Parametric Analysis of Technology Costs for CO₂ Storage in Saline Formations

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Abstract

Over the last decade, a substantial amount of economic, engineering, and geoscience research has focused on storing CO₂ in geological formations. Of those different formations, storage in saline water-bearing formations represents the largest storage potential. Fossil fuel-based power plants in the U.S. (coal and natural gas) contributed to 40% of all CO₂ emissions in 2008 and therefore represent an important factor to address atmospheric CO₂ emissions.

The Water, Energy and Carbon Sequestration Simulation Model (WECSsim) was developed to calculate water use and treatment options, CO₂ injection volumes and the levelized cost of energy (LCOE) results for both a *single* representative power plant paired with a saline formation scenario, and a full power plant *fleet*. The details of the analysis presented here broadly demonstrate the sensitivity of CO₂ capture and storage (CCS) costs in geologic saline formations with water extraction, treatment and reuse to changes in the water demands associated with implementing CCS across the power plant fleet (coal and natural gas).

The majority of the coal and natural gas plants in the U.S. have an avoided cost of \$70–200 per tonne of CO₂. Storing 1.0 Gt/yr of the nation's 2.3 Gt/yr total CO₂ emissions returns an avoided (storage) cost of range 79–143 (57–81) \$/tonne (\$US 2013) under various scenarios. These scenarios include allowing competition between power plants for saline formation space to store CO₂, varying the duration of the storage rights, and permitting the extraction of saline waters for treatment.

Under the same 1 Gt/yr captured scenario, the extracted and treated water volumes could offset 12% of the added water demand due to the parasitic energy requirements of CCS at the national level. The cost of water treatment, using a reverse osmosis system, ranges between approximately \$3.20/m³ water (for larger, older coal-fired plants like the San Juan Power Generating Station) and \$2.60/m³ water for natural gas combined cycle plants (such as the Oyster Creek Power Generating Station) with substantial variability in costs based on plant location and design. For context, the levelized cost of energy (LCOE) composition of the pulverized coal-based San Juan Generation Station is 52%, 43% and 5% for the base LCOE, parasitic energy requirements, and water extraction, treatment and utilization costs, respectively. Similarly, for the Oyster Creek natural gas combined cycle plant, these percentages are 64%, 33%, and 2% of the total LCOE, respectively. In both technology cases the parasitic energy requirement costs far outweigh the cost to extract, treat, transport, and utilize saline formation waters.

Additional results indicate that of the 325 saline formations included in the national-level analysis, the Mt. Simon formation has an estimated capacity to hold 53% of all the CO₂ generated from the U.S. coal and natural gas-based power plants without extracting and treating saline water. The St. Peter Sandstone formation could hold 43%, though with saline water extraction and treatment. These results suggest that focusing research, development and demonstration (RD&D) efforts on careful geologic site selection and reducing the parasitic energy penalty, and its respective costs, will help lower the overall cost of CCS across the U.S. coal and natural gas-based power plant fleet.

Keywords

CO₂ capture and storage, energy and water, system dynamics, desalination, power plants, cooling water

1. Introduction

The analysis presented here examines a single representative power plant paired with a saline formation as well as a national saline formation CO₂ capture and storage (CCS) and water extraction and treatment (WET) assessment.¹ Developing a set of analyses that combine CO₂ storage in saline formations, while also extracting and treating the saline waters presents a value-added opportunity to both manage the volume of CO₂ stored within a given geological formation, and utilizing water resources that could help reduce the net costs of CO₂ management by offsetting additional cooling water requirements. Presenting both the single plant and national analyses gives context to the scale and costs associated with a bottom-up approach to developing a national-level CCS initiative. The details of the analysis presented here is to broadly demonstrate the sensitivity of the performance and costs of CO₂ capture and storage in saline formations to three primary operational variables: (1) percentage of CO₂ captured; (2) parasitic energy load; and (3) efficiency of reverse osmosis treatment of extracted formation water. The levelized cost of energy (LCOE) and avoided costs of CCS change depending upon the water demands associated with implementing CCS across the power plant fleet (coal and natural gas), which is driven by: (1) the parasitic energy requirements; (2) the water treatment costs; and (3) how these systems relate to the overall configuration of the CCS system. The avoided costs differ from the standard capture costs because they take into account the additional cost of makeup power required to support the CO₂ capture and operations costs as outlined by Rubin et al. (2015).

Previous analyses have shown that CO₂ capture costs represent the dominant cost in a CCS cost breakdown, which includes a substantial cost variability when accounting for different geological parameters (Klise, et al., 2013; Roach et al., 2010, 2012, 2014; Heath et al., 2012; Kobos et al., 2011, 2012; Tidwell et al., 2011). Costs of the CCS systems may vary dramatically as well. For example, Rubin et al. (2015) indicate the capital cost estimates of CCS increased since the release of the IPCC special report on carbon dioxide capture and storage (IPCC, 2005). Zapp et al. (2015) explore how additional environmental costs, including toxicity impacts on air and water resources, may impact the overall systems costs using a Life-Cycle Assessment (LCA) methodology. Lacy et al. (2015) also explore uses of CO₂ using the LCA approach for enhanced oil recovery with a combination of coal and natural gas plant configurations to maximize performance and minimize costs. Similarly, Grant and Morgan (2014) developed a model that calculates break-even cost analyses for similar scenarios that the Water, Energy and Carbon Sequestration Simulation Model (WECSsim[®]) can and has developed in a joint paper (Nichols et al., 2014) to help understand how models like these compare across their assumptions and underlying mathematical frameworks. Key research in water treatment for extracted waters whether it be from CCS or enhanced oil recovery (EOR) also highlights the cost of concentrate disposal and type of treatment will greatly alter the cost of water treatment (Sullivan et al., 2013; 2015). Therefore, analyzing and highlighting the uncertainty with existing CCS and WET costs are an important research topic when developing the single power plant or national assessments when using the WECSsim tool and other approaches.

¹ Both the CO₂ capture and storage (CCS) and water extraction and treatment (WET) systems include wells for injecting or extracting the products, as well as any other required energy and infrastructure (e.g., pipeline) infrastructure. For brevity, the two systems are simply referred to as CCS and WET.

Applying a parametric scenario analysis framework helps identify the relative influence of key variables that affect the performance and cost aspects of combined CCS and WET systems. With this information, future research, development and demonstration (RD&D) could target the areas within these systems that may increase performance, and decrease costs. The analysis also reveals that the components of a combined CO₂ storage, water extraction and treatment system are affected most by changing the percentage captured from a representative power plant. The analysis also identifies which locations may hold the largest volume of CO₂ at the least cost. For example, the Mt. Simon and St. Peter Sandstone formations may potentially hold approximately half of the CO₂ produced by the U.S. coal and natural gas-based power plants under initial base case assumptions due to their large size and strategic locations.

One of the larger challenges to quantifying the performance and cost drivers in a combined CCS and WET system remains the ability to collect geologic formation data as it relates to CCS and WET volumes. Over the last decade, the U.S. National Energy Technology Laboratory (NETL) developed several regional partnerships on carbon sequestration and subsequent versions of The National Carbon Sequestration Database (NATCARB) to address these issues and provide researchers the means to begin quantifying the scale, scope and costs of national-level CCS and WET (NETL, 2008; Klapperich, 2014). Additional research efforts also began analyzing and discussing the interconnection of water resources on power supplies in the U.S. to understand how stressed water supplies might affect power production in the future (Tidwell et al., 2011, 2013; Gale et al., 2015).

To estimate the interconnection of CCS and WET in this context, the Water, Energy and Carbon Sequestration Simulation Model (WECSsim) (hereinafter WECSsim) was developed to address the performance and cost impacts at both the single power plant and national-scale levels. The initial findings presented in the national analysis indicate under certain conditions, only a portion of the added cooling water demands for CCS can be met by extracting and treating saline formation waters. Similar findings in previous studies (Kobos et al., 2011; Klise et al., 2013) support this finding at the single power plant level. Additionally, the capture and compression of CO₂ remains the largest share of the added costs to CCS systems as reported in Kobos et al. (2011) and that competition for geologically-favorable storage sites will increase the costs to store CO₂ (Roach et al., 2010, 2012, 2015; Kobos et al., 2008, 2011, 2012). The analyses presented here illustrate a more in-depth, parametric analysis for the results' sensitivity to varying assumptions throughout the WECSsim modules.

2. Methods

The WECSsim model builds upon the Environmental Protection Agency's (EPA) national power plant database and a saline water-bearing formations database developed by the National Energy Technology Laboratory (EPA, 2007; NatCarb, 2008). The model was developed using the system dynamics software, Powersim Studio[®]. WECSsim is a national-scale integrated assessment model, which includes interconnected modules specific to power plants, CO₂ capture technologies, CO₂ storage in saline formations, water extraction and treatment technologies, power plant cooling options, and power costs. WECSsim can be used to evaluate a single existing power plant in the U.S., a single hypothetical power plant specified by the user or the

equations with flow rates through well pipelines and the formation (homogenous isotropic porous media with constant pressure boundaries), the injection flow rate and well spacing develops for each power plant and geological formation CCS system scenario at the national level (Roach et al., 2014; Kobos et al., 2014).

Figure 1 also illustrates the basis of the parameter analyses behind three sets of national level scenarios. First, the percentage of CO₂ captured from all of the coal and natural gas-fired power plants varied from the base case's 90% to 70 and 50%. Next, the parasitic energy requirement to power the CCS and WET systems varied from the base case 30%, to potentially more efficient solutions in the future at 20 and 10%. Finally, the water treatment efficiency using reverse osmosis technology in the base case was 54%, and then varied to increase over time or due to new technologies at 64 and then 74% efficiency levels.

One of the core challenges to develop and refine this integrated assessment model is capturing the salient technology-based 'bottom-up' components while maintaining a model with high-level results to address future infrastructure evolution pathways. This is particularly true with developing the detailed CO₂ injection and water extraction subsystems within WECSsim. Injecting CO₂ in a saline formation provides an opportunity to store large volumes of CO₂ while also extracting saline waters to both provide pressure management (as described by Roach et al., 2015) and a value added product to offset some of the water requirements the parasitic power needs require for additional cooling. Additionally, extracting saline water from the target saline storage formation may be an important pore space and pressure management strategy in the reservoir (Buscheck et al., 2012).

The model therefore offers appropriate complexity with a tunable set of assumptions for CO₂ capture technologies, water treatment technologies, well spacing and permeability assumptions, and power plant cooling options. Each of the scenarios and permutations of the input parameters offers a wide set of cost and performance results at the power plant, and national level. The analysis presented here will illustrate the single power plant and national level of detail using a parametric and scenario analysis framework, respectively.

2.2. Electricity, CCS and saline water extraction, transport and treatment cost modeling

The levelized cost of energy and \$/tonne costs for CO₂ are calculated from a combination of resources. The base levelized cost of energy for the power plants, based on fuel type, plant size, cooling type, and adjusted for inflation were adapted from NETL (2007a). The CCS cost components add to this cost using equation 1.

$$C_{CCS} = C_{CO_2 \text{ capture \& compression}} + C_{CO_2 \text{ transportation and injection}} \quad (1)$$

Where C_{CCS} is cost for CO₂ capture, compression, transportation and injection for subsurface storage. The parameters $C_{CO_2 \text{ capture \& compression}}$ and $C_{CO_2 \text{ transportation and injection}}$ represent the costs for the capturing and compressing the CO₂ using an Amine or Selexol base system, and the costs for transporting and injecting CO₂ in a given geological formation. The Amine and Selexol systems costs were adapted from NETL (2007b), and the transportation and injection

costs (including well costs) were adapted from Ogden, 2002.² Equation 2 illustrates the cost components for the water extraction, transportation, treatment and brine disposal.

$$C_{WET} = C_{H_2O\ wells} + C_{H_2O\ pipeline} + C_{H_2O\ treatment} + C_{bcd} \quad (3)$$

Where C_{WET} is the annual cost for water extraction, transportation and treatment. The parameters $C_{H_2O\ wells}$, $C_{H_2O\ pipeline}$, $C_{H_2O\ treatment}$, and C_{bcd} represent the annual costs for the water extraction wellfield, the pipelines for gathering and transporting the saline water, water treatment costs and disposal costs for the bring concentrate, respectively. The water pipelines transport the extracted saline water back to the power plant location to be treated in the base case. The additional, parasitic energy required to power the CCS and WET systems adds to the overall system's costs calculated by WECSsim. The CCS and WET parasitic energy requirements were adapted from NETL (2007a, 2007b) and USBR (2003). These costs include amortized capital costs and annual operations and maintenance costs (O&M) as also described in Roach et al. (2014) as well as Kobos et al., 2010, 2011, 2014 and Klise et al., 2013.³

3. Results

3.1 Individual Power Plant CCS Costs and Performance Drivers

Extracting saline waters while storing CO₂ in geologic saline formations serves two purposes. First, it can decrease the water requirement loads on surface water supplies to cool the make-up power plant, and second it develops a vastly larger storage resource for the CO₂ by managing pressure and space within the formation(s).

Within this combined CCS and water extraction system are a few key cost and performance metrics of interest including LCOE with a CCS and WET system, the flows of CO₂ from the power plant, and size of illustrative geological formations required to store the CO₂. This includes LCOE with a CCS and WET system, the flows of CO₂ from the power plant, and size of illustrative geological formations required to store the CO₂. To illustrate several technology examples with varying sizes and costs, several configurations were reviewed including a large pulverized coal (PC)-fired power plant (the San Juan Generating Station (SJGS), a coal-based integrated gasification combined cycle power plant (IGCC) (the Polk Generating Station), a natural gas combined cycle plant (NGCC) (the Oyster Creek Unit VIII) and a gas turbine plant (the Black Hawk Station). Additionally, the San Juan Generating Station expands the case study power plant from previous regional analyses (Zammit and DiFilippo, 2004; Kobos et al., 2011) and it represents a very large coal-based power plant common to many regions of the United States.

The cost of CCS on coal-fired power plants largely is a function of the plant's technology, size, and percent CO₂ reduction goals. The capture, transportation and storage capital costs are

² In instances where WECSsim calculates distances between the power plant and selected geological storage formation beyond the 100km parameter used in Ogden (2002), and additional 10% of the capital cost was added for booster pumps along the pipeline.

³ The capital costs for the power plants and saline formations use an 8.02%/year amortization factor in the base case.

dominated by the capture component. This is because of the substantial amount of energy required to power the capture technologies, in most cases an amine-based solvent for the power plants, with the exception of a Selexol solvent used for the integrated gasification combined cycle (IGCC) systems.

Table 1

Illustrative power plant configurations for coal and natural gas plants and base case CO₂ capture, water extraction and treatment results.

Input variables	San Juan Power Generating Station (Pulverized Coal), New Mexico	Polk Generating Station (IGCC), Florida	Oyster Creek Unit VIII (NGCC), Texas	Black Hawk Station (Gas Turbine), Texas
Power plant emissions (CO ₂) (Mmt/yr)	11.7	1.2	1.3	0.76
% CO ₂ captured	90	90	90	90
Base water withdrawals; consumption (m ³ /day)	86,307; 67,002	3,407; 2,650	62,081; 3,785	0; 0
Formation depth (feet)	5,887	4,135	4,597	3,066
Formation size (Mmt)	184,192	2,327,119	573,375	122,137
Formation average salinity (TDS)	20	20	16	21
Formation name	San Juan-Entrada	Cedar Keys Lawson	Woodbine Paluxy	Permian - Mississippian
Number of wells	4	4	1	27
Well spacing (km)	8.85	0.97	4.02	1.29
Plant top sink distance (km)	0	0	118.93	141.62
Size (MW); capacity factor	1,848; 0.7698	1,030; 0.1536	498; 0.6743	254; 0.589
Results parameter				
CO ₂ sink longevity (years)	13,740	1,798,560	422,750	136,370
Treated water stream (m ³ /day)	34,069	3,634	4,694	2,763
% of new CCS water demands met	50	161	62	n/a
Cost of extraction and transport of water (\$/m ³) ²	\$3.40	\$1.08	\$2.07	\$5.54
Cost of water treatment and brine concentrate disposal (\$/m ³)	\$3.29	\$2.52	\$1.75	\$5.48
Total Cost of Water Treatment (\$/m ³)	\$6.69	\$3.60	\$3.82	\$11.02
Base Plant Electricity cost (¢/kWh)	7.05	6.3	7.5	11
Full Water treatment costs; water treatment costs only) (¢/kWh)	0.67; 0.16	0.34; 0.16	0.22; 0.08	0.85; 0.27
CCS cost (¢/kWh)	5.98	3.1	4.01	8.10
Total electricity cost (¢/kWh) ¹	13.7	12.5	11.7	20
CO ₂ storage; avoided cost (\$/tonne stored); (\$/tonne avoided)	61; 80	41; 49	91; 109	129; 155

1. For the San Juan Generating Station scenario, the eGRID (2007) database provided the power plant installed MW, water requirements and power plant CO₂ emissions, costs reflect the \$/tonne CO₂ avoided costs, not the \$/tonne stored as well as H₂O extraction, pipeline transport, treatment and brine disposal costs. The reverse

osmosis plant parameters are as follows: 64% efficient, 3.80 kWh/m³ water electricity use, with 20 parts per thousand (ppt) average total dissolved solids (TDS) (NATCARB, 2008) for the extracted water. The base case also assumes the brine concentrate is transported and dumped (no additional treatment system or costs).

Definitions: million metric tons per year (Mmt/yr), integrated gasification combined cycle (IGCC), natural gas combined cycle (NGCC), CO₂ capture and storage (CCS), megawatts (MW), kilowatt-hours (kWh).

2. All costs are in 2013 \$US.

Table 1 illustrates the four different types of power plants represented in the analysis. Of the 1126 power plants modeled, 554 are pulverized coal, 1 is IGCC, 88 are NGCC and 483 are gas turbines. Therefore the majority of the CO₂ and water demands come from the pulverized coal and natural gas turbine power plants to put the results outlined later in this study into perspective. A few notable differences between the four types of power plants include their widely ranging-installed MW capacity ratings and capacity factors. The San Juan pulverized coal generating station, for example, is a large plant at 1,848 installed MW, produces a relatively large amount of absolute CO₂ emissions to manage and store at 11.7 million metrics tons per year, requires a large amount of water (86,307 m³/day of withdrawals with 67,002 m³/day of that consumed), and is considered a baseload plant with a capacity factor of 0.7698. This plant is substantially larger in most aspects to all three of the natural gas power generating technologies, but also is representative of the majority of today's power plants using coal in the U.S. The Polk, Oyster Creek and Black Hawk power plants are substantially smaller at the 1,030, 498 and 254 MW installed rating, respectively. They do, however, produce less CO₂ per MW installed at 1,165, 2,610 and 2,992 tonnes/MW as compared to the San Juan Generating Station with 6,331 tonnes/MW.⁴ The capacity factor varies substantially between the four types of plants. The low capacity factor and modest CO₂ emissions for the natural gas turbines plants, such as with the Black Hawk Station, results in higher total and avoided CO₂ costs because the capital and operations and maintenance costs (O&M) are burdened by a less concentrated CO₂ stream (compared to pulverized coal) per MWh generated under the base case CO₂ capture, water treatment, and storage assumptions. Thus, Table 1 gives an overall view of the installed MW scale, cost and water requirement differences between coal and the numerous natural gas technologies. With this type of information, more targeted RD&D may be used to develop higher performing solvents and systems engineered towards reducing the CO₂ emissions from natural gas power plants. This need may be enhanced by the changes in the U.S. energy portfolio to reduce the number of coal plants due to retirements or recent EPA Mercury and Air Toxics Standards (MACT) regulations and increase the number or utilization of natural gas power plants, along with the lower cost of domestic natural gas (EPA, 2011).

3.2. Parametric Cost and Performance Sensitivity Analysis

Building from the SJGS representative case, three central cost and performance drivers were adjusted to illustrate the sensitivity of the WECSsim model's results to changes in the input parameters. First, the base case for 90% CO₂ captured from the plant was adjusted to 70% and

⁴ The CO₂ produced per installed MW calculation develops as follows: San Juan Generating Station, 11.7 (Mmt/yr) / 1,848 (MW) = 6,331 tonnes CO₂ produced for each MW of installed capacity; Polk Generating Station, 1.2 (Mmt/yr) / 1,030 (MW) = 1,165 (tonnes CO₂/MW); Oyster Creek Unit, 1.3 (Mmt/yr) / 498 (MW) = 2,610 (tonnes/MW); Black Hawk Station, 0.76 (Mmt/yr) / 254 (MW) = 2,992 (tonnes CO₂/MW).

then 50%. Figures 2 and 3 illustrate the range of fifteen resulting cost and performance metrics that reflect these changes in the percentage of CO₂ captured. Figure 3 is an expansion of those results reported in cents/kWh (2013 \$US) to illustrate how system performance characteristics affect costs on several system sub components.

Fig. 2. Effect of varying the percentage of CO₂ captured at the base plant (San Juan Generating Station) from 90% (base case) to 70% and then 50% on the 15 cost and performance metrics of the base plant. Note, the y-axis units are listed next to each specific metric on the x-axis.

Fig. 3. Expanding select cost results from the San Juan Generating Station base case scenario analysis.

Figure 2 illustrates that the Make-up Power LCOE and CO₂ capture and compression (CCC) Costs for Amine Scrubbing have much larger absolute variations. It is important to note the makeup power by itself costs more than the average LCOE for the LCOE prior to CCS and WET. The makeup power therefore increases the average LCOE for the plant due to these new CCS and WET power requirements. Figure 3 illustrates how the costs of H₂O extraction well costs and brine disposal costs are very sensitive to changes in the percent of CO₂ captured when compared to the other CO₂ and H₂O costs represented in Figure 3.

The second key performance and cost driver that was investigated was the parasitic energy required to capture, compress, and inject CO₂ from the base power plant, which was adjusted to represent increasing technological efficiency. The base case is a 30% parasitic energy load for the base power plant. Two subsequent analyses were developed to illustrate overall lower parasitic energy loads of 20% and 10%. Figure 4 illustrates the effects of reducing the parasitic energy load for CCS on the 15 cost and performance metrics of the SJGS base plant, with Figure 5 providing additional detail on those cost effects that cannot be adequately viewed in Figure 4 due to the scale of the y-axis.

Fig. 4. Effect of varying the percentage of parasitic energy load at the base plant (San Juan Generating Station) from 30% (base case) to 20% and then 10% on the 15 cost and performance metrics of the base plant. Note: the y-axis units are listed next to each specific metric on the x-axis.

Fig. 5. Expanding select results from Figure 4 reporting in cents/kWh.

In Figure 5, it is important to highlight the relatively small effects on the majority of the metrics. However, Figure 4 illustrates that costs per tonne of CO₂ (base and avoided) vary the most.

Lastly, the efficiency of the reverse osmosis (RO) system was adjusted to reflect both an improvement in the technology and a representative decrease in RO efficiency (e.g., if local water quality chemistry results in decreased efficiency – this bounds the analysis to a high, low, and medium range to assess the sensitivity of the metrics to this key technology). The energy consumption (kWh/m³ versus feed water TDS (mg/l)) were used to develop the energy and ultimately cost for several types of water treatment configurations that varied largely in the brine disposal method (Kobos et al., 2014; BOR, 2003).⁵ Figures 6 and 7 illustrate the results of the parametric analysis of the cost and performance metrics effects resulting from the variation of the RO efficiency parameter from 64% (base case) to 54% and then 74%.

⁵ Efficiency (eff) calculated as follows based on ranges from Kobos et al., 2014 and BOR, 2003, Figure 7-8; $\text{eff}(\%) = 1.115 - 0.024 * \text{TDS}(\text{ppt})$.

Fig. 6. Effect of varying the percentage of reverse osmosis system efficiency at the base plant (San Juan Generating Station) from 64% (base case) to 54% and then 44% on the 15 cost and performance metrics of the base plant. Note, the y-axis units are listed next to each specific metric on the x-axis.

Fig. 7. Expanding select results from Figure 6 reporting in cents/kWh.

Figure 7 illustrates the effects of changing the efficiency of reverse osmosis systems on the majority of the metrics in both figures except for the brine disposal costs. A key finding from this sensitivity analysis highlights how LCOE is the most sensitive to adjusting the percentage of CO₂ captured from the base plant, then the parasitic energy required for the CCS systems, and the least sensitive to the water treatment technology efficiency. Thus, if one wanted to reduce the overall cost of the CCS and WET system while limiting the investment in research, development, and demonstration (RD&D), it would be most efficient to determine the desired percent CO₂ capture level and then to focus on reducing the capital costs and improving the CO₂ capture, compression and storage performance (Kobos et al., 2011; Herzog, 2011; Rubin et al., 2015). Complementing the power-plant level sensitivity analyses are the results of the WECSsim-based national-level assessment.

3.3 National-Scale CO₂ and Treated H₂O Results

Complementing the power-plant level sensitivity analyses are the WECSsim-based national-level CO₂, water and formation use results. A large number of scenario analyses can lead to a robust portfolio of parametric analyses to reveal the key drivers when looking to minimize CO₂ emissions, water use, costs, and other salient parameters (Kobos et al. 2012). Figure 8 illustrates a screenshot from WECSsim for the base case where all coal and natural gas-fired power plants capture 90% of their initial CO₂ emissions while competing for available highest-performing geological saline formations.

Fig. 8. The national cost curve for CO₂ capture and storage (CCS) illustrating the avoided cost of CO₂ (red line) and the cost of CO₂ capture (blue line). The flatter section of the lines from approximately zero gigatonnes of CO₂ per year (Gtonne/yr) to 1.5 Gtonne/yr largely represent the coal-fired power plants' costs whereas the steeper slope generally represents the natural gas-fired power plants.

Many of the larger formations that are relatively close to the power plants and that have favorable geological parameters (e.g., high permeability, depths that are favorable to reduce drilling costs, and potentially intersecting wells with formations containing water salinities that are within the range of the reverse osmosis water treatment systems, etc.) comprise a large portion of the preferred low-cost CO₂ storage volumes required for the power plants under consideration.⁶ These are represented on the left hand side of Figure 8, where the cost curves have a more shallow slope, and the bulk of the storage targets are matched with coal-fired power plants (generally far lower cost per tonne avoided CO₂ than natural gas). The power plant and geologic formations that represent the points on the right hand side of the curves with a steeper slope represent those power plants with a low capacity factor and largely natural gas-fired power plants. Plants with a low capacity factor do not produce power for a large portion of a given years' time, but maintain similarly high CCS and water treatment capital costs to amortize over the same time frame. The result is a moderate to in some cases, extremely high (over \$500/tonne CO₂ avoided) CCS cost.

⁶ The storage formation analysis represents the composition of all formations as one of four types with accompanying mean porosity and permeability values (Clean sandstone [13%, 316.2 mD], Dirty sandstone [18, 1.0 mD], Carbonate [14.05%, 6.3 mD] or Gulf Coast [8.1%, 6.3 mD]) (Klise et al., 2013). This analysis also divides each formation into three 762m thick depth intervals starting from 762 m of depth, and ending with 3048 m of depth (Roach et al., 2014).

Figure 9 illustrates the comparable added water demands at the national-scale associated with CCS systems across the entire coal and natural gas-fired power plant fleet. In this scenario, all of the power plants compete for CO₂ storage space in the most favorable saline formations to store CO₂ (the saline formations represent those at least 2,500 feet deep and with a TDS of between 10 and 30 ppt according to the base case criteria to maintain more control over the CO₂, and manage the RO treatment costs, respectively.)

Fig. 9. The national-scale water demands due to CO₂ capture and storage when reducing CO₂ emissions (base case is 90% capture of the CO₂ from the base plant, as well as the parasitic energy plant requirements of 25% beyond the base plant's capacity). The new, extracted and treated offset water volumes appear as the top line in this figure and are meant to convey the relative scale differences between them, as well as the water demand with no CCS where the offset would reduce the additional water supply required to meet the new CCS water demand.

Figure 9 illustrates the additional water required to cool the parasitic energy requirements for CCS (lower area in the graph), as well as the amount of water extracted and treated from the WET operation (upper area in the graph). For context, on the scale of these new water source demands and the new water supplies at 1 Gt/yr of CO₂ storage, the new WET-based waters only meet 12% of the new water requirements.

Figure 10 illustrates the full magnitude of the water demands from power plants capturing CO₂ and the saline formations under consideration for CO₂ storage.

Fig. 10. The full national-level results also including the pre-CCS power plant water demands for the base case water demands as well as the CO₂ capture and storage water demands when reducing CO₂ emissions (base case is 90% capture of the CO₂ from the base plant, as well as the parasitic energy plant requirements of 25% beyond the base plant's capacity). The new, extracted and treated offset water volumes appear as the top line in this figure and are meant to convey the relative scale differences between them, the CCS water demand requiring new water source(s) and the water demand with no CCS.

Figure 10 illustrates all of the cooling water requirements at the national level for the base generation, parasitic energy requirements and new WET-based water supplies. These results illustrate how the WET system presents an opportunity to supply new waters for existing plants, yet the volume extracted does not meet the additional demands required for CCS operations.

3.4 Storage Formation Results

Figure 11 illustrates the top five saline formations in terms of their ability to store CO₂ from a national network of power plants (1126 power plants) looking to store CO₂ with the lowest cost. There may be instances where a power plant has other saline formations closer to it, but the overall systems' cost may be lower to transport and store CO₂ in a formation much further away with more favorable geological performance characteristics.

Fig. 11. The top saline formations in the lower 48 states of the U.S. in terms of number of power plants' CO₂ storage potential when including saline formation water extraction treatment and use. Definitions: Midwest Geological Sequestration Consortium (MGSC), sandstone (SS), Midwest Regional Carbon Sequestration Partnership (MRCSP), Southeast Regional Carbon Sequestration Partnership (SECARB).

For additional context, the table embedded within Figure 11 illustrates the top five geologic formations ranked by their ability to store CO₂ from the power plant fleet. For example, the St. Peter Sandstone (SS) can hold the volume equivalent to 288 power plants that represents 26% of the total power plant fleet (1126 power plants total). CO₂ from 60% of the power plant fleet may be stored in these formations.

Figure 12 illustrates the corresponding CO₂ storage potential in terms of Mmt of CO₂ to the number of power plants (26% of all 1126) represented in WECSsim.

Fig. 12. The top saline formations in the lower 48 U.S. states in terms of CO₂ storage potential when including saline formation water extraction treatment and use. Definitions: Midwest Geological Sequestration Consortium (MGSC), sandstone (SS), Southeast Regional Carbon Sequestration Partnership (SECARB), Midwest Regional Carbon Sequestration Partnership (MRCSP).

The table embedded within Figure 12 illustrates the top five geologic formations ranked by their ability to store the most volume of CO₂ from the power plant fleet. The St. Peter Sandstone can hold the volume equivalent from 43% of the power plant fleet's CO₂ emissions. Additionally, 81% of the power plant fleet's CO₂ may be stored in these 5 formations.

These results assume that an equal volume of water will be extracted from the saline formations that are storing CO₂ from these power plants. There may be cases where the added permitting, cost and engineering challenges of a combined CCS and water extraction and treatment system may not be desired. In such cases, only storing CO₂ would change the national results such that the Mt. Simon formation would then be the most favorable formation due to primarily its size and relatively favorable geological characteristics over the St. Peter Sandstone. Additionally, the storage formation-specific information presented in NATCARB was more favorable to contribute supplemental information in the form of probability distribution functions (PDFs) for permeability than were the data representing the saline waters within those formations. The

saline water formation data for the Mt. Simon Sandstone formation was limited to only a few potentially intersecting wells with greater than 40 parts per thousand (ppt) total dissolved solids (TDS) between 1524 and 2286 meters with no potentially intersecting wells beyond 2286 meters (Roach et al., 2014). Additionally, Finley (2005) describes how their analysis of the Mt. Simon formation assumes salinity gradients of 85 ppt at 1,372 m to assumed values of 100 – 250 ppt at 10,000 feet. Thus, WECSsim selects the St. Peter Sandstone (over the Mt. Simon Sandstone) with an average of 23 ppt TDS for the potentially intersecting wells in the case of a full CCS and water extraction and treatment scenario. These results point to the importance of having complete saline formation datasets, and consideration of new technologies that can treat saline waters with total dissolved solids (TDS) levels beyond 30 – 40 ppt TDS.

To illustrate the national-level, base case scenario with only CCS, the results presented in Figures 13 and 14 illustrate how many power plants' CO₂ emissions may be stored in the top twenty formations in terms of volume, and annual CO₂ storage potential, respectively.

Fig. 13. The top saline formations in the lower 48 U.S. states in terms of number of power plants' CO₂ storage potential without extracting saline waters. Definitions: Midwest Geological Sequestration Consortium (MGSC), sandstone (SS), Midwest Regional Carbon Sequestration Partnership (MRCSP), Southeast Regional Carbon Sequestration Partnership (SECARB).

In the national-level scenario without a WET system, WECSsim selects the Mt. Simon Sandstone formation as the primary location for CCS. The Mt. Simon Sandstone can hold the volume equivalent to 296 power plants, representing 27% of the total power plant fleet. CO₂ from 50% of the power plant fleet may be stored in the top five formations illustrated in Figure 13.

Fig. 14. The top saline formations in the lower 48 states of the U.S. in terms of CO₂ storage potential without extracting saline waters. Definitions: Midwest Geological Sequestration Consortium (MGSC), sandstone (SS), Southeast Regional Carbon Sequestration Partnership (SECARB), Midwest Regional Carbon Sequestration Partnership (MRCSP).

Figure 14 illustrates the top five geologic formations ranked by their storage volume potential for the national analysis. In the absence of a WET system, the Mt. Simon Sandstone can hold the volume equivalent to the volume from 53% of the power plant fleet's CO₂ emissions. The top five formations may hold up to 81% of the total CO₂ emissions.

4. Discussion

This paper expands upon the core findings presented in Kobos et al. (2013) by varying the influence of core cost and performance drivers for power plants to match with the 'most viable'

storage space in saline formations. An initial analysis of a few parameters illustrates the relative effects of CCS technology and water extraction and treatment parameters on the overall system's costs relative to the effects of competition. An example scenario where a large coal-fired power plant (San Juan Generating Station) stores its CO₂ in a very close formation gives insight into several cost and performance sensitivities. The results shown in Figures 2–6 illustrate how varying the percentage of CO₂ captured (including its subsystem capital and operations costs) will have the most influence on system costs (LCOE, avoided cost of CO₂), followed by the parasitic energy percentage requirement to power the CO₂ capture, compression and storage equipment, finally followed by the reverse osmosis percentage efficiency.

At the national level, CO₂ capture and storage technologies may revolutionize the CO₂ management portfolio amongst fuel types – principally coal and natural gas technologies. On one hand, CCS promises to reduce CO₂ emissions from coal-fired power plant dramatically, but at a substantial cost penalty relative to the baseline. However, on the other, a transition to replace coal-fired power plants with natural gas ones may also reduce the amount of CO₂ to be sequestered, while also reducing the water required for those power plants. When taking into account the infrastructure that may be required to replace many coal-fired power plants with natural gas plants, a more in-depth analysis is necessary. The CCS options may provide from an engineering perspective, a manageable solution at the surface from the engineered CCS system (e.g., equipment costs may be more understood reasonably well up to a point), but substantial uncertainty still exists in the subsurface geological formation's performance characteristics (Herzog, 2011; Rubin et al., 2015). In terms of storage capacity, the Midwest and southeast have a large portion of the country's coal-fired power plants as well as attractive (from an economic and performance perspective) set of geologic saline formations.

Figure 15 offers a geospatial representation of the base case CO₂ capture rates for coal and natural gas power plants across the U.S. A sizable portion of the large, pulverized coal plants appear in the Midwestern and Southeastern parts of the country. As such, the distances to either the Mt. Simon Sandstone or St. Peter Sandstone are less than for plants in the Western U.S. Not unexpectedly, WECSsim selects the combination of plants to sinks that draw heavily on the capacity and favored geologic criteria of these two formations for a large portion of the CO₂ stored for the U.S.

Fig. 15. Power plant CO₂ capture rates (Mmt/yr CO₂), base case scenario. The circles represent a scaled representation of specific power plants, and their CO₂ emissions. The larger the circle, the larger the single power plant emits (e.g., a large, pulverized coal plant) compared to a smaller natural gas-powered plant.

The CCS results from WECSsim compared favorably to those of the CO₂ Saline Storage Cost Model (SSCM) developed by the National Energy Technology Laboratory (NETL). The key findings from both modeling approaches resulting in the models choosing CO₂ storage sites that had more favorable geological considerations (e.g., volume to store CO₂) over lower costs or shorter transportation distances via pipelines (Nichols et al., 2014).

A key requirement to consider for future work would be the engineering and cost impacts of including the requirements of EPA's Class VI injection well regulations for the CO₂ injection wells. These regulations will require up front characterization of a storage site, extensive monitoring of the CO₂ plume and pressure front during injection and monitoring of the CO₂ plume, and pressure situation after injection ends. The results presented in this study do not include these costs or other financial aspects throughout the lifetime of the project given they are likely to be extremely site specific, though recognized as important to include as CCS technology deployment extends to new areas of the country.

5. Summary and Conclusions

The initial findings suggest the percentage of CO₂ emissions could be stored in various formations from power plants throughout the U.S. A large effort was made to enhance the NATCARB geological database to assure a reasonable set of assumptions underlie the geological parameters used throughout the WECSsim analysis. The analysis presented here illustrates just a few representative national and regional CCS and WET development scenarios. A challenge for further implementing CCS at either of these scales will be to more fully characterize the site-specific aspects of a combined power plant, CCS and WET system. The value of WECSsim, in this regard, is to serve as an initial screening tool to identify which formations may provide the largest volume to store CO₂, what the limits of salinity may be to treat to need for coal and

natural gas power plants, and appraise the costs of each of these components as it relates to the levelized cost of energy.

At the individual plant level, understanding which site may compete more favorably given their power plant and geologic sink characteristics will also be very important when identifying potential project sites. The results presented in Table 1 illustrate several main points. First, the power plant to geologic sink characteristics will drive the CCS and WET performance and cost requirements. The pulverized coal plant, for example, is substantially larger in generating capacity, CO₂ emissions and water requirements. While the San Juan Generating Station may have lower CCS and avoided CO₂ storage costs, the large scale operations of the plant suggest a large geologic formation will be required to store its CO₂, and the water extracted and treated may not meet the parasitic energy cooling requirements – presenting a challenge to supply the remaining 50% of new water requirements. The natural gas combined cycle representative plant (Oyster Creek) example indicates LCOE may not be as high as with the pulverized coal example, and the water needs for the CCS new water demands may be offset (62%) but still not completely met. The IGCC example system requires less cooling water than NGCC, and hence may offset its new water demands, whereas the Gas Turbine example does not require cooling water. These highlights suggest that NGCC and IGCC are more efficient from a water use perspective than this particular pulverized coal plant, and have lower LCOE with CO₂ capture technologies. However, the \$/tonne of CO₂ stored remains higher for NGCC when compared to pulverized coal or IGCC.

At the national level, varying the percentage captured of power plants' CO₂ emissions from 90 to 50% reduces the total LCOE (that includes CCS and the associated WET systems) the most dramatically from approximately 13.7 cents/kWh to 10.2 cents/kWh compared to varying the efficiency percentage of the parasitic energy requirements or the water treatment efficiency. Changing the base case parasitic energy requirement from 30 to 10% reduces this LCOE to 10.7 cent/kWh. Using reverse osmosis as an initial water treatment technology indicates that within, increasing the efficiency of the technology from 54 to 74% does not change the total LCOE from 13.7 cents/kWh (for within the 10 – 30 ppt TDS levels of salinity). The varying effects of these three types of parametric sensitivity analyses highlights the key areas where new technological improvements may translate into cost savings across the larger WECSsim system.

The results at the national level illustrated in Figures 9 and 10 indicate the volume of water extracted and treated from storing CO₂ in saline formations does not make up for the cooling water requirements of the CCS system. Under the base case scenario, at 1 Gt/yr of CO₂ storage, the new water supplies only meet 12% of the new CCS-system water requirements. This suggests under these power plant and geologic formation assumptions, the tradeoff to decreasing CO₂ emissions can be an increase in the water requirements at the national level.

Figures 11 through 14 further illustrate the site-specific nature of the geologic formation assumptions including CO₂ storage volumes. For example, the St. Peter Sandstone and the Mt. Simon formation can hold the CO₂ equivalent of 288 or 296 out of the nation's 1126 power plants, respectively when either not accounting for or including WET systems. This further suggests large saline formations that have favorable geologic performance characteristics (or more fully detailed data) could be chosen to store a sizable portion of the nation's CO₂.

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