A SIMULATiON STUDY OF Carbon Storage with active reservoir management

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ABSTRACT

As part of the Integrated Midcontinent Stacked Carbon Storage Hub (IMSCS-Hub) project led by Battelle Memorial Institute, a study was conducted to determine the feasibility of storing carbon dioxide (CO_2) in the stacked saline rock formations of the Sleepy Hollow Field (SHF), located in Red Willow County, southern Nebraska.

A series of CO_2 injection simulation scenarios, with and without active reservoir management (ARM; brine extraction), were evaluated to investigate the feasibility of storing 50+ million tonnes (Mt) of CO_2. The results indicated CO_2 injection combined with ARM may enable permanent storage of 50+ Mt of CO_2.

The area of review (AOR), the area in which underground sources of drinking water (USDWs) might be endangered during CO_2 injection, was assessed for the simulation scenarios. In comparison to a case without ARM, brine extraction resulted in a much smaller AOR, covering an area of 42 square miles (108.8 square kilometers [km]), roughly one-fourth the size of an AOR resulting from CO_2 injection without ARM.

The findings presented in this paper indicate that CO_2 injection with ARM can improve the CO_2 storage capacity of a geologic storage complex up to 100% while also reduce the rate of pressure buildup in the subsurface, resulting in a 75% reduction in AOR. This may help in lowering carbon capture and storage project costs, risks, and effort needed to meet monitoring requirements for a storage project.

Keywords: CO_2 storage, CarbonSAFE, stacked storage, active reservoir management, carbon sequestration, brine extraction

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INTRODUCTION

The Midcontinent region of the United States has been the focus of increasing interest for potential carbon capture and storage (CCS) and has been the subject of CO_2 storage resource assessments under the Plains CO_2 Reduction (PCOR) Partnership and the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative, both sponsored by the U.S. Department of Energy (DOE).[1–7]

The DOE CarbonSAFE Initiative was established by the DOE National Energy Technology Laboratory (NETL) to support the development of commercial-scale CCS complexes capable of storing 50+ million tonnes (Mt) from industrial sources for operation in the 2025–2030 time frame. As part of the CarbonSAFE Initiative, the Integrated Midcontinent Stacked Carbon Storage Hub (IMSCS-Hub) team identified a clear strategy to meet DOE's 2025–2030 objective of commercial CCS implementation. The strategy involves developing a CO_2 market and infrastructure that rely on multiple ethanol-based CO_2 sources in the short term and incorporation of multiple coal-based power plant CO_2 sources in the future. The IMSCS-Hub study region consists of a CO_2 source corridor and a stacked storage corridor (Figure 1) that spans Nebraska and Kansas, representing the first large-scale project for the Midcontinent region.[3-5]

The main objectives of this simulation study were to 1) investigate the feasibility of storing 50+ Mt of CO_2 over 30 years in Sleepy Hollow Field (SHF) with and without active reservoir management (ARM); 2) determine resulting area of review (AOR); and 3) examine how ARM would help increase the storage capacity, increase injectivity of the stacked formations present in SHF, and reduce the pressure buildup (and AOR).

1.1 Project Background

The IMSCS-Hub Project Team was led by Battelle and included the Kansas Geological Survey (KGS), the Energy & Environmental Research Center (EERC) at the University of North Dakota, Archer Daniels Midland Company (ADM), Schlumberger, and the University of Nebraska-Lincoln

Conservation and Survey Division (UNL-CSD). Three selected areas were evaluated for the IMSCS-Hub Project: 1) southwest Nebraska near Madrid (Madrid site);
2) southwestern Kansas, Patterson-Heinitz-Hartland Field (PHH); and 3) southwest-central Nebraska, SHF.

This paper discusses a numerical simulation work conducted for SHF as a part of the IMSCS-Hub efforts, assessing the feasibility of storing 50+ Mt of CO_2 over 30 years in the stacked saline formations at SHF in Red Willow County, Nebraska. The simulation work was conducted using a geologic model of SHF built as part of the IMSCS-Hub effort from existing subsurface data consisting of 213 wells in and near the field. The geologic model integrated new data collected from a characterization well (Sleepy Hollow Reagan Unit [SHRU] 86A; API: 26145218050000), drilled to acquire site-specific data. These new data helped fill data gaps to further improve the accuracy of the modeling and simulation work and to provide information and data that would be required to apply for U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) Class VI well permits for dedicated CO_2 storage.

1.2 Sleepy Hollow Field Geology

Porous and permeable Paleozoic deep saline formations have been identified as potential geologic storage targets within SHF in southwest-central Nebraska. The stratigraphy of SHF is characterized by thick stratigraphic successions of marine and nonmarine sedimentary rocks.[8-9] The potential storage zones at the Sleepy Hollow site consist of multiple vertically stacked zones of deep saline limestones and sandstones in the Wabaunsee, Shawnee–Douglas (Topeka, Deer Creek–Oread Formations), Lansing–Kansas City (LKC), and Pleasanton–Marmaton Groups (Figures 2 and 3).[8-9] These deep saline storage zones occur at average depths ranging from 2862 ft (880 m) to 3390 ft (1033 m) with reservoir facies pinching out toward the Cambridge Arch in the northeast and thickening toward the Denver–Julesburg Basin in the west.[9] Potential storage targets within the target zones include sandstone intervals (5–20 ft [1.5–6.1 m] in thickness) in the Wabaunsee and Pleasanton–Marmaton Groups and porous limestones (5–25 ft [1.5–7.6 m] in thickness) in the Shawnee–Douglas and LKC Groups. The average porosity (arithmetic mean) and permeability (geometric mean) of each zone, respectively, are 6% and 2.18 mD for the Wabaunsee, 5% and 1.4 mD for the Shawnee–Douglas, 5% and 0.8 mD for LKC, and 6% and 2.85 mD for the Pleasanton–Marmaton Groups.

In SHF, the C interval of the LKC and local informally named “Sleepy Hollow Sandstone” are oil-bearing and are candidates for CO_2 enhanced oil recovery (EOR) with associated storage. However, the scope of CarbonSAFE objectives is limited to saline storage; therefore, a CO_2 EOR scenario was not simulated under this study.

The Upper Pennsylvanian shale, evaporite, and carbonate Admire and Council Grove Groups are the primary cap rocks for the potential storage complex at the SHF. These units exhibit log responses consistent with tight (i.e., low porosity) nonreservoir lithologies, such as gamma ray (GR) log values greater than 70 American Petroleum Institute GR units (gAPI) for shale and/or effective log porosities less than 5%. The potential storage complex at SHF is separated from the High Plains Aquifer (the lowest underground source of drinking water [USDW] in the area) by more than 1000 ft (304.8 m) of Mesozoic and Cenozoic rock. Hundreds of feet of seal separate the potential storage complex from regionally present but unutilized secondary aquifers in the area around SHF (Figure 2).[10]

1.3 Active Reservoir Management

ARM involves brine extraction from the CO_2 injection well prior to injection or concurrently producing brine from a neighboring extraction well to help reduce pressure buildup in CO_2 storage projects.[11–13] ARM enables optimized operational performance. The specific performance objectives of ARM are to reduce pressure buildup, increase CO_2 injectivity, increase available pore space and storage capacity, and enable greater control of subsurface fluid migration (manipulating CO_2 migration and constraining brine migration in the reservoir).[13] Reducing pressure buildup reduces pore-space competition with adjacent subsurface operations, which may include neighboring CCS operations, shale gas production, deep liquid waste injection, and geothermal energy production.[12] ARM may also help reduce AOR and risks of unintended CO_2 migration (e.g., vertical migration along legacy wellbores, migration through compromised seals, and fault activation and associated migration).

An AOR assessment is necessary for identifying risks associated with CO_2 storage projects and planning a monitoring, verification, and accounting (MVA) program at storage sites. AOR is determined by the extent of CO_2 plumes or the related pressure plumes as a result of CO_2 injection (whichever is larger). A pressure plume is defined as the area where pressure buildup in the formation as result of CO_2 injection is higher than the pressure front. The pressure front is the pressure within the injection zone great enough to force fluids from within the injection zone through a hypothetical open conduit into any overlying USDW. The pressure font was calculated using EPA's pressure front equation (Equation 1):[14]

$$P_{i,f} = P_u + \rho_i g * (z_u - z_i) \qquad \text{[Eq. 1]}$$

Where $P_{i,f}$ is pressure front in the injection zone, P_u is pressure in the USDW, ρ_i is fluid density within the injection zone, g is acceleration due to gravity, z_u is elevation of the USDW, and z_i is elevation of the injection zone.

SIMULATION MODEL DEVELOPMENT

Figure 4 shows the 3D porosity distribution in the tartan model with a size of 25 × 25 miles (40.2 × 40.2 km) for SHF. The geologic model was constructed using well log and core data obtained from drilling a new characterization well, and the geologic model was used in this simulation work.[4] The center of the tartan grid was more refined, with cell dimensions of 500 × 500 ft (0.15 × 0.15 km) within the area enclosed by the purple polygon. The tartan grid coarsened from the grid center outward. The largest grid cells had dimensions of 5000 × 5000 ft (1.52 × 1.52 km) at the edges of the model. This type of upscaling process helped maintain the heterogeneity within the field boundary with a reasonable cell count of approximately 1.15 million for simulation capacity.

The simulation model included 13 formations (Figure 3), with the Admire Group at the top and the Sleepy Hollow Sandstone at the bottom of the model. Of these 13 formations, ten are saline formations that are candidates for CO_2 injection. Table 1 summarizes the means and standard deviations of the effective porosity and permeability of each of the potential saline aquifers for CO_2 storage at SHF. Wabaunsee, Topeka, Deer Creek, and Oread were evaluated for this simulation study as they are thicker and more permeable formations.

Computer Modelling Group's (CMG's) GEM simulator was used to perform the simulations. The simulated time period consisted of 30 years of CO_2 injection and 10 years of postinjection monitoring for the stacked saline formations at the SHF. The fluid model included two components: CO_2 and water. The new data acquired from core analyses and field tests performed at the characterization well, SHRU-86A, were integrated into the simulation model, including formation pressure and temperature gradients, salinity, and capillary pressure data.

Infinite-acting boundary conditions were assumed for the flow simulations. Data from drillstem tests (DST) conducted for the Wabaunsee and Oread Formations confirmed that SHF is underpressured compared to the hydrostatic gradient, which was reported in Kincaid.[15] Hence, the model was equilibrated using the estimated pressure gradient of 0.36 psi/ft (8 kPa/m) from the DST data. The reference datum for the reservoir pressure was at a depth of 2933 ft (0.9 km), with a pressure of 1048 psi (7.23 MPa) (Wabaunsee top at SHRU-86A well). Reservoir temperature was defined linearly varying with depth using a temperature gradient of 0.03°F/ft (0.004°C/m) calculated based on the DST temperature data.

The results from water analyses conducted on the sample collected during the DSTs at SHRU-86A indicated that the average salinity of the water is 68,000 parts per million (ppm) total dissolved solids (TDS). The solubility of CO_2 in brine was modeled via Harvey's correlation for Henry's law constants.[16] Correlations from Rowe and Chou[17] and Kestin and others[18] were used for the density and viscosity, respectively, of the aqueous fluids.

As for rock–fluid characteristics, the CO_2–brine relative permeability tables from the studies of Bennion and Bachu[19,20] were used for three facies (carbonate, mudstone, and sandstone) in this dynamic simulation work. Capillary pressure data were obtained from mercury injection capillary pressure (MICP) tests conducted on the core plugs from the characterization well. J-function values (dimensionless capillary pressure values) were predicted using a curve that best fit experimental J-values from MICP tests and were used for each facies in the simulation model. Figure 5 shows the relative permeability and J-function data for the three facies used in this work.

INJECTION SCENARIO DESIGN

Several scenarios were designed to investigate the feasibility of storing the target amount of 50+ Mt of CO_2. These scenarios include varying numbers of injection wells, horizontal and vertical orientations for wells, different lengths for horizontals, different combinations of stacked formations for injection, and varying locations for injection wells. Table 2 gives the variables and settings in investigating different injection scenarios to meet the target volume of CO_2. A maximum bottomhole pressure (MaxBHP) was used in the model as an injection constraint. MaxBHPs were calculated using a fracture pressure gradient of 0.7 psi/ft (15.8 kPa/m), which was a recommended value to calculate injection pressure when no fracture pressure data were available.[21] A small safety factor (10%) for calculating MaxBHP was applied to ensure injection would not exceed the estimated fracture pressure during the injection process.

Table 3 lists all the scenarios for CO_2 injection with and without ARM considered for evaluating the feasibility of storing 50+ Mt of CO_2 over 30 years in the stacked saline formations at SHF. Scenarios 1–9 consider injection without ARM while Scenarios 10–13 consider injection with ARM. Injection wells were placed in higher-permeability areas and spaced out to minimize pressure interference. A maximum of ten wells were initially set up and tested in the simulation because pressure interference between injection wells would limit the cumulative injected amount in the formations. For scenarios of CO_2 injection with ARM, Scenario 4 without ARM was used as a benchmark case. Horizontal wells were considered for extracting brine and placed in the deeper intervals, namely, the LKC-F interval and the Pleasanton–Marmaton, below the CO_2 injection intervals to minimize breakthrough of injected CO_2 and maximize the volume of brine extracted. A water extraction rate of 10,000 bbl/day (1192 m^3/day) per well was considered in the simulation of CO_2 injection with ARM. Brine extraction wells were placed in a way to minimize the breakthrough of injected CO_2 and maximize the volume of brine extracted to control pressure buildup in the formations.

results AND DISCUSSION

4.1 CO_2 Injection Without ARM

Table 4 summarizes the cumulative CO_2 injected for each scenario evaluated in this study. Scenario 1, with four vertical wells, injected just 19 Mt, which is considerably lower than the target injection amount of 50 Mt. However, four horizontal wells (Scenarios 2–5) resulted in better injectivity than four vertical wells. The horizontal well scenarios of different lengths showed that the amount of CO_2 injected increased with length. The most ideal well length selected was 1.5 miles (2.4 km) as this length was still considered a reasonable length, while 2 miles (3.2 km) was becoming excessively long in terms of drilling operation ease and the costs involved. In addition, the 1.5-mile (2.4-km) length achieved half of the target 50 Mt of CO_2. Hence, Scenario 4 was selected as the benchmark case for all other scenarios in this study.

The cumulative injected amount does not significantly increase with additional wells because of pressure interference in the formations (Table 4, Scenarios 6–9). Five, six, and eight wells injected 26.5, 27.5, and 28.2 Mt of CO_2, respectively. 30 Mt was the maximum amount of CO_2 that could be injected with the use of ten horizontal wells (Scenario 9). Adding six more wells only increased the injected amount by approximately 5 Mt, which was due to 1) well interference between the horizontal wells and 2) additional wells only able to be placed in areas/formations of lower permeability, such as Topeka and Deer Creek, to minimize interference between wells. The original 50-Mt target injection amount was not feasible in these injection scenarios without ARM in SHF.

From the injection scenarios shown in Table 3, Scenario 4 is discussed in detail in this paper and is referred to as “CO_2 injection without ARM” Figure 6 shows the placement of the four wells in the simulation model from Scenario 4. In Scenario 4, CO_2 was injected into Wabaunsee and Oread out of ten potential formations. Vertical migration of injected CO_2 was observed in the underlying formations, most of which took place in Topeka and Deer Creek (not shown).

Figure 7 displays the simulated well injection rates and cumulative CO_2 injected amount for four CO_2 injection wells (two each in the Wabaunsee and Oread Formations) without ARM. Injection rates for each well varied based on the location and formation. Higher injection rates were achieved with injection into Wabaunsee compared to Oread because Wabaunsee is much thicker compared to Oread. The simulation resulted in injection of a cumulative amount of 25.7 Mt of CO_2, about half of the target amount.

Figure 8 displays the cumulative CO_2 injected amount by formation. The stacked storage potential in the study area was 15.4 Mt for Wabaunsee and 10.3 Mt for Oread. In terms of percent of the total injected, the stacked storage potentials are 60% and 40% for the corresponding formations, respectively.

The extents of the CO_2 plumes (lateral distribution of CO_2 saturation) and pressure plumes (Equation1) were evaluated as a result of injection into the stacked formations at SHF to determine the size of the AOR. The simulated pressure plume was much larger than the simulated CO_2 plume in the modeled area; hence the size of AOR would be that of the pressure plume.

Figure 9 illustrates the planar views of the overall (all layers combined) maximum extent of CO_2 plumes at SHF at 15 and 30 years of injection and 10 years postinjection. The predicted CO_2 plume extent was 2.1 × 6.8 miles (3.4 × 11.0 km), 4.7 × 7.3 miles (7.6 × 11.8 km), and 5.1 × 7.4 miles (8.2 × 11.9 km) at the corresponding time periods. During the postinjection period of 10 years, the CO_2 plumes expanded by approximately 0.3 miles (0.5 km) (more to the north and south of the site), indicating CO_2 plume migration is slow as the pressure dissipates out into the formations and stabilizes over time after halting injection.

Figure 9 also illustrates the pressure plume extent (white outline) or AOR (determined by the pressure plume as the pressure plume is larger than the CO_2 plumes) at the end of 30 years of injection. The predicted AOR would cover an area of approximately 155 square miles (401.8 square km) (12.6 × 12.3 miles [20.3 × 19.8 km]).

4.2 CO_2 Injection with ARM

The simulation results from the scenarios in this study of CO_2 injection without ARM indicate that SHF is not a viable site for storing 50 Mt of CO_2 over a time period of 30 years. Hence, the CO_2 injection without ARM scenario was expanded by adding wells for brine extraction and investigated for CO_2 storage with ARM. The feasibility of storing 50 Mt of CO_2 through concurrently injecting CO_2 and extracting brine from the stacked formations was evaluated to help control and limit pressure buildup in the formations as a result of CO_2 injection and increase storage capacity of the formations.

Table 4 also shows the four scenarios (Scenarios 10–13) of CO_2 injection with ARM using varying numbers of wells from one to four for brine extraction. For simulation with ARM, horizontal wells were considered for extracting brine and placed in the deeper intervals, namely, the LKC-F interval and the Pleasanton–Marmaton, below the CO_2 injection intervals to minimize breakthrough of injected CO_2 and maximize the volume of brine extracted. Figure 10 shows cumulative injected CO_2 over 30 years of concurrent CO_2 injection with brine extraction for the scenarios listed in Table 4. With four wells for extraction and four wells for CO_2 injection (Scenario 13), approximately 51 Mt of CO_2, just over the target storage amount, was achieved. Hence, only the detailed results from Scenario 13 are discussed in the remainder of the paper. CO_2 breakthrough was not observed at the extraction wells. The reduction in overall pressure increase due to the extraction of formation water from the lower intervals is the primary reason additional CO_2 could be injected into the formations. For instance, Figure 11 shows the pressures (at the top of Wabaunsee as an example) at the end of CO_2 injection in both scenarios of injection with and without ARM. The reduced pressure increase with ARM is significantly noticeable compared to the scenario without brine extraction.

Bar charts summarize the cumulative CO_2 injection by injection well (Figure 12) and by formation (Figure 13) with and without ARM at SHF. Total injected CO_2 increased considerably, up to a maximum of 10.3 Mt for Inj-1, 11.9 Mt for Inj-2, 14.1 Mt for Inj-3, and 15.2 Mt for Inj-4, showing respective increases of 98%, 133%, 91%, and 90% in injection capacity of the corresponding wells with the help of extracting brine from the formations that are deeper than the injection formations. As for storage capacity by formation, ARM with brine extraction limited the pressure buildup in the Wabaunsee, resulting in an increase of 96% in storage capacity from 15.4 Mt without ARM to 30.1 Mt with ARM. As for the Oread, the storage potential increased from 10.3 to 20.5 Mt (roughly an increase of 100%) when scenarios of only CO_2 injection and CO_2 injection with ARM using four brine extraction wells were compared.

Figure 14 illustrates the planar views of the overall (all layers combined) maximum extent of CO_2 plumes at SHF at 15 and 30 years of injection and 10 years of postinjection from Scenario 13, where 51 Mt of CO_2 injection was achieved by extracting brine using four wells. The predicted CO_2 plume extent was 4.5 × 7.5 miles (7.2 × 12.1 km), 5.3 × 8 miles (8.5 × 12.9 km), and 5.4 × 8.2 miles (8.7 × 13.2 km) at the respective time periods. Figure 14 also illustrates the pressure plume extent (blue outline) at SHF at the end of 30 years of injection for the scenarios with ARM. In Scenario 13, the predicted pressure plume would be much smaller, approximately covering an area of 4 × 7 miles (6.4 × 11.3 km), compared to CO_2 plumes. Hence, in this scenario of CO_2 injection ARM, AOR will be determined by the extent of CO_2 plume at the end of 30 years of injection and its spatial extent would be 42 square miles (108.8 square km), roughly one-fourth of the size of AORs resulting from CO_2 injection without ARM (Figure 15).

The findings presented in this paper indicate that CO_2 injection with ARM can significantly improve CO_2 storage capacity of a geologic storage complex while also reduce the rate of pressure buildup in the subsurface, resulting in a much smaller AOR. For the stacked storage of CO_2 at SHF, the storage capacity can improve by up to 100% for each formation investigated, and the AOR size can be reduced by 75% with the use of ARM, compared to the case of CO_2 injection only.

The brine extracted during the ARM process could be injected into overlying saline formations that are too shallow for supercritical CO_2 injection. The brine could also be injected into the saltwater disposal formation (the Cedar Hills Formation) that is used for the disposal of the coproduced water from oil and gas operations in the region. Further research would be needed to determine the brine storage capacities of such formations and/or investigate potential commercial, industrial, and agricultural uses of the brine extracted.

ARM provides benefits to reservoir management at the costs of drilling brine extraction wells and extracting and disposing brine. These added costs must be offset by the added benefits to the storage operation and/or by creating new, valuable uses of brine that can reduce the added cost.

One of the added potential benefits is that brine extraction wells can be used as actively controlled monitoring wells, providing valuable information about CO_2 plume migration when CO_2 breakthrough occurs, which supports numerical model calibration through history matching and reduces uncertainty in prediction of storage performance. In addition, brine production wells could be later converted to CO_2 injection wells, which would increase overall CO_2 injectivity.[12] Reinjection of extracted brine on top of the CO_2 plume could be an option to accelerate CO_2 dissolution and increase solubility trapping.[12]

Furthermore, revenue could be generated by producing fresh water from the extracted brine through brine desalination, using technologies such as reverse osmosis.[22] Extracted brine could also have the potential of producing enough geothermal energy and water to significantly defray the parasitic energy and resource demands of CO_2 capture, thereby helping to reduce implementation barriers facing CCS.[23,24] These benefits could offset the added costs of CO_2 storage with ARM.

Economics of CO_2 storage and ARM with brine extraction will also require a detailed analysis, which was beyond the scope of this paper. However, because of the smaller size of the AOR associated with ARM, the cost of monitoring should be reduced compared to CO_2 storage without ARM. This also includes risk reduction in both technical and nontechnical areas of the project, such as less likelihood of unintended CO_2 and formation brine migration and fewer landowners from whom to obtain approval, decreasing the likelihood of project rejection by stakeholders and the public.

CONCLUSION

Pressure buildup can restrict CO_2 storage capacity for commercial-scale geologic CO_2 storage when an injection-only scenario is considered. However, ARM incorporates brine extraction with CO_2 injection to reduce pressure buildup and increase injectivity and storage capacity, providing opportunity to make large-scale CO_2 storage projects technically feasible. This study demonstrates these benefits of ARM by investigating the feasibility of injecting and storing 50 Mt of CO_2 into the stacked saline formations at SHF, one of the potential storage sites of the IMSCS-Hub project. A series of CO_2 injection simulation scenarios, with and without ARM, were evaluated for the feasibility of storing 50+ Mt of CO_2 in SHF. The resulting AORs from injection were investigated and compared to quantify the AOR size reductions with ARM. In addition, the increased injectivity and storage capacity of the stacked formations at SHF, as result of ARM application, were assessed.

The results of the CO_2 storage simulations without ARM show that SHF can store 25 Mt of CO_2 with a reasonable number of injection wells (four). However, the results indicated CO_2 injection combined with ARM (brine extraction) may enable permanent storage of 50+ Mt of CO_2, doubling the storage capacity of the storage formations without ARM, providing the large-scale capacity needed by coal-based power plant operators.

In comparison to the case without ARM, brine extraction resulted in a much smaller AOR, covering an area of 42 square miles (108.8 square km), roughly one-fourth of the size of the AOR resulting from CO_2 injection without ARM. The ARM scenario reduced the extent of the pressure buildup by 75% in the formations and improved the storage capacity of the stacked formations in SHF by approximately 100%. ARM and the resulting reduced AOR size may help in lowering CCS project costs, risks, and effort needed to meet monitoring requirements.

The simulation results at SHF suggest that the commercial-scale CO_2 storage sites in the IMSCS-Hub storage corridor, similar to SHF in terms of geology and reservoir quality, can benefit from the application of ARM through increased injectivity, increased storage capacity, reduced pressure buildup, and reduced AOR for monitoring. Additionally, the potential for associated CO_2 storage (a hybrid case of CO_2 EOR and geologic storage), given the existing hydrocarbon resources in the region, may provide technical advantages, infrastructure, and economic incentives needed to successfully commercialize CCS in the region. The above-mentioned ARM benefits are provided at the cost of extracting brine. Economics of CO_2 storage and ARM with brine extraction will require a detailed analysis, which was beyond the scope of this paper. The numerical results from this study should motivate future, detailed techno-economic studies of ARM to help better understand the commercial applicability of ARM to specific large-scale CO_2 storage projects.

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Table 1. Effective Porosities and Permeability Statistics of the Saline Formation in the Upscaled Tartan Grid.

Formation	Effective Porosity, v/v		Permeability, mD	
	Arithmetic Mean	Arithmetic σ (standard deviation)	Geometric Mean	Geometric σ (standard deviation)
Wabaunsee	0.06	0.04	2.18	3.78
Topeka	0.05	0.03	1.52	3.93
Deer Creek	0.04	0.02	0.70	4.75
Oread	0.05	0.03	1.96	3.88
LKC A	0.05	0.03	0.76	2.26
LKC B	0.06	0.03	0.95	2.29
LKC D	0.05	0.03	0.63	2.76
LKC E	0.05	0.03	0.80	2.26
LKC F	0.06	0.03	0.81	2.83
Pleasanton–Marmaton	0.06	0.04	2.85	4.01

Table 2. Varying Parameters and Injection Setting in the Investigation for Different Injection Scenarios.

Number of wells investigated	4–10
Well orientation	Vertical, horizontal
Length of the horizontals	0.5–2 miles (0.8–3.2 km)
Formations investigated	Wabaunsee, Topeka, Deer Creek, Oread
Injection constraint per well	MaxBHP
Group injection constraint	50 Mt of CO_2

Table 3. CO_2 Injection Scenarios with and Without ARM

Scenario	**No. of Injection Wells**	**Well Orientation**	**Length of Horizontal Wells**	**Injection Formation (no. of wells per formation)**	**No. of Brine Extraction Wells**	**Extraction Formation (no. of wells per formation)**
1	Four	Vertical	NA	all candidate formations	NA	NA
2	Four	Horizontal	0.5 mile (0.8 km)	Wabaunsee (two wells), Oread (two wells)	NA	NA
3	Four	Horizontal	0.75 mile (1.2 km)	Wabaunsee (two wells), Oread (two wells)	NA	NA
4	Four	Horizontal	1.5 mile (2.4 km)	Wabaunsee (two wells), Oread (two	NA	NA

				wells)		
5	Four	Horizontal	2 miles (3.2 km)	Wabaunsee (two wells), Oread (two wells)	NA	NA
6	Five	Horizontal	1.5 mile (2.4 km)	Wabaunsee (two wells), Oread (two wells), Topeka (one well)	NA	NA
7	Six	Horizontal	1.5 mile (2.4 km)	Wabaunsee (two wells), Oread (two wells), Topeka (two wells)	NA	NA
8	Eight	Horizontal	1.5 mile (2.4 km)	Wabaunsee (two wells), Oread (two wells), Topeka (two wells), Deer Creek (two wells)	NA	NA
9	Ten	Horizontal	1.5 mile (2.4 km)	Wabaunsee (three wells), Oread (three wells), Topeka (two	NA	NA

				wells), Deer Creek (two wells)			
10	Four	Horizontal	1.5 mile (2.4 km)	Wabaunsee (two wells), Oread (two wells)	One	Pleasanton–Marmaton (one well)	

Continued . . .

Table 3. CO_2 Injection Scenarios with and Without ARM (continued)

Scenario	No. of Injection Wells	Well Orientation	Length of Horizontal Wells	Injection Formation (no. of wells per formation)	No. of Brine Extraction Wells	Extraction Formation (no. of wells per formation)
11	Four	Horizontal	1.5 mile (2.4 km)	Wabaunsee (two wells), Oread (two wells)	Two	LKC F (one well), Pleasanton–Marmaton (one-well)
12	Four	Horizontal	1.5 mile (2.4 km)	Wabaunsee (two wells), Oread (two wells)	Three	LKC F (one well), Pleasanton–Marmaton (two wells)
13	Four	Horizontal	1.5 mile (2.4 km)	Wabaunsee (two wells), Oread (two wells)	Four	LKC F (one well), Pleasanton–Marmaton (three wells)

Table 4. Cumulative CO_2 Injected (Mt) for Each Scenario

Scenario	Brine Extraction	Cumulative CO_2 Injected (Mt)
1	No	15.3
2	No	19.1
3	No	21.8
4	No	25.7
5	No	27.8
6	No	26.5
7	No	27.5
8	No	28.2
9	No	30
10	Yes	33.9
11	Yes	40
12	Yes	46.9
13	Yes	50.6

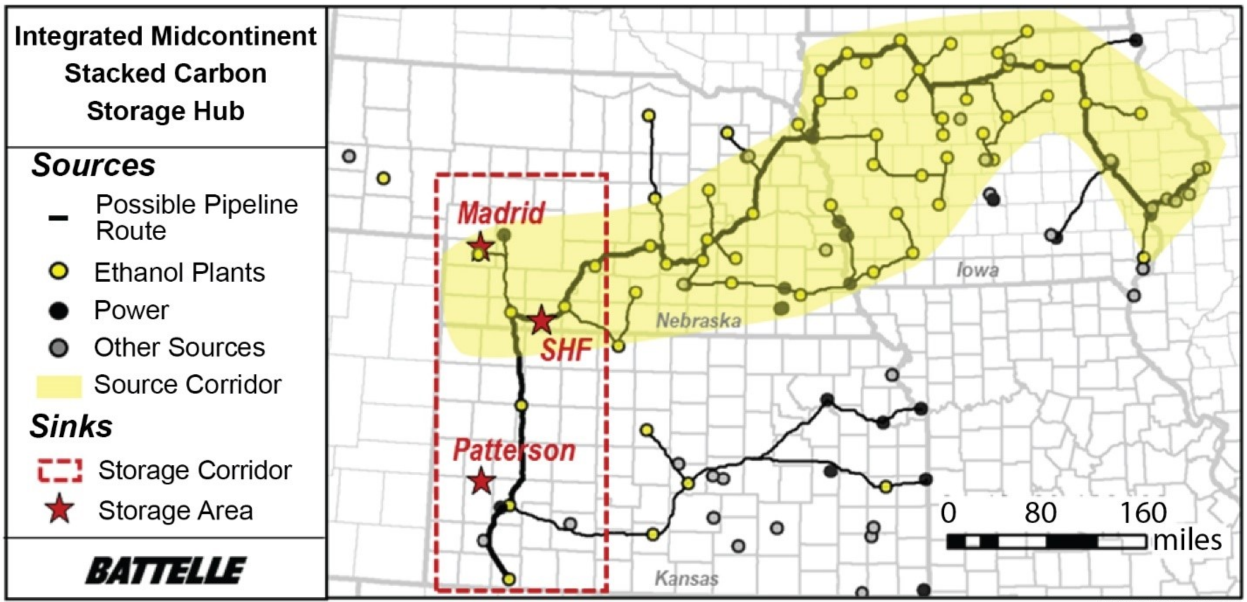

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Figure 1. The IMSCS-Hub study region showing the CO_2 source and stacked storage corridors (modified from the study by Walker and others[5]) (SHF: Sleepy Hollow Field; PHH: Patterson, Heinitz, and Hartland Fields).

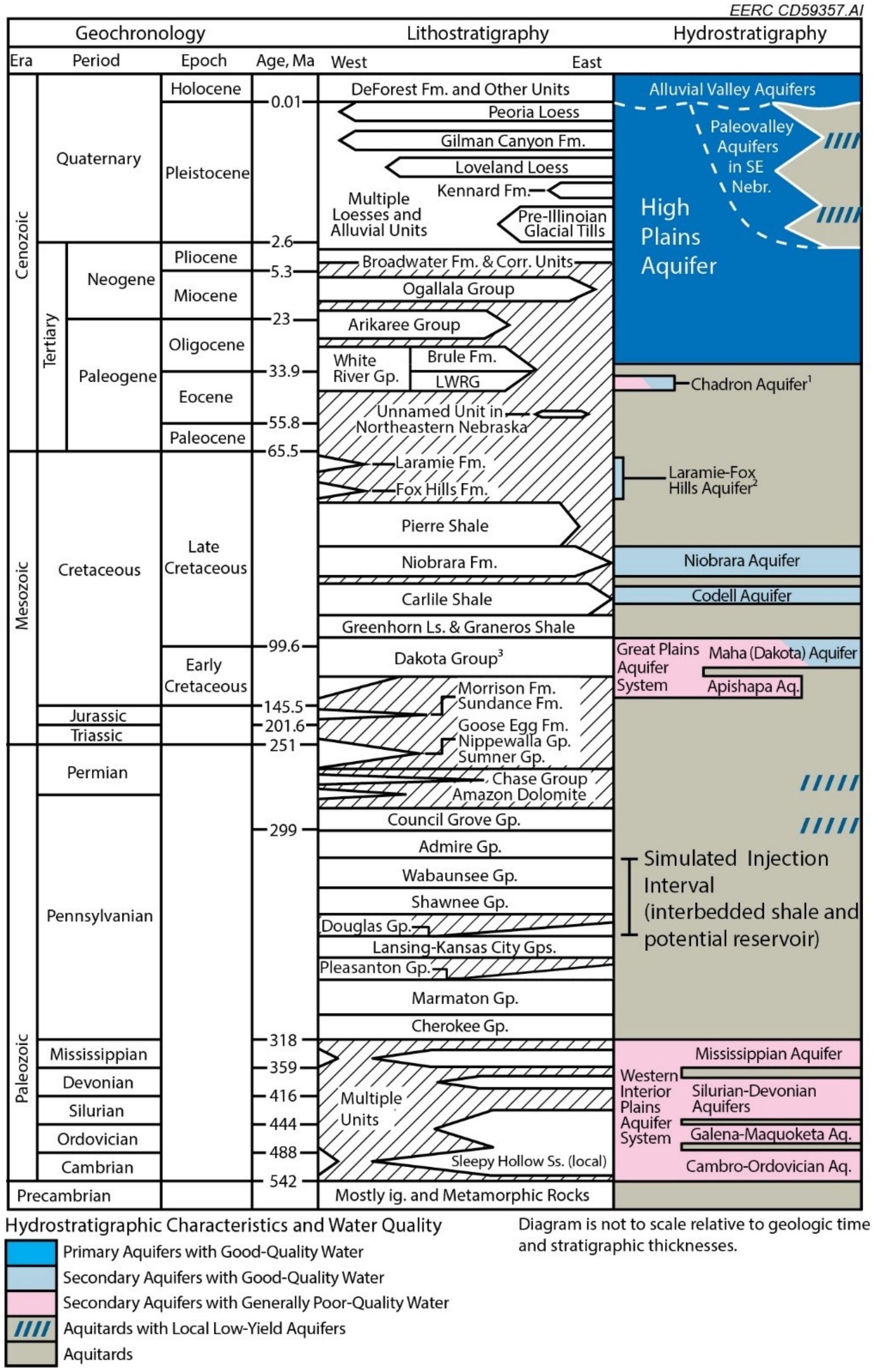

Figure 2. Generalized stratigraphic and hydrologic column of Nebraska (modified from Korus and Joeckel[9]). Simulated injection interval is shown in detail in Figure 3. Aquifers shown between the simulated injection interval and the High Plains aquifer are not used in the study area.[10]

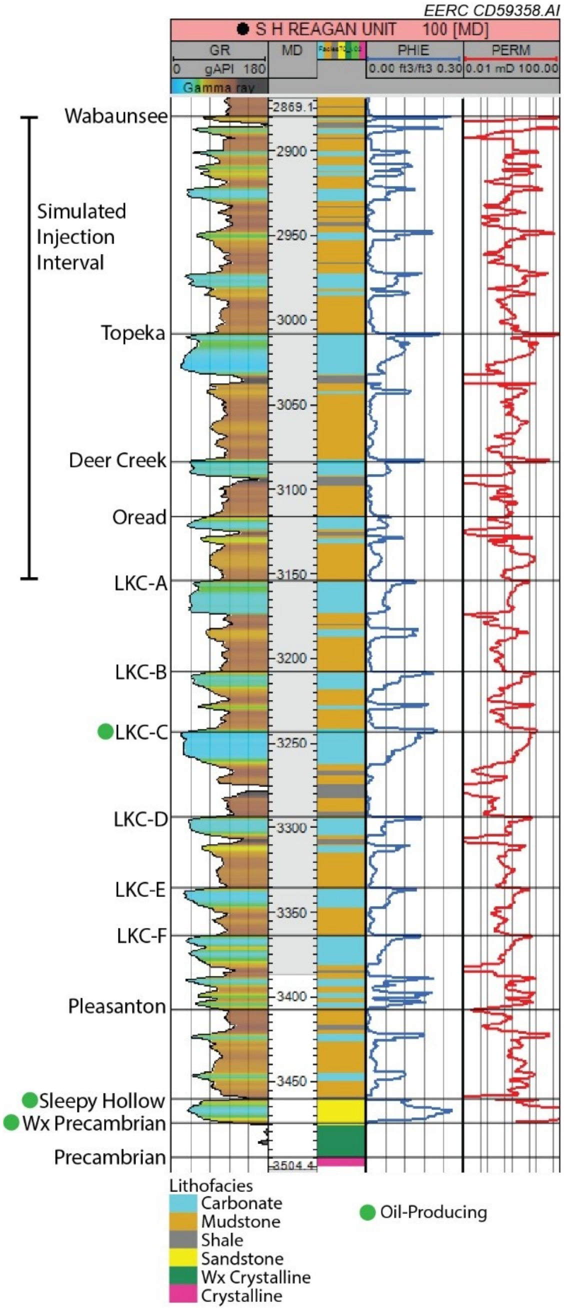

Figure 3. Example model formation tops from the center of the SHF. The GR log reveals the carbonate cycles (bluish units). Potential storage intervals are in areas of low GR response and are separated by tighter zones. Green circles indicate oil-producing intervals. “LKC” abbreviates Lansing-Kansas City; “Wx” abbreviates “weathered.”

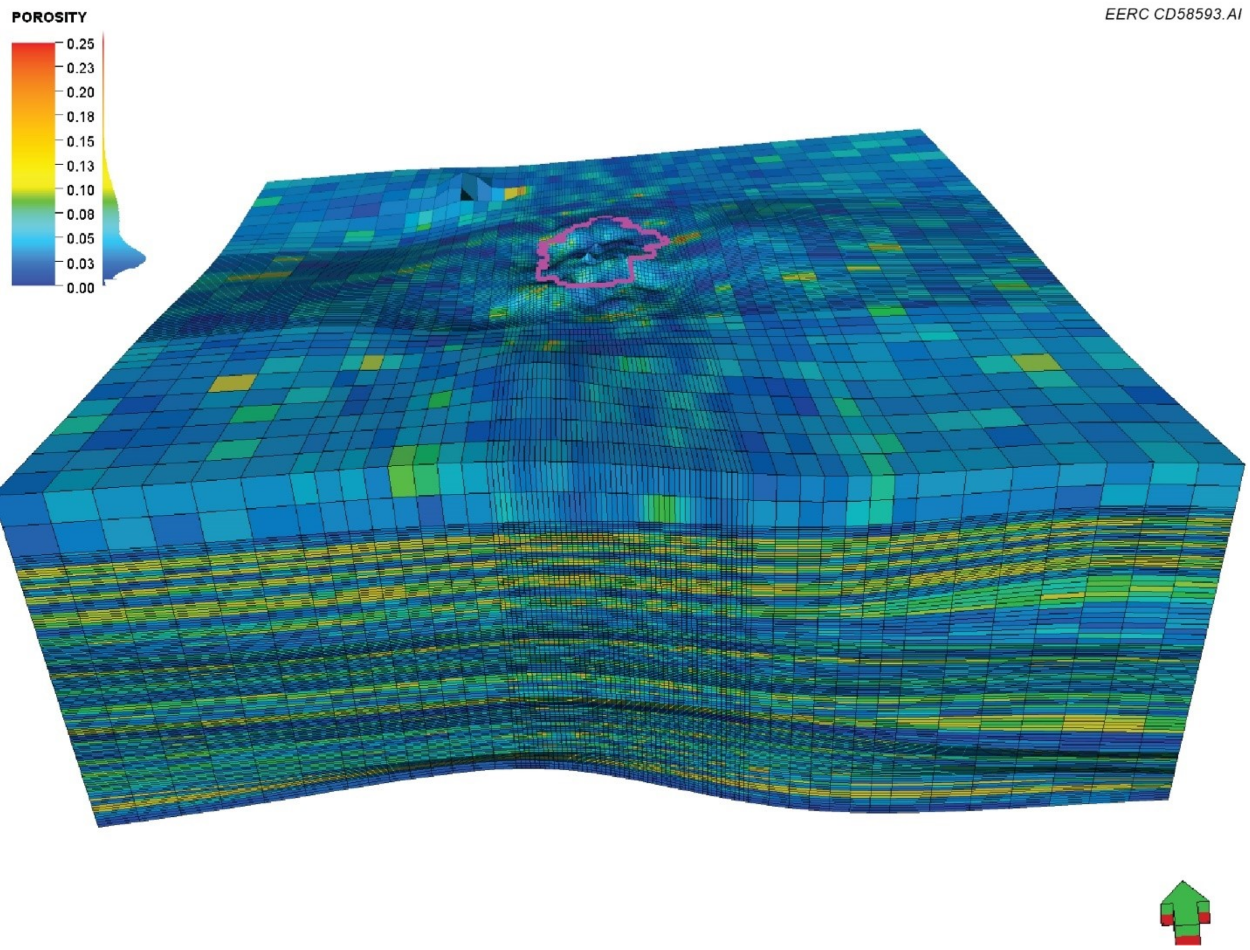

Figure 4. The 3D effective porosity distribution in a tartan grid after upscaling (purple polygon shows SHF boundary). Vertical exaggeration is 60×.

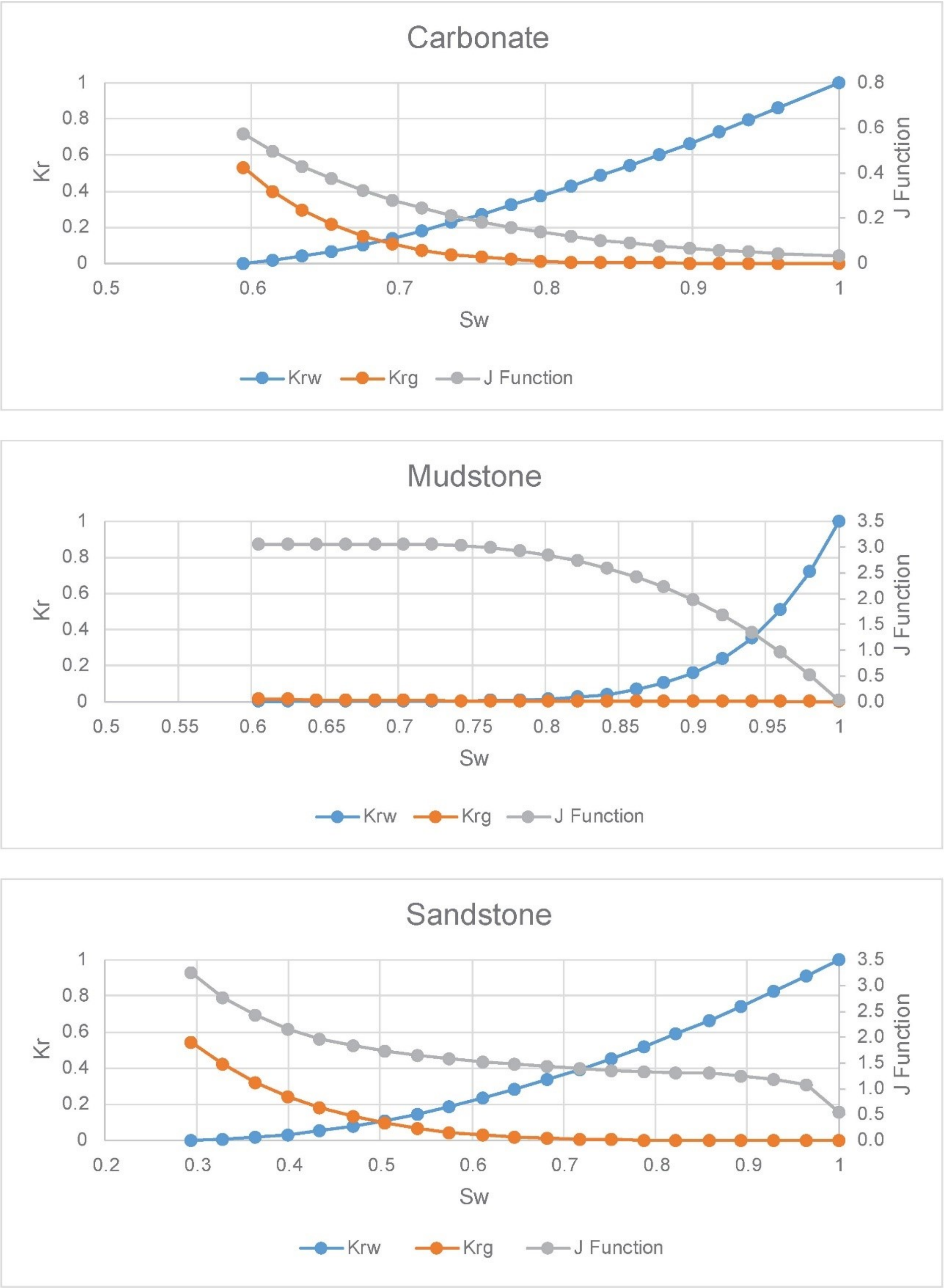

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Figure 5. Relative permeability (water [Krw] and gas [Krg]) and J-function data for carbonate (top), mudstone (middle), and sandstone (bottom) lithofacies.

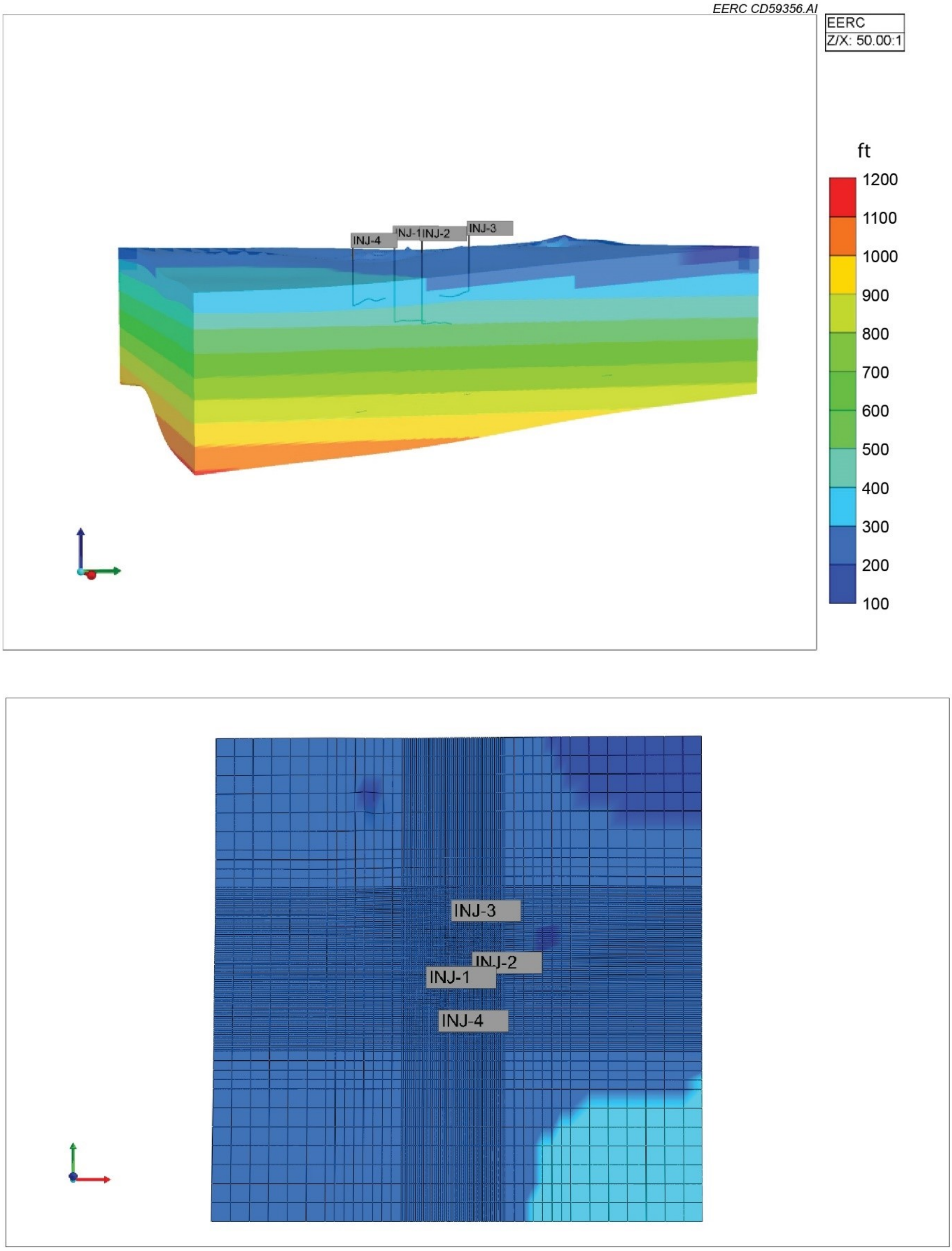

Figure 6. Well placement in four-well scenario (from eastern side [top] and from top view [bottom]). Vertical exaggeration is 50×.

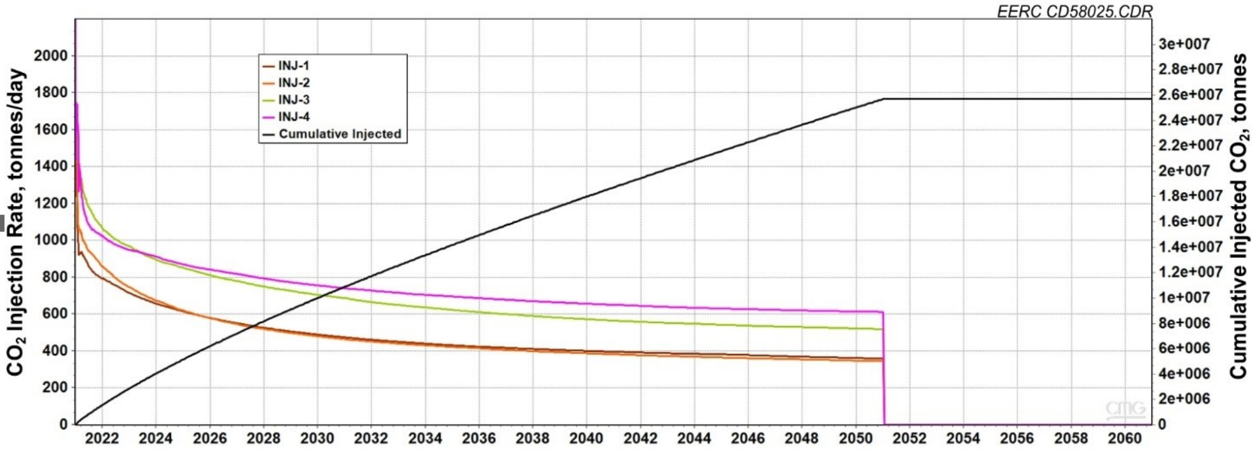

Figure 7. Well injection rate and total injected CO_2 in the CO_2 injection without ARM scenario.

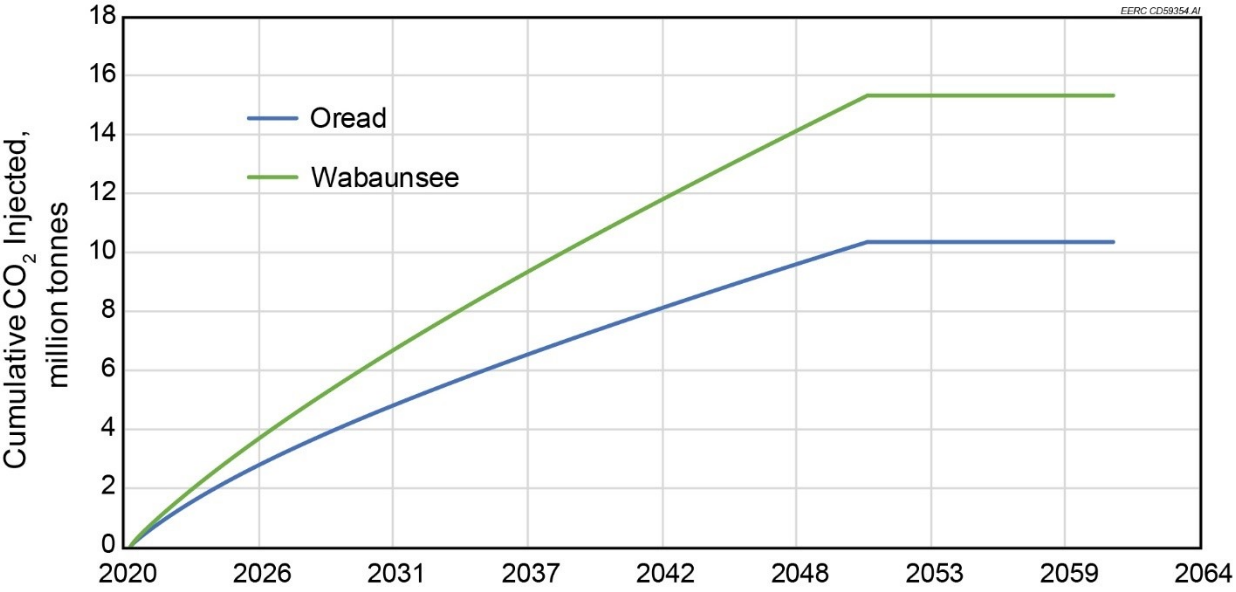

Figure 8. Cumulative injected CO_2 by formation in the CO_2 injection without ARM scenario.

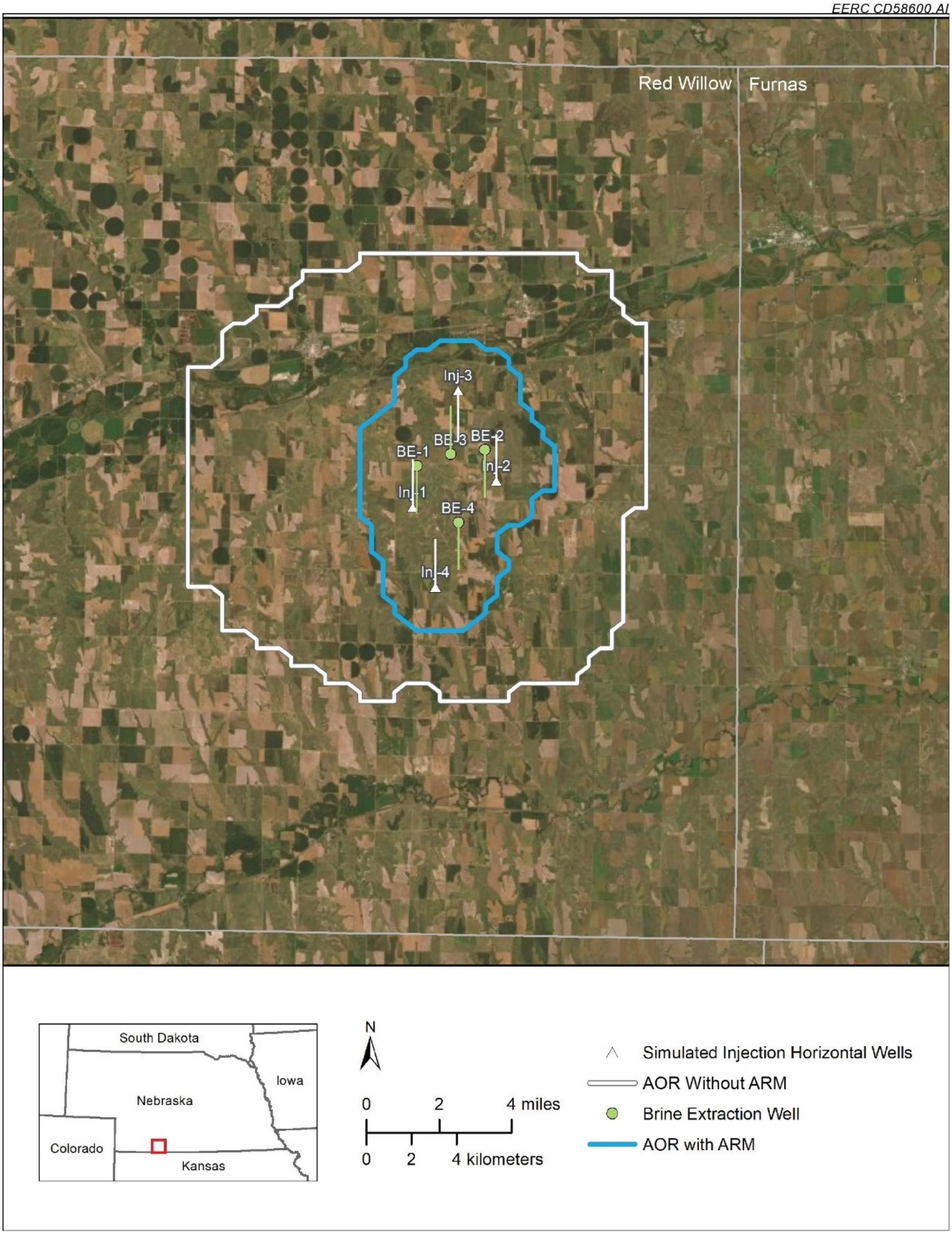

Figure 9. Planar CO_2 plumes and pressure plume in the CO_2 injection without ARM scenario (white triangles show the wellhead locations of the horizontal wells that are placed in different formations).

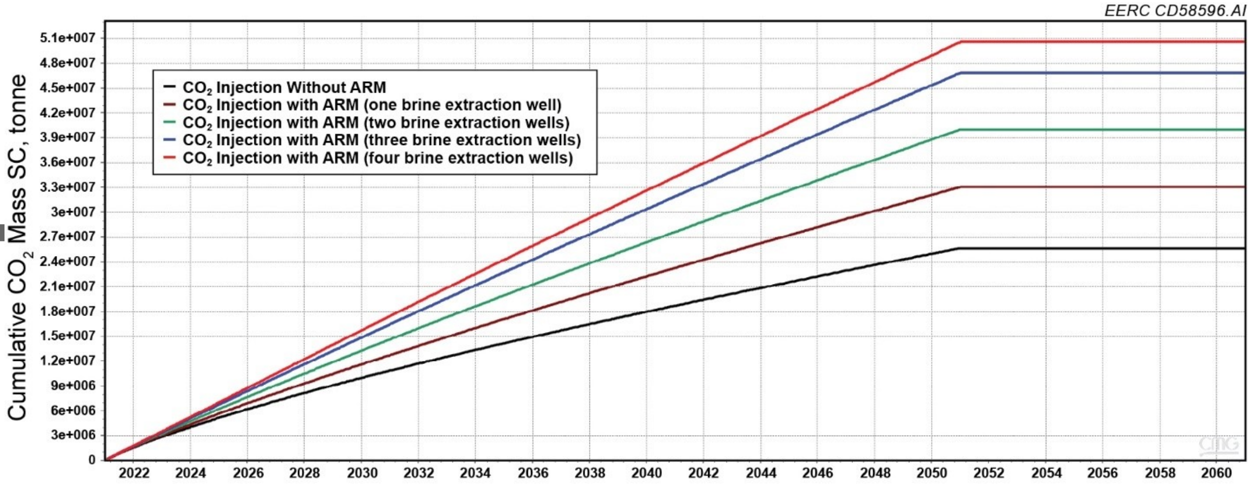

Figure 10. Amount of cumulative CO_2 injected with varying numbers of brine extraction wells.

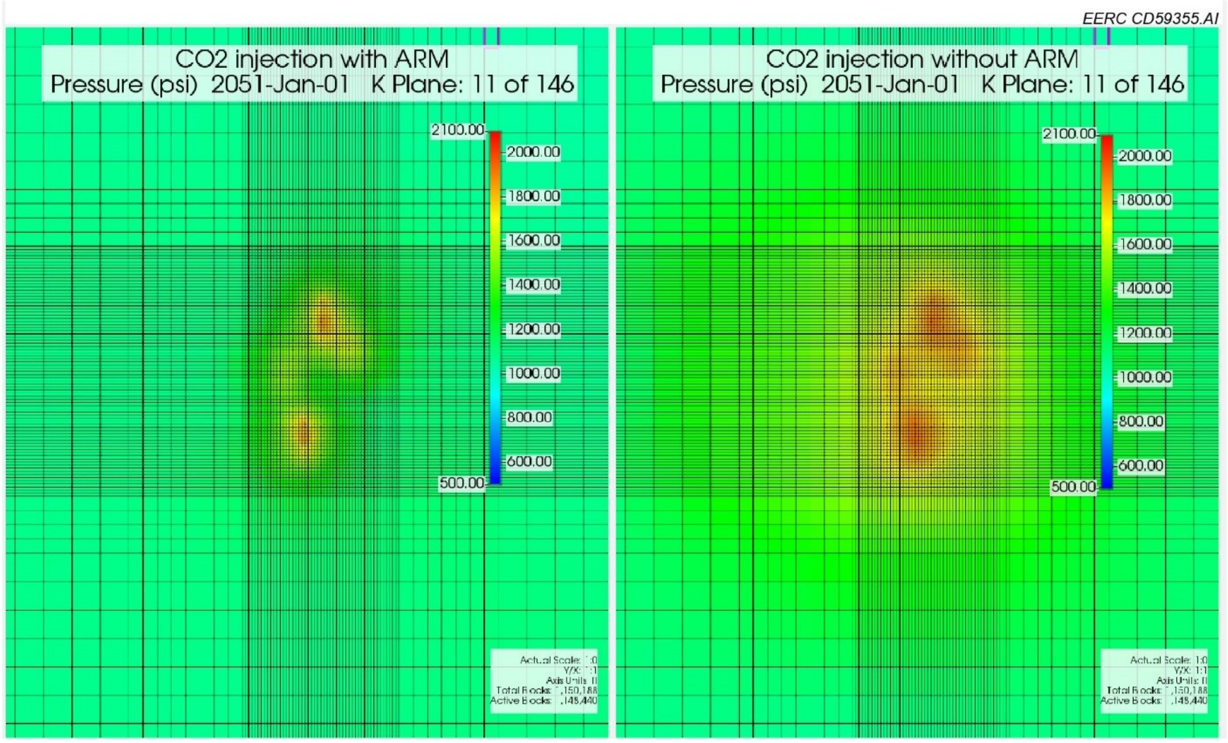

Figure 11. Pressure at the top layer of Wabaunsee (the first injection zone) at the end of CO_2 injection with (left) and without ARM (right).

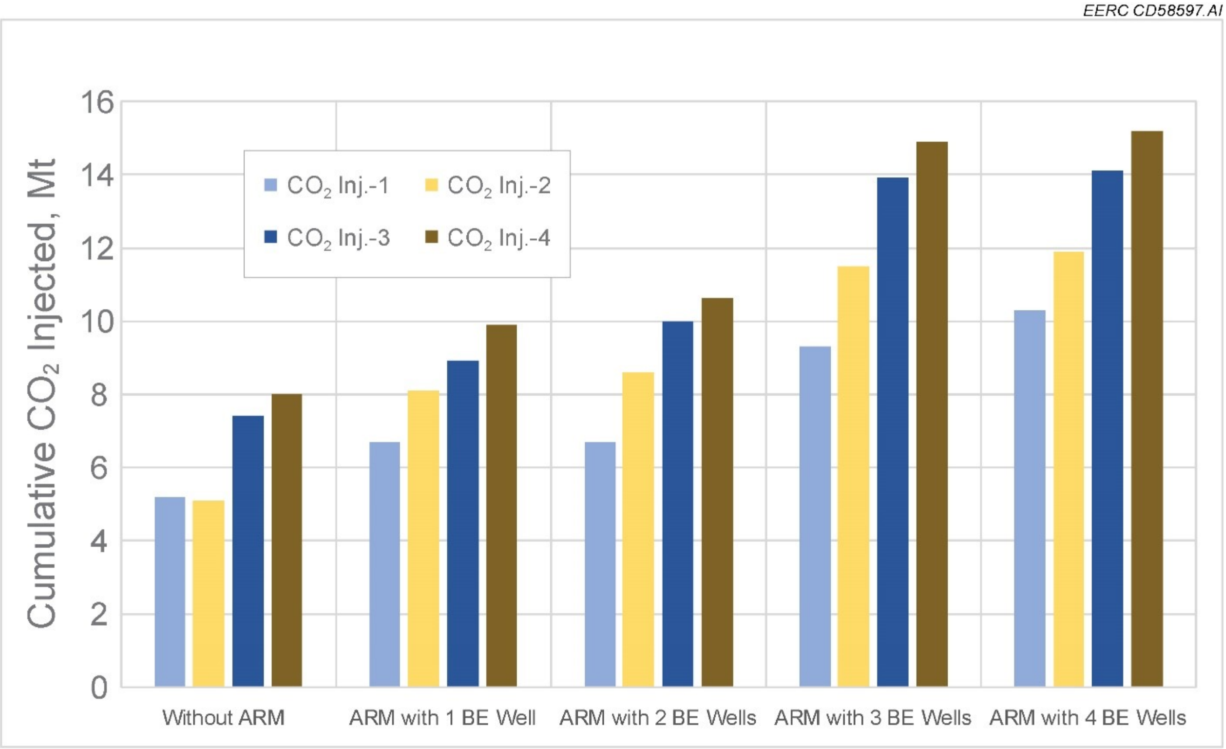

Figure 12. Cumulative CO_2 injected by injection wells for scenarios with and without ARM.

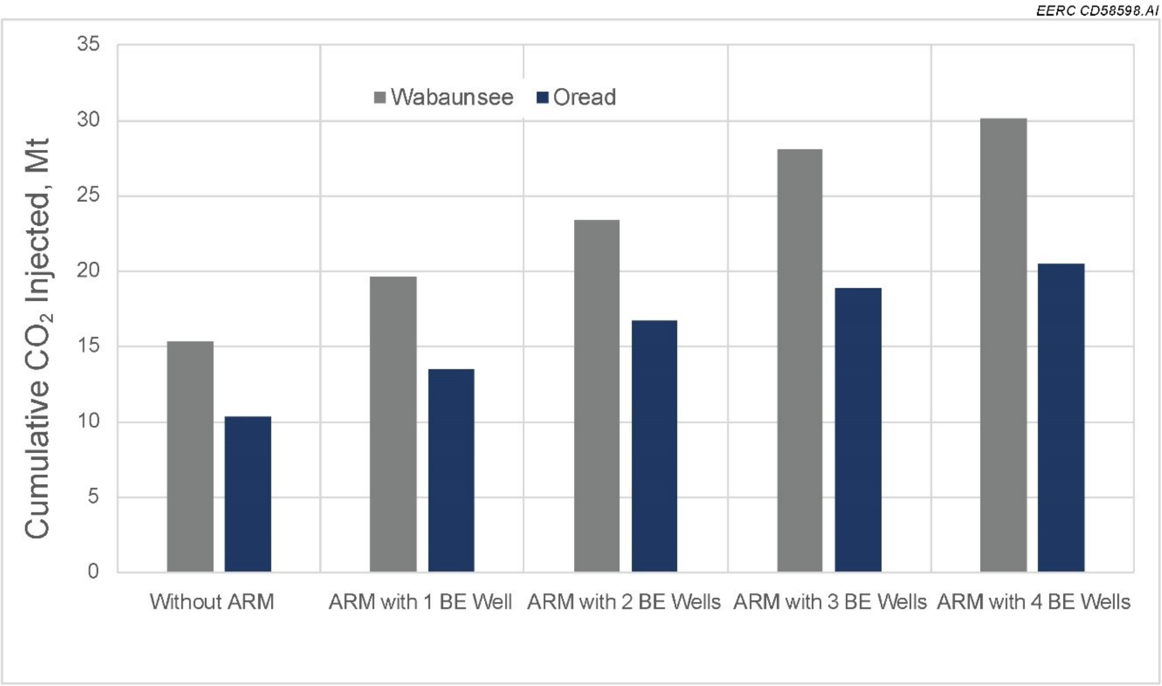

Figure 13. Cumulative injected CO_2 by formation for scenarios with and without ARM.

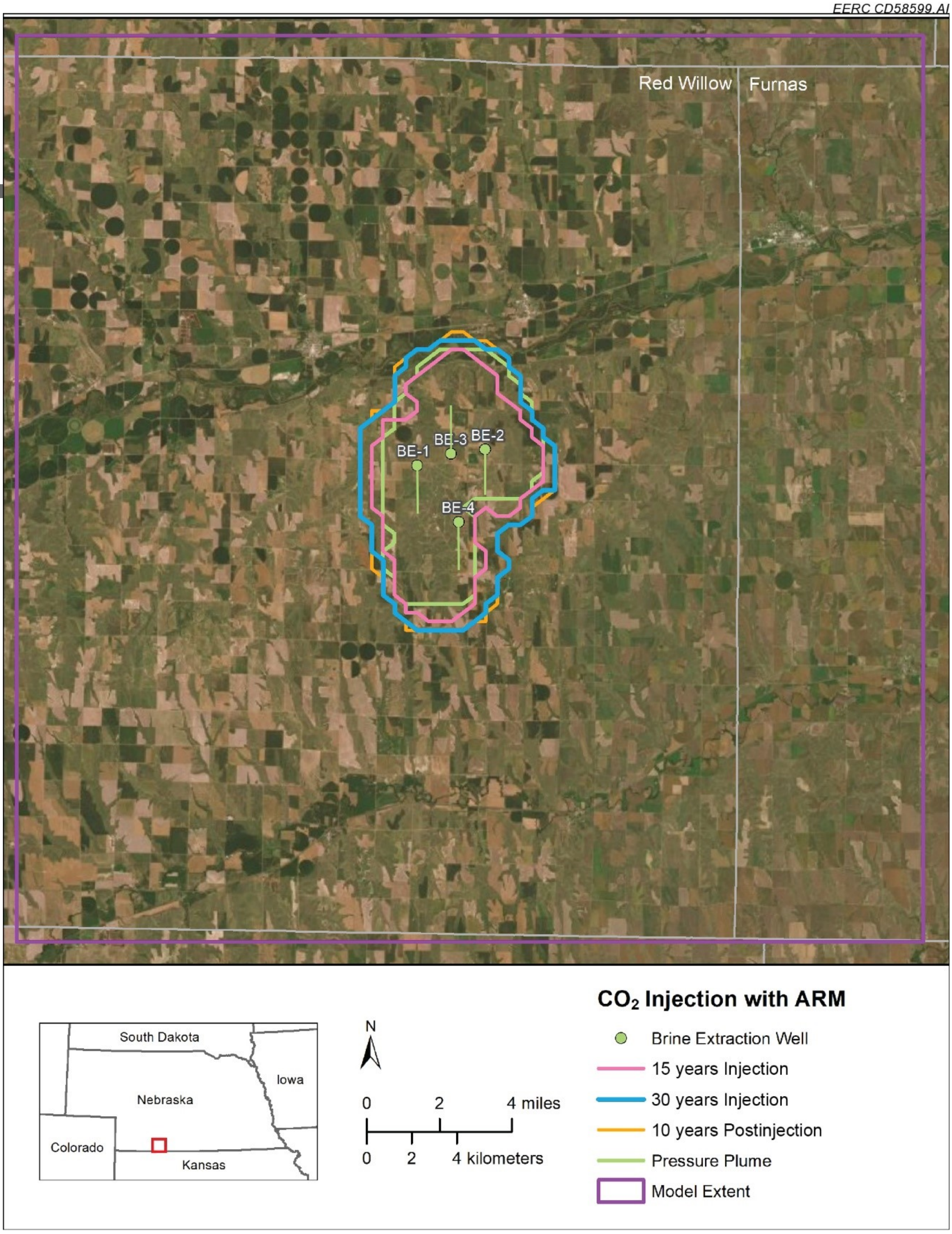

Figure 14. Planar CO_2 plumes and pressure plume in the CO_2 injection with ARM scenario (green dots show the wellhead locations of the horizontal brine extraction wells).

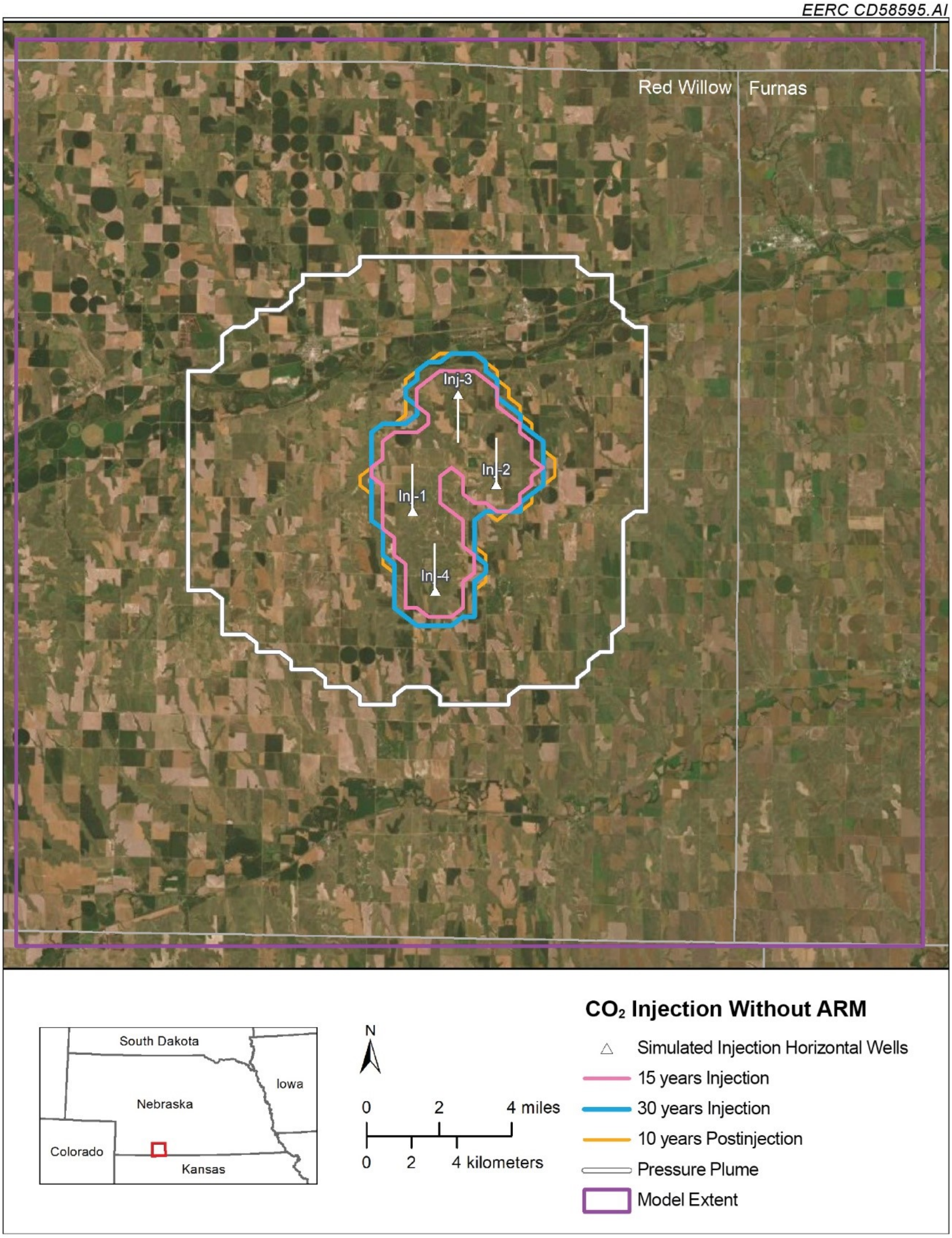

Figure 15. AOR extents with and without ARM.