IMPERIAL COLLEGE LONDON

Department of Earth Science and Engineering
Centre of Petroleum Studies

"Coal Bed Methane System Modeling - Reservoir, Wells and Surface Facilities"

By

EFEOGHENE ORI-JESU

A report submitted in partial fulfillment of the requirements for the M.Sc. in Petroleum Engineering

September 2011

DECLARATION OF OWN WORK

I declare that this thesis:

“Coal Bed Methane System Modeling- Reservoir, Wells and Surface Facilities”

Is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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“*Do not believe everything you read*.”

Hamid Guedroudj
A.C. Gringarten

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Table of Contents

LIST OF TABLES

LIST OF FIGURES

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Coal Bed Methane System Modeling – Reservoir, Wells, and Facilities

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Abstract

Coalbed methane (CBM) holds promise of relatively clean, stable natural gas supply in the emerging global energy map. This project summarizes the modeling of a unit of a coalbed methane reservoir-well-surface facilities system. The project integrates well modeling for different well fluid and pressure conditions, the range of artificial lift parameters and the surface constraints with the reservoir response. An economic cost model is also linked to the system, which incorporates ranges for gas prices, water handling costs, capital and operating costs and discount rates. The instant capability to examine the possible net present values and internal rates of return for a given production stream of gas and water is also demonstrated. The simultaneous optimization of the reservoir, well, surface and economic models in a single simulation run made possible by proprietary oil industry software enables the observation of the system behaviour instead of just the reservoir as has been mostly done in industry. The reservoir effects on this coupled system are presented to explain important considerations in CBM feasibility considerations. The resulting model is scalable to deal with larger fields and well patterns.

Introduction

The place of Coalbed methane (CBM) in the global energy mix has been steadily rising for the last 20 years. The need to degas mines in order to reduce explosion risks to miners first spurred attempts at venting methane from coal mines to the atmosphere before mining operations began. Today, the relatively clean nature of Coalbed methane and the increasing importance of clean energy drive the search for CBM in coal rich regions of the world.

The evaluation of CBM field developments has been focused on reservoir models and only in recent times has the importance of analyzing the system from reservoir to surface facilities as a single unit been considered. This project attempts to integrate the various engineering studies of the CBM reservoir into conjunction with the well and surface facilities modeling. The final aim of the project is to attempt to demonstrate the process of economic evaluation of a new CBM prospect and the crucial factors involved in the business decision to develop or not.

Problem Statement/Justification

The modeling of CBM has focused mainly on the reservoir system, with trends moving from the modified black oil simulator suggested by Seidle and Arri (1990) to the fully compositional models tested in the SPE-Industry collaborative project (Law et al., 2002). The influence of the well and surface constraints have been seen recently to significantly impact the project economics, with pump failures due to poor design and solid deposition on subsurface equipment due to water vaporization, leading to frequent workovers and negative economics (Simpson et al., 2003).

The importance of a surface controlled reservoir-wells-surface network in determining plateaus and estimating deliverability and economics has become clear. The seamless coupling of a numerical simulator with a well model, a surface network and an economics model using new robust modeling tools is a first step in raising confidence levels in CBM field development simulations. It also provides an efficient economic screening tool for new CBM field evaluations.

Objectives

The objectives of this project are

- To model the behaviour of a CBM reservoir, well and surface facilities system
- To determine the sensitivity of the economics of a new CBM field project to various reservoir and facilities parameters.

Literature Review

Coal gas is generated by biogenic and thermogenic processes at the same time coal deposits form. The commercial value of a new CBM find is largely dependent on the amount of gas in place and the permeability of the naturally fractured coal. The typical assumption for a CBM reservoir is a dual porosity system with a tight matrix and a fractured coal system. Deeper buried coals (depths greater than 4,000 – 5,000 ft) have more mature coals and have higher gas adsorption volumes due to the higher carbon content in the matured coals (See Figure 1). However, the higher overburden reduces permeability (the productivity) of the reservoir. Coalbed methane (CBM) is regarded as an unconventional gas resource because majority of the gas in place is held to the surface of the coal (adsorbed) in mono-molecule layers at liquid-like densities (Langmuir, 1918).

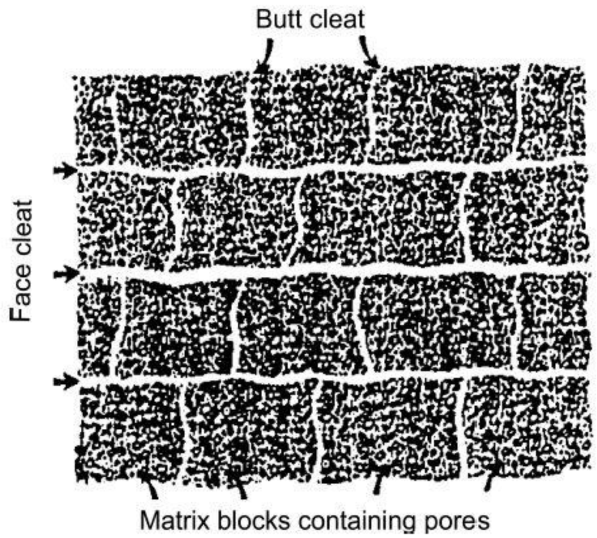


Figure 1: Plan View of Coal Block Showing Cleats (After King, 1986)

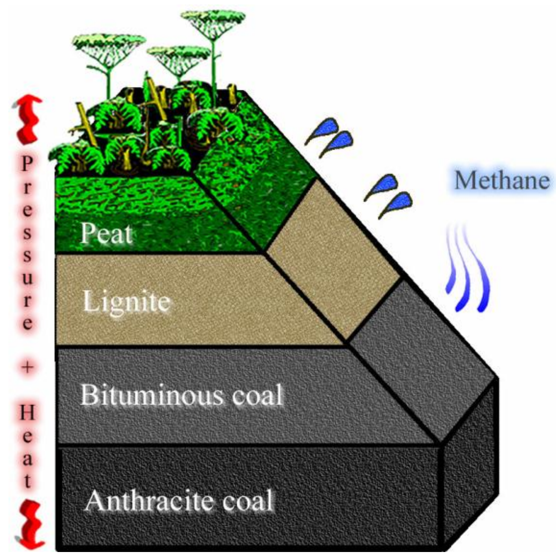


Figure 2: Gas Maturity with Depth (After Halliburton, 2008)

The amount of gas adsorbed depends on the pressure of the reservoir based on the relationship first introduced by Langmuir (1918), with gas evolving as the pressure of the system is dropped (see Appendix B). The steepness of the Langmuir isotherm at lower pressures also means the recovery factor depends on how much the reservoir pressure can be lowered. According to the Intl. Union of Pure and Applied Chemists (IUPAC), the pore structure of coal is heterogeneous and can be broadly classified into macropores (>50 nm), mesopores (2-50 nm) and micropores (< 2nm). Gan et al (1971) found that the pore system in most Eastern US coals should rather be classified into a bidisperse (bimodal) pore model system, with most pore sizes in the ranges of less than 1.2nm and greater than 30 nm. Shi and Durucan (2003) extended this and proposed that a larger volume of gas initially present in the free phase in the macropores was the only way to explain the unexpectedly high production rates from the Powder River Basin, which had coal adsorption values below what would be thought to be commercial.

The cleat structure is composed of two systems of fractures that are perpendicular to each other and to the horizontal bedding of the coal (vertical fractures). The butt cleats are shorter and connect to the more laterally extensive face cleats. (See Figure 2) Diffusion takes place from the micropores through the macropores to the cleats based on a concentration difference described by Ficks Law. Flow from the cleats/fractures to the well is described by Darcy's law (Appendix C). Fracturing the coal, using with water or cross-linked gels, is often needed to enhance productivity of the coal-gas system. Fracturing serves to bypass near wellbore/skin effects and to better connect the well to the natural cleat structure. The amount of gas adsorbed to the coal micro-pore surfaces makes up to around 90-95% of the gas in place, even though the cleats/fractures are originally often 100% saturated with water (Shi and Durucan, 2003).

The drop of pressure in the reservoir system is necessary to allow desorption of gas from the coal surface. This often means dewatering the reservoir, sometimes for a considerable time (1-3 years) or some months before gas production reaches commercial levels. This is a very important factor in determining the commercial success of a CBM project, with many operators uncomfortable with the long period of treating and disposing produced water before any economic returns.

The breakdown of pumps in artificially lifted wells due to the varying well conditions also necessitates frequent workovers. However, the commercial volumes of fully saturated CBM reservoirs could be up to 5 times those of conventional natural gas reservoirs (Marsh, 1987) with longer and more stable field lives as well as cleaner fuel (Halliburton, 2008). The potential for CO_2 storage with enhanced CBM production is also an added incentive to developing CBM as a resource.

Arri and Seidle (1990) suggested the modification of black oil simulators to model CBM reservoir behavior. Desorption of methane from coal induces shrinking of the matrix and causes the cleats/fractures to open or expand, leading to permeability increase. The adsorption of gas (injected carbon dioxide) on coal surfaces causes the reverse effect of matrix swelling leading to cleat closing, lowering the permeability (Palmer and Mansoori, 1996). Permeability changes with reservoir drawdown in CBM reservoirs were investigated by Palmer and Mansoori (1996) who proposed the formula to account for the changes in permeability as a result of changes in cleat porosity in coal bed reservoirs. Shi and Durucan (2003) suggested a matrix shrinkage factor 1.6 to 2.1 times stronger than the Palmer & Mansoori model by re-writing the equation to eliminate the porosity dependency and introduce a cleat volume compressibility term, effectively linking the permeability changes to stress changes with production. The reduction of pore pressure with production stress leads to an increase in effective stress which acts to close the cleats, in opposition to the effect of cleat opening due to methane desorption. A notable comparison study of coal bed reservoir simulators was the joint industry SPE model benchmarking project by Law et al (2002) to study the influence of CO_2/N_2/Flue gas injection for enhanced CBM production.

In addition, several economic project feasibility studies have been carried out for specific CBM fields based only on reservoir properties like porosity and permeability. A good example is the economic analysis of the Alaska CBM field project based on environmental factors and projected demand from local energy users (Petroleum Development Laboratory, University of Alaska/Alaska Department of Natural Resources, 2006).

Methodology/Model Setup

The various parts of the CBM system were setup using proprietary software of the Petroleum Experts Group. This arrangement mimics the actual field practice where the reservoir response is determined by the well and surface facilities response as all the models run at the same time. This is expected to be more realistic than running each program separately.

The Reservoir Model

This was a fully implicit numerical reservoir, with 50,000 grid blocks and full corner point gridding. A single well in the centre of a 160 acre reservoir with thickness 100 ft, and depth 4,000 ft was modeled. Original gas in place was estimated by the model at 11.5 Bcf. The diffusion of gas from the matrix to the cleats is modeled using Fick's Law while the flow from the cleats to the well is described by Darcy's equation for both water and gas phases (see Appendix C). A simple black oil fluid model with methane and water was used for the reservoir fluid. The parameters derived from the SPE joint industry collaborative project by Law et al. (2002) served to ensure conformity with accepted industry field studies (see Table 1). The effects of stress changes on permeability (Shi and Durucan 2005) and diffusivity were included in the model.

The Well and ESP Design

This was done using the parameters shown in Table 2. The well description was built to mimic the behavior of a CBM well with an electric submersible pump (with a down hole gas separator) which would be taken off stream when the gas production reached a particular flow rate or the Gas Liquid Ratio exceeded 3,000 scf/stb. During the artificial lift period, water is pumped up the tubing, while the separated gas at the bottom is produced through the casing annulus. The software capabilities allow the *same* physical well element to behave in as many ways as possible based on the operating vertical lift performance (VLP) curve. The program script can be set to switch the VLP based on a fixed date or fluid properties such as water gas ratio, gas rate or water rate. The condition for well type change was investigated for the reservoir conditions and expected flow rates and a value of a Water Gas Ratio of less than 300 STB/MMscf (Gas Liquid Ratio greater than 3,000 scf/STB) was found to be suitable for natural (unassisted) gas flow.

The Electric Submersible Pump (ESP) design parameters are shown in Table 2. The pump performance was designed for a range of 200 – 500 STB/day and an optimum efficiency of about 44% as shown in Figure 3. The ESP design was incorporated into the well vertical lift performance curve calculations to generate the curves for the dewatering stage of the CBM well.

Figure 4 shows the system plot (IPR, VLP and Pump Intake curves) for the well under ESP lift. The generation of the lift performance curves was done for a wide range of possible cases in the well. Cases were combinations of up to ten well parameters (to constitute a single well scenario). However, for this study, the parameters varied were Pump Frequency (40, 50 and 60 Hz),

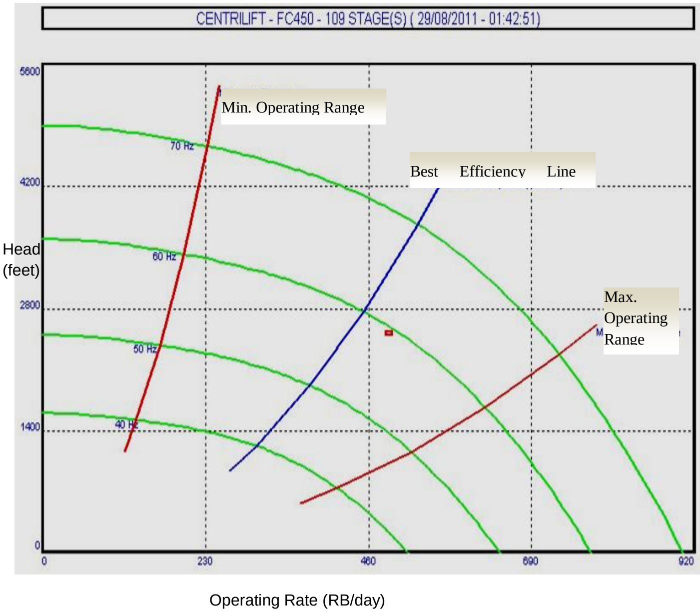


Figure 4: ESP Pump Performance Plot

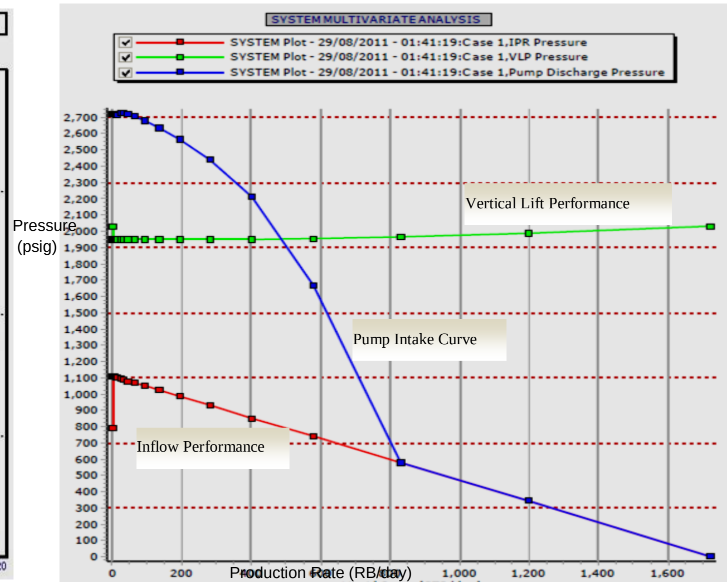


Figure 3: System Plot Showing IPR, VLP, and Pump Intake

Well Head Pressure (50 to 500 psi in 20 steps) and the Gas Liquid Ratio (0 to 1,000,000 scf/STB in 20 steps). This permutation yielded curves for 1200 cases (20 X 20 X 3) of the possible combinations of the above variations. This was the first set of VLPs that would represent the well behaviour for the artificial lift stage.

The system switch to a well under natural gas flow necessitated a separate set vertical lift performance curves. The same process was followed as for the ESP well but the frequency was fixed to 1Hz to ensure the pump did not supply head. When the changeover point is reached, the ESP is taken off and both gas and the associated water are produced up the tubing for a total well life of about 20 years. The vertical lift performance curve is switched at the same time the ESP is taken off to model the changed behavior of the well with time.

The Surface Facilities

The surface facilities provided for pressure control were the separators and pipelines for supply of gas. A plateau rate of 1.5 MMscf/d was fixed for the well to ease comparison between different cases. The well head pressure was also fixed to 100 psi. The pressure and rate limit were the limiting controls for the system simulation. The result plots are based on an easily repetitive unit of the reservoir, the well and the basic surface facilities for a development.

The Cost Model

This was built with Microsoft Excel to provide sensitivities on gas prices, development costs, and rates of return. The development costs for a new CBM field development can be as flexible as the internal operations of a company allow or as varied as the location, but generic estimates for well drilling costs and water treatment were used in this study (see Table 3). The gas price used was a net price varying from $2,000 to $6,000 per MMscf, while the water handling costs varied from $3 – 7 per STB.

Program Flow Sheet/Simulation Workflow

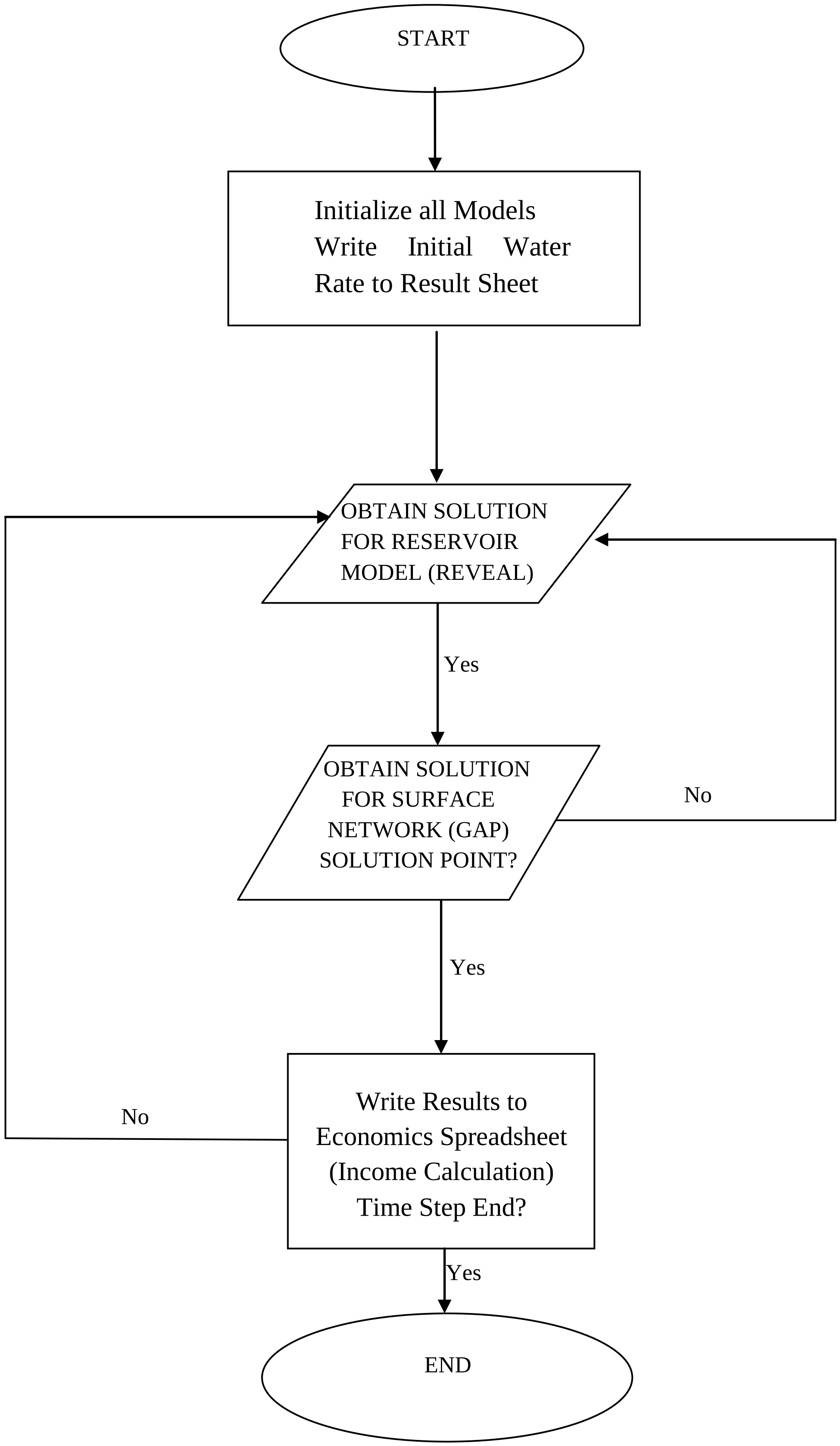


Table 1: Base Model Parameters

PROPERTY	UNIT	VALUE
Reservoir Parameters		
Porosity	fraction	0.01
Permeability	mD	3.65
Initial Pressure	psi	1,110
Reservoir Temperature	F	113
Reservoir Depth	ft	4,112 ft
Initial Water saturation	%	100
Permeability parameters (Shi/Durucan Model, 2003)		
Young's Modulus (E)	psi	421,000
Poisson's ratio (v)	fraction	0.35
Matrix Shrinkage Coefficient	μ-ft3	400
Cleat Volume Compressibility	1/psi	1×10^{-6}
Langmuir Properties		
Langmuir Pressure (P_L)	psia	680
Volume Constant (V_L)	Ton/scf	486
Water Content by Mass	fraction	0.0672
Ash Content by weight	fraction	0.156

Table 2: Well and Fluid Properties

PROPERTY	UNIT	VALUE
ESP parameters		
Depth of Pump	ft	4,000
Liquid Level (depth)	ft	3,500
Number of Stages		175
Operating Frequency	Hz	60
Design flow rate	bbl/day	500
Fluid properties		
Gas Gravity		0.6
Initial Water Cut	%	100
Water Salinity	ppm	100,000
Well Parameters		
Tubing Diameter	in	2.875
Casing Diameter	in	4.5
Wellhead Pressure	psi	100
Water Gas Ratio	STB/MMscf	40
Mechanical Skin		-5

Results and Discussion

The deterministic probability model base case used for the reservoir simulation was based on data from the SPE joint industry project (see Table 1). Variations from this standard set were used to set up other models to study the effects of changing reservoir parameters. Porosity was varied from 0.5 to 10%. Permeability was varied from 0.5 mD to 50 mD. The effect of permeability anisotropy was studied by varying the Kv/Kh ratio with values 0.1, 0.5 and 1.0 (isotropic).

The parallel simulation of the above four models (the reservoir, the wells, the surface facilities and the economic scenario) was run simultaneously for the scenarios considered using the following parameters. (See Tables 1 and 2, and the Program flow sheet in Appendix E). The software programs for simulating the reservoir, the well behaviour, the surface facilities and the output economic sensitivity sheet were all co-ordinated and optimized using a supervisory program also from the Petroleum Experts suite.

The base case was compared in various sensitivity analyses to the results obtained from varying different reservoir parameters. First the porosity was varied using values of 0.5%, 1% (Base Case), 5%, and 10%. The results (Figure 5) showed a trend towards higher production of gas from reservoirs with lower porosity. This is due to the fact that dewatering is accomplished faster (with less water in the pore spaces) and the reservoir pressure can be dropped faster than with higher porosities. Note the breaks in the graph profiles which indicate the times when the ESP is taken off the well and unassisted gas flow begins. The dewatering stage by ESP lasts for a shorter time in the case of reservoirs with low porosity.

The next sensitivity plot (Figure 6) illustrates the effect of varying permeability in a coal bed field. The values chosen to study this effect were 3.65 mD (Base Case), 0.5 mD, 10 mD and 50 mD. The expected effect was more production for higher permeability. This is highly dependent on the extent and connectivity of the fractures present naturally in the coal bed. This effect again is linked to the speed with which reservoir pressure can be dropped in a coal bed reservoir. With higher permeability and better pressure communication throughout the bed, a more uniform pressure drop was observed in the reservoir model, leading to faster gas desorption and more recovery.

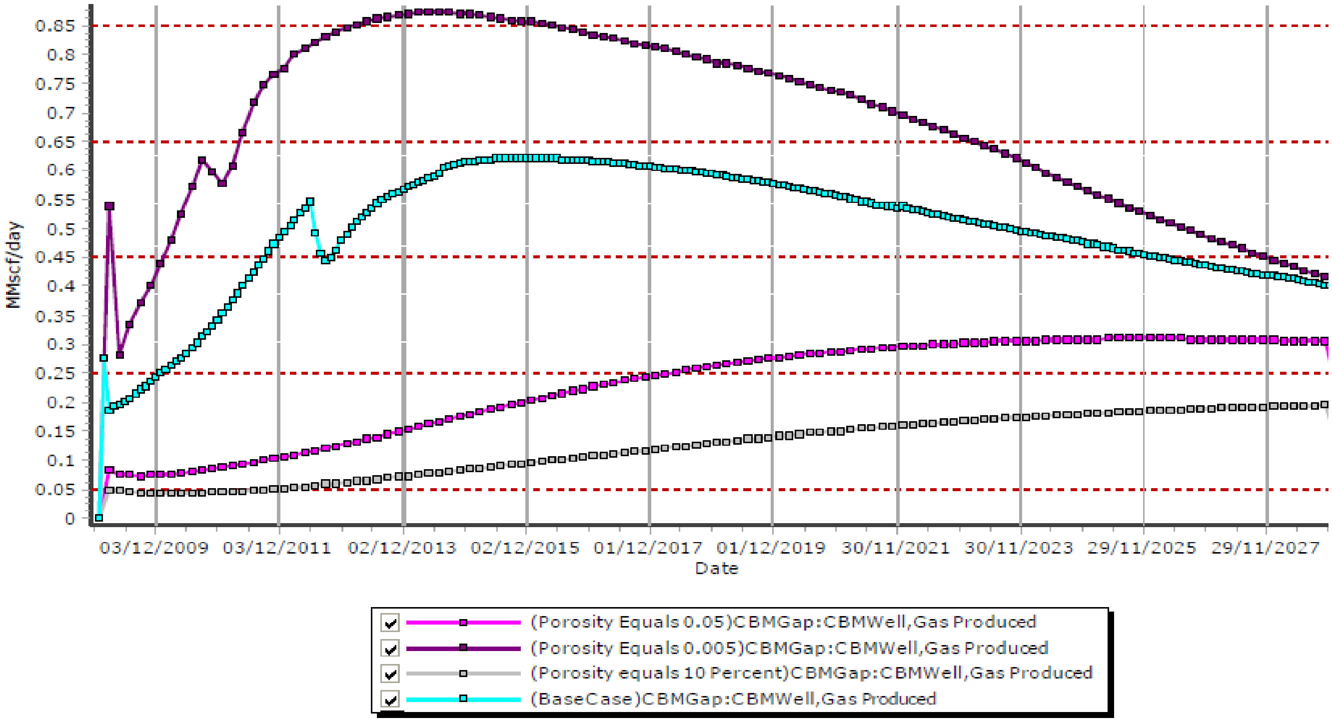


Figure 5: Gas Production Sensitivity to Porosity

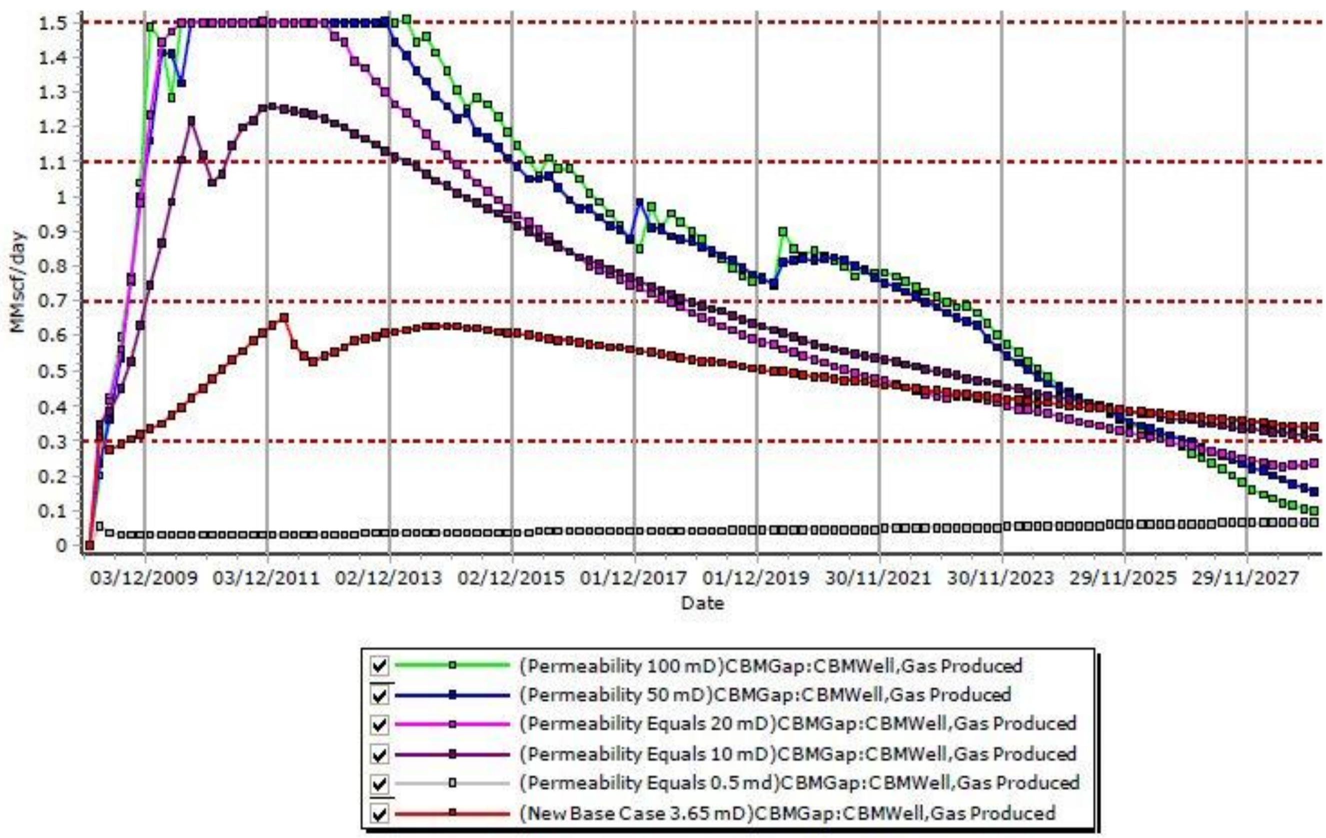


Figure 6: Gas Production Sensitivity to Permeability

An interesting observation was the higher stresses observed in tighter formations with production time. With low permeability, desorption effects concentrate around the wellbore, leading to matrix shrinkage. However the further parts of the reservoir actually become tighter as the formation adjusts to this unbalanced stress, further blocking pressure transmission and fluid communication through the fracture. This would not be overcome even by hydraulic fracturing, which serves only to overcome the near wellbore skin effects. In fact, increasing the permeability contrast between the wellbore region and further parts of the reservoir might serve to actually worsen the case for a reservoir with very low permeability. As seen in the results, a reservoir permeability of less than 1 mD (0.5 mD) would be uneconomic for development.

The effect of permeability is perhaps the strongest on the profitability of a new CBM venture. Shallow, thick coals in the Wyodak coalbeds of the Powder River Basin have been recorded as having permeability values as high as 1 Darcy (Pratt et al., 1999). Despite the low quantity of adsorbed gas in place these coals have produced commercially at better rates than coals with higher gas content in other parts of the world. The importance of the permeability of coal beds in assessing profitability of new CBM ventures is also reflected by the vast attention given it in research and literature.

The effect of varying the Kv/Kh ratio (anisotropy) is shown below. Here the higher rates were observed with isotropic formations. The quick recovery of investment with a more isotropic reservoir is shown by a peak rate which is about twice the peak rate for a reservoir with Kv/Kh ratio z = 0.1. This is crucial to the early return on investment of a CBM field development. The effects of the cumulative production by permeability and anisotropy are shown in Figures 8 and 9 respectively.

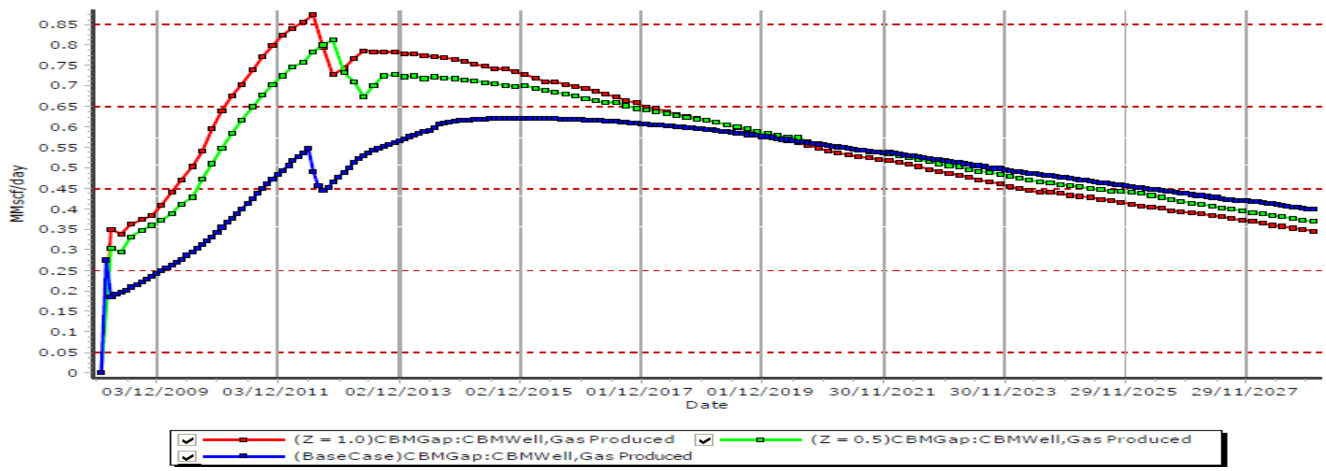
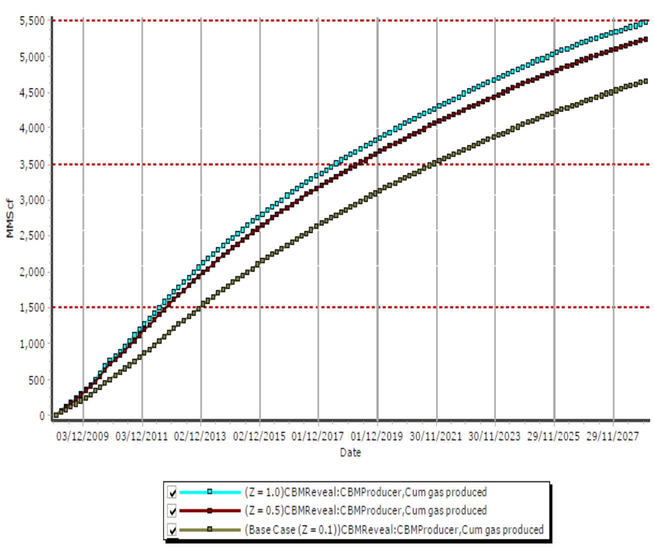


Figure 7: Effect of Anisotropy on Gas Production Rate



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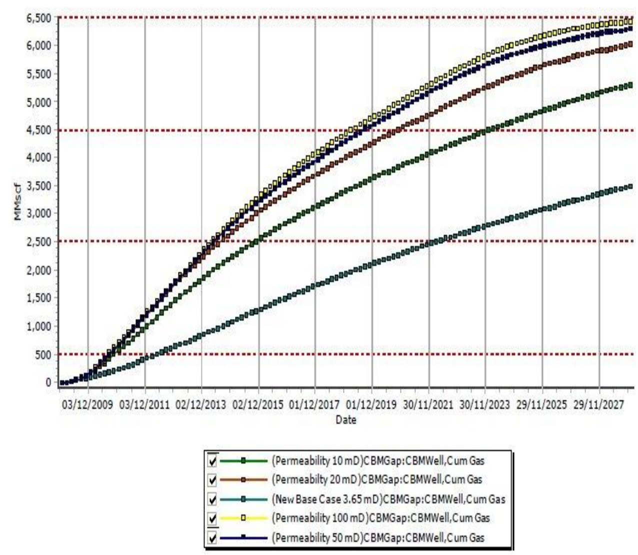

Figure 9: Effect of Anisotropy on Cumulative Production

Figure 8: Effect of Permeability on Cumulative Gas Production

Effect of Wells and Surface Facilities Coupling on Reservoir Response

The effects of the surface restraints on the reservoir production with time are shown in the next two diagrams which show the same reservoir run in a standalone mode (Figure 10), and run in the coupled mode (Figure 11) described here in this paper.

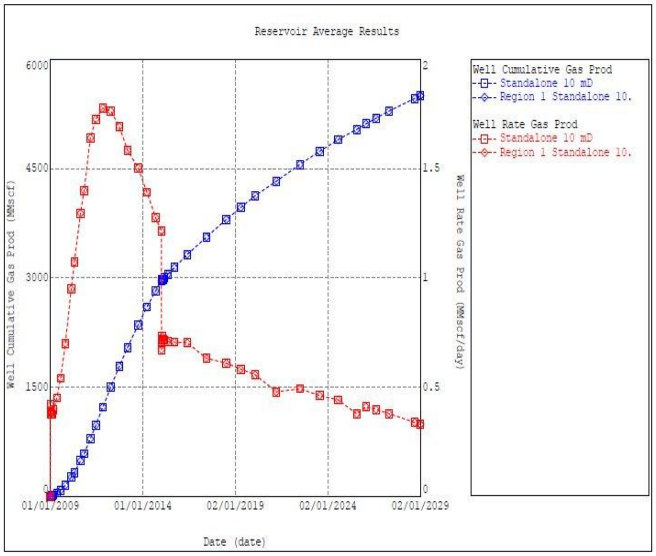

Figure 10: Gas Rates/Cum. Production for Standalone Reservoir

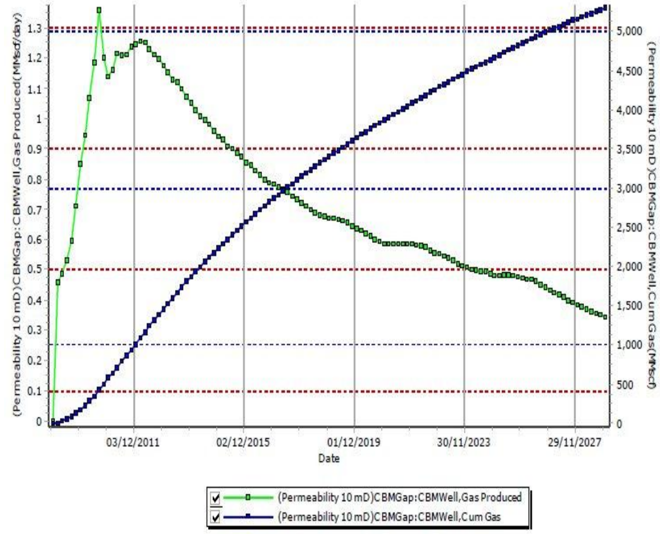

Figure 11: Gas Rates/Cum. Production for Coupled Reservoir

The results above show similar results for the cumulative gas production (5.3 Bcf for the standalone reservoir and 5.5 Bcf for the coupled reservoir). However the peak rates reached in each case are different by about 500 Mcf/d (1.75 MMscf/d for the standalone case and 1.25 MMscf/d for the coupled reservoir). This also was not due to the plateau imposed on the system, as the production maximum rate for the coupled reservoir was set at 1.5 MMscf/d, which was not even reached by the coupled reservoir. While not a hard and fast rule, the wide variation shows that the influence of the surface facilities is significant.

Other sensitivities on the fracture permeability and the coal elastic properties (Poisson ratio, Young's modulus) did not significantly affect gas production rates. Permeability rebound due to stress changes was not significant for this model (multiplier k/ko of 1.002 maximum). It is also thought that the depth of the reservoir (with high overburden stresses and less cleat compressibility) might also be a factor in explaining the relatively small changes in permeability compared with younger coal formations. The tubing size diameter was also varied in 3 steps of 2 inch, 2.875 in and 3.5 inch. These also did not significantly affect well performance (tubing head pressure control was constant at 100 psia).

Economic Results

The economic model was designed to develop scenario results for the same gas and water production profile. The cost of wells and facilities (capital and operating costs) are assumed based on the following table (Table 3) adapted for this case from Reeves (2004) and are used for generic modeling purposes. The economic spreadsheet generates revenue profiles for different gas prices, water handling costs, rates of return. The gas prices had values of $2,000/MMscf (low case), $4,000/MMscf (base case) and $6,000/MMscf (high case). The water handling costs were also given low ($3/STB), base ($5/STB) and high case ($7/STB) values. The interest rates were made to vary from a base case of 10% to 8% (for a high case) and 15% (for a low case). These values can be easily changed to study as many economic scenarios as possible based on internal company expenditure patterns. Based on this, a breakthrough gas price can be set to match the company's expected income from a new development.

Table 3: Model Capital and Operating Costs

	CAPEX	OPEX
Production Wells	$100/ft	$1,000/month
Workovers	$20/ft	n/a
Pipeline	$20,000/in-mile	$0.01/Mcf
Compression	$1500/HP	$0.30/Mcf
Pumping	$200/HP	$2/ton
Gas Processing	n/a	$0.1/Mcf

The illustrative results are shown below:

Gas Price Sensitivity

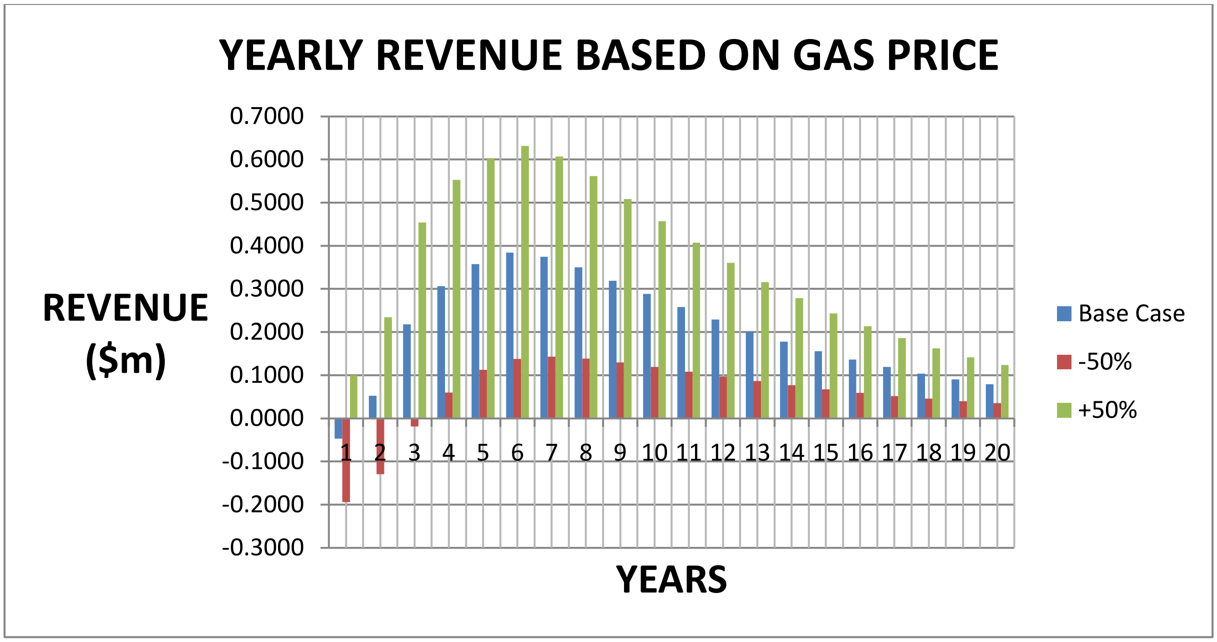

Figure 12: Yearly Revenue Based on Gas Price

From Figure 12, we see that a ±50 % change in gas price results in changes in peak revenue corresponding to ± 40 % level in revenue levels all through the life of the field. The cumulative revenue also has a resulting spread of ±75% because the effect of gas price persists throughout the life of the field (See Figure 13). The pricing of gas is the most essential factor to satisfy investment return goals. And often the availability of cheaper energy options is a deterrent for CBM field development.

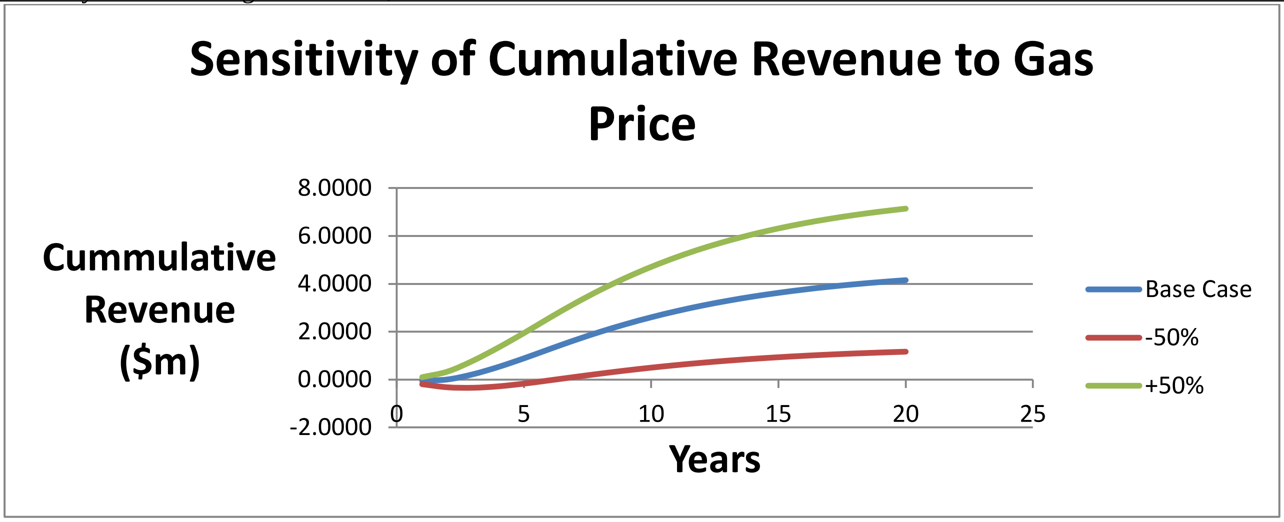

Figure 13: Sensitivity of Cumulative Revenue to Gas Price

Water Price Sensitivity

The water treatment base cost was chosen as $5 dollars per barrel. The same variation of ±50% from the base case was also applied with the following result plot shown in Figure 14.

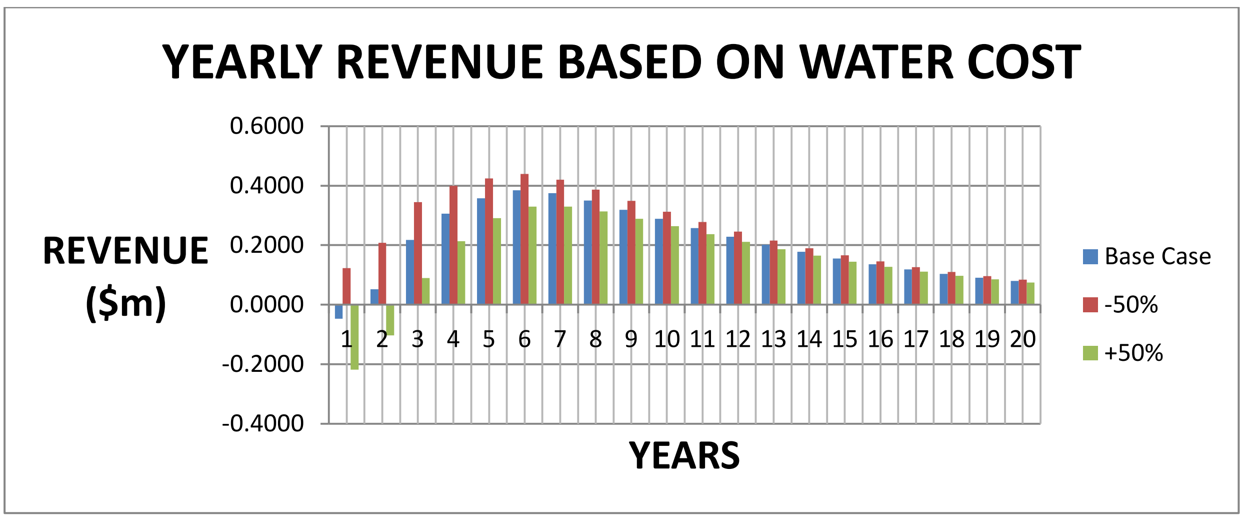

Figure 14: Yearly Revenue Based on Water Cost

As seen above in Figure 14, the variation in revenue profile as a result of varying water treatment cost is not as crucial as that for the gas price. A variation of ±50% in the water treatment cost yields a variation in peak revenue of only about ± 10 % and a 25% variation in cumulative revenue from the base case (See Figure 15). The main costs for water treatment would involve disposal wells for produced water if the water is not of sufficient quality to dispose in surface streams or treat for human use. Then the economics of large scale field development would be necessary to offset the added costs.

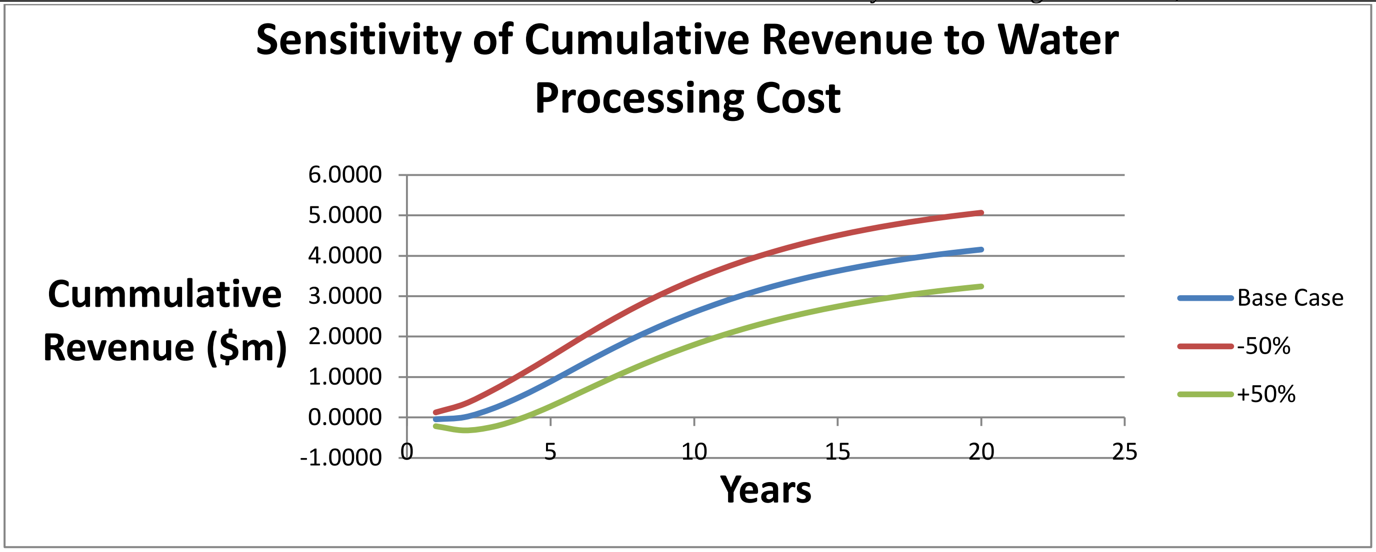

Figure 15: Sensitivity of Cumulative Revenue to Water Processing Cost

The above plots show that the economic parameter with the most effect on profit is the gas price. The plots are based on a discount rate of 10%. The ability to quickly quantify this effect and compare with different scenarios of demand and price is a key selling point of this model set up.

Table 4: NPV and IRR Calculations

Discounted Revenue Calculation

	Base Case	Base Case Less Costs	Net Present Value
	Interest Rate (%)		10
1	-51982.85	-779982.85	-709075.32
2	63233.72	39233.72	32424.56
3	289686.67	265686.67	199614.33
4	448420.79	424420.79	289885.11
5	576356.02	552356.02	342969.63
6	681006.56	657006.56	370863.07
7	730551.99	706551.99	362572.89
8	750190.93	726190.93	338773.43
9	752317.43	728317.43	308877.69
10	747721.67	723721.67	279026.03
11	735356.74	711356.74	249326.20
12	718176.78	694176.78	221186.11
13	694459.28	670459.28	194208.17
14	674501.45	650501.45	171297.36
15	648956.04	624956.04	149609.51
16	626913.77	602913.77	131211.60
17	601044.65	577044.65	114165.21
18	576688.97	552688.97	99405.97
19	554177.32	530177.32	86688.23
20	534391.63	510391.63	75866.46
Total ($m)	11.35	10.17	3.31
	IRR =	44%	

Table 4 shows the sample calculation of Net Present Value and Internal Rate of Return for the Base Case stream case. Varying the interest rate yields different NPV values, while the calculation of Internal rate of return for a particular capital expense and operating costs profile is updated automatically. The revenues calculated from the gas and water streams are fed here as inputs while the simulation runs and various values for the capital and operating costs can be tested to determine acceptable levels of risk and investment return. The example shown here is for a return rate of 10% which converts the stream of income from an undiscounted total sum of $10.2m (after costs) to a net present value of $3.3 m. The Internal Rate of Return calculated there will reduce the stream of income to a net present value of zero if used in the cell for the discount/interest rate. The interest rate could be specified as the lending rate, the company's internal benchmark for new investments, or the interest rate for a competing investment option in the company.

Conclusion

The following conclusions arise from the work:

- The successful integration of reservoir, well, and surface facilities has been demonstrated.
- The results show the dependence of production performance not only on reservoir properties like porosity, permeability and anisotropy, but also on the well design and constraints on pressure and rate at the surface.
- The economic value of a new CBM development depends on representative values for porosity, permeability and anisotropy on the reservoir level. Lower porosity values give higher recoveries due to less water produced and faster reservoir pressure depletion. Higher permeability values are needed for higher gas recovery factors due to the more uniform pressure depletion across the reservoir, as well as the cleat opening due to desorption
- The addition of a flexible economic add-on for instant production data capture and analysis has also been demonstrated as a valuable quick evaluation tool, used for decision making using net present value and internal rate of return.
- Anisotropy can delay the rate at which gas is recovered. Cleat directional permeability is important in evaluating investment returns in new CBM projects.
- Coal permeability change effects were minimal for this model but could be significant in shallow reservoirs with higher cleat compressibility and in situ permeability
- Tubing size and water handling costs had lower effects on the final cumulative revenue than expected.

The results are scalable based on internal company needs and field size and will be useful for an integrated quick look CBM project evaluation.

Further Work Recommended

Time pressures prevented the study of the following aspects of CBM field development.

The utility of coal beds as storage sites for CO_2 storage is second only to saline aquifers. The models for describing the sweep and sorption of CO_2 in coal beds have been tested only to a limited extent. The interaction of CO_2 with coal beds and with connate water as well as matrix swelling due to CO_2 sorption have been thought to be responsible for the slow diffusion of CO_2 through coal beds in attempted enhanced CBM recovery. Further experimental work on quantifying the swelling effects of CO_2 or multigas sorption on core lab samples will also have to be done to ascertain the actual contribution of multigas sorption and desorption with production time.

The effect of well spacing and interference between wells is another aspect of field evaluation to be investigated in further work. The extension of this work to study horizontal wells is also a necessary step.

The use of progressive cavity pumps instead of electric submersible pumps is also a strong economic boost to CBM fields with low productivity potential.

Acknowledgments

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Nomenclature

Bbl/d = Barrels per day
BHP = Bottom Hole Pressure
CBM = Coal Bed Methane
ESP = Electric Submersible Pump
Ft. = Feet
HP = Horsepower
IPR = Inflow Performance Relationship
IRR = Internal Rate of Return
K = Permeability
Ko = Original Permeability
mD = millidarcy
Mscf/d = Thousand standard cubic feet per day
MMscf/d = Million standard Cubic feet per day
NPV = Net Present Value
STB = Stock Tank Barrels
VLP = Vertical Lift Performance

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Appendix A
Milestones in CBM modeling and Critical Literature Review

Author	Paper No.	Year	Paper Title	Major Contribution
Langmuir, I.	Journal of the American Chemical Society Vol. 40	1918	The Adsorption of Gases on Plane Surface of Glass, Mica and Platinum	Established the Isotherm relationship for predicting the Adsorptive capacity of gases on solids
King, G.R., Ertekin T. and Schwerer F.C., 1986	SPE 12258	1986	Numerical Simulation of the Transient Behavior of Coal Seam Degasification Wells	Numerical Simulation of CBM reservoirs introduced
Seidle J.P. & Arri, L.E.	PETSOC-90-118	1990	Use of Conventional Reservoir Models for Coalbed Methane Simulation	Suggested the use of black oil models for CBM modeling
Anbarci, K and Ertekin T.	SPE 20568	1990	A Comprehensive Study of Pressure Transient Analysis with Sorption Phenomena for Single-Phase Gas Flow in Coal Seams	Developed solutions to the diffusivity equation applied to CBM reservoirs for pressure transient analysis.
Sawyer W.K. et al.	PETSOC-90-119	1990	Development and Application of a 3D Coalbed Simulator	Developed a Simulator exclusively for CBM modeling
Stevenson, M.D et al.	SPE 23026	1991	Adsorption/Desorption of Multicomponent Gas Mixtures at In-Seam Conditions	First investigated the sorption/desorption properties of CO_2, Nitrogen and Methane in Coal
King, G.R.	SPE 20730	1993	Material balance Techniques for Coal-Seam and Devonian Shale Gas Reservoirs with Limited Water Influx	Application of material balance to Coalbed Methane recovery
Palmer I. and Mansoori J.	SPE 36737	1996	How Permeability Depends on Stress and Pore Pressure in Coalbeds: A New Model	Developed the formula for the change in permeability with changes in effective stress
Law, D.H.-S. et al.	SPE 75669	2002	Numerical Simulator Comparison Study for Enhanced Coalbed Methane Recovery Processes	Established an industry benchmark for comparing commercial CBM simulators
Simpson, D.A et al.	SPE 80900	2003	Coal Bed Methane Production	Insightful comparative analysis of the artificial lift options for CBM production
Shi, J-Q and Durucan, S.	SPE 87230	2003	A Model for Changes in Coalbed Permeability During Primary and Enhanced Methane Recovery	Decoupled the permeability change formula from porosity and introduced the cleat compressibility term
Shedid, A.S. and Rahman, K.	SPE 120003	2009	Experimental Investigations of Stress-Dependent Petrophysical Properties and Reservoir Characterization of CBM	Investigated the change in Petrophysical properties of Coal with change in stress.

Journal of the American Chemical Society Vol. 40 **(1918)**

The Adsorption of Gases on Mica, Glass and Platinum

Author: Irving Langmuir

Contribution to the understanding of CBM Modeling

Langmuir presented the theoretical basis of adsorption of gases on solid plane surfaces (mica, glass and platinum). His formula is the basis for describing the adsorption of methane on coal surfaces. It has been verified by numerous laboratory experiments and field studies for over 90 years

Objective of the paper:

To develop from first principles, a formula for quantifying the amount of gas adsorbed onto a solid surface with respect to pressure at a constant temperature.

Methodology used:

- Derivation of formulae using assumptions from Van der Waal and Braggs
- Experimental measurement of the amount of different gases adsorbed on mica, glass and platinum.

Conclusion reached:

The amount of gas adsorbed on a plane solid surface can be represented by the general formula:

$$V_e = V_L \frac{bP}{1 + bP}$$

Where V_e = the volume of gas adsorbed, scf/ton or scf/ft^3

V_L = maximum volume adsorbed on the coal, scf/ton or scf/ft^3

b = Langmuir constant (inverse of Langmuir pressure P_L), 1/psi

P = Reservoir pressure, psig

The various assumptions used in this theory are

1. The adsorbed gas forms a layer one molecule thick
2. The same adsorption sites are equally available for adsorption by different species of gas molecules
3. The adsorption is on an open surface and there is no restriction of access to the surface for the gas molecules.
4. The adsorbed molecule does not affect another molecule on a nearby adsorption site.

Comments:

Though widely seen as thermodynamically inconsistent, the agreement with field and experimental data is overwhelming. The assumptions are not all correct (for instance, in tortuous pore paths of coal beds) but they work well in practice.

SPE 12258-PA (1986)
Numerical Simulation of the Transient Behavior of Coal Seam Degasification Wells

Authors: King, G.R., Ertekin T. and Schwerer F.C.

Contribution to the understanding of CBM Modeling

Numerical Simulation of CBM reservoirs introduced

Objective of the paper:

To present a solution for the finite difference equations describing the flow of water and gas through coal beds during coal degasification for unstimulated and fractured coal bed reservoirs

Methodology used:

- The discretization of differential equations representing flow of gas and water in the macropore/cleat system using finite difference methods resulting in 5 algebraic equations with five unknowns
- The reduction of these equations to 2 non-linear equations with unknowns
- The solution of these two equations using the fully implicit, generalized Newton-Raphson procedure

Conclusion reached:

- A non-equilibrium diffusion/sorption model was developed for the flow of gas and water through dual porosity coal seams similar to the Warren and Root solution. The model was also history matched against field examples.
- In hydraulically fractured reservoirs, fractures with dimensionless finite conductivity higher than 100 behave as infinitely conductive fractures.
- The solution does not adequately account for the sorption effects of gas
- The negative decline of gas production when both water and gas are flowing can be predicted by the model

Comments:

The development of this model was the first attempt at modeling a CBM reservoir numerically.

PETSOC-90-118 (1990)

Use of Conventional Reservoir Models for Coal bed Methane Simulation

Authors: Seidle J.P. & Arri L.E.

Contribution to the understanding of CBM Modeling

The paper simplified the modeling of CBM reservoirs by suggesting a modification of balck oil simulators for use in modeling CBM reservoirs.

Objective of the paper:

To demonstrate that coal bed reservoirs could be satisfactorily modeled by conventional black oil reservoir models

Methodology used:

- Material balance using a black oil model
- Comparison with a commercial CBM reservoir simulator: COMETPC

Conclusion reached:

1. Coal Bed reservoirs can be satisfactorily modeled in most cases using Black oil simulators
2. The peak rate and time of reaching it depend on how fast desorption from the coal surface is assumed to occur
3. More flexibility with gridding and refinement was available with the black oil model than with the CBM simulator

Comments:

The assumption that the rate of desorption from the coal is instantaneous is erroneous. Also the permeability variations with effective pressure make gas desorption rates difficult to average over the entire reservoir being considered. However, this method has been used as a quick and easy means of modeling CBM reservoirs since it was introduced.

PETSOC-90-119 (1990)

Development and Application of a 3D Coalbed Simulator

Authors: Sawyer W.K. et al.

Contribution to the understanding of CBM Modeling

This rebutted the idea by Seidle and Arri that CBM reservoirs could be modeled using conventional black oil simulators. The authors also applied the King unsteady state model formulation as well as diffusion through coal beds to the simulator.

Objective of the paper:

To demonstrate the simulation of methane production from coal bed reservoirs using a dedicated modeling program/software for coal.

Methodology used:

Application of the King's unsteady state model, accounting for the effect of desorption from the coal surfaces.

Conclusion reached:

A simulator for modeling methane production from coal beds was developed and tested against other CBM simulators. The effects of desorption, diffusion, matrix permeability change, 3D flow and gravity segregation were incorporated.

Comments:

This paper documented a successful attempt at modeling CBM reservoirs using the available knowledge at that time.

SPE 20568 (1990)

A Comprehensive Study of Pressure Transient Analysis with Sorption Phenomena for Single-Phase Gas Flow in Coal Seams

Authors: Anbarci, K and Ertekin T.

Contribution to the understanding of CBM Modeling

Developed solutions to the diffusivity equation applied to CBM reservoirs for pressure transient analysis.

Objective of the paper:

To develop specialized solutions for pressure transient analysis in CBM reservoirs

Methodology used:

Approximate analytic solutions/inversions from the Laplace domain of the transport equations for gas and water in coal seams

Conclusion reached:

Solutions were developed for the radial/cylindrical coal bed reservoirs with constant pressure or constant rate at the wellbore and three different reservoir/outer boundary conditions: infinite acting reservoir, finite with constant pressure at boundary, and finite with constant rate at the boundary.

Comments:

The authors attempted to discount the effects of numerical inversion of Laplace formulations of the fluid transport equations. The developed method is less friendly to CBM reservoir simulators

SPE 23026 (1991)

Adsorption/Desorption of Multicomponent Gas Mixtures at In-Seam Conditions

Authors: Stevenson, M.D et al

Contribution to the understanding of CBM Modeling

First investigated the sorption/desorption properties of CO2, Nitrogen and Methane in Coal

Objective of the paper:

To test the applicability of models based on adsorbate solution theory to coal gas reservoirs

Methodology used:

Experimental measurement of adsorption onto coal of CH_4, CO_2 and N_2 in isolation and in multicomponent systems

Conclusion reached:

1. Adsorption isotherms differ widely for the gases used in the experiment. Total adsorption depends on the composition and system pressure.
2. The Ideal Adsorbate Solution is generally applicable in many coalbed gas applications
3. The Real Adsorbate Solution (RAS) fails to predict binary and ternary equilibria data for higher pressures due to inability to correctly predict the adsorbate activity coefficients at high pressures.

Comments:

Landmark paper which experimentally investigated the validity of various adsorption models proposed at the time.

SPE 20730-PA (1993)

Material balance Techniques for Coal-Seam and Devonian Shale Gas Reservoirs with Limited Water Influx

Authors: King, G.R.

Contribution to the understanding of CBM Modeling

Modified the Material Balance equation for coal bed reservoirs by including the adsorbed gas effect

Objective of the paper:

To develop two material balance methods applicable to CBM reservoirs: one for estimating gas in place and the other for predicting reservoir behaviour

Methodology used:

Modification of the existing Schilthius material balance equation

Conclusions reached:

1. Material balance techniques can be applied to unconventional gas reservoirs.
2. A p/z method was developed to analyse non-volumetric gas reservoirs.
3. The material balance method can also predict the negative decline experienced in gas reservoirs.
4. Results agreed with those of a finite difference simulator

Comments:

The paper introduced the interesting application for field studies and validation of numerical simulators. The author of this paper also used a material balance method to verify results obtained from numerical simulation results.

SPE 36737 (1996)

How Permeability Depends on Stress and Pore Pressure in Coalbeds: A New Model

Authors: Palmer I. and Mansoori J.

Contribution to the understanding of CBM Modeling
Introduced an equation to describe the changes of permeability with changes in reservoir pressure

Objective of the paper:
To develop an equation for permeability change in coal beds based on changes in reservoir pressure.

Methodology used:
Theoretical formulation and history matching with well behavior

Conclusion reached:

1. Matrix shrinkage and pore volume compressibility effects were modeled not as a constant, but as a function of pressure drawdown during production.
2. If matrix shrinkage is ignored, pore volume compressibility can be fully formulated in terms of poroelastic properties
3. The resulting formula is valid only for small changes in porosity (less than 30%)
4. Pore volume compressibility is largely dependent on the large scale reservoir porosity and bulk modulus

Comments:
The formula here is an industry standard or basis for describing permeability changes with reservoir pressure and matrix shrinkage.

SPE 75669 (2002)

Numerical Simulator Comparison Study for Enhanced Coalbed Methane Recovery Processes

Authors: Law, D.H.-S., Gunter, W.D., and van der Meer, L.G.H.

Contribution to the understanding of CBM Modeling

Established an industry benchmark for harmonizing various commercial simulators in industry

Objective of the paper:

To exercise the various problems of enhanced CBM recovery and to identify areas of improvement for existing commercial simulators of the ECBM process

Methodology used:

- Use of generic data to generate a CBM reservoir
- Create test problems, e.g., Pure CO2 injection or flue gas injection
- Run parallel simulations of the available simulators to identify and analyse the differences

Conclusion reached:

The relative agreement between the simulators on basic modeling problems provided reasonable confidence in the capabilities of commercially available simulators.

Comments:

Landmark/Benchmark study of Enhanced CBM recovery simulation.

SPE 80900 (2003)
Coal Bed Methane Production

Authors: Simpson, D.A., Lea J.F., and Cox, J.C.

Contribution to the understanding of CBM Modeling
Comparative analysis of the various artificial lift options available for low pressure operations in CBM wells

Objective of the paper:
To address design considerations for low pressure and artificial lift operations in CBM wells.

Methodology used:
Analysis of required minimum net positive suction head and failure modes for different artificial lift options

Conclusion reached:
Summary table of the various artificial lift options, their design rates, net positive suction head and failure modes

Comments:
The author provided insight into an often overlooked factor in CBM field evaluation: namely problematic dewatering artificial lift options.

SPE 87230 (2003)

A Model for Changes in Coalbed Permeability During Primary and Enhanced Methane Recovery

Authors: Shi J-Q. and Durucan S.

Contribution to the understanding of CBM Modeling

Decoupled the permeability change formula from porosity and introduced the cleat compressibility term

Objective of the paper:

To more accurately describe the permeability change in coal bed reservoirs with changes in effective stress

Methodology used:

- Theoretical formulation of new permeability formula by relating volumetric matrix strain directly to the amount of gas desorbed
- Validation against a published permeability curve for the San Juan Basin
- History matching with an ECBM project in Alberta, Canada

Conclusion reached:

1. A successful match with the permeability curves of the San Juan Basin below 800 psi was achieved
2. A successful history match with the field project in Alberta Canada was achieved
3. Knowledge of the sorption effects of the produced methane and injected CO_2/N_2 gas in ECBM projects is important to understand the changes that might occur in different parts of the reservoir.

Comments:

The effects of uniaxial stress are yet to be studied to ensure the applicability of this permeability formula in horizontal wells where the uniaxial stress may not be constant. This formula is also an industry recognized alternative to the Palmer and Mansoori model.

SPE 120003 (2009)

Experimental Investigations of Stress-Dependent Petrophysical Properties and Reservoir Characterization of CBM

Authors: Shedid, A.S. and Rahman, K

Contribution to the understanding of CBM Modeling

Experimentally investigated the change in Petrophysical properties of Coal with change in stress

Objective of the paper:

To develop more representative equations for the change in permeability with reservoir parameters for different coals with varying permeability values.

Methodology used:

- Experimental measurement of the porosity, permeability and reservoir quality index for different coal core samples
- Fitting a line of best fit to the resulting data for the relationship between
    - Porosity and stress
    - Permeability and stress
    - Permeability/porosity ratio (k/ k_o) and stress
    - Reservoir Quality index and stress

Conclusions reached:

1. The stress changes in the reservoir have an appreciable effect on the porosity, permeability, k/k_o ratio, reservoir quality index (RQI) and new correlations were developed for these.
2. The effects of changes in net stress are more noticeable in low permeability coal bed reservoirs than in high permeability coals. The water saturation shift is also higher in relative permeability curves of low permeability reservoirs

Comments:

The results were encouraging and are yet to be validated with history matching with field data.

Appendix B

Theory of Adsorption

The Langmuir theory of adsorption of gases on solid surfaces was first postulated in 1918 by Langmuir. The formula is derived in the original paper for different gases on mica, glass and platinum. The formula is

$$V_e = V_L \frac{bP}{1+bP} \tag{B-1}$$

Where V_e = the volume of gas adsorbed, scf/ton or scf/ft^3
V_L = maximum volume adsorbed on the coal, scf/ton or scf/ft^3
b = Langmuir constant (inverse of Langmuir pressure P_L), 1/psi
P = Reservoir pressure, psig

The relationship was developed using the following assumptions:

1. The gas molecules form a layer one molecule thick
2. The gas molecules compete with other molecules which may be present for the same adsorption sites
3. The temperature is constant (isothermal)
4. Adsorption is on an open surface and no restriction to gas adsorption sites exists.

The assumption that the layer is monomolecular is not strictly true but with the tortuosity of pore throats, the resulting forces on external molecules act to mimic the monomolecular layer.
The constant b is derived from measurements of gas desorbed at different pressures in the core lab to measure the relationship between V_e and P. To do this the Langmuir equation is rearranged to present:

$$\frac{P}{V_e} = \frac{1}{bV_L} + \frac{P}{V_L} \tag{B-2}$$

When $\frac{P}{V_e}$ is plotted against P, the slope of the graph gives the inverse of the maximum volume capacity $1/V_L$ while the intercept gives $\frac{1}{bV_L}$. Once b and V_L are obtained, then the rest of the curve can easily be constructed.

The resulting graph looks like this:

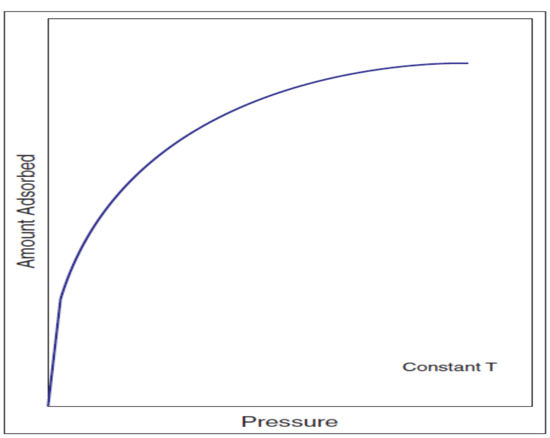

Figure 16: Langmuir Isotherm (After Brunaeur 1938)

It can be seen that the curve is often steeper towards the lower pressures. The implication is that recovery strongly depends on how low the reservoir pressure can be dropped. Sometimes operators are half heartedly preparing to abandon wells, when production suddenly surges with a new lease of life! Reducing bottom hole pressures as low as possible often requires surface compression, depending on the reservoir pressure, to meet customer requirements. These added costs must be offset by the extra value of produced gas.
The Langmuir theory of adsorption is not thermodynamically rigorous, but it shows a surprising agreement with field operators' experiences so far. In the case of multigas systems, the extended Langmuir theory of adsorption is used.

The Extended Langmuir Theory
In the case of multigas systems, the Langmuir theory is extended to give

$$V_i = \frac{(V_{max,i})B_i P_i}{1 + \sum_{j=1}^{n} B_j P_j} \qquad \text{(B-3)}$$

Where V_i = Volume of gas adsorbed of component i, scf/ton or scf/ft^3
$V_{max,i}$ = Maximum possible adsorbed gas of component i, scf/ton or scf/ft^3
B_i, B_j = Langmuir constant of component i, 1/psi
n = total number of gas components
$P_{i,}P_j$ = Pressure of gas component i

The Extended Langmuir theory is used for multigas sorption applications, like where the initial gas composition of the reservoir contains substantial amounts of CO_2 or in enhanced coalbed methane recovery applications (ECBM).

The Ideal Adsorbate Solution
A more thermodynamically rigorous formulation to model the adsorption of gas onto coal using the fugacity was put forward by Myers and Prausnitz (1965). It states that the fugacity of a component in the gas phase must be equal to the fugacity of the same component in the liquid phase for a system to be in equilibrium. It is analogous to the Raoult's Law for bulk solutions (the vapour pressure of a component being equal to the saturation pressure of the liquid at that temperature). It assumes ideal behavior in the gas phase and the adsorbed phase and results in the following equation:

$$y_i P_i^0 = x_i P_i(\pi) \qquad \text{(B-4)}$$

Where $P_i^0$is the vapor pressure of the pure component adsorbed at the same temperature and spreading pressure π as the solution. The spreading pressure for the pure components is defined by the integral:

$$\pi_i^* = \frac{\pi_i A}{R_g T} = \int_0^{P_i^0} \frac{n(P)}{P} dP \qquad \text{(B-5)}$$

where n(P) is the pure component adsorption isotherm. The spreading pressure π is defined as the reduction in surface tension of a surface due to the spreading of the adsorbate over the surface (Ruthven, 1984). At equilibrium, the spreading pressure P_i^0 evaluated for each component at the corresponding reference pressure must be equal.

Thus, for a n component mixture, this equilibrium relation is given as

$$\pi_i^* = \frac{\pi_i A}{R_g T} = \int_0^{P_1^0} \frac{n(P_1)}{P_1} dP_1 = \int_0^{P_2^0} \frac{n(P_2)}{P_2} dP_2 = \int_0^{P_i^0} \frac{n(P_3)}{P_3} dP_3 = \cdots = \int_0^{P_n^0} \frac{n(P_n)}{P_n} dP_n \tag{B-6}$$

Where n is the specific amount adsorbed. The total amount of adsorbed gas in the mixture (for an ideal solution) is given by summing all the individual integrals for the components in the system.

$$\frac{1}{n_t} = \sum_{i=1}^{n} \frac{X_i}{n_i^0} \tag{B-7}$$

The actual amount of each component adsorbed in the mixture is given by

$$n_i = n_t x_i \tag{B-8}$$

Where n_i is the number of moles of the component
n_t is the total number of moles of components in the system
x_i is the mole fraction of the component

The IAS theory is thermodynamically consistent and takes into account the intermolecular interaction in a multicomponent sorption domain. Unlike the ELM, the IAS adsorption isotherm is sensitive to changes in concentration and pressure (i.e. separation factor is not constant) so the values of these have to be predicted fairly accurately.

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Appendix C

Diffusion and Fluid Transport Processes in Coal

Methane is adsorbed to the surface of coal in underground formations. The reduction of reservoir pressure causes desorption to occur, producing gas which is produced along with the water originally present in the pores. The process by which gas desorbed from coal surfaces (in the micropores) reaches the macropores or cleats is known as diffusion and is controlled/described by Fick's Law of diffusion. This law describes a concentration gradient as being the driving force for the flow of gas molecules according to the following formula:

$$\frac{m_g}{A} = -MD_i \nabla C_i \qquad \text{(C-1)}$$

Where m_g is the mass flow rate of gas lbm/day or kg/day

A is the area in sq. ft.

M is the molecular weight

D_i Is the micropore diffusion coefficient in sq. ft/day

∇C_i Is the molar concentration gradient

In terms of simple volumes and well flow rates, the gas flow rate in scf/ton is given by:

$$q_d = \frac{dV}{dt} = -\frac{1}{\tau}[V - V_e(P)] \qquad \text{(C-2)}$$

The V term is the amount of gas still adsorbed on the coal surface, while the $V_e(P)$ term is the volume of gas in the cleats calculated by the Langmuir formula (see Appendix B).

The diffusion time constant τ (also known as the sorption time) describes how long it takes for the desorbed gas to diffuse to the macropores/cleat structure. τ is given by

$$\tau = \frac{1}{aD} \qquad \text{(C-3)}$$

Where a is the Warren and Root's shape factor
D is the diffusion coefficient

Once the gas diffuses to the the cleats or fractures, the gas and water both flow towards the wells by Darcy flow. The equations for each phase are written in terms of saturation, after Shi and Durucan (2008) as:

$$\frac{\delta}{\delta t}\left(\frac{\emptyset S_w}{B_w}\right) = \nabla\left[\frac{kk_{rw}}{\mu_w B_w}(\nabla P_w + y_w \nabla d)\right] - q_w \qquad \text{(C-4)}$$

Similarly for gas,

$$\frac{\boldsymbol{\delta}}{\boldsymbol{\delta t}}\left(\frac{\emptyset \boldsymbol{S_g}}{\boldsymbol{B_g}}\right) = \boldsymbol{\nabla}\left[\frac{kk_{rg}}{\mu_g B_g}\left(\nabla P_g + y_g \nabla d\right)\right] - \boldsymbol{q_g} + \boldsymbol{q_d} \tag{C-5}$$

The terms in the formula above are

$\emptyset$ = Porosity

$\boldsymbol{S_w}, \boldsymbol{S_g}$ = Water and Gas saturations respectively

$\boldsymbol{B_w}, \boldsymbol{B_g}$ = Water and Gas formation volume factors

k_{rw}, k_{rg} = Water and Gas relative permeability respectively

K = absolute permeability

μ_w, μ_g = viscosity of water and gas respectively

$\nabla P_w, \nabla P_g$ = pressure gradients in water and gas phases

The above formulations are standard in modern CBM simulators and are adapted from Shi and Durucan (2008).

References

Shi J-Q. and Durucan S.: "Modeling of Mixed-Gas Adsorption and Diffusion in Coalbed Reservoirs" Paper SPE 114197 presented at the 2008 SPE Unconventional Reservoirs Conference, Keystone, Colorado, U.S.A., February 10-12.

Appendix D

IPR Method in Multiphase CBM production

The Petroleum Experts method of calculating IPR for multiphase flow is to calculate the PI for the main fluid flowing at test conditions and use the constant term to calculate the flow rate of the other phase at other stages using the relative permeability curves.

The equations for the flow of each of the phases is given by

$$Q_w = \frac{KK_{rw}hdP}{141.2\mu_w B_w \left[\ln\frac{r_e}{r_w} - \frac{3}{4} + S\right]} \quad \text{(D-1)}$$

$$Q_g = \frac{KK_{rg}hdP}{141.2\mu_g B_g \left[\ln\frac{r_e}{r_w} - \frac{3}{4} + S\right]} \quad \text{(D-2)}$$

for water (w) and gas (g) respectively.

For a CBM well at the start of production, the common term among the two phases is calculated from Q_w/dP, since water is the dominant phase at an assumed end point saturation of 100%. Krw is at the maximum value. Using known values of μ_w and B_w at the test conditions, the term calculated as a constant is

$$\frac{Kh}{\left[\ln\frac{r_e}{r_w} - \frac{3}{4} + S\right]} \quad \text{(D-3)}$$

Whenever the IPR needs to calculated at an operating point, the above term is used with the relative permeability of that fluid to calculate the production rate. The same well can then be used to model a water well and then a gas well with time, simply by the change of the relative permeability with production. The well design is done in two stages: one for a water well and the gas well stage. The changing well conditions are the trigger in the program to change the vertical lift performance of the well from a water well to a gas well.