CO₂ Sequestration Potential of Texas Low-Rank Coals

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ABSTRACT

The objectives of this project are to evaluate the feasibility of carbon dioxide (CO₂) sequestration in Texas low-rank coals and to determine the potential for enhanced coalbed methane (ECBM) recovery as an added benefit of sequestration. The main objectives for this reporting period were to (1) perform the reservoir simulation and economic analysis of the CO₂ sequestration modeling with sensitivity studies for the base case of pure CO₂ injection, and (2) determine the effects of well patterns/flooding strategies on CO₂ sequestration in the Lower Calvert Bluff Formation (LCB) of the Wilcox Group coals in east-central Texas.

To predict CO₂ sequestration in LCB coal beds, we constructed a pattern reservoir simulation model and selected reservoir parameters representative of two scenarios: one at approximately 6,200-ft depth and the other at 4,000-ft depth. These are typical depths of potential LCB coalbed reservoirs in the focus area of East-Central Texas. Simulation of 100% CO₂ injection in an 80-acre 5-spot pattern (40-ac well spacing) indicates that LCB coals with average net thickness of 20 ft can store 1.55 Bcf of CO₂ at depths of 4,000-ft and 1.75 Bcf of CO₂ at depths of 6,200 ft. ECBM recovery for the 80-acre pattern was 0.54 Bcf with breakthrough occurring in 2,700 days (7.4 years) in the 4,000-ft depth case and 0.67 Bcf with breakthrough in 1,650 days (4.5 years) for the 6,200-ft depth case. Breakthrough was defined as the point when CO₂ comprised 5% of the production stream.

The well-spacing sensitivity study for a 5-spot pattern model at 6,200-ft depth does not show significant sensitivity to total volumes of CO₂ sequestered or methane produced on a unit-area basis. However, breakthrough times ranged from 1,650 days (4.5 years) for 80-acre patterns (40-acre well spacing) to 10,960 days (30 years) for 480-acre patterns (240-acre well spacing). Economic analysis will determine the most viable well spacing for coalbed reservoirs in the focus area.

Preliminary economic modeling, using the current estimated U.S. carbon market price of \$1.33 per ton (\$0.07 per Mscf) for sequestration credits, of CO₂ sequestration and ECBM recovery for 100% CO₂ injection indicates predominately negative economic indicators (NPV and NPV/I) for the reservoir depths and well spacings investigated. Results indicate that projects become more viable as carbon market prices approach the levels currently in effect in Europe. Future sensitivity studies will focus on sensitivity to gas price as well as modeling the effects of injection gas composition.

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INTRODUCTION

The objectives of this project are to evaluate the feasibility of carbon dioxide (CO₂) sequestration in Texas low-rank coals and to determine the potential for enhanced coalbed methane recovery as an added benefit of sequestration. During this reporting period, we conducted base case reservoir simulation and economic studies of CO₂ sequestration and ECBM recovery in the LCB coals in east-central Texas and investigated the sensitivity to well spacing and flooding strategies.

EXPERIMENTAL

Reservoir Modeling Parameters

Simulation studies of Texas low-rank coals are being conducted using average coal properties and reservoir parameters obtained from literature and data collected during this study (Tables 1 – 4). Reservoir data were selected to represent LCB reservoir coals at 4,000 ft and at 6,200 ft depths. LCB average net-coal thickness is 20 ft in the area of study (Ayers and Lewis, 1985; data from this study). A triangular distribution (10 ft, 20 ft, and 30 ft coal thickness) is used in the reservoir simulation model.

Coal reservoir porosity is estimated to be 1%. 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 (TEES, Quarterly Technical Progress Report, Third Quarter 2003). Coalbed in-situ permeability was determined from pressure falloff tests conducted in coal seams in 2 LCB coals in an Anadarko Petroleum Corporation (APC) cooperative well. Well test interpretations indicated that the coal fracture permeability ranges from 1.9 to 4.2 mD. A log-normal distribution of these permeability data with geometric mean of 2.8 mD is used in the reservoir simulation modeling (TEES, Quarterly Technical Progress Report, First Quarter 2005; Pinnacle, 2005). Reservoir anisotropy was not considered in the model. Fracture compressibility of 138e-06 psi⁻¹ is used in the modeling. This is based on values reported for the Fruitland coal in the San Juan basin ($c_p = (233-969)e-06$ psi⁻¹; Palmer and Mansoori, 1996; Palmer and Mansoori, 1998).

Ten sidewall core samples of LCB coal were taken from approximately 6,200-ft depth in an APC well in east-central Texas. The samples were desorbed in 4 canisters, after which the samples were mixed to form a composite sample that was used for proximate analysis and isotherms. 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 (Hampton, Waechter, & Associates, 2004). A triangular distribution of these coal density data with a most likely value of 1.332 g/cc is being used in reservoir simulation. Average total gas content of the coal, including lost gas and projected residual gas, was 395 scf/t on an as-received basis. Based on the mean vitrinite reflectance of 0.54%, this coal is high-volatile C bituminous (RMB Earth Science Consultants, 2005).

Synthetic isotherm data were constructed to model coalbed reservoirs in the 4,000-ft depth range, based on analysis of CH₄ sorption isotherms from 7 wells and one surface mine coal sample (Fig. 1). To estimate CO₂ sorption values, we used a CO₂/CH₄ sorption ratio of approximately 3:1, which was the ratio from coal samples at approximately 4,900-ft depth in the Wilcox Group in Mississippi (Reeves et al., 2005). Langmuir volume and pressure parameters on an as-received basis are 458.5 scf/ton and 1884.0 psia for CH₄, and 1375.5 scf/ton and 1884.0 psia for CO₂ (Fig. 2).

CO₂, CH₄, and N₂ sorptive capacities of LCB coal samples from approximately 6,200-ft depth in an APC cooperative well were measured in the lab. Langmuir volume and pressure parameters on an as-received basis are 961.9 scf/ton and 697.5 psia for CO₂, 363.6 scf/ton and 608.5 psia for CH₄, and 166.1 scf/ton and 2060.7 psia for N₂ (Fig. 2; RMB Earth Science Consultants, 2005).

Gas phase diffusion times considered are 0, 1, and 4 days, as was reported previously. A triangular distribution of these gas phase diffusion times, with a most likely value of 1.0 day, is being used in reservoir simulation. Diffusion time controls the mass transfer rate from matrix (coal) to fracture (cleats).

At a depth of 6,200 ft in the APC cooperative well, we estimate 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 estimate reservoir temperature is 140° F and pressure is 1,730 psia.

RESULTS AND DISCUSSION

Reservoir Modeling

Using the data described above, we built a reservoir model that is one-eighth of a 5-spot to run deterministic and probabilistic simulations. The predicted volumes of CO₂ sequestered and CH₄ produced are scaled to a full pattern in this report. For this research, we plan to run 5 separate simulation investigations, or cases. These cases are (1) CO₂ 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 CO₂ injection/sequestration. This quarter, we report results from Cases 1 and 2. The remaining cases will be presented in the Final Report.

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.

Base Case 1a (4,000-ft injection depth) and Case 1b (6,200-ft injection depth)

To assess reservoir performance during CO₂ sequestration in LCB coals, we conducted probabilistic simulations (1,000 iterations), modeling simultaneous injection of 100% CO₂ and production of CH₄ 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 (Case 1a) and 6,200-ft depth (Case 1b) base case coal seam scenarios are shown in Figs. 3-18.

The reservoir volume swept by CO₂ is relatively high for this single-layer model. Most of the water in the fracture system and the CH₄ 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. Figs. 3-6 and 9-12 show colorfill maps of various reservoir properties at breakthrough, i.e., the time at which CO₂ comprises 5% mole fraction of the produced gas. Figs. 7-8 and 13-14 show production and injection rates and pressure profiles.

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 CO₂ injection in LCB coalbeds in east-central Texas. Figs. 15-18 show cumulative distribution functions for CO₂ sequestered, CH₄ produced, water produced, and breakthrough times. For the base case scenario of 4,000-ft depth (Case 1a), the mean values of the estimated volumes of CO₂ to be sequestered and CH₄ and water volumes to be produced in LCB coals are 1.55 Bcf, 0.54 Bcf, and 75 Mstb, respectively, at breakthrough time of 2,700 days. For the base case scenario of 6,200-ft depth (Case 1b), mean volumes of CO₂ injected and CH₄ and water produced are 1.75 Bcf, 0.67 Bcf, and 74 Mstb, respectively, at breakthrough time of 1,650 days. Results are for an 80-acre 5-spot pattern (40-acre well spacing). These results indicate that CO₂ sequestration and ECMB production are technically feasible in east-central Texas LCB coals.

Base Case 2: Effects of well spacing on CO₂ Sequestration and ECBM

To determine the effects of well spacing on performance of coalbed reservoirs during CO₂ sequestration and ECMB production in the Wilcox coals in east-central Texas, we conducted probabilistic simulation modeling studies (1,000 iterations) of 100% CO₂ gas injection under the base case operating conditions for 80, 160, and 240-acre well spacings 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. Figs. 19-22 show the cumulative distribution functions for the volumes of CO₂ sequestered, CH₄ produced, water produced, and breakthrough times, respectively, for Cases 1b, 2a, 2b, and 2c. Mean values of the estimated volumes of CO₂ that can be sequestered in LCB coals are 1.75, 3.59, 7.25, and 10.94 Bcf for 40, 80, 160, and 240-acre well spacings in a 5-spot injection pattern. Corresponding CH₄ 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. CH₄ 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.

Figs. 23-25 show the cumulative distribution functions for the volumes of CO₂ sequestered, CH₄ 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, the mean values of estimated volumes of CO₂ that can be sequestered in LCB 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 CH₄ production 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 smaller well spacings. However, the sensitivity to well spacing of CO₂ volumes sequestered and methane volumes produced on a unit-area basis is not great. Economic analysis will dictate the most viable well spacing for coalbed reservoirs in the focus area.

Economic Modeling

An economic analysis spreadsheet was developed to assess the reservoir simulation results. Reservoir and well data used in the economic analysis are summarized in Table 5. Economic factors are summarized in Table 6. Gas price and net revenue interest are specified as distributions to help in quantifying the uncertainty in economic performance. Gas price is modeled using a triangular distribution, while net revenue interest is modeled using a uniform distribution. Expenses to be considered in this analysis are given in Table 7 (Reeves et al., 2004; Damen et al., 2005). The economic analysis is conducted for a single pattern. Fieldwide costs, such as the pipeline to transport CO₂ to the field, have been allocated to an individual pattern based on the number of patterns required for a specified well spacing. Other assumptions made in the economic analysis are stated below:

1. All wells are constructed at Time 0. Production and injection begin simultaneously in Year 1.
2. A 21-km (13.05-mile), 24-inch pipeline will be built to transport CO₂ from the power plant to the sequestration site.
3. Pipelines and wells are straight line depreciated over the duration of the project.
4. Net CO₂ sequestration volumes are used to compute sequestration credits. Net sequestered volumes are assumed to be 70% of the total sequestered volume. Revenues from CO₂ sequestration credits are incorporated into the economic model.
5. The economic model is conducted for a maximum of 30 years, even though some of the individual realizations in the probabilistic analysis go beyond 30 years.

Cumulative distribution functions for net present value for Base Cases 1a (4,000 ft) and 1b (6,200 ft) are shown in Fig. 26. Mean values are listed in Table 8. These results indicate the project is not economic for the base case field and economic parameters. Results are more favorable, although still negative, for the shallower depth (4000 ft).

Economic results for the Case 2 studies, sensitivity to well spacing, are shown in Fig. 27 and Table 9. The primary factors affecting economic performance vs. well

spacing are costs (fewer wells with larger well spacing) and project life (longer lives with larger well spacing). Simulation results presented above showed that ultimate volumes of CO₂ sequestered and methane produced, on a unit area basis, did not vary significantly with well spacing. Economic results generally improved with increasing well spacing, which suggests that reduction in costs has greater impact than project life. Some realizations for the 160-acre and 240-acre well spacing cases are profitable (Fig. 27) although, overall, the probability of negative economic performance appears to be about 75% for these spacings under the base case gas price and carbon market price assumptions.

Sensitivity of mean NPV to carbon market price for 4000-ft and 6200-ft formation depths is illustrated in Fig. 28. Projects are not viable with the current U.S. price (\$1.33 per ton CO₂ or \$0.07 per Mscf CO₂). This plot shows that, at 40-acre well spacing, the mean project becomes profitable at carbon market prices currently in effect in Europe (approximately \$20 per ton) for the 4000-ft coals. Higher carbon prices are required at the 6200-ft depth to break even. Sensitivity of mean NPV to carbon market price for different well spacings in 6200-ft coals is illustrated in Fig. 29. This plot indicates that, with well spacings of 80 to 240 acres, mean projects become viable with carbon market prices of 5-10 \$/ton.

Results presented here assume gas prices of \$7.00 to \$8.00 per Mscf, escalated 3% per year. Future studies, to be presented in the final report, will include sensitivity to gas price and CO₂ capture costs. The final report will also include studies investigating the effect of injected gas composition and different production and injection strategies.

CONCLUSIONS

The average volumes of CO₂ that may be sequestered in LCB coals in east-central Texas for 4,000-ft and 6,200-ft depth coal seams with average coal thickness of 20 ft are between 1.55 Bcf and 1.75 Bcf per 80-acre 5-spot pattern. ECBM recovery is estimated to be between 0.54 Bcf and 0.67 Bcf per 80-acre pattern, respectively. Project lives are between 2,700 days (7.4 years) and 1,650 days (4.5 years), respectively.

Study of sensitivity to well spacing for the 6200-ft coals indicates that average injection and production rates decrease with increasing well spacing, while total volumes of CO₂ sequestered and methane produced increase slightly with increasing well spacing. However, the sensitivity to well spacing of CO₂ volumes sequestered and methane volumes produced on a unit-area basis is not great. Project lives increase from 1,650 days (4.5 years) to 10,960 days (30 years) for well spacings ranging between 40 acres and 240 acres per well.

Economic analysis shows that, for 40-acre well spacing, CO₂ sequestration projects in LCB coals in east-central Texas will likely not be economic under base case economic conditions – gas prices of \$7.00 to \$8.00 per Mscf and carbon market prices of \$1.33 per ton CO₂. The likelihood of project viability increases somewhat with increasing well spacing. However, it appears that higher carbon market prices (e.g., prices currently in effect in Europe, approximately \$20 per ton CO₂) will be required to yield profitable projects.

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Table 1 – Static Coal Reservoir Model Parameters

Parameter	Value
Fracture/Cleat Spacing	2.5 inches
Fracture Porosity	1%
Matrix Porosity	1%
Fracture Compressibility	138 e-6 1/psi
Water Density	0.99 g/cm ³ (61.85 lb/ft ³)
Water Viscosity	0.607 cp
Water Compressibility	4.0 e-6 1/psi
Initial Water Saturation	100%
Initial Composition of Gas in Reservoir	100% CH ₄
Grid model	One-eight 5-spot injection pattern
Grid Size	11 x 11 x 1

Table 2 – Uncertain Reservoir Model Parameters and Design Parameters

Parameter	Value
Coal Seam Thickness ⁽¹⁾	10, 20, 30 feet
Fracture Absolute Permeability ⁽²⁾	0.8, 2.8, 10 mD
Coal Density ⁽³⁾	1.289, 1.332, 1380 g/cm ³ (80.5, 83.2, 86.2 lb/ft ³)
Gas Phase Diffusion Time ⁽⁴⁾ (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-acre well spacing

⁽¹⁾ Triangular Distribution⁽²⁾ Log-Normal Distribution⁽³⁾ Triangular Distribution⁽⁴⁾ Triangular Distribution

Table 3 - Base Case 1a, 4,000-ft depth coal seam

Parameter	Value
Depth	4,000 feet
Initial Reservoir Pressure	1,730 psia
Reservoir Temperature	140 °F
Langmuir Isotherm Parameters ⁽¹⁾ :	
V _L , CH ₄	458.5 scf/ton
P _L , CH ₄	1,884 psia
V _L , CO ₂	1,375.5 scf/ton
P _L , CO ₂	1,884 psia
V _L , N ₂	301 scf/ton
P _L , N ₂	6,764 psia
Operating Conditions - Pressure Control :	
Production Well, Pressure and Rate	40 psia, 3.5 MMscf/D
Injection Well, Pressure and Rate	2,175 psia, 3.5 MMscf/D

⁽¹⁾ As Received Basis

Table 4 - Base Case 1b, 6,200-ft depth coal seam

Parameter	Value
Depth	6,200 feet
Initial Reservoir Pressure	2,680 psia
Reservoir Temperature	170 °F
Langmuir Isotherm Parameters ⁽¹⁾ :	
V _L , CH ₄	363.6 scf/ton
P _L , CH ₄	608.5 psia
V _L , CO ₂	961.9 scf/ton
P _L , CO ₂	697.5 psia
V _L , N ₂	166.1 scf/ton
P _L , N ₂	2,060.7 psia
Operating Conditions - Pressure Control :	
Production Well, Pressure and Rate	40 psia, 3.5 MMscf/D
Injection Well, Pressure and Rate	3,625 psia, 3.5 MMscf/D

⁽¹⁾ As Received Basis

Table 5 - Reservoir and Well Data Used in Economic Analysis (Case 1a)

Depth of reservoir (ft)	4,000
Well spacing (ac)	40
Area of 5-spot pattern (sc)	80
Area of field (ac)	30,000
Number of 5-spot patterns in field	375*
Number of injection wells in field	375*
Number of production wells in field	375*

* These will vary with well spacing.

Table 6 - Economic Factors

Factors			Type of distribution
Federal Tax Rate	35	%	Triangular
Discount Rate	10	%	
Gas Price	\$7.00, \$7.50, \$8.00	per Mscf CH ₄	
Gas Price Escalation	3	% per yr	Uniform
Texas Severance Tax	7.5	%	
Net Revenue Interest	75 -80	%	
Carbon Market Price	\$0.07	per Mscf CO ₂	

Table 7 - Costs

Item	Cost	Distribution Type
Lease Acquisition Costs	\$50.00 - \$300.00 per acre	uniform distribution
CO₂ capture cost	\$1.00 - \$2.00 per Mscf	uniform distribution
CO₂ pipeline CAPEX	\$53.33 per inch-mile*	
CO₂ pipeline OPEX	\$0.01 per Mscf	
New Injection Well CAPEX	\$100.00 per ft	
New Injection Well OPEX	\$1,500.00 per month	
New Production Well CAPEX	\$100.00 per ft	
New Production Well OPEX	\$1,500.00 per month	
Gas treatment and compression facilities	\$21,153.13 *	
Produced Methane processing	\$0.50 per Mscf	
Produced Water disposal	\$0.40 per barrel	
Safety, Monitoring and Verification	\$10,000.00 per injector per year	

* Costs allocated to a single 80-acre pattern

Table 8 - Case 1 Economic Results (100% CO₂ Injection, 40-acre well spacing)

	Depth (ft)	Mean NPV	Mean NPV/I
1a	4000	(\$749,214.80)	-0.88
1b	6200	(\$938,025.60)	-0.73

Table 9 - Case 2 Economic Results (100% CO₂ Injection, 6200 ft)

	Well spacing (ac)	Mean NPV	Mean NPV/ I
2a	80	(\$697,410.30)	-0.52
2b	160	(\$462,630.00)	-0.32
2c	240	(\$558,356.80)	-0.36

Fig. 1- Methane adsorption isotherms for the 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. 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 modeling.

Fig. 2- Methane and carbon dioxide sorption isotherms for use as input in reservoir simulation to represent gas adsorption/desorption isotherm behavior in coalbeds 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. 1) and validated by an isotherm from Wilcox coals from 4,898-ft depth in Louisiana (ARI, 2005). $\text{CO}_2\text{:CH}_4$ ratio is 3:1.

Fig. 3- Methane gas mole fraction at breakthrough time of 2,405 days for the 4,000-ft depth base case coal seam scenario in the Wilcox Group, Case 1a.

Fig. 4- CO₂ gas mole fraction at breakthrough time of 2,405 days for the 4,000-ft depth base case coal seam scenario in the Wilcox Group, Case 1a.

Fig. 5- Water saturation in the fracture system at breakthrough time of 2,405 days for the 4,000-ft depth base case, Case 1a.

Fig. 6- Reservoir pressure at breakthrough time of 2,405 days for the 4,000-ft depth base case, Case 1a.

Fig. 7- Gas production rate, water production rate, and bottom hole flowing pressure for the production well, 4,000-ft depth base case, Case 1a. Rates are for an 80-acre 5-spot pattern (40-acre well spacing).

Fig. 8- CO₂ injection rate, bottom hole injection 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. 9- Methane gas mole fraction at breakthrough time of 1,461 days for the 6,200-ft depth base case, Case 1b.

Fig. 10- CO₂ gas mole fraction at breakthrough time of 1,461 days for the 6,200-ft depth base case, Case 1b.

Fig. 11- Water saturation in the fracture system at breakthrough time of 1,461 days for the 6,200-ft depth base case, Case 1b.

Fig. 12- Reservoir pressure at breakthrough time of 1,461 days for the 6,200-ft depth base case, Case 1b.

Fig. 13- Gas production rate, water production rate, and bottom hole flowing pressure for the production well, 6,200-ft depth, Case 1b. Rates are for an 80-acre 5-spot pattern (40-acre well spacing).

Fig. 14- CO₂ injection rate, bottom hole injection pressure, and average field 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. 15- Cumulative distribution functions for CO₂ injected in the 4,000-ft and 6,200-ft depth base case scenarios.

Fig. 16- Cumulative distribution functions for CH₄ produced in the 4,000-ft and 6,200-ft depth base case scenarios.

Fig. 17- Cumulative distribution functions for water produced in the 4,000-ft and 6,200-ft depth base case scenarios.

Fig. 18- Cumulative distribution functions for breakthrough time in the 4,000-ft and 6,200-ft depth base case scenarios.

Fig. 19- Cumulative distribution functions for CO₂ injection, 6,200-ft depth coal reservoir scenario, for 40, 80, 160, and 240-ac well spacings in a 5-spot pattern.

Fig. 20- Cumulative distribution functions for CH₄ production, 6,200-ft depth coal reservoir scenario, for 40, 80, 160, and 240-ac well spacings in a 5-spot pattern.

Fig. 21- Cumulative distribution functions for water production, 6,200-ft depth coal reservoir scenario, for 40, 80, 160, and 240-ac well spacings in a 5-spot pattern.

Fig. 22- Cumulative distribution functions for breakthrough time, 6,200-ft depth coal reservoir scenario, for 40, 80, 160, and 240-ac well spacings in a 5-spot pattern.

Fig. 23- Cumulative distribution functions for CO₂ injection, 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.

Fig. 24- Cumulative distribution functions for CH₄ 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.

Fig. 25- Cumulative distribution functions for 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.

Fig. 26- Distribution of Net Present Values (NPV) for Case 1 (100% CO₂ Injection, 40-acre well spacing) at 4000 ft (Case 1a) and 6200 ft (Case 1b). Gas Price Range: \$7.00 - \$8.00 escalated 3%/year, Carbon Market Price: \$0.07 per Mscf CO₂; Discount Rate: 10%.

Fig. 27- Distribution of Net Present Values (NPV) for Case 2 (100% CO₂ Injection, 6200 ft) for 40-ac (Case 1b), 80-ac (Case 2a), 160-ac (Case 2b) and 240-ac (Case 2c) well spacings. Gas Price Range: \$7.00 - \$8.0000 escalated 3%/year, Carbon Market Price: \$0.07 per Mscf CO₂; Discount Rate: 10%.

Fig. 28- Sensitivity of mean Net Present Value (NPV) to carbon market price for 4000-ft and 6200-ft formation depths. Well Spacing: 40 acres, Gas Price Range: \$7.00 - \$8.00 escalated 3%/year, Discount Rate: 10%.

Fig. 29- Sensitivity of mean Net Present Value (NPV) to carbon market price for different well spacings. Formation Depth: 6200 ft, Gas Price Range: \$7.00 - \$8.00 escalated 3%/year, Discount Rate: 10%.