POTENTIAL FOR CO_2 SEQUESTRATION AND ENHANCED COALBED METHANE PRODUCTION, BLUE CREEK FIELD, NW BLACK WARRIOR BASIN, ALABAMA

A Thesis

by

TING HE

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2009

Major Subject: Petroleum Engineering

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Approved by:

Co-Chairs of Committee,	Walter B. Ayers, Jr.
	Maria A. Barrufet
Committee Member,	Yuefeng Sun
Head of Department,	Stephen A. Holditch

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ABSTRACT

Potential for CO_2 Sequestration and Enhanced Coalbed Methane Production, Blue Creek Field, NW Black Warrior Basin, Alabama.

(December 2009)

Ting He, B.S., University of Science and Technology of China

Co-Chairs of Advisory Committee, Dr. Walter B. Ayers, Jr
Dr. Maria A. Barrufet

Carbon dioxide (CO_2) is a primary source of greenhouse gases. Injection of CO_2 from power plants near coalbed reservoirs is a win-win method to reducing emissions of CO_2 to the atmosphere. Limited studies have investigated CO2 sequestration and enhanced coalbed methane production in San Juan and Alberta basins, but reservoir modeling is needed to assess the potential of the Black Warrior basin. Alabama ranks 9th nationally in CO_2 emissions from power plants; two electricity generation plants are adjacent to the Black Warrior coalbed methane fairway.

This research project was a reservoir simulation study designed to evaluate the potential for CO_2 sequestration and enhanced coalbed methane (ECBM) recovery in the Blue Creek Field of Black Warrior basin, Alabama. It considered the injection and production rate, the components of injected gas, coal dewatering, permeability anisotropy, various CO_2 soak times, completion of multiple reservoir layers and pressure constraints at the injector and producer.

The simulation study was based on a 5-spot well pattern 40-ac well spacing. Injection of 100% CO_2 in coal seams resulted in average volumes of 0.57 Bcf of sequestered CO_2 and average volumes of 0.2 Bcf of enhance methane production for the Mary Lee coal zone only, from an 80-acre 5-spot well pattern.

For the entire Blue Creek field of the Black Warrior basin, if 100% CO_2 is injected in the Pratt, Mary Lee and Black Creek coal zones, enhance methane resources recovered are estimated to be 0.3 Tcf, with a potential CO_2sequestration capacity of 0.88 Tcf. The methane recovery factor is estimated to be 68.8%, if the three coal zones are completed but produced one by one. Approximately 700 wells may be needed in the field. For multi-layers completed wells, the permeability and pressure are important in determining the breakthrough time, methane produced and CO_2 injected. Dewatering and soaking do not benefit the CO_2 sequestration process but allow higher injection rates. Permeability anisotropy affects CO_2 injection and enhanced methane recovery volumes of the field.

I recommend a 5-spot pilot project with the maximum well BHP of 1,000 psi at the injector, minimum well BHP of 500 psi at the producer, maximum injection rate of 70 Mscf/D, and production rate of 35 Mscf/D. These technical results, with further economic evaluation, could generate significant projects for CO_2 sequestration and enhance coalbed methane production in Blue Creek field, Black Warrior Basin, Alabama.

DEDICATION

To God and my parents

ACKNOWLEDGEMENTS

I would like to thank my committee co chairs, Dr. Maria A. Barrufet and Dr. Walter B. Ayers, and my committee member, Dr. Yuefeng Sun, for their guidance and support throughout the course of this research.

I would like to thank El Paso Energy Corporation for suggesting this study and for sponsoring the first part of my research.

Thanks also go to colleagues and the PETE department faculty and staff for making my time at Texas A&M University a great experience.

Finally, thanks to my mother and father for their encouragement and to my friends for their support and love.

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INTRODUCTION

Overview

Atmospheric gases that absorb and emit radiation within the thermal infrared range are called greenhouse gases (GHG). Carbon dioxide (CO_2) is considered the main GHG in the Earth's atmosphere. Attributed to human activities in the industrial era, the atmospheric concentration of CO_2 increased from 280 ppb between 0 and 1800 AD to 385 ppb in 2000 AD (Global Warming 2009) (**Fig. 1**). Conti (2006) estimated that total energy-related CO_2 emissions for the world in 2003 were 25,000 million metric tons (MMT). To put US emissions in a global perspective, CO_2 emissions for the U.S. are estimated to be 5,800 MMT, which is about 23% of the world total (Conti 2006).

As the atmospheric concentration of CO_2 increases, the current impacts and future risks of climate change become more apparent. The Earth's temperature has changed over the past 20,000 years **(Fig. 2)**. Temperature increases since the 1990s have caused people to become climate refugees (Global Warming 2009), and millions more are expected if global warming continues.

To control the increase of GHG and minimize the world economic impact, four options are being explored: (1) less carbon-intensive fuels; (2) more energy-efficient methods of fuel consumption; (3) carbon sequestration; and (4) increased energy conservation

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(White et al. 2005). Because society is strongly dependant on fossil energy, of the four options, CO_2 capture and sequestration provides a potentially valuable tool to reduce the atmospheric concentration of CO_2.

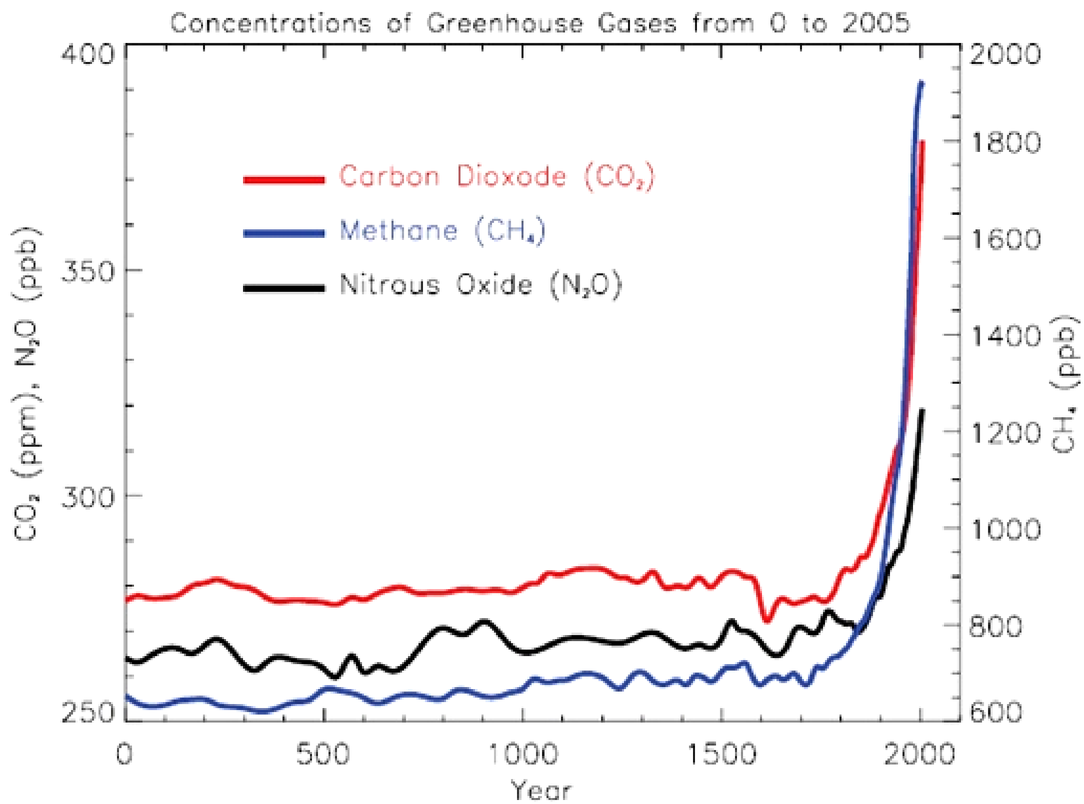

Fig. 1—Atmospheric concentrations of GHG over the last 2000 years (From Global Warming 2009).

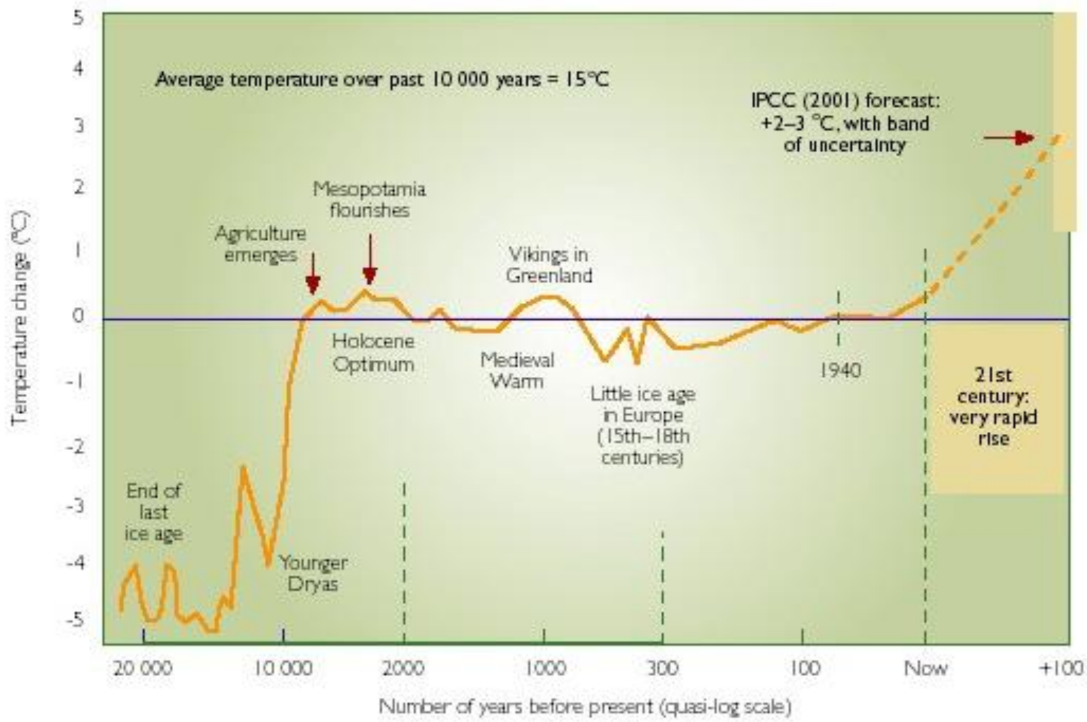

Fig. 2—Variations in earth's average surface temperature over the past 20,000 years (from Global Warming 2009).

Over the last decade, North American onshore conventional gas production has declined **(Fig. 3)**. In the US, unconventional gas production is predicted to increase and to become the main natural gas source over the coming 30 years (Annual Energy Outlook 2009). Coalbed methane (CBM) is an important unconventional resource for the US; economically recoverable coalbed methane in the US is estimated to be approximately 100 Tcf (Nuccio 2000). However, production of CBM in the States is now leveling off **(Fig. 4).** Enhanced coalbed methane (ECBM) recovery has the potential to offset production decline and extend the lives of the CBM wells. Therefore, of the geological CO_2 sequestration options, ECBM is among the most attractive, owing to value-added production of methane (White et al. 2005). CO_2 sequestration in coal seams is a promising option to accelerate CBM production and reduce the cost of a CO_2 sequestration project. Moreover, because injected CO_2 is stored as adsorbed gas in coal, once in place it will not migrate unless the formation is depressurized.

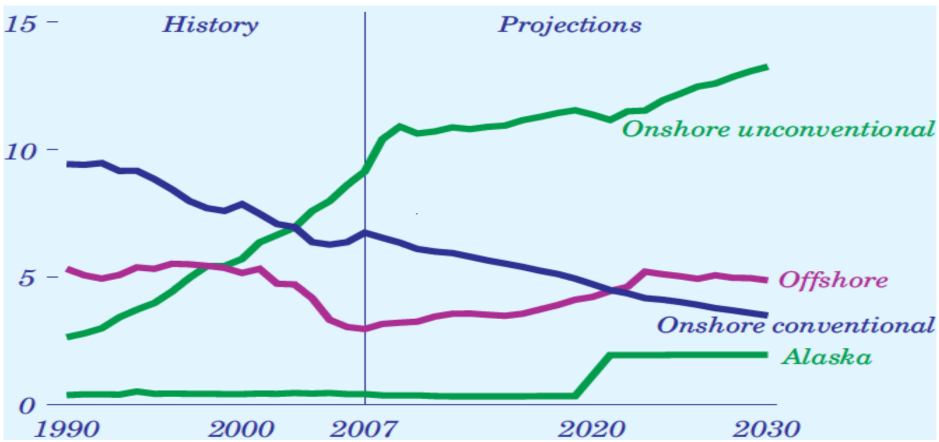

Fig. 3—U.S. natural gas production by source, 1990-2030 (Tcf) (from Annual Energy Outlook 2009).

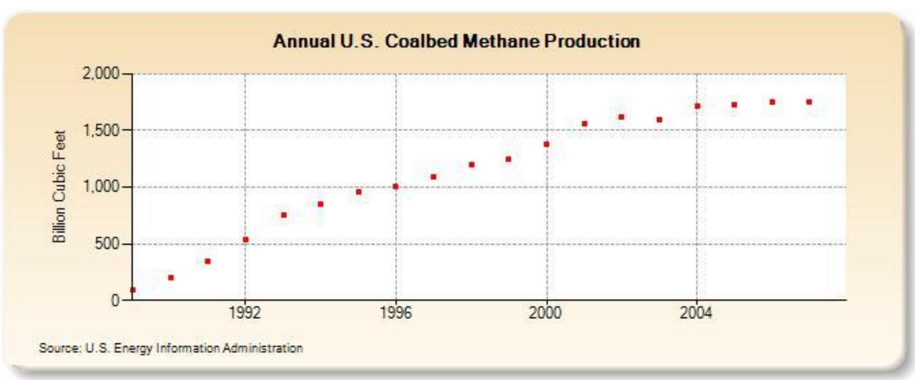

Fig. 4—CBM production in North American (from Annual Energy Outlook 2009).

Previous Work

CO_2 sequestration and ECBM have been studied for years. In 1972, Every and Dell'osso (1972) showed that, in laboratory conditions, CO_2 could effectively displace methane from crushed coal. Tests run on crushed cores have confirmed that CO_2 consumption by permanent adsorption appears to be a means of safely demethanizing coal beds before mining (Fulton et al. 1980; Reznik and Foley 1984). In recent years, laboratory core flooding experiments with flue gas have been carried out under in-situ reservoir parameters (Saikat Mazumder 2008).

As far as can be determined, 1991, Alberta Energy was the first to propose the storage of CO_2 in coal seams for sequestration purposes (Gunter et al. 1997). In 1998, the Alberta Research Council carried out a field test to obtain information on CO_2 storage and ECBM, using the Manville coals at the Fenn Big Valley in Alberta (White et al 2005) and a single-well micropilot test with flue gas injection was performed in 1999. They showed that twice as much CO_2 can be injected as CBM can be produced from a coal seam. In 2000, the design and implementation of a micropilot huff-and puff test, using CO_2 and N_2 as injectants, was performed in one coal seam. These projects show that low-permeability coal seams that may not be commercial under primary production, could still be CO_2 storage sites with the added benefit of improving possibilities for commercial CBM production (Gunter et al. 1997). ECBM field tests have been conducted in the US and several other countries, including Australia and Poland.

In the US, Amoco conducted N_2 injection for ECBM in a small pilot project in the San Juan Basin, Colorado in 1993 (Gunter et al. 1997). The ECBM recovery pilot used four N_2 injection wells surrounding a central production well. Then, Amoco moved forward to the first and largest full-scale N_2-ECBM commercial pilot in Tiffany Unit. It was the first commercial ECBM project in the US.

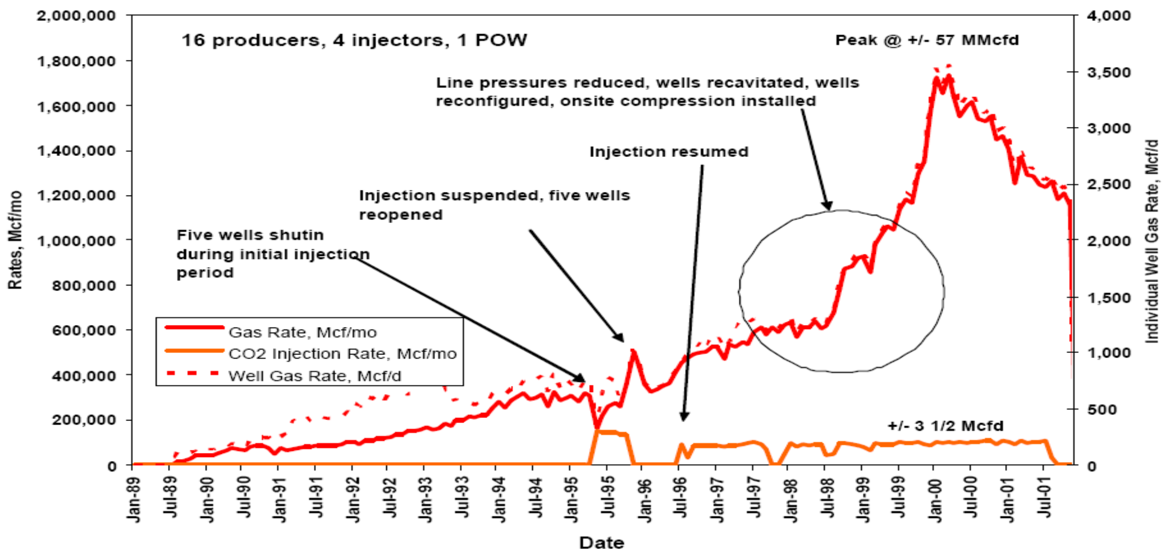

Fig. 5—Production history, Allison Unit (Reeves et al. 2003).

Burlington Resources Allison Unit field was the world's first experimental pure CO_2/ECBM recovery pilot. In April 1995, CO_2 injection began in the Allison Unit of the San Juan Basin, New Mexico; the project was suspended in August 2001 (Reeves et al. 2003). This pilot consisted of 16 producing wells, four CO_2-injection wells, and one pressure-observation well. **Fig. 5** shows the production history of the Allison Unit pilot. In October 2000, the United States Department of Energy (USDOE) started a multiyear

CO_2 sequestration and ECBM projects called the Coal-Seq in the Allison Unit (Reeves et al. 2003). This project proved the economical value of CO_2/ECBM recovery.

In 2003, a field test program of CO_2 sequestration in coal was conducted in the Black Warrior Basin under the auspices of the USDOE Southeastern Regional Carbon Sequestration Partnership (SECARB) (McIntyre et al. 2008). An existing coalbed methane well in the Deerlick Creek field was used for injection (Pashin and Clark 2006). A new (SECARB) test site was selected in Blue Creek field. A single well, single seam field test, the time line is shown in **Table 1**.

Table 1—Time Line of the SECARB Project (McIntyre et al. 2008).

Site Selection	**Complete**
NEPA/Permitting	6/09
Drilling/Coring	7/09
Monitoring	6/09-6/10
Injection Testing	9/09-11/09
Site Closure	6/10

Statement of Problem

Past studies of CO_2 sequestration and ECBM have been conducted in single coal seam and no commercial projects have been conducted in Black Warrior basin. So it is significant to study the potential of CO_2/ECBM production in Black Warrior basin and it is the first time to simulate multi coal seams in this study area.

Black Warrior basin is an extensive area of coal and coalbed methane production in western Alabama **(Fig. 6)**. The coalbed methane is produced from the Pennsylvanian Age Pottsville formation, which is a southwestward-thickening wedge of as much as 9,800 ft of shale, sandstone, and coal (Horsey 1981).

Between 1980 and 2000, CBM wells in Alabama produced approximately1.2 Tcf of gas, which ranks second globally in cumulative coalbed methane production (U.S. Environmental Protection Agency 2004). However, since mid-1990 production of CBM in the Black Warrior basin has been at a plateau. In 2005, 115 wells were drilled in the play by El Paso Energy Corporation (El Paso), and its production rate of gas at 62 Mscf per day is expected to remain nearly constant.

Alabama ranks 9th nationally in CO_2 emissions from power plants (U.S. Environmental Protection Agency 2004), and two coal-fired power plants that serve the Birmingham and Tuscaloosa metropolitan areas are adjacent to the Black Warrior coalbed methane fairway **(Fig. 7)** (Pashin et al. 2004). Geologists indicated that, at current rates of emission, potential exists for sequestration of more than 35 years of emissions from these two coal-fired power plants. Flue gas from the plants can be the injected gas.

El Paso Cooperation, which suggested this study and found the early stage has intended in several CBM projects in the Black Warrior including Blue Creek, White Oak Creek, and Short Creek fields. Then they suggested the project began with Blue Creek field and test the potential for injecting at a commercial scale of up to 50 MMscf/D of CO_2.

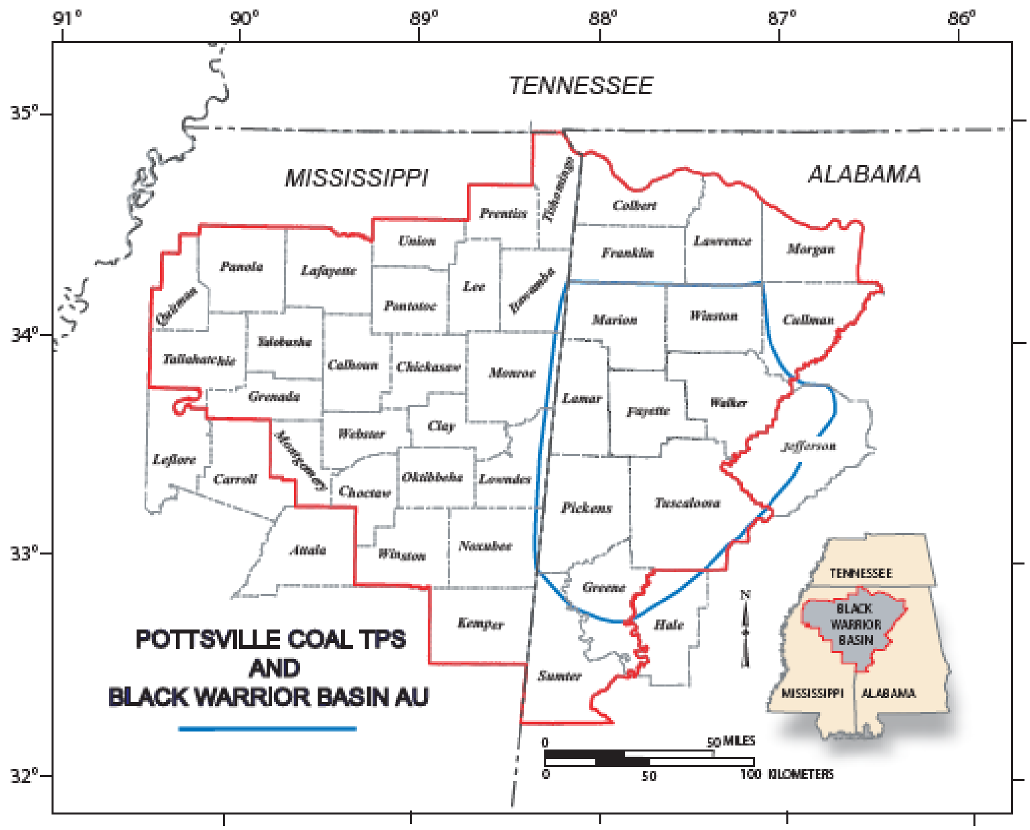

Fig. 6—Location of Pottsville Coal in the Alabama part of the Black Warrior Basin (Hatch and Pawlewicz 2007).

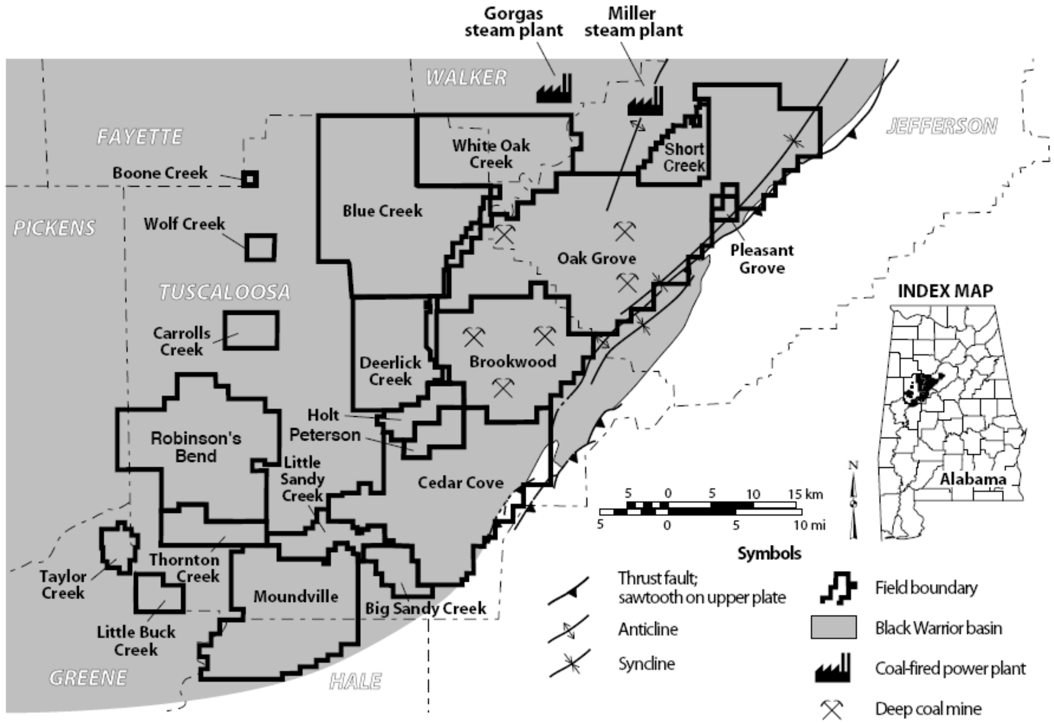

Fig. 7—Coalbed methane fields in the Black Warrior Basin (from Pashin et al. 2004).

Objectives

This research is designed to accomplish the following objectives:

- Estimate the amount of CO_2 that can be sequestered in Blue Creek field of and the amount of ECBM that may be produced.
- Determine the effects of the rate and pressure constraints on CO_2 sequestration and ECBM. Evaluated the roles of variable components of injected gas, coal dewatering, permeability anisotropy, time to soak, and completion of multiple layers coal reservoir.

- Recommend a test program, including CO_2 injection volumes and injection pressure, number of wells, etc., to test the potential for injecting at a commercial scale of up to 50 MMcf/D of CO_2.

Methodology

First, I reviewed the screening model for CO_2 sequestration and ECBM in the Black Warrior basin (Pashin et al. 2004). Next, I collected pertinent data for Blue Creek and White Oak fields in the Black Warrior basin, because of El Paso's interest in these fields. The data were mainly stratigraphic, structural, resource, reservoir property, and production history reports. Then I applied the screening criteria (Pashin et al. 2004) to Blue Creek field and conducted that it appears to be suitable for CO_2 sequestration and ECBM production.

I used the simulator, GEM, to set up a reservoir model to simulate CO_2 sequestration and ECBM in the Pottsville coals in Blue Creek field. The model contains three layers, which are the Pratt, Mary Lee, and Black Creek coal zones.

I designed eight cases to study the factors that may affect CO_2 sequestration and methane production. First, I designed a base case; then, I designed seven additional cases to evaluate the different factors affecting CO_2 sequestration and ECBM production. I considered the injection and production rate, the components of injected gas, coal dewatering, permeability anisotropy, various CO_2 soak times, completion of multiple reservoir layers, and pressure constraints at the injector and producer.

Finally, I selected the optimal constraints and processes to evaluate how much CO_2 can be sequestered and how much CH_4 can be produced from Blue Creek field.

GEOLOGIC DESCRIPTION OF BLACK WARRIOR BASIN

CBM Production History in the Black Warrior Basin

The Black Warrior basin has been a world leader in developing commercial coalbed methane. Methane production from the Black Warrior basin began exclusively as a method to degas underground coal mines (Schraufngel et al. 1994), and initially, it targeted only the Mary Lee seam using a closely spaced configuration to degasify the coal adjacent to underground mines in 3 to 5 years (Wicks et al. 1986). All wells are vertical. The wells drilled between 1975 and 1980 are extremely close-spaced, 15-acre patterns concentrated in eastern Oak Grove and in Pleasant Grove fields in the southeastern part of the Black Warrior basin (Fig. 7) (Pashin et al. 2004; Hatch and Pawlewicz 2007). Most subsequent developments for coalbed methane used 40- and 80-acre well spacings (Pashin et al. 2004). By 1996, approximately 5,000 CBM wells had been permitted in Alabama. By 2000, the number of permitted wells had increased to more than 5,800 (Global Warming. 2009). Newer wells, these have reported less than 3 years of production by 2004, are concentrated in the parts of Blue Creek, White Oak Creek, and Short Creek fields (Pashin et al. 2004) (**Fig. 8)**.

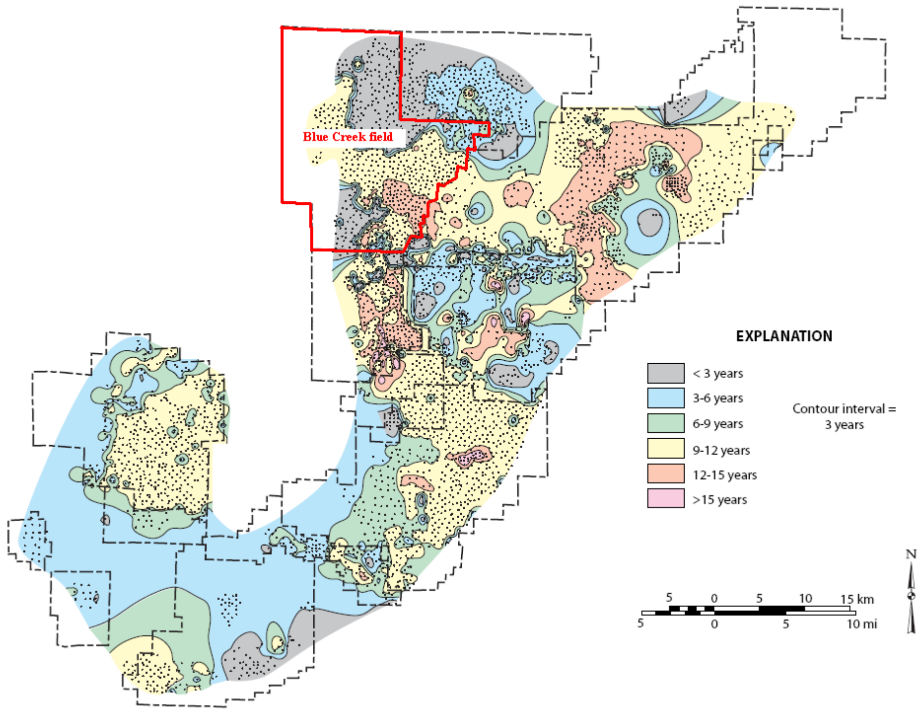

Fig. 8—Map showing years of reported production from CBM wells in the Black Warrior basin (from Pashin et al. 2004).

CBM well production rates range from less than 20 Mcf to more than 1 MMcf per day per well (Global Warming. 2009) (**Fig. 9**). Between 1980 and 2000, CBM wells in Alabama produced 1.2 Tcf of gas, which ranks the basin second globally in cumulative CBM production (U.S. Environmental Protection Agency 2004). By 2004, 80% of the wells had produced between 19 and 710 MMcf of gas, and the average cumulative production of coalbed methane of wells in Blue Creek and White Oak Creek field was slightly less than 500 MMscf per well (Pashin et al. 2004) (**Fig. 10**). From 2000 to 2008, the average annual CBM production increased from 60 Bcf to nearly 115 Bcf for Blue Creek field, and it has remained at that plateau (United States Securities and Exchange Commission 2007) (**Fig. 11**).

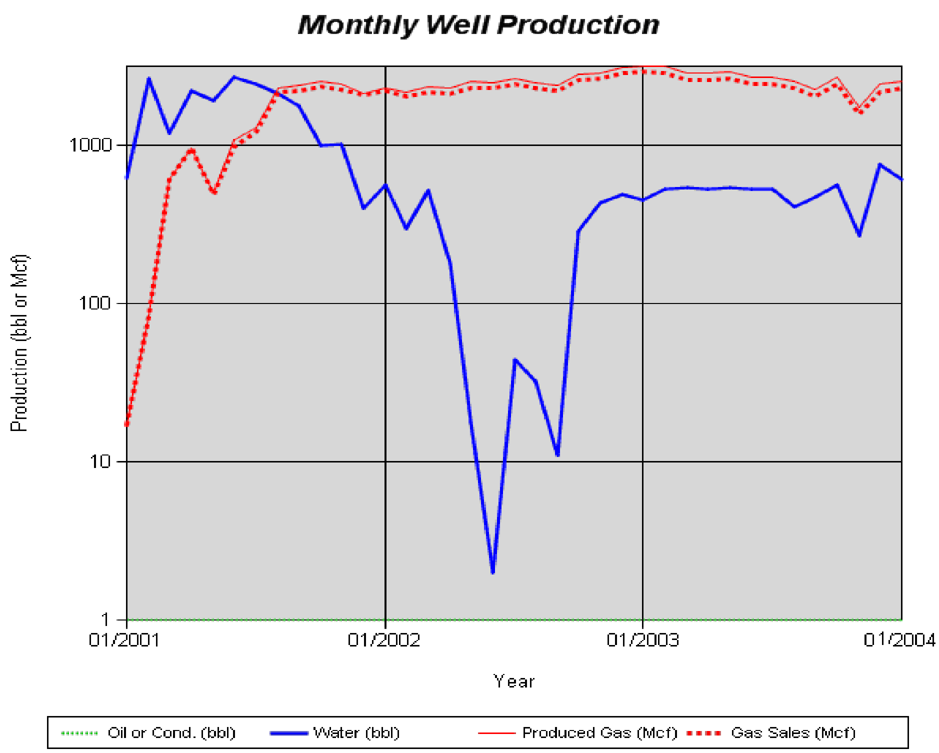

Fig. 9—Production rates of a single well in Blue Creek field from 2001 to 2004 (from Global Warming. 2009).

El Paso Corp has 160,000 net acres of leases in Blue Creek, White Oak Creek, and Short Creek fields, of which 78,000 are undeveloped (United States Securities and Exchange Commission 2007) (**Fig. 11**). By 2008, El Paso operated 1,003 wells in the play, with well spacing of 80 acres (El Paso 2008). **Fig. 11** shows the production which stands at 62 MMscf of gas per day and is expected to remain fairly constant over the next 2 years.

Water production from all wells in the Black Warrior basin since 1991 has a log-normal mean of about 88,500 bbl per year (Pashin et al. 2004). In 2003, wells that produced more than 725 B/D water were in the top 20%; the highest daily individual well production is approximately 1,500 B/D (Groshong et al. 2003).

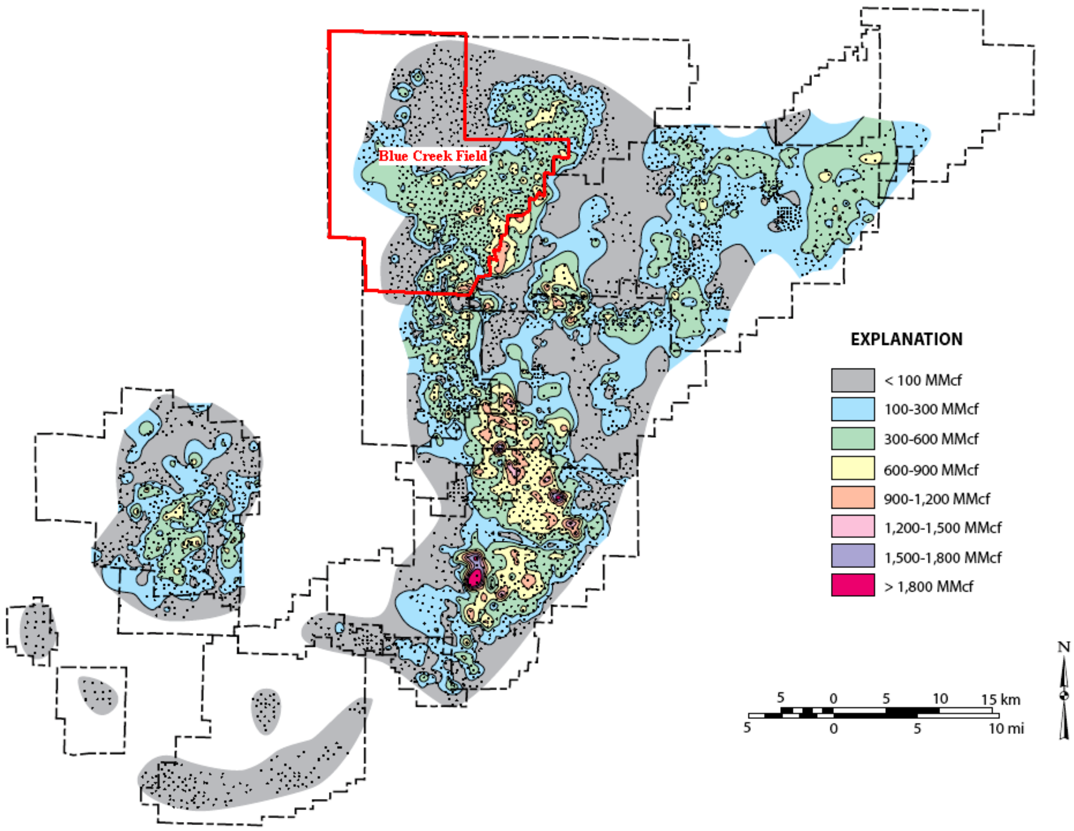

Fig. 10—Cumulative gas production from vertical CBM wells in the Black Warrior basin (from Pashin et al. 2004).

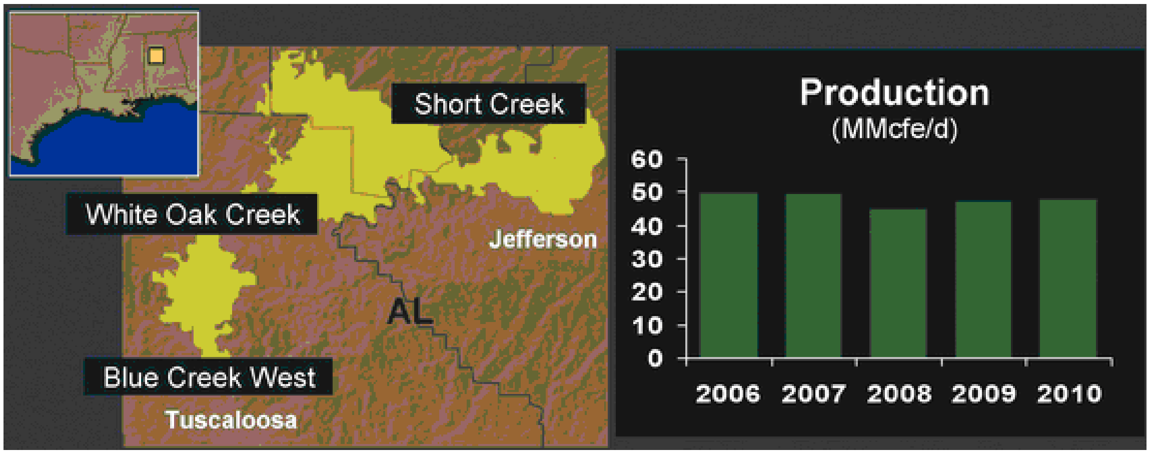

Fig. 11—CBM fields operated by El Paso, and forecasted production (from United States Securities and Exchange Commission 2007).

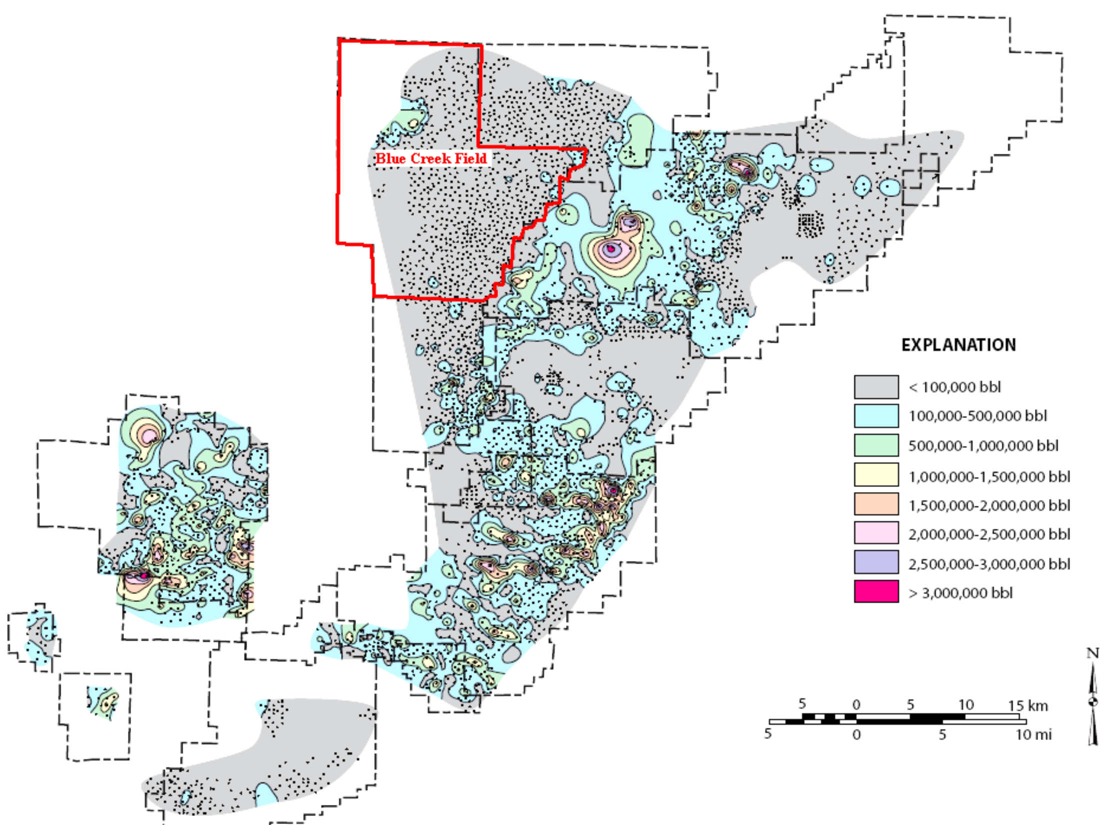

Fig. 12—Cumulative water production from vertical CBM wells in the Black Warrior basin (from Pashin et al. 2004).

Cumulative water production ranges from less than 1000 bbl to more than 3 million bbl per well (**Fig. 12)**. The amount of water produced from most CBM wells is greater than that produced from conventional natural gas wells. Regulations in each state control how produced water may be handled and disposed. Produced water quality in Black Warrior basin is typically poor, with total dissolved solids (TDS) exceeding of 30,000 ppm. **Table 2** shows the water production rates and methods of water disposal for some major CBM producing basins, including the Black Warrior basin (Rice and Naccio 2000).

Table 2—Water Production and Disposal for Some Major CBM-Producing Basins (Rice and Naccio 2000).

Basin	State	No. of wells	Avg. water production (Bbl/day/well)	Water/gas ratio (Bbl/MCF)	Primary disposal method
Black Warrior	Ala.	2,917	58	0.55	Surface disch.
Powder River	Wyo., Mont.	2,737	400	2.75	Surface disch.
Raton	Colo.	459	266	1.34	Injection
San Juan	Colo., N. Mex.	3,089	25	0.031	Injection
Uinta	Utah	393	215	0.42	Injection

Pottsville Formation Stratigraphic and Coal Occurrence

The Black Warrior basin is a late Paleozoic foreland basin that formed adjacent to the juncture of the Appalachian and Ouachita orogenic belts (Hatch and Pawlewicz 2007). The generalized paleogeography of the Pottsville formation is shown in **Fig. 13** (Pashin et al. 2004).

Pottsville formation coal beds accumulated in diverse coastal-plain settings ranging from highstand to early stages of marine regression. The associated sandstone units include a broad range of fluvial and tidal-flat deposits, and the mudstone units represent floodbasin and mudflat environments. Coals are the products of peat swamps, which in the Pottsville formation, formed in a spectrum of domed and low-lying environments that spanned the coastal plain (Pashin et al. 2004).

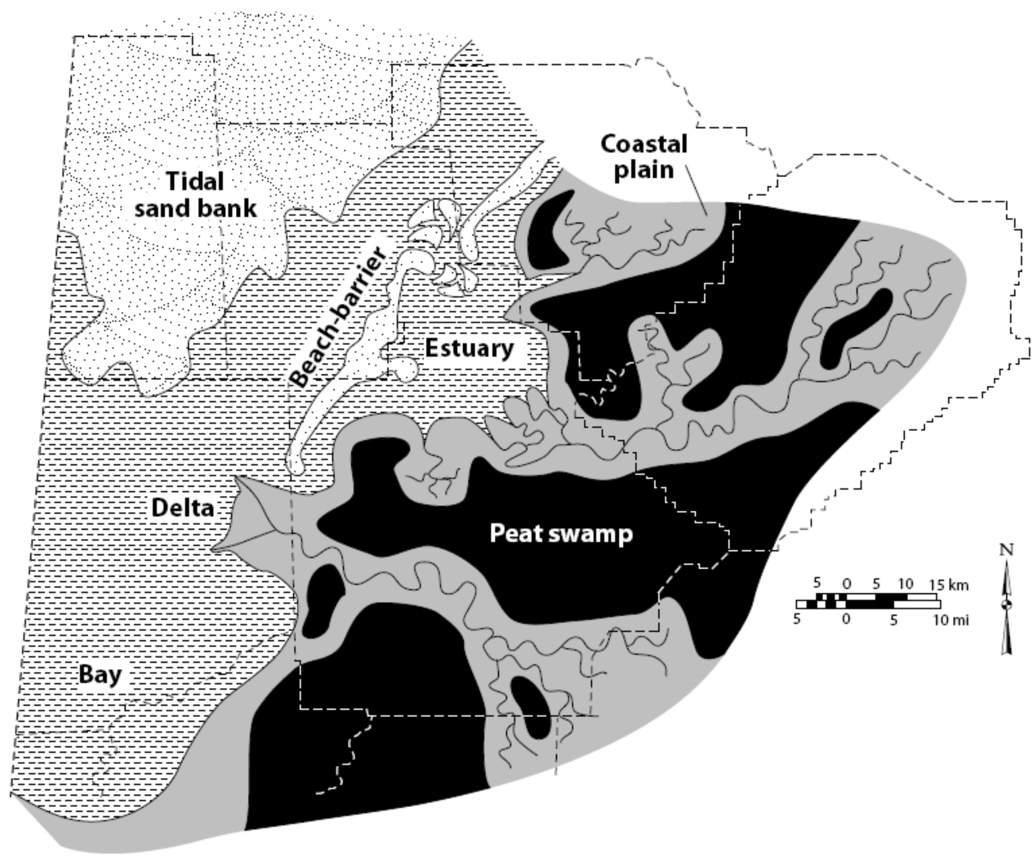

Fig. 13—Generalized paleogeography of the Pottsville formation in the Black Warrior basin of Alabama (from Pashin et al. 2004).

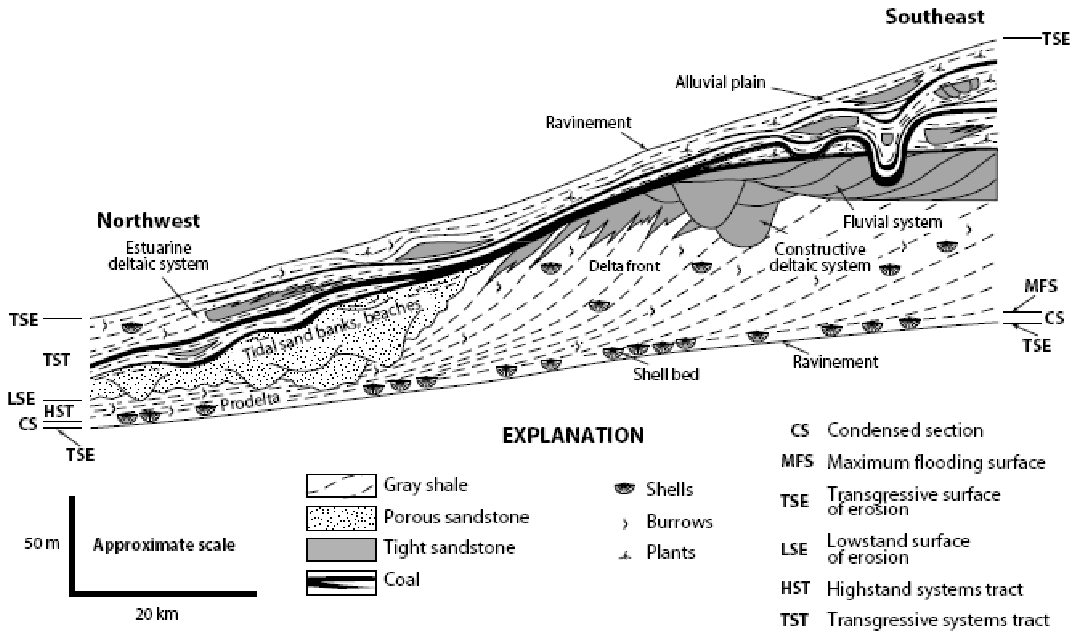

Fig. 14—Idealized depositional cycle in the Pennsylvanian Pottsville formation (from Pashin et al. 2004).

The lower to middle Pennsylvanian Age Pottsville formation is composed principally of shale, sandstone, and coal. Thicknesses of the formation locally exceed 6,000 ft (Hatch and Pawlewicz 2007). The Pottsville formation was deposited in multiple depositional cycles, each containing a coal group or zone that occurs in coastal plain sediments near the top of the cycle (**Fig. 14**). The surfaces at the base of the Pottsville cycles are interpreted as transgressive surfaces of erosion, or ravinements, and the associated fossil concentrations are in condensed sections that rest directly on the ravinement surfaces (Fig. 14) (Pashin et al. 2004). The Pottsville stratigraphic section thickens to the south and southwest both as the result of northward erosion and, because of southward depositional thickening of individual stratigraphic units (Hatch and Pawlewicz 2007).

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The economically important coalbed of the Pottsville formation occur in several widespread coal groups. The potential for coalbed gas occurs in five groups, which in ascending order are the Black Creek, Mary Lee, Pratt, Cobb, and Gwin (**Fig. 15)** (Pashin and Raymond 2004). The Mary Lee coal group is the most important for underground mining and CBM resources.

The petroleum system events chart (**Fig. 16)** shows interpreted timing of elements and processes related to hydrocarbon generation for the Pottsville coal petroleum system. The Pottsville coals are self-sourcing gas reservoirs. Coal gas was generated primarily through thermal maturation of coal during the late Paleozoic Era (Hatch and Pawlewicz 2007).

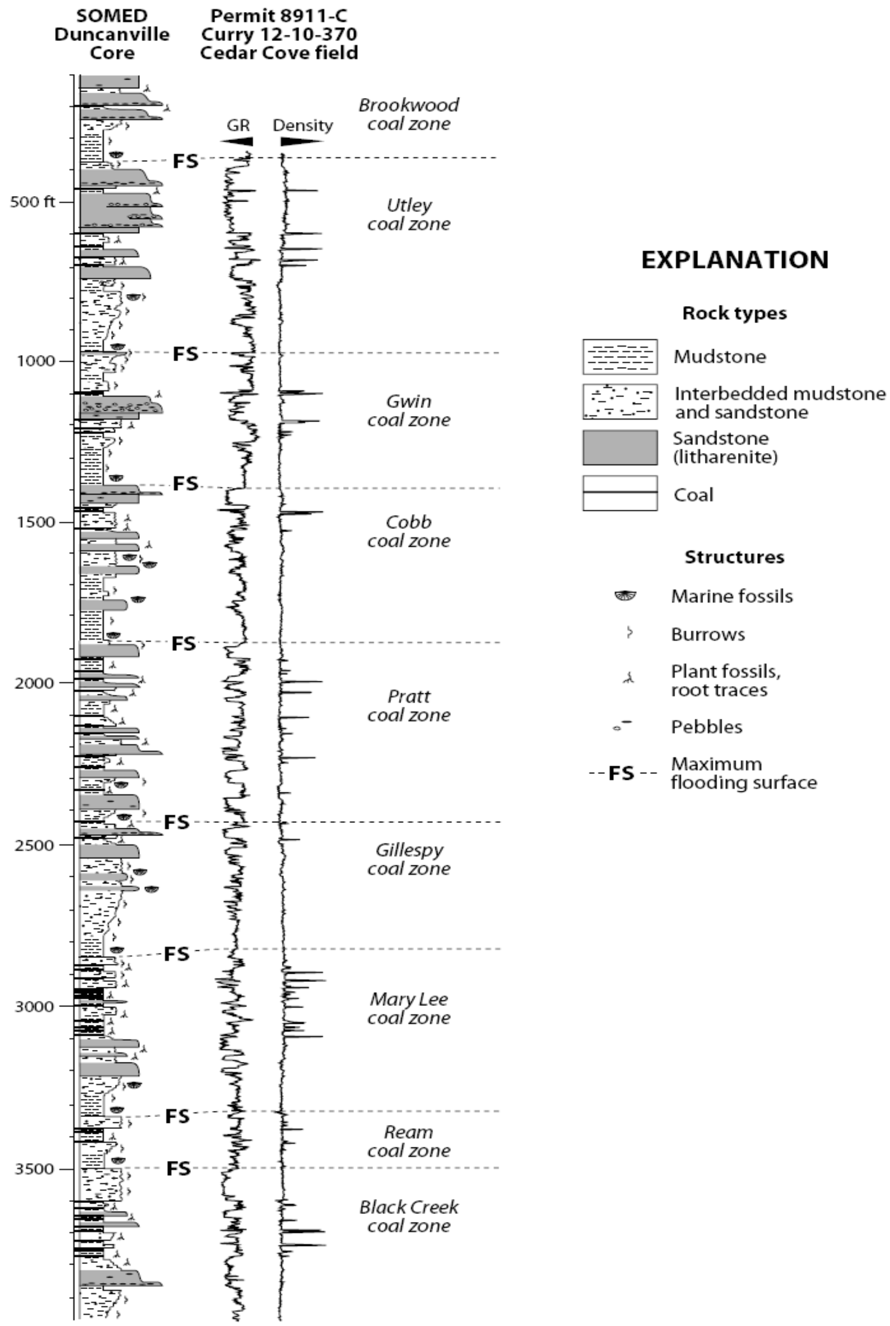


Fig. 15—Core description and geophysical well log of the upper Pottsville formation in Cedar Cove Field showing coal zones and fourth–order maximum flooding surfaces bounding cyclotherms (from Pashin et al. 2004).

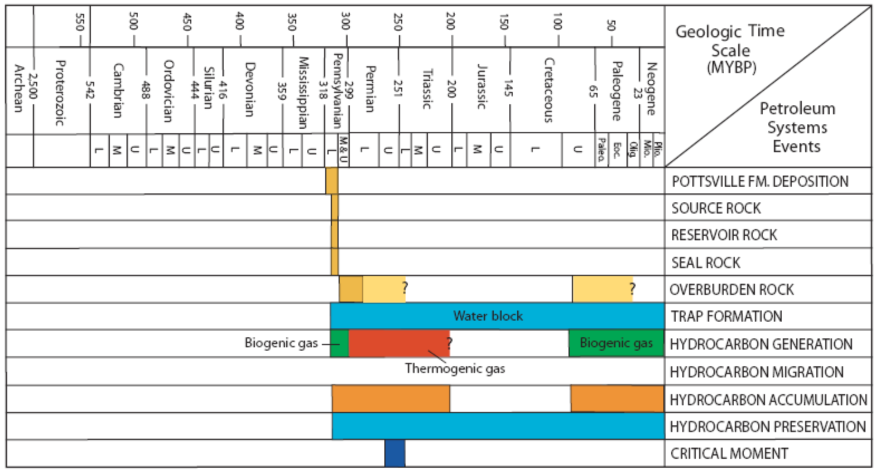


Fig. 16—Petroleum system events chart for the Pottsville formation, Black Warrior basin (from Hatch and Pawlewicz 2007).

Structural Setting of Black Warrior Basin

In a clockwise direction, starting in northernmost Alabama, the Black Warrior basin is bounded by the following provinces: Cincinnati arch, Appalachian basin, Birmingham anticlinorium, Louisiana-Mississippi salt basins, and the Mississippi embayment part of the Illinois basin (**Fig. 17)** (Ryder 1995).

The CBM fairway in the Pottsville formation can be characterized simply as a syncline that plunges southwestward toward the Ouachita orogenic belt and contains numerous superimposed folds and faults. Folds of the Appalachian thrust belt that are superimposed on the southeast margin of this syncline include the Sequatchie anticline, the Coalburg syncline, and the Blue Creek anticline (Hatch and Pawlewicz 2007).

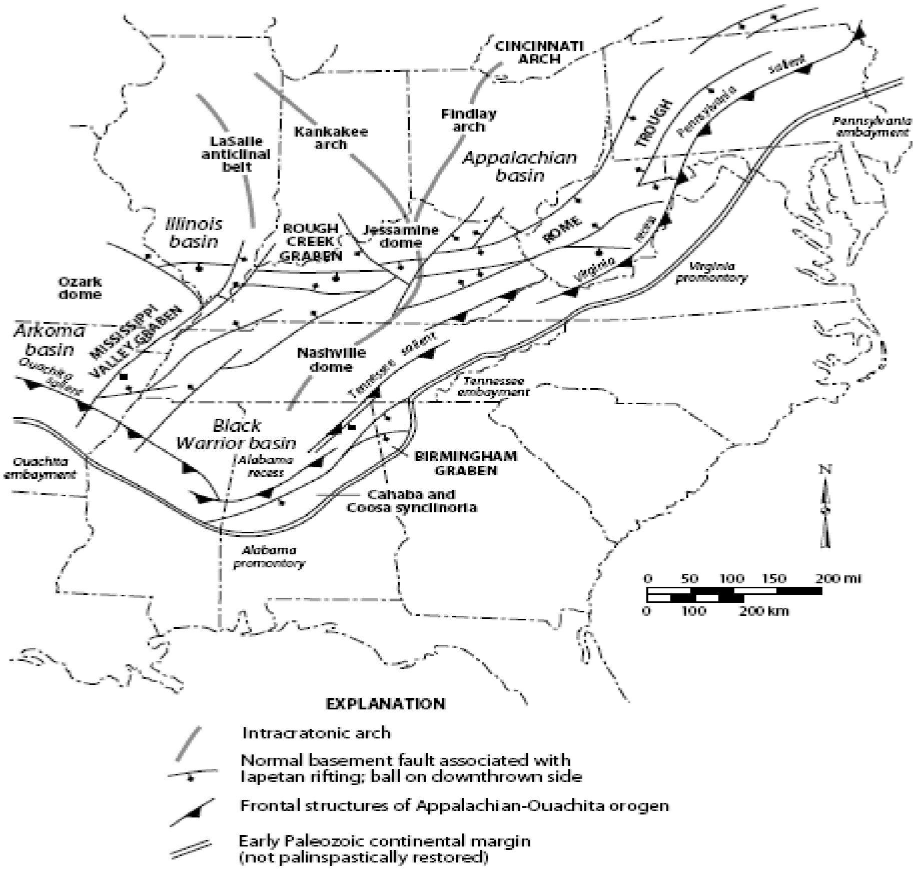


Fig. 17—Tectonic setting of the Black Warrior basin (from Pashin et al. 2004).

The southwest-plunging syncline of the Black Warrior basin is broken by normal faults that generally strike northwestward **(Fig. 18)**. Dip of the faults is generally between 50 and 70°, and the faults form a horst-and-graben system in which approximately 60% of the mapped faults dip southwestward and the remaining faults dip northeastward (Pashin el at. 2004).

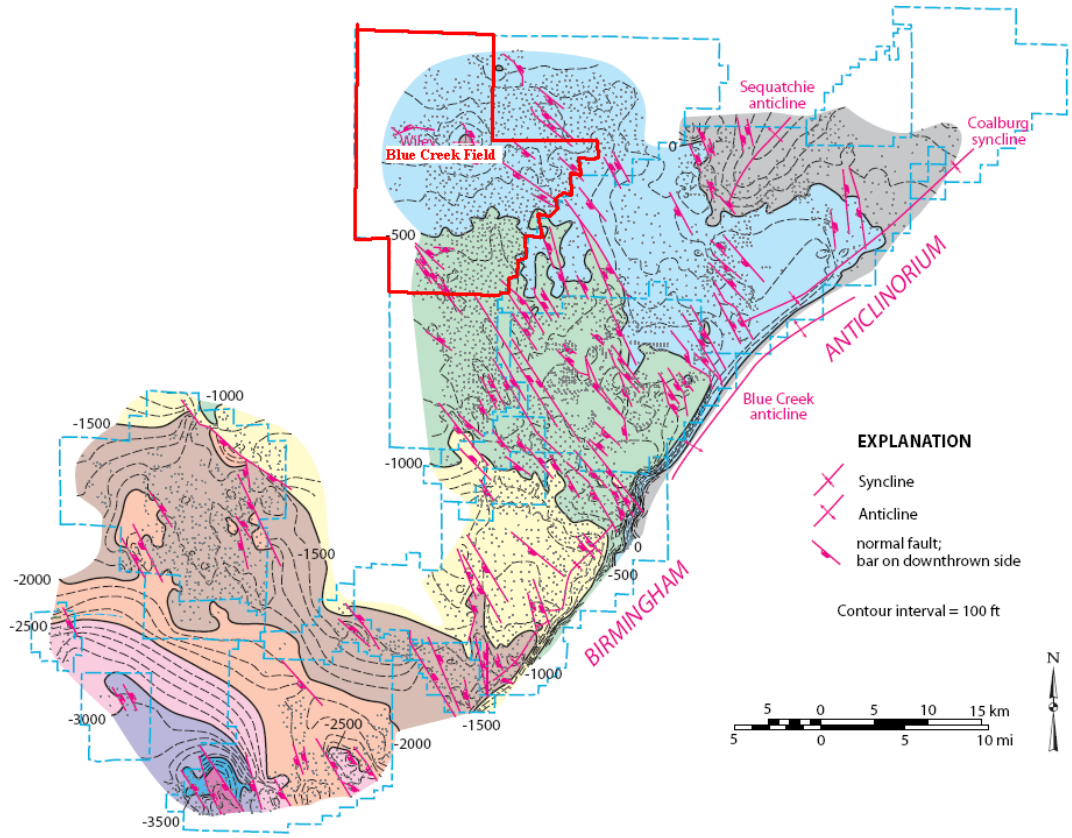


Fig. 18—Generalized structural contour map of the top of the Pratt coal zone in the Black Warrior basin (from Pashin et al. 2004).

Fig. 19 is a generalized elevation contour map of the unconformity separating the Pennsylvanian Age Pottsville formation and Upper Cretaceous strata in the southeastern part of the Black Warrior basin, Alabama. The Pottsville formation is exposed at the surface in the eastern one-third of the Black Warrior basin and is overlain by Cretaceous strata of the Mississippi embayment in the western two-thirds of the basin. All normal faults in the Black Warrior basin terminate at the regional unconformity at the base of the Cretaceous strata, which crop out 300 to 600 ft above sea level. Where present, Cretaceous strata intercept meteoric recharge, causing higher salinity in the underlying Pottsville strata.

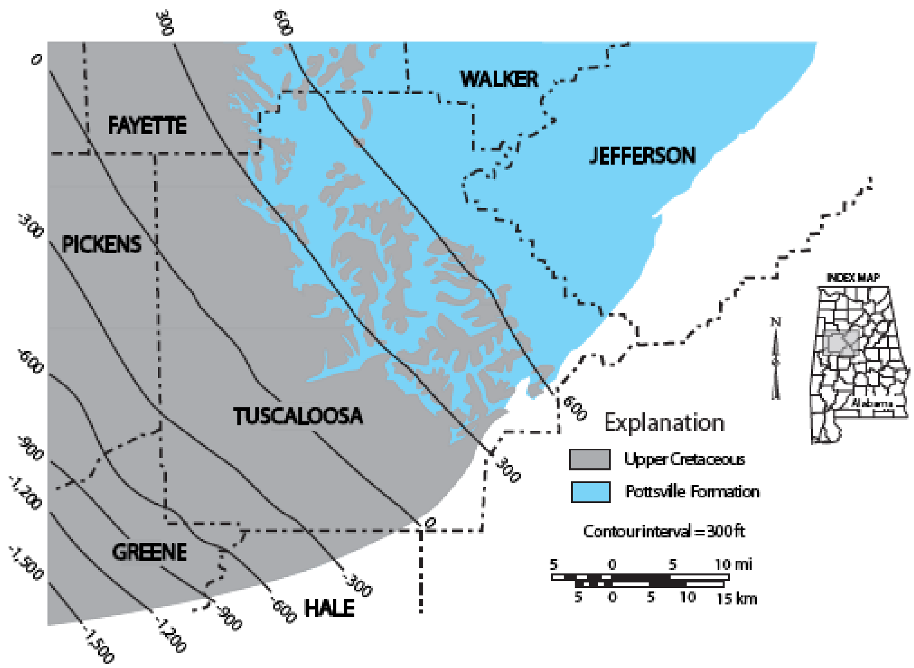


Fig. 19—Generalized elevation contour map of the unconformity separating the Pennsylvanian Pottsville formation and Upper Cretaceous strata in the southeastern part of the Black Warrior Basin, Alabama (from Hatch and Pawlewicz 2007)

Natural fractures in the Pottsville Formation include joints, cleats, and fault-related shear fractures (Pashin et al. 2004). Vertical joints are widespread in shale and sandstone and are typically spaced between 0.5 and 10 m. Closely spaced (0.5 to 2.5 cm) joints in coal are called cleats and are a primary control on aquifer and reservoir quality in the Pottsville coals. Face (dominant) cleats strike N62°E, which is 15° east of the regional systematic joints in noncoal rocks. Face cleats in the localized fracture system along the southeast margin of the basin strike N36°W (**Fig. 20**) (Pashin et al. 2004).

The development of joints and cleats in the Pottsville formation is the result of regional tectonic stresses as well as internal stresses generated by devolatization of organic matter associated with conversion of peat to coal during thermal maturation (Pitman et al. 2003). Cleats in coal have kinematic apertures that are approximately 1 mm wide. Fractures and cleats cause permeability anisotropy as high as 8:1 with greatest flow in the systematic joint direction. Compared to the Pratt coal zone, the Black Creek coal zone has a weaker permeability anisotropy (**Fig. 21**) (Pashin et al. 2004).

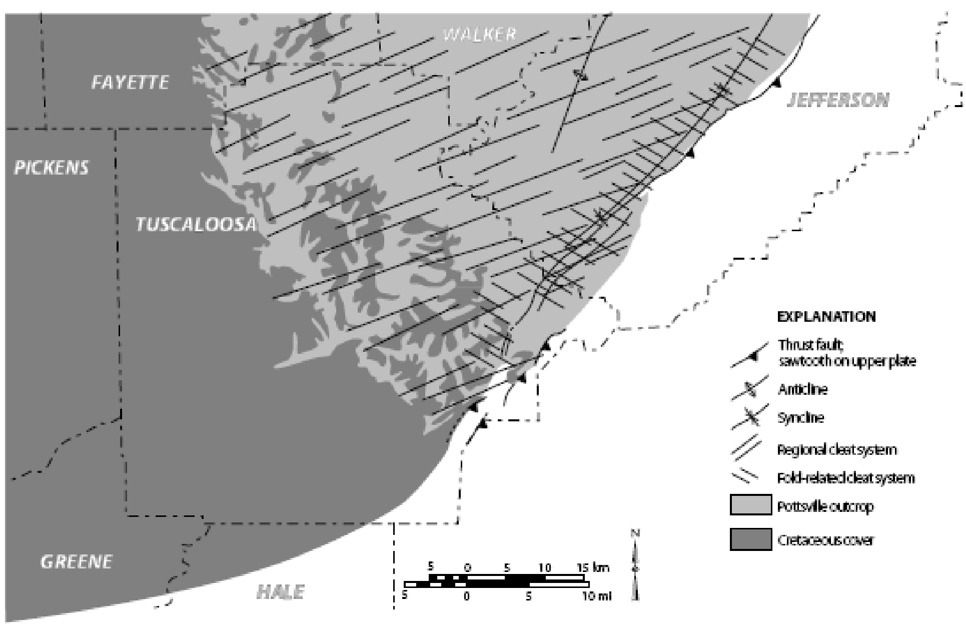


Fig. 20—Cleat system in the eastern Black Warrior basin of Alabama (from Pashin et al. 2004).

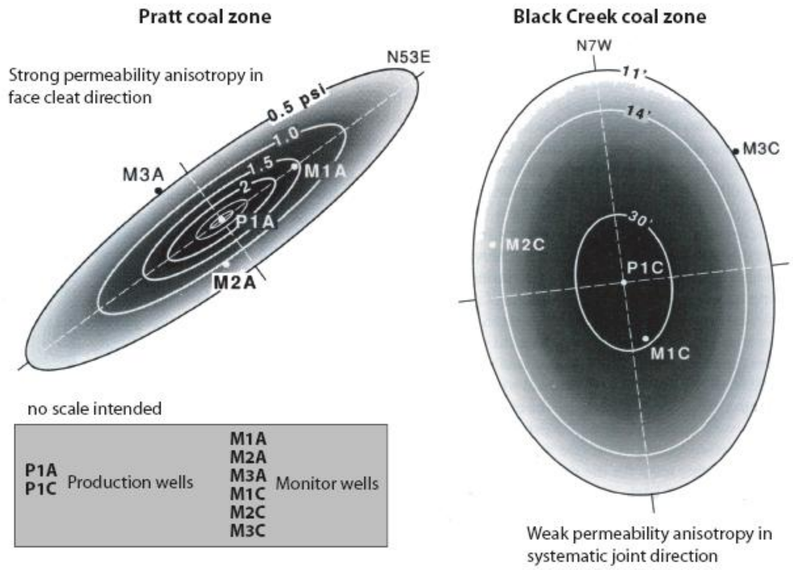


Fig. 21— Permeability anisotropy of the Pratt and Black Creek CBM reservoirs of the Oak Grove field (from Pashin et al. 2004).

Hydrologic Setting of Black Warrior Basin

Pottsville coalbeds are aquifers that must be dewatered (depressurized) to enable gas desorption and production. Produced coalbed water must be disposed in accordance with water composition and state regulations. The Pottsville formation of the Black Warrior basin is an unconfined aquifer (U.S. Environmental Protection Agency 2004). The matrix permeability of Pottsville formation is low for water. For example, sandstones in the CBM fields have permeability of only 0.03 to 0.06 md (Pashin et al 2004). Therefore, water flows within a system of faults, joints, and cleats. In the early 1990s, fresh water production from CBM wells was reported at rates as great as 30 gallons/minute (U.S. Environmental Protection Agency 2004). On the basis of slug tests, the Pottsville formation coals have permeability of 10 and 100 md, which indicate a poorly transmissive system. At a confining pressure of 450 psig, the mean cleat porosity is 1.2% and the absolute permeability is approximately 4.6 md (Gash 1991). Permeability in the coal of the Pottsville formation is highly sensitive to stress (**Fig. 22**) (Mckee et al. 1988). The discrete fracture network (DFN) model for the Black Warrior basin indicates that the Pottsville hydrologic system is highly compartmentalized. Thick marine shale units function as sealing strata of each coal zone (Jin and Pashin 2008).

Composition of formation water produced from Alabama CBM wells ranges from less than 50 to more than 10,000 mg/L TDS (Pashin and Frank 1997). Stiff diagrams (**Fig. 23**) show the composition of formation water in the Pottsville Formation (Pashin et al. 2004). Generally, water quality decreases with increasing depth. Waters exceeding 10,000 mg/L TDS occur below 3,000 ft in areas near deep vertical faults, suggesting upwelling from deeper, more saline zones (Pashin and Frank 1997). Also, salinity is high beneath the Cretaceous unconformity.

Most of the meteoric water recharge to the Pottsville aquifer is precipitation that infiltrates from the surface, but some recharge occurs where stream flow enters the outcrop and moves laterally into the aquifer along folded anticlinal beds (**Fig. 24**). Discharge from the Pottsville aquifer is primarily from the dewatering of coalbeds due to mining and coalbed methane production (Pashin et al 2004).

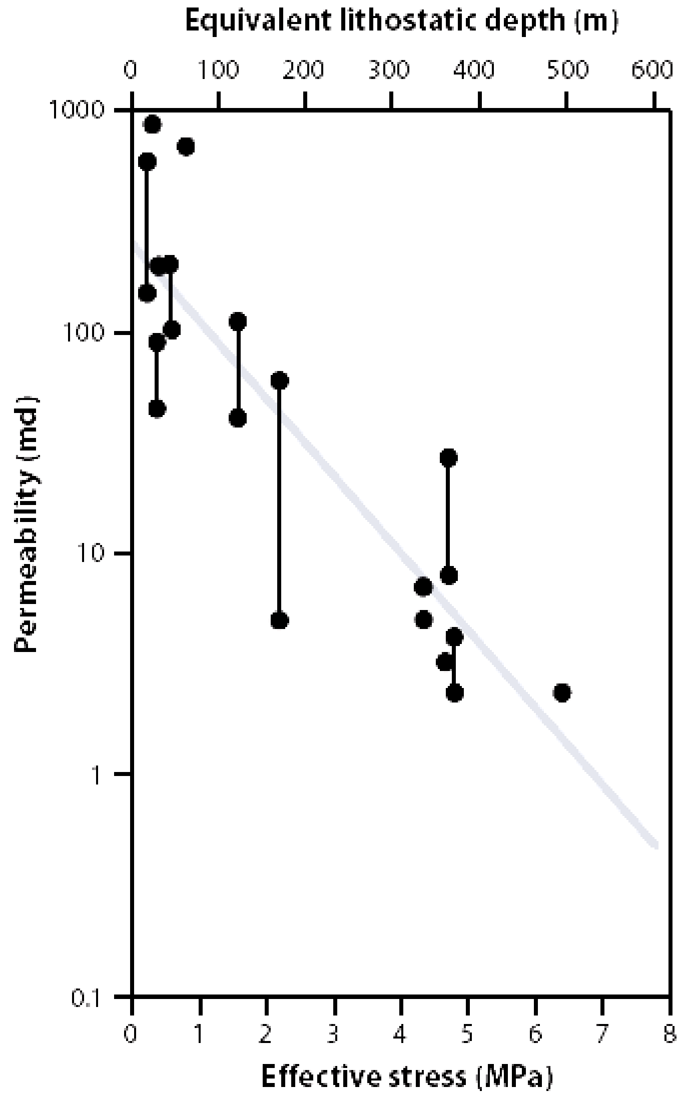


Fig. 22—Plot of permeability versus depth for coal in the eastern Black Warrior basin (from Pashin et al. 2004).

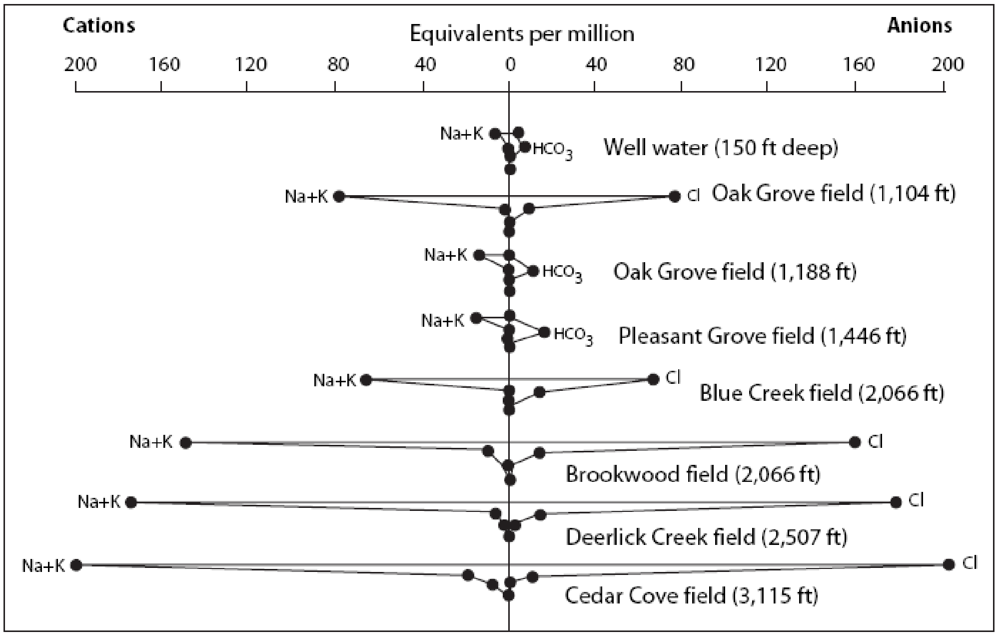


Fig. 23—Composition of Pottsville formation water (from Pashin et al. 2004).

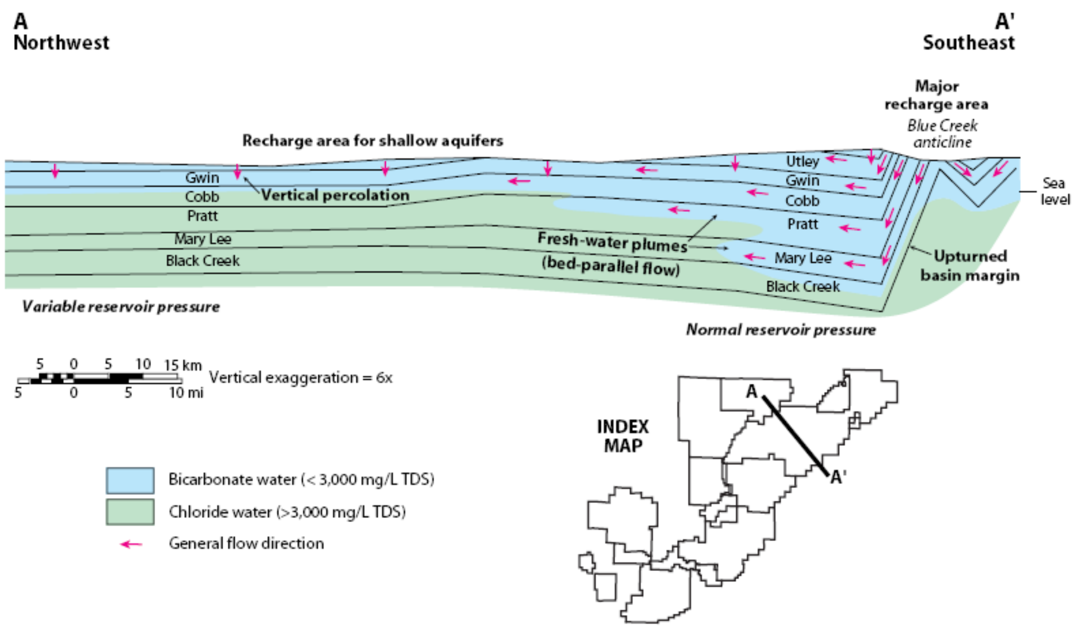


Fig. 24—Generalized structural cross section showing meteoric recharge areas and ground water flow patterns in the upper Pottsville formation (from Pashin et al. 2004).

BLUE CREEK COAL RESERVOIR CHARACTERIZATION

Coal reservoir properties are the key determinants of sequestration capacity and the quantity of CBM that is stored in the coal and that can be accessed through enhanced recovery. Most data of Blue Creek coal reservoirs are from Pashin et al. (2004). Coal quality data in Pashin et al. (2004) were compiled from the databases of the Geological Survey of Alabama and from new core and mine face samples acquired during that study. The coal quality and gas content data obtained from 58 coal samples donated by Jim Walter Resources, Incorporated, and El Paso were analyzed (Pashin et al. 2004). **Table 3** shows the samples from the Blue Creek field.

Table 3—Locality and Stratigraphic Information for Coal Samples in Blue Creek Field (Pashin et al. 2004).

Sample Number	Sample Thickness (ft)	Coal Zone	Latitude	Longitude
AL-TU-EPBC-1131.2	2.02	Pratt	33.42799	87.51589
AL-TU-EPBC-1690.2	1.87	Mary Lee	33.42799	87.51589
AL-TU-EPBC-2051.2	1.07	Black Creek	33.42799	87.51589

Coal Quality

Sorptive capacity of coal varies with coal rank. Coal rank in the Pottsville formation ranges from high-volatile B bituminous to low-volatile bituminous (Pashin et al. 2004) (**Fig. 25**). Until 2004, virtually all coalbed methane production in Alabama was from coal of high-volatile A bituminous rank or higher, which is the rank of coal in the Blue Creek field. An elliptical area having medium- and low-volatile bituminous coal of metallurgical quality is centered near the southeast margin of the Black Warrior basin. Moisture content in the bituminous coal is generally less than 3% (Pashin et al. 2004).

Gas storage capacity of coal varies inversely with inorganic or mineral content. Clay minerals, quartz, pyrite and calcite are the dominant mineral matter in Pottsville coal (Pashin et al. 2004). Ash content ranges from 2 to 30% (Winston 1990); mean ash content increases from 7% in the Black Creek coal zone to 15% in the Mary Lee coal zone (**Fig. 26)**. Total sulfur content of Pottsville coals ranges from 0.2 to 10.5% (Pashin et al. 2004).

Sorptive capacity of coal varies with maceral type and abundance. Generally, vitrinite and liptinite have greater sorptive capacities than does inertinite. Vitrinite content of the Pottsville coalbeds is commonly 70 to 95%. Inertinite content ranges from 5 to 35%, and liptinite content ranges from 0 to 5% (**Fig. 27**) (Pashin et al. 2004). The high vitrinite (Type III kerogen) content indicates that the coal is a gas-prone source rock with limited potential for oil generation.

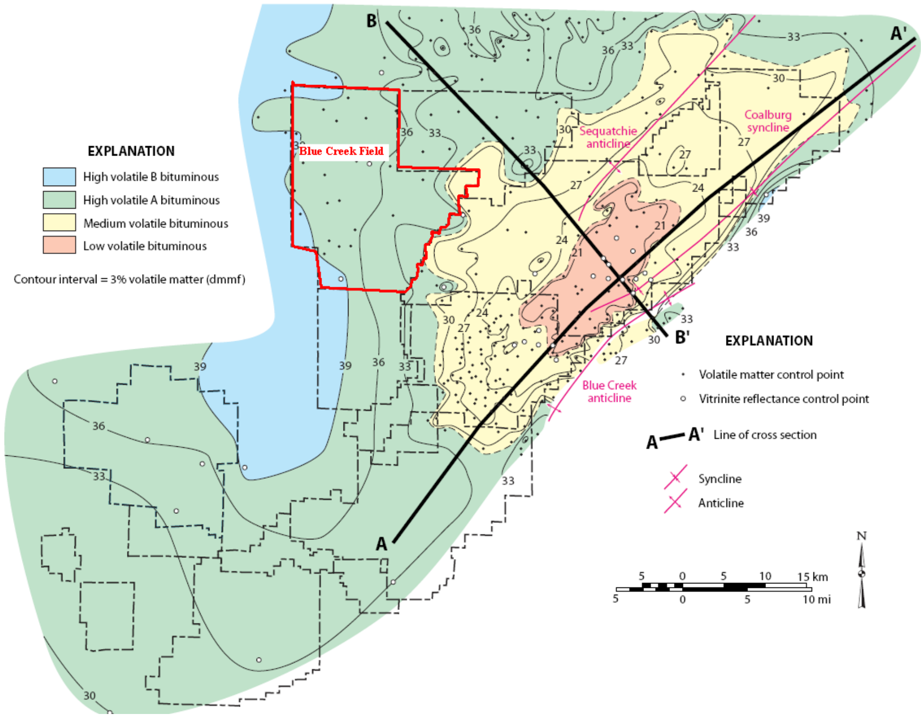


Fig. 25—Coal rank in the Black Warrior based on volatile matter and vitrinite reflectance data from the Mary Lee coal zone (from Pashin et al. 2004).

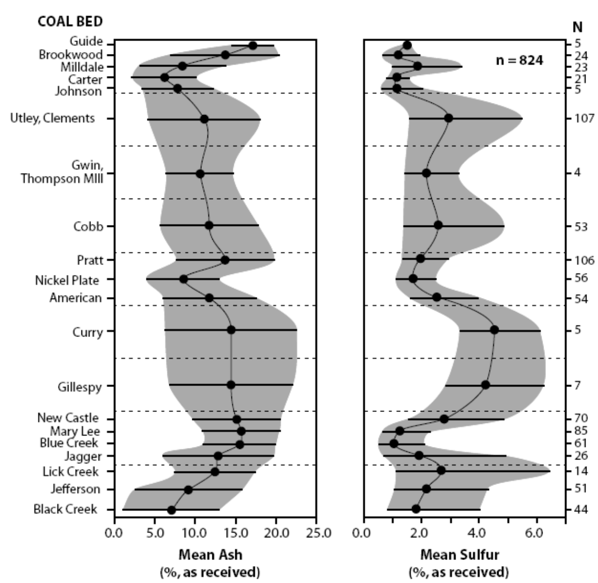


Fig. 26—Relationship of ash and sulfur content to stratigraphy in the Pottsville formation, Black Warrior Basin (from Pashin et al. 2004).

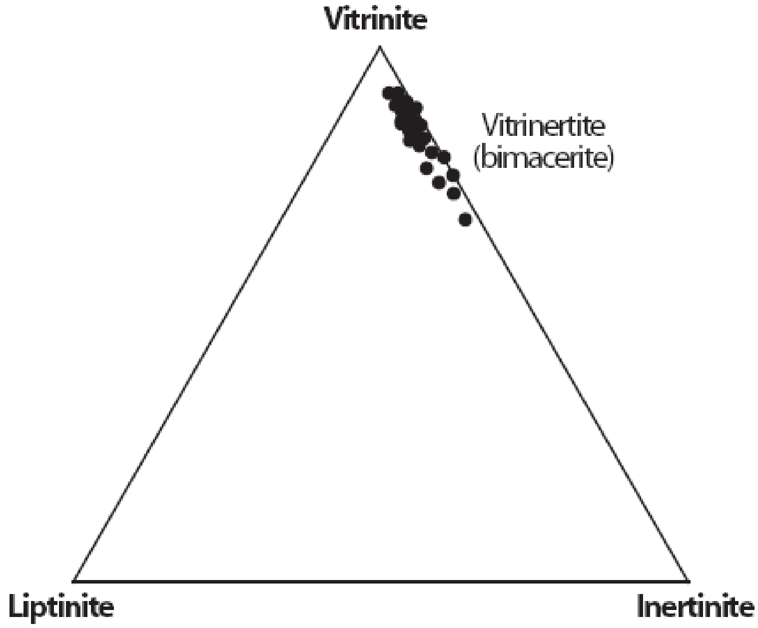


Fig. 27—Ternary plot showing maceral composition of Pottsville coal samples (from Pashin et al. 2004).

Gas Content and Composition

The original gas in place is highly variable in Pottsville coalbeds of the Black Warrior basin. It ranges from nearly 0 to more than 600 scf/ton on an ash-free basis (Winston 1990). Although gas content typically increases with depth, gas content of coal in Black Warrior basin may vary by more than 300 scf/ton within a single coal zone (**Fig. 28**). Gas content in Oak Grove and Brookwood fields is greater than 400 scf/ton whereas lower gas content is typical of other areas. Also, gas content is related to coal quality and depth of reservoir. Low-rank coals in deep layers have lower gas contents than high-rank coal (Colson 1991). **Table 4** and **5** show the gas composition of coal samples from Blue Creek field.

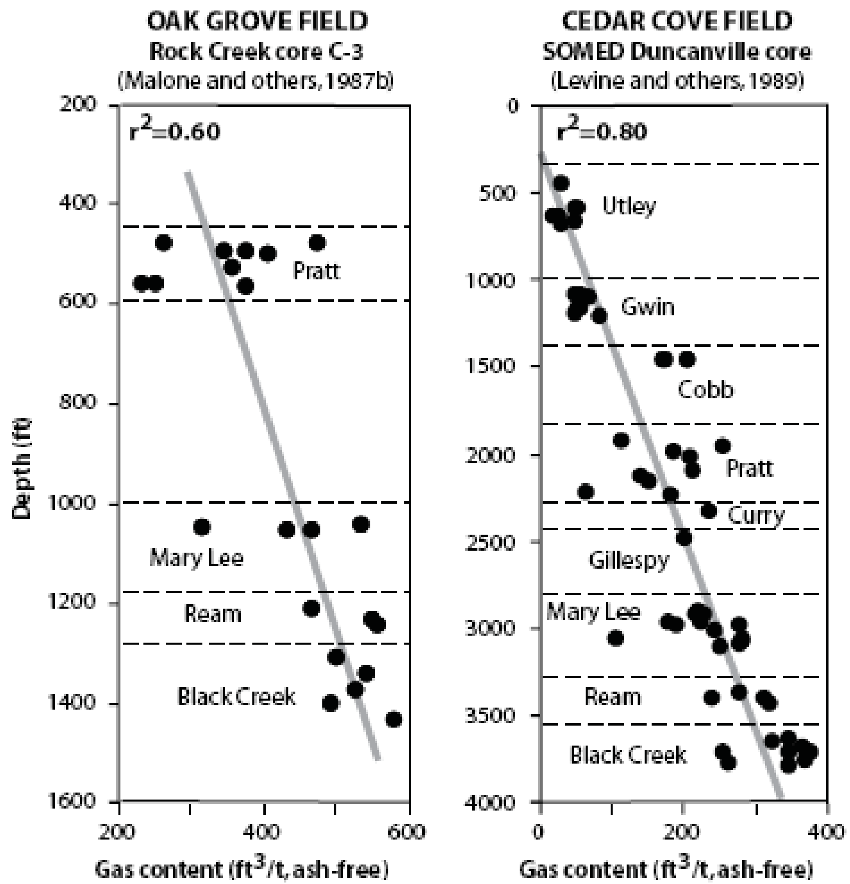


Fig. 28—Plots of gas content vs. depth for Pottsville coal core samples from 2 wells in the Black Warrior basin (from Pashin et al. 2004).

Table 4—Proximate Analysis of Coal Samples from Blue Creek Field (Pashin et al. 2004).

Sample Number	Moisture (%)	Ash (%)	Fixed Carbon (%)	Volatile Matter (%)	Calorific Value (Btu/lb)
AL-TU-EPBC-1131.2	2.35	9.31	54.78	33.56	13,462
AL-TU-EPBC-1690.2	2.34	18.04	51.07	28.56	11,946
AL-TU-EPBC-2051.2	1.66	2.77	62.26	33.31	14,767

Table 5—Ultimate Analysis for Coal Samples in Blue Creek Field (Pashin et al. 2004).

Sample Number	C (%)	H (%)	N (%)	O (%)	Mineral Matter (%)	Total S (%)	Sulfatic S (%)	Organic S (%)	Pyritic S (%)
AL-TU-EPBC-1131.2	79.67	5.11	1.64	2.49	11.15	1.56	0.03	0.83	0.70
AL-TU-EPBC-1690.2	71.58	4.59	1.61	3.07	20.32	0.68	0.02	0.51	0.15
AL-TU-EPBC-2051.2	87.50	5.36	1.75	1.61	3.57	0.96	0.02	0.87	0.08

CH_4, CO_2 and N_2 Adsorption/Desorption Isotherms

Sorption isotherm for carboniferous coal is predicted by Langmuir adsorption theory (Busch et al. 2003). Isotherms of individual coal samples indicate that, above 500 psi, coal holds about twice as much CO_2 as CH_4 and about twice as much CH_4 as N_2 (**Fig. 29**). The sorption capacity of coal decreases with increasing temperature. **Table 6** shows desorption analyses of the composite sample of three sidewall cores from well AL-TU-EPBC in Blue Creek field, which indicates the sorptive capacities of CH_4, CO_2, and N_2 coal for the three coal zones: Pratt, Mary Lee, and Black Creek (Pashin et al. 2004). These data were collected at the temperature of 80^0F, which is the average temperature of reservoirs in Blue Creek field. Pashin et al. (2004) indicated that the Langmuir volume of CO_2 averages 1,000 scf/ton, regardless of rank, on an as received basis. Langmuir volume for CH_4 ranges between 400 and 650 scf/ton, as-received, for high-volatile bituminous A coals. For N_2, Langmuir volume is generally from 200 to 450 scf/ton at that same rank. Langmuir pressure at high-volatile bituminous A rank ranges from 175 to 300 psi for CO_2 and 350 to 870 psi for CH_4. Langmuir pressure is estimated to be from 320 to 1540 psi for N_2.

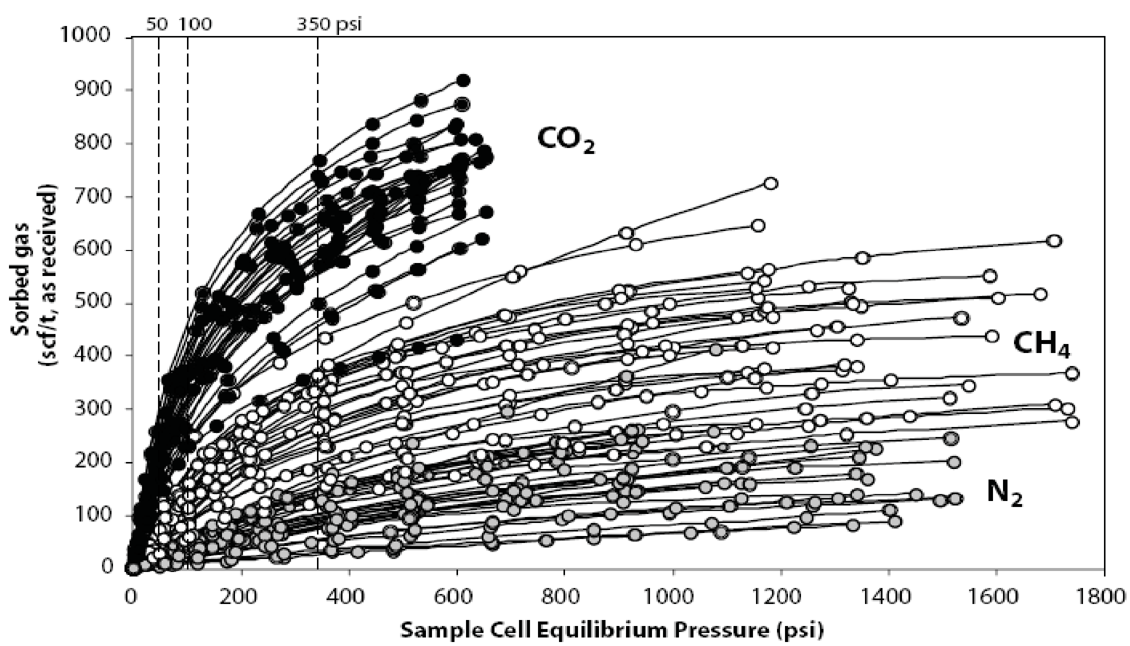


Fig. 29—Isotherm plots showing the sorptive capacities of various Pottsville coal samples for different gas species (from Pashin et al. 2004).

Table 6—Desorption Analysis of Sample From Blue Creek Field (Pashin et al. 2004).

Sample Number	Gas	Adsorption @ 50 psi AR (scf/t)	Adsorption @ 100 psi AR (scf/t)	Adsorption @ 350 psi AR (scf/t)
AL-TU-EPBC-1131.2	CH_4	47.8	102.2	238.3
	CO_2	191.1	311.1	597.4
	N_2	16.9	28.8	77.8
AL-TU-EPBC-1690.2	CH_4	58.5	101.4	228.6
	CO_2	198.3	313.6	586.8
	N_2	11.2	21.7	73.3
AL-TU-EPBC-2051.2	CH_4	39.2	79.7	195.4

Rock Mechanical Properties

Rock mechanical properties of coal affect the volume change of the reservoirs, leading to the changes of production and sequestration . Adsorption or desorption of gas and stress changes may cause coalbed matrix shrinkage or swelling, leading to changes in porosity and permeability. Several models describe these effects, including that published by Palmer and Mansoori in 1996 (Pekot 2003). The rock mechanical properties of coal are needed for the model to simulate considering matrix shrinkage and swelling.

Table 7—Coal Cleat Compressibility for Pottsville Coals in Different Fields of the Black Warrior Basin (Sparks et al. 1995).

Area	Value (1/psi)	Method
Cedar Cove Area	4.74E-4	Derived from stress vs. permeability field data
Oak Grove Area	4.69E-4	Derived from stress vs. permeability field data
Rock Creek Area	4.3E-3	Interference test using four wells
Blue Creek Area	1.0E-4 to 2.0E-4	Lab Testing by TerraTek; performed under simulated production condition
Blue Creek Area	1.0E-3 to 1.0E-4	Lab Testing by TerraTek; performed under hydrostatic compression

Table 7 shows coal cleat compressibility of different fields in Black Warrior basin. Most of the rock mechanics properties were from Rock Creek field. For samples from Blue Creek field, the compressibility ranges from 0.0001 to 0.0002 (1/psi) (Sparks et al. 1995).

RESERVOIR SIMULATION MODEL

Modeling Approach

Several commercial and research models have been developed to simulate CO_2 sequestration/ECBM production. Conventional oil and gas numerical models can be used for primary CBM recovery process. Difference of mole concentration for gas species leads to diffusion and adsorption in the cleat system. Diffusion is controlled by a standard Fickian model for diffusion in free gas. Adsorption is controlled by Langmuir model. CBM numerical simulators used for CO_2/flue gas injection CBM recovery process should include the following features (Law et al. 2002): A brief explanation of the need for a a particular feature follows:

- A dual porosity system

  Coal seams are characterized by two porosity systems: uniformly distributed natural fractures (cleats) and matrix blocks containing a highly heterogeneous porous structure.

- Darcy flow of gas and water in the natural fracture system

  Flow in the fracture system in coal (cleat) is described by Darcy flow, however, the absolute permeability appearing in Darcy's law is not constant but varies in situ with the change in the net overburden stress and with effects associated with desorption and adsorption of gas in the matrix.

- Pure gas diffusion and adsorption in the primary porosity system

  Difference of mole concentration for gas species leads to diffusion and adsorption in the cleat system. Diffusion is controlled by a standard Fickian model for diffusion in free gas. Adsorption is controlled by Langmuir model.

- Coal shrinkage due to methane desorption and swelling due to CO_2 sorption on coal

  As gas is desorbed, matrix volume shrinks which in turn allows cleats to open. Adsorption causes the matrix to swell as illustrated in ***(Fig. 30).***

- Pure and mixed gas adsorption

  Because ECBM involves desorption of methane and adsorption of CO_2, a fundamental requirement is to include different adsorption isotherms for these two gases. The model should characterize the adsorption behavior as a function of pressure, temperature and the concentration of species present in the reservoir.

- Pure and mixed gas diffusion

  Gas phase diffusion values are given for a specified component that describes matrix (coal) to fracture (cleat) mass transfer. The overall mass transfer rate from matrix to fracture will be a product of a diffusion coefficient with an internally determined shape factor.

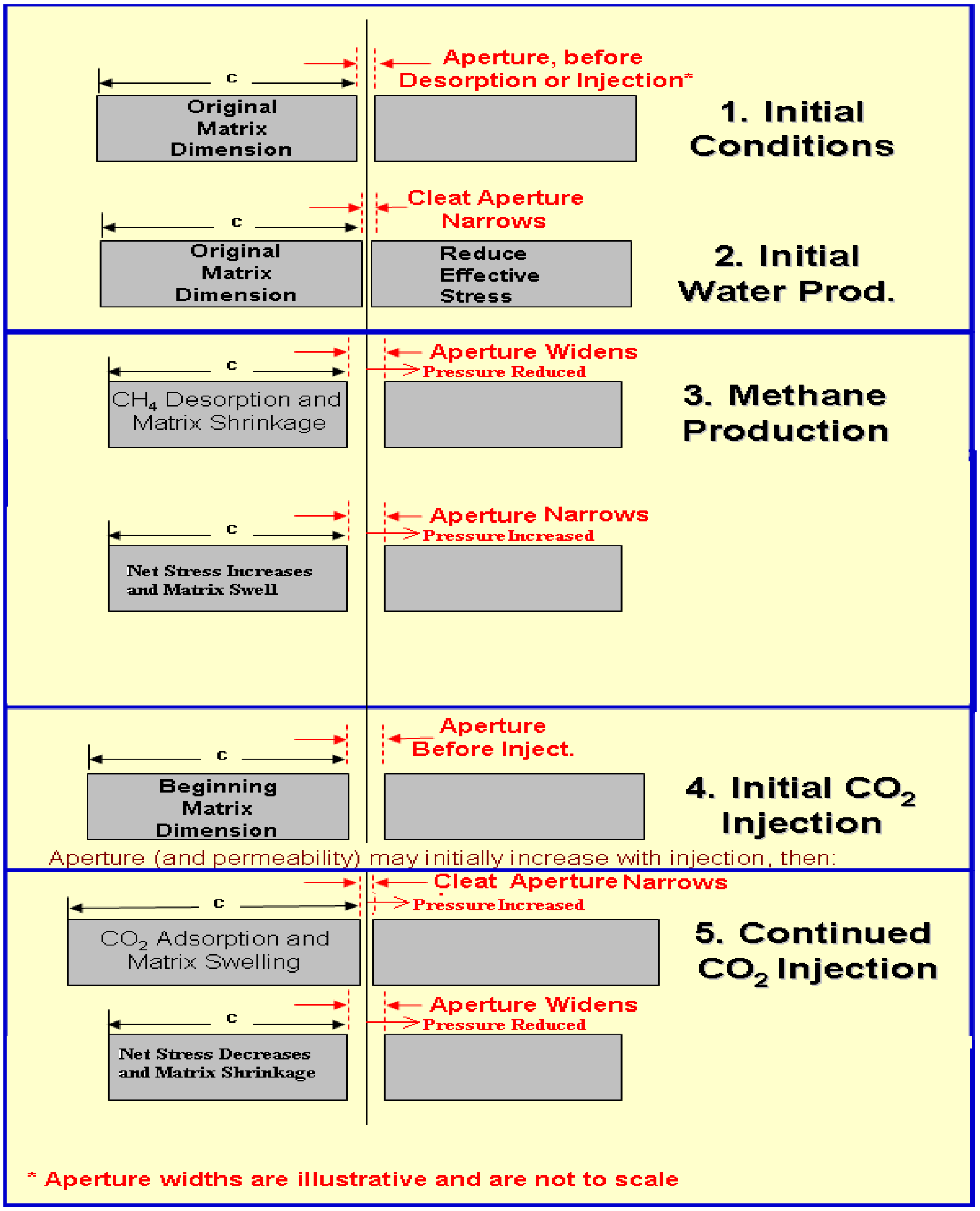


Fig. 30—Matrix swelling and shrinkage effects according to adsorption and desorption of and compressibility of coal (after Ayers 2009*).

For this research project, I used the coalbed simulator, GEM, developed by Computer Modelling Group (CMG) Ltd. GEM is a three-dimensional, finite-difference, multiphase,

* Personal communication, 20, July 2009

dual-porosity, compositional simulator. GEM is capable of modeling CBM reservoir performance under primary and/or enhanced recovery scheme. I selected Peng and Robinson equation of state (EOS) (Peng and Robinson 1976) to calculate the necessary thermodynamic functions in a compositional fluid model description.

I used Palmer and Mansoori (1996) model to evaluate the effects of matrix shrinkage and swelling. Fig. 30 illustrates that pressure reduction results in two competing effects, pore closure from compressibility effects and pore enlargement from matrix shrinkage. Flow in the fracture system in coal is described by Darcy flow. However the absolute permeability appearing in Darcy's law is not constant but varies in situ with change in the net overburden stress and with effects associated with desorption or adsorption of gas in the matrix (Palmer and Mansoori 1996). Eqs. 1 through 5 provide the Palmer and Mansoori relationship, where k, k_i are the current permeability and initial permeability of the reservoir; ϕ, ϕ_i are the current porosity and initial porosity of the reservoir; c_f is the fracture pore volume compressibility (psi^{-1}); E, K, ν, and M are Young's Modulus, Bulk Modulus, Poisson's ratio and Axial Modulus respectively; p_L and ε_L are the Langmuir pressure and strain at infinite pressure, α is the relation parameter of porosity and permeability.

$$\frac{k}{k_i} = \left(\frac{\phi}{\phi_i}\right)^{\alpha} \quad \text{..(1)}$$

$$\frac{\phi}{\phi_i} = 1 + c_f (p - p_i) + \frac{\varepsilon_L}{\phi_i}(1 - \frac{K}{M})(\frac{p_i}{p_i + p_L} - \frac{p}{p + p_L}) \quad \ldots\ldots(2)$$

$$\frac{K}{M} = \frac{1}{3}(\frac{1+\nu}{1-\nu}) \quad \ldots\ldots(3)$$

$$M = E\frac{(1-\nu)}{(1+\nu)(1-2\nu)} \quad \ldots\ldots(4)$$

$$c_f = \frac{1}{\phi_i M} \quad \ldots\ldots(5)$$

Reservoir Grid Model

Using the GEM compositional reservoir simulator, I set up a multilayer reservoir simulation model to predict the behavior of CO_2 injection-CBM production. Because of the symmetry of the model, I used 1/8 of a 5 spot pattern composed of 11X11X5 grid cells with 40-acre well spacing (**Fig. 31)**. Because there are shale layers between the coal zones, I assigned a permeability of zero between these zones. Therefore, the zones have no crossflow, except in the study of multiple-layer completions. All other studies to evaluate the effects of injection and production rates, injector and producer well pressure constraints, components of injected gas, coal dewatering times, permeability anisotropy, and soaking time focus on the single-layer model (**Fig. 32**).

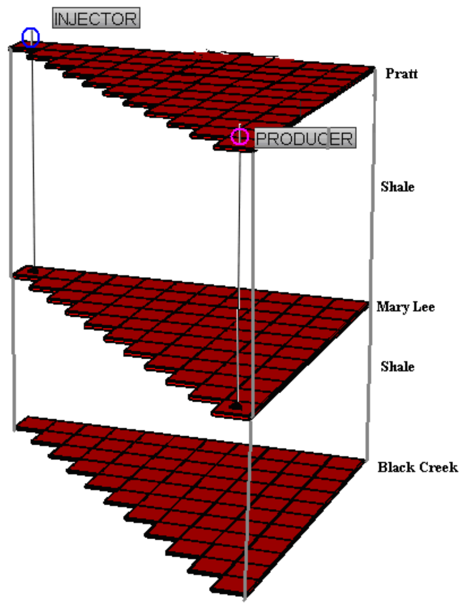


Fig. 31—3D model of 1/8 of a 5-spot pattern in Blue Creek field, 40-acre well spacing.

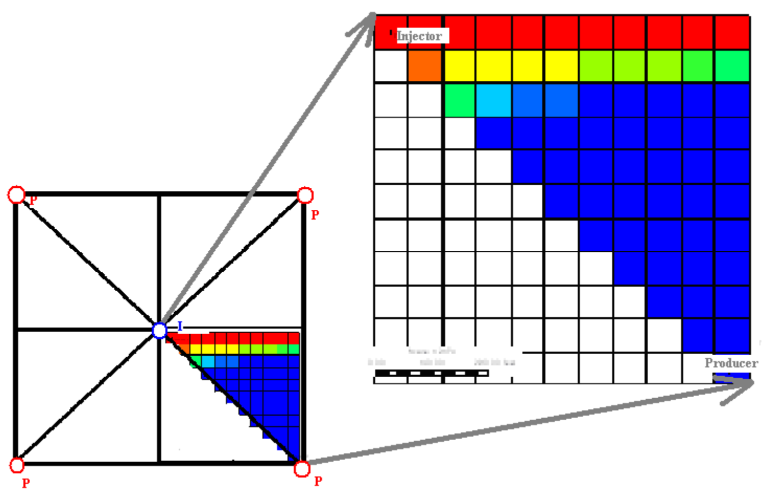


Fig. 32—2D model of 1/8 of a 5-spot pattern in Blue Creek field, 40-acre well spacing.

Selection of Properties Used for the Reservoir Simulation Model

To assess potential for CO_2 sequestration and ECBM production in the Blue Creek field, I collected coal static reservoir properties, rock mechanical properties of matrix, and Langmuir isotherm parameters for the Pratt, Mary Lee, and Black Creek coal zones, which have the greatest gas content. Average coal properties and reservoir parameters obtained from literature and data collected during this study are in **Tables 8 though 11**.

Pashin et al. (2004) indicated the depth, thickness, pressure, temperature, coal density, and gas phase diffusion time for individual coal zones for the Pratt, Mary Lee, and Black Creek in Blue Creek field of Black Warrior basin, Alabama. Pashin et al. (2004) also reported that the cleat spacing increases exponentially with thickness of the coalbed and that mean value of cleat spacing for the Mary Lee coal zone is 0.98 in. As a convenient starting point, I assumed that the coal reservoir is saturated with water, though initial water saturation, which may actually be lower than 100% in parts of Blue Creek field.

Table 8—Coal Static Reservoir Property Estimates for Individual Coal Zones and Used for Simulation (Pashin et al. 2004).

Property	**Value**		
	Pratt	**Mary Lee**	**Black Creek**
Depth (ft)	1,000	1,600	2,020
Thickness (ft)	6	8	4
Pressure (psi)	300	510	620
Temperature (^{o}F)	88.2	93.6	96.5
Cleat Spacing (inches)	0.55	0.98	0.28
Permeability (md)*	100	10	1

* Personal communication with Jack Pashin May, 21 2009

Table 9—Coal Static Reservoir Property Estimated for All Three Coal Zones.

Property	Value
Compressibility (fracture) (1/psi)[**]	0.001
Compressibility (matrix) (1/psi)[***]	$2x10^{-6}$
Water Density (lb/ft^3)	61.2
Water Viscosity (cp)	1.0
Initial Water Saturation (%)	100
Coal Density (lb/ft^3)	93.6
Gas Phase Diffusion Time for CBM (days)	5.8

Table 10—Estimated Rock Mechanical Properties of Matrix for All Three Coal Zones (Barba, 1996)

Rock Property	Pratt	Mary Lee	Black Creek
Poisson's Ratio ν	0.38	0.36	0.34
Young's Modulus E (10^6 psi)	0.4	0.6	0.8
ε_L	0.01	0.01	0.01
a (as in Eq. 5)	3	3	3

Table 11—Langmuir Isotherm Parameters for Gas Species as Indicated in Eq. 6.

Parameter	Value
Langmuir Volume for CH_4 (scf/ton)	411.1
Langmuir Pressure for CH_4 (psi)	322.3
Langmuir Volume for CO_2 (scf/ton)	787.9
Langmuir Pressure for CO_2 (psi)	161.2
Langmuir Volume for N_2 (scf/ton)	172.4
Langmuir Pressure for N_2 (psi)	1,570.2

The parameters for the Langmuir isotherm are shown in **Table 12** and the isotherms are shown in **Fig. 33.** The Langmuir coefficients were calculated from the lab data (Pashin

[**] Personal communication with Ian Palmer, May,05 2009

et al. 2004). The relationship between pressure and desorption of gas can be expressed in Eq. 6.

$$V = \frac{V_L p}{p_L + p} \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(6)$$

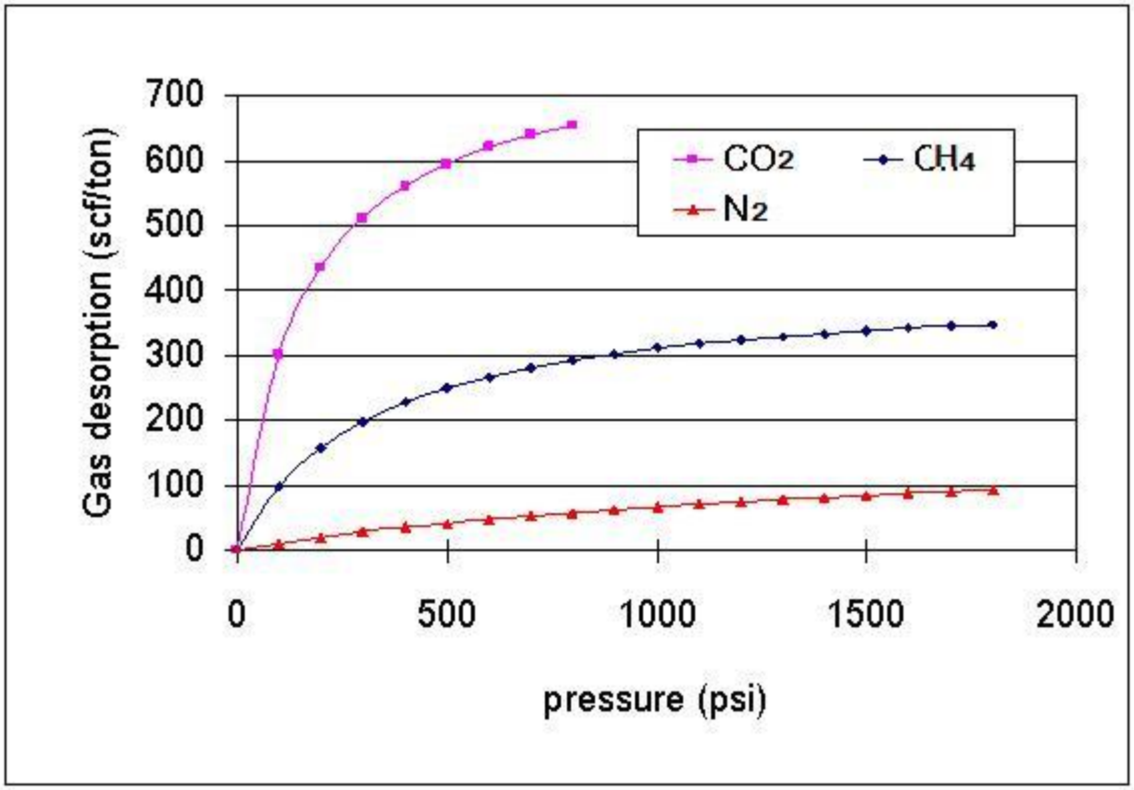


Fig. 33—Isotherm plots showing the sorptive capacities of different gas species in a coal sample for Blue Creek Field, Alabama (from Pashin et al. 2004).

RESERVOIR SIMULATION OF CO_2 SEQUESTRATION AND ENHANCED COALBED METHANE PRODUCTION

Based on the model described in the previous sections, I selected a base case scenario (**Table 12**) in an 80-acre 5-spot pattern (40-acre well spacing) at the beginning of this section. Then, I conducted seven additional studies to optimize the potential for CO_2 sequestration and ECBM production in Blue Creek field (**Table 13**). The following bulleted list indicated the type of study conducted and the rationale for the run:

1. Sensitivity study of the effects of injection and production rate (Because of the unique characteristics of CBM undesirable swelling or shrinkage may occur under different rates)
2. Sensitivity study of the effects of injection gas composition (Because different adsorption characteristics, flue gas may be a more economical source to injected for ECBM)
3. Sensitivity study of the effects of coal dewatering prior to CO_2 injection (Because dewatering can lower the reservoir pressure and may increase the volume of CO_2 that can be sequestered.)
4. Sensitivity study of the effects of permeability anisotropy (Because there are many folds and faults in Black Warrior basin, and the permeability affects the production and injection)
5. Sensitivity study of the effects of time to soak (Because the desorption and adsorption process are not instantaneous)

6. Study of multi-layer completion (Because Blue Creek field in Black Warrior basin has three productive coal zones)
7. Sensitivity study of the effects of well BHP at the injector and producer (Because we can affect adsorption characteristics by modifying the reservoir pressure)

Table 12—Constraints Conditions of the Base Case

Constraints	**Value**
Maximum Pressure at the Injector (psi)	1,500
Minimum Pressure at the Producer (psi)	50
Maximum Injector Rate (scf/D)	70,500
Maximum Producer Rate (scf/D)	35,250
Injected Gas Composition	100% CO_2
Percentage of CO2 in the Producer at Breakthrough	5%

Table 13—Studies to Investigate the Potential for CO_2 Sequestration and ECBM Production (all Other Parameters, Shown as Black Cella, the Same as Base Case Scenario, Shown in Red Italics)

Studies	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Injection rate (scf/D)	141,000	*70,500*	35,250			
Production rate (scf/D)	*70,500*	35,250	17,625			
Injection Gas Composition	*100% CO_2*	50% CO_2 50% N_2	10% CO_2 90% N_2			
Dewatering Time (Year)	*0*	2	4			
Permeability Anisotropy k_x:k_y	5	2	*1*			
Multi-Layer Completion	Pratt	*Mary Lee*	Black Creek	Pratt- Mary Lee	Mary Lee- Black Creek	Pratt- Mary Lee- Black Creek
Maximum BHP at Injector (psi)	*1,500*	1,000				
Minimum BHP at Producer (psi)	*50*	100	500			

CO_2 Sequestration/ECBM Production – Base-Case Scenarios

To investigate optimal reservoir performance during CO_2 sequestration and ECBM in Blue Creek field, I selected a base-case scenario of an 80-acre, 5-spot pattern (40-acre well spacing). A single-layer, Mary Lee completion was chosen as the base case, with producer constraints of BHP of 50 psi and production rate of 35 Mcf/D and injector constraints of BHP of 1,500 psi and injection rate of 70 Mcf/D (**Table 12**). The selections of the constraints are based on the reservoir pressure, the CO_2 that is required to be injected in the objectives and the adsorption isotherm curve. To start, I used pure CO_2 for the base case. Breakthrough was defined by CO_2 equal to or greater than 5% in the produced gas, because greater CO_2 production is not efficient for the storage of CO_2. I assumed that Blue Creek coal was 100% water saturated. The results of the modeling studies for the base case are shown in **Figs. 34 though 37**. All production and injection volumes in the figures are based on 1/8 of the 80-ac 5-spot pattern.

For the base case, the breakthrough time is 1,005 days. The base case simulation indicates that the Mary Lee coal zone in Blue Creek field can store 0.57 Bcf of CO_2 and recover 0.196 Bcf of CBM (Figs. 34 and 35, respectively) on a 40-acre well spacing; 60% of the pore volume of the coal was occupied by CO_2 at breakthrough. According to the reservoir pressure and gas adsorption thermal isotherm curve I calculated that CBM gas in place (GIP) in the Mary Lee coal zone of Blue Creek field is approximately 0.3 Bcf per 80 acres. Thus, the methane recovery factor of the base case is 66%. Cumulative water production of the base case was 21.96 Mbbl at breakthrough (Fig. 36), and the average water saturation had dropped to 44% (Fig. 37).

The CO_2 injection rate remains constant at 70 Mscf/D (Fig. 34), because the well bottomhole pressure (BHP) at the injector did not reach the constraint of 1,500 psi. Initial water production rate was 5.75 bbl/D (Fig 36). It decreased as the production rate of CBM increased. CBM production was initiated after week 12 (Fig. 35), and the production rate increased to more than 20 Mscf/day in Week 75 while daily water production had dropped to 1.79 bbl/D (Fig. 37). The increase in the rate up to this time should be due to pressure reduction and permeability increase due to CBM desorption. Then, the production rate decreases until breakthrough time when the CO_2 composition at the producer exceeds 5% (Fig. 35). The reduction of rate can be attributed to a localized swelling, since CO_2 is reaching the producer. Since the minimum well BHP at the producer is too low the production rate constraint cannot be reached.

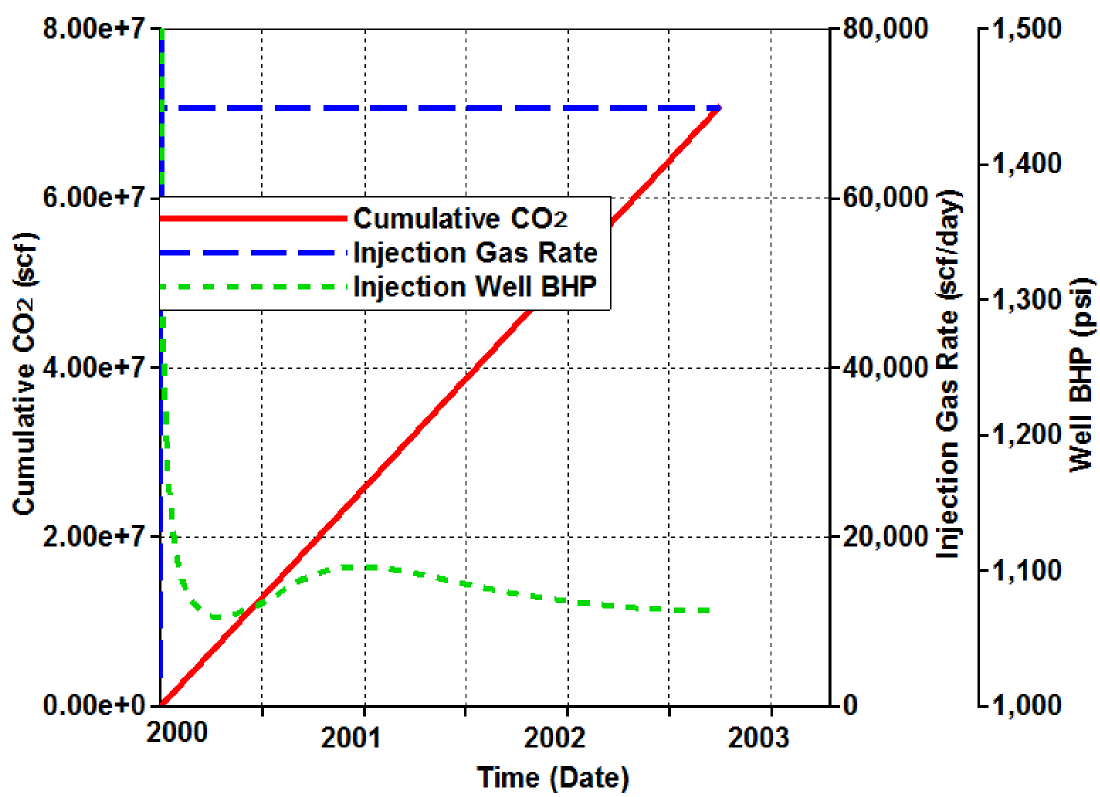


Fig. 34—CO_2 injection rate (scf/D), cumulative CO_2 sequestered (scf), and BHP (psi) for the base case based on 1/8 of 5-spot pattern, 40-acre well spacing.

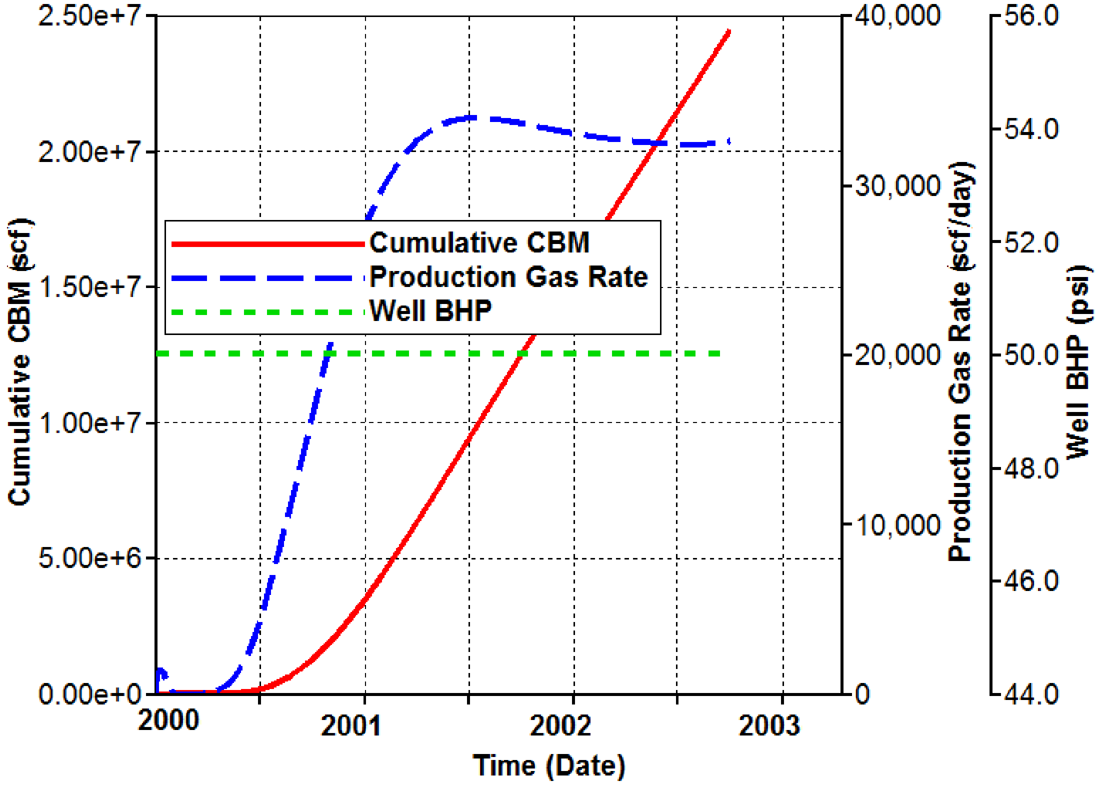


Fig. 35—Methane production rate (scf/D), cumulative methane produced (scf), and BHP (psi) for the base case based on 1/8 of 5-spot pattern, 40-acre well spacing.

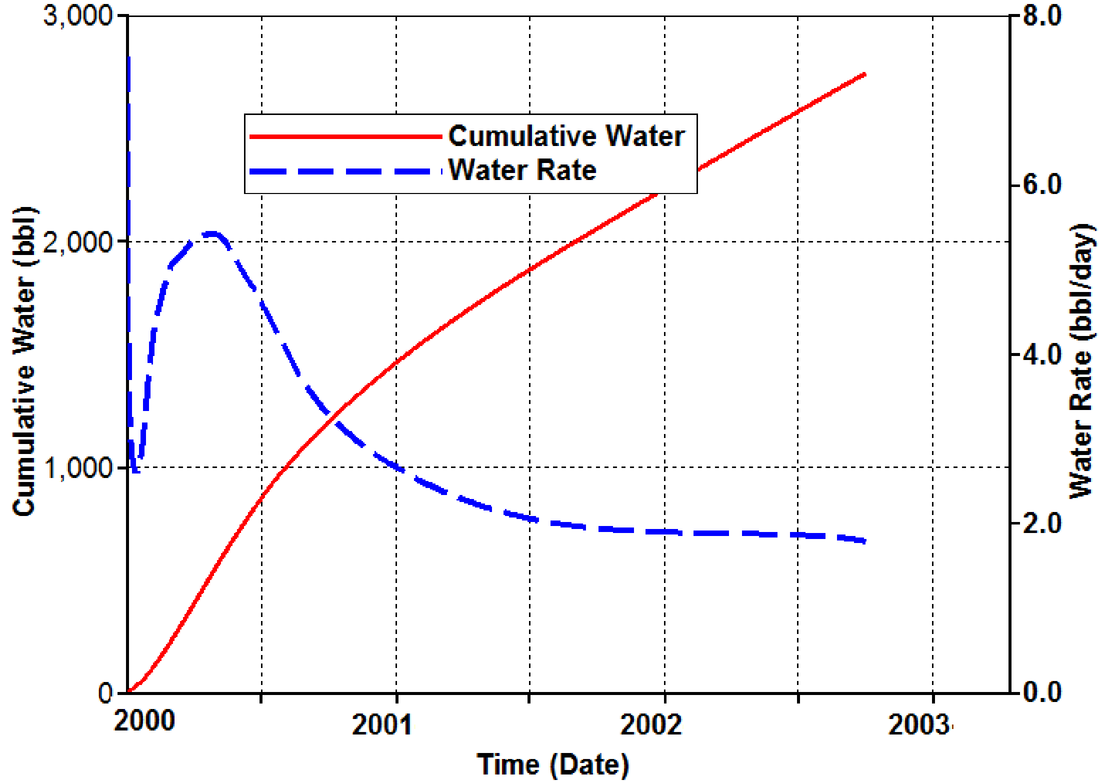


Fig. 36—Water production rate and cumulative water produced for the production well in the base case based on 1/8 of 5-spot pattern, 40-acre well spacing.

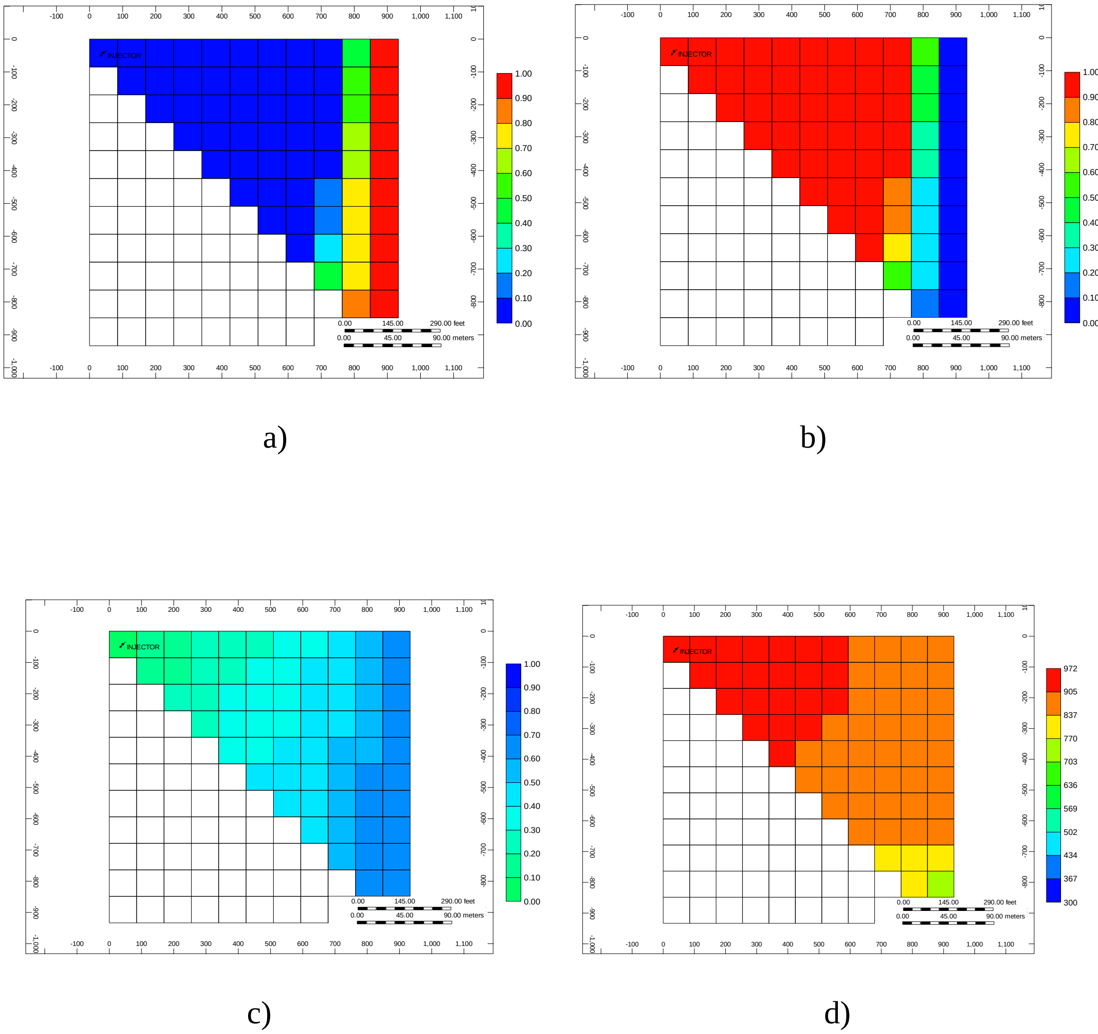


Fig. 37—(a) CO_2 mole fraction, (b) Methane mole fraction, c) water saturation in the fracture system, and d) pressure of the fracture system at breakthrough time (1,004.6 days) for the base case based on 1/8 of 5-spot pattern, 40-acre well spacing.

Fig. 37 shows colorfill maps of various reservoir properties at breakthrough. CO_2 has effectively displaced CBM in nearly 60% of the cells (Fig. 37b). The cells nearest the producer record greatest methane and water reduction (Figs. 37b and 37c, respectively). The initial pressure was approximately 500 psi; reservoir pressure ranged from 500 to 900 psi (Fig. 37d).

Sensitivity Study of the Effects of Injection Rate and Production Rate

To determine the effects of injection and production rates on performance of CO_2 sequestration and ECBM production in Blue Creek field, I conducted three case scenarios of an 80-acre, 5-spot pattern (40-acre well spacing) with pure CO_2. I wanted to find a proper ratio of injection rate to production rate to optimize the CO_2 sequestration and ECBM recovery, therefore I fixed the maximum production rate as the base case and changed the maximum injection rates to make the ratio of injection rate to production rate to be 4, 2, and 1. The injection rate constraints for cases designed to study the effects of injection rates are listed in **Table 14**. I chose these ratios based upon the adsorption isotherms of CO_2 and CBM for coalbed reservoir. The other conditions were chosen the same as those in the Base Case.

Table 14—Constraints for Constant Production Rate Cases

Cases	Maximum Injection Rate (scf/D)	Maximum Production Rate (scf/D)	Ratio of Injection Rate to Production Rate
Ratio 4:1	141,000	35,250	4
Ratio 2:1	70,500	35,250	2
Ratio 1:1	35,250	35,250	1

Table 15—Results of Production Constraints on 1/8 of 5-Spot Pattern, 40-Acre Well Spacing.

Cases	Cumulative CO_2 Injection (MMscf)	Cumulative CBM Production (MMscf)	Cumulative Water Production (bbl)	Break-though Time (Day)
Ratio 4:1	22.1	14.6	3,179.9	2,987
Ratio 2:1	70.9	24.5	2,745.3	1,005
Ratio 1:1	68.8	26.1	3,465.2	1,949

The breakthrough time ranged from 1,004 days to nearly 3,000 days **(Table 15)**. The simulation indicates that CO_2 volume that the Mary Lee coal zone in Blue Creek field can store range from 0.18 to 0.57 Bcf, on a 40-acre well spacing. The storage capacity for the 2:1 ratio is slightly higher than that for the 1:1 ratio, and the process for the 2:1 ratio case can be accomplished in half of the time. When the ratio of injection rate to production rate rise to 4:1, the cumulative CO_2 injection remains constant after time …. (provide) indicating that the target CO_2 rate cannot be achieved (**Fig. 38**).

Although the constraints of maximum production rate for the producers of the three cases are the same, CBM production for Mary Lee coal zone in Blue Creek field ranges from 0.12 Bcf to 0.21 Bcf, on 40-acre well spacing (**Fig. 39**). And the methane recovery factors range from 40% to 70%. The ECBM production of CBM for the 2:1 ratio is slightly lower than that for the 1:1 ratio, but the process for the 2:1 ratio case can be accomplished in half of the time. Lower ratio of injection rate to production rate, as less than 1:1, did not improve the CBM production much. Cumulative water production ranges from 21.96 to 27.71 Mbbl at breakthrough (Table 15).

The CO_2 injection rates remain constant at 70 Mscf/D and 35 Mscf/D, because the injector BHP did not reach the maximum constraints of 1,500 psi (**Fig. 40**). For 2:1 case, the BHP at injector remained at approximate 1,100 psi, which is higher than the BHP at the injector for lower injection rate case (Fig. 40). For 4:1 case, the injection stopped when the BHP at injector built up to the constraint 1,500 psi (Fig. 40).

Higher injection rates can increase the production rate of CBM but shorten the break through time, leading lower CBM production (Table 15). For the Ratio 2:1 and Ratio 1:1 cases in **Fig. 41**, the pressure at the producer builds up more when the injection rate is higher. For the Ratio 4:1 case, the pressure builds up to 750 psi because of the high injection rate and drops sharply when CO_2 cannot be injected.

Thus, I conclude that there is a maximum ratio of injection rate to production rate that CO_2 can be allowed in the coal matrix continuously until breakthrough. Below that ratio, the higher the injection rate is, the sooner the breakthrough happens. Since CO_2 can replace CBM for just half the volume of CO_2 injected, ratio of injection rate to production rate lower than 2:1 cannot improve the production of CBM. So the best strategy to accelerate and maximize storage and production would be to have an "adaptive" injection rate, which can be constrained to accommodate the supply of CO_2. However, from an operational view point, controlling the injection of steady stream of CO_2 may create a need for "temporary" storage of CO_2.

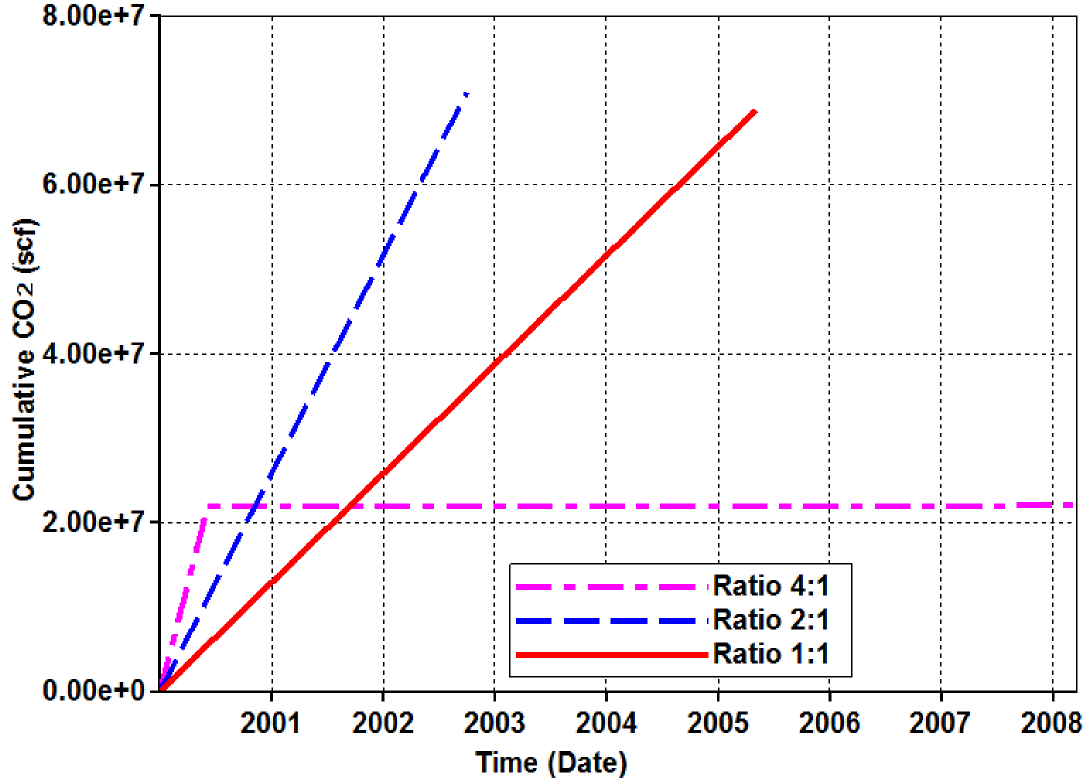


Fig. 38—Cumulative CO_2 sequestered for cases with fixed maximum production rate based on 1/8 of 5-spot pattern, 40-acre well spacing.

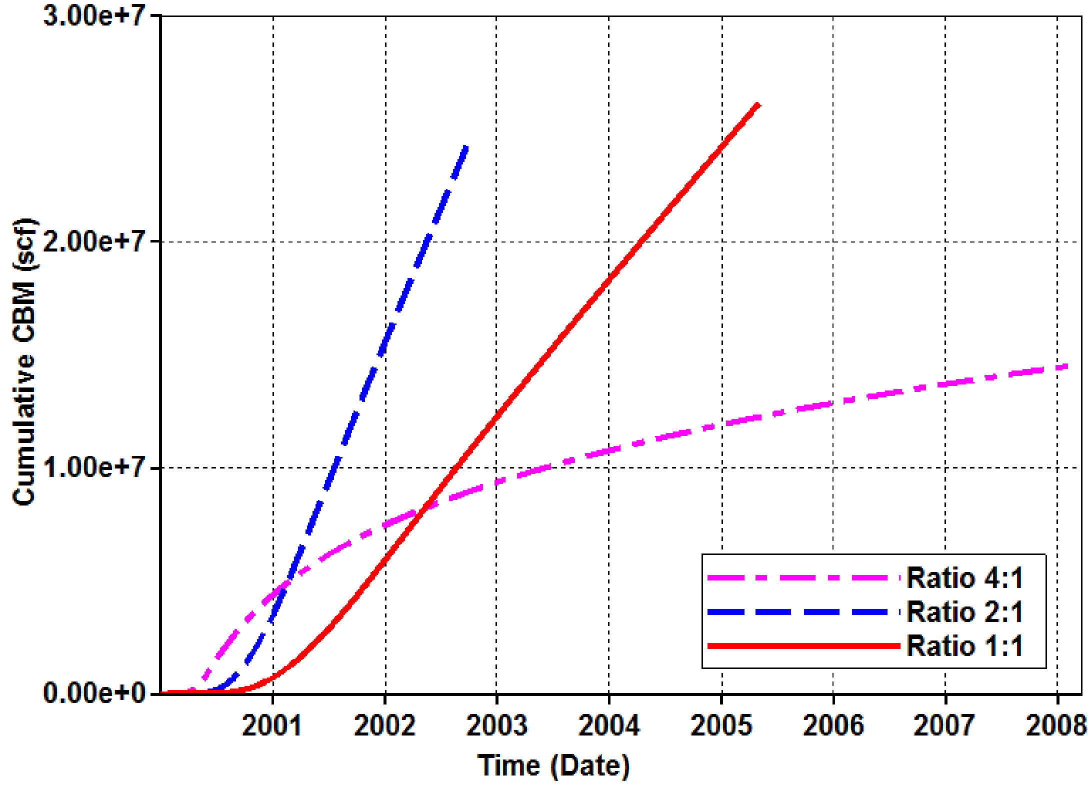


Fig. 39—Cumulative CBM Production for cases with fixed maximum production rate based on 1/8 of 5-spot pattern, 40-acre well spacing.

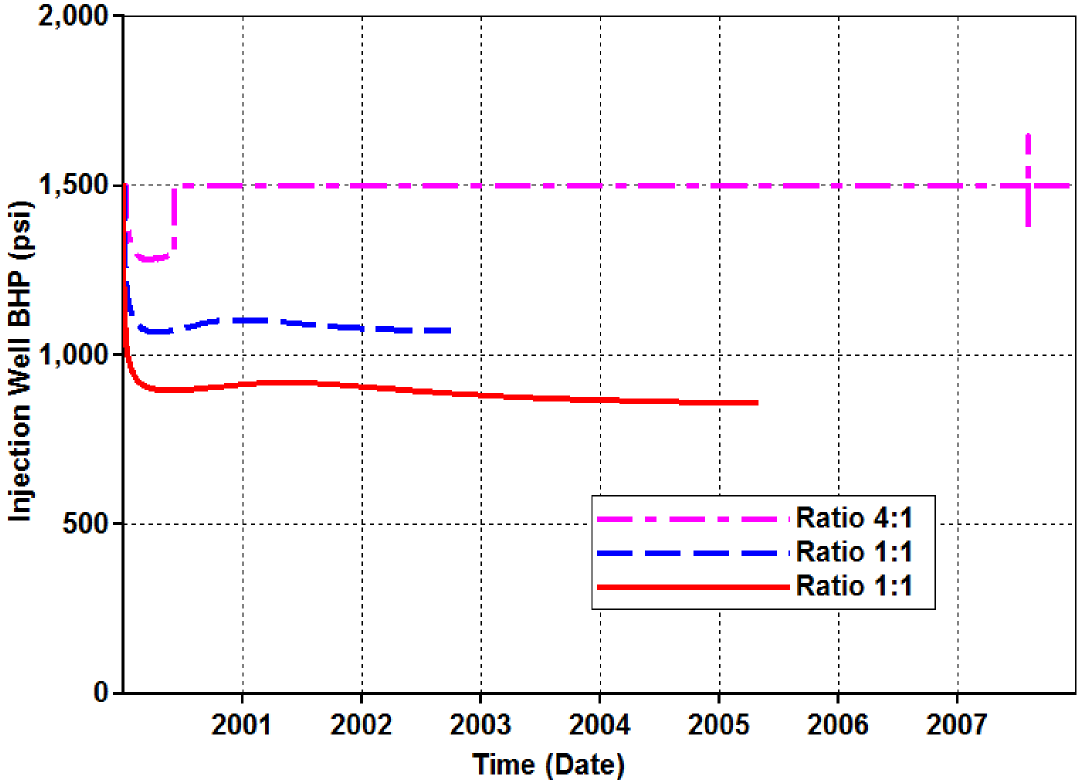


Fig. 40—Well BHP at the injector for cases with fixed maximum production rate based on 1/8 of 5-spot pattern, 40-acre well spacing.

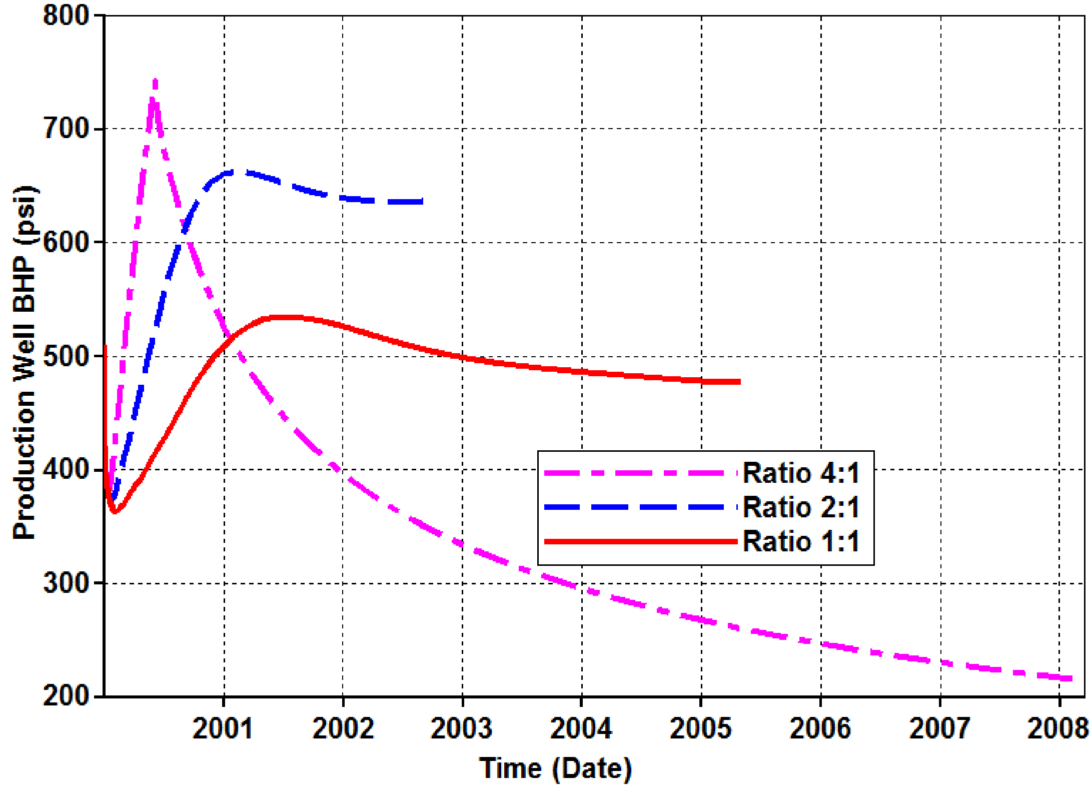


Fig.41—Well BHP at the Producer for cases with fixed maximum production rate based on 1/8 of 5-spot pattern, 40-acre well spacing.

Sensitivity Study of the Effects of Injection Gas Composition

To determine the effects of injection gas composition on performance of CO_2 sequestration and ECBM production in Blue Creek field, I conducted three case studies of an 80-acre, 5-spot pattern (40-acre well spacing). Consider the economical factor, flue gas, which is produced by the power plants, would be a good source of injection gas. So I simulated injection of 100%CO_2 50%CO_2/50%N_2, and flue gas (10%CO_2/90%N_2) (**Table 16)** under the base-case operating conditions. Breakthrough was defined by CO_2 equal to or greater than 5% in the produced gas. There is no constraint on N_2 at the breakthrough time since we wanted to store CO_2, not N_2. The results of the modeling studies with variable injection gas composition are shown in **Table 17** and **Figs. 42 to 45**.

Table 16—Constraints for Injection Gas Composition Cases

Cases	Injected Gas Composition
1	100%CO_2
2	50%CO_2/50% N_2
3	10%CO_2/90% N_2 (Flue Gas)

Table 17—Production and Injection Results for Injection gas composition Cases on 1/8 of 5-Spot Pattern, 40-Acre Well Spacing

Cases	**Cumulative Production of CH_4 (MMscf)**	**Cumulative Production of CO_2 (MMscf)**	**Cumulative Production of N_2 (MMscf)**	**Cumulative Injection of CO_2 (MMscf)**	**Cumulative Injection of N_2 (MMscf)**	**Efficiency (%)**	**Break-through Time (days)**
1	24.26	0.132	0	70.9	0	34	1,004
2	30.22	0.296	54.53	61.7	61.79	25	2,486
3	32.62	1.79	208.7	24.9	224.6	13	6,940

For the three cases, the breakthrough time depended on the mole fraction of CO_2 in the injected gas and ranged from 1,004 to 6,940 days. As expected, the breakthrough time for the injection of flue gas was the longest, whereas it is the earliest for the pure CO_2 injection case (Table 17). The simulation indicates that CO_2 volume that the Mary Lee coal zone in Blue Creek field can store range from 0.2 to 0.57 Bcf, on a 40-acre well spacing. The pure CO_2 injection case can sequester more CO_2 than sequestered by the other cases and sequestration is accomplished in a much shorter timeframe (Fig. 42).

CBM production for Mary Lee coal zone in Blue Creek field ranges from 0.19 Bcf to 0.25 Bcf, on 40-acre well spacing (Fig. 43). Compared with the case of pure CO_2

injection, the CBM recovery factor for the case of flue gas injection increases from 55% to 75%. For the flue gas injection case, although the flue gas contains only about 10% of CO_2, 92.8% of CO_2 injected is sequestered and only 7% of N_2 injected is stored in the coal interval (**Table 17**). This result relates to the lack of limitation on N_2 production constraints and the capacity of the coal to adsorb different kinds of gas in the Blue Creek field of Black Warrior basin and is consistent with the adsorption isotherms.

The cumulative CO_2 injection curves (Fig. 42), which are line, indicate that the injection rates for the three cases were constants and the BHP at the injector did not reach the pressure constraints of 1,500 psi. However, the production rate of CBM varied a lot with time (Fig. 44). When injection gases are 50%CO_2/50%N_2 and flue gas, the production rates of CBM dropped sharply in less than 3 months (Fig. 44). At the same time, the pressure at the producer built up quickly to approximate 1200 psi (Fig. 45). I referred that it was the injection of N_2 that leaded the producer BHP to build up and in turns to limit the injection rate.

Comparing the efficiency (Eq. 7) for the three cases in Table 17, it decreases from 34% to 13% when the percentage of N_2 increases from 0% to 90% in the injection gas. Therefore, I did not see many benefits of injection of flue gas for this CO_2 sequestration project, although it slightly improves the production of CBM. However, economically, injecting flue gas may be more feasible than pure CO_2, since separation of gases would not be required.

$$e = \frac{V_{cum,cbm,p}}{V_{cum,gas,i}} \qquad \text{...}(7)$$

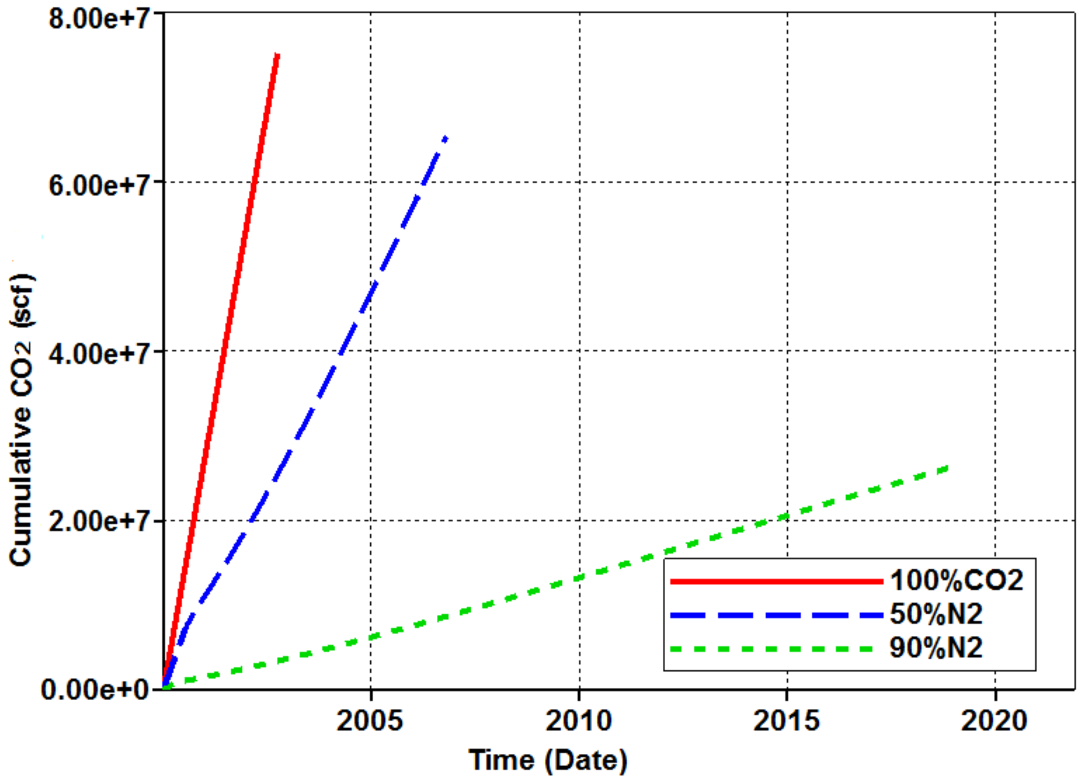


Fig. 42—Cumulative CO_2 injection for cases of 100%CO_2, 50%N_2, or flue gas, based on 1/8 of 5-spot pattern, 40-acre well spacing.

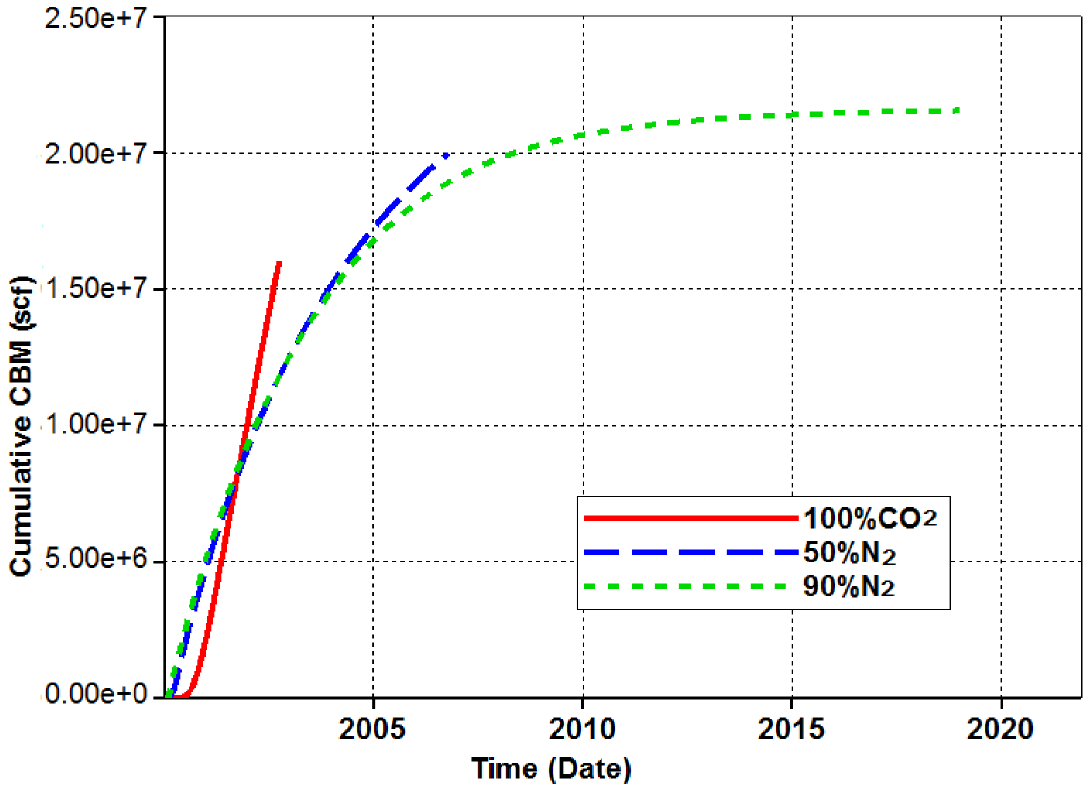


Fig. 43—Cumulative CH_4 production for cases of 100%CO_2 , 50%N_2, or flue gas based on 1/8 of 5-spot pattern, 40-acre well spacing.

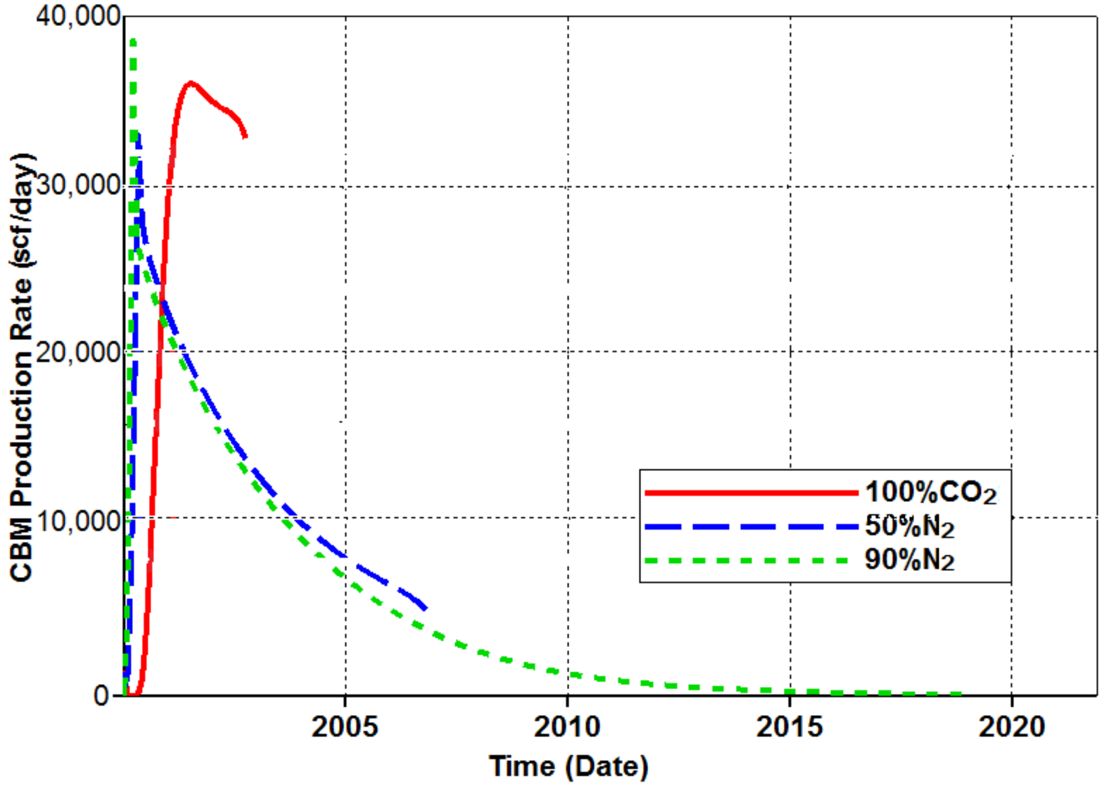


Fig. 44—CBM production rates for cases of 100% CO_2, 50%N_2, or flue gas based on 1/8 of 5-spot pattern, 40-acre well spacing.

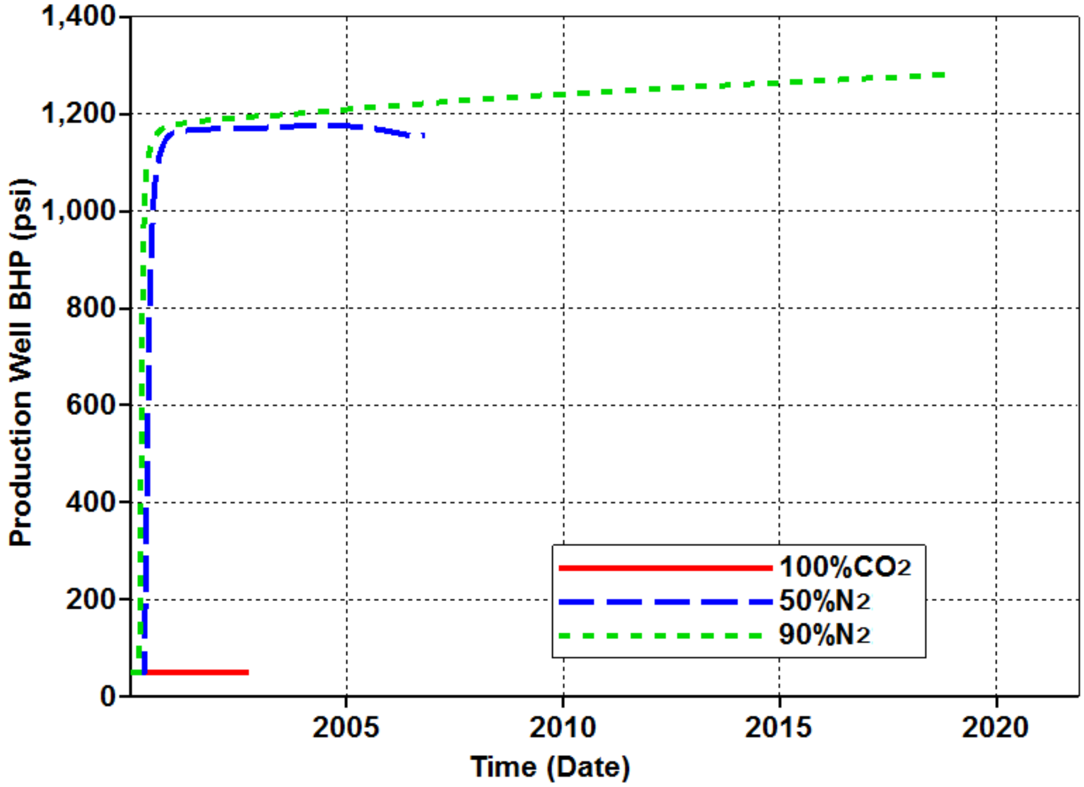


Fig. 45—Production well BHP for cases of 100%CO_2, 50%N_2, or flue gas based on 1/8 of 5-spot pattern, 40-acre well spacing.

Sensitivity Study of the Effects of Coal Dewatering Prior to CO_2 Injection

Water production is one of the most important issues for CBM production. To study the performance effects of dewatering the coals prior to CO_2 injection, I modeled six cases of an 80-acre, 5-spot pattern (40-acre well spacing). For the first three cases, coal is dewatered prior to CO_2 injection, and the initiation of dewatering time is set to 0, 2, or 4 years (**Table 18**). The gas injection rates, production rates, and other constraints are the same as in the base case. Breakthrough was defined by CO_2 concentration equal to or greater than 5% on a molar basis in the produced gas. Then, since dewatering process can decrease the reservoir pressure I want to see if the injection rate of CO_2 can be rise after the coal is dewatered. So I simulate the following three cases with higher maximum injection rates (88 scf/D), labeled “higher *q*” in figures. **Figs. 46 through 50** show the results of the study, and **Table 19** compares the breakthrough time, cumulative gas injected, and cumulative production.

Table 18—Constraints for Dewatering Cases

Cases	Maximum Injection Rate (scf/day)	Maximum Production Rate (scf/day)	Dewatering Time (Year)
0 yr-70scf/D	70,500	35,250	0
0 yr-88scf/D	88,125	35,250	0
2 yr-70scf/D	70,500	35,250	2
2 yr-88scf/D	88,125	35,250	2
4 yr-70scf/D	70,500	35,250	4
4 yr-88scf/D	88,125	35,250	4

Table 19—Production and Injection Results for Dewatering Cases, on 1/8 of 5-Spot Pattern, 40-Acre Well Spacing

Cases	Cumulative Injection of CO_2 (MMscf)	Cumulative Production of CH_4 (MMscf)	Cumulative Production of water (bbl)	Breakthrough Time (days)
0 yr-70 scf/D	70.93	24.49	2,797.26	1,005
2 yr-70 scf/D	70.87	24.74	3,010.82	1,735
4 yr-70 scf/D	70.95	25.02	3,193.16	2,466
0 yr-88 scf/D	57.81	24.92	3,015.99	1,461
2 yr-88 scf/D	74.71	23.98	2,539.28	1,592
4 yr-88 scf/D	75.27	24.54	2,825.64	2,314

First, comparing the first three cases with the same injection rates as base case, breakthrough time ranged from 1,004.6 days to 2,465.6 days (Fig. 46). The breakthrough times are obviously delayed with delayed injection. For all three cases, the simulation indicates that CO_2 volume that the Mary Lee coal zone in Blue Creek field can store are approximate 0.57 Bcf, on 40-acre well spacing (Fig. 46). Although the dewatering time is different, the difference in the cumulative CO_2 injection is as little as 0.1% (Table 19).

For these three cases, CBM production for Mary Lee coal zone in Blue Creek field ranges from 0.196 Bcf to 0.2 Bcf, on 40-acre well spacing (Fig. 47). And the methane recovery factors range from 64% to 67%. When coal was dewatered for 2 years and 4 years, the production of CBM were increased by 1.5% and 2%. Cumulative water production of these three cases ranged from 22.4 Mbbl to 25.5Mbbl at breakthrough (Fig. 48). When coal was dewatered, water production was increased by more than 10% (Table 19).

The lines in Fig. 46 indicate that the CO_2 injection rate remains constant, because the well BHP at the injector did not reach the constraint of 1,500 psi. When coal was being dewatered, the production curves in Fig. 47 and Fig. 48 showed the CBM production rate increased slightly while water production rate decreased. When the injection started, the inflexion of the curve shown in Figs. 47 and 48 indicates injects as CO_2 can increase the production of CBM and water. Dewatering implies depressuring of the reservoir (Fig. 49). When water is produced for 4 years before the injection, the pressure decreases from 510 psi to 430 psi at injector and from 510 psi to 275 psi at the producer. When injection of CO_2 starts, the pressure at the injector increases to a maximum value of approximately 1,000 psi (Fig. 49). As mentioned in the previous part, many factors affect the reservoir pressure.

For this model, I considered the effects of matrix shrinkage and swelling, using the Palmer and Mansoori model (1996) (Eqs. 1 to 5). Adsorption and desorption of gas can lead the coal matrix to swelling and shrinkage, whereas changes of pressure in the cleats can lead to contraction or expansion of the cleat aperture. Dewatering leads to decreased permeability and porosity of the cleat. When CO_2 is injected in the coal, pressure in the cleat increases. Since the partial pressure of CBM is different between the coal matrix and cleat, the CBM is desorbed from coal, leading to matrix shrinkage. As time passes, more and more CO_2 is adsorbed onto the coal, and the pressure in the cleat drops as well. The coal matrix swells, causing the permeability and porosity of the cleat system to decrease. Thus there is a balanced process accounting for different effects as mentioned in Fig. 30.

Fig. 50 shows the changes of permeability and porosity of the fracture system in one block (Block 5,5,3) of the grid, in the middle area between the injector and the producer. The permeability changed from 12 md to almost 25 md when pressure changed by 200 psi (Fig. 51), which is approximately 6 md per 100 psi. This result is consistent with the conclusion of Palmer and Mansoori (1996) that as pressure increases, permeability of coal may increase by 1 md/psi to 4 md/psi. Comparing the permeability change in Fig. 50 with the pressure change in Fig. 49, the trends of the curve for pressure and permeability are nearly the same, indicating the relation between the pressure and the permeability shown in Eq. 1.

Now, considering effects of increasing the maximum injection rates, the cumulative CO_2 sequestered and CBM produced are shown in Figs. 46 and 47. Without dewatering, CO_2 cannot be injected into the well after 2 years' injection. However, for the 4-years dewatering case, CO_2 can be injected until breakthrough occurs, and the cumulative CO_2 sequestered increases by 5 MMscf. Although there is little benefit to dewatering prior to the injection at the same injection rate, if injection rates are higher, more CO_2 can be sequestered. Also, higher injection rates of CO_2 can also increase the production of water (Fig. 48).

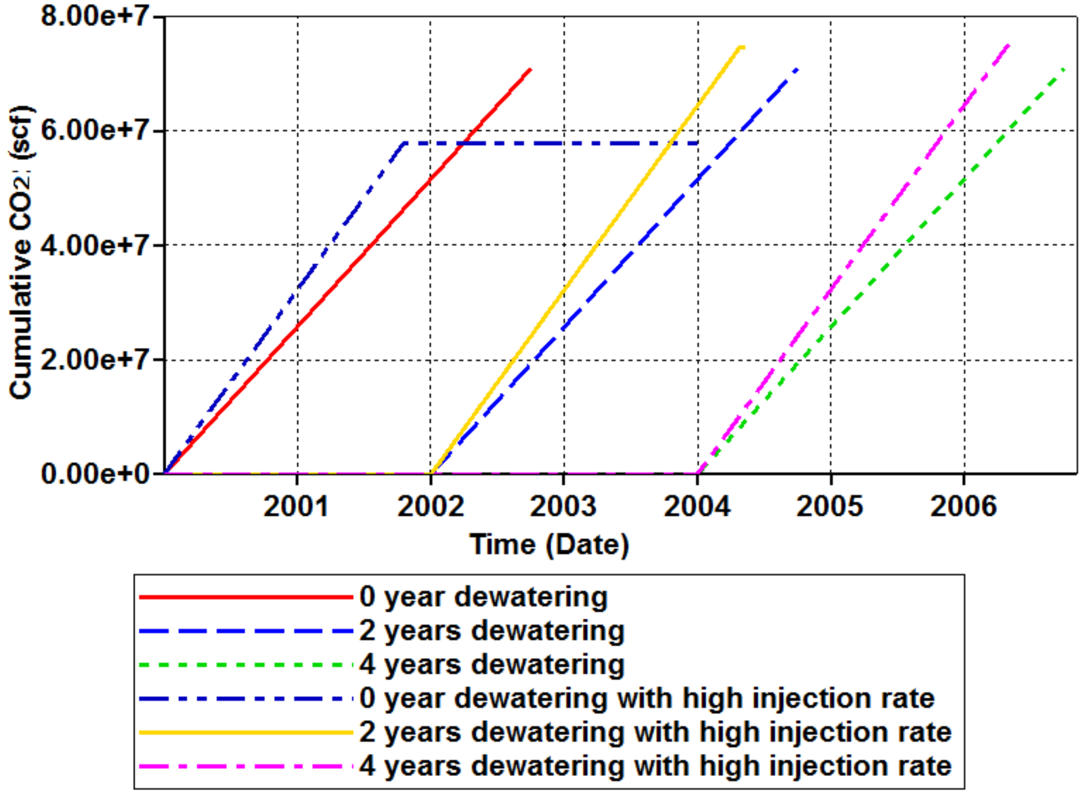


Fig. 46—Cumulative CO_2 injected for cases to study the dewatering operation based on 1/8 of 5-spot pattern, 40-acre well spacing.

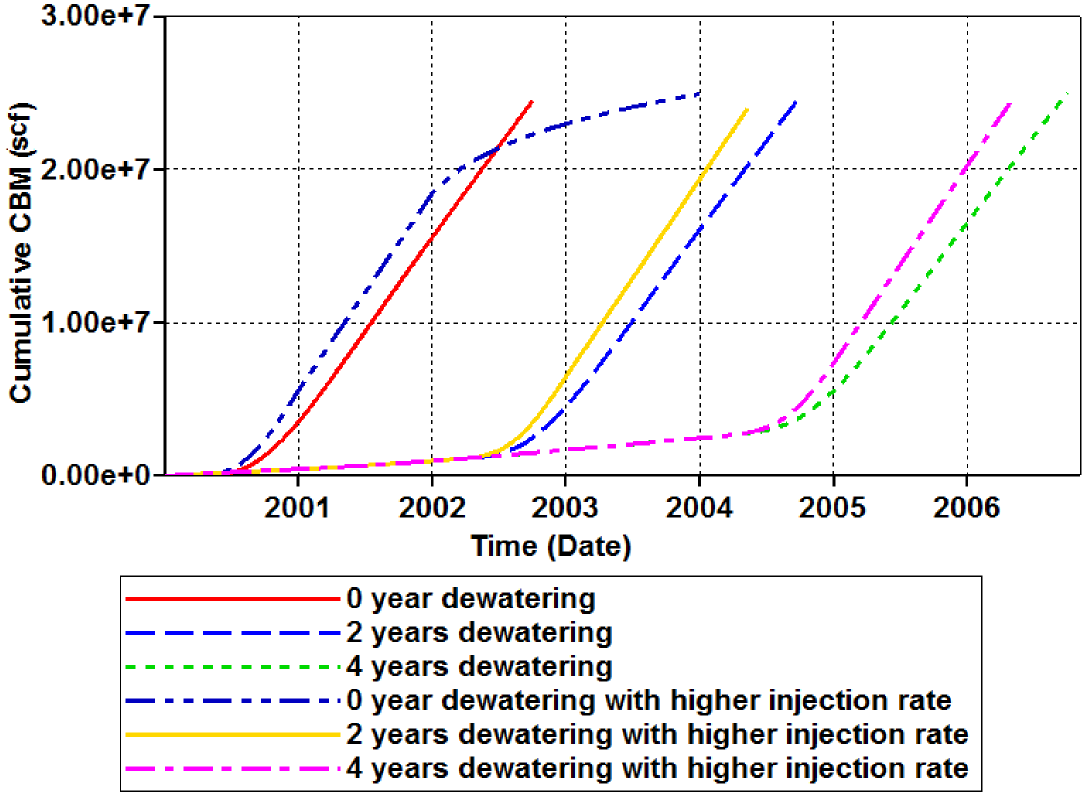


Fig. 47—Cumulative CBM production for cases to study the dewatering operation based on 1/8 of 5-spot pattern, 40-acre well spacing.

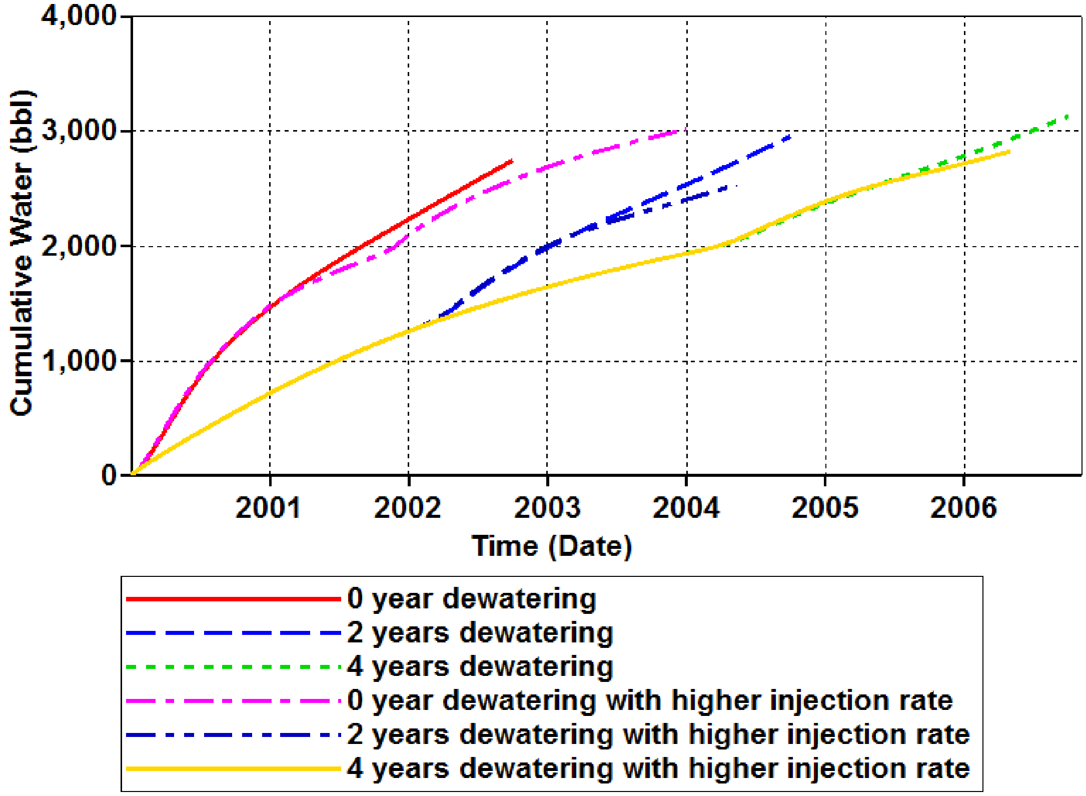


Fig. 48—Cumulative water production for cases to study the dewatering operation based on 1/8 of 5-spot pattern, 40-acre well spacing.

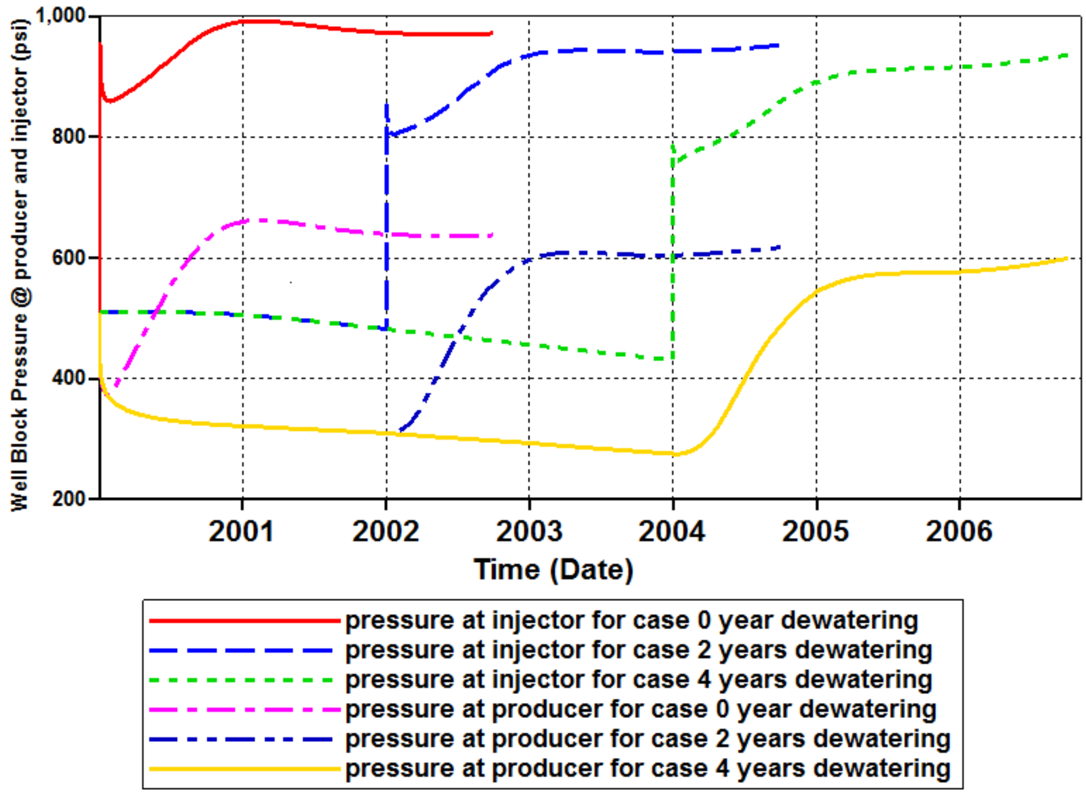


Fig. 49—Well block pressure at producer and injector for cases to study the dewatering operation based on 1/8 of 5-spot pattern, 40-acre well spacing.

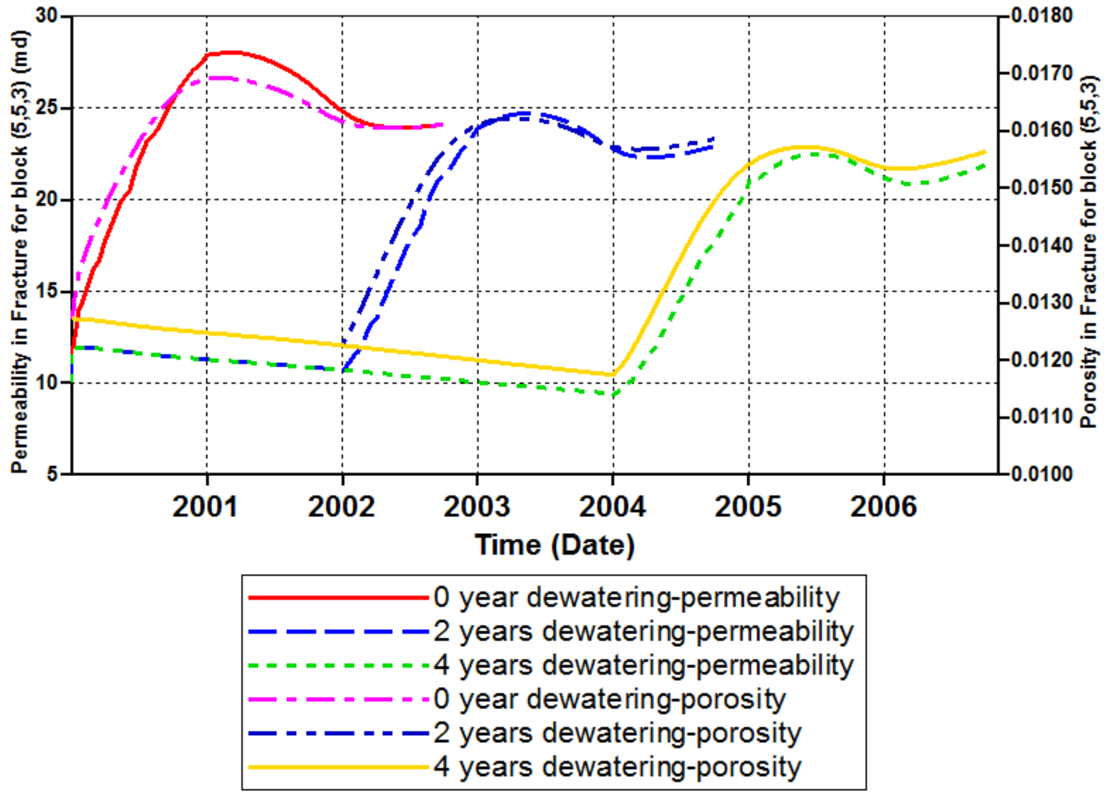


Fig. 50—Permeability and porosity at Block 5,5,3 for cases to study the dewatering operation based on 1/8 of 5-spot pattern, 40-acre well spacing.

Sensitivity Study of the Effects of Permeability Anisotropy

Since there are many folds and faults in Black Warrior basin (Fig. 20), it is significant to analyze the effects on permeability anisotropy. To access permeability anisotropy of coal in Blue Creek field, the model was doubled to ¼ of the 80-acre 5-spot well pattern and rotated by 45^o (**Fig. 51)** so that two producers are at the corners of the right triangle, and one injector is at the right angle point. I conducted three cases with different permeability anisotropies to determine the effects on CO_2 sequestration and ECBM production. Since the permeability anisotropy can be as high as 8:1 in Black Warrior basin (Pashin et al. 2004), permeability anisotropy ratios from 1:1 to 5:1 were considered in this study. Compared to the base case in which the model is 1/8 of the 80-acre, 5-spot model, this model is 1/4 of the 80-acre 5-spot (Fig. 51), so I increased the injection rate to 141 Mcf/day, which is two times the rate for the base case. Breakthrough was defined by CO_2 equal to or greater than 5% in the produced gas. The producer will be shut in when breakthrough occurs, and the simulation ends when another breakthrough happens. **Table 20** and **Figs. 52 through 55** show the results of the modeling.

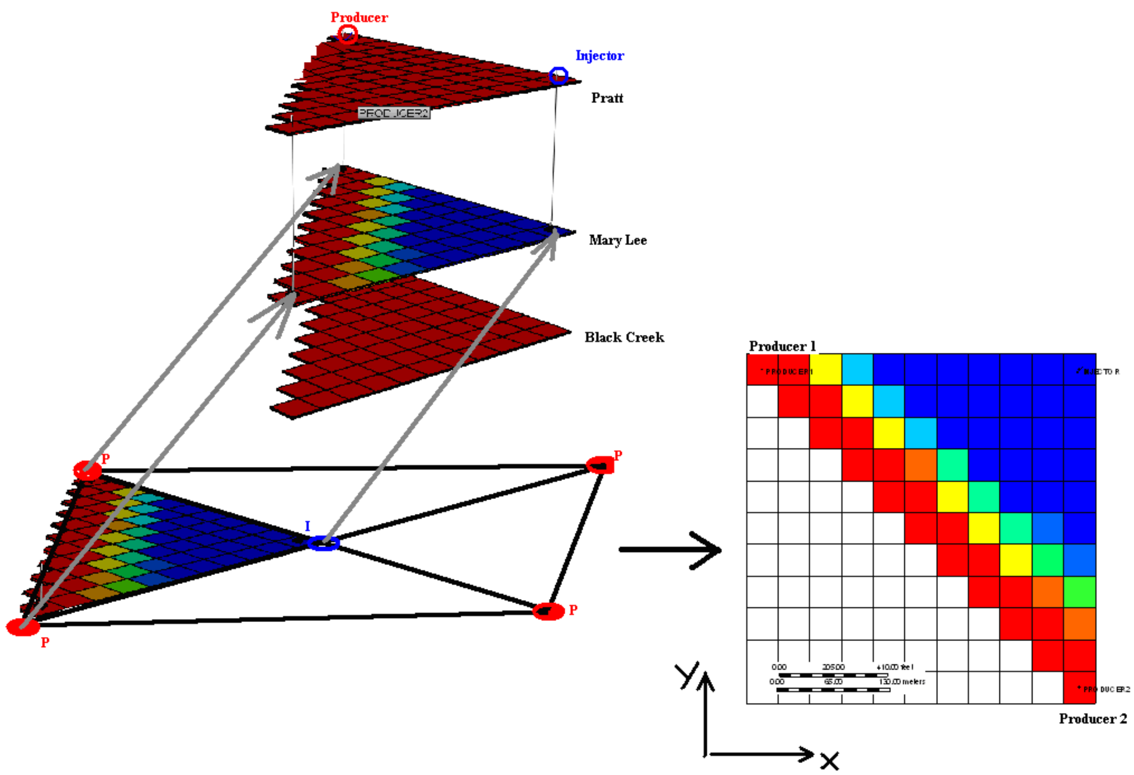


Fig. 51—3D model for study of permeability anisotropy.

Because of the symmetry of the model, breakthrough time for Case 1:1 is 1004.6 days for both producers (Table 20), which is consistent with the base case. For the Case 2:1 and Case 5:1, which has anisotropic permeability, the breakthrough time is different for two producers (Table 20). For both cases, the breakthrough occurred earlier at the producer which in the direction of higher permeability. When the permeability anisotropy ratio is too high, as in Case 5:1, the breakthrough time for the producer which in the direction of lower permeability may be fair long-so long that I had to stop the simulation manually.

Table 20—Production and Injection Results for the Permeability Anisotropy Cases, on 1/4 of 5-spot pattern, 40-acre well spacing

Case	**CO_2 Injected (MMscf)**	**CH_4 Producted for Producer 1 (along X) (MMscf)**	**Cumu-lative Production of CH_4 for Producer 2 (along Y) (MMscf)**	**Cumu-lative Production of CH_4 (MMscf)**	**Break-through Time At Producer 1 (days)**	**Break-through Time At Producer 2 (days)**
1:1	141.8	24.1	24.1	48.2	1,004.7	1,005
2:1	146.6	18.9	32.2	51.1	761.4	3,962
5:1	92.6	14.2	31.5	45.7	1,857.4	-

For the same reason of the symmetry, Case 1:1 sequestered two times as much CO_2 the base case and produced two times as much CBM, which are 1.14 Bcf of CO_2 and 0.39 Bcf (Fig. 52 and Table 20), on 1/4 of 5-spot pattern, 40-acre well spacing. If the permeability is anisotropic, as with Case 2:1, the Mary Lee coal zone in Blue Creek field can store 1.17 Bcf of CO_2 and 0.41 Bcf (Table 20), on 1/4 of 5-spot pattern, 40-acre well spacing. For Case 2:1, the cumulative gas injection and production have been increased slightly, however, the breakthrough time is four times as long as the breakthrough time for isotropic case.

If the permeability is anisotropic, as with Case 2:1, the pressure will build up at the injector (Fig. 53), and no additional CO_2 can be injected as indicated by the steps of green and magenta in Fig. 52. However, the producer in the lower permeability direction continues to produce CBM at decreasing production rates until breakthrough. If the breakthrough time is long enough, as in Case 5:1, because the pressure drops as production continues (Fig. 53), CO_2 can be injected in the well again (Fig. 52).

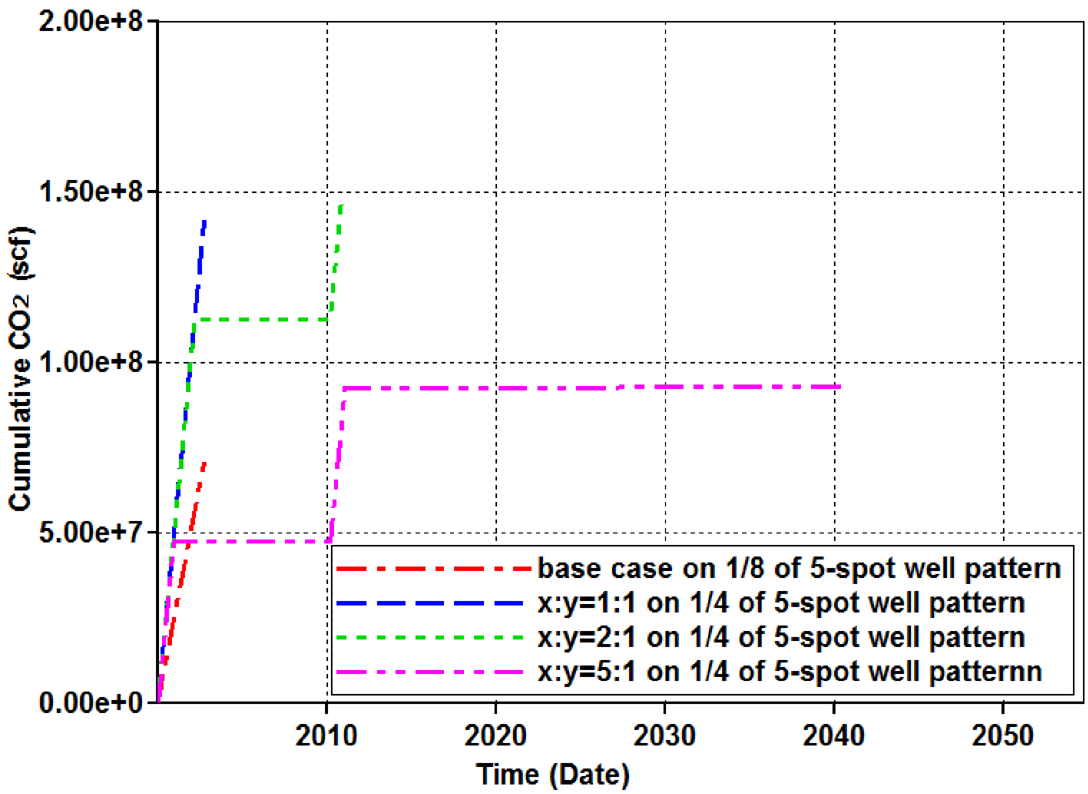


Fig. 52—Cumulative CO_2 injection, for the permeability anisotropy cases based on 1/4 of 5-spot pattern, 40-acre well spacing.

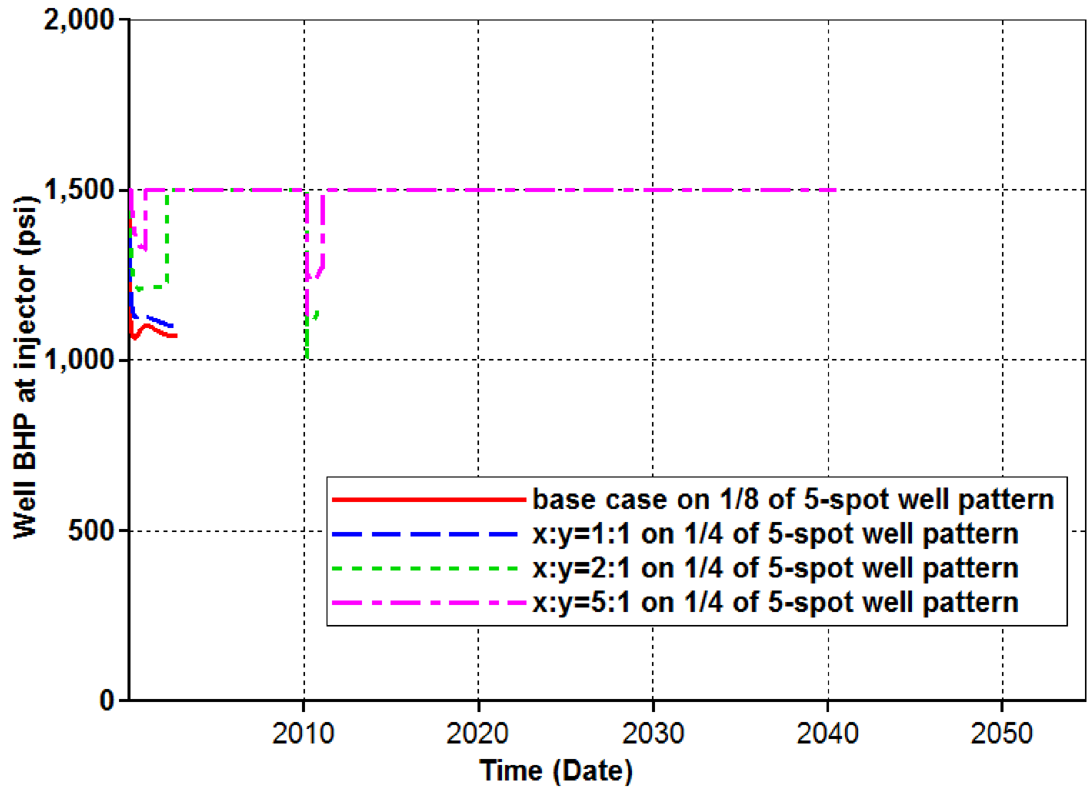
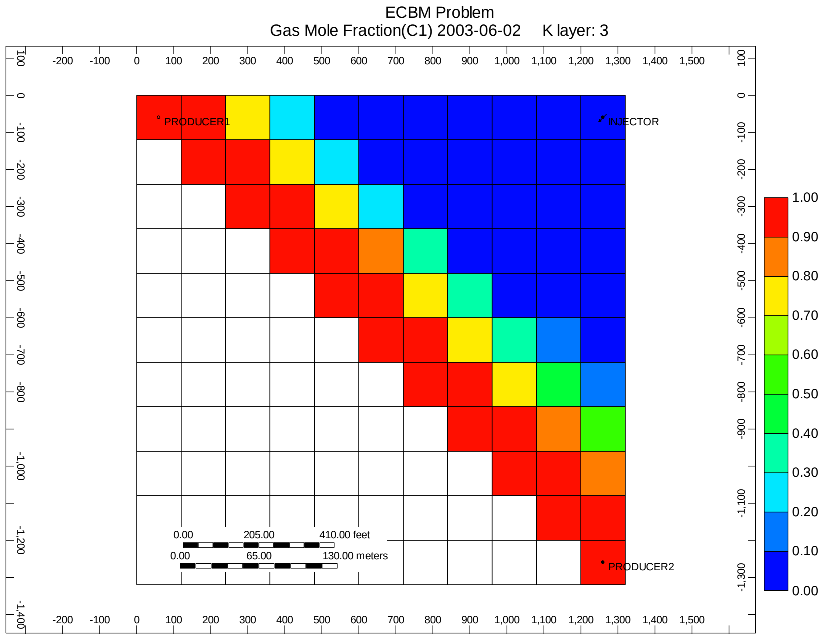
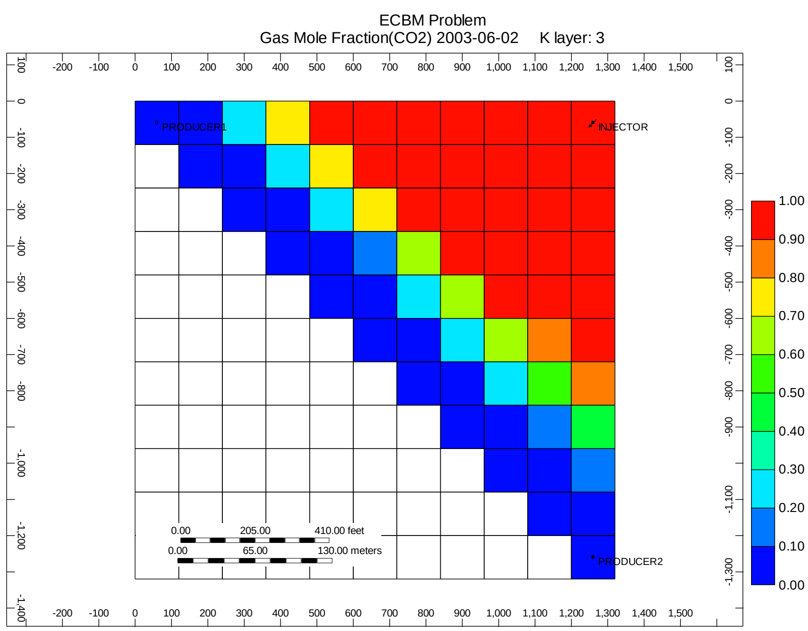


Fig. 53—Well BHP at injector for the permeability anisotropy cases based on 1/4 of 5-spot pattern, 40-acre well spacing.

Fig. 54 shows the colorfill maps distribution of various reservoir properties at the breakthrough time for the anisotropy Case 2:1. More CH_4 is replaced by CO_2 around Producer 1, indicating a more efficient recovery along the x direction (Fig. 54 a). Compared with Fig. 54 b), the concentration of CO_2 added to the concentration of CBM equals to 1. The change of permeability and the pressure around Producer 1 are greater than around Producer 2 because more CBM is replaced in the high-permeability direction (Figs. 54 c and 54 d).

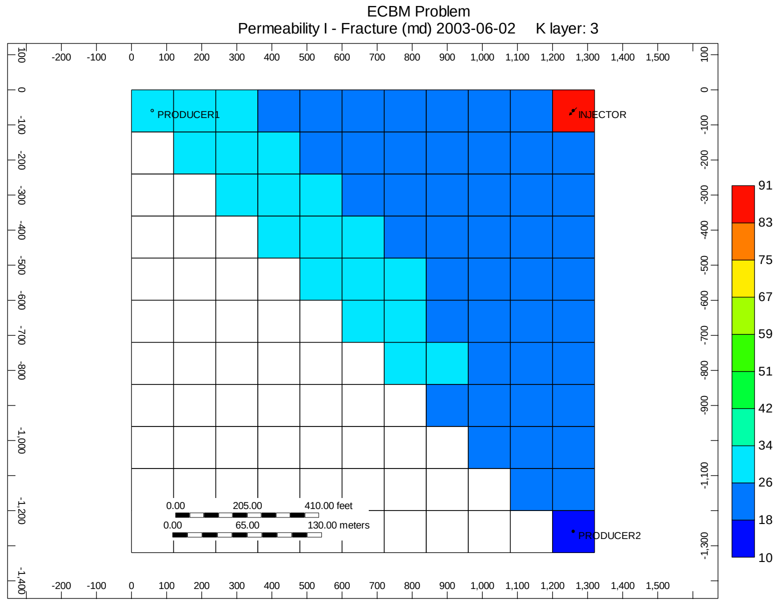


(a)

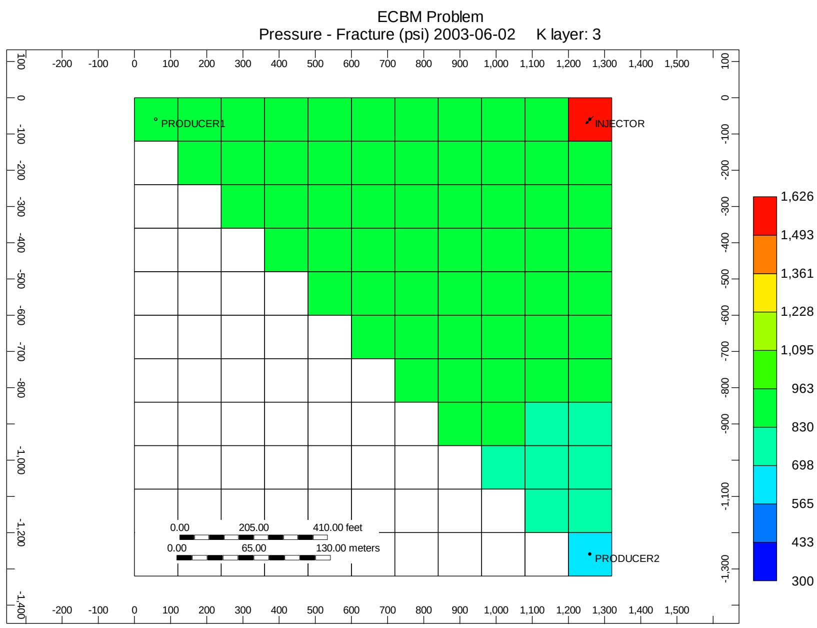


(b)

Fig. 54—(a) Methane mole fraction, (b) CO_2 mole fraction at breakthrough time for Case X:Y=2:1 for the permeability anisotropy cases based on 1/4 of 5-spot pattern, 40-acre well spacing, where horizontal is the x-direction and vertical is the y-direction.



(c)



(d)

Fig. 54—continued. (c) permeability in the fracture system, and (d) pressure of the fracture system at breakthrough time for Case X:Y=2:1 for the permeability anisotropy cases based on 1/4 of 5-spot pattern, 40-acre well spacing, where horizontal is the x-direction and vertical is the y-direction.

Study of the Effects of Soak Time

The desorption/adsorption process is not instantaneous. Stopping injection or production to give time for CO_2 to soak into the reservoir could increase the production and sequestration. Therefore to study the effects of soak time of CO_2 in the Blue Creek field of Black Warrior basin, I conducted four cases with the same constraints as in the base case but under different conditions:

- Open in turn 6 mo: producer and injector open for alternations 6-month periods
- Open in turn 2 mo: producer and injector open for alternations 2-month periods
- Co-open 6 mo: producer and injector open for simultaneous 6-month perods
- Keep production 6 mo: producer open continuously, injector closed and opened for alternations 6-month periods

as shown in **Fig. 55**.

When the injector is shut in, the CO_2 is given time to be adsorbed into the coal matrix to replace the CH_4. The simulations terminate at the breakthrough time. **Figs. 56 through 58** show the results of the study and **Table 21** compares the cumulative CO_2 injected and methane produced.

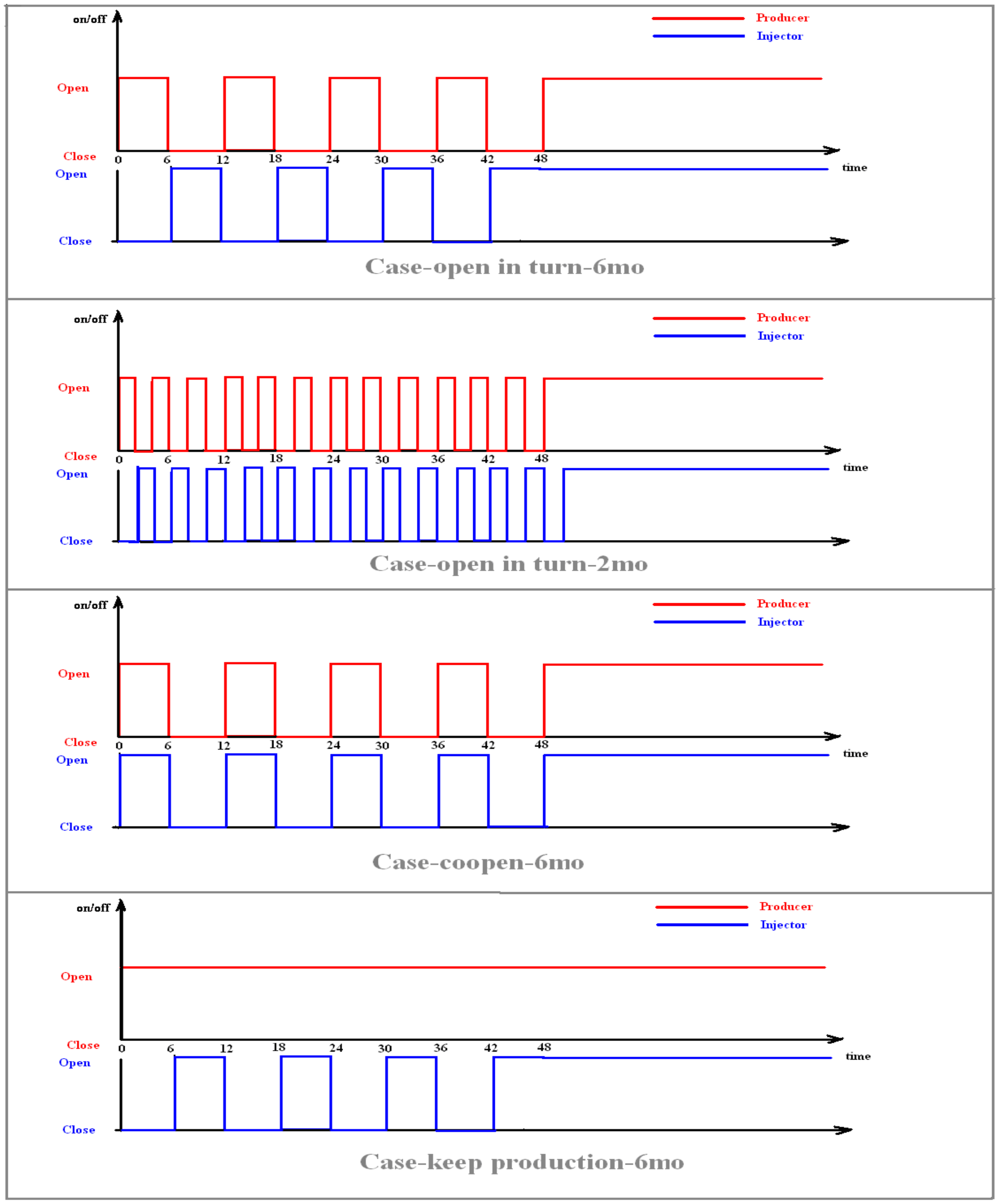


Fig. 55—Timeline of cases to study the effects of CO_2 soak time.

Table 21—Production and Injection Results for Soak Time Cases, on 1/8 of the 80-acre 5-spot pattern.

Case	**Cumulative Injection of CO_2 (MMscf)**	**Cumulative Production of CH_4 (MMscf)**	**Break-through Time (days)**
Open in turn-6 mo	-	-	-
Open in turn-2 mo	72.1	24.9	1,746
Co-open-6 mo	70.8	24.4	1,739
Keep production-6 mo	70.1	25.1	1,729
Base case	70.9	24.5	1,005

For the case of open in turn-6 mo, breakthrough never occurred, since CO_2 can not be injected into the injector because the pressure builds up after two cycles of injection (Fig. 56). For other cases expect base case, breakthrough ranges from 1729 days to 1745 days (Fig. 56 and Table 21). Because I allowed extra two years for gas to soak, so the breakthrough times for these cases are approximately two years later than the base case. The simulation indicates that for the soaking cases, expect the case of open in turn-6 mo, CO_2 volume that the Mary Lee coal zone in Blue Creek field can store ranges from 0.56 Bcf to 0.57 Bcf, on the 80-ac 5-spot pattern (Table 21 and Fig. 56). When the period of the cycle is as short as two months (Open in turn-2 mo), 2 MMscf more CO_2 can be sequestered, than in the base case. For the cases of co-open-6 mo and keep production-6 mo, there are no specific differences from the base case, except a delay in the breakthough time (Table 21).

The cumulative production of CBM for the cases of open in turn-2 mo, co-open-6 mo and keep production-6mo are approximate 0.2 Bcf, on the 80-acre 5-spot pattern (Table

21). The three curves for the cases end at almost the same point (Fig. 57). Thus, there is no great benefit to added soak time for this scale of well pattern. Future work may focus on larger well spacing to study the effects of soak time.

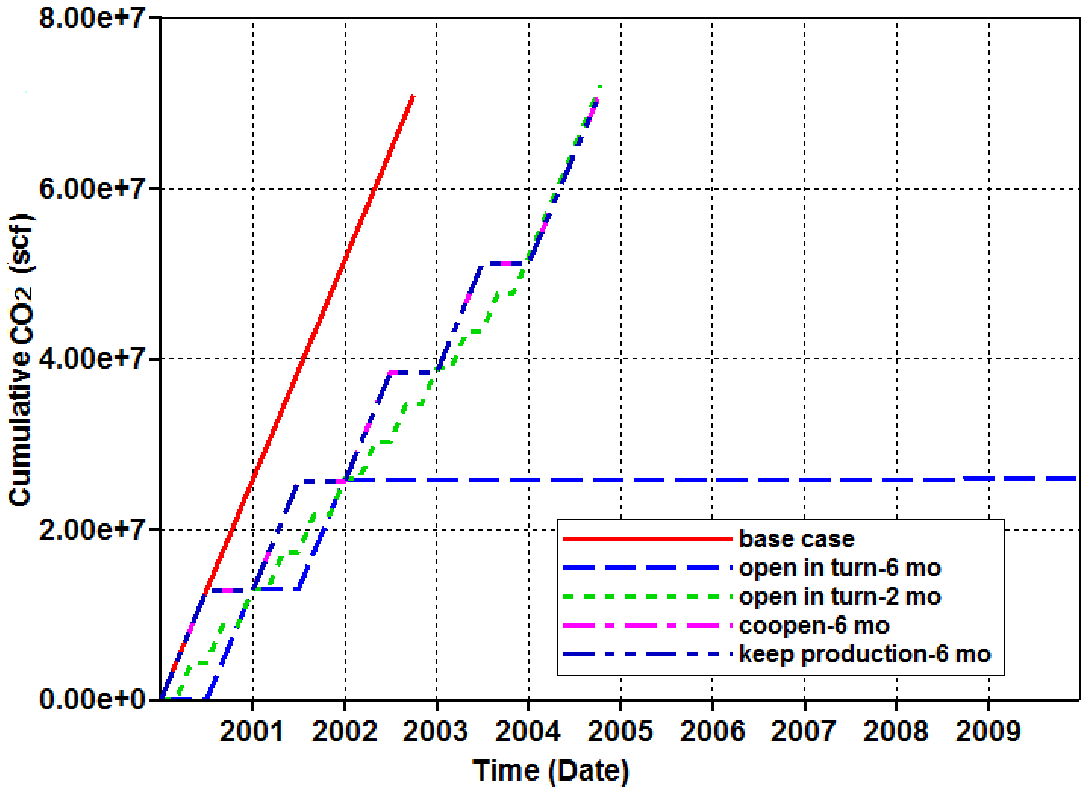


Fig. 56—Cumulative CO_2 sequestered for cases to study the effects of soaking based on 1/8 of 5-spot well pattern, 40-acre well spacing.

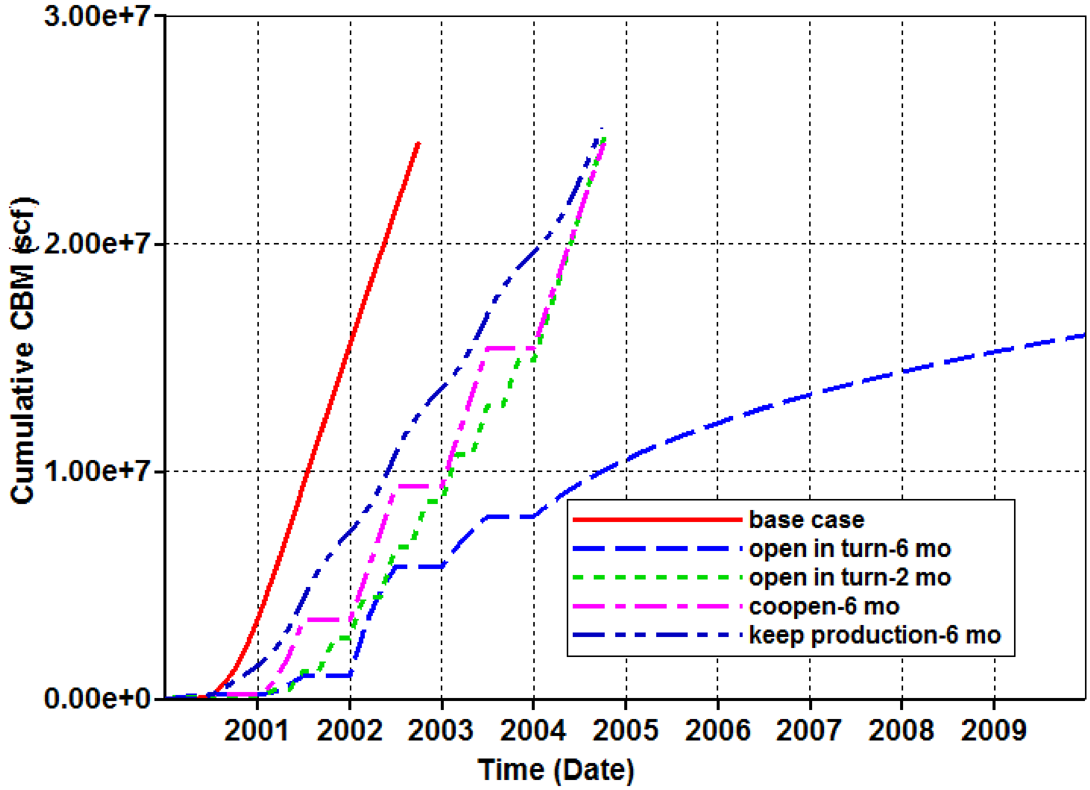


Fig. 57—Cumulative CBM production for cases to study the effects of soaking based on 1/8 of 5-spot well pattern, 40-acre well spacing.

However, the soak models demonstrated effects of desorption and adsorption. Fig. 58 shows the profiles at Block 9,9,3, which is near the injector. The mole fraction of CBM in the block decreases from 1 to almost 0, showing CBM is replaced by CO_2. The pressure in the fracture drops when both producer and injector are shut in (Fig 58). Also the mole fraction of CBM in the matrix drops from 8.4% to 7.7%, indicating the replacement of methane. I conclude that the coal matrix can store more CO_2 than CBM, as mentioned previously.

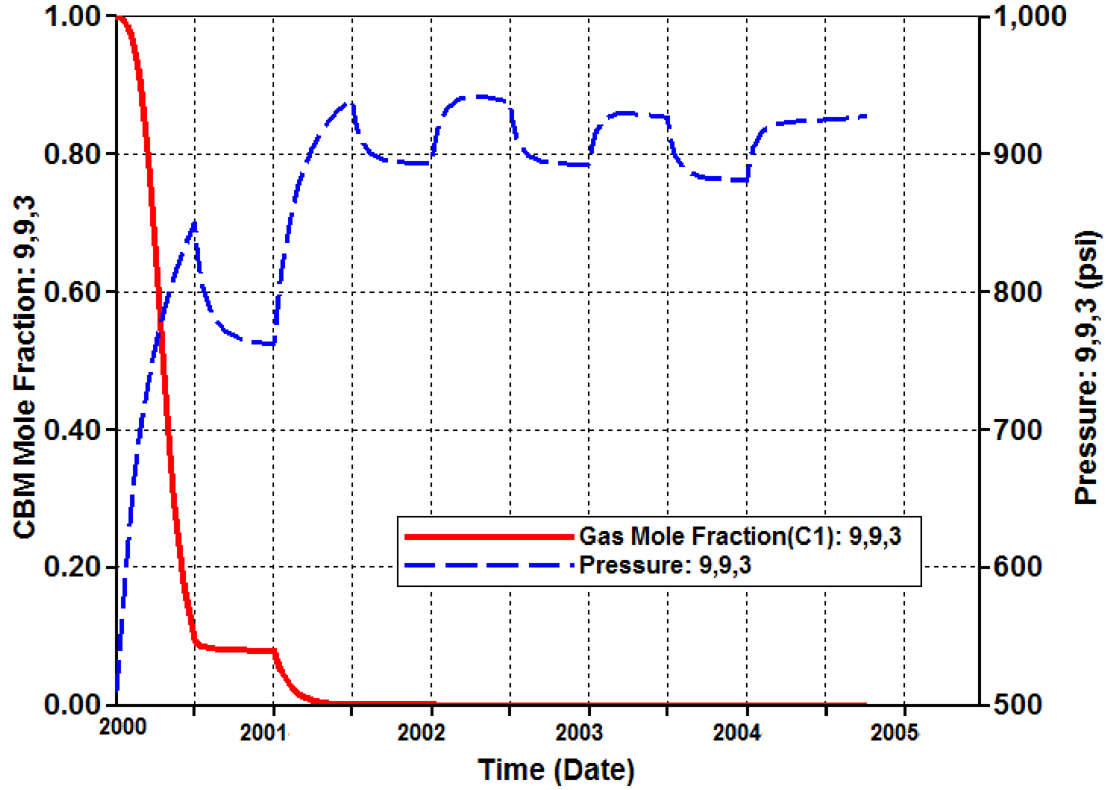


Fig. 58—Mole fraction of CBM and pressure at the Block 9,9,3 for the case of co-open-6 mo based on 1/8 of 5-spot well pattern, 40-acre well spacing.

Study of Multilayer Completion

The geophysical core log (Fig. 15), showed that the Pratt, Mary Lee, and Black Creek are the most economic coal groups for industrial development. Drillinginfo (2009), which is an open source, web-based platform for the US upstream oil and gas industry, shows that most wells in Blue Creek field are complete in the Pratt, Mary Lee, and Black Creek. To study the effects of multilayer completion, I conducted six simulation runs (**Table 22)**. The constraints for these models are the same as those of the base case, except for the maximum injection rate and production rate, which are set to be 10.5 Mcf/D and 52.5 Mcf/D. The cumulative injection and production and are shown in

Table 23, and Figs. 59 and 60. The profiles including mole fraction, permeability and pressure are shown as **Figs. 61 through 62**.

Table 22—Conditions for Completion of Different Layers

Cases	Layer was Completed
P	Pratt
ML	Mary Lee
BC	Black Creek
P-ML	Pratt-Mary Lee
ML-BC	Mary Lee-Black Creek
P-ML-BC	Pratt-Mary Lee-Black Creek

Table 23—Production and Injection Results for Completion of Different Layers

Cases	Cumulative Injection of CO_2 (MMscf)	Cumulative Production of CH_4 (MMscf)	Breakthrough Time (days)
P	43.8	14.7	621
ML	70.9	24.5	1,005
BC	42.6	13.6	4,079
P-ML	45.7	15.5	647
ML-BC	75.2	25.1	1,066
P-ML-BC	45.7	15.5	647

The breakthrough time for the cases of the single layer-P, ML, and BC range from 620 days to 4,078.8 days. Because the Pratt coal zone has the highest permeability and Black Creek coal zone has the lowest permeability, the Pratt coal zone is the first one to breakthrough and the Black Creek coal zone is the last. The simulation indicates that the Mary Lee coal zone can can store 0.57 Bcf of CO_2 and recover 0.196 Bcf of CBM on a 40-acre well spacing (Table 23 and Figs. 59 and 60), which is the most economical coal zone compared to Pratt and Black Creek coal zone.

Then considering Case P-ML, wells are completed in the Pratt and Mary Lee coal zones. The breakthrough time, cumulative CO_2 sequestrated, and CBM produced are nearly the same as in Case P, in which wells are completed in only the Pratt coal zone (Table 23 and Figs. 59 through 60). Also, Case ML-BC, in which wells are completed in the Mary Lee and Black Creek coal zones, has nearly identical results to Case ML, in which wells are completed in only the Mary Lee coal zone. So the breakthrough time, cumul

ative production, and cumulative injection depend mainly on coal zone permeability. The Well BHP at the injector for different single coal zone is different because of the different initial reservoir pressure (Fig. 61). The BHP for case Pratt coal zone is the lowest while the BHP for case Black Creek coal zone is highest. However, when considering Case P-ML and Case P-ML-BC, the BHP at the injector is nearly the same as in Case P, in which wells are completed in only the Pratt coal zone (Fig. 61). Case ML-BC, in which wells are completed in the Mary Lee and Black Creek coal zones, has nearly identical results to Case ML, in which wells are completed in only the Mary Lee coal zone.

The 3D colorfill figures indicate that when the three zones are completed at the same time, the main layer that produces CBM is Pratt, since the breakthrough for it is earliest (Fig. 62). Therefore, it is much better to deal with the layers one by one when conducting CO_2 sequestration and ECBM.

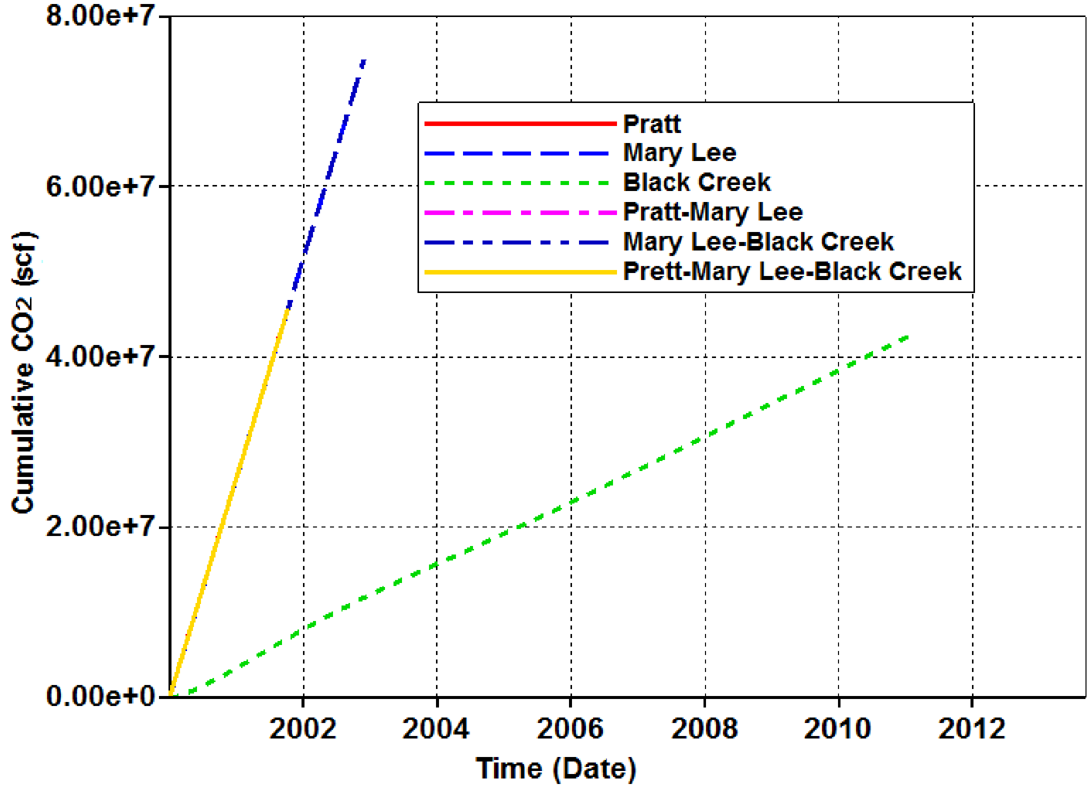


Fig. 59—Cumulative CO_2 injection for the cases to study the completion of different layers based on 1/8 of 40-acre spacing, 5-spot well pattern.

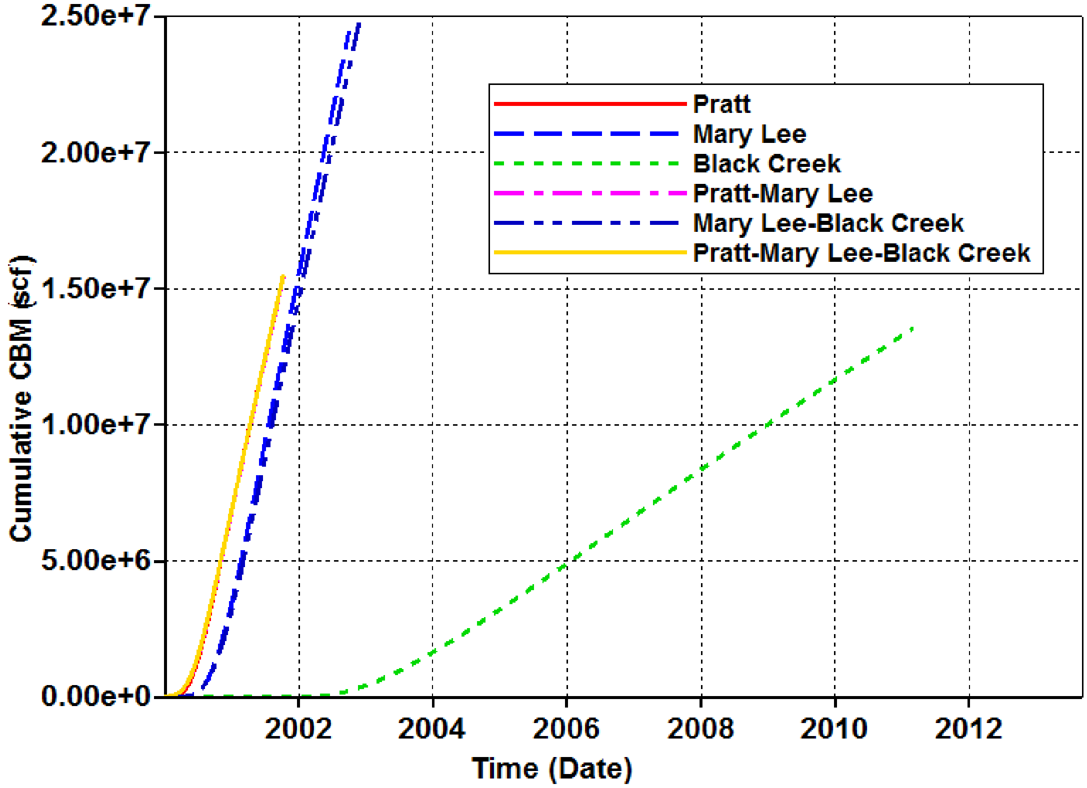


Fig. 60—Cumulative CBM production for the cases to study the completion of different layers based on 1/8 of 40-acre spacing, 5-spot well pattern.

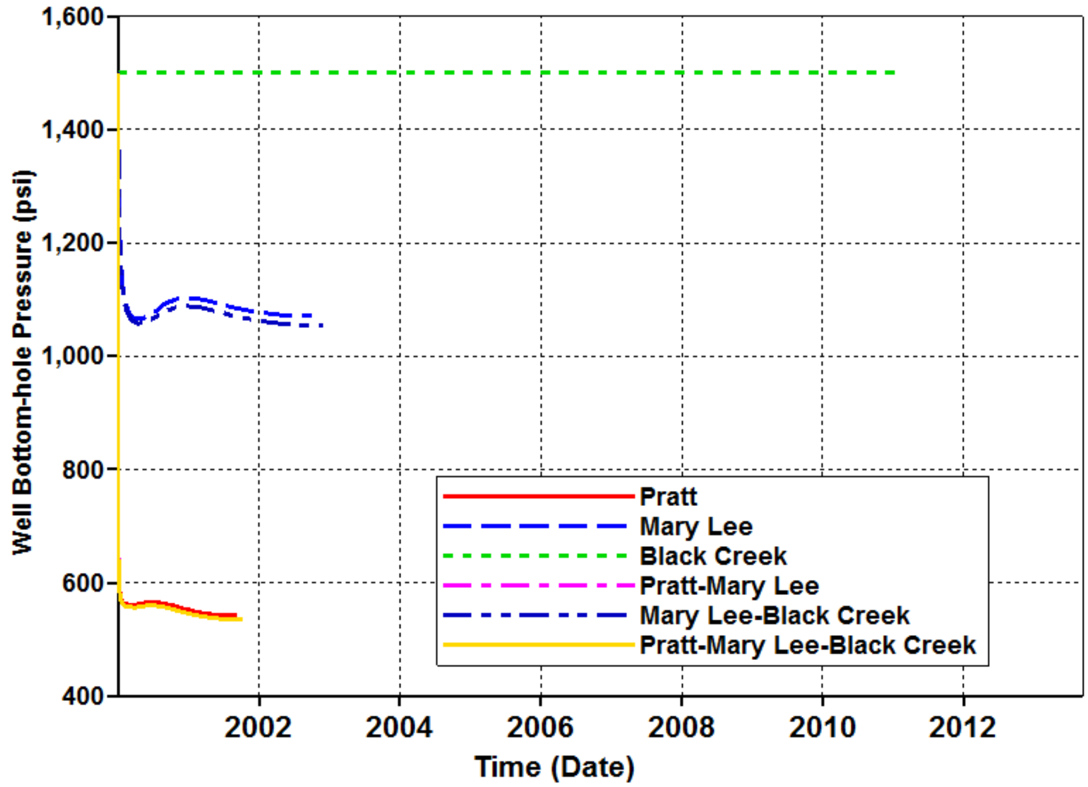


Fig. 61—Well BHP at the injector for the cases to study the completion of different layers based on 1/8 of 40-acre spacing, 5-spot well pattern

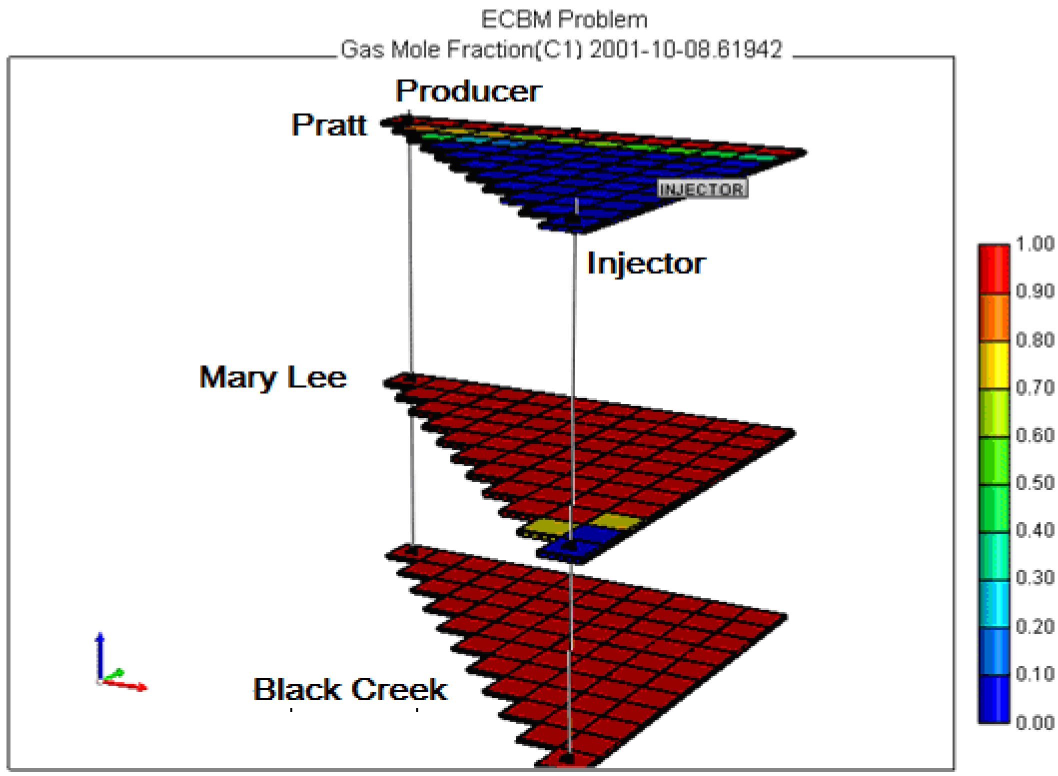


Fig 62—Methane gas mole fraction at breakthrough time the cases to study the completion of different layers based on 1/8 of 40-ac spacing, 5-spot well pattern, where the red arrow is the x-direction, the green arrow is the y-direction and the blue arrow is the z-direction.

Sensitivity Study of the Effects of Well BHP at Injector and Producer

After the sensitivity analysis in previous sections, I conducted six cases with different well BHP constraints in the Mary Lee coal group. The six cases were based on the base case, 80-acre, 5-spot well pattern. Estimation of the total volumes of CO_2 that can be sequestered and total volumes of CBM that can be produced in Blue Creek field of Black Warrior basin were determined from the data obtained during this study.

Table 24—Constraints for Effects of Well BHP at Injector and Producer.

Maximum Pressure at Injector (psi)	**Minimum Pressure at Producer (psi)**	**Cumulative Injection of CO2 (MMscf)**	**Cumulative Production of CBM (MMscf)**	**Cumulative Production of water (bbl)**	**Breakthrough Time (days)**
1500	50	70.9	24.5	2,745.3	1,005
1000	50	69.7	24.7	3,019.5	1,309
1500	100	70.9	24.3	2,701.2	1,005
1000	100	70.0	24.9	3,003.7	1,339
1500	500	75.2	24.6	2,309.9	1,065
1000	500	72.2	25.0	2,790.7	1,827

The pressure constraints do not affect the sequestration and production significantly, unless the pressure threshold is so low that it terminates injection prematurely. However, the breakthrough time varies a lot for these cases, which affects water production (**Table 24**).

On the basis of this modeling, I suggest that a lower injector well BHP constraint and higher producer well BHP (1000 psi, 500 psi) respectively constraint will perform as well as the higher injection pressure and lower producer well BHP (1500 psi, 50 psi) respectively. Gas from the production well will require less compression before entering transmission lines. However, considering the breakthrough time is longer, economic analysis should be included in future work.

Discussion of Potential for CO_2-ECBM Project in Blue Creek Field

If the maximum well BHP at the injector is 1,000 psi, minimum well BHP at the producer is 500 psi, the maximum injection rate is 70 Mscf/D, and the production rate is 35 Mscf/D. **Table 25** shows the volumes of CO_2 that can be sequestered, gas and water that can be produced, and breakthrough time for Pratt, Mary-Lee, and Black-Creek coal zones on 5-spot pattern, 40-acre well spacing.

For the whole Blue Creek field, **Tables 26 and 27** show the estimated CO_2 sequestration and ECBM production. Since the total area of Blue Creek field is 55,973 acres, for an 80-acre 5 spot well pattern, approximately 700 wells are needed in this field. Langmuir curves were used to calculate gas contents for CO_2 and CBM at the specific pressure for each coal zone. Then I calculated the recovery factors for production as the CBM produced divides the GIP of CBM. I also calculated the sequestration factor as the CO_2 sequestered divides the total volume of CO_2 that this coal matrix can theoretically adsorb.

Approximately 0.3 Tcf of CBM can be recovered from the three coal zones in the Blue Creek field with an average recovery factor of 68.8% for the whole field (Table 26). Pashin et al. (2004) state that the two electric generating plants in Alabama release 2.4 Tcf of CO_2 annually. El Paso wishes to inject 50 MMscf of CO_2 per day into Blue Creek field, which is 18.25 Bcf/yr. The total volume of CO_2 that can be sequestered is estimated to be 0.88 Tcf for the three coal zones in Blue Creek Field (Table 27). Thus, the Blue Creek field has the capacity to sequester CO_2 for 48 years, if the injection rate remains at 50 MMcf/D.

Table 25—Simulation Results for the Pratt, Mary-Lee, and Black Creek Coal Zones

Coal zones	**Injected CO_2 (MMscf)**	**Produced CBM (MMscf)**	**Produced Water (bbl)**	**Break-though time (days)**
Pratt	398.4	112	14,896.8	706
Mary-Lee	577.6	200	22,325.6	1,827
Black-Creek	297.6	112	13,619.2	20,150
Total for 80-ac	1,273.6	424	50,841.6	

Table 26—Estimated Volumes of ECBM Production From Blue Creek Field.

Recoverable CBM Resources				
Coal Zones	Pratt	Mary Lee	Black Creek	Total
Coal Thickness, ft	6	8	4	18
Coal Density, ton/ac-ft	1,875.5	1,875.5	1,875.5	
Gas Content, scf/ton	198.2	251.1	270.7	
Pattern Area, ac	80	80	80	
GIP (per 80 ac), Bcf	0.179	0.301	0.162	0.642
Recoverable Resources (per 80 ac), Bcf	0.112	0.202	0.112	0.442
Recovery factor, fraction	0.62	0.66	0.69	0.69
Region Area, ac	55,973			
Number of 80-acre 5 spot patterns	700			
Potential Recoverable Resources (Bcf)	309.4			

Table 27—Estimated Volumes of CO_2 that Could be Sequestered in Blue Creek Field.

Potential Coalbed Sequestration of CO_2 Capacity				
Coal Zones	Pratt	Mary Lee	Black Creek	Total
Coal Thickness, ft	6	8	4	18
Coal Density, ton/ac-ft	1,875.5	1,875.5	1,875.5	
Gas Content, scf/ton	512.5	600.2	625.3	
Pattern Area, ac	80	80	80	
Theoretical Sequestration Capacity (per 80 ac), Bcf	0.46	0.72	0.38	1.56
Sequestered CO_2 Volume (per 80 acre), Bcf	0.398	0.577	0.298	1.270
Sequestration factor, fraction	0.86	0.80	0.79	0.81
Region Area, ac	55,973			
Number of 80-ac 5 spot patterns	700			
Potential Recoverable Resources (Bcf)	889			

CONCLUSIONS AND RECOMMENDATIONS

Conclusions

- Methane resources and CO_2 sequestration potential of the three coal zones in Blue Creek field in Black Warrior basin are significant. Recoverable ECBM resources are estimated to be 0.3 Tcf, based on the reservoir condition without any primary production. Potential CO_2 sequestration capacity is 0.88 Tcf. If CO_2 is injected at 50 MMscf/D, the Blue Creek field has the capacity to sequester CO_2 for 48 years.

- Since lower injector well BHP constraint and higher producer well BHP (1000 psi, 500 psi) respectively constraint performs as well as the higher injection pressure and lower producer well BHP (1500 psi, 50 psi) respectively. For the case of lower injector well BHP constraint and higher producer well BHP (1000 psi, 500 psi), gas from the production well will require less compression before entering transmission lines. So the optimal operating conditions are selected to be a maximum well BHP of 1,000 psi at the injector, minimum BHP of 500 psi at the producer, maximum injection rate of 70 Mscf/D/well, and production rate of 35 Mscf/D/well. For this case, injection of 100% CO_2 in coal seams results in average volumes of CO_2 sequestered of 1.27 Bcf, and average volumes of methane produced of approximately 0.42 Bcf on an 80-acre, 5-spot pattern basis. The recovery factor for CBM is 68.8%.

- Of the three coal zones completed at the same time, the breakthrough time, production and injection results depend mainly on the Pratt coal zone, which has the highest permeability and lowest pressure. Thus, it is better to inject CO_2 into one layer at one time. When the breakthrough occurs in the Pratt coal zone, the well can be shut in at the Pratt zone while injection and production continue at the other zones.

- Dewatering prior to injection of CO_2 delays the time to breakthrough so the initial pressure before injection is lower. Higher injection rate constraints can be achieved without pressure buildup at the injector. For a higher injection rate of 88 Mscf/D, 10% more CO_2 can be sequestrated than in the base case, which has an injection rate of 70 Mscf/D.

- Extra time for soaking makes no big difference for the CO_2 sequestration process in this 80-acre scale well pattern of Blue Creek field. However, a change of fracture pressure was observed when CO_2 adsorbed in the coal matrix.

- Permeability anisotropy effects decrease the volume of CO_2 sequestered and the ECBM recovered. When the anisotropy ratio of permeability along the x axis to the y axis is 5:1, the volume of CO_2 sequestered is 30% less than in case of isotropic permeability. Also, the breakthrough time is delayed to more than 3 times. Therefore, permeability anisotropy should be considered when designing well layout.

- As expected from the Langmuir isotherms, for the Blue Creek field, injection of pure CO_2 has the highest recovery factor, which is two times more than the case of flue gas injected. However, injection of pure CO_2 is likely more costly when considering the capture costs, so economics analysis is needed in future work.

Recommendations

- Economics analysis should be conducted to evaluate the CO_2 sequestration and ECBM potential in Blue Creek field, taking into account the cost for pure CO_2 and flue gas supply, cost to compress the gas for injection, and cost to compress the methane for transportation.

- A pilot project should be implemented to further evaluate the reservoir properties and the potential for CO_2 Sequestration and ECBM. Considering the engineering and economics factors, I recommend that the pilot case be conducted with maximum well BHP of 1,000 psi at the injector, minimum well BHP of 500 psi at the producer, maximum injection rate of 70 Mscf/D, and production rate of 35 Mscf/D.

NOMENCLATURE

c_f	= Fracture pore volume compressibility (psi^{-1})
e	= Efficiency of production
E	= Young's Modulus (psi)
k	= Permeability (md)
k_i	= Initial Permeability (md)
K	= Bulk Modulus (psi)
M	= Axial modulus (psi)
p	= Pressure (psi)
p_i	= Initial pressure (psi)
p_L	= Langmuir pressure (psi)
V	= Desorptive/adsorptive gas volume (scf)
$V_{cum,CBM,p}$	= Volume of cumulative CBM production (scf)
$V_{cum,gas,i}$	= Volume of cumulative gas injection (scf)
V_L	= Langmuir volume (scf)
α	= Relation parameter of porosity and permeability
ε_L	= Strain at infinite pressure
ν	= Poisson's ratio
ϕ	= Fracture porosity at pressure p
ϕ_i	= Initial natural fracture porosity

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