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AN INTEGRATED RESERVOIR CHARACTERIZATION, GEOSTATISTICAL ANALYSIS, OPTIMIZED HISTORY-MATCHING AND PERFORMANCE FORECASTING STUDY OF THE 9-SECTION, 30-WELL PUMP CANYON CO2-ECBM/SEQUESTRATION DEMONSTRATION SITE, SAN JUAN BASIN, NEW MEXICO

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ABSTRACT

The Pump Canyon CO_2-ECBM sequestration demonstration site, located in the northern New Mexico portion of the San Juan basin, is part of the Southwestern Regional Partnership for Carbon Sequestration sponsored by the United States Department of Energy. The objective of the project is to field-test the efficacy of CO_2 sequestration in deep, unmineable coalseams. In support of the demonstration, an integrated reservoir characterization, geostatistical analysis, optimized history-matching and performance forecasting study was performed. Based on available reservoir data such as coal depth and thickness, isotherms, initial pressure and cleat orientation, a three-layer, nine-section, 30-well reservoir simulation model was built. Production data revealed a high degree of reservoir heterogeneity. In order to account for this heterogeneity a geostatiscal approach based on a sequential Gaussian simulation algorithm was used to generate a permeability distribution. A loose correlation between permeability and porosity was applied. An automated history-matching procedure, an iterative technique utilizing a global optimizer and a fractured reservoir simulator, was utilized to match the production data in an unbiased, time-efficient manner. A total of thirteen input parameters, a combination of formation, relative permeability and well properties, were varied during the optimization process. A total of 125 simulator iterations requiring 8-days of unsupervised computing time was required to achieve the match. A performance forecast under CO_2-injection was then performed.

INTRODUCTION

The Southwestern Regional Partnership for Carbon Sequestration (SWP) is one of seven regional partnerships sponsored by the U.S. Department of Energy (DOE), that includes more than 350 organizations extending across 40 states, three Indian nations and four Canadian provinces. Their objective is to determine the most suitable technologies, regulations and infrastructure needs for carbon capture, storage and sequestration in different areas of the country. In the first phase of the program, significant sources of greenhouse gas emissions were inventoried, potential geological sequestration sinks identified, and small-scale sequestration demonstration opportunities developed. In the second phase of the program, which is currently underway, the small-scale geologic sequestration demonstration opportunities previously developed in Phase 1 are being implemented. One of the demonstration sites is the Pump Canyon site, which is investigating CO_2 injection into a deep unmineable coalbed located in the San Juan Basin of northern New Mexico[1]. To aid in the planning of that demonstration, a reservoir characterization and simulation study was used to match historical production from the Pump Canyon site, and then the potential performance of CO_2 injection was forecast.

SITE DESCRIPTION

The Pump Canyon CO_2-ECBM/Sequestration demonstration project is located in San Juan County, northern New Mexico, just within the high-permeability fairway of prolific coalbed methane production (Figure 1). The pilot area for CO_2 injection, and hence the study area for the SWP project, consists of 31 coalbed methane production wells located in a nine section area, Figure 2. Figure 2 also shows the anticipated injection well location, to be drilled in 2008, at the center of section 32, T31N, R8W. The location of the well was based on several considerations including, being within the fairway, its proximity to an existing CO_2 pipeline, as well as being among offset ConocoPhillips-operated production wells to streamline project decision-making and execution. Considerable geologic and reservoir data, such as logs, isotherm data, initial reservoir pressure, production and gas composition, are available for the area, primarily from ConocoPhillips. The Pump Canyon wells produce from three primary Fruitland Formation coal seams, the Upper coal (combination of Blue and P1), the Middle coal (P2 and G1) and the Basal coal (G2, G3, B1 and B2). A summary of basic coal depth, thickness, pressure, and temperature information is provided in Table 1.

RESERVOIR DESCRIPTION

Structure and isopach maps of each coal were constructed based on ConocoPhillips picks of tops and bottoms from logs. The maps were generated using geologic mapping software based on available data from 21 wells. An example structure map for the Upper coal is presented in Figure 3.

Sorption isotherms for both CH_4 and CO_2 were available from five wells in the vicinity of the demonstration. The Langmuir constants are summarized in Table 2. Due to the lack of information for a carbon dioxide isotherm for the Upper coal, estimations were made based on CH_4/CO_2 Langmuir ratios for the Middle and Basal coals. These data were then converted from a dry, ash-free basis into in-situ conditions and appropriate units (using coal density) for use in the reservoir simulator.

Initial reservoir pressure data measured in the late 1980's were available for four wells in the demonstration area. These data indicate an over-pressured reservoir, with an estimated initial pressure gradient in the 0.50-0.57 psi/ft range.

Cleat orientation was measured in the Northeast Blanco Unit #403 well, approximately seven miles to the east of the demonstration site. These data indicated a face-cleat orientation of N35E. The simulation grid was oriented in order to respect a higher permeability in that direction.

Bubble maps of cumulative gas and water production were generated and show highly variable gas and water production, uncorrelated to each other, which suggests that significant reservoir heterogeneity exists. In order to account for this heterogeneity, a geostatistical approach was employed for reservoir characterization purposes. Specifically, gas production was used as a loose proxy for coal permeability, and a geostatistical analysis was performed on this basis. The gas production parameter used was average gas production over the active well life ("production index"). A sequential Gaussian simulation algorithm was adopted for generating fifty (50) 2D realizations of the production index. At each grid block, the arithmetic average of the 50 different simulated values was selected as a central value for a final characterization of each parameter. Based on these central values, a definitive characterization was adopted for the index parameter. This index map was then multiplied by an average permeability to create a permeability map for use in reservoir simulation. The average permeability was a variable parameter during the history-matching process. The final index map is shown on Figure 4. Note the orientation on Figure 4 due to differences in software gridding orientation.

Porosity was assumed to be correlated with permeability. According to Schwerer and Pavone[2], permeability can be related to porosity in a fracture through Equation (1) where k and ϕ are permeability and porosity with the exponent n typically 3.0.

$$\frac{k}{k_i} = \left(\frac{\phi}{\phi_i}\right)^n \qquad (1)$$

Using this equation, porosity was correlated with permeability using Equation (2) where the factor 'a' was allowed to vary during the history-matching process.

$$\phi = a * k^{0.3333} \quad (2)$$

MODEL CONSTRUCTION

The reservoir simulator used for the study was the Advanced Resources International COMET3 (binary isotherm – CH_4 and CO_2) model. Details on the model theory are provided in the references[3,4].

A three-layer (Upper, Middle and Basal), nine-section (section 32 plus the eight surrounding sections) model was constructed to perform the simulation study. The coal structure and thickness information for each layer was directly input per the maps generated. As mentioned earlier, the simulation grid was oriented in order to respect a face-cleat orientation of N35E. A map view of the bottom layer is presented in Figure 5.

The model gridblock dimensions were 57 x 56 x 3 (9,576 total grid blocks, 3,972 of which were active). The nine sections of the model were isolated using no-flow barriers to account for producing wells immediately adjacent to these portions of the study area. Understanding the impact of imperfect boundary conditions, history-matching efforts were focused on the central portion of the model.

HISTORY MATCHING

A computer-assisted procedure was used to facilitate the history-match of the Pump Canyon demonstration site. This procedure is an iterative technique utilizing two software programs: a global optimizer (*ClearVu*) and a fractured reservoir simulator (*COMET3)*.

During the history-match process, the simulations were run with the wells producing on gas rate, while matching gas rate, gas composition and bottomhole pressure (when available), as well as the field average reservoir pressure. Inaccurate water data were not matched. Tables 3 and 4 show the list of the parameters that were kept constant during the simulation and the list of the parameters that were varied respectively, as well as their ranges.

Figure 6 shows the total error function reduction during the optimization process and the evolution and convergence of one of the variables (absolute average permeability). It can be noticed that, even though 250 simulations were run, only about 125 were necessary to obtain convergence. Considering that each run required approximately 1.5 hours, only eight unsupervised days of simulation were needed to obtain a reasonable history-match.

Figures 7 to 9 illustrate the history match results for the three wells (section 32), EPNG Com A 300, EPNG Com A 300S and FC State Com 1. In general, the results were quite good. Of note however is that the gas production rate at the FC State Com 1 well could not be matched. The well produces considerably more gas in later times than can be accounted for in the model. Actual versus simulated cumulative gas and water productions are summarized for the three offset wells in Table 5. They clearly show that more water than reported is being produced.

Table 6 provides the optimized parameters from the history-match. Of note is that an average permeability of 549 md was indicated, with an anisotropy of 1.8. Average porosity was 1.6%.

Overall, the results from the history match were satisfactory, the gas rate at FC State Com 1 notwithstanding. Even the late water production data were matched reasonably well, though these data were not matched during the optimization process (water production data are not reliable). It should be noted that the gas production data were not matched well along the northern border of the nine-section demonstration area, which seems to confirm the hypothesis that gas could be migrating into the pattern area from the north-northeast (whereas no-flow boundaries were assumed).

CO_2 INJECTION FORECAST

In order to evaluate the impact of CO_2 injection on the offset wells (mainly on well EPNG Com A 300 where CO_2 breakthrough is believed most likely due to it's close proximity in the face-cleat direction), CO_2 injection was simulated. The wells were kept on production after the end of the history-match period (November 2006), under bottomhole pressure control (corresponding to the latest value of the bottomhole pressure from the history-match for each well, which ranged from 45 to 47 psi). (Note however that the last bottomhole pressure for the FC State Com 1 well history-match was 5 psi in an attempt to match the observed gas rate. This was increased to 45 psi for the forecast period to better reflect on-the-ground reality, but did cause an anomaly in production when transitioning from the history-match to the forecast.)

Injection was initiated in July 2008, injecting into the three coals with an injection rate of 2000 Mcf/d. A maximum bottomhole pressure limit of 1,800 psi (~0.6 psi/ft) was imposed. The injection was ceased after one year per the program plan and the producing wells remained open for an additional 10 years. Figure 10 shows that a constant injection rate of 2,000 Mcf/d can be achieved without reaching the limit bottomhole pressure and a total of 730 MMcf is injected, Figure 11.

Figure 12 illustrates the methane production rate for each offset well for the injection case compared to the non-injection case. Figure 13 illustrates the methane mole fraction in the three offset wells for this injection case compared to a non-injection scenario. It can be noticed that a rise in CO_2 content occurs in the EPNG Com A 300 well, due to its alignment with the injector in the face cleat direction. There is also a predicted increase in CO_2 content at the FC State Com 1 well under this injection scenario.

Finally, Figure 14 shows the CO_2 content in the Basal coal at the end of the simulation, where the breakthrough can be noticed in EPNG Com A 300 as well as in FC State Com 1.

FINAL REMARKS

A reservoir characterization of the Pump Canyon CO_2-ECBM/sequestration demonstration project area has been developed based upon existing data that incorporates the geologic structure and thickness of the three primary coalseams, methane and carbon dioxide storage capacities, initial reservoir pressures, and cleating orientation.

A geostatistical representation of coalseam permeability and porosity has been developed based upon well performance data to reproduce geological heterogeneities. Pressure transient analysis could be conducted to validate the permeability map.

A computer-assisted procedure was utilized to successfully achieve a history-match of individual well production in the demonstration area. Results of that match indicated an average permeability of 549 md, an average porosity of 1.6% that was correlated to permeability, and a permeability anisotropy of 1.8.

CO_2 injection forecast was performed and indicated incremental methane recovery volumes in the order of 100 MMcf with some increase in CO_2 content of the produced gas in at least two offset wells predicted.

ACKNOWLEDGEMENTS

The authors acknowledge the Southwest Partnership for Carbon Sequestration and the U.S. Department of Energy as the sponsors of this work. We also acknowledge ConocoPhillips as the operator of the site and for their valuable input and assistance, and the valuable contribution of Kinder Morgan CO_2 who are providing the CO_2 and considerable cost-sharing to the project. Finally, we acknowledge NuTech Solutions for their provision of their ClearVu optimizer to perform the history-matching.

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

4. Paul, G. W., Sawyer, W. K., and Dean, R. H.; "Validation 3D Coalbed Simulators", SPE 20733, presented at SPE Annual Technical Conference and Exhibition, Houston, TX, September 23-26, 1990.

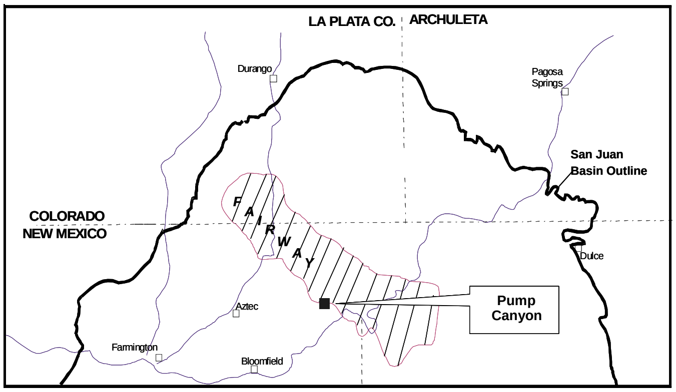

Figure 1: Location of the Pump Canyon Demonstration Site, San Juan Basin

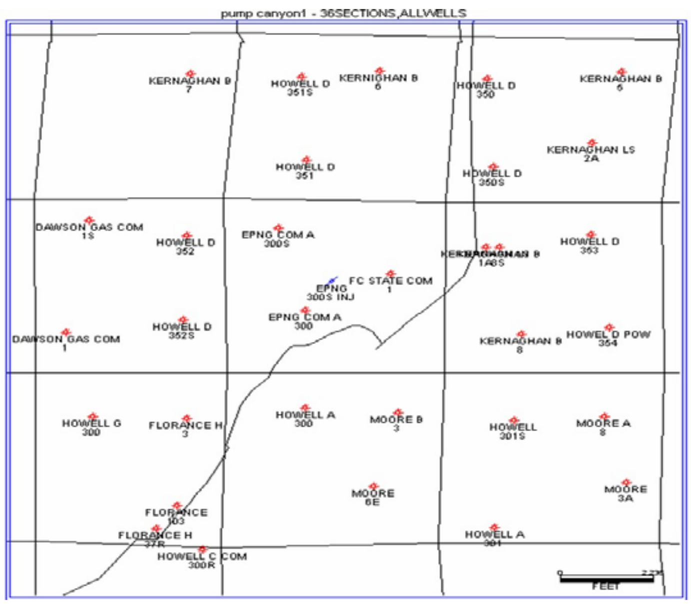

Figure 2: Pump Canyon Demonstration Area Base Map

Table 1: Pump Canyon Basic Coal Reservoir Data

Property	Value
Average Depth to Top Coal	3,012 feet
Average Total Net Thickness	60 feet Upper Coal: 16 feet Middle Coal: 15 feet Basal Coal: 29 feet
Initial Pressure	1500 psi @ 3600 ft above sea level
Temperature	126^{o}F

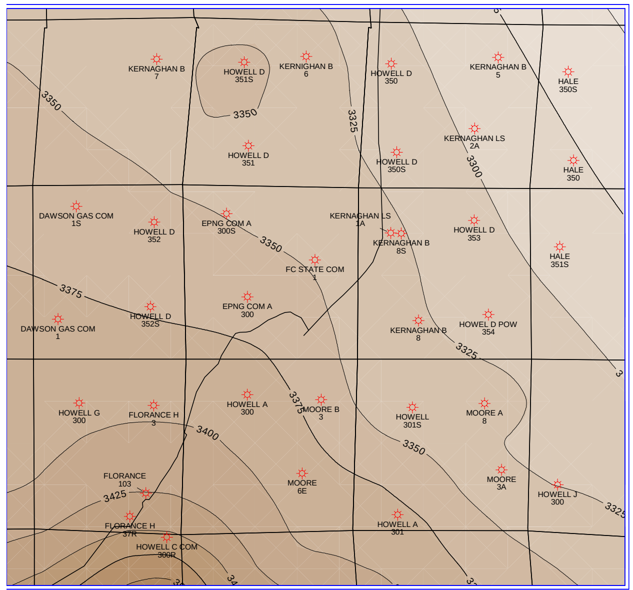

Figure 3: Structure Map, Upper Coal (units in feet above sea level)

Table 2: Langmuir Isotherm Constants

Coal	Methane*		Carbon Dioxide*	
	V_L (scf/ton)	P_L (psia)	V_L (scf/ton)	P_L (psia)
Upper	596 – 766	420 – 672	1234+	317+
Middle	563 - 851	404 – 807	1244	260
Lower	562 – 890	418 – 621	1274 – 1506	253 - 490

*dry, ash-free basis
+ computed based upon CO_2/CH_4 Langmuir constant ratios for middle and lower coals

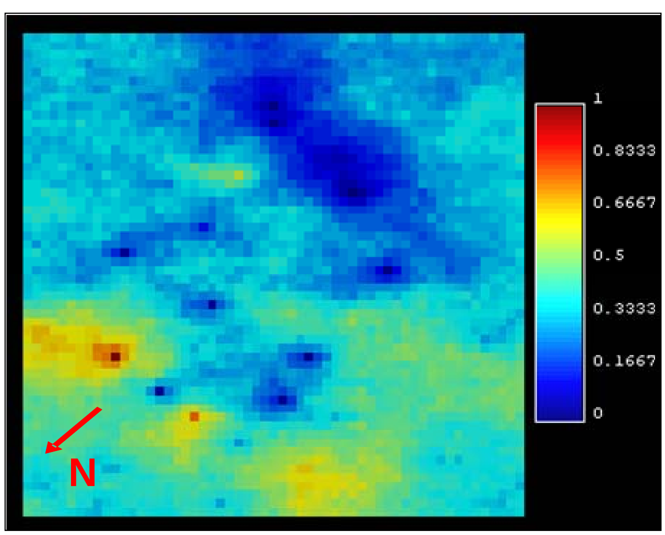

Figure 4: Final Permeability Index Characterization

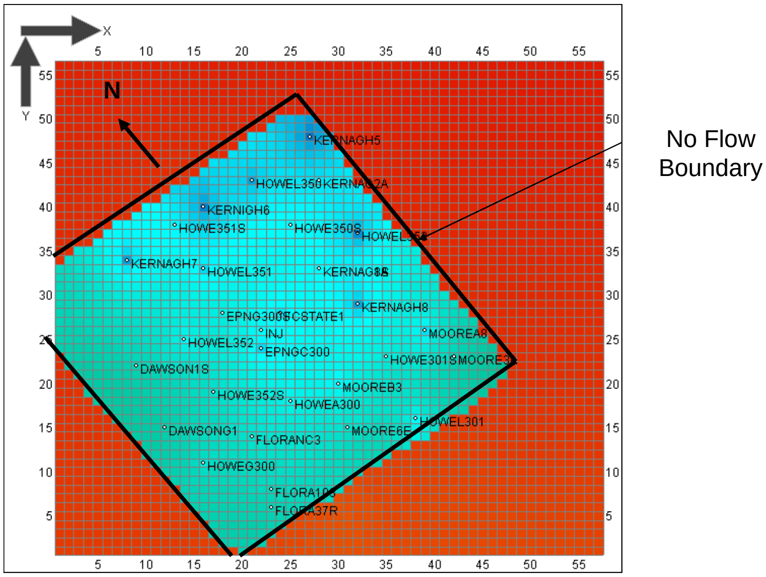

Figure 5: Map View of the Bottom Simulation Layer

Table 3: History-Match Fixed Parameters

Parameters	Units	Value
Formation Properties		
Vertical Permeability	mD	0.0001
In-situ CH4 Langmuir Volume, Layer 1	scf/ton	447
In-situ CH4 Langmuir Volume, Layer 2	scf/ton	436
In-situ CH4 Langmuir Volume, Layer 3	scf/ton	542
CH4 Langmuir Pressure, Layer 1	psi	546
CH4 Langmuir Pressure, Layer 2	psi	606
CH4 Langmuir Pressure, Layer 3	psi	520
Sorption Time, CH4	days	1
In-situ CO2 Langmuir Volume, Layer 1	scf/ton	809
In-situ CO2 Langmuir Volume, Layer 2	scf/ton	766
In-situ CO2 Langmuir Volume, Layer 3	scf/ton	1038
CO2 Langmuir Pressure, Layer 1	psi	317
CO2 Langmuir Pressure, Layer 2	psi	260
CO2 Langmuir Pressure, Layer 3	psi	372
Sorption Time, CO2	days	1
Differential Swelling Factor	-	1.5
Permeability Exponent	-	3
Relative Permeability Relationships		
Maximum Krw	-	1
Irreducible Gas Saturation	-	0

Table 4: History-Match Variables and Ranges

Parameters	Units	Min	Max
Formation Properties			
Porosity Factor a	-	0.001	0.0045
Initial Water Saturation	fraction	0.75	1
Average Absolute Permeability	mD	10	1000
Permeability Anisotropy	fraction	1	5
Pore Compressibility	1/psi	1.00E-05	6.00E-04
Matrix Compressibility	1/psi	1.00E-07	5.00E-06
CO2 Content	fraction	0.01	0.25
Relative Permeability Relationships			
Irreducible Water Saturation	-	0.05	0.4
Maximum Krg	-	0.65	0.95
Krw Exponent	-	1	3
Krg Exponent	-	1	3
Well Parameters			
Initial Skin	-	-1	2
Stimulated Skin	-	-5	0

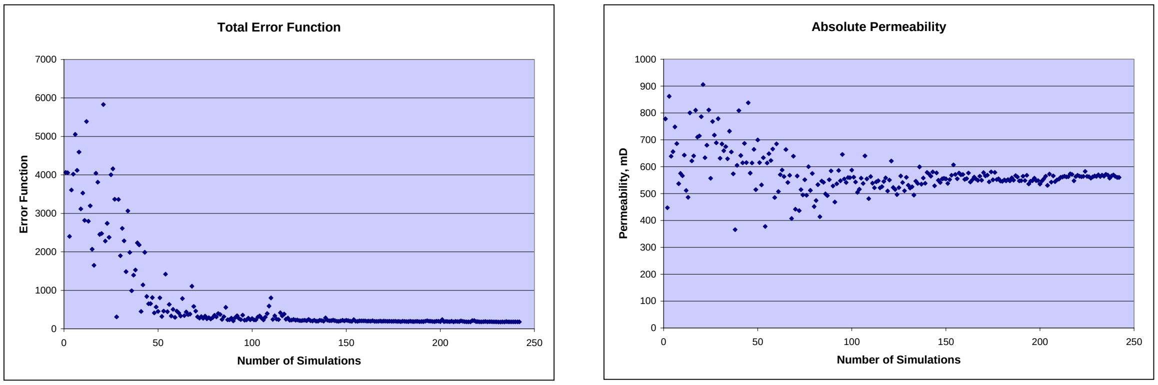

Figure 6: Total Error Function and Absolute Permeability Convergence Plot

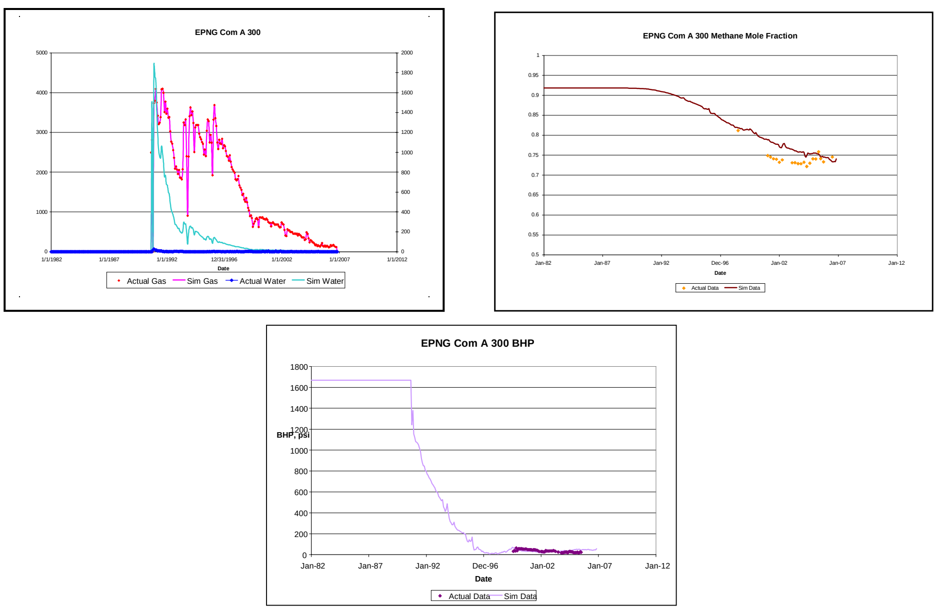

Figure 7: Well EPNG Com A 300 History-Match Results

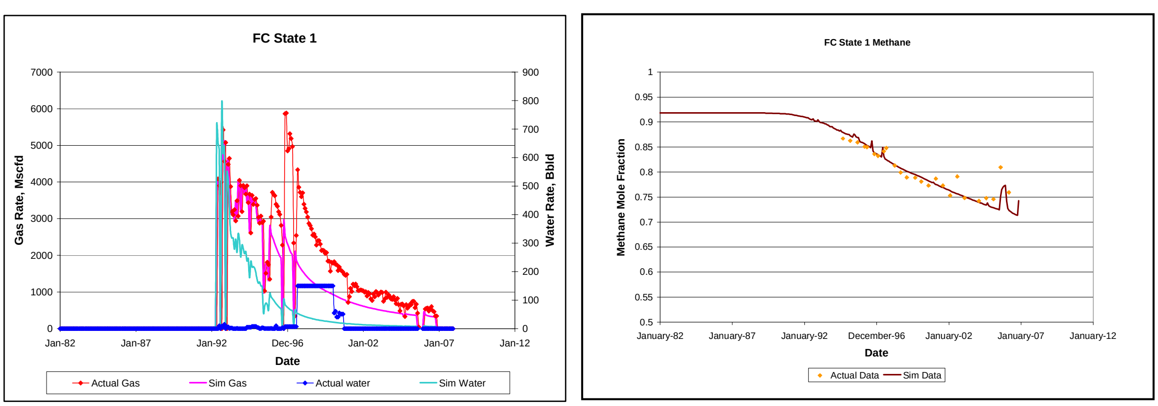

Figure 8: Well FC State Com 1 History-Match Results

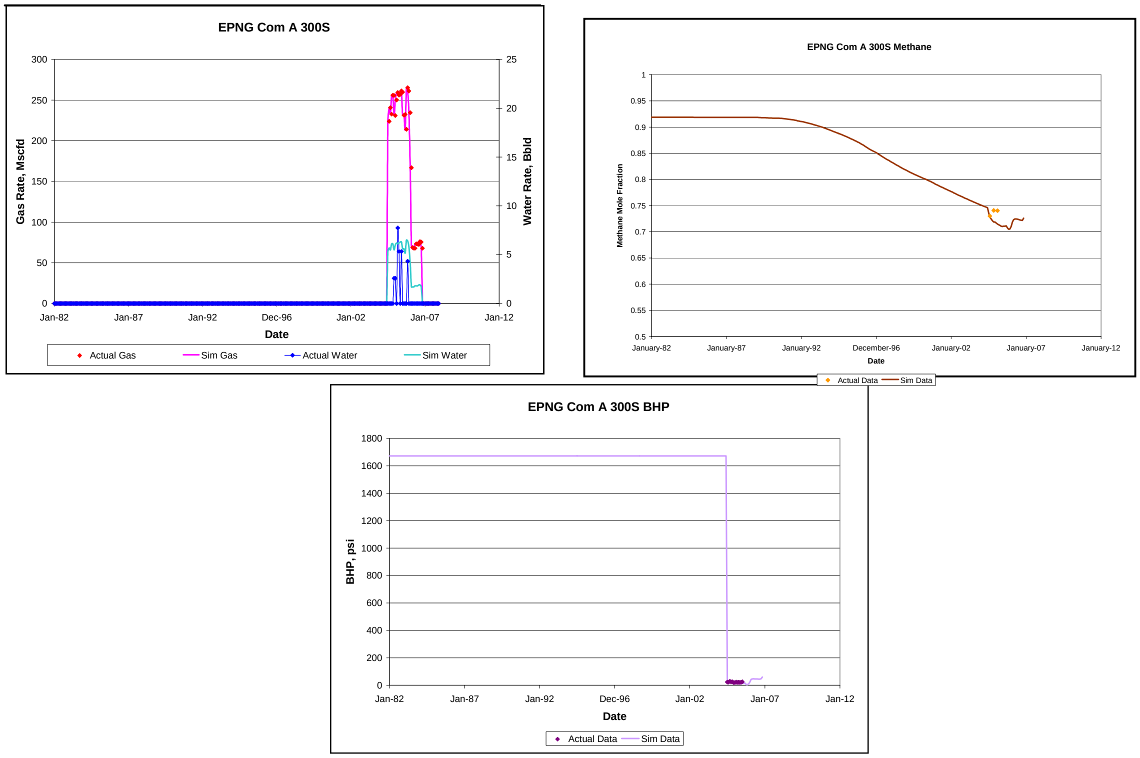

Figure 9: Well EPNG Com A 300S History-Match Results

Table 5: Actual versus Simulated Cumulative Production for the Three Offset Wells

	Actual		Simulated	
	Cum Gas (Mscf)	Cum Water (Bbls)	Cum Gas (Mscf)	Cum Water (Bbls)
EPNG COM A 300S	153,754	850	153,754	3,899
EPNG COM A 300	9,314,614	9,899	9,314,614	994,768
FC STATE COM 1	10,739,371	147,581	7,874,300	485,459

Table 6: Optimized Parameters

Parameters	Units	Min	Max	Optimized
Formation Properties				
Porosity Factor a	-	0.001	0.0045	0.002
Initial Water Saturation	fraction	0.75	1	0.94
Average Absolute Permeability	mD	10	1000	549
Permeability Anisotropy	fraction	1	5	1.8
Pore Compressibility	1/psi	1.00E-05	6.00E-04	3.86E-04
Matrix Compressibility	1/psi	1.00E-07	5.00E-06	3.54E-06
CO2 Content	fraction	0.01	0.25	0.08
Relative Permeability Relationships				
Irreducible Water Saturation	-	0.05	0.4	0.26
Maximum Krg	-	0.65	0.95	0.75
Krw Exponent	-	1	3	2.7
Krg Exponent	-	1	3	2.7
Well Parameters				
Initial Skin	-	-1	2	1.1
Stimulated Skin	-	-5	0	-1.9

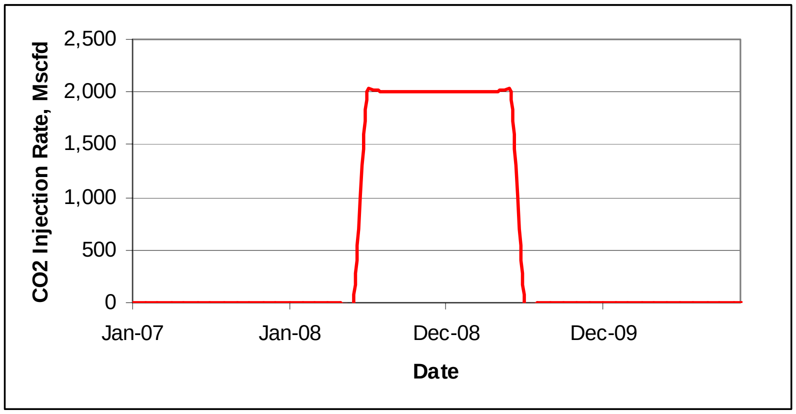

Figure 10: Injection Rate Profile

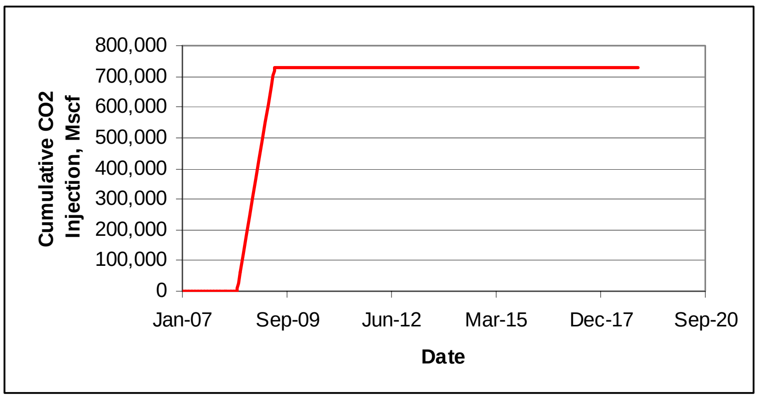

Figure 11: Cumulative CO_2 Injection

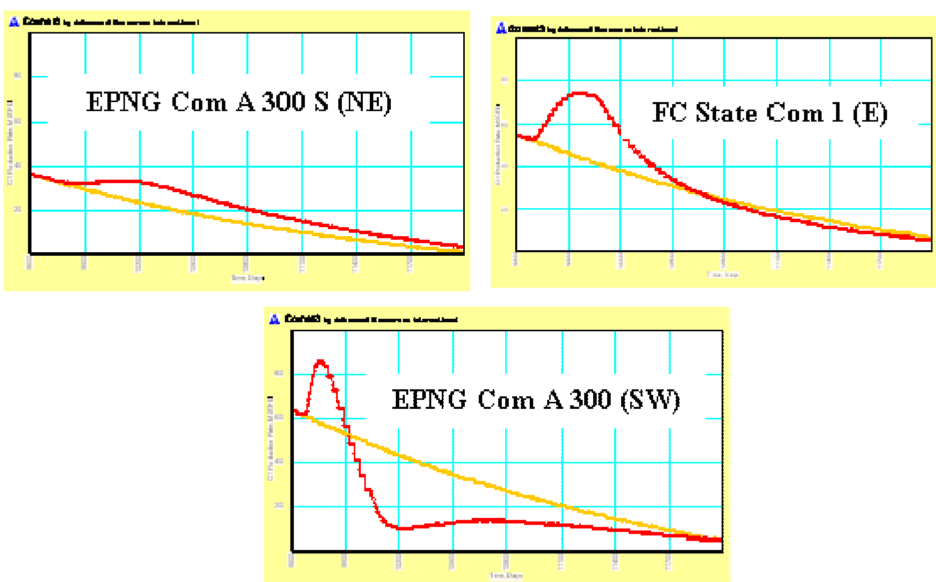

Figure 12: Offset Wells Methane Production Rate

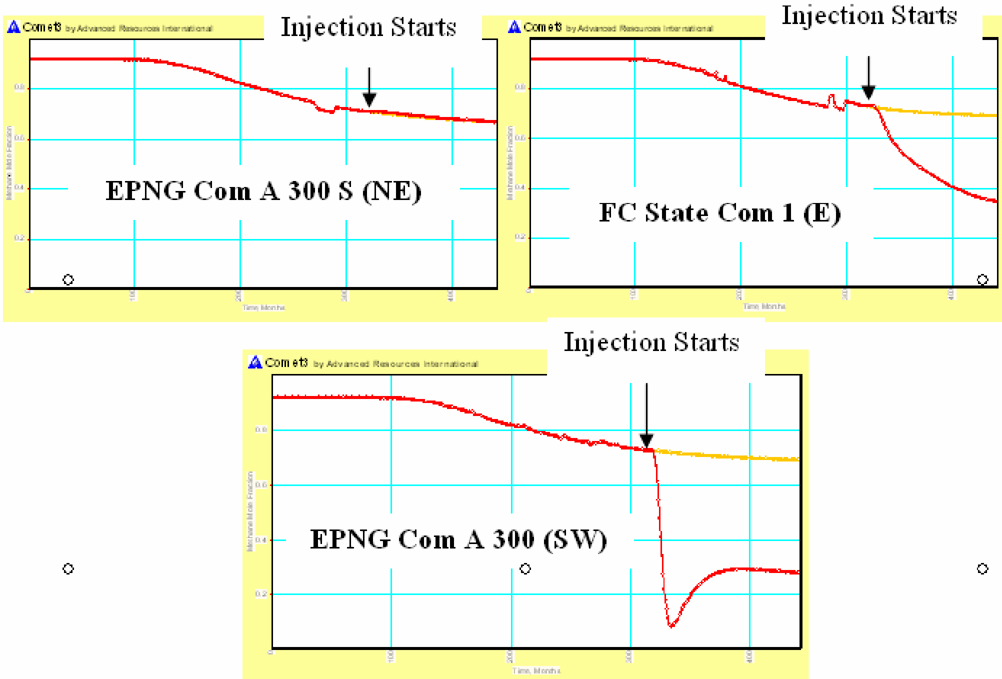

Figure 13: Methane Mole Fraction in Offset Wells

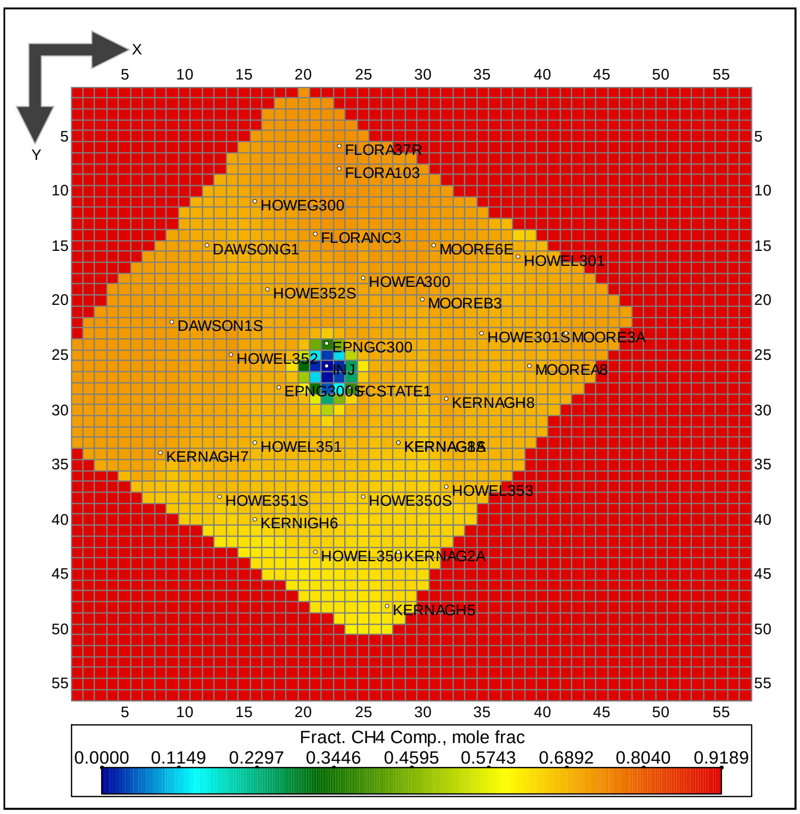

Figure 14: CH_4 Content in Basal Coal at End of Simulation (December 2018)