Final Report: Co-Optimizing Enhanced Water Recovery and CO₂ Sequestration

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1 Summary

The nexus between water and energy is one of the major challenges for present societies. Emerging constraints on the electricity sector to limit carbon dioxide emissions while reducing the freshwater used during the cooling process demonstrates the intrinsic link in the production and use of modern energy. For example, the emission reduction technology of carbon dioxide (CO₂) capture and storage (CCS), where CO₂ is captured from power plants and injected into deep saline aquifers for storage, can cut CO₂ emissions released to the atmosphere, but increase water demand due to the CO₂ capture process. This would increase the overall demand of water for energy production. The simultaneous extraction and treatment of brine, during CO₂ injection into deep saline aquifers, could provide a usable water source. The use of CO₂ to provide a marketable commodity, treated brine in this case, transitions CCS to CCUS, where the “U” refers to the utilization. This process is also known as CO₂ Enhanced Water Recovery (CO₂-EWR). The overall objective of this research is to improve our understanding of how CO₂-EWR can be co-optimized and the relationships between CO₂ sequestration, water extraction, and costs. These relationships result in tradeoffs between the amount of CO₂ injected into the storage formation and the amount of brine removed, reservoir pressure build up or relief due to injection and extraction, increased storage at the expense of brine treatment costs, and dependence on the value of water and CO₂ emissions through a future CO₂ tax or cap-and-trade mechanism.

The research is comprised of three major parts. After learning of the limitations in the CO₂ Predicting Engineered Natural Systems (CO₂-PENS) and the CO₂-PENS Water Treatment (WTM) models that we planned to implement, we shifted to using a finite element heat and mass transfer (FEHM) code developed by Los Alamos National Laboratory (LANL) to model a saline aquifer with CO₂-EWR. A preexisting mesh for the Rock Springs Uplift (RSU) in Wyoming was used to understand the intricate nature of subsurface pressure management through the injection of CO₂ and extraction of brine. The second part of this research is currently in progress and will use the results of the detailed reservoir model to parameterize a generalized equation, based on the Theis groundwater pumping equation, that
incorporates tradeoffs observed in the reservoir models. This equation will be applied to reservoirs without the need for in-depth subsurface flow modeling, specifically targeting Ohio saline aquifers. The final component of this research will consist of a cost-minimization optimization that will use the parameters of the reservoir model and set costs to the injection and storage of CO\textsubscript{2} as well as the production and treatment of brine from the existing saline aquifer. The goal is to implement this research in the Ohio in order to determine the viability of CO\textsubscript{2}-EWR within the state.

2 Problem and research objectives

2.1 Present and emerging stressors of the energy water nexus

The state of Ohio historically has substantial water resources in both groundwater and surface water. Due to high water demand for various activities through manufacturing plants, agricultural irrigation, and thermoelectric power plants the state is moving towards a “Medium to High” or “High” water risk according to the World Resources Institute (WRI) Aqueduct Water Risk Atlas (WRI n.d.). Energy production through thermoelectric power plants is the highest consumer or freshwater and accounts for 77% of freshwater withdrawals in Ohio (Averyt et al. 2011). This freshwater is used to cool thermoelectric power plants and instills the connection between energy and water in Ohio. With the increase in hydraulic fracturing for unconventional hydrocarbon production, energy extraction is another challenge for water availability within the state. Water, typically from surface water sources, is used during the hydraulic fracturing process as water is injected under high pressure into tight shale seams to produce oil and natural gas. The byproduct of the production, flowback water, is highly contaminated (U.S. EPA 2016) and disposed in deep injection wells, treated in wastewater treatment facilities, or reused for subsequent on-site hydraulic fracturing.

Changing environmental conditions due to climate change is another challenge for Ohio’s water resources (Hartmann, D. L.; Tank, A. M. G. K; Rusticucci 2013). The Midwest is projected to endure more extreme
precipitation events, heat waves, and droughts in the future. This will further increase the impact of water resource availability and its connection to energy exploration and production. The increased demand and variability of water due to potential climate change impacts has already started to change the energy market. Combined changes in temperatures and drought resulted in instances where power plants have shut down because they lacked suitable cooling water (Rogers et al. 2013). These instances are increasing over time, resulting in the increased need to understand how to optimize the connection between water and energy.

One of the intersections between water and energy is the increased need to reduce CO₂ emissions, a principle driver of human-induced climate change (Melillo, Richmond, and Yohe 2014). The reduction of CO₂ emissions through improvements to heat rates will increase the water required for thermoelectric power plant cooling unless a new cooling system is implemented, but installing cooling systems to reduce water use and consumption furthers the level of CO₂ emissions released to the atmosphere (Zhang et al. 2014). As a result, the goal of a decreased carbon emission electricity sector will impact the water consumption per unit of electricity generated.

2.2 CO₂ enhanced water recovery (CO₂-EWR)

Emerging policies and regulations to limit harmful CO₂ emissions released during thermoelectric power production may increase the implementation of CO₂ capture and storage (CCS) operations. CCS captures CO₂ from thermoelectric power plant operations and injects the emissions into deep saline aquifers to store. The CO₂ capture process is water intensive resulting in an increased demand for water during energy production. The simultaneous extraction of brine during CO₂ injection is used to manage the pressure buildup of the aquifer and provide a new source of water. The extracted brine typically has high levels of total dissolved solids (TDS) and can be treated to provide a usable water source through CO₂-EWR. The use of extracted brine makes it a marketable commodity and the process of CO₂-EWR is part of the utilization in CO₂ capture, utilization and storage (CCUS). CO₂-EWR could prove a new source of water in water stressed environments and limit the dependency of energy generation on the current
freshwater supplies. Therefore, the object of this research is to empirically assess how water stress engendered by water requirements of existing thermoelectric power plants in Ohio can be reduced while simultaneously reducing the amount of CO$_2$ emitted to the atmosphere from these power plants while understanding the tradeoffs associated with the combined operation.

3 Subsurface modeling of CO$_2$-EWR

3.1 Methodology

The initial strategy of subsurface reservoir modeling involved a reduced form model, CO$_2$-Predicting Engineered Natural Systems (Stauffer et al. 2009). The model’s capabilities tracked the CO$_2$ sequestration pathway starting at the CO$_2$ source and modeling the transport, injection, storage, and the release or leak of CO$_2$ from the storage reservoir. This model was unable to generate data that depicted the intricate nature and dynamic changes of pressure within the reservoir during CO$_2$ injection and brine extraction. The Finite Element Heat and Mass Transfer (FEHM) Code (https://fehm.lanl.gov), developed by Los Alamos National Laboratory (LANL), was used instead to model CO$_2$ and brine, injection, extraction, and flow within a deep, saline aquifer. The simulation uses the control volume finite element method (CVFE) to simulate multi-fluid, multi-phase heat and mass transfer (Zyvoloski 2009). This detailed subsurface flow equation provided more realistic results of multi-fluid flow behavior within a reservoir needed for this research.

A preexisting mesh for the Rock Springs Uplift (RSU) formation was used as the targeted formation for a series of subsurface model scenarios. The formation was characterized through extensive analysis on a test well and geophysical surveys (Surdam et al. 2013; Surdam and Jiao 2007) and has been the subject of numerous DOE-funded investigations specifically interested in using the formation in Wyoming (DEFE0002142, DE-FE0009202, DE-FE0026159, and DE-FE0023328). Through well log analysis, core data and 3D seismic surveys, a nominal heterogeneous permeability field was developed by LANL researchers using the Los Alamos Grid Toolbox (LaGriT) (http://lagrit.lanl.gov). We used the mesh
because it is still highly transferable to other subsurface flow models and will later be used to parameterize a more generalized equation that can be applied to a broader sample of saline aquifers, including Ohio reservoirs.

The RSU was a 50 by 35 square mile area and characterized as a doubly-plunging anticline formation (Surdam 2013; Surdam and Jiao 2007). The Pennsylvanian Weber Sandstone and Mississippian Madison Limestone layers were previously identified as potential CO₂ storage locations within the RSU. Neither the Weber or Madison formation layers were exposed in the RSU and the nearest surface outcrops were 50 to 100 miles from the margins of the structure while the flanks of the structure were nearly 15,000 feet or more below ground. The formation structure was an ideal fluid trapping formation. The Madison formation was the focus of this study. The cap for the formation consisted of 5,000 feet of low-permeability Cretaceous shale. The Wyoming Oil and Gas Fields Symposium Green River Basin in 1979 averaged the porosity of the Madison formation at approximately 10% with a salinity range from 50,000 to 80,000 ppm. The DOE FutureGen project specified that the Madison could accept approximately 8 billion tons of CO₂.

The modeled mesh consisted of a 6 by 6 km top surface area with the Lower Madison formation at an approximate depth between 2.8 to 4.3 km. It was modeled as a sealed domain, which assumed boundaries are sealed, opposed to an open flow boundary which would have permitted movement of CO₂ or brine outside the boundaries of the mesh. The Lower Madison is the only formation with distinct porosities and permeabilities; all other formations were assigned porosities of 0.01 and permeabilities of 1x10⁻¹⁸ m², which designated them as cap-rock seals during CO₂ injection. The mesh coded a geothermal gradient of 25.5°C/km, average surface temperature of 4.4°C, and fracture gradient of 13.6 kPa/m. The CO₂ injector had an initial pressure of 37 MPa, which indicated a fracture pressure of approximately 90 MPa and an overpressure of 53 MPa.

Scenarios, using the FEHM code, were developed to study the impact of CO₂ injection and brine extraction within the Lower Madison formation. Each scenario involved CO₂ injection at the RSU#1
Well, located in the center of the mesh, and brine extraction at a well approximately 1,042m northeast of the injection well. The CO₂ injection and brine extraction rates were constant during a model run but changed between the different modeled scenarios. All other variables were kept constant in the code. CO₂ injection rates were limited to mass flow rates of 4 kg/s, 8 kg/s, 16 kg/s and 32 kg/s. The brine extraction rate was calculated as the mass equivalent to the CO₂ mass extraction rate and included scenarios with no brine extraction. A total of twenty scenarios were modeled with each CO₂ injection rate paired with each brine extraction rate.

FEHM modeled results included the reservoir pressure and temperature of CO₂ and brine at the base of the injection and extraction wells. The surface pressure of the CO₂ or extracted brine was back calculated using the depth of the well and modeled pressure and temperature in order to determine the surface pressure, temperature, and enthalpy needed to pump CO₂ into the reservoir and extract brine. Assumptions included the use of a typical diameter of 0.41m for the injection and extraction well, pipe friction factor of 0.02, and surface CO₂ temperature of 20°C. The enthalpy was multiplied by the mass flow rate in order to determine the pumping power needed to inject the CO₂. This pumping power will be translated as a cost in order to integrate the impacts of the reservoir in the cost-minimization optimization.

3.2 Principle findings

Figure 1 shows the relationship between total CO₂ injected and brine extracted for the twenty modeled scenarios. The initial expectation was that brine extraction increased the storage capacity of CO₂ within the reservoir. Yet a decreasing linear correlation between the total CO₂ injected and brine extracted resulted in higher CO₂ storage for scenarios with less extraction. The four points on the x-axis are the modeled scenarios with zero brine extraction and were excluded in the plot fitted with the linear relationship. The reservoir behaved differently with exclusive CO₂ injection and the optimization must compare the benefits or costs of using CO₂-EWR by comparing them through separate reservoir analysis. The modeled scenarios with zero brine extraction will be incorporated through a binary variable in the optimization.
The negative linear regression in Figure 1 was associated with the early breakthrough time of brine extraction rates represented in Figure 2. The expected lifetime assumed for this model was twenty years. The model was terminated after the twenty-year time frame or once CO$_2$ breakthrough occurred at the extraction well. The high brine extraction rate pulled CO$_2$ through the reservoir at a faster rate because CO$_2$ could travel with less restriction in empty pore space. This indicated that the brine extraction rate had greater impact on the lifetime of the CO$_2$-EWR system compared to the CO$_2$ injection rate and storage.

**Figure 1: Observed relationship with CO$_2$ injection and brine extraction.** The first plot included all data points. The second plot excluded CO$_2$ injection with zero brine extraction and superimposed a linear relationship which was used in mixed-integer linear optimization.
Figure 2: Breakthrough time associated with modeled reservoir scenarios. The CO₂-EWR system had an expected lifetime of twenty years. The model terminated after twenty years or when CO₂ pore saturation at the extractor exceeded 0.001, indicating CO₂ breakthrough. Colors indicated the rate of CO₂ injection. The observable grouping represented the brine extraction rate. A higher brine extraction rate indicated a faster breakthrough time.

The change in overpressure pressure due to CO₂ storage also displayed a linear trend (Figure 3), with a higher change in pressure from more CO₂ injected. The negative overpressures were scenarios with high brine extraction rates, which indicated that a higher extraction rate of brine did allow more CO₂ to be injected. This indicated that an optimal brine extraction rate will be balanced between opening pore space and decreasing the time before CO₂ breakthrough at the extraction well.

Figure 3: The relationship between reservoir overpressure and total CO₂ injected. Overpressure was limited to 53 MPa. The scenario with 32 kg/s of CO₂ injected and zero brine extraction exceeded this
The negative overpressure consisted of high brine extraction rates that decreased the pressure more significantly than pressure build-up from CO$_2$ injection due to fast breakthrough times.

4 Generalized reservoir equation

4.1 Methodology

The detailed reservoir simulations conducted in the first part of this research is site specific to the RSU formation in Wyoming. The goal of this project is to understand how CO$_2$-EWR can be implemented in various deep, saline aquifers, specifically in Ohio. As a result, the second component, which is currently in progress, will be to develop a generalized reservoir pressure equation that is parameterized by the FEHM modeled results. This equation will incorporate the complex interactions of changes in injection or extraction rates of the reservoir and the resulting change in pressure. The equation can then be used in any reservoir to determine if CO$_2$-EWR is viable.

The generalized equation, will be based on the Theis solution for non-leaky aquifers (Fetter 2001). The general Theis equation is applied to a basic, homogeneous, confined, groundwater aquifer with a transient radial flow.

\[
S \frac{\partial h}{\partial t} = T \left[ \frac{\partial^2 h}{\partial r^2} + \frac{1}{r} \frac{\partial h}{\partial r} \right] + w
\]

Where $S$ is storativity [dimensionless]; $h$ is hydraulic head; $t$ is time [day]; $T$ is transmissivity [m$^2$/day] which assumes flow through an aquifer is horizontal; $r$ is the distance between wells [m]; and $w$ is the Theis well function for nonleaky aquifer [dimensionless]. The initial condition assumed is that the hydraulic head is constant in all directions at any time. Darcy’s law at the well head is used to account for pumping of groundwater.

\[
\lim_{r \to 0} \left( r \frac{\partial h}{\partial r} \right) = \frac{Q}{2\pi T}
\]

Where $Q$ is the pumping rate of the well [m$^3$/day]. The solution for the difference in hydraulic head over time and distance is as follows:
\[ h_0 - h(r, t) = \frac{Q}{4\pi T} \int_0^\infty e^{-u} \frac{du}{u} \]

The limit is the well function is \( w(u) \approx -0.5772 + \ln u + u - \frac{u^2}{2 \cdot 2!} - \frac{u^3}{3 \cdot 3!} - \frac{u^4}{4 \cdot 4!} \ldots \)

Wenzel developed a lookup table for this function (Wenzel 1942) which is incorporated in the final equation.

\[ h_0 - h(r, t) = \frac{Q}{4\pi T} w(u) \]

This general equation is used for modeling simple aquifer systems and requires significant assumptions (Fetter 2001). The following assumptions are maintained in the reservoir modeling of the first part of this research. (1) The aquifer is bounded on the top and bottom by a confining layer. (2) The potentiometric surface of the aquifer is horizontal prior to the start of pumping and not changing with time prior to the start of pumping. As a result, all changes in the position of the potentiometric surface are due to the effect of the pumping well with no source of recharge into the aquifer. (3) All flow is radial toward the well. (4) Groundwater flow is horizontal. (5) Darcy’s law is valid. (6) The pumping well and the observation wells are fully penetrating and screened over the entire thickness of the aquifer with an infinitesimal diameter and 100% efficient. (7) The aquifer is compressible and water is released instantaneously from the aquifer as the head is lowered. (8) The well is pumped at a constant rate. Since the Theis equation is used for a simple aquifer system, several assumptions used in the Theis equation are not valid. The assumption that all geologic formations are horizontal and have infinite horizontal extent will need to be addressed due to the current closed boundaries of the FEHM mesh. Additionally, the aquifer material composition is heterogeneous not homogeneous and the groundwater does not have a constant density and viscosity. Finally, we modeled a multi-fluid system (CO\(_2\) and brine). The original Theis equation does not account for multiple fluids.
The FEHM code was validated by the Theis Equation to compare modeled results and demonstrate that the pressure equations implemented in the code were executing properly. This validation test used a revised Theis Equations from Matthews and Russell (Matthews and Russell 1967).

\[ p(r, t) = p_l - \frac{q\mu}{2\pi k h} \left[ -\frac{1}{2} Ei \left( -\frac{\phi\mu cr^2}{4kt} \right) \right] \]

\[ -Ei(-x) = \int_x^\infty \frac{e^{-u}}{u} du \]

Where \( k \) is the reservoir permeability in the radial direction [m\(^2\)]; \( \phi \) is the reservoir porosity [dimensionless]; \( c \) is the fluid compressibility [MPa\(^{-1}\)]; \( \mu \) is the fluid viscosity [Pa\( \times \)s]; \( h \) is the reservoir thickness [m]; \( \Delta h \) is the vertical node spacing [m]; \( r \) is the radial reservoir length [m]; \( \Delta r \) is the radial node spacing; \( q \) is the flow rate [kg/s]; \( p_l \) is the initial pressure [MPa]; \( T \) is the isothermal temperature [°C]; \( \Delta t \) is the time step [s]; \( t \) is the total elapsed time [day]. Using the Theis equation and the modified version used as a check within the FEHM simulator, we will develop an equation and parameterize it to the FEHM simulation results. The resulting equation will have the capabilities to estimate the viability of CO\(_2\)-EWR in various deep, saline aquifers and remove the current requirement to run a site specific subsurface flow model.

5  Optimization format

5.1  Methodology

The final component of this research involved the use of a cost-minimizing approach to determine how to co-optimize CO\(_2\)-EWR in the most economically stable manner. This optimization will be a mixed-integer linear program that will incorporate the reservoir characteristics and tradeoffs associated with the use of enhanced water recovery and the costs associated with a CCUS operation.

The tradeoffs include both the economic and physical perspectives of the amount of CO\(_2\) injected and stored in a single formation compared to the amount of brine removed. Reservoir model results indicate
total storage is more sensitive to the rate of brine extraction compared to the amount of CO$_2$ stored. Additionally, CO$_2$ injection is costly, and these costs increase as the pressure in the reservoir increases from injection. While the removal of brine from the reservoir is similarly expensive, it could reduce reservoir pressure and increase CO$_2$ storage capacity, if extracted at the optimal rate. Producing brine at a specific pressure could reduce the costs associated with treating water through technologies such as reverse osmosis. This will also depend on the level of TDS in the brine and the degree to which water will be treated. Finally, the value of water and CO$_2$ emissions provide an additional consideration. Water in a water abundant area might not be valued as high as a water stressed region, changing the value of water in the model based on the environment. In addition, CO$_2$ emissions through a cap-and-trade mechanism or tax program could put a value on the cost to emit CO$_2$ and provide more incentive for CCUS operations.

These tradeoffs will be incorporated into a cost minimization optimization in order to determine the viability of CO$_2$-EWR operations in aquifers in Ohio.

The following equation is the initial objective function of the optimization.

$$\min \sum_{t=1}^{t=20} (F + M_C(C_C - P_C) + M_B(C_B - P_B) + M_T(C_T - P_T))$$

This minimization equation is subject to the following constraints.

$C_C$ and $C_{BP} = (\Delta h \times$ electricity conversion factor) in which $\Delta h$ is a function of $M_{BP}$ and $M_C$

These two constraints for the cost to inject CO$_2$ and cost to extract brine through a pump place a value on the tradeoffs associated with changes in the reservoir pressure. The change in enthalpy is calculated using the pressure and temperature from the wells modeled in FEHM. The results are back calculated using the depth of the well to determine the surface pressure, temperature, and enthalpy. The change in enthalpy
from the surface to the base of the well is the pumping power necessary to inject or extract from the reservoir. This power can be converted to a cost with price of electricity needed to run the pump.

\[ M_{BT} \leq M_{BP} \]

The brine treated must be less than or equal to the brine produced.

\[ 0 \leq M_{BP} \leq 41 \text{ kg/s of brine} \]

Highest flow rate established in the system with a 20-year life-time.

\[ 0 \leq M_C \leq 12.3 \text{ Mt CO}_2 \]

The total \( \text{CO}_2 \) injected into the reservoir is limited by the overpressure and the fracture gradient. The injection node, initially 37 MPa, is limited to 90 MPa, resulting in an allowable overpressure of 53 MPa. Based on the linear trend of total \( \text{CO}_2 \) injected compared to reservoir overpressure, for \( \text{CO}_2 \) injection with zero brine extraction, the maximum \( \text{CO}_2 \) injected was limited to the allowable overpressure (Figure 4).

\[
y = 4.1083x + 2.356
\]

\[ R^2 = 0.99972 \]

**Figure 4: Linear trend of \( \text{CO}_2 \) injected excluding brine production.** This linear trend was used to calculate the maximum amount of \( \text{CO}_2 \) that could be injected into the reservoir without exceeding the fracture pressure.
\[ M_C = U_1 (M_C) + U_2 (-3.051M_B + 13.246) \]
\[ U_1 = 1 \text{ when } M_{BP} = 0, \ 0 \text{ otherwise} \]
\[ U_2 = 1 \text{ when } M_{BP} > 0, \ 0 \text{ otherwise} \]

This constraint incorporates a binary variable that will indicate when CO₂-EWR is implemented and when CO₂ is injected with zero brine extraction. This will determine if it is more economical to exclude extraction or include enhanced water recovery.

Below are the variables incorporated into the optimization.

\( t = \text{Time (years)} \)

\( F = \text{Fixed cost of operating CO}_2 \text{ injection and brine production and treatment facility [\$]} \)

\( M_C = \text{Mass of CO}_2 \text{ injected [tonnes]} \)

\( C_C = \text{Variable operating cost of CO}_2 \text{ injection [\$/tonnes CO}_2\text{]} \)

\( P_C = \text{Price of CO}_2 \text{ (i.e. benefit) [\$/tonnes CO}_2\text{]} \)

\( M_B = \text{Mass of brine produced [tonnes]} \)

\( C_B = \text{Variable operating cost of producing brine [\$/tonnes brine produced]} \)

\( P_B = \text{Price of brine extracted [\$/tonnes brine produced]} \)

\( M_T = \text{Mass of brine treated [tonnes]} \)

\( C_T = \text{Variable cost of brine treated [\$/tonnes brine treated]} \)

\( P_T = \text{Price of water [\$/tonne brine treated]} \)

\( m = \text{Mass flow rate} \)

\( \Delta h = \text{Change in enthalpy} \)

### 5.2 CO₂-EWR operational costs and the water treatment model

A key component of this research is the analysis of the operational costs for CO₂-EWR and the brine treatment or disposal costs. These costs will drive the cost minimization optimization presented in the previous section. The fixed cost of the operational CCUS system will be based on previously published...
literature, which focused on relating the geologic heterogeneity to the costs and capacities of brine production (Heath et al. 2012; Kobos et al. 2011). The Integrated Environmental Control Model (http://www.cmu.edu/epp/iecm/) will also be used to estimate variable costs, energy requirements, and water usage for CO₂ capture. This model is based on data provided by U.S. EPA eGRID and U.S. EIA forms.

Brine treatment is highly dependent on water chemistry and the intended water end quality. The Water Treatment Model (WTM) developed by LANL is a system-level, mesoscale analysis module within the CO₂-PENS model that analyzes the feasibility of brine extracted during CO₂-EWR operations (Sullivan et al. 2012, 2013; Sullivan, Chu, and Pawar 2015). The only publicly available version of the WTM includes the cost of treatment, the value of energy recovery for specific treatment technology, and the cost of brine concentrate disposal. The treatment methods in the WTM only include single applications of reverse osmosis, nanofiltration, and thermal desalination. We planned to use the WTM but upon discovering its limitations once we were at LANL and could peer into the code, we realized that we needed to do a more fundamental analysis of treatment methods and costs. That work is ongoing, as is the development of a method to generalize from single observations of water quality in a particular formation within the hydrostratigraphic sequence underlying Ohio. Ultimately, the potential costs of treating this water will be inputs to the cost minimization optimization to determine the value of CO₂-EWR operations provided the benefits of pressure control and increased CO₂ storage in the reservoir.

6 Significance

This research builds and expands on the need to address challenges surrounding the nexus between energy and water. The final product of this research will identify viable locations for CO₂-EWR, the potential costs associated with a location, and optimal injection/production management strategies. Results will be site-specific and further implementation of CO₂-EWR will require in-depth analysis and characterization of specific locations, but this research provides the first step in implementing CO₂-EWR
in a generic and optimal manner. The project could inform present and future water and energy planning, as well as public utilities commissions and regulatory agencies with oversight for subsurface injection and production of fluids by identifying the risks, costs, and benefits associated with the use of CO$_2$-EWR.

7 Publication Citations

Journal Articles:


Presentations at Conferences:


8 Number of Students Supported by the Project

This funding directly supported one Master’s student in the Civil, Environmental, and Geodetic Engineering Graduate Program.
9 Professional Placement of Graduates

The Master’s student who was funded by this grant and conducted this work will defend her Master’s Thesis during the summer of 2017. Her Thesis is in part based on the work that was conducted with this funding. She will continue for her Ph.D. at The Ohio State University once her M.S. is completed.

10 Awards or Achievements

Best Student Poster Award at the CO₂ II: Summit Technology and Opportunities Conference, which was hosted by Engineering Conferences International.

11 Additional Funding

The work for this research was seeded by the Water Resource Center and has expanded as a result of the initial funding. The funded Master’s student was able to leverage additional funding to support this research through the Mickey Leland Energy Fellowship summer program. The student worked at Los Alamos National Laboratory where the student enhanced and expanded the existing collaborations with researchers of similar interests. The student received multiple offers for this internship expressing interest in the research funded by the WRC. These initial interactions have led to opportunities to include places and people we do not have existing collaborations for future research. This work also led to three more inquiries for summer 2017 placement of this M.S. student (at the National Energy Technology Laboratory, U.S. DOE headquarters, and Lawrence Livermore National Laboratory), but she chose to stay at OSU to continue this line of research.

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Integrated CO₂ Storage and Brine Extraction

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Abstract

Carbon dioxide (CO₂) capture, utilization, and storage (CCUS) can reduce CO₂ emissions from fossil fuel power plants by injecting CO₂ into deep saline aquifers for storage. CCUS typically increases reservoir pressure which increases costs, because less CO₂ can be injected, and risks such as induced seismicity. Extracting brine with enhanced water recovery (EWR) from the CO₂ storage reservoir can manage and reduce pressure in the formation, decrease the risks linked to reservoir overpressure (e.g., induced seismicity), increase CO₂ storage capacity, and enable CO₂ plume management. We modeled scenarios of CO₂ injection with EWR into the Rock Springs Uplift (RSU) formation in southwest Wyoming. The Finite Element Heat and Mass Transfer Code (FEHM) was used to model CO₂ injection with brine extraction and the corresponding increase in pressure within the RSU. The model was analyzed for pressure management, CO₂ storage, CO₂ saturation, and brine extraction due to the quantity and location of brine extraction wells. The model limited CO₂ injection to a constant pressure increase of two MPa at the injection well with and without extracting brine at hydrostatic pressure. We found that brine extraction can be used as a technical and cost-effective pressure management strategy to limit reservoir pressure buildup and increase CO₂ storage associated with a single injection well.

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1. Introduction

The reduction of greenhouse gas emissions from fossil fuels and the scarcity of water resources throughout the world are two major challenges for the energy sector [1]. CO₂ capture, utilization, and storage (CCUS) technology can store large quantities of CO₂ currently emitted to the atmosphere. The injection of CO₂ into a saline aquifer for storage increases the reservoir pressure limiting the quantity of CO₂ that can be injected per injection well, prompting an increase in the cost of CCUS and reducing its viability as a CO₂ emission reduction technology. Extracting brine during CCUS with Enhanced Water Recovery (EWR) can actively manage the increase in pressure from CO₂ injection and thus maintain or increase the CO₂ storage capacity, reduce the risks linked to reservoir pressure (e.g., induced seismicity and wellbore leakage), and manage the CO₂ plume [2–5]. This extracted brine could be desalinated for beneficial water use to partially or fully offset the water requirements for CCUS, provide additional water for power plant cooling, or satisfy other societal needs including regional water needs such as agriculture, or production of a marketable such as lithium through mineral extraction. The additional extraction wells and potential desalination and disposal of the extracted brine with EWR could be costly [6,7], but the additional CO₂ storage capacity due to brine extraction and the reduction of reservoir pressure during injection could incentivize EWR.

2. Methods

We considered CCUS with EWR by modeling subsurface flow and simulating pressure fluctuations associated with CO₂ injection and brine extraction in a deep, saline aquifer. We modeled CO₂ injection into a heterogeneous formation within the Rock Springs Uplift (RSU) Mississippian Lower Madison Limestone (Madison) formation in southwestern Wyoming. This developed a realistic representation of the pressure buildup scenarios that will determine how the CO₂ storage reservoir reacts to CO₂ injection and brine extraction and to determine potential pressure management strategies for subsurface CO₂ injection.

The RSU formation in Wyoming is a 50 mi x 35 mi area and characterized as a doubly-plunging anticline, which consists of a fold in the subsurface formation layers that can trap the buoyant, injected CO₂, with more than 10,000 feet of closed structural relief [8]. The Madison is the target CO₂ injection formation and is approximately 250 ft. thick at a depth of 7,500 ft. at the crest of the RSU, with the modelled site location greater than 12,000 ft. below ground surface. The subsurface layer is not exposed on the RSU and the nearest surface outcrop are 50 to 100 miles from the margins of the structure, resulting in the maintenance of the original saline characterizations and elimination of meteoric water recharge. The Madison is overlaid with 5,000 feet of low-permeability Cretaceous shale that can serve as a caprock and can store approximately 8 billion tons of CO₂ [8]. The existing fluid in the Madison formation has a salinity range of 50,000 to 80,000 ppm. Drinking water standards in the U.S. by the Environmental Protection Agency (EPA) limit drinking water sources to salinity levels below 10,000 ppm, which eliminates the Madison as a potential drinking water source (40 U.S. C.F.R.§ 144.3 (2016)). A stratigraphic test well (RSU #1) was drilled and completed in 2011 near the Jim Bridger’s Power Plant, the largest point-source of CO₂ emissions in Wyoming, generating approximately eighteen million tons of CO₂ (MtCO₂) per year [8,9]. The well was plugged and abandoned in October, 2013 [9].

The Finite Element Heat and Mass Transfer (FEHM; https://fehm.lanl.gov) Code is a control volume finite element method that simulates subsurface multi-fluid, multi-phase heat and mass transfer or complex subsurface processes in geologically complex basins [10]. We used a heterogeneous permeability and porosity field of the RSU Lower Madison formation characterized by seismic survey [11]. The mesh, developed using LaGriT (http://lagrit.lanl.gov), consists of a six by six km² area conforming the Darby, Lower Madison, Upper Madison, Amsden, and Weber formations interfaces between depths of 2.8 and 4.3 km. The Madison is the only formation with distinct porosities and permeabilities; all other formations were assigned porosities of 0.01 and permeabilities of 1x10⁻¹⁸ m². The Jim Bridger Fault is located approximately 7,500 feet northeast of the RSU #1.
test well, which was used as a hypothetical injection well, and is incorporated in the model as a sealing fault with zero porosity. We modeled a five-spot injection pattern in a sealed domain, with no flow vertical boundary conditions. The injection well (RSU #1) is located in the center of the pattern in a six by six km² mesh with extraction wells located approximately 1,042 m or 3,420 ft. from RSU #1. We simulated CO₂ injection in RSU #1 for two years at a constant pressure approximately two MPa higher than the hydrostatic pressure at the injection location. The first scenario injected CO₂ into RSU #1 without brine extraction in order to understand how CO₂ initially flowed through the reservoir and the potential interaction with closed boundaries and the Jim Bridger’s Fault. The subsequent simulations incorporated up to four brine extraction wells that are equally spaced around the injection well and produce brine at hydrostatic pressure and were compared to the base scenario that did not have brine extraction.

3. Results

Figure 1(a) and 1(b) show the overpressure and CO₂ saturation after two years of CO₂ injection at RSU #1 without brine extraction.

Fig. 1. Baseline CO₂ injection model simulation injecting CO₂ into the RSU #1 well with no brine production for two years of CO₂ injection. The dashed line indicates the Jim Bridger’s Fault and open circles indicate the locations of wells. (a) Overpressure contours in 0.10 MPa intervals; (b) saturation contours with 10% intervals.

The subsequent simulations included extraction wells to produce brine from the reservoir and maintain hydrostatic pressure. Figures 2–5 show the results of simulations with brine extracted from a single extraction well between the RSU #1 and the Jim Bridger’s Fault line (Figure 2), two extraction wells located north of RSU #1 (Figure 3), three extraction wells (Figure 4), and four extraction wells (Figure 5).

Fig. 2. CO₂ injection into the RSU #1 well with brine extraction from a single well. (a) Overpressure contours in 0.10 MPa intervals; (b) pressure contours of the difference between CO₂ injection simulation without brine extraction (Figure 1a) and CO₂ injection with a single well brine extraction (Figure 2a) in 0.10 MPa intervals; (c) saturation contours with 10% intervals.
**Fig. 3.** CO$_2$ injection into the RSU #1 well with brine extraction from two wells. (a) Overpressure contours in 0.10 MPa intervals; (b) pressure contours of the difference between CO$_2$ injection simulation without brine extraction (Figure 1a) and CO$_2$ injection with brine extraction from two wells (Figure 3a) in 0.10 MPa intervals; (c) saturation contours with 10% intervals.

**Fig. 4.** CO$_2$ injection into the RSU #1 well with brine extraction from three wells. (a) Overpressure contours in 0.10 MPa intervals; (b) pressure contours of the difference between CO$_2$ injection simulation without brine extraction (Figure 1a) and CO$_2$ injection with brine extraction from three wells (Figure 4a) in 0.10 MPa intervals; (c) saturation contours with 10% intervals.

**Fig. 5.** CO$_2$ injection into the RSU #1 well with brine extraction from four wells. (a) Overpressure contours in 0.10 MPa intervals; (b) pressure contours of the difference between CO$_2$ injection simulation without brine extraction (Figure 1a) and CO$_2$ injection with brine extraction from four wells (Figure 5a) in 0.10 MPa intervals; (c) saturation contours with 10% intervals.

By increasing the number of wells and the location of these wells surrounding the RSU #1 CO$_2$ injection well, the overpressure is constrained towards the injection well, which limits the extent to which the CO$_2$ injection increases the pressure in the reservoir. The pressure differences in Figures 2b, 3b, 4b, and 5b indicate that the CO$_2$ pressure within the subsurface can be managed through the additional extraction wells. Figures 1b, 2c, 3c, 4c, and 5c display the saturation of CO$_2$ during the two year CO$_2$ injection cycle. Figure 6 shows the 90% CO$_2$ saturation contours for each scenario and shows the increase in the extent of the CO$_2$ plume.
Figure 6. Single 90% CO₂ saturation contours for all scenarios.

Figure 7 shows a time series plot with the amount of CO₂ (MtCO₂) that is injected over the two years. Figure 8 shows the total mass of brine that was extracted and total mass of CO₂ injected for each scenario. Each additional brine extraction well increases the mass of CO₂ that can be injected into the formation and the amount of brine that can be passively extracted from the formation.

Figure 7. The amount of CO₂ that is injected through RSU#1 well into the Madison formation for each brine extraction scenario.
Fig. 8. Comparison of total mass of CO\textsubscript{2} injected in MtCO\textsubscript{2} and brine extracted in Mt for all scenarios.

4. Conclusions

Brine extraction wells can be used as to manage pressure during CO\textsubscript{2} injection and increase CO\textsubscript{2} storage capacity within the saline aquifer formation. Each additional extraction well relieves pressure build-up while increasing storage capacity for injected CO\textsubscript{2}. CO\textsubscript{2} saturation in the reservoir is calculated for each scenario in order to indicate the extent of the CO\textsubscript{2} plume within the subsurface. Each additional brine extraction well increases the amount of CO\textsubscript{2} that can be injected into the CO\textsubscript{2} storage reservoir for a constant overpressure, using the extent of the 90% CO\textsubscript{2} saturations for each scenario as the metric for the size of the CO\textsubscript{2} plumes. The increase in these plumes as more extraction wells are added suggests that there will be an increase in the area of review, and associated costs, for CO\textsubscript{2} plume and leakage monitoring. Overall, brine extraction wells enable pressure management and provide increased storage capacity for CO\textsubscript{2}, yet additional wells add significant expenses to a CCUS operation. Future work should be directed at understanding the cost-benefit relationship of extracting and managing brine during sequestration operations.

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References


