0523

The Tiffany Unit N_2-ECBM Pilot – A Reservoir and Economic Analysis

Scott Reeves, Advanced Resources International, Inc.
Anne Oudinot, Advanced Resources International, Inc.

ABSTRACT

In October, 2000, the U.S. Department of Energy, through contractor Advanced Resources International, launched a multi-year government-industry R&D collaboration called the Coal-Seq project. The Coal-Seq project investigated the feasibility of 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 were the Allison Unit, operated by Burlington Resources, into which CO_2 was injected, and the Tiffany Unit, operating by BP America, into which N_2 was injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The objectives of the field studies were to understand the reservoir mechanisms associated with CO_2 and N_2 injection into coalseams, demonstrate the effectiveness of the ECBM and sequestration processes, demonstrate an engineering capability to model them, and to evaluate ECBM/sequestration economics. In support of these efforts, laboratory and theoretical studies were also performed to understand multi-component isotherm behavior, and coal permeability changes due to swelling with CO_2 injection. This paper presents the results of the Tiffany Unit study, in which a detailed reservoir characterization of the field was developed, the field history was matched using the COMET3 reservoir simulator, future field performance was forecast under various operating conditions, and an economic analysis performed.

INTRODUCTION

In October, 2000, the U.S. Department of Energy (DOE), through contractor Advanced Resources International (ARI), launched a multi-year government-industry R&D collaboration called the Coal-Seq project[1]. The Coal-Seq project investigated the feasibility of 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 were the Allison Unit, operated by Burlington Resources, into which CO_2 was injected, and the Tiffany Unit, operated by BP America (BP), into which N_2 was injected (the interest in understanding the N_2-ECBM process has important implications for CO_2 sequestration via flue-gas injection). The objectives of the field studies were to understand the reservoir mechanisms associated with CO_2 and N_2 injection into coalseams, demonstrate the effectiveness of the ECBM and sequestration processes, demonstrate an engineering capability to model them, and to evaluate ECBM/sequestration economics. In support of these efforts, laboratory and theoretical studies were also performed to understand multi-component isotherm behavior, and coal permeability changes due to swelling with CO_2 injection. This paper presents the results of the Tiffany Unit study, in which a detailed reservoir characterization of the field was developed, the field history was matched using the COMET3 reservoir simulator, future field performance was forecast under various operating conditions, and an economic analysis performed.

SITE DESCRIPTION

The Tiffany Unit ECBM pilot is located in La Plata County, northern Colorado, in close proximity to the border with New Mexico (Figure 1). While the Unit consists of many wells, the pilot area for N_2 injection consisted of 34 coalbed methane (CBM) producer wells and 12 N_2 injectors. The study area well pattern is illustrated in Figure 2. Note that the northwestern part of the study area was previously characterized and modeled by ARI as part of a Gas Research Institute effort to understand reservoir behavior in San Juan Basin coals[2].

The producing history for the study area is shown in Figure 3. The field originally began production in 1983, with N_2 injection beginning in January, 1998. Production just prior to nitrogen injection was about 5 MMcfd, or about 150 Mcfd per well. Injection was suspended in January 2002, after four years of intermittent N_2 injection, to evaluate the results. Several points are worth noting regarding the producing history:

- Nitrogen injection only occurred during the winter months, and was suspended during the summer months. The reason was that the nitrogen was sourced from a cryogenic air separation plant located at the Florida River gas processing facility, and the unit ran less efficiently at temperatures above 65 degrees Fahrenheit. Therefore nitrogen injection was only performed during the cooler winter months.

- The methane production response to N_2 injection was rapid and dramatic. During the initial injection period, total methane rate jumped from about 5 MMcfd to about 27 MMcfd, over a factor of 5. Production responses to subsequent shut-down and injection periods were also pronounced.

RESERVOIR DESCRIPTION

The Tiffany Unit wells produce from four Upper Cretaceous Fruitland Formation coal seams, named the B, C, D and E (from shallowest to deepest) using BP's terminology. A summary of basic coal depth, distribution, thickness, pressure and temperature information is provided in Table 1.

Sorption isotherms for CH_4, N_2 and CO_2 were measured for coal samples taken earlier (and preserved) from injection wells #1 and #10 (in the northwest and southeast portions of the field respectively). After careful quality control checking, the samples were mixed and single-component, binary and ternary isotherms measured[3]. The results for the pure component isotherms are shown in Figure 4, on an as-received basis.

In the previous reservoir study of the area[2], a permeability anisotropy of about 2.4 was determined to exist, with the maximum permeability in the northwest-southeast orientation. This coincides with the measured face-cleat orientation. The geometric average permeability from that study was also determined to be 1.6 md, and the average porosity 0.8%. These properties were initially retained for this study.

RESERVOIR MODEL CONSTRUCTION

The reservoir simulator used for the study was ARI's COMET3 (ternary isotherm – CH_4, N_2 and CO_2) model. Details on the model theory are provided in the references[4,5].

A four-layer (B, C, D, E), full-field model was constructed[6]. The coal structure and thickness information for each layer was directly input per the maps generated. Since information from BP and other sources suggested that the cleat orientations were approximately in the northwest-southeast (face) and northeast-southwest (butt), the model grid was so aligned. Permeability, relative permeability and porosity values were used per the prior study[2]. Finally, the isotherm properties as measured in the laboratory were used.

Additionally, well completion and operating parameters were examined for input into the model. Since the production wells had been restimulated in the mid-1990's, skin factors for these wells was set at –2. Since the N_2 injection wells were not stimulated, those skin factors were set at a value of 0.

The model gridblock dimensions were 73 x 37 x 4 (approximately 10,800 total gridblocks, about 7,800 of which were active), and covered an active area of about 16,400 acres (Figure 5). On average, the gridblock dimensions were 690 ft × 525 feet × 12 feet. 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.

HISTORY MATCH RESULTS

The independent parameter used to drive the simulator was gas production (and injection) rate to maintain material balance, and the dependent (history match) parameters were water production rate, flowing pressure (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.

The primary history match variables were permeability and porosity. These were modified globally to obtain the best overall match for the field. The objective of the study was to understand the mechanisms of the N_2-ECBM process by matching general trends, and not necessarily to make regional changes to the reservoir characterization to achieve matches on an individual well basis. Ultimately, it was found that a geometric average permeability of 13.4 md (retaining the permeability anisotropy of 2.4) and a porosity of 0.2% provided the best overall match.

A comparison of the actual versus simulated field gas rate is presented in Figure 6. The only conclusion that can be derived from this result, since the model was "driven" on gas rate, is that model (as constructed) was capable of delivering the gas volumes required.

Comparison plots of gas and water rates, flowing pressures, and produced gas compositions, for one of the production wells are presented in Figure 7. This was a typical result for many of the wells. Several general comments can be made regarding the results:

- The predicted water production rates were generally close to the actual rates, particularly in later times. BP noted that earlier water production data was suspect, whereas the latter data was more reliable.

- The predicted producing pressures were consistently and significantly higher than the actual values. This phenomenon was also observed in a separate, independent study of the field[7]. Changes in coal permeability and/or wellbore skin factors were unable to materially reduce this discrepancy. The cause for the discrepancy remains unclear.

- The predicted to actual comparisons of produced gas composition matches were of variable quality. In some cases, the predicted onset of gas breakthrough was earlier or later than actual, and increased either too quickly or slowly than actually observed in the field. In other cases however (such as that shown), they were quite good.

A plot of actual to predicted bottomhole injection pressures for N_2 injector well #2 is provided in Figure 8. The predicted injection pressures are in reasonable agreement with the actual values, suggesting the permeability and skin estimates for the injector wells were within reason.

PERFORMANCE FORECASTS

In order to evaluate the long-term performance of the ECBM pilot, under status quo conditions (i.e., no further N_2 injection) as well as under other "what if" future injection scenarios, performance prediction cases were simulated using the history match result as the starting point. The specific cases evaluated included:

1. No N_2 injection (i.e., primary production only).
2. Current conditions (i.e., intermittent N_2 injection until January 2002, and not resuming).
3. Intermittent future N_2 injection.
4. Continuous future N_2 injection.

For each forecast case, an economic limit of 50 Mcfd of methane and 50% N_2 content per well was imposed; reaching those thresholds prompted the well in question to be shut-in in the model. A summary of the results for each case are presented in Table 2. Since the total model area was so large compared to the actual flooded areas, the incremental recovery results were examined on two individual patterns, A & B (Figure 9). Incremental pattern recoveries for the actual pilot (Case 2) were in the 10 - 20% range of original gas-in-place (OGIP). Long-term N_2 injection would have added another 25 – 40% of OGIP to the total recovery, with continuous future injection providing more recovery than intermittent future injection. Thus, the N_2-ECBM was quite effective in enhancing methane recovery at the Tiffany Unit.

ECONOMIC ASSESSMENT

The final element of the study was to evaluate the economic performance of both the actual pilot, as well as the future injection scenarios. The capital, operating and financial assumptions utilized are provided in Table 3. Note that all economics were performed on an incremental basis (i.e., only the incremental production and costs were considered). Further, the effect of Section 29 tax credits was not considered.

<u>Case 2 versus Case 1</u>

This analysis evaluated the performance of the existing pilot, with no future N_2 injection considered. Note that the capital costs for a cryogenic air separation plant are included. It should also be noted that gas processing costs ($0.50/Mcf) have been included to account for costly separation of N_2 from the produced methane. In actuality, due to the small volume of N_2 relative to the total amount of natural gas processed at BP's the Florida River facility, the high N_2 gas was merely blended into the total facility product stream and no costs were actually incurred for separation. We have accounted for these costs in this analysis however to reflect what would be a more common economic reality.

The results are presented in Figure 10. The ultimate net present value (NPV) assuming $2.20/Mcf (at the time) was ($2.9 million). The breakeven gas price was $2.42/Mcf and the breakeven N_2 cost was $0.15/Mcf. This indicates the pilot was uneconomic under the assumed conditions (not accounting for Section 29 tax credits). Having said that however, an alternative scenario is presented that is more representative of today's environment: a more realistic gas price of $4.00/Mcf. Under this assumption, the pilot would have yielded an NPV of over $20 million. Thus N_2-ECBM appears commercially viable today, at least for the conditions that exist at Tiffany.

<u>Cases 3 and 4 versus Case 2</u>

For these analyses, no capital costs were included; they were considered sunk. Further, a gas price of $4.00/Mcf was used to reflect current economic conditions. The results of these analyses are presented in Table 4. Both cases are highly attractive economically, providing NPV's of $30-40 million.

CONCLUSIONS

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

- The injection of N_2 at the Tiffany Unit has resulted in incremental methane recovery over estimated primary recovery. In the swept areas, an incremental methane recovery of approximately 10 - 20% of original-gas-in-place resulted from N_2-ECBM operations. Future N_2 injection was forecast to add another to 25 – 40% of original-gas-in-place to the total recovery.

- At the prevailing gas prices at the time the project was implemented (~$2.20/Mcf), and not considering any tax credit benefits, the pilot itself was uneconomic. However, with today's gas prices of ~$4.00/Mcf, N_2-ECBM appears economically attractive. The breakeven gas price for the conditions at Tiffany was estimated to be ~ $2.40/Mcf.

- Future N_2 injection at Tiffany, assuming a gas price of $4.00/Mcf was also forecast to be economic.

ACKNOWLEDGEMENTS

This work was funded by the U.S. Department of Energy, National Energy Technology Laboratory, contract number DE-FC26-00NT40924. The DOE Project Manager was Charlie Byrer. The authors also wish to acknowledge the valuable contribution of BP America, which provided all the data for the study, invaluable insights, and permission for the results to be published.

REFERENCES

1) Reeves, S. R.: "Geologic Sequestration of CO_2 in Deep, Unmineable Coalbeds: An Integrated Research and Commercial-Scale Field Demonstration Project", SPE 71749, presented at the SPE Annual Technical Conference and Exhibition, New Orleans, September 30-October 3, 2001.

2) Paul, G.W. and Young, G.B.C.: "Characterization of Fruitland Coal through Reservoir Simulation," GRI Topical Report GRI-92/0461, November, 1993.

3) Gasem, K.A.M., Robinson, R.L., and Reeves, S.R.: "Adsorption of Pure Methane, Nitrogen, and Carbon Dioxide and Their Mixtures on San Juan Basin Coal", Topical Report, DOE Contract No. DE-FC26-00NT40924, May, 2002.

4) Reeves, S. and Pekot, L.: "Advanced Reservoir Modeling in Desorption-Controlled Reservoirs," SPE 71090, presented at the SPE Rocky Mountain Petroleum Technology Conference, Keystone, May 21-23, 2001.

5) Sawyer, W.K., Paul, G.W., Schraufnagel, R.A.: "Development and Application of a 3D Coalbed Simulator," CIM/SPE 90-119, presented at the CIM/SPE International Technical Conference, Calgary, June 10-13, 1990.

6) Reeves, S.R., Oudinot, A.Y. and Erickson, D.: "The Tiffany Unit N_2 – ECBM Pilot: A Reservoir Modeling Study", Topical Report, DOE Contract No. DE-FC26-00NT40924, May, 2004.

7) Liang, J., Raterman, K. T., and Robertson, E. P.: "A Mechanistic Model for CO_2 Sequestration in Tiffany Coal Bed Methane Field", 2003 International Coalbed Methane Symposium, Tuscaloosa, AL, May 7-8, 2003.

Table 1: Basic Coal Reservoir Data, Tiffany Unit

Property	Value
Average Depth to Top Coal (B)	3040 feet
No. Coal Intervals	7 total (A, A2, B, C, D, E, F) 4 main (B, C, D, E)
Average Total Net Thickness	47 feet B – 13 ft C – 11 ft D – 9 ft E – 14 ft
Coal Rank	Medium Volatile Bituminous
Initial Pressure	1600 psi
Temperature	120°F

Table 2: Summary of Model Forecast Results

Description	**Case 1** No Injection	**Case 2** Actual N_2 Injection	**Case 3** Future Intermittent N_2 Injection	**Case 4** Future Continuous N_2 Injection
Incremental CH_4 (Bcf) *	n/a	22.3	26.8	36.1
Total N_2 Injected (Bcf)	n/a	15.0	51.4	86.0
Total N_2 Produced (Bcf)	< 0.1	6.1	25.0	40.0
Net N_2/CH_4 Ratio	n/a	0.4	0.4	0.9
Incremental Pattern A Recovery (%OGIP)*	n/a	21.1%	27.2%	37.5%
Incremental Pattern B Recovery (% OGIP)*	n/a	9.4%	25.6%	36.2%

* Incremental recovery for Case 2 is relative to Case 1.
Incremental recoveries for Cases 3 & 4 are relative to Case 2.

Table 3: Economic Analysis Assumptions

Capex	**Value**	**Assumptions**
Cryogenic Air Separation Plant (includes compression)	$ 7.5 million	$250,000/MMcfd of capacity, 30 MMcfd Capacity
Pipeline	$ 4.6 million	$24,000/in-mi, 16 mi, 12-inch line
Field Distribution:	$ 0.7 million	$20,000/in-mi, avg 0.5 mi/well, 6 in lines, 12 wells
Wells	$ 5.0 million	$500,000/ea, fully equipped
Total	***$ 17.8 million***	
Opex		
Injector Well Operating:	$500/mo	Only when active
N_2 Cost	$0.40/Mcf	
Produced Gas Processing	$0.50/Mcf	
Financial		
Gas Price(Case 2 vs Case 1):	$2.20/Mcf	Ex-Field
Gas Price (Cases 3 & 4 vs. Case 2)	$4.00/Mcf	Ex-Field
Net Revenue Interest:	87.5%	
Production Taxes:	8%	
Discount Rate:	12%	

Table 4: Summary of Economic Results, Cases 3 and 4 (Incremental vs. Case 2)

	Case 3	**Case 4**
Assumed Gas Price ($/Mcf)	$4.00	$4.00
Net Present Value ($ millions)	$32.0	$42.2
Breakeven Gas Price ($/Mcf)	$1.49	$1.59
Breakeven Injectant Cost ($/Mcf)	$2.12	$1.89

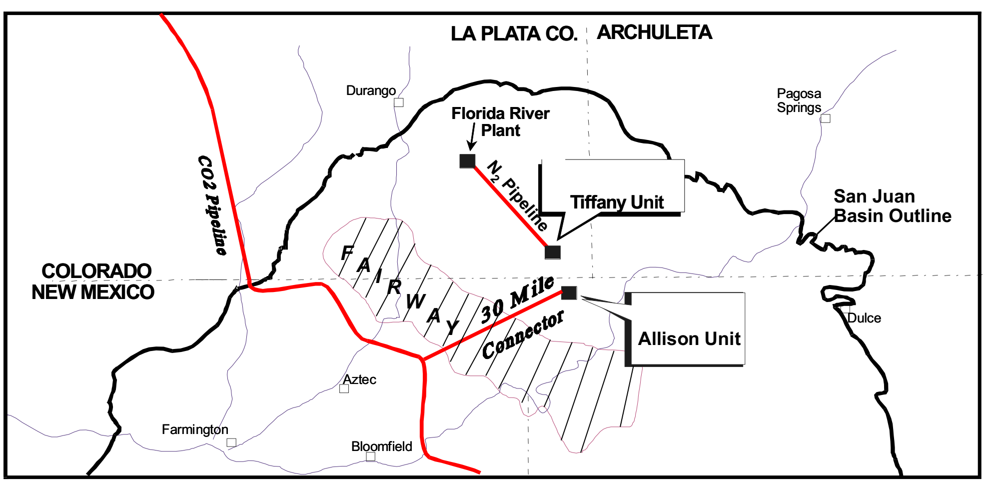

Figure 1: Location of the Tiffany Unit, San Juan Basin

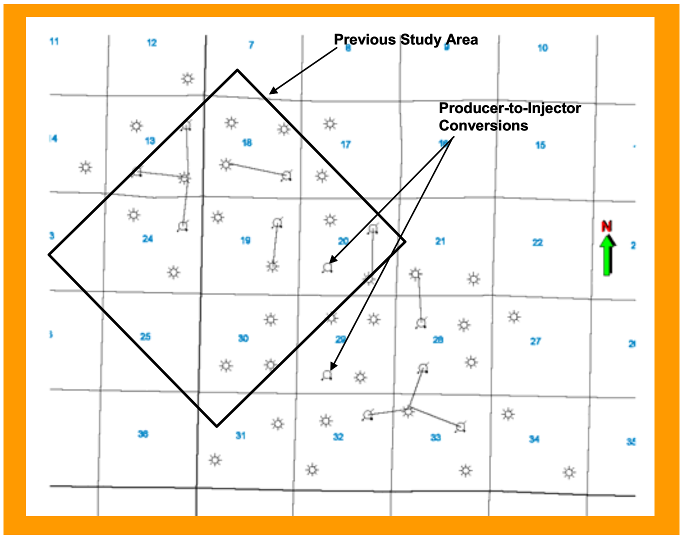

Figure 2: Producer/Injector Well Pattern, Tiffany Unit Study Area

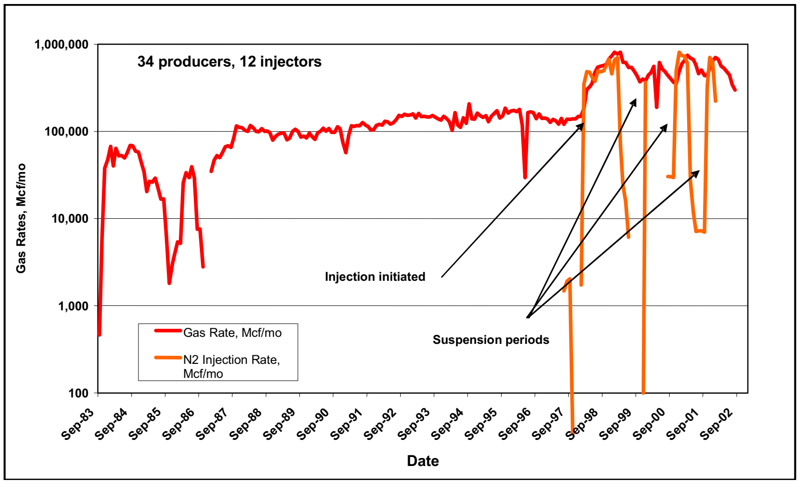

Figure 3: Producing History, Tiffany Unit Study Area

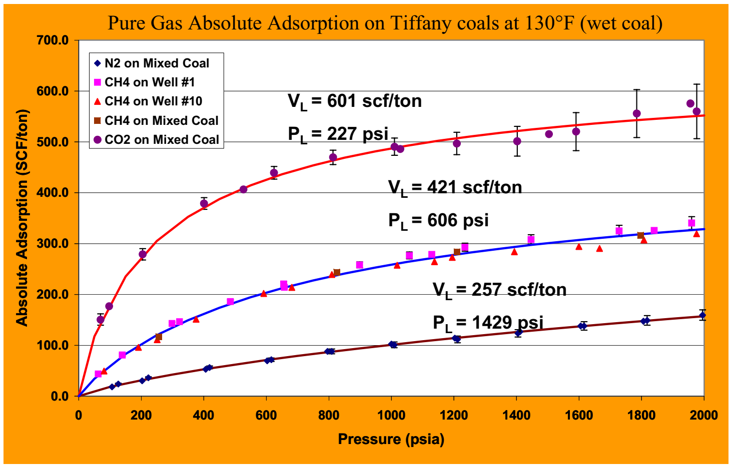

Figure 4: Carbon Dioxide, Methane and Nitrogen Isotherms for Tiffany Coal

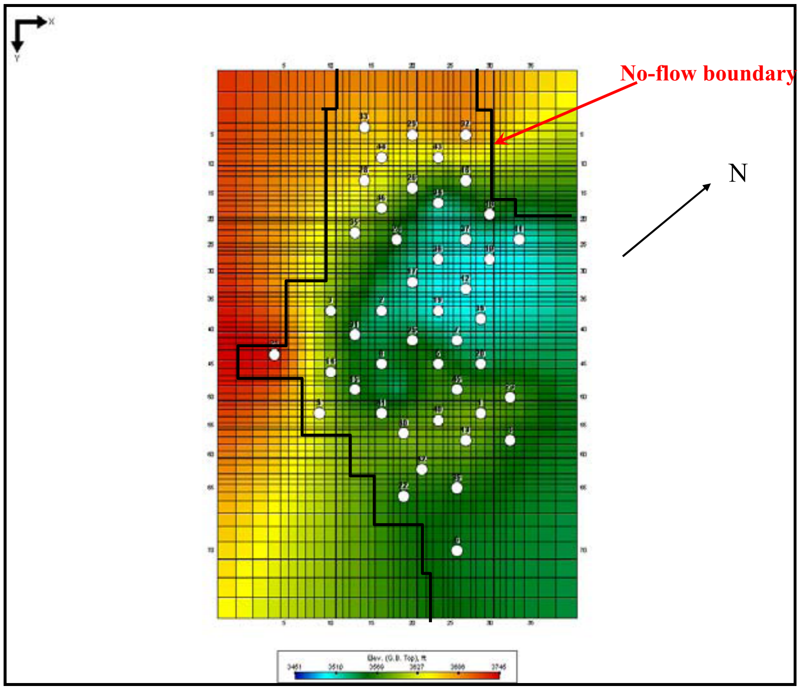

Figure 5: Map View of the Top Layer of the Simulation Model

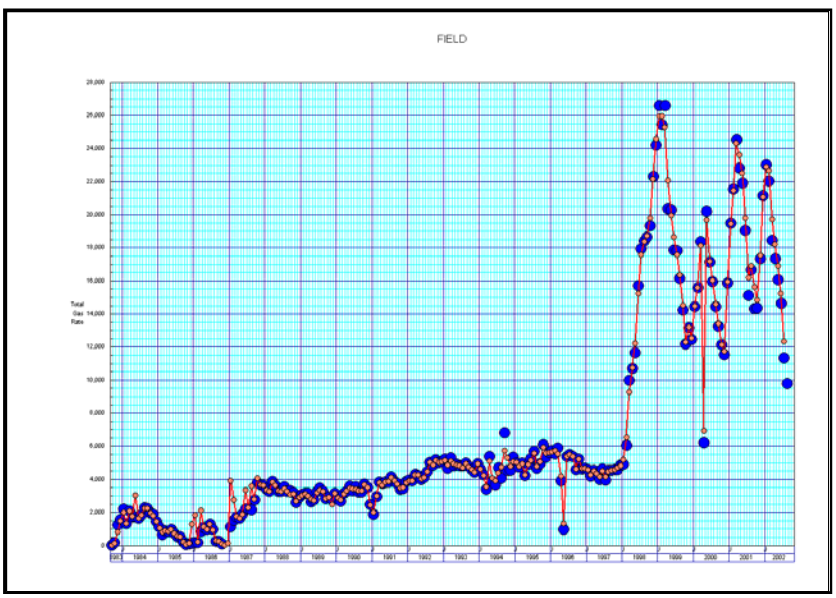

Figure 6: Actual versus Simulated Field Gas Rate, Tiffany

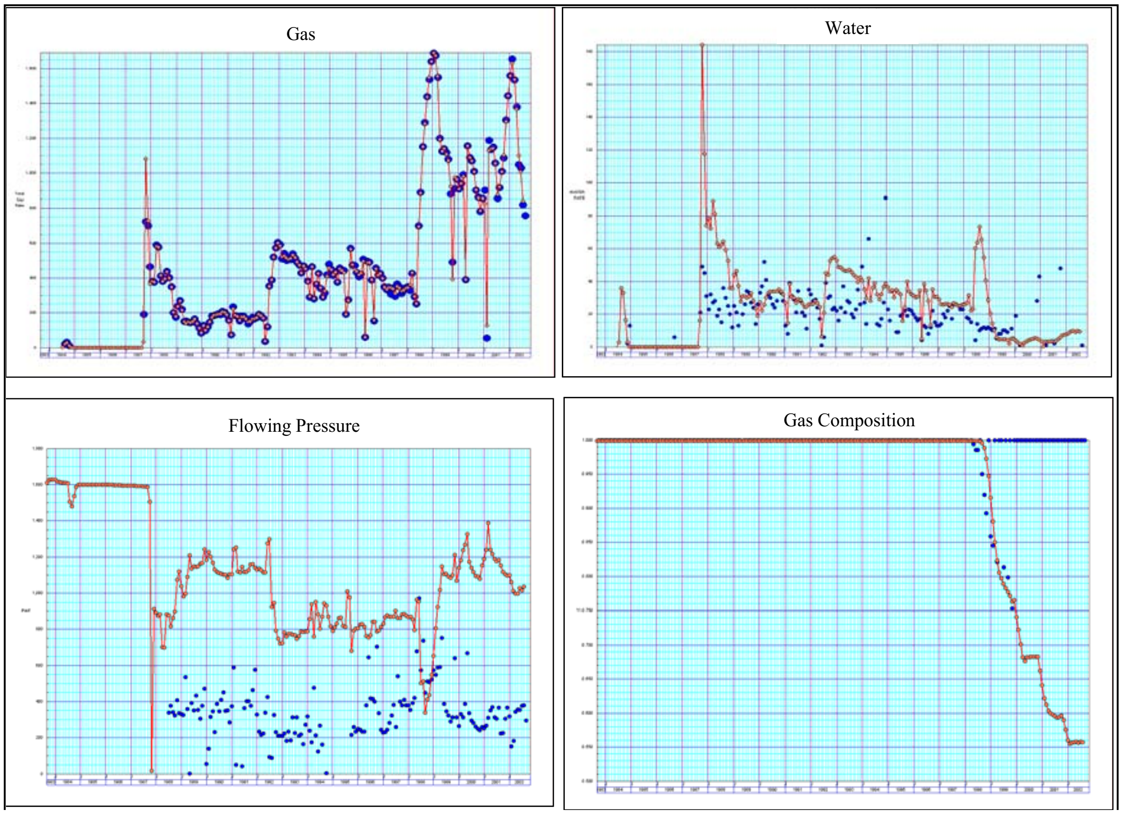

Figure 7: Comparison of Predicted to Actual Well Performance, Baird Gas Unit 18-01 No. 2

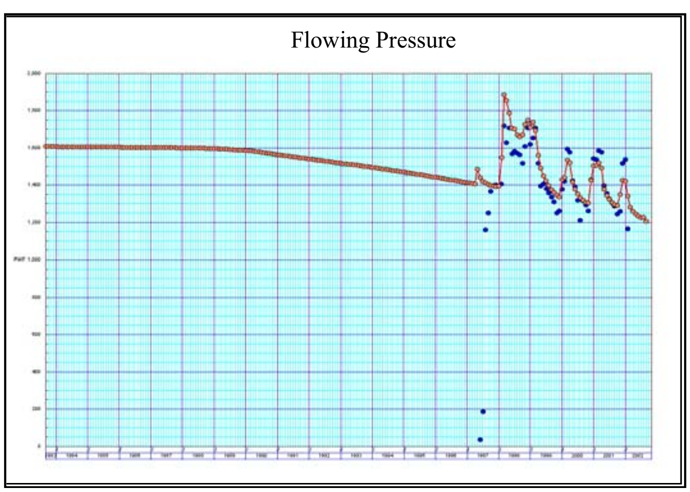

Figure 8: Comparison of Predicted to Actual Bottomhole Injection Pressures, Injection Well #2

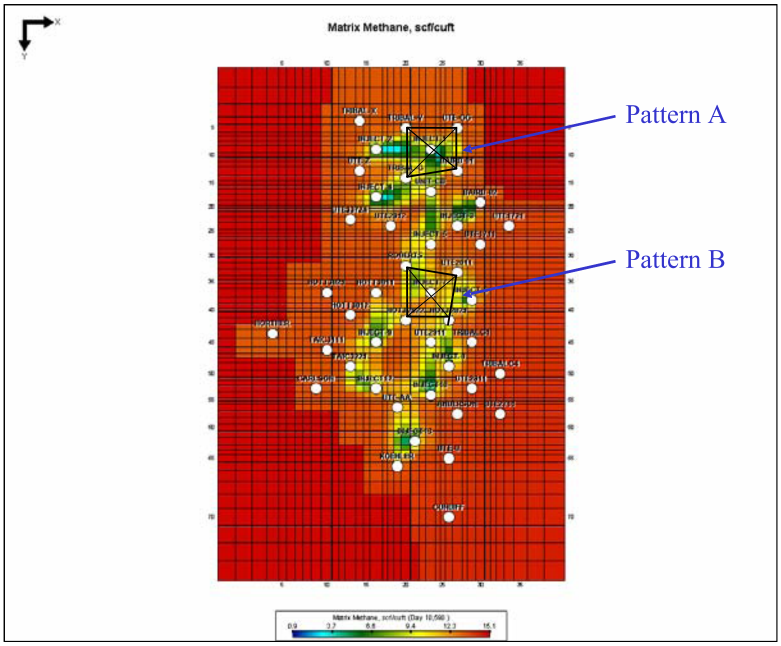

Figure 9: Locations of Patterns A & B, Tiffany Unit Study Area

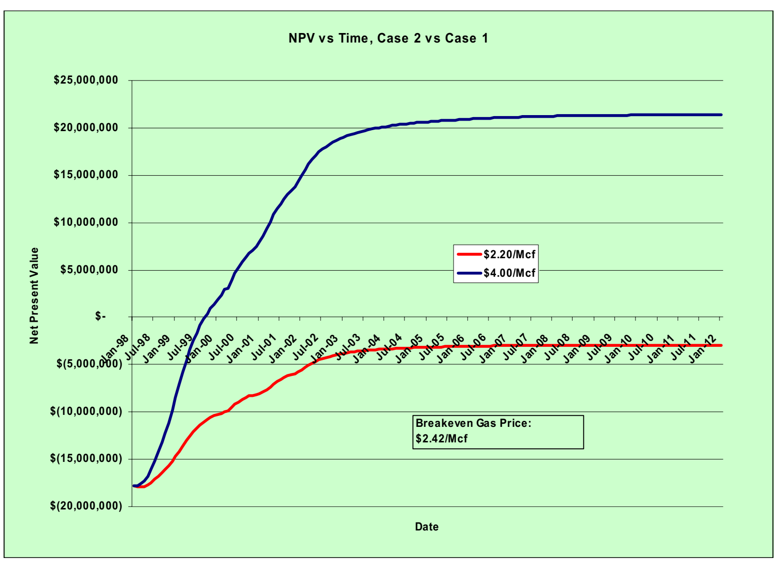

Figure 10: Economic Analysis Results, Case 2 versus Case 1