Evaluation of Large-Scale Carbon Dioxide Storage Potential in the Basal Saline System in the Alberta and Williston Basins in North America

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Abstract

As one of the U.S. Department of Energy's (DOE's) Regional Carbon Sequestration Partnerships, the Plains CO_2 Reduction (PCOR) Partnership has performed a case study on the feasibility of large-scale underground carbon dioxide (CO_2) storage in the basal saline system of central North America. The area of investigation encompasses approximately 1,500,000 km^2 of the Alberta and Williston Basins located in the provinces of Alberta, Manitoba, and Saskatchewan in Canada and the states of Montana, North Dakota, and South Dakota in the United States. The thickness of the system is up to 300 m, with permeability ranging from 0.0001 to 1250 mD and porosity ranging from 0.01% to 25%. The calculated volumetric CO_2 storage resource potential in this saline system is 480 billion metric tonnes. However, this estimate does not consider the time or number of wells required to inject this mass of CO_2, and the realistic injectivity of any given well is highly dependent on the site-specific reservoir properties and pressure buildup during the CO_2 injection. In order to estimate realistic capacity ranges for the basal saline system, injection simulations were carried out to better understand the site-specific parameters such as reservoir properties, well spacing and number, injectivity, and local and regional pressure buildup.

In the study area, the large-scale CO_2 emissions were aggregated as 16 and 25 large-scale CO_2 sources for Scenarios 1 and 2, respectively. Two scenarios, comprising a total of 16 cases, were designed to address the dynamic CO_2 storage capacity and pressure transient. To increase the injectivity and maximize the efficiency of storage resource, various strategies were tested including injection well location and spacing, injection rate optimization, and water extraction during CO_2 injection. Several geologic variations were also tested to determine the effect of different geologic uncertainties on the dynamic storage capacity, including modifications to the ratio of vertical permeability and horizontal permeability (Kv/Kh), boundary condition, and relative permeability. Dynamic simulations were set to initiate in 2014 and ended in the year 2064 for the 50-year injection period. Another 36-year postinjection period followed to check the pressure transient for the whole domain.

The results indicate that the total injected CO_2 is 82.2 Mt for the base case, which includes a single injector at each of the 16 CO_2 source locations in Scenario 1. To improve injectivity, the number of

injection wells was increased to 210. The added wells increased the total injected CO_2 by 37% to 112.3 Mt. In another case, a total of 20 water extractors were placed in conjunction with the injectors at the largest CO_2 emission source location, which resulted in the total CO_2 injected increasing to 183.1 Mt, 63% higher than the previous case. The cases exploring various Kv/Kh ratios showed the resulting effect on the dynamic storage capacity to be very small. However, the case involving changes to the relative permeability curves showed a significant increase in the storage capacity over the base case. A time-stepped injection case involving bringing the 16 injection locations online over a series of years and at an increasing annual injection rate over the injection period showed a better conformance than the case where all the sources begin injecting their full output simultaneously. This is because the higher injection rate in the beginning results in faster reservoir pressure buildup and, ultimately, constrains the injections. In Scenario 2, where emissions were distributed to 25 geologically favorable locations, the total injected CO_2 is increased to 1949 Mt. Converting all of the vertical injectors to horizontal wells, the mass of CO_2 increases 39.2% to 2040 Mt. By adding a total of 163 water extractors around all injectors, the total injected CO_2 is 2644 Mt, which is 50.8% of the total expected CO_2 emission. With the high range value of the rock compressibility for the reservoir, the amount of total injected CO_2 was enhanced to 3112 Mt, which is about 60% of the total emission source. Overall, all of the optimal operations addressed in this study show moderate to significant effects on CO_2 injection. Regarding the reservoir pressure monitoring, when compared with the initial pressure, the maximum pressure after the 50-year injection period was increased about 800 psi, which is lower than the limitation of the reservoir pressure. After the 36-year postinjection period, the pressure difference with respect to initial pressure was decreased to ~400 psi.

The successful exploration of the case study for CO_2 storage in the basal saline system of central North America provides a basic guideline to address evaluations of large-scale CO_2 storage demonstration projects. Specifically, the efforts help to answer questions regarding reservoir pressure buildup over the injection and postinjection periods and CO_2 movement tracking. Finally, this study underscores the potential difference in CO_2 storage potential between estimates made with volumetric approaches and those made with dynamic methodologies.

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