Comparison of Hydrocarbon Accumulations in Global Marine Carbonate Sequences and Its Implication for Exploration*

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Abstract

Marine carbonates are important oil and gas exploration plays. By the end of 2008, those recoverable reserves found in marine carbonates, primarily distributed along the northern margin of Gondwana as well as the western and eastern margins of Euramerica, account for 42.1% of the total oil and gas reserves in the world, based on our recent research. Stratigraphically, they are largely reservoired in Cretaceous, Jurassic, Paleogene, Permian, Neogene and Carboniferous rocks. A comparison of Chinese basins with global basins indicates that marine carbonate sequences in China, particularly those in the Tarim and Sichuan basins, possess the essential elements for the formation of significant hydrocarbon accumulations. The distribution of oil and gas in marine carbonate sequences are mainly controlled by the source kitchen and regional seal, especially evaporite seal. Within the prospective areas, the major paleo-highs, paleo-slopes, large structural trends and/or zones with good reservoirs are the most favorable fairways. Within the fairways, traps, lithofacies, diagenesis and/or structural fracturing dominate the distribution of hydrocarbon accumulations.

Overview of Global Marine Carbonates Petroleum Resources

Marine carbonates are important hydrocarbon exploration plays and produce 50% of the global total oil production (Mazzullo, 2004). Oil production in the Middle East accounts for 30% of the global total production (BP, 2011) and 83% of the oil is from marine carbonates. Compared with marine carbonates distributed abroad, marine carbonates are underexplored and poorly understood. Even though in-place oil and gas resources in marine carbonates in China are estimated to be more than 30 billion tons (b.t.) oil equivalent, the discovery maturity is only 6% (Mu Shuling et al., 2009). Thus, marine carbonates have a huge exploration potential and are an important strategic domain for finding new oil and gas reserves in China (Jin Zhijun, 2010).

Based on the data from various organizations including USGS (Gautier et al., 1995; USGS, 2000), IHS database (IHS, 2009), ExxonMobil (Markello et al., 2006) and StatoilHydro (Ehrenberg and Nadeau, 2005; Ehrenberg et al., 2009), this study did a statistical analysis of petroleum resources in marine carbonates. By the end of 2008, 2P (proved and probable) reserves in marine carbonates are 96.09 b.t. of oil, 70.57 Tcm of gas and 6.03 b.t of condensate, i.e. 158.80 b.t of oil equivalent. Oil, gas and condensate reserves in marine carbonates account for 44.0%, 38.1% and 59.0% of the total oil, gas and condensate reserves respectively. In terms of oil equivalent, reserves in marine carbonates make up 42.1% of the total reserves.

Global Distribution of Reserves in Marine Carbonates

Oil and gas resources in marine carbonates are not uniformly distributed, but their distribution shows certain patterns. Regionally, discoveries have been made in marine carbonates in more than 60 basins. The discovered oil and gas are concentrated along the northern margin of Gondwana as well as the western and eastern margins of Euramerica, namely the present day Arabian, Zagros, Southern Gulf of Mexico, Volga-Ural, North Caspian, Sirt, Karakum, Alberta, Anadarko, Timan-Pechora and Greater Sarawak basins (Figure 1). Each of these basins contain oil and/or gas reserves greater than 1.364 b.t. oil equivalent (10 billion boe) and the total reserves in these basins account for 91.4% of the global total reserves in marine carbonates. Of these 12 basins, the North Caspian Basin, Karakum Basin, Alberta Basin, Anadarko Basin and Greater Sarawak Basin are rich in gas and the others are rich in oil.

Marine carbonates are widely distributed in China and cover 1/3 of the total onshore area of China. They are extensively developed in the Tarim, Sichuan, Ordos basins and the North China Platform where giant fields have been discovered in marine carbonates.

Petroleum reserves are widely distributed through marine carbonate sequences from the Precambrian to the Neogene. The main reservoirs are Cretaceous and Jurassic. The secondary reservoirs are Paleogene, Permian, Neogene and Carboniferous. Reserves contained in these 6 reservoirs account for 90.7% of the total reserves in marine carbonate sequences (Figure 2). Oil and gas in marine carbonates in China are primarily distributed in the Upper Paleozoic (Jin Zhijun, 2010).

Comparison Study of Chinese Basins with Foreign Basins

Based on the similarities of hydrocarbon distribution characteristics and geological features, this research screens out three foreign basins which are similar to the Tarim and Sichuan basins in China. They are the Williston Basin in North America, Timan-Pechora Basin in Russia and Canning Basin in Australia.

Regional Tectonic Setting

Tectonic and sedimentary frameworks of sedimentary basins are controlled by the regional geological setting. The plates where the Tarim and Sichuan basins are located are much smaller than the North American Plate where the Williston Basin is located and East European Platform where the Timan-Pechora Basin lies. The two Chinese basins are surrounded by fold belts, which led to the strong structural deformation in the Tarim and Sichuan basins. The Williston Basin is located within the stable North American Craton and is far from the orogenic belt so that the structural deformation in the basin was very weak. The eastern margin of the Timan-Pechora Basin went through compressive collision. Therefore, relatively strong deformation occurred in a foreland setting in the eastern part of the basin.

Source Rocks

Source rock features of the Tarim Basin and the analogy basins are presented in Table 1. Paleozoic source rocks were developed in the Tarim, Sichuan, Williston, Timan-Pechora and Canning basins. They are found in different strata in these basins. Middle Cambrian source rocks are present only in the Tarim Basin and Lower Ordovician source rocks are limited to the Canning Basin. Middle-Upper Ordovician sources and Carboniferous-Permian sources are developed in the Tarim and Williston basins. Silurian sources are found both in the Sichuan Basin and Timan-Pechora Basin. Devonian sources are developed in the three foreign basins. Carboniferous sources occur in all of these basins. Yet Permian sources are distributed in the Timan-Pechora, Tarim and Sichuan basins. Therefore, the Tarim Basin shares high similarity in source rocks with the Williston, Sichuan and Timan-Pechora basins.

The Tarim and Sichuan basins have a lower content of organic matter than the basins abroad, both in the maximum and mean values (Table 1). It must be pointed out that source rocks are widely distributed in the Tarim Basin with a certain scale. The large-scale sources and great hydrocarbon generation quantity provide material basis for the generation of oil and gas in the Tarim Basin. Paleozoic source rocks in the Tarim Basin consist mainly of Type II kerogen with minor Type I and Type III. Kerogen contained in the Williston and Timan-Pechora basins are primarily Type I and Type II. Maturity of Lower Paleozoic sources in the Chinese basins is remarkable higher than the basins abroad. The Sichuan Basin has the highest maturity. The hydrocarbon enrichment degree is determined by kerogen type and organic maturity.

Early Paleozoic sources are characterized by multiple phases of hydrocarbon charging, while Mesozoic and Cenozoic source rocks have only one phase of hydrocarbon charging (Table 1). Cambrian and Ordovician sources in the Tarim Basin have three phases of hydrocarbon generation/expulsion. Carboniferous source rocks have two phases.

Reservoirs

Paleozoic carbonate major reservoirs are developed in all of the five analogous basins and sandstone reservoirs can also be found in these basins. Compared with the basins abroad, Cambrian and Ordovician carbonates in the Tarim Basin have much lower porosities. However, it should be pointed out that Lower Paleozoic marine carbonates in the Tarim Basin are dominated by karstic and fractured reservoirs, while reservoirs in basins abroad are dominated by dolomites. Simple comparison is inappropriate because of the different reservoir porosity types. In the Tarim Basin, there are many fractures developed in the karstic carbonate reservoirs. Therefore, the permeability can still reach more than 100 md even if the porosity is not high. Nevertheless, permeability of carbonate reservoirs in the Tarim Basin is generally lower than the basins abroad.

In the world's most important marine carbonate basin, the Persian Gulf Basin, the major oil-producing reservoir is the Upper Jurassic Arab Formation, composed of granular carbonates with a porosity of 19% on average; the major gas-producing reservoir is the Upper Permian Khuff Formation carbonates with a porosity of 7.8% on average (Ehrenberg et al., 2007).

Conclusions and Implications

1) Marine source rocks in Chinese basins have a lower content of organic matter and higher maturity than the analogous basins abroad. But the large volume of source rocks can make up the disadvantages to some extent.

2) Marine carbonate reservoirs in Chinese basins tend to be buried deeply because of the later superposition of continental sedimentary sequences. As a result, the reservoir properties are not as good as the analogous basins abroad. But the development of karstic reservoirs can greatly improve their properties.

3) The comparison studies of similar basins indicate that marine carbonate basins in China, especially the Tarim and Sichuan basins, have basic geological conditions favorable for the formation of giant marine carbonate fields. Innovative ideas and exploration workload are the keys to make further significant breakthroughs in exploration.

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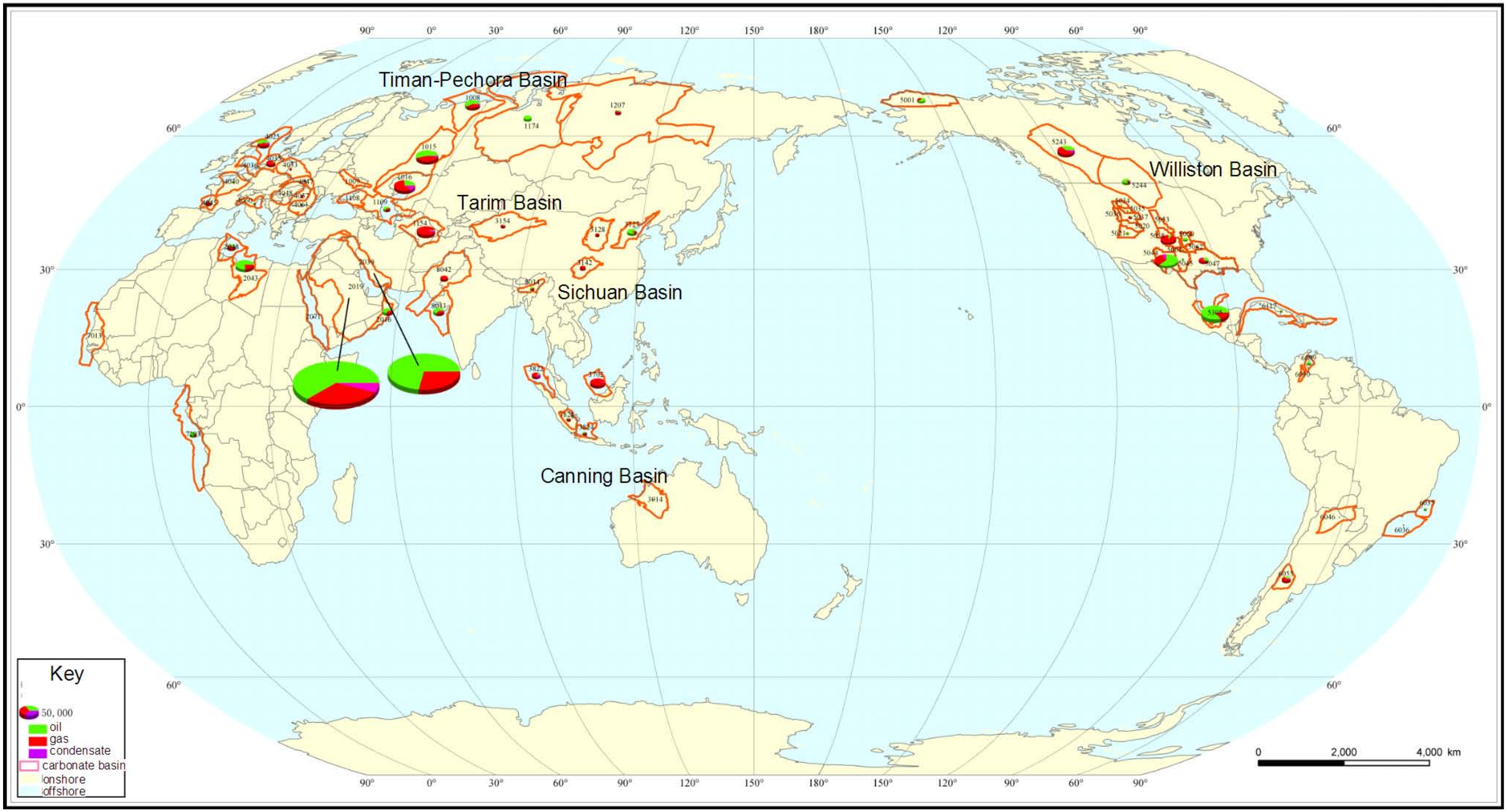

Figure 1. Distribution of oil and gas 2P reserves in marine carbonates in sedimentary basins of the world. Pie size represents the amount of discovered reserves.

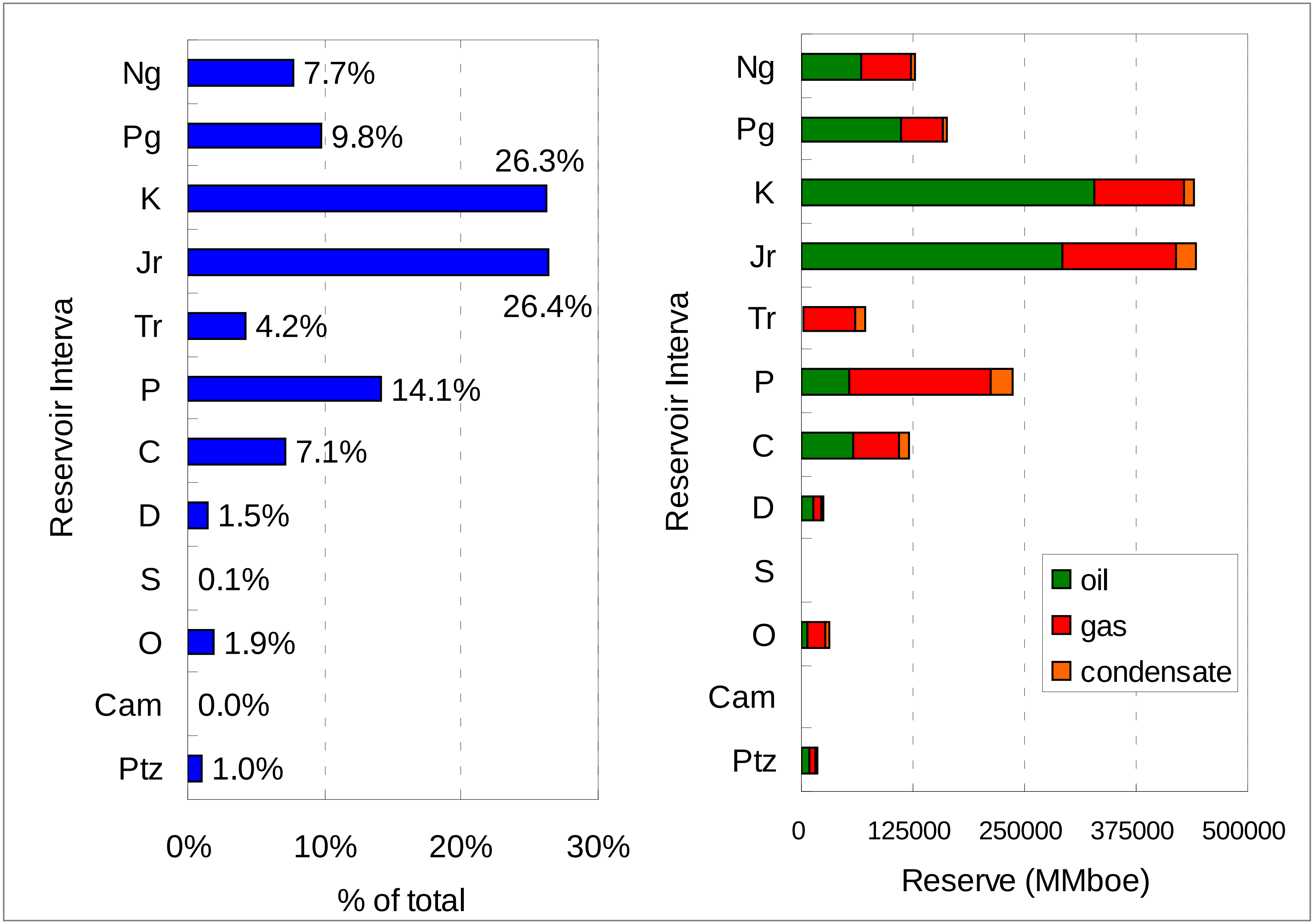

Figure 2. Stratigraphic distribution of oil and gas 2P reserves in marine carbonates of the world.

Basin	Age	Formation	Lithology	Facies	TOC (%)	Ro (%)	Kerogen Type	Hydrocarbon Expulsion Time
Tarim	T-J	Triassic-Jurassic	mudstone, coal	lacustrine-swamp	0.5-1.5, mean 1.12	0.33-0.88	II/III	Cretaceous-Tertiary
	C-P	Carboniferous-Permian	mudstone, marly carbonate	coastal swamp	1.29-1.97	0.8-1.1	II/III	Cretaceous-Tertiary, Permian-Triassic
	O_{2+3}	Middle-Upper Ordovician	marl, lime mudstone	marine	1.56	0.81-1.3	II/III	Ordovician-Silurian, Carboniferous-Triassic, Cretaceous-Tertiary
	$Є_{1+2}$	Middle-Lower Cambrian	mudstone, marly conbonate	marine	0.81-5.17	1.29-2.95	I/II	Ordovician-Silurian, Carboniferous-Triassic, Cretaceous-Tertiary
Sichuan	J_1	Ziliujing Formation	dark mudstone	lacustrine	0.4-1.2	0.7-1.7	I/II	Middle Jurassic-Late Cretaceous, Late Cretaceous-present
	T_3	Xujiahe Formation	gray and black mudstone with coal seams	lake shorezone,, swamp	mostly 1.0-4.0	1.0-1.7	III	Late Jurassic-Tertiary (mostly gas)
	P_2	Longtan Formation	carbonate, coal, dark mudstone	shallow shelf	0.3-12.0, mean 2.0	0.9-3.4	I/II/III	Late Triassic-Early Cretaceous, Middle Cretaceous-Tertiary
	P_1	Maokou and Qixia Formations	carbonate	carbonate ramp	0.3-0.9, mean 0.4	>2.0	I/II	Late Triassic-Late Jurassic, Early Cretaceous-Tertiary
	S_1	Longmaxi Formation	grey-black mudrock	Shallow to deep shelf	0.4-3.1, mean 0.8	2.0-4.0	I	Triassic-Middle Jurassic, Late Jurassic-Late Cretaceous
	$Є_1$	Qiongzhusi Formation	black carbonaceous shale	shallow shelf	0.3-4.2, mean 0.6	>2.5	I	Late Silurian-Late Triassic, Early Cretaceous-Tertiary
Williston	C_2	Tyler Formation	shale		mean 1.68		II	Late Cretaceous-present
	C_1	Lodgepole Formation	shale		mean 4		II	Late Cretaceous-present
	D_3-C_1	Bakken Formation	shale		6-20, mean 10		II	Late Cretaceous-present
	D_3	Duperow Formation	limestone		mean 0.7		I	Cretaceous-Paleogene
	D_2	Winnipegosis Formation	muddy limestone		4.8-20, mean 9		II	Cretaceous
	O_{2+3}	Red River Formation	muddy limestone		1-14, mean 8		I	Permian, Late Cretaceous
Timan-Pechora	P_1		shale, mudstone, coal bed		0.5-25, mean 5-7	0.68-0.98	III	Late Jurassic-Eocene
	D_3	Domanik Formation	shale, limestone	shelf	0.1-23.6	0.76-1	II	Permian-Cretaceous
	D_2	Afoninskiy Group	shale		0.5-0.7	0.76-1	II/III	Carboniferous-Early Permian
	O-D_1		mudstone, carbonate		0.1-13.1	0.76-1	II	Early Devonian-Jurassic
Canning	C1	Laurel Formation	shale	marine	0-3, mean 0.8			Carboniferous-Permian
	D2-3	Gogo Formation	shale	marine	mean 1.5			Carboniferous-Permian, Triassic-Tertiary
	O1	Upper Goldwyer Formation	shale	marine	1-6.4, mean 1.85		II	Silurian-Tertiary

Table 1. Geological and geochemical features of Chinese and foreign analogue basins.