

Geochemical evaluation of produced petroleum from the Middle Permian Lucaogou reservoirs Junggar Basin and its implication for the unconventional shale oil play

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ABSTRACT

The shale of the Middle Permian Lucaogou Formation in the Jimusaer Sag has become one of the most important prospects for unconventional shale oil production in China. The Lucaogou Formation develops two sweet spots, the upper ($P_{2l_2}^{2-2}$) and lower ($P_{2l_1}^{2-2}$) sweet spots, which are not more than 150 m apart. Interestingly, oils produced from the lower sweet spots have higher densities and viscosities than those in the upper sweet spots. Meanwhile, these high-viscosity oils have brought technical challenges to shale oil production. In this paper, geochemical data from 78 source rock solvent extracts and 17 oil samples from various depths were employed to elucidate unconventional petroleum systems and the reason for high viscosities. The source rocks of the Lucaogou Formation are good to excellent, primarily type II and II-III kerogens, and are now in the early-peak oil window. Oils produced from the $P_{2l_1}^{2-2}$ interval are characterized by abundant polar compounds, which are derived from the $P_{2l_1}^{2-2}$ and $P_{2l_1}^{1-1}$ intervals source rocks with relatively high marine sources contribution. Oils in the $P_{2l_2}^{2-2}$ interval are generated from the $P_{2l_2}^{2-2}$ interval source rocks with relatively high terrigenous-marine sources contribution. Terpane biomarker ratios indicate all oil samples are derived from lacustrine source rocks. The distributions of terpanes and steranes in these samples are similar, with high quantities of C_{29} steranes and low amounts of diasteranes. Migration from sources to reservoirs in the Lucaogou shale oil systems is short-distance given thermal maturity considerations. All oil samples have experienced slight biodegradation (PM level 1–2) at most. The sources and thermal maturities are the primary reasons for the high viscosities of the crude oils produced from the $P_{2l_1}^{2-2}$ interval. This research also indicates the Lucaogou shale petroleum system could be divided into two subsystems, and the production of different unconventional petroleum subsystems requires different strategies.

1. Introduction

The shale oil resource system is an organic-rich mudstone unit, and the oil produced by it remains in the organic-rich interval or migrates to the adjacent organic-poor interval (Jarvie, 2012). Shale oil was difficult to exploit in the past due to the limitation of exploration and development technology, but now it is getting more and more attention with the advancement of technology and is an important replacement field for hydrocarbon exploration in the 21st century. According to data released by China National Petroleum Corporation (CNPC) in 2016, China has a

huge potential for shale oil resources, with roughly 14.5 billion tons of recoverable resources (Zou et al., 2020). In contrast to the successfully commercialized marine shale series in the United States, China's continental shale oil has the characteristics of low maturity ($R_o = 0.5\text{--}1.1\%$), high density ($\rho = 0.78\text{--}0.93 \text{ g/cm}^3$), high wax content ($10\%\leq$) and poor mobility ($GOR = 20\text{--}60 \text{ m}^3/\text{m}^3$) (Yang et al., 2015; Li et al., 2019; Zhao et al., 2020). Besides, shale oil in China is still in its primary developmental stage and is fraught with various unresolved challenges. As the consequences of high-frequency climatic variability, shale oil migration and accumulation processes within lacustrine

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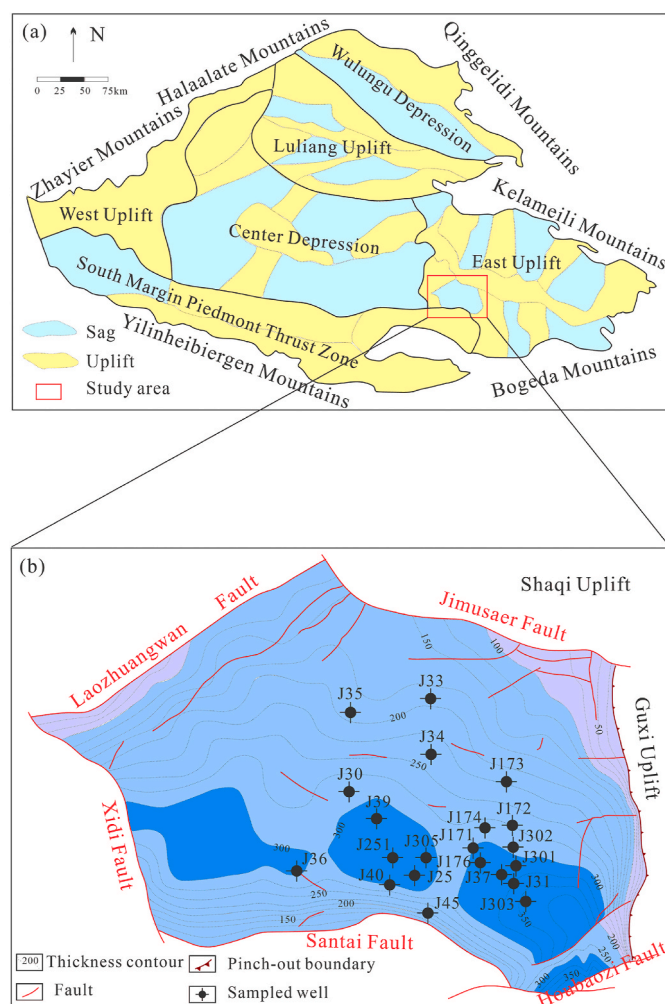


Fig. 1. Location map of the sampling wells of the Lucaogou Formation. (a) Jimusaer Sag's location in the Junggar Basin; (b) thickness contour distribution and sampling well sites for the Lucaogou Formation in the Jimusaer Sag (revised from B. Wu et al., 2019a, 2019b).

systems are more complex than the marine counterpart (Katz and Lin, 2014).

The Jimusaer Sag, located in the southeastern Junggar Basin, northwestern China, is one of the most petroliferous petroleum provinces in the Junggar Basin. It has become one of China's most significant shale oil exploration and development locations, where shale oil reserves exceed 1.112 billion tons (Du et al., 2019; Li and Zhu, 2020). Commercial oil flows have been discovered in the Jimusaer Sag's Middle Permian Lucaogou Formation. Interestingly, oils extracted from the deep Lucaogou Formation (the P_{2l1}^2 interval) have higher densities and viscosities than those in the shallow Lucaogou Formation (the P_{2l2}^2 interval) (Li et al., 2020; Wang et al., 2021). Although the nature/type and maturity of organic matter in source rocks are the main controlling factors for oil physical properties during oil generation and expulsion (Tissot and Welte, 1984), other secondary alterations may also subsequently change them during migration and within the reservoirs (Rowland et al., 1986). The most significant of these is biodegradation. Microorganisms preferentially consume n-alkanes during biodegradation, resulting in crude oil qualities deterioration (Peters and Moldowan, 1991; Larter et al., 2003; Jones et al., 2008). Since biodegradable organisms usually live maximum at temperatures around 80 °C, oil in shallower reservoirs is often more susceptible to biodegradation than oil in deeper reservoirs (Wenger et al., 2001; Larter et al., 2006). However, the temperature of the deep Lucaogou Formation has exceeded 80 °C.

Therefore, biodegradation may not be the main cause, and there should be other reasons for this unusual phenomenon here. Based on organic petrology observations, Wang et al. (2021) attributed the occurrence of high-viscosity crude oil to the blooming of green algae (telalginite). Besides, the higher viscosity has negative economic impacts on wellhead prices because of the need to use special development strategies (Huo et al., 2019).

This study will focus on the Lucaogou Formation in the Jimusaer Sag. The goal of this paper is to fully understand the unconventional petroleum systems and the cause of high viscosities, not only from the source rock perspective, but also from detailed geochemical analysis of the produced oil. Such research may also be able to guide production in the Jimusaer Sag.

2. Geological setting

The Junggar Basin is a representative intracontinental superimposed basin in China, located at the junction of the Kazakhstan plate, the Siberian plate and the Tarim plates. The Jimusaer Sag is a minor structural unit in the Junggar Basin's southeastern region, covering approximately 1300 km² (Fig. 1a; Kuang et al., 2012; Cao et al., 2017). The sag is a dustpan-shaped sag that gradually rises from west to east, bounded by faults in the north, west and south, respectively. It is bounded to the southwest and northwest by the Xidi Fault and Laozhuangwan Fault, to the south by the Santai Fault and the north by the Jimusaer Fault (Fig. 1b; Xi et al., 2015; Bai et al., 2017). Several tectonic events including Hercynian, Indosinian, Yanshan, and Himalayan movements have occurred in the sag. Among them, the Cenozoic Himalayan movement controlled the current structural pattern (Fang et al., 2007; Wu et al., 2013). Despite the fact that the sag has been subjected to several periods of tectonic movement, the stratigraphic dip in the sag ranges from 3° to 5°, and there are no large-scale faults (Zhi et al., 2019).

The Jimusaer Sag is filled by Permian to Quaternary sedimentary succession underlain by Middle Carboniferous basement and the maximum thickness of the strata exceeds 5000m in the west (Zhi et al., 2019). The Lucaogou Formation is distributed throughout the sag, with an average thickness of 200–350 m, which is consistent with the overall structural morphology of the sag. It was developed in a saline lacustrine setting and consists of fine-grained mixed sedimentary succession, including mudstones, siltstones, sandstones and carbonates (Wu et al., 2016). Based on third-order cycles and lithological variations, the formation would be further subdivided into the P_{2l1}^2 , P_{2l1}^1 , P_{2l2}^2 and P_{2l2}^1 intervals from base to top (Fig. 2; Zhang et al., 2019a, 2019b). The petrophysical characteristics indicate that high porosity and high permeability reservoirs are developed in the upper (P_{2l2}^2) and lower (P_{2l1}^2) sweet spots. Specifically, the sedimentary rocks of the upper sweet spot were deposited in the shore lacustrine and beach bar environments, covering approx. 400 km² and ranging in thickness from 0 to 45 m; the sedimentary rocks of the lower sweet spot were developed in the shallow and semi-deep to deep lacustrine settings, covering approx. 1275 km² and ranging in thickness from 0 to 65 m; Based on the actual oil production data available, these sweet spots are the major shale oil exploration and production prospects in this region (Guo et al., 2019; Wang et al., 2020).

Previous research has revealed that high-quality source rocks of grey-black and dolomitic mudstone are distributed throughout the Lucaogou Formation. The source rock contains high levels of total organic content (0.65–15.51 wt%), which is oil-prone (mainly type I and II kerogens) and has reached peak oil-generation stage (Cao et al., 2016). The upper and lower sweet spots in the sag are the primary contributors to commercial oil flow. The oil physical properties of the Lucaogou Formation generally exhibit higher density, freezing point and viscosity. Basin modeling suggests that the Lucaogou Formation entered the oil generation stage at the end of the Jurassic, and reached its peak oil-generation stage from the Cretaceous to the present (Lai et al., 2016). This continuous charging process is favorable to the accumulation of

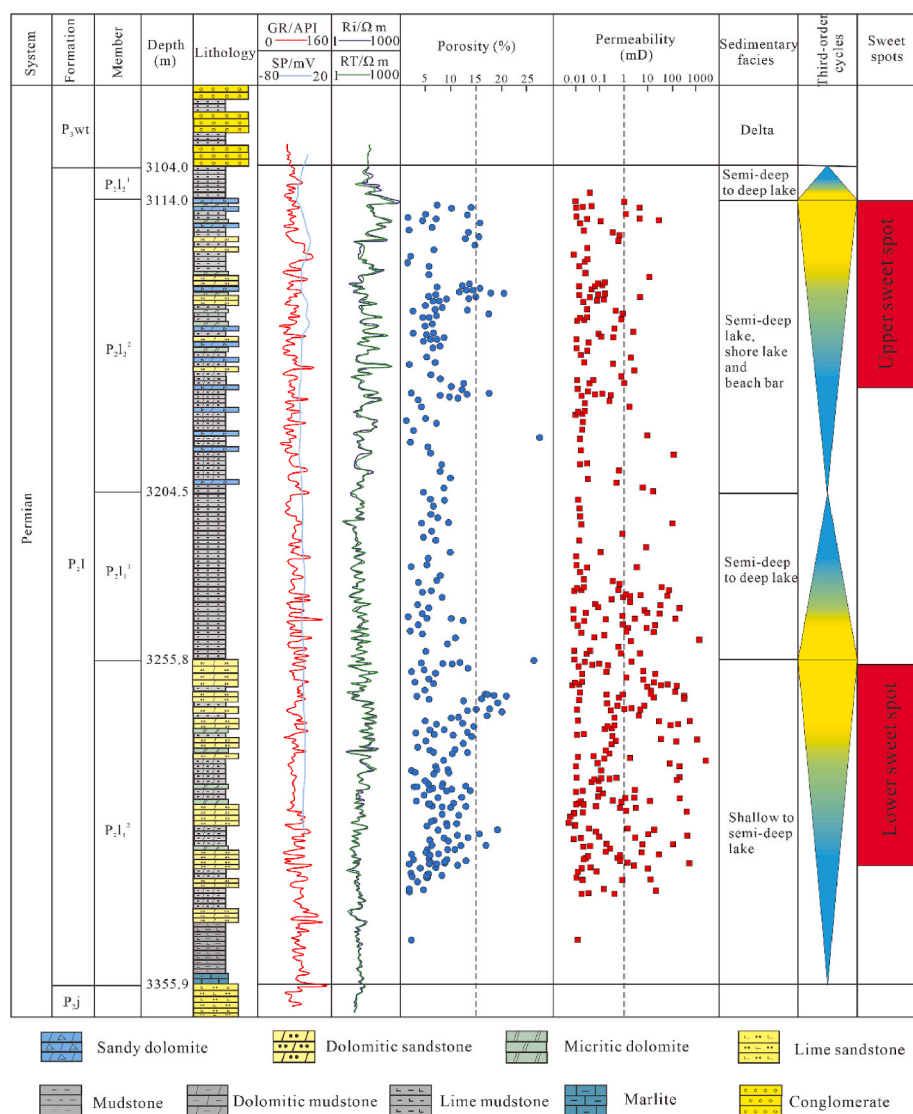


Fig. 2. The Lucaogou Formation stratigraphic column diagram in the Jimusaer Sag (according to Wu et al., 2016).

shale oil.

3. Methods

3.1. Samples and separation

In the Jimusaer Sag, 78 core samples and 17 crude oil samples were obtained from 21 wells. The lithology of these core samples is mainly dark mudstone and shale. The detailed locations of these samples are shown in Fig. 1b. Furthermore, these core samples and oil samples used for systematic analysis come from different intervals, including P_{2l1}^2 , P_{2l1}^1 and P_{2l2}^2 (Tables 1 and 2).

These core samples were ground into 100 mesh particle size before being extracted in a Soxhlet device for 72 h using a dichloromethane/methanol combination (93:7). The asphaltenes were removed by precipitation in petroleum ether. Using column chromatography, all deasphalted extracts were separated into saturated hydrocarbons, aromatic hydrocarbons, and resins (2g alumina and 3g silica gel). The elution solvents were petroleum ether, dichloromethane: petroleum ether (2:1) and dichloromethane: methanol (93:7), respectively. Simultaneously, a tiny sample of powder after extraction was tested for TOC and Rock-Eval pyrolysis using conventional analytical methods. The physical properties of crude oil, including density, viscosity, freezing point, and wax

content, are offered by the PetroChina Xinjiang Oilfield Company.

3.2. Petrographic analysis

For maceral characterization and composition analyses, polished sections were prepared of selected samples mounted in epoxy. The organic petrological analysis was conducted on a Leica microscope with a 50-x oil immersion objective utilizing reflected light. The mean random reflectance was determined with an oil immersion lens and a Leica microscope equipped with a CRAIC Microscope photometer. The measured reflectance values were calibrated with standards of known reflectance (Saphir, $R_o = 0.589\%$, Gadolinium-gallium-garnet, $R_o = 1.725\%$). In this research, the R_o of some samples was measured (Table 1).

3.3. GC-MS

Agilent 7890-5975c gas chromatograph-mass spectrometer was used to analyze the saturated fractions. The detecting environments were as follows: HP-5MS quartz capillary column (30 m × 0.25 mm) with a 0.25-μm coat; helium was employed as the carrier at a linear velocity of 1 mL/min; the GC oven temperature was first kept at 50 °C for 1min, then programmed from 50 °C to 310 °C at a rate of 3 °C/min, and

Table 1

TOC, Rock-Eval pyrolysis, R_o and bulk compositions of source rock samples.

Well	Depth (m)	Member	TOC (%)	S_1 (mg/g)	S_2 (mg/g)	$S_1 + S_2$ (mg/g)	HI (mg/g. TOC)	T_{max}	R_o (%)	Sat/%	Aro/%	Res/%	Asp/%	Sat/Aro
J31	2712.9	$P_21_2^2$	6.44	0.06	29.02	29.08	451	450	0.74	44.42	19.33	28.39	7.86	2.30
J31	2717.0	$P_21_2^2$	1.49	0.01	2.78	2.79	187	442		61.52	16.01	20.23	2.25	3.84
J31	2720.7	$P_21_2^2$	3.79	0.07	10.41	10.48	275	442	0.74	44.01	18.86	31.74	5.39	2.33
J31	2725.5	$P_21_2^2$	2.24	0.09	2.99	3.08	134	442		58.91	15.23	24.14	1.72	3.87
J174	3110.9	$P_21_2^2$	3.55	0.66	8.35	9.01	235	448		50.54	17.22	30.87	1.37	2.94
J174	3117.8	$P_21_2^2$	5.57	0.53	22.48	23.01	404	449	0.78	37.83	26.35	32.77	3.04	1.44
J174	3122.1	$P_21_2^2$	2.84	0.49	8.85	9.34	312	448		62.53	15.78	20.00	1.69	3.96
J174	3122.6	$P_21_2^2$	3.96	0.33	17.32	17.65	437	450	0.87	49.34	14.48	31.91	4.28	3.41
J174	3145.4	$P_21_2^2$	3.73	0.47	24.99	25.46	670	452	0.87	28.00	16.00	51.69	4.31	1.75
J174	3146.2	$P_21_2^2$	1.88	0.25	3.11	3.36	165	445	0.80	54.81	12.30	30.21	2.68	4.46
J174	3150.2	$P_21_2^2$	2.48	0.64	3.20	3.84	129	448	0.88	74.56	8.19	16.67	0.59	9.11
J174	3162.0	$P_21_2^2$	3.22	0.17	10.76	10.93	334	453	0.84	47.44	14.21	36.36	1.99	3.34
J174	3177.6	$P_21_2^2$	3.39	0.21	7.80	8.01	230	455	0.83	56.44	9.20	30.37	3.99	6.13
J174	3183.8	$P_21_2^2$	3.85	0.22	7.85	8.07	204	452	0.87	44.75	11.18	39.33	4.74	4.00
J174	3188.6	$P_21_2^2$	2.92	0.36	7.18	7.54	246	449	0.89	55.81	11.34	30.81	2.04	4.92
J174	3196.3	$P_21_2^2$	6.99	0.32	32.23	32.55	461	452	0.89	52.94	13.53	30.29	3.24	3.91
J251	3601.2	$P_21_2^2$	0.94	0.04	2.74	2.78	290	437		61.96	14.14	22.36	1.54	4.38
J251	3604.0	$P_21_2^2$	3.24	0.02	11.19	11.21	345	447		51.94	26.57	20.00	1.49	1.96
J251	3605.1	$P_21_2^2$	0.98	0.01	1.26	1.27	129	443		60.60	20.94	17.08	1.38	2.89
J251	3608.7	$P_21_2^2$	0.96	0.01	0.61	0.62	64	442		54.57	19.51	24.70	1.22	2.80
J251	3613.7	$P_21_2^2$	1.19	0.03	2.03	2.06	171	440		56.98	15.40	26.46	1.16	3.70
J251	3618.9	$P_21_2^2$	0.99	0.03	1.15	1.18	116	438		55.30	17.94	24.71	2.05	3.08
J251	3630.7	$P_21_2^2$	1.26	0.02	1.58	1.60	126	445		54.01	18.01	26.32	1.66	3.00
J251	3631.3	$P_21_2^2$	3.30	4.59	10.41	15.00	315	443		58.94	16.53	21.87	2.66	3.56
J34	3672.6	$P_21_2^2$	12.27	0.37	74.53	74.90	607	448		20.27	19.45	50.14	10.14	1.04
J30	4045.9	$P_21_2^2$	1.97	0.03	1.30	1.33	66	451		51.48	17.86	26.79	3.87	2.88
J30	4047.2	$P_21_2^2$	0.46	0.01	0.90	0.91	196	445		69.84	10.59	13.49	6.08	6.60
J30	4052.3	$P_21_2^2$	0.85	0.02	1.81	1.83	214	443		74.32	10.27	13.29	2.12	7.24
J36	4131.8	$P_21_2^2$	10.47	1.78	42.63	44.41	407	446		55.62	20.71	20.12	3.55	2.69
J36	4132.4	$P_21_2^2$	0.77	0.03	1.21	1.24	156	448		71.52	15.73	12.17	0.59	4.55
J36	4136.9	$P_21_2^2$	5.69	0.09	39.01	39.10	686	443		49.84	12.77	24.92	12.47	3.90
J36	4137.6	$P_21_2^2$	3.62	0.78	16.77	17.55	464	450		63.53	14.82	21.09	0.57	4.29
J36	4192.0	$P_21_2^2$	9.12	0.85	38.37	39.22	421	449		45.21	22.15	30.84	1.80	2.04
J31	2851.7	$P_21_1^1$	2.25	0.06	9.97	10.03	443	443	0.75	19.88	16.91	49.56	13.65	1.18
J31	2863.6	$P_21_1^1$	1.92	0.07	6.87	6.94	357	440		37.50	17.18	41.56	3.75	2.18
J174	3216.7	$P_21_1^1$	1.08	0.29	1.03	1.32	95	446		59.36	8.89	28.26	3.49	6.68
J174	3218.0	$P_21_1^1$	2.05	0.36	4.60	4.96	224	447	0.87	37.42	14.72	45.40	2.46	2.54
J174	3223.2	$P_21_1^1$	1.88	1.31	2.53	3.84	135	441	0.87	52.83	12.15	33.33	1.69	4.35
J174	3224.3	$P_21_1^1$	7.93	1.17	44.66	45.83	563	449	0.91	34.34	14.01	42.03	9.62	2.45
J174	3227.1	$P_21_1^1$	3.23	1.09	6.98	8.07	216	447	0.86	41.85	15.17	36.80	6.18	2.76
J174	3237.8	$P_21_1^1$	6.44	0.61	28.16	28.77	437	448	0.87	13.34	10.30	71.82	4.54	1.29
J251	3733.0	$P_21_1^1$	3.33	0.63	8.46	9.09	254	445		47.48	19.81	29.24	3.46	2.40
J34	3781.6	$P_21_1^1$	8.60	0.11	50.79	50.90	590	448		13.67	12.33	49.67	24.33	1.11
J34	3783.2	$P_21_1^1$	1.38	0.17	5.79	5.96	420	441		43.55	18.91	32.09	5.45	2.30
J34	3784.5	$P_21_1^1$	0.99	0.03	1.79	1.82	180	443		52.15	18.63	26.07	3.15	2.80
J30	4147.0	$P_21_1^1$	1.23	0.02	0.61	0.63	49	448		50.87	20.81	26.30	2.02	2.44
J30	4153.6	$P_21_1^1$	0.91	0.04	0.84	0.88	93	446		62.33	16.07	19.39	2.22	3.88
J36	4211.4	$P_21_1^1$	2.81	0.44	10.14	10.58	361	448		61.29	16.10	21.98	0.62	3.81
J36	4213.2	$P_21_1^1$	1.57	0.04	2.83	2.87	180	448		61.42	14.19	23.46	0.93	4.33
J36	4217.9	$P_21_1^1$	1.67	0.05	6.25	6.30	374	441		50.47	13.79	34.49	1.25	3.66
J36	4228.5	$P_21_1^1$	6.34	0.42	37.47	37.89	591	448		46.13	20.17	32.60	1.10	2.29
J31	2897.3	$P_21_2^2$	0.63	0.05	1.31	1.36	208	441		51.59	15.66	27.82	4.93	3.30
J174	3264.2	$P_21_1^2$	8.35	1.40	35.64	37.04	427	450	0.91	23.98	13.90	53.95	8.17	1.72
J174	3286.7	$P_21_1^2$	8.16	1.16	39.94	41.10	489	446	0.85	21.11	12.03	44.28	22.58	1.76
J174	3298.6	$P_21_1^2$	3.97	1.93	12.05	13.98	304	447	0.87	31.05	16.58	49.21	3.16	1.87
J174	3302.7	$P_21_1^2$	0.97	0.34	0.94	1.28	97	445	0.89	38.42	15.82	43.78	1.98	2.43
J174	3309.4	$P_21_1^2$	3.76	0.39	16.24	16.63	432	453	0.93	45.08	14.08	38.87	1.97	3.20
J174	3323.4	$P_21_1^2$	4.72	1.46	18.91	20.37	401	449	0.90	34.35	16.90	46.54	2.22	2.03
J174	3327.9	$P_21_1^2$	2.91	0.69	9.86	10.55	339	445	0.89	18.95	19.57	59.63	1.86	0.97
J174	3336.4	$P_21_1^2$	3.52	0.64	11.16	11.80	317	454	0.90	52.95	16.96	28.02	2.06	3.12
J251	3739.9	$P_21_1^2$	6.15	0.22	29.32	29.54	477	449	0.87	13.58	15.43	64.20	6.79	0.88
J251	3748.8	$P_21_1^2$	3.17	0.41	5.66	6.07	179	448	0.88	33.54	16.02	40.18	10.27	2.09
J251	3753.1	$P_21_1^2$	6.03	0.64	30.08	30.72	499	445	0.88	12.65	10.00	33.24	44.12	1.27
J251	3759.2	$P_21_1^2$	2.48	0.51	4.60	5.11	185	445		2.90	40.64	47.10	9.35	0.07
J251	3764.7	$P_21_1^2$	1.31	0.31	1.60	1.91	122	440		46.84	15.32	35.73	2.11	3.06
J251	3769.0	$P_21_1^2$	1.96	0.48	5.58	6.06	285	446		46.55	17.08	33.88	2.48	2.72
J251	3770.7	$P_21_1^2$	7.09	0.16	22.05	22.21	311	447		13.50	14.50	48.75	23.25	0.93
J251	3772.7	$P_21_1^2$	5.35	0.32	14.56	14.88	272	442		13.74	13.74	46.00	26.52	1.00
J251	3775.4	$P_21_1^2$	2.14	1.06	1.83	2.89	85	437		56.34	18.59	24.51	0.56	3.03
J251	3778.5	$P_21_1^2$	8.60	0.18	35.15	35.33	409	443		15.45	17.20	58.31	9.04	0.90
J251	3785.8	$P_21_1^2$	1.46	0.08	2.28	2.36	156	439		53.80	18.24	27.05	0.91	2.95
J34	3814.5	$P_21_1^2$	1.06	0.08	2.42	2.50	227	444		52.38	18.45	23.51	5.65	2.84
J35	4071.9	$P_21_1^2$	1.61	0.03	2.25	2.28	140	454		51.44	17.89	25.24	5.43	2.88

(continued on next page)

Table 1 (continued)

Well	Depth (m)	Member	TOC (%)	S ₁ (mg/g)	S ₂ (mg/g)	S ₁ + S ₂ (mg/g)	HI (mg/g TOC)	T _{max}	R _o (%)	Sat/%	Aro/%	Res/%	Asp/%	Sat/Aro
J35	4076.7	P ₂ l ₁ ²	0.54	0.03	0.65	0.68	119	444		64.98	15.73	18.70	0.59	4.13
J35	4076.8	P ₂ l ₁ ²	0.86	0.35	1.23	1.58	143	445		71.19	17.55	9.61	1.66	4.06
J35	4079.3	P ₂ l ₁ ²	6.36	0.06	20.39	20.45	320	448		31.42	19.05	26.35	23.18	1.65
J35	4083.5	P ₂ l ₁ ²	0.79	0.02	0.92	0.94	117	446		54.87	14.16	27.14	3.83	3.87
J35	4086.2	P ₂ l ₁ ²	0.65	0.05	0.56	0.61	86	445		63.58	13.27	19.76	3.39	4.79

Abbreviations: Sat refers to saturated hydrocarbons; Aro refers to aromatic hydrocarbons; Res refers to Resins; Asp refers to asphaltenes; Sat/Aro refers to saturated/aromatic hydrocarbons.

Table 2

Bulk oil properties and SARA analysis results for the oil samples.

Well	Depth (m)	Member	Density (g/cm ³)	Viscosity (mPa•s)	Freezing Point (°C)	Wax content (%)	Sat/%	Aro/%	Res/%	Asp/%	Sat/Aro
J303	2598–2604	P ₂ l ₂ ²	0.88	33.70	30.00	15.96	68.75	14.58	15.48	1.19	4.71
J301	2762–2776.5	P ₂ l ₂ ²	0.88	33.30	19.60	12.33	69.01	14.33	13.66	3.00	4.82
J37	2830–2849	P ₂ l ₂ ²	0.88	42.70	26.00	11.16	64.16	12.43	21.96	1.45	5.16
J302	2840–2845	P ₂ l ₂ ²	0.87	32.01	27.90	16.15	65.41	10.45	23.59	0.54	6.26
J302	2853–2870	P ₂ l ₂ ²	0.88	37.10	26.40	14.96	62.75	16.33	18.92	2.00	3.84
J172	2920–2970	P ₂ l ₂ ²	0.89	57.70	29.10	13.76	64.78	14.28	18.28	2.66	4.54
J176	3028–3063	P ₂ l ₂ ²	0.88	36.20	20.00	11.10	67.13	13.37	17.83	1.67	5.02
J171	3074–3102.5	P ₂ l ₂ ²	0.89	48.10	8.00	6.43	57.71	15.79	23.67	2.83	3.65
J173	3088–3109	P ₂ l ₂ ²	0.88	33.00	15.90	13.07	58.68	14.67	25.15	1.50	4.00
J174	3116–3146	P ₂ l ₂ ²	0.88	41.15	26.00	12.58	65.47	18.75	14.59	1.19	3.49
J25	3403–3425	P ₂ l ₂ ²	0.89	58.00	24.00	11.00	57.05	12.82	26.60	3.53	4.45
J45	3279–3283	P ₂ l ₁ ²	0.91	216.20	4.50	2.89	56.55	17.54	23.30	2.62	3.22
J305	3565–3588	P ₂ l ₁ ²	0.91	148.50	−3.80	3.64	55.22	18.10	22.70	3.99	3.05
J40	3579–3626	P ₂ l ₁ ²	0.92	279.90	16.10	3.65	53.29	27.68	14.54	4.50	1.93
J33	3664–3717	P ₂ l ₁ ²	0.90	76.70	3.10	4.89	50.18	18.91	22.19	8.72	2.65
J39	3982–3987	P ₂ l ₁ ²	0.90	49.93	2.40	4.97	59.94	14.51	14.20	11.36	4.13
J36	4209–4255	P ₂ l ₁ ²	0.90	71.40	−4.00	5.44	52.47	16.50	21.78	9.24	3.18

Abbreviations: Sat refers to saturated hydrocarbons; Aro refers to aromatic hydrocarbons; Res refers to Resins; Asp refers to asphaltenes; Sat/Aro refers to saturated/aromatic hydrocarbons.

isothermally maintained at 310 °C for 30min; the electron impact energy was controlled at 70 eV. The mass spectrometer was conducted in full scan and SIM modes. These compounds were identified using the standard test method for biomarkers in sediment and crude oil by GC-MS (GB/T18606-2001) (Gao et al., 2018). The parameters reported in this paper are calculated from peak areas of individual constituents.

4. Results

4.1. Geochemical characteristics of oil samples

4.1.1. Physical properties

The physical property data obtained from the 16 wellhead surface crude oil samples are presented in Fig. 3 and Table 2. The fluid properties of crude oil from the P₂l₁² and P₂l₂² intervals vary substantially. The crude oils from the P₂l₂² interval are presented by low densities (0.87–0.89 g/cm³), low viscosities (32.01–58.00 mPa s) at 50 °C, high freezing points (8.00–30.00 °C) and high wax contents (6.43–16.15%), while the oils from the P₂l₁² interval are marked by high densities (0.90–0.92 g/cm³), high viscosities (49.93–279.90 mPa s) at 50 °C, low freezing points (−4.00–16.10 °C) and low wax contents (2.89–5.44%). These highly variable physical properties have a strong correlation with depth and different intervals (Fig. 3). These phenomena reveal that these crude oils may be derived from source rocks with different depositional environments and organic matter inputs.

4.1.2. SARA analysis

Column chromatography separation results for all crude oil samples are compiled in Table 2. Table 2 obviously demonstrates that the samples from the P₂l₂² interval have comparatively high saturated hydrocarbon contents (>57%) and low resin plus asphaltene contents (15.77–30.13%), with saturated/aromatic ratios ranging from 3.49 to 6.26. Compared with the samples from the P₂l₁² interval, the bulk

compositions of the P₂l₁² interval crude oil show the opposite characteristics. Normalized these bulk compositions from the P₂l₁² interval show higher resins and asphaltenes compared to the P₂l₂² oils (Fig. 4a). The content of polar compounds (aromatics, resins plus asphaltenes) in crude oils show a tendency to gradually increase with the increase of buried depth (Fig. 4c–d), while the content of saturated hydrocarbons is the reverse (Fig. 4b).

4.1.3. Biomarker analysis

4.1.3.1. Normal alkanes and acyclic isoprenoids. The distribution of normal alkanes and acyclic isoprenoids in crude oil aliphatic fractions could be utilized to elucidate organic matter source, depositional setting, and maturity (Powell and McKirdy, 1973; Mackenzie, 1984; Tissot, 1984). It is noticed that the distributions of normal alkanes and acyclic isoprenoids of the saturated hydrocarbons in crude oils from the P₂l₁² and P₂l₂² intervals differ significantly. Compared with the P₂l₂² interval, the P₂l₁² interval is characterized by remarkably abundant acyclic isoprenoids (iC₁₄, iC₁₅, iC₁₆, iC₁₈, iC₁₉ and iC₂₀), hopanes and β-carotane (Fig. 5). The preponderance of isoprenoids implies significant photosynthetic activity, while the high concentration of n-C₁₇ in n-alkanes is due to algal input (Gibert et al., 1975; Afonso et al., 1994). The high carotanes abundance in the Lucaogou Formation is associated with the development of photosynthetic cyanobacteria (Jiang and Fowler, 1986; Ding et al., 2020). These biomarker assemblages reveal that the crude oils from the P₂l₁² interval originate from hydrocarbon rocks which are deposited in an evaporitic, restricted and shallow lacustrine environment.

The pristane/phytane (Pr/Ph) ratio has been developed to determine organic matter's redox conditions and depositional settings (Didyk et al., 1978). The Pr/Ph values of these crude oils are between 1.08 and 1.58 (Table 3), with greater values in the P₂l₂² interval (1.13–1.58) than in the P₂l₁² interval (1.08–1.24). The scatter plot between Pr/n-C₁₇ and

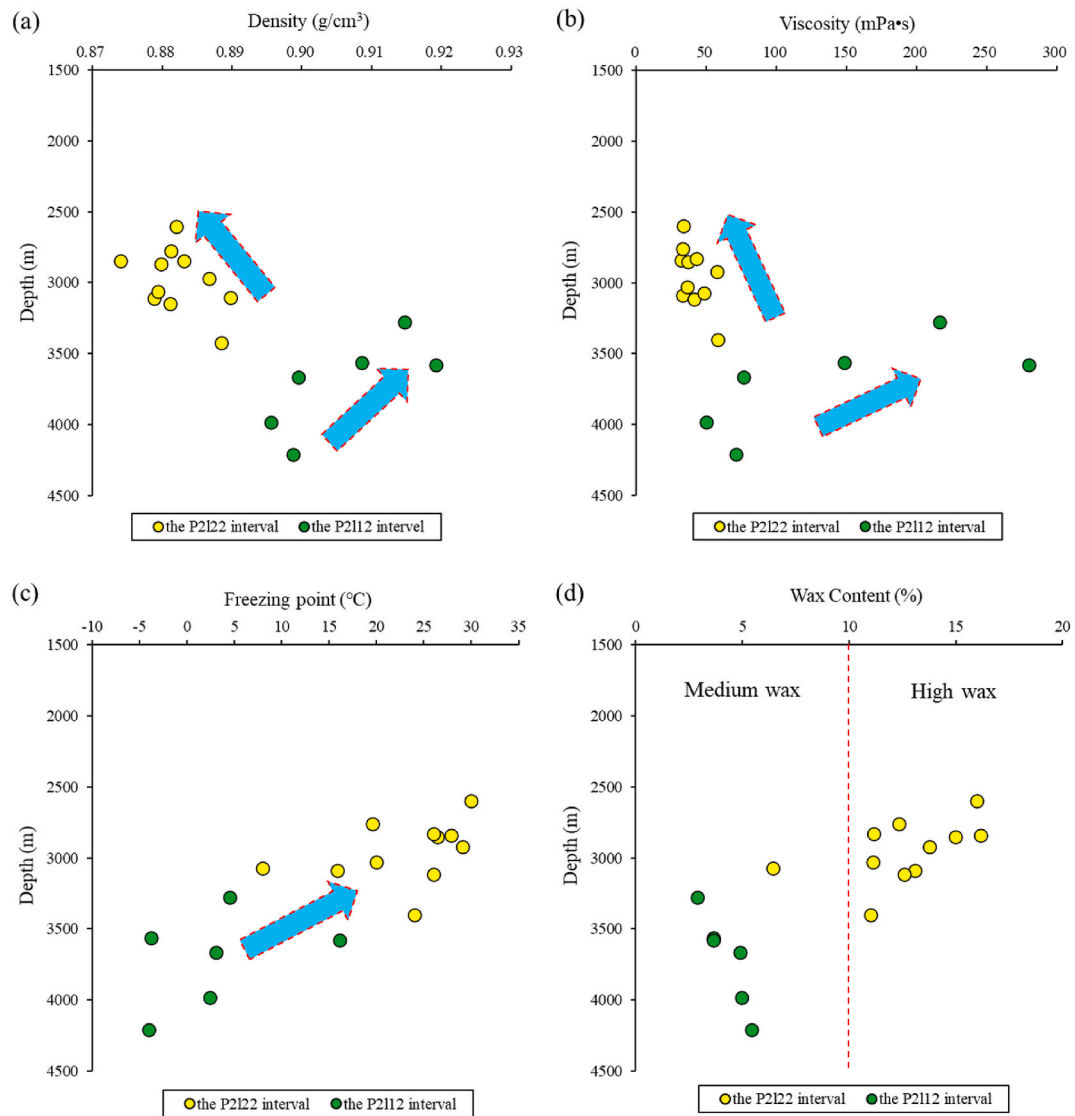


Fig. 3. Relationships between depth and bulk oil properties in studied oils. (a) Density versus depth; (b) viscosity versus depth; (c) freezing point versus depth; (d) wax content versus depth.

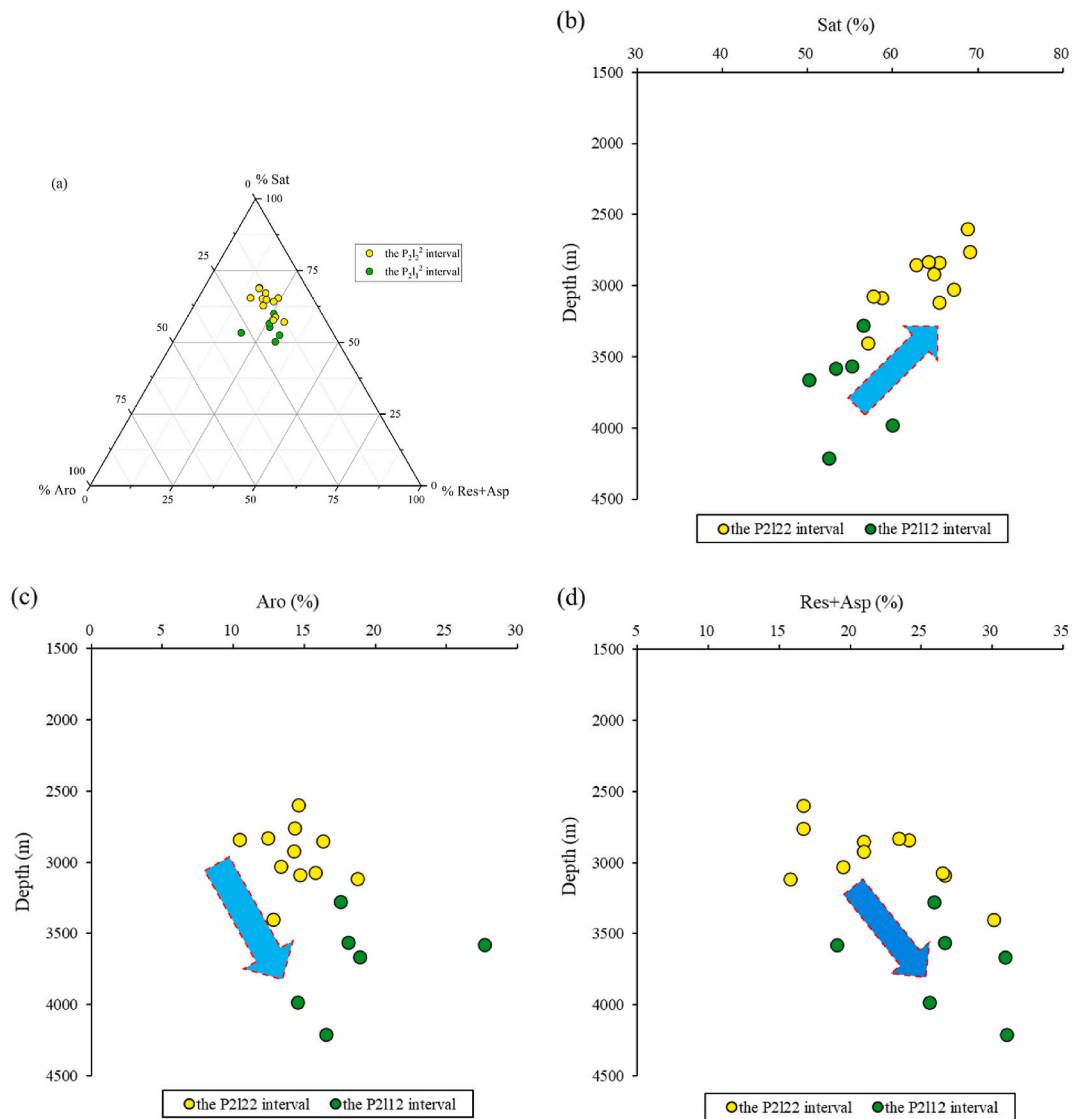


Fig. 4. SARA analysis results for studied oil samples. (a) Ternary plot of normalized SARA results for oils; (b) Sat versus depth; (c) Aro versus depth; (d) Resin + Asp versus depth. Sat refers to saturated hydrocarbons; Aro refers to aromatic hydrocarbons; Res + Asp refers to resins plus asphaltenes.

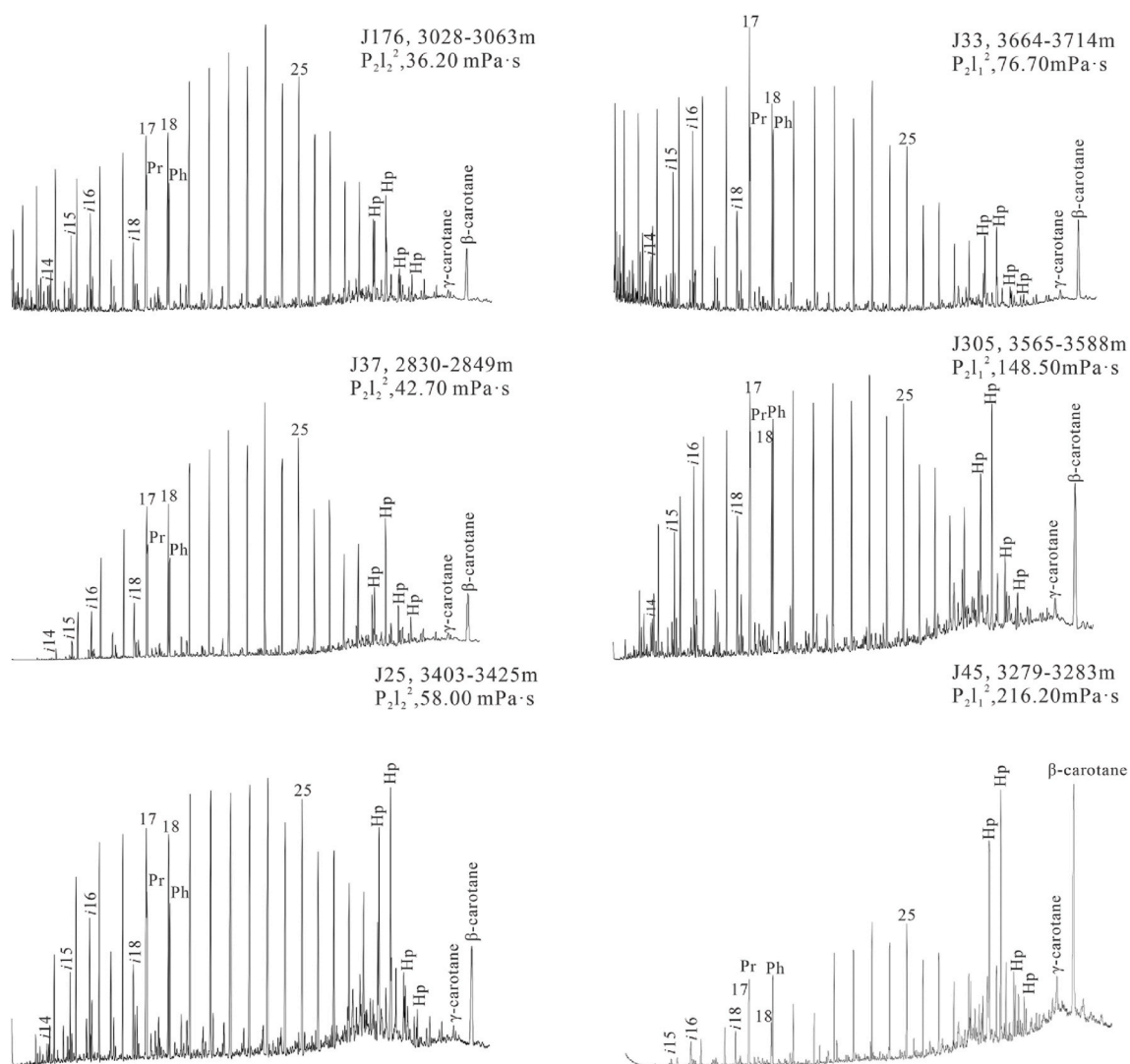


Fig. 5. Representative gas chromatograms of saturated hydrocarbons for oil samples. *i*14-*i*18 = C_{14} ~ C_{18} acyclic isoprenoids; Pr = pristane; Ph = phytane; 17, 18, 25 = C_{17} , C_{18} and C_{25} normal alkanes; Hp = hopanes.

Table 3

List of biomarker parameters for oil samples from different intervals.

Well	Depth (m)	Member	Pr/ <i>n</i> -C ₁₇	Ph/ <i>n</i> -C ₁₈	TAR	Pr/Ph	CPI	OEP	β-carotane/ C _{max}	IAI	C ₂₂ / C ₂₁ TT	C ₂₄ / C ₂₃ TT	C ₂₆ / C ₂₅ TT	C ₃₁ R/ C ₃₀ H
J303	2598–2604	P ₂ l ₂ ²	1.37	0.89	1.18	1.58	1.37	1.28	30.11	1.01	0.12	0.43	1.84	0.12
J301	2762–2776.5	P ₂ l ₂ ²	1.15	0.86	0.72	1.42	1.33	1.23	36.66	0.87	0.15	0.44	1.90	0.14
J37	2830–2849	P ₂ l ₂ ²	1.22	0.89	0.74	1.41	1.36	1.24	36.67	0.91	0.13	0.44	2.44	0.15
J302	2840–2845	P ₂ l ₂ ²	1.07	0.71	0.70	1.55	1.37	1.24	23.26	0.79	0.05	0.35	1.64	0.10
J302	2853–2870	P ₂ l ₂ ²	1.05	0.73	0.64	1.45	1.42	1.23	26.52	0.80	0.13	0.44	2.31	0.14
J172	2920–2970	P ₂ l ₂ ²	1.03	0.75	0.63	1.42	1.17	1.24	24.08	0.78	0.15	0.38	2.21	0.15
J176	3028–3063	P ₂ l ₂ ²	0.89	0.75	0.54	1.28	1.30	1.18	32.93	0.75	0.15	0.46	2.30	0.18
J171	3074–3102.5	P ₂ l ₂ ²	1.04	0.97	0.57	1.24	1.09	1.20	52.51	0.86	0.15	0.43	2.32	0.16
J173	3088–3109	P ₂ l ₂ ²	1.22	0.96	0.75	1.32	1.44	1.26	33.08	0.91	0.12	0.47	2.54	0.16
J174	3116–3146	P ₂ l ₂ ²	0.85	0.72	0.57	1.26	1.32	1.18	26.98	0.74	0.15	0.44	2.27	0.18
J25	3403–3425	P ₂ l ₂ ²	0.80	0.69	0.89	1.13	1.20	1.21	23.21	0.78	0.15	0.43	2.10	0.18
J45	3279–3283	P ₂ l ₁ ²	1.72	2.42	0.78	1.08	1.57	1.13	119.79	1.80	0.16	0.43	1.73	0.19
J305	3565–3588	P ₂ l ₁ ²	1.36	1.64	0.52	1.11	1.33	1.13	129.16	1.27	0.16	0.43	2.17	0.16
J40	3579–3626	P ₂ l ₁ ²	1.38	1.71	0.40	1.08	1.22	1.14	109.20	1.39	0.15	0.45	2.36	0.18
J33	3664–3717	P ₂ l ₁ ²	1.27	1.49	0.37	1.11	1.32	1.15	79.23	1.14	0.14	0.44	2.32	0.17
J39	3982–3987	P ₂ l ₁ ²	1.17	1.15	0.42	1.24	1.21	1.12	61.11	1.05	0.15	0.48	2.34	0.17
J36	4209–4255	P ₂ l ₁ ²	1.35	1.54	0.47	1.10	1.37	1.16	63.72	1.25	0.16	0.43	2.48	0.19

Well	C ₂₉ / C ₃₀ H	Ga/ C ₃₀ H	C ₃₀ M/ C ₃₀ H	20S/(20S + 20R) C ₃₂ H	C ₂₇ ST/ %	C ₂₈ ST/ %	C ₂₉ ST/ %	C ₂₉ / C ₂₈ ST	C ₂₉ / C ₂₇ ST	C ₂₉ αββ/(ααα+αββ)	C ₂₉ ααα 20S/(20S + 20R)
J303	0.43	0.16	0.18	0.56	21.28	37.87	40.85	1.08	1.92	0.26	0.39
J301	0.50	0.17	0.19	0.56	21.42	37.53	41.05	1.09	1.92	0.29	0.41
J37	0.52	0.17	0.22	0.58	21.82	33.46	44.72	1.34	2.05	0.29	0.41
J302	0.49	0.13	0.14	0.54	17.38	35.34	47.27	1.34	2.72	0.26	0.38
J302	0.53	0.16	0.21	0.56	20.15	37.06	42.79	1.15	2.12	0.26	0.40
J172	0.54	0.17	0.21	0.57	19.83	36.95	43.23	1.17	2.18	0.26	0.39
J176	0.64	0.17	0.24	0.58	18.74	34.98	46.28	1.32	2.47	0.32	0.42
J171	0.57	0.16	0.21	0.58	19.98	34.01	46.01	1.35	2.30	0.33	0.45
J173	0.53	0.18	0.22	0.56	20.83	34.06	45.11	1.32	2.17	0.25	0.37
J174	0.69	0.17	0.25	0.57	17.31	36.98	45.71	1.24	2.64	0.29	0.41
J25	0.62	0.14	0.23	0.57	16.35	38.31	45.34	1.18	2.77	0.32	0.46
J45	0.64	0.18	0.33	0.55	13.33	33.82	52.85	1.63	3.99	0.25	0.40
J305	0.64	0.16	0.24	0.58	14.19	33.82	51.99	1.45	4.34	0.30	0.45
J40	0.68	0.17	0.34	0.55	14.08	33.68	52.24	1.55	3.71	0.23	0.38
J33	0.69	0.15	0.21	0.59	14.87	34.37	50.76	1.48	3.41	0.34	0.48
J39	0.70	0.17	0.24	0.57	11.98	36.00	52.02	1.56	3.96	0.41	0.46
J36	0.66	0.21	0.23	0.59	13.45	32.87	53.68	1.54	3.66	0.35	0.45

Abbreviations: Pr/*n*-C₁₇ = pristane/*n*-heptadecane; Ph/*n*-C₁₈ = phytane/*n*-octadecane; TAR = (*n*-C₂₇+*n*-C₂₉+*n*-C₃₁)/(*n*-C₁₅+*n*-C₁₇+*n*-C₁₉) *n*-alkanes in TIC; Pr/Ph = pristane/phytane; CPI = 1/2 × [(C₂₅+C₂₇+C₂₉+C₃₁+C₃₃)/(C₂₄+C₂₆+C₂₈+C₃₀+C₃₂)+(C₂₅+C₂₇+C₂₉+C₃₁+C₃₃)/(C₂₆+C₂₈+C₃₀+C₃₂+C₃₄)] *n*-alkanes in TIC; OEP = (C₂₁+6C₂₃+C₂₅)/(4C₂₂+4C₂₄) *n*-alkanes in TIC; β-carotane/C_{max} = β-carotane/C_{max} × 100 in TIC; IAI = (*i*-C₁₅+*i*-C₁₆+*i*-C₁₈+*i*-C₁₉+*i*-C₂₀)/(*n*-C₁₃+*n*-C₁₄+*n*-C₁₆+*n*-C₁₇+*n*-C₁₈) in TIC; TT = tricyclic terpane; C₃₁R/C₃₀H = C₃₁ 22R homohopane/C₃₀αβ hopane; C₂₉/C₃₀H = C₂₉ norhopane/C₃₀ hopane; Ga/C₃₀H = gammacerane/C₃₀-hopane; C₃₀M/C₃₀H = C₃₀-moretane/C₃₀-hopane; 20S/(20S + 20R) C₃₂H = 20S/(20S + 20R) C₃₂-hopane; C₂₇ST/%, C₂₈ST/%, C₂₉ST/%; relative abundance of 20R-C₂₇, C₂₈ and C₂₉ ααα steranes; C₂₉/C₂₈ST = 20R-C₂₉ααα sterane/20R-C₂₈ααα sterane; C₂₉/C₂₇ST = 20R-C₂₉ααα sterane/20R-C₂₇ααα sterane; C₂₉ αββ/(ααα+αββ) = C₂₉ steranes αββ/(αββ+ααα); C₂₉ ααα 20S/(20S + 20R) = C₂₉ ααα steranes 20S/(20S + 20R).

Ph/*n*-C₁₈ (Fig. 6a) suggests a mixed terrigenous-marine source for the P₂l₂² interval samples and a marine source for the P₂l₁² interval samples based on the discriminant diagram of Shannmugam (1985). Terrestrial to aquatic ratios (TAR) range from 0.37 to 0.78 in the P₂l₁² interval and 0.54 to 1.18 in the P₂l₂² interval, further indicating a more terrestrial organic matter input in the P₂l₂² interval (Fig. 6b). Terrestrial plants are the primary source of odd-numbered *n*-alkanes in the C₂₇–C₃₁ range (Sass-Gustkiewicz and Kwecińska, 1994; Duan and He, 2011). High odd-to-even predominance (OEP) in the P₂l₂² interval samples also indicates enrichment in terrestrial organic matter (Fig. 6c). Oil samples show a limited range in the carbon preference index (CPI) from 1.09 to 1.57 with approximate values between the P₂l₁² interval samples (1.21–1.57) and the P₂l₂² interval samples (1.09–1.44), which is ascribed to the charging of low-maturity crude oil. Through the cross-plots of IAI versus Pr/*n*-C₁₇, IAI versus Pr/*n*-C₁₈, β-carotane/C_{max} versus IAI, it can be seen that the P₂l₁² interval samples are more enriched in isoprenoids and β-carotane (Fig. 6d–f). These data suggest significant differences in depositional redox conditions and organic matter inputs of the source of the crude oils (Fig. 6).

4.1.3.2. Terpanes. The abundance of tricyclic terpanes (TT) is lower in all crude oil samples than in the hopane (H) series, as seen in the *m/z* 191 mass chromatogram (Fig. 7). The values of C₂₂/C₂₁TT and C₂₄/

C₂₃TT have ranges of 0.05–0.16 and 0.35–0.48, respectively (Table 3). The relationship between the C₃₁R/C₃₀H ratios and the C₂₆/C₂₅TT ratios is shown in Fig. 8a, which is commonly used to differentiate marine and lacustrine crude oils (Peters et al., 2005). Fig. 8b depicts another discriminant diagram based on the ratios C₂₄/C₂₃TT and C₂₂/C₂₁TT. These diagrams illustrate that the source of crude oils from the P₂l₁² interval and the P₂l₂² interval is similar, and both are typical lacustrine crude oils. In marine and non-marine source rock depositional settings, gammacerane denotes a stratified water column, which is usually caused by hypersalinity at depth (Sinningh Damsté et al., 1995). The gammacerane index (Ga/C₃₀H) of the P₂l₁² and P₂l₂² intervals is quite low, with average values of 0.17 and 0.16, correspondingly. The ratio of C₂₉/C₃₀H is less than 1.0, indicating a siliciclastic depositional environment (Peters et al., 2005). The ratio of crude oils from the P₂l₁² interval (0.64–0.70) is generally higher than that of the P₂l₂² interval (0.43–0.69) (Table 3 and Fig. 8c). The thermal maturity of crude oils is equivalent to the maturity of its source rock at the time of expulsion, and it can be assessed indirectly through biomarker ratios. The 20S/(20S + 20R) C₃₂H ratio is quite reliable for assessing maturity through immaturity to early oil generation (Seifert et al., 1980; Mackenzie et al., 1984; Peters et al., 2005). The values of the P₂l₁² and P₂l₂² intervals are 0.55–0.59 and 0.54–0.58, respectively (Table 3), which are near to or exceed the equilibrium value (0.55–0.60), suggesting that it has reached

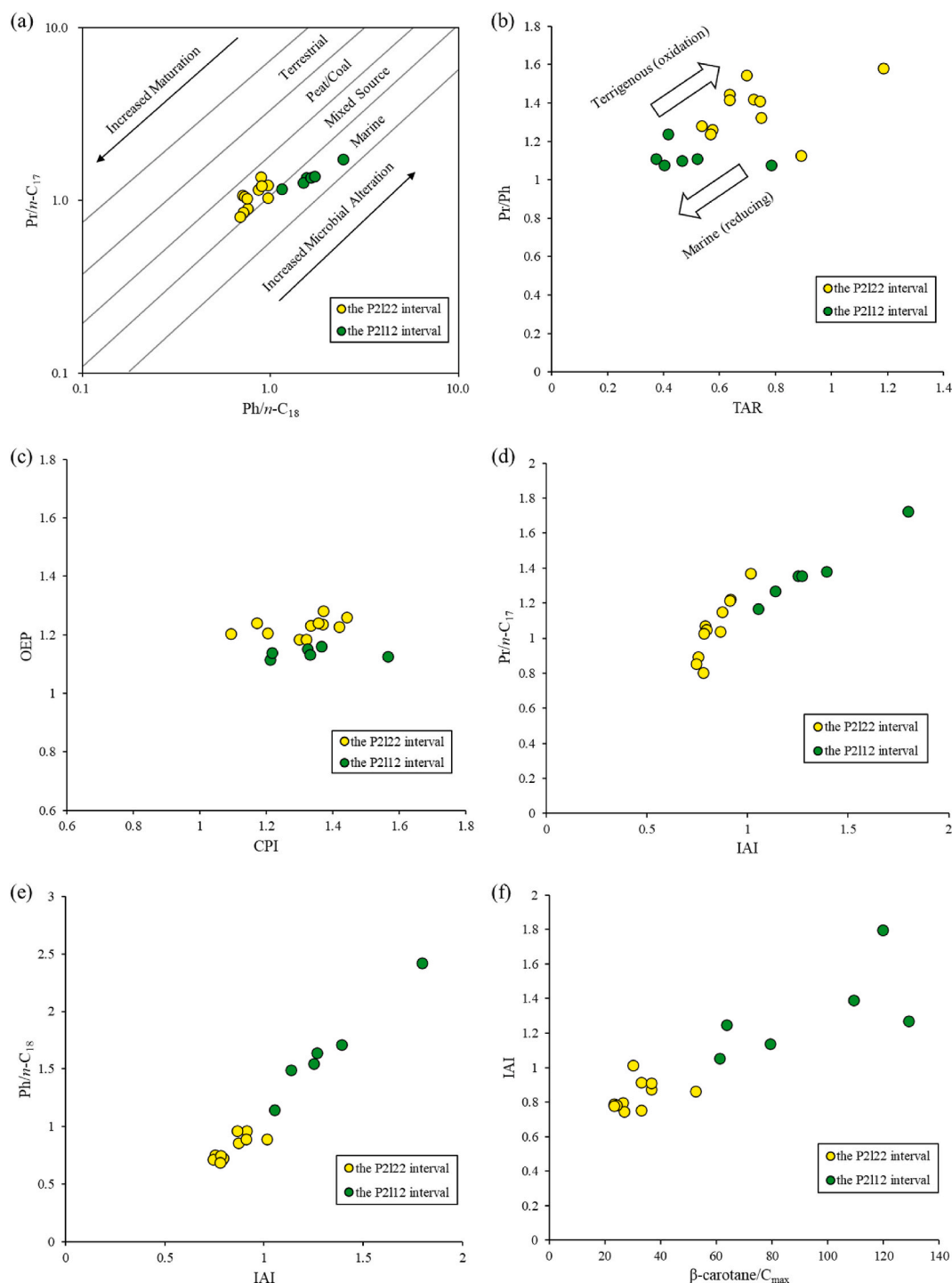


Fig. 6. Correlation between normal alkanes and acyclic isoprenoids relative abundance in crude oils. (a) $\text{Ph}/n\text{-C}_{18}$ ratios versus $\text{Pr}/n\text{-C}_{17}$ ratios; (b) Pr/Ph ratios versus TAR ratios; (c) CPI ratios versus OEP ratios; (d) IAI ratios versus $\text{Pr}/n\text{-C}_{17}$ ratios; (e) IAI ratios versus $\text{Ph}/n\text{-C}_{18}$ ratios; (f) $\beta\text{-carotane}/C_{\max}$ ratios versus IAI ratios. Abbreviations: $\text{Pr}/n\text{-C}_{17}$ = pristane/*n*-heptadecane; $\text{Ph}/n\text{-C}_{18}$ = phytane/*n*-octadecane; $\text{TAR} = (n\text{-C}_{27} + n\text{-C}_{29} + n\text{-C}_{31}) / (n\text{-C}_{15} + n\text{-C}_{17} + n\text{-C}_{19})$ *n*-alkanes in TIC; Pr/Ph = pristane/phytane; $\text{CPI} = 1/2 \times [(C_{25} + C_{27} + C_{29} + C_{31} + C_{33}) / (C_{24} + C_{26} + C_{28} + C_{30} + C_{32}) + (C_{25} + C_{27} + C_{29} + C_{31} + C_{33}) / (C_{26} + C_{28} + C_{30} + C_{32} + C_{34})]$ in TIC; $\text{OEP} = (C_{21} + 6C_{23} + C_{25}) / (4C_{22} + 4C_{24})$ in TIC; $\beta\text{-carotane}/C_{\max} = \beta\text{-carotane}/C_{\max} \times 100$ in TIC; $\text{IAI} = (i\text{-C}_{15} + i\text{-C}_{16} + i\text{-C}_{18} + i\text{-C}_{19} + i\text{-C}_{20}) / (n\text{-C}_{13} + n\text{-C}_{14} + n\text{-C}_{16} + n\text{-C}_{17} + n\text{-C}_{18})$ in TIC.

or exceeded the early oil generation stage (Table 3 and Fig. 8d). The thermal stability of moretane is less than that of hopane (Peters et al., 2005). This ratio ($C_{30}\text{M}/C_{30}\text{H}$) is near 0.8 in immature sediments and spans from 0.15 to 0.05 in mature organic matter (Seifert et al., 1979). The $C_{30}\text{M}/C_{30}\text{H}$ ratios of crude oil samples tested in the P_{21}^2 and P_{22}^2 intervals are 0.21–0.33 and 0.14–0.25, respectively, suggesting that these samples are thermally matured (Table 3 and Fig. 8d).

4.1.3.3. Steranes. The supply of organic matter influences the distribution of regular C_{27} , C_{28} , and C_{29} steranes. Previous research has revealed that C_{27} steranes are mostly produced from aquatic organisms and algae, C_{29} steranes may be derived from higher plants, and C_{28} steranes are frequently associated with phytoplankton communities such as diatoms, coccolithophores, and dinoflagellates (Huang and Meinschein, 1979; Moldowan et al., 1985). Furthermore, several

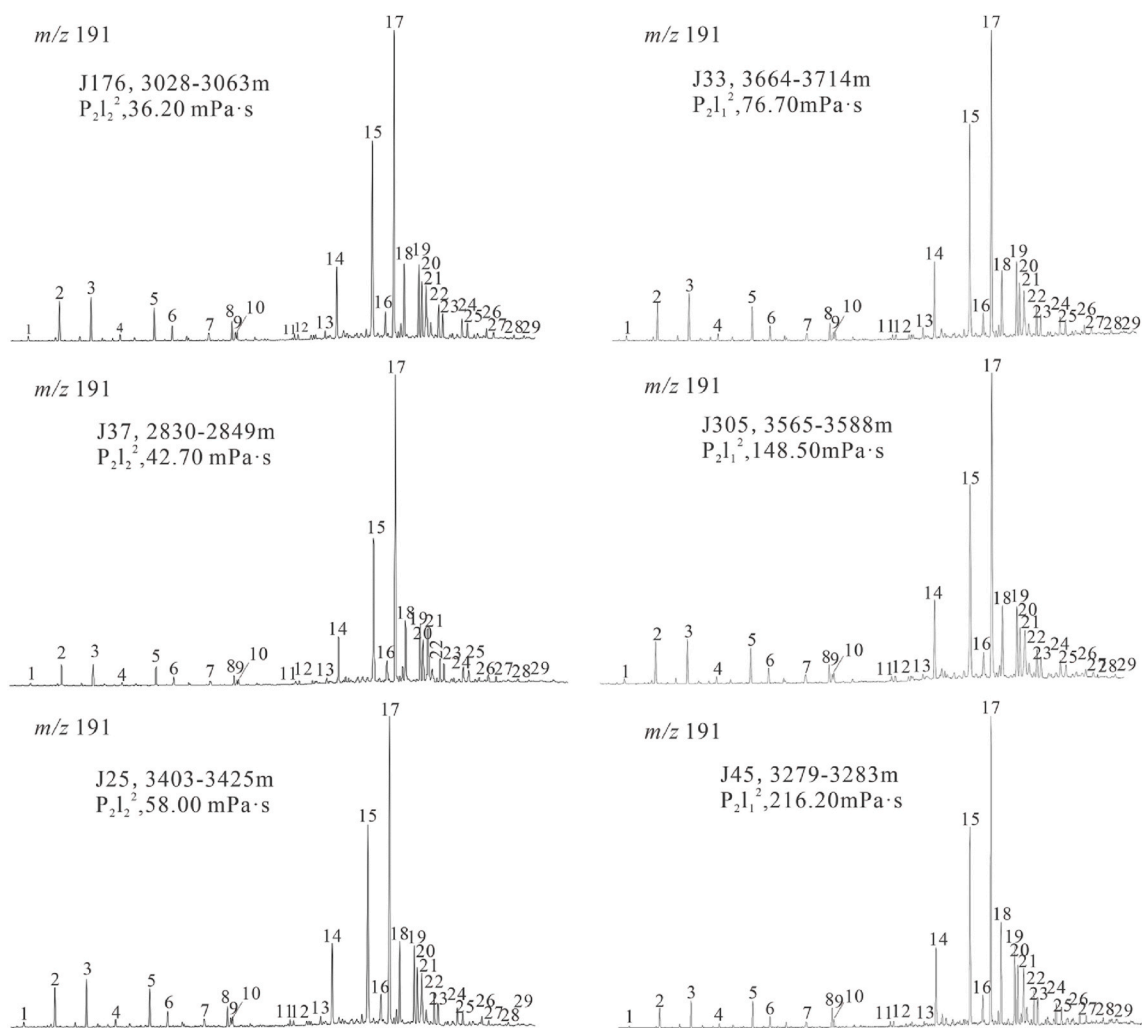


Fig. 7. Representative m/z 191 mass chromatograms illustrating the characteristics of tricyclic terpanes and hopanes in crude oil samples. Compound numbers refer to Table 4.

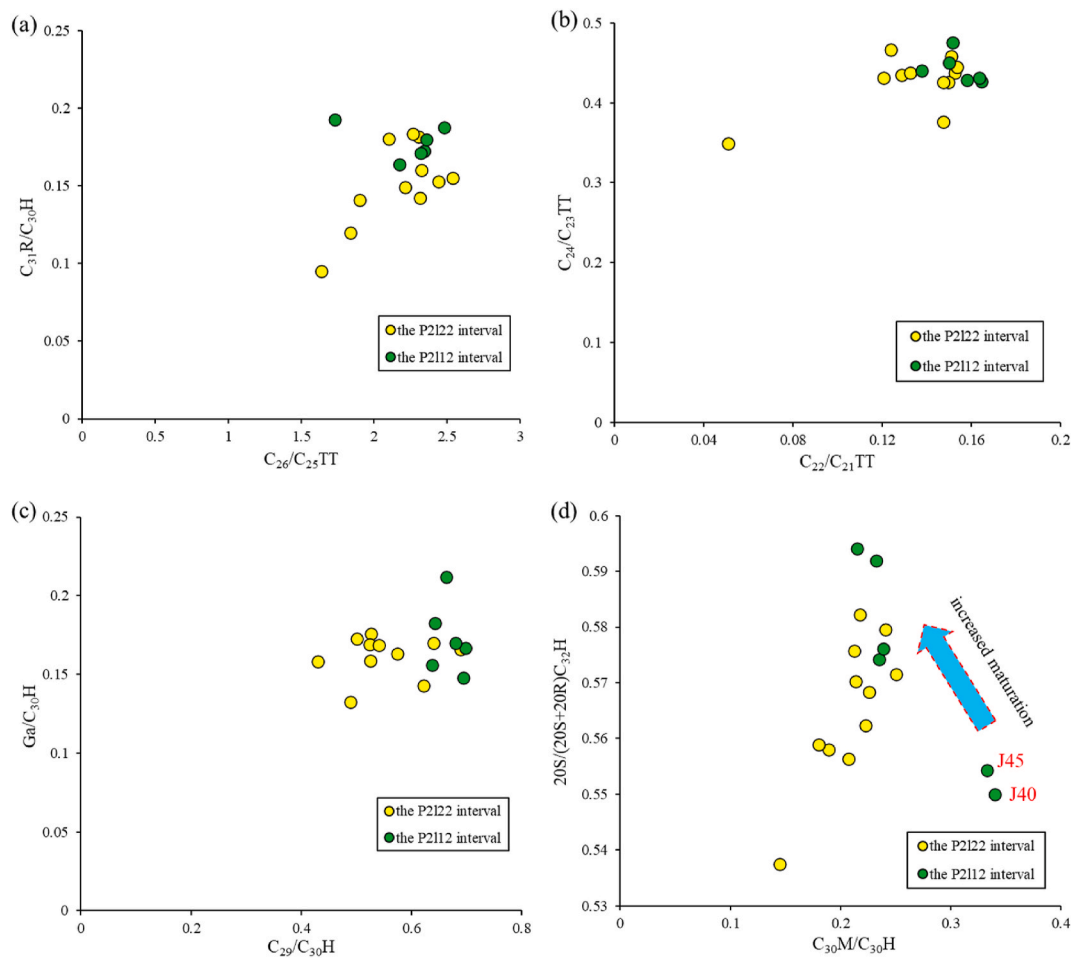


Fig. 8. Terpanes analysis results for studied oil samples. (a) $C_{26}/C_{25}TT$ versus $C_{31}R/C_{30}H$; (b) $C_{24}/C_{23}TT$ versus $C_{22}/C_{21}TT$; (c) $C_{29}/C_{30}H$ versus $Ga/C_{30}H$; (d) $C_{30}M/C_{30}H$ versus $20S/(20S + 20R) C_{32}H$. Abbreviations: TT = tricyclic terpane; $C_{31}R/C_{30}H$ = C_{31} 22R homohopane/ $C_{30}\alpha\beta$ hopane; $C_{29}/C_{30}H$ = C_{29} -norhopane/ C_{30} -hopane; $Ga/C_{30}H$ = gammacerane/ C_{30} -hopane; $C_{30}M/C_{30}H$ = C_{30} -moretane/ C_{30} -hopane; $20S/(20S + 20R) C_{32}H$ = $20S/(20S + 20R) C_{32}$ -hopane.

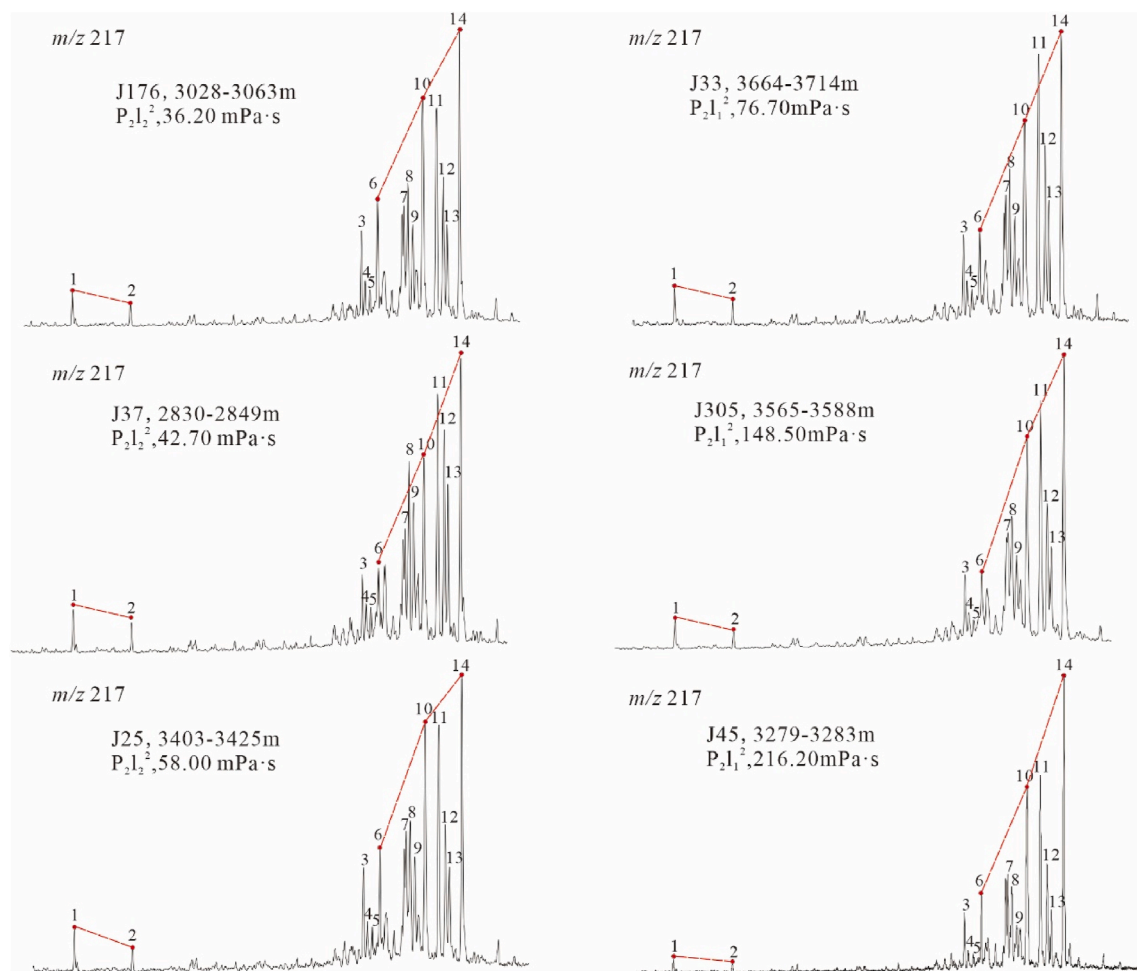


Fig. 9. Representative m/z 217 mass chromatograms illustrating the characteristics of steranes in crude oil samples. Compound numbers refer to Table 4.

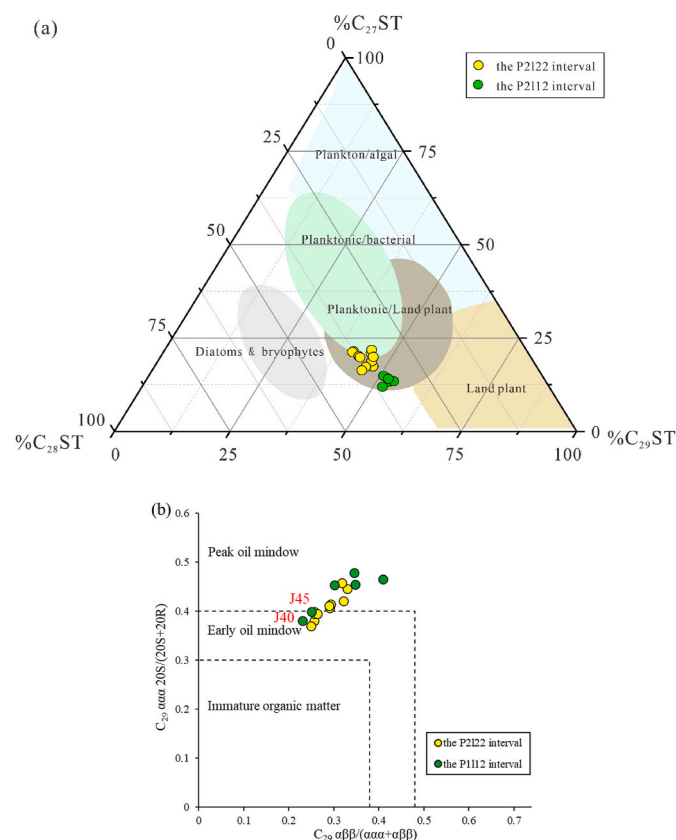


Fig. 10. Steranes analysis results for studied oil samples. (a) Ternary plot of C_{27} , C_{28} , C_{29} ($\alpha\alpha R$) regular steranes results for crude oils; (b) cross-plot of C_{29} $\alpha\beta\beta/(\alpha\alpha\alpha+\alpha\beta\beta)$ against C_{29} $\alpha\alpha\alpha$ 20S/(20S + 20R). Abbreviations: C_{29} $\alpha\beta\beta/(\alpha\alpha\alpha+\alpha\beta\beta)$ = regular steranes C_{29} $\alpha\beta\beta/(\alpha\beta\beta+\alpha\alpha\alpha)$; C_{29} $\alpha\alpha\alpha$ 20S/(20S + 20R) = regular steranes C_{29} $\alpha\alpha\alpha$ 20S/(20S + 20R).

microorganisms, including green algae, cyanobacteria and freshwater eustigmatophytes, have been reported as possible alternative sources of C_{29} steranes (Volkman, 1986; Fowler and Douglas, 1987; Riboulleau et al., 2007).

All oil samples show a high abundance of regular steranes and pregnane series, and low content of diasteranes in m/z 217 mass chromatograms (Fig. 9). The shale oil samples' C_{27} – C_{29} regular steranes distributions are roughly similar, indicating that they have similar organic matter origins and depositional paleoenvironments. Fig. 10a depicts the normalized C_{27} to C_{29} ($\alpha\alpha R$) sterane abundances, implying different organic inputs between C_{27} steranes and C_{29} steranes in the P_{211}^2 interval and the P_{212}^2 interval. The C_{29} component is higher in the P_{211}^2 interval samples than in the P_{212}^2 interval samples. In Table 3, the high ratios of C_{29}/C_{28} and C_{29}/C_{27} ($\alpha\alpha R$) steranes in the P_{211}^2 interval samples don't necessarily indicate that higher plant organic matter input is dominant, because these compounds may also come from other sources. The sterane isomerization ratios C_{29} $\alpha\beta\beta/(\alpha\alpha\alpha+\alpha\beta\beta)$ and C_{29} $\alpha\alpha\alpha$ 20S/(20S + 20R) are two commonly utilized maturity evaluation parameters (Seifert et al., 1980; Mackenzie et al., 1984). These ratios indicate that the crude oils in the P_{211}^2 interval have entered the peak oil window except for wells J45 and J40, while the crude oils in the P_{212}^2 interval are currently in the early-peak oil window (Fig. 10b).

4.2. Geochemical characteristics of source rock samples

4.2.1. Source rock properties

The TOC values of hydrocarbon source rocks of the Lucaogou Formation are highly variable, ranging from 0.63% to 12.27% (Table 1). The TOC content of the P_{211}^2 interval ranges from 0.54% to 8.60%, with

an average of 3.50%. In the P_{211}^1 interval, the TOC varies from 0.91% to 8.60%, with an average of 3.09%; in the P_{212}^2 interval, the TOC range was 0.46%–12.27%, with an average of 3.53% (Table 1). The free hydrocarbon (S_1) and pyrolysable hydrocarbon (S_2) values span from 0.01 to 74.53 mg HC/g rock, with an average of 6.65 mg HC/g rock, according to Rock-Eval pyrolysis data from 78 source rock samples in the sag. Based on the relationship between TOC and S_1+S_2 value (Robison et al., 1999; Hao et al., 2007) (Fig. 11a), the source rocks of the Lucaogou Formation are mainly good to excellent source rocks. The P_{211}^1 interval (49–591 mg HC/g TOC; average = 309 mg HC/g TOC) has higher hydrogen index (HI) values than the P_{211}^2 interval (85–499 mg HC/g TOC; average = 265 mg HC/g TOC) and the P_{212}^2 interval (64–686 mg HC/g TOC; average = 292 mg HC/g TOC). The cross plot of T_{max} and HI reveals that the Lucaogou Formation's source rocks are rich in type II and II-III kerogens, and are in the early-peak oil window (Espitalié et al., 1977; Katz, 1983) (Fig. 11b). In the study area, the vitrinite reflectance values corresponding to burial depths of 2713–3753 m vary between 0.74% and 0.93% (Fig. 11c), suggesting that the Lucaogou Formation source rocks have entered in early-peak oil thermal maturity consistent with T_{max} values.

4.2.2. SARA analysis

Table 1 summarizes the SARA fractionation results of the 78 source rock samples. The saturated hydrocarbon content gradually increases from the P_{212}^2 interval to the P_{211}^2 interval and the average saturate to aromatic ratio is 2.35 in the P_{211}^2 interval, 2.91 in the P_{211}^1 interval and 3.71 in the P_{212}^2 interval. The abundance of resin and asphaltene fractions in the samples within the P_{211}^2 interval has a wide range of values (Fig. 12a). Fig. 12b–d shows the relationship between the SARA analysis results and the corresponding depth. The extractions in the P_{211}^2 interval are characterized by low saturate (2.90–71.19%; average = 37.64%), high resins plus asphaltenes (11.26–77.36%; average = 45.53%), while the extractions in the P_{212}^2 interval are characterized by higher saturate (20.27–74.56%; average = 53.93%) and lower resins plus asphaltenes (12.76–60.27%; average = 29.93%). Interestingly, there is no obvious correlation between the aromatic content in the extractions from different intervals and its corresponding depth (Fig. 12c). These observations are similar to those reported above for crude oils from different intervals.

4.2.3. Biomarker analysis

4.2.3.1. Normal alkanes and acyclic isoprenoids. Gas chromatograms of saturated hydrocarbons from Jimusaer Sag source rock samples are demonstrated in Fig. 13. It is noticed that the normal alkane distributions of saturated hydrocarbons in rock extracts of different intervals are almost unimodal. The abundance of acyclic isoprenoids (iC_{14} , iC_{15} , iC_{16} , iC_{18} , iC_{19} and iC_{20}) and β -carotane in the P_{211}^2 and P_{211}^1 intervals are substantially higher than in the P_{212}^2 interval, suggesting that algae and photosynthetic cyanobacteria contribute more to the organic matter in the P_{211}^2 and P_{211}^1 intervals. Of n -alkanes, n - C_{20} to n - C_{23} alkanes turn out to be the most abundant, indicating the contribution of lacustrine brackish water algae or aquatic macrophytes (Collister et al., 1994; Zhang et al., 2018). Besides, the high relative abundance of hopanes in the total ion chromatograms of all samples (Fig. 13), is consistent with a higher contribution of aquatic macrophytes (Tissot and Welte, 1984).

The Pr/Ph ratios of the solvent extracts vary from 0.54 to 2.26 (Table 5), with lower values in the P_{211}^2 interval (0.84–1.45, average = 1.08) and the P_{211}^1 interval (0.54–2.26, average = 1.10) relative to the P_{212}^2 interval (1.03–1.93, average = 1.32), although there is some overlap. The presence of a high Pr/Ph ratio in solvent extracts from the P_{212}^2 interval is generally associated with the high input of terrestrial organic matter (Peters et al., 2000; Hackley et al., 2020). The scatter plot between Pr/ n - C_{17} and Ph/ n - C_{18} (Fig. 14a) of the solvent extracts reveals a marine source for the P_{211}^2 and the P_{211}^1 interval and a source for the

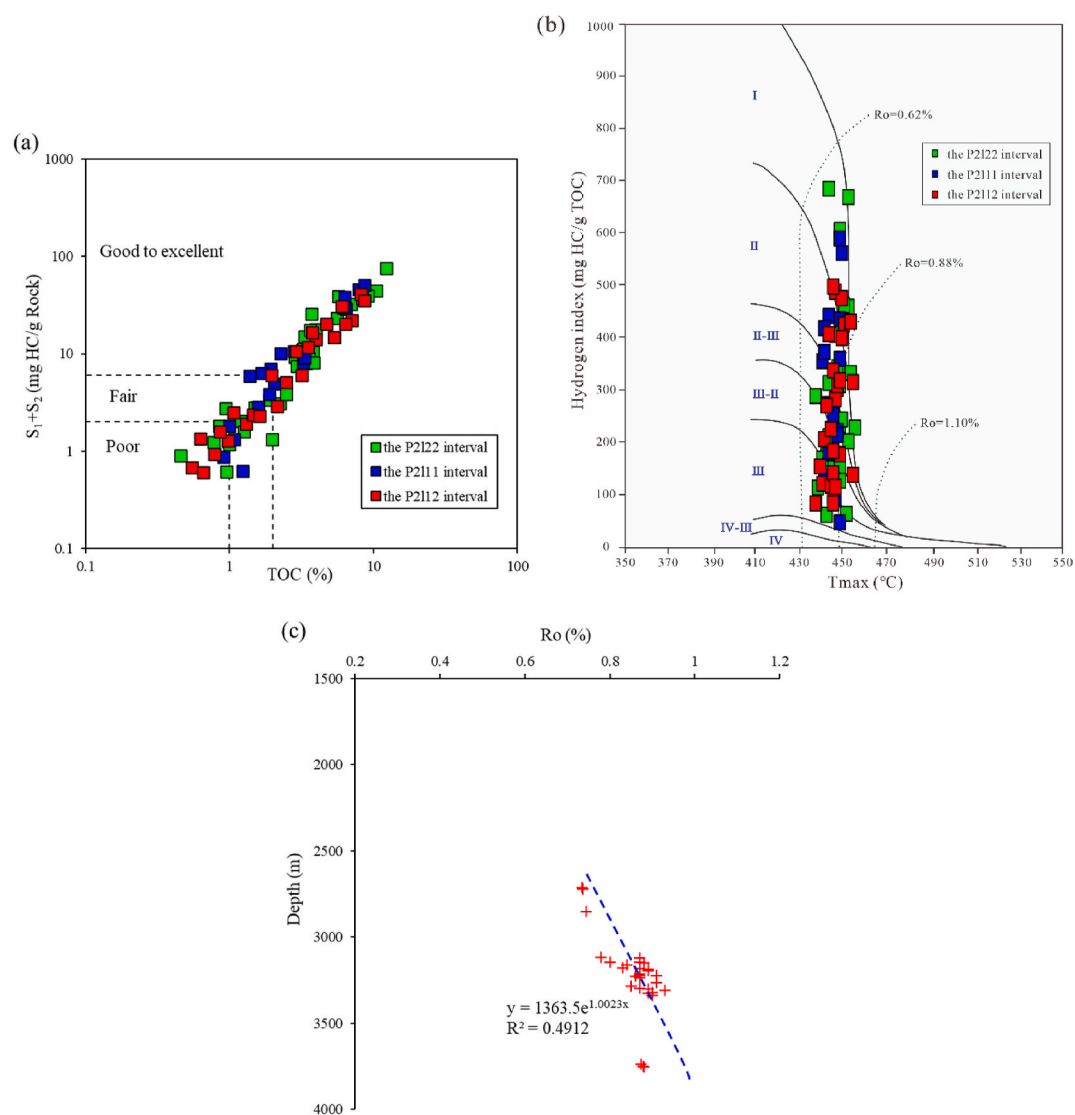


Fig. 11. Variation of (a) TOC with (S_1+S_2), (b) T_{max} with hydrogen index, and (c) vitrinite reflectance (R_o) with depth for source rocks from the different intervals.

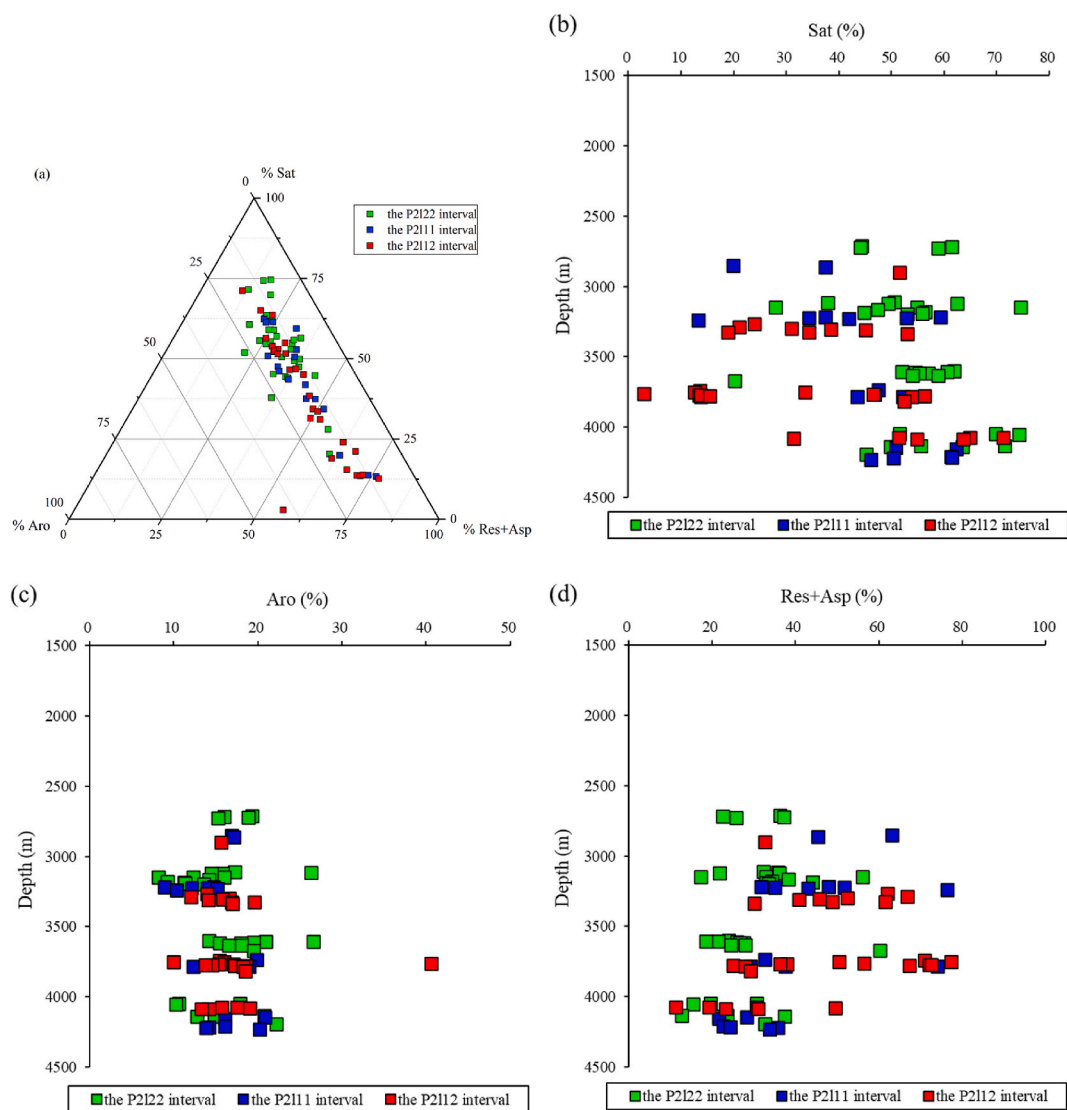


Fig. 12. SARA analysis results for studied source rock samples. (a) Ternary plot of normalized SARA results for oils; (b) Sat versus depth; (c) Aro versus depth; (d) Resin + Asp versus depth. Sat refers to saturated hydrocarbons; Aro refers to aromatic hydrocarbons; Res + Asp refers to resins plus asphaltenes.

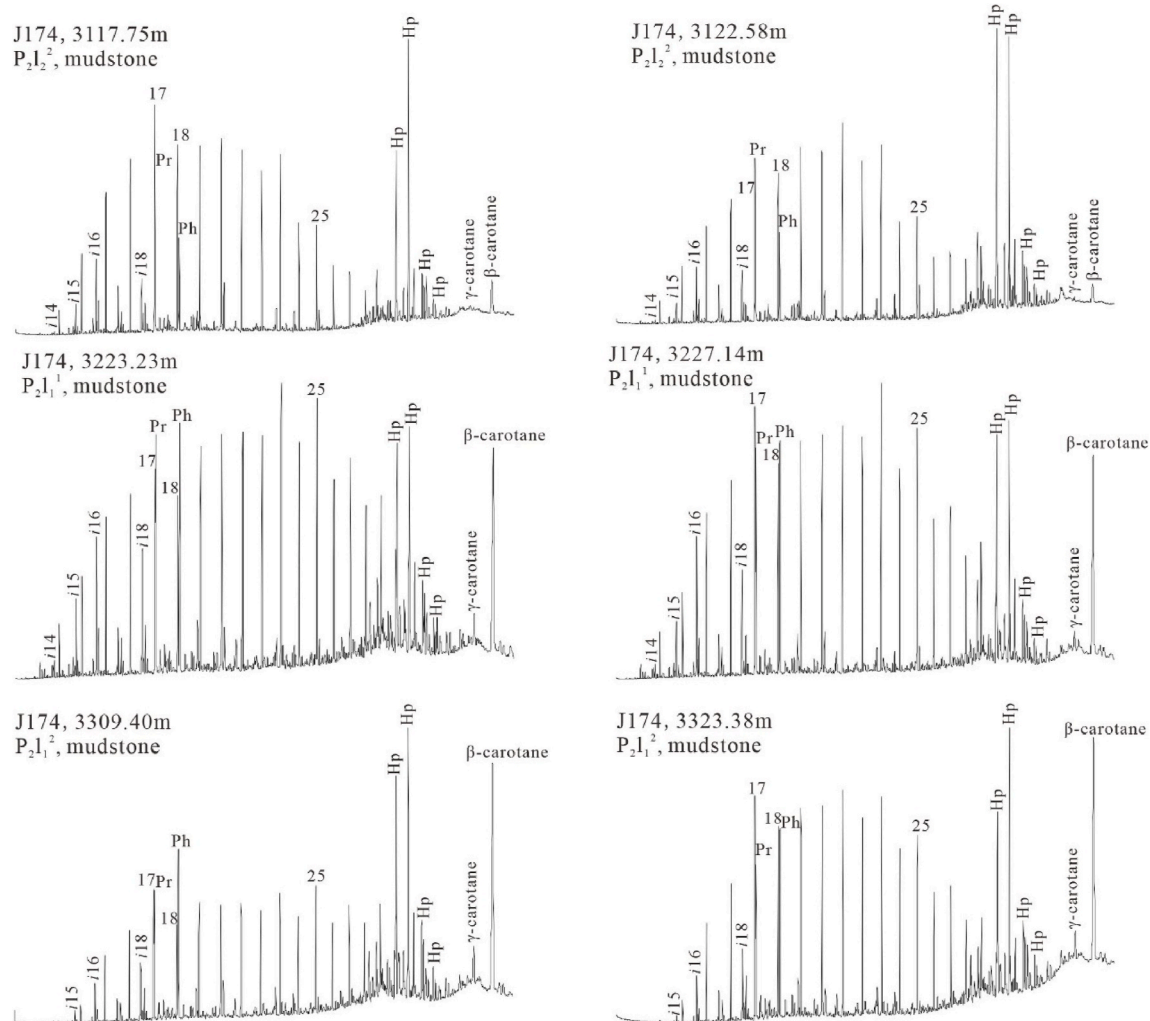


Fig. 13. Representative saturated hydrocarbon gas chromatograms for source rocks. i14-i18 = C₁₄~C₁₈ acyclic isoprenoids; Pr = pristane; Ph = phytane; 17, 18, 25 = C₁₇, C₁₈ and C₂₅ normal alkanes; Hp = hopanes.

Table 4

Compound numbers for hopanes and steranes in Figs. 7, 9, 15, 17 and 22.

Peak	M ⁺ (m/ z)	Compounds	Peak	M ⁺ (m/ z)	Compounds
1	191	C ₁₉ tricyclic terpane	23	191	C ₃₂ 17α(H), 21β(H)-homohopane (22R)
2	191	C ₂₀ tricyclic terpane	24	191	C ₃₃ 17α(H), 21β(H)-homohopane (22S)
3	191	C ₂₁ tricyclic terpane	25	191	C ₃₃ 17α(H), 21β(H)-homohopane (22R)
4	191	C ₂₂ tricyclic terpane	26	191	C ₃₄ 17α(H), 21β(H)-homohopane (22S)
5	191	C ₂₃ tricyclic terpane	27	191	C ₃₄ 17α(H), 21β(H)-homohopane (22R)
6	191	C ₂₄ tricyclic terpane	28	191	C ₃₅ 17α(H), 21β(H)-homohopane (22S)
7	191	C ₂₅ tricyclic terpane	29	191	C ₃₅ 17α(H), 21β(H)-homohopane (22R)
8	191	C ₂₄ tetracyclic terpane	1	217	C ₂₁ pregnane
9	191	C ₂₆ tricyclic terpane	2	217	C ₂₂ pregnane
10	191	C ₂₆ tricyclic terpane	3	217	5α(H), 14α(H), 17α(H)-cholestane (20S)
11	191	C ₂₈ tricyclic terpane	4	217	5α(H), 14β(H), 17β(H)-cholestane (20R)
12	191	C ₂₈ tricyclic terpane	5	217	5α(H), 14β(H), 17β(H)-cholestane (20R)
13	191	C ₂₇ 18α(H), 22,29,30-trisnorhopane	6	217	5α(H), 14α(H), 17α(H)-cholestane (20R)
14	191	C ₂₇ 17α(H), 22,29,30-trisnorhopane	7	217	24-methyl-5α(H), 14α(H), 17α(H)-cholestane (20S)
15	191	C ₂₉ 17α(H), 21β(H)-norhopane	8	217	24-methyl-5α(H), 14β(H), 17β(H)-cholestane (20R)
16	191	C ₂₉ 17β(H), 21α(H)-norhopane	9	217	24-methyl-5α(H), 14β(H), 17β(H)-cholestane (20S)
17	191	C ₃₀ 17α(H), 21β(H)-hopane	10	217	24-methyl-5α(H), 14α(H), 17α(H)-cholestane (20R)
18	191	C ₃₀ 17β(H), 21α(H)-hopane	11	217	24-ethyl-5α(H), 14α(H), 17α(H)-cholestane (20S)
19	191	C ₃₁ 17α(H), 21β(H)-homohopane (22S)	12	217	24-ethyl-5α(H), 14β(H), 17β(H)-cholestane (20R)
20	191	C ₃₁ 17α(H), 21β(H)-homohopane (22R)	13	217	24-ethyl-5α(H), 14β(H), 17β(H)-cholestane (20S)
21	191	Gammacerane	14	217	24-ethyl-5α(H), 14α(H), 17α(H)-cholestane (20R)
22	191	C ₃₂ 17α(H), 21β(H)-homohopane (22S)			

P₂L₂² interval. The scatter plot of Pr/Ph versus TAR again indicates that there is greater terrestrial organic matter input in the P₂L₂² interval (Fig. 14b). The CPI and OEP values in solvent extracts show that there is no systematic difference between source rocks in different intervals (Fig. 14c). Through the diagrams of IAI and Pr/n-C₁₇, IAI and Pr/n-C₁₈, β-carotene/C_{max} and IAI (Fig. 14e–f), it can be seen that the P₂L₁² and the P₂L₁¹ interval source rock samples have higher isoprenoids and β-carotene content. These biomarker assemblages also imply that the P₂L₁² and the P₂L₁¹ interval are developed in a reducing, carbonate-rich, evaporitic, and shallow water environment.

4.2.3.2. Terpanes. The m/z 191 mass chromatograms of saturated hydrocarbons in all source rock samples show moderate abundances of pentacyclic terpanes and lower abundances of tricyclic terpanes and tetracyclic terpanes (Fig. 15). Sedimentary hopanoids are mostly produced by bacteria (Ourisson et al., 1982). Among them, the abundance of C₃₀ hopane is the highest. The concentration of homohopanes decreases from C₃₁ to C₃₅ in all samples (Fig. 15). C₃₄ and C₃₅

homohopanes appear only in low abundance or are not detectable in the extracts, indicating a fresh-water lacustrine depositional environment.

Gammacerane has been observed in all of the samples tested, but at very low concentrations in some of them. Ga/C₃₀H varies from 0.12 to 0.31, between 0.16 and 0.32, and from 0.05 to 0.25 for the P₂L₁², P₂L₁¹ and P₂L₂² interval shales, respectively (Table 5). The gammacerane index values are not significant in the studied shale samples, indicating brackish depositional environments. Values of C₂₉/C₃₀H above 1.0 usually indicate deposition of anoxic carbonate and marl source rocks (Peters et al., 2005). C₂₉/C₃₀H ranges from 0.53 to 0.80, between 0.44 and 0.88, and from 0.29 to 1.08 for the P₂L₁², P₂L₁¹ and P₂L₂² interval shales, respectively (Table 5; Fig. 16a). The ratios C₃₁R/C₃₀H (0.11–0.30, Table 5) and C₂₆/C₂₅TT (1.82–3.32, Table 5) distinguish marine and lacustrine-derived oils (Fig. 16b). Values < 0.25 and > 1.0 suggest deposition under a lacustrine environment for C₃₁R/C₃₀H and C₂₆/C₂₅TT ratios, respectively (Zumberge, 1987; Peters et al., 2005). This attribute is consistent with a lacustrine origin of organic matter (Adekola et al., 2012). Similarly, the relationship between C₂₂/C₂₁TT and C₂₄/C₂₃TT reveals that source rock samples from different intervals are deposited under essentially similar lacustrine settings (Fig. 16c). The ratios of 20S/(20S + 20R) C₃₂H for the P₂L₁², P₂L₁¹, and P₂L₂² interval shale samples vary from 0.56 to 0.60, 0.55 to 0.60, and 0.53 to 0.60, respectively, having reached the equilibrium point (0.55–0.60) (Table 5). This means that these samples have achieved or exceeded the early stage of oil generation. The C₃₀M/C₃₀H ratios of the source rock samples examined in the P₂L₁², P₂L₁¹, and P₂L₂² intervals, respectively, vary from 0.15 to 0.44, 0.23 to 0.39, and 0.14 to 0.48, suggesting that these samples are thermally mature (Table 5; Fig. 16d).

4.2.3.3. Steranes. Fig. 17 illustrates the m/z = 217 mass chromatograms of typical rock extracts from different intervals. High concentrations of regular steranes and pregnane series are present in all 78 source rock samples. It can be found that all source rock samples have the same distribution pattern (C₂₉>C₂₈>C₂₇) of regular steranes C₂₇–C₂₉. C₂₉ (ααR) sterane concentrations in the P₂L₁² (36.63–64.80%; average = 52.24%) and P₂L₁¹ (35.96–58.90%; average = 48.68%) intervals are higher than those in the P₂L₂² interval (34.53–53.94%; average = 44.22%). The approximate abundance of C₂₇–C₂₉ (ααR) steranes in different intervals may suggest a common eukaryotic source (Fig. 18a). The C₂₉/C₂₇ (ααR) ratios of the P₂L₁², P₂L₁¹ and P₂L₂² interval source rock samples range from 2.20 to 7.89 (average = 4.33), between 0.96 and 6.19 (average = 3.61), from 1.10 to 4.21 (average = 2.39), respectively (Table 5). The C₂₉/C₂₈ (ααR) ratios of in the P₂L₁², P₂L₁¹ and P₂L₂² intervals source rock samples range from 0.68 to 2.40 (average = 1.56), between 1.13 and 1.87 (average = 1.35), from 0.74 to 1.71 (average = 1.27), respectively (Table 5). These attributes cannot be explained as the main source of higher plants in this area, because these components might potentially be derived from other sources. The sterane isomerization parameters (C₂₉ αββ/(ααα+αββ) and C₂₉ ααα 20S/(20S + 20R)) are commonly used to determine the maturity of source rocks. These ratios imply that the source rocks in the P₂L₁² and P₂L₁¹ intervals have entered the peak oil window, but the P₂L₂² interval is presently in the early-peak oil window (Fig. 18b).

5. Discussion

5.1. Lucaogou shale source rock characterization

Previous work (Gao et al., 2016; Hu et al., 2018; Zhang et al., 2020) and results of this study (Table 1 and Fig. 11) suggest that the Lucaogou Formation shales are organic-rich source rocks with high hydrocarbon potential. These studies as well as some published articles (Ding et al., 2019; Yang et al., 2019; Kong et al., 2020) have interpreted the Lucaogou shale as high-quality source rocks. Several studies have concluded that the organic matter in different intervals consists of a

Table 5

List of biomarker parameters for source rocks from different intervals.

Well	Depth (m)	Member	Pr/n-C ₁₇	Ph/n-C ₁₈	TAR	Pr/Ph	CPI	OEP	β-carotane/C _{max}	IAI	C ₂₂ /C ₂₁ TT	C ₂₄ /C ₂₃ TT	C ₂₆ /C ₂₅ TT	C ₃₁ R/C ₃₀ H
J31	2712.9	P ₂ 1 ₂ ²	0.87	0.68	0.40	1.46	1.32	1.23	25.14	0.76	0.11	0.38	2.26	0.13
J31	2717.0	P ₂ 1 ₂ ²	1.04	0.71	0.89	1.38	1.32	1.25	24.09	0.87	0.13	0.42	2.31	0.14
J31	2720.7	P ₂ 1 ₂ ²	1.14	0.75	0.58	1.54	1.46	1.26	37.91	0.89	0.11	0.41	2.86	0.11
J31	2725.5	P ₂ 1 ₂ ²	1.02	0.86	0.60	1.23	1.31	1.19	38.74	0.92	0.12	0.42	2.38	0.15
J174	3110.9	P ₂ 1 ₂ ²	2.67	2.43	1.12	1.08	1.17	1.17	158.29	2.19	0.13	0.42	2.70	0.14
J174	3117.8	P ₂ 1 ₂ ²	0.84	0.85	0.10	1.23	1.36	1.12	21.69	0.84	0.12	0.39	2.15	0.11
J174	3122.1	P ₂ 1 ₂ ²	1.12	0.69	0.53	1.87	1.27	1.21	3.45	0.86	0.12	0.44	2.57	0.20
J174	3122.6	P ₂ 1 ₂ ²	1.50	1.04	0.40	1.69	1.09	1.20	22.43	1.22	0.12	0.40	2.82	0.14
J174	3145.4	P ₂ 1 ₂ ²	0.87	0.86	0.44	1.16	1.15	1.17	9.82	0.83	0.13	0.36	2.08	0.18
J174	3146.2	P ₂ 1 ₂ ²	0.50	0.45	0.54	1.03	1.28	1.21	3.23	0.45	0.12	0.44	2.44	0.30
J174	3150.2	P ₂ 1 ₂ ²	0.34	0.14	0.93	1.93	1.46	1.22	0.00	0.26	0.11	0.45	2.05	0.23
J174	3162.0	P ₂ 1 ₂ ²	0.15	0.08	0.37	1.46	1.30	1.18	0.00	0.14	0.28	0.52	2.06	0.20
J174	3177.6	P ₂ 1 ₂ ²	0.26	0.22	1.16	1.05	1.24	1.20	1.75	0.27	0.17	0.43	2.06	0.29
J174	3183.8	P ₂ 1 ₂ ²	0.35	0.22	0.57	1.35	1.18	1.18	2.75	0.32	0.13	0.36	2.10	0.22
J174	3188.6	P ₂ 1 ₂ ²	0.92	0.58	0.77	1.46	1.26	1.25	4.94	0.71	0.14	0.37	2.47	0.18
J174	3196.3	P ₂ 1 ₂ ²	0.95	0.69	0.23	1.50	1.26	1.21	18.35	0.74	0.12	0.37	2.53	0.18
J251	3601.2	P ₂ 1 ₂ ²	1.05	1.03	0.71	1.12	1.26	1.15	43.99	1.00	0.15	0.46	2.30	0.15
J251	3604.0	P ₂ 1 ₂ ²	0.99	0.94	0.43	1.14	1.27	1.15	47.05	0.91	0.15	0.43	2.29	0.17
J251	3605.1	P ₂ 1 ₂ ²	0.99	0.57	0.63	1.54	1.30	1.22	71.62	0.78	0.13	0.39	2.31	0.15
J251	3608.7	P ₂ 1 ₂ ²	1.03	1.04	0.52	1.05	1.32	1.15	46.48	1.01	0.16	0.44	2.41	0.18
J251	3613.7	P ₂ 1 ₂ ²	0.76	0.61	4.14	1.36	1.17	1.04	12.34	0.65	0.14	0.40	2.40	0.15
J251	3618.9	P ₂ 1 ₂ ²	1.22	1.41	0.43	1.07	1.38	1.12	90.18	1.27	0.16	0.45	2.57	0.18
J251	3630.7	P ₂ 1 ₂ ²	1.22	1.42	0.50	1.03	1.26	1.11	104.64	1.25	0.15	0.46	2.57	0.18
J251	3631.3	P ₂ 1 ₂ ²	1.21	1.40	0.41	1.10	1.28	1.11	91.08	1.18	0.15	0.46	2.43	0.21
J34	3672.6	P ₂ 1 ₂ ²	1.22	1.36	0.42	1.13	1.27	1.08	122.96	1.22	0.14	0.44	2.46	0.19
J30	4045.9	P ₂ 1 ₂ ²	0.53	0.29	0.93	1.59	1.25	1.30	4.92	0.43	0.16	0.44	2.19	0.21
J30	4047.2	P ₂ 1 ₂ ²	0.29	0.17	0.66	1.34	1.26	1.20	0.65	0.25	0.17	0.40	2.02	0.21
J30	4052.3	P ₂ 1 ₂ ²	0.11	0.06	0.23	1.49	1.27	1.19	0.00	0.11	0.18	0.41	1.82	0.21
J36	4131.8	P ₂ 1 ₂ ²	0.79	0.64	0.51	1.23	1.30	1.18	25.11	0.65	0.17	0.40	2.32	0.13
J36	4132.4	P ₂ 1 ₂ ²	0.91	0.66	1.18	1.18	1.30	1.22	17.11	0.76	0.15	0.47	2.34	0.16
J36	4136.9	P ₂ 1 ₂ ²	0.62	0.48	0.61	1.20	1.30	1.18	17.68	0.52	0.15	0.38	2.10	0.16
J36	4137.6	P ₂ 1 ₂ ²	0.73	0.55	0.90	1.14	1.29	1.19	20.55	0.66	0.15	0.42	2.11	0.14
J36	4192.0	P ₂ 1 ₂ ²	0.87	0.61	0.37	1.54	1.24	1.19	29.68	0.68	0.14	0.38	2.41	0.18
J31	2851.7	P ₂ 1 ₁ ¹	3.21	8.05	0.26	0.68	1.74	1.26	66.10	4.17	0.11	0.40	3.11	0.19
J31	2863.6	P ₂ 1 ₁ ¹	3.33	13.37	0.30	0.54	1.89	1.32	99.12	5.57	0.10	0.40	3.16	0.21
J174	3216.7	P ₂ 1 ₁ ¹	1.78	2.19	0.89	1.06	1.22	1.26	28.57	1.90	0.15	0.42	2.44	0.26
J174	3218.0	P ₂ 1 ₁ ¹	1.35	1.85	0.37	1.02	0.73	1.19	155.21	1.49	0.14	0.41	2.59	0.23
J174	3223.2	P ₂ 1 ₁ ¹	1.64	1.91	0.53	1.16	1.20	1.29	100.00	1.67	0.14	0.42	2.52	0.24
J174	3224.3	P ₂ 1 ₁ ¹	1.34	1.60	0.27	1.19	1.13	1.30	43.97	1.38	0.11	0.39	2.75	0.19
J174	3227.1	P ₂ 1 ₁ ¹	1.55	1.86	0.48	1.13	1.21	1.26	93.61	1.58	0.11	0.39	2.72	0.18
J174	3237.8	P ₂ 1 ₁ ¹	1.32	1.67	0.19	1.16	1.15	1.20	0.00	1.40	0.11	0.37	2.48	0.16
J251	3733.0	P ₂ 1 ₁ ¹	4.10	1.77	1.24	2.26	1.64	1.14	425.96	2.58	0.12	0.47	2.29	0.13
J34	3781.6	P ₂ 1 ₁ ¹	1.18	1.59	0.51	0.97	1.15	1.10	8.19	1.31	0.13	0.37	2.20	0.16
J34	3783.2	P ₂ 1 ₁ ¹	2.01	2.89	0.51	0.93	1.42	1.19	127.79	2.10	0.16	0.44	2.50	0.21
J34	3784.5	P ₂ 1 ₁ ¹	1.96	2.79	0.36	0.97	1.42	1.18	60.16	2.06	0.15	0.44	2.46	0.19
J30	4147.0	P ₂ 1 ₁ ¹	1.54	1.78	0.39	1.07	1.29	1.14	79.38	1.52	0.16	0.44	2.34	0.17
J30	4153.6	P ₂ 1 ₁ ¹	1.40	1.59	0.36	1.13	1.27	1.22	34.24	1.47	0.17	0.43	2.26	0.22
J36	4211.4	P ₂ 1 ₁ ¹	1.25	1.00	1.27	1.25	1.24	1.13	87.50	1.19	0.15	0.41	2.46	0.18
J36	4213.2	P ₂ 1 ₁ ¹	1.20	1.25	0.38	1.20	1.40	1.22	0.00	1.31	0.16	0.38	2.23	0.19
J36	4217.9	P ₂ 1 ₁ ¹	1.55	1.66	0.95	1.01	1.31	1.16	138.99	1.53	0.17	0.42	2.15	0.16
J36	4228.5	P ₂ 1 ₁ ¹	0.96	1.15	0.20	1.10	1.40	1.15	12.54	0.97	0.14	0.38	2.18	0.16
J31	2897.3	P ₂ 1 ₁ ²	2.38	5.09	0.36	0.92	1.44	1.25	230.85	3.03	0.11	0.43	3.32	0.18
J174	3264.2	P ₂ 1 ₁ ²	1.27	1.68	0.17	1.19	1.00	1.20	31.75	1.39	0.12	0.38	2.11	0.16
J174	3286.7	P ₂ 1 ₁ ²	1.49	2.17	0.31	1.01	1.45	1.20	108.70	1.64	0.10	0.41	2.18	0.17
J174	3298.6	P ₂ 1 ₁ ²	2.29	3.84	0.49	0.92	1.62	1.17	614.29	2.57	0.12	0.42	2.83	0.17
J174	3302.7	P ₂ 1 ₁ ²	0.92	1.00	1.40	0.94	1.43	1.13	10.50	1.01	0.15	0.40	1.86	0.19
J174	3309.4	P ₂ 1 ₁ ²	1.52	2.66	0.64	0.84	1.55	1.22	250.32	1.86	0.14	0.41	2.70	0.20
J174	3323.4	P ₂ 1 ₁ ²	1.38	1.73	0.52	0.95	1.38	1.18	181.94	1.49	0.15	0.42	2.70	0.19
J174	3327.9	P ₂ 1 ₁ ²	0.86	0.62	0.44	1.45	1.37	1.14	73.18	0.71	0.13	0.41	2.71	0.19
J174	3336.4	P ₂ 1 ₁ ²	0.39	0.30	0.98	1.17	1.29	1.12	6.90	0.36	0.17	0.43	2.37	0.22
J251	3739.9	P ₂ 1 ₁ ²	0.68	0.72	0.14	1.19	1.37	1.15	6.94	0.69	0.13	0.36	2.09	0.17
J251	3748.8	P ₂ 1 ₁ ²	1.23	1.48	0.37	1.08	1.26	1.15	77.78	1.27	0.15	0.36	2.27	0.27
J251	3753.1	P ₂ 1 ₁ ²	1.28	1.49	0.43	1.08	1.31	1.12	92.92	1.26	0.16	0.43	2.43	0.20
J251	3759.2	P ₂ 1 ₁ ²	1.06	1.28	0.25	1.13	1.21	1.10	94.84	1.06	0.14	0.44	2.40	0.17
J251	3764.7	P ₂ 1 ₁ ²	0.72	0.90	0.17	1.12	1.25	1.08	18.80	0.77	0.14	0.38	2.30	0.20
J251	3769.0	P ₂ 1 ₁ ²	0.94	1.13	0.20	1.09	1.17	1.11	33.74	0.97	0.13	0.44	2.19	0.20
J251	3770.7	P ₂ 1 ₁ ²	1.16	1.39	0.25	1.16	1.42	1.10	63.47	1.14	0.15	0.40	2.41	0.25
J251	3772.7	P ₂ 1 ₁ ²	0.93	1.07	0.13	1.25	1.05	1.05	29.64	0.93	0.14	0.41	2.31	0.18
J251	3775.4	P ₂ 1 ₁ ²	1.17	1.33	0.40	1.12	1.29	1.09	95.32	1.15	0.15	0.45	2.48	0.19
J251	3778.5	P ₂ 1 ₁ ²	1.21	1.35	0.39	1.15	1.34	1.06	139.15	1.17	0.17	0.44	2.44	0.26
J251	3785.8	P ₂ 1 ₁ ²	0.72	0.83	0.13	1.26	1.14	1.07	17.19	0.72	0.14	0.41	2.11	0.19
J34	3814.5	P ₂ 1 ₁ ²	1.16	1.41	0.45	1.07	1.23	1.11	74.03	1.22	0.17	0.45	2.38	0.19
J35	4071.9	P ₂ 1 ₁ ²	2.14	2.93	0.38	1.02	1.49	0.92	523.81	2.31	0.18	0.53	2.63	0.19
J35	4076.7	P ₂ 1 ₁ ²	1.06	1.29	0.34	1.06	1.20	1.05	50.85	1.16	0.17	0.49	2.42	0.17

(continued on next page)

Table 5 (continued)

Well	Depth (m)	Member	Pr/n-C ₁₇	Ph/n-C ₁₈	TAR	Pr/Ph	CPI	OEP	β-carotane/C _{max}	IAI	C ₂₂ /C ₂₁ TT	C ₂₄ /C ₂₃ TT	C ₂₆ /C ₂₅ TT	C ₃₁ R/C ₃₀ H
J35	4076.8	P ₂ 1 ₁ ²	1.08	1.32	0.40	1.04	1.21	1.05	68.38	1.19	0.19	0.51	2.43	0.18
J35	4079.3	P ₂ 1 ₁ ²	1.06	1.42	0.24	1.06	1.24	1.06	100.00	1.16	0.18	0.53	2.43	0.17
J35	4083.5	P ₂ 1 ₁ ²	1.00	1.22	0.72	0.88	1.25	1.08	118.75	1.10	0.20	0.51	2.42	0.19
J35	4086.2	P ₂ 1 ₁ ²	1.04	1.27	0.73	0.89	1.31	1.06	128.57	1.13	0.20	0.53	2.45	0.20
Well	C ₂₉ / C ₃₀ H	Ga/ C ₃₀ H	C ₃₀ M/ C ₃₀ H	20S/(20S + 20R) C ₃₂ H	C ₂₇ ST/ %	C ₂₈ ST/ %	C ₂₉ ST/ %	C ₂₉ / C ₂₈ ST	C ₂₉ / C ₂₇ ST	C ₂₉ αββ/(ααα+αββ)	C ₂₉ ααα 20S/(20S + 20R)			
J31	0.47	0.18	0.22	0.56	26.95	32.72	40.33	1.23	1.50	0.21	0.38			
J31	0.44	0.15	0.19	0.57	25.51	32.59	41.89	1.29	1.64	0.25	0.39			
J31	0.47	0.32	0.21	0.53	19.30	31.15	49.55	1.59	2.57	0.19	0.31			
J31	0.56	0.17	0.23	0.58	20.28	33.85	45.87	1.36	2.26	0.31	0.43			
J174	0.50	0.22	0.15	0.58	15.10	33.42	51.48	1.54	3.41	0.23	0.32			
J174	0.47	0.18	0.19	0.57	21.56	33.61	44.84	1.33	2.08	0.24	0.41			
J174	0.79	0.21	0.29	0.56	14.59	31.46	53.94	1.71	3.70	0.18	0.31			
J174	0.81	0.16	0.20	0.55	11.81	40.22	47.97	1.19	4.06	0.20	0.34			
J174	0.78	0.18	0.27	0.57	17.19	37.55	45.26	1.21	2.63	0.26	0.40			
J174	0.76	0.09	0.48	0.55	18.71	46.72	34.57	0.74	1.85	0.17	0.32			
J174	1.08	0.05	0.28	0.56	23.54	40.71	35.75	0.88	1.52	0.17	0.32			
J174	0.93	0.15	0.26	0.54	18.41	43.77	37.83	0.86	2.06	0.18	0.32			
J174	0.69	0.09	0.27	0.57	20.73	38.37	40.91	1.07	1.97	0.21	0.37			
J174	0.79	0.18	0.34	0.53	19.71	40.89	39.40	0.96	2.00	0.16	0.30			
J174	0.63	0.16	0.23	0.57	23.23	36.78	39.99	1.09	1.72	0.21	0.36			
J174	0.63	0.15	0.36	0.55	20.53	38.06	41.42	1.09	2.02	0.19	0.32			
J251	0.56	0.16	0.21	0.58	18.82	32.83	48.34	1.47	2.57	0.36	0.45			
J251	0.61	0.20	0.23	0.59	18.34	32.49	49.18	1.51	2.68	0.33	0.45			
J251	0.54	0.18	0.29	0.58	30.71	27.85	41.44	1.49	1.35	0.23	0.41			
J251	0.64	0.17	0.22	0.59	15.82	33.64	50.54	1.50	3.19	0.37	0.46			
J251	0.64	0.18	0.22	0.59	22.06	30.62	47.32	1.55	2.15	0.26	0.44			
J251	0.67	0.17	0.25	0.57	13.07	34.83	52.10	1.50	3.98	0.34	0.45			
J251	0.66	0.17	0.25	0.60	13.82	33.12	53.06	1.60	3.84	0.33	0.45			
J251	0.66	0.20	0.27	0.58	12.63	34.22	53.15	1.55	4.21	0.32	0.45			
J34	0.68	0.14	0.27	0.59	13.27	36.42	50.31	1.38	3.79	0.30	0.46			
J30	0.60	0.10	0.18	0.59	16.95	39.03	44.02	1.13	2.60	0.38	0.47			
J30	0.68	0.11	0.20	0.59	19.05	38.28	42.67	1.11	2.24	0.39	0.49			
J30	0.72	0.06	0.22	0.58	20.78	44.68	34.53	0.77	1.66	0.34	0.51			
J36	0.29	0.14	0.14	0.59	34.13	28.28	37.60	1.33	1.10	0.35	0.48			
J36	0.34	0.11	0.16	0.58	28.46	33.18	38.36	1.16	1.35	0.36	0.47			
J36	0.36	0.17	0.16	0.57	30.22	30.79	39.00	1.27	1.29	0.35	0.49			
J36	0.35	0.14	0.16	0.59	27.60	32.41	39.98	1.23	1.45	0.36	0.47			
J36	0.66	0.19	0.28	0.58	18.03	35.18	46.79	1.33	2.59	0.29	0.47			
J31	0.88	0.17	0.30	0.55	11.63	38.54	49.83	1.29	4.28	0.19	0.33			
J31	0.85	0.32	0.36	0.56	9.44	35.31	55.24	1.56	5.85	0.19	0.33			
J174	0.81	0.26	0.35	0.56	13.15	40.85	46.01	1.13	3.50	0.24	0.40			
J174	0.78	0.22	0.35	0.58	12.56	39.06	48.38	1.24	3.85	0.23	0.40			
J174	0.69	0.20	0.39	0.57	14.48	35.55	49.96	1.41	3.45	0.22	0.39			
J174	0.76	0.22	0.35	0.56	16.37	37.29	46.35	1.24	2.83	0.20	0.38			
J174	0.73	0.19	0.32	0.55	15.29	37.91	46.80	1.23	3.06	0.21	0.38			
J174	0.81	0.20	0.33	0.58	13.73	37.97	48.29	1.27	3.52	0.21	0.40			
J251	0.44	0.23	0.25	0.60	37.45	26.59	35.96	1.35	0.96	0.25	0.42			
J34	0.83	0.21	0.31	0.58	15.23	38.70	46.07	1.19	3.03	0.29	0.46			
J34	0.78	0.20	0.34	0.58	11.23	37.03	51.75	1.40	4.61	0.30	0.45			
J34	0.73	0.19	0.30	0.58	11.32	36.06	52.61	1.46	4.65	0.31	0.45			
J30	0.74	0.16	0.25	0.59	12.43	35.34	52.23	1.48	4.20	0.40	0.49			
J30	0.81	0.24	0.25	0.59	9.52	31.58	58.90	1.87	6.19	0.42	0.45			
J36	0.70	0.19	0.23	0.59	18.50	35.76	45.74	1.28	2.47	0.34	0.48			
J36	0.68	0.20	0.23	0.58	17.69	37.23	45.08	1.21	2.55	0.36	0.48			
J36	0.71	0.20	0.23	0.58	16.50	34.24	49.25	1.44	2.98	0.35	0.46			
J36	0.76	0.25	0.25	0.59	16.04	36.15	47.81	1.32	2.98	0.32	0.46			
J31	0.73	0.20	0.34	0.56	11.47	33.58	54.96	1.64	4.79	0.21	0.35			
J174	0.80	0.21	0.30	0.59	15.08	34.25	50.67	1.48	3.36	0.25	0.44			
J174	0.74	0.20	0.31	0.58	16.19	33.23	50.58	1.52	3.12	0.25	0.43			
J174	0.54	0.15	0.29	0.58	9.97	33.85	56.18	1.66	5.64	0.23	0.39			
J174	0.80	0.13	0.24	0.58	9.80	53.57	36.63	0.68	3.74	0.25	0.43			
J174	0.59	0.13	0.32	0.58	12.55	36.07	51.38	1.42	4.09	0.22	0.41			
J174	0.54	0.20	0.21	0.59	18.36	34.09	47.56	1.40	2.59	0.29	0.42			
J174	0.56	0.21	0.21	0.59	19.65	37.04	43.32	1.17	2.20	0.28	0.44			
J174	0.53	0.12	0.19	0.59	19.08	38.10	42.82	1.12	2.24	0.31	0.43			
J251	0.70	0.19	0.25	0.58	19.99	35.00	45.01	1.29	2.25	0.31	0.43			
J251	0.76	0.31	0.44	0.59	13.15	32.15	54.70	1.70	4.16	0.25	0.41			
J251	0.65	0.20	0.27	0.58	11.81	34.13	54.06	1.58	4.58	0.31	0.45			
J251	0.68	0.19	0.26	0.59	13.77	34.67	51.56	1.49	3.74	0.31	0.46			
J251	0.71	0.26	0.30	0.59	13.47	35.14	51.39	1.46	3.82	0.31	0.44			
J251	0.69	0.23	0.29	0.58	12.66	33.02	54.32	1.64	4.29	0.27	0.44			
J251	0.72	0.31	0.38	0.58	11.92	32.66	55.42	1.70	4.65	0.27	0.42			
J251	0.72	0.20	0.27	0.59	12.87	35.09	52.04	1.48	4.04	0.27	0.44			

(continued on next page)

Table 5 (continued)

Well	C ₂₉ / C ₃₀ H	Ga/ C ₃₀ H	C ₃₀ M/ C ₃₀ H	20S/(20S + 20R) C ₃₂ H	C ₂₇ ST/ %	C ₂₈ ST/ %	C ₂₉ ST/ %	C ₂₉ / C ₂₈ ST	C ₂₉ / C ₂₇ ST	C ₂₉ αββ/(ααα+αββ)	C ₂₉ ααα 20S/(20S + 20R)
J251	0.62	0.14	0.27	0.58	13.22	35.87	50.91	1.42	3.85	0.30	0.45
J251	0.70	0.27	0.31	0.59	8.51	32.13	59.36	1.85	6.98	0.29	0.42
J251	0.70	0.19	0.31	0.60	15.13	36.05	48.82	1.35	3.23	0.25	0.44
J34	0.66	0.17	0.21	0.59	12.50	33.24	54.26	1.63	4.34	0.40	0.47
J35	0.59	0.21	0.15	0.59	8.21	26.98	64.80	2.40	7.89	0.49	0.48
J35	0.58	0.14	0.16	0.57	10.12	32.12	57.76	1.80	5.71	0.50	0.47
J35	0.57	0.15	0.17	0.58	10.17	31.70	58.13	1.83	5.72	0.50	0.48
J35	0.54	0.18	0.16	0.60	10.03	32.52	57.45	1.77	5.73	0.45	0.52
J35	0.53	0.13	0.17	0.59	11.60	32.06	56.34	1.76	4.86	0.49	0.51
J35	0.54	0.13	0.17	0.59	11.05	30.91	58.03	1.88	5.25	0.48	0.49

Abbreviations: Pr/*n*-C₁₇ = pristane/*n*-heptadecane; Ph/*n*-C₁₈ = phytane/*n*-octadecane; TAR = (n-C₂₇+n-C₂₉+n-C₃₁)/(n-C₁₅+n-C₁₇+n-C₁₉) *n*-alkanes in TIC; Pr/Ph = pristane/phytane; CPI = 1/2 × [(C₂₅+C₂₇+C₂₉+C₃₁+C₃₃)/(C₂₄+C₂₆+C₂₈+C₃₀+C₃₂)+(C₂₅+C₂₇+C₂₉+C₃₁+C₃₃)/(C₂₆+C₂₈+C₃₀+C₃₂+C₃₄)] *n*-alkanes in TIC; OEP = (C₂₁+6C₂₃+C₂₅)/(4C₂₂+4C₂₄) *n*-alkanes in TIC; β-carotane/C_{max} = β-carotane/C_{max} × 100 in TIC; IAI = (i-C₁₅+i-C₁₆+i-C₁₈+i-C₁₉+i-C₂₀)/(n-C₁₃+n-C₁₄+n-C₁₆+n-C₁₇+n-C₁₈) in TIC; TT = tricyclic terpane; C₃₁R/C₃₀H = C₃₁ 22R homohopane/C₃₀αβ hopane; C₂₉/C₃₀H = C₂₉ norhopane/C₃₀ hopane; Ga/C₃₀H = gammacerane/C₃₀-hopane; C₃₀M/C₃₀H = C₃₀-moretane/C₃₀-hopane; 20S/(20S + 20R) C₃₂H = 20S/(20S + 20R) C₃₂-hopane; C₂₇ST/%, C₂₈ST/%, C₂₉ST/%; relative abundance of 20R-C₂₇, C₂₈ and C₂₉ ααα steranes; C₂₉/C₂₈ST = 20R-C₂₉ααα sterane/20R-C₂₈ααα sterane; C₂₉/C₂₇ST = 20R-C₂₉ααα sterane/20R-C₂₇ααα sterane; C₂₉ αββ/(ααα+αββ) = C₂₉ steranes αββ/(αββ+ααα); C₂₉ ααα 20S/(20S + 20R) = C₂₉ ααα steranes 20S/(20S + 20R).

mixture of algae, bacteria and higher plants in different proportions, with varying degrees of influence on the accumulation of shale oil (Gao et al., 2016). The above studies also illustrated the Lucaogou shale source rocks display biomarkers, major and trace elements variability.

According to the above papers, the “representative” Lucaogou shale (78 samples) geochemical characteristics from source rock extracts involve: The Lucaogou Formation’s source rocks are mostly good to excellent, and the organic matter is primarily type II and II-III kerogens, which is now in the early-peak oil window; From the P₂l₁² to P₂l₂² interval, the proportions of saturated hydrocarbons gradually increase, while the proportions of resins plus asphaltene gradually decrease, and the proportions of aromatic hydrocarbons remain almost unchanged. Compared with the P₂l₂² interval, the P₂l₁² and P₂l₁¹ intervals are characterized by remarkably abundant acyclic isoprenoids (iC₁₄, iC₁₅, iC₁₆, iC₁₈, iC₁₉ and iC₂₀) and β-carotane; Based on the isoprenoid ratios Pr/*n*-C₁₇ and Ph/*n*-C₁₈ of the extracts, the organic matter in the P₂l₁² and P₂l₁¹ intervals comes mostly from marine sources, while the organic matter in the P₂l₂² interval comes primarily from terrigenous-marine sources; The distribution characteristics of terpanes in the extracts from different intervals are similar, and they are typical lacustrine source rocks; The distribution characteristics of regular steranes C₂₇–C₂₉ in Lucaogou Formation extracts are similar (C₂₉>C₂₈>C₂₇), lacking diasteranes, while the concentrations of C₂₉ (αααR) sterane in the P₂l₁² and P₂l₁¹ intervals are relatively high. In summary, the differences between acyclic isoprenoids, β-carotane and C₂₉ (αααR) sterane are some of the more distinct characteristics for different intervals of shale. Extracts that contain abundant acyclic isoprenoids and β-carotane indicate a reducing, carbonate-rich, evaporitic, and shallow water environment (Ding et al., 2020).

5.2. Oil to oil and oil to source correlation

We have already presented the differences in physical properties and several geochemical indicators of crude oil samples from the P₂l₁² and P₂l₂² intervals. Pr/*n*-C₁₇, Ph/*n*-C₁₈, TAR, Pr/Ph, IAI and β-carotane/C_{max} could be adopted as discriminators for identifying oil families of the Lucaogou unconventional shale oil systems (Fig. 6). The maturity proxies associated with sterane isomerization for all oil samples show a restricted range, suggesting near-source accumulation. Other geochemical parameters have a broad range, but there is generally overlap between these values for most samples. For example, C₂₉/C₃₀H, Ga/C₃₀H, C₂₂/C₂₁TT, C₂₄/C₂₃TT, C₂₆/C₂₅TT and C₃₁R/C₃₀H present approximate values for most oil samples, indicating that these crude oils are derived from lacustrine source rocks. The P₂l₁² interval samples are enriched in the C₂₉ regular sterane components relative to the P₂l₂² interval samples. The high concentration of C₂₉ steranes cannot be

interpreted as the main source of higher plants in this area, because these components might potentially be derived from other sources. Summarizing, a series of geochemical parameters suggest that the Lucaogou Formation crude oils are derived from lacustrine source rocks, but there are still differences in the source of crude oil between the P₂l₁² and P₂l₂² intervals.

Multiple crucial proxies indicate that the P₂l₁² interval oils originate from the P₂l₁¹ and P₂l₁² interval shales, while the P₂l₂² interval oils are derived from the P₂l₂² interval shales. For example, the discriminant plots between Pr/*n*-C₁₇ and Ph/*n*-C₁₈ of solvent extracts reveal marine origins in the P₂l₁² and P₂l₁¹ intervals and mixed sources in the P₂l₂² interval (Fig. 14). The P₂l₂² interval oils display a mixed source and plot similar to the P₂l₂² interval source rocks (Fig. 19a), indicating a good oil-source rock correlation. This conclusion can be further supported by normal alkanes distribution using the TAR values. Compared with other intervals oils and solvent extracts, the P₂l₂² interval oils have higher TAR and Pr/Ph values, and are similar to P₂l₂² interval solvent extracts (Fig. 19b). Although these proxies are impacted by thermal maturity, similar thermal maturity (sterane isomerization parameters) in our entire sample set suggests that the proxies are subject to similar degrees of thermal evolution in all samples. Some other significant indicators, IAI and Pr/*n*-C₁₇, IAI and Pr/*n*-C₁₈, β-carotene/C_{max} and IAI, contribute supplemental evidence for the P₂l₂² interval source for the P₂l₂² interval oils, and P₂l₁² and P₂l₁¹ interval sources for the P₂l₁² interval oils (Fig. 19c and d). These oils are locally sourced, considering the good agreement between oil maturity and the thermal maturity of source rocks in shale systems. It is more reasonable to assume short-distance migration of petroleum from source rocks to reservoirs within the shale oil systems, as shown in Fig. 20.

5.3. Discrepancies in oil viscosity

There is a significant difference in the oil viscosity between the P₂l₁² and P₂l₂² intervals (Fig. 3), which affects the production of crude oil. Crude oil in the P₂l₁² interval is dominated by aromatics and resins plus asphaltene (Fig. 21a–c) and originates from the source rocks of the P₂l₁² and P₂l₁¹ intervals in the Jimusaer Sag (Fig. 20). The produced petroleum contains a large number of polar compounds (e.g. acyclic isoprenoids, β-carotane), contributing to its high density and viscosity (Fig. 21d). Furthermore, thermal maturity is another critical factor in reducing viscosity. As illustrated in Fig. 21e–f, crude oil viscosity in the P₂l₁² interval shows a strong negative correlation with the sterane ratios (C₂₉ αββ/(ααα+αββ) and C₂₉ ααα 20S/(20S + 20R)), while there is no significant correlation between the crude oil viscosity in the P₂l₂² interval and the sterane ratios (C₂₉ αββ/(ααα+αββ) and C₂₉ ααα 20S/(20S + 20R)). This suggests that the maturity of the source rocks affects the

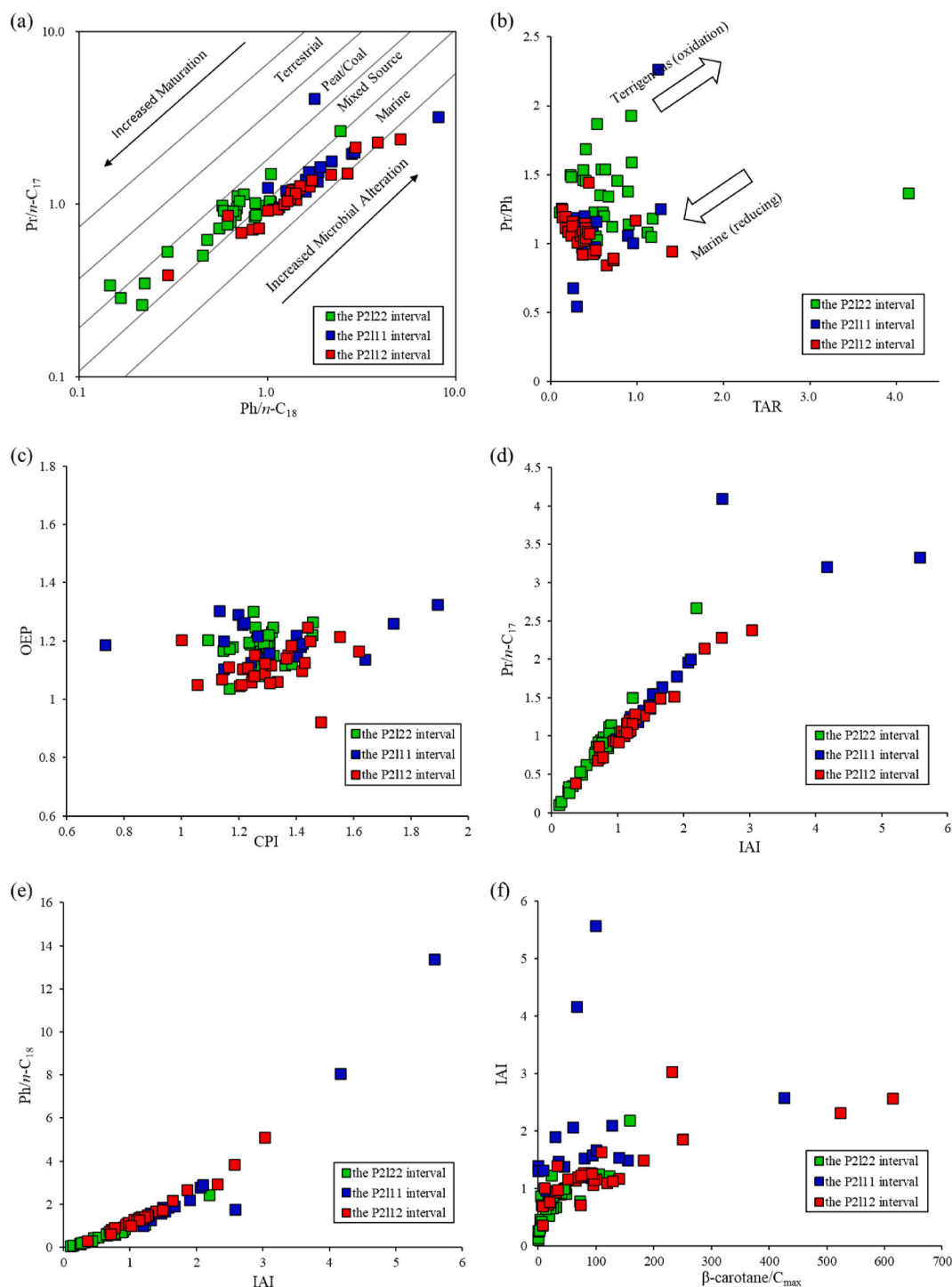


Fig. 14. Correlation between normal alkanes and acyclic isoprenoids relative abundance in source rocks. (a) $Ph/n-C_{18}$ ratios versus $Pr/n-C_{17}$ ratios; (b) Pr/Ph ratios versus TAR ratios; (c) CPI ratios versus OEP ratios; (d) IAI ratios versus $Pr/n-C_{17}$ ratios; (e) IAI ratios versus $Ph/n-C_{18}$ ratios; (f) $\beta\text{-carotane}/C_{\max}$ ratios versus IAI ratios. Abbreviations: $Pr/n-C_{17}$ = pristane/*n*-heptadecane; $Ph/n-C_{18}$ = phytane/*n*-octadecane; TAR = $(n-C_{27}+n-C_{29}+n-C_{31})/(n-C_{15}+n-C_{17}+n-C_{19})$ n-alkanes in TIC; Pr/Ph = pristane/phytane; CPI = $1/2 \times [(C_{25}+C_{27}+C_{29}+C_{31}+C_{33})/(C_{24}+C_{26}+C_{28}+C_{30}+C_{32})+(C_{25}+C_{27}+C_{29}+C_{31}+C_{33})/(C_{26}+C_{28}+C_{30}+C_{32}+C_{34})]$ in TIC; OEP = $(C_{21}+6C_{23}+C_{25})/(4C_{22}+4C_{24})$ in TIC; $\beta\text{-carotane}/C_{\max}$ = $\beta\text{-carotane}/C_{\max} \times 100$ in TIC; IAI = $(i-C_{15}+i-C_{16}+i-C_{18}+i-C_{19}+i-C_{20})/(n-C_{13}+n-C_{14}+n-C_{16}+n-C_{17}+n-C_{18})$ in TIC.

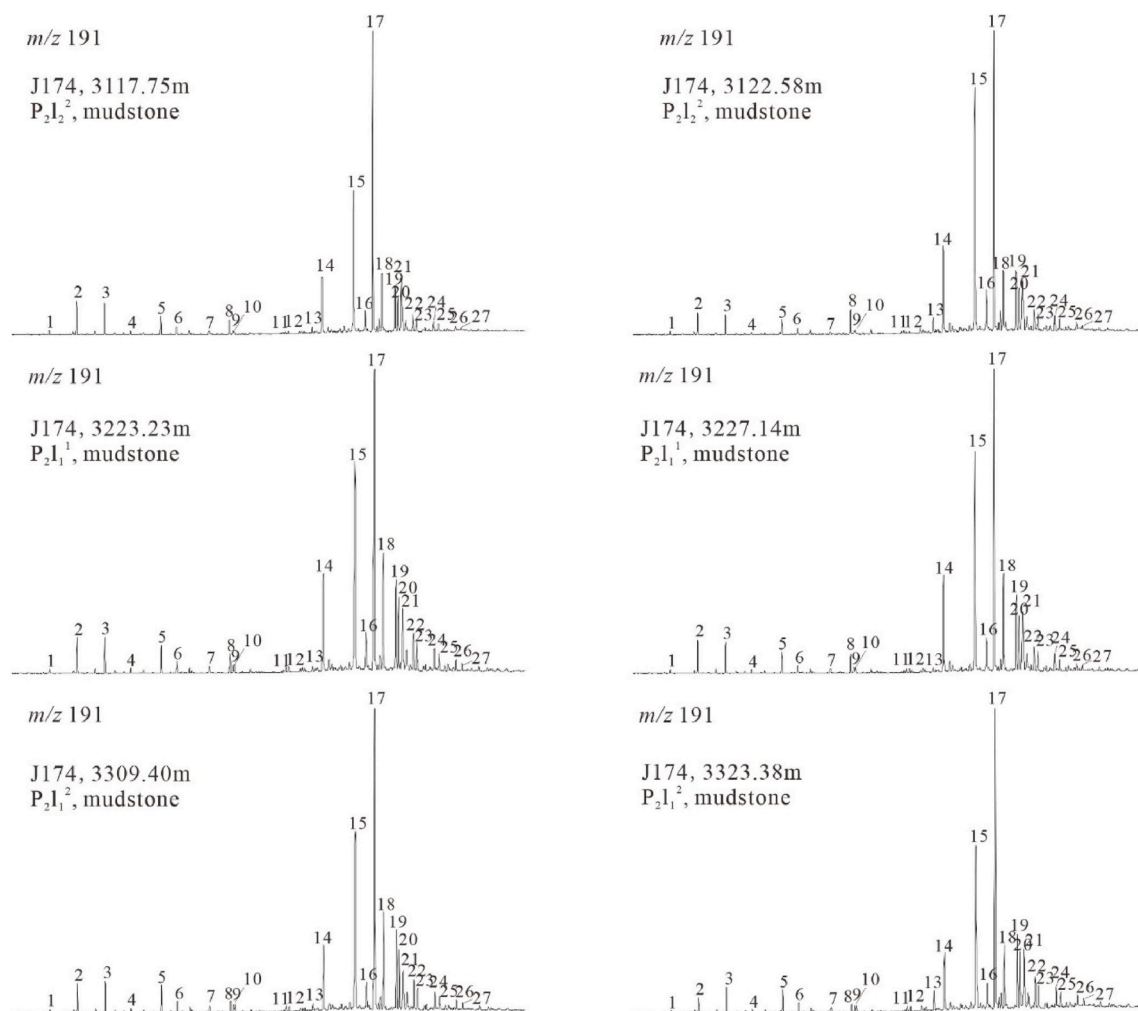


Fig. 15. Representative m/z 191 mass chromatograms illustrating the characteristics of tricyclic terpanes and hopanes in source rock samples. Compound numbers refer to Table 4.

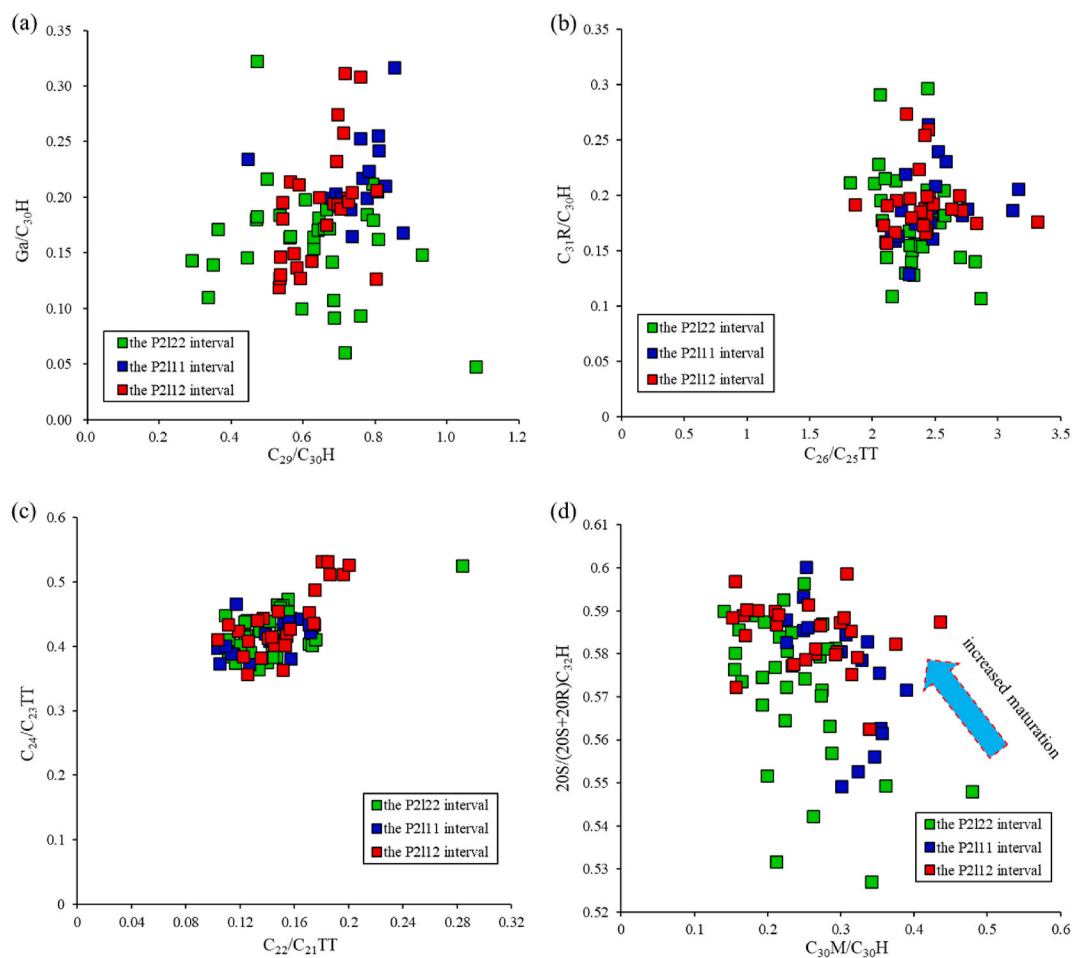


Fig. 16. Terpanes analysis results for studied oil samples. (a) $C_{29}/C_{30}H$ versus $Ga/C_{30}H$; (b) $C_{26}/C_{25}TT$ versus $C_{31}R/C_{30}H$; (c) $C_{24}/C_{23}TT$ versus $C_{22}/C_{21}TT$; (d) $C_{30}M/C_{30}H$ versus $20S/(20S + 20R) C_{32}H$. Abbreviations: TT = tricyclic terpene; $C_{31}R/C_{30}H$ = C_{31} 22R homohopane/ $C_{30}\alpha\beta$ hopane; $C_{29}/C_{30}H$ = C_{29} -norhopane/ C_{30} -hopane; $Ga/C_{30}H$ = gammacerane/ C_{30} -hopane; $C_{30}M/C_{30}H$ = C_{30} -moretane/ C_{30} -hopane; $20S/(20S + 20R) C_{32}H$ = $20S/(20S + 20R) C_{32}$ -hopane.

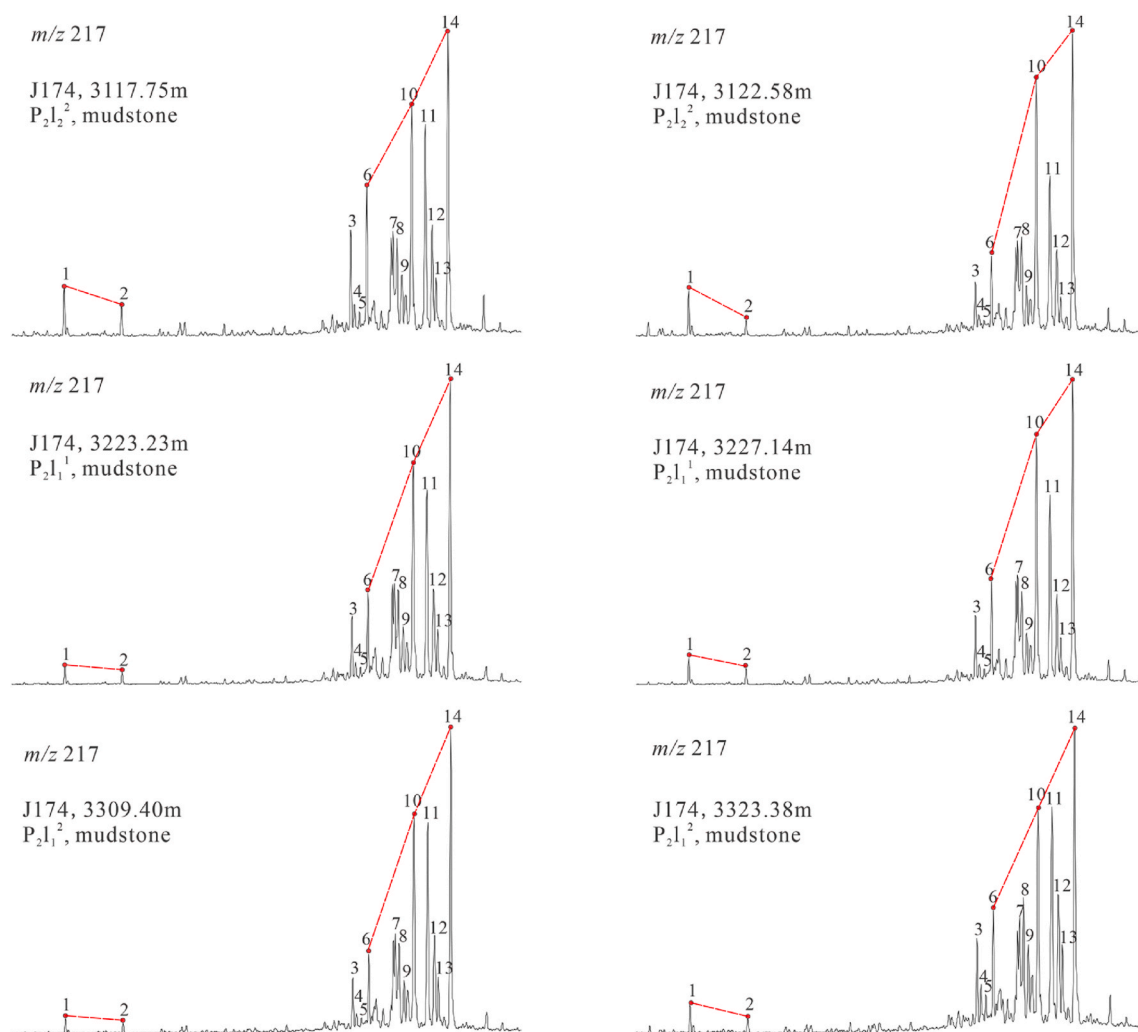


Fig. 17. Representative m/z 217 mass chromatograms illustrating the characteristics of steranes in source rock samples. Compound numbers refer to Table 4.

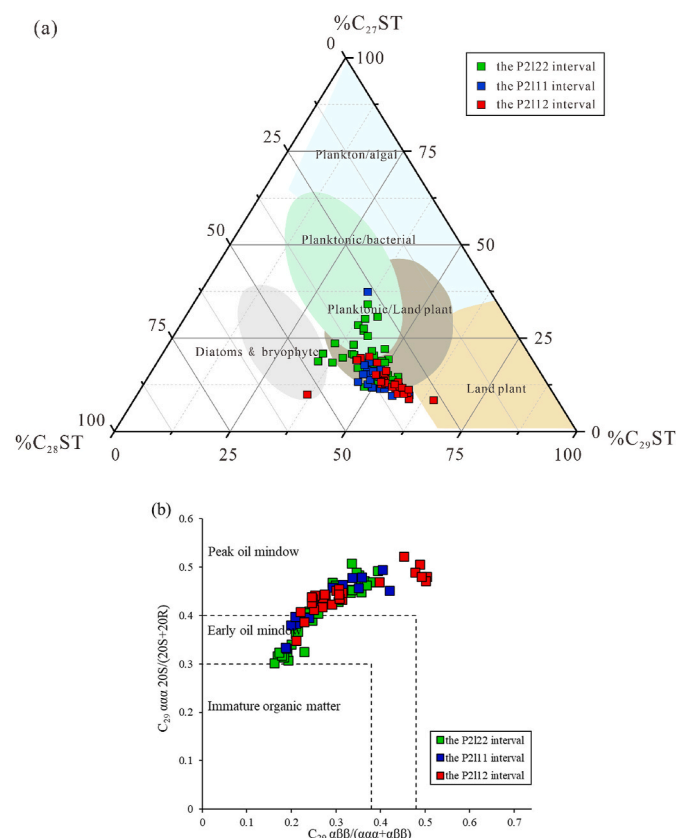


Fig. 18. Steranes analysis results for studied source rocks. (a) Ternary plot of C_{27} , C_{28} , C_{29} ($\alpha\alpha R$) regular steranes results for crude oils; (b) cross-plot of C_{29} $\alpha\beta\beta/(\alpha\alpha\alpha+\alpha\beta\beta)$ against C_{29} $\alpha\alpha\alpha$ 20S/(20S + 20R). Abbreviations: C_{29} $\alpha\beta\beta/(\alpha\alpha\alpha+\alpha\beta\beta)$ = regular steranes C_{29} $\alpha\beta\beta/(\alpha\beta\beta+\alpha\alpha\alpha)$; C_{29} $\alpha\alpha\alpha$ 20S/(20S + 20R) = regular steranes C_{29} $\alpha\alpha\alpha$ 20S/(20S + 20R).

physical characteristics of crude oil in the P_{211}^2 interval, and the lower the maturity of the source rocks, the heavier the crude oils. Biodegradation often leads to crude oil rich in polar and asphaltene fractions (Wenger et al., 2001; Jones et al., 2008). Fig. 5 shows the representative GC signatures of crude oils in different intervals. In all samples, *n*-alkanes and acyclic isoprenoids series compounds are virtually never eliminated, and there is no apparent unresolved complex mixture (UCM) hump. Nor have 25-norhopanes been observed in any of the oil samples (Fig. 22). As a result, the crude oils in the Lucaogou Formation have only suffered slight biodegradation (PM level 1–2), which has had minimal influence on the crude oils' physical characteristics. Summarizing, the main reason for the abnormal observation of high-viscosity crude oil in the deeper and hotter formations of the Jimusaer Sag is the difference in biogenic sources and thermal maturities.

5.4. Understanding the charging model

In order to better understand the unconventional Lucaogou shale oil charging model, it is required to first identify the spatial distribution and genetic relationship of the source-reservoir assemblages. Secondly, the migration pathways and dynamics between source rocks and reservoirs need to be elucidated.

The logging and drilling data show that throughout the sag, the

reservoirs are primarily developed in the P_{211}^2 and P_{212}^2 intervals (Fig. 23). The P_{211}^2 sedimentary facies zones include shallow to semi-deep lake facies, while the P_{212}^2 sedimentary facies zones include semi-deep lake, shore lake and beach bar facies. The rapid facies change of various sedimentary facies zones in the plane and the lower gentle slope, make these reservoirs isolated lithologic reservoirs. These reservoir zones exhibit high porosity (8%–18%) and high oil saturation (36%–73%), and are the main pay zones in unconventional shale oil systems (Fig. 23). FMI imaging logging reveals the presence of conductive fractures, high-resistivity fractures and laminae fractures in the Lucaogou Formation (Fig. 24). Affected by the invasion of drilling fluids during the drilling process, conductive fractures present as continuous or semi-closed dark sinusoidal curves (Fernández-Ibáñez et al., 2018). High-resistivity fractures are those that are totally or partially filled with high-resistance materials (including quartz and calcite), resulting in bright sinusoids in imaging logging (Lyu et al., 2016). Laminae fractures refer to porous fractures oriented parallel to the sediment bedding surface, which exhibit the characteristics of alternating bright and dark in imaging logging (Zhang et al., 2019a, 2019b). Under the combined effect of regional tensile stress and overpressure, the conductive fractures and laminae fractures appear to open and close periodically, which become the pathways of downward or upward migration of hydrocarbons. The main factors that control the hydrocarbon charging capacity are buoyancy, excess pressure and capillary force (Duan et al., 2013). The buoyancy steadily decreases and the capillary force increases as the reservoirs get tighter and tighter. When the buoyancy is smaller than the capillary force, the hydrocarbon finds it difficult to overcome the capillary force and migrate under the buoyancy. As a result, buoyancy is unlikely to constitute an effective driving force for hydrocarbon migration in tight reservoirs. Excess pressure created by under compaction and hydrocarbon generation in source rocks, on the other hand, can be a major driving force for lateral and vertical hydrocarbon migration (Tokunaga et al., 2000; Yao et al., 2018). The maximum excess pressure observed in well J174 is located in the source rock of the P_{211}^2 interval (Fig. 23). Excess pressure within the P_{211}^1 interval is lower than that at the bottom of the overlying P_{212}^2 interval, which makes it difficult for hydrocarbons within the P_{211}^1 interval to migrate upward effectively. As a result, this can cause lateral and downward migration of hydrocarbons within the P_{211}^1 interval through fractures and pores. In order to further analyze the charging mechanism in unconventional plays, it is necessary to understand the law of in situ fluids migration. Due to the obvious differences in mass fraction, molecular structure, solubility, and absorption of gas components, this fractionation phenomenon can be used to indicate gas migration characteristics, especially in unconventional oil and gas reservoirs where the migration is short-distance (Orangi et al., 2011; Wood and Sanei, 2016). Previous research has demonstrated that the iso-butane/*n*-butane ratio (iC_4/nC_4) could be employed to explain the thermal maturity and migration properties of hydrocarbons (Pixler, 1969; Prinzhofer et al., 2000; Zumberge et al., 2012). Fig. 23 shows that iC_4/nC_4 ratios close to the bottom of the P_{211}^1 interval are lower than that close to the top of the P_{211}^2 interval. These indicate that the fractionation phenomenon occurs in the P_{211}^1 interval, and the hydrocarbons migrate downward from the P_{211}^1 interval to the P_{211}^2 interval. This result is consistent with the oil to source correlation results in the previous section, that is, the crude oils in the P_{211}^2 interval originate from the source rocks of the P_{211}^2 and P_{211}^1 intervals. Summarizing, except for the P_{211}^2 and P_{212}^2 intervals as a self-contained source-reservoir system, the hydrocarbons generated from the P_{211}^1 interval source rocks are downwardly charged into the reservoirs of the P_{211}^2 interval through

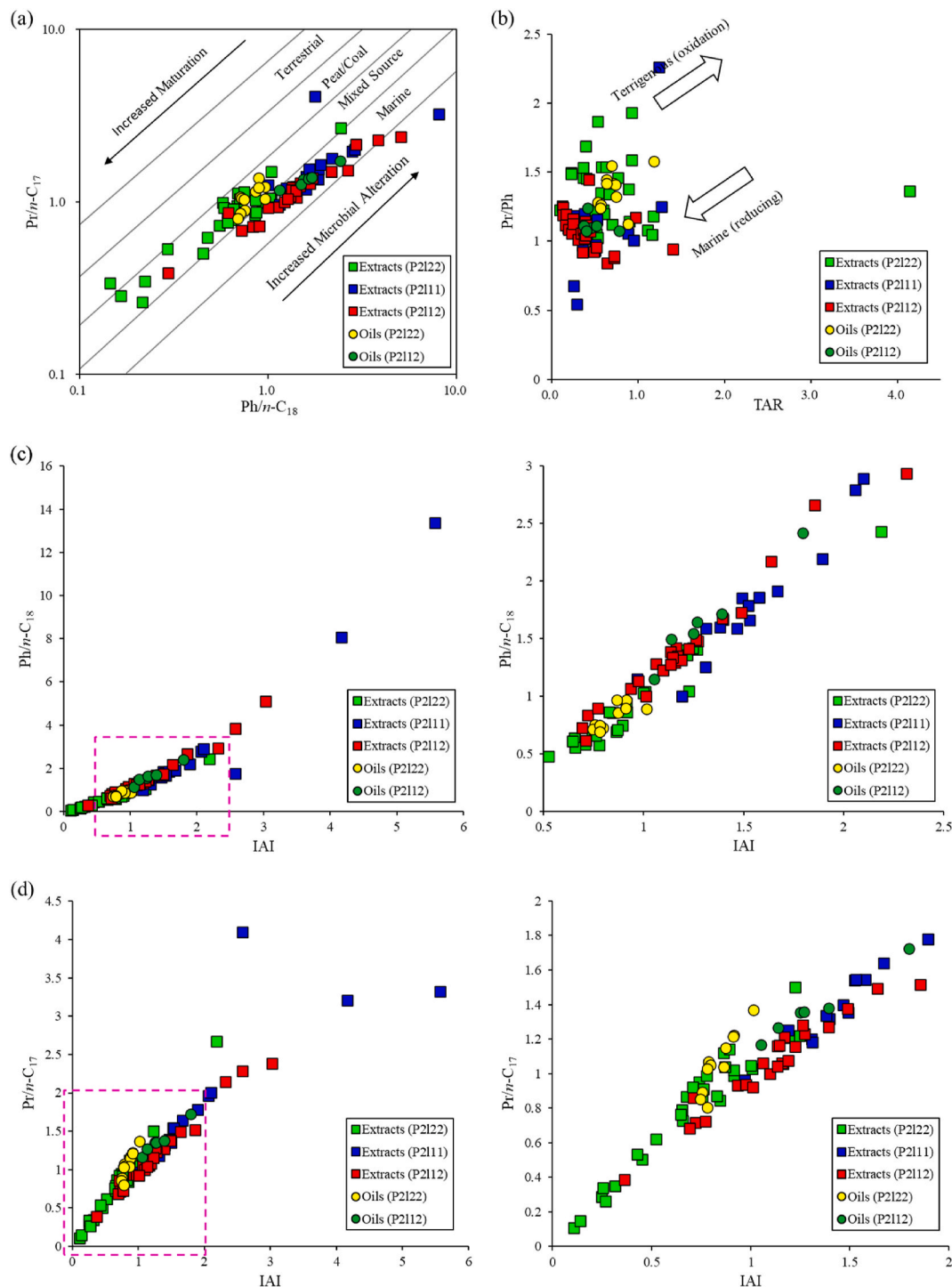


Fig. 19. Crossplots of representative biomarker parameters, including (a) Ph/n-C₁₈ ratios versus Pr/n-C₁₇ ratios; (b) Pr/Ph ratios versus TAR ratios; (c) IAI ratios versus Ph/n-C₁₈ ratios; (d) IAI ratios versus Pr/n-C₁₇ ratios; Abbreviations: Pr/n-C₁₇ = pristane/n-heptadecane; Ph/n-C₁₈ = phytane/n-octadecane; TAR = (n-C₂₇+n-C₂₉+n-C₃₁)/(n-C₁₅+n-C₁₇+n-C₁₉) n-alkanes in TIC; Pr/Ph = pristane/phytane; IAI = (i-C₁₅+ i-C₁₆+ i-C₁₈+ i-C₁₉+ i-C₂₀)/(n-C₁₃+n-C₁₄+n-C₁₆+ n-C₁₇+ n-C₁₈) in TIC.

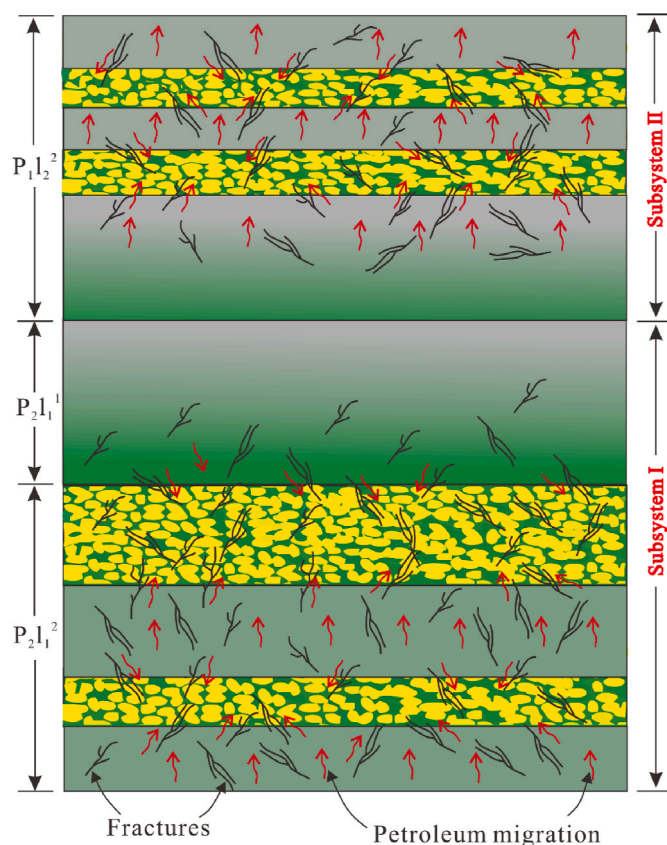


Fig. 20. The Lucaogou shale petroleum system model in the Jimusaer Sag. The two subsystem models are identified by the oil-oil/source correlation. The presence of hydrocarbons is presented by the green in the figure. The hydrocarbon migration direction is presented by the red arrows. The black branches indicate the fracture networks. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

fractures or pores (Fig. 20).

5.5. Lucaogou shale petroleum system

Utilizing oil-to-oil and oil-to-source correlations, the Lucaogou shale petroleum system consists of two subsystems. The P_{2l2}^2 interval oils are dominated by the migrated fraction of the P_{2l2}^2 interval source rocks, whereas the P_{2l1}^2 interval oils (high viscosities and polar compounds) signatures are reflective of the in-situ derived petroleum from the P_{2l1}^2 and P_{2l1}^1 intervals. Moreover, migration from source rocks to reservoirs is short-distance, which is another reason to influence the crude oil physical properties. For the lower subsystem, the P_{2l1}^1 interval plays a significant role as source and seal units in the petroleum accumulation process (Fig. 20). Understanding the Lucaogou shale petroleum system is critical to regional sweet spot analysis as well as crude oil performance. For the upper sweet spots, the generation product can be estimated based on the understanding of organic matter type in the P_{2l2}^2 interval. For the lower sweet spots, shale oil production requires a better understanding of the organic matter types and in-situ maturity of the P_{2l1}^2 and P_{2l1}^1 intervals.

6. Conclusions

A detailed geochemical analysis of 17 crude oil samples and 78 source rock extracts from 21 wells in the Lucaogou shale oil systems was performed. From the research conducted, we could draw the following conclusions:

- (1) The source rocks of the Lucaogou Formation are good to excellent, containing predominantly type II and II-III kerogens, and are now in the early-peak oil window. Compared with the P_{2l2}^2 interval, the P_{2l1}^2 and P_{2l1}^1 intervals source rocks are characterized by remarkably abundant polar compounds (e.g., resins plus asphaltene, acyclic isoprenoids, and β -carotane). The organic matter in the P_{2l1}^2 and P_{2l1}^1 intervals originates mostly from marine sources, while the organic matter in the P_{2l2}^2 interval comes primarily from terrigenous-marine sources. Terpane biomarker ratios indicate the Lucaogou shale is a typical lacustrine source rock. The distribution of steranes in these samples is similar, with a high abundance of C_{29} steranes and a low abundance of diasteranes.
- (2) There are obvious differences in the physical properties between the crude oil samples from the P_{2l1}^2 and P_{2l2}^2 intervals, among which the samples from the P_{2l1}^2 interval are characterized by high densities, high viscosities, low freezing points, and low wax contents. P_{2l1}^2 interval oil samples have higher concentrations of acyclic isoprenoids, hopanes, and β -carotane than P_{2l2}^2 interval oil samples. Terpane biomarker ratios indicate all oil samples originate from lacustrine source rocks.
- (3) Comparison of multiple distinguishing parameters (e.g. $Pr/n-C_{17}$, $Ph/n-C_{18}$, TAR, Pr/Ph , IAI, and β -carotane/ C_{max}) suggests the source of the P_{2l1}^2 interval oils is from the P_{2l1}^2 and P_{2l1}^1 intervals shales, while the P_{2l2}^2 interval oils are derived from the P_{2l2}^2 interval shales. Migration from sources to reservoirs in the Lucaogou shale oil systems is short-distance based on thermal maturity considerations.
- (4) The occurrence of high viscosity crude oils in the deeper and hotter formations (the P_{2l1}^2 interval) of the Jimusaer Sag is associated with sources and thermal maturities.
- (5) Through the source-reservoir assemblages, migration pathways, excess pressure, and geochemical trace analysis of typical wells, it can be found that the P_{2l1}^2 and P_{2l2}^2 intervals are self-contained source-reservoir systems, while the hydrocarbons generated from the P_{2l1}^1 interval source rocks could migrate downward into the P_{2l1}^2 interval reservoirs through pores and fractures. These results are consistent with the oil-to-source correlation results.
- (6) Based on the difference in crude oil physical properties and oil-oil/source correlation, the Lucaogou shale petroleum system could be divided into two subsystems.

CRedit author statement

Yazhou Liu: Conceptualization, Methodology, Writing-original draft, Writing- review & editing. **Jianhui Zeng:** Conceptualization, Methodology, Supervision, Funding acquisition, Resources. **Jun Jin:** Supervision, Editing. **Guangqing Yang:** Validation, Investigation, Visualization. **Baoli Xiang:** Guidance, Editing. **Ni Zhou:** Guidance of organic geochemistry. **Wanyun Ma:** Guidance of organic geochemistry. **Juncheng Qiao:** Supervision, Guidance, Editing. **Shengqian Li:** Writing- review & editing, Visualization. **Shuning Liu:** Investigation, Visualization.

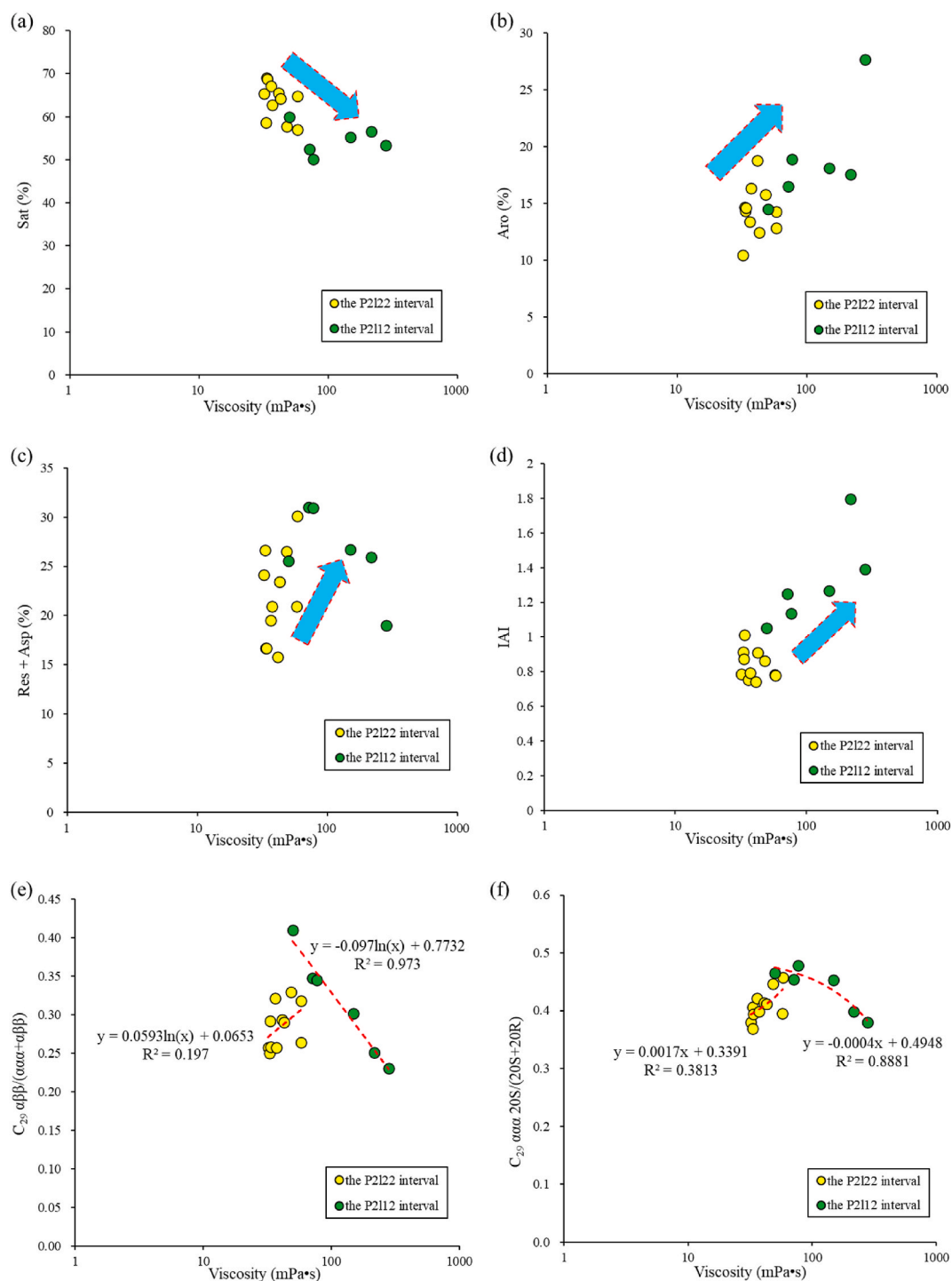


Fig. 21. Scatter diagrams between viscosity and geochemical parameters, including (a) Viscosity versus Sat; (b) Viscosity versus Aro; (c) Viscosity versus Res + Asp; (d) Viscosity versus IAI; (e) Viscosity versus $C_{29} \alpha\beta\beta/(\alpha\alpha\alpha+\alpha\beta\beta)$; (f) Viscosity versus $C_{29} \alpha\alpha\alpha 20S/(20S + 20R)$; Abbreviations: Sat = saturated hydrocarbons; Aro = aromatic hydrocarbons; Res + Asp = resins plus asphaltenes; $C_{29} \alpha\beta\beta/(\alpha\alpha\alpha+\alpha\beta\beta)$ = regular steranes $C_{29} \alpha\beta\beta/(\alpha\beta\beta+\alpha\alpha\alpha)$; $C_{29} \alpha\alpha\alpha 20S/(20S + 20R)$ = regular steranes $C_{29} \alpha\alpha\alpha 20S/(20S + 20R)$.

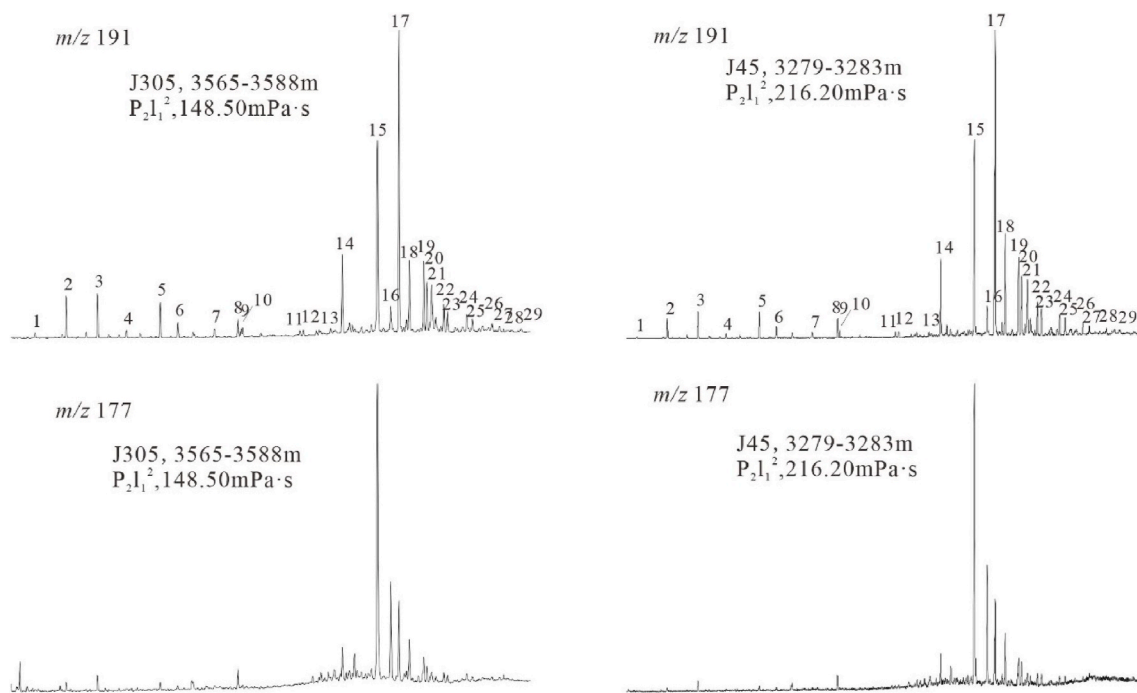


Fig. 22. Comparison of mass chromatograms of typical crude oil samples at m/z 177 and m/z 191. Compound numbers refer to Table 4.

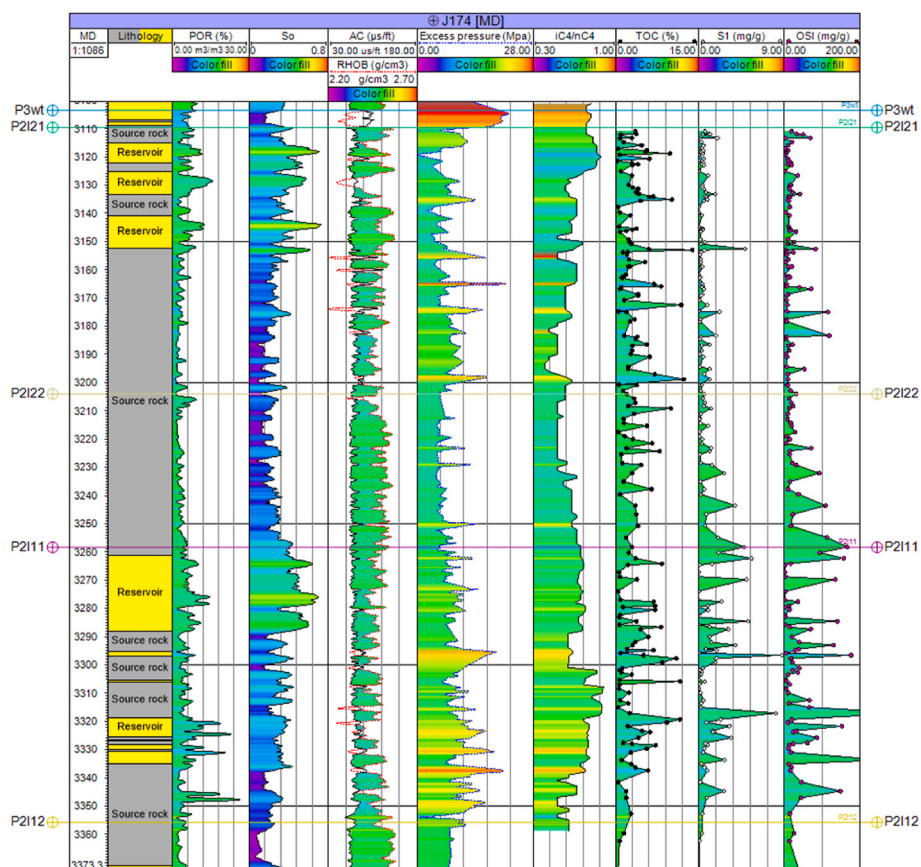


Fig. 23. The conventional well logs, excess pressure, iC_4/nC_4 and Rock-Eval pyrolysis data for Well J174 in Jimusaer Sag. POR = porosity; S_o = oil saturation; AC = acoustic transit time; RHOB = Formation bulk density; Excess pressure = Formation pore pressure - hydrostatic pressure; OSI = $S_1/TOC \times 100$.

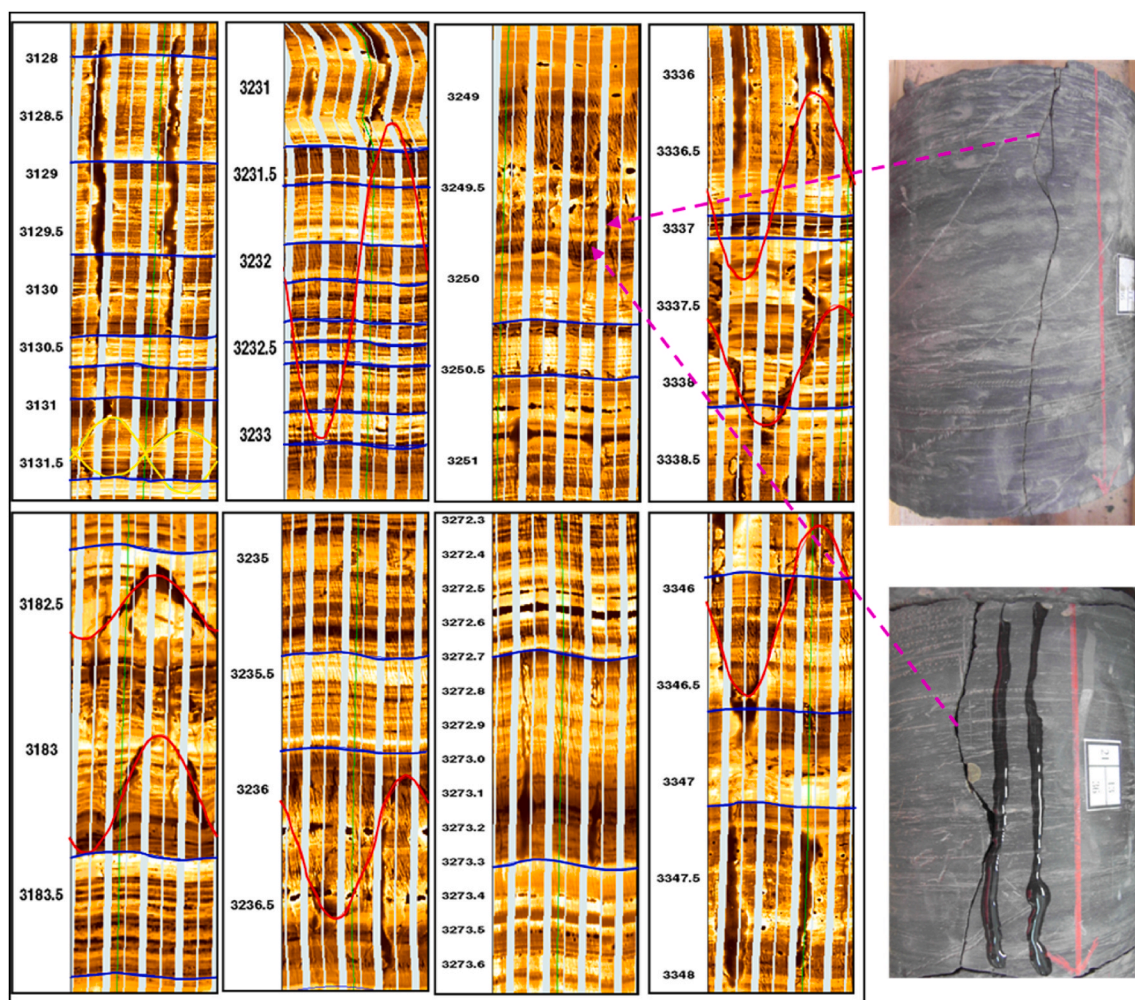


Fig. 24. Fractures detected by FMI image log in Well J174. Conductive fractures, as shown by the red line; high-resistance fractures, as indicated by the yellow line; and laminae fractures, as indicated by the blue line. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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