ABSTRACT

Typically, gas content of coals in Illinois Basin is low and desorption time high, leading to low gas production rates. Furthermore, recovered gas contains high concentrations of nitrogen, resulting in poor quality gas. These unique characteristics of coals have been deterrents to rapid growth of this resource in the State. The proposed study was, therefore, aimed at working closely with the coalbed methane (CBM) producers in Illinois in order to develop and test a means to model and predict the quality of CBM and variations in coal permeability, the former affecting the sellability of gas and latter impacting gas production rates.

Since nitrogen desorbs preferentially in a methane/nitrogen environment, it was believed that the quality of recovered CBM would improve with continued production. Hence, sorption isotherms for pure methane and nitrogen were established, and the results were used to develop a theoretical isotherm for a binary methane/nitrogen mixture. This was followed by establishing isotherms for the binary mixture. The modeled and experimental isotherms were compared and found to be in excellent agreement. It was also found that the concentration of nitrogen goes down with continued production. However, the decline was found to be slow and not significant to meet the pipeline requirements, suggesting that nitrogen rejection units would be required for a fairly long period of time after CBM production commences.

In order to project production rates, a permeability ‘trend’ over time was established in the laboratory by replicating in situ conditions accurately and measuring the permeability variation using core from a CBM operation in Illinois. A similar trend was also established for core from the San Juan Basin. The two trends were similar below ~450 psi, which is the upper limit of gas pressures encountered in Illinois. There was a continuous increase in permeability suggesting that the flowrate would improve with continued production. A comparison with the field permeability trend in the San Juan Basin confirmed this. This is a very positive finding for CBM production in Illinois.

Finally, integrating the laboratory measurements and field parameters obtained for a CBM producing field in Illinois, gas production simulation exercises were carried out. The results showed that gas production rates improved although did not compare with other US basins. Also, the actual improvement would depend on the variation in diffusion behavior of coal with continued production. Finally, the simulation results showed that concentration of nitrogen in the recovered gas would decline after approximately four years of production.
EXECUTIVE SUMMARY

The overall objective of the proposed research was to enhance and support the development of coalbed methane (CBM) operations in Illinois. The study was based on the experience and observations of CBM operators in the State. Two issues that have kept this resource from growing in Illinois, at a pace as rapid as has occurred in other basins, are the gas ‘quality’ and production rates. First, the recovered gas has high concentrations of nitrogen, up to 20%, resulting in produced gas that does not meet the pipeline requirements. Second, a long period of dewatering is necessary prior to gas production due to coals being under-saturated and, when the reservoir starts producing gas, production rates are typically low. The specific objectives of the proposed study, therefore, were to carry out a laboratory and numerical investigation that would enable projecting gas quality and production rates from CBM reservoirs in Illinois.

At the time this study started, it was believed that both the problems mentioned above would improve with time. The basis for this was the experience and observations in the San Juan Basin, which is currently the most lucrative one for CBM operators. The issue of gas quality in San Juan Basin has been found to be the opposite of that encountered in Illinois, that is, the gas quality declines with continued production, with a gradual increase in the concentration of CO₂ in the recovered gas. This is attributed to CO₂ being more sorptive than methane in a methane/CO₂ environment, with the coal releasing methane preferentially over CO₂. Based on the preferential sorption behavior of coal in a nitrogen/methane environment, it was believed that nitrogen would desorb preferentially over methane, and the quality of recovered CBM would, therefore, improve with continued production.

It was also believed that CBM production rate from Illinois reservoirs would improve with continued production. Again, the basis for this was the experience in San Juan Basin, where CBM production during the last ~20 years has exceeded all expectations and projections. This is attributed to significant increases in coal permeability with continued production. In order to project production rates, the permeability “trend” for the reservoir/region must be known. Hence, an experimental technique to accurately replicate in situ conditions was developed in order to establish permeability variation with continued gas production for core obtained from CBM operations in southern Illinois. In order to calibrate the experimental technique and findings of the work, core was also obtained from a producing reservoir in the San Juan Basin and tested for permeability trend. The results for the San Juan coal were compared with the field established trend in the basin, based on production data. Using the findings, the permeability trend for Illinois coals was determined.

The first task of this study included establishing sorption isotherms for pure methane and nitrogen. Using the results, and a theoretical model for binary gas sorption behavior, isotherm for binary methane/nitrogen mixture representative of in situ gas composition in southern Illinois was developed. This was followed by establishing isotherms in the laboratory for methane/nitrogen binary mixture of same composition. The laboratory and modeled results were compared to determine if pure gas sorption isotherms can be used
to develop isotherms for multi-component gas mixtures for Illinois coals. Also, during desorption, concentration of nitrogen in the gas being released was monitored to establish the gas quality trend. Finally, nitrogen concentration in the recovered gas from actual CBM reservoirs was obtained from one of the CBM operators in Illinois to compare the results obtained in the laboratory.

The second task in this study included permeability measurements for core obtained from a CBM operation in Illinois and another from an operation in the northern part of San Juan Basin. Permeability testing included applying vertical and horizontal stresses to core in order to replicate in situ conditions, and then saturating it with methane at in situ gas pressure. The pressure was then brought down gradually in a step-wise fashion to replicate primary recovery of methane by the depletion method. At the end of each pressure step, flowrate through the core was measured and permeability calculated. Hence, at the end of the tests, two complete permeability trends became available, one for Illinois coal and the other for San Juan coal. Since permeability variation with production in the San Juan Basin is much better understood, a relationship between the two, trend established in the laboratory and that observed in the field, was established. This, along with the laboratory established permeability trend for Illinois coal, was used to estimate the changes in permeability for southern Illinois coals.

The results of the sorption work clearly showed that the laboratory derived isotherm for binary gas mixture was in excellent agreement with the modeled isotherm using the Extended Langmuir (EL) model, particularly at low pressures. Fortunately, the gas pressure in Illinois coals is low, making the application of the model extremely valuable. This is a very useful finding since the information required to use the EL model is single gas sorption isotherms and in situ gas composition. Both of these are measured/developed during CBM exploration and are known. This finding can, therefore, be used as a very convenient technique to determine the degree of under-saturation in CBM reservoirs. Furthermore, based on the specific tests completed, there is no doubt that coal in southern Illinois is under-saturated, confirming that the dewatering period prior to actual production of gas would typically be significant. The results also showed that concentration of nitrogen in the recovered gas would decline from the original value although it will continue to be high for a fairly long period. This was a disappointing finding because nitrogen rejection units would probably be required for a significant period during the initial part of a reservoir’s life. In Illinois, given the low gas contents encountered, the extra capital and operational expenditure incurred in doing so would make CBM production from several gas bearing coals less attractive.

The results of the laboratory measurement of permeability showed a continuous increase with pressure decline. Hence, coal permeability in southern Illinois should be expected to increase over the entire life of a producing reservoir, resulting in improved production rate as CBM recovery from a reservoir progresses. The increase in permeability with continued production is definite although the degree of increase is somewhat uncertain. Drawing on the findings for the San Juan coals, this can be significant although, at this time, it is not possible to estimate this due to the short history of CBM production in Illinois. On the non-specific side, it was found that the permeability trend established in
the laboratory is fairly conservative, given that San Juan Basin coals have exhibited permeability increases in the field of as much as 100 times. Extrapolating this to Illinois coals, it is believed that permeability increase would be significant here as well and the production rate would almost certainly improve, but to a lesser degree than is typical in the San Juan Basin. The uncertainty lies due to the unknown behavior about the changes in diffusion rates in Illinois coals with pressure decline. In most other basins, gas production is believed to be permeability controlled since the sorption times are short and diffusion has no role in impacting gas production. In Illinois, on the other hand, the sorption times are very long and the production may very well be diffusion controlled. If this is, in fact, the case, then the increased permeability might not reap the anticipated fruit during the initial production period. However, once the diffusion behavior changes, there will be a direct impact on gas production.

As a final step, findings of the study were integrated with test results obtained from field testing. The results of the latter were provided by BPI Energy. Using this, simulation exercises were carried out for a reservoir in southern Illinois. The simulation results showed that gas production rate from Illinois coals will not be comparable to those encountered in other basins, and this is to be expected. However, after production rate peaks, the high level is sustainable for a long period of time due to improved diffusion behavior. Furthermore, simulation results showed that concentration of nitrogen would decline with continued production although this would probably not happen as quickly as desired by CBM operators. Nitrogen rejection units would, therefore, be required for as long as four years, at which time, nitrogen concentration would become almost negligible.

The study started with two industrial partners, Peabody Natural Gas (PNG) and BP America. Both partners had agreed to provide cores/samples from their CBM operations, and the results of tests completed. Unfortunately, PNG decided not to pursue CBM interests in Illinois. For initial part of the study, this operator started negotiations with CNX Gas, which took over the acreage and existing operation of PNG in Illinois. During later part of the study, not much information could be obtained from CNX Gas since the company was new in Illinois. The takeover is considered positive since CNX Gas has significant experience and expertise with CBM operations in the Appalachian Basin. The coals there are also under-saturated and the company has a good track record of success there for several years.

To ensure flow of information from actual CBM operation in Illinois, BPI Energy, the primary CBM operator in the State with more than 100 wells, was contacted. They took over the role of PNG and provided information throughout the duration of this study. Information from the San Juan operation was available from BP America. Finally, although ISGS was not an official partner in this study, information about gas content and composition collected/generated by them was available.
OBJECTIVES

Overall Objectives: The overall objective of this study was to support and enhance coalbed methane (CBM) activity in Illinois by assessing the issues of gas quality and permeability variation, the two factors affecting gas production rates and sellability of the recovered gas.

Specific Objective of the Study: In order to achieve the primary objective, the following specific objectives were pursued during the project period:

1. Determine the rate and level of decline in the concentration of N₂ in the gas recovered from coals with continued production in southern Illinois.
2. Predict the variation in permeability of coal with continued CBM production in southern Illinois.
3. Determine short- and long- term CBM production rates, overall recovery, and gas quality variations in typical gas bearing reservoirs in southern Illinois.

The tasks completed as a part of this study were as follows:

TASK 1 – CBM Gas Quality Trend with Continued Production in Southern Illinois:
This task was aimed at determining the decline in the concentration of nitrogen in the produced CBM in southern Illinois. It included combining a study of sorption of nitrogen and methane on coal to determine the degree of preferential ad/de- sorption of the two gases in a methane/nitrogen environment. Using the sorption results, gas quality trend was established. The results were also used in simulation of the variation in concentration of nitrogen in the recovered methane. Finally, application of the Extended Langmuir sorption model for Illinois coals was tested.

Task 1 was divided into following sub-tasks:

(a) Basic Coal Characterization: Since gas content of a reservoir is measured as volume per unit mass of coal, free from all non-carbonaceous components (dry, ash-free basis), proximate and ultimate analyses were carried out using ASTM standards to quantify the mass of coal present in the sample.

(b) Sorption Isotherms: The sorption of individual pure gases, methane and nitrogen, on coal was measured in the laboratory at reservoir temperature using the volumetric gas expansion method. The results were used to obtain the Langmuir Volume and Pressure Constants \( V_L \) and \( P_L \) for each of the two gases. Utilizing the pure gas sorption parameters and Extended Langmuir (EL) model, a binary gas mixture isotherm of known gas composition, representative of in situ gas, was developed. Following this, desorption isotherm was established for a multi-component gas mixture of methane and nitrogen at reservoir binary gas composition. The only modification required to do this was to incorporate the use of gas chromatograph (GC) to determine the gas composition during desorption. The desorbing gas was sampled at each pressure step during desorption to determine the composition of free and adsorbed portions of each of the two gases. Sorption isotherms were then established for total gas, as well as the two individual
components. The experimental isotherm results were compared with those obtained using the EL model.

**TASK 2 – Establishing Permeability “Trend”:** The objective of this task was to establish permeability variation trend for use in predicting permeability changes over the life of production wells, and its impact on long-term gas production in southern Illinois. The tests replicated CBM production by the primary recovery technique using pressure depletion method. Since enhanced coalbed methane technique (ECBM) is currently not practiced at any operation in the State, this was not pursued. The permeability of coal cores was measured in the laboratory under field replicated conditions of stress, temperature, pressure, and gas composition.

**TASK 3 – Simulation of Long-Term Gas Quality and Production:** Simulation of long-term CBM production from CBM reservoirs in the Delta field in Illinois was carried out using the CBM simulator, COMET3. The simulator, most widely used for commercial production of CBM, is capable of handling multiple gases, ECBM options, wells that have been fractured, multi-seam wells, and horizontal CBM wells emanating from vertical wells. Data obtained from the laboratory work was integrated with field data in order to develop a CBM production model for southern Illinois.

**TASK 4 – Reporting and Communication:** This task included maintaining very close contact with BPI Energy, Edwardsville, and BP America, Houston, personnel throughout the project duration. The progress reports for the project were prepared and submitted on a regular basis, and information about their field and analytical work was obtained. Most importantly, cores of coal were obtained from their drilling program. Finally, good communication was maintained with the Illinois State Geological Survey (ISGS) personnel throughout the project duration.

**INTRODUCTION AND BACKGROUND**

Estimates of CBM reserves in Illinois vary between 21 and 25 trillion cu ft (TCF), of which nearly 3 TCF is recoverable with existing technology [1, 2]. Although presence of gas bearing seams, along with reasonable gas content, indicates significant potential for CBM production in the State, development of this resource has been slow. At the present time, there is one major CBM operator in Illinois, namely BPI Energy, with more than 100 CBM wells. The second operator, CNX Gas, completed taking over the Peabody Natural Gas (PNG) operations and acreage in Illinois in 2007. The operator, with significant operational experience in the Appalachian Basin, is expected to be the second largest CBM operator in Illinois.

To date, recovered gas in Illinois is known to contain high concentration of nitrogen, between 10-20%, making the gas quality somewhat “poor” since it does not meet the pipeline requirements. This has necessitated use of nitrogen rejection units to process the recovered methane, making the CBM operations less lucrative. Furthermore, coals are under-saturated with methane, requiring long dewatering periods before commencement of gas production. Finally, sorption time of Illinois coals is extremely long, with coals
tending not to release the gas easily, and thus resulting in low production rates. The permeability of Illinois coals is medium, in the range of 10-50 md. Coupled with long sorption time, low gas content, under-saturated coals, this has resulted in low production rates. On the positive side, the gas bearing coals in Illinois are shallow and, therefore, require smaller capital.

It is generally believed that two factors that would make a difference in the level of CBM activity in Illinois are gas quality and production rates. The gas production is governed by diffusion rates in the coal matrix, and more importantly, permeability of coal. Gas quality is governed by the preferential sorption property of coal in a nitrogen/methane environment. Permeability of coal, in general, has been studied by several researchers and operators although, given the non-homogeneous nature of coal, permeability trends for different basins/reservoirs vary significantly and most of the work is very site specific. However, the second issue is unique to Illinois since other basins have not encountered such high concentrations of nitrogen in the recovered gas. Hence, this study was aimed at evaluating the variation in the concentration of nitrogen with continued production, more specifically, determining if the nitrogen concentration would decline as gas production progresses, and secondly, determining if the gas production rates would improve with continued production due to increased permeability.

The basis for the study was observations at CBM operations in other basins, like the San Juan, where CO₂ is often an integral part of the produced gas. The concentration of CO₂ in the produced CBM increases gradually with continued production. This is attributed to the preferential sorption behavior of coal, where CO₂ is preferentially sorbed over methane, that is, CO₂ is the last component to desorb and flow out in a methane/CO₂ binary mixture. Furthermore, lab studies using 10% CO₂ have shown that methane is the first component to desorb in a CO₂/methane environment, and the concentration of CO₂ increases only after a significant decline in gas pressure. Using this logic suggests that the concentration of nitrogen would decline with time since nitrogen is significantly less sorptive than methane. In a methane/nitrogen environment, nitrogen would desorb preferentially over methane and result in release of nitrogen first, suggesting that the gas quality would improve with continued production. At this time, there are no studies suggesting this although a few basic studies have reported the relative methane/nitrogen sorption to be between 3 and 5 [3, 4].

As for CBM production rates, once again, drawing from experience and observations in the San Juan Basin, it is believed that production would improve with time. Reservoir permeability increases of as much as 50 to 100 times have been measured in the San Juan Basin. In fact, the typical accepted ultimate recovery of 40-60% when these operations commenced in the late eighties is now believed to exceed 90% since several reservoirs in the basin are being depleted to as low as 60 psi by pressure depletion method alone. This is attributed to large increases in permeability enabling drawdown to such low pressures. Of course, this would have been considered impossible until a few years ago, when the abandonment pressure was expected to be ~150 psi. Finally, a recent study, sponsored by the ICCI, has shown that the Diffusion Coefficient (D) also increases significantly with continued desorption, with a positive impact on gas production rates [5]. This has also
been recently shown to be true for Canadian coals [6]. Both these factors suggest improved gas production rates with continued production.

Since the basis of this research study was findings, observations, and CBM production history in another basin, it was decided to carry out a calibration exercise using coal from San Juan Basin. Hence, as a final step, the current study also included establishing permeability trend for a core from the San Juan Basin. The two trends established in the laboratory were compared for similarities and differences. The study, in its entirety, included (a) determining the variation in the concentration of nitrogen in the gas recovered from Illinois coals with continued production, (b) predicting the variation in permeability of coal with continued CBM production in southern Illinois, and (c) determining short- and long-term CBM production rates and gas quality variations in typical gas bearing reservoirs in southern Illinois.

EXPERIMENTAL PROCEDURES

Sample Procurement and Preparation

Based on preliminary work on CBM resource assessment completed by the ISGS, cores of coal were selected from Herrin, Springfield and Seelyville seams in southern Illinois. Cores were preserved in their native state to prevent any damage due to weathering by storing them in an environmental chamber, with no source of light and under controlled conditions of temperature and humidity.

Sorption Experiments

Sample Preparation: Powdered samples were used for sorption experiments in order to reduce the duration of the experiment by minimizing the distance that gas molecules must diffuse through, prior to entering the "free" phase. Pieces of coal were first broken into lumps approximately half an inch in size. These were then ground in a ball mill and sieved to obtain the desired sample size of 40-100 mesh (0.425-0.149 mm). Prior to starting an experiment, approximately 80 g of pulverized sample was placed in the environmental chamber for ~24 hours at 73°F and 97% relative humidity. After attaining moisture equilibrium, one gram of sample was used for moisture and ash analysis, following the ASTM procedures D 3173 - 87 and D 3174 - 97, and the rest was used for the sorption experiment.

Experimental Setup and Procedure: The design of experimental setup was based on the method of mass balance utilizing the volumetric analysis method and the gas expansion technique to measure the quantity of sorbed gas.

The experimental setup consisted of a stainless steel fixed volume cylinder (FV), and another stainless steel sample container (SC) that held the powdered coal sample, separated by a two-way valve. A schematic of the setup is shown in Figure 1. Gas was allowed to expand from the FV to SC (during adsorption) or vice-versa (during desorption). A filter was placed between the two to prevent fine coal particles being
transferred from SC to FV. Since the process of sorption is very sensitive to temperature, the entire setup was placed in a constant temperature water bath, which maintained the temperature to within 0.2°C of the set value. A pressure transducer was attached to the fixed volume cylinder. By monitoring the pressure before and after the expansion, volume of gas moving into, or out of the SC was calculated. Prior to every sorption experiment, the calibration of the setup was carried out to determine the void volume in sample container by expanding helium from FV to SC, and measuring the equilibrium pressure.

A total of seven sets of ad/de sorption experiments were performed as a part of this task. Six of these were for methane and nitrogen for samples taken from Herrin, Seelyville and Springfield seams. Finally, one isotherm was established for a 75/25 binary gas mixture of methane/nitrogen for a sample taken from Herrin seam. The maximum pressure was ~1200 psi for methane, ~700 psi for nitrogen, and ~1200 psi for the binary mixture. Once the highest pressure for the adsorption isotherm was reached, desorption isotherm was obtained by reducing the gas pressure in steps until pressure in the sample container was reduced approximately to 100 psi, at which time the experiment was terminated. For each step of the test using methane/nitrogen mixture, composition of desorbing gas was measured by collecting a small amount of desorbed gas and passing it through gas chromatograph for analysis.

**Permeability Experiments**

**Sample Preparation:** Just prior to testing, three inch lengths of cores were cut and their top and bottom ends polished to enable proper placement in the triaxial cell.
Experimental Setup and Procedure: In order to replicate the conditions in situ, controlling and monitoring of external stress conditions and gas pressure are critical. The experimental setup for permeability measurement was, therefore, capable of independent control of stress conditions, gas pressure (upstream and downstream), and measurement of gas flowrate. Figure 2 shows a schematic of the experimental setup. The setup comprised of a triaxial cell, a loading system, and a means to monitor and measure flowrate. The axial stress was applied by placing the cell in a load frame while the confining stress was applied by connecting the triaxial cell to a hydraulic pump. A perforated steel disk was placed at each of the two ends of the sample to distribute (and collect) the gas and prevent small particles from entering the gas lines. The temperature of the triaxial cell was kept constant using a heating tape and temperature controller. The gas lines at the inlet and outlet ends were placed in the water bath, set at same temperature as that of the triaxial cell. The gases entering and coming out of the triaxial cell were, therefore, at the same temperature. A relief valve was used to keep the downstream pressure constant.

Experimental Conditions: Two experiments were performed under this task. For the first experiment, a core sample taken from the Herrin seam in Illinois Basin was used. The sample was subjected to axial and confining stresses of 1250 and 850 psi respectively, both representative of estimated stresses in situ. The maximum methane pressure for this sample was 450 psi, once again, representative of in situ pressure. The second experiment was carried out using a core from the San Juan Basin, provided by BP America, taken from their operations in northern part of the basin. The axial and confining stresses for this sample were 1900 and 1400 psi respectively, and the maximum methane pressure was 860 psi.

Prior to flow measurements, a pressure gradient was applied across the core. Typical pressure gradient for every pressure step was between 40 and 60 psi. The pressure, temperature, and flowrate at both ends (upstream and downstream) were monitored continuously. When all parameters became, and remained, constant (equilibrium condition), flowrate measurements for the particular conditions were made. Using the measured flowrate, permeability of the sample was calculated. Since it took between eight and fifteen days to attain equilibrium for each pressure step, a complete permeability test required three to four months.

RESULTS AND DISCUSSION

TASK 1 – CBM Gas Quality Trend with Continued Production in Southern Illinois

The sorption experiments conducted were based on the standard volumetric accounting principles. The amount of gas adsorbed at a given pressure was calculated on the basis of Gibbs isotherm principle. Gibbs adsorption isotherm calculation assumes constant void volume within coal throughout the pressure steps. It neglects the volume occupied by adsorbed gas at each pressure step when calculating the amount of “free” gas. The difference between Gibbs and absolute adsorption is significant at high pressures, and the relationship used to calculate the absolute volume is given as [7]:
Figure 2: Schematic of the experimental setup to measure permeability.

\[ V_{\text{abs}} = \frac{V_{\text{Gibbs}}}{\rho_{\text{gas}}} \left(1 - \frac{\rho_{\text{gas}}}{\rho_{\text{abs}}}\right) \]  

(1)

where, \( V_{\text{abs}} \) and \( V_{\text{Gibbs}} \) are absolute and Gibbs sorption respectively, and \( \rho_{\text{gas}} \) and \( \rho_{\text{abs}} \) are densities of the gas in gaseous and adsorbed phases respectively. The experimental sorption data was analyzed using Langmuir isotherm model, given as:

\[ V = \frac{P V_L}{P + P_L} \]  

(2)

where, \( P \) is equilibrium gas pressure, \( V \) is volume of gas adsorbed, \( V_L \) is Langmuir Volume representing the maximum volume that can be sorbed at infinite pressure, and \( P_L \) is Langmuir Pressure at which the sorbed volume is half the maximum volume.

The samples tested were first analyzed for ash and moisture content. The results are shown in Table 1.
### Table 1: Sample characteristics.

<table>
<thead>
<tr>
<th>Seam</th>
<th>Sample 1</th>
<th>Sample 2</th>
<th>Sample 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seam (%)</td>
<td>10.8</td>
<td>9.5</td>
<td>6.1</td>
</tr>
<tr>
<td>Moisture (%)</td>
<td>6.6</td>
<td>5.5</td>
<td>4.4</td>
</tr>
<tr>
<td>Temperature (°F)</td>
<td>73</td>
<td>73</td>
<td>73</td>
</tr>
</tbody>
</table>

**Single Gas Sorption**

Gas sorption measurement for pure methane and nitrogen were conducted for Herrin, Seelyville and Springfield samples at 73°F for pressures up to 1200 psi for methane and 700 psi for nitrogen. The phase densities for adsorbed methane and nitrogen used for conversion of Gibbs to absolute adsorption were 0.421 and 0.808 g/cm³ respectively. The absolute sorption isotherms are shown in Figure 3. The Langmuir Constants obtained for the samples tested are shown in the Table 2. It is apparent that all isotherms are of Type 1, according to Brunauer’s classification [8]. Table 2 includes the relative sorption of methane and nitrogen at maximum sorption capacity (V_L) as well as 400 psi since this is the approximate pressure encountered in situ. For Herrin and Springfield coals, the relative absolute sorption at 400 psi is 3.3 and 2.9 respectively, and for Seelyville coal, it is slightly lower, 2.7:1. A possible reason for this is the higher affinity of Seelyville coal for methane. It is apparent from Figure 3 that the sample with higher sorptive affinity for methane has a higher sorptive affinity for nitrogen as well. However, there is no relationship between the basic characteristics of the three coal types and their respective sorption capacities. Finally, Herrin and Springfield coals have very similar sorption characteristics, with the ratio of the methane/nitrogen Langmuir Volumes close to 2.

**Binary Mixture Gas Sorption**

Following the sorption experiments using pure gases, one sorption isotherm was established for a methane/nitrogen mixture for Herrin coal at 73°F and pressure up to 1200 psi. The measurements were conducted at a feed composition of 75/25 methane/nitrogen. Figure 4 shows the isotherm for the methane/nitrogen mixture, along with the component isotherms for the two pure gases for the coal type. Figure 5 shows the isotherm for the gas mixture, along with the theoretically developed isotherm for the composition. The theoretical isotherm was obtained using the Extended Langmuir model (EL) given as:

\[
V_i = \frac{(V_L)_i b_i P_i}{1 + \sum_j b_j P_j}
\]  

(3)

where, \( V_i \) is sorbed volume of gas ‘i’ in the mixture, \( V_L \) is Langmuir Volume for pure gas and \( b \) is a modified form of the Langmuir Pressure for pure gas, given as \( 1/P_L \), and \( P_i \) and \( P_j \) are partial pressures of individual gases in free phase.
Table 2: Langmuir Constants for absolute adsorption.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Methane</th>
<th>Nitrogen</th>
<th>V_L (scf)</th>
<th>P_L (psia)</th>
<th>V_L (scf)</th>
<th>P_L (psia)</th>
<th>V_L Sorption Ratio (Methane: Nitrogen)</th>
<th>Relative Sorption at 400 psia (Methane : Nitrogen)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Herrin</td>
<td>490</td>
<td>586</td>
<td>254</td>
<td>1266</td>
<td>1.9:1</td>
<td>3.3:1</td>
<td>3.3:1</td>
<td></td>
</tr>
<tr>
<td>Seelyville</td>
<td>511</td>
<td>366</td>
<td>293</td>
<td>784</td>
<td>1.7:1</td>
<td>2.7:1</td>
<td>2.7:1</td>
<td></td>
</tr>
<tr>
<td>Springfield</td>
<td>386</td>
<td>360</td>
<td>208</td>
<td>788</td>
<td>1.9:1</td>
<td>2.9:1</td>
<td>2.9:1</td>
<td></td>
</tr>
</tbody>
</table>

Figure 3: Methane and nitrogen sorption isotherms for Herrin, Seelyville and Springfield coals.

Figure 6 shows the desorption isotherm for methane/nitrogen mixture for Herrin coal, along with the isotherm for the two individual component gases. The estimates for mixture absolute adsorption were calculated assuming ideal solution additive volumes in the adsorbed phase (weighted average of adsorption phase densities of methane and nitrogen). Figure 7 shows the relative percentage of methane and nitrogen in the desorbing mixture.

From Figure 4, it can be seen that the adsorption volume decreases with increased dilution of methane with nitrogen. This is expected due to the lower sorptive affinity of coal for nitrogen. Table 3 shows the Langmuir Constants for the mixed gas sorption obtained from experimental results, along with the values obtained using the EL model.
Figure 4: Isotherms for pure methane, nitrogen and 75/25 mixture for Herrin coal.

Figure 5: Experimental and modeled isotherms for 75/25 gas mixture for Herrin coal.
Overall, the isotherm established in the laboratory and that predicted by the EL theory are in good agreement as shown in Figure 5. However, the predicted values at lower pressures show a better fit since there is an apparent deviation from the experimental data at higher pressures. Fortunately, the gas pressure encountered in Illinois Basin is low and the EL theory can be used without loss of any accuracy, indeed a valuable finding. However, the agreement between the two sets of Langmuir Constants, as shown in Table 3, is not very good. Finally, Figure 7 shows that nitrogen desorbs faster than methane, and methane concentration increases with continued desorption, resulting in an improvement in gas quality although the improvement is not significant.

The average initial gas content of Illinois Basin is 150 scft at a reservoir pressure of 200 to 400 psi. Based on the isotherms shown in Figure 3, it is obvious that coals are undersaturated with methane at this pressure. It would, therefore, reasonable to expect a significant amount of dewatering required prior to commencement of actual gas production.
It is also clear from the mixed gas sorption results that the concentration of nitrogen in the recovered gas decreases gradually. In a methane/nitrogen environment, nitrogen desorbs preferentially over methane and the quality of recovered gas would improve with continued production. However, there is still significant amount of nitrogen in the desorbing gas, and nitrogen rejection units to process the recovered gas would be required almost throughout the life of producing reservoirs.

**TASK 2 – Establishing Permeability “Trend”**

**Permeability Calculation**

Darcy’s equation, modified for compressible fluids, was used to calculate the permeability of coal. The equation is given as:

\[
k = \frac{\mu Q_o L P_o}{A \Delta P P_m}
\]  

(4)

where, \(\mu\) is the viscosity of the gas, \(Q_o\) is the volumetric flowrate at outlet, \(A\) is the cross-sectional area of the sample, \(L\) is the sample length, \(P_o\) is the gas pressure at outlet, \(\Delta P\) is the pressure difference between upstream and downstream ends, and \(P_m\) is the mean gas pressure.
Permeability Results

The first permeability test was carried out using a well preserved core taken from Herrin seam in Illinois Basin. The sample was subjected to axial and confining stresses of 1250 and 850 psi respectively. It was then saturated with methane at 450 psi. Following this, a pressure gradient of ~50 psi was applied across the two ends and flow measurement was made. The gas pressure was then reduced in steps of 100 psi. At each pressure step, the sample was allowed to equilibrate for several days, and when there was no change in the gas pressure, flow measurements were made. A total of four flowrate measurements were made at four pressure steps – starting at 450 psi and up to 150 psi. The permeability was then calculated for each pressure step. The ratio of the permeability for each pressure step to that of the initial permeability, that is, the permeability value determined at ~450 psi, was plotted as a function of the mean gas pressure. This is shown in Figure 8.

![Figure 8: Laboratory established permeability trend for Herrin coal.](image)

The trend shown in Figure 8 shows a general increase in permeability with decreasing gas pressure. Below 150 psi, the measured permeability trend was extrapolated in order to obtain permeability at ~100 psi, the anticipated abandonment pressure.

The second experiment was carried out using a coal sample taken from the San Juan Basin. The core was subjected to an axial and confining stresses of ~1,900 and ~1,400 psi respectively since the basin is significantly deeper than Illinois Basin. Following this, the sample was saturated at a mean gas pressure of 860 psi, and a set of flow measurements were made. The gas pressure was then decreased in steps, down to 60 psi. Flow measurements were made at equilibrium conditions for each pressure step and
permeability was calculated. The ratio between the measured permeability at each pressure step to that of the initial permeability, that is, permeability at ~860 psi, was plotted as a function of mean gas pressure. The experimental results are shown, along with the best fit, in Figure 9.

Figure 9: Laboratory established permeability trend for San Juan coal.

Since the purpose of this experiment was to calibrate the results obtained for Illinois coal, the two trends were compared. The differences are significant and apparent. The permeability trend exhibited by the San Juan coal does not show a continuous increase with decreasing gas pressure, as is the case for coal from Illinois Basin, shown in Figure 8. Instead, there was a decrease in permeability initially with decreasing gas pressure. However, for gas pressure below 400 psi, there was a rebound in permeability. Below this pressure, permeability increased gradually with decreasing gas pressure, all the way to 50 psi. Hence, the permeability trend can be divided into two parts, one up to ~400 psi showing a decreasing trend, and the second below 400 psi and up to 50 psi, showing an increasing trend. The decrease in permeability is almost eleven times followed by an increase of just over four times. In spite of this increase, the final permeability was 40% of the initial permeability value, suggesting an overall reduction in permeability with continued reduction of gas pressure.

During the last few years, since CBM production in US basins have matured, researchers [9, 10] have reported that there are two opposing mechanisms with significant impact on gas production as recovery from a CBM reservoir progresses. The first is an increase in effective stress (defined as the difference between external stress and pore pressure) with
decrease in gas pressure, which tends to close the cleat aperture thus resulting in decreased permeability. The second is the shrinkage of coal matrix due to gas desorption, which dilates the cleat aperture thus resulting in increased permeability. The combined effect of effective stress and sorption-induced shrinkage dictates the permeability trend for any coal seam. The overall permeability decreases when the former dominates, and increases when the latter prevails.

The first reason for the difference between the two permeability trends measured for the two coal types is the difference in external stress conditions. Illinois coals are shallower than San Juan coals and the stresses are, therefore, significantly lower. Hence, the permeability reduction due to the effective stress effect is not significant. Also, the gas pressure in Illinois coals is substantially lower, resulting in substantial desorption of gas as soon as the CBM operation commences. This results in significant matrix shrinkage and shows as an increase in permeability for the duration of the operation. However, in case of San Juan coal, this positive effect is suppressed due to the higher stresses posing an opposing effect due to increased effective stress, negating the effect of matrix shrinkage initially. Only after matrix shrinkage becomes significant, that is, below 400 psi, does this effect become more dominant than the stress effect, resulting in increased permeability. To illustrate this effect, the permeability is shown along with the respective sorption isotherm in Figure 10 for Illinois coal. Figure 11 shows the same effect for San Juan coal.

Figure 10: Variation of permeability and sorbed volume with pressure for Herrin coal.
Figure 11: Variation of permeability and sorbed volume with pressure for San Juan coal.

The finding that the permeability first decreases, and is then followed by a rebound, is also shown in the numerical modeling of permeability changes with depletion in the San Juan Basin [11]. Although the phenomenon is discussed in detail in publications by the model developers, they do admit the shortcoming of the model since permeability decrease is typically not observed in the field in San Juan Basin. Since the permeability of San Juan coals increases throughout the operation, the model has been recently revised to include suppression of the stress-dependent permeability loss due to cleat closure effect [12]. Where the stresses are low, like in the Illinois Basin, permeability may very well increase continuously over the production period due to the dominant effect of matrix shrinkage and associated increase in permeability. This is coupled with the effect of increased effective stress being suppressed.

Based on the experimental results, it is apparent that, for San Juan coals, the two effects are dominant in the two pressure regimes. However, for Illinois coals, there is only one pressure regime and only one effect is dominant. The two permeability trends, therefore, give some insight to the coupled effect of cleat closure due to increased effective stress and cleat dilation due to matrix shrinkage associated with gas desorption. It is apparent from the way these experiments were carried out, that in situ conditions were not replicated properly. Hence, developer of one of the numerical permeability models most commonly used, was contacted. His recommendation is that the experiments should not be carried out following the stress controlled technique. The stresses in situ change substantially with continued gas production. What does not change in situ is the dimension of coal in the horizontal direction. Since flow of gas in coal is controlled by vertical cleats, horizontal fractures and bedding planes really have no role in
permeability. Furthermore, the impact of matrix shrinkage under field conditions can best be replicated by maintaining uniaxial strain conditions, that is, the dimension of coal in the horizontal direction not be allowed to change. In fact, any induced strain in the horizontal direction results in changes in the stress conditions, and this, in turn, affects the permeability. The numerical models are based on the assumption of uniaxial strain conditions and that would be the way to carry out the experiments. The physical model used in the numerical modeling is shown in Figure 12 [12].

**Figure 12: Physical representation for flow modeling [12].**

**TASK 3 – Simulation of Long-term Gas Quality and Production**

As a part of this task, the effect of composition of gas-in-place, permeability and sorption time on gas production rates was examined using coalbed methane reservoir simulator, COMET3. Langmuir Constants determined from sorption experiments were used in the simulation. Other parameters were provided by BPI Energy for Delta field in southern Illinois. Details of these simulation runs are provided in the following sections.

**Effect of Gas Composition**

The impact of composition of gas-in-place on methane production rate was examined using a reservoir with a single production well, located in the center of the simulated area. The reservoir parameters used for the simulation study are listed in Table 4. Langmuir Constants for pure methane, nitrogen and binary gas mixture obtained from sorption experiments were used in the simulation. Figure 13 shows the effect of gas-in-
place composition on production rates. Figure 14 shows the corresponding cumulative
gas production. It is evident from the figure that production rate of methane and the
overall recovery are higher for gas-in-place consisting of pure methane, compared to
when it is diluted with 25% nitrogen. This is expected due to two reasons. First, the
amount of gas-in-place is less when the gas is not pure methane since nitrogen is
significantly less sorptive than methane. This explains the fact that the production rate is
lower than with pure methane. Second, nitrogen is an integral part of the recovered gas.
After it is removed by the nitrogen rejection unit, the amount of useful gas, that is,
methane, reduces further, as shown by the lowermost plot in Figure 13. With continued
production, the amount of nitrogen in the recovered gas decreases and this is shown as a
reduction in the difference between the recovered gas and pure methane. The cumulative
production results show that the difference in the amounts of “sellable” gas can be as
high as 40% when the gas-in-place contains nitrogen, a significant difference. To
illustrate this further, Figure 15 shows the production rates for a period of ten years and
Figure 16 shows the corresponding cumulative production. It is obvious that, after four
years, the recovered gas is almost pure methane since the two plots, recovered gas and
methane produced, converged. Hence, after approximately four years of continuous
production, nitrogen removal will no longer be necessary. Another interesting finding is
that although the production rate after this, for the remaining life of the reservoir, is lower
than in the case of pure methane, the difference is not significant. This finding has merit
although the fact that the improvement in gas quality would take four years might be
somewhat disappointing for operators in the State.

<table>
<thead>
<tr>
<th>Type of data</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial reservoir pressure</td>
<td>230 psi</td>
</tr>
<tr>
<td>Langmuir volume (V_L)</td>
<td>490 scft - methane</td>
</tr>
<tr>
<td></td>
<td>254 scft - nitrogen</td>
</tr>
<tr>
<td>Langmuir pressure (P_L)</td>
<td>586 psia - methane</td>
</tr>
<tr>
<td></td>
<td>1266 psia - nitrogen</td>
</tr>
<tr>
<td>Initial gas content</td>
<td>150 scft</td>
</tr>
<tr>
<td>Pore volume compressibility</td>
<td>1x10^{-4} to 3x10^{-6} psi(^{-1})</td>
</tr>
<tr>
<td>Depth of coal seam</td>
<td>1100 ft</td>
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<tr>
<td>Cleat permeability</td>
<td>49 md in X and Y direction</td>
</tr>
<tr>
<td></td>
<td>25 md in Z direction</td>
</tr>
<tr>
<td>Face cleat orientation</td>
<td>Face cleat NE, butt cleat NW</td>
</tr>
<tr>
<td>Sorption time</td>
<td>100 days for methane</td>
</tr>
<tr>
<td></td>
<td>50 days for nitrogen</td>
</tr>
</tbody>
</table>
Figure 13: Gas production rates for pure methane and binary gas mixture over a two-year period.

Figure 14: Cumulative production for pure methane and binary gas mixture over a two-year period.
Figure 15: Long-term gas production rates for pure methane and binary gas mixture over a ten-year period.

Figure 16: Cumulative production for pure methane and binary gas mixture over a ten-year period.
Effect of Permeability and Sorption Time on Long-term Gas Production

Field data from pilot wells provided by BPI was used for the simulation. Input reservoir parameters for the simulation exercise are shown in Table 5. A five-well pilot with 64-acre well spacing simulation grid was designed. The grid and the layout of the pilot wells are shown in Figure 17.

The effect of permeability on gas production was examined for two values, 21 md measured in the field and 2 md measured in the laboratory. Similarly, the impact of sorption time, $\tau$, on gas production was tested for two different sorption times, 425 and 45 days. The results showing production rate over a ten-year period is are shown in the Figure 18. The corresponding cumulative production is shown in Figure 19. The simulation results clearly show higher gas production rates for the higher permeability reservoir. This is expected since higher permeability provides better connectivity within the reservoir. It is also apparent that the initial gas production rate is higher for the low sorption time. Once again, this is expected due to the early release of methane after commencement of gas production. However, long-term production rates are not very sensitive to change in sorption time. This is also apparent in the overall recovery over the simulated period. The only concern at this time is that this may very well be a shortcoming of commercial CBM simulators since all packages are based on permeability controlled production rather than diffusion based flow.

Table 5: Input reservoir parameters for the simulation.

<table>
<thead>
<tr>
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<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial reservoir pressure</td>
<td>241 psi</td>
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<tr>
<td>Langmuir volume ($V_L$)</td>
<td>511 scft</td>
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<tr>
<td>Langmuir pressure ($P_L$)</td>
<td>366 psia</td>
</tr>
<tr>
<td>Initial gas content</td>
<td>148 scft</td>
</tr>
<tr>
<td>$In situ$ gas composition</td>
<td>3% N$_2$, 0.2% CO$_2$, rest methane</td>
</tr>
<tr>
<td>Pore volume compressibility</td>
<td>$1\times10^{-9}$ to $3\times10^{-6}$ psi$^{-1}$</td>
</tr>
<tr>
<td>Depth of coal seam</td>
<td>560 ft</td>
</tr>
<tr>
<td>Cleat permeability</td>
<td>21 md, 2 md</td>
</tr>
<tr>
<td>Face cleat orientation</td>
<td>Face cleat NE, butt cleat NW</td>
</tr>
</tbody>
</table>
Figure 17: Grid design for the five-well pilot.

Figure 18: Effect of reservoir permeability and sorption time on gas production rate over a ten-year period.
It is apparent from the simulation results that permeability has such a significant influence on production rate that even for an increase in the value of $\tau$ of ten times does not have a significant impact on production rate. Furthermore, in its current form, COMET3 is based on the assumption that diffusion behavior does not change with continued production, that is, the value of $\tau$ remains constant over the life of a reservoir. However, preliminary evidence for Illinois and Canadian coals shows that the gas diffusion rates improve significantly at low pressure values, a very favorable finding for Illinois coals where the *in situ* pressure is low to begin with. How this can be fed into the simulator is not very clear at this time. The developers of the simulator, COMET3, are in the process of modifying the package to allow using a variable value of $\tau$ over the simulation period. Finally, the results shown in Figure 16 make it absolutely clear that low permeability and long sorption times cannot possibly result in profitable production of coalbed methane in Illinois. Even if diffusion properties change to the advantage of CBM production at low pressure, the production rate would still be far too low for commercial CBM production.

**TASK 4 – Reporting and Communication**

The study started with two industrial partners, Peabody Natural Gas (PNG) and BP America. Both partners had agreed to provide cores/samples from their CBM operations, and the results of tests completed. Unfortunately, PNG decided not to pursue CBM interests in Illinois. For initial part of the study, this operator started negotiations with CNX Gas, which took over the acreage and existing operation of PNG in Illinois. During
later part of the study, not much information could be obtained from CNX Gas since the company was new in Illinois. The takeover is considered positive since CNX Gas has significant experience and expertise with CBM operations in the Appalachian Basin. The coals there are also under-saturated and the company has a good track record of success there for several years.

To ensure flow of information from actual CBM operation in Illinois, BPI Energy, the primary CBM operator in the State with more than 100 wells, was contacted. They took over the role of PNG and provided information throughout the duration of this study. Information from the San Juan operation was available from BP America. Finally, although ISGS was not an official partner in this study, information about gas content and composition collected/generated by them was available.

Finally, reporting included submitting monthly reports to ICCI.

CONCLUSIONS AND RECOMMENDATIONS

Based on the work completed as a part of this study, the following conclusions are made:

- The sorption results showed that Extended Langmuir model can be used to predict the binary gas mixture isotherm accurately for Illinois coals. This is certainly not true for other basins where the gas pressure is significantly higher. This finding makes determination of the degree of under-saturation very convenient. Using the sorption isotherms for pure gases and in situ gas composition, and these two pieces of information are available for every potential CBM reservoir/field, the binary or tertiary gas mixture isotherm can be developed for in situ composition. Using the measured gas content value, the degree of under-saturation can be determined.

- The concentration of nitrogen in the recovered gas is expected to decline from the original value. However, the recovered gas would continue to have high concentrations of nitrogen for a fairly long period. This was a disappointing finding because, if this is found to be the case in field, nitrogen rejection units would be required for the initial period in a reservoir’s life, and this can be fairly long. In Illinois, given the low gas contents encountered, the extra capital and operational expenditure incurred in doing so would make CBM production from several gas bearing coals less attractive economically.

- The permeability of coal in the Delta field of southern Illinois should be expected to increase over the life of CBM producing reservoirs. This would result in increased production rate as CBM recovery from a reservoir progresses. Although the increase in permeability with continued production is definite, the magnitude of the increase is somewhat uncertain. At this time, it is not possible to estimate this from field production data, given the short history of CBM production in Illinois. However, once more production data becomes available, and a history match exercise is completed, increase in permeability can be predicted more reliably.

- A comparison of the permeability trend established for San Juan Basin coal and the actual trend observed in the field suggests that laboratory established trend is
conservative since the actual permeability increase is higher than that measured using cores of coal. Extrapolating this to Illinois coals, it is believed that the permeability increase in coals in the State can be significant and the production rate would almost certainly improve. The uncertainty lies due to the variation in the diffusion behavior of coals in Illinois Basin. In most other basins, gas production is believed to be permeability controlled since the sorption times are relatively low. In Illinois, on the other hand, sorption times are very long and the production may very well be diffusion controlled. If this is the case, the increased permeability might not reap the anticipated fruit during the initial production period. However, once the diffusion behavior changes, there will be a direct impact on gas production.

- The simulation results showed that the gas production rate from Illinois coals will not be comparable to those encountered in other basins. However, after the production rate peaks, the high level is sustainable for a long period of time due to improved diffusion behavior. At this time, the production history in the State is rather short and this conclusion may be somewhat far fetched. Furthermore, simulation results showed that the concentration of nitrogen would decline with continued production although this would probably not happen as quickly as desired by CBM operators. First, this is somewhat contradictory to the finding of the sorption part of the study where nitrogen was present in the desorbing gas almost throughout the desorption period. Second, the period during which the nitrogen concentration is unacceptably high requiring use of nitrogen rejection units may last for four years. This finding requires further discussion with the developers of COMET3 to ensure that this finding is not resulting from the way the simulator has been set up.

Based on the work completed as a part of this study, following recommendations are made for continued research:

- Effort should be made to establish a numerical model that would be suitable for permeability prediction for Illinois coals. The basis of the model should be principles of rock mechanics and theory of sorption induced matrix strain. The model should have the capability of handling under-saturated coals, which is a unique feature of CBM in Illinois Basin. Since most models are independent of size, they are applicable to laboratory sized samples just as they are for actual reservoirs. Hence, any suitable model can be tested rigorously in the laboratory, followed by numerical crunching. Similar exercise for the San Juan Basin has proved to be extremely valuable. To begin with, the existing models should be tried to see if one is able to successfully model changes in permeability with depletion.

- There is no information available for pore volume compressibility \( (C_p) \) of coals in Illinois. Although this parameter has a truly significant impact on permeability changes with continued production, the values currently used by CBM operators in Illinois are ones used for San Juan coals. In fact, even for a basin as prolific as San Juan, accurate values of \( C_p \) are not always available. Furthermore, with production in the San Juan Basin maturing, there is serious doubt about the value of \( C_p \) remaining constant throughout the life of a producing reservoir. This must be measured in the
laboratory for typical coals in Illinois to obtain a reliable value, and this must be followed by field tests to obtain *in situ* values of $C_p$.

- The diffusion behavior of gas in Illinois coals should be investigated further since this may very well be the factor that is going to determine the future of CBM activity in the State. This is being currently pursued as a part of a research study funded by ICCI. The impact of diffusion should then be incorporated in the simulation exercise. Since effort is currently being made to modify the COMET3 simulator, it might be possible to simulate diffusion controlled production from coal seams.
REFERENCES


DISCLAIMER STATEMENT

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