Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO_2 Capture Project

Geologic Storage of Carbon Dioxide with Monitoring and Verification

Volume 2

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Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO_2 Capture Project

Geologic Storage of Carbon Dioxide with Monitoring and Verification

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Chapter 14

CO_2 STORAGE IN COALBEDS: CO_2/N_2 INJECTION AND OUTCROP SEEPAGE MODELING

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ABSTRACT

Methane (CH_4) production from coalbeds can be enhanced by injection of carbon dioxide (CO_2), nitrogen (N_2), or a mixture of both (flue gas) to accelerate methane production at sustained or increased pressures. Coal has the capacity to adsorb considerably more CO_2 than either methane or nitrogen. However, the actual field performance of enhanced methane recovery processes, wherein CO_2 is concurrently stored, is largely dictated by how effectively injected gases contact and interact with coalbeds over the active project lifetime. By history matching the early nitrogen breakthrough time and nitrogen cuts in BP's Tiffany Unit, simulation indicated that the injected N_2 may only contact a small portion of the total available pay, which was evidenced by the spinner surveys conducted in some of the N_2 injectors. As a possible explanation, the elevated pressure affected by N_2 injection may expand the coal fractures on the preferential permeability trends in the Tiffany Unit. Simulation prediction of CO_2–N_2 mixed gas injections was performed following the history matching in the pilot area. Methane seepage has already been observed from many locations along the north and west Fruitland outcrops in the San Juan Basin. The concern is that injected CO_2 could likely follow the methane seepage paths and leak from the outcrops. Based on the geological setting of the Fruitland coal outcrop, a representative seepage model was used to simulate the effects of CO_2 contact volume (net pay interval) in coal and the injection distance from the outcrop on methane and CO_2 seepage. Under certain conditions, simulation predicted that a large volume of methane and CO_2 breakthrough could occur if the CO_2 injection wells are placed too close to the outcrop.

INTRODUCTION

There is a growing consensus in the international community that CO_2 emission from burning fossil fuels plays an important role in global climate change. Of the storage options currently under consideration, geologic storage of CO_2 in coal formations is considered to be one of the methods with significant short-term potential. A recent report by Reeves [1] estimates that the total storage potential in unmineable coalbeds in the US alone is about 90 gigatonnes for CO_2 storage, with an additional benefit of 152 trillion cubic feet of methane recovery.

Quantitative modeling is necessary to estimate storage capacity, in situ concentration, transport velocity, CO_2 sweeping volume, and the timeframe for filling, monitoring, and storage. The actual CO_2 storage capacity of coal is largely determined by how effectively injected gases contact and interact with the reservoir over the active project lifetime. The economic limit for methane recovery and CO_2 storage is usually dictated by CO_2 breakthrough, poor injectivity or a variety of other factors that make further operation economically prohibitive. Obvious factors, which may control contact and interaction, include gas adsorption isotherms, reservoir heterogeneity, respective roles of convective and diffusive transports in a fractured medium, CO_2 dissolution in water, and the effect of CO_2 adsorption on coal permeability. In this study, the focus was placed on an actual field case (Tiffany Unit), the sensitivity study of critical coal reservoir properties, and CO_2 seepage from outcrops. This approach establishes a link between the first-hand knowledge from an actual field performance and a more realistic CO_2 seepage forecast. A compositional model, BP-Amoco's GCOMP [2], was used in the simulation of the history match and CO_2-N_2 mixed gas injections in the pilot area. The sensitivity study and outcrop seepage modeling were performed on the COMET2 [3,4] CBM simulator developed by the Advanced Resources International. COMET2 can only model single gas or binary gas mixtures (CH_4-N_2 or CH_4-CO_2) but provides more coalbed-specified features, such as coal matrix shrinkage/swelling, which GCOMP does not provide.

Nitrogen Injection in the Tiffany Unit

In the San Juan Basin, two commercial demonstration projects of enhanced coalbed methane recovery (ECBM) by gas injection have been implemented at the Allison and Tiffany Units [5,6] (Figure 1). Carbon dioxide is being injected into the Fruitland coal in the Allison Unit, operated by Burlington Resources, while nitrogen injection into the same coal formation is being tested at the Tiffany Unit, operated by BP America Inc. The field performance of N_2-ECBM not only provides valuable knowledge of how the coal formation interacts with injected N_2 while the coal swelling due to CO_2 injection is absent, but also has important implications for CO_2 storage via flue-gas injection.

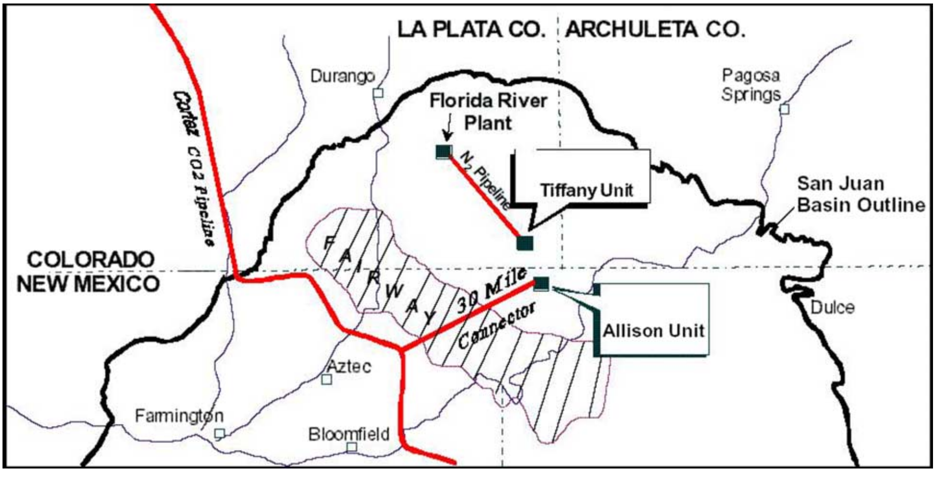

Figure 1: Locations of Tiffany and Allison Units, San Juan Basin [5].

The Tiffany Unit is located in the southern Colorado portion of the San Juan Basin (Figure 1). The pilot area for nitrogen injection is about 10,000 acre and consists of 36 production wells and 12 nitrogen injection wells with a mix of 320 and 160-acre well spacing (Figure 2). Methane is being produced from five Upper Cretaceous Fruitland Formation coal seams, named A, B, C, D, and E (from shallowest to deepest) [6]. A summary of basic coal reservoir properties is provided in Table 1. Note that the reported coal permeability of 1–3 md [6] appears much lower than the permeability of 3–8 md obtained from the history match of primary production in the Tiffany Unit.

Of the 12 N_2 injection wells, 10 were drilled directionally from existing production well pads. The remaining two injection wells were converted production wells. The directional wells were realigned vertically before penetrating the coal horizons. All injection wells were cased, perforated in the coal seams, and hydraulically fractured. To avoid the potential connection with N_2 injection into non-coal strata the wells were not intentionally hydraulically fractured. The production wells were completed with casing and then perforated and simulated by hydraulic fracturing. After the water production declined to a low rate, the wells were configured with a tubing/packer arrangement and produced on natural flow [5].

The source of the injected nitrogen is a cryogenic air separation plant located at BP's Florida River gas processing facility (Figure 1). Injection operations at the field began in February 1998 and continued intermittently until January 2002. Because generation costs become prohibitively high when the ambient

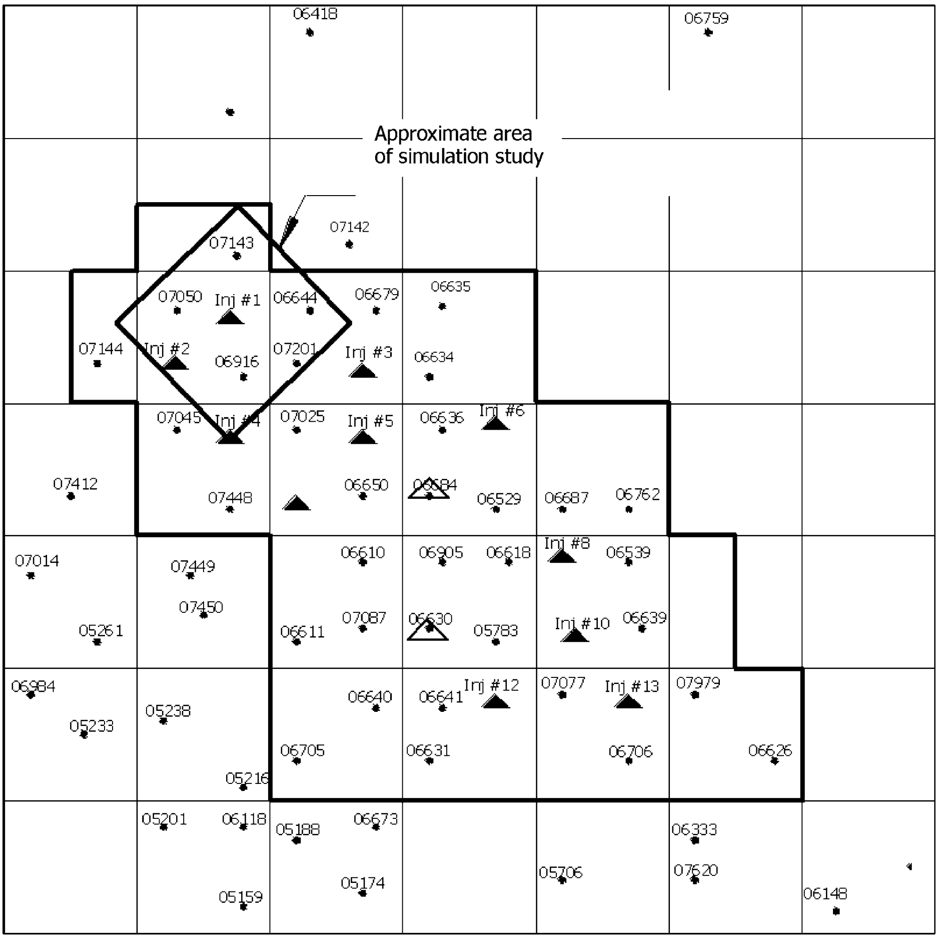

Figure 2: Injection/production well configurations and the area of simulation study, Tiffany Unit.

TABLE 1
TIFFANY UNIT BASIC COAL RESERVOIR PROPERTIES

Property	Value
Number of coal seams	5 (A, B, C, D, and E)
Total coal thickness	40–60 ft
Approximate depth to coal	3200 ft
Original reservoir pressure	1620 psi
Original reservoir temperature	120 °F
Coal seam porosity	0.01–0.02
Coal seam permeability	1–3 md

temperature was greater than 65 °F, BP adopted the strategy of injecting primarily during the cooler (winter) months. Nitrogen injection was suspended after January 2002. The injection of N_2 resulted in a 5-fold increase in methane production [6].

Early N_2 breakthrough was observed from many producing wells. Figure 3 shows the injection history of four injection wells in comparison to the N_2 breakthrough time and N_2 cut responses from the five production wells in the simulation study area. N_2 cuts from all wells except Well 6644 reached 20% in about 1 year after the beginning of N_2 injection. Simulation has shown that Well 6644 is not aligned to any injector on the preferential permeability trends. In an internal report by Raterman [7], two distinct kinds of breakthrough were identified. The first type is characterized by a strong methane response. This behavior is consistent with a homogeneously fractured coal description wherein volumetric sweep of the target coals are largely unaffected. The second type of breakthrough is not associated with coal but rather a distinct thief zone or fracture network.

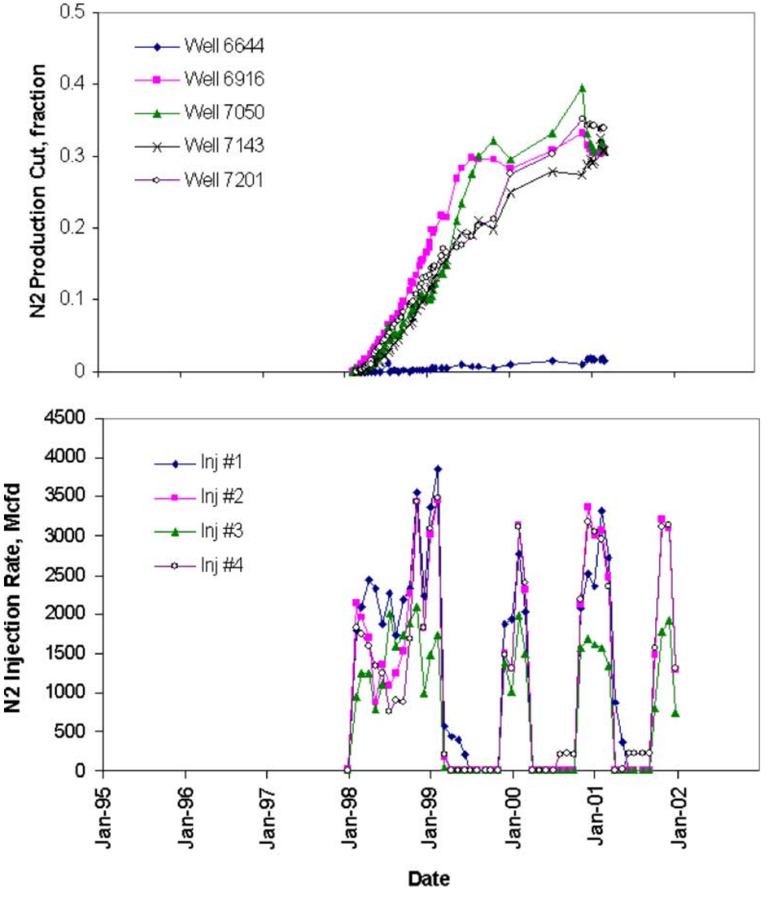

Figure 3: Nitrogen breakthrough time and nitrogen cut responses to nitrogen injection, Tiffany Unit.

In October 1996, a single well injectivity test was conducted in the Southern Ute Gas Unit "U" #1 producer [7]. The test was designed to specifically assess the potential for poor N_2 sweep at Tiffany field. Initially, perforation and fracture integrity were evaluated by breakdown test that consisted of isolating 3 ft sections of the perforated interval, injecting a small water volume, and recording the threshold pressure at which flow was initiated. The testing data indicated that over 95% of the 54 ft interval, including all the five coal seams, in the well was open. Within the open interval, fluid entry pressures appeared relatively uniform. Following the breakdown test the well was placed on production to remove the injected water. The well was then reconfigured for N_2 injection. An analysis of the spinner survey, conducted in the well during N_2 injection, revealed that about 75% gas flow entered approximately 25% of the perforated interval. The highly conductive zone is mostly associated with coal seam B. Similar results were later observed from spinner surveys conducted in other N_2 injectors including Injector #1 and #4 in the simulation study area (Figure 2).

With BP's proposal to supplement the nitrogen injection with the CO_2 captured from its gas processing plant, the effectiveness of combined CO_2 storage and ECBM recovery was assessed including a full-field simulation modeling. The model provided a good history match of the primary production but was unable to predict N_2 breakthrough time and N_2 cut responses at the majority of the responding producers. The proposed injection of CO_2 was postponed due to economic considerations.

ECBM Modeling

Coal has the capacity to hold considerably more CO_2 than either methane or nitrogen in the adsorbed state, in an approximate ratio of 4:2:1 for typical Fruitland coal [6,8,9]. The injected CO_2 becomes preferentially adsorbed onto the coal and thereby displaces methane from the coal matrix. On the other hand, the injection of N_2 will decrease the partial pressure of gaseous methane in the cleat system. As a result, methane desorbs and is pulled into the gaseous phase to achieve partial pressure equilibrium. The N_2-ECBM process is generally referred to as methane stripping. However, the actual field performance of enhanced methane recovery processes is largely dictated by how effectively injected gases contact and interact with the coalbed over the active project lifetime. As observed from spinner surveys, it is likely that a highly conductive coal zone may exist within the Tiffany field. The elevated pressure by N_2 injection could expand the coal fractures on the preferential permeability trends and result in poor N_2 sweep. Early N_2 breakthrough and high N_2 cuts suggest that the permeability on the preferential trends appears much higher than initially assessed even in the low-pressure regions near the producers. Consequently, simulation models that can provide good historical matches of primary productions are often proven inadequate in many aspects to accurately match field performances during the gas injection phase [10–12].

The porous structure of coal is normally described using the Warren and Root [13] concept, wherein the coal matrix blocks are considered to be rectangular parallelepipeds or cubes, and the fractures are considered to be parallel cleats between the matrix blocks. The two orthogonal cleat sets, perpendicular to bedding, are commonly referred to as face (dominant) and butt (subordinate) cleats. Permeability is essentially negligible in the matrix of coal. The aspect ratio of face cleat permeability to butt cleat permeability and cleat orientations largely dictate the preferential permeability trends of coal. The factors that control the permeability of cleats are frequency, connectivity, and aperture width. Gas movement in coal is controlled by diffusion in the coal matrix and the water–gas transport through the cleat system is described by Darcy's law for two-phase flow. Conventional compositional reservoir models, such as GCOMP, have successfully been used to model the primary methane production [10,11,14] and have been attempted to simulate the ECBM process. In this approach, coal is treated as immobile oil and instantaneous gas diffusion is assumed in the coal matrix. The sorption of gas mixtures is described by equilibrium K-values. GCOMP also provides a coal degasification option, in which the multi-component gas sorption is modeled by the extended Langmuir model. The extended Langmuir model is used by most CBM simulators, such as the COMET2/3. In addition, CBM simulators provide more coalbed-specified features that are lacking in conventional models, such as dual porosity/dual permeability, Fick's law for gas diffusion in coal matrix, and coal shrinkage (swelling) due to gas desorption (adsorption).

Methane production rates are commonly used as the well constraint in the history match of the primary production recovery process, while reservoir and well parameters are tuned to achieve a match on water production rates and bottomhole pressures. During the ECBM phase, CO_2 or N_2 is injected by either gas rate or pressure control. However, this simulation approach may encounter difficulty in matching the bottomhole producing pressures for both phases. As observed in Tiffany Unit, initial methane producing rates are usually low even though under low bottomhole producing pressures. The slow release of methane is due to the slow drawdown of coal potentiometric surface. The drawdown could take several months until a sizeable quantity of CBM water has been produced. In order to match both the initial low gas rates and the low bottomhole flowing pressures, a lower permeability often has to be set near the producers. In contrast, during the gas injection phase, the early N_2 breakthrough time and high N_2 cuts indicate the existence of high-permeability trends linking injectors to producers. In other words, a reservoir model resulting from the history match of primary production may not be adequate in simulating the gas injection phase if coal reacts differently to the pressure increase by gas injection.

TIFFANY UNIT SIMULATION STUDY

Previously, a full-field simulation model was developed by BP-Amoco's engineers, which incorporates the full geologic description. The description consists of the five coal seams, some of which do not extend throughout the unit. Coal continuity and thickness are greatest in the northern portion of the field. The model provided good historical matches of the field performance during the primary production period. During the subsequent enhanced recovery phase, N_2 was injected into the field to accelerate methane recovery. However, the field model was unable to predict nitrogen breakthrough time and nitrogen cut responses at the majority of the responding producers. The actual N_2 breakthrough time was much earlier than that predicted by the field model. As evidenced by spinner surveys, the nitrogen injection would have to be restricted into one geological layer, i.e. coal seam B, which accounts for only 25% of the total pay but extends throughout the unit. However, the injectivity tests, such as conducted in the Southern Ute Gas Unit "U" #1 [7], showed nearly uniform fluid entry pressures at most perforated intervals. For a more meaningful history match of the gas injection phase, instead, we developed a 3-layer mechanistic model specific to CO_2 storage in the Fruitland coal of the Tiffany Unit. The simulation area is a five-spot pattern in the northern part of the field where BP planned to conduct a micro-pilot test of CO_2 injection. Figure 2 shows that the pattern consists of one in-pattern and three off-pattern injectors as well as four in-pattern and one off-pattern producers.

Model Description

To match the field performance during the enhanced recovery phase, we assumed that the high-permeability streaks or conduits such as fractured and well-cleated coal within each geologic layer contributed to the early nitrogen breakthrough. Although the high-permeability pay dominates early production response, the long-term response is mostly dictated by the amount of gas exchanged between high and low-permeability packages. Instead of dividing each geologic layer into a fast and a slow component, we modified the model to include a high-permeability fast layer sandwiched between two low-permeability slow layers. In this mechanistic model, the fast layer represents well-cleated and fractured coal from all geological layers while the slow layers represent coal with little or no fracture development from the same geological layers. Initially, a northwest–southeast permeability trend was assumed and the simulation grid blocks were rotated 45° counter-clockwise to match the field permeability trend. However, later from history matching of N_2 injection, it was found that the preferential permeability trend orients roughly along the north–south direction in the simulation area.

History Matching

During history matching, layer thickness, permeability, and vertical transmissibility between layers were adjusted to control N_2 breakthrough time and N_2 cut response. Figure 4 shows that the mechanistic model matched the nitrogen breakthrough time and nitrogen cut reasonably well for all in-pattern producers. The total gas production rate was used as the producing control for all in-pattern producers. As shown in Figure 5, the model resulted as a good match for all producers. However, in order to match nitrogen breakthrough time and nitrogen cut, the vertical transmissibility had to be set to zero. This means that there was no communication between the fast and the slow layers. In this model, nitrogen was allowed to enter all three layers, not just the high-permeability fast layer. However, because the permeabilities of layers 1 and 3 were low and there is no communication between the fast and the slow layers, most of the injected nitrogen entered the high-permeability fast layer. Figures 6–8 show the nitrogen saturations at the end of the nitrogen injection for the high-permeability fast layer (Layer 2) and the two low-permeability slow layers (Layers 1 and 3), respectively. From Figure 6, we can clearly see the preferential permeability trends between the injectors and the producers. A comparison between Figure 6 and Figures 7 and 8 shows that at the end of the nitrogen injection, the nitrogen saturations were very high in the fast layer (Layer 2) and very low in the slow layers (Layers 1 and 3). This is consistent with the observation from spinner surveys and implies that the nitrogen injection and enhanced methane recovery were mostly restricted to only about one-third of the available pay.

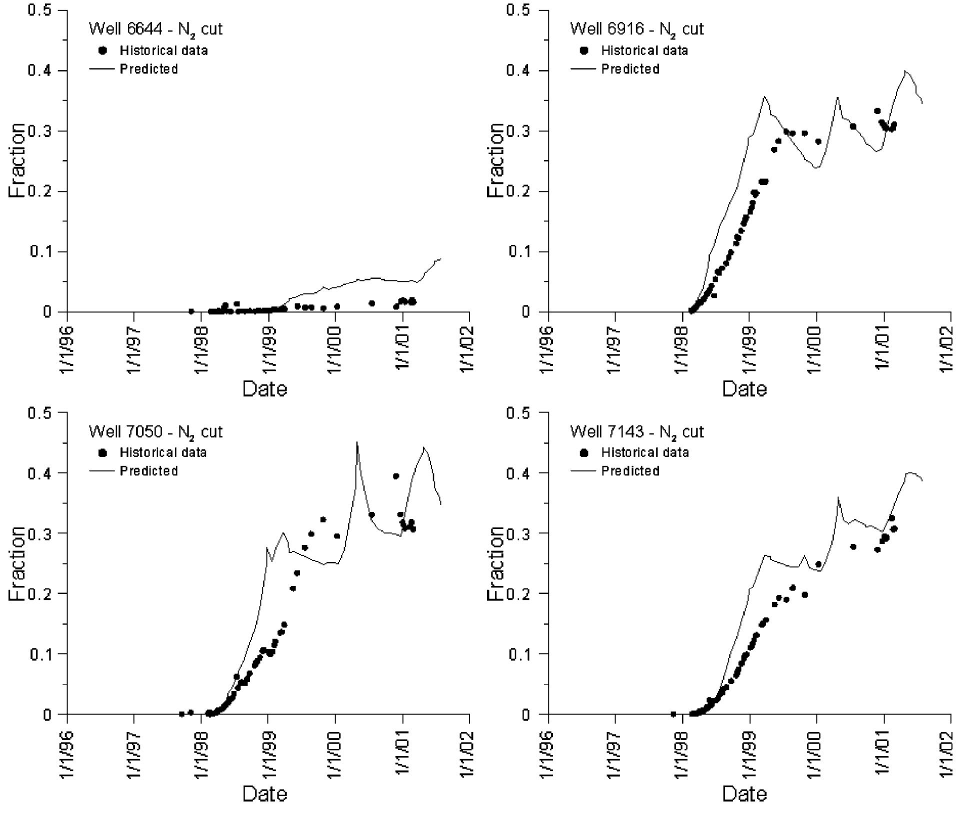

Figure 4: Nitrogen production cut.

Figure 9 shows that the mechanistic model did a reasonable job, matching the bottomhole flowing pressures of all in-pattern producers during the enhanced recovery phase. However, it overestimated the bottomhole flowing pressures during the primary production period for all but one producer. As shown in Figure 9, the mechanistic model matched the pressure responses of Well 6644 reasonably well during both the primary, except in the initial producing period, and the enhanced recovery phases. As discussed before, the difficulty in matching the early bottomhole flowing pressures is because a large pressure drawdown due to a low bottomhole pressure will instantaneously desorb a large volume of methane from coal matrix in the grid block where a producer is placed. The instantaneous gas release does not represent the actual behavior of typical CBM wells during the initial producing period.

Figure 6 shows that unlike other producers, Well 6644 is not linked to any injector on the preferential permeability trends in the simulation area. In other words, the well is least affected by the pressure increase during the gas injection. These findings suggest that the coal formation along the preferential permeability trends in the simulation area reacted differently to pressure depletion during the primary production period and gas injection during the enhanced recovery phase. During nitrogen injection, the elevated pressure may cause coal fractures along a highly conductive zone not only to expand but also to extend from injectors to producers, which was indicated from spinner surveys conducted in some of the N_2 injectors. This permeability enhancement may be additionally supported by matrix shrinkage caused by a lower

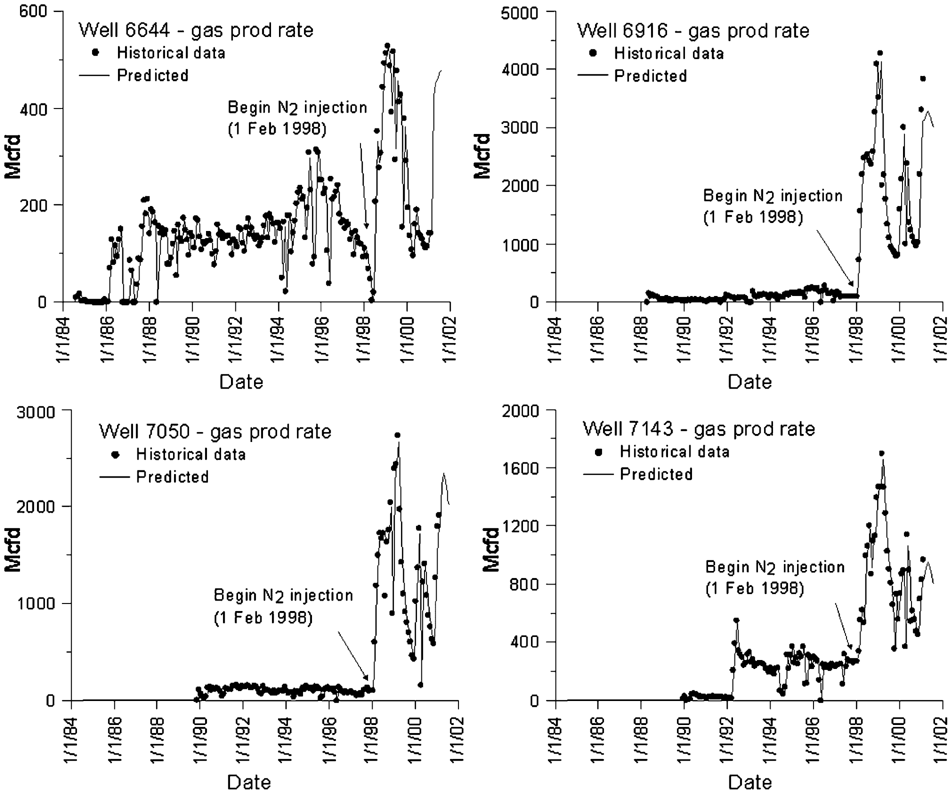

Figure 5: Total gas production rate.

equilibrium adsorbed nitrogen concentration (phase volume) vs. methane. One possible way to satisfactorily simulate both the primary and enhanced recovery phases is to apply negative skin factors to wells on the preferential permeability trends during nitrogen injection but not during the primary production period. Another way is to use one stress–permeability relationship during primary production and a different one during enhanced recovery with gas injection. Also, different stress–permeability relationships might be required for different injector/producer pairs with different degrees of connectivity. Unfortunately, no such specific experimental data are available. Since the mechanistic model is based on field performance during the enhanced recovery phase with N_2 injection, it should be adequate in predicting the field performance during the subsequent CO_2 and N_2 injections.

Model Predictions

The important factors that control the lifetime of an ECBM project are the inert gas (CO_2 and N_2) production and the inert gas cut with time. While methane production represents the income potential, it is the amount of inert gas reprocessed that actually determines the economic limit for an ECBM project. The injection of different mixtures of CO_2 and N_2 was simulated to evaluate their effects on inert gas production and retained CO_2 in coal. The same model settings from the history matching were used except the well controls in the injectors and producers during the injection period from 2/26/1998 to 1/1/2010. In all cases, a continuous injection was assumed with a constant total injection rate of CO_2 and N_2 mixtures. Figure 10 shows the effect of CO_2 content on the cumulative methane, CO_2, N_2, and total gas productions. With an increase in CO_2 percentage in the injected mixture, the cumulative methane production shows an increasing trend while the total cumulative gas production

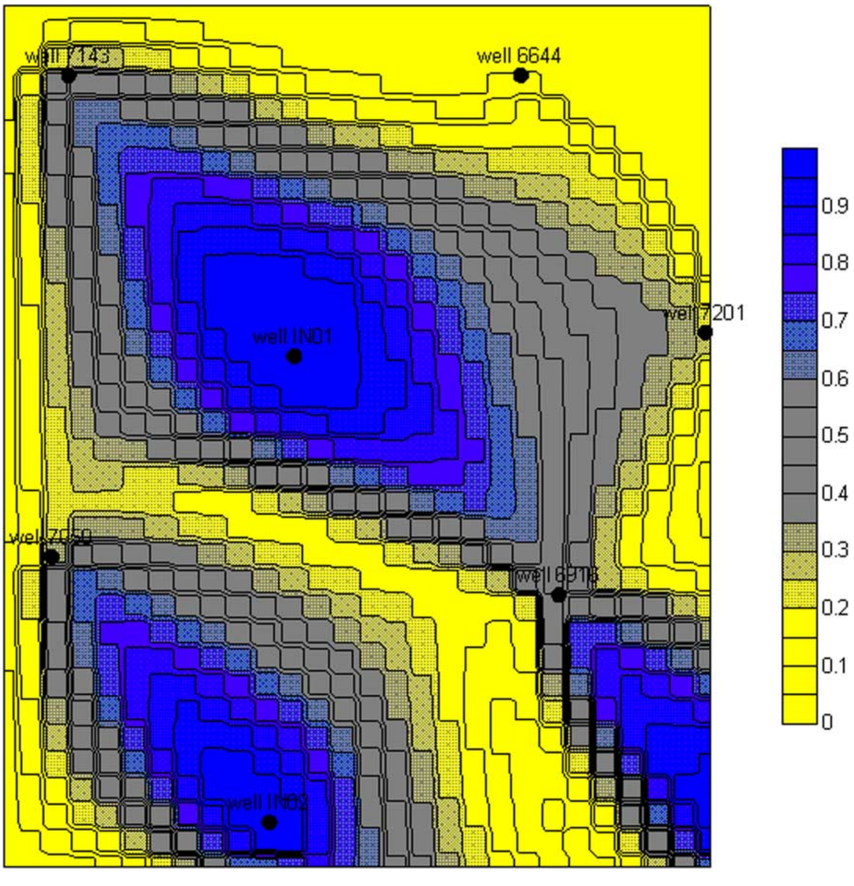

Figure 6: N_2 saturation at the end of history matching (Layer 2).

decreases. Because the coalbed gas in the Tiffany Unit contains about 2–6% CO_2, a certain amount (680 mmscf) of CO_2 was produced when only N_2 was injected as shown in Figure 10. Figure 11 shows the estimated retaining percentage of injected CO_2 in coal. The CO_2 retaining percentage increases as the CO_2 content in the injected gas mixture increases, and reaches to about 44% under 100% CO_2 injection. The estimation was made by subtracting the produced CO_2 and the amount of CO_2 produced under 100% N_2 injection from the total injected CO_2. Coal swelling and permeability reduction due to CO_2 adsorption, which was not considered in this modeling, could significantly increase the CO_2 sweeping volume. Therefore, CO_2 retaining percentage in coal could be much higher for the actual field performance of CO_2-ECBM processes.

EFFECTS OF COALBED PROPERTIES

By virtually reducing the coal thickness, the mechanistic model achieved the history matching of the actual N_2 breakthrough time and production cut. The question is what are the effects of other coalbed properties. To identify dominant reservoir factors, a sensitivity study was performed. Here the COMET2 CBM simulator was used to provide a comparison with GCOMP. Based on the Tiffany field data, a single-well model was used for matching the primary production and a dual-well model was used for matching

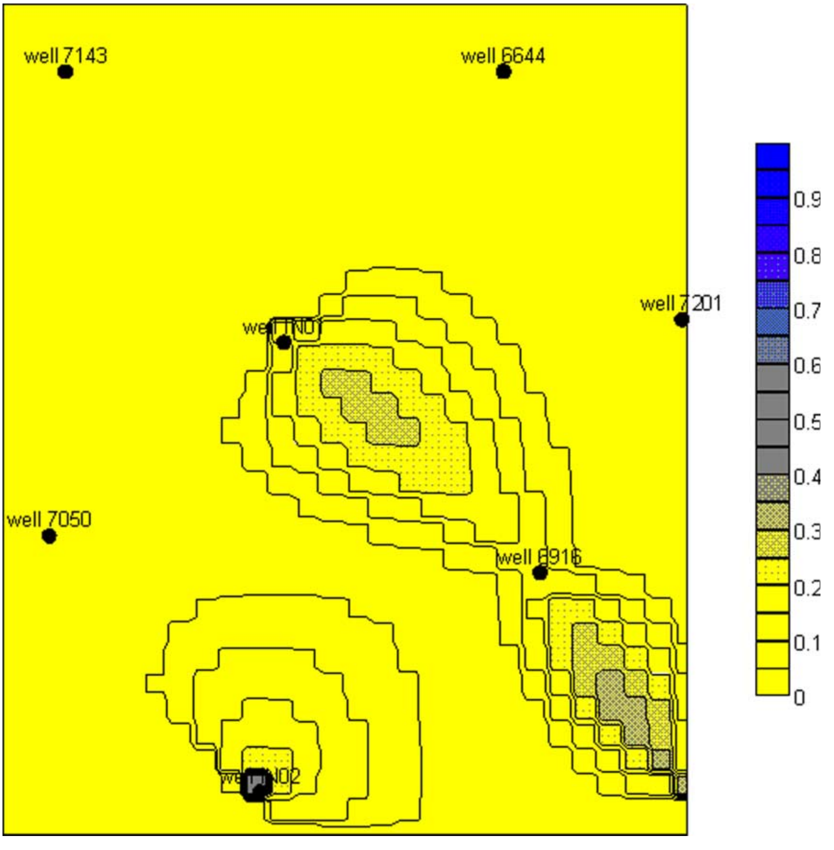

Figure 7: N_2 saturation at the end of history matching (Layer 1).

the performance of N_2 injection. In all cases, no CO_2 was initially assumed in coalbed gas. For comparison, CO_2 injections were also simulated under same model settings and assumptions. Since wells produced on natural flow, fixed bottomhole pressures were used as the producing control. The findings from this sensitivity study are summarized below.

Isotherms

For a pure gas (CH_4, CO_2, or N_2), laboratory-measured isotherm data of Fruitland coal can usually be described by the Langmuir adsorption isotherm model, given by Eq. (1)

$$C = \frac{V_L P}{P_L + P} \tag{1}$$

where C is the adsorbed gas content, P the coal formation pressure, and V_L and P_L the two Langmuir constants. Simulations show that isotherms are the most dominant factor affecting gas production. Laboratory-measured isotherms (CH_4, CO_2, and N_2) on dry coal are available from the Tiffany field [6]. However, the gas content in dry coal (at any given pressure) is significantly higher than that in wet coal as in the reservoir condition. The simulated methane production rates appeared much higher than the actual rates when the methane isotherm on dry coal was used. Instead, the methane isotherm used in simulation was

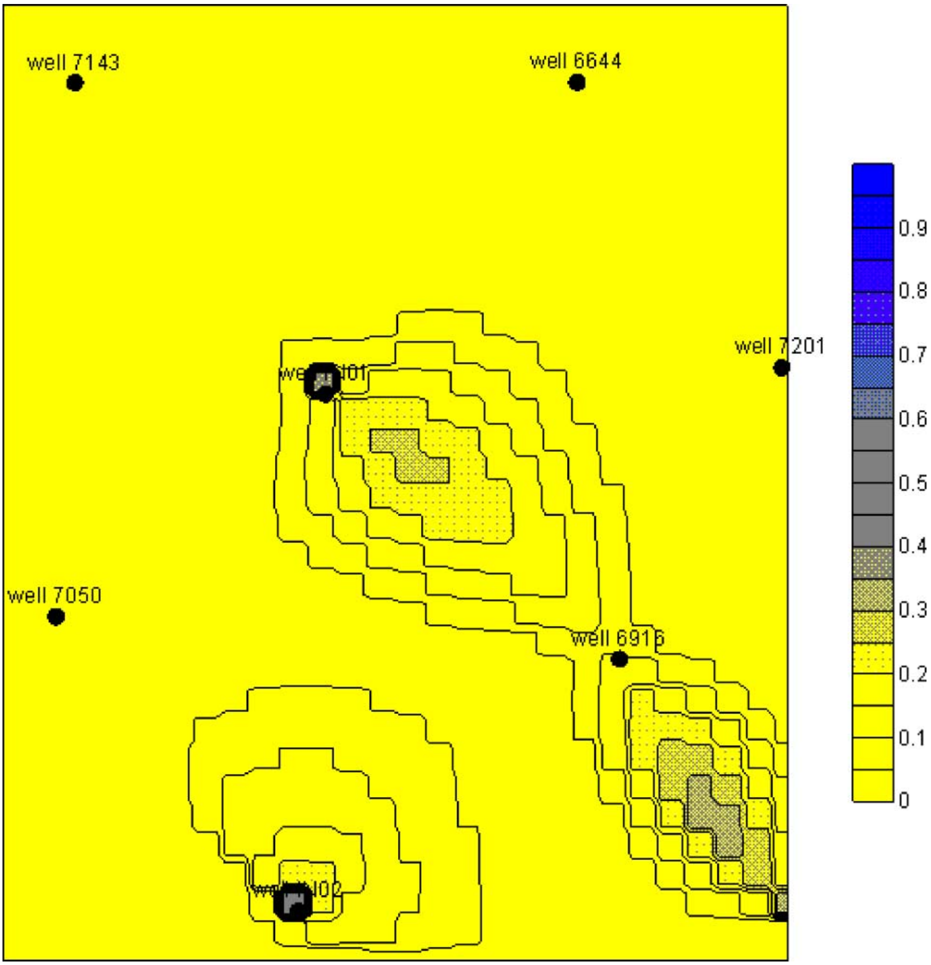

Figure 8: N_2 saturation at the end of history matching (Layer 3).

obtained from matching the primary production. CO_2 and N_2 isotherms were accordingly rescaled using the ratio between the field and laboratory methane isotherms.

Initial Methane in Place

The initial methane in place consists of free gas in the cleat system and the adsorbed gas on the coal matrix. The adsorbed gas (initial gas content) can be estimated from the net pay coal volume and the initial reservoir pressure via Eq. (1) if the methane isotherm is available, either from laboratory or from history matching. Measured initial reservoir pressures are usually available and regarded as reliable data. When the initial pressure is high enough, e.g. greater than 1200 psi in the Tiffany Unit, coal becomes nearly fully saturated with methane. In that case, the initial gas content is usually not very sensitive to the initial pressure.

Porosity and Permeability

In matching the primary production, the gas to water production ratio was found to be very sensitive to cleat porosity. The coal porosity (mainly cleat porosity) is usually very small and initially filled with water, such

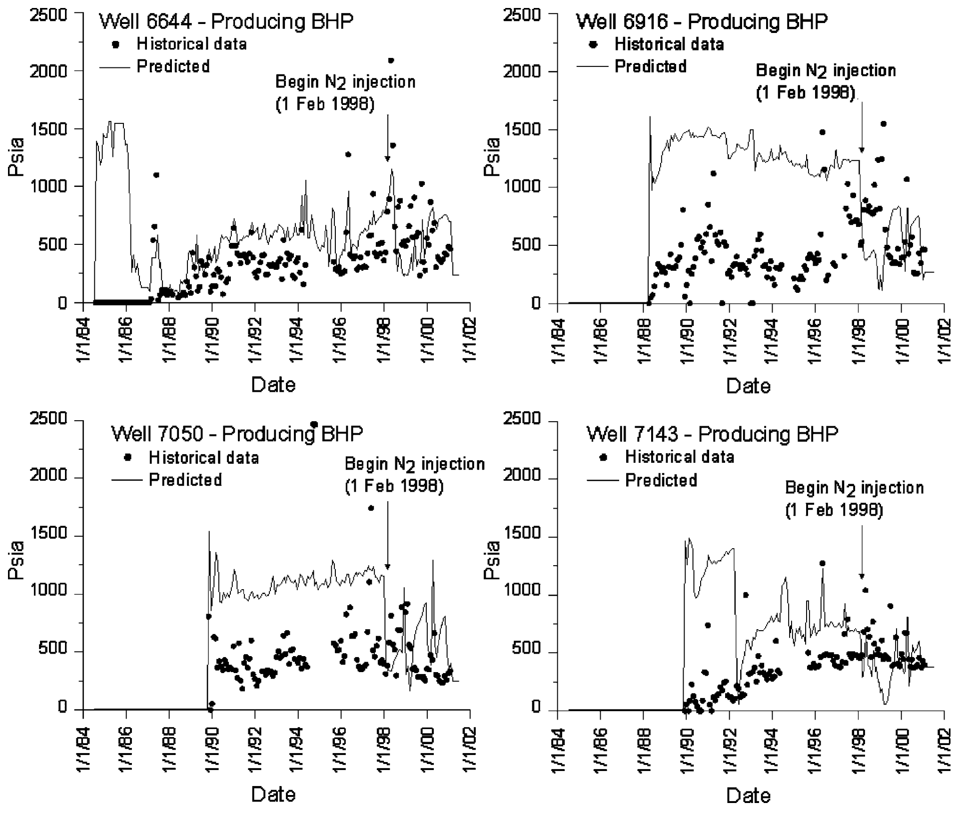

Figure 9: Bottomhole flowing pressures.

as in the Tiffany where the average coal porosity is about 1%. A field permeability trend exists in the simulation study area, which orients roughly along the north–south direction. As demonstrated by the history match of the five production wells in the study area (Figure 12), the face cleat permeabilities (K_x) obtained from history matching are generally higher than the reported coal permeabilities [6] (Table 1). In addition, Figure 12 also shows that the permeability aspect ratio of face cleat permeability to butt cleat permeability (K_y) could have significant effect on gas and water production rates, and an acceptable historical match can be achieved by adjusting the butt cleat permeability (and therefore the permeability aspect ratio). As shown in Figure 12, the actual methane and water production trends generally fall between the curves simulated with the permeability aspect ratio of 2:1 and 3:1.

Relative permeabilities

As shown in Figure 12, simulations predicted much higher initial gas rates than the actual gas rates. This is due to the low bottomhole pressure control, close to 1 atm, set in the production wells. When a simulation begins a large pressure drawdown instantaneously occurs in the grid block in which the well is placed and causes a large volume of methane to desorb from the coal matrix. This behavior does not represent the actual field case. The actual pressure (potentiometric surface) drawdown in coalbeds is usually much slower than that simulated and so is the methane release. This again explains the difficulty in matching the bottomhole pressure when the methane production rate is used as the well control (Figure 9). Tuning relative permeabilities was proven insignificant when a large pressure drawdown becomes the dominant factor of methane release.

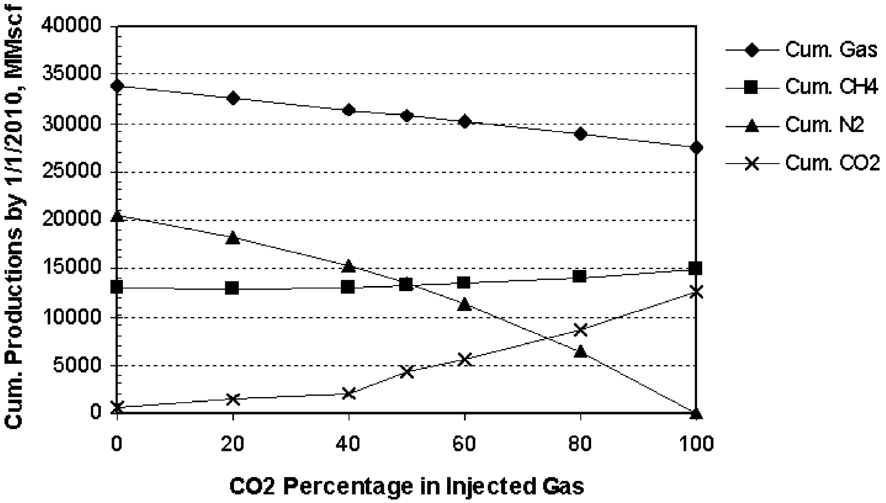

Figure 10: Predicted performance of N_2–CO_2 mixed injections (Well 7201 is excluded).

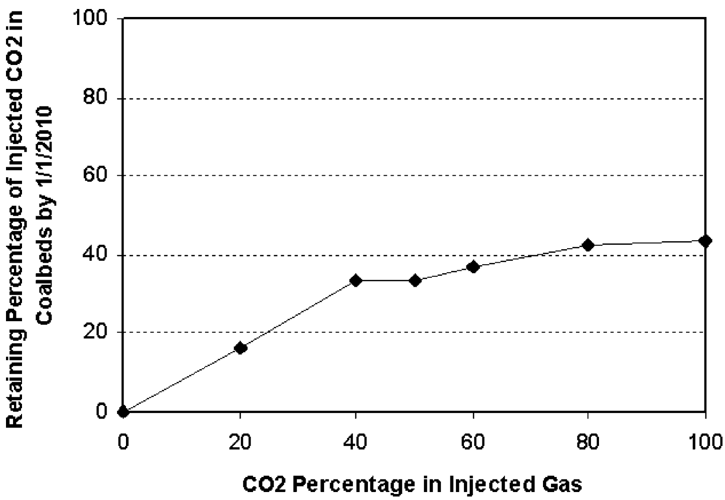

Figure 11: The retaining percentage of injected CO_2 in coalbeds vs. the CO_2 content in the injected gas mixture (Well 7201 is excluded).

For water or gas flooding in conventional oil and gas reservoirs, relative permeabilities are among the most important reservoir properties. A change in relative permeabilities could significantly affect the simulation prediction of water or gas producing rates. However, in coalbeds, injected CO_2 or N_2 could be entirely adsorbed by the coal before reaching a production well if a large CO_2/N_2–coal contact volume (or a large coal thickness) is assumed. To verify the assumption, a dual model consisting of a pair of injection–production wells on a 160-acre well spacing was used to simulate nitrogen injections. If a net pay thickness of 50 ft (the average coal thickness in the Tiffany Unit) is used, Figure 13 shows that little difference resulted even with a large variety of gas relative permeability sets, where the same water relative

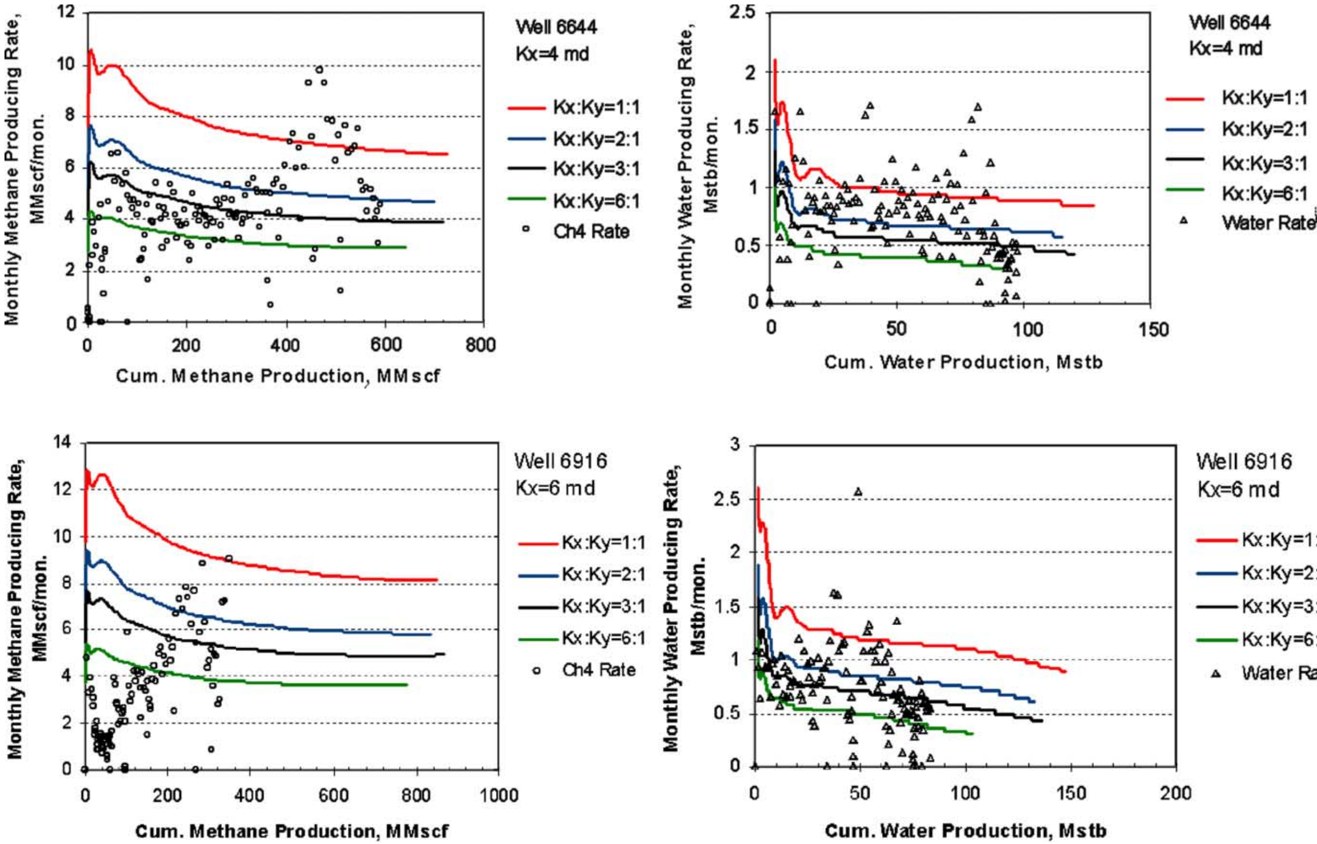

Figure 12: Effect of the permeability aspect ratio on methane (left) and water (right) production rates. In all figures, simulated curves from high to low appear in ascending order of the permeability aspect ratios.

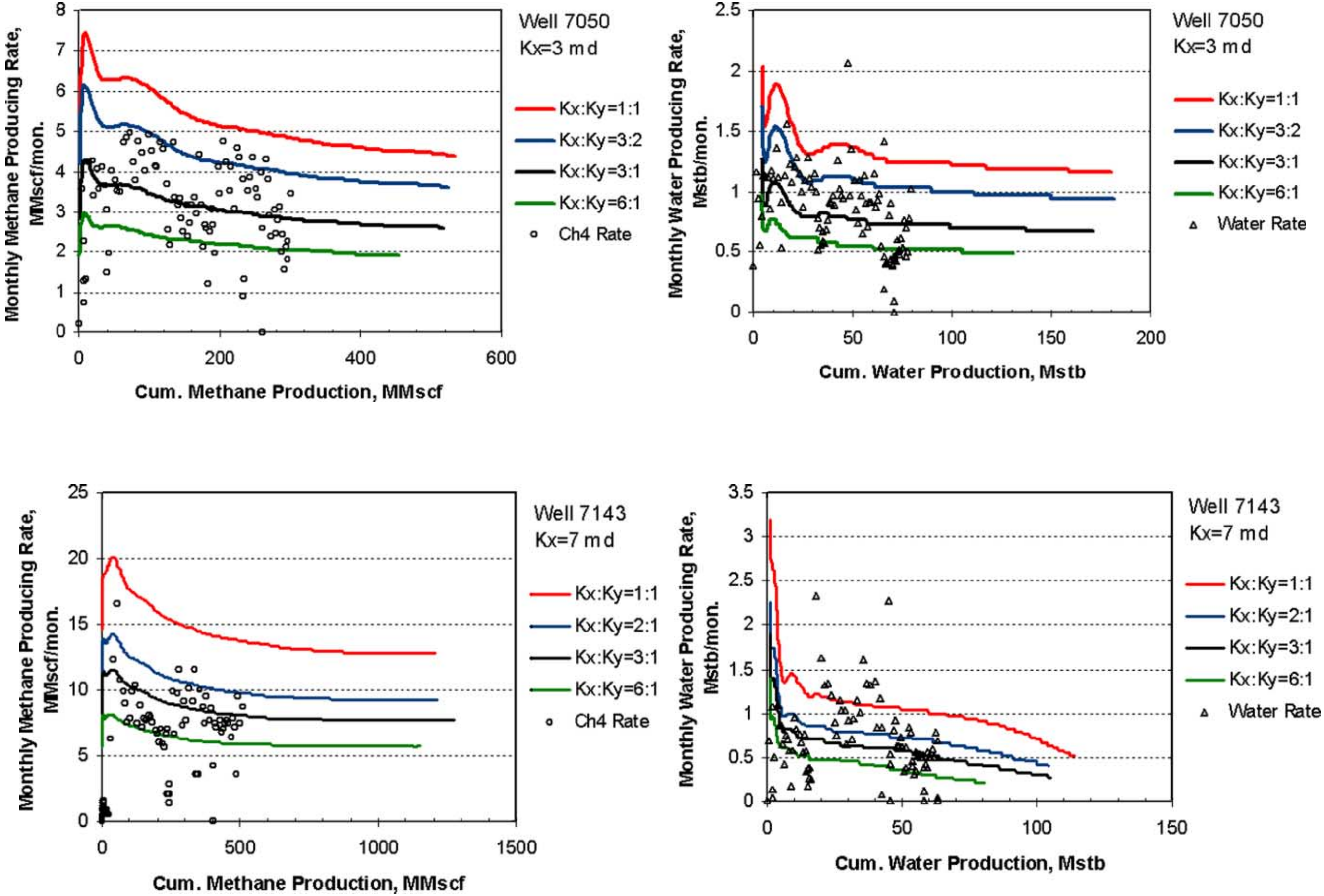

Figure 12: Continued.

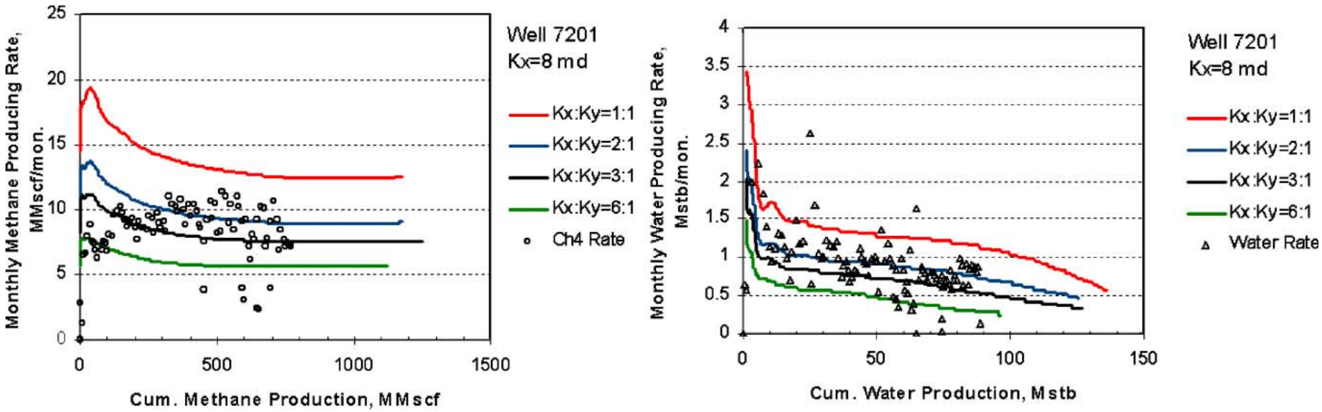

Figure 12: Continued.

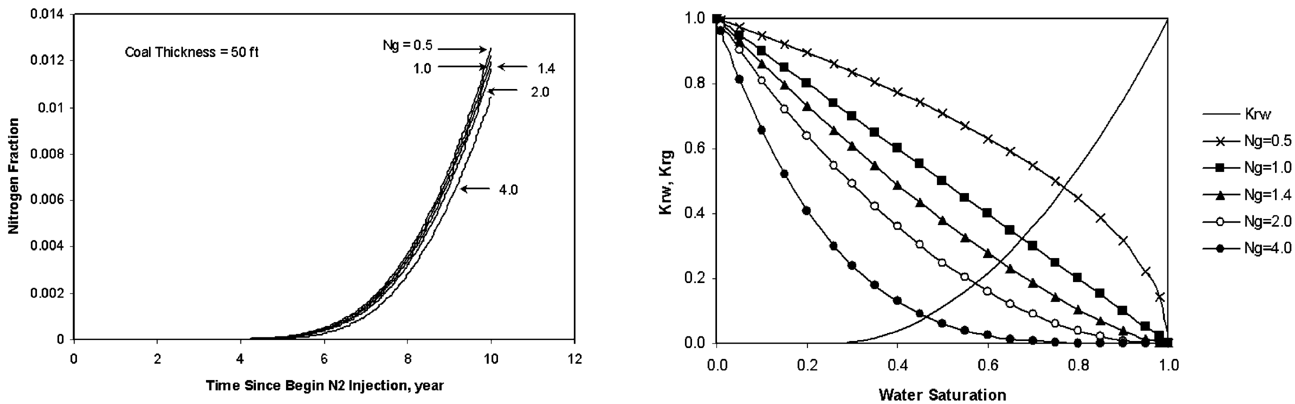

Figure 13: Nitrogen production cuts (left) simulated with different relative permeability curves (right). In the left figure, simulated curves are in ascending order of N_g from left to right.

permeability used for primary production was assumed. In Figure 13, N_g is the parameter used to define a gas relative permeability curve by Eq. (2):

$$K_{rg} = (1 - S_w)^{N_g} \tag{2}$$

Coal Matrix Shrinkage and Swelling

Cleat permeability is directly dependent on the width of the cleats and the cleat frequency. Cleat frequency is generally assumed to be constant, but cleat width is dependent on the in situ stress, the coal properties, and the gas content of the coal. Coal shrinks on desorption of gas and expands again upon readsorption, which changes the cleat width as well as permeability [3,15–18]. The matrix shrinkage (volumetric strain) due to the release of the adsorbed gas can be modeled with a Langmuir curve analogous to the adsorbed gas isotherm [18]. The coal shrinkage and permeability model developed by Sawyer et al. [3] was applied in the COMET2 simulator. No injectivity loss due to N_2 injection was observed in the Tiffany Unit. Because no laboratory data of coal shrinkage/swelling were available from the Tiffany field, different parameter settings were tested for CO_2 injection. In some cases, the increase of bottomhole pressure caused by permeability reduction became too high to sustain the injection rate because of the restricted injection pressure. More importantly, when a total net pay of 50 ft was used simulations failed to predict any CO_2 breakthrough even for a simulated time of more than 100 years. This is not consistent with what observed from the Allison Unit [6,9].

CO_2/N_2 Contacted Volume in Coal

Besides the gas relative permeability, other key reservoir parameters were also tuned in an attempt to match the early N_2 breakthrough time and high N_2 cuts (Figure 3). It was found that an acceptable match could be achieved only if a significant reduction in N_2–coal contact volume was assumed. The left figure of Figure 14 shows the effect of the net pay thickness on the N_2 breakthrough time and N_2 cut. In comparison with the actual field performance (Figure 3), it suggests that only about one-tenth to one-fifth of the total pay interval may be contacted by the injected N_2. The result is consistent with the findings from the mechanistic model. Under the same model settings and assumptions, the effect of CO_2–coal contact volume was also examined. A much-delayed CO_2 breakthrough was predicted as illustrated in the right figure of Figure 14. In comparison to an N_2 breakthrough time of about 2 years, the predicted CO_2 breakthrough time may occur about 20 years after the CO_2 injection on a 160-acre well spacing in the Tiffany Unit. The CO_2 breakthrough time is also much later than that predicted by the mechanistic model (Figure 10).

OUTCROP SEEPAGE MODELING

Methane seepage has been observed from the Pine River [19–21], South Texas Creek, Valencia Canyon, Soda Springs, and other areas [22–24] along the north and west Fruitland outcrops. If injection wells are placed too close to seepage sites, the injected CO_2 or N_2 could likely follow the methane seepage paths and seeps from the outcrops. To examine potential seepage scenarios, a representative seepage model was developed. The model represents a simplified geological setting of the north and west Fruitland outcrops [24]. The focus was on CO_2 injection because potential CO_2 seepage paths must be assessed for any large-scale CO_2 storage in the basin.

Model Configuration

Figure 15 shows the configuration of the representative seepage model. The model is a 2-layer, 1.25-mile by 12-mile strip with a downward dip of 2.92° from the outcrop to the bottom of the basin. There are a total of 240 (5 by 48) grids in each layer with a grid size of 0.25 mile (1320 ft). The model consists of two seepage wells to represent the 1.25-mile outcrop and three water recharge wells placed just below the water table. A total of 28 production wells were placed in the strip with a 160-acre well spacing. Production wells were perforated only in the top layer, and water recharge wells were opened only to the bottom layer. The thickness ratio between top and bottom layers was set to 10:1.

Groundwater Recharge

The annual precipitation in the Colorado portion of San Juan basin varies from 10 to 30 in. per year [25,26]. Along the Fruitland outcrop, an average precipitation of 22 in. per year was used in this study. The recharge

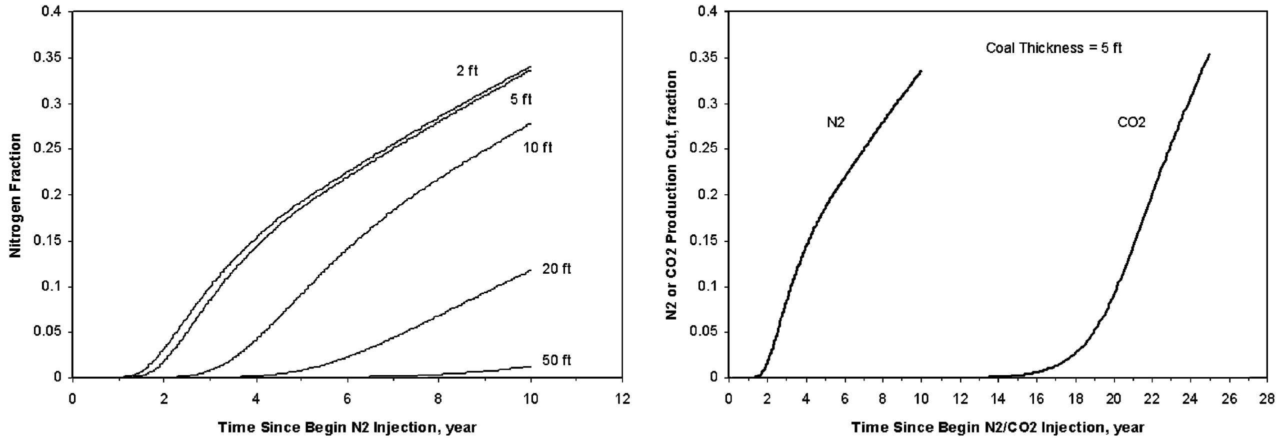

Figure 14: Nitrogen production cuts simulated with different coal net pay thicknesses (left). The comparison between nitrogen and CO_2 breakthrough time and cuts with a net pay interval of 5 ft (right).

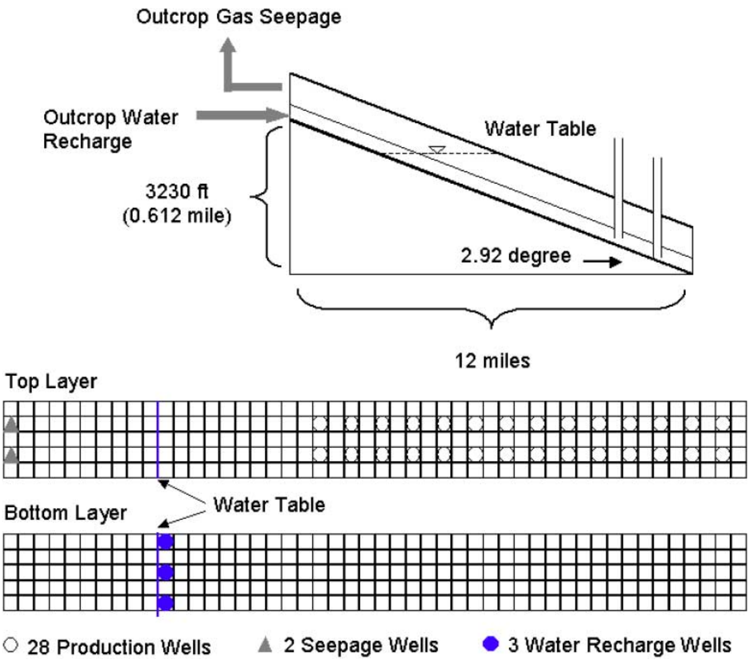

Figure 15: The configuration of the representative seepage model of the Fruitland coal outcrops.

rate is only about 1% of the precipitation [25,26]. Most recharge water migrates to adjacent rivers and creeks. An estimated 15% of the recharge water actually enters the basin. Based on above statistics, an estimated outcrop recharge rate of about 100 barrels per mile per day was calculated and used in the representative seepage model.

Preferable Scenarios

Because of the capillary pressure force, a water-saturated zone above injected CO_2 could help to prevent CO_2 migrating up to outcrops. As illustrated in Figure 15, 28 production wells were placed on a 160-acre well spacing where the top two wells were vertically 673 ft below the water table and horizontally more than 2.5 mile away from the water table. Various CO_2 injection schemes have been simulated, which includes converting 2–14 production wells to CO_2 injection wells. To examine the effect of CO_2 sweeping volume on methane and CO_2 seepage, a variety of coal thickness was used, ranging from 2 ft to an approximate average thickness of 52 ft of the Fruitland coal. Simulations started with a stabilization period of 100 years to stabilize the methane seepage rate at the current level. Carbon dioxide was then injected in the converted injection wells at a rate of 3200 Mcf per day for 30 years. After the CO_2 injection simulations continued for another 200 years without any production or injection. For all cases, no CO_2 seepage was predicted from the outcrop. Also as shown in Figure 16, no significant change in methane seepage was predicted even for cases with small pay intervals (small CO_2–coal contact volumes) of 2–5 ft.

Extreme Scenarios

When methane recovery reaches an economic limit, the priority objective will change to effectively store the injected CO_2. The extraction of a large quantity of CBM water that is required to release methane from coal surface usually causes a large drawdown of the potentiometric surface of depleted coalbeds. Consequently, it may result in a drawdown of the water table in coal seams and increase

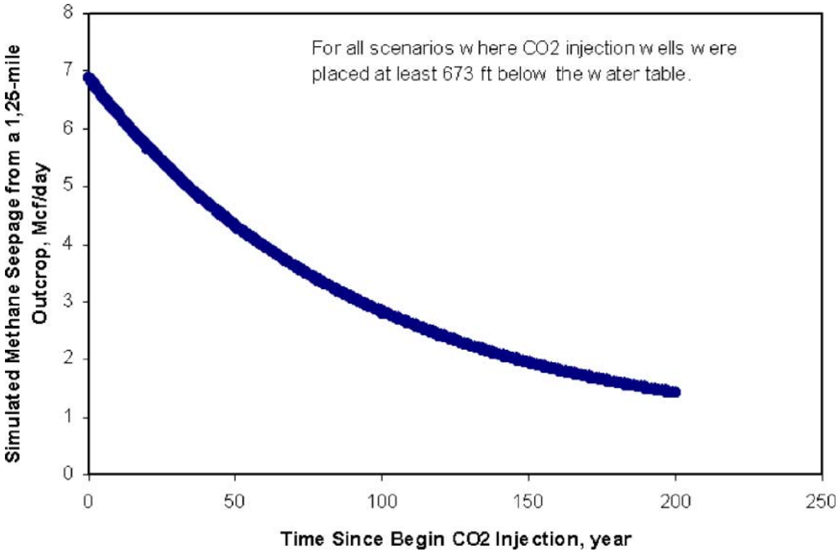

Figure 16: Simulated methane seepage under preferable CO_2 injection scenarios.

the risk of CO_2 migrating above the water table. To simulate the worst-case scenarios, two CO_2 injection wells were placed above the water table. The same injection rate and simulation scheme used for the preferable scenarios were used in simulating the extreme scenarios. Cases with various combinations of coal thickness, between 2 and 50 ft, and the distance of injection wells to the outcrop, from 1 to 5 mile, have been simulated. Figures 17 and 18 show that a large CO_2 and methane breakthrough may occur if the CO_2 injection wells are placed too close to the outcrop (within 2 mile). Figures 19 and 20 show that CO_2 and methane seepage rates reduced significantly when the injection wells were located more than 2 mile away from the outcrop.

DISCUSSIONS

The heterogeneity of the Fruitland coal in both its distribution and composition [27–29] strongly affects the effectiveness of the gas injection for ECBM and CO_2 storage. Methane recovery efficiency is on a well-by-well basis as observed in the Tiffany and Allison Units. Critical factors include cleat permeability, coal seam continuity, CO_2/N_2 sweeping volume, coal shrinkage/swelling, and seal integrity to prevent leakage of injected gas.

A good understanding of the sorption of CH_4, CO_2, N_2, and water mixtures on coal is essential for a credible modeling of the gas injection processes. Given the complexity of mobile gas mixtures of unequally sized molecules with different interactions adsorbed on the heterogeneous surface of coal matrices, the prediction of multi-component adsorption equilibriums on wet coal from single-component data is one of the most challenging problems in ECBM simulation. Simple analytical models, such as Langmuir, Gibbs, or potential theory based approaches [30,31] often show difficulty in accurately predicting the sorption behaviors of a mixture that contains three or more components [8,32].

Accordingly, further improvement to CBM simulation model is needed, especially in modeling coal structure reactions to gas injection and the multiple component adsorption/desorption processes.

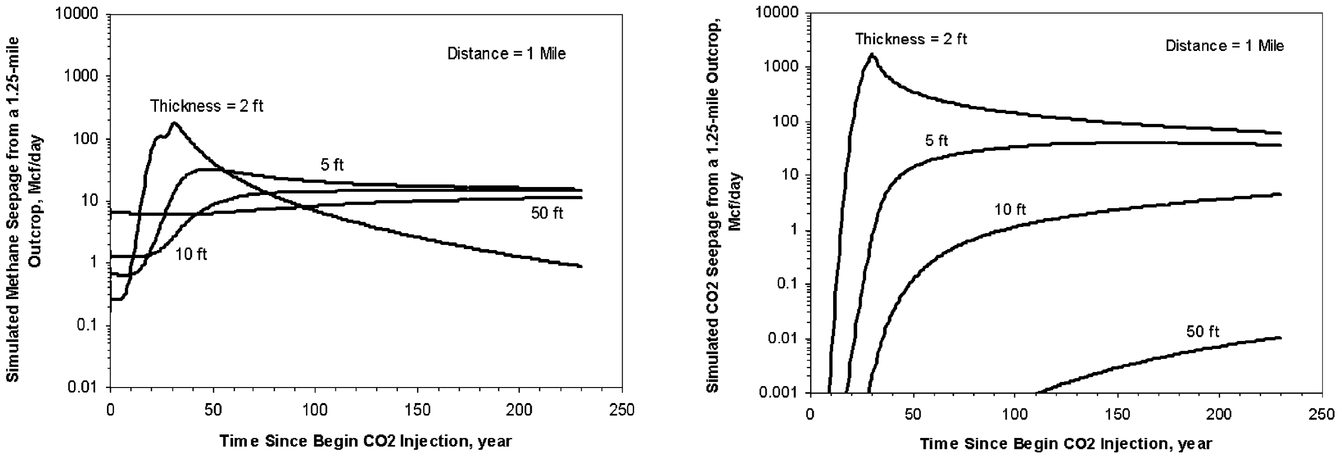

Figure 17: Methane and CO_2 seepage rates vs. coal net pay thickness where the injection is 1 mile from the outcrop.

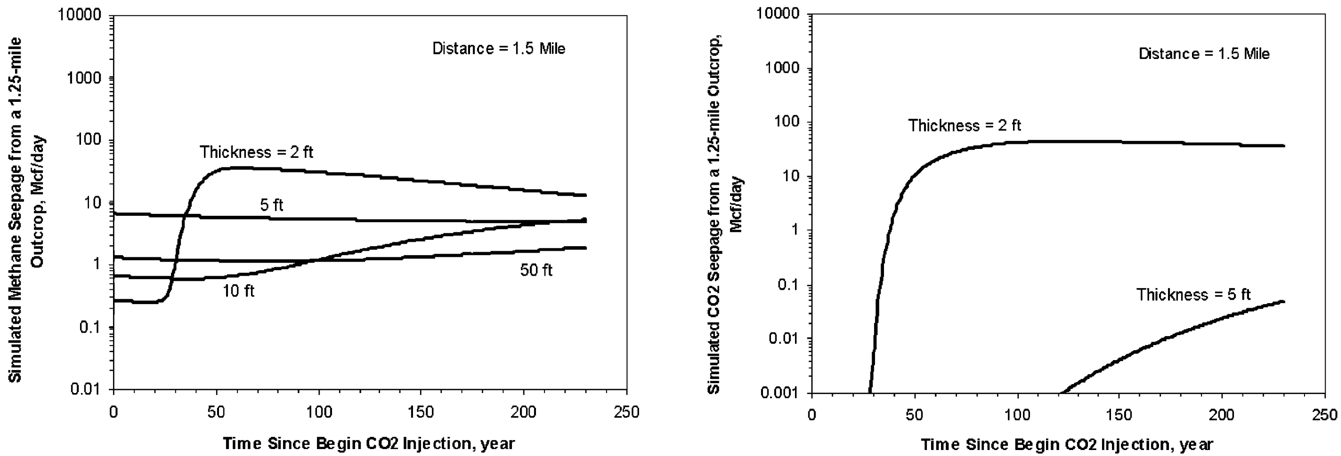

Figure 18: Methane and CO_2 seepage rates vs. coal net pay thickness where the injection is 1.5 mile from the outcrop.

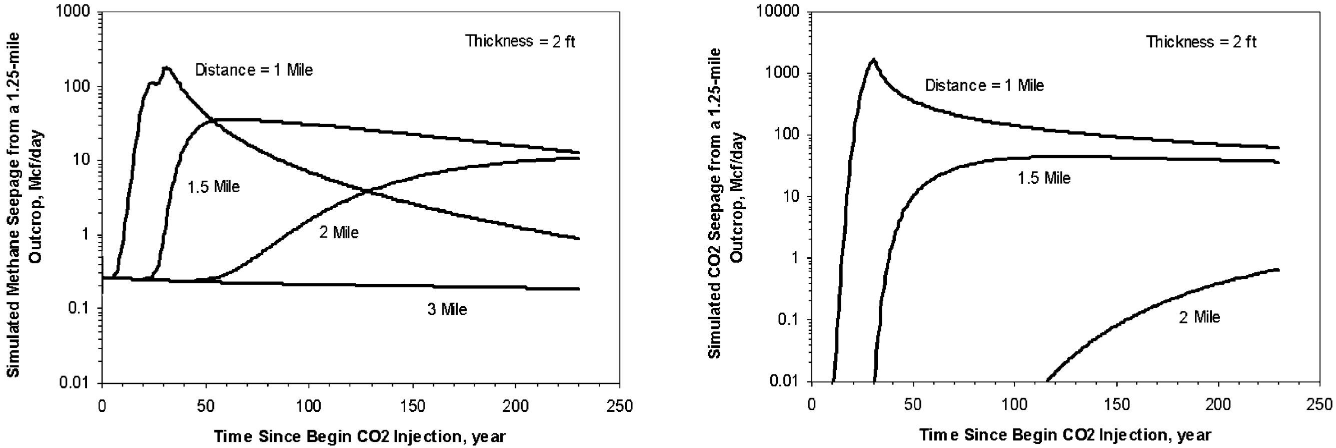

Figure 19: Methane and CO_2 seepage rates vs. injection distances using a net pay thickness of 2 ft.

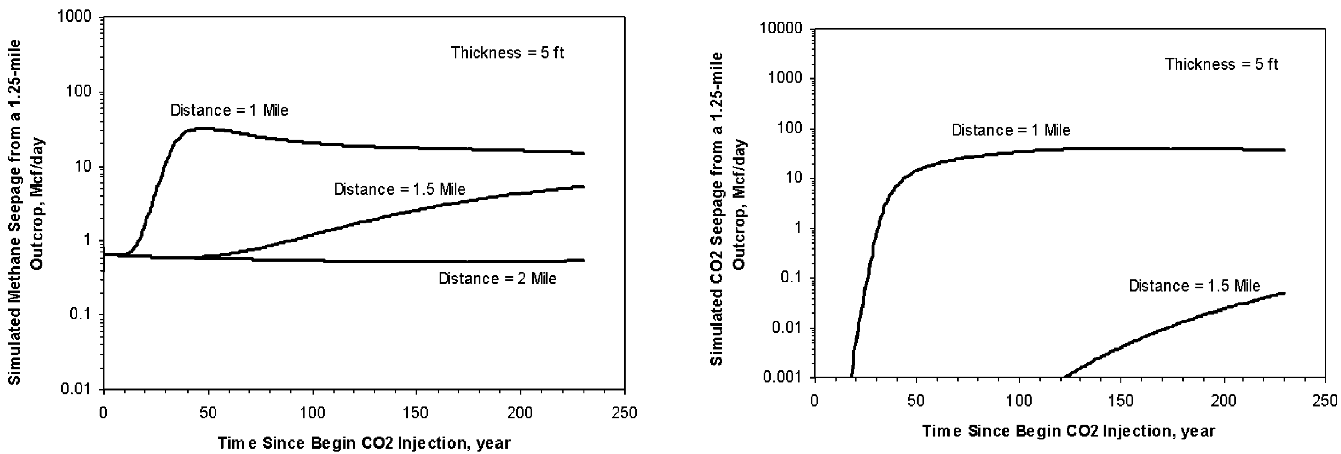

Figure 20: Methane and CO_2 seepage rates vs. injection distances using a net pay thickness of 5 ft.

CONCLUSIONS

Conventional compositional reservoir simulators, such as GCOMP, and currently available CBM simulators, such as COMET2/3, are generally capable of modeling the primary methane production in coalbeds but may encounter more difficulties in the history match and prediction of gas (CO_2, N_2, or CO_2–N_2 mixture) injection processes. With the limitations discussed in the chapter and the specific data set from the Tiffany Unit, the following conclusions have been drawn from this simulation study.

Simulations should use sorption isotherms measured under the actual reservoir conditions. Laboratory-measured isotherms on dry coals need to be rescaled by matching field history performance. Without rescaling, the simulation forecast of CO_2 or N_2 injection may not be accurate.

During the primary production, the gas to water production ratio is very sensitive to cleat porosity in low porosity coalbeds, such as in the Tiffany Unit.

Based on the history match, simulation verifies that the field permeability aspect ratio in Tiffany Unit is approximately in the range of 2:1 to 3:1.

During nitrogen injection, the elevated pressure caused the coal fractures on the preferential permeability trends not only to expand but also to extend from injectors to producers. Even in the low-pressure regions near the producers, the permeabilities were higher than expected.

Simulation models that match the primary production history may not be accurate in forecasting CO_2 or N_2 injection due to the heterogeneity of coalbeds and the reaction of coal structure to gas injection.

To match the early N_2 breakthrough time and high N_2 cuts, the coal thickness had to be reduced to one-third of the average total pay (50 ft) for the mechanistic model, and one-tenth (5 ft) for the dual model. This suggests that the injected N_2 may only contact a small portion of the available coal volume.

In matching the gas (CH_4, CO_2, or N_2) production cut, it may not be effective to tune the gas relative permeability while gas–coal contact volume and gas adsorption/desorption are the more dominant factors.

Under preferable scenarios, if CO_2 injection wells are placed below the water table, vertically more than 673 ft below the water table in the simulated cases, no significant change in methane seepage from outcrop was predicted by the seepage model. In a simulated period of 200 years, no CO_2 seepage from outcrop was predicted after 30-year CO_2 injection.

Under the worst case scenario, where CO_2 injection wells were placed above the water table, the seepage model predicted that a large CO_2 and methane breakthrough could occur if the sweeping volume of injected CO_2 is limited and CO_2 injection wells are placed too close to an outcrop, e.g. within 2 mile.

NOMENCLATURE

C	coal matrix gas content, scf/ton coal
K_{rg}	gas relative permeability, dimensionless
K_{rw}	water relative permeability, dimensionless
K_x	face (dominant) cleat permeability, md
K_y	butt (subordinate) cleat permeability, md
N_g	gas relative permeability parameter, dimensionless
P	coal reservoir pressure, psi
P_L	Langmuir pressure constant, psi
S_g	gas saturation, dimensionless
S_w	water saturation, dimensionless
V_L	Langmuir volume constant, scf/ton coal
BP	British Petroleum

BLM Bureau of Land Management
CCP CO_2 Capture Project
CBM coalbed methane
CRADA Cooperative Research and Development Agreement
DOE Department of Energy
ECBM enhanced coalbed methane recovery
INEEL Idaho National Engineering and Environmental Laboratory
JIP Joint Industry Program
NETL National Energy Technologies Laboratory

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