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ORIGINAL ARTICLE

Fracture development in shale and its relationship to gas accumulation

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Abstract Shale with high quartz, feldspar and carbonate, will have low Poisson's ratio, high Young's modulus and high brittleness. As a result, the shale is conducive to produce natural and induced fractures under external forces. In general, there is a good correlation between fracture development in shale and the volume of brittle minerals present. Shale with high TOC or abnormally high pressure has well-developed fractures. Shale fracture development also shows a positive correlation with total gas accumulation and free gas volume, i.e., the better shale fractures are developed, the greater the gas accumulation and therefore the higher the gas production. Fractures provide migration conduits and accumulation spaces for natural gas and formation water, which are favorable for the volumetric increase of free natural gas. Wider fractures in shale result in gas loss. In North America, there is a high success ratio of shale gas exploration and high gas production from high-angle fracture zones in shale. Good natural gas shows or low yield producers in the Lower Paleozoic marine organic matter-rich rocks in the Sichuan Basin are closely related to the degree of fracture development in brittle shales.

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1. Introduction

Recent successful exploration for marine shale gas in North America (Hill and Nelson, 2000; Curtis, 2002; Warlick, 2006; Li, X.J., et al., 2009; Nie et al., 2009b; Tan, 2009), found that low porosity and permeability shale, rich in organic matter, with sufficient fractures or a significant fracture systems formed by micro-fractures and nano-pores/fissures may be an effective natural gas reservoir (Sun et al., 2008). Natural fracture development will affect not only the recovery potential of a shale gas reservoir, but also determine the quality of shale gas reservoir and gas production (Montgomery et al., 2005; Bowker, 2007; Nie et al., 2009b). Fracture development contributes to the volumetric increase of free natural gas, desorption of adsorptive gas and the increase of total gas accumulation in shale (Curtis, 2002; Chen et al., 2009; Li, D.H., et al., 2009; Nie et al., 2009b). Many studies have been made on the origin of fractures and their distribution in shale gas reservoirs as well as gas accumulation conditions. However, analysis of the dominant factors controlling shale fracture development and research on the relationship between shale fracture development and gas accumulation needs further study. Based on analyses of dominant factors affecting fracture formation in shale gas reservoirs and statistical analyses of gas accumulation data from China and elsewhere, this paper describes the dominant factors controlling shale fracture development and the relationship between shale fracture development and gas accumulation in order to provide constraints for expediting strategic investigation and target selection of shale gas resources in China.

2. Shale fracture development

There are many factors influencing fracture development and distribution in shale gas reservoirs. Compared with other types of reservoir rock, highly plastic shale reservoirs with high total organic carbon (TOC) have several common features and also special features in terms of fracture development. These features consist of non-tectonic and tectonic factors which are intrinsic and extrinsic factors, respectively, that control fracture development in shale.

2.1. Non-tectonic factors

Non-tectonic factors influencing fracture development in shale gas reservoirs include lithology and mineral composition, rock mechanics, TOC, abnormal high pressure, shale thickness, dehydration and ductile properties of clay minerals, compaction and pressure solution during diagenesis, thermo-contraction, differential erosion, and weathering denudation. Under the same stress, lithology and mineral composition, rock mechanics, TOC and abnormal high pressure are the major factors influencing fracture development (Hill and Lombardi, 2002; Ding et al., 2003; Zhao et al., 2008).

2.1.1. Lithology and mineral composition

Shale lithology and mineral composition are the main intrinsic factors controlling fracture development in shale. Shale as a general lithologic terminology includes dark siliceous, calcareous, carbonaceous, ferruginous, sandy shale varieties and oil shale (Li et al., 2007). Shale has complex mineral composition. Beside clay minerals such as kaolinite, montmorillonite and illite, it contains many clastic and authigenic minerals, such as quartz, feldspars, mica, calcite, dolomite, phosphosiderite, siderite and pyrite. The mineral content can be determined using elemental capture spectroscopy (ECS), X-ray diffraction (XRD) and scanning electron microscope (SEM) techniques (Table 1).

Fig. 1A shows plots of mineral compositions of the Devonian−Carboniferous marine shales under development in the United States. The data can be conveniently divided into two mineral composition fields. In the overlapping area of mixed lithologies such as Bossier shale, sandstone and siltstone, the contents of quartz, feldspar and pyrite are less than 40%, carbonate is >25%, and clay minerals are <50%. In the Ohio, Woodford and Barnett shales, the contents of quartz, feldspar and pyrite are 20%−80%, carbonate is <25%, and clay minerals are in the range from 20% to 80%. In the Barnett Formation of Mississippi System in the Fort Worth Basin, gas-producing dark calcic-siliceous shale has a clay mineral content of 27%, mainly consisting of illite with minor montmorillonite, and a quartz content of 35%−50%, averaging about 45%. The Devonian Ohio shale in the Appalachian Basin has a quartz content of 45%−60%. In North America, the Devonian−Carboniferous shale gas reservoirs have high content of biogenetic organic silica (e.g., radiolaria), and high quartz, mostly >40%, some up to 75%. The siliceous matrix is mainly clay-silt-sized quartz, and the shale is finely laminated. The shale gas fields under development have well-developed natural fracture systems normally due to very high quartz content which increase the brittleness of the shale.

Fig. 1B illustrates mineral compositions of the Lower Paleozoic Cambrian and Silurian gas-bearing marine dark shale from well Changxin-1 at the Changning structure in the Weiyuan area of the Sichuan Basin, China. Based on the mineral composition of 225 shale samples taken from 3 wells penetrating the Lower Cambrian Qiongzhusi dark shale in the Weiyuan area, the clay content ranges from 15% to 21% (av. 18.5%); quartz content between 59% and 69% (av. 62%); plagioclase 19%−25% (av. 22%); carbonate (calcite and dolomite) 7%−13% (av. 9.5%). Based on test results of 64 graptolitic dark shale samples taken from 4 wells in the Lower Silurian Longmaxi Formation, the clay content ranges from 26% to 41% (av. 34%); quartz 45%−76% (av. 61.5%); plagioclase is rare and carbonate content (calcite and dolomite) is in the range of 7%−20% (av. 13.5%). In this area, the Cambrian shale is rich in plagioclase and has similar quartz content, much lower clay and slightly lower carbonate compared to the Silurian shale (Table 1).

In the Lower Silurian Longmaxi Formation of the Changning structure in the southern Sichuan Basin, dark shale from well Changxin-1 has 20%−30% of quartz, 10%−25% of carbonate (calcite + dolomite), sometimes up to 35%, and 1%−4% of pyrite. Drilling results show that, fractures are well developed in the shale interval in well Changxin-1 due to its high carbonate content. However, the presence of micro-fissures in shale layers in the Weiyuan area is attributed to the high quartz content and moderately abundant carbonate and feldspar (Table 1). From this evidence, it is concluded that the brittle nature of the shale is the result of high contents of quartz, carbonate and feldspar. Therefore, natural and induced fractures tend to be formed under external forces and fracture development is favorable for gas migration and accumulation.

Dark shale rich in quartz is brittle, leading to better development of fractures compared to the more “plastic” gray shale rich in calcite (Hill and Lombardi, 2002; Nie et al., 2009a; Li, D.H., et al., 2009). Feldspar and dolomite also increase the brittleness of dark shale (Nelson, 1985). If shale has less swelling clay minerals but more silica, carbonate and feldspar, the rock is highly brittle and likely to be fractured. In shales with identical mineral compositions, the finer the grain size, the more conducive to fracture development it is, and vice versa (Zeng and Xiao, 1999; Li, D.H., et al., 2009). Fractures normally develop where there is a change in lithology.

During artificial fracturing, silica-rich shale is more prone to fracturing than clay-rich shale (Li et al., 2007; Tan, 2009). Siltstone, fine sandstone or sandstone interbeds as well as the presence of open or incompletely filled natural fractures in shale can enhance the permeability of shale reservoirs. Shale gas has higher permeability in faulted and fractured rocks (Li, X.J., et al., 2009).

2.1.2. Rock mechanics

Fractures are the results of rock rupture and their development has long been debated. Five conditions conducive for fracture

Table 1 Statistics of relationship between fracture development and lithology/mineral content in shale reservoirs.

Country	Basin	Formation	Shale lithology and sedimentary environment	Clay content (%)	Quartz content (%)	Feldspar content (%)	Carbonate content (%)	Fracture development	Gas accumulation
United States	West Texas	Devonian Bossier Fm.	Mixture of shale, sandstone and siltstone	29	30	8	>25	Developed	Shale gas
	Fort Worth abyssal foreland basin	Mississippi Barnett Fm.	Calcic-siliceous shale, calcareous mudstone containing clay; deep slope in still water-basin facies	27	$\frac{35-50(*)}{45}$	7	8	Micro-fissures well developed	Shale gas
	Appalachian Foreland basin	Devonian Ohio Fm.	Carbonaceous shale, silty shale; deep water sedimentary environment locally		40–60			Many groups of high-angle fractures developed	Shale gas
	Michigan Craton Basin	Devonian Antrim Fm.	Dark shale, gray and green shale interbedded with carbonate; marine deep water sediments		20–41			Two groups of NE & NW orthogonal nearly-vertical natural fractures developed	Shale gas
	Arkama Passive continental margin	Devonian Woodford Fm.	Siliceous shale, sedimentary environment in still water	25	$\frac{35-50}{45}$	9	8	Fracture network developed	Shale gas
China	Craton basin in Sichuan Basin, China	Lower Cambrian Qiongzhusi Fm.	Dark gray-dark carbonaceous shale, silty shale and siltstone, neritic continental shelf facies	$\frac{15-21}{18.5}$	$\frac{59-69}{62}$	$\frac{19-25}{22}$	$\frac{7-13}{9.5}$	Micro-fissures developed; basically filled with secondary calcite, dolomite and quartz	Rich showing of shale gas
		Lower Silurian Longmaxi Fm.	Rich in graptolite dark gray-dark silty shale, carbonaceous shale, siliceous shale intercalated with argillaceous siltstone; neritic – abyssal continental shelf facies	$\frac{26-41}{34}$	$\frac{45-76}{61.5}$	Rarely	$\frac{7-20}{13.5}$		Active shows of shale gas
	Craton basin in Changning structure, Sichuan basin	Lower Silurian Longmaxi Fm.	Rich in graptolite dark gray-dark silty shale, carbonaceous shale, siliceous shale intercalated with argillaceous siltstone; neritic – abyssal continental shelf facies	30–60	20–30	3–10	10–25	Well developed	Shale gas

Note : $*$: $\frac{\text{Minimum} - \text{Maximum}}{\text{Average}}$.

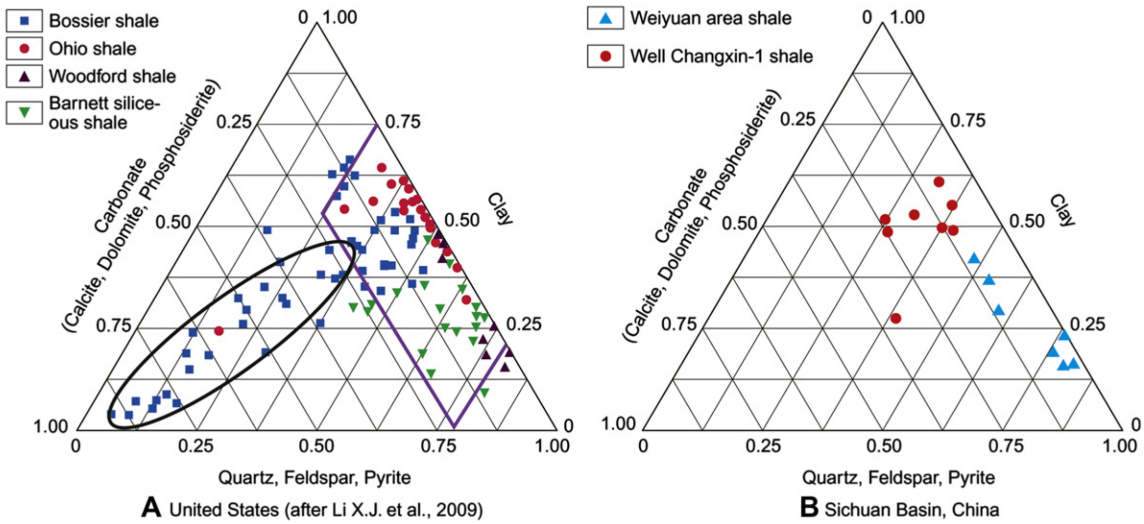

Figure 1 Ternary diagrams showing mineral compositions of Paleozoic marine shale reservoirs.

formation have been suggested: single shear strength, dual shear strength, triple shear strength, strain energy density and maximum tension stress strength. The most widely accepted of the five conditions is the Coulomb–Mohr generalized single shear strength principle and Griffith generalized maximum tension stress strength principle (Price, 1966). The main parameters used to describe elastic deformation of rocks include the Young's modulus, shear strain modulus, volumetric elastic modulus and Poisson's ratio, which reflect rock tensile strength, shear strength, compressive strength and lateral relative compressibility, respectively. Rock shear rupture is not only related to shear stress on the rupture surface, but also normal stress on the rupture surface. The stress condition at each point is determined by the tectonic stress field. In order to determine whether rock rupture has occurred at any point in the tectonic stress field or determine the development of fractures, the concept of rupture value (I) is introduced, which is defined as $I = \tau_n/[\tau]$, where τ_n is the shear force on surface and $[\tau]$ is the ultimate shear stress. For $[\tau] = C + \sigma_n \tan\varphi$, C is rock cohesion, σ_n is the normal stress on the shear rupture surface, φ is internal friction angle and $\tan\varphi$ is the internal friction coefficient. If $I < 1$, then, no fractures are generated; if $I \geq 1$, fractures are generated. Based on the value of I, fracture development can be identified (Xu et al., 2000). When a rock is subjected to a generalized tension, tension-shear or tension rupture may occur. In this case, the Coulomb–Mohr principle is not applicable. The plan rupture principle based on the Griffith strength theory can be used to identify the rupture (Yu, 1998; Zan et al., 2002). This principle is based on tension rupture, and is virtually an equivalent maximum tension stress theory suitable for the determination of tension rupture. If the tensile strength of a brittle material is identified, the effective tension stress σ_E can be used as a characteristic parameter to describe the development of tensile fractures and tension-shear fractures in the rock. This is defined as the tension stress condition in a rock. The greater σ_E is, the higher is the possibility of tension rupture. This is especially the case in homogeneous carbonate rocks. The tensile strength of rocks differs slightly, and σ_E tends to have a positive correlation with the development of tensile fractures or tension-shear fractures. Namely, higher σ_E indicates greater rupture potential and the development of a larger number of fractures, i.e., when $\sigma_E \geq \delta$, potential tensile fractures (including tension-shear fractures) may be produced. A positive value for δ ($\delta \geq 0$) refers to the tensile strength of a rock.

Above discussion on fracture generation in rocks shows that shale would rupture when the stress reaches the ultimate strength of the shale. Shale rupture can be divided into two types, tensile rupture and shear rupture. Under identical stress field, fracture development from shale rupturing is closely related to the parameters of rock mechanics of different lithologies, such as Young's modulus (E), shear strain modulus (G), volumetric elastic modulus (K), Poisson ratio (μ), cohesion (C), internal friction angle (φ) and rock rupture strength under different confined pressures. These parameters may be obtained from HTHP three-axis tests for rock mechanics.

Based on experimental analysis of rock mechanics parameters for different lithologies from four reservoirs with dominant dark argillaceous shale and siltstone interbedded with fine sandstone and medium sandstone in the Huoshaoshan oilfield in the eastern Junggar Basin, China (Xu et al., 2000), the influence of rock mechanics parameters of various argillaceous shale on fracture development can be illustrated. In three-axis rock mechanics experiments under various confined pressures, 34 cores from different depths in 5 wells were tested, including 12 argillaceous siltstone, 10 silty mudstone, 9 pure mudstone and 3 dolomitic mudstone samples. Parameters such as rupture strength, elastic modulus, Poisson's ratio, cohesion and internal friction angle indicate that: (1) different argillaceous shales have different rupture strengths. Specifically, dolomitic mudstone has the highest rupture strength of 215–239 MPa, followed by silty mudstone at 110–207.6 MPa, argillaceous siltstone at 105.5–196.5 MPa, and pure mudstone has the lowest value at 99.75–171.5 MPa; (2) mechanics parameters of different argillaceous shales such as Young's modulus, Poisson's ratio, cohesion and internal friction angle are different. Dolomitic mudstone has the largest values of all parameters and very high cohesion, indicating the highest resistance to tension, shear and compression. Poisson's ratio and Young's modulus of argillaceous siltstone, silty mudstone and dolomitic mudstone in four reservoirs (Fig. 2) show a negative correlation. Dolomitic mudstone with high rupture strength has a higher Poisson's ratio but lower Young's modulus, while silty

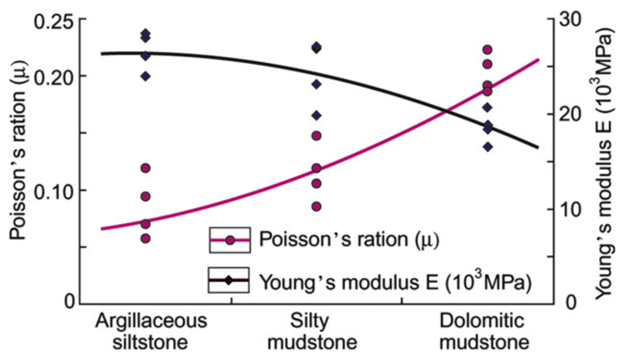

Figure 2 Variation of mechanical parameters of different mudstone, Huoshaoshan oilfield in Junggar Basin, NW China.

mudstone and argillaceous siltstone with less rupture strength have a lower Poisson's ratio but higher Young's modulus. Therefore, under identical tectonic stress conditions, argillaceous shale with low rupture strength is more brittle and prone to produce fractures. This type of brittle shale rich in organic matter is the preferred target for strategic screening of shale gas resources.

2.1.3. Total organic carbon (TOC)

TOC not only controls the overall gas accumulation in shale, but also influences fracture development. Generally, shale in the fracture zone has a high exploration success ratio and high gas production corresponding to high TOC (Xu et al., 2000). Under identical geodynamic conditions, rock mineral composition and mechanical properties, TOC is an important factor affecting fracture development in shale (Hill and Lombardi, 2002). Shale with high contents of organic matter and quartz is more brittle, less tensile strength, and is prone to produce natural and induced fractures under external forces (Pan et al., 2009), which is in turn favorable for the desorption of shale gas, free gas accumulation and flow. In North America, most of dark shales have high TOC (TOC > 2%) as well as high biogenic organic siliceous matter (normally >30%). This type of siliceous shale rich in organic matter is very brittle and easily develops fractures or micro-fracture systems. For example, the Barnett shale in the Fort Worth Basin has TOC content in the range of 1.0%–13.0% (av. 4.5%) and quartz contents of 35%–50% (av. 45%). Micro-fissures are abundant. The abundance of organic matter is attributed to a high sea level at the beginning of shale deposition when nutrient-rich upwelling occurred. As a result, deep slope – basin facies sediments accumulated in a strongly reducing environment that preserved the organic matter. The shale protolith sediments mainly included bathyal mud (from shallow water continental shelf) and bio-skeleton remains. Burial of the siliceous biosome (such as radiolaria) resulted in high content of siliceous matter in the TOC-rich shale (Li, X.J., et al., 2009).

Based on the relationship between TOC and fracture development in shale under exploitation for shale gas worldwide (Table 2), the higher the TOC in shale, the greater the total gas accumulation, corresponding to a high volume of free gas and better development of fractures. The relationship between TOC and fracture development can be divided into four levels: (1) TOC <2.0%, poor fracture development; (2) TOC at 2.0%–4.5%, moderate fracture development; (3) TOC at 4.5%–7.0%, good fracture development; (4) TOC >7%, very good fracture development (Fig. 3). Experimental result of Jarvie et al. (2003) also provided evidence for the data listed in Table 2. Shale with TOC of 7.0% would consume 35% of organic carbon during hydrocarbon generation, which would increase the pore volume of the shale by 4.9% (Jarvie et al., 2003). Based on this deduction, higher TOC will produce more ultra-micro pores in the shale matrix and a greater number of micro-fissures, corresponding to higher abundance of the shale gas reservoir.

2.1.4. Abnormal high pressure

Abnormal high fluid pressure is an intrinsic factor of rock rupture. For dark laminar thick argillaceous shale rich in organic matter, rapid deposition results in under-compaction. In a closed state, abnormally high fluid pressure would be created because of the combination of clay mineral conversion and dehydration, hydrocarbon generation, hydrothermal pressurizing and cementation. Abnormally high-pressure fractures might be produced when excessive fluid pressure (> hydrostatic pressure) equals to 1/2 or 1/3 of matrix pressure (Ding et al., 2003). Fractures tend to be closed when fluid pressure in pores is less than that in fractures. Generally, the opening and closing of fractures under abnormally high pressure is a multi-cycle process. During this process, small fractures formed early are continuously extended by later rupture, hence forming larger vertical tensile fractures and a large number of micro-fractures as well as some shear fractures. Therefore, a certain sized fractured shale gas reservoirs could easily form in the distribution zone of high-pressure massive shale (gas generating zone).

2.2. Tectonic factors

Tectonic factors are also an extrinsic factor for rock rupture. Primary tectonic effects related to fracture development include: (1) under local or regional tectonic stress, a shale zone with higher plasticity experiences ductile shear rupture and produces tectonic fractures. These are mainly high-angle shear fractures and tension-shear fractures, usually associated with faults or folds and form in groups nearly perpendicular to the bedding plane, with well-defined orientation and a smooth fracture surface. In shale, these kinds of high-angle tectonic fractures are mainly developed and some might extend through the shale into a sandstone reservoir as trans-layer fractures; (2) under extensional or compressional conditions, a few low angle decollement fractures parallel to bedding planes might be produced by shear stress acting along the low permeability shale bedding planes. These fractures are mainly distributed at the top and bottom of the shale, and generally have highly variable attitudes. Obvious features of scratch and mirror plane structures are developed on the fracture plane (Zeng and Xiao, 1999); (3) under the action of horizontal compression and pressure solution, tectonic sutures may be formed which are perpendicular or nearly perpendicular to bedding surfaces. When the suture column is parallel or nearly parallel to the bedding plane, it is referred to as a parallel suture; (4) vertical load fractures may be formed when the vertical load exceeds the compression strength of shale; (5) vertical differential load fractures may be generated when shale is ruptured due to uneven load from the overlying strata; (6) a significant amount of extensional and compressional fractures may be formed by the mechanical rupture of confined rocks as a result of the invasion of magma under high pressure (Ning, 2008); (7) salt domes are conducive for shale fracture development. Due to basement uplifting and faulting, many small folds and irregular flow directions exist in salt rocks (Zhang and Yuan, 2002).

As a consequence of the above mentioned features, tectonic stresses control fracture development. Tectonic fractures are formed during the concentration and release of tectonic stress. Over

Table 2 Data showing relationship between TOC and fracture development in shale.

Country	Basin	Formation	TOC (%)	Total gas accumulation (m^3 t^{-1})	Adsorptive gas volume (m^3 t^{-1})	Free gas volume (m^3 t^{-1})	Fracture development
United States	Appalachian foreland basin	Devonian Ohio Fm.	0.5–23.0	1.70–2.83	0.85–1.42 (50%)	0.85–1.42 (50%)	Many groups of high-angle fractures well developed
	Michigan Cratonic basin	Devonian Antrim Fm.	0.3–24.0	1.13–2.83	0.79–1.98 (70%)	0.34–0.85 (30%)	Two groups of NE & NW orthogonal nearly-vertical natural fractures moderately developed – well developed
	Illinois cratonic basin	Devonian New Albany	1.0–25.0	1.13–2.64	0.57–1.32 (50%)	0.56–1.32 (50%)	Fracture system well developed
	Fort Worth abyssal foreland basin	Mississippi Barnett Fm.	1.0–13.0	8.49–9.91	4.25–5.00 (50%)	4.24–4.91(50%)	Micro-fissures very developed
	San Juan foreland basin	Cretaceous Lewis Fm.	0.5–3.0	0.37–1.27	0.28–0.95 (75%) (**)	0.09–0.32 (25%)	Fracture network moderately developed
China	Cratonic basin in Weiyuan area, Sichuan Basin	Lower Cambrian Qiongzhusi Fm.	$\frac{0.4-11.07(*)}{2.25(85)}$	0.27–1.03			Micro-fissures developed; basically filled with secondary crystals such as calcite, dolomite and quartz
		Lower Silurian Longmaxi Fm.	$\frac{0.51-4.45}{2.09(61)}$				
	Cratonic basin in Changning structure, Sichuan Basin	Lower Silurian Longmaxi Fm.	$\frac{0.45-8.75}{2.93(153)}$				Fractures very developed

Note : $*: \frac{\text{Minimum} - \text{Maximum}}{\text{Average (sample quantity)}}$ $**:$ (75%) – Gas accumulation percent.

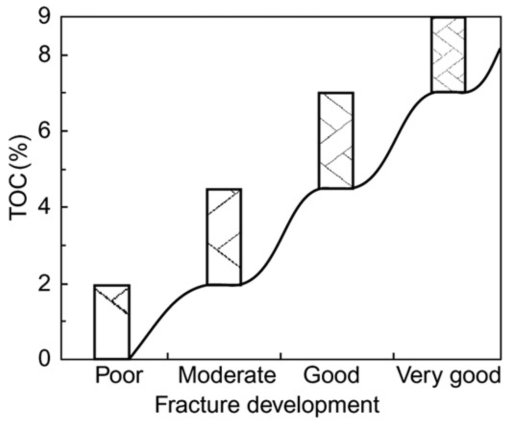

Figure 3 Relationship between TOC and fracture development in shale.

a period with equivalent stress variation, the area with the greater stress variation gradient would have higher probability to produce fractures. For example, at locations where there is a marked change in the stratigraphy, such as in a basin structure, a fault convergence zone, the apex of a tight anticline and the transitional zone between the slope and base of sag, the stress variation gradient is high and shale deformation is severe. In such areas, shale fractures are usually very well developed (Xiang, 2008).

Under similar geological conditions, fracture development in brittle shale is closely related to faults. In a shale zone close to fault zone, fractures are well developed with high density. Fracture density is also significantly affected by fault scale and intensity of faulting. Under the same rock facies, fractures are more easily produced when the fault size is larger and faulting activity is more intensive in the shale zone. Although the area of shale fracture development may be closely related to a fault zone, or a particular fault, the zone of fracture development might not always exist near faults, reflecting the complicated nature of the relationship between faults and fracture development (Ning, 2008). Tectonic fractures can effectively improve the performance of a shale reservoir and could particularly increase permeability of a shale reservoir. Since tectonic fractures are mainly developed within the breaking points of fold structures as well as nearby fault zones, high-yield areas of shale gas reservoirs tend to be distributed in these locations (Xiang, 2008).

3. Relationship between shale fracture and gas accumulation

On the basis of previous discussion, it is clear that shale fractures are closely related to gas accumulation and gas production. As shown in Table 2, there is a positive relationship between fracture development in shale, total gas accumulation and free gas volume. This relationship is mainly attributed to the special gas generation mechanism in shale gas reservoirs compared to conventional low permeability gas reservoirs. Shale gas diffuses from micropores in the shale matrix to the large pores and fractures, following Darcy's law, but adsorptive gas on the pore surface in the matrix may be desorbed under certain pressures, and Darcian flow is not applicable (Zhang et al., 2004). Fracture development promotes the volumetric increase of free gas and desorption of the adsorptive gas in shale (Curtis, 2002). Fracture development also determines the quality of a shale gas reservoir. In general, if fractures are well developed, shale gas reservoirs are of good quality, and if fractures or micro-fractures are well developed in shale, shale gas accumulations are highly enriched.

Fractures have dual contributions to the formation of a shale gas reservoir. On the one hand, they provide migration channels and accumulation space for natural gas and formation water, and therefore increase of total free gas accumulation in shale. Normally, shale has very low initial permeability. If natural fractures are not well developed, artificial fracturing is necessary to generate additional fractures so as to communicate with the well bore and provide more pressure drawdown and a larger area for gas desorption. For storage and development of shale gas, especially during the initial production period of a single well,

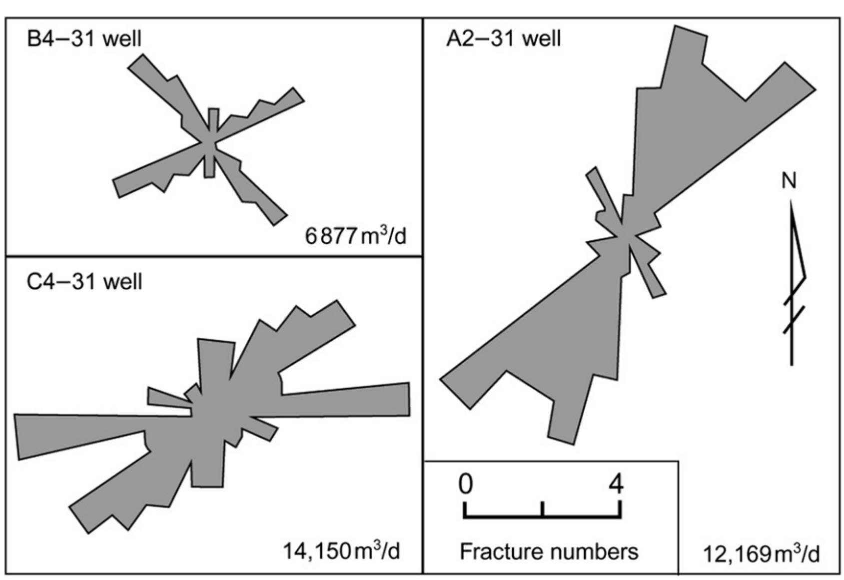

Figure 4 Rose diagrams comparing fracture orientation and abundance with gas production Antrim shale, Michigan Basin (Decker et al., 1992).

fractures play a significant role. On the other hand, if fracture size is too great, natural gas may be dissipated.

Fractured shale gas, as a non-conventional natural gas, may have a thermal cracking, biogenic or hybrid origin. Shale gas with a thermal origin is mainly adsorbed by organic matter, then expelled via fractures, or occupies pore spaces in shale (Pan et al., 2009). Thermal origin shale gas reservoirs are dependent on gas diffusion and accumulation via micro-fractures, whereas faults and macro-fractures may destroy the gas reservoir. Under abnormal high pressure conditions generated by gas generation from thermal cracking, fractures are produced along the stress concentration face and lithological contact/transitional face, which provide the threshold porosity and permeability necessary for gas accumulation (Zhang and Pan, 2009). The forming of gas reservoirs with a biogenic origin is closely related to the active exchange of fresh water. Fractures act as conduits of formation water. In places where faults are well developed, formation water is active and also the physiological activity of methanogenesis microorganism so that more gas can be generated. Fractures provide conduits for gas diffusion and accumulation, and tectonic stress may play a positive role (Martini et al., 2003; Li, D.H., et al., 2009). Areas under development usually have well-developed fracture systems. For instance, two groups of NW and NE near vertical natural fractures are mainly developed in the shale gas recovery tracts in the Antrim Formation of the northern Michigan Basin. Shale gas production is related to micro-fracture development in the Barnett shale in Newark East gas field in the Fort Worth Basin. Economic recoverable reserves in the New Albany shale in the Illinos Basin are also associated with a fracture system. Fractures are gas accumulation spaces and gas flow conduits, and are necessary for the migration of shale gas from matrix pores to the well bore. Recoverable reserves of shale gas ultimately depend on the fracture occurrence, density, combination feature and openings in the reservoir (Hill and Lombardi, 2002; Li et al., 2007; Li, D.H., et al., 2009; Zhang and Pan, 2009).

The dispersivity of fracture density and orientation is the overall major geological factor controlling shale gas productivity. More fractures and a high dispersed trend correspond to higher gas production (Decker et al., 1992) (Fig. 4). Open, mutually perpendicular fractures or numerous sets of natural fractures will increase shale gas production (Hill and Nelson, 2000). All high-yield gas wells in the eastern United States are located in fracture zones, while wells located in areas with poorly developed fractures have low or no gas production. For example, the highest yield gas wells are mostly distributed along NE-trending zone of high-angle fractures in the Devonian shale of the Big Sandy gas field in the Appalachian Basin. Although natural fracture system is usually favorable for shale gas recovery, sometimes they can obstruct artificial fractures and hence reduce shale gas recovery (Bowker, 2007; Li, X.J., et al., 2009).

4. Conclusions

(1) If shale has high contents of quartz, feldspar and carbonate, it will have low Poisson's ratio, high Young's modulus and high brittleness. As a result, the shale will develop natural and induced fractures under external forces. Fracture development generally has a positive correlation with the proportion of brittle minerals in shale. Fractures are well developed in shale with high TOC or under abnormally high pressure. The higher the TOC, the more ultra-micro pores are present in the shale matrix, the more micro-fractures are generated, and the higher the gas enrichment.

(2) Fractures have dual contributions to the formation of shale gas reservoirs. They provide migration conduits and accumulation space for natural gas and formation water, and they help to increase of total free gas accumulation and desorption of adsorptive natural gas. A greater number of fractures and more dispersed distribution correspond to a higher gas production. However, if the fracture size is too large, loss of natural gas will occur. If large fractures are well developed, gas production will be lower.

(3) Shale fractures are closely related to shale gas accumulation and production. There is a positive correlation between fracture development, total gas accumulation and free gas volume. The better the fractures are developed in shale, the greater the gas accumulation and therefore production. There is a high success ratio of shale gas exploration and high gas production in fracture zones in North America. Good gas shows or low yield producers from the Lower Paleozoic marine shale rich in organic matter in the Sichuan Basin in China are closely related to the degree of fracture development.

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