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Representing Carbon Dioxide Transport and Storage Network Investments within Power System Planning Models

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Abstract: Carbon dioxide (CO_2) capture and storage (CCS) is frequently identified as a potential component to achieving a decarbonized power system at least cost; however, power system models frequently lack detailed representation of CO_2 transportation, injection, and storage (CTS) infrastructure. In this paper, we present a novel approach to explicitly represent CO_2 storage potential and CTS infrastructure costs and constraints within a continental-scale power system capacity expansion model. In addition, we evaluate the sensitivity of the results to assumptions about the future costs and performance of CTS components and carbon capture technologies. We find that the quantity of CO_2 captured within the power sector is relatively insensitive to the range of CTS costs explored, suggesting that the cost of CO_2 capture retrofits is a more important driver of CCS implementation than the costs of transportation and storage. Finally, we demonstrate that storage and injection costs account for the predominant share of total costs associated with CTS investment and operation, suggesting that pipeline infrastructure costs have limited influence on the competitiveness of CCS.

Keywords: carbon capture and storage; power system modeling; electricity systems

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1. Introduction

Carbon dioxide (CO_2) capture and storage (CCS)—the process of capturing CO_2 from an industrial exhaust stream or, in the case of direct air capture (DAC), ambient air and storing it permanently or for use in other industrial processes—has garnered increasing attention in recent years given its potentially critical role in achieving a decarbonized US power system (and, more broadly, a decarbonized economy) [1–3]. The deployment of variable renewable energy (VRE) technologies such as wind, solar, and some hydroelectric technologies can achieve deep reductions in power system CO_2 emissions when combined with storage technologies and with limited costs. As the VRE share of total generation approaches 100%, costs increase non-linearly [1,4–6], predominantly driven by declining relative contributions of VRE to meeting resource adequacy needs [5,7]. As such, a number of studies conclude that achieving a zero-carbon target at lowest cost is supported through deployment of other low- to negative-emitting, non-VRE technologies such as biomass, geothermal, hydropower, CCS, hydrogen, and nuclear to meet this final portion of the load [1,2,6,8].

CCS technologies, including both electricity generation with CCS and DAC, have been a focus of analysis due to their ability to supply electricity with low to net-negative emissions or, in the case of DAC, to act purely as a source of negative emissions. Such negative emission technologies could enable the continued use of fossil generation technologies by offsetting their direct emissions [9]. DAC technologies are also frequently identified in economy-wide decarbonization pathways as a crucial component to offsetting the limited remaining greenhouse gas emissions after lower-cost options have been exhausted [10,11]. Note, we often refer to DAC and bioenergy with CCS (BECCS) as carbon dioxide removal (CDR) technologies since their operation leads to a net drawdown of CO_2 from the atmosphere if the CO_2 is permanently stored.

The recent passage of the Inflation Reduction Act of 2022 (IRA) [12] in the United States has further increased attention toward CCS. IRA increases the value of the CO_2 utilization and storage incentives previously established in the Internal Revenue Code's Section 45Q and extends them through 2032. It also increases the likelihood of future investments in CCS projects by broadening the definition of qualifying facilities and allowing for direct payment and transferability of the incentives.

Despite CCS often being identified as key technology in meeting low- or zero-carbon targets in the electricity sector at least cost, the treatment of CCS is generally highly simplified in power system models used to evaluate decarbonization pathways. Therefore, the purpose of this paper is to present a method for representing CCS capacity investment and retrofit decisions, as well as infrastructure requirements for pipeline and storage. The data for retrofits and reservoir-specific characteristics are specific to the USA, while the data for characterizing greenfield capacity investment and pipeline infrastructure are applicable in other regions as well with the necessary consideration to non-engineering aspects. Additionally, we present a means to interpret and parameterize the necessary characteristics for CCS network considerations while also providing a guide to the constraints necessary in linear programs. Finally, we provide readers with a comparison across CCS representation approaches—more specifically, between the simplified cost adder approach typically seen in investment decision-making models and the more detailed representation explained here. The method presented here highlights the need for greater granularity in the characteristics of CCS storage and a more detailed representation of the costs and opportunities for CCS equipment.

Detailed further below, power system capacity expansion models (CEMs) typically have minimal or no representation of the physical or technical constraints associated with CTS infrastructure operation, and CTS costs are most commonly captured through a fixed volumetric cost adder. Such an approach fails to capture the implications of the spatial distribution and variations in characteristics of storage reservoirs, as well as the costs and constraints of the infrastructure necessary to transport, inject, and monitor the CO_2 in a reservoir over time, all of which can impact the costs and competitiveness of CCS. Additionally, as the installation of CCS competes with or complements other decarbonization pathways and represents a large portion of a plants' capital costs, it is important to accurately capture both operational and locational considerations. Efforts to spatiotemporally optimize CTS network expansion have generally not simultaneously considered investment in CO_2 capture, transport, and storage infrastructure, as well as the investment in and operation of electricity generation technologies [13].

In recent years, however, several leading energy sector and power system planning models have developed improved representations of CTS investment and operations that better characterize these constraints. Table 1 summarizes the representation of CO_2 transportation and storage for several widely publicized models, including the National Energy Modeling System (NEMS) [14]; the U.S. Regional Economy, Greenhouse Gas, and Energy Model (US-REGEN) [15]; GenX [16]; and the U.S. Environmental Protection Agency's implementation of the Integrated Planning Model (IPM) [17]. The level of detail with which each aspect of CTS is represented varies considerably, but three of the four models surveyed account for regional variation in the cost and availability of CO_2 end uses explicitly or via supply curves and represent opportunities for investment in inter-regional CO_2 pipelines. NEMS and IPM include the use of CO_2 in enhanced oil recovery (EOR) as a second end use in addition to underground storage. NEMS has the most advanced CTS representation of the models surveyed, with spatially explicit representations for CTS with integer investment decisions and interaction with its oil and gas sector modules to determine EOR demand.

Table 1. Summary of the representation of CO_2 storage potential and CTS infrastructure in US models used to evaluate power sector decarbonization pathways.

Model	Sectoral Coverage	CO_2 Storage Representation	CTS Infrastructure Representation
NEMS	Energy system	Explicit EOR and saline storage costs, capacities, and locations	Pipelines can be built from plant locations to transshipment hubs and onward to EOR fields and saline injection terminals, all explicitly resolved. Integer decisions for pipeline diameter, site development, and injection wells.
US-REGEN	Energy system	State-aggregated injection cost and storage capacity	Cost of 20-mile pipeline to resource is assumed. Inter-regional pipelines can be built once in-state storage is exhausted.
GenX	Power	None [a]	None [a]
IPM	Power	Regional injection and storage cost curves for saline aquifer storage, depleted oil and gas fields, and EOR. Supply is decremented by exogenously estimated carbon capture, utilization, and storage from industrial sources.	Pipelines can be built directly from regions building CCS to regions with EOR or storage capacity, with a 100-mile minimum length.

[a] Development of a CTS representation in GenX is underway.

There is currently no peer-reviewed literature presenting a general methodology for adding a detailed representation of CTS network infrastructure investment options to a CEM and no literature that explores the impacts of such a representation on power sector and CTS network investment pathways. In this paper, we develop such a methodology and apply it to a CEM—specifically, the Regional Energy Deployment System (ReEDS, [18]). To evaluate the implications of including the explicit representation of CTS infrastructure investment and operation, we compare results from a suite of stylized scenarios simulated with and without the CTS network representation for the conterminous United States under a national power sector CO_2 emissions reduction target mandating net-zero emissions from the sector by 2050. We then synthesize the findings from model results into broader conclusions about CTS and its influence on the economics of CCS.

2. Materials and Methods

This section begins with an overview of the ReEDS model, including the existing representation of CCS technologies. We identify the potential limitations of the legacy treatment of CTS in the model and the benefits of including an explicit representation and tracking of the costs and constraints of CTS network infrastructure components: pipeline, injection, and storage. We then describe the new representation and introduce a set of generalized constraints that can be used to implement it within a typical linear capacity expansion planning problem. We describe the data that are needed to populate the detailed CTS representation, which include costs for CO_2 pipelines and underground storage in saline aquifers, along with limits on CO_2 injection rates and total storage capacities by aquifer. This methodology section concludes by introducing the ReEDS scenario analysis, the results of which are presented in Section 3.

2.1. ReEDS Model Overview

ReEDS, developed by the National Renewable Energy Laboratory (NREL), is a publicly available model used to analyze the evolution of continent-scale bulk (here, "bulk" refers to high-voltage, utility-scale transmission and transmission connected generation and storage resources. This is distinct from "distributed" or distribution-connected resources. ReEDS does not capture distributed resource adoption decision making but rather uses exogenously parameterized projections of distributed solar resource deployment and associated generation, and therefore, it accounts for their dispatch in bulk-scale investment and operational decision-making) electricity systems given a set of assumptions about future changes in load, policy, fuel prices, as well as technology cost and performance projections [18]. The representation presented here is available in the publicly-available ReEDS software (https://github.com/NREL/ReEDS-2.0) as of version 9b159a1, posted 2 May 2024.

The model is typically solved to co-optimize investments in the bulk electricity system and its operation across the conterminous United States through 2050, and it is structured as a linear program that minimizes system investment and operational costs for one modeled year at a time, stepping forward (recursively) into the future. We refer to this as the ReEDS primary model when necessary while referencing the subroutine for resource adequacy as the Augur module.

In the ReEDS model, investment and retirement decisions (in generation, transmission, and energy storage. Note that ReEDS represents all major generation and energy storage technology options, including fossil fueled (both with and without CCS), nuclear, solar, wind, geothermal, biomass, hydroelectric, hydrogen, battery, pumped hydroelectric, and DAC technologies.) and chronological economic dispatch are determined. The linear program consists of a cost-minimizing objective function that is subject to typical CEM constraints (e.g., hourly supply and demand balance, planning reserve requirement, transmission flow balance, provision of operating reserves), as well as various technology- and policy-specific constraints.

To maintain the computational tractability of this complex optimization, two key methods are implemented. First, the conterminous United States is divided into 134 regions, also referred to as balancing areas over which the core power system constraints are enforced. Transmission between regions and interconnections is represented by aggregated transmission interfaces that can be endogenously upgraded. Intra-regional transmission (and distribution) is not explicitly captured, with the exception of "spur-line" transmission required to connect new wind and solar resources.

Second, hourly dispatch for the full year is simplified into a reduced-order dispatch across four hour "time slices" within 33 representative days. The representative days are chosen to portray a range of possible periods with low or high VRE availability across technology combinations (for example, a high solar and low wind day), as well as various load profiles and across regions.

2.2. Incumbent CTS Representation in ReEDS

The most recent version of ReEDS includes representations of coal, natural gas, and biomass-powered generation facilities with CCS, as well as DAC. Their costs and operational constraints are captured analogously to all other generation technologies represented in ReEDS: capital costs, operations-and-maintenance (O&M) costs, and heat rates (or efficiencies) are captured independently, as are the associated operating constraints, including maximum and minimum operating capacity and maximum ramp rate. Cost and performance assumptions for each technology vary by year according to projections that are exogenously specified. Regional multipliers for capital costs are also used to account for regional differences in the costs of labor.

Although representations of these technologies exist in the current version of ReEDS, only the generation and CO_2 capture components are tracked explicitly. The costs associated with CTS infrastructure are simply captured with a fixed volumetric cost adder applied to each metric ton (tonne) of CO_2 captured. A recent study using separate data and assumptions from this work developed regional CO_2 storage supply curves for Texas and represented them in ReEDS to study the impacts of improving CO_2 storage modeling on investment pathways, but that study was limited in spatial scope and did not consider transportation of CO_2 between regions [19]. As such, until now, investment in the infrastructure components and associated capacity constraints of CTS infrastructure were not explicitly represented in ReEDS. In accordance with an estimate from the National Energy Technology Laboratory, the default value for the volumetric adder was assumed to be \$15/tonne (2020 \$) for the levelized cost of CTS (LCCTS) via injection into underground saline aquifers [20].

2.3. New CTS Representation in ReEDS

2.3.1. Overview and Regionality

Using a constant adder to account for costs of all components of CTS fails to capture the implications of the spatial distribution and the variation in characteristics of storage reservoirs, as well as the costs and constraints of infrastructure necessary to transport, inject, and monitor the CO_2 in the reservoir over the long term. These differences can all impact the costs and competitiveness of CCS and, as a result, the broader set of investment and operational outcomes determined within the model. Thus, we developed a new CTS representation, detailed here, which includes spatially explicit tracking of investment, capacity, and operations of CO_2 pipelines, injection, and storage in underground saline aquifers. Various solutions for storing or sequestering CO_2 have been proposed, but the injection of refrigerated liquid CO_2 into underground saline aquifers is broadly considered to have the most potential for being safe, reliable, and cost-effective at scale. As such, this is the only method we consider.

The new CTS representation leverages both the underlying ReEDS regionality—the 134 balancing areas over which electricity supply and demand are balanced and transmission is modeled—as well as a spatially explicit representation of the extent and characteristics of underground saline aquifers suitable for the long-term storage of CO_2. To enable ReEDS to construct CO_2 pipelines that can connect any balancing area to any saline aquifer, we devised two categories of pipelines. The model can build a pipeline between any two regions, creating a topology that allows for inter-regional routes that connect any region with any other region by chaining from one adjacent region to the next. We term these "trunk" pipelines. Figure 1a shows this topology of 509 possible pipeline segments in blue, along with the locations of all saline aquifers in semitransparent green.

"Spur" pipeline capacity, on the other hand, can be built to connect any region within 200 miles (322 km) of a saline aquifer (excluding paths that would necessitate the construction of submarine pipelines), directly to the aquifer's nearest edge for injection and storage. Regions with centroids that intersect a saline aquifer can build CO_2 injection facilities into the underlying aquifer, with an assumed spur pipeline distance of 20 miles (32 km). This results in 1474 possible spur line routes (including the pipelines for centroids that sit atop aquifers). The routes are mapped in Figure 1b.

To calculate each trunk and spur pipeline route distance, we measured from the load-weighted centroid of each region. This means that the assumed pipeline end points are often located near the population center within each region. The distances were computed as the shortest path between each set of coordinates (shown in Figure 1).

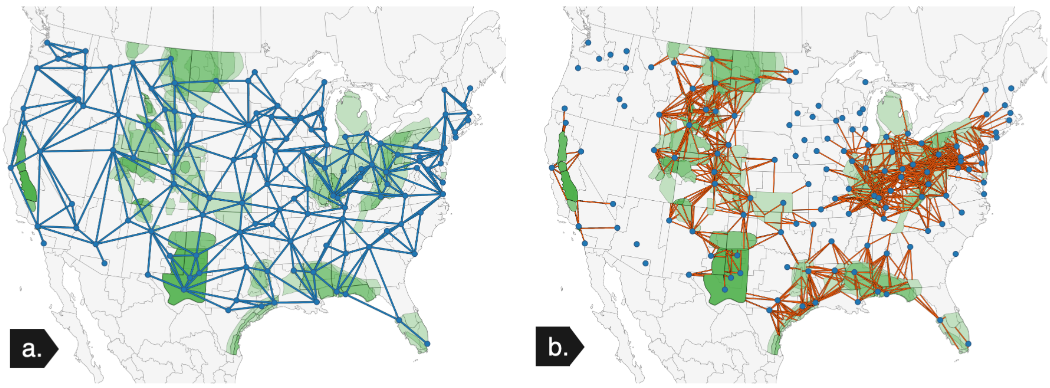

Figure 1. Topology of CTS pipeline investment options included in ReEDS, with (**a**) all possible inter-regional trunk pipeline routes shown in blue and (**b**) all possible spur pipeline routes between region centroids and saline aquifers in orange. All saline aquifers included as storage options in the model are shown in green. Light gray lines separate model regions.

2.3.2. Data

To implement the explicit representation of CTS infrastructure and the spatially explicit constraints on CO_2 storage potential, two key data sources were developed:

1. Pipeline costs: cost estimates for CO_2 pipelines (inclusive of booster pumps), and
2. Injection and storage capacity and costs: site-specific injection and storage capacity limits and levelized costs of CO_2 injection and long-term maintenance of a storage reservoir.

Pipeline Costs

Capital, fixed O&M, and variable O&M costs were developed for the transport of liquid CO_2 via pipeline using the U.S. Department of Energy's Office of Fossil Energy and Carbon Management (FECM)/NETL CO_2 Transport Cost Model (CO2_T_COM) [21], an open-source techno-economic model of CO_2 pipeline costs. Note, all existing CO_2 pipeline networks in the United States carry CO_2 as a pressurized gas, but the prior research has indicated that liquid CO_2 transport may represent the cost-optimal approach for future CTS infrastructure built to a scale that would accommodate hundreds of millions of tonnes of CO_2 throughput each year. The design of such infrastructure would require minimal deviation from established technologies that enable transportation of liquid natural gas and other products that are gaseous at atmospheric pressure and temperature [22]. The model uses as inputs the length of pipeline, the net elevation change along the length of pipe, the maximum daily and average annual mass flow rates, the number of booster pumps, and the pressures at the inlet and outlet of booster pumps to calculate costs.

Given the trade-offs in costs between the pipeline diameter and the number of booster pumps necessary (to accommodate a specific mass flow rate), for this study, the CO2_T_COM was implemented alongside a separate optimization approach that identified the least-cost combination of pipeline diameter and number of booster pumps under a range of assumed maximum CO_2 flow rates (from 10 tonnes/hour to more than 5500 tonnes/hour) and distances of transport (50–2000 miles; 80–3219 km). Figure 2 shows the resulting capital cost range by pipeline length and maximum flow.

Figure 2 demonstrates that the primary driver of pipeline costs is the maximum mass flow rate. This rate ultimately determines the diameter of the pipe and, along with the distance, the number of booster pumps. Given that ReEDS is a linear model, it is not feasible to implement a functional form for pipeline costs and have length and flow determine costs when costs are declining with further investment or utilization; as such, we specified costs for two types of pipeline that can be deployed within ReEDS: (1) long-distance, inter-regional pipelines, presented in Figure 1a, and (2) generally shorter distance "spur" pipelines, presented in Figure 1b. ReEDS determines the cost-minimizing combination of trunk and/or spur pipelines that allow for the transport of CO_2 to storage reservoirs. We assumed an identical cost for both types of pipelines: $3000 per tonne-mi/hour. This cost was selected based on the estimated cost of the average capacity of trunk and spur pipelines built across a range of low- to zero-carbon scenarios simulated with varying assumptions for pipeline costs, and it is equivalent to a pipe sized to accommodate the CO_2 emissions flow from 1 GW of natural gas combined-cycle (Gas-CC) capacity operating at full capacity.

CO_2 Injection and Storage Costs and Capacity

We relied on the FECM/NETL CO_2 Saline Storage Cost Model (CO2_S_COM) to estimate the injection and storage capacities and the associated costs for saline aquifers identified in NETL's National Carbon Sequestration Database [23–25].

Underground CO_2 storage entails a host of capital and operating expenditures. Chief among these are project planning and permitting, site characterization, construction of injection facilities and deep monitoring wells, operation of injection facilities, and post-injection site care followed by site closure. Using the CO2_S_COM, we simplified these components into a simple, 30-year, levelized cost (per tonne) of injection and storage for each aquifer over a range of assumed injection capacity factors from 10–90%. For each aquifer, this levelized metric, sometimes referred to as a "first-year breakeven cost of

CO_2", represents the revenue (per tonne of CO_2) required to offset all capital, O&M, and regulatory and financing costs of an injection and storage project from inception until site closure.

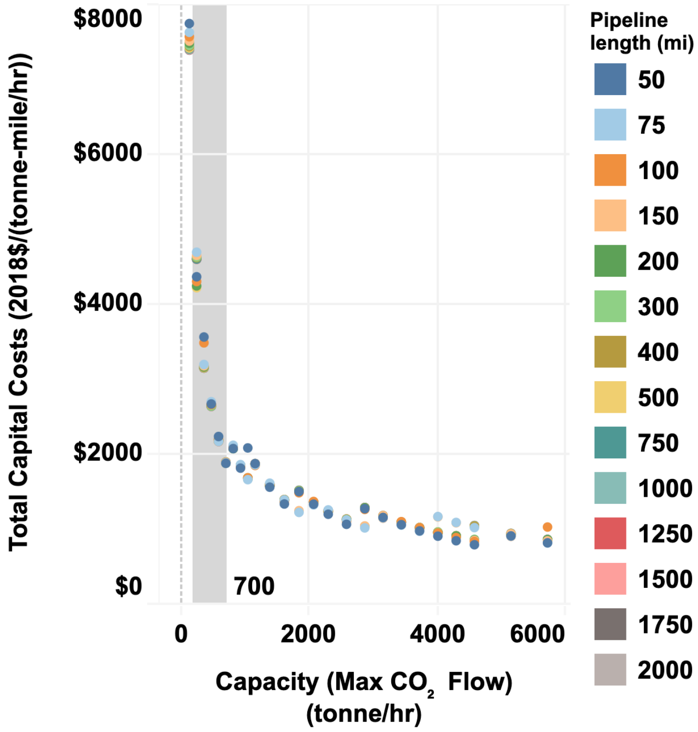

Figure 2. Estimated per-mile capital costs of refrigerated liquid CO_2 pipelines by length and pipe diameter. The shaded region shows the approximate emissions rate of a 1-GW Gas-CC plant operating at full capacity.

Figure 3 depicts the levelized cost of injection and storage associated with cumulative storage capacity within a set of defined regions. We observe higher injection and storage costs in the Rocky Mountain states, whereas the other regions show abundant resource at well below $10 per tonne of CO_2 at higher capacity factors. The increased utilization of injection well capacity reduces levelized costs because the fixed costs are spread over a greater quantity of CO_2 injected.

Given that ReEDS is a linear model, a fixed capacity factor needs to be assumed. After executing sensitivity scenarios with different assumed capacity factors, we found that endogenously determined operations converged on a range from 80–95% and opted to set 80% as the default assumption.

The curves in Figure 3 are truncated at 50 Gtonnes; in fact, approximately 866 Gtonnes of CO_2 storage capacity have been characterized across the conterminous United States in our data set, enough to capture 100% of the U.S. power sector's direct CO_2 emissions for over 500 years if emissions were to remain flat from 2021 onward. The vast majority of this saline storage is not necessary to meet the needs of power sector CO_2 storage, even in scenarios with relatively high deployment and operation of CCS facilities. As such, the levelized costs of CTS of aquifers accessed in a suite of exploratory ReEDS simulations never exceeded a cost of $17.70/tonne (2020 $). Similar findings were reported in the literature [20]. Given this, to reduce computational burden, we excluded all aquifers with levelized injection and storage costs of more than $20/tonne (2020 $) from the model's investment options.

Figure 4 maps the spatial extents and the levelized cost of injection and storage (at an 80% capacity factor) for each of the 314 saline aquifers identified. One hundred fifty-five of these were less than $20/tonne and included as investment options. These polygons, rather than the regional supply curves depicted in Figure 3, constitute the set of investment options within ReEDS, with pipeline topologies and costs calculated using the geometries.

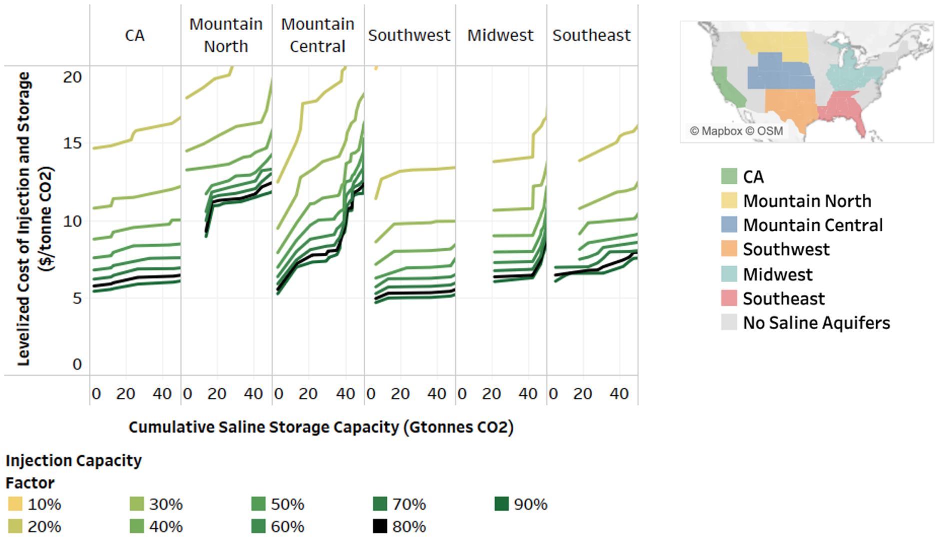

Figure 3. Regional supply curves for CO_2 storage via injection into saline aquifers by assumed capacity factor of injection facilities. The 80% capacity factor curves (shown in black) are used to parameterize costs of injection and storage within the model. These curves do not consider CO_2 transport costs.

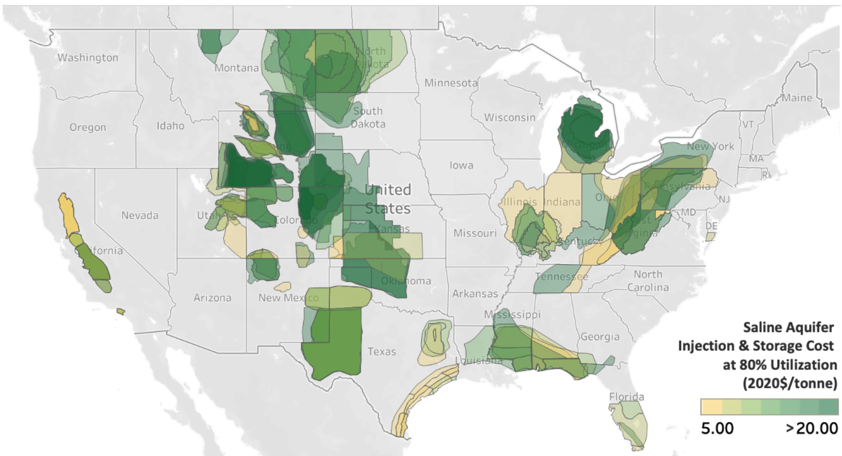

Figure 4. Map of the spatial extent of saline aquifers in the conterminous US and the associated levelized cost of injection and long-term storage of CO_2 in each saline aquifer identified for this work, assuming 80% utilization factor. Polygons are semi-transparent to show where multiple saline aquifer basins overlap at different depths.

2.4. CTS Network Formulation

Here, we define the detailed CTS representation described qualitatively above as an addition to the classical linear capacity expansion planning problem (which, for brevity, is not restated here). Numerous variables and constraints can be included in the capacity expansion problem, so we defer to other sources in the literature for a typical formulation. See Section II, subsection A of [26] for a high-level summary of the nonlinear mathematical program from which linear representations are derived and Section 4 of [27] for an exhaustive formulation of the problem as a mixed-integer program to which the CTS constraints and objective function terms described here could directly be applied. These modifications are generalized for any mathematical programming-based, cost-minimizing CEM and are presented almost exactly as we implemented them in the ReEDS supply module.

The revised objective function is presented in Equation (1). Note that the original and revised objective functions in ReEDS include investment and operational components. The combination of these objective function components allows for a multifactor model that simultaneously includes the long-term capacity expansion decisions and shorter-term operation and performance decisions for both power system and CCS systems. The objective function minimizes the cost of meeting load by building, operating, and retiring generation, transmission, storage, and CDR technologies.

$$\begin{aligned} \min \quad & f_0 + f \\ \text{s.t.} \quad & [\ldots, \mathcal{C}, \mathcal{G}, \mathcal{H}, \mathcal{K}] \in \Omega_0 \\ & [\mathcal{C}, \mathcal{G}, \mathcal{H}, \mathcal{K}, \mathcal{T}, \mathcal{S}, \mathcal{F}, \mathcal{Q}] \in \Omega, \end{aligned} \tag{1}$$

where f_0 is the scalar-valued objective cost function of the capacity expansion planning problem before adding the CTS terms described here, f is the new CTS cost function terms, $[\ldots]$ is the set of all decision variables that are not involved in the CTS representation, Ω_0 is the set of all constraint equations not involved in the CTS network formulation, and Ω is the CTS constraints to be described below. To add the CTS representation to the CEM, we require the following nonnegative decision variables: (unless otherwise noted, units of "tonnes" refer to metric tons of CO_2).

$\mathcal{C}_{r,h,t}$: CO_2 captured [tonnes/hour]
$\mathcal{G}_{i,r,h,t}$: apparent power generation [MW]
$\mathcal{H}_{r,h,t}$: hydrogen production [tonnes H_2/hour]
$\mathcal{K}_{i,r,h,t}$: CO_2 captured by DAC [tonnes/hour]
$\mathcal{T}_{r,r',t}$: trunk pipeline capacity [tonnes/hour]
$\mathcal{F}_{r,r',h,t}$: trunk pipeline CO_2 flow [tonnes/hour]
$\mathcal{S}_{r,a,h,t}$: spur pipeline capacity [tonnes CO/hour]
$\mathcal{Q}_{r,a,h,t}$: CO_2 stored by spur pipeline [tonnes/hour]

which are defined over sets

i: technology
r: region
a: saline aquifer
h: model period (can be configured to span one or multiple hours)
t: modeled year.

Parameters in the following equations are

$c^{\mathcal{T}}$: discounted annualized capital cost of trunk pipeline [2020 \$/((tonne/hour)-mi)]
$c^{\mathcal{S}}$: discounted annualized capital cost of spur pipeline [2020 \$/((tonne/hour)-mi)]
$o^{\mathcal{T}}$: annual fixed O&M cost of trunk pipeline [2020 \$/((tonne/hour)-mi-yr)]
$o^{\mathcal{S}}$: annual fixed O&M cost of spur pipeline [2020 \$/((tonne/hour)-mi-yr)]
$c_a^{\mathcal{Q}}$: cost of CO_2 injection and storage in aquifer a [2020\$/tonne]
$m_{r,r'}$: trunk pipeline route distance between regions r and r' [mi]
$m_{r,a}$: spur pipeline route distance between regions r and aquifer a [mi]
w_h: time-period-to-hour weighting factor [hours/period]
w_t: model-year-to-year weighting factor [yr/model year]
x_i: CO_2 capture rate of technology i [tonnes/MWh]
p: CO_2 intensity of hydrogen production via steam methane reforming with CCS (SMR-CCS) [tonnes/tonne H_2]
l_a: physical limit on CO_2 injection mass flow rate at aquifer a [tonnes/hour]
y_a: physical cumulative storage capacity at aquifer a [tonnes]

The pipeline and reservoir parameter derivations are explained in Section 2.3.2 and the capacity costs and performance parameters are explained in Section 2.5.

2.4.1. New Objective Function Terms

We start by adding several new terms to the CEM's objective function to represent the costs of building and operating trunk and spur pipelines, along with the cost of CO_2 injection and storage:

$$f = \sum_{r,r'} c^{\mathcal{T}} m_{r,r'} \mathcal{T}_{r,r',t} \tag{2}$$

$$+ \sum_{r,a} c^{\mathcal{S}} m_{r,a} \mathcal{S}_{r,a,t} \tag{3}$$

$$+ \sum_{r,r'|t' \leq t} o^{\mathcal{T}} m_{r,r'} \mathcal{T}_{r,r',t'} \tag{4}$$

$$+ \sum_{r,a|'t \leq t} o^{\mathcal{S}} m_{r,a} \mathcal{S}_{r,a,t'} \tag{5}$$

$$+ \sum_{r,a,h} c_a^{\mathcal{Q}} w_h \mathcal{Q}_{r,a,h,t} \tag{6}$$

$$\forall t$$

Terms (2) and (3) capture the capital costs of building trunk and spur pipelines, respectively, allowing each to be assigned different costs per tonne/hour. Similarly, Terms (4) and (5) account for fixed O&M costs of new and previously built pipeline capacity. In Term (6), we capture the entire cost of building and operating CO_2 injection and storage infrastructure as an aquifer-specific variable cost. Note that we do not account for some benefits such as by-products according to Li et al. [28] or re-use of the stored CO_2.

The costs associated with CO_2 capture are accounted for in the costs of operating CCS technologies, which are part of the legacy objective function, f_0, because they are unchanged in the CTS representation.

With the costs of CTS infrastructure defined, we must define the new constraint equations that comprise Ω. The next three subsections lay out these constraints.

2.4.2. CO_2 Capture Equation

Although the constraint accounting for CO_2 capture is unchanged in the detailed CTS representation, we include it here for context. The total amount of CO_2 captured in each region, period, and modeled year is the sum of all generation-CCS emissions and emissions captured by SMR-CCS and DAC, which are accounted for separately because they do not generate electricity:

$$\mathcal{C}_{r,h,t} = \sum_i x_i \mathcal{G}_{i,r,h,t} + p\mathcal{H}_{r,h,t} + \sum_i \mathcal{K}_{i,r,h,t} \forall r, h, t \tag{7}$$

2.4.3. Trunk and Spur Pipeline Capacity Limits

Net flow on each trunk pipeline segment cannot exceed its capacity in any period:

$$\sum_{t' \leq t} \mathcal{T}_{r,r',t'} + \sum_{t' \leq t} \mathcal{T}_{r',r,t'} \geq \mathcal{F}_{r,r',h,t} + \mathcal{F}_{r',r,h,t} \forall r, r', h, t \tag{8}$$

Similarly, the flow on each spur pipeline into injection wells in each period cannot exceed the spur pipeline's capacity:

$$\sum_{t' \leq t} \mathcal{S}_{r,a,h,t'} \geq \mathcal{Q}_{r,a,h,t} \forall r, a, h, t \tag{9}$$

2.4.4. Network Flow Balance

Here, we enforce the conservation of CO_2 mass flow. The flow leaving a given region (to another region via trunk pipeline segment or a spur line to enter storage) must be equal to capture in that region plus the net flow of CO_2 into that region on trunk pipelines:

$$\sum_{a} \mathcal{Q}_{r,a,h,t} = \mathcal{C}_{r,h,t} + \sum_{r'} (\mathcal{F}_{r',r,h,t} - \mathcal{F}_{r,r',h,t}) \forall r, h, t \tag{10}$$

Note that we could eliminate $\mathcal{Q}$ by substituting (9) into (10) and in the following equations wherever $\mathcal{Q}$ appears, but having a variable to explicitly track CO_2 storage by spur pipeline and aquifer is useful for reporting and analysis.

2.4.5. Physical Limitations on CO_2 Storage

Each saline aquifer has a maximum CO_2 injection rate that is determined by the unique geology of each basin; note that this does not account for potential for modifications of the CO_2 stream itself, such as those demonstrated in [29]. The sum of CO_2 flow from all spur pipelines injecting into a given aquifer must be less than the aquifer's physical limit in each period:

$$l_a > \sum_{r} \mathcal{Q}_{r,a,h,t} \forall r, h, t \tag{11}$$

In addition to a maximum injection rate, each saline aquifer has a finite capacity to store CO_2. The cumulative storage of CO_2 must never exceed this physical limit:

$$y_a > \sum_{r,h,t|t' \leq t} w_{t'} w_h \mathcal{Q}_{r,a,h,t'} \forall a, t \tag{12}$$

Having defined the topology of possible CTS network investments, new objective function terms f, and CTS constraints, Ω, all that remains to implement the detailed CTS representation is to populate the parameters defined here with the pipeline and storage cost assumptions.

2.5. Scenario Analysis

To evaluate how the inclusion of the explicit representation of CTS infrastructure impacts model outcomes, we simulate three core scenarios, denoted in italics, both with and without the explicit CTS infrastructure representation: (1) a no-new-policy reference scenario (*No New Policy*), (2) a scenario that achieves net-zero CO_2 emissions by 2050 (*Net Zero*) scenario, and (3) a scenario that achieves net-zero CO_2 emissions by 2050 under favorable conditions for CCS deployment (*Net Zero*, *LGP*, *AdvCCS*). The *No New Policy* scenario serves as a baseline in which no new electricity sector policies are enacted beyond those in place by March 2022. (As such, the passage of IRA and its extension and increase in 45Q CCS incentives are not reflected in the scenario.) The *Net Zero* scenario uses identical assumptions with the exception of the implementation of a CO_2 cap and trade policy in which electricity sector net-CO_2 emissions must linearly decrease from present-day values to zero in 2050. The *Net Zero*, *LGP*, *AdvCCS* scenario is identical to the *Net Zero* scenario, but assumes lower-cost natural gas (low gas prices, or LGP) and lower costs and improved performance of fossil, hydrogen, and especially CCS technologies—"AdvCCS" refers to this assumption of advanced research and development. Finally, given the uncertainty in the future costs of CO_2 pipelines and storage infrastructure, particularly given that non-material costs could vary considerably depending on future regulatory structures and social acceptance or opposition, we ran sensitivities for each of the two *Net Zero* scenarios in which we scaled the pipeline and storage costs described in Sections 2.3.2 by 0.5, and 2. We refer to these sensitivities as "low" and "high" costs, respectively, with the central case referred to as "reference".

Table 2 summarizes the assumptions made in each of these scenarios and sensitivities. The retrofit assumptions for existing facilities are presented in Table 3 and do not vary by scenario. Cost and performance projections for fossil, hydrogen, and CCS technologies (including new and retrofit CCS and DAC) were developed for this study based on a bottom-up engineering analysis of technology component costs. In addition, the resulting estimates were compared to cost data from a collection of recent proprietary quotes from vendors of fossil and CCS technologies. These projections are catalogued for 2025 and 2050 in Tables 4–6. Note that the capital costs for retrofits assumed in Table 6 include both the costs associated with retrofitting existing equipment to transition to the technology listed in the "To Technology" columns as well as facility refurbishment costs associated with extending its operational lifetime. The costs and performance projects are used in the f_0 portion of the objective function to parameterize the investment and operational costs of electricity generating units. Cost and performance projections for all other technologies are from the NREL Annual Technology Baseline Moderate case [30]. Regional natural gas prices are derived from the U.S. Energy Information Administration (EIA) 2023 Annual Energy Outlook [31] Reference and High Oil and Gas Supply cases, respectively, for the reference and LGP assumptions used in this analysis [31]. The additional assumptions made in these ReEDS simulations are discussed in Appendix A.

Importantly, regardless of the level of detail of CTS infrastructure representation, the costs for retrofitting existing coal- and natural-gas-fired units are unique to each representative facility. These values come from the NEMS existing unit database [14] and include the retrofit cost as well the heat rate, operating costs, and fixed maintenance costs of the upgraded facility. A derate is applied to the resulting capacity to account for the need to power the CCS equipment itself and is determined using the same method as the NEMS model [14]. Information on the costs and performance adjustments to existing retrofit units are presented in Table 3. The additional power requirement for the generating units' carbon capture equipment is assumed to be produced at the plant itself and is reflected through the heat rate increase. For retrofit units, this heat rate increase is reflected in the far-right column of Table 3; for newly-built units, it is reflected as the difference between the no-capture and with-capture heat rates in Table 4.

Table 2. Base scenario assumptions.

Scenario	Policy	Fossil/H_2/CCS	Natural Gas Price	VRE
No New Policy	No new policy	Moderate	Reference	Moderate
Net Zero	Net zero by 2050	Moderate	Reference	Moderate
Net Zero, LGP, AdvCCS	Net zero by 2050	Advanced	High Oil and Gas Supply	Moderate

Table 3. Retrofit Cost Assumptions for Existing Generating Units for 90% Capture Rate; Derived from NEMS Electricity Generating Unit Database [14].

Technology	Retrofit Cost (2020 $/MW)			FOM Increase (2020 $/MW-yr)			VOM Increase (2020 $/MWh)			Heat Rate Increase (BTU/kWh)		
	Wtd Avg [a]	Lowest 25% [b]	Std Dev	Wtd Avg	Lowest 25%	Std Dev	Wtd Avg	Lowest 25%	Std Dev	Wtd Avg	Lowest 25%	Std Dev
Coal	2610	1910	1410	18.2	17.4	1.6	– – – – 4.75 [c] – – – –			4176	2992	3051
Gas-CC-CCS	1878	1457	973	– – – – N/A [d] – – – –			7.82	6.39	2.95	1630	1341	1371

[a] Weighted average by nameplate capacity; [b] Lowest 25% represents the nameplate capacity-weighted average of the lowest cost 25% of available retrofit capacity for that characteristic; [c] Static across all units; [d] Not available in [14]; FOM costs for existing Gas-CC units that retrofit to Gas-CC-CCS assumed as the unit's non-upgraded FOM costs, plus the difference between greenfield Gas-CC-CCS and Gas-CC FOM costs.

Table 4. 2025 and 2050 technology cost and performance assumptions produced for this study.

Technology	Capture Rate (%)	Capital Cost (2020 $/kW)			Fixed O&M (2020 $/kW-yr)			Variable O&M (2020 $/MWh)			Heat Rate (MMBtu/MWh)			CO_2 Emissions Rate (kg/MMBtu)
		2025	2050 Mod.	2050 Adv.	2025	2050 Mod.	2050 Adv.	2025	2050 Mod.	2050 Adv.	2025	2050 Mod.	2050 Adv.	
SCPC [a]	N/A	2619	2084	2084	72	69	69	7.9	7.4	7.4	8.5	7.8	7.8	87.1
	90	4579	3214	2927	123	107	96	14.4	12.3	10.8	10.8	10.0	9.2	8.7
	99	4795	3366	3065	128	112	100	15.3	13.2	11.6	11.4	10.5	9.7	0.1
Cofire [b]	N/A	2940	2407	2407	79	76	76	7.9	7.4	7.4	9.0	8.2	8.2	86.0
Gas-CC [c]	N/A	961	748	715	27	25	23	1.8	1.6	1.5	6.4	6.2	6.1	52.8
	90	2519	1734	1369	66	51	40	5.8	4.8	3.9	7.2	6.9	6.6	5.3
	97	2603	1792	1414	68	52	42	6.1	5.0	4.1	7.3	7.0	6.7	0.2
Gas-CT [d]	N/A	850	664	634	22	20	18	4.4	4.0	3.8	9.7	9.6	9.5	53.4
RE-CC [e]	N/A	974	758	724	27	24	22	1.7	1.6	1.5	6.2	6.1	6.0	0.0
RE-CT [f]	N/A	858	670	640	22	20	18	4.4	4.0	3.8	9.7	9.6	9.5	0.0
BECCS [g]	90	5768	3953	3481	163	145	133	14.9	12.8	11.1	11.9	10.9	10.0	−60.0
	99	6000	4112	3621	163	145	133	16.0	13.7	11.9	12.7	11.6	10.6	−71.2

[a] Supercritical pulverized coal; [b] This technology consists of a supercritical boiler burning 51–49% coal-to-biomass fuel mix by mass; [c] Gas combined cycle; [d] Gas combustion turbine; [e] Hydrogen combined cycle; [f] Hydrogen combustion turbine; [g] This technology consists of a pure-biomass-burning advanced ultra supercritical boiler.

Table 5. 2025 and 2050 DAC cost and performance assumptions produced for this study.

Technology	Capital Cost (Million 2020$ /net tonne/hour)			Fixed O&M (Million 2020$ /yr-net tonne/hour)			Variable O&M (2020 $/tonne CO_2) [a]			Conversion Rate (tonnes CO_2/MWh) [a]		
	2025	2050 Mod.	2050 Adv.	2025	2050 Mod.	2050 Adv.	2025	2050 Mod.	2050 Adv.	2025	2050 Mod.	2050 Adv.
Electric DAC [b]	11.3	8.49	5.66	0.54	0.53	0.51	47.3	33.6	32.9	0.227	0.233	0.240
NG DAC [c]	14.8	11.1	7.4	0.31	0.31	0.30	80.8	60.6	40.3	0.328	0.335	0.344

[a] These values do not include the cost of electricity, which is endogenously determined in ReEDS, or natural gas, which has an exogenously specified price. Additionally, NG DAC energy input has been converted from mmBTU of natural gas to MWhs using a factor of 0.293 MWh/mmBTU; [b] All-electric, solvent-based DAC system; [c] This technology consists of a solvent-based DAC system that burns natural gas for plant electricity and to heat the calciner. Flue gas is captured by the system and the conversion rates listed reflect net system values. Upstream natural gas leakage can be accounted for in emissions accounting within ReEDS but is not in the results presented here. Here, units of MWh refer to heat input from natural gas rather than electricity.

Table 6. 2025 and 2050 retrofit capital costs for new builds produced for this study.

From Technology (Uncontrolled)	To Technology	To Capture Rate (%)	Retrofit Cost (2020 $/kW)		
			2025	2050 Mod.	2050 Adv.
Coal [a]	SCPC	90	2679	1177	1292
		99	3129	1375	1510
Gas-CC	Gas-CC	90	2021	810	1027
		97	2114	847	1074
	RE-CC	N/A	487	362	379
Gas-CT	RE-CT	N/A	425	317	332

[a] Applies to all existing and endogenously built uncontrolled coal capacity.

To compare results from these various CTS-network-enabled (henceforth "CTS Network") cost sensitivities with results using the legacy values of the per-tonne cost adder previously used in ReEDS, we ran *Net Zero* scenarios with values of $15 (historically the default value) and $36/tonne, representing a higher estimate from [20]. These are henceforth referred to as "Legacy Adder" scenarios.

Although this scenario framework allows for quantification of the impact of the inclusion of the CTS network representation relative to the incumbent $15 per tonne CTS cost adder, it does not allow us to isolate the effects of introducing the new CTS network constraints from differences driven solely by the differences in cost assumptions between the two approaches. As noted, the legacy method uses a $15 per tonne adder, whereas the CTS network representation uses component costs. These are not directly comparable; however, we can calculate a national average LCCTS for each CTS Network simulation, and use that as the point of comparison. To isolate the impact of the cost assumptions from the impact of the structural representation of CTS infrastructure, for each CTS Network cost sensitivity, we ran a "Harmonized Adder" in which we altered the value of the CTS cost adder from $15 per tonne to a value equal to the LCCTS endogenously determined in the CTS network sensitivity in each year. The resulting nationally (CO_2-weighted) averaged LCCTS in a given year and scenario are identical in both the harmonized adder and CTS network simulations. Differences between the paired scenarios are thus driven by the impact of transmission constraints and spatial variability in the cost and capacity of storage formations.

3. Results

We begin exploring the ReEDS model results by summarizing the investment pathways (capacity built by technology) and operations (annual electricity generation and CO_2 capture) through 2050. The subsequent subsections describe the scale and geographical distribution of CTS network investments, evaluate pipeline and storage cost sensitivities, and compare results from the CTS network scenarios with the legacy adder and harmonized adder versions of each scenario. We discuss the implications of these demonstrative results for the consideration of CTS in power system models, and we compare results from our modeling with the existing literature on CTS infrastructure development.

3.1. Base Scenario Results-Capacity, Generation, and CO_2 Capture

Figure 5 compares total capacity, generation, and CO_2 captured by modeled year across the conterminous United States for the three base scenarios with and without the detailed CTS representation. No CCS is built in the *No New Policy* scenario, regardless of the CTS representation, so only the *CTS-network-enabled* version is shown.

The annual electricity generation increases substantially in the coming decades in all scenarios due to the assumed growth in load. Note, the scenarios assume an equivalent load growth of 72% from 2022 to 2050. Under the *No New Policy* scenario, this increase in demand is met with increasing contributions from VRE generation supported by diurnal battery storage, coupled with continued generation from Gas-CC and the existing nuclear. The coal share of generation, while relatively steady in the near-term, is either replaced by Coal-CCS retrofits or declines in latter years as aging plants are retired and the remaining fleet is out-competed by VRE technologies, which continue to decline in cost, and natural gas. Note that all Coal-CCS capacity is the result of retrofitting existing facilities and there are no new, "greenfield" builds of Coal-CCS across all scenarios. However, as the 45Q incentive lasts for only 12 years from time of retrofit, the coal with CCS generation and capacity typically phase out by 2040. Gas-CC units that are retrofitted with CCS will begin to appear around 2034 and be primarily located in California, given the state's power sector emissions limit.

The net-zero scenarios absent LGP and AdvCCS shown in Figure 5 all exhibit similar behavior through 2040/2045. Across all scenarios, the declining limit on CO_2 emissions drives increased deployment and generation from clean energy technologies—primarily VRE—with the share of total generation increasing from 23% in 2022 to 81% and 71% by 2050 in the CTS-network-enabled versions of the *Net Zero* and *Net Zero*, *LGP*, *AdvCCS* scenarios, respectively. Generation from non-CCS coal and oil–gas–steam (OGS) technologies declines to nearly zero by mid-century, with almost all capacity retired by 2050. Gas-CC with CCS capacity and generation is present in all cases but increased dramatically in the Net Zero, LGP, AdvCCS scenarios relative to all others. Specifically, 2050 gas generation comprises 587 TWh under the CTS network scenario and 726 TWh under the harmonized adder scenario compared to an average of 153 TWh under the Net Zero assumptions. Similarly, coal with CCS retrofits increase from an average of 120 TWh per year from 2028–2040 under the Net Zero scenarios to slightly over double at 248 TWh per year from 2028–2040 under the Net Zero, LGP, AdvCCS scenarios.

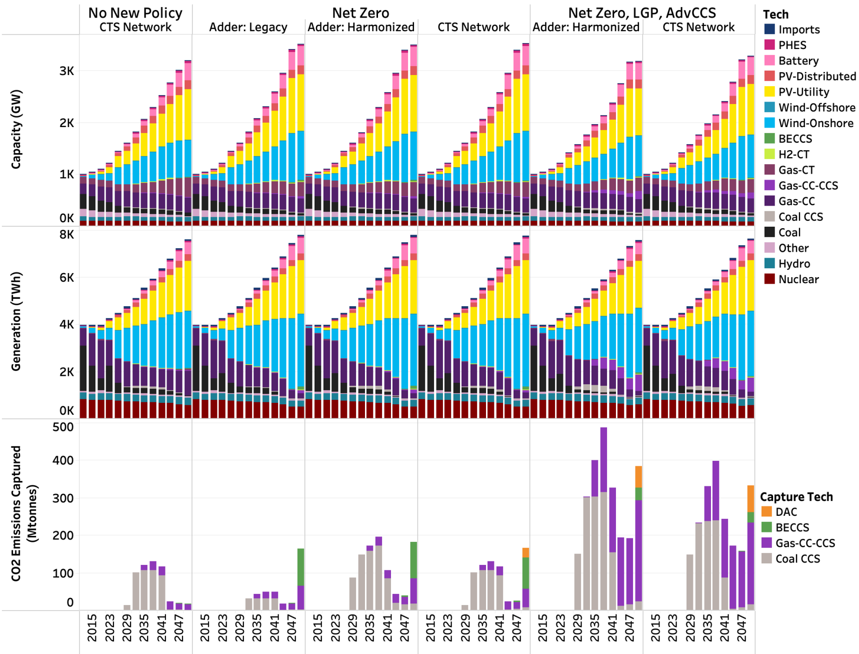

Figure 5. Evolution of total capacity (top), primary electricity generation (middle), and total mass of CO_2 captured each modeled year in the *No New Policy* scenario and *Net Zero* scenarios under the explicit CTS network representation, along with their LCCTS-equivalent *legacy* harmonized adder counterparts and the $15/tonne legacy representation. Points on generation plots demarcate busbar load. Technologies categorized as other are concentrated solar power (CSP), biomass and landfill gas (Bio + LFG), and oil–gas–steam (OGS).

Although the trends are highly consistent across the net-zero scenarios, differences emerge in the last 10 years of the period modeled. Across all net-zero cases, retrofitted Coal-CCS is phased out by 2040 while Gas-CC-CCS, BECCS, and DAC technologies are deployed. Gas-CC-CCS is used primarily as a source of generation, whereas BECCS and DAC are used primarily (and in the case of DAC, completely) as a source of negative emissions—to offset emissions from uncontrolled Gas-CC generation, as well as the limited uncaptured emissions associated with Gas-CC-CCS generation. Despite the consistency in the deployment of these technologies across the net-zero cases, the levels of each deployed and total CO_2 captured differ with total CO_2 captured ranging from approximately 180 Mtonnes per year to more than 400 Mtonnes per year in 2050.

Comparing the legacy adder *Net Zero* case to the associated CTS network case shows that the new CTS infrastructure representation results in a substantial increase in CCS deployment and CO_2 captured, primarily from coal-CCS in the 2028–2040 timeframe; however, this result is driven by the combination of the addition of the explicit CTS infrastructure representation and the costs assumed for CTS components. Given that costs are not harmonized between the two runs, this result alone does not allow attribution of the change to the CTS network implementation alone.

Thus, we turn to a comparison of the CTS network cases to the respective harmonized adder cases, which show that CCS technology deployment and the associated CO_2 captured are 6% and 5% less in the CTS network cases than in their harmonized adder counterparts. This occurs despite the fact that the cost adders used in the harmonized adder cases are explicitly calculated as the yearly LCCTS values from the associated CTS network cases. This result indicates that explicitly accounting for CTS infrastructure investment, operation, and constraints creates a moderate disincentive for CO_2 deployment and use. Indeed, this finding holds across the suite of cost sensitivity scenarios, with the CTS network representation decreasing overall CO_2 capture by an average of 4% from each sensitivity's harmonized adder case.

Finally, comparing the *Net Zero* scenarios to the *Net Zero*, *LGP*, *AdvCCS* scenario demonstrates that substantially more Gas-CC-CCS and DAC are deployed under the *Net Zero*, *LGP*, *AdvCCS* scenario, driven by the more favorable natural gas price and technology conditions. The decline in CO_2 captured by BECCS is primarily driven by the fact that the technology improvements assumed for Gas-CC-CCS and DAC under the "Advanced CCS" cost and performance projections outpace those for BECCS.

3.2. CTS Network Investments

Figure 6 maps the CCS and CTS infrastructure buildout in 2050 for both the harmonized adder and CTS network simulations of the two net-zero scenarios. Note the entire suite of potential reservoirs and pipeline options are available in these scenarios, and the results presented in Figure 6 reflect only those that are endogenously built.

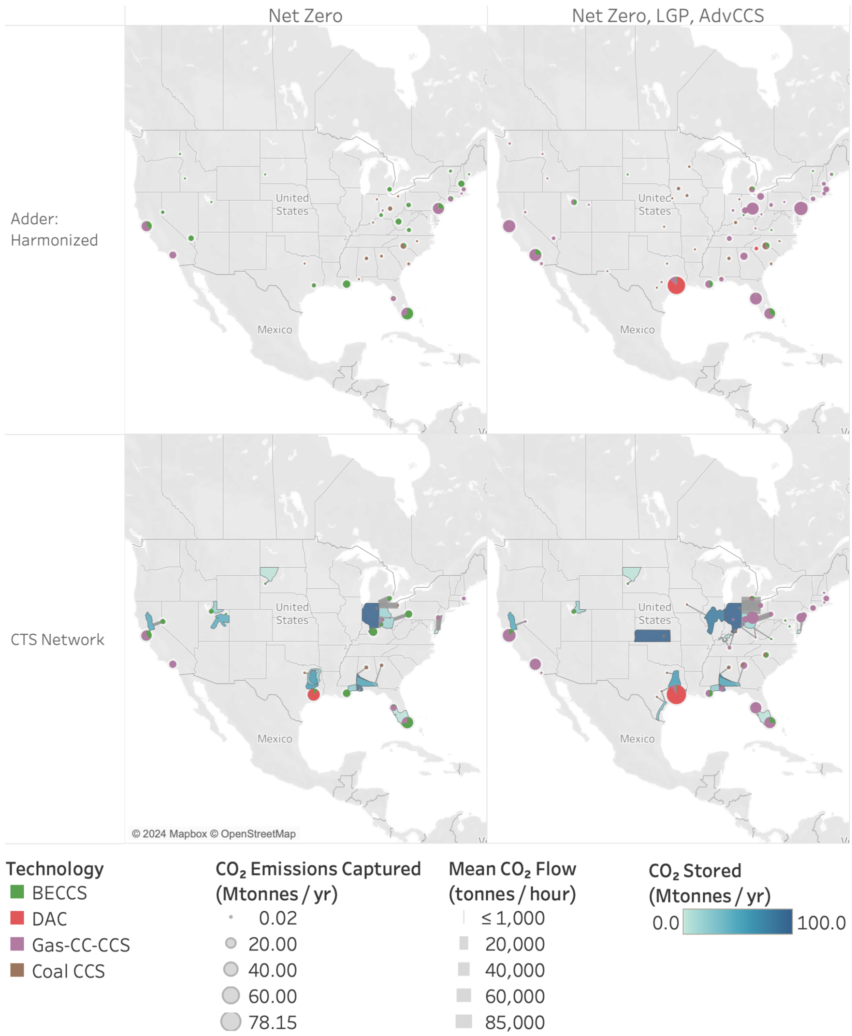

Figure 6. Maps of CCS and CTS operation in 2050 from the *Net Zero* and *Net Zero*, *LGP*, *AdvCCS* scenarios with the detailed CTS representation and the LCCTS-equivalent harmonized adder. The pie charts are sized to show CO_2 captured, CO_2 pipelines are sized to show total CO_2 mass flow, and CO_2 saline aquifers are colored to show cumulative CO_2 stored. Note that no pipelines or aquifers appear in the harmonized adder maps because the model is not explicitly representing them.

Two key findings are demonstrated by these maps. First, comparing the harmonized adder cases to their respective CTS network cases shows that the introduction of CTS network constraints to the model, in addition to reducing the total volume of CO_2 captured (as noted above), leads to a spatial consolidation of CCS investments in both scenarios. Under the *Net Zero* scenario, enabling the detailed representation reduces the number of regions investing in CCS projects from 26 to 16, and in the *Net Zero*, *LGP*, *AdvCCS* scenario, the number of regions falls from 49 to 35. Across the entire set of cost sensitivities, we observe an average decrease of 27% in the number of balancing areas hosting CCS investments under the CTS network representation.

Second, irrespective of the scenario or CTS representation, we observe clear consistency in the spatial distribution of CCS capacity deployed. This consistency results from the fact that natural gas prices as well as plant- and region-specific differences in capital costs are key drivers of CCS costs and empirically drive the location of investments. The majority of 2050 CCS investments in both scenarios are in Gas-CC-CCS and gas-powered DAC capacity, and the majority of investments in these technologies occur in the eastern Midwest and Texas, where natural gas prices are projected to remain among the lowest in the country. These regions also host some of the lowest cost lithologies for saline storage in the country, minimizing the need for long interstate CO_2 pipelines. Finally, the transition from Coal-CCS, primarily built in the same regions given the existing units' locations, to Gas-CC-CCS and gas-powered DAC implies a utilization of previously built CCS infrastructure.

In both CTS network cases, we observe that more than 65% of all CO_2 captured in 2050 is stored in just two formations: the Mount Simon basin, located in Indiana and several neighboring states; and the Frio basin, which runs along the Texas Gulf Coast.

Next, we expand upon these reference CTS cost results by comparing them with sensitivities.

3.3. Sensitivity of CTS Investments to Infrastructure Costs

CO_2 capture and CTS investments in 2050 for the full suite of CTS cost sensitivities are compared in Figure 7, along with the $15 (the default legacy adder value) and $36 per-tonne "high-cost" legacy adder scenarios as points of comparison.

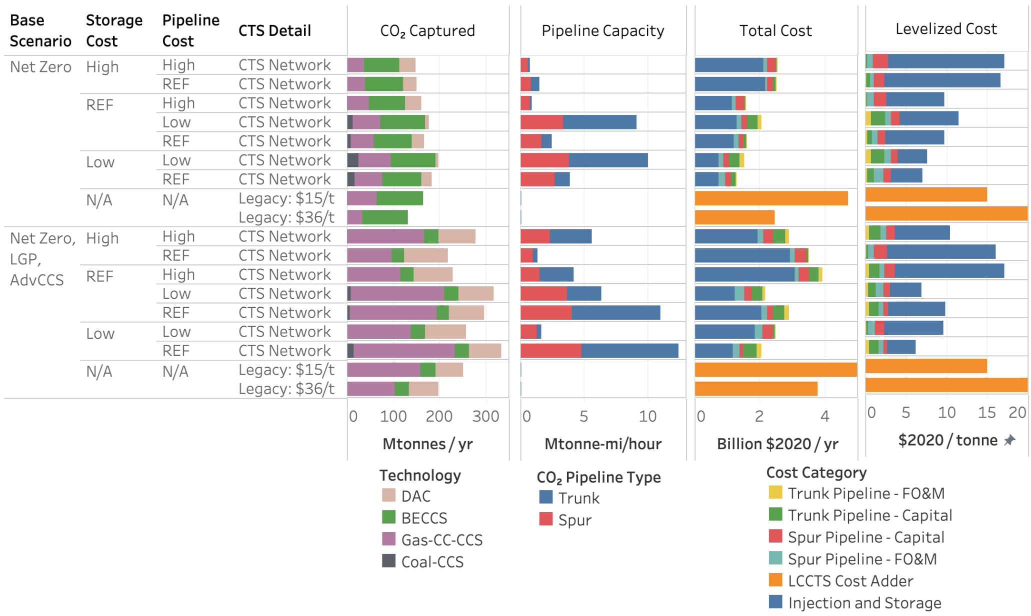

Figure 7. Summary of CO_2 capture, pipeline capacity, total annual cost of CTS infrastructure and operation, and the levelized cost of CTS in 2050 for each sensitivity. Note: The LCCTS entry for the $36/tonne legacy adder scenario exceeds the axis limits.

We observe that CO_2 capture is relatively insensitive to CTS costs under the Net Zero scenarios, increasing 1.22× from the minimum to the maximum volumes. That range is expanded under the Net Zero, LGP, AdvCCS scenario, which sees a 1.63× increase from its minimum to maximum amounts of CO_2 captured.

The total capture in 2050 ranges from 176 to 192 Mtonnes per year in the *Net Zero* sensitivities and 341 to 393 Mtonnes per year in the *Net Zero*, *LGP*, *AdvCCS* sensitivities.

To contextualize the scale of these investments, we can look to the scale of the existing infrastructure. As of 2015, NETL's database of CO_2 pipelines indicated that nearly 50 pipelines spanned roughly 4500 miles (7242 km) in the United States and Canada, with most pipelines located in the Permian Basin region for EOR [32]. Although the existing pipelines could accommodate 200 Mtonnes/yr, the actual mass throughput was substantially less, at 68 Mtonnes/yr. With this much of a lower capacity factor (38%) than the 85–99% determined by ReEDS for the operation of future CTS infrastructure investments, the 85–240% increase in overall US and Canadian CO_2 capacity modeled in these sensitivities would enable a 225–630% increase in annual CO_2 throughput.

The contributions from each CCS technology built are broadly similar to the results from the base scenarios that we summarized above, with Gas-CC-CCS accounting for roughly 1/6 to 1/3 of CO_2 capture in the *Net Zero* sensitivities and 3/4 in the *Net Zero*, *LGP*, *AdvCCS* sensitivities. The figure would be substantially different across all cases in the 2028–2040 time period when Coal-CCS is the primary contributor to carbon captured. Still, smaller amounts of Coal-CCS remain in 2050 under some scenarios where storage and pipeline costs are favorable enough to discourage their endogenous retirement.

Most of the difference in the 2050 total CO_2 capture from one sensitivity to the next is attributable to differences in Gas-CC-CCS generation, with CO_2 capture from DAC and BECCS varying relatively less. The reason for this difference in CTS cost sensitivity across technologies stems from the different roles each technology plays in the power system. DAC and BECCS are largely built to allow for the continued operation of the existing, uncontrolled Gas-CC fleet (rather than Gas-CTs due to the former's higher efficiency), thereby maintaining its ability to provide peaking capacity. This combination of existing, uncontrolled fossil generation and CDRs is a lower-cost alternative for ensuring resource adequacy than building new zero-carbon capacity, and it remains so by a margin larger than the range of CTS costs imposed in these sensitivities. Gas-CC-CCS, on the other hand, is built in regions where additional energy is needed to meet load, and competes with a wide range of zero-carbon generation technologies, such as RE-CC, geothermal, and VRE. The cost differences are smaller between Gas-CC-CCS (paired with some CDR to cover the fraction of its emissions that are not captured) and these other technologies, so investments shift predominantly toward wind and RE-CC as the cost of CTS is increased.

Moving on to transportation infrastructure, we compare total distance-weighted pipeline investment in the second column of Figure 7, where each segment's CO_2 mass flow capacity is multiplied by its length. Here, we note that quadrupling the pipeline costs reduces the total pipeline investment by roughly 10× in both *Net Zero* scenarios, but it has little impact on total CO_2 capture in comparison. This reflects a shift toward investment in CCS closer to saline aquifers and a trade-off with transmission investments, which increase (on a similar MW-mi basis) by 1.4× and 1.3× across the *Net Zero* and *Net Zero*, *LGP*, *AdvCCS* cost sensitivities, respectively, with increasing CTS costs as generation from the CCS capacity is transmitted over a longer distance to load centers.

Higher pipeline costs also shift transport investments toward spur pipelines directly connecting capture sites to storage sites as long-distance trunk pipelines become less economical; similarly, CCS investments shift closer to saline aquifers (as opposed to a shift in which aquifers are developed). These findings provide credence and further insight into the previous modeling efforts that used coarse regional CTS cost estimates to assert that pipeline costs are likely to have little effect on CO_2 capture [33].

The distribution and utilization of injection wells and saline storage are not compared in Figure 7, but we note that across the suite of sensitivities, few saline aquifers reach the cumulative injection limits enforced in Equation (12) and force captured CO_2 elsewhere. In several sensitivities, however, the geologically imposed limit on hourly injection rates (described in Equation (11)) is binding for some periods at several aquifers, so that constraint is likely contributing to the construction of longer pipelines and the development of higher-cost aquifers. The limitation on injection rates is also reached under several scenarios that have significantly higher Coal-CCS deployment given its higher emissions capture rate.

Among the CTS-network-enabled sensitivities, the total annualized cost of building and operating CTS infrastructure in 2050 ranges from $1.1 billion (2020 $) in the low-cost pipeline and storage *Net Zero* sensitivity to almost $3.9 billion under the high-cost storage and reference pipeline costs in the *Net Zero*, *LGP*, *AdvCCS* scenario, reflecting as much as 2.4% of bulk electricity system costs in 2050.

One of the more striking findings from the results compared in Figure 7 is the breakdown of CTS costs between transportation and storage. Amid the *Net Zero* cost sensitivities, pipeline costs account for 10–40% of total CTS costs, with the rest attributed to storage and injection. The pipeline costs represent less than 20% of the total CTS costs in most sensitivities. This underlines the finding that although pipeline costs are important in influencing the regional distribution of CCS investments, they are likely to play only a minor role in determining CCS capacity at a national scale.

Translating these system costs into a LCCTS by dividing by total CO_2 captured, we note that LCCTS is more sensitive to pipeline and storage costs than the overall levels of CO_2 capture. LCCTS varies from $5.60 to $17.41/tonne in the *Net Zero* scenarios and from $5.33 to $17.67/tonne in the *Net Zero*, *LGP*, *AdvCCS* sensitivities. This increase of approximately 3.15× and 3.31× in LCCTS for a 4× change in pipeline and storage costs suggests that investments in generation assets and their operations can be shifted to some degree to concentrate CCS and CTS investments closer to lower-cost saline aquifers, buffering against some of the cost increase.

The LCCTS as determined in these sensitivities are broadly lower than those previously estimated in the literature, as in [20]. The values of $15/tonne and $36/tonne previously used in the legacy adder CTS representation are much higher than all but the high-cost storage sensitivities and result in substantially less CCS investment. These differences might be partly driven by differing assumptions (especially with regard to the density of monitoring wells), but with reference cost assumptions resulting in an LCCTS roughly half the previous value of $15/tonne, our results suggest that such an estimate might be too high.

4. Discussion

In this study, we have developed a generalized methodology for the explicit representation of CO_2 pipeline and storage infrastructure investments and operation as an addition to the classical CEM problem. We have described the cost and availability of the saline storage of CO_2 in the United States and assumptions to populate the CTS representation with pipeline and storage costs before presenting findings and comparisons from running the ReEDS model with the previous simple adder approach and the explicit representation of pipeline and reservoirs presented here. In short, the methods presented here include the data and constraints required to represent the operation of CCS-enabled power plants and direct air capture facilities, as well as the required network and storage needed to transport and store the captured emissions, respectively.

The methods presented here are useful for the energy modeling community in that they present the workflow required for a detailed representation of CCS/CTS in a continental-scale power expansion model. The interpretation of the input data from the NETL cost models requires matching the assumptions from the ReEDS model, as well as summarizing the parameters into terms that are within the capabilities of linear programs, noting that linear programs retain the computational tractability for modeling at such scales. The data are also useful to researchers in that (a) the reservoir characteristics include the costs and constraint parametrization, as well as the retrofit cost data are relevant to those within the USA, and (b) the remaining data focused on greenfield investment costs and performance, as well as pipeline and spurline costs, and the characteristics can serve as a baseline regardless of regionality. The methods serve as a guideline for how to conceptualize detailed CCS equipment investment and operational decisions within long-term planning models. Although ReEDS is presented as an exemplary application, the methods here are generalizable to other systems that require CTS, and all the data are publicly available through the ReEDS GitHub repository. Finally, the results serve to demonstrate the impact of the methodology developments in the representation of direct air capture and carbon-capturing electricity generation technologies in net-zero power systems.

We find that an explicit representation of CTS infrastructure consolidates the geographic distribution of CCS investments and tends to slightly decrease overall CO_2 capture relative to a simplified CTS cost adder approach that uses an equivalent LCCTS (i.e., the harmonized adder cases). We show how the latter effect is primarily due to the CTS constraints themselves rather than a difference in overall LCCTS between scenarios, and that the effect is moderate (reducing capture by <13% in the scenarios modeled).

Under the core *Net Zero* scenario using the explicit CTS representation, approximately 720 miles (or 1159 km) of CO_2 pipeline will be built by 2050, transporting 172 Mtonnes of CO_2 per year to storage locations concentrated in the Gulf Coast, Pennsylvania, and the Midwest. Storage of this magnitude represents approximately 13% of 2020 U.S. power sector CO_2 emissions [34]. The construction of CO_2 pipeline infrastructure of this magnitude would represent an 87% increase in CO_2 pipeline capacity and a 230% increase in annual throughput from 2015.

The CTS cost sensitivity results indicate that CCS investment is relatively insensitive to pipeline, injection, and storage cost assumptions, and that deployment of DAC and BECCS technologies in particular is nearly unaffected by the CTS cost assumptions due to the very high value such technologies provide in a net-zero emissions system and the limited number of competing technologies.

We also find that injection and storage costs comprise the majority share (65–90%) of the total CTS costs, with pipeline infrastructure comprising 10–35% of the costs. Furthermore, we find that the constraints imposed by the operational and physical limits of CTS infrastructure rarely bind within the optimization. Given this, a detailed CTS network representation might not be necessary if the spatial distribution and scale of CTS infrastructure is not highly relevant, for instance, in studies focused solely on national-scale outcomes; however, including the detailed representation in the model has a minimal impact on model solve times and enhances our understanding of alternative investment pathways with rich information about an important aspect of the location, capacity, and operation of future CO_2 transportation and storage infrastructure.

Caveats and Research Opportunities

Political and cultural considerations are likely to play a substantial role in planning decisions given the cross-boundary nature of pipeline infrastructure. These drivers or constraints on CTS infrastructure deployment and operation are not considered in this analysis or within the model.

Nonetheless, the methodology described here enables us to begin addressing a new palette of research questions about the role of CTS in the electricity sector, as well as its linkage with other parts of the economy. We conclude by identifying several obvious paths for further investigation and improvement of the CTS representation presented here.

As alluded to above, there are numerous existing CO_2 pipelines in the United States today, most of which serve the EOR market. This existing pipeline infrastructure could be included in the modeling framework with additional data and would not require modification of the constraints themselves. However, a caveat is necessary with the higher realized pipeline capacity factors as we are representing the investment through continuous variables, which allows for exact sizing to fit needs; representation with discrete variables is overly computationally intensive and remains for future research.

From a broader perspective, the methods and data developed here could be applied with further considerations to several aspects of CTS. First, the high-level representation of CTS infrastructure avoids social and environmental impacts and considerations; inclusion of these factors, especially at the local level, would be a valuable contribution to the literature. Second, although we explore the sensitivity of results to CTS component costs, the analysis would benefit from further exploration of "tipping points" for various cost components, as well as changing market conditions such as energy prices and political conditions. Finally, we are actively working to include the CTS representation in a combined industry–power-capacity expansion model.

Some of the prior works have shown EOR to comprise a substantive share of the end use for captured CO_2 [35]; under economy-wide decarbonization scenarios, while EOR demands for CO_2 could decline, other end uses for CO_2 could grow and could, therefore, influence decisions around carbon capture and CTS infrastructure. Thus, expanding the representation of potential end uses for CO_2 could be valuable but would require some additional complexity (i.e., addition of oil production sites) that is currently outside of the purview of ReEDS. In addition, there is no representation of the further use of CO_2 such as mineralization [36].

We do not currently consider CO_2 leakage from the CO_2 pipeline and injection network or from the saline aquifers themselves, but the addition of this feature would be straightforward, especially considering the extensive work carried out by many investigators, especially the National Risk Assessment Partnership (NRAP), a multiyear research-and-development effort sponsored by FECM that involves several national laboratories. For example, NRAP's open-source integrated assessment model can be used to estimate leakage risk for a storage project [37].

Finally, although we have focused here on the electricity-sector-related CTS infrastructure investments, previous multi-model efforts have produced comprehensive, cross-sectoral projections for CTS deployment [38]. Considering CO_2 sources and sinks outside the electricity sector would be required to contextualize the CTS investments presented in scenario results here as part of a broader future ecosystem for trading, transporting, utilizing, and storing CO_2. In particular, our finding that injection and storage costs make up the majority of CTS costs might be a power-sector-specific outcome, because other industries might have more limiting siting and technology alternatives.

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Data Availability Statement: The model and data used in this analysis are publicly available at: https://github.com/NREL/ReEDS-2.0, accessed on 1 May 2024.

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Abbreviations

The following abbreviations are used in this manuscript:

Acronym	Translation
45Q	Portion of the IRA specific to CCS incentives
AdvCCS	Indicator for reduced CCS costs
BECCS	Biomass burning generator with CCS
CCS	CO_2 capture and storage
CDR	carbon dioxide removal
CEM	Capacity expansion model
CO_2	Carbon dioxide
CO2_S_COM	CO_2 Saline storage cost model
CO2_T_COM	CO_2 transport cost model
CTS	CO_2 transportation, injection, and storage
DAC	Direct air capture, powered by electricity
EOR	Enhanced oil recovery
FECM	Fossil energy and carbon management
Gas-CC	Gas-fired combined cycle generator
Gas-CC-CCS	Gas-CC unit with CCS
Gas-CT	Gas-fired combustion turbine generator
IPM	Integrated planning model
IRA	Inflation Reduction Act
LCCTS	Levelized cost of CTS
LGP	Low gas price
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratory
NG DAC	Direct air capture, powered by natural gas
NRAP	National Risk Assessment Partnership
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
OGS	Oil–gas–steam generator
RE-CC	Renewable-fuel powered combined cycle unit
ReEDS	Regional Energy Deployment System
SCPC	Supercritical pulverized coal
VRE	Variable renewable energy

Appendix A. ReEDS Modeling Assumptions

We made several choices in configuring these ReEDS simulations to minimize the effects of path dependency (where small changes in model results in early years across scenarios lead results to diverge from one another over time), to isolate the effects of the CTS representation and simplify the interpretation of results. First, although ReEDS offers the ability to represent natural gas prices with supply curves, we opted to represent the natural gas supply as perfectly inelastic, with natural gas prices varying regionally and temporally but consistently across scenarios with no impact from consumption.

To further facilitate the comparison of results, we enforced the supply and demand constraint on hydrogen production at the national level, with the model's explicit representation of hydrogen transport investment options disabled. In keeping with the simplified hydrogen representation and a power-sector-focused analysis, we did not include an exogenous demand for hydrogen.

We used default values for all other model settings. These settings can be viewed in cases.csv within the main branch of the open access model repository.

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