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Vertical heterogeneity of permeability and gas content of ultra-high-thickness coalbed methane reservoirs in the southern margin of the Junggar Basin and its influence on gas production

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ABSTRACT

Ultra-high-thickness (>15 m) is one of the unique features of coalbed methane (CBM) reservoirs in Junggar basin, Xinjiang, China. However, there are few studies on the vertical permeability and gas content heterogeneity of ultra-high-thickness reservoirs. We use the Fukang west block on the southern margin of the Junggar Basin as a characteristic-example. Logging data describe the vertical distributions of the permeability and gas content of ultra-high-thickness CBM reservoirs. Flow modeling is used to explore the influence of those vertical heterogeneity on gas production. The results show that there is clear heterogeneity of these two parameters across the reservoir - from top to base - with different functional variabilities at shallow, intermediate and deep burial depths. At shallow depth (800–1100 m) the heterogeneity is controlled mainly by the increasing geo-stress and coalification. Permeability gradually decrease from the reservoir top to the base due to depth-increasing stress while gas content gradually increases due to permeability and depth-increasing degree of coalification. At intermediate depths (1100–1500 m) these two parameters show no particular trend. At the deep depths (1500–2000m) the reverse trend is observed as permeability increase from the reservoir top to the base while gas content gradually decreases. This heterogeneity is of great significance in the evaluation of the reserve, the recoverable resource and in the optimization of gas production. Neglecting the vertical heterogeneity of gas content across the seam results in a mis-estimation of ~4.4% of the recoverable resource with a 40% chance of exceeding this mis-estimation if only a single sample within the seam is used. The vertical heterogeneity exerts a significant influence on gas production, and the influence will be greater when the reservoirs with larger gas content. Production optimization favors perforation of separated rather than adjacent stages.

1. Introduction

As a plentiful unconventional energy source, coalbed methane (CBM) has been extensively explored and developed (Moore, 2012; Lau et al., 2017). Given China's geological setting, abundant CBM enrichment is apparent in the Qinshui and Ordos Basins (Cai et al., 2011; Qin et al., 2017) with even more abundant and undeveloped resources in Xinjiang (Li et al., 2013; Qin et al., 2017).

The Xinjiang CBM reservoirs are characteristically thick, with single layers exceeding 15 m in thickness (Kang et al., 2018b; Li et al., 2018), and steeply-dipping. For CBM development, thicker coal indicates a greater resource and development potential per unit area. Coal is a heterogeneous hydrocarbon source with fracture characteristics (permeability) and storage (gas content) exerting important impacts on CBM production (Moore, 2012). In these steeply-dipping and ultra-thick (SDUT) coal reservoirs, heterogeneity, driven by depth within the section and also vertical effective stress gradients, is more apparent than in flat-lying thin seams. Previous studies have used a variety of methods to probe the physical properties of coal reservoirs to determine optimal development strategies and recovery. However, these past works have principally focused on horizontal CBM reservoirs (Pashin, 2010; Ou et al., 2018; Li et al., 2018) with few studies on the controls of vertical heterogeneity on production from steeply-dipping CBM reservoirs. The principal reason is that the current development of China's CBM is

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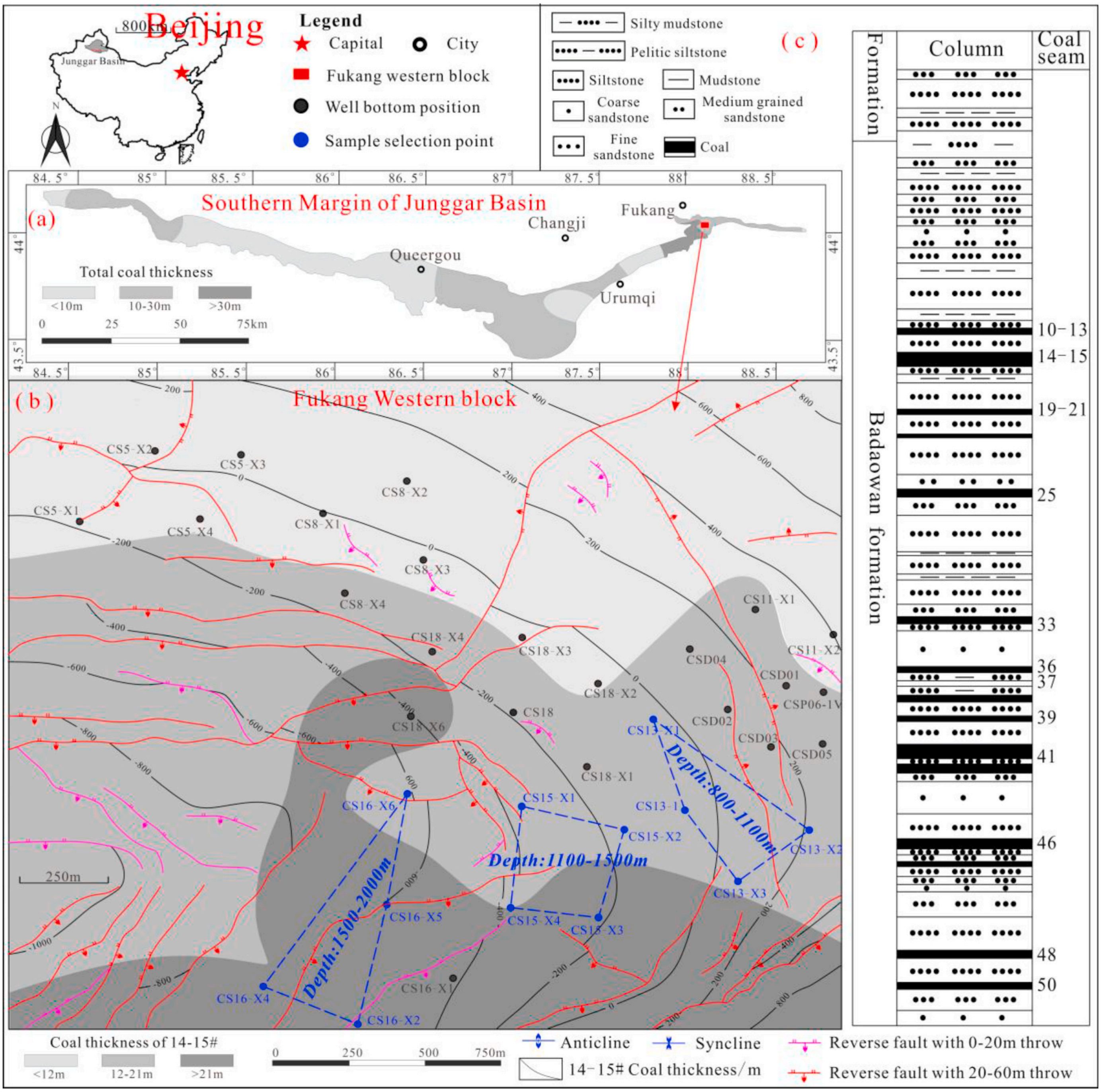

Fig. 1. Geological structure and comprehensive histogram of the study area.

mainly concentrated in the Qinshui and Ordos basins and in southwestern China (Qin et al., 2017) where the reservoirs are thin and flat-lying (Tao et al., 2014). In such cases, vertical heterogeneity in the reservoir exerts little control on gas production. With the vigorous development of SDUT CBM reservoirs in Xinjiang, it is necessary to understand the respective roles of this heterogeneity - driven both by stress gradients and bed thickness. This heterogeneity is accentuated since each section of these SDUT reservoirs contains different coal-forming materials and has experienced different coal-forming processes (Su et al., 2005; Moore, 2012). Neglecting this apparent heterogeneity in permeability and gas content in SDUT CBM reservoirs potentially results in significantly inaccurate estimations of the CBM resource. Furthermore, typical well completions perforate only a section of the well, requiring that sweet spots are defined *a priori* and *rationally* to target zones of high productivity. This highlights the needs to understand the systematics of variation of these two principal characteristics of permeability and gas content that especially define productivity of SDUT CBM reservoirs.

A principal challenge in evaluating the vertical heterogeneity of SDUT CBM reservoirs is in recovering a suitable spatial density of samples. The Xinjiang CBM reservoirs are low-rank coals ($R_{o,max}$<0.65%) (Li et al., 2018) with the low strength making it difficult to collect complete coal cores of 10 m or more during drilling. This shortcoming may be circumvented by using borehole logging data to provide an important adjunct to information normally recovered from direct sampling (Fu et al., 2010a, b; Li et al., 2011; Hatherly, 2013; Teng et al., 2015; Xu et al., 2016; Hou et al., 2017). Geophysical logging methods include using acoustic, electrical and radioactive signals as

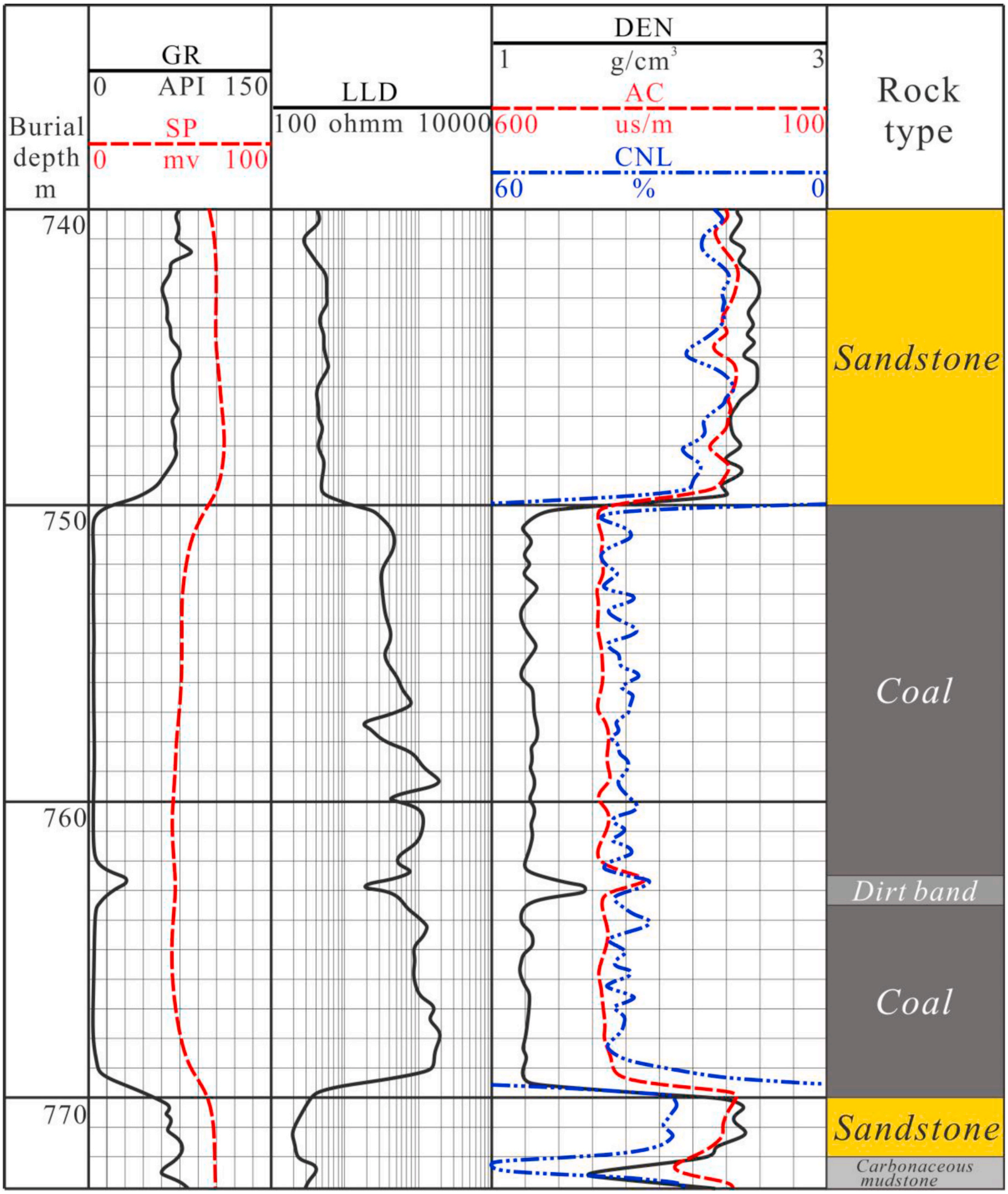

Fig. 2. The logging response of CSD01 well.

proxies for the physical and chemical characteristics of rocks (Morin, 2005; Yegireddi and Bhaskar, 2009; Hatherly, 2013). Typical logging methods in coal reservoirs include sonic (AC), natural gamma (GR), spontaneous potential (SP), compensated neutron (CNL), density (DEN), deep lateral resistivity (LLD) logs (Zhou et al., 2014; Teng et al., 2015; Xu et al., 2016; Hou et al., 2017). Different logging methods probe different reservoir characteristics (Hatherly, 2013). Proper calibration of logging techniques against the measured characteristics of physical samples potentially allows the logging-only determination of the broad spatial evaluation of coal structure, coal strength, permeability, porosity, gas content and other parameters (Hawkins et al., 1992; Fu et al., 2009a, 2009b; Li et al., 2011; Zhou and Yao, 2014; Teng et al., 2016; Chen et al., 2017a, 2017b; Hou et al., 2017). AC, CNL, DEN and LLD logs may be used to measure the gas content and permeability of coal (Fu et al., 2009a, 2009b), DEN and LLD used to evaluate the distribution of coal permeability (Li et al., 2011) and AC, DEN, GR and LLD used to evaluate structure (Teng et al., 2016; Hou et al., 2017). Such combination of various logging methods enables characterization of the variation of physical properties of ultra-thick coal reservoirs with in-seam depth to be determined, absent a large suite samples – provided suitable calibrations are available. This is the method advanced in the work described here.

The following uses the Fukang west block on the southern margin of the Junggar Basin in Xinjiang as a characteristic lithotype example to explore the roles of vertical heterogeneity in permeability and gas content of SDUT CBM reservoirs to determine systematic trends in variation - and to guide selection of sweet-spots for exploration. Sampled data from a total of 12 CBM wells, completed to different burial depths, are correlated against logging data to define trends in the heterogeneity. These characterizations are used to define the impact of gas content heterogeneity on both reserve estimation and recovery estimates. Reservoir modeling (Eclipse, Schlumberger) is used to explore the co-influence of systematic variations in permeability and gas content on gas production and to optimize locations of wellbore perforations to maximize production.

2. Geological background

The southern margin of the Junggar Basin is the most important CBM enrichment area in Xinjiang, China, representing a key area for the current development of CBM (Kang et al., 2018b; Li et al., 2018). The southern margin of the Junggar Basin is located in the Urumqi Piedmont depression in the North Tianshan Junggar structural area. This province has undergone strong structural deformation, forming the North Tianshan Foreland Fold thrust belt and the Bogda foreland thrust nappe structural belt (Li et al., 2018). The thickness of the coal seams gradually increases from west to east. Most of the coal seams in the western part of the southern margin of the Junggar basin are <10 m thick, with those in the center and east routinely increasing to ~20 m and with the seams of the Fukang mining area exceeding 30 m (Fig. 1a). The main coal-bearing strata are the Lower Jurassic Badaowan Formation and the Middle Jurassic Xishanyao Formation. The main CBM resource is in the Badaowan Formation (Kang et al., 2018b). The Badaowan Formation, in the eastern part of the southern margin of the Junggar Basin, has many high thickness coal seams (Fig. 1a). The Fukang mining area contains 18–49 seams with thicknesses in the range 31–66 m. The single layer thickness of the high-methane content CBM reservoir in the target area is over 15 m (Fig. 1a).

Reservoir development within the Fukang west block is relatively mature with ~40 production wells (Fig. 1b) and a complete suite of geological and production data available. The average daily gas production rate of the most prolific well (CSD01) in the block exceeds 10,000 m^3/d with the average daily production rate of most vertical wells exceeding 4000 m^3 - showing the significant potential for CBM development (Kang et al., 2018b; Li et al., 2018). Consequently, this is selected as the research focus in this work. In the Fukang west block, the structure comprises a series of synclines and anticlines transected by reverse faults (Fig. 1c). The target stratum for CBM development is the Badaowan Formation (Fig. 1c), comprising glutenites, fine sandstones, silty mudstones, grey mudstones and coal seams (Fig. 1c). Among them, the #14–15 coal seam is the main target for CBM production, with a thickness between 10 and 35 m, an average thickness of ~20 m and with thickness increasing gradually from north to south (Fig. 1b). The coals in the block are mainly high volatility bituminous coals (vitrinite reflectance ~ 0.64%), with principal macerals of vitrinite and inertinite (Kang et al., 2018).

3. Data and processing methods

Logging data available for the CBM block are synthesized and incorporated into mathematical models to represent the production response of the reservoirs. These models accommodate the observed distribution of permeability and gas content that are unique to SDUT coal reservoirs. In the following we define depths in two ways. We use "burial depth" to identify the vertical depth of the sampled point below the surface, and "in-seam depth" to represent the distance of the sampled point in the direction perpendicular from the seam top, within the stratigraphic section.

3.1. Logging responses of coal

The principal difficulty in studying vertical heterogeneity in SDUT CBM reservoirs is the absence of complete core samples representing the full ~20 m seam thickness for direct data measurement. However, logging data from a large number of CBM production wells are available - enabling this research. A variety of well-log inversion-models have been established to indirectly evaluate reservoir physical properties and characteristics (Fu et al., 2009a; Zhou and Yao, 2014; Teng et al., 2015; Chen et al., 2017a, 2017b). However, due to the complexity and diversity of provenance of coal reservoir materials in different basins, universally applicable well logging inversion models are not available. Therefore, it is first necessary to establish relationships between the well logging and sampled data.

Table 1
Measured and logging data of gas content for wells within the study area.

WELL	No	LLD	DEN	CNL	DEP	V_{gad}
		Ω·m	g/cm^3	PU	m	/m^3·t^{-1}
CSD01	A2	1493.00	1.23	97.00	759.90	11.65
CSD03	A3	3026.90	1.22	95.20	970.90	11.24
CS13-1	A1	127.06	1.42	51.50	988.83	7.19
	A3	260.21	1.37	56.30	1076.75	5.58
	A6	467.96	1.46	55.48	1123.98	8.97
	A8	1498.29	1.41	57.23	1159.67	7.37
CS16-X1	A2	719.90	1.42	59.10	1370.00	13.20
	A4	43.30	1.69	53.00	1442.00	14.20
FK1	43	317.60	1.37	55.13	860.10	7.43
	45–2	6428.98	1.29	55.61	961.15	7.33
FK6	45–2	126.67	1.38	50.97	1060.32	7.21
FK16	A9	1358.88	1.22	66.75	820.39	9.02
	A8	704.79	1.24	66.41	853.50	7.43
	A7	6363.19	1.34	66.38	873.94	10.79
	A5	22,721.00	1.18	71.83	922.17	12.41
	A4	392.07	1.21	62.02	992.40	7.95
	A3	253.23	1.19	72.96	1002.37	9.68

WELL-WEll number; No-coal seam number; LLD-Deep lateral resistivity logging; DEN-Density logging; CNL-Neutron logging; DEP-Burial depth; V_g-Measured gas content; PERF- Perforation thickness; K-Measured permeability.
\-No data; FK1、FK6、FK16、FK17 are CBM wells adjacent to the study block.

Logging methods applied to the CBM wells in the study area include AC, CNL, DEN, GR, LLD and SP. Although these logging techniques can distinguish between coal seams and the inorganic host rocks (Morin, 2005; Yegireddi and Bhaskar, 2009; Hatherly, 2013), our desire here is to characterize fine-scale variation in reservoir properties across a single seam. Fig. 2 shows the logging response curve for borehole CSD01 in the study area – identifying organic (coal) and inorganic (sandstone and argillites) facies. However, within the same coal seam, different logging methods have different sensitivities (Fig. 2) (Hatherly, 2013). Compared with the significant difference in the signature between coal and sandstone, the differences within the coal seams are small. The signatures of AC, GR and SP logging change minimally within the coal seam - identifying them as unsuitable as a sensitive discriminant of coal properties (Fig. 2). Conversely, CNL, DEN and LLD are sensitive to petrophysical changes within the coal seam, identifying them as suitable proxies to study the distribution of physical properties across the coal seam. GR methods use remnant radioactivity to distinguish lithology but this parameter is insensitive to porosity and gas content. SP detects flow rates and is a useful discriminant between permeable and impermeable portions of the reservoir, but is not sensitive to subtle changes in permeability within the coal seam. Thus, in Fig. 2, there is little change in GR and SP values within the coal seam. AC methods define the sensitivity of porosity to acoustic velocity and may be used to define gas content distribution (Fu, 2009a,b). AC is more sensitive to coal reservoir characteristics than SP and GR (Fig. 2), but less sensitive than CNL, DEN and LLD. LLD characterizes reservoir properties by evaluating reservoir resistivity and may be used to define fracture development and material composition (Fu et al., 2009a; Li et al., Teng et al., 2015; Hou et al., 2017). DEN, which uses gamma ray to monitor the density and fluid properties of rocks, is widely used for the analysis of reservoir porosity and gas content (Fu et al., 2009a; Li et al., 2011; Teng et al., 2015; Hou

Table 2
Measured permeability and logging data recovered from wells within the study area.

WELL	No	LLD	DEN	CNL	DEP	PERF	*K*
		Ω·m	g/cm^3	PU	m	m	mD
CS11-X1	A5	855.17	1.31	65.76	995.45	15.00	0.335
CSD01	A2	1492.87	1.23	97.46	760.00	10.84	16.640
CSD02	A2	554.06	1.23	95.65	932.70	12.00	1.620
CSD03	A3	3026.90	1.22	95.24	970.90	5.80	0.064
CSD04	A3	12,576.57	1.34	88.63	1045.75	4.70	0.243
CS15-X4	A5	1305.63	1.31	57.66	1424.00	8.00	0.009
FK1	43	959.80	1.29	55.45	960.00	10.00	0.060
	45–2	233.436	1.36	55.17	859.9	15.60	0.170
FK2	A2	195.59	1.29	55.60	477.43	16.54	0.988
FK6	45–2	101.78	1.30	56.34	1060.00	10.00	0.019
FK17	41	4261.80	1.18	61.90	842.00	4.00	0.050

WELL-WEll number; No-coal seam number; LLD-Deep lateral resistivity logging; DEN-Density logging; CNL-Neutron logging; DEP-Burial depth; V_g-Measured gas content; PERF- Perforation thickness; K-Measured permeability.
\-No data: FK1、FK6、FK16、FK17 are CBM wells adjacent to the study block.

Table 3
Inversion of physical parameters based on logging parameters.

Parameters	Equation	R^2	Sig
K/mD	*EXP(-0.000148*LLD-12.1692*DEN+0.0895*CNL-0.0061*DEP-17.5359)*	0.80	0.028
V_g/m^3·t^{-1}	*0.000192*LLD+8.777*DEN+0.151*CNL+0.007*DEP-19.242*	0.72	0.003

Sig.

et al., 2017). CNL is used to measure hydrogen content in the reservoir and to define reservoir characteristics. It is widely used to determine the degree of fracturing (Fu et al., 2009a; Teng et al., 2015; Hou et al., 2017) with these logging methods used to study fracturing and material composition of the coal reservoir (Fu, 2009a,b; Teng, 2015). Permeability and gas content are mainly controlled by fracture and material composition of the reservoir (Hawkins et al., 1992; Fu et al., 2009a; Roslin and Esterle, 2015; Teng et al., 2015; Hou et al., 2017) and are identified by the logs (Fig. 2). Thus, LLD, DEN and CNL are selected for calibration against recovered samples - as these are the best discriminant in the coal reservoir (Table 1 and 2). Burial depth is included as an auxiliary parameter, since vertical stress distribution exerts a significant influence on physical properties like permeability, gas content and degree of coal metamorphism with burial depth used as an indirect indicator of geo-stress (Chen et al., 2017a, 2017b). These data are used to determine permeability and gas content distribution with burial depth, as they all exert an important impact on CBM production (Kang et al., 2018b).

The gas content is recovered from field desorption data obtained by the USBM method (Table 1). Gas content are collocated at the same discrete in-seam locations, for multiple locations, with permeability measured across the entire perforated horizon (Kamal and Six, 1993; Clarkson et al., 2007). For the study block, the measured permeability is a comprehensive reflection of the full 10 m thickness of the reservoir - an average value of the logging data within the perforation range is selected to correspond to the measured permeability (Table 2).

3.2. Establishing the logging inversion mathematical model

Previous studies have shown that the logging response is linearly correlated with gas content and log permeability (Fu et al., 2009a; Li et al., 2011; Chen et al., 2017a, 2017b), so a log inversion model of gas content and permeability is obtained by multivariate linear fitting with SPSS statistical analysis (Table 3). A linear correlation coefficient of >0.7 (Fig. 3) is apparent between logging and sample data, indicating a significant correlation. The significance test can be used to judge the validity of the fitting result. If the significance result is lower than a certain set threshold (generally 0.05), the fitting result is considered credible, otherwise the credibility is reduced (Craparo and Robert, 2007). Following this significance test, a significance of 0.028 and 0.003 is returned, respectively, which are both less than 0.05, indicating that the linear fit is statistically significant.

To systematically study the vertical heterogeneity of the SDUT coal reservoirs, three well pads, CS13, CS15 and CS16, are selected with burial depths of 800–1100 m, 1100–1500 m and 1500–2000 m, respectively. Each of these well pads accommodates four wells, corresponding to a total of 12 wells. The coal reservoir in this study area is steep dipping at ~50° below the horizontal - this results in a significant change in burial depth along dip of the seam. This straightforwardly enables study of the vertical heterogeneity in stress in SDUT reservoirs by maximizing stress change down-dip and minimizing other variations in properties. The selected coal seam is the A2 coal seam representing the main gas production seam in the study block. The seam thickness is ~20 m, with the top 20 m selected for the study if the thickness is greater than 20 m.

4. Results and discussion

The distribution of controlling state parameters within the reservoir are recovered from the borehole logs and used to identify mechanistic controls and resulting trends in their distribution. The properties are included in mathematical models for resource evaluation, gas drainage and used to evaluate optimal methods of recovery and estimates of recoverable reserves.

4.1. Vertical heterogeneity in physical characteristics of SDUT CBM reservoirs

SDUT CBM reservoirs at different burial depths exhibit unique characteristics in the distribution of state variables controlling reservoir performance across in-seam depth. Key parameters controlling initial gas production and potential recovery are permeability and gas content that may be recovered from calibrated logs.

The permeability in the shallow SDUT CBM reservoir (800–1100 m) decreases gradually with increasing in-seam depth (Fig. 4a). Permeability at the shallowest burial depth (CS13-X2 and CS13-X3; depth

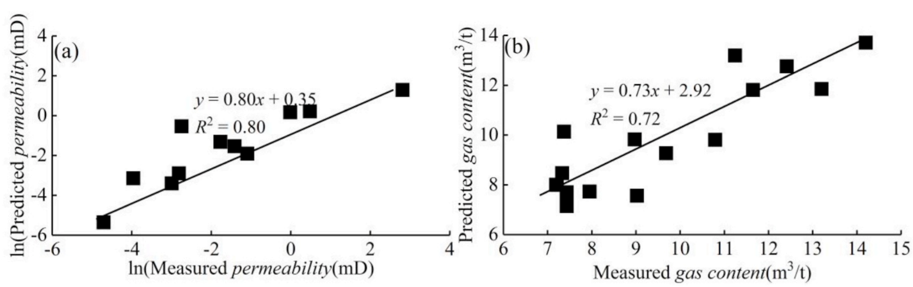

Fig. 3. Correspondence between well logging inversion data and measured data.

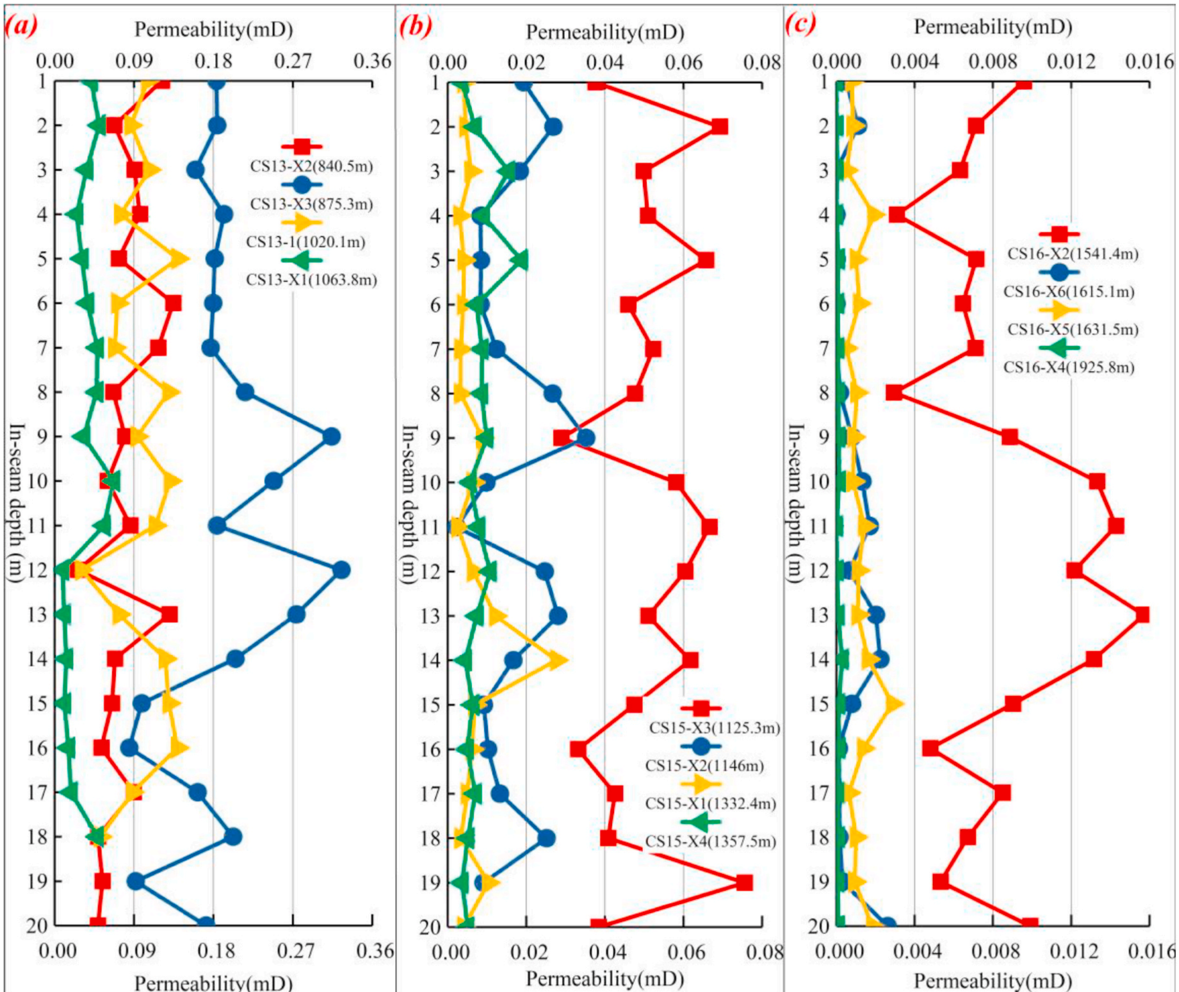

Fig. 4. Vertical heterogeneity in permeability of SDUT CBM reservoirs with in-seam depth, recovered from well.

840.5 m and 875.3 m), exhibits the most obvious decreasing trend with location in the seam - average permeability difference between the upper 10 m and the lower 10 m is 0.02 mD. With increasing burial depth, the difference in permeability between the upper and lower well section decreases (~0.01 difference for the remaining 2 wells) (Fig. 4a). At intermediate burial depths (1100–1500 m) the permeability shows no significant systematic trend within in-seam depth (Fig. 4b). The differences in the average permeability of the upper and lower parts of the 2 wells are only −0.0012 mD, 0.0020 mD, −0.004 mD, and 0.003 mD, respectively, with positive and negative values. At deep burial depths (1500–2000 m) the permeability of the three wells increases with increasing in-seam depth (Fig. 4c) - the opposite sense of this change at shallow burial depths. This shows that the vertical heterogeneity of permeability in deep SDUT coal reservoirs is different from that in shallow SDUT coal reservoirs.

The gas content in the shallow SDUT CBM reservoir (800–1100 m) increases gradually with increasing in-seam depth (Fig. 5a). The difference in average gas content of the four wells between the upper 10 m and the lower 10 m is ~0.5 m^3/t. The average gas content of CS13-X2 at shallow burial depth is 6.5 m^3/t, while that of CS13-X1 at a deep burial depth is ~10 m^3/t. At intermediate burial depth (1100–1500 m) the gas content gradually becomes irregular with in-seam depth, and no obvious principle observed (Fig. 6b). The gas contents of CS15-X3 and CS15-X1 fluctuate around averages of 10.0 m^3/t and 11.5 m^3/t, respectively – there is no overall trend (Fig. 5b). The vertical gas contents of CS15-X2 and CS15-X4 decrease slightly with in-seam depth, but the fluctuation is more significant than the trend (Fig. 5b). At deep burial depths (1500–2000 m) the vertical gas content increases with increasing in-seam depth (Fig. 5c). The average gas content of the upper 10 m of the 3 wells are greater than that of the lower 10 m, except for well CS16-X5 (Fig. 5c). The measured gas content data also show clear heterogeneity in the vertical direction, and the gas content distribution with in-seam depth is different at different burial depths (Fig. 6). CSD01 and CS16-X1 are the only two production wells with measured data in the study block. The data show that the vertical gas content of CSD01 (750 m; coal thickness is 16 m) increases gradually with increasing in-seam depth with a clear trend (Fig. 6). The difference in gas content between the upper 8 m and lower 8 m is ~0.5 m^3/t. The gas content of CS16-X1 (1359 m; coal thickness is 24 m) decreases with in-seam depth. The difference between the upper 12 m and lower 12 m is ~1.5 m^3/t. Combining the measured data with the logging inversion data, it is apparent that the heterogeneity of the SDUT coal reservoirs and in particular the vertical heterogeneity with in-seam depth are different for different burial depths.

4.2. *Quantitative characterization and analysis of the vertical heterogeneity of SDUT coal reservoirs*

From the above results, it can be seen that the SDUT coal reservoirs exhibit significant heterogeneity with in-seam depth and that this heterogeneity is different for different burial depths. The description and analysis are mainly qualitative and the results not intuitive; however, a

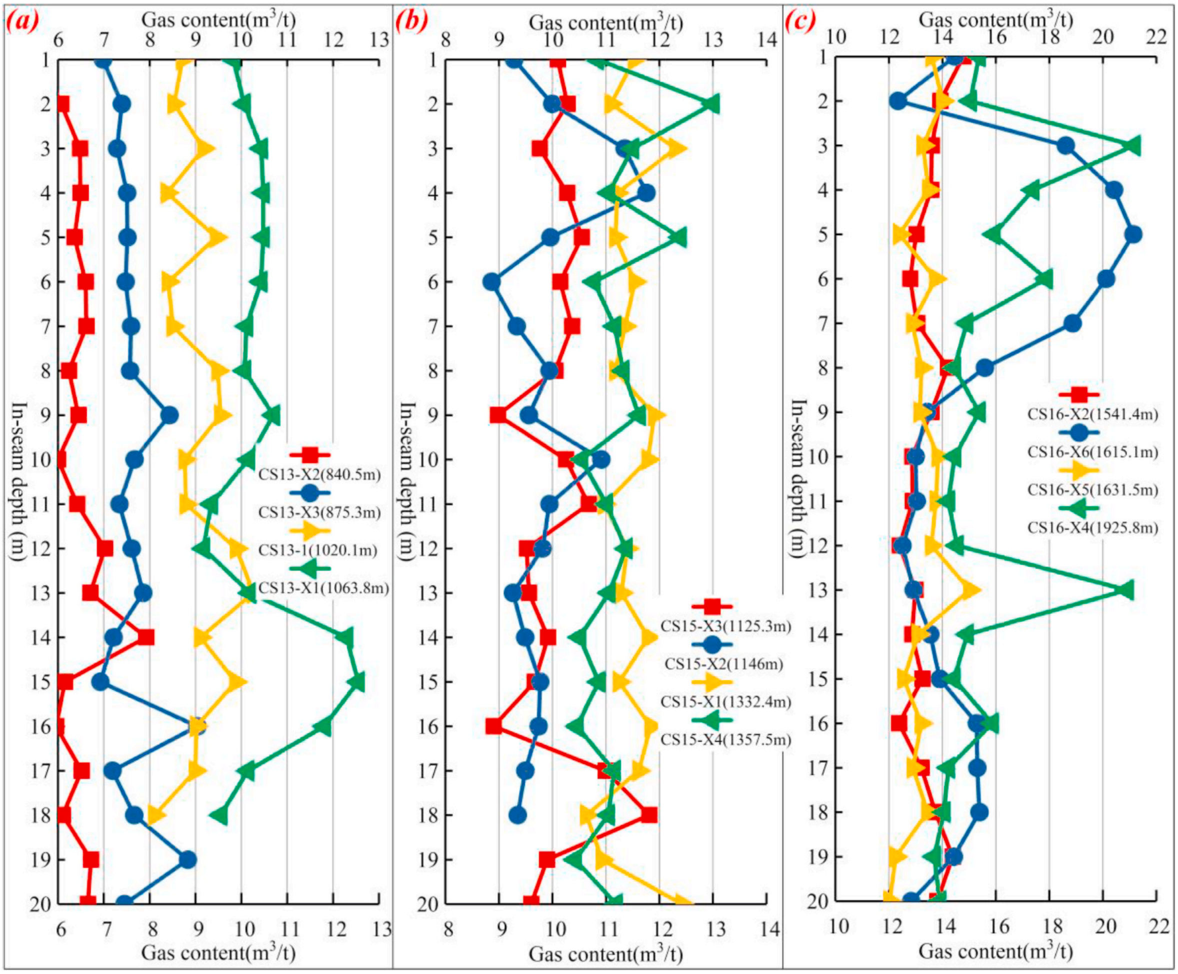

Fig. 5. Vertical heterogeneity in gas content of SDUT CBM reservoirs with in-seam depth, recovered from well logs.

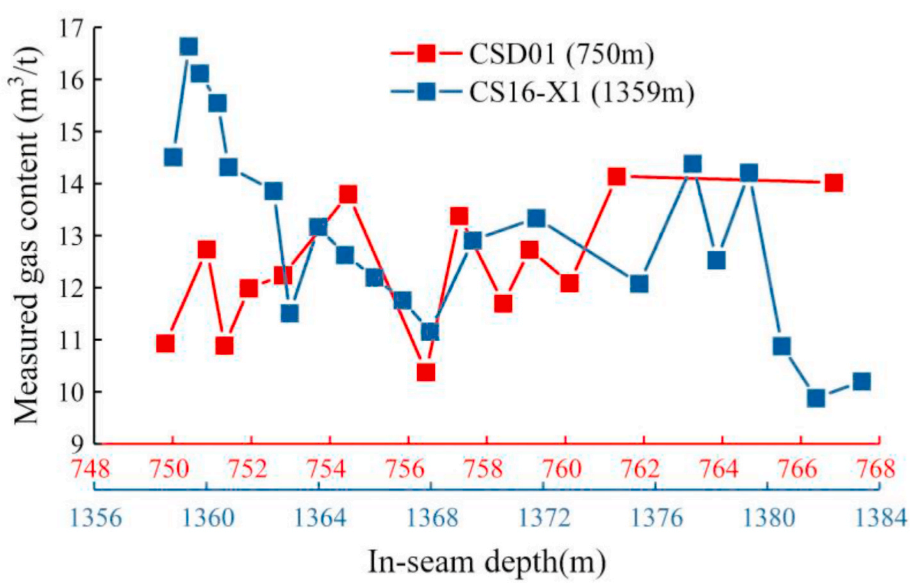

Fig. 6. Vertical heterogeneity of measured gas content of SDUT CBM reservoirs with in-seam depth, as a function of burial depth.

quantitative analysis may clarify and reveal certain process-based controls. Therefore, a Spearman rank correlation analysis is used to quantitatively analyses the vertical heterogeneity of the SDUT coal reservoirs. The Spearman rank correlation analysis can effectively characterize the nonlinear correlation features of the reservoir (Fierer and Pearson, 1961) and is more suitable for the nonlinear distribution shown in the above figure. The Spearman rank correlation coefficient (SRCC) is positive, which means that the two variables are positively

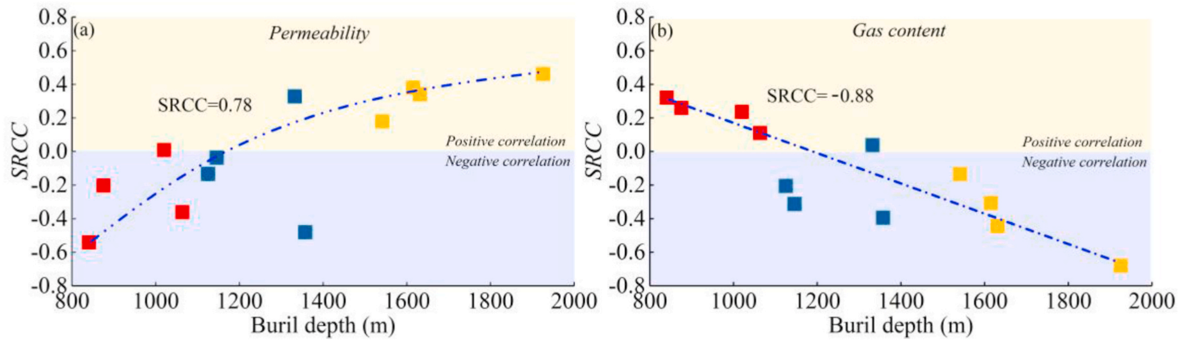

Fig. 7. Variation of SRCCs with burial depth for the various physical parameters defining the reservoir.

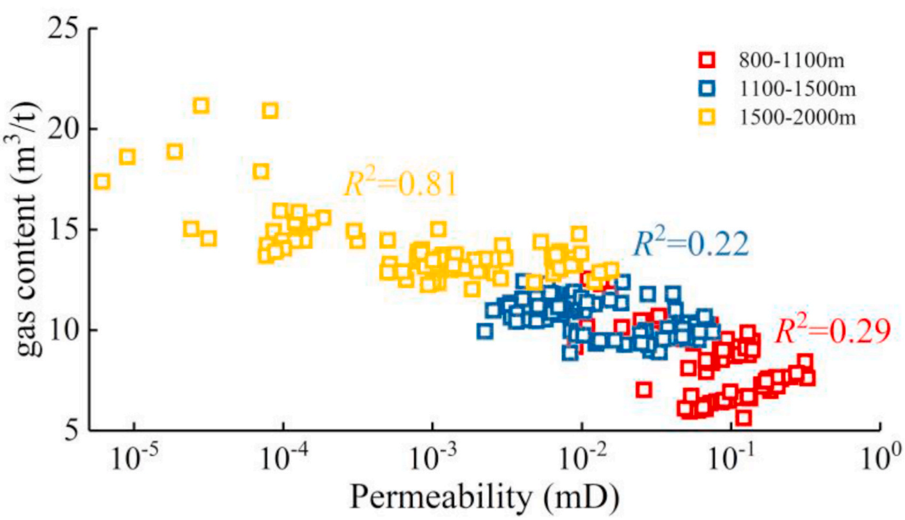

Fig. 8. Distribution of permeability and gas content in different burial depth range.

correlated, and vice versa. For a detailed calculation of the Spearman rank correlation coefficient, please refer to Kang et al. (2018b).

The ultra-thick coal reservoir is divided into 1 m increments across the in-seam depth, numbered 1 through 20 from the seam-top. The physical parameters of permeability and gas content are associated with each of these 1 m tall samples. The SRCCs of these physical parameters for different burial depths are shown in Fig. 7. The SRCC of the permeability of the SDUT coal reservoirs increases with increasing burial depth, changing from a negative correlation to a positive correlation (Fig. 7a). The SRCC of the gas content gradually decrease and changed from a positive correlation to a negative correlation with increased burial-depth - an opposite result to the SRCC representing permeability (Fig. 7b). This indicates that there is a strongly heterogeneous distribution of reservoir parameters in SDUT coal reservoirs but that the heterogeneity is systematic with different burial depths. Therefore, in this study area, it is suggested that the heterogeneous distribution exhibits opposite trends between shallow and deep (Fig. 7). We have developed a corresponding relationship between permeability

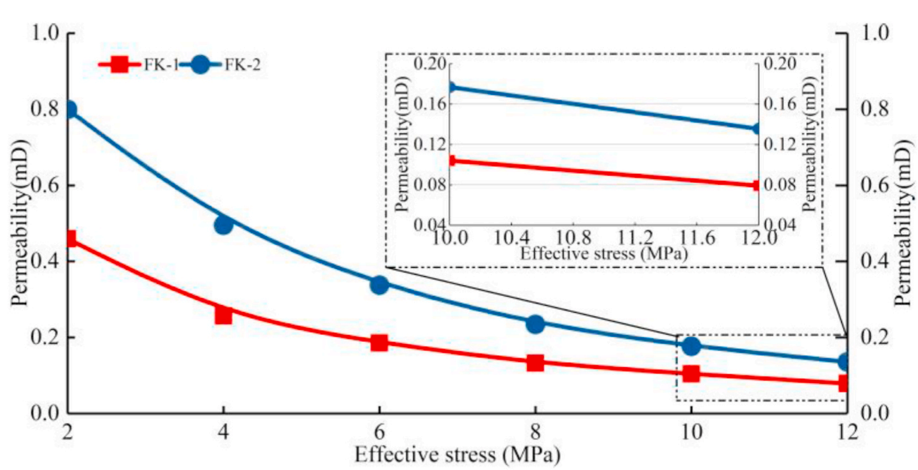

Fig. 9. Permeability and effective stress distribution recovered from reservoir samples buried at a depth of 650 m in the study block.

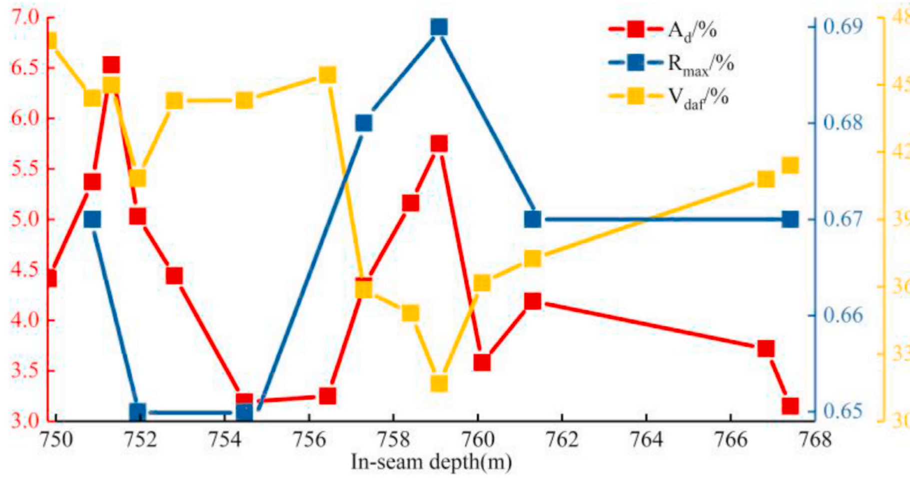

Fig. 10. Measured ash yield, vitrinite reflectance and volatile yield of SDUT CBM reservoirs in well CSD01.

and gas content across the seam for an ultra-thick reservoir (Fig. 8) and found that permeability and gas content are negatively correlated. This shows that the size distribution of permeability directly affects the distribution of gas content, since high permeability correlates with high methane loss (Laxminarayana and Crosdalea, 1999; Ramandi et al., 2016; Thakur, 2017).

Permeability characterizes the fluid flow capacity of the reservoir (Ramandi et al., 2016; Thakur, 2017) and with a strong sensitivity to stress. With increasing in-seam depth and vertical geo-stress, the coal reservoir fractures tend to close, resulting in decreases in permeability. Therefore, the permeability of shallow SDUT coal reservoirs gradually decreases and the SRCC is negative (Fig. 7a). The coal reservoir in the study block is mainly low-rank coal with low strength, and the permeability are strongly stress-sensitive (Wang et al., 2018; Liu et al., 2019). For coal reservoirs with a thickness of ~20 m, the stress difference from the reservoir top to base is approximately 0.54 MPa base on the geo-stress gradient (Chen et al., 2017a, 2017b), and the permeability difference is ~0.01 mD. According to the measured permeability-stress curve of the shallow reservoir samples in the study area, the change in the permeability is relatively consistent (Fig. 9), indicating that the vertical distribution of permeability in shallow SDUT coal reservoir are likely principally controlled by the geo-stress. The gas content is affected by the formation and preservation of methane in coal reservoirs (Laxminarayana and Crosdale, 1999). The gradually reduced permeability also increases the migration resistance of methane (Fig. 8), which is more conducive to the preservation of methane. For the measured data, the grade of metamorphism increases slightly and decrease of ash yield with in-seam depth (Fig. 10), that mean the gas generation capacity and adsorption capacity correspondingly increase, which also benefit the gas content increase with in-seam depth (Laxminarayana and Crosdale, 1999).

In the deeper reservoir (1500–2000 m) the high geo-stress leaves the fractures at residual compaction (Laubach et al., 1998; Moore, 2012), with this stiffening resulting in little stress-sensitivity to permeability. Rather, permeability is affected by many other factors, such as degree of fracture development, fracture morphology, material composition differences (Dawson and Esterle, 2010) - geo-stress is no longer the dominant factor. This is not to say that geo-stress is no-longer important in mediating permeability change but rather that the importance of stress is reduced into only a narrow range of burial depths. During the initial stage of coal formation, sedimentary plants need layers that are hundreds of meters in thickness, and it takes tens of millions of years for these layers to accumulate (Stach and Murchison, 1982). Therefore, structural controls and facies differences originating during the formation period are also significant, and influence the evolution of fractures and fracture morphology (Dawson and Esterle, 2010). These material differences also exist in the shallow SDUT reservoir (800–1100 m) but its influence is smaller than that of geo-stress. The average permeability of the four wells (800–1100 m) in the shallow SDUT coal reservoirs is ~0.103 mD, while that of the four wells (1500–2000 m) in the deep SDUT coal reservoirs is ~0.003 mD. At the top and bottom of the shallow SDUT coal reservoir, the permeability changes approximately 0.01 mD under the geo-stress - this is more than 20 times that of the deep reservoir permeability, so the effect of material difference on permeability is very small in the shallow reservoir. Another possible reason for this result is that the selected CBM wells are located in a syncline (Fig. 1), and there is an inclined stratum with a large dip angle between the syncline axis and the horizontal plane (Kang et al., 2018b). The four wells with a burial depth of 1500–2000 m are in the deep part of the inclined formation and are close to the synclinal axis. During folding, the

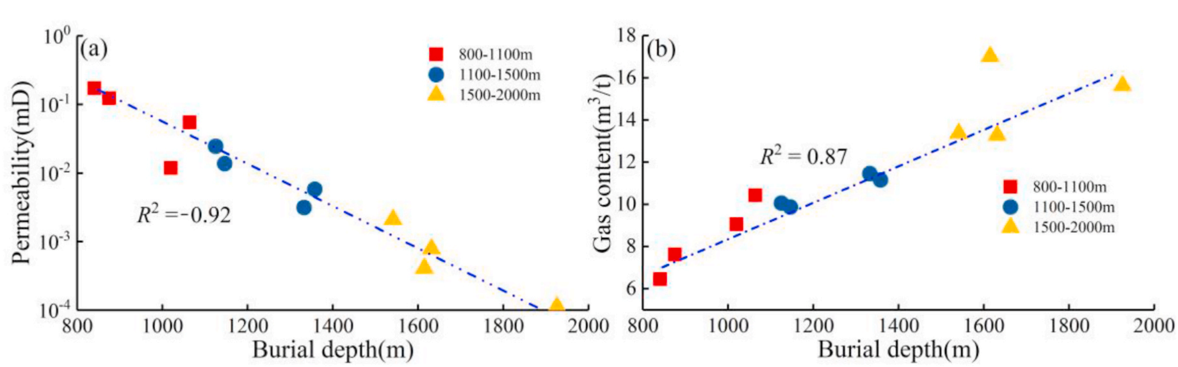

Fig. 11. Distribution of physical parameters at different burial depth within the study block.

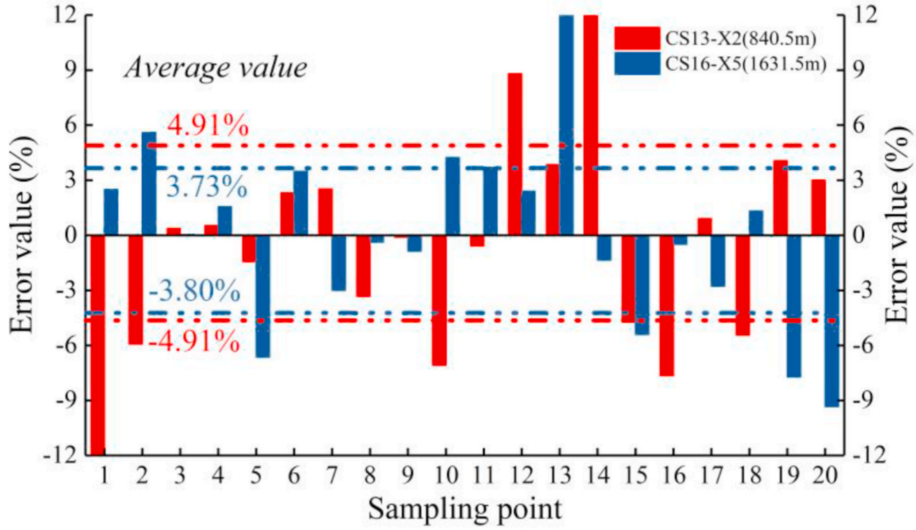

Fig. 12. Errors in resource calculations at different sampling points.

external radius of the synclinal axis will be in tension, with this extension increasing towards the base of the ultra-thick coal reservoir (Scott et al., 2007; Hamilton et al., 2012) – this results in an increase in fracture permeability. For the deep coal reservoirs, similar to the shallow SDUT coal reservoirs, the gas content is low where the permeability is high, and vice versa (Fig. 8) - confirming that permeability has an overriding influence on gas content. Relative to the shallow reservoir, the correlation with permeability is very high (Fig. 8). This is because the permeability of the deep reservoir is low. The permeability determines the flow capacity of methane, that is, the potential for methane escape. For the shallow reservoir, the permeability is high, and other factors such as the characteristics of the roof and floor and the hydrological environment all affect the amount of gas that may escape (Bustin and Clarkson, 1998; Scott, 2002; Hamilton et al., 2012).

The permeability, gas content of the SDUT coal reservoirs were averaged to obtain the distribution of these parameters between the three ranges of burial depths (Fig. 11). The permeability shows a significant negative exponential decrease with an increase in burial depth, with a linear correlation coefficient of up to 0.92 (Fig. 11a) - identifying the significant control of stress on permeability. The gas content increases linearly with increasing burial depth, with a linear correlation coefficient reaching 0.85 (Fig. 11b). The relationship between the two parameters and burial depth is generally consistent with previous research results (Clarkson et al., 1997; Bustin and Clarkson, 1998; Crossdale et al., 1998; Dawson and Esterle, 2010; Shen et al., 2015). Thus, it is worth noting that the distribution of the physical parameters with burial depth is not directly mapped to the vertical distribution of the SDUT coal reservoirs with in-seam depth change; that is, the vertical distribution of physical properties in the narrow burial depth range of the SDUT coal reservoirs is not completely consistent with the change in the large range of the burial depths. This is because, although the SDUT coal reservoirs are much thicker than thin and flat-lying coal reservoirs, the change in its depth is much smaller than that of the overall burial depth; thus, the influence of stress on some parameters is relatively small, while other factors, such as the composition of coal forming materials and structural adjustment, become the leading factors. Therefore, the change in reservoir physical properties with burial depth cannot be directly mapped to the vertical distribution of the SDUT coal reservoirs, which needs a targeted analysis.

4.3. The effect of vertical heterogeneity on resource assessment and gas production

The purpose of studying the heterogeneity within in-seam depth of ultra-thick reservoir is to define its influence on resource assessment and production. Resource evaluation is an important prerequisite for CBM development with gas content distribution an important parameter affecting resource calculation. Gas content and permeability are important parameters to define potential CBM production (Qin et al., 2017). We evaluate the influence of heterogeneity in vertical gas content on resource evaluation and the influence of gas content/permeability distribution on CBM production.

4.3.1. Impact of vertical heterogeneity on CBM resource assessment

Resource evaluation is an important prerequisite in defining favorable areas for production (Qin et al., 2017) and for ultra-high-thickness coal reservoir, the multiple sampling is required due to the strongly heterogeneous in gas content (Figs. 4, 5 and 7). Therefore, the vertical gas content distributions of wells CS13-X2 and CS16-X5 are taken as representative samples to evaluate the impact of selecting different sampling locations on the resulting resource assessment.

The CBM resources may be evaluated from:

$$G = A \times h \times V \times \rho \tag{1}$$

where G is the volume of the CBM resource over a certain area, A where h is the effective thickness of the coal layer; V is the gas content; and ρ is the coal density. For ultra-thick coal reservoirs, due to the vertical heterogeneity of the gas content, the calculation may be modified as:

$$G = A \times \sum_{1}^{n} (h_i \times V_i) \times \rho \tag{2}$$

where h_i is the thickness of each sampling point in the ultra-thick coal reservoir, taken as 1 m in this current work, with V_i representing the gas content in each 1 m thick interval. The result from Eq. (2) is taken as the actual resource and that from Eq. (1) as a conventional, but potentially inaccurate, estimate. Because the calculated area and density of the resources are the same, the two evaluations may be directly compared.

The results show average positive 4.3% and negative 4.4% calculation errors between the true resource and where a single sampling point is used (Fig. 12) for an average absolute error of 4.4%. Although an ~4.4% error may seem small, the resources of the southern margin of the Junggar Basin account for about 2.58 trillion m^3 of China and ~7%

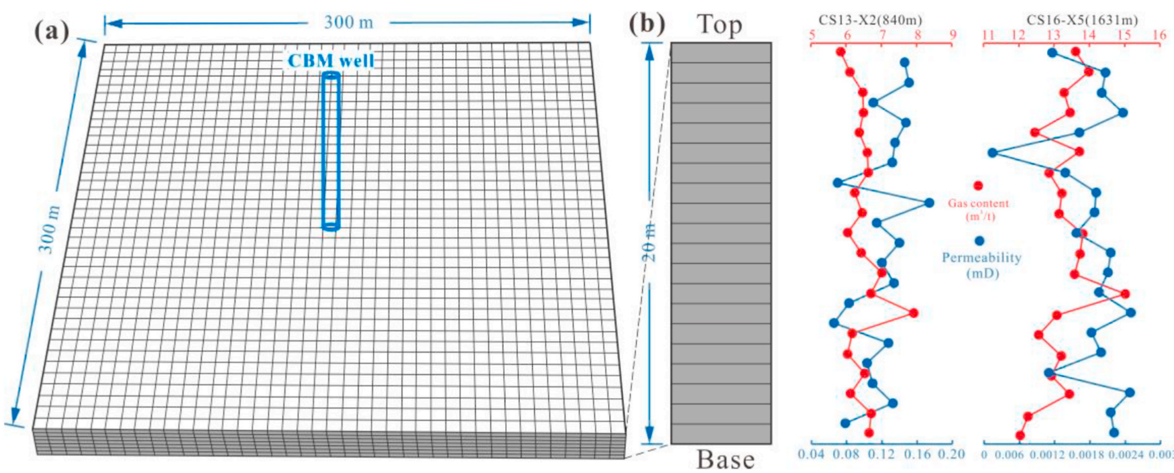

Fig. 13. Grid for numerical simulation (a) and vertical distribution of gas content and permeability of SDUT CBM reservoirs (b) gas contents and permeability across the seam.

Table 4
Gas content and permeability for the four simulation modes.

Parameters	Gas content	Permeability	Simulation Purpose
Model1: Homogeneity in gas content and permeability	Average value of vertical gas content	Average value of vertical permeability	This is a comparative basis for the influence of vertical heterogeneity on gas production of ultra-thick coal reservoirs.
Model2: Heterogeneity in permeability	Average value of vertical gas content	Actual vertical permeability value	Separate analysis of the effect of vertical heterogeneity distribution of permeability on gas production in ultra-thick reservoirs
Model3: Heterogeneity in gas content	Actual vertical gas content value	Average value of vertical permeability	Separate analysis of the effect of vertical heterogeneity distribution of gas content on gas production in ultra-thick reservoirs
Model4: Heterogeneity in gas content and permeability	Actual vertical gas content value	Actual vertical permeability value	Analysis of the synergistic effect of vertical heterogeneity of permeability and gas content on gas production in ultra-thick reservoirs

Table 5
Reservoir parameters used in the numerical simulations.

Parameters	Value		Parameters	Value	
	CS13-X2	CS16-X5		CS13-X2	CS16-X5
Production time/a	10 years		Langmuir volume/m^3/t	11.53	15.38
Burial depth/m	840	1635.5	Langmuir pressure/MPa	2.9	
Thickness/m	20		Mesh quantity	40 × 40 × 20	
Grid Range/m	300 × 300		Poisson's ratio	0.25	
Reservoir pressure/MPa	8.4	16.4	Young's Modulus/MPa	4000	
Gas content/m^3/t	8.58	11.11	Strain at infinite pressure	0.01226	
BHP/MPa	0.7		Palmer-Mansoori exponent	3	
Reservoir temperature/°C	30		Cleat compressibility	$1.0062*10^{-7}$	

Note: the setting of reservoir temperature is based on the intermediate value of the current ground temperature of the two wells, not the actual reservoir temperature of the two wells. The purpose of this setting is to eliminate influencing factors and better study the influence of heterogeneity of ultra-high-thickness on gas production.

of China's CBM resources (Liu et al., 2009). Thus, an error of 4.4%, corresponds to ~114.4 billion m^3 - equivalent to the resources of several important individual CBM blocks in southwest China (Liu et al., 2009). It is clear that the error of 8 sampling points out of the 20 sampling points is greater than the average value, and two of them exceed 10% (Fig. 12). This means that if random sampling is used, there is a 40% chance that the calculation error of the resource will exceed the average – suggesting the need to collect more samples in the evaluation of SDUT reservoirs.

4.3.2. *Impact of vertical heterogeneity of permeability and gas content on gas production*

As discussed above, SDUT coal reservoirs are highly heterogeneous with different heterogeneity characteristics at different burial depths (Fig. 7). We analyze the influence of this heterogeneity on gas production by using permeability and gas content of wells CS13-X2 (840 m) and CS16-X5 (1615 m).

Production simulations are conducted with Eclipse (Wang et al., 2012; Sayyafzadeh et al., 2015; Kang et al., 2019) using a 300 m × 300 m × 20 m grid with 40 × 40 × 20 (Fig. 13a) nodes in the x-, y- and z-directions. The z-direction represents the in-seam thickness of the 20 m thick SDUT reservoir and accommodates the corresponding true distribution of permeability and gas content (Fig. 13b). The following models and assumptions are used in the model to simulate gas and water flows of the coal reservoir: Dual porosity, Equilibrium initialization, Palmer-Mansoori rock type compaction, Langmuir-type sorption isotherm with a single component, Fick diffusion law (Kang et al., 2019; Fan et al., 2019a, 2019b). Because the original permeability of the reservoir is very low, the gas production is also low. To show the influence of permeability heterogeneity on gas production from the SDUT reservoir, the vertical permeability of wells CS13-X2 and CS16-X5 was increased first 10-fold then 500-fold. The reservoir is approximated as a horizontal reservoir, without influence of dip and fault for more targeted analysis of the influence of vertical gas content and permeability heterogeneity, and used to examine four modes of heterogeneity (Table 4). After determining the permeability and gas content, the basic parameters were set according to Table 5, recovered from the formation parameters of the well.

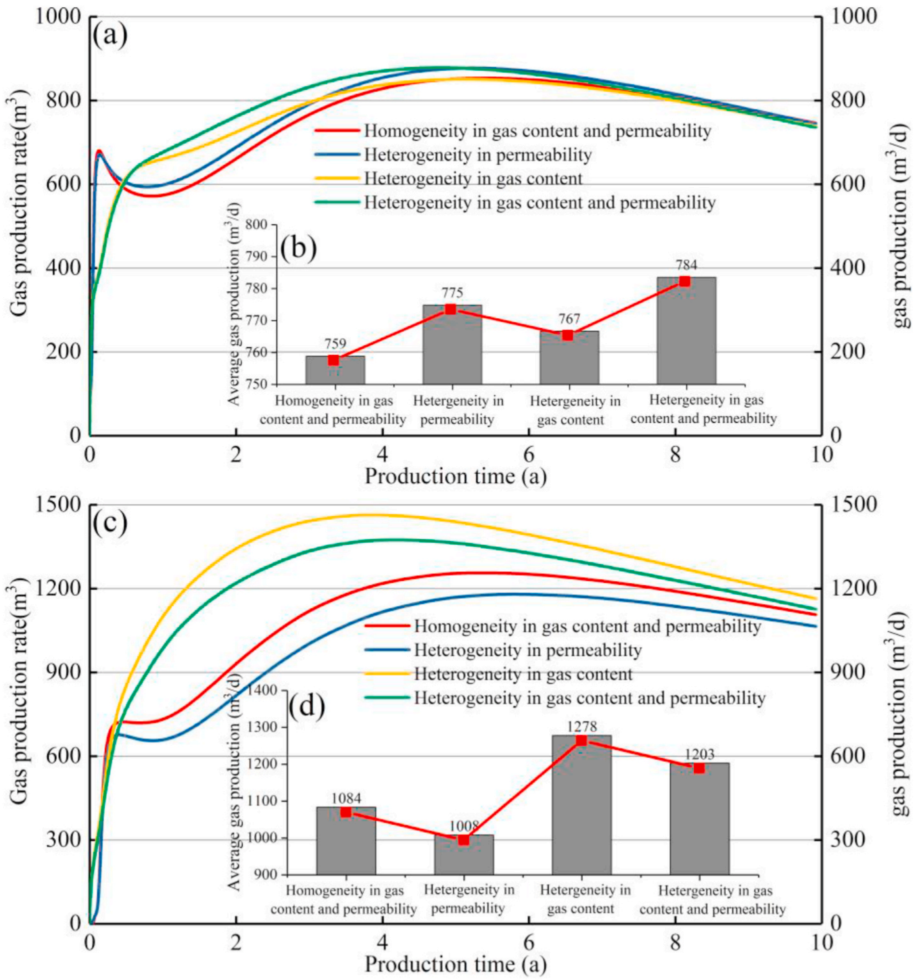

Fig. 14. Gas production profile and average daily gas production with a heterogeneous distribution of permeability and gas content of SDUT CBM reservoirs with depth.

The simulations indicate a minimal impact of vertical heterogeneity of permeability and gas content in SDUT reservoirs on gas production (Fig. 14). The average gas content and permeability of well CS13-X2 are set as control. When both the permeability and gas content of the SDUT coal reservoirs are vertically heterogeneous, the difference between the gas production profile and that of the control group is the largest – as the effects of heterogeneity are additive. Average gas production more directly reflects the influence of heterogeneity (Fig. 14b). Well CS16-X5 production data, representing deep burial, show similar characteristics to Well CS13-X2, representing shallow burial. Comparing the parameters of CS13-X2 and CS16-X5, well CS13-X2 has higher permeability and lower gas content, while well CS16-X5 exhibits the opposite trend. In addition, the permeability of well CS13-X2 decreases with in-seam depth and the gas content increases, and well CS16-X5 exhibits the opposite trend. The gas production data under these two conditions show the same characteristics, indicating that the exact form of the heterogeneity or its trend with depth has little influence on production. Considering permeability and gas heterogeneity, the gas production increase of CS16-X5 well with deeper burial depth is larger than that of CS13-X2 well with shallower burial depth (Fig. b, d). Compared with CS13-X2, CS16-X5 has smaller permeability and larger gas content (Fig. 13b). This shows that the permeability and gas content heterogeneity will have a more significant impact on gas production in reservoirs with larger gas content.

Although the simulation results suggest that the heterogeneity of permeability and gas content with depth has effect on gas production, but it's not very obvious, this ignores choices of perforation depths and fracturing orientation. For thin coal reservoirs, fracturing impacts the entire thickness of the reservoir (Lv et al., 2012; Tao et al., 2014). However, for the SDUT reservoirs, perforation and fracturing after

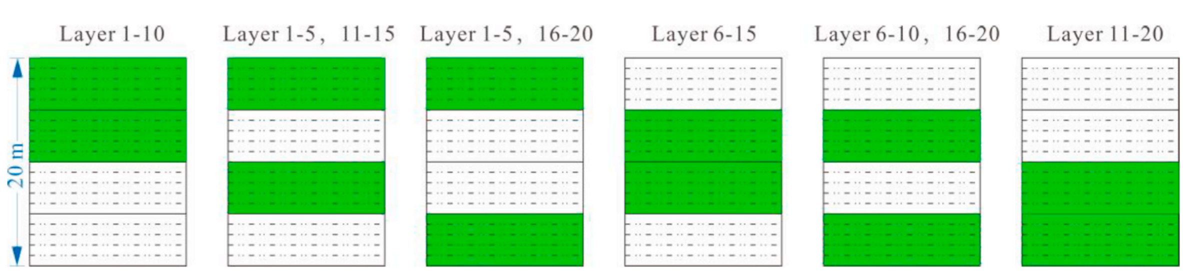

Fig. 15. Schematic diagram of the locations of perforations within SDUT CBM reservoirs.

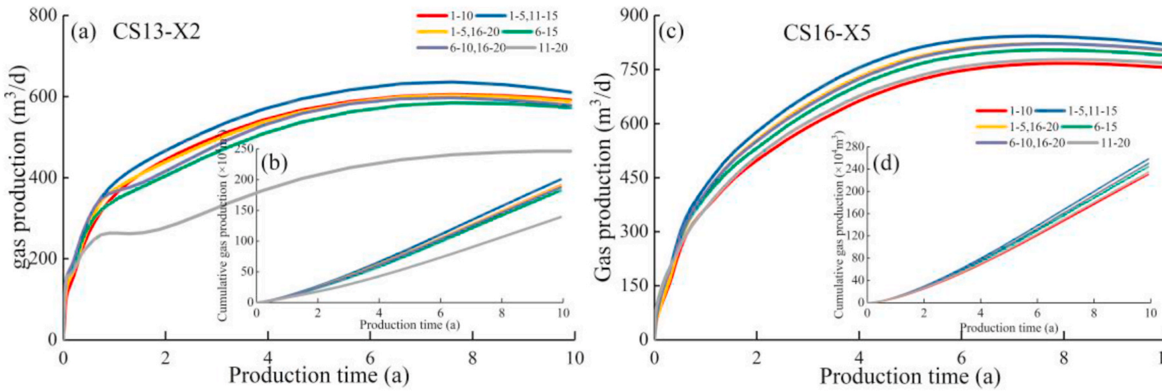

Fig. 16. Gas production rates for different combinations of perforation configuration.

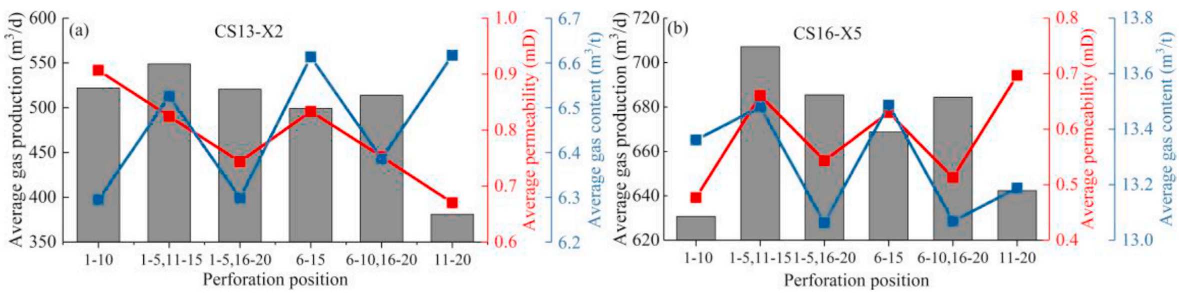

Fig. 17. Average gas production from different perforation configurations.

cementing are not implemented over the full thickness of the reservoir - that is, that part of the vertical profile of the reservoir is not connected to the wellbore. Therefore, it is necessary to study gas production for different perforation locations to define the optimal location(s). Perforation and fracturing for SDUT reservoirs are generally performed on stages 5 m in length, comprising a maximum of two sets (Fig. 15).

Simulations using the parameters of Table 5 indicate that well CS13-X2 (shallow burial) returns a significantly lower gas production rate when perforated in the lower part of the reservoir with no obvious difference between production for the remaining five perforation combinations. The difference between maximum and minimum peak gas production is approximately 150 m^3/d (Fig. 16a) representing ~25% of the peak production. Cumulative gas production and daily average gas production show similar characteristics (Fig. 16b). The daily gas production and cumulative gas production of well CS16-X5 are different for different perforation combinations. The gas production is highest for perforations at mid-depth within the reservoir, and the lowest when perforated at the base (Fig. 16c and d).

The variation in production for different perforation layouts is apparent from the average daily gas production. Permeability and gas content and their distribution are important factors affecting gas production through the selection of perforation locations. Fig. 16 represents these impacts of perforation layout. Logically, perforating at the location of the lowest permeability results in the lowest daily gas production, even though the gas content at this location is not the lowest (Fig. 17). This indicates that permeability has a greater impact on gas production than gas content. Surprisingly, gas production at perforation locations with higher permeability and gas content is lower than that at perforations with lower permeability and gas content. For example, in well CS13-X2, the average permeability and gas content at perforation positions 6–15 are larger than those at perforation positions 6–10 + 16–20, although gas production at 6–15 is lower (Fig. 17). This is because interlayer interference promotes pressure relief and methane desorption in adjacent layers and correspondingly increases gas production. For the 6–15 layout there are only two surfaces connected to the remainder of the reservoir (top and bottom) whereas configurations 6–10 and 16–20 are in contact with three adjacent coal interfaces (Fig. 15). Amongst the six perforation combinations, two contact only a single coal interface (1–10 and 11–20), two contact two interfaces (6–15 and 1–5+16-20) and the other two contact the three interfaces (Fig. 15). Thus, gas production is maximized when the perforated stages are not adjacent and access the maximum number of coal interfaces, and especially where the perforated zone is of high permeability.

We note that these results relate exclusively to the Fukang west block on the southern margin of the Junggar Basin and that although defined by specific depths, the definitions of "deep," "intermediate" and "shallow" are subjective. The research results are complete for the current study area and indicate that there are systematic trends in response and that such reservoirs should not be treated as homogeneous. However, more data are needed to confirm whether this response is characteristic for SDUT coal reservoirs in general.

5. Conclusions

The Fukang west block on the southern margin of the Junggar Basin in Xinjiang province, China, is taken as a characteristic example of a steeply-dipping ultra-thick (SDUT) CBM reservoir. We explore the unique characteristics of vertical heterogeneity in permeability and gas content of SDUT coal reservoirs by inverting logging data. The total CBM reserve is estimated and is shown to be conditioned by the vertical heterogeneity in gas content across the seam. Finally, these data are used in simulations of flow and transport incorporating permeability evolution (Eclipse) and honoring the initial logging data to study the influence of both *across-seam* and *burial-depth/geo-stress* related heterogeneity in permeability and gas content on gas production and to thereby prescribe optimal methods for recovery. The study yields the following conclusions related to SDUT CBM reservoirs:

1) The permeability of these reservoirs are strongly and systematically heterogeneous from the reservoir top to base. The vertical

permeability gradually decreases with increasing in-seam depth for shallow burial depths in the range 800–1100 m. Conversely, for deeper burial depths (1500–2000m) permeability gradually increases with increasing in-seam depth.

2) The gas contents also vary strongly from the reservoir top to base. At shallow burial depths (800–1100 m), gas content gradually increases with increasing in-seam depth but decrease across the seam at deeper burial depths (1500–2000m). To some extent, the change of permeability determines the distribution of gas content, especially that in the deep coal reservoir.
3) At intermediate burial depths (1100–1500 m), no systematic changes with in-seam depth are apparent for the parameters of permeability and gas content. This intermediate depth represents a transition in burial depth, between shallow and deep burial, where reservoir heterogeneity is controlled by a variety reinforcing and diminishing factors with no dominant control.
4) Evaluating the resource by ignoring the heterogeneity in the initial gas content with in-seam depth yields an average overestimation of approximately 4.3% and underestimation of approximately 4.4% in the calculated resource using the simplified logging data. If the reservoir is randomly sampled, then there is a 40% probability that the calculation error will exceed the average.
5) The vertical heterogeneity in permeability and gas content exert a significant influence on gas production, and the influence will be greater when the reservoirs with larger gas content. Production optimization favors the utilization of perforation stages that are not adjacent and that consequently perforate coalbed layers with a maximum number of interfaces with the reservoir. Gas production is maximized for the perforation of zones with the highest permeability.

Author contribution

Junqiang Kang: Data curation, Writing - original draft, Methodology. Xuehai Fu: Conceptualization, Methodology, Software. Derek Elsworth: Writing- Reviewing and Editing. Shun Liang: Writing- Reviewing and Editing.

Declaration of competing interest

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

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Appendix A. Supplementary data

Supplementary data related to this article can be found at https://doi.org/10.1016/j.jngse.2020.103455.

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