

CBM Resources/reserves classification and evaluation based on PRMS rules

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Abstract. This paper introduces a set of definitions and classification requirements for coalbed methane (CBM) resources/reserves, based on Petroleum Resources Management System (PRMS). The basic CBM classification criterions of 1P, 2P, 3P and contingent resources are put forward from the following aspects: ownership, project maturity, drilling requirements, testing requirements, economic requirements, infrastructure and market, timing of production and development, and so on. The volumetric method is used to evaluate the OGIP, with focuses on analyses of key parameters and principles of the parameter selection, such as net thickness, ash and water content, coal rank and composition, coal density, cleat volume and saturation and absorbed gas content etc. A dynamic method is used to assess the reserves and recovery efficiency. Since the differences in rock and fluid properties, displacement mechanism, completion and operating practices and wellbore type resulted in different production curve characteristics, the factors affecting production behavior, the dewatering period, pressure build-up and interference effects were analyzed. The conclusion and results that the paper achieved can be used as important references for reasonable assessment of CBM resources/reserves.

1. Introduction

With the increasingly rigorous situation of conventional oil and gas supply in the world, the research and development of unconventional energy become the main issue of energy development in the 21st century. Coalbed Methane (CBM) is one of the major unconventional resources, and has the characteristics of abundant resources, high calorific value, low pollution and high security, which can become an important supplement to the conventional resources. Therefore it is imminent and important to investigate the situation of CBM resource/reserves and carry out the evaluation work of CBM.

2. Overview of the PRMS

In March 2007, the SPE Board, along with the WPC, AAPG, and SPEE approved the new Petroleum Resources Management System (PRMS). The companion document “Guidelines for Application of the PRMS” was published in November 2011. The PRMS contains a series of definitions, standards and guidelines for the classification of conventional and unconventional petroleum resources[1].



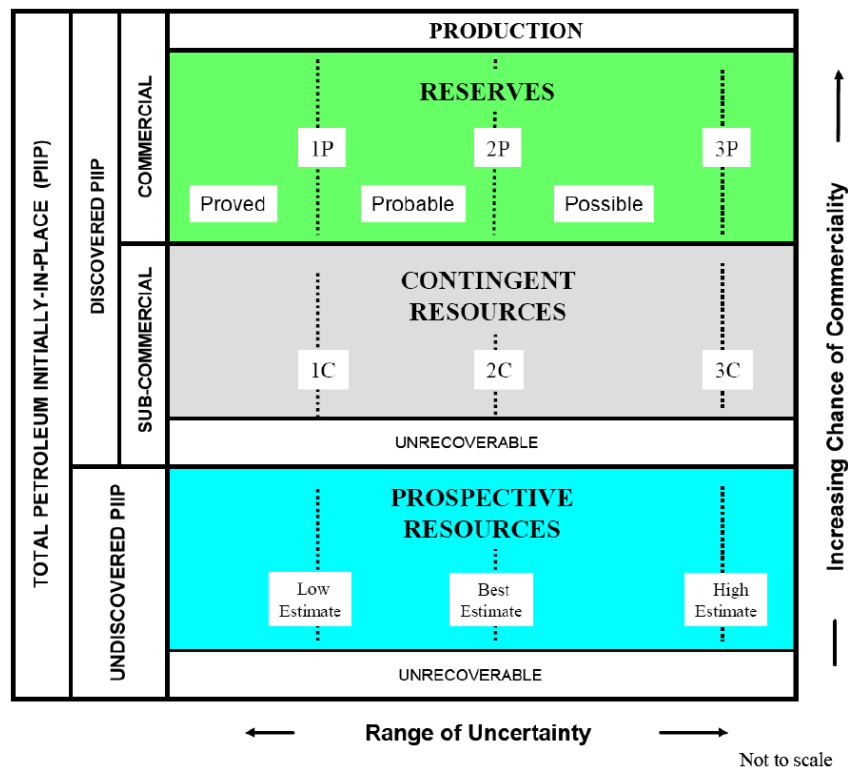


Figure 1. PRMS reserves and resources classification framework.

The resources/reserves classification system of PRMS is “Project-Based”. In vertical, according to whether they are discovery or not as well as the chance of commerciality, total petroleum initially-in-place (PIIP) are classified as undiscovered, sub-commercial and commercial, their corresponding recoverable resources are classified as prospective resources, contingent resources, reserves and production. In horizon, according to the range of uncertainty, reserves and contingent resources are divided into 1P/2P/3P and 1C/2C/3C respectively[2-6], the prospective resources are sub-classified as low/best/high estimates (Figure 1).

3. Reserves classification principles and evaluation processes of CBM

Based on the guidelines of PRMS, the general requirements for classification of CBM reserves are put forward from the following aspects: ownership, drilling requirements, testing requirements, regulatory considerations, economic requirements, infrastructure and market, timing of production and development, and so on[7].

3.1. Reserves

The CBM volumes are discovered, remaining (as of the evaluation date), technically and economically recoverable to known accumulations from a given date forward under defined conditions. Demonstrated commercial production potential (pilot test), marketable gas composition and commercial gas content(coal sample, gas sample), depth within accepted economic limits within coal fairway, development plan feasible, economically viable, market exists, firm commitment to develop within a reasonable time frame, approvals exist and imminent[8-10].

Proved (P1): If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimation. Conditions should be satisfied:

Proved Developed (PD): Applies to the nominal drainage area for producing (PDP) or non-producing (PDP) wells that have proven to have commercial quantities of gas. Non-producing reserves that are near to existing infrastructure, and require minor capital, should normally be developed within a two-year period. Well spacing will vary depending on the geological conditions[11].

Proved Undeveloped (PUD): Demonstrated commercial success in project or repeated commercial success in nearby analogous project, typically 1 well spacing from Proved developed location (Figure 2), if the permeability is high and the lateral continuity of the coals is good or regional experience justifies it, this may be increased to 2 well spacings[12]. PUD reserves must have drilling plan and should be developed in 5 years.

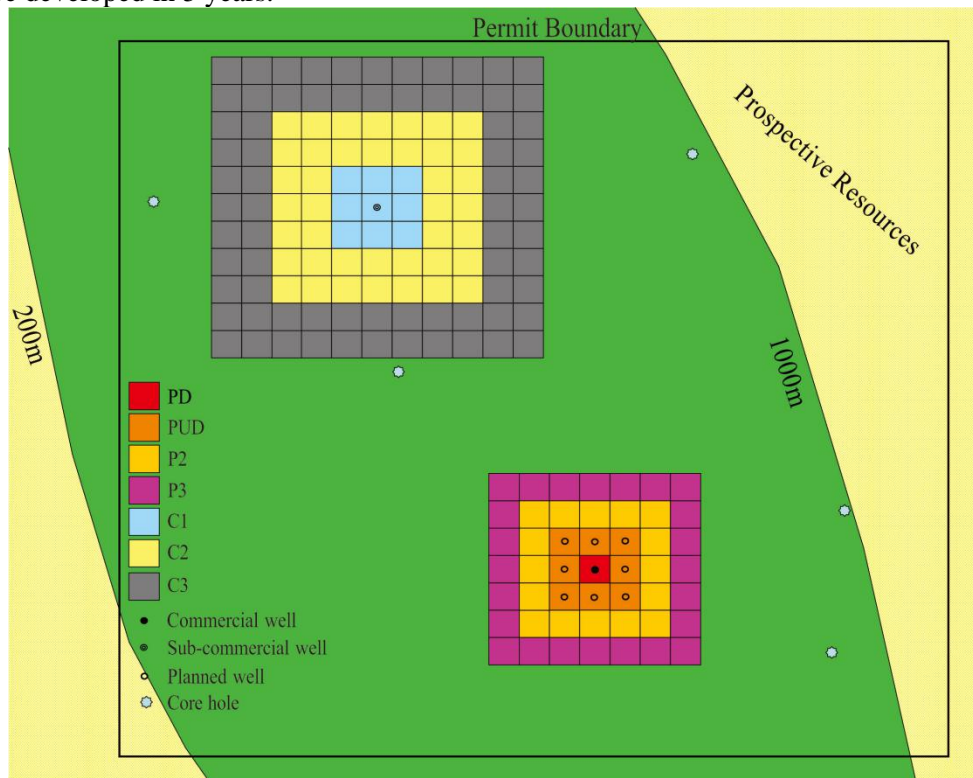


Figure 2. Conceptual P1/P2/P3 and C1/C2/C3 areas used in the CBM industry.

Probable (P2): It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the Proved plus Probable Reserves (2P). When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will be equal or exceed the 2P estimate. Conditions should be satisfied: (1) must have all regulatory approvals unless near to approval and no significant issues raised; (2) development must be economic under constant or forecast pricing with all future costs; (3) demonstrated commercial success in project or commercial success in analogous projects not nearby; (4) immediately adjacent to the Proved Area where geological continuity and consistency of character of coals is certain, typically 1 well spacing distance from Proved location, may be extended to greater distances if coal geology, coal quality and local experience permits.

Possible (P3): A low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will be equal or exceed the 3P estimate. Conditions should be satisfied: (1) no reserves should be booked if regulatory approvals have not been obtained unless immediately offsetting approved lands; (2) development must be economic under constant or forecast pricing with all future costs; (3) some doubt whether the recovery will be commercially successful; (4) coal must

be observed on logs within 3 well spacing of a producing or tested CBM well confirming economic productivity; (5) adjacent to the Probable Area where geological continuity and consistency of character of coals is certain, typically 1 well spacing distance from Probable location, may be extended to greater distances if coal geology, coal quality and local experience permits.

3.2. Contingent resources

The CBM volumes are discovered, technically recoverable resources form known accumulations that are not currently economic. Such as (1) gas content (coal sample), permeability undemonstrated or sub-economic, rates not yet demonstrated to be commercial; (2) gas composition are not marketable or market are not assured; (3) 4-6 spacings from undemonstrated or sub-economic well location and inside the observation area on logs within 6 spacings radius; (4) requires as yet unproven well technology e.g. untried stimulation techniques or horizontal/multi-lateral wells; (5) outside areas that can be accessed legally (e.g. protected land); (6) development plan immature or sub-economic, (7) lack of approvals. The general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively, the associated incremental quantities are defined as C1/C2/C3.

4. Evaluation processes

Take a CBM Project in middle development stage as an example, a detailed description of evaluation processes, key parameters and main points of dynamic and static methods is presented (Figure 3).

Combined with geology, seismic and logging data, the key parameters of volumetric method are determined, then the OGIP is calculated and recovery factor is determined. According to dynamic producing data and output data, dynamic methods, such as production decline methods, isothermal adsorption curve methods and numerical simulation methods, are used to calculate recoverable reserve. The comparison and amendment between static method and dynamic method are used to improve the computational accuracy of recoverable reserves.

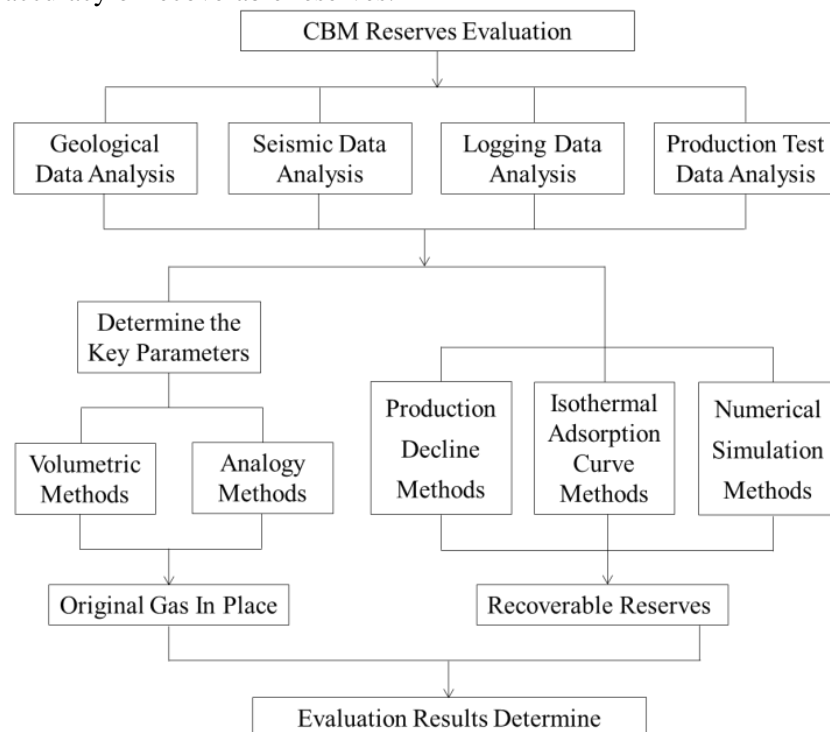


Figure 3. Reserves evaluation flowchart for CBM.

5. Key parameters and factors affecting production performance

5.1. Pool area

By all kinds of geological boundaries of coal seams, such as fault, pinch-out etc. If there is no obvious boundaries, the pool area is defined by the limits of effective reservoir isopach, contour lines by wells with limit production, coal mineral boundaries, natural geographical boundaries or artificial boundaries for reserve estimation.

5.2. Net pay

Net pay constitutes the portion of the total coal thickness that is capable of containing natural gas, calculated by eliminating those intervals that do not meet certain cut-off criteria such as ash content and coal rank.

5.3. Ash, water content and coal density

A core sample is comprised of pure coal, ash and water. Whole core or sidewall core are usually used for proximate analysis and determining the relative coal, ash and water content. During the proximate analysis procedure, the sample density will be first be calculated on an “as-received” basis, that is with the ash and water included, after drying the sample and separating the ash, the resulting pure coal density will be calculated (dry ash-free). “As-received” coal density will vary with ash content, water content and rank of coal, but the “dry ash-free” density will vary only with rank. A 50% ash content is deemed to be the maximum cut-off for reservoir quality coal unless otherwise proven to be productive.

5.4. Adsorbed gas content

Adsorbed gas volumes are determined by collecting freshly-cut reservoir coal core in airtight gas canisters and measuring the total volume of gas liberated from the coal after it is crushed. The total gas content is the sum of the gas content that is lost prior to sealing the canister, the measured gas content, and the residual gas content remaining in the samples at the end of the measurements. To avoid the significant errors, it is necessary to shorten the time of coal sample retrieved from the well and transferred to sealed containers[13-15].

5.5. Reservoir pressure

The midpoint of perforations of a single well, and the common reservoir datum of multi-well pools. Bottom-hole pressures are more reliable than surface pressure measurements. Whatever single point, or static gradient, pressure measurements are only reliable when the well has been shut in for a sufficiently long time. If reservoir pressures are still increasing at the time of pressure measurement, continuous pressure measurements over a period of several days must be taken, and pressure transient analyses conducted, to properly determine the estimated average reservoir pressure.

5.6. Initial production and production data selection

CBM well production characteristics of general performance: production climbing stage, gas production rises and water production declines in short-term; intermediate stage, gas production peak occurs, and then keep exponential decline for a long time, low water production; in the late production cycle, the output of gas production curve into hyperbolic decline with low and stable water output. Initial gas output is the key parameter used to predict the future production change, so the production data points most relevant to the future trend are selected as the initial production. Usually, the first month average production after dewatering period is used as the initial output. Generally speaking, data that most closely represent stabilized conditions from the subject well was selected. It is not appropriate to conduct decline analysis on a well presently in the transient or dewatering phase.

5.7. Declining rate

A minimum period of six months is recommended to establish a predictable decline trend. Typical CBM well will exhibit exponential-hyperbolic decline behavior.

$$q(t) = q_i(1 + bD_i t)^{-1/b} \quad (1)$$

$q(t)$ is instantaneous production, Mscf/d; q_i is the initial production, Mscf/d; b is Arps's decline exponent, dimensionless; D_i is initial decline rate, (days)⁻¹; t is time, days.

" b ": Historical production data determines the hyperbolic index (b value). In Arps decline curve: $b=0$ for exponential decline, $b=1$ for harmonic decline, $0 < b < 1$ for hyperbolic decline. But in actual production application, CBM decline index is greater than 1 in most cases, and the typical curve in line with hyperbolic decline curve, called generalized hyperbolic decline.

" D_{min} ": minimum value of annual decline, should be determine once the decline curve matches the production history. Usually, CBM reservoirs in a geological area will have a typical " b " value " D_{min} " value, and analogy method is the best way is to choose " D_{min} " value.

5.8. Recovery factor

Estimates of recovery factor may be determined through analysis of the desorption curve, by performance (where sufficient production history exists), or by comparison with established, offsetting, analogous developments. When use the adjacent mature project as an analog, parameters such as reservoir depth, coal rank, gas content, density, thickness, saturation condition, permeability, drainage radius, etc. must be determined, and the consistency of the character of the coal between the subject area and the analogous area can be established[16].

5.9. Dewatering period estimation

It is important to estimate the length of the dewatering period. Decline analysis must exclude the production data in the dewatering period. Attention should also be paid to cases where water production is coming from sands as well as coals[17-18].

5.10. Pressure build-up analysis

Pressure transient analyses can provide an indication of the permeability of the coals, and will be useful both for the determination of peak production rates and the comparison with analogous producing wells[19].

5.11. Interference effects

Interference effects must be considered and accounted for during decline analysis for mature and/or high-permeability CBM developments. Generally, high recovery factors are indicators of potential interference within a CBM development[20].

6. Example

Take A and B Area in X CBM Field in Bowen Basin of Australia as example, syncline structure, gas content 11-12m³/t, permeability 0.1-10mD, double-branch SIS horizontal well is given priority to development and length of horizontal section is 800-1200m (Figure 4).

A area has 16 producing wells and 4 planning wells. OGIP is 2418MMscf per well, ultimate recoverable reserves (EUR) calculated by static method is 2009MMscf per well, recovery factor (RF) is 0.83 per well; EUR calculated through PHDwin software is 2151MMscf per well, RF is 0.89 per well(Table 1).

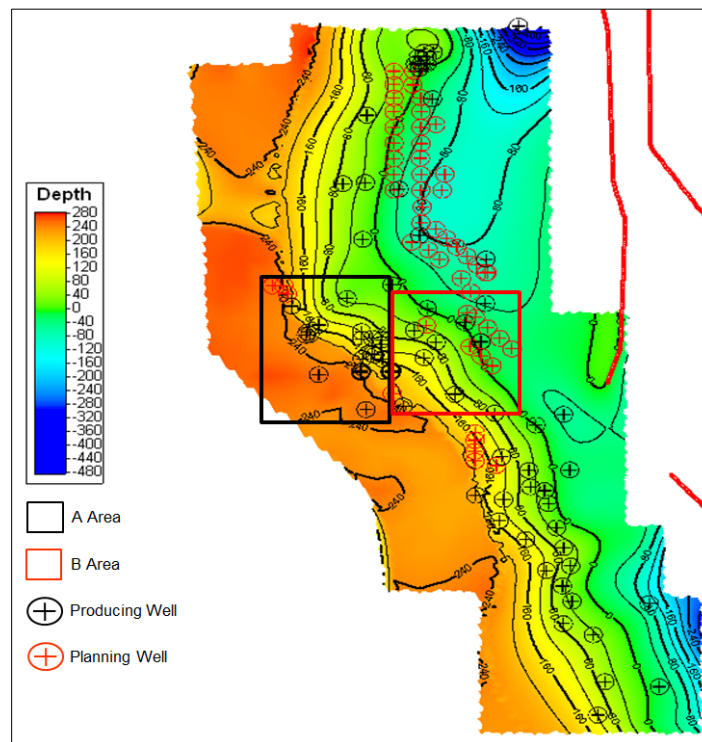


Figure 4. Well Location of XX Formation in X CBM Field.

Table 1. 16 Wells calculation results in A area (MMSCF).

Well Number	Static Method			Dynamic Method			
	OGIP	EUR	RF	EUR	Cum	Reserve	RF
A-1	3280	2850	0.87	3225	1922	1303	0.98
A-2	2080	1770	0.85	1914	1042	872	0.92
A-3	1870	1370	0.73	1778	1048	730	0.95
A-4	1760	1500	0.85	1607	813	794	0.91
A-5	1160	890	0.77	924	709	215	0.80
A-6	2520	2390	0.95	2402	1406	996	0.95
A-7	3018	2480	0.82	2947	1722	1225	0.98
A-8	2120	1850	0.87	2053	1151	902	0.97
A-9	2650	1460	0.55	1408	810	598	0.53
A-10	2300	1980	0.86	1945	1210	735	0.85
A-11	2910	2670	0.92	2726	1629	1097	0.94
A-12	3710	3340	0.90	3653	2055	1598	0.98
A-13	3200	2990	0.93	3162	2057	1105	0.99
A-14	2040	1360	0.67	1535	998	537	0.75
A-15	2590	2140	0.83	2189	1291	898	0.84
A-16	1480	1110	0.75	949	520	429	0.64
SUM	38688	32150		34417	20383	14034	
Per Well	2418	2009	0.83	2151			0.89

B area has 12 producing wells and 9 planning wells. OGIP is 2156MMscf per well, EUR calculated by static method and dynamic method is 1424MMscf/well and 1532MMscf/well respectively, and the corresponding recovery factor is 0.66/well and 0.71/well(Table 2).

Table 2. 12 Wells calculation results in B area (MMSCF).

Well Number	Static Method			Dynamic Method			
	OGIP	EUR	RF	EUR	Cum	Reserve	RF
B-1	2740	2190	0.80	2353	1704	649	0.86
B-2	1990	1360	0.68	987	791	196	0.50
B-3	1410	920	0.65	1110	625	485	0.79
B-4	2920	1980	0.68	2280	1651	629	0.78
B-5	2260	1350	0.60	1571	1034	537	0.70
B-6	1390	1000	0.72	1172	745	427	0.84
B-7	2540	1450	0.57	1530	1083	447	0.60
B-8	1880	1190	0.63	1225	674	551	0.65
B-9	1720	1180	0.69	1276	672	604	0.74
B-10	2050	1400	0.68	1830	1099	731	0.89
B-11	2850	1690	0.59	1602	1000	602	0.56
B-12	2120	1380	0.65	1449	978	471	0.68
SUM	25870	17090		18385	12056	6329	
Per	2156	1424	0.66	1532			0.71

A area located in relatively high structural position, with sufficient gas supply, first used watered-out region after dropping the pressure to develop, the average EUR per well is higher than B area. The evaluation results of static method and dynamic method are reasonable. This example used average EUR per well of dynamic method to predict the future drilling related reserves. PD reserves of A and B area is 20363MMscf, planning wells had already approved, the corresponding reserves is PUD reserves, 22392MMscf, total P1 reserves is 42755MMscf(Table 3).

Table 3. CBM reserves booking of A and B area (MMSCF).

Block	PD	PUD Well	EUR/WELL	PUD	P1
A Area	14034	4	2151	8604	22638
B Area	6329	9	1532	13788	20117
Total	20363	13		22392	42755

7. Conclusions

The classification of CBM reserves/resources is closely related to the cognition level of geological conditions, technical and economic conditions. With the promotion of exploration and development, the reserves/resources of low level can be gradually upgraded to higher level. Once the economic benefit meets the commercial development in 3C area, 3C resources can be upgraded to 3P reserves.

The evaluation of CBM reserves/resources is a dynamic process, gradually converging to the truth value. The productivity of CBM reservoirs is controlled by five key factors, such as pool area, thickness, gas content, permeability, and saturation state. When the volumetric method is used, precision of parameters above directly affects the rationality of evaluation results. When the dynamic method is used, the dewatering period, pressure build-up and inter-well interference effects should be adequate considered first, then initial production and declining rate are reasonably determined. Multiple methods can be used to determine CBM reserves/resources, although different evaluation methods yield to different results, the evaluation results of using a particular method should be substantiated through utilizing a second method for the determination of CBM reserves and resources.

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