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Project Title: **FEASIBILITY OF FLUE GAS INJECTION IN ILLINOIS COAL AND ITS IMPACT ON FLOW PROPERTIES**

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ABSTRACT

Application of enhanced coalbed methane recovery (ECBM) techniques can increase coalbed methane (CBM) production from less than 50% of the gas-in-place to more than 90%. Since the gas content of Illinois coals is relatively low, ECBM techniques can have a significant economic impact on commercial CBM production. Technically proven, ECBM involves injecting either a low adsorbing gas, like nitrogen, or a higher adsorbing gas, like CO_2, into coal. The objective of this study was to determine the feasibility of injecting power plant flue gas, primarily nitrogen and CO_2, to draw on the advantages of the two techniques, and determine its viability to enhance CBM production in Illinois. The study was aimed at evaluating the effect of injecting flue gas on flow characteristics of coal, and its impact on CBM production and CO_2 sequestration.

Permeability of cores of coal, taken from the Illinois Basin, was estimated under *in situ* conditions of stress, temperature and pressure. Coal permeability was first measured for methane, replicating the primary pressure depletion method. This was followed by injection of 'simulated' flue gas, and finally, pure CO_2, to determine the impact of ECBM on permeability variation trends for the three options. The results clearly showed that the permeability change with flue gas injection is less compared to that with pure CO_2. Also, the coals tested exhibited no permeability loss associated with continued injection of CO_2. This may be due to the relatively shallow depth of coal, and lower *in situ* stresses.

Under a separate effort, the impact of injecting flue gas on the solid and fracture structure of coal was determined in the laboratory. The results indicated that the effect of injecting flue gas on coal matrix is negligible. The matrix swelling induced by CO_2 in the flue gas compensated for the shrinkage due to desorption of methane. Hence, no permeability damage is anticipated with flue gas injection as a result of matrix swelling.

Using the experimental results and other relevant data, several simulations were carried out to determine the feasibility of ECBM by flue gas/CO_2 injection and CO_2 sequestration. The results showed that the amount of methane recovered increased with flue gas injection, with the added advantage of increased CBM production earlier in the reservoir life, and sequestering most of the CO_2. The results further suggested that ECBM with flue gas injection should be considered after partial production by the pressure depletion method, rather than for the entire life of the reservoirs. Finally, the incremental methane production and CO_2 sequestration benefits were not as significant with flue gas injection as with pure CO_2.

EXECUTIVE SUMMARY

The overall objective of this study was to determine the technical feasibility of enhancing the production of coalbed methane (CBM) from Illinois coals, while simultaneously sequestering CO_2, by injecting flue gas into CBM reservoirs. Given the relatively low gas content of Illinois coal, there is excellent potential to increase the recovery of available CBM by employing an enhanced coalbed methane recovery (ECBM) technique, coupled with the potential to sequester large quantities of CO_2. Hence, the primary focus of this research effort was to carry out a preliminary study to determine the viability of the application of ECBM by flue gas injection.

Two ECBM concepts by injection of a second gas have been developed and tested on pilot scales. Technically proven, ECBM technique involves injecting either a low adsorbing gas, like nitrogen, or a higher adsorbing gas, like CO_2, into coal. The downside to using CO_2 is that it drastically reduces the permeability of coal due to matrix swelling, as observed at the CO_2 injection sites in the US, Canada and Poland. Also, it needs to be separated from the power plant exhausts prior to injection, adding to the overall cost of sequestering CO_2. Injection of nitrogen, on the other hand, necessitates its separation at the downstream end due to its early breakthrough at the production well. This study was aimed at determining the feasibility of injecting power plant flue gas, consisting primarily of nitrogen and CO_2, into coal in order to draw on the advantages of the two techniques, and evaluate its viability for CBM production, along with its effectiveness to sequester the CO_2 contained in the flue gas.

Two important properties, both affected significantly by *ad/de-* sorption of gas, and impacting the implementation of ECBM technology in Illinois, were investigated in this study. The flow response of coal to flue gas injection was determined on a laboratory-scale to evaluate the long-term ECBM potential. An experimental setup for flow measurement was used to determine the permeability of coal, and its variation, with continued flue gas injection. To closely replicate field conditions, the experimental system enabled controlling and monitoring of the external stress conditions, gas pressure and temperature, representative of Illinois reservoirs, while measuring the gas flowrate. Since injection of an adsorbing gas also results in a change in the microstructure of solid coal matrix and fracture aperture, thus resulting in a change in the permeability, a separate experimental study was conducted to measure the changes in the volume of coal matrix when exposed to flue gas. For the sake of completeness, and enable comparison of the various ECBM techniques, both experiments were also conducted using pure methane and CO_2. Finally, a simulation exercise was carried out to determine the methane production potential of Illinois coal, considering different ECBM techniques, and recommend the best ECBM method for CBM production and CO_2 sequestration. The results of the experimental study, along with information obtained from the Illinois State Geological Survey (ISGS), were used as input for the simulation.

To start with, some basic laboratory characterization tests (sorption isotherms, ash and proximate analysis) were conducted using the cores obtained from the Illinois Basin. This phase also included determination of representative flue gas composition, similar to that

emitted by coal-fired power plants in southern Illinois. Based on discussions with power plant personnel, composition of the 'simulated' flue gas was determined to be 87% N_2 and 13% CO_2.

The permeability of a core of coal taken from the Seelyville seam in the Illinois Basin was measured in the laboratory by replicating reservoir conditions of stress, pressure and temperature. Methane permeability was first measured at reservoir pressure for different effective stress levels by changing the mean gas pressure, maintaining the external stresses constant, the situation being replication of the primary pressure depletion method. For a change in the horizontal effective stress from ~350 to ~750 psi, the permeability decreased from 36 to 10 md. This was followed by determining the permeability as a function of gas pressure at constant effective stress conditions. The results showed that the permeability decreased with decrease in gas pressure. The two experiments were repeated with flue gas, and finally, with CO_2.

The flue gas and CO_2 permeability variation trends established for both cases were the same as that for methane. The permeability to all gases decreased log-linearly with increase in effective stress. A reduction in permeability is expected since increased stresses compact the cleats in coal, resulting in cleat closure and, therefore, reduced permeability. The permeability variation was the largest in case of pure CO_2, followed by flue gas containing 13% CO_2, and the smallest with methane. The unexpected permeability response was its variation with gas pressure. With continued flue gas/CO_2 injection and its adsorption, the corresponding swelling of the coal matrix was expected to result in a significant permeability loss, and this was not the case in the laboratory.

The results of the experimental work involving measurement of coal matrix volumetric strain showed that the coal matrix "swells" with injection of CO_2. However, with injection of flue gas to replace methane, the swelling was almost negligible at higher pressure. At lower pressures, injection of flue gas appeared to induce some swelling. Furthermore, the swelling due to CO_2 injection was significantly greater than that for methane or flue gas. This is consistent with the fact that the sorption capacity of coal to CO_2 is significantly higher than that for methane. The small to negligible swelling with flue gas injection suggests that application of the ECBM technique by flue gas injection in Illinois Basin would result in permeability remaining practically unaltered. Finally, the volumetric strain trends were found to resemble that of the sorption isotherms established, suggesting a linear relationship between the amount of gas adsorbed and the strain induced by it.

After completing the experimental phase of the study, the acquired information about coal volume 'swelling' and dynamic permeability was used to carry out a simulation exercise to project the long-term gas production from relevant coals in Illinois, and determine the ECBM technique which would work successfully. Using the results (sorption isotherm data, swelling factor, permeability and porosity data) and other relevant data, simulation runs were carried out using the CBM simulator COMET3. Five different alternatives were simulated. The first one was a simple case of CBM production with different well spacings, using the typical pressure depletion technique. Based on the results, 40-acre well spacing was found to be the optimum and was used for all subsequent simulations. The second and third alternatives simulated were for the CO_2/N_2 ECBM injection alternatives. The fourth was for flue gas injection following partial production, recovering approximately 50% of the gas-in-place by the primary pressure depletion method. The last alternative simulated was for flue gas injection commencing at the start of the CBM operation. The results of each simulation run provided an estimate of gas production over the life of the reservoir, incremental methane production with the ECBM technique, the amount of CO_2 sequestered, and the amounts of N_2 injected and produced. The results provided the information in order to determine the best alternative suitable for Illinois coal, based on a comparative analysis. ECBM with CO_2 injection appeared to be more promising in terms of the methane recovery fraction and the total CO_2 sequestered. Flue gas injection after 1000 days appeared to give better results than flue gas injection commencing from the beginning of CBM production, the only difference being the higher methane production rate during earlier stages of CBM production in the latter case. N_2 injection improved the recovery as well as production rates although the overall recovery was not as good as with CO_2 injection.

Based on the findings of this study, it is concluded that permeability loss associated with CO_2 injection is somehow coupled with the external stress conditions. The three sites where CO_2 has been practiced are all at significantly greater depths than coals in the Illinois Basin, that is, subjected to high stresses. All three have experienced significant permeability loss. However, the results of this study suggest that, in Illinois, injection of CO_2 would not result in permeability loss due to swelling of the coal matrix although there will be some permeability reduction with CO_2 injection due to the fact that coal permeability to CO_2 is lower than that to methane. This is further corroborated by the results of the second set of experiments where injection of flue gas resulted in negligible swelling. Hence, its injection would not result in any permeability loss. A general conclusion made is that 13% CO_2 results in swelling of the coal matrix that is similar in magnitude to the shrinkage associated with desorption of methane, that is, swelling with flue gas injection compensates for the shrinkage due to methane desorption.

The above observations support application of ECBM with flue gas injection in the Basin. Hence, injection of flue gas should be considered when planning CBM operations in Illinois, since it can have a significant economic impact on commercial CBM production. Consideration should be given to high pressure injection of flue gas. First, this would result in improved economics of the operation resulting in higher overall recovery and early production rates. Second, the permeability damage as a result of flue gas injection would be almost negligible. In fact, there might even be a permeability enhancement since the measured permeability at high flue gas pressure was higher than that to methane. Even at low pressures, the permeability loss would be minimal compared to pure CO_2 injection.

The final conclusion of the work completed is that flue gas ECBM would not have a significant sequestration potential since the amount of CO_2 sequestered as well as the incremental CBM produced were both found to be rather small. However, high pressure injection might result in improved overall recovery and production rates although this will have to be weighed against the extra expenditure in compressing the nitrogen component of the flue gas prior to injection. Since most of the nitrogen is recovered at the production wells, there is no economic benefit to doing so. Furthermore, nitrogen requires separation at the downstream end due to its early breakthrough. A detailed economical analysis is necessary to determine the viability of the option although this would depend primarily on the carbon credits in the US, and this is an unknown at this time.

OBJECTIVES

Overall Objective: The overall objective of this research study was to determine the technical feasibility of injecting flue gas into coal as a means to enhance the commercial production of coalbed methane from Illinois coals, while simultaneously, sequestering CO_2.

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

I. Estimate the permeability of coal cores simulating primary depletion production and enhanced gas recovery alternatives using flue gas injection;
II. Determine the effect of injecting simulated flue gas on the solid and fracture compressibility of coal, and calculate the corresponding changes in fracture porosity and permeability;
III. Obtain adequate information about other coal properties pertaining to primary coalbed methane (CBM) and enhanced coalbed methane (ECBM) production for use as input parameters in simulating long-term gas production; and
IV. Carry out a detailed analysis for the flue gas injection alternative as a means to enhance CBM recovery, and sequester CO_2, using simulation.

The work was divided into the following different tasks/sub-tasks:

Task I: Basic Coal Characterization Tests: This task included the following sub tasks:

a) Procurement/Preparation of Coal Samples: This sub-task included collecting coal cores from the Illinois State Geological Survey (ISGS) drilling program and preserving these in their native state to prevent weathering. The objective was to test coal samples representative of *in situ* coal reservoir conditions. Preparation of core samples included cutting/grinding appropriate test specimens for permeability and volumetric strain experiments, and powdered samples for sorption experiments.
b) Coal Characterization Tests: This sub-task included conducting some basic coal characterization tests like ash, moisture and density analysis for the samples using standard testing procedure and equipment available at SIU.
c) Sorption Characteristics: This sub-task included establishing methane sorption isotherms for the coal samples to determine the ability of coal to retain/release methane.
d) Simulation of Flue Gas: This sub-task required deciding on the appropriate composition of the 'simulated' flue gas for the experimental work, so as to represent typical power plant exhaust gases in southern Illinois.

TASK II: Flue Gas Permeability Measurement: 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 task was aimed at establishing permeability variation trends over the life of production wells, and its impact on long-term gas production potential in Illinois, with injection of flue gas as a means to enhance the CBM production.

TASK III: Impact of Flue Gas Injection on Physical Structure of Coal: This task was intended to determine if injecting flue gas into a CBM reservoir resulted in a significant change in the physical structure of coal. The primary objective was to measure the volumetric strain induced as a result of flue gas injection under constant conditions of temperature and pressure, and evaluate its impact on cleat porosity and permeability.

TASK IV: Simulation and Economics - CO_2 Sequestration/CBM Production by Flue Gas Injection: This task included incorporation of the experimental results and data from the ISGS to carry out a simulation exercise to evaluate the potential of enhanced CBM production and CO_2 sequestration in the state, and compare the production with and without flue gas injection for Illinois coals. It also included evaluating the impact of the variation in coal permeability on long-term gas production potential in Illinois. A commercial CBM simulator, with the capability of simulating enhanced recovery scenario, was used for this.

Task V: Reporting and Communication: This task included maintaining very close contact with the ISGS personnel throughout the project duration, reporting project progress on a regular basis, obtaining information from them about their field and analytical work, providing pertinent information to them, and most importantly, obtaining cores from their drilling program. This task also included dissemination of the results to potential CBM developers and researchers at various forums and conferences.

INTRODUCTION AND BACKGROUND

Since the gas content of Illinois coal is low compared to other US basins with significant CBM activity, like the San Juan, 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 CBM, also presents significant potential to sequester large quantities of CO_2. However, prior to any full-scale commercial CBM production, it is critical to conduct elaborate testing of coal in order to carry out an accurate assessment of flow characteristics of coal.

The ECBM technique involves injecting a second gas into a coal reservoir in order to improve the recovery of methane over the primary pressure depletion method. Two techniques have been tried to achieve the enhancement of CBM recovery. The first technique involves injecting nitrogen into a CBM reservoir. Nitrogen flushes the gaseous methane from the cleats, thus creating a disequilibrium condition in a system containing both methane and nitrogen. As a result, methane desorbs and is drawn into the gaseous phase to achieve equilibrium partial pressure [1, 2]. The second technique involves injection of CO_2, which gets preferentially adsorbed onto coal, thus displacing methane [3]. The injection of either gas improves the production rate and ultimate recovery of methane substantially. However, early breakthrough of nitrogen at the production well necessitates additional expenditure to separate it from methane, while a dramatic decline in permeability of coal is observed subsequent to CO_2 injection. To draw on the advantages of the two techniques, direct injection of flue gas (primarily nitrogen and CO_2), might be a viable option to improve the project economics. Injection of flue gas should delay the early breakthrough of nitrogen, compared to a pure nitrogen injection, and methane production should be enhanced due to displacement by CO_2, with the added advantage of sequestering the CO_2. The success of this method, however, would depend on the ability of coal to work as a filter, separating nitrogen and CO_2, retaining CO_2, and allowing nitrogen to flow through. One of the two most critical parameters determining this ability is the permeability of coal due to its dynamic nature, requiring that a good knowledge about its variation over the life of a reservoir be acquired prior to making any long-term CBM production projections. This is even more critical where a second gas is injected to enhance the production of gas, further affecting the permeability of coal. Hence, this research study aimed at developing a good understanding of the following:

1. *The feasibility of injecting power plant flue gas into coal and evaluating its viability for CBM production and CO_2 sequestration in Illinois coals.*

2. *The effect of injecting flue gas on the flow characteristics of coal and its impact on long-term gas production potential.*

3. *Changes in the physical structure of coal associated with injection of flue gas, and the impact of coal matrix volumetric changes on coal permeability.*

4. *Flue gas injection as a means to enhance CBM recovery, and sequester CO_2.*

Based on the brief background presented above, this study was conducted to: 1) measure the permeability of coal to flue gas and predict its variation over the life of a reservoir, 2) estimate the changes in flow characteristics of coal as a result of volumetric strain associated with flue gas injection, and 3) conduct simulation studies and analyze the flue gas injection alternative to enhance the CBM recovery, and sequester CO_2.

EXPERIMENTAL PROCEDURES

Basic Coal Characterization Tests

Procurement/Preparation of Coal Samples: Based on the preliminary work on CBM resource assessment completed by the ISGS, cores of coal were obtained from the exploratory drilling program currently underway as a joint effort between ISGS and several industrial partners. 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. For permeability experiments, appropriate lengths of core were cut, and their top and bottom ends polished to enable proper placement in the triaxial cell. The tests were carried out on cylindrical samples, 3 inches in diameter and ~3 inches long, depending on the length of the cores received. Rectangular samples (prisms) and half-cores were prepared for the volumetric strain experiments. The samples with the least cleats were selected for experimental work to ensure that the measured properties were for coal matrix alone.

Coal Characterization Tests: Ash, moisture, and density analyses were conducted for the samples to be used for the permeability and volumetric strain experiments. The results were used as input parameters in the simulation work. Standard ASTM procedures, D 3173-87 and D 3174-97, were followed for moisture and ash analyses respectively.

Sorption Characteristics: Sorption isotherms were established following the procedure detailed in the final report for the ICCI Project: 02-1/6.1A-4 [4]. For the sake of completeness, a brief description of the procedure is presented here. Powdered samples were used for sorption experiments in order to reduce the duration of the experiment. The procedure involved preparing pulverized samples of coal (40-100 mesh) using portions of the 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 equilibration. 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, based on mass balance procedure, sorption experiments were carried out for methane up to a final pressure of ~1100 psi. Once the maximum pressure for the adsorption isotherm was attained, the process was reversed to obtain the desorption isotherm.

Simulated Flue Gas: For matrix properties and flow experiments, 'simulated' flue gas, similar in composition to that emitted by coal-fired power in close proximity to the CBM 'hot spots' in southern Illinois was used. Based on discussions with power plant personnel, appropriate composition for 'simulated' flue gas was determined to be 87% N_2 and 13% CO_2.

Flue Gas Permeability Measurement

Experimental Setup and Procedure: The setup and procedure for the permeability experiment was similar to that discussed in the final report for the ICCI Project 03-1/7.1B-2 [5]. A brief description is provided here for convenience. 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 gas 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 seam in the Illinois Basin at a depth of 1500 feet, with the gas pressure of virgin coal estimated to be ~650 psi. The estimated *in situ* reservoir temperature was 83.5^{o}F. Hence, all tests were carried out at these conditions of temperature, maximum gas pressure, and levels of external stresses.

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. The core sample, properly sealed with the shrinkage tubing, was then placed in the cell, which 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.

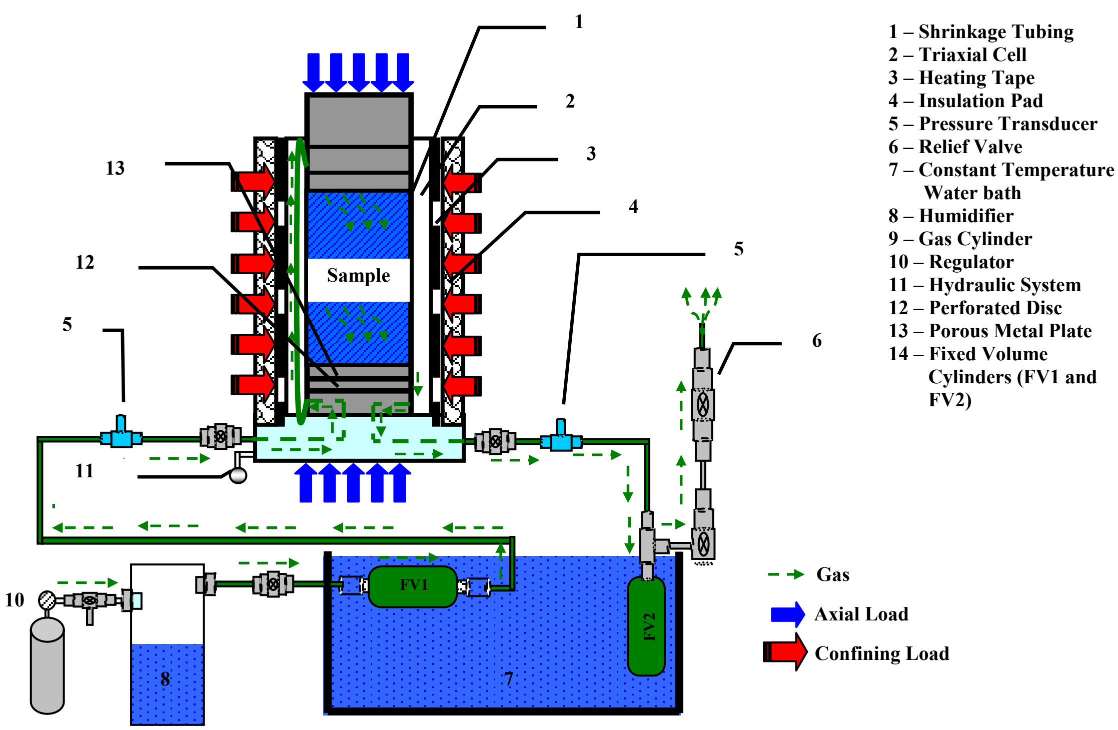

Figure 1: Schematic of the permeability setup.

Before injecting gas into the sample, the triaxial cell was properly insulated to maintain constant temperature throughout the experiment. 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 50 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 attained steady values, 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.

Impact of Flue Gas Injection on Physical Structure of Coal

This part of the study followed the same experimental procedure described in the final report for the ICCI Project 02-1/6.1A-4 to determine the viability of using Illinois coal for CO_2 sequestration and methane production [4]. Rectangular specimens (prisms) and half cores, cut from coal cores, were used for measurement of volumetric strain due to changes in gas composition, maintaining all other experimental conditions (external pressure, temperature, and humidity) constant. The experimental setup for the study was designed to enable measurement of volumetric strain due to changes in gas composition, keeping the total gas pressure constant. Since sorption is very sensitive to temperature, the pressure vessels were placed in a constant temperature bath, as shown in Figure 2.

Figure 2: Constant temperature water bath with four the pressure vessels for volumetric strain measurement.

Four samples were first subjected to increasing helium pressure up to ~750 psi. Since helium is non-adsorptive, the measured strain was purely due to the mechanical compression of the solid coal, resulting from the change in the external pressure. After attaining equilibrium at ~750 psi, all four samples were subjected to step-wise increasing concentration of methane, maintaining the total pressure constant at ~750 psi. This was achieved by injecting methane while bleeding helium/(helium + methane) mixture out. At equilibrium, volumetric strain due to methane adsorption was measured for all four samples. Two of the samples (Nos. 1 and 2) were then subjected to increasing helium pressure, maintaining the total pressure constant, to measure the change in strain due to methane desorption, representing the primary depletion technique of CBM production. However, for the second sample (No. 2), flue gas was injected instead of helium after methane partial pressure dropped to approximately 50% of the initial pressure. This experiment replicated the conditions *in situ* for the ECBM alternative with flue gas injection, commencing after partial production by pressure depletion. Following the same procedure, increasing concentration of CO_2 and flue gas were injected in the other two samples (Nos. 3 and 4) respectively, maintaining the total pressure constant. The procedure was continued until the gas within, and surrounding, the sample (No. 3) was pure CO_2, and for sample No. 4 was flue gas. This experiment replicated the conditions for a CBM reservoir subjected to ECBM option (with CO_2 and flue gas injection) from the commencement of CBM production. At each equilibrium step, a sample of gas was analyzed using the gas chromatograph (GC), and concentration of gas mixture in each of the vessels was measured. Thus, at each equilibrium step, strain due to decreasing methane, increasing CO_2/flue gas injection was measured. Once the above experiment was completed, all four samples were saturated either with helium (Sample 1), flue gas (Samples 2 and 4) or CO_2 (Sample 3).

RESULTS AND DISCUSSION

Task I: Basic Coal Characterization Tests

Samples were prepared using cores from the Seelyville seam (Jasper County) in the Illinois Basin. Bulk density was measured using the water displacement technique. Ash and moisture content were measured using the pulverized sample, 40-100 mesh in size, and following the ASTM procedures. The results are shown in Table 1.

Table1: Basic Coal Characterization Test Results

Moisture Content	5.95 %
Ash Content	8.36 %
Density	1.36 g/cc

Following the procedure described in the section above, and using the Langmuir Equation, adsorption and desorption isotherms were established for several samples. The isotherms for the sample from the Seelyville seam are shown in Figure 3. Following the common practice, sorption results are presented on a dry and ash free (daf) basis. Gas content of the Seelyville seam, approximately 175 standard cu ft per ton (scft/ton) at reservoir pressure of 650 psi, is also shown on the Figure. It is clear that the coal seam is undersaturated with methane at this pressure, suggesting that it would require significant amount of dewatering to bring the pressure down before CBM production commences. Also, it is apparent that adsorption and desorption isotherms followed almost the same path, with minimum hysteresis.

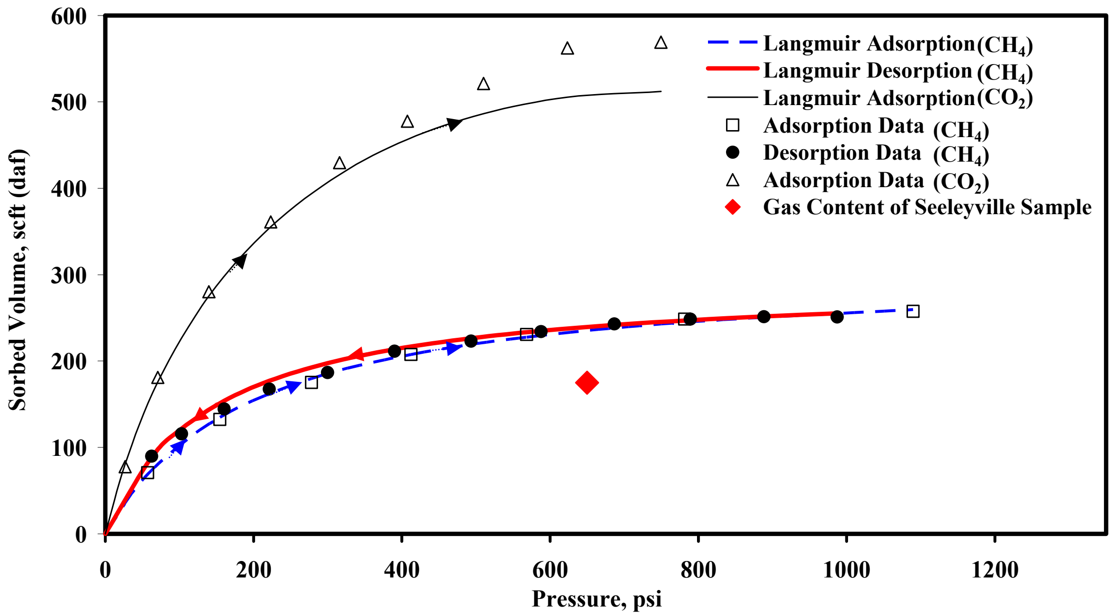

Figure 3: Sorption isotherms for Seelyville sample.

<u>TASK II: Flue Gas Permeability Measurement</u>

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

$$k = \mu \frac{Q_0}{A} \frac{LP_0}{\Delta P P_m} \tag{1}$$

where, μ is the viscosity of gas, Q_0 is the volumetric flowrate 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, ΔP is the pressure difference between upstream and downstream, P_m is the mean gas pressure $[(P_0 + P_i)/2]$, and P_i is the inlet pressure. All parameters in this equation were either known, or measured during the experiment. Using the measured gas flowrate and pressure conditions for the experimental conditions, permeability was calculated.

Permeability Results

<u>Methane Permeability Results</u>: The test was conducted in two phases. First, the sample was subjected to a constant axial stress of 1500 psi, and confining stress of 1000 psi

respectively, which are both representative of the stresses *in situ*. The temperature throughout the test was maintained at 83±1^{0}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 eq. (1). For a change in the horizontal effective stress from ~350 psi to ~750 psi, the permeability decreased from ~36 to ~10 md, a reduction of 72%. The permeability variation with changes in effective horizontal stress is shown in Figure 4. It is evident from the graph that the permeability decreases log-linearly with increase in effective horizontal stress.

In the second phase, the core was subjected to a constant effective stress throughout the experiment. The effective (axial and confining) stresses were maintained at approximately 850 and 350 psi respectively throughout the experiment. The gas flow measurements were made by varying the mean gas pressure, and permeability of the sample to methane was determined. The permeability results for this phase are shown in Figure 5. The results clearly show that the permeability decreases linearly with decrease in mean gas pressure.

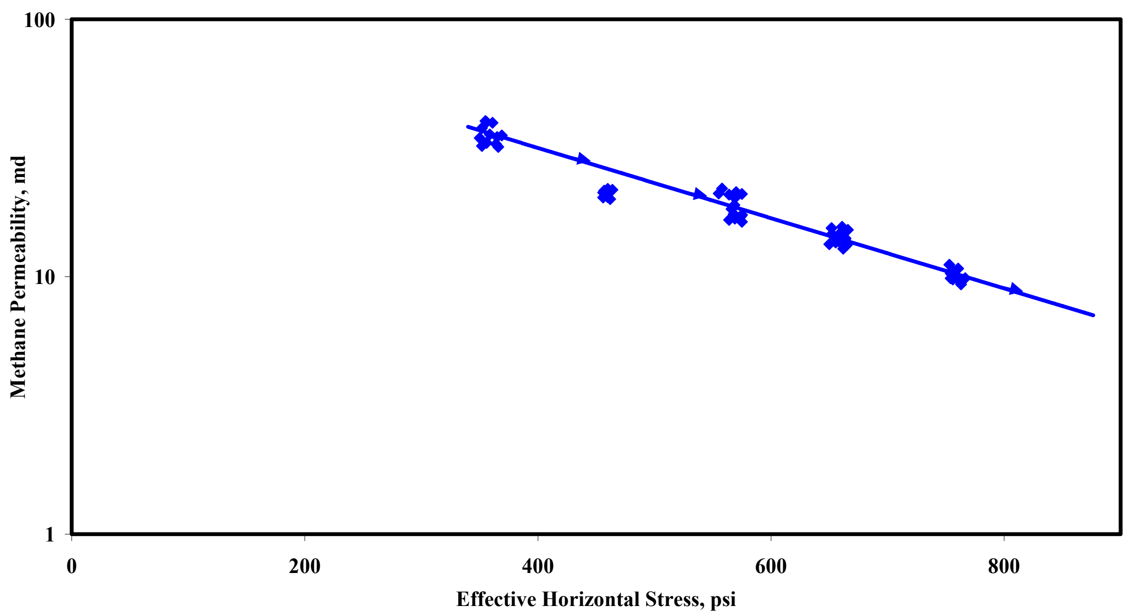

Figure 4: Variation in methane permeability with changes in horizontal effective stress.

<u>Flue Gas Permeability Results</u>: As a continuation of the above experiment under same experimental conditions of temperature, pressure and stress, the core was tested using simulated flue gas. 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 flue gas is shown in Figure 6, along with changes for methane and CO_2. For the second phase of the experiment using flue gas, the sample was subjected to a constant axial and

confining stress of 1500 and 1000 psi respectively. Using the flow measurements, permeability of the sample to flue gas was determined. For a change in horizontal effective stress from ~350 to ~850 psi, the permeability decreased from ~34 to ~4 md, a reduction of 87%. The variation in permeability with changes in horizontal effective stress for flue gas, along with that for methane and CO_2, is shown in Figure 7.

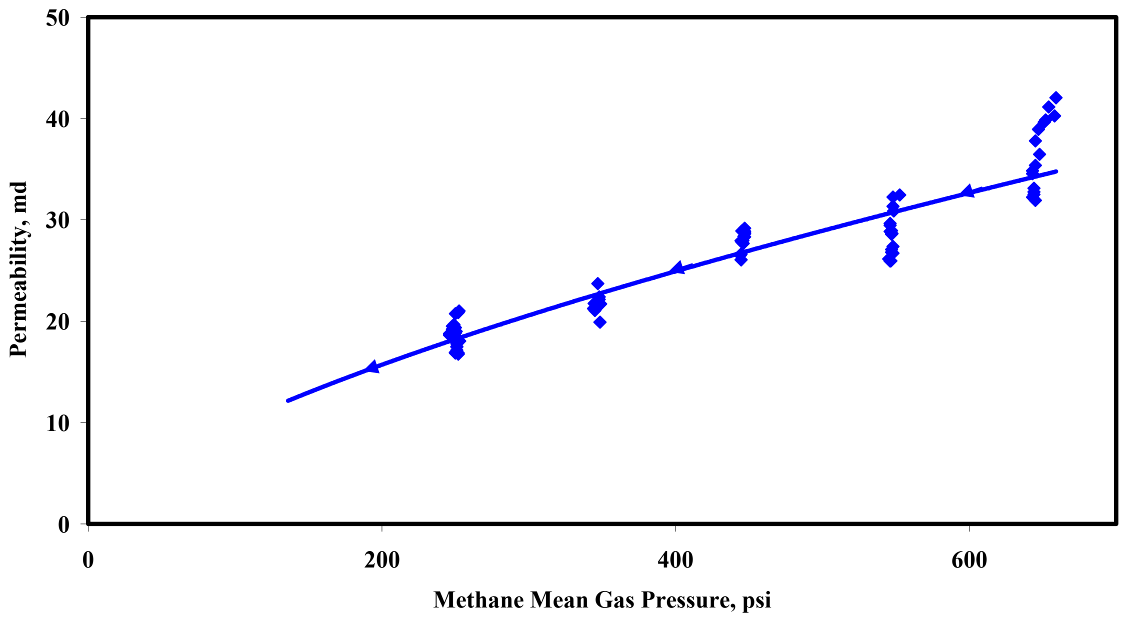

Figure 5: Variation in permeability with changes in methane mean gas pressure – constant effective stress.

<u>CO_2 Permeability Results</u>: For the last part of the experiment, the same procedure was followed and permeability measurements were completed for pure CO_2. The variation in permeability with changes in mean gas pressure (at constant effective stresses) for CO_2, and changes in horizontal effective stress (at constant axial and confining stress) are shown in Figure 6 and 7 respectively. With change in horizontal effective stress from ~350 to ~850 psi, the permeability reduction was in excess of 90% (Figure 7).

<u>Comparative Permeability Results</u>: Based on the calculated permeability for these three gases, permeability changes were estimated and a comparative analysis was carried out. The results are shown in Figure 8. The plot shows the permeability ratio k_f/k_i (k_i is the initial permeability and k_f is the measured permeability for each step) as a function of effective mean stress, defined as the average of the three principal stresses minus the reservoir pressure, that is, [(axial stress + 2(confining stress)) – reservoir pressure]. Mathematically, Effective Mean Stress = $(\sigma_v + \sigma_{hmax} + \sigma_{hmin})/3$ – Reservoir Pressure. For this case, $\sigma_{hmax} = \sigma_{hmin}$, where, σ_v is the vertical stress, and σ_{hmax} and σ_{hmin} are the horizontal maximum and minimum stresses.

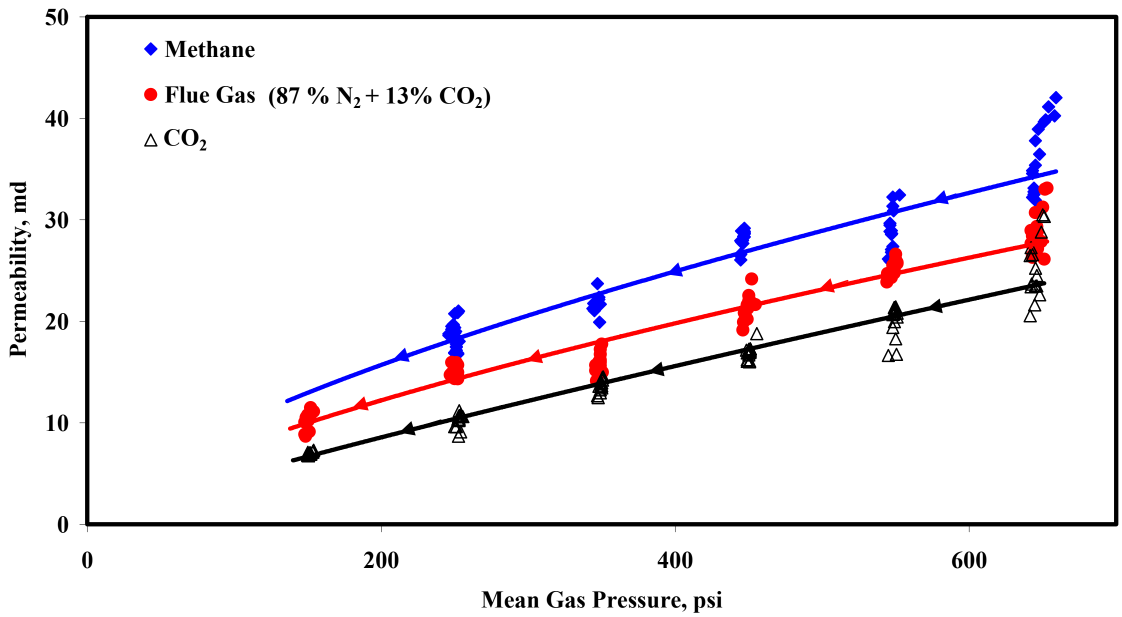

Figure 6: Variation in permeability with changes in mean gas pressure at constant effective stress for the three gases.

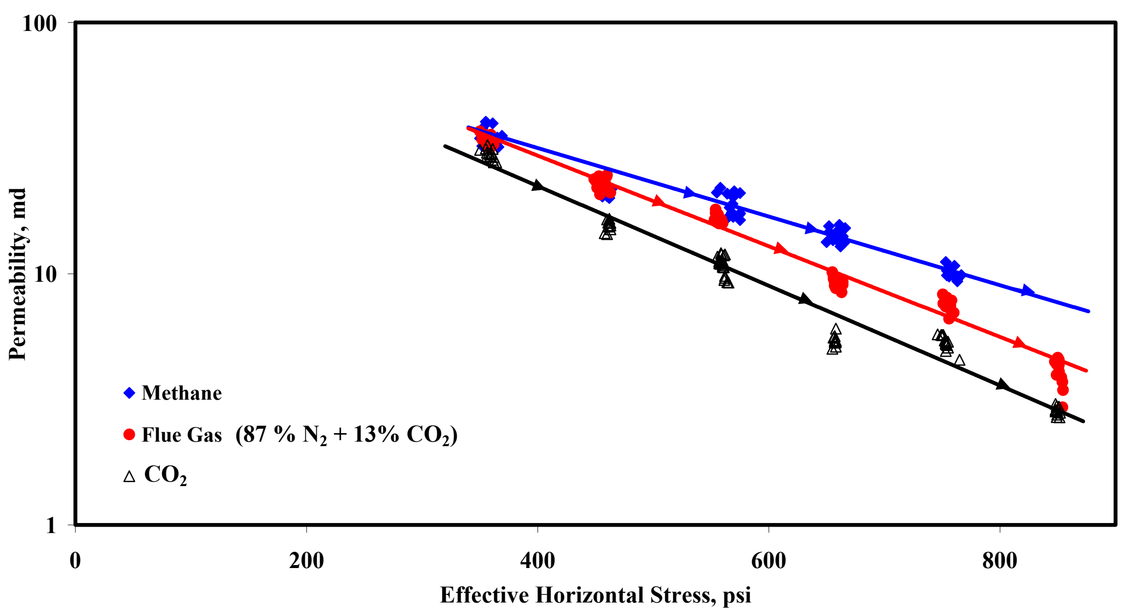

Figure 7: Variation in permeability with changes in horizontal effective stress for the three gases.

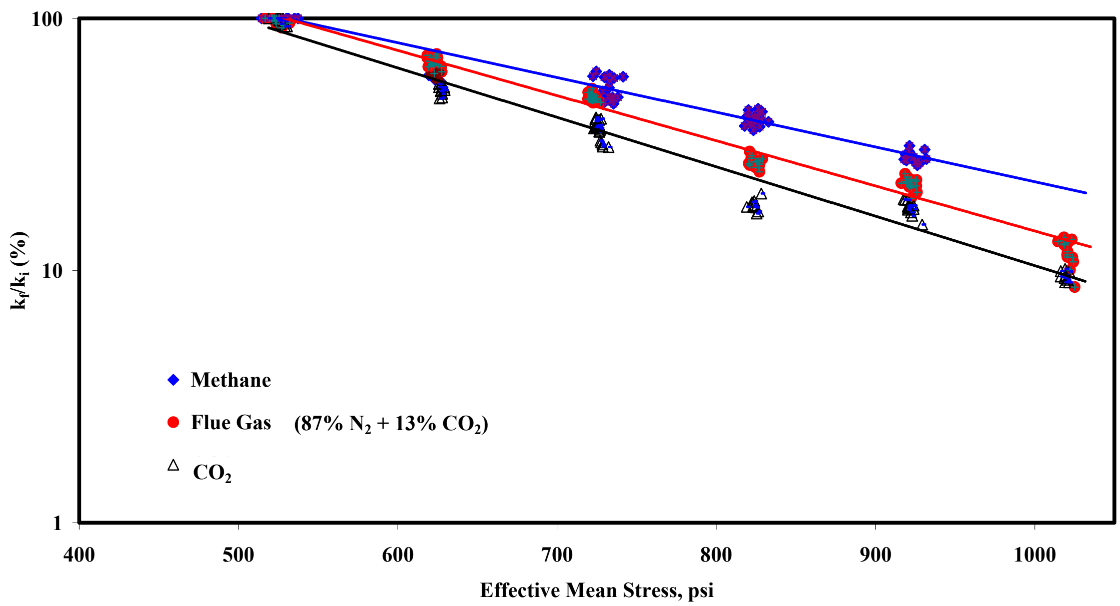

Figure 8: Percentage permeability variation with changes in effective mean stress for the three gases.

It is evident from the results that the permeability to all gases decreases log-linearly with increase in effective stress. This is expected since increased effective stress compacts the cleats in coal, resulting in cleat closure and, therefore, reduced permeability. Also, the permeability variation is greater in case of pure CO_2, followed by flue gas with 13% CO_2, and the least with methane. The established trend of permeability reduction with stress also correlates well with the findings of earlier studies, illustrating the exponential relationship of the form:

$$k = Ae^{B\sigma_h} \tag{1}$$

where, σ_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 coal [6, 7, 8].

TASK III: Impact of Flue Gas Injection on Physical Structure of Coal

Matrix Volumetric Strain Calculations: Strain data at each equilibrium step was measured and used to calculate the total volumetric strain. Based on the calculated volumetric strain, the matrix "shrinkage" (in case of methane depletion) and matrix "swelling" (in the case of CO_2 and flue gas injection) coefficients were calculated. The shrinkage/swelling coefficient is defined as the rate of change of coal matrix volume with change in gas pressure of a sorbing gas. For ease of understanding, the two are represented separately here, shrinkage coefficient as $C_m^{\dagger}$ and swelling coefficient as C_m^{*} respectively. Mathematically, these are given as:

$$C_m^\dagger \text{ or } C_m^* = \frac{1}{V_m}\left(\frac{dV_m}{dP}\right) \quad (2)$$

where, V_m is the matrix volume, and dP is the change in applied pressure at both internal and external surfaces.

Strain Results

Helium Injection Results: The first part of the experimental phase involved dosing all samples with helium to a pressure of ~750 psi while monitoring the strain continuously. As expected, the volume of coal matrix decreased with helium injection due to compression of the coal grains. The matrix, or grain, compressibility (C_m), defined as the change in the volume of solid grains as a result of changes in external pressure was calculated using the equation:

$$C_m = \frac{1}{V_m}\left(\frac{dV_m}{dP}\right) \quad (3)$$

where, V_m is the volume of solid coal and dP is the change in pressure. The average matrix compressibility was calculated to be -6.08E-4 psi^{-1}. For the pressure 0-750 psi range, the strain is assumed to be linear with pressure and the corresponding results are shown in Figure 9.

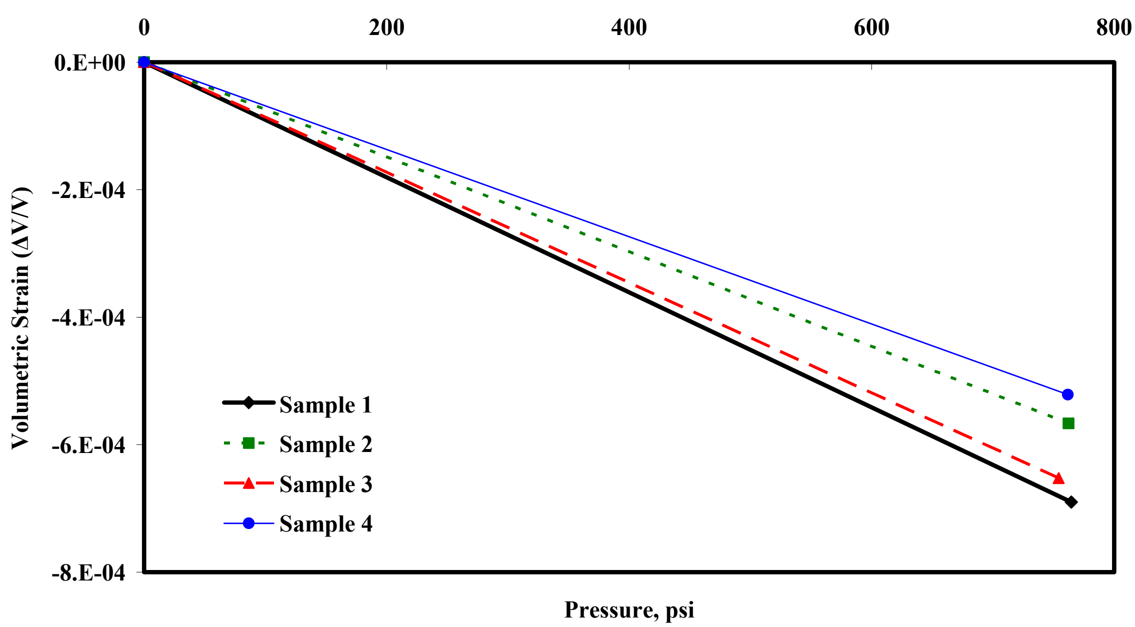

Figure 9: Volumetric strain of coal samples with increasing helium pressure.

<u>Methane Adsorption Results</u>: For the second part of the experimental work, methane was injected in all four samples, maintaining the total pressure constant at ~750 psi. This was achieved by injecting methane, while bleeding helium/(helium + methane) mixture out. At equilibrium, volumetric strain due to methane adsorption was measured for all four samples, as shown in Figure 10. Using eq. 2, the *swelling* coefficient for the samples was calculated. For methane injection, the swelling coefficient ranged from 3.77E-6 to 6.00E-6 psi^{-1}, with an average of 4.63E-6 psi^{-1}. This is more than 100 times the calculated matrix, or grain, compressibility. For pressures up to ~700 psi, the volume of coal matrix increased by ~0.31% due to methane adsorption.

<u>Methane/CO_2 and Methane/Flue Gas Exchange Results</u>: For the next part of the experiment, CO_2 and flue gas were injected in two of the samples (Nos. 3 and 4) respectively, maintaining the total pressure constant. This was achieved by injecting CO_2/flue gas while bleeding methane/(methane + CO_2/flue gas) mixture out. With each CO_2/flue gas injection, the volumetric strain for methane/CO_2 exchange was measured. The results of volumetric strain for methane/CO_2 and methane/flue gas exchange are shown in Figure 11. The results show that injection of pure CO_2 (No. 3) results in considerable strain, in excess of three times that induced with methane at 700 psi. The strain induced in sample No. 4 as a result of injecting simulated flue gas (13% CO_2 + 87% N_2) is negligible, suggesting that 13% CO_2 has the same swelling behavior as that of pure methane. The swelling induced from adsorption of CO_2 component of the flue gas is compensated by the shrinkage due to methane desorption since the two processes occur simultaneously. For pressure steps up to 700 psi, the volume of coal matrix increased by ~0.58% due to methane/CO_2 exchange, and was almost negligible due to methane/flue gas exchange.

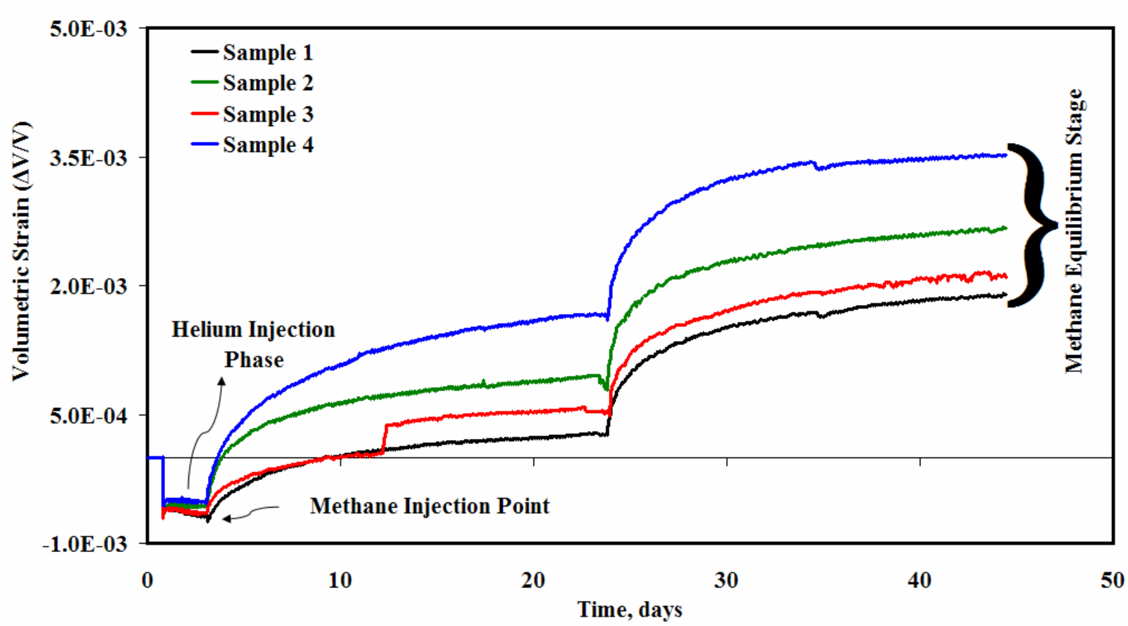

Figure 10: Volumetric strain of coal samples with time for increasing methane pressure.

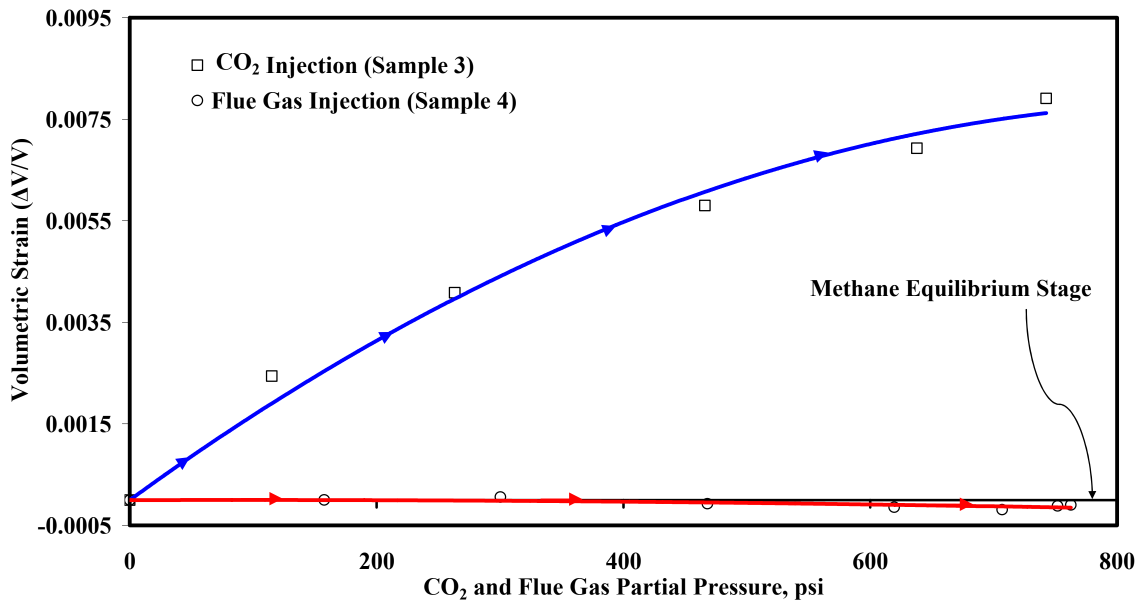

Figure 11: Volumetric strain for methane/CO_2 and methane/flue gas exchange.

<u>Methane Desorption Results</u>: Following the same procedure, two of the samples (Nos. 1 and 2) were subjected to increasing helium pressure, maintaining the total pressure constant, to measure the change in strain due to methane desorption, representing the primary depletion scenario. The results of methane desorption are shown in Figure 12. Desorption path (in sample 1) shows some hysteresis in terms of undergoing slightly more shrinkage than the adsorption induced swelling. At lower pressures, the strain becomes less than that measured at zero pressure, suggesting some non-reversible volumetric strain induced with ad/de sorption of methane. In the second sample (No. 2), flue gas was injected instead of helium after the methane partial pressure dropped to approximately 50% of the starting pressure. Injection of flue gas induces some swelling, although it is not significant. The swelling induced due to adsorption of CO_2 component of the flue gas probably dominates over the shrinkage due to methane desorption since the two processes occur simultaneously.

Figure 13 shows the volumetric strain as a function of partial pressure of methane for each injection/desorption step for all four samples taken from the Seelyville seam. The results show that the swelling due to carbon dioxide injection is significantly greater than that for methane. This is consistent with the fact that the sorption capacity of coal for CO_2 is significantly higher than that for methane. However, the swelling due to simulated flue gas (13% CO_2) injection is negligible favoring the ECBM technique by flue gas injection since this would result in permeability remaining practically unaltered.

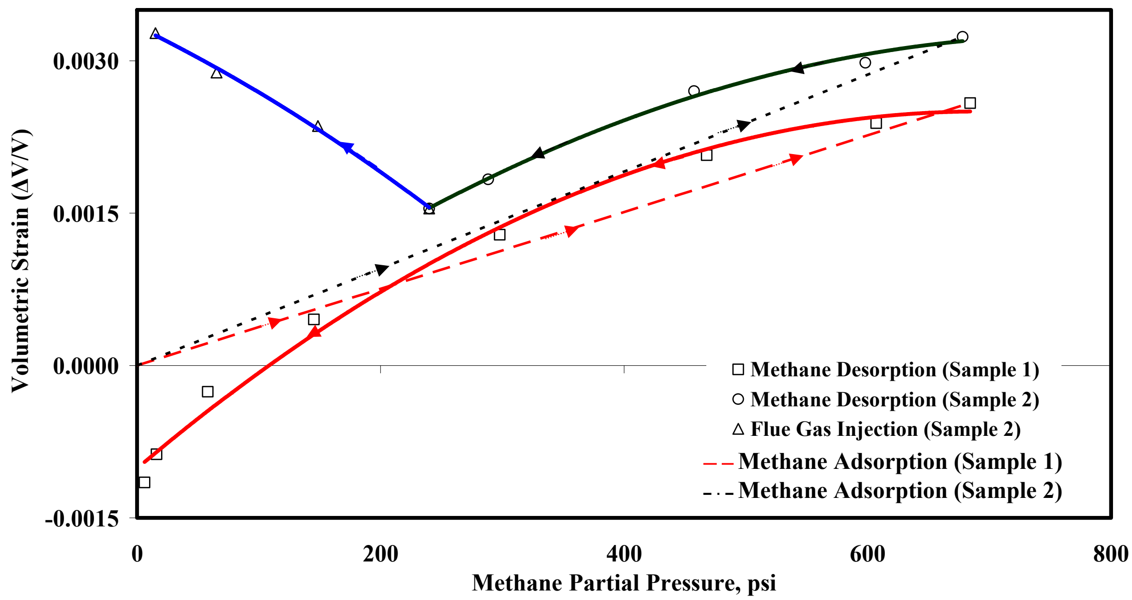

Figure 12: Volumetric strain for desorption of methane.

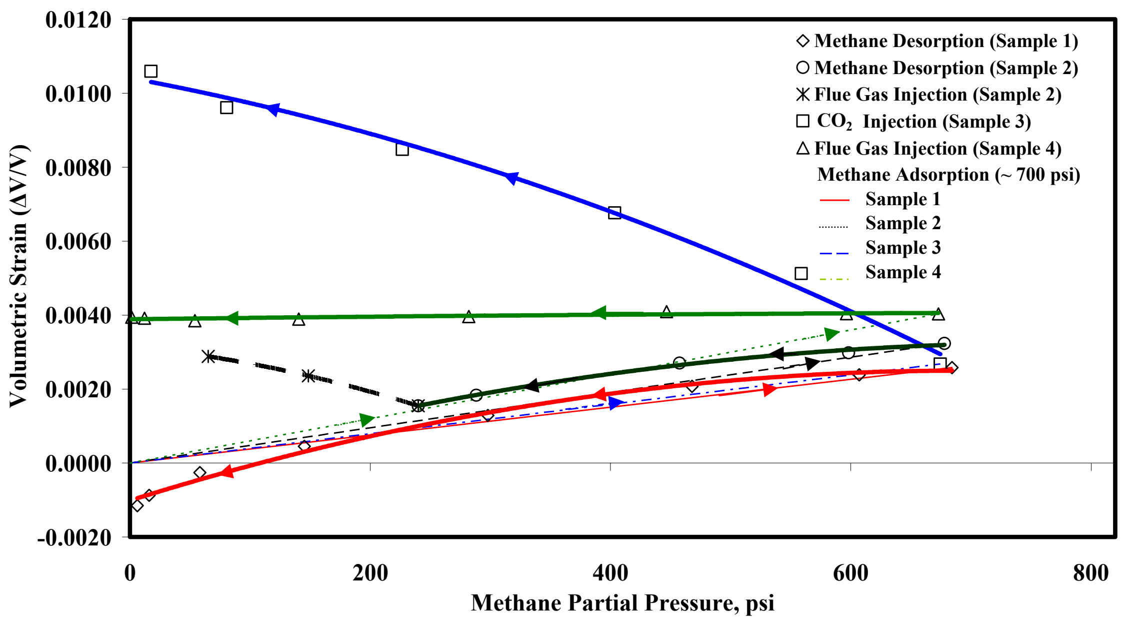

Figure 13: Volumetric strain for sorption of methane/flue gas/CO_2.

Sorption-Volumetric Strain Relationship: An interesting aspect of the volumetric strain-pressure relationship is its similarity to the sorption isotherms. The sorption isotherm for similar coal was established, as detailed in **Task I** above. Figure 14 shows the sorption-pressure and volumetric strain-pressure relation for methane on the same plot, suggesting a near linear relationship between the sorption induced volumetric strain and the sorbed volume of methane. 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 for shrinkage/swelling. The volumetric strain follows the desorption curve closely at higher pressures. However, at lower pressures, greater volumetric strain is induced with desorption. Hence, there is some non-reversible volumetric strain generated with desorption of methane.

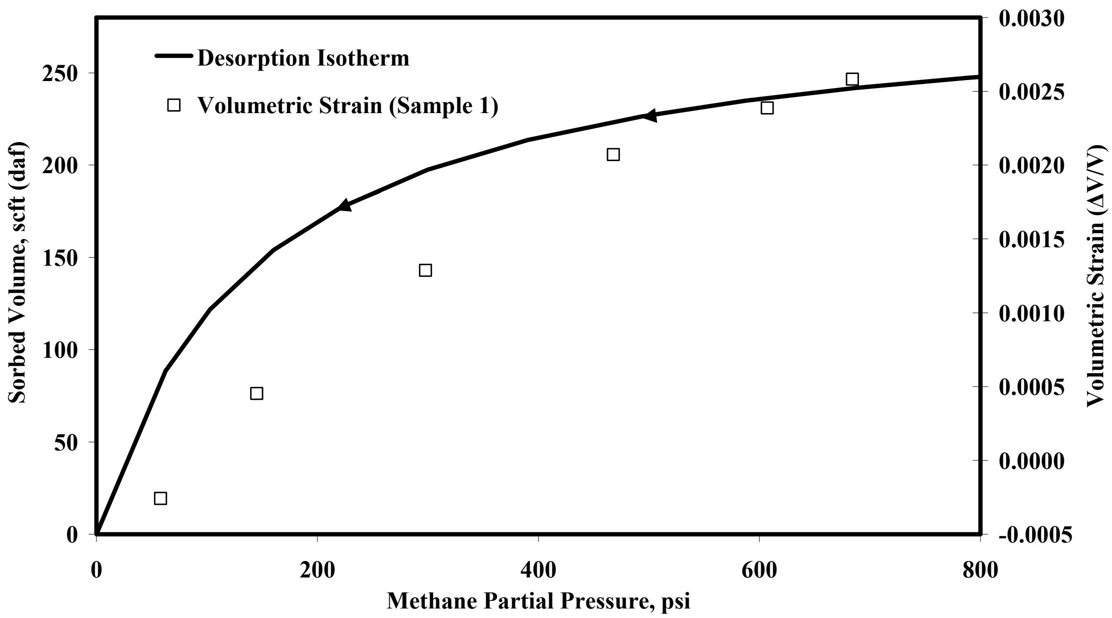

Figure 14: Sorbed volume and volumetric strain vs. methane pressure for Seeleyville coal sample.

<u>TASK IV: Simulation of CO_2 Sequestration/CBM Production by Flue Gas Injection</u>

Using the results of the experimental work, and other required data, a detailed simulation exercise was carried out to determine the effects of flue gas injection on long-term CBM recovery and CO_2 sequestration potential in Illinois coals. The coal and reservoir property data required for the simulation study were 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 in the Illinois Basin, not all properties of Illinois coals were available. For parameters not available, average values of properties of currently CBM producing regions were used, or assumed. 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.

Table 2: Input Parameters used for Simulation

Coalbed Properties	
Net coal seam thickness	9 ft
Depth of coal seam	1495 ft
Fracture permeability (along cleats)	~35 md
Fracture permeability (along bedding plane)	~3 md
Fracture porosity	.01 (1%)
Cleat spacing	0.1 in
Coal compressibility	200 x 10^{-6}/ psi
Matrix shrinkage compressibility	2 x 10^{-6}/psi
Coal density	1.36 g/cc
Sorption Characteristics	
Langmuir volume (CH_4, CO_2, N_2)	(533, 1097, 197) scft
Langmuir pressure (CH_4 ,CO_2, N_2)	(512, 229, 1382) psia
Sorption time (CH_4, CO_2, N_2)	(10, 15, 5) days
Reservoir Properties	
Temperature	83.5^{0}F
Reservoir pressure	650 psi
Water saturation	0.75
Water viscosity	0.73 cp
Gas Composition	
CH_4, CO_2, N_2, other gases	0.92, 0.07, 0.01, none
Drainage area	One-fourth of 40 acres
Bottom-hole Pressure (production well)	10 psia
Bottom-hole Pressure (injection well)	800 psia

The following different alternatives were simulated:

- A base case of CBM production with different well spacings, simulating primary methane recovery for duration of approximately 3000 days, was first constructed. Once the production results for the base case were established, various ECBM options were developed and compared with this.
- The first and second ECBM alternatives were considered with pure CO_2 and N_2 respectively, where CO_2/N_2 was injected after 1000 days of primary production for the remaining duration of the simulated period. Methane production rate, cumulative

production over the life of the reservoir, incremental methane production, and CO_2/N_2 breakthrough were evaluated. The amount of CO_2 sequestered prior to significant breakthrough, amount of nitrogen required for injection, and the amount of nitrogen recovered, were also estimated.

- The third ECBM alterative was considered with 'simulated' flue gas, where flue gas was injected after 1000 days of primary production for the remaining period simulated. For this alternative also, methane production rate, cumulative production over the life of the reservoir, incremental methane production, and CO_2/N_2 breakthrough were evaluated. The amount of CO_2 sequestered, prior to significant breakthrough, was estimated.
- The final simulation included repetition of the above option, except that flue gas injection commenced from the beginning of CBM production.

Primary Recovery (Base Case): For the base case, a standard 5-spot well pattern was used. Only a quadrant of the symmetric 5-spot pattern was simulated for a duration of approximately 3000 days. Cartesian grid-block geometry was selected to represent the reservoir. The 'simulated' quadrant was represented by 41 x 41 x 1 grid-blocks in the x, y and z directions respectively. The aerial (x-y) shape of the grid was square, and the dimension of the grid in the z-direction (depth) was kept equal to the seam thickness. Two producer wells were placed diagonally opposite the two ends of the grid.

The optimum well spacing used for the base case was determined by analyzing the influence of well spacing on CBM and water production. Three simulation runs were carried out with well spacing of 40-acres, 80-acres and 160-acres respectively. These values were selected on the basis of average well spacing used in other CBM producing basins in the US. Figure 16 shows the methane recovery fraction for the three well spacing values. From the results, it is evident that 40-acre well spacing provided a higher methane recovery than the other two cases. This is indicative of the positive effect of rapid dewatering in the case of 40-acre well spacing, as shown in Figure 17. It is evident from the results that the cumulative water production in the case of 40-acre well spacing reaches its steady level much earlier than the other two cases. Also, Illinois Basin is characterized by coals of low to medium permeabilities (10-40 md) and relatively high desorption times (10-100 days), resulting in slow movement of the gas in coal. It is, therefore, advantageous to keep the well spacing small to minimize the distance that the gas molecules need to move in order to reach a producing well. Based on the above results, 40-acre well spacing was used to simulate the primary methane recovery (base case) and ECBM alternatives. All the results are for the quadrant shown.

Using the input data, grid-block geometry and well pattern, as detailed above, the primary recovery of methane was simulated for a period of 3000 days. The cumulative methane production for the base case was approximately 132,000 thousand standard cubic feet (Mscf), as shown in Figure 18, translating to an average daily production rate of ~43 Mscfd. The gas in place (GIP) was calculated to be 186,000 Mscf.

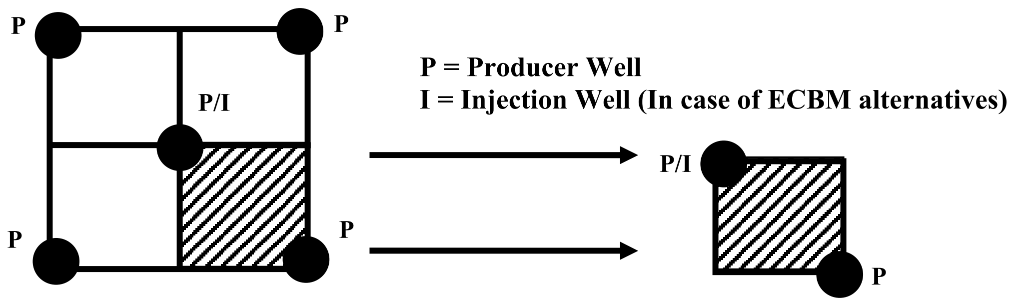

Figure 15: Five-spot well pattern and the simulated quadrant.

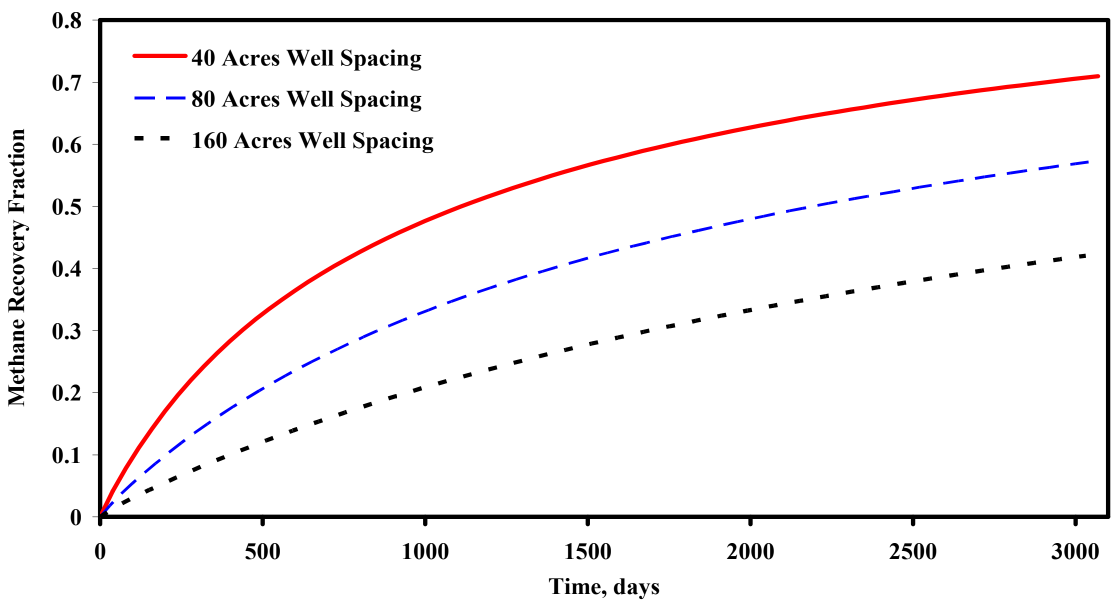

Figure 16: Primary methane recovery fraction for different well spacing.

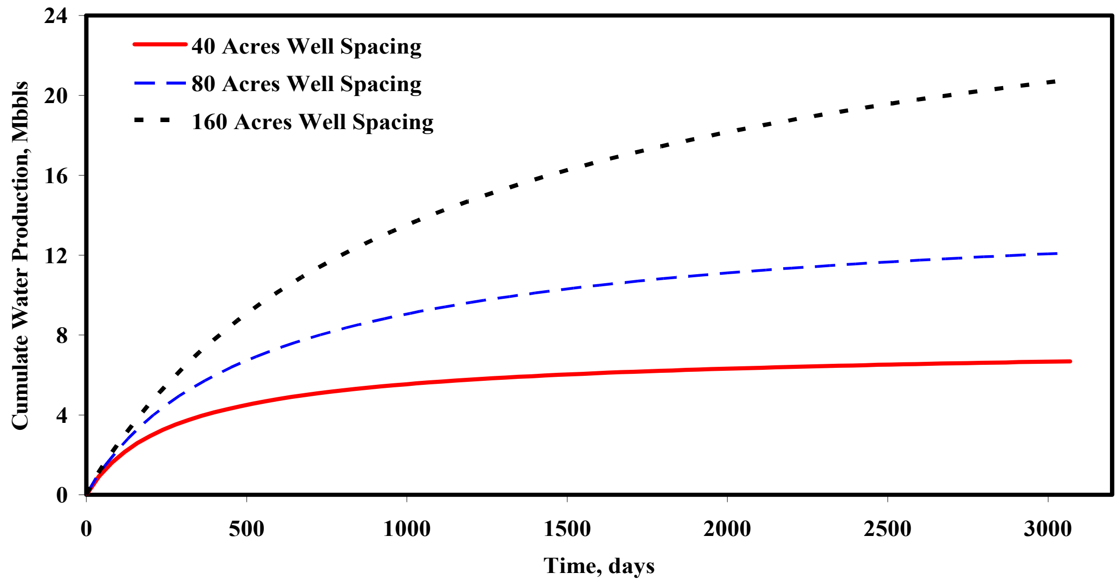

Figure 17: Cumulative water production for different well spacing.

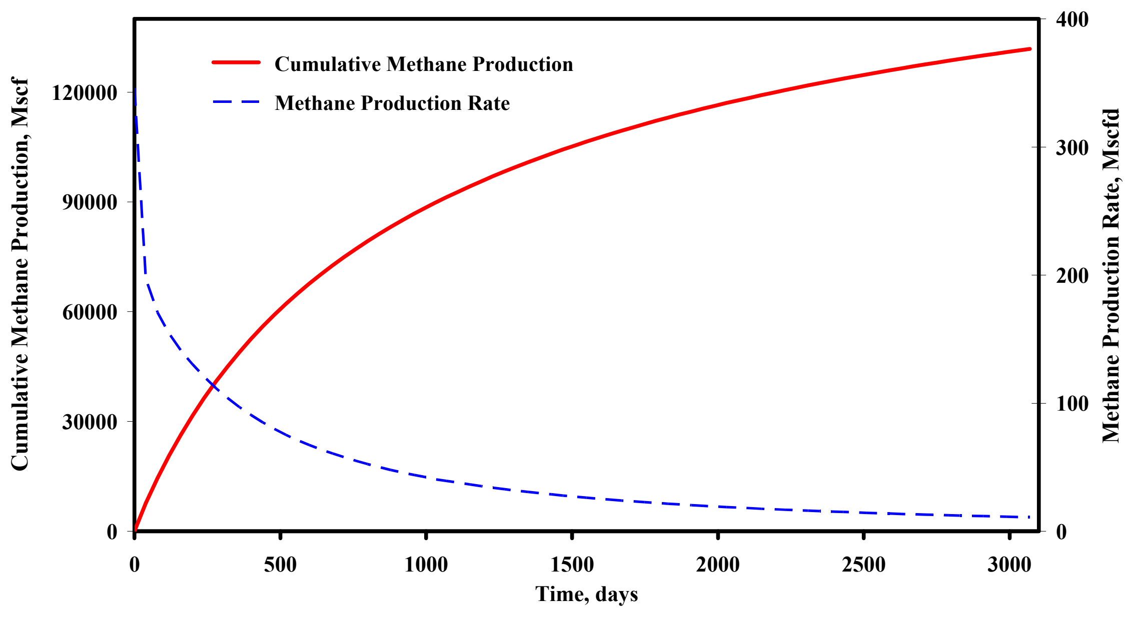

Figure 18: Cumulative production and production rate for the primary recovery case.

Enhanced Methane Recovery with CO_2 Injection: For enhanced methane recovery (ECBM), the injector and producer wells were placed at the corners of the quadrant, as shown in Figure 15. The base case was modified to CO_2 injection case by injecting CO_2 at a pressure of 800 psi, after 1000 days of primary production, for the remaining period simulated. CO_2 injection was started after partial production of ~48% of the GIP, with methane production rate dropping to 42 Mscf/day. The results obtained were compared with the base case in order to analyze the effect of CO_2 injection, and are shown in Figure 19. The result was an increase in the methane recovery to 98% of the GIP, compared to 71% with primary depletion method over a period of 3000 days.

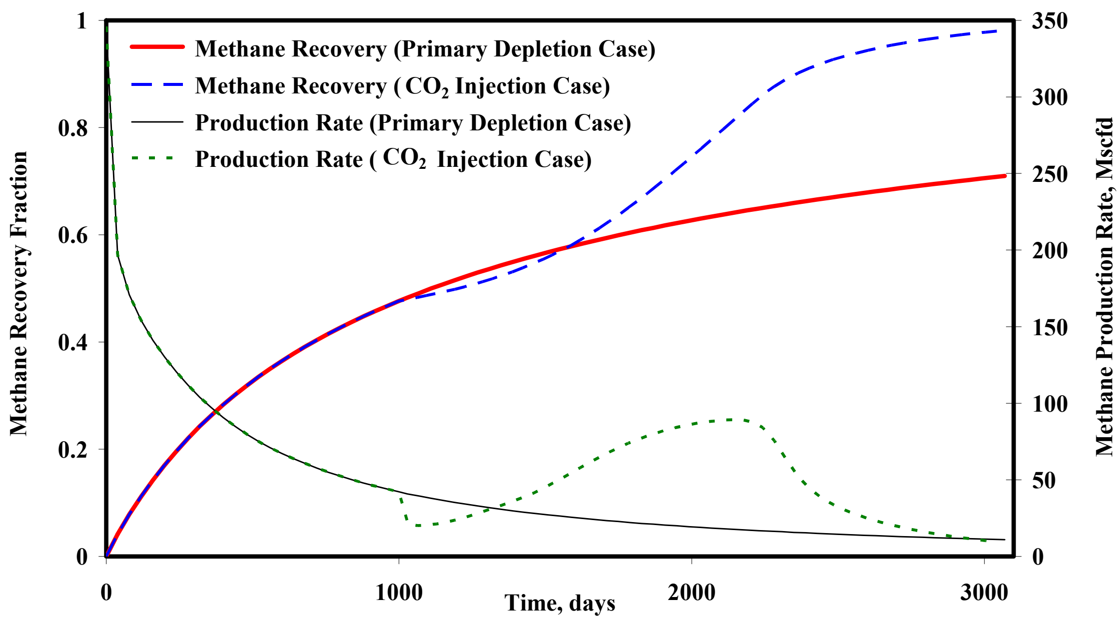

Figure 19: Methane recovery fraction and methane production rate with and without CO_2 injection.

Considering the economics in terms of having 4% CO_2 breakthrough in the production, necessitating earlier abandonment, the overall methane recovery came out to be 90% of the GIP. Figure 20 shows the incremental methane recovery in comparison with the primary depletion method, considering 4% CO_2 breakthrough as the abandonment criterion. This increase in methane production of ~45,000 Mscf was achieved by continuous CO_2 injection over a period of ~1350 days. Nearly 440,000 Mscf of CO_2 was injected during the period, of which ~430,000 Mscf was retained in the coal. The results also show that the effect of CO_2 injection on methane recovery is not instantaneous. It becomes prominent only after considerable amount of CO_2 has been injected, that is, after ~200 days of continuous CO_2 injection. This corroborates well 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 CO_2 injection is due to the preferential adsorption of CO_2 over CH_4 in coal, and the ability of CO_2 to displace majority of the methane from the coal matrix. The ratio of net CO_2 sequestered to incremental methane recovery is approximately 5:1 which supports the experimental findings showing CO_2 to be between 2 and 7 times more sorptive than methane. Finally, the results illustrate the CO_2 sequestration potential. Approximately 98% of the injected CO_2 is sequestered, with 4% breakthrough as the abandonment criterion. From the simulation results, methane production will probably be discontinued after ~2350 days due to significant CO_2 breakthrough, unless carbon credits justify continued injection.

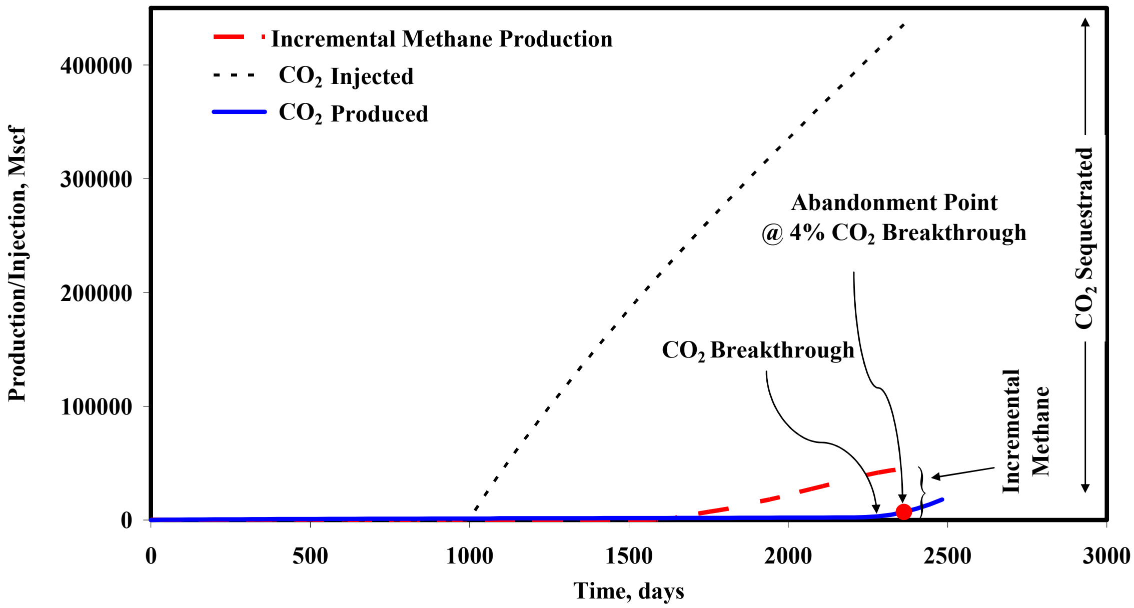

Figure 20: Incremental methane recovery and CO_2 sequestered with CO_2 injection.

Enhanced Methane Recovery with N_2 Injection: Using the same input data, grid-block geometry, and well pattern, as detailed above, the base case was modified to N_2 injection case by injecting N_2 at a pressure of 800 psi, after 1000 days of primary production. The results obtained were compared with the base case in order to analyze the effect of N_2 injection, and are shown in Figure 21. The result was an increase in the methane recovery to 96% of the GIP, compared to 71% with primary depletion method over a period of 3000 days. From these results, it is evident that the methane production rate increased immediately following the commencement of N_2 injection.

Considering 50% N_2 breakthrough in production as the abandonment criterion, methane recovery was 77% of the GIP. Figure 22 shows the incremental methane recovery compared to primary depletion method, considering the above criterion. Nitrogen breakthrough occurs much earlier since it does not get preferentially adsorbed (like CO_2). This is contrary to CO_2 injection, where there was a lag between the start of injection and increase in methane production rate. Significant nitrogen breakthrough starts after ~260 days of continuous injection. From the simulation results, methane production will probably be discontinued after ~1800 days due to significant nitrogen breakthrough. An increase in methane production of ~31,500 Mscf was achieved by continuous nitrogen injection, compared to that of primary recovery method, over a period of ~800 days.

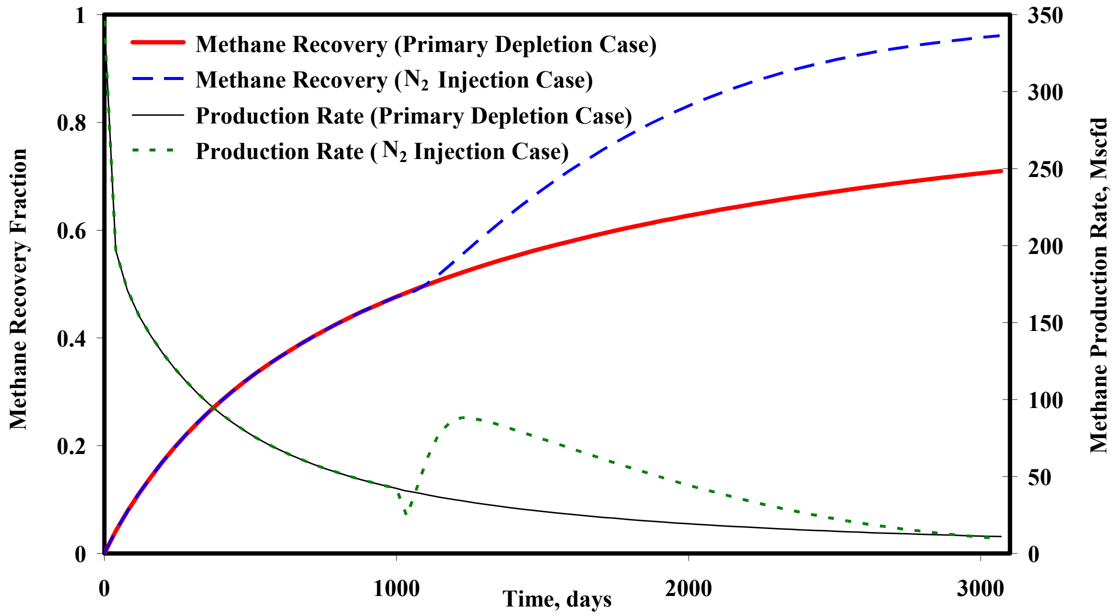

Figure 21: Methane recovery fraction and methane production rate with and without N_2 injection.

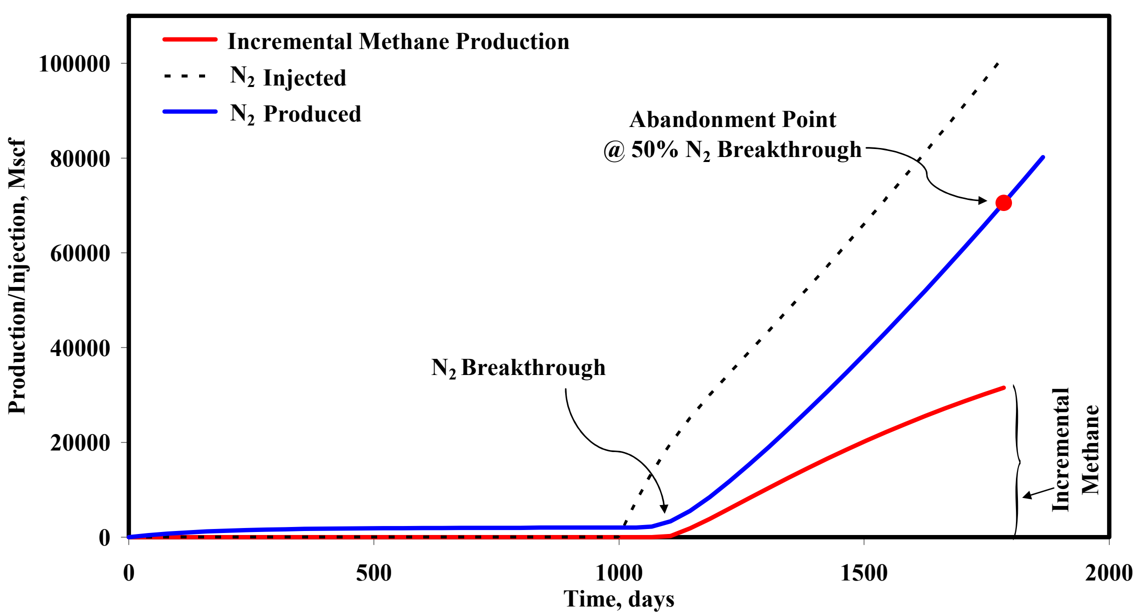

Figure 22: Incremental methane recovery with N_2 injection.

Enhanced Methane Recovery with Flue Gas Injection: The first simulation run considered injecting the simulated flue gas with the same composition (87% N_2 + 13% CO_2) as that used in the experimental work. The base case was modified to flue gas injection case by injecting flue gas at a pressure of 800 psi after 1000 days of primary production. The results obtained were compared with the base case, as shown in Figure 23. The result was an increase in the methane recovery to 96% of the GIP, compared to 71% with primary depletion method, over a period of 3000 days. Since N_2 component in the flue gas used is high, the results were similar to that for pure N_2 injection. It is also evident from the results that methane production rate increased immediately following the commencement of injection.

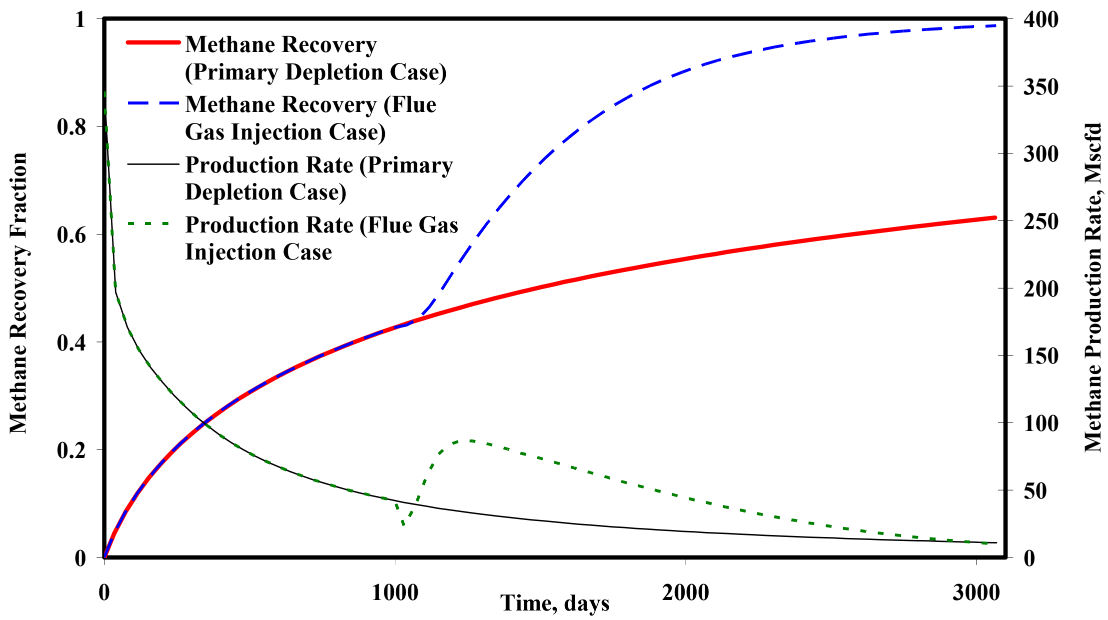

Figure 23: Methane recovery fraction and methane production rate with and without flue gas injection.

Considering 4% CO_2 or 50% N_2 breakthrough in production as the abandonment criterion, methane recovery was 78% of the GIP. Nearly 15,000 Mscf of CO_2 was injected during the period, of which nearly 85% was retained in the coal. Figure 24 shows the incremental methane recovery compared to primary pressure depletion method, considering the above criterion. An increase in methane production of ~31,500 Mscf was achieved by continuous flue gas injection over a period of ~800 days. At abandonment, CO_2 breakthrough was only 1.6%.

Since the gas content of coal in Illinois Basin is not as high as in some of the other US basins, injection of the second gas as soon as CBM production starts, is being considered. Considering this, a flue gas injection case was simulated by injecting flue gas at a pressure of 800 psi from the commencement of the CBM operation. The results obtained were compared with flue gas injection case after 1000 days of primary production, as shown in Figure 25. Although methane production rate increases immediately with flue

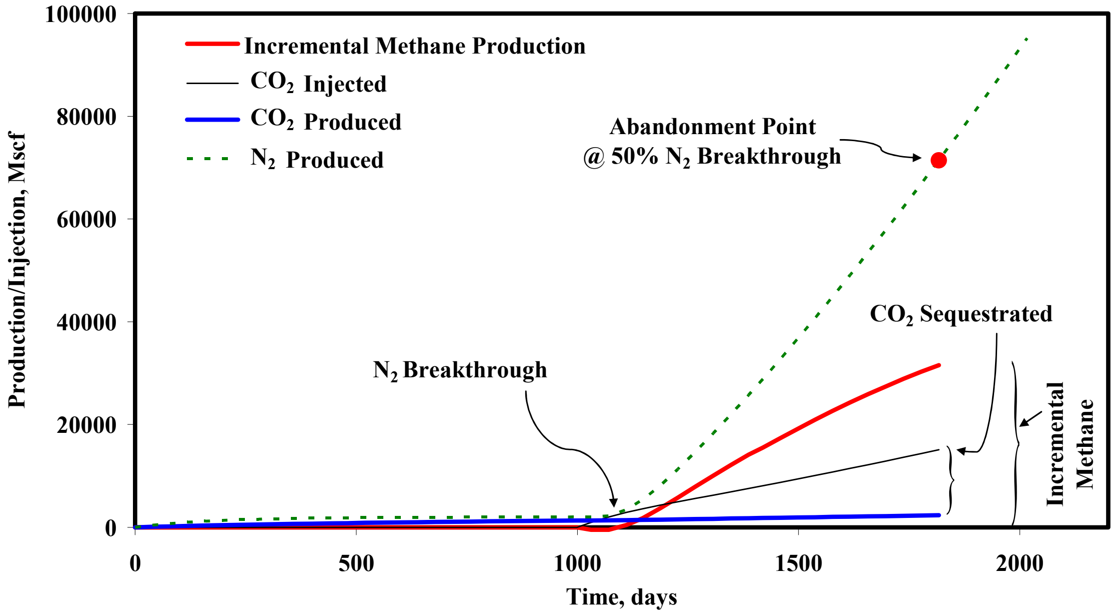

Figure 24: Incremental methane recovery and CO_2 sequestered with flue gas injection after 1000 days.

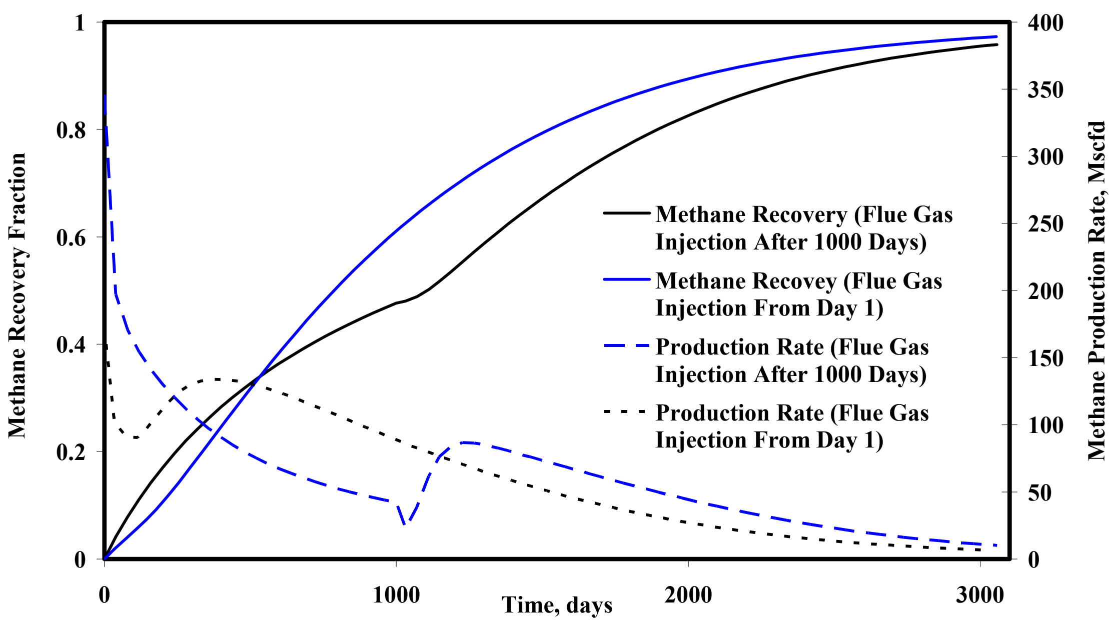

Figure 25: Methane recovery fraction and methane production rate with flue gas injection.

gas injection commencing from the start of operation, the overall methane recovery is only 70% due to early nitrogen breakthrough. Again, considering 4% CO_2 or 50% N_2 breakthrough in production as the abandonment criterion, nearly 13,500 Mscf of CO_2 was injected during the period, of which nearly 87% was retained in the coal. Figure 26 shows the incremental methane recovery with flue gas injection for this alternative. An increase in methane production of ~33,000 Mscf was achieved by continuous flue gas injection over a period of ~1200 days.

A comparative analysis of the alternatives simulated is summarized here. ECBM with CO_2 injection after 1000 days seems to be more promising in terms of the methane recovery fraction and the total CO_2 sequestered. ECBM with N_2 and flue gas injection after 1000 days is similar in terms of methane recovery, the only advantage being that of CO_2 sequestration in the latter case, suggesting preference of flue gas over N_2 injection. Flue gas injection after 1000 days gives better results than injection commencing from the beginning of CBM production, the only difference being higher methane production rates in the early production stage in the latter case. Higher percentage of nitrogen in the flue gas may be the reason, suggesting that a detailed simulation study for flue gas mixture, with varying N_2 and CO_2 concentrations, should be carried out to obtain an optimum ratio of N_2 and CO_2 that would result in maximum methane production and CO_2 sequestered. This "enriching" the flue gas prior to injection is being considered in Canada.

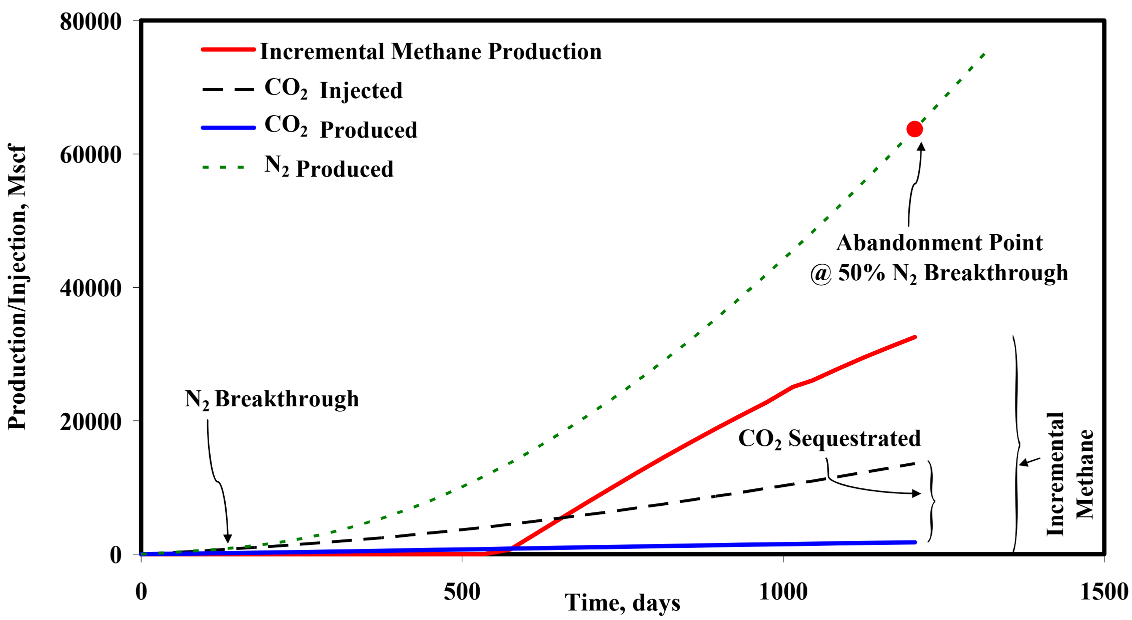

Figure 26: Incremental methane recovery and CO_2 sequestered with flue gas injection commencing from the beginning of CBM operation.

CONCLUSIONS AND RECOMMENDATIONS

Based on the work completed, two categories of conclusions can be made, some that are specific to Illinois and others that are general. The specific conclusions are as follows:

- The permeability of coal decreases log-linearly with stress. This is expected since high stresses compact the cleats present in the coal and result in a significant reduction in permeability. The permeability of coal also decreases linearly with mean gas pressure. Both these findings suggest that permeability of Illinois coals would decrease with continued production by the pressure depletion method alone, since this technique results in a decrease in gas pressure and increase in effective stress. Hence, serious consideration should be given to ECBM.
- In Illinois, injection of CO_2/flue gas would not result in a permeability loss although there will be some permeability reduction with CO_2 injection due to the fact that coal permeability to CO_2 is lower than that to methane. For the case of flue gas injection, this is further corroborated by the results of the strain experiments where injection of flue gas resulted in negligible swelling.
- All three gases – methane, flue gas and CO_2 – follow the same permeability variation trend. However, the permeability reduction with increase in stress, as well as decrease in pressure, was the largest for pure CO_2, followed by flue gas containing 13% CO_2, and the smallest for methane. This suggests that although injection of CO_2/flue gas would result in an immediate reduction in permeability, a continuous decline will not occur since injection results in increased gas pressure and decreased effective stress, both of which ensure constant permeability in the worst case.
- Consideration should be given to high pressure injection of flue gas. First, this would result in improved economics of the operation resulting in higher overall recovery and higher early production rates. Second, the permeability damage as a result of flue gas injection would be almost negligible. In fact, there might even be permeability enhancement since the measured permeability at high flue gas pressure is higher than that to methane.
- The coal matrix "swells" significantly with injection of CO_2. This swelling is greater than that induced by sorption of methane or flue gas. On the other hand, with injection of flue gas to replace methane, the swelling is almost small to negligible. The small swelling with flue gas injection suggests that application of ECBM by flue gas injection in Illinois Basin would result in permeability remaining practically unaltered, favoring ECBM by flue gas injection.
- A 40-acre well spacing is optimum for CBM production in the basin.
- ECBM with CO_2 injection is the most promising technique in terms of the methane recovery fraction as well as total CO_2 sequestered.
- ECBM by N_2 injection in Illinois coals would improve the recovery and production rates although the overall recovery would not be as good as with CO_2 injection.
- Flue gas injection after 1000 days gives better results than injection commencing at the beginning of CBM production, the only difference being the higher methane production rate during the earlier stages of CBM production in the latter case. When coupled with the fact that all of the nitrogen in the flue gas will have to be compressed prior to injection, for no economical benefit since most of it is produced

almost immediately, injection of flue gas for the entire life of a reservoir is not going to be economical. Furthermore, nitrogen requires separation at the downstream end due to its early breakthrough, resulting in additional expenditure.

- Flue gas ECBM would probably not have significant sequestration potential since the amount of CO_2 sequestered as well as the incremental CBM produced were both found to be rather small.

The general conclusions that can be drawn from the findings of this study are as follows:

- The permeability response to changes in gas pressure was unexpected. With continued flue gas/CO_2 injection, and its adsorption, the corresponding swelling of the coal matrix is expected to result in a significant permeability loss. This was not the case in the laboratory, although significant swelling of the matrix was measured with CO_2 injection. This suggests that permeability loss with CO_2 injection is not a universal phenomenon. There probably is a more dominating effect, other than swelling, that results in this loss. Since a major difference between the three sites where permeability loss has been observed and Illinois coals is the depth and, therefore, stress conditions. Hence, there may be a significant coupling of the stress and swelling effects. If this is, in fact, the case, it can have a significant impact on CBM production as well since the permeability is typically expected to increase with continued production and this might not occur in Illinois reservoirs.
- The volumetric strain trends were found to resemble that of the sorption isotherms established, suggesting a linear relationship between the amount of gas adsorbed and the strain induced by it. Hence, it might be possible to estimate the shrinkage/ swelling behavior from isotherms alone.
- 13% CO_2 in flue gas results in swelling of the coal matrix that is similar in magnitude to the shrinkage associated with desorption of methane, that is, swelling with flue gas injection compensates for the shrinkage due to methane desorption. This was found to be true for matrix strain as well as permeability behavior.

It is recommended that the following research venues be pursued:

- A detailed economical analysis is necessary to determine the viability of ECBM options although this would depend primarily on the carbon credits in the US. Although not known at this time, the February 2006 GHG Transactions states that "Passage of a national greenhouse regulatory framework is a distinct possibility ….".
- The coupled effect of stress and matrix swelling needs studying in detail, rather than evaluating the two effects separately, and assuming that their impact on permeability is independent of each other.
- In Illinois, CBM is found to contain high concentrations of nitrogen. This has been discouraging producers to continue production, as well as deterring new producers to make investments into CBM ventures. A technique that would enable predicting the "gas quality" must be developed to determine if the nitrogen concentration would decrease with continued production, brining the CBM up to pipeline standards. If not, separation of nitrogen should be taken into consideration during the economic analysis of commercial CBM production.

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