ABSTRACT

Commercial production of coalbed methane (CBM) depends primarily on the gas content of coal, and its ability to transmit gas, namely its permeability. Since the gas content of southern Illinois coal is sufficient to promote the growth of this resource, this research investigation was aimed at studying the flow behavior of coal in the gas bearing portions of the Illinois Basin, and its variation over the life of CBM reservoirs. Furthermore, the study included evaluating the effect of injecting CO₂ on the flow characteristics of coal.

The permeability of coal was estimated for well preserved cores of coal, obtained from Herrin and Springfield seams, under in situ conditions of stress, temperature and pressure. The results obtained clearly suggest that the permeability of these coals should be considered medium to high, compared to other CBM producing basins in the US. The results further suggest that, with continued gas recovery, CBM production would change significantly and this should be taken into consideration when planning such operations. Finally, the gas content of Illinois coals is somewhat lower than in other US basins, and enhanced recovery of methane should be considered for the entire life of the reservoirs in the basin. Since the permeability is fairly high, the negative impact of the associated permeability loss on gas production might be tolerable.

As a supporting exercise, the capacity of coal to retain methane and CO₂ was measured for the coals tested. This was followed by evaluating the incremental methane recovery by flooding the coal with CO₂. The results show that significant additional methane can be recovered by mixing/injecting CO₂, even when the overall pressure in the reservoir is high. Also, the CO₂ sequestration potential of the coals is three to five times the amount of methane recovered. Estimation of the adverse impact of CO₂ injection on flow continued by measuring the CO₂ induced volumetric strain. The results show that there will be a loss of permeability with CO₂ injection although a part of this damage will be compensated for by an increase in permeability due to increased fluid pressure.

Using the laboratory results and ISGS data, a comprehensive simulation exercise was carried out to estimate the CBM production potential in the Illinois Basin, for both primary and enhanced recovery methods. The results of the simulation show that the amount of methane recovered increases with CO₂ injection, and the amount of CO₂ that can be sequestered is significant. The negative impact of CO₂ injection is, once again, shown in the results. Finally, the results of the sensitivity analysis show that the pore-volume compressibility of coal has a major impact on long-term gas production, and this should be evaluated accurately.
EXECUTIVE SUMMARY

The overall objective of this study was to determine the technical feasibility of producing coalbed methane (CBM) from Illinois coal on a commercial level, and sequestering carbon dioxide (CO\textsubscript{2}) in coal. Although the Illinois State Geological Survey (ISGS) is assessing the gas content of various coals in southern Illinois, primarily the Springfield, Herrin, and Davis seams, there is little data available on flow characteristics of coal. This study was, therefore, aimed at evaluating the flow behavior of Illinois coal on a laboratory scale and using the relationships established in the laboratory, along with data collected by ISGS, to estimate the CBM potential by simulating long-term gas production. The main focus of the study was to conduct some of the basic tests on cores/samples of coal taken from the three seams of interest, and determine the dynamics of flow characteristics in typical CBM reservoirs with continued production, with and without the CO\textsubscript{2} sequestration option.

Since the primary thrust of the study was to measure flowrates through coal under field-simulated conditions, and estimate the permeability, an experimental setup for flow measurement was first designed and fabricated. The experimental system enabled control and monitoring of the external stress conditions and gas pressure at temperatures representative of Illinois reservoirs, while measuring the gas flowrate. Initial trial tests were then carried out using sandstone samples due to their simple, well understood and documented behavior. Based on these tests, certain modifications were made to improve the setup. After the setup was modified, a coal sample from the Herrin seam was used for a second trial test. The measurement of flow rates and calculation of permeability for the sample under field conditions was repeated several times while trying to maintain the pressure gradient and effective stress constant. The results of the trial coal sample confirmed proper working of the setup, and also provided a good handle on operation of the setup.

Following the procedure developed during the trial tests, a permeability test was started using a well preserved core of coal taken from the Springfield seam. The core was taken from a depth of ~880 ft. The estimated temperature at the location and depth was 72°F. The flow measurements were completed for different effective stress levels by changing the mean gas pressure, but maintaining the axial and confining stresses constant. For an increase in the horizontal effective stress from 180 to 480 psi, the permeability decreased from 75 to 6 md. This is as expected since any increase in the external stress results in compaction of the flow paths for coal (cleat closure) and, hence, a reduction in permeability. This was followed by determining the permeability at constant effective stress conditions. The results showed that the permeability decreased with decrease in gas pressure. This can be attributed to a loss in the driving force to move the gas. This finding is different from some of the results reported in the past although all of the past work has been carried out for deep coalbeds, that is, highly stressed coals. Finally, the above two experiments were repeated to estimate the permeability of coal to CO\textsubscript{2}. The CO\textsubscript{2} permeability trends established for both cases were the same as for methane with one major difference. The permeability to CO\textsubscript{2} was found to be much lower than that to methane, clearly showing that higher sorptive gas exhibits lower permeability.
As a part of the basic coal characterization exercise, sorption of gases on coal and its impact on the microstructure of coal were studied. A study of the sorption behavior is not only critical to predict and optimize the process of methane recovery from CBM reservoirs, but also to evaluate and optimize any potential CO2 sequestration plan. Hence, this part of the study had two purposes. First, it was aimed at performing sorption characterization of different Illinoisan coals by conducting adsorption experiments using pure methane. Second, it aimed to determine the potential for enhancement of CBM recovery by CO2 flooding of coal, partially saturated with methane, and study the binary adsorption equilibria for methane and CO2. Hence, as a first step, sorption experiments were carried out using coals from Herrin, Springfield and Davis seams for pure methane and CO2. The adsorption volumes measured experimentally (Gibbs adsorption) were converted to absolute sorption, which takes into account the volume occupied by the sorbed phase, and the difference between the two can be significant. For the samples tested, the difference was between 15 and 22% for methane, and 15% for CO2. Furthermore, the experimental adsorption data was analyzed using the Langmuir model, the one most commonly used in the CBM industry.

The impact of CO2 injection on release of methane from partially saturated coals was tested by a series of steps, where CO2 was injected/mixed during desorption. The results of the CO2 mixing steps showed that most of the methane content can be “stripped” from the coal, even when the total pressure remained relatively high. The incremental methane recovery by CO2 mixing was significant. The experimental results clearly suggest that a significant amount of methane in the low-pressure region of the isotherm can be recovered by mixing CO2 with the coal. This is usually the amount that is left behind, when a producing well is abandoned, due to low flowrates, that is, the operation becomes uneconomical. The selectivity ratio for CO2 over methane was found to be close to 3:1. This suggests that the coal is capable of storing three times more CO2 than methane, and that each incremental volume of methane produced would result in sequestration of three volumes of CO2. The interesting finding is that, in the low pressure region of the isotherm, this ratio approaches 6:1, suggesting even greater potential to sequester CO2 in the coal.

As found earlier, the results of the experimental work involving measurement of coal matrix volumetric strain showed that the coal matrix “shrinks” with release of methane, and “swells” with injection of CO2, and that the CO2 induced swelling is greater than the shrinkage induced by release of methane. The differential CO2:CH4 swelling is 2.2:1. This is consistent with the fact that the sorption capacity of coal for CO2 is significantly higher than that for methane. A permeability reduction can, therefore, be expected as a result of CO2 injection. Hence, although there will be an adverse effect of injecting CO2 on permeability, the initial permeability of coal is relatively high, and under field conditions, the overall effect on gas production might not be as negative as the findings suggest. Besides, the permeability results have shown that, with increase in gas pressure resulting from CO2 injection, the permeability would increase, thus compensating for some of the permeability damage.
After the results of the experimental work (sorption isotherm data, changes in permeability, shrinkage and swelling coefficients) and data from the ISGS became available, simulation runs were carried out, using the commercial CBM simulator COMET3, to evaluate the potential of long-term CBM production and CO2 sequestration. Since the experimental and field exploration work for assessment of CBM production potential in Illinois is still ongoing, not all the values of input parameters required for the simulation were available. For input parameters with values that were not available, average representative values of currently producing reservoirs in other US basins were used. Thus, simulation cases were constructed using the most representative available values of input parameters for the southern Illinois region.

Several different alternatives were considered for the simulation study. The first one was a simple base case of CBM production with different well spacing using the usual pressure depletion technique to project long-term production. The second was for the ECBM (Enhanced Recovery) alternative, that is, CO2 injection after partial production. For the two alternatives, several simulations were carried out with five main objectives: first, to establish a primary production model for the region; second, to evaluate the impact of CO2 injection on gas production; third, to estimate the impact of sorption induced matrix swelling on gas production; fourth, to estimate the CO2 sequestration potential; and finally, to carry out a sensitivity analysis of the input parameters having the highest impact on production.

After constructing the base case, simulation runs were carried out using different well layouts. It was realized that the five-spot pattern, the typical industry standard, is an optimum pattern for the Illinois Basin regions studied. Using the five-spot well pattern, simulation runs were carried out and the results were analyzed, mainly in the form of methane and water production rates, and reservoir pressure, as a function of time. The analysis of results provided a preliminary estimate of methane production potential in Illinois. The results, mainly gas content and water saturation, indicated that the ultimate CBM recovery was approximately 25% of the initial gas-in-place over a 1600 day period. As the initial reservoir pressure in the coal seams is not very high, the time taken for the reservoir pressure decline to reach a level below which CBM operation is no longer economical, was found to be rather short.

The results of the sensitivity analysis carried out to determine the impact of different input parameters on CBM production indicated that the most important ones were the permeability, pore volume compressibility, water saturation, and reservoir pressure. Thus, in order to obtain accurate production forecasts through simulation, it is essential to obtain reliable values of these parameters for Illinois coal. Under the best circumstances, that is, using the optimum but realistic values of input parameters, methane recovery can be increased to 50% of the initial gas-in-place, and this is still somewhat low.

For the ECBM alternative (CO2 injection), methane recovery increased to 90% of the initial gas-in-place over the 1600 day period simulated. Also, the effect of matrix swelling due to CO2 injection started to become prominent shortly after the injection of CO2 commenced, resulting in a rapid decrease in the reservoir permeability. Another
interesting finding was that the time taken for CO₂ to breakthrough to recovery wells was long, more than 1000 days. This has two distinct advantages. First, it is indicative of the excellent potential for CO₂ sequestration in the basin. Second, from a more practical point of view, it does not adversely affect the quality of gas being recovered. Furthermore, over the period of 1600 days simulated, the difference between the amount of CO₂ injected and recovered, that is, the net amount of CO₂ sequestered, was found to be approximately 1 billion cu ft. Finally, it required a significant amount of CO₂ injection prior to noticing the positive impact on CBM production. This finding was in agreement with the results of the sorption experiments, where the partial pressure of methane had to be reduced substantially before incremental methane production took place.

The assessment made and conclusions drawn, based on the simulation exercise, are still somewhat premature since there are several factors that are unknown about the basin. The most important one, and the one that has a severe impact on simulation results, is the pore volume compressibility, which in the case of coal is actually the “cleat compressibility”. The results obtained to date should, therefore, be considered preliminary and used with caution although they provide a good idea on the CBM production potential in Illinois, as well as the potential to sequester CO₂. Further studies are required to understand the physical structure of coal affecting the permeability, that is, the cleat characteristics, and estimate the value of pore volume compressibility for Illinois coals.
OBJECTIVES

**Overall Objectives:** The overall objective of this research study was to determine the technical feasibility of producing coalbed methane from Illinois coal on a commercial level by evaluating the permeability of coal, its variation over the life of production wells, and its impact on long-term gas production potential in Illinois.

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

I. Determine the permeability of coal cores taken from gas bearing parts of the Illinois Basin;
II. Establish permeability variation trends using the laboratory results, information gathered by the ISGS, and that available in the open literature;
III. Obtain adequate information about some of the other basic coal properties pertaining to CBM production for use as input parameters in simulating long-term gas production potential; and finally,
IV. Conduct a preliminary simulation exercise to determine the methane production potential of Illinois coal.

The tasks planned for the study are briefly described below:

**Task I: Permeability Testing:** This task included laboratory measurement of permeability of coal cores under simulated *in situ* conditions of stress, temperature, pressure, and gas composition, the situation being analogous to that of a virgin reservoir. The objective was to establish permeability variation trends, for use in predicting permeability changes over the life of production wells, and its impact on long-term gas production potential in Illinois, with and without injection of CO₂ as a means to enhance the CBM production.

**Task II: Other Coal Characterization Tests:** This task included the following sub-tasks:

a) **Sorption Characteristics:** Establishing methane/CO₂ sorption isotherms for the coal samples obtained from the exploratory wells drilled by ISGS to determine the ability of coal at these sites to retain/release methane and store CO₂.
b) **CO₂/Methane Displacement Experiments:** Evaluating the potential of enhanced methane recovery at the sites of exploratory wells by injecting CO₂ during the desorption part of the sorption cycle, and measuring the amount of additional methane released; and
c) **Changes in Physical Structure of Coal:** Determining if injection of CO₂ into a CBM reservoir resulted in a significant change in the physical structure of coal by measuring the volumetric strain induced in the coal matrix as a result of de/ad-desorption of methane/CO₂.

**Task III: Information Exchange with ISGS:** Since there is no commercial CBM activity in the state at this time, most of the current exploratory work is being carried out
by the Illinois State Geological Survey (ISGS) under the auspices of Department of Community and Economic Opportunity (DCEO) at the State level, and Department of Energy (DOE) at the Federal level. Hence, this task included maintaining very close contact with the ISGS personnel throughout the project duration, obtaining information from them about their field and analytical work, providing pertinent information to them, and finally, obtaining cores from their drilling program.

**Task IV: Gas Production Projection – Simulation:** This task included using the experimental results, and data from the ISGS, to carry out a fairly detailed simulation exercise to evaluate the potential of long-term CBM production and CO$_2$ sequestration in the state, and the difference in production with and without CO$_2$ injection for Illinois coal. It also included evaluating the impact of the variation in coal permeability on long-term gas production potential in Illinois.

**Task V: Communication:** This task included dissemination of the results to as large a community as possible by communicating the findings to potential CBM developers and researchers at various forums and conferences.

**INTRODUCTION AND BACKGROUND**

Economical viability of a coalbed reservoir depends primarily on the gas content of coal and permeability of the reservoir. Furthermore, coal permeability being dynamic in nature, requires that a good knowledge about its variation over the life of a reservoir be acquired prior to making any long-term gas production projections. This is even more critical in situations where a second gas is injected to enhance the production of gas, further affecting the permeability of coal.

Limited information available for the Illinois Basin suggests that the gas content of the coal varies significantly across the basin. Although there are several “sweet spots” for commercial production of CBM, there are also regions within the basin with low gas content. However, tremendous success with recovery of methane in the Powder River Basin, where the gas content is low to very low, has increased optimism that CBM can also be recovered commercially from the Illinois Basin. As for the second factor, the coal is well cleated. The permeability is, therefore, expected to be good.

Combining the above two findings, Illinois has definite potential for economic recovery of CBM. However, since the gas content of Illinois coal is low compared to other US basins with significant CBM activity, enhanced coalbed methane (ECBM) techniques can have a significant economic impact on commercial CBM production, and these must be considered when planning CBM or CO$_2$ sequestration operations. With enormous coal reserves in the basin, ECBM, apart from providing excellent potential to increase the recovery of available CBM, also presents a vast potential to sequester large quantities of CO$_2$. However, prior to any full-scale commercial CBM production, it is critical to carry out elaborate testing of coal in order to obtain accurate assessment of flow characteristics of the coal. Hence, this research study was aimed at developing a good understanding of the following:
1. The permeability of Illinois coal, its variation over the life of production wells, and its impact on long-term gas production potential.

2. The mechanism of binary adsorption of methane and carbon dioxide on coal, and the ability of carbon dioxide to displace methane from coal.

3. Changes in the physical structure of coal associated with release of methane, retention of CO₂, and the impact of coal matrix volumetric change on coal permeability.

Based on the brief background presented above, this study was initiated in order to: 1) measure the permeability of coal in order to establish and predict its variation over the life of a reservoir, with and without CO₂ injection, 2) better understand the sorption mechanism of coal in a multi-gas environment, and investigate whether methane recovery with CO₂ injection is, in fact, enhanced, and 3) estimate the changes in flow characteristics of coal as a result of volumetric strain associated with CO₂ injection, and as a final step, 4) carry out simulation of long-term gas production for different alternatives using the results of the study, with and without CO₂ injection, along with the potential for sequestration of CO₂.

**EXPERIMENTAL PROCEDURES**

**Sample Procurement and Preparation**

Based on the preliminary work on CBM resource assessment completed by the ISGS, cores of coal were obtained from the ongoing exploratory drilling program of ISGS in the Herrin, Springfield and Davis 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**

Establishing sorption isotherms and carrying out flooding experiments was a continuation of the work completed under a prior ICCI study [1]. This involved preparing pulverized samples of coal (40-100 mesh) using parts of the coal cores. Prior to sorption experiments, ~80 g of the sample was taken and placed in the environmental chamber, at reservoir temperature and 96% relative humidity, for 24-36 hours for moisture equilibrium. Of the moisture equilibrated sample, one gram was used for moisture and ash analyses, and the rest was used for the sorption experiment. Using the standard volumetric technique using the mass balance procedure, sorption experiments were carried out for methane and CO₂ up to a final pressure of 1500 and 800 psi respectively (the maximum available bottle pressures). Once the maximum pressure for the adsorption isotherm was reached, the process was reversed to obtain the desorption characteristics.
For CO₂ flooding experiments, the adsorption test was completed following the standard procedure. During the desorption part of the cycle, standard procedure was followed until the pressure reduced to ~500 psi. CO₂ was then injected at a pressure of ~500 psi. After equilibrium, the gas composition was measured using a gas chromatograph (GC). Using the measured molar composition, the partial pressures of the two gases were calculated. This allowed further calculation of the volume of each gas adsorbed/desorbed. The procedure was repeated until the partial pressure of methane reduced to less than 100 psi.

**Permeability Experiments**

**Sample Preparation:** Just prior to testing, appropriate 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 simulate the conditions *in situ*, controlling and monitoring of the external stress conditions and gas pressure are very important. The experimental setup for permeability measurement was, therefore, designed to have independent control of stress conditions, gas pressure (upstream and downstream), and measurement of gas flowrate. The setup consisted of a triaxial cell, a loading system, and a means to monitor and measure flowrate. A schematic of the experimental setup is shown in Figure 1. The setup enabled applying both confining and axial stresses independently to simulate the *in situ* conditions. The axial stress was applied by placing the cell in a load frame. The triaxial cell was connected to a hydraulic pump to provide the confining stress. The perforated steel disks and porous metal plates were placed at both ends of the sample to distribute (and collect) the gas and prevent small particles from entering the tubing. The temperature of the triaxial cell was kept constant using a heating tape and temperature controller. The gas containers at the inlet and outlet were placed in the water bath, set at the same temperature as that of the triaxial cell. The gases entering and coming out of the triaxial cell were, therefore, at the same temperature. To keep the downstream pressure constant, a relief valve was used.

**Experimental Conditions:** Cores used for the permeability experiments were taken from a depth of 880 feet, with the gas pressure of virgin coal estimated to be ~600 psi. The estimated reservoir temperature at the depth was estimated to be 72°F. Hence, all tests were carried out at these conditions of temperature, maximum gas pressure, and levels of external stresses. The tests were carried out on cylindrical cores of coal, 3 inches in diameter and ~3 inches long, depending on the length of the cores received.

Prior to testing, the core, along with the perforated steel disks and porous metal plate, was sealed using PVC shrinkage tubing in order to avoid seepage of oil into the core during application of stress. This is shown in Figure 2. The core setup was then placed in the cell, which in turn, was placed in the load frame. The sample was then stressed triaxially, using the loading frame for axial stress and hydraulic pump for confining stress.
Before injecting gas into the sample, the triaxial cell was properly insulated to maintain constant temperature throughout the experiment, as shown in Figure 3. The core sample was then saturated with gas, at the desired pressure, by injecting gas through the inlet, keeping the outlet closed. After attaining pressure equilibrium, a pressure gradient of 40-60 psi was applied across the sample using a relief valve. 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 for the gas was calculated. The testing procedure was the same for methane and CO$_2$. Since it took between eight and fifteen days to attain equilibrium for each pressure step, a complete permeability test required three to four months.
Changes in Physical Structure of Coal

This part of the study was a continuation of the work completed for ICCI to determine the viability of using Illinois coal for CO₂ sequestration and methane production during the year 2002-03 [1]. Rectangular specimens (prisms), cut from a block of coal using a handsaw, were used to enable measurement of volumetric strain due to changes in gas composition, maintaining all other experimental conditions (external pressure, temperature, humidity) constant.

Three samples were first subjected to increasing helium pressure in steps of 400 psi and volumetric strain was measured at equilibrium for each step. After attaining equilibrium at 1500 psi, one of the samples was left alone to serve as the control test. The second sample was subjected to increasing concentration of methane, maintaining the total pressure constant at 1500 psi. For the third sample, same procedure was followed using CO₂ instead of methane. Once the second sample was completely saturated with methane, carbon dioxide was injected to determine the volumetric strain for methane/CO₂ exchange.

RESULTS AND DISCUSSION

Task I: Permeability Testing

Preliminary Testing: Following the method described in the section above, trial tests were initially carried out using sandstone samples due to their simple, well understood, and documented behavior. The purpose of these tests was to understand the procedure and ensure proper working of the entire setup. Based on these tests, minor modifications were made to improve the setup. To confirm proper working of the setup with coal, and gain some experience with operation of the setup prior to using valuable cores, a sample from the Herrin seam was used for one permeability test.
**Permeability Calculation:** Darcy’s equation, modified for compressible fluids, was used to calculate the permeability of coal. The equation is given as:

\[ k = \mu \frac{Q_0}{A} \frac{L}{\Delta P} \frac{P_0}{\Delta P_m} \]

where, \( \mu \) is the viscosity of the gas, \( Q_0 \) is the volumetric flow rate at the outlet, \( A \) is the cross sectional area of the sample, \( L \) is the length of the sample, \( P_0 \) is the gas pressure at the outlet, \( \Delta P \) is the pressure difference between upstream and downstream, and \( P_m \) is the mean gas pressure \([P_0 + P_1]/2\).

**Permeability Results:** The first permeability test was initiated using a well preserved core taken from the Springfield seam. The core was taken from a depth of 880 ft. The test was conducted in two phases. In the first phase, the sample was subjected to a constant axial stress of 930 psi, and confining stress of 600 psi respectively, which are both representative of the stresses *in situ*. The temperature throughout the test was maintained at 72±1°F. The gas flow measurements were carried out for varying effective stress levels by changing the mean gas pressure, maintaining the applied axial and confining stresses constant. Using the flow measurements, permeability of the sample to methane was determined using equation (1). For a change in the horizontal effective stress from 180 psi to 480 psi, the permeability decreased from 75 to 6 md. The permeability variation with change in effective stress is shown in Figure 4. It is evident from the graph that the permeability decreases log-linearly with increase in effective stress. This is expected since increased effective stress compacts the cleats in the coal, resulting in cleat closure and reduced permeability.

![Figure 4: Variation in permeability with changes in horizontal effective stress.](image-url)
In the second phase, the sample was subjected to a constant effective stress throughout the experiment. The axial and confining effective stresses were maintained at approximately 860 and 510 psi respectively. The gas flow measurements were made by varying the mean gas pressure, and permeability of the sample for methane was determined. The permeability results for this phase are shown in Figure 5. It is evident from the results that the permeability decreases linearly with decrease in mean gas pressure. This finding was somewhat unexpected since a reduction in pressure results in shrinkage of coal matrix, and thus increased permeability. From these results, it appears that there is a coupled effect due to external applied stress and the volumetric strain induced by desorption of methane. At high stresses, like those encountered in the San Juan Basin, the permeability does increase with reduction in pore pressure.

![Permeability vs. Mean Gas Pressure](image)

Figure 5: Variation in permeability with changes in mean gas pressure – constant effective stress.

As a continuation of the above experiment under the same experimental conditions of temperature, pressure and stress, the core was tested using CO₂. The test was, once again, conducted in two phases, maintaining the applied axial and confining stress constant in the first phase, and the effective stress constant in the second phase. The gas flow measurements were made by varying the mean gas pressure. The change in permeability with changes in mean gas pressure for methane and CO₂ is shown in Figure 6. From these permeability trends, it is evident that, at zero mean gas pressure, the permeability becomes zero – as expected.

For the second phase of experiment using CO₂, the sample was subjected to a constant axial and confining stress of 940 and 610 psi respectively. Using the flow measurements, permeability of the sample to CO₂ was determined. For a change in horizontal effective stress from 330 to 515 psi, the permeability decreased from 3.2 to 1 md. The variation in permeability with changes in horizontal effective stress for methane and CO₂ is shown in Figure 7. It is evident from the graph that the permeability decreases with increase in effective stress. The trend of permeability variation vs. effective stress also correlates...
well with the findings of earlier studies illustrating the exponential relationship of the form [2]:

$$k = Ae^{B \sigma_h}$$  \hspace{1cm} (2)

where, $\sigma_h$ is the horizontal effective stress and A and B are constants. The value of A represents the permeability at zero stress, and B depends on the type of particular coal. At zero effective stress, the permeability of coal sample to methane is 300 md while that to CO$_2$ is 30 md – difference of an order of magnitude. This might be the explanation for the field observations made at Burlington Resources’ Allison site, where a reduction of in situ coal permeability of two orders of magnitude, is suspected. Of course, the CO$_2$ injection site was at a depth of ~1800 feet and the injection pressures used were very high [3].

![Graph showing variation in permeability with mean gas pressure.](image)

Figure 6: Variation in permeability with changes in mean gas pressure – constant effective stress.

**Changes in Physical Structure of Coal**

Since this was a continuation of the work completed under the ICCI project 02-1/6.1A-4 [1] entitled, “Viability of CO$_2$ Sequestration and Methane Production in Illinois Coal”, a brief description of results reported earlier is included here for the sake of completeness.

The first part of the experimental phase involved dosing all samples with increasing amounts of helium while monitoring the strain continuously. Using the measured strain, the volumetric strain was calculated for each sample and, as expected, the volume of coal matrix decreased with increasing gas pressure due to compression of the coal grains. This was followed by injecting methane in one of the pressure vessels, maintaining the total pressure constant. For the third sample, helium was bled out to reduce the pressure to approximately 850 psi, and CO$_2$ was then injected.
The results showed that the swelling due to carbon dioxide adsorption was significantly greater than that for methane. This was consistent with the fact that the sorption capacity of coal for CO₂ is significantly higher than that for methane [4]. Using the same approach as that used for estimating matrix shrinkage coefficient, the swelling coefficients for samples were calculated.

As a part of the current study, carbon dioxide was injected into a methane saturated sample to determine the volumetric strain for methane/CO₂ exchange. Methane was first bled out to reduce the pressure to approximately 850 psi, and after attaining equilibrium, CO₂ was injected at 850 psi, maintaining the total pressure constant. With subsequent injections, volumetric strain was calculated for each step. The results are shown in Figure 8. The plot shows the change in volumetric strain due to increasing methane, CO₂, and methane/CO₂ exchange pressure in the samples. For pressures up to 745 psi, the volume of coal matrix increased by ~0.65% due to methane adsorption alone, by ~1.2% due to CO₂ adsorption, and by 1.02% by methane/CO₂ exchange. It is evident from these results that the volumetric strain due to methane/CO₂ exchange is less compared to that of CO₂ adsorption alone. This is due to the fact that, in the case of methane/CO₂ exchange, a part of the swelling of coal matrix resulting from adsorption of CO₂ is compensated for by shrinkage of the coal matrix due to desorption of methane, since the two processes occur simultaneously.

For the final phase of the experiment, the sample saturated with pure CO₂ was desorbed by injecting helium and bleeding out CO₂, maintaining the total pressure constant. The complete adsorption/desorption phase for CO₂ and methane/CO₂ exchange are shown in Figure 9. The results show that the path taken by desorption is very similar to that taken by adsorption.
Figure 8: Volumetric strain of samples with respect to partial pressure of methane, CO₂ and methane/CO₂ exchange.

Figure 9: Volumetric strain for pure CO₂ and methane/CO₂ exchange.

**Sorption-Volumetric Strain Relationship:** An interesting aspect of the volumetric strain-pressure relationship is its similarity to the sorption isotherms. The sorption isotherm of similar coal was established, as detailed out in the Sorption Experiments section. Figure 10 shows the sorption-pressure and volumetric strain-pressure relation for methane on the same plot, suggesting a linear relationship between the sorption induced volumetric strain and the sorbed volume of methane. This is further shown in Figure 11. The relationship compares well with the previous results reported [5]. Thus, it is possible to estimate the volumetric strain associated with methane sorption for a given type of coal, if the sorption isotherm is known, along with the constant of proportionality.
Figure 10: Sorbed volume and volumetric strain vs. methane pressure.

Figure 11: Sorbed volume-volumetric strain relationship for methane.

However, a similar plot for CO$_2$, shown in Figure 12, did not exhibit such a clear linear relationship. The plot shows that, during the initial CO$_2$ sorption steps, the volumetric strain is much higher, but soon reaches a saturation level. The plot is steeper at lower pressure values and becomes nearly flat as the pressure increases. This might be due to a very high sorptive affinity of the particular coal for CO$_2$ at low pressures, a finding that supports injection of CO$_2$ into coal from a sequestration point of view.
Figure 12: Sorbed volume and volumetric strain vs. pressure for CO$_2$.

**TASK II: Other Coal Characterization Tests**

**Methane and CO$_2$ Sorption/Displacement Tests**

**Sorption Isotherms:** This sub-task was divided into two parts: single gas sorption analysis and CO$_2$ flooding. Single gas sorption experiments on the Illinoisan coals were completed for methane and CO$_2$. The Gibbs adsorption was determined experimentally. The absolute sorption, which is more representative at higher pressures, was calculated from the Gibbs adsorption using the equation below:

$$V_{\text{abs}} = \frac{V_{\text{Gibbs}}}{\frac{\rho_{\text{gas}}}{L} - \frac{\rho_{\text{ads}}}{P}}$$

(3)

where, $V_{\text{abs}}$ and $V_{\text{Gibbs}}$ are the absolute and Gibbs sorption respectively, and $\rho$ is the density of the gas. The value for the sorbed density for methane and CO$_2$ were taken from Arri et al [3] to be 0.421 g/ml and 1.18 g/ml respectively. The experimental sorption data were analyzed using the Langmuir isotherm model [6], given as:

$$V = \frac{PV_L}{P + P_L}$$

(4)

where, $P$ is the equilibrium gas pressure, $V$ is the volume of gas adsorbed, $V_L$ is the Langmuir monolayer volume, and $P_L$ is the Langmuir pressure constant. The Langmuir constants for the samples tested are shown in Table 1, and the absolute sorption isotherms
are shown in Figure 13. All isotherms are of Type I, according to Brunauer’s classification [7]. It can be seen from Table 1 that the range of the relative absolute sorption \( \frac{V_{CO2}}{V_{CH4}} \) is 2.2-3:1. Also, Herrin seam not only has the largest capacity to sorb methane/CO\textsubscript{2}, but also has the highest relative sorption ratio.

| Sample  | Methane | | CO\textsubscript{2} | | Relative sorption |
|---------|---------| | | | |
|         | \( V_L \) (scft) | \( P_L \) (psi) | \( V_L \) (scft) | \( P_L \) (psi) | |
| Herrin  | 603     | 740 | 1324 | 347 | 3:1 |
| Springfield | 338     | 474 | 785  | 314 | 2.5:1 |
| Davis   | 364     | 372 | 644  | 163 | 2.2:1 |

**Table 1: Langmuir Parameters for Absolute Sorption**

**Figure 13: Sorption isotherms for Illinois coal samples.**

**CO\textsubscript{2} Flooding:** The adsorption isotherm for a sample from the Herrin seam was first established for a maximum pressure of 1260 psi. At 1260 psi, the methane content was 380 scft. By a series of desorption steps, the pressure was reduced to 535 psi and the methane content reduced to 248 scft. At this point, CO\textsubscript{2} was allowed to mix with the methane in the sample at a pressure of 550 psi. After equilibrium, the total pressure of the system was measured to be 539 psi. The partial pressure of methane came down to 231 psi, and the gas content reduced to 207 scft. This step was repeated for second CO\textsubscript{2} “injection” at similar pressure, that is, 550 psi, and a third time at 545 psi. The three CO\textsubscript{2} injection steps brought the methane content down from 248 scft to 15 scft, a release of additional 233 scft, even when the total pressure remained high (approximately 540 psi). The amount of additional methane recovered as a result of the three injection steps is
43% of the maximum methane content of the coal sample ($V_L$ for the sample tested was 540 scft). The ratio of adsorbed CO$_2$ to desorbed methane was approximately 6:1. The experimental results are shown in Figure 14 and 15. Figure 14 suggests that, with injection of CO$_2$, incremental sorbed methane can be released while maintaining the total pressure relatively high (~550 psi). However, a closer look at Figure 15 indicates that the rate of release of methane with reduction in partial pressure of methane is slow initially, until the latter comes down to ~100 psi, after which most of the methane is released. Hence, it is possible to recover most of the sorbed methane by CO$_2$ mixing, provided the partial pressure of methane is brought down significantly. From a practical point of view, this translates to a significant amount of CO$_2$ injection prior to seeing its enhancement impact.

![Figure 14: Methane desorbed with CO$_2$ flooding - Herrin sample.](image)

The experimental results were similar for coals from the Springfield and Davis seams. Based on the results, it appears that using CO$_2$ to enhance the production of methane would have multiple advantages. First, the gas content of Illinois coals is relatively low, and the primary depletion technique alone is not going to result in adequate long-term production of methane since a large fraction of methane is going to remain adsorbed at the time of abandonment. Second, even though the CO$_2$ injection and final storage pressure can not be very high (0.8 psi per foot of depth), injected CO$_2$ will be able to “strip” most of the methane from coal, leaving very little behind at the time of abandonment. Furthermore, the relative sorption of the coal at low pressures is high. Hence, there is potential for sequestration of large quantities of CO$_2$ even at relatively low pressures. In fact, for each molecule of incremental methane released, four to six molecules of CO$_2$ will be retained by the coal at permissible pressures. Finally, the
injection pressure would probably be ~500 psi, favoring the economics of ECBM and sequestration in the Illinois Basin since a major cost of CO₂ injection is the compression cost and the associated heating required to ensure that the CO₂ does not liquefy/freeze like, at the RECOPOL site in Poland, for example.

![Desorption isotherm with CO₂ flooding - Herrin sample.](image)

**Figure 15:** Desorption isotherm with CO₂ flooding - Herrin sample.

**TASK III: Information Exchange with ISGS**

Throughout the project duration, very good contact was maintained with the ISGS personnel. ISGS provided well preserved cores for this research study. ISGS personnel also provided the results of their findings on a regular basis. For the simulation part of the study, they provided “best guess” estimates for some of the input parameters, for which no measured values were available, based on a database developed by them. Although the database is developed using values from the San Juan and Black Warrior Basins, and the numbers might not be applicable for the Illinois Basin, these were the best values available. Finally, meetings with the ISGS personnel helped tremendously focus on future research issues that need to be pursued in order to promote the growth of CBM production and CO₂ sequestration in Illinois.

**TASK IV: Gas Production Projection – Simulation**

The results of the experimental work discussed in Tasks II and III suggest that the injected CO₂ into deep coals not only displaces additional methane while getting adsorbed, but also results in a decrease in the fracture permeability due to the associated swelling of the coal matrix [3, 8, and 9]. In an actual CBM reservoir, this would impede
the flow of CO$_2$/CH$_4$ with significant impact on the economic feasibility of the ECBM option. Hence, the experimental results, along with the information gathered by the ISGS from the exploratory wells drilled in southern Illinois, were used to carry out a fairly detailed simulation exercise to determine the effects of CO$_2$ injection on methane recovery. The coal and reservoir property data required for the simulation study were primarily obtained from the following three sources:

1. **Flow Characterization Lab, SIU**: Sorption data ($V_L$, $P_L$), differential swelling factor ($C_k$), matrix shrinkage compressibility ($C_m$), and permeability ($k$);
2. **ISGS Exploration Data**: Coal seam data (extent, thickness, rank, depth, fracture water saturation, pore compressibility, porosity, etc.); and
3. **Literature Survey/Published data**: Production schedule and rates, bottom hole pressure, relative permeability, permeability exponent, run control parameters, etc.

Since the exploration and research work is still ongoing, not all properties of Illinois coals were available. For parameters not available, average values of properties of currently CBM producing regions were used. Hence, the results of the simulation exercise should be reviewed/used with caution.

A sample test reservoir, with coal properties representative of Illinois Coal Basin, was developed. The input parameters used are shown in Table 2. A base case scenario simulating primary methane recovery for duration of 1600 days was first constructed. In order to analyze the effect of CO$_2$ injection, this was modified to include CO$_2$ injection by continuously injecting CO$_2$ after 200 days of primary production, for the remaining period simulated.

<table>
<thead>
<tr>
<th>Table 2: Input Parameters Used for Simulation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Coalbed Properties</strong></td>
</tr>
<tr>
<td>Net coal seam thickness</td>
</tr>
<tr>
<td>Depth of coal seam</td>
</tr>
<tr>
<td>Fracture permeability</td>
</tr>
<tr>
<td>Fracture porosity</td>
</tr>
<tr>
<td>Coal compressibility</td>
</tr>
<tr>
<td>Matrix shrinkage compressibility</td>
</tr>
<tr>
<td>Differential swelling factor</td>
</tr>
<tr>
<td>Coal density</td>
</tr>
<tr>
<td><strong>Sorption Characteristics</strong></td>
</tr>
<tr>
<td>Langmuir volume (CH$_4$,CO$_2$)</td>
</tr>
<tr>
<td>Langmuir pressure (CH$_4$, CO$_2$)</td>
</tr>
</tbody>
</table>
**Base Case:** The base case simulated one-fourth of a 40-acre reservoir, with a production well located in one corner of the square quadrant. The primary production was simulated for a duration of 1600 days. Some of the results obtained through initial simulation, for example, the initial gas content and permeability variation, were compared with the results calculated from analytical methods in order to verify the validity of the model. The results obtained from the simulator matched closely with those calculated by analytical methods, thus improving the confidence of the model. The base case results were then analyzed for percentage methane and water recovery. The initial gas content and final methane production are shown in the Table 3.

<table>
<thead>
<tr>
<th>Table 3: Base Case Results</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Initial CH₄ Content (bcf)</strong></td>
</tr>
<tr>
<td>0.026348</td>
</tr>
</tbody>
</table>

**CO₂ Injection Case:** The base case was modified to CO₂ injection case by injecting CO₂ at a pressure of 800 psi, after 200 days of primary production, for the remaining period simulated. The results obtained were compared with the base case in order to analyze the effect of CO₂ injection, and are shown in Figure 16. The result was a significant increase in the methane recovery as a result of CO₂ injection.

![Figure 16: Cumulative methane production with and without CO₂ injection.](image)
Figure 17 shows the incremental methane recovery with CO₂ injection in comparison to the base case. The methane recovery with CO₂ injection was approximately 90% of the initial gas-in-place, which is an increase of about 350% compared to methane recovery in the base case by primary depletion. This increase in methane production of ~18,000 Mscf was achieved by continuous CO₂ injection for a period of 1400 days. Nearly 120,000 Mscf of CO₂ was injected during the period, of which ~100,000 Mscf was retained in the coal. The results also show that the effect of CO₂ injection on methane recovery is not instantaneous. It becomes prominent only after considerable amount of CO₂ has been injected, that is, after 200 days of continuous CO₂ injection. This corroborates the findings of the flooding experiments, where substantial methane is released only after the partial pressure of methane is reduced substantially. Hence, it would also be reasonable to assume that the enhancement of methane recovery achieved by CO₂ injection is due to the preferential adsorption of CO₂ over CH₄ in coal, and the ability of CO₂ to displace majority of the methane from the coal matrix. The results of CO₂ injection case are shown in Table 4. The ratio of net CO₂ sequestered to incremental methane recovery is approximately 5:1 (90000Mscf/18000Mscf), which supports the findings showing CO₂ to be 3 to 6 times more sorptive on coal than methane.

![Figure 17: Incremental methane recovery vs. CO₂ injection.](image)

Table 4: CO₂ Injection Case Results

<table>
<thead>
<tr>
<th>Initial CH₄ Content (bcf)</th>
<th>Cumulative CO₂ Injected (bcf)</th>
<th>Cumulative CH₄ Produced (bcf)</th>
<th>Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.026348</td>
<td>0.13</td>
<td>0.0239</td>
<td>90%</td>
</tr>
</tbody>
</table>
Matrix Swelling: The third simulation was carried out to estimate the adverse effect of matrix swelling due to injection of CO₂, and the associated adsorption, resulting in coal matrix volumetric strain. This was estimated by comparing two cases, one taking into account the matrix swelling effect, and the other ignoring it. The results are shown in Figure 18. It can be seen in Figure 18 that, when the matrix swelling is considered, the surge in methane production rate due to CO₂ injection is absent. This absence of increased methane production rate can be attributed to a decrease in permeability of coal caused by matrix swelling. The results highlight the negative impact of matrix swelling on methane production by comparing the production rates for the two cases.

![Figure 18: Methane production rate with and without the effect of matrix swelling.](image)

CO₂ Sequestration: Figure 19 shows the potential for CO₂ sequestration in the Illinois Basin. It is apparent that approximately 75% of injected CO₂ is being sequestered, with very little breakthrough occurring, and that too after a considerable post-injection period. From the simulation results, it appears that methane production will be discontinued after ~1300 days due to significant CO₂ breakthrough, unless the carbon credits justify continued injection.

Permeability Variation: The variation in permeability due to primary production was analyzed for the period simulated using the model proposed by Palmer and Mansoori [10]. The model considers the effects of both pore volume compressibility and matrix shrinkage compressibility. Although the model has not been subjected to rigorous testing in the field, it is based on solid rock mechanics principles. It is given as:
where,

\[
\phi = 1 + \frac{1}{M \phi_i} (P - P_i) + \frac{\varepsilon L}{\phi_i} \left( \frac{K}{M} - 1 \right) \left( \frac{P}{P + P_L} - \frac{P_i}{P + P_L} \right)
\]

(5)

\[
\frac{k}{k_i} = \left( \frac{\phi}{\phi_i} \right)^3
\]

(6)

where,

- \( M \) = Constrained axial modulus, psi
- \( K \) = Bulk modulus of coal, psi
- \( \varepsilon_L \) = Langmuir dimensionless strain constant
- \( P \) = Reservoir pressure, psi
- \( P_i \) = Initial reservoir pressure, psi
- \( P_L, V_L \) = Langmuir constants
- \( \frac{k}{k_i} \) = Permeability as a fraction of initial permeability

Application of the model requires values for coal moduli, and reservoir pressure at different times, to obtain the variation in permeability. The reservoir pressures at different times were obtained from the base case simulation, and used as input into the Palmer and Mansoori model. Figure 20 shows the variation in permeability \( \frac{k}{k_i} \) with variation in reservoir pressure. It can be seen that after an initial decrease in the
permeability, the permeability rebounds and improves with continued production although the increase in permeability due to the matrix shrinkage effect is fairly small. The actual change in the permeability is probably less important at this stage since there is some uncertainty about the values of the input parameters. However, the important finding is that there is a rebound in permeability and that the rebound pressure is approximately 250 psi.

Figure 20: Permeability variation with CH₄ production based on Palmer and Mansoori model.

Sensitivity Analysis: During the initial trial simulation runs, it was realized that gas production was extremely sensitive to the values of two input parameters: cleat permeability and pore volume compressibility. Also, these two parameters were selected because dependable estimates for these two were not available. Hence, the preliminary sensitivity analysis concentrated on varying the values of these two input parameters in various simulations, and analyzing the impact on gas production. Based on the database developed by ISGS, the value of pore-volume compressibility of coal ranges between 100 – 800 x 10⁻⁶/psi. The results of the sensitivity analysis for the base case are shown in the Table 5 and 6.

The findings of the sensitivity analysis show that, for the case simulated using the best case, a permeability of 50 md and pore-volume compressibility of 200 x 10⁻⁶/psi, the primary CH₄ recovery is still only 43%. The value dips significantly if the permeability is lower. Once again, this suggests the need for employing ECBM techniques for improved methane production in the state.
Table 5: Sensitivity of Production to Permeability

<table>
<thead>
<tr>
<th>Permeability (md) (x, y-dir)</th>
<th>Pore-volume compressibility (psi⁻¹)</th>
<th>Methane Recovery (%)</th>
<th>Water Recovery (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>200 x 10⁻⁶</td>
<td>16</td>
<td>8</td>
</tr>
<tr>
<td>20</td>
<td></td>
<td>26</td>
<td>12</td>
</tr>
<tr>
<td>50</td>
<td></td>
<td>43</td>
<td>17</td>
</tr>
</tbody>
</table>

Table 6: Sensitivity of Production to Pore-volume Compressibility

<table>
<thead>
<tr>
<th>Permeability (md) (x, y-dir)</th>
<th>Pore-volume compressibility (1/psi)</th>
<th>Methane Recovery (%)</th>
<th>Water Recovery (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>20</td>
<td>100 x 10⁻⁶</td>
<td>27</td>
<td>11.1</td>
</tr>
<tr>
<td></td>
<td>800 x 10⁻⁶</td>
<td>20.4</td>
<td>13</td>
</tr>
</tbody>
</table>

**TASK V: Communication**

The work carried out as a part of this project was discussed with other researchers and potential producers at several opportunities that arose during the last eighteen months. For the research community, presentations were made at Eurock 2004 and 2004 International Carbon Sequestration Conference. One presentation will be made at the 2005 International Coalbed Methane Symposium, and another at the 2006 SME Annual Meeting. Informal presentation of the work and progress was also made at the Industrial Advisory Board Meeting of TerraTek in Salt Lake City, Utah and at the Coal-Seq Forum in Washington, D.C.

**CONCLUSIONS AND RECOMMENDATIONS**

The specific conclusions based on the work completed to date are as follows:

1. All Illinois coals have a preferential sorptive affinity for CO₂ over methane; the final relative sorption ratio (Langmuir Volumes) varies between 2:1 and 3:1. The results of the CO₂ flooding experiments suggest that significant amount of incremental methane in the low pressure region of the isotherm can be recovered by repeatedly flooding the coal, partially saturated with methane, with CO₂ until the partial pressure of methane is reduced significantly. Also, in the pressure range of interest, the relative sorption ratio is much higher. In fact, for each molecule of methane produced, it is possible to adsorb, and sequester, three to five molecules of CO₂.

2. The permeability measurement results suggest high to medium permeability values making several Illinois coals suitable for CBM operations. The measured variation in
permeability further suggests that, with continued drainage, CBM production would change significantly. It is felt that by employing an enhanced recovery technique, the CBM recovery potential can be increased significantly and this should be taken into consideration when planning for commercial operations.

3. The permeability trend shows that change in effective stress due to changes in gas pressure is the main contributing factor in bringing about the permeability reduction. Matrix shrinkage due to desorption of methane, or swelling due to injection of CO₂, does not seem to have a significant influence on the permeability variation for the coals tested.

4. There is a linear decrease in permeability with pressure decline. This is perhaps due to a decreased “push” for the gas to continue moving. This favors application of an ECBM technique by gas injection, since the pressure decline encountered with the pressure decline method would be prevented.

5. The swelling due to methane/CO₂ exchange is less compared to sorption of CO₂ alone. This suggests that the simultaneous process of shrinkage due to methane desorption and swelling due to CO₂ injection reduces the permeability damage due to swelling alone, once again, favoring the ECBM technique by CO₂ injection.

6. The sorption-induced volumetric strain is linearly proportional to the amount of methane sorbed. However, in case of CO₂, this linear relationship fails. This might be due to the fact that the amount of CO₂ adsorbed in the low pressure region of the isotherm is significantly larger compared to methane. This is apparent from the low P₄ values for CO₂ as well. The practical implication of this is that large quantities of CO₂ can be sequestered at low pressures thus favoring the economics of CO₂ sequestration in Illinois coals.

7. The results of the simulation exercise suggest that injection of CO₂ can increase the production of methane significantly. Furthermore, the coals in Illinois have tremendous potential to sequester CO₂. The matrix swelling due to sorption of CO₂ can reduce the permeability drastically. It is not very clear how much of this will be compensated for by the increase in permeability due to increased gas pressure, and matrix shrinkage induced by the release of methane.

Based on the above specific conclusions and findings, it is concluded that an enhanced coalbed methane recovery technique should be considered in Illinois throughout the production period, as opposed to following the primary depletion method for initial production. Even at relatively low injection pressures, as would be the case in Illinois, it is possible to strip 90% of gas-in-place from the coals. The real enhancement would occur only after substantial injection has taken place. The increased pressure resulting from the injected CO₂ would have several benefits. First, it would reduce the increase in effective stress, and dampen the negative impact of increased stress on permeability. Second, it would promote the flow of gas due to increased driving force pushing the methane out. Finally, it would result in sequestration of large quantities of CO₂.
From a sequestration point of view, more CO$_2$ can be sequestered if relative sorption capacity of coal for CO$_2$ is higher. This is also true from a carbon credits point of view, if and when these credits go into effect. However, from an economic point of view, the lower the relative sorption capacity, the smaller the amount of CO$_2$ that must be injected to obtain the incremental gas recovery. For Illinois coals, the relative sorption at low pressures is high and this favors CO$_2$ sequestration and incremental methane production in the state. However, it also means that a large quantity of CO$_2$ will have to be injected in order to recover any significant amount of incremental methane. This may very well happen if there are adequate carbon credits to support such an operation.

Based on the experience gathered during this study, and discussions with the ISGS personnel, it is recommended that the following areas of research be pursued further:

1. The desorption times for most Illinois coals have been found to be very long suggesting low diffusion rates and/or large cleat spacing. Studies must, therefore, be carried out to understand the mechanism of diffusion of gas in the coal matrix of Illinois coals.

2. Injection of CO$_2$ results in lowering of the coal permeability due to its higher sorption affinity for coal. Nitrogen, on the other hand, is weakly sorbing. It has been shown in one laboratory study and one pilot field study that injection of nitrogen can also result in enhanced recovery of methane. Hence, injection of a mixture of the two gases should be considered as a means to enhance the gas recovery. CO$_2$ would do so by displacing the methane, while nitrogen would impact the flow of methane towards the production wells by reducing the partial pressure of methane, and providing the driving force required for movement of gas. A major benefit of this would be the potential of using flue gas, consisting primarily of nitrogen and CO$_2$. The result would be a significant savings since separation of nitrogen to obtain a CO$_2$ stream will not be necessary at the upstream end. However, nitrogen, due to its early breakthrough, would require separation from methane at the downstream end. Hence, along with the technical feasibility of this alternative, economics of the option should also be evaluated carefully.

3. Since cleats are the dominating factor influencing the permeability of coal, a study should be undertaken to study cleat characteristics (spacing, continuity, aperture), and how these change with depletion as well as injection of a second gas.

4. One parameter having a major impact on long-term gas production is the pore volume compressibility, $C_p$, which in the case of coal is the “cleat” compressibility. There is absolutely no information available about the value of this parameter for Illinois coals. The values available in the literature are primarily for the San Juan and Black Warrior Basins, and given the difference in coal type, these might be far from representative of Illinois coals. Hence, a study must be undertaken to obtain reliable estimates for $C_p$.

Some of the above recommendations will be pursued at SIU in the future under the auspices of Illinois DCEO and US DOE.
REFERENCES


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