THE ROLE OF STATIC AND DYNAMIC MODELING IN THE FORT NELSON CCS PROJECT

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Spectra Energy Transmission (SET) and the Energy & Environmental Research Center (EERC), through the Plains CO_2 Reduction (PCOR) Partnership, are investigating the feasibility of a commercial-scale carbon capture and storage (CCS) project to mitigate carbon dioxide (CO_2) emissions from SET's Fort Nelson Gas Plant (FNGP) in northwestern British Columbia, Canada. The storage target being evaluated is a deep saline formation within a Devonian-age carbonate reef complex in proximity to the FNGP. Natural gas processing at the FNGP produces a waste gas stream that is primarily CO_2, but which also includes up to 5% hydrogen sulfide (H_2S) and a small amount of methane (CH_4). As such, it is referred to as a "sour" CO_2 stream. Approximately 2 million tonnes of sour CO_2 a year is being considered for geologic storage. To help characterize the target injection formations and seals, guide the risk assessment efforts, and develop effective monitoring, verification, and accounting (MVA) programs, the PCOR Partnership has conducted several rounds of detailed modeling and predictive simulations of injection at the Fort Nelson site.

The results of the Fort Nelson modeling activities will provide insight regarding 1) the movement and fate of dense-phase sour CO_2 in a deep brine-saturated carbonate reservoir environment; 2) the impact of dense-phase sour CO_2 on the integrity of sink and seal rocks in a deep brine-saturated reservoir environment; 3) the potential effects that large-scale sour CO_2 injection may have on neighboring natural gas production fields; and 4) the deployment of selected MVA techniques. The sour CO_2 produced from the Fort Nelson gas-processing plant is proposed to be injected into a Devonian-age carbonate formation at a depth of approximately 6900 to 7200 feet (2100 to 2200 meters).

Extensive static modeling, dynamic modeling, and simulation activities have been conducted since 2008 for this CCS feasibility project. The regional petrophysical reservoir model covers a volume defined by 39 km × 67 km × 800 m, containing the injection formation and adjacent gas pools (Clarke Lake Slave Points A and B). The static model has been developed iteratively over the course of the project. Specifically, three versions of the static model have been created, with each version using newly acquired data to refine or build upon the version that preceded it. Data sets upon which the static models are based include publicly available historical well files, commercially available well data, acquisition of existing 2-D and 3-D seismic surveys, log analysis, core testing results, and data generated by the drilling and testing of an exploratory well.

The dynamic modeling and simulations include base case and initial scenario explorations, modeling optimizations and validations (history matching), and predictive simulations with sour CO_2 injection before and after history matching. The investigation scenarios include injection of 50 and 100 million tonnes of sour CO_2 over a period of 25 and 50 years, respectively. These injection scenarios were followed by 75 and 50 years of postinjection monitoring of the CO_2 plume for a total of 100 years. The potential for CO_2 plume migration to the adjacent gas pools (Clarke Lake Slave Points A and B) was also evaluated. The key conclusions include the following:

- A dynamic model based on the completed Version 3 geologic model was constructed for the purpose of matching the historical gas and water production, water disposal data, and scattered bottomhole pressures in nearby areas to the gas pools. Through the history-matching process, the geologic model was validated and improved by decreasing the realistic range of several key geologic properties, including permeability, fault transmissibility, vertical to horizontal permeability ratio (k_v/k_h), and others.

- Two potential injection locations were evaluated with respect to storage capacity, and results suggest that both appear to have sufficient capacities to accommodate target injection volumes.

The results of these modeling activities have served as a critical component of the risk assessment program for the Fort Nelson CCS project. Specifically, the modeling results play a primary role in the identification of risks related to the injection operation, reservoir management, potential leakage pathways, and potential impacts to neighboring gas fields. By predicting the movement of the sour CO_2 plume and the propagation of pressure away from potential injection sites, the modeling results provide much of the basis for finalizing site location decisions and developing a cost-effective MVA program. Finally, the modeling also provides insight and direction for conducting the next iteration of site characterization activities (i.e., exploratory wells, seismic surveys, injection tests, etc.) which will further guide the injection plans and monitoring program.