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Fluid inclusion evidence for an early, marine-sourced oil charge prior to gas-condensate migration, Bayu-1, Timor Sea, Australia

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Abstract

The distribution of oil-bearing fluid inclusions (FI) in currently gas-bearing Jurassic reservoir sandstones from Bayu-1 (Northern Bonaparte Basin, Timor Sea) is consistent with the Bayu gas-condensate field originally containing a palaeo-oil column beneath a thick palaeo-gas cap. In order to assess the origin of the oil trapped in the FIs and its relationship, if any, to the gas condensate, a detailed molecular geochemical study was carried out on a FI oil extract and a condensate sample recovered from a similar interval by Modular Formation Dynamics Tester (MDT). Compared to the condensate, the FI oil was generated from a more marine-influenced, less clay-rich source rock or source facies, which was deposited in a less oxic environment with greater eukaryotic input. The source rock of the condensate was more terrigenous and had greater microbial input. The Bayu FI oil contains a greater amount of C₂₈ and C₂₉ tricyclic terpanes than the Bayu condensate, and particularly compared to the Elang/Plover sourced oils from further to the northwest (e.g. Corallina and Laminaria), which are more terrestrially-dominated. The Bayu condensate has previously been attributed to either the marine Cretaceous Echuca Shoals Formation, or mixed sourcing from the less terrestrially-influenced facies of the Jurassic Elang and Plover formations, together with the marine Flamingo Group. Analysis of the FI oil confirms a more marine-influenced source facies of the palaeo-oil, with the Echuca Shoals Formation being the most likely source based on oil–oil and oil–source correlations. The FI oil appears to represent a marine source end-member and it is likely that mixing of this oil (sourced from the Echuca Shoals Formation) with hydrocarbons sourced from the more terrestrially dominated Plover/Elang source facies could account for the intermediate composition of the currently reservoirized condensate. A discrete ‘Flamingo Group’ is not required and this oil family may not be present in the Bayu area. The differences are nevertheless subtle and a contribution from the Flamingo Group cannot be completely discounted. The FI oil has a mid-oil window maturity (~0.75% vitrinite reflectance equivalent, VRE), whereas the currently reservoirized condensate has a higher maturity (~0.9% VRE). These maturity data are consistent with early expulsion from the more labile, marine-derived organic matter in the Echuca Shoals Formation, followed by expulsion of large amounts of condensate from the more terrestrially-dominated Elang and Plover formations. Three possible transition mechanisms from gas over oil to condensate are consistent with the FI petrographical and geochemical data. The first charge may have (1) been lost by breaching of the seal, (2) been displaced by the condensate, or (3) been partly dissolved in the later condensate charge. A combination of factors 2 and 3 is considered most likely, but further investigation is required to assess these options. The FI oil at Bayu-1 predominantly represents a different hydrocarbon charge compared to the condensate liquid, and so by analogy the large residual oil columns that are observed elsewhere in the Northern Bonaparte Basin are unlikely to be due to water-washing of a pre-existing gas-condensate column similar to Bayu-Undan.

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Keywords: Fluid inclusion; Oil; Condensate; Biomarkers; Aromatic hydrocarbons; Timor Sea; Migration

1. Introduction

An investigation of fluid inclusion oils from reservoir sandstones of the Bayu-Undan gas-condensate field has been completed to assess the composition and retention of palaeo-oil charge to this structure. In the Timor Sea region

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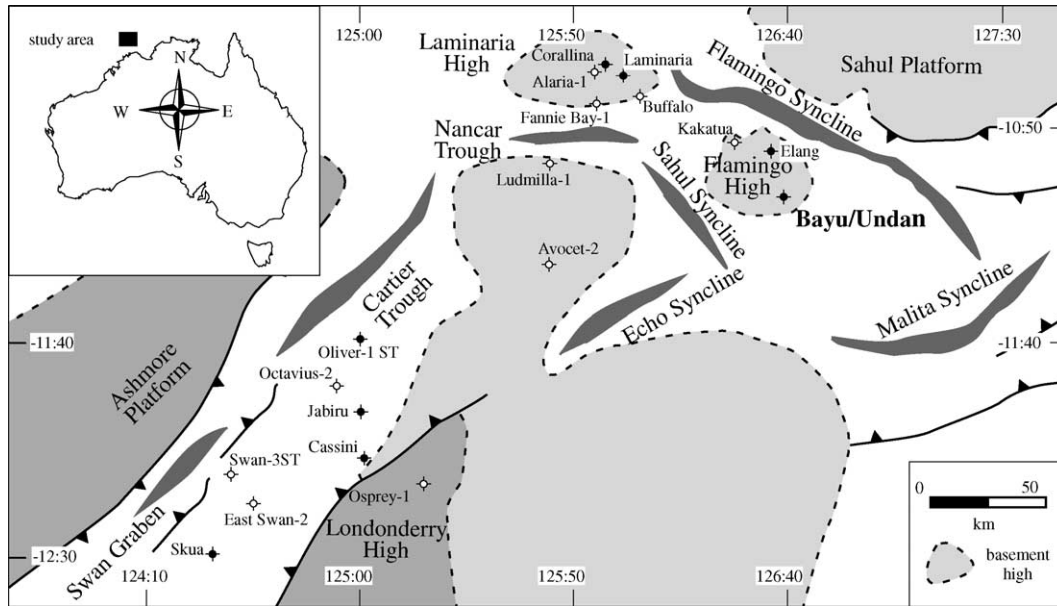


Fig. 1. Location map of the study area in the Timor Sea, northwest Australia, showing structural elements and the position of the Bayu/Undan condensate field in the northern Bonaparte Basin.

of northwest Australia (Fig. 1), the presence of gas in an otherwise oil-dominated system is an important factor in defining the economic feasibility of plays (e.g. Lisk, Brincat, Eadington, & O'Brien, 1998; Lisk, O'Brien, & Brincat, 1997), so it is important to understand the controls on the hydrocarbon fill and retention history. The objective of this study is to produce a charge history model for the field in order to understand the relative importance of key source facies in producing a liquid charge to this trap, and to evaluate the transition from oil accumulation to the current gas-condensate column. Specifically, the aims of this paper are to:

1. Define the geochemical composition of the trapped fluid inclusion oil at Bayu-1.
2. Provide constraints on the charge history at Bayu-1, including possible transition mechanisms from gas over oil to gas-condensate.

2. Geological setting and background

The Bayu-Undan gas-condensate field in the Northern Bonaparte Basin, northwest Australia (Fig. 1) was discovered in early 1995 by Phillips Petroleum Company (Brooks, Goody, O'Reilly, & McCarty, 1996). The discovery well, Bayu-1, intersected a gross 155 m gas column within Middle Jurassic sandstones (Elang and Plover formations) (Fig. 2) at a top reservoir depth of 2,954.5 mSS (2,973.5 mRT) (Fig. 3).

The Northern Bonaparte Basin contains mainly light oils and gas-condensate, reservoired primarily in the Elang and Plover formations, although some wells also intersected oil

SYS.	SER.	STAGE	PALYNOZONE	LITHOSTRATIGRAPHY
CRETACEOUS	LOWER	APTIAN	<i>O. davidii</i>	DARWIN FORMATION (RADIOLARITE)
		BARREMIAN	<i>A. cinctum</i>	
		HAUTERIVIAN	<i>M. australis</i>	ECHUCA SHOALS FORMATION
	VALANGINIAN	<i>M. testudinaria</i>		
	UPPER	BERRIASIAN	<i>P. burgerii</i>	FLAMINGO GROUP
		TITHONIAN	<i>S. tabulata</i>	
KIMMERIDGIAN		<i>P. iehiense</i>		
JURASSIC	MIDDLE	OXFORDIAN	<i>D. swanense</i>	CLEIA (FRIGATE) FORMATION
		CALLOVIAN	<i>W. clathrata</i>	
	LOWER	TOARCIAN	<i>W. spectabilis</i>	ELANG FORMATION
		PLIENSACHIAN	<i>W. digitata</i>	
		SINEMURIAN	<i>W. indolata</i>	
	UPPER	BATHONIAN	<i>D. complex</i>	PLOVER FORMATION
		BAJOCIAN	<i>C. turbatus</i>	
AALENIAN		<i>C. torosa</i>		
LOWER	HETTANGIAN	<i>C. torosa</i>	Plover Formation	
	RHAETIAN			
	NORIAN	<i>M. crenulatus</i>		

Fig. 2. Stratigraphic table of the northern Bonaparte Basin (modified after Brooks et al., 1996; Gorter & Hartung-Kagi, 1998).

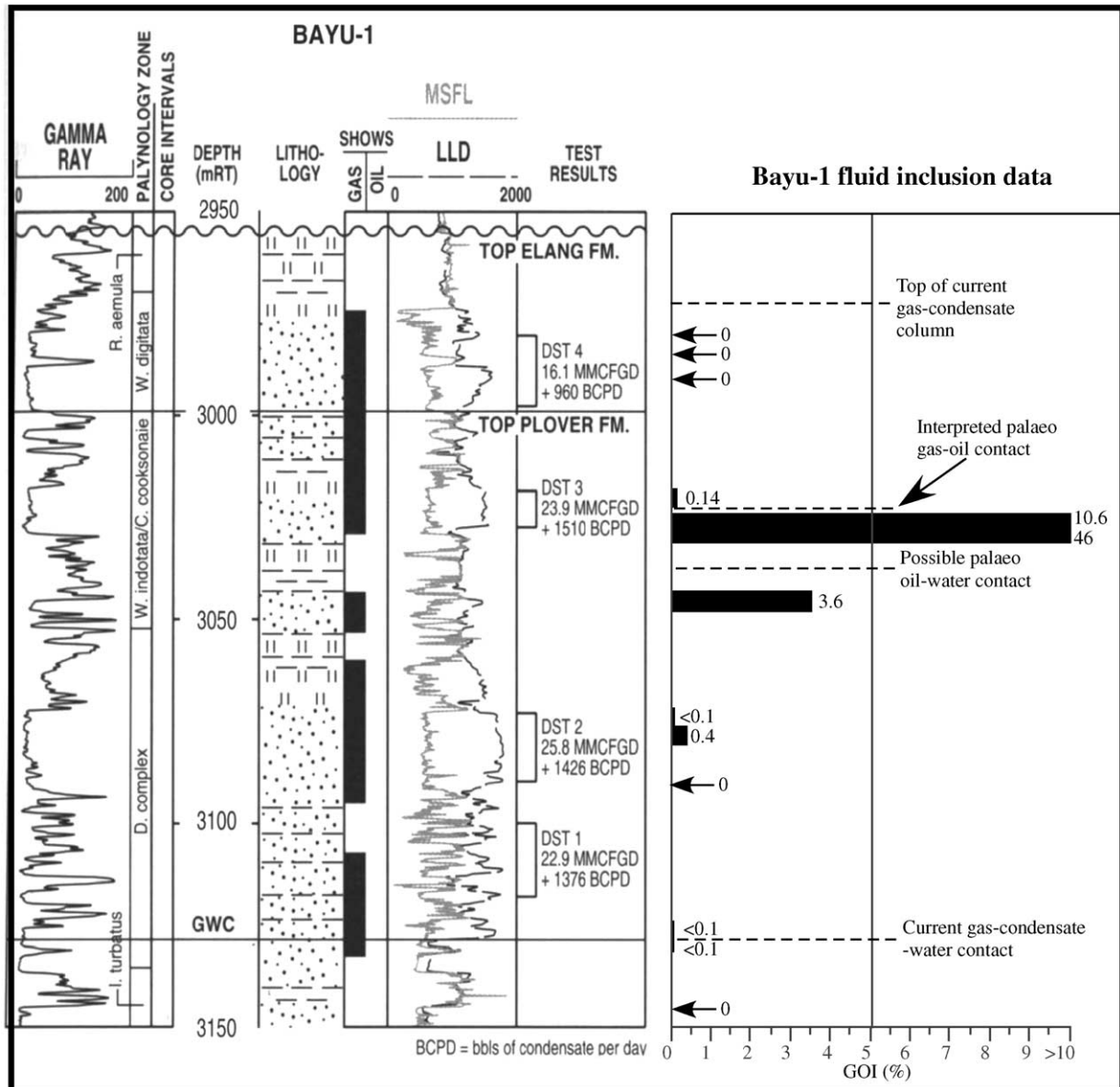


Fig. 3. Bayu-1 reservoir summary, GOI data and interpreted palaeo fluid contacts (modified from Brooks et al., 1996). GOI values have been revised since preliminary publication of these data (George, Lisk et al., 2002).

reservoired in the Early Cretaceous (Preston & Edwards, 2000). These hydrocarbons are mainly sourced from Middle to Upper Jurassic marine source rocks with variable terrigenous inputs (Edwards et al., 2004; Preston & Edwards, 2000). Variability in the geochemical composition of the more terrestrially-dominated Elang/Plover reservoirs present in most of the oilfields from the region has been attributed to either facies variations within the main source interval, or more probably to additional generation from other source intervals, such as the terrestrially-dominated Frigate Formation and the marine-dominated Flamingo Group. A second group of oils reservoirs in the Early Cretaceous Darwin Formation have been shown to correlate with sediment extracts from

the Early Cretaceous Echuca Shoals Formation (Preston & Edwards). Additionally, a previously unrecognised oil generative source rock in the Nancar Trough area has recently been proposed to have generated oils such as those at Ludmilla-1 (George, Volk et al., 2002). These oils (the Nancar oil family) contain unusually high abundances of mid-chain substituted monomethylalkanes. Oils from the Laminaria High and some from the northern Vulcan Sub-Basin show some similar characteristics to the Nancar oil family and may be co-sourced (George et al., 2004; George, Volk et al., 2002).

Previous studies have highlighted a complex oil-source match for the currently reservoir gas-condensate at Bayu-Undan. Brooks et al. (1996) tentatively ascribed the source

of the Bayu-Undan condensate to the marine Early Cretaceous Echuca Shoals Formation or to a less terrestrially-influenced facies of the Jurassic Elang and Plover formations. A contribution from the dominantly marine Flamingo Group has also been suggested (Preston & Edwards, 2000), whilst the Cleia (Frigate) Formation (Fig. 2) has also been cited as a potential source of marine oils in the Malita Graben or southern Sahul Syncline (Gorter & Kirk, 1995).

In addition to the complex source influences in the Northern Bonaparte Basin, episodes of in situ alteration, fault seal or top seal leakage, and gas recharge and/or mixing are likely to have contributed to a relatively complicated charge history. Many workers have identified fault seal failure in the Neogene to be the principal control on the retention of hydrocarbons in the basin (e.g. Brincat, Lisk, Kennard, Bailey, & Eadington, 2004; Brincat, O'Brien, Lisk, DeRuig, & George 2001; Castillo et al., 2000; De Ruig, Trupp, Bishop, Kuek, & Castillo, 2000; Shuster, Eaton, Wakefield, & Kloosterman, 1998). An alternative mechanism proposed by Newell (1999) challenged this assertion by suggesting that water-washing, driven by dewatering of sediments during Neogene plate collision near the island of Timor, was a major process controlling the present distribution and composition of hydrocarbon accumulations in the Northern Bonaparte Basin (Newell, 1999). In particular, it was proposed that under-filled oil fields on regional highs, such as the Laminaria–Corallina structure (Fig. 1) may have once contained much larger gas-condensate columns that were subsequently extensively water-washed, leading to ~90% volume reduction and residual oil accumulations in the highest crests only (Newell, 1999). Certainly, geochemical evidence such as the very low contents of benzene and toluene in most of the Northern Bonaparte Basin oils suggests that some water-washing has occurred (George et al., 2004; Newell, 1999; Preston & Edwards, 2000). Newell (1999) suggested that the Bayu-Undan gas-condensate field, which has not been affected by extensive water-washing, reflects either a more recent hydrocarbon charge, as suggested by thermal modelling, and/or a lesser water flow in the regional Elang/Plover aquifer than to the northwest of the Bonaparte Basin.

The abundance, distribution and composition of oil inclusions can be used to provide clearer data on (1) the extent of the palaeo-oil column at Bayu-1, and (2) the composition of that palaeo-oil. Preliminary petrological and geochemical data on Bayu-1 have been published by George, Lisk, Eadington, & Quezada (2002).

3. Experimental methods and samples

Two analytical methods have been used to investigate the oil saturation history (Grains containing Oil Inclusions; GOI) and the geochemical composition of palaeo-oils

(Molecular Composition of Inclusions; MCI) in samples of sandstone from the Bayu-1 well.

The frequency of oil-bearing fluid inclusions in thirteen rotary sidewall core samples (2,980–3,146 mRT) from the current gas-condensate column in Bayu-1 has been determined using a petrographic approach known as the GOI method. Full details of this technique can be found in Eadington, Lisk, & Krieger (1996) and Lisk et al. (1998). In brief, GOI analysis is a point counting technique that records the frequency of quartz and feldspar grains that contain oil inclusions. The GOI method is designed to evaluate the oil saturation history of sandstone reservoirs by comparing the values derived from each sample with an empirical database of samples taken from more than 40 current day oil fields. This database typically reveals at least one order of magnitude difference in the percentage of grains containing oil inclusions between samples taken from current oil zones, compared to samples with demonstrably low oil saturation from beneath the oil–water contact (unpublished CSIRO data and Lisk et al., 1998). GOI values above a threshold of 5% are interpreted to demonstrate the presence of a palaeo-oil column, irrespective of the current fluid phase in the reservoir (Lisk, Brincat, O'Brien, Eadington, & Faiz, 1999; Lisk & Eadington, 1994; Lisk et al., 1998).

The geochemical composition of oil trapped within FIs in quartz grains of the Bayu-1 reservoir sandstone (3,028–3,031 mRT cuttings interval) has been determined by the MCI technique. A detailed description of this method is provided in George, Lisk, Eadington, & Quezada (1998) and George, Lisk, Eadington, Quezada, Krieger et al. (1996). Briefly, the cuttings sample was mechanically (using mortar and pestle) and chemically (using hydrogen peroxide and hydrochloric acid) disaggregated, and quartz grains were separated from other lithologies using magnetic and heavy liquid separation. Potential surface contaminations on the quartz grains were removed using successive treatments of solvents, hydrogen peroxide and chromic acid. The quartz concentrate (3.26 g) was crushed under solvent (dichloromethane: methanol, 93:7) to release oil from the FIs into the solvent (the off-line analytical technique for C₁₁₊ hydrocarbons). The level of background contamination was determined by preparing and analysing a system blank under exactly the same conditions before and after analysis of the FI oil. A subsample of the quartz concentrate (50.8 mg) was also crushed in a glass-coated, metal insert of a Quantum MSSV-1 Thermal Analysis System (the on-line analytical technique for C₁₁₋ hydrocarbons).

Condensate from 3089.6 mRT (MDT-2) in Bayu-1 was analysed for comparison with the Bayu-1 FI oil. The condensate was fractionated using column chromatography (150 mm) on activated alumina above silica gel and a step-wise elution with 100 ml petroleum ether (aliphatic fraction) and 150 ml of a 1:4 vol% mixture of petroleum ether and dichloromethane (aromatic fraction). An aliquot

of the aliphatic hydrocarbons was separated by urea adduction into an adducted hydrocarbon fraction (mainly *n*-alkanes and monomethyl alkanes) and a non-adducted hydrocarbon fraction (mainly isoprenoids and cyclic alkanes).

The FI oil and the condensate fractions were analysed by gas chromatography–mass spectrometry (GC–MS) using an AutoSpecQ system (George, Lisk, Eadington, Quezada, Krieger et al., 1996; George, Lisk et al., 1998). The GC was fitted with a DB5MS 60 m fused silica column (i.d. 0.25 mm, film thickness 0.25 μ m) for the off-line technique, and a GC5 25 m fused silica column (i.d. 0.25 mm, film thickness 0.3 μ m) for the on-line technique. For the off-line technique, most hydrocarbon ratios were determined from single ion monitoring (SIM) data, except for some biomarker ratios, which were determined in metastable reaction monitoring (MRM) mode. For the on-line technique, low molecular weight hydrocarbons were detected by magnet scanning (*m/z* 50–550), after which areas of target peaks in mass chromatograms were converted to flame ionisation detector (FID)-equivalent data using response factors, before data manipulation. Whole condensate was analysed by split injection using the same apparatus and analytical conditions as was used to analyse the FI oil.

4. Results and discussion

4.1. Petrographic data

Most of the thirteen analysed samples from the gas-condensate column at Bayu-1 contain oil inclusions, but only two samples (3,026.5 and 3,028.1 mRT) have GOI values above an empirical threshold ($>5\%$) for oil accumulation (Fig. 3). A third sample (3046.1 mRT) has a lower GOI (3.6%), but this sample is strongly cemented and it is likely that poor reservoir quality has contributed to its lower value. The two consecutive high GOI samples are interpreted as defining the presence of a palaeo-oil column in these presently gas-bearing sandstones at Bayu-1. Samples from higher in the reservoir have low GOI values (<0.2) and are consistent with a zone of low oil saturation overlying this palaeo-oil column. Given the lack of an intervening capillary barrier, this zone of low GOI values is interpreted as a palaeo-gas column. Samples from lower in the reservoir also have low GOI values (<0.5) and are interpreted as defining a palaeo-water zone. Based on these results the palaeo gas–oil contact is positioned between 3,020 and 3,026.5 mRT, and a palaeo oil–water contact is positioned between 3,028.1 and 3,046.1 mRT (Fig. 3).

The fluorescing fluid inclusions documented in these samples are extremely small, mostly less than 5 microns in diameter. Their small size makes recognition difficult, particularly at lower magnifications, and hinders accurate estimation of the liquid–vapour ratio. For most two-phase inclusions, the percent vapour appears to be in the range of

10–40%. Some three-phase (oil + water + vapour) inclusions were also documented. The inclusions are irregular in shape and occur within authigenic quartz overgrowths and on healed fractures through detrital quartz in about equal proportions. The inclusions nearly all exhibit blue fluorescence colour (George, Ruble, Dutkiewicz, & Eadington, 2001).

The GOI data reported here differ from those originally reported in George, Lisk et al. (2002), which were first completed for a confidential report in 1995. The variations recorded in samples with low GOI ($<0.5\%$) are not significant and the position of the inferred palaeo-gas oil contact remains unchanged. More significant changes are recorded in the three samples with elevated GOI values and the revised values are proportionally lower than previously reported. The lowermost of these three samples now falls below the empirically-derived threshold for oil accumulation and this influences the position of the inferred palaeo-oil water contact reported in this paper compared to that reported in George, Lisk et al., (2002). The revised GOI value for the lowermost high GOI sample (3.6%) remains high relative to the other low GOI values and is considerably higher than would be expected for a water zone sample, where GOI values rarely exceed 1%. In interpreting the significance of this result it is considered possible that high oil saturation may have extended to this depth, and that the previously reported position of the palaeo-oil water contact may be correct. However, given that this value falls below the threshold for oil accumulation (5%), the more conservative interpretation that is followed here is to place the base of high palaeo-oil saturation immediately below the 3,028.1 mRT sample, which would define a ‘palaeo-oil down to’ rather than a palaeo-oil water contact. The sample used for the geochemical analyses conducted in this study remains within the conservatively-inferred palaeo-oil zone and hence this change has no direct bearing on the veracity of the geochemical results.

The exact causes of the variations seen in the repeated GOI data are difficult to conclusively ascertain. The fluorescing fluid inclusions documented in these samples are extremely small (mostly less than 5 microns in diameter), which makes their recognition difficult. The original values were some of the first samples on which GOI numbers were collected, with the technique only being developed in the previous year (Lisk & Eadington, 1994). Some variations could be attributed to the equipment used at the time, or to the method used to estimate the counts of total grains and grains with oil inclusions. The use of less rigorous inclusion identification protocols may also have influenced the original values, but all of these factors are unlikely to be solely responsible for these variations. The experience of the analyst may also have been an influence, but this is difficult to assess. The updated GOI values reported in this paper have been carefully scrutinised by multiple analysts to ensure their accuracy.

4.2. Geochemical data

4.2.1. Low molecular weight hydrocarbons

The relative abundance of *n*-alkanes in the Bayu-1 FI oil, as determined by the on-line MSSV method, is shown in Fig. 4. The distribution maximises at C₅, and rapidly decreases to C₇. No *n*-alkanes >C₁₄ could be detected in the Bayu-1 FI oil by this method, although off-line data clearly shows that C₁₅–C₃₂ *n*-alkanes are present (see Section 4.2.2). Similar low responses of higher molecular weight hydrocarbons during on-line crushing has been noted in many other FI oil samples (e.g. Bigge, Petch, Macleod, Larter, & Aplin, 1995; George, Lisk, Eadington, Quezada, Krieger et al., 1996; George, Lisk et al., 1998), and are likely due to adsorption of higher molecular weight hydrocarbons on the freshly crushed quartz grains in the MSSV inlet. The extent of this molecular weight discrimination is less when the yield of oil from inclusions is higher (George, Greenwood, et al., 1997; George, Lisk et al., 1998). The condensate sample is dominated by low molecular weight *n*-alkanes, with a maximum at *n*-C₇ (Fig. 4).

The main application of the on-line analytical data is for comparison of the C₅ to C₉ hydrocarbons in the Bayu-1 condensate and the FI oil (Fig. 5). The most abundant compounds present in the FI oil are the *n*-alkanes, *i*-pentane, furan, methylfurans, benzene, methylcyclohexane and toluene. A full range of other low molecular weight hydrocarbons was also detected, including branched alkanes, cyclohexane, methyl-, dimethyl- and ethylmethylcyclohexanes, methyl- and dimethylcyclopentanes, and the xylenes (Fig. 5). The same compounds are present in the condensate, except for furan and methylfurans. The overall distribution of C₅ to C₉ hydrocarbons in the Bayu-1 condensate is less skewed to the low molecular weight region compared to the FI oil. Benzene and toluene are more

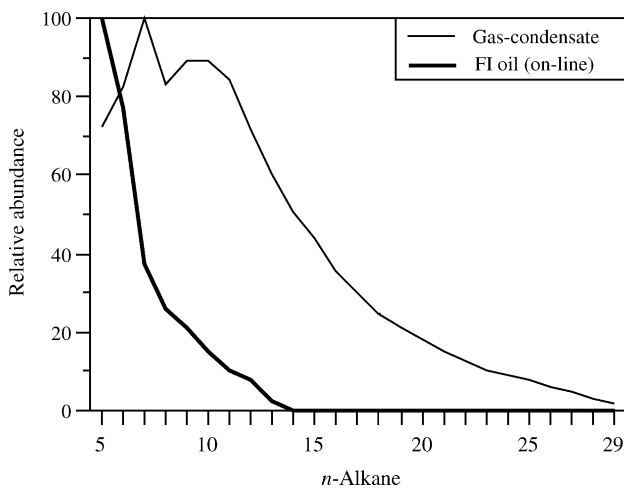


Fig. 4. Relative abundance of *n*-alkanes in the Bayu-1 FI oil and the Bayu-1 condensate, as determined by the on-line MSSV method. Abundances were calculated from *m/z* 57 mass chromatograms and are expressed as FID-equivalent.

abundant in the FIs than in the condensate by factors of 50 and 4 respectively, relative to methylcyclohexane (Fig. 5). Other differences include relatively higher amounts of 3-methylpentane, *n*-hexane, methylcyclopentane, 2-methylhexane, 2-methylheptane, *n*-octane and the substituted aromatic hydrocarbons in the FIs. Ratios summarising some of these differences are given in Table 1. The on-line experiment was carried out in duplicate, with only minor variation in results.

It is noticeable that some of the compounds in high abundance in the Bayu-1 FI oil are highly water soluble. Furan (10,000 ppm; Dean, 1985), methylfuran (3,000 ppm; Dean), benzene (1,740 ppm; McAuliffe, 1966) and toluene (515 ppm; McAuliffe, 1966) are the four most water soluble compounds detected. Water-washing removes the most water soluble components of oils. The character of the liquid analysed by the on-line technique suggest that it is derived principally from aqueous FIs, with a small contribution from oil-bearing FIs, as has previously been proposed for some other Australian samples by Ruble, George, Lisk, and Quezada (1998). Note, however, that many samples rich in oil inclusions that have been analysed using the on-line technique do not have anomalously large amounts of water-soluble compounds (George, Greenwood, et al., 1997; George, Lisk et al., 1998; George et al., 2004). The Bayu-1 FI oil sample analysed has a high frequency of oil inclusions (GOI=46%), but these are small and contain small volumes of oil. Because of the cube root relationship between radius and volume, the size of inclusions is as important as the number of inclusions in determining the volume of oil recovered (e.g. George, Volk et al., 2001). In this sample, it is likely that aqueous FIs have contributed the majority of the compounds detected. The presence of smaller amounts of relatively insoluble hydrocarbons such as the branched alkanes, alkylcyclopentanes and alkylcyclohexanes suggests a small contribution from the oil inclusions. The water-soluble compounds in the aqueous inclusions probably reflect interaction of the formation water with petroleum, prior to trapping as aqueous inclusions (Ruble et al., 1998). This interpretation provides support for at least some water-washing in the Northern Bonaparte Basin, although it does not necessarily corroborate Newell's (1999) hypothesis of water-washing in this region leading to extensive hydrocarbon column volume loss.

Low molecular weight hydrocarbon ratios for Bayu-1 FI oil and gas condensate were carefully compared, as some are undoubtedly affected by the contribution from the aqueous inclusions (Table 1). This includes any ratios that might be used to assess evaporative fractionation or water-washing of the included oil. Ratios of less water soluble hydrocarbons are for the most part similar for the Bayu-1 FI oil and gas condensate (Table 1). Maturity parameters such as the heptane and isoheptane values and the *n*-C₇/methylcyclohexane ratio are very similar, and are consistent with mature oils (e.g. Thompson, 1987). This is corroborated by the *C*_{temp} parameter (Mango, 1997) for the Bayu-1

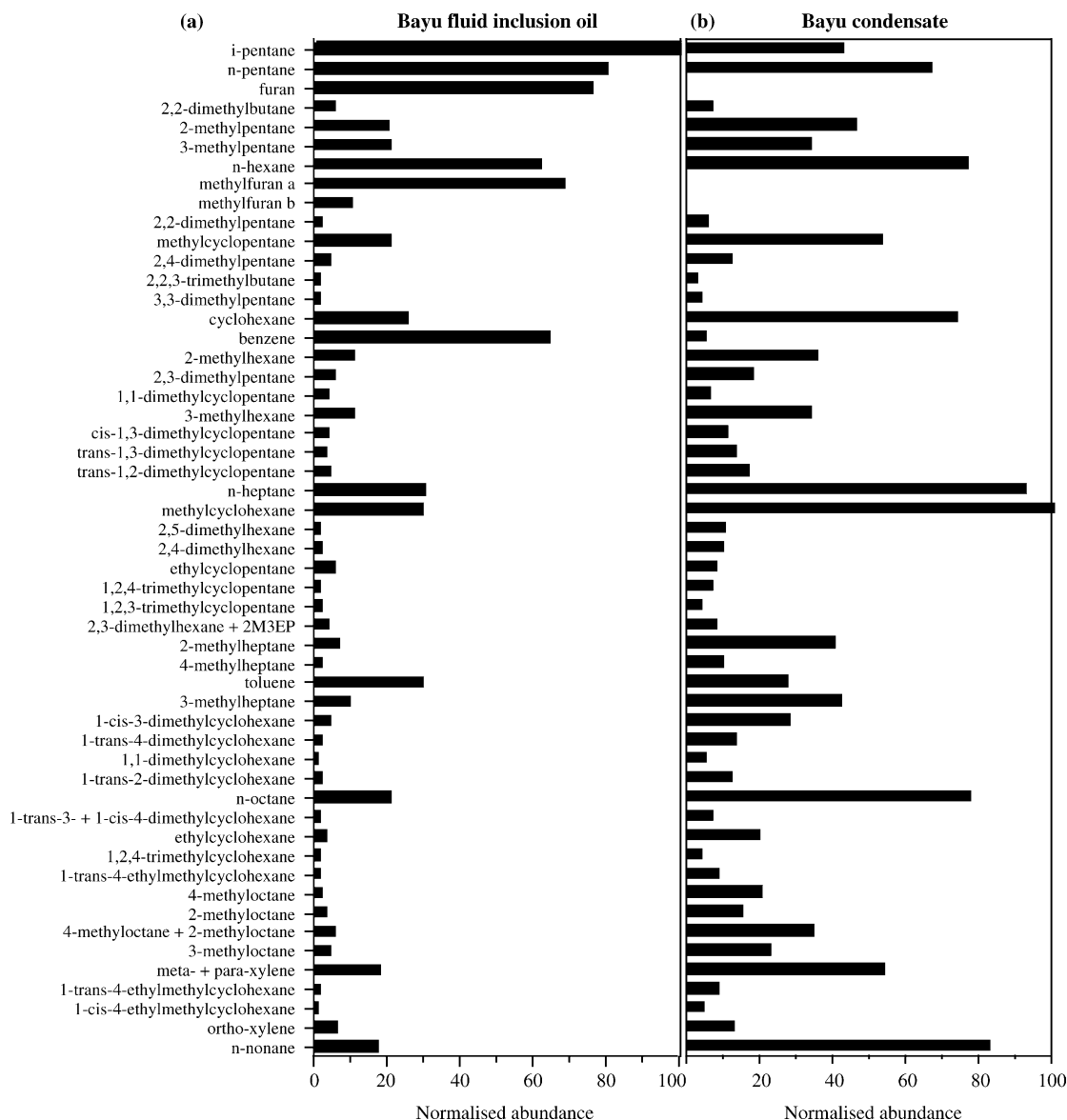


Fig. 5. Relative distribution of low molecular weight (C_5 – C_9) hydrocarbons in (a) Bayu-1 FI oil and (b) Bayu-1 condensate. 2M3EP=2-methyl-3-ethylpentane. Abundances were calculated from GC–MS mass chromatograms and are expressed as FID-equivalent.

FI oil (136°C) and the gas condensate (134°C), which fall within the range reported for Elang and Plover reservoired oils in the Northern Bonaparte Basin (133 – 138°C ; Preston & Edwards, 2000). Other ‘Mango’ parameters are also similar for the Bayu-1 FI oil and gas condensate (Table 1).

4.2.2. *n*-Alkanes and isoprenoids

The m/z 85 mass chromatogram was used to monitor for the presence of *n*-alkanes and isoprenoids in the aliphatic hydrocarbon fraction of the Bayu-1 condensate, the Bayu-1 FI oil (off-line analysis) and the blank (Fig. 6). *n*-Alkanes from n - C_9 to n - C_{32} are present in the FI oil, with a maximum at n - C_{22} and an odd carbon number preference for the high molecular weight homologues, as measured by the carbon preference index ($\text{CPI}_{26-32}=1.17$; Table 2). The blank

contains no detectable *n*-alkanes (Fig. 6b), providing confidence in the results for the FI oil. A total of 1,475 ng of C_{12} – C_{32} *n*-alkanes was recovered from the FI oil (452 ng/g quartz). The low abundance of C_9 – C_{14} *n*-alkanes may be partially due to evaporation of the FI oil obtained by off-line analysis down to a volume ready for GC–MS analysis (typically 200 μl), a process which also removes most $<C_9$ hydrocarbons (Ahmed & George, 2004). Stringent conditions were followed in the laboratory to minimise these effects. The C_{15} – C_{18} *n*-alkanes are also of lower abundance than n - C_{19} (Fig. 6), which is not considered to be due to sample work-up procedures (cf. similarly prepared Jabiru-1A FI oil in George, Greenwood, et al., 1997; also see Ahmed & George, 2004). The *n*-alkane profile from the off-line analysis (C_{22} maxima), together

Table 1
Low molecular weight hydrocarbon ratios for Bayu-1 FI oil and condensate

Low molecular weight ratio	Bayu-1 FI oil	Bayu-1 condensate
<i>i</i> -C ₅ / <i>n</i> -C ₅	1.25	0.63
Benzene/ <i>n</i> -C ₆	1.04	0.06
Toluene/ <i>n</i> -C ₇	0.97	0.29
(<i>n</i> -C ₆ + <i>n</i> -C ₇)/(cyclohexane + methylcyclohexane)	1.7	0.97
Heptane value (H; Thompson, 1979)	24.1	23.1
Isoheptane value (I; Thompson, 1987)	2.0	1.7
<i>n</i> -C ₇ /methylcyclohexane	1.01	0.92
Cyclohexane/methylcyclopentane	1.2	1.4
<i>n</i> -C ₇ /2-methylhexane	2.9	2.6
<i>n</i> -C ₇ /methylcyclopentane	1.4	1.7
3-methylpentane/benzene	0.32	7.3
Methylcyclohexane/toluene	1.01	3.7
Cyclohexane/benzene	0.39	16.1
3-methylpentane/ <i>n</i> -C ₆	0.33	0.44
Benzene/toluene	2.2	0.17
Methylcyclopentane/methylcyclohexane	0.70	0.53
Toluene/ <i>o</i> -xylene	5.2	2.1
<i>m</i> - + <i>p</i> -xylene/ <i>n</i> -C ₈	0.85	0.70
K1: (2-MH + 2,3-DMP)/(3-MH + 2,4-DMP)	1.08	1.17
P2: 2-MH/3-MH	0.99	1.05
2,4-DMP/2,3-DMP	0.76	0.67
C _{temp} (°C) (Mango, 1997)	136	134
K2: P3/(P2 + N2)	0.40	0.39
N2/P3	0.80	0.77

All ratios were derived from magnet scan data, corrected to FID-equivalent data using response factors. Mango parameters (see Mango, 1997, for review): MH, methylhexane; DMP, dimethylpentane; DMCP, dimethylcyclopentane; P2, 2-MH + 3-MH; P3, 3,3-DMP + 2,3-DMP + 2,4-DMP + 2,2-DMP; N2, 1,1-DMCP + *c*1,3-DMCP + *t*1,3-DMCP; C_{temp}(°C), 140 + (15 × ln (2,4-DMP/2,3-DMP)).

with the data from on-line analysis (above) which indicates trapping of low molecular weight *n*-alkanes (Fig. 4), suggests an overall bimodal *n*-alkane distribution, possibly associated with trapping of both oil and condensate.

Relative to the whole condensate (inset to Fig. 6c), low molecular weight *n*-alkanes are depleted ($\leq n$ -C₁₂) in the aliphatic fraction of the condensate due to normal evaporation during sample work-up. The condensate has virtually no odd-over-even carbon number preference (CPI_{26–32} = 1.05; Table 2). Ratios of the isoprenoids to *n*-alkanes are somewhat higher for the FI oil compared to the condensate, but the Pr/Ph ratio of the FI oil (0.94) is much lower than the condensate (2.6) and other oils in the Northern Bonaparte Basin (2.6–4.0; Preston & Edwards, 2000).

4.2.3. Tri- and tetracyclic terpanes

C₁₉ to C₂₉ tricyclic terpanes (cheilanthanes) and the C₂₄ tetracyclic terpane were detected in the Bayu-1 FI oil using MRM chromatograms (Fig. 7a). The Bayu-1 condensate also contains these compounds, as well as the C₃₀ and C₃₁

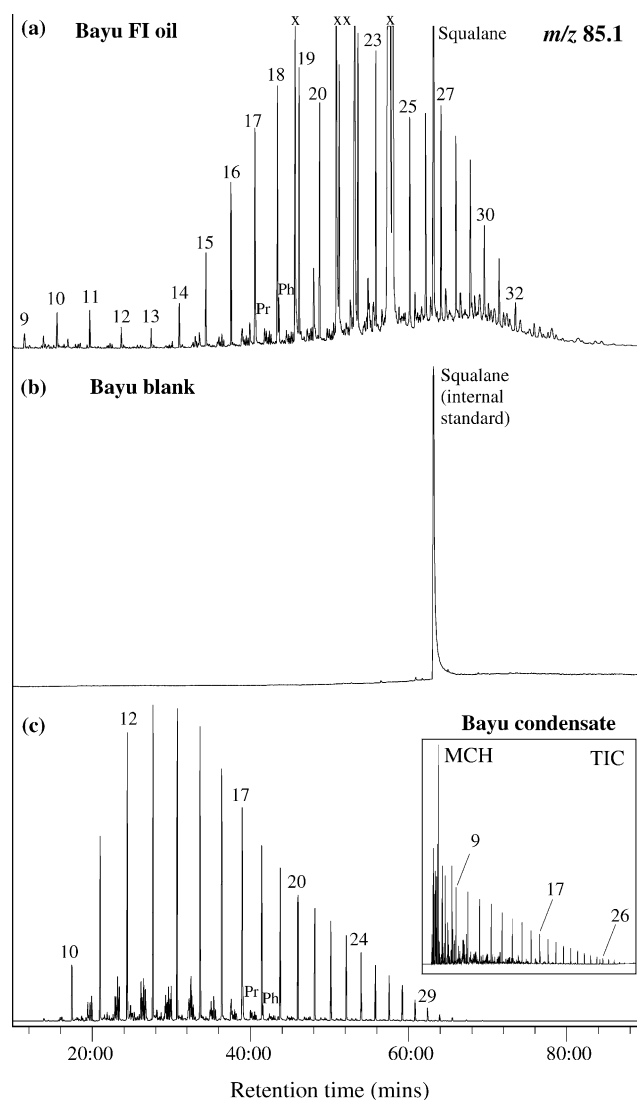


Fig. 6. Partial *m/z* 85.1 mass chromatograms for (a) Bayu-1 FI oil, (b) the blank associated with analysis of the Bayu-1 FI oil, and (c) Bayu-1 condensate (aliphatic fraction), showing the distribution of *n*-alkanes and isoprenoids. The inset to (c) is the total ion chromatogram (*m/z* 50–550) of split injected Bayu-1 gas condensate. Numbers refer to *n*-alkane chain length; Pr, pristane; Ph, phytane; x, unidentified contaminants. The squalane was added as an internal standard. The blank is drawn to the same scale as the FI oil chromatogram.

tricyclic terpanes (Fig. 7b). The relative abundance of these terpanes was measured in the *m/z* 191 mass chromatograms. In both samples the terpanes are of lower abundance than the pentacyclic triterpanes: for example, C₂₃ tricyclic terpane is a fifth the abundance of C₃₀ $\alpha\beta$ hopane (Table 2). There are some significant differences in the terpane distributions of the Bayu-1 FI oil and condensate. The FI oil contains very low amounts of C₁₉–C₂₁ tricyclic terpanes, whereas C₁₉ is the most abundant tricyclic terpane in the condensate. In contrast, the FI oil contains greater amounts of the extended C₂₈ and C₂₉ tricyclic terpanes relative to C₃₀ $\alpha\beta$ hopane than the condensate. The more terrestrially-dominated Plover, Elang and Frigate formations are characterised by higher

Table 2
Aliphatic hydrocarbon ratios for Bayu-1 FI oil and condensate

Aliphatic hydrocarbon ratio	Bayu-1 FI oil	Bayu-1 condensate
Pristane/phytane (Pr/Ph)	0.94	2.6
Pr/n-C ₁₇	0.43	0.40
Ph/n-C ₁₈	0.36	0.19
Carbon preference index (CPI _{26–32})	1.17	1.05
Wax index [(n-C ₂₁ + n-C ₂₂)/(n-C ₂₈ + n-C ₂₉)]	1.5	5.5
C ₂₃ tricyclic terpane/C ₃₀ αβ hopane	0.20	0.22
C ₂₄ tetracyclic terpane/C ₃₀ αβ hopane	0.08	0.11
C ₂₃ tricyclic terpane/C ₂₁ tricyclic terpane	4.6	1.4
C _{23–26} tricyclic terpanes/C _{19–21} tricyclic terpanes	6.7	0.83
C ₂₄ tetracyclic/C ₂₆ tricyclic terpanes	0.84	1.08
C ₁₉ tricyclic terpane/(C ₁₉ tricyclic terpane + C ₂₃ tricyclic terpane)	0.04	0.62
C ₂₄ tetracyclic terpane/(C ₂₄ tetracyclic terpane + C ₂₃ tricyclic terpane)	0.30	0.33
∑C ₂₈ tricyclic terpanes/C ₃₀ αβ hopane	0.17	0.13
Ts/(Ts + Tm)*	0.55	0.71
C ₂₉ Ts/(C ₂₉ Ts + C ₂₉ αβ hopane)*	0.18	0.32
(C ₂₉ Ts/C ₃₀)*	0.30	0.63
C ₂₉ */C ₂₉ αβ hopane*	0.05	0.17
C ₃₀ */C ₃₀ αβ hopane*	0.05	0.18
C ₃₀ §/C ₃₀ αβ hopane*	0.01	0.04
C ₂₉ 25-norhopane/C ₂₉ αβ hopane*	0.13	0.13
C ₃₀ hopane αβ + / (αβ + βα)*	0.95	0.92
C ₃₂ αβ 22S/(22S + 22R)*	0.58	0.56
C ₃₃ αβ 22S/(22S + 22R)*	0.60	0.59
C ₃₅ /(C ₃₅ + C ₃₄) homohopanes*	0.45	0.36
Homohopanes/C ₃₀ αβ hopane*	1.9	1.05
Gammacerane/C ₃₀ αβ hopane*	0.04	0.03
(Oleanane and/or lupane)/C ₃₀ αβ hopane*	0.05	0.17
28,30-BNH/C ₃₀ αβ hopane*	0.18	0.03
C ₂₉ αβ hopane/C ₃₀ αβ hopane*	0.80	0.62
C ₂₉ ααα + αββ steranes/C ₂₉ αβ + βα hopanes	0.37	0.03
C ₂₇ :C ₂₈ :C ₂₉ ααα 20R steranes (%)*	50:24:26	48:25:27
C ₃₀ /(C ₂₇ + C ₂₈ + C ₂₉) ααα 20R steranes (%)*	4.9	2.7
C ₂₇ βα diasteranes/ααα + αββ steranes*	0.53	2.4
C ₂₈ βα diasteranes/ααα + αββ steranes*	0.64	3.4
C ₂₉ βα diasteranes/ααα + αββ steranes*	0.52	1.8
C ₂₉ steranes ααα 20S/(20S + 20R)*	0.56	0.56
C ₂₉ steranes αββ/(αββ + ααα)*	0.56	0.54
C ₂₉ βα diasteranes 20S/(20S + 20R)*	0.55	0.58

For biomarker abbreviations see caption to Fig. 9 and Table 3. All ratios were derived from SIM data, except those marked * which were derived from MRM data.

C₁₉/(C₁₉ + C₂₃) tricyclic and C₂₄ tetracyclic/(C₂₄ tetracyclic + C₂₃ tricyclic terpane) ratios than the more marine-dominated Flamingo Group and Echuca Shoals Formation (Fig. 8, Preston & Edwards, 2000). On a correlation diagram of these two parameters, the Bayu-1 FI oil plots with the Darwin Formation-reservoired oils such as Elang West-1,

Kakatua North-1 and Layang-1, near the Echuca Shoals Formation source rock field (Fig. 8). The Bayu-1 condensate analysed in this work, together with other Bayu-Undan condensate samples, plot near the Flamingo Group and the more marine part of the Plover and Elang formations (Fig. 8). Extended C₂₈ and C₂₉ tricyclic terpanes are generally of very low abundance in terrestrially-dominated oils in the Northern Bonaparte Basin. For example, Corallina-1 oil (MDT: 3,187 m) has a ∑C₂₈ tricyclic terpanes/C₃₀ αβ hopane ratio of <0.001, whereas Bayu-1 condensate has a ratio of 0.13 and the FI oil an even higher ratio (0.17; Table 2). Darwin Formation-reservoired oil from Elang West-1 has a similarly high ∑C₂₈ tricyclic terpanes/C₃₀ αβ hopane ratio as Bayu-1 condensate (Preston & Edwards, 2000). The higher C₂₈ and C₂₉ tricyclic terpane content in the Bayu-1 FI oil is likely a result of a greater marine and lesser terrigenous influence for this oil.

4.2.4. Pentacyclic triterpanes

The pentacyclic triterpanes in Bayu-1 FI oil and condensate are dominated by C₃₀ αβ hopane and the ubiquitous series of C₂₇–C₃₅ 17α-hopanes (Fig. 9a and c). Any contribution from the blank was negligible, as shown by the m/z 191 mass chromatogram for the blank (Fig. 9b). The C₂₉/C₃₀ αβ hopane ratio is slightly greater for the FI oil compared to the condensate, and the FI oil contains more C₃₁ homohopanes relative to C₃₀ αβ hopane than the condensate (Fig. 9 and Table 2). The distribution of homohopanes shows a steady fall from C₃₁ to C₃₅ in both the condensate and the FI oil, but this fall is slower for the FI oil (Fig. 9). Consequently the amount of C₃₅ homohopanes is higher in the FI oil than in the condensate (6.6 cf. 3.4% of the total homohopanes). A small amount of gammacerane was detected in both the FI oil and the condensate by MRM analysis (Fig. 9d and e) but is of low abundance relative to C₃₀ αβ hopane (gammacerane index <0.05; Table 2). A small peak eluting just prior to C₃₀ αβ hopane gives a signal in the m/z 412 → 191 chromatogram and elutes at the same position as oleanane, and is more abundant in the condensate (Fig. 9 and Table 2). This peak could be oleanane, lupane, or another unidentified C₃₀ triterpane (Nytoft, Bojesen-Koefoed, Christiansen, & Fowler, 2002). If it is oleanane or lupane, then this implies a likely angiosperm content in the source rock, and thus a probable Cretaceous-or-younger age constraint.

A peak eluting just after Tm has a large m/z 177 ion and also appears in the m/z 384 → 191 chromatograms (Fig. 9d and e), suggesting that it is a C₂₈ isomer. This peak is assigned as the C₂₈ 25,30-bisnor-17α(H)-hopane (cf. Rullkötter & Wendisch, 1982; Subroto, Alexander, & Kagi, 1991). The isomer eluting a little later is assigned as the C₂₈ 29,30-bisnor-17α(H)-hopane (Summons & Powell, 1987; Subroto et al., 1991). A third C₂₈ hopane (28,30-bisnorhopane) was also identified, but no trisnorhopane could be detected. In the FI oil the bisnorhopanes vary in abundance in the order 28,30 > 29,30 > 25,30 (Fig. 9d). The 28,30-bisnorhopane is

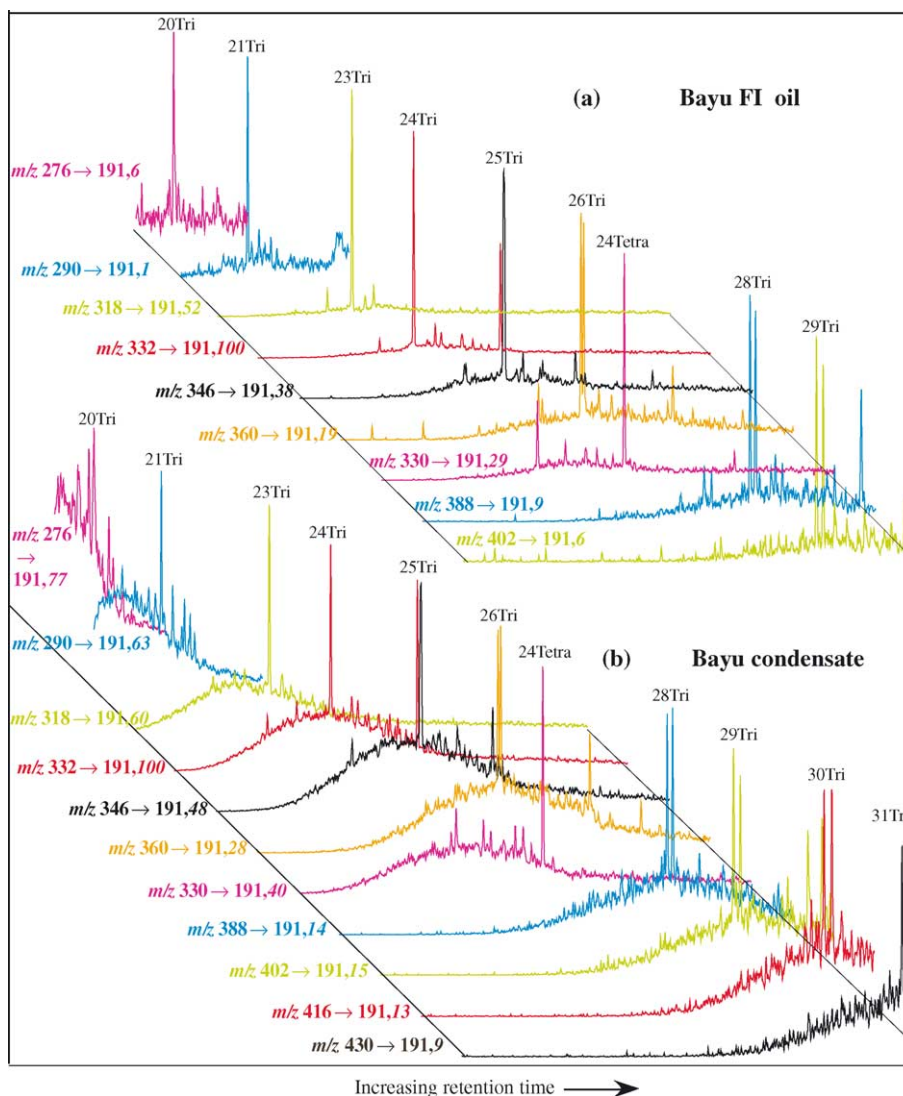


Fig. 7. Partial MRM chromatograms (m/z 276, 290, 318, 332, 346, 360, 330, 388, 402, 416 and 430 \rightarrow 191) showing the distribution of C_{20} to C_{31} tricyclic and C_{24} tetracyclic terpanes in (a) Bayu-1 FI oil and (b) Bayu-1 condensate (non-adducted fraction). Relative abundances of the MRM chromatograms are shown in italics.

a significant isomer in the m/z 191 trace of the FI oil (Fig. 9a), with a 28,30-BNH/ C_{30} $\alpha\beta$ hopane ratio of 0.18 (Table 2). In contrast, this ratio is much lower in the condensate (0.03) and the three bisnorhopane isomers have similar abundances (Fig. 9e). The FI oil and the condensate have similar C_{29} 25-norhopane/ C_{29} $\alpha\beta$ hopane ratios (0.13), well below the threshold of 0.55 suggested by Blanc and Connan (1992) for being a conclusive indicator of heavy biodegradation. However, values of 0.13 are somewhat greater than other Timor Sea oils (e.g. Jabiru FI oil, 0.04; Jabiru production oil, 0.06; Skua FI oil, 0.004), so could indicate a palaeobiodegradation event, or direct input of 25-norhopanes from the source rock (cf. Noble et al., 1985).

All $22S/(22S+22R)$ ratios for the extended homohopanes are close to end-point values (0.56 to 0.6; Table 2). The C_{30} $\alpha\beta/(\alpha\beta+\beta\alpha)$ ratios (0.95 and 0.92 for the FI oil and condensate, respectively) are typical for oils

derived from source rocks matured to at least the middle of the oil generation window, and are too close to be able to differentiate the thermal maturities of the FI oil compared to the condensate. The ratios $Ts/(Ts+Tm)$ and $C_{29}Ts/(C_{29}Ts+C_{29}$ $\alpha\beta$ hopane) are higher for the condensate, which suggests a higher thermal maturity (Table 2). These ratios, however, can also be influenced by source, in which case they would also indicate a less oxygenated, less clay-rich source rock for the FI oil. Another difference between the Bayu-1 FI oil and condensate is the relative abundance of diahopanes. The C_{29} and C_{30} diahopanes (C_{29}^* and C_{30}^*) are present in the FI oil in only minor amounts (Fig. 9d), whereas these isomers are more abundant in the condensate (Fig. 9e). Furthermore, peaks assigned as the C_{31}^* – C_{33}^* diahopane doublets are also present in the condensate (Fig. 9e). An early-eluting C_{30} rearranged triterpane ($C_{30}\delta$) that co-occurs with diahopanes and is characteristic of

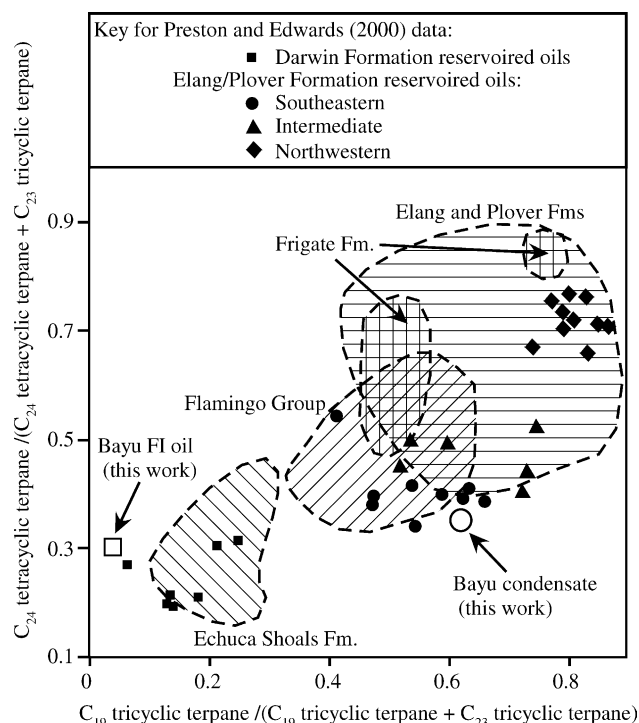


Fig. 8. Cross plot of C_{19} tricyclic terpene/(C_{19} tricyclic terpene + C_{23} tricyclic terpene) versus C_{24} tetracyclic terpene/(C_{24} tetracyclic terpene + C_{23} tricyclic terpene), calculated from the m/z 191 mass chromatograms, showing the greater marine influence for the source of the Bayu-1 FI oil compared to other oils in the Northern Bonaparte Basin, including Bayu-1 condensate. Oil and source rock fields are taken from Preston and Edwards (2000).

Jurassic-sourced oils in Australia and Papua New Guinea (George, Greenwood, et al., 1997; George, Krieger et al., 1997) is present in the condensate, but has a very low relative abundance in the FI oil. The greater amounts of these rearranged hopanes is consistent both with greater thermal maturity for the condensate, and/or a more clay-rich source rock, deposited in a more oxic environment, for the condensate.

4.2.5. Steranes and diasteranes

Sterane and diasterane distributions are shown in m/z 217 mass chromatograms (Fig. 10a and c) and MRM chromatograms (Fig. 10d and e). Virtually no steranes or diasteranes were detected in the blank (Fig. 10b). The Bayu-1 FI oil and the condensate have very different distributions of steranes and diasteranes, which is due to the much greater amount of diasteranes relative to steranes in the condensate. At each carbon number (C_{27} to C_{30}), $\beta\alpha$ diasteranes are between two and three times more abundant than steranes in the condensate, whilst in the FI oil the steranes are about twice as abundant as the $\beta\alpha$ diasteranes (Table 2). High diasterane contents are suggestive of clay-rich, oxic source rocks, but are also likely influenced by the higher maturity of the condensate as compared to the FI oil. The carbon number distribution of the steranes and the diasteranes is

very similar in both samples, with a dominance of C_{27} steranes (for the $\alpha\alpha\alpha$ R isomers, 48 to 50% C_{27}). The C_{30} 24- n -propylcholestanes are present in both the FI oil and the condensate, with a higher $C_{30}/(C_{27} + C_{28} + C_{29})$ $\alpha\alpha\alpha$ 20 R sterane ratio for the FI oil, suggesting that it is derived from a source rock containing more marine organic matter (Moldowan, Seifert, & Gallegos, 1985). Peaks in the m/z 414 \rightarrow 231 MRM chromatograms of both the Bayu-1 FI oil and the condensate are assigned as being due to the 3 β -methylsteranes, 4 α -methylsteranes and dinosteranes (Fig. 10d and e; Table 3). The presence of dinosteranes is consistent with sourcing from Triassic or younger sediments (Summons, Volkman, & Boreham, 1987; but also see Moldowan and Talyzina (1998)).

The sterane/hopane ratio is much lower for the condensate and is typical of terrigenous and/or microbially reworked organic matter (Table 2). This suggests greater prokaryotic input to the source rock of the condensate. The higher sterane/hopane ratio for the FI oil reflects a greater eukaryotic input to its source rock and is typical of marine organic matter (plankton, algae).

The C_{29} sterane thermal maturity parameters show little difference between the two samples. The C_{29} $\alpha\alpha\alpha$ 20S/(20S + 20R) ratios are 0.56 and at their end-points, but the C_{29} $\alpha\beta\beta/(\alpha\beta\beta + \alpha\alpha\alpha)$ ratios of 0.54 and 0.56 are further from the end-point (0.70), thus indicating that both the FI oil and the condensate have thermal maturities near the middle of the oil window (Table 2). This is consistent with the $\beta\alpha$ diasterane 20S/(20S + 20R) ratios, which are all close to the end-point value of ~ 0.6 .

4.2.6. Aromatic hydrocarbons

Aromatic hydrocarbons were detected in the Bayu-1 FI oil and the condensate, including alkylnaphthalenes, alkylphenanthrenes, alkylbiphenyls and alkylbenzothiophenes. The condensate is dominated by the lower molecular weight alkylnaphthalenes, whereas alkylnaphthalenes and alkylphenanthrenes are of similar abundance in the FI oil (Fig. 11). This variation is consistent with other off-line data for the FI oil, which indicates that it contains greater amounts of higher molecular weight hydrocarbons than the condensate. Although both the FI oil and the condensate have relatively low amounts of alkylbenzothiophenes (Fig. 11), the phenanthrene/dibenzothiophene ratio is slightly higher for the condensate (Table 4), showing that the FI oil contains more S-containing compounds than the condensate. Mass chromatograms showing the distribution of C_3 – C_5 alkylnaphthalenes, C_1 – C_2 alkylphenanthrenes and C_1 – C_2 alkylbiphenyls in the Bayu-1 FI oil and the condensate are shown in Figs. 12–14, respectively. These figures also show that the contribution to the aromatic hydrocarbons from the blank is negligible.

The aromatic hydrocarbon distributions for the Bayu-1 FI oil and the condensate are similar, with only slight differences being noted at the molecular level. Aromatic hydrocarbons can provide source information when certain

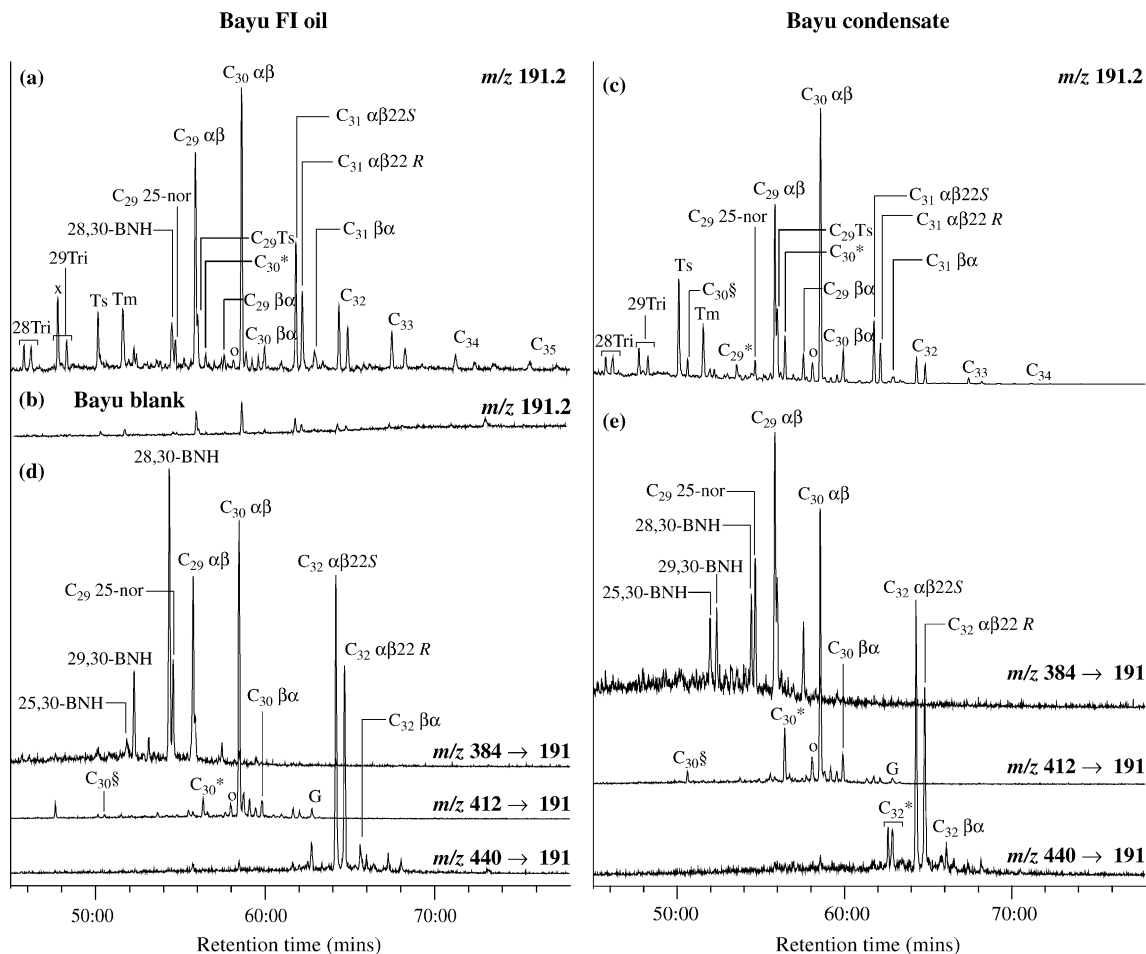


Fig. 9. Partial m/z 191.2 mass chromatograms of (a) Bayu-1 FI oil, (b) the blank associated with analysis of the Bayu-1 FI oil, and (c) Bayu-1 condensate (non-adducted fraction) showing the distribution of triterpanes. The blank is drawn to the same scale as the FI oil chromatogram. Also partial MRM chromatograms (m/z 384, 412 and 440 \rightarrow 191) for (d) Bayu-1 FI oil and (e) Bayu-1 condensate (non-adducted fraction) showing the distribution of C_{28} , C_{30} and C_{32} hopanes, respectively. Peak assignments define stereochemistry at C-22 (*S* and *R*); $\alpha\beta$ and $\beta\alpha$ denote 17α (H)-hopanes and 17β (H)-moretanes respectively. 28 tri, C_{28} tricyclic terpanes; 29 tri, C_{29} tricyclic terpanes; x, unknown; Ts, C_{27} 18α (H), 22,29,30-trisnorneohopane; Tm, C_{27} 17α (H), 22,29,30-trisnorhopane; $C_{30}\S$, C_{30} rearranged triterpane (unidentified structure); C_{29}^* , C_{30}^* and C_{32}^* , 17α (H)-diahopanes; C_{29} Ts, 18α (H)-30-norneohopane; BNH, bisnorhopane; 25-nor, 25-norhopane; o, oleanane; lupane or other unidentified C_{30} triterpane.

isomers are present in high abundance (e.g. Alexander, Larcher, Kagi, & Price, 1988). For the FI oil, there is evidence of a slightly greater input of *Araucariacean*-type plants, as indicated by higher relative amounts of 1,2,5-TMN, 1-MP, 1,7-DMP and retene than in the condensate. However, ratios of these isomers to other isomers which are not source specific (Table 4) do not fall above the benchmark values ascribed by Alexander et al. for significant *Araucariacean*-type plant input. 1,2,7-TMN is only present in small amounts (Fig. 12) and thus there is no corroboratory evidence of angiosperm input to the source rocks of either the FI oil or the condensate (Strachan, Alexander, & Kagi, 1988). These aromatic data suggest either that there is only a slight source difference between the FI oil and the condensate, which is not corroborated by the aliphatic hydrocarbon data, or that the aromatic hydrocarbons parameters are insensitive to the source variations that are apparent from the biomarker data.

Various aromatic ratios, which provide thermal maturity information for the Bayu-1 FI oil and the condensate, are given in Table 4. With the exception of the methylnaphthalene ratio (MNR), which can be affected by evaporation effects during sample work-up, all other ratios indicate a higher maturity for the condensate compared to the FI oil. These ratios mostly indicate that the maturity difference is significant but within the oil window. For example, the methylphenanthrene index (MPI) values of 0.60 and 0.79 for the FI oil and the condensate equate to calculated equivalent reflectances (R_c) of 0.76 and 0.87%, respectively, using Radke and Welte's (1983) equation. Other calibrations of aromatic hydrocarbon ratios to vitrinite reflectance may be less reliable, and include a trimethylnaphthalene ratio (TNR-2; Radke, Rullkötter, & Vriend, 1994), which gives somewhat higher values (0.84% for the FI oil; 0.97% for the condensate), and the methyl dibenzothiophene ratio (MDR; Radke, 1988), which gives greater separation between

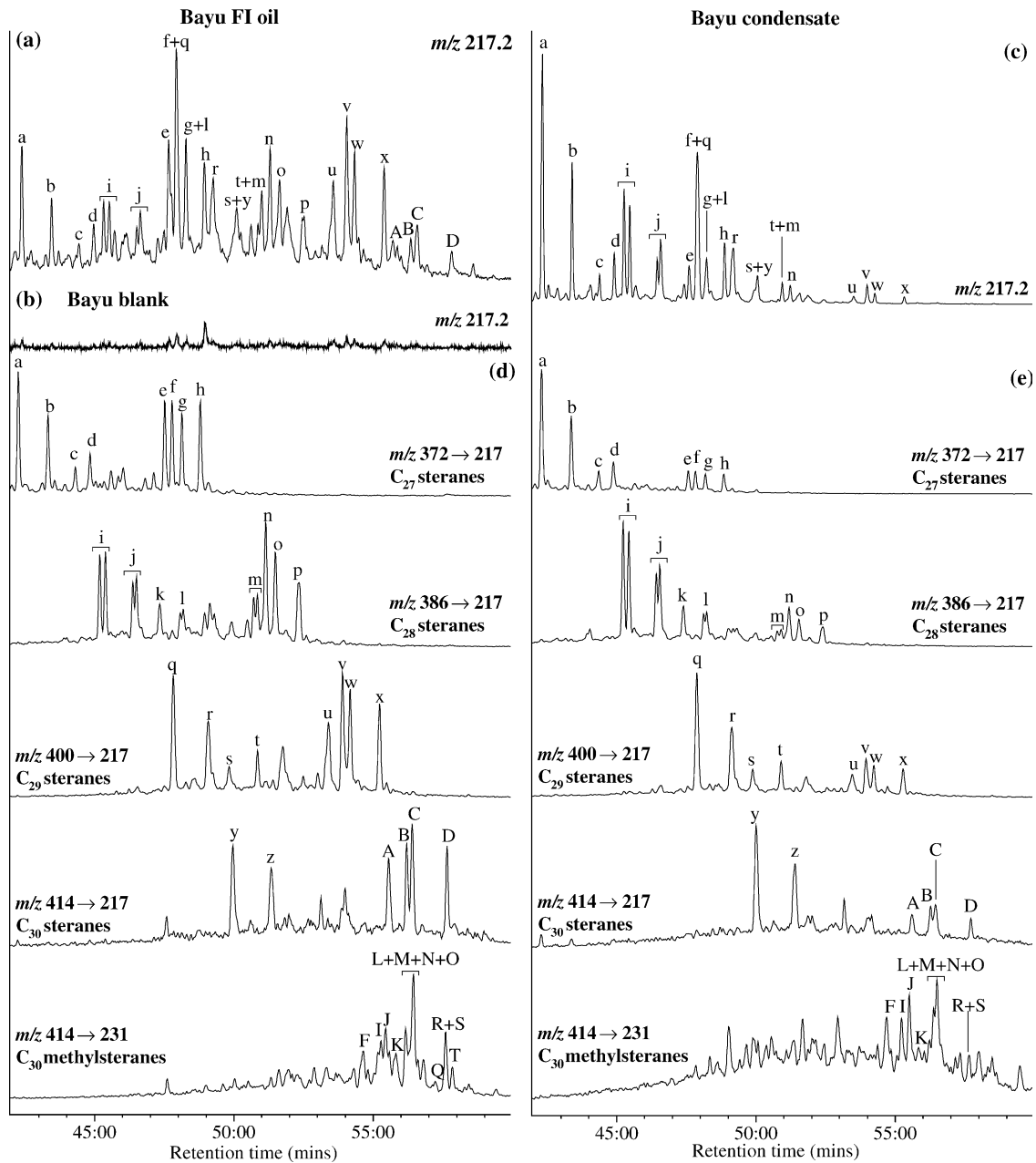


Fig. 10. Partial m/z 217.2 mass chromatograms of (a) Bayu-1 FI oil, (b) the blank associated with analysis of the Bayu-1 FI oil, and (c) Bayu-1 condensate (non-adducted fraction) showing the distribution of steranes and diasteranes. The blank is drawn to the same scale as the FI oil chromatogram. Also partial MRM chromatograms (m/z 372, 386, 400 and 414 \rightarrow 217, and 414 \rightarrow 231) for (d) Bayu-1 FI oil and (e) Bayu-1 condensate (non-adducted fraction) showing the distribution of C_{27} , C_{28} , C_{29} and C_{30} steranes and diasteranes, and C_{30} methylsteranes, respectively. Peak assignments are defined in Table 3.

the maturities (0.67% for the FI oil; 1.15% for the condensate). A similarly large separation in maturities is also suggested by the alkylbiphenyl ratios (Table 4). Three alkylnaphthalene maturity parameters (TNR = trimethylnaphthalene ratio; TeMNR = tetramethylnaphthalene ratio; PMNR = pentamethylnaphthalene ratio) were recently defined by van Aarssen, Alexander, and Kagi (1999) and van Aarssen, Bastow, Alexander, and Kagi (2000) (see Table 4). These three ratios show that, relative to the main grouping of Australian oils (van Aarssen et al., 1999, 2000),

Bayu-1 condensate has one of the higher maturities, and Bayu-1 FI oil has one of the lower maturities.

5. Interpretation

5.1. Palaeo oil column and fluid contacts in Bayu-1

Conventional oil shows indicating the presence of residual oil in Bayu-1 reservoir include solvent extracts

Table 3

Peak assignments for steranes, diasteranes and methylsteranes in the *m/z* 217 mass chromatograms and MRM chromatograms

Peak	Sterane, diasterane and methylsterane assignments	Abbreviation
a	13 β (H),17 α (H)-diacholestane (20S)	C ₂₇ $\beta\alpha$ 20S diasterane
b	13 β (H),17 α (H)-diacholestane (20R)	C ₂₇ $\beta\alpha$ 20R diasterane
c	13 α (H),17 β (H)-diacholestane (20S)	C ₂₇ $\alpha\beta$ 20S diasterane
d	13 α (H),17 β (H)-diacholestane (20R)	C ₂₇ $\alpha\beta$ 20R diasterane
e	5 α (H),14 α (H),17 α (H)-cholestane (20S)	C ₂₇ $\alpha\alpha\alpha$ 20Ssterane
f	5 α (H),14 β (H),17 β (H)-cholestane (20R)	C ₂₇ $\alpha\beta\beta$ 20Rsterane
g	5 α (H),14 β (H),17 β (H)-cholestane (20S)	C ₂₇ $\alpha\beta\beta$ 20Ssterane
h	5 α (H),14 α (H),17 α (H)-cholestane (20R)	C ₂₇ $\alpha\alpha\alpha$ 20Rsterane
i	24-methyl-13 β (H),17 α (H)-diacholestane (20S)*	C ₂₈ $\beta\alpha$ 20S diasterane
j	24-methyl-13 β (H),17 α (H)-diacholestane (20R)*	C ₂₈ $\beta\alpha$ 20R diasterane
k	24-methyl-13 α (H),17 β (H)-diacholestane (20S)	C ₂₈ $\alpha\beta$ 20S diasterane
l	24-methyl-13 α (H),17 β (H)-diacholestane (20R)*	C ₂₈ $\alpha\beta$ 20R diasterane
m	24-methyl-5 α (H),14 α (H),17 α (H)-cholestane (20S)*	C ₂₈ $\alpha\alpha\alpha$ 20Ssterane
n	24-methyl-5 α (H),14 β (H),17 β (H)-cholestane (20R)	C ₂₈ $\alpha\beta\beta$ 20Rsterane
o	24-methyl-5 α (H),14 β (H),17 β (H)-cholestane (20S)	C ₂₈ $\alpha\beta\beta$ 20Ssterane
p	24-methyl-5 α (H),14 α (H),17 α (H)-cholestane (20R)	C ₂₈ $\alpha\alpha\alpha$ 20Rsterane
q	24-ethyl-13 β (H),17 α (H)-diacholestane (20S)	C ₂₉ $\beta\alpha$ 20S diasterane
r	24-ethyl-13 β (H),17 α (H)-diacholestane (20R)	C ₂₉ $\beta\alpha$ 20R diasterane
s	24-ethyl-13 α (H),17 β (H)-diacholestane (20S)	C ₂₉ $\alpha\beta$ 20S diasterane
t	24-ethyl-13 α (H),17 β (H)-diacholestane (20R)	C ₂₉ $\alpha\beta$ 20R diasterane
u	24-ethyl-5 α (H),14 α (H),17 α (H)-cholestane (20S)	C ₂₉ $\alpha\alpha\alpha$ 20Ssterane
v	24-ethyl-5 α (H),14 β (H),17 β (H)-cholestane (20R)	C ₂₉ $\alpha\beta\beta$ 20Rsterane
w	24-ethyl-5 α (H),14 β (H),17 β (H)-cholestane (20S)	C ₂₉ $\alpha\beta\beta$ 20Ssterane
x	24-ethyl-5 α (H),14 α (H),17 α (H)-cholestane (20R)	C ₂₉ $\alpha\alpha\alpha$ 20Rsterane
y	24- <i>n</i> -propyl-13 β (H),17 α (H)-diacholestane (20S)	C ₃₀ $\beta\alpha$ 20S diasterane
z	24- <i>n</i> -propyl-13 β (H),17 α (H)-diacholestane (20R)	C ₃₀ $\beta\alpha$ 20R diasterane
A	24- <i>n</i> -propyl-5 α (H),14 α (H),17 α (H)-cholestane (20S)	C ₃₀ $\alpha\alpha\alpha$ 20Ssterane
B	24- <i>n</i> -propyl-5 α (H),14 β (H),17 β (H)-cholestane (20R)	C ₃₀ $\alpha\beta\beta$ 20Rsterane
C	24- <i>n</i> -propyl-5 α (H),14 β (H),17 β (H)-cholestane (20S)	C ₃₀ $\alpha\beta\beta$ 20Ssterane
D	24- <i>n</i> -propyl-5 α (H),14 α (H),17 α (H)-cholestane (20R)	C ₃₀ $\alpha\alpha\alpha$ 20Rsterane
F	3 β -methyl-24-ethylcholestane (20S)	3 β -methyl 20S
I	3 β -methyl-24-ethylcholestane (14 β ,17 β (H), 20R)	3 β -methyl $\beta\beta$ 20R
J	3 β -methyl-24-ethylcholestane (14 β ,17 β (H), 20S)	3 β -methyl $\beta\beta$ 20S
K	4 α -methyl-24-ethylcholestane (20S)	4 α -methyl 20S
L	4 α -methyl-24-ethylcholestane (14 β ,17 β (H), 20R)	4 α -methyl $\beta\beta$ 20R
M	4 α -methyl-24-ethylcholestane (14 β ,17 β (H), 20S)	4 α -methyl $\beta\beta$ 20S
N	2 α -methyl-24-ethylcholestane (20R)	2 α -methyl 20R
O	3 β -methyl-24-ethylcholestane (20R)	3 β -methyl 20R
Q	4 α ,23S, 24R-trimethylcholestane (20R)	4 α ,23S,24R dinost 20R
R	4 α -methyl-24-ethylcholestane (20R)	4 α -methyl 20R
S	4 α ,23R, 24R-trimethylcholestane (20R)	4 α ,23R,24R dinost 20R
T	4 α ,23R, 24S-trimethylcholestane (20R)	4 α ,23R,24S dinost 20R

*, isomeric peaks (24S and 24R); dinost, dinosterane isomers.

of an Elang Formation rotary sidewall core of a tight sandstone at 2,978 mRT, near the top of the gas-condensate column, which displayed fluorescence, and a deeper sample at 3,146.1 mRT, which had no fluorescence (Gorter & Hartung-Kagi, 1998), but in general these indications are inconclusive about the presence of a prior oil column. Gorter and Hartung-Kagi (1998) suggested that these two samples represent evidence that Elang-type oil is or was present in the Bayu structure, and is now reservoirized only in tighter lithologies not flushed by the later gas charge.

The GOI results in Bayu-1 (Fig. 3), in contrast, strongly suggest that, prior to the migration of the gas condensate that is currently reservoirized in the Bayu-Undan field, separate oil and gas legs were present. The GOI technique

has been widely used as a tool to locate prior oil accumulation in gas fields and to assess the oil-leg potential (Brincat, Lisk et al., 2004; Lisk et al., 1997; Lisk, O'Brien, & Eadington, 2002). The precise dimension of the palaeo hydrocarbon column present in Bayu-1 is limited by the broad sampling interval and by uncertainty in interpretation of the 3.6% GOI value at 3046.1 mRT, but can be constrained to be within 2–53 m (oil) and 46–53 m (gas). Whilst there is no direct evidence to confirm the presence of a palaeo-gas cap (i.e. numerous gas-filled inclusions), this interpretation is considered most likely in the absence of major capillary barriers separating the zone of high GOI values from the overlying low GOI value. Similar inferred palaeo-gas caps have been reported from

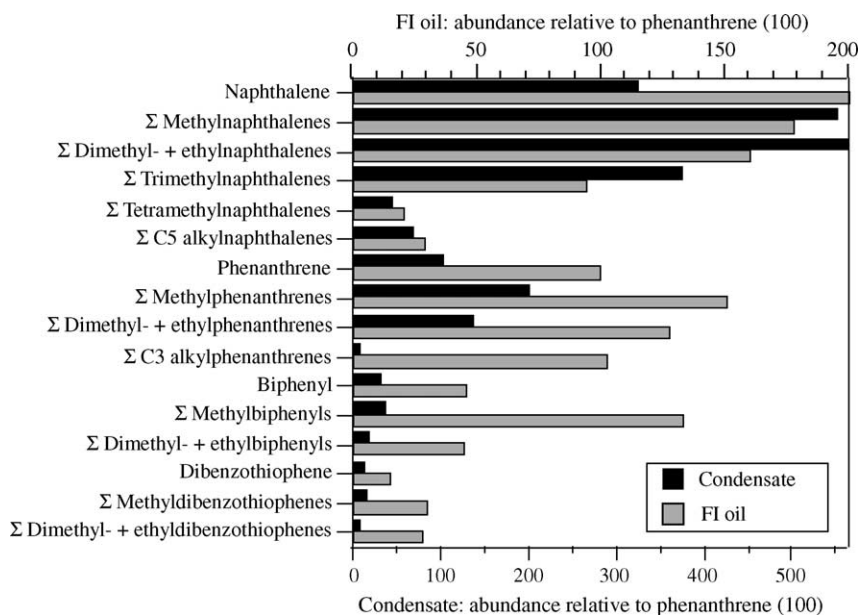


Fig. 11. Distribution of naphthalene, phenanthrene, biphenyl, dibenzothiophene and alkylated homologues in the FI oil and condensate in Bayu-1. Values calculated by the responses in the m/z 128.1, 142.1, 156.1, 170.1, 184.1, 198.1, 178.1, 192.1, 206.1, 220.1, 154.1, 168.1, 182.1, 184.0, 198.0, and 212.0 mass chromatograms.

other parts of the Timor Sea (Lisk et al., 1998) and their presence is supported by basin modelling results that predict an early gas charge (Kennard et al., 1999).

The fluid trapped within the fluorescing inclusions is considered to be predominantly oil, rather than condensate, based on the relatively low, visually estimated, percent vapour in most of these inclusions and the position of the palaeo-oil water contact well above the current gas–water contact. Inclusions that contain condensate would have been trapped in the reservoir as a single phase (non-fluorescing gas), with a small amount of liquid condensing from the gas as the sample was retrieved to the surface. Liquid–vapour ratios in condensate inclusions would be expected to have a high, constant percent vapour (e.g. see Alderton & Bevins, 1996), and this is not observed in the majority of fluorescing inclusions seen in these samples. A more compelling argument against the fluorescing inclusions containing condensate rather than oil comes from the near absence of fluorescing inclusions below the inferred palaeo-oil water contact and above the current gas–water contact. If the fluorescing inclusions do not contain oil, then an explanation is required for the near absence of such inclusions throughout the rest of the current gas column. Whilst variable trapping conditions could be invoked to explain this observation, this is likely to produce much more variable GOI profiles rather than the continuously high or continuously low profiles that are observed in this field and many others (Lisk et al., 1997; 2002; 1998). In addition to the petrographic evidence the geochemical data on the inclusion oil is particularly convincing, showing the presence of much larger amounts of high molecular weight hydrocarbons than are present in the condensate.

Table 4
Aromatic hydrocarbon ratios for Bayu-1 FI oil and condensate

Aromatic hydrocarbon ratio	Bayu-1 FI oil	Bayu-1 condensate
Methylnaphthalene ratio (MNR: 2-MN/1-MN)	1.5	0.92
DNR-1 (2,6- + 2,7-DMN/1,5-DMN)	2.4	3.1
TNR-1 (2,3,6-TMN/1,4,6- + 1,3,5-TMN)	0.79	1.18
TNR-2 (2,3,6- + 1,3,7-TMN/1,4,6- + 1,3,5- + 1,3,6-TMN)	0.74	0.95
Log (1,2,5-TMN/1,3,6-TMN)	−0.28	−0.69
Log (1,2,7-TMN/1,3,7-TMN)	−0.71	−1.04
TeMNR-1 (2,3,6,7-TeMN/1,2,3,6-TeMN)	1.1	1.8
TMNr (1,3,7-TMN/(1,3,7- + 1,2,5-TMN))	0.57	0.80
TeMNR (1,3,6,7-TeMN/(1,3,6,7- + 1,2,5,6-TeMN))	0.69	0.80
PMNr (1,2,4,6,7-PMN/(1,2,4,6,7- + 1,2,3,5,6-PMN))	0.38	0.63
MPI: $1.5 \times [3\text{-MP} + 2\text{-MP}]/[P + 9\text{-MP} + 1\text{-MP}]$	0.60	0.79
R_c (0.6 x MPI-1 + 0.4), from Radke and Welte, (1983)	0.76	0.87
MPDF: $((3\text{-MP} + 2\text{-MP})/\Sigma\text{MPs})$	0.45	0.50
log (1-MP/9-MP)	0.05	0.02
MPR: 2-MP/1-MP	1.02	1.11
DMPR ($[3,5\text{-} + 2,6\text{-DMP} + 2,7\text{-DMP}]/[1,3\text{-} + 3,9\text{-} + 2,10\text{-} + 3,10\text{-DMP} + 1,6\text{-} + 2,9\text{-} + 2,5\text{-DMP}]$)	0.26	0.28
Log (1,7-DMP/1,3- + 3,9- + 2,10- + 3,10-DMP)	−0.21	−0.36
Fluoranthene/fluoranthene + pyrene	0.59	0.43
MBpR: 3-MBp/2-MBp	21	58
DMBpR-x: 3,5-DMBp/2,5-DMBp	8.1	27
DMBpR-y: 3,3'-DMBp/2,3'-DMBp	14	35
Log (Retene/9-MP)	−1.2	−1.7
Phenanthrene/dibenzothiophene	7.0	9.8
MDR: 4-MDBT/1-MDBT	2.2	8.8

MN, methylnaphthalene; DMN, dimethylnaphthalene; MDBT, methyl dibenzothiophene; for other abbreviations see captions to Figs. 12–14. All ratios were derived from SIM data.

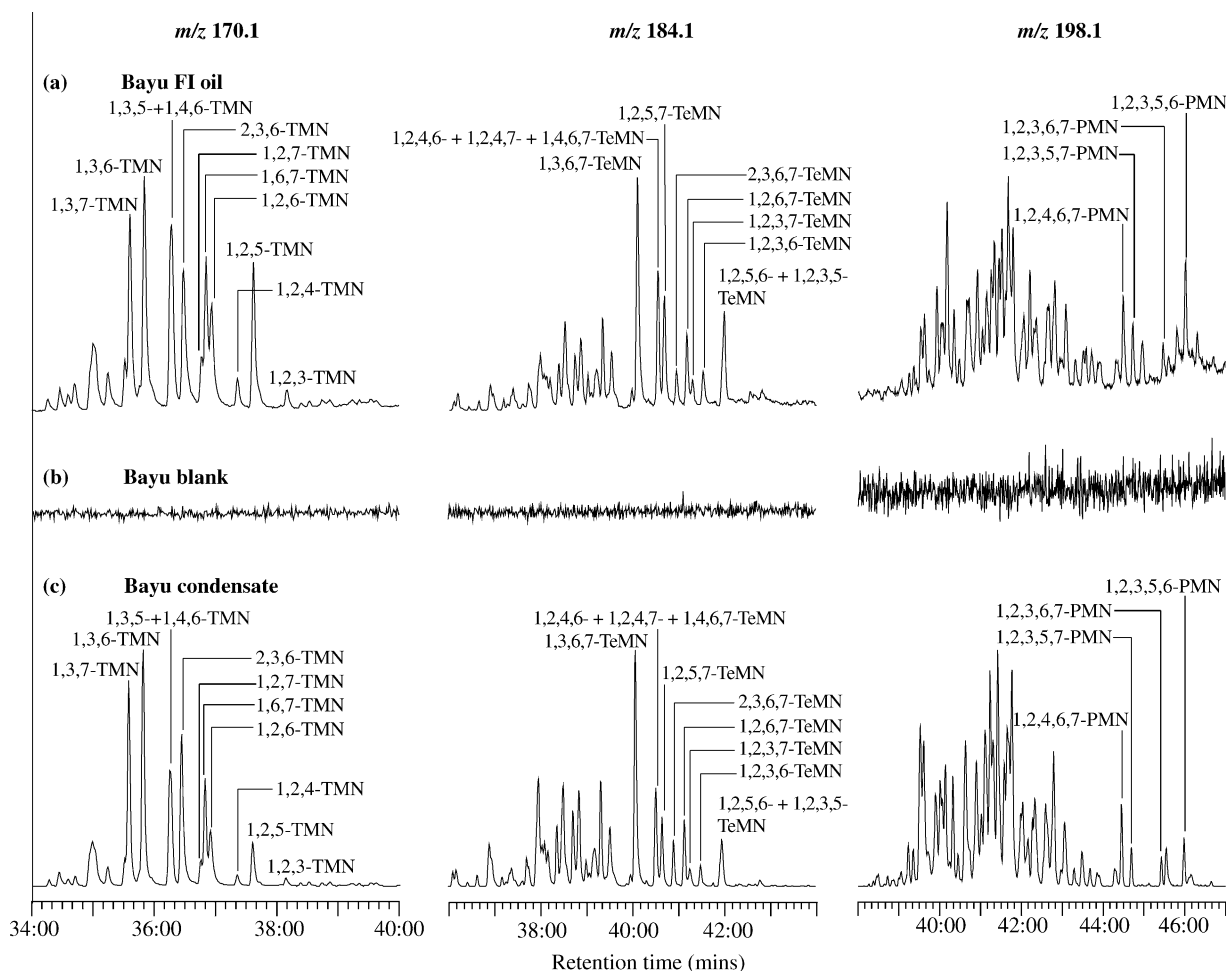


Fig. 12. Partial m/z 170.1, 184.1 and 198.1 mass chromatograms for (a) Bayu-1 FI oil, (b) the blank associated with analysis of the Bayu-1 FI oil, and (c) Bayu-1 condensate (aromatic fraction), showing the distribution of trimethylnaphthalenes (TMN), tetramethylnaphthalenes (TeMN) and pentamethylnaphthalenes (PMN). The blank is drawn to the same scale as the FI oil chromatogram.

Based on prior experience of compositions of oil trapped in FIs (e.g. George, Eadington, Lisk, & Quezada, 1998; George, Greenwood, et al., 1997; George, Krieger et al., 1997; George, Lisk et al., 1998; Isaksen, Pottorf, & Kenssen, 1998; Karlsen, Nedkvitne, Larter, & Bjørlykke, 1993; Lisk, George, Summons, Quezada, & O'Brien, 1996), it is likely that these oil inclusions contain oil from the earliest oil charge into the Bayu-Undan reservoir. Whilst a small number of inclusions appeared to have a low liquid–vapour ratio and could represent inclusions trapped as gas that subsequently condensed out a liquid rim during retrieval of the samples to the surface (a condensate inclusion), this could not be demonstrated unequivocally. Despite the absence of petrographic evidence to support the presence of condensate, it is, however, considered possible that the analysed sample may have contained some condensate inclusions within a population dominated by oil inclusions. This is based on (1) the bimodal distribution of n -alkanes, and (2) the similarity of low molecular weight hydrocarbon parameters for the FI oil

and the condensate, except for those influenced by the contribution of water soluble compounds from co-occurring aqueous inclusions (Ruble et al., 1998). For example, maturity parameters such as the heptane and isoheptane values, the n - C_7 /methylcyclohexane ratio, and the C_{temp} parameter suggest that C_7 hydrocarbons in the condensate and the FI oil have similar maturities (Table 1), whereas maturity parameters based on aromatic hydrocarbon parameters (C_{12} – C_{16}) suggest that the condensate is significantly more mature than the FI oil. This evidence suggests that the low molecular weight hydrocarbons ($< \sim C_{10}$) that were analysed were derived mainly from condensate inclusions, whereas higher molecular weight hydrocarbons ($> \sim C_{12}$) were derived mainly from oil inclusions. One implication of this result is that samples above and below the palaeo-oil column in Bayu-1, which would be expected to also contain condensate inclusions, should provide similar on-line geochemical data to the FI oil analysed here and the condensate, if they were to be analysed. This has not yet been carried out.

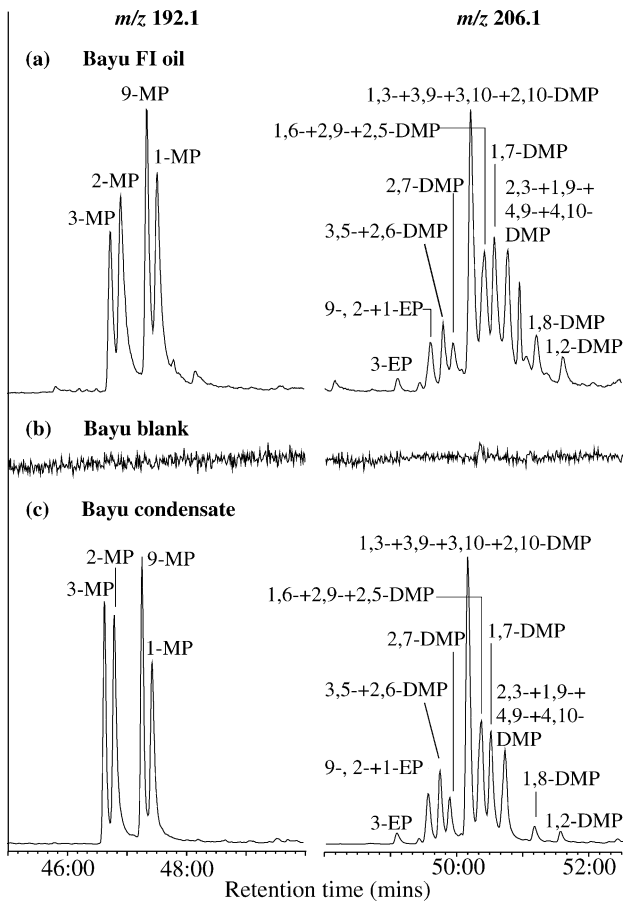


Fig. 13. Partial m/z 192.1 and 206.1 mass chromatograms for (a) Bayu-1 FI oil, (b) the blank associated with analysis of the Bayu-1 FI oil, and (c) Bayu-1 condensate (aromatic fraction), showing the distribution of methylphenanthrenes (MP) and dimethylphenanthrenes (DMP). The blank is drawn to the same scale as the FI oil chromatogram.

5.2. Source of the palaeo oil

The biomarker data suggest that the high molecular weight hydrocarbons in the FI oil were generated from a different source rock or source rock facies, compared to the high molecular weight hydrocarbons in the condensate. The source rock of the FI oil contained terrigenous organic matter, as shown by the slight odd-over-even n -alkane predominance and the presence of terrigenous biomarkers, but in lesser quantities than the source rock of the condensate. The source rock of the FI oil was deposited in a less oxic, more marine depositional environment, was less clay-rich, and had greater eukaryotic organic matter input than the source rock for the condensate, which had more terrigenous and microbial input. This is shown by (1) the low Pr/Ph ratio of the FI oil, (2) the lower $C_{29}Ts/C_{30}^*$ ratio of the FI oil, (3) the greater relative amount of C_{35} hopanes and 28,30-bisnorhopane in the FI oil, (4) the lower relative amounts of diahopanes and diasteranes in the FI oil, (5) the higher sterane/hopane ratio for the FI oil, (6) the higher $C_{29} \alpha\beta$ hopane/ $C_{30} \alpha\beta$ hopane ratio for the FI oil, (7) the higher

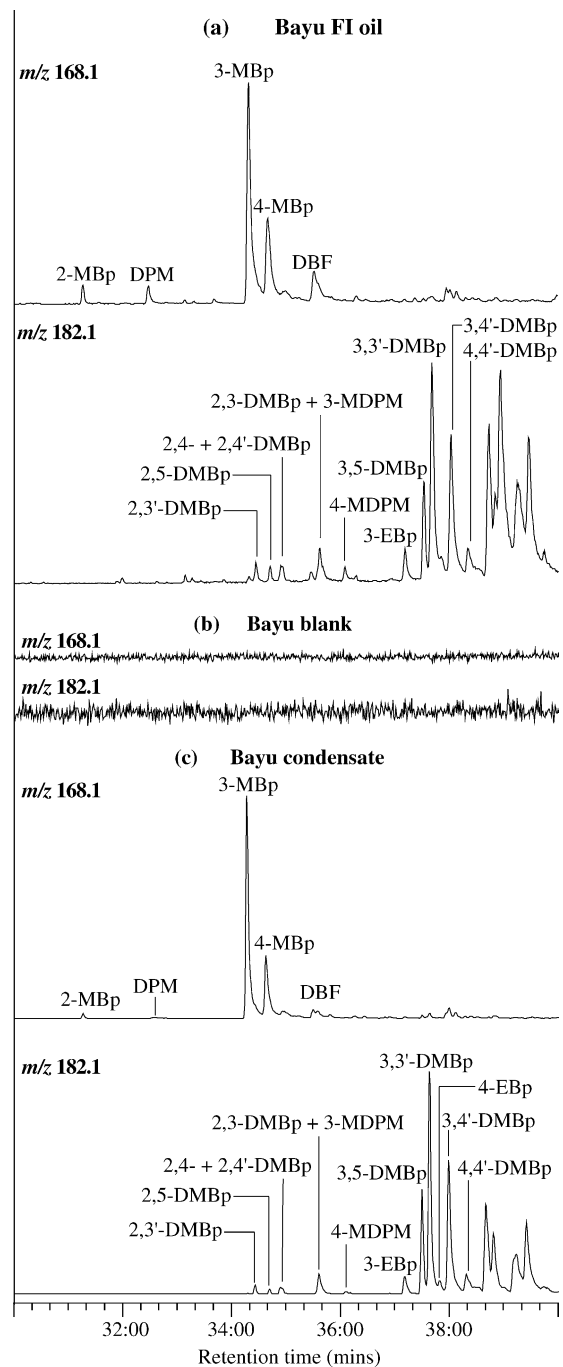


Fig. 14. Partial m/z 168.1 and 182.1 mass chromatograms for (a) Bayu-1 FI oil, (b) the blank associated with analysis of the Bayu-1 FI oil, and (c) Bayu-1 condensate (aromatic fraction), showing the distribution of methylbiphenyls (MBp), diphenylmethane (DPM), dimethylbiphenyls (DMBp), ethylbiphenyls (EBp) and methyl-diphenylmethanes (MDPM). The blank is drawn to the same scale as the FI oil chromatogram.

relative amounts of C_{30} 24- n -propylcholestanes in the FI oil, (8) the very low relative amounts of C_{19} – C_{21} tricyclic terpanes in the FI oil, and (9) the greater relative amounts of the C_{28} and C_{29} tricyclic terpanes in the FI oil. Although some of these source-related parameters are likely to have also been influenced by the interpreted higher maturity of

the condensate (e.g. $C_{29}Ts/C_{30}^*$, diahopane/hopane, diasterane/sterane; see below), the other parameters are unlikely to have been significantly influenced by maturity. The aromatic hydrocarbons reveal only slight differences in source input to the FI oil and the condensate, with slightly greater input of *Araucariacean*-type plants in the source rock of the FI oil. In this study these compounds are not so useful for distinguishing source differences as the terpane and sterane biomarkers.

The Bayu-Undan condensate has been considered a marine end-member of Northern Bonaparte oils (Gorter & Hartung-Kagi, 1998), or a less terrestrially-influenced facies of the Elang and Plover Formations, together with the Flamingo Group (Preston & Edwards, 2000). This paper has shown that the palaeo oil leg in Bayu-1, represented by the FI oil, has a greater marine character than the condensate, so can be considered to be the best end-member marine oil known so far in the Northern Bonaparte Basin. This is consistent with the extract data from sidewall cores at 2,978 and 3,146.1 mRT in Bayu-1, which were attributed to 'Elang-type' oil reservoirs only in tighter lithologies not flushed by the later gas charge in Bayu-1 (Gorter & Hartung-Kagi). In many respects the Bayu-1 FI oil most closely correlates with the Darwin-reservoired oils such as Elang West-1, Kakatua North-1, Layang-1 (e.g. Fig. 8), which are thought to be derived from the Echuca Shoals Formation (Preston & Edwards, 2000). Brooks et al. (1996) assigned the Bayu condensate to a Echuca Shoals Formation source, but this was challenged by Preston & Edwards (2000) who considered a Flamingo Group source more likely, based on the Oxfordian to Tithonian section being too thick to have allowed hydrocarbons generated in the Echuca Shoals Formation to have migrated by fault-juxtaposition into Elang and Plover formation reservoirs (Preston & Edwards, 2000). The possible presence of oleanane and/or lupane in the Bayu condensate and fluid inclusion oil would be consistent with at least partial sourcing from the Cretaceous Echuca Shoals Formation, but this supposition remains unconfirmed.

5.3. Maturity of the palaeo-oil

The alkane/isoprenoid and biomarker ratios of the FI oil and the condensate suggest a maturity in the middle of the oil window. This is confirmed by the $22S/(22S + 22R)$ ratios for the extended homohopanes, the $C_{30} \alpha\beta/(\alpha\beta + \beta\alpha)$ hopane ratio, the $\beta\alpha$ diasterane $20S/(20S + 20R)$ ratio and the $C_{29} \alpha\alpha\alpha$ $20S/(20S + 20R)$ sterane ratio, which are close to end-point values and show no significant difference between the FI oil and the condensate. The $C_{29} \alpha\beta\beta/(\alpha\beta\beta + \alpha\alpha\alpha)$ ratio is further from its end-point, thus indicating that both the FI oil and the condensate have a thermal maturity near the middle of the oil window. The higher CPI and the lower $Ts/(Ts + Tm)$ and $C_{29}Ts/(C_{29}Ts + C_{29} \alpha\beta\text{hopane})$ ratios in the FI oil compared to the condensate suggest a higher thermal maturity for the condensate compared to the FI oil, although care has to be exercised in the interpretation

of these ratios as they can be source-influenced. Similarly, the higher content of diahopanes and diasteranes in the condensate compared to the FI oil is consistent both with a higher thermal maturity for the condensate, and a more oxic, more clay-rich depositional environment for the source rock that generated the condensate (see previous section).

The biomarker ratios are not very useful for maturity differentiation in mature oils and condensates because of their limited dynamic range (e.g. van Graas, 1990). Instead, aromatic thermal maturity indicators can be used to derive relative and absolute maturities. Most of these (DNR-1, TNR-1, TNR-2, TeMNR-1, TMNr, TeMNR, PMNr, MPI, MPDF, MPR, DMPR, MBpR, DMBpR-x, DMBpR-y and MDR; Table 4) also support a greater maturity for the condensate compared to the FI oil. Although none of these parameters have been unequivocally calibrated to vitrinite reflectance, particularly when there are source differences as in this study, they can be used to suggest that the high molecular weight hydrocarbons in the FI oil were generated at a maturity of about 0.7–0.8% vitrinite reflectance equivalent (VRE), whilst the high molecular weight hydrocarbons in the condensate were generated at a maturity of about 0.9%. The maturity data acquired in this study for a Bayu-1 condensate sample (MDT-2) are similar to published data for other Bayu-Undan condensate samples (0.90–0.95% VRE; Preston & Edwards, 2000). The maturity of the Bayu-1 FI oil is similar to the maturities of crude oils and FI oils in the Laminaria oilfield (George et al., 2004; Preston & Edwards, 2000).

5.4. Variations in condensate composition at Bayu

Previously published biomarker data for other Bayu-Undan condensate samples (Preston & Edwards, 2000) are for the most part similar to data acquired in this study on a Bayu-1 condensate sample (MDT-2). Tricyclic terpane distributions (e.g. Fig. 8) and sterane/diasterane distributions (e.g. compare Fig. 10c with Fig. 17d of Preston & Edwards, 2000) are very similar. However, there are differences between the hopane distributions of Bayu-1 condensate in the MDT-2 oil (Fig. 9c) and DST-1 (Fig. 16d of Preston & Edwards, 2000). In particular, Ts, $C_{29}Ts$ and C_{30} diahopane are significantly more abundant in DST-1 compared to MDT-2. It is unlikely that variations such as these in standard m/z 191 mass chromatograms would be caused by inter-laboratory or inter-instrumental differences, so this variation is interpreted as suggesting that the DST-1 sample of the condensate is more mature than the MDT-2 sample. Some support for a maturity difference comes from aromatic hydrocarbon data. The range of VRE values derived from the MPI for Bayu-Undan condensates (0.90–0.95%; Preston & Edwards) are slightly higher than the VRE of the MDT-2 sample (0.87; Table 4), supporting a lower maturity for the MDT-2 sample. DST-1 was taken from slightly deeper in the condensate column (3,101–3,120 mRT) than the MDT-2 sample (3,089.6 mRT).

This apparent variation in maturity between Bayu condensate samples could be attributed to the different sampling methods, or to some degree of compartmentalisation within the reservoir.

5.5. Constraints on the charge history at Bayu

Previous oil–source correlations for the Bayu-Undan condensate include the Echuca Shoals Formation (Brooks et al., 1996) and mixing of hydrocarbons from the Elang and Plover formations (more terrigenous) and the dominantly-marine Flamingo Group (Preston & Edwards, 2000). A mixing scenario is consistent with the FI results, which indicate a dual charge. However, it is difficult to attribute the Bayu FI oil to the Flamingo Group based on its geochemistry, and it more closely matches the Echuca Shoals Formation (e.g. Fig. 8). Furthermore, whilst the Bayu condensate appears to match more closely with the Flamingo Group, the charge history implied by the FI results provides an alternative explanation. Mixing of an early oil charge, derived from the more labile, marine-derived organic matter in the Cretaceous Echuca Shoals Formation, with a later gas or gas-condensate charge derived from the more terrestrially-dominated Elang and Plover formations is likely to produce an intermediate signature that could resemble a Flamingo Group sourced oil. A discrete ‘Flamingo Group’ is not required and this oil family may not be present in the Bayu area. The differences are nevertheless subtle and a contribution from the Flamingo Group cannot be completely discounted.

Three possible transition mechanisms from gas over oil to condensate are consistent with the FI petrographical and geochemical data. The first charge may have (1) been lost by breaching of the seal, followed by resealing and recharge with the currently reservoirised condensate, (2) been displaced by the condensate without interaction between the incoming gas and displaced oil, or (3) been partly dissolved in the later condensate charge. The third possibility is supported by the occurrence of marine-derived biomarkers such as C₃₀ 24-*n*-propylcholestanes in the condensate, and the interpreted mixed sourcing of the condensate (Preston & Edwards, 2000). A combination of factors 2 and 3 is considered most likely, but further investigation is required to assess these options.

If mixing of the early marine-derived oil charge with later charge from the Elang and Plover Formations occurred, then biomarkers present in the FI oil should all be present, albeit in reduced relative concentrations, in the currently reservoirised condensate. Although biomarker ratios are significantly different for the FI oil and the condensate, no biomarkers are unique to the FI oil and therefore the mixing hypothesis cannot be discounted. However, mixing could not be simply an early oil being dissolved into a later dry gas to form a condensate, because significant amounts of high molecular weight hydrocarbons

must have been added by the later charge to cause the variation in the biomarker ratios.

Constraints on the mixing hypothesis are provided by the most different biomarker ratio for the FI oil and the condensate, namely the ratio of diasteranes to steranes. This was calculated for the C₂₇, C₂₈ and C₂₉ carbon numbers (Table 2), as well as the sum of all three. In this paper, the sum is used (Table 5). To fully constrain mixing, both end member compositions need to be known. Unfortunately, in this case only the high molecular weight components of the FI oil can be considered an end member. During mixing, the sterane and diasterane composition of the currently reservoirised condensate (Cc) represents the contribution of an unknown end member (denoted Cp) with the FI oil. Furthermore, in order to shift the FI oil composition towards Cc, Cp must have been more enriched in diasteranes relative to steranes than Cc is. The diasterane/sterane ratio of Cc is 2.47, which is higher than for many crude oils and condensates. It would be unlikely to find a condensate with a ratio >3, unless the condensate had undergone heavy biodegradation or was of a very much higher thermal maturity (Seifert & Moldovan, 1978).

In Table 5, calculated mixing volumes of possible Cp compositions (diasterane/sterane ratios of 2.5–5.0) are given. This calculation is on a volume basis (inclusion oil and condensate liquid), and assumes similar absolute concentrations of diasteranes and steranes in Cc and Cp, and makes no consideration of another mass balance constraint, which is filling of the reservoir when

Table 5
Calculated theoretical mixing volumes of the end member condensate (Cp) with the Bayu-1 FI oil to give the currently reservoirised condensate (Cc) at Bayu-1, on the basis of diasterane/sterane ratios

	D/S ^a	Mixing volume
FI oil	0.56	–
Condensate (Cc)	2.47	–
Cp (1)	2.5	140 parts Cp (1)+1 part FI oil gives D/S=2.47
Cp (2)	2.6	35 parts Cp (2)+1 part FI oil gives D/S=2.47
Cp (3)	2.7	20 parts Cp (3)+1 part FI oil gives D/S=2.47
Cp (4)	2.8	14 parts Cp (4)+1 part FI oil gives D/S=2.47
Cp (5)	2.9	11 parts Cp (5)+1 part FI oil gives D/S=2.47
Cp (6)	3.0	9 parts Cp (6)+1 part FI oil gives D/S=2.47
Cp (7)	3.5	5.5 parts Cp (6)+1 part FI oil gives D/S=2.47
Cp (8)	4.0	4 parts Cp (6)+1 part FI oil gives D/S=2.47
Cp (9)	5.0	3 parts Cp (6)+1 part FI oil gives D/S=2.47

^a Diasterane/sterane ratio (C₂₇+C₂₈+C₂₉ βα diasteranes/ααα+αββ steranes).

the condensate liquid is dissolved into the gas. Mixing volumes of in excess of 9 parts Cp:1 part FI oil are required, unless geochemically unreasonable diasterane/sterane ratios of the end member condensate are considered. Furthermore, if biomarkers were less abundant in the later higher maturity charge of condensate, as would be likely, then this mixing volume would have to be even greater to cause the shift in diasterane/sterane ratios. The conclusion from this mixing calculation is that if mixing of the early charge with a condensate did take place, it involved a much larger volume of condensate than early oil charge.

Some evidence has been gained from this study to enable comment on the theory that the present distribution and composition of hydrocarbon accumulations in the Northern Bonaparte Basin is controlled by extensive water-washing of earlier very large gas-condensate fields (Newell, 1999). The deduced presence of water-soluble compounds in aqueous inclusions in Bayu-1 suggests interaction of the formation water with petroleum, prior to trapping as aqueous inclusions. This provides support for at least some water-washing in the Northern Bonaparte Basin. The distribution of oil inclusions in Bayu-1 defines a palaeo oil and gas column, but condensate inclusions could not conclusively be observed petrographically in Bayu-1, despite their presence being suggested by the on-line geochemical data on the Bayu-1 inclusion oil. It could be argued that the inability to detect condensate inclusions petrographically means that an alternative charge history for Bayu might be continuous accumulation of condensate and continuous water washing (Newell, 1999), resulting in a gradual increase in the amount of oil and eventually oil inclusion formation to define the palaeo oil zone. In this scenario, Bayu-Undan would represent an early stage of producing an oil zone by water washing, that was destroyed by later condensate accumulation, whereas other Northern Bonaparte oilfields (e.g. Laminaria, Corallina) would be the result of this process continuing to a more complete stage (Newell, 1999). The strongest argument against this proposal are the significant geochemical differences between the Bayu FI oil and the Bayu condensate, which suggest that the FI oil at Bayu has features that could not arise from water washing of a condensate (e.g. the differences in source and maturity parameters). The conclusion from this observation is that the FI oil at Bayu represents a different hydrocarbon charge compared to the condensate liquid, with the proviso discussed above regarding possible mixing volumes. A further implication is that the large residual oil columns that are observed elsewhere in the Northern Bonaparte Basin (Newell, 1999), defined in part by the abundance of oil-bearing FIs (e.g. George et al., 2004), are unlikely to be due to a pre-existing gas-condensate column similar to Bayu-Undan. More detailed consideration of the distribution and composition of the residual oil columns in the Northern Bonaparte Basin and how these impact on

the water-washing theory will be the subject of another, more regionally oriented paper.

6. Conclusions

1. The distribution of oil-bearing FIs in Bayu-1 suggests that the trap originally contained a palaeo-oil column beneath a thick gas cap.
2. Geochemical analysis of inclusion oil by an on-line technique suggests the presence of both oil and condensate inclusions, although the latter could not be observed conclusively by petrographical methods.
3. Biomarker data suggest that the high molecular weight hydrocarbons in the FI oil were generated from a less clay-rich source rock that contained more marine and less terrigenous organic matter input, and was deposited in a less oxic depositional environment, compared to the source rock that generated the high molecular weight hydrocarbons in the condensate.
4. It is likely that the palaeo oil leg at Bayu, represented by the FI oil, was derived from the more marine influenced Echuca Shoals Formation, with a maturity of ~ 0.7 – 0.8% VRE, whilst later expulsion of large amounts of condensate was from the more terrestrially-dominated Elang and Plover Formations at a higher maturity ($\sim 0.9\%$ VRE).
5. The most likely transition mechanism from gas over oil to condensate is dissolution of the early oil charge into a much larger volume of condensate and/or flushing of oil across the spill-point.
6. The FI oil at Bayu-1 predominantly represents a different hydrocarbon charge compared to the condensate liquid, and so by analogy the large residual oil columns that are observed elsewhere in the Northern Bonaparte Basin are unlikely to be due to water-washing of a pre-existing gas-condensate column similar to Bayu-Undan.

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