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AN OVERVIEW OF THE POTENTIALS AND PROSPECTS OF COALBED METHANE EXPLORATION AND EXPLOITATION IN THE PERMO-CARBONIFEROUS COAL MEASURES OF THE BARAKAR FORMATION, JHARIA BASIN, INDIA

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(13 figures, 2 tables)

ABSTRACT. The Permian Barakar coal formation of the Jharia Basin, Damodar valley, India has a very active role to play in the future energy scenario of India. However, in general coal seams are poorly understood with respect to their behaviour as a gas reservoir. Gas is predominantly stored in an adsorbed and a compressed state. For the exploration and assessment of coalbed methane it is important to understand the mechanism of adsorption, retention and accumulation of methane gas within seams, during the coalification. The gas storage capacity of a saturated coal seam varies non-linearly as a function of pressure, as described by Langmuir (1916). The Langmuir constants, that define the gas storage as a function of pressure for saturated coals, are measured in the laboratory providing an adsorption isotherm. At low pressure, the relationship between storage capacity and pressure is linear as in Henry's Law isotherm. It provides predictive information into "Gas Storage Capacity" and "Recovery Factor". A study on the sorption characteristics of seams from the Jharia basin, India, led to the generation of an adsorption isotherm. The approach adopted here for CBM reserve prediction, uses a modified mass balance and a field example of the coal seams of Barakar Formation. The methods presented here use the well-documented gas storage records and production history of the reservoir, to estimate the ultimate reserve recovery for the next twenty years. The objective can be achieved by optimising completion design, well spacing and simulation designs. Each of these optimisations requires accurate prediction of long-term well production. In this work two techniques are discussed, to estimate coalbed methane well production; a production decline technique and a material balance and flow equation calculation. The usefulness depends on the data available for analysis and the required accuracy of the production forecast. In general, both methods satisfy for producing wells within established well patterns, which have production profiles with a consistent decline trend. Reservoir simulation is applicable to all stages of the well life. However, it is most useful in areas where an abundance of core, log, and well test data are available. Molecular diffusion of methane in a coal matrix has been quantified by determining a sorption time, t (days), which is related to cleat spacing (ft) and the diffusion coefficient (ft^2/day). An effort is made to use a diffusion coefficient or diffusivity as a tool for seam-to-seam correlation.

Keywords: coalbed methane, Jharia basin, Barakar formation, India, recovery factor, isotherm, sorption, pseudo-steady state.

1. Introduction

India, which has the sixth largest coal reserves in the world, is expected to have a reasonable potential for coalbed methane. In 1992 evaluation started with a well test in the Parbatpur Block of the Jharia basin. Since then, efforts are being made to exploit this energy source cost effectively. About 99% of the coal reserves of India are in the Gondwana basins, while the remaining are in the Tertiary basins (Figure 1). The Gondwana basins have been prioritised for evaluating their coalbed methane plays, with the Jharia and East Bokaro Basins on the top (Peters, 2001).

Coalbed methane exploration and exploitation activities are still in the initial stages of research and development. Geo-scientific, reservoir and production characteristics are integrated to evaluate the coalbed methane production of the Jharia basin for the next twenty years. In this study a production decline technique and a material balance and flow equation calculation are discussed on their usefulness.

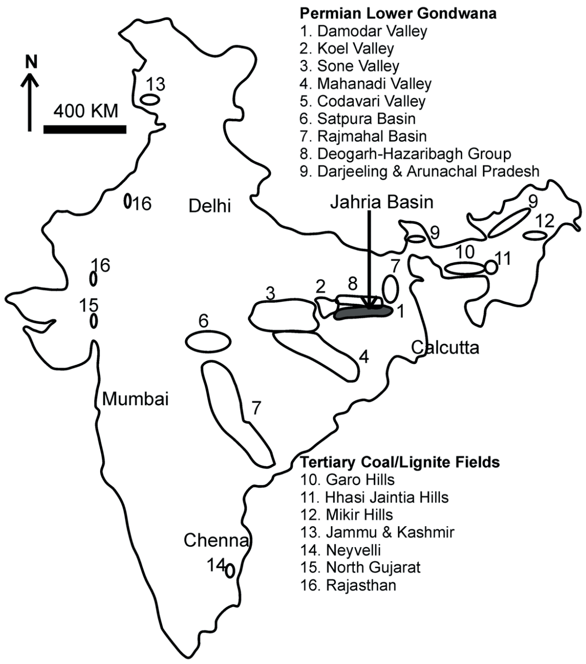

Figure 1: Major coal fields in India. Revised after the Atlas of India, 1983.

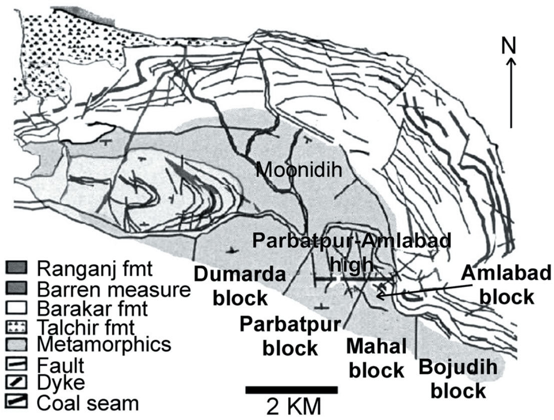

Figure 2. Regional tectonic settings of the Jharia basin.

2. Geology and Structure of Jharia Basin

The Jharia basin is a sickle-shaped Gondwana basin with an extent of about 450 km^2. Lower Gondwana sediments are surrounded on all sides by Pre-Cambrian metamorphics, (Figure 2). The Barakar formation is the main coal bearing stratigraphic unit. Although, more coal seams are also pr esent in the Raniganj Formation. Locally igneous intrusions affect the coal quality. The southern and northern basin margins are faulted. These faults, which are still active, created numerous fault blocks.

High-resolution lineament studies carried out in Jharia basin indicate the presence of three lineaments, in their order of dominance, NNE-SSW, NE-SW and NW-SE. Field examination of cleat and fracture system indicates that the cleat systems are open. Other fractures like joints are also open, but in the vicinity of faults these fractures are reduced by secondary fillings and 'gouge'. As a result the Parbatpur block is, at the level of seam XV, subdividing into about 24 fault blocks. The coals contain buff coloured, coarse to medium grained, feldspathic sandstones, grits, shales, and carbonaceous shales. The pre-stimulation permeabilities range from 0.01 to 3.5 mD. The cleat system in the coal of this area is well developed. The total coal reserve (for seams IX-XVIII) of this block is estimated at 800 MMT. The major contributor of the coal are the seams XV to XVIII, with a reserve of 400 MMT.

Presently CBM activities are confined within the unmined Parbatpur block, in the SE part of the basin. This block occupies an area of approximately 18 km^2. Here two prominent E-W trending, doubly plunging synclines, are flanking an anticlinal high (the Parbatpur-Amlabad high). Tectonically it is a half graben structure with an inlier. The anticlinal area is dissected by a number of criss-cross faults indicating a compressed stress pattern.

BLOCK	STRIKE OF THE STRATA	AMT./ DIR. OF DIP	FAULTS	FOLDS	CLEAT DIRECTION
Amlabad	N-S turns to E-W	60-100 / North and South	Dungri-Petia fault passes along the eastern boundary	A domal structure occurs in NE portion over the B2 anticline	N250E-S250W to N650W-S650E
Parbatpur	NE-SW turns to E-W	100-120 / West and South	Large no of multi-directional fault, great boundary fault to the south of the block	Two domal structures occur in the centre over the B2 anticline	

Table 1. Comparative details of the structural elements of the study area.

Basin	Damodar
Formation	Barakar
Seam	XV
Mine	Amlabad
Sample No.	M/A/1
Vitrinite	57 %vol.
Inertinite	42.6 %vol.
Liptinite	0.4 %vol
Vitrinite Reflec.	1.08 %
Mineral Matter	14.82 % dry mass
Pure coal	85.18 % dry mass
Moisture as recorded	1.35 % mass
Equivalent moisture	3.49 % mass
Helium density	1.5gm/cc
ASTM Rank	Medium to high volatile bituminous
Temperature	46°C
Depth	375 m
Thickness	2.28 m

Table 2. Coal Petrography.

In the block area, the Barren Measure Formation (middle Permian) is exposed, underlain by the Barakar Formation (lower Permian) and the Talchir Formation (upper Carboniferous) on Archean Metamorphics or basement. A detail of the structural elements of the studied area is presented in Table 1. Around the area, gas rich mines of the Jharia coalfield are located, having emission rates over 14 m^3/ton. The Barakar coal seams are the main exploration targets.

3. Gas Storage Capacity and Recovery factor

A sorption isotherm is a primary coal analysis that is measured on coal. It is assumed that they can be fit to the Langmuir relation (Langmuir, 1916). The isotherm including the parameters for the coal sample is represented as follows:

$$G_s = V_L(1 - fad)P / P + P \qquad \text{(eq. 1)}$$

The above parameters of a typical Langmuir isotherm of the coal sample, as described in Table 2, are:

V_L = 586.37Scf/ton

fad = 0.196

P = 525psi

P_L = 360psi

G_s = 279.66Scf/ton

The isotherm of the coal sample is shown in Figure 3.

In a coalbed methane reservoir, the volumetric reserve calculation is the product of gas in place (*GIP*) and the estimated recovery factor at the economic limit. The Gas recovery factor (R_f) is the most difficult parameter in the volumetric equation to estimate accurately.

The recovery factor can be estimated from the isotherm using; $R_f = (Cgi - Cga)/Cgi$. Here R_f is the recovery factor, Cgi the initial sorbed gas concentration and Cga the abandonment pressure sorbed gas concentration.

The major disadvantage of this method is that the average reservoir pressure at abandonment is usually estimated as the abandonment pressure. The pressure is dependent on the future economic condition in addition to reservoir properties and production history of the reservoir. Thereby, the abandonment pressure (*Pa*) is defined as the pressure where the gas rate becomes too low, and the production of CBM no longer will be cost effective. (Joubert et al., 1973 and Moffat et al., 1953).

In the previous case (figure 3) the Langmuir pressure is about 360 psi. Below this pressure the well will produce. An abandonment pressure of 100 psi is assumed for the estimation of a recovery factor.

Hence, the gas content at initial pressure (*Cgi*) is 364 Scf/ton, the gas content at abandonment pressure (*Cga*) is 114 Scf/ton and based on the above, the recovery factor (R_f) is estimated to be 68.7% (Crossdale et al. 1998 and Diamond et al., 1998).

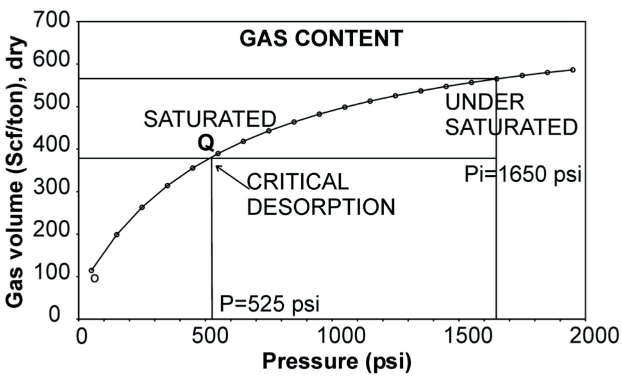

Figure 3. Langmuir sorption curve for coal, representative for its methane capacity.

4. The Advanced Mass Balance Technique

The mass balance technique neglects the storage of gas in the cleat system. The amount of cleat related gas is insignificant compared to the adsorbed gas in the coal matrix. The technique relates the adsorbed gas content directly to reservoir pressure without consideration for cleat system fluids or cumulative water production from the cleats. Hence the dewatering of the coal in the wet areas will not affect the linear nature of the modified pressure function versus the cumulative gas production data, during the early producing life of the well. In practical terms, it does not matter how the pressure declines; the Langmuir isotherm defines the remaining gas adsorbed on the coal as a function of pressure. (King, 1993 and Jensen et al., 1997). The initial equation is as follows, where G_P is the current gas produced, $OGIP$ is the original gas in place (Bcf).

$$G_P = OGIP - CGIP \qquad \text{(eq. 2)}$$

Connecting the gas in place (G_P), to the area connected to the wells in acres (A), net coal thickness in feet (h), and coal density (d) in tons/ (acre-foot) gives:

$$GIP = V * A * h * d \qquad \text{(eq. 3)}$$

Substituting (eq. 3) in (eq. 2) gives:

$$G_P = V_i * A * h * d - [P/(P+P_L)] * V_L * A * h * d$$
(eq. 4)

The expression on the right of the (eq. 4) is obtained by substituting Langmuir's equation for current gas content (V). Substituting Langmuir's equation for V_i we obtain the final equation in slope intercept form:

$$[P/(P+P_L)] = -1/(V_L Ahd) * G_P + [P_i/(P_i+P_L)]$$
(eq. 5)

Equation 5 presents a graphical analysis of pressure behavior that can be used as an independent ultimate recovery prediction tool to complement simulation predictions, where:

$-1/(V_L Ahd)$ is the slope, and, $[P_i/(P_i+P_L)]$ is the y-intercept.

5. Case Study

One of the Wells, (X) is located at the expected no-flow boundary between the surrounding producing wells. This allows the measured pressures to be indicative of the reservoir pressure, since it is not subject to near well pressure draw down effects. The pressure data used is

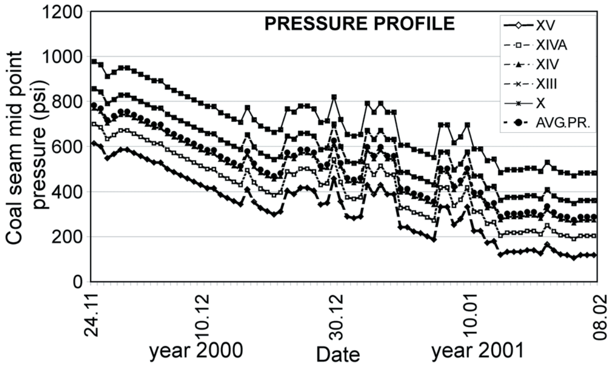

Figure 4: Pressure drop of various seams and average seam pressure drop, during production.

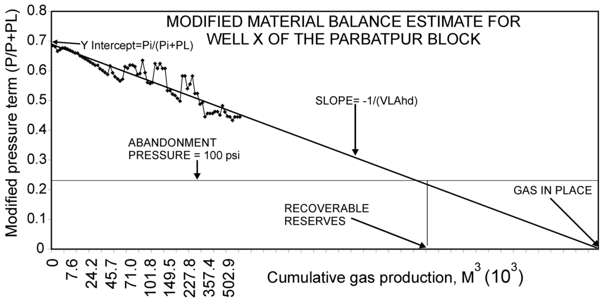

Figure 5. Estimated gas reserves as a function of pressure and the cumulative gas production.

an average of the pressure profiles of all the five producing coal seams, as shown in Figure 4. The cumulative production data, associated with each pressure, is the sum of the five producing coal seams. Figure 5 illustrates the application of the Well X production data set. The cumulative gas produced is plotted on the X-axis and the modified pressure term ($P/P+P_L$) on the Y-axis. The X-intercept of the data extrapolation yields the original gas in place in the drainage area. An average Langmuir pressure (P_L) value of 360 psi was used, as derived from equation 1. An expected abandonment pressure of 100psi is assumed.

Extrapolation of the pressure and cumulative production data back to the Y-axis yields a calculation of the initial pressure. Analysis of the slope of the extrapolated line is useful for determining information about reservoir properties like Langmuir volume, drainage area, thickness of producing zone and the density of the coal. It provides a qualitative check of the whole reservoir.

Collectively a practical method for coal gas reserve estimation, using reservoir pressures, has been presented. To increase confidence in an estimate the advanced mass balance technique provides an accurate estimate of the ultimate recovery from a coalbed, to compare the decline curve, reservoir simulation and volumetrics.

6. Role of the Permeability in Techno-Economics

Worldwide experience of the CBM production establishes the fact that producibility varies widely within a basin. Variation in the permeability of the producing coal seams is the main reason. It is the principal controlling factor for efficiency of dewatering process, upon which the decline in reservoir pressure, and by that de-sorption and production of CBM, largely depends. A fall in producibility with decreasing permeability has led in the CBM industry to define one millidarcy as the lowest limit of permeability for economic exploitation. Below this value production is uneconomical, since the dewatering process starts to be inefficient. In contrast with conventional reservoirs, the permeability of a coal seam is the most important criterion, followed by the gas content and the seam thickness. Permeability in coals is highly stress-dependent, which expresses itself in reduction with depth. Shallow depths favour faster desorption of the gas during pressure decline. (Bodden et al. 1998).

The Barakar formation in Jharia basin has been subdivided into the Lower Barakar, Middle Barakar and Upper Barakar as shown in Figure 6. Lower Recovery factors for the Lower Barakar sequence is primarily due to the following reasons:

- A lower permeability ranging from 0.1 to 0.01 mD.
- A reasonably high cleat porosity, resulting in an initial high amount of water within the drainage area of a well.
- Low permeabilities related to water phase, which make dewatering, de pressurisation and gas desorption a slow process. A high irreducible water saturation of 45 to 50 % also affects efficiency of the dewatering process.

In spite of their enormous thickness deeper, low permeability coal seams tend to yield very low recoveries. Thickness can only add to the reserves in place. They play no role in the improvement of the flow characteristics and therefore no role in improving the efficiency of dewatering. Hence, dewatering is the very basis of CBM production and is likely to affect the techno economics.

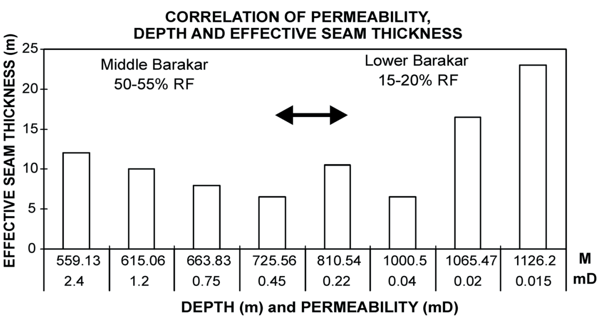

Figure 6. Barakar coal seams, net thickness versus permeabilities.

7. Production Decline Analysis

Production decline trends of producing CBM wells can be analysed to estimate future production for coalbed wells. Decline curve analysis is widely accepted in the conventional oil and gas industry, since it only requires the well production history. Using a decline curve analysis technique for CBM wells is complicated by the fact that it may take several months to years to show a "declining" production trend. Well spacing, permeability, producing conditions, and the diffusion characteristics of coal all affect the shape of the production profile. (Choote et al., 1986, Hanby, 1991). Analysis of pressure transients in simulated cases show that the decline trend is established when the outer flow boundary effects dominate the flow characteristics (pseudo-steady state flow). Therefore, declining production trends tend to be best developed in wells that are part of a producing well pattern, in which each well is interfering with other production wells.

The criteria for declining curve techniques are:

- Decreasing gas and water rates.
- Consistent slopes in gas rates for at least six months.
- The production life is more than 22 months, including a six months decline period.
- The wells are showing interference behaviour.

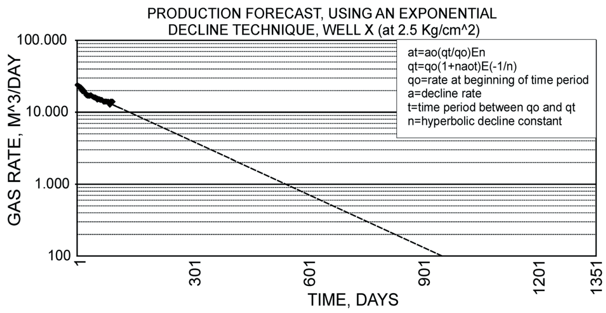

Figure 7. Production forecast, using production rate, time and an exponential decline technique.

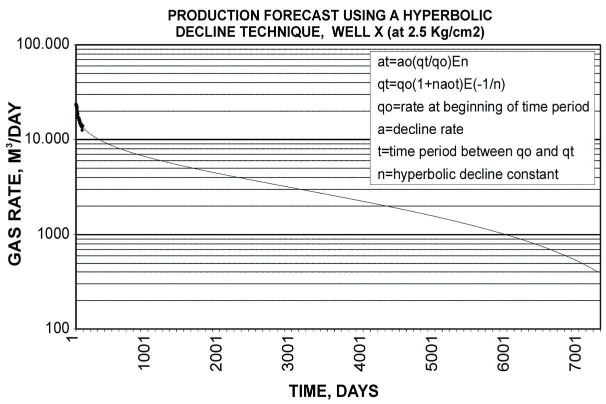

Figure 8. Production forecast, using production rate, time and an hyperbolical decline technique.

Usually not all the parameters are met for each well. However, when most of the criteria are met, there is a high degree of confidence in the production forecast based on the decline analysis. Figures 7 and 8 illustrate the use of both the exponential decline technique and the hyperbolic decline technique for estimating the future production of our example well (Well X) with a comingled production.

Exponential decline curve equations are used most often for analysing oil and gas wells. This type of decline is a constant percentage decline, which is characterized by straight line on a graph of production against time. Here the log of the production rate is plotted against the production time. The set of exponential decline equations are:

a) $$q_t = q_0 e^{-at} \quad \text{(eq. 6)},$$

where (q_t) is the production rate, using the initial production rate (q_0) and cumulative producing time (t).

b) $$a = \frac{\ln q_0 - \ln q_t}{t} \quad \text{(eq. 7)}$$

The equation calculates the decline rate (a) from a fit of measured production data, with;

c) $$t = \frac{-\ln(q_t / q_0)}{a} \quad \text{(eq. 8)},$$

as the time-rate (t) equation, and;

d) $$LR = \frac{q_0 - q_t}{q_0} = 1 - e^{-at} \quad \text{(eq. 9)},$$

as the loss ratio, (LR).

The equations 6 to 9 are used to calculate the cumulative production (G_P):

e) $$G_p = \frac{q_0 - q_t}{a} \quad \text{(eq. 10)}$$

In this study, the coalbed methane production data partly follow the exponential decline equation. The time zero of the production data has to be reset to the point where the production data starts with an exponential decline. This adjustment reduces the time span. To estimate the initial production rate, the rate data are extrapolated. To apply these equations, the units for decline rate and production rates must be consistent (i.e., decline rate expressed as "percent per day" and production rate as "Sm^3 per day").

Figure 7 shows the semi log graph of daily production rate plotted against time for Coalbed Methane well with a backpressure of 2.5 bar. For this analysis the last six months of production data have been analysed. A least squares fit of the production data gave a decline rate as shown on individual plots. This line was extrapolated and used to estimate the ultimate recovery at some economic limit.

The same set of production data is also used to fit into the hyperbolic decline equations. A hyperbolic decline is characterised by a constant change of decline rates with respect to time (i.e. the derivative of the exponential decline equation). The set of hyperbolic decline equations are:

a) $$q_t = q_0(1 + na_0 t)^{-1/n} \quad \text{(eq. 11)}$$

This equation is used to calculate production rate (q_t) using initial production rate (q_0) and cumulative producing time (t), as function where n is the hyperbolic decline constant and a_0 varying decline rate.

b) $$a_t = a_0(q_t / q_0)^n \quad \text{(eq. 12)}$$

This equation calculates the decline rate (a_t) from a fit of measured production data.

c) $$t = (q_t / q_0)^{-n} - 1/na_0 \quad \text{(eq. 13)},$$

is the time rate (t) equation, and;

d) $$LR_t = 1 - (1 + na_t)^{-1/n} \quad \text{(eq. 14)}$$

is represents the loss ratio (LR_t).

Equations 11 to 14 are used to calculate the cumulative production (G_P):

e) $$G_P = \frac{q_0{}^n}{(1-n)a_0(q_0{}^{1-n} - q_t{}^{1-n})} \quad \text{(eq. 15)}$$

Figure 8. is the semi log graph of daily production rates plotted against time with a hyperbolic fit.

7.1. Analysing the Suitability of the Procedure

Before the comparison of the exponential decline method with the hyperbolic decline method, it is stated that an exponential decline method is more suited for oil and gas production prediction rather than coalbed methane production forecasting. Going by the typical production profile of a coalbed methane well, this profile differs

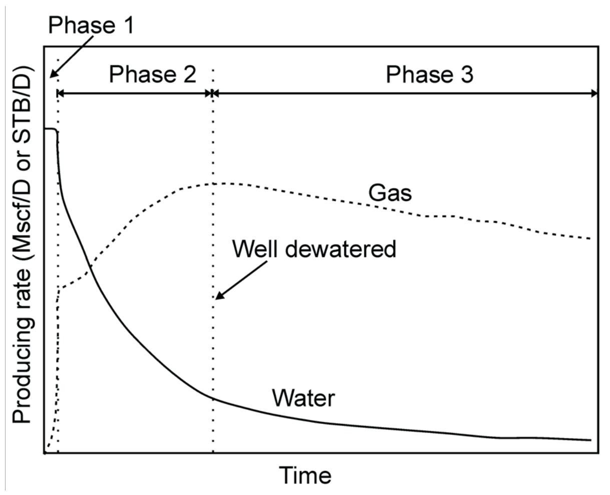

Figure 9. Production phases of a well during production.

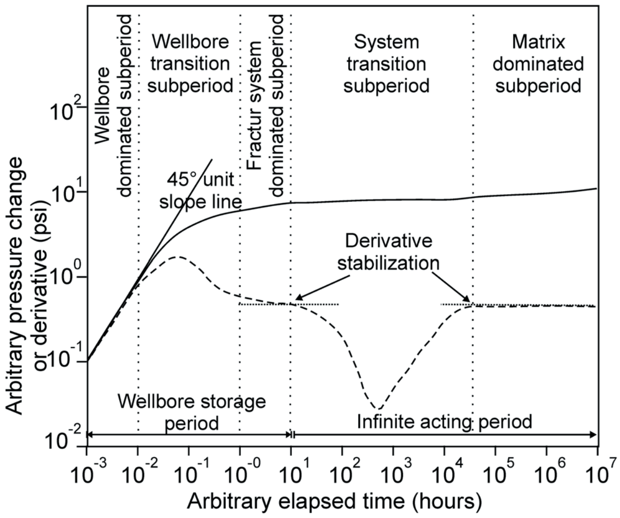

Figure 10. Pressure stages in a well during its production life.

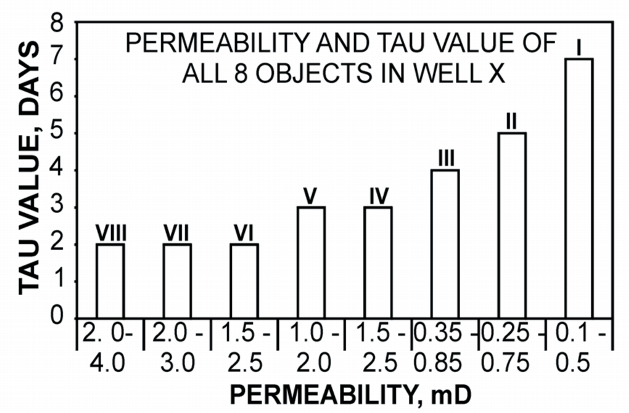

Figure 11. Tau values and permeabilities of the seams in well X.

significantly from the typical decline of a conventional gas well as shown in Figure 9. The "Phase 3" of a production profile begins when reservoir flow conditions have stabilised, the well has reached its peak gas rate, and the gas production is characterised by a more typical decline trend. The well is dewatered at the beginning of Phase 3. During this phase water production is low and/or negligible, and the relative permeabilities for gas and water change very little. The pseudo-steady state flow persists for the rest of Phase 3 and the producing rates of gas and water are controlled by the physical properties of coal, as well as the boundary conditions. Classic pressure transient behaviour of a dual porosity reservoir is based on mathematical models, which are developed by Warren and Root (1997). The classic behaviour does not occur in coalbed methane reservoirs. In an idealised dual porosity reservoir the pressure derivative profile is divided into an initial well bore storage period followed by an infinite acting period. The unit slope of the profile is 45° during the well bore storage period. At the end of the well bore storage period most of the fluid production originates from the reservoir. The infinite acting period in the classic dual porosity reservoir is characterised by three sub-periods, a fracture system dominated sub-period, a system transition sub-period and a matrix system dominated sub-period. During the fracture system dominated sub-period, the production originates from the secondary porosity. As time continues, the fracture system dominated sub-period ends as fluid starts to flow from the matrix system. In between a system dominated sub-period a production fall and a corresponding rise in the pressure derivative is observed. This classic pressure behaviour does not occur in coal gas reservoirs that produce both gas and water. The single-phase flow tends to occur during the fracture system dominated sub-period and the multiphase flow tends to occur during the matrix system dominated sub-period. The change from single to multiphase flow changes the fluid flow rate through the reservoir and the resulting derivative behaviour is as shown in Figure 10. So the resulting derivative profile removes the possibility of an exponential decline with a constant decline rate. It favours a model with an initially high decline rate followed by a lower decline rate. The profile tends to stabilise corresponding to the derivative stabilization with a hyperbolic decline fit in a period of 4 to 4.5 years as shown in Figure 8. (Holditch, 1990, Sawyer, 1987 and Schwerer, 1984).

In the production well of this example with a commingled production of five seams with varying permeabilities and varying τ values, the system is considered in a τ versus permeability plot (Figure 11). A lower τ value signifies smaller cleat spacing, i.e. higher cleat intensity and a higher diffusion coefficient. When regarded in terms of production, a higher permeable seam will desorb faster, attain its peak early and allow the infinite acting period to be dominated by a prolonged production of a high permeable reservoir with peak production of a less permeable reservoir, results in a stable production for a time span of 4 to 4.5 years. (Ettinger et al. 1966).

This is different in case of a less permeable seam, because of its higher τ value. The peak production is delayed and the well bore storage is more pronounced. Accordingly, when such five seams with different relative permeabilities are allowed to produce together, a case of constant production decline rate is never expected. The interference of a declining production of a high permeable reservoir with peak production of a less permeable reservoir, results in a stable production for a time span of 4 to 41/2 years.

7.2. Analysis using the Mass Balance Technique

As presented by King (1993), this technique incorporates the effects of gas desorption from the coal matrix as well as dynamic changes in gas and water permeability in the coal fractures. To use this technique a " Material balance simulator" was programmed. It is not widely used for production analysis and forecasting of coalbed methane wells. This technique is theoretically sound within the boundary, of the assumptions used to generate the solutions. The technique is useful for validating recovery calculations, generated by reservoir simulators, and for estimating well performances of mature producing fields in which sufficient reservoir data is available. The assumptions inherent in the material balance technique are as follows (King, 1993):

- It assumes equilibrium between the free gas and adsorbed gas in the reservoir (saturation conditions with respect to the isotherm).
- It requires accurate estimate of key reservoir data such as pressures, desorption isotherm, permeability characteristics etc.
- It assumes pseudo-steady state desorption characteristics.
- It models well bore damage or stimulation using, skin factors (not applicable for hydraulically fractured wells).

In the present technique, developed by Seidle (1991) and Yee et al. (1993), a coalbed methane reservoir has to reach the dewatered phase, which is defined by:

- A declining gas production rate trend (outer boundary dominated, pseudo-steady state flow), and
- Changes in the relative permeabilities of gas and water in the reservoir.

This technique combines a coalbed methane material balance equation with a gas deliverability equation, to forecast gas production rates. The technique is used on the production data of an example well (Well Y).

Equation 16 is used to calculate the gas flow rate (q_g).

$$q_g = \frac{K_g h[m(avg.p) - m(pwf)]}{1{,}422T[\ln re/rw - 3/4 + s + Dn_D qg]}$$
(eq.16) ,

where:

K_g is the effective permeability to gas (md), h the thickness, $m(avg.p)$ the real gas pseudo-pressure, which corresponds to he average reservoir pressure (psi^2/cp), $m(pwf)$ the real gas pseudo-pressure, which corresponds to the bottom hole pressure (psi^2/cp). T is the reservoir temperature (R), re the drainage radius (ft), rw the well bore radius (ft), s the well bore skin factor and Dn_D non-Darcy flow coefficient (D/MScf).

The real gas pseudo-pressure in equation 16 changes with the average reservoir pressure at every point of time.

$$m(p) = 2\int_{pb}^{p} p/\mu gzdp \qquad \text{(eq. 17)}$$

Where p is the pressure (psi), pb is an arbitrary base pressure, μg is the gas viscosity (cp) and z is the compressibility factor.

The following example illustrates the use of Seidle's analytic technique for long-term gas production of the barefoot seam of Well Y (1019.2 to 1049.40 mts.). The figures 12 and 13 show graphically the result of the forecast calculations.

Other than the eqations 16, 17, the developed simulator takes into account:

- Gas initially held in the coal cleats.
- Initial absorbed gas in the coal matrix.
- Water influx into and production from the coal fracture system.
- Gas remaining in the coal cleats.
- Gas remaining in the coal matrix.

A combined expression accounts for the cumulative produced gas volume:

$$\begin{aligned} G_P &= [7.758*10^{-3} Ah\phi_f(1-S_{wi})1/B_{gi}] \\ &+[1.306*10^{-6} Vm\rho_B Ah(bpi/1+bpi)] \\ &+[0.001(W_e/B_w - W_p)/avg.B_g] \qquad \text{(eq. 18)} \\ &-[7.758*10^{-3} Ah\phi_f(1-S_{wi})1/B_g] \\ &-[1.360*10^{-6} V_m\rho_B Ah(bavg.p/1+bavg.p)] \end{aligned}$$

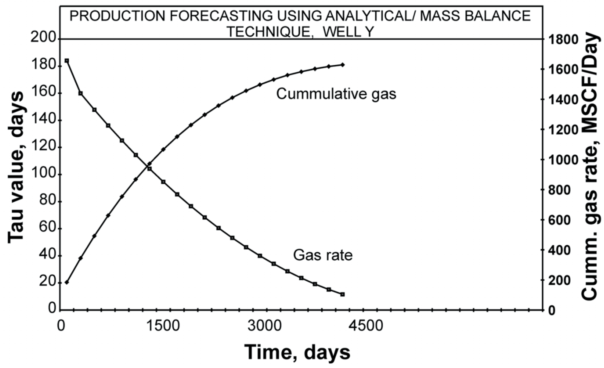

Figure 12. Tau values and cumulative gas production against time.

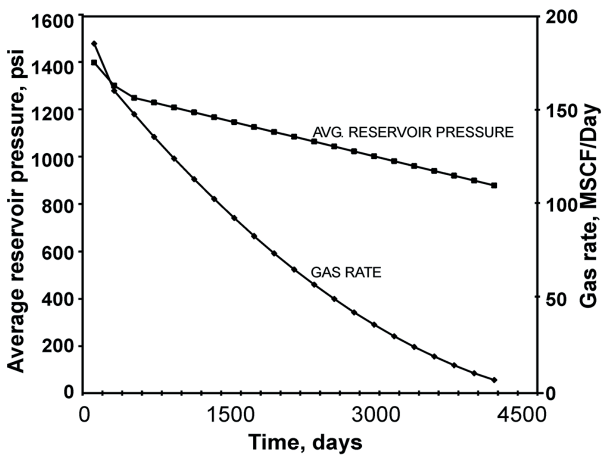

Figure 13. Average reservoir pressure and production rate over time.

8. Conclusions

Coal reservoirs are systems of storage and transport mechanisms that can be characterised using mathematical models. Simulation studies have shown that well to well interference effects improve the economic recovery of gas from water saturated coal seams. To evaluate coalbed methane reservoirs accurately, it is essential to acquire and integrate the proper reservoir data. Material balance calculations for estimating gas-in-place for coalbed methane reservoirs have been derived from conventional material balance equations by adding terms to account for desorption mechanisms. Material balance methods also can be coupled with flow equations to predict future production rates. Optimising recovery from coalbed methane reservoirs requires accurately predicting long term well production. Techniques for forecasting production of CBM wells under pressure depletion, include volumetric calculations, production decline analysis, material balance and flow equation calculations, and reservoir simulation. Decline curve techniques and material balance calculations generally agree with the profiles for producing wells within established well patterns that have a consistent production decline trend. Reservoir simulation is applicable to all stages of the well life. However, it is most useful in areas where an abundance of reservoir data and well test data are available. In the course of the study it was observed that Tau values can be used as a fingerprint of each coal seam and thus can be used as a tool for seam to seam correlation. To use material balance technique, a simulator was developed using Seidle's Mass Balance equations.

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All the above mentioned case studies contain the final analysis of the data using corresponding techniques, but original reservoir, reserve and production data are purposefully omitted because they stand as confidential.

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Nomenclature

a	Constant/varying decline rate
A	Area, acres
avg. p	Average reservoir pressure, psi.
b	Langmuir isotherm constant, psi^{-1}
B_{gi}	Gas formation volume factor at p_i, rcf/Scf.
Bavg.g	Average gas formation volume factor, reservoir volume / surface volume.
B_w	Water formation volume factor, bbl/STB
CGIP	Current gas in place, Bcf
d	Density of coal, tons/acre-foot
Dn_D	Non-Darcy flow coefficient, D/Mscf
fad	Correction for ash, moisture content, dimensionless
G_S	Gas storage capacity, Bscf
G_P	Current or cummulative gas produced, Bscf
h	Height of producing interval or coal thickness, feet
K_g	Effective permeability to gas, md.
LR	Loss ratio (“ effective” decline)
m(avg.p)	Real gas pseudo-pressure corresponding to the average reservoir pressure (*avg.p*), psi^2 /cp.
m(pwf)	Real gas pseudo-pressure corresponding to flowing bottom hole pressure (*pwf*), psi^2 /cp
m(p)	Real gas pseudo pressure
n	Hyperbolic decline constant
OGIP	Original gas in place, Bcf
p	Pressure, psi
pb	Arbitrary base pressure, psi
pi	Initial reservoir pressure, psia
P	Reservoir pressure, psi
P_L	Langmuir Pressure; pressure where the coal storage capacity is half the Langmuir volume
q	Surface gas flow rate, Mscf/day
q_0	Gas rate at time t=0, Mscf/day
q_t	Gas rate at time t, Mscf/day
re	Drainage radius, ft
rw	Well bore radius, ft
s	well bore skin factor, dimensionless
S_{wi}	Initial water saturation, fraction
t	Time period between q_0 and q_t, hrs, days
T	Reservoir temperature, °R
V	Gas content at pressure P, Scf/ton
V_i	Initial gas content at pressure P_i, Scf/ton
V_L	Langmuir Volume, the maximum gas storage capacity of the ash free coal, Scf/ton
Vm =	Matrix volume, ft^3
w_e	Water influx, Mbbl
w_p	Cumulative water produced. MSTB
Z	Real gas compressibility factor, dimensionless
ϕ_f	Interconnected fracture (effective porosity), fraction.
μg	Gas viscosity, cp
ρ_B	Bulk density, g/cm^3