INVESTIGATION OF FEASIBILITY OF INJECTING POWER PLANT WASTE GASES FOR ENHANCED COALBED METHANE RECOVERY FROM LOW RANK COALS IN TEXAS

A Thesis

by

LUKE DUNCAN SAUGIER

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

MASTER OF SCIENCE

August 2003

Major Subject: Petroleum Engineering

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Approved as to style and content by:

Duane McVay (Co-chair of Committee)	Walter Ayers (Co-chair of Committee)
Lawrence Wolken (Member)	Hans Juvkam-Wold (Head of Department)

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ABSTRACT

Investigation of Feasibility of Injecting Power Plant Waste Gases for Enhanced Coalbed Methane Recovery from Low Rank Coals in Texas. (August 2003)

Luke Duncan Saugier, B.S., Texas A&M University;

Co-chairs of Advisory Committee: Dr. Duane McVay
Dr. Walter Ayers

Greenhouse gases such as carbon dioxide (CO_2) may be to blame for a gradual rise in the average global temperature. The state of Texas emits more CO_2 than any other state in the U.S., and a large fraction of emissions are from point sources such as power plants. CO_2 emissions can be offset by sequestration of produced CO_2 in natural reservoirs such as coal seams, which may initially contain methane. Production of coalbed methane can be enhanced through CO_2 injection, providing an opportunity to offset the rather high cost of sequestration. Texas has large coal resources. Although they have been studied there is not enough information available on these coals to reliably predict coalbed methane production and CO_2 sequestration potential.

The goal of the work was to determine if sequestration of CO_2 in Texas low rank coals is an economically feasible option for CO_2 emissions reduction. Specific objectives included estimation of CO_2 injection and methane production rates, and a determination of the relative importance of coal reservoir parameters. A data set was compiled for use in simulating the injection of CO_2 for enhanced coalbed methane production from Texas coals. Simulation showed that Texas coals could potentially produce commercial volumes of methane if production is enhanced by CO_2 injection.

The efficiency of the CO_2 in sweeping the methane from the reservoir is very high, resulting in high recovery factors and CO_2 storage. The simulation work also showed that certain reservoir parameters, such as Langmuir volumes for CO_2 and methane, coal seam permeability, and Langmuir pressure, need to be determined more accurately.

An economic model of Texas coalbed methane operations was built. Production and injection activities were consistent with simulation results. The economic model showed that CO_2 sequestration for enhanced coalbed methane recovery is not commercially feasible at this time because of the extremely high cost of separating, capturing, and compressing the CO_2. However, should government mandated carbon sequestration credits or a CO_2 emissions tax on the order of $10/ton become a reality, CO_2 sequestration projects could become economic at gas prices of $4/Mscf.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

FIGURE Page

1. INTRODUCTION

1.1 GREENHOUSE GASES

Although there is some skepticism as to the relationship between greenhouse gas emissions and global warming, greenhouse gas emissions monitoring and restrictions are a political and economic reality. The greenhouse gas that will most likely see the largest change in emissions regulations in the near future is carbon dioxide (CO_2). The focus of most of the regulatory efforts for CO_2 is on point sources such as refineries and power generation plants. Among the 50 states, Texas is the largest power producer and consumer and, as such, has a correspondingly large number of point sources for greenhouse gases.

1.2 SOURCES OF GREENHOUSE GAS EMISSIONS IN TEXAS

The largest source of CO_2 emissions in Texas is the transportation sector. Unfortunately, individual CO_2 sources in the transportation sector are small and numerous, making it infeasible to capture and sequester the CO_2 generated. The second largest source of CO_2 emissions in Texas is point sources such as power plants, petrochemical plants, and cement plants. An ongoing Department of Energy (DOE) study being performed at Texas A&M University has found that power plants are the largest point sources, many emitting several million tons of CO_2 per year. One ton of CO_2 is equal to approximately 19 Mscf.

This thesis follows the style and format of *SPE Reservoir Evaluation & Engineering.*

Power plant waste gas is primarily nitrogen (N_2) and CO_2. CO_2 concentration varies from 3% to 13%, and the remaining gas fraction is more than 92% N_2. Other gases, such as NO_x, SO_2, and un-combusted oxygen, are also present in small quantities. Coal-fired power plants are the largest CO_2 emitters. Their waste gas streams vary in concentration from about 8 to 13% CO_2. Wong, Gunter, and Mavor[1] and others[2-4] have found that most of the costs of sequestering CO_2 from power plants come from separation and compression, and not transportation and injection. Hereafter the term "capture" will refer to the process of separating CO_2 from other waste gases and compressing it to pressures sufficient for transportation and injection. The capital and operating costs for CO_2 capture are most usefully expressed by valuing the dry compressed gas output on a dollars per Mscf basis. The most commonly used CO_2 capture process is the Fluor Econamine FG process. Typically, CO_2 captured in this manner costs approximately $2/Mscf. The largest component of this cost is the energy needed. Thus, most of the research in this area focuses on developing less energy-intensive capture methods. Iijima[5] presents a proprietary process, developed by Mitsubishi Heavy Industries and successfully implemented at two power plants in Japan, that lowers the cost of CO_2 capture to $0.40-$0.70/Mscf. Capture costs can be lowered further through economies of scale and by application of the capture process to flue gas streams that are richer in CO_2. Coal-fired power plant waste streams commonly contain 13% CO_2, whereas gas-fired power plant flue gas contains only about 3% CO_2. Thus, large coal-fired plants are the most economic in terms of CO_2 capture.

The high cost of CO_2 separation and capture raises the question of whether or not it would be cheaper to inject the entire waste gas stream. Unfortunately, injecting the entire flue gas stream is not feasible because of the amount of energy needed to compress such a large volume of gas for injection. Not only is the energy cost prohibitive, but the CO_2 generated in the compression of a waste gas stream containing 10% or less CO_2 is actually greater than the CO_2 volume sequestered.[6]

1.3 GREENHOUSE GAS SEQUESTRATION

There are several options for sequestering CO_2 that is vented into the atmosphere. These options are broadly grouped into three categories:

- Biosphere Sinks – natural incorporation of CO2 into oceans and forests,
- Geosphere Sinks – injection of CO_2 into natural reservoirs, and
- Material Sinks – use of CO_2 in wood products, chemicals, or plastics.
- CO_2 injection falls under the category of geosphere sinks, in which the greenhouse gas is sequestered in the earth. One distinct advantage of geosphere sinks is the possibility of using injected CO_2 to increase hydrocarbon recovery, thereby reducing costs (e.g., CO_2 injection is commonly used in enhanced oil recovery projects). The purpose of my work was to assess the financial and technical viability of reducing CO_2 point source emissions in Texas by injecting CO_2 into coal seams.

1.4 COALBED METHANE

Over the last 15 years coalbed methane (CBM) has become a well-established part of the domestic gas industry. Currently, about ten percent of U.S. natural gas production is from coalbed methane wells. Gas is stored in coal seams through a process called adsorption. An increase in the partial pressure of the gas in the presence of coal causes gas to chemically adsorb on the coal surface. A decrease in partial pressure releases gas from the coal surface. This pressure-adsorption relationship is modeled for the constant temperature environment found in coal seams using the Langmuir isotherm (Fig. 1). Normally methane is the only gas present in the coal reservoir, so the partial pressure for methane is essentially equal to the reservoir pressure. The reservoir pressure is reduced by producing the water in the formation. As the pressure decreases, the methane desorbs from the coal surface and flows through fractures (cleats) to the wellbore.

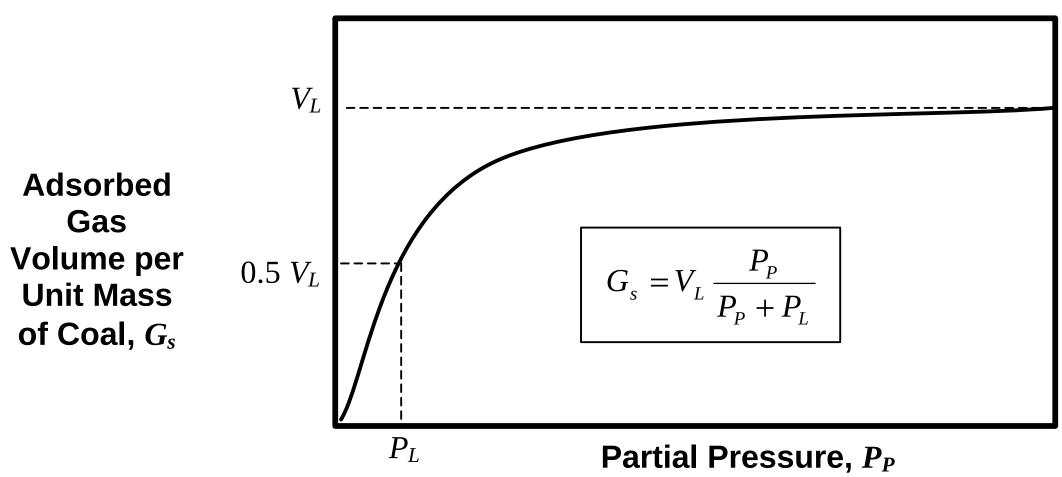

Fig. 1- The relationship between partial pressure and the gas adsorbed to a unit mass of coal is described by the Langmuir isotherm.

1.5 ENHANCED COALBED METHANE PRODUCTION (ECBM)

In the last few years several pilot projects in Colorado and New Mexico have shown the viability of injecting gases such as CO_2 and N_2 into coalbed methane wells as a method of production enhancement. Coal is known to preferentially adsorb CO_2 over methane and to adsorb several times more volumes of CO_2 than methane. Thus, when CO_2 is injected into a coal seam it displaces the methane from the coal surface. N_2, on the other hand, is less preferentially adsorbed compared to methane. Injection of N_2 maintains or increases total reservoir pressure but decreases the partial pressure of methane. Thus, the methane desorbs from the coal. It is useful to envision CO_2 injection as a methane displacement process and N_2 injection as a methane stripping process.

The concept of injecting CO_2 and N_2 into coalbed methane wells to enhance production was shown to be technically viable in a DOE project involving BP, Advanced Resources International (ARI), and Burlington Resources. In late 2002, Reeves[7], Reeves and Schoeling[8], and Reeves[9] published papers detailing the results of two pilot tests in the San Juan Basin where CO_2 and N_2 were injected. They concluded that “the project has demonstrated that both CO_2 and N_2 injection can materially improve gas recoveries from coal seams; and *the processes can be reasonably modeled with today's numerical simulators*.” [9] (italics added)

1.6 TEXAS COALS

The state of Texas has vast coal resources, nearly all of which are lignite concentrated in the Gulf Coast region. East-central Texas alone has lignite resources of approximately 37.5 billion tons. This same region is home to many of the power plants in Texas, because this is the most populated region of the state and because many of these power plants use the lignite as fuel. Conventional wisdom was that lignite would store about twice as much CO_2 as methane, but recent studies of low rank coals from the U.S. Great Plains region have shown that lignite may be able to store as much as 10 times as much CO_2 as methane.[10] The composition of Texas lignite is well documented. However, the CO_2 storage capacity and methane content of Texas lignite are largely unknown, as are most of the other coal properties relevant to sequestration of CO_2, such as permeability and the rate at which gas diffuses through the coal matrix.

1.7 OBJECTIVES

The overall goal of my work was to determine if sequestering CO_2 in Texas low rank coals is an economically feasible option for CO_2 emissions reduction. A great deal of reservoir modeling has been done to investigate gas injection for ECBM in the San Juan Basin and other producing CBM regions but little or none has been done for Texas. CO_2 injection modeling needs to address the following questions relevant to Texas low rank coals:

- What is a reasonable expectation for CO_2 injection on a per well basis (rate and total volume)?
- What is a reasonable expectation for methane production on a per well basis (rate and total volume)?
- How long can an area be used for injection before CO_2 breakthrough occurs and production and injection must be halted?

- Which reservoir parameters are most important relative to the questions above?

To accomplish my objectives I first built a detailed economic model of coalbed methane and CO_2 sequestration operations in Texas. The economic model is designed to calculate cash flows and net present value (NPV), and to model how changes in gas price realization, CO_2 capture costs, CO_2 sequestration credit value, and project financing structure affect these economic indicators. Estimated costs are presented for all capital and operating expenditures including lease acquisition, pipeline and well construction and hookup, and production and injection well operating costs. Furthermore, royalties, severance tax, basis differential, BTU discounts, and other factors relevant to revenue are included so as to present as realistic a model as possible. Key inputs to this economic model are the volume of CO_2 that can be sequestered in a typical well and the volume of methane likely to be produced as a result. Thus, numerical reservoir models were required to simulate injection and production.

A basic reservoir simulation was run for combinations of the most important reservoir parameters. This amounted to many thousands of runs. Analysis of the data allowed a determination of the relative importance of the coal reservoir parameters varied in the study. In addition, several reservoir simulations were run to model different well operating decisions. The simulation results were used to form reasonable estimates of the performance of injection and production wells, and this was incorporated into the economic model. In turn, the economic model was used to determine whether or not CO2 sequestration projects are currently economical. Several different economic scenarios, such as different gas prices or the possibility of carbon sequestration credits, were examined.

This thesis contains two major sections – reservoir modeling and economic modeling. In the reservoir modeling section I first discuss selection of the reservoir simulator and compilation of the coalbed simulation data set. After explaining the basic model and operating parameters, I present the results of the simulation runs and the sensitivity of these results to reservoir parameters and operational parameters. In the economic modeling section, I explain the economic model I developed and present the results of the economic sensitivity testing. Following these two sections, I draw conclusions regarding the need for additional data collection, the importance of certain reservoir parameters, and the feasibility of an economical sequestration project at the present time and in the future.

2. NUMERICAL RESERVOIR MODEL

2.1 GOALS

There were two primary goals in simulating injection of CO_2 for sequestration and ECMB. First, through reservoir simulation I wanted to determine likely values for CO_2 injection, methane production, and CO_2 breakthrough time for use in the development of an economic model of CO_2 sequestration in Texas coals. The second goal was to determine the relative importance of each coal reservoir parameter and identify parameters critical to the success of large-scale CO_2 sequestration in Texas lignites.

2.2 METHODOLOGY

2.2.1 Compilation of the Simulation Data Set

First, a literature survey was performed to choose an appropriate reservoir simulator. Law *et al.*[11] of the Alberta Research Council (ARC) compared five different reservoir simulators available for modeling ECBM: GEM, SIMED II, COMET 2, ECLIPSE, and GCOMP. All are commercial simulators with the exception of GCOMP, which is proprietary BP software. The only requirement for participation in the study was the ability to model CO_2 injection and methane production for a coalbed methane reservoir. Two "test problems" were proposed by ARC and modeled in the five simulators by representatives of the respective companies. All simulators were able to model the problems proposed, and all results matched the results from the other simulators closely. However, I determined that, based on the features each offered, only two simulators were appropriate for use in this study: SIMED II or GEM. ECLIPSE and

COMET 2 are both black oil simulators modified to model coalbed methane operations and are only capable of handling two types of gas, methane (CH_4) and CO_2. Because future work is expected to involve modeling simultaneous injection of CO_2 and N_2, these two simulators were rejected as inadequate. GCOMP does not allow modeling of dual porosity reservoirs and so it was rejected as inadequate. GEM is a compositional simulator capable of modeling both mixed gas diffusion and non-instantaneous diffusion rates. It is part of the Computer Modeling Group's (CMG's) package of simulation tools. A license for GEM is owned by Texas A&M, and several people here are familiar with its use. Thus, I decided that GEM would be the most convenient numerical reservoir simulator to use in this study.

Next, I familiarized myself with coalbed methane simulation by modeling the two "test problems" proposed by ARC[11]. The first test problem is a single-layer radial reservoir simulation of CO_2 injection, pressure falloff, production, and finally pressure buildup. The second test problem is a single-layer 10x10 grid representing ¼ of a standard five-spot pattern. The injection and production wells are placed in two opposing corners of the grid, and production and injection commence immediately and continue throughout the 182.5 day simulation. In both test problems my results match those of Law *et at.* almost exactly, indicating that I can correctly model standard CO_2 injection/coalbed methane production problems using GEM.

I next began to build a dataset for simulation of CO_2 injection and methane production for Texas lignites. To do this I gathered relevant data from published literature. Much of the data set came from several studies of Texas Gulf Coast lignites conducted by the Texas Bureau of Economic Geology in the early 1980's.[12-15] These resources were valuable because they provided information on coal thickness, depth, pressure, density, water salinity, and areal extent. Additionally, the Ph.D. dissertation of Brimhall[16] was useful in ascertaining coal properties important to reservoir simulation, such as permeability. Finally, some of the most useful data came from cores of Wilcox coal in the Sabine uplift area in 1999 taken by the United States Geological Survey (USGS) in cooperation with Texas A&M.[17] Taken from a depth of several hundred feet, these cores were an invaluable source of data on Langmuir volumes for CO_2 and methane, Langmuir pressures, and desorption time. From all these sources I compiled a set of coal seam properties. Throughout this process I consulted with Dr. Walter Ayers Jr. and received the benefit of his extensive knowledge of and experience with Texas lignites. I also spoke with Walt Sawyer at Schlumberger's Pittsburgh, PA, office about his experiences with building data sets for simulation of coalbed methane reservoirs.

To quantify the uncertainty associated with simulation predictions, I determined high, low, and most likely values for some reservoir parameters (Table 1). I surveyed the literature to determine the parameters most likely to have an impact on CO_2 sequestration and methane production activities.

I found several relevant papers: Odusote,[*] Sams *et al.*,[18] and Remner *et al.*[19] The most useful was Odusote. All three papers investigated the effects of coal seam properties on gas movement in bituminous coal seams. Odusote specifically focused on the effect of coal seam properties on ECBM as determined by numerical reservoir simulation. Their results indicate that permeability, coal density, Langmuir volume and pressure constants, diffusion time, and initial reservoir pressure are the parameters most likely to affect methane recovery and CO_2 sequestration. Odusote created a base case data set and then varied one reservoir parameter at a time and compared the results to the base case. I too created a base case data set to be used in simulation, but rather than vary one parameter at a time, I varied multiple parameters. The base case data set I generated for Texas lignite is presented in Table 1. Parameters considered to be most important (based upon the three papers cited above) are in bold print, and ranges are given for each. The middle value is the most likely value, and these are used in the base case. Following the table is an explanation of the ranges given for the most relevant coal seam properties.

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[*] Personal communication with O. Odusote, Texas A&M University, College Station, Texas (2003)

Table 1–Base Case Coal Reservoir Properties

Coal Seam Thickness	10 feet
Depth	2000 feet
Fracture/Cleat Spacings	2.5 inch
Fracture Porosity	0.005
Fracture Absolute Permeability	**1, 5, 20 md**
Fracture Compressibility	100e-6 1/psi
Water Density	61.8 lb/ft^3
Water Viscosity	0.6 cp
Water Compressibility	8.7e-8 1/psi
Coal Density	**78, 80, 82 lb/ft^3**
V_L, CO_2	**600, 800, 1000 scf/ton**
V_L, CH_4	**60, 80, 100 scf/ton**
P_L, CO_2	**300, 400, 500 psi**
P_L, CH_4	400 psi
Diffusion Time	**0, 1, 4 day**
Initial Reservoir Pressure	**500, 1000, 2000 psi**
Initial Water Saturation	100%
Initial Composition of Gas in Reservoir	100% CH_4
Initial Coal Gas Content	100% saturated

- **Fracture Absolute Permeability** [1, **5**, 20] md–The value of approximately 5 md comes from the Brimhall[16] dissertation. However, Ayers indicated that the permeability could be as high as 20 md or much lower than 1 md.* A permeability of 1 md was used as a lower bound for this experiment.
- **Coal Density** [78, **80**, 82] lb/ft^3–The base value comes from "Coal Resource Classification System of the U.S. Geological Survey"[13] and is the median value for lignite. Values greater than 80 lb/ft^3 represent higher ash content lignites and values less than 80 lb/ft^3 represent cleaner, higher rank coals.

* Personal communication with W. Ayers, Texas A&M University, College Station, Texas (2003)

- **Langmuir Volume of CO_2** [600, **800**, 1000], **CH_4** [60, **80**, 100] scf/ton – These data come from the USGS cores taken in the Wilcox coals near the Sabine uplift. Methane and CO_2 desorption isotherms were run at constant temperatures. The cores were only tested at pressures below 300 psi so the results were straight line extrapolated to the pressures expected to be encountered at depths of interest.
- **Langmuir Pressure of CO_2 & CH_4** [300, **400**, 500] psi – These data come from the USGS cores taken in the Wilcox coals near the Sabine uplift. Methane and CO_2 desorption isotherms were run at constant temperatures. Langmuir pressures for carbon dioxide and methane will be varied separately but over the same range. The cores were only tested at pressures below 300 psi so the results were straight line extrapolated to the pressures expected to be encountered at depths of interest.
- **Diffusion Time** [0, **1**, 4] days–Diffusion time takes into account both the amount of time required for the gas to diffuse through the coal and also the time required for the gas to desorb from the coal. Data from the USGS Wilcox cores indicate that desorption time is less than one day. Past studies indicate that coalbed gas production is unlikely to be diffusion limited.[*] Thus, four days was selected as a reasonable upper bound on diffusion/desorption time.
- **Reservoir Pressure** [500, **1000**, 2000] psi–These pressures are based upon likely depths of coal seams as taken from several published studies of East-

Central Texas coals. The middle reservoir pressure, 1,000 psi, is used as the most likely value, reflecting the desire to inject into relatively shallow coals to save on drilling and compression costs.

2.2.2 Base Case Simulation

The next step was to determine realistic injection and production rates and volumes for Texas Gulf Coast lignites in order to build an economic model of potential operations. To accomplish this, the base case data set was used to perform a series of simulations. The simulations modeled ¼ of a standard 5-spot pattern. Both injector and producer begin operation at the start of simulation. The producer is primarily rate constrained to operate at 3 MMscf/d and secondarily pressure constrained to operate at 40 psi. The effective constraint is the pressure constraint. Likewise, the injector is primarily rate constrained to operate at 1 MMscf/d and secondarily pressure constrained to operate at 2,000 psi. In the case of the injection well, the rate constraint is the effective constraint. Simulation ends when CO_2 is 5% of the production stream. Wells were assumed to be drilled on a spacing of 1.25 acres per well. A single-layer 11x11 grid was used. Fig. 2 shows the dimensions and orientation of the simulation grid used.

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* Personal communication with W. Ayers, Texas A&M University, College Station, Texas (2003)

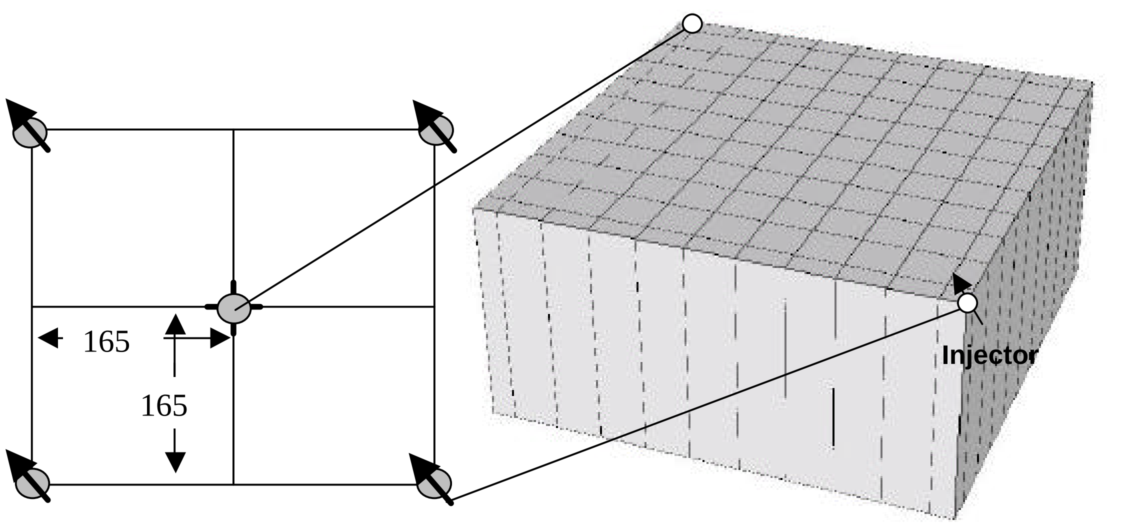

Fig. 2–Gridding used in reservoir model. Base case dimensions shown.

Fig. 3 shows the CO_2 injection rate and bottomhole pressure in the injection well for the base case. Fig. 4 shows the methane production rate, bottom hole pressure in the producing well, and water production rate for the base case.

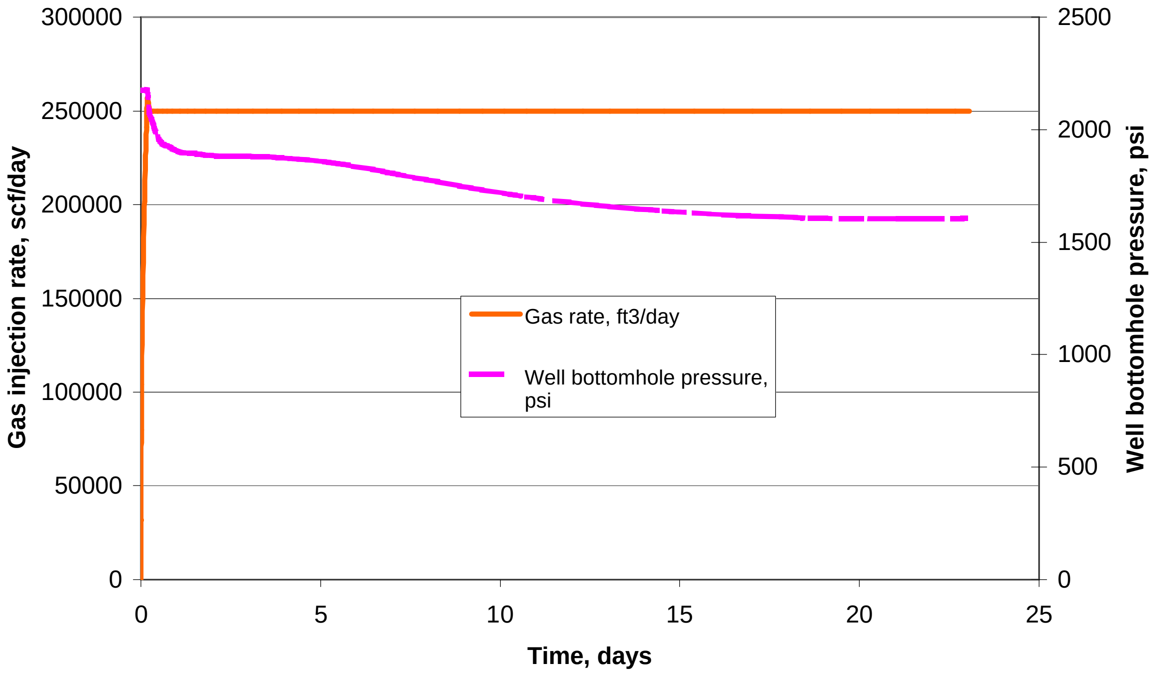

Fig. 3-CO_2 injection rate and bottom hole pressure for the base case injection well, 1.25 acres per well spacing. Rates are for 1/4 well.

Fig. 4 shows that a slug of gas is produced very early in the life of the well. When the well is turned on, the pressure in the wellbore immediately drops to the minimum allowable flowing pressure, 40 psi, and the water in the cleats immediately surrounding the wellbore is produced. Before this water can be replaced with water from deeper in the formation, the cleats fill with methane desorbed from the coal immediately surrounding the wellbore.

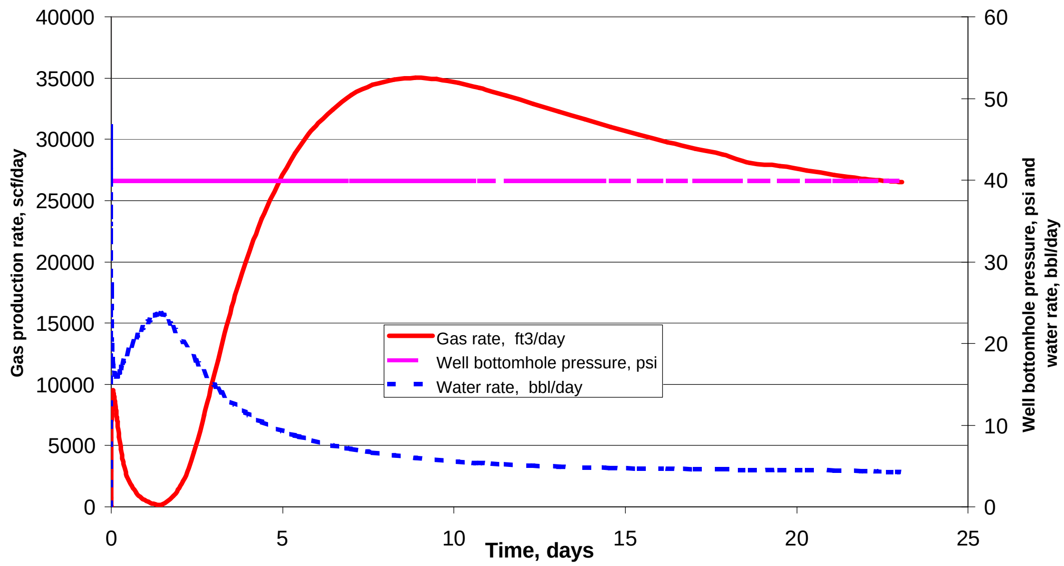

Fig. 4-Methane production rate, water production rate, and bottom hole pressure for the base case production well, 1.25 acres per well spacing. Rates are for 1/4 well.

This methane is quickly displaced by water from deeper in the formation, which limits the permeability to methane. Thus, methane production falls off until enough water has been produced to lower the pressure enough to allow methane to desorb and force the water from the cleats. Fig. 5 shows that the average reservoir pressure for the base case is maintained relatively constant. The data file used to generate these figures is included in Appendix I. The rates shown in these figures are ¼ of the per-well rate because only ¼ of a pattern was modeled.

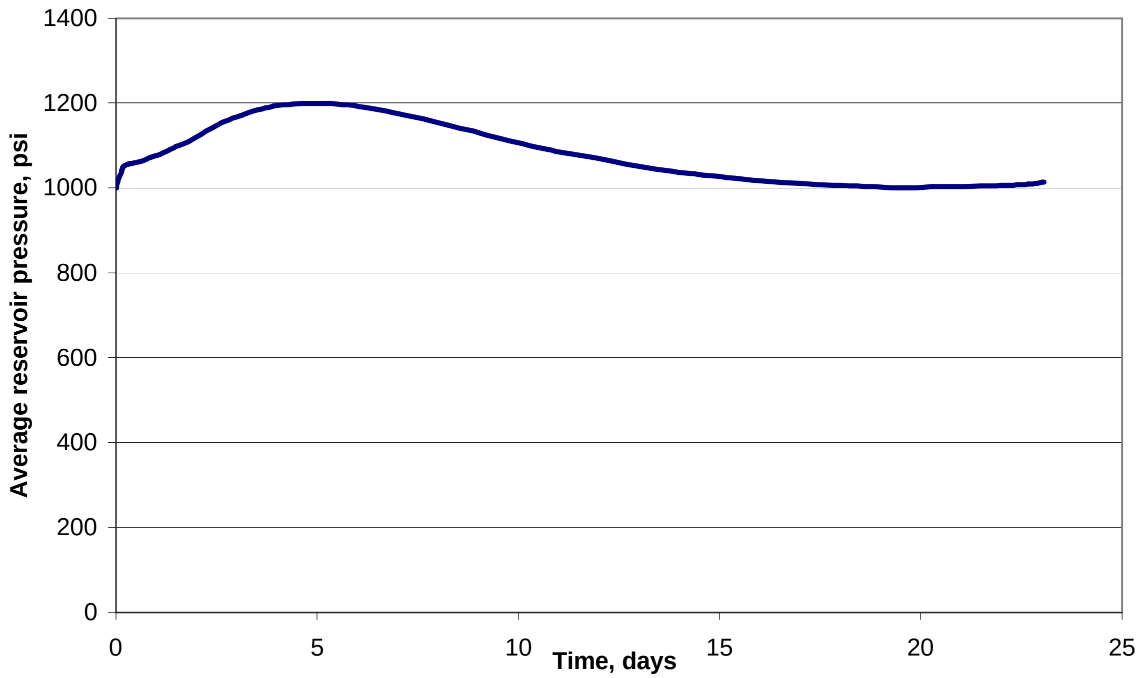

Fig. 5-Average reservoir pressure for the base case simulation, 1.25 acres per well spacing.

2.2.3 Experiment to Determine Sensitivity of Performance to Coal Properties

Odusote compared his base case to the same case with one parameter changed. They repeated this process for every reservoir parameter. While this is useful in determining the magnitude of change in result caused by a change in one variable, it is not useful in determining the effects of changes in multiple variables. For example, how will production and injection rates change in a coal with lower permeability but higher density than the base case? The Odusote procedure is useful for a fairly complete and reliable data set. Such a situation might arise if one were working in a limited area or in a very homogeneous reservoir. Such is not our case. The area of interest for this study is a large part of the entire Texas Gulf Coast region and coals are known to be highly heterogeneous. Thus, a more rigorous analysis of possible production and injection scenarios was warranted.

After identifying the reservoir parameters whose change can have a significant effect on production and injection, a likely range of values was assigned to each (as described above). I decided to make a separate simulation run for every possible combination of the three values for every variable. Since seven critical variables had been identified, this meant a total of 3^7, or 2,187, runs. Clearly it is not feasible to run so many simulations manually. Thus, I wrote a program that allows the user to enter a data set into one spreadsheet and the parameters to be changed in another spreadsheet. The user enters the number of parameters to be tested, the number of values to be tested for each parameter, and finally, the values for each parameter and their location in the data set. When run, the program replaces the parameter values in the data set with the set to be analyzed, sends the data set to GEM, and runs it. Upon completion of the run the program pulls the relevant data (breakthrough time, CO_2 volume sequestered, and methane produced) from the output files generated and records them in a third spreadsheet. This process is repeated for every possible combination of variables. When executed on a Pentium III with 380 MB of RAM the program took approximately 18 hours to run. Simulation yielded a large data set–2,187 sets of breakthrough time, CO_2 sequestered, and methane produced along with the combinations of variables that generated the results.

2.2.4 Experiments to Determine Sensitivity of Performance to Operational Parameters

The final step in this phase was to run simulations of a few different producing scenarios to see what affect this would have on the results. These simulations used the base case reservoir parameters. There were two parts in this final step. In the first part the well spacing was varied from the base case 1.25 acre per well to 80 acre per well. The number of grid blocks remained the same in all situations but the sizes of the grid blocks were changed. Table 2 shows the new grid block sizes. The simulation remained single layer.

Table 2? Sizes of Grids for Larger Well Spacings

Acres per well	Feet per side of ¼ 5-spot pattern	Feet per side of 9 main blocks	Feet per side of two ½ length end blocks
1.25	165	16.5	8.2
10	466.7	46.7	23.35
20	660	66	33
40	933.4	93.3	46.7
80	1320	132	66

In the second section, changes were made to the manner in which the wells were operated. Three scenarios were run, all using 20 acre per well spacing.

- Scenario 1–both producer and future injector are produced for thirty days. After 30 days one well is changed from production to injection and continues as such until the end of simulation.

- Scenario 2 (base scenario used in testing reservoir parameters)–Injectors begin injecting and producers begin producing at the start of the simulation and continue throughout.
- Scenario 3–Production well begins production at start of scenario. After 30 days the injector begins injection.

The effect of each production scenario on the three results categories was plotted. All results from this final experiment are presented in the Results and Observations section of this thesis.

2.2.5 Analysis of Importance of Parameters

The simulation experiment was designed to generate results useful for gaining insight into the relationships between multiple variables. Some information can be gleaned from simple plots of each result versus simulation run number. This is discussed in the Results and Observations section of this report. Further insight comes through performing analysis of variance (ANOVA) on the results. To perform ANOVA, I used two programs designed for use with a commercial spreadsheet: Essential Experimental Design[20] and Essential Regression[21]. These programs are provided by Steppan, Werner, and Yeater and are available as freeware on the World Wide Web.

My original experiment was a full factorial design for seven factors, each having three levels (variables). The difference between a three-level problem and a two-level problem is the number of experiments–in my case 2,187 vs. 128, respectively. I was primarily concerned with the interaction between parameters and less concerned with the effects of different parameter values at this point, so I decided to reduce the number of levels to two. The middle or “most likely” value was discarded and only the high and low values for each parameter were considered. Thus, the new problem was a full factorial design with seven factors but only two levels. As it turned out, a full factorial design for seven factors is extremely difficult to analyze and in fact is not strictly necessary for good results. It is statistically unlikely that the interaction of three or more factors will have any real significance in determining the value of the response variable (result). By limiting the problem scope to consideration of interactions between no more than two variables, the software is able to perform a full analysis with only 64 experiments (simulation runs).

After using the Essential Experimental Design program to generate the combinations of factor levels needed for each of the 64 experiments I wrote a program that searched through the simulations already run and picked out the required results. When the data set was complete, I used the Essential Regression program to analyze the data.

The software first identifies relationships between the response variable and all factors and combinations of factors. Then, it systematically eliminates the less significant terms in the relationship until elimination of any more terms will diminish the accuracy of the relationship, that is, until only significant terms remain. Implicit in this process are two assumptions. The first assumption is that the relationship is correct and that any difference between the predicted results and the observed results is due to experimental error. Second, the software assumes that this experimental error is not associated with any one term, and that the error is normally distributed. Our primary interest is in ordering the terms of the relationship according to importance, so these assumptions should not be cause for concern. A discussion of the analysis is included in the Results and Observations section of this thesis

2.3 RESULTS & OBSERVATIONS OF SENSITIVITY TO RESERVOIR PARAMETERS

2.3.1 Methane Produced

Fig. 6 is a plot of methane produced for all 2,187 simulation runs. Because of the order in which the simulations were run, points that are close together on the *x*-axis usually have similar properties.

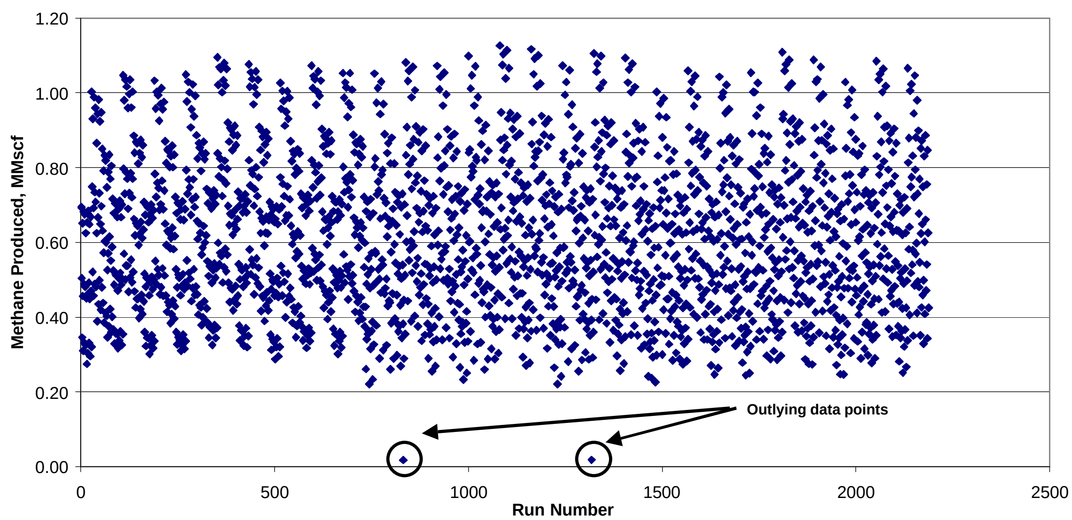

Fig. 6-Cumulative methane production for 1/4 of a 1.25 acre per well spacing 5-spot pattern. Results from all runs are shown.

However, there appears to be little knowledge we can glean from Fig. 6 other than a general range of methane we can expect to produce from a 1.25 acre per well five-spot pattern. Cumulative methane production values can be expected to fall into a range of 265 to 1,150 Mscf for a pattern this size. The data set contains two outlying data points that appear in the plots for cumulative methane produced, CO_2 injected, and breakthrough time. These two data points are from simulation runs that caused the simulator to crash. The simulation runs had large changes in composition, and needed to be modeled with a smaller time step than the simulator was capable of modeling. Given that these are two data points out of 2,187, and that the data are used statistically, these two data points are unlikely to affect the results and conclusions.

2.3.2 CO_2 Injected

Fig. 7 is a plot of cumulative CO_2 injected for every simulation run made. Compared to Fig. 6, Fig. 7 provides a wealth of interesting information. Here, the groupings according to reservoir properties are clearly visible, owing to the order in which the runs were made. The data appears to group into three main clusters (A1, A2, and A3). Each cluster is further divided into three more clusters (B), and these second level clusters seem to divide again into three more clusters (C).

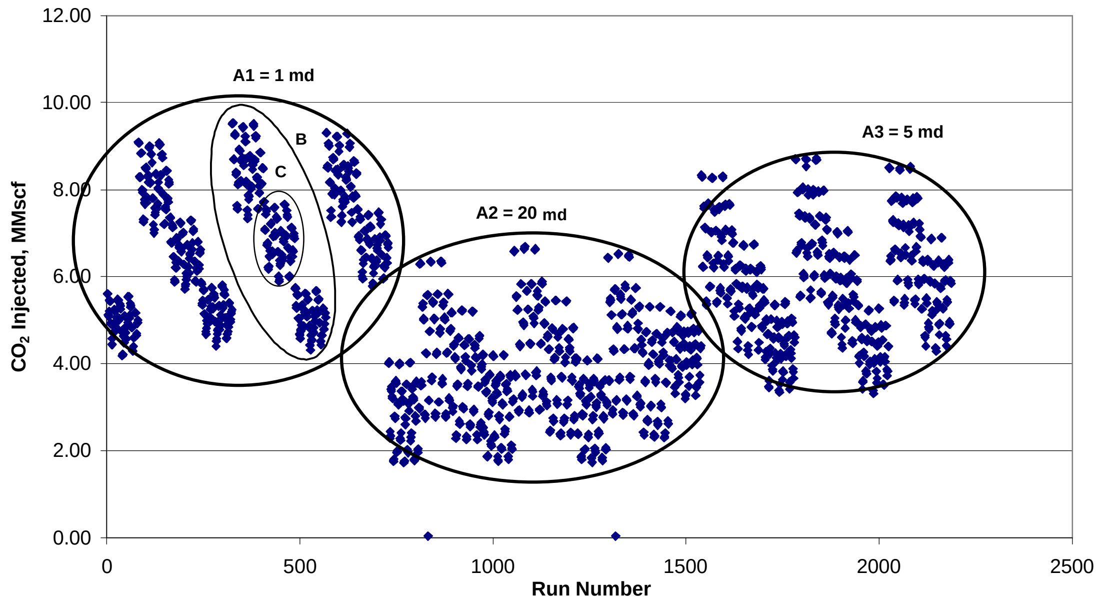

Fig. 7-Cumulative CO_2 injected into 1/4 of a 1.25 acre per well spacing 5-spot pattern. Results from all runs are shown.

By observing the raw simulation data and the parameters that generated the results I was able to determine that the A1, A2, and A3 clusters are grouped by permeability–1 md, 20 md, and 5 md, respectively. That they are observably grouped is an artifact of the run order, but it is still useful in that it allows us to observe relative effects of these three factors. Thus, we see that absolute fracture permeability has a significant effect on CO_2 injection. The raw simulation data also shows that the C clusters are grouped by Langmuir volume for CO_2. This parameter is relatively important, as shown by the consistently large vertical changes associated with successive data groupings. The B clusters correspond to coal density, which appears to be less significant. Even though groupings by coal density are clear we do not see any large vertical changes from group to group, indicating that the volume of CO_2 injected is not particularly sensitive to this factor. Another interesting observation is the vertical spread of points associated with the different permeability groups. The Langmuir volume groups (C) are more vertically condensed inside the lower permeability groupings (A1 – 1 md) and less so inside the higher permeability groupings (A2 – 20 md, A3 – 5 md).

2.3.3 Breakthrough Time

Fig. 8 is a plot of breakthrough time for every simulation run. The raw simulation data show that the groupings in Fig. 7 correspond to the same parameters as the clusters in Fig. 8. The clearest grouping is by permeability, indicating that permeability has a large effect on breakthrough time.

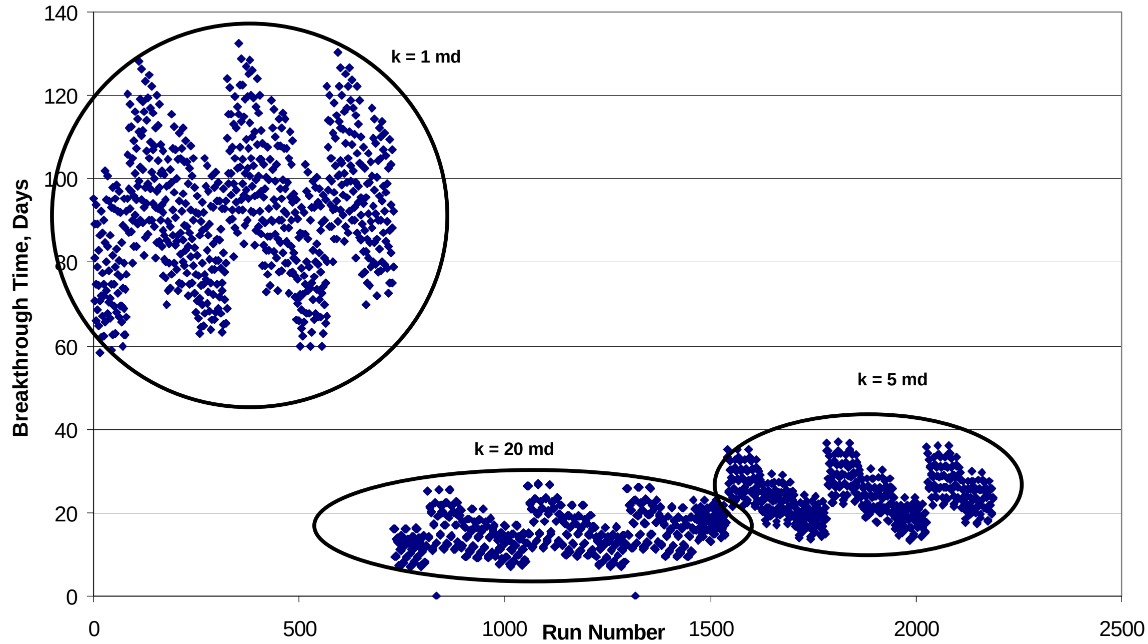

Fig. 8-Breakthrough time, defined as 5% CO_2 in the production stream, for 1/4 of a 1.25 acre per well spacing 5-spot pattern. Results from all runs are shown.

2.3.4 Methane Production Statistics

Basic statistics for the data presented in Fig. 6 (cumulative methane production) were calculated, and the histogram and cumulative distribution function (cdf) for the data are presented in Fig. 9.

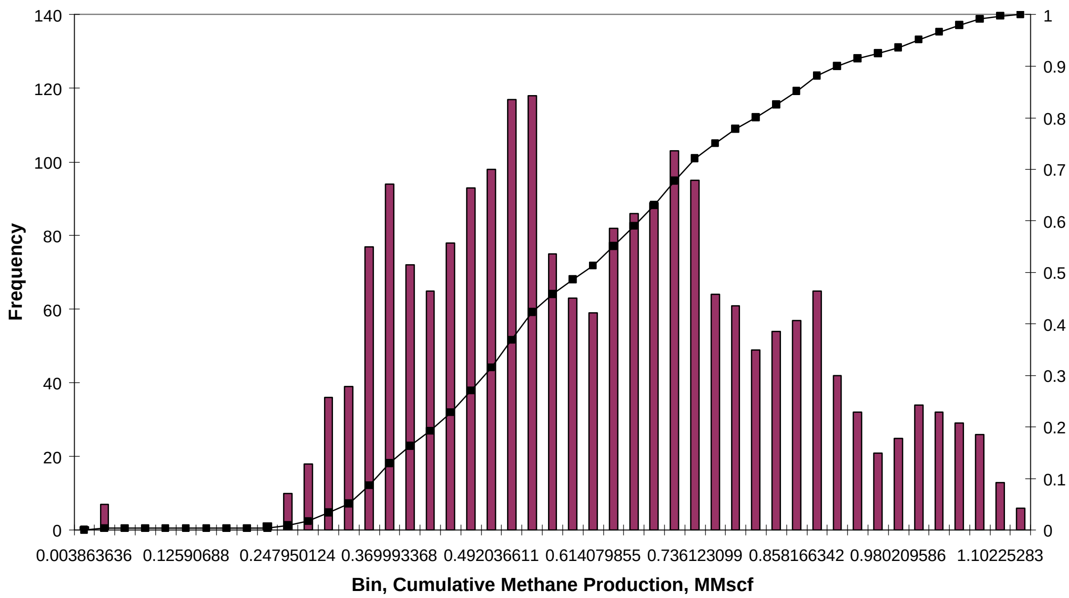

Fig. 9-Statistics for cumulative methane production.

The distribution appears to be normal and is, perhaps, slightly skewed to the left. Relevant statistics are summarized in Table 3 below. The minimum value excludes the two outlying data points.

Table 3? Cumulative Methane Production Statistics

Minimum Value	220 Mscf
Maximum Value	1,127 Mscf
Mean Value	617 Mscf
Standard Deviation	209 Mscf
90% probability values greater than:	353 Mscf
10% probability values greater than:	907 Mscf

The cumulative methane production data were also analyzed using the Essential Regression software. The goal of the analysis was to determine which reservoir parameters, or factors, have the greatest effect on the response variable.

The relationship the Essential Regression software proposes for cumulative methane production is:

$$M = b_0 + b_1(P_i * V_{LC1}) + b_2(V_{LC1} * r_{coal}) + b_3(P_i * k_a) + b_4(P_i) \text{ ....(1)}$$

The R^2 value is a measure of how much of the total variability of a data set is accounted for by a relationship that models that data set. For this relationship R^2 is 0.928. This means that 92.8% of the total variability in cumulative methane production can be accounted for using these four terms. Put another way, the residuals (difference between observed values and calculated values) associated with this relationship cover only 7.2% of the total range of the result. This indicates that the relationship is a useful tool in describing the way the result changes with changes in the related factors. Furthermore, the software provides the information presented in Table 4:

Table 4? Relative Importance of Parameters to Cumulative Methane Production

Term	Probability Term Will Equal Zero
$V_{LC1} * r_{coal}$	8.2e-6%
$P_i * k_a$	.07%
P_i	0.14%
$P_i * V_{LC1}$	7.7%
Const	8.2%
All Terms	6.7e-31%

Table 4 shows the probability that the coefficient of a given term is equal to zero. If the coefficient of a term is zero the term has no effect on the model and is unimportant. Thus, this information is useful for determining the relative importance of each term in the model. The probability that all coefficients are equal to zero is also shown. If all terms are equal to zero then there is no relationship. The extremely low likelihood of all coefficients in this relationship being equal to zero is reflected in the large R^2 value discussed earlier. Ranked in order of importance, the terms are: $V_{LC1} * r_{coal}$, $P_i * k_a$, P_i, and $P_i * V_{LC1}$.

This result is consistent with my intuition. The product of the volume of methane stored per mass of coal and the density of the coal should be important in determining the amount of methane recovered from the coal. The least important term in this model, other than the constant, is $P_i * V_{LC1}$, as indicated by the 7.7% chance that it's coefficient will be equal to zero. This indicates that the product of these two parameters is much less significant. However, recall that this is simply the least important parameter included in the model. All other parameters and combinations of parameters are relatively less important than this combination of parameters.

2.3.5 CO_2 Injection Statistics

Fig. 10 is a histogram and the associated cdf for the cumulative CO_2 injection data presented in Fig. 7. The histogram shows a fairly uniform triangular distribution. Relevant statistics are summarized in Table 5 below. The minimum value excludes the two outlying data points.

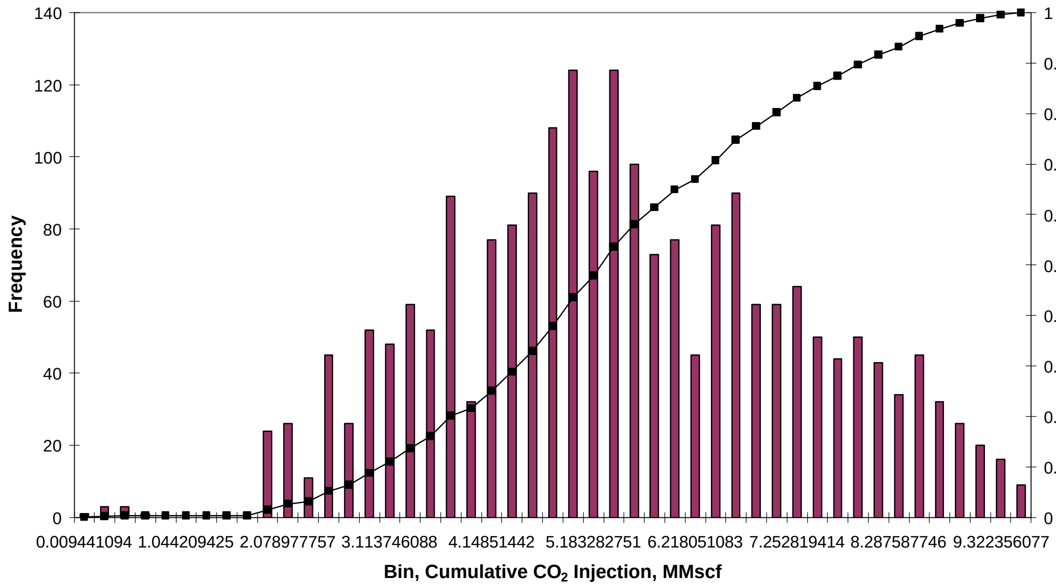

Fig. 10-Statistics for cumulative CO_2 injection.

Table 5? Cumulative CO_2 Injection Statistics

Minimum Value	1,730 Mscf
Maximum Value	9,529 Mscf
Mean Value	5,377 Mscf
Standard Deviation	1,794 Mscf
90% probability values greater than:	3,002 Mscf
10% probability values greater than:	7,873 Mscf

The cumulative CO_2 injection data were also analyzed using the Essential Regression software yielding the following relationship:

$$C = b_0 + b_1(V_{LCO_2}) + b_2(r_{coal} * k_a) + b_3(P_L * V_{LC1}) \text{ ....(2)}$$

This relationship between cumulative CO_2 injected and the parameters shown above does only an adequate job of describing the variation of CO_2 injected, as indicated by its R^2 value of 0.714. This relationship is significantly less representative than that for cumulative methane production. Although there are fewer parameters than in the methane production relationship, all parameters are fairly important, as shown in Table 6.

Table 6? Relative Importance of Parameters to Cumulative CO_2 Injection

Term	Probability Term Will Equal Zero
V_{LCO2}	6.8e-12%
$r_{coal} * k_a$	2e-7%
$P_L * V_{LC1}$	1.7%
Const	9.6%
All Terms	2.6e-14%

Again, most of the parameters identified as important can be explained. For example, it is obvious that the Langmuir volume of CO_2 should have an effect on the total volume of CO_2 injected before breakthrough. The likelihood that all coefficients will be equal to zero is low, but is much greater than for the methane production relationship. The smaller number of relevant parameters and the generally poorer fit of the relationship seems to indicate that the amount of CO_2 that can be injected is affected by many different parameters at a lower level.

2.3.6 Breakthrough Time Statistics

Fig. 11, the histogram and the associated cdf for the breakthrough time data, shows that the distribution is clearly bimodal. The two sub-distributions result from different values of permeability. The distribution on the right is simulation runs with 1 md permeability. The distribution on the left is simulation runs with 5 or 20-md permeability. The overlap of results from 5 and 20-md runs is surprising. I believe that more data on the effect permeability has on breakthough time (more simulation runs using different values of permeability) would yield a log-normal distribution. This supposition may be supported by the leftward skew and narrowness of the distribution on the left and the much broader nature of the distribution on the right, which is consistent with a log-normal distribution.

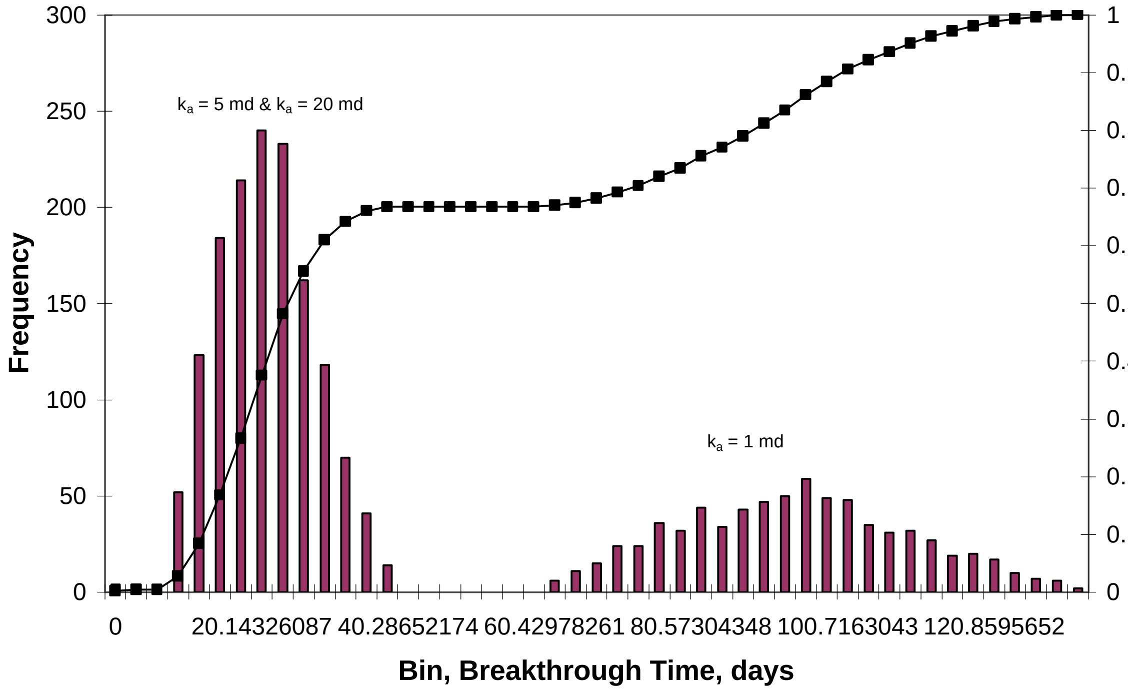

Fig. 11-Statistics for breakthrough time.

Statistics for the data as a whole and for the two sub-distributions are shown in Table 7 below. The minimum value excludes the two outlying data points.

Table 7? Breakthrough Time Statistics

Minimum Value		6.98 days	
Maximum Value		132.37 days	
Mean Value		43.45 days	
Standard Deviation		35.80 days	
90% probability values greater than:		16 days	
10% probability values greater than:		101 days	
Statistics for Lower Distribution		**Statistics For Higher Distribution**	
Mean Value	19.29 days	Mean Value	91.77 days
Standard Deviation	6.58 days	Standard Deviation	15.99 days

The breakthrough time data was also analyzed using the Essential Regression software, yielding the following relationship.

$$B = b_0 + b_1(k_a) + b_2(P_i * V_{LCO_2}) + b_3(P_i * k_a) + b_4(P_L * V_{LC1}) \quad \text{.........................(3)}$$

The R^2 value of 0.943 indicates that this is a good description of how breakthrough time varies with changes in reservoir parameters. Table 8 reinforces the validity of the observations made about breakthrough time in Fig. 8–absolute fracture permeability is clearly the most important parameter in determining breakthrough time. This is because injected fluid will move more rapidly through the reservoir to the production well when fracture permeability is high.

Table 8? Relative Importance of Parameters to CO_2 Breakthough Time

Term	Probability Term Will Equal Zero
Const	6.8e-20%
k_a	5.1e-17%
P_i* V_{LCO2}	4.7e-8%
P_i* K_a	3.4e-3%
P_L * V_{LC1}	5.6%
All Terms	6e-34%

2.4 EFFECTS OF PRODUCTION SCENARIOS

Fig. 12 shows the effects that the three different production scenarios have on breakthrough time, methane produced, and CO_2 injected. There is an apparent lack of importance of the production and injection timing. It was expected that producing the injector for one month would lower reservoir pressure and allow more CO_2 injection early in the life of the well, but this is clearly not the case.

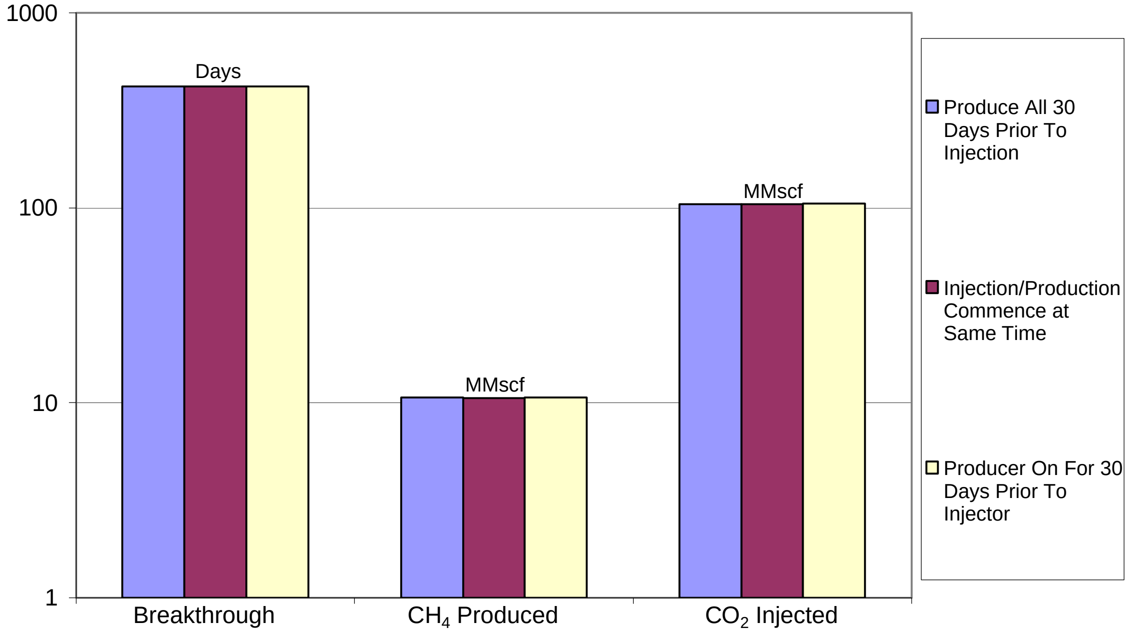

Fig. 12-Effects of different production scenarios on cumulative methane production, cumulative CO_2 injection, and breakthrough time. Results are for 1/4 well on 20 acre per well spacing.

Figs. 13 and 14 show why production timing has so little importance. Fig. 13 is the CO_2 injection rate profile for ¼ of a 5-spot pattern drilled on 10 acre per well spacing. Fig. 14 is the CO_2 injection rate profile for ¼ of a 5-spot pattern drilled on 80 acre per well spacing. The well bottomhole pressure is also shown.

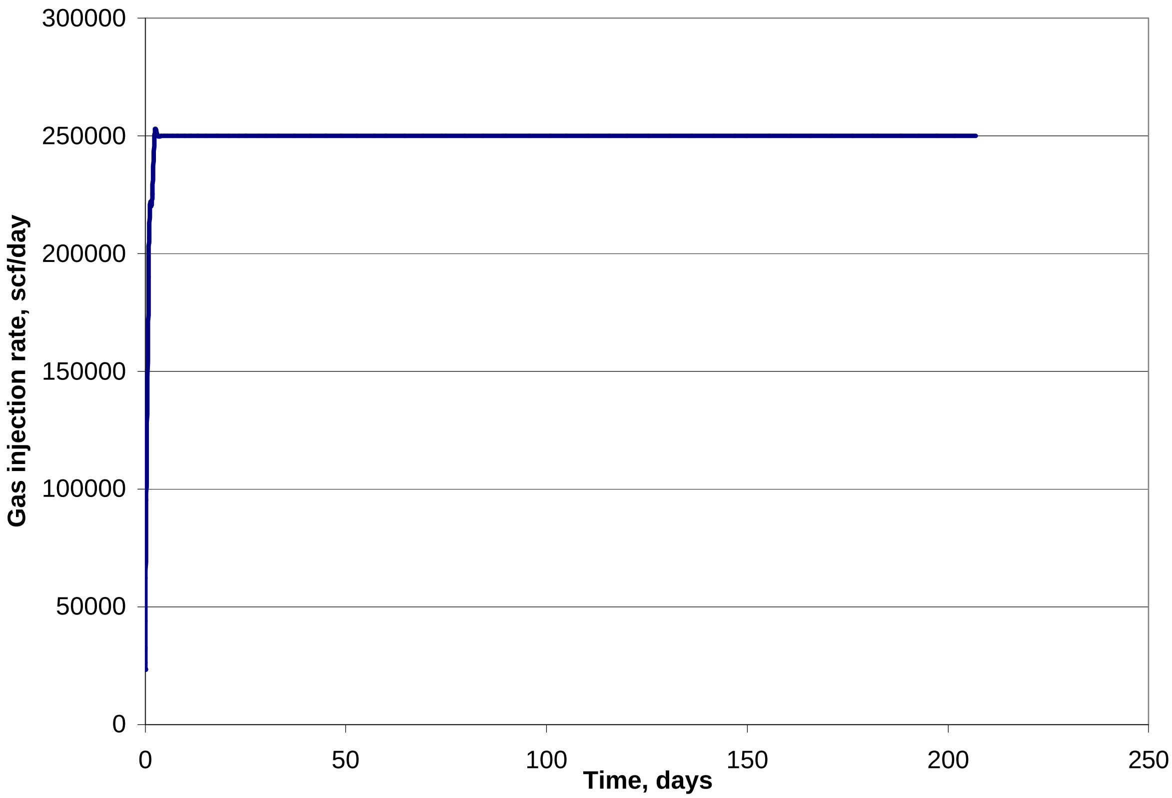

Fig. 13-CO_2 injection rate for the 10 acre per well spacing case. Rate is for 1/4 well.

Both are cases in which injection and production were begun at the same time. These figures show that, except for a short period of time at the beginning of the life of the well, the injector is limited by injection rate, not pressure. The time period over which the well “ramps up” to full injection is extremely short – less than two weeks for the 10 acre per well spacing case and less than two months for the 80 acre per well spacing case. The reason for this is that the production well lowers the pressure in the injection well very quickly. Fig. 14 shows that the injection well bottomhole pressure begins to decrease as soon as the maximum injection rate is reached. Considering how quickly the well can be expected to reach full injection, it would seem that producing the injection well to lower the local reservoir pressure is unnecessary.

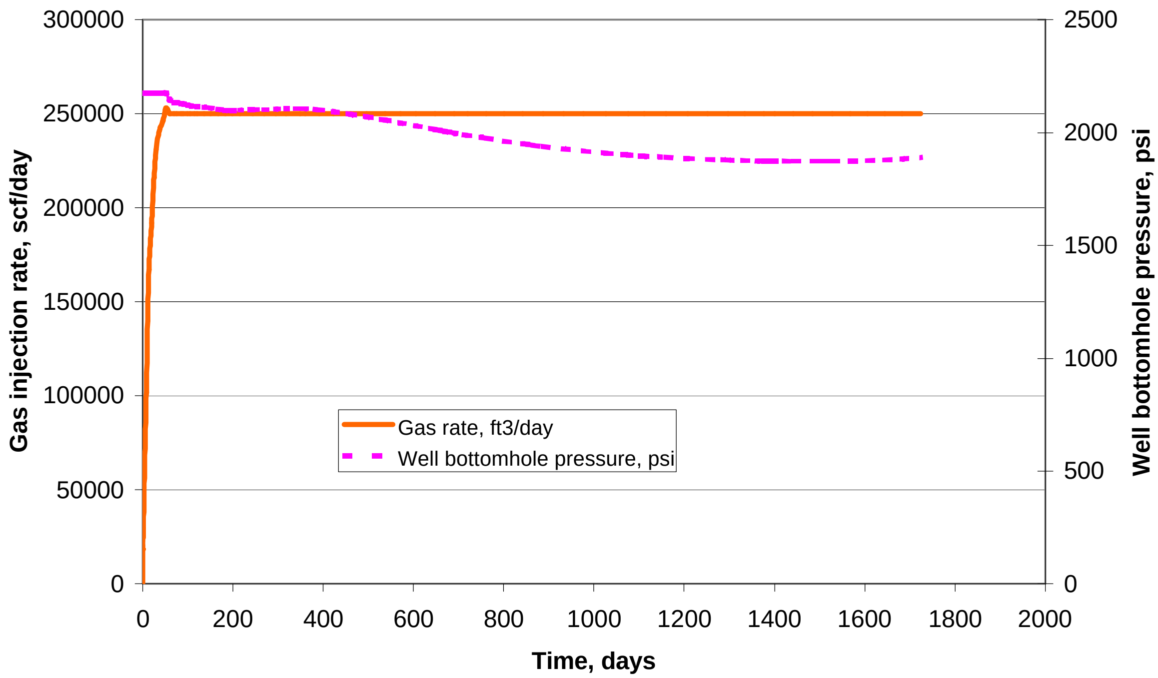

Fig. 14-CO_2 injection rate and injection well bottom hole pressure for the 80 acre per well spacing case. Rates are for 1/4 well.

If the injection well is not pressure limited but rate limited (that is, the effective constraint in the simulation is the rate constraint) this raises the question of what the maximum possible injection rate is. One more simulation run was made to determine this. A base case data set was run for 80 acre per well spacing with the rate constraint removed. The well bottomhole pressure and CO_2 injection rate are shown in Fig. 15. The level of injection modeled in all other cases is a maximum of 1 MMscf/d per well, or 250 Mscf/d per well for the ¼ well model used. Fig. 15 shows that removal of the rate constraint results in injection rates that are greater than 250 Mscf/d but not dramatically so. Thus, the 1 MMscf/d injection well rate constraint is reasonable.

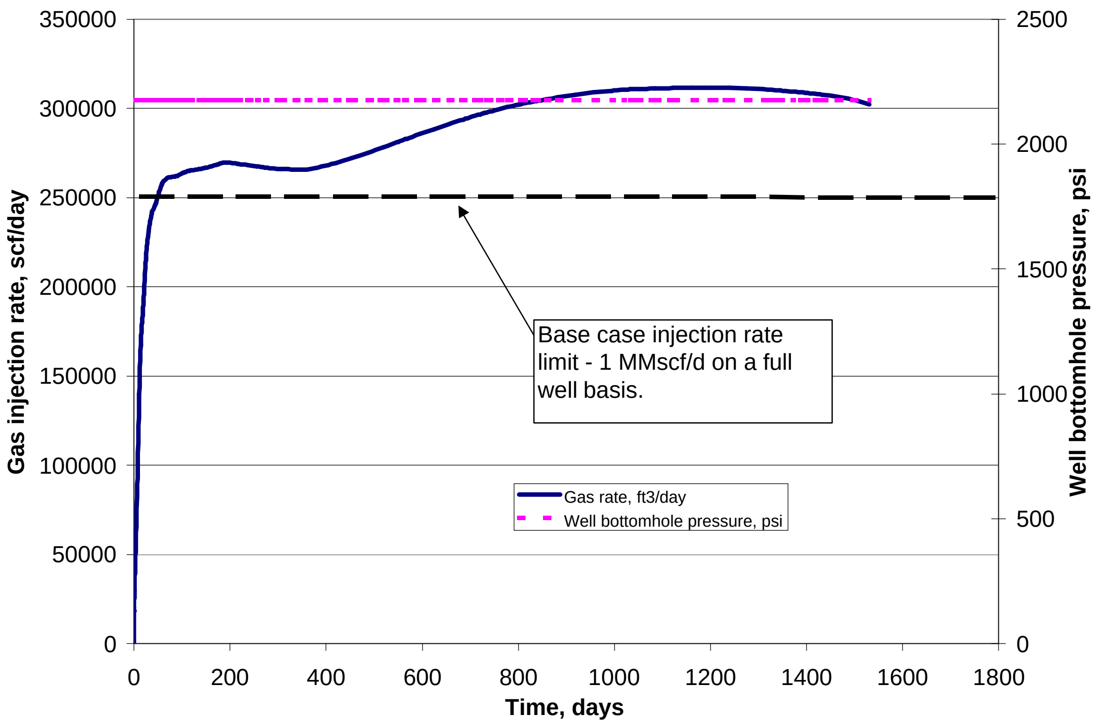

Fig. 15-CO_2 injection rate and bottomhole pressure for the 80 acre per well spacing case. Rates are for 1/4 well and there is no injection rate constraint.

2.4.1 Effect of Well Spacing

Fig. 16 shows the effect that changing the well spacing has on each of the variables considered. A simple trend line was fitted to each data set, and these indicate an almost perfectly linear relationship between each observed variable and well spacing.

$$\begin{aligned} B &= 21.789A - 22.496 \\ C &= 5.4122A - 5.3913 \\ M &= 0.5362A - 0.3997 \end{aligned} \qquad (4)$$

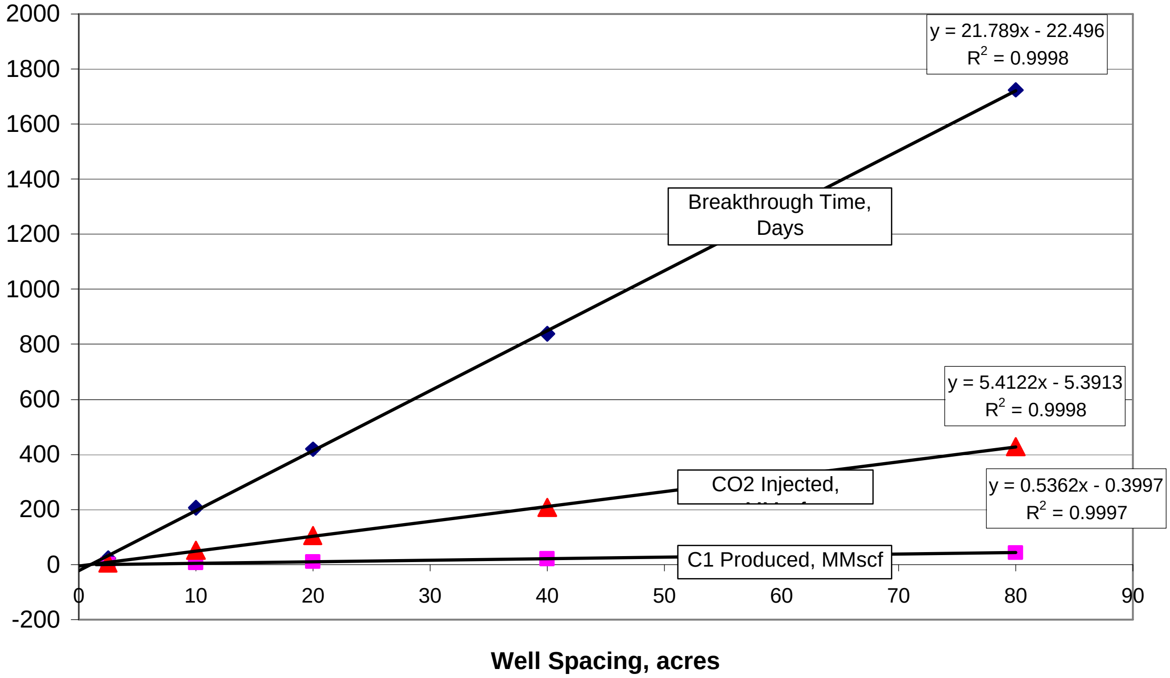

Fig. 16-Effects of well spacing on cumulative methane production, cumulative CO_2 injection, and breakthrough time.

The linear relationship can be readily explained. In the simulations I ran the effective mobility of the injected CO_2 was very low in relation to the methane. The diffusion time for these runs is set to one day, so the CO_2 is adsorbed onto the matrix very quickly as it is injected. Furthermore, the matrix can adsorb ten times as much CO_2 as methane. This combination of quick diffusion into the matrix and large coal adsorptive capacity means that the CO_2 will not bypass the matrix blocks and move quickly to the producing well. Thus, the sweep efficiency is very high and the relationship between well spacing and the results of interest is linear.

These linear relationships allow the results from the 1.25 acre per well spacing simulation runs to be scaled so that they are relevant to larger well spacings, eliminating the need for additional time-consuming simulations. The slope of the cumulative methane produced line is one-tenth that of the cumulative CO_2 injected line. This is because Langmuir volume for methane is set to one-tenth the Langmuir volume of CO_2 for these simulation runs. If this relationship changed we would expect to see a change in the relationship between the slopes. Figs. 17, 18, and 19 show the performance of the 80 acre per well spacing case, the largest well spacing run.

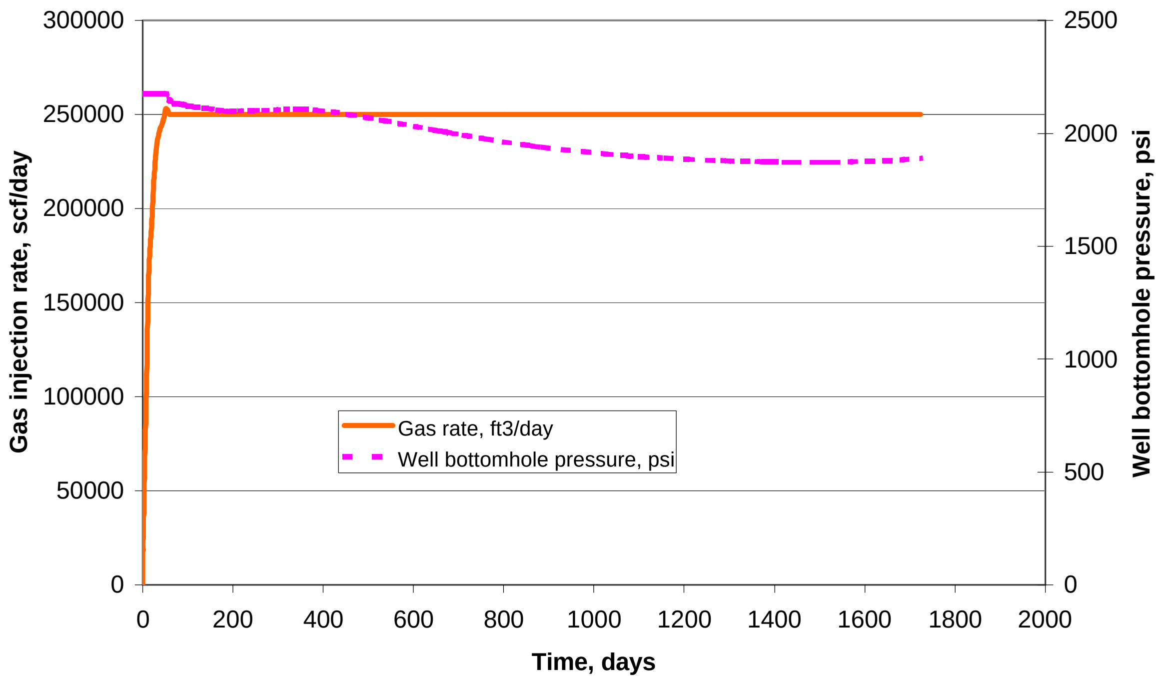

Fig. 17-CO_2 injection rate and injection well bottom hole pressure for the 80 acre per well spacing case. Rates are for 1/4 well.

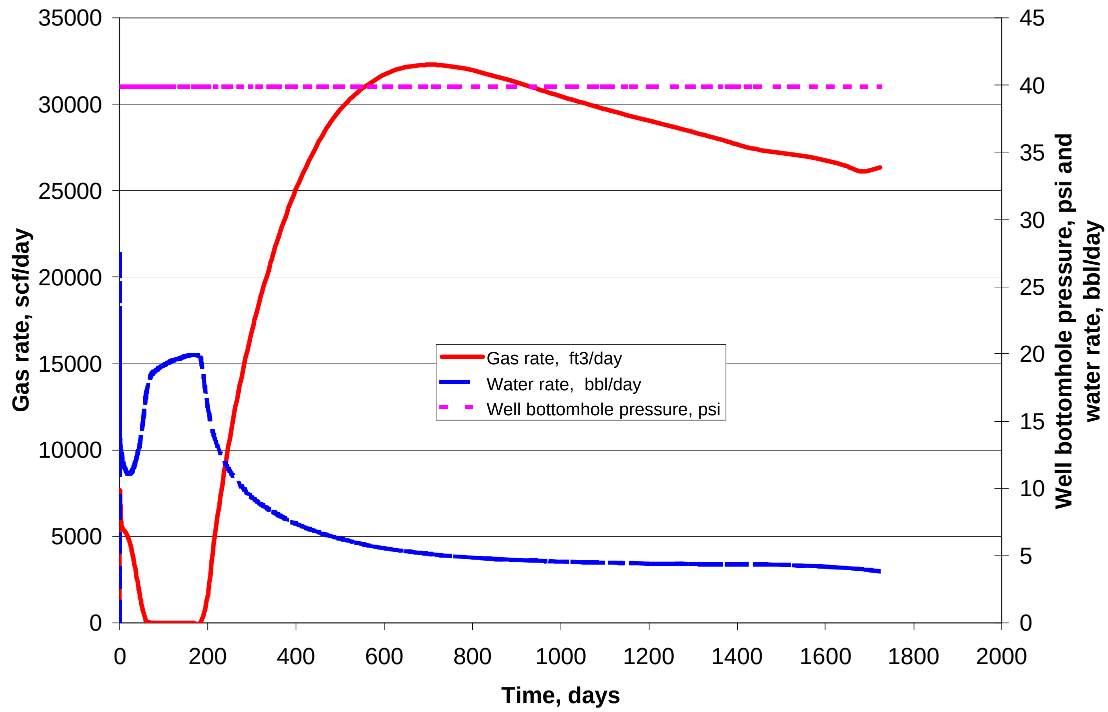

Fig. 18-Methane and water production rates and producing well bottomhole pressure for the 80 acre per wells spacing case. All rates are for 1/4 well.

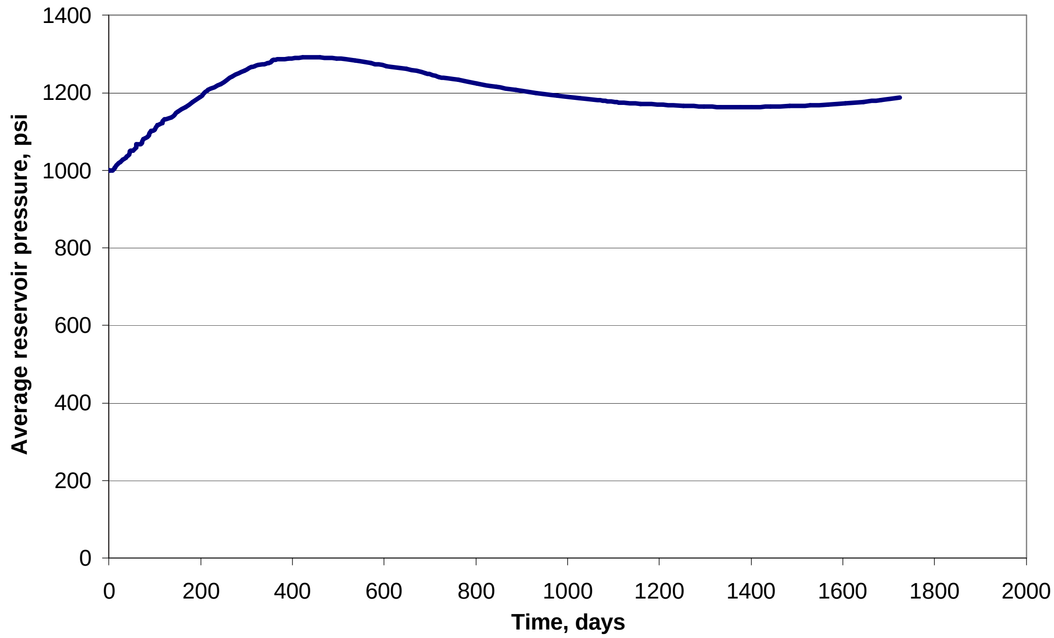

Fig. 19-Average reservoir pressure for the 80 acre per well spacing case.

2.5 POTENTIAL ERRORS AND THEIR IMPACTS

There is a potential problem with the simulation results. Regardless of initial reservoir pressure, the producing well is operated at 40 psi bottom hole pressure, with a volumetric rate limit so high as to be ineffective. The injection well is operated at a maximum bottom hole pressure of 2,000 psi, and at a maximum rate of 250 Mscf/d (corresponding to 1 MMscf/d on a full well scale), also without regard to initial reservoir pressure. This results in the average reservoir pressures being drawn down extremely low in the simulation cases with high initial reservoir pressure. Also, the low initial reservoir pressure cases are over-pressured by the high-pressure injection. This is unrealistic –we would expect well operating pressures to be managed so as to maintain average reservoir pressure close to the initial reservoir pressure. To assess the impact of this unrealistic condition on the results of my work, I made additional simulation runs using the base case reservoir data set, but modified the well operating pressures so as to maintain average reservoir pressure relatively constant. Average reservoir pressure is maintained within 500 psi of the initial reservoir pressure in the high pressure (2,000 psi) case, within 250 psi in the medium pressure (1,000 psi) case, and within 100 psi in the low pressure (500 psi) case. The maximum injection rate was reached in the high pressure and medium pressure cases, but not the low case. The well operating conditions I used to achieve these results are summarized in Table 9.

Table 9–Operating Conditions for Reservoir Pressure Control

P_i	Injection Well Pressure & Rate		Production Well Pressure & Rate	
2000 psi	2000 psi	250 Mscf/d	875 psi	Unlimited
1000 psi	2000 psi	250 Mscf/d	40 psi	Unlimited
500 psi	875 psi	250 Mscf/d	40 psi	Unlimited

For the high and low pressure cases, operating the wells in this more realistic way had an impact on CO_2 breakthrough time, cumulative methane produced, and cumulative CO_2 injected. In the medium initial reservoir pressure case the average reservoir pressure is maintained at a reasonable level under the base case operating conditions. The percentage change in the results appear in Table 10.

Table 10–Percent Change in Results from Base Case Operating Conditions to Pressure Control Operating Conditions

	Breakthrough Time	Cumulative CO_2 Injection	Cumulative Methane Production
2000 psi	Increased 26%	Decreased 2%	Decreased 18%
1000 psi	0%	0%	0%
500 psi	Increased 181%	Decreased 11%	Increased 19%

The change to more realistic operating conditions had the greatest impact on breakthrough time. The impact on cumulative CO_2 injected and cumulative methane produced is less, but still significant. The medium pressure case (1,000 psi) shows no change in results because, as stated before, the base case operating conditions are sufficient to maintain average reservoir pressure close to initial reservoir pressure. This potential flaw in the experiment should have little impact on the reservoir parameters sensitivity study. However, it will impact the economic analysis. Well performance assumptions were made for the economic analysis based on the initial assumptions regarding reservoir pressure. The large increases in breakthough times means that the economic model may assume more frequent well drilling than would actually be necessary. Thus, the economic model may be conservative.

2.6 DISCUSSION OF RESERVOIR SENSITIVITY ANALYSIS

Regression analysis allows the critical parameters to be ranked according to their effects on cumulative methane production, CO_2 injection and breakthrough time. The combination of Langmuir pressure and Langmuir volume for methane is significant, as is the combination of initial reservoir pressure and permeability. Interestingly, cumulative CO_2 injection is not particularly sensitive to initial reservoir pressure. Probably the least important parameters are diffusion time, which is never significant enough to appear in the regression equations, and Langmuir pressure, which is significant only in its combination with Langmuir volume for methane.

The ratio of CO_2 injected to methane produced is slightly more than ten to one, which is also the ratio of Langmuir volume for CO_2 to Langmuir volume for methane. This indicates excellent sweep of the reservoir–the CO_2 is displacing nearly all the methane before it breaks through to the producing well. In the base case the recovery efficiency is 85%. If there is more methane in place than expected, this good sweep efficiency could result in significantly more methane production than my work predicts.

This brings into question the accuracy of the data set used in simulation. While the data are the best available at this time there is a large degree of uncertainty in most of the parameters. Future work should attempt to determine Langmuir volumes and absolute fracture permeability more accurately. The main problem with the current simulation data set is that the significance of the parameters is tied to the ranges over which the parameters are varied. Clearly, even if the least important parameter is varied over a large range it will become relatively more important. Similarly, varying an important parameter over a small range will decrease its importance relative to the other parameters. Acquisition of more data should give a clearer picture of the distribution of values for each parameter. Such information would allow us to populate a series of simulations with reasonable values whose probability is known. This, in turn, would allow a more accurate quantification of the effect that each parameter or combination of parameters has on each response variable.

3. ECONOMIC MODEL

The economic model is for the capture and injection of all the CO_2 generated by a 444 MW power plant – approximately 180 Mscf/d of pure CO_2. This is approximately the output of the Gibbons Creek lignite-burning power plant near College Station, Texas. This power plant emits 1% of all CO_2 emissions in Texas. Simulation results were useful in setting the performance of the wells in the economic model. All injection wells inject one MMscf/d of CO_2. This is the rate at which wells in the pilot projects in the San Juan basin were able to inject, and simulation showed this to be reasonable. Each production well is assumed to produce 120 Mscf/d for the life of the well. This is consistent with reservoir simulation results, which showed methane production rates of 120 to 160 Mscf/d. Simulation showed that, owing to ECBM operations, methane production rate remains reasonably constant over the life of the well until CO_2 breakthrough. Wells drilled in the area of the Gibbons Creek plant are likely to encounter 30 feet of net coal thickness. Wells are drilled in a five-spot pattern on 80 acre per well spacing, so the ratio of injection to production wells is one to one. Based on the simulation results, wells drilled on 80 acre per well spacing in 30-foot thick coals should have a minimum 10-year operating life before CO_2 breakthrough in the production wells. Thus, in the economic model all wells are operated for 10 years before being replaced with new wells. My model assumes an effort will be made to drill shallower coals (1,000 to 4,000 feet) to save costs; thus, a composite 3,000 foot TD well is assumed.

There is a need for 180 injection and 180 production wells based on the injection rates from simulation. The wells are drilled at a rate of 36 per year, so it is 10 years before the entire CO_2 stream is injected. CO_2 breaks through to the production wells after 10 years, so new production and injection wells are needed. Thus, the well drilling rate is constant at 36 wells per year for the 17-year life of the model.

3.1 EXISTING ECONOMIC MODELS

Several financial models for coalbed methane operations have been published. The three models I found most helpful are summarized below:

1. Lloyd Byrne[22]: Byrne published comprehensive financial models for coalbed methane operations in all the major producing areas in April 2001. His model is based on average costs for operations in each basin. No modeling was done for operations in Texas because there was no Texas coalbed gas production at that time.
2. W. Thomas Goerold[23]: Goerold's model is specific to operations in the Powder River Basin. He takes particular care to model water disposal costs in that region. His model is based on the Powder River Basin model published by Byrne.
3. Griffiths & Pilcher[24]: This model is specific to coalbed methane operations in Texas. It does not provide any details regarding basis differential (difference between local gas price and quoted hub price, e.g., Henry Hub gas), field use, BTU discounts, or treating and transportation.

I used features of each of these models to develop a detailed economic model of coalbed methane operations in Texas. Drilling and several other costs were taken from the Griffiths & Pilcher model. The Byrne model was used to determine the netback price that can be expected from selling produced gas. The Goerold model was helpful in its detailed explanation of assumptions, operating costs, and royalties.

3.2 EXPLANATION OF THE TEXAS CBM MODEL

The economic model for the most likely, or base, case can be broken down into five parts: financial assumptions, capital expenditures (CAPEX), operating expenditures (OPEX), revenues, and overall cash flows (Appendix II). The first four parts are used in the generation of the fifth part. The best way to explain the model is to examine each of these parts in sequence.

3.2.1 Financial Assumptions

For this model I assumed that all capital costs are straight-line depreciated over a 10-year period. Typically, companies depreciate assets based on what has been done in the past. Thus, every company has a slightly different depreciation method, and straight-line depreciation is a fair and simple approximation. The federal income tax rate is set to 35% of taxable income. The model further assumes that if revenue for tax purposes is negative, then this loss will be carried forward to the following year. The discount rate, or cost of capital, is assumed to be 10%. Different project financing scenarios can be modeled by changing the discount rate assumption. All costs and prices are assumed to increase at a rate of 3% per year. Inflation is assumed to be 2% per year.

3.2.2 Capital Expenditures (CAPEX)–Non-Discounted

The cost of drilling production and injection wells is assumed to be $217,500 per well, based on costs from the Griffiths & Pilcher model. The cost to tie in each well to the production/injection system is assumed to be $30,000, based upon anticipated production rates and well depth. This cost takes into account all capital expenditures for water and methane gathering, water treatment, and water disposal. The information is specific to South Texas and is available from the Energy Information Agency (EIA).[25]

I assumed drilling costs to be 75% intangibles, which are amortized fully the year in which they occur. The other 25% of drilling costs are assumed to be tangibles and are depreciated over 10 years. This tangible/intangible assumption and the way in which it allows drilling costs to be treated reflects the assumption that, for tax purposes, the company funding the project will be viewed as an independent rather than a major.

The model assumes that acquisition of a lease of appropriate size will cost $100,000. This one time expense is amortized over 10 years. The model also assumes that a short pipeline will be built from the power plant to the injection location. This CO_2 pipeline is assumed to cost $500,000 and is depreciated over a 10-year period.

3.2.3 Operating Expenditures (OPEX)–Non-Discounted

Injection and production well operating costs are assumed to begin the year after they are drilled, at the same time they begin production or injection. Production well operating costs are assumed to be $1,000 per month. These data come from the EIA and are based on production rate, well depth, and producing area (assumed to be South Texas). Injection well operating costs are assumed to be $300. This difference in well costs reflects the fact that production wells will probably need some kind of artificial lift to remove water from the well.

Pipeline operating costs, or transportation costs, are assumed to be $0.05 per Mscf of CO_2. In addition, the cost of capturing the CO_2 from the power plant flue gas stream is assumed to be \$0.50 per Mscf. This assumes that the latest CO_2 capture technology (presented by Iijima[5]) is used and that there are economies of scale due to the size of the plant and the large fraction of CO_2 in the waste gas stream. It also assumes that there are no CO_2 sequestration credits given for injecting the CO_2. Changing this assumption can change the price of capturing the CO_2. For example, a CO_2 sequestration credit of \$19 per ton can be modeled by reducing the cost of capturing CO_2 by \$1 per Mscf to -\$0.50. A negative number indicates that the captured CO_2 actually has value should it be sequestered. All injection wells are assumed to inject 1 MMscf/d.

3.2.4 Revenue–Non Discounted

Goerold[22] says that federal production royalties can be assumed to be 12.5% and private royalties can be assumed to be 20%, resulting in a weighted average of 15.65%. This number is used here and royalties are subtracted from yearly gas production prior to sale.

The gas price realization is assumed to be \$4/Mscf. This is based upon the recent New York Mercantile Exchange (NYMEX) price for natural gas delivered to the Henry Hub in Louisiana. Of course, not all gas produced in the United States is delivered to the Henry Hub. Thus, there are discounts based on where the gas is sold, due to the differences in local markets, demand, and distribution networks. This difference is called basis differential. This model assumes basis differential to be \$0.20, reflecting the difference between the mid-continent gas price and the Henry Hub gas price. There are further discounts for the difference in BTU's (assumed to be \$0.13), for field use and compression (assumed to be \$0.19), and for treating and transportation (assumed to be

$0.44). It is important to remember that these discounts are not a percentage of the NYMEX price but are in fact fixed. Thus, any price increase goes directly into the revenue stream. All of these price discounts are subtracted from the NYMEX price. After all price discounts, Texas state severance tax is 7.5% of the netback price, $3.04 in this case.

3.2.5 Cash Flows

The cash flows section is a summary and final processing of the four previous parts of the economic model. The sum lines from the CAPEX, OPEX, and Revenue sections are all included here. In addition, there is a separate line for the total depreciation amount for each year. The difference between revenue and the sum of OPEX and depreciation is the revenue for tax purposes, from which federal income taxes are calculated. The difference between revenue and the sum of CAPEX, OPEX, and taxes is shown in the Undiscounted Cash Flow line. The next line shows cash flow with cost of capitol taken into account, and is labeled as discounted cash flow. Inflation is then taken into account for the discounted cash flow yielding a deflated discounted cash flow. The final line is a running sum for the deflated discounted cash flow – the cumulative deflated discounted cash flow. The final entry in this line is the net present value (NPV). This value is also shown just below the final line. NPV for the base case is a loss of $139 million after 17 years (Appendix II).

3.3 SENSITIVITY TESTING USING ECONOMIC MODEL

Project economics were tested for sensitivity to gas price realization under different regulatory and fiscal conditions. First, the sensitivity of the base case to gas price realization was tested. Next, I looked at what would happen if Texas state severance taxes were forgiven. A third scenario considered was the creation of CO_2 sequestration credits by the government.

3.3.1 Base Case Gas Price Sensitivity

The assumed natural gas price in the base case is $4/Mscf. As with any project, it is important to test the sensitivity of project economics to potential changes in the revenue stream. The project NPV was -$139 million under the base case assumptions. The gas price assumption was raised until NPV was zero. For the base case assumptions, the project was found to break even at a NYMEX gas price of $9.93/Mscf (Line 1, Fig. 20). While this is an extremely high price for natural gas it is not out of the realm of possibility. In fact, the price for natural gas has exceeded this price at times within the last few years, reflecting surging demand and relatively flat supply of natural gas in the United States. Furthermore, should the government provide tax incentives for the development of coalbed methane similar to those enacted in 1992, this could add another dollar above the NYMEX price to the gas price realization. This is unlikely at present.

3.3.2 Texas State Severance Tax Forgiven

Line 2 in Fig. 20 shows the sensitivity of NPV to gas price realization under the assumption that Texas state severance tax will be forgiven. Texas state severance tax is 7.5% of the value of the gas minus the cost to move the gas to the point of sale. It is possible that severance tax could be forgiven in the interests of reducing CO_2 emissions and promoting development of coalbed methane resources. For Line 2 in Fig. 20, gas price is varied from the initial assumption of \$4/Mscf to the breakeven price of \$9.26/Mscf. Suspension of the Texas state severance tax would lower the breakeven gas price for this project by \$0.67, or 7.5%. This is true for all other cases considered– suspension of severance tax will lower the breakeven price by 7.5%.

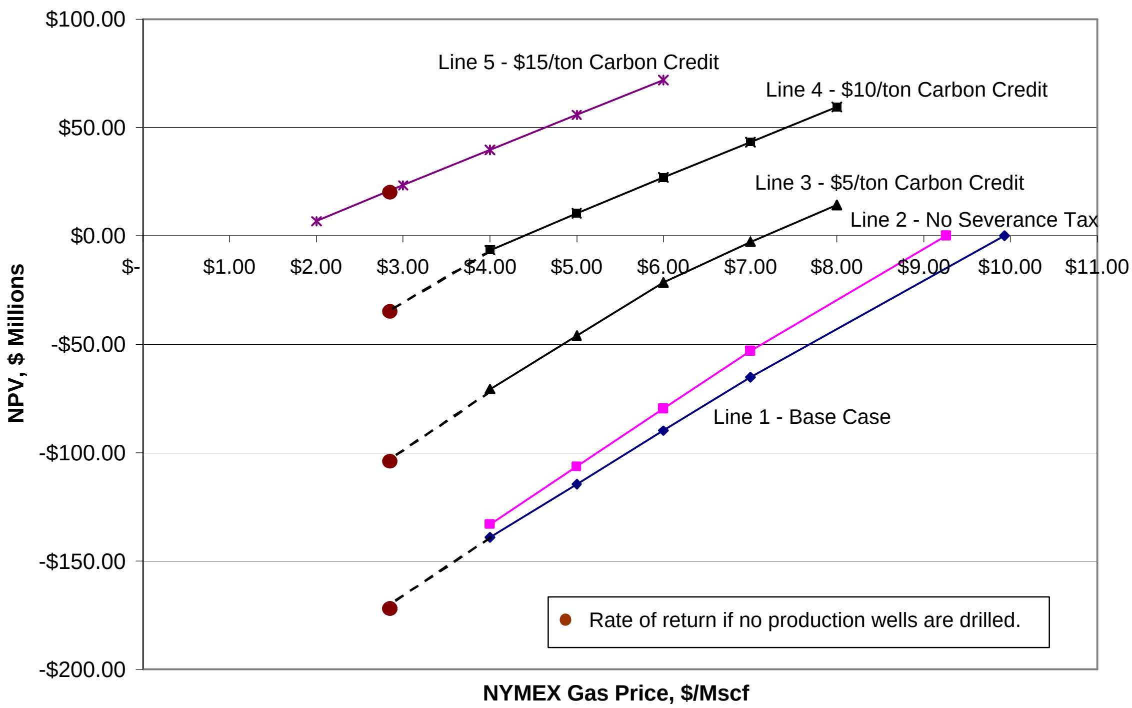

Fig. 20-Sensitivity of NPV to NYMEX gas price under different project scenarios.

3.3.3 Impact of Carbon Sequestration Credits

One of the largest costs for point source sequestration projects is capture of the CO_2 in the flue gas stream. These costs can be lowered through economies of scale and application of advanced technologies. Another way these costs can be offset is by the government enacting a CO_2 emissions tax or establishing carbon sequestration credits.

These two options are effectively the same thing – they place some value on carbon dioxide injected into the ground because it is not vented to the atmosphere. The sequestered carbon is generally valued on a dollars-per-ton basis. The assumptions implicit are that the sequestration activities associated with this project are recognized as valid by regulatory authorities and the credits are approved. In fact, approval of credits could end up being difficult, but there is presently no formal process for verifying carbon sequestration credits.

I examined the impact on project economics of carbon credits valued at $5, $10, and $15 per ton. At 19 Mscf/ton CO_2 these credits amount to $0.26, $0.52, and $0.78 per Mscf of CO_2 captured, respectively. The impact on project economics is dramatic (Lines 3, 4, and 5, Fig. 20). The breakeven gas prices for the three cases are $7.16/Mscf, $4.38/Mscf, and $1.60/Mscf, respectively. CO_2 capture costs are a large part of the total costs of this project, and anything that lowers these costs is beneficial to project economics.

3.3.4 Elimination of Production Wells

Besides capture of CO_2, the largest cost item is drilling wells. If each production well can be expected to make only 120 Mscf/d, perhaps it would be better to simply eliminate production wells and focus on injection of the CO_2. For production wells to add to project economics, it must be shown that the revenue generated by the production wells exceeds the additional costs incurred by drilling and operating them. By running the previously discussed scenarios without the costs or revenues of production wells I generated a set of points corresponding to the NPV of each project scenario without production wells. In Fig. 20 the curves from the previous scenarios are extended with dotted lines to these points, and we see that it is worth drilling the methane production wells if the price of gas is above \$2.85/Mscf. This result is approximate because I did not actually model CBM well performance without CO_2 injection. However, the analysis shows that production wells do have a positive impact on project economics and that the 120 Mscf/d production rate is enough to cover the costs of drilling and operating production wells under realistic gas pricing scenarios.

3.4 ECONOMIC MODEL DISCUSSION

A CO_2 sequestration/ECBM project is unlikely to be economically viable in Texas under the current environmental laws and gas price structure. This is not to say that an economical project is impossible, merely that it is unlikely. With no CO_2 credits, gas prices would have to be close to \$10/Mscf for the project to have a positive NPV.

The two largest costs associated with this project are the costs of drilling wells and capturing CO_2. However, the approximately \$10 million per year well drilling cost is small compared to the over \$50 million per year CO_2 capture cost. This finding agrees with Wong, Gunter, and Mavor's[4] statement that the main cost associated with CO_2 sequestration is capture of the CO_2. In order to make sequestration projects in Texas coals financially viable the cost of CO_2 capture must be reduced or offset. This could happen in several ways. Improved capture technology can lower costs but advances are likely to take years and are usually slow in being adopted. The most likely method for dramatic cost "reduction" is the imposition by the government of tax credits related to CO_2 sequestration. CO_2 emissions are a global problem and cause few, if any, local problems. Therefore, CO_2 sequestration credits are ideal for trading. Assuming that sequestration in deep unmineable coal seams is accepted as a valid and stable means of sequestration, sale of the carbon credits acquired through injection could dramatically offset the cost of capturing CO_2 from flue gas.

According to Kilgore, an employee of the company Natsource, which is currently involved in trading CO_2 credits, there is a very limited but real market for CO_2 credits at this time.[*] The motivation for purchasing credits is purely altruistic, and the credits are sold for $1 per ton of CO_2 sequestered or less. It is interesting to note that while some countries, such as Norway, have enacted a CO_2 emissions tax, there is no international market for CO_2 sequestration credits. Given the global nature of the CO_2 problem and the lack of local detrimental effects, there is no reason why a company in Norway should not be able to purchase approved CO_2 sequestration credits from a company in the United States to offset its emissions in Norway. That this is not the case is indicative of the fact that environmental legislation is often highly politicized and emotionally driven. Perhaps such transactions will be accepted in the future.

Institution of the CO_2 credits considered in this study, $5, $10, and $15 per ton, would all dramatically increase the likelihood of sequestration projects being carried out. A credit of just $5/ton of CO_2 sequestered would cause the project to be economic at gas prices competitive with those for imported LNG. If the production wells produce more than 120 Mscf/d the carbon credit value required to make the project economic would be

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[*] Personal communication with K. Kilgore, Natsource, New York City (2003)

even lower. Elimination of the Texas state severance tax or a substantial amount of government funding would further improve economics.

4. CONCLUSIONS

1. Based on a survey of the literature, reservoir properties for Texas coals are expected to fall in the following ranges:

Fracture Absolute Permeability	1 to 20 md
Coal Density	78 to 82 lb/ft^3
Langmuir Volume for CO_2	600 to 1,000 scf/ton
Langmuir Volume for Methane	60 to 100 scf/ton
Langmuir Pressure for CO_2 and Methane	300 to 500 psi
Diffusion Time	0 to 4 days
Initial Reservoir Pressure	500 to 2,000 psi

   There is significant uncertainty in the properties, since they are based on little measured data.

2. The most significant coal reservoir parameters are fracture permeability, Langmuir volumes for CO_2 and methane, and reservoir pressure. Further data collection is warranted, and should focus on determining the most significant parameters with greater accuracy.

3. Given the parameter values we used, coalbed methane wells in the Gulf Coast of Texas can be expected to produce on the order of 120 Mscf/d of methane. Likewise, injection wells can be expected to inject at rates of approximately 1 MMscf/d of CO_2 into the same coal seams.

4. Injection/production activities should be able to continue for up to 10 years before breakthrough, even in thin coals of only 10 ft thickness. However, breakthrough times for individual patterns will vary with well spacing and coal thickness.
5. The injected CO_2 is very effective in sweeping the methane from the reservoir, with methane recovery efficiencies of around 85%.
6. Separation and compression of CO_2 from the flue gas stream are by far the largest cost items for CO_2 sequestration/ECBM projects in Texas.
7. The existing market for CO_2 sequestration credits provides insufficient economic support for CO_2 sequestration/ECBM projects in low rank Texas coals, but CO_2 sequestration credits of as little as \$5/ton CO_2 or gas prices above \$6/Mscf would dramatically improve project economics.

NOMENCLATURE

r_{coal} = coal density, lb/ft^3

A = area, acres

B = breakthrough time, days

b_x = constant

C = CO_2 injected, MMscf

Gs = gas storage capacity, scf/ton

k_a = absolute fracture permeability, md

M = methane produced, MMscf

V_L = Langmuir volume – the total volume of gas that a given mass of coal can adsorb at a given temperature, scf/ton.

P_i = initial reservoir pressure, psi

P_L = Langmuir pressure – the pressure at which the volume of gas that remains adsorbed to the coal is equal to exactly one half the Langmuir volume, psi

P_P = partial pressure, psi

V_{LC1} = Langmuir volume for methane, scf/ton

V_{LCO2}=Langmuir volume for CO_2, scf/ton

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APPENDIX I

Input file for GEM, reservoir modeling software. This is the file used to model the base case.

```
*RESULTS SIMULATOR GEM
**
** GMSMO014.DAT: Enhanced Coal Bed Methane
**------------------------------------------------------------------
**------------------------------------------------------------------
**
** FILE:  GMSMO014.DAT
**
** MODEL: CART 11x11x1 GRID           ENHANCED COAL BED METHANE
**        3 COMPONENTS                CO2 DISPOSAL
**
**------------------------------------------------------------------
**
** Enhanced Coal Bed Methane problem.
**
**------------------------------------------------------------------


**------------------------------------------------------------------


*FILENAMES     *OUTPUT     *SRFOUT     *RESTARTOUT     *INDEX-OUT
*MAINRESULTSOUT
*TITLE1       'ECBM         Problem'
*INUNIT       *SI
**Dimensioning setting used because of fully implicit setting below
*DIM    *MDIMPL    100

*WSRF         *WELL         0
*WSRF         *GRID0
**SUMMARY

**WSRF        *GRID         1
**WSRF        *WELL         1
**WPRN        *GRID         *TIME

**WPRN        *WELL         1
```

```
*WRST       0

**OUTSRF    *RES   *ALL

**OUTSRF    *GRID *PRES *SW *SG *Y1 *Y2 *Y3 *DENW *DENG *VISG *ADS1
*ADS2 *ADS3
**OUTPRN    *RES   *ALL

**OUTPRN    *GRID *PRES *SW *SG *Y1 *Y2 *Y3 *DENW *DENG *VISG *ADS1
*ADS2 *ADS3
**OUTPRN    *WELL       *ALL


**------------------------------------------------RESERVOIR DATA------

*GRID *CART 11 11 1

*KDIR *DOWN


*DUALPOR


*DI    *IVAR        2.5 5 5 5 5 5.294 5 5 5 5 2.5
*DJ    *JVAR        2.5 5 5 5 5 5.294 5 5 5 5 2.5
*DK    *CON  3.048

*PAYDEPTH *CON  609.6


*DIFRAC     *CON  0.0635

*DJFRAC     *CON  0.0635

*DKFRAC     *CON  0.0635


*POR  *FRACTURE *CON  0.005

*POR  *MATRIX     *CON  0.005


*PERMI       *FRACTURE *CON  5
```

```
*PERMJ       *FRACTURE *CON  *EQUALSI

*PERMK       *FRACTURE *CON  *EQUALSI


*PERMI       *MATRIX   *CON  0.0001

*PERMJ       *MATRIX   *CON  0.0001
*PERMK       *MATRIX   *CON  0.0001

*CPOR        *MATRIX         1.45E-07
*CPOR        *FRACTURE       2.00E-05
**PRPOR      *MATRIX         7.65E+03
**PRPOR      *FRACTURE       7650

**--------------------------------------------------FLUID COMPONENT DATA

**Insert file written by WINPROP based on library components

**The following is the fluid component
**property data in GEM 98.00 format.
**The units specification keyword should
**be specified in the I/O control section.
**It appears here as a reminder of the unit system
**used in WinProp to generate this data.

**      PVT   UNITSCONSISTENT      WITH  *INUNIT    *SI

*MODEL       *PR
*NC   2      2
*TRES        45
*PVC3        1.20E+00
*COMPNAME
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*SG   3.00E-01    8.18E-01
*TB   -1.61E+02   -7.85E+01
*PCRIT       4.54E+01    7.28E+01
*VCRIT       9.90E-02    9.40E-02
*TCRIT       1.91E+02    3.04E+02
*AC   8.00E-03    2.25E-01
*MW   1.60E+01    4.40E+01
*HCFLAG      0.00E+00    0.00E+00
*BIN
1.03E-01
```

```
*VSHIFT
          0.00E+00    0.00E+00
*VISCOR   *HZYT
*MIXVC    1.00E+00
*VISVC
          9.90E-02    9.40E-02
*VISCOEFF
          1.02E-01    2.34E-02    5.85E-02    -4.08E-02    9.33E-03
*OMEGA
          4.57E-01    4.57E-01
*OMEGB
          7.78E-02    7.78E-02
*PCHOR
          7.70E+01    7.80E+01
*ENTHCOEF
          -5.58E+00   5.65E-01    -2.83E-04   4.17E-07     -1.53E-10
1.96E-14
          4.78E+00    1.14E-01    1.01E-04    -2.65E-08    3.47E-12
-1.31E-16

*REFPW    101.325
*DENW     990
*CW       5.80E-07
*VISW     6.07E-01

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          0.1      0.0013    *int
          0.15     0.002     *int
          0.2      0.007     *int
          0.25     0.015     *int
          0.3      0.024     *int
          0.35     0.035     *int
          0.4      0.049     *int
          0.45     0.067     *int
          0.5      0.088     *int
          0.55     0.116     *int
          0.6      0.154     *int
```

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        0.7     0.251   *int
        0.75    0.312   *int
        0.8     0.392   *int
        0.85    0.49    *int
        0.9     0.601   *int
        0.95    0.731   *int
        0.975   0.814   *int
        1       1       0

*SLT
**      Sl      Krg     Krog
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        0.05    0.835   *int
        0.1     0.72    *int
        0.15    0.627   *int
        0.2     0.537   *int
        0.25    0.466   *int
        0.3     0.401   *int
        0.35    0.342   *int
        0.4     0.295   *int
        0.45    0.253   *int
        0.5     0.216   *int
        0.55    0.18    *int
        0.6     0.147   *int
        0.65    0.118   *int
        0.7     0.09    *int
        0.75    0.07    *int
        0.8     0.051   *int
        0.85    0.033   *int
        0.9     0.018   *int
        0.95    0.007   *int
        0.975   0.0035  *int
        1       0       0.00001

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**SGT
**      0.01    0       1       0
**      1       1       0       0
**SWT
**      0       0       1       0
**      1       1       0       0
*SWT
**      Sw      Krw     Krow
```

```
        0       0       0.00001
        0.05    0.0006  *int
        0.1     0.0013  *int
        0.15    0.002   *int
        0.2     0.007   *int
        0.25    0.015   *int
        0.3     0.024   *int
        0.35    0.035   *int
        0.4     0.049   *int
        0.45    0.067   *int
        0.5     0.088   *int
        0.55    0.116   *int
        0.6     0.154   *int
        0.65    0.2     *int
        0.7     0.251   *int
        0.75    0.312   *int
        0.8     0.392   *int
        0.85    0.49    *int
        0.9     0.601   *int
        0.95    0.731   *int
        0.975   0.814   *int
        1       1       0

*SLT
**      Sl      Krg     Krog
        0       1       0
        0.05    0.835   *int
        0.1     0.72    *int
        0.15    0.627   *int
        0.2     0.537   *int
        0.25    0.466   *int
        0.3     0.401   *int
        0.35    0.342   *int
        0.4     0.295   *int
        0.45    0.253   *int
        0.5     0.216   *int
        0.55    0.18    *int
        0.6     0.147   *int
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        0.7     0.09    *int
        0.75    0.07    *int
        0.8     0.051   *int
        0.85    0.033   *int
        0.9     0.018   *int
```

```
        0.95    0.007   *int
        0.975   0.0035  *int
        1       0       0.00001

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*RTYPE      *FRACTURE   *CON 2
*ROCKDEN    *MATRIX     *CON 1281.47
*ROCKDEN    *FRACTURE   *CON 1434

*ADGMAXC 'C1'   *MATRIX     *CON 0.111699   ** gmol/kg of rock
*ADGMAXC 'CO2'  *MATRIX     *CON 1.11699    ** gmol/kg of rock
*ADGCSTC 'C1'   *MATRIX     *CON 3.13E-04   ** 1/kPa
*ADGCSTC 'CO2'  *MATRIX     *CON 3.63E-04   ** 1/kPa
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*ADGCSTC 'CO2'  *FRACTURE   *CON 0

*COAL-DIF-TIME  'CO2'  *CON 1
*COAL-DIF-TIME  'C1'   *CON 1

**------------------------------------------------INITIAL CONDITION---

**from the other file I made
*INITIAL
*VERTICAL  *OFF

*PRES *MATRIX           *CON 6895
*PRES *FRACTURE         *CON 6895
*SW   *MATRIX           *CON 0.00001
*SW   *FRACTURE         *CON 0.999
*ZGLOBAL *MATRIX        *CON 1 0
*ZGLOBAL *FRACTURE      *CON 1 0

**------------------------------------------------NUMERICAL-----------

*NUMERICAL

**------------------------------------------------WELL DATA-----------

*RUN
*DATE       2000   1   1
*AIMSET     *FRACTURE   *CON 3
*AIMSET     *MATRIX     *CON 3
```

```
*DTWELL     1.00E-06
*DTMIN      1.00E-07

*WELL 1     'PRODUCER'
        *PRODUCER 1
        *OPERATE    *MAX *STG   25000
        *OPERATE    *MIN *BHP   275
        *MONITOR    *MAX *M02   5       *STOP
        *GEOMETRY        *K
        0.0365 0.249 0.25   0
        *PERF *GEO  1
        1       1       1       1

*WELL 2 'INJECTOR'
        *INJECTOR   2
        *INCOMP     *SOLVENT    0       1
        *OPERATE    *MAX *STG   7079.205
        *OPERATE    *MAX *BHP   15000
        *GEOMETRY        *K
        0.0365 0.249 0.25   0
        *PERF *GEO  2
        11      11      1       1

*TIME 25
*TIME 30
*TIME 45
*TIME 60
*TIME 75
*TIME 90
*TIME 105
*TIME 120
*TIME 150
*TIME 182.5
*STOP
```

APPENDIX II
Detailed coalbed methane economic model.

Luke Saugier, Texas A&M University
Texas Coalbed Methane CO2 Sequestration
Detailed Economic Model of Injection of All CO2 Emissions from a 444 MW Power Plant - 180 MMSCFD

FINANCIAL ASSUMPTIONS

Capital Costs Depreciated in 10 Yrs	10%	per year
Federal Tax Rate	35%	

Assume costs similar to Powder River Basin
If REVENUE FOR TAX PURPOSES is not positive then this loss rolls over to the next year

Year		*0*	*1*	*2*	*3*	*4*	*5*
Discount Rate	10%	1.00	0.91	0.83	0.75	0.68	0.62
Cost Escalation	3%	1.00	1.03	1.06	1.09	1.13	1.16
Inflation	2%	1.00	0.98	0.96	0.94	0.92	0.91

CAPEX - Non Discounted
Assumptions

10% of wells drilled each year for 10 years
pipeline construction is started and completed in year 1
lease acquired in year 0

Cost of drilling Production Well	$	217,500.00	3000' depth
Cost of drilling Injection Well	$	217,500.00	assuming injection is identical to production
Cost to Tie In Well	$	30,000.00	
Number of Production Wells		180	
Number of Injection Wells		180	

UNDISCOUNTED CASH FLOW

Year			*0*	*1*	*2*	*3*	*4*	*5*
Lease Acquisition	$	100,000.00	$ 100,000.00					
Lease Acquisition Amortization			*$ 10,000.00*	*$ 10,000.00*	*$ 10,000.00*	*$ 10,000.00*	*$ 10,000.00*	*$ 10,000.00*
Pipeline/Flowline Construction	$	500,000.00		$ 500,000.00				
Pipeline Construction Depreciation				*$ 50,000.00*	*$ 50,000.00*	*$ 50,000.00*	*$ 50,000.00*	*$ 50,000.00*
Number of Production Wells Drilled	*# wells*				*18*	*18*	*18*	*18*
Number of Injection Wells Drilled	*# wells*				*18*	*18*	*18*	*18*
Production Well Cost			$ -	$ -	$ 4,487,886.00	$ 4,505,072.58	$ 4,522,774.76	$ 4,541,008.00
Prod Well Amortization		75%			*$ 3,365,914.50*	*$ 3,378,804.44*	*$ 3,392,081.07*	*$ 3,405,756.00*
Prod Well Depreciation		25%			*$ 112,197.15*	*$ 224,823.96*	*$ 337,893.33*	*$ 451,418.53*
Injection Well Cost			$ -	$ -	$ 4,487,886.00	$ 4,505,072.58	$ 4,522,774.76	$ 4,541,008.00
Inj Well Amortization		75%			*$ 3,365,914.50*	*$ 3,378,804.44*	*$ 3,392,081.07*	*$ 3,405,756.00*
Inj Well Depreciation		25%			*$ 112,197.15*	*$ 224,823.96*	*$ 337,893.33*	*$ 451,418.53*
CAPITAL COSTS			**$ 100,000.00**	**$ 500,000.00**	**$ 8,975,772.00**	**$ 9,010,145.16**	**$ 9,045,549.51**	**$ 9,082,016.00**
DEPRECIATION & AMORTIZATION			**$ 10,000.00**	**$ 60,000.00**	**$ 7,016,223.30**	**$ 7,267,256.80**	**$ 7,519,948.80**	**$ 7,774,349.07**

OPEX - Non Discounted
Assumptions
Production and Injection well operating costs are the same
Well operating costs begin the year after they are drilled
Injection and Production begin the year after wells are drilled

Production Well Operating Cost	$	1,000.00	$/month
Injection Well Operating Cost	$	300.00	$/month
Pipeline Tarif	$	0.05	$/MSCF
CO2 Capture Cost (powerplant)	$	0.50	$/MSCF
CO2 Injection per well		1000	MSCF/day

All costs increased at 3% per year

UNDISCOUNTED CASH FLOW

Year		*0*	*1*	*2*	*3*	*4*	*5*
Production Wells Operating Cost		$ -	$ -	$ -	$ 236,029.03	$ 486,219.81	$ 751,209.60
Injection Wells Operating Cost		$ -	$ -	$ -	$ 70,808.71	$ 145,865.94	$ 225,362.88
CO2 injection volume	*mscf/year*	*0*	*0*	*0*	*6570000*	*13140000*	*19,710,000.00*
CO2 Cost		$ -	$ -	$ -	$ 3,589,608.20	$ 7,394,592.88	$ 11,424,646.00
CO2 Transport Cost		$ -	$ -	$ -	$ 358,960.82	$ 739,459.29	$ 1,142,464.60
OPERATING COSTS		**$ -**	**$ -**	**$ -**	**$ 4,255,406.76**	**$ 8,766,137.92**	**$ 13,543,683.08**

6	*7*	*8*	*9*	*10*	*11*	*12*	*13*
0.56	0.51	0.47	0.42	0.39	0.35	0.32	0.29
1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47
0.89	0.87	0.85	0.84	0.82	0.80	0.79	0.77

6	*7*	*8*	*9*	*10*	*11*	*12*	*13*
$ 10,000.00	*$ 10,000.00*	*$ 10,000.00*	*$ 10,000.00*	*$ -*	*$ -*	*$ -*	*$ -*
$ 50,000.00	*$ 50,000.00*	*$ 50,000.00*	*$ 50,000.00*	*$ 50,000.00*	*$ -*	*$ -*	*$ -*
18	*18*	*18*	*18*	*18*	*18*	*18*	*18*
18	*18*	*18*	*18*	*18*	*18*	*18*	*18*
$ 4,559,788.24	$ 4,579,131.89	$ 4,599,055.84	$ 4,619,577.52	$ 4,640,714.84	$ 4,662,486.29	$ 4,684,910.88	$ 4,708,008.21
$ 3,419,841.18	*$ 3,434,348.92*	*$ 3,449,291.88*	*$ 3,464,683.14*	*$ 3,480,536.13*	*$ 3,496,864.72*	*$ 3,513,683.16*	*$ 3,531,006.15*
$ 565,413.24	*$ 679,891.54*	*$ 794,867.93*	*$ 910,357.37*	*$ 1,026,375.24*	*$ 1,142,937.40*	*$ 1,147,863.02*	*$ 1,152,936.41*
$ 4,559,788.24	$ 4,579,131.89	$ 4,599,055.84	$ 4,619,577.52	$ 4,640,714.84	$ 4,662,486.29	$ 4,684,910.88	$ 4,708,008.21
$ 3,419,841.18	*$ 3,434,348.92*	*$ 3,449,291.88*	*$ 3,464,683.14*	*$ 3,480,536.13*	*$ 3,496,864.72*	*$ 3,513,683.16*	*$ 3,531,006.15*
$ 565,413.24	*$ 679,891.54*	*$ 794,867.93*	*$ 910,357.37*	*$ 1,026,375.24*	*$ 1,142,937.40*	*$ 1,147,863.02*	*$ 1,152,936.41*
$ 9,119,576.48	**$ 9,158,263.77**	**$ 9,198,111.69**	**$ 9,239,155.04**	**$ 9,281,429.69**	**$ 9,324,972.58**	**$ 9,369,821.76**	**$ 9,416,016.41**
$ 8,030,508.84	**$ 8,288,480.90**	**$ 8,548,319.63**	**$ 8,810,081.02**	**$ 9,063,822.75**	**$ 9,279,604.23**	**$ 9,323,092.36**	**$ 9,367,885.13**

6	*7*	*8*	*9*	*10*	*11*	*12*	*13*
$ 1,031,661.18	$ 1,328,263.77	$ 1,641,734.03	$ 1,972,817.05	$ 2,322,287.50	$ 2,690,950.64	$ 3,079,643.52	$ 3,489,236.10
$ 309,498.36	$ 398,479.13	$ 492,520.21	$ 591,845.12	$ 696,686.25	$ 807,285.19	$ 923,893.05	$ 1,046,770.83
26280000	*32850000*	*39420000*	*45990000*	*52560000*	*59130000*	*65700000*	*65700000*
$ 15,689,847.18	$ 20,200,678.24	$ 24,968,038.30	$ 30,003,259.36	$ 35,318,122.45	$ 40,924,874.39	$ 46,836,245.13	$ 48,241,332.49
$ 1,568,984.72	$ 2,020,067.82	$ 2,496,803.83	$ 3,000,325.94	$ 3,531,812.24	$ 4,092,487.44	$ 4,683,624.51	$ 4,824,133.25
$ 18,599,991.43	**$ 23,947,488.97**	**$ 29,599,096.37**	**$ 35,568,247.47**	**$ 41,868,908.45**	**$ 48,515,597.66**	**$ 55,523,406.22**	**$ 57,601,472.67**

VITA

LUKE DUNCAN SAUGIER
312 Webster #2303
Houston, TX 77002

EDUCATION

B.S. Petroleum Engineering, Texas A&M University, May 2001	3.6 GPA

HONORS & ACTIVITIES

E.I.T., Texas	2001
Member of SPE	1997–present
Member of ΠΕΤ Petroleum Eng. Honor Society	1999–present
President of ΠΕΤ Omicron Chapter, Texas A&M University	2000
Winner, SPE Student Technical Presentation Contest, Gulf Coast Regional Division	2001
NCAA Athlete (Rifle)	1998-1999
GTE Scholar Athlete Award	1999

EXPERIENCE

Hilcorp Energy Company – Reservoir Engineer — June 2003–present

Halliburton – Engineer, contract work — Nov.–Jan. 2002
- *Performed FPSO Benchmarking Study*

Texas A&M University - Teaching Assistant — Aug. 2001–Jan. 2002
- *Taught Visual Basic twice a week to 15 undergraduate students*

Kerr – McGee Oil & Gas Co. - Production Engineer — May–Aug. 2001
- *Pursued production optimization and recompletion opportunities for several offshore GOM blocks*
- *Oversaw recompletions, wireline & coiled tubing work, fishing operations, nitrogen flowback*

Vastar Resources - Reservoir Engineering Intern — May–Aug. 2000
- *Performed pressure transient analysis & material balance calculations to update reserves for over 80 coalbed methane wells in San Juan Basin*