addition, there are a software limitation on the maximum number of layers that could be used for modelling. The reason for a minor hydrocarbon generation and expulsion phase during the Neogene could be related to the elevation of temperature due to the rapid burial during the Neogene.

DORADO-NORTH WELL

The hydrocarbon generation in the Late Jurassic sentiments under the optimistic scenario takes place from the Cenomanian to the Santonian (100-85 Ma). Peak hydrocarbon generation in the Early Cretaceous sediments mainly takes place during the Late Cretaceous, excluding the Albian sediments, which continued to generate hydrocarbons up to the middle Eocene (~45 Ma). Peak hydrocarbon generation in the Cenomanian and Turonian sediments, takes place during the Maastrichtian to late Eocene, while in the Santonian and Coniacian sediments during the Eocene. A lesser hydrocarbon generation (2-4 kg/m^3) takes place in the Santonian and Coniacian sediments compared to that (~15 kg/m^3) in the sediments older than the Coniacian. It is seen that oil generated in the Late Cretaceous sediments thermally cracks into natural gas from the Maastrichtian to late Eocene. No significant hydrocarbon generation could be seen in the Campanian and younger sediments under the optimistic scenario. Like in the case of the Pearl-1 well, oil generation in the Late Jurassic and younger sediments under the pessimistic scenario is less than 1.0 kg/m^3. This is a much lesser quantity compared to oil generation under the optimistic scenario.

Table 2 TOC and Rock-Eval pyrolysis data with depth for the Pearl-1 well (from unpublished reports held at PRDS). S_1 and S_2 in mg HC/ g rock. S_3 in mg CO_2/ g rock. HI = Hydrogen Index in mg HC/g TOC, OI= Oxygen Index in mg CO_2/g TOC), PI= Production Index (S_1/S_1+S_2). n.d. = not detected

Depth (m)	TOC (% wt.)	S_1	S_2	S_3	HI	OI	PI	S_2/S_3	T_{max} (°C)
560	0.26	0.004	0.22	1.05	85.8	405.0	0.018	0.21	415.8
870	0.36	0.004	0.69	1.10	190.8	306.1	0.006	0.62	415.8
1,017	0.36	0.004	0.70	0.61	194.4	170.0	0.006	1.14	415.8
1,131	0.69	0.005	1.99	1.34	288.7	193.6	0.003	1.49	n.d
1,185	0.58	0.003	1.21	1.15	209.1	197.9	0.002	1.06	420
1,197	0.88	0.017	2.46	1.34	279.0	152.6	0.007	1.83	424
1,209	1.00	0.009	2.71	0.93	271.3	92.8	0.003	2.92	426
1,317	0.58	0.003	0.51	0.87	87.9	150.2	0.006	0.59	417
1,354	0.48	0.001	0.23	0.66	47.7	137.5	0.004	0.35	414
1,386	0.68	0.022	0.57	0.65	83.8	95.9	0.037	0.87	419
1,416	0.66	0.021	0.53	0.59	80.5	89.2	0.038	0.90	423
1,424	2.36	0.013	3.46	0.91	146.6	38.7	0.004	3.79	432
1,436	0.23	0.03	0.16	1.16	69.6	505.7	0.158	0.14	425
1,442	0.26	0.03	n.d	0.98	n.d	377.7	n.d	n.d	n.d
1,582	0.62	0.003	0.58	0.70	93.5	112.1	0.005	0.83	424
2,002	0.58	0.005	0.13	1.95	21.6	336.2	0.038	0.06	422
2,590	0.79	n.d	0.46	0.29	58.2	36.7	n.d	1.59	420
2,649	0.54	n.d	0.19	0.24	35.2	43.5	n.d	0.81	414
2,740	2.55	0.002	1.11	0.33	43.3	12.9	0.002	3.35	448
2,890	0.56	0.001	0.23	0.36	41.1	63.4	0.004	0.65	425
2,908	0.69	n.d	0.36	0.40	52.2	58.0	n.d	0.90	445
2,920	0.78	0.18	0.24	0.39	30.8	50.0	0.429	0.62	454

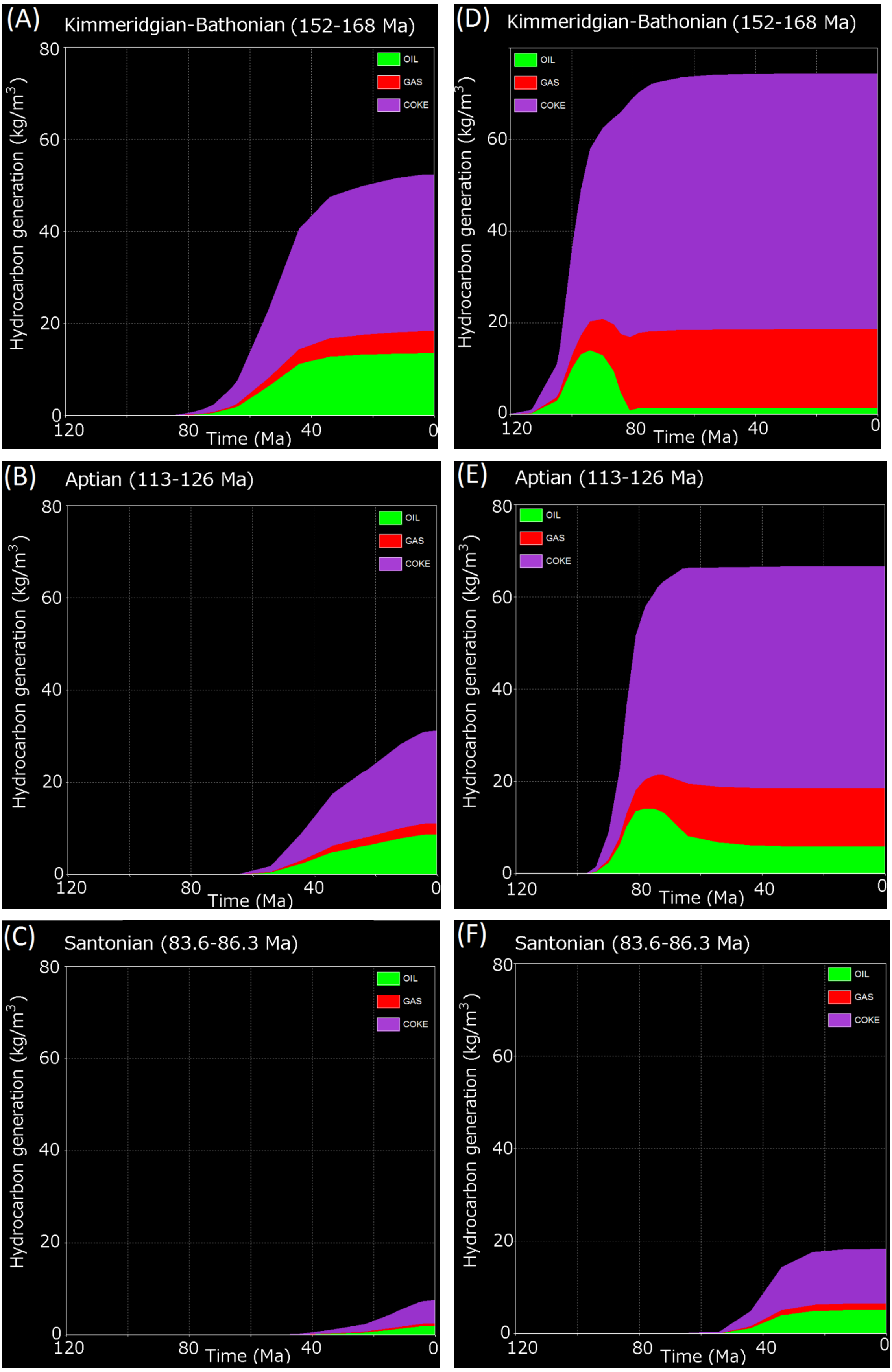

Fig. 9 Timing of oil and gas generation under optimistic scenario for selected stratigraphic intervals (A, B & C) in the Pearl-1 well and (E, F & G) in the Pseudo Mannar Deep well. Hydrocarbon generation is in kilograms per unit volume of rock (kg/ m^3)

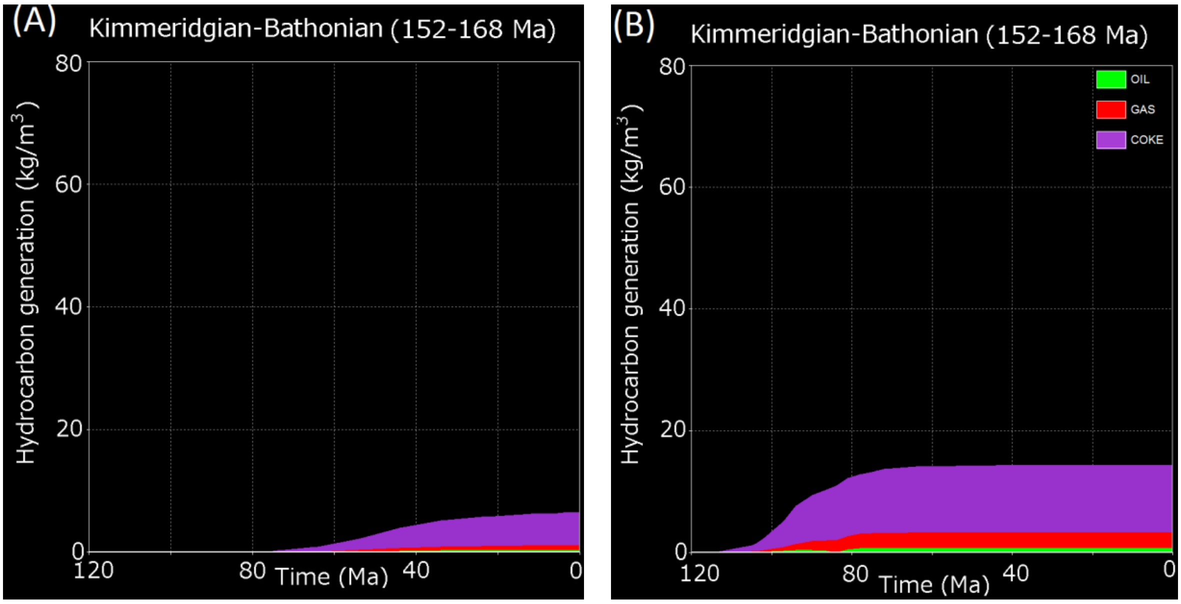

Fig. 10 Timing of oil and gas generation under pessimistic scenario for Kimmeridgian to Bathonian sediments in wells (A) Pearl-1 and (B) Pseudo Mannar Deep. Hydrocarbon generation is in kilograms per unit volume of rock (kg/ m^3)

Oil expulsion from the Late Jurassic sediments takes place from the Cenomanian to early Campanian (~95-80 Ma). However, gas expulsion from these sediments takes place from the Campanian to middle Palaeocene, an extended period, compared to the period of oil expulsion (Fig. 11B). Peak oil expulsion from the Valanginian to Berriasian sediment takes place from the Turonian to middle Campanian (~90-80 Ma), while peak gas expulsion from the same stratigraphic interval takes place from the Coniacian to the end of Maastrichtian. Oil and gas expulsion from the Hauterivian to Barremian, Aptian and Albian sediments takes place from the Santonian to late Palaeocene, the Santonian to middle Eocene and the Maastrichtian to middle Eocene, respectively. Though hydrocarbon generation in the Cenomanian and Turonian sediments is roughly the same as that in the earlier sediments (Table 3), relatively a lesser amount of hydrocarbon is expelled from the Turonian to Cenomanian sediments. Though hydrocarbons are generated in the Santonian sediments, the expulsion does not take place. Timing of oil and gas expulsion in both the optimistic and pessimistic scenarios is more or less the same. Nevertheless, the

Table 3 Summary of oil generation and generation timing for different stratigraphic intervals in the Pearl-1, Dorado-North and Pseudo Mannar-Deep wells under the optimistic source character scenario. Oil generation is in kilograms per unit volume of rock (kg/ m^3). Timing of oil cracking is also listed

Stratigraphic interval		Pearl-1			Dorado-North			Pseudo Mannar Deep		
		Gen. timing (Ma)	Oil Cracking (Ma)	Oil Gen. (kg/m^3)	Gen. timing (Ma)	Oil Gen. (kg/m^3)	Oil Cracking (Ma)	Gen. timing (Ma)	Oil Cracking (Ma)	Oil Gen. (kg/m^3)
Late Cretaceous	Campanian	-	-	-	-	-	-	40-30	-	3
	Santonian	30-5	-	2	45-35	2	-	65-30	-	9
	Coniacian	-	-	-	55-25	4	-	70-30	-	12
	Turonian	45-5	-	4	65-35	10	-	77-30	-	15
	Cenomanian	-	-	-	70-35	15	-	80-70	-	15
Early Cretaceous	Albian	-	-	-	80-45	15	-	85-75	75-40	15
	Aptian	60-10	-	10	85-65	15	-	95-80	80-75	15
	Hauterivian -Barremian	-	-	-	85-75	15	-	100-90	90-70	15
	Berriasian to Valanginian	70-35	-	15	90-75	15	-	105-90	90-72	15
Late Jurassic	Tithonian	-	-	-	95-85	15	75-40	110 90	90- 77	15
	Bathonian -Kimmeridgian	78-35	-	12	100-85	12	70-35	120-95	95-80	15

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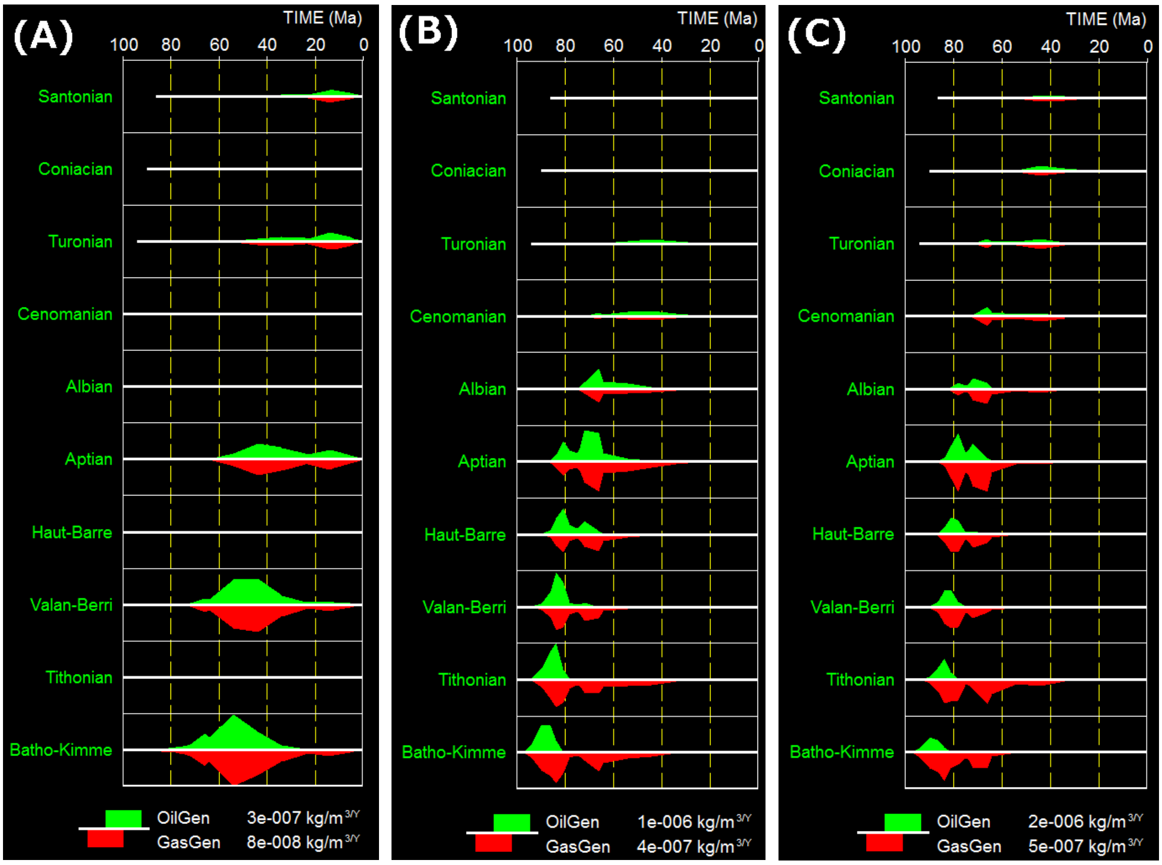

Fig. 11 Timing of oil and gas expulsion from sediment in a stratigraphic column at (A) Pearl-1, (B) Dorado-North, and (C) Pseudo Mannar Deep well locations under optimistic scenario (TOC = 2.5% and Type II and III kerogens 50% each). Haut-Barre = Hauterivian-Barremian, Valan-Berri = Valanginian to Berriasian, and Batho-Kimme = Bathonian- Kimmeridgian

amount of hydrocarbon expulsion under the optimistic scenario is more than 100 times greater than that under the pessimistic scenario.

The Cenomanian, Turonian and earlier sediments can produce roughly the same amount of hydrocarbon per unit volume of rock (Table 3). However, the thinner Cenomanian and Turonian sections generate and expel relatively a smaller amount of hydrocarbons than thicker and older sections. Oil produced in the Late Jurassic sediments thermally cracks into natural gas due to high formation temperatures. The maximum temperature recorded in the Dorado-North well has been around 180 ^{o}C. It is because of oil cracking into gas that the oil expulsion stops prior to the stopping of gas expulsion. The reduction of hydrocarbon expulsion from the Late Jurassic and Early Cretaceous sediments around 70 Ma (the valley seen around 70 Ma in Fig. 11B) could be due to the reduction of formation temperature related to the upliftment, which gave rise to the Cretaceous-Palaeogene (K-Pg) unconformity.

PSEUDO MANNAR-DEEP WELL

Hydrocarbon generation in the Late Jurassic sediments under the optimistic scenario takes place from the Aptian to Turonian. Hydrocarbon generation in the Early Cretaceous sediments takes place from the late Albian to Campanian. The Cenomanian to Campanian sediments generates hydrocarbon from the Campanian to middle Oligocene. Oil generated in the Late Jurassic and Early Cretaceous sediments thermally cracks into natural gas from the Cenomanian to middle Eocene. Almost all oil generated in the Kimmeridgian to Bathonian sediments, which had a maximum formation temperature of around 220 ^{o}C at the end of the late Cretaceous (Fig. 9D), cracks into natural gas. Hydrocarbon generation in the Campanian sediment is smaller (~3 kg/ m^3) compared to that in the sediments older than the Campanian. The sediments younger than the Campanian do not generate a significant quantity of hydrocarbon. Oil generation in the Late Jurassic and younger sediments is around 1.0% kg/m^3 under the pessimistic scenario, which is much smaller quantity compared to the amount of oil

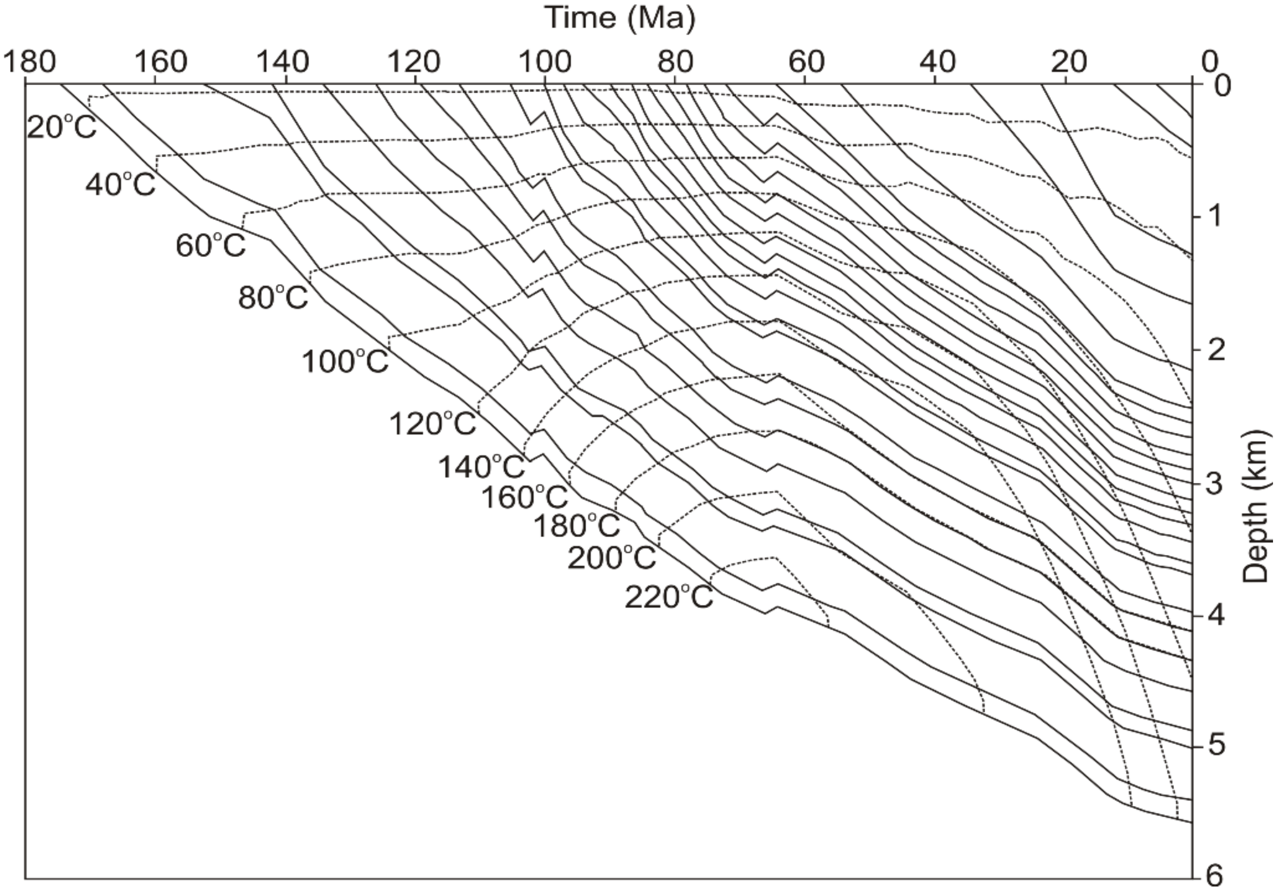

Fig. 12 Burial history plot for the pseudo-Mannar-Deep well. Depth is in metres (m) below sea floor. The dashed contour (isotherm) shows changes in the formation temperatures from the Middle Jurassic to Recent

generation in the same stratigraphic intervals under the optimistic scenario (Figs. 9 & 10). Timing of hydrocarbon expulsion from the Late Jurassic and Early Cretaceous sediments in the Pseudo Mannar-Deep well is roughly similar to the hydrocarbon expulsion from the same aged sediments in the Dorado-North well. However, the duration and the quantity of oil expelled from each stratigraphic interval in the PMD well are smaller compared to that in respective stratigraphic intervals in the Dorado-North well (Fig. 11B & C). A smaller quantity of oil and gas expels from the Cenomanian to Santonian sediments. Timing of oil and gas expulsion in each stratigraphic interval under the optimistic and pessimistic scenarios is more or less the same. However, the amount of hydrocarbon expels under the optimistic scenario is more than 100 times greater than that under the pessimistic scenario. There is always a time lag of about 5 Ma between the hydrocarbon generation and expulsion.

Oil produced in the Albian and older sections in the Pseudo-Mannar-Deep well cracks into natural gas due to high formation temperatures (Table 3 & Fig. 9D &E). The integrated burial and thermal history plot shows that thermal cracking of oil starts at around 120-140 ^{o}C (Fig. 12). Increasing formation temperatures from the Pearl-1 well towards the Pseudo-Mannar-Deep well could be due to the stratigraphic thickness and heat flow increasing from north to south of the Mannar Basin (Fig. 2 and Table 1). The timing and quantity of oil expulsion from the Late Jurassic and Early Cretaceous sediments are smaller due to cracking of oil into natural gas (Fig. 11B & C). Gas expulsion from the Late Jurassic and Early Cretaceous sediments take place for a longer period due to the continuous production of gas through oil cracking.

MODELLED HYDROCARBON MIGRATION AND ACCUMULATION

Modelling results under the optimistic scenario show some oil accumulations close to 100% oil saturation mainly in Late Cretaceous sandstones (Fig. 13A). In addition, a few oil accumulations with low oil saturations (~20%) are seen in the Early Cretaceous and Palaeogene sections. A

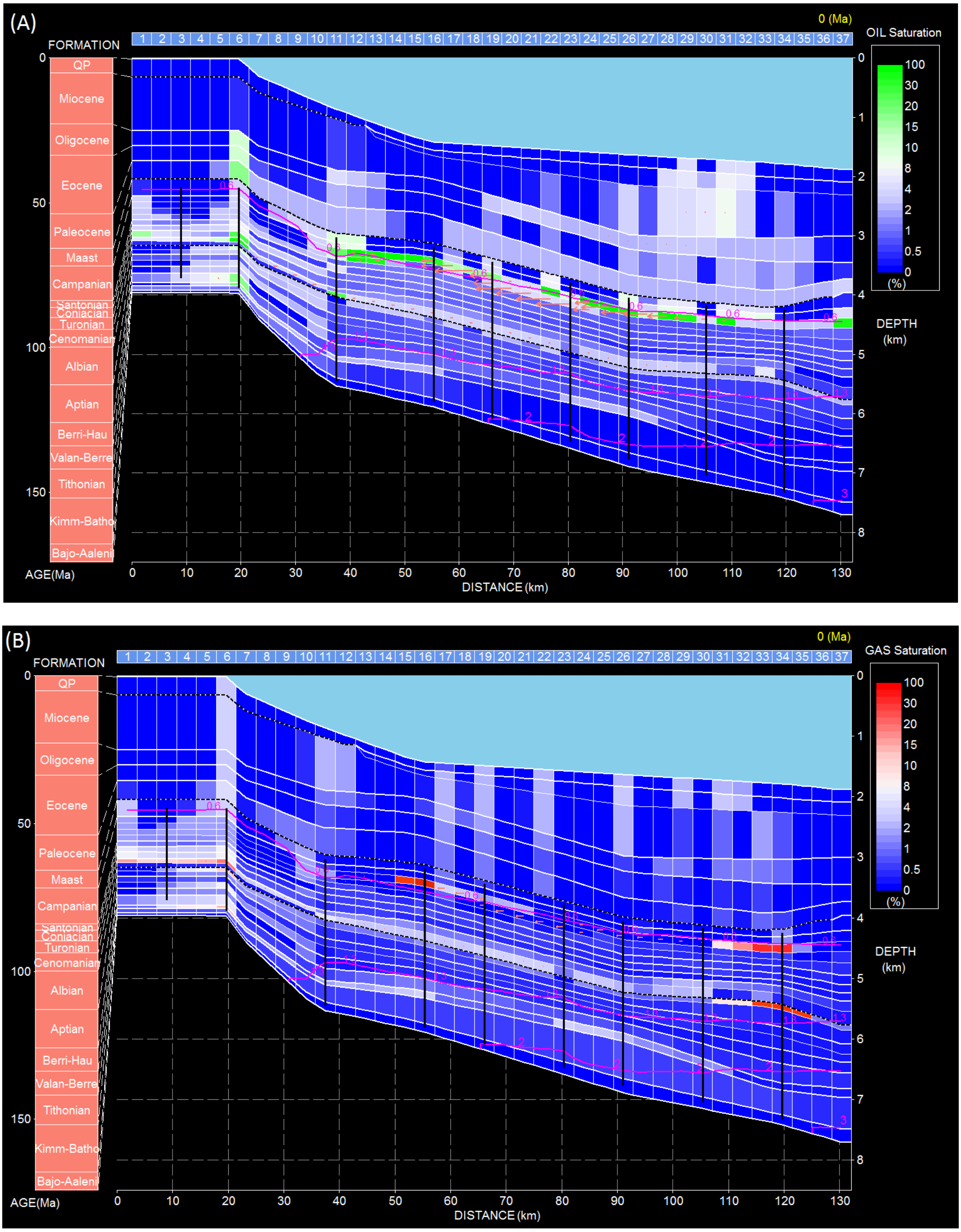

Fig. 13 Modelled present day (A) oil and, (B) gas accumulation along the X-X' section under the optimistic scenario. Fig. 1 shows the location of X-X' section. Red colour arrows indicate direction of horizontal oil and gas flow. Purple colour contours indicate the computed vitrinite reflectance in %R_o

couple of gas accumulations with close to 100% gas saturation could be seen in the Albian and Cretaceous sandstones under the optimistic scenario (Fig. 13B). In addition, oil and gas accumulation seems to take place in Cretaceous sandstones under the moderate scenario (TOC = 1.5%, Type II kerogen = 20%, and type III kerogen =80%; Fig. 14). No significant oil

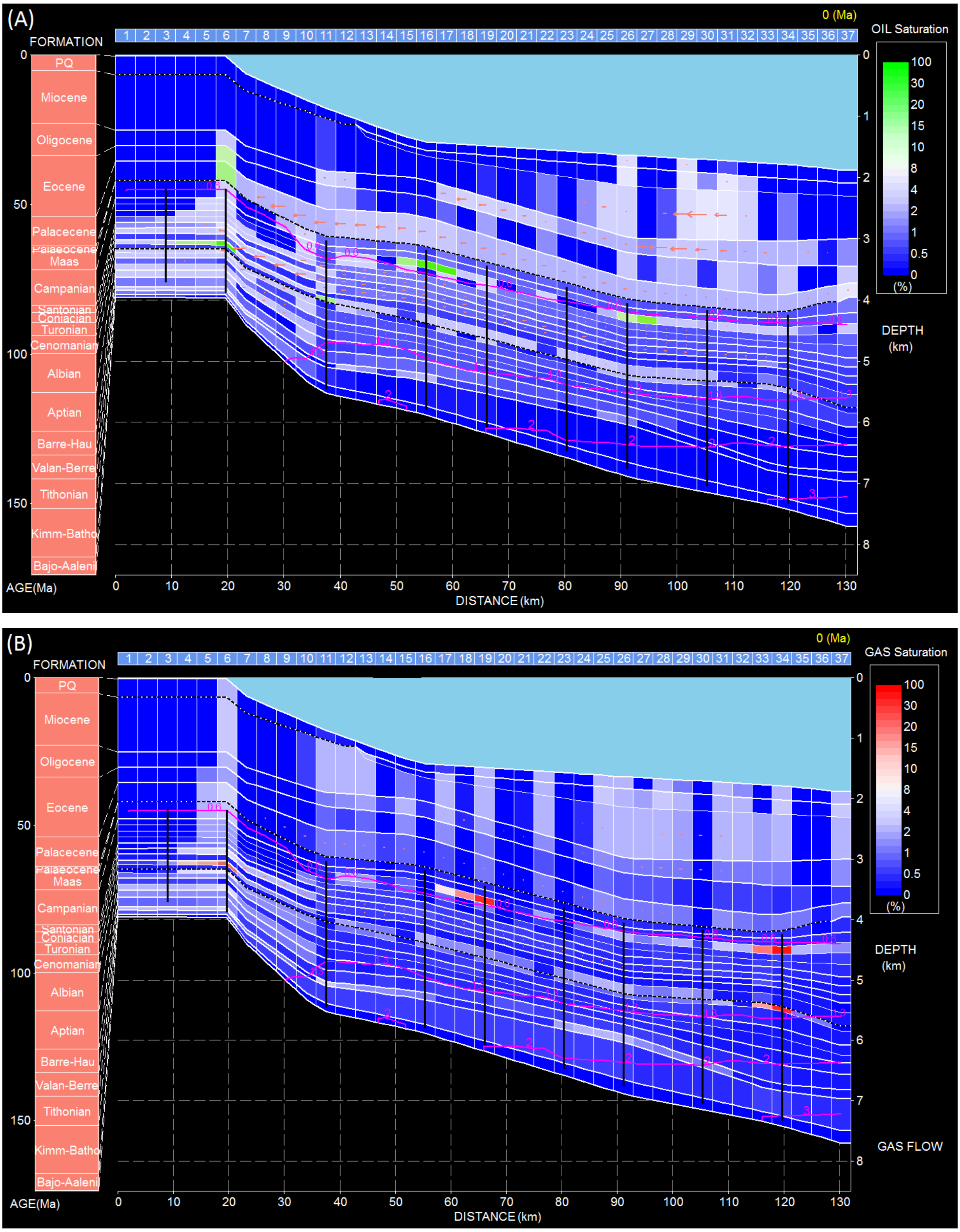

Fig. 14 Modelled present day (A) oil and, (B) gas accumulations along the X-X' section under moderate source character scenario (TOC = 1.5% and Types II kerogen 20%, remaining 80% being Type III kerogen). Fig. 1 shows the location of X-X' section. Red colour arrows indicate direction of horizontal oil and gas flow. Purple colour contours indicate the computed vitrinite reflectance in %R_o

accumulation takes place under the pessimistic scenario. However, a gas accumulation with close to 100% gas saturation could be seen in Albian sandstones under the pessimistic scenario. The red coloured arrows in Figs. 13 and 14 show the direction of hydrocarbon migration, mainly from the carrier beds in the southern part of the Mannar Basin in deep water depths towards the potential reservoirs in shallow water depths in the northern part. The purple coloured contours in Figs. 13 and 14 show the vitrinite reflectance (VR) calculated using SIMPLE R_o%. The data show that the VR of the Late Jurassic sediments in the Pseudo Mannar-Deep well exceeds 3 %R_o.

Modelling results further suggest that the optimistic source character scenario of 2.5% TOC and Types II and III kerogen 50% each have potential to generate oil and gas deposits in the Mannar Basin. On the other hand, the pessimistic source character scenario of 0.5% TOC and presence of only Type III kerogen in claystones is not good enough to produce economically viable oil deposits, yet may give rise to natural gas deposits. Since some sandstone layers were assumed to extend almost across the entire length of the stratigraphic section, the hydrocarbon migration seems to take place from southern part of the Mannar Basin in deep water depths towards the shallow water depths in the north. Results in the accumulation modelling show that the probability of occurring hydrocarbon deposits in the Late Cretaceous sandstone could be higher. Modelling results also suggest that a lager quantity of hydrocarbons expelled from source rocks in the Mannar Basin could have leaked into the ocean. More than 2 %R_o of VR show over maturity of sediments beyond which no hydrocarbon generation takes place (Petersen, 2002). The Late Jurassic and Early Cretaceous (Berriasian to Barremian) sediments in the Pseudo Mannar Deep well is over matured. The over maturity (VR = 2 %R_o) line in Fig. 13 could be expected to enter into the sediments younger than the Berriasian age further south of the Pseudo Mannar Deep well.

PETROLEUM SYSTEM IN MANNAR BASIN

SOURCE ROCKS

If the Mannar Basin is to produce economically viable oil deposits its Early Cretaceous and older sediments should have a good hydrocarbon source character. The Aptian and Turonian–Cenomanian ages experienced, well-known global oceanic anoxic events (e.g., Schlanger and Jenkyns, 1976; Arthur *et al*., 1987). These anoxic events (OAE) might have given rise to good hydrocarbon source rocks in the Mannar Basin. Fine grained sedimentary rocks with 1% or higher TOC could be considered as having good hydrocarbon source potential (Peters and Cassa, 1994). Based on the previously mentioned discussions on the source potential of the Cauvery Basin by Cantwell *et al*. (1978); Chandra *et al*. (1991) and on the Late Jurassic mudstone in the Aadigama graben by Ratnayake and Sampei (2015), it could be thought that the Early Cretaceous and older sediments in the Mannar Basin might have at least 1.0% of average TOC and at least 10-15% contribution from Type II kerogen. Based on the modelled hydrocarbon accumulation under the moderate source characteristic scenario (Fig. 14), it could be thought that the Mannar Basin might accommodate economically viable oil and gas deposits. Due to increasing formation temperatures towards the southern part of the Mannar Basin, the potential for having natural gas deposits could be higher towards the southern part of the basin. The source of thermogenic gas encountered in the Dorado and Barracuda wells in 2011 could be the Early Cretaceous and/or older claystones in the Mannar Basin.

CONCLUSIONS

The Campanian to younger sediments in the northern Mannar Basin, which has been derived from vascular land plants, is rich in type III and IV kerogen and has poor hydrocarbon source potential. If the Santonian to Cenomanian sediments have a good source potential it could have expelled relatively a smaller quantity of oil and natural gas. The productivity of this stratigraphic interval increases from north to south of the Mannar Basin. Early Cretaceous to older potential source rocks in the Mannar Basin, have not been penetrated by exploration wells. The source character of this deeply buried sediments is uncertain. In the event of the Early Cretaceous to older sediments having good hydrocarbon source potential, oil and gas could have been expelled mainly during the Late Cretaceous, which is followed by a couple of minor expulsion phases in the Palaeogene and in the Neogene. The time lag between the oil generation and expulsion in the Mannar Basin is around 5 Ma. The oil cracking starts at 120-140 ^oC. The probability of occurring natural gas deposits increases towards the southern part of the Mannar Basin. Even if the deeply buried sediments have a poor hydrocarbon source potential of around 0.5% TOC content and only Type III kerogen they could still give rise to economically viable gas deposits. The potential source rocks in the Mannar Basin could be expected to have an average TOC content of at least 1% and 10-15% contribution from Type II kerogen, in which case economically feasible oil and gas deposits may occur mainly in sandstones in the Cretaceous stratigraphic interval. The potential hydrocarbon traps in the Mannar Basin include tilted/rotated fault blocks, anticlinal closures, channel fills and stratigraphic pitchouts. The igneous rocks interbedded with sandstones may also act as hydrocarbon traps and seals. Both vertical and lateral drainage systems might occur in the Mannar Basin.

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