The Allison Unit CO_2 – ECBM Pilot: A Reservoir Modeling Study

Topical Report

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Abstract

In October, 2000, the United States Department of Energy, through contractor Advanced Resources International (ARI), launched a multi-year government-industry research & development collaboration called the Coal-Seq project. The Coal-Seq project is investigating the feasibility of carbon dioxide (CO_2) sequestration in deep, unmineable coalseams by performing detailed reservoir studies of two enhanced coalbed methane (ECBM) recovery field projects in the San Juan basin. The two sites are the Allison Unit, operated by Burlington Resources, and into which CO_2 is being injected, and the Tiffany Unit, operating by BP America, into which nitrogen (N_2) is being injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The purposes of the field studies are to understand the reservoir mechanisms of CO_2 and N_2 injection into coalseams, demonstrate the practical effectiveness of the ECBM and sequestration processes, demonstrate an engineering capability to model them, and to evaluate sequestration economics. In support of these efforts, laboratory and theoretical studies are also being performed to understand and model multi-component isotherm behavior, and coal permeability changes due to swelling with CO_2 injection. This report describes the results of an important component of the overall project, the Allison Unit reservoir study.

The Allison Unit is located in the northern New Mexico portion of the prolific San Juan basin. The study area consists of 16 methane production wells, 4 CO_2 injection wells, and one pressure observation well. The field originally began production in July 1989, and CO_2 injection operations for ECBM purposes commenced in April, 1995. CO_2 injection was suspended in August, 2001, to evaluate the results of the pilot. In this study, a detailed reservoir characterization of the field was developed, the field history was matched using the COMET2 reservoir simulator, and future field performance was forecast under various operating conditions.

Based on the results of the study, the following conclusions have been drawn:

- The injection of CO_2 at the Allison Unit has resulted in incremental methane recovery over estimated ultimate primary recovery, in a proportion of approximately one volume of methane for every three volumes of CO_2 injected.
- The study area was successfully modeled with ARI's COMET2 model. However, aspects of the model remain uncertain, such as producing and injecting bottomhole pressures, CO_2 content profiles of the produced gas, and the pressure at the observation well.
- There appears to be clear evidence of significant coal permeability reduction with CO_2 injection. This permeability reduction, and the associated impact on CO_2 injectivity, compromised incremental methane recoveries and project economics. Finding ways to overcome and/or prevent this effect is therefore an important topic for future research.
- From a CO_2 sequestration standpoint, the incremental methane recoveries (based solely on the conditions encountered at the Allison Unit), can provide a meaningful offset to CO_2 separation, capture and transportation costs, on the order of \$2–5/ton of CO_2.

Table of Contents

List of Tables

List of Figures

1.0 Introduction

In October, 2000, the Department of Energy (DOE), through contractor Advanced Resources International (ARI), launched a multi-year government-industry research & development collaboration called the Coal-Seq project[1]. The Coal-Seq project is investigating the feasibility of carbon dioxide (CO_2) sequestration in deep, unmineable coalseams by performing detailed reservoir studies of two enhanced coalbed methane recovery (ECBM) field projects in the San Juan basin. The two sites are the Allison Unit, operated by Burlington Resources, and into which CO_2 is being injected, and the Tiffany Unit, operating by BP America, into which nitrogen (N_2) is being injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The purposes of the field studies are to understand the reservoir mechanisms of CO_2 and N_2 injection into coalseams, demonstrate the practical effectiveness of the ECBM and sequestration processes, demonstrate an engineering capability to model them, and to evaluate sequestration economics. In support of these efforts, laboratory and theoretical studies are also being performed to understand and model multi-component isotherm behavior, and coal permeability changes due to swelling with CO_2 injection. This report describes the results of an important component of the overall project, the Allison Unit reservoir study.

2.0 CO_2-ECBM Process

Before describing the field study and its' results, a brief description of the CO_2-ECBM process is presented to assist those readers not familiar with this technology. It does, however, assume that the reader does have some understanding of the reservoir mechanics of coalbed methane (CBM) reservoirs.

CO_2 is more adsorptive on coal than methane. While the degree of higher adsorptivity is a function of many factors, typically cited numbers suggest coal can adsorb 2-3 times more CO_2 at a given pressure than methane (CH_4) (although evidence exists it can be as high as 10-15 times that of methane for low rank coals). Example sorption isotherms for CO_2, CH_4, and N_2 on wet San Juan basin coal are illustrated in Figure 1.

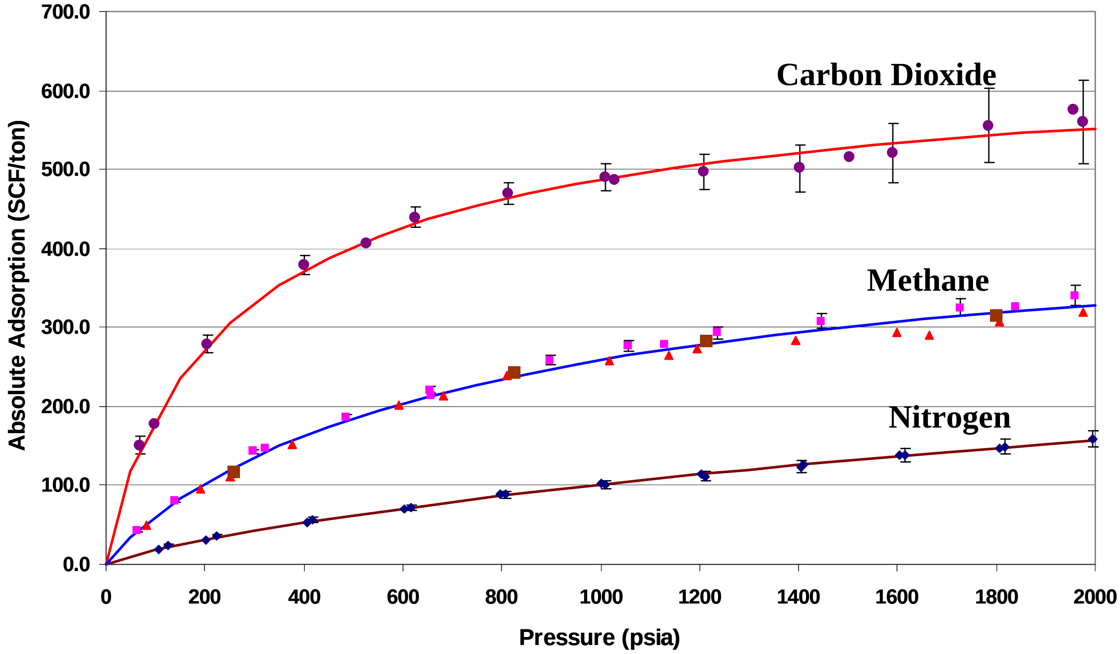

Figure 1: Sorption Isotherms for CO_2, CH_4 and N_2 on Wet San Juan Basin Coal

In concept, the process of CO_2-ECBM is quite 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 space. The displaced methane then diffuses into the cleat system, and migrates to and is produced from production wells. As more CO_2 is injected, the radius of displaced methane expands. 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. A more detailed description of the process can be found in the references for the interested reader[1,2].

Due to the infancy of the technology, very little field data exists to validate our knowledge of the process, and its' economic potential. The Allison Unit is the first and only multi-well, multi-year CO_2-ECBM field pilot in the world today, and hence represents a unique opportunity to study and understand the technology.

3.0 Site Description

The Allison Unit CBM project is located in San Juan County, New Mexico, in close proximity to the border with Colorado (Figure 2). While the Unit consists of many wells, the pilot area for CO_2 injection, and hence the study area for the Coal-Seq project, consists of 16 CBM producer wells, 4 CO_2 injectors, and one pressure observation well (POW #2). The study area well pattern is illustrated in Figure 3. At the center of the study area is a five-spot of CBM producers on nominal 320 acre spacing (wells 130, 114, 132 and 120 at the corners, and well 113 in the center), with the four CO_2 injectors roughly positioned on the sides of the five-spot between the corner producer wells (creating a nominal 160 acre spacing between injectors and producers). POW #2 is located on the eastern border of the central pattern, and the remaining CBM producers surround this central pattern. Three perimeter wells, #61, #12M and #62, were the source of coal samples for isotherm testing, but were not part of the model area.

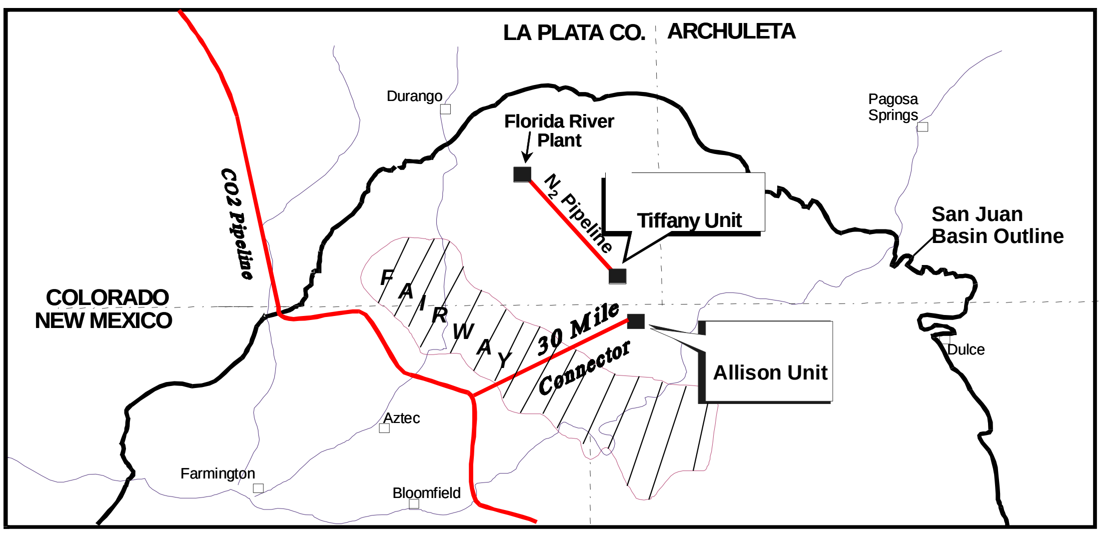

Figure 2: Location of the Allison Unit, San Juan Basin

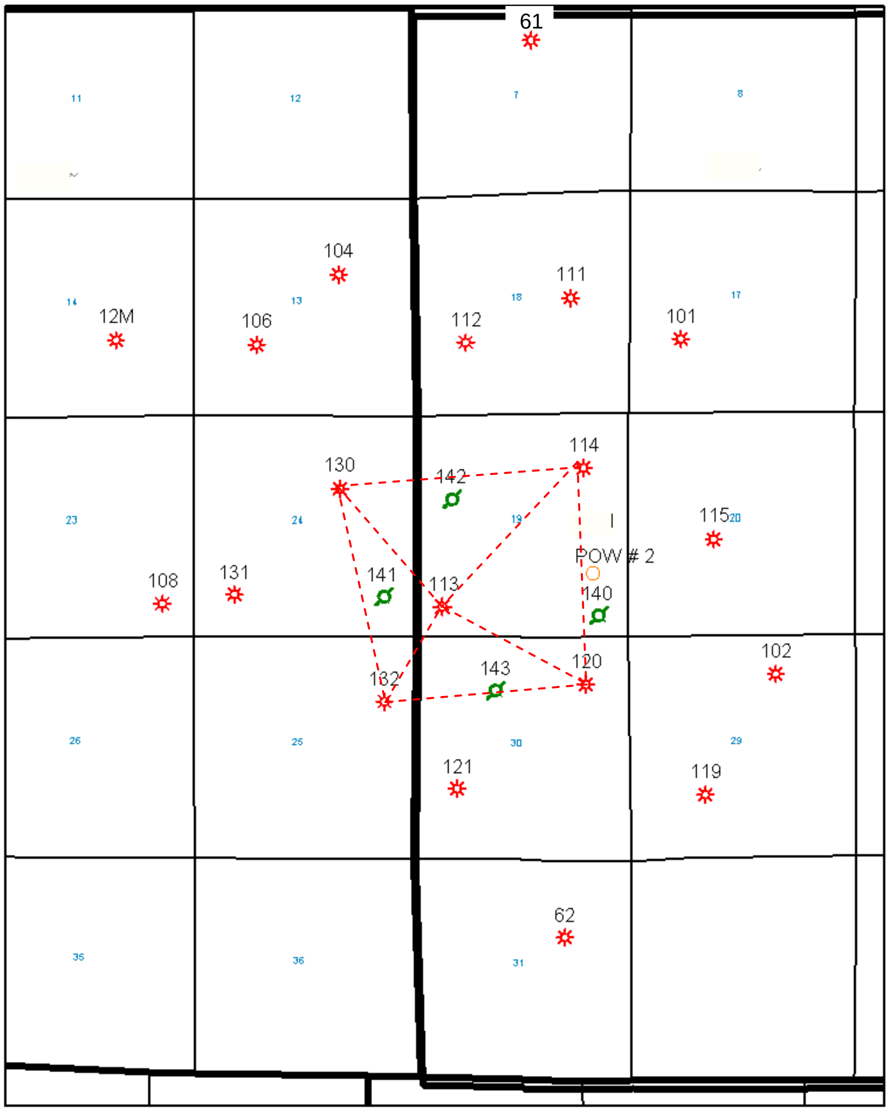

Figure 3: Producer/Injector Well Pattern, Allison Unit

The producing history for the study area is shown in Figure 4. The field originally began production in 1989, with CO_2 injection beginning in 1995. Injection was suspended in August 2001 to evaluate the results. Several points are worth pointing out regarding the producing history:

- Upon commencement of the injection operations, the five producer wells in the central five-spot pattern were shut in. The purpose was to facilitate CH_4/CO_2 exchange in the reservoir. After about six months, CO_2 injection was suspended for about another six months, during which time the five shut-in producers were re-opened. These activities can be clearly identified in Figure 4; their impact on long-term production performance however, if any, is unclear.

- Shortly after CO_2 injection began, a program of production enhancement activities unrelated to the CO_2-ECBM pilot was implemented. Those activities included well recavitations, well reconfigurations (conversion from tubing/packer completions to annular flow with a pump installed for well dewatering), line pressure reductions due to centralized compression, and also the installation of on-site compression. These activities largely coincided with the dramatic increase in production observed beginning in mid-1998.

These effects are illustrated for an individual well in Figure 5. In this case, the well was recavitated within a month of the start of CO_2 injection. The line pressure reduction did not appear to immediately impact well performance due to the well configuration at the time (tubing flow). However once the well was reconfigured to annular flow with a dewatering pump, reduced line pressure was directly exposed to the producing coal seams in the annulus and production increased significantly. Production again increased when on-site compression was installed. One can easily appreciate the difficulty these operations create when attempting to isolate and understand the impact of CO_2 injection on field performance. Hence a comprehensive reservoir simulation study, that accounts for each and every one of these events, was chosen to try to isolate and evaluate the impact of CO_2 injection on field performance.

CO_2 Source

The CO_2 being injected at Allison is sourced from natural CO_2 reservoirs located in the Cortez area of New Mexico. CO_2 from these reservoirs is delivered to West Texas for enhanced oil recovery projects via a high pressure pipeline, operated by Kinder Morgan, that runs through the San Juan basin. Burlington Resources constructed a 36 mile, 4-inch diameter spur from this main pipeline to the Allison Unit. CO_2 is delivered from the pipeline at a pressure of approximately 2200 psi, and it is reduced to approximately 1500 psi, primarily due to friction, prior to injection.

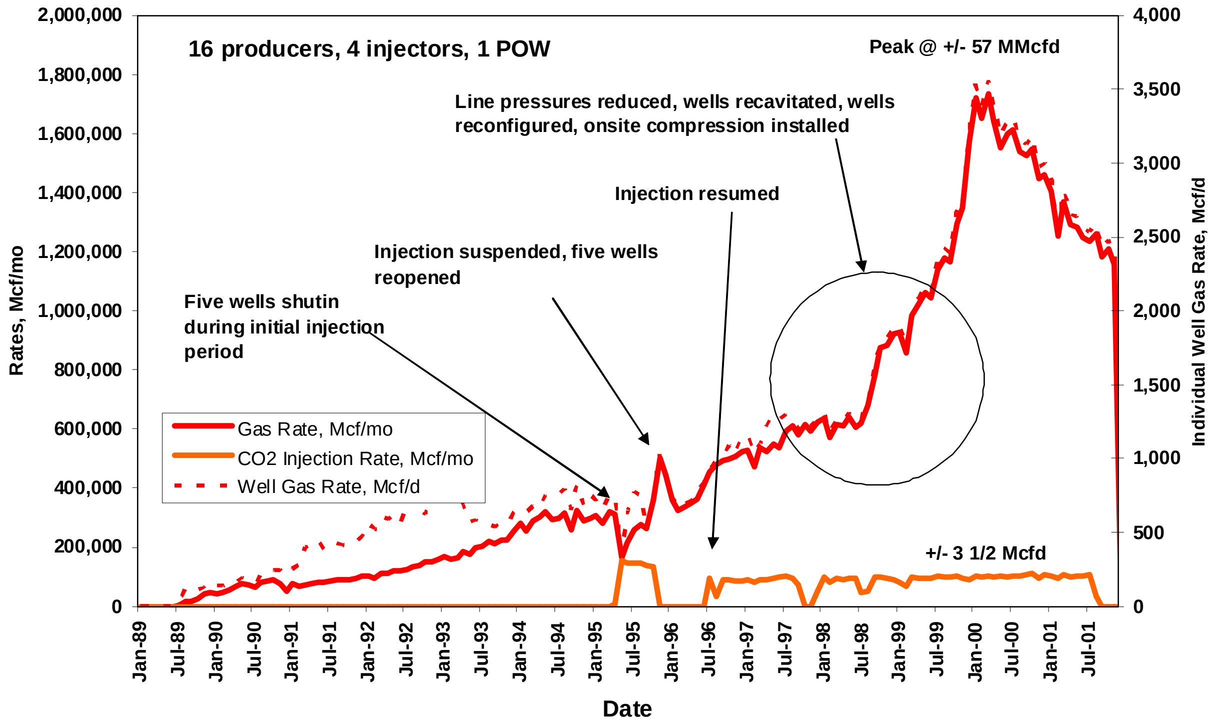

Figure 4: Producing History, Allison Unit Study Area

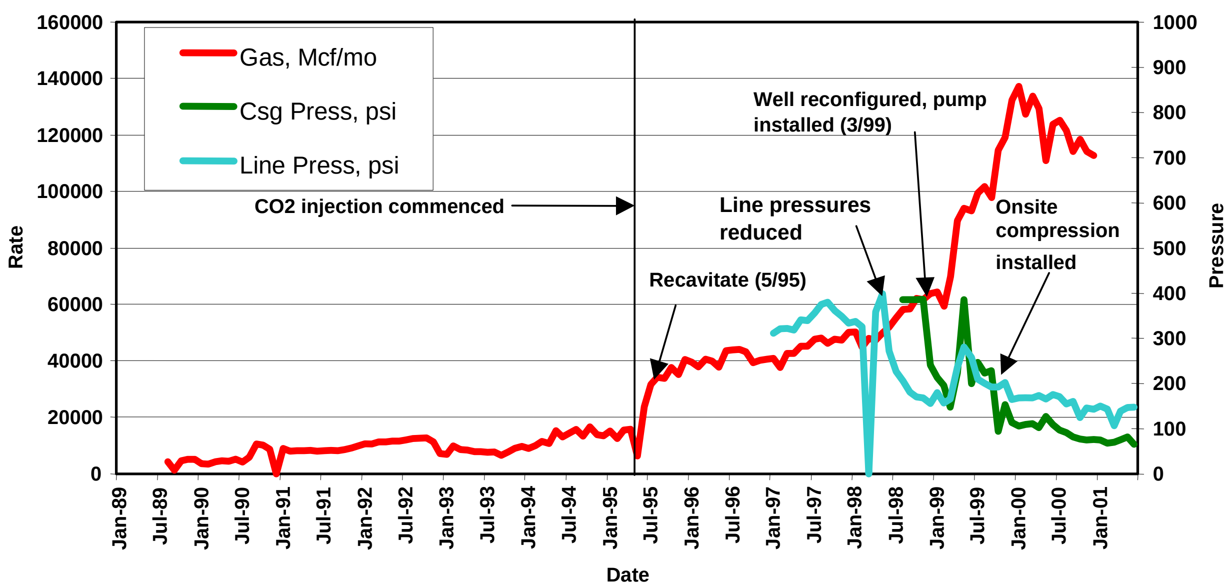

Figure 5: Producing History, Individual Allison Unit Well

The Allison Unit wells produce from three Upper Cretaceous Fruitland Formation coal seams, named the Yellow, Blue and Purple (from shallowest to deepest) using Burlington Resources' terminology. A summary of basic coal depth, thickness, pressure and temperature information is provided in Table 1.

Table 1: Allison Unit Basic Coal Reservoir Data

Property	Value
Average Depth to Top Coal	3100 feet
Number of Coal Intervals	3 (Yellow, Blue, Purple)
Average Total Net Thickness	43 feet Yellow – 22 ft Blue – 10 ft Purple – 11 ft
Initial Pressure	1650 psi
Temperature	120°F

In general, the wells are top-set above the coal intervals with 7-inch casing cemented into place. The coal intervals were then drilled with a 6-1/4 inch bit with water to below the deepest target coal (Purple). The coals were then cavitated and 5-1/2 inch perforated liners installed without cement. The wells were then configured for commingled gas/water production up the tubing.

In the case of the CO_2 injection wells, the wells were drilled to total depth, and 5-1/2 inch casing run and cemented into place. The coal intervals were then perforated, and perforation breakdown treatments performed. The coal intervals in the injection wells did not receive massive stimulation treatments to prevent possible communication pathways being created into bounding non-coal layers. The downhole configuration for injection wells consists of a tubing and packer arrangement, however the internal surface of the tubing is coated with fiberglass to prevent corrosion. In addition, the CO_2 is heated to approximately reservoir temperature prior to injection to prevent expansion/contraction of the well tubulars during suspension periods.

4.0 Reservoir Description

Structure contour and isopach maps of each coal and interburden horizon were constructed based on lithologic picks made by Burlington Resources. A sample structure map for the Yellow coal is presented in Figure 6, and the total net coal isopach is presented in Figure 7. A gentle dip in the area exists towards the south-southwest, where the coals also thicken slightly.

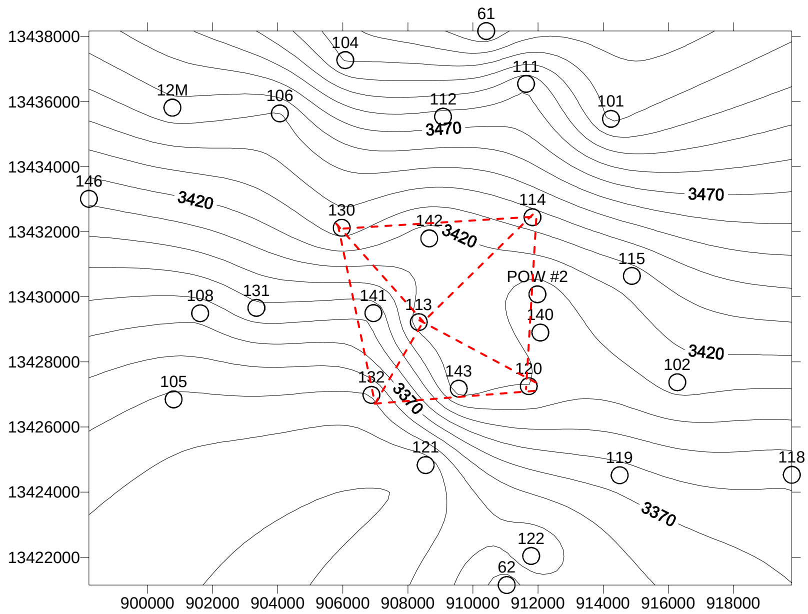

Figure 6: Structure Map, Yellow Coal (units in feet above sea level)

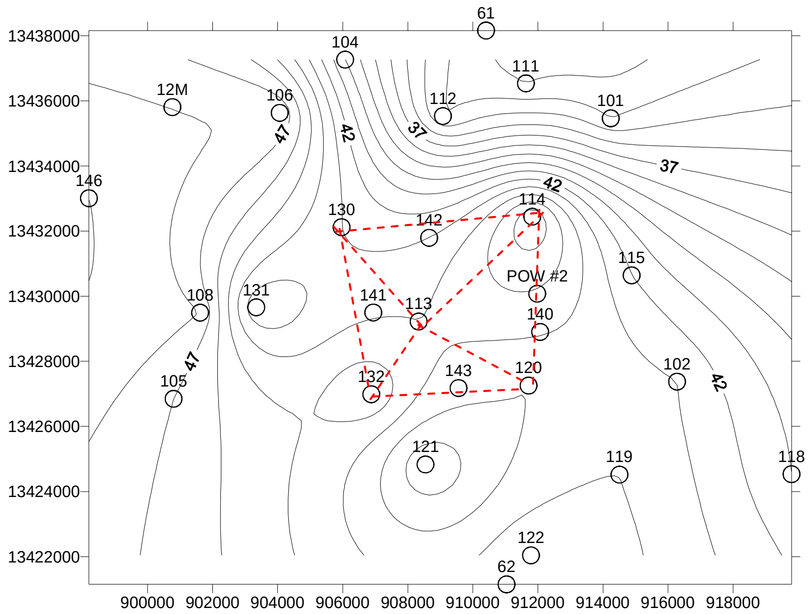

Figure 7: Total Net Coal Isopach, Allison Unit Study Area (units in feet)

Sorption isotherms for both CH_4 and CO_2 were measured for six coal samples taken from three wells in the area (two samples each from wells 61, 62 and 12M, Figure 3). Together with coal density data from well logs, a correlation between coal density and Langmuir volume was developed for CH_4 and CO_2, which are shown in Figures 8 and 9. Note that the high-density end-points were assumed based on Burlington Resources experience in the area. Average CH_4 and CO_2 isotherms based on these data for each coal interval, on a raw basis and at an average density of 1.5 grams per cubic centimeter (g/cc), are shown in Figures 10 and 11. Langmuir parameters are provided in Table 2.

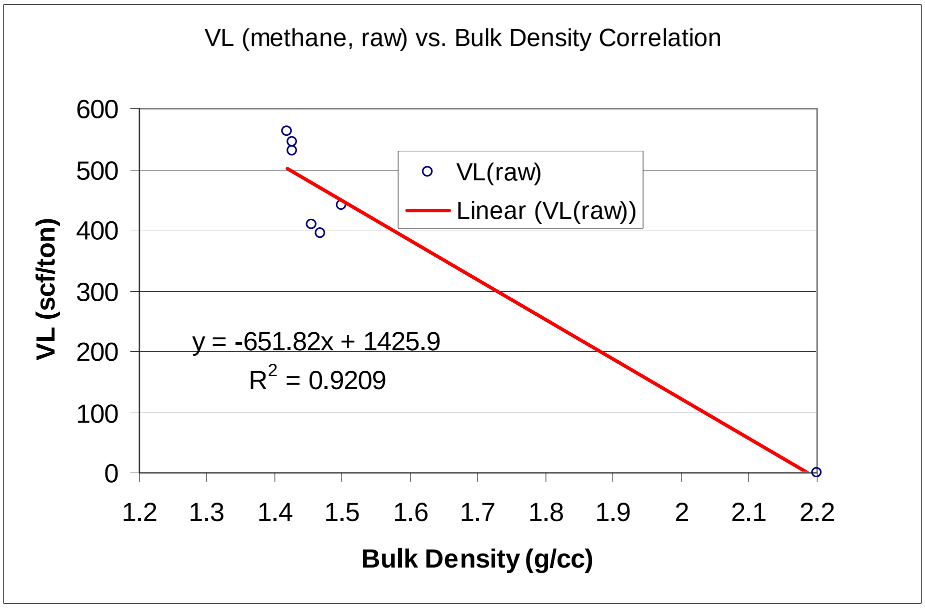

Figure 8: Langmuir Volume vs. Coal Density Correlation, Methane

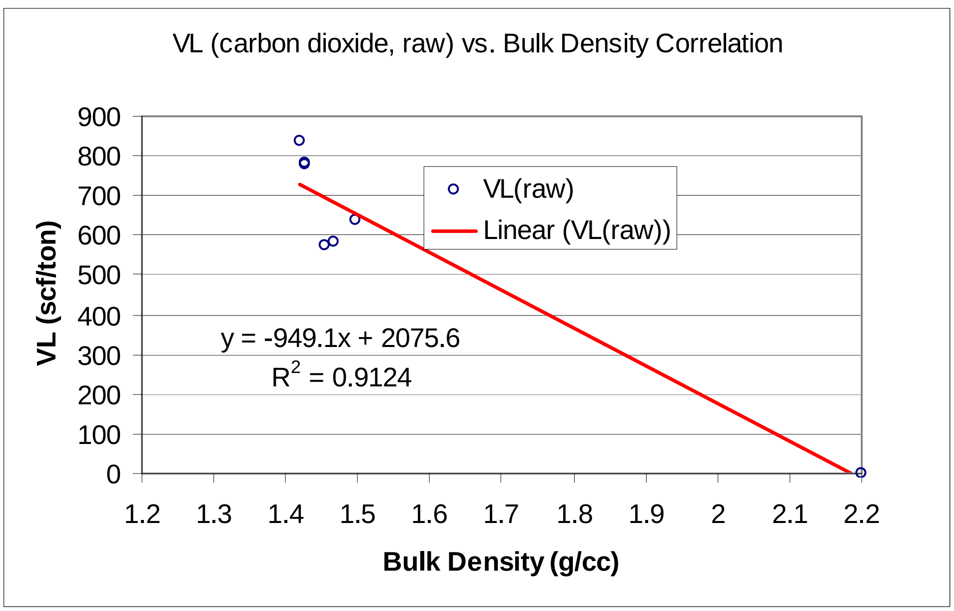

Figure 9: Langmuir Volume vs. Coal Density Correlation, Carbon Dioxide

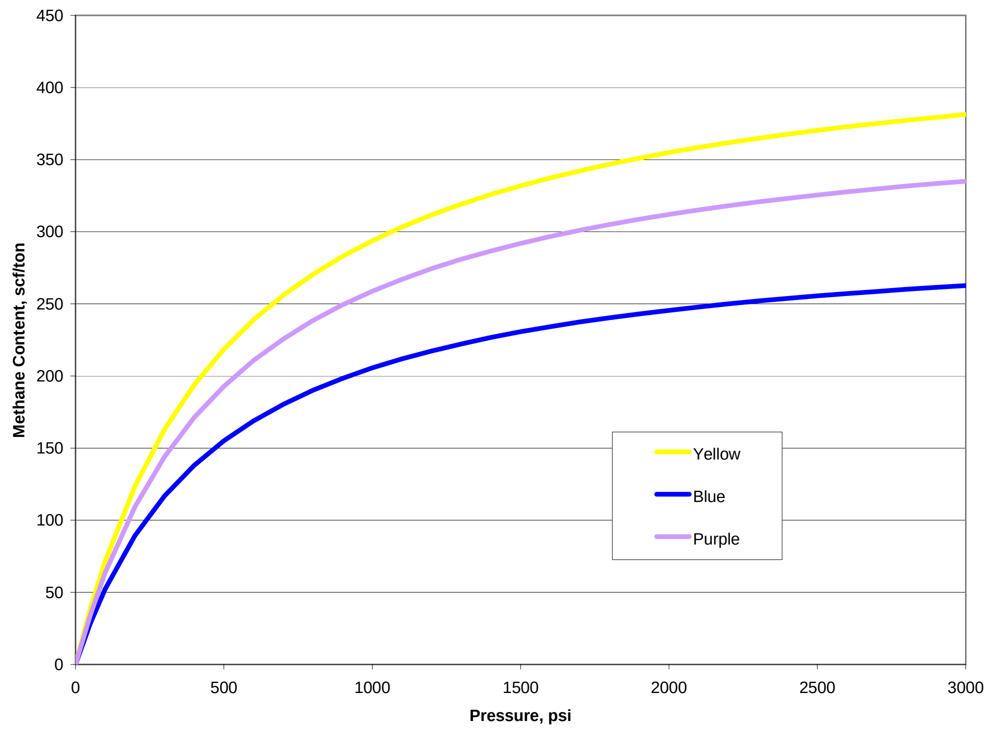

Figure 10: Methane Sorption Isotherms, Allison Unit Study Area

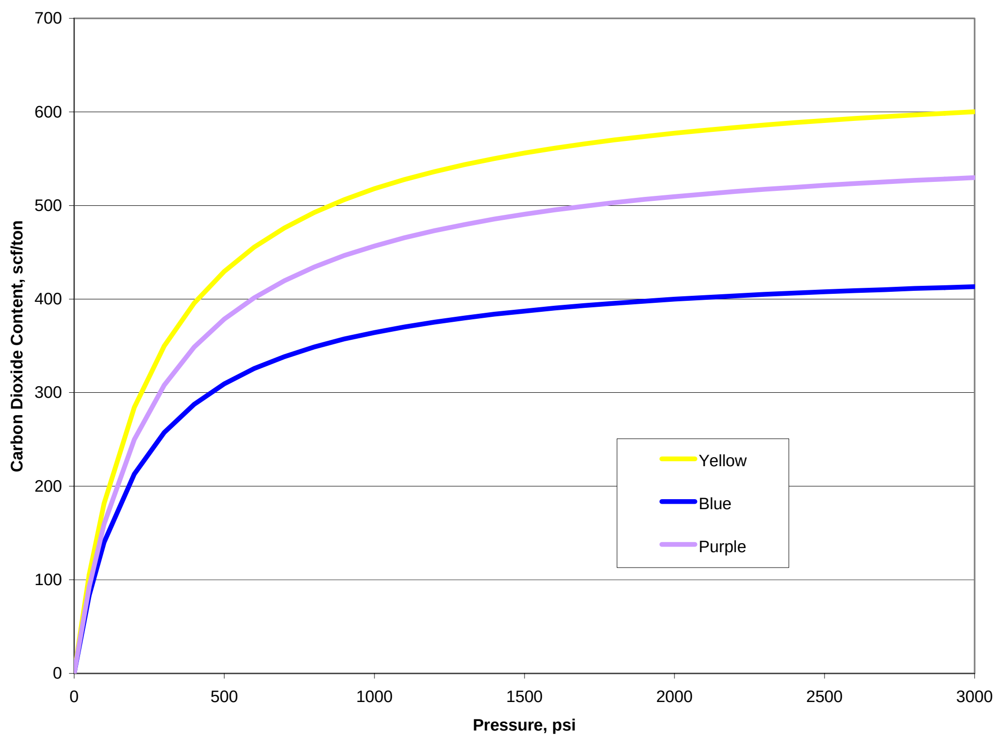

Figure 11: Carbon Dioxide Sorption Isotherms, Allison Unit Study Area

Table 2: Langmuir Constants, by Layer

	Carbon Dioxide		Methane	
	V_L SCF/ton(ft^3/ft^3)	P_L, psi	V_L SCF/ton(ft^3/ft^3)	P_L, psi
Yellow	652 (30.5)	259	448 (21.0)	525
Blue	443 (23.8)	216	305 (16.4)	484
Purple	576 (28.4)	261	393 (19.4)	519

Using coal density maps generated for each coal seam, based on log-derived coal density data, Langmuir volume (V_L) maps were created for each coal layer. During this procedure, consistency was established between the density basis for the core analysis and log results. Interestingly, it was found that little variation in Langmuir volume occurred within a given coal layer (when converted to units of volume/volume), but considerable variations existed from layer to layer. Table 3 summarizes these results, and their implication to methane resource distribution.

Table 3: Layer Sorption Properties and Distribution of Methane Resource

Zone	V_L (scf/ton)	Log Density (g/cc)	Average Thickness (ft)	Gas-in-place
Yellow	448	1.50	22	55%
Blue	305	1.72	10	19%
Purple	393	1.58	11	26%

Relative permeability curves were derived for the field using a novel procedure developed by Burlington Resources. The procedure involves the following steps:

1. Estimate initial mobile water in place by performing decline curve analysis on water production for each well.

2. Compute effective water permeability versus time using Darcy's Law and accounting for reservoir pressure depletion via material balance.

3. Use water material balance to calculate mobile water saturation versus time.

4. Plot effective water permeability versus mobile water saturation.

5. Repeat steps 2 & 3 for gas.

6. Plot the ratio of effective water permeability to effective gas permeability versus mobile water saturation.

7. Adjust the absolute value of mobile water saturation for each well until the curves developed in step 5 approximately overlie each other.

8. Determine actual porosity by assuming a residual water saturation.

9. Adjust relative permeability curves accordingly.

This procedure, while requiring considerable judgment, yields both a relative permeability relationship for the entire field, as well as a distribution of porosity across the field. When applied to Allison, the relative permeability curves (after curve-fitting) and porosity maps that resulted are presented in Figures 12 and 13 respectively (assuming a residual water saturation of zero). Note that the right-hand portion of the water relative permeability curve in Figure 12 was smoothed to facilitate more stable reservoir modeling. Porosity values ranged from a high of 0.3% in the southwest to as low as 0.05% in the northwest.

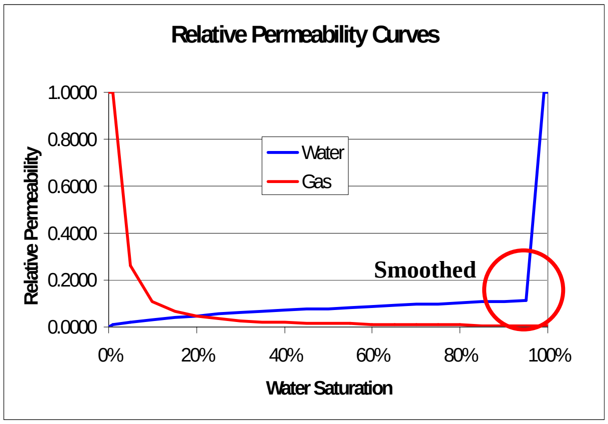

Figure 12: Relative Permeability Curves, Allison Unit

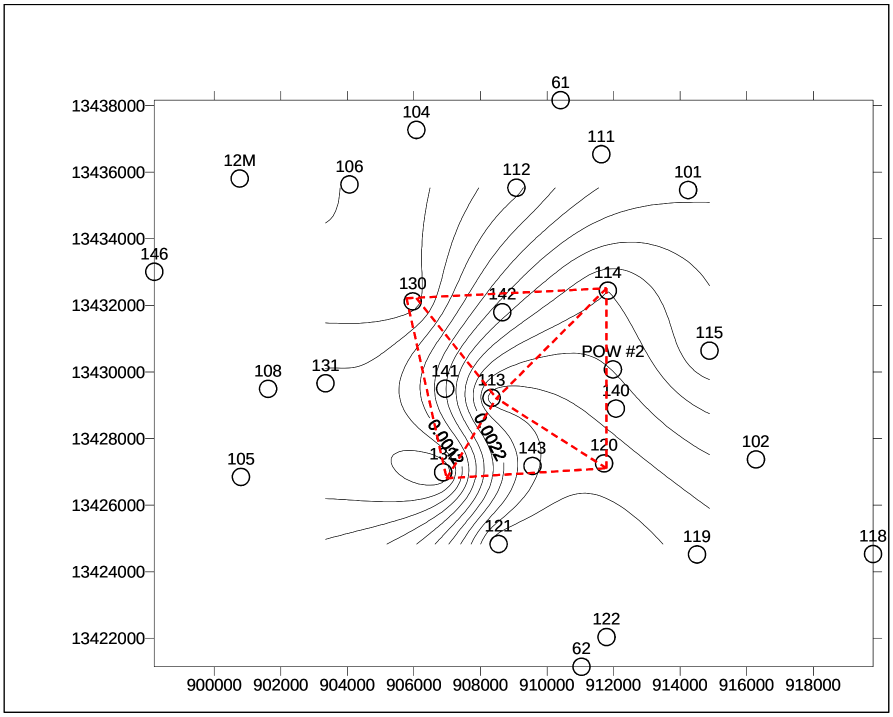

Figure 13: Porosity Map, Allison Unit (units in fractions)

A comparison was made between the relative permeability curves derived here and others, both laboratory and simulator derived, from the San Juan Basin[3]. That comparison is shown in Figure 14, and suggests that these curves are markedly different, and more "conservative" for gas flow, than even the laboratory-derived results.

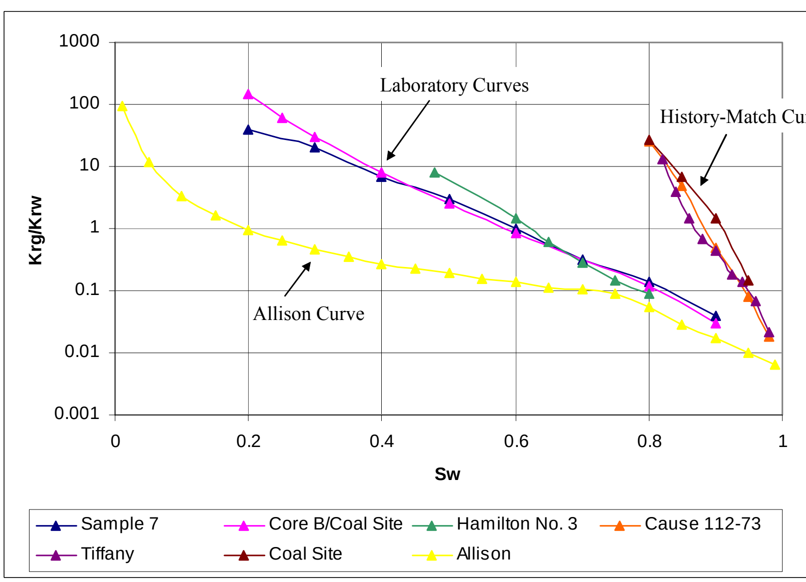

Figure 14: Comparison of Relative Permeability Curves

In May, 2000, pressure buildup tests were performed on 12 wells in the Allison Unit, eight of which were inside the study area. Pressure data were collected at the surface. Analysis of the data provided estimates of effective gas permeability, skin factor, and reservoir pressure. Two adjustments of the results were made to 1) derive absolute permeability from the effective gas permeability results and 2) correct to initial conditions – accounting for both pressure-dependent permeability and matrix shrinkage.

For the first correction, the following procedure was used:

1. Estimate effective permeability to water just prior to shut-in using Darcy's Law.

2. Compute the ratio of effective water permeability to effective gas permeability.

3. For that ratio, lookup the corresponding relative permeability to gas based on the relative permeability curves developed for the field.

4. Compute absolute permeability based on effective gas permeability and relative gas permeability at that point in time.

This procedure was applied to for each well for which data was available, and the correlation was developed between the "measured" effective gas permeability and "corrected" absolute permeability. That correlation is provided in Figure 15.

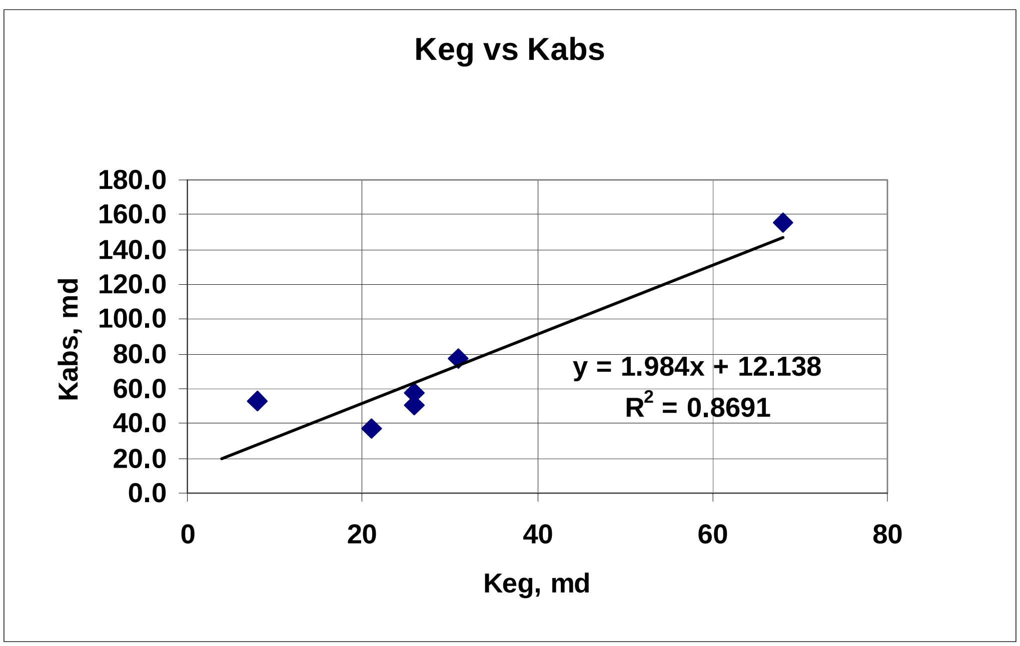

Figure 15: Correlation between Effective Gas and Absolute Permeability

Since water production data was not available for all wells, for those wells with pressure transient data but not water data upon which to apply this procedure, the correlation shown in Figure 15 was used to estimate absolute permeability. Note that the correlation suggests that absolute permeability is about twice the effective permeability to gas. A permeability map of the field was then generated, and is shown in Figure 16. Permeability values ranged from 30-150 millidarcies (md) with higher permeabilities concentrated within the central 5-spot pattern.

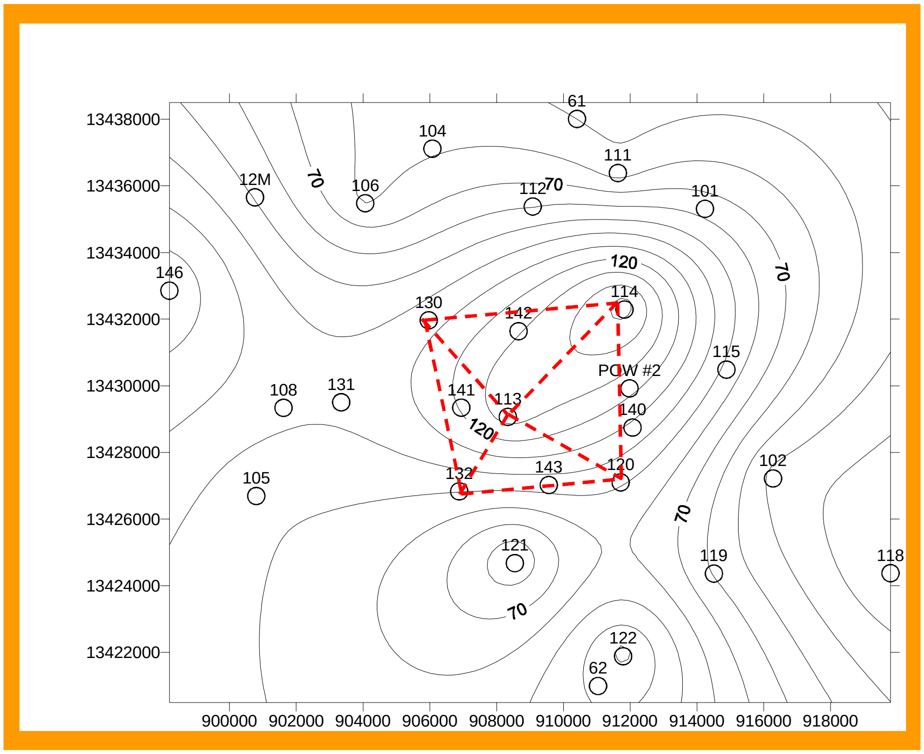

Figure 16: Permeability Map for Allison Unit

To make the second correction, a somewhat subjective and judgmental adjustment was made. The pressure transient test results suggested that reservoir pressure was in the 500 – 600 psi range in May, 2000. Based on ARI's permeability function model[4], and using nominal values for pore-volume compressibility, matrix compressibility, permeability exponent, and differential swelling factor, it was estimated that the original, in-situ permeability values (at a pore pressure of 1650 psi) were about 10% higher than in May, 2000. Note that over this pressure range, permeability changes would be largely dominated by pressure-dependent permeability changes, not matrix compressibility. Hence the values shown in Figure 16 were increased by 10% for input into the reservoir model.

A final step in the reservoir characterization process was to estimate the variables that control changes in permeability as a function of pressure and gas concentration. Specifically, these variables are pore volume compressibility-C_p; matrix compressibility-C_m; and differential swelling factor-C_k.

The formulas relating coal permeability to these parameters are:

$$\phi = \underbrace{\phi_i \left[1 - C_p \left(P - P_i\right)\right]}_{\text{Pressure-Dependent Term}} \quad - \quad \underbrace{\left(1 - \phi_i\right) C_m \left(\frac{\Delta P_i}{\Delta C_i}\right)\left[C - C_i + C_k \left(C_t - C\right)\right]}_{\text{Concentration-Dependent Term}}$$

and

$$k = \left(\frac{\phi}{\phi_i}\right)^n$$

Note that the terminology is defined in the Nomenclature (Section 13).

To estimate these parameters, the results of injection/falloff tests performed in the four CO_2 injection wells, performed in August 2001 (when they were shut-in), were utilized. Those tests suggested that coal permeability values in the regions near the injector wells, and hence heavily influenced by CO_2, were <1 md. Using the estimated initial in-situ permeability values as estimated from the permeability map shown in Figure 16, and the values determined from the August 2001 injection/falloff tests (as well as the prevailing reservoir pressure at that time) the variables for the permeability function model were estimated using the analytic model presented above. The resulting values are presented in Table 4.

Table 4: Estimated Permeability Function Parameters

Well No.	Porosity*	C_p (x10^{-6}) (1/psi)	C_m (x10^{-6}) (1/psi)	C_k
140	0.23%	200	1	1.25
141	0.16%	200	1	1.10
142	0.17%	200	1	1.15
143	0.25%	200	1	1.20

*from porosity map

The resulting value of C_p is consistent with that used in other modeling studies of San Juan basin CBM projects[3], however the derived values for both C_m and C_k are somewhat less than those obtained from laboratory data[4].

The analytic model of permeability changes with pressure (and gas concentration), for both CH_4 and CO_2, based on the data in Table 4, is presented in Figure 17. Note that this plot, assumes a differential swelling factor of 1.0, an initial permeability of 100 md, an initial pressure of 1600 psi, and a porosity of 0.25%.

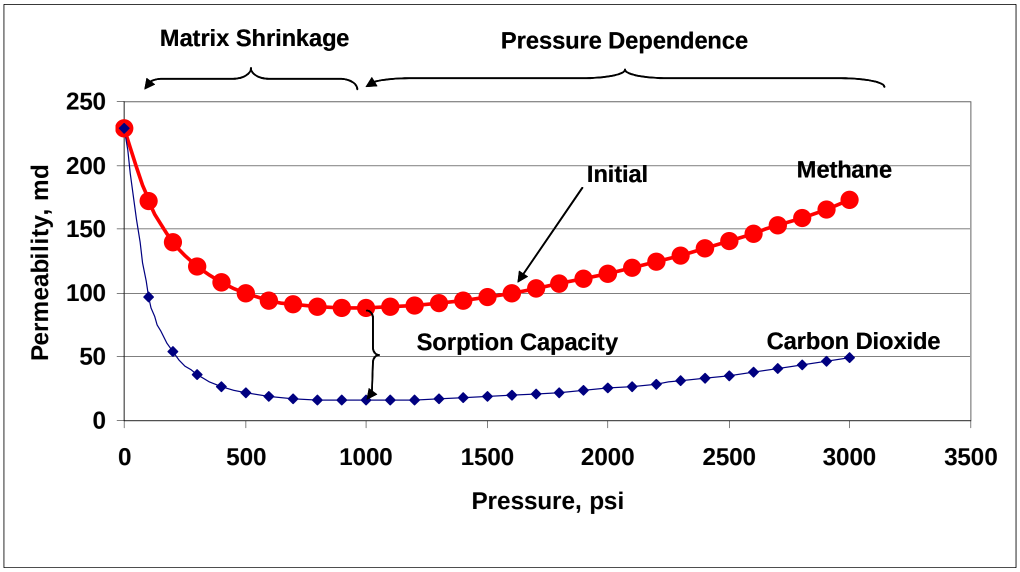

Figure 17: Permeability Changes with Pressure and Concentration

This concluded the reservoir description of the Allison Unit. The reservoir model construction is described in the following section.

5.0 Model Construction

The reservoir simulator used for the study was ARI's COMET2 (binary isotherm – CH_4 and CO_2) model. Details on the model theory are provided in the references[5].

A three-layer (Yellow, Blue, Purple), full-field model was constructed to perform the simulation study. The coal structure and thickness information for each layer was directly input per the maps generated. Information from Burlington Resources and other sources suggested that the cleat orientations were approximately in the north-south and east-west directions, and hence the model grid was so aligned (and there was no evidence of permeability anisotropy). A map view of the top layer, and a north-south and west-east cross-sections of the model, are presented in Figures 18 - 20.

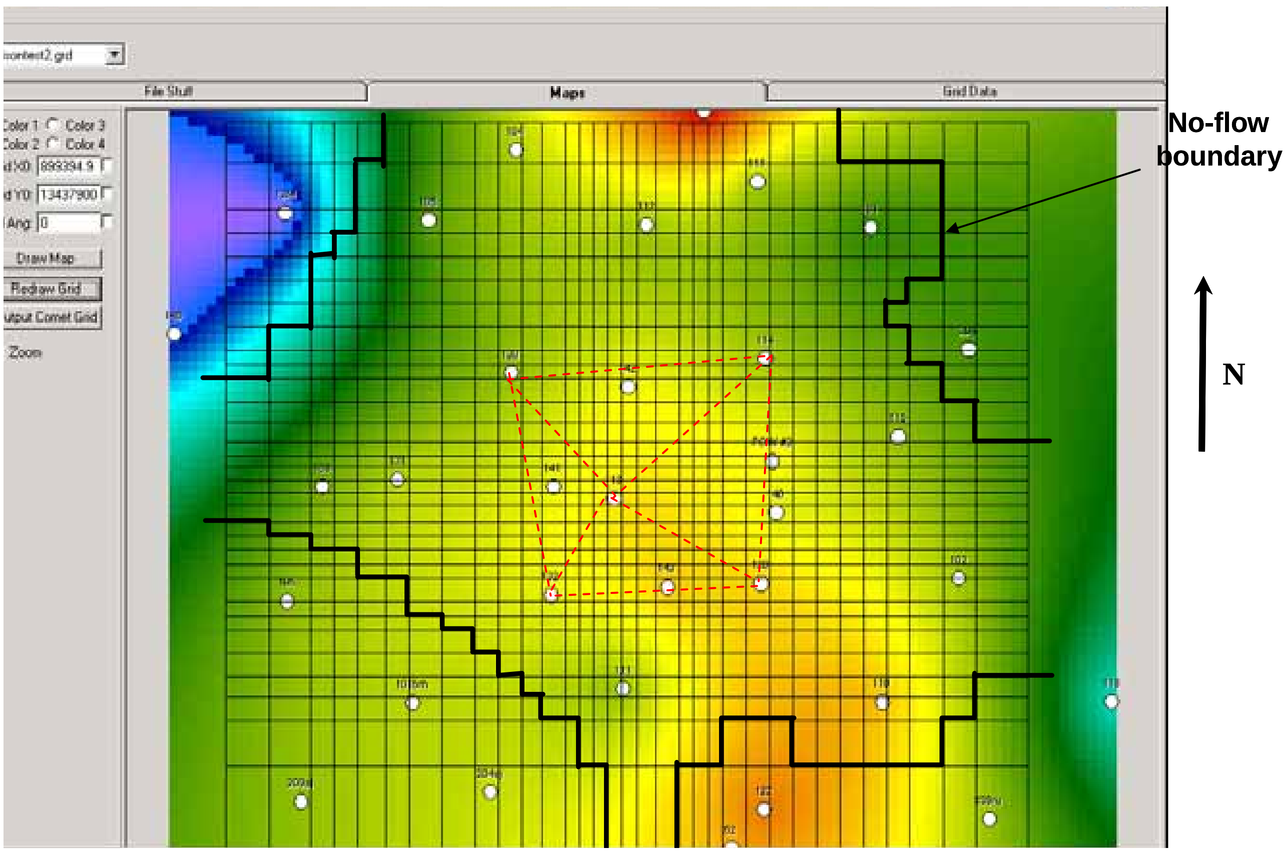

Figure 18: Map View of the Top Simulation Layer

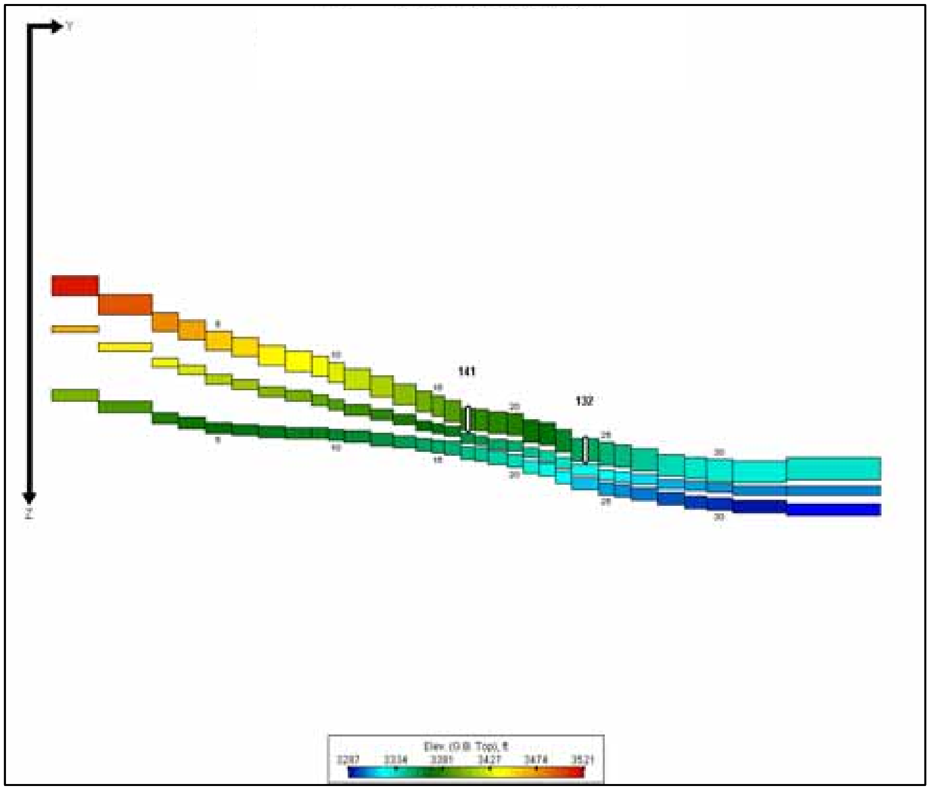

Figure 19: North-South Cross Section of the Simulation Model

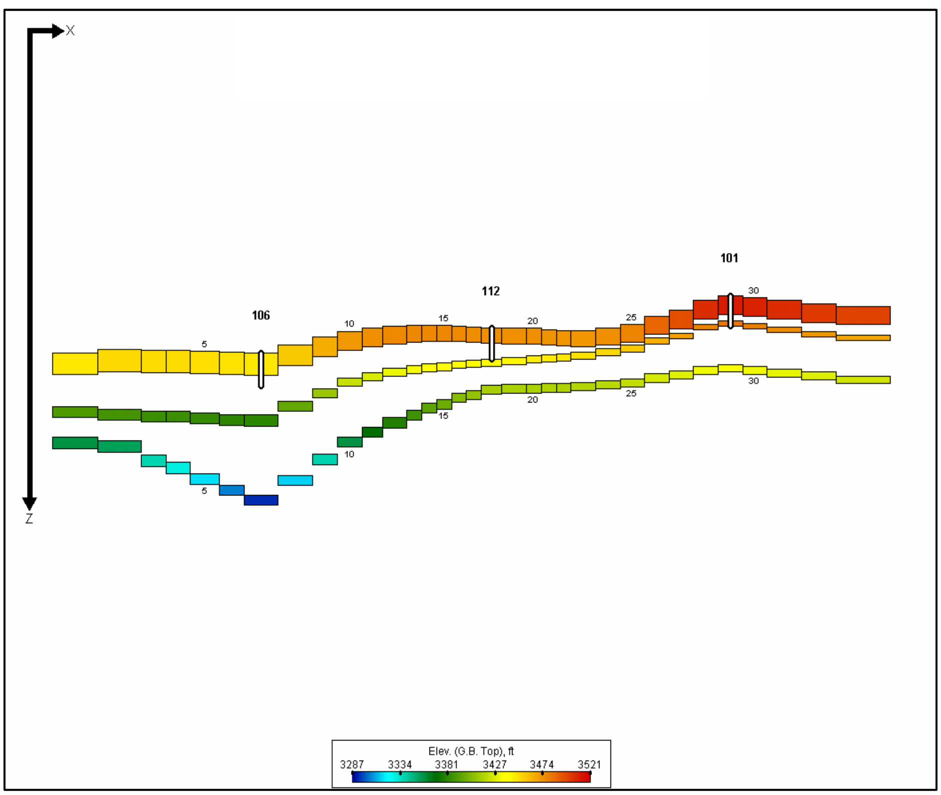

Figure 20: West-East Cross Section of the Simulation Model

The model gridblock dimensions were 33 x 32 x 3 (approximately 3,200 total grid blocks, 2,600 of which were active), representing an area of about 7,100 acres. The corners of the model were isolated using no-flow barriers to account for producing wells immediately adjacent to these portions of the study area.

The Langmuir volume and pressure values were constant for each layer, but varied for each layer based on Table 2. The porosity map presented in Figure 13 was used for all layers. However, a minimum porosity value of 0.15% was imposed – lower values of porosity were judged to be unreasonable. The permeability of each layer was per the map presented in Figure 16, but with the values increased by 10% as explained in the previous discussion. Other relevant reservoir parameters are presented in Table 5.

Table 5: Reservoir Parameters used in Simulation Model

Parameter	Value	Source	Remarks
Initial Pressure	1650 psi	Burlington	~0.53 psi/ft
Reservoir Temperature	120º F	Burlington	
Initial Water Saturation	95%	Assumed	
Initial Gas Content	Per Isotherm	Assumed	Equilibrium value
Sorption Time	10 days	Assumed	Same for CH_4 & CO_2
Fracture Spacing	1 inch	Assumed	
Gas Composition	95.5% CH_4, 4.5% CO_2	Gas Composition Measurement	
Relative Permeability	Figure 12	Independent Analysis	
Perm Function Parameters	Table 4*	Independent Analysis	

* Note: A differential swelling factor of 1.0 was adopted for the model.

Additionally, well completion and operating parameters were examined for input into the model. This was particularly important given the complexity of the field history, and the desire to isolate and study the effects of CO_2 injection.

First, to account for the recavitation operations in the producing wells, the procedure presented below was adopted. This procedure assumes that the well producing pressure before and after the restimulation treatment did not change significantly (i.e., well operating practices did not substantially change before/after the recavitation treatment), and that the entire effect of the treatment should be reflected in the gas rate.

1. Compile the computed skin factors based on the May, 2000 pressure transient tests. Where actual values were not available, assume an average value. Since all recavitation treatments were performed prior to May, 2000, the skin values derived from the well tests performed at that time represent the post-recavitation values for skin factor.

2. Determine the actual gas production immediately preceding and following the recavitation operations from the production history data. Compute the folds-of-increase in production resulting from the operation.

3. Using conventional flow theory, compute the change in skin factor required to achieve the production response observed, assuming all other parameters remain unchanged.

4. By taking the post-recavitation skin, and the computed change in skin, compute the pre-recavitation skin factor.

The results of applying this procedure are presented in Table 6. Note that in the model a maximum constraint for pre-recavitation skin factor of +10 was imposed.

Table 6: Estimated Skin Factor Changes Due to Recavitation

Well #	Date	Pre-Rate (mcf/mo)	Post-Rate (mcf/mo)	FOI	Post-Skin	Measured/ Average	Pre-Skin
101	Nov-93	71	1089	15.3	-1.9	Average	89.1
102	Jun-96	14994	39697	2.6	-1.5	Measured	9.6
104	Jan-96	5632	17342	3.1	-1.9	Average	11.3
106	May-95	14616	40270	2.8	-3.8	Measured	4.0
108	Jun-95	9849	64397	6.5	-1.9	Average	33.3
111	Jan-99	15726	33215	2.1	-3.6	Measured	1.6
112	May-95	487	28758	59.1	-1.5	Measured	390.3
113	Aug-98	37434	82264	2.2	-1.5	Measured	6.6
114	Aug-98	49490	88532	1.8	-1.3	Measured	4.2
115	Jul-98	36905	62431	1.7	-1.9	Average	2.5
119	Jun-98	49540	96394	1.9	-2.4	Measured	3.1
120	Apr-96	12963	45745	3.5	-1.9	Average	14.2
121	Jun-98	33185	53465	1.6	-2.3	Measured	1.3
130	Dec-98	36638	54872	1.5	-1.9	Average	1.3
131	Mar-96	15296	43482	2.8	-1.9	Average	9.8
132	Nov-93	8693	39418	4.5	-1.9	Average	20.5

For the injector wells, skin factor values determined from the August, 2001 injection/falloff tests were used. These values were in the –2 to –4 range, and are believed reasonable since the CO_2 injection pressures were close to the fracturing pressure of the coals (2,300 – 2,500 psi bottomhole pressure at a depth of about 3,100 feet – a pressure gradient of about 0.77 psi/ft).

Finally, based on well completion records, producer well #106 was not completed in the Purple horizon, and injector well #143 was not completed in the Yellow horizon.

6.0 Initial Model Results

The independent parameter used for the reservoir model was gas production (and injection) rate to maintain material balance, and the dependent (history match) parameters were water production rate, flowing pressures (producing and injecting), and gas composition. Note that only some of these data were available for some periods for some wells; whatever was available was used. In addition, the pressure history at POW #2 was available, as were the reservoir pressures at some of the producing wells in May 2000 based on the pressure transient tests.

A comparison of the actual versus model field gas rate is presented in Figure 21. A complete set of plots comparing the initialization run results to the actual data are provided in Appendix A. The only conclusion that can be derived from this result, since the model was "driven" on gas rate, is that model (as initially constructed) was capable of delivering the gas volumes required. (However, it should be noted that one well - #119 – was not achieving the required gas rate towards the end of the simulation period.)

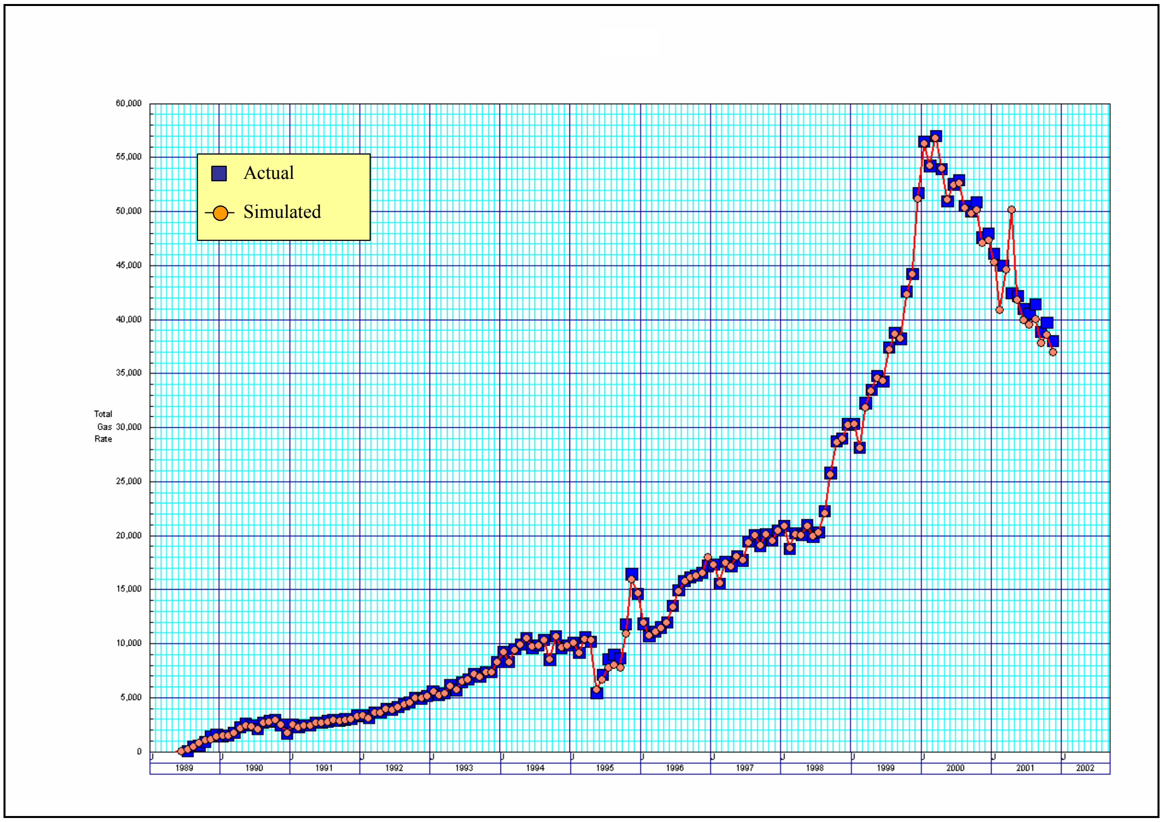

Figure 21: Actual versus Simulated Field Gas Rate

The actual versus model pressure at POW#2 for the initial simulation run is presented in Figure 22. Actual pressure data is only available after the commencement of CO_2 injection. At that time, there appears to be excellent agreement between actual and predicted pressure, suggesting that material balance (at least during primary production) is being achieved, and hence values for original gas/water storage capacities, as well as depletion characteristics, are reasonable. After that, however, there is considerable difference in pressure values. Of note is that the estimated pressure at the location of POW #2 based on the May, 2000 pressure transient analysis (PTA) is reasonably close to the simulated value.

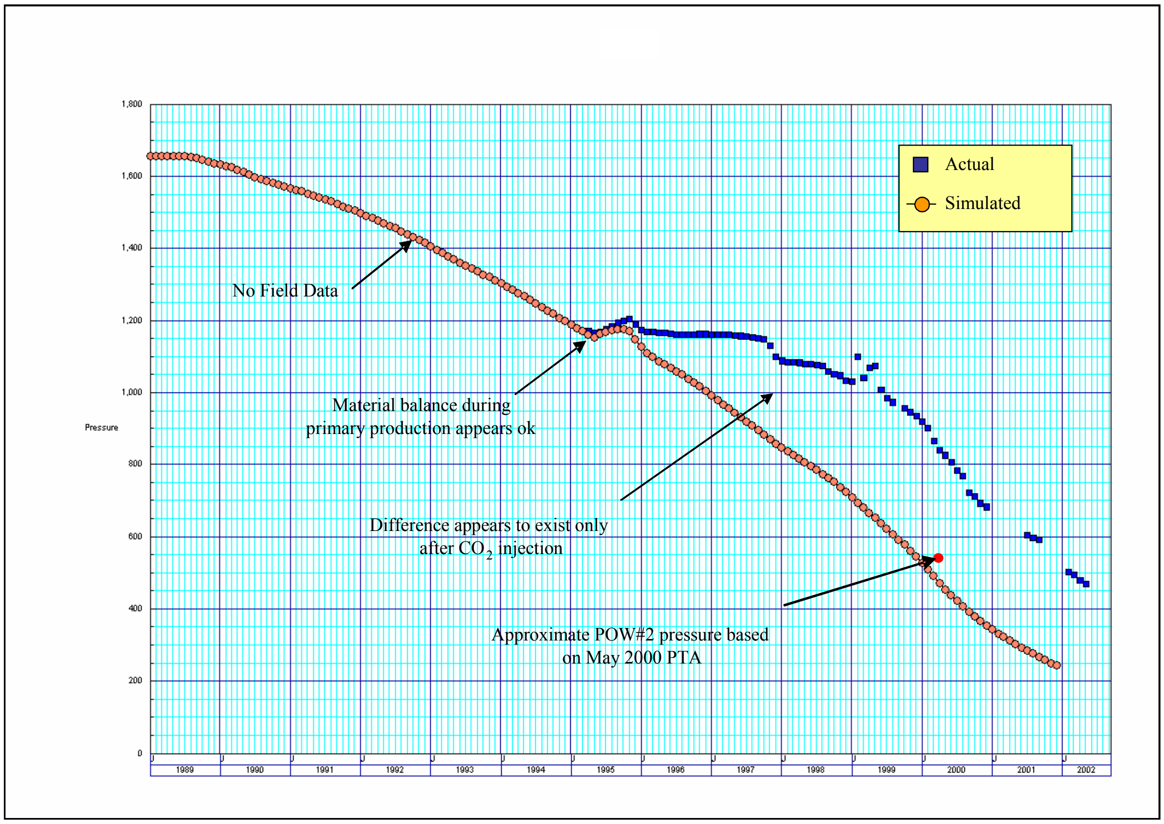

Figure 22: Actual versus Simulated Pressure at POW#2

Comparison plots of actual versus simulated gas and water rates, flowing pressures, and produced gas compositions, for well 113 are presented in Figure 23. This well was selected for presentation because it was the central well of the 5-spot, it had data for comparison in all categories, and it had observable CO_2 breakthrough. In addition, this well reasonably typifies the differences in simulated versus actual results for the other wells. No "history matching" to the actual data was performed up to this point; these are the results of the initial model run. Several general comments can be made regarding the results:

- The quality of the water rate predictions varied, with some being too high and some too low. However, on balance the predictions were considered within reason (and that could be easily "fixed" with regional variations in porosity and/or water relative permeability).

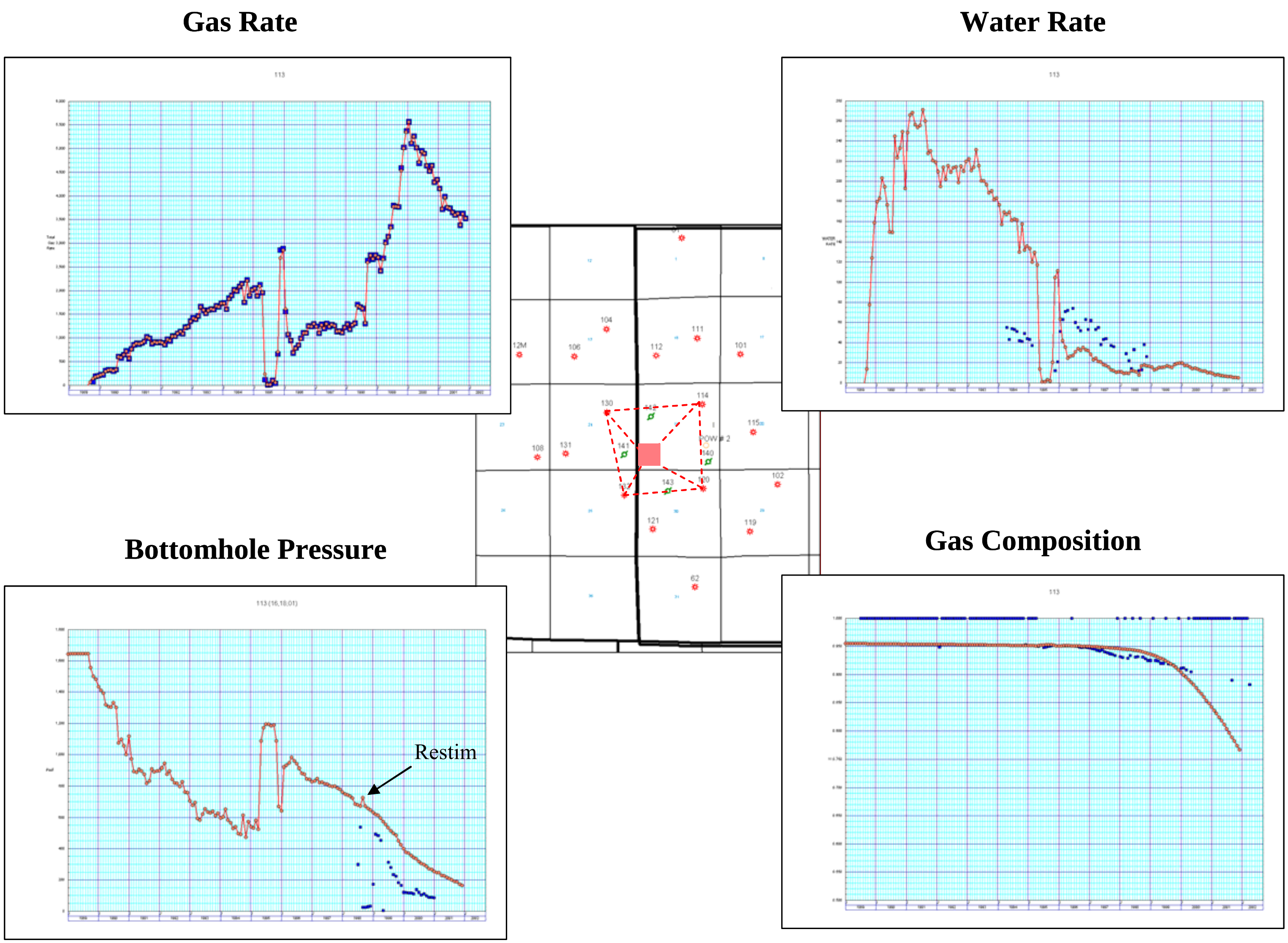

Figure 23: Actual versus Simulated Well Performance, Well 113

- In all cases, the predicted bottomhole flowing pressures were higher than the measured values – which were actually surface casing pressure data – usually by 200-300 psi. While some difference might be expected due to the different types of data being compared (surface vs. downhole), the magnitude of the difference seems large. (The wells are believed to be pumped-off with little water head existing above the coal seam.) In most cases the predicted flowing pressures appear smooth through the period when the recavitation operations were performed. This result was per the model design.

- In general, the trend in gas composition was reasonably well replicated. Note that due to limitations of the COMET2 model, gas composition could not be changed regionally in the model (an average value across the field is used). Hence one must examine the degree to which the prediction and data are parallel to each other, understanding that each would have to be calibrated to a different regional base-case composition. In some cases (most noteworthy well #113), the increase in CO_2 content of the produced gas occurs more rapidly than that actually observed.

A comparison of actual to simulated bottomhole injection pressures for CO_2 injector well #142 is provided in Figure 24. Note that the results for the other three injector wells were very similar. In this case, the actual bottomhole pressure history data was computed using long-term surface pressure data, and flowing pressure gradients obtained during the August, 2001 injection/falloff tests. The simulated pressures are considerably lower than the actual values.

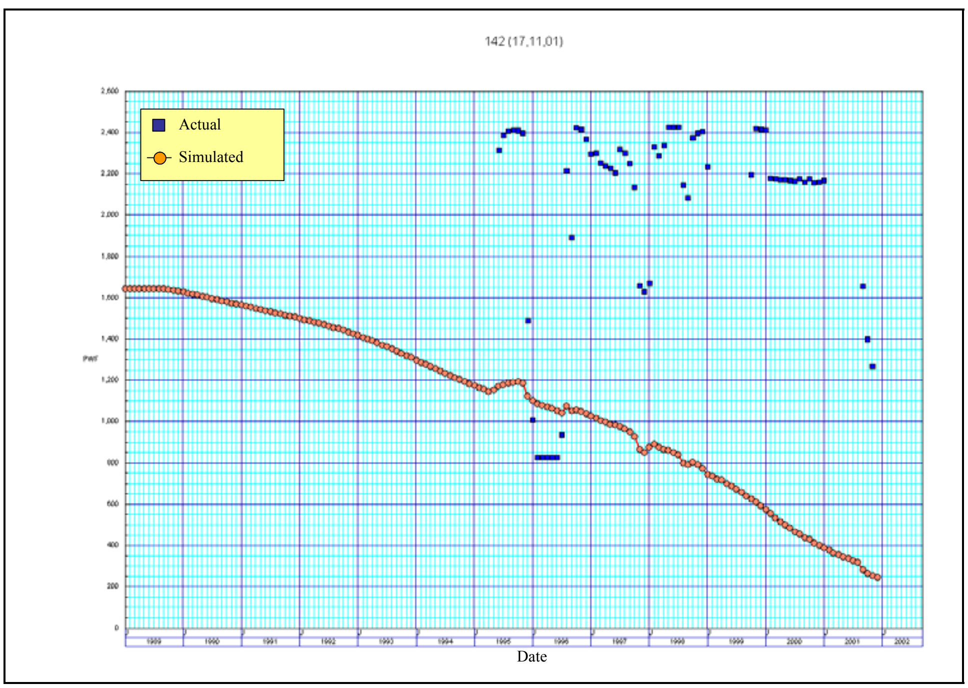

Figure 24: Actual versus Simulated Bottomhole Injection Pressures, Well 142

7.0 History Matching

The primary objective of this study was to generally calibrate this reservoir model to the field observations at Allison to better understand the CO_2-ECBM sequestration process in coalseams. As such, the focus of history-matching was to make “global” adjustments to reservoir properties and observe if they better replicated overall field behavior. It was not the intention of this effort to make regional adjustments to reservoir properties purely for the sake of achieving a match, without independent technical evidence to justify such changes. As such, the history-matching process involved on varying a selected number of key inputs known to significantly affect field performance, and observe what overall effect they had on match quality. Those key inputs were:

- Permeability, including the absolute value, the functions that control pressure - and concentration – dependent variations, and relative permeability.
- Sorption behavior, including isotherm character and sorption time, for both methane and CO_2.

7.1 Permeability

The first and most obvious strategy to close the gap between simulated and actual producing/injecting pressures was to reduce coal permeability. However, reductions could only be performed to the point where gas production rate from the model could not be maintained to match the actual rates.

To test the impact of lower permeability, permeability was decreased to 10% of the original value (an extreme case). Several noteworthy observations can be made from this scenario:

- The gas production rate in the model could not be sustained to match actual rates (Figure 25). By inference, the simulated bottomhole flowing pressures in many of the producing wells was now too low, rather than too high.

- Next, even at this level of reduced permeability, while improved over the initial case the predicted injection well pressures were still much too low (Figure 26).

- The trends in reservoir pressure at POW #2 were much better replicated with the low permeability (Figure 27), albeit with values that are too high (material balance error).

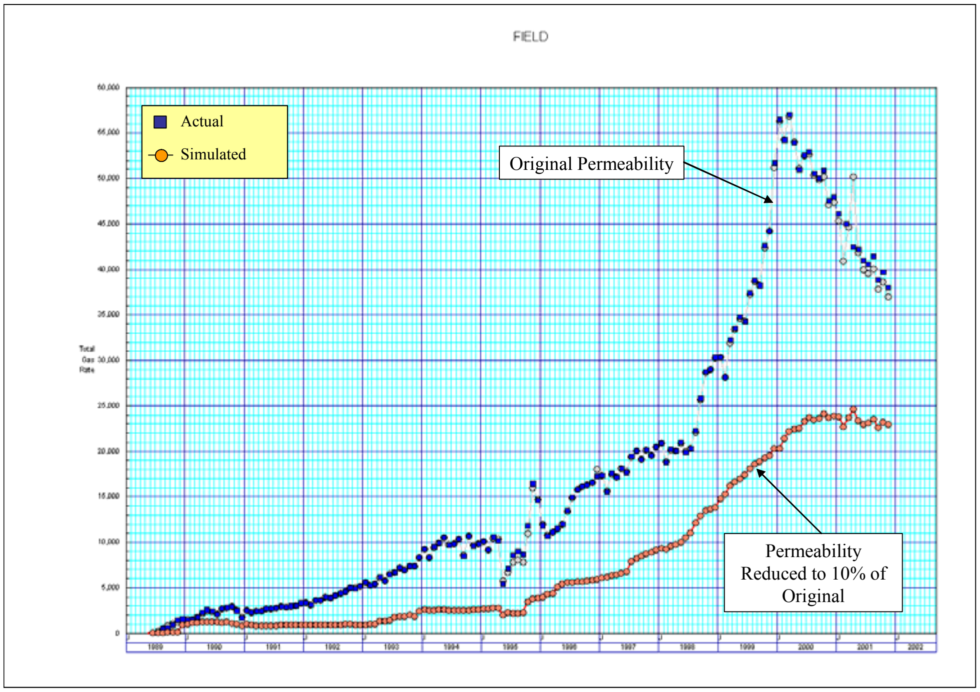

Figure 25: Actual versus Simulated Field Gas Rate, Permeability Reduced to 10% of Original Value

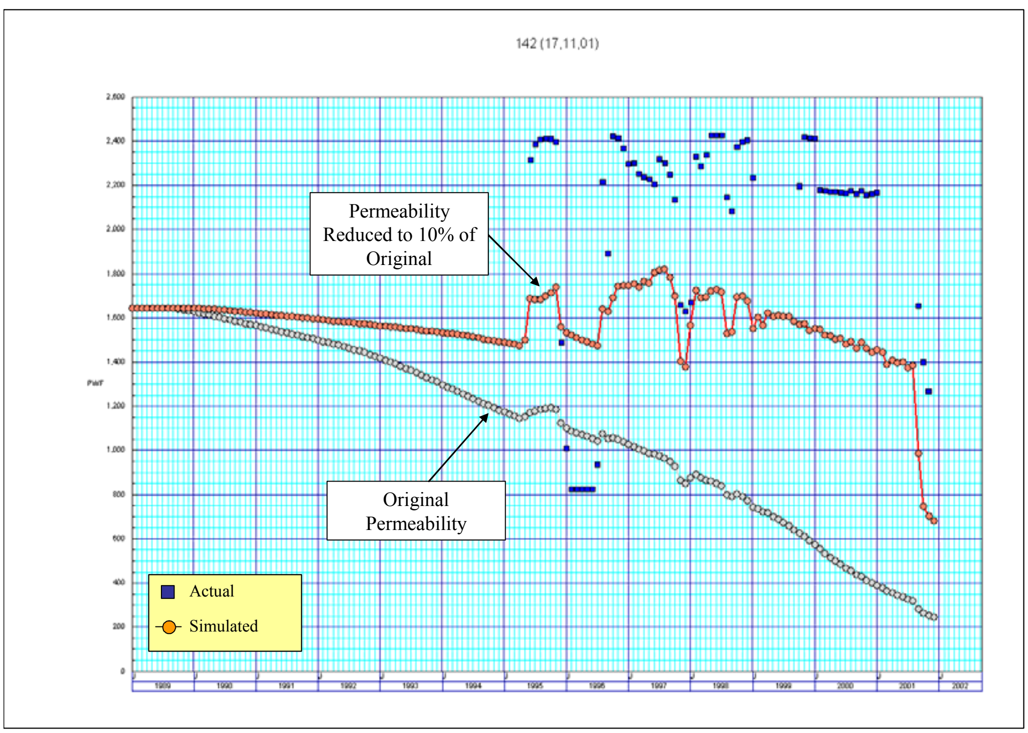

Figure 26: Actual versus Simulated Bottomhole Pressure for Injector #142, Permeability Reduced to 10% of Original Value

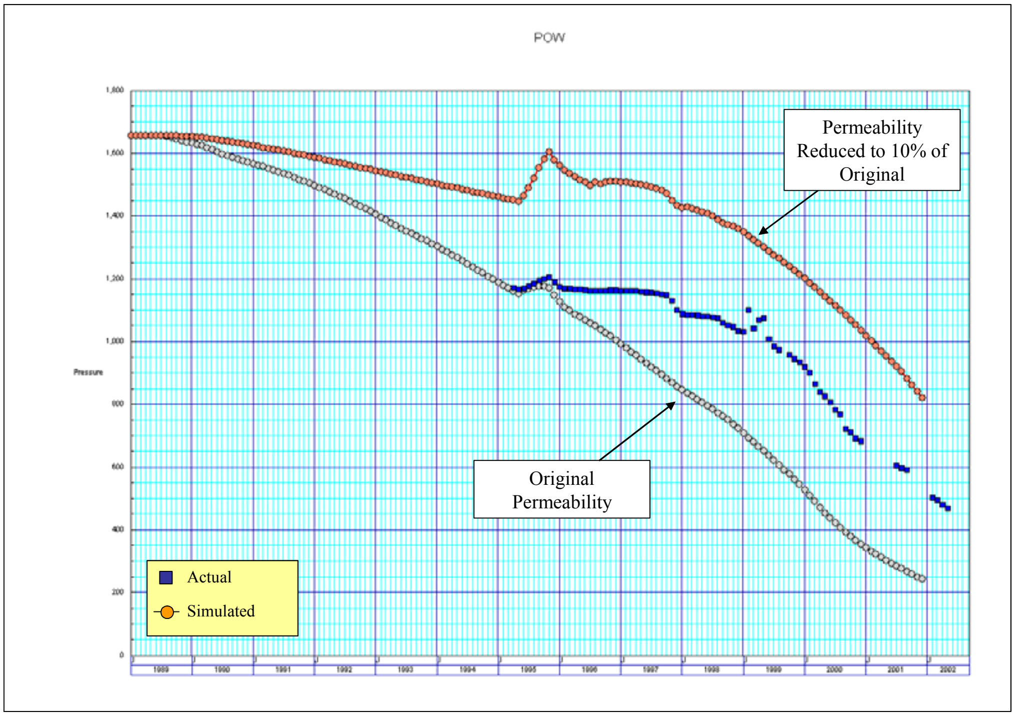

Figure 27: Actual versus Simulated Reservoir Pressure at POW #2, Permeability Reduced to 10% of Original Value

Further experimentation with permeability indicated that even slight reductions in permeability (from the original values) resulted in a gas deliverability shortfall by the model; despite the bottomhole pressure discrepancies in both the producer and injector wells, the model is just able to maintain gas rates at the original values of permeability used. In fact, even with the original permeability, well #119 does not make the required rate for it's entire history (see Appendix A).

Examination of the producing pressures at well #113, now with permeability reduced to 50% of the original value, sheds some light on why that may be occurring (in the model), as shown in Figure 28. This figure clearly illustrates that the model cannot sustain the gas rate prior to CO_2 injection, but can easily match the rates after CO_2 injection. This response, typical for many wells, indicates reservoir permeability needs to be high to match primary production, and that reservoir flow characteristics change significantly with CO_2 injection.

At this point in the modeling process, it was decided to retain the original values for permeability, to maintain required produced gas volumes during primary production, plus the fact that there was little independent basis to support significant changes.

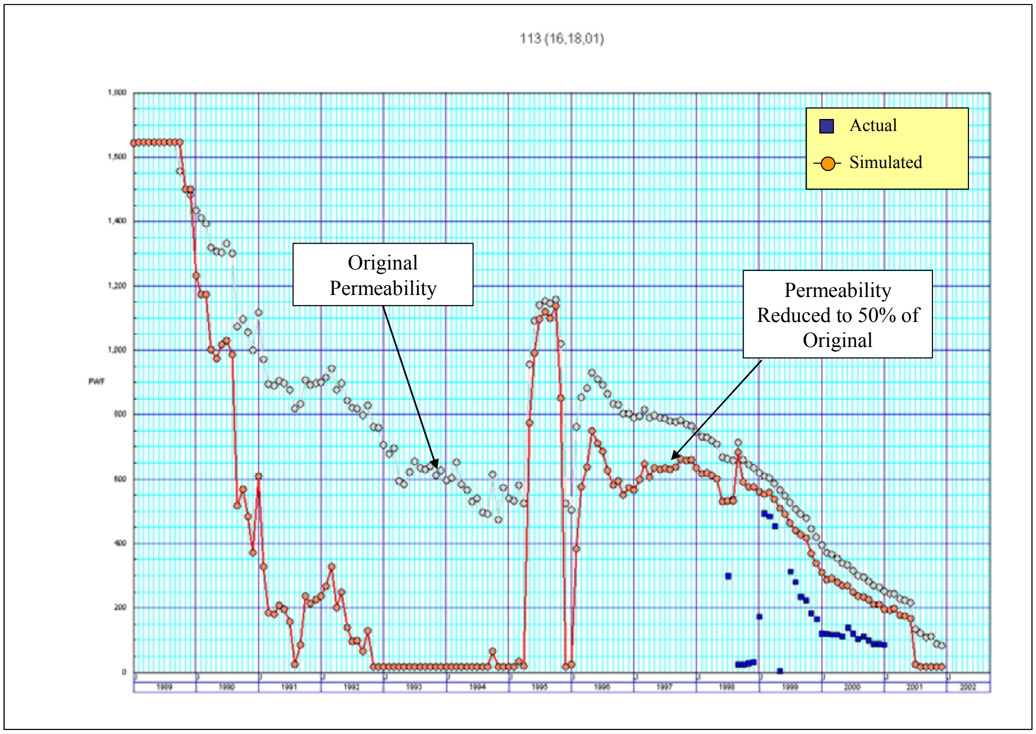

Figure 28: Actual versus Simulated Producing Pressure for Well #113, Permeability Reduced to 50% of Original Value

Next, attempts were made to improve the history-match by adjusting the functions that control pressure- and concentration-dependent permeability (specifically pore-volume compressibility and matrix compressibility), as well as relative permeability. After considerable experimentation with these variables, improvements in the match could not be achieved. As a result, while many different strategies related to permeability were tested to achieve a better history match, none provided that result in a satisfactory manner. Thus no changes were made to the initial model in this respect. Having stated that however, it is worth noting that the model appears to provide a reasonable replication of field behavior through the period of primary production, as indicated by material balance (pressure) match for POW#2 at the end of that period (Figure 22), and only after CO_2 injection do things change significantly.

7.2 Sorption Behavior

There is evidence based on laboratory studies performed as part of the Coal-Seq project that extrapolating single-component isotherm data to multi-component situations cannot be done very accurately, regardless of the sorption model used (i.e., extended Langmuir, equations of state, etc.)[6]. In addition, there is no explicit accounting for bi-directional diffusion in the coal matrix (i.e., CO_2 going in and CH_4 coming out) within COMET (or any other reservoir model that we are aware of). These factors may have something to do with the difficulty in achieving a match, and can be (at least crudely) investigated by making changes to the coal sorption properties, specifically the Langmuir parameters and sorption time.

The first sensitivity performed in this regard looked at decreasing (by 50%) the Langmuir pressure for each methane and carbon dioxide. This would cause either gas to require more pressure to adsorb/desorb a similar volume compared to the initial isotherm, and hence simulates a heightened “resistance” to diffusion resulting from bi-directional flow. The results for pressure at POW#2, flowing bottomhole pressure at well #113, gas composition at well #113, and injection pressure at well #142 are shown in Figure 29.

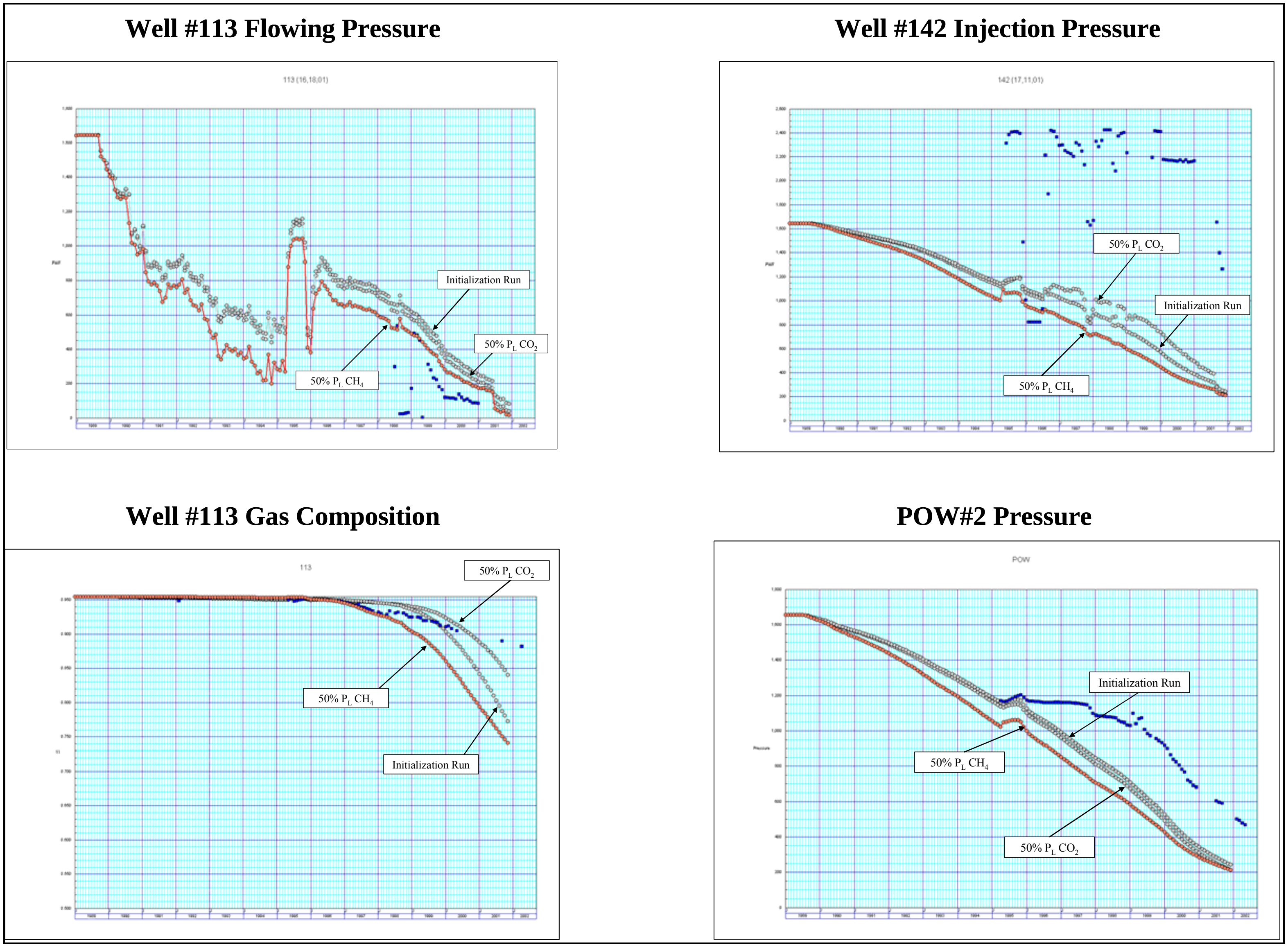

Figure 29: Actual versus Simulated Results, Langmuir Pressure for Methane and Carbon Dioxide at 50% of Original Value.

The results are very interesting. First, a pressure discrepancy becomes evident at POW#2 when the methane Langmuir pressure is reduced. This suggests that the original isotherm is a reasonable representation of reservoir conditions for the primary production period. However, after CO_2 injection, the results in terms of flowing bottomhole pressures and gas composition at well #113 are improved with a reduced Langmuir pressure for methane. Further, the reduced carbon dioxide Langmuir pressure appears to also improve the injection pressure profile at well #142. These results again suggest that the original sorption isotherms appear reasonable for the primary production period, but the flow behavior changes when CH_4 and CO_2 mix in the reservoir, those changes being possibly related to binary sorption and/or diffusion

A sensitivity run was also made varying sorption time, but significant changes in the original results were not observed. Therefore, similar to the result with permeability variations, it was decided to retain the original sorption properties in the model, since they seem to replicate primary production results reasonably well, and there is not a way to dynamically change them in the model where and when CO_2 makes contact with the reservoir.

In the end, while many attempts were made to improve the history match from the initialization run, including variations in permeability, permeability functions and sorption properties, among many others not discussed, a combination of lack of independent evidence to support such changes, and not significant enough improvements, led us to retain the original model as the best result from this study. That said, however, we believe that there are some fundamental changes in reservoir mechanics that occur when CO_2 comes into contact with the coal that we cannot currently explain nor model. While speculative, mechanisms such as competitive adsorption and bi-directional diffusion come to mind as possible explanations, that need future R & D to understand. Again, it is believed that the technical results of this study are best presented in this manner, leaving the reader the opportunity to consider possible causes for the discrepancies between actual and modeled data.

This concluded the history match process. A map-view of methane content at the end of the history-match (December 2001) is presented in Figure 30. Note the relatively uniform reservoir pressure as a result of high overall coal permeability, as well as the near-perfect displacement of methane by the CO_2.

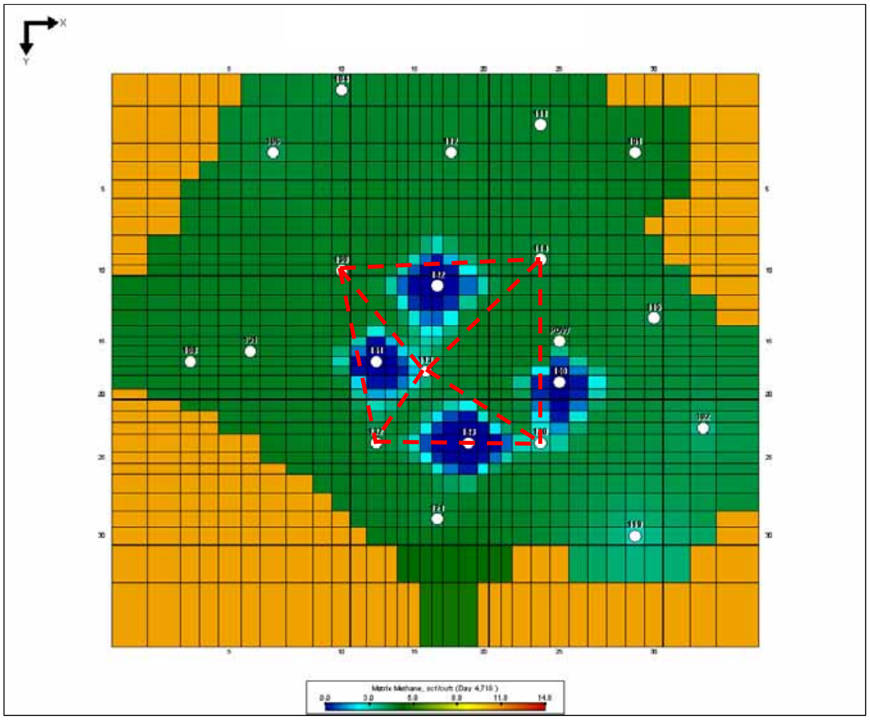

Figure 30: Map View of Methane Content (Layer 2) at End of History Match Period

8.0 Performance Forecasts

In order to evaluate the long-term performance of the ECBM pilot, under status-quo conditions (i.e., no further CO_2 injection) as well as under several "what-if" future injection scenarios, field performance cases were modeled using the initialization run results as a base case. The specific cases evaluated included:

1. No CO_2 injection (i.e., primary production only).

2. Current conditions (i.e., CO_2 injection until August 2001, and not resuming).

3. Continuous future CO_2 injection (at same rate).

4. Limited future CO_2 injection (at same rate).

5. Aggressive, continuous future CO_2 injection.

6. Aggressive, limited future CO_2 injection.

For each forecast case, the model assumed flowing bottomhole pressures in the producing wells approximately equal to the most recent values for each producing well (about 75 psi). Skin factors were increased for each well to ensure actual and modeled pressures at the end of the history match period were consistent, and hence achieve a smooth transition from history match to forecast periods. In addition, an economic limit of 50 Mcfd of methane per well and 50% CO_2 content per well was imposed; reaching those thresholds prompted the well in question to be shut-in in the model. It is important to note that since the model is predicting CO_2 breakthrough too early, the incremental methane recoveries in this analysis will be understated. A description and the results for each case are presented below.

Case 1: No CO_2 Injection

This baseline case assumed no CO_2 injection at any time, and that the field was produced via primary depletion through March 2005 (10 years after initial injection). The total methane recovery for this case was 100.4 Bcf, out of an original in-place value of 152 Bcf (active model area), for a recovery factor of 66%. Volumetric average final pressure for the (active) model was 83 psi. Note that 7.7 Bcf of in-situ CO_2 was also produced in this case.

Case 2: Current Conditions

This case assumes the actual conditions to date, specifically CO_2 injection beginning in April 1995 and ending in August 2001, according to actual volumes and rates, but with no further injection until the forecast end date of March, 2005.

A comparison plot of total gas rate for Case 2 versus Case 1 is presented in Figure 31. Note that after about 60 months the incremental methane rate becomes increasingly negative, indicating the "catch-up" period for a rate-acceleration effect. That trend reverses upon cessation of CO_2 injection, ultimately reaching zero at about 120 months. The total methane recovery for Case 2 was 102.0 Bcf, the incremental methane recovery was 1.6 Bcf, and the total CO_2 injection volume was 6.4 Bcf, for a CO_2:CH_4 ratio of 4.0:1. However, about 1.6 Bcf of injected CO_2 was reproduced, and after accounting for this, the CO_2/CH_4 ratio decreases to 3.0:1. This is consistent (slightly higher) with the sorptivity ratios according to the isotherms at the volumetric average final pressure for the (active) model of 85 psi. These results are in reasonable agreement with previous modeling work at Allison published by Burlington Resources[7]. Total sequestration volume for this case is 277,000 tons of CO_2.

Figure 32 shows how the CO_2/CH_4 ratio varies over time for this case. This plot corresponds to the incremental recovery plot in Figure 31. Upon initial injection, the ratio rises rapidly as expected. When injection was suspended the ratio begins to drop rapidly, but to levels well below the 3:1 equilibrium level. This suggests that a significant rate-acceleration effect exists. Upon the resumption of injection the ratio remains below the equilibrium value, but begins to rise and at an increasing rate when the rate-acceleration "catch-up" period begins (when the incremental methane rate in Figure 31 becomes negative). The ratio peaks at a value of about 3.3:1, at a time corresponding to the end of the "catch-up" period, at which time it begins to again decline, presumably to the ultimate equilibrium value of around 2.6-2.9:1.

Table 7 breaks down the incremental recovery results by well. It is worth noting that half of the total incremental recovery was produced by one well, #132, at the southwest corner of the central 5-spot. The well with the second-highest incremental, well #114 (with 0.4 Bcf), is located at the northeast corner of the central 5-spot. This NE-SW trend follows the high-permeability trend through the center of the field. Also note that, presumably due to early CO_2 breakthrough, well #113 is predicted to recover less methane than if no CO_2 had been injected. Most wells on the perimeter of the simulated well showed little or no change in methane recovery and are outside of the area of influence of the CO_2 injection.

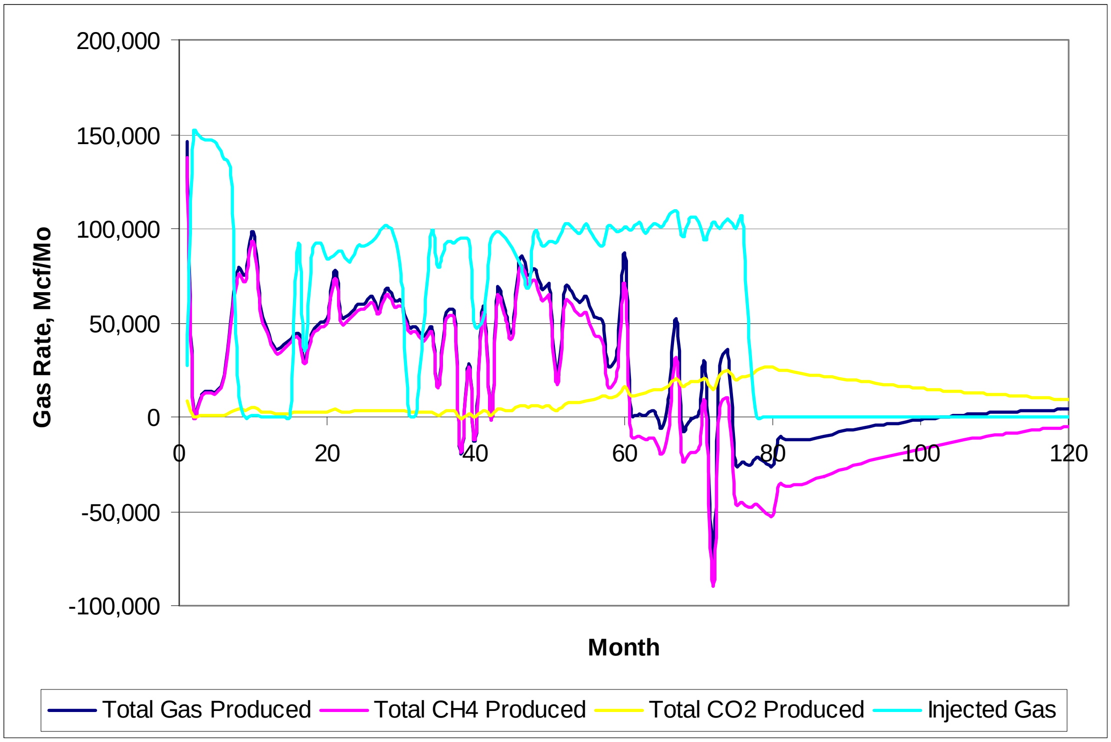

Figure 31: Incremental Gas Rates, Case 2 versus Case 1

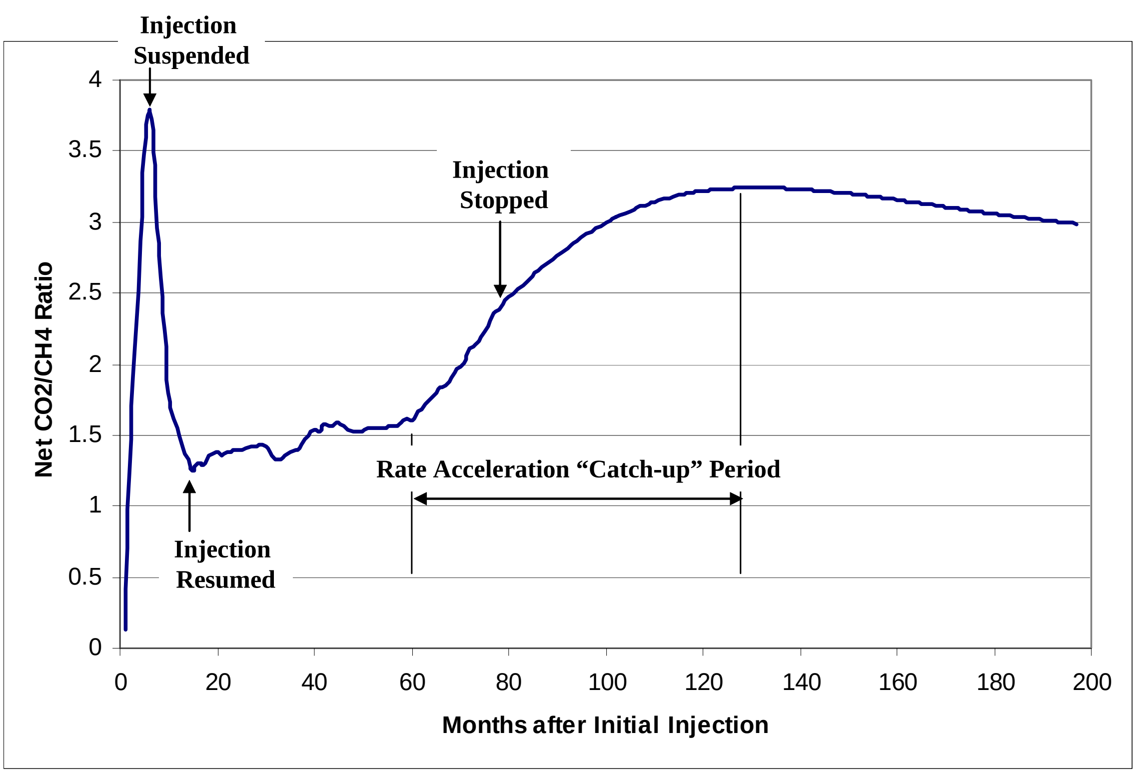

Figure 32: CO_2/CH_4 Ratio as a Function of Time

Table 7: Case 2 – Incremental Methane Recoveries by Well

Well	Without Injection (Bcf)	With Injection (Bcf)	Incremental (Bcf)
101	1.0	1.0	------
102	6.3	6.4	0.1
104	3.1	3.2	0.1
106	8.2	8.2	-----
108	6.3	6.3	-----
111	3.3	3.1	(0.2)
112	5.7	5.8	0.1
113	10.4	9.5	(0.9)
114	10.3	10.7	0.4
115	6.0	6.2	0.2
119	10.4	10.4	-----
120	5.6	5.9	0.3
121	7.3	7.6	0.3
130	4.8	5.1	0.3
131	5.6	5.7	0.1
132	6.1	6.9	0.8
TOTAL	**100.4**	**102.0**	**1.6**

Case 3: Continuous Future CO_2 Injection

This case assumes that CO_2 injection resumed in January, 2003, at a constant rate approximately equal to the last recorded rates (1,000 Mcf/day for wells #140, #141, #142 and 500 Mcf/day for well #143). The forecast end date was June, 2011 (8 ½ years after resumption of CO_2 injection).

A plot of incremental gas rate for Case 3 versus Case 2 is presented in Figure 33. Note that several wells were shut-in due to exceeding the maximum CO_2 content criteria of the produced gas (50%). The total methane recovery for Case 3 was 103.6 Bcf and the incremental methane recovery over Case 2 was 1.6 Bcf. The total incremental CO_2 injection volume was 11.1 Bcf, for a CO_2:CH_4 ratio of 6.9:1. After accounting for about 0.4 Bcf of incremental reproduced CO_2, this ratio declines to 6.7:1. Volumetric average final pressure for the (active) model was 98 psi. Incremental sequestration volume for this case is 618,000 tons of CO_2.

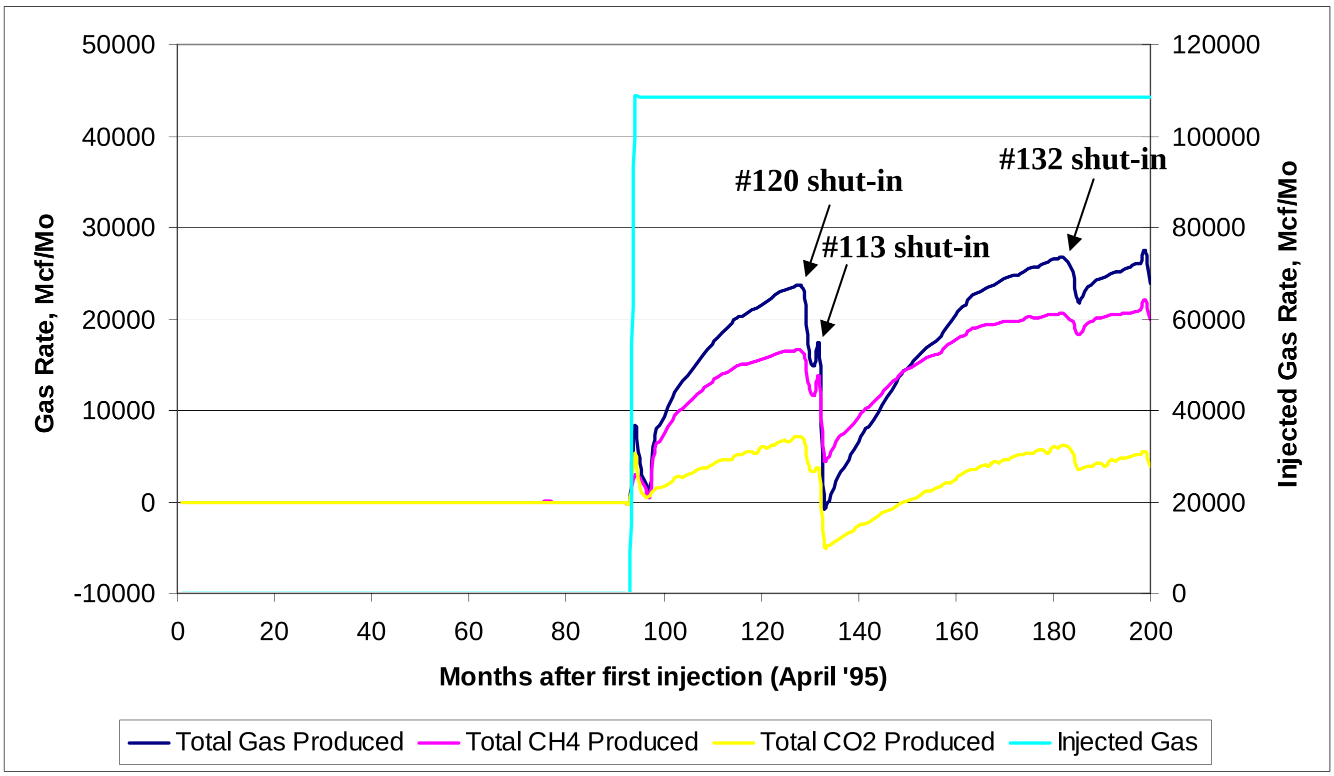

Figure 33: Incremental Gas Rates, Case 3 versus Case 2

Case 4: Limited Future CO_2 Injection

Rather than continuous future CO_2 injection, Case 4 assumes CO_2 injection for a period of 12 months, also starting in January, 2003, and at the same rates as Case 3. The forecast end date was June, 2011.

A plot of incremental gas rate for Case 4 versus Case 2 is presented in Figure 34. The total methane recovery for Case 4 was 102.4 Bcf and the incremental methane recovery over Case 2 was 0.4 Bcf. The total incremental CO_2 injection volume was 1.3 Bcf, for a CO_2:CH_4 ratio of 3.3:1. After accounting for about 0.2 Bcf of incremental reproduced CO_2, this ratio decreases to 2.7:1. Volumetric average final pressure for the (active) model was 85 psi. Incremental sequestration volume for this case is 64,000 tons of CO_2.

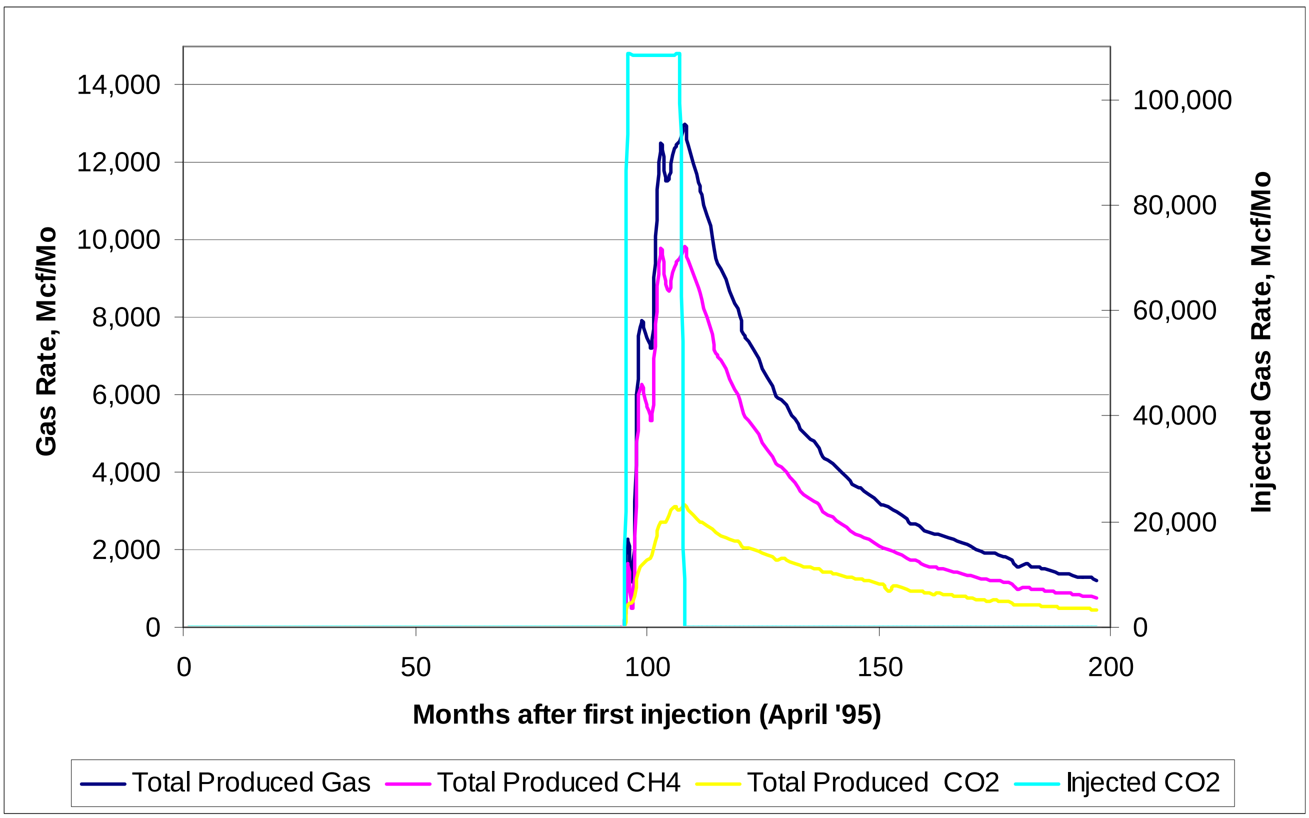

Figure 34: Incremental Gas Rates, Case 4 versus Case 2

Case 5: Aggressive, Continuous Future CO_2 Injection

It is clear from the preceding forecast cases that CO_2 injection volumes are limited, and as such so too are the incremental methane recoveries. For improved economic performance, given the sunk capital costs involved, higher CO_2 injection volumes would be beneficial. While it is acknowledged that to achieve higher injection rates, some work to the injection wells would be required to improve injectivity, this case is worth evaluating. To do so, Case 5 assumes injection rates at four times those of the preceding cases, or 4,000 Mcf/day for wells #140, #141, #142 and 2,000 Mcf/day for well #143. Consistent with the earlier cases, injection resumed in January 2003 and the forecast end date was June, 2011.

A plot of incremental gas rate for Case 5 versus Case 2 is presented in Figure 35. Note that many wells were shut-in for exceeding the maximum CO_2 content criteria for the produced gas of 50%. The total methane recovery for Case 5 was 106.3 Bcf, and the incremental methane recovery over Case 2 was 4.3 Bcf. The total incremental CO_2 injection volume was 45.2 Bcf, for a CO_2:CH_4 ratio of 10.5:1. After accounting for 1.4 Bcf of incremental reproduced CO_2, this ratio decreased to 10.2:1. Volumetric average final pressure for the (active) model was 154 psi. Incremental sequestration volume for this case is 2.5 million tons of CO_2.

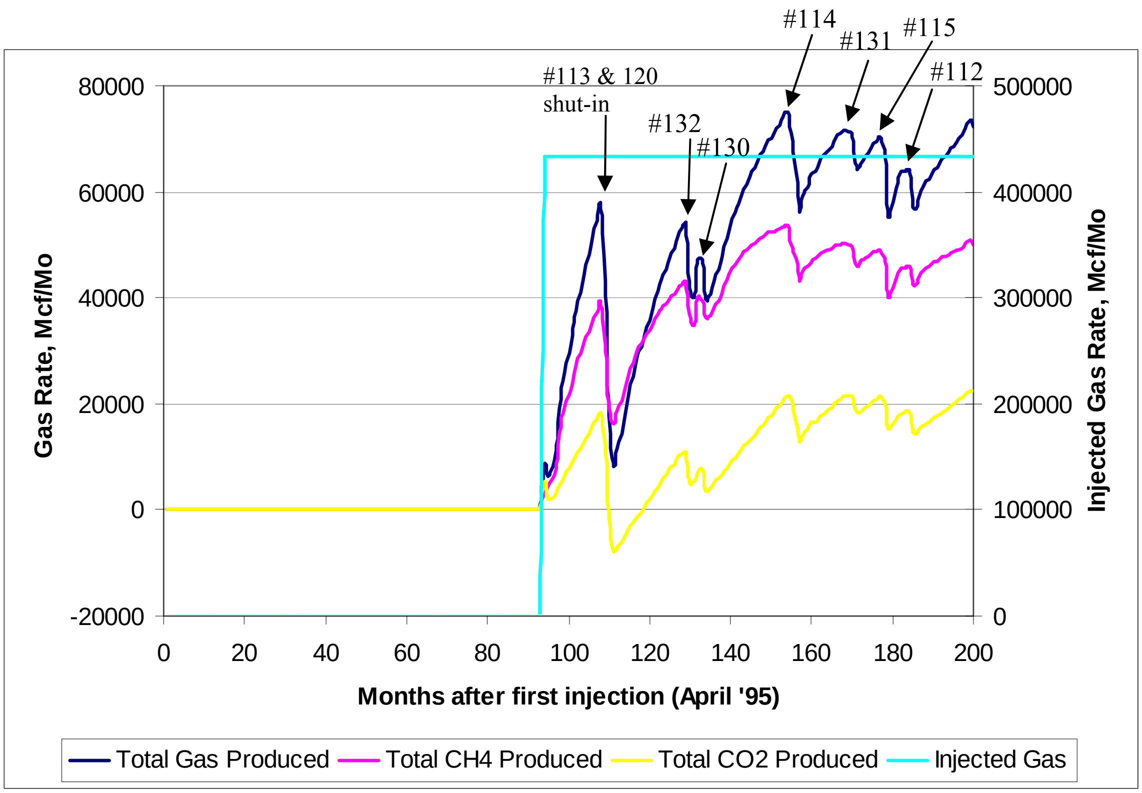

Figure 35: Total and Incremental Gas Rates, Case 5 versus Case 2

Case 6: Aggressive, Limited Future CO_2 Injection

This case also assumes aggressive CO_2 injection (at a rate four times the earlier rate), but for a period of only 12 months. Again, injection start date was January 2003 and the forecast end date was June, 2011.

A plot of incremental gas rate for Case 6 versus Case 2 is presented in Figure 36. Note that several wells were shut-in for exceeding the maximum CO_2 content criteria for the produced gas of 50%. The total methane recovery for Case 6 was 103.3 Bcf, and the incremental methane recovery over Case 2 was 1.3 Bcf. The total incremental CO_2 injection volume was 5.4 Bcf, for a CO_2:CH_4 ratio of 4.1:1. After accounting for 0.5 Bcf of reproduced CO_2, this ratio decreases to 3.8:1. The Volumetric average final pressure for the active model area was 87 psi. Incremental sequestration volume for this case is 283,000 tons of CO_2.

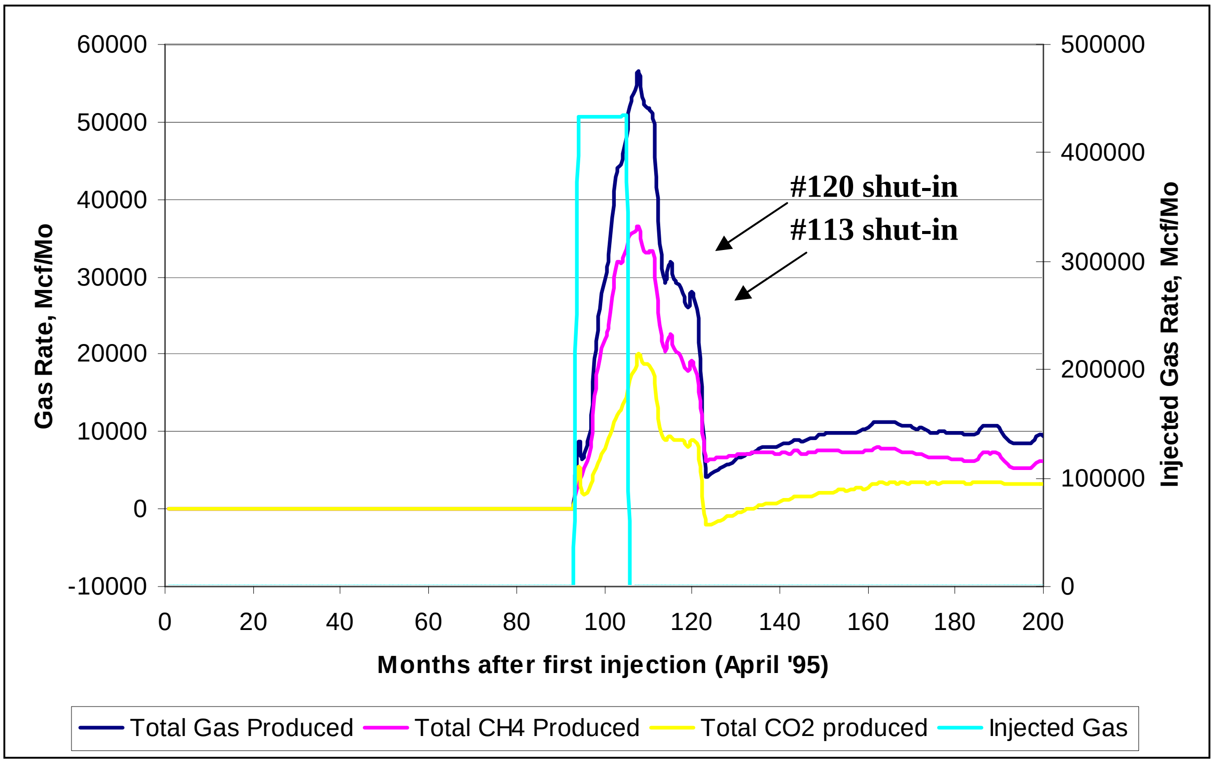

Figure 36: Incremental Gas Rates, Case 6 versus Case 2

A summary of the results for each run is presented in Table 8.

Table 8: Summary of Model Forecast Results

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Total CH_4 Produced (Bcf)	100.4	102.0	103.6	102.4	106.3	103.3
Incremental CH_4 (Bcf)	0	1.6	3.2	2.0	5.9	2.9
Incremental CH_4 Recovery (% OGIP)	0	1.1%	2.1%	1.3%	3.9%	1.9%
Total CO_2 Injected (Bcf)	0	6.4	17.5	7.7	51.6	11.8
Total CO_2 Produced (Bcf)	7.7	9.3	9.7	9.5	10.7	9.8
CO_2/CH_4 Ratio	0	3.0	4.8	3.0	8.2	3.3

It is clear from these results that, while the absolute values of incremental methane recoveries seem reasonable in relation to the injected CO_2 volumes, particularly in those cases where the reservoir system was allowed to equilibrate (i.e., CO_2 injection ceased a production continued, allowing the CO_2 to work its way through the reservoir, resulting in a CO_2/CH_4 ratio of about 3:1), the incremental recoveries in terms of percentage of original gas-in place (OGIP) are almost insignificant and warrant further examination. In the cases where the CO_2/CH_4 ratios exceed 3-3½:1, one should expect that had injection ceased and the forecast period been extended, incremental methane recovery would have increased (and some injected CO_2 reproduced) to bring that ratio into line. The implication is that to achieve the "equilibrium" CO_2/CH_4 replacement ratio specific to a given reservoir setting (about 3:1 in this case), some time is required after the cessation of CO_2 injection for the system to equilibrate.

9.0 Discussion of Results

The most striking result from the forecasts is that so little incremental methane is recovered, particularly when stated as a percentage of OGIP. (It is worth reiterating that due to more rapid CO_2 breakthrough in the model than actually observed, incremental methane recoveries are understated.) As a first step in understanding the forecast results, it is useful to examine the CO_2/CH_4 ratios. Figure 37 presents the equilibrium CO_2/CH_4 ratios based on the isotherms presented in Figures 10 and 11. Note that, for these specific isotherms, the ratio increases with decreasing pressure (and are fairly consistent for each seam). For the ending reservoir pressures for the cases presented in the previous section (typically 80 to 100 psi), the equilibrium ratio is approximately 2.6 – 2.9. Thus, in those cases with ratios of 3-3½:1 (where injection ceased and production continued), the ratio is approximately the equilibrium value, accounting for some system inefficiencies.

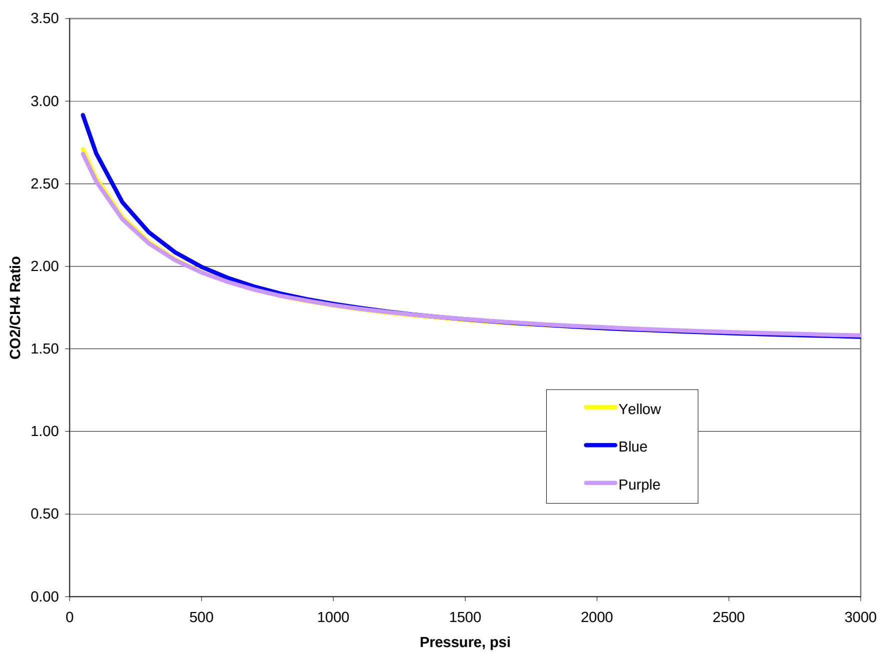

Figure 37: CO_2/CH_4 Sorption Ratios, Case 2

The primary problem at Allison was that, due to significant permeability and injectivity loss with CO_2 injection, only limited volumes of CO_2 could be injected. Finding ways to overcome or prevent this type of permeability/injectivity loss is therefore an important topic for future research, and critical if CO_2-ECBM/sequestration is to become a viable sequestration option.

Another aspect of the Allison results to keep in perspective is that the effects of CO_2 injection were primarily observed in the central 5-spot pattern, and not the outer reaches of the model area, where a large portion of the 152 Bcf OGIP resides. If one takes an average OGIP of 9.5 Bcf/well (152 Bcf/16 wells), then the incremental recovery of 0.8 Bcf for well #132 represents about 8% of OGIP. Further, since it is a corner well, only half of it's drainage area was affected by the flood (Figure 38); this incremental recovery factor would therefore potentially double to about 16% for a fully developed CO_2 injection pattern.

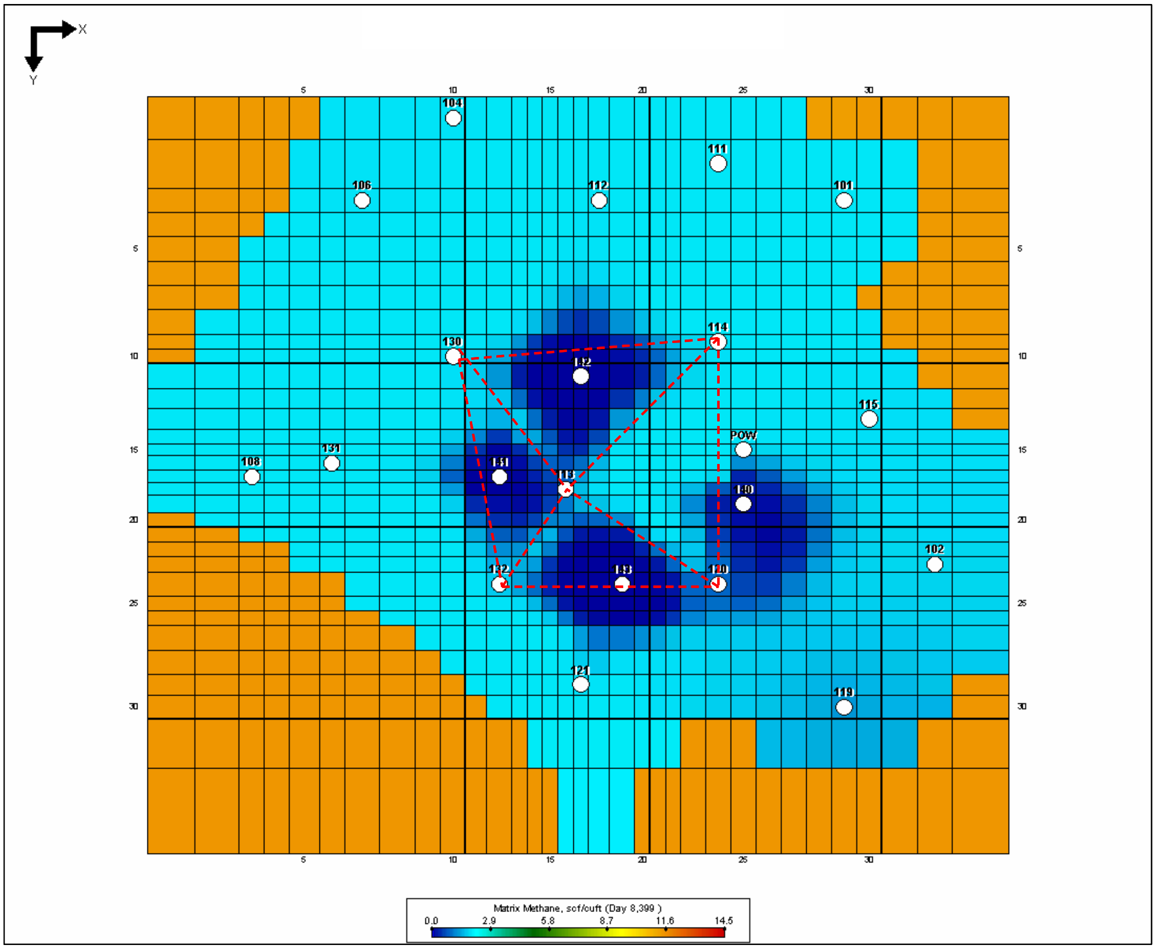

Figure 38: Map View of Methane Content (Layer 2) at End of Forecast Period (Case 2)

Finally, the pilot itself was not of optimal design (as we always learn with the benefit of 20/20 hindsight). Some of the injector/producer spacings were too close, most notably 141/113, resulting in early breakthrough, poor sweep efficiency and reduced recovery. One can easily observe in Figure 38 the large unswept area in the eastern quadrant of the five-spot pattern, the gas in which would presumably have been recovered (by #113) had it not experienced early CO_2 breakthrough. This "inefficiency" was probably magnified in this analysis in that we know the incremental methane recoveries are already understated due to more rapid CO_2 breakthrough in the model than actually observed, plus the fact that we imposed a 50% maximum CO_2 content in the produced gas (a higher number, if operationally feasible, would also have the effect of increasing methane recovery).

In summary, the results from Allison do make sense, and the low incremental methane recoveries on a gross basis are understandable. However, the requirements for higher recoveries are also clear – specifically larger injection volumes, enhanced injectivity, and optimal well placement.

10.0 Economic Assessment

The final component of this study was to evaluate the economic performance of both the actual pilot and the various future CO_2 injection scenarios. The capital, operating and financial assumptions utilized are presented in Table 8. Note that all economics were performed on an incremental basis (i.e., only the incremental production and costs were considered).

Table 9: Economic Analysis Assumptions

Capex	
CO_2 Hot Tap:	$175,000
36 mi (4 inch) Pipeline:	$3.5 million ($24,000/in-mi)
Field Distribution:	$80,000 ($20,000/in-mi)
Wells	$1.6 million ($400,000/ea; fully equipped)
Total	$5.355 million
Opex	
Injector Well Operating:	$1,000/mo (active only)
CO_2 Cost	$0.30/Mcf
Produced Gas Processing	$0.25/Mcf
Financial	
Gas Price:	$2.20/MMBTU (ex-field)
Methane BTU Content	1.04 MMBTU/Mcf
Net Revenue Interest:	87.5%
Production Taxes:	8%
Discount Rate:	12%

Case 1 versus Case 2

This case evaluates the performance of the existing pilot, with no future CO_2 injection considered. Note that the hot-tap and pipeline capital costs are included for this case, but only allocated at 25% of the total since the working assumption is that it would also be used for additional pilots and/or large-scale CO_2 flood implementation. The economic results of this case are presented in Table 10.

Table 10: Economic Analysis Results: Case 2 versus Case 1

	@ 5 years	@10 years
Net Present Value	($627k)*	($1,809k)
Breakeven Gas Price	$2.57/MMBTU	$3.60/MMBTU
Breakeven CO_2 Cost	$0.12/Mcf	($0.12/Mcf)

*Maximum (least negative) NPV occurs at ~ 5 years.

It appears that the pilot was uneconomic, even after allocating the hot-tap and pipeline spur only at 25% of the total cost. However, at least at the 5-year point, where the net present value is maximum (least negative), the breakeven gas price ($2.57/MMBTU) is not an unreasonable expectation, suggesting this process is economically promising, even with incremental methane recoveries understated. From another perspective, reducing the CO_2 cost from $0.30/Mcf to the breakeven value of $0.12/Mcf (at 5-years) would be equivalent to a tax credit of about $3.11/ton of CO_2. Note that the breakeven tax credit is the same as the net sequestration cost, and importantly assumes a delivered CO_2 cost equal to the approximate market value (in the San Juan basin) of $0.30/Mcf ($5.19/ton of CO_2).

This CO_2 cost may be an optimistic assumption for other locations, or as a proxy for CO_2 separation and capture costs as part of a carbon sequestration program. Any increase in costs over this assumption would have to be added to the tax credit to achieve a breakeven condition. For example, if actual CO_2 separation and capture costs were $30/ton of CO_2 ($11.73/Mcf, for advanced technology amine separation from coal-fired power plant fire gas), and compression and transportation costs were $3/ton ($0.17/Mcf), then the required tax credit for a breakeven condition would be $28.50/ton of CO_2 for case 4 (30 + 3 – 5.19 + 0.69). The implication of this analysis is than while incremental methane recovery achieved with CO_2 injection in coalseams provides meaningful value to offset CO_2 separation and capture costs, these costs are still too high and must come down, and/or tax incentives provided, to achieve a financially breakeven result for industry.

Cases 3, 4, 5, 6 versus Case 2

In these cases, no capital costs are considered; they are considered sunk for the purpose of this analysis. The results of these cases are presented in Table 11. All cases are presented at the end of the forecast period (June 2011, 8 ½ years after resumption of CO_2 injection).

Table 11: Economic Analysis Results, Cases 3, 4, 5, 6 versus Case 2

	Versus Case 2			
	Case 3	**Case 4**	**Case 5**	**Case 6**
Net Present Value	($1,040k)	($38k)	($5,063k)	($301k)
Breakeven Gas Price	$3.67/MMBTU	$2.38/MMBTU	$4.82/MMBTU	$2.64/MMBTU
Breakeven CO_2 Cost	$0.15/Mcf $2.60/ton	$0.26/Mcf $4.50/ton	$0.12/Mcf $2.08/ton	$0.24/Mcf $4.15/ton
Breakeven CO_2 Tax Credit	$0.15/Mcf $2.60/ton	$0.04/Mcf $0.69/ton	$0.18/Mcf $3.11/ton	$0.06/Mcf $1.04/ton

Similar to the previous case, each of these cases appear to favor short-term CO_2 injection (cases 4 and 6) over long-term injection (cases 3 and 5) from an ECBM economic perspective. However, purely from a CO_2 sequestration perspective, tax credits of generally <$3/ton of CO_2 would be required for a profitable sequestration operation, again considering the reasonableness of the CO_2 cost assumptions

11.0 Case for Carbon Sequestration

Since all previous runs were considered primarily from an ECBM economic optimization perspective, and since this study was funded under DOE's carbon sequestration program, a final simulation was performed to evaluate the economic results for maximum CO_2 sequestration. For this run case 5 was merely extended until all wells were shut-in, and the reservoir pressure reached 75% of the original pressure, or 1,240 psi. This assumes that the original CO_2 injection was performed on a stand-alone ECBM basis (to cover the capital costs for injection), and that the field was then converted to sequestration service.

The results of this case, which ran to January 2038 (35 years after resumption of injection in January 2003), suggested a total methane recovery of 111.4 Bcf, and an incremental methane recovery of 9.4 Bcf. The total incremental CO_2 injection volume was 178.6 Bcf. After accounting for 3.5 Bcf of incremental reproduced CO_2, the total incremental sequestration volume is over 10 million tons of CO_2, or 2.8 million tons of carbon. The large volume of unrecovered methane (over 40 Bcf) is probably due to the fact that the wells were shut-in when CO_2 content reached 50%, and that the model predicts CO_2 breakthrough too early (i.e., incremental methane recovery is understated). The pressure history for the model area is shown in Figure 39.

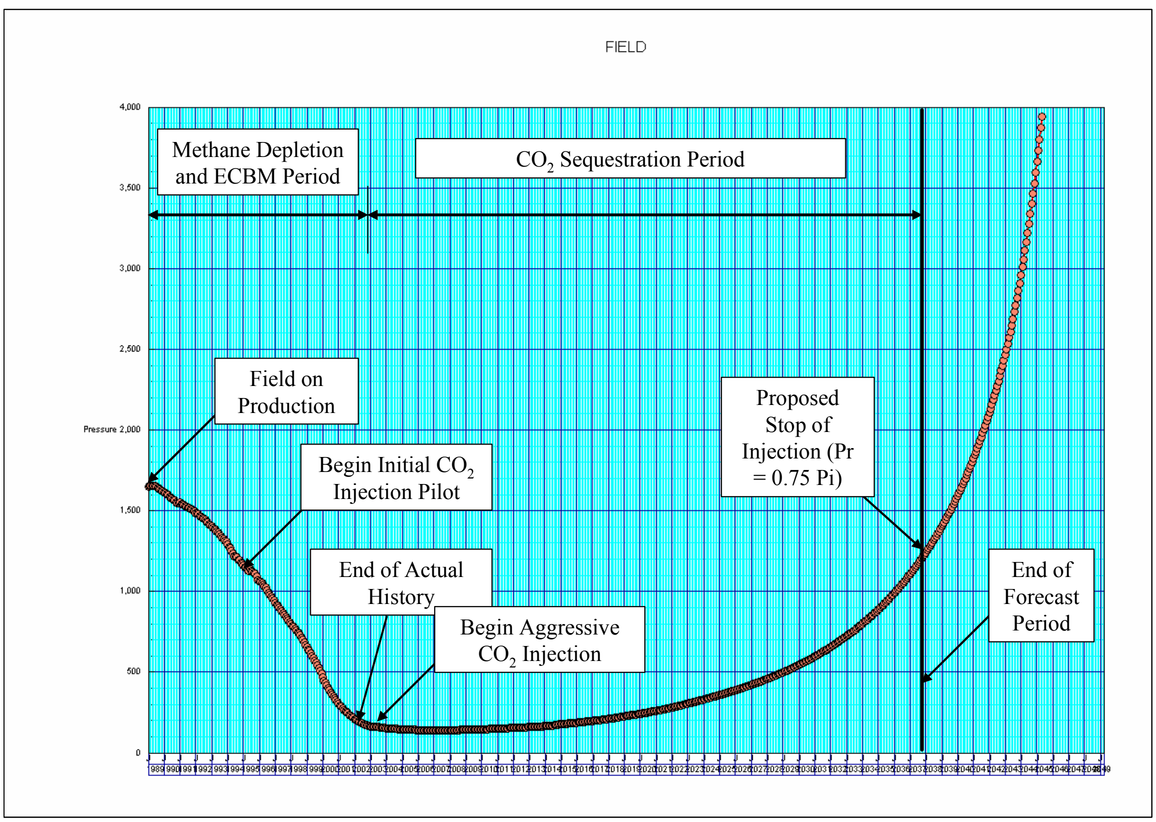

Figure 39: Reservoir Pressure History for the CO_2 Sequestration Cost

Economic assessment on this basis yields a breakeven CO_2 cost of \$0.12/Mcf, which equates to a breakeven tax credit of \$3.11/ton of CO_2 or \$11.41/ton of carbon. These results suggest that large CO_2 volumes can potentially be sequestered at reasonable net costs in coalseams.

12.0 Conclusions

Based on the results of this study, the following conclusions have been drawn:

- The injection of CO_2 at the Allison Unit has resulted in incremental methane recovery over estimated ultimate primary recovery, in approximately a proportion of one volume of methane for every three volumes of CO_2 injected.

- The study area was successfully modeled with ARI's COMET2 model. However, aspects of the model remain uncertain, such as producing and injecting bottomhole pressures, CO_2 content profiles of the produced gas, and the pressure at the observation well.

- There appears to be clear evidence of significant coal permeability reduction with CO_2 injection. This permeability reduction, and the associated impact on CO_2 injectivity, compromised incremental methane recoveries and project economics. Finding ways to overcome and/or prevent this effect is therefore an important topic for future research.

- From a CO_2 sequestration standpoint, the incremental methane recoveries (based solely on the conditions encountered at the Allison Unit), can provide a meaningful offset to CO_2 separation, capture and transportation costs, on the order of $2–5/ton of CO_2.

13.0 Nomenclature

ARI	-	Advanced Resources International
Bcf	-	billions of cubic feet
BTV	-	British Thermal Units
C	-	absorbed gas concentration
Capex	-	capital expenditures
CBM	-	coalbed methane
cc	-	cubic centimeters
CH_4	-	methane
C_i	-	initial adsorbed gas concentration
Ck	-	differential swelling factor
cm	-	matrix compressibility
CO_2	-	carbon dioxide
Cp	-	pore volume compressibility
C_t	-	total absorbed gas concentration
DOE	-	Department of Energy
$	-	dollars (U.S.)
E	-	Young's modulus, psi
ECBM	-	enhanced coalbed methane recovery
f	-	decimal fraction, dimensionless
FOI	-	folds of increase
ft	-	feet
g	-	grams
Gt	-	gigatonnes
k	-	permeability, millidarcy
kabs	-	absolute permeability
keg	-	effective gas permeability
ki	-	initial permeability, millidarcy
M	-	constrained axial modulus, psi
Mcf	-	thousand of cubit feet
Mcfd	-	thousands of cubic feet per day
md	-	millidarcies
mo	-	month

MUGS	-	Model of Unconventional Gas Supply
MW	-	megawatts
n	-	permeability exponent
N_2	-	nitrogen
NPV	-	net present value
ºF	-	degrees Fahrenheit
OGIP	-	original gas in place
Opex	-	operating expenditures
P	-	pressure
%	-	percent
P_i	-	initial pore pressure
P_L	-	Langmuir pressure
psi	-	pounds per square inch
psia	-	pounds per square inch absolute
PTA	-	pressure transient analysis
SCF	-	standard cubic feet
Sm	-	matrix swelling coefficient, ton/scf
SMV	-	storage monitoring and verification
Tcf	-	trillions of cubic feet
Tmv	-	time value of money
U.S.	-	United States
V_L	-	Langmuir volume
vs	-	versus
β	-	inverse of Langmuir pressure, psi^{-1}
γ	-	grain compressibility, psi^{-1}
εL	-	Langmuir strain, dimensionless
εm	-	bulk strain due to matrix swelling, dimensionless
υ	-	Poisson's ratio
Φ	-	porosity
$Φ_i$	-	initial porosity

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Appendix A:

Comparison Plots - Initialization Run versus Actual Data

Note: Actual data represented by square data points, simulated data by circle data points.