CARBON DIOXIDE STORAGE OPTIMIZATION

Plains CO_2 Reduction (PCOR) Partnership
Task 2 – Deliverable D2

Prepared for:

Joshua Hull

National Energy Technology Laboratory
U.S. Department of Energy
626 Cochrans Mill Road
PO Box 10940
Pittsburgh, PA 15236-0940

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Prepared by:

Nicholas W. Bosshart
Matthew L. Belobraydic
Arelys Y. Salazar
Thomas P. McGuire
Chantsalmaa Dalkhaa
Jin Lu
Lawrence J. Pekot
Merry D. Tesfu
James A. Sorensen
Kevin C. Connors

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

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EXECUTIVE SUMMARY

The PCOR Partnership, sponsored by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), aims to foster the development of infrastructure and accelerate deployment of carbon capture, utilization, and storage (CCUS) in the northwest quadrant of North America, comprising ten U.S. states and four Canadian provinces. The PCOR Partnership region hosts many notable CCUS investigative and operational projects, and the PCOR Partnership continues to be an important component of a national strategy for cost-effective reduction of greenhouse gas emissions.

The growing number of planned and operational CCUS projects, worldwide and within the PCOR Partnership region, attests to the immense amount of prior research conducted to provide a sound foundation for the geologic storage of CO_2. However, potential for optimization remains in many saline aquifer CO_2 storage subdisciplines, which is the focus of this investigation, with the intent of accelerating widespread CCUS deployment.

CO_2 storage optimization can be defined in many ways. In this investigation, optimization of field operational techniques and constraints are considered, as well as the resulting impacts and implications for injectivity and potential storage resource, land ownership and pore space leasing, monitoring requirements to satisfy regulatory/permitting guidance, and capital and operational cost expenditures. The goal of this study was to investigate means of storage optimization in a fixed unit area over an assumed time frame to determine the most cost-efficient means of maximizing injectivity and cumulative stored CO_2.

For this report, CO_2 storage optimization was investigated using numerical simulations of CO_2 injection (eight separate cases) in a hypothetical scenario targeting the Cambrian-Ordovician Deadwood and Black Island Formations (informally referred to as the Basal Cambrian System [BCS]). An initial numerical simulation (Base Case) was conducted to determine a minimum operational footprint needed to store at least 45 Mt of CO_2 over a 12-year time frame with a basic four-well (vertical) CO_2 injection approach. This minimum operational footprint was approximately 5 mi × 5 mi (8 km × 8 km) in extent and used to inform well placements in seven additional simulation cases. The series of simulation cases were designed to investigate three techniques with potential to maximize per well injectivity and overall storage resource potential while minimizing CO_2 plume footprints and capital and operational expenditures: 1) the use of horizontal wells, 2) brine extraction, and 3) increased well count/decreased well spacing. Combinations of these techniques were also investigated. The numerical simulation results were then used to perform high-level economic feasibility assessments of these three storage optimization variables.

The potential value of the hypothetical simulation cases was assessed using the guidance of the Internal Revenue Service (IRS) regarding tax credits available for stored CO_2 under 26 U.S. Code § 45Q – Credit for Carbon Oxide Sequestration, enabling operators of qualified storage sites to apply for tax credits per tonne of stored CO_2 over a 12-year period. For the purposes of this high-level economic feasibility assessment, a simplifying assumption is made that the hypothetical scenario will receive tax credits in the amount of US$50 per tonne of stored CO_2 for the entire 12-year duration. The cumulative injected CO_2 masses for each simulation case were used to calculate potential tax credit value. Costs for factors directly impacted by the variables considered in the numerical simulation cases, including costs for well installation, brine disposal by a third party (for brine extraction cases), monitoring of injected CO_2, and pore space leasing, were estimated for each case to assess economic feasibility of the operational techniques investigated. Other costs are discussed briefly (e.g., capture infrastructure costs, on-site brine handling) but were outside the scope of this investigation. Such costs need to be considered in determining the final cost of stored CO_2 per tonne, overall project net value, and viability.

Of the three variables tested in this investigation, brine extraction appears to represent the single-most impactful means of optimizing CO_2 storage with the geologic assumptions of this hypothetical BCS scenario. Simulation cases not considering brine extraction had the lowest cumulative stored CO_2 masses and correlative lower value when considering 45Q tax credits.

Increasing well number and decreasing well spacing within a unit area, by itself, appears to provide little incremental benefit to cumulative stored CO_2 and is more costly in well completion costs. However, a combination of increasing well density with brine extraction may be an option with significant benefit.

Horizontal well CO_2 injection without brine extraction had the least compelling result, in terms of margin value between potential 45Q tax credit value and summed costs. Benefits were observed in storage efficiency, reduced operational footprint, and reduced overall CO_2 plume footprint. However, there was no clear benefit to cumulative stored CO_2, and the benefits afforded by reduction in overall CO_2 plume footprint were offset by the relatively high well costs. Brine extraction with horizontal well CO_2 injection, however, did provide benefit to cumulative stored CO_2 mass great enough to bring the margin value between potential 45Q tax credit value and summed costs into competitive standing. This approach may be the most suitable and optimal approach if ground surface constraints are restrictive to a future potential CCUS project.

The results of this investigation should not be taken to mean that any single approach is the best, most optimal approach for all scenarios. Different geologic assumptions may yield different and more beneficial means to optimize CO_2 storage in different locations. Variables expected to have significant impact on the results include degree of compartmentalization, degree of heterogeneity, petrophysical characteristics of the interval(s) being targeted, and availability of colocated alternate reservoirs which may serve as brine disposal formations. All of these geologic considerations and other nontechnical constraints, including sensitivities at the ground surface, should be considered in determining a means to optimize the geologic storage of CO_2.

A last important result of this investigation is the documentation of an approach to optimize CO_2 storage in testing varying operational techniques through numerical simulation. This approach, through associated thought exercises and technical evaluations, may enable visibility of promising means of cost reduction and overall project value elevation in other locations.

Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

CARBON DIOXIDE STORAGE OPTIMIZATION

INTRODUCTION

The PCOR Partnership, sponsored by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), aims to foster the development of infrastructure and accelerate deployment of carbon capture, utilization, and storage (CCUS) in the northwest quadrant of North America, comprising ten U.S. states and four Canadian provinces. The PCOR Partnership region hosts many notable CCUS investigative and operational projects, and the PCOR Partnership continues to be an important component of a national strategy for cost-effective reduction of greenhouse gas emissions. Some of the most well-known CCUS operations in the PCOR Partnership region include 1) the Plains CO_2 Reduction Partnership Phase III commercial-scale CO_2 enhanced oil recovery (EOR) demonstration project for the Bell Creek oil field in southeastern Montana, with successful monitoring of over 5 million tons of associated CO_2 storage incidental to EOR operations; 2) two DOE-sponsored Carbon Storage Assurance Facility Enterprise (CarbonSAFE) feasibility assessments of commercial-scale dedicated storage for the coal-based Minnkota Power Cooperative Milton R. Young Station located near Center, North Dakota (ND CarbonSAFE Project; in association with Project Tundra) and the coal-based Basin Electric Power Cooperative Dry Fork Station near Gillette, Wyoming; 3) a commercial-scale CO_2 capture and storage project at an ethanol production facility in North Dakota (Red Trail Energy [RTE]), currently proceeding through the final approval/permitting process; 4) the operational Shell Quest project in Alberta, Canada; 5) the large-scale CO_2 EOR operation at Weyburn in Saskatchewan; and 6) dedicated storage at the SaskPower Aquistore Project located near Estevan, Saskatchewan. Figure 1 shows a PCOR Partnership region map and CCUS projects within the region.

The growing number of planned and operational CCUS projects, worldwide and within the PCOR Partnership region, attests to the immense amount of prior research conducted to provide a sound foundation for the geologic storage of CO_2. An encompassing body of work has been completed to better understand saline aquifer storage potential by reservoir type, effects of reservoir boundary conditions, long-term CO_2 migration, CO_2 trapping mechanisms, monitoring injected CO_2, assessing risks and mitigation measures for CO_2 storage sites, regulatory and permitting challenges for CO_2 storage operations, proper CO_2 injection well construction, and many other facets of CO_2 storage. Generally, the scientific underpinnings, best practices, and approaches to CCUS deployment are well understood. However, potential for optimization remains in many saline aquifer CO_2 storage subdisciplines, which is the focus of this investigation, with the intent of accelerating widespread CCUS deployment.

Figure 1. Proposed PCOR Partnership region showing focus areas, pipelines, and CCUS projects. GPSP stands for Great Plains Synfuels Plant. BEST stands for Brine Extraction and Storage Test. CCA stands for Cedar Creek Anticline. DGC stands for Dakota Gasification Company.

CO_2 storage optimization can be defined in many ways. In this investigation, optimization of field operational techniques and constraints are considered, as well as the resulting impacts and implications for injectivity and potential storage resource, land ownership and pore space leasing, monitoring requirements to satisfy regulatory/permitting guidance, and capital and operational cost expenditures. In this report, optimization included maximizing per well injectivity and overall storage resource potential while minimizing CO_2 plume footprints and capital and operational expenditures associated with each of these considerations.

Two approaches to this investigation were considered initially: 1) investigating storage optimization around a fixed goal of stored CO_2 over an assumed time frame and determining the most cost-efficient means of meeting this goal (e.g., finding the most cost-efficient means of storing CO_2 emissions associated with energy generation at 500-MW coal-based power plant) and 2) investigating storage optimization around a fixed unit area over an assumed time frame and determining the most cost-efficient means of maximizing injectivity and cumulative stored CO_2. Both approaches are valid perspectives of storage optimization. The former represents a practical exercise, generally more in alignment with the interests of a CO_2 source owner/operator, that is likely to occur in future feasibility and initial evaluation studies for potential CCUS projects. Similar investigations are ongoing in early-stage commercial CO_2 storage studies, such as projects sponsored by DOE NETL under the CarbonSAFE Initiative, which are aimed at developing permitted CO_2 storage facilities capable of storing emissions from specific CO_2 sources. The latter approach to CO_2 storage optimization is generally more in alignment with the interests of a CO_2 storage site owner/operator. This approach is aimed at generating information in support of future potential business case scenarios where a storage site operator wishes to maximize CO_2 injection rate and storage performance within a given area, which may occur while receiving CO_2 from a single large-scale source or even several sources. From recent PCOR Partnership experiences, this approach and business model are gaining interest among entities interested in joining the CCUS movement. However, few investigations of this type have been conducted while considering regional storage targets of interest in the PCOR Partnership region, such as the BCS, and fewer have attempted to develop economic evaluations to support optimized approaches. Thus this approach was considered as the focus of this investigation.

A series of numerical simulations were conducted to investigate means of storage optimization around a fixed unit area with the overall goal of determining the most cost-efficient means of maximizing cumulative stored CO_2. This case study was developed around a hypothetical scenario targeting the Cambrian-Ordovician Deadwood and Black Island Formations (informally referred to as the Basal Cambrian System [BCS]). The series of simulation cases were designed to investigate three techniques with potential to optimize CO_2 storage: 1) the use of horizontal wells, 2) brine extraction, and 3) increased well count/decreased well spacing. Combinations of these techniques were also investigated. The numerical simulation results were then used to perform high-level economic feasibility assessments of these three storage optimization variables for potential use in the PCOR Partnership region to minimize well construction and operational costs.

The following sections of this report discuss prior published research pertaining to each of these variables, the assumptions made in this case study (including geologic characteristics of the BCS), numerical simulation design and results analysis, the outcomes of high-level economic feasibility assessment (integrating results from numerical simulation), and an overall summary of this work.

BACKGROUND

The use of horizontal wells, brine extraction, and well count/spacing are three actionable variables that can be applied to optimize CO_2 storage in saline aquifers, and the effect of each on resulting CO_2 storage potential is different. This section is the product of literature review, summarizing high-level results and conclusions of prior investigations related to each variable considered in this study.

VERTICAL WELLS

Operational examples of vertical CCUS wells without offset brine production in the Basal Cambrian System (BCS) of the PCOR Partnership region are available in the SaskPower Aquistore and Shell Quest Projects. The Aquistore injection rate is constrained by CO_2 availability to approximately 60,000 tonnes annually, with a total injected CO_2 mass over 370,000 tonnes at the time of this report's development (personal correspondence with PTRC, 2021). However, this rate is not a maximum rate, and the BCS reservoir at the Aquistore site is expected to be capable of receiving more CO_2, if higher injection rates were desired. The Shell Quest CO_2 injection wells are documented to inject at rates up to about 545,000 tonnes of CO_2 per year per injection well (Rock and others, 2017; Tawiah and others, 2020) into a BCS injection interval net thickness of approximately 150 ft (46 m), which is the same net thickness assumed for this study.

Scenarios considered in the investigation using vertical CO_2 injection wells without offset brine extraction were expected to exhibit the most conservative injection rates of the various scenarios investigated here.

HORIZONTAL WELLS

Horizontal wells have been shown to increase per well CO_2 injection rates through increased storage formation contact; however, the effect on storage efficiency is less clear. Liu and others (2015) showed the use of horizontal wells may be able to double the injection rate per well, while only increasing the CO_2 plume size by 44%, which implies a significant increase in the storage efficiency compared to equal numbers of vertical wells. Other research has shown a more modest 27% improvement in injection rates with 9840 ft (3000 m) horizontals over vertical wells (Okwen and others, 2011). Okwen and others (2011) also indicated that, in strongly vertically anisotropic reservoirs, horizontal wells are likely to result in lower storage efficiencies compared to vertical wells. Gorecki and others (2015) conducted basin-scale CO_2 injection assessments to reach ultimate storage potential over thousands of years of simulated injection. The results showed horizontal wells may enable more rapid injectivity in the short term (over decades) but have no significant impact on ultimate storage potential.

An operational example of a horizontal CO_2 injection well is the Sleipner Project in the Norwegian North Sea. The Sleipner Project uses a single horizontal well with perforated interval approximately 328 ft (100 m) in length and has a terminal inclination of 83 degrees (Chadwick and others, 2008; Torp and Brown, 2005). This well was perforated into unconsolidated sand with 2–5-Darcy permeability and is capable of sustained injection rates of up to 0.9 million tonnes (Mt) per year, but rates have been gradually curtailed because of limited CO_2 availability (Furre and others, 2017; Chadwick and others, 2008). Another example of horizontal well CO_2 injection is found in the In Salah CO_2 Storage Project in central Algeria. In Salah used three long horizontal wells that enabled injection of approximately 4 Mt of CO_2 from 2004 until injection was suspended in 2011 (7 years), resulting in an average injection rate of approximately 200,000 tonnes per injection well per year (Stork and others, 2015).

BRINE EXTRACTION

Extracting in situ brine has the potential to simultaneously minimize the CO_2 plume footprint and maximize total CO_2 storage potential of a formation by relieving formation pressure buildup during CO_2 injection (Agada and others, 2017; Anderson and Jahediesfanjani, 2019; Heath and others, 2013). Relieving pressure buildup also contributes to increasing the sustainable injection rates of CO_2 injection wells (Santibanez-Borda and others, 2019; Anderson and Jahediesfanjani, 2019). Some results have shown an expected benefit of brine production is a 112%–145% increase in CO_2 injection rate (Buscheck and others, 2012; Santibanez-Borda and others, 2019). However, employment of brine extraction implies a greater number of well penetrations through the primary confining zone, and an increased number of well penetrations is also associated with an increased risk of unintended CO_2 migration from the intended storage formation (Mission Innovation Carbon Capture, Utilization, and Storage Experts' Workshop, 2017).

For compartmentalized storage formations, brine extraction is likely to be the most significant factor that may increase storage efficiency (Craig and others, 2014; Gorecki and others, 2015). For open formations, brine extraction enhances the storage efficiency, but the effect in open boundary systems is not as significant as for closed boundary systems (Gorecki and others, 2015). In CCUS projects with associated brine production, optimizing storage performance balances the increase in storage efficiency of injected CO_2 with minimizing CO_2 breakthrough to the brine production wells (Tao and Bryant, 2013; Shamshiri and Jafarpour, 2010; Dai and others, 2014). Additionally, the challenge of handling and disposal of large quantities of brine must also be reviewed for the expected CO_2 storage strategies (Buscheck and others, 2012; Jie and others, 2017; Jahediesfanjani and others, 2019).

WELL COUNT/SPACING

Increasing injection well count over a project area has also been explored as a possible way to increase CO_2 storage efficiency in deep saline formations (Anderson and Jahediesfanjani, 2019; Heath and others, 2013). However, substantial pressure interference is likely when multiple wells are injecting simultaneously, even in geologically "open" reservoirs. An increased number of well penetrations is also associated with an increased risk of unintended CO_2 migration from the intended storage formation (Mission Innovation Carbon Capture, Utilization, and Storage Experts' Workshop, 2017). Pressure interference can cause storage efficiency and injection rate penalties for closely spaced injection well patterns, decreasing the utility and performance of the additional wells for a fixed storage area (Heath and others, 2013). The increase in cost of additional injection wells, along with the potential for decreasing incremental injectivity, indicates there is a limit to the number of injection wells that would generate positive results for a given project area. However, multiwell injection scenarios that may assume well patterns with a regular spacing, starting all wells at the same time, and attempting to maintain a constant injection rate for the project duration may not provide the optimal storage efficiency result. Interwell areas may remain upswept as formation brine is surrounded by injectors and trapped in place. Staggered well patterns, stepped timing of injection well start-ups, and adjusted rates may offer better brine displacement and increased efficiency.

Similarly, brine extraction wells will draw injected CO_2 toward their location, eventually suffering CO_2 breakthrough, limiting their effectiveness (Shamshiri and Jafarpour, 2010; Dai and others, 2014). If extraction wells are located and constructed with the intent of their eventual conversion to CO_2 injection after breakthrough, storage efficiency and plume management may be improved. In long-term projects, repeated application of this technique may be possible. Additional study of these methods may be warranted.

OPTIMIZING CO_2 STORAGE: ASSUMPTIONS AND CONSIDERATIONS

As stated in the Introduction, the focus of this investigation was storage optimization around a fixed unit area over an assumed time frame and determining the most cost-efficient means of maximizing injectivity and cumulative stored CO_2. This analysis required assumptions for desired injection rates, duration of operation, and intended total stored CO_2 mass, as well as assumptions regarding reservoir conditions and characteristics. This investigation assumes a minimum annual CO_2 injection rate of 3.75 Mt per year, an operational duration of 12 years, and a minimum total stored CO_2 mass of 45 Mt. This case study was based upon a hypothetical scenario targeting the sandstones within the BCS (Figure 2), which was selected due to its widespread occurrence in the PCOR Partnership region (Figures 3 and 4) and the intent to generate information transferable to other locations of interest in the region. The geologic characteristics of the BCS and the assumptions applied in geologic model development and numerical simulation are discussed below.

GEOLOGIC CHARACTERISTICS

Reservoir quality and characteristics are among the most important factors for prospective CCUS operations. Industrial CO_2 sources are fixed locations, and longer transport distance increases project cost. Therefore, acceptable, local conditions are assumed and represented by suitable/adequate geology (able to receive the intended amount of CO_2 at the rate required of the project) proximal to the CO_2 source.

As different industrial CO_2 sources emit a range of CO_2 volumes, suitable geology will vary between different CCUS operations. Factors generally affecting the suitability of a potential storage formation include petrophysical properties (porosity and permeability), net porous and permeable rock thickness, and lateral connectivity of porous and permeable rock. Additionally, a potential saline storage formation is assumed to be deeper than 2600 feet (800 m), so that the pressure and temperature conditions are effective at keeping injected CO_2 in the supercritical state. The storage formation salinity must be greater than 10,000 mg/L total dissolved solids (TDS) to surpass the key metric used to define underground sources of drinking water (USDW) in the Code of Federal Regulations (CFR) Underground Injection Control Program (Underground Injection Control Program, 2014).

The geologic characteristics of this investigation were based upon the sandstones of the Cambrian-Ordovician Deadwood and Black Island Formations (Figure 2). This Deadwood and Black Island interval has been informally referred to as the BCS. These extensive units comprise

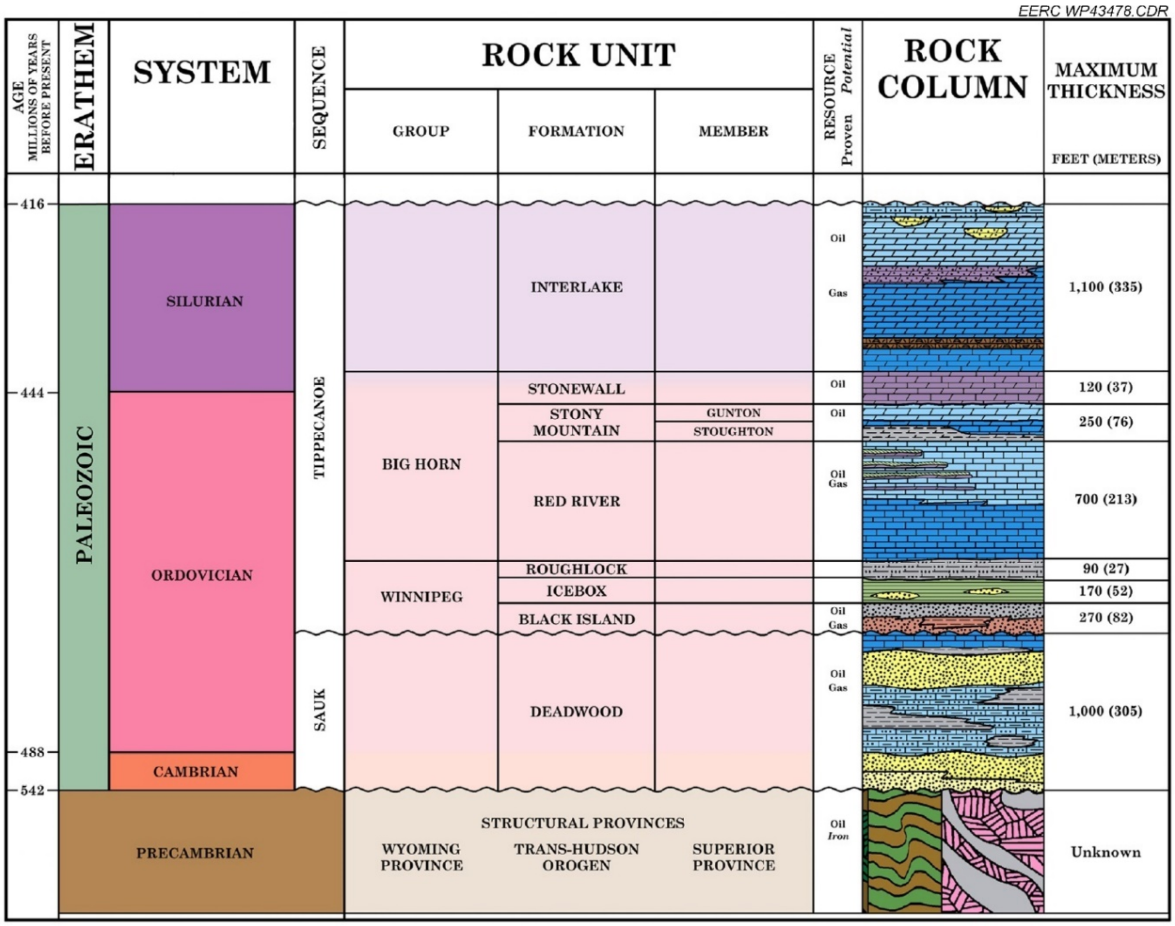

Figure 2. Stratigraphic column showing the early Paleozoic strata of the Williston Basin (modified from Murphy and others [2009]).

coarse- to fine-grained quartzose and glauconitic sandstone that is locally conglomeratic at the base (Bell, 1970; Carlson and Thompson, 1987; Macke, 1993; LeFever, 1996). The depositional environments have been interpreted as marine foreshore to shoreface, tidal flat, and fluvial to alluvial, where conglomeratic (LeFever, 1996). The BCS blankets the Precambrian basement and is widespread throughout the U.S. and Canadian portions of the Williston Basin and greater Western Canada Sedimentary Basin. This interval is also the target of the Shell Quest and SaskPower Aquistore Projects.

The BCS exists at depths greater than 12,000 ft below sea level in the center of the Williston Basin and shallows to the basin margins, with the exception of near the Alberta Rocky Mountain foothills (Figure 3). Outcrops occur in the northeastern portion of South Dakota and the Central Montana uplift, the Little Rocky Mountains, and the Big Snowy Mountains of Montana. The BCS comprises multiple sand benches with a total gross thickness exceeding 1000 ft (305 m) near the depocenter of the Williston Basin (Figure 4). An example well log display is shown in Figure 5 from the J-LOC1 well (NDIC File No. 37380; API No. 33-065-00019), located near Center, North Dakota, and drilled as part of Project Tundra site characterization activities. A core photo for the same well is also included (Figure 6), showing sandstone from the upper BCS sand bench in this well.

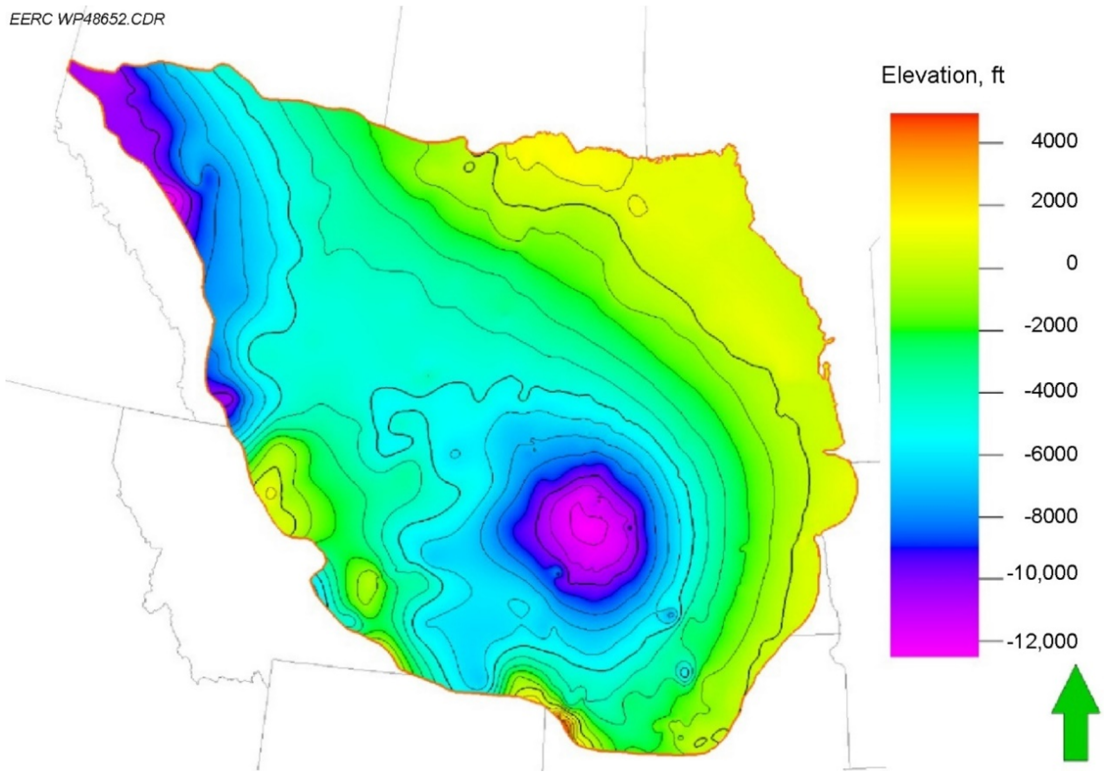

Figure 3. General structure of the BCS (Peck and others, 2014).

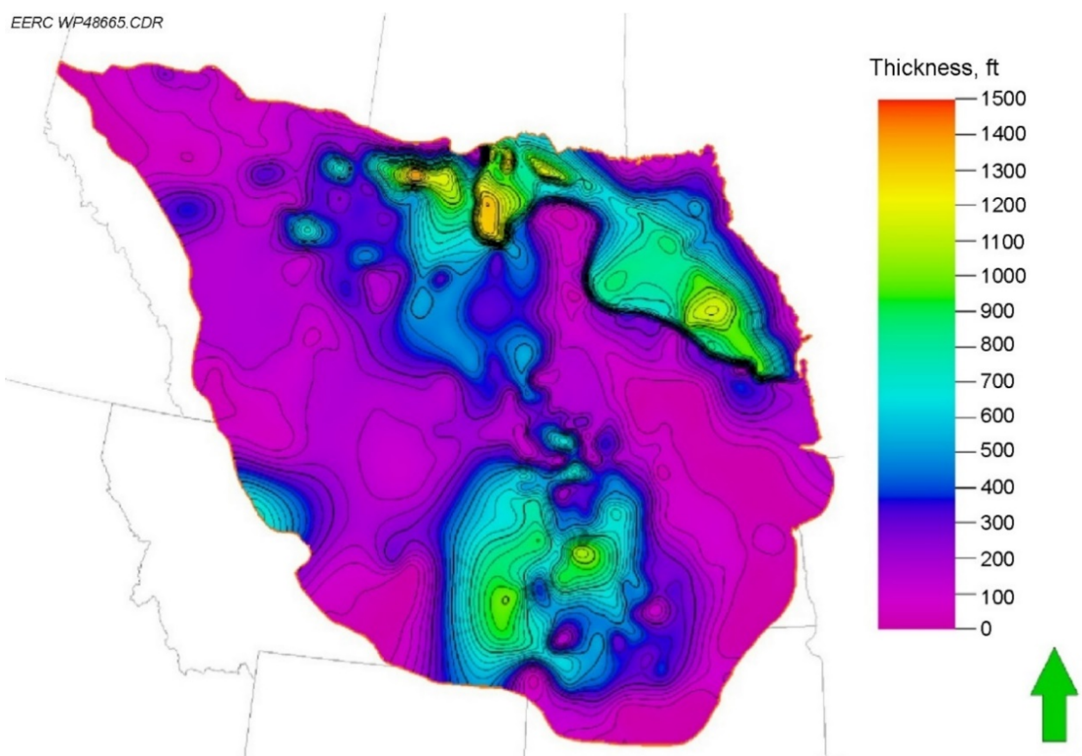

Figure 4. Isopach map of the BCS (Peck and others, 2014).

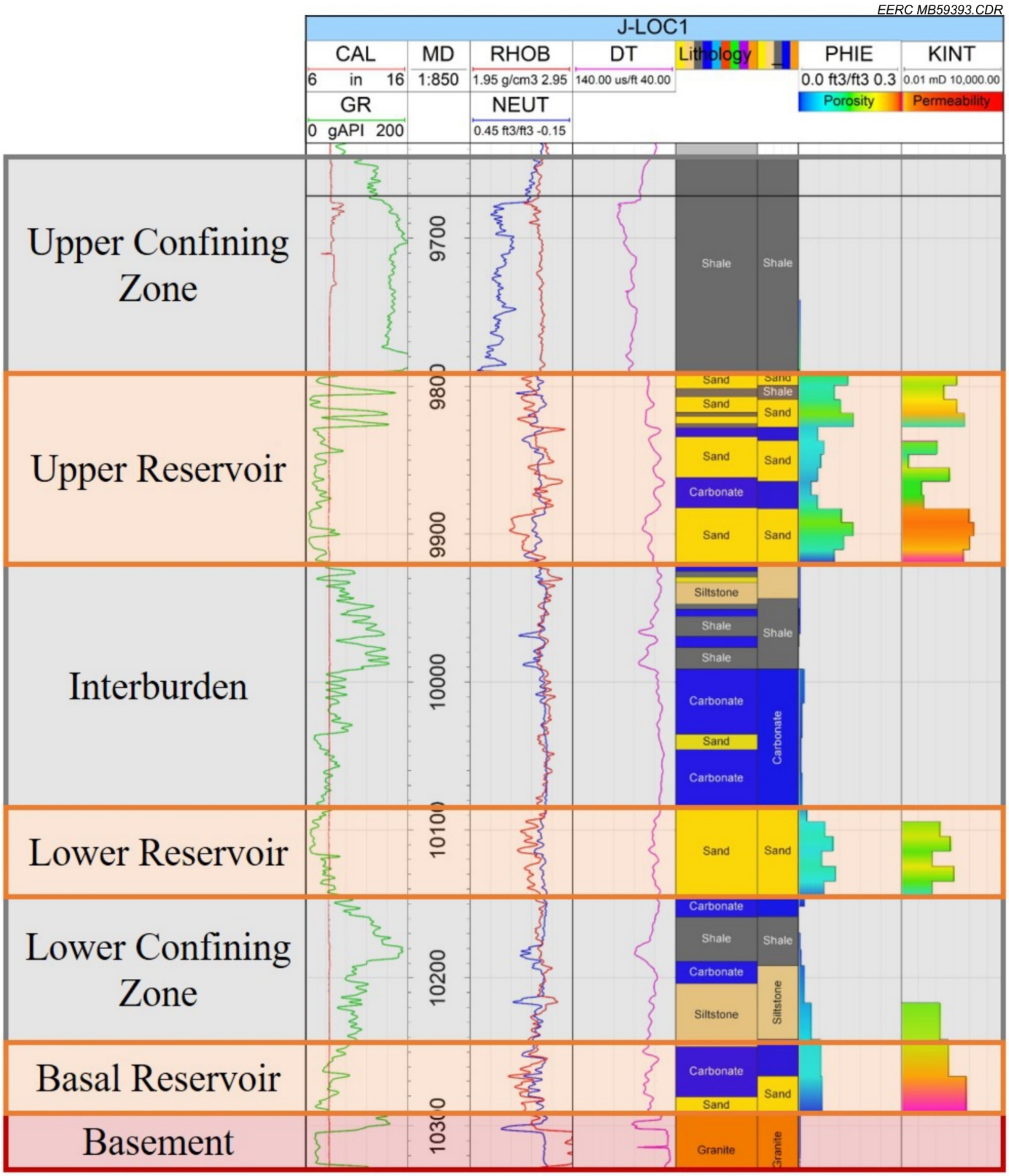

Figure 5. Example BCS well log display from the J-LOC1 well (NDIC File No. 37380) showing the BCS subintervals. Tracks from left to right include gamma ray (GR; green) and caliper (CAL; red), measured depth (MD), neutron porosity (NEUT; blue), density (RHOB; red), sonic travel time (DT; purple), interpreted lithofacies (LITHOLOGY; varying colors by rock type), upscaled interpreted lithofacies (varying colors by rock type), effective porosity (PHIE; black with color fill), and intrinsic permeability (KINT; black with color fill).

Figure 6. Core samples from the upper reservoir of the BCS, acquired in the J-LOC1 well (NDIC File No. 37380). The recorded depths of this interval are from 9887 ft (upper left) to 9897 ft (lower right), grading from an unstructured quartz sandstone at the top down through cross-bedded sandstone and then into a sandy mudstone with lenticular and wavy, fine-grained interbeds. This well was drilled with an oil-based mud, which is the cause of the dark brown staining from 9888 to 9889 ft.

The in situ brine salinity within the BCS ranges widely, with a maximum of nearly 350,000 mg/L TDS near the Williston Basin center. The brine salinity tapers off toward the basin margins where TDS levels are in the 5000–10,000-mg/L range (Peck and others, 2014). This study assumes a salinity of 256,000-mg/L TDS.

Average porosity of the reservoir portions of the BCS are approximately 11% with a maximum of 38%. Geometric mean permeability is approximately 4 mD, with some measurements exceeding 1 Darcy (Peck and others, 2014).

Dedicated CO_2 storage operations generally tend to avoid areas of existing or future potential oil and gas production to avoid the possibility of posing risks or impacts (e.g., potentially causing an operator to encounter unexpectedly high pressure during well drilling, causing unintended hydrocarbon migration and other unexpected consequences of nearby injection). Hydrocarbon accumulations do exist within the BCS but are not widespread in occurrence. For the purposes of this study, water saturation was assumed to be 100%.

An assumption of CO_2 density during injection was needed for static volumetric storage calculations of this investigation, and density is a function of both temperature and pressure, both of which generally increase with depth below the ground surface. CO_2 density has an inverse relationship with temperature (increasing temperature results in decreasing density) and a direct relationship with pressure (increasing pressure results in increasing density). This investigation assumed a BCS interval with an upper and lower reservoir present and an average net sand thickness (both upper and lower reservoir combined) of 150 ft (46 m) at a (measured) depth of 9500 ft (2900 m). Characterization activities conducted as part of the North Dakota CarbonSAFE activities yielded a BCS temperature measurement of 180°F (82°C) at the depth assumed for this investigation. A pressure gradient of 0.47 psi/ft was calculated for the BCS, yielding an initial pressure estimation of approximately 4500 psi (31 MPa). However, CO_2 density estimation should reflect the pressure associated with injection. U.S. Environmental Protection Agency (EPA) guidance for Underground Injection Control (UIC) Class VI (dedicated CO_2 injection well) states an injection well maximum bottomhole pressure (BHP) should not exceed 90% of the fracture initiation pressure within the injection and primary confining zones (U.S. Environmental Protection Agency, 2018; Minimum Criteria for Siting, 2014). With an assumed fracture pressure gradient of 0.8 psi/ft, fracture pressure at a depth of 9500 ft is estimated at 7615 psi (52.5 MPa). Maximum BHP, limited at 90% of fracture pressure, would be 6850 psi (47.2 MPa). With the expected temperature (180°F [82°C]) and maximum BHP injection pressure (6850 psi [47.2 MPa]) at the hypothetical scenario depth of 9500 ft (2900 m), maximum CO_2 density in the near-wellbore region during injection is assumed to be about 53 lb/ft^3 (856 kg/m^3) using the equation of state (EOS) of Span and Wagner (1996). A gradient in CO_2 density from 53 lb/ft^3 (856 kg/m^3) in the near-wellbore region would be expected to taper with distance from the injection location, with far-field regions (areas experiencing minimal pressure buildup) having conditions (4500 psi [31 MPa] and 180°F [82°C]) resulting in an estimated minimum CO_2 density of 46.6 lb/ft^3 (746 kg/m^3).

STATIC STORAGE RESOURCE ESTIMATION AND BASE CASE WELL CONSIDERATIONS

The pore volume expected in the hypothetical BCS scenario, assuming net sand thickness of 150 ft (46 m) and with an average porosity of 11%, is roughly 1.5 million cubic feet (42,500 cubic meters) per acre. If a maximum CO_2 density of 53 lb/ft^3 (856 kg/m^3) and a P_{50} open boundary clastic saline formation efficiency factor of 14% are applied (Goodman and others, 2011; Klenner and others, 2014; Peck and others, 2014), maximum storage potential is approximately 5100 tonnes per acre, or no greater than 3.3 Mt per mi^2 (1.3 Mt/km^2), during the injection time frame.

With the hypothetical scenario described above, it is unlikely that one CO_2 injection well would be able to meet the minimum rate desired (3.75 Mt CO_2 per year for 12 years, with a minimum total stored CO_2 mass of 45 Mt). The number of CO_2 injection wells required would be determined by a complex matrix of factors, including well orientation (vertical or horizontal), whether brine extraction is implemented, degree of geologic heterogeneity (compartmentalization and layering), perforated interval thickness, injection tubing size and roughness, completion/stimulation design, wellhead temperature, compression output capability/wellhead pressure, and well pattern design/spacing. Numerical simulations of CO_2 injection conducted as part of the North Dakota CarbonSAFE Project, supported by field brine injection testing results, suggest per well (vertical well without employing brine extraction) CO_2 injectivity may be as much as 1.1 Mt per year. With adequate spacing to avoid interwell pressure interference during injection, this would lead to an estimated requirement of four or five CO_2 injection wells. The total footprint of the minimum injected CO_2 mass goal (45 Mt) may be expected to occupy an area not less than 14 mi^2 at the end of a 12-year injection operation, assuming the maximum storage potential of 3.3 Mt per mi^2 (1.3 Mt/km^2) estimated in the preceding paragraph. This extent would be expected to expand slightly during the postinjection time frame under the effects of pressure dissipation and density-driven migration (due to the effects of buoyancy).

These static assumptions and volumetric calculations helped inform initial expectations of storage performance (e.g., estimated maximum storage potential, number of wells, and minimum total footprint of injected CO_2) and reduced guesswork in the initial simulation case design around a representative baseline BCS geologic model.

GEOLOGIC MODEL DESCRIPTION AND SIMULATION SCENARIOS

Model Description

To allow for well spacing tests, the model extent was 30 mi (48.3 km) in lateral dimensions with an area of 900 mi^2 (2331 km^2) that was divided into individual cells with lengths and widths of 1500 ft by 1500 ft (500 m by 500 m) and an average thickness of 16 ft (5 m). The structural framework was constructed to represent an upper confining zone, an upper reservoir, an interburden confining zone, a lower reservoir, a lower confining zone, and the upper 50 ft (15.2 m) of the Precambrian basement. On average, the model had a gross thickness of 682 ft (208 m) with an upper reservoir thickness of 118 ft (36 m) and lower reservoir thickness of

64 ft (19.5 m), separated by interburden confining zone with a thickness of 164 ft (50 m). The upper confining zone had a thickness of 147 ft (45 m), and the lower confining zone was 139 ft (42.4 m) thick. For simulations, the cell thickness averaged 10 ft (6 m) in the reservoir sections and 23 ft (7 m) for the interburden and confining zones. The resulting grid is approximately 450,000 cells.

Lithofacies distributions for the model consisted of sandstone, siltstone, shale, carbonate and, because a small of the underlying Precambrian was included in the geologic model, undifferentiated igneous/metamorphic basement. The facies for all zones were distributed using the sequential indicator simulation algorithm in Petrel. The upper confining zone consists of shale with the lower confining zone more of a mixture of siltstone, shale, and carbonate, with a consistent 34 ft (10 m) of continuous shale within 20 ft (6 m) of the lower reservoir base. The upper reservoir and lower reservoir are primarily sandstone, with higher heterogeneity found in the upper reservoir. The interburden consists of mostly carbonate with minor components of siltstone and shale (Table 1).

Table 1. Lithofacies Distribution in the BCS Model

	Lithofacies Type, %				
Model Interval	**Sand**	**Siltstone**	**Shale**	**Carbonate**	**Igneous/Metamorphic**
Upper Confining	0	0	100	0	0
Upper Reservoir	73	0	10	17	0
Interburden	1	19	18	62	0
Lower Reservoir	100	0	0	0	0
Lower Confining	2	26	26	46	0
Basement	0	0	0	0	100
Entire Model	40	7	22	26	5

Petrophysical properties were distributed using variograms assessed from available data. Little lateral anisotropy was present in the data. Major and minor variogram ranges were estimated at 6000 ft (1830 m). The vertical variogram was estimated at 10 ft (3 m). The porosity volume was distributed using the Gaussian random function algorithm in Petrel for each lithofacies and zone. Porosity results are similar to the mean and standard deviations found in published BCS results from core and well logs. Permeability values were distributed with conditioning to the previously distributed porosity volume using a logarithmic trend and the Gaussian random function algorithm in Petrel. The upper reservoir resulted in mean of 11% porosity and standard deviation of 4%, with values ranging from 1% to 30% and a geometric mean of 2.2 mD for permeability with a range of 5E-8 to 4550 mD. The lower reservoir resulted in a mean of 12% porosity and standard deviation of 4%, with values ranging from 1% to 27%, and a geometric mean of 6.9 mD for permeability with a range of 5E-8 to 830 mD (Table 2).

Table 2. Petrophysical Property Statistics in the BCS Model

Model Interval	Permeability, mD			Porosity, vol/vol			
	Min.	Geometric Mean	Max.	Min.	Mean	Max.	Std. Dev.
Upper Reservoir	5E-08	2.2	4549	0.01	0.11	0.30	0.04
Upper Res. Sandstone	5E-08	2.8	4549	0.01	0.12	0.30	0.04
Upper Res. Shale	5E-08	0.22	1243	0.01	0.09	0.26	0.04
Upper Res. Carbonate	5E-08	2.1	3102	0.01	0.11	0.26	0.04
Lower Reservoir	5E-08	6.9	830	0.01	0.12	0.27	0.04
Lower Res. Sandstone	5E-07	7.0	830	0.01	0.12	0.27	0.04
Lower Res. Carbonate	5E-08	0.02	76	0.01	0.05	0.21	0.03

Other modeled properties included water saturation, temperature, and pressure. For the purposes of this investigation, water saturation was set at 100%. Temperature was calculated for the true vertical depth (TVD) using a projected gradient of 0.015°F/ft (0.268°C/m) from the surface at 40°F (4.4°C) to 9500 ft (2900 m) at 180°F (82°C). The upper reservoir averaged 180°F (82°C), and the lower reservoir averaged 183°F (84°C). Using the pressure gradient of 0.47 psi/ft (0.011 MPa/m), the average pressure of the upper reservoir is 4490 psi (30.9 MPa), with an average of 4610 psi (31.8 MPa) for the lower reservoir.

Simulation Scenarios

An initial numerical simulation sensitivity analysis (drawing upon prior static/volumetric estimates of maximum storage potential, number of wells, and minimum total footprint of injected CO_2) was conducted to determine a minimum operational footprint needed to store at least 45 Mt of CO_2 over a 12-year time frame with a basic four-well (vertical) CO_2 injection approach. To clarify, injected CO_2 was not required to be contained within this footprint, only well placements. This minimum operational footprint, with well spacing great enough to minimize the effects of pressure interference while meeting the minimum stored CO_2 goal, was approximately 5 mi × 5 mi (8 km × 8 km) in extent. This was the operational footprint assumed for the Base Case and used to inform well placements in seven additional simulation cases (total of eight cases). The series of simulation cases were designed to investigate the three variables identified with potential to maximize per well injectivity and overall storage resource potential while minimizing CO_2 plume footprints and capital and operational expenditures: 1) the use of horizontal wells, 2) brine extraction, and 3) increased well count/decreased well spacing. Combinations of these techniques were also investigated. The simulation cases are briefly described below and summarized in Table 3. The numerical simulation results were then used to perform high-level economic feasibility assessments of these three storage optimization variables for potential use in the PCOR Partnership region to minimize well construction and operational costs:

- A Base Case (Case 1) was run with four vertical CO_2 injection wells (box pattern with 5-mi [8-km] well spacing, no "inside" injection well which would be expected to act in a "closed" manner) to meet the goals of the hypothetical BCS scenario, minimum injection well group rate of 3.75 Mt per year for 12 years (minimum total of 45 Mt stored CO_2) (Figure 7).

Table 3. Simulation Cases Designed to Test CO_2 Optimization Techniques for a Hypothetical BCS Scenario

Case No.	Optimization Parameter(s)	Injection Well Type	Injection Well Number	Injection Well Spacing, mi	Extraction Well Number	Boundary Conditions
1	Base case	Vertical	4	5	N/A	Open
2	Closed boundaries	Vertical	4	5	N/A	Closed
3	Brine extraction	Vertical	4	5	1	Open
4	Brine extraction/closed boundaries	Vertical	4	5	1	Closed
5	Horizontal wells	Horizontal	4	5	N/A	Open
6	Horizontal wells/brine extraction	Horizontal	4	5	1	Open
7	Increased well count	Vertical	8	2.5	N/A	Open
8	Increased well count/brine extraction	Vertical	8	2.5	2	Open

- Case 2 was a closed boundary version of the Base Case (Case 1), conducted to investigate the sensitivity of CO_2 injection in the BCS to boundary conditions.

- Two cases (Cases 3 and 4) were run with four vertical CO_2 injection wells (same as Base Case) and one centralized vertical brine extraction well (5-spot pattern, 1:4 ratio, maximum rate of 30,000 bbl/day). One of these cases had closed boundaries (Case 4).

- Two cases (Cases 5 and 6) were run with four horizontal CO_2 injection wells (two surface locations with a spacing of 5 mi [8 km] and two wells at each surface location, one in each reservoir; laterals 1 mi [1.6 km] in length), with one case employing brine extraction (one centralized vertical production well, 1:4 ratio, maximum rate of 15,000 bbl/day between both reservoir intervals) during simulated CO_2 injection (Case 6) (Figure 8). A lower maximum extraction rate of 15,000 bbl/day was used in this case to mitigate CO_2 production with the shorter brine extraction-to-injection well offset distance (3.5 mi in diagonal orientation in Cases 3 and 4; 2.5 mi in Case 6 with horizontal well surface locations spaced 5 mi apart).

- Two cases (Cases 7 and 8) were run with tighter well spacing (half the spacing of the Base Case), with the number of vertical CO_2 injection wells increased to eight (octagonal pattern, no “inside” injection wells which would be expected to act in a “closed” manner). One such case was conducted with brine extraction (two centralized vertical brine extraction wells, 1:4 ratio, each with maximum rates of 30,000 bbl/day) during simulated CO_2 injection (Case 8) (Figure 9).

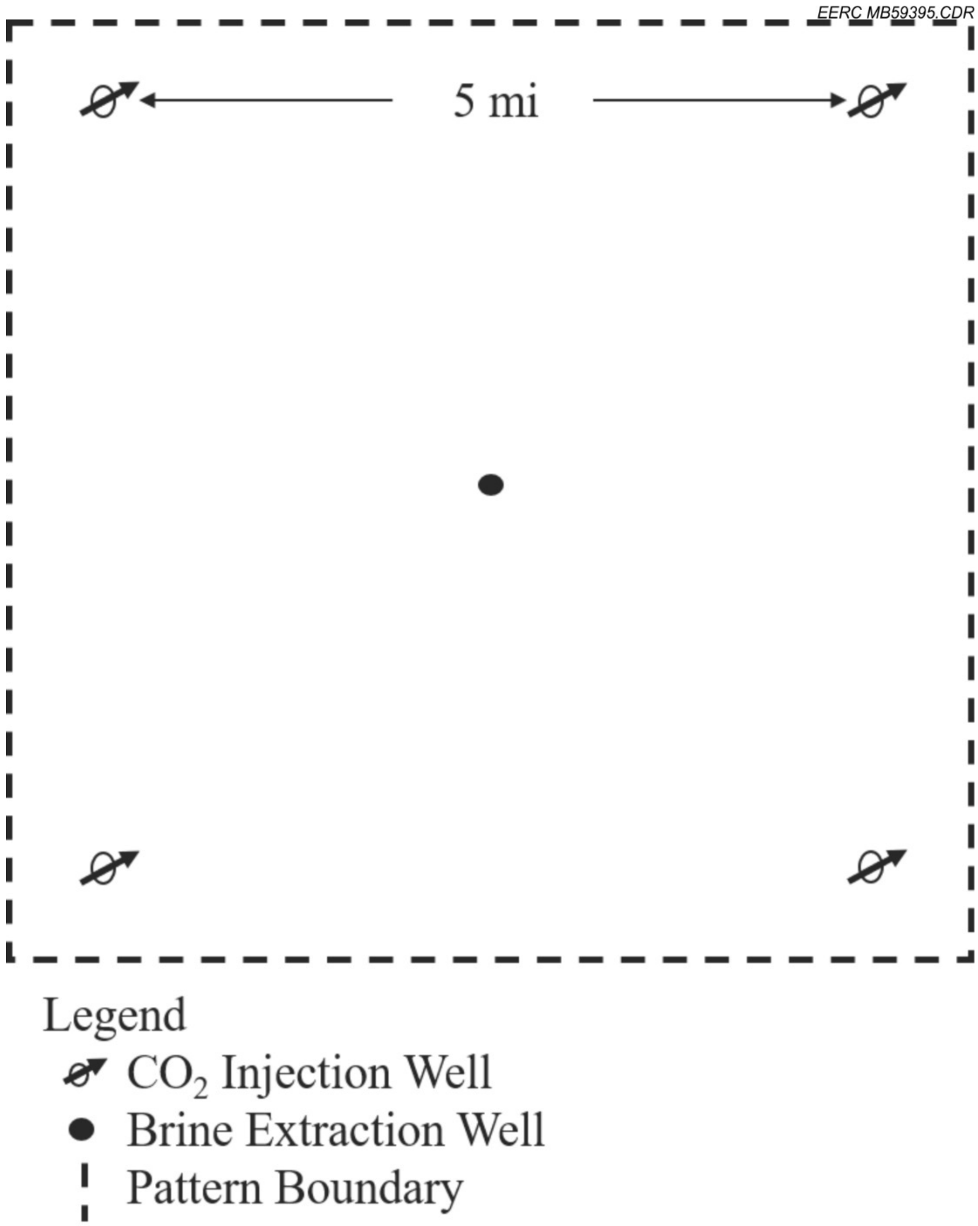

Figure 7. Well placement diagram for Cases 1–4 with four vertical CO_2 injection wells and, for Cases 3 and 4, a centralized brine extraction well. The pattern boundary in this figure (dashed line) is an arbitrary line drawn outside of the pattern of wells used in numerical simulation, and this boundary does not represent the extent of the simulation model.

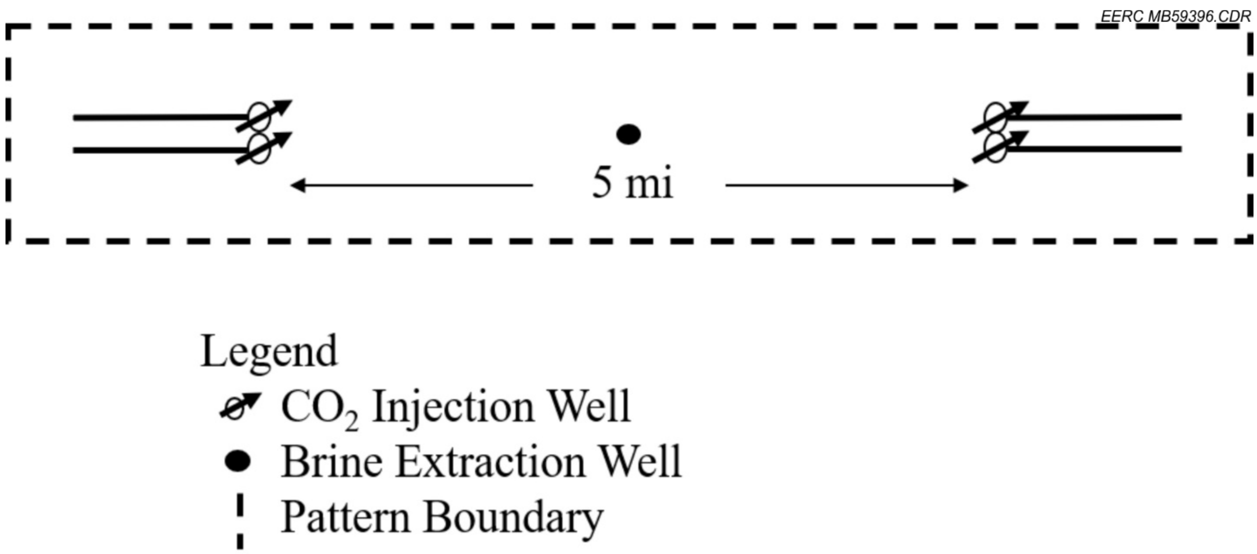

Figure 8. Well placement diagram for Cases 5 and 6 with four horizontal CO_2 injection wells (1 mi [1.6 km] lateral) and, for Case 6, a centralized brine extraction well. The pattern boundary in this figure (dashed line) is an arbitrary line drawn outside of the pattern of wells used in numerical simulation, and this boundary does not represent the extent of the simulation model.

These cases were designed to test the previously mentioned variables within the similar operational characteristics, footprint, and well spacings. For cases with vertical wells, perforations were set through the entire upper and lower reservoir intervals. All cases had maximum BHP constraints set to govern individual well injectivity. These BHP constraints were calculated at 90% of an assumed fracture pressure gradient of 0.8 psi/ft (0.72 psi/ft) at the top of the well perforation. Rock compressibility was set to be 5.925×10^{-6} psi^{-1}. Brine extraction wells in all cases were conducted with a 1:4 ratio with CO_2 injection, and extraction wells were centralized to minimize pressure buildup inside the pattern and potential migration of injected CO_2 away from the pattern. Operating minimum BHP for extraction wells was set at 1000 psi. For the horizontal well cases (Figure 8), the two most porous and permeable sand benches were targeted, with wells at a given surface location completed in separate sand benches. Figures 7–9 show well placement diagrams for the cases described above.

ANALYSIS AND DISCUSSION

As previously discussed, this investigation focused on optimizing CO_2 storage in the BCS with a hypothetical scenario requiring a minimum CO_2 injection rate of 3.75 Mt per year for 12 years for a minimum total stored CO_2 mass of 45 Mt. In the set of simulation scenarios investigated, nearly all met the minimum goals of the hypothetical scenario of interest, with the exception of Case 5, which nearly met the goal (300,000 tonnes short). The following section discusses numerical simulations conducted to investigate the effects of changing well orientation

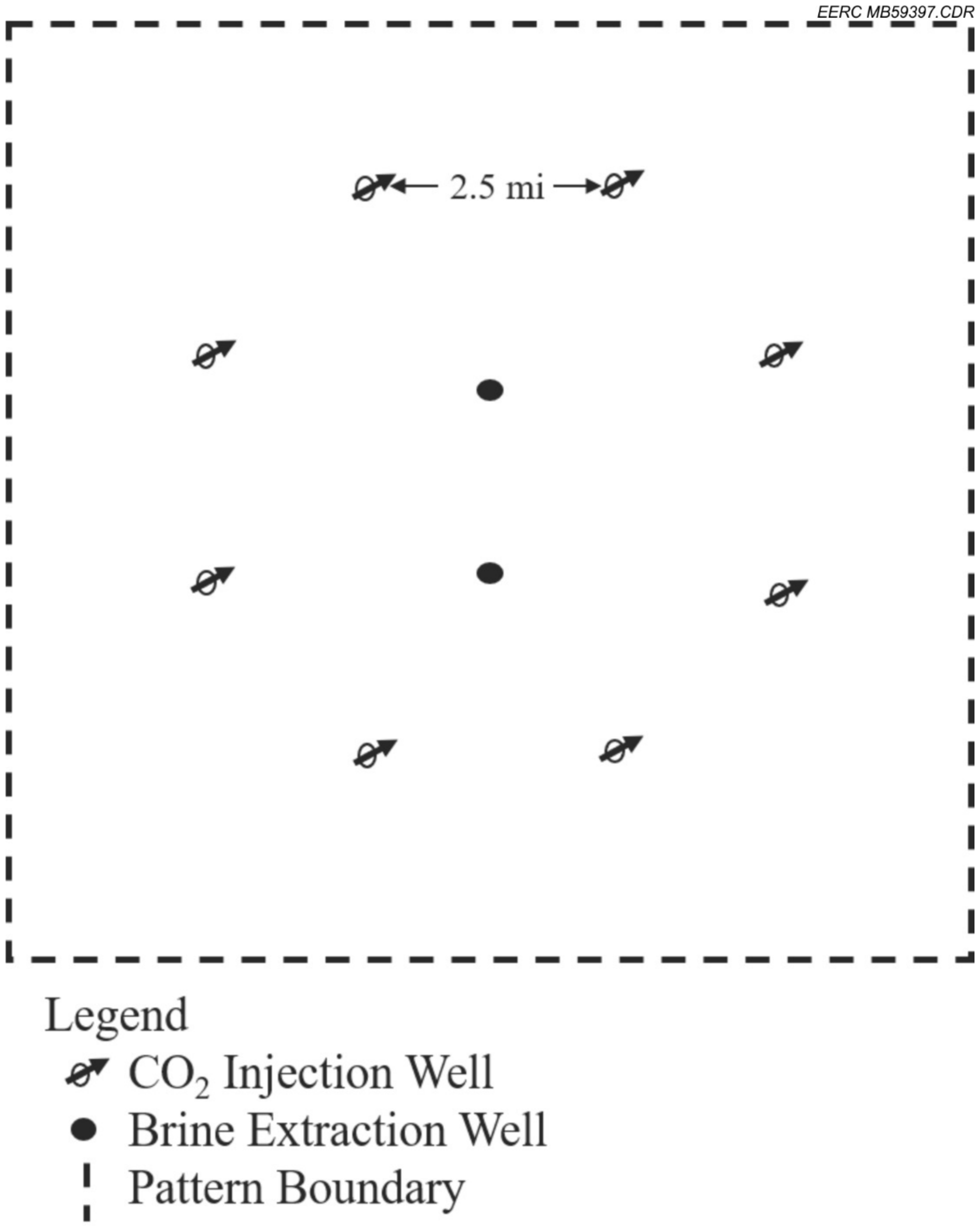

Figure 9. Well placement diagram for Cases 7 and 8 with eight vertical CO_2 injection wells and, for Case 8, two centralized brine extraction wells. The pattern boundary in this figure (dashed line) is an arbitrary line drawn outside of the pattern of wells used in numerical simulation, and this boundary does not represent the extent of the simulation model.

(horizontal vs. vertical), comparison in the use or absence of brine extraction, and changing well count/spacing. Table 4 contains the simulated stored CO_2 mass results for all cases, and Figure 10 shows a graph of simulated cumulative injected CO_2 for all cases. A brief discussion of combinations of these variables is included, followed by high-level economic feasibility assessments.

Table 4. Results of CO_2 Injection Numerical Simulations

Case No.	Case Description	Simulated Stored CO_2, Mt	Simulated Produced Brine, MMbbl
1	Base case; four vertical injection wells, 5-mi spacing, no brine extraction, open boundaries	50.0	N/A
2	Closed boundaries; Case 1 with closed boundaries	46.1	N/A
3	Brine extraction; Case 1 with one brine extraction well; open boundaries	58.1	115.0
4	Brine extraction/closed boundaries; Case 1 with one brine extraction well, closed boundaries	54.6	116.0
5	Horizontal wells; four horizontal injection wells, 5-mi spacing, no brine extraction, open boundaries	44.7	N/A
6	Horizontal wells/brine extraction; Case 5 with one brine extraction well; open boundaries	52.0	71.2
7	Increased well count; eight vertical injection wells, 2.5-mi spacing, no brine extraction, open boundaries	51.4	N/A
8	Increased well count/brine extraction; Case 7 with two brine extraction wells, open boundaries	75.4	236.0

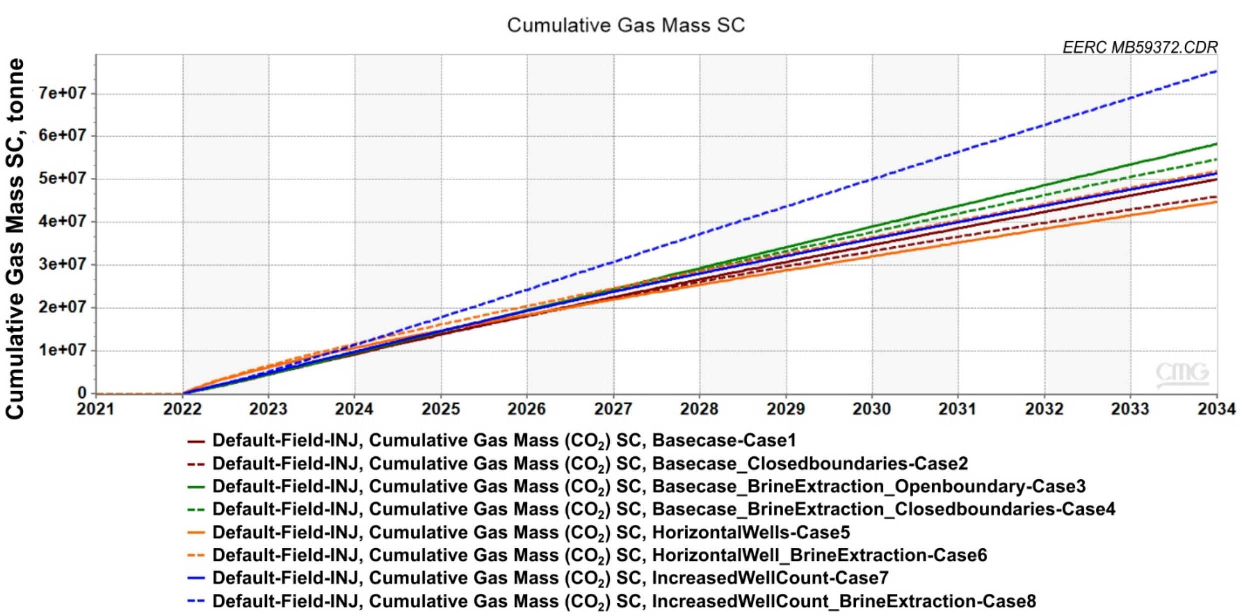

Figure 10. Graph showing simulated cumulative injected CO_2 for all cases.

Base Case (Case 1)

The Base Case (Case 1; four vertical CO_2 injection wells with a spacing of 5 miles) resulted in a cumulative stored mass of 50.0 Mt of CO_2, exceeding the minimum goal of the hypothetical scenario described above (45 Mt of CO_2 in a 12-year time frame). Total injection rate (all wells together) was as high as 4.8 Mt/year during the first few years of simulated injection. This slowed to about 3.8 Mt/year at the end of the simulated 12-year injection interval. Average well injectivity was approximately 1.2 Mt/year in the beginning, slowing to 1.0 Mt/year near the end of the simulation, with an overall per well average just above 1 Mt/year. Figure 11 shows a map view of gas per unit area – total (ft) for the Base Case (Case 1). Gas per unit area – total (ft) was calculated as a vertical summation of simulated CO_2 saturation (%) for each cell multiplied by the pore space within the grid cell (ft^3) divided by the area of the grid cell (ft^2), and the resulting map shows the lateral extent of injected CO_2 around each injection well. The Base Case (Case 1) had a combined plume area of 20.0 mi^2 (51.8 km^2). Figure 12 shows simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for the Base Case (Case 1). Calculated storage potential from the result was 2.5 Mt per mi^2 (1.0 Mt/km^2). This case was used as the basis for comparison with other cases testing potential means of storage optimization in the BCS.

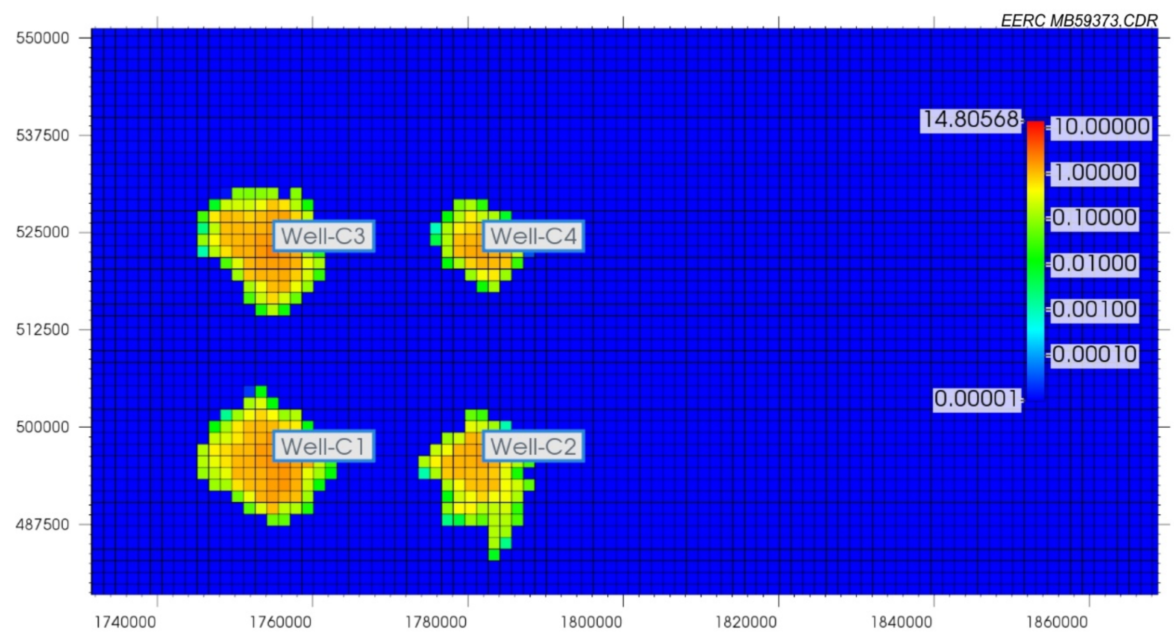

Figure 11. Map view showing CO_2 plume extents (gas per unit area – total [ft]) for the Base Case (Case 1) with a total stored CO_2 mass of 50 Mt, combined plume area of 20.0 mi^2 (51.8 km^2), and average plume size of 5 mi^2 (13 km^2). Note that the figure does not show the full simulated area.

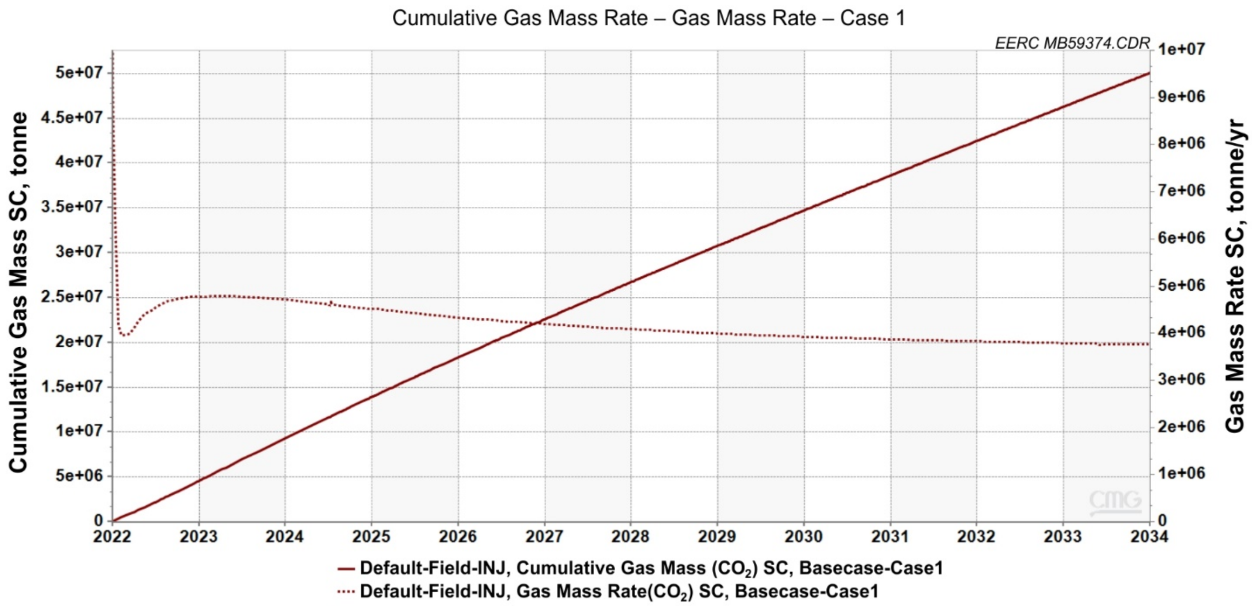

Figure 12. Graph showing simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for the Base Case (Case 1).

Closed Boundaries

Case 2 was run with the same well placement and design as the Base Case (Case 1), except with closed boundaries. Case 2 resulted in a cumulative stored CO_2 mass of 46.1 Mt, slightly exceeding the overall goal of the hypothetical scenario. Total injection rate (all wells together) was as high as 4.8 Mt/year during the first few years of simulated injection. This slowed to about 3.0 Mt/year at the end of the simulated 12-year injection interval. Average well injectivity was approximately 1.2 Mt/year in the beginning, slowing to 0.8 Mt/year near the end of the simulation, with an overall per well average of 1.0 Mt/year. Figure 13 shows a map view of gas per unit area – total (ft) for Case 2 with a combined plume area of 18.6 mi^2 (48.1 km^2), and Figure 14 shows simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 2.

In comparison with the Base Case (Case 1), the overall stored CO_2 mass of Case 2 was decreased by 4.0 Mt (9%). Pressure buildup from the closed boundary set in the simulation was beginning to show pronounced effects over the 12-year operation, but the 30-mi × 30-mi (48.3-km × 48.3-km) grid extent was great enough to accommodate injection at the scale required of the hypothetical scenario. Calculated average storage potential for Case 2 was 2.5 Mt of stored CO_2 per mi^2 (1.0 Mt/km^2).

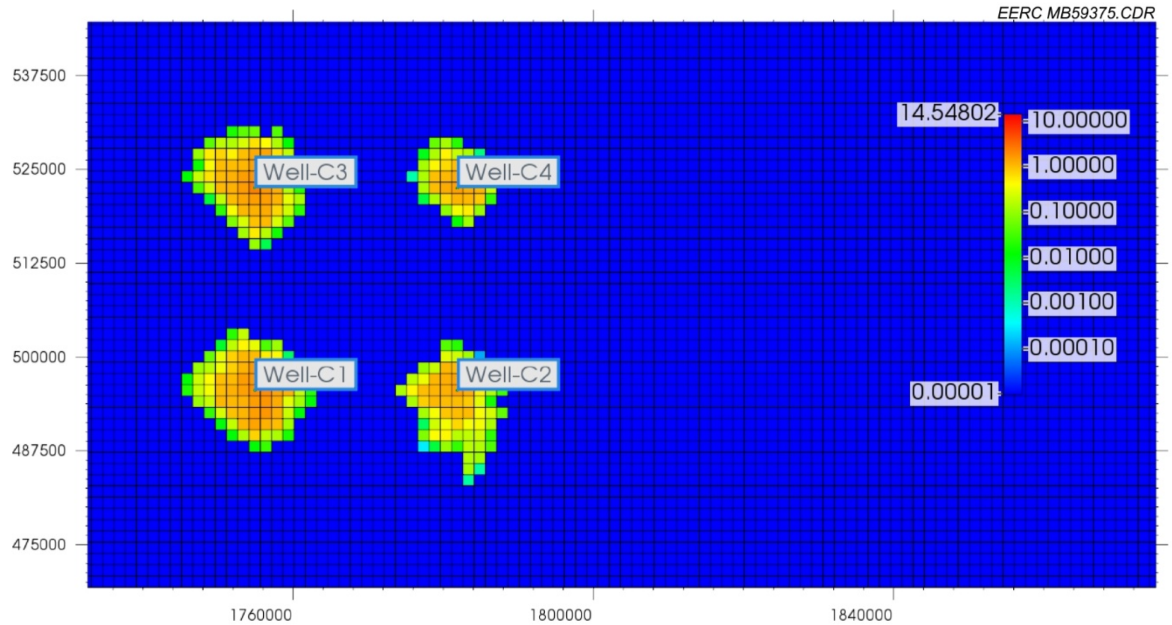

Figure 13. Map view showing CO_2 plume extents (gas per unit area – total [ft]) for Case 2, with a total stored CO_2 mass of 46.1 Mt, combined plume area of 18.6 mi^2 (48.1 km^2), and average plume size of 4.7 mi^2 (12 km^2). Note that the figure does not show the full simulated area.

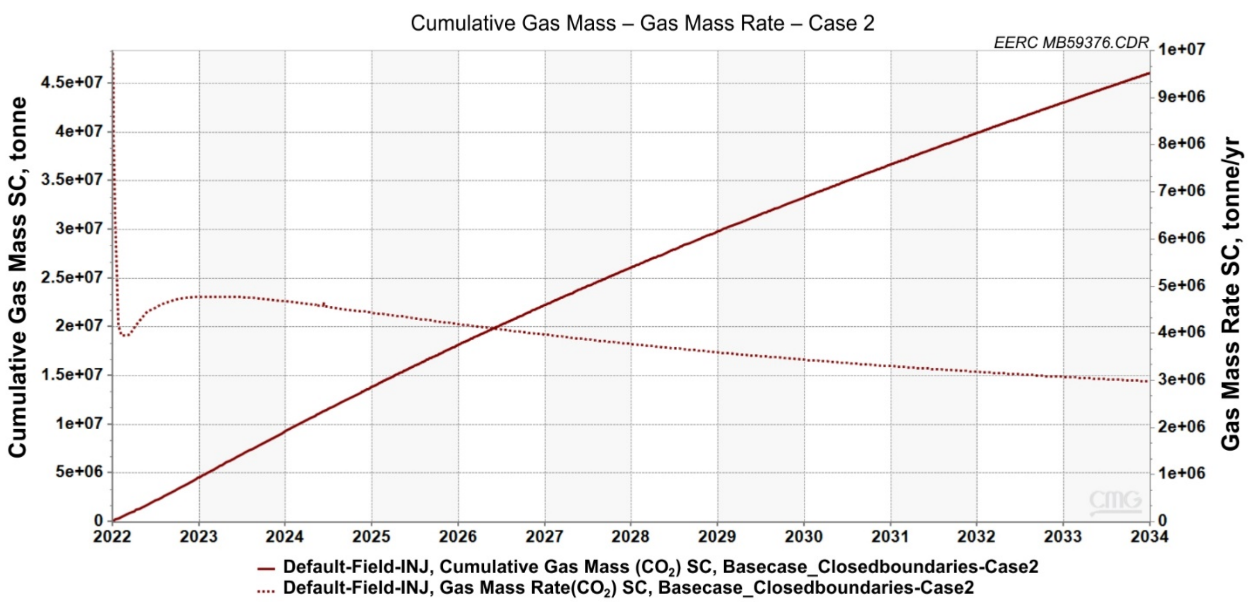

Figure 14. Graph showing simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 2.

Horizontal Versus Vertical Wells

A horizontal well case (Case 5) resulted in simulated injection of 44.7 Mt of CO_2, just short of meeting the minimum goal of the hypothetical scenario. Total injection rate (all wells together) in Case 5 was greater than 5.0 Mt/year during the first year of simulated injection. This slowed over the duration of the operation to about 3.1 Mt/year at the end of the simulated 12-year injection interval. Average well injectivity exceeded 1.3 Mt/year in the beginning, slowing to 0.8 Mt/year near the end of the simulation, with an overall per well average just below 0.9 Mt/year. Figure 15 shows a map view of gas per unit area – total (ft) for Case 5 with a combined plume area of 15.9 mi^2 (41.2 km^2), and Figure 16 shows simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 5. This case demonstrated the second-best overall storage efficiency (only exceeded by Case 6, with horizontal wells and brine extraction), with an average of 2.8 Mt of stored CO_2 per mi^2 (1.1 Mt/km^2) (within 0.5 Mt/mi^2 [0.19 Mt/km^2] of the calculated maximum storage potential [3.3 Mt/mi^2] from static and volumetric assumptions).

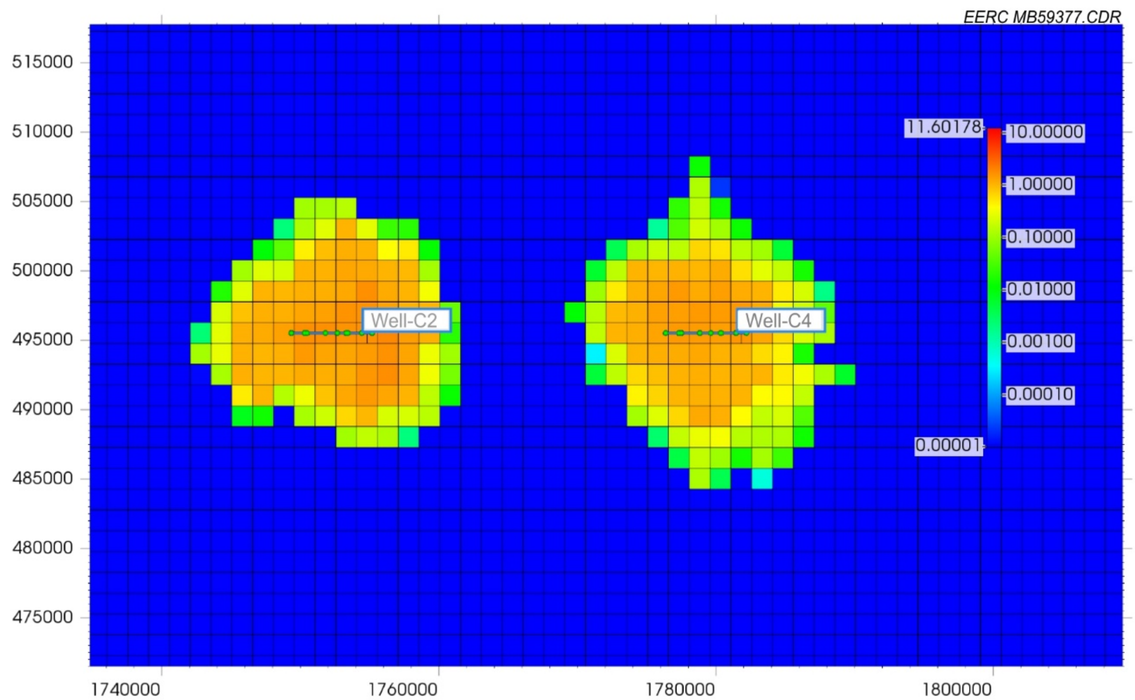

Figure 15. Map view showing CO_2 plume extents (gas per unit area – total [ft]) for Case 5, with a total stored CO_2 mass of 44.7 Mt, combined plume area of 15.9 mi^2 (41.2 km^2), and average plume size of 8 mi^2 (20.6 km^2). Note that the figure does not show the full simulated area.

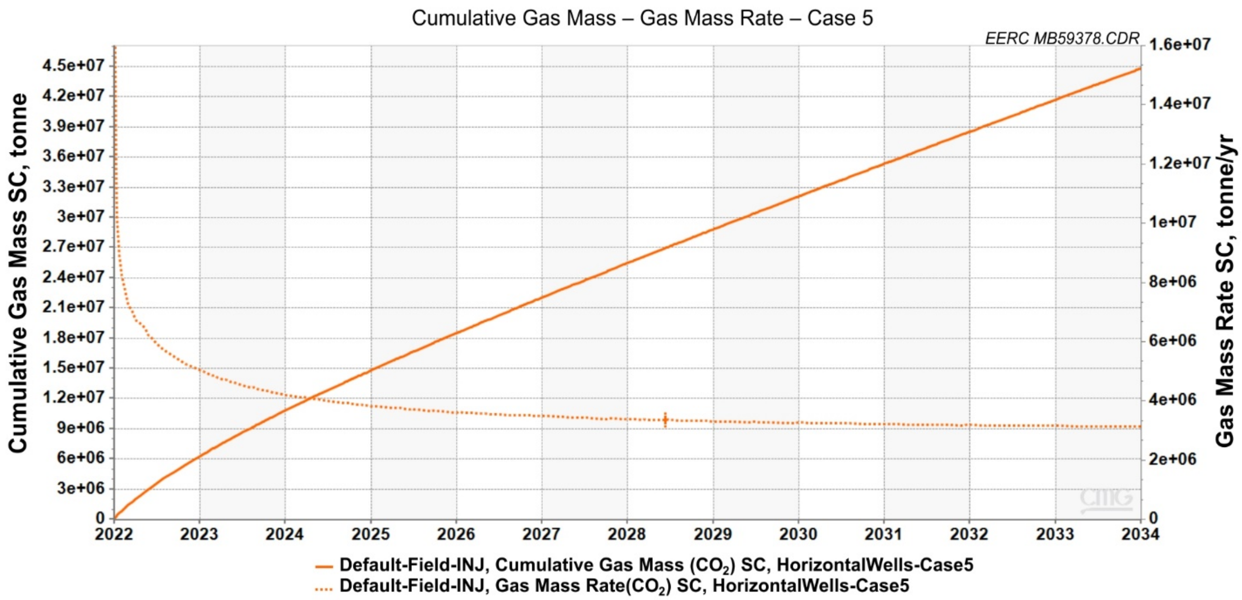

Figure 16. Graph showing simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 5.

Compared with the Base Case (Case 1, four vertical CO_2 injection wells without brine extraction), Case 5 (four horizontal wells without brine extraction) resulted in a decrease of 5.4 Mt of stored CO_2 (11% reduction). Average per well injection rate was higher with horizontal wells early in the operation (1.3 Mt/year with horizontal wells in comparison to 1.2 Mt/year in vertical wells). However, the average per well injection rate with horizontal wells dropped faster than that of vertical wells over the duration of the injection operation (0.8 Mt/year with horizontal wells in comparison to 1.0 Mt/year with vertical wells).

In the hypothetical scenario, vertical wells appear slightly more effective with the geologic and injection assumptions noted above. The horizontal well approach does seem to enable greater initial injection rates, but the smaller operational footprint leads to longer-term local pressure buildup and injectivity reduction. The 11% reduction in simulated stored CO_2 in comparison to the Base Case (difference of 5.4 Mt with Case 1) is significant, and the horizontal wells are expected to be more expensive. This approach would likely not represent an optimal solution with a goal of maximizing storage potential while minimizing well costs. However, implementing horizontal wells with the reduction in operational footprint and 20% reduction in CO_2 plume area would be expected to yield other potential benefits in minimizing ground surface sensitivities, including minimizing the amount of land impacted directly by the operation, reducing pore space leasing requirements, decreasing the area of required monitoring, and perhaps enabling an operator to better avoid land/pore space ownership complications, sensitive environments, and wildlife habitats. In situations where these considerations are important, a horizontal well approach may well be suitable and optimal.

Brine Extraction

Brine extraction with vertical CO_2 injection wells was simulated in Cases 3 and 4, both with a single centralized brine extraction well with operating constraints of minimum BHP of 1000 psi (6.9 MPa) and maximum rate of 30,000 bbl/day. Case 3 had open lateral boundaries, and Case 4 had closed lateral boundaries. Case 3 resulted in a simulated stored CO_2 mass of 58.1 Mt with a combined plume area of 22.5 mi^2 (58.2 km^2). Calculated storage potential for Case 3 was 2.6 Mt per mi^2 (1.0 Mt/km^2). Case 4 resulted in a simulated stored CO_2 mass of 54.6 Mt with a combined plume area of 21.4 mi^2 (55.5 km^2). Calculated storage potential for Case 4 was also 2.6 Mt per mi^2 (1.0 Mt/km^2).

The impact of brine extraction was assessed in comparing the Base Case (Case 1) with Case 3 for open boundary conditions and in comparing Cases 2 and 4 for closed boundary conditions. Brine extraction in Case 3 resulted in an increase in simulated stored CO_2 mass of 8 Mt (16%) in comparison to the Base Case (Case 1) without brine extraction. Brine extraction with closed boundaries resulted in an increase in simulated stored CO_2 mass of 8.5 Mt (18.5%). Figures 17 and 20 show map views of gas per unit area – total (ft) for Cases 3 and 4, respectively. Figures 18 and 21 show simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Cases 3 and 4, respectively. Figures 19 and 22 show simulated water production and CO_2 production rates for Cases 3 and 4, respectively.

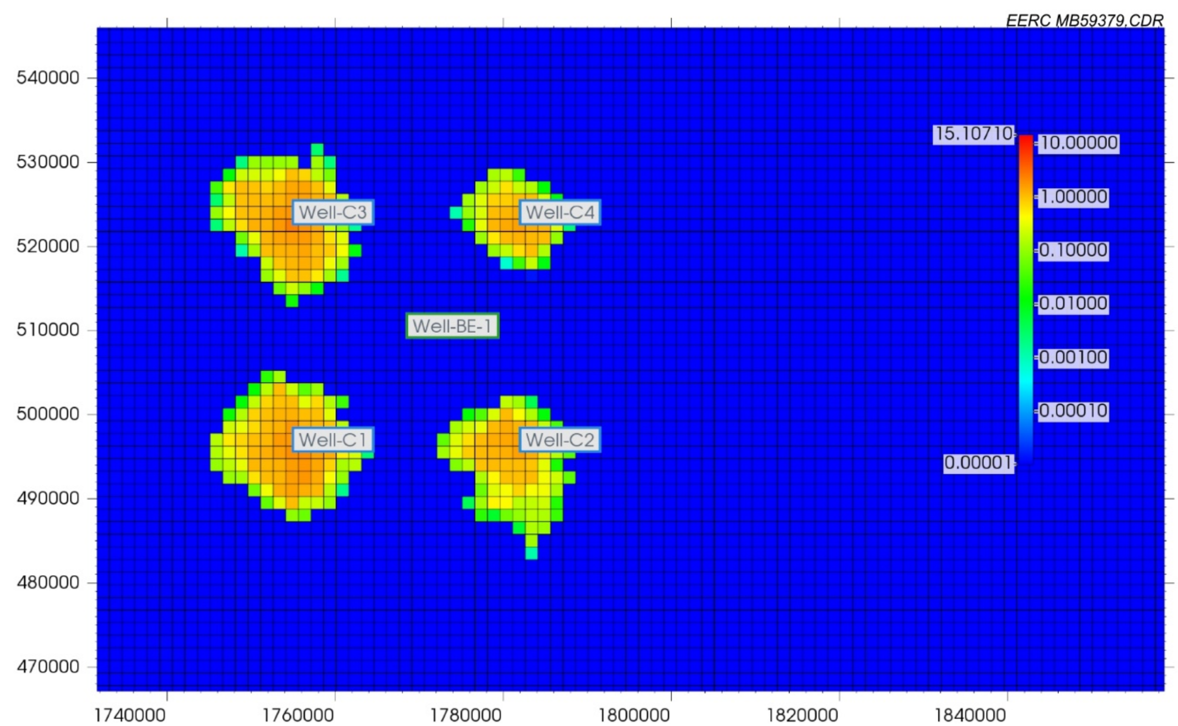

Figure 17. Map view showing CO_2 plume extents (gas per unit area – total [ft]) for Case 3, with a total stored CO_2 mass of 58.1 Mt, combined plume area of 22.5 mi^2 (58.2 km^2), and average plume size of 5.6 mi^2 (14.6 km^2). Note that the figure does not show the full simulated area.

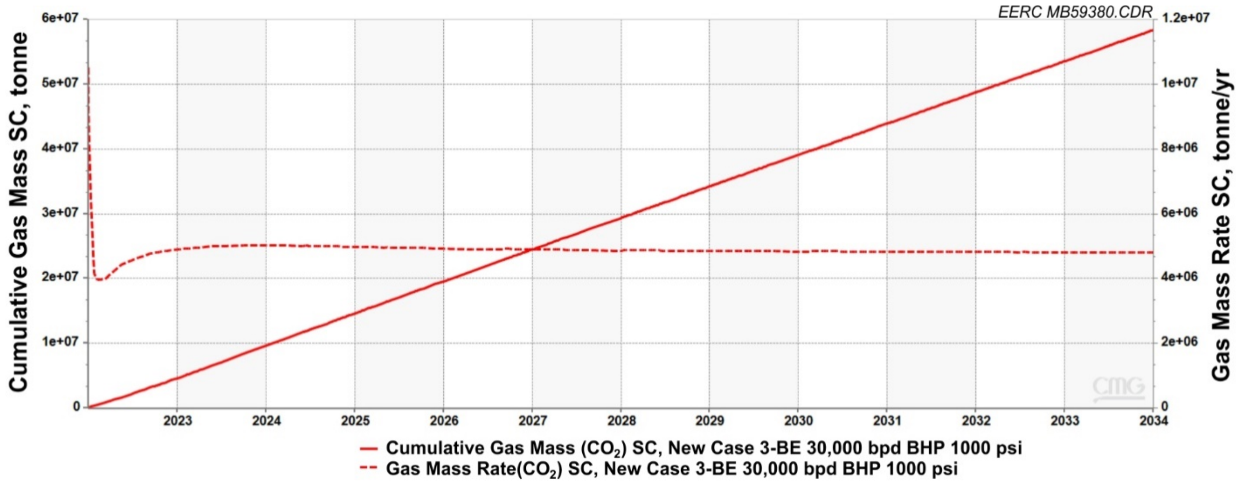

Figure 18. Graph showing simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 3.

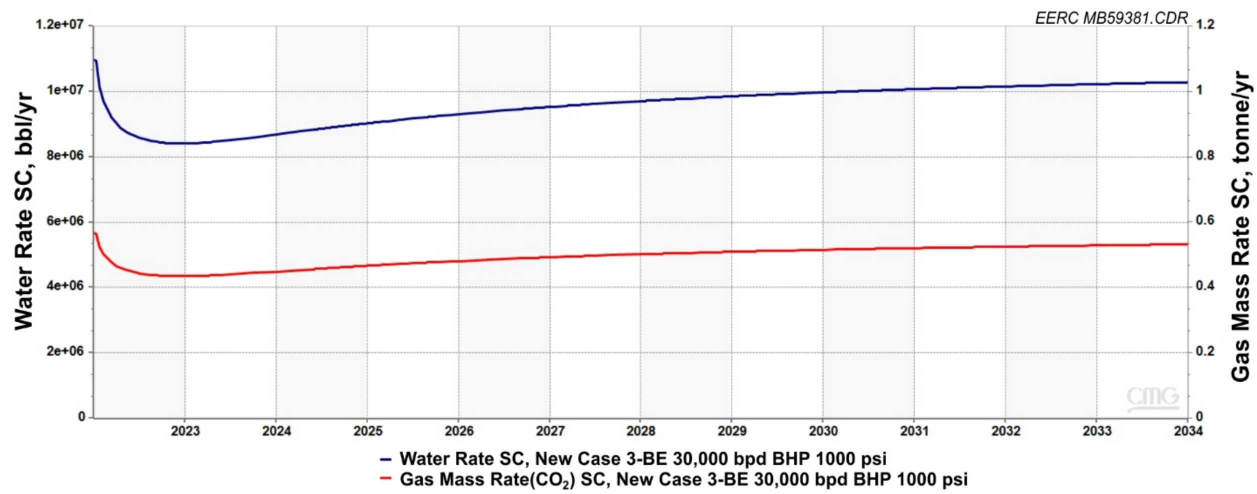

Figure 19. Graph showing simulated water production rate (blue curve) and CO_2 production rate in the brine extraction well (red curve) for Case 3.

The comparison of both cases supports the conclusions of many other publications that brine extraction may yield significant increases to CO_2 storage efficiency and potential. These results also support the conclusion of Gorecki and others (2015), indicating brine extraction is more effective in closed systems than for open systems with aquifer support. As noted previously, the grid extent was 30 mi × 30 mi (48.3 km × 48.3 km), large enough to accommodate injection at the rate desired of the hypothetical scenario (for the given operational time frame) even with closed boundaries. It would be expected that a longer operational scenario or more compartmentalized reservoir (decreased lateral connectivity) would show more pronounced results of brine extraction in comparison to open boundary scenarios with aquifer support.

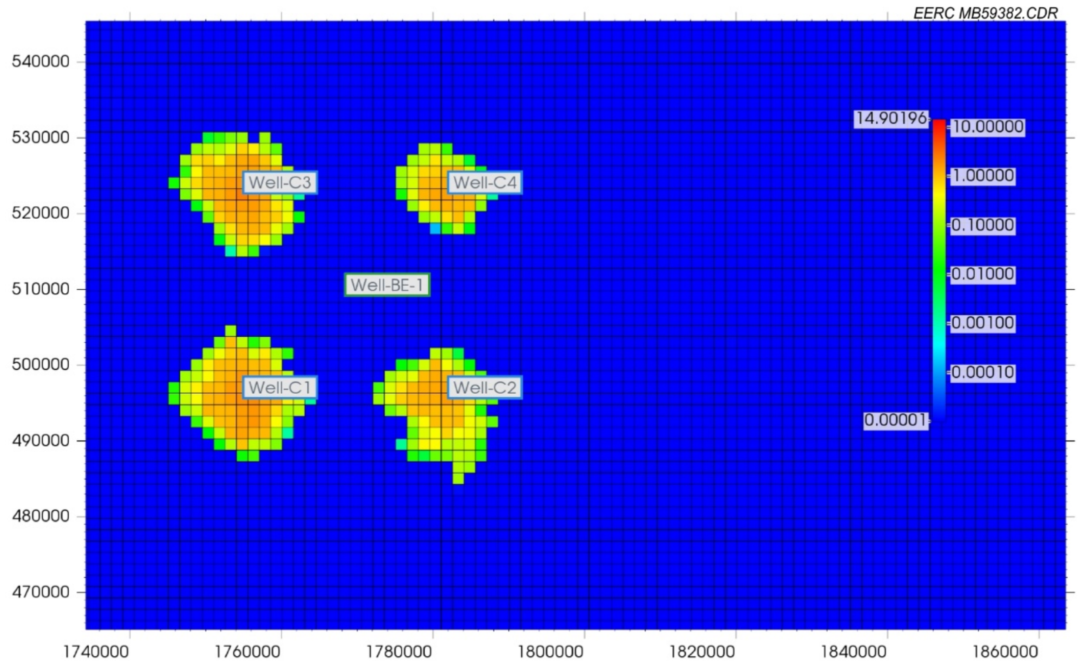

Figure 20. Map view showing CO_2 plume extents (gas per unit area – total [ft]) for Case 4, with a total stored CO_2 mass of 54.6 Mt, combined plume area of 21.4 mi^2 (55.5 km^2), and average plume size of 5.4 mi^2 (13.9 km^2). Note that the figure does not show the full simulated area.

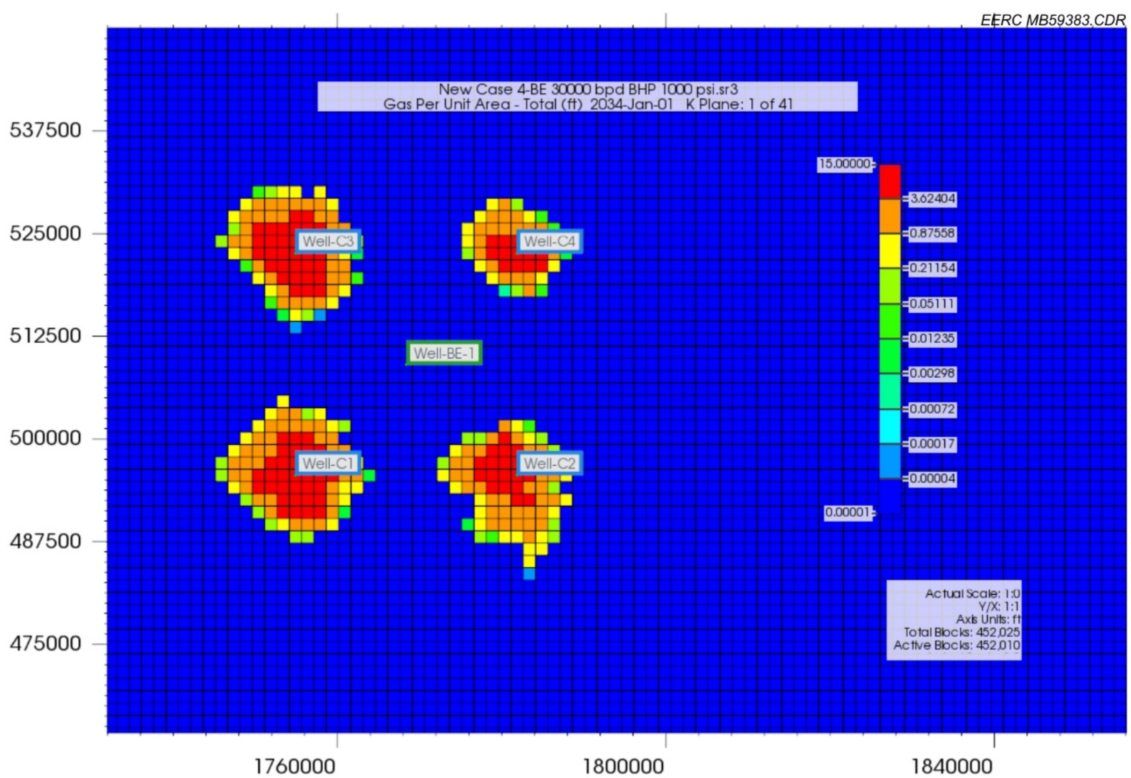

Figure 21. Graph showing simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 4.

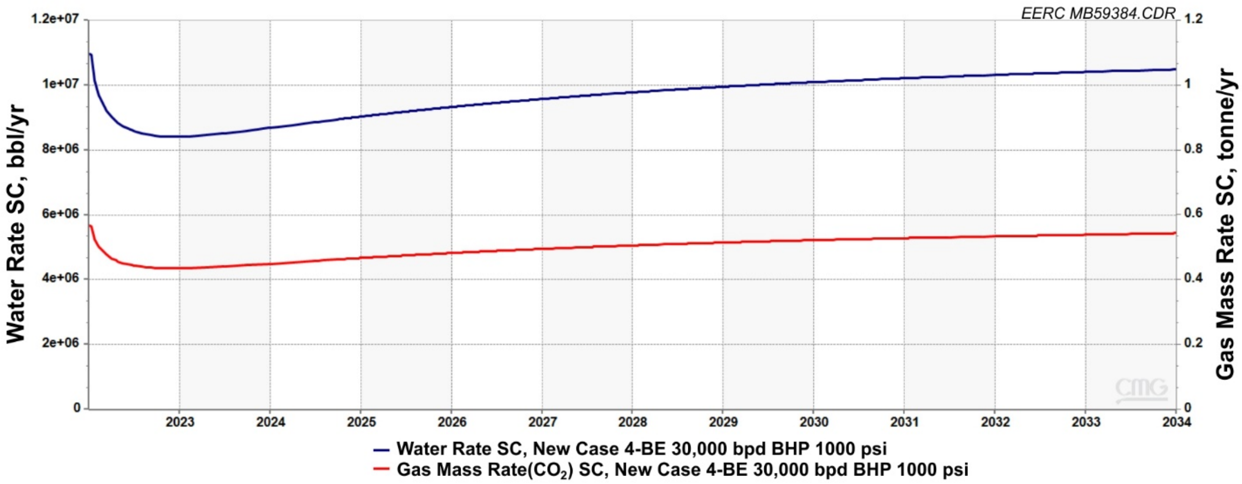

Figure 22. Graph showing simulated water production rate (blue curve) and CO_2 production rate in the brine extraction well (red curve) for Case 4.

Well Count/Spacing

Case 7 (eight vertical injection wells in an octagonal pattern [half the spacing of the Base Case] without brine extraction) resulted in a cumulative stored mass of 51.4 Mt of CO_2, exceeding the overall goal of the hypothetical scenario (45 Mt of stored CO_2), with a combined plume area of 24.1 mi^2 (62.4 km^2). Total injection rate (all wells together) was as high as 5.1 Mt/year during the first few years of simulated injection. This slowed to about 3.7 Mt/year at the end of the simulated 12-year injection interval. Average well injectivity was approximately 0.6 Mt/year in the beginning, slowing to 0.5 Mt/year near the end of the simulation, with an overall per well average just above 0.5 Mt/year. Figure 23 shows a map view of gas per unit area – total (ft) for Case 7, and Figure 24 shows simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 7. Storage efficiency for Case 7 was the worst out of the cases simulated in this study, with a calculated average storage potential of 2.1 Mt per mi^2 (0.8 Mt/km^2)

Compared with the Base Case (Case 1, four vertical CO_2 injection wells without brine extraction), Case 7 resulted in an increase of 1.4 Mt of stored CO_2 (1% increase). Overall average per well injection rate was about half of the Base Case (just above 0.5 Mt/year in comparison to 1 Mt/year). Pressure buildup quickly limits the effectiveness of the injection wells with tighter spacing, and the results strongly suggest that without any other means of mitigating pressure buildup (e.g., brine extraction), an injection strategy is much more efficient with a minimal number of vertical injection wells needed to reach the goals of a CCUS project. Depending upon the scale of the project, an additional well (or for very large projects, an additional few wells) above the minimum needed to meet the desired overall injection rate may alleviate concerns around injection well maintenance and downtime during workovers, but there does not appear to be a significant benefit to storage efficiency or injectivity by simply adding more injection wells in a tighter pattern (even if there are no "inside" injection wells that would intuitively be expected to perform in a "closed system" manner).

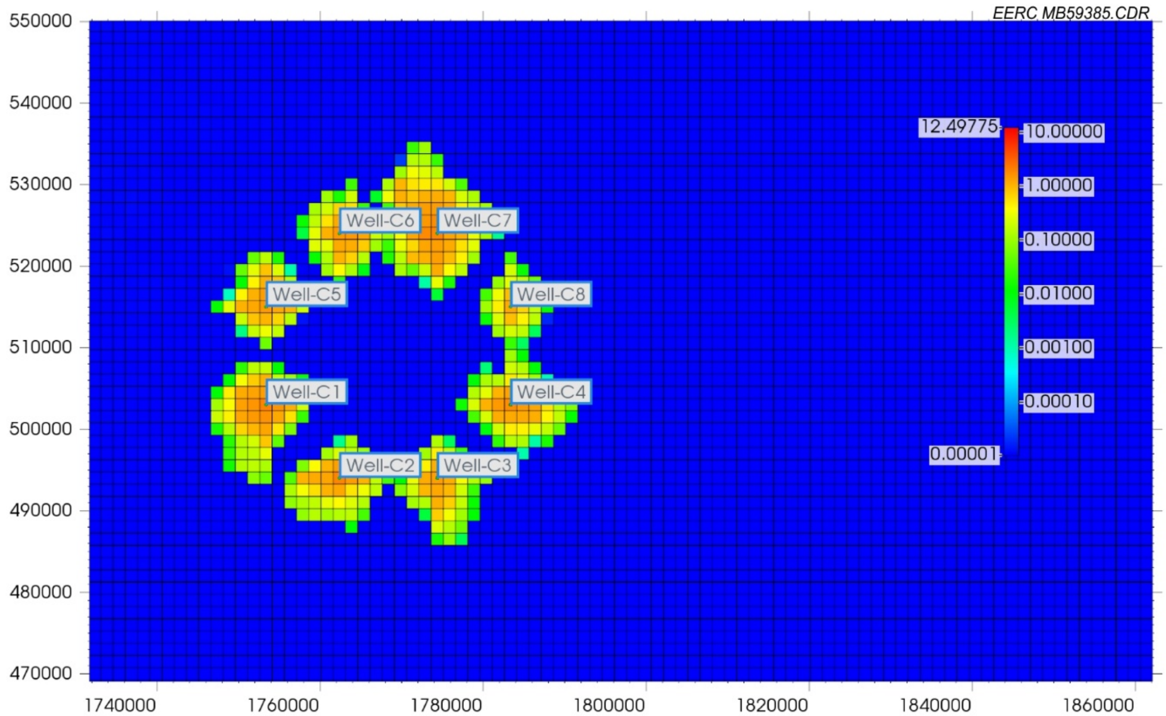

Figure 23. Map view showing CO_2 plume extents (gas per unit area – total [ft]) for Case 7, with a total stored CO_2 mass of 51.4 Mt, combined plume area of 24.1 mi^2 (62.4 km^2), and average plume size of 3 mi^2 (7.8 km^2). Note that the figure does not show the full simulated area.

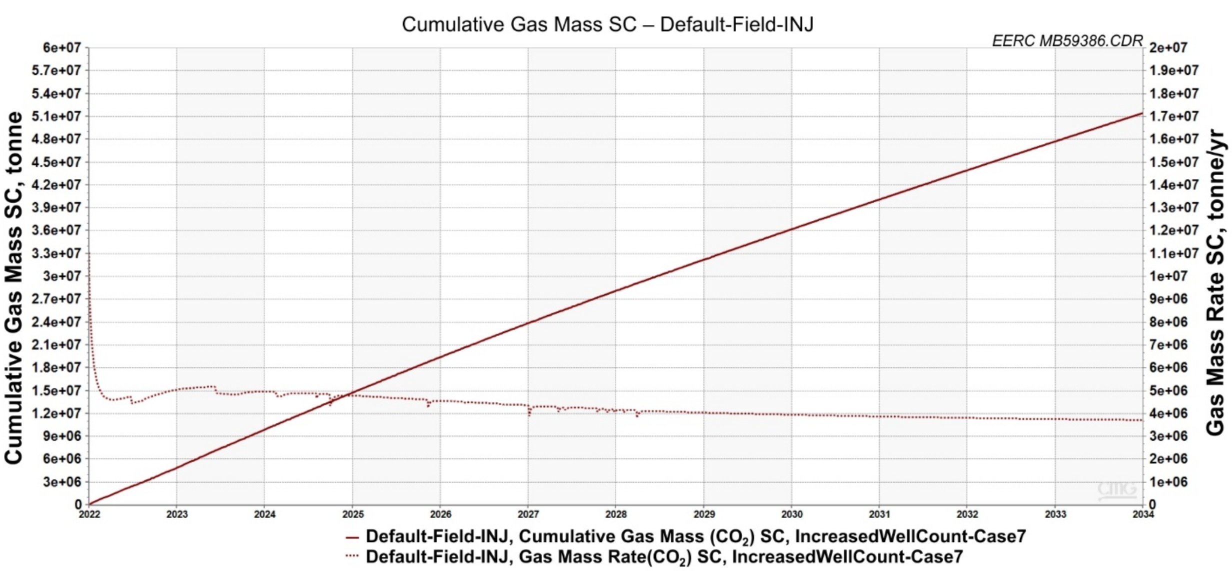

Figure 24. Graph showing simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 7.

Combination Scenarios

Horizontal Wells with Brine Extraction

Case 6 was conducted to investigate the effects of horizontal well CO_2 injection with brine extraction. When brine extraction is considered (in this case, a single centralized brine extraction well with operating constraints of minimum BHP of 1000 psi [6.9 MPa] and maximum rate of 15,000 bbl/day), Case 6 resulted in simulated injection of 52 Mt of CO_2 with a combined plume area of 18.2 mi^2 (47.2 km^2). A lower maximum extraction rate of 15,000 bbl/day was used in this case to mitigate CO_2 production with the shorter brine extraction-to-injection well offset distance (3.5 mi in diagonal orientation in Cases 3 and 4; 2.5 mi in Case 6 with horizontal CO_2 injection well surface locations spaced 5 mi apart).

Overall average well injection rate was approximately 1.1 Mt/year (a 17% increase in rate from Case 5 where brine extraction was not considered), and the increase in simulated stored CO_2 enabled by brine extraction with horizontal injection (comparing with Case 5) was 16%. Case 6 demonstrated the best overall storage efficiency, with a calculated average storage potential of 2.9 Mt per mi^2 (1.1 Mt/km^2) (within 0.4 Mt/mi^2 [0.15 Mt/km^2] of the calculated maximum storage potential [3.3 Mt/mi^2] from static and volumetric assumptions). In comparison to the Base Case (Case 1), horizontal wells with brine extraction resulted in an increase of 1% in cumulative stored CO_2 and increase in overall per well injection rate of 10%. Figure 25 shows a map view of gas per unit area – total (ft) for Case 6. Figure 26 shows simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 6. Figure 27 shows simulated water production and CO_2 production rates for Case 6.

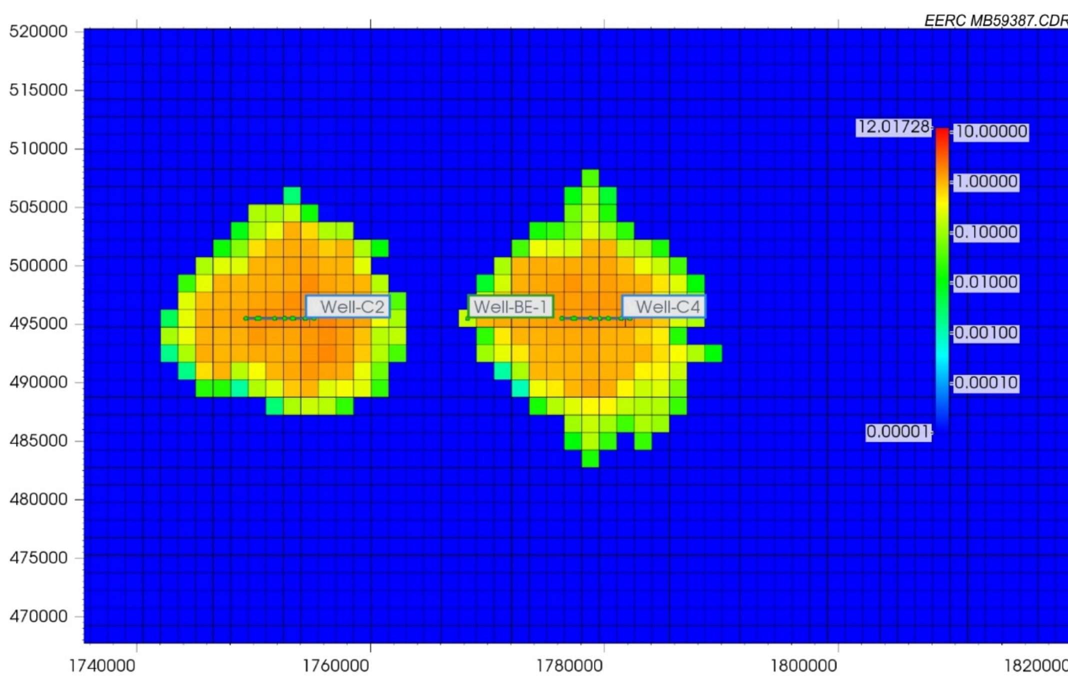

Figure 25. Map view showing CO_2 plume extents (gas per unit area – total [ft]) for Case 6, with a total stored CO_2 mass of 52 Mt, combined plume area of 18.2 mi^2 (47.2 km^2), and average plume size of 9.1 mi^2 (23.6 km^2). Note that the figure does not show the full simulated area.

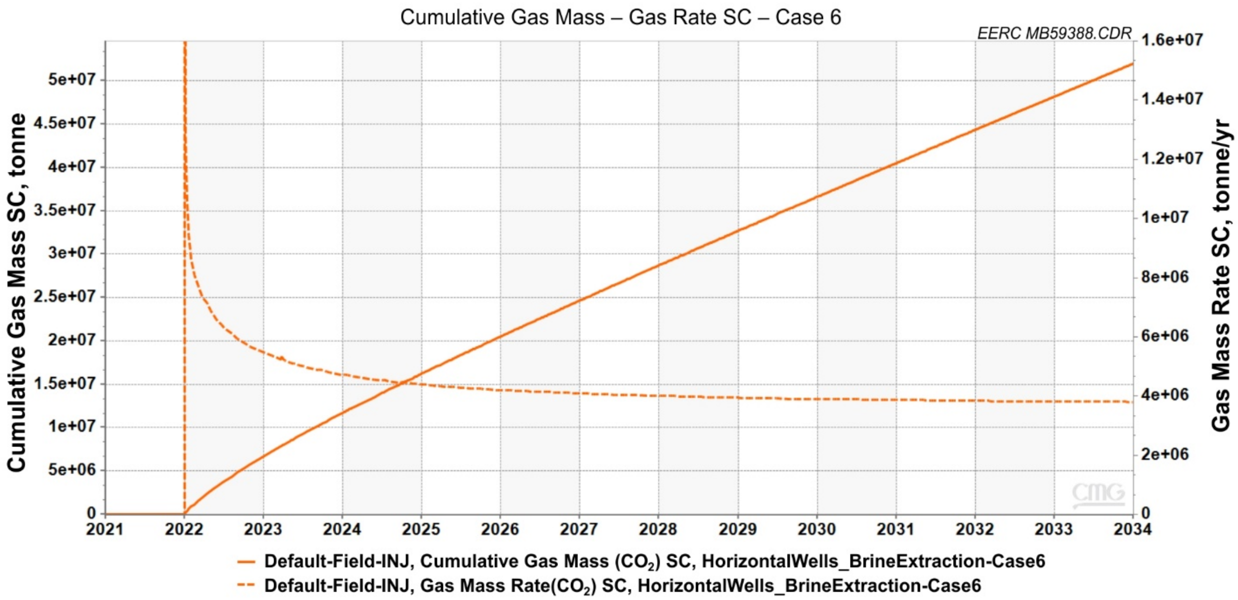

Figure 26. Graph showing simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 6.

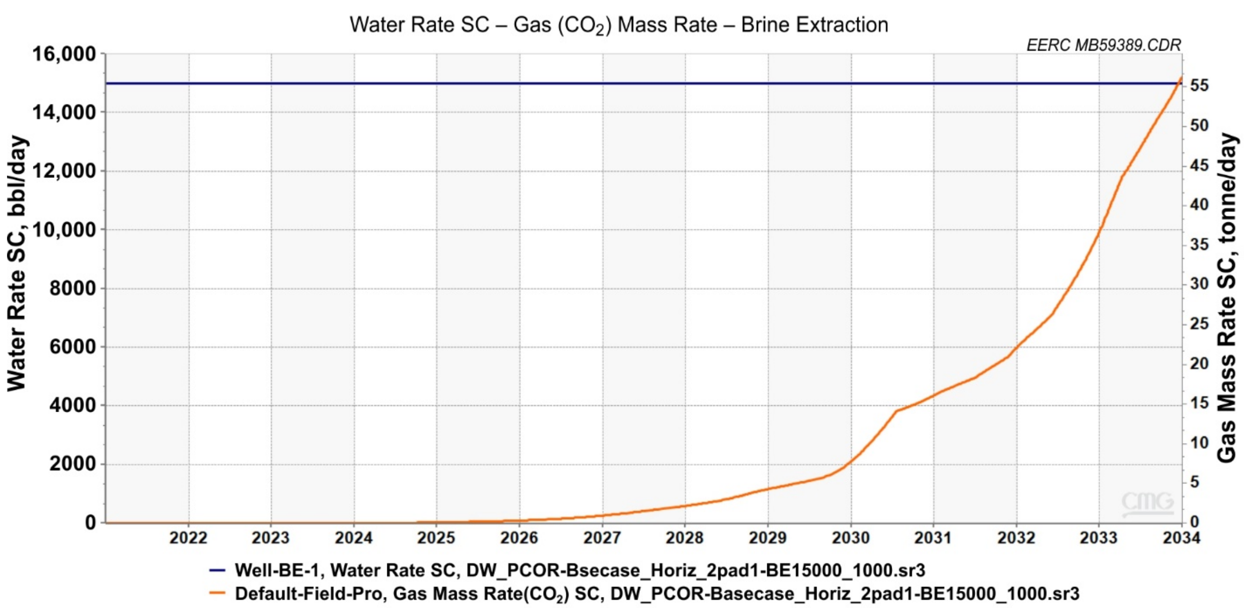

Figure 27. Graph showing simulated water production rate (blue curve) and CO_2 production rate in the brine extraction well (orange curve) for Case 6.

The distance from the brine extraction well to each horizontal injection well was approximately 2.5 mi (4 km). At this offset, slow CO_2 production began in the brine extraction well after 5 years (halfway through the intended injection time frame), and CO_2 production increased slightly after 8 years of operation, indicating growing communication with CO_2 injection wells. Over the last 6 years of simulated operation, 43,000 tonnes of CO_2 were produced (average rate of 20 tonnes/day [7200 tonnes/year]). This represented less than a tenth of 1% of the overall injected CO_2 mass. However, even this minor amount of CO_2 production represents an additional challenge for a storage site operator. An operator will need to decide what to do with this CO_2, faced with options including venting (which may result in difficulties around public perception of the project), adding separation equipment and on-site compression to reinject the produced CO_2 (which is expected to be more costly), or converting the extraction well to an injection well when an unacceptable CO_2 production rate threshold is exceeded (if the well was constructed to meet UIC Class VI well construction requirements).

Increased Well Count with Brine Extraction

When using eight vertical injection wells with two centralized brine extraction wells (Case 8, brine extraction wells with operating constraints of minimum BHP of 1000 psi (6.9 MPa) and maximum rate of 30,000 bbl/day per well, maximum of 60,000 bbl/day in total between both production wells), the simulation resulted in 75.4 Mt of injected CO_2 and a combined plume area of 33.8 mi^2 (87.5 km^2). While the overall stored CO_2 mass is significantly higher for this case than any others investigated here, storage efficiency in Case 8 was the second worst of the cases simulated (next to Case 7 with eight vertical wells and no brine extraction), with a calculated average storage potential of 2.2 Mt per mi^2 (0.9 Mt/km^2). Overall average per well injection rate was 0.8 Mt/year (a 49% increase in rate from Case 7 where brine extraction was not considered), and the increase in simulated stored CO_2 when implementing brine extraction with horizontal injection (comparing with Case 7) was 47%. In comparison to the Base Case (Case 1), doubling the number of wells with half the initial well spacing while including brine extraction resulted in an increase of 51% in cumulative stored CO_2 with a 20% reduction in overall average per well injection rate. Figure 28 shows a map view of gas per unit area – total (ft) for Case 8. Figure 29 shows simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 8. Figure 30 shows simulated water production and CO_2 production rates for Case 8.

The distance from the brine extraction well to each vertical injection well was approximately 2.5 mi (4 km). At this offset, 70,000 tonnes of CO_2 were produced over the last 6 years of operation (average rate of 32 tonnes/day [11,700 tonnes/year]). This represented less than a tenth of 1% of the overall injected CO_2 mass. As discussed above for Case 6, an operator will need to decide what to do with this CO_2, faced with options including venting, adding separation equipment and on-site compression to reinject the produced CO_2, or converting the extraction well to an injection well when an unacceptable CO_2 production rate threshold is exceeded.

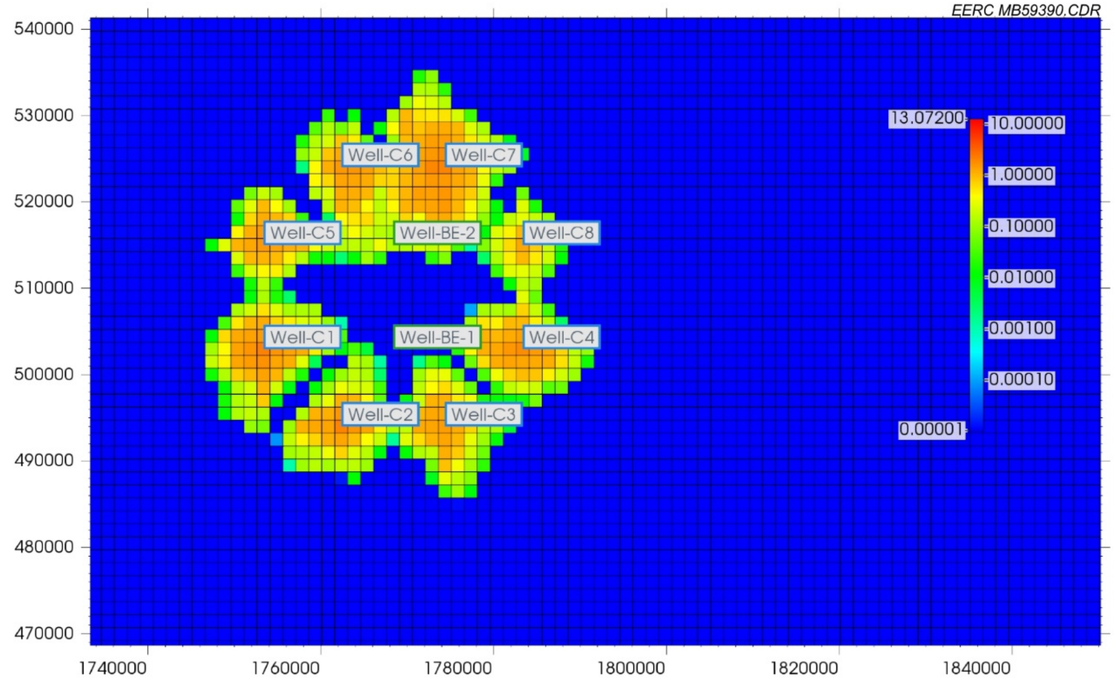

Figure 28. Map view showing CO_2 plume extents (gas per unit area – total [ft]) for Case 8, with a total stored CO_2 mass of 75.4 Mt, combined plume area of 33.8 mi^2 (87.5 km^2), and average plume size of 4.2 mi^2 (10.9 km^2). Note that the figure does not show the full simulated area.

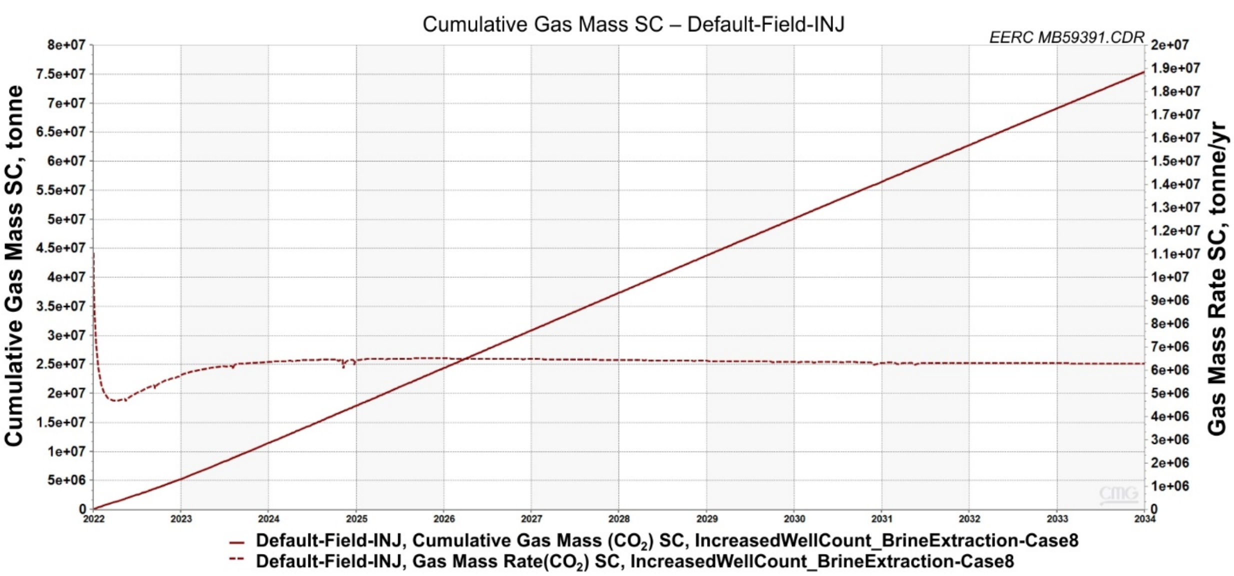

Figure 29. Graph showing simulated cumulative injected CO_2 and total CO_2 injection rate (all wells combined) for Case 8.

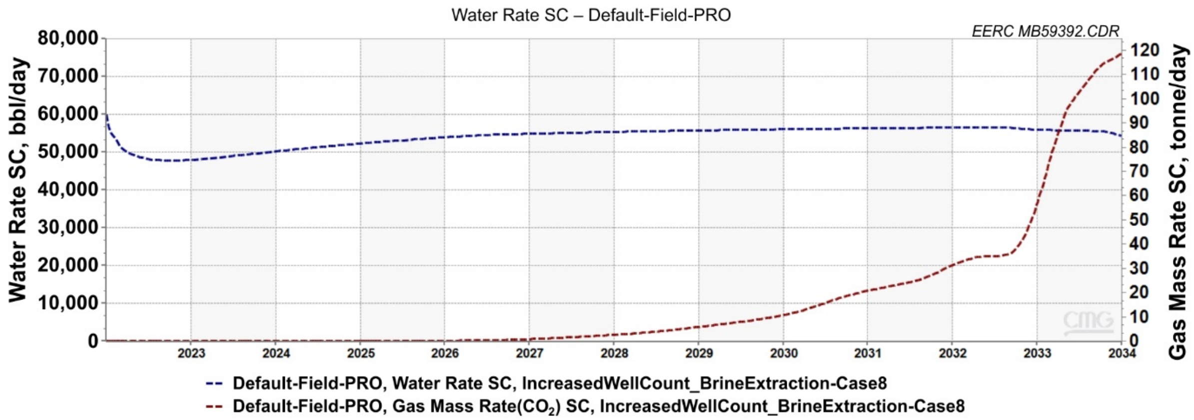

Figure 30. Graph showing simulated total water production rate (both production wells combined, blue curve) and total CO_2 production rate (both production wells combined, red curve) for Case 8.

High-Level Economic Assessment

The potential value of the hypothetical simulation cases investigated here was assessed using the guidance of the Internal Revenue Service (IRS) regarding tax credits available for stored CO_2 under 26 U.S. Code § 45Q – Credit for Carbon Oxide Sequestration, enabling operators of qualified storage sites to apply for tax credits per tonne of stored CO_2. The tax credit value for dedicated CO_2 storage is established by linear interpolation between US$22.66 and US$50 for any taxable year beginning in a calendar year after 2016 and through the end of 2026. The tax credit is available for a duration of 12 years of operation. For the purposes of this high-level economic feasibility assessment, a simplifying assumption is made that the hypothetical scenario will receive tax credits in the amount of US$50 per tonne of stored CO_2 for the entire 12-year duration. The cumulative injected CO_2 masses for each simulation case were used to calculate potential tax credit value. Table 5 contains the calculated 45Q tax credit value for each simulation case.

Table 5. Stored CO_2 for Each Simulated Case with the Projected 45Q Tax Credit Value and 12-year CO_2 Plume Area

Case No.	Simulated Stored CO_2, Mt	12-year Combined Plume Area, mi^2	45Q Tax Credit Value, $B
1	50.0	20.0	2.500
2	46.1	18.6	2.305
3	58.1	22.5	2.905
4	54.6	21.4	2.730
5	44.7	15.9	2.235
6	52.0	18.2	2.600
7	51.4	24.1	2.570
8	75.4	33.8	3.770

The cost for commercial-scale CO_2 storage can be widely variable based upon desired well type and number, intended well completion depth (and associated well drilling and completion specifications), project area and landowner considerations (monitoring footprint and area requiring pore space leasing), development of well permit applications, and infrastructure (capture facility type and scale, compression requirements, and CO_2 transport distance).

This investigation draws upon recent prior PCOR Partnership research and acquired well construction cost estimates to approximate capital expenditures for well installation. This includes vertical and horizontal CO_2 injection well installation in the BCS at a hypothetical scenario depth of 9500 ft (2900 m), brine extraction well installation into the BCS at the same depth, and brine disposal well installation into the sandstones of the Early Cretaceous Inyan Kara Formation at a hypothetical scenario depth of 4000 ft (1200 m).

Numerical simulation results were used to calculate the areal extent of injected CO_2. Plume extent was used to estimate costs for monitoring and pore space leasing.

The cost for development of permit applications for any type of well is not included in this assessment. This cost is expected to vary by location and permitting authority. Costs and approval time frame are expected to differ if submitting to a state, federal, or provincial governmental entity.

Infrastructure costs were not evaluated in detail during this investigation. These costs would include CO_2 capture, CO_2 transportation (pipeline installation and operation) and, for brine extraction cases, costs for on-site brine and produced CO_2 handling. The transportation and on-site brine/CO_2 handling costs are expected to represent a small fraction of the overall infrastructure capital expenditure, which will likely be dominated by costs for the CO_2 capture system and compression. IEAGHG (2014) estimated total capital cost for postcombustion capture at a power generation facility to be approximately US$4400 per kilowatt. For a 500-MW coal-based powerplant, which may generate as much CO_2 as the minimum rate considered in this investigation (3.75 Mt per year), a capture and compression system would cost approximately US$2B. Achieving greater detail around these costs was outside the scope of this investigation. Such costs need to be considered in determining the final cost of stored CO_2 per tonne, overall project net value, and economic viability. For this economic assessment, the most important costs directly related to the variables considered in numerical simulations were evaluated, including well installation costs, cost estimates for alternate means of brine disposal (disposal by a third party versus installation of dedicated brine disposal wells to service the project), estimated costs for monitoring the injected CO_2, and estimated costs for pore space leasing.

Estimated Well Installation Costs

Estimated well construction costs vary widely by intended mode of well operation (e.g., CO_2 injection, production, brine disposal, dedicated monitoring, etc.), location of interest, depth, and other well design considerations, including diameter, casing type, cement type, completion/stimulation design, outfitting with monitoring technology (if desired), and others. Drawing upon recent prior knowledge gained from PCOR Partnership research and acquired cost estimates for different types of wells, this study assumes a cost for a vertical CO_2 injection well completed within the BCS of US$5.0M to US$7.5M, with an average of US$6.3M. Relative to the assumed average cost of a vertical CO_2 injection well (US$6.3M), the following cost ratios are assumed for all types of wells considered in this investigation:

- Vertical CO_2 injection well: 0.8× to 1.2× that of a vertical CO_2 injection well
- Horizontal CO_2 injection well: 1.3× to 1.9× that of a vertical CO_2 injection well
- Brine extraction well: 0.6× to 1.2× that of a vertical CO_2 injection well
- Brine disposal well: 0.6× to 0.8× that of a vertical CO_2 injection well

Estimated Costs for Third-Party Produced Brine Disposal

For the simulated cases implementing brine extraction, two options exist for produced brine disposal: 1) transport to and disposal by a third party or 2) installing dedicated brine disposal wells in close proximity to the brine extraction well(s). If brine disposal by a third party is desired, produced water disposal has an additional ~$2–$4 per bbl cost for transportation and injection into a disposal formation (Energy & Environmental Research Center [EERC], 2020). Table 6 shows the estimates for third-party brine disposal for each of the cases where brine extraction is employed, ranging from US$230M to nearly US$1B across the investigated cases. For all cases implementing brine extraction, the estimated costs for brine disposal by a third party greatly exceed the cost of installing dedicated brine disposal wells, which are estimated below with the costs expected for the construction of all well types in the simulation scenarios analyzed. The additional costs for on-site temporary brine storage, handling, and operational costs for the disposal wells have not been analyzed, but these additional costs are not expected to exceed the difference between the cost of dedicated brine disposal well construction and the costs associated with third-party brine disposal. Therefore, this economic assessment proceeds with assumed costs for construction of dedicated brine disposal wells to service the simulated scenarios implementing brine extraction.

Table 6. Produced Brine Volumes and Estimated Costs for Third-Party Brine Disposal for Each Simulation Case

Case No.	Produced Brine, MMbbl	Brine Disposal Estimate
1	NA	–
2	N/A	–
3	115.0	$230M–$460M
4	116.0	$232M–$464M
5	N/A	–
6	71.2	$142M–$285M
7	N/A	–
8	236.0	$472M–$944M

Estimated Costs for Construction of Injection, Production, and Dedicated Brine Disposal Wells

With the ratios included above, a 1-mi (1.6-km) horizontal well cost would then be estimated at US$8.3M to US$12M. A brine extraction well would range between US$3.8M and US$7.5M, and the cost of a brine disposal well would range between US$3.8M and US$5.3M. The Base Case (Case 1) would have a total well cost of US$20.2M to US$30.2M, with an average estimated cost of US$25M. In comparison to the average estimated cost of a vertical CO_2 injection well (US$6.3M), Case 6 (with four horizontal CO_2 injection wells, one brine extraction well, and one brine disposal well) had total estimated well costs between US$40.3M and US$60.5M. For ease of comparison, Table 7 contains well type and number assumptions for each case, cost of each case normalized to the estimated average cost of a single vertical CO_2 injection well completed in the BCS, and overall estimated well costs for each simulation case.

For brine disposal well number estimation, EERC (2020) noted that disposal wells completed within the Cretaceous sandstones of the Inyan Kara Formation within the Dakota Group were capable of achieving injection rates in excess of 5 MMbbl per year (~14,000 bbl/day). This study made the assumption that maximum injection rates of brine disposal wells were 15,000 bbl/day. With this assumption, one brine disposal well would be required to meet the disposal rates of brine extraction in Case 6, and the increased brine extraction rates of Cases 3, 4, and 8 (30,000 bbl/day/well) would require twice the number of brine disposal wells than number of extraction wells (two brine disposal wells for Cases 3 and 4; four brine disposal wells for Case 8).

Table 7. Number and Type of Wells Required for Each Simulation Case, Estimated Well Cost Normalized to a Single Vertical CO_2 Injection Well (assumed average cost of US$6.3M), and Total Estimated Well Construction Costs

Case No.	V[1] H[2] E[3] D[4]	Normalized Cost to Single Vert. Inj. Well	Total Estimated Well Construction Costs
1	4:0:0:0	3.2–4.8	$20.2M–$30.2M
2	4:0:0:0	3.2–4.8	$20.2M–$30.2M
3	4:0:1:2	5.0–7.6	$31.5M–$47.9M
4	4:0:1:2	5.0–7.6	$31.5M–$47.9M
5	0:4:0:0	5.2–7.6	$32.8M–$47.9M
6	0:4:1:1	6.4–9.6	$40.3M–$60.5M
7	8:0:0:0	6.4–9.6	$40.3M–$60.5M
8	8:0:2:4	10.0–15.2	$63.0M–$95.8M

[1] V vertical CO_2 injection well number.
[2] H horizontal CO_2 injection well number.
[3] E brine extraction well number.
[4] D brine disposal well number.

Estimated Monitoring Costs

Cost information for storage monitoring is quite variable with the types of monitoring approaches desired and location, including site-specific geologic characteristics and ground surface constraints, but Intergovernmental Panel on Climate Change (IPCC, 2005) has previously estimated costs associated with monitoring to add US$0.1– US$0.3 per tonne of CO_2 stored, while noting that these estimates do not include any well remediation or long-term liabilities. Monitoring costs will also be dependent upon what technologies are used, the length of the monitoring time frame, regulatory requirements, and monitoring technology evolution, which may reduce cost per tonne or cost per unit area. Adjusting the rates reported by IPCC (2005) for inflation, the estimated rates would be US$0.14–US$0.41 per tonne of stored CO_2. The authors assumed that these rates were most applicable to simplified scenarios where vertical CO_2 injection wells were used in the absence of other variables which may affect site-specific CO_2 storage efficiency and stored CO_2 per unit area (e.g., brine extraction, horizontal well CO_2 injection). There is an expectancy that CO_2 storage monitoring costs increase or decrease not only by the amount of stored CO_2 but also by the size of the area to be monitored. Using these values, costs were estimated for the Base Case (Case 1), and then injected CO_2 plume size ratios (in comparison to the Base Case [Case 1]) were used to estimate monitoring costs for all other simulation cases. This yielded a range of US$0.35M to US$1.0M per mi^2 (US$0.14M/km^2 to US$0.40M/km^2) in estimated monitoring costs, with total estimated monitoring costs ranging from US$5.6M to US$34.6M across all simulation cases considered here (Table 8).

Table 8. Plume Size Ratios in Comparison to the Base Case (Case 1) and Estimated Monitoring Costs for Each Simulation Case

Case No.	Simulated Stored CO_2, Mt	12-year Combined Plume Area, mi^2	Plume Size Ratio in Comparison to the Base Case	Estimated Monitoring Costs
1	50.0	20.0	1.00	$7.0M–$20.5M
2	46.1	18.6	0.93	$6.5M–$19.0M
3	58.1	22.5	1.12	$7.9M–$23.0M
4	54.6	21.4	1.07	$7.5M–$22.0M
5	44.7	15.9	0.79	$5.6M–$16.3M
6	52.0	18.2	0.91	$6.4M–$18.7M
7	51.4	24.1	1.20	$8.4M–$24.7M
8	75.4	33.8	1.69	$11.8M–$34.6M

Estimated Pore Space Leasing Costs

Similar to estimated costs associated with storage monitoring, information is sparce regarding pore space leasing costs. The rates associated with pore space payments are expected to be decided in negotiations between a storage project operator and pore space owner. For the purposes of this economic feasibility study, while drawing upon experience gained from unpublished PCOR Partnership research and discussion with PCOR Partnership members, rates of US$0.1–US$0.3 per tonne of stored CO_2 were assumed. The pore space leasing costs ranged from US$0.21M to US$0.86M per mi^2 (US$0.08M/km^2 to US$0.33M/km^2) with total estimated pore space leasing costs ranging from US$4.5M to US$22.6M across all simulation cases considered here (Table 9).

Table 9. **Estimated Pore Space Leasing Costs for Each Simulation Case**

Case No.	Simulated Stored CO_2, Mt	Simulated Stored CO_2 per Plume Area, Mt/mi^2	Estimated Total Pore Space Leasing Costs
1	50.0	2.50	\$5.0M–\$15.0M
2	46.1	2.48	\$4.6M–\$13.8M
3	58.1	2.59	\$5.8M–\$17.4M
4	54.6	2.55	\$5.5M–\$16.4M
5	44.7	2.81	\$4.5M–\$13.4M
6	52.0	2.85	\$5.2M–\$15.6M
7	51.4	2.13	\$5.1M–\$15.4M
8	75.4	2.23	\$7.5M–\$22.6M

Recommendations from the Economic Feasibility Assessment

The estimated costs of well installation, monitoring, and pore space leasing were compiled for each simulation case investigated in this study. Table 10 includes summed estimated costs for well installation, monitoring, and pore space leasing for each simulation case. Table 10 also includes the potential 45Q tax credit value (assuming US\$50 per tonne of stored CO_2) and the difference between potential 45Q tax credit value and summed costs. Cost estimates for capture infrastructure, CO_2 transport, on-site brine and CO_2 handling (for cases implementing brine extraction), and other operational considerations were outside the scope of this investigation and have not been evaluated. As such, no attempt has been made to delineate potential net project value or overall cost per tonne of stored CO_2.

Table 10. Simulated Stored CO_2; Stored CO_2 Mass per mi^2; Estimated Cost for Wells, Monitoring, and Pore Space; Potential 45Q Tax Credit Value; and Difference Between 45Q Value and Costs for Each of the Simulation Cases

Case No.	Simulated Stored CO_2, Mt	Stored CO_2 Mass Per mi^2, Mt/mi^2	Cost for Wells, Monitoring, and Pore Space	Potential 45Q Tax Credit Value	Difference Between 45Q Value and Costs
1	50.0	2.50	\$0.032B–\$0.066B	\$2.500B	\$2.434B–\$2.468B
2	46.1	2.48	\$0.031B–\$0.063B	\$2.305B	\$2.242B–\$2.274B
3	58.1	2.59	\$0.045B–\$0.088B	\$2.905B	\$2.817B–\$2.860B
4	54.6	2.55	\$0.044B–\$0.086B	\$2.730B	\$2.644B–\$2.686B
5	44.7	2.81	\$0.043B–\$0.078B	\$2.235B	\$2.157B–\$2.192B
6	52.0	2.85	\$0.052B–\$0.095B	\$2.600B	\$2.505B–\$2.548B
7	51.4	2.13	\$0.054B–\$0.101B	\$2.570B	\$2.469B–\$2.516B
8	75.4	2.23	\$0.082B–\$0.153B	\$3.770B	\$3.619B–\$3.688B

When the summed estimated costs for well installation, monitoring, and pore space leasing are considered, the trend tends to follow the greatest cost component included here, that being the cost of well installation. The Base Case (Case 1) and Case 2 (the closed boundary version of the

Base Case [Case 1]), using four vertical CO_2 injection wells, are the lowest cost options, ranging from US$31M to US$66M. Case 2 is the least costly, as the closed boundary conditions resulted in lower overall stored CO_2 mass and smaller overall injected CO_2 footprint (lower estimated monitoring and pore space leasing costs). Case 5, with four horizontal wells, is the next least expensive option, ranging from US$43M to US$78M, although this case did not quite meet the minimum cumulative stored CO_2 goal of 45 Mt. Cases 3 and 4, each with four vertical CO_2 injection wells and a single centralized brine extraction well, are the next least costly, ranging from US$45M to US$88M. Case 6 (four horizontal CO_2 injection wells with a single centralized brine extraction well) and Case 7 (eight vertical CO_2 injection wells) were close in summed estimated costs, ranging from US$54M to US$101M. Case 8 (eight vertical CO_2 injection wells with two centralized brine extraction wells) was the most costly option, with summed estimated cost ranging between US$82M and US$153M.

When the difference between potential 45Q tax credit value and estimated summed costs is considered, the differences are wide, with the exclusion of the cost of capture infrastructure (estimated at a cost of approximately US$2B for the minimum rate assumed for this study and increasing with the increasing capture capacity). The margin value is mainly a function of stored CO_2 and potential 45Q tax credit value. Case 8 (eight vertical CO_2 injection wells with two centralized brine extraction wells) holds the widest margin, ranging from US$3.6B and US$3.7B. Costs to capture the 75.4 Mt of CO_2 stored in Case 8 would also be expected to be the greatest, which may close the gap between Case 8 and the other cases. Case 8 is followed by Cases 3 and 4 (four vertical CO_2 injection wells with one centralized brine extraction well), ranging from US$2.6–US$2.9B, and Case 6 (four horizontal CO_2 injection wells with one centralized brine extraction well) at approximately US$2.5B.

There is a clear trend in the margins between potential 45Q tax credit value and summed costs. The cases with the widest margins all implemented brine extraction, as the benefit afforded in increasing overall stored CO_2 mass translated to much greater potential 45Q tax credit value.

Of the three variables tested in this investigation, brine extraction appears to represent the single-most impactful means of optimizing CO_2 storage with the geologic assumptions of this hypothetical BCS scenario. Simulation cases not considering brine extraction had the lowest overall cumulative stored CO_2 masses, ranging from 44.7 to 51.4 Mt, and correlative lower value when considering 45Q tax credits.

Increasing well number and decreasing well spacing within a unit area, by itself, appears to provide little incremental benefit to cumulative stored CO_2 and is more costly in well completion costs. However, a combination of increasing well density with brine extraction may be an option with significant benefit.

The simulation case with only horizontal well CO_2 injection (no brine extraction) had the least compelling result, in terms of margin value between potential 45Q tax credit value and summed costs. Benefits were observed in storage efficiency, reduced operational footprint, and reduced overall CO_2 plume footprint (with associated cost reductions for monitoring and pore space leasing). However, there was no clear benefit to cumulative stored CO_2, and the benefits afforded by reduction in overall CO_2 plume footprint were offset by the relatively high cost for well installation. Brine extraction with horizontal well CO_2 injection, however, did provide interesting results in benefit to cumulative stored CO_2 mass great enough to bring the margin value between potential 45Q tax credit value and summed costs into competitive standing. This approach, horizontal wells with brine extraction, may be the most suitable and optimal approach if ground surface constraints (i.e., landowner or monitoring considerations) are restrictive to a future potential CCUS project.

SUMMARY AND CONCLUSION

This investigation focused on a hypothetical CO_2 storage scenario in the BCS. Means of optimizing the hypothetical storage operation were assessed, with focus placed on optimization of field operational techniques and constraints, as well as the resulting impacts and implications for injectivity and potential storage resource, land ownership and pore space leasing, monitoring requirements to satisfy regulatory/permitting guidance, and capital and operational cost expenditures. For the purposes of this report, CO_2 storage optimization was focused on a fixed unit area over an assumed time frame and determining the most cost-efficient means of maximizing injectivity and cumulative stored CO_2.

Three operational techniques were investigated: 1) the use of horizontal wells, 2) brine extraction, and 3) well count/spacing. Numerical simulations were conducted to investigate the effects of each and provide inputs for high-level economic feasibility to increase potential project value by minimizing the cost per volume of CO_2 injected. The potential value of the hypothetical simulation cases investigated here was assessed using the guidance of the IRS regarding tax credits available for stored CO_2 under 26 U.S. Code § 45Q – Credit for Carbon Oxide Sequestration, enabling operators of qualified storage sites to apply for tax credits per tonne of stored CO_2 over a 12-year period. For the purposes of this high-level economic feasibility assessment, a simplifying assumption is made that the hypothetical scenario will receive tax credits in the amount of US$50 per tonne of stored CO_2 for the entire 12-year duration. The cumulative injected CO_2 masses for each simulation case was used to calculate potential tax credit value.

Infrastructure costs were not evaluated in detail during this investigation. These costs would include CO_2 transport (CO_2 pipeline installation and operation) and, for brine extraction cases, costs for on-site brine and produced CO_2 handling. These costs are expected to represent a small fraction of the overall infrastructure capital expenditure, which will likely be dominated by costs for the CO_2 capture system and compression. Achieving greater detail around these costs was outside the scope of this investigation. Such costs need to be considered in determining the final cost of stored CO_2 per tonne, overall project net value, and viability. For this economic assessment, the greatest expected costs which would likely be directly related to the variables considered in numerical simulations were evaluated, including well installation costs, cost estimates for alternate means of brine disposal (disposal by a third party versus installation of dedicated brine disposal wells to service the project), estimated costs for monitoring the injected CO_2, and estimated costs for pore space leasing.

This report does not take into account many site-specific considerations that are expected to influence project cost and/or project feasibility. Well costs may differ from the assumptions made here, depending upon many factors. Costs for monitoring are likely to differ depending upon site-specific details, including the type of technologies that are used, the length of the monitoring time frame, regulatory requirements, and monitoring technology evolution. Information is sparce regarding estimated costs associated with pore space leasing. The rates associated with pore space payments are expected to be decided in negotiations between a storage project operator and pore space owner. The assumed rates for pore space leasing used in this investigation relied upon experience gained from unpublished PCOR Partnership research and discussion with PCOR Partnership members. The cost for development of permit applications for any type of well is not included in this assessment. This cost is expected to vary by location and permitting authority. Costs and approval time frame are expected to differ if submitting to a state, federal, or provincial governmental entity.

Of the three variables tested in this investigation, brine extraction appears to represent the single-most impactful means of optimizing CO_2 storage with the geologic assumptions of this hypothetical BCS scenario. Simulation cases not considering brine extraction had the lowest overall cumulative stored CO_2 masses, ranging from 44.7 to 51.4 Mt, and correlative lower value when considering 45Q tax credits. Brine extraction, if implemented, is expected to be a much more expensive if brine disposal by a third party is desired or required (e.g., lack of a suitable local brine disposal formation). Cost-savings may be realized by constructing dedicated disposal wells to service the brine extraction operation. Additionally, some of the brine extraction cases here resulted in CO_2 production. This produced CO_2 was in minor quantities for all cases, representing less than a tenth of 1% of the overall injected CO_2 mass. However, even this minor amount of CO_2 production represents an additional challenge for a storage site operator. An operator will need to decide what to do with this CO_2, faced with options including venting (which may result in difficulties around public perception of the project), adding separation equipment and on-site compression to reinject the produced CO_2 (which is expected to be more costly), or consider converting the extraction well to an injection well when an unacceptable CO_2 production rate threshold is exceeded (if the well was constructed to meet UIC Class VI well construction requirements).

Increasing well number and decreasing well spacing within a unit area, by itself, appears to provide little incremental benefit to cumulative stored CO_2 and is more costly in well completion costs. However, a combination of increasing well density with brine extraction may be an option with significant benefit.

The simulation case with only horizontal well CO_2 injection (no brine extraction) had the least compelling result, in terms of margin value between potential 45Q tax credit value and summed costs. Benefits were observed in storage efficiency, reduced operational footprint, and reduced overall CO_2 plume footprint (with associated cost reductions for monitoring and pore space leasing). However, there was no clear benefit to cumulative stored CO_2, and the benefits afforded by reduction in overall CO_2 plume footprint were offset by the relatively high cost for well installation. Brine extraction with horizontal well CO_2 injection, however, did provide interesting results in benefit to cumulative stored CO_2 mass great enough to bring the margin value between potential 45Q tax credit value and summed costs into competitive standing. This approach, horizontal wells with brine extraction, may be the most suitable and optimal approach if ground surface constraints (i.e., landowner or monitoring considerations) are restrictive to a future potential CCUS project.

The results of this investigation should not be taken to mean that any single approach is the best, most optimal approach for all scenarios. Different geologic assumptions may yield different and more beneficial means to optimize geologic CO_2 storage in different locations. Geologic variables expected to have significant impact on the results include degree of lateral compartmentalization, degree of vertical heterogeneity (e.g., multiple porous and permeable sand benches separated by baffles versus thick, porous, and permeable reservoir intervals), petrophysical characteristics of the interval(s) being targeted, and availability of colocated alternate reservoir intervals which may serve as brine disposal formations. All of these geologic considerations and other nontechnical constraints, including sensitivities at the ground surface, should be considered in determining a means to optimize the geologic storage of CO_2.

A last important result of this investigation is the documentation of an approach to optimize CO_2 storage in testing varying operational techniques through numerical simulation. This approach, through associated thought exercises and technical evaluations, may enable visibility of promising means of cost reduction and overall project value elevation in other locations.

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