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Reservoir Characterization of the Broom Creek Formation For Carbon Dioxide Sequestration

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RESERVOIR CHARACTERIZATION

OF THE BROOM CREEK

FORMATION FOR CARBON

DIOXIDE SEQUESTRATION

Prepared by:

Justin J. Kringstad

As a Geological Engineering Design Project

Geology & Geological Engineering Department
University of North Dakota

May 2007

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ACKNOWLEDGMENTS

I would like to offer a most sincere thank you to the group of people who made this senior design possible. First, to my design advisor, Dr. Zheng-Wen Zeng of the Geology and Geological Engineering Department, University of North Dakota, for getting me started in the department's Petroleum Engineering Laboratory and pushing me to a level of academic performance that would have otherwise been unknown.

Next, I would like to thank the Plains CO_2 Reduction Partnership (PCOR) at the Energy and Environmental Research Center (EERC). The PCOR team, in particular Steven A. Smith, Dr. Anastasia A. Dobroskok, James A. Sorensen, and Wesley D. Peck, played a vital role in providing me with data, reports, and feedback throughout all stages of my senior design. The PCOR team is one of the world's leading research groups working on CO_2 sequestration, and I am very proud to have had the opportunity to work so closely with them.

EXECUTIVE SUMMARY

This engineering design is aimed at providing a thorough investigation on the potential of carbon dioxide (CO_2) sequestration in the Williston Basin's Broom Creek Formation. The objective of the design is to characterize the Broom Creek's reservoir properties and provide detailed results of CO_2 sequestration capacity, plume migration, and safety level. The methodology used to obtain results is an incorporation of geology, reservoir engineering, and injection operations. The reservoir simulation operations were conducted using Schlumberger's ECLIPSE (Schlumberger, 2006).

INTRODUCTION AND OBJECTIVES

Since the beginning of the industrial revolution, the concentration of CO_2 in Earth's atmosphere has been continually rising. This rise in CO_2 concentration can be partly attributed to the combustion of fossil fuels for energy production. Scientists strongly believe that concentrations of CO_2 in the atmosphere are directly related to a pattern of global warming (Bennaceur et al., 2004). However, the industrialized nations of the world are dependent on fossil fuels to meet their energy and industrial needs economically.

Due to their relative abundance and low cost, fossil fuels, such as coal, oil, and natural gas, will continue to dominate the United States' energy supply in the foreseeable future. In order to limit the adverse effects on Earth's climate, methods must be implemented to eliminate most or all of the CO_2 emissions associated with using fossil fuels.

There exist two types of sequestration techniques: indirect and direct (EERC, 2006). Indirect sequestration involves capturing previously released CO_2 from the atmosphere by means of plants and soil (EERC, 2006). Direct sequestration involves the capture and long-term storage of CO_2 in a safe and secured location. Four main methods of direct sequestration include deep ocean sequestration, geologic storage in oil and gas reservoirs, sequestration in uneconomic coal seams, and hydrodynamic trapping in deep saline aquifers (DOE, 1999).

The state of North Dakota, located in north central United States, contains a great wealth of both coal and petroleum. The Williston Basin (Figure 1), located mainly in northwest North Dakota, is rich in hydrocarbons and has potentially many well suited locations for geologic sequestration of CO_2. The basin is full of potential CO_2 enhanced oil recovery (EOR) projects, uneconomic coal seams, abandoned oil fields, and deep saline aquifers. If North Dakota is to continue its usage and production of fossil fuels, it will need to develop capture and storage techniques of CO_2 in one or more of the previously mentioned media.

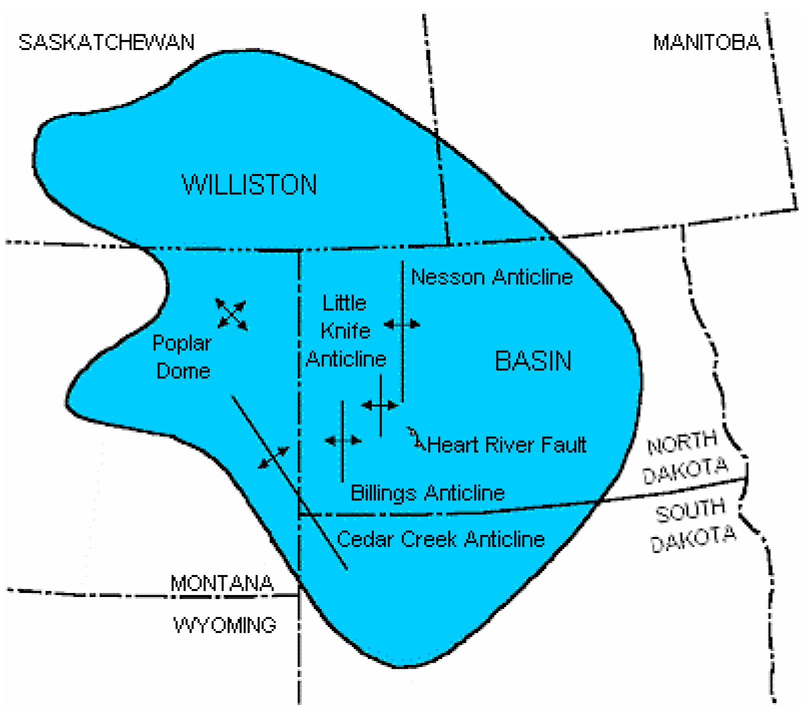

Figure 1. Location of the Williston Basin and major geologic structures (Heck et al., 2006).

One emerging technology could drastically change the way North Dakota and the United States produce and consume energy. The technology is known as “Clean Coal” or “Zero Emissions Coal.” The United States Department of Energy (DOE) has started a zero emissions coal project called FutureGen. FutureGen utilizes coal gasification for electricity and hydrogen production, while capturing and sequestering the waste CO_2 in a safe geologic location (DOE, 2006).

The objective of this engineering design is to evaluate the Broom Creek Formation (Permian) for its effectiveness as a long-term storage location for CO_2 sequestration. The location of the study will take place in Bowman County, North Dakota (Figure 2). The design utilizes state-of-the-art reservoir simulation models to determine CO_2 storage capacities, reservoir characteristics, and safe rates of CO_2 injection.

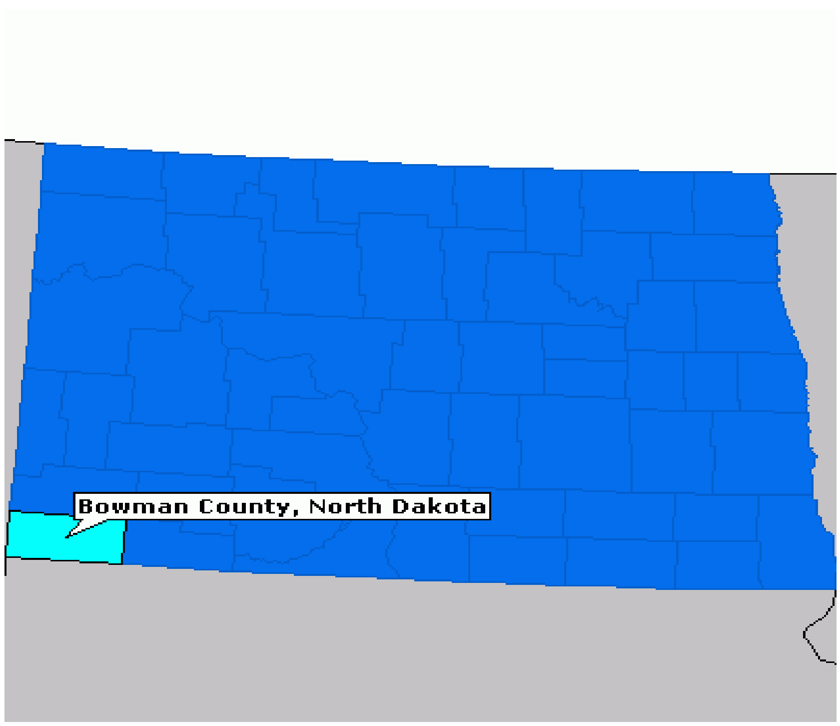

Figure 2. Location of Bowman County in southwest North Dakota (www.epodunk.com).

PROBLEM DEFINITION

The CO_2 emissions from United States power plants are largely unregulated. Scientists, environmentalists, and politicians alike would like to formulate a safe and secure system of eliminating the waste CO_2. DOE has a $1 billion dollar FutureGen project started, aiming at creating the world's first CO_2 emission free fossil fuel power plant. In 2006, The Plains CO_2 Reduction (PCOR) Partnership, a program at the Energy and Environmental Research Center (EERC) of the University of North Dakota in Grand Forks, proposed a location for the construction of a FutureGen site in Bowman County, North Dakota (State of ND, 2006). During the final stages of site selection, DOE decided not to chose the Bowman County site for its prototype power plant.

Despite DOE's final location decision, it is necessary for North Dakota's energy producers to establish possible locations for future CO_2 sequestration of power plant emissions. The site in Bowman County, proposed by PCOR's Team North Dakota, can be seen in Figure 3 (State of ND, 2006). The CO_2 sequestration, as proposed by the PCOR team, would take place in the saline aquifer found in the Broom Creek Formation (Permian).

Figure 3. State of North Dakota proposed CO_2 injection site (Google Earth image).

PRELIMINARY ANALYSIS

The Broom Creek Formation exists as the upper unit of the Minnelusa Group and extends throughout much of southwest North Dakota (Rygh, 1990). The Broom Creek (Figure 4), is composed of reddish-brown to pink quartzarenite, with some thin beds of dolostone (Rygh, 1990). Unconformably overlying the Broom Creek is the Opeche Formation (Permian). The Opeche Formation consists of thick shale beds, averaging 113 feet in the design region, extending throughout much of southwest North Dakota and the Williston Basin (State of ND, 2006). The saline aquifer targeted for the CO_2 sequestration is confined by the overlying Opeche and the underlying Amsden and Tyler Formations (Rygh, 1990). The Broom Creek aquifer makes an excellent candidate for CO_2 injection due to its high porosity and permeability, wide lateral extent, good seals on top and bottom, and its distance from any significant faults (State of ND, 2006). Rygh (1990) gave further testimony to the formation's sealing competency by describing the large nitrogen accumulations found throughout the Broom Creek Formation.

Figure 4. Broom Creek Sandstone (www.dmr.nd.gov/oilgas/feeservice/getscoutticket.asp)

In the proposed injection region, the depth to the top of the Broom Creek Formation ranges from 5,600 to 6,600 feet (State of ND, 2006). The average thickness of the Broom Creek in the study region is 150 feet. Figure 4 is a three dimensional image created in ECLIPSE's GridSim application. Figure 4 is a thirteen mile wide by eight mile long block surrounding the proposed injection site. The Opeche Formation is the top layer, the Broom Creek Formation is the middle layer, and the Amsden Formation is the lower layer. The view is from the southwest direction with the depths indicated by the colors shown on the key. The three surrounding wells were used to construct the geological model. As shown by elevation in Figure 5, the Broom Creek Formation dips slightly to the northwest at an angle of approximately 0.35 degrees (State of ND, 2006).

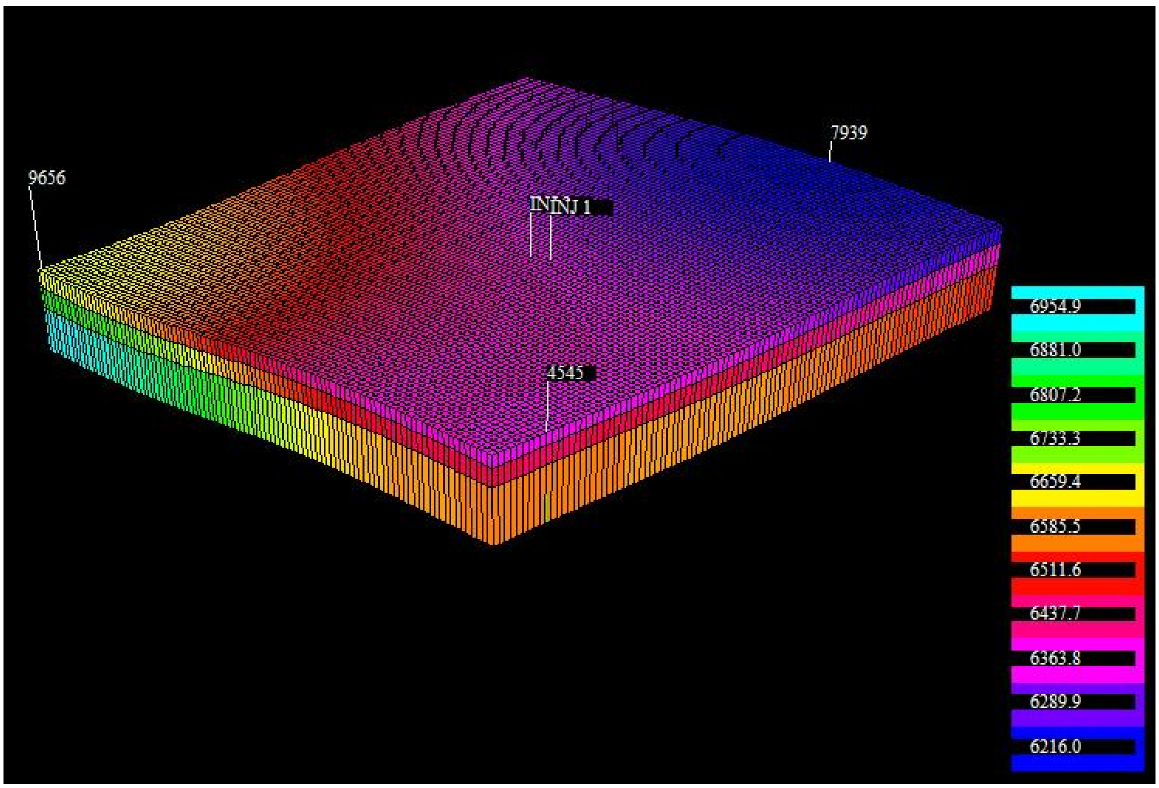

Figure 5. Three-dimensional image of the Broom Creek and surrounding formations.

Rygh (1990) determined the Broom Creek Formation is characterized by three primary lithofacies. The lithofacies are as follows: 1) nearshore marine sandstone lithofacies, 2) marine carbonate lithofacies, and 3) eolian sandstone lithofacies. It will be determined through the current design which region of the Broom Creek will be used for injection, since each of the Broom Creek's lithofacies will have a different affect on the CO_2 plume after injection.

Relatively little research has been conducted on the Broom Creek Formation in the proposed injection region. Basic reservoir characteristics, such as porosity and permeability, have been estimated by the PCOR research team from surrounding well wireline logs and a Broom Creek saltwater injection well. The effective porosity of the Broom Creek is estimated to be 14% (State of ND, 2006). Initial laboratory analysis found an average permeability value 350 millidarcy (mD) for the Broom Creek sandstone. Further lab analysis of three Broom Creek core samples will reveal the accuracy of these initial results, and should provide a much better understanding of the formation properties. It should be mentioned that the Broom Creek is not a homogeneous formation. Each of the three Broom Creek lithofacies, nearshore marine sandstone, marine carbonate, and eolian sandstone, will have its own reservoir properties.

The in situ hydrostatic pressure of the Broom Creek Formation is between 2,600 psi and 2,800 psi in the proposed injection study area (State of ND, 2006). Figure 6 shows the Broom Creek hydrostatic pressure distribution throughout much of the Williston Basin. The proposed injection region is indicated by the red dot. The temperature of the Broom Creek Formation in the study area ranges from 162°F to 174°F (State of ND, 2006). A map showing the Broom Creek temperature distribution can be seen in Figure 7, with the proposed injection site indicated by the red dot.

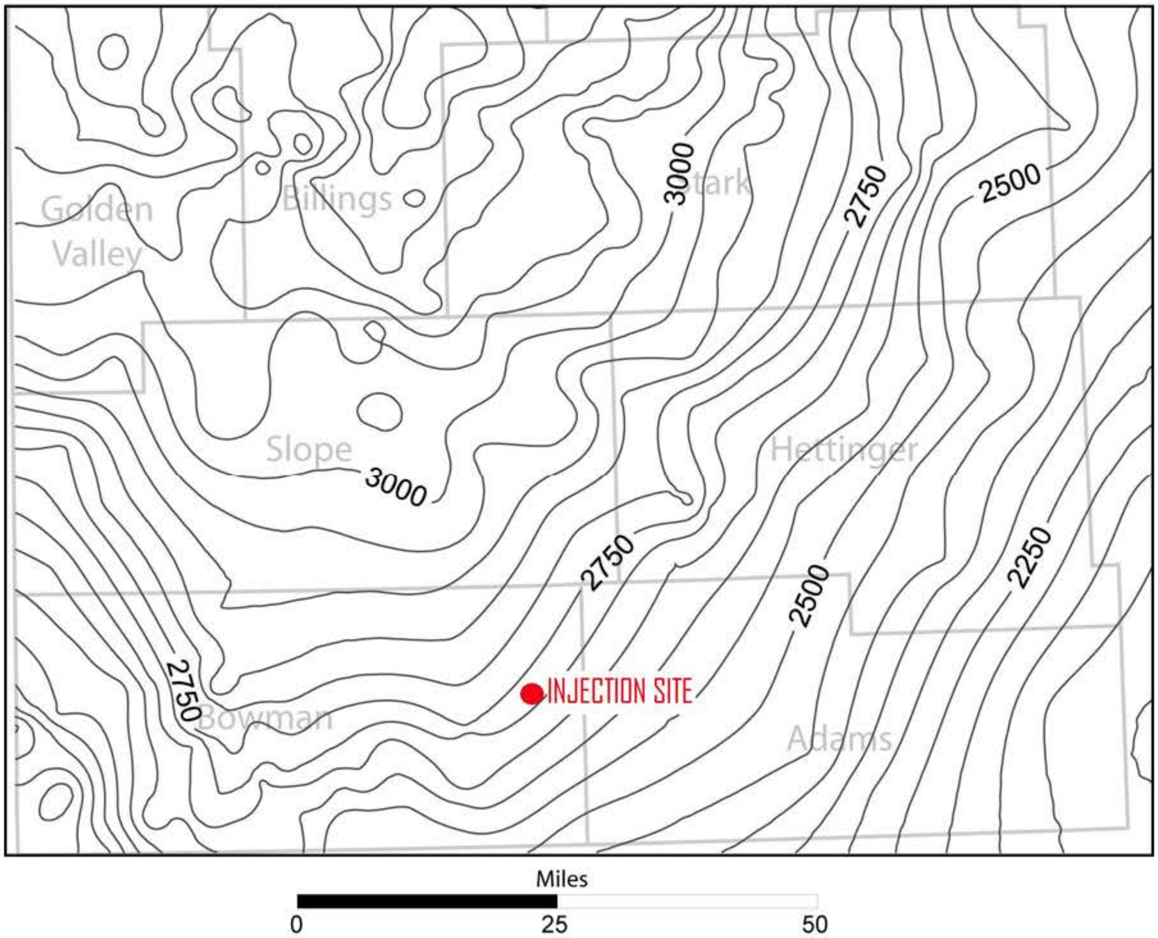

Figure 6. Hydrostatic pressure of the Broom Creek (Modified from State of ND, 2006).

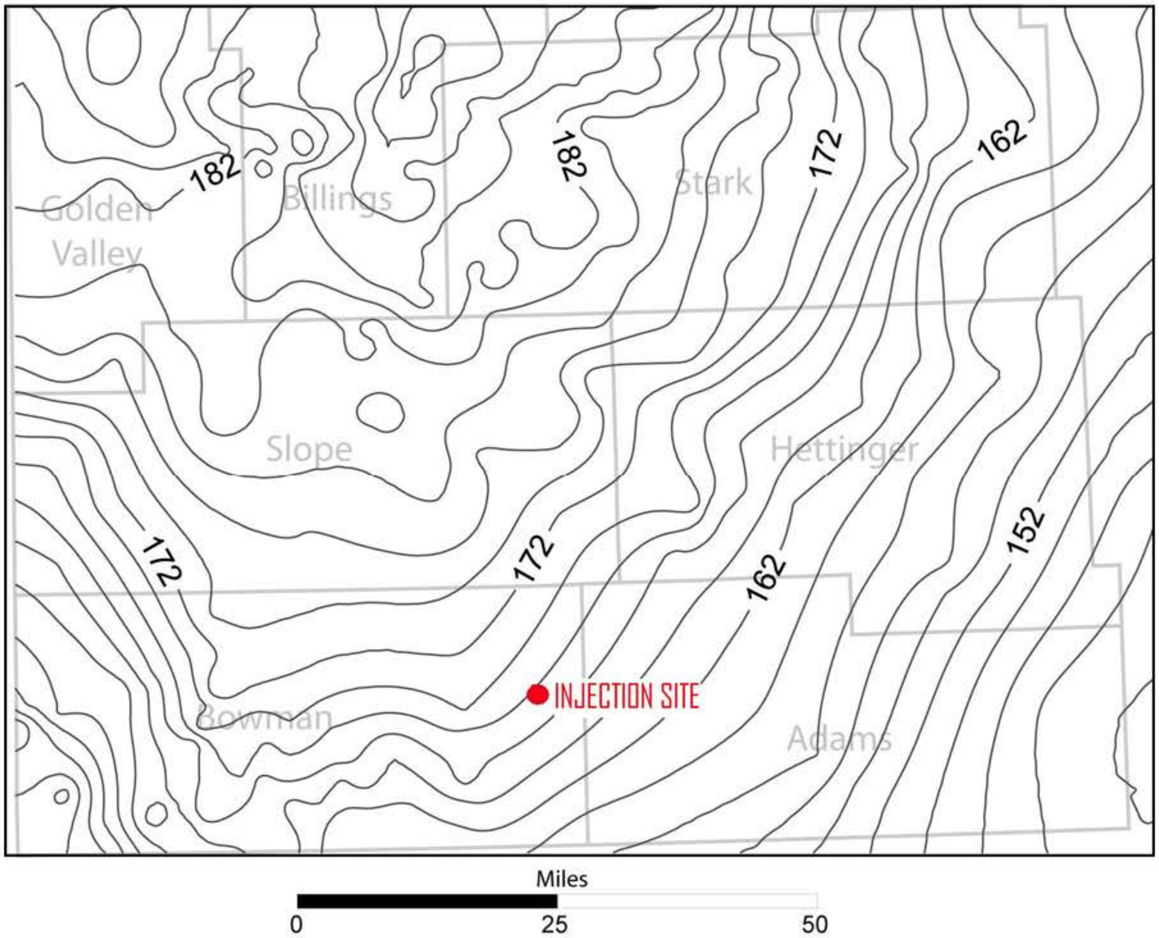

Figure 7. Broom Creek Formation temperature (°F) distribution (Modified from State of ND, 2006).

Groundwater flow and chemistry are two very important considerations before beginning any injection project. The horizontal flow of groundwater in the Minnelusa Group occurs in the northeast direction (Hoda, 1977). The total dissolved solids (TDS) values of the Broom Creek Formation range from 10,000 to 15,000 ppm in the area of proposed injection (Rygh, 1990). The TDS values continue to increase towards the center of the Williston Basin, where values approach 300,000 ppm (Rygh, 1990).

DESIGN CONSTRAINTS

Legal

The North Dakota Department of Mineral Resources Oil & Gas Division has set an injection fracture gradient of 0.7 psi/ft. At an injection depth of 6,500 ft, the maximum allowed bottom hole injection pressure is 4,550 psi (Sorensen et al., 2006).

Geology

Due to the lack of hydrocarbons, relatively few studies have been conducted on the Broom Creek Formation in southwest North Dakota. In fact, only three core samples exist at the North Dakota Geological Survey Core Library, none of which are less than 45 miles from the proposed injection site. Some simple formation properties are available, such as formation tops, thicknesses, and TDS of the formation water. The remaining reservoir characteristics, including porosity of each section of the Broom Creek, the strength of the formation, and the vertical and horizontal permeability, will need to be interpreted from wireline logs and lab tests of the three core samples from wells scattered across western North Dakota.

Social/Political

While most members of society and government agree on incorporating measures to limit CO_2 emissions into the atmosphere, many may not want a pilot program disposing high amounts CO_2 around their homes and businesses. This attitude may be alleviated by educating the people in the surrounding communities and by ensuring all aspects of the disposal have been deemed completely safe.

Economic

The added costs associated with carbon sequestration may cause business and political leaders to avoid using this technique. The added cost has been estimated by

David and Herzog (2000) to be an additional 1.5-2 cents/kWh of electricity. David and Herzog (2000) later predicted that within the next decade, the cost could be lowered to 1 cent/kWh. However, if electric customers were originally charged 6 cents/kWh and the rate went up to 7.5 cents/kWh, this would represent a 25% increase in their electric bill. One way to minimize the customer's initial cost would be through proper legislation and tax incentives for the new CO_2 free electricity.

Safety

Safety is the main concern for everyone involved with the CO_2 sequestration project. One industry safety concern is for the drill operators when they reach the Broom Creek Formation. The Broom Creek Formation is notorious for blowouts in the Williston Basin, due to the high pressure nitrogen gases trapped in the formation; however there is no indication of nitrogen accumulation in the design area. Proper mud weight and drilling procedures should greatly reduce the risk of a blowout. The largest safety factor facing this project is the CO_2 plume generated by the injection. Every possible angle for CO_2 escape must be considered, and if there is any doubt about the security of the plume gases, the proper corrections must take place or a new design must be implemented.

ALTERNATIVE DESIGNS

One alternative to sequestering the CO_2 in deep saline aquifers is transporting the CO_2 by pipeline to the nearby Cedar Creek and Nesson anticlines for enhanced oil recovery utilization. Through CO_2 enhanced oil recovery techniques, the Williston Basin could contain an additional 277 million barrels of possibly recoverable oil (Nelms and Burke, 2004). Another method involves piping the CO_2 to areas of uneconomic coal seams for sequestration. The estimated storage capacity in North Dakota's uneconomic lignite coal is 598.7 million short tons (Nelson et al., 2005). The technique of sequestration in coal seams also offers the possibility of producing natural gas, which may otherwise be uneconomical to produce (Nelson et al., 2005). Finally, one other technique would be to create a national network of pipes to allow for deep ocean sequestration along the coasts of the United States.

FINAL DESIGN SELECTION

Deep saline aquifer sequestration in Bowman County was chosen as the final design due to its large storage capacity and the ideal reservoir characteristics of the Broom Creek Formation. The final design utilizes a reservoir simulation model from Schlumberger's ECLIPSE and three separate injection plans. The reservoir simulation model for studying the CO_2 movement in the aquifer is constructed using the ECLIPSE black-oil reservoir simulator. In order to use the black-oil simulator, a two-phase simulation was utilized. Water exists in the liquid phase and the CO_2 exists in the gas phase. The data used to create the geologic model is a combination of core, wireline log, and laboratory data.

PLANS AND SPECIFICATIONS

The following is a basic overview of the tasks required to build and run the reservoir simulation model (Modified from Zeng(2006)).

(1) Data collection and analysis

   a. Geologic data

   b. Well log data (permeability, porosity, depths, thickness)

   c. Laboratory permeability test data

d. Reservoir fluid data (PVT, fluid properties)
e. Reservoir rock properties (relative permeability, capillary pressure, compressibility)

(2) Geologic model development

a. Structural model
b. Geometry of formations

(3) Reservoir model establishment

a. Initial reservoir pressure distribution
b. Initial reservoir temperature distribution
c. Reservoir porosity distribution
d. Reservoir permeability distribution
e. Fluid saturation distribution
f. Relative permeability
g. Capillary pressure
h. PVT tables and data for water and CO_2
i. Injection well design
j. Operational conditions

(4) Forecasting Simulation

a. Planning three different injection cases
b. Preparing input data for each case
c. Review and analysis of predicted performance

These tasks were completed using a variety of approaches. The following is a summary of the approaches (Modified from Zeng (2006)).

(1) Collection of data from:

   a. Existing public and private records

   b. Analog data from similar design projects

   c. New data from laboratory testing

(2) Models was constructed based upon generally accepted techniques:

   a. Geologic model includes geologic data and well log data

   b. Reservoir model was generated using drilling, well log, and laboratory results

(3) Reservoir simulation was conducted using the leading edge industrial software: Schlumberger's ECLIPSE

BUDGET

The following budget is designed to provide a rough estimate of costs that may be incurred while the proposed sequestration operation is being designed and researched. Labor costs are based on the average entry level wages for a petroleum engineer (U.S. Department of Labor, 2006). The labor hours allotted for the design are assumed to be adequate to finish the required tasks. No costs are represented for the actual well drilling or injection of CO_2.

Table 1. Budget proposal for design completion

Broom Creek Reservoir Characterization Budget

Category	Estimated Quantity	Estimated Cost per Unit	Estimated Subtotal
Research			
Initial Subject Research (80 hrs @ $25/hr)	80	$25.00	$2,000.00
Lab Analysis Work (120 hrs @ $25/hr)	120	$25.00	$3,000.00
Geologic Model Creation (80 hrs @ $25/hr)	80	$25.00	$2,000.00
Reservoir Simulation Exercises (80 hrs @ $25/hr)	80	$25.00	$2,000.00
Presentation and Analysis of Results (40 hrs @ $25/hr)	40	$25.00	$1,000.00
Research Costs Total			**$10,000.00**
Software			
ECLIPSE Lease ($4,000/Month)	2	$4,000.00	$8,000.00
Software Costs Total			**$8,000.00**
Hardware			
Computer	1	$1,500.00	$1,500.00
Printer	1	$100.00	$100.00
Core Flooding System Maintenance	1	$1,000.00	$1,000.00
Lab Supplies	1	$1,000.00	$1,000.00
Misc. Supplies and Publications	1	$200.00	$200.00
Hardware Costs Total			**$3,800.00**
ESTIMATED CHARACTERIZATION GRAND TOTAL			**$21,800.00**

SCHEDULE

The proposed time schedule assumes one qualified petroleum engineer is performing the required tasks and is working on the design for forty hours per week.

Table 2. Proposed schedule for task completion

Time (Week, since the start of design)	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Initial data collection and analysis	------	------								
Lab analysis			-------	-------	-------					
Geologic model creation						------	------			
Reservoir model creation						------	------			
Reservoir simulation exercises								------	------	
Presentation and analysis of results										------

Simulation Parameters

The Broom Creek CO_2 injection simulation was performed using Schlumberger's ECLIPSE software. Several initial assumptions needed to be made in order to conduct the simulation exercises. First, the simulation assumes a homogeneous and isotropic reservoir. Next, it is assumed that CO_2 does not go into solution with the formation water and exists only in the gas phase. The simulation also assumes that the overlying Opeche Fm. has zero vertical permeability and rock strength characteristics adequate for CO_2 injection. Also, due to poor well control in the injection region, a constant thickness and dip is used to build the geologic model. Table 1 describes the initial simulation parameters used to characterize the Broom Creek Fm. APPENDIX A provides the CO_2 PVT properties imported to ECLIPSE for simulation calculations. APPENDIX B provides formulas and calculations for: Residual Gas Saturation (S_{gr}), Irreducible Water Saturation (S_{wir}), and Critical Water Saturation (S_{cr}).

Table 3. ECLIPSE simulation parameters

INPUT VALUES FOR BROOM CREEK SIMULATION	
Simulation Run Time, years	1,000
Simulation Time Step, days	1,500
Model Length, ft	100,000
Model Width, ft	100,000
Model Thickness, ft	150
Depth at top of fm. at injection well, ft	6,500
Formation Temperature, °F	169
Initial Formation Pressure, psi at 6,500ft	2,814
Formation Dip, degree	0.35
Aquifer Salinity, ppm	10,000
Formation Horizontal Permeability, md	350
Formation Vertical Permeability, md	350
Formation Porosity, φ	0.14
Residual Gas Saturation, S_{gr}	0.41
Irreducible Water Saturation, S_{wir}	0.056
Critical Water Saturation, S_{cr}	0.295
Grid	34x39x9
Injection Rate, Mscf/day	78,500
Injection Period, years	30

The proposed FutureGen power plant would need to sequester at least one million metric tons of CO_2 per year, for at least 30 years (State of ND, 2006). The simulations performed in this design inject 78,500 Mscf of CO_2 per day for 30 years, totaling approximately 50 million metric tons of CO_2 over 30 years. The value of 50 million metric tons exceeds the FuturGen requirements and should be considered adequate at proving the Bowman County region as a possible sequestration target.

The simulation exercises start with ten years of no injection actions. Starting at year ten CO_2 injections begin at 78,500 Mscf/day and continues for 30 years. Following the 30 years of injection, the wells are shut-in and injection stops. The simulations are allowed to run for a total of 1,000 years, during which the injected CO_2 is allowed to migrate and become trapped in the pore space of the Broom Creek Fm.

Injection Wells

Three different injection well cases were modeled to observe the effect on CO_2 plume shape and migration. The first injection case uses a vertical injection well, Figure 8, which is perforated in the bottom 75 feet of the Broom Creek Fm. The second case, Figure 9, is a short, 500 foot, horizontal well, fifteen feet off the bottom of the formation and running perpendicular to the dip direction. The third case, Figure 10, is similar to the second, but the horizontal segment extends for 5,280 feet.

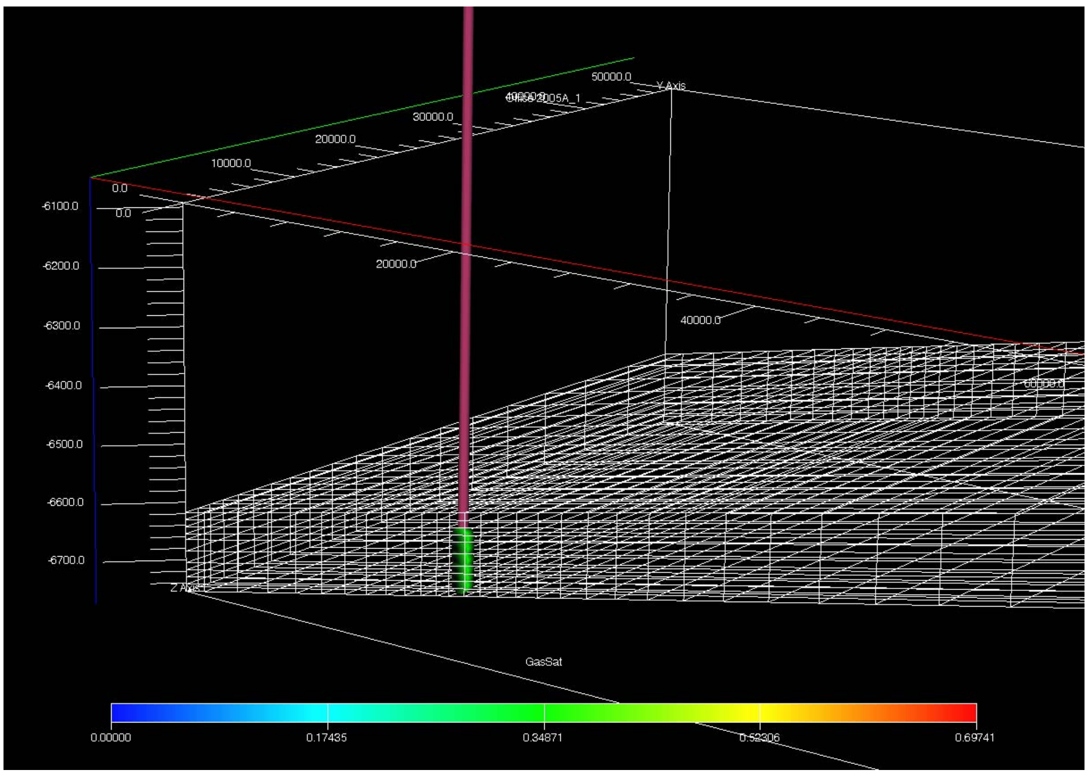

Figure 8. Vertical injection well connection (vertical exaggeration added for detail).

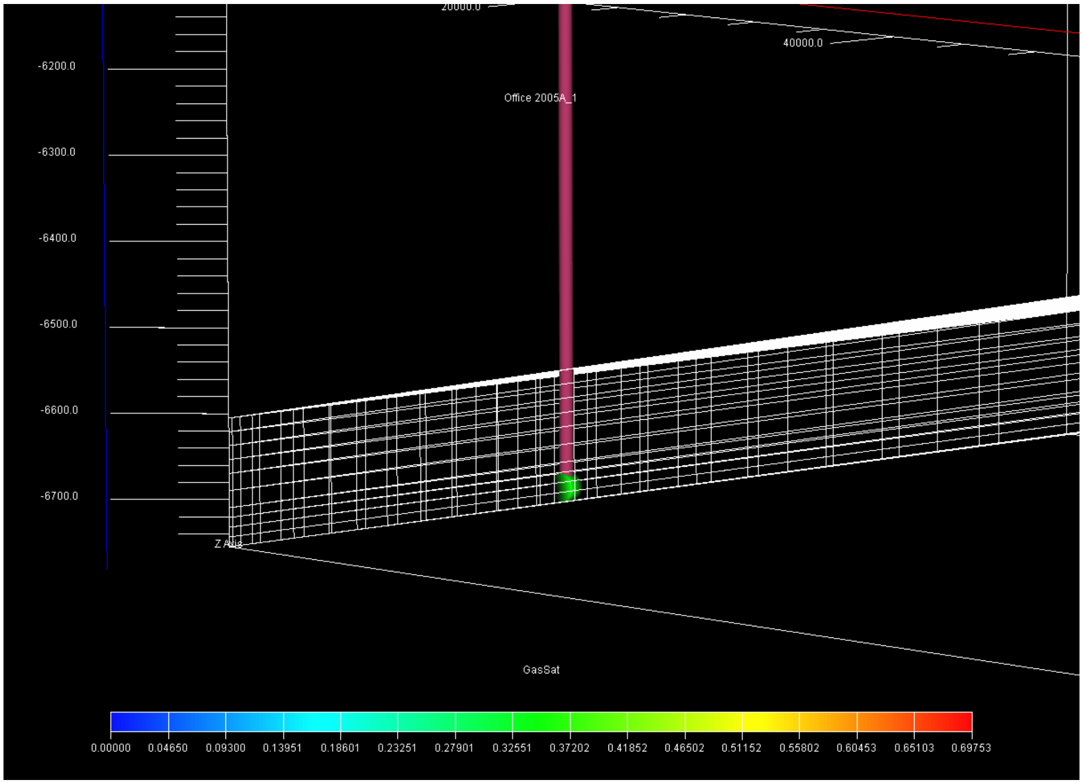

Figure 9. Horizontal injection well, 500 ft leg (vertical exaggeration added for detail).

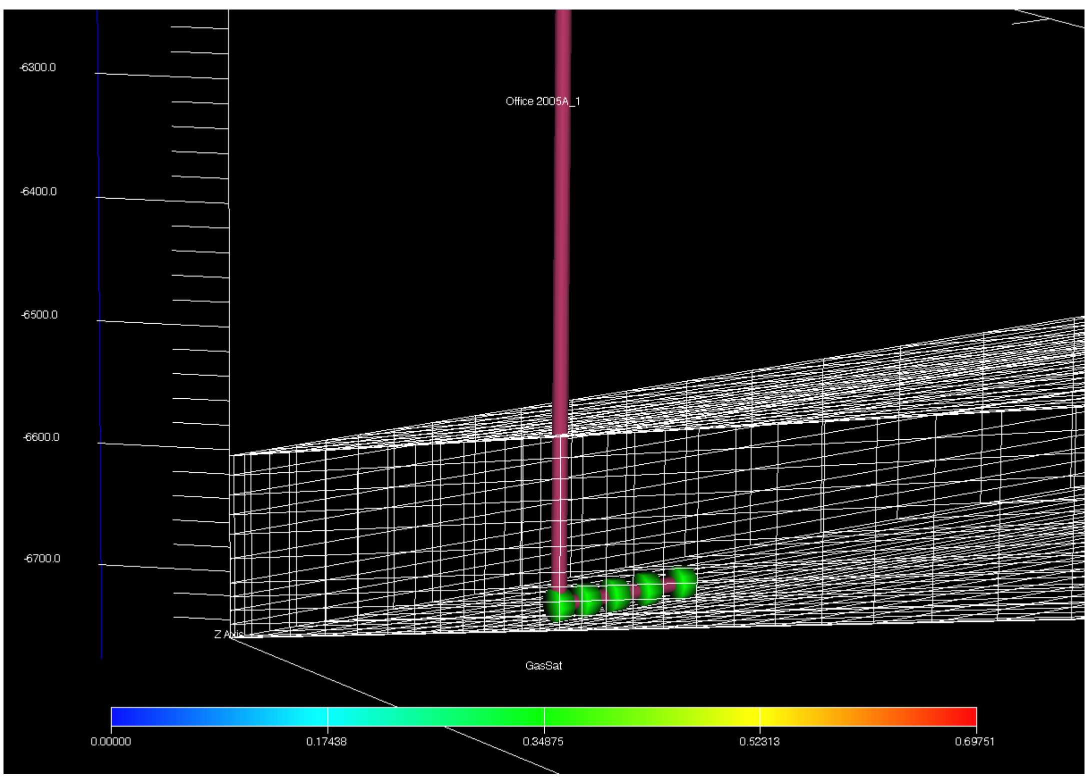

Figure 10. Horizontal injection well, 5,280 ft leg (vertical exaggeration added for detail).

Simulation Results

The ECLIPSE reservoir simulations, Figures 11-13, provide excellent insight into the long term fate of sequestered CO_2. It can be seen in the simulation results that the CO_2 will form a cone shaped plume and travel updip until all of the CO_2 is trapped as residual gas inside the Broom Creek Fm. The images shown indicate the change in formation gas saturation through time. The scale found with the images is formation gas saturation.

Bottom hole injection pressure (APPENDIX C) and formation pressure (APPENDIX D) are two great concerns when performing any injection operations. The North Dakota Department of Mineral Resources Oil & Gas Division limits bottom hole and formation pressure to 4,550 psi for the Broom Creek Fm. at the proposed injection site. Results obtained by ECLIPSE indicate that peak bottom hole pressures range from approximately 3,050 psi in the 5,280 ft horizontal well to 3,600 psi in the vertical injection well. In all three cases the peak occurred immediately after injection begins and continues to lower as injection continues.

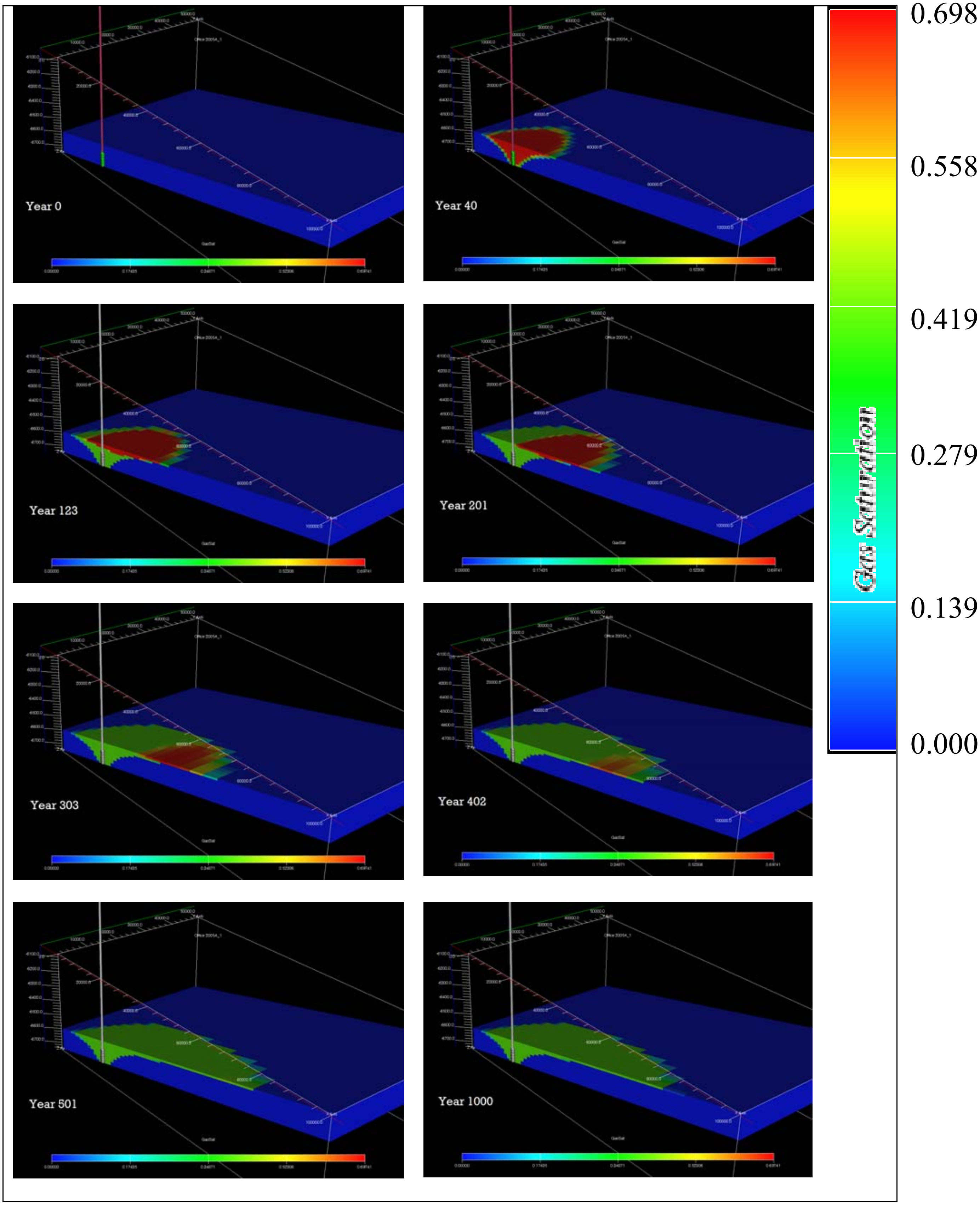

Figure 11. Vertical well simulation results (vertical exaggeration added for detail).

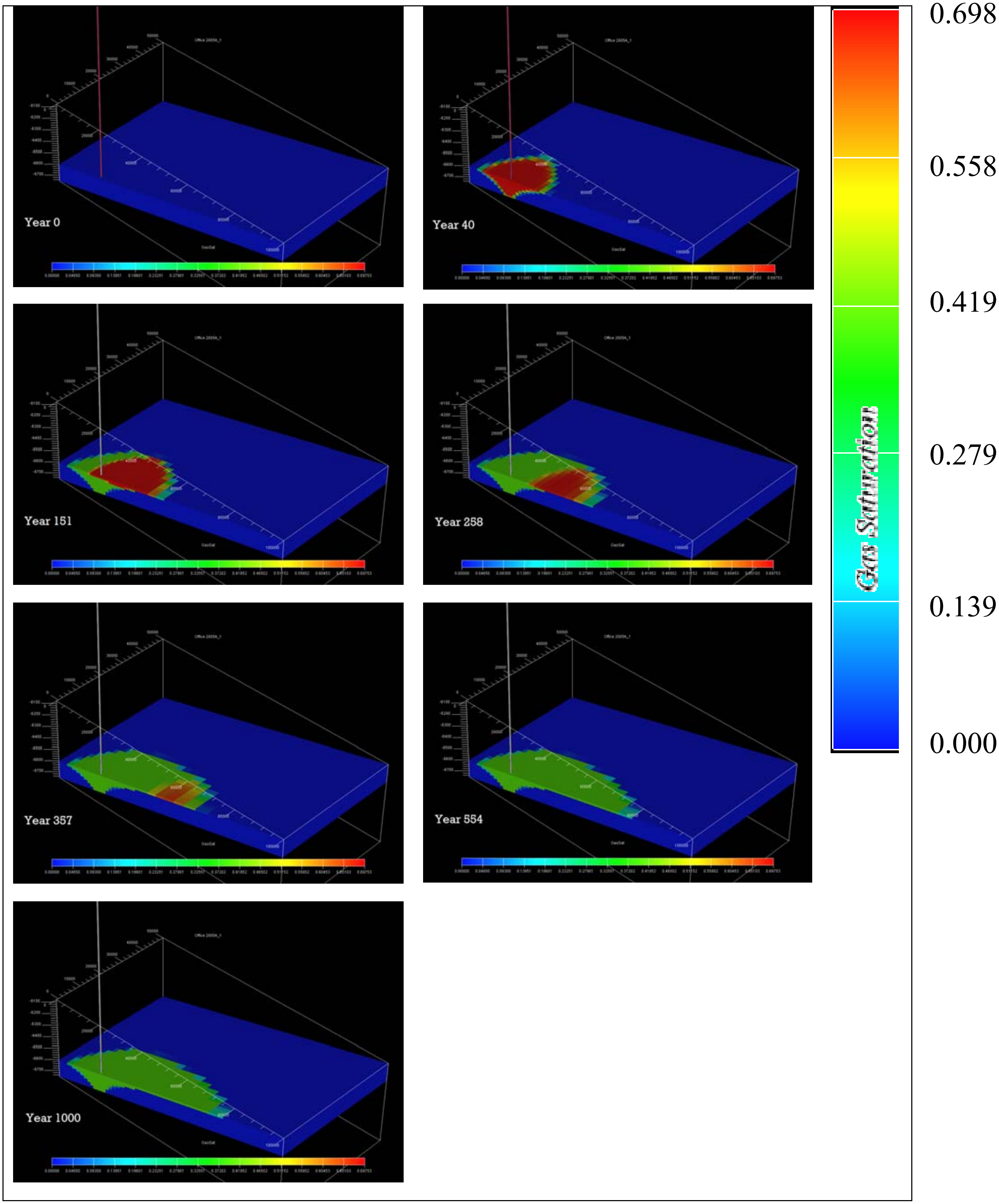

Figure 12. Horizontal well simulation results, 500 ft leg (vertical exaggeration added for detail).

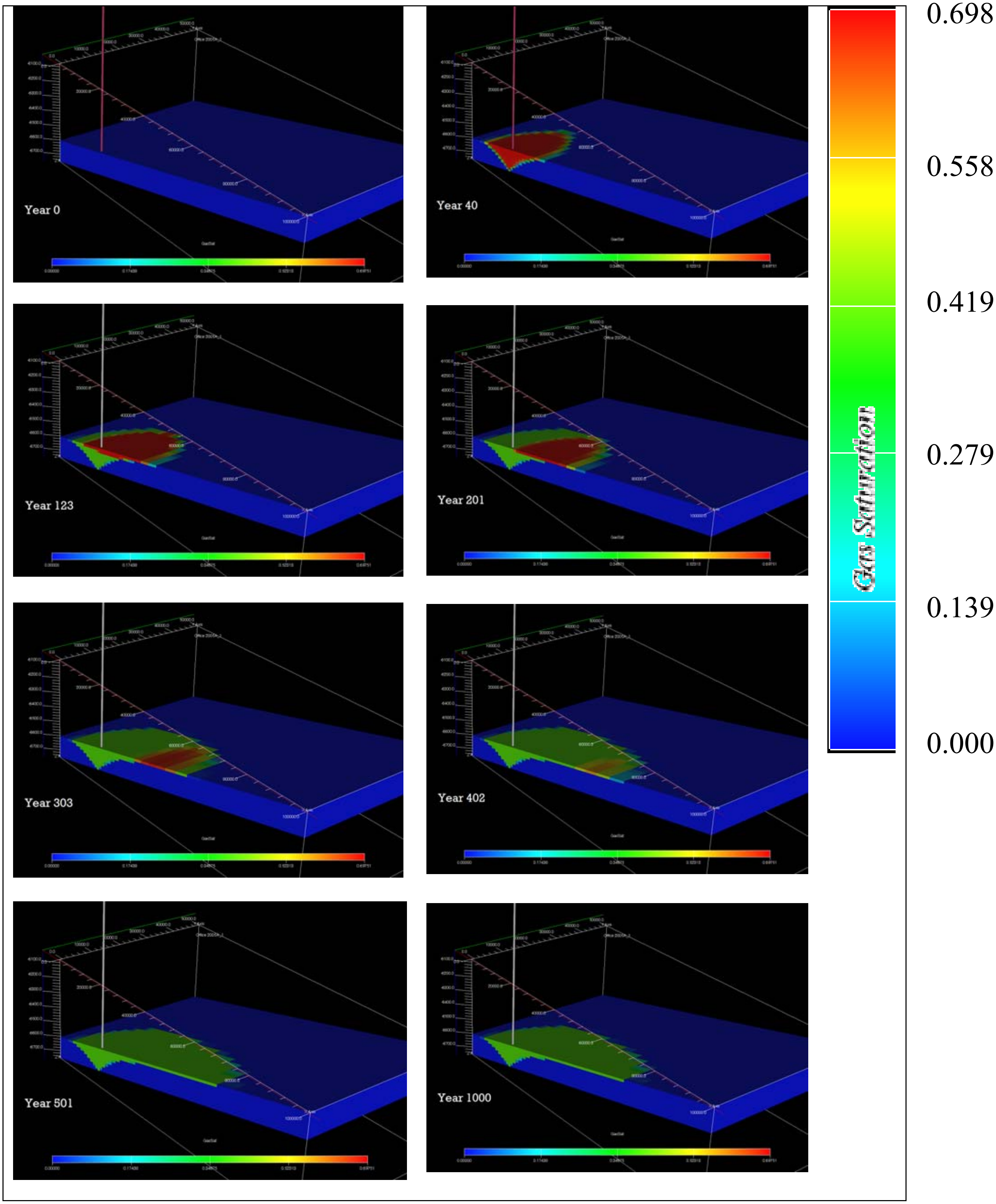

Figure 13. Horizontal well simulation results, 5,280 ft leg (vertical exaggeration added for detail).

CO_2 Plume Migration

Due to the density difference between the Broom Creek Fm. water and the injected CO_2, the CO_2 migrates upward and collects under the Opeche shale. This collection of CO_2 begins lateral updip travel while continuing to be subjected to buoyancy forces. Lateral plume migrations experienced in during the reservoir simulations ranged from 10.6-12.1 miles updip from the injection well.

The results obtained from the reservoir simulation, Figure 14, show that CO_2 plume shape and migration differ greatly from the original FutureGen calculations proposed by Sorensen et al., 2006. Original FutureGen calculations assumed a cylindrical plume with no horizontal migration. Simulations results show a very distinct cone shaped plume and significant updip travel of the CO_2 plume. This updip plume migration only becomes a concern when the plume travels into regions with an inadequate cap rock or improperly cemented wells.

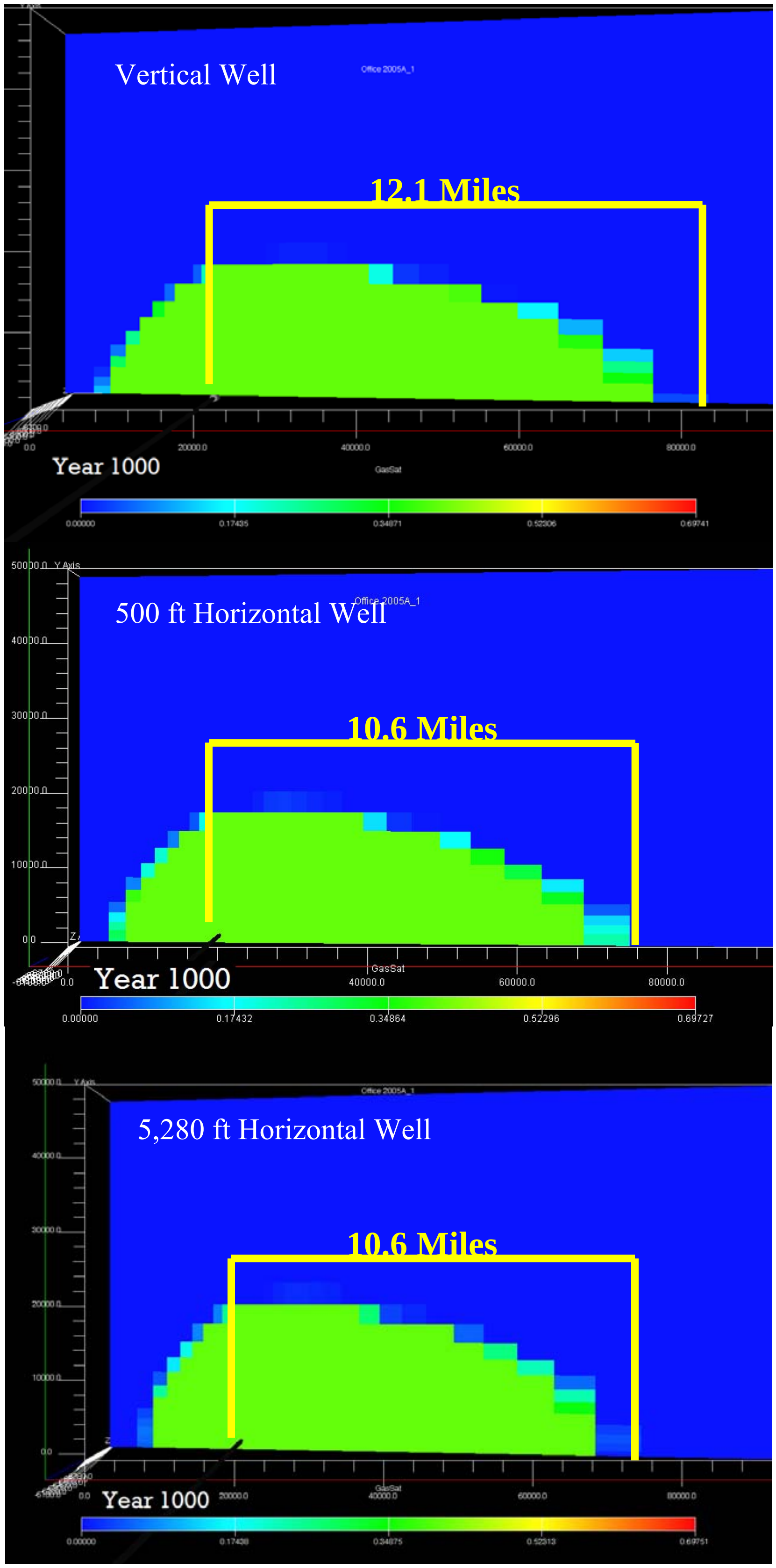

Figure 14. Overhead view of CO_2 plume migration for the three injection scenarios.

SIMULATION LIMITATIONS

The reservoir simulations presented in this design project are limited by several factors. The first thing to consider is that reservoir simulation exercises are only as good as the data provided and the engineering operating the system. In the simulation presented in this design, the data was very limited and many large assumptions needed to be made in order to execute the simulation. Another limitation to the simulation was the inability to model CO_2 entering into solution with the aquifer. If CO_2 solution was modeled, it can be assumed that the CO_2 plume size would be reduced and the safety level increased. Finally, the ECLIPSE program used for the simulation was unable to model any chemical reaction between the CO_2 and reservoir rock.

CONCLUSION

Geologic sequestration in saline aquifers has been suggested to be a suitable technique for the permanent storage of large volumes of CO_2 collected from industrial sources. The Williston Basin's Broom Creek Formation appears to have adequate reservoir properties to characterize it as a safe and secure storage location for many years of CO_2 injection operations. Through the proposed reservoir characterization and simulation, it shall be determined how the CO_2 plume will migrate and interact with the Broom Creek and surrounding formations. These simulation exercises are designed to help engineers and scientists design future CO_2 injection programs in the Williston Basin and around the world.

Plume shape and migration distances can be altered slightly depending upon the style of injection well. It was shown through the simulation exercises that a horizontal well in the Broom Creek Fm. would produce shorter CO_2 plume migration. However, the added costs of drilling horizontal injections wells may be too high to justify their usage in CO_2 sequestration.

Future work on the Broom Creek Fm. should include simulations exercises utilizing CO_2 dissolution, mineral trapping, and pore trapping. Also, as more structural data is collected on the Broom Creek Fm., more detailed geologic models can be built and will provide researchers with an even more accurate portrayal of the injected CO_2's fate. Finally, this engineering design was aimed only at the reservoir engineering portion of CO_2 sequestration, and many drilling and injection engineering issues would need to be solved before any proposed operations could take place.

APPENDIX A

CO_2 PVT Properties generated by Calsep's PVTsim (Calsep, 2005) for simulation

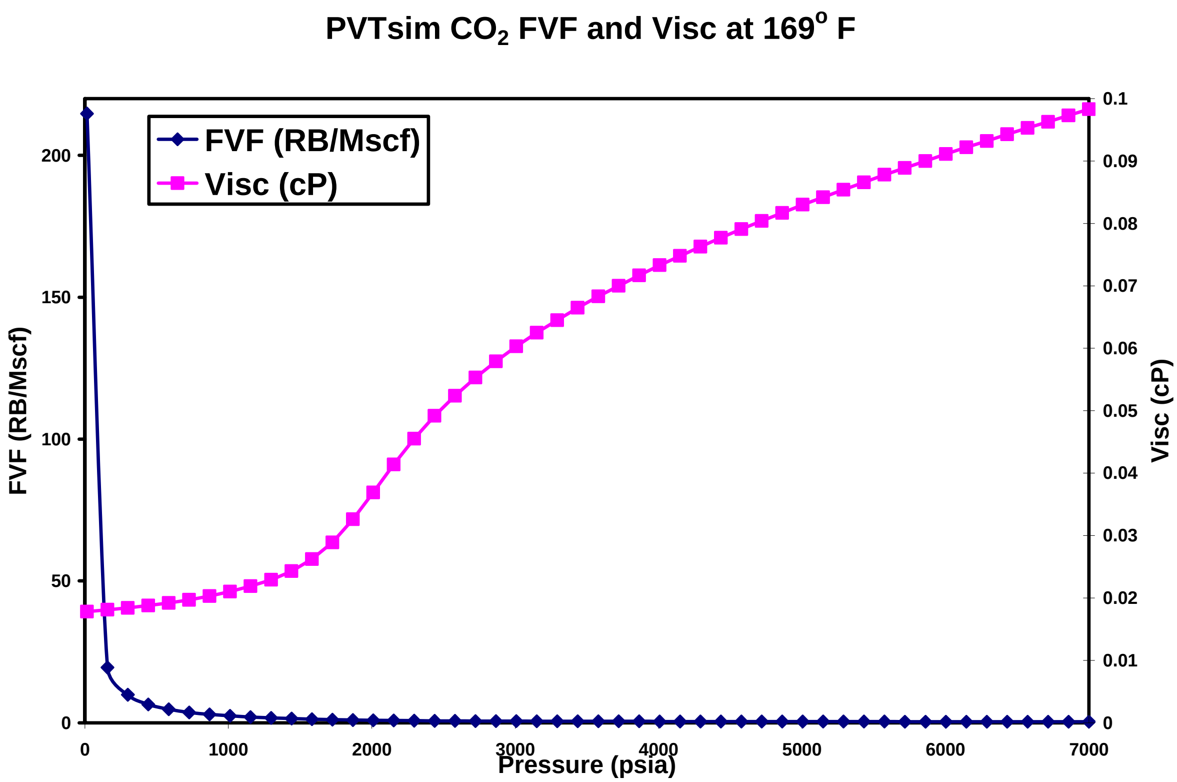

Figure A-1. CO_2 PVT properties generated by Calsep's PVTsim.

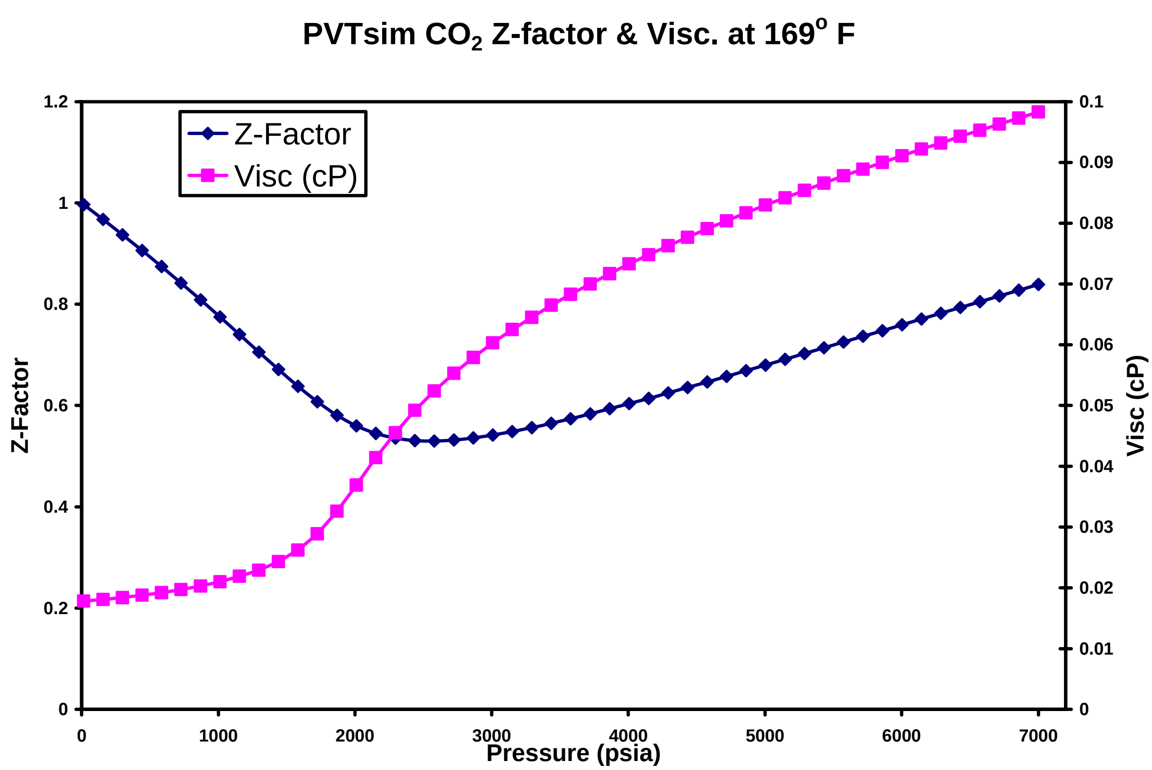

Figure A-2. CO_2 PVT properties generated by Calsep's PVTsim.

Table A-1. PVT properties for CO_2 at reservoir conditions

CO_2 properties at 169 °F from PVTsim				
Pressure psia	**Visc cP**	**Z factor**	**B_g (RB/scf)**	**B_g (RB/Mscf)**
14.7	0.0178	0.997	0.21475922	214.7592197
157.26	0.0181	0.9674	0.019478782	19.47878237
299.81	0.0184	0.9371	0.009897234	9.897233518
442.37	0.0188	0.9061	0.006485814	6.485813513
584.93	0.0192	0.8744	0.004733477	4.733476732
727.49	0.0197	0.8419	0.003664439	3.664438821
870.04	0.0203	0.8087	0.002943217	2.943216552
1012.6	0.021	0.7748	0.002422845	2.422845287
1155.16	0.0219	0.7403	0.002029269	2.029268907
1297.71	0.0229	0.7056	0.00172169	1.721689832
1440.27	0.0243	0.6712	0.001475645	1.475645463
1582.83	0.0262	0.638	0.001276322	1.276322424
1725.39	0.0289	0.6074	0.001114709	1.114708993
1867.94	0.0326	0.5809	0.000984719	0.984719296
2010.5	0.0369	0.5599	0.000881821	0.881820892
2153.06	0.0414	0.5449	0.000801373	0.801372932
2295.61	0.0455	0.5356	0.000738782	0.738782253
2438.17	0.0492	0.5309	0.000689482	0.689481687
2580.73	0.0524	0.53	0.00065029	0.650290326
2723.29	0.0553	0.5319	0.000618458	0.618457831
2865.84	0.0579	0.5359	0.000592115	0.592114656
3008.4	0.0603	0.5416	0.000570055	0.570055407
3150.96	0.0625	0.5485	0.000551198	0.55119813
3293.51	0.0645	0.5563	0.00053484	0.53484023
3436.07	0.0665	0.5648	0.000520483	0.520483156
3578.63	0.0683	0.5739	0.000507801	0.507800846
3721.19	0.07	0.5835	0.000496516	0.496515727
3863.74	0.0717	0.5935	0.000486392	0.486392448
4006.3	0.0733	0.6037	0.000477146	0.477146456
4148.86	0.0748	0.6142	0.000468765	0.468764836
4291.41	0.0763	0.6248	0.000461015	0.461014946
4433.97	0.0777	0.6356	0.000453905	0.453905173
4576.53	0.0791	0.6466	0.000447377	0.447376719
4719.09	0.0804	0.6576	0.000441243	0.441242705
4861.64	0.0817	0.6688	0.0004356	0.435599589
5004.2	0.083	0.68	0.000430277	0.430277115
5146.76	0.0842	0.6912	0.000425249	0.425249495
5289.31	0.0854	0.7025	0.000420554	0.420553548
5431.87	0.0866	0.7138	0.000416103	0.416103309
5574.43	0.0878	0.7252	0.000411937	0.411937494
5716.99	0.0889	0.7366	0.000407979	0.407979438
5859.54	0.09	0.7479	0.000404161	0.404160628
6002.1	0.0911	0.7593	0.000400575	0.4005753
6144.66	0.0922	0.7707	0.000397156	0.397156336
6287.21	0.0932	0.7821	0.000393893	0.393893046

6429.77	0.0943	0.7936	0.000390823	0.390823091
6572.33	0.0953	0.805	0.000387838	0.387838138
6714.89	0.0963	0.8164	0.00038498	0.384979928
6857.44	0.0973	0.8277	0.000382195	0.38219494
7000	0.0983	0.8391	0.000379568	0.379568073

Calculations for formation volume factor (B_g), as found in Towler (2002)

$$B_g\left(\frac{RB}{scf}\right) = 0.00503676\left(\frac{z*T}{p}\right) \qquad \text{(A1)}$$

$$T(R) = °F + 459.67 \qquad \text{(A2)}$$

Sample calculation at 14.7 psia

$$B_g\left(\frac{RB}{scf}\right) = 0.00503676\left(\frac{0.997*(169+459.67)}{14.7}\right) = 0.21476\frac{RB}{scf}$$

$$B_g\left(\frac{RB}{scf}\right)*1{,}000 = B_g\left(\frac{RB}{Mscf}\right)$$

$$0.21476\frac{RB}{scf}*1{,}000 = 214.76\frac{RB}{Mscf}$$

APPENDIX B

Broom Creek reservoir calculations

Residual gas saturation (S_{gr}), as found in Holtz (2002)

$$S_{gr_{MAX}} = -0.9696\phi + 0.5473 \qquad \text{(B1)}$$

$$\phi = 0.14$$

$$S_{gr_{MAX}} = -0.9696*(0.14) + 0.5473 = 0.4116 \approx 41\%$$

Irreducible water saturation (S_{wir}), as found in Holtz (2002)

$$S_{wir} = 5.159\left(\frac{\log(k)}{\phi}\right)^{-1.559} \qquad \text{(B2)}$$

$$\phi = 0.14$$
$$k = 350mD$$

$$S_{wir} = 5.159\left(\frac{\log(350)}{0.14}\right)^{-1.559} = 0.056 = 5.6\%$$

Critical water saturation (S_{wc}), as found in Byrnes (2005)

$$S_{wc} = 0.16 + .053*\log(k) \qquad \text{(B3)}$$

$$k = 350mD$$

$$S_{wc} = 0.16 + .053*\log(350) = 0.2948 = 29.5\%$$

APPENDIX C

Simulation bottomhole pressure results

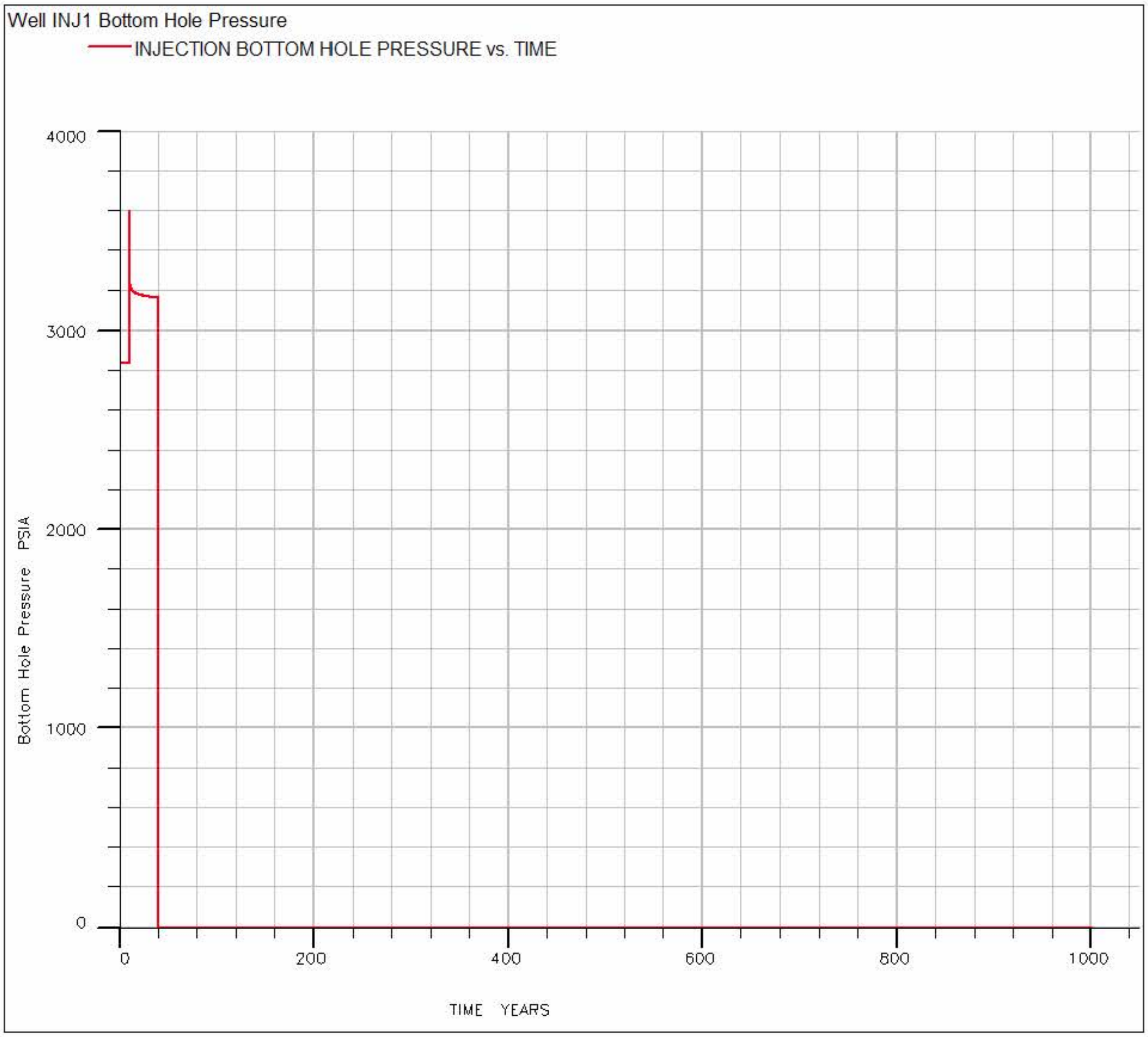

Figure C-1. Vertical injection well bottom hole pressure.

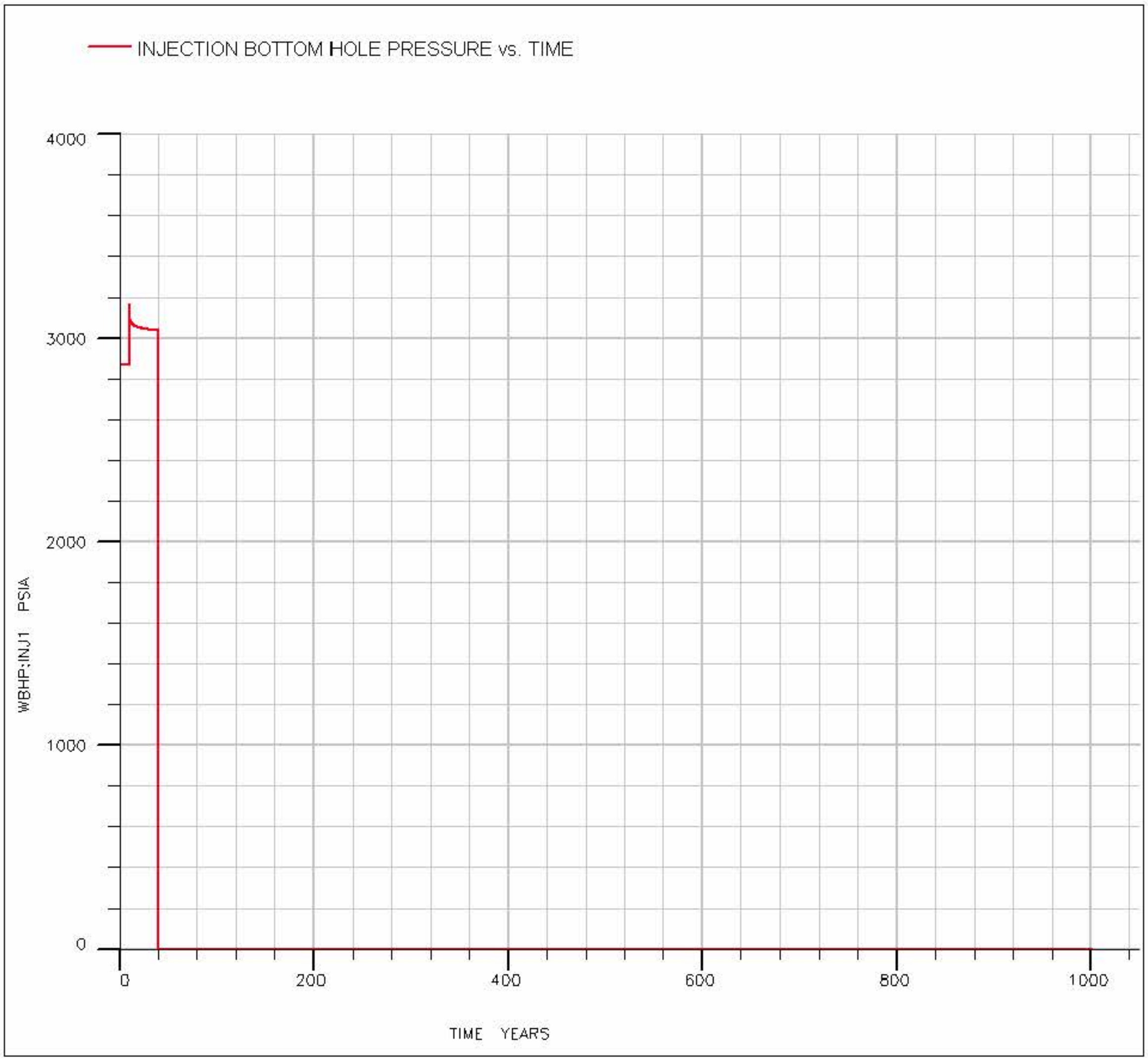

Figure C-2. 500 ft horizontal injection well bottomhole pressure.

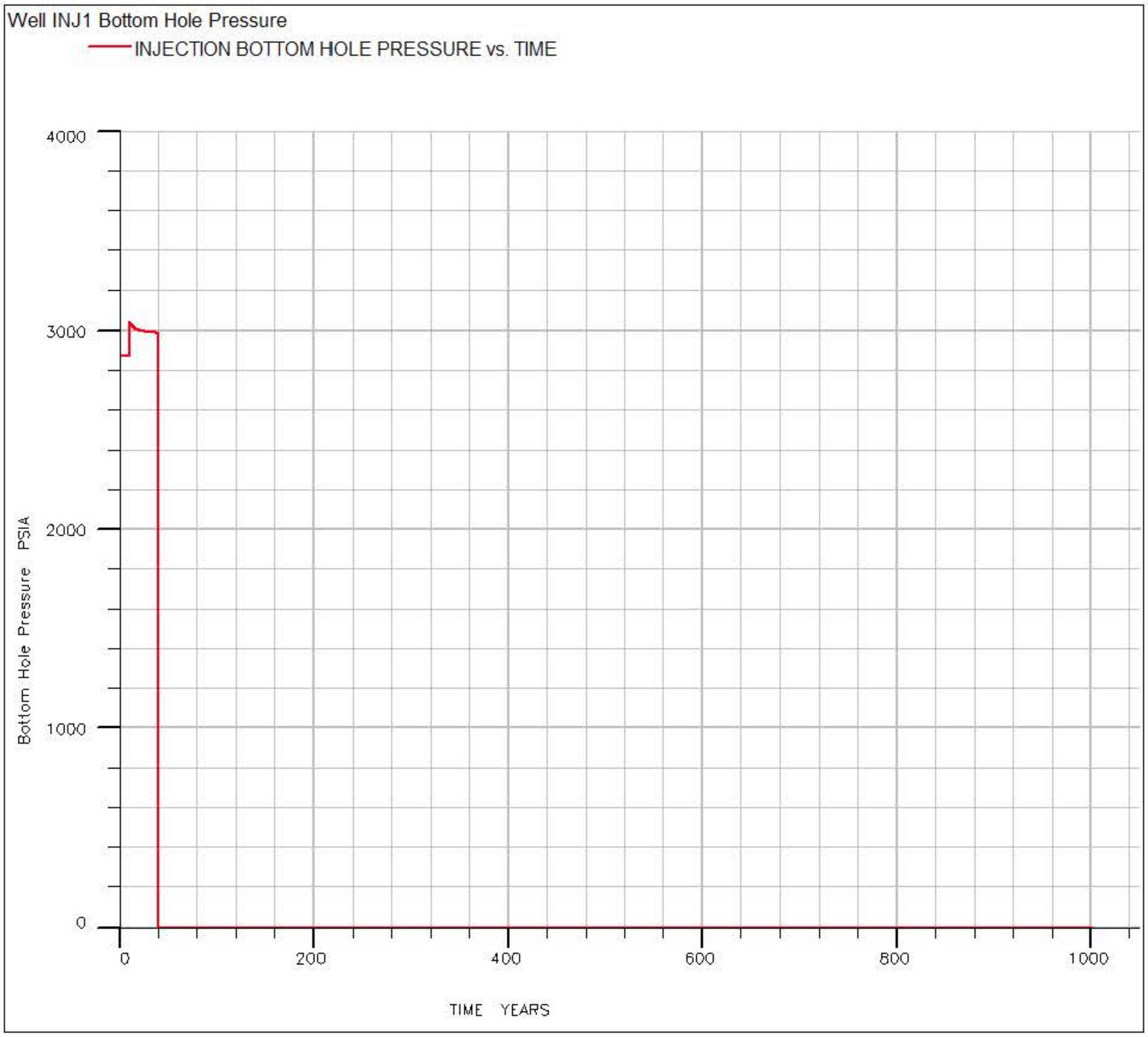

Figure C-3. 5,280 ft horizontal injection well bottomhole pressure.

APPENDIX D

Broom Creek simulation field pressure results

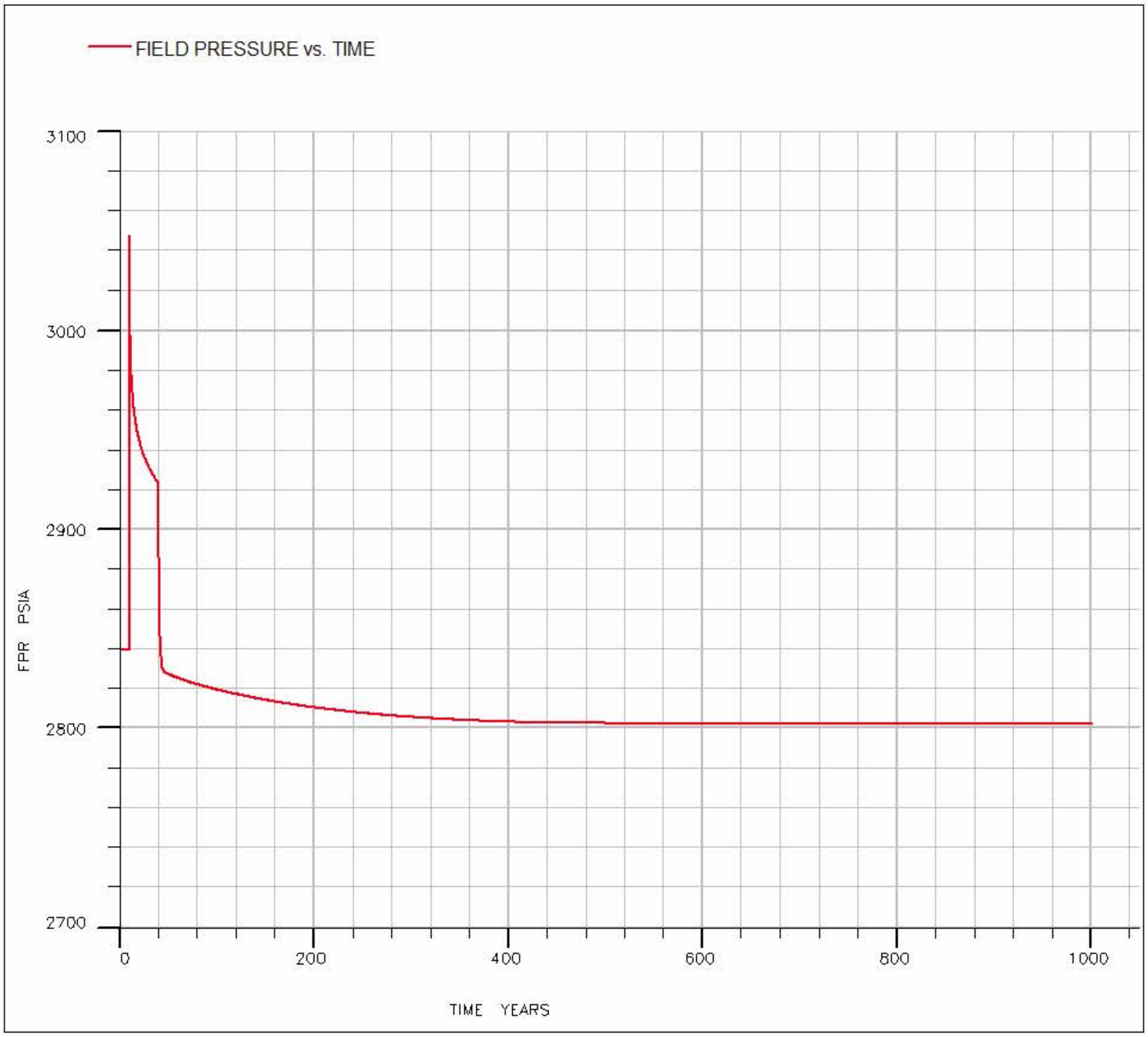

Figure D-1. Vertical injection well field pressure results.

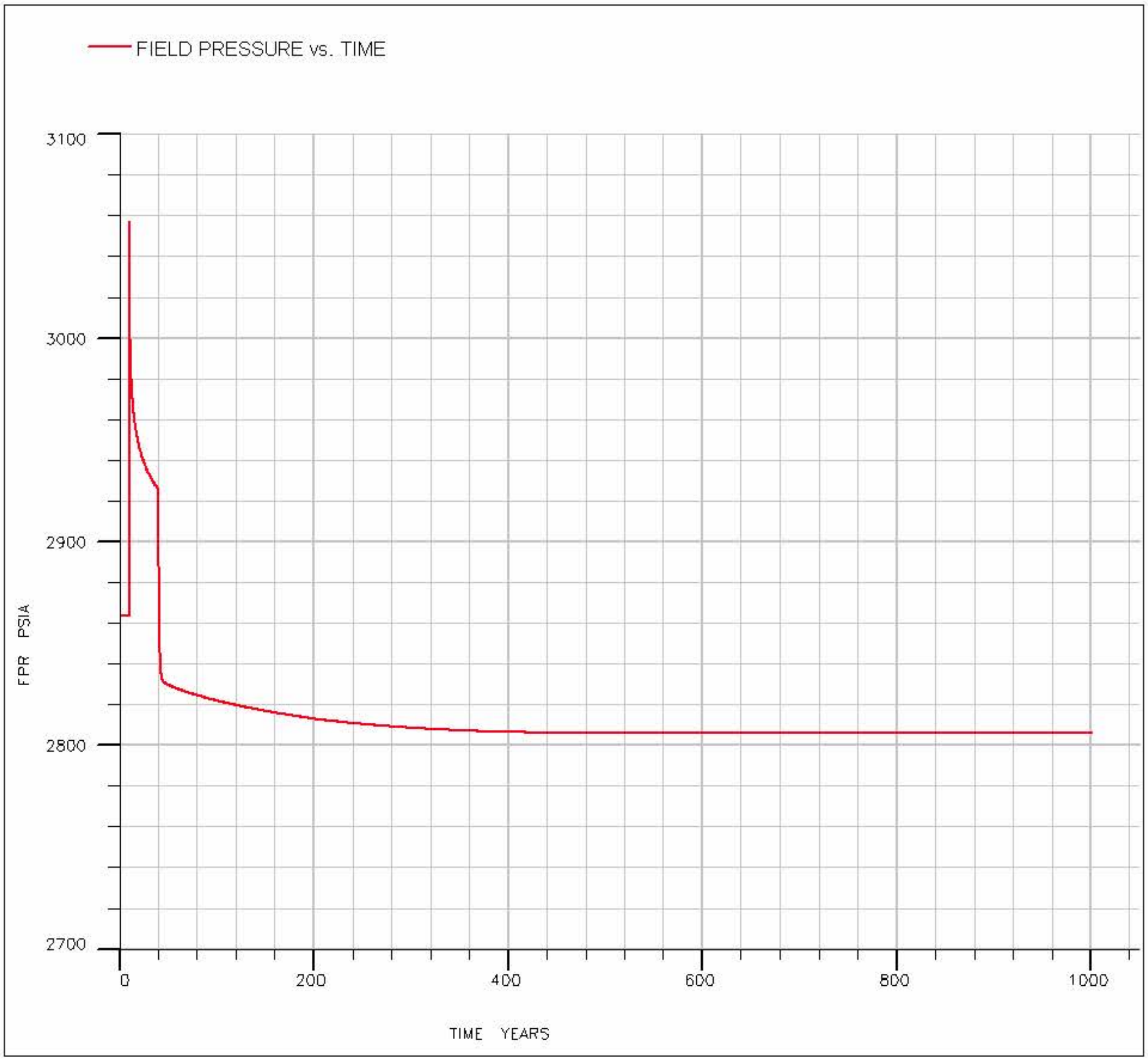

Figure D-2. 500 ft horizontal injection well field pressure results.

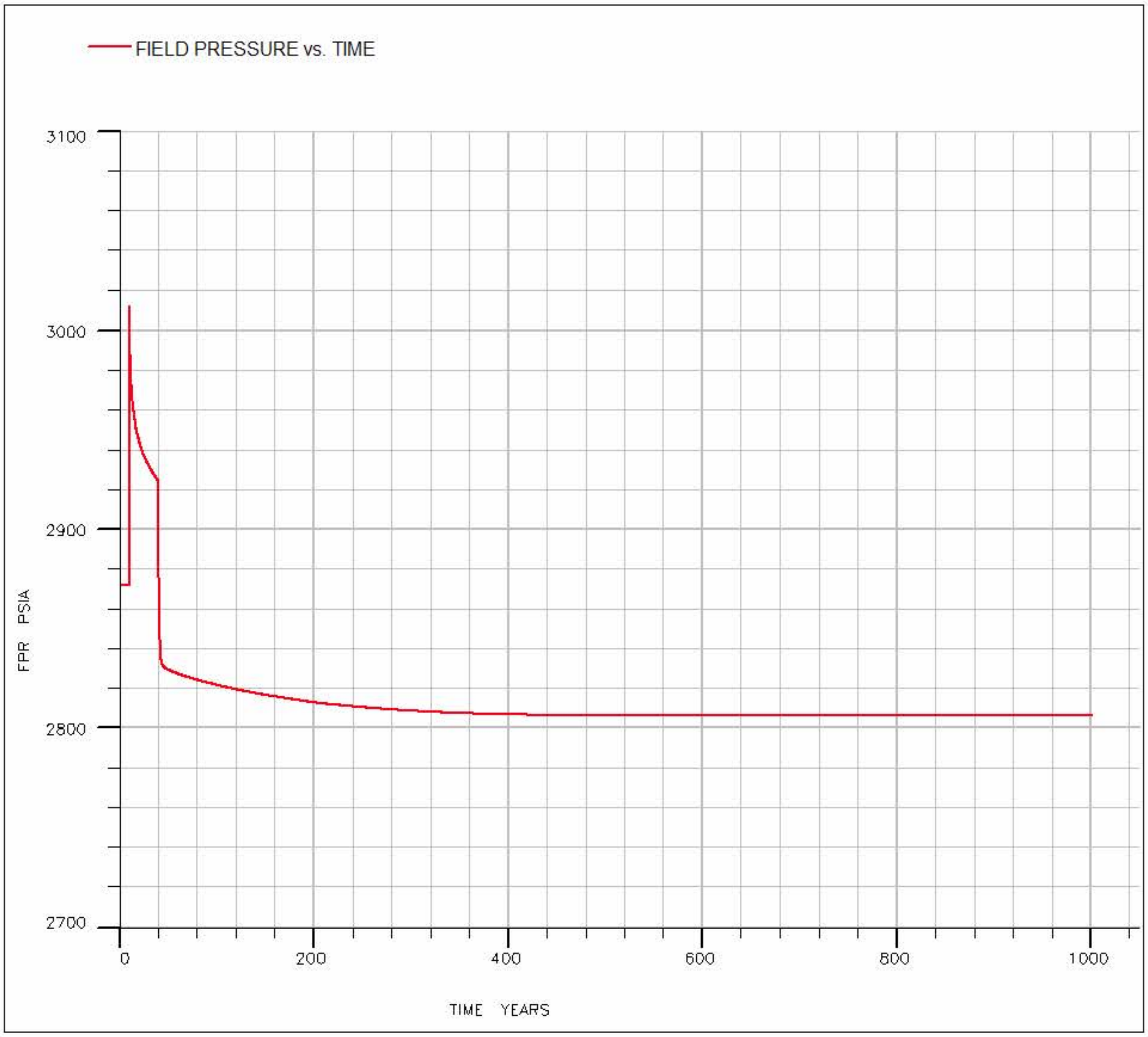

Figure D-3. 5,280 ft horizontal injection well field pressure results.

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