GEOLOGIC MODELING AND SIMULATION REPORT FOR THE AQUISTORE PROJECT

Plains CO_2 Reduction (PCOR) Partnership Phase III
Task 1 – Deliverable D93, Update 2

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EERC DISCLAIMER

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

GEOLOGIC MODELING AND SIMULATION REPORT FOR THE AQUISTORE PROJECT

EXECUTIVE SUMMARY

The Plains CO_2 Reduction (PCOR) Partnership, through the Energy & Environmental Research Center (EERC), continues to support the Petroleum Technology Research Centre (PTRC) Aquistore project. This support has been in the form of geologic characterization; involvement in the Science, Engineering, and Research Committee (SERC); involvement in public outreach; developing geologic models; and running predictive simulations on the expect injection program at the site. The Aquistore project is part of the world's first commercial postcombustion carbon capture, utilization, and storage project from a coal-fired power-generating facility, the SaskPower Boundary Dam, located in Saskatchewan, Canada, and acts as a storage site for a portion of the captured CO_2 from the Boundary Dam power plant. The Aquistore site includes one injection well and a 152-meter offset observation well. Both wells were drilled and completed in the Deadwood and Black Island Formations. Injection at the Aquistore site was initiated in April 2015; at the time of this report, the daily injection rate ranged from approximately 300 to 500 tonnes per day.

To better understand the storage implications of injecting carbon dioxide (CO_2), history-match field pressure response, and predict CO_2 plume evolution at the Aquistore site, the EERC has constructed a simplified simulation model based on reservoir physical properties obtained from previous mean probability (P50) static geologic model realization. Simulations have been conducted utilizing this model to better understand both operational and geologic uncertainties that may exist at the Aquistore site. The simulations are an update to those completed in the previous update of the original report entitled Geologic Modeling and Simulation Report for the Aquistore Project, Deliverable (D) 93, approved in 2014.

In this update, a regional-scale model extends beyond the 34-square-kilometer PTRC 3-D seismic survey area. A local grid refinement (LGR) system near both the injection and observation wells was introduced for the history-matching and uncertainty analysis. Spinner log survey and pressure test data provided by partners were used and evaluated to adjust the near-wellbore local permeability in order to history-match the field pressure data. As of January 9, 2016, approximately 24,000 tonnes of CO_2 has been injected during a series of relatively short operating periods. However, the injection rate during these short operating periods increased near the end of year 2015 to a level of 300 to 500 tonnes per day, based on the quantity of CO_2 made available from the pipeline.

The two wells have been closely monitored, and history matching was performed while reconciling rate, pressure, temperature, variations in injectivity, and injection flow. The current data set is well replicated by the simulation. However, CO_2 breakthrough at the observation well has not yet been observed, and geophysical imaging of the CO_2 plume has not yet been attempted. Thus important performance confirmations remain to be made, and additional reporting of project performance will be appropriate in the future. A new set of injection forecasts is presented, with some cases directly comparable to the previously published, pre-history match results.

GEOLOGIC MODELING AND SIMULATION REPORT FOR THE AQUISTORE PROJECT

INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership, through the Energy & Environmental Research Center (EERC), is collaborating with the Petroleum Technology Research Centre (PTRC) and SaskPower on site characterization; modeling and simulation; risk assessment; public outreach; and monitoring, verification, and accounting (MVA) activities for the Aquistore project. As the world's first commercial postcombustion carbon capture, utilization, and storage (CCUS) project, situated near the town of Estevan, Saskatchewan, Canada, and the U.S.–Canada border, the Aquistore research project is managed by PTRC and serves as buffer storage of carbon dioxide (CO_2) from the SaskPower Boundary Dam CCUS project. To date, an injection well and an observation research well (~152 meter apart) have been drilled and completed at the Aquistore site, with CO_2 injection initiated in April 2015. 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 storage capacity of the Aquistore site, is conducting updated dynamic simulations to history-match field data, and is providing the important findings and the predictive results from simulations. The history match and predictive results are used to estimate CO_2 breakthrough time, pressure evolution at the observation well, and CO_2 plume extent and update the model property characterizations. The technique will aid the interpretation of MVA activities 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 nearly 3500 meters below the surface, this saline system is situated below 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 a 3-D seismic survey, petrophysical core data, and a comprehensive logging suite. All of such available data were incorporated in model development and dynamic simulations that were reported in the previous Deliverable (D) 93 and its update (Peck and others, 2014b; Liu and others, 2014). This report updated the studies including construction of a new, simplified simulation model, with average reservoir physical properties obtained from the previous static model. The model size is based on the same model extent of the 34-square-kilometer static model area, with similar fine scale for the area where both wells are located (Figures 1–4). The simulation was updated with the near-real-time field data provided by SaskPower to history-match the field pressure response.

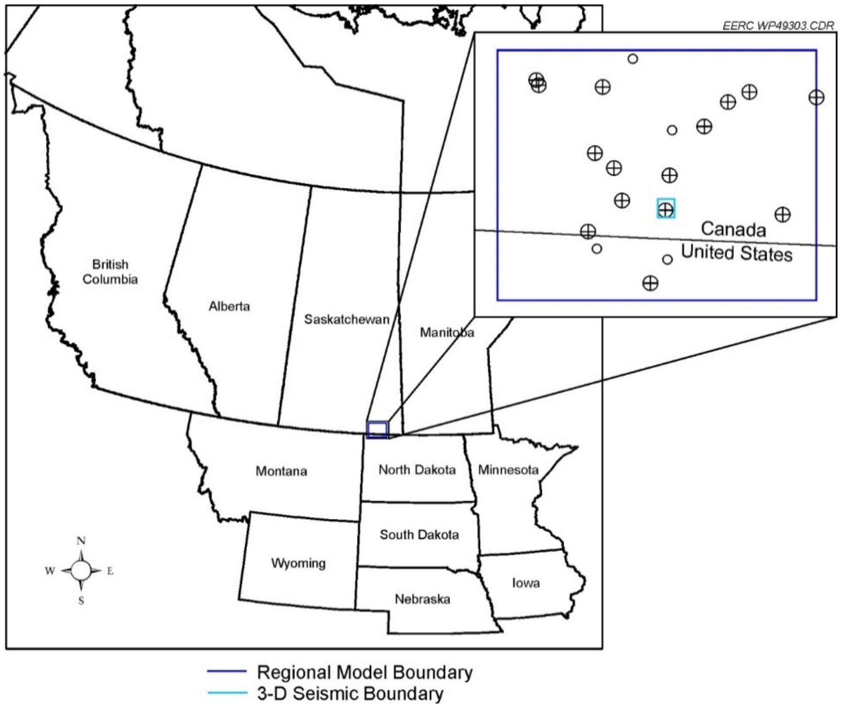


Figure 1. Regional model that includes portions of North Dakota and Saskatchewan, with an area of 9740 square kilometers, and a refined model of 34 square kilometers around the observation and injection wells.

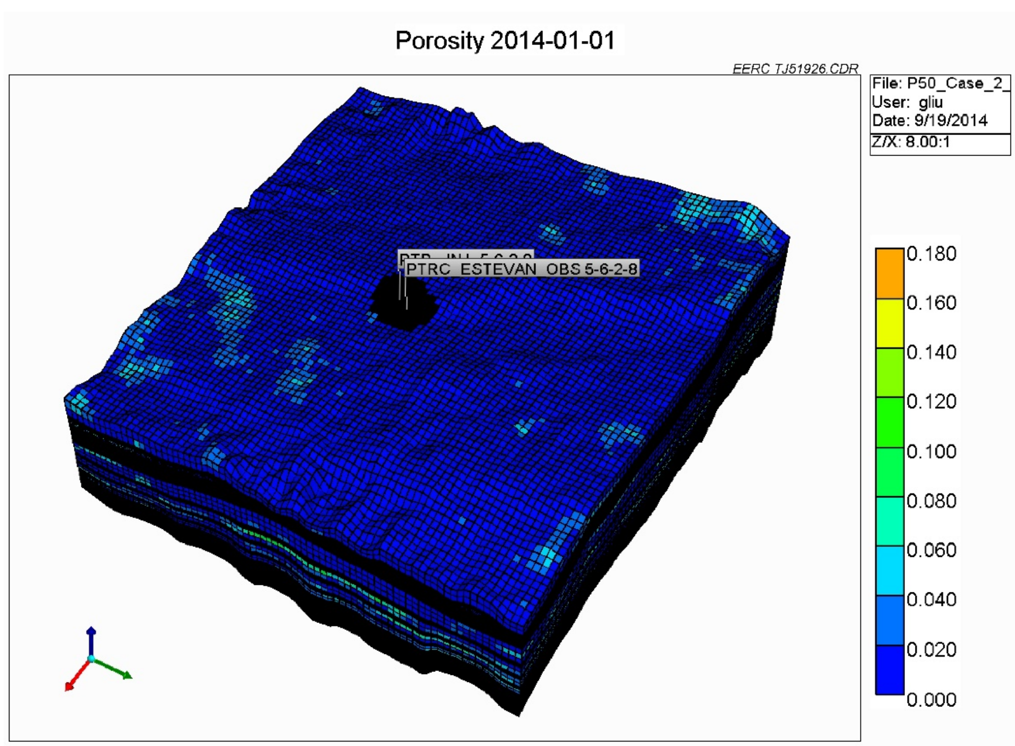


Figure 2. Previous static model with local grid refinement (Liu and others, 2014).

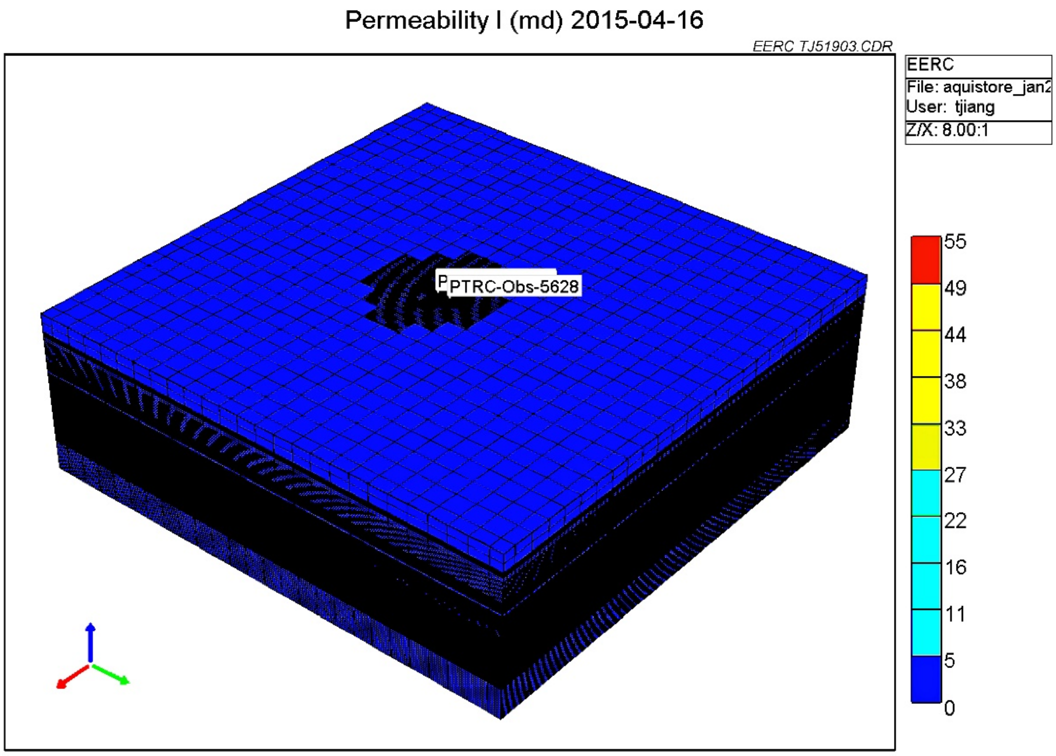


Figure 3. Simulation model with local grid refinement constructed for history matching.

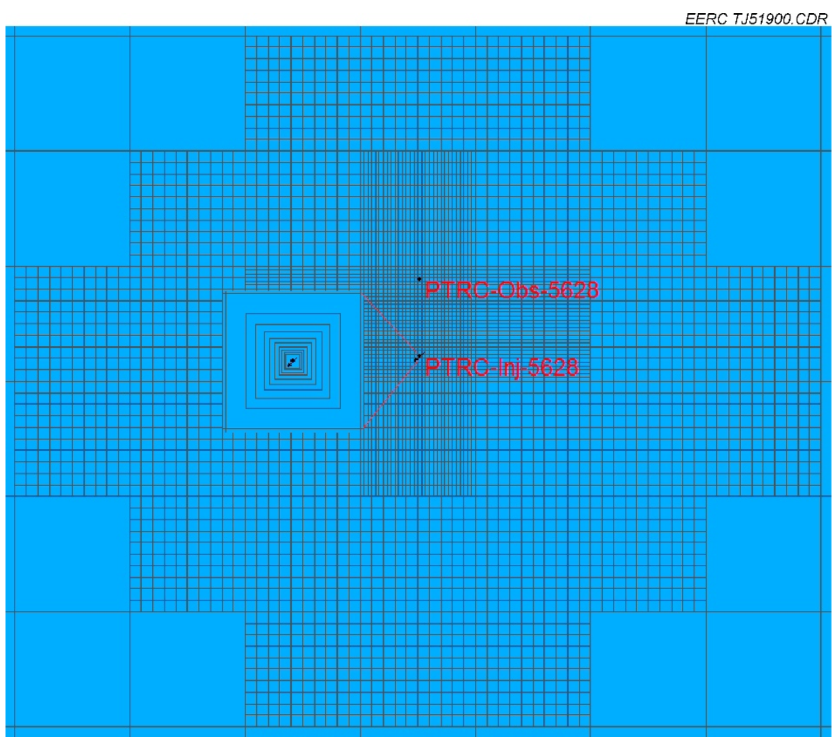


Figure 4. Close-up of the local grid refinement around the observation and injection wells in Figure 3. The largest cells are 228.6 × 228.6 meters; the smallest cells are 7.62 × 7.62 meters.

BACKGROUND

This report documents the update to the simulation model and adjustments to physical properties to history-match the field data, predict the plume extension and breakthrough time, and evaluate the sensitive parameters for the simulation and uncertainties. Previous work was performed before the start of injection, and thus no performance history matching could be done before now. Reservoir physical properties were obtained based on the previous static geologic model from the original report entitled Geologic Modeling and Simulation Report for the Aquistore Project, D93, originally submitted in March 2014, and its update, approved in September 2014. The main content of the original D93 and the Update included the following:

- A regional-scale model that was first constructed to determine the regional stratigraphic reservoir and non-reservoir zones. From this regional model, a fine-scale model was confined to the extent of the 34-square-kilometer PTRC 3-D seismic survey area, with higher structural resolution. Integration of the data derived from the regional model and the data from the 3-D seismic survey were combined in a robust and heterogeneous model around the Aquistore injection well and the observation well.

- The volumetric CO_2 storage capacities with the P10, P50, and P90 cases of the fine-scale model were assessed based on the approach described in U.S. Department of Energy (DOE) Atlas III (U.S. Department of Energy Office of Fossil Energy, 2010) which builds on the IEA Greenhouse Gas R&D Programme (IEAGHG) work of Gorecki and others (2009).

- A total of nine simulation cases were designed to verify the volumetric CO_2 storage capacities by considering pressure interference and other operational factors such as boundary conditions, injection rates, relative permeabilities, and time lengths.

- CO_2 plume extensions and pressure responses during injection and postinjection periods were also assessed.

- The first CO_2 breakthrough time, pressure change, plume extent, and CO_2 movement probability distribution for three cases, with the different injection rate and injection period.

- Uncertainty over geologic realizations was assessed for each case to evaluate its influence on CO_2 injection behavior and underground movement.

APPROACH

The primary approach used in this update was to history-match the field near-real-time injection data and pressure response to predict the breakthrough time and CO_2 plume evolution. Because the previous static model took a long time to run and it was difficult to match the history data, a new simulation model was needed to achieve efficient history matching. This approach began with the construction of a simplified dynamic simulation model, with physical properties obtained from the previous static model, to analyze sensitive parameters that affect history matching. Then model physical properties were updated and numerical approaches introduced to history-match the data, finally providing predicted results.

Based on the sensitivity analysis, history matching was affected by permeability, transmissibility, and numerical skin value. Rock type and corresponding relative permeability curve selection will affect CO_2 movement and plume extent. With the findings from simulations, uncertainty parameters may provide insights to the MVA plan.

DYNAMIC SIMULATION AND MODEL SETTINGS

Simulation Grid Settings

Figures 3 and 4 show the simulation model built for this study. In this model, a total of 120 layers were used, compared to 102 for the original static model, in order to increase resolution for selected layers. The vertical thickness of each layer ranges from 1.26 to 2.76 meters, with the exception of the two top nonreservoir layers, each with a thickness of 12.63 meters. Local grid refinement (LGR) vertical resolution remains the same as the regional model. The refined vertical layers will minimize the numerical error for the cells vertically close to perforation Interval 2 and perforation Interval 3. One injection well and one observation well were placed in each of the refined grids, ~152 meters apart. Additionally, a hybrid local refinement was introduced to the blocks where the injector is located to more accurately simulate the near-wellbore radial flow behavior in the early injection stage.

Fluid and Rock Model Settings

The fluid model includes two components, CO_2 and brine. The CO_2 is allowed to dissolve into brine to mimic the nature of the saline system undergoing CO_2 injection. Correlations from Rowe and Chow (1970) and Kestin and others (1981) were used for the aqueous fluids density and viscosity, respectively. Solubility of CO_2 in water is modeled via Harvey's correlation for Henry's Law constants (Harvey, 1996). The rock–fluid models used in the simulation model were based on lithology of the previous static geologic model. Figure 5 shows the three sets of relative permeability curves that were used in the simulations, including RPT 1 and RPT 2 obtained by Bennion and Bachu (2005), and RPT 3 measured and provided by Schlumberger Reservoir Laboratories (2013). RPT 1 and RPT 2 were used for perforated zones, and RPT 3 was used for the zones between perforations.

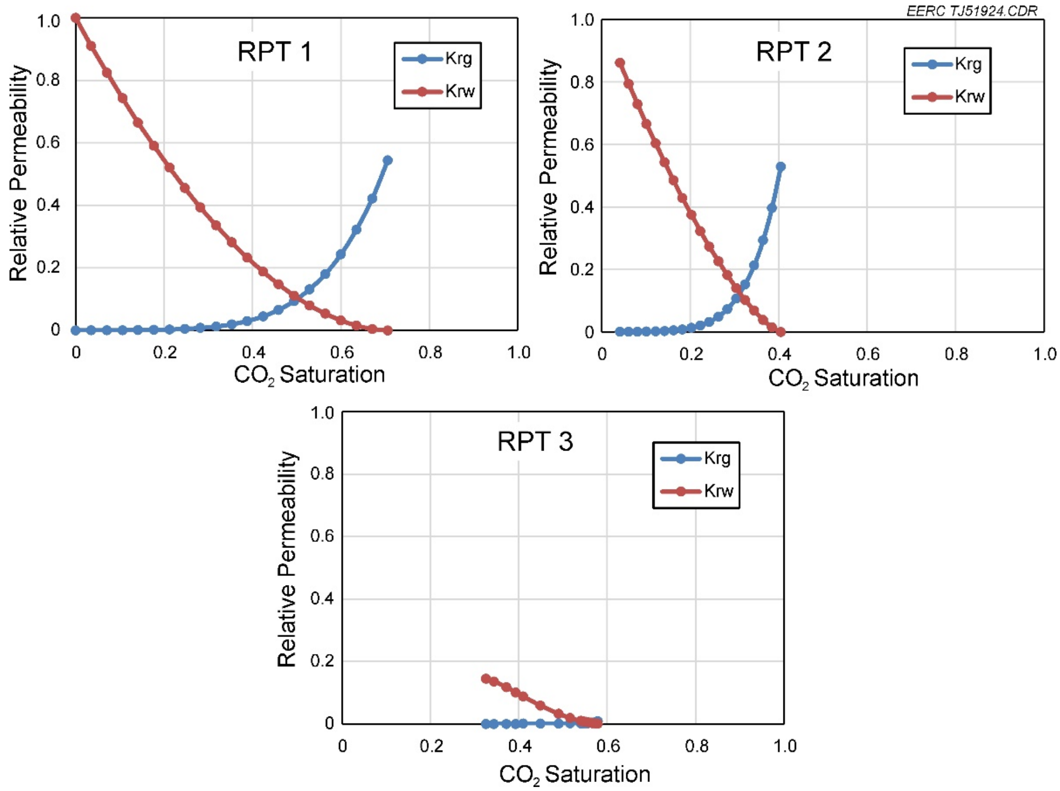


Figure 5. Three sets of relative permeability curves used for the simulation.

Numerical Settings

For the near-real-time simulation, improper numerical settings would result in computational inefficiency and error and cause small time steps. Thus various numerical parameters, such as maximum pressure change, convergence tolerance, and maximum Newton iterations, were tuned to produce the lowest optimized critical point, which is a function of total central processing unit (CPU) run time, material balance error, and solver failure percentage. The global objective function and total CPU run time were reduced up to 42% after the numerical tuning and optimized for simulation runs with eight cores; increasing the core number would not improve the elapsed time significantly.

Pre-History Match

The purpose of history-matching field data is to estimate the CO_2 saturation profile, estimate pressure distribution in the reservoir, update reservoir property characterization, and predict the possible CO_2 breakthrough at the observation well. History matching is a time-consuming process and depends on various parameters, such as reservoir model properties, numerical settings, the fluid model, and operation conditions. Sensitivity analysis should be done in order to determine the most sensitive parameters that affect the simulation result and the parameters that may be less critical to history matching.

In this update, Computer Modelling Group, Ltd's (CMG's) CMOST sensitivity analysis workflow was adopted to determine the key parameters that affect the results of history matching. Parameters, such as skin factor, transmissibility, and ratio of horizontal and vertical permeability, were chosen, using a response surface proxy model to determine the parameters that significantly affect the simulation results. Sensitivity analysis results are shown in Figures 6 and 7. The target value was define from field data in CMOST, and the minimum and maximum values were calculated from the ranges of sensitive parameters. It can be seen that skin factor and transmissibility, which are both a function of permeability, greatly affect the injector bottomhole pressure response. The reduced permeability and skin factor would significantly affect injectivity. Skin factor is a characterization of the formation damage zone around the wellbore and is defined as:

$$s = \left(\frac{k}{k_s} - 1\right) \ln\left(\frac{r_s}{r_w}\right), \qquad \text{[Eq. 1]}$$

where k is reservoir permeability, k_s is permeability of the damage zone, r_s is radius of the damage zone around the wellbore, and r_w is wellbore radius. The greater the contrast between k_s and k and the deeper into the formation the damage extends, the larger the numerical value of s, and there is

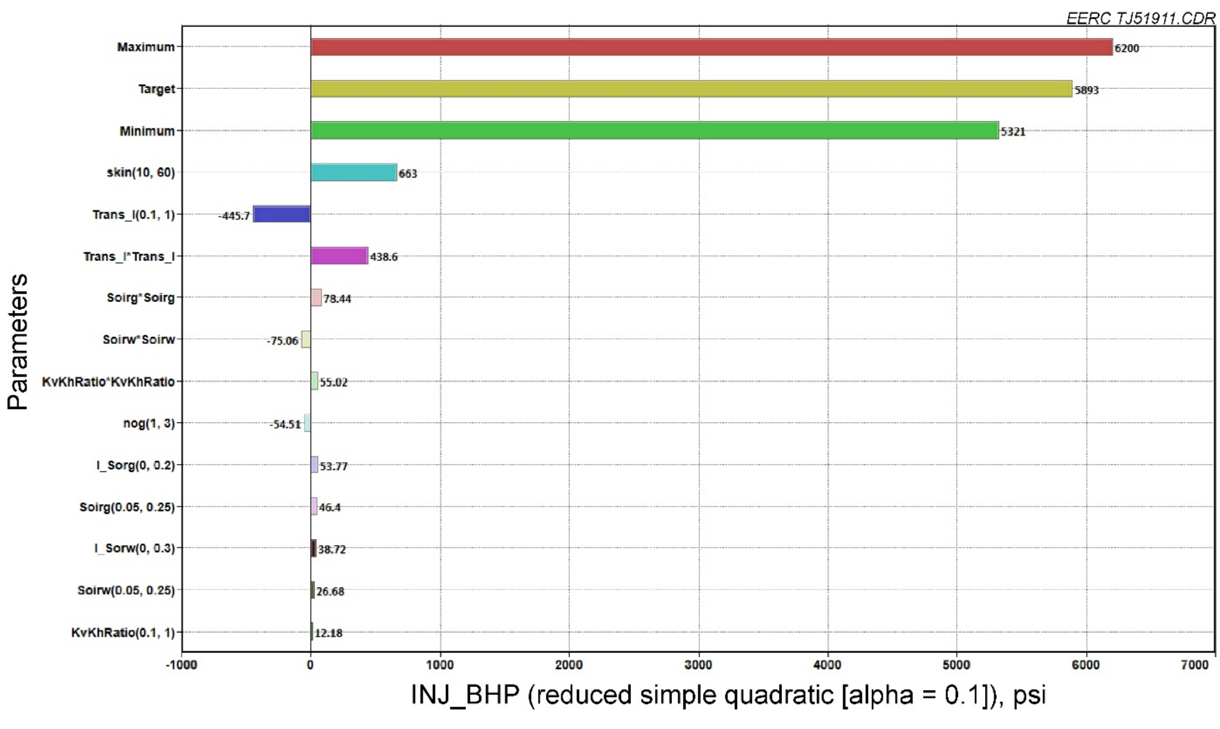


Figure 6. Sensitivity analysis of injection well pressure response to chosen parameters.

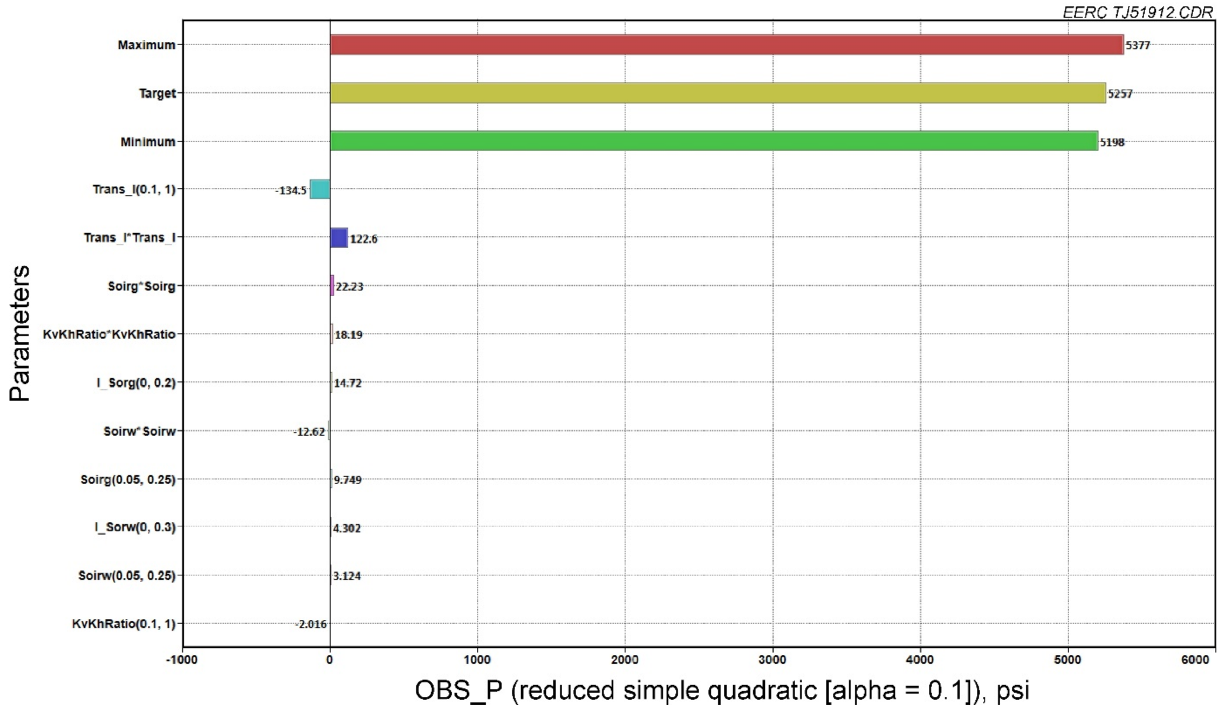


Figure 7. Sensitivity analysis of observation well pressure response to chosen parameters.

no upper limit for s (Lee, 1982). Table 1 shows an estimated range of skin factor value that would be used in this model, based on the estimation of permeability reduction and radius of the near-wellbore formation damage. It can be seen that permeability reduction would substantially increase the skin factor value when damage zone permeability is reduced by 10 times, whereas the radius of the damage zone plays a less significant role in increased skin factor value.

Table 1. Estimated Range of Skin Factor Value Based on Permeability Reduction and Radius of Near-Wellbore Formation Damage

k_s	r_w	s
0.50 * k	200 * r_w	4.7
0.50 * k	1000 * r_w	6.3
0.25 * k	200 * r_w	14.1
0.25 * k	1000 * r_w	19.0
0.10 * k	200 * r_w	42.4
0.10 * k	1000 * r_w	56.9

DYNAMIC SIMULATION RESULTS AND DISCUSSION

The Aquistore field pressure and rate data were acquired from SaskPower and PTRC. The field pressure, rate, and downhole temperature data are shown in Figure 8. Because of a data-reporting system issue and scheduled power plant maintenance shutdowns, there were periods of time that have no pressure data or CO_2 injection stopped. History matching was conducted using near-real-time updates of field injection using rate as the input constraint, with a maximum downhole pressure constraint set as 42,750 kPa, or 6200 psi, which is 90% of reservoir fracture pressure (Peck and others, 2014a).

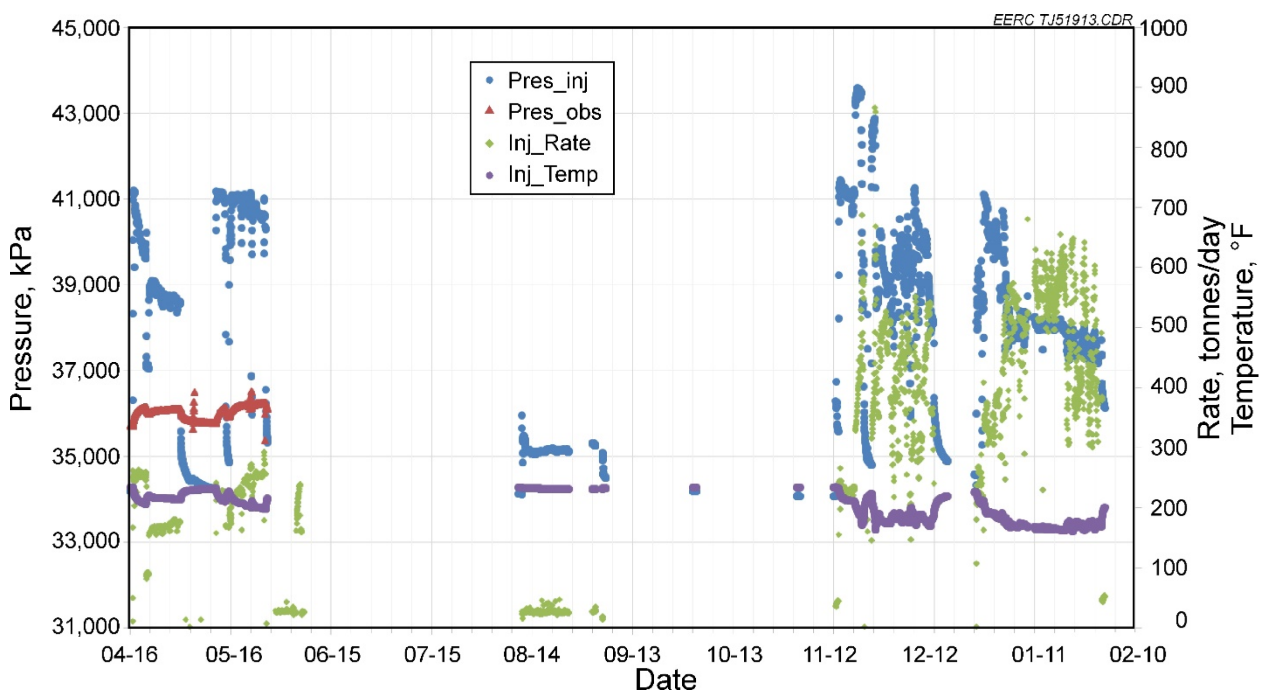


Figure 8. Field pressure, rate, and temperature data provided by SaskPower.

Other important data regarding the injection flow profile were provided by spinner log surveys, such as shown in Figure 9, conducted by Schlumberger Carbon Services on April 20, 2015. Figure 9 indicates that ~40% to ~50% of total flow was observed at perforation Interval 2 and perforation Interval 4, while perforation Interval 1 took only ~10%, and there was no injection into perforation Interval 3. The spinner log data were further used to adjust local permeability in order to match both the pressure response and the injection flow profile.

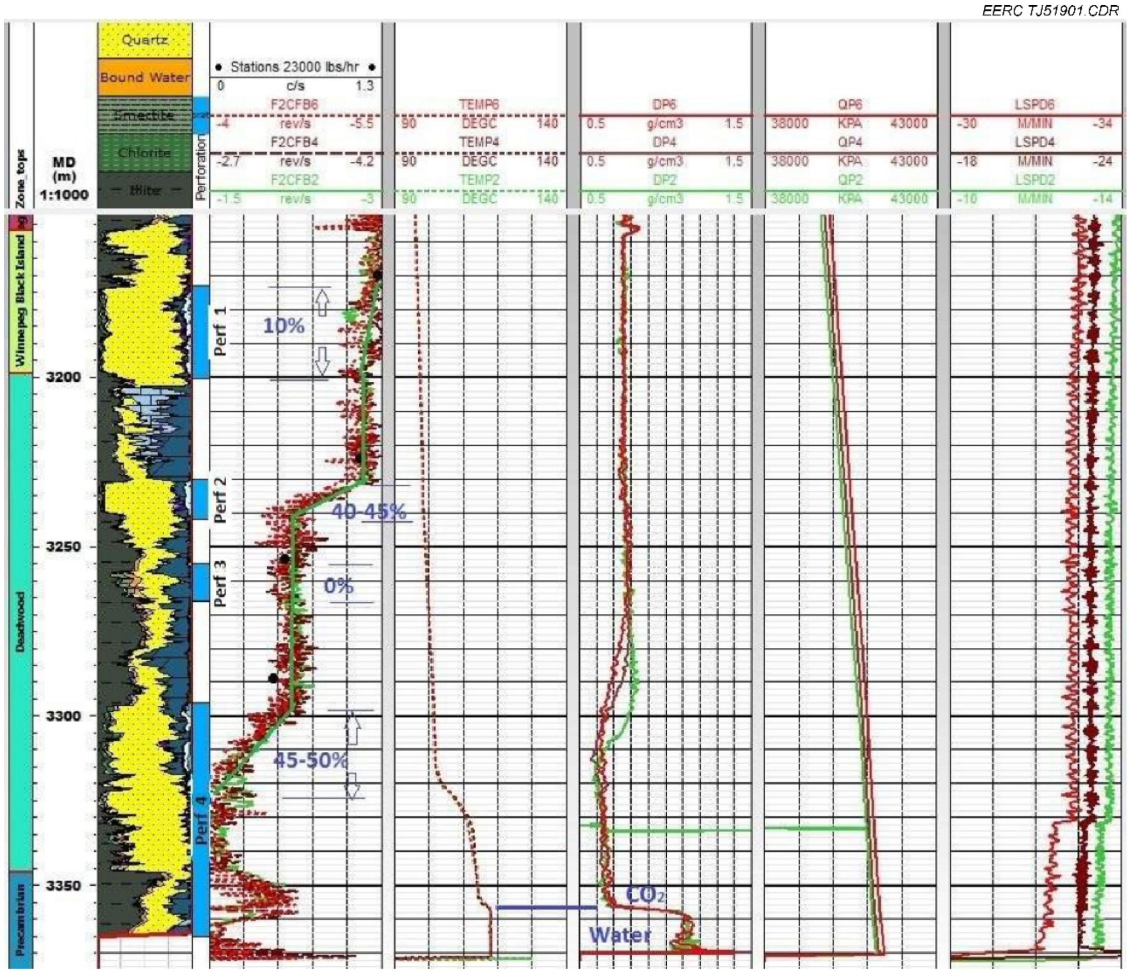


Figure 9. Production log data with CO_2 injection rate of 23,000 lb/hr (Schlumberger Carbon Services, 2015).

In order to match the history data, a permeability reduction in radius of 22.86 meter, or 75 feet, around the wellbore in the perforated intervals was set, as shown in Figure 10. For perforation Intervals 1, 2, and 4, the permeability was reduced by half, and the permeability of perforation Interval 3 was reduced to nearly zero near the wellbore, as the production log data show Interval 3 was totally plugged and no CO_2 flow was observed in this perforation interval. A possible reason for this condition is that previous water injection for well testing may have caused clay content swelling in the formation, which substantially reduced the permeability near the wellbore.

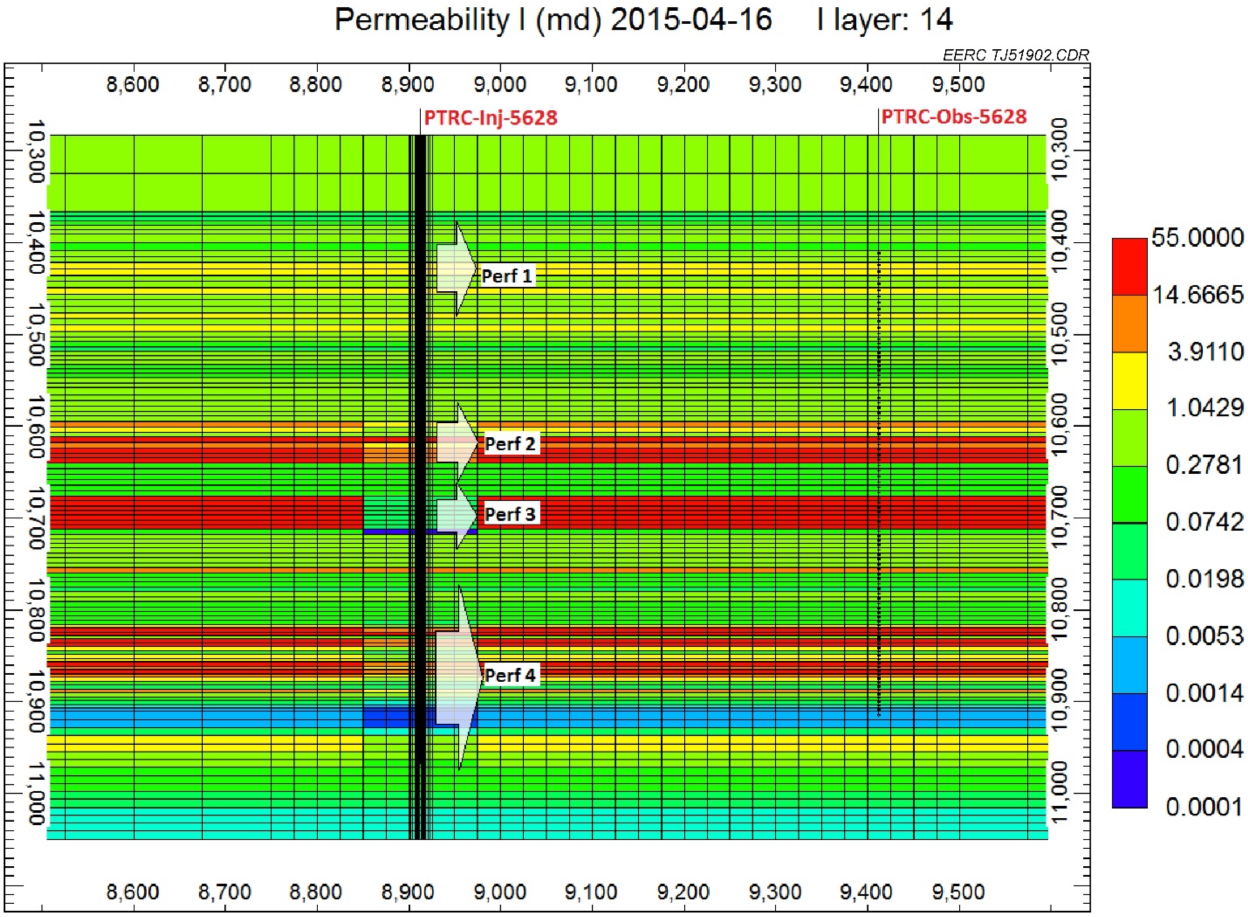


Figure 10. Permeability distribution and permeability reduction in the near-wellbore area.

However, after the permeability reduction there was still a mismatch of injection well pressure response between the simulation and history data. Thus additional skin factor was brought into the simulation. The effects of this on injection and observation well pressure responses were evaluated for different wellbore damage conditions, shown in Figures 11 and 12. In Figure 11, elimination of the skin value (green dashed line) resulted in a significant reduction of injection pressure response during the CO_2 injection period compared with base simulation results (blue solid line). For the case without skin value but with additional permeability reduction near the wellbore (reduced by half compared with the base simulation result, brown dashed line), the pressure response was higher than other cases in the first injection period, but dropped afterward. For the case with no permeability reduction or skin factor, the pressure response is the lowest among these cases (black dash line). Thus the injectivity would be too high compared to the wellbore performance. The pressure response of observation well decreased when there was no permeability reduction (Figure 11); however, this effect is limited on the observation well compared with that on the injection well.

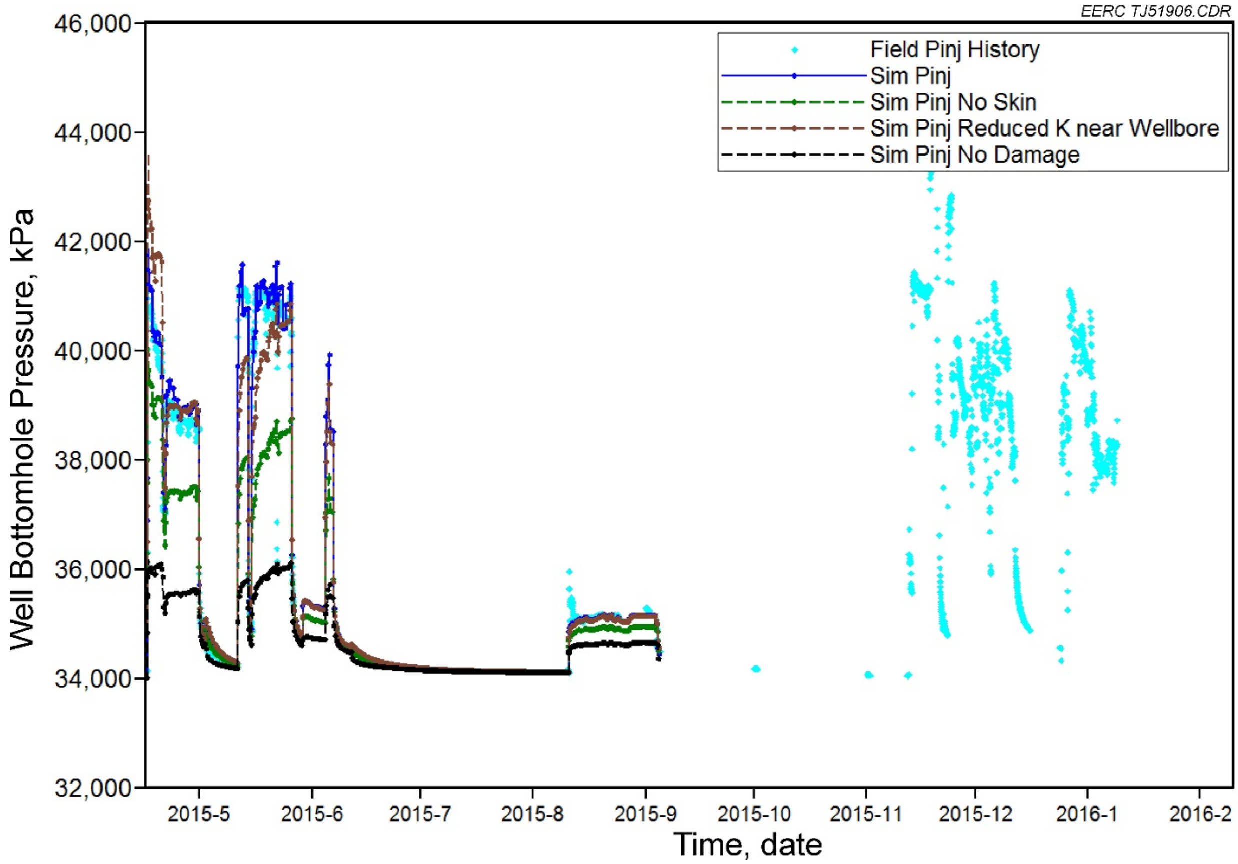


Figure 11. Injection pressure response for different wellbore damage.

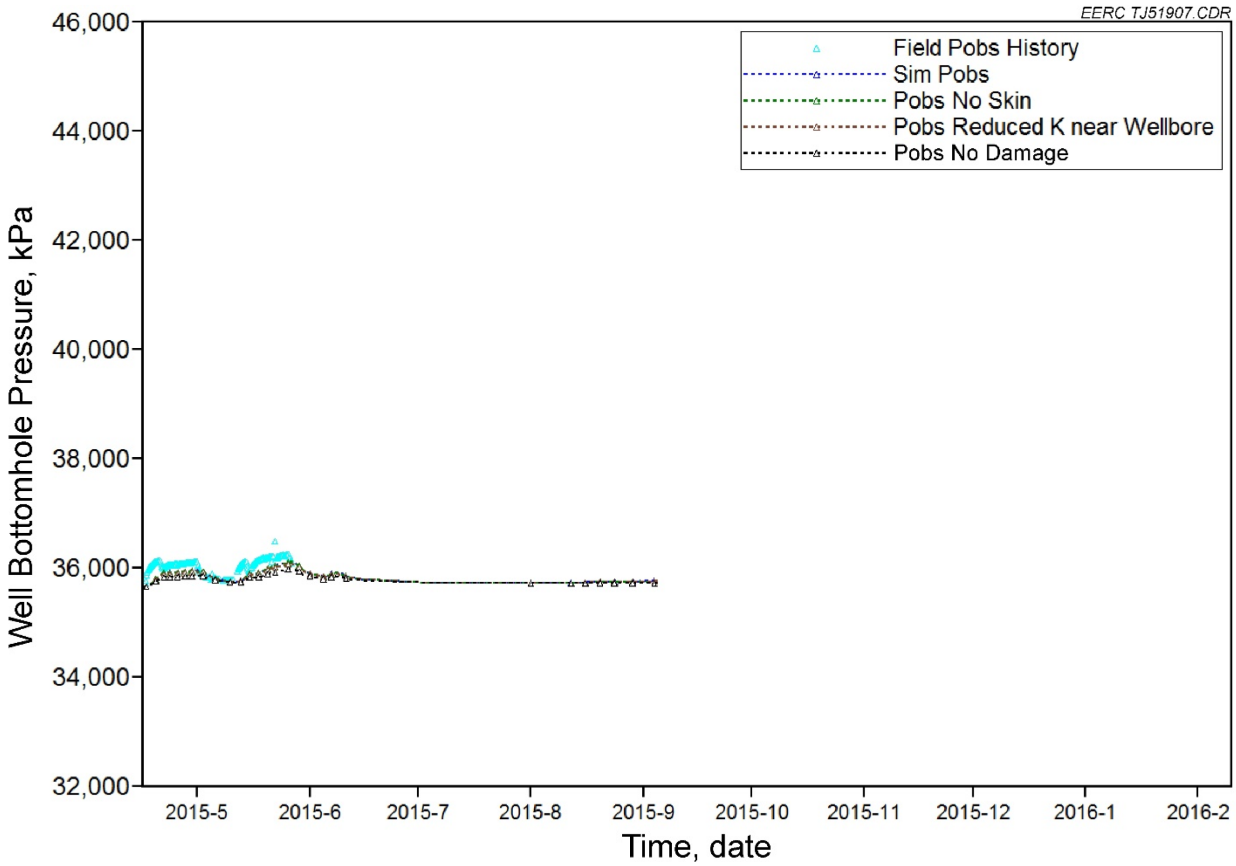


Figure 12. Observation well pressure response.

The result of this work was an improved history match result with respect to injection well pressure and flow distribution during the injection period from April through October 2015, as shown in Figure 13 and Figure 14. Figure 15 shows cumulative CO_2 injection in different perforated intervals from history-matching simulation, which indicates overall agreement with the spinner log survey that perforated. Intervals 2 and 4 took the majority of the CO_2 injected. Later in the year, well injectivity improved, which has introduced new and uncertain parameters in addition to the near-wellbore permeability reduction and skin factor. Simulation of this later time well performance is discussed further below.

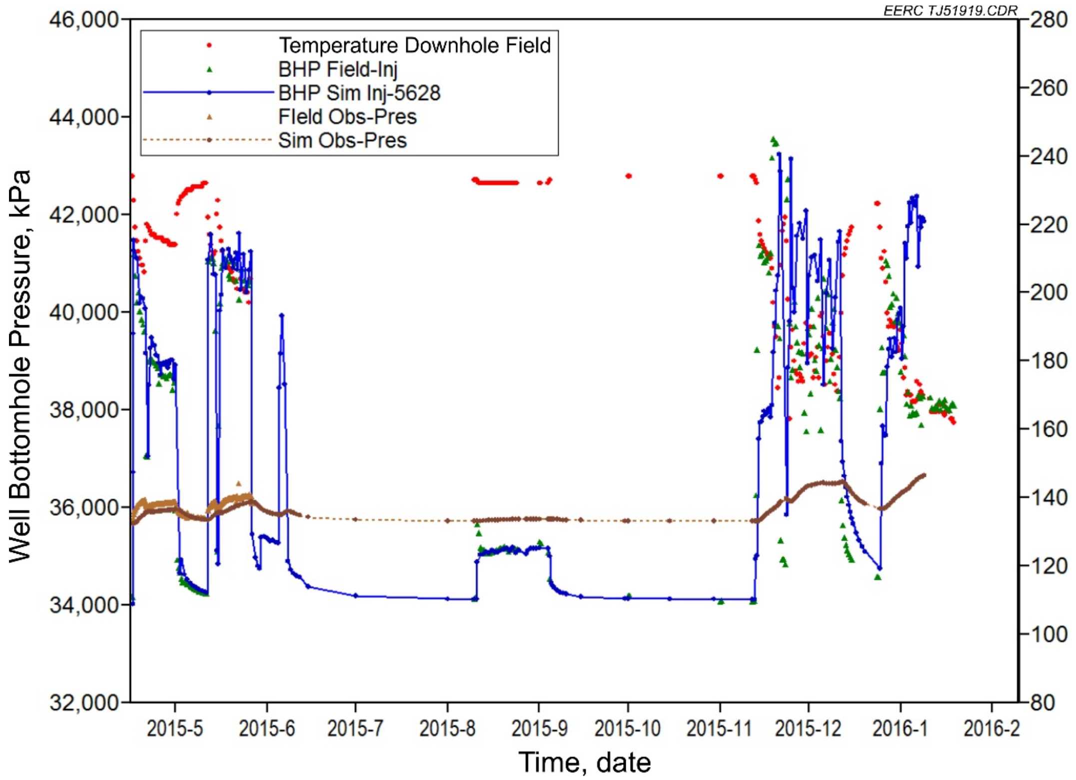


Figure 13. Field downhole temperature data and history match of field pressure response.

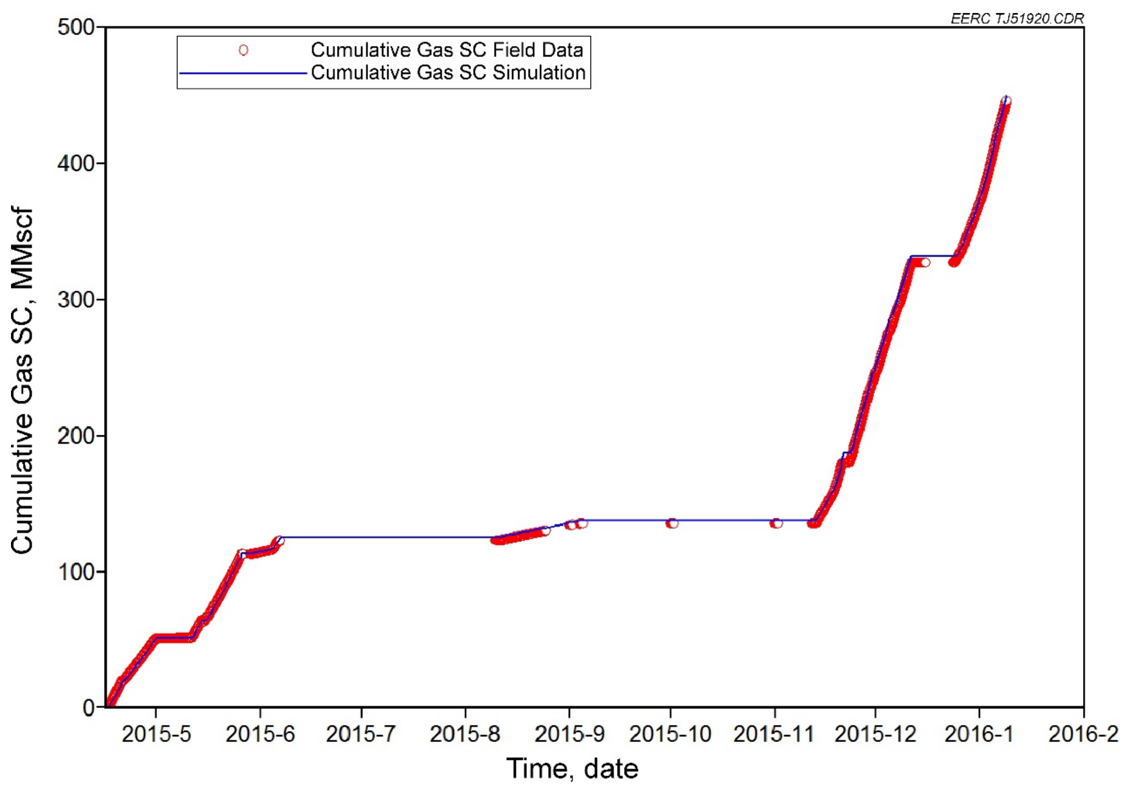


Figure 14. Cumulative gas injection match (unit in millions of standard cubic feet).

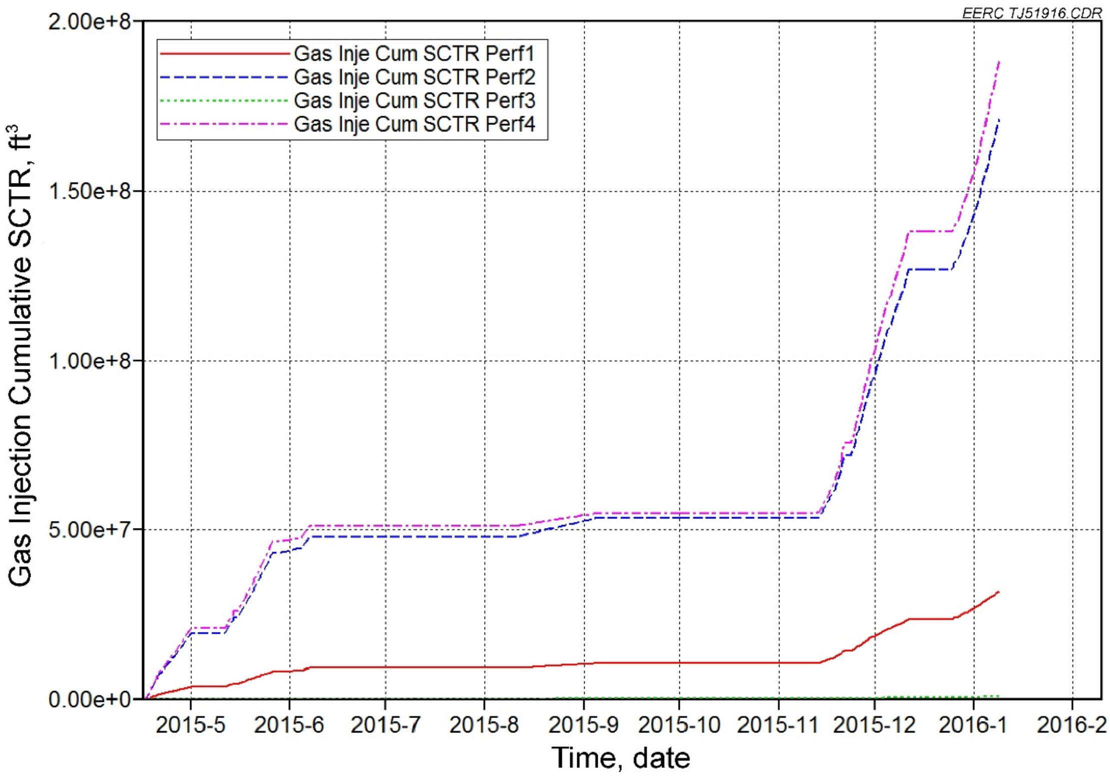


Figure 15. Cumulative CO_2 injected into each perforated interval.

The simulation results of pressure response overall match well when an additional skin factor value of 4–11 was applied to the injector at selected time steps. This dynamic skin change mainly occurred at the time when the injection rate had a sudden increase or decrease or simply when the well resumed injection after a shut-in. This could be attributable to the difference between the cool CO_2 fluid and the high reservoir temperature. It can be seen from Figure 13 that while injection rate increased, downhole temperature decreased.

Temperature changes would affect the pressure response in the field. Similar to the flow test, gas flow in infinite-acting reservoirs can be expressed as follows:

$$\psi_{(p_{wf})} = \psi_{(p_i)} + 50300 \frac{p_{sc}}{T_{sc}} \frac{q_g T}{kh} \left[1.151 \log\left(\frac{1688 \phi \mu_i c_{ti} r_w^2}{kt}\right) - \left(s + D\left|q_g\right|\right)\right] \qquad \text{[Eq. 2]}$$

where $\psi_{(p)}$ is pseudo-pressure and $D\left|q_g\right|$ is non-Darcy flow pressure drop caused by the high velocity of the gas flow near the wellbore (Lee, 1982). Since $\psi_{(p_i)}$, p_{sc}, T_{sc}, k, h, ϕ, μ_i, c_{ti}, r_w, and t are known parameters, this form is simplified as $\psi_{(p_{wf})} = f_{(T,s,D|q_g|)}$. Assuming $D\left|q_g\right|$ is constant so the bottomhole pressure would be the function of temperature and skin. Figure 16 shows the effect of decreasing downhole temperature and changing rates on pressure response, and Figure 17 shows more detail of this effect during the first 2-months of injection. It indicates that while rate increases (gray dot and violet line) downhole temperature (red dot) decreases.

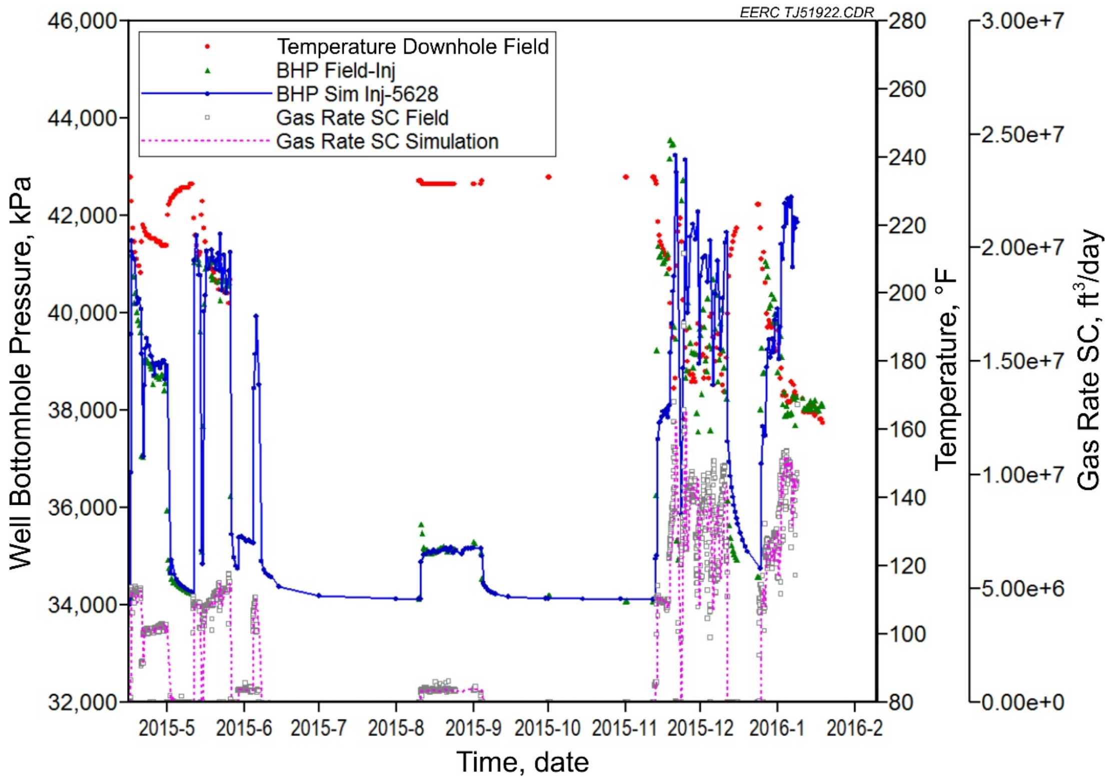


Figure 16. Temperature and rate effect on injector pressure response.

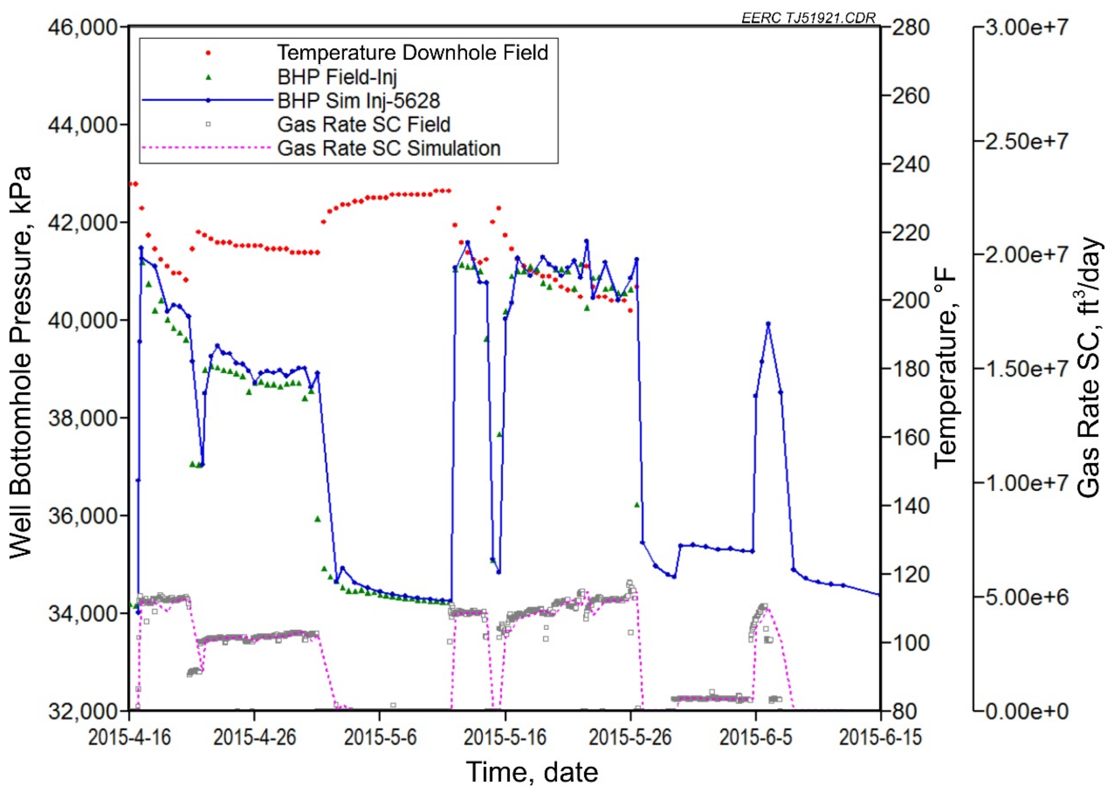


Figure 17. Temperature and rate effect during the first 2-month injection.

Changing the skin on those dates is needed to keep the simulation pressure (blue solid line) matching the field data (green triangle) before November 2015. Since the compositional simulation is an isothermal process that assumes the temperature of injection fluid and reservoir is kept constant during the simulation process, reconciling the skin is an approach to history-match the dynamic pressure change.

The CO_2 capture facility was shut down for scheduled maintenance in September and October 2015. When injection was resumed on November 12, the operating permit was temporarily modified to allow the injection pressure to reach 95% of formation fracture pressure (45,125 kPa). Matching the pressure response after this time became more complicated. Field data, shown in Figure 18, indicate that on November 20, the injection rate increased to as high as 700 tonnes per day, from the previous rate of 200 to 300 tonnes per day. However, the injection pressure actually decreased. The well completion settings used prior to this production restart could not describe this behavior, and a skin value of zero has been used since November in order to better match the pressure response. A possible explanation is that while increasing the injection, the cold CO_2 flow was able to improve the wellbore performance, perhaps bypassing the formation skin zone so that the increased pressure caused by any near-wellbore formation damage was eliminated. Nevertheless, the overall pressure match cannot be maintained, particularly after early January, as shown in Figure 19. Because of the frequent and large rate change variations, the bottomhole temperature continues to play an important role in well performance.

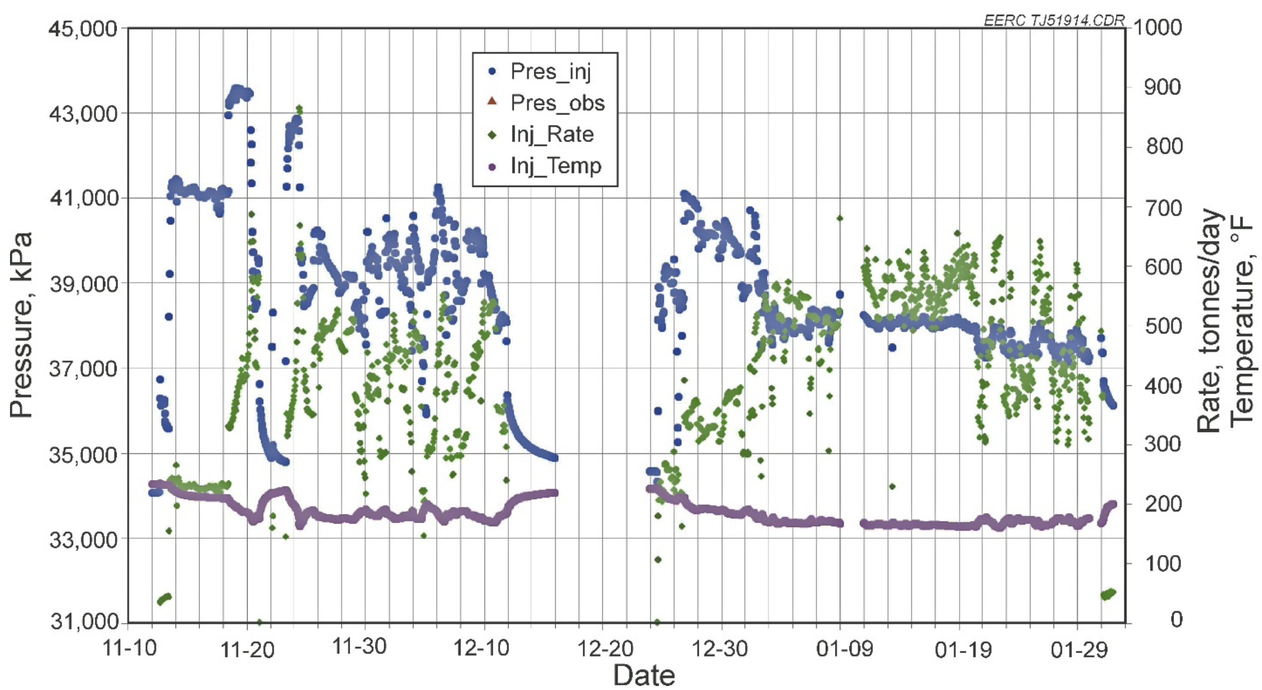


Figure 18. Field pressure, rate, and temperature data since November 10, 2015.

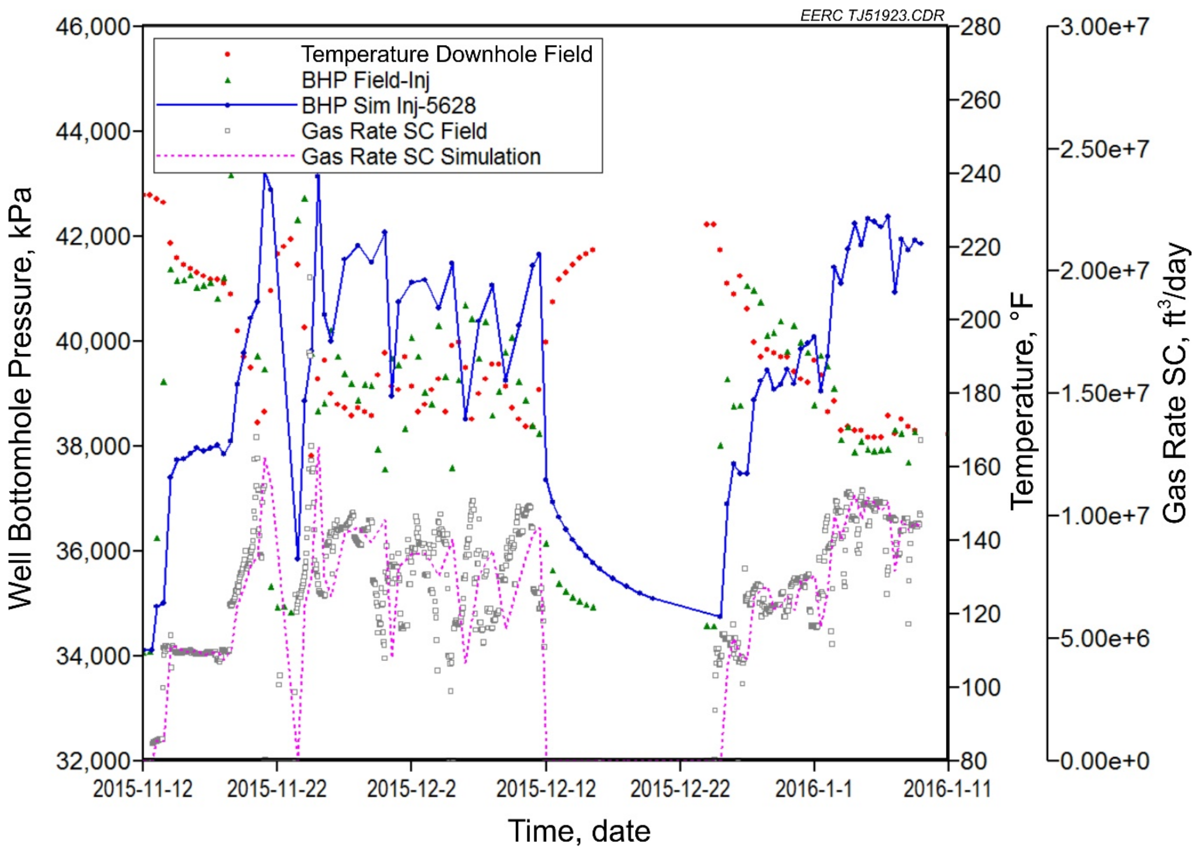


Figure 19. History match from November 12 to January 9, 2016.

The field data shown in above Figure 18 indicate that the downhole temperature has been declining since November, while the injection rate increased, even as injection pressure declined. The temperature dropped as low as 162°F in January 2016, from the original formation temperature of 235°F. Figure 20 shows the temperature effect on the injectivity index. The injectivity index is defined as:

$$\text{Injectivity Index} = q/(p_{wf} - p_i) \qquad \text{[Eq. 3]}$$

where q is surface flow rate, p_{wf} is wellbore downhole pressure, and p_i is initial reservoir pressure. Figure 20 shows that the injectivity index was ranging from 0.03 to 0.05 tonnes/d/kPa during April to July, and the downhole temperature did not go below 195°F (green dots). Since resuming injection in November, the injectivity index and temperature were in ranges similar to before (blue dots). However, when higher injection rates occurred after November 20, the temperature had dropped to as low as 170°F and the injectivity index has significantly improved, up to 0.12 tonnes/d/kPa. This phenomenon was not a temporary effect. Injection was stopped in mid-December, which allowed the bottomhole temperature to recover to nearly formation temperature. When injection resumed, the injectivity index (yellow dots) was higher, 0.05 to 0.06 tonnes/d/kPa, even in the temperature range of 195° to 230°F, which was the same temperature range of the data in the April to July time period. In January 2016, the injectivity index

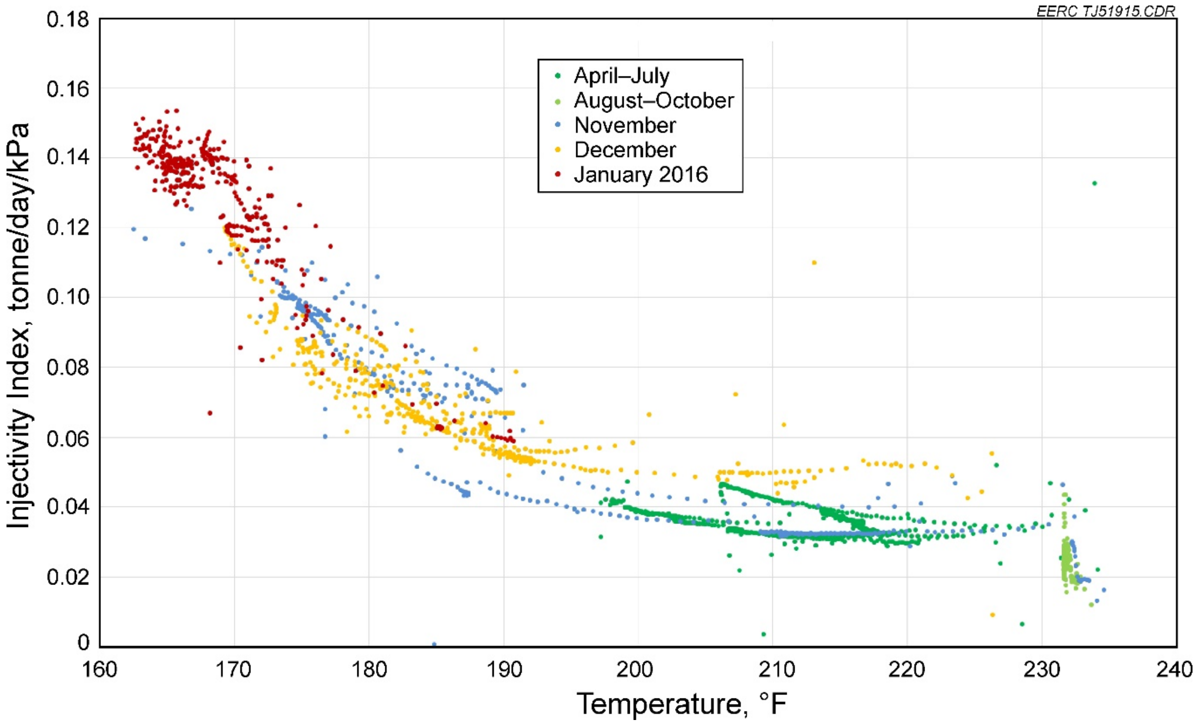


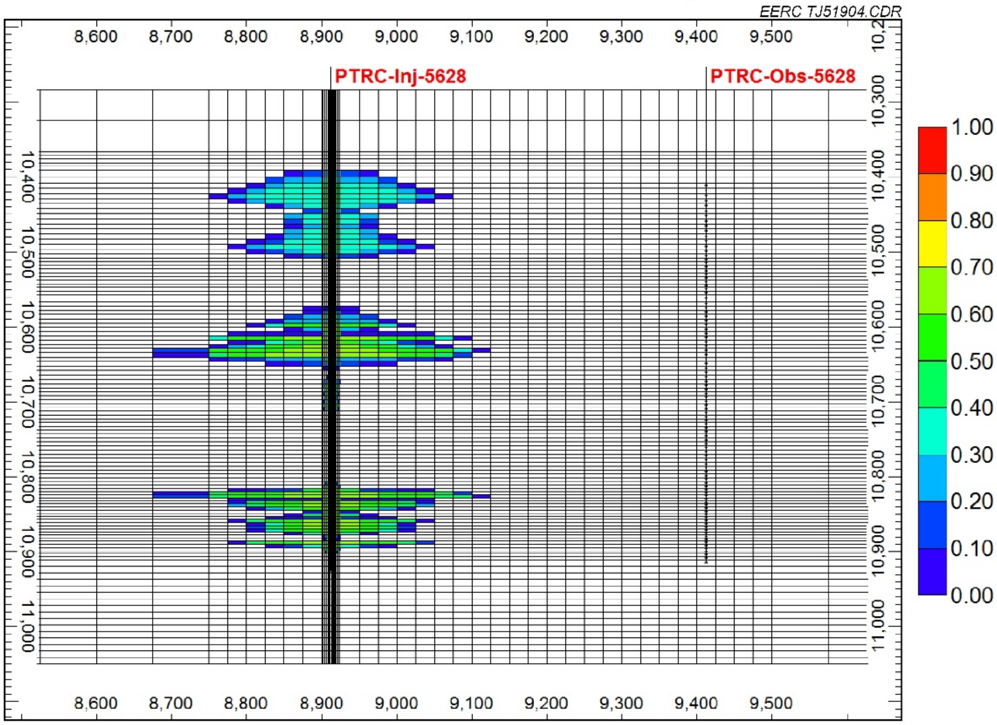
Figure 20. Temperature effect on injectivity index.

(dark red dots) further improved to 0.12 to 0.15 tonnes/d/kPa in the temperature range of 160° to 170°F, which is about 60°F below the reservoir temperature. It clearly indicates that lower bottomhole temperature is associated with improved injectivity. Additional well data, such as a planned spinner log survey and pulsed-neutron log, will be helpful to evaluate the cause of wellbore performance improvement.

CO_2 Plume Development

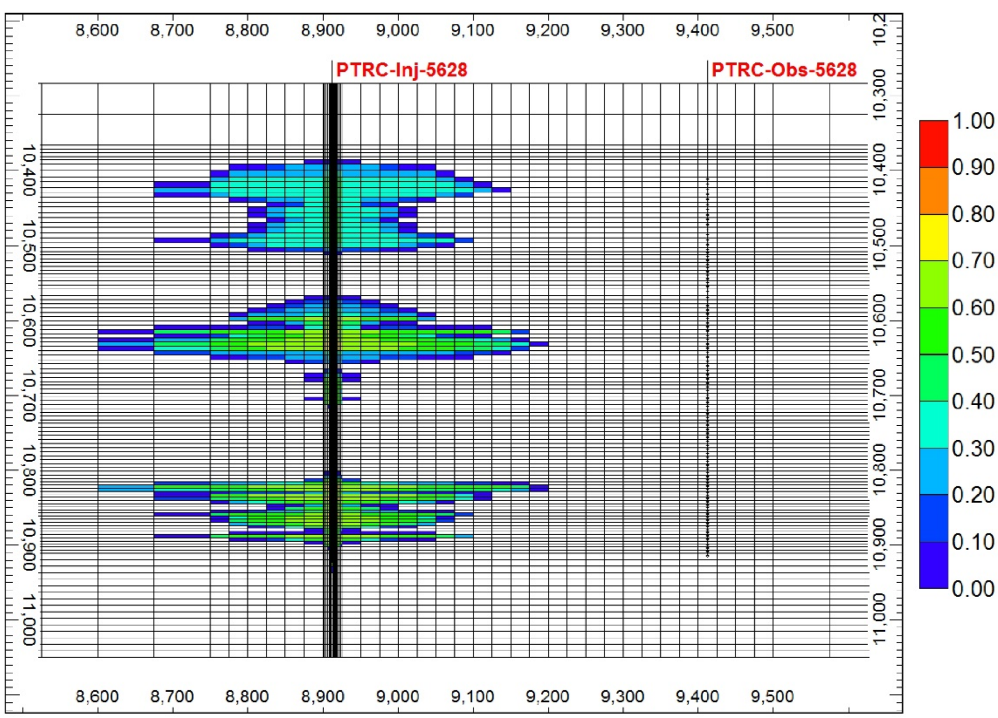
The CO_2 plume evolution based on the history-matched simulation is shown in Figures 21 and 22. The results match the spinner log data, and it can be seen that the CO_2 plume is approaching the observation well, so the breakthrough would be expected soon. The third perforation interval is effectively plugged off so it did not take a great amount of CO_2. However, it should theoretically take a significant amount of CO_2 because of its relatively better physical properties. It is also worth noting that the use of a different relative permeability curve would affect the CO_2 flow behavior, which would thus change the plume size and distribution. If RTP1 and RTP2 were switched for selected layers, for example, the CO_2 plume would be shown as in Figure 23, which indicates that CO_2 breakthrough would have already occurred at the observation well. New pulsed-neutron log data and a geophysical image of the CO_2 plume will be very helpful in evaluating the CO_2 plume evolution in the reservoir so that continued improvements in plume description can be made. It is also worth noting that during the well shut-in period in summer 2015, there was no reservoir pressure buildup. The bottomhole pressure dropped back to ~34,150 kPa, which is close to initial reservoir pressure. It indicates that injected CO_2 did not occupy the reservoir volume to restrict further CO_2 injection into the formation.

Gas Saturation 2015-05-01 I layer: 14



(a)

Gas Saturation 2015-07-01 I layer: 14



(b)

Figure 21. History match CO_2 plume evolution from a) 5/1/15, b) 7/1/15, c) 12/1/15, and d) 1/9/16 (continued).

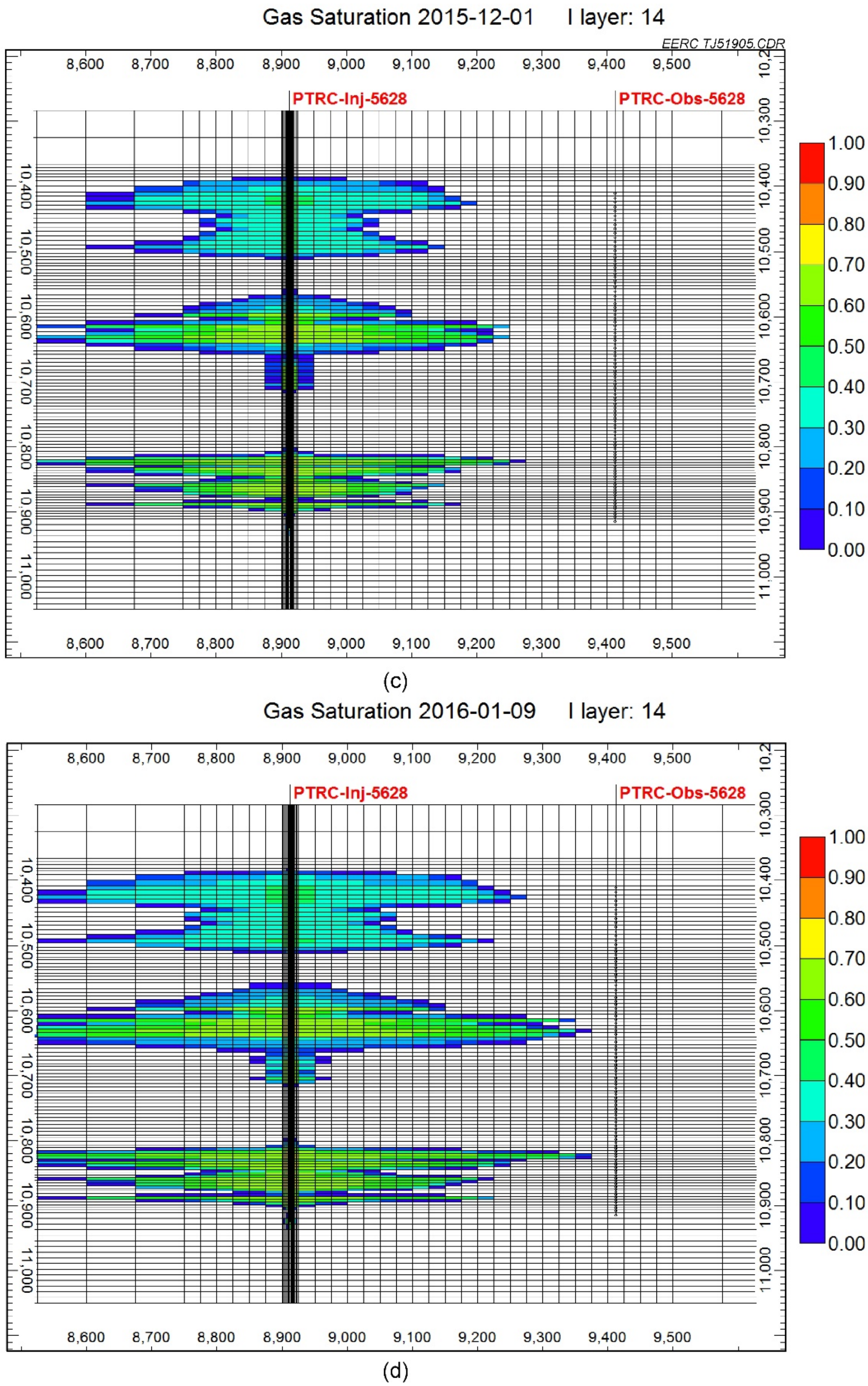


Figure 21 continued. History match CO_2 plume evolution from a) 5/1/15, b) 7/1/15, c) 12/1/15, and d) 1/9/16.

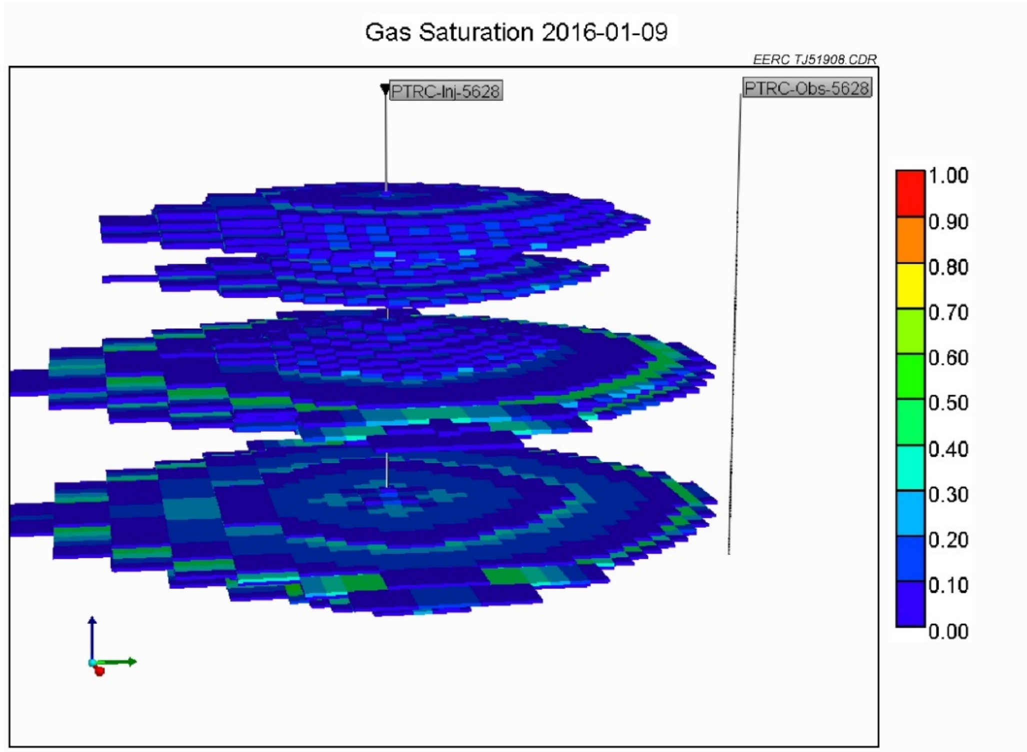


Figure 22. 3-D view of CO_2 plume evolution.

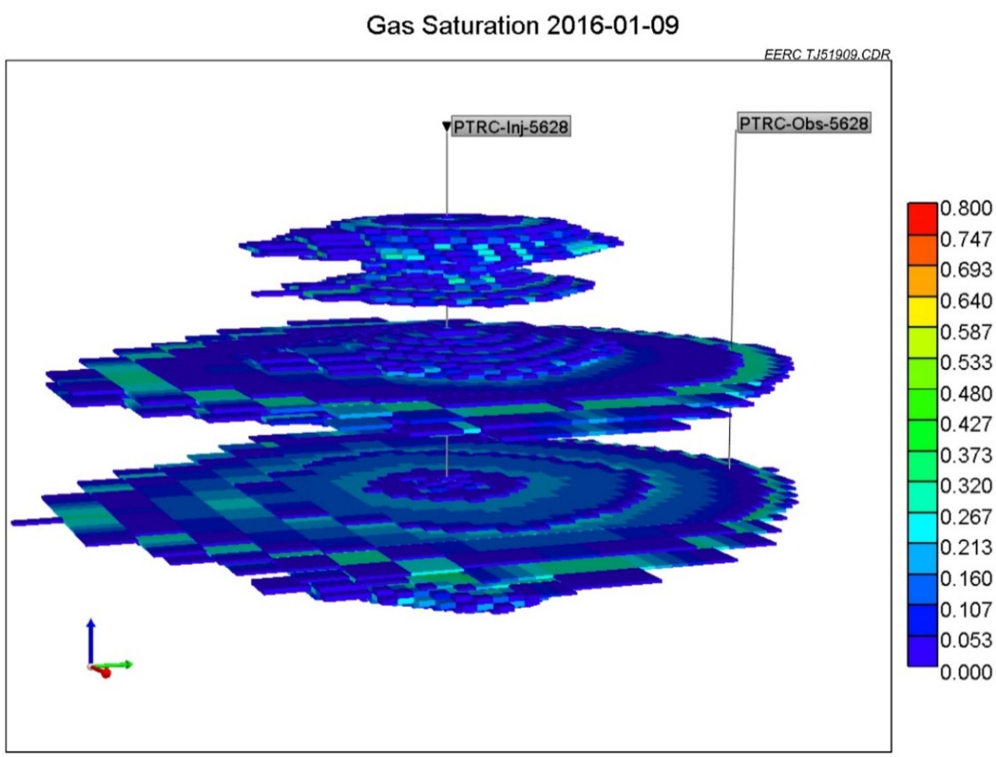


Figure 23. CO_2 plume 3-D view for different relative permeability case.

FUTURE WORK

Considerable work remains regarding geologic modeling and simulation of the Aquistore project.

CO_2 has not yet been observed at the observation well. When this occurs, an important update to the history match will be appropriate. In conjunction with this work, the intermediate-region permeability, between the near-wellbore and the observation well, needs to be investigated to further improve the history match of the observation well pressure.

From April 2015 until January 2016, approximately 25,000 tonnes of CO_2 has been injected at the Aquistore site. The SaskPower operational plans suggest that considerably more injection is planned for 2016 and, therefore, continued close monitoring of site performance is warranted. Related to higher levels of injection, the understanding and numerical modeling of the variability of the well's injectivity index and its relationship with bottomhole injection temperature are of critical importance.

Simulation forecasting of long-term performance is needed. Comparisons can be made with earlier forecasts that were made before injection started and any history matching was performed. Additional forecasts are needed to determine if site performance expectations can be met and to gauge the potential for long-term, large-scale CO_2 storage at the Aquistore site.

CONCLUSIONS

An attempt to match the historical data has been made, and the current operational data set was well replicated by the simulations. To date, CO_2 breakthrough at the observation well has not been observed, and further model improvements can be expected when CO_2 breakthrough is confirmed.

Numerical tuning and sensitivity analysis using a surface proxy model suggest that proper numerical tuning would improve simulation run time, and the simulation results of field pressure response were affected by the transmissibility and skin factor, which are both a function of reservoir permeability and near-wellbore damage zone permeability reduction. The results indicate that the rock physical properties need to be adjusted for the static model to improve the model accuracy.

It was also found that bottomhole temperature has a significant effect on the injectivity index. An injectivity index of 0.03 to 0.05 tonnes/d/kPa was observed during April to July, with a downhole temperature range of 195° to 230°F. When injection rate increased significantly beginning in November and downhole temperature dropped to the range of 160° to 170°F, the injectivity index improved to 0.12 to 0.15 tonnes/d/kPa in January 2016, an improvement of 300 to 500 percent. However, the specific factor that improved the injectivity index is unknown. Future field data, such as a new spinner log survey and pulsed-neutron log would be very helpful in evaluating the flow performance for the injector.

Although the simulation model matches the overall pressure response of the injection and observation wells, an improved history match can be done as more field data, such as new spinner log survey, pulsed-neutron log, and 4-D seismic data, become available. Geologic uncertainty remains, which influences interpretation of CO_2 injection behavior; important performance confirmations remain to be made in the field, and these will greatly assist history-matching efforts.

The studies covered in this project are limited to a history match of the field data up to January 9, 2016. Simulation studies with more comprehensive data sets would provide a more reliable solution to update the static model and reduce the geologic uncertainties and thus aid in the planning, development, and operation of MVA activities at the Aquistore site.

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