Abstract

One of the unresolved issues in the evaluation of coalbed methane (CBM) reserves is whether the long term production profile is exponential or hyperbolic. The type of decline used to forecast production can have a significant effect on the remaining reserves; hence, a thorough investigation of CBM decline is warranted.

Before investigating the decline behavior of CBM wells, the literature on conventional gas decline analysis is summarized and the factors affecting production performance are discussed. The production performance of CBM is then investigated and compared to conventional gas performance. Simulations were conducted in order to determine the sensitivity of the hyperbolic decline exponent, b, to different reservoir and operating conditions. It was determined that several parameters, including the flowing pressure, affect the decline of conventional gas and CBM wells.

Introduction

The objective of this study is to review traditional decline analysis and discuss its applicability to CBM. Traditional decline analysis is based on the Arps’ equation which was introduced in the 1940’s. It is an empirical relation that extrapolates a production forecast based on a curve fit of historical data. The general equation is given by

\[ q = \frac{q_i}{(1 + D_i b t)^b} \]  

where \( q \) is the rate, \( q_i \) is the initial rate, \( D_i \) is the initial decline rate, and \( b \) is the hyperbolic decline exponent.

The initial decline rate, \( D_i \), and decline exponent, \( b \), are constants used to calculate rate as a function of time. The theoretical limits on the decline exponent are 0 and 1. There are three specialized forms of the equation: exponential, hyperbolic and harmonic. Exponential decline is defined by a b value of 0 and can be recognized in several ways:

1. The decline rate, \( D_i \), is constant at all time
2. A plot of gas rate versus cumulative gas production will be a straight line
3. A plot of the logarithm of gas rate versus time will be a straight line

Hyperbolic decline is defined by a b value between 0 and 1 and can be recognized if:

1. The decline rate, \( D_i \), is decreasing constantly with time.
2. A plot of gas rate versus cumulative gas production has a concave upward appearance.

Use of the exponential equation produces a more conservative reserve estimate than the hyperbolic equation, given the same
initial decline rate, $D_i$. It is often difficult to distinguish between exponential and hyperbolic decline without a considerable amount of data, so it is up to the judgment of the evaluator to use an appropriate $b$ value. Analogous production history is often used as guidance. The choice of $b$ value not only influences the estimate of reserves, but it also affects how long and at what rates the well will produce, which directly affects the economics of a project.

Though Equation 1 is widely used, it does have limitations. It is only valid during boundary-dominated-flow, and when the well’s flowing pressure is constant. Fetkovich (2) created type curves that combine transient solutions with the boundary-dominated stems of the Arps’ equation. The type curve allows the entire data set to be analyzed, but it is still limited by the constant flowing pressure assumption. Modern techniques (3) have been developed to account for variable flowing pressure but they are out of the scope of this study.

### Decline Performance of Conventional Gas Wells

It is well known that the theoretical rate-time solution for a single phase liquid under volumetric depletion, flowing at constant wellbore pressure, is exponential decline ($b=0$). Fetkovich (4, 5) related the value of $b$ directly to the drive mechanism of the reservoir, which for volumetric depletion is the total system compressibility. Unlike that of a single phase liquid system, the compressibility of a gas reservoir is not constant. It varies approximately as the inverse of the average reservoir pressure, which explains why gas decline rates correspond to $b$ values larger than 0.

### Factors Affecting Conventional Gas Decline

To investigate what reservoir and operating conditions influence the value of $b$ for gas wells, the literature was reviewed and simulations were conducted. The consensus, and our results indicate that gas declines correspond to $b$ values between 0 and 0.5. The following parameters had a significant effect on the production decline of gas wells:

- Wellbore flowing pressure (constant)
- Fluid Properties
- Turbulence, which is affected by
  - Initial Reservoir Pressure
  - Permeability
- Multiple, no crossflow layers

### Magnitude of Flowing Pressure

The effect of backpressure (wellbore flowing pressure) on the decline of a gas well was investigated by simulating gas production at different constant flowing pressures. Unlike the behaviour of a liquid system, it was observed that, in a gas well, the $b$ value depends on the magnitude of the flowing pressure. As the backpressure is increased (ratio of $P_{wf}/P_i$ increased), the $b$ value decreases, as illustrated in Figure 1. In other words, at low drawdowns ($P_{wf} - P_{wf}$), (which is equivalent to a high backpressure) the production decline curve tends towards the exponential solution ($b=0$). Other authors (2, 5) have also observed this relationship between high flowing pressure and low $b$ values.

Carter (6) investigated this effect further by defining a drawdown parameter, $\lambda$, which is the ratio of the viscosity-compressibility product evaluated at the initial and average wellbore flowing conditions. Its value varies between 1 and 0.5 and accounts for changing fluid properties with changes of flowing wellbore pressure.

$$\lambda = \frac{(\mu_{ci})}{(\mu_{ci})_{avg}}$$  \hspace{1cm} (2)

Voelker (8) related the $b$ value to the $\lambda$ parameter and concluded that $b$ values greater than 0 are caused by changing fluid properties during depletion. For example, a $\lambda$ of 1 indicates that the “average” viscosity-compressibility product during depletion is equal to the initial product, and thus, the fluid properties are constant and the $b$ value approaches zero. At a high drawdown, $\lambda$ approaches 0.5, which corresponds to a large change in the viscosity-compressibility product and $b$ value approaching 0.5.

### Variable Reservoir Fluid Properties

Fraim and Wattenbarger (7) demonstrated that gas production data will decline exponentially if plotted against normalized-time, $t_n$, which corrects for changes in fluid properties with declining reservoir pressure:

$$t_n = \int \frac{\mu_{ci} c_{i}}{\mu_{ci}} dt$$  \hspace{1cm} (3)

This corrected time function is very similar to the “pseudo-time” function used in modern production decline analysis as described by Agarwal et al (10). While this transformation accounts for the non-constant reservoir fluid properties, its use in mainstream reserve evaluations is still relatively limited, because of the extensive data requirement and iterative calculations. However, with the propagation of continuous rate and pressure monitoring (SCADA) this analysis (10) is being used more frequently in reservoir engineering studies.

### Turbulence

Another condition that was found to affect the $b$ value was turbulence. The Forcheimer equation (17) relates the pressure drop in the reservoir to the sum of the laminar ($Aq$) and turbulent ($Bq^2$) pressure drops using the following equation.

$$\frac{P_R - P_{wf}}{2} = Aq + Bq^2$$  \hspace{1cm} (4)

Based on Equation 4, it is clear that the turbulent pressure drop is proportional to the flowrate squared; and, because the flowrate is largely affected by permeability and reservoir pressure, these variables will also have an effect on the $b$ value. Other authors (9) observed that as permeability and initial
reservoir pressure increase the decline profile changes significantly.

Equation 4 is often used in the form of Equation 5, known as the backpressure equation:

\[ q = C \left( \frac{P_R^2 - P_{wf}^2}{n} \right)^n \]

(5)

Here, \( n \) represents the degree of turbulence. A value of \( n = 1 \) represents laminar flow and a value of 0.5 represents turbulent flow.

For fully turbulent cases (\( n=0.5 \)), Equation 4 reduces to a form similar to Equation 5:

\[ q = \frac{1}{B} \left( \frac{P_R^2 - P_{wf}^2}{0.5} \right)^{0.5} \]

(6)

Fetkovich \(^{(5)}\) coupled the backpressure equation (5) with a material balance equation to obtain a rate-time relation.

\[ q = \frac{q_i}{1 + (2n - 1) \left( \frac{q_i}{G} \right) t} \]

Using Equation 1 and 7, the following expression for \( b \) as a function of the turbulence factor can be derived \(^{(5)}\).

\[ b = \frac{2n - 1}{2n} \]

(8)

Equation 8 (which is applicable under the conditions of very low flowing pressure) provides a relationship between the \( b \) value of hyperbolic decline and turbulence. It shows that \( b \) approaches zero as turbulence \( (n) \) increases. Our simulations confirm this finding, which is illustrated in Figure 3b.

**Layered Reservoirs**

Declining gas production data from single layer, conventional gas reservoirs is typically matched using a \( b \) value of 0.5 or less. However, according to Fetkovich \(^{(10)}\), \( b \) values as high as 1 (i.e. harmonic) can be used to match the decline from layered gas reservoirs. Based on this observation, Fetkovich believed that most gas wells that can be matched with \( b > 0.5 \) must be producing from a layered reservoir. An example is shown in Figure 3c.

Values of \( b \) greater than 1 have been reported for some situations (e.g. tight gas wells). However, in these cases, the data that is matched is still in transient flow and is not boundary dominated; hence, Arps’ decline curve analysis is not applicable. In his work, Fetkovich simulated the behavior of two-layered gas systems and observed that if one layer depletes quicker than the other, the \( b \) value increases. This occurs when one layer is more productive (i.e. higher permeability or less skin damage) than the other and the early gas production is dominated by the more productive layer, while the late time production is dominated by the less productive layer. The overall decline profile that results has a high initial decline rate, followed by a shallow stabilized decline. This differential depletion can be approximated using a smooth hyperbolic decline curve with a value of \( b \) between 0.5 and 1.

**Changing \( b \) value**

Previous authors \(^{(7, 9)}\) have noted that the \( b \) value used to match gas production data is often not constant and decreases at late time.

A constant \( b \) value implies a continuously decreasing value of the annual percentage decline rate, \( D \). Late in the life of a well, the decline rate, \( D \), can become so low that the reserves become overstated. For this reason, industry is cautious about using a constant \( b \) value. To minimize this problem, Robertson \(^{(13)}\) introduced the generalized hyperbolic equation which limits \( D \) to an ultimate minimum exponential decline rate.

From our simulations, it was observed that under certain situations, the \( b \) value decreased near the end of a well’s life; however, it was a gradual decrease rather than an abrupt change. The decreasing \( b \) value is related to the change in fluid properties. Figure 2 illustrates the late time decrease in \( b \) on a Fetkovich type curve. A decreasing \( b \) value occurred under the following scenarios:

- High drawdown with
- High Initial Pressure
- Moderate Initial Pressure with
  - Low Permeability (0.1 mD)
  - Moderate Permeability (5 mD)
- Moderate Initial Pressure with
- High Initial Pressure with
- Moderate Drawdown

Schmidt et al \(^{(9)}\) observed that a constant \( b \) value could be fitted to simulated data up to the dimensionless rate \( q_{2\pi t_0} = 0.03 \). This observation was tested against our own simulations, and we found that it was true for most cases. It was noted that the deviation from a constant \( b \) value occurred after 90% of the reserves had been produced. Accordingly, using a constant \( b \) caused only a marginal overestimation (\(-5\%)\) of reserves in most cases.

It is therefore concluded that a well may exhibit a decreasing \( b \) value in the end stages of depletion. But, for all practical purposes, a constant \( b \) value is a good approximation, because the decrease in the \( b \) value is only observed very late in the life of a well, and has little effect on the total reserves.

**Discussion**

Gas production from single layer, conventional gas reservoirs can be matched with \( b \) values between 0 and 0.5. A minimum \( b \) value of 0 implies that the fluid properties are relatively constant during depletion, whereas a \( b \) value of 0.5 implies that the change in fluid properties is significant. Because the change in fluid properties becomes more significant at lower reservoir pressures, the value of \( b \) is proportional to the depletion of the reservoir. Factors such as wellbore drawdown and turbulence,
affect the pressure depletion and therefore have a strong effect on the b value. For example, a low wellbore drawdown does not reduce the reservoir pressure as significantly as a high wellbore drawdown, which results in less fluid property change, and therefore a lower value of b. Similarly, turbulence near the wellbore reduces the drawdown within the reservoir and therefore reduces the value of b.

In practice, many gas wells (ex. tight gas wells) are produced at the highest possible drawdown. For these cases, b values that approach 0.5 are anticipated. High deliverability wells, on the other hand, may be choked in order to restrict gas production, which would decrease the drawdown and the b value. There may also be a considerable pressure drop near the wellbore caused by turbulence, which will also reduce the b value.

It was also determined that the b value used to match gas well decline is not constant and decreases at late time. However, this change occurs so late in the production history (i.e. after 90% of the reserves have been produced) that it has little significance on the total reserves.

Summary - Conventional Gas Decline
1. The hyperbolic exponent, b, is usually between 0 and 0.5
2. Low drawdowns result in b values approaching zero – Figure 3a. High drawdowns (tight gas wells) have b values approaching 0.5
3. As turbulence increases, b approaches zero –Figure 3b
4. Multi-layer reservoirs can have b values between 0.5 and 1 – Figure 3c
5. The value of b can change, but for all practical purposes, this occurs so late in the life of a well that it is of little consequence - Figure 2

Decline Performance of CBM Wells
Production of gas from coal differs from that of conventional reservoirs because of the manner in which the gas is stored. In conventional reservoirs, the gas is compressed in the pore volume of the reservoir, while in CBM reservoirs the majority of the gas is adsorbed onto the surfaces of coal in a liquid-like state. Gas storage by adsorption is typically modeled using a Langmuir isotherm. The isotherm is defined by two properties: Langmuir volume ($V_L$) and Langmuir pressure ($P_L$). $V_L$ is the maximum amount of gas that can be adsorbed by the coal at infinite pressure. The pressure needed to adsorb half of the Langmuir volume corresponds to $P_L$. Examples of two typical Langmuir isotherms ($V_L = 14$ cc/g), with two different Langmuir pressures are shown in Figure 4. As this plot shows, the amount of gas stored by adsorption increases non-linearly with pressure. The gas is produced by reducing the pressure in the reservoir, which causes the gas to desorb from the coal. However, because a large fraction of the gas is stored at low pressure, the reservoir pressure must be reduced significantly in order to produce a majority of the adsorbed gas. Also, in view of the non-linearity of the isotherm, the decline rate is expected to be hyperbolic, because an increased volume of gas is desorbed at lower pressures (late-life production).

CBM reservoirs are often wet, and will produce significant quantities of water prior to any gas production. A production profile for a typical CBM well was generated using the reservoir properties listed in Table 1, and is shown in Figure 5.

This production profile can be clearly divided into two stages:
1. Inclining Trend: During this stage a significant volume of water is produced, which reduces the reservoir pressure and allows the gas to desorb. This causes the water saturation to decrease, which increases the relative permeability to gas, thus increasing the gas deliverability.
2. Declining Trend: During this stage the gas rate peaks and boundary dominated flow prevails. The relative permeability to water and gas remains relatively constant because the water saturation decreases very slowly. The gas production declines during this stage because of decreasing reservoir pressure.

Once the well produces past its peak production rate, a decline analysis may be used to estimate the future reserves.

The use of decline curve analysis to predict CBM reserves was first documented by Hanby (12) who used exponential declines to perform economic evaluations for CBM wells in the Warrior Basin. Other authors (13, 14) later derived expressions for the gas decline rate in CBM wells to theoretically justify exponential decline. The following approximate equation for gas decline rate was presented by Seidle (15)

$$D_g = \frac{1}{q} \frac{dq}{dt} = \frac{2Jp_pZ^*}{Z^*_G(1 - \frac{p}{Z^* \frac{dz^*}{dp}})} \quad \cdots \quad (9)$$

These authors suggested that because the reservoir pressure changes very slowly during boundary dominated flow, the decline rate should be constant. In fact, inspection of this equation shows the decline rate, $D$, to be dependent on pressure, $p$, which means that $D$ should not be constant (implying non-exponential behaviour). A fifty-year gas production forecast from a CBM well was simulated using the properties listed in Table 1. This simulation, shown in Figure 6, illustrates that, indeed, the decline rate is not constant (hence, the assumption of a constant decline rate is not valid) and the observed curvature in the log-rate versus time plot indicates that the decline over the whole life of the well is not exponential.

Another observation that can be made from Figure 6 is that for first 30 years the well appears to be declining exponentially (i.e. straight line of semi log plot). However, at late time (> 30 years) it is clear that the production profile is hyperbolic. If an exponential forecast had been used to estimate reserves for this well, it would have underestimated the ultimate reserves by more than 15%, which is shown in Figure 7.

Many CBM wells, especially in Canada, have not produced long enough to establish a unique declining trend which makes matching the data with a unique b value difficult. In situations such as these it is common practice to use b values from analogous wells. However, in newer CBM developments, like the Horseshoe Canyon there is little long term analogous information available. Figure 8 shows an example of
Horseshoe Canyon well that was produced at a relatively constant flowing pressure throughout its life. The decline trend can be matched with any $b$ value between 0 and 0.6, as shown in Figure 8, and because there is limited historical and analogous data, a unique value of $b$ cannot be determined. For this reason, CBM decline was investigated in further detail (similar to the preceding investigation of conventional gas reservoirs), in order to obtain a better understanding of what $b$ values might be expected from different types of CBM reservoirs.

Factors Affecting CBM Decline

Aminian et al. (15) have investigated the impact of key reservoir parameters on CBM decline using a numerical simulator. They found that the following parameters had little effect on the shape of the decline curve:

- fracture permeability
- fracture porosity
- coal thickness
- drainage area
- skin factor
- sorption time
- initial gas content

However, they did find that the wellbore flowing pressure, relative permeability and Langmuir pressure had significant effects on the shape of the decline curve.

Following the same approach, we ran simulations to investigate the effect of the following variables on the decline exponent, $b$:

- flowing pressure
- initial pressure
- Langmuir volume
- Langmuir pressure
- initial water saturation
- relative permeability to gas and water
- matrix shrinkage
- multiple CBM layers

Flowing Pressure

The simulations were performed assuming that the wells were produced at 90% drawdown (This is typical of many CBM gas operations). Upon matching the declining portion of the data we found a majority of the cases could be matched with a $b$ value of 0.4, which is consistent with the typical $b$ value for conventional gas.

Another similarity between conventional gas and CBM decline is that the $b$ value approaches 0 with decreasing drawdown (increasing flowing pressure) - similar to Figure 1. Figures 9 and 10 show the production histories for two CBM wells and illustrate the effect of the flowing pressure on the decline behaviour. Both wells were drilled into the same formation and had similar initial pressures and coal properties. However, one is produced at a much lower flowing pressure than the other. The well in Figure 9 has been produced at 96% drawdown (i.e. $P_{wf}/P_i = 0.04$) since it began declining, and the production history can be matched with a $b$ value of 0.8. The well in Figure 10 has been consistently produced at an 85% drawdown (i.e. $P_{wf}/P_i = 0.15$) during the declining period, and is matched with a $b$ value of 0.1.

Initial Reservoir Pressure

Previous authors (15) have concluded that initial pressure does not affect the shape of the CBM decline. However, our simulations showed that as the initial pressure decreased, the $b$ value approached 0. This is consistent with the observation that at small drawdowns (low initial pressure) the hyperbolic decline exponent, $b$, tends towards zero. Upon further inspection we noticed that the abandonment rate chosen for our simulations (250 m$^3$/d) affected the value of $b$ more significantly than the initial pressures. For example, if two wells are abandoned at the same rate but one is producing from a low pressure coal and the other from a high pressure coal, the well producing from the low pressure coal reaches the abandonment rate much earlier. And, as Figure 6 shows the time to see hyperbolic decline can be very long in CBM reservoirs. Therefore, the low pressure well may not exhibit a hyperbolic decline prior to reaching the abandonment rate.

Adsorption Characteristics

The adsorption characteristics of the coal ($V_L$ and $P_L$) were also studied to determine their effect on the $b$ value. The simulations conducted varied $V_L$ between 6 and 22 cc/g and it was determined that the value of $b$ was not sensitive to this parameter. However, when the sensitivity of the $b$ value to $P_L$ was studied, it was observed that the $b$ value increased as $P_L$ decreased. This effect is caused by the non-linear shape of the isotherm. As Figure 4 shows, the lower the $P_L$ the steeper (more non-linear) the isotherm. At late time, when the reservoir pressure is depleted, more gas desorbs from the coals with the lower $P_L$. This tends to stabilize the late time gas production which translates into a higher $b$ value. For very low Langmuir pressures, a value of $b$ greater than 0.5 was required to match the gas production data. However, for the most common values of $P_L$ encountered in practice, the $b$ value used to match the data was around 0.4 to 0.5.

Initial Water Saturation

Simulations were performed to determine the effect of initial water saturation on the decline of CBM reservoirs. The simulations showed that as the initial water saturation decreased, the $b$ value increased. This effect was associated with the increased relative permeability to gas in coals with lower water saturations. As the relative permeability to gas increases (i.e. as initial water saturation decreases) more gas can be produced. This causes the reservoir pressure to deplete more rapidly, allowing more gas to desorb, which increases the $b$ value. For very low initial water saturations this effect can become very significant and $b$ values greater than 0.5 may be required to match the gas production data, as shown in Figure 11c. However, in most wet CBM developments $b$ values greater than 0.5 are not typically observed.

Matrix Shrinkage

Due to the high compressibility and the gas adsorption properties of coals, the permeability of the coal may change as the reservoir pressure is reduced. During the initial stages of
production, the permeability of the coal may be reduced as the overburden pressure compresses the fracture volume. However, as more and more gas is desorbed and produced, the volume of the coal matrix is reduced. This effect increases the permeability of the coal and is referred to as “matrix shrinkage”.

The effect of matrix shrinkage on CBM decline was studied by simulating several cases with varying magnitudes of matrix shrinkage. Based on these simulations, it was found that the b value decreases as the effect of matrix shrinkage increases as shown in Figure 11d. This is consistent with the overall observation that any phenomenon that results in a lower drawdown in the reservoir tends to decrease the b value. It is important to note that these lower b values did not translate into lower reserves estimates, because the increased permeability caused by matrix shrinkage increases the peak gas rate and, correspondingly, the total amount of gas produced.

Layered CBM Reservoirs

To characterize the decline of multi-layer CBM reservoirs two layer reservoir models were simulated (similar to Fetkovich\(^{10}\) for conventional gas reservoirs). These simulations produced similar results to those of conventional gas reservoirs, showing that the value of b increases (0.5 – 0.8). The production decline performance of a single layer reservoir compared to a two-layer reservoir is shown in Figure 11e.

Discussion

Gas production decline from wet, single layer coals can be matched with b values between 0 and 0.5, similar to conventional gas wells. The value of b used to match the production history is proportional to the wellbore drawdown and may approach 0 in low drawdown scenarios. The effect of turbulence is relatively insignificant in CBM wells compared to conventional gas wells because of the relatively low production rates experienced in CBM operations. And, because CBM is typically produced at the highest possible drawdown it is reasonable to expect b values of 0.4 to 0.5.

Furthermore, due to the adsorption mechanism of CBM, significant volumes of gas will desorb as the reservoir pressure depletes, which stabilizes the late time gas rates and increases the b value. Simulation shows that the value of b used to match theoretical CBM production data can exceed 0.5, for dry coals and multi-layered systems. However, it is recommended that the evaluation engineer take caution when using b values greater than 0.5, as they may result in extremely long forecasts (which increases the reserves, but has little effect on the Net Present Value).

Based on these theoretical observations, it is expected that the late time production performance of CBM wells will follow a hyperbolic decline. However, as Figure 6 shows, the hyperbolic trend may not be distinguishable from an exponential trend until a considerable amount of time has passed. It may be many more years before unique hyperbolic profiles are distinguishable in practice, as Figure 8 illustrates. However, an exponential decline can significantly underestimate the ultimate reserves if the actual decline follows a hyperbolic trend.

Summary – CBM Decline

1. Production decline of CBM usually matches a hyperbolic decline exponent, b, between 0 and 0.5. However, during the early life of a well, a b value of 0.5 is indistinguishable from that of 0 – Figure 8.
2. Low drawdowns result in b values approaching zero. However, most CBM operations produce at the highest drawdown possible, which results in b values approaching 0.5 – Figure 11a.
3. A lower initial pressure results in a lower drawdown, and a correspondingly lower b value.
4. As the Langmuir pressure decreases, the isotherm becomes more non-linear and the b value increases - Figure 11b.
5. The Langmuir volume \( V_L \) does not affect the b value.
6. High initial water saturations in the fracture network decrease the value of b, as shown in Figure 11c.
7. Matrix shrinkage tends to reduce the b value – Figure 11d.
8. Multi-layer CBM reservoirs exhibit b values greater than 0.5 when there is a significant contrast between layer properties – Figure 11e.

Conclusion

Based on theoretical simulations it was found that CBM decline can be modeled adequately using Arps’ equation. The value of b used to forecast CBM production is significantly affected by many factors including the operational conditions. However, because most CBM wells are produced at high drawdown, it is expected that their production performance will follow a b value greater than 0. Although a CBM decline may initially appear exponential, it has been shown theoretically that a hyperbolic decline trend will develop later in the life of the well, as the pressure depletes. Determining the appropriate value of b to use can be difficult as there are few CBM analogies available at the present time to use as guidance. Therefore, an evaluator may have to rely on theoretical principles in order to estimate a suitable value of b.

For both conventional gas and CBM wells, any factor that lowers the drawdown in the reservoir will cause the decline to approach exponential behaviour. Any factor that increases the drawdown will result in b values approaching 0.5.

Overall, in spite of the more complex production mechanisms, CBM decline behaviour is not that different from that of conventional gas wells.

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NOMENCLATURE

\[ A = \text{Laminar Flow Factor} \left[ \frac{kPa(a)^2}{m^3/d} \right] \]

\[ b = \text{Decline Exponent} \]

\[ B = \text{Inertial Turbulent Flow Factor} \left[ \frac{kPa(a)^2}{m^3/d} \right] \]

\[ c_{ni} = \text{Total Compressibility at Initial Reservoir Pressure [kPa}^{-1}] \]

\[ c_{ti} = \text{Total Compressibility at Average Reservoir Pressure [kPa}^{-1}] \]

\[ C = \text{Backpressure Coefficient} \left[ \frac{m^3}{d \cdot kPa(a)^2} \right] \]

\[ D = \text{Nominal Decline Rate [% / year]} \]

\[ D_g = \text{Nominal Gas Decline Rate [% / yr]} \]

\[ D_i = \text{Initial Nominal Gas Decline Rate [% / yr]} \]

\[ G_i = \text{Initial Gas in Place [m}^3] \]

\[ J = \text{Productivity Index} \left[ \frac{m^3}{d \cdot kPa(a)^2} \right] \]

\[ n = \text{Turbulence Factor (backpressure exponent)} \]

\[ p = \text{Pressure [kPa(a)]} \]

\[ p_i = \text{Initial Pressure [kPa(a)]} \]

\[ p_{av} = \text{Average Reservoir Pressure [kPa(a)]} \]

\[ q = \text{Gas Flowrate [m}^3/d] \]

\[ q_i = \text{Initial Gas Flowrate [m}^3/d] \]

\[ t = \text{Time [Years]} \]

\[ t_p = \text{Normalized Time [Years]} \]

\[ Z^* = \text{Gas Deviation Factor (Modified) for Unconventional Gas}^{13} \]

\[ Z_i^* = \text{Gas Deviation Factor (Modified) for Unconventional Gas}^{13} \text{evaluated at Initial Reservoir Pressure} \]

\[ \lambda = \text{Carter’s Drawdown Parameter} \]

\[ \mu_i = \text{Gas Viscosity evaluated at Initial Reservoir Pressure [mPa-s]} \]

\[ \mu = \text{Gas Viscosity evaluated at Average Reservoir Pressure [mPa-s]} \]

\[ \mu_{avg c_i,avg} = \text{Mean Viscosity-Compressibility Product over the interval between } p_i \text{ and } p_{av} \text{[kPa}^{-1}] \]

REFERENCES

17. ENERGY RESOURCES CONSERVATION BOARD OF ALBERTA; Theory and Practise of the Testing of Gas Wells, Fourth Edition. 1979
Figure 1: Effect of increased flowing pressure on conventional gas decline. Normalized Gas Rate \( \left( \frac{q}{q_i} \right) \) versus time on log-log scale.

Figure 2: Decreasing \( b \) value during late stages of production. Fetkovich Type Curve and Simulated Production Data on log-log scale.
Figure 3a: Effect of Drawdown on Conventional Gas Decline.

Figure 3b: Effect of Turbulence on Conventional Gas Decline.
Figure 3c: Effect of Multiple Layers on Conventional Gas Decline.

Figure 4: Langmuir isotherm with same $V_L$ ($14$ cc/g) showing the effect of different $P_L$. 
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</tr>
</tbody>
</table>

Table 1: Data used to create Figures 5, 6, and 7.

Figure 5: Typical CBM Production Profile. Gas/Water Rates (m³/d) versus Time (Years)
Figure 6: Fifty-year simulation showing hyperbolic decline after 30 years of production.

Figure 7: Reserve estimation based on exponential decline shows underestimation by more than 15%.
Figure 8: Example from Horseshoe Canyon shows that a number of b values can be used to match the same production history.

Figure 9: CBM well produced at $P_0/P_i = 0.04$ (96% Drawdown). Red line matches data using $b = 0.8$. 

13
Figure 10: CBM well produced at $P_{wf}/P_i = 0.15$ (85% Drawdown). Red line matches data using $b = 0.1$.

Figure 11a: Effect of Drawdown on CBM Decline.
Figure 11b: Effect of Langmuir Pressure on CBM Decline.

Figure 11c: Effect of Initial Water Saturation on CBM Decline.
Figure 11d: Effect of Matrix Shrinkage on CBM Decline.

Figure 11e: Effect of Multiple Layers on CBM Decline.