

Evaluation of Coalbed Methane Reservoirs

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Introduction

The key parameters for the evaluation of coalbed methane (CBM) prospects are the gas resources, reserves and deliverability. Coalbed methane reservoirs are dual-porosity media where the vast majority of the gas is stored in the low permeability coal matrix (primary porosity) by sorption. The flow to production wells, however, occurs through the coal's natural fracture system (secondary porosity), which stores relatively small amounts of gas, because coal matrix practically has no permeability. Therefore, properties of the coal matrix have the greatest effect on estimates of the volume of gas-in-place and gas recovery, whereas natural fracture system properties control CBM reservoir deliverability. Coal matrix properties can be reliably obtained from the interpretation and integration of core and log data. However, numerous challenges that are involved in data acquisition and analysis can complicate accurate determination of initial gas-in-place (Nelson, 1999). Gas content and storage capacity are the key parameters for determination of the gas resources and reserves, both of which must be measured directly from core samples. Core data acquisition and analysis is an indispensable step in evaluating any coalbed methane project. Natural fracture system permeability and relative permeability are the key parameters which most influence deliverability. Natural fracture system permeability can only be accurately estimated by well testing. Table 1 lists the key required data for analysis of coalbed methane reservoirs and their primary sources.

Gas-in-Place

The vast majority of the gas in CBM reservoirs is stored in the coal matrix by sorption. The following equation is generally used to estimate the total initial adsorbed gas in a CBM reservoir:

TABLE 1: Required Data and Their Sources for Analysis of CBM Reservoirs

PROPERTY	SOURCE
Storage Capacity	Core Measurements
Gas Content	Core Measurements
Diffusivity	Core Measurements
Pore Volume Compressibility	Core Measurements
Gross Thickness	Well Logs
Effective Thickness	Well Logs
Pressure	Well Tests
Absolute Permeability	Well Tests
Relative Permeability	Simulation
Porosity	Simulation
Fluid Properties	Composition and Correlations
Gas Composition	Produced and Desorbed Gas
Drainage Volume	Geologic Studies

$$G = 1359.7 Ah \overline{\rho_c} \overline{G_c} \quad (1)$$

Where:

G = Gas-in-Place, scf

A = Reservoir Area, acres

h = Thickness, feet

$\overline{\rho_c}$ = Average In-Situ Coal Density, g/cm³

$\overline{G_c}$ = Average In-Situ Gas Content, scf/ton

As it can be seen from Equation 1, average in-situ gas content, coal thickness, reservoir or well drainage area, and average in-situ coal density are the parameters that are needed for estimating gas-in-place in a CBM reservoir. These parameters will be discussed below. Numerous challenges are involved in the acquisition and analysis of data to determine the various parameters in Equation 1. Therefore to minimize errors, established

protocols (Mavor *et al.*, 1996) must be followed when assessing the gas-in-place in coalbed reservoirs.

Gas Content

Gas content is the standard volume of gas per unit weight of coal or rock and usually is reported in units of standard cubic feet per ton (scf/ton). This section provides a brief overview of gas content determination. Detailed information on the theory and procedures for determining the gas content of coal samples can be found elsewhere (McLennan, et al 1995). The desorbed gas is estimated by the “Direct Method” or canister desorption test (Diamond and Levine, 1981). The canister desorption test is conducted by placing a freshly cut conventional core sample in a sealed container (canister) and measuring the amount of gas released as a function of time. This test, if conducted properly, usually provides reliable estimate of gas content (Mavor, et al 1994). Because temperature has a significant impact on diffusion rates, the test must be conducted at reservoir temperature. The desorbed gas volumes must be corrected for ambient pressure variation during the measurements. In addition to the desorbed gas volume measured during or canister desorption test, “lost gas” and “residual gas” volumes must be evaluated to determine the total desorbed gas volume. “Lost gas” is volume of the gas that desorbs from the sample during the recovery process before the core sample can be sealed in a desorption canister. “Residual gas” is the gas that remains sorbed on the sample at the conclusion of the canister desorption test.

Lost gas volume is estimated by analyzing the data obtained during the canister desorption tests. This analysis method is based on the solution of a partial differential equation describing constant temperature diffusion following an instantaneous change in boundary gas concentration. This solution suggests that the cumulative desorbed gas is proportional to the square root of the elapsed time since the inception of gas desorption. The inception of gas desorption is referred to as “time zero” which usually occurs during the core recovery process. Proper estimation of the “time zero” has a significant impact on the accuracy of the estimated lost gas volume (McLennan, et al 1995). Maintaining the sample temperature during the test at the reservoir temperature is also critical in obtaining

accurate results. In addition to the lost gas volume, estimates of diffusion coefficient and sorption time can be also obtained from Direct Method of analysis. Lost gas volume usually is the greatest source of error in the total gas content estimate (Nelson, 1999). Pressure coring can eliminate the lost gas but because of difficulties involved in operating the specialized equipment and the added expenses, its use has been limited to research studies. The residual gas volume is estimated by crushing the entire desorption sample to smaller than a 60 mesh grain size and measuring the gas volume released at the reservoir temperature.

The total gas volume is the summation of the lost gas, desorbed gas, and residual gas volumes. The total gas volume is reported at standard temperature and pressure, and it reflects the total estimated gas volume in the coal at initial reservoir pressure and temperature. The measured gas volume is divided by the mass of the sample, and then converting to units of scf/ton. This allows consistent comparison of the gas volumes from various samples. The basis for reporting gas content depends on the manner in which the sample mass is determined. Commonly used bases for reporting coal gas content are the raw basis; the air-dry basis; the dry, ash-free basis; the dry, mineral-matter-free basis; the “pure coal” basis; and the in-situ basis.

The raw basis uses the actual sample weight, regardless of the moisture content or the presence of non-coal material in the canister sample. “Air-dry” implies that all extraneous material is removed from the sample and that the entire sample has been allowed to dry to a constant equilibrium weight in a laboratory climate. Because the gas is stored by sorption only in the organic matrix of the coal, the air-dry weight must be corrected for “non-coal” components such as residual moisture and ash. Proximate analysis of the samples is usually performed to determine the moisture content, volatile matter content, ash content, and fixed carbon content of the coal. Proximate analysis is a standard coal analysis technique with detailed specified procedures (American Society for Testing and Materials, 1994). When sulfur is present mineral-matter determined by proximate analysis does not adequately account for non-coal content. To accurately estimate the mineral-matter, detailed compositional analysis such as “ultimate analysis” can be used. Ultimate

analysis is a standard analytic procedure that provides the chemical makeup of the coal as percentages of carbon, oxygen, hydrogen, nitrogen, sulfur, and ash. If the correction to gas content is based on individual sample composition, the gas content is referred to as the dry, ash-free basis or the dry, mineral-matter-free basis.

Coal composition is not uniform throughout the reservoir; therefore, gas content is not constant. To obtain statistically reliable estimate of in-situ gas content, the gas content from multiple samples having a broad range of compositional values must be measured. An inverse linear relationship between the gas content and the “non-coal” fraction has been shown to exist (McLennan, et al 1995). Consequently, a linear regression analysis on the results of the multiple sample gas content measurements is performed to establish the relationship between total gas content and the “non-coal” fraction. The “pure coal” gas content is estimated by extrapolating the regression line to pure coal (zero ash and moisture content). “Pure coal” gas content estimates can be used to compare gas contents from different geographic or geologic location. In cases where multiple samples are not available, the dry, ash-free basis or dry, mineral-matter-free basis can be used in place of “pure coal” gas content.

The linear relationship between total gas content and the “non-coal” fraction developed by regression analysis can be used to determine in-situ gas content for any amount of ash present in the formation (Mavor and Nelson, 1997). Since the bulk density can be correlated with ash content, a correlation between gas content and bulk density can be developed which allows for a continuous vertical estimate of gas content. Consequently, the average reservoir density in conjunction with equilibrium moisture contents can be used to determine average in-situ gas content. The average in-situ gas content is the value that must be used for gas in place calculations.

The term “coalbed methane” is commonly used even though often the gas produced from coal contains significant amounts of carbon dioxide, nitrogen, water and heavier molecular weight hydrocarbons. Therefore, the composition of desorbed gas should be

measured during desorption test to determine the total *methane content* which would be different from the total gas content (Saulsberry, et al 1997).

Reservoir Area

The reservoir area is usually estimated based on the well spacing if the coal seam can be assumed to be laterally continuous. Structural and stratigraphic variations throughout the reservoir determine the three dimensional distribution of the coal. Therefore, geological evaluations can provide clues about coal seam continuity and its other pertinent characteristics. However, it may be difficult to identify localized stratigraphic variations. Three dimensional seismic data can be also used to determine coalbed methane reservoir geometry.

Reservoir Thickness

Gross coal thickness usually can be determined accurately with wireline logs. Open-hole density logs generally provide the most reliable and cost-effective estimates of gross thickness in newly drilled wells. The gross reservoir thickness is commonly computed by summing the thicknesses of the intervals having densities less than a cut-off value generally equal to the coal ash density. However, using a too low value for density cut-off can lead to erroneous estimates. Determining net thickness is more complicated because it requires evaluating how much of the gross coal thickness actually contributes to production. Resistivity logs, well tests, production logs, or zonal isolation tests can be used to estimate the net thickness.

In-Situ Density

The correct in-situ density should be estimated from open-hole density log data. A common practice of using a value of 1.32 to 1.36 g/cm³ for the average in-situ density can lead to erroneous results (Nelson, 1999). In the absence of well log data, in-situ density can be estimated based on the density of the ash, moisture, and organic (pure coal) fractions by the following Equation:

$$\frac{1}{\rho} = \frac{f_a}{\rho_a} + \frac{1 - (f_a + f_w)}{\rho_o} + \frac{f_w}{\rho_w} \quad (2)$$

Where:

$$\begin{aligned}\rho &= \text{bulk density, g/cm}^3 \\ \rho_a &= \text{ash density, g/cm}^3 \\ \rho_o &= \text{pure coal density, g/cm}^3 \\ \rho_w &= \text{moisture density, g/cm}^3 \\ f_a &= \text{ash content, fraction} \\ f_w &= \text{moisture content, fraction}\end{aligned}$$

Gas Reserves

To reliably estimate gas reserves for a CBM reservoir, gas desorption behavior in addition to gas content must be determined. A variety of models have been used to describe the gas sorption behavior as a function of pressure. The most common model in use for coal is the Langmuir isotherm which can be described by the following equation:

$$G_s = (1 - f_a - f_m) \frac{V_L P}{P_L + P} \quad (3)$$

Where:

G_s = Gas storage capacity, scf/ton

P = Pressure, psia

V_L = Langmuir volume constant, scf/ton

P_L = Langmuir pressure constant, psia

Determining accurate sorption isotherms requires a properly prepared sample and correct laboratory procedures. This section provides a brief overview of sorption isotherms determination. Detailed information on the theory and procedures for determining of the sorption isotherms can be found elsewhere (McLennan, et al 1995). The isotherm is determined by grinding the coal (core sample) to a fine mesh and systematically measuring the amount of gas that the coal can store at various pressures. The test results are used to determine Langmuir parameters P_L and V_L . It is critical to use the correct moisture content and perform the isotherm tests at reservoir temperature. Accepted practice is to perform sorption isotherm measurements at the equilibrium moisture content. The equilibrium moisture content, which is defined by ASTM standards, is assumed to be the same as the in-situ moisture content. The measured isotherm data must be normalized to a dry, ash-free basis because it is important to have the sorption

isotherm and gas content values on the same basis. If significant quantities of other gases besides methane are present in the coal, isotherms for the other gases need to be determined in addition to a pure methane isotherm.

A typical sorption isotherm illustrated in Figure 1. The initial gas content is also plotted on the same graph. It should be noted that the isotherm defines the maximum gas adsorptive capacity as a function of pressure. The gas content of the coal could be less than this maximum value as illustrated in Figure 1. When the initial content is below the equilibrium with the isotherm, no free gas will be present and the natural fracture system (cleats) will be filled with water. Gas desorption initiates once the pressure in the cleat system is lowered to “critical desorption pressure” normally by water production. Below critical desorption pressure, the gas content will be the maximum value (as determined by the isotherm) down to abandonment pressure. If the initial reservoir conditions (pressure and gas content), desorption isotherm, and abandonment pressure are available, the recovery factor at the economic limit can estimate using the following equation:

$$R_f = \frac{C_{gi} - C_{ga}}{C_{gi}} \quad (4)$$

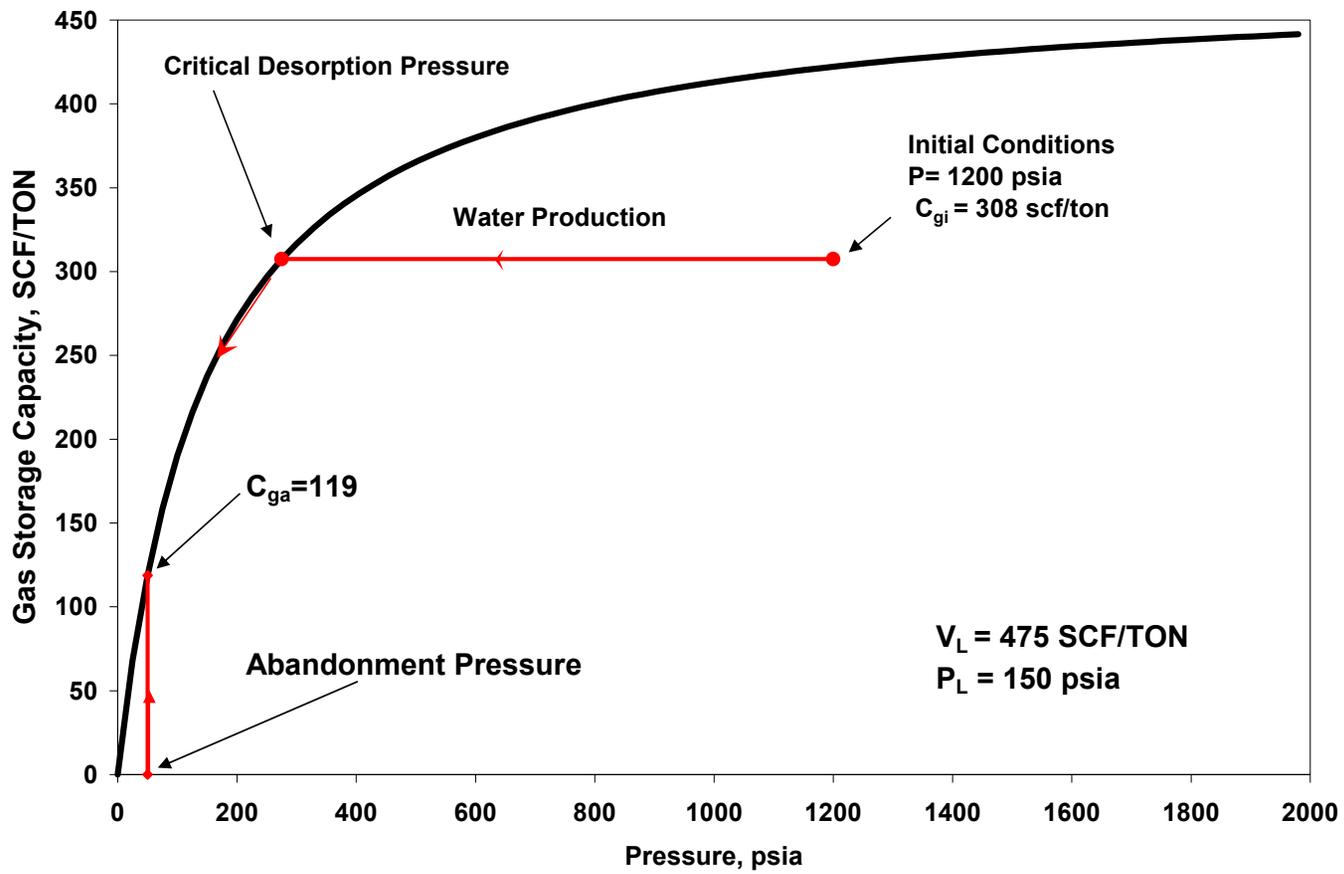
Where:

R_f = Gas recovery factor at economic limit, fraction

C_{gi} = Initial average gas content, scf/ton (dry ash-free)

C_{ga} = Gas storage capacity at abandonment pressure, scf/ ton (dry ash-free)

Gas reserves can be calculated by multiplying gas-in-place by the estimated recovery factor at the economic limit.



Deliverability

The flow of fluids (gas and water) to the wellbore in CBM reservoirs takes place through the natural fracture system (cleats). Therefore, properties of the natural fracture system have the greatest effect on gas and water production rates. Accurate estimate of deliverability requires accurate estimates of the coal natural fracture system flow properties. Absolute permeability and relative permeability are two of the most important natural fracture system flow properties that affect gas and water production rates.

Pressure transient testing is the only reliable way to accurately estimate in-situ natural fracture system permeability. Permeability measurements on core samples are not representative of the reservoir because of difficulty in obtaining competent core samples from the more fractured portions of the reservoir. The technology for designing, conducting and interpreting oil and natural gas well tests can be applied to coalbed methane reservoirs. However, characteristics of CBM reservoirs must be considered in the interpretation of the well test results. These characteristics include dual porosity system, two-phase flow, stress dependent properties of coal, and multiple seams. Production from CBM reservoirs is characterized by single-phase gas diffusion through the coal matrix and two-phase gas and water flow through the cleat system. The flow of gas from the coal matrix to cleat system is controlled by desorption process. To account for gas desorption, a new term referred to as sorption compressibility (c_d) is included in definition of the total compressibility factor (Bumb and McKee, 1998) as follows:

$$c_t = S_g c_g + S_w c_w + c_f + c_d \quad (5)$$

Where:

S_g = Fracture system gas saturation, fraction

c_g = Gas compressibility, psi^{-1}

S_w = Fracture system water saturation, fraction

c_w = Water compressibility, psi^{-1}

c_f = Fracture system pore volume compressibility, psi^{-1}

c_d = Sorption compressibility, psi^{-1}

The sorption compressibility term (c_d) is defined as follows (Bumb and McKee, 1998):

$$c_d = \frac{B_g \rho_c V_L (1 - f_a - f_m)}{32.0368 (p_L + \bar{p})^2 \phi} \quad (6)$$

Where:

B_g = Gas formation volume factor, ft³/scf

\bar{p} = Average pressure of the natural fracture system, psia

ϕ = Porosity of the natural fracture system, fraction is zero when fluid does not

The sorption compressibility is zero when there is no flow from the matrix into the natural fracture system. When the matrix is contributing to fluid flow, sorption compressibility would dominate the total compressibility factor.

Even though it is possible to obtain estimates of cleat system permeability from test data measured during two phase flow, the results would be highly dependent on the relative permeability relationship assumed. Therefore, it is advantageous to conduct tests under single phase flow conditions. In an under-saturated CBM reservoir, such as the one illustrated in Figure 1, the initial reservoir pressure is above critical desorption pressure and the natural fracture system (cleats) is saturated with water. If an injection/falloff test is conducted by injecting water, the pressure in natural fracture system remains above than critical desorption pressure and single-phase flow conditions will prevail during the test. Further, the reservoir behaves as a single porosity system since the coal matrix is not affected during the test. This allows the use of single porosity models to interpret the test results.

When performing injection/falloff tests, it is important to inject at low rates to avoid fracturing the coal and to minimize permeability changes due to stress effects. An inexpensive procedure for conducting injection/falloff test is “Tank Test” that reduces the injection pressure. The procedure is based on using gravity drainage of water from a tank rather than using pumping equipment to inject water. The Tank Test can be performed in hydrostatically low pressured reservoirs where the pressure gradient is less than 0.4 psi/ft.

In reservoirs that primarily produce gas, it may be more desirable to inject gas for injection/falloff test or conduct drawdown/buildup tests. Accurate estimates of the natural fracture system effective permeability can be obtained from multiphase flow interpretation methods if saturation changes are small. This would occur if a reservoir is producing at slowly changing gas-water ratios. When fluid saturations change rapidly, such as when the reservoir pressure is near the critical desorption pressure, accurate test analysis will be difficult.

The primary objective of well testing in CBM reservoir is to obtain estimates of the natural fracture system pressure, permeability, and skin factor. However, well tests can also be conducted after hydraulic fracturing to obtain estimates of the induced fracture properties. The results of well test interpretations must be combined with geological information, wireline log data, core analysis results, and fluid properties to predict future production rates under a variety of operating conditions. It has been reported (Harpalani and Schraufnagel, 1990) that as gas is desorbed from coal matrix, the coal matrix shrinks with a subsequent change in porosity and permeability of the cleat system (Seidle and Huitt, 1995). Shrinkage effects generally become significant at low pressures (Palmer and Mansoori, 1996). This could lead to better deliverability during late stages of production. The inclusion of matrix shrinkage effects has been shown to improve the prediction of long term deliverability of CBM reservoirs (Thungsuntonkhun and Engler, 2001).

Relative permeability is one of the key parameters in determining the deliverability of CBM reservoirs. Recorded measurements of relative permeability in coal (Gash, 1991, Puri et al 1991) are sparse despite the importance of relative permeability. It is generally accepted that laboratory measurements on core samples do not provide accurate indicator of CBM reservoir relative permeability. The relative permeability curves derived from a history match do not resemble laboratory measured curves in the published literature (Saulsberry et al 1996). The discrepancies are attributed to the fact that the small conventional core plugs used to measured relative permeability in the laboratory do not adequately reflect the presence of natural fractures. Furthermore, it is difficult to obtain competent core samples from highly fractured section of the reservoir. History matching is the only practical method to obtain realistic relative permeability values. History

matching involves using a reservoir simulator to reproduce gas and water production data. Simulators have been developed specifically to account for the complex characteristics of coal. When production has not been initiated or when production history is limited, relative permeability has to be assumed.

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