Preliminary Geologic Modeling and Flow Simulation Study of CO_2 Sequestration in a Depleted Oil Reservoir

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Abstract Sequestration of carbon dioxide (CO_2) in depleted oil reservoirs is one of the viable options for carbon management. This paper describes the preliminary modeling and flow simulation part of a DOE sponsored CO_2 sequestration project. The main objective of the project is to understand the feasibility of long term sequestration of CO_2 in a depleted oil reservoir through a field demonstration experiment. Before the actual CO_2 injection begins, it was necessary to determine feasibility of injection. Advanced geologic modeling and flow simulation techniques were used to develop a model for the proposed target interval. A geologic model was developed using data available from well logs and cores. Subsequently, porous media flow simulations were used to match the historic production data. Values of a number of unknown reservoir rock and fluid properties were determined by trial and error method due to lack of appropriate data. The reservoir model thus verified was subsequently used to determine feasibility of injecting CO_2 over a period of one month. A number of injection scenarios were tested to determine the response of the reservoir over a wide range of injection rates and regulatory operational constraints. The preliminary injection studies indicate that proposed amount of CO_2 could be injected in the target interval without violating regulatory constraints. It was also observed that the injected CO_2 plume could be of an extent to be monitored through a variety of proposed monitoring techniques.

Introduction

Safe, long-term sequestration of carbon dioxide (CO_2) is fast becoming a need because of the environmental impact of increased amounts of greenhouse gases in the atmosphere.

A number of alternatives are currently being studied to permanently remove CO_2 from the atmosphere. These can be divided in three main categories, ocean, terrestrial and geologic disposal. The potential capacities (in terms of amount of CO_2 disposed) of these alternatives vary. It is believed that ocean can accommodate as much as 1300 Gt of carbon, while geologic and terrestrial options can sequester up to 300 and 10 Gt of C, respectively, from the atmosphere. There are multiple geologic settings that can be used for geologic disposal, including, deep aquifers, depleted oil and gas reservoirs, coal beds and natural serpentinites/ultramafics caverns, etc. Each of the alternatives has advantages and disadvantages. Injection of CO_2 in depleted oil and gas reservoirs is one of the options where technology already exists because of the use of CO_2 in enhanced oil recovery operations. Recent advances in injection and drilling techniques make this a cheaper option. The knowledge of handling large amounts of CO_2 (which will be necessary for it to become a viable sequestration alternative) already exists, as enhanced recovery operations routinely handle large amounts of CO_2. This option also has an added benefit of possible additional recovery of oil and gas from the reservoir. Even with the technological advances and long history of CO_2 injection in enhanced oil recovery operations, a number of unknowns still exist. These unknowns include coupled physicochemical processes involving CO_2, water, oil and reservoir rock, capacity of reservoir for long-term sequestration and long-term fate of injected CO_2. In addition to increased understanding of fate of injected CO_2, precise and accurate monitoring technologies for determining presence and location of injected CO_2 are also lacking. All these issues need to be addressed before this alternative becomes a viable sequestration option.

Objective

This paper discusses parts of an ongoing field demonstration project to study sequestration of CO_2 in a depleted oil reservoir. The goal of the project is to improve understanding of mechanisms associated with this sequestration option and predict ultimate fate of injected CO_2 in the reservoir. Westrich et al. (2001) provides an overview of the various aspects of the project. One part of the project involves performing modeling and flow simulation studies associated with various aspects of this project, including,

1. Characterizing the study site and improving the existing understanding of the site geology and fluid flow dynamics.
2. Determining whether proposed amount of CO_2 can be injected in the target interval given the operational and regulatory constraints.
3. Aiding in the design of proposed geophysical monitoring techniques.
4. Improving the understanding of CO_2 migration through the reservoir.
5. Developing models for coupled physicochemical reactions to predict long-term fate of injected CO_2.

The first three objectives were part of the initial site-characterization study and were precursors to the actual injection. The site characterization study involved development of a geologic model, validation of the geologic model through production history match and preliminary injection studies. The scope of these preliminary simulations was limited because it modeled CO_2 injection using simple approximations. The details of the initial site-characterization studies are provided below.

Study Site

The study site chosen is a depleted oil reservoir in southeastern New Mexico (Figure 1). The field was first produced in 1984. Currently the wells are owned and operated by Strata Production Company (SPC) of Roswell, NM. To date, the field has produced more than 250,000 barrels of oil. All of the production has been through primary production. Increased water cut and reduced reservoir pressure has depleted the production and reduced profitability of the field in recent years. No secondary or enhanced recovery operations have been tried in the field following primary recovery. SPC owns five wells drilled and/or completed in the target interval. Currently only one of the five wells is on production. The proposed sequestration plan calls for converting one of the shut off wells to an injector and injecting CO_2 in one of the reservoir intervals. The currently producing well and two of the shut off wells will be used as monitoring wells.

Geology and Geologic Model

The productive zones are part of the Queen sands. The structure itself is a dome like structure. There are no faults present and fracturing is either completely absent or minimal so that it has no effect on oil in place or reservoir flow dynamics. The target injection interval consists of three distinct sands, namely A, B and C. In certain parts of the reservoir, sand B separates in two sands, B1 and B2. For the most part, the sands in the reservoir appear to be spatially continuous. The data available to characterize the reservoir was limited. No seismic data were available to help understand reservoir geology and develop a preliminary model. 3-dimensional seismic surveys are planned during the second year of the project, which will be used to improve the geologic model. The available geologic data primarily included well log data. The logs included Gamma Ray, Neutron Porosity, Density Porosity and Dual Laterologs (resistivity). The data was available for 11 wells in the region including the wells operated by SPC. In addition, core data were available for one of the wells, Stivason Federal 1. The core data consisted of porosity and permeability measurements.

A geologic model was developed to define the spatial extent of the sands and the spatial distributions of reservoir rock properties. The steps in developing the geologic model included first identifying the spatial extent of the interval of interest and developing a framework model defining the volumetric extent of the sands. The available log data were analyzed to identify tops and bottoms of the sands in all of the wells. The values for depths of sand tops and bottoms were subsequently used to create 2-dimensional surfaces representing their spatial extent. These surfaces were then used to generate a 3-dimensional stratigraphic framework model. The horizontal extent of the model was 6400 feet in x and y directions, while the sand thickness varied on the order of tens of feet.

The framework model was populated with reservoir rock properties, porosity and permeability. A correlation between the available core porosity and permeability data was calculated (Figure 2) for well Stivason Federal 1. This cross-correlation was used to generate permeability values at each well location from the porosity logs for corresponding well. 3-dimensional distributions of porosity and permeability values were generated from these log values. Figures 3-5 show the geologic model. The general structure is shown in Figure 3, while distributions of porosity and permeability are shown in Figures 4 and 5.

History Match

Before performing CO_2 injection studies, the geologic model was validated through a past production data match. The historic production data were available for the wells including amounts of oil, water and gas produced for every month. The data needed to perform multi-phase fluid flow simulations, such as relative permeability, capillary pressure curves, and thermodynamic data were not available. In order to perform the history match exercise, values for these properties were determined through a trial and error process of matching the past production data. This was deemed acceptable because for preliminary modeling study we wanted to get an estimate of the reservoir response to injection. The above approach for performing history match calculations would provide the necessary information of possible current reservoir pressure and saturation states. It would also provide information on the probable range of values for different parameters whose values are unknown as well as provide a general idea of reservoir dynamics. The history match was performed by constraining the oil production rates and matching the water and gas production rates. Once a satisfactory match for the historic production data was obtained the resulting model along with the saturation and pressure values were used to perform injection scenarios. The exercise provided some idea of the reservoir dynamics. The reservoir has produced mainly through depletion gas drive. There is very little, if any, aquifer support present. The simulation results indicate that at present the average reservoir pressure might be around 300-400 psia, though the exact measurement for reservoir pressure is not available at this time. There is still significant amount of oil left, but its economic recovery would require application of secondary or enhanced recovery methods. The initial estimates of relative permeability indicate that this is a water-wet reservoir. The saturation and pressure distributions predicted by the simulation studies at the end of history match exercise were used as the initial conditions for CO_2 injection studies.

CO_2 Injection

As mentioned earlier, the purpose of the preliminary simulation studies was to determine the feasibility of injecting a given amount of CO_2. Initial estimates called for injecting 1000-3000 tons of CO_2 over a period of one month. Simulations were performed to determine whether it is possible to inject that much CO_2 given operational and regulatory constraints. Regulatory constraints limited bottom hole injection pressures to 2900 psia. This constraint was calculated by the state regulation of injecting such that the pressure at the injection point does not exceed the hydrostatic pressure gradient by 0.2 psia/ft. We also wanted to know whether the available surface facilities would be able to handle injection of the proposed amount of CO_2. In the simulations, CO_2 was injected at the critical temperatures and pressures of CO_2. This condition assured that CO_2 would be injected as super-critical liquid. Simulations were performed using four different injection rates, namely, 1000, 2000, 4000 and 10,000 tons/month. For each rate, the injection was carried over for one month. After a month, the injection was stopped and the fate of injected CO_2 was monitored in the reservoir. As mentioned earlier, certain simplifying assumptions were used to perform injection simulations. The simulations were performed using ECLIPSE, an oil industry-standard simulator. A black oil model was used. The model assumed that CO_2 did not dissolve in water. The model did not account for diffusion of CO_2 and geochemical reaction of CO_2 with the reservoir rock. It also did not account for any compositional effects of CO_2 injection.

The simulations results are compared in Table 1. Table 1 shows the average bottom hole pressure in the target layer along with total amount of CO_2 injected over a period of one month. As seen from the Table, with the given regulatory pressure constraint complete injection is possible only for 1000 and 2000 tons. For the injection rates of 4000 and 10000 tons the bottom hole pressure reaches the state regulatory constraint. For 4000 tons/month rate, the well bottom hole pressure exceeds the imposed constraint only briefly and falls below the constraint for rest of the injection period. For the rate of 10,000 tons/month, the bottom hole pressure reaches 2900 psia within a period of days, once injection begins. In both these cases, the simulator changes the injection rate once the bottom hole constraint is exceeded. The new rate is calculated based on the constraint, resulting in lower total amount of CO_2 injection. Thus, the preliminary studies show that it is possible to inject at least 2000 tons of CO_2 in a month as proposed without exceeding regulatory constraints. Based on the simulator predicted bottom hole pressure, the surface injection pressures were calculated. For both 1000 and 2000 tons/month rates, this pressure was of the order of 1000 psia. The planned surface injection facilities are equipped to handle pressures of this order.

We also studied the migration of injected CO_2. As mentioned earlier, one of the objectives of these simulations was to see if the proposed geophysical monitoring tools would be able to detect the injected CO_2 plume. One of the techniques proposed is surface seismic survey. In order to ascertain feasibility of using surface seismic surveys, it was necessary to perform preliminary analyses of saturation and pressure changes. Changes in saturation and pressure result in changes in density, which can be characterized using seismic surveys. Figures 6-9 show time dependent saturation of CO_2 in the reservoir. Figures 6 and 8 show saturation at the end of the month (when injection stops) for rates 1000 and 2000 tons, while Figures 7 and 9 show the saturations one year after the injection was stopped. In the figures, two vertical cross-sections are shown through the injection well, Stivason Federal #4 (stiv_fed4 in the figure). The two wells producing from this interval, namely, Stivason Federal #5 (stiv_fed5) and Sun Pearl #2 (sun_pearl2), are also shown in the figures. The white color represents initial CO_2 saturation, which is assumed to be zero. As can be seen from Figures 6 & 8, the injection rate changes the extent of the plume migration. The extent of plumes as shown in the figures is a bit deceptive. Although, the plume appears to extend about 1300 feet from the injection well for both the rates, the saturation values in the grid blocks at the plume boundary are only around 0.02% and 0.8% for 1000 & 2000 tons/month respectively. After the injection is stopped, the plume does travel significant distances. For the rate of 1000 tons/month, the plume boundary extends up to 1700 feet from the injection well but the saturation at the boundary reaches only 0.03%. On the other hand, the saturations at 1100 & 1300 feet from the well reach values of 20% & 11%, respectively. Similarly, for the rate of 2000 tons/month, the plume boundary extends to 1900 feet one year after the injection is stopped, but the actual saturation value at the boundary reaches only 0.4%. For this case, the saturation at a distance of 1500 feet from the injection well reaches 22%. For 1000 tons/month injection rate, the saturation front of 40% extends only about

500 feet from the injection well at the end of injection, while after a year it extends by another 400 feet. On the other hand, for 2000 tons/month injection rate, the saturation front of 40% extends 700 feet from the injection well at the end of injection well and by another 400 feet one year after injection is stopped. Seismic surveys can also be used to monitor changes in pressure. Figures 10 & 11 show the reservoir pressures at the end of injection and 1 year after injection for the rate of 1000 tons/month, while Figures 12 & 13 show the same for 2000 tons/month. The change in reservoir pressure, calculated as the difference in the pre-injection and post-injection pressure, is shown in Figures 14-17. As can be seen from the pressure diagrams, there seems to be significant pressure disturbance. The pressure disturbance travels farther than the saturation disturbance. For 1000 tons/month injection rate the pressure at a distance of 1000 feet from the injection well changes by 100 psia at the end of injection. On the other hand, for the injection rate of 2000 tons/month, the pressure change of 100 psia is observed at a distance of 1300 feet from the injection well. The pressure disturbance subsides once the injection is stopped. As can be seen from Figures 15 & 17, the average pressure difference (compared to the pressure before injection begins) is about 10 psia for 1000 tons/month and 15-20 psia for the rate of 2000 tons/month. Note that the above mentioned numbers are only for one layer in the reservoir. Both the saturation and pressure disturbances do not travel as much distance in other layers. The target injection interval is at a depth of about 5000 feet from the surface. The average thickness of the entire interval is about 30 to 40 feet, while that of the above mentioned layer is about 10 feet. With the resolution of the surface seismic surveys, the above mentioned saturation and pressure variations may be detected together. Along with the other proposed well bore monitoring techniques such as micro-seismic survey, the injected plume may be monitored.

Conclusions and Future Work

Preliminary flow simulation study results are reported for feasibility of CO_2 injection in a depleted oil reservoir. The feasibility was studied given operational and regulatory constraints. Simulation results indicate that at least 2000 tons of CO_2 in the form of super-critical liquid can be injected in the reservoir over a period of one month. The second objective of simulations was to provide guidelines for determining feasibility of proposed geophysical monitoring techniques. Simulation results indicate that the combined saturation and pressure difference waves generated by injected CO_2 can be monitored through proposed monitoring tools, including surface seismic surveys. Future work may include the following:

- Incorporating additional data in the geologic model from the surrounding wells.
- Performing geostatistical analysis on reservoir properties distributions and understanding their effect on the behavior of injected CO_2.
- Increasing complexity of the flow simulation models by taking into account solubility of CO_2 in water, compositional effects and geochemical reactions with reservoir rock.

Acknowledgements

The authors wish to acknowledge the financial support from the Department of Energy's National Energy Technology Laboratory. The overall support of Mark Murphy from Strata Production Company is also appreciated.

References

Westrich. H. R. et al., Sequestration of CO_2 in a Depleted Oil Reservoir: An Overview, NETL Carbon Sequestration Conference Proceedings, May 15-17, 2001.

Table 1 Amounts of CO_2 Injected Over a Period of 1 Month.

Injection Rate (tons/month)	Total Amount of CO_2 injected in a month (tons)	Maximum injection bottom hole pressure (psia)
1,000	1,000	1,250
2,000	2,000	1,525
4,000	3,975	2,900 (briefly)
10,000	7,186	2,900

Figure 1. A map showing the study-site.

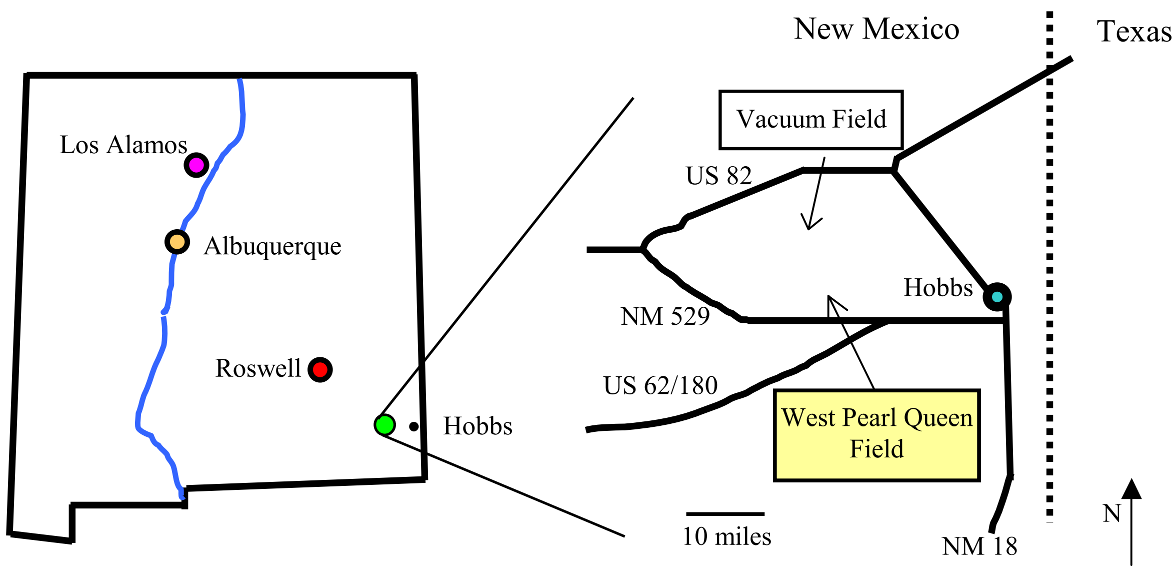

Figure 2. Porosity-permeability core data for well Stivason Federal 1.

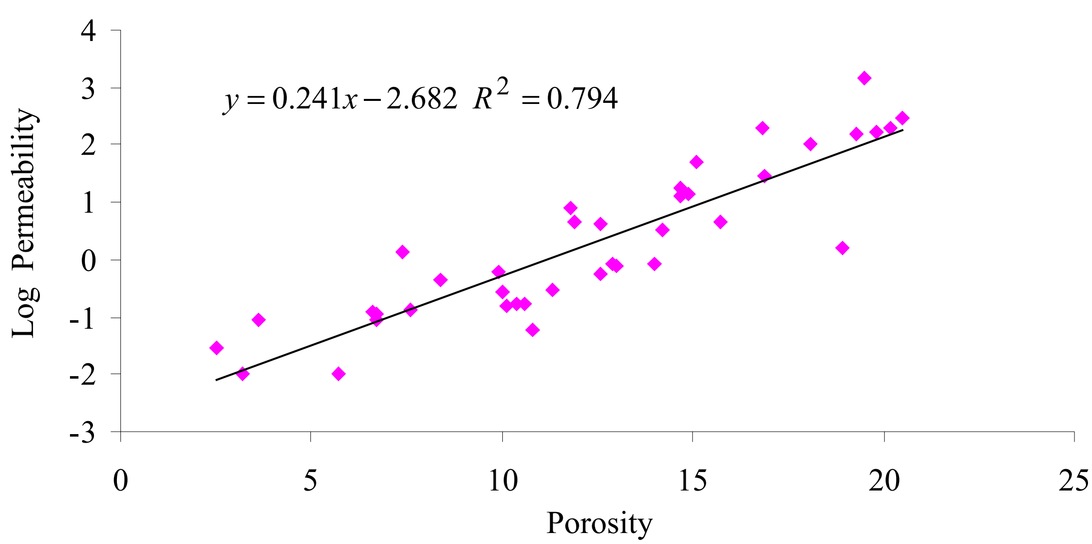

Figure 3. Structure of the target interval in the geologic model along with the wells (values shown are sub-sea elevation in feet).

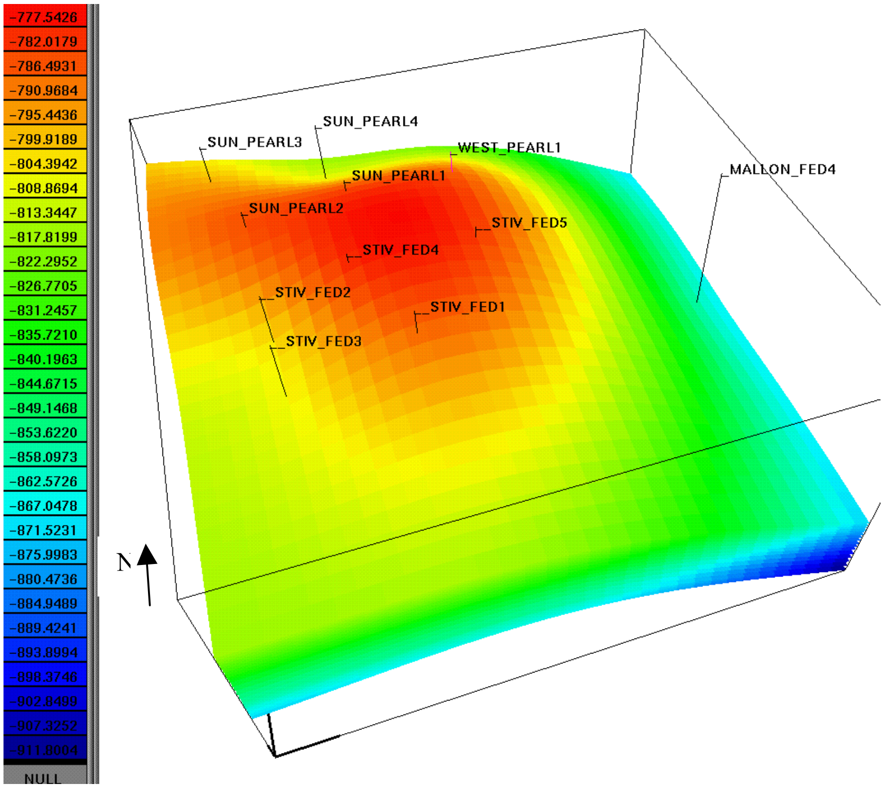

Figure 4. A cross-sectional view of the geologic model showing porosity distribution.

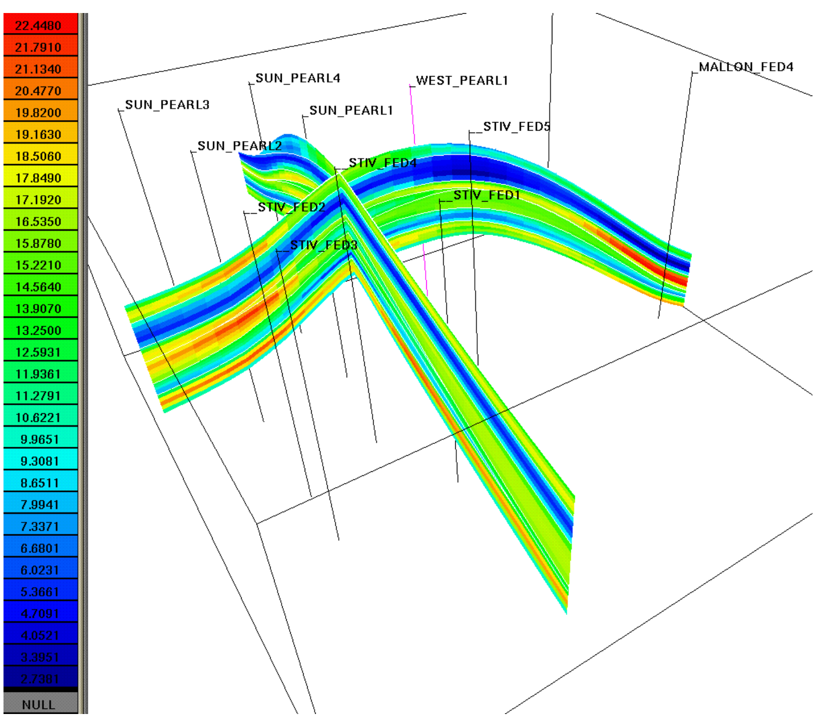

Figure 5. A cross-sectional view of the geologic model showing permeability distribution.

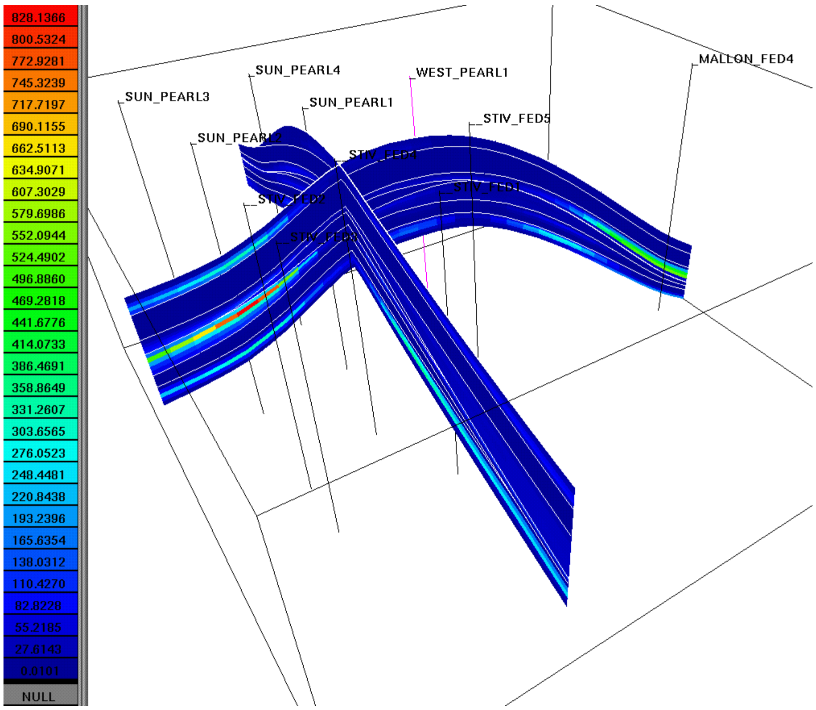

Figure 6. CO_2 saturation distribution at the end of injection period for the rate of 1000 tons/month.

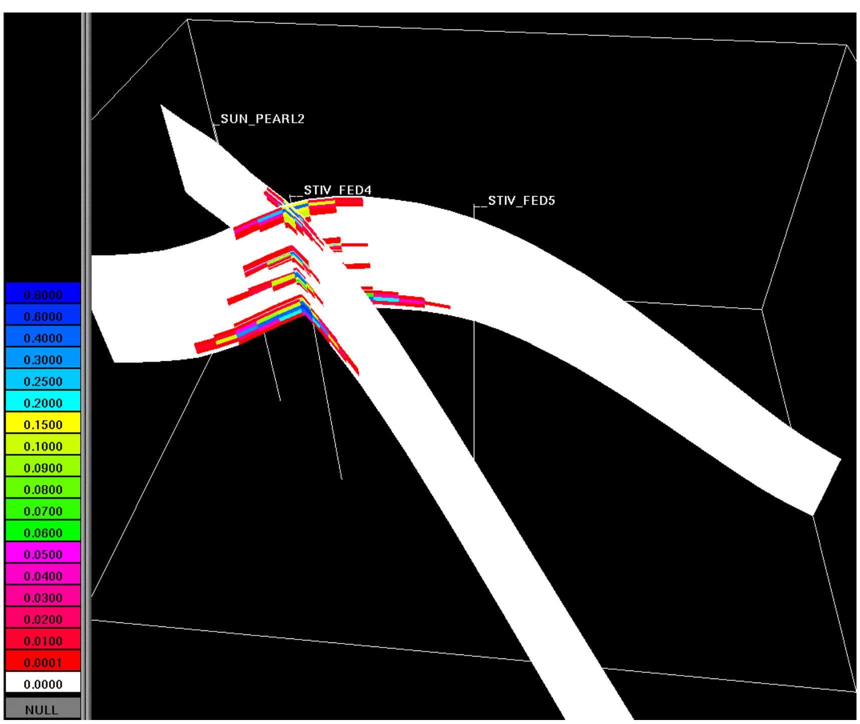

Figure 7. CO_2 saturation distribution 1 year after injection for the rate of 1000 tons/month.

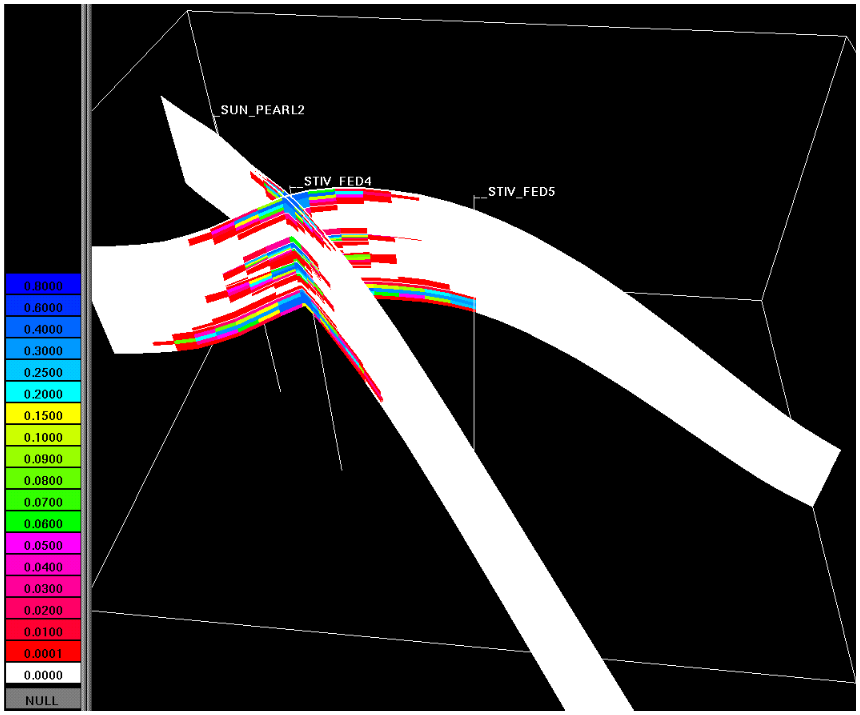

Figure 8. CO_2 saturation distribution at the end of injection period for the rate of 2000 tons/month.

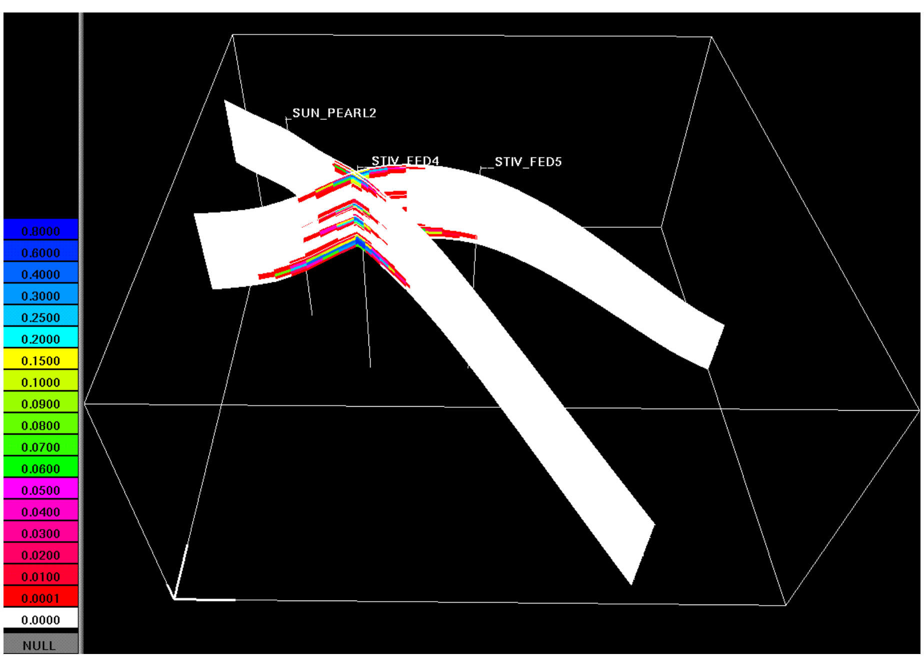

Figure 9. CO_2 saturation distribution 1 year after injection for the rate of 2000 tons/month.

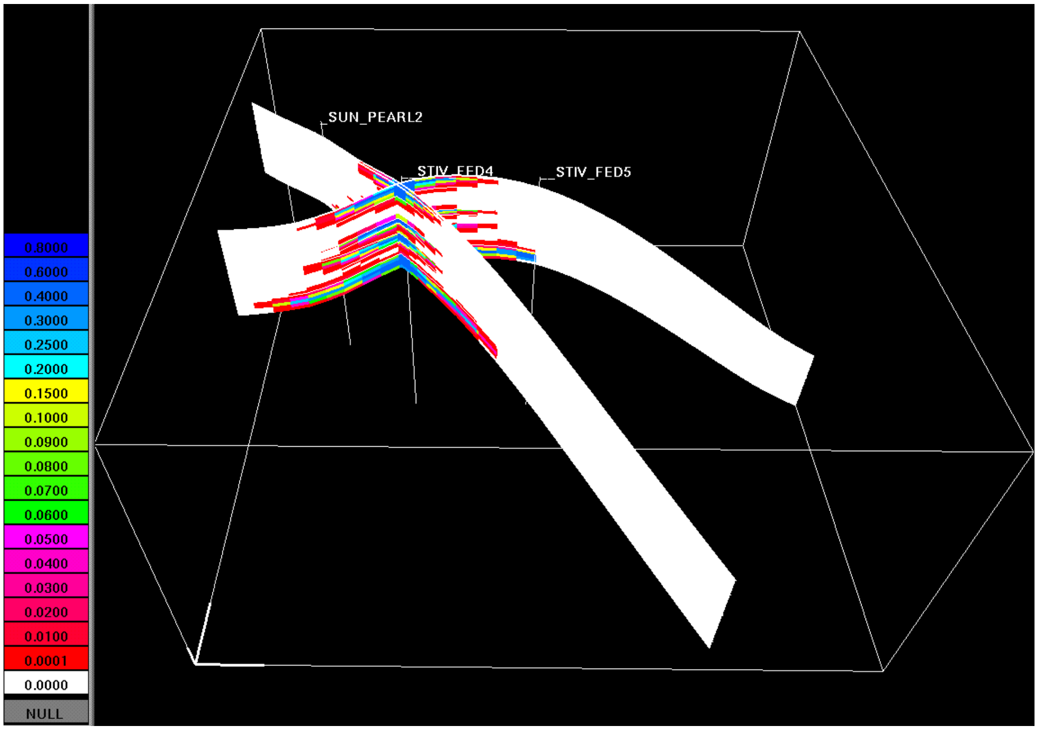

Figure 10. Reservoir pressure at the end of injection for the rate of 1000 tons/month.

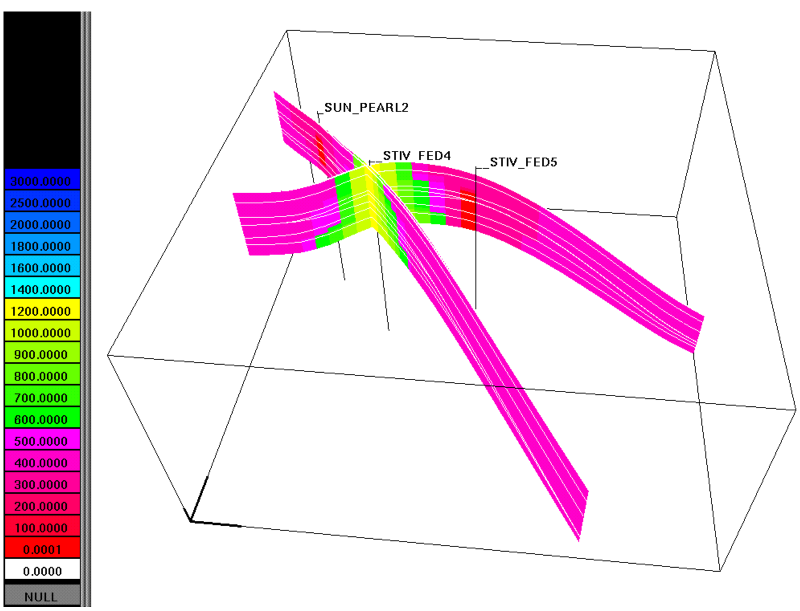

Figure 11. Reservoir pressure 1 year after injection for the rate of 1000 tons/month.

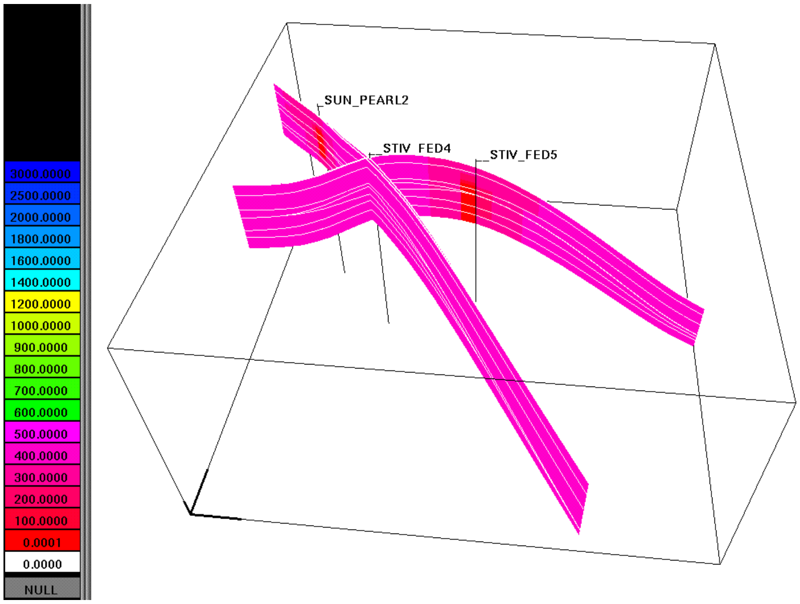

Figure 12. Reservoir pressure at the end of injection for the rate of 2000 tons/month.

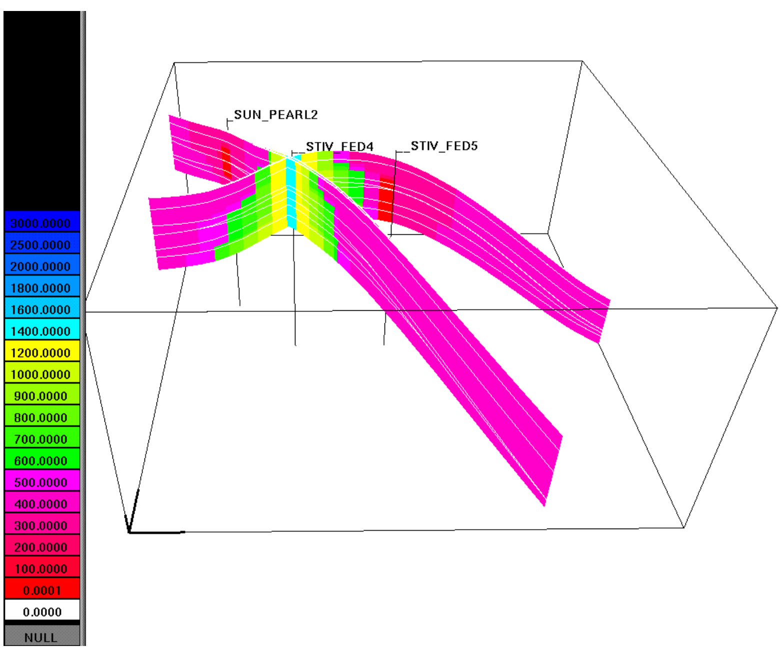

Figure 13. Reservoir pressure 1 year after injection for the rate of 2000 tons/month.

Figure 14. Pressure difference due to CO_2 injection at the end of injection for 1000 tons/month.

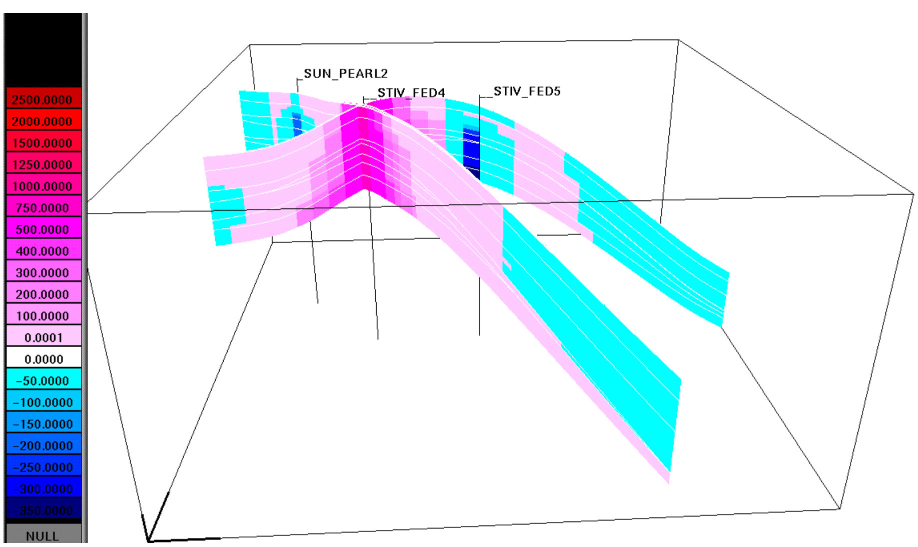

Figure 15. Pressure difference due to CO_2 injection 1 year after injection for 1000 tons/month.

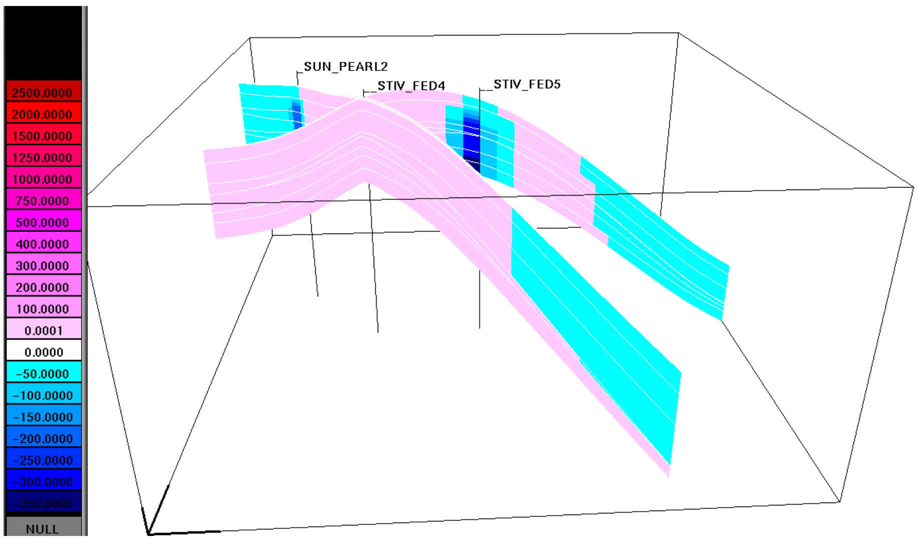

Figure 16. Pressure difference due to CO_2 injection at the end of injection for 2000 tons/month.

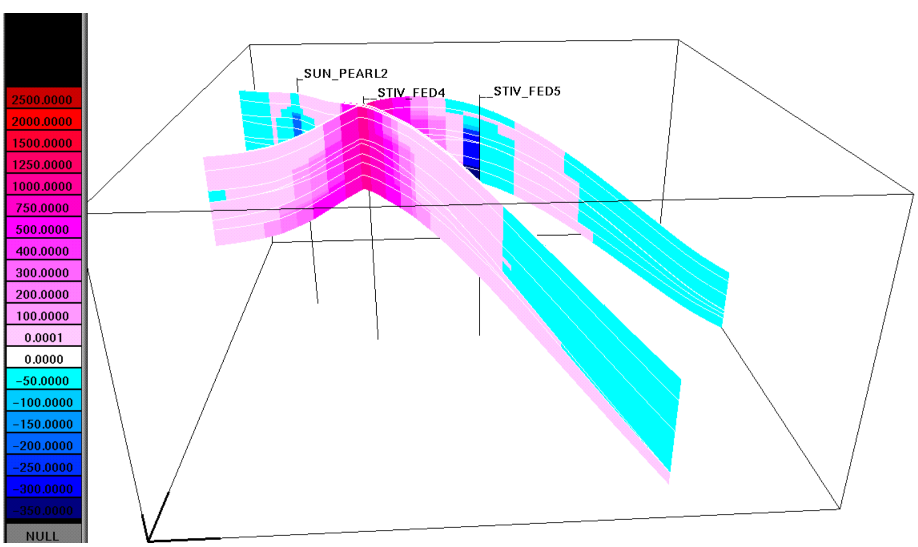

Figure 17. Pressure difference due to CO_2 injection 1 year after injection for 2000 tons/month.