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Extended abstract

Geochemical evidence for a new Triassic petroleum system on the western margin of Australia

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Abstract. The unexpected discovery of oil in Triassic sedimentary rocks of the Phoenix South 1 well on Australia's North West Shelf (NWS) has catalysed exploration interest in pre-Jurassic plays in the region. Subsequent neighbouring wells Roc 1–2, Phoenix South 2–3 and Dorado 1–3 drilled between 2015 and 2019 penetrated gas and/or oil columns, with the Dorado field containing one of the largest oil resources found in Australia in three decades. This study aims to understand the source of the oils and gases of the greater Phoenix area, Bedout Sub-basin using a multiparameter geochemical approach. Isotopic analyses combined with biomarker data confirm that these fluids represent a new Triassic petroleum system on the NWS unrelated to the Lower Triassic Hovea Member petroleum system of the Perth Basin. The Bedout Sub-basin fluids were generated from source rocks deposited in paralic environments with mixed type II/III kerogen, with lagoonal organofacies exhibiting excellent liquids potential. The Roc 1–2 gases and the Phoenix South 1 oil are likely sourced proximally by Lower–Middle Triassic TR10–TR15 sequences. Loss of gas within the Phoenix South 1 fluid due to potential trap breach has resulted in the formation of in-place oil. These discoveries are testament to new hydrocarbon plays within the Lower–Middle Triassic succession on the NWS.

Keywords: Roebuck Basin, Bedout Sub-basin, fluids, source rocks, organic geochemistry, biomarkers, isotopes, Triassic, Keraudren Formation.

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Introduction

In 2014, the surprise discovery of oil in Phoenix South 1 on Australia's North West Shelf (NWS) heralded the Bedout Sub-basin as a new oil province in Australia (Fig. 1*a*). The Dorado oil field, discovered in 2018 and located about 40 km south of Phoenix South 1, is one of the largest oil resources found in Australia in decades (Weller and Amiribesheli 2018; Cockerill 2020) and confirms the magnitude of the resources in the Bedout Sub-basin. However, whether these discoveries represent a new oil province is challenged by the presence of gas in the Greater Phoenix area wells, Roc 1–2, Phoenix South 2–3 and Dorado 1–3.

To better assess the potential for finding similar plays elsewhere on the margin, it is essential to understand the source of the oils and gases in the greater Phoenix area, which is accomplished using a geochemical approach. Analyses of fluids provide information on the source rock they derive from, including kerogen type, age and maturity at the time of hydrocarbon generation. Oil–gas–source correlations using isotopic and molecular data provide insights into the most likely source rock from which the fluids of the Bedout Sub-basin derive.

Samples and methods

The oils, natural gas and rock samples analysed in this study for bulk isotopic and biomarker compositions are listed in Table 1. The Phoenix South 1 oils were recovered from the Middle Triassic Barret Member between TR15.0_SB and TR16.0_SB, whereas the Roc 1–2 gases and condensates were taken from the Lower to Middle Triassic Caley Member between TR10.0_SB and TR15.0_SB (Thompson *et al.* 2018; Rollet *et al.* 2019) (Fig. 1*b*). The methods and data have been reported in Grosjean *et al.* (2019*a*, 2019*b*, 2019*c*, 2020*a*). At the time of this study, fluids from the recently drilled Dorado wells were not yet available for analysis but will be included in further work.

Oil and gas geochemistry of Bedout Sub-basin fluids

Roc 1–2 both encountered rich gas condensates with condensate-to-gas ratios of 50.5 and 55.8 bbl/mmscf, respectively. While methane is the dominant component of these natural gases (Grosjean *et al.* 2019*b*), they are considered wet gases with $C_1/(C_1–C_5)$ of 82.8%, where wet gases are defined by this ratio as being <98% (Tissot and Welte 1984).

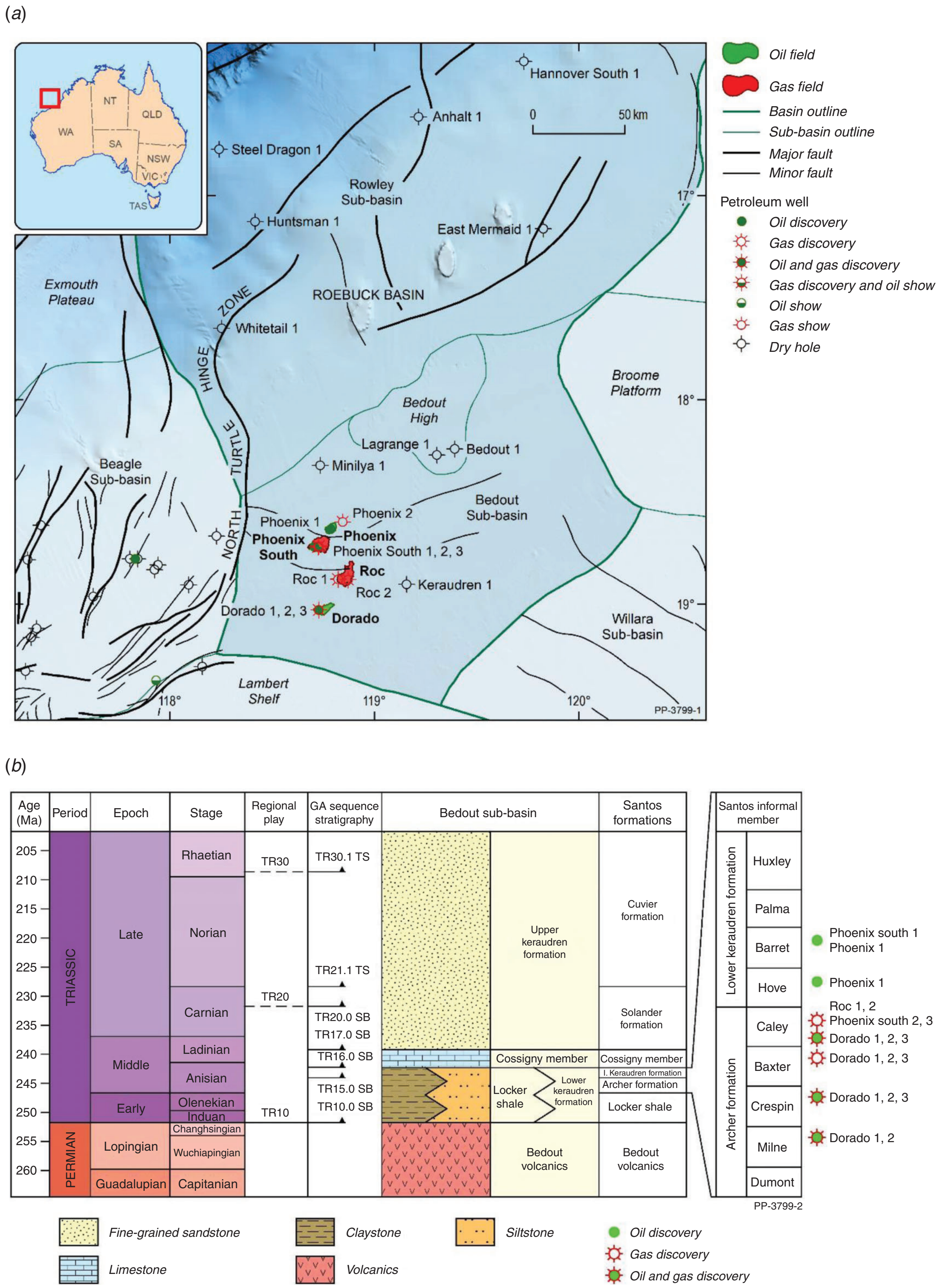

Fig. 1. (*a*) Regional map of the Roebuck Basin showing main structural elements, petroleum wells and hydrocarbon fields and discoveries. (*b*) Permian–Triassic tectono-stratigraphic chart of the Bedout Sub-basin based on the nomenclature after Marshall and Lang (2013) and the Geologic Timescale 2016 (Ogg *et al.* 2016) showing oil and gas discoveries and formation names by Santos Ltd (Thompson *et al*. 2019; Thompson 2020).

Table 1. Bulk properties and relevant geochemical ratios for petroleum fluids and rocks analysed during this study

Gases

Sample no.	Sample ID	GeoMark ID	Well	Top depth (mRT)	Base depth (mRT)	Sample type	Sequence	Sampling details	C1/(C1–C5)%[A]	δ13C methane (‰)[B]	δ13C ethane (‰)[B]	δ13C propane (‰)[B]	δ13C n-butane (‰)[B]	δ13C n-pentane (‰)[B]	δD methane (‰)[C]
2709628	20179095		Roc 1	4403.5		Gas	TD within lower TR10	MDT. Ex-MPSR 2602	82.8	–43.9	–31.15	–27.82	–27.26	–26.77	–180.2
2635995	20179005		Roc 2	4292.4	4325.5	Gas	TD within lower TR10	DST 1. Sample No 1.50	82.8	–44.9	–32.60	–29.07	–28.52	–28.01	–171.6

Oils and condensates

Sample no.	Sample ID	GeoMark ID	Well	Top depth (mRT)	Base depth (mRT)	Sample type	Sequence	Sampling details	API gravity (°)	S (wt.%)	Pr/Ph[D]	C19/C23[E]	Tet/C23[F]	δ13C oil (‰)[B]	δ13C sats (‰)[B]	δ13C aros (‰)[B]	VREQ-5
2673490	20179025	AU1173	Phoenix South 1 ST2	4232.5		Oil	TD within TR15	MDT. Ex-MPSR 2248	48.1	0.03	4.03	3.94	2.02	–29.4	–30.2	–27.7	n.d.
2673491	20179026	AU1174	Phoenix South 1 ST2	4232.5		Oil	TD within TR15	MDT. Ex-MPSR 2082	49.3	0.01	4.13	3.76	1.97	–29.5	–30.1	–27.6	0.98
4273714	20209014	AU1258	Roc 2	4322.02		Condensate	TD within lower TR10	MDT. Ex MPSR 3348	42.8	0.04	2.53	2.69	1.28	–27.8	–29.6	–26.6	1.15
4273715	20209015	AU1259	Roc 2	4294.5	4325.5	Condensate	TD within lower TR10	DST 1. Sample No 1.51	52.3	0.08	2.61	3.70	1.72	–27.3	–30.0	–26.6	1.15
4273716	20209016	AU1260	Roc 1	4395.5	4406.0	Condensate	TD within lower TR10	MDT. Ex MPSR 2645	43.3	0.02	2.53	4.27	1.47	–27.8	–29.9	–27.1	1.17

Source rocks																	
Sample no.	**Sample ID**	**GeoMark ID**	**Well**	**Top depth (mRT)**	**Base depth (mRT)**	**Sample type**	**Sequence**	**TOC (wt.%)**	**S2 (mg HC/g rock)**	**HI (mg HC/g TOC)**	**Pr/Ph[D]**	**C19/C23[E]**	**Tet/C23[F]**	**δ13C EOM (‰)[B]**	**δ13C sats (‰)[B]**	**δ13C aros (‰)[B]**	**VREQ-5**
2808563	20190033	XAU0144	Roc 2	4350.46		Core	TD within lower TR10	23.12	98.27	425	5.99	5.40	10.91	–25.1	–29.8	–24.5	0.78
2808566	20190036	XAU0145	Roc 2	4365.12		Core	TD within lower TR10	2.8	7.97	284	3.68	1.14	4.69	–29.0	–32.5	–28.2	0.81
2808567	20190037	XAU0146	Roc 2	4366.25		Core	TD within lower TR10	4.86	16.74	345	4.84	4.87	9.44	–27.8	–31.2	–26.6	n.d.
2808572	20190042	XAU0147	Roc 2	4370.23		Core	TD within lower TR10	16.86	72.66	431	6.81	4.38	8.66	–26.1	–30.7	–25.2	0.81
2808573	20190043	XAU0148	Roc 2	4370.73		Core	TD within lower TR10	12.62	51.19	406	5.77	4.12	9.70	–27.5	–30.9	–26.6	n.d.
2808580	20190050	XAU0149	Roc 2	4388.3		Core	TD within lower TR10	2.82	7.04	249	5.24	1.89	6.04	–28.8	–32.3	–27.7	n.d.

[A]$C_1/(C_1–C_5)\%$ = methane/(methane + ethane + propane + *i*-butane + *n*-butane + *i*-pentane + *n*-pentane) × 100; [B]Carbon isotopic values ($\delta^{13}C$) are reported relative to Vienna Peedee Belemnite (VPDB); [C]Deuterium isotopic values (δD) are reported relative to VSMOW; [D]Pr/Ph = pristane/phytane; [E]C19/C23 = C_{19} tricyclic terpane/C_{23} tricyclic terpane; [F]Tet/C23 = Tetracyclic terpane/C_{23} tricyclic terpane; n.d. = not determined.

The Phoenix South 1 oils and Roc 1–2 condensates are light fluids (API gravity 43–49°), low in sulfur (S = 0.01–0.08 wt.%) and non-biodegraded. The low gas-to-oil ratios in the range 1691–1764 scf/bbl for the Phoenix South 1 oils are inconsistent with an API > 45°, implying that the oils are undersaturated with respect to gas (Murray and He 2020). Based on vitrinite reflectance equivalent (VREQ-5) data derived from a proprietary combination of aromatic hydrocarbons analysed by GC/MS-MS QQQ at GeoMark Research, the Roc 1–2 condensates are more thermally mature (mean VREQ-5 = 1.16%) than the Phoenix South 1 oils (VREQ-5 = 0.98%) generated at peak oil maturity. The pristane-to-phytane (Pr/Ph) ratios of the Phoenix South 1 oils and Roc 1–2 condensates are in excess of 2.5 (Table 1), indicative of a suboxic/oxic depositional environment for the source rock. Terpanes and steranes distributions reveal mixed marine-terrestrial inputs to the organic matter and a clastic source rock. There is no increased abundance of C_{33} alkylcyclohexane in these fluids, a biomarker diagnostic for the end-Permian mass extinction event and prevalent in Lower Triassic-sourced Perth Basin oils (Grosjean *et al.* 2011 and references therein). The low relative amount of retene, a polyaromatic compound likely derived from Araucariaceae conifers that evolved during the Jurassic (Alexander *et al.* 1988), is in agreement with a pre-Jurassic age. The carbon isotopic composition ($\delta^{13}C$) of the saturated hydrocarbon fractions ranges from –30.2 to –29.6‰, which is within the range of values observed globally for crude oils derived from Triassic source rocks (Andrusevich *et al.* 1998).

An effective tool for understanding the potential source of gases and oils is to compare the compound-specific isotopic analyses of linear alkanes of the fluids with those of the source rocks from which they may be derived. Carbon isotopic values of alkanes for the fluids in the greater Phoenix area wells fall between the Lower–Middle Jurassic fluids from the Browse Basin, the Jurassic fluids from the Beagle Sub-basin, the Permian fluids of the Perth Basin and the Lower Triassic fluids of the Perth Basin (Fig. 2*a*). Linear alkanes of the Phoenix South 1 oils are on average 1.5‰ more depleted in ^{13}C than the Roc 1–2 condensates, which is in agreement with a lower thermal maturity (Clayton and Bjorøy 1994). The alkane carbon isotopic profiles of the Roc 2 gas/condensate pair follow a smooth continuum inferring cogeneration by the same source rock at the same maturity (Boreham *et al.* 2001).

Source rock geochemical characteristics

Based on the stratigraphic emplacement of the oil and gas discoveries within Lower to Middle Triassic reservoirs between TR10.0_SB and TR17.0_SB (Fig. 1*b*), Lower to Middle Triassic rocks were investigated for their hydrocarbon source potential using publicly available Rock-Eval pyrolysis data to identify the most suitable candidates for oil to source correlations. Sediments between TR10.0_SB and TR15.0_SB were deposited in a fluvial-deltaic environment with occasional minor marine influences (Abbott *et al.* 2019; Rollet *et al.* 2019). In the Bedout Sub-basin, sedimentary rocks that have available geochemical data have a mean total organic carbon (TOC) content of 3.1 wt.% and a mean genetic potential S1 + S2 of 9.4 mg hydrocarbons (HC)/g rock, exhibiting good to excellent hydrocarbon-generating potential. With a mean hydrogen index (HI) of 229 mg HC/g TOC, these source rocks consist mainly of mixed type II/III kerogens and organofacies D/E in the kerogen classification by Pepper and Corvi (1995), capable of generating both oil and gas. However, about one-fifth of the rocks analysed within the Caley Member in Roc 2 stand out as excellent oil-prone source rocks having TOC > 4 wt.% (up to 23.2 wt.%) and HI > 300 mg HC/g TOC (Rollet *et al.* 2019; Grosjean *et al.* 2019*a*). Caley Member shales are enriched in the maceral liptinite, an oil-prone source rock organic component. Liptinite in these shales consists of a mixture of algal-derived lamalginite, marine plankton *tasmanitids*, brackish–freshwater algae *Botryococcus*-related telalginite and the land–plant maceral sporinite (Fig. 3*a–c*) (Ranasinghe and Crosdale 2019). The combination of terrestrial and freshwater/marine algal macerals suggests a deltaic to lagoonal environment, which is supported by detailed sedimentological, ichnological and palynological observations on Roc 2 cores (Allgöwer and Lignum 2019). Pyrolysis products from pyrolysis–gas chromatography are dominated by *n*-alkenes/*n*-alkanes pairs extending to long chain lengths, reflecting a prevailing algal contribution and confirming the oil-prone nature of the kerogen (Fig. 3*d*). The high abundance of aromatic and phenolic compounds among the pyrolysis products indicates a significant land–plant contribution (Larter 1985; Mahlstedt and Horsfield 2019). Bulk kinetics show a narrow activation energy (Ea) distribution (Fig. 3*e*) consistent with the cracking of mixed aquatic–terrestrial organic matter and petroleum generation occurring between 145°C and 210°C for a geologic heating rate of 3 K/Ma.

With VREQ-5 in the range 0.78–0.81%, the Caley Member source rocks analysed in Roc 2 are not as thermally mature as the fluids. Biomarker distributions are consistent with a mixed marine to terrestrial clastic depositional environment. The carbon isotopic compositions of C_{14}–C_{32} linear alkanes show values between –29 and –38‰ (Grosjean *et al.* 2020*b*), with alkanes isotopic profiles nested in between those of the Lower Triassic Perth Basin oils and the Jurassic-sourced fluids of the Browse Basin, similar to the fluids in Roc 1–2 and Phoenix South 1 (Fig. 2*b*).

With a mean TOC content of 1.4 wt.% and HI in the range 33–331 mg HC/g TOC in wells of the Bedout Sub-basin, fluvio-deltaic sedimentary rocks between TR15.0_SB and TR16.0_SB are not as organic-rich as the sequence below but the organic matter consists of mixed type II/III kerogen adequately capable of generating oil and gas (Rollet *et al.* 2019).

A new Triassic petroleum system

Biomarker and isotopic data of the Bedout Sub-basin fluids analysed in this study suggest sourcing from a clastic source rock consistent with a Triassic age and deposition under suboxic/oxic conditions with mixed marine and terrestrial organic matter inputs. The fluid geochemistry in Phoenix South 1 and Roc 1–2 indicates that they represent a new Triassic petroleum system on the western margin of Australia unrelated to the Lower Triassic petroleum system of the Perth Basin. The inferred depositional environment for the source rock is in agreement with derivation from type II/III fluvio-deltaic to lagoonal source rocks present in the Bedout Sub-basin between TR10.0_SB and TR16.0_SB

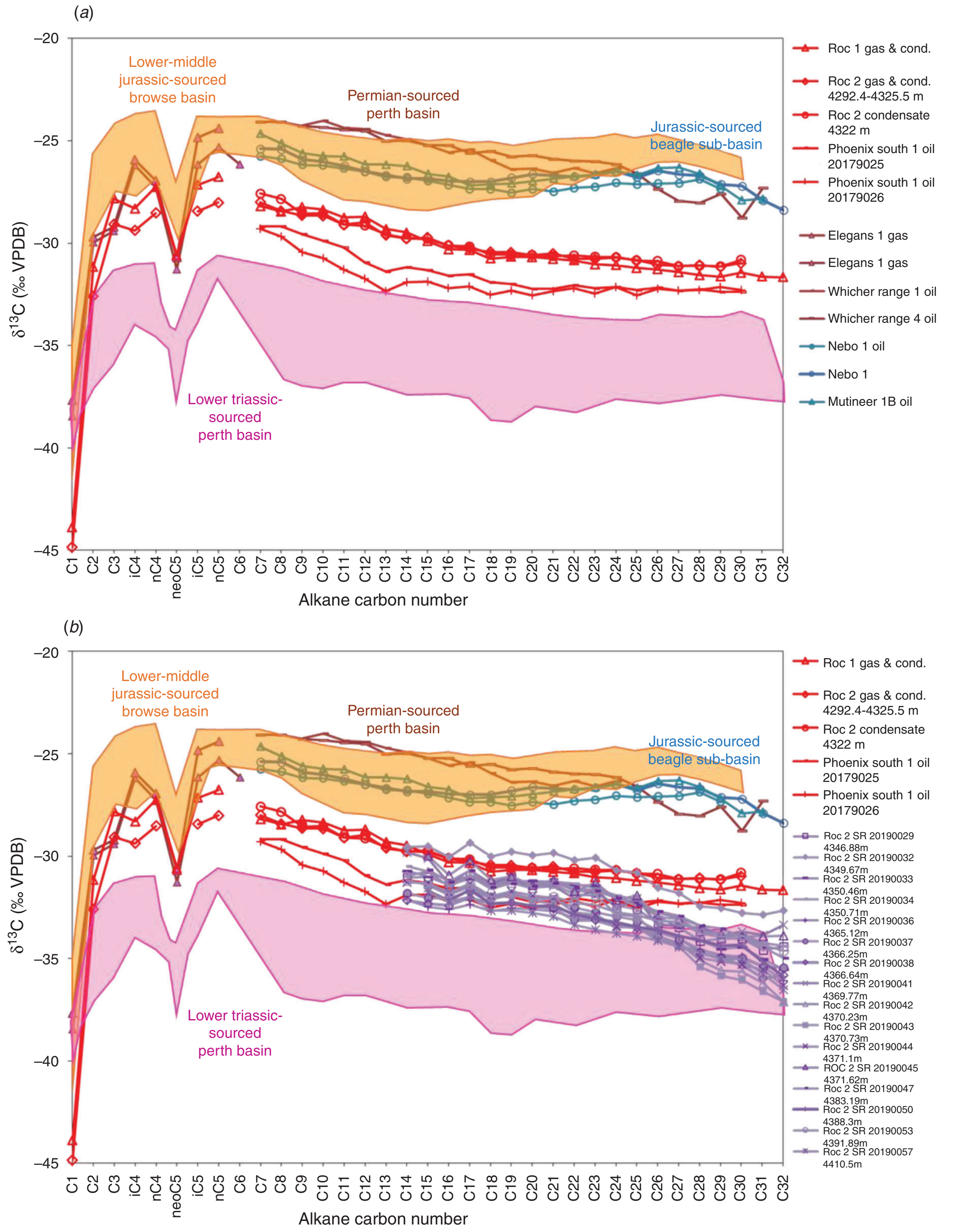

Fig. 2. Carbon isotopic compositions of C_1–C_5 gaseous hydrocarbons and C_7–C_{32} *n*-alkanes of (*a*) fluids from the Bedout Sub-basin (red), Browse Basin sourced by Lower–Middle Jurassic source rocks (orange), Beagle Sub-basin (blue), Perth Basin sourced by Permian source rocks (brown), Lower Triassic source rocks (pink) and (*b*) of source rocks from the Caley Member in Roc 2 (purple) (data from Grosjean *et al*. 2020*b*).

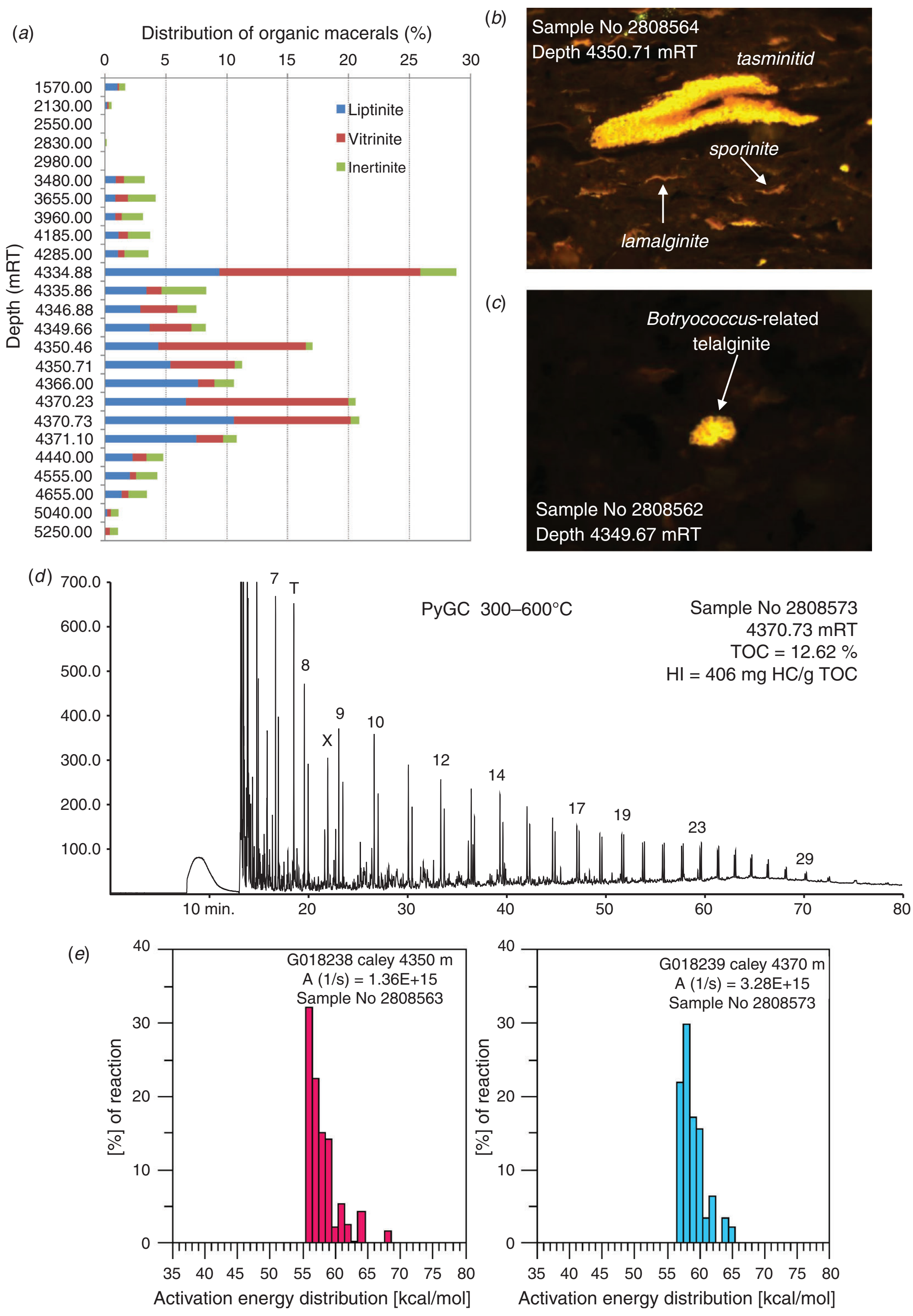

Fig. 3. (*a*) Distribution of organic macerals in % of abundance in Roc 2 source rocks. (*b*) Photomicrograph of sample 2808564 (4350.71 mRT) in blue light excitation showing lamalginite, *tasmanitids* and sporinite. (*c*) Photomicrograph of sample 2808562 (4349.67 mRT) in blue light excitation *Botryococcus*-related telalginite. (*d*) Pyrolysis gas chromatogram of Caley Member kerogen 2808573 (4370.73 mRT). Doublets of *n*-alkenes/*n*-alkanes are indicated by their carbon number. T = toluene; X = meta-plus para-xylene. (*e*) Activation energy distributions of samples 2808563 (4350.46 mRT) and 2808573 (4370.73 mRT) based on heating rates 0.7, 2.0, 5.0 and 15.0 K/min.

(Rollet *et al.* 2019). Caley Member source rocks from the Roc 2 well are too immature to have generated the Phoenix South 1 and Roc 1–2 fluids but exhibit carbon isotopic ratios and biomarker distributions correlating broadly with those of the fluids. Sedimentary packages between TR10.0_SB and TR16.0_SB extend to the northwest of the Phoenix South and Roc wells, where they are anticipated to reside in fully mature generative kitchens and provide the effective source of the recovered fluids. The difference in thermal maturity between the Phoenix South 1 oil reservoired in the Barret Member (VREQ-5 = 0.98%) and the Roc 1–2 condensates (mean VREQ-5 = 1.16%) in the deeper Caley Member reservoir suggests derivation from discrete source pods of similar character but of different thermal maturities with the occurrence of stacked source/reservoir pairs separated by intraformational seals (Thompson 2020). This scenario is supported by the presence of a regionally continuous, fine-grained Hove Member providing a top and lateral seal to the Roc and Phoenix South discoveries (Thompson 2020).

The finding of both oil and rich gas condensates in wells of the greater Phoenix area is consistent with hydrogen-rich source rocks of D/E facies. Significantly, D/E sourced fluids are the most susceptible to phase separation as the generation window is close to saturation pressure, which can lead to dual-phase (oil and gas) accumulations (He and Murray 2019). The fluid phase is also controlled by processes such as spill-fill, leakage and in-reservoir alteration (Murray and He 2020). The Phoenix South 1 oil accumulation is undersaturated with respect to gas, which suggests that loss of gas has enriched the remaining fluid in heavy hydrocarbons resulting in the formation of oil. Supplementary work on the Dorado fluids will further improve the understanding of this significant new petroleum system on the NWS of Australia.

Conflicts of interest

All authors confirm there are no conflicts of interest.

Declaration of funding

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