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Characteristics and accumulation mechanisms of the Dongfang 13-1 high temperature and overpressured gas field in the Yinggehai Basin, the South China Sea

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The Dongfang 13-1 is located in the diapiric structure belt of the Yinggehai Basin. The formation pressure of its main gas reservoir in the Miocene Huangliu Formation is up to 54.6 MPa (pressure coefficient=1.91) and the temperature is as high as 143°C (geothermal gradient 4.36°C/100 m), indicating that it is a typical high-temperature and overpressured gas reservoir. The natural gas is interpreted to be coal-type gas derived from the Miocene mature source rocks containing type II_2-III kerogens as evidenced by high dryness index of up to 0.98 and heavy carbon isotopes, i.e., the $\delta^{13}C_1$ ranging from −30.76‰ to −37.52‰ and $\delta^{13}C_2$ ranging from −25.02‰ to −25.62‰. The high temperature and overpressured Miocene petroleum system is related mainly to diapir in the Yinggehai Basin and contains more pore water in the overpressured reservoirs due to undercompaction process. The experimental and calculated results show that the solubility of natural gas in formation water is as high as 10.5 m^3/m^3 under the temperature and pressure conditions of the Sanya Formation, indicating that at least part of the gas may migrate in the form of water-soluble phase. Meanwhile, the abundant gas source in the Basin makes it possible for the rapid saturation of natural gas in formation water and exsolution of soluble gas. Therefore, the main elements controlling formation of the Dongfang 13-1 gas pool include that (1) the diapir activities and accompanying changes in temperature and pressure accelerate the water-soluble gas exsolution and release a lot of free gas; (2) submarine fan fine sandstone in the Huangliu Formation provides good gas-water segregation and accumulation space; and (3) the overlying overpressured mud rocks act as effective caps. The accumulation mechanism reveals that the high temperatural and high pressure structure belt near the diapir structures has a good potential for large and medium-sized gas field exploration.

Dongfang 13-1 high temperature and overpressured gas field, accumulation mechanism, diapiric belt, Yinggehai Basin

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The Yinggehai Basin is a Cenozoic conversion extensional basin developed in the passive continental margin of the northern South China Sea, and extends to the Northwest (Figure 1). Young age, high temperature and high pressure, thick deposit (Upper Tertiary to Quaternary of 8000–10000 m thick) and diapir structures are important geological features of this basin (Dong and Huang, 2000; Hao et al., 2001). The Miocene mudstones of the Meishan-Sanya formations deposited under neritic environments are considered the main source rocks of the basin (Huang et al., 2003). The marine sandstone and mudstone developed within the Huangliu, Yinggehai and Quaternary strata formed good reservoir-seal assemblages. The conversion faults, diapirism and accompanying pressure releasing have profound impacts on the vertical migration and accumulation of natural gas. Since 1991, the DF1-1 gas field and Ledong gas pool group have been found successively in the shallow layers

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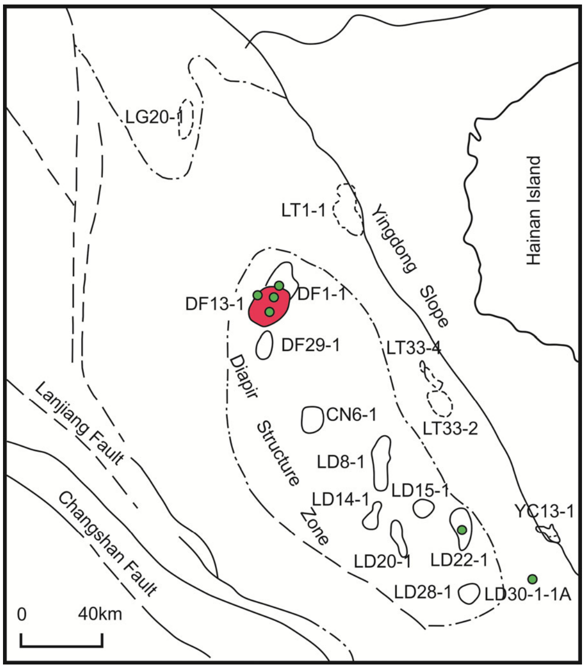

Figure 1 Map showing the structural divisions of the Yinggehai Basin and the location of the DF13-1 high temperature and overpressured gas pool.

(above the abnormal pressure system) of the diapir zone, but the exploration success rate in the overpressured reservoirs is still very low. So there was a hot debate on whether large-scale free gas reservoir could be formed in the high-temperature and overpressured area (Zhang and Dong, 2000; Hao et al., 2001). However, with detailed geological researches and newly developed drilling technologies for high temperature and overepressured reservoirs, the Dongfang 13-1 gas field, a high quality commercial gas reservoir, was recently discovered in the overpressured strata. This gas discovery has led to the extensive attentions to the gas accumulation mechanisms in the overpressured system of the Yinggehai Basin. The purpose of this paper, therefore, is to document the geological and geochemical characterization of the gas field, and to investigate the mechanism of gas accumulation within high temperature and overpressured system, which will help to determine the favorable exploration targets for large and medium-sized gas fields in high temperature and overpressured (HTOP) areas of the Yinggehai Basin.

1 Characteristics of DF 13-1HTOP gas reservoir and its gas source

1.1 Geological characteristics of DF13-1HTOP gas reservoir

DF13-1 HTOP gas field, formed under the background of Dongfang 1-1 diapir, is a composite lithologic and structural gas reservoir containing multiple sets of sand bodies that are connected laterally in wide scales (Wang and Pei, 2011). The main gas reservoirs are located under the depth of 2500–3000 m with an average geothermal gradient of 4.36°C/100 m and the pressure coefficient of 1.8–2.0. The top surface of overpressure in the DF1-1 diapir is about 2420 m and becomes shallower towards the structure axis. The strong overpressured zone (pressure coefficient: Cp>1.6) covers the lower part of the Huangliu Formation, Meishan Formation, and Sanya Formation. For the well D14 located on the wing part of diapir, the main gas production layer in the Huangliu Formation is composed mainly of light gray fine-grained sandstones of large submarine fan with a burial depth of 2910–2997 m. The average porosity of the reservoirs ranges from 14.6% to 15.7% based on the logging interpretation with permeability ranging from 2.5×10^{-3} to 7.4×10^{-3} μm^2. Especially the top part of the gas reservoir has the best physical properties and the DST test reveals a gas flow of up to 6.3×10^5 m^3/d, showing a high production potential. The measured pressure and temperature at depth of 2945 m (altitude −2922 m) is 54.6 MPa (the pressure coefficient being up to 1.91) and 143°C respectively, indicating it is a typical HTOP gas reservoir (Figure 2).

1.2 Characteristics and sources of natural gas

Seven exploration wells have been drilled to the Miocene Huangliu Formation in Dongfang 13-1 gas field, and a high production gas reservoir has been discovered in the wing part of the structure. According to gas component analysis of D14-1/2 and D4M, the hydrocarbon gas accounts for 69.51%–79%, CO_2 for 13.87%–22.66% and N_2 for 6.11%–7.71%. The dryness index (C_1/C_{1-5} by volume) ranges from 0.97 to 0.98, and the $\delta^{13}C_1$ ranges from −30.76‰ to −37.52‰, both of which indicate that the gas is derived from deep source rocks with high maturity levels. The $\delta^{13}C_2$ values ranging from −25.02‰ to −25.62‰ (Table 1) are heavier than −28‰ and indicate that the gas is coal-type gas according to natural gas identification plots proposed by Dai (1993). The $\delta^{13}C_{CO2}$ values in hydrocarbon-rich layers are measured to be −5.18‰ to −6.62‰, which are 2‰ to 3‰ lighter than those of CO_2-rich gas. For CO_2^- rich layers, their $\delta^{13}C_{CO2}$ values range from −2.64‰ to −4.02‰ and are quite close to those of inorganic CO_2 in the Dongfang 1-1 shallow gas field, indicating they might have similar origins from thermal decomposition of calcareous mudstone of the Miocene source rocks (Dong and Huang, 1999; Huang et al., 2004). According to previous studies, the natural gas in the shallow gas field of Dongfang 1-1 is derived mainly from the deep, highly mature Miocene Meishan-Sanya marine mudstones (Dong and Huang, 1999; Huang et al., 2002). Since the natural gas composition, methane, and ethane carbon isotopic values in the Dongfang13-1 HTOP gas reservoir are similar to those in the Dongfang1-1 shallow gas reservoirs, it is reasonable to infer that they have similar maturity and genetic origins (Figure 3).

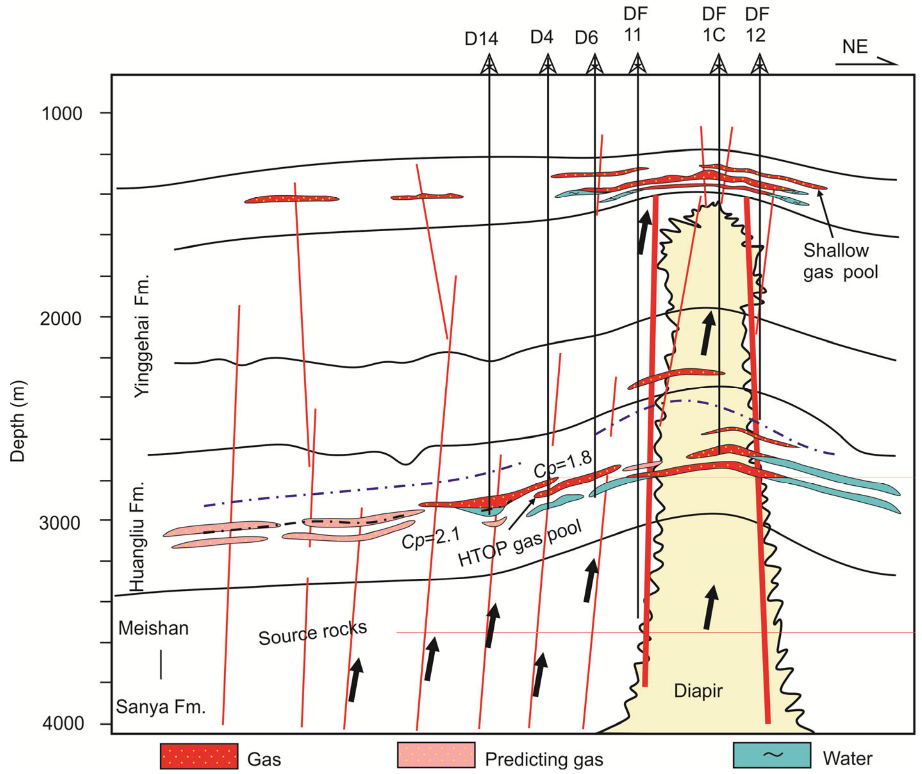

Figure 2 A cross section through the DF13-1 high temperature and overpressured gas field, showing the key petroleum system elements. *Cp*=pressure coefficient.

Table 1 Chemical and isotopic compositions of reservoired gases from the Huangliu Formation in the DF13-1 gas pool

Sample No.	Depth (m)	Composition (%)			C_1/C_{1-5}	$\delta^{13}C$(‰)		
		C_{1-5}	N_2	CO_2		C_1	C_2	CO_2
DF14-2	2910–2918	79.23	6.90	13.87	0.98	–37.52	–25.61	–6.17
DF14-1	2933–2963	78.99	6.11	14.90	0.98	–37.30	–25.02	–5.18
D4-M	2865	69.51	7.71	22.66	0.98	–32.92	–25.62	–6.62
D4-1	2906–2912	43.66	6.30	50.05	0.98	–30.76	—	–2.64
D6-2	2819–2836	41.38	4.79	53.71	0.97	–32.72	–25.23	–4.02
D6-1	2852–2865	23.22	2.97	73.79	0.98	–31.92	–25.19	–3.94

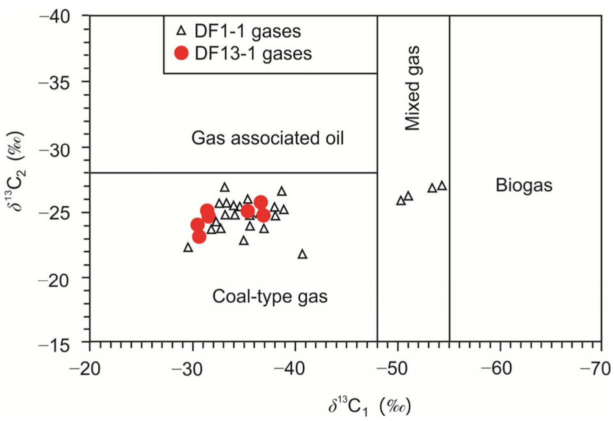

Figure 3 Cross plot of $\delta^{13}C_1$ *vs.* $\delta^{13}C_2$ values for the gas samples collected from the DF13-1 gas pool.

2 Experiments on gas solution in HTHP formation water

The formation water always accompanies during the processes of gas generation, migration and accumulation and thus it is not avoidable for the interactions between gas and formation water, such as the solubility of gas in water. Many authors carried out experiments on hydrocarbon gas solubility in water (Price, 1979; Hao and Zhang, 1993; Fu et al., 2000) to understand the dissolving characteristics of natural gas in formation water, but these experimental data cannot meet the needs of HTOP gas reservoirs in the Yinggehai Basin due to their low temperature and pressure conditions (pressure: 5–40 MPa, temperature: 40–140°C). For this reason, we carried out a series of experiments on gas solution (mainly methane) in formation water under different temperature conditions and formation water salinity that could well represent the geological conditions of central diaper zone in the Yinggehai Basin.

2.1 Experimental conditions of temperature and pressure

Pressures: 20 to 120 MPa, including six measuring points: 20, 40, 60, 80, 100, and 120 MPa; temperatures: 90 to 200°C, including five measuring points: 90, 120, 150, 175, and 200°C

2.2 Gas sample and formation water salinity in experiments

The methane (C_1) content of the gas sample used in the experiments is up to 95.19%, and the ethane (C_2) accounts for 1.96%, C_3 for 0.7%, iC_4 for 0.20%, nC_4 for 0.10%, iC_5 for 0.09%, nC_5 for 0.07%, C_6 for 0.94%, N_2 for 0.74%. It has a high dryness index ($C_1/C_{1–5}$ by volume) of 0.96 and belongs to dry gas. The formation water used in the experiments was prepared according to the data of formation water from the Yinggehai Basin. The prepared formation water has a salinity of 19029 mg/L and falls to the $NaHCO_3$ type according to the Surin classification.

2.3 Workflow

First, the gas sample is introduced into the dissolving chamber containing an appropriate amount of formation water, then the gas pressure is pumped up to the designed level, and the whole system is heated to the designed temperature. After the solution reaches balance, the gas-saturated formation water is released from the HTHP dissolving chamber to the collection chamber where the temperature and pressure are ambient. The volumes of released gas and degassed formation water then are measured to calculate gas solubility in formation water. The chemical composition of released gas is analyzed using gas chromatography.

2.4 Experimental results

The experimental results are listed in Table 2. It reveals that natural gas has a relatively high solubility under HTHP (Figure 4(a)–(d)). For example, at temperature of 150°C and pressure of 20 MPa, the gas solubility is only 3.1 m^3/m^3, but the gas solubility goes up to 5.8 m^3/m^3 when the pressure increases to 60 MPa. We also note the decrease of solubility of n-alkanes gas in the formation water with increasing carbon numbers, following the order of $C_1>C_2>C_3>C_4$. For example, the ratios of methane content in water-soluble gas to methane content in the original gas sample (C_1 aqueous/C_1 original) raise up when pressure and temperature increase, and the ratio of aqueous C_2 to original C_2 becomes gradually smaller when pressure and temperature increase. For the ratio of aqueous C_3 to original C_3, we have the same conclusion as C_2. In view of this, the gas exsolution due to changes in temperature and pressure will release more amounts of lower-carbon number alkane gases than higher carbon number alkane gases, thus increasing the dryness index of natural gas. This process is also called as "methanation"(Liu et al., 2004).

Table 2 Experiment date about methane solubility in formation water

T (°C)	Solubility (m^3/m^3)					
	20 MPa	40 MPa	60 MPa	80 MPa	100 MPa	120 MPa
90	2.38	3.97	5.16	6.18	6.76	
120	2.64	4.13	5.46	6.34	6.84	
150	3.11	4.51	5.79	6.54	7.06	7.72
175	3.49	4.83	5.94	6.65	7.3	7.86
200	3.84	5.05	6.13	6.82	7.49	8.02

3 Formation mechanisms of Dongfang 13-1 HTOP Gas Field

3.1 Abnormal high pressure system and natural gas migration in Miocene

The measured and calculated data show that the top surface of regional overpressure in the Yinggehai Basin is about 3000 m and the burial depth of the main source rocks in the Miocene Meishan-Sanya formations is between 4500 and 8000 m with a pressure coefficient up to 2.1. Previous studies illustrated that the formation of abnormal overpressure was caused mainly by compaction disequilibrium during the rapid sedimentation of mudstones (Dong and Huang, 2000). Meanwhile, the aquathermal expansion under the high geothermal gradient (average 4.4°C/100 m) and gas generation in the study area also promote the overpressure. The seismic and drilling data reveal that the respective thickness of Neogene and Quaternary sediments in the central depression of Yinggehai Basin is up to 6000–7000 m and 1500 m respectively, and the sedimentation rate is as high as 850 m/Ma, with an average of 450 m/Ma. It is the successive and rapid sedimentation that results in compaction disequilibrium among the huge thickness of marine fine sized sediments. For mudstones adjacent to the permeable layers, such as sandstones, their formation water can be quickly expelled and their porosity and permeability are correspondingly reduced. Thus these mudstones can act as new barriers for the rapid expelling of formation water from the centered mudstones where part of overloading is supported by formation water due to the ductility of mudstones, leading to the formation of fluid overpressure. Therefore, there may be abundant formation water in the overpressured Miocene strata although they are deeply buried under very high temperatures. As natural gas has a relatively high solubility in the HTHP formation water (Price, 1979; Hao and Zhang,

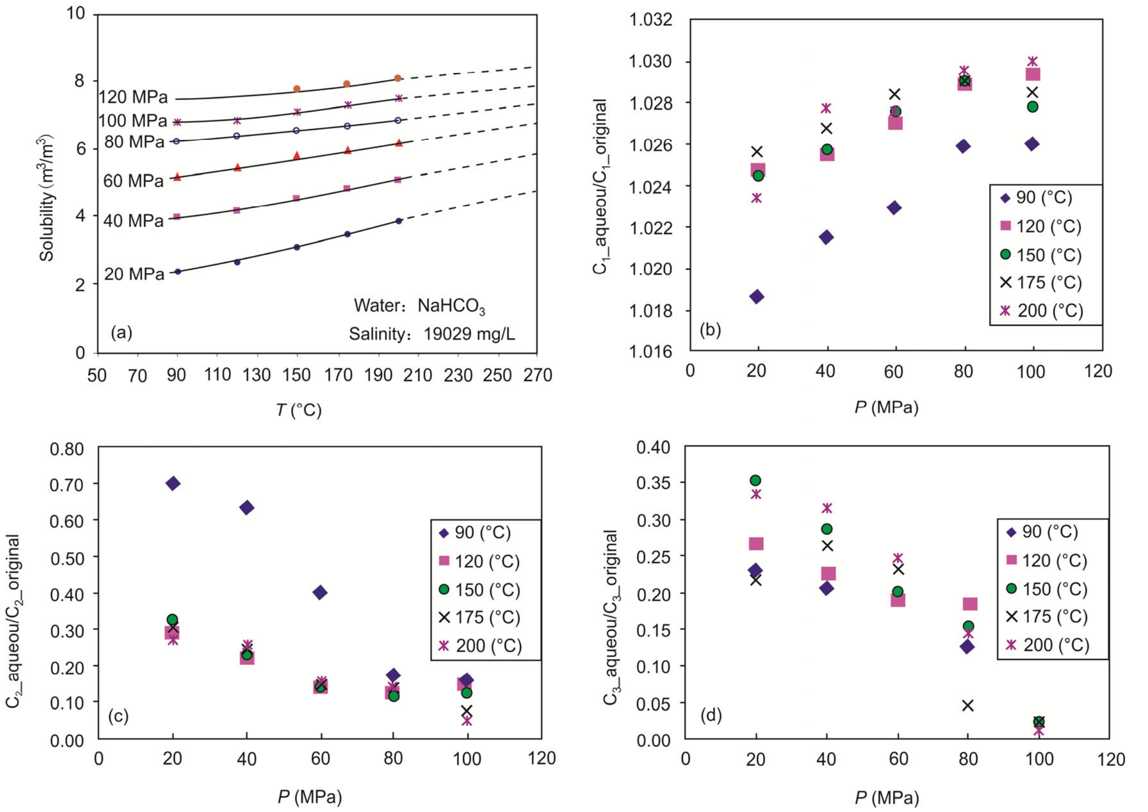

Figure 4 Aqueous methane, ethane and propane solubilities under different pressures and temperatures. (a) Solubility curves of methane in formation water; (b) a plot of C_{1_a}/C_{1_o} ratios *vs*. pressures and temperatures; (c) a plot of C_{2_a}/C_{2_o} ratios *vs*. pressures and temperatures; (d) a plot of C_{3_a}/C_{3_o} ratios *vs*. pressures and temperatures.

1993; Fu et al., 2000), the natural gas generated from source rocks in the deep HTHP system may exist in a water-solution phase at the first stage. Once the formation water is gas-saturated, the free gas phase appears. When the gas-saturated formation water migrates along the diapir fracture to the shallower part during the period of diapiring, some free gas will be released due to the falling of temperature and pressure and the gas will exist in a mixed phase of free and solution (Luo et al., 2000). With further decrease of temperature and pressure in normally pressured strata, most of the gas dissolved in formation water will be totally released to form free gas phase. Therefore there may be considerable natural gas migration in water-solution manner during the period of diapir formation. And the migration mechanism in HPHT system will be discussed in detail in the later section.

The main geochemical evidence for the gas migration in water-solution phase is relatively elevated concentration of aromatic hydrocarbons, such as benzene and toluene in the gas. The water-solution also has an obvious effect on the relative content of light hydrocarbons. The order of the light hydrocarbon solubility in water is: Aromatics>cycloalkanes>paraffins. Due to the different solubility, light hydrocarbon composition in natural gas can change greatly after they are released from aquifers and the content of benzene and toluene in light hydrocarbons will increase obviously, so the ratios of benzene/nC_6 and toluene/nC_7 are important indicators to validate aqueous phase migration (Liu et al., 2004; Zhang Q X and Zhang Q M, 1991; Mcauliffe, 1978; Liu and Li, 2012). On the contrary, the relative content of light aromatic benzene and toluene will be reduced significantly due to their polarity during the hydrocarbon phase migration. As illustrated in Figure 5, the

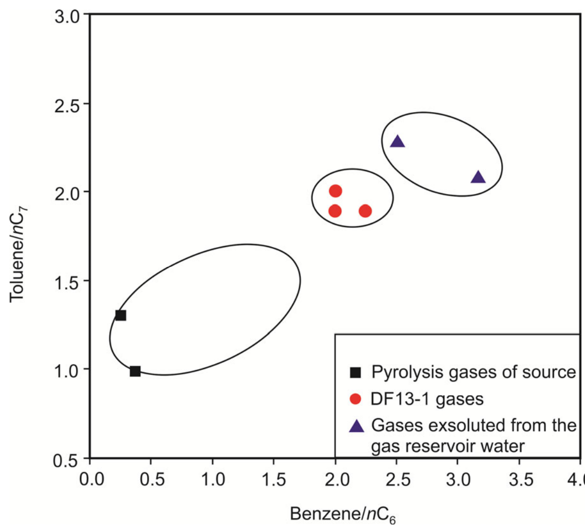

Figure 5 A plot of Ben/nC_6 *vs*. Tol./nC_7 of light hydrocarbons for the different types of gases.

respective ratios of benzene to nC_6 and toluene to nC_7 are 2.0–2.25 and 1.89–2.0, both of which are significantly higher than those in the pyrolysates of Miocene Meishan source rock. However, these ratios for the light hydrocarbons released from the formation water in Dongfang gas field under temperatures of less than 95°C are close to or slightly larger than the reservoir gas. This is consistent with the results of Liu et al. (2004) and indicates that the natural gas in the DF 13-1, at least in part, has migrated to the reservoirs in water-solution phase.

Usually, the most favorable accumulation place in an overpressured environment is near the top surface of overpressure (Hunt, 1990; Roberts and Nunn, 1995) and the mechanisms for oil and gas accumulation inside the interior of overpressured compartments are quite complex. The diapiric structure belt of the Yinggehai Basin is a local abnormally high pressure area. Due to the activities of diapir, HPHT fluids in deep migrate along the fracture zone to the shallow, leading to shallower overpressure top surface in young strata. The drilling reveals that the formation pressure coefficient in the diapir already reaches to 1.5 around 2000 m and usually greater than 1.8 below 3000 m. Therefore, the intensive overpressure has doubtlessly exerted profound effects on the efficiency of oil and gas charging, sealing ability of cap rocks, solution-desolution of natural gas, and even the free gas migration and accumulation in this area. These will be discussed in detail in later sections.

3.2 Water-soluble gas release and free gas accumulation under differential pressures

During migration process of water soluble gas, the formation water saturated with gas could release some gas to form free gas phase when the temperature and pressure are reduced significantly due to change of geological conditions. These free gases will accumulate to form gas pools in suitable traps. The diapir is the most unique geological phenomenon in the Yinggehai Basin (Dong and Huang, 2000). During Neogene, the Yinggehai Basin was in the structural stage of plastic tensile and thermal subsidence with little faulting activities. However, the developments of many diapirs provided vertical pathways for upward migration of deep fluids. On the basis of experimental data, combined with the geological conditions of the area, the mechanisms of water soluble gas release and the accumulation of free gas under differential pressures will be discussed below.

Based on the experimental data listed in Table 2, the solubility of natural gas in HPHT formation water is regressed by the following equation:

$$S(P,\ T,\ M)=(4.83665\times\ln(P)+3.50736\times\exp(-M/10000)+0.01788\times T-13.93967)^{0.8}, \tag{1}$$

where S is solubility of natural gas (m^3/m^3), M is formation water salinity (mg/L), P is pressure (MPa), T is temperature (°C).

By using the above equation, the natural gas solubility in formation water can be calculated for different strata under various temperature and pressure conditions in the DF13-1 gas field. In the case of DF14S, the main source rocks are the Meishan-Sanya formations that have a present burial of 4000 to 7000 m and have entered the main stage of gas generation. By assuming that there are adequate gas source and formation water, the natural gas solubility in formation water at different depths can be calculated according to the data of temperature, pressure, and formation water salinity in DF14S, then the relationship between the natural gas solubility with depth can be established (Figure 6). It is obvious to see that the natural gas solubility in formation water is reduced significantly with the decrease of burial, temperature, and pressure. For example, at the depth of 6000 m (gas source kitchen, T=278°C, P=138 MPa), the solubility is up to 9.2 m^3/m^3, but it decreases sharply to 5.6 m^3/m^3 at the depth of 3000 m (T=147°C; P=57.6 MPa). Especially the natural gas solubility is only 2.7 m^3/m^3 at the depth of 2000 m (T=103°C; P=22 MPa) in the normally pressured zones. In other words, about 3.6 m^3 free gas will be released from one cubic meter of formation water when the gas-saturated

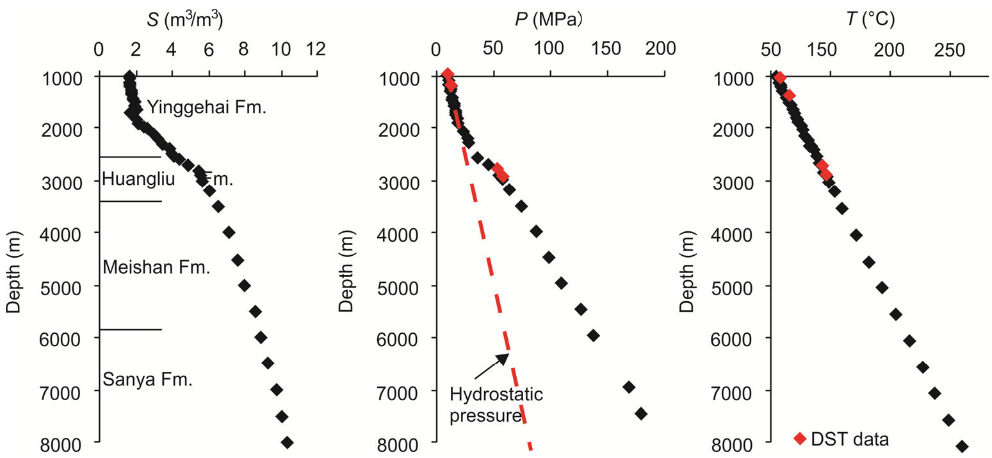

Figure 6 Calculated gas solubility in formation water with depths corresponding to pressures and temperatures for the well DF14S.

formation water migrates rapidly from the depth of 6000 m to the present gas reservoir depth of about 3000 m under the temperature and pressure conditions in the diapir zone of the Yinggehai Basin. The diapiring activities usually result in the upward migration of massive gas-saturated formation water with rapid decrease of temperature and pressure that leads to the oversaturation and gas desolution from formation water (Luo et al., 2000). Thus the released gas can be accumulated in favorable trap as free gas phase.

During the intermittents of diapiring, the rapid migration of natural gas in water-solution phase gradually ceases and the migration is caused mainly by the differential pressure between the reservoir and the source layer that can be described by Darcy model with the assumption that the formation water is abundant and natural gas saturated.

In formula:

$$Q_W = \frac{K\Delta PSt}{\mu_W H} C_g, \tag{2}$$

Q_W is water solution gas quantity through percolation (m^3), K is permeability (10^{-3} μm^2), ΔP is differential pressure (MPa), S is area (m^2), t is percolation time (Ma), μ_W is formation water viscosity (Pa·s), H is thickness of caprock (m), C_g is gas solubility (m^3/m^3).

Therefore, the released gas through percolation along the fractures and caps can be estimated when geological parameters are optimized.

Previous studies showed that the diapir activity of the Yinggehai Basin had an episodic characterization (Dong and Huang, 1999 , 2000; Hao et al., 2001; Xie et al., 1999). With the periodic rapid decrease of temperature and pressure in the HPHT zone (Dong and Huang, 2000; Hao et al., 2001), the free gas will be also periodically released from the formation water due to the decrease of solubility. Then these free gases will migrate upward further with the residual water-solution gas under the driving of overpressure and buoyancy. When these free gases migrate to the reservoir, the reduced temperature and pressure further release free gas from the formation water and form gas reservoirs dominated by free gas. In addition, during the diapir intermittent period, some free gas also can be released during the percolation of gas saturated HPHT formation water.

3.3 Diapir fracture and rapid upward-migration of water soluble gas

Five rows of NS-trending mud diapirs developed in the central depression of the Yinggehai Basin (Figure 1). Previous studies showed that the formation and development of the diapiris in the Basin could be divided into three stages: the generation of overpressure, the uplifting-extending, and the fracturing-diapiring (Dong and Huang, 2000). Depending on the energy differences between overpressured fluid-pocket and sealing capacity of cap rocks, some diapirs are weak piercing, but the others are strong piercing. According to the seismic data, the overpressure in DF1-1 diapir might be formed about 5 Ma ago, then the uplifting-extending and Piercing-fracturing in following Pliocene and was still active till early Quaternary (Figure 7(a)). This is consistent with formation time of gas reservoir in the diapir area. For example, the DF1-1 shallow gas field was formed about 2Ma ago (Huang et al., 2002), the formation time of the DF13-1 HTOP gas field was earlier, about 3.7–1.8 Ma ago(Wang and Pei, 2011); In the area of LD 8-1, the strong diapir activities extended to Quaternary, as evidenced by the visible submarine collapse structure above the LD8-1 diapir in seismic sections (Figure 7(b)). The diapirism is caused by the interaction of overpressure fluid induced fracturing and tectonic stress field and has a significant effect on the migration and accumulation of natural gas (Huang et al., 2005).

While the faults and fractures caused by diapir activity provide the main pathways (Xie et al., 1999), the overpressure beneath the diapirs can act as the main driving forces for the upward migration of gas generated from the deep Meishan-Sanya source rocks(Huang et al., 2010). The Seismic records show that a lot of faults have developed in DF1-1 diapir (Figure 7(a)) and many micro-fracturing can be seen within the Meishan and Huangliu formations. Most of these faults/ fractures cut through the overpressure system and transition zone and disappear into the normally

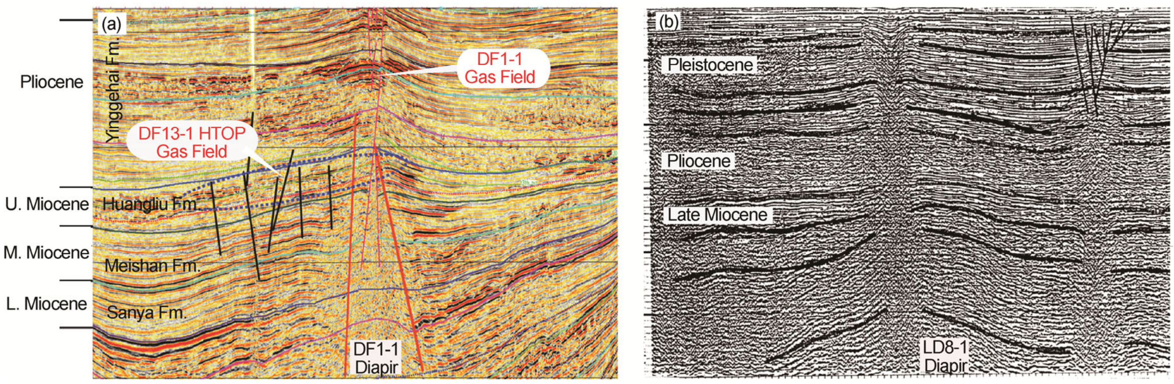

Figure 7 Seismic profile through the DF1-1 (a) and LD8-1 (b) diapiric structures, showing the diapir piercing zone and associated faults.

pressured zone. In the seismic profiles, diapir appears as blank reflection zone or fuzzy area, but the trans-layer fluid fracturing surface can be seen on shallow layer, with a dip of 70° to 90° and strike of nearly north-south. Despite their minor fault throws, the faults can extend horizontally up to several hundred meters, even 2000 m. It is noteworthy that in the wing part of the diapir overpressured zone, the pressure relief may occur frequently due to the subtle pathway systems that are formed by hydraulic fracturing. Therefore the traps near the pressure relief area are the most favorable target for gas accumulation. As illustrated in Figure 2 and Figure 7(a), many micro-faults develop on the west side of DF1-1 gas field, some of which have extended downward to the source rocks of the Meishan-Sanya formations and extended upward into the sand bodies of Huangliu Formation, disappearing into the massive mudstones. Genetically, these minor faults were the results of large diapir activities in DF area during the Early-Mid Pliocene. They connect the deeper source rocks and the shallower sandstone reservoirs in DF13-1 gas field and provide excellent pathways for gas upward migration. Thus, the diapir zone of the Yinggehai Basin (including the shallow normal pressure zone and HTOP zone) is the most beneficial places for natural gas accumulation.

3.4 Overpressured caprocks and submarine fan fine sandstones controlling the accumulation of gases

Whether the HPHT mudstone caprocks on the upper part of Huangliu Formation in the Yinggehai Basin could seal the underlying abnormally high pressured gas reservoir is the key for gas accumulation. Generally, the capacity of overpressured mudstones to seal free gas is not determined directly by the ovepressure, but closely related to the combination of capillary sealing (replacement pressure) and the excess fluid pressure that may enhance the capillary sealing capacity of surrounding tight strata. Therefore, the caprocks can seal the free gas when its sealing capacity (replacement pressure+surplus pressure) is larger than the surplus pressure of gas reservoir, i.e., the difference pressure between the reservoir fluid pressure and the hydrostatic pressure at the same depth. Otherwise, the cap-rocks fail. The difference between cap-rock seal pressure and the surplus pressure of gas reservoir can be used to evaluate the sealing capacity of cap rocks. The larger the difference pressure, the better the sealing capacity.

By comparing the displacement pressure and surplus pressure of caprocks and the surplus pressure of gas reservoirs in DF 13-1 gas field, it clearly illustrates the former is larger than the latter, indicating the caprocks is effective of sealing the gas in reservoirs (Figure 8). It should be noted that the caprock of D14 near the wing part of diapir is different from that of DF1C and DF11 near the core part of the diapir (Figure 2). The former contains about 220m thickness of TST-HST neritic mudstone in the upper part of the

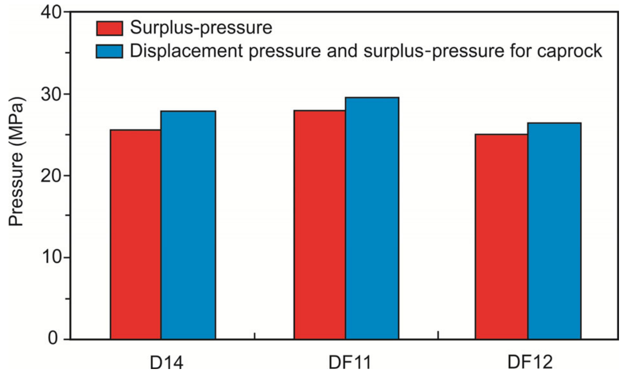

Figure 8 Comparison of reservoir surplus-pressures with the sealed pressures (displacement pressure + surplus-pressure) of caprocks in the DF13-1 gas pool.

Huangliu Formation. This set of mudstone is highly ductile, widely distributed, and well compacted with a pressure coefficient of 1.5 to 1.8. When the lithology, physical property, and breakthrough pressure are compared between the caprocks for the three wells, it is evident that the caprock of D14 well has the largest density (averaging 2.58 g/cm^3), smallest Δt-sonic interval transit time (averaging 89.88 μs/ft), and largest break-through pressure (Pt: averaging 5.16 MPa). On the contrary, the respective break-through pressures of caprocks for the well DF1C and DF11 are only 0.22 MPa and 3.71 MPa (Wang and Pei, 2011), illustrating the caprock of the well D14 has the best sealing capacity. Therefore, the upward migration of HPHT fluids to the shallower the Huangliu Formation will significantly weaken the sealing capacity of caprocks in the core part of diapir, but this effect becomes insignificant in the wing part of diapir. This mechanism provides an effectual sealing for the form of the DF13-1HTOP gas reservoir. On the other hand, although the overpressured traps near the core part of DF1-1 dirpir in the Yinggehai Basin breaks periodically to release natural gas, the abundant gas charging (Huang et al., 2010) also makes it possible to form commercial gas pools that has a smaller gas column than those in the wing part of the diapir.

The drilled results show that high quality reservoir is also one of the key factors of the DF13-1 HTOP gas field. For example, a set of marine fan sandstones (Xie and Fan, 2010) was encountered in the lower part of the Huangliu Formation (2910–3006 m) in the well D14. The sandstone is dominated by medium-fine sandstones with some siltstones on the top and interlayered grey siltstones and mudstones at the bottom. The average log porosity is 14.6%–15.7%, the permeability ranges from 2.5×10^{-3} to 7.4×10^{-3} μm^2, and the reservoir has a very high DST production. The Huangliu Formation reservoir encountered at the depth of 2895–2912 m in DF13 well near the DF14 well (Figure 1), however, is dominated by muddy siltstones deposited under shallow shoal environment with more mudstones bands, and the siltstones only have a permeability of $(0.2–0.6)\times10^{-3}$ μm^2 despite their high porosity of 14%–16% and are interpreted as poor gas reservoir based on the log data. These geological facts illustrated that although the geological conditions for gas upward migration are excellent in the HTOP diapir zone of the Yinggehai Basin, the key factor controlling the formation of giant gas field is the development of high quality reservoirs, which would provide exsolution space for the injected water-soluble gases and their accumulation in free gas phase to form giant gas pools.

The newly acquired and processed 3D seismic data reveal that there are many lithological traps around of the DF13-1 that are similar to those in the DF13-1 gas field. These traps cover an area of about 800 km^2. The major target reservoirs, HTOP Huangliu reservoir, are buried moderately and formed under favorable depositional environments. Therefore, these traps will be the most important exploration targets of the Yinggehai Basin in the future.

4 Conclusions

(1) The DF 13-1 gas field, formed under the background of diapir activity, has combined lithologic and structural traps that contain vertically overlapped and laterally connected sandbodies. As the main gas production layers, the Huangliu marine sandstone reservoir is at the depth of 2500–3000 m with an average of geothermal gradient of 4.36°C/100 m and pressure coefficient of 1.8–2.0 and belongs to typical HTOP gas field. The natural gas is derived mainly from the Miocene Meishan-Sanya Formation source rocks and genetically belongs to coal-type gas with high maturity.

(2) Given that the uncompacted Miocene strata contain abundant HTHP formation water that can dissolve much natural gas, the gas migration through water-solution phase is probably one of important migration ways in the diapir zone of the Yinggehai Basin. During the upward migration of gas-saturated formation water, some gas will be released due to the falling of temperature and pressure to form free gas that can migrate further with the water-solution gas to the shallower reservoir where more free gas will be released to form a gas pool. This is probably one of important gas migration ways for the formation of DF 13-1 HTOP gas field.

(3) The gas source in the Yinggehai Basin is abundant and the diapir activity and the associated faults and fracture provide excellent pathways for the rapid upward migration of free gases and water-soluble gases. Meanwhile, the sealing capacity of caprocks and the high quality of reservoirs are the key geological elements controlling the accumulation and enrichment of natural gas in the DF13-1 gas field.

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