CO_2 Sequestration Potential of Texas Low-Rank Coals

Quarterly Technical Progress Report

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ABSTRACT

The objectives of this project are 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. The main objectives for this reporting period were to perform reservoir simulation and economic sensitivity studies to (1) determine the effects of injection gas composition, (2) determine the effects of injection rate, and (3) determine the effects of coal dewatering prior to CO_2 injection on CO_2 sequestration in the Lower Calvert Bluff Formation (LCB) of the Wilcox Group coals in east-central Texas.

To predict CO_2 sequestration and ECBM in LCB coal beds for these three sensitivity studies, we constructed a 5-spot pattern reservoir simulation model and selected reservoir parameters representative of a typical depth, approximately 6,200-ft, of potential LCB coalbed reservoirs in the focus area of East-Central Texas.

Simulation results of flue gas injection (13% CO_2 - 87% N_2) in an 80-acre 5-spot pattern (40-ac well spacing) indicate that LCB coals with average net thickness of 20 ft can store a median value of 0.46 Bcf of CO_2 at depths of 6,200 ft, with a median ECBM recovery of 0.94 Bcf and median CO_2 breakthrough time of 4,270 days (11.7 years). Simulation of 100% CO_2 injection in an 80-acre 5-spot pattern indicated that these same coals with average net thickness of 20 ft can store a median value of 1.75 Bcf of CO_2 at depths of 6,200 ft with a median ECBM recovery of 0.67 Bcf and median CO_2 breakthrough time of 1,650 days (4.5 years). Breakthrough was defined as the point when CO_2 comprised 5% of the production stream for all cases.

The injection rate sensitivity study for pure CO_2 injection in an 80-acre 5-spot pattern at 6,200-ft depth shows that total volumes of CO_2 sequestered and methane produced do not have significant sensitivity to injection rate. The main difference is in timing, with longer breakthrough times resulting as injection rate decreases. Breakthrough times for 80-acre patterns (40-acre well spacing) ranged from 670 days (1.8 years) to 7,240 days (19.8 years) for the reservoir parameters and well operating conditions investigated.

The dewatering sensitivity study for pure CO_2 injection in an 80-acre 5-spot pattern at 6,200-ft depth shows that total volumes of CO_2 sequestered and methane produced do not have significant sensitivity to dewatering prior to CO_2 injection. As time to start CO_2 injection increases, the time to reach breakthrough also 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.

Preliminary economic modeling results using a gas price of \$7 - \$8 per Mscf and CO_2 credits of \$1.33 per ton CO_2 indicate that injection of flue gas (87% N_2 - 13% CO_2) and 50% N_2 - 50% CO_2 are more economically viable than injecting 100% CO_2. Results also indicate that injection rate and duration and timing of dewatering prior to CO_2 injection have no significant effect on the economic viability of the project(s).

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INTRODUCTION

The objectives of this project are to evaluate the feasibility of carbon dioxide (CO_2) 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 reservoir simulation and economic studies of CO_2 sequestration and ECBM recovery in the Lower Calvert Bluff (LCB) coals in east-central Texas to investigate the effects of injection gas composition, injection rate, and dewatering of the coals prior to CO_2 injection.

EXPERIMENTAL

Reservoir Modeling Parameters

Simulation studies of Texas low-rank coals were conducted using coal properties and reservoir parameters obtained from literature and data collected during this study (TEES, Quarterly Technical Progress Report, Second Quarter 2005). Table 1 summarizes the model parameters selected to represent LCB reservoir coals at a depth of 6,200 ft.

CO_2, CH_4, and N_2 sorption isotherms of LCB coal samples from approximately 6,200-ft depth in an Anadarko Petroleum Corporation (APC) cooperative well were measured in the laboratory (Fig. 1; RMB Earth Science Consultants, 2005). Langmuir volume and pressure on an as-received basis are 961.9 scf/ton and 697.5 psia, respectively, for CO_2, 363.6 scf/ton and 608.5 psia for CH_4, and 166.1 scf/ton and 2060.7 psia for N_2. These isotherm data were used to model variable injected gas composition.

A comparison of CO_2/CH_4 sorption capacity ratios for coal samples from two surface mines and 12 wells is presented in Fig. 2. Vitrinite reflectance ranges from 0.33% to 1.40% for coals from Gulf Coast, Powder River, Forest City, Illinois, N. Appalachian, Cherokee, Piceance, Warrior, and San Juan Basins (Reeves, *et al.*, 2005). For the 6,200-ft depth Wilcox coal sample, CO_2/CH_4 ratio is approximately 2.5.

A comparison of N_2/CH_4 sorption capacity ratios for coal samples from one surface mine and 11 wells is presented in Fig. 3. Vitrinite reflectance ranges from 0.36% to 1.40% for coals from Gulf Coast, Powder River, Forest City, Illinois, N. Appalachian, Cherokee, Piceance, Warrior, and San Juan Basins (Reeves, *et al.*, 2005). For the 6,200-ft depth Wilcox coal sample, N_2/CH_4 ratio is approximately 0.32 at reservoir pressure of 2,680 psia, and decreases as pressure declines.

CMG GEM, a compositional reservoir simulator, was used in conjunction with a decision analysis tool, @Risk, for probabilistic reservoir modeling of variable injected gas composition. Deterministic modeling was performed to study the effects of injection rate and coal dewatering on CO_2 sequestration and ECBM production potential.

RESULTS AND DISCUSSION

Reservoir Modeling

Using the parameters described above, we built a reservoir model that is one-eighth of a 5-spot to run deterministic and probabilistic reservoir simulations. The predicted volumes of CO_2 sequestered and CH_4 produced are scaled to a full pattern in this report. For this research, we ran 5 separate simulation investigations, or cases. These cases are (1) CO_2 sequestration base case scenarios of 100% CO_2 injection in 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. Results from Cases 1 and 2 were reported in the previous quarter. This quarter, we report results from Cases 3, 4 and 5.

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

Case 3: Effects of injection gas composition on CO_2 sequestration and ECBM

To determine the effects of injection gas composition on performance of coalbed reservoirs during CO_2 sequestration and ECMB production in the Wilcox coals in east-central Texas, we conducted probabilistic simulations, each consisting of 1,000 iterations, modeling simultaneous injection of 50% CO_2-50% N_2 (Case 3a), flue gas (13% CO_2-87% N_2, Case 3b), and production of CH_4 under the base case operating conditions, in an 80-acre 5-spot pattern (40-acre well spacing) for the 6,200-ft depth base case. Injection of 100% CO_2 was reported previously as Case 1b. The results of the modeling studies for the 6,200-ft depth coal seam scenario with variable injection gas composition are shown in Figs. 4-32.

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. The high recovery efficiencies result from using a termination criterion of 5% CO_2 mole fraction in the produced gas 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. Figs. 4-7, 11-15, and 19-23 show colorfill maps of various reservoir properties at breakthrough, i.e., the time at which CO_2 comprises 5% mole fraction of the produced gas. Figs. 8-10, 16-18, and 24-26 show production and injection rates and pressure profiles.

The probabilistic simulation results indicate that variable injection gas composition, as well as coal properties and reservoir parameters, contribute significantly to uncertainties in potential performance of CO_2/N_2 injection in LCB coal beds in east-central Texas. Figs. 27-32 show cumulative distribution functions for CO_2 sequestered, CH_4 produced, water produced, N_2 produced, N_2 injected, and breakthrough times for Cases 1b, 3a, and 3b.

Simulation results of 100% CO_2 injection (Case 1b) 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 at depths of 6,200 ft with an ECBM recovery of 0.48 to 0.85 Bcf, water produced of 54 to 94 Mstb, and CO_2 breakthrough time of 970 to 2,430 days. All ranges represent 80% confidence intervals (P_{10} to P_{90}).

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).

These results indicate that CO_2 sequestration and ECMB production are technically feasible in east-central Texas LCB 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).

Case 4: Effects of injection rate on CO_2 sequestration and ECBM

To determine the effects of injection rate on performance of coalbed reservoirs during 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 reduced pressure drop between injector and producer (Table 1).

Case 1b reported results of the 40-ac well spacing case with the producer well controlled in the model by constant bottom hole flowing pressure of 40 psia and the injector well controlled by a bottom hole injection pressure of 3,625 psia. A modified case with the producer well controlled by constant bottom hole flowing pressure of 500 psia and the injector well controlled by a bottom hole injection pressure of 3,625 psia was selected to model the effect of variable injection rate. Wells are secondarily controlled in the model by maximum gas production and injection rates of 3,530 Mcf/D. Figs. 33-35 show cumulative gas production and injection and average reservoir pressure for the most-likely, least-favorable, and most-favorable sets of reservoir parameters under these two well operating conditions.

There are no significant differences in the cumulative volumes of CH_4 produced or CO_2 injected due to the lower injection rate. The difference is represented in CO_2 breakthrough time, with longer breakthrough times as injection rates decrease. Breakthrough times for 80-acre patterns (40-acre well spacings) 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. Reduced pressure drop between injector and producer affects the gas rate profiles and breakthrough times. This impact will be evaluated in the economic modeling section.

Case 5: Effects of coal dewatering on CO_2 sequestration and ECBM

To determine the effects of dewatering the coals prior to CO_2 injection on performance of coalbed reservoirs during CO_2 sequestration and ECMB production in the Wilcox coals in east-central Texas, we conducted deterministic simulation modeling studies of 100% CO_2 gas 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, we modified Case 1b, starting the CO_2 injection after 6 and 18 months of initial production. We performed deterministic sensitivity analysis for the most-likely, least-favorable, and most-favorable reservoir parameters. Figs. 36 and 37 show cumulative gas production and injection for the 6,200-ft depth reservoir, dewatering the coals 0, 6 and 18 months prior to CO_2 injection. Figs. 38-41 show 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.

The dewatering sensitivity study for a 5-spot pattern model at 6,200-ft depth with pure CO_2 injection 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 spacings) ranged from 850 days (2.3 years) to 5,380 days (14.7 years) for the reservoir parameters and well injection/production schedules investigated. This impact will be evaluated in the economic modeling section.

Economic Modeling

Economic analysis was conducted on Cases 3, 4 and 5 to study the effects of flue gas composition, injection rate and dewatering prior to CO_2 injection. The economic analysis spreadsheet previously developed and described was modified for these analyses.

Case 3: Effects of injection gas composition on CO_2 sequestration and ECBM

The additional injection gas compositions investigated were 87% N_2 -13% CO_2 (Case 3a) and 50% N_2 -50% CO_2 (Case 3b). Project data used in the economic analyses of Cases 3a and 3b, as well as Case 1b, are summarized in Table 2. Economic parameters are summarized in Table 3. 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 considered in the analyses of Cases 3a and 3b are given in Tables 4 and 5, respectively (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 CO_2 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 CO_2 from the power plant to the sequestration site.

3. Pipelines and wells are straight-line depreciated over the duration of the project.

4. Net CO_2 sequestration volumes are used to compute sequestration credits. Net sequestered volumes are assumed to be 70% of the total sequestered volume. Revenues from CO_2 sequestration credits are incorporated into the economic model.

5. The economic analysis is conducted for a maximum of 30 years, even though some of the individual realizations in the probabilistic analysis go beyond 30 years.

6. For Case 3a, the flue gas emitted from the plant is assumed to be at the desired 87% N_2 - 13% CO_2 composition. The cost, including treatment and compression, for delivery to the field is assumed to be \$0.50 per Mscf (Reeves, *et al.*, 2004). Nitrogen rejection is assumed to be \$0.50 per Mscf wellstream (Reeves, *et al.*, 2004). The N_2 and CH_4 production volumes are combined to obtain the wellstream volume, which provides the basis for the cost.

7. For Case 3b, the cost to deliver a 50% N_2 -50% CO_2 composition of injection gas to the field, which includes treatment, compression, initial capture and re-combination with original flue gas to produce the required concentration, is assumed to be \$0.50 -\$1.00 (uniform distribution), which is between the costs for delivery of 100% CO_2 and 87% N_2 -13% CO_2. Nitrogen rejection is assumed to be \$0.50/Mscf wellstream as in Case 3a.

Distributions of net present value (NPV) for 100% CO_2, 87% N_2 -13% CO_2 and 50% N_2 -50% CO_2 injection gas are compared in Fig. 42. It appears from Fig. 42 that injecting 100% CO_2 is the least economically viable and that injecting 50% N_2 -50% CO_2 is the most economically viable scenario. CO_2 capture costs, which are high in Case 1b and reduced in Cases 3a and 3b, appear to be responsible for most of the difference in economic performance between the 100% CO_2 injection case and the cases with increased N_2 content in the injection gas.

The 50% N_2 -50% CO_2 case (3a) also appears to be more economically viable than the 87% N_2 -13% CO_2 case (3b). As N_2 content in the injection gas increases, CO_2 capture costs decrease and methane production, and thus revenue, increases. However, if N_2 content gets too high, as for flue gas in Case 3b, N_2 rejection costs associated with excessive N_2 production hurt the economics. We believe Case 3a, 50% N_2 -50% CO_2, is the best case of the three because it has the best balance of reduced CO_2 capture costs, increased revenue from methane production, and lower N_2 rejection costs.

Case 4: Effects of injection rate on CO_2 sequestration and ECBM

Project data and economic parameters used in the analysis of Case 4, effect of injection rate, are contained in Tables 2 and 3. Costs are presented in Table 6, and represent costs for 100% CO_2 injection. Economic results are presented in Tables 7 and 8. It appears from Tables 7 and 8 that changing the injection rate produces no significant effect on the NPV and NPV/I economic indicators.

Case 5: Effects of coal dewatering on CO_2 Sequestration and ECBM

Project data and economic parameters used in the analysis of Case 4, effect of dewatering prior to CO_2 injection, are contained in Tables 2 and 3. Costs are presented in Table 6, and represent costs for 100% CO_2 injection. Economic results are presented in Tables 9, 10 and 11. It appears that the duration of dewatering prior to CO_2 injection produces no significant effect on the NPV and NPV/I economic outcomes.

CONCLUSIONS

The average volumes of CO_2 that may be sequestered in LCB coals with average net thickness of 20 ft in east-central Texas for 100% CO_2, 50% CO_2-50% N_2, and 13% CO_2-87% N_2 injection gas compositions are 1.75, 1.19 and 0.46 Bcf per 80-acre 5-spot pattern, respectively. ECBM recovery is estimated to be 0.67, 0.86 and 0.94 Bcf per 80-acre pattern, respectively. Project lives are 1,650 days (4.5 years), 2,750 days (7.5 years), and 4,270 days (11.7 years), respectively.

Economic modeling indicates that NPV ranges from ($850,026) to $659,817 for Case 3a (87% N_2-13% CO_2) and from ($930,625) to $1,045,561 for Case 3b (50% N_2–50% CO_2). These NPV values are significantly larger than those for the 100% CO_2 injection case, which ranged from ($1,787,541) to $187,010. The best economic performance is obtained with a 50% N_2–50% CO_2 injection gas composition.

There were no significant effects of injection rate on cumulative volumes of CH_4 produced or CO_2 injected in LCB coals in east-central Texas. Longer breakthrough times were observed with lower injection rates. 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), 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 investigated, respectively. The effects of injection rate on economic performance were minimal for the rates investigated in this study.

No significant sensitivity of total volumes of CO_2 sequestered or methane produced was observed as a result of dewatering the coals prior to starting pure CO_2 injection, for a 5-spot pattern model at 6,200-ft depth. The main difference is seen in time to CO_2 breakthrough, with longer breakthrough times observed as dewatering time 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. The effects of dewatering prior to CO_2 injection on economic performance were minimal for the cases investigated in this study.

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Table 1 – Summary of Reservoir Model Parameters

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
Uncertain Reservoir 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
Base Case 6,200-ft depth coal seam scenario	
Parameter	**Value**
Depth	6,200 feet
Initial Reservoir Pressure	2,680 psia
Reservoir Temperature	170 ^oF
Langmuir Isotherm Parameters (5) :	
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
Injection Rate Case:	
Operating Conditions - 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) Triangular Distribution
(2) Log-Normal Distribution
(3) Triangular Distribution
(4) Triangular Distribution
(5) As Received Basis

Table 2 - Project Data Used in Economic Analysis

Depth of reservoir (ft)	6,200
Well spacing (ac)	40
Area of 5-spot pattern (ac)	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

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Table 3 - Economic Parameters

Parameters			**Type of distribution**
Federal Tax Rate	35	%	
Discount Rate	10	%	
Gas Price	\$7.00, \$7.50, \$8.00	per Mscf CH_4	Triangular
Gas Price Escalation	3	% per yr	
Texas Severance Tax	7.5	%	
Net Revenue Interest	75 -80	%	Uniform
Carbon Market Price	\$0.07	per Mscf CO_2	

Table 4 – Costs for Case 3a (87% N_2 - 13% CO_2; 6200 ft, 40-ac well spacing)

Item	**Cost**		**Distribution type**
Lease Acquisition Costs	\$175.00	per acre	uniform distribution
FLUE GAS pipeline CAPEX	\$0.67	per inch-mile	
FLUE GAS pipeline OPEX	\$0.50	per Mscf FLUE GAS	
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 (Nitrogen Rejection)	\$0.50	per Mscf Wellstream	
Produced Water disposal	\$0.40	per barrel	
Safety, Monitoring and Verification	\$10,000.00	per injector per year	

***** Cost allocated to a single 80-ac pattern

Table 5 - Costs for Case 3b (50% N_2 - 50% CO_2; 6200 ft, 40-ac well spacing)

Item	Cost		Distribution type
Lease Acquisition Costs	$175.00	per acre	uniform distribution
FLUE GAS pipeline CAPEX	$53.33	per inch-mile	
FLUE GAS pipeline OPEX	$0.75	per Mscf FLUE GAS	
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 (Nitrogen Rejection)	$0.50	per Mscf Wellstream	
Produced Water disposal	$0.40	per barrel	
Safety, Monitoring and Verification	$10,000.00	per injector per year	

***** Cost allocated to a single 80-ac pattern

Table 6 - Costs for Economic Analysis of Cases 4 and 5

Item	Cost	
Lease Acquisition Costs	$175.00	per acre
CO_2 capture cost	$1.50	per Mscf
CO_2 pipeline CAPEX	$26,666.67	per inch-mile
CO_2 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	$0.00	
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

Table 7 - Effect of Injection Rate on Economic Performance (100% CO_2, 6200 ft; FBHP = 40 psi, IBHP = 3625 psi)

Scenario		NPV	NPV/I
1	Least favorable	($1,362,343.24)	-1.05
2	Most likely	($884,373.30)	-0.68
3	Most favorable	$61,983.42	0.05

Table 8 - Effect of Injection Rate on Economic Performance (100% CO_2, 6200 ft; FBHP = 500 psi, IBHP = 3165 psi)

Scenario		NPV	NPV/I
1	Least favorable	($1,391,842.79)	-1.08
2	Most likely	($818,002.64)	-0.63
3	Most favorable	($163,342.29)	-0.13

Table 9 – Effect of Dewatering on Economic Performance (Simultaneous injection and production, 100% CO_2, 6200 ft)

Scenario		NPV	NPV/I
1	Least favorable	($1,362,343.24)	-1.05
2	Most likely	($884,373.30)	-0.68
3	Most favorable	$61,983.42	0.05

Table 10– Effect of Dewatering on Economic Performance (Dewatering for 6 months, 100% CO_2, 6200 ft)

Scenario		NPV	NPV/I
1	Least favorable	($1,370,576.80)	-1.06
2	Most likely	($909,465.81)	-0.70
3	Most favorable	$15,059.82	0.01

Table 11 – Effect of Dewatering on Economic Performance (Dewatering for 18 months, 100% CO_2, 6200 ft)

Scenario		NPV	NPV/I
1	Least favorable	($1,363,333.04)	-1.06
2	Most likely	($874,113.29)	-0.68
3	Most favorable	$21,485.14	0.02

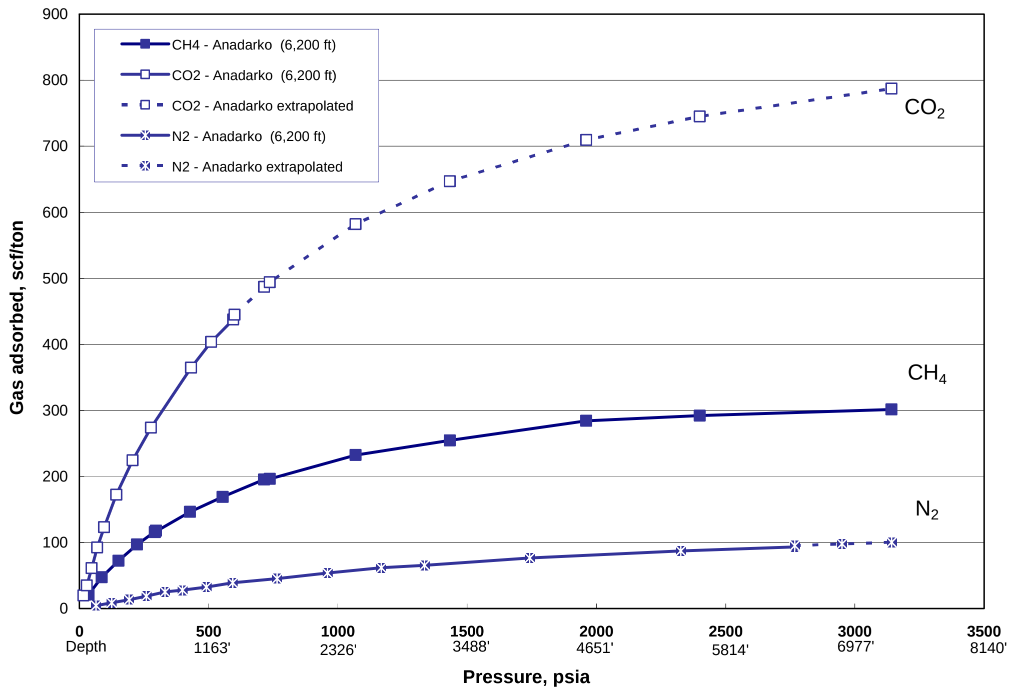

Fig. 1- Methane, carbon dioxide, and nitrogen sorption isotherms for use as input in reservoir simulation to represent gas adsorption/desorption isotherm behavior in coal beds at approximately 6,200-ft depth in the Wilcox Group, east-central Texas.

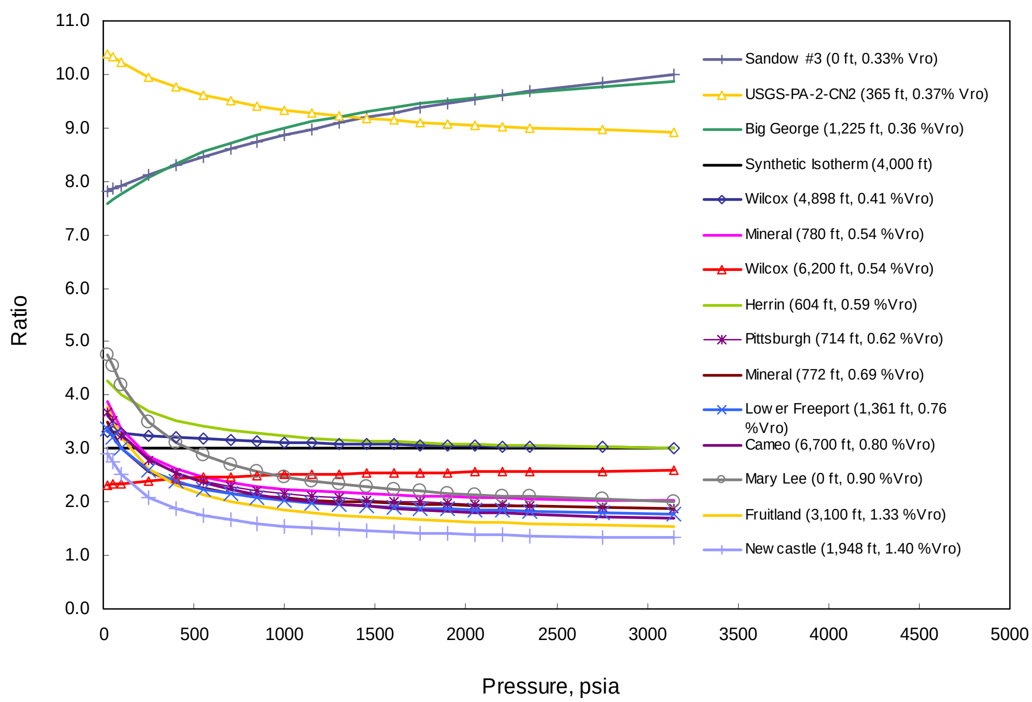

Fig. 2- Carbon dioxide/methane sorption capacity ratios for coal samples from two surface mines and 12 wells. Vitrinite reflectance ranges from 0.33% to 1.40% for coals from Gulf Coast, Powder River, Forest City, Illinois, N. Appalachian, Cherokee, Piceance, Warrior, and San Juan Basins. (Reeves, S. *et al.*, 2005). For the 6,200-ft depth coal seam scenario, CO_2:CH_4 ratio is approximately 2.5:1.

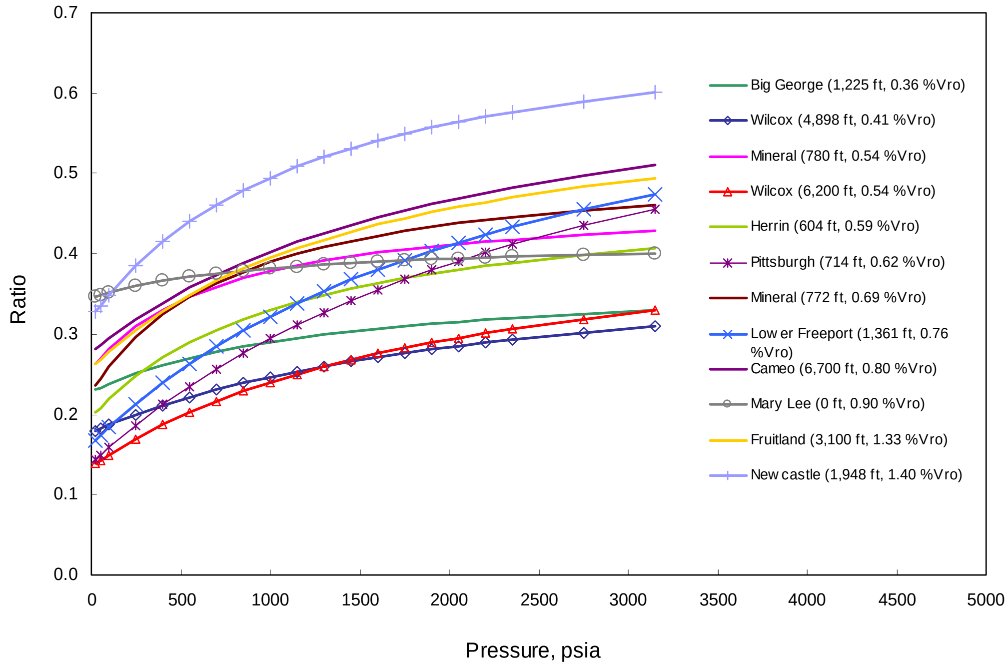

Fig. 3- Nitrogen/methane sorption capacity ratios for coal samples from one surface mine and 11 wells. Vitrinite reflectance ranges from 0.36% to 1.40% for coals from Gulf Coast, Powder River, Forest City, Illinois, N. Appalachian, Cherokee, Piceance, Warrior, and San Juan Basins. (Reeves, S. *et al.*, 2005). For the 6,200-ft depth coal seam scenario, N_2:CH_4 ratio is 0.32:1 at reservoir pressure of 2,680 psia, and decreases as pressure declines.

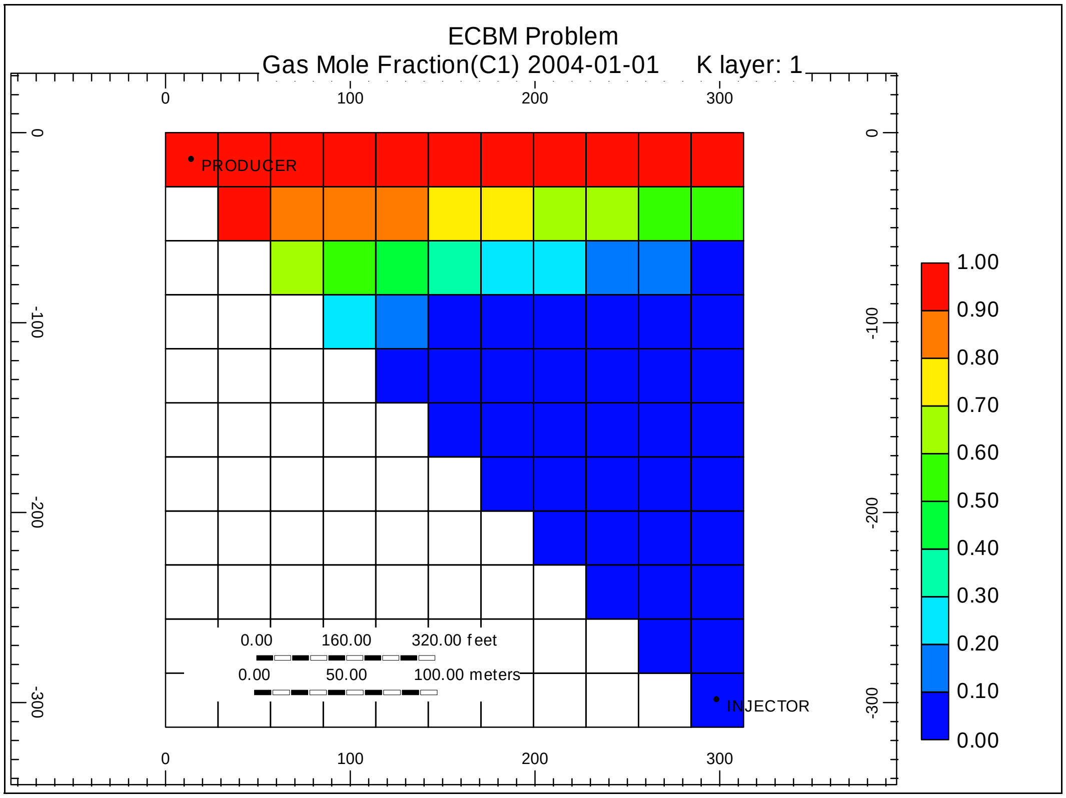

Fig. 4- Methane gas mole fraction at breakthrough time of 1,461 days for the 6,200-ft depth base case, Case 1b (100% CO_2 injection).

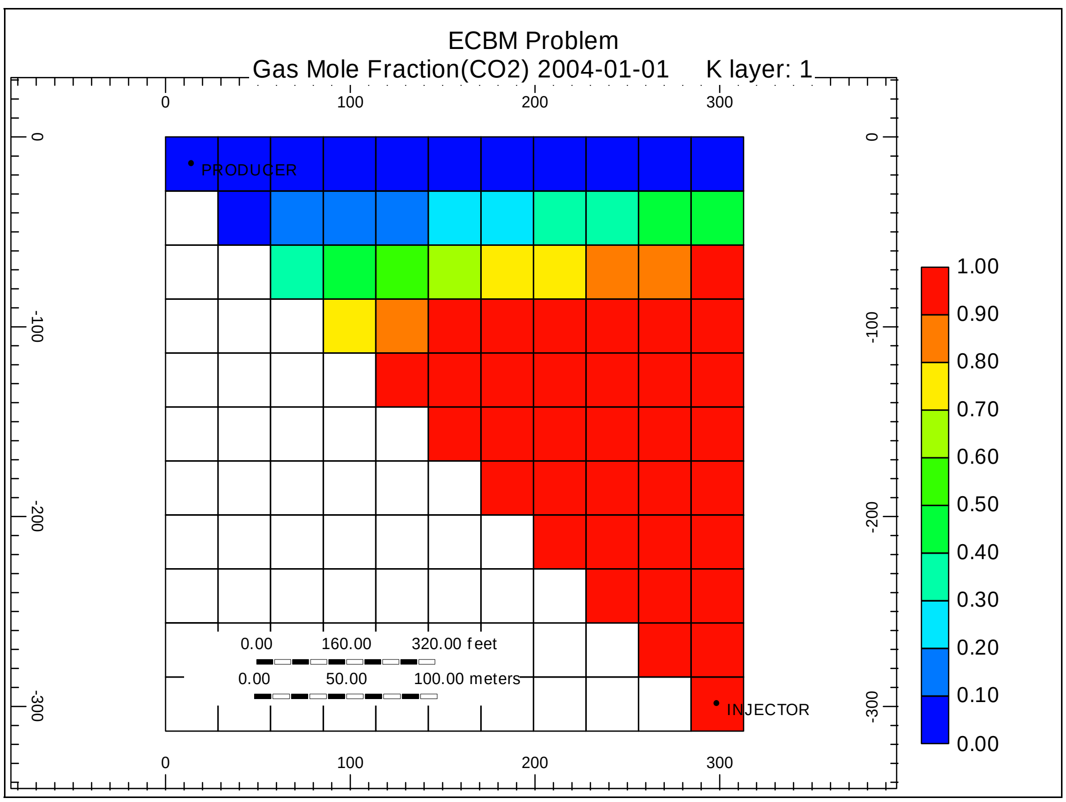

Fig. 5- CO_2 gas mole fraction at breakthrough time of 1,461 days for the 6,200-ft depth base case, Case 1b (100% CO_2 injection).

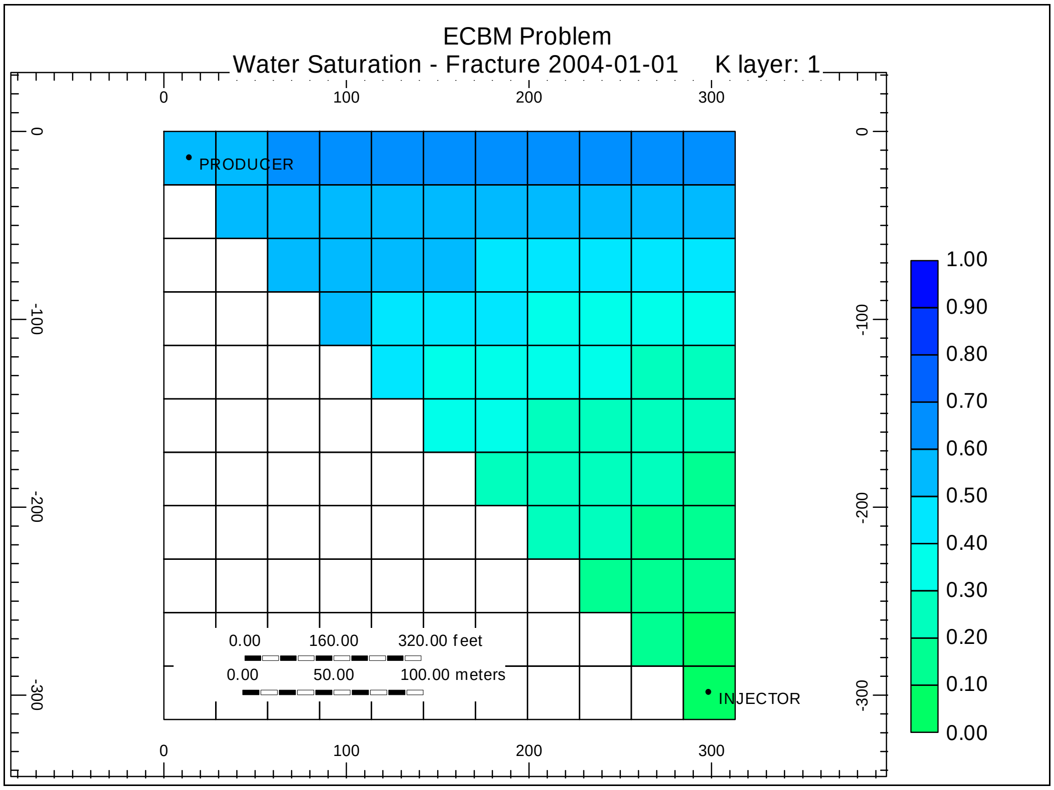

Fig. 6- Water saturation in the fracture system at breakthrough time of 1,461 days for the 6,200-ft depth base case, Case 1b (100% CO_2 injection).

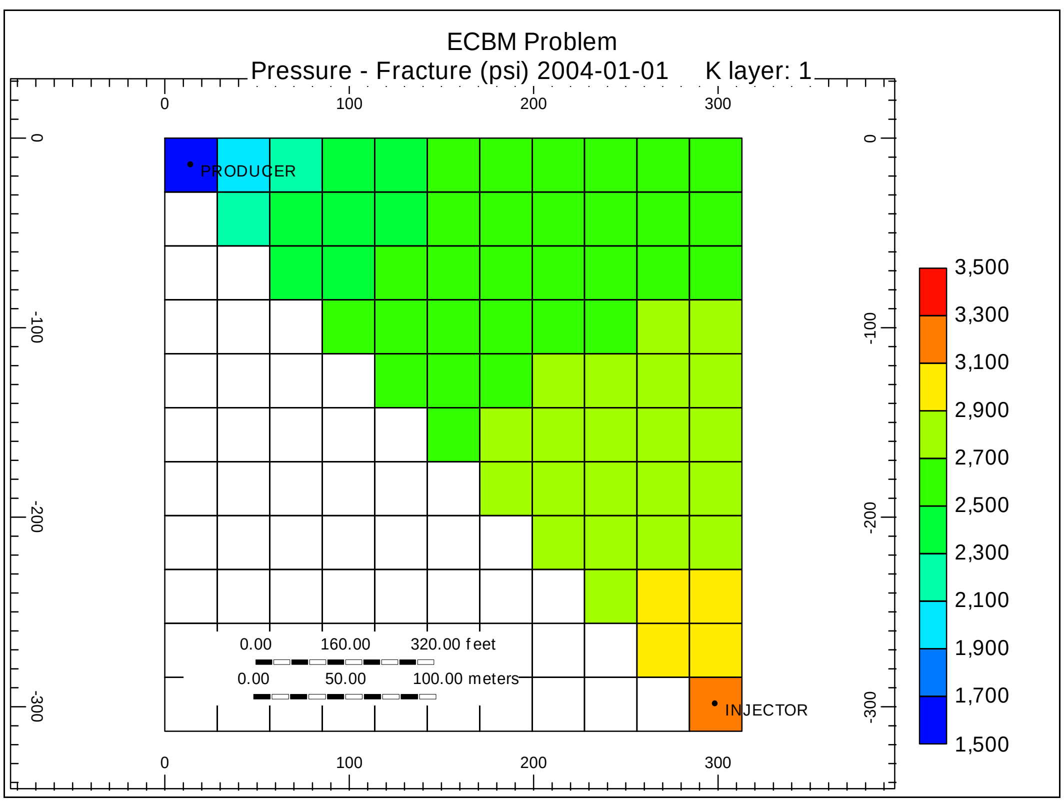

Fig. 7- Reservoir pressure at breakthrough time of 1,461 days for the 6,200-ft depth base case, Case 1b (100% CO_2 injection).

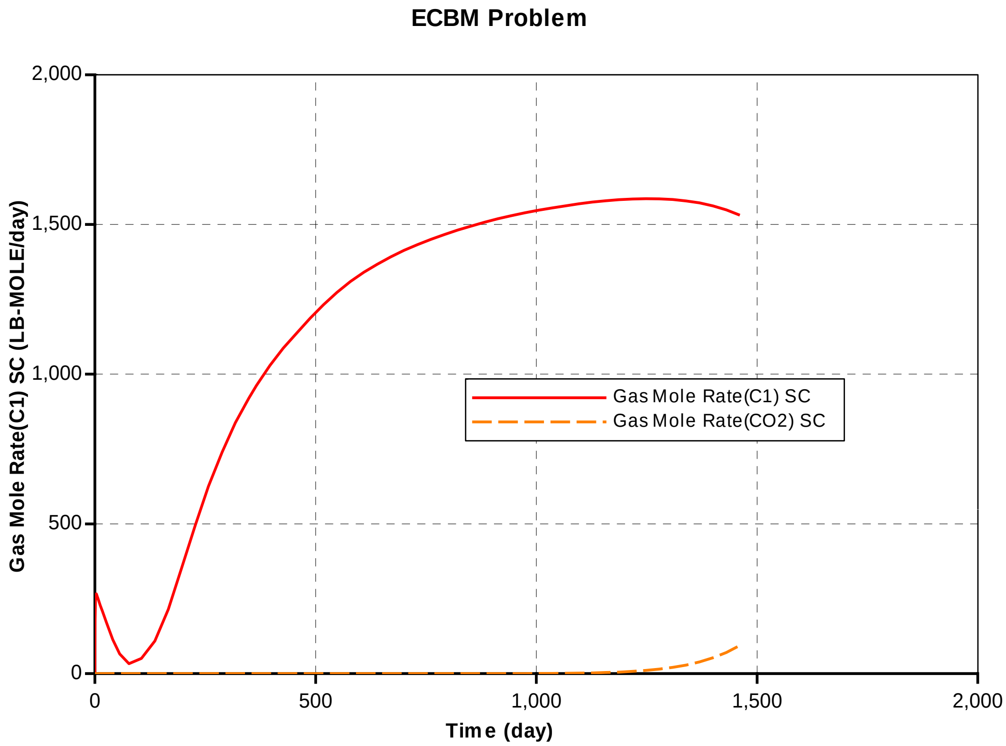

Fig. 8- Methane and CO_2 gas mole production rates, 6,200-ft depth, Case 1b (100% CO_2 injection). Mole rates are for an 80-acre 5-spot pattern (40-acre well spacing).

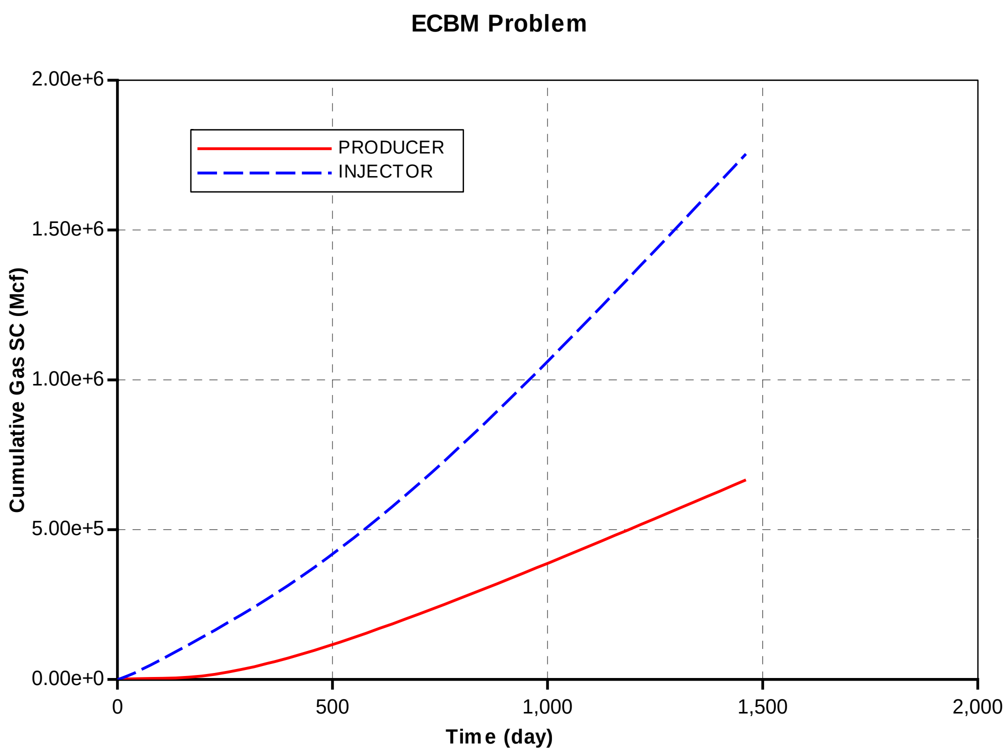

Fig. 9- Cumulative gas production and injection, 6,200-ft depth, Case 1b (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

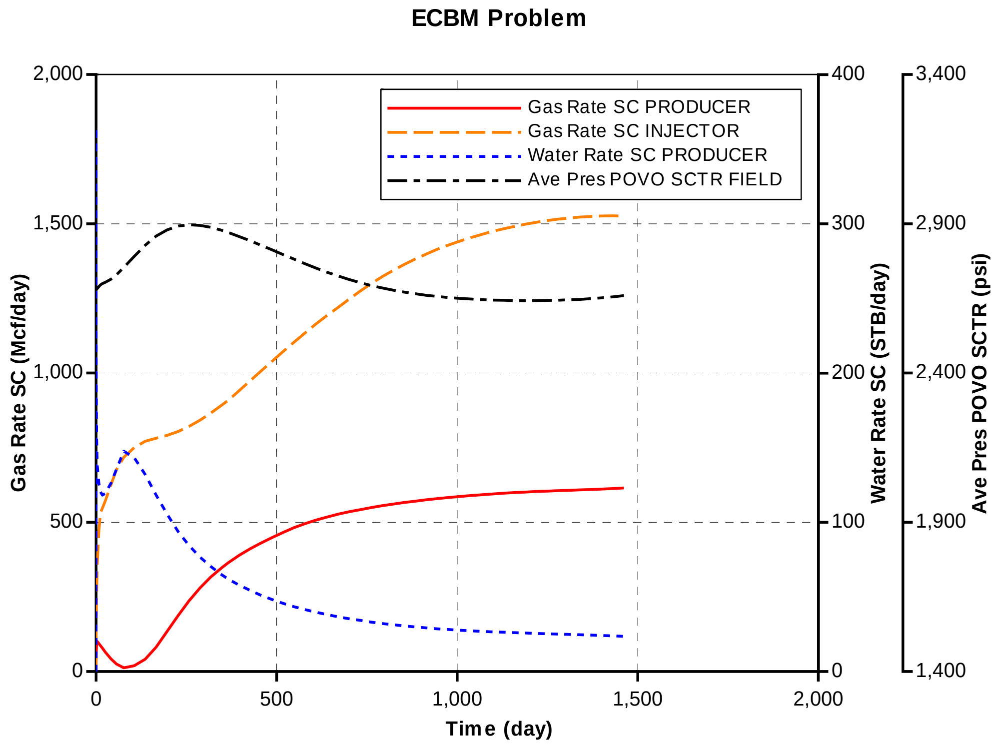

Fig. 10- Gas production and injection rates, water production rate, and average field pressure for the 6,200-ft depth base case, Case 1b (100% CO_2 injection). Rates are for an 80-acre 5-spot pattern (40-acre well spacing).

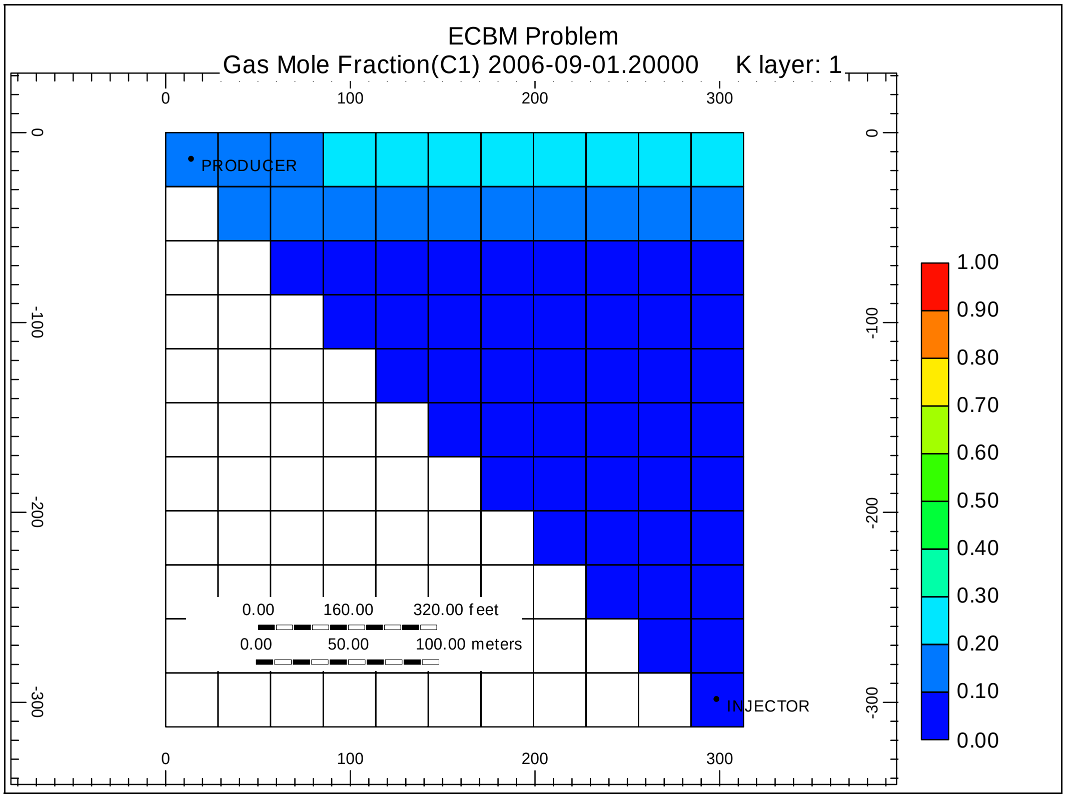

Fig. 11- Methane gas mole fraction at breakthrough time of 2,435 days for the 6,200-ft depth reservoir scenario, Case 3a (50% CO_2 – 50% N_2 injection).

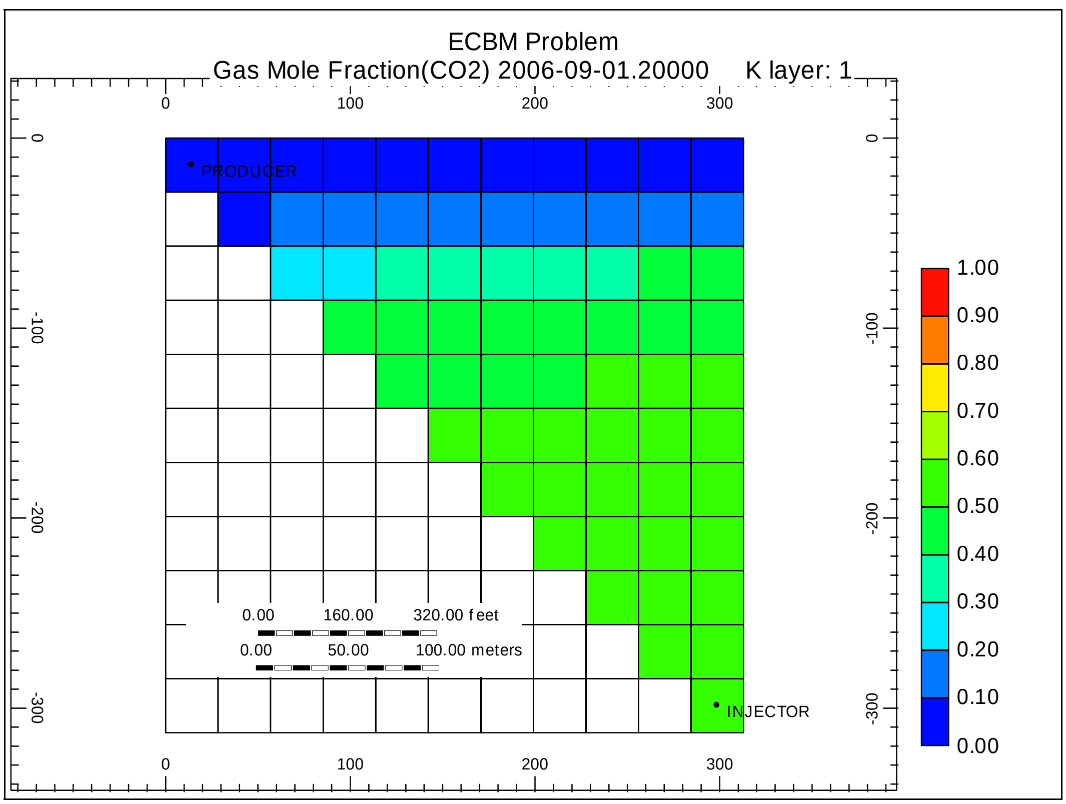

Fig. 12- CO_2 gas mole fraction at breakthrough time of 2,435 days for the 6,200-ft depth reservoir scenario, Case 3a (50% CO_2 – 50% N_2 injection).

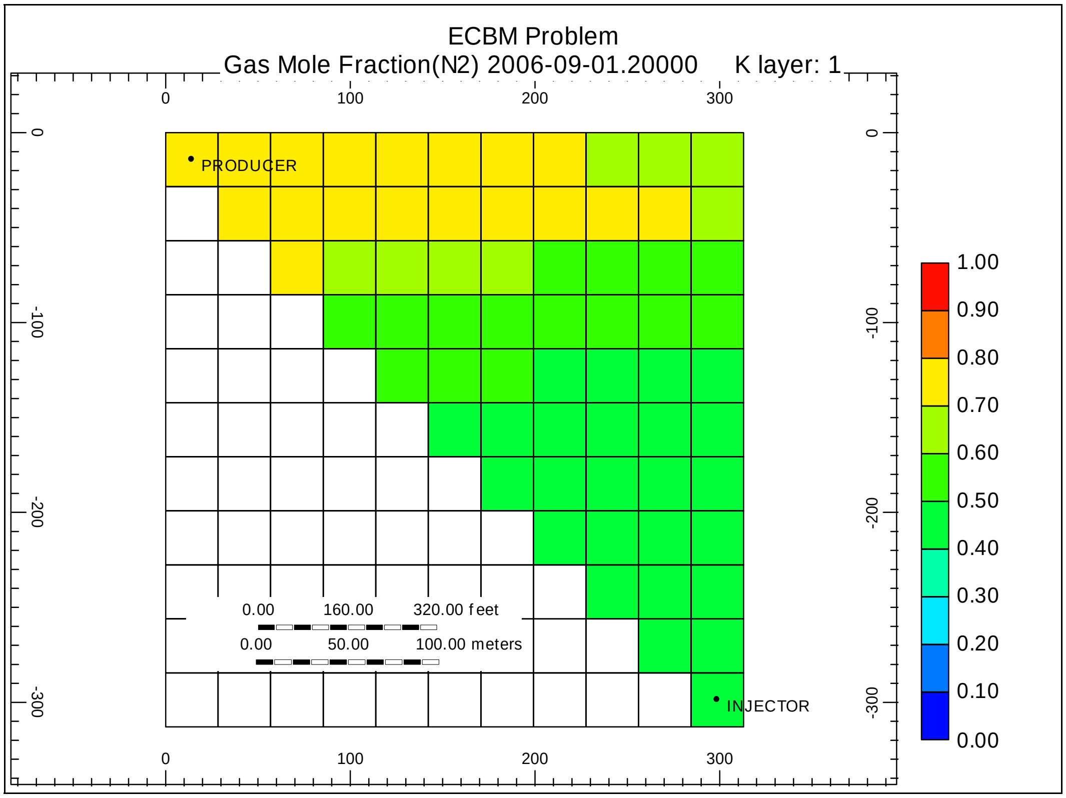

Fig. 13- N_2 gas mole fraction at breakthrough time of 2,435 days for the 6,200-ft depth reservoir scenario, Case 3a (50% CO_2 – 50% N_2 injection).

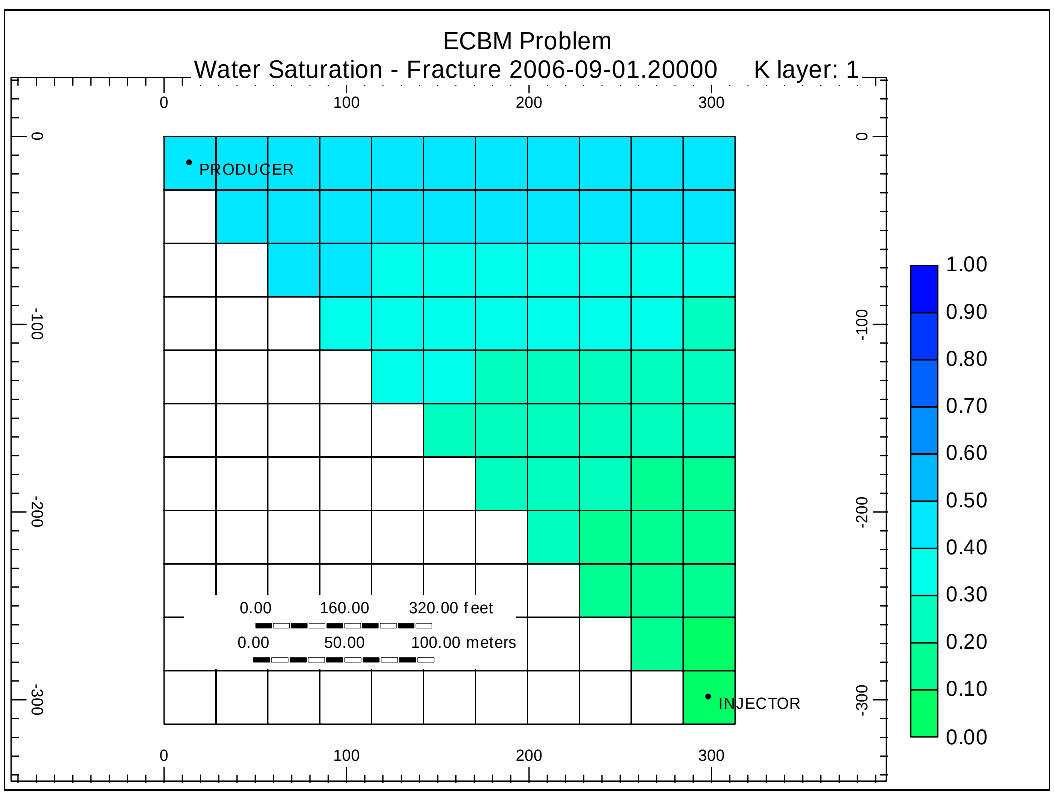

Fig. 14- Water saturation in the fracture system at breakthrough time of 2,435 days for the 6,200-ft depth reservoir scenario, Case 3a (50% CO_2 – 50% N_2 injection).

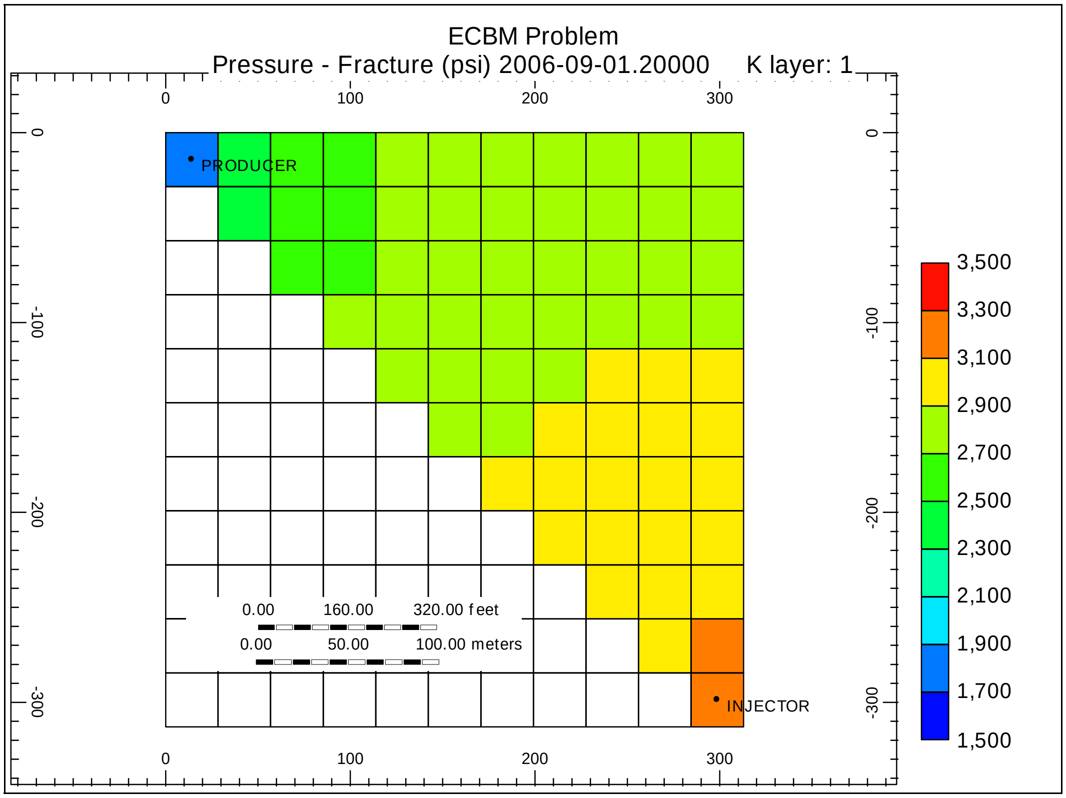

Fig. 15- Reservoir pressure at breakthrough time of 2,435 days for the 6,200-ft depth reservoir scenario, Case 3a (50% CO_2 – 50% N_2 injection).

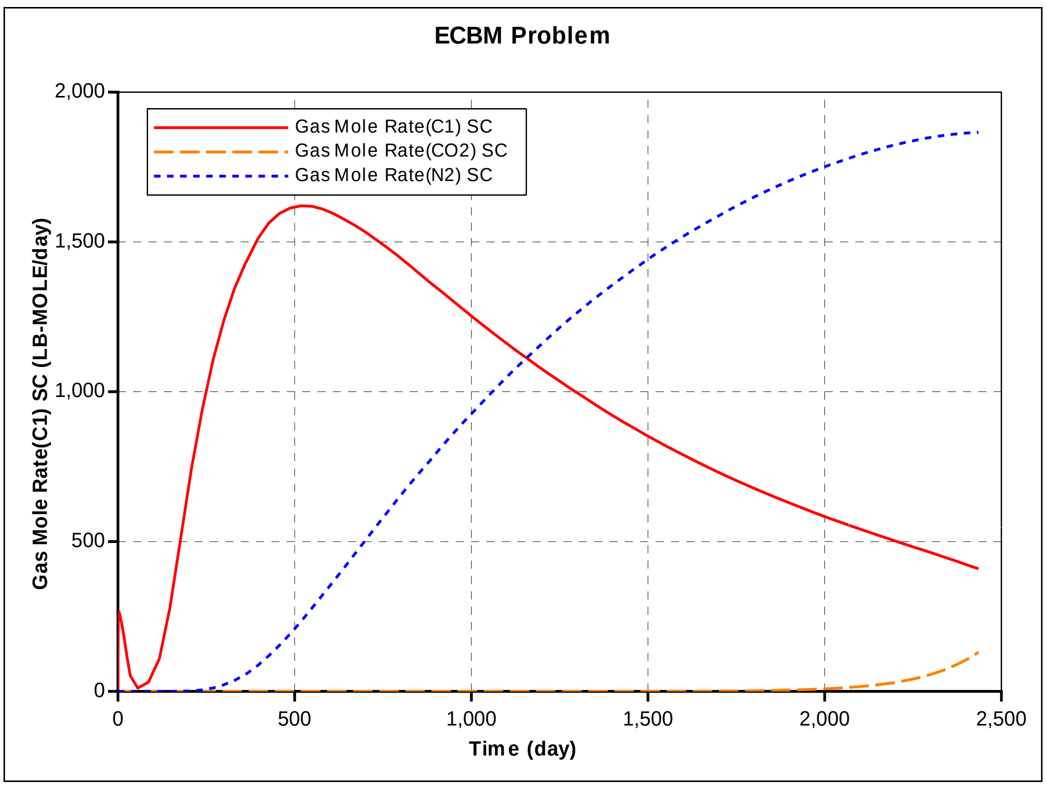

Fig. 16- Methane, CO_2, and N_2 gas mole production rates for the 6,200-ft depth reservoir scenario, Case 3a (50% CO_2 – 50% N_2 injection). Mole rates are for an 80-acre 5-spot pattern (40-acre well spacing).

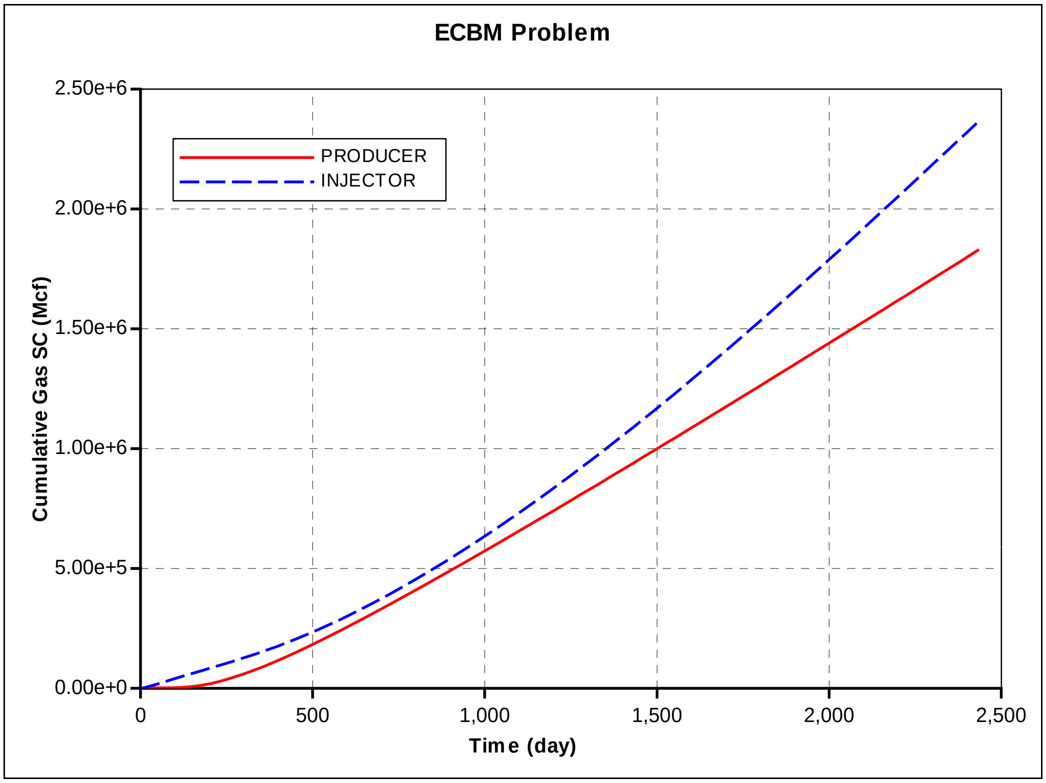

Fig. 17- Cumulative gas production and injection for the 6,200-ft depth reservoir scenario, Case 3a (50% CO_2 – 50% N_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

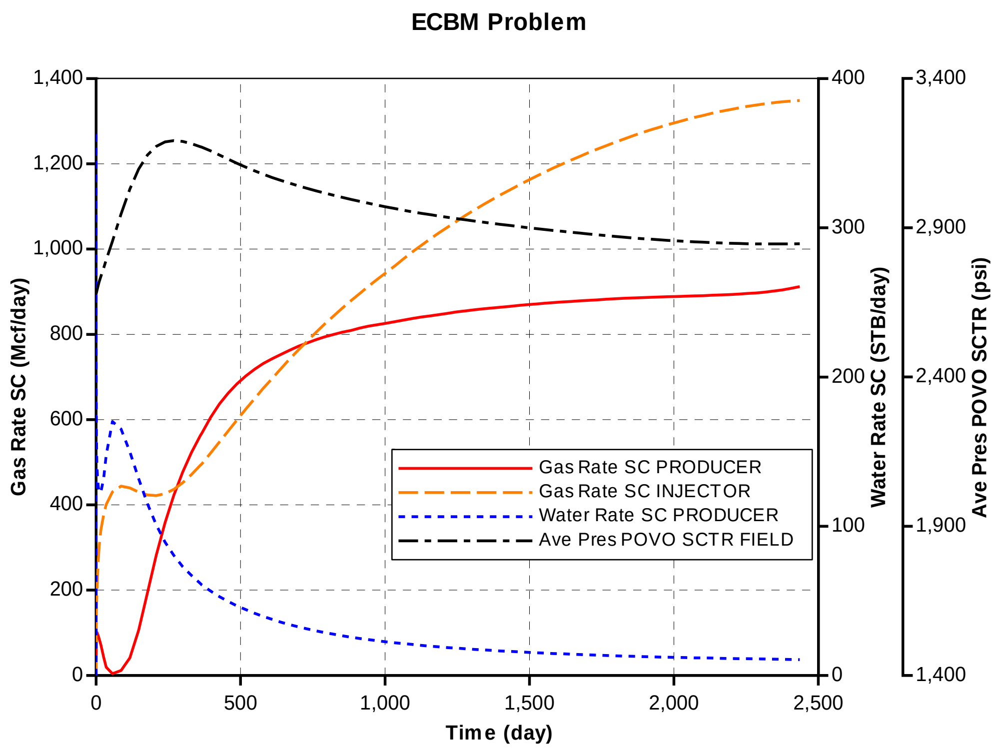

Fig. 18- Gas production and injection rates, water production rate, and average field pressure for the 6,200-ft depth, Case 3a (50% CO_2 – 50% N_2 injection). Rates are for an 80-acre 5-spot pattern (40-acre well spacing).

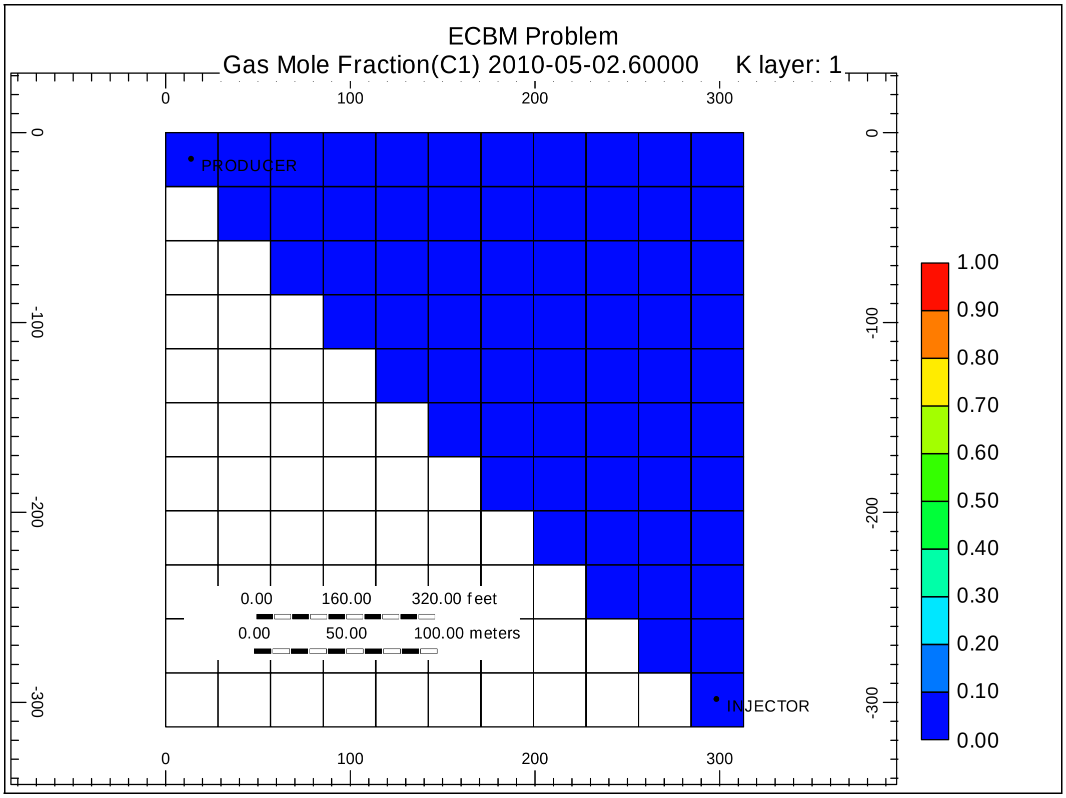

Fig. 19- Methane gas mole fraction at breakthrough time of 3,775 days for the 6,200-ft depth reservoir scenario, Case 3b (13% CO_2 – 87% N_2 injection).

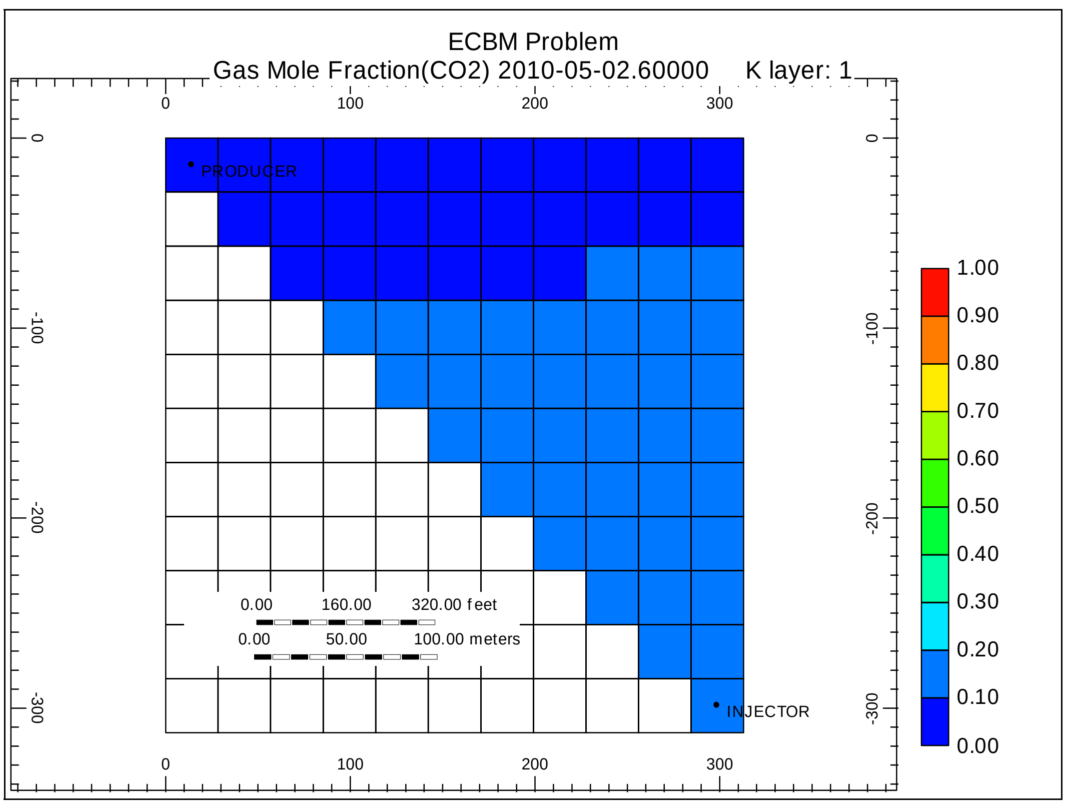

Fig. 20- CO_2 gas mole fraction at breakthrough time of 3,775 days for the 6,200-ft depth reservoir scenario, Case 3b (13% CO_2 – 87% N_2 injection).

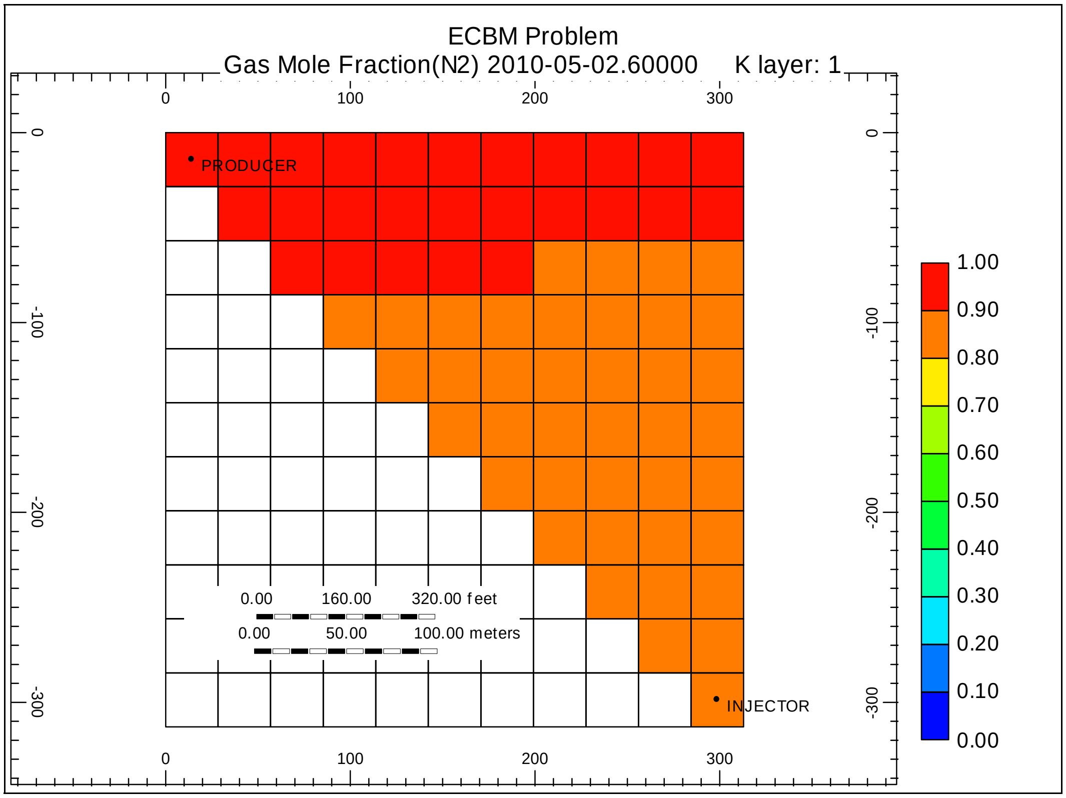

Fig. 21- N_2 gas mole fraction at breakthrough time of 3,775 days for the 6,200-ft depth reservoir scenario, Case 3b (13% CO_2 – 87% N_2 injection).

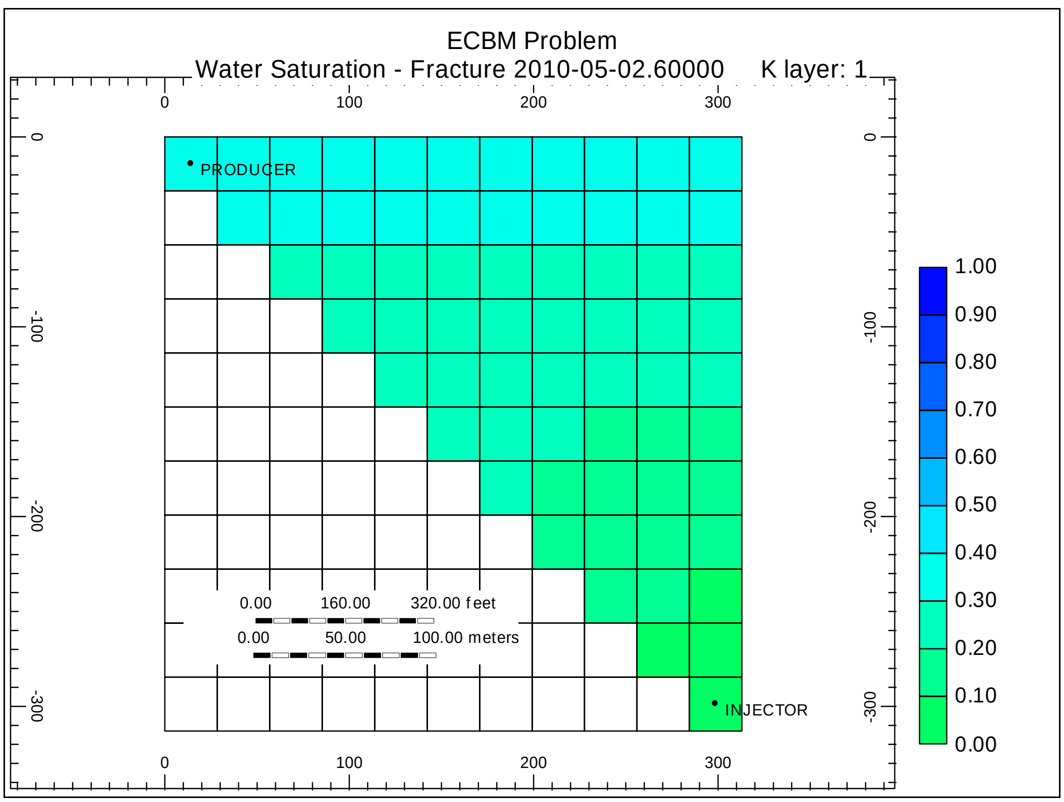

Fig. 22- Water saturation in the fracture system at breakthrough time of 3,775 days for the 6,200-ft depth reservoir scenario, Case 3b (13% CO_2 – 87% N_2 injection).

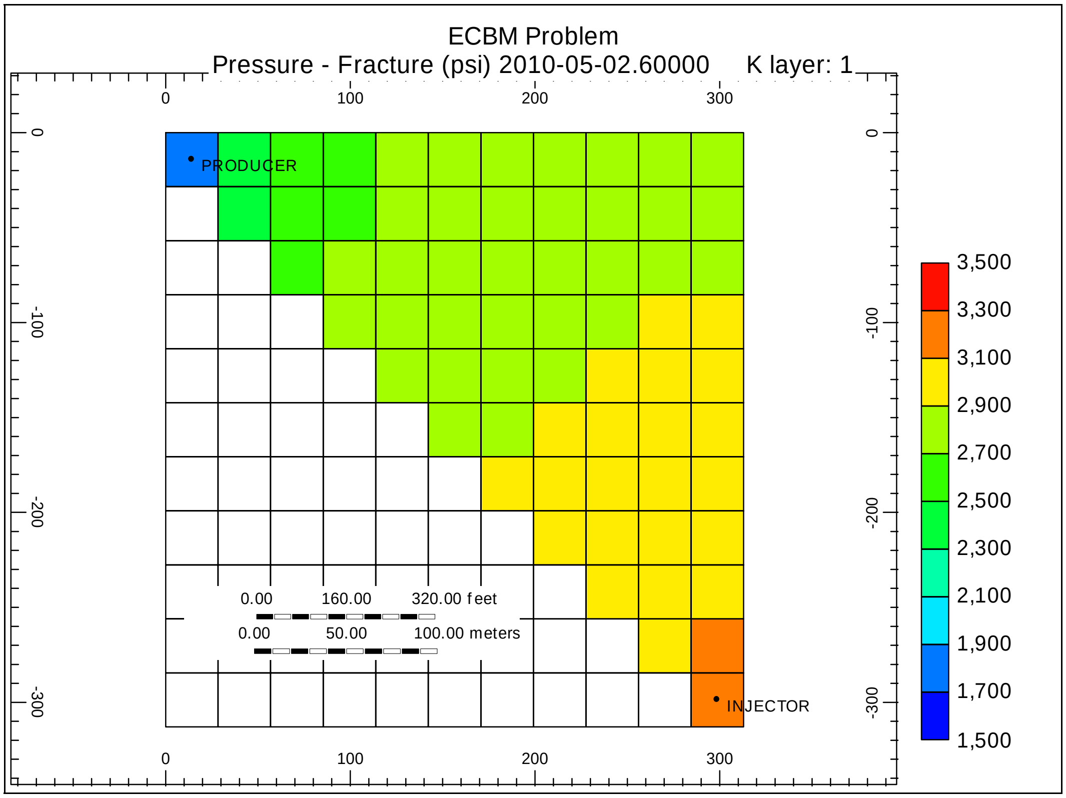

Fig. 23- Reservoir pressure at breakthrough time of 3,775 days for the 6,200-ft depth reservoir scenario, Case 3b (13% CO_2 – 87% N_2 injection).

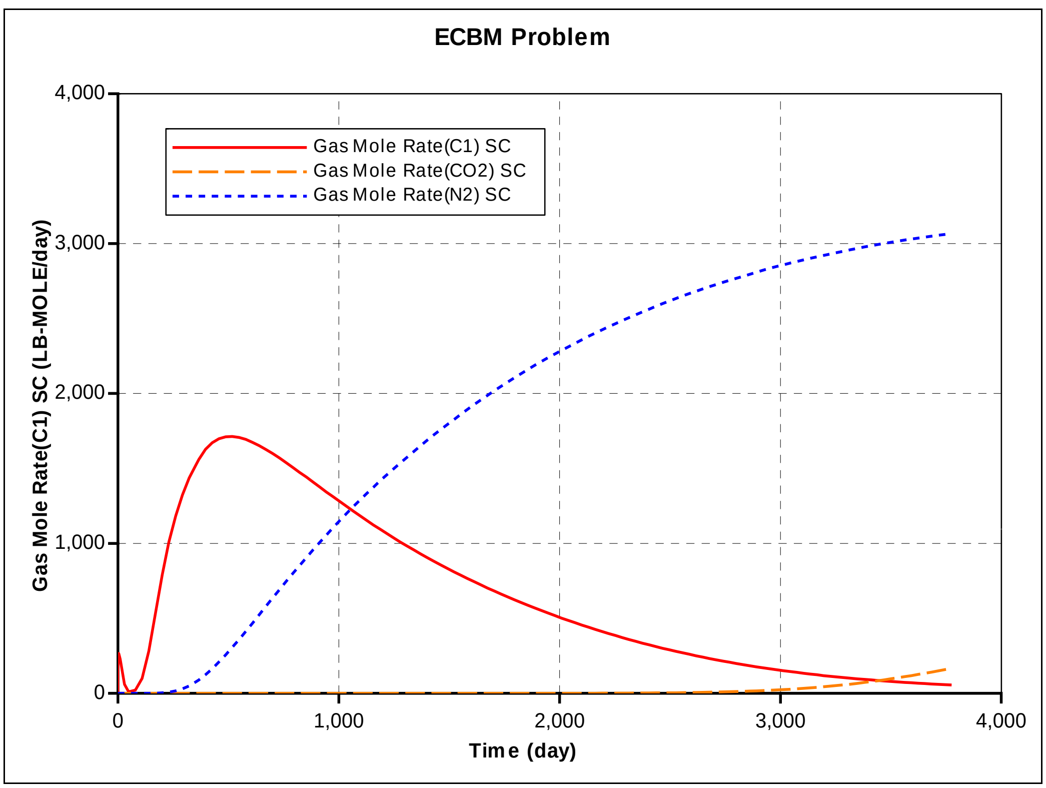

Fig. 24- Methane, CO_2, and N_2 gas mole production rates for the 6,200-ft depth reservoir scenario, Case 3b (13% CO_2 – 87% N_2 injection). Mole rates are for an 80-acre 5-spot pattern (40-acre well spacing).

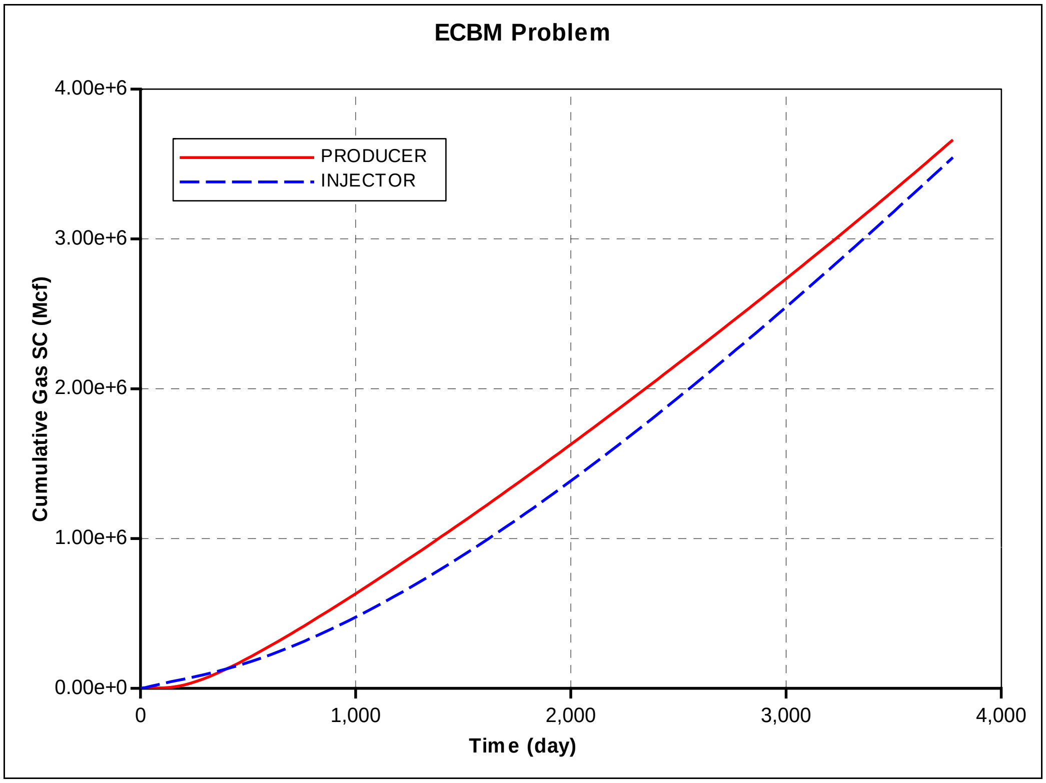

Fig. 25- Cumulative gas production and injection for the 6,200-ft depth reservoir scenario, Case 3b (13% CO_2 – 87% N_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

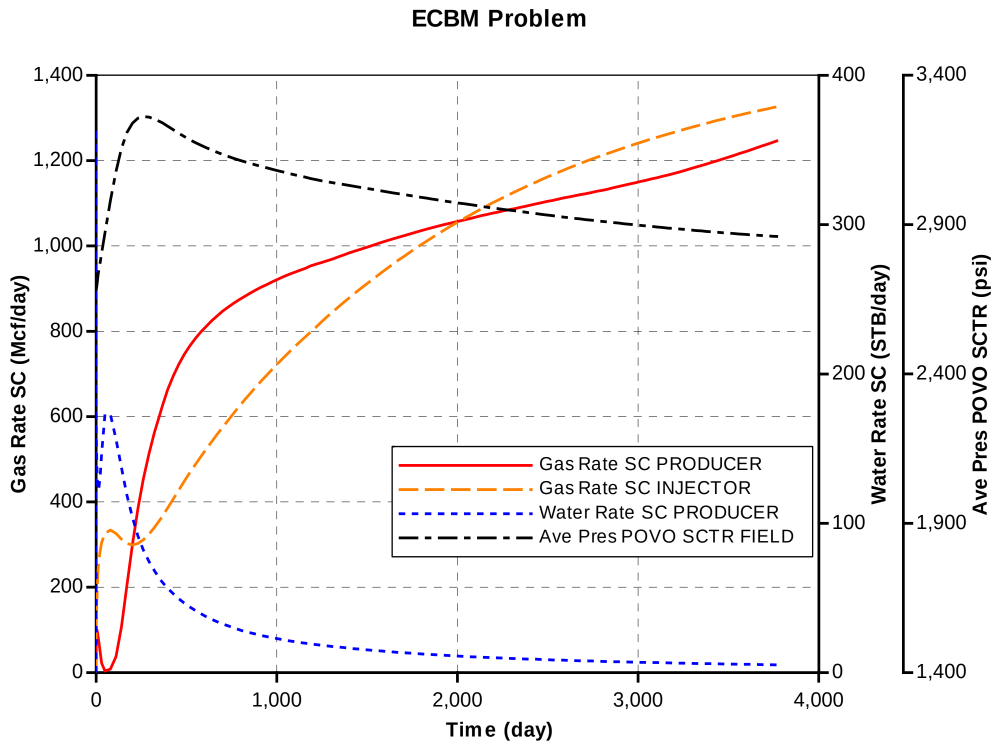

Fig. 26- Gas production and injection rates, water production rate, and average field pressure for the 6,200-ft depth, Case 3b (13% CO_2 – 87% N_2 injection). Rates are for an 80-acre 5-spot pattern (40-acre well spacing).

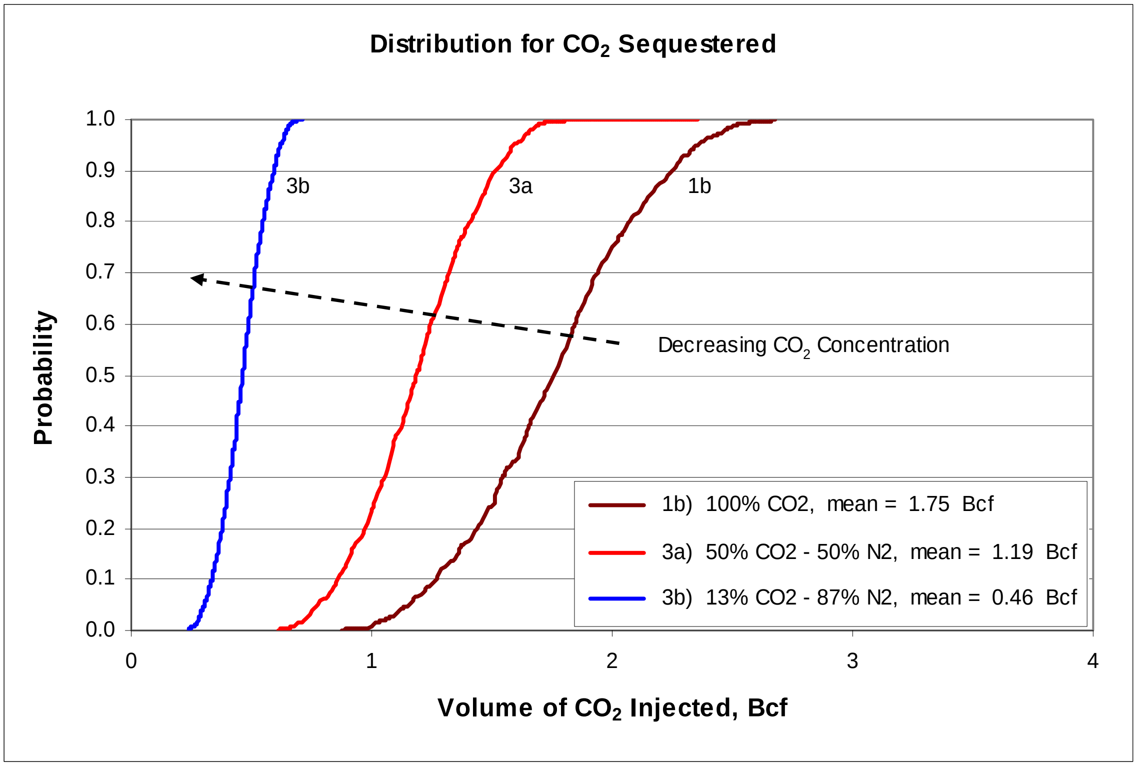

Fig. 27- Cumulative distribution functions for CO_2 injected per 80-acre 5-spot pattern in the 6,200-ft depth reservoir scenarios, Cases 1b, 3a, and 3b.

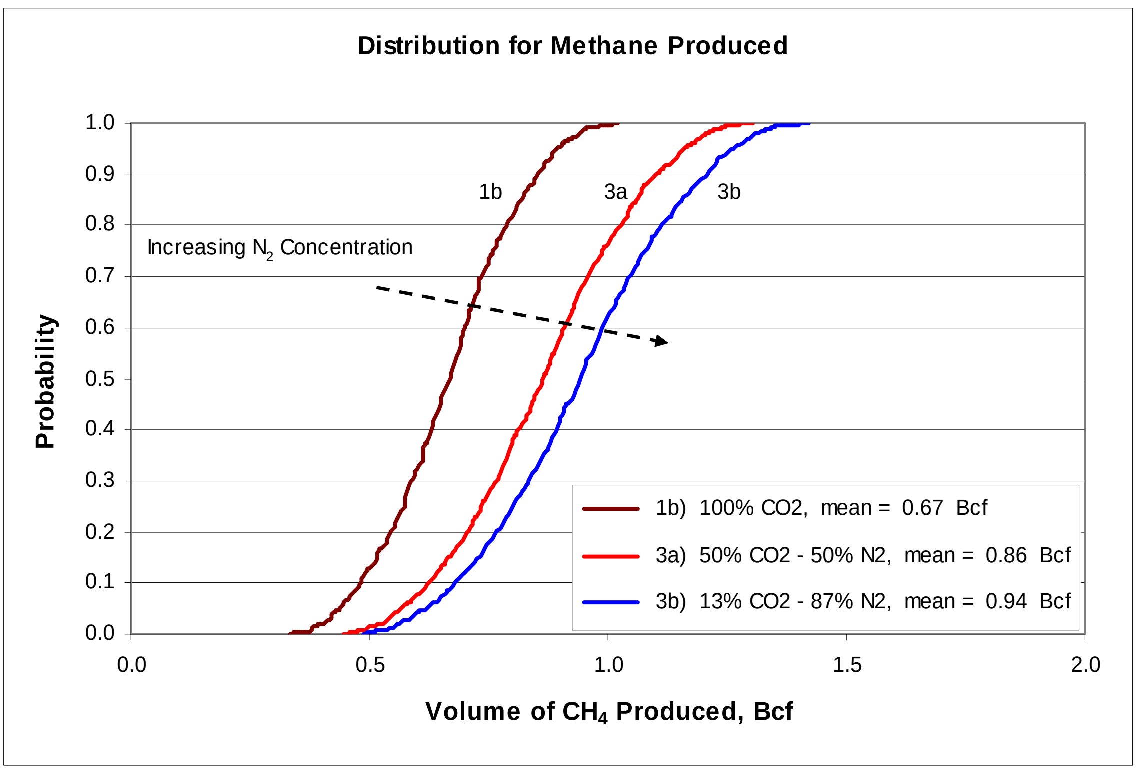

Fig. 28- Cumulative distribution functions for CH_4 produced per 80-acre 5-spot pattern in the 6,200-ft depth reservoir scenarios, Cases 1b, 3a, and 3b.

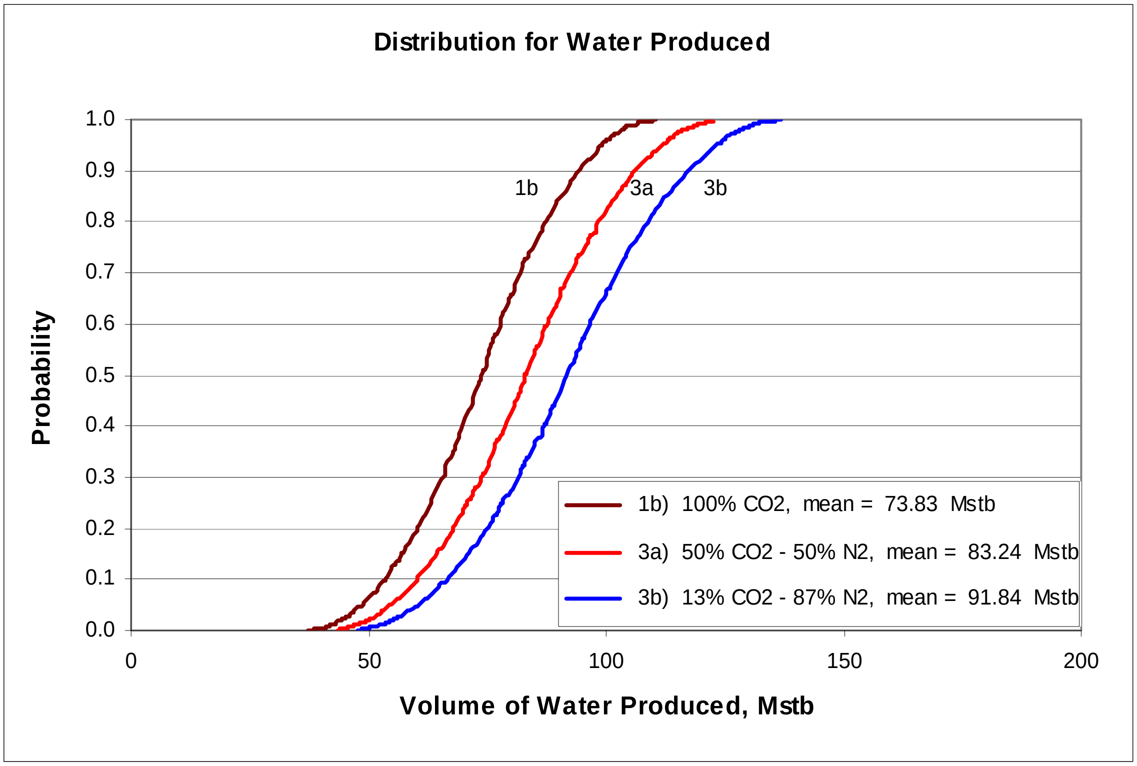

Fig. 29- Cumulative distribution functions for water produced per 80-acre 5-spot pattern in the 6,200-ft depth reservoir scenarios, Cases 1b, 3a, and 3b.

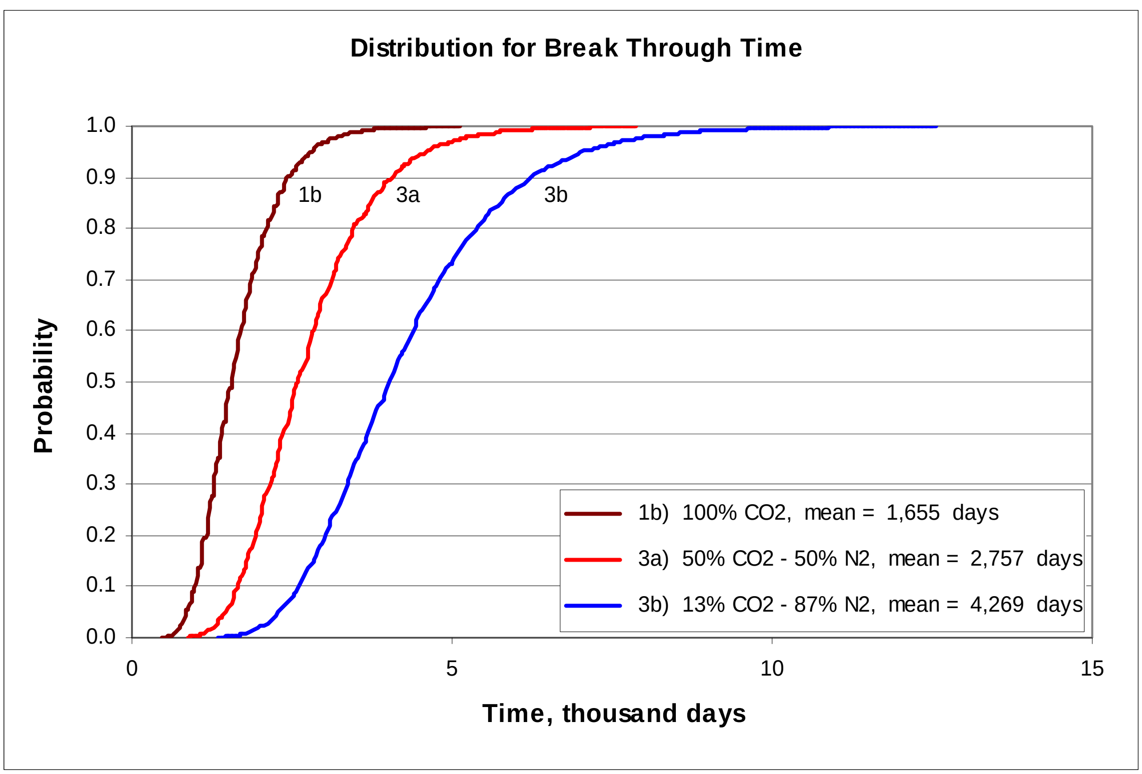

Fig. 30- Cumulative distribution functions for breakthrough time for 80-acre 5-spot patterns in the 6,200-ft depth reservoir scenarios, Cases 1b, 3a, and 3b.

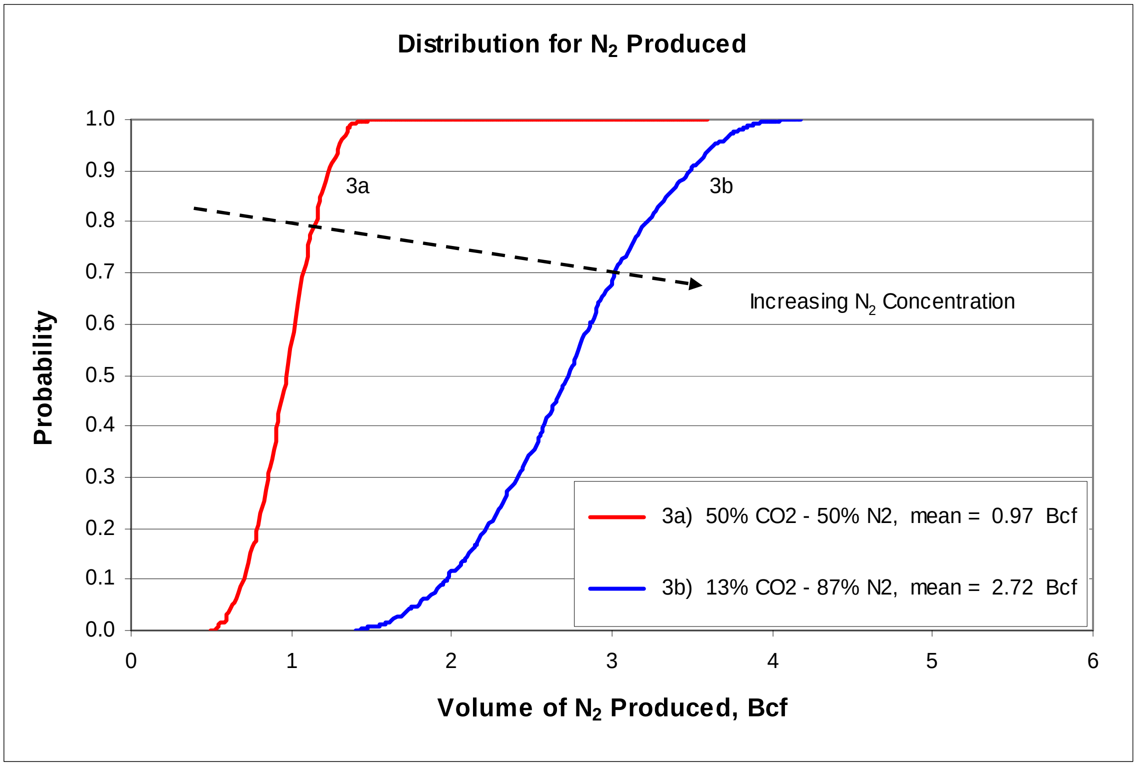

Fig. 31- Cumulative distribution functions for N_2 production per 80-acre 5-spot pattern in the 6,200-ft depth reservoir scenarios, Cases 3a and 3b.

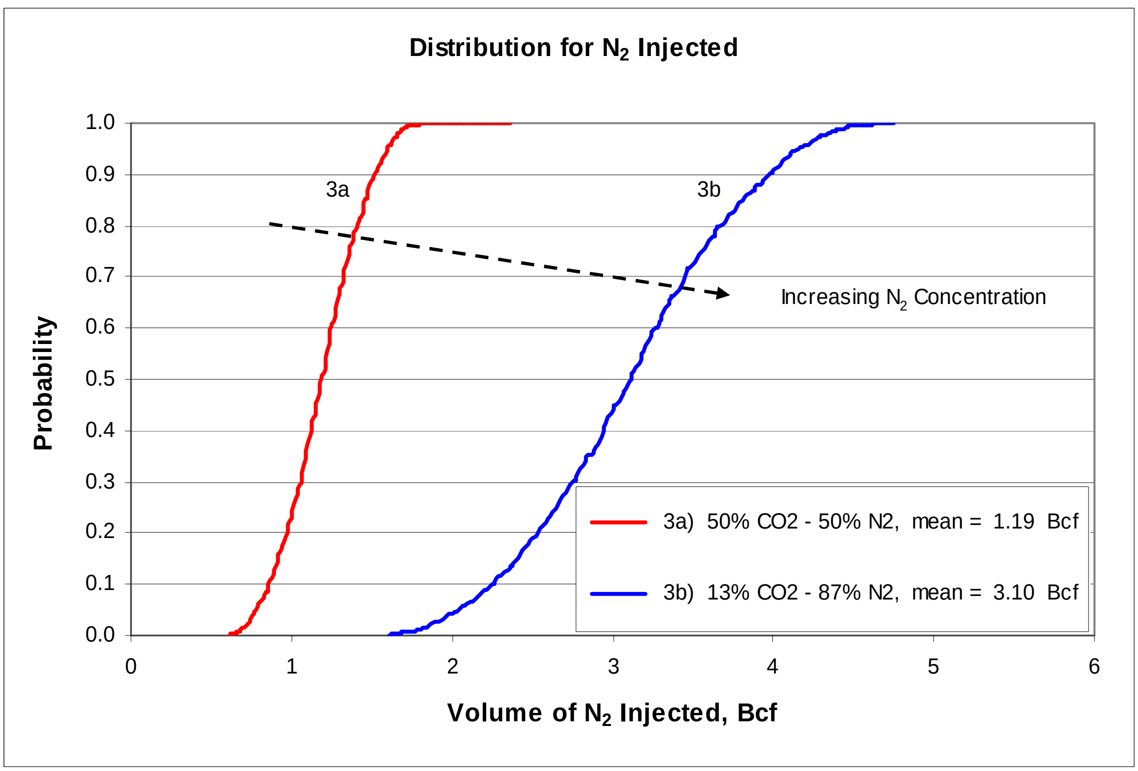

Fig. 32- Cumulative distribution functions for N_2 injection per 80-acre 5-spot pattern in the 6,200-ft depth reservoir scenarios, Cases 3a and 3b.

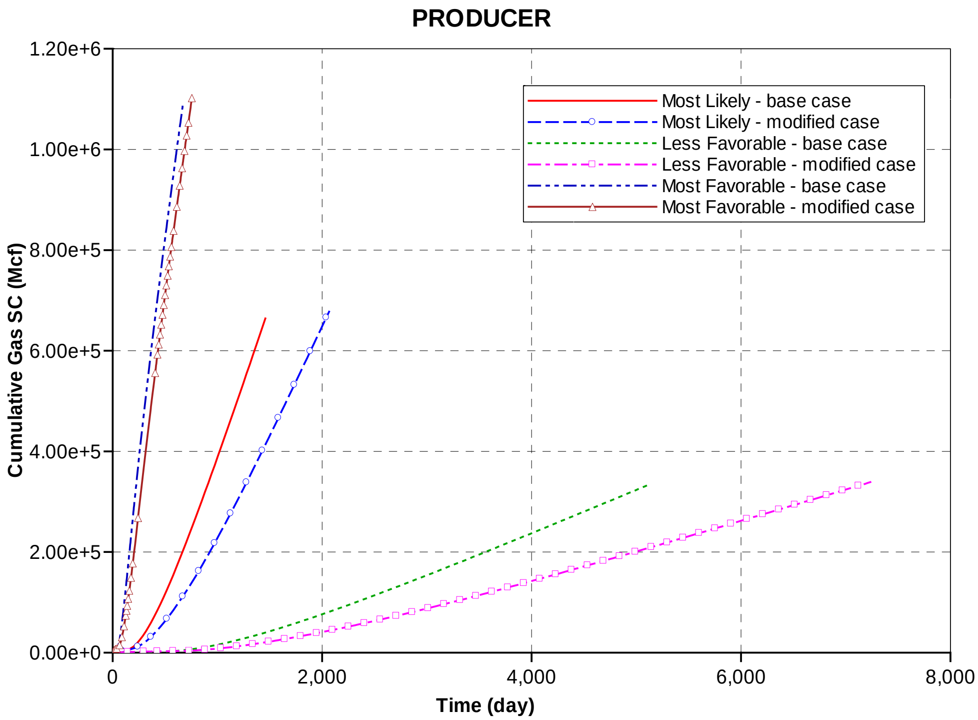

Fig. 33- Cumulative CH_4 production for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, under different well operating conditions, Case 4 (100% CO_2 injection). Modified case represents lower drawdown. Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

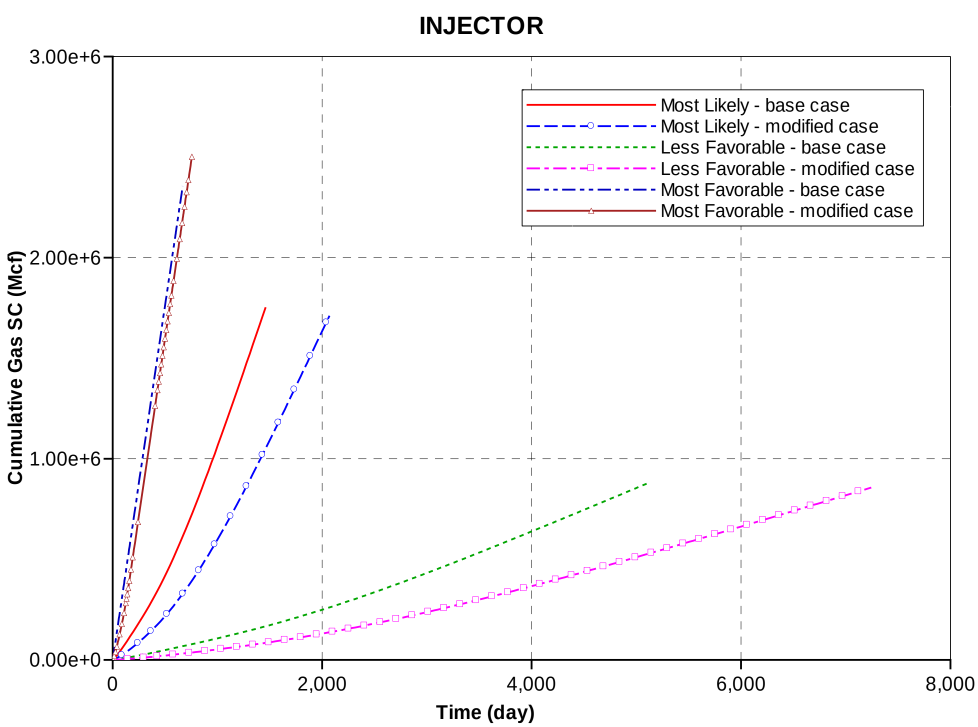

Fig. 34- Cumulative CO_2 injection for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, under different well operating conditions, Case 4 (100% CO_2 injection). Modified case represents lower drawdown. Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

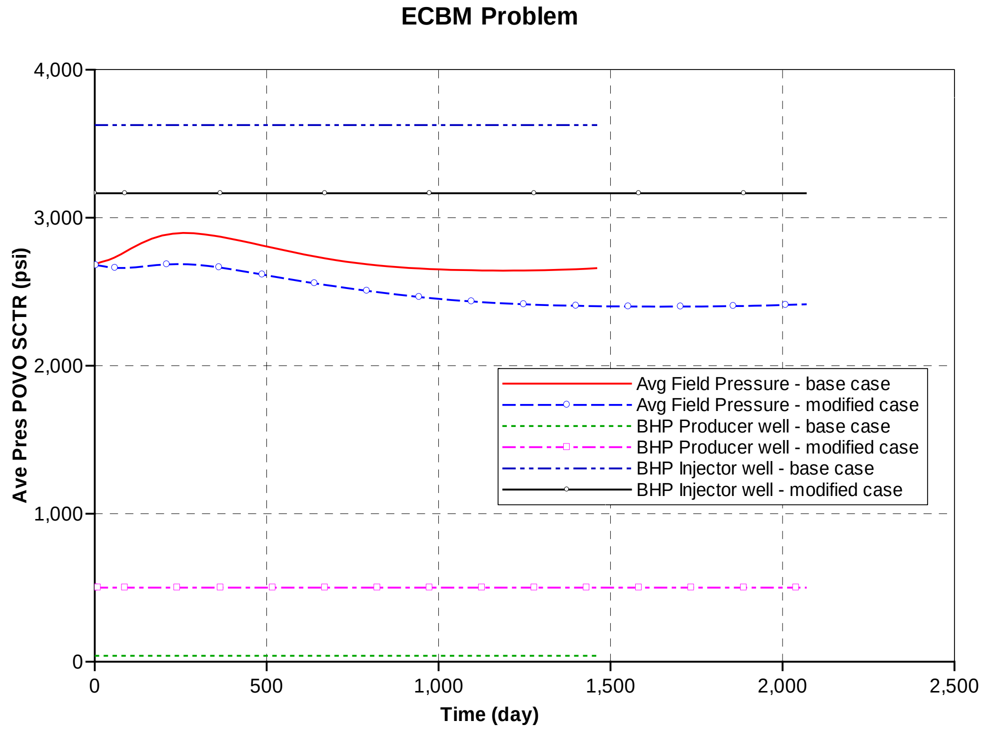

Fig. 35- Average field pressure and bottom hole pressure in the producer and injector wells for the 6,200-ft depth, in an 80-acre 5-spot pattern (40-acre well spacing), Case 4 (100% CO_2 injection), for the most-likely reservoir parameters. Modified case represents lower drawdown.

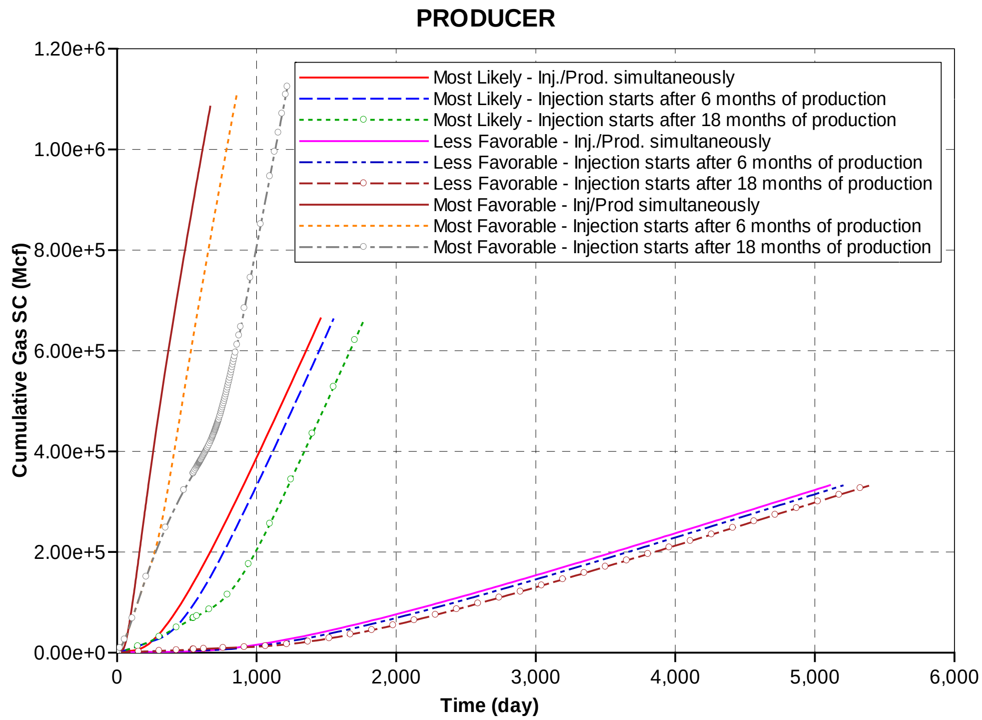

Fig. 36- Cumulative CH_4 production for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, dewatering the coals 6 and 18 months, Case 5 (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

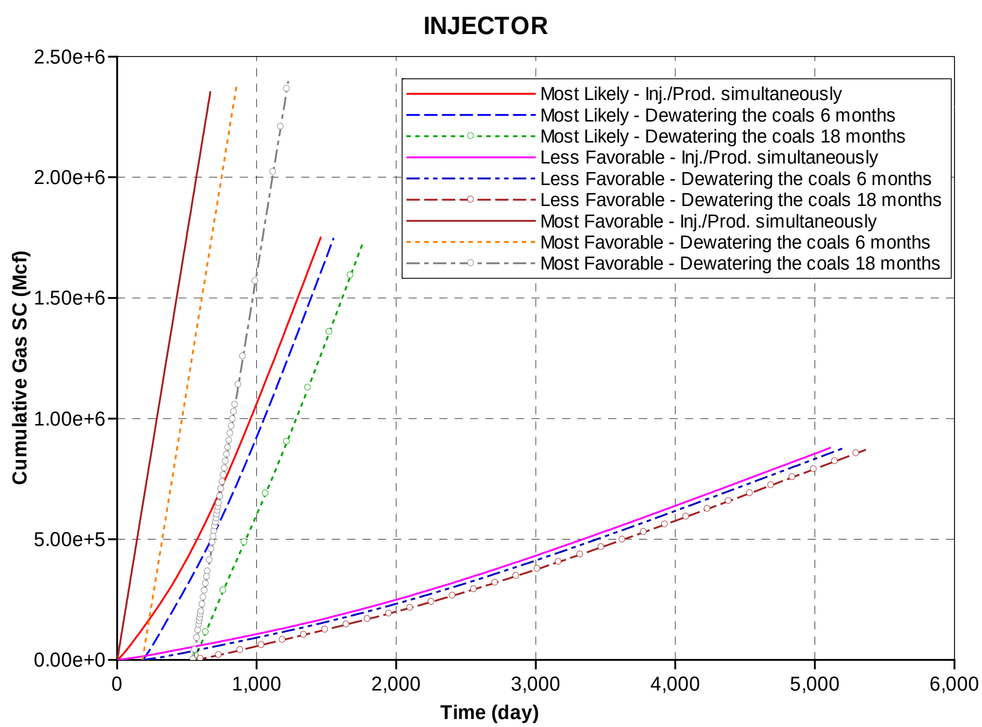

Fig. 37- Cumulative CO_2 injection for the 6,200-ft depth reservoir scenario for the most-likely, least-favorable, and most-favorable reservoir parameters, dewatering the coals 6 and 18 months, Case 5 (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

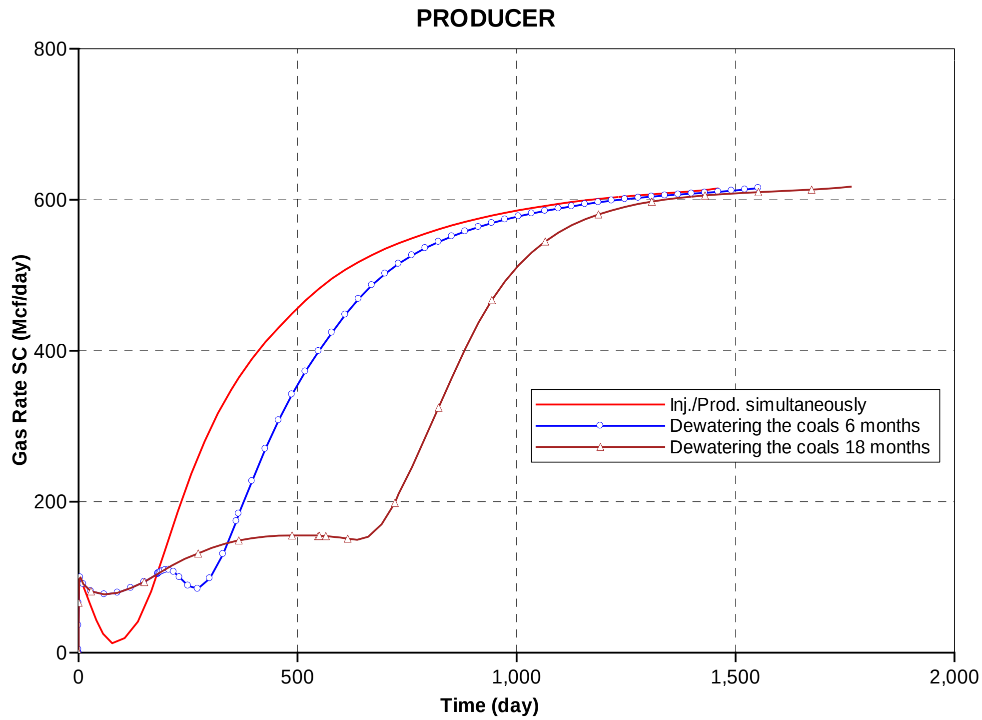

Fig. 38- CH_4 production rates for the 6,200-ft depth reservoir scenario for the most-likely reservoir parameters, dewatering the coals 6 and 18 months, Case 5 (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

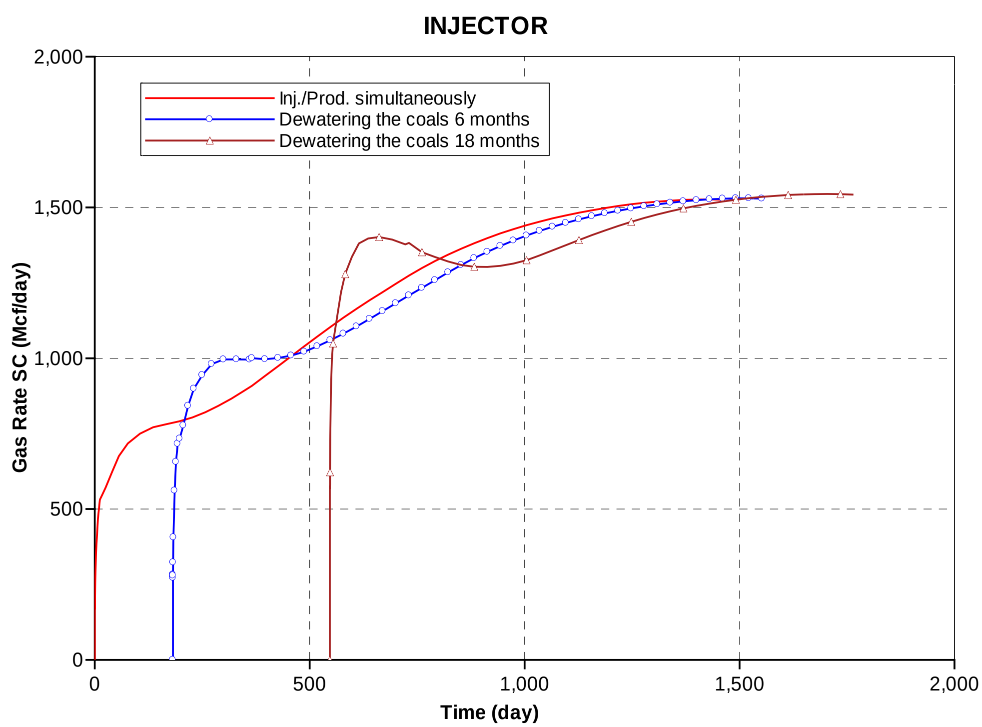

Fig. 39- CO_2 injection rates for the 6,200-ft depth reservoir scenario for the most-likely reservoir parameters, dewatering the coals 6 and 18 months, Case 5 (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

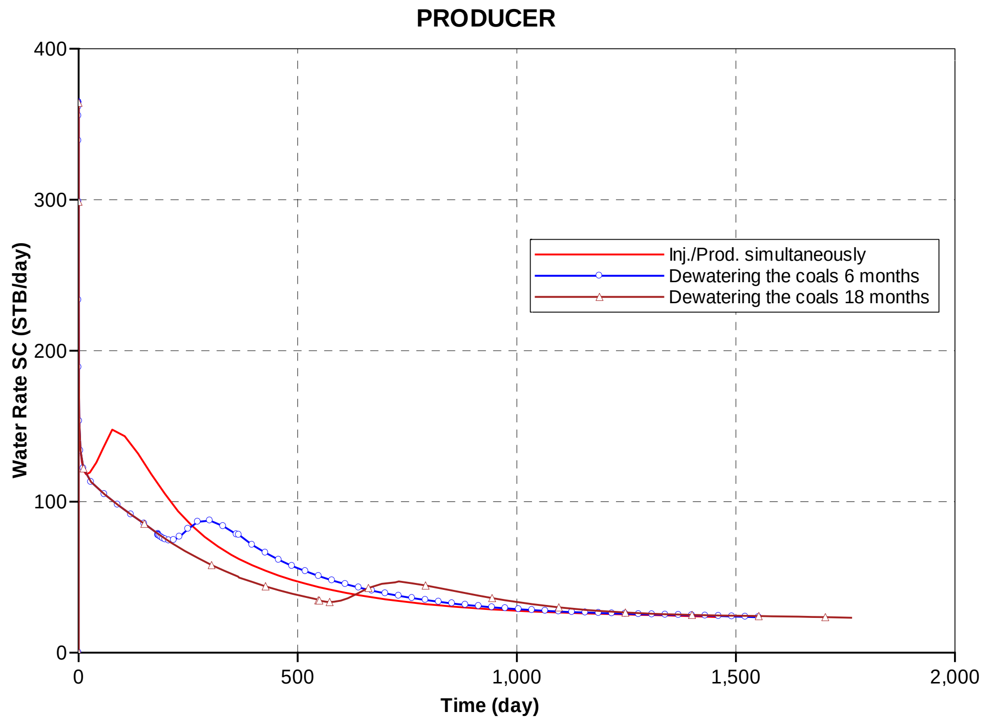

Fig. 40- Water production rates for the 6,200-ft depth reservoir scenario for the most-likely reservoir parameters, dewatering the coals 6 and 18 months, Case 5 (100% CO_2 injection). Volumes are for an 80-acre 5-spot pattern (40-acre well spacing).

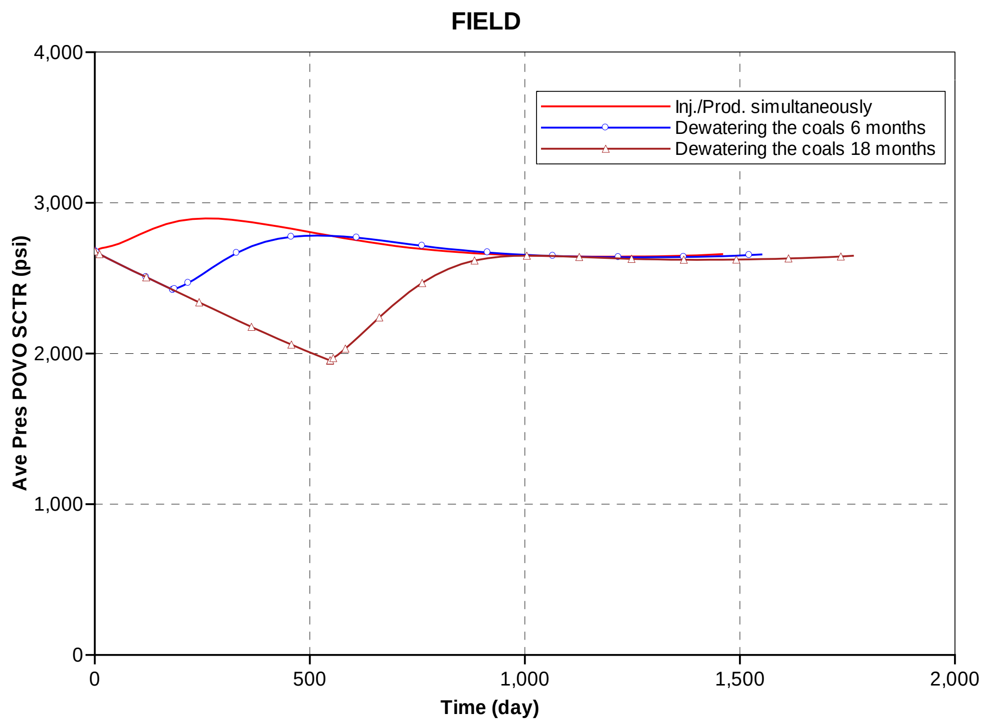

Fig. 41- Average field pressure for the 6,200-ft depth coal seam scenario, in an 80-acre 5-spot pattern (40-acre well spacing), Case 4 (100% CO_2 injection), for the most-likely reservoir parameters, dewatering the coals 6 and 18 months.

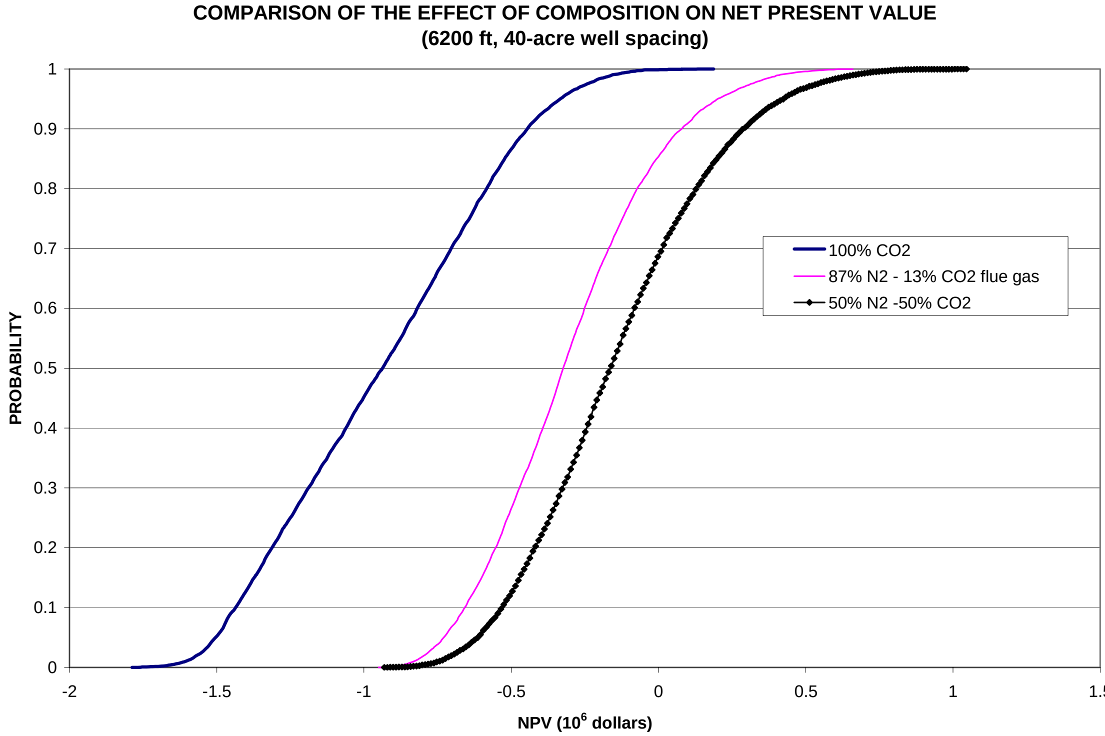

Fig. 42 - Cumulative probability distributions of NPV for three different injection gas compositions (6200 ft, 40-acre well spacing).