MODEL DEVELOPMENT OF THE AQUISTORE CO_2 STORAGE PROJECT

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Abstract

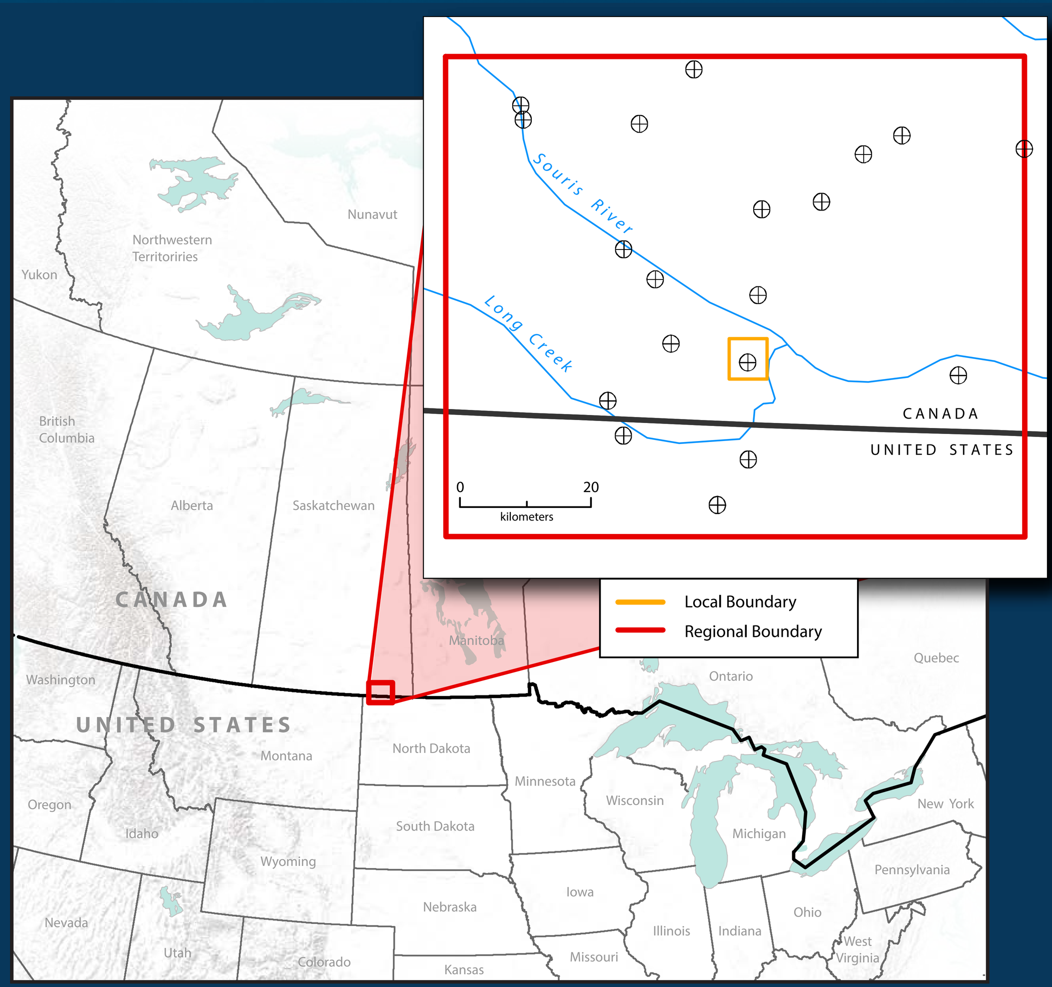
The Plains CO_2 Reduction (PCOR) Partnership, through the Energy & Environmental Research Center, is collaborating with Petroleum Technology Research Centre (PTRC) in site characterization; risk assessment; public outreach; and monitoring, verification, and accounting activities at the Aquistore project. The Aquistore project is a carbon capture, utilization, and storage (CCUS) project situated near Estevan, Saskatchewan, Canada, and the U.S.–Canada border. This project is managed by PTRC and will serve as buffer storage of carbon dioxide (CO_2) from the SaskPower Boundary Dam CCUS project, the world's first commercial-scale postcombustion CCUS project from a coal-fired electric generating facility. To date, an injection well and an observation research well (~152 m apart) have been drilled and completed at the Aquistore site, with injection anticipated to begin in fourth quarter 2014. Using a combination of site characterization data provided by PTRC and independently acquired information, the PCOR Partnership has constructed a static geologic model to assess the potential volumetric storage capacity of the Aquistore site and provide the foundation for dynamic simulation of the dynamic storage capacity. The results of the predictive simulations will be used in the risk assessment process to help define an overall monitoring plan for the project and to assure stakeholders that the injected CO_2 will remain safely stored at the Aquistore site.

The deep saline system targeted for storage comprises the Deadwood and Black Island Formations, the deepest sedimentary units in the Williston Basin. At over 3150 m below the surface, this saline system is situated below most oil production and potash-bearing formations in the region and provides a secure location for the storage of CO_2. Characterization data acquired from the Aquistore site for these formations include petrophysical core data, a comprehensive logging suite, and 3-D seismic data for structural control.

Approach

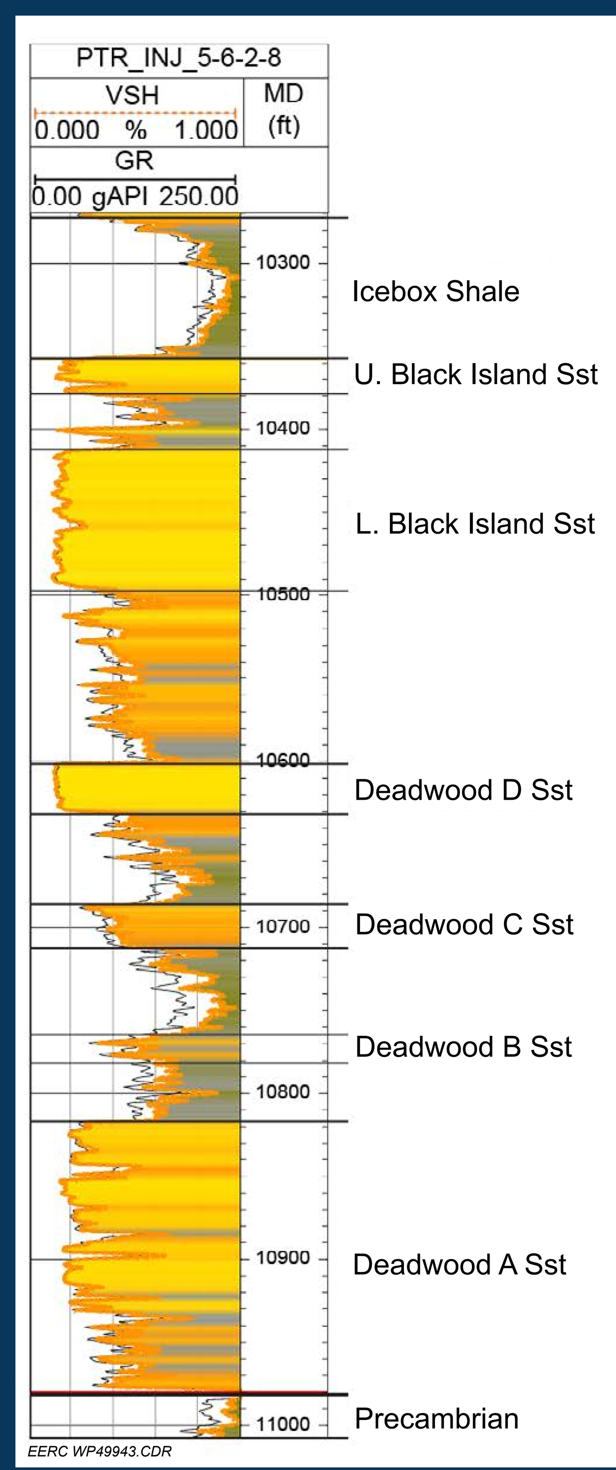
The workflow for model development and optimization included 1) petrophysical log analysis, 2) stratigraphic correlation and structural analysis, 3) data analysis, 4) petrophysical modeling, 5) uncertainty analysis, and 6) model upscaling and grid refinement. Total porosity and shale volume were calculated on 15 wells using the neutron density and gamma ray methods, respectively. Porosity results were also calibrated to data measured from routine core analysis data performed on whole and sidewall core. The shale volume derived by the petrophysical analysis was used to divide the model into 12 traceable zones, including six sand units (two in the Black Island and four in the Deadwood Formation) and six shale units throughout the regional study area.

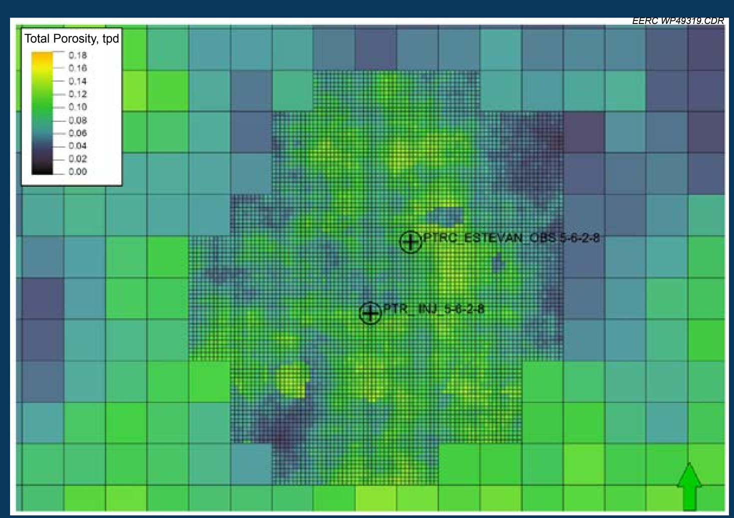
To evaluate the targeted saline system, and thus its viability as a potential sink, the geocellular model was used as the framework for an assessment of the dynamic storage capacity of the system. Through the dynamic simulation effort, two main objectives were established for this project: 1) assess the dynamic storage capacity of the saline system and 2) assess the risk by simulating the reservoir performance during CO_2 injection and postinjection. To address these objectives, the refined model (33.9 km²) was used to determine the injectivity of study area through the various injection rates and periods to investigate the timing of CO_2 breakthrough in the observation well and near-wellbore CO_2 movement. All of the dynamic simulations were performed using Computer Modelling Group Ltd.'s (CMG's) Compositional & Unconventional Reservoir Simulator (GEM) (www.cmgl.ca/) on a 184-core, high-performance parallel computing cluster.



Regional-Scale Model
- 9472 km²
- Limited well control
- 12 stratigraphic zones, 102 layers
- Saline system varies from 34 to 200 m thick

Local-Scale Model
- 33.9 km², same size as 3-D seismic extent
- 7.6 x 7.6 and 76 x 76 m grid size
- Zonation and vertical resolution same as regional-scale model
- Includes four pseudo-wells generated from regional-scale model





Local grid refinement created to keep the grid resolution around the observation and injection wells while reducing the overall model cell size to increase and optimize the dynamic simulation. Large cells are 76 × 76 m and small cells are 7.6 × 7.6 m.

Results

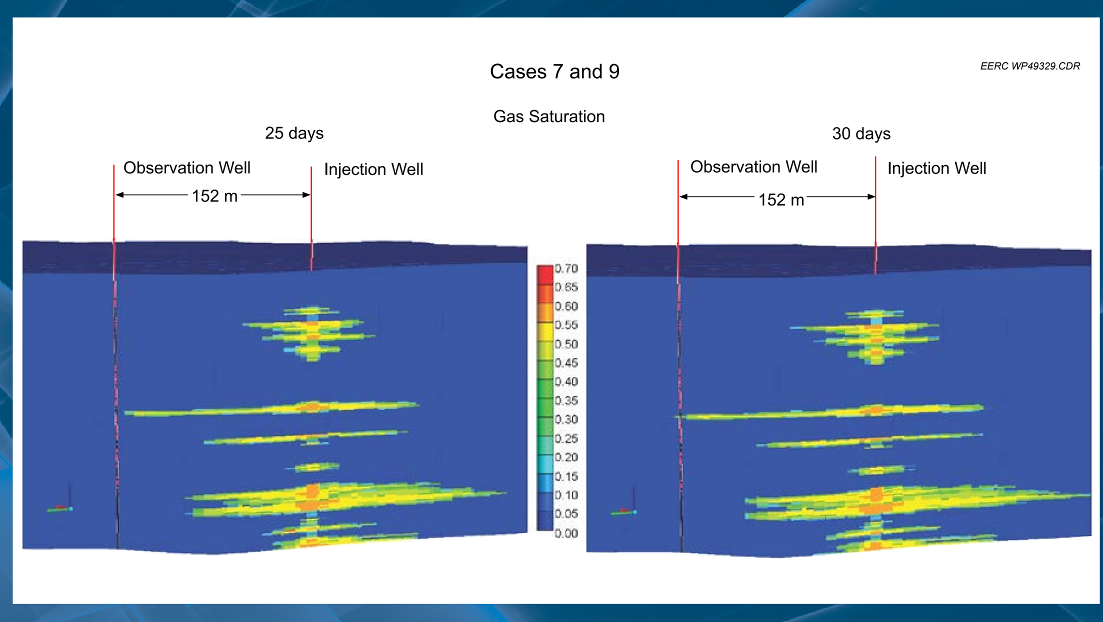
Based on the simulation results, the storage of CO_2 in the study area using the existing two-well configuration is feasible, depending on the volume of CO_2 available from the Boundary Dam power plant. The static CO_2 capacity for the local-scale model ranges from 8.4 to 27.1 million tonnes (Mt) for the P10 and P90 confidence levels, respectively. The maximum simulated injectivity for the current injection well is 0.73 Mt/yr based on the geological characterization of the study area. Based on these simulation results, the maximum storage potential of the Aquistore site with one injection well is approximately 34 Mt after 50 years. However, this can be improved based on optimization operations such as multiple injectors, formation water extraction, and horizontal injection. The larger-capacity value obtained through the dynamic modeling suggests that the storage coefficient used in the static approach may be too low and that the CO_2 will successfully interact with a larger percentage of the system.

Based on the simulated CO_2 injection cases, the earliest CO_2 breakthrough to the observation well may happen in as few as 15 days with a 0.73-Mt/yr injection rate. The breakthrough time at the observation well may be extended to 1 month if the injection rate is reduced to 0.3 Mt/yr. The simulated overall CO_2 breakthrough in the other reservoir zones occurred after about 3 months of injection with the low injection rate, and this breakthrough time was reduced to about 45 days at the high injection rate. The simulated pressure response in all cases indicated that the system was locally pressure-limited in the open-system cases, as an injection rate of 1 Mt/yr was not achieved in any case. In the closed-system cases, pressure was also limited by boundary conditions, which resulted in a much lower injection rate.

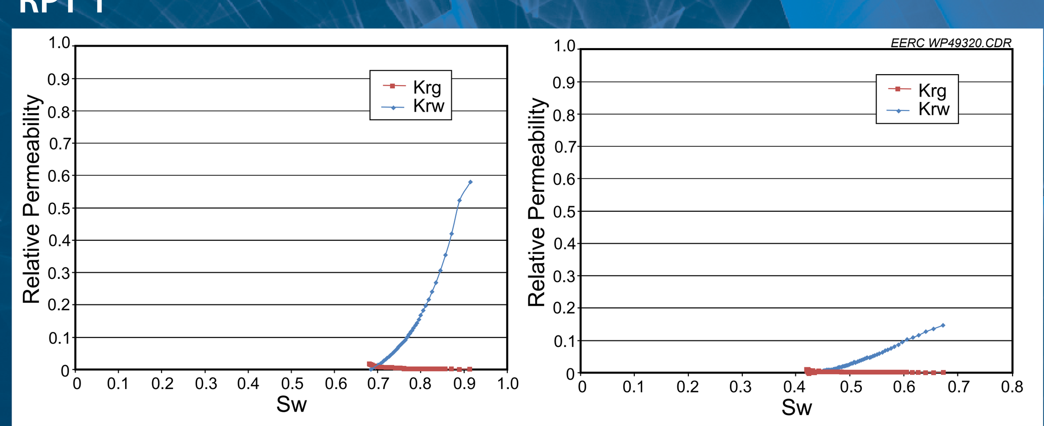
Simulation Results Summary for Nine Cases by Varying Simulation Factors

Case	Boundary conditions	Injection rate, Mt/year	Injection period, years	Relative permeability	Total injected CO_2, Mt	Breakthrough, days
1	Closed	1	50	RPT 1[1]	1.505	N/A*
2	Closed	1	50	RPT 2[2]	6.337	N/A
3	Opened	1	50	RPT 2	33.652	N/A
4	Opened	1	5	RPT 2	3.663	10
5	Opened	1	1	RPT 2	0.671	15
6	Opened	0.3	5	RPT 2	1.593	25
7	Opened	0.3	5	RPT 3[3]	1.465	25
8	Opened	0.3	1	RPT 2	0.290	30
9	Opened	0.3	1	RPT 3	0.286	30

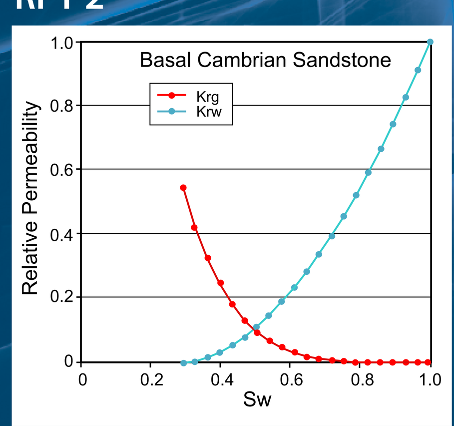
*Not applicable.



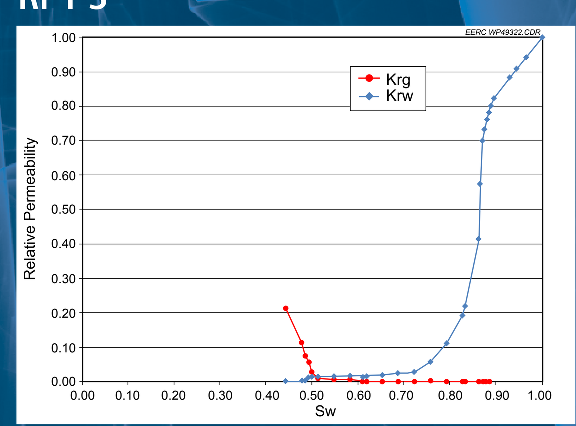
RPT 1



RPT 2



RPT 3



PCOR Partnership 2003 – Present

Acknowledgments

The authors extend thanks and recognition to PTRC and, specifically, Neil Wildgust and Kyle Worth for sharing detailed geologic information related to the injection and observation wells drilled for the Aquistore project. We also thank Schlumberger Carbon Services for providing its base model for our use and review and Wade Zaluski of Schlumberger for providing access to the Aquistore core as well as core plugs for our testing and examination.

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