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# Modes of Shale-Gas Enrichment Controlled by Tectonic Evolution

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**Abstract: The typical characteristics of shale gas and the enrichment differences show that some shale gases are insufficiently explained by the existing continuous enrichment mode. These shale gases include the Wufeng–Longmaxi shale gas in the Jiaoshiba and Youyang Blocks, the Lewis shale gas in the San Juan Basin. Further analysis reveals three static subsystems (hydrocarbon source rock, gas reservoirs and seal formations) and four dynamic subsystems (tectonic evolution, sedimentary sequence, diagenetic evolution and hydrocarbon-generation history) in shale- gas enrichment systems. Tectonic evolution drives the dynamic operation of the whole shale-gas enrichment system. The shale-gas enrichment modes controlled by tectonic evolution are classifiable into three groups and six subgroups. Group I modes are characterized by tectonically controlled hydrocarbon source rock, and include continuous in-situ biogenic shale gas ($I_1$) and continuous in-situ thermogenic shale gas ($I_2$). Group II modes are characterized by tectonically controlled gas reservoirs, and include anticline-controlled reservoir enrichment ($II_1$) and fracture-controlled reservoir enrichment ($II_2$). Group III modes possess tectonically controlled seal formations, and include faulted leakage enrichment ($III_1$) and eroded residual enrichment ($III_2$). In terms of quantity and exploitation potential, $I_1$ and $I_2$ are the best shale-gas enrichment modes, followed by $II_1$ and $II_2$. The least effective modes are $III_1$ and $III_2$. The categorization provides a different perspective for deep shale-gas exploration.**

**Key words: shale gas, enrichment mode, tectonic evolution, hydrocarbon source, gas reservoir, seal formation**

## 1 Introduction

The Energy Information Agency (EIA, 2015, 2016) recognizes 139 shale gas formations in 97 basins in 43 countries worldwide. The volume of recoverable shale gas reserves may be as high as $220.69\times10^{12}$ $m^3$. Shale gas has become the most important clean-energy source in the modern era. Advances in shale-gas enrichment research lead not only to theoretical breakthroughs in shale gas exploration, but also to the discovery of more productive areas for commercial shale-gas development.

As more shale gas reservoirs are discovered, the existing continuous enrichment mode has proved increasingly inappropriate, and sometimes yields incorrect information on shale-gas exploration. Therefore, a new shale gas enrichment mode including both the existing continuous enrichment mode and new enrichment modes is required.

To achieve this goal, this study analyzed the typical shale gas characteristics and their enrichment differences based on an extensive literature survey. A complete shale gas enrichment mechanism was built, and its structures and relationships were analyzed using the main factors of fluid mineral formation. Tectonic evolution is identified as the primary mechanism of the dynamic evolution of shale-gas enrichment. Based on the characteristics and levels of tectonic evolution in static shale-gas enrichment subsystems, the study built three groups with six subgroups of new shale-gas enrichment modes controlled by tectonics.

## 2 Geological Settings

As in conventional oil and gas resources, shale gas enrichment primarily requires a powerful hydrocarbon source, a perfect gas reservoir, a tight seal formation, and a good spatio-temporal relationship (Magoon and Dow,

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1994; Pollastro et al., 2007; Ou 2015; Ou et al., 2016e; Cui Jingwei et al., 2017), as shown in Fig. 1. A powerful hydrocarbon source provides the shale gas reservoir with sufficient hydrocarbons to drive the shale gas enrichment. Shale reservoirs are the tightest fluid mineral reservoirs discovered to date. A shale reservoir with well-developed pores and fractures and an abundance of brittle minerals is productive and commercially developable (Lan Chaoli et al., 2016; Li Yufeng et al., 2018; Ou et al., 2016e, 2018a; Ou Chenghua and Li Chaochun, 2017a). Owing to the high gas potential energy from large-scale hydrocarbon generation and the strong gas diffusion capabilities, the shale layer and the top and bottom seal formations must be tightly sealed; otherwise, shale gas will escape from the shale layer and become a gas source for other areas, preventing enrichment of the shale layer. Finally, if the spatiotemporal relationship is ignored in the shale-gas enrichment (Ou et al., 2015; Ou Chenghua et al., 2016a; Ou Chenghua et al., 2016b) and only the hydrocarbon generation is considered, the shale gas accumulation and enrichment are insignificant. The generated shale gas must fill the high-quality shale reservoir over the same duration and extent and must be continuously sealed by the top and bottom seal formations (Ren Bo et al., 2016). When these conditions are satisfied, the shale gas reservoir can be both developable and long-lasting.

Being dominated by nanopores (Chen Fangwen et al., 2018), shale-gas enrichment modes differ from conventional oil and gas resources. Early in 1995, the Unites States Geological Survey (USGS) introduced the concept of "continuous" oil and gas reservoirs when evaluating US shale gas (Gautier, 1996). Shale gas reservoirs were defined as continuous by Curtis in 2002 (Curtis, 2002), and were assigned to continuous enrichment reservoirs by the USGS in 2005 (Schmoker, 2005). The "continuous" concept was later introduced in China and is widely applied in shale-gas exploration (Zou Caineng et al., 2009, 2013; Ou et al., 2016e, 2018c).

As the continuous shale-gas enrichment mode, the shale reservoir stores biogenic gas, thermogenic gas, or both gases. This mode is characterized by a hidden accumulation mechanism, short migration, and multiple lithological trappings. Shale-gas enrichment involves vast adjacent areas with boundaries limited only by the shale

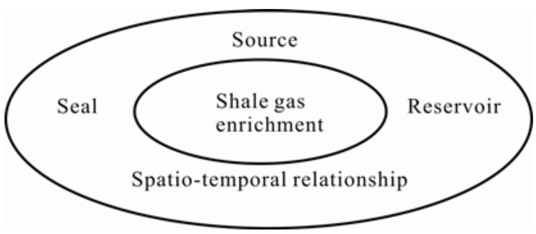


Fig. 1. Important factors of shale gas enrichment.

reservoir distribution (Gautier et al., 1996; Curtis, 2002; Zou Caineng et al., 2009, 2013). In the continuous shale-gas enrichment concept, the shale reservoir is both a hydrocarbon source rock and a gas reservoir with sealant capabilities. This source–reservoir–seal mode emphasizes hydrocarbon sourcing and reservoir accumulation, and relegates sealing to a less important role. It neglects the gas separation between the source rock and the gas reservoir, and the effects of tectonic evolution on the gas reservoir and seal formation.

The Barnett shale, located in the Fort Worth Basin in the US, is a well-known shale gas reservoir (Carlson, 1994; Bowker, 2007; Pollastro et al., 2007ab) that exemplifies the continuous shale-gas enrichment mode (Pollastro, 2007a, 2007b). In fact, the Barnett shale is influenced by tectonic evolution. The Fort Worth Basin is a back-arc foreland basin formed in the late Paleozoic Marathon–Ouachita orogeny (Walper, 1982; Montgomery et al., 2005). The Cambrian to Lower Ordovician formation is carbonate sediment from the passive continental margin, and the Mississippian formation resulted from foreland sedimentation, in which the Barnett shale and Chappel limestone are deposited. The Barnett shale is up to 3000 m thick in the northeast of the basin. As it gradually changes to limestone, its thickness decreases from the west to the center of the basin (Loucks and Ruppel, 2007; Jarvie et al., 2007). The Barnett shale was eroded from the Late Devonian to the Early Permian. The source rock was mature, and abundant hydrocarbons were generated from the Permian to the Cretaceous after the first and second oil crackings. Thereafter, the whole formation began to uplift, gradually forming the Barnett shale-gas enrichment area (Curtis, 2002; Hill et al., 2007; Jarvie, 2007). Although the resultant Barnett shale gas reservoir is vast and connected, tectonic evolution facilitated the appropriate burial depth for substantial hydrocarbon generation and the required hydrocarbon-expulsion depth during the shale-gas enrichment and accumulation processes (Ou, 2016; Ou et al., 2015; Ou Chenghua et al., 2016cd). Therefore, the effect of tectonic evolution on hydrocarbon generation, expulsion, and enrichment cannot be neglected.

The Wufeng–Longmaxi shale in Jiaoshiba Block, located in the Sichuan Basin, is strongly influenced by tectonic evolution and renowned for its abundant reserves and large production capacity (Guo Tonglou and Zhang Hanrong, 2014; Guo Xusheng et al., 2014; Ou et al., 2016e,2017b, 2018ac; Ou Chenghua and Li Chaochun, 2017a). The Wufeng–Longmaxi shale lies above the Ordovician Linxiang tight limestone and below the Silurian Xiaoheba tight mudstone. The Sichuan Basin, located west of the Yangtze platform, is a complex compressional superimposed basin. Its lower part is the Sinian-to-Silurian cratonic basin, its top part is the Permian-to-Neogene foreland basin, and its middle part (from Devonian to Carboniferous) is missing (Chen et al., 1994; Yan et al., 2003). The Sichuan Basin structure is complex with largely different tectonic styles. The Jiaoshiba Block locates in the southeast fold area of the Sichuan Basin. This block has formed a wide and gentle anticlinal structure with a flat, intact main body and steep wings. The structure was cut by faults following three uplift and subsidence episodes since the Paleozoic (Guo Tonglou and Zhang Hanrong, 2014; Guo Xusheng et al., 2014; Fig. 2). Hydrocarbons were generated from the Hercynian to the Early Indo Chinese Epoch, with significant increases from the Middle Indo Chinese Epoch to the Early Yansha Epoch. Hydrocarbon generation was maximized during the Early Cretaceous (Dai et al., 2014; Guo Tonglou and Zhang Hanrong, 2014; Guo Xusheng et al., 2014) and the shale gas accumulated in the anticline after multi-step migration (Dai et al., 2014; Guo Tonglou and Zhang Hanrong, 2014; Guo Xusheng et al., 2014). Clearly, tectonic evolution changed the structure of the Jiaoshiba Block, separating the reservoir from its source rock. The shale gas was not enriched in-situ but migrated over a certain distance before enriching in a different part of the same shale formation. Thus, tectonic evolution also significantly influences the hydrocarbon generation, expulsion, and enrichment processes.

## 3 Typical Shale Gas Enrichment Samples

### 3.1 Continuous in-situ biogenic Antrim shale gas in Michigan Basin

One continuous in-situ biogenic shale gas is the Antrim shale gas from the Michigan Basin (see Table 1), a typical cratonic basin covering $31.6\times10^4$ km$^2$. The Devonian Antrim shale gas is widely distributed in this basin. The reservoir parameters are as follows: burial depth=200–700 m, average thickness=32 m, average porosity=9%, total organic carbon (TOC)=1%–20%, $R_o$=0.4%–0.6%, and $\delta^{13}$C=-54.4‰–57.4‰. The amount of gas adsorption is 70%, the average reservoir pressure and gas content are 2.76 MPa and 3.53 m$^3$/t, respectively, and the shale-gas geological and recoverable reserves are $(9911–21520)\times10^8$ m$^3$ and $(3115–5352)\times10^8$ m$^3$, respectively. Fractures are well developed in the Antrim shale outcrop and their number decreases with increasing burial depth. The fresh water from the basin margin injects into the fractures through an unconformity plane, necessitating gas production with water drainage (Curtis, 2002; Jarvie, 2007; Song, 2006). Development began in 1940, and the gas production was maximized at $56\times10^8$ m$^3$ in 1998. The gas production can decrease but was stable at $25\times10^8$ m$^3$ in 2015 (EIA, 2016).

### 3.2 Continuous in-situ thermogenic Barnett shale gas in Fort Worth Basin

The Barnett shale gas reservoir in the Fort Worth basin, U.S.A., is a representative example of continuous in-situ thermogenic shale gases (Table 1). The role and impact of tectonic evolution of this reservoir on the hydrocarbon source rocks, hydrocarbon generation, and hydrocarbon expulsion have been analyzed in “Geological Settings”. The gross output of the Barnett shale gas in the Fort Worth Basin comprises over half of North America’s natural gas output (Bowker, 2007; Martineau, 2007). Production peaked at $502.6\times10^8$ m$^3$ in 2012 and gradually decreased to $375.7\times10^8$ m$^3$ by 2015 (EIA, 2016).

As a typical foreland basin, the Fort Worth basin covers 10878 km$^2$, and the Mississippian Barnett shale-gas enrichment zones are widely distributed. The burial depth is 1950–2550 m, and the geological and recoverable reserves are $(15291–57200)\times10^8$ m$^3$ and $(962–2832)\times10^8$ m$^3$, respectively. The shale-gas thickness exceeds 107 m in the core enrichment zones, and exceeds 30 m in the extended zones. The shale gas reservoirs are distributed continuously with decreasing thickness trends from the northeast to the southwest and northwest (Montgomery et al., 2005; Gaudlip, 2006). Deposited in a deep-water slope and basin environment, the Barnett shale is a black siliceous shale with rich organic matter and fine siltstone sediment. Its top and bottom are sealed by compact

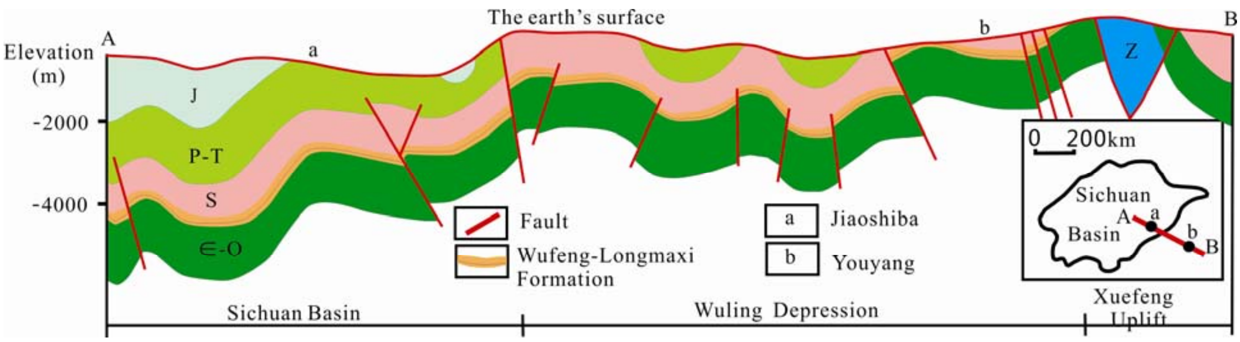


Fig. 2. Cross-section of the structure and stratigraphic distribution of the Sichuan Basin and its southeast margin.

**Table 1 Types, characteristics, and examples of tectonically controlled shale-gas enrichment modes**

| Group | Sub-group | Characteristics | | | | Examples |
|---|---|---|---|---|---|---|
| | | Tectonic evolution | Hydrocarbon source | Gas reservoir | Seal formation | |
| I Tectonically controlled hydrocarbon source | $I_1$ Continuous in-situ biogenic shale gas | Slope zones on edges of Craton Basin underwent small-scale subsidence and uplift. The burial depth of the gas reservoir is less than 1500 m | Developed organic-matter- rich mud shale, high total organic carbon, low carbon isotope values, low mature hydrocarbon generation, and in-situ hydrocarbon accumulation | Mainly in mud shale, large total shale thickness with primary intergranular pores and tectonic fractures, high water content in reservoir stratum; high adsorption gas content and low formation pressure; vast and contiguous enrichment areas | Dense formation developed in shale top-bottom strata or interbedded with dense formation, rare fractures, good hydrodynamic sealing capacity of the dense rock formation | Antrim shale gas reservoir in the Michigan Basin |
| | $I_2$ Continuous in-situ thermogenic shale gas | Centre or slope zones in foreland basin underwent rapid overall subsidence, stable burial, and slow uplift. The burial depth of the gas reservoir exceeds 1500 m | Dark coloured organic-matter-rich mud shale, high total organic carbon, high carbon isotope values, mature hydrocarbon generation and highly efficient in-situ hydrocarbon accumulation | Mainly in thick-laminated the siliceous mud shale, highly brittle mineral content, micropores and small lamellation cracks, locally visible tectonic fractures and no water in reservoir; medium-to-low adsorption gas content and high formation pressure; vast and contiguous enrichment areas | Thick dense rock formation developed in shale top-bottom strata, with weak deformation, rare fractures and good sealing capacity | Wide distribution in North America, e.g. Barnett shale gas reservoir in the Fort Worth Basin |
| II Tectonically controlled gas reservoir | $II_1$ Anticline controlled reservoir enrichment | Tectonically adjusted areas in foreland basin underwent rapid subsidence, burial, and multi-stage uplift adjustment. The burial depth exceeds 1500 m | Organic-matter-rich mud shale, high total organic carbon, high carbon isotope values, mature hydrocarbon generation, and hydrocarbon accumulation in higher portions of tectonic structures | Mainly in thick-laminated mud shale, highly brittle mineral content, micropores and lamellation fractures, locally developed tectonic fractures at edges only, and no water in reservoir; medium-to-low adsorption gas content and super-high formation pressure; distribution of enrichment areas is controlled by anticline | Thick dense rock formation developed in shale top-bottom strata, with rare fractures and good sealing capacity | Jiaoshiba shale gas resevoir in the Sichuan Basin |
| | $II_2$ Fracture controlled reservoir enrichment | Fracture-developed slope areas in foreland basin underwent rapid subsidence, burial, and multi-stage uplift adjustment. The burial depth exceeds 1500 m | Organic-matter-rich mud shale, high total organic carbon, high carbon isotope values, mature hydrocarbon generation, and hydrocarbon accumulation in fracture-developed zones | Mainly in thick-laminated mud shale, highly brittle mineral content, micropores, possible presence of water in reservoir stratum; slightly high adsorption gas content and low formation pressure; distribution of enrichment areas is controlled by fracture zone | Fractures partly occur in the direct seal formation of shale top-bottom strata with medium sealing performance, which overlies or underlies the developed indirect seal formation with good sealing capacity | Lewis shale gas reservoir in the San Juan Basin (US) |
| III Tectonically controlled seal formation | $III_1$ Faulted leakage enrichment | Strong tectonic transformation areas at the edges of the foreland basin underwent rapid subsidence, burial and multi-stage uplifting transformation, causing the burial burial depth exceeded 1500 m during the main hydrocarbon-generation period, and currently varies from 500 to 4000 m | Organic-matter-rich mud shale, high total organic carbon, high carbon isotope values, mature hydrocarbon generation, hydrocarbon accumulation inside fault blocks | Mainly in thick-laminated mud shale, developed fractures, possible presence of water in reservoir; high adsorption gas content and low formation pressure; distribution of enrichment areas is controlled at the scale of single fault block | Faults are developed in the seal formation of shale top-bottom with poor sealing capacity, local undeveloped faults with a certain regional sealing capacity | Youyang shale gas reservoir in the Sichuan Basin |
| | $III_2$ Eroded residual enrichment | | Organic-matter-rich mud shale, high total organic carbon, slightly high carbon isotope values, mature hydrocarbon generation and residual shale hydrocarbon accumulation | Mainly in mud shale, developed secondary pores and lamellation fractures, undeveloped tectonic fractures, high water content in reservoir; slightly high adsorption gas content and low formation pressure; distribution of enrichment areas is controlled at the scale of residual reservoir-caprock system | The Direct seal formation of shale top-bottom strata; some shales denuded and eroded with generally poor sealing performance, certain localized sealing capacity | Youyang shale gas reservoir in the Sichuan Basin |

marlstone (Fig. 2; Bowker, 2007). The Barnett shale contains clay minerals (<30%), quartz minerals (8%–58%; average 34.5%), locally visible carbonate rocks (21.7%), pyrite (9.7%), and phosphate (3.3%). Its reservoir parameters are as follows: total porosity=4%–5%, TOC=3%–13% (average 4.5%) with I–$II_1$ kerogen, $R_o$=1.0%–1.4%, and $\delta^{13}C_1$=-47.6‰–41.1‰. The adsorption gas content, reservoir pressure and gas content are ~20%, 20.7–27.6 MPa and 8.5–9.9 $m^3$/t, respectively, and there is no water (Curtis, 2002; Pollastro et al., 2007ab; Montgomery et al., 2005; Hickey et al., 2007).

### 3.3 The anticline-controlled Wufeng–Longmaxi shale gas in the Jiaoshiba Block

The Wufeng–Longmaxi shale gas reservoir, located in the Jiaoshiba Block in the Sichuan Basin, China, is a representative example of anticline-controlled reservoir enrichment (Table 1). The role and impact of the tectonic evolution of this reservoir on the hydrocarbon source rocks, hydrocarbon generation, and hydrocarbon expulsion have been analyzed in "Geological Settings". The shale-gas reservoir enrichment area of the Jiaoshiba Block exceeds 300 $km^2$. At the burial depth of 2250–3500 m, the Wufeng–Longmaxi shale gas is 89 m thick on average, and both the internal and external zones of the shale-gas reservoir enrichment area are stable and widely distributed, with geological reserves of more than 3500×$10^8$ $m^3$. High-quality shale distributes in the lower part, where the average thickness is 38 m and the recoverable reserves exceed 2600 × $10^8$ $m^3$. The Jiaoshiba Block is China's largest shale gas reservoir, with an expected production capability of 50 × $10^8$ $m^3$ per annum by the end of 2017.

The shale gas enrichment area in the Jiaoshiba Block locates in the main body of a wide and gentle anticlinal structure, which is flat and intact with an increased dip angle on the anticlinal limbs (Ou et al., 2016e, 2017b, 2018ac; Ou Chenghua and Li Chaochun, 2017a). The area is cut by multiple faults (Fault 1, Fault 2, Fault 3, Fault 4, and Fault 5; see Figs. 2–3). The core of the anticlinal structure is characterized by high enrichment and a high single-well production capacity of the shale gas, whereas the narrow, steep wings nearby the faults are less enriched with low or even non-existent single-well production capacity.

Deposited in a deep-water neritic environment, the high-quality shale distributed below the Wufeng–Longmaxi shale is a black carbonaceous and siliceous shale with rich organic matter, which gradually transforms to arenaceous and argillaceous shale in a shallow-water neritic environment (Liang Chao et al., 2012). The Wufeng–Longmaxi high-quality shale has developed micro-lamellation fractures in the enrichment zone and large tectonic fractures near the limb faults. It contains clay minerals (<10%–63%), quartz (26%–80%), feldspar (6%–33%), calcite (2%–10%), and pyrite (1%–13%). The total reservoir porosity is 4%–6%, and the TOC is 3.02%–4.34% with I–$II_1$ kerogen. The average reservoir pressure coefficient is 1.55 with significant super-compaction, the gas content is 0.89–5.19 $m^3$/t, and there is no water (Liang et al., 2014; Guo Tonglou and Zhang Hanrong, 2014; Guo Xusheng et al., 2014).

### 3.4 The fracture-controlled Lewis shale gas in San Juan Basin

The Lewis shale gas reservoir in the San Juan Basin in the U.S. is a representative example of fracture-controlled reservoir enrichment (Table 1). The San Juan Basin is a typical foreland basin formed during the Mesozoic that underwent subsidence and sedimentation in the Middle Jurassic Period. Regional black Lewis shales were deposited by large-scale transgression during the Cretaceous and Laramie tectonic movement in the Late Cretaceous, which formed the current tectonic structures. The San Juan Basin is 241 km long in the north-to-south direction, 161 km wide, and covers an area of 2849 $km^2$ (Peterson et al., 1968; Curtis, 2002; Lorenz et al., 2003).

Lewis shales are widely developed in the middle and northern zones of the San Juan Basin, and are locally wedged outward in the southern zones. With burial depths of 914–1829 m and a thickness of 152.4–579 m (effective net thickness of the gas-containing shale=61–91 m), Lewis shale can be divided into four layers. The lowest layer has a high permeability ratio, which may be related to two widely developed groups of west–east and south–north fractures. These two fracture groups are present not only in the Lewis shale, but also in its surrounding sandstone reservoirs. Consequently, they provide excellent channels for the supply of hydrocarbon substances from the Lewis shales to the adjacent sandstone oil and gas reservoirs (Laubach, 992; Hill and Nelson, 2000; Lorenz et al., 2003).

The Lewis shale has relatively high TOC and $R_o$ values (0.45%–2.5% and 1.6%–1.88%, respectively), and strong hydrocarbon-generation capacity. As the upper and lower seal formations are unaffected by the fractures, the geological reserves are 27411×$10^8$ $m^3$, with a maximum of 9.6×$10^8$ $m^3/km^2$ (Hill and Nelson, 2000; Curtis, 2002). However, the reservoir pressure of Lewis shale is only 6.89–10.34 MPa. The pressure gradient and gas content are 4.52–5.65 MPa/km and 0.425–1.274 $m^3$/t, respectively, and the gas absorption content is 60%–85% (Hill and Nelson, 2000; Curtis, 2002). These features are related to the release of reservoir pressure through the fractures.

Lewis shale gas, discovered only in the 1990s, maintains an average daily gas production of 2000–5000 $m^3$ (Hill and Nelson, 2000; Frantz et al., 2000).

### 3.5 Faulted leakage and eroded residual Wufeng–Longmaxi shale gas in the Youyang Block

The Wufeng–Longmaxi shale gas in the Youyang Block of the Sichuan Basin in China is a representative example of a faulted leakage enrichment and eroded residual enrichment (Table 1). Located on the south-eastern slope of the Wuling depression outside the south-eastern edge of the Sichuan Basin and uplifted adjacent to the Xuefeng (Fig. 2), the Youyang region has experienced multiple stages of tectonic movements, including the Caledon, Indo-Chinese, Yanshan, and Himalayan. These movements are evidenced by the large-scale regional uplift structures caused by intense multi-stage compression, sustained tectonic faulting, and eroding, as well as a series of NNE–NE fault systems of unequal scale. These fault systems have divided the shale gas into different fault blocks (Fig. 4). Mostly deposited in the shelf-basin environment, the Wufeng–Longmaxi shale consists of black carbonaceous and siliceous shale sediments rich in graptolite (Zhang Qian et al., 2018). The shale is strongly deformed (Ou et al., 2018ac) with marked variations in the dip angles and burial depths (0–3520 m, Fig. 4).

The Wufeng–Longmaxi hydrocarbon source rocks were at a low mature stage ($R_o$<0.6%) prior to the Late Permian, and reached maturity from the end of the Late Permian to the end of the Middle Triassic. Their oil generation peaked after the Middle Triassic. The wet-gas condensate stage occurred at the end of the Early Jurassic, the over-mature stage after the Middle Jurassic, and the dry-gas stage during the Middle Cretaceous (about 80 Ma). The Wufeng–Longmaxi Formation has always been deeply buried, so has continuously generated sufficient hydrocarbons for subsequent shale-gas accumulation. However, after several uplift events, the formation finally formed its current shale-gas accumulation features (Zeng et al., 2013; Liang et al., 2014; Tuo et al., 2016; Yan et al., 2016; Zhao Jianhua et al., 2016; Fig. 4).

Despite the moderate burial depth of the shale gas in the central part of the Youyang Block, tectonic movements have generated a large number of dense, very high-angled outcropped faults, which severely damaged the preservation conditions of the Wufeng–Longmaxi shale gas. Therefore, only areas far from the faults have preserved their dispersed shale-gas enrichment zones (Fig.

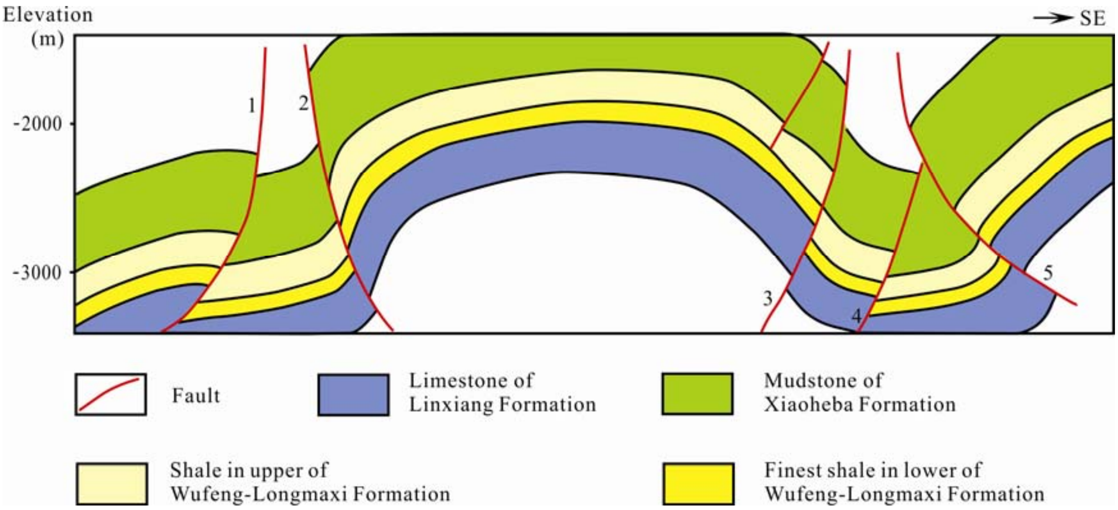


Fig. 3. Cross-section of the structure and stratigraphic section of Jiaoshiba Block in the Sichuan Basin.

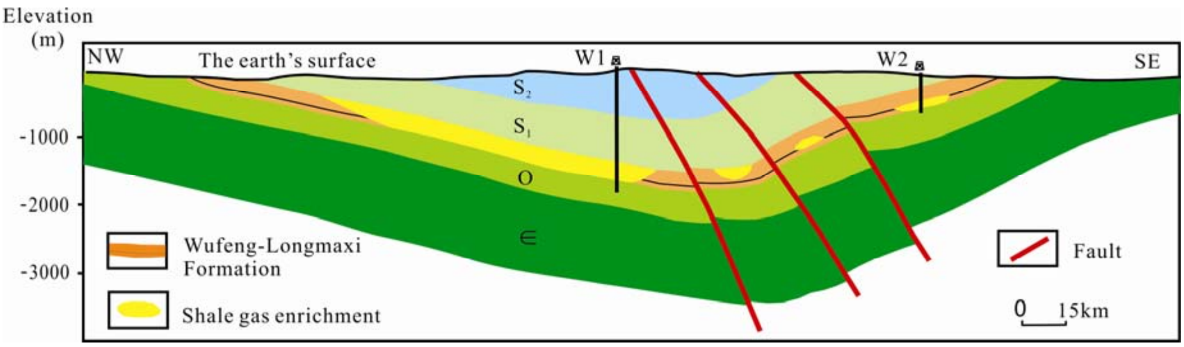


Fig. 4. Cross-sections of the tectonic, stratigraphic, and shale-gas enrichment zones in Youyang Block, beyond the southeast edge of the Sichuan Basin.

4), forming the typical faulted leakage enrichment. The existence of faulted leakage enrichment zones is directly evidenced by substrata No. 3 and No. 4 in W1 (see Fig. 4 and Table 2).

As the Wufeng–Longmaxi shales are uplifted above the ground surface, the gas reservoirs and seal formations around the Youyang Block have eroded. However, some shale-gas accumulation zones are preserved in regions at a certain depth below the eroded zones, forming the typical eroded residual enrichment. The existence of eroded residual enrichment zones is directly evidenced by substrata No. 4 and No. 5 in W2 (see Fig. 4 and Table 3).

## 4 Results and Discussions

### 4.1 Configuration of shale gas enrichment

As demonstrated in Fig. 1, a shale gas reservoir is enriched through the source–reservoir–seal system within a specific domain, over which the spatiotemporal relationship holds (Ou Chenghua et al., 2016a; Ou et al., 2016b). Within this domain, static and dynamic factors interact to establish an enrichment system of complex internal structures and relationships (see Fig. 5). The shale-gas enrichment system can be split into three static subsystems (the hydrocarbon source rock, the gas reservoir, and the seal formation), and four dynamic subsystems (tectonic evolution, the sedimentary sequence, diagenetic evolution, and hydrocarbon generation). The shale-gas enrichment varies under the control of the dynamic subsystems over the static subsystems.

Generally, the gas reservoir of a shale gas is not separated from the hydrocarbon source rock. However, during long-term geological evolution, shale gas generated inside the shale may migrate over different distances (Guo Tonglou and Zhang Hanrong, 2014; Ren Bo et al., 2016; Feng Dongjun et al., 2016), meaning that some gas reservoirs are located away from the shale-gas generation site. Migration is confirmed by the typical shale-gas enrichment differences discussed in Section 3.

The hydrocarbon source rock, gas reservoir, and seal formation are the existing static geological components of shale-gas enrichment. The hydrocarbon source dictates the

**Table 2 Basic parameters of W1, representing a faulted leakage enrichment mode in the centre of the Youyang Block**

| Strata number | Top depth (m) | Bottom depth (m) | Thickness (m) | Siliceous content (%) | Clay content (%) | Pyrite content (%) | Average Porosity (%) | Average TOC (%) | Total gas content ($m^3/t$) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 3387.6 | 3398.0 | 10.4 | 42.3 | 55.1 | 0.2 | 1.4 | 0.8 | 0.75 |
| 2 | 3413.4 | 3423.4 | 10.0 | 54.9 | 32.8 | 0.7 | 1.4 | 1.1 | 1.08 |
| 3 | 3423.4 | 3434.9 | 11.5 | 56.5 | 28.5 | 1.5 | 2.4 | 2.4 | 2.49 |
| 4 | 3436.9 | 3446.9 | 12.0 | 68.3 | 22.3 | 2.5 | 2.6 | 2.3 | 2.51 |
| 5 | 3446.9 | 3449.2 | 2.3 | 35.6 | 31.4 | 1.3 | 1.0 | 0.5 | 0.83 |

**Table 3 Basic parameters of W2, representing an eroded residual enrichment mode at the periphery of the Youyang Block**

| Strata number | Top depth (m) | Bottom depth (m) | Layer thickness (m) | Porosity (%) | Gas saturation (%) | TOC (%) | Gas content ($m^3/t$) |
|---|---|---|---|---|---|---|---|
| 1 | 550.0 | 552.0 | 2.0 | 1.9 | 57.4 | 1.4 | 0.61 |
| 2 | 555.0 | 557.0 | 2.0 | 1.9 | 60.1 | 1.3 | 0.60 |
| 3 | 563.0 | 582.0 | 19.0 | 1.6 | 63.1 | 1.4 | 0.64 |
| 4 | 582.0 | 585.8 | 3.8 | 3.2 | 65.0 | 3.0 | 1.29 |
| 5 | 587.5 | 594.6 | 7.1 | 3.8 | 63.3 | 4.0 | 1.90 |

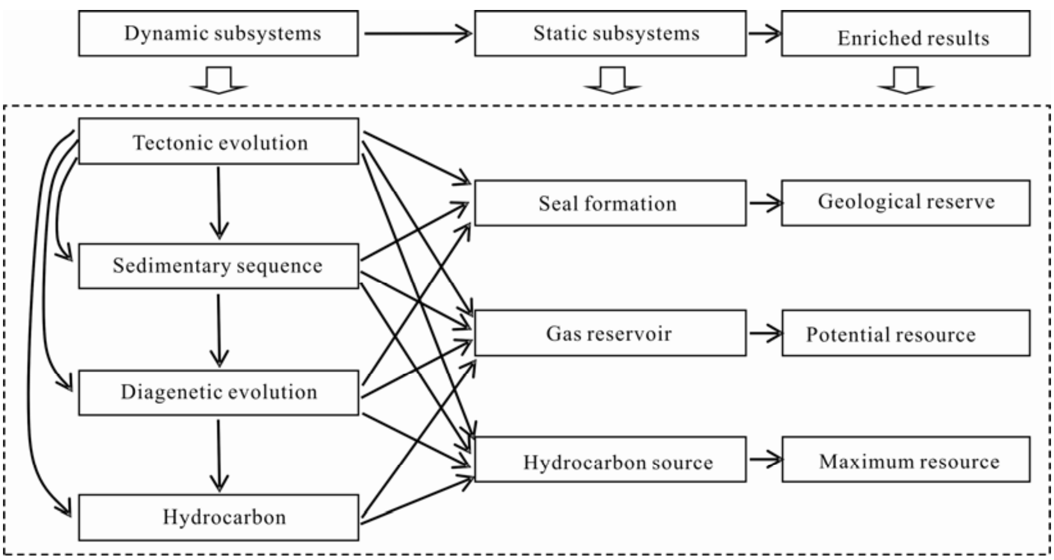


Fig. 5. Configuration of shale gas enrichment systems

maximum resource that can be enriched. The gas reservoir determines the potential resource (generally below 30% of the maximum), and the seal formation limits the real shale-gas reserves (generally below 50% of the potential). These static subsystems function through various interactions and couplings exerted by the four dynamic subsystems (Ou Chenghua et al., 2016cd; 2018b). The hydrocarbon source rock, gas reservoir, and seal formation are sedimentary sequences controlled by various sedimentation processes in specific palaeo-geographic environments throughout various lithological periods. The characteristics of the palaeo-geographic environments and accommodation spaces differ under the effects of tectonic evolution. These differences are the primary drivers of different sedimentary sequences. The variation in burial depths due to tectonic uplift and subsidence of static geologic bodies is fundamental to diagenetic evolution and various diagenetic processes (Yu Songyuan et al., 2017).

Shale gas consists of biologically and thermally generated gas with individual generation limitations (Curtis, 2002; Hill et al., 2007; Pollastro, 2007a, b). Therefore, gas generated from a hydrocarbon source rock has specific stages and histories, all related to the formation temperature and pressure history of its burial. The burial history of a formaiton is the formation, sedimentation and diagenesis record that accompanies tectonic uplift and subsidence (Ou et al., 2016e, 2018bc).

As confirmed by the typical shale-gas enrichment differences discussed in Section 3, tectonic evolution controls the dynamics of the shale-gas enrichment mechanism, and hence (to a large extent) the factors in the dynamic and static subsystems. The shale enrichment mechanisms are linked to their tectonic evolution drivers in Fig. 5. Shale-gas enrichment modes controlled by tectonic evolution are further classifiable into three enrichmnt modes that depend on the degree of control over the hydrocarbon source, gas reservoir, and seal formation: namely, tectonically controlled hydrocarbon source rock, tectonically controlled gas reservoirs, and tectonically controlled seal formations. Each mode can be subdivided into two sub-modes based on the strength of the tectonic control. Thus, one can define three groups and six subgroups of shale gas enrichment modes (see Table 1). Generally, a stable, slightly active, and strongly active tectonic zone is dominated by a tectonically controlled hydrocarbon-source enrichment mode, a tectonically controlled gas-reservoir enrichment mode, and a tectonically controlled seal-formation enrichment mode, respectively (Yu Songyuan et al., 2017).

### 4.2 Tectonically controlled hydrocarbon source (I)

As discussed above, tectonic control of the shale-gas enrichment mode usually develops in a craton or foreland basin. Owing to the stable secular tectonic subsidence, the basin accommodation space is stable, and a marine (or lacustrine) deep-water palaeo-geographic environment develops. A sedimentary sequence of shale and compact limestone is then easily formed. The shale containing rich organic matter and compact limestone eventually transforms into the shale-gas source rock, reservoir, and seal formation. Tectonic evolution largely affects the hydrocarbon generation from the source rock and the properties of the hydrocarbons. Therefore, the tectonically controlled shale-gas enrichment mode is further classifiable into two subgroups: continuous in-situ biogenic shale gas ($I_1$) and continuous in-situ thermogenic shale gas ($I_2$).

When the tectonic subsidence is insignificant, the shale is shallow and expels no water. When fresh water is injected from the basin margin, biogenic gas is formed in the shale, which is rich in organic material under anoxic, low temperature, and watery conditions. The continuous in-situ biogenic gas ($I_1$) forms after the shale gas accumulation in the shale. This shale-gas enrichment mode is found in the Antrim shale gas reservoir in the Michigan Basin (see subsection 3.1 for details), the New Albany shale gas reservoir in the Illinois Basin, the Niobrara shale gas reservoir in the Nebraska Basin, and the shale gas reservoir in the Sanhu lacustrine area in the Qaidam Basin, China. This enrichment mode is characterized by low-maturity source rocks, low reservoir pressure, many kinds of fracture developments, high water saturation, high levels of gas adsorption, a complete source–reservoir–seal system, and wide-area distribution of the shale-gas enrichment region. These properties are detailed in Table 1 and Fig. 6a.

Conversely, when the tectonic subsidence is significant, a deep reservoir is formed in which the formation temperature and pressure increase gradually, expelling water from the pore space by compaction or vaporization. Organic materials, such as kerogen and asphalt, begin to thermally degrade or crack, generating significant amounts of hydrocarbons. These processes generate a continuous in -situ thermogenic shale gas ($I_2$). This type of shale gas reservoir is widely distributed across North America. Examples are the Barnett shale gas in the Fort Worth Basin (detailed in subsection 3.2), the Woodford shale gases in the Ardomore and Anadarko Basins, the Fayetteville shale gas in the Arkoma Basin, the Pearsall shale gas in the Maverick Basin, and the Gothic shale gas in the Paradox Basin. This mode is characterized by high maturity, high reservoir pressure, minor fractures, medium –high levels of gas adsorption, a complete source–reservoir–seal system, and large-area distribution of the shale-gas enrichment region. These properties are shown

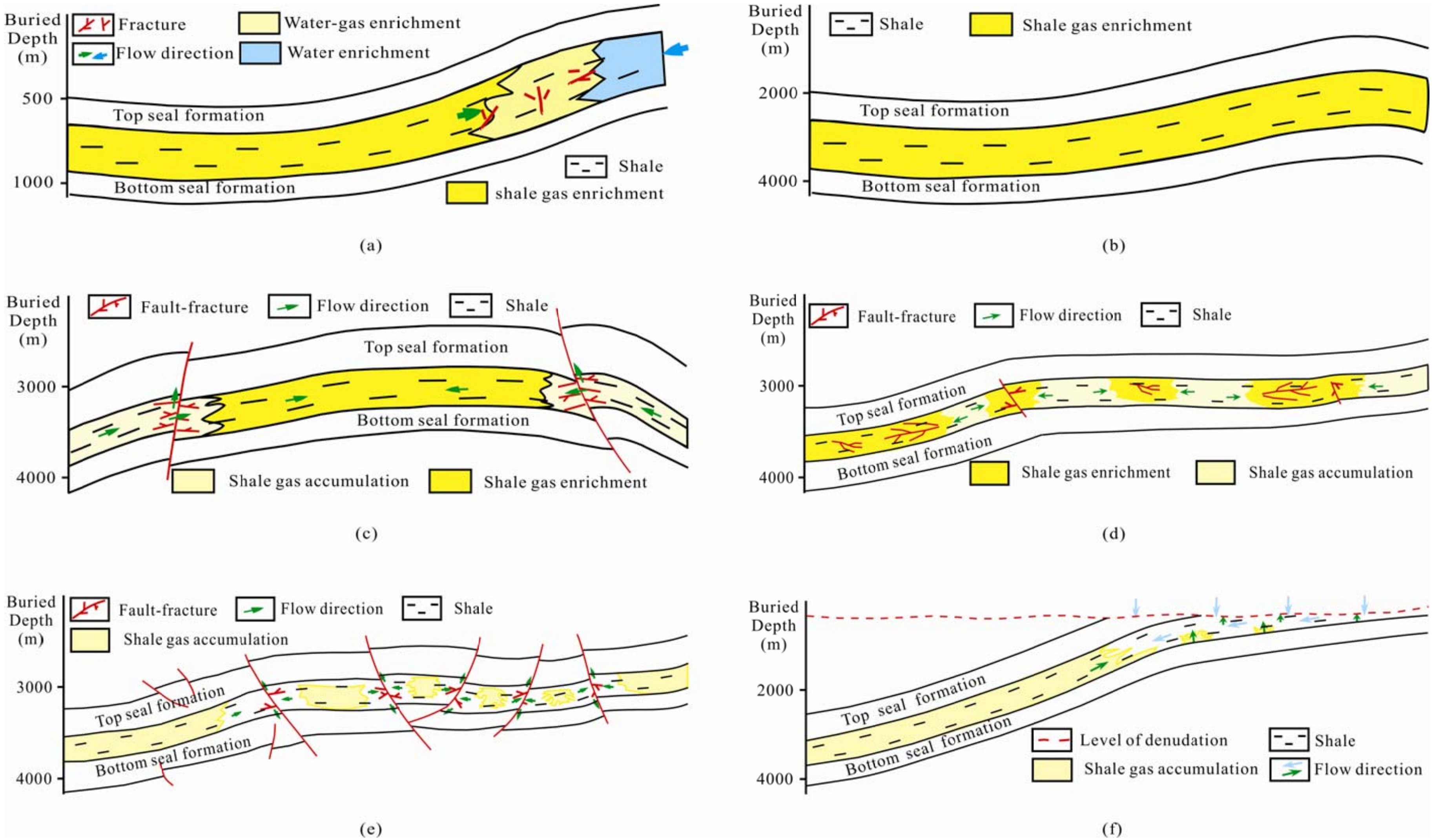


Fig. 6. Shale-gas enrichment modes controlled by tectonics.

(a), $I_1$: Continuous in-situ biogenic shale-gas enrichment mode, (b), $I_2$: Continuous in-situ thermogenic shale-gas enrichment mode, (c), $II_1$: Anticline-controlled reservoir enrichment mode, (d), $II_2$: Fracture- controlled reservoir enrichment mode, (e), $III_1$: Faulted leakage enrichment mode, (f), $III_2$: Eroded residual enrichment mode.

in Table 1 and Fig. 6b.

In these two shale-gas enrichment subgroups, the burial depth determined by tectonic subsidence limits the hydrocarbon-generation mechanism (a biogenic or thermogenic process) of organic matter in the shale. Furthermore, diagenetic processes underlie the formation of the pore-fracture system in the shale reservoir and the densification of its upper and lower seal formations. The gas reservoir development controls the shale gas distribution, leading to widespread, continuous development of the shale gas.

### 4.3 Tectonically controlled gas reservoir (II)

Tectonically controlled gas reservoirs usually develop in foreland basins. The hydrocarbon source rocks and seal-formation sedimentary sequence are formed through sedimentation in the foreland basin, similarly to the tectonically controlled hydrocarbon-source enrichment mode. A large quantity of hydrocarbons is generated and accumulated at burial depths exceeding the thermal decomposition gas threshold of kerogen. During the formation of a foreland basin, frequent tectonic movements alter the spatial form or inner structure of the shale gas reservoir; consequently, the originally enriched shale gas accumulates in a new part of the reservoir. The tectonically controlled gas-reservoir enrichment mode can be classified into two subgroups: anticline-controlled reservoir enrichment ($II_1$) and fracture-controlled reservoir enrichment ($II_2$), depending on the various gas-reservoir properties caused by the tectonic evolution.

Areas containing gas reservoirs sustained intense tectonic compression during the formation of the foreland basin. After formation, the gas reservoirs were intensely folded by substantial generation or expulsion of hydrocarbons in the source rocks. These reservoirs were originally located in the monoclinic structure of the slope zone in the basin or in the syncline of the basin center, which eventually evolved into an anticline structure (Ou et al., 2015; Ou Chenghua et al., 2016cd). The wings of these anticlines often induce various compressive reverse faults and related structural fractures (Ou Chenghua et al., 2016cd; Ou et al., 2015, 2018a). In addition, strata uplift reduces both the burial depth and the formation pressure, desorbing vast amounts of gas. The expanding free gas abruptly increases the pore pressure inside the gas reservoir, forcing the opening of lamellation fractures inside the reservoir (Ou, 2015; Ou Chenghua et al., 2016a, 2017a; Ou et al., 2016b).

This although the gas potential energy in high-position gas reservoirs increases via this process, it remains far below the gas potential energy in low-position reservoirs, because the high temperatures and pressures at low positions facilitate hydrocarbon generation. In contrast, the low temperatures and pressures at high positions weaken the hydrocarbon-generating ability. Moreover, faults and induced structural fractures on the anticlinal wing, and the open lamellation fractures in the anticlinal core, allow fluid flow channels to develop in the gas reservoir, thereby forming the anticline-controlled reservoir enrichment ($II_1$) mode with vast amounts of shale gas converging from low positions to high positions. A representative example of this enrichment mode is the Jiaoshiba Block in the Sichuan Basin, China (see subsection 3.3 for details). Besides the previously mentioned properties, the type $II_1$ mode features highly mature hydrocarbon source rock, high pressure, fracture development in the anticlinal wing, open lamellation fractures in the anticlinal core, no water, and medium gas adsorption. As the source–reservoir–seal system is complete, the shale-gas enrichment zone is controlled by the distribution and scale of the anticline. The properties are shown in Table 1 and Fig. 6c.

During the formation of the foreland basin, the source rock begins or ends its hydrocarbon generation or expulsion. Meanwhile, several tectonic movements occur in the gas reservoir. The violent changes in burial depth dramatically alter the formation temperature and pressure. The processes of gas adsorption, desorption, and free-gas compression and expansion are continuously repeated, facilitating the activation of various non-structural fractures in the gas reservoir (David et al., 2014; Ou et al., 2015; Ou Chenghua et al., 2016cd). Repeated stress changes due to tectonic uplift and subsidence also induce many structural fractures (Ou, 2016; Ou Chenghua et al., 2016cd), leading to discontinuous fracture zones in different areas of the gas reservoir. Tectonic movements change the shale-gas potential energy in the gas reservoir. The potential energy is lowered in the fracture zones, where the storage space is increased, inducing a preferential direction of shale-gas migration and enrichment. This process leads to fracture- controlled reservoir enrichment ($II_2$). A representative example of this mode is the Lewis shale gas reservoir in the San Juan Basin (detailed in subsection 3.4) (Curtis, 2002; Hill and Nelson, 2000), and possibly the Devonian shale from the Appalachian Basin. Besides the previously discussed properties, this mode features highly mature hydrocarbon source rock, medium pressure, diagenetic and tectonic fracture development, and high gas adsorption. The source –reservoir–seal system is complete, and the shale-gas enrichment zone is controlled by the distribution of the fracture zone. The properties are shown in Table 1 and Fig. 6d.

These two shale-gas enrichment subgroups are subjected to compressive tectonic movements or multi-stage tectonic uplift and subsidence, causing anticline of the shale gas reservoir or fracture zones. Consequently, the original shale gas is either adjusted and enriched, or accumulated in the high-position folding or fracture zones. As the tectonic movement is not large, the seal formation at the top and bottom of the gas reservoir is well developed, and the shale gas re-accumulates in the interior of the shale reservoir. The spatial distribution of the shale gas is predominantly controlled by the scale of the anticline or the fracture zone, so the continuous shale-gas enrichment zone is localized rather than widespread.

### 4.4 Tectonically controlled seal formation (III)

The tectonically controlled seal-formation enrichment mode develops in a strongly active tectonic zone at the margin or periphery of a foreland basin. The development progresses similarly to tectonically controlled hydrocarbon sources and tectonically controlled gas reservoirs. A favorable sedimentary sequence forms during the early foreland basin development. After hydrocarbon generation and enrichment, the margin or periphery of the foreland basin is changed by tectonic movements. Tectonic motions also damage the reservoir and its top or bottom seal formations. Based on the damage degree of the seal formations, the tectonically controlled seal-formation enrichment mode is classifiable into two subgroups: faulted leakage enrichment ($III_1$) and eroded residual enrichment ($III_2$).

After a series of compressional or tensional tectonic motions, faults and fractures develop in the core of the shale gas reservoir, cutting the reservoir and seal formations into several faulted blocks, releasing the reservoir gas (Ou et al., 2016e), and damaging the original shale gas reservoir. However, some of the shale gas far from the fault or fracture is trapped in the reservoir by the seal formations. The faulted leakage enrichment ($III_1$) mode is exemplified by the Wufeng–Longmaxi shale gas in the Youyang Block (detailed in subsection 3.5). This mode is characterized by well-developed faults in the shale gas reservoir, highly mature source rock, low reservoir pressure, low gas adsorption, damage to the reservoir-preservation system, and a shale gas distribution controlled by the scale of the faulted blocks. The specific characteristics are shown in Table 1 and Fig. 6e.

After several tectonic uplifts, the shale gas reservoir is shallowed and the dip angle usually increases. The gas reservoir and seal formation outcrop leach atmospheric air and water, freeing the adsorbed gas and releasing the shale gas. Contrarily, the nitrogen and carbon dioxide in the air and fresh water enter the shale gas reservoir. When the gas release is equilibrated between gas release and with the water injection, the gas re-accumulates in the reservoir, forming the eroded residual enrichment ($III_2$) mode. This mode is typified by the Wufeng–Longmaxi shale gas in the Youyang Block (detailed in subsection 3.5), and is characterized by a damaged reservoir and seal formation, highly mature source rock, low pressure, low gas adsorption, and high water saturation. The shale gas distribution is controlled by the distribution of the residual reservoir and seal formation. The specific characteristics are shown in Table 1 and Fig. 6f.

In these two shale-gas enrichment subgroups, multi-stage tectonic uplift and subsidence causes intense transformation, with fault or erosion of the original shale gas reservoir. The gas reservoir and its top and bottom seal formations are either cut by faults or eroded. Consequently, the shale gas re-converges and secondary faults develop in the seal formation (if fractured) or its residual (if eroded). The spatial distribution of the shale gas reservoirs is mainly controlled by the extent of fracture development or erosion, resulting in a sporadically distributed shale-gas accumulation zone.

### 4.5 Scientific significance of classifying the tectonic shale-gas enrichment modes

In terms of quantity and exploitation potential, modes $I_1$ and $I_2$ are the best shale-gas enrichment modes, followed by $II_1$ and $II_2$. The least effective modes are $III_1$ and $III_2$. However, based on the exploration and development histories of conventional oil and gas resources, the high-quality shale gas reservoir resources will deteriorate under gradual exploration and development. Eventually, shale gas reservoirs will be dominated by medium-grade resources of types $II_1$ and $II_2$, and even low-grade resources of types $III_1$ and $III_2$. This deterioration seriously challenges the exploration and development of shale gas. The present classification into three groups and six subgroups of shale-gas tectonic enrichment modes will promote a differential perspective of shale gas exploration.

## 5 Conclusions

(1) The typical shale-gas characteristics and enrichment differences were examined in four different shale reservoirs distributed in four basins. The obtained characteristics were insufficiently explained by the existing continuous enrichment mode, necessitating the proposition of a new shale-gas enrichment mode that includes both the existing continuous enrichment mode and newly introduced enrichment modes. The new shale-gas enrichment mode promotes the continuous exploration of shale gas.

(2) A shale-gas enrichment system consists of three static subsystems (hydrocarbon source rock, gas reservoir,

and seal formations) and four dynamic subsystems (tectonic evolution, the sedimentary sequence, diagenetic evolution, and the hydrocarbon-generation history). Tectonic evolution originally drives the dynamic enrichment of the shale gas reservoir, and primarily controls the shale gas characteristics. Under tectonic evolution effects, only the enriched shale gas currently preserved in the seal formations is suitable for practical prospecting and extraction.

(3) The shale gas enrichment modes controlled by tectonic evolution are classified into three groups representing the three static subsystems. Each group can be subdivided into two sub groups governed by different effects of the tectonic evolution. Ultimately, the tectonically controlled shale-gas enrichment mode consists of six subgroups in three groups. Tectonically controlled hydrocarbon source rock (type I) includes the continuous in-situ biogenic shale gas ($I_1$) and continuous in-situ thermogenic shale gas ($I_2$) modes. Tectonically controlled gas reservoirs (type II) include the anticline-controlled reservoir enrichment ($II_1$) and fracture-controlled reservoir enrichment ($II_2$) modes. Finally, tectonically controlled seal formations (type III) include the faulted leakage enrichment ($III_1$) and eroded residual enrichment ($III_2$) modes. Clearly, modes $I_1$ and $I_2$ are the best shale-gas enrichment modes for prospecting and development, followed by $II_1$ and $II_2$, whereas $III_1$ and $III_2$ are the least effective. These shale gas enrichment modes provide a differential perspective on deep shale-gas exploration.

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