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A Geospatial Cost Comparison of CO_2 Plume Geothermal (CPG) Power and Geologic CO_2 Storage

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CO_2 Plume Geothermal (CPG) power plants can use gigatonne-levels of CO_2 sequestration to generate electricity, but it is unknown if the resources that support low-cost CPG power align with the resources that support low-cost CO_2 sequestration. Here, we estimate and compare the geospatially-distributed cost of CPG and CO_2 storage across a portion of North America. We find that the locations with lowest-cost CO_2 storage are different than the locations with lowest-cost CPG. There are also locations with low-cost CO_2 storage (<\$5/tCO_2) that do not support CPG power generation due to insufficient reservoir transmissivity or temperature. Thus, CPG development may require electricity prices that are greater than the levelized cost of electricity (LCOE) to offset the increased cost of sequestration. We introduce the "Additional Cost of Electricity (ACOE)" metric to account for this cost and add it to the LCOE to calculate breakeven electricity prices that are required for CPG development. We find that breakeven prices are lower when new CO_2 injection wells are drilled specifically for CPG (i.e., "greenfield" CPG development) compared to if only existing CO_2 sequestration injection wells are used (i.e., "brownfield" CPG development). This is because comparatively few wells are needed for sequestration-only, and the increased power capacity from having more CPG wells outweighs the increased costs from more drilling. We also find that sequestered CO_2 could be used to approximately triple the United States geothermal electricity power capacity via a single CPG "sweet spot" in South Dakota, but that breakeven electricity price for this development is on the order of \$200/MW_eh.

Keywords: sedimentary basin geothermal, SCO2T, CCS, site screening, genGEO, CPG

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1 INTRODUCTION

1.1 Background and Motivation

Geologic CO_2 sequestration is the injection of CO_2 into the subsurface to permanently isolate it from the atmosphere, and is part of CO_2 capture and storage (CCS), where CO_2 is captured from large point sources or the air directly, possibly transported, and then injected underground (Bui et al., 2018; IPCC, 2005). Geologic CO_2 storage is essential for meeting climate goals. The Intergovernmental Panel on Climate Change suggests that limiting climate warming to 1.5°C or 2°C could require injecting up to ~1,200 gigatonnes of CO_2 (GtCO_2) by 2,100 (Rogelj et al., 2018), which may require injecting up to ~70 GtCO_2/yr (Zahasky and Krevor, 2020). For reference, global CCS infrastructure only supported injecting ~40 million tonnes of CO_2 per year (40 MtCO_2/yr, or 0.04 GtCO_2/yr) in 2020 (Global CCS Institute, 2020). In the United States, the Princeton Net Zero

America study suggests that injecting between 0.9 and 1.7 $GtCO_2$/yr is required to transition the country to a net-zero emission economy by 2050, which is 1.3–2.4 times larger than the country's oil production on a volume equivalent basis and entails drilling thousands of CO_2 injection wells across the country (Larson et al., 2020; Jenkins et al., 2021).

While sequestering CO_2 across the United States and the world is necessary to address climate change, deciding where to inject the CO_2 is not simple. Saline aquifers in sedimentary basins are the primary geologic formations considered for CO_2 sequestration and the cost and capacity of a given CO_2 storage site are dependent on the geology of these aquifers, which is inherently uncertain (Anderson, 2017; Middleton et al., 2020b; Vikara et al., 2017). First, even after a potential site has been thoroughly characterized, which requires substantial time and investment in itself, the CO_2 injectivity and capacity of the site, and thus its cost, is largely unknown until at-scale CO_2 injection starts (Eiken et al., 2011). Second, while sedimentary basins are ubiquitous (e.g., underlying approximately half of North America (NETL, 2015)), the geology of these formations also varies geospatially, so the cost and capacity of CO_2 sequestration can change from one location to another (Ogland-Hand et al., 2022b). Third, knowledge of the lowest-cost CO_2 sequestration locations alone is insufficient because the CO_2 sources, CO_2 transportation network, and existing energy infrastructure can all influence the targeted sequestration location (Hannon and Esposito, 2015; Grant et al., 2018; Middleton and Yaw, 2018). For example, it is possible that the lowest-cost CO_2 sequestration site may not be the least-cost location to target when also considering the location of CO_2 sources and the transportation infrastructure required to connect them together. Or, if the CO_2 source is an electric power plant, it is also possible that injecting CO_2 at more expensive sequestration sites is optimal if it avoids building new electricity transmission infrastructure (Ogland-Hand et al., 2022a).

In addition to these previously studied and more well-known considerations, the location for CO_2 storage may also be influenced by the option of using the sequestered CO_2 to generate electricity with a CO_2 Plume Geothermal (CPG) power plant. In CPG power plants, geologically stored CO_2 is used as a geothermal heat extraction fluid: a portion of the sequestered CO_2 is intentionally produced back to the surface with a production well, expanded through a turbine to generate electricity, cooled and condensed, then re-injected with an injection well so none of the CO_2 is released back to the atmosphere (Adams et al., 2015). While water is traditionally used to extract geothermal heat for power production, our prior work demonstrated that using CO_2 results in more geothermal heat extracted and in lower-cost electricity generation (Adams et al., 2021, 2015). As a consequence, it is possible that CPG technology could expand the geothermal power resource base to include sedimentary basins, which have historically been excluded from geothermal power assessments (Adams et al., 2021; Van Brummen et al., 2022).

In addition to its potential to expand the geothermal resource base, CPG is also the only CO_2 utilization technology we are aware of that can leverage gigatonne-levels of CO_2 sequestration required to meet climate goals. For example, our prior work suggests that the CO_2 requirements of CPG are on the order of 2 to 7 $MtCO_2/MW_e$, depending on the geology of the CO_2 sequestration site (Adams et al., 2021). Thus, depending on the geology, the suggested 0.9 to 1.7 $GtCO_2$/yr from the Princeton Net Zero America may support between 1.2 and 7.8 GW_e/yr of CPG power capacity. For reference, the total installed capacity of geothermal power plants across the entire United States is ~3.8 GW_e (EIA, 2020). Consequently, there could be substantial value for sequestration projects to consider the potential for CPG when deciding where to inject CO_2, especially because dispatchable low-carbon power (i.e., geothermal plants) has been shown to reduce the cost of decarbonizing electricity (Sepulveda et al., 2018; Bistline and Blanford, 2020). Despite this possibility, how the potential for CPG power generation may affect the location of CO_2 sequestration has yet to be quantitatively investigated.

1.2 Contributions of This Paper

In this paper, we estimate the geospatial cost of CPG power and compare it to the geospatial cost of CO_2 storage. This is novel for multiple reasons. For one, it is the first study to estimate the geospatial cost of CPG power and present fine-resolution supply curves for CPG power plants. This builds upon our prior work that presented lower-resolution capacity and cost estimates for CPG power plants (Adams et al., 2021). Our higher-resolution investigation allows us to answer, for example, if CPG power plants can be deployed across an entire sedimentary basin. Second, by comparing the geospatial costs of CPG and CO_2 storage to one another, we are the first to investigate if the low-cost locations for CPG align with the low-cost locations for CO_2 storage. This knowledge could have substantial implications for the future of both CPG and CCS. Lastly, our study is also the first to quantify the power implications of using pre-existing CO_2 storage injection wells in CPG power plants (i.e., "brownfield" development) instead of drilling new injection wells (i.e., "greenfield" development). Our prior work demonstrated that brownfield development reduced the cost of CPG power plants compared to greenfield development, but did not investigate the impact of constraining the number of CPG power plants to the number of CO_2 injection wells (Adams et al., 2021).

2 MATERIALS AND METHODS

Our methodology consists of integrating pre-existing data and tools over three tasks:

1) Enhancing the professional version of the Sequestration of CO_2 Tool [SCO_2T^{PRO} (Middleton et al., 2020a, 2020b; Ogland-Hand et al., 2022b), referred to as SCO_2T in this paper] to estimate the cost of CPG and the power that a single CPG power plant could generate as a function of the five geologic properties that define a saline aquifer: geothermal temperature gradient, permeability, net thickness, porosity, and depth (or pressure). **Section 2.1** further describes these enhancements. **Section 2.1** also describes the CO_2 storage site

design conditions (e.g., number of monitoring wells per injection well) assumed within SCO_2T for this study.

2) Applying SCO_2T to a portion of the NATCARB dataset to determine the geospatial variability in the cost and capacity of geologic CO_2 storage and of CPG power plants at a fine resolution. **Section 2.2** describes this dataset and how it was used in this study.
3) Using the output data from SCO_2T to estimate a) the levelized cost of electricity (LCOE) of CPG power; b) the total number of CPG power plants that a given area, volume of sequestered CO_2, and CO_2 injection wells could support, and c) the breakeven price of electricity needed to inject CO_2 in the lowest-cost location for CPG compared to the lowest-cost location for CO_2 storage. **Section 2.3** describes these calculations.

2.1 Enhancements Made to SCO_2T and Input Assumptions

SCO_2T is an Excel-based tool that replicates full-physics dynamic reservoir simulations via reduced-order models to estimate the capacity and cost of geologic CO_2 storage given five primary geologic properties (Chen et al., 2020; Middleton et al., 2020a; Middleton et al., 2020b; Ogland-Hand et al., 2022a; Ogland-Hand et al., 2022b). As such, when applied to an input dataset of geospatial geologic properties, SCO_2T can be used to estimate the geospatially-distributed cost and capacity of CO_2 storage. **Section 2.1.1** describes how we enhanced SCO_2T to also estimate the geospatial cost and capacity of CPG when applied to an input dataset of geospatial geologic properties.

Additionally, our prior work demonstrates that the site-level design factors of CO_2 storage sites (e.g., number of monitoring wells drilled per injection well) can change the cost of geologic CO_2 storage by a similar order of magnitude as geology (Ogland-Hand et al., 2022a). These site-level design factors are specified in SCO_2T as user inputs. **Section 2.1.2** describes the input assumptions used for this study.

2.1.1 Enhancements

Our prior work used the generalizable GEOthermal techno-economic simulator (genGEO) to estimate the cost and capacity of a CPG power plant over a large parameter space of reservoir depths, geothermal temperature gradients, and reservoir transmissivities (Adams et al., 2021). The reservoir transmissivity is the product of the reservoir thickness and permeability. This genGEO output data, which is publicly available on GitHub (https://github.com/GEG-ETHZ/genGEO), includes the specific capital cost of brownfield and greenfield CPG power plants [$\$/kW_e$] and the power generated by a single CPG power plant [MW_e] for each combination of geologic conditions across the parameter space. In our prior work, we used the subset of this output data with a 35°C/km temperature gradient as a look-up table to estimate the specific cost and power capacity of a CPG power plant using 2-D linear interpolation (Adams et al., 2021). Here we follow the same approach: we create an Excel MACRO within SCO_2T that uses 3-D linear interpolation (across depth, transmissivity, *and* temperature gradient) to estimate the generation capacity of a single CPG power plant and the specific capital cost for any combination of geologic input data. As such, we improve upon our prior work by no longer assuming a constant temperature gradient and embedding this interpolation within SCO_2T directly.

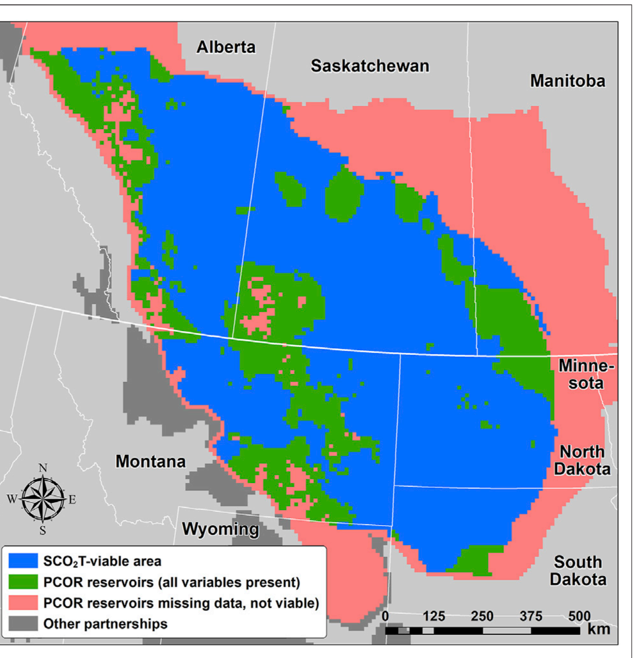

FIGURE 1 | Geographic Area Used in This Study. Image taken from Ogland-Hand et al. (2022b).

The genGEO output data is in 2019 dollars and we use the dollar year adjustment factors from the Regional Energy Deployment System model to adjust to 2017 dollars, which are currently used in SCO_2T (NREL, 2019).

2.1.2 Input Assumptions

In this study, we use the baseline SCO_2T input assumptions that our prior work suggests provides representative costs across different scenarios of site-level designs (Ogland-Hand et al., 2022a), with thirteen exceptions:

1) A square well pattern
2) CO_2 injection well diameter of 0.41 m
3) One CO_2 injection well per site
4) A maximum of 1 $MtCO_2$/yr injected per site
5) Zero brine production wells per site
6) One CO_2 injection pump per well
7) Zero stratigraphic wells/site
8) Zero old oil and gas wells per site that must be plugged prior to CO_2 injection
9) Zero old water drinking wells that need to be plugged prior to injection
10) Zero back-up CO_2 injection wells drilled per site
11) Zero above-zone monitoring wells drilled per injection well

12) One in-zone monitoring well drilled per injection well
13) Zero drinking water monitoring wells drilled per injection well

We change these thirteen input assumptions from the SCO_2T baseline scenario to align with the assumptions embedded within the genGEO data. Future work could improve how genGEO is integrated within SCO_2T.

2.2 Data

As shown in **Figure 1**, we use the portion of the NATCARB dataset (NETL, 2015) that was collected and generated by the Plains CO_2 Reduction (PCOR) partnership (PCOR, 2021). While the NATCARB dataset spans the entirety of the United States, our prior work demonstrates that the PCOR data is the only subset that is viable for SCO_2T because it is the only portion that reports a permeability, porosity, temperature, depth, and thickness within the SCO_2T input geology range (Ogland-Hand et al., 2022b). In other words, in this study, we apply SCO_2T to all saline aquifers across the United States that can be defined from a single publicly available dataset. The NATCARB database divides the country into 10 × 10 km grid cells, thus using this data means our results have a 10 × 10 km resolution.

The NATCARB dataset provides gross thickness data for each grid cell, but SCO_2T is an effective parameter tool. As a result, we use three net-to-gross ratio assumptions to convert gross thickness to net (i.e., effective) thicknesses: 10%, 20%, and 60%. These ratios are the approximate p5, p50, and p95 net-to-gross ratios, respectively, from the USGS National Assessment of Geologic Carbon Dioxide Storage Resources for the subsurface formations in PCOR (USGS, 2013). In prior work, we used only the p50 value as the net-to-gross ratio instead of multiple scenarios (Ogland-Hand et al., 2022b). Here we use scenarios because 1) holding everything else constant, the cost of CPG power generation and the cost of CO_2 storage both decrease with increasing reservoir thickness (i.e., with increasing net-to-gross ratio) (Middleton et al., 2020b; Adams et al., 2021), but 2) it has yet to be studied if the magnitude of this sensitivity is the same for CPG power generation and CO_2 storage.

2.3 Using SCO_2T Output Data

2.3.1 Levelized Cost of Electricity

Following our prior work, we estimate the LCOE for CPG power using **Eq. 1** (Adams et al., 2021).

$$LCOE = SpCC * \frac{CRF + F_{O\&M}}{CF * 8760} \quad (1)$$

Where SpCC is the specific capital cost of the CPG power plant and is an output of SCO_2T [$/MW$_e$]; CRF is the capital recovery factor and is an input assumption that is a function of the interest rate and the number of years over which the power plant is financed [%/yr]; $F_{O\&M}$ is the fraction of capital cost that is spent annually on operation and maintenance and is an input assumption [%/yr]; CF is the annual capacity factor of the CPG power plant and is an input assumption [%]; and 8,760 is the number of hours in a year [hr/yr]. Our prior work demonstrated that the financing assumptions can change the LCOE of a power plant by upwards of 40% (Adams et al., 2021), so in this study, we use three different scenarios of financing assumptions (**Table 1**).

TABLE 1 | Financing scenarios assumptions.

Financing assumption	$LCOE_{CCS}$	$LCOE_{Ormat}$	$LCOE_{Lazard}$
CRF [%/yr]	5.2	6.2	10
$F_{O\&M}$ [%/yr]	5.5	5.5	4.5
CF [%]	95	95	85

The $LCOE_{CCS}$ scenario uses the same CRF used to estimate the annualized cost of CO_2 storage within SCO_2T. As a result, this scenario can be thought of as representative if the CPG power plant owners receive a similar cost of debt as the CO_2 storage operators receive. The $LCOE_{Ormat}$ scenario uses the financing assumptions from Ormat, which is a major geothermal power plant company (Adams et al., 2021). This scenario is representative of financing conditions of the geothermal power industry. Lastly, $LCOE_{Lazard}$ scenario uses the financing assumptions used by Lazard when providing their annual LCOE reports that compare the cost of different electricity generation technologies (Lazard, 2019).

2.3.2 Total Number of CPG Power Plants

In prior work, we scaled up the power capacity of a single CPG power plant across sedimentary basins using 1) the CO_2 storage capacity of the basin and 2) the amount of CO_2 suggested to be required for a single CPG power plant (Adams et al., 2021). Here, we improve on this methodology by using SCO_2T outputs directly. SCO_2T estimates the CO_2 storage capacity across a given area (e.g., a 10 × 10 km NATCARB grid cell) by estimating the CO_2 plume area of a single CO_2 injection well and then increasing the number of injection wells based on the number of plumes that fit in the given area (100 km^2 for NATCARB grid cells). As a result, we limit the number of CPG power plants at a brownfield site to the number of CO_2 injection wells that SCO_2T suggests could be drilled for storing CO_2. For greenfield CPG sites, we set the number of CPG power plants to be 78.5 in every NATCARB grid cell because 1) given the methodology of SCO_2T, the CO_2 plume area across all wells is 78.5% of the user-defined area (e.g., 78.5 km^2 for a NATCARB grid cell) as a circle with a diameter equal to the side of a square will encompass 78.5% of the area of the square; and 2) the current CPG power plant design assumes a 1 km^2/power plant footprint (Adams et al., 2021).

2.3.3 Breakeven Electricity Price

For this study, we define the breakeven electricity price as the price of electricity that is required to financially breakeven when CO_2 is stored in a location with the least expensive CPG power compared to using the location with the least expensive CO_2 storage. The breakeven electricity price is defined as **Eq. 3**, which is derived by equating revenue from electricity sales (left side of

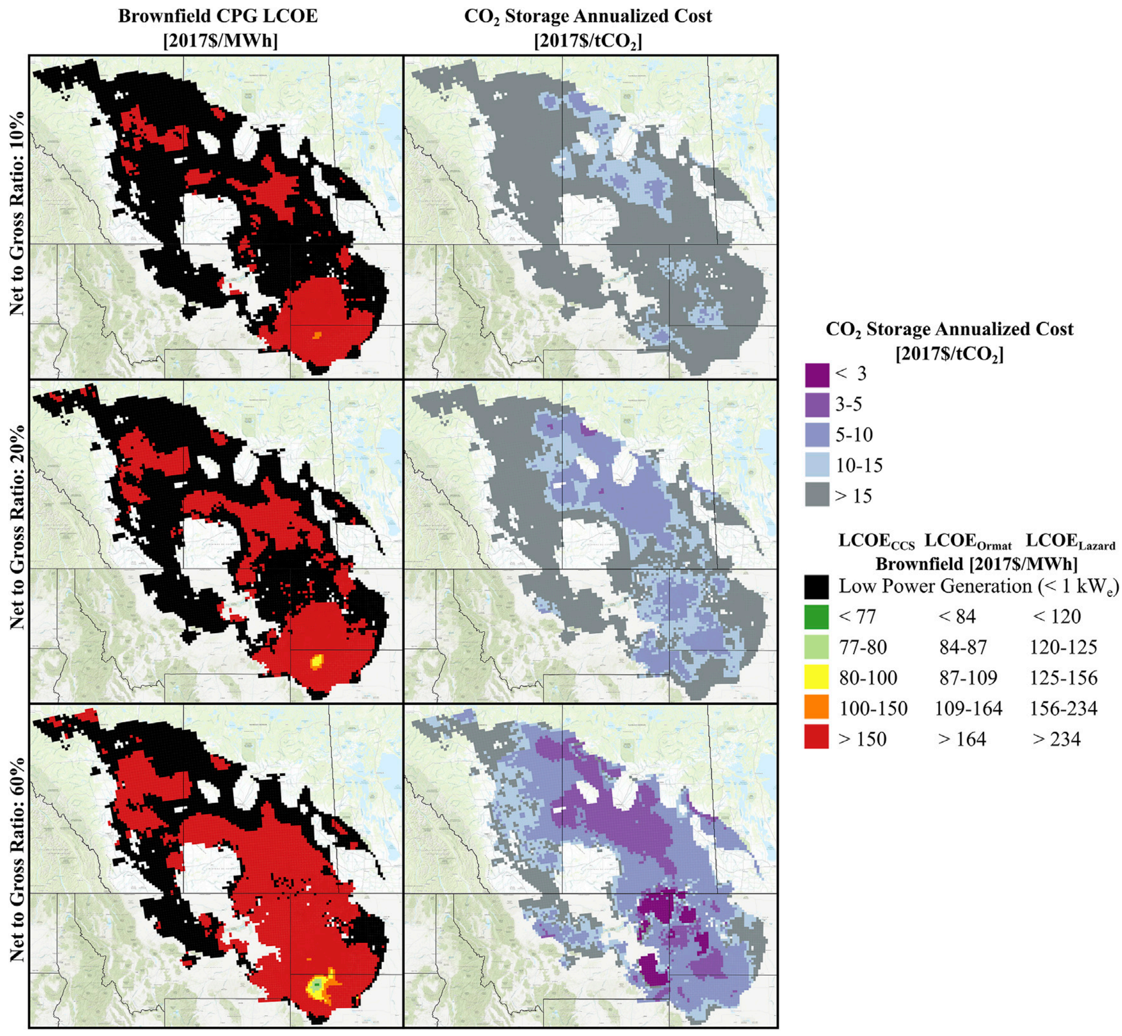

FIGURE 2 | Geospatial Variability in Cost of CO_2 Plume Geothermal Power Plants and CO_2 Storage Across the PCOR Area. For CPG maps (left column), low power generation areas (black grid cells) are locations in which the power generation from one CPG power plant was less than 1 kW_e.

Eq. 2 to the cost of generating electricity and storing CO_2 (right side of **Eq. 2**):

$$P_{Breakeven} * C * 8760 * CF = LCOE * C * 8760 * CF + \alpha * \beta \quad (2)$$

$$P_{Breakeven} = LCOE + \frac{\alpha * \beta}{C * 8760 * CF} \quad (3)$$

Where $P_{Breakeven}$ is the breakeven electricity price [$/MW$_e$h]; C is the generation capacity of the CPG power plants [MW_e]; 8,760 is the number of hours in a year; α is the quantity of CO_2 stored [tCO_2]; and β is the change in cost of CO_2 storage [$/$tCO_2$] between the location the least expensive CPG power compared to the location with the least expensive CO_2 storage and is calculated by subtracting the CPG power supply curve from the geologic CO_2 storage supply curve.

Because **Eq. 3** shows that the breakeven electricity price is the LCOE plus an additional factor, we simplify the breakeven price equation to **Eq. 5** by defining the additional factor (**Eq. 4**):

$$ACOE = \frac{\alpha * \beta}{C * 8760 * CF} \quad (4)$$

$$P_{Breakeven} = LCOE + ACOE \quad (5)$$

Where the ACOE is the "Additional Cost of Electricity (ACOE)" and represents the change in cost of CO_2 storage. As shown in **Eq. 5**, the breakeven electricity price would be equal to the LCOE in situations where the ACOE was zero [i.e., situations where there was no change in the cost of CO_2 storage (i.e., $\beta = 0$)].

For this study, we calculate the breakeven electricity price for three different scenarios of capacity factors for both greenfield and brownfield CPG development: 95%, 50%, and 30%. It is unknown what the capacity factor of dispatchable low-carbon power plants will be in the future, and we use these three scenarios to investigate a variety of possibilities. Across all three of these capacity factor scenarios, the LCOE is calculated using the CRF and $F_{O\&M}$ from the $LCOE_{CCS}$ scenario (**Table 1**).

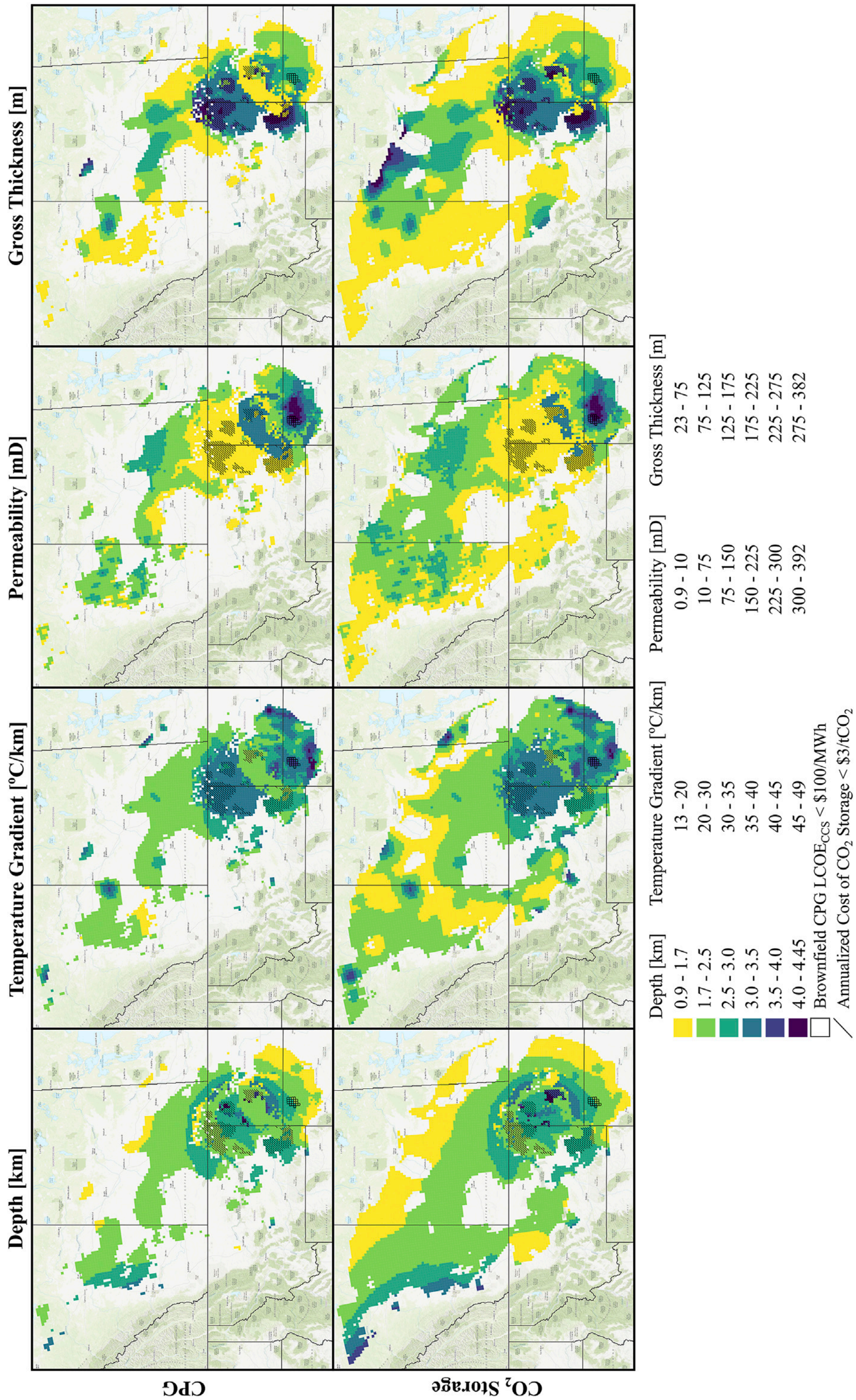

FIGURE 3 | Geologic Conditions That Yield the Lowest Cost When the Net-to-Gross Ratio is 60%. For CPG (top row of maps), the geology of grid cells with low power generation (black area in **Figure 2**) are not plotted.

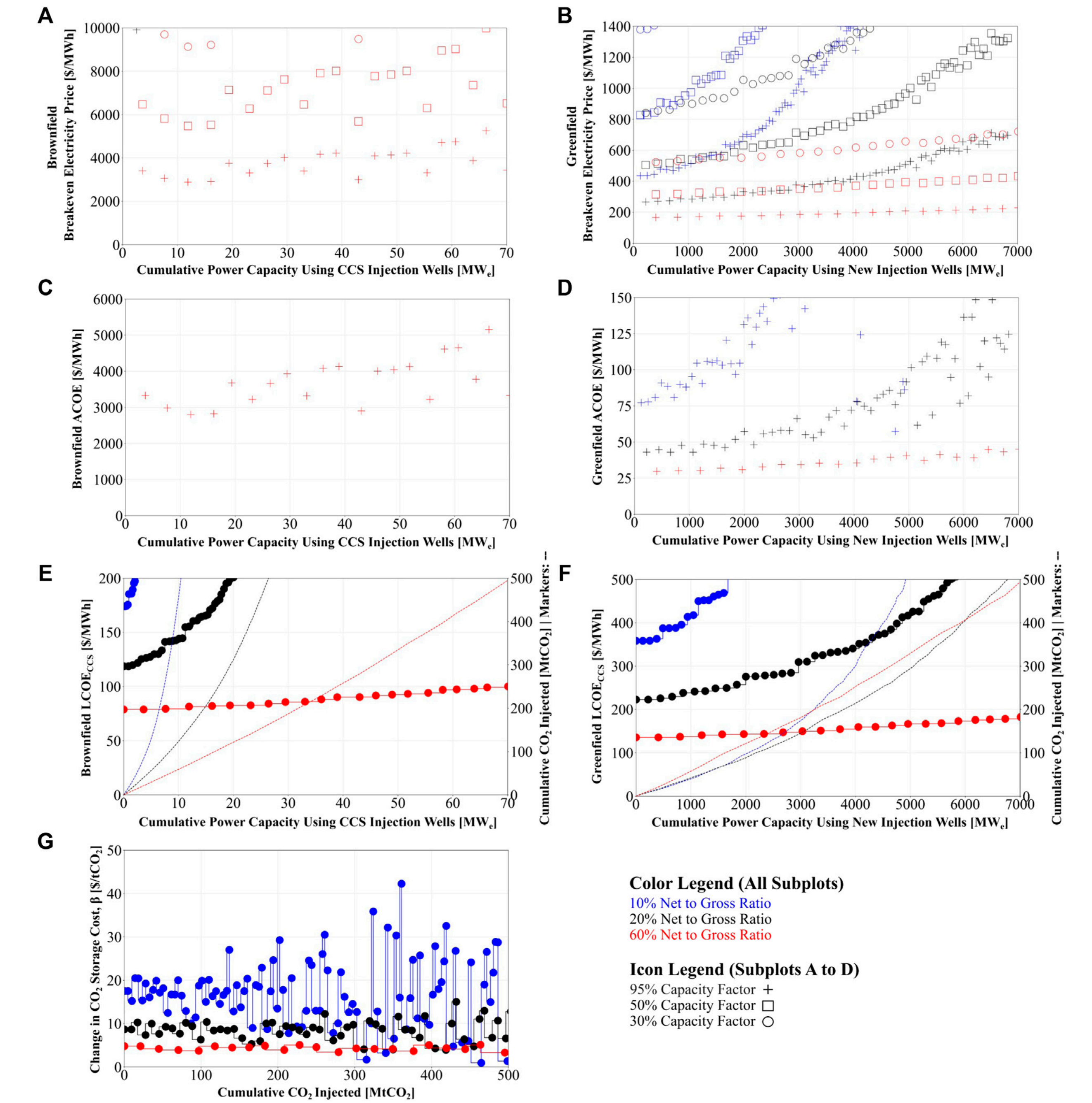

FIGURE 4 | Brownfield Breakeven Electricity Prices **(A)**, Greenfield Breakeven Electricity Prices **(B)**, Brownfield ACOE Supply Curve **(C)**, Greenfield ACOE Supply Curves **(D)**, Brownfield LCOE Supply Curve **(E)**, Greenfield LCOE Supply Curve **(F)**, Change in Cost of CO_2 Storage Between CPG "sweet spot" locations and CO_2 storage "sweet spot" locations **(G)**. Subplots E and F also show the cumulative CO_2 injected as a function of the cumulative CPG power capacity on the right *y*-axis.

3 RESULTS

3.1 Geospatial Cost of CPG Power Capacity and CO_2 Storage

The left column of **Figure 2** shows that, across all the net-to-gross ratio scenarios, there exists 1) a "sweet-spot" location in South Dakota with low-cost CPG power generation, and 2) locations that do not support CPG power generation (i.e., black grid cells). For example, even with an assumed net-to-gross ratio of 10%, there is still geology in South Dakota that could support <$150/MWh or cheaper power generation, depending on the financing of CPG. As South Dakota is not well-known for having geothermal energy resources amenable for power generation, **Figure 2** supports our prior work that suggests CPG could vastly expand the geothermal resource base (Adams et al., 2021; Van Brummen et al., 2022). On the other hand, because there is also geology across PCOR that cannot support CPG geothermal power generation, even with a net-to-gross ratio of 60%, **Figure 2** simultaneously demonstrates that CPG cannot expand the geothermal resource base to any location within a sedimentary basin.

Figure 2 also shows that across PCOR, the locations for lowest-cost CPG power plants are not the same locations for lowest-cost CO_2 storage. For example, across all net-to-gross ratio assumptions, the "sweet-spot" locations with low-cost CO_2 storage are not in the "sweet-spot" CPG location in South Dakota. This finding means that developing the cheapest CPG power plants in PCOR would require storing CO_2 in more expensive locations than may otherwise be targeted if CCS projects only considered the cost of sequestration. Further, some locations with inexpensive CO_2 storage (<$5/t$CO_2$) are also locations that do not support CPG power generation at all. For example, in central Saskatchewan when the net-to-gross ratio is 60%. Thus **Figure 2** suggests 1) it is possible for the cost of CPG to be higher if CO_2 storage operators only inject where the cost of sequestration is the lowest, and 2) that it is also possible that CPG technology may be unable to use the geologically stored CO_2 to provide power, depending on where CO_2 is injected.

Figure 3 shows the least cost geologic data for both CPG and CO_2 storage. CPG and CO_2 storage maps are plotted on different rows because there are multiple formations within the PCOR data, so the geologic layer (depth) that results in the lowest-cost CPG can be different than the layer that results in the lowest-cost CO_2 storage. **Figure 3** can be used to understand 1) why the lowest-cost locations for CPG are not the same as the lowest-cost locations for CPG; and 2) why there are some locations that cannot support CPG power generation.

Our prior work collectively demonstrates that, holding everything else constant, the LCOE of CPG and the annualized dollar per tonne cost of CO_2 storage both decrease with increasing depth, increasing thickness, increasing permeability, or increasing geothermal temperature gradient (Middleton et al., 2020b; Adams et al., 2021). As a result, a hypothetical deep and thick geologic formation with high permeability and a high temperature gradient would result in low-cost CPG power and low-cost geologic CO_2 storage. **Figure 3** demonstrates, however, that in the PCOR region, 1) these hypothetical subsurface conditions that are "optimal" across all four of these parameters do not exist, and 2) the magnitude of the cost sensitivities to geologic conditions are different between CPG and geologic CO_2 storage. For example, **Figure 3** suggests that in "non-optimal" (i.e., real) geologic conditions, the cost of CO_2 storage can be low if the reservoir is thick and deep enough, even if permeability is low (see slashed locations where cost of CO_2 storage is <$3/t$CO_2$). In contrast, **Figure 3** suggests that locations in PCOR with high permeability, moderate thickness, and a high temperature gradient provide the lowest-cost CPG power generation (see boxed locations where Brownfield CPG LCOE<$100/MW$_e$h). In other words, even though the

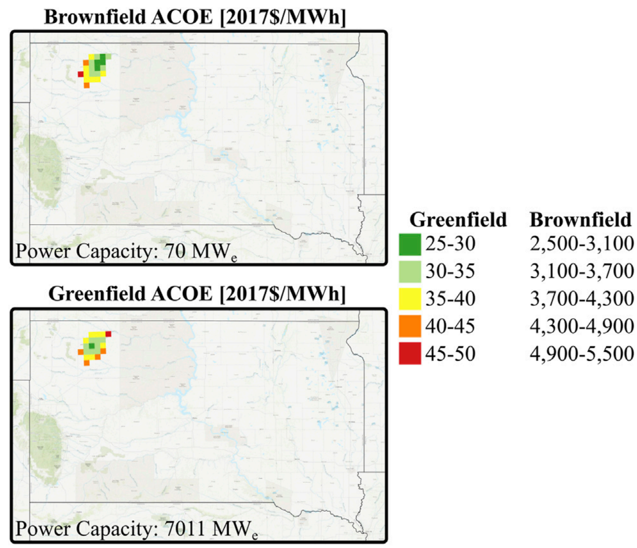

FIGURE 5 | Additional Cost of Electricity (ACOE) for Brownfield and Greenfield Development Across the South Dakota CPG "Sweet Spot" When the Capacity Factor is 95%.

thickness and depth are high in the "sweet-spot" locations for CO_2 storage, these are not the "sweet-spot" locations for CPG power generation because the permeability and temperature gradient are too low.

Figure 3 also suggests that the areas that cannot support CPG power generation (i.e., the black grid cells in **Figure 2**) are due to a too low transmissivity or a too low geothermal temperature gradient. For example, there are almost no grid cells on the CPG map with a geothermal temperature gradient between 13°C/km and 20°C/km (yellow grid cells). Further, the area in the northwest tip of the PCOR region has generally low transmissivity with permeabilities between 0.9 and 10 mD (yellow grid cells) and low gross thicknesses between 23 and 75 m (yellow grid cells), and this area also has almost no grid cells that support CPG power generation.

3.2 Breakeven Price of Electricity

Figure 4 shows the breakeven prices of electricity (subplots A and B) and the intermediate results that the breakeven electricity prices are a function of across the lowest-cost 500 MtCO_2 injected: ACOE (subplots C and D); LCOE (subplots E and F); and the change in cost of CO_2 storage, β (subplot G). All subplots in **Figure 4** plot the cost or price as a function of cumulative capacity deployed.

Subplots A and B of **Figure 4** show that the breakeven electricity prices for greenfield developments are an order of magnitude smaller compared to brownfield development. For example, when the capacity factor is 95% and the net-to-gross ratio is 60%, the greenfield breakeven electricity price is between ~$170/MW$_e$h to ~$220/MW$_e$h compared to ~$2,500/MW$_e$h to ~$5,000/MW$_e$h for brownfield development. The breakeven electricity price is lower for greenfield development because the increase in power generation capacity from having more CPG power plants outweighs the increase in LCOE from having to drill more wells. As seen in subplot E, the 500 $MtCO_2$ injected across the lowest-cost CPG grid cells can only support about 70 MW_e of CPG power capacity with brownfield development. This power capacity is low because there is approximately one CO_2 injection well in most of the grid cells within the CPG "sweet spot" thus only one CPG power plant with brownfield development. In contrast, as shown in subplot F, because 78.5 CPG power plants can be developed at greenfield sites, the power capacity that this 500 $MtCO_2$ can support increases to about 7 GW_e when the net-to-gross ratio is 60%.

The other primary takeaway from **Figure 4** is that the ACOEs are greater than zero, thus the breakeven electricity prices are greater than the LCOEs. This occurs because the "sweet spot" CPG grid cells can hold megatonnes of CO_2 and the change in cost of CO_2 is also greater than zero (i.e., α and β are both greater than zero). For example, as shown in subplot G, when the net-to-gross ratio is 60%, the CO_2 storage capacity of each grid cell is at least ~20 $MtCO_2$ across the CPG "sweet-spot" (i.e., α is ~20 $MtCO_2$) and injecting CO_2 in these grid cells costs ~\$5/tCO_2 more than in the CO_2 storage "sweet spots" in PCOR (i.e., β is ~\$5/tCO_2). As a result, the annual value from generating electricity with the sequestered CO_2 must exceed the cost of operating the power plant by ~\$100M (\$5/tCO_2*20 $MtCO_2$) to break even. As seen in subplots C and D, when the net-to-gross ratio is 60%, the increase in cost of more expensive CO_2 storage equates to an ACOE of at least ~\$3,000/MWh for brownfield development and ~\$30/MWh for greenfield development. The ACOE is also generally higher for lower net-to-gross ratios, indicating that the decrease in generation capacity (C in **Eq. 4**) outweighs the decrease in CO_2 storage capacity (α in **Eq. 4**) that occurs when the thickness decreases. The ACOE can decrease as the cumulative CPG power capacity increases because, as shown in subplot G, β can decrease for increasing amounts of cumulative CO_2 injected (i.e., increasing cumulative CPG power capacity).

To complement the LCOE maps in **Figure 2**, **Figure 5** shows the ACOE for both greenfield and brownfield development across the South Dakota CPG "sweet spot" when the capacity factor is 95%. As shown in **Eq. 4**, the ACOE increases with a decreasing capacity factor, which is expected because holding everything else constant, electricity would have to be worth more to financially break even if less electricity was sold. As a result, the ACOE values shown in **Figure 5** are "floor" numbers that would increase with lower capacity factor scenarios.

The PCOR dataset used in this study includes 8,346 10 × 10 km grid cells, and as shown in **Figure 5**, the geographic extent of the CPG "sweet spot" in South Dakota is only 21 of these grid cells. Thus, the South Dakota CPG "sweet spot" is only 0.25% of the geographic area considered for this study. But, as also shown in **Figure 4** and referenced in **Figure 5**, the power capacity of this area for greenfield development is 7 GW_e. As stated in **Section 1**, the total installed capacity of geothermal power plants across the entire United States is ~3.8 GWe (EIA, 2020). In other words, if CO_2 was stored in the CPG "sweet spot," this 2,100 km^2 area could have the potential to approximately triple the geothermal power capacity in the United States. But as shown in **Figure 4**, breakeven electricity prices are at least ~\$170/MWh (~\$140/MWh LCOE + ~\$30/MWh ACOE). For reference, from 2014 to 2020, average wholesale electricity prices across the United States ranged from \$30/MWh to \$50/MWh (EIA, 2021).

4 DISCUSSION

Prior work has discussed the mutual benefits of CPG and CCS. For example, CPG was first introduced as an approach for offsetting costs of CCS by creating an additional revenue stream (i.e., selling electricity) for CO_2 sequestration (Randolph and Saar, 2011). And, CCS could offset some costs of CPG via brownfield development if CCS injection wells are used within CPG power plants (Adams et al., 2021). Our results here suggest, for the first time, that these mutual benefits may not always be available: 1) because the ACOE can be greater than zero, CPG may increase the cost of CCS by requiring CO_2 to be injected in more expensive locations than may otherwise be targeted; and 2) the breakeven price of electricity required for CPG deployment can be lower if new injection wells are drilled instead of using CO_2 storage injection wells.

There are caveats to our findings, which are listed below. These were beyond the scope of this study but could be areas of focus for future work.

- We do not consider the cost of CO_2 transportation. As discussed in **Section 1**, depending on the locations of CO_2 sources, it may cost less to transport CO_2 to the CPG "sweet spot" locations compared to the CO_2 storage "sweet spot" locations. As a result, it is possible that the ACOE, thus the breakeven electricity prices, would be lower than suggested here if it accounted for transportation.
- Our breakeven electricity prices assume that the CO_2 storage operator is considering CO_2 storage locations across the entire PCOR region. But if this region was smaller, the "sweet spot" locations for CPG may better align with the "sweet spot" locations for CO_2 storage. For example, the ACOE would be smaller if the region of consideration was constrained to just South Dakota because the lowest-cost resources for geologic CO_2 storage in South Dakota are higher than the CO_2 storage "sweet spots" across PCOR. There may be a good reason to limit the region of consideration of CCS infrastructure given the increased difficulty of building infrastructure like CO_2 pipelines that cross political lines like state or country boundaries.
- We do not consider the option for CO_2 storage operators to increase the injection well density by overlapping the CO_2 plumes. Our prior work demonstrated that overlapping CO_2 plumes is a viable approach to increasing the CO_2 storage capacity of sequestration sites (Middleton et al., 2020b). By increasing the amount of CO_2 injection wells, this planning

decision would also in turn increase the number of CPG power plants under brownfield development and thus the amount of electricity that could be sold.

- We limit the per well CO_2 injection rate to 1 $MtCO_2$/yr because it is an accepted operational maximum for industrial CO_2 injection wells (Middleton et al., 2020a), but our prior work demonstrates that the cost of geologic CO_2 storage is sensitive to this assumption (Middleton et al., 2020b). For example, holding everything else constant, the cost of geologic CO_2 storage begins to increase with increasing depth after the 1 $MtCO_2$/yr constraint is reached. As a result, the ACOE could be smaller than reported here in scenarios that did not consider the 1 $MtCO_2$/yr injection rate constraint. Relaxing this constraint could be appropriate in situations where CO_2 was injected for the specific purpose of developing a CPG power plant.

5 CONCLUSION

In this study, we estimate and compare the geospatial cost of CPG with the geospatial cost of CO_2 storage across the PCOR region subset of the NATCARB database. We find that:

1) In the PCOR region, the locations with lowest-cost CO_2 storage are different than the locations with lowest-cost CPG power generation. Further, geologic conditions also exist that result in CO_2 storage under \$5/tCO_2 but do not support CPG power generation. As a result, the breakeven electricity prices required to inject CO_2 in "sweet spot" CPG locations may be greater than the LCOE to account for the increased cost of CO_2 storage (i.e., the ACOE can be greater than zero).
2) In the PCOR region, the electricity price required to inject CO_2 in locations with lowest-cost CPG power generation instead of lowest-cost CO_2 sequestration are an order of magnitude greater for brownfield CPG developments than for greenfield CPG developments. Greenfield developments have a lower breakeven cost than brownfield because the increased power capacity from having more wells outweighs the increase in LCOE from more drilling.
3) In the PCOR region, there is potential to approximately triple the United States geothermal electricity generation capacity using CPG technology but high electricity prices are needed to develop this capacity (~\$140/MW_eh LCOE + ~\$30/MW_eh ACOE = ~\$170/MW_eh electricity price).

In addition to the suggestions for future work listed in **Section 4** another important next step for future work is applying SCO_2T across the United States to identify additional "sweet spot" locations and determine how representative our PCOR findings are to the entire country. As our prior work demonstrated, there is no single publicly available dataset of deep saline formation properties that can be applied to SCO_2T across the entire country (Ogland-Hand et al., 2022b). As a result, executing this idea would require combining multiple geologic property datasets with one another.

DATA AVAILABILITY STATEMENT

The original contributions presented in the study are included in the article/supplementary material, further inquiries can be directed to the corresponding author.

AUTHOR CONTRIBUTIONS

JO-H: Conceptualization, Methodology, Software, Validation, Formal analysis, Investigation, Data Curation, Writing—Original Draft, Visualization, Supervision. BA: Methodology, Resources, Writing—Review and Editing, Visualization. JB: Methodology, Writing—Review and Editing, Visualization. RM: Methodology, Resources, Writing—Review and Editing, Visualization, Project administration, Funding acquisition.

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SUPPLEMENTARY MATERIAL

The Supplementary Material for this article can be found online at: https://www.frontiersin.org/articles/10.3389/fenrg.2022.855120/full#supplementary-material

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Conflict of Interest: JO-H, JB, and RM are employed by Carbon Solutions LLC. a commercial entity, and BA declares that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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