THE ECONOMIC FEASIBILITY OF ENHANCED COALBED METHANE RECOVERY USING CO_2 SEQUESTRATION IN THE SAN JUAN BASIN

A Thesis

by

ANGENI AGRAWAL

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

May 2007

Major Subject: Petroleum Engineering

THE ECONOMIC FEASIBILITY OF ENHANCED COALBED METHANE RECOVERY USING CO_2 SEQUESTRATION IN THE SAN JUAN BASIN

A Thesis

by

ANGENI AGRAWAL

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

Approved by:

Co-Chairs of Committee,	Richard Startzman
	Robert Wattenbarger
Committee Member,	Philip Rabinowitz
Head of Department,	Stephen Holditch

May 2007

Major Subject: Petroleum Engineering

ABSTRACT

The Economic Feasibility of Enhanced Coalbed Methane Recovery Using CO_2
Sequestration in the San Juan Basin. (May 2007)

Angeni Agrawal, B.S., The University of Texas at Austin

Co-Chairs of Advisory Committee: Dr. Richard Startzman
Dr. Robert Wattenbarger

Carbon dioxide emissions are considered a major source of increased atmospheric CO_2 levels leading towards global warming. CO_2 sequestration in coal bed reservoirs is one technique that can reduce the concentration of CO_2 in the air. In addition, due to the chemical and physical properties of carbon dioxide, CO_2 sequestration is a potential option for substantially enhancing coal bed methane recovery (ECBM).

The San Juan Fruitland coal has the most prolific coal seams in the United States. This basin was studied to investigate the potential of CO_2 sequestration and ECBM. Primary recovery of methane is controversial ranging between 20-60% based on reservoir properties in coal bed reservoirs[15]. Using CO_2 sequestration as a secondary recovery technique can enhance coal bed methane recovery up to 30%.

Within the San Juan Basin, permeability ranges from 1 md to 100 md. The Fairway region is characterized with higher ranges of permeability and lower pressures. On the western outskirts of the basin, there is a transition zone characterized with lower ranges of permeability and higher pressures. Since the permeability is lower in the transition zone, it is uncertain whether this area is suitable for CO_2 sequestration and if it can deliver enhanced coal bed methane recovery.

The purpose of this research is to determine the economic feasibility of sequestering CO_2 to enhance coal bed methane production in the transition zone of the San Juan Basin Fruitland coal seams. The goal of this research is two-fold. First, to determine whether there is a potential to enhance coal bed methane recovery by using CO_2 injection in the transition zone of the San Juan Basin. The second goal is to identify the optimal design strategy and utilize a sensitivity analysis to determine whether CO_2 sequestration/ECBM is economically feasible.

Based on the results of my research, I found an optimal design strategy for four 160-acre spacing wells. With a high rate injection of CO_2 for 10 years, the percentage of recovery can increase by 30% for methane production and it stores 10.5 BCF of CO_2. The economic value of this project is \$17.56 M and \$19.07 M if carbon credits were granted at a price of \$5.00/ton. If CO_2 was not injected, the project would only give \$15.55 M.

TABLE OF CONTENTS

Page

CHAPTER

CHAPTER Page

LIST OF FIGURES

CHAPTER I

INTRODUCTION

Coal Bed Methane

As an unconventional resource, coal bed reservoirs contain a significant amount of methane, accounting for 10% of the total natural gas reserves in the United States[1]. A coal bed reservoir differs from a conventional reservoir because of its dual porosity system, its method of production, and its phenomenon of pressure dependent permeability. In addition, the surface area of coal on which the methane is adsorbed is very large, holding up to five times the volume of gas contained in a conventional sandstone gas reservoir.

Dual Porosity

Coal is heterogeneous and is characterized by macro pores and micro pores. The macro pores are known as cleats, which is a well defined network of natural fractures, subdivided into face cleats and butt cleats. The flow regime through the cleat system is characterized by Darcy flow. Initially, it is assumed that cleats are 100% saturated with water with no free gas and methane is adsorbed to the surface of coal[2]. The micro pores are the matrix system, where gas constituents such as methane and carbon dioxide reside on the surface of the coal and undergo a process of adsorption and desorption by means of diffusion. Adsorption and desorption of gas from the surface of methane are primarily controlled by the increase and decrease of reservoir pressure.

This thesis follows the form and style of the *Journal of Petroleum Technology*.

Methane Production

If water is present in the cleat system, primary production initially goes through a process of dewatering. This dewatering process reduces the reservoir pressure, causing a reduction in the partial pressure of gas from the matrix of the coal. Eventually the reservoir reaches a critical pressure where desorption of methane begins, which can take months or even years to reach. As the pressure decreases, the methane desorbs from the coal surface and flows through fractures towards the well bore.

Pressure Dependent Permeability

One of the unique characteristics of coal bed methane is the phenomenon of pressure dependent permeability. As the reservoir pressure decreases, the cleat permeability increases. This is due to coal matrix shrinkage with pressure drawdown, causing the cleats to open and increasing the ability of flow. The two effects of cleat compression and matrix shrinkage act in opposite directions on permeability and this mathematical expression is displayed in Equation 1.

$$-d\phi = -\frac{1}{M}dp + \left[\frac{K}{M} + f - 1\right]\gamma dp - \left[\frac{K}{M} - 1\right]\alpha dT. \qquad \text{Equation 1}$$

The term in dT is a temperature expansion/contraction term. This is directly analogous to matrix shrinkage, where cleat width increases as gas desorbs during pressure drawdown[3].

This phenomenon allows for a possible consideration for CO_2 sequestration due to the impact of matrix swelling. When CO_2 is injected into the coal, the matrix of the coal tends to swell. This swelling reduces the width of the cleats, decreasing the permeability.

If permeability increases with pressure drawdown, then the cleat system can handle the matrix swelling caused with CO_2 sequestration. For this study, the Palmer & Mansoori model is used to account for pressure dependent permeability.

Pressure Dependent Porosity

Along with pressure dependent permeability, porosity tends to increase with decreasing reservoir pressure. The total horizontal stresses reduce because of matrix shrinkage and a reduction in pore pressure. The behavior of porosity with respect to permeability is displayed in the equation below[3].

$$\frac{k}{k_0} = \left(\frac{\phi}{\phi_0}\right)^3, \qquad \text{Equation 2}$$

As mentioned above, pressure dependent porosity is beneficial for accounting for matrix swelling caused by CO_2 sequestration. This is also represented by the Palmer and Mansoori method[4].

ECBM/CO_2 Sequestration Process

Based on the Langmuir isotherm, carbon dioxide has a higher affinity to the coal matrix compared to methane. Therefore, coal can adsorb 2-3 times more volumes of carbon dioxide than methane. Since carbon dioxide has a higher affinity to coal, it displaces the methane. The injection of CO_2 maintains the reservoir pressure, displacing methane into the cleat system, improving the ultimate recovery.

Allison Unit CO_2 – ECBM Pilot

The Allison Unit is the first and only multi-well, multi-year CO_2 -ECBM field pilot in the world today, and represents a unique opportunity to study and understand the technology. This unit is located on the northern part of the San Juan Basin and was investigated by Burlington Resources. Even though it is not located in the Fairway of the San Juan Basin, it has an average initial permeability of 100 md and an initial porosity of .25%[5]. The Allison Unit has four CO_2 injection wells and seven methane production wells drilled with 320 acre spacing. The production wells were drilled in the late 1980's and injection was investigated five years after production. The huff and puff method was initially implemented by injecting CO_2 and shutting in the wells for 6 months. This method was detrimental for gas production. Some of the causes of reduction in gas production were due to water encroachment and contact with bypassed reservoir area[6]. Another method investigated was continuous injection of carbon dioxide and production of methane. In this scenario, there was enhanced methane production[6]. However, the results were preliminary with limited operational data and this pilot is an opportunity to explore the potential in other regions of the San Juan Basin[6]. In the Allison unit, the permeability was higher and pressures were lower, but it is uncertain if a region with lower permeability and higher pressures would also give any incremental methane production with CO_2 sequestration. A particular area to investigate is the transition zone in the San Juan Basin, where average initial permeability is 1 md.

San Juan Basin

The San Juan Basin is the most prolific coal bed methane development accounting for over 75% of the total worldwide CBM production[6]. The San Juan Basin has coal beds dated to the Cretaceous period. The permeability of this basin ranges from 1-100 millidarcy. On the outskirts of the Fairway seen in yellow in the Figure 1 below, there is a transition zone where average initial permeability is 1 md and initial reservoir pressure is 1500 psia. The reason this region was selected for this study was due to its key reservoir properties. If CO_2 sequestration can lead to enhanced coal bed methane recovery in the transition zone, then results of CO_2 sequestration and ECBM will be far greater in the Fairway of the San Juan Basin.

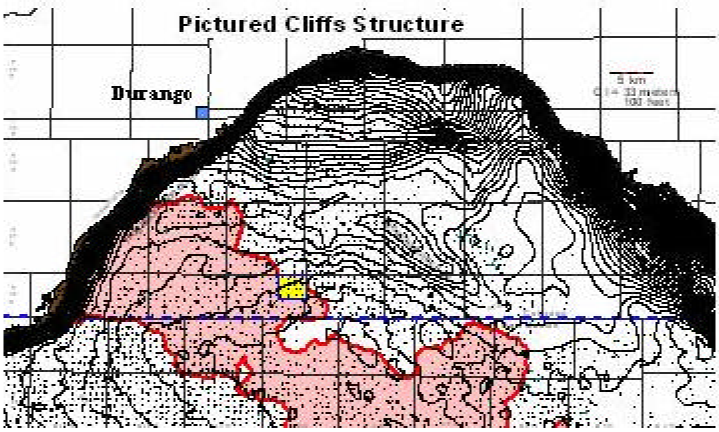


Figure 1: Transition Zone in the San Juan Basin (yellow) and Fairway (red)

Reservoir Selection Criteria

The 640 acre section selected for this research was based on a reservoir selection criterion based on lease, well ownership, pay thickness, connectivity, and location.

In order to avoid unitization issues, the four wells selected are apart of the same lease and are 100% owned by BP. Based on well log analysis, all the wells have an average pay thickness of 50 feet/well and even though there is sufficient pay thickness, often times, the pay zones can be disconnected. Well logs depicted good connectivity with all four wells based on pay thickness. In addition, the location of the four wells in the transition zone is a good indicator for determining the potential of CO_2 sequestration and ECBM in a lower permeability and higher pressure area and offer implications for the potential results for the rest of the San Juan Basin.

Objective

The objective of my work is to determine if sequestering CO_2 to obtain enhanced coal bed methane production is economically feasible in the transition zone of the San Juan Basin. The only pilot study done on CO_2/ECBM in the San Juan Basin is in the Allison Unit conducted by Burlington Resources. It is still a novice technology and very little field data exists to validate the process and economic potential. The pilot led companies to believe that ECBM/CO_2 represents an opportunity to further study and understand its potential.

There are several constituents of my research, all leading to determine the economic feasibility for CO_2 sequestration.

1. Is there a potential to enhance coal bed methane by CO_2 sequestration in the transition zone of the San Juan Basin which is characterized with lower ranges of permeability?
2. Is there any notable CO_2 sequestered in the process?
3. Can CO_2 Sequestration/ECBM be an economic prospect?
4. What economic situations does this prospect become uneconomical?

In order to accomplish my objectives, I first selected a 4 well, 640 acre section in the San Juan Basin and history matched the production from these wells using CMG GEM simulator. After my reservoir model was calibrated to behave as my reservoir, CO_2 injection was investigated. Once I ran several cases to optimize a design strategy for enhanced methane recovery and CO_2 sequestration, an economic model was developed. Within the economic model, several parameters were considered such as, capital and operating expenditures, royalties, severance tax, and carbon credits. A sensitivity analysis was conducted to determine possible scenarios that could make a project like this uneconomical based on economic risk in gas price and capital and operating expenditures.

I first discuss the initialization of my reservoir model and the technique used to history match the four wells in the San Juan Basin. Then I discuss the methodology used for CO_2 Sequestration and ECBM. I present the results of the simulation runs for the Model Case and the optimal design strategy. To validate this study, I discuss the economic feasibility and sensitivity in different price fluctuations. Finally, based on my results, I draw conclusions on the potential of sequestering CO_2 and enhancing coal bed methane in the San Juan Basin.

CHAPTER II

RESERVOIR MODEL

CMG GEM

Computer Modeling Group (CMG GEM) is a multi-component, multi-phase reservoir simulator used to model coal bed methane reservoirs. It incorporates dual porosity, diffusion time, adsorption and desorption of gas, and coal matrix shrinkage and swelling. The multi-component sorption that occurs on the coal matrix is accounted for by using the Peng-Robinson equation of state. Gas and water flow is simulated by the Darcy model based on relative permeability input data. The sorption time constant indicates the rate at which gas exchanges between the coal matrix and the cleat system[7]. It is important to note that the equilibrium of the diffusion time constant is not adequate with real time due to computations within the simulator. For this research, CMG GEM simulator was used to conduct all simulation runs for history matching, CO_2 sequestration, and forecasting production.

Initializing the Reservoir Model

In order to initialize the reservoir model, I created an appropriate grid size, incorporated geologic data, reservoir data, and pressure and production history for each well.

The grid size of the reservoir model is 10*10*9 grid blocks. This 640 acre representation was surrounded by no-flow boundaries. There are four continuous coal seams that were lumped together simply to reduce computation time for the simulator since it is known that communication among these seams and between wells exist. Geologic maps were created for the reservoir model which includes pay thickness, density of the coal, and top depths. The reservoir data input for the simulator is displayed in Table 1. In order to conduct history matches for the four wells, production and pressure data were input into the simulator. Production data was directly imported into the simulator. The pressure data provided by BP was well head pressure data, which I used to calculate the bottom hole pressure using fluid levels and perforation data found on well completion design schematics. The calculated bottom hole pressure data was inputted into the simulator.

Table 1. Reservoir Prop.					
Reservoir Thickness	50	feet	**Initial Water Saturation (fracture)**	100%	
Initial Reservoir Pressure	1550	psia	**Reservoir Temperature**	120	F
Sorption Volume (CH4)	555	scf/ton	**Initial Mole Fraction of CH4**	100%	
Sorption Volume (CO_2)	709	scf/ton	**Initial Mole Fraction of CO_2**	0%	
Sorption Pressure (CH4)	500	psia	**Reservoir Drainage Area**	160	acres
Sorption Pressure (CO_2)	215	psia	**Coal Desorption time**	1	day
Rock Density	1.6	gm/cc	**Fracture Spacing**	0.1	feet
Depth	3225	feet	**Average Initial Permeability**	1.5	md

Table 1. Rock and Reservoir Properties

History Matching Methodology

In order to accurately history match the four wells, I fixed my calculated bottom hole pressure data and matched my gas rates and water rates. There was a criterion I followed to achieve my objective for history matching. This criterion involved a procedure using history matching parameters to achieve the objective.

Objective

The objective for history matching was to match the cumulative gas production and water production for all four wells within 5% of their history data. This cutoff was an acceptable benchmark for accurate history matching. In order to achieve this objective, each well was history matched individually in order to determine which parameters affected the gas rates and water rates. Once individual matches were achieved, the wells were placed together and adjustments were made for the entire model.

History Matching Parameters

The three key parameters considered to achieve a suitable history match for consideration of CO_2 injection were cleat permeability, cleat porosity, and skin.

Permeability is one of the most important parameters for coal bed methane production[8]. The changes in the cleat permeability are considered to be primarily controlled by the prevailing horizontal stresses[8]. Permeability has a direct relationship with flow rates and was the first parameter considered in order to achieve viable gas rate and water rate matches.

Since it is assumed that the cleats are initially 100% saturated with water while methane is adsorbed to the matrix of the coal, cleat porosity represents the initial water storage in the system. This phenomenon gave leverage on matching water rates effectively.

Skin was considered in order to incorporate all workovers to fine tune gas rate matches. Three out of the four wells in the 640 acre area had some workover done and evidently improved the gas rate matches.

Model Case Results

Figure 2 is a depiction of the history matched cumulative gas rates and water rates for all four wells. The gas rates are on a logarithmic scale, while the water rates are on a Cartesian scale.

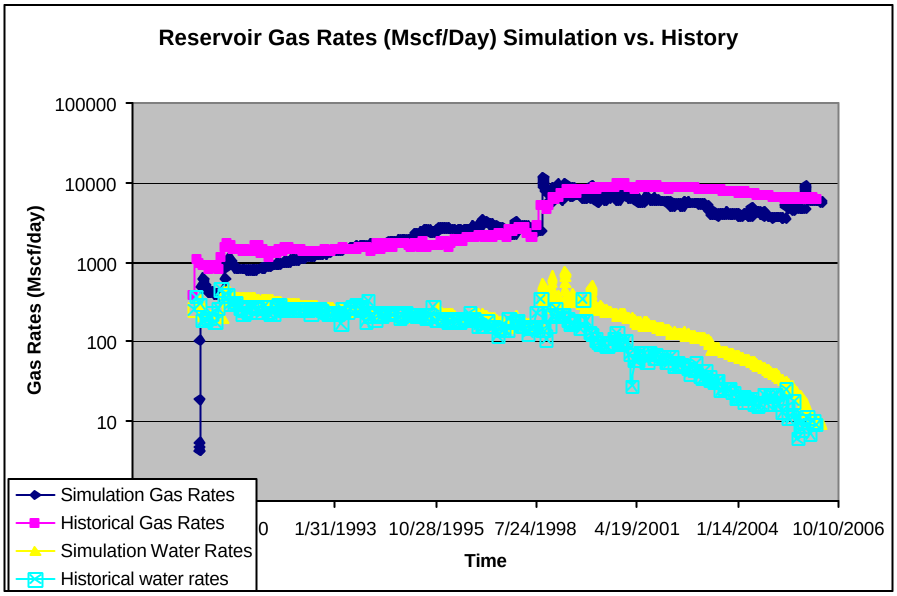


Figure 2. History Matched Cumulative Gas Rates and Water Rates

CHAPTER III

CO_2 SEQUESTRATION/ECBM

Background

Coal bed methane recovery can primarily improve by nitrogen injection and carbon dioxide injection. Although both of these constituents can improve the recovery, their behavior is quite different in coal bed methane and is illustrated in Figure 3.

Nitrogen injection is primarily implemented to improve the recovery of coal bed methane. As seen in the figure below, nitrogen has a significantly lower affinity to coal than methane and carbon dioxide. Physically, nitrogen reduces the partial pressure of methane which allows methane to diffuse from the matrix of the coal with greater ease, hence improving the recovery of coal bed methane at a faster rate.

The injection of CO_2 into coal beds has several advantages: 1) reduces production time of coal bed methane; 2) increases reserves by improving the recovery of CBM; and, 3) sequesters CO_2[1]. Carbon dioxide has unique characteristics that allow it to be such a great candidate for ECBM. CO_2 is more adsorptive to coal than methane, adsorbing 2-3 times more CO_2 at a given pressure than methane. In concept, the process of CO_2-ECBM is simple. As CO_2 is injected into a coal reservoir, it is preferentially adsorbed into the coal matrix, displacing the methane that exists in that area. The displaced methane then diffuses into the cleat system, and migrates to the production wells through Darcy flow. The process is relatively efficient in theory and, as implied from the isotherms, should require 2-3 volumes of injected CO_2 per volume of incrementally produced methane[5].

Based on the figure below, as the reservoir pressure decreases with time, the rate at which methane desorbs increases. Therefore, ideal times for CO_2 injection is at lower pressures. As discussed earlier, as the reservoir pressure decreases, the matrix tends to shrink, increasing the permeability over time. However, with injection of CO_2 the matrix begins to swell which reduces the pathway of flow, decreasing the permeability. In order to determine if a potential for CO_2 sequestration exists, it is imperative that the reservoir reaches an appropriate pressure where it can sustain the swelling of the matrix caused by CO_2 injection. Dealing with a region like the transition zone, where the pressure is initially higher and the permeability is lower, it makes the entire system much more complicated.

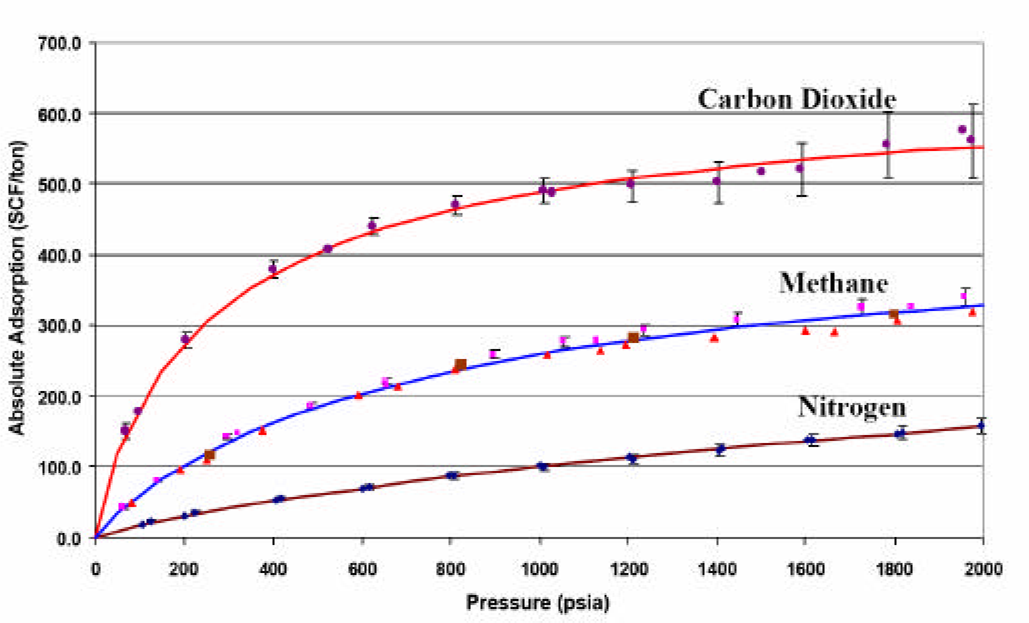


Figure 3. Langmuir Isotherm

CHAPTER IV

DESIGN OPTIMIZATION

Model Case

In order to determine whether CO_2 sequestration and ECBM is economical and results in an improved recovery, it is important to consider how the reservoir behaves without any CO_2 injection. The reservoir recovers 32% of the methane in place by year 2050 with no added stimulation in the forecasted results from CMG GEM simulator. The total cumulative production from year 2020 to 2050 was 10 BCF. Wells 1 and 2 began production in 1990, while wells 3 and 4 began production in 1998. Below is a description of the method I used to find an optimal design scenario.

Optimization Scheme

Before determining the economic feasibility for a CO_2 sequestration and ECBM project, I first found an ideal design scheme based on the optimization of produced methane. In order to determine an optimal design scenario, I considered the location of the injector, the injection pressure, the duration of injection of CO_2, and its effects on the sweep efficiency for methane. For all of the scenarios, I produce all four wells I begin injection of CO_2 from 2008 until 2050.

Injector Location

There are two specific locations investigated for CO_2 injector placement. For both scenarios, the injection pressure was constrained at a maximum of 2500 psia. The injection pressure constraint was set based on the fracture pressure for this reservoir.

Since there are four 160-acre spaced wells, I first considered a pattern similar to a 5-spot inverted pattern with four producers and one injector. Figure 3 and Figure 4 display the two scenarios investigated for injector placement. In these diagrams, the darker shaded region is the area of methane swept from primary recovery, while the lighter shaded region is the area of methane swept due to CO_2 injection. In Figure 4, the secondary recovery area for methane is not as large as expected, primarily due to CO_2 producing in the gas stream very early on due to the proximity of the injector with the production wells. The location of this injector does not seem ideal since it leaves a large amount of methane in the reservoir area and produces a large amount of CO_2 in the gas stream within 10 years of injection.

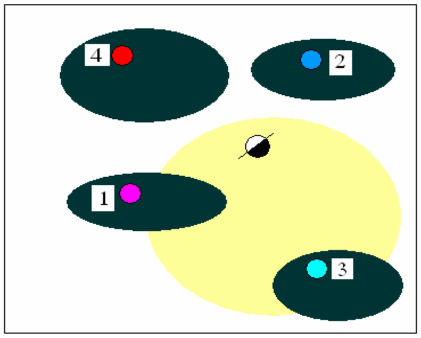


Figure 4. Injector Location Scenario I

The second scenario investigated for injector location was placing it at the bottom left hand corner of the 640 acre area depicted in Figure 5. There is a far greater sweep of methane and adsorption of CO_2 with this injector placement. The reason for this is primarily due to the injector having a greater distance from the producer wells, allowing sufficient time for the carbon dioxide to adsorb to the matrix of the coal and displace the methane.

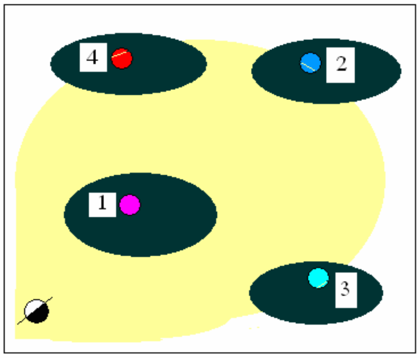


Figure 5. Injector Location Scenario II

From both of the scenarios investigated, the better location for the injector placement is at the bottom left hand corner of the 640 acre area.

Injection Pressure and Time

Initially, all scenarios had an injection pressure of 2500 psia based on the fracture pressure of the reservoir. However, there were situations where CO_2 was injected at such high rates that the reservoir could not handle the amount of CO_2. In several scenarios, high volumes of CO_2 produced in the gas stream. Specifically, Well 1 in Figure 5 produced high rates of CO_2 within the first 10 years of injection. In order to find an optimal design strategy, the various parameters investigated was the amount of years of injection, the pressure of injection, and the shut-in time for producers that had 30% of the gas stream production composed of carbon dioxide. From this trial and error, there were three design scenarios that had a variation of the parameters discussed that gave acceptable results. An optimal design strategy was selected based on the economic analysis and was further investigated with a sensitivity analysis.

Design Scenarios

There are three design scenarios compiled from several trial and error runs that gave acceptable results of CO_2 Sequestration and ECBM.

Case 1

To maintain sufficient reservoir pressure and refrain from ineffectively inject carbon dioxide by not allowing enough time for displacement of methane, this scenario was designed with continuous and slow injection of carbon dioxide. For the first 13 years of CO_2 injection, the injection pressure was maintained at 1300 psia. After these 13 years, CO_2 was composed of greater than 30% of the gas stream for Well 1. From this point, well 1 was shut in and the injection pressure of CO_2 was changed to 1000 psia for the remaining 30 years of injection. The methane produced at the end of 2050 was 12.6 BCF, which is a 25% increase from the Model Case and a 39.4% ultimate recovery of reserves. Over the 43 years of continuous slow injection, 15 BCF of CO_2 was injected and 14.7 BCF of CO_2 was sequestered, a 98% adsorption rate. The results of well by well performance compared to the Model Case and the effect of CO_2 injection is depicted in APPENDIX I.

Case 2

This scenario is characterized with a continuous high rate injection of CO_2. Once again, injection of CO_2 began in 2008 but injection and production continued only until 2039, simply due to the high amount of CO_2 developing in the production stream. The injection pressure remained constant throughout the entire life of the reservoir at 1500 psia. Once again Well 1 experienced high production of CO_2 by year 2020 and therefore was shut in. Since the injector is placed in a distance from the remaining wells, it resulted in high CO_2 sequestration and improved methane recovery. This scenario produced 12.1 BCF of methane, which is slightly lower than Case 1, giving a 20% increase in recovery and a 38% ultimate recovery for the reservoir area. There was an injection of 18.9 BCF of CO_2 in 32 years opposed to 15 BCF in 43 years in Case 1. It sequestered 18.4 BCF of CO_2, which is a 97% adsorption rate for CO_2. The well by well performance is illustrated in Appendix I.

Case 3

Finally, the third scenario was a high rate, limited injection of CO_2. The purpose of this case was to examine if the injection of CO_2 at an injection pressure of 2500 psia for a continuous rate of 10 years would allow sufficient time for adequate adsorption of CO_2 and displacement of methane. After 10 years of injection, the injector was shut in and production continued until 2050. Similar to the rest of the scenarios, Well 1 was shut in, but since the gas stream contained more than 30% recovery, it was shut-in in year 2017. This case resulted in a production of 13.1 BCF, which is higher than the other 2 cases giving a 30% increase in recovery rate and a 41% ultimate recovery of the reservoir area. Since the injection period was 10 years, 11.5 BCF of CO_2 was injected and 10.5 BCF was sequestered, resulting in a 92% adsorption rate. The well by well performance is illustrated in Appendix I.

Preliminary Conclusions

Based on the design scenarios, for enhanced coal bed methane recovery, Case 3 seems to have the best results on cumulative production and percent increase in recovery. From a CO_2 sequestration point of view, Case 2 had the most CO_2 sequestered, although Case 1 had a higher adsorption rate. These conclusions are adjusted with an analysis of the economics for each case and the effects of carbon credits.

CHAPTER V

ECONOMIC MODEL

Background

In order to determine the optimal design scenario, I chose to maximize the net present value. Even though a case may present an improved recovery of methane, if there is no improvement in the net present value, the improved recovery is meaningless from an operating company point of view. In order to determine the economic feasibility of a CO_2 sequestration and ECBM project, an economic model was developed. Some of the details discussed are the financial assumptions, and the capital expenditures (CAPEX) and operating expenditures (OPEX).

Financial Assumptions

Before developing my economic model, I made some financial assumptions. All of my economic scenarios were conducted before federal income taxes. For this reason, depreciation was not considered. The discount rate for all cases is set at 12%. For the Model Case and the three design cases the gas price used is \$6/MMBTU where 1040 MMBTU/MCF, resulting in a gas price of \$6.24/MCF. The production royalty is 12.5% and the production tax is assumed to be 8%[5]. To determine the optimal design case, no annual escalation of gas price was considered.

CAPEX/OPEX

The only capital expenditure for this project was the drilling and completion of an injector well and the construction of the pipeline to the field. For a fully equipped injector including a 7 mile pipeline from the Florida River plant to the field area, the CAPEX is $1.6 M.

The operating expenditures in most researched CO_2 Sequestration work involve high costs of CO_2 capture and transportation, making several projects uneconomical[9]. Because BP emits approximately 10 MMCF of CO_2 per day, this carbon dioxide is readily available for injection. Therefore, capture cost are not relevant for the economic analysis and the area investigated is relatively near the Florida River plant where transportation costs are minimal. The only operating expenditures involved is a total gas processing cost of $.30/MCF of gas, and injector operating cost of $1500/month, and a compressor cost of $.1/MCF of CO_2 injected[10]. An additional analysis involves an inclusion of carbon credits just to see how the result of the economic analysis improves and by what degree. The carbon credit used for the additional analysis uses a value of $5/ton which is $.26/MCF of CO_2 injected, the same value used in the economics for the Allison pilot study.

The spreadsheet for each case is available in Appendix I.

CHAPTER VI

ECONOMIC FEASIBILITY

Background

In order to determine the economic feasibility of the project, first an analysis is conducted to determine if there is any monetary gain from a CO_2 sequestration project. If there is a financial gain, the next goal is to determine if the net present value (NPV) improves compared to the Model Case for each case scenario.

.

Economic Feasibility without Carbon Credits

The results from the economic model show that the Model Case gives a NPV of $15.55 M at year 2008 with production until 2050.

Case 1 resulted in a NPV of $15.43 M, which is not as profitable as the Model Case. Even though there is a 25% increase in methane recovery compared to the Model Case, it is still not preferred. The reason the NPV is not higher in Case 1 is simply due to a slow improvement in methane production over time and an additional cost for processing any CO_2 gas produced.

Case 2 resulted in a NPV of $15.88 M. There is a slight improvement in the net present value. This case seems good because although the improvement in NPV is comparatively small, the process also results in 18.4 BCF of CO_2 sequestered.

Case 3 results in the highest NPV of $17.56 M. Although there was limited years of injection, the rates were so significant that it was enough to enhance the methane production dramatically earlier in the life of the injector well.

The result of these cases compared to the Model Case is illustrated in Figure 6.

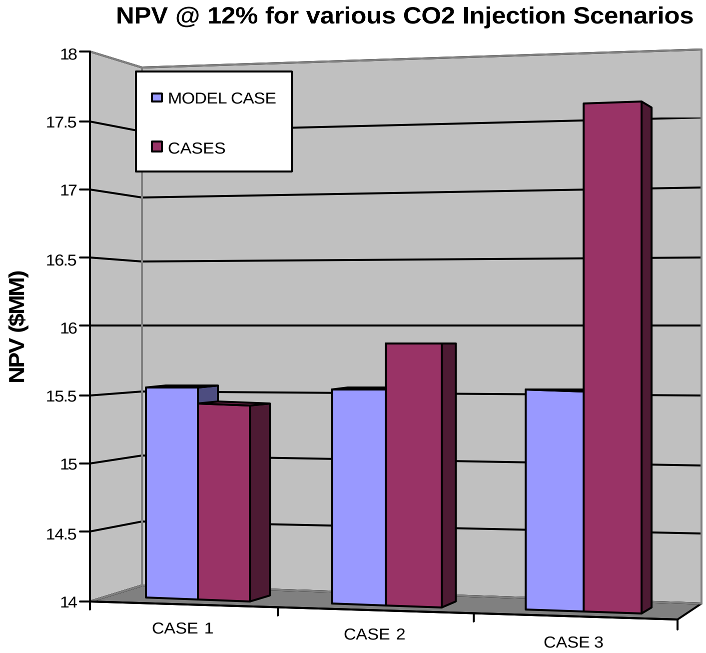


Figure 6. Net Present Value @ 12% Model Case vs. Cases 1, 2, and 3

Economic Feasibility with Carbon Credits

Although the United States does not follow the Kyoto Protocol, it is interesting to note how these results change with a carbon credit incentive CO_2 sequestered. For this analysis the carbon credit assigned is \$5/ton of CO_2, which is \$.26/MCF of CO_2 sequestered.

Case 1 improves from \$15.43 M to \$16.27 M. Hence, by including carbon credits in the economic model, Case 1 went from a not preferred project to a preferred one, since it has a greater NPV than the Model Case.

Case 2 compared to the rest of the cases had the most CO_2 sequestered at a value of 18.4 BCF. The NPV went from \$15.88 M to \$17.01 M. This increase again, is due to the credit obtained with CO_2 sequestered.

Case 3 had the least amount of CO_2 sequestered with a value of 10.5 BCF. The NPV went from \$17.56 to \$19.07. The reason Case 3 still has a higher NPV is because the reservoir was injected with CO_2 with very high rates and the money obtained for the amount of CO_2 sequestered was earlier in the project with an additional boost of methane produced.

The comparison of the Model Case and the design scenarios with and without carbon credits is depicted in Figure 7 below.

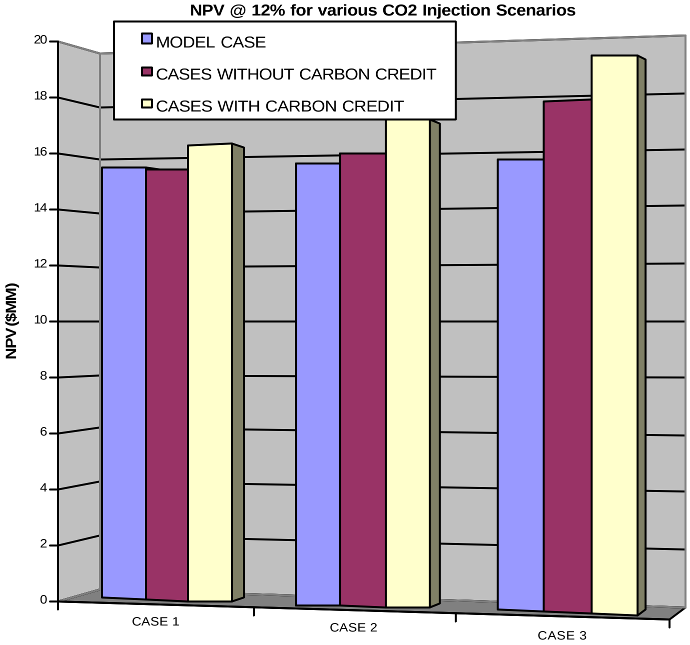


Figure 7. Net Present Value for Design Scenarios with Carbon Credit

Optimal Design Case

From the economic analysis of the three design scenarios, it is evident that without carbon credits and with carbon credits, Case 3 is the optimal design scenario. The ability to inject at high rates and allow this pressure to be maintained for the remaining life of the reservoir, results show a dramatic improvement in methane recovery and CO_2 sequestration. In order to determine the effects of altering economic parameters such as gas price, operating expenditures, and price escalation, a sensitivity analysis is conducted to see the results on the optimal design case which is Case 3.

CHAPTER VII

SENSITIVITY ANALYSIS

Objective

Even though Case 3 is the optimal design scenario, it is uncertain if this case will be ideal under circumstances where there is variability in gas prices, price escalation, operating expenditures, and carbon credits. The objective of the sensitivity analysis is to determine economic situations that make this design case uneconomical compared to the Model Case.

Gas Price

For all previous analyses discussed, a fixed gas price of $6.24/Mcf was used. In order to determine the economic constraints for this project, the impact on NPV for the Model Case and Case 3 with gas price varying from $3/MMBTU to $10/MMBTU was determined. Case 3 becomes uneconomical with respect to the Model Case if gas price went below $3/MMBTU seen in Figure 8. In addition, as gas price increases, the difference in NPV between the Model Case and Case 3 increases.

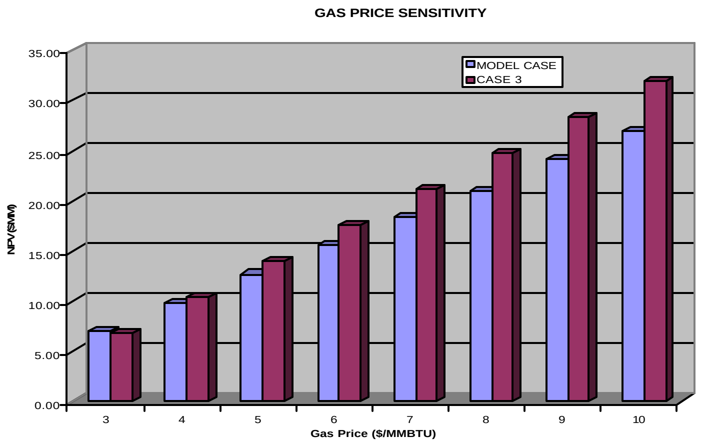


Figure 8. Gas Price Sensitivity Model Case vs. Case 3

Annual Gas Price Escalation

Another economic parameter that can fluctuate is annual gas price escalation. From Figure 9, similar to the gas price sensitivity, the difference between the Model Case and Case 3 increases with an increase in gas price escalation.

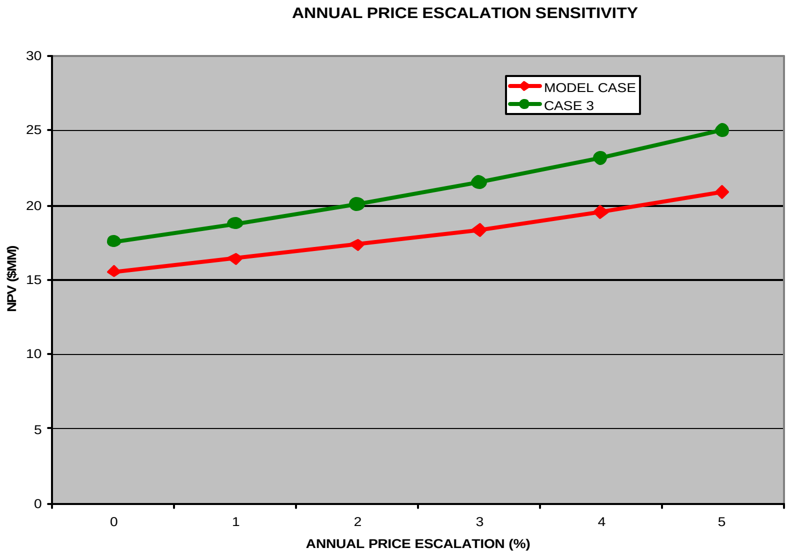


Figure 9. Annual Gas Price Escalation Sensitivity

Produced Gas Processing Cost

Since the produced gas processing cost applies both to the methane and carbon dioxide production, it was interesting to note whether this cost affected Case 3 with an increase in production cost compared to the Model Case which has no additional cost of CO_2. In Figure 10, it is evident that there is no dramatic affect on Case 3 with an increase in production cost. In fact, both the Model Case and Case 3 have the same trend with increase in production cost.

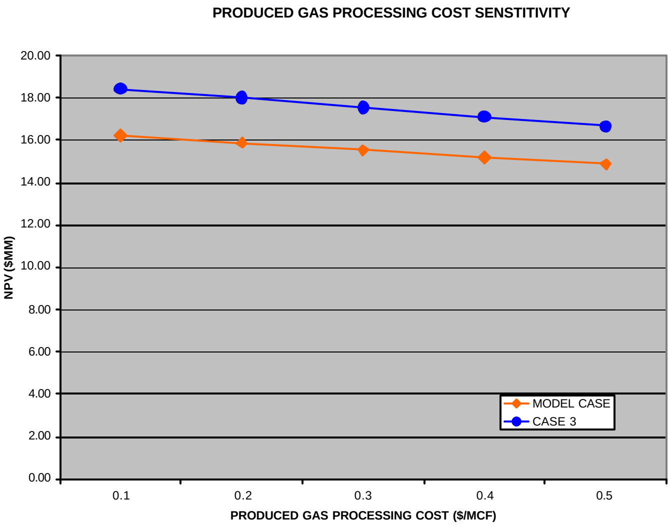


Figure 10. Produced Gas Processing Cost Sensitivity

CO_2 Costs

Based on literature, it is established that the key parameter that makes a CO_2 sequestration project uneconomical is the costs associated with CO_2 injection. Fortunately, since CO_2 is readily available at the Florida River plant, the only cost associated with CO_2 injection is the compression of CO_2 for injection. Although the United States does not follow the Kyoto Protocol, it is interesting to note how the varying changes in CO_2 cost compare in the carbon credit model of Case 3 with the original Case 3. Figure 11 displays the effects of an increase in CO_2 costs when there is no allocation of carbon credits. It is evident that if CO_2 costs exceed \$.4/MCF of CO_2, the project is uneconomical compared to the Model Case.

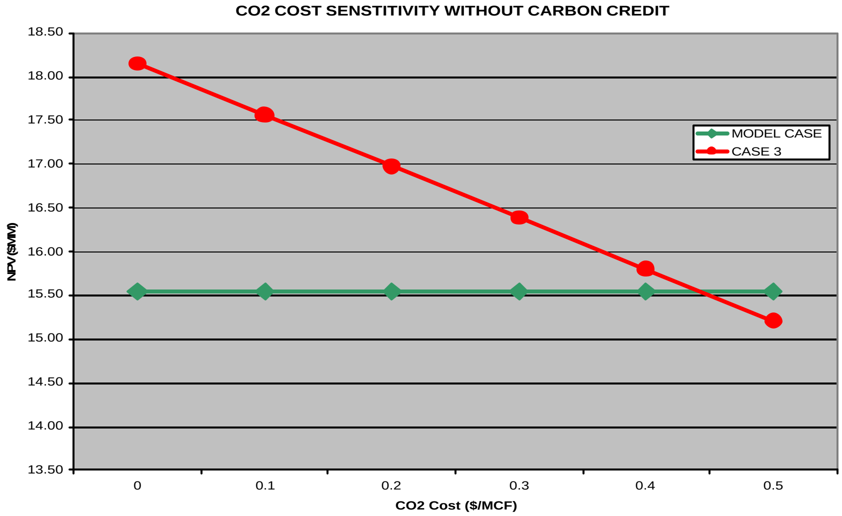


Figure 11. CO_2 Cost with no Carbon Credit

However, if carbon credits were considered in the economic model, then the project would remain economical compared to the Model Case. In Figure 12 there is a downward trend in Case 3 but it still has an NPV value higher than the Model Case at a CO_2 compression cost of \$.5/MCF of CO_2.

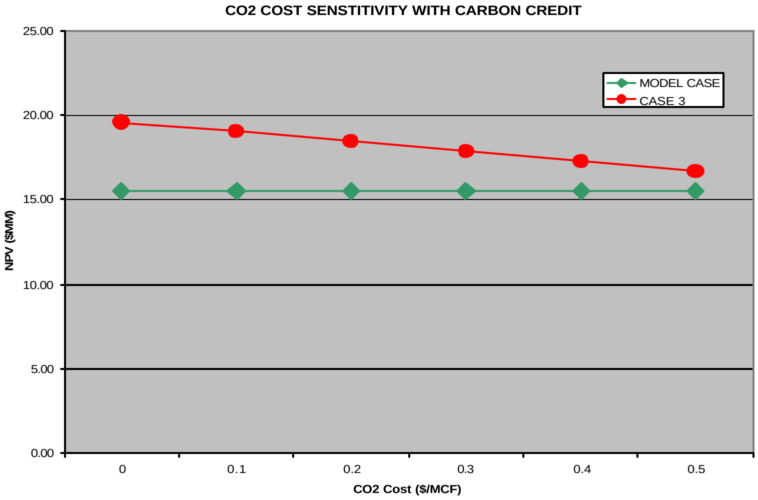


Figure 12. CO_2 Cost with Carbon Credit

Carbon Credit

As noted, if carbon credits were granted for CO_2 sequestration projects, the NPV would increase substantially with the increase in carbon credit price compared to the Model Case. Figure 13 is a graph that compares all the three design cases with carbon credits with the Model Case. If the carbon credit was $30/ton of CO_2, the NPV of CO_2 Sequestration and ECBM project for Case 3 would almost double compared to the Model Case.

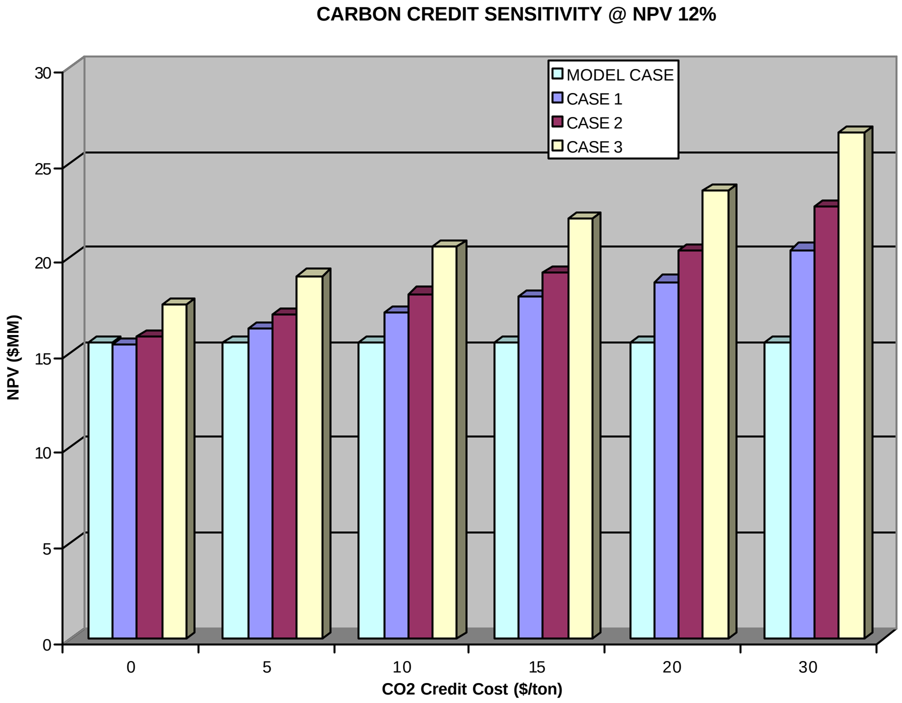


Figure 13. Carbon Credit Sensitivity

CHAPTER VIII

CONCLUSIONS/RECOMMENDATIONS

My research involved selecting a reservoir section to examine the potential of CO_2 sequestration and ECBM in the transition zone of the San Juan Basin. After history matching four pre-existing wells, CO_2 injection was considered to determine if there is a potential to improve methane recovery and if CO_2 is sequestered. By developing an economic model, I found an optimal design strategy coupled with a sensitivity analysis by maximizing the net present value. Based on the analysis, several conclusions can be drawn.

1. CO_2 sequestration is physically possible in low to medium permeability coal bed methane reservoirs.
2. CO_2 sequestration improves coal bed methane recovery and enhances the economic value of the coal bed methane reservoir.
3. If the cost of CO_2 compression is greater than $.3/MCF or the price of gas is less than $3/MCF and carbon credits are not granted, the project may not be economical compared to a case where no CO_2 injection is considered (Model Case).
4. Economic gains are increased in areas where CO_2 is emitted and is readily available for injection, resulting in minimal CO_2 costs.
5. The economic value of the project is greatly enhanced where CO_2 is emitted and carbon credits are granted as a result of the Kyoto Protocol.

6. Project success depends on strategic CO_2 injection. It is found that the most efficient way to inject CO_2 is to set maximum injection pressure below the fracture pressure, for a limited period of time. This will allow for a substantial boost in recovery early in the project. Slow continuous injection gives a delayed effect of enhance methane recovery resulting in an uneconomical project compared to a Model Case that has no injection of CO_2.

Based on this research and conclusions, I recommend that a field study should be conducted to confirm the results of this thesis. In addition, since this research provides enough information to believe that CO_2 sequestration does enhance coal bed methane recovery and is economically feasible in low to medium permeability regions of the San Juan Basin, further research should be done to determine the economic potential of CO_2 sequestration in high permeability regions of the San Juan Basin. Furthermore, a CO_2 sequestration project can give improved returns with the inclusion of carbon credits gives great incentive to explore for coal bed methane in International countries where the Kyoto Protocol is followed.

REFERENCES

1. Gorucu, F.B., Jikich, S.A., Bomhal, G.S., Sams, W.N., Ertekin, T. M., and Smith, D.H.: "Matrix Shrinkage and Swelling Effects on Economics of Enhanced Coalbed Methane Production and CO_2 Sequestration in Coal," paper SPE 97963 presented at the 2005 SPE Eastern Regional meeting, Morgantown, WV, 14-16 September.

2. Saugier, L.D.: "Investigation of Feasibility of Injecting Power Plant Waster Gases for Enhanced Coaled Methane Recovery from Low rank Coals in Texas," M.S. Thesis, Texas A&M University, College Station TX (2003).

3. Palmer, I. and Mansoori, J.: "How Permeability Depends on Stress and Pore Pressure in Coal beds: A New Model," paper SPE 52607 presented at the 1996 SPE Annual Technical Conference & Exhibition, Denver, 6-9 October.

4. Shi, J.Q., and Durucan, S.: "A Model for Changes in Coalbed Permeability During Primary and Enhanced Methane Recovery," *SPE Reservoir Evaluation and Engineering,* (2005) 7, 291.

5. Reeves, S., Taillefert, A., and Pekot, L.: "The Allison Unit CO_2 – ECBM Pilot: A Reservoir Modeling Study," *Topical Report*, Advanced Resources International, Houston, TX (2003).

6. Stevens, S. H., Spector, D., and Riemer, P.: "Enhanced Coalbed Methane Recovery using CO_2 Injection: Worldwide Resource and CO_2 Sequestration Potential," paper SPE 48881 presented at the 1998 SPE International Conference and Exhibition in China, Beijing, China, 2-6 November.

7. Jikich, S. A.: "Economics of Enhanced Coalbed Methane and CO_2 Sequestration with Horizontal Wells," paper SPE 91391 presented at the 2004 Eastern Regional meeting, Charleston, West Virginia, 15-17 September.

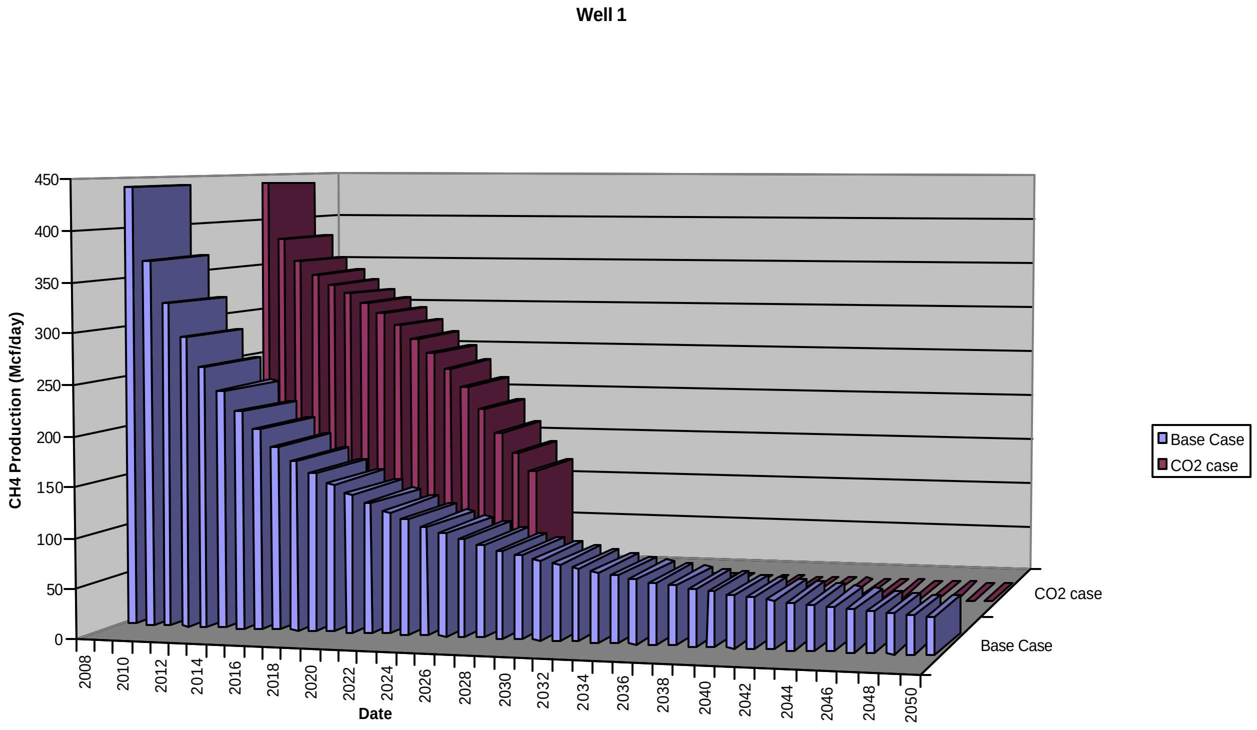
8. Shi, J.Q., and Durucan, S.: "Changes in Permeability of Coal Beds during Primary Recovery – Part1: Model Formulation and Analysis," *SPE Reservoir Evaluation and Engineering,* (2003) 5, 150.

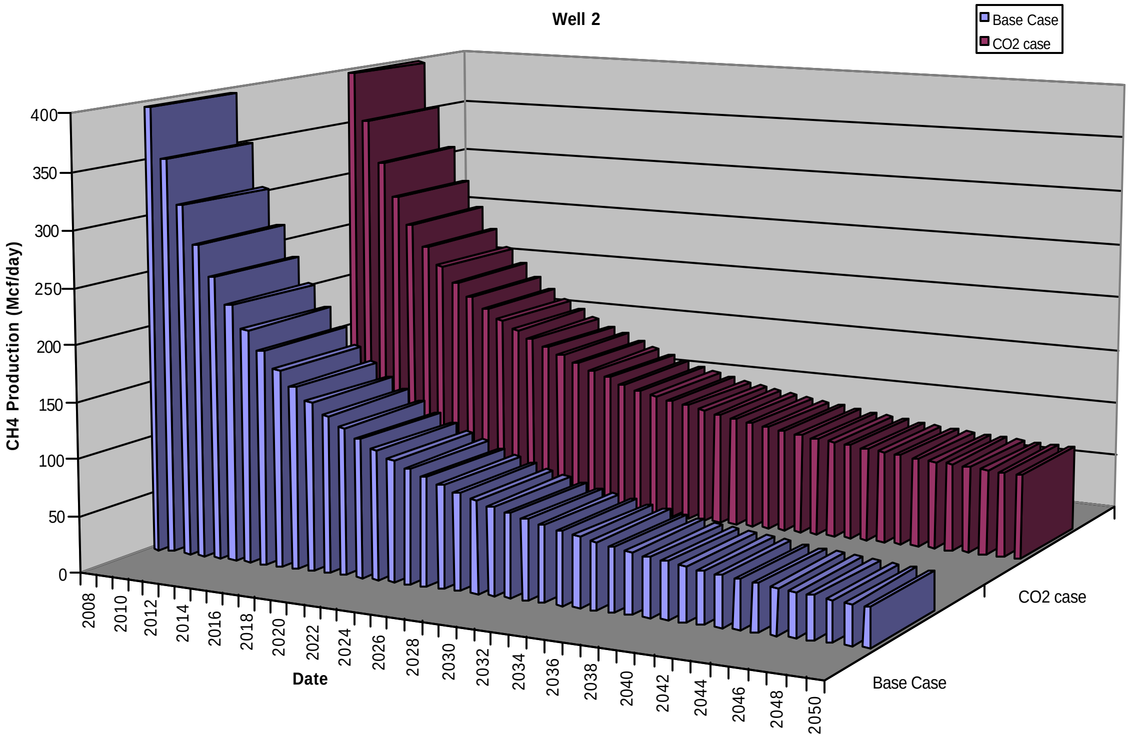
9. Wong, S., Gunter, W.D., and Mavor, M.J.: "Economics of CO_2 Sequestration in Coalbed Methane Reservoirs," paper SPE 59785 presented at the 2000 SPE/CERI Gas Technology Symposium, Calgary, Alberta, Canada, 3-5 April.

10. Reeves, S., Davis, D.W., and Oudinot, A.Y.: "A Technical and Economic Sensitivity Study of Enhanced Coalbed Methane Recovery and Carbon Sequestration in Coal," *Topical Report*, Advanced Resources International, Inc, Houston, TX (2004).

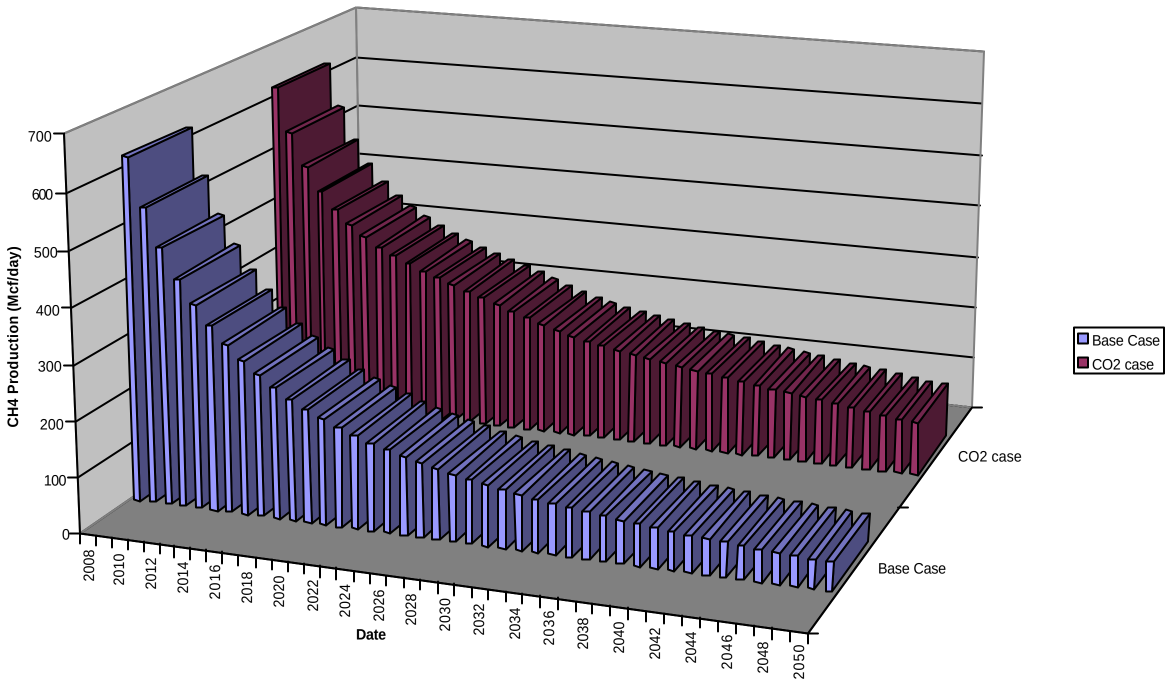
APPENDIX

Design Scenario Case 1 vs. Model Case

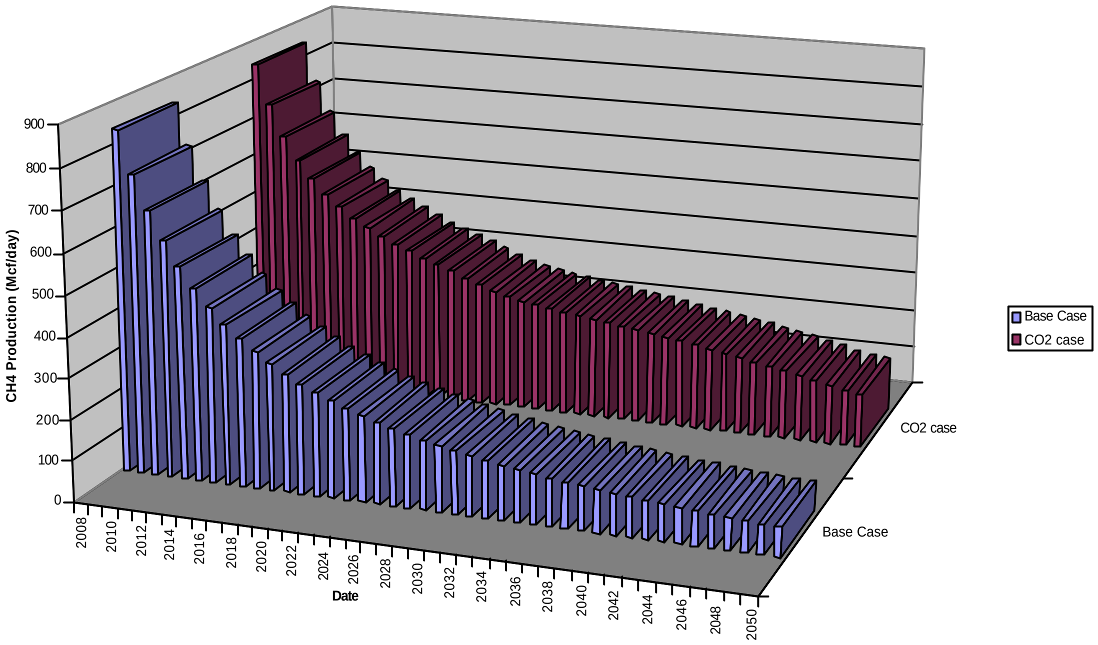


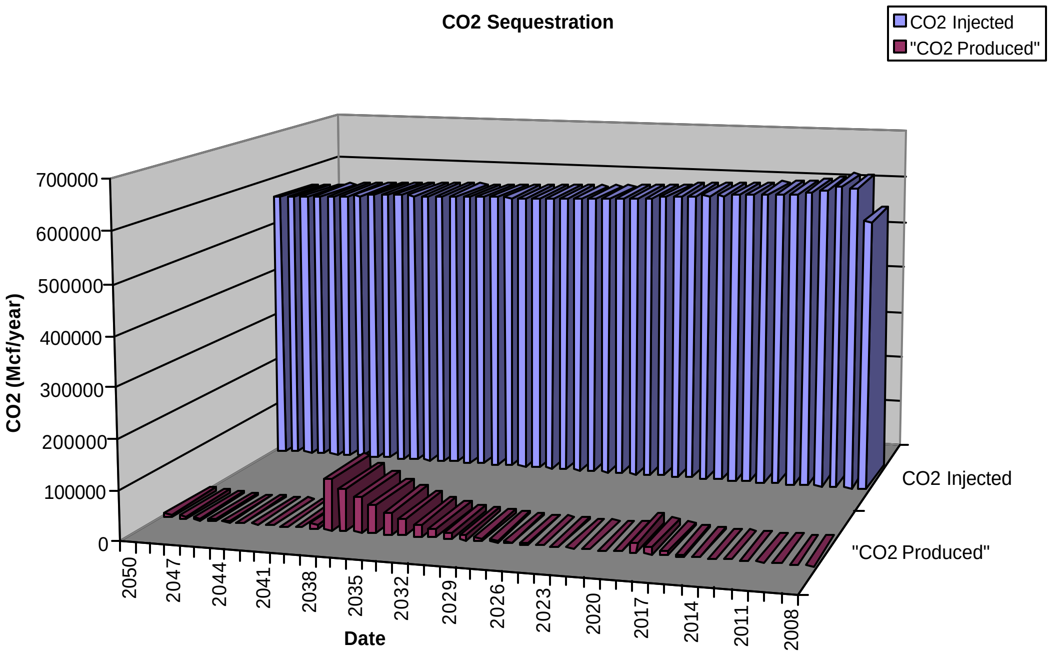

Well 2
Base Case
CO2 case
CH4 Production (Mcf/day)
0
50
100
150
200
250
300
350
400
Date
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
2050
Base Case
CO2 case

Well 3

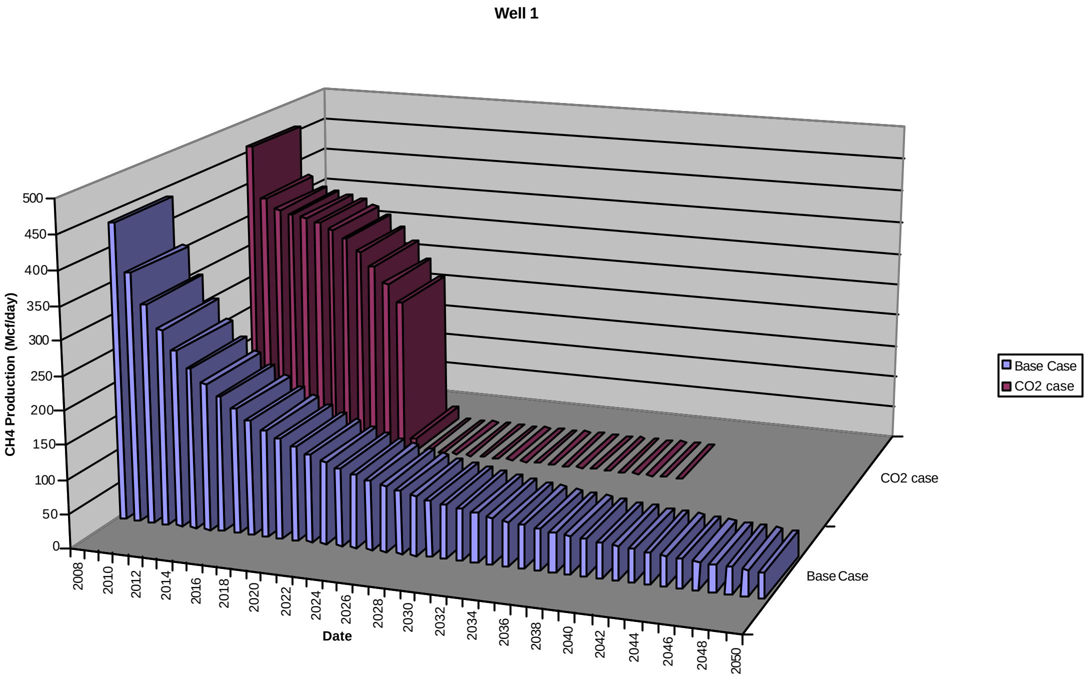

CH4 Production (Mcf/day)
700
600
500
400
300
200
100
0
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
2050
Date
CO2 case
Base Case
Base Case
CO2 case

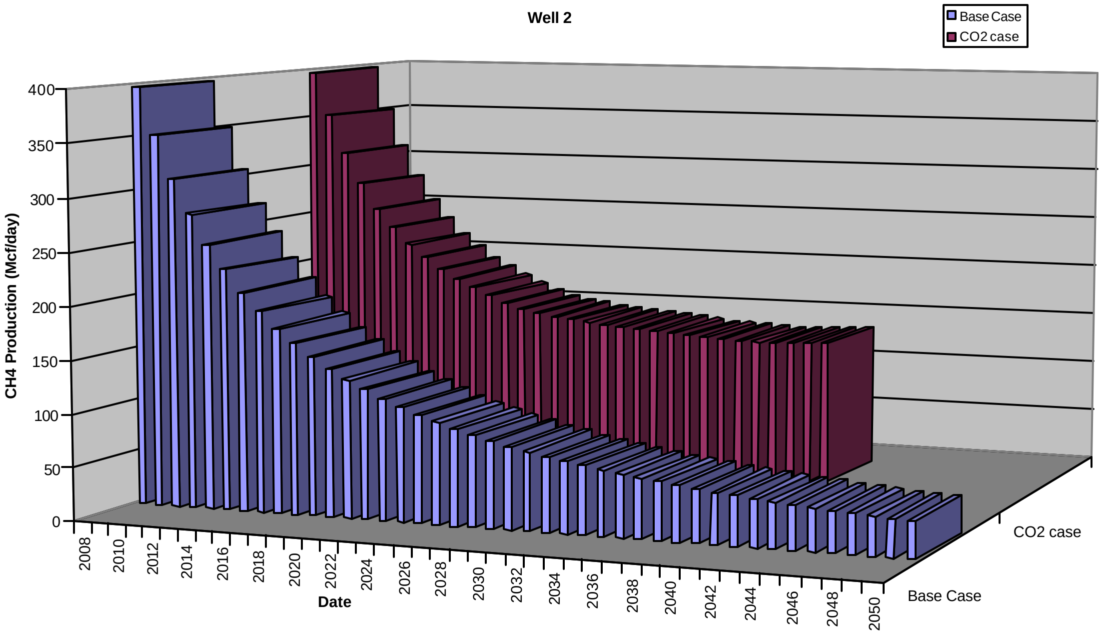
Well 4

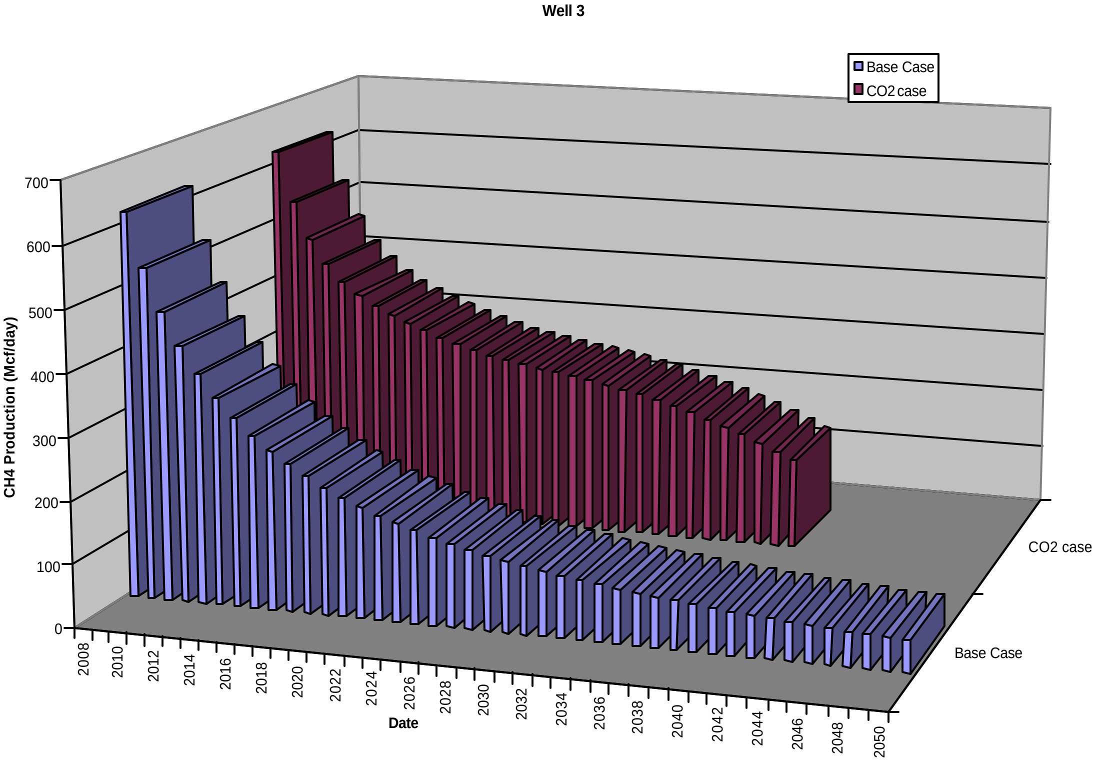

CH4 Production (Mcf/day)
900
800
700
600
500
400
300
200
100
0
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
2050
Date
CO2 case
Base Case
Base Case
CO2 case

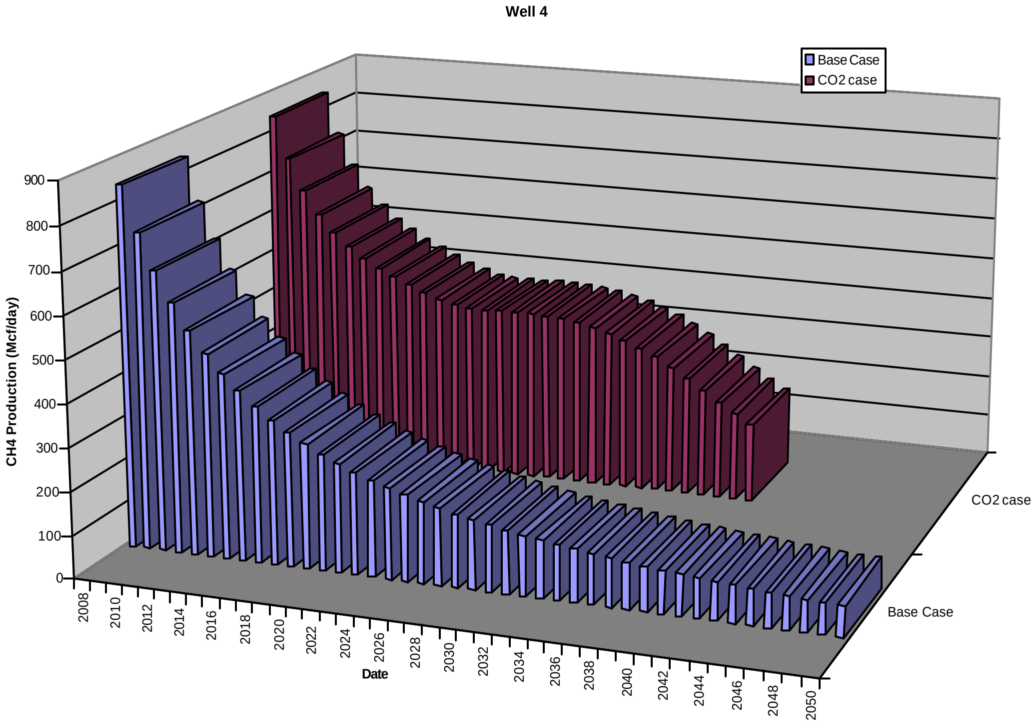

CO2 Sequestration
CO2 Injected
"CO2 Produced"
CO2 (Mcf/year)
700000
600000
500000
400000
300000
200000
100000
0
2050
2047
2044
2041
2038
2035
2032
2029
2026
2023
2020
2017
2014
2011
2008
Date
CO2 Injected
"CO2 Produced"

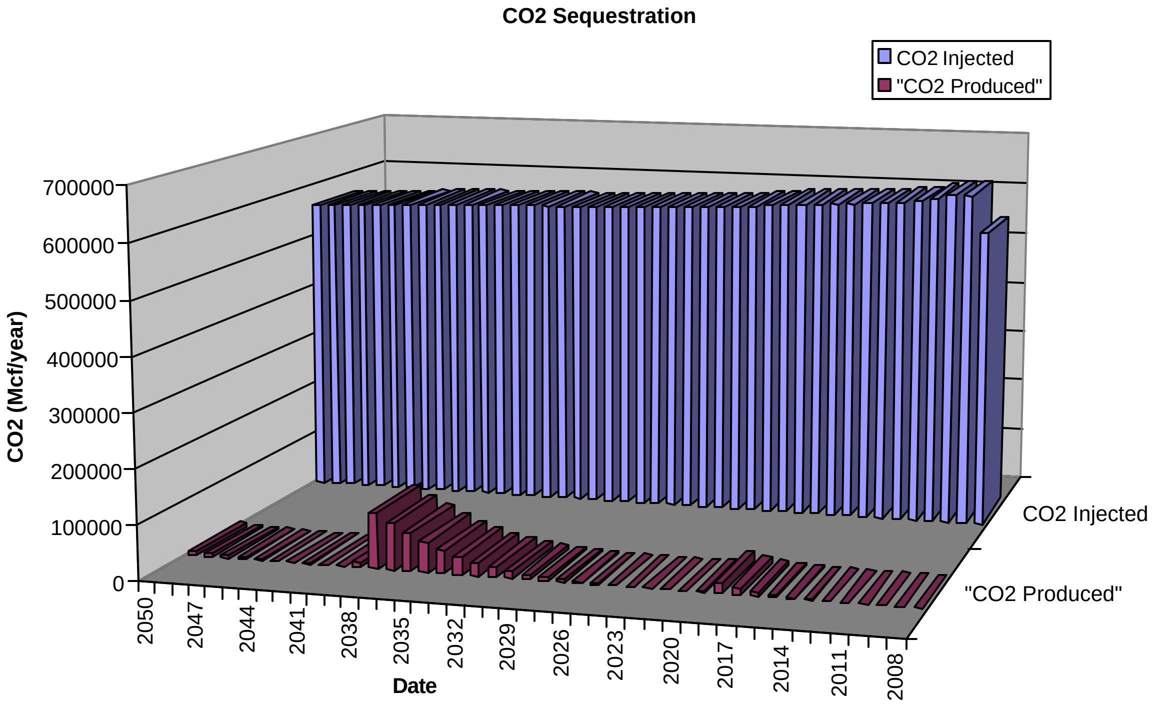
Design Scenario Case 2 vs. Model Case



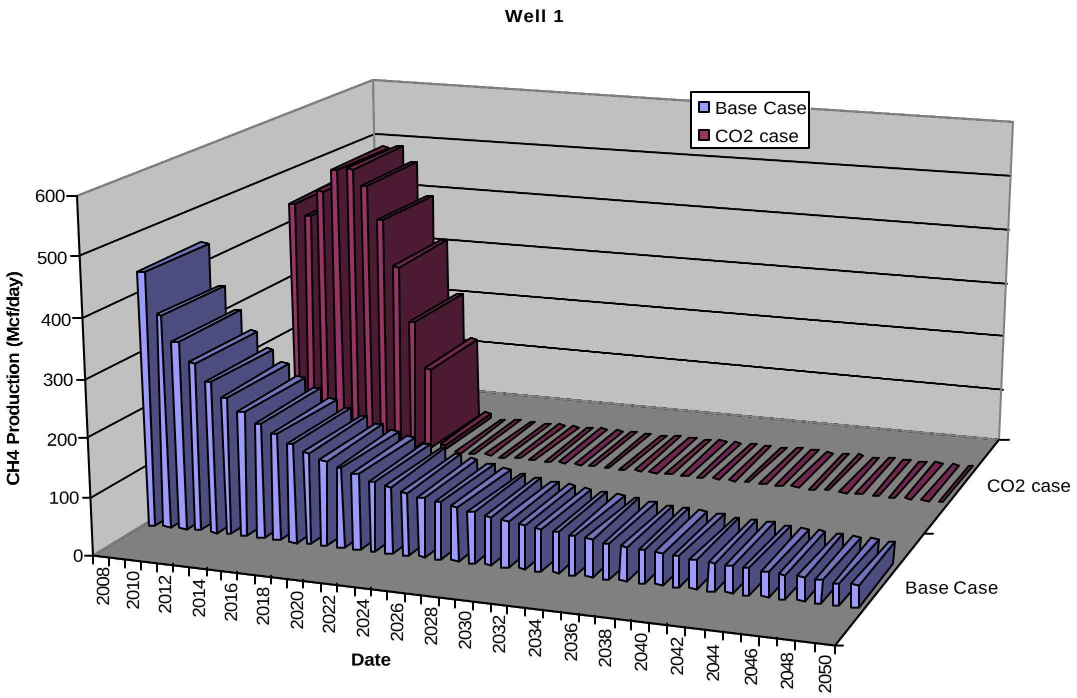

Well 2
Base Case
CO2 case
CH4 Production (Mcf/day)
0
50
100
150
200
250
300
350
400
Date
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
2050
CO2 case
Base Case

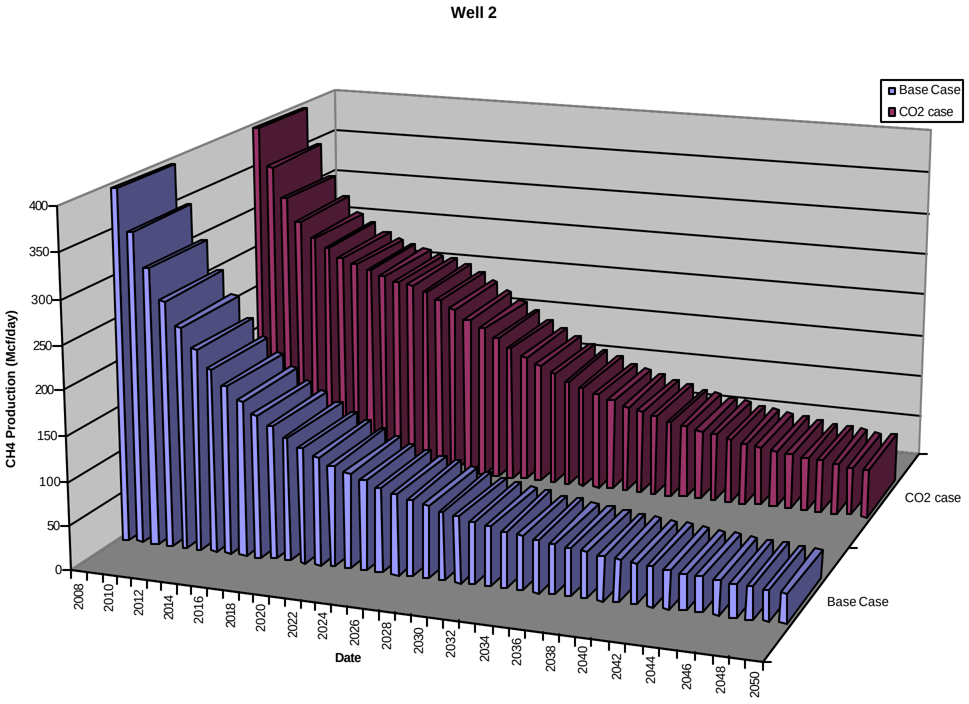

Well 3
Base Case
CO2 case
CH4 Production (Mcf/day)
0
100
200
300
400
500
600
700
Date
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
2050
CO2 case
Base Case


Well 4
Base Case
CO2 case
CH4 Production (Mcf/day)
0
100
200
300
400
500
600
700
800
900
Date
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
2050
CO2 case
Base Case

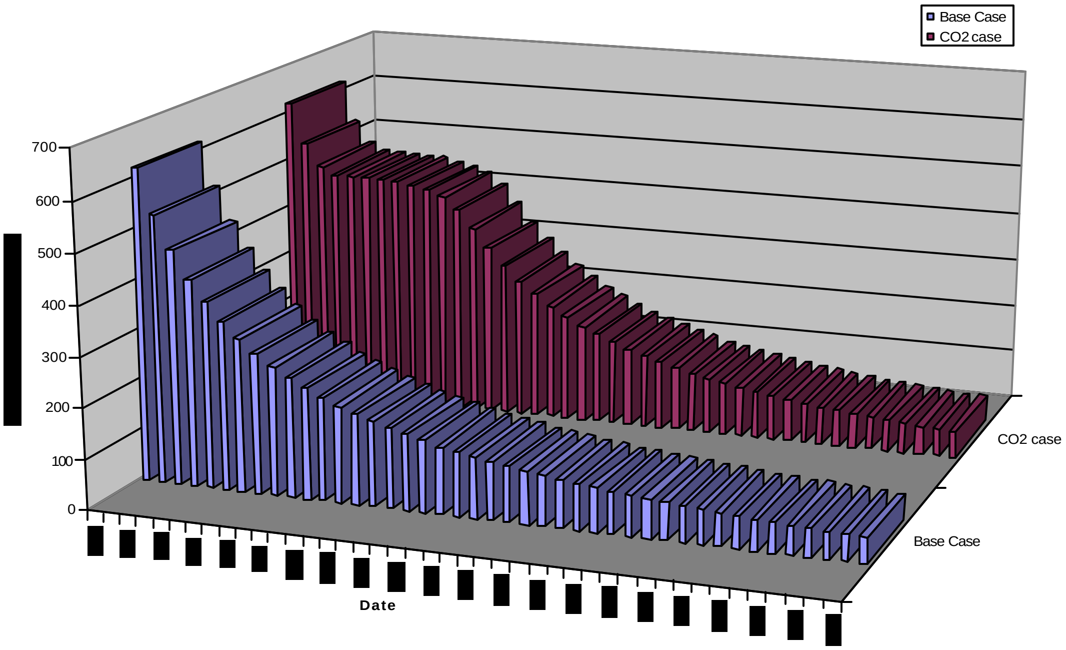

CO2 Sequestration
CO2 Injected
"CO2 Produced"
CO2 (Mcf/year)
0
100000
200000
300000
400000
500000
600000
700000
Date
2050
2047
2044
2041
2038
2035
2032
2029
2026
2023
2020
2017
2014
2011
2008
CO2 Injected
"CO2 Produced"

Design Scenario Case 3 vs. Model Case

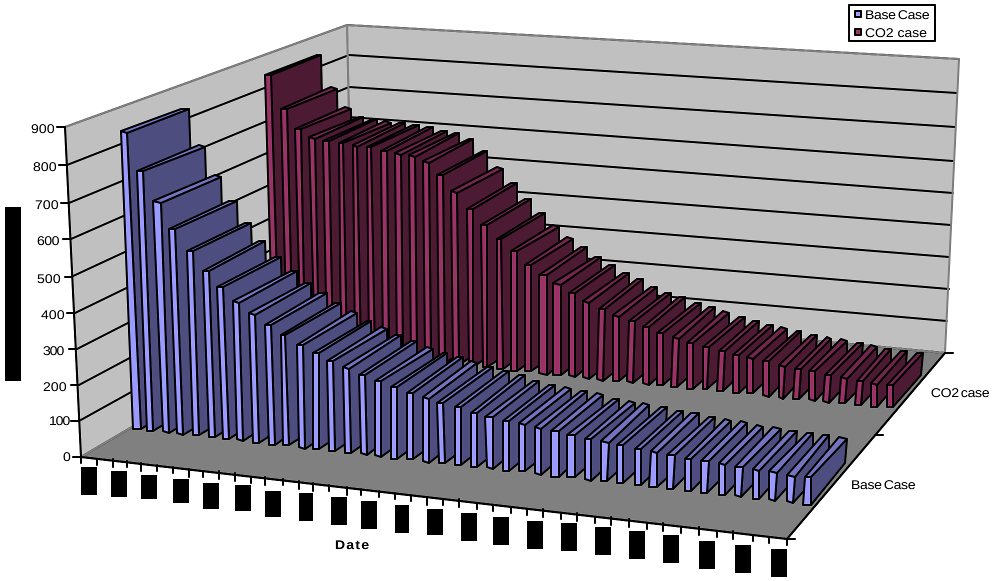


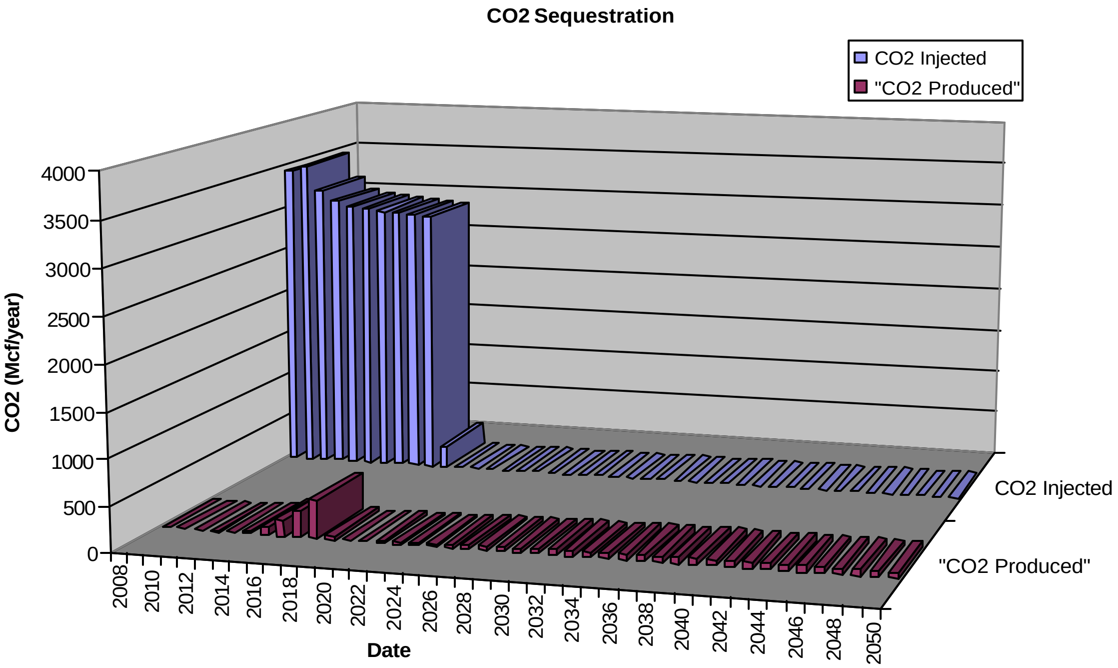


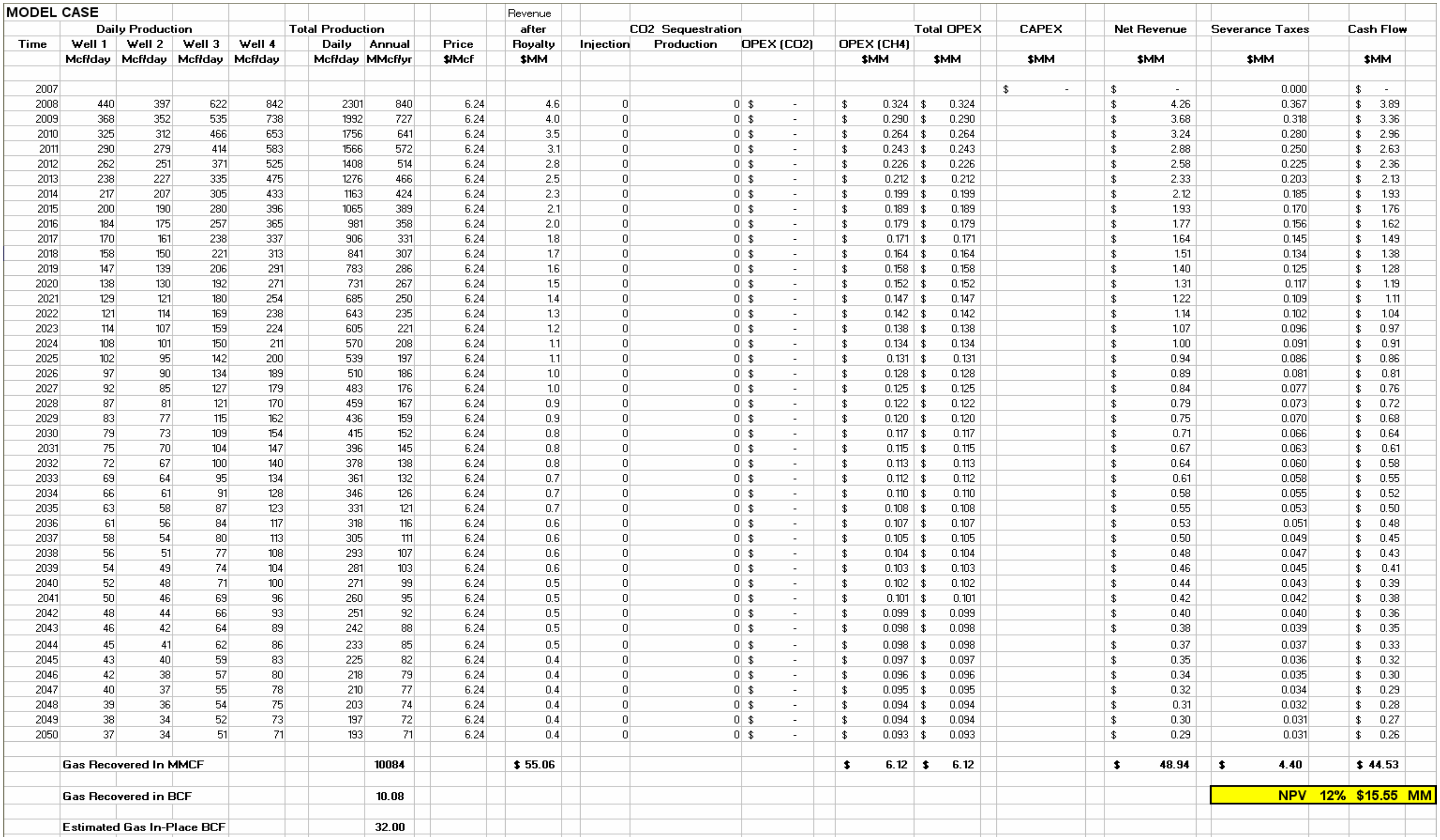
Well 3


Base Case
CO2 case
700
600
500
400
300
200
100
0
Date
CO2 case
Base Case

Well 4

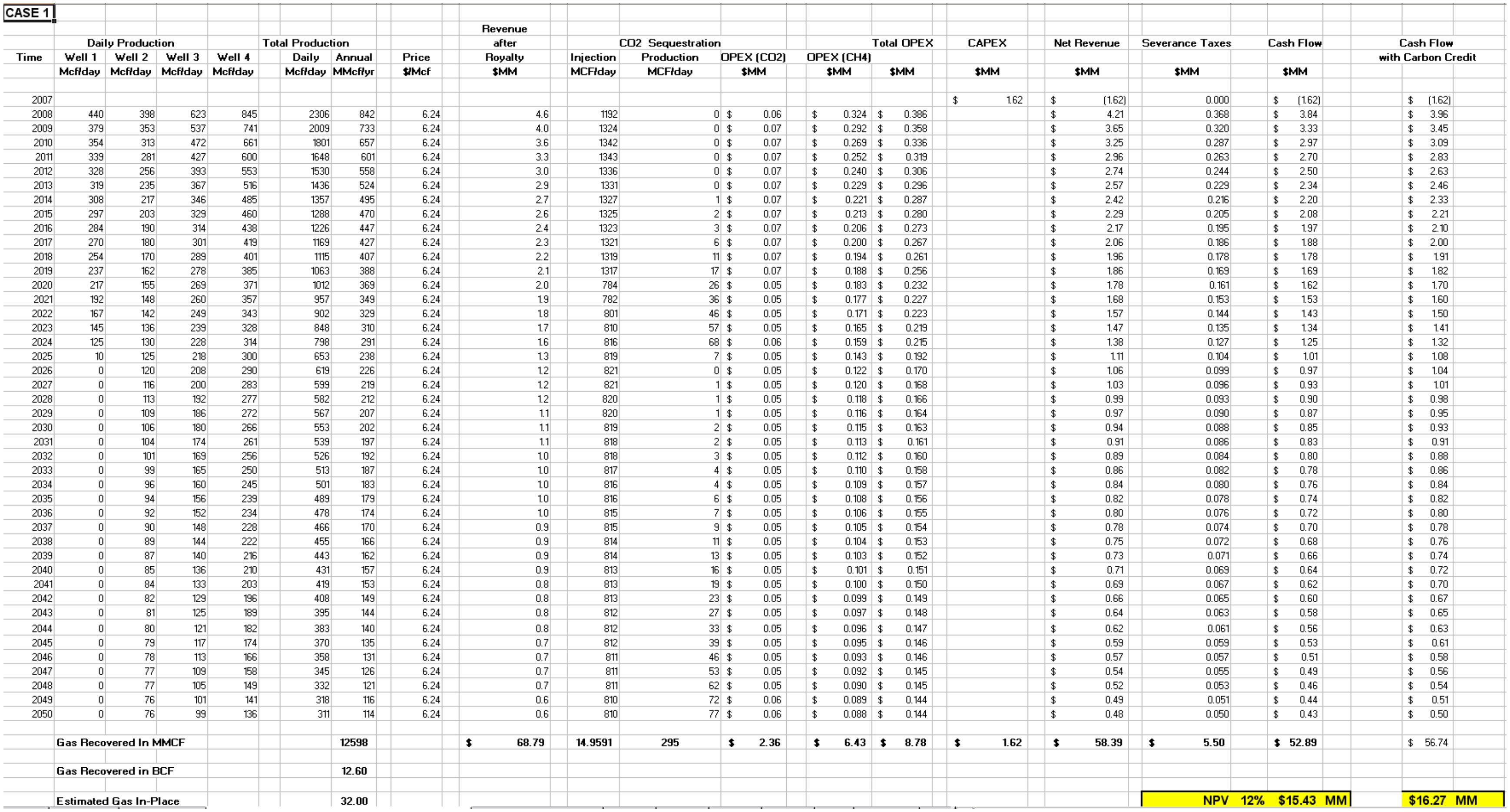

Base Case
CO2 case
900
800
700
600
500
400
300
200
100
0
Date
CO2 case
Base Case


CO2 Sequestration
CO2 Injected
"CO2 Produced"
CO2 (Mcf/year)
4000
3500
3000
2500
2000
1500
1000
500
0
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
2044
2046
2048
2050
Date
CO2 Injected
"CO2 Produced"



MODEL CASE								Revenue									
	Daily Production				Total Production			after	CO2 Sequestration				Total OPEX	CAPEX	Net Revenue	Severance Taxes	Cash Flow
Time	Well 1	Well 2	Well 3	Well 4	Daily	Annual	Price	Royalty	Injection	Production	OPEX (CO2)	OPEX (CH4)					
	Mcf/day	Mcf/day	Mcf/day	Mcf/day	Mcf/day	MMcf/yr	$/Mcf	$MM				$MM	$MM	$MM	$MM	$MM	$MM
2007														$ -	$ -	0.000	$ -
2008	440	397	622	842	2301	840	6.24	4.6	0	0	$ -	$ 0.324	$ 0.324		$ 4.26	0.367	$ 3.89
2009	368	352	535	738	1992	727	6.24	4.0	0	0	$ -	$ 0.290	$ 0.290		$ 3.68	0.318	$ 3.36
2010	325	312	466	653	1756	641	6.24	3.5	0	0	$ -	$ 0.264	$ 0.264		$ 3.24	0.280	$ 2.96
2011	290	279	414	583	1566	572	6.24	3.1	0	0	$ -	$ 0.243	$ 0.243		$ 2.88	0.250	$ 2.63
2012	262	251	371	525	1408	514	6.24	2.8	0	0	$ -	$ 0.226	$ 0.226		$ 2.58	0.225	$ 2.36
2013	238	227	335	475	1276	466	6.24	2.5	0	0	$ -	$ 0.212	$ 0.212		$ 2.33	0.203	$ 2.13
2014	217	207	305	433	1163	424	6.24	2.3	0	0	$ -	$ 0.199	$ 0.199		$ 2.12	0.185	$ 1.93
2015	200	190	280	396	1065	389	6.24	2.1	0	0	$ -	$ 0.189	$ 0.189		$ 1.93	0.170	$ 1.76
2016	184	175	257	365	981	358	6.24	2.0	0	0	$ -	$ 0.179	$ 0.179		$ 1.77	0.156	$ 1.62
2017	170	161	238	337	906	331	6.24	1.8	0	0	$ -	$ 0.171	$ 0.171		$ 1.64	0.145	$ 1.49
2018	158	150	221	313	841	307	6.24	1.7	0	0	$ -	$ 0.164	$ 0.164		$ 1.51	0.134	$ 1.38
2019	147	139	206	291	783	286	6.24	1.6	0	0	$ -	$ 0.158	$ 0.158		$ 1.40	0.125	$ 1.28
2020	138	130	192	271	731	267	6.24	1.5	0	0	$ -	$ 0.152	$ 0.152		$ 1.31	0.117	$ 1.19
2021	129	121	180	254	685	250	6.24	1.4	0	0	$ -	$ 0.147	$ 0.147		$ 1.22	0.109	$ 1.11
2022	121	114	169	238	643	235	6.24	1.3	0	0	$ -	$ 0.142	$ 0.142		$ 1.14	0.102	$ 1.04
2023	114	107	159	224	605	221	6.24	1.2	0	0	$ -	$ 0.138	$ 0.138		$ 1.07	0.096	$ 0.97
2024	108	101	150	211	570	208	6.24	1.1	0	0	$ -	$ 0.134	$ 0.134		$ 1.00	0.091	$ 0.91
2025	102	95	142	200	539	197	6.24	1.1	0	0	$ -	$ 0.131	$ 0.131		$ 0.94	0.086	$ 0.86
2026	97	90	134	189	510	186	6.24	1.0	0	0	$ -	$ 0.128	$ 0.128		$ 0.89	0.081	$ 0.81
2027	92	85	127	179	483	176	6.24	1.0	0	0	$ -	$ 0.125	$ 0.125		$ 0.84	0.077	$ 0.76
2028	87	81	121	170	459	167	6.24	0.9	0	0	$ -	$ 0.122	$ 0.122		$ 0.79	0.073	$ 0.72
2029	83	77	115	162	436	159	6.24	0.9	0	0	$ -	$ 0.120	$ 0.120		$ 0.75	0.070	$ 0.68
2030	79	73	109	154	415	152	6.24	0.8	0	0	$ -	$ 0.117	$ 0.117		$ 0.71	0.066	$ 0.64
2031	75	70	104	147	396	145	6.24	0.8	0	0	$ -	$ 0.115	$ 0.115		$ 0.67	0.063	$ 0.61
2032	72	67	100	140	378	138	6.24	0.8	0	0	$ -	$ 0.113	$ 0.113		$ 0.64	0.060	$ 0.58
2033	69	64	95	134	361	132	6.24	0.7	0	0	$ -	$ 0.112	$ 0.112		$ 0.61	0.058	$ 0.55
2034	66	61	91	128	346	126	6.24	0.7	0	0	$ -	$ 0.110	$ 0.110		$ 0.58	0.055	$ 0.52
2035	63	58	87	123	331	121	6.24	0.7	0	0	$ -	$ 0.108	$ 0.108		$ 0.55	0.053	$ 0.50
2036	61	56	84	117	318	116	6.24	0.6	0	0	$ -	$ 0.107	$ 0.107		$ 0.53	0.051	$ 0.48
2037	58	54	80	113	305	111	6.24	0.6	0	0	$ -	$ 0.105	$ 0.105		$ 0.50	0.049	$ 0.45
2038	56	51	77	108	293	107	6.24	0.6	0	0	$ -	$ 0.104	$ 0.104		$ 0.48	0.047	$ 0.43
2039	54	49	74	104	281	103	6.24	0.6	0	0	$ -	$ 0.103	$ 0.103		$ 0.46	0.045	$ 0.41
2040	52	48	71	100	271	99	6.24	0.5	0	0	$ -	$ 0.102	$ 0.102		$ 0.44	0.043	$ 0.39
2041	50	46	69	96	260	95	6.24	0.5	0	0	$ -	$ 0.101	$ 0.101		$ 0.42	0.042	$ 0.38
2042	48	44	66	93	251	92	6.24	0.5	0	0	$ -	$ 0.099	$ 0.099		$ 0.40	0.040	$ 0.36
2043	46	42	64	89	242	88	6.24	0.5	0	0	$ -	$ 0.098	$ 0.098		$ 0.38	0.039	$ 0.35
2044	45	41	62	86	233	85	6.24	0.5	0	0	$ -	$ 0.098	$ 0.098		$ 0.37	0.037	$ 0.33
2045	43	40	59	83	225	82	6.24	0.4	0	0	$ -	$ 0.097	$ 0.097		$ 0.35	0.036	$ 0.32
2046	42	38	57	80	218	79	6.24	0.4	0	0	$ -	$ 0.096	$ 0.096		$ 0.34	0.035	$ 0.30
2047	40	37	55	78	210	77	6.24	0.4	0	0	$ -	$ 0.095	$ 0.095		$ 0.32	0.034	$ 0.29
2048	39	36	54	75	203	74	6.24	0.4	0	0	$ -	$ 0.094	$ 0.094		$ 0.31	0.032	$ 0.28
2049	38	34	52	73	197	72	6.24	0.4	0	0	$ -	$ 0.094	$ 0.094		$ 0.30	0.031	$ 0.27
2050	37	34	51	71	193	71	6.24	0.4	0	0	$ -	$ 0.093	$ 0.093		$ 0.29	0.031	$ 0.26
	Gas Recovered In MMCF					**10084**		**$ 55.06**				**$ 6.12**	**$ 6.12**		**$ 48.94**	**$ 4.40**	**$ 44.53**
	Gas Recovered in BCF					**10.08**										**NPV 12%**	**$15.55 MM**
	Estimated Gas In-Place BCF					**32.00**											

Model Case: Economic Model



CASE 1																		
	Daily Production				Total Production			Revenue after Royalty	CO2 Sequestration				Total OPEX	CAPEX	Net Revenue	Severance Taxes	Cash Flow	Cash Flow with Carbon Credit
Time	Well 1	Well 2	Well 3	Well 4	Daily	Annual	Price		Injection	Production	OPEX (CO2)	OPEX (CH4)						
	Mcf/day	Mcf/day	Mcf/day	Mcf/day	Mcf/day	MMcf/yr	$/Mcf	$MM	MCF/day	MCF/day	$MM	$MM	$MM	$MM	$MM	$MM	$MM	
2007														$ 1.62	$ (1.62)	0.000	$ (1.62)	$ (1.62)
2008	440	398	623	845	2306	842	6.24	4.6	1192	0	$ 0.06	$ 0.324	$ 0.386		$ 4.21	0.368	$ 3.84	$ 3.96
2009	379	353	537	741	2009	733	6.24	4.0	1324	0	$ 0.07	$ 0.292	$ 0.358		$ 3.65	0.320	$ 3.33	$ 3.45
2010	354	313	472	661	1801	657	6.24	3.6	1342	0	$ 0.07	$ 0.269	$ 0.336		$ 3.25	0.287	$ 2.97	$ 3.09
2011	339	281	427	600	1648	601	6.24	3.3	1343	0	$ 0.07	$ 0.252	$ 0.319		$ 2.96	0.263	$ 2.70	$ 2.83
2012	328	256	393	553	1530	558	6.24	3.0	1336	0	$ 0.07	$ 0.240	$ 0.306		$ 2.74	0.244	$ 2.50	$ 2.63
2013	319	235	367	516	1436	524	6.24	2.9	1331	0	$ 0.07	$ 0.229	$ 0.296		$ 2.57	0.229	$ 2.34	$ 2.46
2014	308	217	346	485	1357	495	6.24	2.7	1327	1	$ 0.07	$ 0.221	$ 0.287		$ 2.42	0.216	$ 2.20	$ 2.33
2015	297	203	329	460	1288	470	6.24	2.6	1325	2	$ 0.07	$ 0.213	$ 0.280		$ 2.29	0.205	$ 2.08	$ 2.21
2016	284	190	314	438	1226	447	6.24	2.4	1323	3	$ 0.07	$ 0.206	$ 0.273		$ 2.17	0.195	$ 1.97	$ 2.10
2017	270	180	301	419	1169	427	6.24	2.3	1321	6	$ 0.07	$ 0.200	$ 0.267		$ 2.06	0.186	$ 1.88	$ 2.00
2018	254	170	289	401	1115	407	6.24	2.2	1319	11	$ 0.07	$ 0.194	$ 0.261		$ 1.96	0.178	$ 1.78	$ 1.91
2019	237	162	278	385	1063	388	6.24	2.1	1317	17	$ 0.07	$ 0.188	$ 0.256		$ 1.86	0.169	$ 1.69	$ 1.82
2020	217	155	269	371	1012	369	6.24	2.0	784	26	$ 0.05	$ 0.183	$ 0.232		$ 1.78	0.161	$ 1.62	$ 1.70
2021	192	148	260	357	957	349	6.24	1.9	782	36	$ 0.05	$ 0.177	$ 0.227		$ 1.68	0.153	$ 1.53	$ 1.60
2022	167	142	249	343	902	329	6.24	1.8	801	46	$ 0.05	$ 0.171	$ 0.223		$ 1.57	0.144	$ 1.43	$ 1.50
2023	145	136	239	328	848	310	6.24	1.7	810	57	$ 0.05	$ 0.165	$ 0.219		$ 1.47	0.135	$ 1.34	$ 1.41
2024	125	130	228	314	798	291	6.24	1.6	816	68	$ 0.06	$ 0.159	$ 0.215		$ 1.38	0.127	$ 1.25	$ 1.32
2025	10	125	218	300	653	238	6.24	1.3	819	7	$ 0.05	$ 0.143	$ 0.192		$ 1.11	0.104	$ 1.01	$ 1.08
2026	0	120	208	290	619	226	6.24	1.2	821	0	$ 0.05	$ 0.122	$ 0.170		$ 1.06	0.099	$ 0.97	$ 1.04
2027	0	116	200	283	599	219	6.24	1.2	821	1	$ 0.05	$ 0.120	$ 0.168		$ 1.03	0.096	$ 0.93	$ 1.01
2028	0	113	192	277	582	212	6.24	1.2	820	1	$ 0.05	$ 0.118	$ 0.166		$ 0.99	0.093	$ 0.90	$ 0.98
2029	0	109	186	272	567	207	6.24	1.1	820	1	$ 0.05	$ 0.116	$ 0.164		$ 0.97	0.090	$ 0.87	$ 0.95
2030	0	106	180	266	553	202	6.24	1.1	819	2	$ 0.05	$ 0.115	$ 0.163		$ 0.94	0.088	$ 0.85	$ 0.93
2031	0	104	174	261	539	197	6.24	1.1	818	2	$ 0.05	$ 0.113	$ 0.161		$ 0.91	0.086	$ 0.83	$ 0.91
2032	0	101	169	256	526	192	6.24	1.0	818	3	$ 0.05	$ 0.112	$ 0.160		$ 0.89	0.084	$ 0.80	$ 0.88
2033	0	99	165	250	513	187	6.24	1.0	817	4	$ 0.05	$ 0.110	$ 0.158		$ 0.86	0.082	$ 0.78	$ 0.86
2034	0	96	160	245	501	183	6.24	1.0	816	4	$ 0.05	$ 0.109	$ 0.157		$ 0.84	0.080	$ 0.76	$ 0.84
2035	0	94	156	239	489	179	6.24	1.0	816	6	$ 0.05	$ 0.108	$ 0.156		$ 0.82	0.078	$ 0.74	$ 0.82
2036	0	92	152	234	478	174	6.24	1.0	815	7	$ 0.05	$ 0.106	$ 0.155		$ 0.80	0.076	$ 0.72	$ 0.80
2037	0	90	148	228	466	170	6.24	0.9	815	9	$ 0.05	$ 0.105	$ 0.154		$ 0.78	0.074	$ 0.70	$ 0.78
2038	0	89	144	222	455	166	6.24	0.9	814	11	$ 0.05	$ 0.104	$ 0.153		$ 0.75	0.072	$ 0.68	$ 0.76
2039	0	87	140	216	443	162	6.24	0.9	814	13	$ 0.05	$ 0.103	$ 0.152		$ 0.73	0.071	$ 0.66	$ 0.74
2040	0	85	136	210	431	157	6.24	0.9	813	16	$ 0.05	$ 0.101	$ 0.151		$ 0.71	0.069	$ 0.64	$ 0.72
2041	0	84	133	203	419	153	6.24	0.8	813	19	$ 0.05	$ 0.100	$ 0.150		$ 0.69	0.067	$ 0.62	$ 0.70
2042	0	82	129	196	408	149	6.24	0.8	813	23	$ 0.05	$ 0.099	$ 0.149		$ 0.66	0.065	$ 0.60	$ 0.67
2043	0	81	125	189	395	144	6.24	0.8	812	27	$ 0.05	$ 0.097	$ 0.148		$ 0.64	0.063	$ 0.58	$ 0.65
2044	0	80	121	182	383	140	6.24	0.8	812	33	$ 0.05	$ 0.096	$ 0.147		$ 0.62	0.061	$ 0.56	$ 0.63
2045	0	79	117	174	370	135	6.24	0.7	812	39	$ 0.05	$ 0.095	$ 0.146		$ 0.59	0.059	$ 0.53	$ 0.61
2046	0	78	113	166	358	131	6.24	0.7	811	46	$ 0.05	$ 0.093	$ 0.146		$ 0.57	0.057	$ 0.51	$ 0.58
2047	0	77	109	158	345	126	6.24	0.7	811	53	$ 0.05	$ 0.092	$ 0.145		$ 0.54	0.055	$ 0.49	$ 0.56
2048	0	77	105	149	332	121	6.24	0.7	811	62	$ 0.05	$ 0.090	$ 0.145		$ 0.52	0.053	$ 0.46	$ 0.54
2049	0	76	101	141	318	116	6.24	0.6	810	72	$ 0.06	$ 0.089	$ 0.144		$ 0.49	0.051	$ 0.44	$ 0.51
2050	0	76	99	136	311	114	6.24	0.6	810	77	$ 0.06	$ 0.088	$ 0.144		$ 0.48	0.050	$ 0.43	$ 0.50
	Gas Recovered In MMCF					**12598**		**$ 68.79**	**14.9591**	**295**	**$ 2.36**	**$ 6.43**	**$ 8.78**	**$ 1.62**	**$ 58.39**	**$ 5.50**	**$ 52.89**	$ 56.74
	Gas Recovered in BCF					**12.60**												
	Estimated Gas In-Place					**32.00**										**NPV 12% $15.43 MM**		**$16.27 MM**

Case 1: Economic Model

CASE 2

	Daily Production				Total Production			Revenue after Royalty	CO2 Sequestration				Total OPEX	CAPEX	Net Revenue	Severance Taxes	Cash Flow	Cash Flow with Carbon Credit
Time	Well 1	Well 2	Well 3	Well 4	Daily	Annual	Price		Injection	Production	OPEX (CO2)	OPEX (CH4)						
	Mcf/day	Mcf/day	Mcf/day	Mcf/day	Mcf/day	MMcf/yr	$/Mcf	$MM	MCF/day	MCF/day	$MM	$MM	$MM	$MM	$MM	$MM	$MM	
2007														$ 1.62	$ (1.62)	0.000	$ (1.62)	$ (1.62)
2008	463	398	623	845	2328	850	6.24	4.6	1530	0	$ 0.07	$ 0.327	$ 0.401		$ 4.24	0.371	$ 3.87	$ 4.01
2009	383	353	537	741	2014	735	6.24	4.0	1714	0	$ 0.08	$ 0.293	$ 0.373		$ 3.64	0.321	$ 3.32	$ 3.48
2010	366	313	475	664	1818	664	6.24	3.6	1718	0	$ 0.08	$ 0.271	$ 0.352		$ 3.27	0.290	$ 2.98	$ 3.15
2011	361	282	432	607	1683	614	6.24	3.4	1698	0	$ 0.08	$ 0.256	$ 0.336		$ 3.02	0.268	$ 2.75	$ 2.91
2012	357	257	403	565	1582	578	6.24	3.2	1679	0	$ 0.08	$ 0.245	$ 0.325		$ 2.83	0.252	$ 2.58	$ 2.74
2013	351	237	381	533	1503	549	6.24	3.0	1669	1	$ 0.08	$ 0.237	$ 0.316		$ 2.68	0.240	$ 2.44	$ 2.60
2014	342	221	364	508	1435	524	6.24	2.9	1662	2	$ 0.08	$ 0.229	$ 0.308		$ 2.55	0.229	$ 2.32	$ 2.48
2015	328	208	350	487	1373	501	6.24	2.7	1657	6	$ 0.08	$ 0.222	$ 0.301		$ 2.43	0.219	$ 2.22	$ 2.37
2016	311	197	338	468	1313	479	6.24	2.6	1653	11	$ 0.08	$ 0.216	$ 0.295		$ 2.32	0.209	$ 2.11	$ 2.27
2017	289	187	327	451	1254	458	6.24	2.5	1649	20	$ 0.08	$ 0.209	$ 0.290		$ 2.21	0.200	$ 2.01	$ 2.17
2018	263	179	316	436	1195	436	6.24	2.4	1644	34	$ 0.08	$ 0.203	$ 0.285		$ 2.10	0.190	$ 1.91	$ 2.06
2019	234	171	307	422	1135	414	6.24	2.3	1640	54	$ 0.08	$ 0.196	$ 0.280		$ 1.98	0.181	$ 1.80	$ 1.95
2020	18	164	298	410	891	325	6.24	1.8	1636	6	$ 0.08	$ 0.170	$ 0.248		$ 1.53	0.142	$ 1.39	$ 1.54
2021	0	159	290	406	855	312	6.24	1.7	1629	0	$ 0.08	$ 0.148	$ 0.225		$ 1.48	0.136	$ 1.34	$ 1.50
2022	0	155	284	406	845	308	6.24	1.7	1621	1	$ 0.08	$ 0.147	$ 0.224		$ 1.46	0.135	$ 1.33	$ 1.48
2023	0	153	279	408	839	306	6.24	1.7	1615	1	$ 0.08	$ 0.146	$ 0.223		$ 1.45	0.134	$ 1.32	$ 1.47
2024	0	151	274	408	833	304	6.24	1.7	1609	2	$ 0.08	$ 0.145	$ 0.222		$ 1.44	0.133	$ 1.31	$ 1.46
2025	0	149	269	408	826	301	6.24	1.6	1604	3	$ 0.08	$ 0.144	$ 0.221		$ 1.42	0.132	$ 1.29	$ 1.45
2026	0	147	265	406	817	298	6.24	1.6	1601	5	$ 0.08	$ 0.144	$ 0.220		$ 1.41	0.130	$ 1.28	$ 1.43
2027	0	145	260	402	807	295	6.24	1.6	1597	7	$ 0.08	$ 0.142	$ 0.219		$ 1.39	0.129	$ 1.26	$ 1.41
2028	0	144	254	396	794	290	6.24	1.6	1595	11	$ 0.08	$ 0.141	$ 0.218		$ 1.36	0.127	$ 1.24	$ 1.39
2029	0	142	248	388	779	284	6.24	1.6	1592	17	$ 0.08	$ 0.139	$ 0.217		$ 1.33	0.124	$ 1.21	$ 1.36
2030	0	141	242	378	760	278	6.24	1.5	1590	24	$ 0.08	$ 0.137	$ 0.216		$ 1.30	0.121	$ 1.18	$ 1.33
2031	0	140	234	365	739	270	6.24	1.5	1589	34	$ 0.08	$ 0.135	$ 0.215		$ 1.26	0.118	$ 1.14	$ 1.29
2032	0	138	226	349	714	261	6.24	1.4	1587	48	$ 0.08	$ 0.132	$ 0.213		$ 1.21	0.114	$ 1.10	$ 1.24
2033	0	138	218	330	686	250	6.24	1.4	1585	66	$ 0.08	$ 0.129	$ 0.212		$ 1.15	0.109	$ 1.04	$ 1.19
2034	0	137	208	309	654	239	6.24	1.3	1584	89	$ 0.09	$ 0.126	$ 0.211		$ 1.09	0.104	$ 0.99	$ 1.13
2035	0	137	197	285	619	226	6.24	1.2	1582	117	$ 0.09	$ 0.122	$ 0.210		$ 1.02	0.099	$ 0.93	$ 1.07
2036	0	136	186	260	583	213	6.24	1.2	1581	151	$ 0.09	$ 0.118	$ 0.210		$ 0.95	0.093	$ 0.86	$ 1.00
2037	0	137	174	235	546	199	6.24	1.1	1579	190	$ 0.10	$ 0.114	$ 0.210		$ 0.88	0.087	$ 0.79	$ 0.92
2038	0	137	162	211	510	186	6.24	1.0	1578	232	$ 0.10	$ 0.110	$ 0.211		$ 0.81	0.081	$ 0.72	$ 0.85
2039	0	138	150	188	476	174	6.24	0.9	1577	276	$ 0.11	$ 0.106	$ 0.212		$ 0.74	0.076	$ 0.66	$ 0.79
	Gas Recovered In MMCF					**12120**		**$ 66.18**	**18.92**	**513**	**$ 2.62**	**$ 5.60**	**$ 8.22**	**1.62**	**$ 56.34**	**$ 5.29**	**$ 51.05**	$ 55.89
	Gas Recovered in BCF					**12.12**												
																NPV 12% $15.88 MM		**$17.01 MM**

Case 2: Economic Model

CASE 3								Revenue										
	Daily Production				Total Production			after		CO2 Sequestration			Total OPEX	CAPEX	Net Revenue	Severance Taxes	Cash Flow	Cash Flow
Time	Well 1	Well 2	Well 3	Well 4	Daily	Annual	Price	Royalty	Injection	Production	OPEX (CO2)	OPEX (CH4)						with Carbon Credit
	Mcf/day	Mcf/day	Mcf/day	Mcf/day	Mcf/day	MMcf/yr	$/Mcf	$MM	MCF/day	MCF/day	$MM	$MM	$MM	$MM	$MM	$MM	$MM	
2007														$ 1.62	$ (1.62)	0.000	$ (1.62)	$ (1.62)
2008	441	397	622	846	2306	842	6.24	4.6	3434	0	$ 0.14	$ 0.325	$ 0.468		$ 4.13	0.368	$ 3.76	$ 4.09
2009	419	353	541	745	2058	751	6.24	4.1	3510	0	$ 0.15	$ 0.297	$ 0.443		$ 3.66	0.328	$ 3.33	$ 3.67
2010	468	315	494	687	1964	717	6.24	3.9	3227	0	$ 0.14	$ 0.287	$ 0.423		$ 3.49	0.313	$ 3.18	$ 3.49
2011	508	289	479	662	1938	707	6.24	3.9	3100	3	$ 0.13	$ 0.284	$ 0.416		$ 3.45	0.309	$ 3.14	$ 3.44
2012	513	271	477	654	1915	699	6.24	3.8	3052	11	$ 0.13	$ 0.282	$ 0.412		$ 3.40	0.305	$ 3.10	$ 3.39
2013	482	259	477	652	1871	683	6.24	3.7	3026	34	$ 0.13	$ 0.277	$ 0.409		$ 3.32	0.298	$ 3.02	$ 3.31
2014	422	250	477	650	1799	657	6.24	3.6	3007	82	$ 0.14	$ 0.269	$ 0.406		$ 3.18	0.287	$ 2.89	$ 3.17
2015	337	243	473	646	1699	620	6.24	3.4	2990	166	$ 0.15	$ 0.258	$ 0.403		$ 2.98	0.271	$ 2.71	$ 2.98
2016	240	236	468	641	1584	578	6.24	3.2	2975	285	$ 0.16	$ 0.245	$ 0.403		$ 2.75	0.253	$ 2.50	$ 2.76
2017	152	231	460	634	1477	539	6.24	2.9	2962	411	$ 0.17	$ 0.234	$ 0.405		$ 2.54	0.236	$ 2.30	$ 2.55
2018	10	226	449	629	1314	479	6.24	2.6	246	43	$ 0.03	$ 0.216	$ 0.248		$ 2.37	0.209	$ 2.16	$ 2.18
2019	0	223	423	615	1261	460	6.24	2.5	0	8	$ 0.00	$ 0.192	$ 0.193		$ 2.32	0.201	$ 2.12	$ 2.12
2020	0	218	385	580	1182	432	6.24	2.4	0	12	$ 0.00	$ 0.183	$ 0.185		$ 2.17	0.189	$ 1.98	$ 1.98
2021	0	209	348	533	1090	398	6.24	2.2	0	16	$ 0.00	$ 0.173	$ 0.175		$ 2.00	0.174	$ 1.82	$ 1.82
2022	0	199	314	485	999	365	6.24	2.0	0	21	$ 0.00	$ 0.163	$ 0.166		$ 1.82	0.159	$ 1.67	$ 1.66
2023	0	189	284	441	914	333	6.24	1.8	0	25	$ 0.00	$ 0.154	$ 0.157		$ 1.66	0.146	$ 1.52	$ 1.52
2024	0	178	259	400	836	305	6.24	1.7	0	30	$ 0.00	$ 0.146	$ 0.149		$ 1.52	0.133	$ 1.38	$ 1.38
2025	0	167	236	364	767	280	6.24	1.5	0	34	$ 0.00	$ 0.138	$ 0.142		$ 1.39	0.122	$ 1.27	$ 1.26
2026	0	158	217	332	706	258	6.24	1.4	0	38	$ 0.00	$ 0.131	$ 0.135		$ 1.27	0.113	$ 1.16	$ 1.16
2027	0	149	200	303	651	238	6.24	1.3	0	41	$ 0.00	$ 0.125	$ 0.130		$ 1.17	0.104	$ 1.06	$ 1.06
2028	0	140	184	277	602	220	6.24	1.2	0	44	$ 0.00	$ 0.120	$ 0.125		$ 1.07	0.096	$ 0.98	$ 0.97
2029	0	132	171	255	558	204	6.24	1.1	0	47	$ 0.01	$ 0.115	$ 0.120		$ 0.99	0.089	$ 0.90	$ 0.90
2030	0	125	159	235	518	189	6.24	1.0	0	50	$ 0.01	$ 0.111	$ 0.116		$ 0.92	0.083	$ 0.83	$ 0.83
2031	0	119	148	216	483	176	6.24	1.0	0	53	$ 0.01	$ 0.107	$ 0.113		$ 0.85	0.077	$ 0.77	$ 0.77
2032	0	113	138	200	451	165	6.24	0.9	0	55	$ 0.01	$ 0.103	$ 0.109		$ 0.79	0.072	$ 0.72	$ 0.71
2033	0	107	129	185	422	154	6.24	0.8	0	57	$ 0.01	$ 0.100	$ 0.106		$ 0.73	0.067	$ 0.67	$ 0.66
2034	0	102	121	172	395	144	6.24	0.8	0	59	$ 0.01	$ 0.097	$ 0.104		$ 0.68	0.063	$ 0.62	$ 0.62
2035	0	97	114	160	371	136	6.24	0.7	0	60	$ 0.01	$ 0.095	$ 0.101		$ 0.64	0.059	$ 0.58	$ 0.57
2036	0	93	107	149	349	128	6.24	0.7	0	62	$ 0.01	$ 0.092	$ 0.099		$ 0.60	0.056	$ 0.54	$ 0.54
2037	0	89	101	139	329	120	6.24	0.7	0	63	$ 0.01	$ 0.090	$ 0.097		$ 0.56	0.053	$ 0.51	$ 0.50
2038	0	85	96	130	311	114	6.24	0.6	0	64	$ 0.01	$ 0.088	$ 0.095		$ 0.52	0.050	$ 0.48	$ 0.47
2039	0	82	91	122	294	107	6.24	0.6	0	65	$ 0.01	$ 0.086	$ 0.093		$ 0.49	0.047	$ 0.45	$ 0.44
2040	0	78	86	115	279	102	6.24	0.6	0	66	$ 0.01	$ 0.085	$ 0.092		$ 0.46	0.044	$ 0.42	$ 0.41
2041	0	75	81	108	264	96	6.24	0.5	0	66	$ 0.01	$ 0.083	$ 0.090		$ 0.44	0.042	$ 0.39	$ 0.39
2042	0	72	77	101	251	92	6.24	0.5	0	67	$ 0.01	$ 0.082	$ 0.089		$ 0.41	0.040	$ 0.37	$ 0.37
2043	0	70	74	96	239	87	6.24	0.5	0	67	$ 0.01	$ 0.080	$ 0.088		$ 0.39	0.038	$ 0.35	$ 0.34
2044	0	67	70	90	228	83	6.24	0.5	0	67	$ 0.01	$ 0.079	$ 0.086		$ 0.37	0.036	$ 0.33	$ 0.32
2045	0	65	67	86	217	79	6.24	0.4	0	67	$ 0.01	$ 0.078	$ 0.085		$ 0.35	0.035	$ 0.31	$ 0.31
2046	0	63	64	81	208	76	6.24	0.4	0	67	$ 0.01	$ 0.077	$ 0.084		$ 0.33	0.033	$ 0.30	$ 0.29
2047	0	61	61	77	199	72	6.24	0.4	0	67	$ 0.01	$ 0.076	$ 0.083		$ 0.31	0.032	$ 0.28	$ 0.27
2048	0	59	58	73	190	69	6.24	0.4	0	67	$ 0.01	$ 0.075	$ 0.082		$ 0.30	0.030	$ 0.27	$ 0.26
2049	0	57	56	70	182	66	6.24	0.4	0	67	$ 0.01	$ 0.074	$ 0.081		$ 0.28	0.029	$ 0.25	$ 0.25
2050	0	56	54	68	178	65	6.24	0.4	0	67	$ 0.01	$ 0.073	$ 0.081		$ 0.27	0.028	$ 0.25	$ 0.24
	Gas Recovered In MMCF					**13086**		**$ 71.45**		**976**	**$ 1.64**	**$ 6.45**	**$ 8.09**	**$ 1.62**	**$ 61.75**	**$ 5.72**	**$ 56.03**	$ 58.80
	Gas Recovered in BCF					**13.09**												
	Estimated Gas In-Place					**32.00**										**NPV 12% $17.56 MM**		**$19.07 MM**

Case 3: Economic Model

VITA

Name:	Angeni Agrawal
Born:	Houston, TX, USA
Parents:	Mr. Bipin and Mrs. Rekha Agrawal
Permanent Address:	Department of Petroleum Engineering 3116 TAMU Richardson Building College Station, TX
Education:	M.S. Petroleum Engineering Texas A&M University 2007 B.S. Petroleum Engineering, The University of Texas at Austin 2005
Member:	Society of Petroleum Engineers