Carbon Management in Net-Zero Energy Systems

White Paper

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EVOLVED ENERGY RESEARCH

ABOUT THIS REPORT

Environmental Defense Fund commissioned Evolved Energy Research to advance understanding of how carbon management in energy and industry could play a role in achieving net-zero greenhouse gas emissions in the U.S. by 2050. The Bernard and Anne Spitzer Charitable Trust provided financial support for this study.

PREPARED BY

Gabe Kwok
Ben Haley
Ryan Jones

EVOLVED ENERGY RESEARCH

ABOUT EVOLVED ENERGY RESEARCH

Evolved Energy Research (EER) is a research and consulting firm focused on questions posed by transformation of the energy economy. Their consulting work and insight, supported by complex technical analyses of energy systems, are designed to support strategic decision-making for policymakers, stakeholders, utilities, investors, and technology companies.

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Executive Summary

Background

Recent studies from the international community suggest that meeting net-zero greenhouse gas (GHG) emissions by mid-century will require managing the capture of billions of tons of carbon dioxide (CO_2). The technologies to do so exist today, at least at the prototype or demonstration stage, and may be crucial for decarbonizing key sectors and drawing down atmospheric CO_2. However, despite its potential, the role of carbon management remains largely nascent.

This paper sets out to provide a deeper understanding of carbon management's role in energy and industry through answering key questions: how much CO_2 capture is required? Which technologies capture significant quantities of CO_2? When is CO_2 stored or utilized? How sensitive are outcomes to alternative assumptions? How could strategies vary regionally?

Approach

The analytical approach for this study is based on our EnergyPATHWAYS and Regional Investment and Operations (RIO) models. Pairing both models to simulate the U.S. energy and industrial system is a framework that has been applied in recent net-zero analyses, including *Carbon-Neutral Pathways for the United States (Williams et al., 2021)* and Princeton University's *Net-Zero America* study (Larson et al., 2021).

The scope of our analysis includes technological carbon management solutions in the energy and industrial system, while non-technical carbon management (e.g., nature-based solutions) are outside the scope. We model a suite of carbon capture technologies and CO_2 applications, including retrofits of existing energy infrastructure, negative emissions technologies (NETs), CO_2 storage in geologic formations and CO_2 utilization for synthetic fuels. We identify their cost-optimal deployment across sixteen U.S. regions to achieve deep emissions reductions.

We construct a Core Net Zero (CNZ) scenario where the U.S. economy achieves net-zero GHG emissions by 2050 at least-cost using baseline energy technology cost and resource availability assumptions. This baseline provides a starting point to compare against a range of modeled uncertainties that could materially affect carbon management outcomes. We explored alternative: fossil fuel costs; geologic sequestration cost and potential; biomass cost and potential; renewables cost and potential; electrolysis costs; and end-use electrification rates.

Our base assumption for achieving net-zero GHG emissions by 2050 is: (a) modeled energy and industry (E&I) CO_2 decreases to 0.0 Gt; and (b) the combination of non-CO_2 emissions and the land sink sum to zero using carbon dioxide equivalents with GWP100 (a common simplification for economy-wide net zero analyses). Since the trajectories for non-CO_2 mitigation and lank sink enhancement are both highly uncertain and affect the need for carbon management in the energy system to maintain net-zero GHG emissions, we further modeled 2050 E&I CO_2 targets of -0.5 Gt and 0.5 Gt.

However, it is becoming increasingly clear that short-lived non-CO_2 gases, such as methane, are disproportionately responsible for global warming impacts on shorter timeframes. This suggests that non-CO2 gases are both a great liability to net-zero objectives (because they cause warming) and a great opportunity (because mitigation of their production and leakage presents an efficient pathway to reduce warming). This caveat emphasizes the importance of research we are currently undertaking to develop improved methods that can adequately consider the climate impacts of all GHGs over multiple timescales.

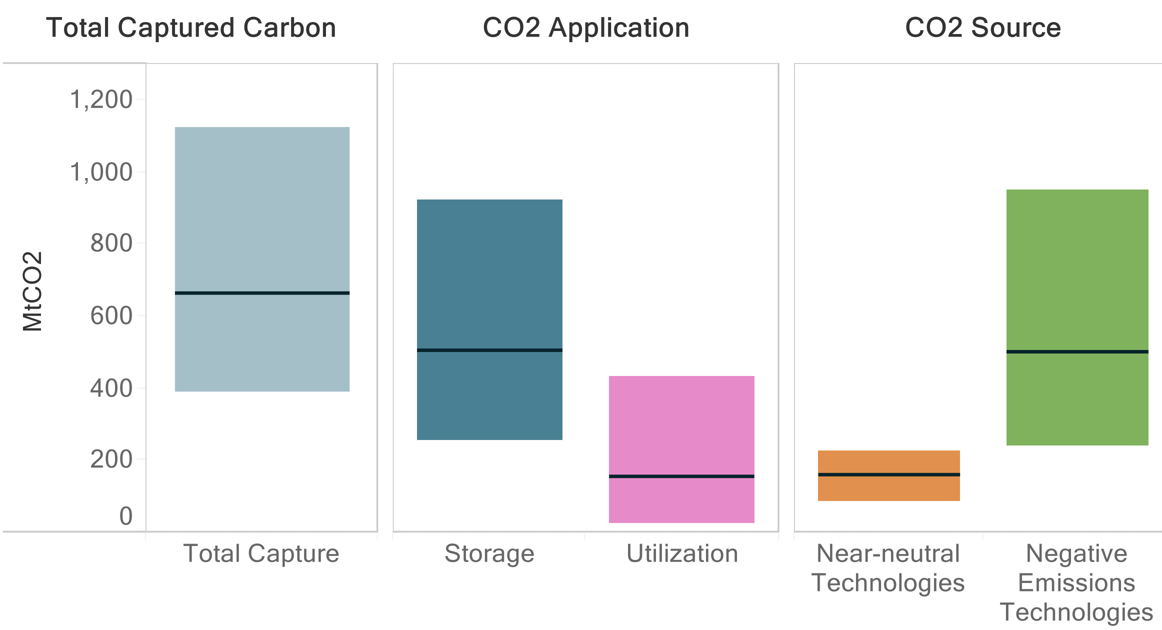
Key findings

Carbon management is a pillar of a least-cost pathway to net-zero

We find that carbon capture deployment in energy and industry is necessary by mid-century even assuming success across all other mitigation strategies, including highly aggressive energy efficiency, electrification, electricity decarbonization, enhancement of the land sink and mitigation of non-CO_2 emissions. In the CNZ scenario, nearly 700 $MtCO_2$ is captured by mid-century, which is equivalent to about 10% of today's U.S. gross GHG emissions or all energy CO_2 emissions in Texas. Accounting for a variety of uncertainties, total CO_2 capture ranges from 400 to 1,100 $MtCO_2$. If the current land sink shrinks and/or non-CO_2 emissions prove more difficult to abate, the importance of carbon management in energy and industry is further increased.

Both CO_2 storage and utilization for synthetic fuel production are important applications. Storage ranges from 300 to 900 $MtCO_2$, which is well below estimated geologic sequestration potential, while CO_2 utilization ranges from 100 to 400 $MtCO_2$ across most circumstances. Captured CO_2 is overwhelmingly supplied from NETs (250 to 950 $MtCO_2$), including bioenergy with carbon capture, utilization, and storage (BECCUS) for fuel production and direct air capture (DAC). Near-neutral technologies, where fossil fuel is an input and 90% to 100% of emissions are captured, provide a much smaller share of CO_2 supply.

Carbon Management Metrics in 2050 with Modeled Uncertainties



Note: range reflects modeled uncertainties and line represents baseline projection (Core Net Zero scenario).

Negative emissions technologies are well-suited for net-zero GHG emissions

As emissions reductions accelerate from 2030 to 2050, CO_2 capture shifts towards NETs and these technologies supply three-quarters of total carbon capture in the CNZ scenario. BECCUS for fuel production is generally the lowest-cost option for supplying negative emissions due to: (1) its carbon capture efficiency (e.g., approximately 70-140 $MtCO_2$ is captured per 100 million tons of biomass); and (2) its versatility to displace fossil fuels. However, its deployment is constrained by an uncertain supply of sustainable biomass. Although DAC is not deployed in the CNZ scenario, it is an important technology to supply negative emissions under very plausible circumstances that may arise on the path to net-zero, such as slower consumer uptake of electric vehicles or lower biomass availability. Our analysis confirms that NETs deployment does not delay or avoid other mitigation strategies so long as a strong net-zero target is in place.

Fossil-based carbon capture faces hurdles in a net-zero context

Carbon capture at fossil-based power generation and hydrogen production facilities have characteristics that disadvantage their deployment. First, the electricity sector shifts towards very high levels of variable renewable energy (>70% of generation), which encourages investment in electrolysis, a competitor of blue hydrogen, and discourages thermal power generation. Second, large-scale deployment requires significantly scaling up CO_2 storage infrastructure. For example, if these technologies supplied one-third of end-use electricity and hydrogen demand, then approximately 1,200 $MtCO_2$ of annual storage would be required. Finally, carbon capture in these two sectors can only address their own emissions, whereas NETs can flexibly address residual emissions from any sector in the economy.

Achieving net-zero without carbon management has significant trade-offs

Excluding carbon management as a strategy is "technically feasible" but entails scaling biomass and renewable resources to potentially problematic levels (e.g., more than one billion tons of biomass). Given uncertainty about the supply of sustainable biomass and the challenges of siting renewables, taking carbon management off the table amplifies the risk of missing net-zero.

Prioritize carbon management's long-term role

Today's research and funding is largely focused on: (a) deploying point-source carbon capture at existing fossil-based facilities (e.g., retrofits of fossil power plants); and (b) using CO_2 for enhanced oil recovery (EOR), which often requires long-distance CO_2 pipeline networks. However, much of this infrastructure that is a retrofit candidate faces declining utilization and/or limited remaining operating lifetimes in the context of net-zero. In contrast, our analysis shows carbon capture technology is almost exclusively applied to new energy infrastructure and that significant capture (> 100 $MtCO_2$/yr) occurs 20 to 30 years from today. As a result, we believe focus should be expanded towards areas that better align with achieving net-zero in the long-term, including: (1) fostering the development of NETs; (2) placing value on both CO_2 storage and beneficial CO_2 utilization in low-carbon fuels; and (3) identifying and developing regional integrated carbon management hubs with shared infrastructure.

CO_2 is managed differently across the U.S. and is primarily used intra-regionally

We find significant variations in the sources of captured CO_2 and its application across U.S. regions due to differences in biomass, renewables and geologic sequestration potential. Nearly all captured CO_2 is stored or utilized within several hundred miles of the point of capture and not typically transported long distances across the U.S. Furthermore, since CO_2 utilization to produce synthetic fuel can be accomplished intra-regionally, there is little need to transport CO_2 long-distances to oil-producing regions for EOR.

Innovation across the carbon management supply chain is needed

Carbon management's ability to contribute towards net-zero GHG emissions depends on innovation across a chain of CO_2 capture, transportation, utilization and storage infrastructure. In our analysis, nearly all captured CO_2 in 2050 is from technologies currently in the demonstration or protype stage, and technologies that utilize CO_2 are at a similar stage of development. This suggests that significant research, development, and demonstration (RD&D) is necessary to ensure the technologies most compatible with a least-cost net-zero energy system (e.g., NETs and synthetic fuel production) are deployed in a timely manner.

The risk of carbon capture extending the life of fossil fuels is low if we are on a path to net-zero

One key concern about carbon management is that it facilitates continued fossil fuel use, but our net-zero analysis finds large reductions in fossil fuel consumption (80-90% below 2005 levels by 2050). However, carbon management technologies could enable some fossil fuel use, such as heat or feedstocks for industrial applications that are challenging or very expensive to abate. Since carbon management does not inherently address non-CO_2 pollution, such as methane, it will be important for policymakers to monitor and address co-pollutants associated with carbon management, lest they negate its near- and long-term climate benefits.

Background

U.S. and international deep decarbonization studies have identified energy system strategies that are necessary for achieving emissions reductions consistent with climate stabilization targets. Energy efficiency, end-use electrification, and electricity decarbonization, commonly referred to as the “three pillars”, feature consistently across a large body of technical work demonstrating low-carbon energy systems aligned with “80% by 2050” targets.[1] Analyses consistent with more aggressive greenhouse gas (GHG) ambition, such as “net-zero by 2050”, have identified carbon management as a fourth pillar of deep decarbonization.[2]

As shown in Figure 1, carbon management consists of two approaches: (1) technical solutions in energy and industry; and (2) non-technical or natural solutions outside of the energy system, such as afforestation/reforestation and ocean-based carbon dioxide removal (CDR). In this paper, we assess technical carbon management options, including carbon capture at fossil-based power plants and industrial facilities, as well as negative emissions technologies such as direct air capture and bio-energy with carbon capture.

Figure 1 Carbon Management Approaches and Technologies

Carbon Management		
Technical (energy & industry)	Fossil-based point source carbon capture	Power plants
		Industrial facilities
	Negative emission technologies (“NETs”) or Carbon dioxide removal (“CDR”)	Direct air capture
		Bio-energy with carbon capture
Non-technical (natural)		Afforestation/Reforestation
		Soil carbon sequestration
		Enhanced mineralization
		Ocean-based CDR

[1] See Williams et al. (2014)

[2] See Haley et al. (2018) and Williams et al. (2020).

Technological carbon management research has primarily focused on its role to decarbonize specific sectors (e.g., electric power) or fuels (e.g., hydrogen), as well as individual technology assessments. In the U.S., recent studies have considered the role of carbon capture retrofits at existing facilities, the use of captured CO_2 in enhanced oil recovery (EOR) and the development of long-distance CO_2 transportation to address spatial mismatches between existing emissions sources and geologic sequestration sites.[3] Net-zero energy system-wide studies show a wide range of results for the total quantity of CO_2 captured, the sources of captured CO_2 (e.g., fossil fuel or biomass) and its application (e.g., sequestration or utilization).

The goal of this white paper is to advance understanding of how carbon management in energy and industry could play a role in achieving net-zero GHG emissions in the U.S. The technologies, sectors, and applications where carbon management could be implemented to support net-zero is vast. Our analysis incorporates a wide range of uncertainties to further understand what drives alternative carbon management outcomes and which technologies are robust in the long run.

The remainder of this paper is organized as follows. Section 2 provides an overview of the scope of carbon management technologies and applications considered in this work and our modeling approach and assumptions. Section 3 presents analytical results for carbon management in the context of a net-zero GHG emissions, and Section 4 summarizes key findings and conclusions.

[3] For example, see Edwards and Celia (2018) and Great Plains Institute (2020).

Approach and Assumptions

Carbon Management Scope

To understand the contribution of carbon management to meet net-zero GHG emissions, we evaluated a suite of carbon capture technologies and applications of CO_2 across the energy and industrial sectors, as shown in Figure 2. We represent retrofits of existing energy infrastructure such as fossil power plants, corn ethanol facilities and cement production, as well as new fuel production facilities that could play a meaningful role in a deeply decarbonized energy system.

We categorize carbon capture at power generation, blue hydrogen and industrial facilities as near-neutral emissions technologies since their energy input is fossil fuel and capture rates range from 90% to 100%. This designation refers to combustion and process emissions at the facilities and does not account for potential upstream or downstream GHG emissions leakage, an important consideration that we discuss later in this paper. In the electric power sector, we model retrofits of existing fossil resources, as well as new gas-fired resources with capture rates of 90% and 100% (i.e., Allam Cycle). We model carbon capture in the cement industry due its high level of emissions and lack of alternative decarbonization options, and we note that other industrial sectors (e.g., iron and steel) could apply carbon capture.

Direct air capture (DAC) and the capture of CO_2 in the production of biofuels (also referred to as bioenergy with carbon capture, utilization, and storage or "BECCUS") are categorized as technical negative emissions technologies ("tech NETs") since they extract CO_2 directly from the atmosphere or indirectly through the CO_2 embodied in biomass.[4] Strategies outside of the energy sector that increase terrestrial carbon sequestration ("land NETS") are not explicitly modeled, but we include a range of alternative land sink assumptions in our analysis, as discussed below.[5]

Once captured, CO_2 follows two possible routes: (1) sequestration in geologic formations; or (2) utilization in the production of synthetic fuels, such as liquids and methane.[6] Our modeling

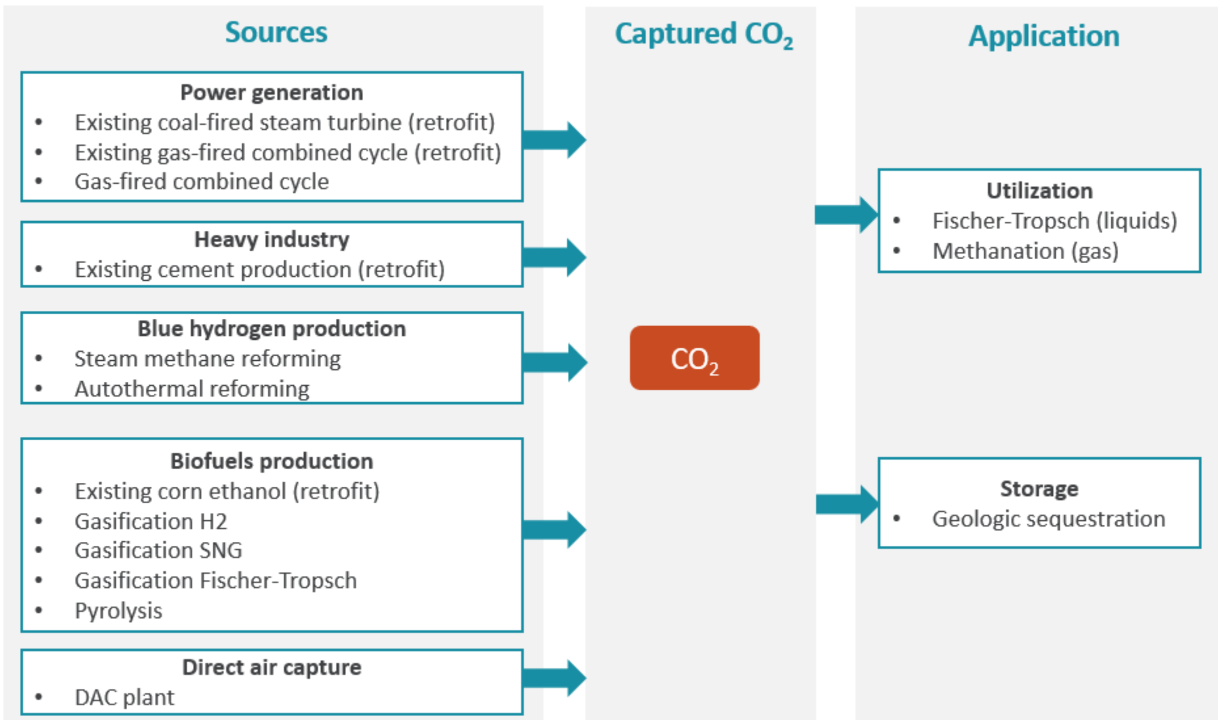
[4] We refer to captured biogenic and atmospheric CO_2 as "NETs CO_2".

[5] Technical and natural negative emissions technologies are collectively referred to as "carbon dioxide removal" (CDR) in other work, while land NETS are frequently described as "natural climate solutions."

[6] See IEA (2019) for an extensive review of CO_2 utilization technology options.

approach identifies the cost-optimal carbon capture technology deployment and application of CO_2 to meet net-zero emissions as part of the solution for the broader energy system.

Figure 2 Modeled CO_2 Sources and Applications



Study Approach and Modeling Framework

Recognizing that carbon management outcomes to achieve net-zero GHG emissions are sensitive to alternative assumptions, we used the following approach. First, we construct a **Core Net Zero (CNZ)** scenario reflecting our base assumptions and this is the starting point to compare all other sensitivities against. Next, we implement multiple sensitivities off the CNZ scenario that reflect **uncertainties** affecting the cost and viability of various carbon management options. This process allows us to test the robustness of our results and draw additional insights, including insights for lawmakers looking to pass policy to improve carbon management tools and practices. We explore a range of uncertainties around fossil fuel prices; resource potential; technology costs; end-use electrification rates; and energy and industrial CO_2emissions reduction targets. Finally, we evaluate topic-specific **case studies** to better understand the role of fossil-based carbon capture technologies and the implications of not pursuing the innovation needed for carbon management to be technologically ready.

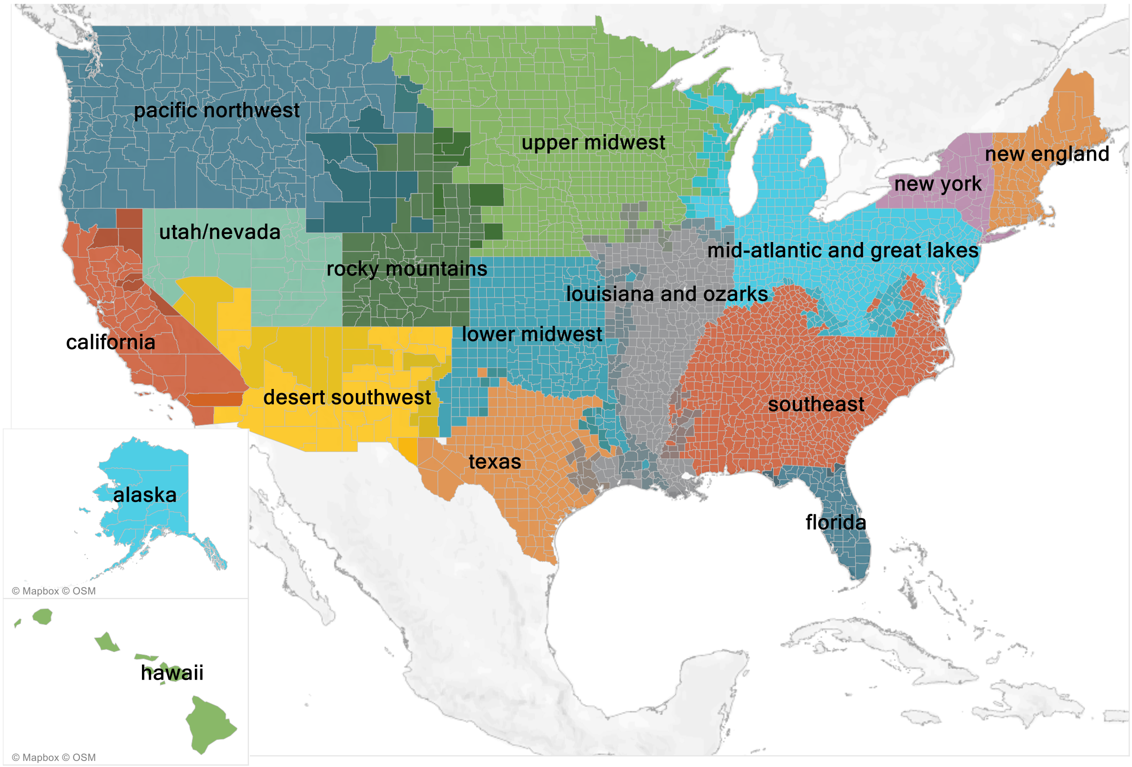
The analytical approach for this study is based on our EnergyPATHWAYS (EP) and Regional Investment and Operations (RIO) models. Pairing both models to simulate the overall U.S. energy and industrial (E&I) system is a framework that has been applied in recent U.S. net-zero analyses, including *Carbon-Neutral Pathways for the United States* and Princeton University's *Net-Zero America* study.[7] This framework includes two steps: (1) EP produces a bottom-up projection of final energy demand for all end-uses across the economy based on user-defined energy efficiency and fuel switching levers; and (2) RIO determines the cost-optimal energy supply to meet energy demand projections from EP, while meeting annual emissions and additional constraints.

Optimal investments across the electricity and fuels sectors are determined simultaneously. This unique framework is well-suited to evaluate carbon management because the supply and demand for captured CO_2 crosses multiple sectors and it captures dynamic interactions that occur as lines between traditionally distinct sectors become blurred over time. For example, a DAC facility: (a) is a major electric load; (b) can supply CO_2 for synthetic fuel production; and (c) can supply CO_2 for sequestration to address residual or "legacy" emissions in any sector.

We represent the U.S. E&I system across 16 geographic regions, as depicted in Figure 3. These regions are characterized by important differences that affect how deep decarbonization occurs, including: (a) resource endowments such as renewable resource potential and quality, biomass feedstock supply and geologic sequestration availability; and (b) electric transmission constraints between regions. Regional carbon management implications are strongly influenced by resource endowments, which we discuss in detail in section 3.2.

[7] See Williams et al. (2021) and Larson et al. (2020).

Figure 3 Modeled Regions



GHG Emissions Accounting

In this section, we describe: (1) the scope of emissions covered in our modeling; (2) our assumptions about emissions outside the scope of our modeling; and (3) a description of accounting conventions as they relate to carbon management. All scenarios evaluated in this study are in the context of achieving economy-wide net-zero GHG emissions by 2050 in the U.S. However, the scope of our modeling is limited to E&I CO_2 emissions, which includes four components:

1. **Gross energy**: CO_2 emissions from fossil fuel consumption or fossil carbon that is extracted and embedded in products. It accounts for fossil fuel used in power generation, transportation, hydrogen production and directly by end-uses, such as appliances in buildings. Emissions are an output from our modeling.

2. **Gross industry**: CO_2 emissions from industrial processes, such as cement production. Its trajectory is an exogenous input based on projected industrial activity.

3. **Product sequestration**: CO_2 emissions sequestered in durable products, such as plastics. Its trajectory is an exogenous input based on projected economic activity.[8]

4. **Geologic sequestration**: CO_2 emissions sequestered in geologic formations. Reflects all sequestration from both near-neutral and negative emissions technologies.

Net E&I CO_2, the sum of the four components above, is the primary emissions constraint applied in our modeling and our base input assumption is 0.0 Gt by 2050. Reaching net-zero GHG emissions also requires changes to non-CO_2 GHG emissions and the land sink, which are currently ~1.3 Gt CO_2e and -0.8 Gt CO_2e, respectively. Based on plausible non-CO_2 mitigation and land sink enhancement trajectories from the literature, we assume that the land sink and non-CO_2 GHGs sum to zero by 2050.[9] Table 1 illustrates the GHG accounting conventions described above using an example calculation of net-zero GHG by 2050.

Table 1 Example of Net-Zero GHG Emissions Accounting and Modeling Methods

Category	Sub-Category	Modeling Method	Line Item	$GtCO_2e$ (2050)
E&I CO_2	Gross energy	Optimized output from RIO	[A]	0.6
	Gross industry	Exogenous assumption used as input into RIO	[B]	0.2
	Product sequestration	Exogenous assumption used as input into RIO	[C]	-0.3
	Geologic sequestration	Optimized output from RIO	[D]	-0.5
	Net E&I CO_2	**Input constraint used in RIO**	**[E=A+B+C+D]**	**0.0**
Non-CO_2	**CH_4, N_20 & F-gases**	Assumption	[F]	0.9
Land Sink	**Net LULUCF**	Assumption	[G]	-0.9
GHG	**Net GHG**		**[H=E+F+G]**	**0.0**

[8] The U.S. EPA alternatively adjusts for carbon stored in products by subtracting from total fuel consumption, whereas we alternatively track unadjusted fuel consumption since we allow fuel supply decarbonization. For an overview of the EPA's methodology, see Section 3.2 of U.S. EPA (2021).

[9] See Section 4.2 from Williams et al. (2020) for a detailed discussion.

Base Assumptions

Table 2 summarizes key assumptions from the CNZ scenario that are applied consistently across the analysis unless specified otherwise. All scenarios achieve net-zero GHG emissions by mid-century, while delivering energy services projected from the U.S. Department of Energy's (DOE) Annual Energy Outlook 2021 (AEO). We use publicly available data from U.S. government agencies or laboratories to characterize fuel costs and technology cost and performance, and rely on our experience modeling net-zero U.S. energy systems to develop assumptions for end-use efficiency and electrification.

Table 2 Key Base Assumptions

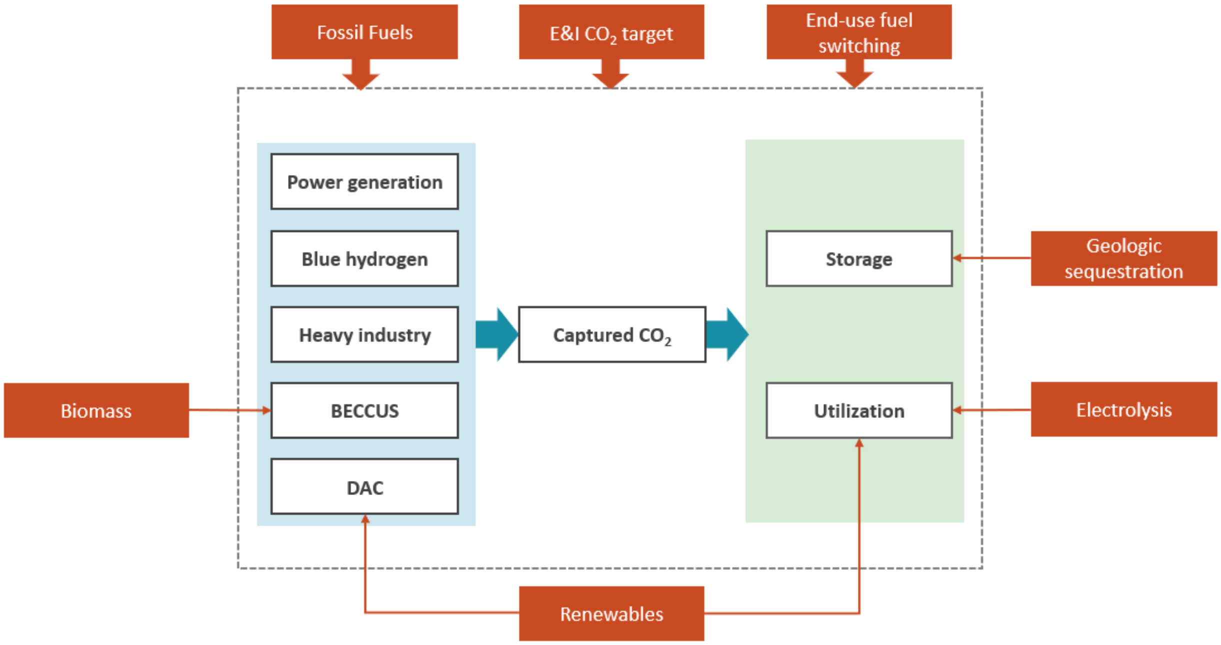
Category	Assumption
Emissions Targets	-Net GHG: 50% below 2005 levels by 2030 and net-zero by 2050 -Net E&I CO_2: limited to 3.2 $GtCO_2$ in 2030 and 0.0 $GtCO_2$ in 2050
End-Uses	-Demand for energy services are consistent with AEO 2021 -Energy efficiency and fuel switching to electricity and hydrogen-based fuels is generally consistent with the Central scenario from *Carbon-Neutral Pathways for the United States* (Williams et al., 2020)
Fossil Fuel Prices	-Cost projections are from the AEO 2021 Reference Case -Indicative fuel costs in 2050: natural gas is $3.7/MMBtu and liquid fuels are approximately $20.0/MMBtu (crude oil is ~$95/barrel)
Geologic Sequestration	-Storage potential is from Princeton University's Net-Zero America Project (NZAP) study (1.9 $GtCO_2$ of annual injection) -Cost of transportation and storage is derived from NZAP and excludes near-term EOR benefits
Biomass	-Cost and potential are derived from DOE's Billion-Ton Study (BTS) -BTS feedstock potential is modified to exclude 50% of herbaceous energy crops, resulting in approximately 750 million tons of total potential
Renewables	-Cost & performance trajectories are from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) 2020 Moderate Scenario -Resource potential for wind and solar resources is derived from NREL's Regional Energy Deployment System (ReEDS) 2020 Reference Access siting regime assumption -We assume 75% of available potential for onshore and offshore wind potential (5.9 TW and 3.7 TW, respectively). Utility-scale solar deployment is further constrained up to 1.5% of available land area in each region (3.7 TW across the contiguous U.S.).
Electrolysis	-Assumed capital cost of $250/kW-e and efficiency of 72.5% by 2050
Direct Air Capture	-Cost & performance is derived from Larsen et al. (2019) mid-range values -Indicative levelized cost of capture (excludes transport and storage) is $110 per metric ton in 2050

Sensitivity Analysis Assumptions

We considered seven sources of uncertainty that could have a material impact on carbon management outcomes, including: (1) fossil fuel costs; (2) geologic sequestration cost and potential; (3) biomass cost and potential; (4) renewables cost and potential; (5) electrolysis cost; (6) end-use fuel switching rates; and (7) E&I CO_2 targets. Some factors are controllable or partially controllable through policy, such as a carbon tax affecting fossil fuel costs or R&D funding for energy technologies that reduce their cost, while others are outside of policymaker's control. The range of uncertainties were selected to aid understanding of which factors drive more or less carbon management but do not capture every possible scenario.

Figure 4 illustrates interactions between the areas of uncertainty and carbon capture sources and applications modeled in this study. Some uncertainties directly impact specific technologies, while others more broadly affect the need for captured carbon. For example, the cost and potential of biomass feedstocks directly affects the competitiveness of BECCUS technologies, whereas fossil fuel prices affect broader carbon management decisions in two ways: (1) they are a major cost component of natural gas-fired power generation and hydrogen production facilities with carbon capture; and (2) they provide the avoided cost or economic signal to use fossil fuels or synthetic fuels. In general, higher fossil fuel costs encourage CO_2 utilization for fuels production, whereas lower fossil fuel costs encourage CO_2 storage to offset fossil fuel consumption. Below we discuss our modeling implementation for each area of uncertainty.

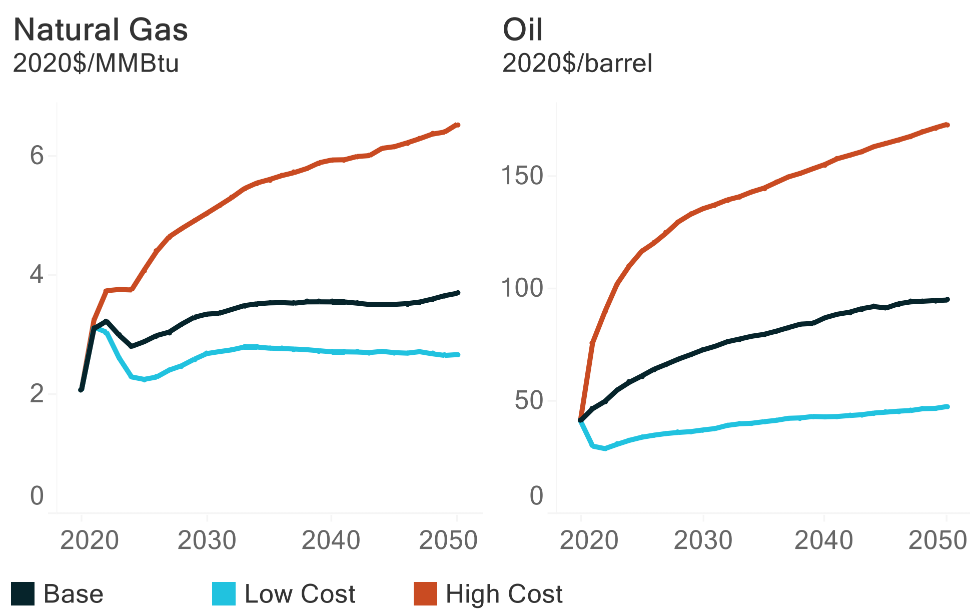
Figure 4 Interactions between Modeled Uncertainties and Carbon Management



Fossil fuel costs

We develop low- and high-cost ranges for natural gas and petroleum products separately using AEO 2021 scenarios, as shown in Figure 5. For natural gas cost ranges, we use the High Oil and Gas Supply scenario for low costs and Low Oil and Gas Supply for high costs. For petroleum products, we use the Low Oil Price and High Oil Price scenarios for low and high costs, respectively.

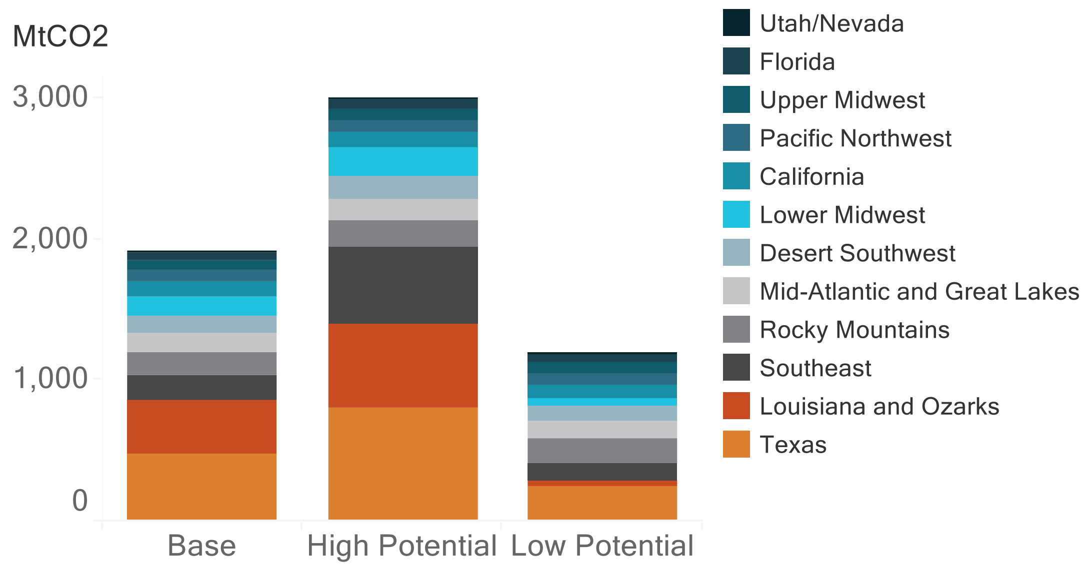
Figure 5 Fossil Fuel Cost Ranges



Geologic sequestration cost and potential

Our base assumption assumes geologic sequestration potential is equal to 1.9 $GtCO_2$, and we consider: (a) a low potential of 1.2 $GtCO_2$, based on a NETL estimate; and (b) a high potential of 3.0 $GtCO_2$ based on the *Expanded CO_2 Storage Capacity Case* from the NZAP study. A comparison of potential for each modeled region is shown in Figure 6. Our base combined CO_2 transport and storage costs ranges from a low of approximately \$25/tCO_2 to \$70/tCO_2. We examine the implications of varying costs by +/- \$20/tCO_2, which could reflect uncertainty about the cost of safely storing CO_2 permanently, transportation costs based on different utilization or potential economic incentives.

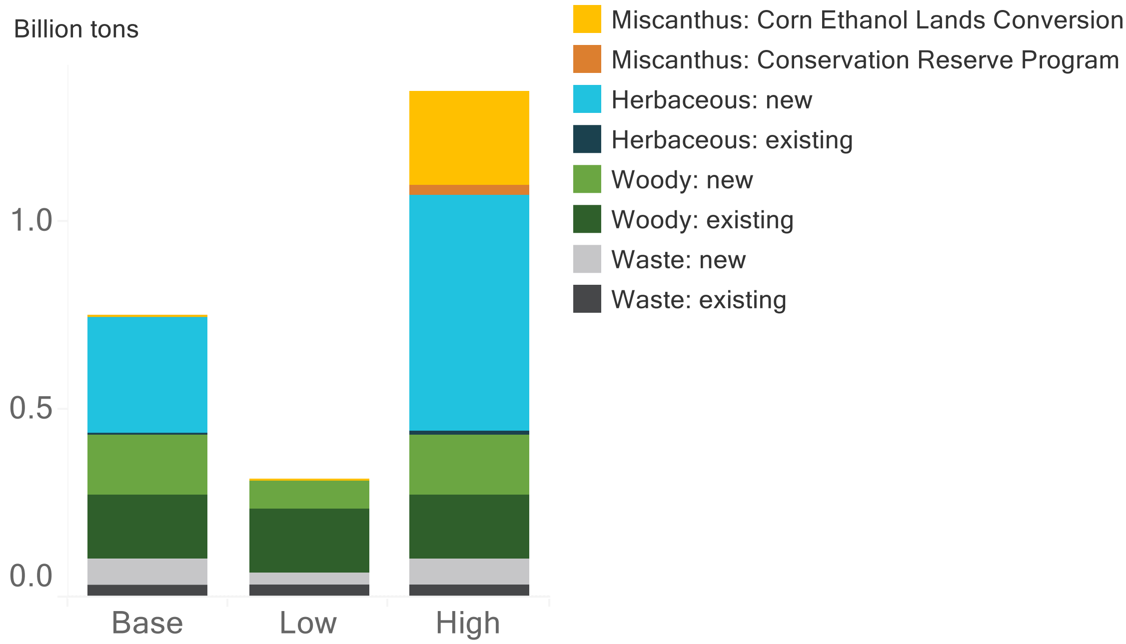
Figure 6 Geologic Sequestration Potential Ranges



Biomass cost and potential

We consider low and high sensitivities for biomass feedstock availability and costs separately. For biomass potential, we use: (a) the DOE Billion Ton Study for potential from waste, woody and herbaceous energy crops; and (b) Princeton's NZAP study for additional potential from land currently used to grow corn for ethanol and Conservation Reserve Program lands. We apply alternative screens to crop categories, which results in biomass potential ranging from approximately 0.3 to 1.3 billion tons, as shown in Figure 7. Biomass costs are implemented as a supply curve that matches resource bins from the Billion Ton Study, with costs ranging from $80 to $150/ton ($4.7 to $8.8/MMBtu) for herbaceous crops. Our high- and low-cost estimates apply +$50 and -$50/ton to the supply curves, respectively.

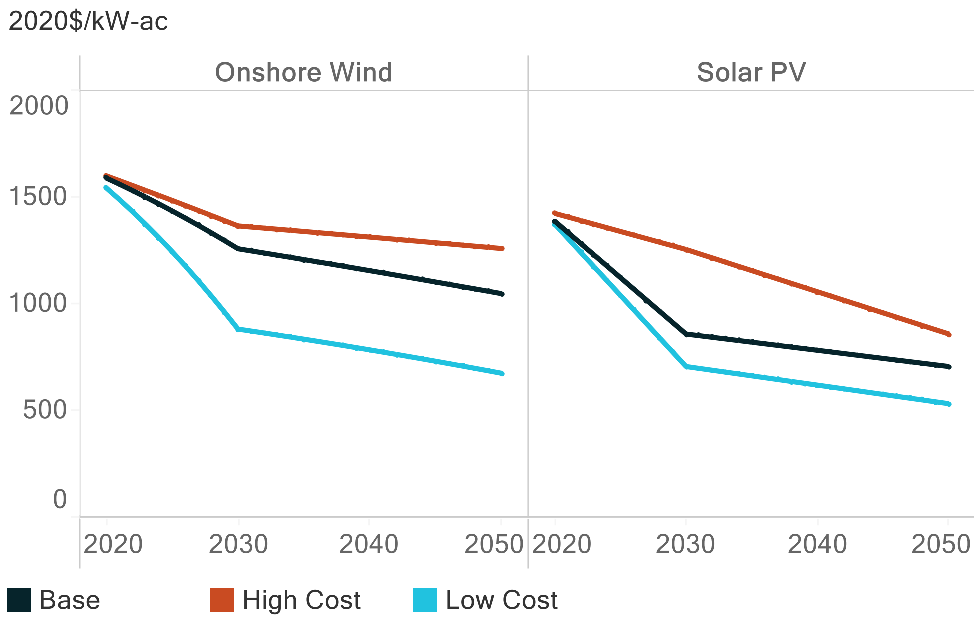
Figure 7 Biomass Potential Ranges



Renewables cost and potential

For wind and solar cost and performance trajectories, we use NREL's 2020 ATB to define high- and low-cost projections. Our low-cost projections use ATB's *Advanced Technology Innovation Scenario*, while our high-cost projections follow the *Conservative Technology Innovation Scenario*. Figure 8 provides capital cost trajectories for onshore wind and utility-scale solar through 2050. Gross renewable potential is derived from NREL's ReEDS 2020 *Reference Access* scenario. For onshore and offshore wind resources, we assume 50% of available potential for our low potential sensitivity and 100% for our high potential sensitivity (75% for our base potential). Utility-scale solar is constrained by the percentage of available land area in each region with up to 0.5% in the low potential sensitivity and 2.5% in the high potential sensitivity (1.5% for our base potential).

Figure 8 Wind and Solar Capital Costs



Electrolysis cost

Synthetic electric fuel production costs are characterized by very high feedstock costs, with H_2 and CO_2 feedstocks representing approximately 60% and 30% of production costs, respectively. As a result, electrolytic hydrogen production costs affect whether it is more economic for captured CO_2 to be: (a) utilized for synthetic electric fuel production; or (b) stored in geologic formations. Our base assumption for electrolysis reflects a capital cost of $250/kW-e and efficiency of 72.5% by 2050. We consider a range of future cost and performance trajectories for electrolyzers, including: (a) a low-cost sensitivity where capital costs realize $100/kW-e and a 75% efficiency by 2050; and (b) a high-cost sensitivity of $400/kW-e and a 70% efficiency by 2050.

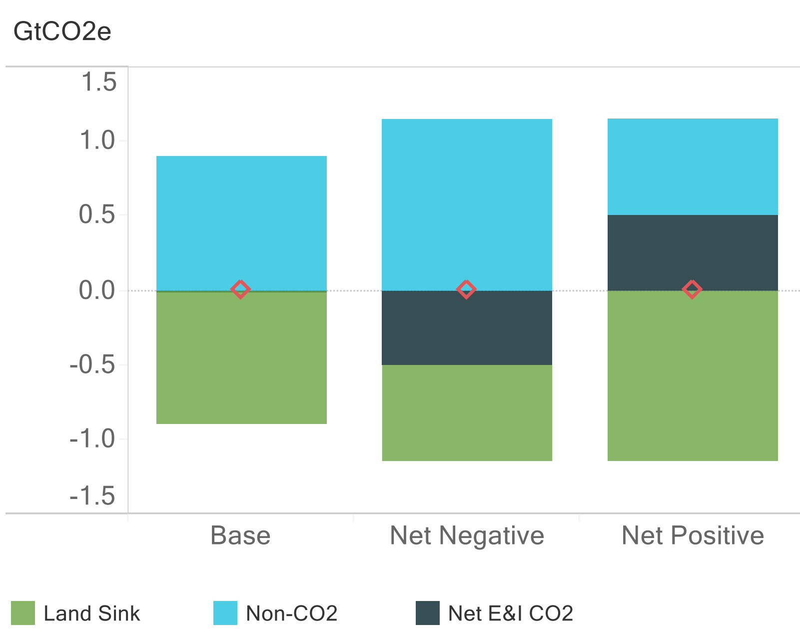
End-use fuel switching

The rate at which end-uses switch to electricity and hydrogen-based fuels is inversely related to residual fuel demand. Lower fuel switching rates increase residual fuel demand and demand for captured CO_2. We evaluated alternative fuel switching rates, including: (a) delayed fuel switching sensitivity where consumer adoption is slower by 20 years relative to the baseline; and (b) an accelerated fuel switching sensitivity where uptake is 10 years faster than the baseline. Relative to the baseline, delayed fuel switching increases liquid and gaseous fuel demand by 10,600 TBtu by 2050. Accelerated electrification has a limited impact on 2050 fuel demand, because the electrification in the CNZ scenario is already aggressive; however, accelerated electrification does decrease fuel demand in years leading up to 2050 (e.g., 2040).

Energy and industry CO_2 emissions target

In our modeling, net-zero GHG emissions in 2050 are achieved when the sum of the following sources and sinks is equal to zero: (1) net E&I CO_2 emissions; (2) non-CO_2 emissions; and (3) the land sink. Our base assumption is that net E&I CO_2 emissions decrease to 0.0 GtCO_2 by 2050, and non-CO_2 emissions and the land sink sum to zero.[10] However, there is considerable uncertainty about the mitigation trajectories for non-CO_2 and the land sink, which ultimately affects the target for E&I CO_2 to maintain net-zero GHG emissions. For example, if enhancing the land sink and/or non-CO_2 mitigation proves very challenging, then net negative (i.e., more aggressive) E&I CO_2 emissions are required to maintain net-zero GHG. Alternatively, if more aggressive non-CO_2 reductions and natural climate solutions prove feasible, then a net positive (i.e., less burdensome) E&I CO_2 target is possible. To highlight the impact of this uncertainty, we evaluate a net negative target of -0.5 Gt CO_2 by 2050 and a net positive target of +0.5 Gt CO_2, as illustrated in Figure 9.

Figure 9 Illustrative 2050 GHG Emissions Target by Component



[10] This is a plausible mitigation assumption for non-CO_2 and the land sink. See section 4.2 of Williams et al. (2020).

Carbon Management's Role

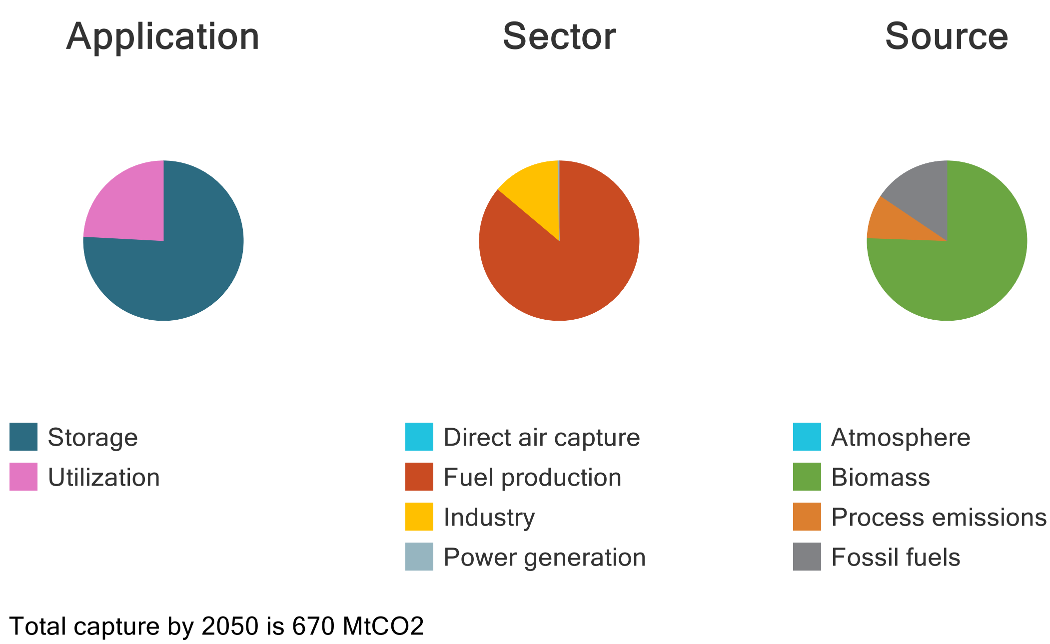
In this section, we present analytical results and takeaways specific to the role of carbon management in the U.S. when aligned with a target of net-zero GHG emissions by 2050, as well as an interim target of 50%reductions below 2005 levels by 2030. We report a variety of metrics, such as total captured carbon, CO_2 supplied by technology and the application of captured CO_2 (storage; utilization). We describe results for the Core Net-Zero (CNZ) scenario and uncertainties together, and first present national results followed by regional results. Finally, we explore the broad energy system impacts for select case studies.

Overview

Key metrics

Carbon management's importance grows over time with annual capture increasing from approximately 60 $MtCO_2$ in 2030 to almost 700 $MtCO_2$ by mid-century in the CNZ scenario. This is equivalent to roughly 10% of current gross U.S. GHG emissions. Around 75% of captured CO_2 in 2050 is stored in geologic formations, with the remaining 25% utilized to produce synthetic hydrocarbon fuels (Figure 10). CO_2 is primarily captured at fuel production facilities (~90%) and the remainder occurs at heavy industry facilities, specifically cement. Power generation and direct air capture are not sources of CO_2 in the CNZ scenario, but they do feature with alternative circumstances, such as when zero-carbon energy resources (biomass, renewables) are limited or more costly. The importance of NETs to meet net-zero at least-cost is highlighted by the fact that bioenergy accounts for around 75 percent of CO_2 captured, while fossil fuel and industrial process emissions account for the remainder.

Figure 10 Carbon Management Metrics in the Core Net Zero scenario: 2050

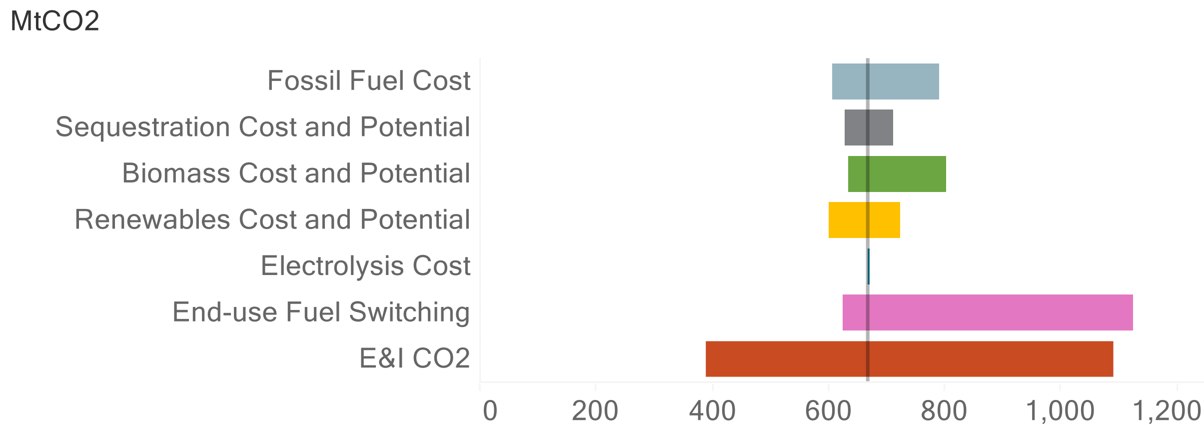


Total captured carbon

Taking into account uncertainty around the availability of zero-carbon energy resources, fossil fuel costs, technology costs, end-use fuel switching rates and the emissions target for E&I CO_2, we find both common themes and large variations in carbon management outcomes. The overall volume of captured carbon ranges from as low as 400 Mt CO_2 to 1,100 Mt CO_2 across all uncertainties (Figure 11). Uncertainty around the E&I CO_2 target results in the broadest range of captured carbon requirements, which suggests that in establishing a net-zero GHG emissions target for the U.S., long-run non-CO_2 and land sink goals should be clarified to plan for the mitigation burden placed on the E&I sectors and the resulting carbon capture infrastructure requirements. For example, if the E&I CO_2 target is net-negative, then an additional 400 Mt CO_2 is captured relative to the CNZ scenario. Importantly, if additional progress is realized in reducing non-CO_2 emissions and/or enhancing the land sink through natural climate solutions (i.e., a net-positive E&I CO_2 target), carbon capture is still a least-cost strategy and is not completely avoided.

The next largest uncertainty is the rate of fuel switching to electricity and hydrogen-based fuels across end-uses. Slower-than-anticipated fuel switching substantially increases capture volume, while faster-than-anticipated switching reduces but does not eliminate the economic deployment of carbon capture. Capture volume is most sensitive to fuel switching rates in the transportation sector since CO_2 utilization is used for liquid fuel production, whereas buildings and industry predominantly consume gaseous fuels. For the most part, carbon capture volumes consistently range from approximately 600 to 800 Mt CO_2 across the other uncertainties.

Figure 11 Range of Carbon Capture across Key Uncertainties: 2050

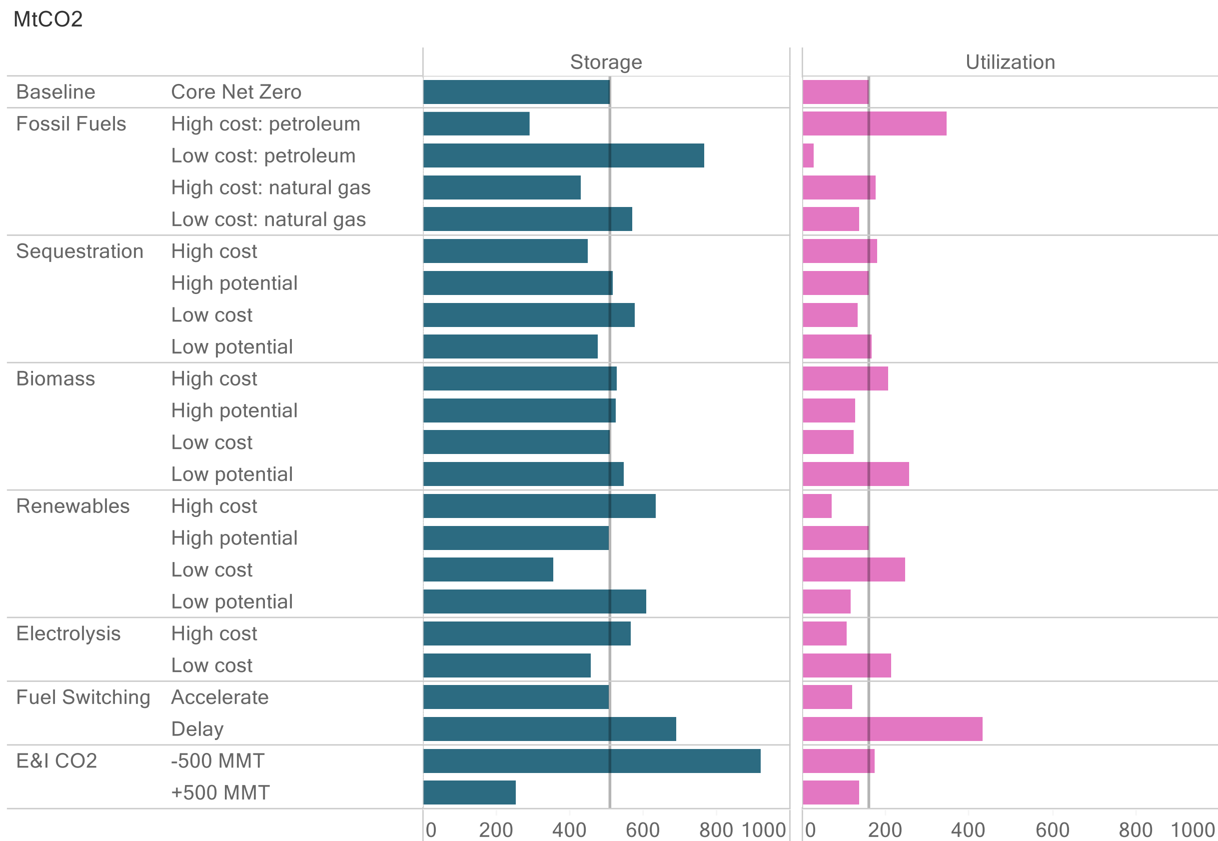


Applications

Once captured, CO_2 is either sequestered in geologic formations or utilized to produce low-carbon fuel. We find that captured CO_2 is applied to both applications across a wide range of uncertainties (Figure 12). Annual injection into geologic formations in 2050 ranges from approximately 250 to 920 Mt CO_2. The quantity of sequestered CO_2 is highly sensitive to fossil fuel prices since lower natural gas and petroleum costs incentivize continued fossil fuel consumption that is offset by CCS, while higher fossil fuel costs represent an increased avoided cost and economical signal for CO_2 to be utilized (CCU) for alternative fuels instead of sequestered. Sequestration is also sensitive to changes in the delivered cost of sequestration, with the analysis suggesting a decrease in the delivered cost of sequestration by \$20/tCO_2 increases annual sequestration by approximately 100 Mt CO_2 and vice versa. Uncertainty surrounding sequestration potential has a muted impact since the U.S. has large saline formations and the storage requirements in the CNZ scenario represent only about one-quarter of base potential. The fact that storage potential vastly exceeds requirements could provide decision-makers with flexibility to consider other factors when siting sequestration.

CO_2 utilization for fuel production ranges from 20 to 430 Mt CO_2 due to physical and economic drivers. Physical drivers of higher CO_2 utilization for fuel production include: (a) a decrease in biomass potential, which results in a scarcity of drop-in biofuels that are replaced by synthetic electric fuels; and (b) a delay in end-use fuel switching, which increases residual fuel demand that must be decarbonized. Lower electrolysis and renewable costs are economic drivers for higher CO_2 utilization over sequestration, since they reduce the cost of electrolytic hydrogen that is synthesized with captured CO_2 to produce low carbon fuels. In all our scenarios, CO_2 is utilized for liquid fuel rather than gaseous fuel production due to the former's higher avoided cost.

Figure 12 Carbon Capture Application: 2050



Sources

Carbon capture technology is deployed at five types of facilities: (1) bio-refineries producing hydrogen, methane, liquid hydrocarbons and heavy hydrocarbons ("BECCUS"); (2) direct air capture ("DAC") plants; (3) heavy industrial facilities; (4) autothermal and steam reforming plants producing blue hydrogen; and (5) power plants. We find that negative emissions technologies (BECCUS and DAC) are the predominant source of captured CO_2, and their long-run annual capture rate is 2.0-5.0x the capture from near-neutral technologies (Figure 13). BECCUS consistently supplies 400-500 $MtCO_2$ across the range of uncertainties since their value to a net-zero energy system is twofold: (1) they directly provide drop-in, carbon-neutral fuel; and (2) captured CO_2 can be sequestered or utilized.

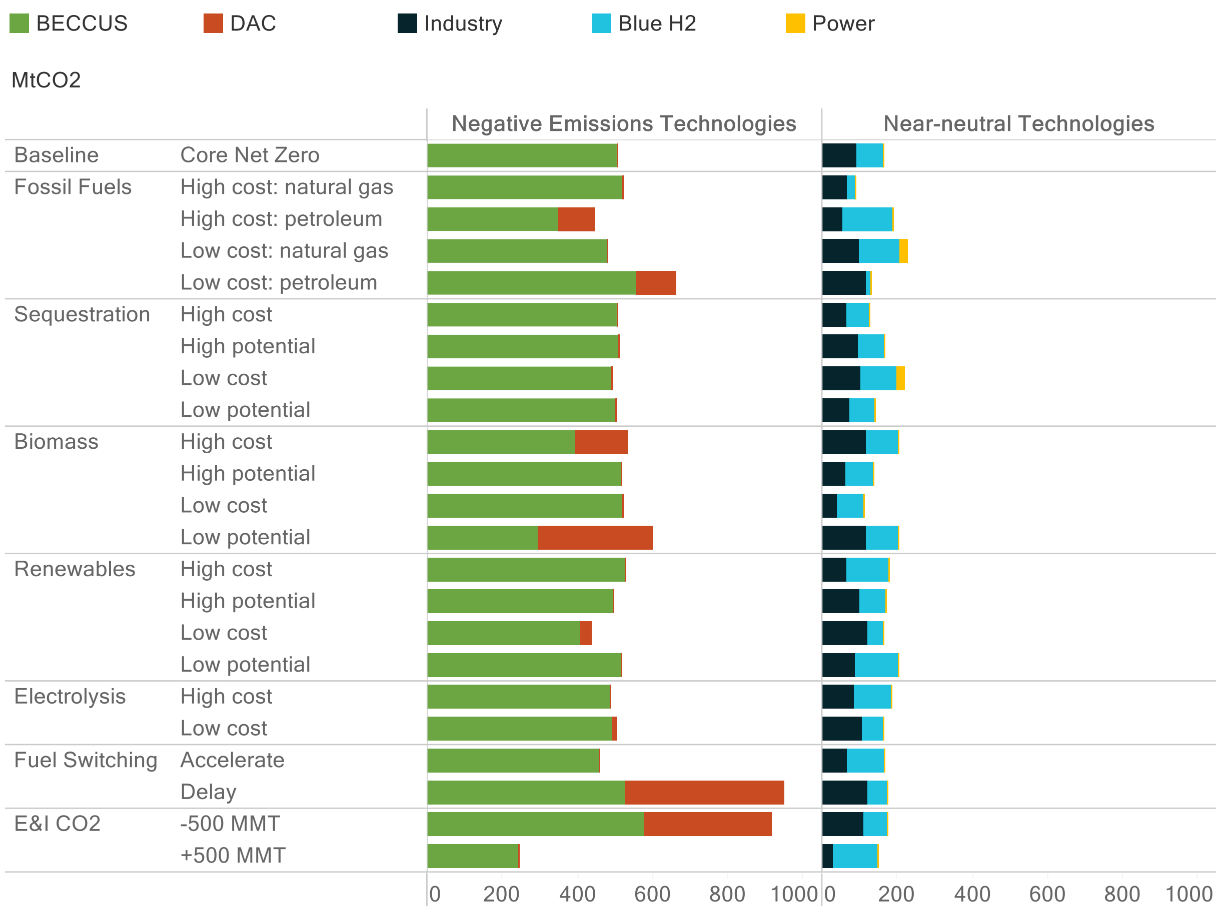
Although DAC is not deployed in the Core Net Zero scenario, it is an important technological backstop as a source of negative emissions. In circumstances where biomass availability is low, end-use fuel switching is delayed or the E&I sectors face a more stringent emissions target, DAC is deployed at scale (annual capture of 100 to 400 Mt CO_2).[11] DAC is also moderately deployed (~100 Mt CO_2) when petroleum costs deviate significantly from their baseline trajectory due to geographic differences between where NETs are available and where utilization is needed. For example, higher petroleum product costs incentivize utilization of CO_2 to produce synthetic electric fuels and further displace liquid fossil fuels. However, some regions that are ideal candidates for CO_2 utilization due to high renewable quality and low-cost electrolytic hydrogen do not have sufficient incremental NETS CO_2 to capture from biomass and it is cheaper to deploy DAC than to import biomass-derived NETS CO_2 from other regions. On the other hand, lower petroleum product costs encourage continued fossil fuel consumption that is offset via storage of negative emissions, but some regions with incremental, low-cost storage potential lack sufficient incremental biomass and deploy DAC as an alternative CO_2 source.

Near-neutral technologies generally capture between 100 to 200 Mt CO_2 by 2050, and this is primarily from: (1) cement facilities where carbon capture is used to abate process and fuel combustion emissions; and (2) blue hydrogen production facilities where natural gas and geologic sequestration is plentiful (i.e., Gulf Coast). Carbon capture at existing and new power plants is a minimal source primarily due to the challenge of maintaining high capacity factors to justify capital-intensive investments when the electricity grid shifts to very high levels of variable renewables. Carbon capture on power generation and hydrogen production facilities share two characteristics that disadvantage their deployment: (1) they can only counteract their own emissions, whereas NETS can address emissions from any hard-to-abate sector; and (2)

[11] Haley et al. (2018) and Larsen et al. (2019) identify DAC deployment under similar circumstances.

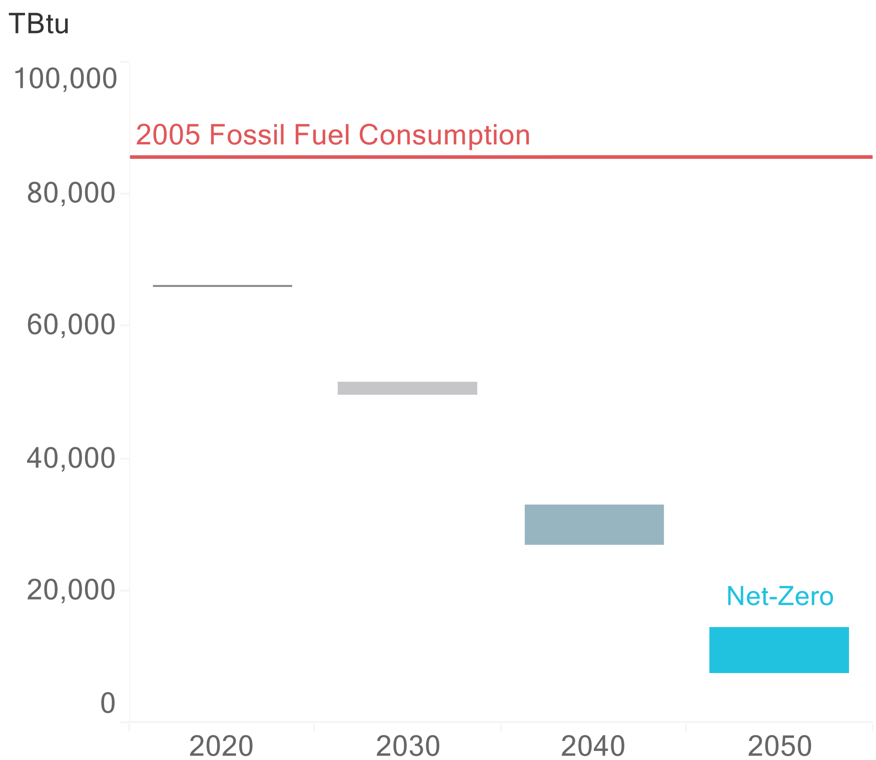
alternative technologies are available, including renewables and nuclear for power generation and electrolysis for hydrogen. On the contrary, carbon capture at cement production facilities is critical due to a lack of alternative production methods today.

Figure 13 Carbon Capture by Technology: 2050



The sources of captured CO_2 outlined above challenge the argument that CCUS facilitates the continuation of high levels of fossil fuel CO_2 emissions, at least as a technical matter in the context of economy-wide net-zero GHGs. To further illustrate this point, we compare historical fossil fuel consumption against projected demand through 2050 when all modeled scenarios are net-zero compliant (Figure 14). Despite the wide range of uncertainties considered, fossil fuel consumption is 80-90% below 2005 levels by 2050 and 88% below in the CNZ scenario. Most of the remaining fossil fuel use is in industry, where feedstocks are expensive to substitute, rather than in the power sector.

Figure 14 Uncertainty Range in Annual Fossil Fuel Primary Energy Consumption[12]



Summary of Uncertainties

Table 3 summarizes how carbon management is affected by alternative assumptions in our modeled uncertainties.

[12] 2005 fossil fuel consumption is from Table 1.3 of EIA's Annual Energy Review (EIA, 2020).

Table 3 Summary of Uncertainties

Uncertainty	Impact
Fossil Fuels	**Natural gas costs** • Primarily affect CCS levels while CCU levels are less impacted. • Higher natural gas costs reduce capture from blue hydrogen and cement plants (steam is a major cost of capture), and storage volumes fall, and vice versa **Petroleum product costs** • Petroleum product costs have a strong impact on how CO_2 is applied and the capture from BECCUS. • Higher petroleum product costs incentivize higher CO_2 utilization, which displaces additional fossil fuels and reduces storage volumes, while lower costs nearly eliminate CO_2 utilization and increase storage
Sequestration	**CO_2 delivery and storage costs** • Storage volumes and capture from fossil-based facilities is sensitive to the cost of delivering and storing CO_2 **Geologic sequestration potential** • Changes to sequestration potential have a minimal impact since potential far exceeds net-zero requirements.
Biomass	**Biomass cost** • Primary impact is competition for CO_2 capture from BECCUS facilities and other technologies, while net volume is similar **Biomass potential** • One of the most important carbon management determinants. • Low biomass potential creates a demand for DAC.
Renewables	**Renewable costs** • Cost of wind and solar resources has dynamic impacts: higher costs increase CO_2 capture from blue hydrogen (since electrolysis is less economic), reduce CO_2 utilization (since hydrogen is more expensive) and nearly all captured CO_2 is stored; lower costs direct CO_2 previously allocated to storage towards utilization **Renewable potential** • Low renewable potential has a similar impact as higher renewable cost, while higher potential has a minimal impact
Electrolysis	**Electrolysis cost** • Primary impact is the application of captured CO_2: lower electrolysis costs direct CO_2 towards CCU, and vice versa.
Fuel Switching	**End-use rate of adoption** • Slower fuel switching results in higher residual fuel demand and captured carbon, and vice versa. • The rate of fuel switching in the transportation sector affects outcomes the most due to the use of liquid fuels
Emissions	**Energy & industry CO_2 target** • Net negative target increases captured carbon beyond 1 Gt CO_2 and necessitates DAC, while a net positive target reduces but does not eliminate captured CO_2

Regional Infrastructure Implications

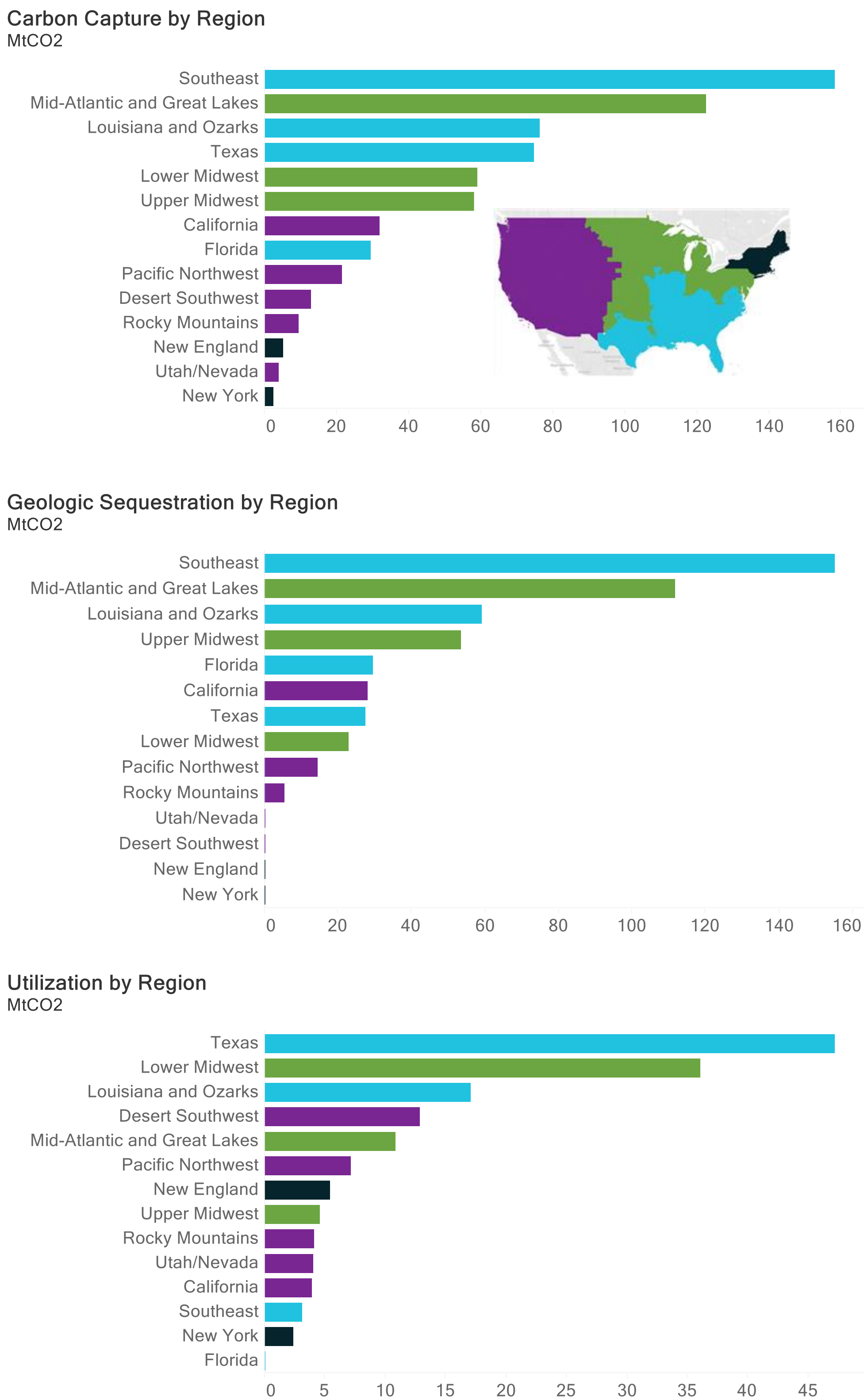
Carbon management strategies vary widely across U.S. regions, including the capture technologies deployed and its use (Figure 15). Regional carbon management differences are primarily driven by the potential and cost of three resources: (1) geologic sequestration; (2) biomass; and (3) renewables.

In the CNZ scenario, half of all captured carbon in the U.S. is managed in regions along the Gulf Coast (Louisiana and Ozarks, Southeast, Florida, Texas). This area has low-cost saline formations that store more than half of all sequestered CO_2. Carbon is supplied from facilities located within the region, including BECCUS fuel production facilities (due to ample biomass resources), blue hydrogen plants and cement facilities. CO_2 utilization is concentrated in regions across the Great Plains (Texas, Lower Midwest) since the area's high-quality onshore wind resources enable low-cost electrolytic hydrogen that is paired with captured carbon for fuel synthesis. Although most regions direct nearly all captured CO_2 towards either storage or utilization, Texas is unique in that it splits a large volume between both applications, because it is well-endowed in sequestration, biomass and renewable resources (most regions only contain two of each resource at scale).

Regions across the Midwest (Great Lakes and Upper Midwest), which currently locate most of the U.S. fuel ethanol production capacity, become an important source of negative emissions. The area transitions away from ethanol towards advanced biofuels and the captured CO_2 from bio-refineries is sequestered in the limited geologic sequestration across the area.

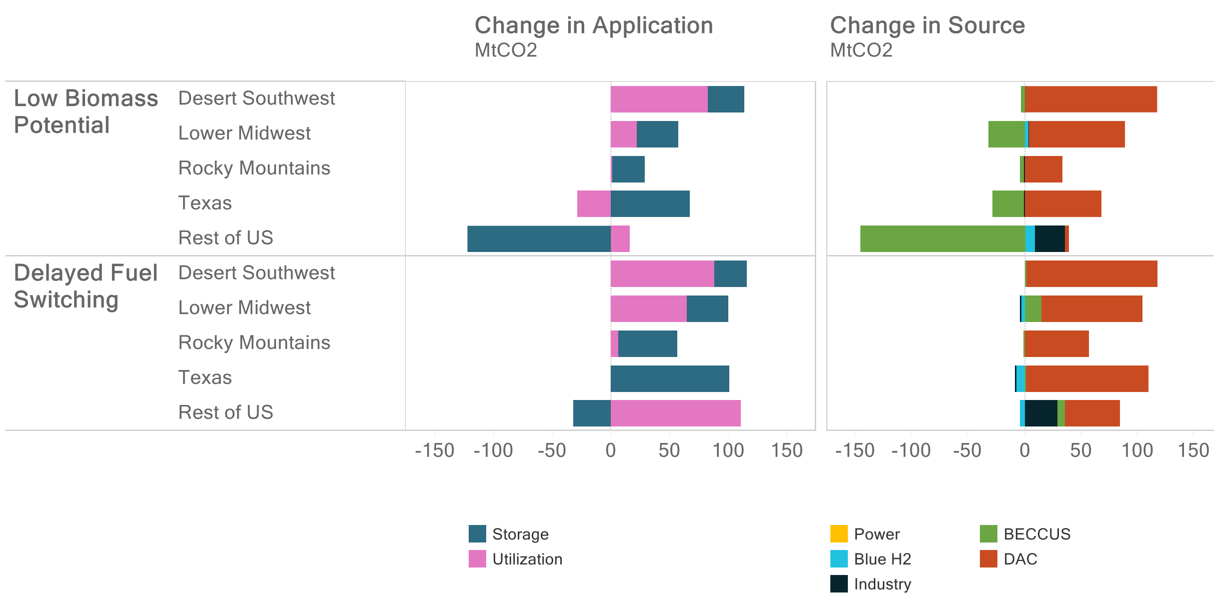
Carbon management in the Northeast and West is limited (~10% of total CO_2 capture) due to a small share of national biomass supply and limited heavy industry. The Northeast is further challenged by zero sequestration potential and relatively expensive renewables (i.e., offshore wind) that results in high-cost CO_2 utilization. Across the West, the majority of California's captured carbon is sequestered, while states in the Northwest and Desert Southwest take advantage of high-quality renewables to produce synthetic fuels.

Figure 15 Regional Carbon Management Metrics: Core Net Zero Scenario (2050)



Regional carbon management strategies are generally consistent across the range of uncertainties, but the exception occurs when the supply of negative emissions decreases or overall demand for negative emissions increases. Under both circumstances, DAC is deployed at scale in regions across the Great Plains, including the Lower Midwest, Texas, Rocky Mountains and Desert Southwest (Figure 16). Lower biomass potential translates into a decline in negative emissions from BECCUS facilities across the country, but this impact is primarily in regions with high feedstock concentrations (e.g., Southeast). In response, DAC is deployed in the four wind-rich regions that facilitate additional CO_2 utilization and sequestration. Similar deployment patterns occur in the circumstance where end-use fuel switching is slower-than-anticipated. Higher residual fuel demand increases overall demand for CO_2 to decarbonize fuel (utilization) or offset additional emissions (storage), and DAC is the marginal economic resource to supply NETS CO_2 (there is a small increase in capture from BECCUS, but this is limited by incremental biomass feedstock availability).

Figure 16 Change in Carbon Management Metrics (Relative to CNZ Scenario, 2050)



CO_2 capture deployed at stationary sources distributed across the country will require delivery infrastructure to connect CO_2 sources with geologic formations and/or fuel synthesis facilities. Delivery requirements are expected to vary significantly depending on where carbon capture is deployed. Illustrative examples of where delivery infrastructure is minimized include: (a) a bio-refinery in Louisiana where biomass is gasified and captured CO_2 is sequestered in a nearby saline formation; or (b) an energy complex in Kansas where CO_2 capture (DAC), electricity generation (wind) and hydrogen production (electrolysis) are co-located to produce synthetic electric fuels. In contrast, illustrative examples of long-distance CO_2 transport could be needed at: (a) carbon capture retrofits on existing coal-fired power plants in the Upper Midwest, where captured emissions could exceed storage potential; and (b) carbon capture in the Northeast and Pacific Northwest, which both lack CO_2 storage potential.

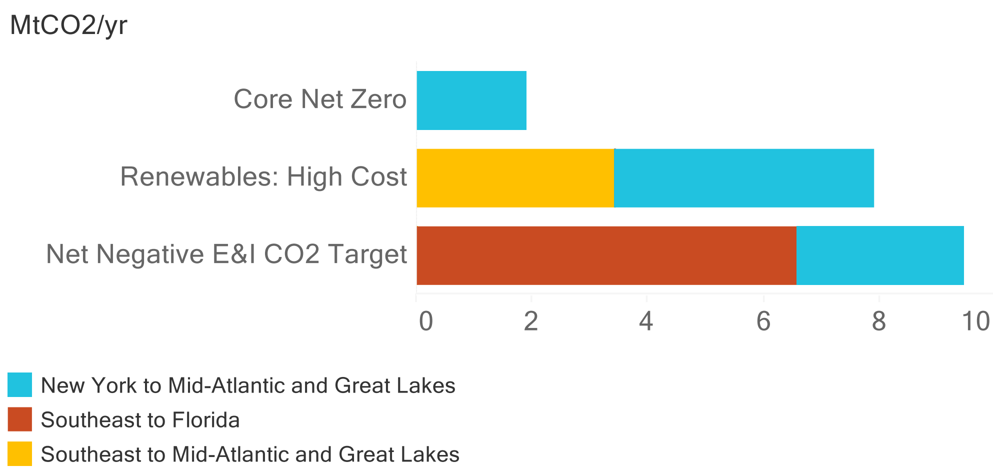
We find minimal *inter*-regional CO_2 transportation infrastructure in our CNZ scenario and across most uncertainties. One qualification to this result is that some of the modeled regions are large and could still require intra-regional infrastructure to connect sources and sinks. For example, in the Southeast region, long-distance pipelines may be needed connect CO_2 captured in the Carolinas to the Gulf Coast.

Other work has posited that inter-regional CO_2 pipelines will be needed to support carbon management. The difference between our work and others' is driven by three factors. First, we find that carbon capture technology is best deployed at new fuel production facilities, specifically bio-refineries (BECCUS), whereas prior research has focused on retrofitting existing CO_2-intensive facilities such as coal-fired power plants and ethanol facilities. Many of these sources are concentrated in the Midwest and continuing historical utilization of these resources with carbon capture results in an imbalance between CO_2 volumes and local storage potential, thus driving the case for a long-distance CO_2 transportation network. In this analysis, a significant portion of existing fossil infrastructure retires or operates at lower utilization rates over time, and these factors do not justify capital-intensive carbon capture retrofit costs. For example, on-road transportation electrification decreases both gasoline fuel demand as well as ethanol demand, while existing gas-fired power plants operate infrequently as the generation mix shifts primarily towards renewable resources. The second reason that significant inter-regional CO_2 transportation is not pervasive is that we allow captured CO_2 to be economically utilized, which is not considered in other analyses. This route allows for CO_2 to be transported shorter distances or co-located at the same facility. It is generally lower cost to utilize CO_2 than to transport via long-distance pipeline and sequester. Finally, we exclude any revenues associated with enhanced oil recovery (EOR) from the analysis. The value of storing CO_2 geologically via EOR is often touted as a significant economic driver to pursue carbon capture on existing fossil facilities and develop long-distance CO_2 transportation.[13] However, that value declines over time with a binding net-zero commitment due to declining liquid fossil fuel demand. In addition, even if the oil price remains high, then the economic signal is to utilize CO_2 to produce low-carbon synthetic fuel to displace liquid fossil fuel. This often can be accomplished intra-regionally and complements a renewable-heavy electricity system.

Since there is typically enough sequestration potential or economic utilization opportunities to manage captured CO_2 intra-regionally, CO_2 transmission capacity between regions is small (Figure 17). In the CNZ scenario, a small (~ 2 $MtCO_2$/yr) corridor is developed between New York and the Mid-Atlantic by 2050 to transport captured CO_2 from New York that cannot be sequestered and is expensive to utilize. Generally, additional inter-regional CO_2 transmission is developed when local potential is depleted. For example, a net negative E&I CO_2 target results in ~6 $MtCO_2$/yr transport from the Southeast to Florida since the Southeast's sequestration potential is depleted. Higher-than-anticipated renewable costs result in additional CO_2 transportation capacity, because the cost of utilizing CO_2 increases and captured CO_2 is alternatively transferred to neighboring regions with available storage. The primary takeaway is that the quantity of CO_2 transported inter-regionally is very small relative to total captured carbon (less than 1%), and nearly all captured carbon is managed intra-regionally. One area for future research is on the repurposing of existing fossil fuel pipeline (gas or oil) to carry CO_2 to connect sources with sinks. This analysis did not analyze those opportunities, which would be lower cost than greenfield development of CO_2 pipelines analyzed here. Under such scenarios, inter-regional transport may take on greater importance.

[13] See, for example, Edwards and Celia (2018).

Figure 17 Inter-Regional CO_2 Transmission Corridor Capacity: 2050



Case Studies

In addition to the CNZ scenario and uncertainties considered above, we examine two case studies to better understand the role of fossil-based carbon capture technologies and the importance of carbon management to achieve net-zero. These case studies include: (1) a scenario where the fixed cost of gas-fired power and hydrogen production facilities with carbon capture is equal to their unabated technology equivalents; and (2) a scenario where carbon capture technology deployment is prohibited entirely (e.g., applies to both fossil-based and negative emissions technologies).

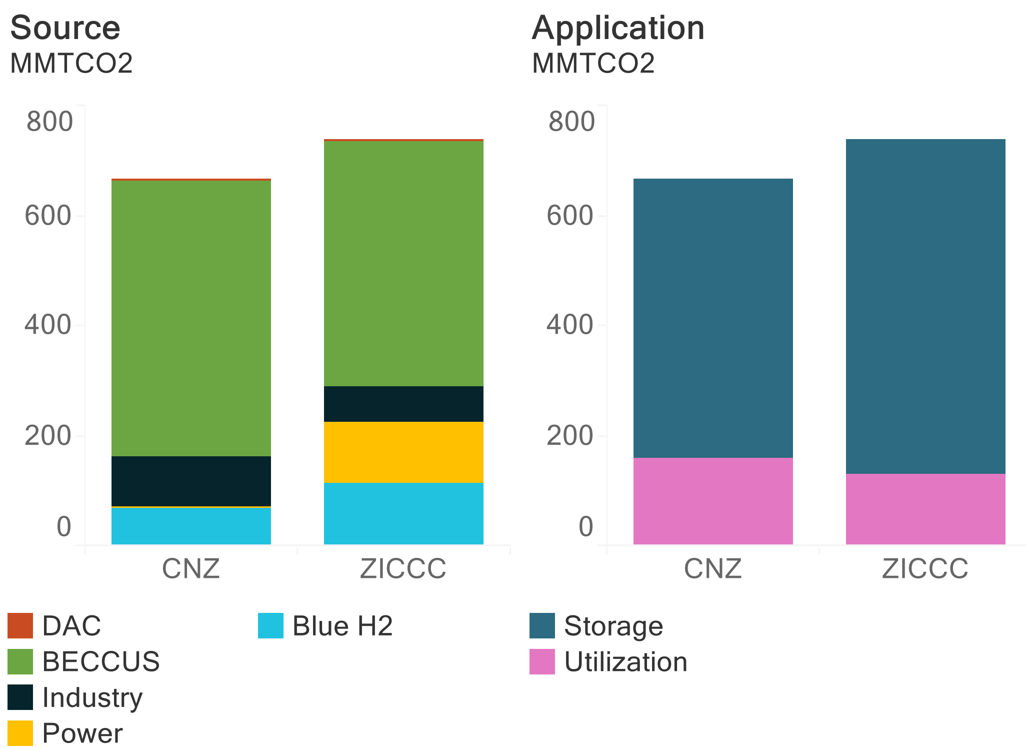
Zero incremental CO_2 capture cost for fossil-based technologies

As explained above, one of the primary findings from the analysis is the limited role of carbon capture at fossil-based technologies relative to NETs. Carbon capture is rarely deployed in power generation, while blue hydrogen is frequently deployed but in a limited role (i.e., it is never the principal source of hydrogen production). Lower-cost natural gas and geologic sequestration increase capture from both sources, but the changes from the baseline are not prolific.

To understand if the cost of carbon capture technology is the primary barrier, we examinate an alternative Zero Incremental Carbon Capture Cost (ZICCC) scenario where the capital and fixed O&M costs of gas combined cycle and steam methane reformation with carbon capture is equal to their unabated technology equivalents.

We find that even under significant fixed cost reductions, fossil-based carbon capture still maintains a limited role (Figure 18). Captured carbon from power generation and hydrogen production increases by approximately 150 Mt CO_2 by 2050 and only displaces about 50 Mt CO_2 from BECCUS, and there is a minor impact on CO_2 utilization. Blue hydrogen's share of total hydrogen production increases from 15% to 25%, while gas-fired plants with carbon capture make up less than 5% of total electricity generation.

Figure 18 Carbon Capture Metrics for the CNZ and ZICCC Scenarios: 2050



The limited role of fossil-based power generation and hydrogen production in carbon management, even considering lower technology, natural gas and geologic sequestration costs, is a result of three factors. First, a net-zero economy necessitates a decarbonized electricity supply, and deployment of variable wind and solar resources is the least-cost strategy. This electricity system: (a) encourages deployment of electrolysis since the technology can address seasonal energy imbalances between load and renewable generation; and (b) discourages utilization of technologies with high variable costs (e.g., gas-fired power plants with carbon capture) since zero-marginal cost electricity is available for most of the year. Second, as discussed in Section 3.1, the primary disadvantage of fossil-based carbon capture technologies is that they can only offset their own emissions, whereas NETs can offset emissions from hard-to-abate sectors. Finally, large-scale deployment of fossil-based carbon capture technologies requires significantly scaling up CO_2 storage infrastructure. For example, if one-third of end-use electricity consumption and hydrogen demand by 2050 was met by gas power plants with carbon capture and blue hydrogen, respectively, then this would require approximately 1,200 $MtCO_2$ of annual storage. Although this is within technical storage potential, it would introduce additional infrastructure and siting challenges (total CO_2 capture in the CNZ scenario is less than 700 $MtCO_2$).Even under the most accommodating assumptions, carbon management remains largely in service of addressing emissions from long-distance transportation and industry, rather than fossil-based power generation and hydrogen production.

What if carbon management is not a strategy?

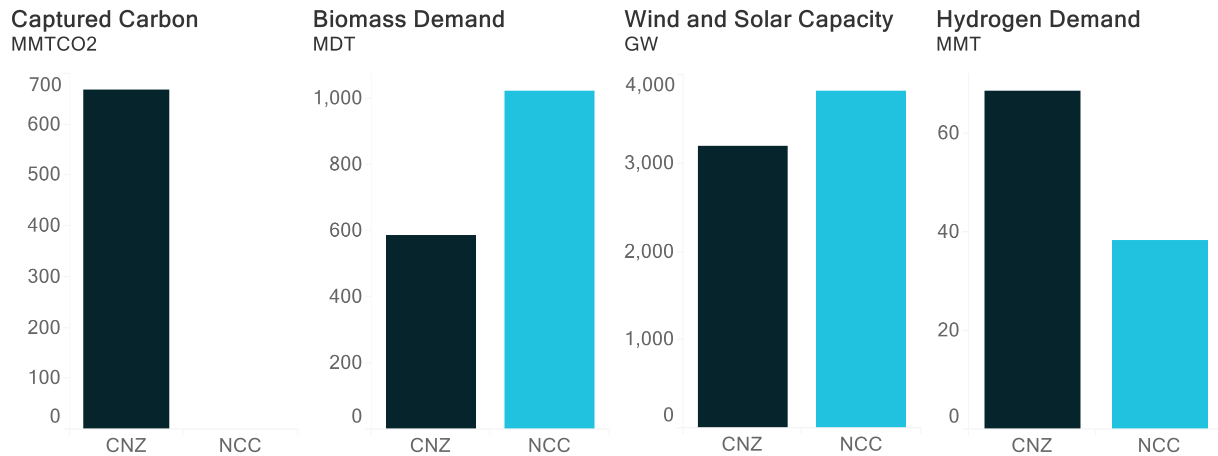
Despite CCUS featuring prominently in net-zero analyses, skepticism remains across areas of its supply chain, including: (a) the projected cost of CO_2 capture; (b) the impacts of transportation infrastructure; and (c) the potential for carbon capture on fossil-based facilities to obscure upstream emissions impacts (e.g., fugitive methane leakage). To inform the implications of not pursuing the innovation needed for CCUS to be technologically ready, we evaluated a No Carbon Capture (NCC) scenario that achieves net-zero without carbon capture technologies.

Figure 19 compares key energy system metrics against the CNZ scenario in 2050. We find that achieving net-zero E&I CO_2 emissions without CCUS is technically feasible, but there is a trade-off with significantly higher biomass consumption and renewable resource deployment.[14] Under this scenario, the entire U.S. biomass potential (one billion tons) is used to produce low-carbon fuels by 2050 – a steep increase from 600 million tons in the CNZ scenario. This quantity of biofuels production is needed since all the carbon stored in the biomass is inefficiently re-released into the atmosphere rather than being captured. More renewables (+600 GW, an increase of roughly 20 percent) are also needed as hydrogen production shifts exclusively towards electrolysis since BECCUS and blue hydrogen are prohibited and additional processes such as steam production are electrified. Overall hydrogen demand falls by approximately one-half since CO_2 cannot be combined with H_2 feedstocks for synthetic fuel production. The

[14] Modeled feasibility required increasing both biomass and renewables to their high potential sensitivities.

economic impact of this trade-off is an additional $200 billion per year in energy spending by 2050.

Figure 19 Energy System Metrics for the Core Net Zero (CNZ) and No Carbon Capture (NCC) Scenarios: 2050



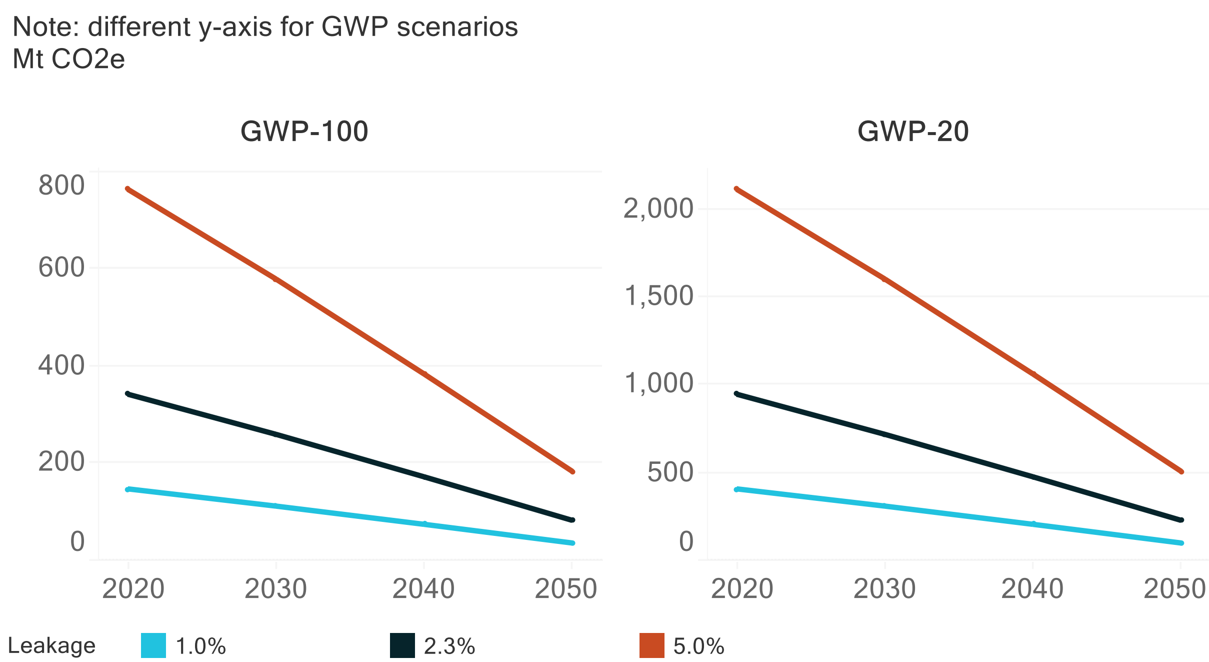
The CNZ scenario features unparalleled rates of renewable deployment and biomass consumption, and scaling both resources faces implementation challenges. Renewables already facing siting challenges today and biomass used for energy production could introduce land use conflicts. Excluding carbon management as a strategy increases the risk of not realizing net-zero by overlying on renewables and biomass, and this risk is exacerbated if other implementation challenges arise, such as slower-than-anticipated electrification rates. The diversification benefit from carbon management is most valuable to industry and long-distance transportation, which rely on NETs and synthetic-based fuels to decarbonize or offset emissions.

Non-CO_2 Considerations

As discussed in Section 2, we assume the U.S. achieves net-zero GHG emissions by 2050 through a combination of: (a) endogenous (i.e., modeled) E&I CO_2 reductions; and (b) exogenous non-CO_2 mitigation and land sink enhancement assumptions. Methane emissions associated with the oil and natural gas supply chain are a significant contributor to existing non-CO_2 emissions. Although our modeling explicitly accounts for CO_2 emissions from fuel combustion at fossil-based technologies with carbon capture (as well as all other technologies) when determining cost-optimal investments, it does not account for upstream or downstream non-CO_2 emissions, such as methane leaks from pipelines supplying blue hydrogen production. As the U.S. and other countries consider carbon management strategies, it is important to consider their non-CO_2 emissions impacts as well, particularly due to concerns about avoiding near-term warming effects from highly potent GHGs.

To understand the scale of potential impact, we conducted ex-post calculations of methane leakage. We considered alternative leakage rates and global warming potential (GWP) assumptions for projected oil and gas demand from our modeling. Applying a leakage rate of 2.3% and GWP100 values, we find methane leakage of approximately 340 Mt CO_2e in 2020 (~7% of current CO_2 emissions), reduced to 80 Mt CO_2e by 2050 as fossil fuel consumption is deeply reduced (Figure 20).[15] Employing a GWP20 value accounting for near-term warming increases this effect to 950 Mt CO_2e in 2020 (~20% of current CO_2 emissions), reduced to 230 Mt CO_2e in 2050. By mid-century, approximately one-quarter of this leakage is attributed to blue hydrogen production, emphasizing the importance of addressing fugitive emissions in advance of deploying carbon management infrastructure.

Figure 20 Estimated CH_4 Emissions from Oil and Gas Systems: Core Net Zero Scenario



[15] Base leakage rate is from Alvarez et al. (2018)

These estimates highlight implications for decision-makers considering carbon management as a net-zero GHG strategy. Non-CO_2 emissions, and even fugitive methane emissions alone, are a material risk to achieving climate targets. Since carbon capture technologies do not directly address and could exacerbate these emissions, it is imperative to address leakage. Although our analysis above demonstrates the potential scale of methane leakage risk, energy system models do not incorporate non-CO_2 emissions or near-term warming potentials into their decision-making. Future analysis incorporating these effects could render alternative technology choices and applications based on leakage and near-term warming.

Conclusions and Key Findings

Carbon management is a key strategy for putting the U.S. on a path towards achieving net-zero GHG emissions. We modeled a suite of CCUS technologies across a broad range of uncertainties to identify their long-term role. Based on our analysis, we identify the following key findings.

Carbon management is a pillar of a least-cost pathway to net-zero

Reaching net-zero GHG emissions requires pursuing a diverse range of strategies across the economy. Even assuming success across all other strategies (highly aggressive energy efficiency, electrification, electricity decarbonization, enhancement of the land sink and mitigation of non-CO_2 emissions), carbon capture deployment in energy and industry will still be necessary by 2050. To reach net-zero, our analysis identifies that the U.S. will need to capture between 400 and 1,100 $MtCO_2$ annually by mid-century when considering a range of uncertainties. In the CNZ scenario, nearly 700 $MtCO_2$ is captured, which is equivalent to about 10% of today's U.S. gross GHG emissions or all energy-related CO_2 emissions in Texas, the highest-emitting state. If the current land sink shrinks and/or non-CO_2 emissions prove more difficult to abate, the importance of carbon management in the energy system is further increased. However, the upper bound of captured carbon (1,100 $MtCO_2$) is less than one-quarter of current emissions, meaning that even the most optimistic vision of carbon management is not a substitute for other emissions reductions strategies.

When net-zero emissions are reached in 2050, more than 500 $MtCO_2$ is sequestered in geologic formations in the CNZ scenario. Annual injection ranges from approximately 300 to 900 $MtCO_2$, which is well below estimates of U.S. geologic sequestration potential. Utilization of captured CO_2 is another beneficial pathway for captured carbon, and approximately 150 $MtCO_2$ is utilized for synthetic liquid fuel production in the CNZ scenario. This amount of CO_2 utilization supports low-carbon fuels that could supply roughly 80% of today's aviation fuel demand.

Negative emissions technologies are well-suited for net-zero

The carbon management supply chain evolves substantially over time. In the near-term (2030), total captured carbon is approximately 60 $MtCO_2$ and is supplied from an equal mix of fossil- and biomass-based technologies with carbon capture. In the long-term (2030 to 2050), the focus of

CO_2 capture shifts towards NETs, including BECCUS for fuel production and DAC. By mid-century, total carbon capture increases to nearly 700 $MtCO_2$ and NETs supply three-quarters of the total.

This long run shift towards NETs reflects both the appeal of CO_2 utilization for fuels to address remaining gross emissions in sectors like aviation, and the need to draw down additional atmospheric CO_2 to achieve net-zero. Besides NETs, carbon capture in the cement industry is another important technology due to the sector's limited decarbonization options, while carbon capture in hydrogen production and power generation is limited (less than 100 $MtCO_2$). We discuss the advantages and disadvantages of technology options below.

Negative emissions technologies

We find that NETs are the predominant long-run source of captured CO_2 across a range of uncertainties. BECCUS is generally the least-cost technology option for providing negative emissions and consistently captures 400 to 500 $MtCO_2$. This is due to: (1) its carbon capture efficiency (e.g., approximately 70 to 140 $MtCO_2$ is captured per 100 million tons of biomass used in fuel production); and (2) its versality to displace fossil fuels as a drop-in fuel. However, deployment is constrained by an uncertain supply of sustainable biomass and the need for bio-refineries to be located near feedstocks given biomass transport costs.

Although DAC is not deployed in the CNZ scenario, it is an important technological backstop to supply negative emissions. First, DAC's importance is contingent on very plausible circumstances that may arise on the path to net-zero, including a limited supply of biomass and slower consumer uptake of electric vehicles and appliances. Second, DAC helps manage the risk of implementation failures outside of the energy sector, including a lack of progress to reduce non-CO_2 emissions or enhancement of the land sink. Unlike BECCUS, DAC can be located nearly anywhere with open land, with costs driven by energy availability and geologic sequestration potential. Its high cost but flexibility means that it could benefit from direct innovation, as well as innovation for technologies that represent a large share of production costs (e.g., renewables to power DAC facilities) or uses (e.g., geologic sequestration). Finally, the analysis imposes an economy-wide emissions constraint that starts today and continues until 2050, but our ability to implement such policy is far from certain and failure to meet that trajectory may increase the need for negative emissions in later years.

It is important to note that the idea of a negative emissions technology "backstop" is associated with moral hazard risk, the idea that their existence might delay efforts to directly reduce emissions. Our analysis confirms that NETs do not serve as a substitute for direct emissions reductions today and are most important in the long run.

Near-neutral emissions technologies

For technologies where fossil fuel is the input and 90%-100% of emissions are captured ("near-neutral technologies"), carbon capture deployment and prioritization vary. In the cement industry, carbon capture is consistently deployed as a solution to address its emissions since other mitigation solutions do not exist. This is one of the few sectors where carbon capture is applied to existing infrastructure, and the amount captured is constrained by the size of the cement industry (approximately 130 $MtCO_2$).

We find that blue hydrogen production facilities are a consistent but limited source of captured CO_2 (approximately the same capture volume as heavy industry, ~100 $MtCO_2$), while carbon capture is rarely deployed at existing or new power plants. Although both sectors can utilize relatively low-cost natural gas, they share characteristics that disadvantage their deployment. First, in a net-zero energy system, the electricity sector contains very high levels of variable renewable energy (>70% of generation) which encourages investment in electrolysis, a competitor of blue hydrogen, and discourages thermal power generation. Second, large-scale deployment requires significantly scaling up CO_2 storage infrastructure. For example, if these technologies supplied one-third of end-use electricity and hydrogen demand, then approximately 1,200 $MtCO_2$ of annual storage would be required. Finally, carbon capture in these two sectors can only address their own emissions, whereas NETs are flexible by addressing residual emissions from any sector in the economy.

Innovation across the carbon management supply chain is needed

Carbon management's ability to contribute towards net-zero GHG emissions depends on innovation across a chain of CO_2 capture, transportation, utilization and storage infrastructure. In our analysis, nearly all captured CO_2 in 2050 is from technologies currently in the demonstration or protype stage only, and technologies that utilize CO_2 are at a similar stage of development. This suggests that significant research, development, and demonstration (RD&D) is necessary to ensure the technologies most compatible with a least-cost net-zero energy system are deployed in time. Specifically, innovation is needed to demonstrate large-scale deployment of BECCUS, DAC and synthetic fuels. Innovation is less critical for transport given that CO_2 pipelines are already used extensively; however, storage in geologic formations would benefit from greater clarity on cost and annual injection potential. Overall, investing in innovation for negative emissions technologies can manage risks associated with the path to net-zero.

Technology Readiness Level Across Carbon Management

Category	Sub-category	TRL
Capture	Power generation	Demonstration
	Hydrogen production	Early adoption
	Heavy industry: cement	Large prototype
	Fuel production: bioenergy	Demonstration
	Direct air capture	Large prototype
Transport	Pipeline	Mature
Utilization	Synthetic methane	Demonstration
	Synthetic hydrocarbons	Large prototype
Storage	Saline formations	Early adoption

We find that failing to pursue the innovation needed for CCUS technologies to be technologically ready creates significant trade-offs and challenges for achieving net-zero. We modeled a scenario without carbon management as a strategy and found that while realizing net-zero E&I CO_2 emissions is ‘technically feasible’, the trade-off entails scaling biomass and renewables to potentially problematic levels. Compared to the CNZ scenario, forgoing carbon management increases biomass consumption from 600 million tons to more than one billion tons and renewable deployment from 3.2 to 3.8 TW. These deployment levels may be plausible but given the uncertainty about the supply of sustainable biomass and the challenges of siting renewables, taking carbon management off the table amplifies the risk of missing the net-zero target. In addition, it is worth noting that this scenario hinges on all other mitigation strategies in the energy and non-energy sectors being met and leaves little room for error.

Prioritize carbon management's long-term role

Today's carbon management research and funding is primarily focused on: (a) deploying point-source carbon capture at existing fossil-based facilities; and (b) using CO_2 for EOR, which often requires long-distance CO_2 pipeline networks to connect existing emissions sources and oil-producing regions. On the path to achieving net-zero by 2050, much of the energy infrastructure that is a near-term candidate for carbon capture retrofits will likely be retired or operate less frequently. Gasoline fuel demand is modeled to decrease by 25% by 2030 relative to today and 55% by 2035 due to improved fuel economy and transportation electrification, while ethanol production would likely decrease commensurately. Most coal-fired resources retire during this timeframe in a least-cost pathway, while gas-fired resources operate at lower capacity factors.

In contrast, our analysis shows: (1) significant carbon capture (> 100 $MtCO_2$/yr) occurs 20 to 30 years from today; and (2) carbon capture technology is almost exclusively applied to new energy infrastructure, with retrofits in heavy industry being the exception. As a result, we believe focus should be expanded towards areas that align with achieving net-zero in the long-term, including: (1) fostering the development of NETs; (2) placing value on both CO_2 storage and beneficial utilization; and (3) identifying and developing regional integrated carbon management hubs with shared infrastructure. These efforts lay the groundwork for future carbon management without conflicting with implementing known near-term decarbonization strategies (e.g., scaling renewable electricity; increasing light-duty electric vehicle sales to at least 50% by 2030, etc.).

CO_2 is managed differently across the U.S. and is primarily used intra-regionally

The U.S. energy system already demonstrates significant regional variations in terms of energy consumption and production, and we find that regional carbon management strategies in the future could have similar outcomes. Differences in the sources of captured CO_2 and its application are primarily explained by regional resource endowments, including biomass feedstock supply, renewable resource quality and geologic sequestration potential.

Regions along the Gulf Coast, which are endowed with plentiful saline formations, are responsible for capturing half of all CO_2 and sequestering an even greater share. Across the Great Plains, CO_2 tends to be utilized due to the area's high-quality onshore wind resources, which enables low-cost electrolytic hydrogen that is paired with captured CO_2. The Midwest transitions away from its existing corn ethanol industry towards advanced biofuels and the captured CO_2 from bio-refineries is sequestered in the region. Carbon management in the Northeast and West is limited (~10% of total CO_2 capture) due to a relatively small share of national biomass supply and heavy industry.

We find that nearly all captured CO_2 is stored or utilized intra-regionally (e.g., within several hundred miles of the point of capture and not typically transported long distances across the U.S.). The focus of applying carbon capture on new biofuels production facilities rather than a broad swath of existing CO_2-intensive infrastructure suggests more of a need for hub-and-spoke infrastructure instead of long-distance CO_2 transmission to connect regions. Furthermore, since CO_2 utilization to produce synthetic fuel can be accomplished intra-regionally, there is little need to transport CO_2 long distances to oil-producing regions such as Wyoming or the Permian Basin.

A caveat to this finding on CO_2 transport is that the analysis is based on minimizing the total cost of achieving net-zero at the national level. In practice, climate policy primarily driven by states without improved coordination across the U.S. could result in alternative outcomes including more mismatch between CO_2 sources and their uses. A further caveat is that repurposing of long-distance infrastructure currently used for fossil fuel transport may provide an alternative avenue for CO_2 transport.

The risk of carbon capture extending the life of fossil fuels is low if we are on a path to net-zero

One key concern about carbon management is that it facilitates continued fossil fuel use, but our net-zero analysis finds large reductions in fossil fuel consumption (80-90% below 2005 levels by 2050). However, carbon management technologies could enable some fossil fuel use, such as heat or feedstocks for industrial applications that are challenging or very expensive to abate. Such steep declines in fossil fuel consumption are necessary for the U.S. economy to reach net-zero, because scaling negative emissions technologies to levels near today's energy sector emissions (~5,000 $MtCO_2$) and deploying fossil-based carbon capture technologies to supply a significant share of energy needs are both uneconomic and exceeds current estimates of annual CO_2 injection potential.

Since carbon management does not inherently address non-CO_2 pollution, such as methane, it will be important for policymakers to monitor and address co-pollutants associated with carbon management, lest they negate its near- and long-term climate benefits. Certain carbon capture technologies could increase non-CO_2 emissions due to their interactions with the oil and gas supply chain (e.g., blue hydrogen production), where methane leakage is a significant contributor to near-term warming. Addressing leakage is a high-priority mitigation strategy for achieving climate targets in general, and it would help address potential unintended consequences from carbon management that were not explicitly modeled in this paper.

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2443 Fillmore St #380-5304 | San Francisco, CA, 94115
info@evolved.energy | Tel: 844-566-136

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