Hindawi Publishing Corporation
Journal of Petroleum Engineering
Volume 2013, Article ID 803706, 8 pages
http://dx.doi.org/10.1155/2013/803706

Research Article

A Field Study on Simulation of CO_2 Injection and ECBM Production and Prediction of CO_2 Storage Capacity in Unmineable Coal Seam

Qin He, Shahab D. Mohaghegh, and Vida Gholami

Department of Petroleum and Natural Gas Engineering, West Virginia University, Morgantown, WV 26505, USA

Correspondence should be addressed to Shahab D. Mohaghegh; shahab.mohaghegh@mail.wvu.edu

Received 22 August 2012; Revised 18 November 2012; Accepted 22 November 2012

Academic Editor: Serhat Akin

CO_2 sequestration into a coal seam project was studied and a numerical model was developed in this paper to simulate the primary and secondary coal bed methane production (CBM/ECBM) and carbon dioxide (CO_2) injection. The key geological and reservoir parameters, which are germane to driving enhanced coal bed methane (ECBM) and CO_2 sequestration processes, including cleat permeability, cleat porosity, CH_4 adsorption time, CO_2 adsorption time, CH_4 Langmuir isotherm, CO_2 Langmuir isotherm, and Palmer and Mansoori parameters, have been analyzed within a reasonable range. The model simulation results showed good matches for both CBM/ECBM production and CO_2 injection compared with the field data. The history-matched model was used to estimate the total CO_2 sequestration capacity in the field. The model forecast showed that the total CO_2 injection capacity in the coal seam could be 22,817 tons, which is in agreement with the initial estimations based on the Langmuir isotherm experiment. Total CO_2 injected in the first three years was 2,600 tons, which according to the model has increased methane recovery (due to ECBM) by 6,700 scf/d.

1. Introduction

Fossil fuels are currently playing a significant role in the whole world's energy supply. However, its damage to the environment, especially the CO_2 emission resulting in the green house effect, has gotten more and more attention. At present, several geological CO_2 sequestration technologies, such as CO_2 injection into saline aquifer, CO_2-EOR, CO_2-ECBM, and so forth, have been studied to minimize the CO_2 release into the atmosphere, and these projects have been operating all over the world [1–6]. Studies have shown that unmineable coal seams (seams too deep or too thin to be mined economically) are pretty attractive as one of the promising options for CO_2 sequestration because of their large CO_2 sequestration capacity, long time CO_2 trapping, and extra enhanced coal-bed methane (ECBM) production benefits [1, 7–10]. Field experience with CO_2 injection into coal seam is limited, although field tests are planned or are being conducted in the USA, Canada, Poland, Australia, and Japan [3].

However, unlike conventional reservoirs, gas flow in the coal seams can cause the cleat permeability and porosity variation during the injection/production process. Once gas is injected and adsorbed on the coal matrix, the matrix will swell, and correspondently decrease the cleat permeability and porosity [11, 12]. Due to its special features and the nature of gas retention in CBM reservoirs, simulating the production and injection will have more complexity compared to conventional resources.

Similar to conventional naturally fractured reservoirs, coal is characterized as a dual-porosity system consisting of matrix and cleat, in which majority of the gas is stored within the coal matrix by a process of adsorption and a small amount of free gas exists in the cleats or fractures [13]. Once CO_2 is injected into the coal seam, it will be held by coal surface because of its higher affinity to the coal matrix than methane, and then displaces the methane to boost extra natural gas production. Figure 1 shows a schematic representation of the CO_2 sequestration-ECBM process. It is estimated by

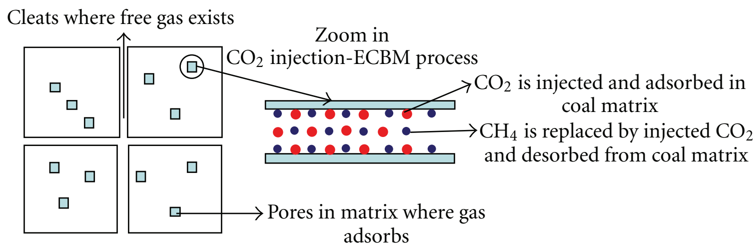


Figure 1: A schematic representation of CO_2 sequestration-ECBM production.

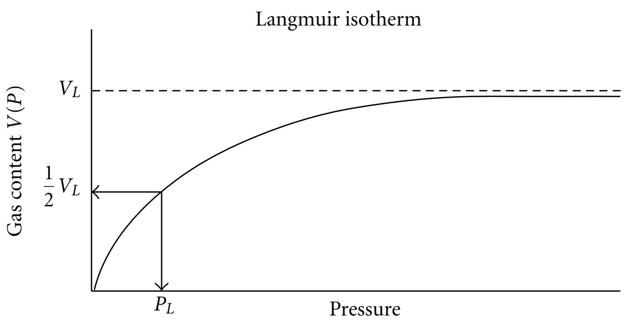


Figure 2: Langmuir isotherm function.

laboratory measurements that this process, known as CO_2-enhanced coal bed methane, can store twice as much CO_2 as the methane desorbed or even more [14].

The entire gas flow mechanism can be summarized in three steps: (1) desorption: once free gas or water is produced from fracture systems in coal seams, pressure starts to be released, then the adsorbed gas will be desorbed from the matrix surface, which can be described by Langmuir isotherm equation; (2) diffusion: due to the gas molecular concentration difference, gas will diffuse from matrix surface to cleats/micro-pores; (3) Darcy's flow: gas in the cleats and natural fractures will flow to the wellbore by Darcy's flow [15]. Recently, the numerical reservoir simulator have become the most popular tool to predict coal seam performance and provides a good understanding of gas flow from the reservoir to the wellbore [16].

1.1. Langmuir Isotherm. The gas adsorption/desorption process can be described by the typical formulation of Langmuir isotherm:

$$V(P) = \frac{V_L P}{P_L + P}. \tag{1}$$

As shown in Figure 2, Langmuir volume (V_L) is the maximum amount of gas that can be adsorbed on a piece of coal at infinite pressure. Langmuir pressure (P_L) is the pressure at which the Langmuir volume can be adsorbed. $V(P)$ is the amount of gas at different pressure, also known as gas content (scf/ton). Whenever the Langmuir volume and Langmuir pressure are known, the adsorbed gas amount can be calculated at any pressure.

1.2. Diffusion. Diffusion is the fact that particles move/spread from high concentration to low concentration region. Diffusion of gas out of the coal matrix can be expressed by a simple diffusion equation. The diffusion process in coal seams can be described by either diffusion coefficient or coal desorption time input in the simulator [16]:

$$\frac{\partial C}{\partial t} = \frac{1}{\tau}\left[\overline{C} - C\left(P_f\right)\right]. \tag{2}$$

1.3. Coal Shrinkage and Swelling. One of the unique characteristics of coal seam is the phenomenon of pressure dependent permeability. As the production from the reservoir takes places, two distinct phenomena occur. First, the reservoir pressure declines, which causes the pressure in the fractures to decline as well, which in turn leads to an increase in the effective stress within the cleats causing the cleats to be more compactable, so the cleat permeability will decrease. At the same time, the gas that has been desorbed is coming out of the matrix, which causes the matrix to shrink and the cleats to open-up; thereby the cleat permeability will be increased. As a function of the pressure drop, compressibility dominates in early time and shrinkage dominates in the late time [16]. Palmer and Mansoori model [17] is used to simulate the permeability change process during production/injection in this model:

$$\begin{gathered} \frac{\varnothing}{\varnothing_0} = 1 + C_f\left(\frac{P-P_0}{\varnothing_0}\right) + \frac{\varepsilon_\propto}{\varnothing_0}\left(\frac{K}{M}-1\right)\left(\frac{P}{P+P_L} - \frac{P_0}{P_0+P_L}\right), \\ \frac{K}{K_0} = \left(\frac{\varnothing}{\varnothing_0}\right)^3. \end{gathered} \tag{3}$$

2. Project Description

From 2009, the CO_2 sequestration with ECBM production project began in Marshall County, West Virginia. The objective of this project was to help mitigate climate change by providing an effective and economic way to permanently store CO_2 in un-minable coal seams. In advance of CO_2 injection, four horizontal coalbed methane wells (MH5, MH11, MH18, and MH20) were drilled into the un-minable Upper Freeport coal seam, which are 1,200 to 1,800 feet below the ground. These wells have been producing coalbed methane since 2004. The center located wells (MH18 and MH20) have been converted to CO_2 injection wells since

Table 1: Initial reservoir parameters used in the model.

Input parameters	Value	Unit	Input parameters	Value	Unit
Average reservoir depth	1200	ft	Poisson ratio	0.3	
Average formation thickness	4	ft	Young's Modulus	125,000	psia
Fracture spacing I/J/K	0.02	ft	CO_2 Strain	0.0065	
Perm I-Matrix	0.01	md	CH_4 Strain	0.0045	
Perm J-Matrix	0.01	md	Palmer/Mansoori exponent	3	
Perm K-Matrix	0.001	md	CO_2 Langmuir Pressure	240	psia
Perm I-Fracture	0.2	md	CO_2 Langmuir Volume	890	scf/ton
Perm J-Fracture	0.2	md	CH_4 Langmuir Pressure	402	psia
Perm K-Fracture	0.02	md	CH_4 Langmuir Volume	452	scf/ton
Porosity-Matrix	0.004		CO_2 Sorption time	100	days
Porosity-Fracture	0.001		CH_4 Sorption time	100	days
Rock compressibility-Matrix	$1.00E-06$	1/psi	Rock compressibility-Fracture	$1.00E-06$	1/psi

September 2009 [18]. 20,000 short tons are planned to be injected through well MH18 and MH20 in two years.

Several questions come with this project and need to be investigated: how much CO_2 can be stored in this coal seam? How long does the injection process take? Which parameters affect the injection and production the most? These questions could be answered by an effective coal seam model, which was represented by a dual-porosity system to show the fluid flow through both matrix and cleat under the particular conditions in this site. The following assumptions were considered for the modeling and simulation purpose.

(1) The initial seam pressure is hydrostatic pressure, which is 0.28 psi/ft after water is produced.

(2) The flow in the coal seam is single phase including only CH_4 and CO_2.

(3) The fluid flow in the cleat system is a laminar flow due to the larger pore size and it is governed by Darcy's Law, while the flow in the matrix is a diffusional flow due to smaller pore size and governed by Fick's Law.

(4) Palmer and Mansoori equation is used to allow the natural permeability and porosity to vary as a function of pressure.

In most cases, the actual in situ seam data is unavailable, which leads to the requirements of some assumptions on certain parameters, such as, in this case, matrix/cleat permeability, matrix/cleat porosity, geo-mechanical properties (Young's modulus, Poisson ratio), and so forth. Table 1 summarizes the initial physical parameters in the model.

3. History-Matching Results and Discussion

As indicated before, the CO_2 sequestration-ECBM production project went through three stages: primary methane (CBM) recovery, CO_2 injection, and secondary methane (ECBM) recovery. MH18 and MH20 were firstly performed as production wells from January 2005 to July 2007 with a following two-year shut in period; thereafter, they were transferred into CO_2 injection wells since September 2009. MH5 and MH11 keep on methane production from the all the way from beginning to present. All well productions and injection were simulated starting from the start day until the date the most updated data have been recorded and reported (August 2012 in this paper).

However, different performance of MH18 and MH20 in different time periods introduced a lot of complexity on the history matching process. A key factor should be respected in the history matching: either for initial methane production or the following CO_2 injection, well properties (MH18 or MH20) must stay the same in the model; thereby what was changed is only the operation type.

The results of sensitivity analysis were very valuable in back and forth model parameter adjustment. Sensitivity analysis is known as the study of how the variation (uncertainty) in the output of a mathematical model can be apportioned, qualitatively or quantitatively affected by the change of different variations in the input of the model [19]. Sensitivity analysis of coal modeling properties is widely studied and is addressed that it will be an important tool in future decision making [19–21]. In this case, related coal parameters, including cleat permeability, porosity, CH_4 desorption time, CO_2 desorption time, CH_4 Langmuir volume, CO_2 Langmuir volume, and Palmer and Mansoori parameters have been tested in the model. The comparison of coal physical property influences can be concluded based on the study result as: Young's modulus and Poisson ratio have little effect, while sorption time, cleat permeability, strain, and Langmuir isotherm are the key parameters that affect CH_4 production and CO_2 injection most.

The actual in-seam data for both methane production and CO_2 injection in Upper Freeport coal seam were reported daily as shown in Figure 3. The average minimum bottom hole pressure in production wells is 20 psia, and the average maximum BHP in injection wells is 900 psia. The daily injection rate is set as constraint. The trend could be observed in the production; the methane production rate has clearly increased in MH5 and MH11 after July 2009 due to the CO_2 injection. A gradual decline trend in injection rate can be noticed in the injection wells, especially in MH18, which can be a consequence of the permeability changes occurring during desorption/adsorption process on coal.

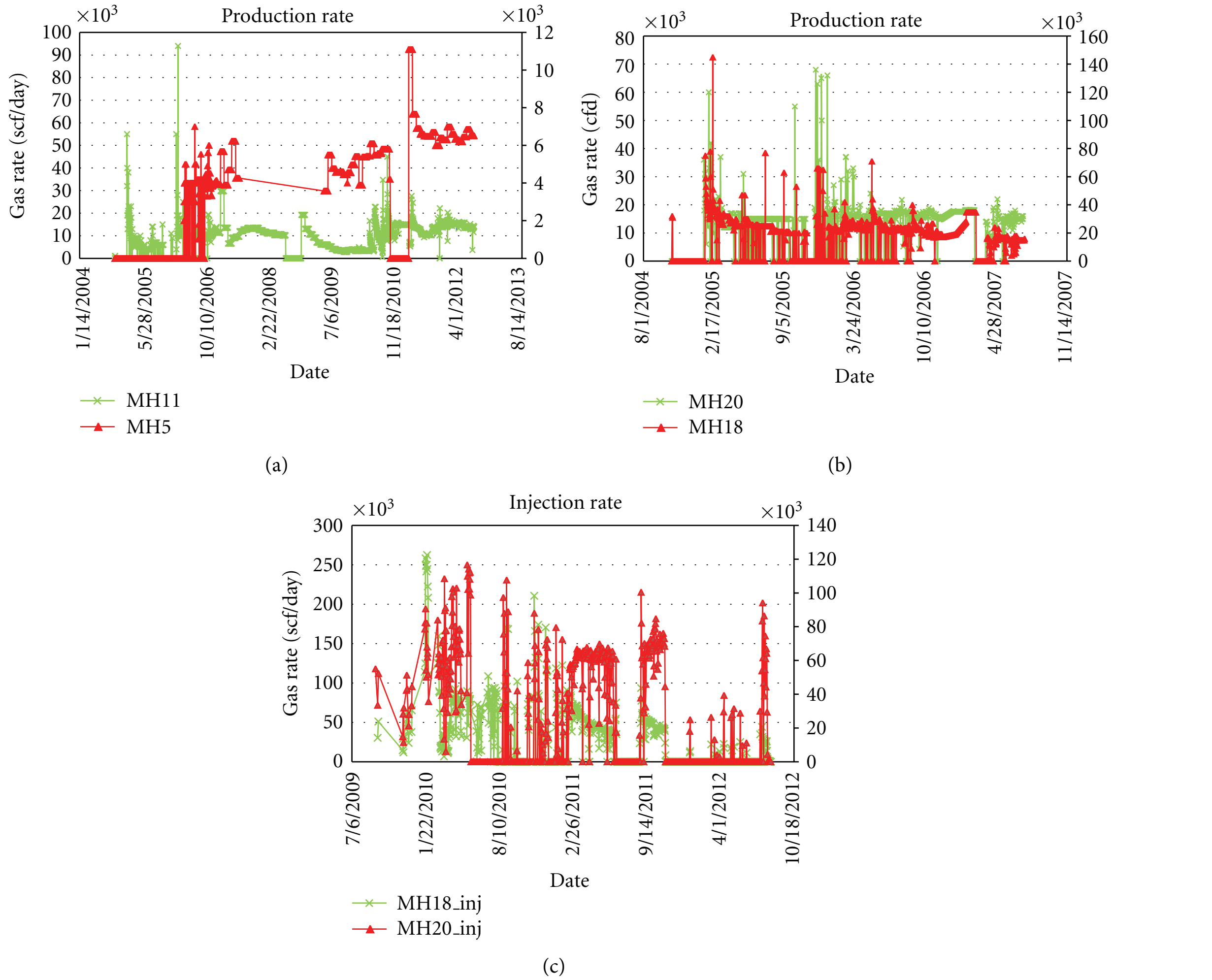
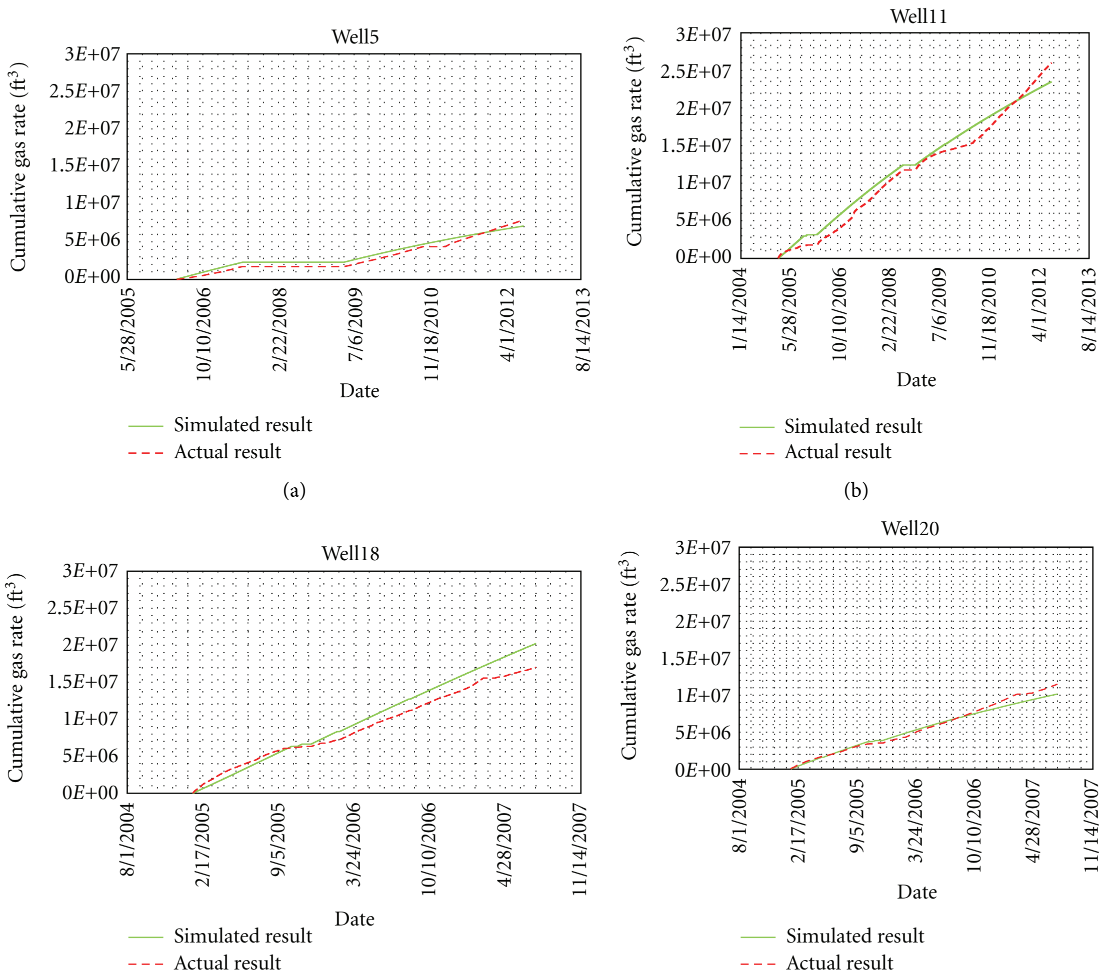


FIGURE 3: Actual CH_4 production rate/CO_2 injection rate in Upper Freeport coal seam. (a) CH_4 production rate in MH11 and MH5, (b) CH_4 production rate in MH18 and MH20, (c) CO_2 injection rate in MH18_inj and MH20_inj (MH18 and MH20 after conversion to Injection wells).

No regular tracking pattern of daily rate was observed because of frequent shut-in operations due to weather, equipment damage, or other unpredictable reasons during the injection process. Therefore, cumulative rates are considered to be the history matching target by setting bottom hole pressure as constraints in the model. History matching was performed for six wells, and final existing reservoir properties, including permeability, porosity, Langmuir isotherm parameter, sorption time, and so forth, as appropriate, were determined by history matching. The history matching results are illustrated in Figures 4 and 5 and the coal parameters are listed in Table 2. It is important to note that the degree of component isotherm and sorption time at any given in-situ condition is directly related to the rank of the coal. Values may change in a large range from different coal seams.

Figure 4 shows the fairly good history matching result of CH_4 cumulative production for all production wells. Green line and red line represents the simulated result and actual data, respectively. As shown in Figure 4(a), well5 was shut in from July 2007 to April 2009 and October 2010 to March 2011, which can be seen from two short straight lines in red cumulative curves. 7×10^6 ft^3 CH_4 could be produced from well5 by August 2012 with a stable increase. As illustrated in Figure 4(b), well11 had a short shut-in period of three months; that is why no production increase is shown in October 2005 and from July 2008 to November 2008. Totally, 2×10^7 ft^3 CH_4 were produced from well11 by August 2012, a sharp build-up could be observed after the start of large CO_2 injection on September 2009, which is because of ECBM production. Figures 4(c) and 4(d) show the cumulative CH_4 production of well18 and well20 from January 2005 to July 2007, respectively, before they were shut-in and transferred to CO_2 injection well. MH18 produced 1.6×10^7 ft^3 CH_4, while MH20 had a total of 1×10^7 ft^3 CH_4 production at the end of production period.

Figure 5 shows cumulative CO_2 injection history matching in MH18 and MH20 after they were converted into injection wells. Red dashed line represents actual CO_2 injection



(a) (b) (c) (d)

Figure 4: CH_4 cumulative production history matching. (a) CH_4 cumulative production in MH5, (b) CH_4 cumulative production in MH11, (c) CH_4 cumulative production in MH18, (d) CH_4 cumulative production in MH20.

data from September 2009 to August 2012, while green line shows simulation results for both wells. Certain plateaus could be seen in the curves during the whole injection periods, which is because of the shut-in times resulting from operational reasons, such as weather affects, equipment damage, and so forth. More CO_2 was injected through well18 (maximum amount of 2.5×10^7 ft^3 CO_2), compared to 2.5×10^7 ft^3 CO_2 injection in well20. The total amount of injected CO_2 through MH18 and MH20 has been almost 3,000 tons in the first three years, with an average ECBM increase of an approximation of 6,700 scf/day.

4. CO_2 Sequestration Capacity in Coal Seam

There are four main CO_2 storage mechanisms in coal seams: (a) stratigraphic and structural trapping, (b) hydrodynamic trapping, (c) mineral trapping, and (d) adsorption trapping. In un-mineable coal seams, adsorption trapping is the main sequestration method. This is the process of accumulation of injected gases which is adsorbed on the surface of micropores within the coal matrix. The adsorption capacity will mostly depend upon Langmuir isotherm factors [22]. Figure 6 illustrates the final Langmuir Isotherm in Upper Freeport coal seam in this case.

Two assumptions have been made in order to simplify the calculation here.

(1) No water production data was reported in this case; the coal reservoir was simulated with single phase production with only CH_4 and CO_2.

(2) Adsorption trapping is the main sequestration method in un-mineable coal seam, which was considered as the only storage mechanism without including free gas in the fractures in this study.

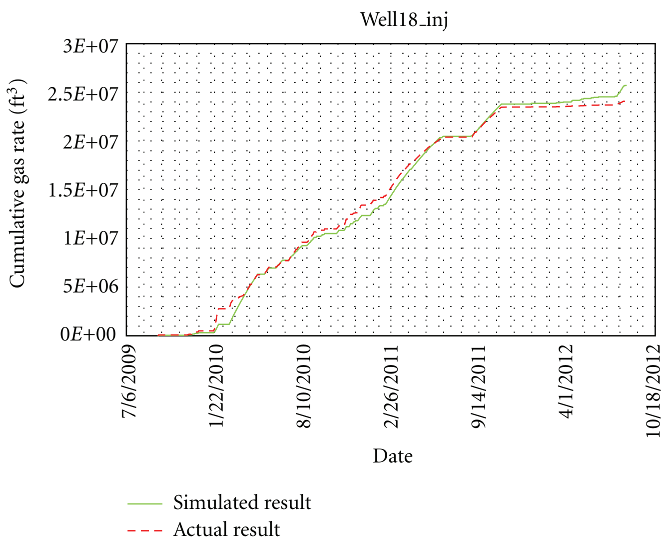
The CO_2 adsorption capacity in the coal seam can be calculated as

$$\mathrm{OGIP} = A \times h \times \rho_b \times G_{ci} = V \times \rho_b \times G_{ci}, \quad (4)$$

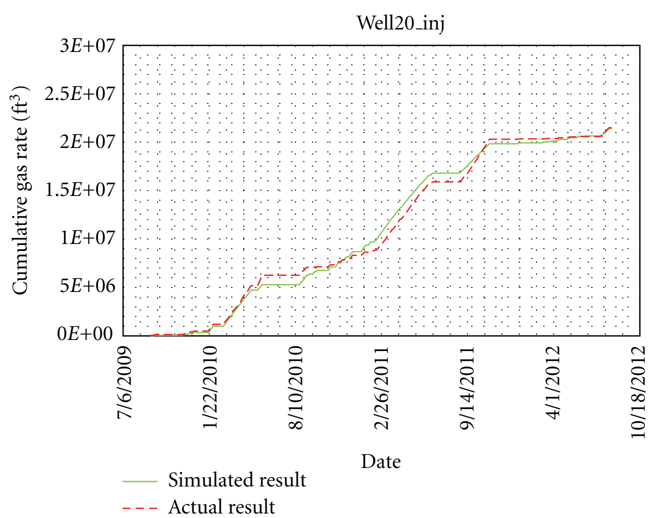
where $V_L = 800$ scf/ton, $P_L = 412$ psia, $P = 0.28$ psi/ft $\times$ 1200 ft = 360 psi, and $V(P) = G_{ci} = V_L P/(P_L + P) = 800 \times$

Table 2: History matched reservoir parameter setting.

Input parameters	Value	Unit	Input parameters	Value	Unit
Average reservoir depth	1200	ft	Poisson ratio	0.3	
Average formation thickness	4	ft	Young's Modulus	125,000	psia
Fracture spacing I/J/K	0.015	ft	CO_2 Strain	0.0025	
Perm I-Matrix	0.01–0.02	md	CH_4 Strain	0.0045	
Perm J-Matrix	0.01–0.02	md	Palmer/Mansoori exponent	3	
Perm K-Matrix	0.001–0.002	md	CO_2 Langmuir Pressure	412	psia
Perm I-Fracture	0.2–0.4	md	CO_2 Langmuir Volume	800	scf/ton
Perm J-Fracture	0.2–0.4	md	CH_4 Langmuir Pressure	628	psia
Perm K-Fracture	0.02–0.04	md	CH_4 Langmuir Volume	652	scf/ton
Porosity-Matrix	0.002–0.004		CO_2 Sorption time	140	days
Porosity-Fracture	0.001–0.002		CH_4 Sorption time	350	days
Rock compressibility-Matrix	1.00$E-06$	1/psi	Rock compressibility-Fracture	1.00$E-06$	1/psi



(a)



(b)

Figure 5: Cumulative CO_2 injection history matching. (a) Cumulative CO_2 injection in MH18_inj, (b) Cumulative CO_2 injection in MH20_inj.

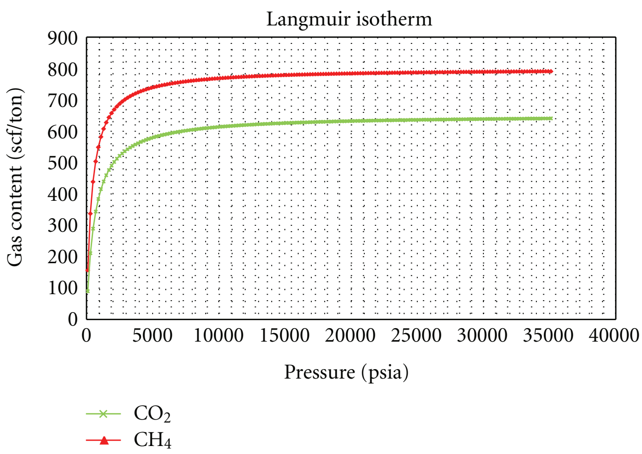


Figure 6: Existing Langmuir isotherm for CO_2 and CH_4 in Upper Freeport Coal seam.

360/(412 + 360) = 373 scf/ton, where, ρ_b = 85 lbs/ft^3, V = 25,193,558 ft^3, 1 ton = 2,000 lbs, Coal tonnage = 85 × 25,193,558/2,000 = 1,069,466 tons, OGIP = 1,069,466 tons × 373 scf/ton/17,483 ton/scf = 22,817 tons (coal seam volume and coal density were provided and were used directly).

5. Summary and Conclusions

The modeling and history matching process of methane production and ECBM as well as CO_2 injection in a coal bed seam was explained in this work. This process was performed using conducting actual data analysis and sensitivity analysis of related coal seam physical properties on four horizontal wells drilled in Upper Freeport coal seam. Results of history matching were compiled to show the initial and existing condition in the coal seam. CO_2 sequestration capacity prediction was completed according to the Langmuir isotherm properties obtained from the history matched reservoir model.

The simulation of CH_4 gasification and CO_2 injection process was quite complicated. The special swelling and shrinkage features and the nature of gas retention in CBM reservoirs make the modeling and history matching of production and injection data in coal bed methane more complex because of the permeability and porosity variations compared to conventional resources.

Sensitivity analysis results suggested that sorption time, cleat permeability, strain, and Langmuir isotherm are the most influential parameters during CH_4 production and CO_2 injection process. It is concluded by the Langmuir isotherm parameters from history matched model that the total CO_2 sequestration capacity is about 22,817 tons excluding the free gas part in the cleat system. The total CO_2 injection amount in the first three years was 4.5×10^7 ft^3 or 2,600 tons, which caused an increase of 6,700 scf/day in CH_4 production rate from other two wells.

Nomenclature

D: Diffusion coefficient

$\overline{C}$: Average gas concentration in the matrix

τ: Desorption time, days

$C_f((P-P_0)/\varnothing_0)$: Stress-dependent permeability term

$(K/M-1)(P/(P+P_\varepsilon)-P_0/(P_0+P_\varepsilon)(K/M-1)(P/(P+P_\varepsilon)-(P_0/(P_0+P_\varepsilon))))$: Matrix shrinkage term

Φ_i: Initial fracture porosity, %

C_f: Pore volume compressibility, 1/psi

P: Initial pressure, psi

M: Axial modulus, psi

K: Bulk modulus, psi

ε: Langmuir strain

P_L: Langmuir pressure, psi

V_L: Langmuir volume, scf/ton

A: Drainage area, ft^2

h: Net pay, ft

ρ_b: Bulk density, lbs/ft^3

G_{ci}: Gas Content, scf/ton

$\varnothing_i$: Porosity, %

B_{gi}: Initial formation volume factor, STB/scf

OGIP: Original gas in place, tons

V: Coal volume, ft^3.

Acknowledgments

This project was funded by the Department of Energy, National Energy Technology Laboratory, Consol Energy, through a support contract with URS Energy and Construction, Inc. The authors want to acknowledge the important contributions of Consol Energy for the field data available for analysis. Acknowledgment is also extended to Tom Wilson in WVU for providing the geological maps for the studied field in this research. Thanks go to Computer Modeling Group Ltd. (CMG) for providing the software to do the PEARL research group at WVU.

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