INTEGRATED MODELING AND SIMULATION FOR CO_2 EOR AND CO_2 STORAGE IN THE ZAMA PINNACLE REEFS OF ALBERTA BASIN, CANADA

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ABSTRACT

Since December 2006, the Zama oil field in northwestern Alberta, Canada, has been the site of acid gas (approximately 70% carbon dioxide and 30% hydrogen sulfide) injection for the simultaneous purpose of enhanced oil recovery (EOR), acid gas disposal, and carbon dioxide (CO_2) storage. The Energy & Environmental Research Center, through the Plains CO_2 Reduction Partnership Program, characterized and built integrated reservoir models for several of these Devonian-aged pinnacle reefs. These pinnacle reefs are encountered at an average depth of 1500 m (4900 ft) and are typically 16 hectares (40 acres) at their base and 120 m (400 ft) tall. A large variation in both porosity and permeability is observed for these variably dolomitized carbonate pinnacles.

Data were limited for each pinnacle reef; thus the F pool was selected as the pinnacle with the most associated data to be used in an integrated workflow for detailed modeling activities (Figure 1). Three core plugs were made available for analysis from reservoir rock that underwent CT scanning and QEMSCAN analysis to produce a microscale facies model. These results were then upscaled into a multimineral petrophysical analysis to correlate with the formation microimaging and other geophysical well logs to produce a detailed macrofacies interpretation. Rock–fluid inversion was utilized for populating initial water saturation and end-point saturation values for oil, gas, and water phases. These results were then upscaled into a 3-D geocellular framework and

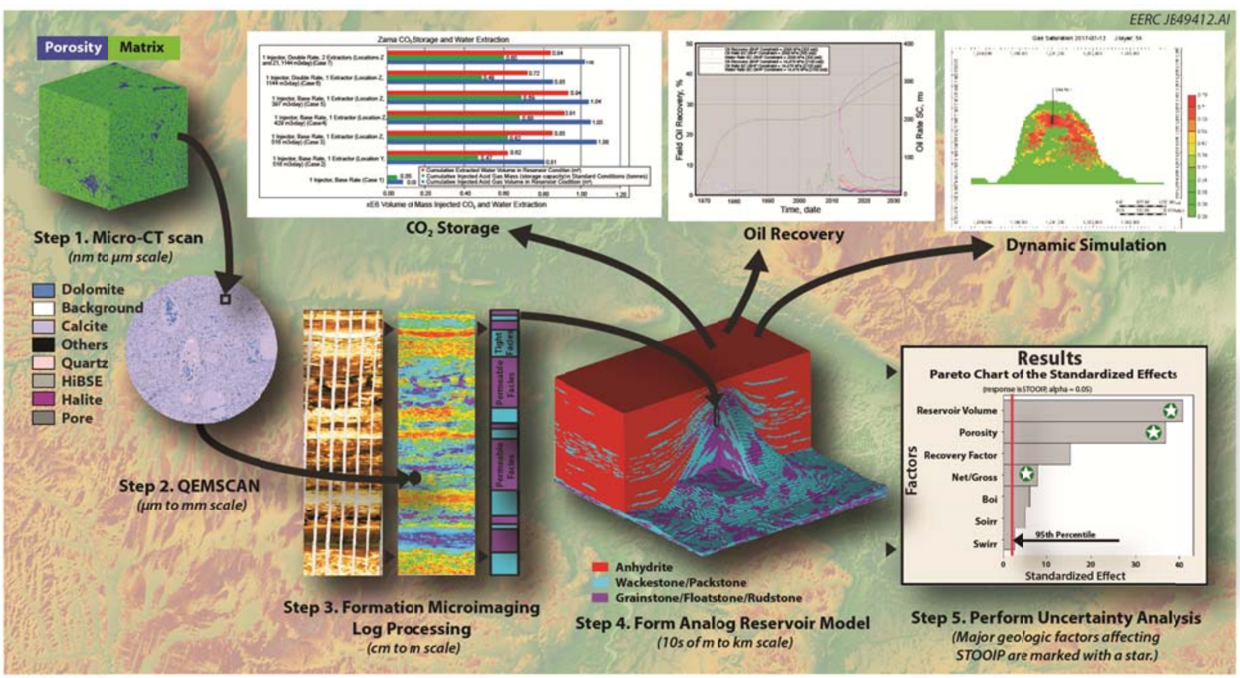

Figure 1. Workflow used in F Pool pinnacle reef modeling and simulation efforts (STOOIP is standard OOIP (modified from Knudsen et al., 2011).

distributed using a multiple point statistics workflow, producing the following reservoir properties: facies, porosity, horizontal and vertical permeability, water and oil saturations, pressure, and temperature. The initial static model consists of an oil zone (Zama and Keg River Formations) at the top portion of the reef and lower Keg River aquifer (below oil–water contact [OWC]). One of the equiprobable realizations of the constructed static geological model was then exported to CMG Modelling Group Ltd.'s GEM for performing dynamic simulations.

For the Version 1 static model, seven cases of simultaneous acid gas injection and formation water extraction, along with a case of gas injection only (Case 1), were tested in predictive simulation runs. These cases include acid gas injection through an injector well (Gas Inj-1) placed in a selected high-permeability zone of the oil zone situated in the top portion of the structure. In all cases, a maximum injection pressure constraint of 22,753 kPa (3300 psi) was used. In Case 1, acid gas at the injection rate of 0.113 MMt/year (million tonnes a year) was injected without the extraction of formation water, storing 0.05 MMt of CO_2. In Cases 2 and 3, a water extraction well was placed in the bottom portion (the water zone below OWC) of the reef structure, storage capacity was increased to 0.47 MMt and 0.62 MMt, respectively. In Cases 4 and 5, two different extraction well production rates (standard conditions of 15.5°C [60°F] and 101.25 kPa [14.7 psi]) of 429 m^3/day and 397 m^3/day were tested. For these cases, an increase in excess of 1300% was observed in the storage capacity compared to Case 1. The gas breakthrough times varied from 4.5 years (Case 3) to 6.5 years (Case 5). A blowdown scenario (i.e., an increase in both gas injection and water extraction rates) was simulated in Cases 6 and 7, resulting in a tenfold increase in storage capacity compared to Case 1. These cases provided insight on extraction of formation water assisted by acid gas injection using a suitably located injection and extraction well pair results in maximum storage capacity at Zama F Pool.

Based on the initial history-matching and predictive simulation efforts with the Version 1 static model, a new and enhanced static model (Version 2) was constructed. This model has a heterogeneous distribution of initial water saturation and end-point saturation values for oil, gas, and water phases. One of the equiprobable static realizations (P10 OOIP [original oil in place]) was chosen for performing detailed history matching and predictive simulations. Case 8 had the following EOR configuration, i.e., acid gas injection through one injector and oil production through two existing producers was continued for the next 20 years. Based on historical gas injection data, a maximum acid gas injection rate of 1.06e5 m^3/day (3.75 MMscf/day) with recycling of all of the produced gas was used. In the case of production wells, two different minimum bottomhole pressure constraints of 2068 kPa (300 psi) and 14,478 kPa (2100 psi) were tested. Incremental oil recovery varied from 12.6% to 16.2% with a maximum of 0.30 MMt of CO_2 that can be stored. Case 9 added a water extraction well, and shows a 5% increase in incremental oil recovery (16.2% to 22.1%) compared to Case 8, resulting in an additional storage capacity gain of 1.01 MMt.

The results of detailed static and geologic modeling performed in this study suggest that water extraction from an underlying water zone (aquifer) can effectively be used for additional gain in both oil recovery and CO_2 storage capacity in a closed system like the Zama F Pool. A combination of top-down gas injection EOR coupled with bottom water extraction appears to provide a new way to increase overall recovery efficiency and storage capacity in such reservoirs. Static models of three of the six additional pinnacles were used to conduct dynamic simulations of various combinations of acid gas injection, EOR, and water extraction. The predicted EOR potential indicated acid gas EOR may yield an additional 6.2% to 15.6% of the OOIP. The simulated CO_2 utilization results for the modeled Zama pools averaged approximately 0.62 tonnes/bbl or 11 Mscf/bbl. With respect to storage capacity, the three individual pinnacles ranged from 0.18 MMt to 1.22 MMt of CO_2, with the average storage capacity of the three pinnacles being nearly 0.4 MMt. Assuming the 840 other pinnacle reefs in the Zama Field have similar storage capacity, the CO_2 storage capacity may be nearly 336 MMt. This case study has implications for EOR opportunities in residual oil zones commonly found in pinnacle reef structures around the world.

Reference

Knudsen, D.J., Gorecki, C.D., Smith, S.A., Sorensen, J.A., Steadman, E.N., and Harju, J.A., 2011, Methodology for assessing uncertainties affecting STOOIP and production in the Zama F Pool, Zama Subbasin, Alberta, Canada: Poster presented at Rocky Mountain Sectional American Association of Petroleum Geologists, Cheyenne, Wyoming, June.