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Tiffany Coal Bed Methane Field**

**J. Liang  
E. P. Robertson  
K. T. Raterman (ConocoPhillips)**

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## A MECHANISTIC MODEL FOR CO<sub>2</sub> SEQUESTRATION IN TIFFANY COAL BED METHANE FIELD

J. Liang, Idaho National Engineering & Environmental Laboratory (INEEL);  
 K.T. Raterman, ConocoPhillips; E.P. Robertson, INEEL

### ABSTRACT

The objective of this project is to develop mechanistic models specific to CO<sub>2</sub> sequestration in BP's Tiffany coal bed methane (CBM) field. In this study, the original field model was modified to match the field performance of a 5-spot pattern in the northern part of the Tiffany Field where BP plans to perform a micro-pilot test. The modified model consists of one 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.

The model successfully matched the performance of the 5-spot pattern during the enhanced recovery period (N<sub>2</sub> injection). However, in order to match nitrogen breakthrough times and nitrogen cut the vertical transmissibility between layers had to be set to zero. During gas injection, nitrogen was allowed to enter all three layers, not just the high-permeability fast layer. However, because the permeabilities of the slow layers 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. This suggests that the future gas injection and CO<sub>2</sub> sequestration may be restricted to only one third of the total available pay.

For future gas injections, the modified model predicted early CO<sub>2</sub> breakthrough with high CO<sub>2</sub> cut. This suggests that the actual CO<sub>2</sub> sequestration capability of the Tiffany Field might not be as high as originally expected. This is a direct consequence of the reduced available pay in the modified model. The modified model also predicted early inert gas (N<sub>2</sub> plus CO<sub>2</sub>) breakthrough and high inert gas cut during future gas injections. If this is confirmed in the pilot test, the high volume of inert gas produced could overwhelm the reprocessing capability resulting in early termination of the project.

### INTRODUCTION

There is a growing consensus in the international community that CO<sub>2</sub> emissions from burning fossil fuels play an important role in global climate change. Despite the recent controversy of who should bear the most burden in reducing the CO<sub>2</sub> emission, it is inevitable that deep cuts in CO<sub>2</sub> emission will be required in the near future. Recent efforts in reducing the carbon content in fuels and improving the energy efficiency can certainly help in reducing the amount of CO<sub>2</sub> released into the atmosphere. However, large-scale carbon sequestration will definitely be required to achieve the targeted atmospheric CO<sub>2</sub> level of 550 ppm by 2025.

Of the sequestration options available, geologic sequestration of CO<sub>2</sub> in coal formations is considered one of the methods with the greatest short-term potential. Coal beds typically contain a large amount of methane-rich gas that is adsorbed onto the surface of the coal. Tests have shown that CO<sub>2</sub> is roughly twice as adsorbing on coal as methane, giving it the potential to efficiently displace methane and remain sequestered in the bed. Enhanced recovery of coal bed methane (CBM) by CO<sub>2</sub> injection has been demonstrated in limited field tests, but much more work is necessary to understand and optimize the process. Work is also needed to develop better estimates of the potential capacity of cost-effective coal bed sequestration in the United States.

To date, only one commercial demonstration of enhanced methane recovery by gas injection has been implemented. This is BP's Tiffany project in the San Juan Basin, Colorado. The Tiffany Field consists of 38 producer and 10 injector wells. The current Tiffany field model incorporates the full geologic description. The description consists of five coal layers, some of which do not extend throughout the unit.

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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<sub>2</sub> was injected into the field to accelerate methane recovery. The field model was proven inadequate in many aspects to accurately match field performance during the enhanced recovery phase. Most importantly, it failed to predict nitrogen breakthrough times and nitrogen cut responses at the majority of the responding producers. The actual N<sub>2</sub> breakthrough times were much earlier than that predicted by the field model. For the field model to better match the N<sub>2</sub> breakthrough times and N<sub>2</sub> cut responses, the nitrogen injection would have to be restricted into one geological layer, which accounts for only 25% of the total pay. However, this would violate production-log data from the injectors, which showed nearly uniform injection into most perforated intervals. With BP's proposal to supplement the nitrogen injection with the CO<sub>2</sub> captured from its gas processing plant, it is vital that the field model be modified to reflect the actual field performance during gas injection so that the reservoir's true potential for enhanced recovery and CO<sub>2</sub> sequestration can be determined. The objective of this project is to develop mechanistic models specific to CO<sub>2</sub> sequestration in BP's Tiffany coal bed methane (CBM) field.

### RESERVOIR PERFORMANCE MODELING

The validity of a particular model description will be determined from its ability to predict injected gas breakthrough times, cumulative production (methane, nitrogen, and carbon dioxide), and methane cut. The desired outcome of the process is an estimate of actual CO<sub>2</sub> sequestration capability and project lifetime, which is in part dictated by the CO<sub>2</sub> breakthrough time and the CO<sub>2</sub> production cut with time. (The amount of CO<sub>2</sub> reprocessed will determine the economic limit for the project.)

In this report, we focus on a five-spot pattern in the northern part of the field where BP plans to conduct a micro-pilot test in the near future. The five-spot pattern consists of one in-pattern and three off-pattern injectors as well as four in-pattern and one off-pattern producers. The ultimate objective is to develop a full-field model for CO<sub>2</sub> sequestration in the Tiffany Field.

#### 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 in large part 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. Also, the horizontal permeability ( $k_h$ ) in every grid block was rotated 45° counter clockwise to match the field permeability trend (north-south) in the simulation area.

#### History Matching

During history matching, layer thickness and permeability were adjusted to control gas breakthrough. Vertical transmissibility between layers was manipulated to match late time response. The modified model matched the nitrogen breakthrough times and nitrogen cut reasonably well for all in-pattern producers. The model also did a good job matching the total gas production for all in-pattern producers. However, in order to match nitrogen breakthrough times 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 the slow layers 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. Figs. 1, 2, 3 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 Fig. 1, we can clearly see the

preferred permeability trends between the injectors and the producers. A comparison between Fig. 1 and Figs. 2, 3 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 implies that the nitrogen injection and enhanced methane recovery were mostly restricted to only about one third of the available pay. The impact of this on the recoverable reserves and ultimately the sequestration capacity of the reservoir will be discussed in the next section.

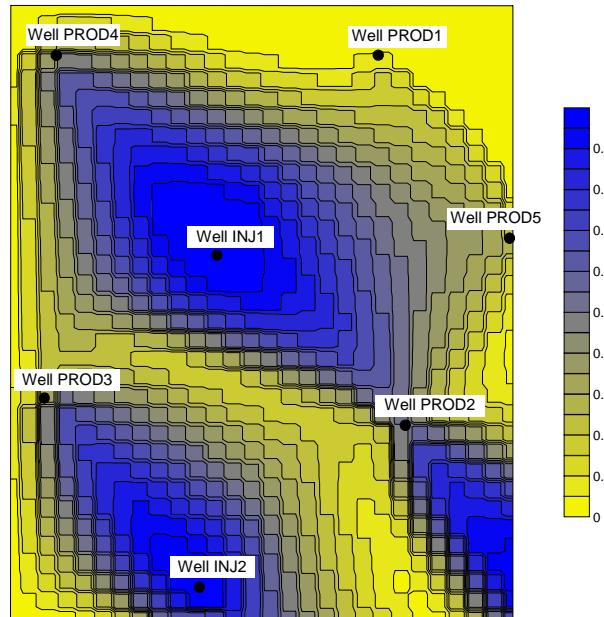


Fig. 1.  $\text{N}_2$  saturations at the end of history matching (Layer 2).

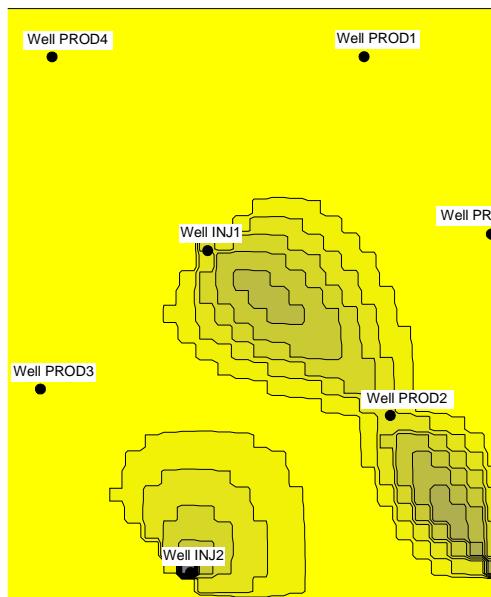


Fig. 2.  $\text{N}_2$  saturations at the end of history matching (Layer 1).

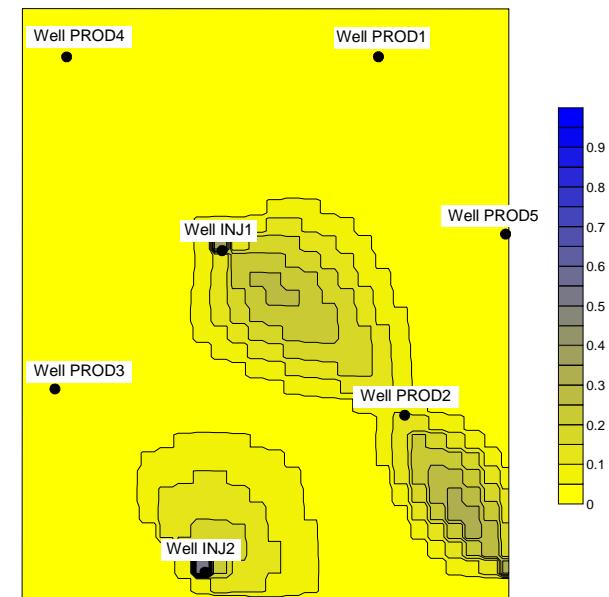


Fig. 3.  $\text{N}_2$  saturations at the end of history matching (Layer 3).

The modified 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. The modified model matched the pressure responses of Well PROD1 reasonably well during both the primary and the enhanced recovery phases. Unlike other producers, this well is not linked to any injector on the preferred 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 preferred 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 caused coal fractures along the preferred 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. This permeability enhancement may be additionally supported by matrix shrinkage caused by a lower equilibrium adsorbed nitrogen concentration (phase volume) versus methane. One possible way to satisfactorily simulate both the primary and enhanced recovery phases is to apply negative skin factors to wells on the preferred 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, the simulator that we are using right now does not have this capability. Since the modified model is based on field performance during the enhanced recovery phase with N<sub>2</sub> injection, it should be adequate in predicting the field performance during the subsequent CO<sub>2</sub> and N<sub>2</sub> injections.

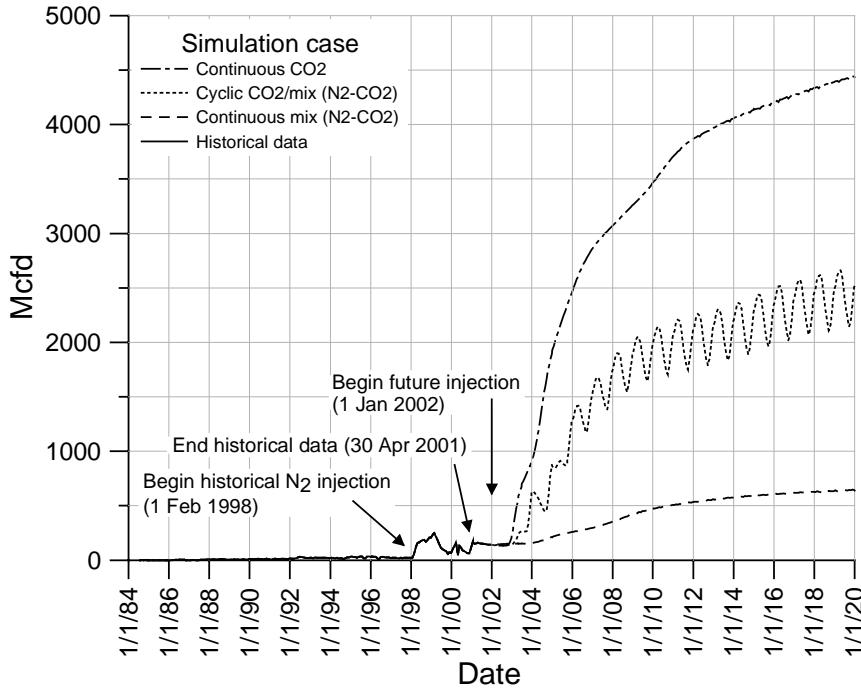
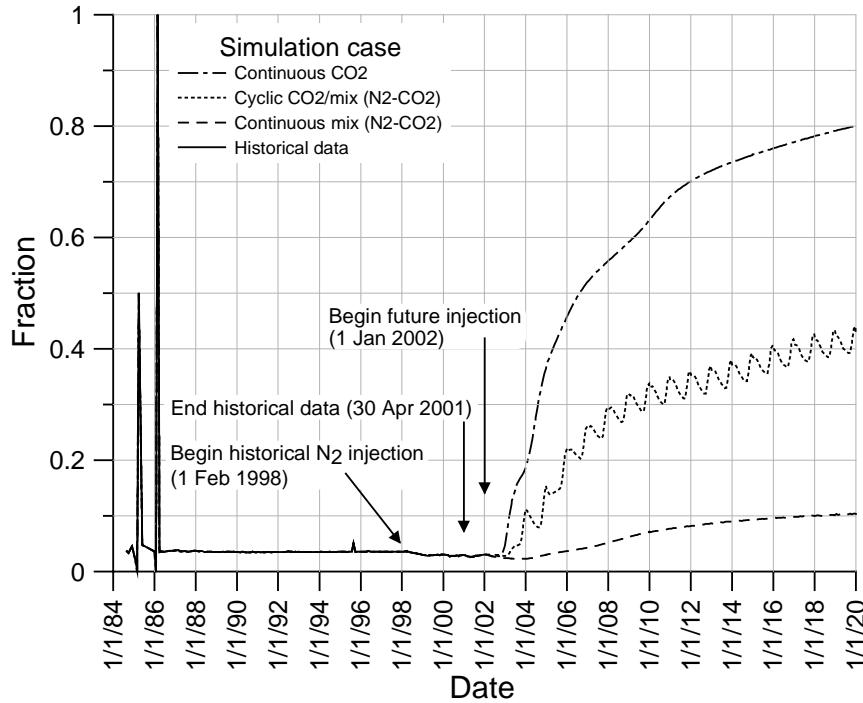
## MODEL PREDICTIONS

The important factors that control the project lifetime and actual CO<sub>2</sub> sequestration capability are the inert gas (CO<sub>2</sub> and N<sub>2</sub>) 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 a CO<sub>2</sub> sequestration project. In this report, we explored three different injection scenarios to study their effects on inert gas production and inert gas cut. In the first scenario, we simulated a continuous injection of pure CO<sub>2</sub>. In the second scenario, we simulated a continuous injection of a mixture of 76% N<sub>2</sub> and 24% CO<sub>2</sub>. In the third scenario, we took into account the seasonal fluctuation of the nitrogen processing capability at Tiffany Field. In this case, we alternated the injection between the N<sub>2</sub>-CO<sub>2</sub> mixture (Nov. through April) and pure CO<sub>2</sub> (May through Oct.). In all three scenarios, the simulation of future injections ran from 01/01/2002 to 01/01/2020. The total volume of gas injected is constant between scenarios.

### Daily CO<sub>2</sub> Production Rate and CO<sub>2</sub> Cut

Figs. 4 and 5 summarize the daily CO<sub>2</sub> production rate and the CO<sub>2</sub> cut with time for the entire 5-spot pattern (excluding Well PROD5), respectively. Fig. 4 shows that the CO<sub>2</sub> breakthrough occurred within one year after the injection began. After breakthrough, the daily CO<sub>2</sub> production rate for all three gas-injection scenarios increased continuously until the end of simulation period. Fig. 4 also shows that the increase in daily CO<sub>2</sub> production rate was most significant for the case of continuous CO<sub>2</sub> injection. The CO<sub>2</sub> cut shown in Fig. 5 basically followed the similar trend. For the case of continuous CO<sub>2</sub> injection, the CO<sub>2</sub> production cut increased quickly after breakthrough reaching 50% in less than 5 years. The increase was however, less dramatic for the other two gas-injection scenarios.

The important message here is that the modified model predicted early CO<sub>2</sub> breakthrough with high CO<sub>2</sub> cut during future gas injections. This suggests that the actual CO<sub>2</sub> sequestration capability of the Tiffany Field might not be as high as originally expected. This is a direct consequence of the reduction of the available pay in the modified model.

Fig. 4. Daily total CO<sub>2</sub> production (excluding Well PROD5).Fig. 5. Daily total CO<sub>2</sub> cut (excluding Well PROD5).

#### Daily Total Inert Gas Production Rate and Inert Gas Cut

The amount of daily inert gas production that on-site facilities can handle is a limiting factor that determines the economic limit for a CO<sub>2</sub> sequestration project. Figs. 6 and 7 show that for all three gas-injection scenarios, both the daily total inert gas (N<sub>2</sub> plus CO<sub>2</sub>) production and the inert gas cut rose quickly after the gas-injection began. Fig. 7 shows that for the cyclic CO<sub>2</sub>/N<sub>2</sub>-CO<sub>2</sub> and continuous N<sub>2</sub>-CO<sub>2</sub>

cases, the inert gas cut reached 50% in less than 2 years. The case of continuous CO<sub>2</sub> injection however, showed a two-year delay in inert gas breakthrough (Fig. 6). Also, in this case, the inert gas cut did not reach 50% until 4 years into the gas injection (Fig. 7). This delay in inert gas breakthrough was caused by CO<sub>2</sub> being twice as adsorbing on coal than methane.

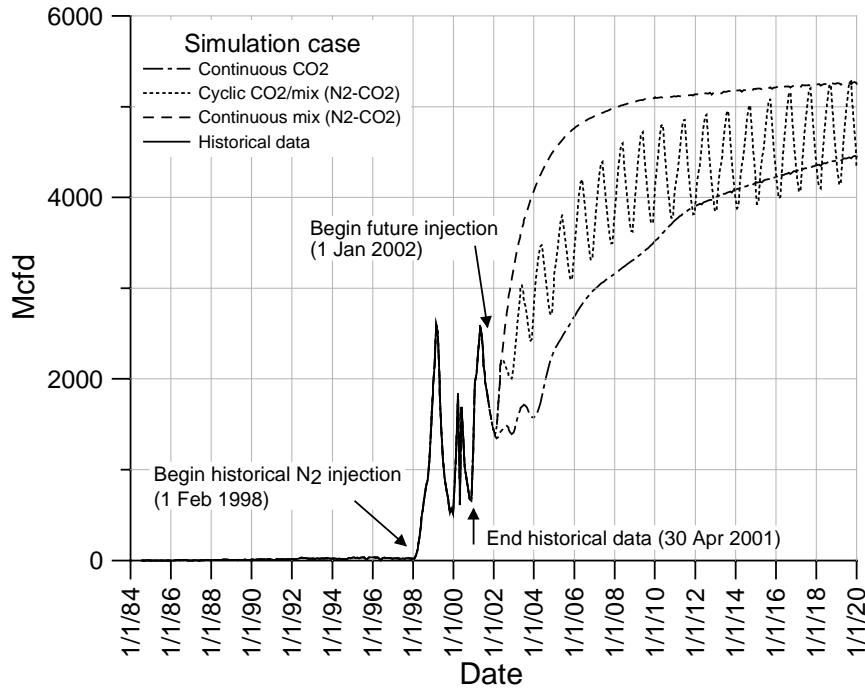


Fig. 6. Daily total inert gas production (excluding Well PROD5).

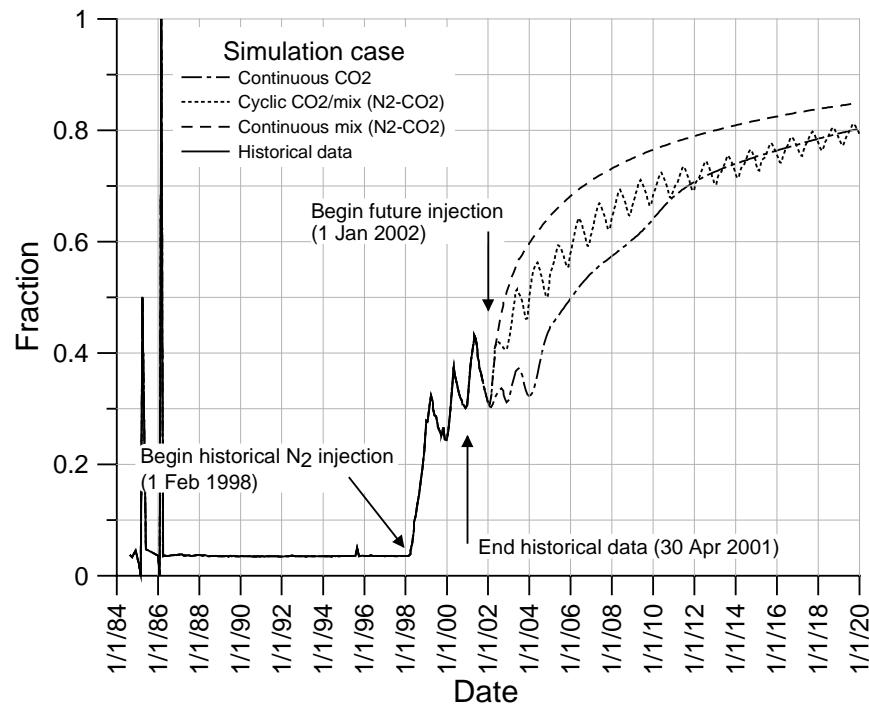


Fig. 7. Daily total inert gas cut (excluding Well PROD5).

The simulation results demonstrate that without adequate inert gas reprocessing capability, the predicted early breakthrough of inert gas and high inert gas cut can severely shorten the project lifetime and further limits the CO<sub>2</sub> sequestration capability of the Tiffany Field.

### Methane Production

Fig. 8 shows that the methane production followed a gradual decline trend during the gas-injection period. For the case of continuous CO<sub>2</sub> injection, the methane production showed an initial jump and then followed basically the same decline trend as in other gas-injection scenarios. Fig. 9 shows that the cumulative amount of methane recovered during the gas-injection period was proportional to the CO<sub>2</sub> content in the injection gas. (The higher the CO<sub>2</sub> content in the injection gas, the higher the methane recovery.) This is consistent with the theory that CO<sub>2</sub> is more efficient in displacing methane from coal formation.

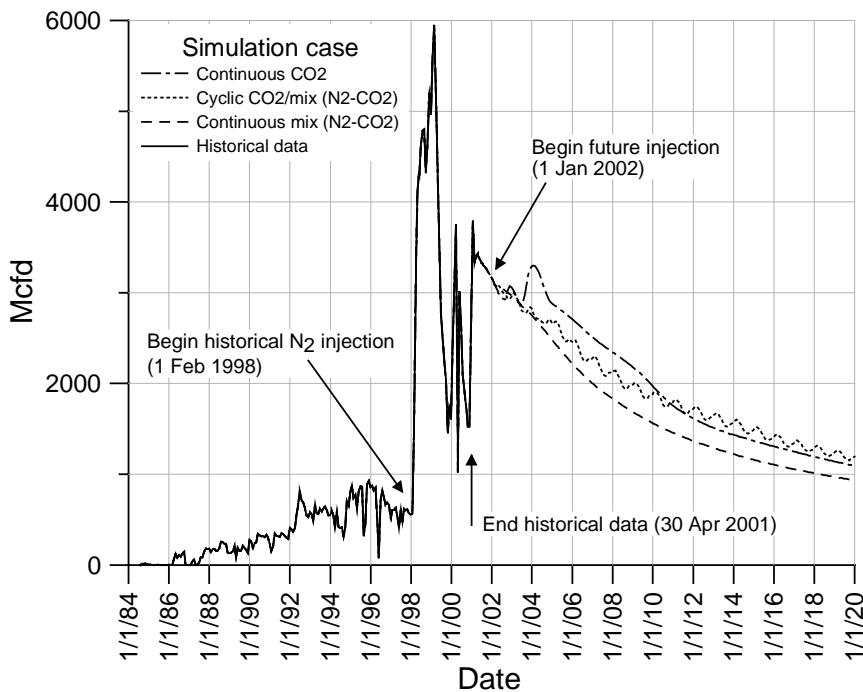


Fig. 8. Daily total methane production (excluding Well PROD5).

### SUMMARY

1. A modified field model was developed to match the field performance of a 5-spot pattern in the northern part of the Tiffany Field where BP plans to perform a micro-pilot test.
2. The modified model consists of one 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.
3. The model successfully matched the performance of the 5-spot pattern during the enhanced recovery period (N<sub>2</sub> injection). However, in order to match nitrogen breakthrough times and nitrogen cut the vertical transmissibility had to be set to zero. During gas injection, nitrogen was allowed to enter all three layers, not just the high-permeability fast layer. However, because the permeabilities of the slow layers 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. This suggests that the future gas injection and CO<sub>2</sub> sequestration may be restricted to only one third of the total available pay.

4. During nitrogen injection, the elevated pressure caused the coal fractures on the preferred 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.
5. The modified model predicted early CO<sub>2</sub> breakthrough with high CO<sub>2</sub> cut during future gas injections. This suggests that the actual CO<sub>2</sub> sequestration capability of the Tiffany Field might not be as high as originally expected. This is a direct consequence of the reduction of the available pay in the modified model.
6. The modified model also predicted early inert gas (N<sub>2</sub> plus CO<sub>2</sub>) breakthrough and high inert gas cut during future gas injections. The high volume of inert gas produced could overwhelm the reprocessing capability resulting in early termination of the project.

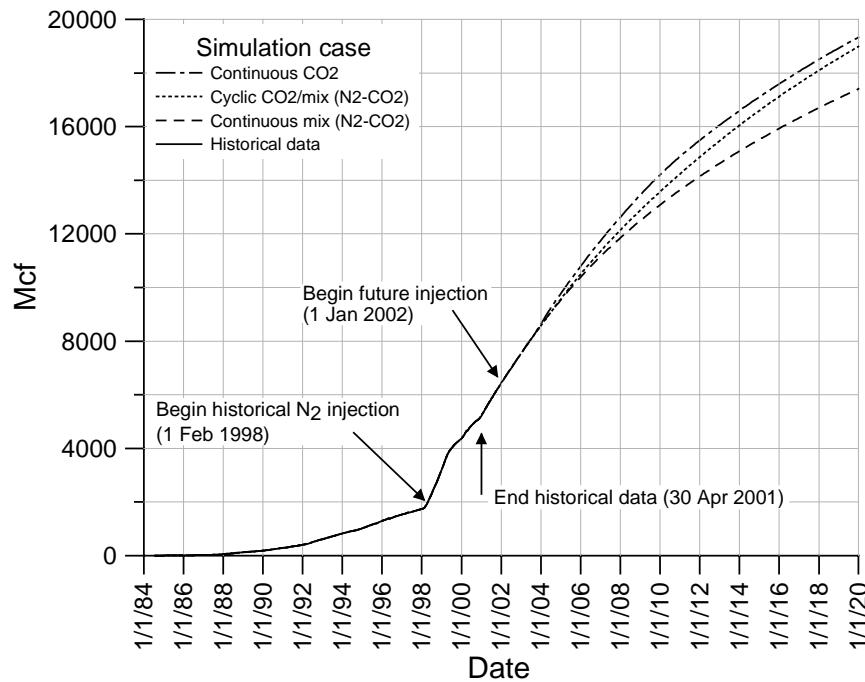


Fig. 9. Total cumulative methane production (excluding Well PROD5).