CO_2 Sequestration Potential of Texas Low-Rank Coals

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ABSTRACT

Injection of CO_2 in coalbeds is a plausible method of reducing atmospheric emissions of CO_2, and it can have the additional benefit of enhancing methane recovery from coal. Most previous studies have evaluated the merits of CO_2 disposal in high-rank coals. The objective of this research was to determine the technical and economic feasibility of CO_2 sequestration in, and enhanced coalbed methane (ECBM) recovery from, low-rank coals in the Texas Gulf Coast area.

Our research included an extensive coal characterization program, including acquisition and analysis of coal core samples and well transient test data. We conducted deterministic and probabilistic reservoir simulation and economic studies to evaluate the effects of injectant fluid composition (pure CO_2 and flue gas), well spacing, injection rate, and dewatering on CO_2 sequestration and ECBM recovery in low-rank coals of the Calvert Bluff formation of the Texas Wilcox Group..

Shallow and deep Calvert Bluff coals occur in two, distinct, coalbed gas petroleum systems that are separated by a transition zone. Calvert Bluff coals < 3,500 ft deep are part of a biogenic coalbed gas system. They have low gas content and are part of a freshwater aquifer. In contrast, Wilcox coals deeper than 3,500 ft are part of a thermogenic coalbed gas system. They have high gas content and are part of a saline aquifer. CO_2 sequestration and ECBM projects in Calvert Bluff low-rank coals of East-Central Texas must be located in the deeper, unmineable coals, because shallow Wilcox coals are part of a protected freshwater aquifer.

Probabilistic simulation of 100% CO_2 injection into 20 feet of Calvert Bluff coal in an 80-acre 5-spot pattern indicates that these coals can store 1.27 to 2.25 Bcf of CO_2 at depths of 6,200 ft, with an ECBM recovery of 0.48 to 0.85 Bcf. Simulation results of flue gas injection (87% N_2 - 13% CO_2) indicate that these same coals can store 0.34 to 0.59 Bcf of CO_2 with an ECBM recovery of 0.68 to 1.20 Bcf.

Economic modeling of CO_2 sequestration and ECBM recovery indicates predominately negative economic indicators for the reservoir depths (4,000 to 6,200 ft) and well spacings investigated, using natural gas prices ranging from $2 to $12 per Mscf and CO_2 credits based on carbon market prices ranging from $0.05 to $1.58 per Mscf CO_2 ($1.00 to $30.00 per ton CO_2). Injection of flue gas (87% N_2 - 13% CO_2) results in better economic performance than injection of 100% CO_2.

CO_2 sequestration potential and methane resources in low-rank coals of the Lower Calvert Bluff formation in East-Central Texas are significant. The potential CO_2 sequestration capacity of the coals ranges between 27.2 and 49.2 Tcf (1.57 and 2.69 billion tons), with a mean value of 38 Tcf (2.2 billion tons), assuming a 72.4% injection efficiency. Estimates of recoverable methane resources range between 6.3 and 13.6 Tcf, with a mean of 9.8 Tcf, assuming a 71.3% recovery factor. Moderate increases in gas prices and/or carbon credits could generate attractive economic conditions that, combined with the close proximity of many CO_2 point sources near unmineable coalbeds, could enable commercial CO_2 sequestration and ECBM projects in Texas low-rank coals.

Additional studies are needed to characterize Wilcox regional methane coalbed gas systems and their boundaries, and to assess potential of other low-rank coal beds. Results from this study may be transferable to other low-rank coal formations and regions.

TABLE OF CONTENTS

Page

LIST OF TABLES

TABLE **Page**

LIST OF FIGURES

FIGURE **Page**

EXECUTIVE SUMMARY

Abundant Wilcox Group and younger low-rank coals occur throughout the Gulf Coastal Plain, from Mexico to Alabama, underlying numerous electric generating plants that are point source emitters of CO_2. The objectives of this project were to evaluate the feasibility of carbon dioxide (CO_2) sequestration in Texas low-rank coals and to determine the potential for enhanced coalbed methane (ECBM) recovery as an added benefit of sequestration.

To assess the technical and economic feasibility of CO_2 sequestration in, and ECBM recovery from, low-rank coals in the Texas Gulf Coast area, we evaluated locations of point source emitters of CO_2 and the characteristics of local, low-rank coal deposits. We characterized coal properties based on review of the literature, analysis of core samples and well pressure transient test data obtained during this study, and data acquired through a data-sharing agreement with Anadarko Petroleum Corporation. We conducted reservoir simulation and economic modeling studies of both CO_2 and flue gas injection scenarios to evaluate the effects of well spacing, injectant fluid composition, injection rate, and dewatering on CO_2 sequestration and ECBM recovery.

The Calvert Bluff formation of the Wilcox Group in East-Central Texas was selected to assess the potential for CO_2 sequestration and ECBM in low-rank coals, because there are many power plants in the area, coal resources are abundant, the deep coal is known to contain methane, and there is industry interest in the both methane resources and CO_2 sequestration.

Shallow Wilcox coals are high-rank lignites and are thermally immature for oil generation. Thermal maturity increases with depth, and deep Wilcox coals in East-Central Texas are high-volatile C bituminous rank and are in the oil-generation/early gas-generation window. Shallow and deep Wilcox coals occur in two, distinct, coalbed gas petroleum systems that are separated by a transition zone. Wilcox coals < 3,500 ft deep are part of a biogenic coalbed gas system. They have low gas content (<50 scf/t (standard cubic feet per ton); as received), isotopically light carbon in the methane, and are part of a freshwater aquifer. In contrast, Wilcox coals deeper than 3,500 ft are part of a thermogenic coalbed gas system. They have high gas content (100 to 430 scf/t; as received), isotopically heavier carbon in the methane, and they are part of a saline aquifer. Boundary between the two coalbed gas systems is transitional; its regional occurrence requires further study with additional data. CO_2 sequestration and ECBM projects in Calvert Bluff low-rank coals of East-Central Texas must be located in the deeper (> 3,500 ft deep), unmineable coals of the thermogenic coalbed gas system, because shallow Wilcox coals are part of a protected freshwater aquifer.

To evaluate the potential for CO_2 sequestration and ECBM in low-rank coals, we conservatively modeled 20 ft of Calvert Bluff net coal thickness in the region of the Sam K. Seymour power plant in East-Central Texas. However, maps made for this research show that the Wilcox Group total coal thickness ranges between 50 and 140 ft in seams > 2 ft thick, and total coal thickness for the Calvert Bluff formation of the Wilcox Group is 25 to 75 ft. Calvert Bluff coal occurs in 5 to 20 seams; 1 to 6 seams are greater than 5 ft thick. The thickest individual Calvert Bluff coal in each well ranged from 6 to 12 ft.

Probabilistic simulation of 100% CO_2 injection in an 80-acre 5-spot pattern indicates that Wilcox Group low-rank coals can store 1.27 to 2.25 Bcf of CO_2 at depths of

6,200 ft, with an ECBM recovery of 0.48 to 0.85 Bcf. CO_2 sequestration volumes decrease and ECBM production increases with increasing N_2 content in the injected gas. Simulation results of 50% CO_2 - 50% N_2 injection in the same 80-acre 5-spot pattern indicate that these coals can store 0.86 to 1.52 Bcf of CO_2, with an ECBM recovery of 0.62 to 1.10 Bcf. Simulation results of flue gas injection (87% N_2 - 13% CO_2) indicate that these same coals can store 0.34 to 0.59 Bcf of CO_2 with an ECBM recovery of 0.68 to 1.20 Bcf.

Economic modeling of CO_2 sequestration and ECBM recovery for 100% CO_2 injection indicates predominately negative economic indicators for the reservoir depths and well spacings investigated, using natural gas prices ranging from \$2 to \$12 per Mscf and CO_2 credits based on carbon market prices ranging from \$0.05 to \$1.58 per Mscf CO_2 (\$1.00 to \$30.00 per ton CO_2). Injection of flue gas (87% N_2 - 13% CO_2) results in better economic performance than injection of 100% CO_2. We conclude that CO_2 sequestration/ECBM projects in Lower Calvert Bluff coals in East-Central Texas will not be profitable over the full range of economic conditions investigated in this study. However, with gas prices and/or carbon market prices at the high ends of the ranges investigated, projects are likely to be economically viable.

There is a potential fairway for significant CO_2 sequestration and enhanced coalbed methane production in low-rank coals of Calvert Bluff formation (Wilcox Group) of the Gulf Coastal plain, East-Central Texas. Two electric power plants are point-source emitters of CO_2 in this fairway; CO_2 from 4 additional, nearby power plants could be transported to injection sites. The potential CO2 sequestration capacity of the Calvert Bluff coals in the 2,930-mi^2 (1,875,200-ac) fairway ranges between 27.2 and 49.2 Tcf (1.57 and 2.69 billion tons), with a mean value of 38 Tcf (2.2 billion tons), assuming a 72.4% injection efficiency. We estimate recoverable methane resources between 6.3 and 13.6 Tcf, with a mean of 9.8 Tcf, assuming a 71.3% recovery factor.

We recommend additional reservoir characterization and evaluation of petroleum systems, including: (1) gas desorption of whole cores and additional sorption isotherms, especially in freshwater interval; (2) isotopic and compositional analyses of desorbed coalbed gas samples; (3) vitrinite reflectance data; and (4) water compositional analyses to calibrate resistivity logs and map water quality. The primary objective would be to determine the extent and characteristics of the thermogenic coalbed gas system and the boundary between this and the shallow, biogenic coalbed gas system.

INTRODUCTION

Anthropogenic greenhouse gas emissions have potentially contributed to global warming during the last few decades. The most important greenhouse gases that contribute to this effect are water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide, tropospheric ozone, and man-made chlorofluoro-carbons, with CO_2 accounting for 63.6% of the relative contribution. The primary CO_2 source is coal combustion for electricity generation, which is the largest source of energy from the earth (Ahmed, 1981).

Texas power plants emitted more CO_2 in 2002 than those in any other state. The estimated amount of CO_2 emitted in 2002 from combustion of fossil fuels (gas, lignite, and coal) by major power plants in Texas was about 248,808,000 tons (Texas Environmental Profiles, 2002). About 160,000,000 tons were emitted from combustion of lignite and coal, which accounted for approximately 7.7% of total CO_2 emissions from coal in the U.S.

Fig. 1 shows the estimated amount of CO_2 emitted and fuel type by power plant for the 20 largest Texas CO_2 emitters. CO_2 emissions from these power plants range from 20.7 to 2.5 million tons per year. **Fig. 2** depicts the relative contribution of CO_2 emissions from the top 20 power plants in Texas. These 20 power plants account for 67% of the Texas CO_2 emissions from combustion of fossil fuels mentioned above.

CO_2 sequestration in geological formations such as coal seams is a plausible method for reducing atmospheric emissions while fossil fuels are still being used (Sams et al., 2002) and, at the same time, enhancing methane recovery. CO_2 injection accelerates coalbed methane production and reduces the cost of a sequestration project.

Coal natural gas reservoirs are considered to be dual-storage systems (Mavor et al., 2003). Therefore, coalbed methane reservoirs are typically modeled with dual-porosity/single-permeability characteristics when forecasting well or field performance. Coal-gas reservoirs are characterized by matrix (coal) and fracture (cleat) systems. In the production process, as the fluid pressure decreases, gas desorbs from the coal into the matrix porosity, diffuses through the bulk matrix, and then flows into and through the fractures. Similarly, during CO_2 injection for carbon sequestration, the pathway for CO_2 sorption is exactly reversed (Sams et al., 2002).

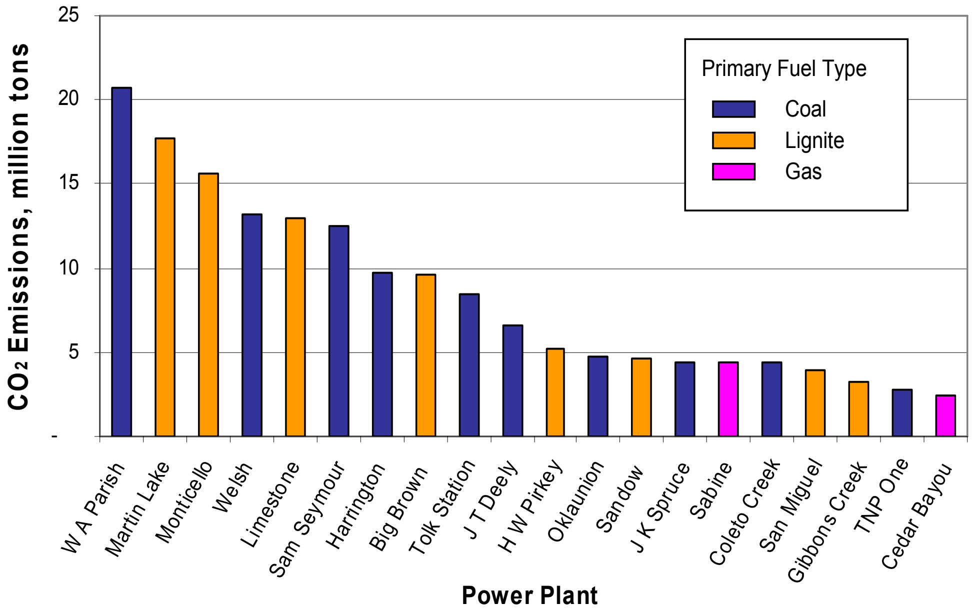


Fig. 1. CO_2 emissions from the top 20 power plants in Texas, 2002.

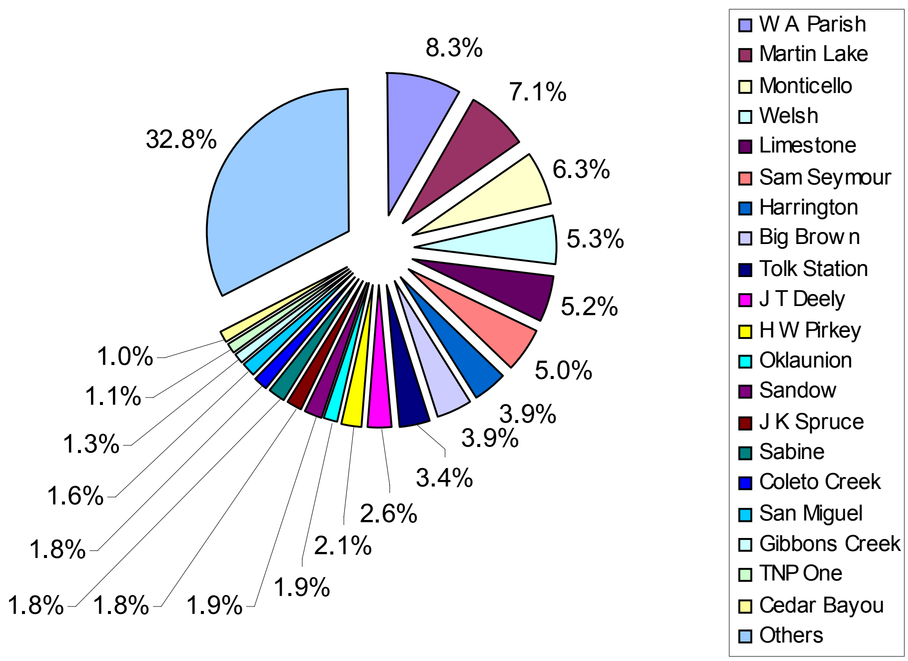


Fig. 2. Relative CO_2 emissions from the 20 largest power plants in Texas, 2002.

The CO_2 sequestration/enhanced coalbed methane (ECBM) recovery process takes place when methane in the primary storage system is replaced with CO_2, which adsorbs preferentially to the coal as compared to methane. This process increases methane production and stores CO_2 in the coal. A sequestration project typically terminates when CO_2 breaks through at the production wells after the majority of the well pattern has been swept.

Knowledge of (1) sorption capacity, or isotherm behavior, of gaseous species and, (2) coal permeability changes with gas injection is critical for better understanding of CO_2 sequestration/ECBM recovery processes. Reservoir simulators are being improved to include features that account for coal-matrix swelling from CO_2 adsorption on coal, mixed-gas adsorption/desorption and diffusion, compaction/dilation of the natural fracture system under stresses, and non-isothermal effects of gas injection. A comparison (Law et al., 2002) of numerical simulators for ECBM recovery with pure CO_2 injection identified areas of improvement needed to correctly model complicated mechanisms involved in the ECBM recovery process.

CO_2 sequestration/ECBM production has been investigated in high-rank coals. Reservoir simulation studies and field tests are being conducted to assess CO_2 sequestration potential and ECBM recovery in these coals. Two field projects in the San Juan basin of New Mexico are investigating the ECBM recovery process. One is the Allison Unit, operated by Burlington Resources Inc., into which CO_2 is being injected, and the second is the Tiffany Unit, operated by BP America Inc., into which N_2 is being injected (Reeves, 2003). These projects, funded by the Department of Energy (DOE) in a collaboration agreement with industry, are testing the process in high-rank coals.

No field project currently is attempting to sequester CO_2 in low-rank coals. Abundant low-rank coals in the Gulf Coastal plain, specifically in Texas, could be possible targets for CO_2 sequestration and enhanced methane production. A map of Texas showing the Wilcox Group outcrop and locations of the 20 largest electrical generating plants in terms of the quantities of CO_2 emitted is shown in **Fig. 3**. Close proximity of many CO_2 point sources near unmineable coal beds make this area among the best in the U.S. to assess the viability of CO_2 sequestration in low-rank coals and to test technology that may be transferable to other low-rank coals of the U.S. and the world.

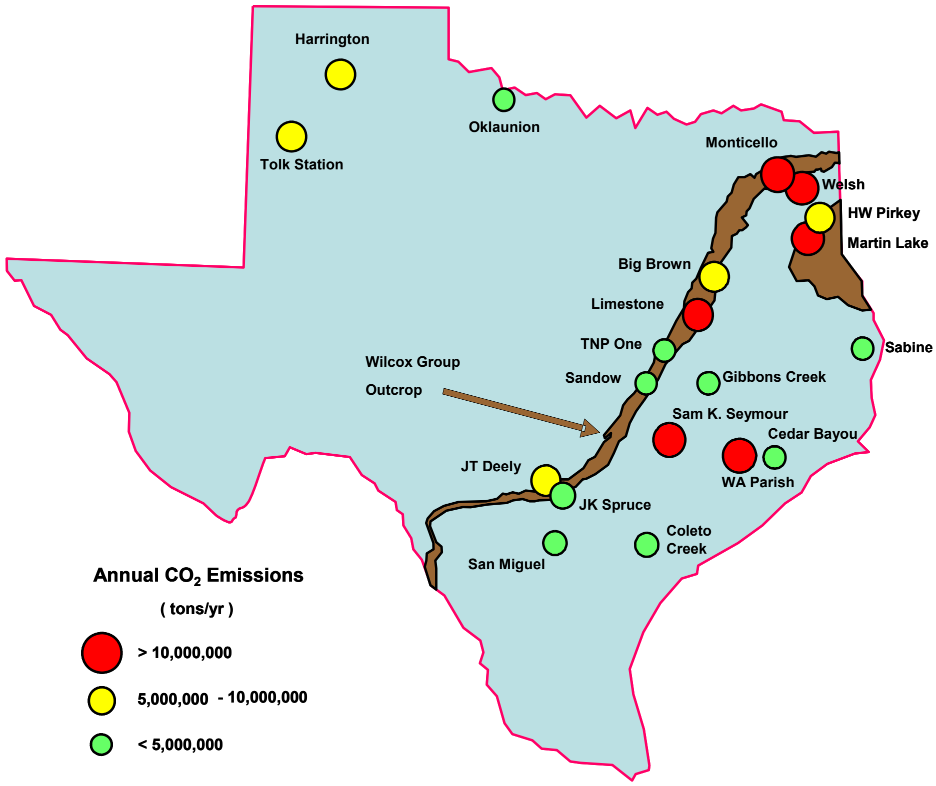


Fig. 3. Wilcox Group outcrop and locations of the 20 largest Texas CO_2 emitters, 2002. Emissions are reported in tons/year.

Prior to this project, fundamental properties of Texas coals were well known and published (Kaiser et al., 1980; Tewalt, 1986; Mukhopadhyay, 1989). However, other parameters important to CO_2 sequestration, such as sorptive capacities for different gas species, were poorly known as they can be determined only by analyzing core samples. It had been widely reported that coals will adsorb approximately twice as much CO_2 as methane, but tests on low-rank coal samples from the Northern Great Plains and Texas indicated that these coals may adsorb 6 to 18 times as much CO_2 as methane. Data concerning the in-situ gas content and composition and the sorptive capacity for different gas species were lacking for Texas coals. Permeability is an important property that affects both the injection of CO_2 for sequestration and producibility of coalbed methane. Only limited permeability data for East-Central Texas coal beds were available, from in-situ gasification studies conducted in the late 1970's and early 1980's. Additional data collection, coal reservoir characterization and reservoir modeling were needed in order to assess the potential for CO_2 sequestration in, and enhanced methane production from, Texas low-rank coals.

Project Objectives

The objectives of this research were to evaluate the feasibility and the environmental and economic impacts of sequestration of carbon dioxide (CO_2) in Texas low-rank coal beds.

Specific project goals were to:

(1) Determine the locations and quantities of anthropogenic CO_2 sources near possible coal injection sites,
(2) Evaluate the technical feasibility and volume of CO_2 that could be sequestered in Texas coals, and
(3) Determine the potential for enhanced coalbed methane (ECBM) recovery as an added benefit of sequestration.

Methods

The project objectives were achieved by combining analysis of Texas power plant flue gas emissions, detailed characterization of prospective coal beds, and computer simulation of CO_2 sequestration in the coals. To characterize prospective coals for CO_2 injection, we collected data from public sources, determined coal characteristics from outcrops and mines, collected sidewall core coal samples for detailed analysis, and conducted well tests for determining in-situ fracture permeability.

We conducted a parametric simulation study using a pattern model and reservoir characteristics of the Wilcox Group low-rank coals in East-Central Texas. Reservoir simulation was coupled with Monte-Carlo simulation to conduct probabilistic reservoir modeling studies consisting of thousands of simulation runs to quantify the uncertainty in our forecasts of CO_2 sequestration and methane production. From the simulation results we determined volumes of CO_2 that can be sequestered, and impact on coalbed methane production on a pattern and regional basis.

Finally, we performed probabilistic economic modeling of CO_2 sequestration and ECBM recovery on a pattern basis, incorporating injection and production results from our reservoir simulation studies.

EXPERIMENTAL

Experimental procedures conducted as part of this research included desorption of sidewall and cutting samples of coal to assess coalbed gas contents, and isotherm studies of coals to determine adsorption capacities for CO_2, CH_4, and N_2. Other experimental procedures were field tests of permeability of two coal beds. Experimental procedures were conducted by industry service providers using standard industry practices. Results of all experiments are discussed in the appropriate sections of this report.

RESULTS AND DISCUSSION

Site Selection and Characterization of Texas Low-Rank Coals for CO_2 Sequestration and Enhanced Coalbed Methane Recovery

Most of the 20 major electricity generating plants that emit CO_2 in Texas are in the eastern part of the state (**Fig. 3**). Past studies of the CO_2 sequestration potential of coal focused on high-rank (bituminous) coals (Carroll and Pashin, 2003 ; Mavor et al., 2004). However, in East Texas, as in many areas of the U.S. and the world, there are no high-rank coals, but low-rank coals are abundant. Economic methane production from low-rank (subbituminous) coals has been demonstrated in the Powder River Basin of Wyoming and Montana (Ayers and Zuber, 1999). Successful primary production of gas from the Powder River Basin indicates that low-rank coals may have adequate reservoir properties for CO_2 sequestration. Thus, a primary objective of this study was to model the potential for CO_2 sequestration and ECBM in low-rank coals.

In this chapter, we describe the process by which we selected the coal-bearing formation and the area that were modeled for CO_2 sequestration and ECBM. For the selected area, we report the coal and coalbed gas properties and describe the CH_4, CO_2, and N_2 sorptive capacities of the coal, all of which are parameters used in the reservoir modeling (see section on **Simulation Approach,** p. 63). Finally, we describe two inferred coalbed petroleum systems; these are (1) a shallow biogenic gas system and (2) a deeper thermogenic gas system. The model is based on the deeper thermogenic system. The shallow system would be rejected for CO_2 sequestration, owing to the presence of freshwater aquifer sandstones interbedded with coal beds; moreover, coals in the shallow petroleum system have insufficient volumes of adsorbed methane to warrant testing for primary gas production or to offset costs of CO_2 sequestration. Validity and extents of these petroleum systems should be tested in future work, to guide projects for either primary production of coalbed methane or CO_2 sequestration with enhanced coalbed methane production.

Selection of a Low-Rank Coal Formation and a Potential Area for CO_2 Sequestration and Enhanced Coalbed Methane Production

Overview of the Selection of the Coal-Bearing Unit and the Region for Coal Reservoir Modeling

To select the coal-bearing formation and the area for coal reservoir modeling, we reviewed literature concerning coal occurrences to assess the (1) presence and abundance of coal near CO_2 point source emitters, (2) amount of data available to determine coal properties, (3) favorability of coal reservoir properties, and (4) opportunities for cost-sharing data collection with oil and gas operators. We narrowed the choice to two potential areas having the same coal-bearing formation. Next, we entered an agreement for data-sharing and cooperative data collection with Anadarko, and on the basis of our analysis of the data, we selected a final area for coal characterization and reservoir modeling. For the selected area, we collected and analyzed data from two cooperative wells with Anadarko Petroleum Corporation (Anadarko). We mapped coal properties and integrated all geologic and hydrologic data to build a model for reservoir simulation and to develop petroleum systems models for the region.

There are four primary coal-bearing units in eastern Texas. From oldest to youngest, these are the Cretaceous age Olmos Formation (South Texas) and the Tertiary age Wilcox, Claiborne and Jackson Groups (**Figs. 4** and **5**). For the Jackson Group, the coal-bearing formations are the Manning and the Wellborn, which have coal deposits in East-Central and South Texas. For the Claiborne Group, the coal-bearing formation is the Yegua formation, which has coal in East-Central Texas. In the Wilcox Group, the coal-bearing formations are the Hooper and Calvert Bluff formations. The Wilcox is the most prolific coal-bearing formation in the Gulf Coastal Plain. It crops out from Texas to Alabama (**Fig. 5**), and provides coal to fuel numerous mine-site electricity generating plants that are CO_2 point source emitters. From outcrops in the Gulf Coastal Plain (**Figs. 4** and **5**), these coal-bearing strata dip basinward, toward the Gulf of Mexico.

On the basis of literature review, discussions with other researchers and industry representatives, and occurrence of coal relative to point sources of CO_2 (compare **Figs. 3** and **4**), we narrowed our focus to the Wilcox Group coals in (1) East-Central Texas, in the vicinity of the Gibbons Creek and Sam K. Seymour power plants, and (2) the Sabine Uplift area of East Texas, in the vicinity of Martin Lake power plant (**Fig. 4**). Then, we eliminated the Sabine Uplift area of East Texas area after assessing the Wilcox hydrology. Fresh groundwater in the Wilcox formation in the vicinity of the Martin Lake power plant would require transporting the CO_2 several tens of miles to a deeper Wilcox coal injection site. For the Gibbons Creek and Sam K. Seymour areas, we purchased well logs, made cross sections of the coal intervals, and revised regional coal maps. On the basis of those maps, review of the regional geology and hydrology, and assessment of the data obtained from Anadarko, we selected the Sam K. Seymour site for reservoir characterization and modelling. More detailed descriptions of these steps and the Data Exchange Agreement with Anadarko are in the following sections.

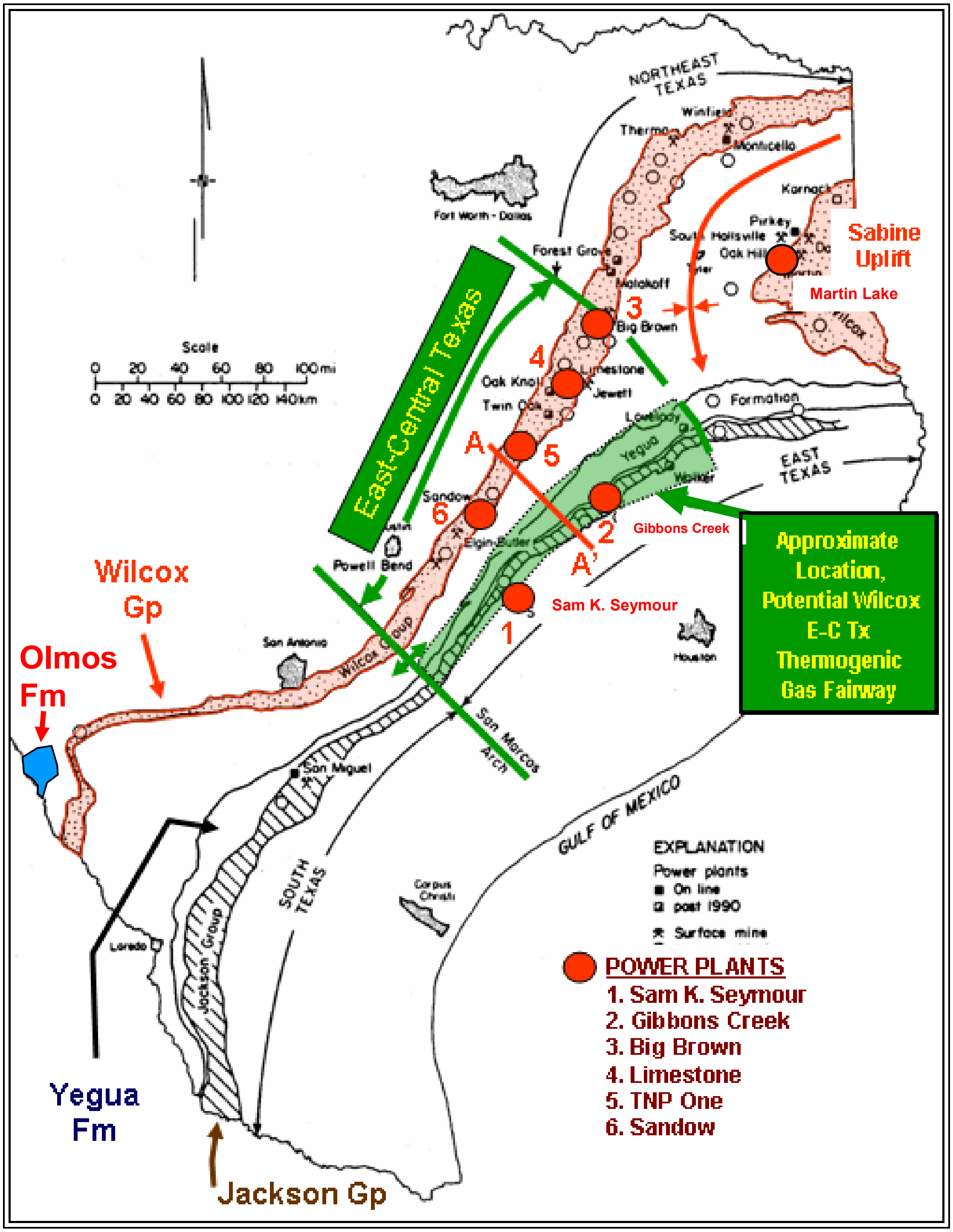


Fig. 4. **Map of Texas showing the Wilcox outcrop, location of the East-Central Texas area, and locations of the six electrical generating plants in East-Central Texas (modified from Kaiser, (1985).**

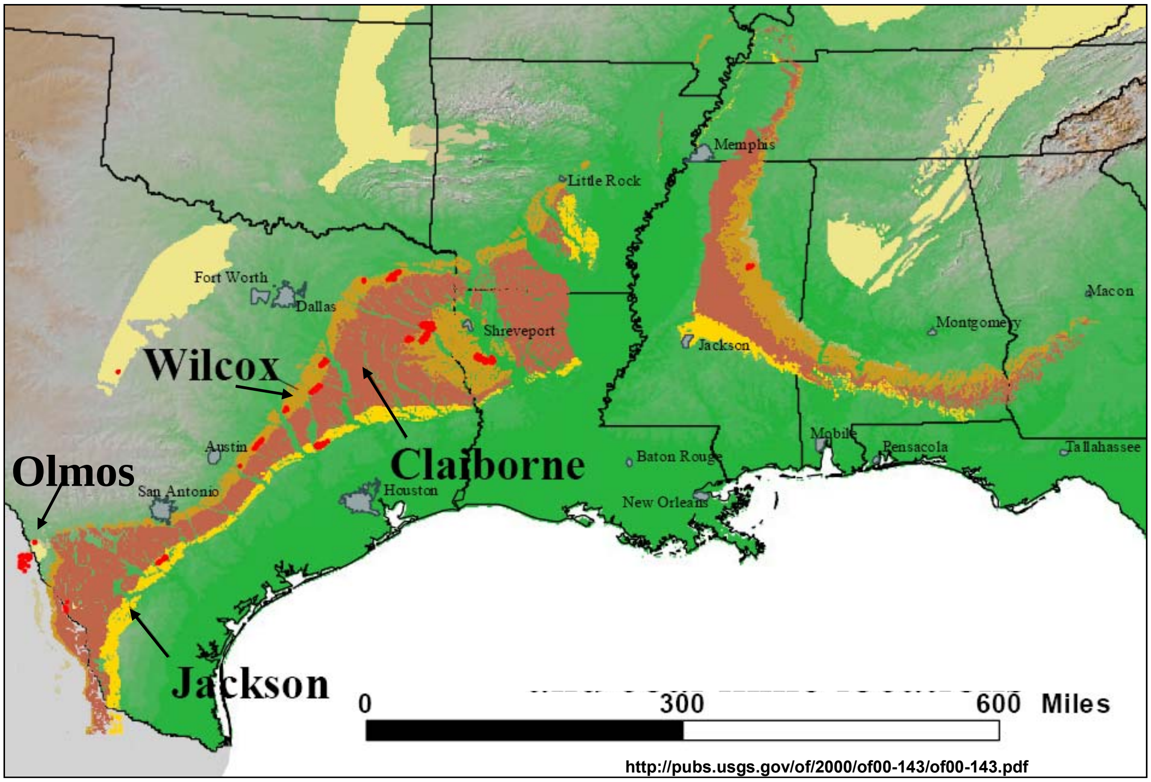


Fig. 5. Outcrop of Gulf Coastal Plains coal-bearing strata (Olmos, Wilcox, Claiborne, and Jackson), which dip basinward toward the Gulf of Mexico (USGS, 2000).

Texas Coal Production and Resources

In 2005, Texas was ranked 5th in the nation in coal production, and it produced 45.9 million short tons (41.6 million metric tons) of coal that were used primarily to generate electrical power (EIA, 2006). Texas coal was produced from 13 surface mines that accounted for 4.1% of U.S. total coal production (EIA, 2006). Twelve mines that produce from the Wilcox Group accounted for 93% of the Texas coal production. One surface mine in the Jackson Group accounted for the remaining 7% of the Texas coal production in 2005 (EIA, 2006).

Knowledge of Texas coal resources provided a basis for assessing the potential for CO_2 sequestration in, and enhanced production of coalbed methane from, Texas low-rank coals. Texas' shallow (less than 200 ft deep) coal resources are estimated to be 23.7 billion short tons in the Wilcox and Jackson Groups and in the Yegua Formation (**Figs. 4 and 6**) (Kaiser et al., 1980). For the Cretaceous Olmos Formation in South

Texas, Mapel (1967) reported 525 million short tons of inferred coal resources to a depth of 3,000 ft. In the early 1980's, the Texas Bureau of Economic Geology mapped coal resources and hydrology of deep-basin (200 to 2,000 ft deep) lignite in the Wilcox Group in East and East-Central Texas, to assess the viability of in-situ gasification (Ayers and Lewis, 1985; Kaiser, 1990). Ayers and Lewis (1985) reported 6.5 billion short tons of deep Wilcox coal in East-Central Texas, between 200 and 2,000 ft deep, and they estimated an additional 31 billion short tons (tons) of coal between depths of 2,000 and 6,000 ft in East-Central Texas. For the Sabine Uplift area in East Texas, Kaiser (1990) estimated 5.5 billion tons of coal in coal seams greater than 5 ft thick, between 200 and 2,000 feet deep. These Wilcox studies focused on the East and East-Central Texas areas due to the (1) abundance of coal resources and (2) significant number of in-situ gasification tests of coals being conducted by industry and by university researchers. These past resource studies were vital to the assessment of potential CO_2 sequestration project sites.

To evaluate the viability of CO_2 sequestration and ECBM production in low-rank coals requires knowledge of coal properties, including (1) coal quality, (2) coal sorptive capacity for CO_2, CH_4 and N_2, (3) in-situ methane and CO_2 content of coals, (4) formation temperature and pressure, and (5) coalbed permeability. Generally, sorptive capacity of coal for CO_2, CH_4 and other gases increases with coal rank or thermal maturity and decreases with increasing moisture and/or ash (inorganic) content. Moreover, the cleat (natural fracture) density of coal, which determines permeability, varies directly with coal rank and inversely with ash content.

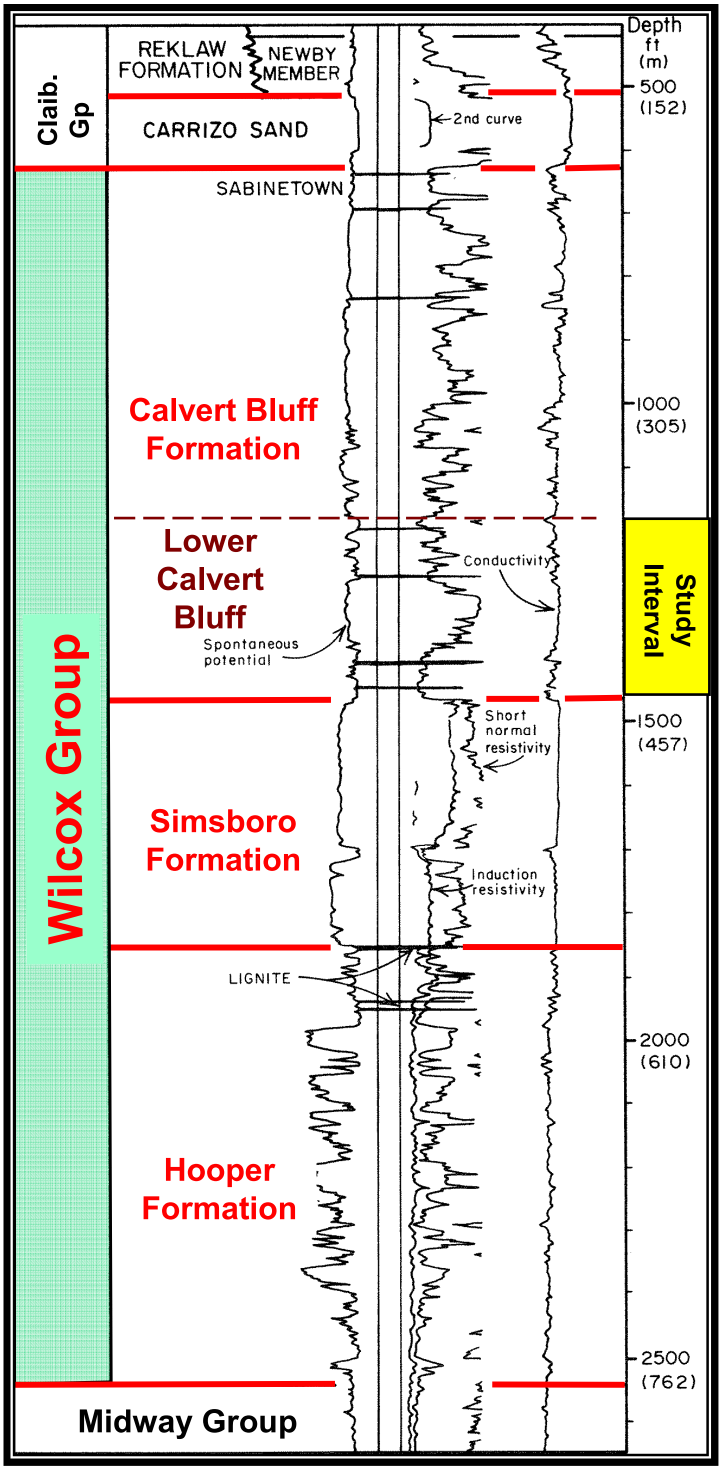


Fig. 6. **Composite well log showing Tertiary coal-bearing strata of Texas (Ayers and Lewis, 1985). The "Study Interval" was the stratigraphic interval that was modeled in the Sam K. Seymour area (Fig. 4), East-Central Texas.**

Texas Coal Properties

For Wilcox, Yegua, and Jackson coals, published coal-property data pertinent to reservoir behavior were available from studies of (1) coals less than 200-ft deep, which is the depth limit of surface mining (Kaiser et al., 1980; Tewalt, 1986), and (2) deep-basin coals (between 200 and 2,000 ft deep (Kaiser, 1990; Tewalt, 1986), which was the depth limit imposed in earlier investigations of in-situ gasification. Proximate analyses of the Texas shallow coals are reported in **Table 1**. Those analyses include equilibrium moisture, volatile matter, fixed carbon, ash, sulfur, and heating value (Btu/lb).

Table 1. Proximate analyses (as received), near-surface (<200 ft deep) Wilcox, Yegua, and Jackson coals, from Tewalt (1986).

		Wilcox east-central	Wilcox northeast	Wilcox east	Wilcox overall	Jackson east	Jackson south	Jackson overall	Yegua east
					As-received basis				
Moisture %	$\bar{X}$	31	32	33	32	41	28	35	36
	S	4	4	3	4	6	5	8	6
	R	29	29	25	29	42	25	44	29
	C	0.13	0.12	0.09	0.12	0.15	0.18	0.23	0.17
	N	184	116	384	684	196	132	328	32
Volatile matter %	$\bar{X}$	29	28	27	28	23	25	23	26
	S	4	3	3	3	4	6	4	4
	R	26	21	20	26	23	33	41	17
	C	0.14	0.11	0.11	0.11	0.16	0.24	0.17	0.14
	N	163	100	384	647	196	56	252	32
Fixed carbon %	$\bar{X}$	25	26	24	24	15	17	15	19
	S	4	4	4	4	4	4	4	4
	R	23	20	26	27	21	16	21	17
	C	0.16	0.15	0.18	0.18	0.25	0.24	0.27	0.18
	N	163	100	384	647	196	56	252	32
Ash %	$\bar{X}$	15	14	16	15	22	30	24	19
	S	9	7	7	8	10	10	11	9
	R	44	37	44	44	43	37	43	39
	C	0.60	0.50	0.44	0.53	0.50	0.33	0.46	0.47
	N	184	116	384	684	196	88	284	32
Sulfur %	$\bar{X}$	0.9	0.7	1.1	1.0	1.3	2.0	1.5	1.0
	S	0.4	0.3	0.6	0.6	0.7	1.0	0.8	0.4
	R	2.9	1.9	4.1	4.1	6.4	8.2	8.4	1.6
	C	0.44	0.43	0.54	0.60	0.50	0.50	0.53	0.43
	N	160	107	371	638	200	88	288	31
Btu/lb	$\bar{X}$	6,613	6,614	6,347	6,460	4,640	5,179	4,805	5,752
	S	997	990	774	882	960	1,207	1,069	783
	R	6,863	7,344	5,452	7,884	4,581	7,515	7,515	3,701
	C	0.15	0.15	0.12	0.14	0.21	0.23	0.22	0.14
	N	166	107	371	644	200	88	288	31

(Continued on next page)

Table 1 (cont.)

		Wilcox east-central	Wilcox northeast	Wilcox east	Wilcox overall	Jackson east	Jackson south	Jackson overall	Yegua east
					Dry basis				
Volatile matter %	$\bar{X}$	42	42	40	41	39	33	38	41
	S	5	5	5	5	8	8	8	7
	R	35	27	32	35	45	45	55	27
	C	0.12	0.12	0.13	0.12	0.21	0.24	0.21	0.16
	N	128	90	374	592	180	50	230	31
Fixed carbon %	$\bar{X}$	36	39	36	36	25	23	25	31
	S	7	5	6	6	7	6	7	7
	R	35	36	42	38	35	31	32	30
	C	0.19	0.13	0.17	0.17	0.28	0.26	0.25	0.21
	N	128	90	374	592	180	50	230	31
Ash %	$\bar{X}$	21	21	23	23	36	40	37	29
	S	11	10	10	10	14	11	13	12
	R	58	64	59	64	60	46	60	42
	C	0.52	0.48	0.43	0.43	0.39	0.28	0.35	0.41
	N	166	115	387	668	181	125	306	32
Sulfur %	$\bar{X}$	1.4	1.1	1.6	1.5	2.2	2.5	2.3	1.6
	S	0.6	0.5	1.0	0.8	0.9	0.7	0.9	0.7
	R	4.5	2.8	5.9	5.9	5.2	4.5	5.2	2.7
	C	0.43	0.45	0.62	0.53	0.41	0.28	0.39	0.44
	N	172	102	387	661	321	128	449	32
Btu/lb	$\bar{X}$	9,722	9,850	9,550	9,641	8,047	7,234	7,808	9,103
	S	1,709	1,435	1,343	1,455	1,684	1,522	1,677	1,505
	R	8,734	9,314	9,075	9,665	8,918	7,774	9,260	6,042
	C	0.18	0.15	0.14	0.15	0.21	0.21	0.21	0.17
	N	148	106	374	628	303	126	429	31
Equilibrium moisture %	$\bar{X}$	29	32	31	30	37	29	34	35
	S	3	1	2	2	3	3	5	3
	R	14	3	8	14	18	15	23	11
	C	0.10	0.03	0.06	0.72	0.09	0.09	0.14	0.09
	N	18	7	24	49	126	64	190	14

$\bar{X}$ = arithmetic mean
S = standard deviation
R = range
C = S/$\bar{X}$ coefficient of variation
N = number of analyses

These earlier studies revealed that near-surface Wilcox coals are better quality than Yegua and Jackson coals. Shallow Wilcox coals are high-rank lignite to low-rank subbituminous coals (Tewalt, 1986) (Mukhopadhyay, 1989) with average heating value of 6,460 Btu/lb as received (9,641 Btu/lb, dry basis) (**Table 1**). Yegua and Jackson coals have respective average heating values of 5,752 and 4,805 Btu/lb, as received (9,103 and 7,808 Btu/lb, dry basis). Moreover, average ash content for Wilcox coals is 15%, as received (23%, dry basis),whereas respective average ash contents for the Yegua and Jackson coals are 19 and 24%, as received (29 and 37%, dry basis) (**Table 1**). Wilcox coals appear to have more favorable reservoir properties than either the Yegua or Jackson coals. Data for deeper (200 to 2,000 ft deep) Wilcox coal seams indicate that thermal maturity increases with depth (Mukhopadhyay, 1989), which affects coal reservoir properties (see section on **Wilcox Thermal Maturity**, p. 39). Because the maximum depth of the published Texas coal properties was less than 2,000 ft depth, it was important that we obtain deeper samples in this study to determine potential for CO_2 sequestration and ECBM production.

Focus on the Calvert Bluff Formation of the Wilcox Group in East-Central Texas

South Texas Olmos and Wilcox Coals

Initially, we assessed CO_2 sequestration potential of all coals in the Texas Coastal Plain. Although there is only one major power plant in South Texas, we assessed the Olmos and Wilcox coals of South Texas, because both formations had ongoing coalbed methane tests by industry, which could have provided insights to coal reservoir properties and potential for CO_2 sequestration. The most advanced coalbed methane exploration in Texas is in the bituminous coals of the Olmos Formation in Maverick County, northwest of Laredo, Texas, where two companies have leased more than 250,000 acres and have permitted more than 60 wells (per. com., R. Scott and W. Lang, July 2001). These companies have drilled and/or recompleted and tested approximately 30 wells. Results of these coals tests indicate non-commercial methane production and suggest poor potential for CO_2 sequestration in the Olmos coals.

Successful methane production from low-rank coals in the Powder River Basin of Wyoming and Montana led to coalbed methane exploration in Wilcox Group coals in the Gulf Coastal Plain of Texas and Louisiana. However, review of South Texas coal properties and production performance of the single South Texas Wilcox coalbed well suggested that South Texas Wilcox coal has poor reservoir quality in comparison to coals in other parts of Texas. The indications of poor Wilcox and Olmos reservoir quality and limited CO_2 emissions in South Texas led us to eliminate South Texas from the study.

East-Central Texas Yegua and Jackson Coals

Yegua and Jackson coals have been mapped and coal resources have been reported for the East-Central Texas area (Kaiser, 1974; Kaiser et al., 1980; Kaiser et al., 1978). After reviewing the literature, we eliminated the Yegua and Jackson coals as primary focus of the study, because these coals are much thinner and less abundant than Wilcox coals, and they appear to have lower cleat density and permeability. However, these coals could be secondary CO_2 sequestration targets where they overlie deeper Wilcox primary coal reservoirs.

Wilcox Coals in East-Central and East Texas

Wilcox coals in East and East-Central Texas have been well characterized (Ayers et al., 1986; Kaiser, 1974; Kaiser, 1990; Kaiser et al., 1980). This vast region has tremendous coal resources available for sequestration, and there are many point-source power plants throughout the region (**Fig. 4**). Moreover, operating companies have collected coal reservoir data from several wells, and earlier (1970's) coal in-situ gasification test data provided useful information about reservoir properties. Finally, the regional hydrologic framework has been described (Ayers et al., 1986) (Fogg and Blanchard, 1986), which is important in determining viability and placement of projects for CO_2 sequestration and ECBM.

Selection of Three Potential Sites (Sam K. Seymour, Gibbons Creek, and Martin Lake)

Combining information on power plant CO_2 emissions, coal occurrences, and coal reservoir properties, we concluded that the top three power plants that should be considered for potential CO_2 sequestration are Gibbons Creek, Sam K. Seymour, and Martin Lake (**Figs. 1, 3 and 4**). Pertinent information for these three areas is summarized in **Table 2**.

Gibbons Creek and Sam K. Seymour power plants are in Grimes and Fayette counties, respectively, in East-Central Texas (**Figs. 3 and 4**). In 2002, Gibbons Creek power plant emitted 3.22 million short tons of CO_2. The Wilcox group in that area contains 8 to 16 lignite seams greater than 2 ft thick (**Table 2**). The depth of injection for this area would range from 2,800 to 7,500 ft subsea.

Table 2. Summary of coal properties near Sam K. Seymour, Gibbons Creek, and Martin Lake power Plants.

	Area 1	Area 2	Area 3
Power Plant	Sam K. Seymour	Gibbons Creek	Martin Lake
Type of Fuel	Western Coal	Texas Wilcox Lignite	Texas Wilcox Lignite
CO_2 Emissions, 2002 (million tons)	12.48	3.22	17.72
Potential Injection/ Production Strata	(1) Yegua Formation (2) Wilcox Group (L. Cal. Bluff, Hoop. Fm.)	Wilcox Group (L. Cal. Bluff, Hoop. Fm.)	Lower Wilcox Group
Number of Coal Beds >5 ft Thick	(1) 2 - 4 (2) ~ 8	Between 8 and 16	2 - 4
Depth of Injection	(1) >2000 ft. SSL (2) > 5,700 ft. SSL	2,800 – 7,500 ft SSL	~2000 ft. SSL

Sam K. Seymour Power Plant emitted 12.48 million short tons of CO_2 in 2002 (**Table 2**). In this area, the regional structure map indicates that the Calvert Bluff formation of the Wilcox Group would be more than 5,700 ft deep. This formation has approximately 8 coal seams that are greater than 5 ft thick that could be targeted for CO_2 sequestration and ECBM. Secondary targets would be 2 to 4 Yegua formation lignite seams with individual thicknesses greater than 5 ft the, at injection depths greater than 2,000 ft.

Martin Lake power plant, located in the Sabine Uplift area (**Table 2** and **Figs. 3 and 4**), produced 17.72 million short tons of CO_2 in 2002. The lower Wilcox in the plant vicinity contains 2 to 4 individual coal seams greater than 5 ft thick (Kaiser, 1990). The depth of CO_2 injection for this area would be at about 2,000 ft subsea.

To assess favorability of the coals for CO_2 sequestration, we made preliminary coal maps and cross sections for each of the three proposed areas, using 27 well logs digitized from hardcopy logs purchased from a commercial vender. These well logs include gamma-ray, self-potential, resistivity, sonic, and density curves. **Fig. 7** shows typical Wilcox Group coal occurrences in well logs from Fayette and Grimes counties, respective locations of Sam K. Seymour and Gibbons Creek power plants. For each of the three areas, we made fence diagrams and correlated Wilcox coal-bearing intervals, and we made structure, isopleth (number of coal seams), and net-coal thickness maps. Then, we calculated coal resources. This information was integrated with reviews of regional hydrology to narrow the focus of the study.

Restriction of the Study to East-Central Texas Wilcox Coals

Simultaneously with the above preliminary assessments of coal characteristics in the vicinity of the three power plants, we reviewed regional hydrology of East-Central and East Texas. We found that the Martin Lake plant is in an unfavorable location for CO_2 sequestration and ECBM, owing to its hydrologic position in the meteoric recharge area (Wilcox outcrop) on the Sabine Uplift (**Fig. 4**). The Wilcox formation water is fresh in the vicinity of the Martin Lake plant; it would be necessary to transport CO_2 approximately 70 mi to downdip locations where the Wilcox formation is a confined aquifer, ground water is slightly saline, and sequestration and ECBM could be tested. Therefore, we eliminated the Martin Lake East Texas site from the study and focused on East-Central Texas. In the next section, we (1) review the Wilcox regional depositional systems and coal occurrence, (2) describe coal properties at the Gibbons Creek and Sam K. Seymour, and (3) explain selection of the Sam K Seymour area for detailed reservoir characterization and for reservoir simulation and economic modeling of CO_2 sequestration and ECBM.

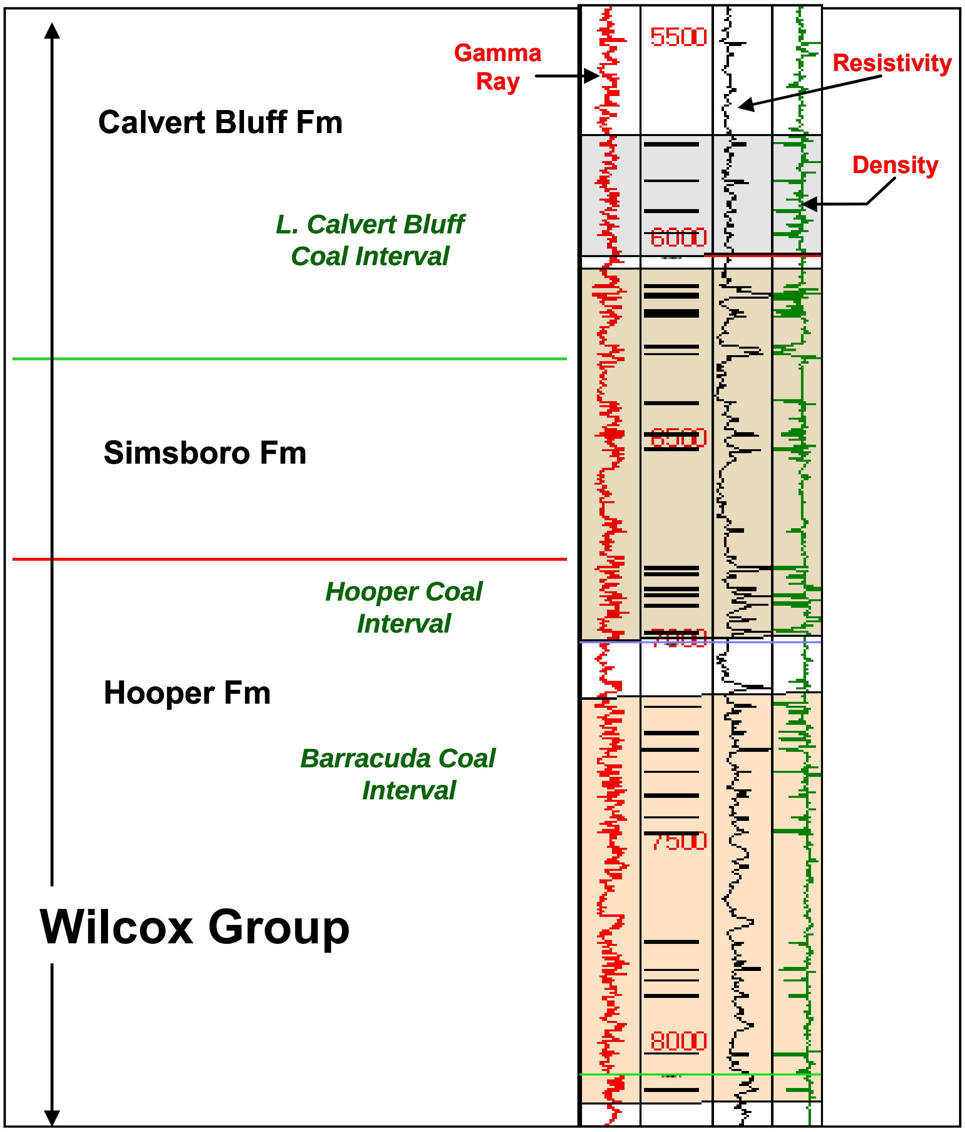


Fig. 7. Well log from East-Central Texas showing typical Wilcox Group coal occurrences and nomenclature. Bars in the depth track signify coals identified on the basis of well-log responses. Depth is in feet.

Coal Characterization of the Calvert Bluff Formation (Wilcox Group), East-Central Texas

Regional Coal Geology

In East-Central Texas, Wilcox strata dip gently (1 to 2 degrees/mi) coastward from the outcrop belt, where several mine-site power plants utilize Wilcox coal as the primary fuel for generation of electricity (**Figs. 4** and **8**) (Ayers and Lewis, 1985). In this region, the Wilcox formation was deposited in the ancient (Paleocene-Eocene) fluvial-deltaic systems that prograded southeastward into the Houston embayment and were fed by rivers that originated in the Rocky Mountains (Ayers et al., 1986; Fisher and McGowen, 1967; Kaiser et al., 1978). Wilcox fluvial sandstones are major aquifers in East-Central Texas.

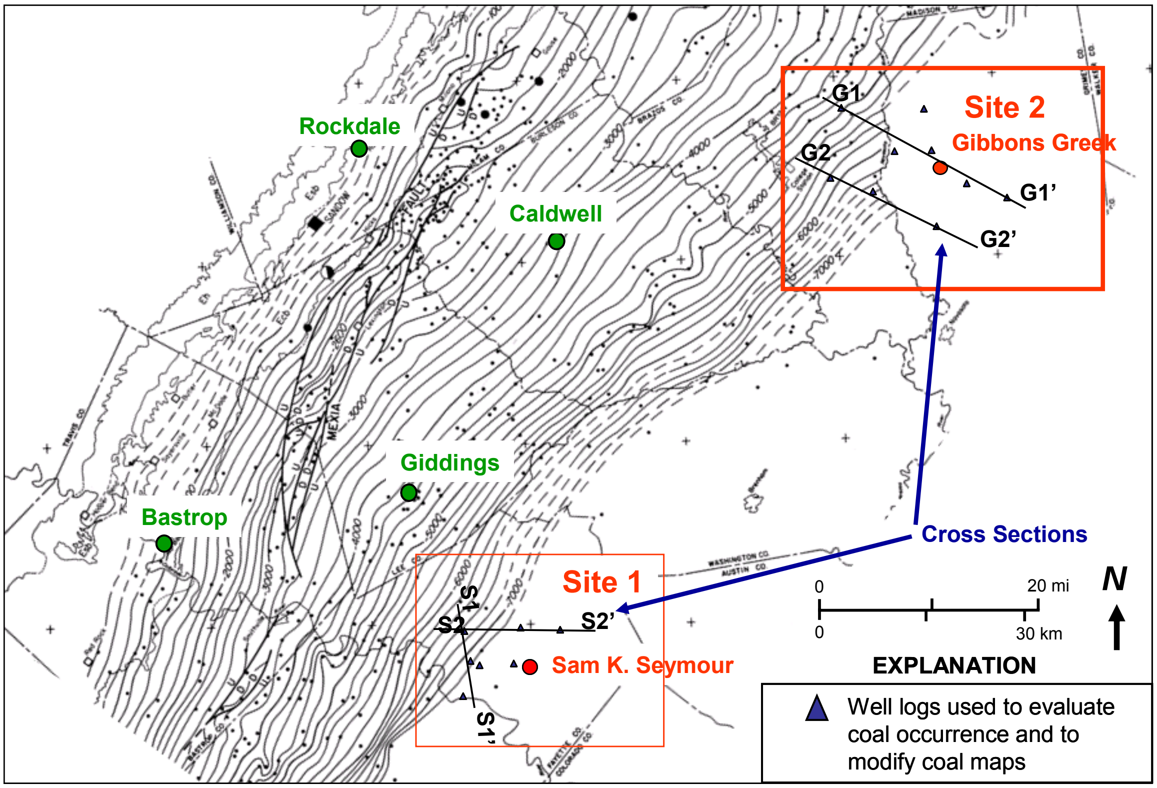


Fig. 8. **Structure on <u>base</u> of the Wilcox Group and locations of well log data used to modify and extend existing regional coal maps from Ayers and Lewis (1985). The Lower Calvert Bluff formation coals, which are the focus of this study, are shallower than the base of Wilcox. Wilcox strata dip gently (1 to 2 degrees) basinward.**

Coal is common in the both the Hooper and Calvert Bluff Formations. The updip, shallow Simsboro formation is sand-rich (**Fig. 6**), and it is the principle aquifer unit in the Wilcox Group. Downdip, the Simsboro formation contains more shale and coal beds (**Fig. 7**). Wilcox peats (coals) formed in floodplain and delta plain settings, adjacent to fluvial and distributary systems. Generally, the coals are dip-elongate, and along strike coal beds split and pinch out into fluvial/distributary sandstones (Ayers and Lewis, 1985;

Kaiser, 1974; Kaiser et al., 1978). Published coal isopleth (number of coal seams) maps that were made to evaluate the potential for in-situ gasification of Wilcox coals (Ayers et al., 1986; Ayers and Lewis, 1985) were used to identify electric generating plants that are near thick low-rank coals that could be targets for CO_2 sequestration and ECBM. Those maps were made using conventional oil and gas well logs (typically, spontaneous potential and resistivity surveys) that do not uniquely identify coal. Coal was operationally identified by a baseline spontaneous potential and high resistivity response in known coal-bearing zones. This operational definition was verified by wells that had density/porosity surveys (**Fig. 7**) and by coal reports on mud logs.

In East-Central Texas, we focused on Sam K. Seymour and Gibbons Creek power plants, which are distal from outcrop meteoric recharge and overlie deep (4,000 to 7,000 ft) Wilcox strata that contain saline formation water (**Fig. 8**) (See **Wilcox Hydrology** section, p. 36). In this region, we evaluated the Calvert Bluff formation coal for CO_2 sequestration and ECBM, because the Calvert Bluff contains nearly half of the total Wilcox coal, and it is not as deep as the coal-bearing Hooper Formation (**Fig. 6**). Deeper Hooper formation and shallower Yegua and Jackson coals could be additional CO_2 sequestration targets.

Owing to the poor vertical resolution of coal beds by typical oilfield logs, previous workers did not map the thickness of deep Calvert Bluff coal beds in East-Central Texas; instead, they mapped number of coal beds greater than 2 ft thick and number of coal beds greater than 5 ft thick (**Figs. 9** and **10**)(Ayers et al., 1986). Downdip limit of the earlier study was slightly northwest of the Sam K. Seymour and Gibbons Creek power plants. The Simsboro overburden lines on the maps (**Figs. 9** and **10**) show the approximate drilling depth to the base of the Calvert Bluff Formation.

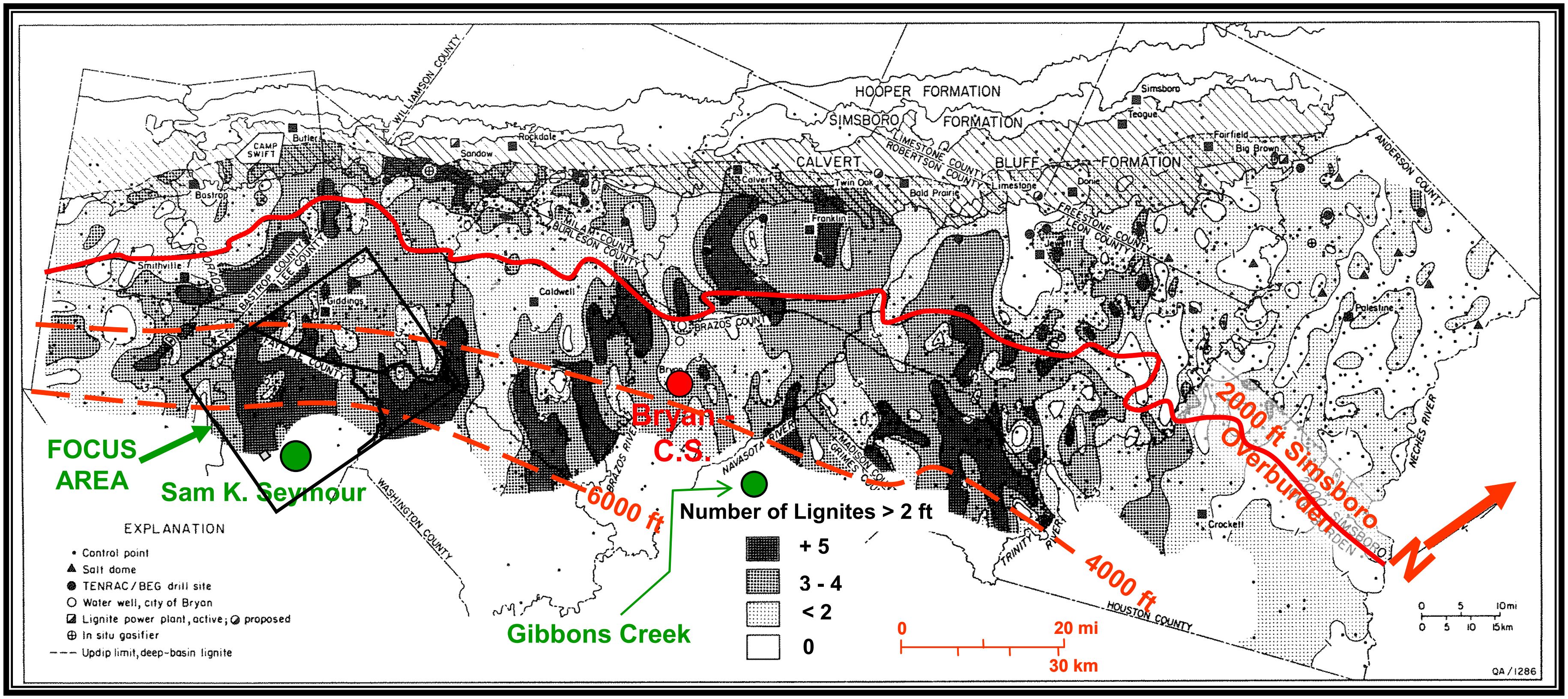


Fig. 9. **Isopleth map showing total number of coal beds >2 ft thick in the Calvert Bluff formation, East Central Texas, modified from Ayers et al. (1986). The heavy (red) contours show depth to top of the Simsboro formation (base of the Calvert Bluff).**

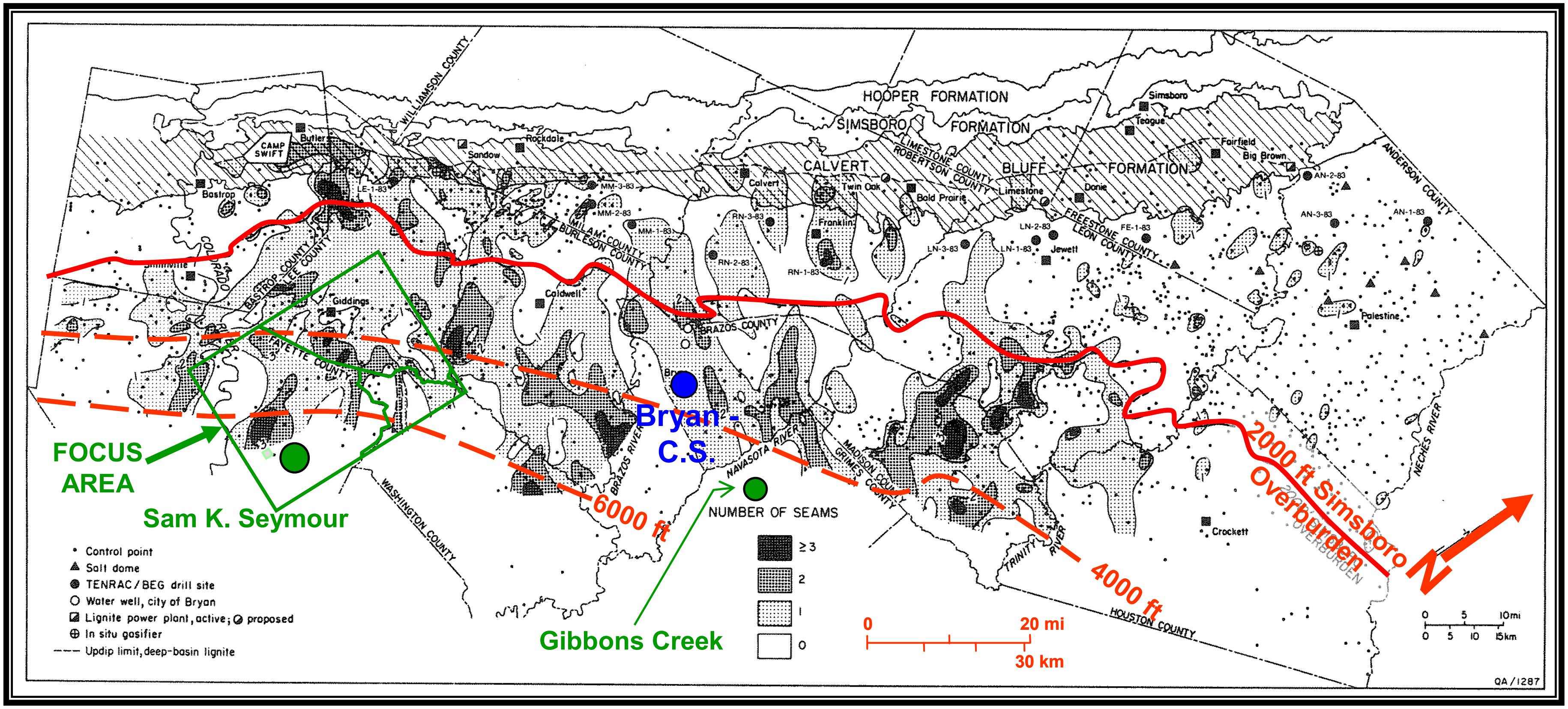


Fig. 10. Isopleth map showing total number of coal beds >5 ft thick in the Calvert Bluff formation, East Central Texas, modified from Ayers et al. (1986). The heavy (red) contours show depth to top of the Simsboro formation (base of the Calvert Bluff).

The regional maps show 1 to more than 5 Lower Calvert Bluff coal beds greater than 2 ft thick and 0 to 2 coal beds greater than 5 feet thick in the vicinity of Gibbons Creek power plant (**Figs. 9** and **10**). Northwest of Sam K. Seymour power plant, the maps shows 3 to more than 5 Lower Calvert Bluff coal beds greater than 2 ft thick and 0 to 1 coal bed greater than 5 ft thick (**Figs. 9** and **10**) These coals could be targets for CO_2 sequestration and ECBM production, but clearly, it was necessary to revise the regional coal occurrence maps to assess coal occurrence and properties nearer the power plants.

Using 7 digitized logs for the Sam K. Seymour area and 9 logs for the Gibbons Creek area, we made 2 cross sections for each area, correlated Calvert Bluff and Hooper coals, and extended the regional Hooper and Calvert Bluff maps from coal Ayers et al. (1986) to assess coal occurrence and to guide the decision for final site characterization. For each area and formation, we mapped the total number of coal beds. Maps of the total number of Calvert Bluff (Upper and Lower Calvert Bluff) coals >2 ft thick are shown in **Figs. 11** and **12 (**modified areas in boxes). The types of well logs available included density, natural gamma-ray, acoustic, resistivity, and caliper logs. The suite of logs available for interpretation varied greatly among the wells. Coal beds were identified on the basis of low density and acoustic velocity. Gamma ray log responses are commonly low, whereas resistivity values are high in coal beds (**Fig. 7**).

Coal zones or packages are correlatable on a regional scale. At least two of the coal beds in both the Hooper and the Calvert Bluff Formations at both potential sequestration sites can be correlated for 6 to 10 mi (10 to 17 km). However, correlation of individual coal beds is difficult and equivocal because of the discontinuous character of coal (peat) deposits that formed in fluvial (Calvert Bluff) and delta plain settings (Hooper) (Ayers and Lewis, 1985). These depositional environments of the coals may limit the lateral extent of most individual coal beds to a few miles. Coal beds split and pinch out toward channel-fill sand complexes or, in other settings, individual, thin coal beds merge into one thicker bed. Commonly, coal bed correlations are complex.

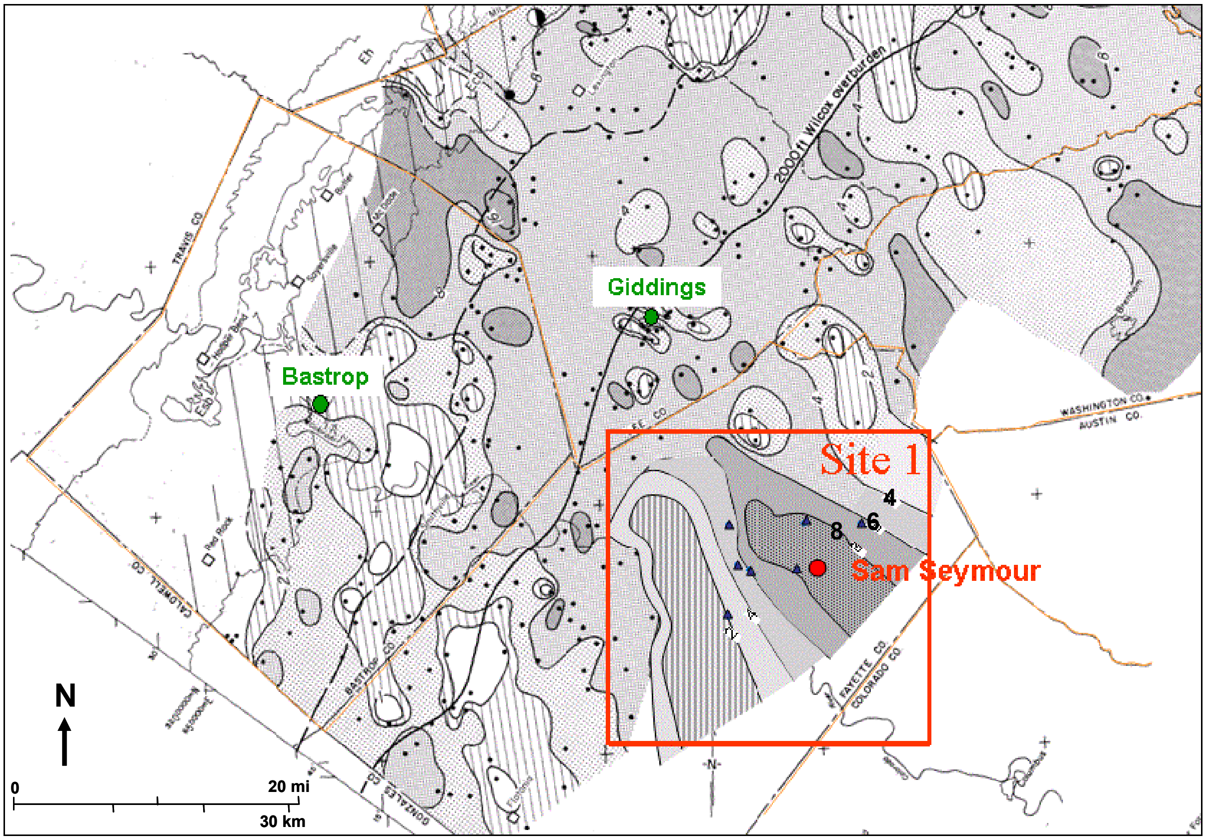


Fig. 11. Revised total Calvert Bluff isopleth map showing number of coal bed beds >2 ft thick for Sam K. Seymour area (Site 1). Wells used to modify the regional map are shown as triangles. Modified from Ayers and Lewis (1985).

The quality and resolution of the well log data were poor in some wells, which made it difficult to determine coal seams thicknesses. Therefore, only coal beds greater than or equal to 2 ft thick were included in the evaluation. In the Sam K. Seymour area, there are 2 to 8 coal beds in the total Calvert Bluff (**Fig. 11**) and 3 to 5 coal beds in the Hooper Formation (map not shown). In the Gibbons Creek area, there are 4 to 8 coal beds in the total Calvert Bluff (**Figs. 12**) and 1 to 6 coal beds in the Hooper Formation (map not shown). Thus, from the preliminary maps and cross sections, both the Sam K. Seymour and the Gibbons Creek area appear to have significant coal resources for CO_2 sequestration. The final decision to model Calvert Bluff coals in the vicinity of Sam K. Seymour power plant resulted from an opportunity to access data previously collected near that plant by Anadarko, and the opportunity to share costs of additional data collection with Anadarko.

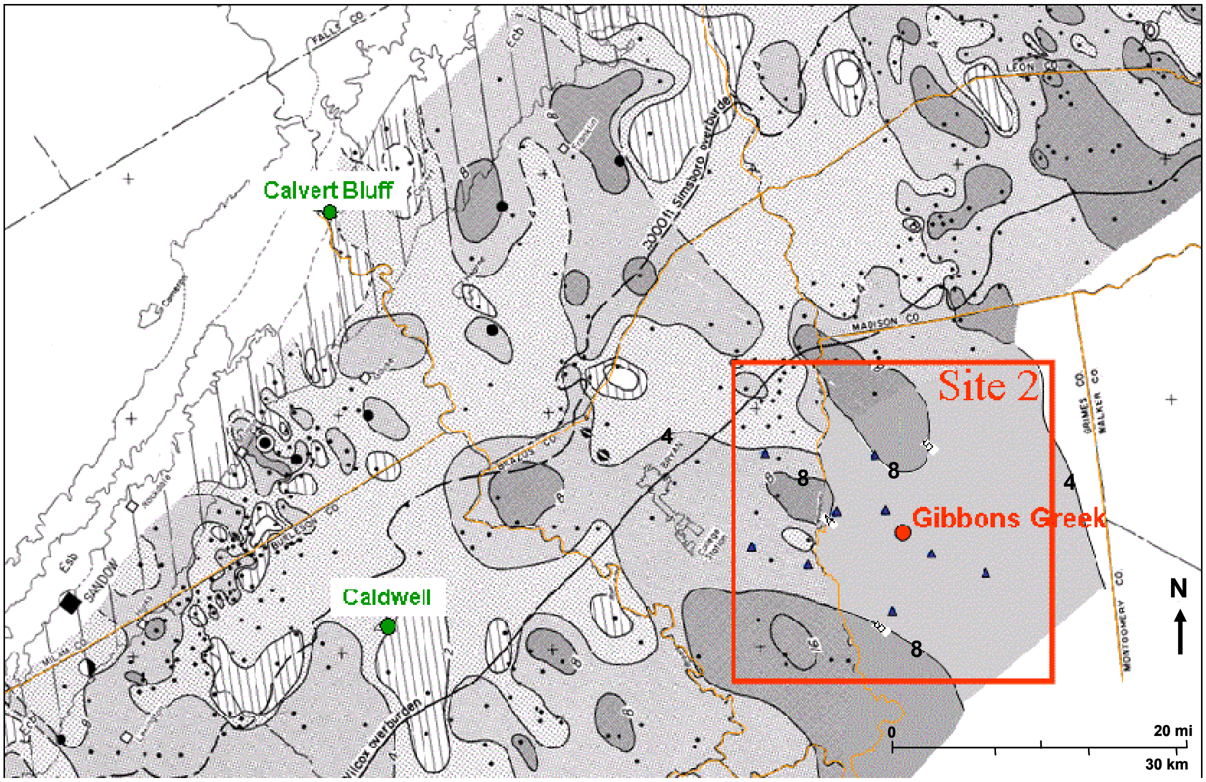


Fig. 12. Revised total Calvert Bluff isopleth map showing number of coal bed beds >2 ft thick for Gibbons Creek area (Site 2). Wells used to modify the regional map are shown as triangles. Modified from Ayers and Lewis (1985).

Data Acquisition and Coal Reservoir Characterization of the Sam K. Seymour Site

Initially, we intended to use a Texas A&M University drilling rig to obtain samples necessary for coal characterization, gas content and composition analyses, and CO_2, CH_4, and N_2 sorption isotherms. However, the University drilling rig has a 1,000-ft drilling limit. As we assessed the potential for CO_2 sequestration and enhanced coalbed gas production, it was clear that we would have to test Wilcox coals greater than 3,500 ft deep, because (1) many shallower coals in the Wilcox Group were interbedded with protected aquifer sandstones (see below, **Wilcox Hydrology**, p. 36), and (2) preliminary data indicated that sorptive capacity and methane content of Wilcox coals are markedly higher at depths greater than 3,500 ft. Therefore, after considerable discussion, we signed an agreement for cooperative formation sampling, well testing, and data exchange with Anadarko, who had been testing Wilcox coalbed gas potential in the area while drilling for deeper formations.

The data sharing agreement with Anadarko provided a much larger and more robust database than if we had drilled the 3 wells initially planned. Anadarko agreed to share valuable Wilcox coalbed reservoir data that they had previously collected from several wells. Also, as part of this agreement, we (1) collected and analyzed Wilcox sidewall cores from an Anadarko well that was drilled to a deeper target, and (2) reentered an existing Anadarko well and tested permeability of two deep (>4,000 ft) Calvert Bluff coal beds in the Sam K. Seymour area. Additionally, we collected and analyzed data from an Anadarko shallow (<2,000-ft) Wilcox coalbed well in Louisiana. Finally, Anadarko provided digital logs for approximately 200 wells. Many of these well logs included density/porosity surveys that could be used for detailed coal mapping and characterization in the Sam K. Seymour area. Locations of Anadarko cooperative wells are confidential.

Thus, we focused our detailed study and reservoir modeling near Sam K. Seymour power plant, owing to the (1) relatively high CO_2 emissions of the plant, (2) presence of thick Wilcox coals, (3) location of this area basinward of the Wilcox freshwater zone, and (4) access to Anadarko's database of existing samples and their interest in collecting additional data.

Data Available and Data Collected

No Wilcox coal samples suitable for laboratory characterization (e.g., sorption isotherms) were found in core repositories. For example, existing samples at The University of Texas Bureau of Economic Geology reportedly are oxidized and few in number. Therefore, to further characterize Wilcox coal reservoirs, we (1) collected coal samples in a surface mine in East-Texas, (2) retrieved Wilcox Group sidewall core samples from one Anadarko cooperative well in Texas in the Sam K. Seymour area and from another well in Louisiana, (3) tested permeability of 2 coal beds in an Anadarko well, (4) evaluated analyses of previous Anadarko Wilcox coal tests, and (5) described coal cleat (natural fractures) from one outcrop and 3 surface mines.

Coal Characterization of Sam K. Seymour Study Area

Anadarko provided geophysical well logs from approximately 200 wells in the vicinity of Sam K. Seymour power plant. The suite of logs available for the wells included density, natural gamma ray, acoustic, resistivity, and caliper logs. However, density/porosity logs were available to map coal thickness for only 20% of the wells. Coals were identified from density/porosity logs on the basis of their low density and high porosity (**Fig. 7**). In wells that lacked density and porosity logs, coal was operationally defined by a sharp, low-gamma ray peak and a high resistivity, exceeding the resistivity response of adjacent sandstones. This operational definition was verified in wells that had density or porosity logs, as well as resistivity and gamma ray logs (**Fig. 7**). With this well log data set, we were able to confidently identify and map significantly more coal beds than had previous workers.

Coal Occurrences

The elevation of the base of the Calvert Bluff Formation is 3,200 to 7,000 ft in the Sam K. Seymour detailed study area (**Fig. 13**). Calvert Bluff coal beds in this region are far too deep to be mined. The present depth limit of surface mines in Texas is approximately 200 ft, and Calvert Bluff strata are too unconsolidated for underground mining. Total Wilcox coal thickness in coals greater than 2 ft thick ranges between 50 and 140 ft; total coal thickness in the Lower Calvert Bluff is 25 to 75 ft, accounting for approximately half of the total Wilcox coal thickness (**Figs. 14a** and **14b**). Calvert Bluff coals occur in 5 to 20 seams. The number of Lower Calvert Bluff coal seams greater than 5 ft thick ranges from 1 to 6 (**Fig. 15a**). The thickest Lower Calvert Bluff coal in each well ranges from 6 to 12 ft thick (**Fig. 15b**); individual thick coal beds may not correlate between wells.

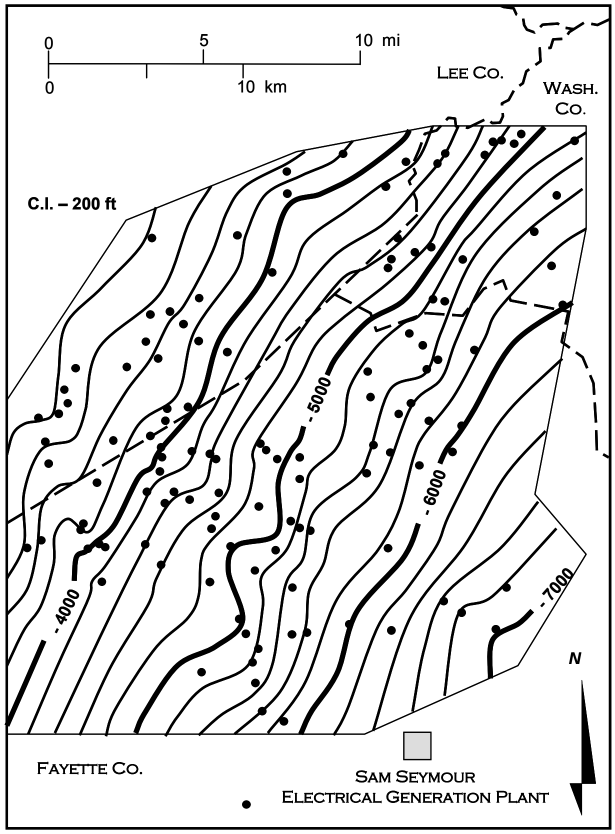


Fig. 13. Structure map of the base of the Calvert Bluff formation, Sam K. Seymour area.

For the combined Hooper and Barracuda coal intervals (**Fig. 7;** both coal intervals are part of the Hooper formation), total coal thickness is 25 to 90 ft in 4 to 30 coal beds. There are 0 to 3 coal beds greater than 5 ft thick in the Hooper interval (**Fig. 16**) and 2 or fewer coal beds greater than 5 ft thick in the Barracuda interval. Maximum individual bed thickness is 14 ft for the Hooper interval and 6 ft for the Barracuda interval (maps not shown). Thus, the reservoir simulation model for the Sam K. Seymour area is based on Lower Calvert Bluff coals; Hooper and Barracuda coals are generally thinner and considerably deeper than Lower Calvert Bluff coals, which makes them less desirable targets for CO_2 sequestration and ECBM.

Coal Proximate Analysis, Sam K. Seymour Area

There are few analyses of coal properties for the Sam K Seymour area. For the Anadarko-TAMU cooperative well (Well APCL2), we obtained proximate analysis of the composite sample of 10 sidewall cores taken over a 148-ft depth interval (6,118 –

6,262 ft). The results showed that the coal had 4.53% moisture, 37.48% volatile matter, 9.86% ash, 48.12% fixed carbon, and a heating value of 12,405 BTU/lb, as received. Sulfur content was 1.31%.

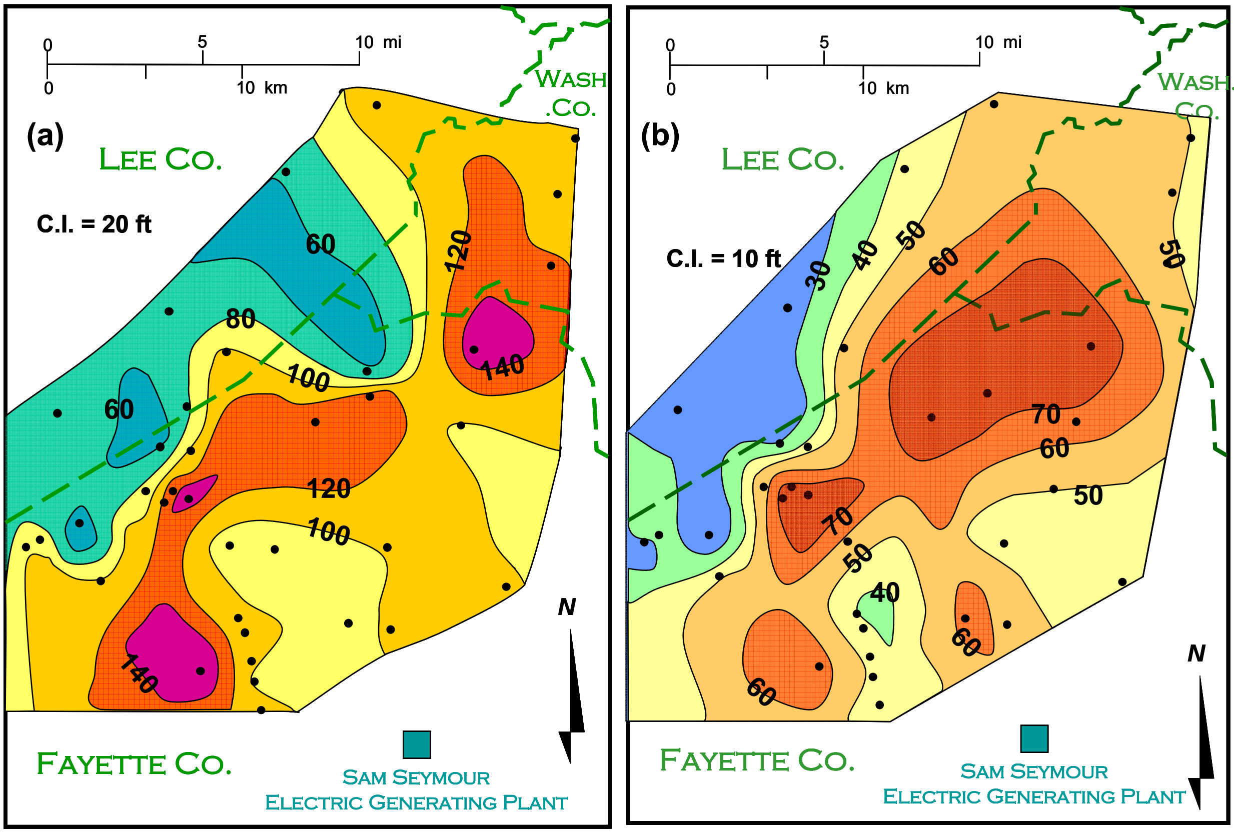


Fig. 14. Total coal thickness in the Wilcox Group (a) and the Lower Calvert Bluff formation (b), Sam K. Seymour area. Approximately half of the Wilcox coal is in the Lower Calvert Bluff formation.

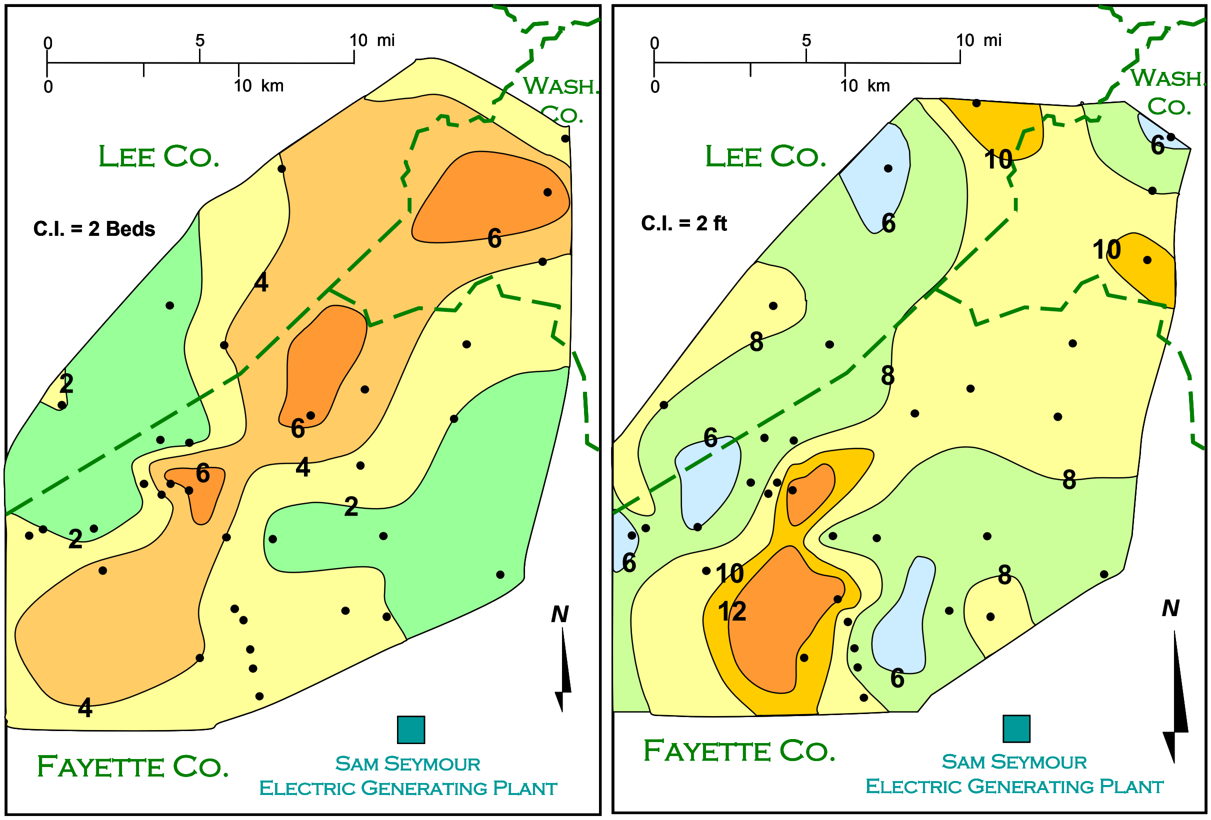


Fig. 15. (a) Total number of Lower Calvert Bluff coal beds >5 ft thick, and (b) thickness of the thickest individual Lower Calvert Bluff coal bed, Sam K. Seymour area.

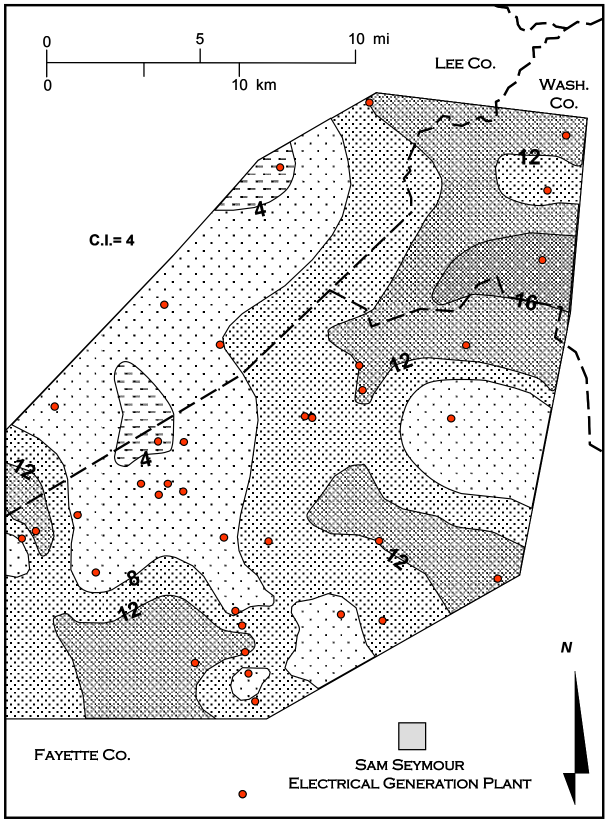


Fig. 16. Total number of coal beds in the Hooper coal interval, Sam K. Seymour area. Barracuda coal interval (Fig. 7) excluded.

Regional Cleat Analysis

Cleats (natural fractures in coal) are essential for both CO_2 sequestration and enhanced coalbed methane production. Coal permeability depends on the cleat density (number of fractures per unit distance along the coal bed), aperture (fracture width), and connectivity. Cleat orientation may impose permeability anisotropy that affects well completions and field design. To assess regional Wilcox coal cleat characteristics, we described coal cleats at one outcrop and in 3 surface mines in East-Central Texas. Commonly, all coal beds in a region have similar cleat orientations, because cleat orientation was determined by regional, far-field tectonic stresses at the time of coalification. The major controls on cleat spacing are structural setting, ash (inorganic) content of the coal, and thermal maturity.

Coals of the Jackson Group (**Figs. 4 and 5**) were studied at outcrops near Lake Somerville (**Fig. 17**), which is near Sam K. Seymour power plant. Generally, Jackson face cleats strike N60-65ºE, and butt cleats strike N150-155ºE (**Table** 3 and **Fig. 17**). Face cleat orientation in Jackson coal seams parallel the orientation of natural fractures (joints) in sandstones, also exposed at Lake Somerville. Jackson coal cleats are not uniformly spaced, and they terminate vertically at coalbed margins. Due to the deep weathering of coal at Lake Somerville, we were unable to describe cleat spacing, or fracture density (fractures/unit distance).

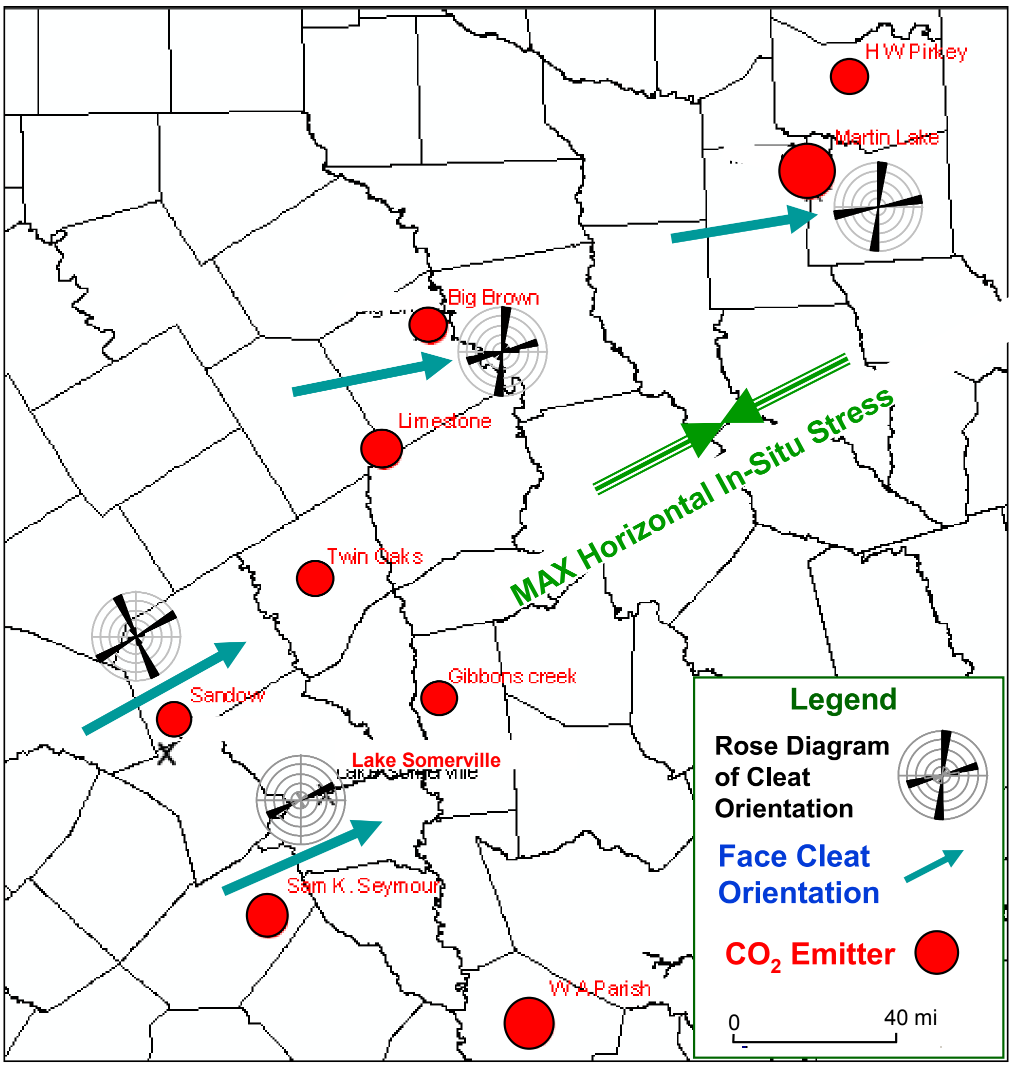


Fig. 17. Rose diagrams and schematic presentation of cleat trends at outcrop and mines from this study. Rosettes are in 10º intervals. Regional in-situ stress direction from Baumgardner (1987).

Table 3. Orientation and spacing of coal cleats at Sandow surface mine (Lower Calvert Bluff coal) and Somerville outcrop (Jackson Group coal).

Sandow Mine : Upper Wilcox- Coal thickness --8 ft							
STOP-1: Location: N30°27.855' W 97°07.112' Altitude: 316 ft				STOP-2: Location: N30°33.013' W 97°03.148' Altitude: 317 ft			
Fracture orientation				Fracture orientation			
Face Cleat	Distance between face cleats	Butt Cleat	Distance between butt cleats	Face Cleat	Distance between face cleats	Butt Cleat	Distance between butt cleats
N60°E	6.7 inch	N145°E	6.0 inch	N60°E		N165°E	
N60°E	2.6 inch	N160°E	3.15 inch	N65°E	4 inch	N172°E	4.7 inch
N60°E	2.8 inch	N150°E	6.0 inch	N67°E	7.9 inch	N162°E	7.1 inch
N60°E	2.0 inch	N160°E	3.54 inch				

Lake Somerville: Jackson-Manning				Jackson-Whitsett			
Location: N30°19.017' W 96°31.048' Altitude: 269 ft				Location: N30°19.08' W 96'31.019' Altitude: 287 ft			
Fracture orientation				Fracture orientation			
Face Cleat	Distance between face cleats	Butt Cleat	Distance between butt cleats	Face Cleat	Distance between face cleats	Butt Cleat	Distance between butt cleats
N65°E		N155°E		N60°E		N150°E	

At Alcoa's Sandow surface mine near Rockdale, Texas (**Fig. 17**), we described cleat properties at highwall exposures. An 8-ft thick lower Calvert Bluff formation (upper Wilcox Group; **Fig. 6**) lignite at Sandow is exposed in the 80-ft highwall that is comprised predominately of sand and mudstone. We described Wilcox coal cleats in two pits located about 7 miles apart. At the first pit, face cleats trends averaged N60ºE, and butt cleats trends averaged N145ºE. Cleats at the first pit are not uniformly spaced, and they terminate within bedding intervals. Face cleats spacing ranged between 2 and 7 inches (**Table 3**). In the second pit, orientations were very similar to the first. Face cleat orientations ranged between N 60-67º E, and face cleats spacing ranged between 4 and 8 inches. The orientation of the butt cleats was a little more variable with values from N172-162ºE. Butt cleat spacing ranged between 4.7 and 7 inches (**Table 3**).

At Big Brown surface mine (**Fig. 17**), we described cleats in upper Wilcox Group lignite at highwalls in two mine pits located about 0.7 mile apart. In the first pit, face cleat orientations averaged N80°E, and average butt cleat trend was due north. Fractures were not uniformly spaced, and they terminated within bedding intervals. Face cleat spacing ranged between 1.4 and 13.8 inches (**Table** 4). In the second pit, face cleat orientations ranged between N65-85ºE, and face cleat spacing ranged between 2.8 and 6.7 inches. The orientations of butt cleats ranged from due north to N30ºE, and butt cleat spacing ranged between 2.8 and 7.6 inches (**Table 4** and **Fig. 17)**.

At Martin Lake mine, we described Wilcox coal cleats in two pits approximately 3.6 miles apart. In both pits, face cleat trends averaged N80°E, and the butt cleat trend was N02ºE. Face cleat spacing ranged between 2 and 8.7 inches, and butt cleat spacing ranged between 4.3 and 10.2 inches (**Tabl**e **4** and **Fig. 17**).

Table 4. Orientation and spacing of Upper Calvert Bluff coal cleats at Big Brown and Martin Lake surface mines.

Big Brown : Upper Wilcox							
Seam thickness -~8 ft **STOP-1: Location: N31°49.059'** **W 96°05.286'** **Altitude: 188 ft**				**Seam thickness -~7 ft** **STOP-2: Location: N31°49.489'** **W 96°04.820'** **Altitude: 222 ft**			
Fracture orientation				Fracture orientation			
Face Cleat	Distance between face cleats	Butt Cleat	Distance between butt cleats	Face Cleat	Distance between face cleats	Butt Cleat	Distance between butt cleats
N80°E	13.8inch	N0°E	7.9inch	N65°E	2.8inch	N10°E	7.5inch
N85°E	1.4inch	N0°E	1.4inch	N70°E	6.7inch	N20°E	2.8inch
N78°E		N0°E		N75°E	6.7inch	N30°E	
				N85°E		N0°E	

Martin Lake : Upper Wilcox							
Seam thickness -~6 ft **STOP-1: Location: N32°15.160'** **W 94°31.534'** **Altitude: 270 ft**				**Seam thickness -~8 ft** **STOP-2: Location: N32°12.989'** **W 94°33.983'** **Altitude:**			
Fracture orientation				Fracture orientation			
Face Cleat	Distance between face cleats	Butt Cleat	Distance between butt cleats	Face Cleat	Distance between face cleats	Butt Cleat	Distance between butt cleats
N80°E	4.3inch	N05°E	10.2inch	N80°E	8.7inch	N05°E	7.1inch
N80°E		N0°E		N80°E	6.7inch	N0°E	4.33inch
N80°E		N0°E		N78°E	2.0inch	N0°E	

In East-Central and East Texas, face cleats generally trend east-northeastward, and butt cleats trend northwestward **(Fig. 17)**. Face cleat trends measured in this study are consistent with the trend (N65ºE) of natural fractures in the Austin Chalk in Giddings field, East-Central Texas, where its average depth is 10,000 ft (Drake et al., 2001). This regional similarity between the trends of outcrop and surface mine face cleats and sandstone natural fractures and the fracture trend of deep limestones indicates that these regional fracture sets resulted from the same far-field stress. Moreover, it suggests that, in the subsurface areas where CO_2 sequestration and ECBM production would occur (stratigraphically, between the surface and the Austin Chalk), the face cleat trend should also be northeast. This fracture orientation may result in permeability anisotropy that imparts an east-northeast-elongate pattern to fluid movement in either injection or production projects in coal reservoirs. Also, it should be noted that this face cleat orientation facilitates meteoric recharge and basinward migration of groundwater from outcrop areas in East-Central Texas.

Wilcox Hydrology

The Carrizo Sandstone and the sandstones of the Wilcox Group (**Fig. 6**) compose the Carrizo-Wilcox Aquifer, which is classified as a "major" aquifer in East-Central Texas, ranking third in water production among Texas aquifers. The major water-bearing units in the Carizzo-Wilcox Aquifer are the sandstones of the Simsboro and Carrizo formations (Fig. 6). Although the updip, shallow Wilcox strata contain freshwater, the deeper Wilcox water is saline. We reviewed Wilcox hydrology to establish the downdip limit of fresh water, because it is unlikely that CO_2 injection will be allowed in freshwater aquifers. Additionally, hydrology provides insights to the dynamics of coalbed gas systems.

Groundwater that contains less than 1,000 mg/L of total dissolved solids (TDS) is classified as fresh water, whereas slightly saline water has TDS between 1,000 and 3,000 mg/L, moderately saline water contains 3,000 to 10,000 mg/L, and very saline water has 10,000 to 35,000 mg/L TDS (Heath, 1983). The U.S. Environmental Protection Agency (EPA) and the Texas Railroad Commission (RRC) define an aquifer as a protected Underground Source of Drinking Water (USDW) if TDS of the water is less than 10,000 mg/L (EPA, 2001). However, injection may be allowed in an "exempted aquifer." To be considered an exempted aquifer, the USDW must be an aquifer that does not currently serve as a source of drinking water and cannot now, and will not in the future, serve as a source of drinking water, for one of several reasons, including TDS between 3,000 and 10,000 mg/L (moderately saline water) (EPA, ; RRC).

Wilcox groundwater TDS varies inversely with formation resistivity (Fogg and Blanchard, 1986). Therefore, to define groundwater quality, formation resistivity from geophysical well logs may be mapped. Resistivity of the maximum (thickest) Simsboro formation sandstone reflects regional Wilcox hydrology (**Fig. 18**) (Ayers et al., 1986; Ayers and Lewis, 1985). Fresh, meteoric water (high resistivity) enters the Wilcox Group at outcrop and migrates basinward (southeastward) into the Gulf Coast basin (Ayers et al., 1986; Dutton et al., 2006); resistivity decreases basinward as groundwater reacts with rocks and mixes with saline formation water. In the Wilcox of East Texas, the 20-ohm-m contour is approximately equivalent to 1,000 mg/L TDS (fresh water) (Fogg and Blanchard, 1986), and thus CO_2 sequestration and/or ECBM projects must be located downdip (basinward) of the 20-ohm-m contour (fresh water) (**Fig. 18**), in areas where the water is at least moderately saline. Additional data are required to define the boundaries between slightly and moderately saline water on the TDS contour maps. Existing Wilcox TDS maps are for the primary aquifer unit, which is the sand-rich Simsboro formation. However, we recommend CO_2 sequestration in coals of the Calvert Bluff formation. Further studies are needed to evaluate TDS of the shalier Calvert Bluff formation and vertical communication between the Calvert Bluff and Simsboro formations.

To inject CO_2 in Wilcox coals, those power plants located on the Wilcox outcrop (and utilizing Wilcox coals) will have to transport the CO_2 20 to 40 miles basinward, whereas Sam K. Seymour and Gibbons Creek power plants overlie the Wilcox where formation water is slightly saline to saline. The water-well field for the cities of Bryan and College Station is located updip (northwest) of the cities, where resistivity exceeds 20 ohm-m, and thus formation water is fresh (**Fig. 18**).

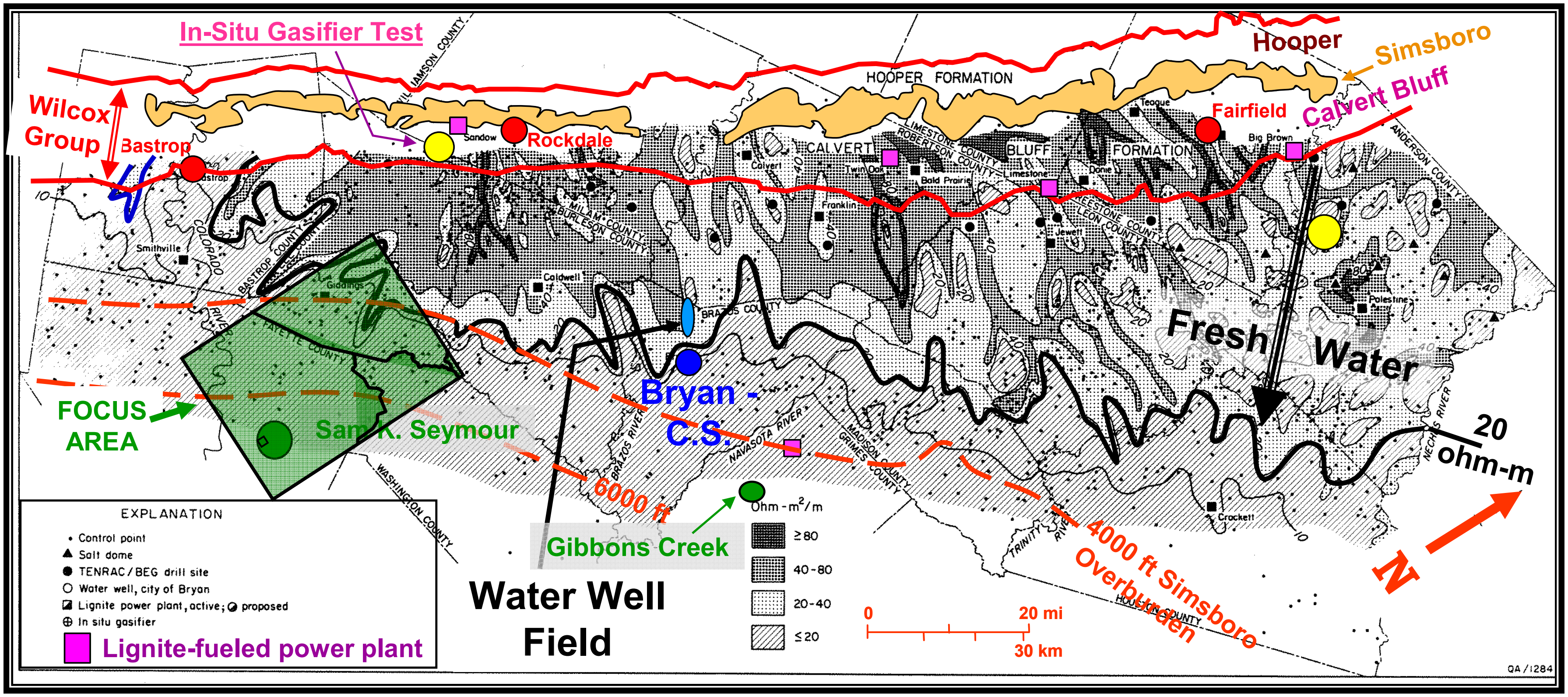


Fig. 18. Resistivity of the maximum (thickest) Simsboro formation sandstone is greatest (>80 ohm-m) near outcrop, where fresh water recharges the formation. Resistivity decreases southeastward, indicating basinward increase in formation water salinity. Water well field for Bryan and College Station (C.S.) is located updip of the cities, where resistivity exceeds 20 ohm-m. Modified from Ayers et al. (1986).

Wilcox Thermal Maturity

Thermal maturity of coal indicates whether the coal has generated hydrocarbons, and it influences other coal properties, such as sorptive capacity for gas species and cleat spacing. Although there are several coal parameters that may be used to determine thermal maturity, the most abundant data available for this study were 76 analyses of vitrinite reflectance measured for coal samples that ranged in depth from surface mines to 6,675 ft. Many of these values were from a report by Mukhopadhyay (1989), which focused on Wilcox coals less than 2,500 ft deep. Anadarko provided 8 vitrinite reflectance (R_o) reports for Lower Calvert Bluff, Hooper, and Barracuda coals from 5 wells in the region of Sam K. Seymour power plant and, during this study, we obtained additional vitrinite reflectance values from 2 cooperative wells with Anadarko. Other Wilcox thermal maturity data evaluated in this study, but not included in the graph of thermal maturity vs. depth for East-Central Texas (**Fig. 19**), were from South, East-Central, and East Texas and Louisiana, from studies by the U.S. Geological Survey (Warwick et al., 2000b).

From the first Anadarko/TAMU cooperative well (well APCL2) in the Sam K. Seymour area, we obtained vitrinite reflectance from a composite Calvert Bluff coal sample of sidewall cores taken from a 148-ft depth interval (6,116 – 6,274 ft). Mean value of vitrinite reflectance was 0.54% for the composite sample, indicating coal rank of high-volatile C bituminous.

From the second Anadarko/TAMU cooperative well, in Louisiana, we obtained vitrinite reflectance from 5 Wilcox coal samples from depths between 1,845 and 1,967 ft. Vitrinite reflectance of these samples ranged between 0.42 and 0.46%, indicating coal rank of subbituminous C to subbituminous B.

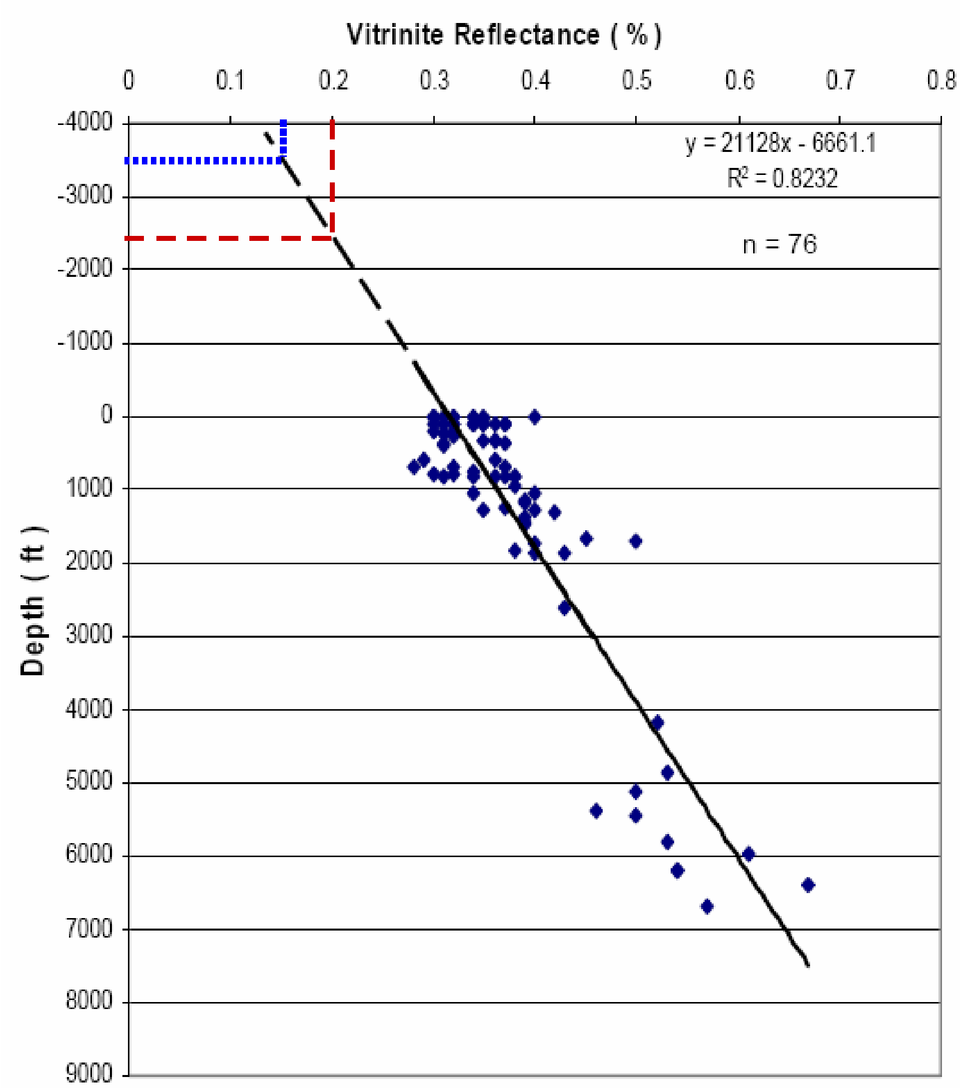


Fig. 19. Vitrinite reflectance (R_o) vs. depth graph for Wilcox coal samples in East Texas. Thermal maturity increases with depth of Wilcox coal occurrence. Zero value is the present earth surface. R_o values of 0.15 and 0.20 are typical values for modern peats, which suggests that 2,500 to 3,500 ft of strata have been eroded from the area.

To assess the relation between thermal maturity and depth in East-Central Texas, we graphed this relation for all data from that region. Thermal maturity of Wilcox coals increases with depth, from high-rank lignite (Ro ≅ 0.35%) at Sandow mine to high-volatile C bituminous (Ro = 0.67%) at 6,382 ft (**Fig. 19**). Shallow Wilcox coals are thermally immature for oil generation; the oil generation window (Ro ≅ 0.6%) occurs at approximately 6,000-ft depth, near the lower limit of data available for this study. The peak gas generation window should be deeper, at approximately 10,000-ft depth ($Ro \cong 0.78\%$). Projection of the trend line to vitrinite reflectances of 0.20% and 0.15% (**Fig. 19**), which represent the range of values typically measured for peats (P. Mukhopadhyay, per. com., November 2006), indicates that 2,500 to 3,500 ft of overburden have been eroded from the area.

Methane in Wilcox coal may be (1) early stage thermogenic, (2) migrated thermogenic, or (3) biogenic in origin. Shallow Wilcox coalbed methane is most likely biogenic gas, considering that the shallow Wilcox is thermally very immature and is a dynamic aquifer with fresh water extending several tens of miles into the basin from outcrop, to formation depths of approximately 3,000 ft (**Fig. 18**). However, the composition of coalbed gas in Wilcox coals deeper than 3,500 ft, where formation water is saline, suggests that this deeper gas is most likely early stage thermogenic or migrated thermogenic gas (See section on **Coalbed Gas Chemical and Isotopic Compositions**, p.52). Thermal maturity of these deeper Wilcox coals (high-volatile C bituminous rank), places them at higher rank than that of Fort Union coals (subbituminous C to subbituminous B) of the Powder River basin, which host a robust biogenic coalbed methane play.

Gas Content, Sorption Isotherms, Gas Saturation, and Gas Composition

Coalbed Gas Database

Evaluation of the potential for CO_2 sequestration and ECBM requires knowledge of the in-situ coalbed gas content and composition, as well as sorptive capacity of the coal for different gas species. These data were necessary to build the Wilcox coal reservoir simulation model. The only published data of these types were from a shallow (~365-ft depth) Wilcox study in Panola County, East Texas (Warwick et al., 2000a). As part of the Data Exchange Agreement with TAMU, Anadarko provided more than 75 gas desorption analyses from Wilcox coal cuttings and sidewall cores that were recovered from 5 wells. Sample depths ranged between 1,826 and 7,325 ft and were from wells drilled to deeper oil and gas targets, with exception of one well that was drilled specifically as a coalbed methane test well. Also included in the Anadarko database were three sorption isotherms, 13 analyses of gas chemical composition, and one analysis of methane isotopic composition.

Wilcox Coalbed Gas Content

Table 5 summarizes gas content desorption analyses of approximately 75 samples from 5 wells, provided by Anadarko. Samples from 4 of the wells were sidewall cores, whereas samples from the 5th well were cuttings. Both sidewall cores and cuttings give anomalously low values of desorbed gas, because small sample size allows escape of large quantities of gas (lost gas) during core recovery.

In 4 of the 5 Anadarko wells having desorption data, average coalbed gas content (as received; AR) in the 3 coal-bearing intervals (Lower Calvert Bluff, Hooper, and Barracuda) ranged between 152 and 330 scf/t (**Table 5**). Generally, Wilcox average gas content increases with increasing stratigraphic and measured depth, as is indicated by the increase from 216 scf/t for the Lower Calvert Bluff to 276 scf/t for the deeper Barracuda interval (**Table 5**, and **Fig. 20**).

Table 5. Average gas content of Wilcox coal-bearing intervals, based on approximately desorption of approximately 75 sidewall core and cutting samples from 5 wells, provided by Anadarko Petroleum Corporation. Well C data are not included in the Interval averages of the last column, because Well C is inferred to be in a different petroleum system from that of the other samples. Average gas content increases with stratigraphic depth and is greatest in the Barracuda interval in each well.

Coal Interval	**Average Gas Content (scf/t, as received), by Wells (A-E)**					
	A	**B**	**C**	**D**	**E**	**AVERAGE**
L. Calvert Bluff	271	252	14	152	190	***216***
Hooper	273	251	18	176	206	***226***
Barracuda	330	292			206	***276***
AVERAGE	***291***	***265***	***16***	***164***	***201***	***239***

In Well C (**Table 5**), the Calvert Bluff and Hooper coals samples were relatively shallow (depths between 1,800 and 2,600 ft), and the gas content was low, whereas in the other 4 wells, Calvert Bluff, Hooper, and Barracuda samples were from depths ranging between 3,957 and 7,325 ft. We attribute the marked differences in gas content to presence of two Wilcox coalbed gas systems (see section on **Wilcox Coalbed Gas Systems**, p. 56).

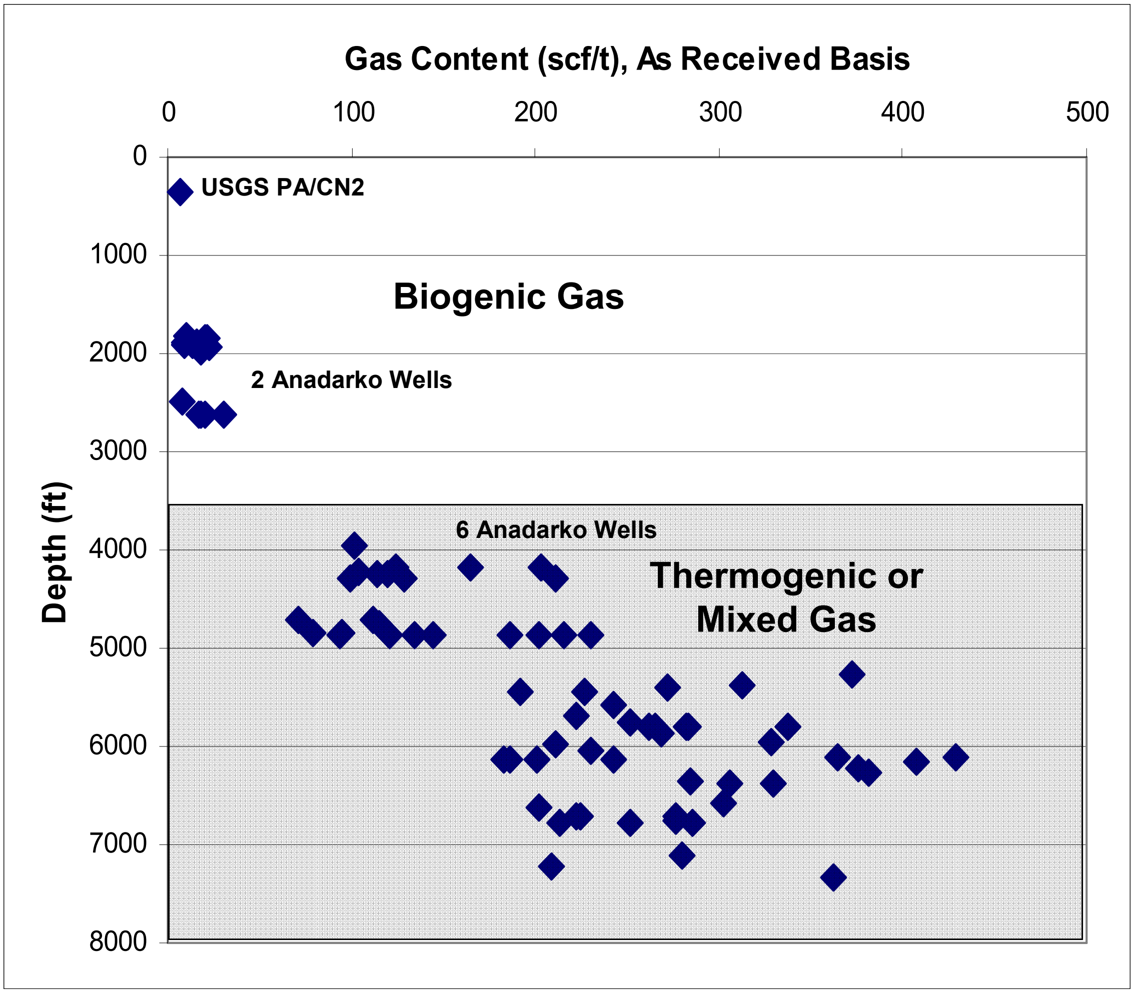


Fig. 20. Gas content (as received) vs. depth graph for Wilcox coal samples in East Texas.

For the Anadarko/TAMU cooperative well in the Sam K. Seymour area (well APCL2), the 10 sidewall core samples (**Fig. 21**; from 6,116 – 6,274 ft) were desorbed in 4 canisters. Total gas content (measured, lost, and projected residual gas) of coals from the four canisters, based on a polynomial fit for lost gas, ranged from 365 to 429 scf/t with an average total gas content of 395 scf/t (as-received basis) (**Table 6**). Lost gas values ranged from 43 to 47% of the total gas and averaged approximately 45% of the total gas. The service company that desorbed the samples concluded that estimated values of lost gas may be inaccurate, owing to the long retrieval time (49 minutes), fluctuation of ambient temperature, and/or high diffusivity of the coal (HWA, 2004). Projected residual gas was approximately 5% of in-situ gas content. While there is some uncertainty in the values, these high measured gas content values corroborate previous Anadarko test results and indicate significant methane resources in deep Wilcox coals.

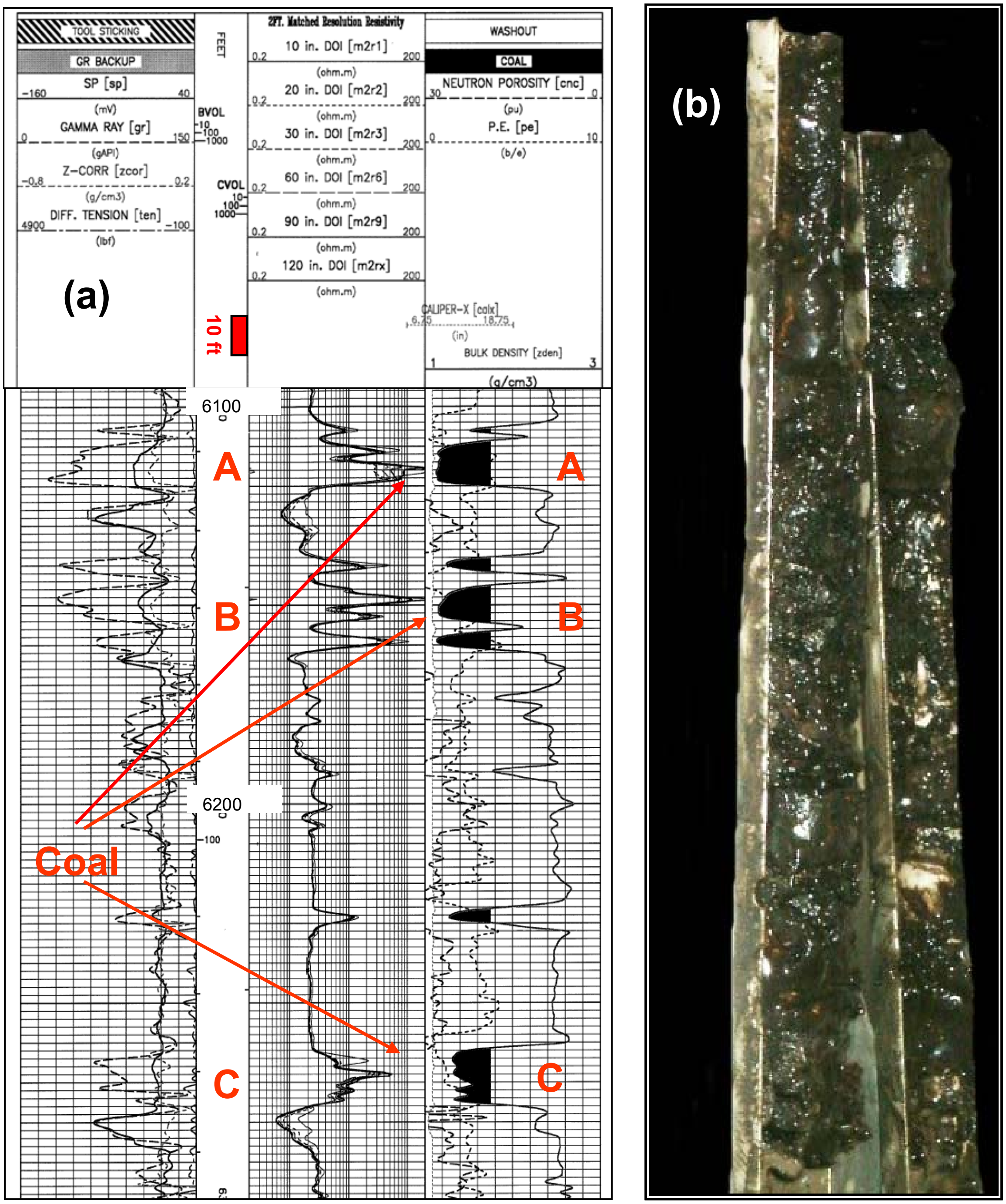


Fig. 21. **(a) Three Lower Calvert Bluff coals in the Anadarko –TAMU cooperative well APCL2 in the Sam Seymour area were selected, and (b) 10 rotary sidewall cores were taken for gas content determination, coal characterization, and sorption isotherms.**

For the Anadarko/TAMU cooperative well in Louisiana, Anadarko collected and desorbed Wilcox coal cuttings from 6 intervals between depth of 1,845 and 1,969 ft. Reported values of total gas content for these samples ranged from 9.1 to 21.2 scf/t (as received) and averaged 17.0 scf/t. These gas content values are similar to those reported for coals at comparable depth in Anadarko wells in the Sam K. Seymour area (**Fig. 20** and **Table 5,** Well C), and they are consistent with USGS tests of shallow Wilcox coal in East Texas. From a well in Panola County, East Texas, the USGS reported that Wilcox coalbed gas content ranged from 4 to 8 scf/t (as received) for 16 Wilcox coal samples recovered from depths between 355 and 373 ft (average depth 365 ft) in one well (Warwick et al., 2000a).

Table 6. Results of desorption from 10 rotary sidewall cores taken from 3 Lower Calvert Bluff coals in the Anadarko–TAMU cooperative well APCL2, in the Sam K. Seymour area. The 10 samples were desorbed in 4 canisters. All measurements are on an as-received basis. Data from Hampton, Waechter and Associates (HWA, 2004).

Canister No.	Coal Bed		(1) Lost Gas (scf/ton)	(2) Lost + Measured Gas (scf/ton)	(3) Total Gas (scf/ton)
	Top (MD, ft)	Bottom (MD, ft)			
1	6112	6114	195.2	411.3	429.3
2	6116	6118	161.6	362.7	365.0
3	6148	6152	174.5	392.1	407.5
4	6264	6274	179.8	359.0	382.1
Sidewall Core Averages			**177.2**	**375.6**	**394.8**

1. Lost gas content determined using polynomial fit
2. Without residual gas
3. Lost + Measured + Projected Residual Gas
4. MD = measured depth

In **Fig. 20**, the 365-ft sample (PA/CN2) is from the USGS test in Panola County, East Texas. Anadarko data in the 1,800 to 2,800-ft interval are from 2 Anadarko wells; one well is in the Sam K. Seymour area, and the other is the Anadarko/TAMU cooperative well in Louisiana. The 6 deep wells (**Fig. 20**) are Anadarko wells in the Sam K. Seymour area of East-Central Texas. Generally, coalbed gas content of the deep (>3,500 ft) coal samples exceeds 100 scf/t, whereas shallow (<3,500 ft) coals have low gas content (<30 scf/t). The Wilcox coalbed methane distribution (**Fig. 20**) suggests the presence of two, dissimilar coalbed gas content populations, which is supported by gas composition studies (see section on **Coalbed Gas Chemical and Isotopic Compositions**, p. 52**).**

Isotherm Analysis of Wilcox Coal Sorptive Capacity

The volumes of CH_4 recovered and CO_2 sequestered will depend on gas in place and the sorption properties of the coal, which are determined from isotherms. CO_2, CH_4, and N_2 sorption isotherms of APCL2 coal samples from approximately 6,200-ft depth in the APCL2 well were measured in the laboratory (**Fig. 22**) (RMB, 2005). Langmuir volume and pressure on an as-received basis are 961.9 scf/t and 697.5 psia, respectively, for CO_2, 363.6 scf/t and 608.5 psia for CH_4, and 166.1 scf/t and 2,060.7 psia for N_2.

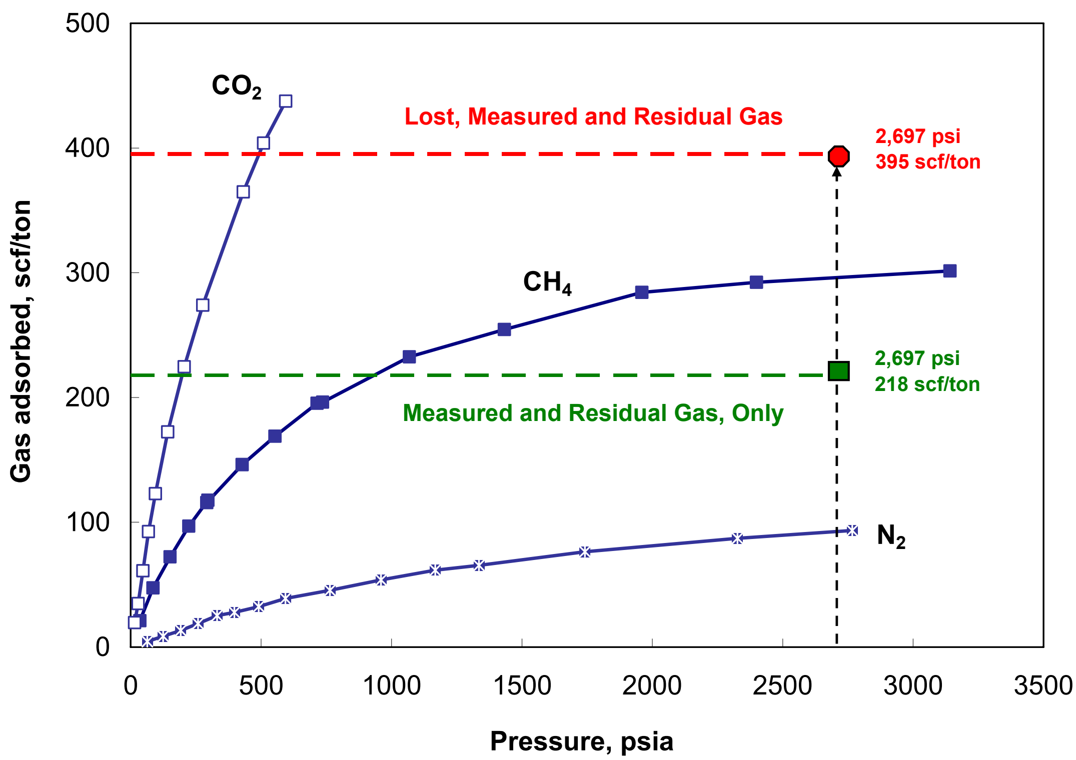


Fig. 22. Sorption isotherms (as-received basis) for Lower Calvert Bluff coal samples, average depth of 6,200 ft, Well APCL2, East-Central Texas. Total gas (lost, measured, and residual gas) exceeds the sorption capacity of the coal, indicating a problem with the desorption analysis. Nevertheless, the sum of measured and residual gas content is high (218 scf/t), validating Anadarko's previous measurements of coalbed gas content at similar depths (Table 5).

These sorption isotherms for CO_2, CH_4, and N_2 (RMB, 2005) were measured to maximum pressures of 595, 3142, and 2767 psia, respectively, at 168°F. Ideally, isotherms would have been measured from 0 psia to pressures greater than reservoir pressure, which is approximately 2,680 psi, assuming a freshwater hydrostatic gradient of 0.432 psi/ft and average depth of 6,200 ft. However, limitations of laboratory equipment relative to the CO_2 critical point restricted CO_2 adsorption analysis to pressures less than 595 psia.

Comparison of the desorbed gas content values with the CH_4 isotherm (as received) for the APCL2 well indicates that the Wilcox coals tested from this well are saturated with CH_4 and should require no depressurization to initiate gas production (**Fig. 22** and **Table 6**). However, the fact that estimated total methane content at reservoir temperature and pressure plots above the isotherm suggests that the lost gas component may have been overestimated (HWA, 2004). Therefore, we also plotted the sum of measured and calculated residual gas content only (218 scf/t) for comparison (**Fig. 22**).

Adsorption isotherms for pure CO_2 (3 samples) and CH_4 (4 samples) for Wilcox coals, including well APCL2, are shown in **Fig. 23**, and the relationships of CO_2 vs. CH_4 sorptive capacities are shown in **Fig. 24**. At any given pressure, methane storage capacity of Wilcox coal increases with depth of the sample, owing to increased thermal maturity (**Fig. 23**).

At 1,000 psia (projecting the CO_2 curve in **Fig. 23**), the ratio of CO_2:CH_4 sorptive capacity is about 2.5:1 for well APCL2 (**Fig. 24**). This ratio is low in comparison to laboratory results for Wilcox coals from the Sandow surface mine, the USGS Panola County well (PA/CN2; (Warwick et al., 2000a), and previous studies of other low rank coals (**Fig. 25**). In the Sandow and PA/CN2 cases, as with other adsorption studies of low-rank coals by the USGS, the CO_2:CH_4 ratio was approximately 10:1 (**Figs. 24** and **25**).

Based on USGS and Sandow mine analyses, Garduno et al. (2003) used a 10:1 ratio of CO_2:CH_4 in preliminary reservoir modeling of low-rank coals for this study. However, the 2.5:1 ratio of CO_2:CH_4 obtained for the APCL2 samples is similar to results from higher rank, bituminous coals in other basins (Carroll and Pashin, 2003). This result (2.5:1 of CO_2:CH_4), based on only the APCL2 well, suggests that Wilcox coals in this area will sequester less CO_2 per ton of coal than anticipated on the basis of earlier studies of low-rank coals (10:1 CO_2:CH_4 storage capacity). However, methane sorption by the deep coals is higher, which partially offsets the ratio differences, and enhanced coalbed methane production potential of the Sam K. Seymour area should be greater than was predicted by (Garduno et al., 2003).

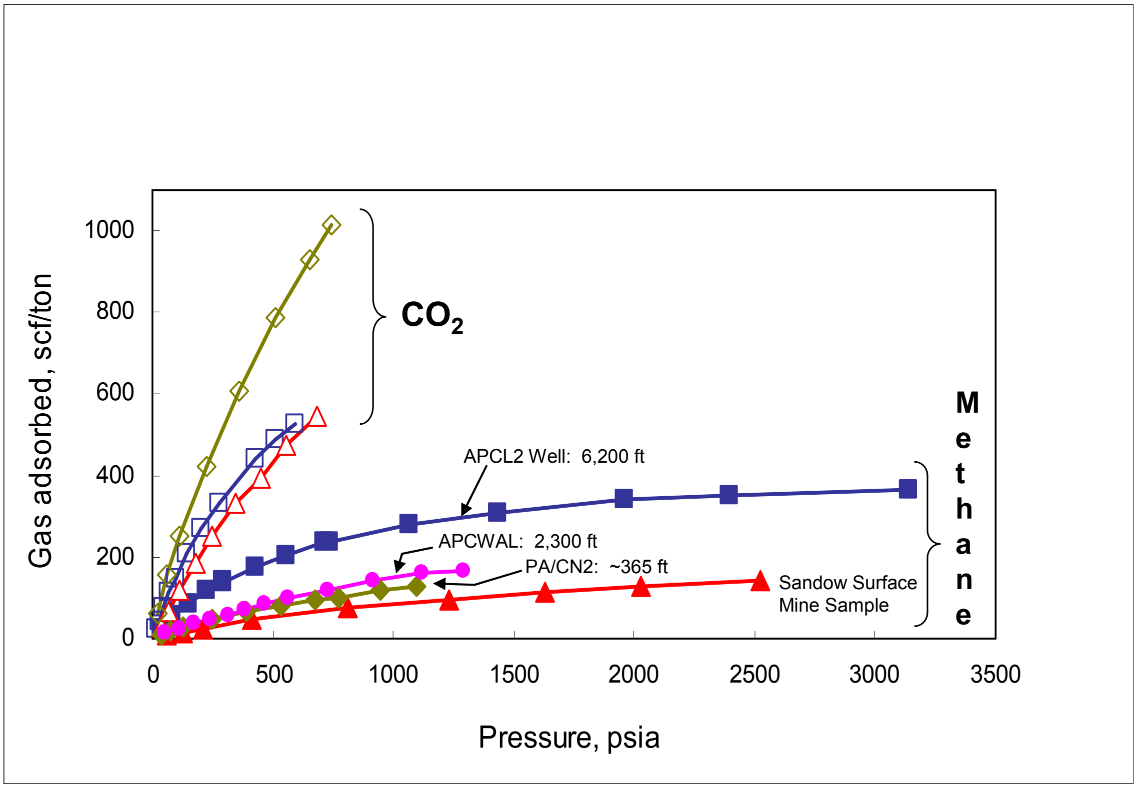


Fig. 23. Comparison of methane (4 samples) and carbon dioxide (3 samples) adsorption isotherms for Wilcox coal samples (dry, ash-free basis) from Sandow surface mine and 3 East-Central Texas wells. Depths are approximate or average depths for each sample. Values for carbon dioxide are plotted as open versions of the symbols used for methane for the same well. Increased adsorption capacity with depth of coal samples results from increased thermal maturity.

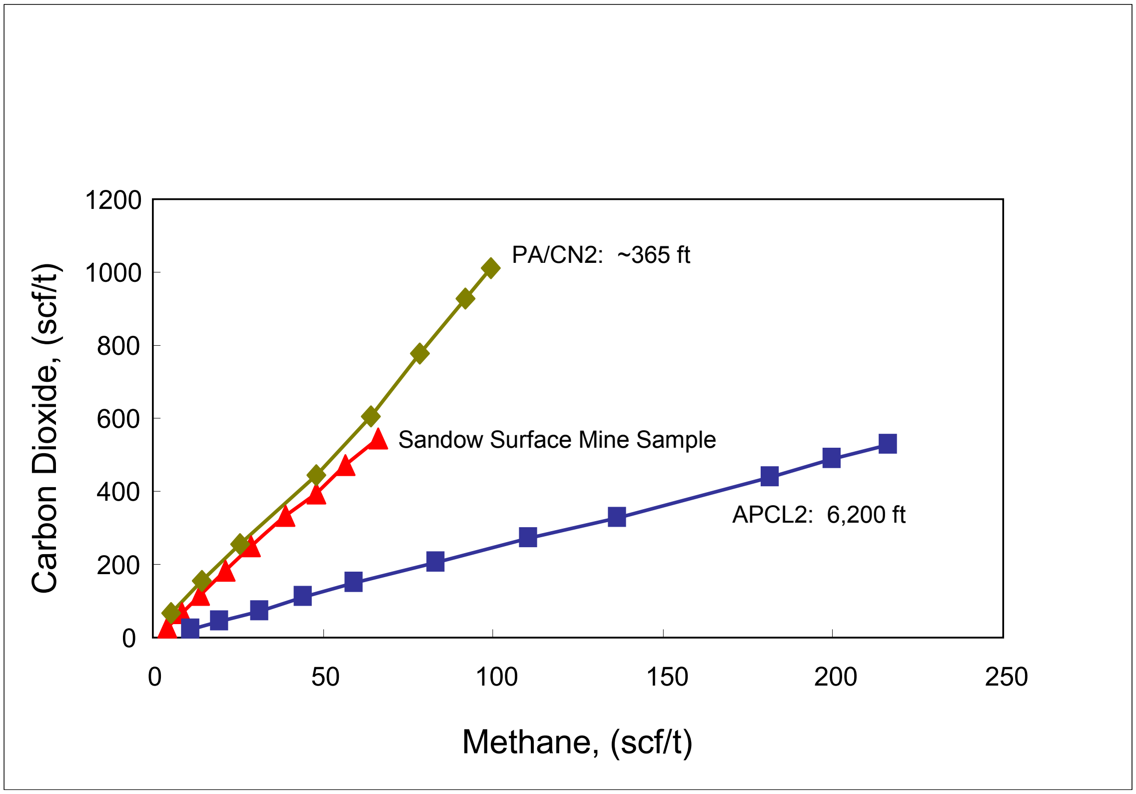


Fig. 24. Scatter plot of methane vs. carbon dioxide adsorption isotherms values for Wilcox coal samples from Sandow surface mine and 3 East-Central Texas wells (dry, ash-free basis). The ratio of carbon dioxide to methane sorption is much lower for the deeper coal (APCL2 well) than for the shallower, lower-rank samples, but methane sorption is higher for APCL2 than for shallower coals (Fig. 23).

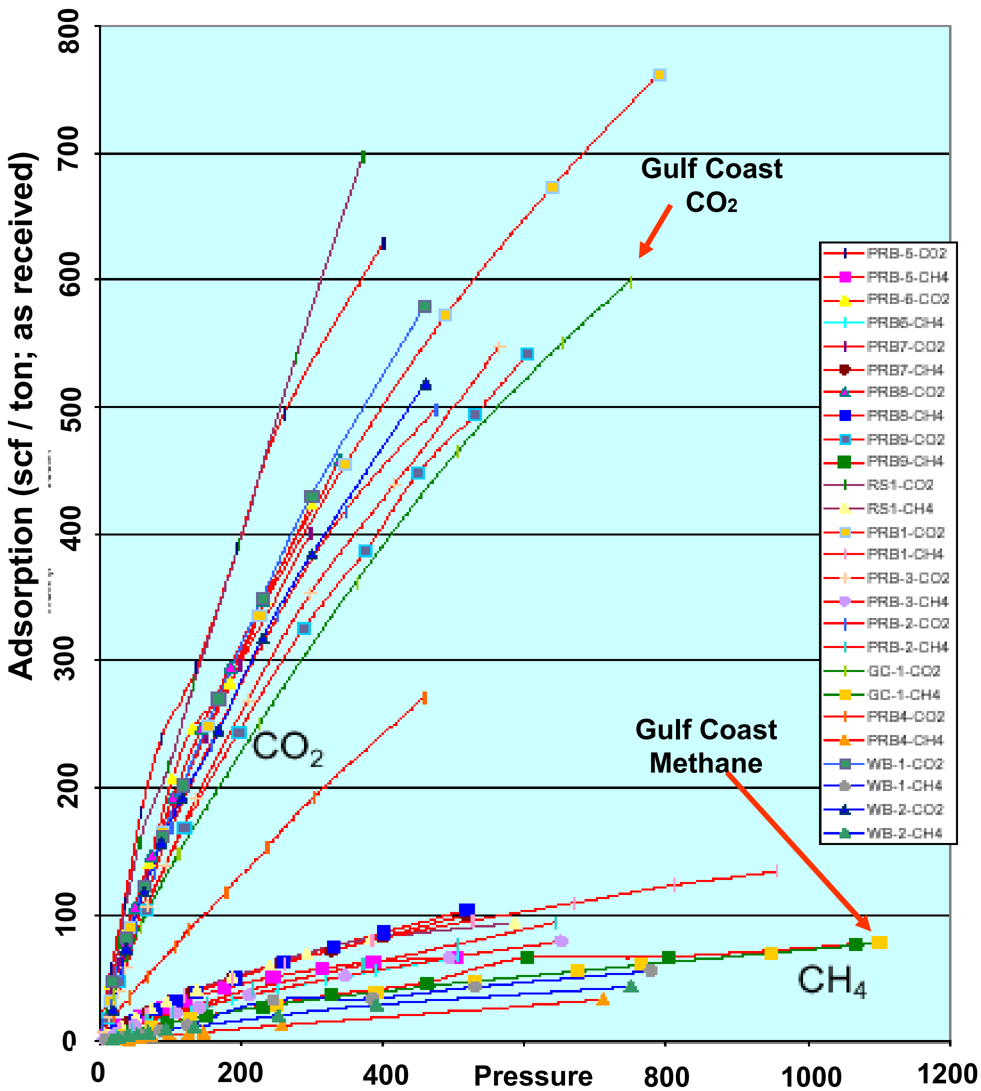


Fig. 25. Methane and carbon dioxide sorption isotherm data for low-rank coals from several U.S. basins, including the Gulf Coast Basin (Stanton et al., 2001). The ratio of carbon dioxide to methane sorption generally is 10:1, which is much higher than that reported for high-rank coals (generally, 2:1) or that measured for Wilcox coal from 6,200-ft depth in Well APCL2 (2.5:1).

Regional geologic, hydrologic and engineering analyses, including the above isotherm studies, indicate that reservoir properties and gas content of Wilcox coals deeper than 3,500 ft differ from those of the shallow Wilcox coals. To model CO_2 sequestration and ECBM production of these extensive, deeper Wilcox coals in the Sam K. Seymour area, we constructed synthetic CH_4 isotherms, using sorption isotherms from 6 Anadarko wells (including APCL2), USGS Well PA/CN2, and the Sandow surface mine coal sample (**Fig. 26**). The Anadarko 2,300-ft and 5,400-ft isotherms were used to interpolate CH_4 sorption values at 4,000-ft depth (**Fig. 27**). The CO_2/CH_4 sorption ratio of approximately 3:1, which was the ratio from coal samples at approximately 4,900-ft depth in the Wilcox Group in Louisiana (Reeves et al., 2005), was used to estimate CO_2 sorption values at 4,000-ft depth (**Fig. 27**). The N_2/CH_4 sorption ratio of approximately 0.27:1 at reservoir pressure of 1,720 psia, and decreasing ratios as a function of pressure (which was the relation from coal samples at approximately 4,900-ft depth in the Wilcox Group (Reeves et al., 2005)), was used to estimate N_2 sorption values at 4,000 ft. Langmuir volume and pressure parameters on an as-received basis for the synthetic isotherm for coals at approximately 4,000-ft depth were estimated to be 458.5 scf/t and 1,884 psia for CH_4, 1,376 scf/t and 1,884 psia for CO_2, and 301 scf/t and 6,764 psia for N_2.

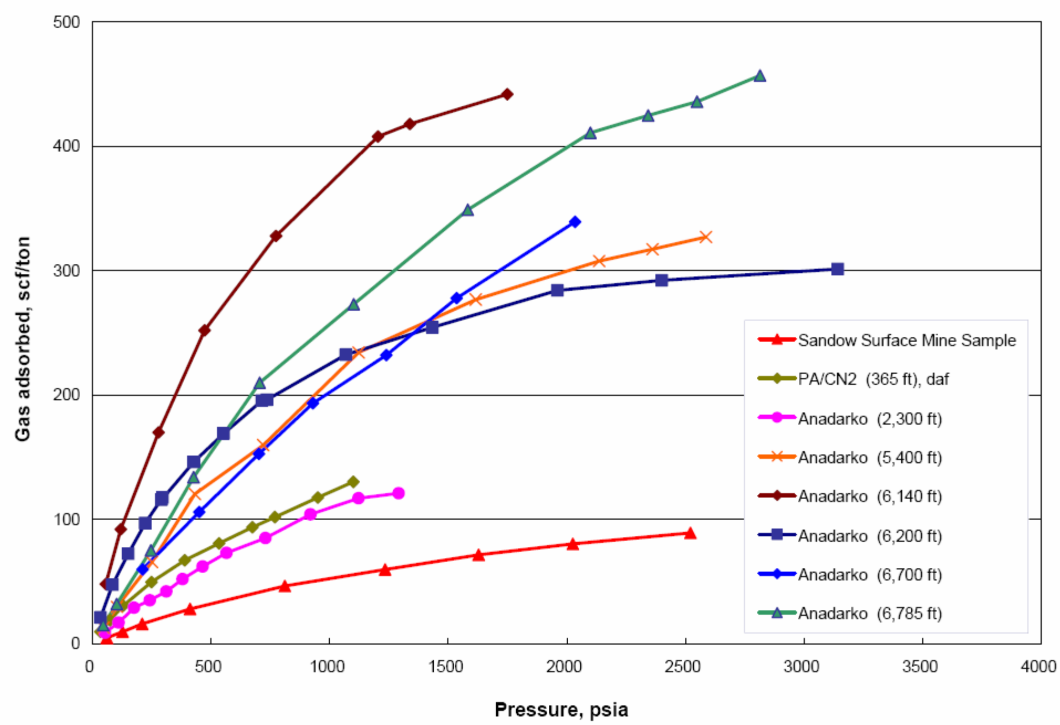


Fig. 26. Methane adsorption isotherms for Wilcox coal samples from one surface mine and 7 East-Central Texas wells. PA/CN2 is from a Wilcox coal sample collected in East Texas by the U.S. Geological Survey (Warwick et al., 2000a). Approximate or average sample depths are shown. The Anadarko 2,300-ft and 5,400-ft isotherms were used to construct a synthetic 4,000-ft isotherm for reservoir modelling.

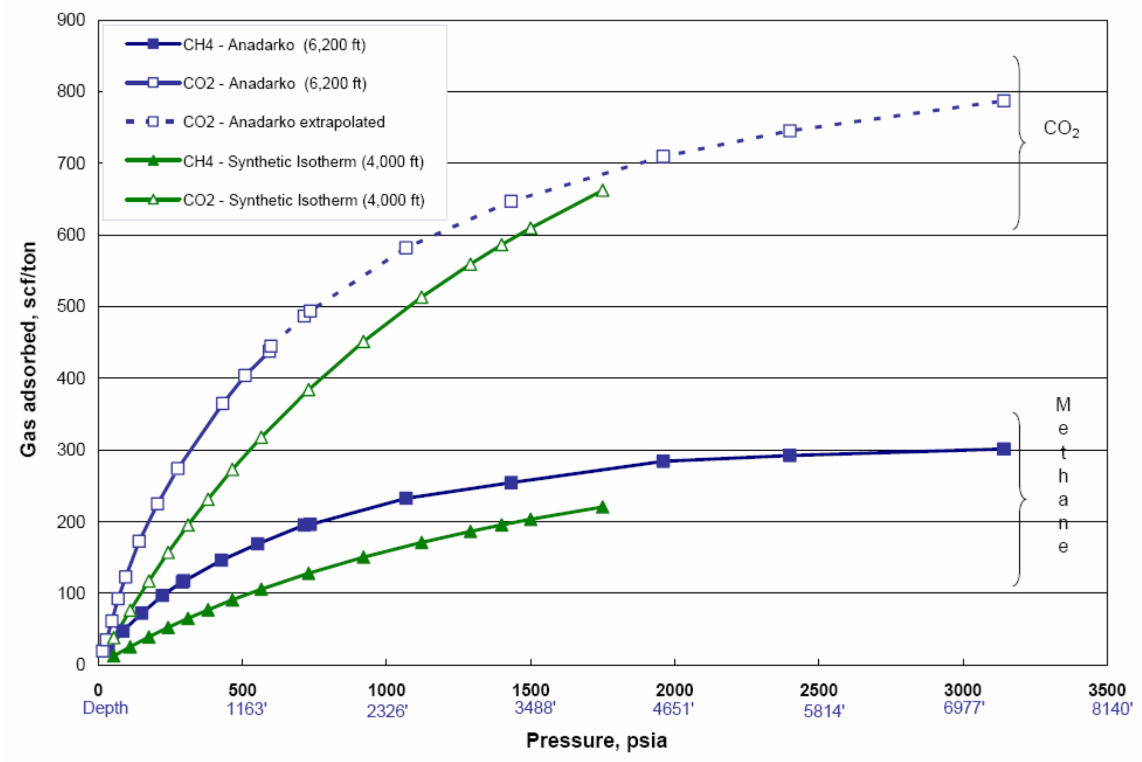


Fig. 27. Methane and carbon dioxide sorption isotherms used as input in reservoir simulation to represent gas adsorption/desorption isotherm behavior in coal beds at approximately 6,200-ft and 4,000-ft depth in the Wilcox Group, East-Central Texas. The isotherms for the 4,000-ft case were interpolated from other isotherms (see Fig. 26) and validated by an isotherm from Wilcox coals from 4,898-ft depth in Louisiana (Reeves et al., 2005). CO_2:CH_4 ratio is 3:1.

Coalbed Gas Chemical and Isotopic Compositions

Chemical Composition

Chemical and isotopic analyses of natural gas are useful to determine gas heating value, as well as gas origins and occurrences, which are necessary when evaluating the volume of CH_4 that may be produced from different regions, by either primary or enhanced recovery. The analyses of gas composition available for this study are very limited (12 analyses from 5 wells). Anadarko provided 8 analyses of gas chemical composition from one well and one analysis of gas chemical composition from 3 other wells. During this study, we collected and analyzed chemical composition of deep (6,200 ft) gas samples from the APCL2 cooperative well. These limited analyses suggest two markedly different coalbed gas systems in East-Central Texas, consistent with the coalbed gas content assessment.

Wilcox gas chemical composition values are quite variable, and there is uncertainty concerning the quality of the analyses. From existing Anadarko samples, CH_4 content ranged between 93 and 100% (mole %); ethane and heavier hydrocarbons (C_{2+}) ranged between 0 and 6%, and CO_2 ranged between 0 and 5%. Six gas samples desorbed from the Anadarko APCL2 sidewall cores (approximately 6,200 ft depth) had average gas composition of 94.3% methane, 3.0% ethane, and 0.7% propane, with traces of the heavier hydrocarbons. Carbon dioxide averaged 1.7% in the coalbed gas.

Wilcox coalbed gas wetness (defined as C_1/C_{1+} (Scott et al., 1994)) ranges from 89.08% to 99.63% (**Fig. 28a**). In the one Anadarko well with 8 gas compositional analyses (**Fig. 28a**, samples between 3,956 and 4,856 ft), gas wetness increases with depth for 7 of the samples. There is one outlier, which is the wettest sample (89.08). Samples at depths greater than 5,000 ft deep are from 4 different wells. There is considerable scatter in the data. However, ignoring the outlier of Well 1 (**Fig. 28a**), gas wetness generally increases with depth, which we infer is due to increased volumes of either early stage thermogenic or migrated thermogenic gas with increased depth. Alternatively, the dryer gas in the shallower Wilcox coal may result from biodegradation of migrated heavier hydrocarbons.

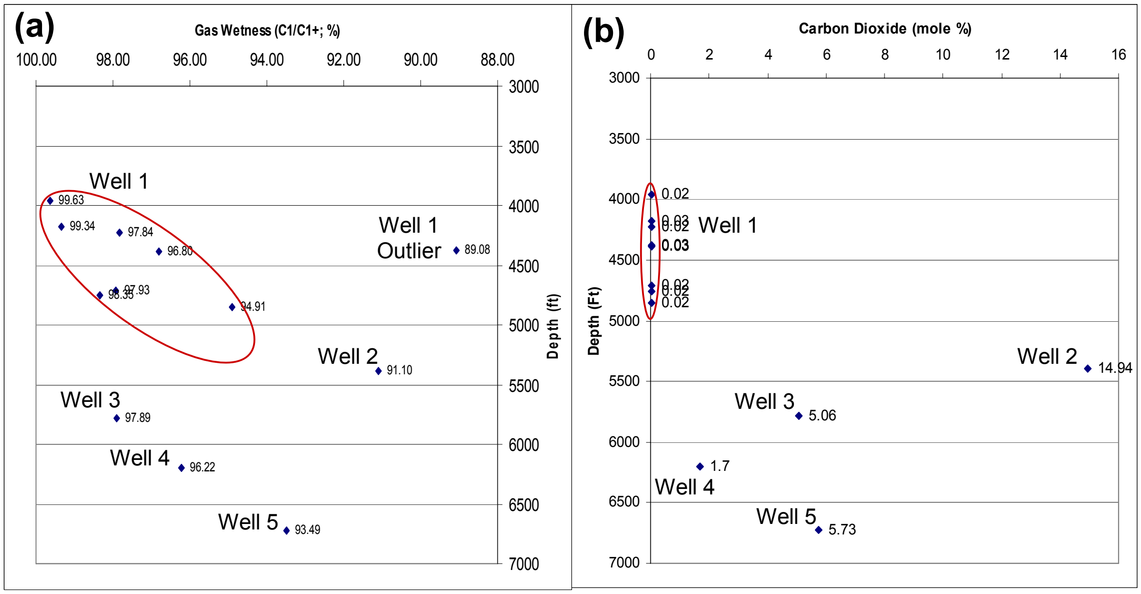


Fig. 28. (a) Gas wetness (C_1/C_{1+}) vs. depth and (b) carbon dioxide vs. depth for 12 samples from 5 East-Central Texas wells.

CO_2 compositions of all Well 1 samples, except the outlier, are low values, whether real or due to analytical error. The deep coalbed gas samples had 1.7 to 14.9% CO_2, but there is no clear trend, and there are too few samples and too much uncertainty in the analyses to draw any conclusions (**Fig. 28b**).

Coalbed Gas Isotopic Composition

Isotopic analyses of carbon and hydrogen may be used to determine whether the methane originated by biogenic or thermogenic processes. In the Anadarko data base, there was one carbon isotopic analysis of methane from a coalbed gas sample from 5,800-ft depth. For that coalbed gas sample, Anadarko determined both chemical composition of the gas and isotopic composition of carbon ($\delta^{13}C$) in the methane. For that sample, a plot of C_1 / C_2+C_3 (50.2) versus δ^{13} C (-47.9 $^0/_{00}$) (Bernard diagram, **Fig. 29**) suggests a thermogenic origin of the gas, with some mixing of biogenic. On the same Bernard diagram (**Fig. 29**), the shallow (365 ft) Wilcox coalbed gas sample from the USGS well (Well PA/CN2) in East Texas plots near the transition between the microbial zone and thermogenic zone (δ^{13} C = -55.8 $^0/_{00}$), but gas dryness (C_1/ C_2+C_3 = 15,000) indicates a biogenic origin (Warwick et al., 2000a). For this same USGS sample, a plot of δ^{13}C versus the hydrogen isotopic composition (δ D) of methane indicates predominantly biogenic gas, possibly mixed with thermogenic gas (**Fig. 30**) (Warwick et al., 2000a).

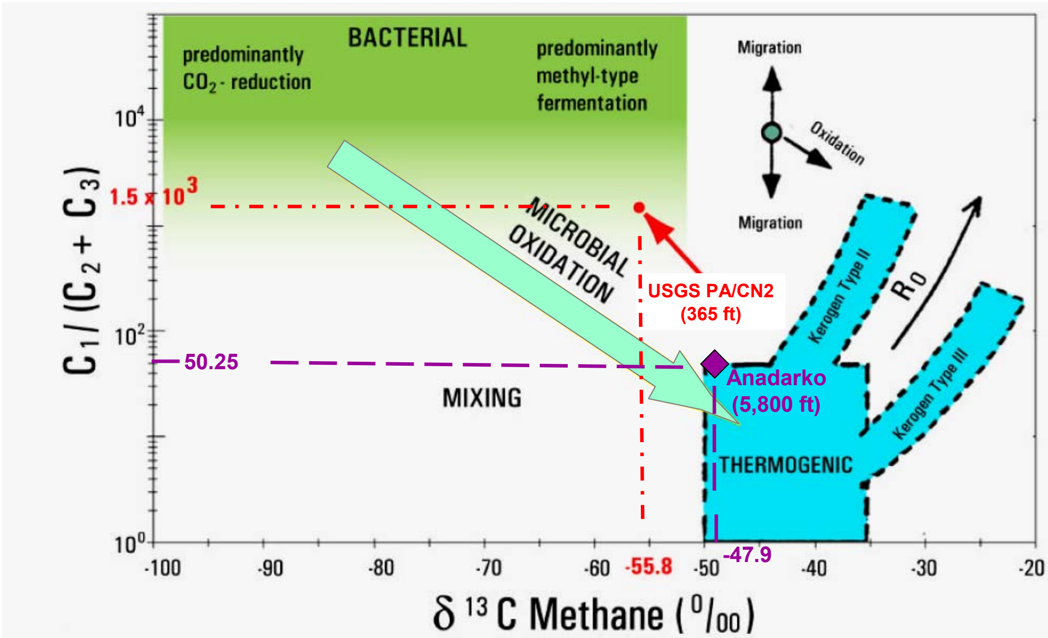


Fig. 29. **Bernard diagram isotopic composition of carbon (δ^{13} C) vs. gas wetness, defined here as $C_1/(C_2+C_3)$, for USGS sample PA/CN2 (from 365-ft depth), and for an Anadarko deeper well sample (5,800 ft). Both samples suggest mixed origin, but the PA/CN2 gas sample is mainly of biogenic origin, whereas the Anadarko sample is primarily of thermogenic origin.**

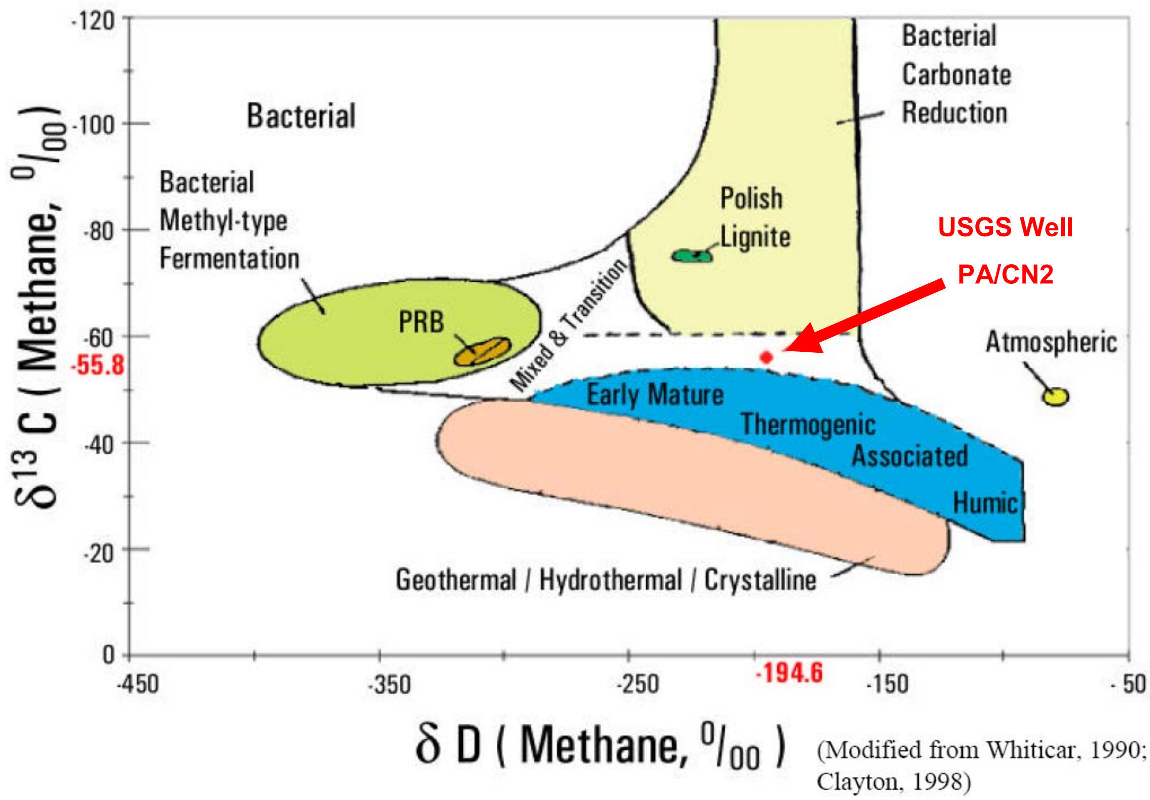


Fig. 30. Plot of isotopic composition of hydrogen (δD) and carbon (δ^{13} C) from a Wilcox gas sample from 365 ft in USGS Well PA/CN2, East Texas. The gas sample is in the mixed or transition zone between biogenic and thermogenic gas. Figure from Warwick et al. (2000a).

Wilcox Coalbed Gas Systems

Knowledge of Wilcox coalbed gas systems is essential for evaluating the potential for CO_2 sequestration and ECBM production. We suggest that there are two Wilcox coalbed gas systems in East-Central Texas. These are a biogenic system and a thermogenic system. We infer that the boundary between these systems is transitional and may occur at different depths throughout East-Central Texas, but generally, it occurs at approximately 3,000 to 4,000-ft depth. Evidence for two Wilcox coalbed gas systems is based on integration of (1) regional hydrology, (2) gas content of the coal beds, (3) gas chemical composition, (4) analyses of methane stable isotopes, and (5) thermal maturity of the coal.

Biogenic Methane System

The Wilcox biogenic coalbed gas system is a shallow system (**Figs. 31** and **32**). It extends from outcrop to approximately 3,500-ft depth. This system is dominated by the Wilcox freshwater aquifer. Dynamics of Wilcox hydrology are clarified by the map of Simsboro formation resistivity (**Fig. 18**), which shows high resistivity (low TDS, fresh water) near outcrop and basinward decrease in resistivity (increase in salinity). Wilcox coals and sandstones behave as an integrated aquifer system, similar to Fruitland formation coals and sandstones of the San Juan Basin (Kaiser et al., 1994). From outcrop recharge areas, fresh water, carrying microbes, sweeps basinward approximately to the 20-ohm-m, freshwater contour (approximately 1,000 mg/L TDS) (**Fig. 18**).

Gas content of shallow Wilcox coals is less than 30 scf/t (**Fig. 20**, samples less than 3,500 ft deep). We infer that shallow Wilcox coalbed gas is biogenic, because it is isotopically light ($\delta^{13}C = -55.8\ ^{0}/_{00}$) (**Fig. 30**). Biogenic origin of the gas is further supported by the coal rank. Coals in this shallow interval are thermally immature (**Fig. 19**, vitrinite reflectance of 0.34 to 0.45%) and should not have generated thermogenic gas. These coals have not entered the oil generation window (Ro ≅ 0.6%), which precedes the gas generation window (Ro ≅ 0.78%).

Thermogenic Coalbed Gas System

From the downdip limits of Wilcox coal (+10,000 ft?), the Wilcox thermogenic coalbed gas systems extends updip to approximately 3,500-ft depth, where it interfingers with the shallow, biogenic coalbed gas system (**Fig. 32**). Wilcox groundwater of the thermogenic system is slightly-to-moderately saline at the interface with the biogenic coalbed gas system (**Fig. 18**, 20-ohm-m contour), and salinity increases basinward (**Fig. 18**, basinward decrease in resistivity to low, single-digit values). We recognize that the TDS-resistivity transform used in the freshwater, biogenic system is of questionable accuracy for the area of the deeper, thermogenic system, owing to different chemical composition of the water in the two regions, and revision of the resistivity map in the deeper Wilcox would better delineate the thermogenic coalbed gas system.

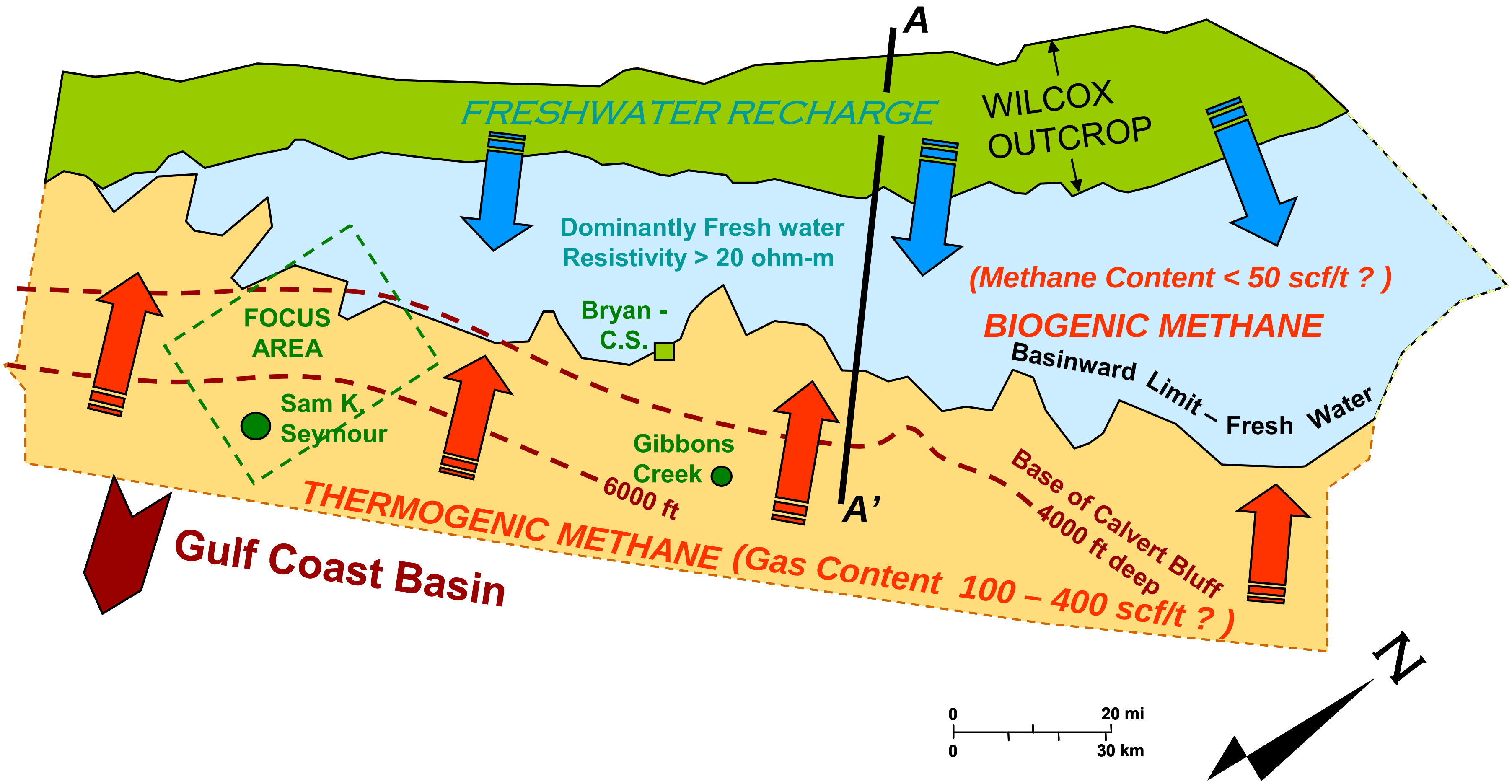


Fig. 31. Schematic view of coalbed gas systems for the Wilcox Group, East-Central Texas. A biogenic coalbed gas system is present in the shallow Wilcox, whereas a thermogenic coalbed gas system is present in the deeper Wilcox. See text for further explanation and Fig. 32 for cross section A-A'.

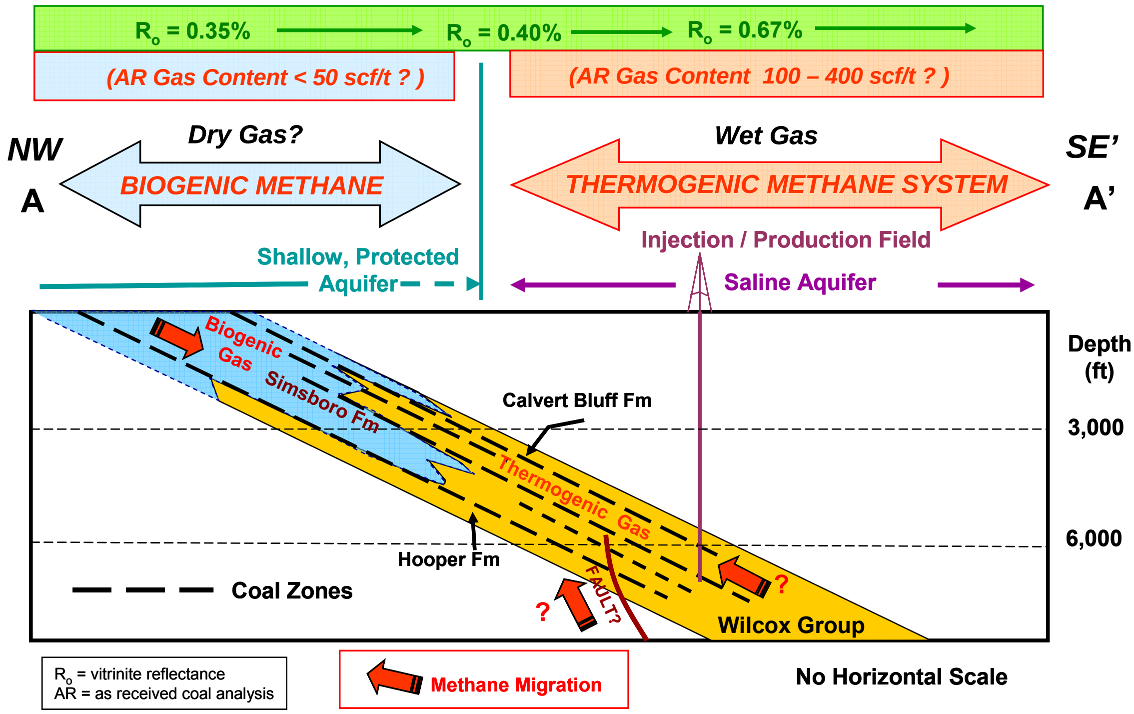


Fig. 32. Schematic cross section of coalbed systems for the Wilcox Group, East-Central Texas. A biogenic coalbed gas system is inferred for the shallow Wilcox, whereas a thermogenic coalbed gas system is present in the deeper Wilcox. See Fig. 31 for cross section location and text for further explanation.

Gas content of Wilcox coals in the thermogenic system is 100 to 430 scf/t (**Fig. 20**, samples greater than 3,500 ft deep). We infer that deep Wilcox coalbed gas is early stage thermogenic gas that either originated in-situ in the Wilcox coals or migrated updip from more mature coals or shales. The conclusion that this gas is of thermogenic origin is supported by the chemical composition of the coalbed gas. Heavy hydrocarbons are abundant (C_{2+} as much as 6%) in the coalbed gas. Moreover, the coalbed methane from the lone deep sample has isotopically heavier carbon than that present in the shallow PA/CN-2 well (**Fig. 29**; $\delta^{13}C = -47.9\ ^0/_{00}$ vs. $\delta^{13}C = -55.8\ ^0/_{00}$), which is consistent with stronger thermogenic contribution to the deeper gas. Thermogenic origin of the gas is further supported by the coal rank. Vitrinite reflectance of Wilcox coals greater than 3,500 ft ranges from 0.50 to 0.67% (**Fig. 19**). East-Central Texas coals more than 6,000-ft deep are thermally mature for oil generation (top of oil window is at Ro ≅ 0.6%), and early stage gas generation is possible at this coal rank.

Implications of Wilcox Coalbed Gas Systems for CO_2 Sequestration and ECBM

These tentative models of coalbed gas systems have important implications for CO_2 sequestration and for primary and enhanced production of Wilcox coalbed gas. We infer CO_2 sequestration would not be allowed in Wilcox coal beds of the shallow, biogenic gas system, because they are part of the protected Wilcox/Carizzo freshwater aquifer. However, the shallow coals contain little methane that could be produced by enhanced coalbed methane production associated with the CO_2 sequestration. Therefore, CO_2 sequestration in the shallow coals would not benefit from the cost offset of ECBM. Moreover, owing to lower thermal maturity and shallow depth (and lower formation pressures), coals of the biogenic system can store less methane than deeper coals.

The thermogenic coalbed gas system is basinward of the Wilcox freshwater aquifer and, thus, CO_2 injection/sequestration should be allowed. Although the sorption ratio of CO_2:CH_4 for the deep, thermogenic system (2.5:1) is much less than that for the shallow, biogenic system (10:1), the amount of CO_2 that can be stored is similar for the two systems (**Fig. 23**; compare Sandow and APCL2 isotherms for CO_2 and CH_4), because sorptive capacity for methane is greater in the deeper, higher rank coals. In addition, Wilcox coals are deeper and formation pressure is greater, which, combined with higher thermal maturity, indicate that coals of the thermogenic coalbed system can store more methane than shallower coals. Importantly, the thermogenic coalbed gas system has greater coalbed methane resources to be produced by ECBM, to offset costs of CO_2 sequestration. Of course, with increased coal drilling depths, well costs will increase, and greater overburden pressure may adversely affect reservoir permeability and, thus, flow rates.

Further testing and analysis are needed to verify the existence of two coalbed gas systems, define the boundary between them and better characterize coalbed reservoir and fluid properties. Additional data, especially gas compositional and isotopic analyses, are necessary to define the limits of the coalbed gas systems, in terms of both depth and geographic occurrence.

Wilcox Coals Permeability Estimation from Well Tests

Permeability is a critical parameter affecting the extraction of gas from coal beds (Seidle et al., 1991). Our characterization included determination of absolute coal fracture permeability from two Wilcox coals perforated in the Anadarko APCT2 well.

Water injection/fall-off pressure transient tests are recommended to best determine permeability in coalbed methane reservoirs (Zuber et al., 1990), as opposed to withdrawing fluids from the formation, which may result in methane desorption. Well test analysis becomes difficult in the presence of two-phase flow conditions and the combined mechanisms of diffusion and gas flow in porous media.

Pinnacle Technologies conducted two injection/falloff tests in the APCT2 well, with the objective of determining in-situ permeability to water in multiple perforated intervals. Low-rate equipment specially designed for testing coalbed methane reservoirs was used to conduct the injection/falloff tests. Bottom-hole pressures were measured in both well tests performed, while surface injection rates were measured at the injection unit. Fracture gradients based on breakdowns pumped prior to the injection tests were used to determine maximum surface injection pressure (Pinnacle Technologies Inc., 2005).

Data from both injection/falloff tests were of good quality, and their results are presented in **Table 7**. The first injection/falloff test was conducted in one coal seam with perforated thickness of 7 ft at approximately 4,200-ft depth. Semi-log analysis of the pressure falloff data resulted in coal seam permeability to water of 1.9 md, a skin factor of -4.9, and an average reservoir pressure of 1,851 psi (**Table 7** and **Fig. 33**). Average reservoir pressure is equivalent to a gradient of 0.44 psi/ft. The reservoir temperature was estimated to be 145 ^{o}F.

Table 7. Interpretation results of pressure injection/falloff tests conducted in East-Central Texas Wilcox coals.

Depth, ft	4,200	4,000
Permeability, md	1.9	4.2
Skin factor	-4.9	-1.9
Pressure, psia	1,851	1,687

The second injection/falloff test was conducted in one coal seam with perforated thickness of 3 ft at approximately 4,000-ft depth. Semi-log analysis of the pressure falloff data resulted in coal seam permeability to water of 4.2 md, a skin factor of -1.9, and an average reservoir pressure of 1,687 psi (**Table 7** and **Fig. 34**). Average reservoir pressure is equivalent to a gradient of 0.43 psi/ft. The reservoir temperature was estimated to be 140 ^{o}F.

In both tests, negative skin factors indicate that the tested zones are stimulated, most likely a combined result of open cleats, perforating activities, and the injection tests creating microfractures near the wellbore.

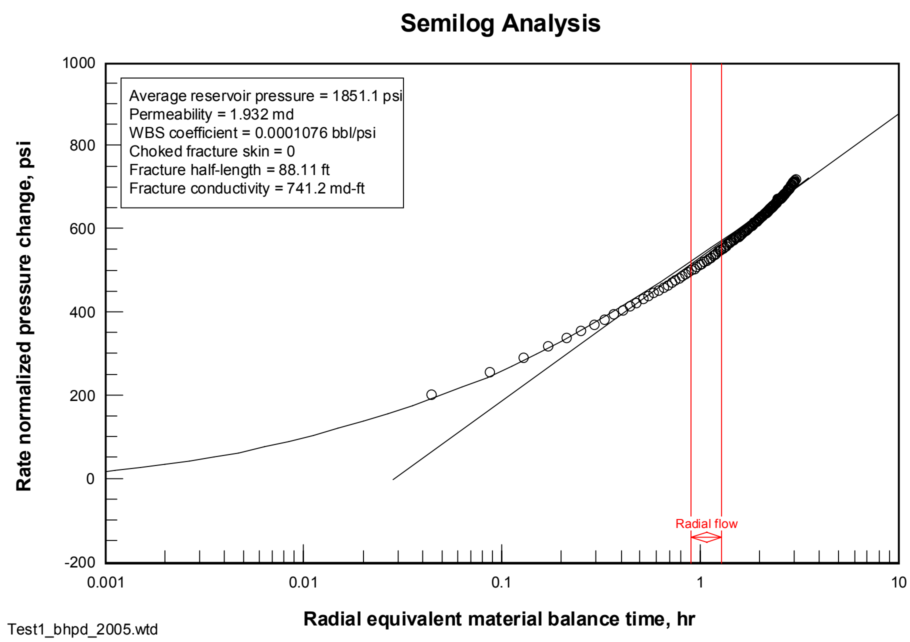


Fig. 33. Pressure falloff interpretation for the first coal seam test, from Well APCT2 at approximately 4,200 ft depth in the Wilcox Group.

The permeability values obtained from these two tests are near the permeability value used in preliminary simulation modeling, 5.0 md (Garduno et al., 2003). The geometric mean of these measured permeability data is 2.8 md. A log-normal distribution derived from the calculated permeability data was used as input in the probabilistic reservoir simulation modeling, described in the next section.

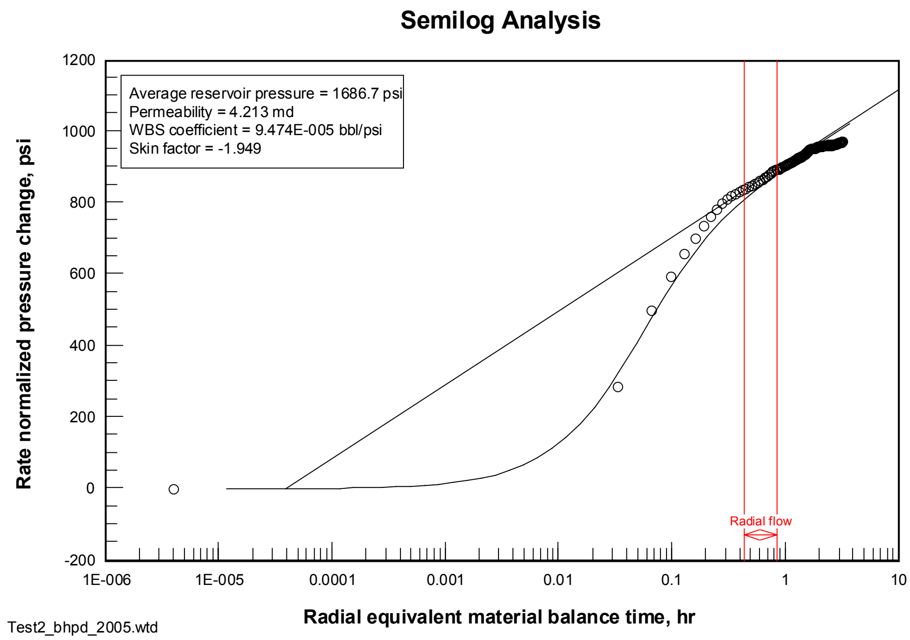


Fig. 34. Pressure falloff interpretation for the second coal seam test, from Well APCT2 at approximately 4,000-ft depth in the Wilcox Group.

Simulation of CO_2 Sequestration and Enhanced Coalbed Methane Production

Simulation Approach

In this section, we discuss important considerations in modeling CO_2 sequestration/ECBM production. In general, commercial and research coalbed methane (CBM) simulators are developed to model primary recovery processes, taking into account important features to properly evaluate the performance of coalbed reservoirs. In order to correctly model the ECBM recovery process via CO_2 and/or N_2 injection, CBM simulators are being improved to account for additional complex reservoir mechanisms. Important features in modeling primary and enhanced coalbed methane recovery processes are as follows (Law et al., 2003):

- Dual porosity,
- Multiple gas components,
- Multiphase flow in the natural fracture system,
- Pure- and mixed-gas diffusion between the coal matrix and the natural fracture system,

- Pure- and mixed-gas adsorption/desorption at the coal surface,
- Compaction/dilation of the natural fracture system due to stresses,
- Coal matrix shrinkage/swelling due to gas desorption/adsorption,
- Non-isothermal adsorption of the injected gas, and
- Water effects on gas flow kinetics in the coal matrix.

Capability to handle multiple gas components is an essential feature in modeling ECBM recovery processes with flue gas. Recent advances in numerical simulation for CBM/ECBM recovery processes have focused on multi-component gas transport in in-situ bulk coal and changes of coal properties during methane production (Wei et al., 2005).

Considering the features required for modeling ECBM recovery processes, the coalbed simulator GEM developed by Computer Modelling Group (CMG) Ltd. was selected for conducting deterministic and probabilistic simulation studies. GEM is a three-dimensional, finite-difference, multiphase, dual-porosity, compositional simulator. It has the option to select the Peng-Robinson equation of state (EOS) to calculate the necessary thermodynamic functions. The Palmer and Mansoori (Palmer and Mansoori, 1996, 1998) model to calculate change in absolute permeability and fracture porosity with reservoir pressure is available in GEM. The simulator is capable of modeling coalbed methane reservoir performance under primary and/or enhanced recovery schemes.

We coupled reservoir simulation (GEM) with Monte-Carlo simulation (@RISK by Palisade Corporation) to conduct probabilistic reservoir modeling studies consisting of thousands of simulation runs to quantify the uncertainty in our forecasts of CO_2 sequestration and methane production.

Reservoir Model Parameters

Reservoir data were selected to represent Wilcox Group Lower Calvert Bluff reservoir coals at 4,000 ft and 6,200 ft depths. These are typical depths of potential Lower Calvert Bluff coalbed reservoirs in East-Central Texas. Average coal properties and reservoir parameters obtained from literature and data collected during this study were used as model input and are shown in **Tables 8-10**.

Table 8. Coal static reservoir property estimates.

Property	Value
Fracture/Cleat Spacing	2.5 inches
Fracture Porosity	1%
Matrix Porosity	1%
Fracture Compressibility	138×10^{-6} 1/psi
Water Density	0.99 g/cm^3 (61.85 lb/ft^3)
Water Viscosity	0.607 cp
Water Compressibility	4.0×10^{-6} 1/psi
Initial Water Saturation	100%
Initial Composition of Gas in the Reservoir	100% CH_4

Table 9. Uncertain reservoir property estimates and design parameters.

Property/Parameter	Value
Coal Seam Thickness $^{(1)}$	10, 20, 30 ft
Fracture Absolute Permeability $^{(2)}$	0.8, 2.8, 10 md
Coal Density $^{(1)}$	1.289, 1.332, 1.380 g/cm^3 (80.5, 83.2, 86.2 lb/ft^3)
Gas Phase Diffusion Time$^{(1)}$ (Sorption Time)	0, 1, 4 days
Injection Gas Composition	100% CO_2, 13% CO_2 - 87% N_2, 50% CO_2 - 50% N_2
Well Spacing	40, 80, 160, 240 acres
Permeability Anisotropy Ratio	1:1, 2:1, 4:1, 8:1
$^{(1)}$ Triangular Distribution $^{(2)}$ Log-Normal Distribution	

Coal thickness

Lower Calvert Bluff average net coal thickness is 20 ft in the area of study (Ayers and Lewis, 1985). A triangular distribution (10, 20, and 30 ft coal thickness) was used in the reservoir simulation model to help quantify uncertainty.

Coal porosity

Coal porosity of 1% is estimated to be a representative value in the study area. In dual-porosity models (Computer Modelling Group (CMG) Ltd., 2005), fracture porosity is the fraction of fracture system void space per volume of bulk reservoir rock. Matrix porosity is the fraction of void space in a piece of unfractured matrix material per unit bulk volume.

Table 10. Parameters for base case coal seam scenarios.

Property/Parameter	4,000-ft depth	6,200-ft depth
Initial Reservoir Pressure	1,730 psia	2,680 psia
Reservoir Temperature	140 °F	170 °F
Langmuir Isotherm Parameters [1] :		
V_L, CH_4	458.5 scf/t	363.6 scf/t
P_L, CH_4	1,884 psia	608.5 psia
V_L, CO_2	1,375.5 scf/t	961.9 scf/t
P_L, CO_2	1,884 psia	697.5 psia
V_L, N_2	301 scf/t	166.1 scf/t
P_L, N_2	6,764 psia	2,060.7 psia
Operating Conditions - Pressure Control :		
Production Well, Pressure and Rate	40 psia, 3.5 MMscf/D	40 psia, 3.5 MMscf/D
Injection Well, Pressure and Rate	2,175 psia, 3.5 MMscf/D	3,625 psia, 3.5 MMscf/D
Operating Conditions Injection Rate Case - Pressure Control :		
Production Well, Pressure and Rate		500 psia, 3.5 MMscf/D
Injection Well, Pressure and Rate		3,165 psia, 3.5 MMscf/D
[1] As-received basis		

Fracture spacing

Coal fracture/cleat spacing was estimated to be approximately 2.5 inches on the basis of coal descriptions from Sandow, Big Brown, and Martin Lake surface mines (Texas Engineering Experiment Station (TEES), 2003). Fracture spacing is used to calculate the matrix-to-fracture transfer coefficient according to shape factor type. Gilman & Kazemi (GK) and Warren & Root (WR) shape factor formulations are available options in calculating matrix-to-fracture flows within grid blocks for dual-porosity models in GEM.

Coal permeability

A log-normal distribution of coal fracture permeability based on well test results (1.9 to 4.2 md, with geometric mean of 2.8 md) was used in the reservoir simulation modeling.

Rock compressibility

Matrix compressibility of 1×10^{-6} psi^{-1} and fracture compressibility of 138×10^{-6} psi^{-1} were used in the simulation model. Pore volume compressibility measurements reported for the Fruitland coal in the San Juan basin are $c_p = (233\text{-}969) \times 10^{-6}$ psi^{-1} (Palmer and Mansoori, 1996).

Coal density

Bulk density of the coal samples ranged between 1.292 g/cc and 1.389 g/cc, with an average value of 1.332 g/cc, from Lower Calvert Bluff coal samples taken at approximately 6,200-ft depth in an APC well in East-Central Texas (Hampton, 2004). A triangular distribution of these coal density data with a most likely value of 1.332 g/cc was used in reservoir simulation.

Isotherm parameters

Langmuir volume and pressure parameters for the 6,200-ft depth coal seam scenario are 363.6 scf/t and 608.5 psia for CH_4, 961.9 scf/t and 697.5 psia for CO_2, and 166.1 scf/t and 2060.7 psia for N_2 (RMB Earth Science Consultants Ltd., 2005). Synthetic isotherm for coals at approximately 4,000-ft depth were estimated to be 458.5 scf/t and 1884.0 psia for CH_4, 1375.5 scf/t and 1884.0 psia for CO_2, and 301 scf/t and 6764 psia for N_2 (as received basis).

Diffusion time

Diffusion time controls the mass transfer rate from matrix (coal) to fracture (cleats). Gas phase diffusion times considered were 0, 1, and 4 days based on published values. Sorption times reported for Fort Union coals (Mavor et al., 2003) in the Powder River basin (subbituminous C), Upper Medicine River coals (Mavor et al., 2004) in the Western Canada Sedimentary basin (hvB bituminous), and Pottsville coals (Bromhal et al., 2005) in the Black Warrior basin (hvA bituminous) are 42.6-50.7 hours, 4.93 hours, and 5.8 days, respectively. For Texas low-rank coals of interest, 4 days was selected as a reasonable upper bound on diffusion/desorption time. A triangular distribution of these gas phase diffusion times, with a most likely value of 1.0 day, was used in reservoir simulation.

Reservoir pressure and temperature

At a depth of 6,200 ft in the APCL2 cooperative well, we estimated that reservoir temperature is 170°F and pressure is 2,680 psia, assuming a freshwater hydrostatic gradient of 0.435 psi/ft. At a depth of 4,000-ft, we estimated that reservoir temperature is 140°F and pressure is 1,730 psia.

Gas content

At reservoir pressure, gas content is estimated to be 295 scf/t and 220 scf/t for the 6,200-ft and 4,000-ft depth coal seam scenarios, respectively.

Relative permeability

In naturally fractured reservoirs, straight-line curves are typically used. However, published data for relative permeability relationships for coal reservoirs have been found to be useful for matching actual production in a variety of coal basins (Mavor et al., 2003). **Fig. 35** shows gas-water relative permeability curves based upon the relationship published by Gash (1991) and Gash et al. (1993) for coal in the Fruitland formation, San Juan basin. Capillary pressure is assumed to be zero.

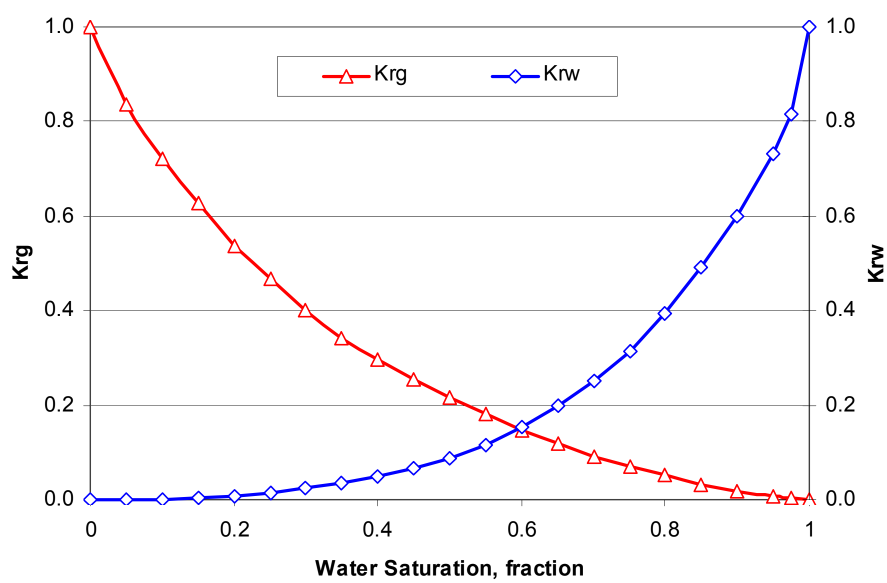


Fig. 35. Relative permeability curves used in simulation studies.

Operational constraints

Operating conditions for the producer wells in the model are controlled, primarily, by minimum constant bottom-hole flowing pressure of 40 psia, and secondarily, by maximum gas production rate of 3,530 Mcf/D, for both base case scenarios. For the injector wells, maximum bottom-hole injection pressure of 2,175 psia and maximum gas injection rate of 3,530 Mcf/D are used for the 4,000-ft depth scenario, and maximum bottom-hole injection pressure of 3,625 psia and maximum gas injection rate of 3,530 Mcf/D are used for the 6,200-ft depth scenario.

Pattern Reservoir Simulation Model

We used a reservoir grid model (**Fig. 36**) that is one-eighth of a 5-spot pattern to run both deterministic and probabilistic simulations using the GEM compositional reservoir simulator developed by Computer Modeling Group Ltd (CMG). The predicted volumes of CO_2 sequestered and CH_4 produced are scaled to a full pattern in this report.

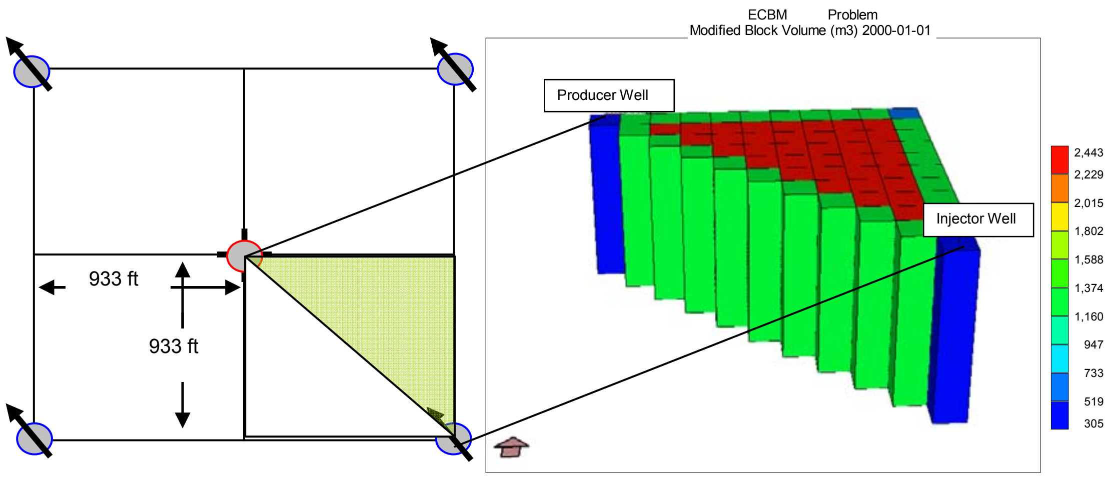


Fig. 36. Cartesian, orthogonal grid model of a 1/8 5-spot pattern, 40-acre well spacing.

A grid sensitivity study was performed by redefining the single-layer grid model from 11x11x1 to 20x20x1 grid cells in a 5-spot pattern with 40-acre well spacing. Comparison of saturation and pressure distributions, recovery efficiency, and production and injection performance of wells indicated no negative impacts resulting from use of the coarser grid model, allowing us to use it with confidence (Mattax and Dalton, 1990).

Results for these two grid resolutions are shown in **Fig. 37**. Differences in cumulative CO_2 injection and CH_4 production are about 1.5%, indicating adequacy of the coarser grid. The computer time is reduced by a factor of 6 using the coarser-grid model.

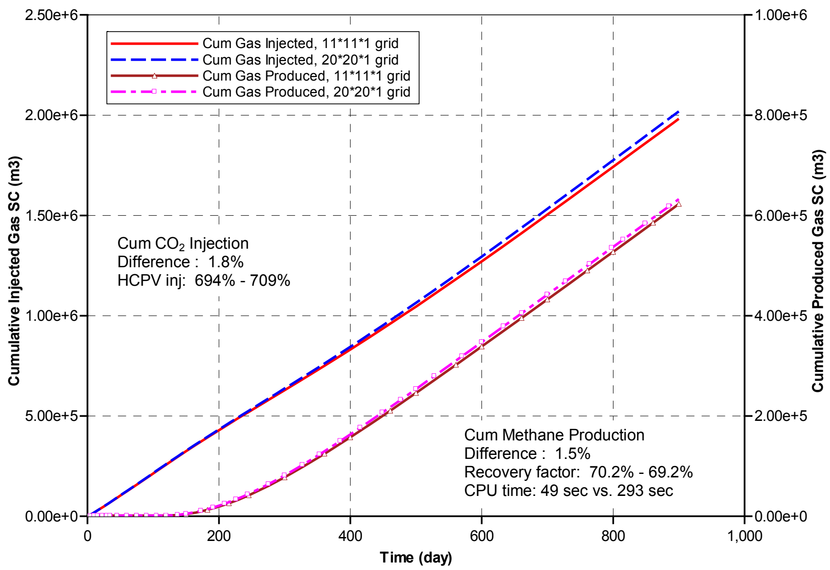


Fig. 37. Grid sensitivity results for cumulative CO_2 injection and CH_4 production profiles, two grid sizes at 900 days of simulation time.

Reservoir Simulation Studies

To predict CO_2 sequestration and ECBM production in the Wilcox Group Lower Calvert Bluff coal beds, we conducted six separate simulation investigations, or cases. These cases are (1) CO_2 sequestration base case scenarios for 4,000-ft and 6,200-ft depth coal beds in the Lower Calvert Bluff Formation of East-Central Texas, (2) sensitivity study of the effects of well spacing on sequestration, (3) sensitivity study of the effects of injection gas composition, (4) sensitivity study of the effects of injection rate, (5) sensitivity study of the effects of coal dewatering prior to CO_2 injection/sequestration, and (6) sensitivity study of the effects of permeability anisotropy on CO_2 sequestration and enhanced methane recovery. On the basis of the probabilistic simulation results, we estimated potential volumes of CO_2 that may be sequestered in, and CH_4 that may be produced from, the Wilcox Group low-rank coals in East-Central Texas.

Case 1: CO_2 Sequestration/ECBM Production Base Case Scenarios

To assess reservoir performance during CO_2 sequestration in Lower Calvert Bluff coals, we conducted probabilistic simulations (1,000 iterations), modeling simultaneous injection of 100% CO_2 and production of CH_4 under the base case operating conditions, in an 80-acre 5-spot pattern (40-acre well spacing). The results of the modeling studies for the 4,000-ft depth (Case 1a) and 6,200-ft depth (Case 1b) base case coal seam scenarios are shown in **Fig. 38** and **Fig. 40** (colorfill maps of various reservoir properties at breakthrough), **Fig. 39** and **Fig. 41** (production and injection rates and pressure profiles), **Fig. 42** (cumulative distribution functions for CO_2 sequestered, CH_4 produced, water produced, and breakthrough times), and **Fig. 43** (cumulative distribution functions for methane recovery and CO_2 injection factors).

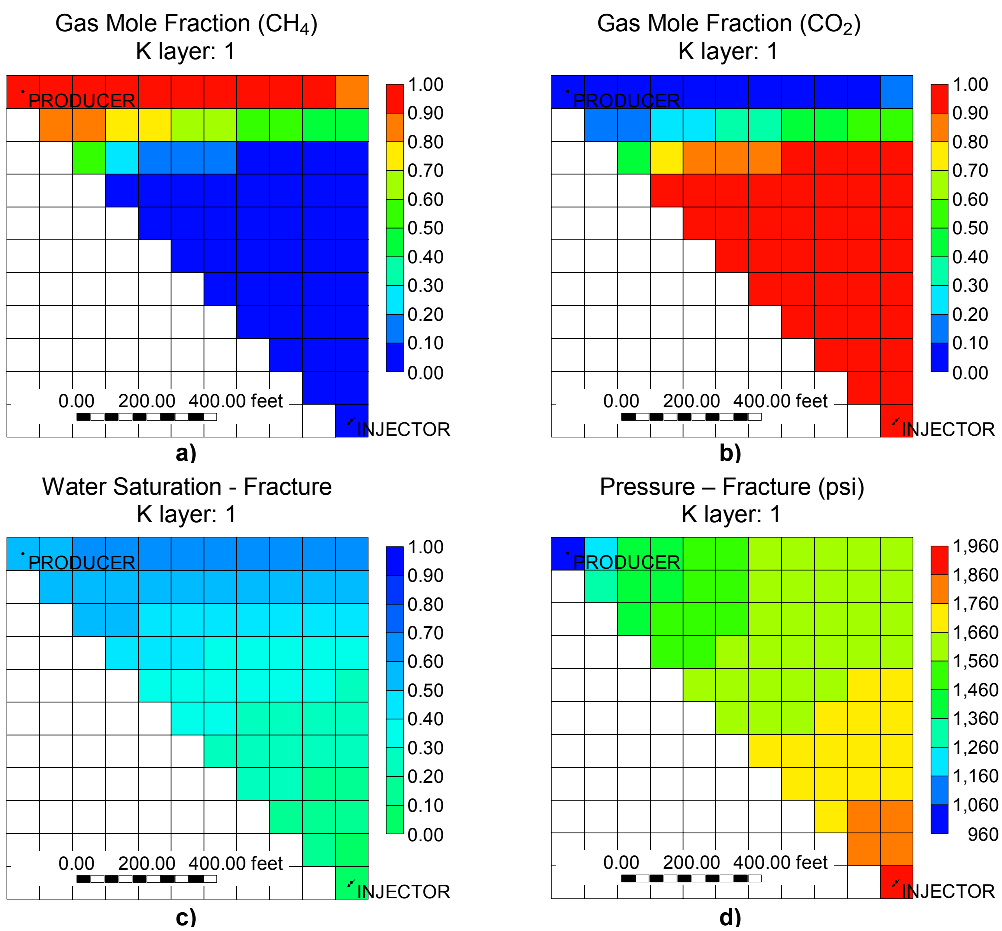
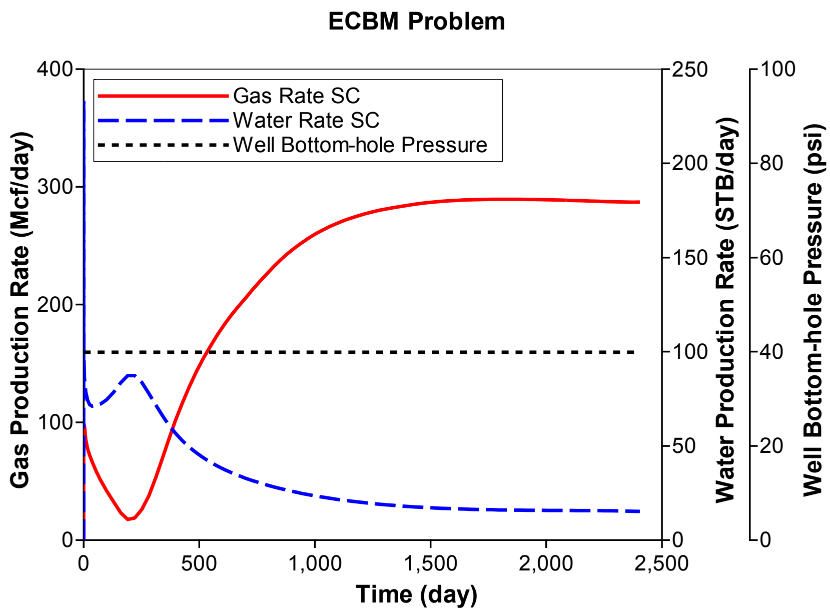
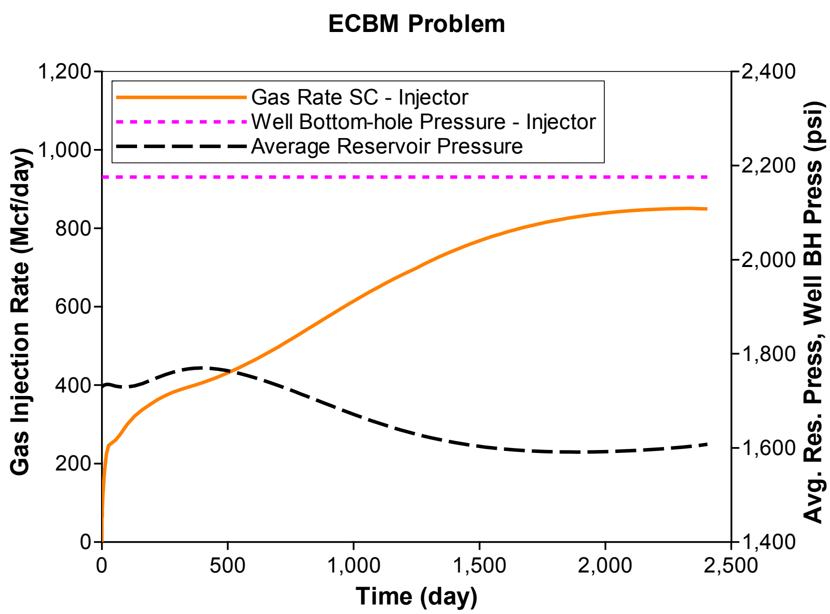


Fig. 38. a) Methane gas mole fraction, b) CO_2 gas mole fraction, c) water saturation in the fracture system, and d) reservoir pressure at breakthrough time of 2,405 days for the 4,000-ft depth base case coal seam scenario in the Wilcox Group, Case 1a.



a)



b)

Fig. 39. a) Production and b) injection profiles for gas rate, water rate, bottomhole pressure, and average reservoir pressure for the 4,000-ft depth base case, Case 1a. Rates are for an 80-acre 5-spot pattern (40-acre well spacing).

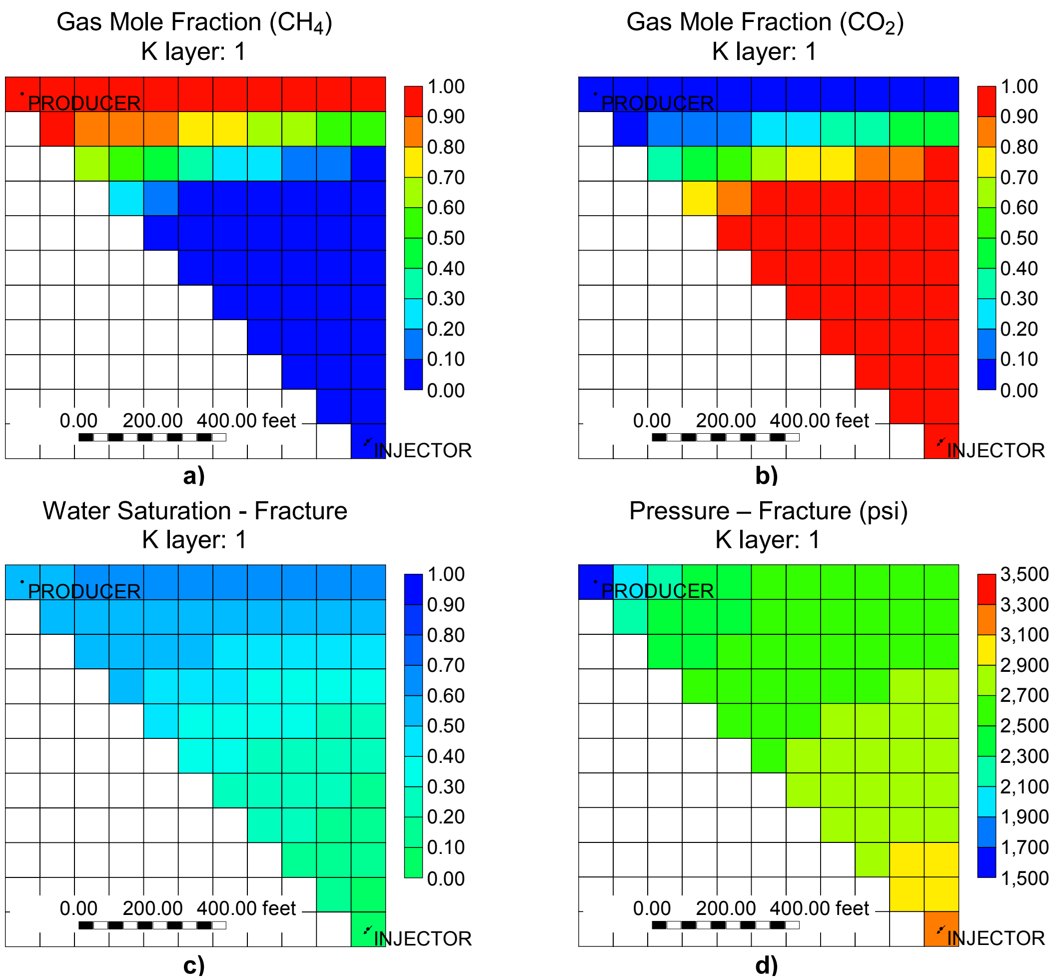


Fig. 40. a) Methane gas mole fraction, b) CO_2 gas mole fraction, c) water saturation in the fracture system, and d) reservoir pressure at breakthrough time of 1,461 days for the 6,200-ft depth base case coal seam scenario in the Wilcox Group, Case 1b.

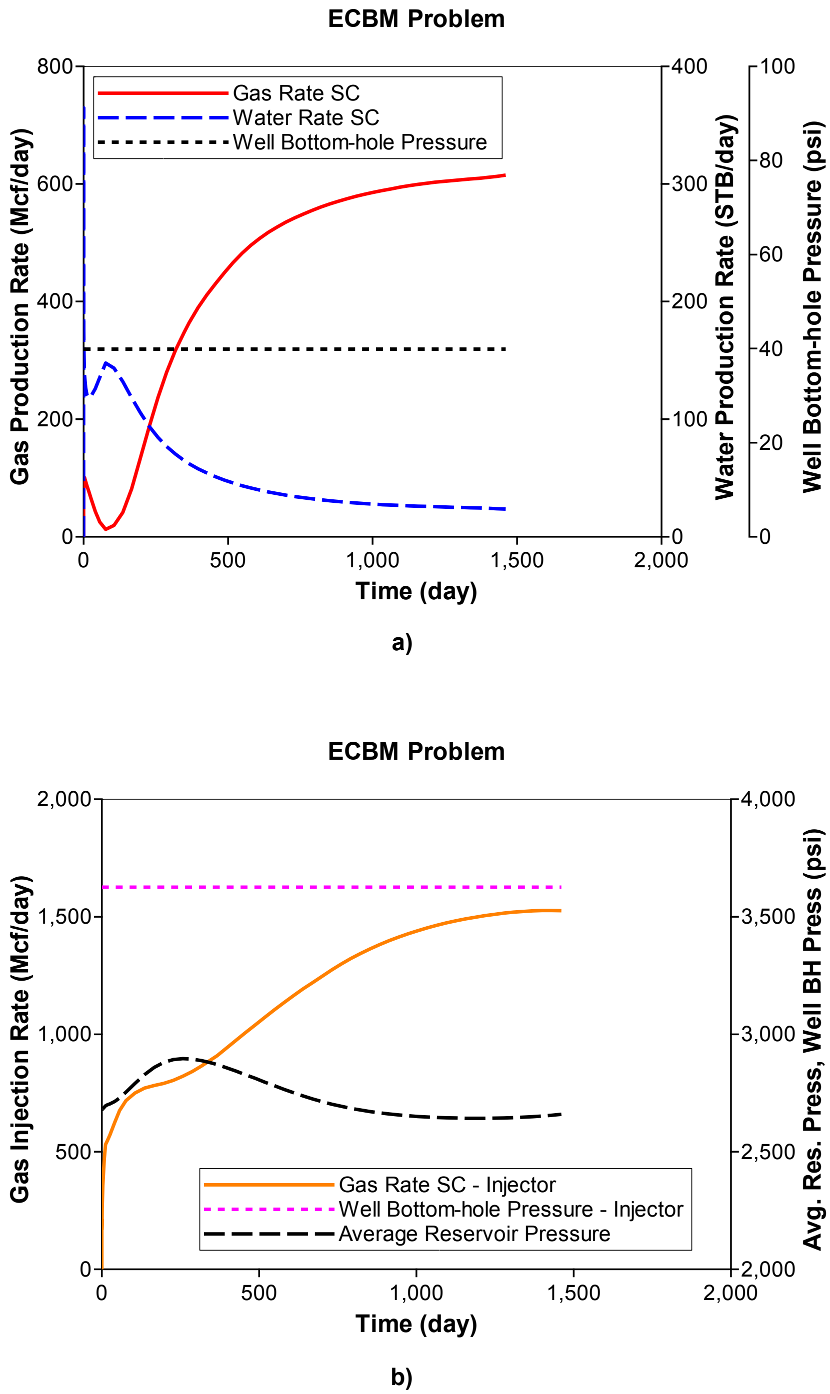


Fig. 41. a) Production and b) injection profiles for gas rate, water rate, bottom hole pressure, and average reservoir pressure for the 6,200-ft depth base case, Case 1b. Rates are for an 80-acre 5-spot pattern (40-acre well spacing).

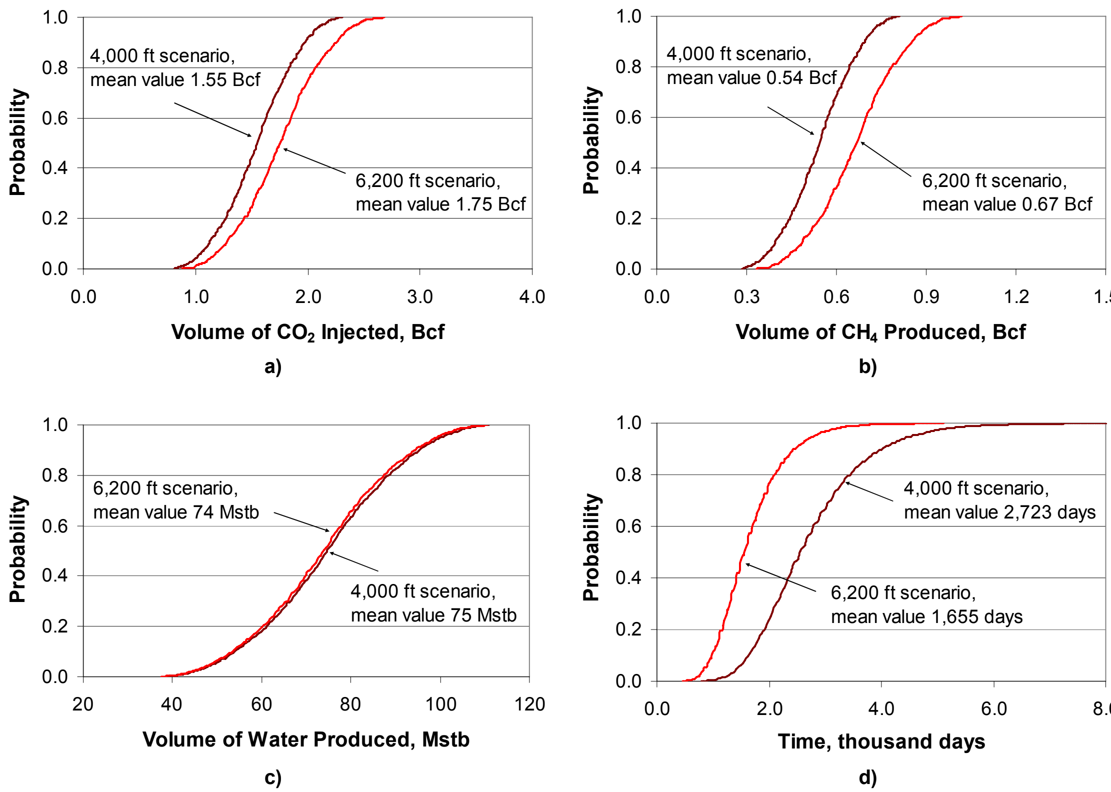


Fig. 42. Cumulative distribution functions for a) CO_2 injected, b) CH_4 produced, c) water produced, and d) breakthrough time in the 4,000-ft and 6,200-ft depth base case scenarios.

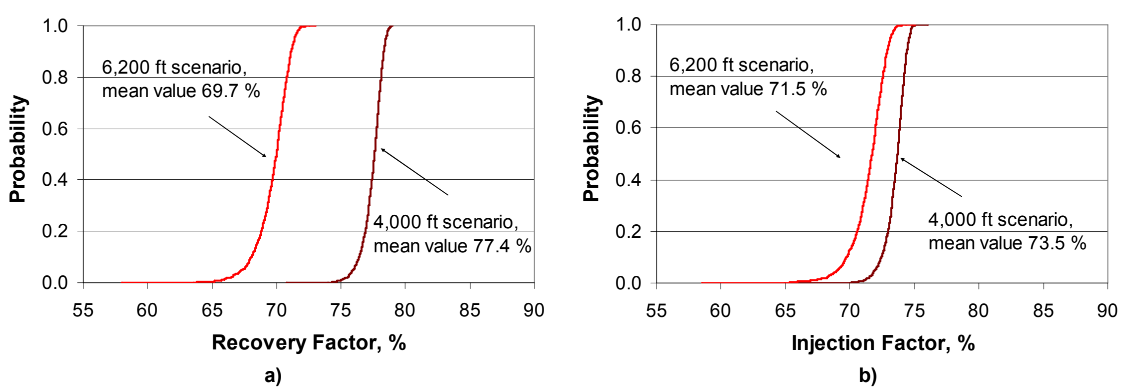


Fig. 43. Cumulative distributions functions for a) gas recovery factor and b) gas injection factor, for the 4,000-ft and 6,200-ft depth base case scenarios.

The reservoir volume swept by CO_2 is relatively high for this single-layer model. Most of the water in the fracture system and the CH_4 in both the coal matrix and fracture system are produced. Methane recovery factors are 77.4% and 69.9% for the 4,000-ft and 6,200-ft scenarios, respectively, using the most-likely values of reservoir parameters in deterministic simulations. Breakthrough is defined as the time at which CO_2 comprises 5% mole fraction of the produced gas.

The probabilistic simulation results indicate that variability in coal properties (isotherm data, gas content, coal density, gas diffusion time) and reservoir parameters (reservoir pressure, fracture permeability) contribute significantly to uncertainties in potential performance of CO_2 injection in Lower Calvert Bluff coal beds in East-Central Texas.

For the base case scenario of 4,000-ft depth (Case 1a), simulation results of 100% CO_2 injection in an 80-acre 5-spot pattern indicate that these coals with average net thickness of 20 ft can store 1.12 to 1.98 Bcf of CO_2 with ECBM recovery of 0.39 to 0.69 Bcf, water production of 54 to 95 Mstb, and CO_2 breakthrough time of 1,640 to 4,020 days. All ranges of results presented here and throughout this paper represent 80% confidence intervals (P_{10} to P_{90}).

For the base case scenario of 6,200-ft depth (Case 1b), probabilistic simulation results of 100% CO_2 injection in an 80-acre 5-spot pattern indicate that these coals with average net thickness of 20 ft can store 1.27 to 2.25 Bcf of CO_2 with ECBM recovery of 0.48 to 0.85 Bcf, water production of 54 to 94 Mstb, and CO_2 breakthrough time of 970 to 2,430 days.

CO_2 injection factor is defined as the percentage of the theoretical maximum coal sequestration capacity injected. Simulation results of 100% CO_2 injection in an 80-acre 5-spot pattern show mean values of methane recovery and CO_2 injection factors of 77.4% and 73.5%, respectively, at depths of 4,000 ft (Case 1a). Recovery and injection factors average 69.7% and 71.5%, respectively, at depths of 6,200 ft (Case 1b).

Case 2: Effects of Well Spacing on CO_2 Sequestration and ECBM Production

To determine the effects of well spacing on performance of coalbed reservoirs during CO_2 sequestration and ECMB production, we conducted probabilistic simulation modeling studies (1,000 iterations) of 100% CO_2 gas injection under the base case operating conditions for 80, 160, and 240-acre well spacing for the 6,200-ft depth base case. These simulation studies are denoted as Cases 2a, 2b, and 2c, respectively. Case 1b reported results of the 40-ac well spacing case.

Fig. 44 shows cumulative distribution functions for volumes of CO_2 sequestered, CH_4 produced, water produced, and breakthrough times, respectively, for Cases 1b, 2a, 2b, and 2c. Mean values of the estimated volumes of CO_2 that can be sequestered in Lower Calvert Bluff coals are 1.75, 3.59, 7.25, and 10.94 Bcf for 40, 80, 160, and 240-acre well spacing, respectively, in a 5-spot injection pattern. Corresponding CH_4 production values are 0.67, 1.36, 2.76, and 4.16 Bcf, at breakthrough times of 1,655, 3,443, 7154, and 10,967 days, respectively. CH_4 recovery factors range from 69.9% to 72.7% for Cases 1b to 2c using the most-likely values of reservoir parameters in deterministic simulations.

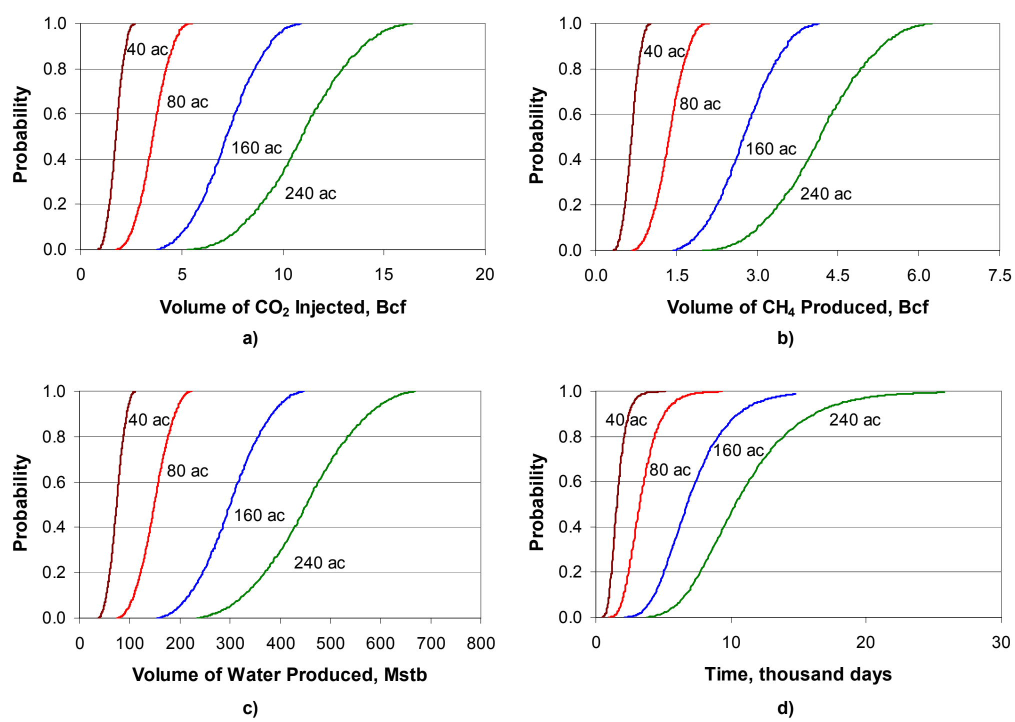


Fig. 44. Cumulative distribution functions for a) CO_2 injection, b) CH_4 production, c) water production, and d) breakthrough time, 6,200-ft depth coal reservoir scenario, for 40, 80, 160, and 240-ac well spacings in a 5-spot pattern.

Fig. 45 shows the cumulative distribution functions for the volumes of CO_2 sequestered, CH_4 produced, and water produced normalized to a 40-acre well spacing (80-acre pattern area) basis. For the 6,200-ft depth base case scenario, mean values of estimated volumes of CO_2 that can be sequestered in Lower Calvert Bluff coals are 1.75, 1.79, 1.81, and 1.82 Bcf per 80 acres for 40, 80, 160, and 240-acre well spacing, respectively, in a 5-spot injection pattern. Corresponding normalized CH_4 production mean values are 0.67, 0.68, 0.69, and 0.69 Bcf per 80 acres. Thus, total injected and produced volumes increase slightly with increasing well spacing, even though average production and injection rates increase with decreasing well spacing. However, the sensitivity to well spacing of CO_2 volumes sequestered and methane volumes produced on a unit-area basis is not great.

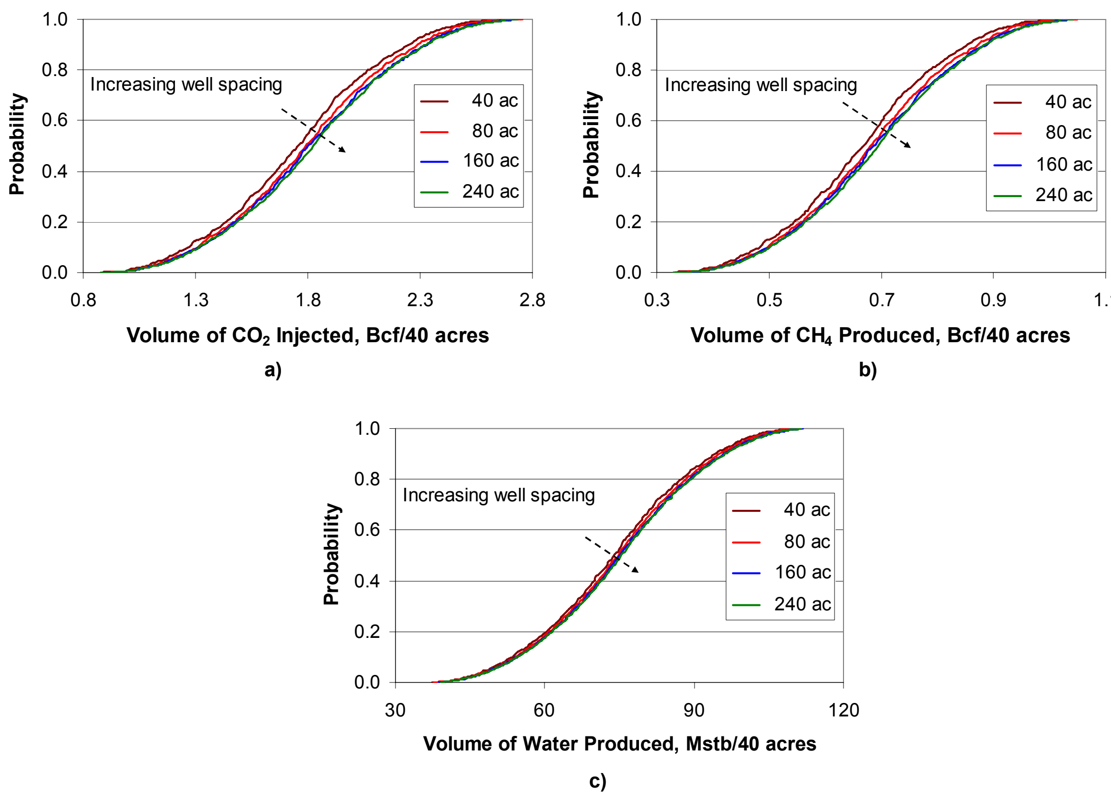


Fig. 45. Cumulative distribution functions for a) CO_2 injection, b) CH_4 production, and c) water production, 6,200-ft depth reservoir scenario, for 40, 80, 160, and 240-ac well spacing in a 5-spot pattern, normalized to a 40-acre well spacing (80-acre pattern area) basis.

Case 3: Effects of Injection Gas Composition on CO_2 Sequestration and ECBM Production

To determine the effects of injection gas composition on performance of CO_2 sequestration and ECMB production in Wilcox coals in East-Central Texas, we conducted probabilistic simulations, each consisting of 1,000 iterations, modeling injection of 50% CO_2-50% N_2 (Case 3a) and flue gas (13% CO_2-87% N_2, Case 3b) under base case operating conditions in an 80-acre 5-spot pattern (40-acre well spacing) for the 6,200-ft depth case. Case 1b reported results of 100% CO_2 injection.

The reservoir volumes swept by CO_2 and/or N_2 are relatively high for this single-layer model. Mole percents of methane recovered are 69.5%, 90.2%, and 98.2% for Cases 1b, 3a, and 3b, respectively, for the 6,200-ft depth scenario using the most-likely values of reservoir parameters in deterministic simulations. These high recovery efficiencies result from using a termination criterion of 5% CO_2 mole fraction in the produced gas (CO_2 breakthrough) and no cutoff based on N_2 content. This termination criterion does not necessarily represent an economic limit. Most of the water in the fracture system and the CH_4 in both the coal matrix and fracture system are produced in these cases. **Figs. 46** and **47** show colorfill maps of various reservoir properties at breakthrough for Cases 3a and 3b.

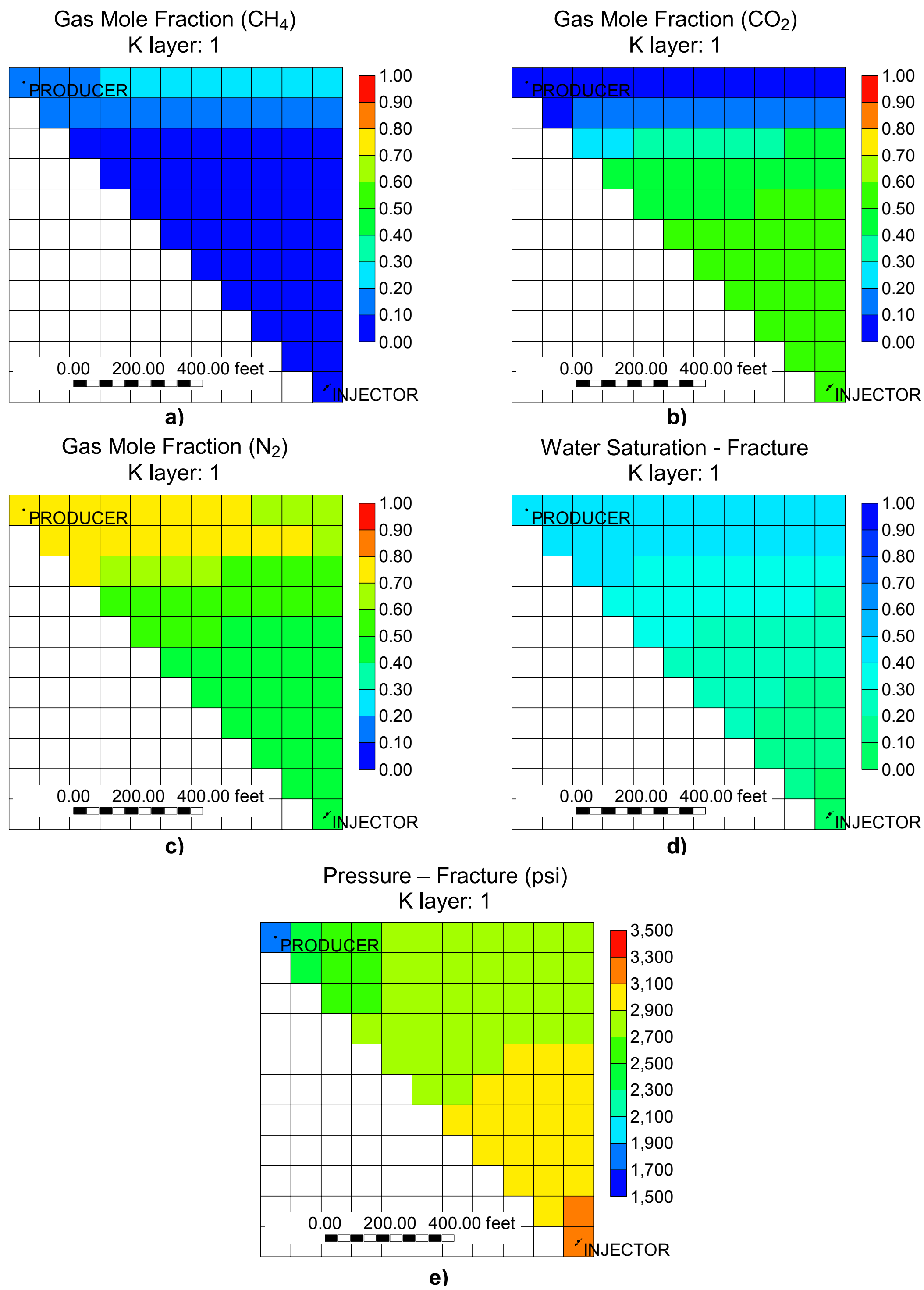


Fig. 46. a) Methane gas mole fraction, b) CO_2 gas mole fraction, c) N_2 gas mole fraction, d) water saturation in the fracture system, and e) reservoir pressure at breakthrough time of 2,435 days for the 6,200-ft depth reservoir scenario, Case 3a (50% CO_2 – 50% N_2 injection).

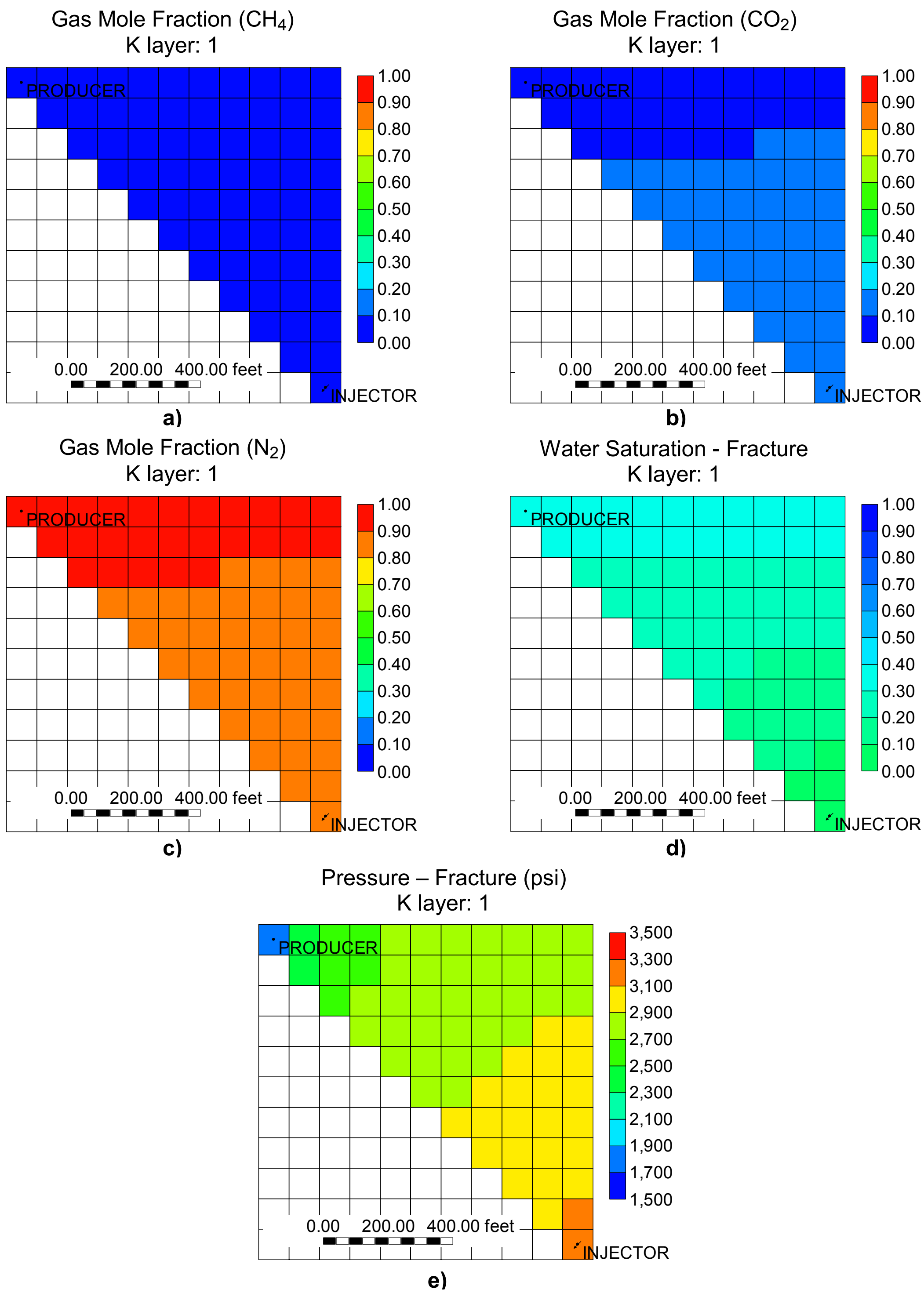


Fig. 47. a) Methane gas mole fraction, b) CO_2 gas mole fraction, c) N_2 gas mole fraction, d) water saturation in the fracture system, and e) reservoir pressure at breakthrough time of 3,775 days for the 6,200-ft depth reservoir scenario, Case 3b (13% CO_2 – 87% N_2 injection).

Fig. 48 shows methane, CO_2, and N_2 gas mole production rates for Cases 1b, 3a and 3b, respectively, using the most-likely values of reservoir parameters in deterministic simulations. Mole rates are for an 80-acre 5-spot pattern (40-acre well spacing). In Cases 3a and 3b, N_2 breaks through at the production well relatively early and, by the time CO_2 breaks through, the N_2 gas mole production rate exceeds the methane rate. These results are consistent with field tests and previous simulation results (Mavor et al., 2002), (Reeves et al., 2004). **Fig. 49** shows the corresponding cumulative total gas production and injection profiles.

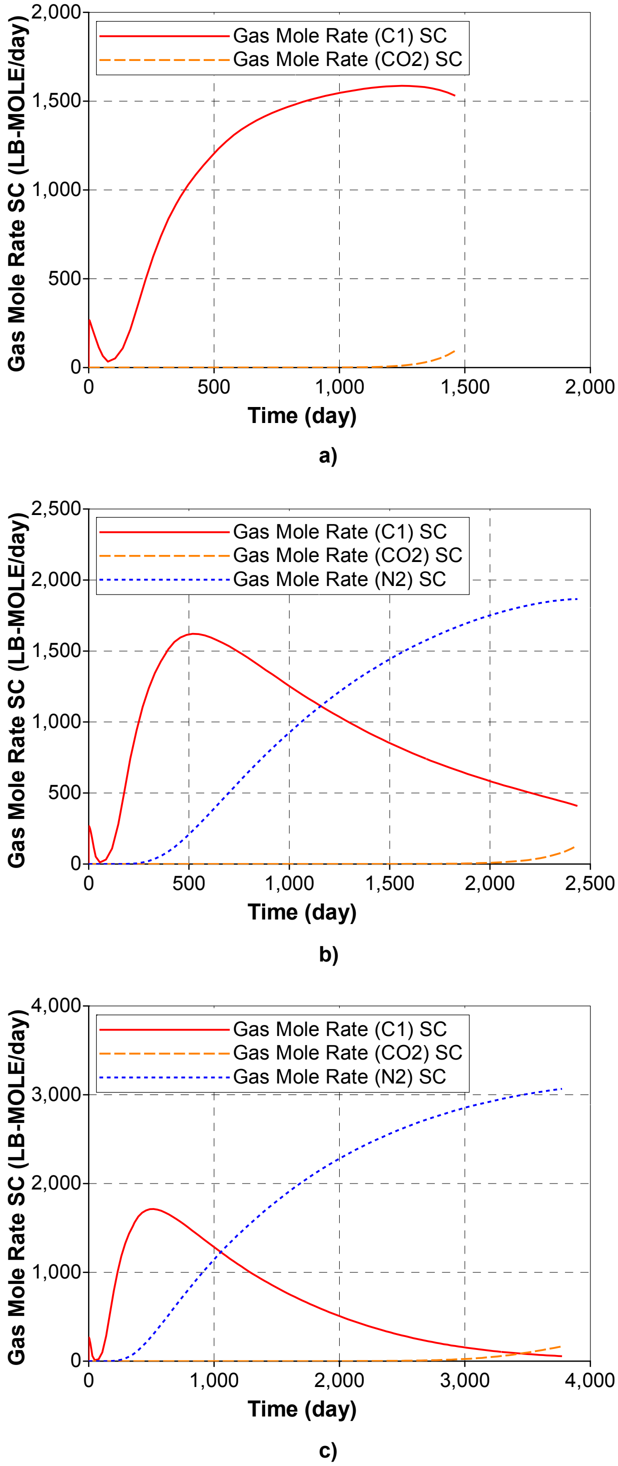


Fig. 48. Methane, CO_2, and N_2 gas mole production rates for the 6,200-ft depth reservoir scenario. a) Case 1b (100% CO_2 injection), b) Case 3a (50% CO_2 – 50% N_2 injection), and c) Case 3b (13% CO_2 – 87% N_2 injection). Mole rates are for an 80-acre 5-spot pattern (40-acre well spacing).

Fig. 50 shows cumulative distribution functions for CO_2 sequestered, CH_4 produced, water produced, and breakthrough times for Cases 1b, 3a, and 3b. The probabilistic simulation results indicate that injection gas composition has a significant impact on performance of CO_2/N_2 injection in Lower Calvert Bluff coal beds in East-Central Texas. Simulation results of 50% CO_2-50% N_2 injection (Case 3a) indicate that these coals can store 0.86 to 1.52 Bcf of CO_2 at depths of 6,200 ft with an ECBM recovery of 0.62 to 1.10 Bcf, water produced of 60 to 106 Mstb, and CO_2 breakthrough time of 1,670 to 4,080 days. Simulation results of 13% CO_2-87% N_2 injection (Case 3b, typical flue gas composition) indicate that these same coals can store 0.34 to 0.59 Bcf of CO_2 at depths of 6,200 ft, with an ECBM recovery of 0.68 to 1.20 Bcf, water produced of 66 to 117 Mstb, and CO_2 breakthrough time of 2,620 to 6,240 days. Results are for an 80-acre 5-spot pattern (40-acre well spacing). All ranges represent 80% confidence intervals (P_{10} to P_{90}).

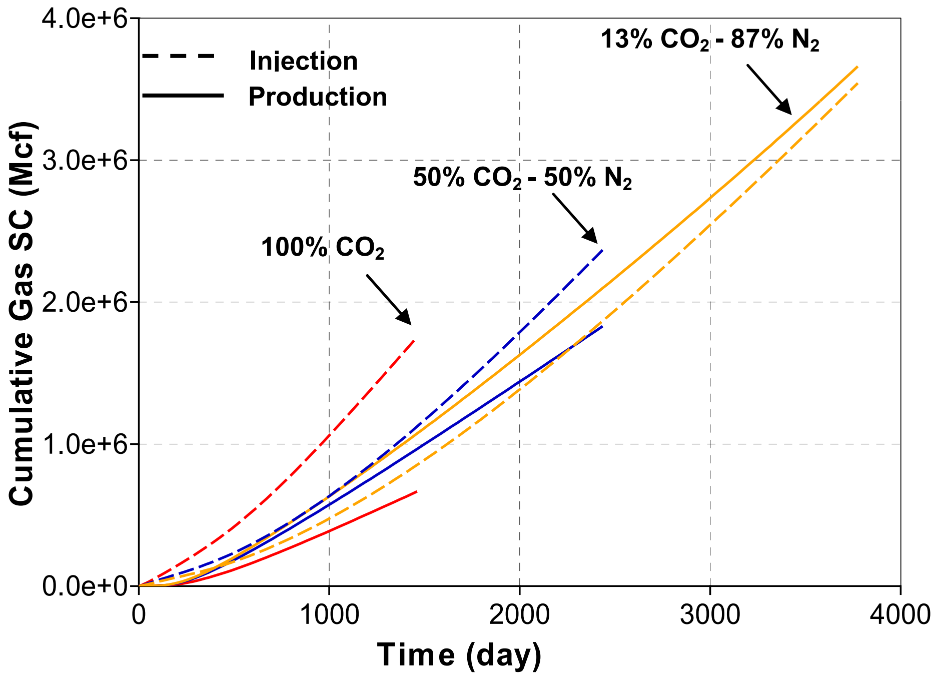


Fig. 49. Cumulative total gas production and injection for the 6,200-ft depth reservoir scenario. Case 1b (100% CO_2 injection), Case 3a (50% CO_2 – 50% N_2 injection), Case 3b (13% CO_2 – 87% N_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

These results indicate that CO_2 sequestration and ECMB production with injection gas compositions ranging from typical flue gas (13% CO_2-87% N_2) to 100% CO_2 are technically feasible in East-Central Texas Lower Calvert Bluff coals. The results also indicate that increasing N_2 content in the injection gas results in improved methane production performance, which is consistent with other published results (Reeves et al., 2004), (Wo and Liang, 2004).

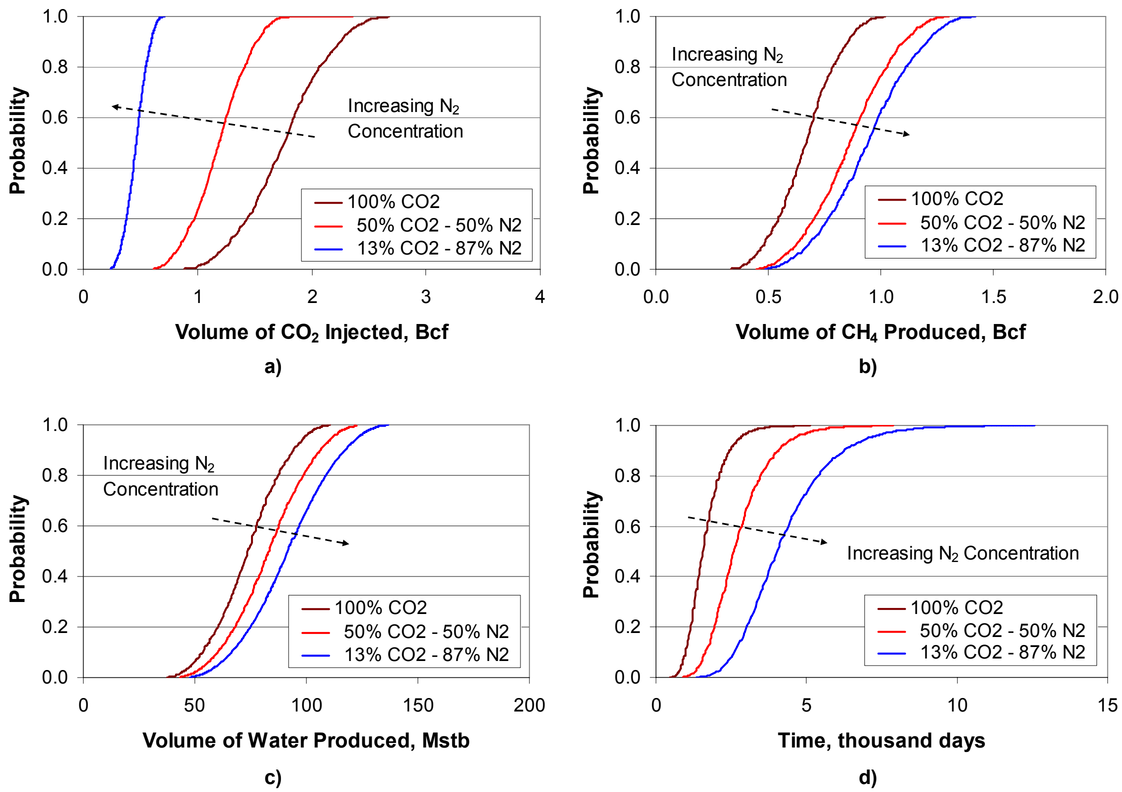


Fig. 50. Cumulative distribution functions for a) CO_2 injected, b) CH_4 produced, c) water produced, and d) breakthrough time, per 80-acre 5-spot pattern in the 6,200-ft depth reservoir scenarios, Cases 1b, 3a, and 3b.

Case 4: Effects of Injection Rate on CO_2 Sequestration and ECBM Production

To determine the effects of injection rate on performance of CO_2 sequestration and ECMB production in Wilcox coals in East-Central Texas, we conducted deterministic simulation modeling studies of 100% CO_2 gas injection for the 6,200-ft depth base case (Case 1b) under two sets of operating conditions, base case operating conditions and conditions in which the pressure drop between injector and producer is reduced by 920 psi (**Table 10**).

Case 1b was the 40-ac well spacing case with the production well constrained at a constant bottom hole flowing pressure of 40 psia and the injection well constrained at a constant bottom hole injection pressure of 3,625 psia. A modified case with the production well constrained by a constant bottom hole flowing pressure of 500 psia and the injection well constrained by a bottom hole injection pressure of 3,165 psia was selected to model the effect of variable injection rate. Wells are secondarily constrained in the model by maximum gas production and injection rates of 3,530 Mcf/D. **Figs. 51** and **52** show cumulative gas production and injection vs. time for the most-likely, least-favorable, and most-favorable sets of reservoir parameters under these two sets of operating conditions. **Fig. 53** shows average reservoir pressure vs. time for the most-likely set of reservoir parameters under these two sets of operating conditions.

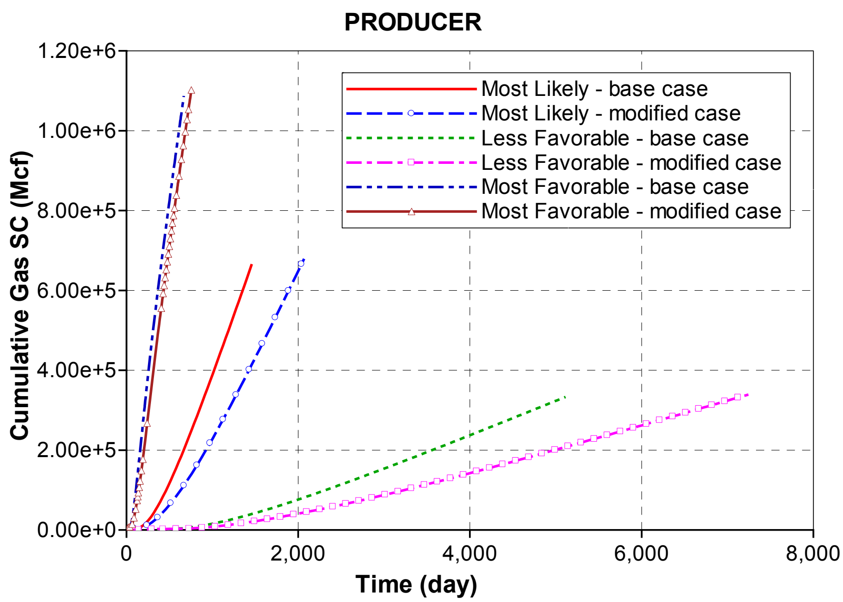


Fig. 51. Cumulative CH_4 production for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, under different well operating conditions, Case 4 (100% CO_2 injection). Modified case represents lower pressure drop between injector and producer. Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

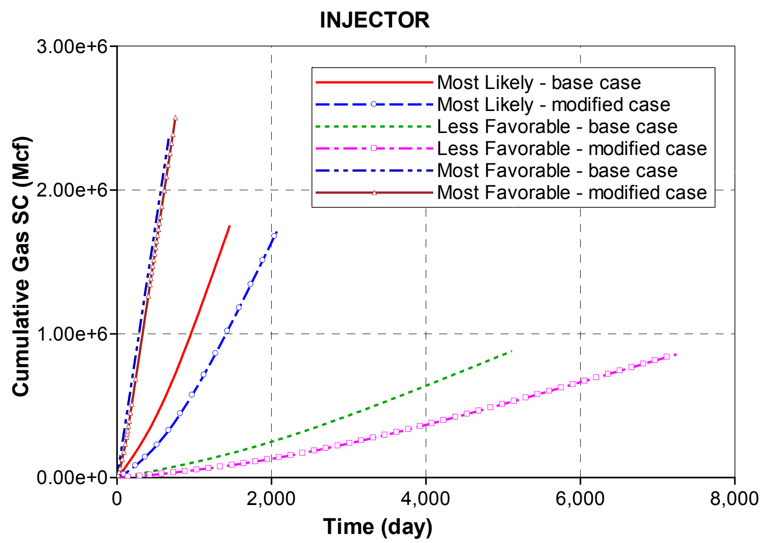


Fig. 52. Cumulative CO_2 injection for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, under different well operating conditions, Case 4 (100% CO_2 injection). Modified case represents lower pressure drop between injector and producer. Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

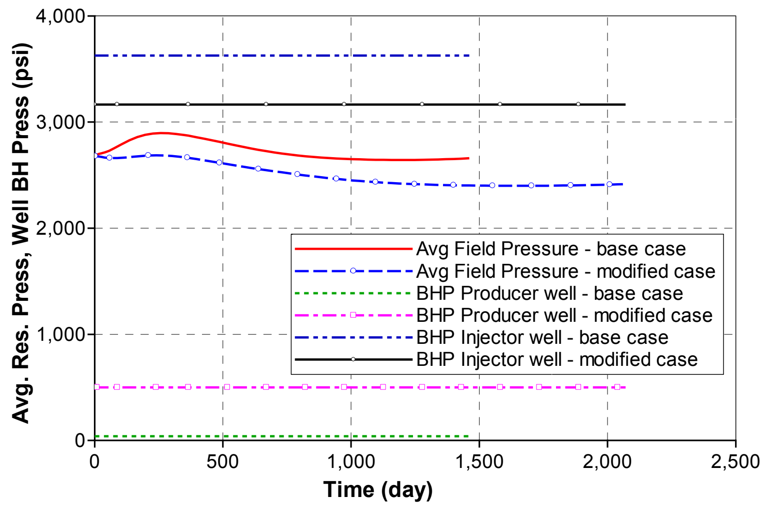


Fig. 53. Average field pressure and bottom hole pressure in the producer and injector wells for the 6,200-ft depth, in an 80-acre 5-spot pattern (40-acre well spacing), Case 4 (100% CO_2 injection), for the most-likely reservoir parameters. Modified case represents lower drawdown.

There are no significant differences in the cumulative volumes of CH_4 produced or CO_2 injected due to the lower injection rate. The primary differences are in project lives, with longer breakthrough times as rates decrease. Breakthrough times for 80-acre patterns (40-acre well spacing) ranged from 670 days (1.8 years) to 750 days (2.0 years), from 1,460 days (4.0 years) to 2,070 days (5.6 years), and from 5,110 days (14.0 years) to 7,240 days (19.8 years) for the most-favorable, most-likely and least-favorable reservoir parameters, respectively, under the well operating conditions investigated.

Case 5: Effects of Coal Dewatering on CO_2 Sequestration and ECBM Production

To determine the effects of dewatering the coals prior to CO_2 injection on performance of CO_2 sequestration and ECMB production in Wilcox coals in East-Central Texas, we conducted deterministic simulation modeling studies of 100% CO_2 injection under the base case operating conditions for two production/injection schedules for the 6,200-ft depth base case.

To compare with the case in which injection and production start simultaneously (Case 1b), we modified this case to start CO_2 injection after 6 months and after 18 months of production. We performed deterministic sensitivity analysis for the most-likely, least-favorable, and most-favorable reservoir parameters. **Figs. 55** and **56** show cumulative gas production and injection for 100% CO_2 injection in the 6,200-ft depth reservoir, dewatering the coals 0, 6 and 18 months prior to CO_2 injection. **Fig. 54** shows the CH_4 production rates, CO_2 injection rates, water production rates, and average field pressure, respectively, for the 6,200-ft depth reservoir scenario with the most-likely reservoir parameters.

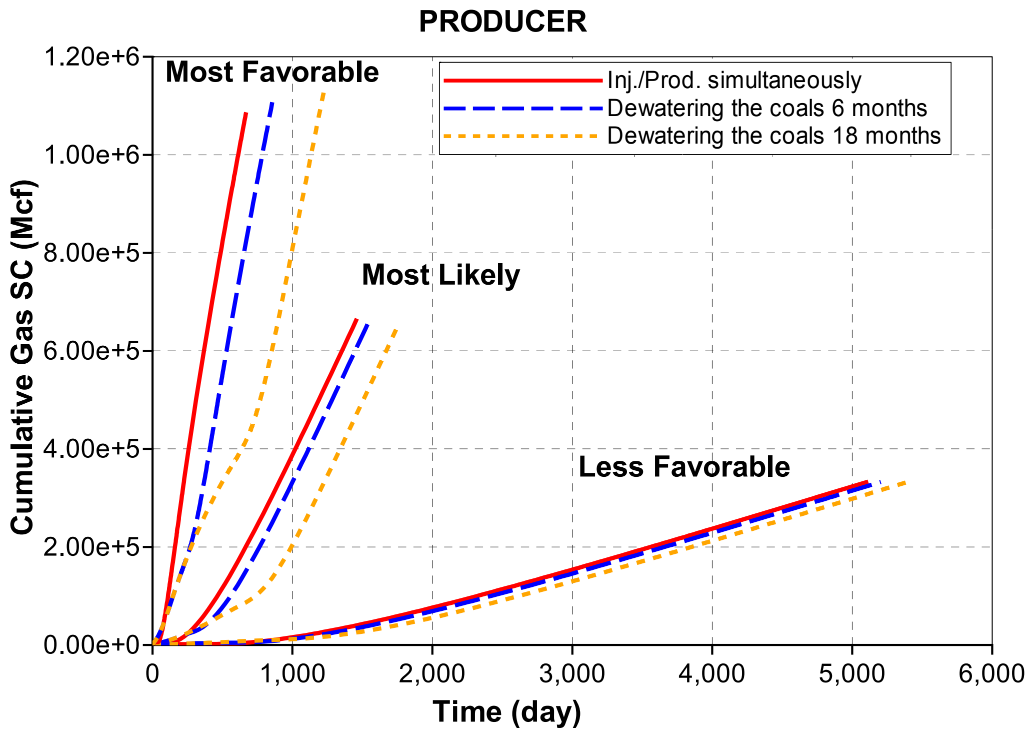


Fig. 54. Cumulative CH_4 production for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, dewatering the coals 0, 6, and 18 months, Case 5 (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

The dewatering sensitivity study shows that total volumes of CO_2 sequestered and methane produced are not sensitive to the start of injection relative to the start of production. However, as time to start CO_2 injection is increased, the total time to reach CO_2 breakthrough increases. Breakthrough times for 80-acre patterns (40-acre well spacing) ranged from 850 days (2.3 years) to 5,380 days (14.7 years) for the reservoir parameters and well injection/production schedules investigated.

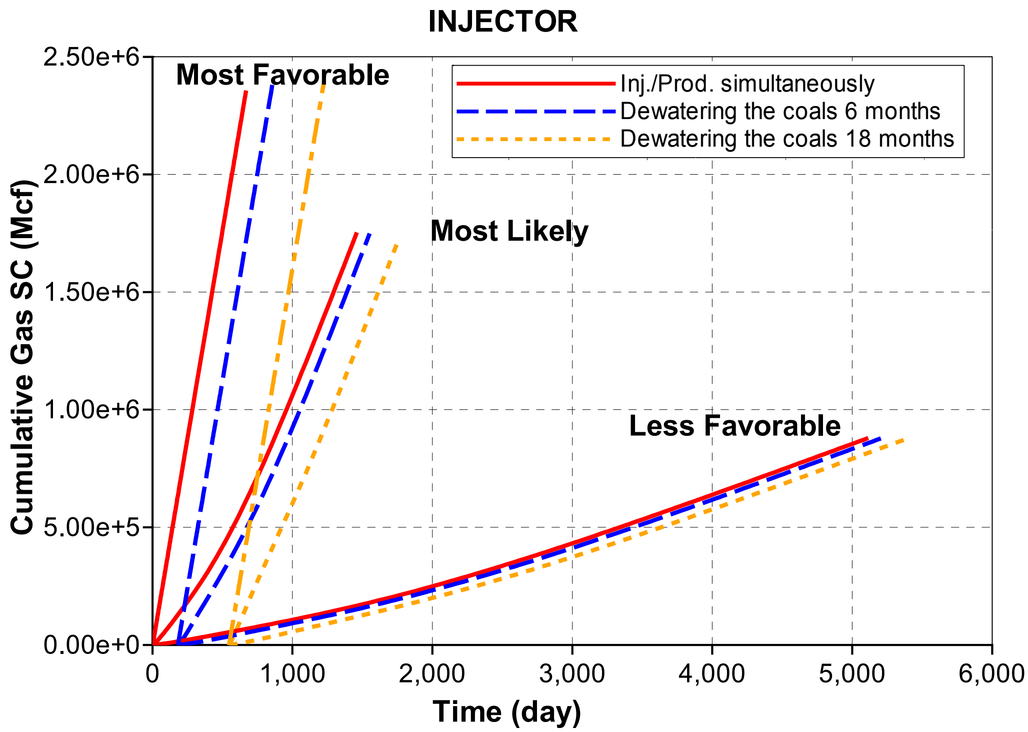


Fig. 55. Cumulative CO_2 injection for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, dewatering the coals 0, 6, and 18 months, Case 5 (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

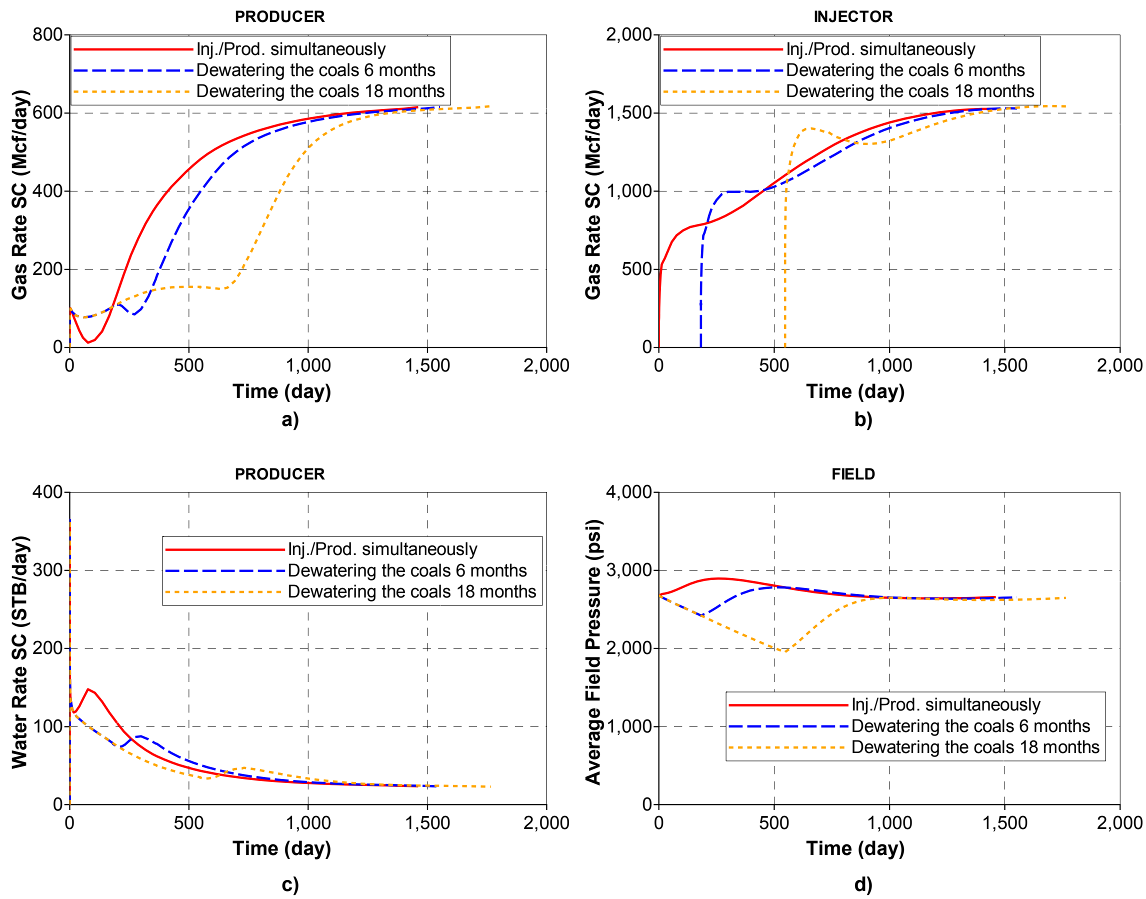


Fig. 56. a) CH_4 production rates, b) CO_2 injection rates, c) water production rates, and d) average field pressure for the 6,200-ft depth coal seam scenario for the most-likely reservoir parameters, dewatering the coals 0, 6, and 18 months, Case 5 (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

Case 6: Effects of Permeability Anisotropy on CO_2 Sequestration and ECBM Production

To determine the impacts of permeability anisotropy on performance of CO_2 sequestration and ECMB production in Wilcox coals in East-Central Texas, we conducted deterministic reservoir modeling studies of 100% CO_2 injection for the 6,200-ft depth coal seam scenario, using the most-likely values of reservoir parameters, under the base case operating conditions. We used permeability anisotropy ratios of face cleat permeability (k_x) to butt cleat permeability (k_y) of 1:1, 2:1, 4:1 and 8:1, in all cases preserving the same average permeability, $\sqrt{k_x k_y} = 2.8$ md.

A permeability anisotropy ratio of 1.74:1 was measured in a 4-well interference test conducted in 1980 in East-Central Texas lignite as part of a Texas A&M University underground coal gasification project (Schubarth, 1983). Permeability anisotropy measured in a coal seam in the Bowen basin, Queensland, by a multiple interference test was 2.8:1 (Wold et al., 1996). This is considered to be a moderate degree of anisotropy, lying within the range of ratios measured at the Rock Creek site in the Warrior basin (Koenig, 1986), where measurements in three seams identified a well-developed anisotropy ratio of 17:1, a moderate anisotropy ratio of 2.3:1, and a virtually 1:1 isotropic case. A permeability anisotropy ratio of 4:1 was obtained from type curve analysis of a four-well injection interference test conducted at the Dartbrook Mine, in the Sydney coal basin, Australia (Wold and Jeffrey, 1999). Permeability anisotropy ratios from 1:1 to 8:1 are considered to be a reasonable range for this sensitivity study (**Table 9**).

Results of sensitivity study using a diagonal orientation in which the line connecting producer and injector wells is offset 45° with the permeability axes (Case 6a), a parallel orientation with face cleat permeability (k_x) aligned with the line connecting injector and producer wells (Case 6b), and a parallel orientation with butt cleat permeability (k_y) aligned with the injector and producer wells (Case 6c) are shown in **Figs. 57**, **58** and **59**, respectively.

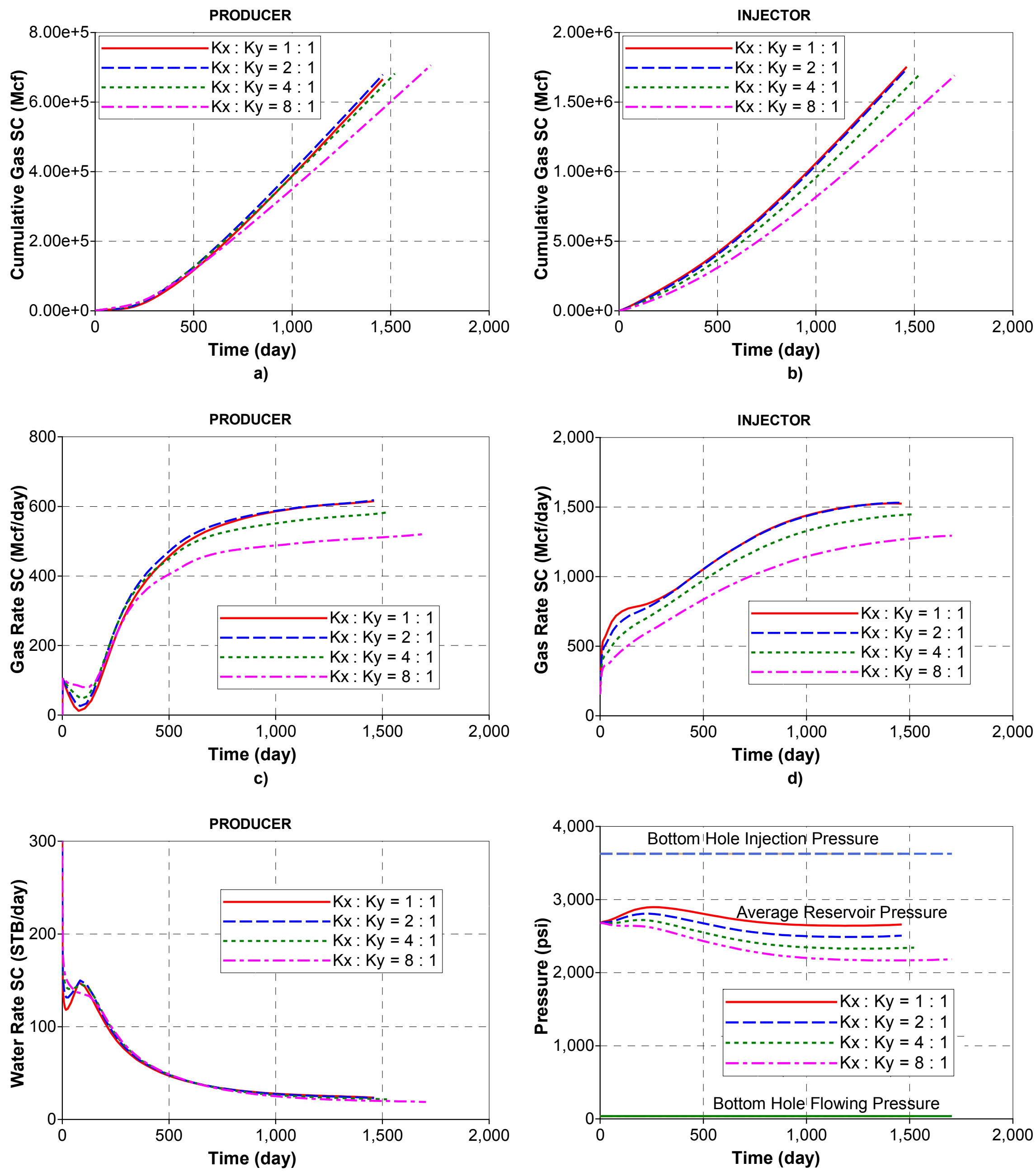


Fig. 57. Effect of permeability aspect ratio on a) cumulative CH_4 production, b) cumulative CO_2 injection, c) CH_4 production rates, d) CO_2 injection rates, e) water production rates, and f) average field pressure, for the 6,200-ft depth coal seam scenario and the most-likely reservoir parameters, using a diagonal orientation, Case 6a (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

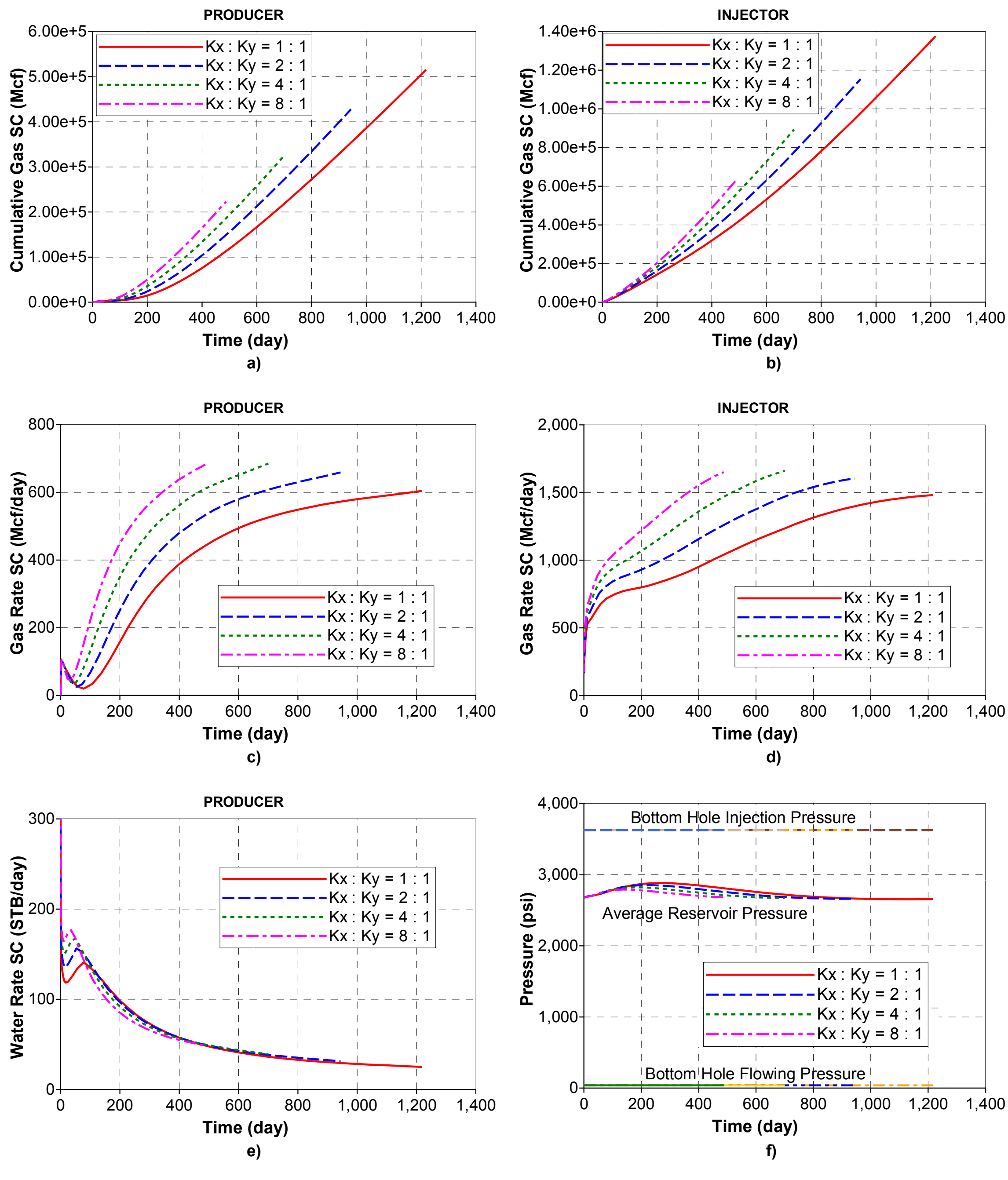


Fig. 58. Effect of permeability aspect ratio on a) cumulative CH_4 production, b) cumulative CO_2 injection, c) CH_4 production rates, d) CO_2 injection rates, e) water production rates, and f) average field pressure, for the 6,200-ft depth coal seam scenario and the most-likely reservoir parameters, using a parallel orientation with face cleat permeability (k_x) aligned with the injector and producer wells, Case 6b (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

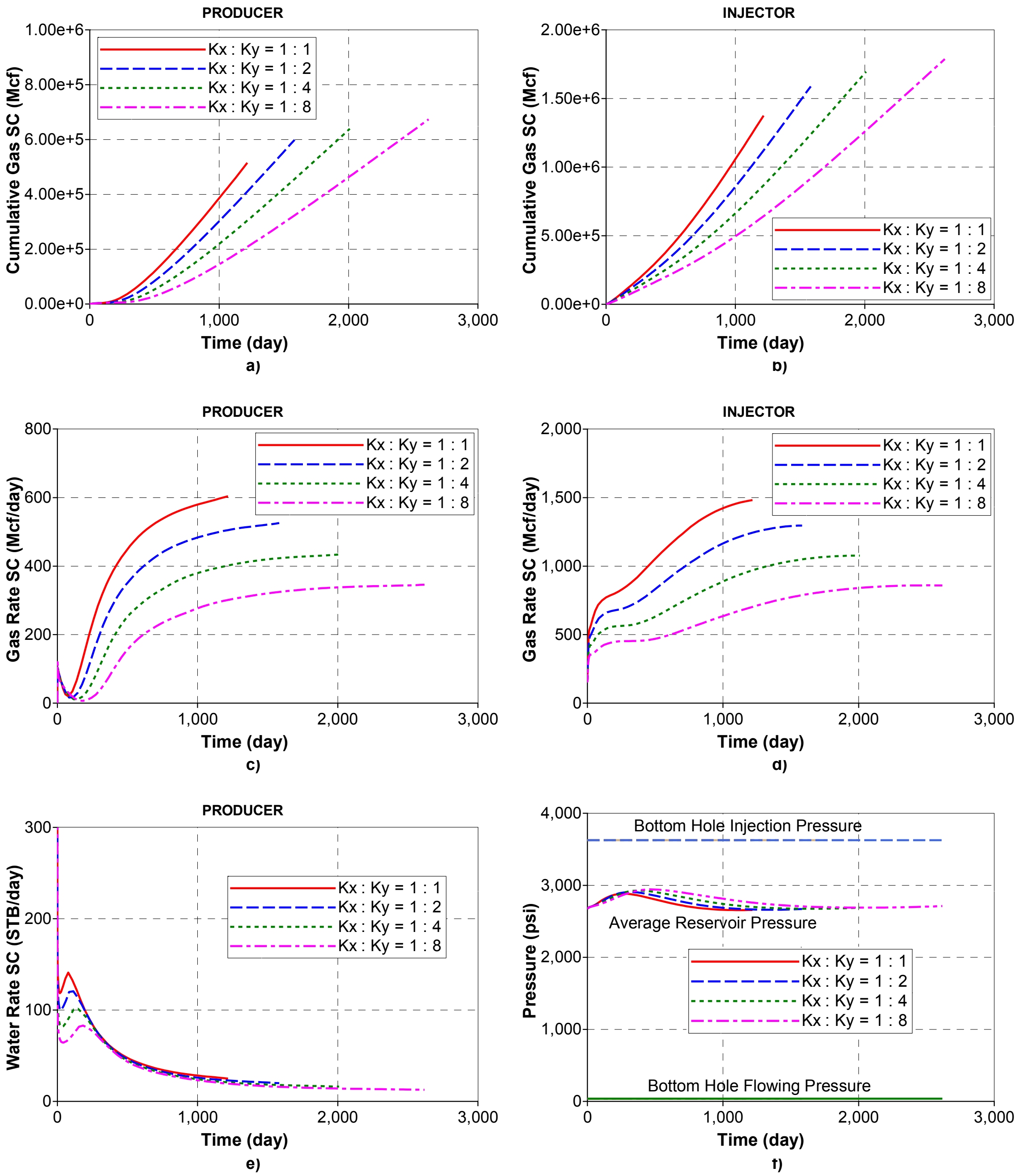


Fig. 59. Effect of permeability aspect ratio on a) cumulative CH_4 production, b) cumulative CO_2 injection, c) CH_4 production rates, d) CO_2 injection rates, e) water production rates, and f) average field pressure, for the 6,200-ft depth coal seam scenario and the most-likely reservoir parameters, using a parallel orientation with butt cleat permeability (k_y) aligned with the injector and producer wells, Case 6c (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

We first simulated a diagonal orientation in which the line connecting producers with injectors is offset 45° with the permeability axes (Case 6a) (**Fig. 57**). Using this diagonal orientation, anisotropic permeability sensitivity studies for 100% CO_2 injection indicate that methane production and CO_2 injection rates decrease with increasing permeability aspect ratio. There are no significant differences in the total volumes of CH_4 produced or CO_2 injected due to increasing permeability anisotropy. The primary differences are in project lives, with longer breakthrough times as injection rates decrease with increasing permeability aspect ratio. Breakthrough times for 80-acre patterns (40-acre well spacing) ranged from 1,460 days (4.0 years) to 1,700 days (4.7 years), for the reservoir parameters and permeability aspect ratios investigated. Simulation results indicate that Lower Calvert Bluff coals can store 1.75 to 1.69 Bcf of CO_2 at depths of 6,200 ft with an ECBM recovery of 0.67 to 0.71 Bcf and water produced of 74 to 79 Mstb, for permeability anisotropy ratios increasing from 1:1 to 8:1, respectively. Methane recovery factors range between 69.9% and 74.2% at breakthrough.

Next, we simulated a parallel orientation with face cleat permeability (k_x) aligned with the line connecting injector and producer wells (Case 6b) (**Fig. 58**). Grid orientation effects contribute to an earlier breakthrough time for the isotropic case for the parallel grid as compared to the diagonal grid. This prevents a direct comparison of diagonal orientations to parallel orientations; however, the variation in performance with anisotropy ratios for the respective orientations should still be relevant. For the parallel orientation with face cleat permeability (k_x) aligned with the injector and producer wells, there are significant decreases in the cumulative volumes of CH_4 produced and CO_2 injected due to increasing permeability anisotropy. Gas injection and production rates increase with increasing permeability aspect ratio, causing rapid CO_2 breakthrough at the production well and hence reducing the cumulative volumes of CO_2 injected and CH_4 produced. Simulation results indicate that these coals can store only 1.37 to 0.63 Bcf of CO_2 at depths of 6,200 ft with an ECBM recovery of 0.51 to 0.23 Bcf, water produced of 67 to 46 Mstb, and CO_2 breakthrough time of 1,220 to 490 days, for permeability anisotropy increasing from 1:1 to 8:1, respectively. Gas recovery factors range between 54.1% and 23.5% at breakthrough, indicative of low sweep efficiency.

Using a parallel orientation with butt cleat permeability (k_y) aligned with the injector and producer wells (Case 6c) (**Fig. 59**), there are significant differences in the volumes of CH_4 produced or CO_2 injected due to increasing permeability anisotropy. Gas injection and production rates decrease with increasing permeability aspect ratio, causing longer CO_2 breakthrough times and increasing the cumulative volumes of CH_4 produced and CO_2 injected. Simulation results indicate that these coals can store 1.37 to 1.79 Bcf of CO_2 at depths of 6,200 ft with an ECBM recovery of 0.51 to 0.67 Bcf, water produced of 67 to 74 Mstb, and CO_2 breakthrough time of 1,220 to 2,620 days, for permeability anisotropy increasing from 1:1 to 8:1, respectively. Gas recovery factors range between 54.1% and 70.8% at breakthrough, indicative of improved sweep efficiency.

Based on these results for an 80-ac, 5-spot pattern, permeability anisotropy has potentially significant effects on carbon sequestration and ECBM projects due to the effects on injection and production rates, which will dictate CO_2 sequestration capacity and ECBM recovery. The degree and orientation of the anisotropy are influenced by the regional geology, i.e., structural trends, stress direction, and fracture orientation. Recognition of the magnitude and orientation of permeability anisotropy in coal reservoirs is important for optimal design and production practices.

Overall Potential Volumes of CO_2 Sequestration/ECBM Production in East-Central Texas Low-Rank Coals in the Wilcox Group

We estimated the total volumes of CO_2 that may be sequestered in, and total volumes of methane that may be producible from, Wilcox Group low-rank coals in East-Central Texas. This analysis was based on (1) cost-sharing data for more than 50 coal samples provided by Anadarko Petroleum Corporation, (2) data obtained during this study (3) published reports, and (4) probabilistic simulation modeling for a vertical well, using the base-case coal seam scenario for Wilcox Group coal between 4,000-ft and 6,200-ft depth in East-Central Texas.

On the basis of our analysis, we tentatively conclude that the fairway for CO_2 sequestration and enhanced methane production in Calvert Bluff formation coal of East-Central Texas is the thermogenic gas system that extends from approximately 3,500 ft to more than 6,200 ft deep (**Figs. 4** and **31**). For conservative calculation of potential thermogenic coalbed gas in place in East-Central Texas, we used an upper depth limit of 4,000 ft and a lower depth limit of 6,200 ft. The East-Central Texas Coastal Plain area encompassed by the Calvert Bluff depth range of 4,000 to 6,200 ft deep is estimated to be 2,930 mi^2 (1,875,200 ac).

Probabilistic Estimation of Potential Volumes

Table 11 shows the input parameters used to quantify uncertainty in our forecast of the potential volumes of CO_2 that can be sequestered in, and methane that can be produced from, the Wilcox Group low-rank coals in East-Central Texas.

Table 11. Parameters for estimating volume of CO_2 that can be sequestered in and methane that can be produced from Calvert Bluff coals in East-Central Texas.

Parameter	Value	Distribution Form	Distribution Parameters
Coal Thickness	10, 20, 30 ft	Normal	μ = 20, σ = 4.1
Coal Density	1591, 1644, 1704 ton/ac-ft (1.289, 1.332, 1.380 g/cm^3)	Normal	μ = 1646, σ = 23.25
Gas Content	125, 250, 300 scf/t	Beta General	α_1 = 3.78 , α_2 = 2.06, min = 80, max = 300
CO_2 Storage (V_L, CO_2)	620, 920, 1000 scf/t	Beta General	α_1 = 3.20, α_2 = 1.85, min = 590, max = 1000
Recovery Factor	60, 75, 80 %	Beta General	α_1 = 3.07, α_2 = 2.00, min = 0.58, max = 0.80
Injection Factor	50, 72, 75 %	Beta General	α_1 = 21.95, α_2 = 2.50, min = 0.50, max = 0.75
Area	80 acres		

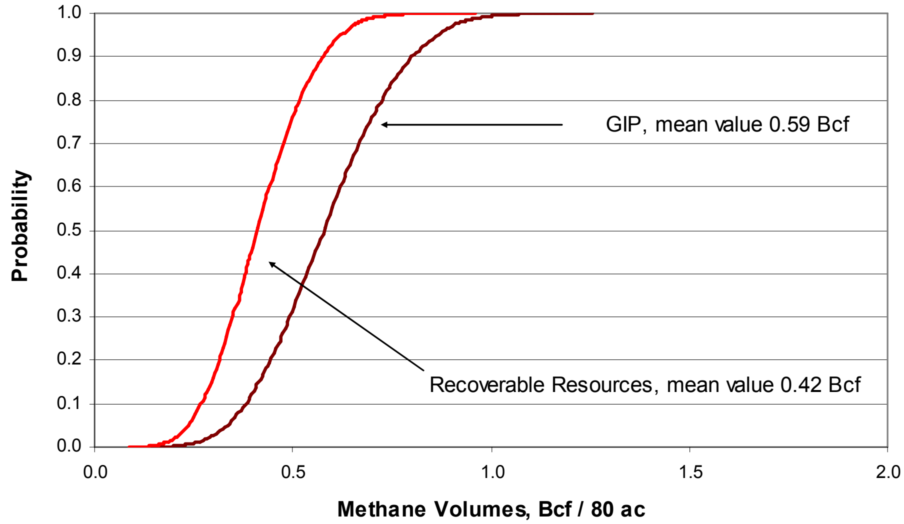
We estimated the original gas in place (OGIP) adsorbed in the coal reservoirs for an 80-acre, 5-spot pattern, using probabilistic input parameters in the volumetric equation. Multiplying by a probability distribution for gas recovery factor obtained from reservoir modeling studies described above (base-case coal seam scenarios), we obtained a range of recoverable methane resources on a pattern basis. A similar procedure was used to calculate the maximum theoretical CO_2 sequestration capacity of the Wilcox coals. Multiplication by an injection factor yields a range of potential CO_2 volumes that can be sequestered on a pattern basis. We used Monte Carlo simulation with 10,000 iterations to account for uncertainty in our estimates. **Table 12** shows the expected values of CH_4 to be produced and CO_2 to be stored in Wilcox coals (base-case coal properties), on a pattern basis and a regional basis, assuming 80-acre, 5-spot patterns. Our analysis suggests that 38 Tcf (2.2 billion tons) of CO_2 could be sequestered, resulting in production of 9.8 Tcf of methane from the 2,930-mi^2 area (**Table 12**).

Table 12. Expected values for coalbed methane GIP and recoverable resources, and theoretical sequestration capacity and CO_2 sequestered volumes, Calvert Bluff coals, East-Central Texas.

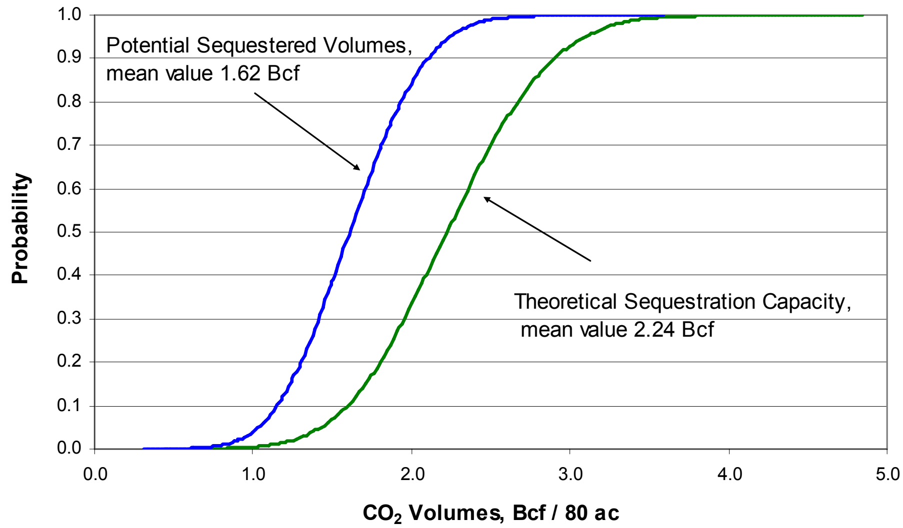
Recoverable Coalbed Methane Resources		**Potential Coalbed Sequestration Capacity**	
Coal Thickness, ft	20	20	Coal Thickness, ft
Coal Density, ton/ac-ft	1646	1646	Coal Density, ton/ac-ft
Gas Content, scf/t	222	850	CO_2 Storage (V_L, CO_2), scf/t
Recovery factor, fraction	0.713	0.724	Injection Factor, fraction
Pattern Basis			
Pattern Area, ac	80	80	Pattern Area, ac
GIP (per 80 ac), Bcf	0.586	2.238	Theoretical Sequestration Capacity, Bcf
Recoverable Resources (per 80 ac), Bcf	0.418	1.621	Sequestered CO_2 Volume (per 80 ac), Bcf
East-Central Texas Region			
Region Area, ac (2,930 sq. miles)	1,875,200	1,875,200	Regional Area, ac
Number of 80-ac 5 spot patterns	23,440	23,440	Number of producer/injector wells
GIP (region area), Bcf	13,730	52,460	Theoretical Sequestration Capacity, Bcf
Potential Recoverable Resources (region area), Bcf	9,790	38,000	Potential CO_2 Seq. Volume (region area), Bcf

Fig. 60 (a) shows cumulative distribution functions for GIP and recoverable methane resources for target coal reservoirs, base case, in the Calvert Bluff formation of the Wilcox Group in East-Central Texas. The mean value of the OGIP is 0.59 Bcf of CH_4, and considering an average recovery factor of 71.3% (from previous modeling), the mean volume of CH_4 that can be produced from the Wilcox Group coals in East-Central Texas is 0.42 Bcf per 80-acre, 5-spot pattern.

Fig. 60 (b) shows cumulative distribution functions for the maximum theoretical sequestration capacity and potential CO_2 volumes to be stored in these coals, on an 80-ac 5-spot pattern basis, again using base-case reservoir properties. This analysis indicates that the mean value of the theoretical sequestration capacity is 2.24 Bcf of CO_2 per pattern. Using an average injection efficiency factor of 72.4% (from previous modeling), the mean volume of CO_2 that can be sequestered in Wilcox Group coals in East-Central Texas is 1.62 Bcf per pattern.



(a)



(b)

Fig. 60. Cumulative distribution functions for: (a) OGIP and recoverable methane resources, and (b) theoretical sequestration capacity and potential CO_2 sequestration volumes, for target coal reservoirs in the Wilcox Group in East-Central Texas. Volumes are for an 80-acre, 5-spot pattern (40-acre well spacing).

Table 13 summarizes the results for an 80-acre 5-spot pattern and extrapolation to the 2,930-mi^2 estimated target area, where the Lower Calvert Bluff formation of East-Central Texas is 4,000 ft to 6,200 ft deep. The analysis assumes perfect positive correlation of volumes between patterns in the region. The results indicate that the potential CO_2 volume to be stored in Lower Calvert Bluff low-rank coals in Texas ranges between 27 and 49 Tcf (1.57 and 2.69 billion tons), and the recoverable methane resources from these coals ranges between 6.3 and 13.6 Tcf.

Six major power plants are located in the East-Central Texas region. These power plants and their annual CO_2 emissions (Texas Environmental Profiles, 2002) are as follows: Limestone - 13 MM tons; Sam K. Seymour - 12.5 MM tons; Big Brown - 9.6 MM tons; Sandow - 4.6 MM tons; Gibbons Creek - 3.2 MM tons; and TNP One - 2.8 MM tons. Collectively, they emit 45.7 MM tons of CO_2/year. Sequestration capacity of the Lower Calvert Bluff low-rank coals in East-Central Texas equates to 34 to 59 years of emissions from these six power plants.

Table 13. Range of uncertainty in potential volumes of CH_4 to be produced from, and CO_2 to be sequestered in, Lower Calvert Bluff low-rank coals in the Wilcox Group in East-Central Texas.

Area basis	Total Recoverable CH_4 Volumes, Bcf			Total CO_2 Sequestration Volumes, Bcf		
	P_{10}	Mean	P_{90}	P_{10}	Mean	P_{90}
Pattern area	0.270	0.418	0.580	1.160	1.621	2.100
East-central Texas area	6,330	9,790	13,600	27,190	38,000	49,220
				Total CO_2, MM tons		
				1,570	2,195	2,690

Economic Analysis of CO_2 Sequestration and Enhanced Coalbed Methane Production

Several researchers have investigated the economics of CO_2 sequestration and ECBM recovery. Wong et al. (2000) evaluated a conceptual 100-well CO_2-ECBM field development in the Alberta Plains region in a reservoir located at 4,200-ft depth containing 30 ft of coal in two seams. Well spacing was 320 acres in each 5-spot pattern, while gas-in-place volume was 4.4 Bcf per pattern. A 95% CO_2 stream delivered at 2,000 psig at a cost of $1.00 per Mscf was assumed. A 12% real rate of return was used for discounted cash flow analysis. Total ECBM recovery of 72% was predicted using a commercial simulator. The net volume ratio of CO_2 injection to CH_4 production was assumed to be 2:1. On this basis, the supply price for CBM was computed as $2.89 per Mscf. It was determined that the cost of delivered CO_2 was the most significant cost factor in their analysis. While it was assumed that new wells were drilled in their analysis, they concluded that recompletion of existing wells could reduce costs. They also concluded that potential credits for CO_2 avoided will have a significant effect on the economics. Wong et al. (2000) also reviewed an Amoco Production Company N_2 injection pilot for ECBM in the San Juan Basin. They found that N_2 injection increases methane production more quickly than expected from CO_2 injection and that N_2 breakthrough at production wells occurs more quickly, thus increasing processing costs. They also suggested that flue gas injection might be more effective and that there may be an optimal mix of CO_2-N_2 where a balance can be struck between CO_2 storage and process economics.

Reeves et al. (2004) developed an economic model for CO_2-ECBM/sequestration. Their study considered three types of power plants emitting CO_2 – the Pulverized Coal (PC), the natural gas combined cycle (NGCC) and the integrated gasification combined cycle (IGCC). A project size of 100 five-spot well patterns with 50 ft of coal and an injection rate of 50 Mscf/d per ft of coal was assumed. Analysis was done at a gas price of $4 per MMBTU and a discount rate of 10% with no credits. They found that injecting 100% CO_2 resulted in lower sequestration costs but a greater breakeven gas price than injection of flue gas. They also found that entirely new projects were more economical than existing projects. They concluded that N_2-ECBM appears to be more favorable than CO_2-ECBM, but an injection stream composed of mostly CO_2 is best for sequestration economics.

Kuuskra (2004) evaluated a hypothetical CO_2-ECBM project comprising one township (36 square miles) with 144 production wells and 100 new injection wells. Natural gas price was assumed to be $4 per Mscf, while CO_2 costs were assumed to be

\$0.75 per Mscf. The gas in place was 900 Bcf. It was concluded that incentives for CO_2 capture and storage of \$50 per metric ton would make the project economic.

Wong et al. (1999) evaluated a conceptual 100-well, 5-spot pattern flue-gas ECBM development in the Alberta Plains region using a commercial simulator. A flue-gas stream delivered to the field at 2,000 psig at a cost of \$0.50 per Mscf was assumed. The net ratio of flue-gas injection to production of CH_4 was assumed to be 0.73:1 by volume. Production was terminated when the N_2 content of the production stream exceeded 30%. Total CBM recovery of 57% was obtained from reservoir simulation. Economic analysis indicated that flue gas-ECBM requires a supply price of \$1.58 per Mscf compared to \$2.89 per Mscf for CO_2-ECBM (Wong et al., 2000), which implies that flue gas injection is economically superior to CO_2 injection. It was also concluded that sequestration credits would improve economics.

Most of the technical and economic feasibility studies of CO_2 sequestration and ECBM production presented in the literature were conducted in high-rank coals. As demonstrated in previous sections, CO_2 sequestration and enhanced methane production in low-rank coals in the Gulf Coastal plain, specifically in Texas, are technically feasible. Since economic results for high-rank coals do not necessarily translate to low-rank coals due to their differences in properties, we assessed the economics of CO_2 sequestration and ECBM recovery in Texas low-rank coals.

Development of Economic Model

Probabilistic economic analysis was conducted for a single 5-spot pattern and incorporated injection and production results from our reservoir simulation studies. Fieldwide costs, such as the cost of a pipeline to transport CO_2 to the field, have been allocated to an individual pattern based on the number of patterns required for a specified well spacing. Underlying assumptions in the economic analysis are stated below:

- All wells are constructed at Time 0. Production and injection begin simultaneously in Year 1.
- Pipeline and well costs are straight-line depreciated over the duration of the project.
- The maximum life of the project allowed for economic analysis was 20 years.

Economic Model Parameters

The parameters used in the economic analysis are listed in **Table 14** and further explained below.

Table 14. Economic Model Parameters

Parameters	Value	Units
Federal Tax Rate	35	%
Discount Rate	10	%
Gas Price (1)	2.00, 4.00, 12.00	\$/Mscf CH_4
Gas Price Escalation	3	%/yr
Texas Severance Tax	7.50	%
Net Revenue Interest (2)	75, 80	%
Carbon Market Price (2)	0.05, 1.58	\$/Mscf CO_2
Net-to-Gross CO_2 Injection Ratio for CO_2 Sequestration Credits	70	%
Area of field	30,000	acres
Area of 5-spot pattern	80, 160, 320, 480	acres
(1) Triangular Distribution (2) Uniform Distribution		

Gas Price. A triangular distribution was used to model uncertainty in gas prices. Minimum, most-likely and maximum values of \$2.00, \$4.00 and \$12.00 per Mscf of CH_4 were used for the gas price distribution. This triangular distribution was escalated at a rate of 3% per year.

Net Revenue Interest. A uniform distribution was used to model uncertainty in net revenue interest. Minimum and maximum values of 75% and 80% were used, based on typical royalty interests in the area.

Carbon Market Price. The term "carbon market price" is used in this report to represent the price of CO_2 in the carbon market - a market in which entities (governments, companies) trade in CO_2 to fulfill local or Kyoto Protocol obligations. The carbon market is more developed in Europe than in the United States. The carbon market in the United States has a significantly lower CO_2 price (\$0.07 per Mscf or \$1.33 per ton of CO_2) (Chicago Climate Exchange, 2006) compared to Europe (\$1.05 per Mscf or \$20.00 per ton of CO_2). In this study, a uniform distribution was used to model the uncertainty in carbon market price. Minimum and maximum values of \$0.05 per Mscf (\$1.00 per ton) of CO_2 and \$1.58 per Mscf (\$30.00 per ton) of CO_2 were used.

Sequestration Credits. It has been suggested by Wong et al. (1999) that the costs of CO_2 capture must be lowered or credits for CO_2 sequestration must be created in order to make CO_2 sequestration economic. There is currently no official method of computing and applying credits to carbon sequestration projects. Wong et al. (1999, 2000) also suggest that CO_2 credits must be based on a "CO_2 avoided" basis. Reeves et al. (2004) and King (2004) are in agreement with this concept. In other words, CO_2 produced in the processes used for CO_2 capture and CO_2 emitted during the compression process must be accounted for in computing a net CO_2 sequestered or CO_2 avoided. Thus, the operator does not receive credit for all the CO_2 sequestered. Reeves et al. (2004) give an example calculation of the net CO_2 sequestered for an IGCC plant. However, the method for calculating the values is not stated. Wong et al. (2000) also provide an illustrative example. The computed net sequestered CO_2 is about 64% of the CO_2 injected.

In our economic analysis, CO_2 credits are treated as an additional source of revenue for the company undertaking the project. A net-to-gross CO_2 sequestered ratio of 70% is assumed. Thus, Sequestration Credits = 70% * Volume of CO_2 Injected * CO_2 Market Price.

Area. We assumed a project area of 30,000 acres, based on preliminary studies (Saugier, 2003). Studies were run at different well spacings (40, 80, 160, and 240 ac). The number of 5-spot patterns required was computed by dividing the project area by the pattern area corresponding to each well spacing.

Costs

The costs are listed in **Tables 15** to **18** and are further explained here. Costs common to all three injection cases are listed in **Table 15**. Specific costs are listed in **Tables 16, 17** and **18** for the 100% CO_2 injection, 87% N_2 - 13% CO_2 flue gas injection and 50% N_2 - 50% CO_2 flue gas injection cases, respectively.

Table 15. Costs for 100% CO_2, 87% N_2-13% CO_2 and 50% N_2-50% CO_2 Injection

Item	Cost	Units
Lease Acquisition Costs (1)	50.00, 300.00	$/acre
Injection Gas Pipeline CAPEX	53.33	$/inch-mile (*)
New Injection Well CAPEX	100.00	$/ft
New Injection Well OPEX	1,500.00	$/month
New Production Well CAPEX	100.00	$/ft
New Production Well OPEX	1,500.00	$/month
Gas Treatment and Compression Facilities CAPEX	21,153.13	$ (*)
Produced Water Disposal	0.40	$/bbl
Safety, Monitoring and Verification	10,000.00	$/injector/yr
(1) Uniform Distribution (*) Cost computed for a single 80-acre pattern		

Table 16. Costs specific to 100% CO_2 injection

Item	Cost	Units
CO_2 Capture Cost (1)	1.00, 2.00	$/Mscf
CO_2 Pipeline OPEX	0.01	$/Mscf
CO_2 Compression OPEX	0.30	$/Mscf CO_2
(1) Uniform Distribution		

Table 17. Costs specific to 87% N_2-13% CO_2 injection

Item	Cost	Units
Injection Gas Pipeline OPEX	0.50	$/Mscf of Injected Gas
Produced Methane Processing (Nitrogen Rejection)	0.50	$/Mscf Wellstream

Table 18. Costs specific to 50% N_2-50% CO_2 injection

Item	Cost	Units
Injection Gas Pipeline OPEX (1)	0.50, 1.00	$/Mscf of Injected Gas
Produced Methane Processing (Nitrogen Rejection)	0.50	$/Mscf Wellstream
(1) Uniform Distribution		

Lease Acquisition Costs. A uniform distribution was used to model uncertainty in lease acquisition costs. Minimum and maximum values of $50.00 and $300.00 per acre were used based on typical costs in the area.

Injection Gas Pipeline Costs. The injection gas (pure CO_2 or mixed flue gas) pipeline CAPEX is computed based on a cost of $20,000/inch-mile (Reeves et al., 2004) for the entire project. This cost was divided by the number of 5-spot patterns to obtain the cost per inch-mile (**Table 15**). This cost ($53.33 per inch-mile) is multiplied by an assumed pipeline diameter of 24 inches and pipeline length of 21 km (13.05 miles). These values were obtained from Moore and Doctor (2005) based on expected pipeline capacity for this project.

A CO_2 injection pipeline OPEX of $0.01/Mscf was used for the 100% CO_2 injection studies (Reeves et al., 2004), as shown in **Table 16**. A flue-gas injection pipeline OPEX of $0.50 per Mscf was used for the 87% N_2 - 13% CO_2 flue gas studies, as shown in **Table 17**. This cost includes particulate removal, dehydration and compression costs (Wong et al., 1999).

A uniform distribution between $0.50 and $1.00 per Mscf was used to model uncertainty in injection gas pipeline OPEX for the 50% N_2 - 50% CO_2 flue gas studies, as shown in **Table 18**. This higher cost implicitly includes some CO_2 capture costs, which were not included separately for this case, required to produce a 50% N_2 - 50% CO_2 mixture from flue gas.

Production Well Costs. The new production well CAPEX includes roads, locations, drilling, completion, stimulation, production equipment and flowlines (Reeves et al., 2004).

Injection Well Costs. Costs are similar to those of production wells (Reeves et al., 2004).

Gas Treatment and Compression Facility Costs. This is the capital cost of the gas treatment and compression facilities. It is computed for this project based on a cost of $84,613 (70,000 Euros) per well for 160-acre well spacing, from Damen et al. (2005).

Water Disposal Costs. Disposal costs include the cost to transport water to the disposal well (either by gathering pipelines or trucking), the cost to inject the water, and the costs to maintain the injection well. Injection operating costs are estimated to be $0.40 per barrel.

Safety, Monitoring and Verification Costs. This includes estimated costs to ensure the proper implementation of the sequestration project (Reeves et al., 2004).

CO_2 Capture Costs. This is the cost of separating CO_2 from the flue gas emitted by the power plant and compressing to pressures sufficient for pipeline transportation. A uniform distribution was used to model uncertainty in CO_2 capture costs. Minimum and maximum values of $1.00 and $2.00 per Mscf of CO_2 were used (**Table 16**) (Wong et al., 2000).

Injected Gas Compression Costs. The injected gas (CO_2 or flue gas) compression OPEX is the cost of compressing the gas to the required wellhead injection pressure (Reeves et al., 2004).

Produced Methane Processing Costs. This includes the cost of separating methane from the other waste gases and compression. Nitrogen rejection cost of $0.50 per Mscf of wellstream gas was used for the flue gas injection studies (Reeves et al., 2004).

The economic parameters and costs described above were combined with relevant reservoir simulation and production results in a spreadsheet to compute economic yardsticks using Monte Carlo simulation (10,000 iterations). Uncertainties in reservoir properties were incorporated by sampling randomly from the database of 1000 simulation runs from the appropriate Monte Carlo reservoir modeling study, while uncertainties in economic parameters were incorporated by sampling randomly from the appropriate economic parameter distributions. Economic results are presented as cumulative probability distributions, which reflect the combined uncertainties in both reservoir properties and economic parameters.

A true economic limit was applied in the economic calculations, as opposed to the 5% CO_2 concentration limit in the produced gas that was applied in the reservoir modeling described in previous sections. Economic results are presented in terms of present value ratio (NPV/I, ratio of net present value to investment).

Economic Results

For each of the first five reservoir simulation studies described above, we conducted a corresponding economic assessment. These cases are (1) CO_2 sequestration base case scenarios for 4,000-ft and 6,200-ft depth coal beds in the Lower Calvert Bluff Formation of East-Central Texas, (2) sensitivity study of the effects of well spacing on sequestration, (3) sensitivity study of the effects of injection gas composition, (4) sensitivity study of the effects of injection rate, and (5) sensitivity study of the effects of coal dewatering prior to CO_2 injection/sequestration.

Case 1: CO_2 Sequestration/ECBM Production Base Case Scenarios

The economic results from this study are presented in **Fig. 61**. To ensure that the results are not dependent on the number of iterations used in the Monte Carlo simulation, this case was also run with 1000 iterations (similar to the number used in the reservoir simulation studies). Results with 1000 iterations (**Fig. 62)** compare well with results with 10,000 iterations (**Fig. 61**), indicating that 10,000 iterations is sufficient for Monte Carlo simulation.

The dotted vertical line in **Fig. 61** represents the demarcation between positive and negative NPV/I. Most of the probability lies in the negative NPV/I region, indicating 100% CO_2 injection is not economically feasible for these base cases with the ranges of gas prices and carbon credits investigated. NPV/I for Case 1a (4,000 ft) is usually less than that for Case 1b (6,200 ft). This is attributed primarily to lower volumes of CO_2 injected and lower volumes of CH_4 produced for Case 1a (4000 ft) than Case 1b (6200 ft). The impact of volumes injected and produced is apparently greater than the impact of the greater costs associated with the deeper reservoir.

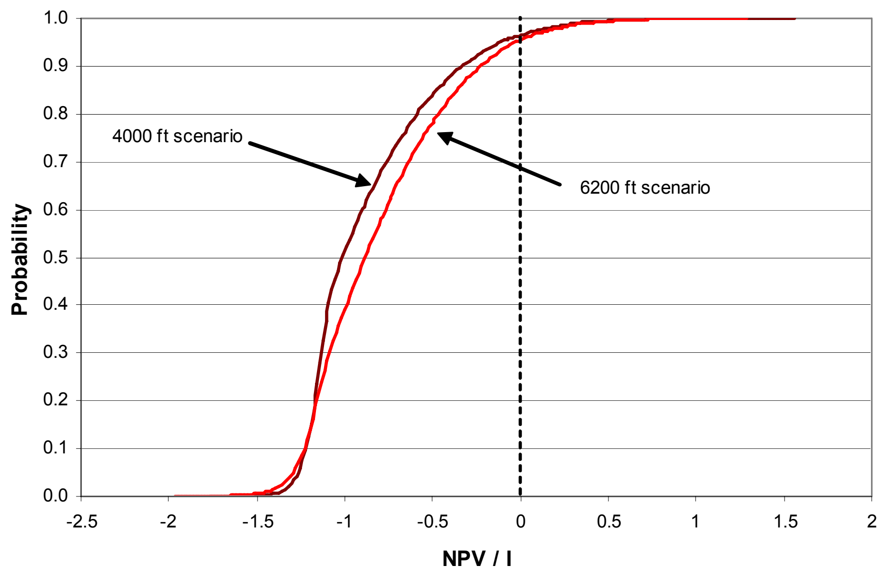


Fig. 61. Cumulative distribution functions of NPV/I for Case 1 (4000 ft and 6200 ft).

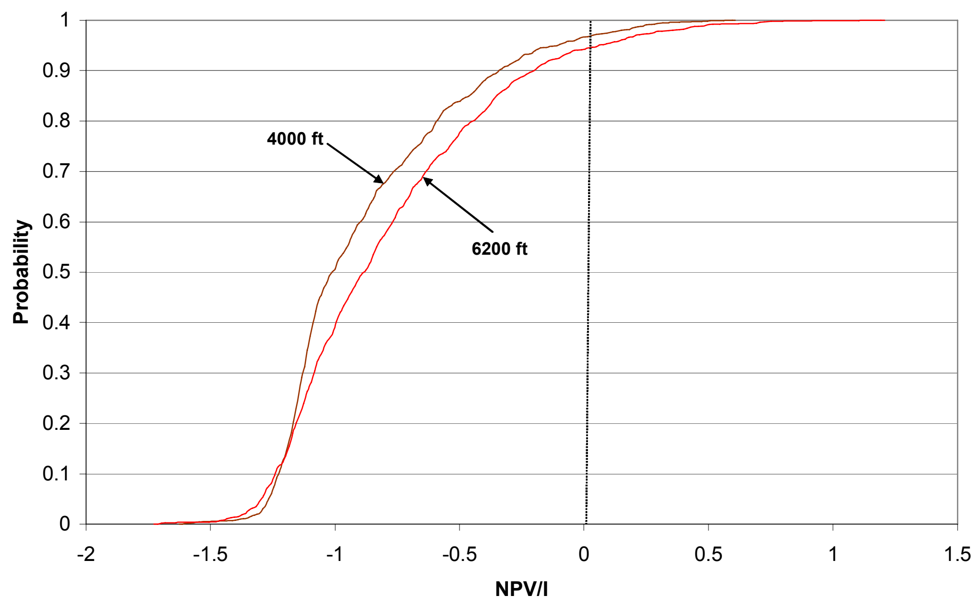


Fig. 62. Cumulative distribution functions of NPV/I for Case 1 (4000 ft and 6200 ft) run with 1000 iterations.

Case 2: Effects of Well Spacing on CO_2 Sequestration and ECBM Production

The cumulative distribution functions for NPV/I for the different well spacings are shown in **Fig. 63**. Economic analysis for the 160-acre and 240-acre well spacing cases were conducted for 30 yrs since the breakthrough times were significantly longer than 20 yrs. The economics improve with increasing well spacing, particularly at the upper end of the cumulative distribution functions, most likely due to lower capital expenditures and well operating costs associated with increasing well spacing. However, the economic results are still predominately negative for these cases with 100% CO_2 injection at 6,200 ft.

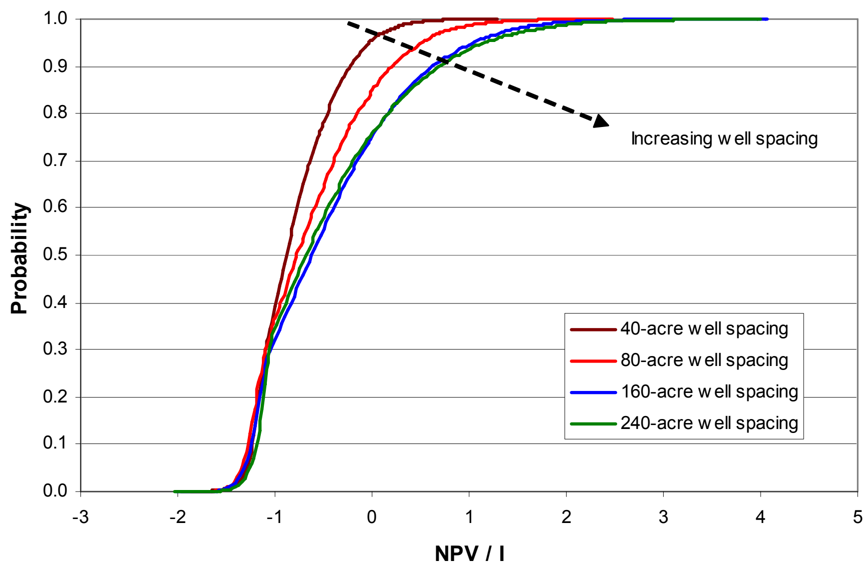


Fig. 63. Cumulative distribution functions of NPV/I for Case 2 (100% CO_2 injection, 6200 ft).

Case 3: Effects of Injection Gas Composition on CO_2 Sequestration and ECBM Production

Economic results from this study are presented in **Fig. 64**. The economic results improve significantly with addition of N_2 to the injection gas stream, although the economics are still predominately negative. The differences between Case 3a (87% N_2 - 13% CO_2) and Case 3b (50% N_2 - 50% CO_2) are small. The differences in economic performance between 100% CO_2 injection and the other two cases with N_2 in the injection gas are due primarily to (1) increased CO_2 capture costs for the 100% CO_2

injection case and (2) lower methane production and, thus, lower gross revenue for the 100% CO_2 injection case.

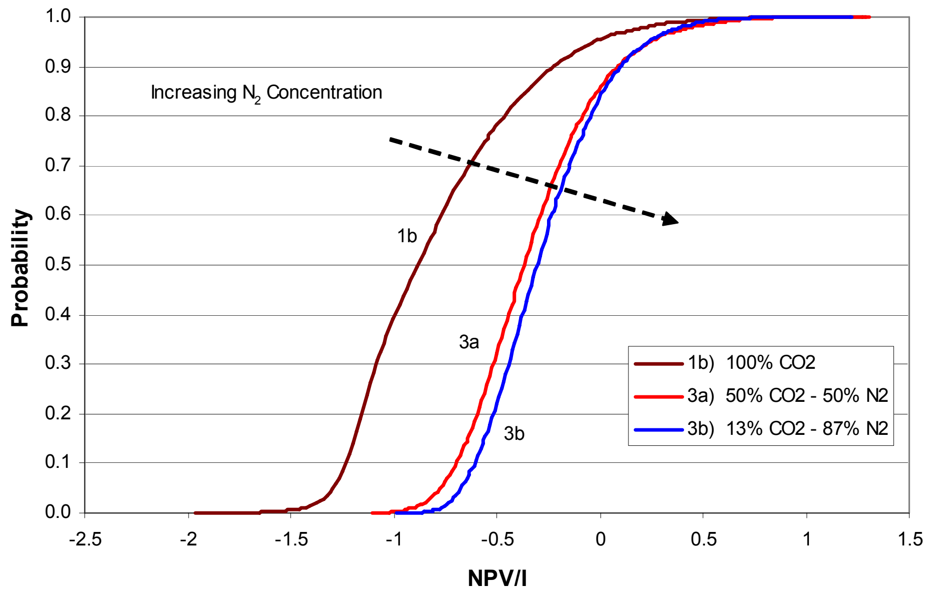


Fig. 64. Cumulative distribution functions of NPV/I for Case 3 (40-ac well spacing, 6200 ft).

Case 4: Effects of Injection Rate on CO_2 Sequestration and ECBM Production

Economic results from this study are presented in **Fig. 65**. The effect of lowering the pressure drop between injector and producer, and thus the injection rate, on NPV/I is not significant for the cases investigated in this study.

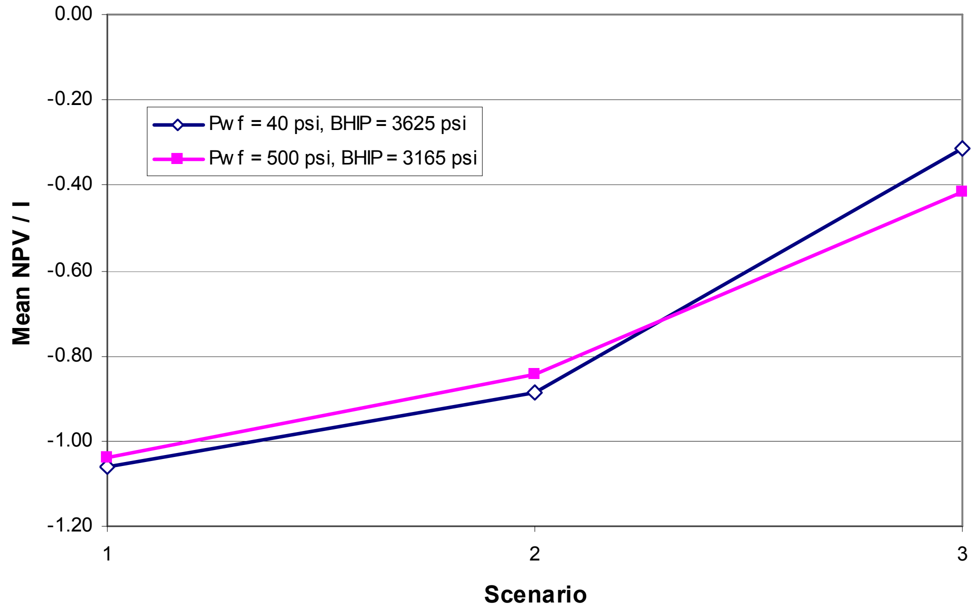


Fig. 65. Plot of NPV/I for different injection rate cases for (1) least-favorable, (2) most-likely and, (3) most-favorable reservoir property scenarios.

Case 5: Effects of Coal Dewatering on CO_2 Sequestration and ECBM Production

Economics from this study are presented in **Fig. 66.** Dewatering the coals prior to CO_2 injection does not have a significant impact on economic performance of CO_2 sequestration and ECMB production for the cases investigated in this study.

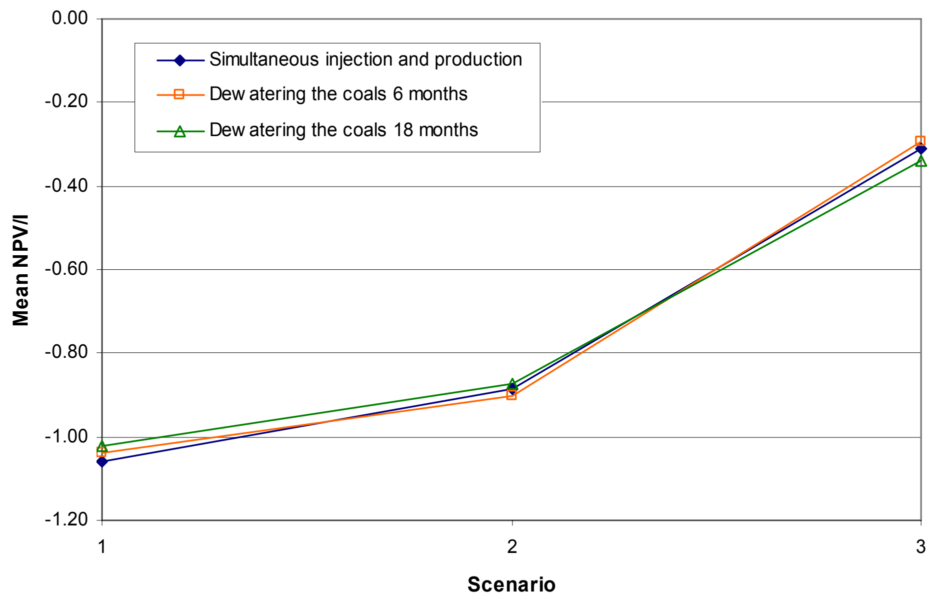


Fig. 66. Plot of NPV/I for different dewatering times prior to production for (1) least-favorable, (2) most-likely and, (3) most-favorable reservoir property scenarios.

Analysis of all the investigations conducted in this project indicates that economics are predominately negative, with some exceptions, for CO_2 sequestration and ECBM recovery projects in the Wilcox Group coals in East-Central Texas, assuming economic conditions current at the time of the investigations. We note that the investigations conducted were sensitivity studies from a base case of 100% CO_2 injection at 40-ac well spacing, which in hindsight is seen to be one of the least economical scenarios. Design and optimization studies should be considered in future work to more thoroughly investigate flue gas injection and greater well spacings, which appear to be more economical, and other design parameters.

The economic conditions investigated in this study included gas prices ranging from \$2/Mscf to \$12/Mscf and CO_2 credits based on carbon market prices ranging from \$0.05 to \$1.58 per Mscf CO_2 (\$1.00 to \$30.00 per ton CO_2). Further analysis indicated that CO_2 sequestration/ECBM projects are more likely to be viable with gas prices and/or carbon market prices at the upper ends of these ranges investigated. These favorable economic conditions are not unattainable given recent gas price history and current carbon market prices in Europe. More favorable economic conditions, combined with the close proximity of many CO_2 point sources near unmineable coalbeds, could generate significant CO_2 sequestration and ECBM potential in Texas low-rank coals.

Technology Transfer

As part of the technology transfer component of this study, we presented talks and papers at professional conferences, regional geologic and engineering society meetings, two Coal-Seq Forums, and other venues. These technology transfer activities are listed in the Appendix.

Website

We have developed a website containing all technical reports, papers, presentations, references, and theses relevant to this project. It can be accessed at:
http://coalsequest.tamu.edu

CONCLUSIONS

Reservoir Characterization

- Abundant Wilcox Group and younger low-rank coals occur throughout the Gulf Coastal Plain, from Mexico to Alabama, underlying numerous electric generating plants that are point source emitters of CO_2.
- The Calvert Bluff formation of the Wilcox Group in East-Central Texas was selected to assess the potential for CO_2 sequestration and ECBM in low-rank coals because there are many power plants in the area, coal resources are abundant, the deep coal is known to contain methane, and there is industry interest in the both methane resources and CO_2 sequestration.
- In the region of the Sam K. Seymour power plant in East-Central Texas, Wilcox Group total coal thickness ranges between 50 and 140 ft in seams > 2 ft thick. Total coal thickness for the Calvert Bluff formation is 25 to 75 ft, which is half of the total Wilcox Group coal. Calvert Bluff formation coal occurs in 5 to 20 seams; 1 to 6 seams are greater than 5 ft thick. The thickest individual Calvert Bluff coal in each well ranged from 6 to 12 ft.
- Shallow Wilcox coals are thermally immature. Thermal maturity increases with depth, and deep Wilcox coals in East-Central Texas are high-volatile C bituminous rank.
- Gas content of Wilcox coals < 3,500 ft deep is <50 scf/t, whereas gas content of Wilcox coals between 3,500 and 6,700 ft deep ranges between 100 and 430 scf/t, as received.
- There are two coalbed gas petroleum systems in the Wilcox Group of East-Central Texas, separated by a transition zone.
- The shallow, biogenic Wilcox coalbed gas system is connected to aquifer recharge and is characterized by low (<50 scf/t) methane content, dry gas of probable biogenic origin, and fresh formation water.
- The deep, thermogenic Wilcox coalbed gas system has higher methane content (commonly 100 – 400 scf/t), wet gas of thermogenic (in-situ or migrated) origin, and saline formation water.

- The boundary between the two coalbed gas systems is transitional; its regional occurrence requires further study with additional data.
- Although potential for CO_2 sequestration and ECBM is significant in Wilcox Group low-rank coals of East-Central Texas, injection must be in the deeper (> 3,500 ft deep), unmineable coals of the thermogenic coalbed gas system; shallower Wilcox coals are part of a protected freshwater aquifer.
- The data-sharing agreement with Anadarko Petroleum Corporation was invaluable to this study. The data available as a result of this agreement allowed us to characterize Wilcox coals in the area of Sam K. Seymour power plant for reservoir simulation and economic assessment of the viability of CO_2 sequestration and ECBM.

Reservoir Simulation and Economic Modeling

- Injection of 100% CO_2 in Lower Calvert Bluff low-rank coal seams at 4,000-ft and 6,200-ft depth with average net coal thickness of 20 ft results in average volumes of CO_2 sequestered between 1.55 and 1.75 Bcf and average volumes of methane produced between 0.54 and 0.67 Bcf on an 80-acre 5-spot pattern basis.
- CO_2 sequestration volumes decrease and ECBM production increases with increasing N_2 content in the injected gas. The best economic performance is obtained with flue gas (13% CO_2-87% N_2) injection, compared to injection gas compositions with increasing amounts of CO_2.
- Well spacing sensitivity studies for 100% CO_2 injection indicate that total volumes of CO_2 sequestered and methane produced on a unit-area basis do not change significantly with spacing, up to 240 acres per well. The likelihood of project economic viability increases somewhat with increasing well spacing.
- Dewatering the coals prior to starting pure CO_2 injection does not significantly impact reservoir or economic performance for an 80-acre 5-spot pattern at 6,200-ft depth.
- Anisotropic permeability sensitivity studies for 100% CO_2 injection show significant differences in the cumulative volumes of CH_4 produced and CO_2 injected due to permeability anisotropy, depending on the orientation of injection

patterns relative to the orientation of permeability anisotropy.

- Economic analysis shows that CO_2 sequestration/ECBM projects in Lower Calvert Bluff coals in East-Central Texas will most likely not be profitable over the full range of economic conditions investigated in this study – gas prices ranging from \$2/Mscf - \$12/Mscf and CO_2 credits based on carbon market prices ranging from \$0.05 to \$1.58 per Mscf CO_2 (\$1.00 to \$30.00 per ton CO_2). Projects are more likely to be viable with gas prices and/or carbon market prices at the upper ends of the ranges investigated.
- CO_2 sequestration potential and methane resources of the Lower Calvert Bluff low-rank coals in East-Central Texas are significant. The potential CO_2 sequestration capacity of the coals ranges between 27.2 and 49.2 Tcf (1.57 and 2.69 billion tons), with a mean value of 38 Tcf (2.2 billion tons), assuming a 72.4% injection efficiency. We estimate recoverable methane resources between 6.3 and 13.6 Tcf, with a mean of 9.8 Tcf, assuming a 71.3% recovery factor.

RECOMMENDATIONS

Additional studies and data are necessary to verify and further define the two coalbed gas systems and the transitional boundary between them, and to better assess potential for CO_2 sequestration and ECBM. The recommended studies and data collection include:

- whole core gas desorption;
- isotopic and compositional analyses of coalbed gas samples;
- coal sample desorption and additional sorption isotherms, especially in freshwater and transitional areas;
- vitrinite reflectance data; and
- water compositional analyses to calibrate resistivity logs and map water quality.

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LIST OF ACRONYMS AND ABBREVIATIONS

AR	as received
Bcf	billion cubic feet
CBM	coalbed methane
CH_4	methane
CMG	Computer Modelling Group Ltd.
CO_2	carbon dioxide
DOE	Department of Energy
ECBM	enhanced coalbed methane
EOS	Equation of State
ft	feet
M	meters
Mcf	thousand cubic feet
mg/L	milligrams/liter
mi	miles
N_2	nitrogen
ohm-m	ohm-m^2/m
R_o	vitrinite reflectance
scf/t	standard cubic feet per ton
SSL	subsea level
tcf	trillion cubic feet
TDS	total dissolved solids
USGS	U. S. Geological Survey
TAMU	Texas A&M University

APPENDIX – Technology Transfer Activities

Presentations, Abstracts, and Papers

McVay, D. A., Gonzalo Hernandez-A., R. O. Bello, W. B. Ayers, Jr., J. A. Rushing, S. K. Ruhl, M. F. Hoffmann, and R. I. Ramazanova, ***in review,*** Evaluation of the Technical and Economic Feasibility of CO_2 Sequestration and Enhanced Coalbed Methane Recovery in Texas Low-Rank Coals, *in* CO_2 Sequestration in Geological Media: American Association of Petroleum Geologists, Special Publication.

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