GEOLOGIC MODELING AND SIMULATION OF CO_2 STORAGE IN THE CLOVERLY FORMATION, WESTERN NEBRASKA, USA

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INTRODUCTION

The Energy & Environmental Research Center (EERC) at the University of North Dakota conducted a prefeasibility study for a commercial-scale carbon dioxide (CO_2) geologic storage complex in western Nebraska, USA. Regional geologic models were built for two potential storage complexes: the Cretaceous Cloverly Formation (Dakota Group) and Permian Cedar Hills Formation.

Dynamic flow simulation was conducted to assess the prefeasibility of storing 50 million tonnes (Mt) of CO_2 over 25 years in a portion of the Cloverly Formation in Nebraska. Given the high degree of uncertainty in the geologic heterogeneity of the sandstone, three probability distributions of formation properties (optimistic [P90], average [P50], and conservative [P10]) were considered for numerical simulations.

OBJECTIVES

The main goals of the simulation study were to investigate the following for each distribution (model):

- Volumetric CO_2 storage potential.
- Potential locations and number of injection wells required to inject 50 Mt of CO_2 over 25 years in the Cloverly Formation.
- Wellhead pressure (WHP) ranges for injection wells and the associated parameter impact on WHP via a sensitivity analysis.
- An optimum WHP as a required injection (operation) pressure to inform infrastructure design.
- Area of review, which is determined by the extent of CO_2 plume and pressure plume as a result of CO_2 injection into the formation.
- Postinjection CO_2 plume migration and pressure stabilization.

GEOLOGIC MODEL

The Cloverly regional model was populated with lithofacies and geostatistical porosity and permeability to determine total pore volume (net area × net thickness × distributed porosity). The Cloverly simulation model (Figure 1) was clipped from the Cloverly regional model. Petrophysical data were calculated based on legacy core data. The major and minor influence ranges of the geostatistical Cloverly models were determined from the literature for fluvial channel sands (IEA Greenhouse Gas R&D Programme, 2009).

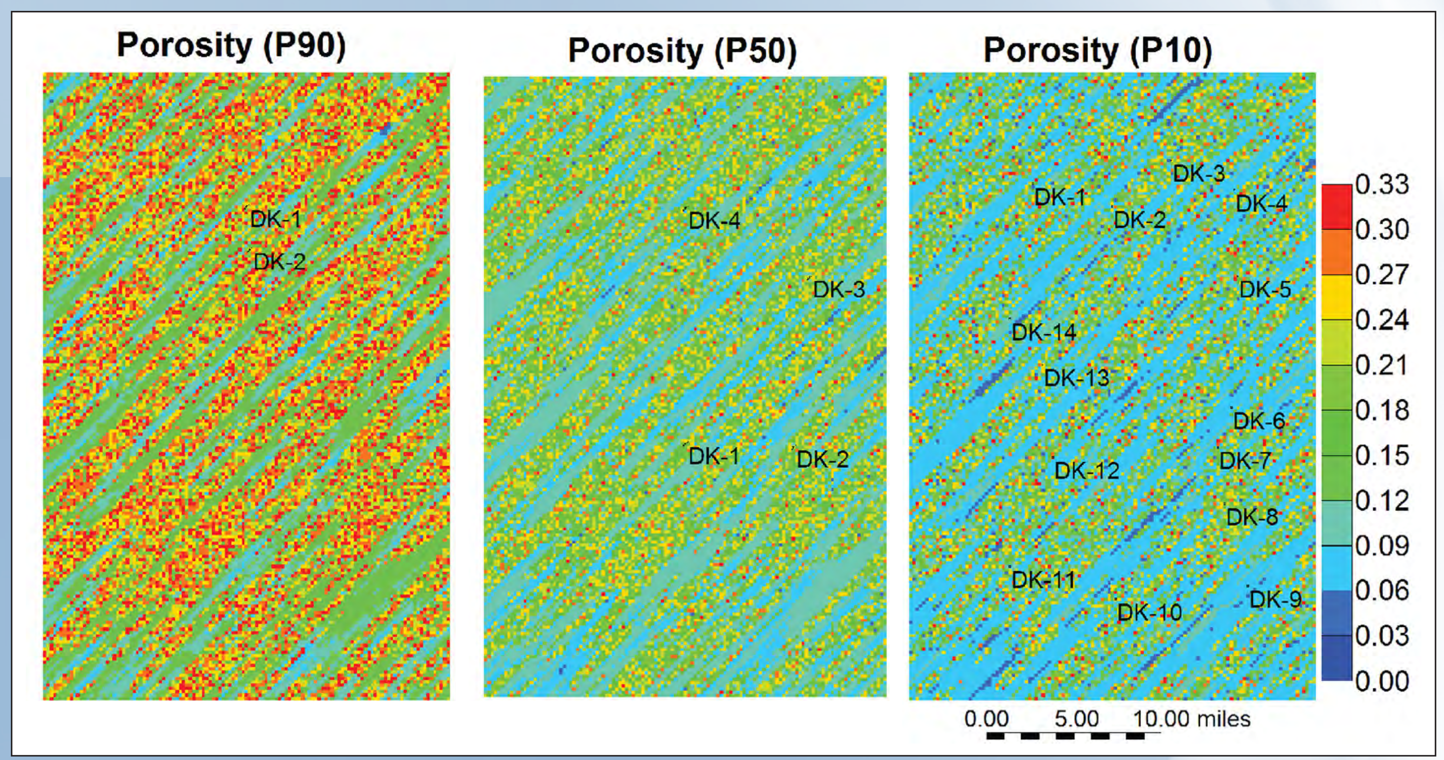
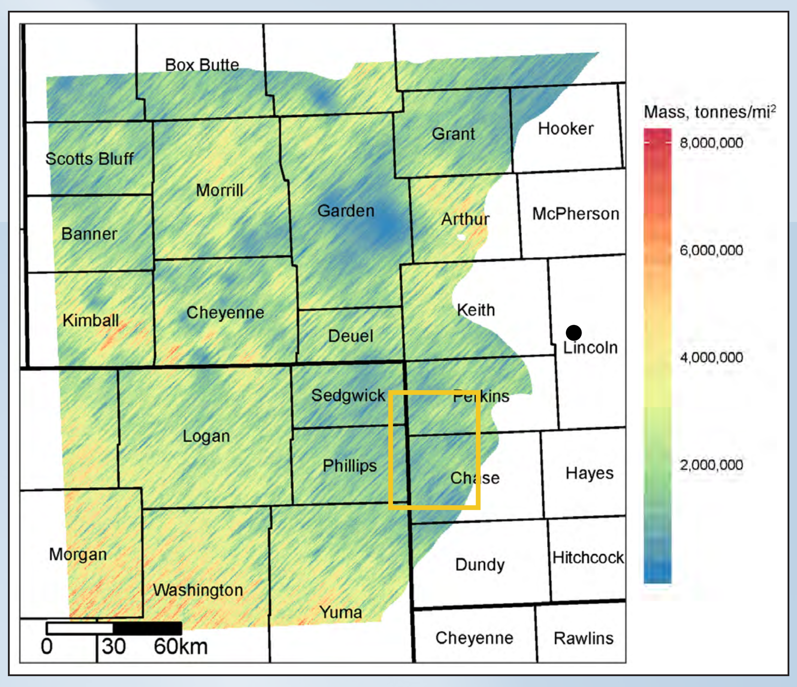


Figure 1. Porosity distributions (in plan view) with the potential well locations for CO_2 injection for P90, P50, and P10 models (from left to right). The injection wells are labeled "DK" (Dakota).

VOLUMETRIC STORAGE POTENTIAL

A modified U.S. Department of Energy (DOE) method of calculating CO_2 storage potential in saline formations was used for the regional Cloverly model (Peck and others, 2014). This method applies different Esaline values to total porosity estimates based on known factors incorporated into a model: net area, net thickness, and net porosity (Figure 2). To estimate the size of a 50-Mt CO_2 plume based on the volumetric storage potential, a moving-window algorithm was used (Figure 3).

Figure 2. Regional volumetric CO_2 storage potential estimate for the Cloverly Formation (P50 known net area and net thickness Esaline), summed vertically. Dot represents the Gerald Gentleman Station. Gold rectangle denotes simulation model area.



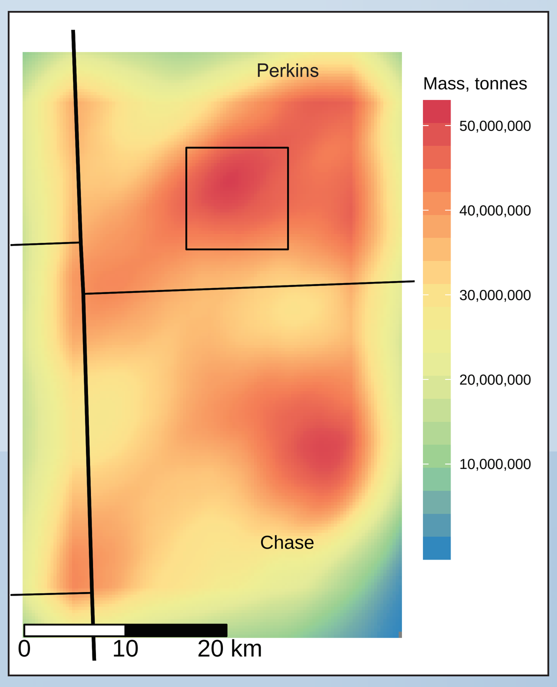


Figure 3. Simulation model volumetric CO_2 storage potential estimate in the Cloverly Fm within a 6.2-mile (10-km)-square moving window (size denoted by square in Perkins County). The color of each grid cell represents the amount of storage potential within a square window centered on that cell.

CO_2 AND PRESSURE PLUMES

The simulation results indicate that two, four, and 14 injection wells will be potentially required for the respective P90, P50, and P10 models to store 50 Mt of CO_2 over a time period of 25 years (Figure 4). The extent of the pressure plume was extensively large in all three models because the high shale content in the model does not allow pressure to dissipate uniformly, resulting in directional and larger pressure plumes (Figure 5).

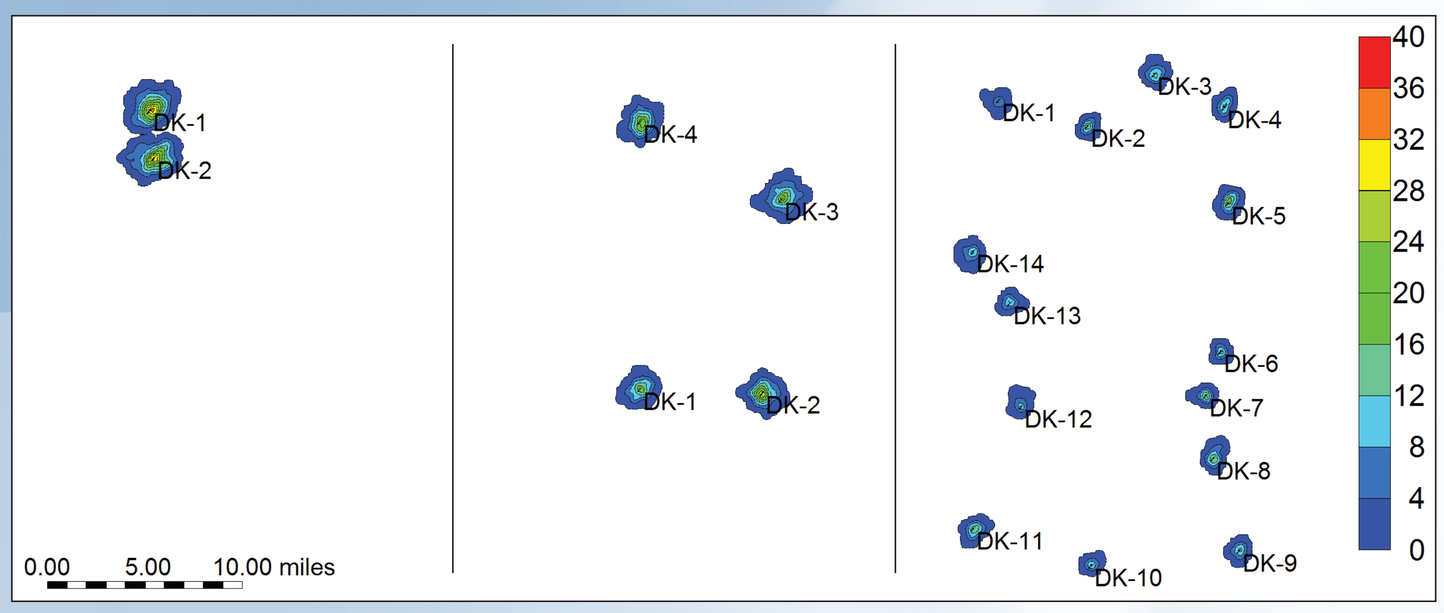
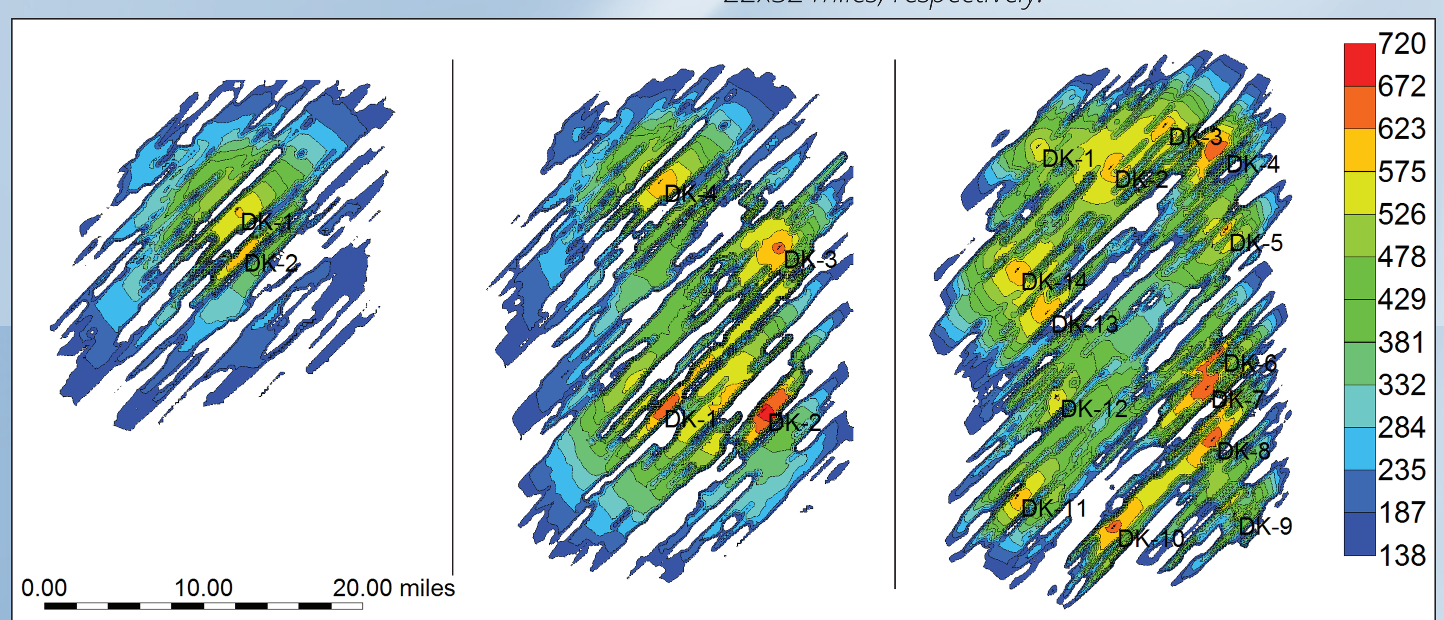


Figure 4. Simulated CO_2 plumes (in plan view) for the P90, P50, and P10 models (from left to right) at the end of a 25-year CO_2 injection operation. CO_2 per Unit Area = CO_2 Saturation x Porosity x Thickness. The CO_2 plume diameters measure approximately 3.5, 3, and 2 miles around each injection well, respectively.

Figure 5. Simulated pressure plumes (in plan view) for the P90, P50, and P10 models (from left to right) at the end of a simulated 25-year CO_2 injection operation. The lower limit in pressure scale is bounded by the pressure threshold value of 138 psi. The pressure plume dimensions measure approximately 20x20, 21x30, and 22x32 miles, respectively.



WELLHEAD PRESSURE SENSITIVITY

Based on the information obtained from the sensitivity analysis (Figure 6), CO_2 injection at an optimum WHP was investigated to inform infrastructure design and associated economic study. Two different tubing sizes (3.5- and 4.5-inch diameters) were selected to investigate the required maximum WHP. A higher wellhead temperature of 90°F was used in this investigation to determine an optimum WHP for CO_2 injection. Table 1 gives the simulated WHP values for 3.5- and 4.5-inch tubing for the respective models. Based on this investigation, a WHP of 1300 psi using a larger tubing size of 4.5 inches was suggested for the required injection pressure because maintaining injection at a lower pressure is a cost-effective decision for the infrastructure design (gas compression system).

Model	WHP (psi), 3.5-inch Tubing	WHP (psi), 4.5-inch Tubing
P90	1900	1300
P50	1500	1260
P10	1250	1240

Table 1. Simulated Maximum WHPs with Different Tubing Sizes

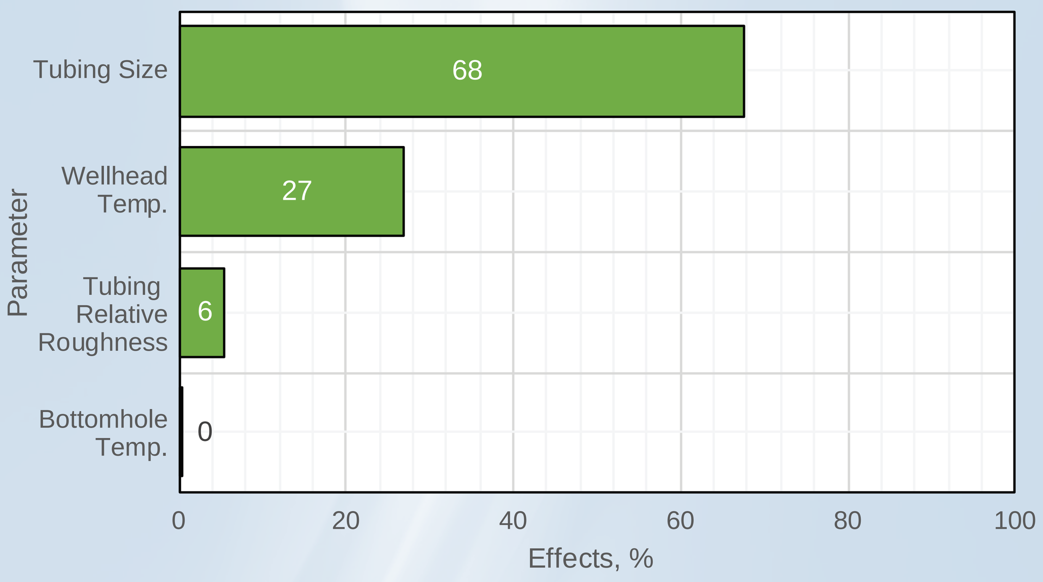


Figure 6. Relative effect of well parameters on WHP.

POSTINJECTION

The CO_2 plume per well grew by 1 mile to approximately 4.0 miles at the end of the 100-year postinjection simulation period. To demonstrate how small the pressure plume became during the postinjection period, the remaining pressure buildup (maximum value of 350 psi) at the end of 40 years of postinjection is shown in Figure 7, compared to the pressure plume at the end of the 25-year injection period shown in Figure 5 (the middle image, P50 model).

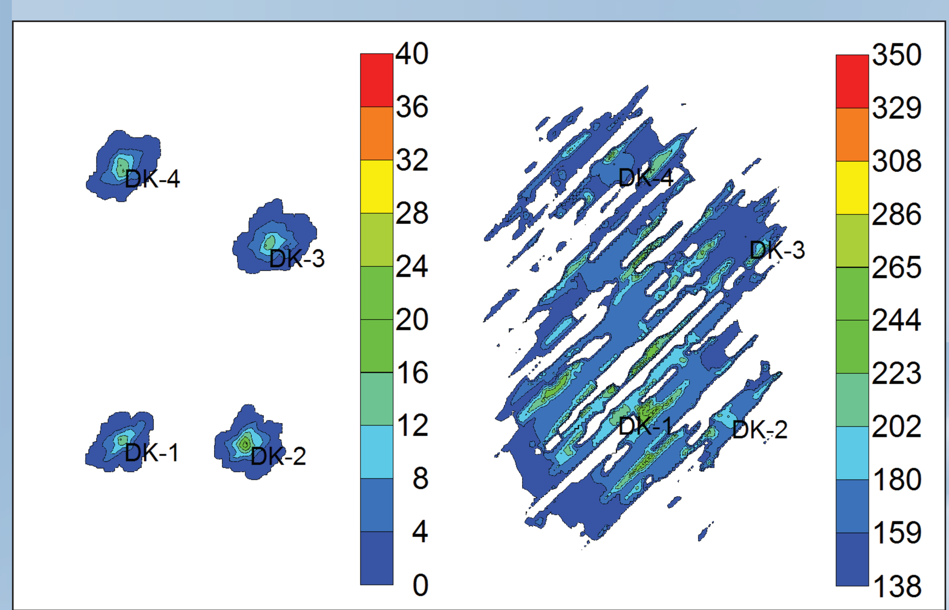


Figure 7. The postinjection CO_2 plume (in plan view) after 100 years of postinjection (left) and pressure plume extent after 40 years of postinjection (right).

REFERENCES

IEA Greenhouse Gas R&D Programme, 2009, Development of storage coefficients for CO_2 storage in deep saline formations: IEA Greenhouse Gas R&D Programme Technical Study, Report No. 2009/13.

Peck, W.D., Glazewski, K.A., Klenner, R.C.L., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2014, A workflow to determine CO_2 storage potential in deep saline formations: Energy Procedia, v. 63, p. 5231–5238.

ACKNOWLEDGMENTS

This research is supported by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), Award Number FE0026516, as part of DOE's Carbon Storage program. This work is being done in collaboration with the Computer Modelling Group Ltd. (CMG). CMG provides the EERC with in-kind cost share in the form of reservoir modeling and simulation software necessary to complete the project objectives. National Risk Assessment Partnership (NRAP) tools were employed for the risk assessment validation.