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Cost and deployment consequences of advanced planning for negative emissions with direct air capture in the U.S. Eastern Interconnection

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ABSTRACT

Negative emissions systems differ from net-zero systems by deploying significantly more negative emission technologies. The emerging literature on negative emission power systems assumes straight transition pathways from the present systems to final negative emissions systems. Such straight transition paths are unlikely, as deployment of negative emission technologies such as direct air capture might occur via crash course to respond to climate crises and utilities are investing towards net-zero systems instead of negative emissions systems. In this paper, to inform policymakers of the different outcomes of planning for negative emissions systems at different timelines, we quantify the value of planning for a negative emissions power system beginning now versus after achieving a net-zero emissions system in 2050. We apply a macro-scale capacity expansion planning model to the Eastern Interconnection power system to quantify the technological deployments and cost consequences of these two decarbonization pathways to reach a negative emission power system. We find advanced planning for a negative emissions system favors more deployment of storage technologies, which increases system flexibility and allows for better utilization of renewable generation to reduce investments in other technologies, including transmission lines. This change in distribution of investments across technologies leads to small annual cost saving of $6 billion, or 1%. We also find that further delay in planning for a negative emission system after reaching net-zero by 5, 10, and 15 years could significantly increase total system cost by 29%, 35%, and 41% respectively due to higher deployment of negative emission technologies. Our results indicate that, given small annual cost saving from advanced planning for a negative emission power system, economically utilities are on the right path in planning for a net-zero power system by 2050. However, planning should not be delayed further after reaching net-zero to avoid missing cumulative emission targets or significant cost consequences.

1. Introduction

Limiting global average temperature increases to 2 or 1.5 °C above pre-industrial levels generally requires the global economy to reach net-zero or negative emissions [1,2]. In nearly all net-zero and negative emission pathways, the electric power sector reaches zero or near-zero emissions [1]. Net-zero and negative emissions systems differ in the magnitude of carbon dioxide (CO_2) removal (CDR) with massive deployment of CDR characterizing negative emission pathways [1–5]. Among CDR approaches, one of the most promising and scalable is direct air capture (DAC) [2]. The two DAC processes that are furthest in the development are those that remove CO_2 directly from ambient air using either liquid solvents (liquid solvent DAC) or solid sorbents (solid sorbent DAC). Captured CO_2 can be sequestered or used to make products, e.g. liquid fuels [3,6]. DAC plants are not location-dependent and thus can be installed at or away from CO_2 polluting point sources [7], making their deployment more convenient than other types of NETs [8]. Although DAC is an emerging technology, its early commercialization efforts show potential for its implementation at industrial and utility scale. So far, a few companies have reached early commercialization successes, including Canadian-based Carbon Engineering, which develops liquid solvent DAC [9], and Swiss-based Climeworks [10] and U.S.-based Global Thermostat [11], both of which develop solid sorbent DAC.

Both types of DAC require significant heat and/or electricity inputs, which can be sourced from the power systems [12], to capture CO_2 from the air then store it underground or in products [3,9,13]. Given these significant energy input requirements, massive deployment of DAC in line with net-zero or negative emission targets would significantly increase electricity and/or thermal demands. Thus, planning for

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future large-scale DAC deployment is important for utilities and power sector decisionmakers.

While net-zero emission power systems are extensively researched [14–19], studies exploring achieving negative emissions systems using power system models to capture power system features and constraints at high spatio-temporal resolution are relatively scarce [15,20,21]. [20] examines the feasibility of reaching net-zero and negative emission targets in a 100% renewable European power system by 2050. They find that an all renewable power system is 30% more expensive than a power system with other low-carbon resources, such as nuclear and carbon capture and storage (CCS), and poses challenges to reaching negative emission targets. [21] uses a capacity planning model to quantify the role of bioenergy with carbon capture and storage (BECCS) in decarbonizing the Western Electricity Coordinating Council (WECC) power system by 2050. They find that including BECCS in WECC's power portfolio along with massive deployment of renewable resources and aggressive reduction of fossil fuel generation can achieve a negative emission power system by 2050. [15] uses a capacity planning and dispatch model to show that investments in DAC and BECCS along with other low carbon technologies lower the costs of achieving decarbonization targets in the U.S. power system. They also find that DAC have more significant impacts as emission policies become more stringent, displacing advanced nuclear and long-duration storage.

This strand of literature offers valuable insights into technological, financial, and policy needs for achieving their targeted power systems. However, a key gap among these studies is that they only consider a straight transition pathway to net-zero systems or negative emissions systems from present or near-present systems. [22] examines the values of different transition pathways to reach a net-zero European energy system by quantifying the capacity investments and economic impacts of an early versus late transition pathway, i.e. a pathway with a stringent versus lenient short-term CO_2 emission cap. They find that an early transition pathway reduces total decarbonization cost by 5%. While this study indicates some value in advanced planning for net-zero systems, its analysis does not extend to negative emissions systems. Reaching negative emissions systems following a straight transition path from current systems is especially unrealistic for two reasons. First, large-scale deployment of negative emissions technologies, particularly DAC, might occur abruptly, e.g. to avert severe or catastrophic damages from climate change [23]. Such a crash course would not evolve from a present system, but instead from some future partially- or fully-decarbonized system. Second, most utilities are not currently planning for negative emissions systems, but rather for net-zero or higher emitting systems [24]. Existing research has not quantified the consequences of transitioning to negative emissions systems from future decarbonized systems versus current systems. These consequences could be significant given the massive scale of DAC electricity consumption in many negative emissions pathways [1–5].

To fill the research gap above and inform decarbonization planning, we use a macro-scale capacity expansion (CE) model to quantify the cost and energy infrastructure investment outcomes of different decarbonization pathways to reach net negative emission targets in a power system. Specifically, we compare these outcomes resulted from planning for a negative emissions power system before versus after achieving a net-zero emissions system to understand the value of advanced planning. We formulate a CE model, then apply our model to the Eastern Interconnection (EI) power system for scenarios that vary when DAC deployment begins.

Our CE model optimizes investment in and operation of DAC alongside electricity generator, storage, and transmission assets. We use DAC as our CDR due to its early commercial success and scalability [25], and due to food, land use, and water concerns surrounding BECCS [26]. Additionally, [15] has shown that for a highly negative emission target, DAC is responsible for the majority of carbon removal, crossing BECCS to become the most dominant CDR technology at emission reduction targets higher than 105% below 2005 levels in 2050. Our emissions constraints driving decarbonization in our CE model capture the fact that DAC might be deployed not only by the power sector, but also by non-power-sector actors, e.g. industrial facilities to offset their CO_2 emissions, as these sectors have used CDR technologies extensively in the past [27]. To quantify the robustness of our results, we conduct sensitivity analyses for uncertainties in DAC deployment costs and other factors that restrict mass deployments of various technologies, reflecting technology availability and scalability.

The rest of the paper proceeds as follows. Section 2 introduces our modeling framework, data input, and scenarios considered for this study. Section 3 presents results. Section 4 provides further discussion. Finally, Section 5 concludes.

2. Methods

2.1. Capacity expansion model

The capacity expansion (CE) model (Fig. 1) is a linear program that optimizes new capacity investments, operations of new and existing units, and inter-regional electricity transfers by minimizing total system costs subject to system and unit-level constraints. Total system costs equal the sum of the cost of electricity generation of existing and new units and the cost of new capacity investments. Electricity generation costs equal the sum of fixed operations and maintenance (O&M) costs and variable electricity generation costs, which include fuel costs and variable O&M costs. Like most other macro-energy system models [15,16,28–31], the CE model is deterministic and runs for a fixed time horizon without foresight (i.e., myopically) (see Section 2.3 for details on the time horizon). In each time step, the CE model can add any number of coal steam with carbon capture and sequestration (CCS), natural gas combined cycle (NGCC), NGCC with CCS, nuclear, wind, solar generators, battery and long-duration storage (hydrogen) units, as well as DAC units and transmission line capacities.

The novelty of our CE model is its option to integrate mass deployment of DAC at different timelines into the electric power systems using electricity inputs sourced from the grid. Two most common macro-scale models have incorporated DAC and other negative emission technologies in order to determine its values in meeting climate targets - the Integrated Assessment Models (IAMs) and the long-term power system planning model, or capacity expansion (CE) models. IAMs, due to their breadth, assume simplified representations of the global climate and economic sectors, and thus have limited ability to capture the characteristics and detailed operation of power systems, which CE models are capable of. Thus, CE models are a preferred modeling choice to capture the interactions between negative emission technology deployment and power systems' infrastructure and operations.

The CE model includes unit and system-level constraints, which drive investment and operational decisions of all technologies including DAC. Unit-level constraints limited site-specific hourly wind and solar generation based on resource availability; generator operations based on engineering and economic features; and technology-specific investments. DAC is incorporated into the CE model as units with negative capacity and generation, which incurs electricity demand. System-level constraints enforce market clearing conditions on an hourly basis, including balancing of electricity supply, demand and electricity transfers on an hourly regional basis; limiting inter-regional electricity transfers; and enforcing a cap on annual CO_2 emissions. To capture inter-regional transmission of electricity, we use the transport method, which is widely adopted in macro-energy system models [16,29,32]. The transport method constrains hourly inter-regional flows of electricity between regions to a fixed net transmission capacity. For computational tractability, we run the CE model in hourly intervals for one representative time block per season, with 21 sequential days in each time block, and three representative days in each peak time block. In each time step, the model can add any amount of capacity upgrades in existing transmission capacities and any number of new capacity resources in

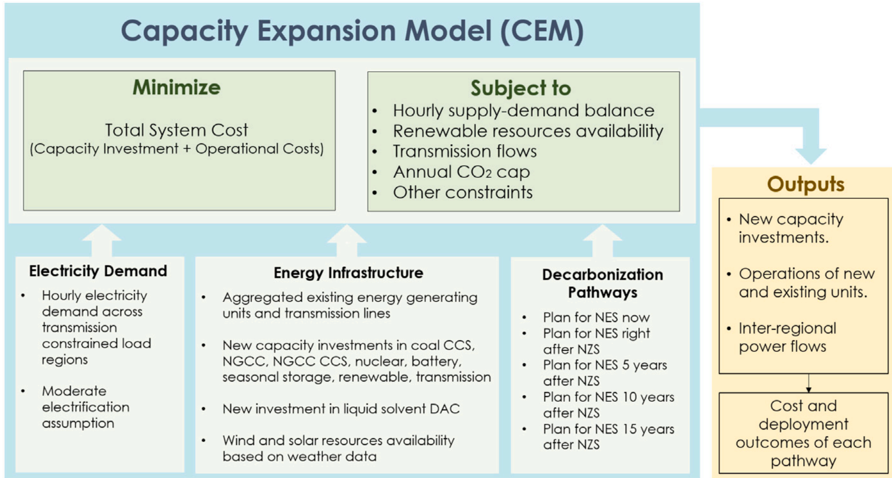


Fig. 1. Overview of the CE model.

nine technology types (Table 2). For the full CE model formulation, see the Supplementary Information (SI). The CE model is programmed in the General Algebraic Modeling System (GAMS) [33,34] and solved using CPLEX Version 20.1.0.1 [35].

In each scenario and pathway, using the CE model's emission and cost outputs, we calculate the marginal abatement cost of CO_2 as:

$$MAC_h^{CO_2} = \frac{\sum_y \pi_{yh}}{\sum_y E_{yh}^{CO_2}} \tag{1}$$

where $MAC_h^{CO_2}$ is the marginal abatement cost of CO_2 in scenario h, $E_{yh}^{CO_2}$ is total CO_2 emission reduction in year y for pathway h, which is calculated as the difference between the annual emission cap of that year and the initial emission level in 2020, and π_{yh} is total annualized system cost in year y for pathway h to meet targeted CO_2 emission reduction $E_{yh}^{CO_2}$.

2.2. Data

We apply the CE model to the Eastern Interconnection (EI) power system for the year 2050, and years 2055, 2060, and 2065 for delayed planning scenarios. For computational tractability, we divide the EI power system into six transmission congestion regions, reflecting existing balancing authorities or planning regions: the Midcontinent Independent System Operator (MISO), New York ISO (NY), ISO New England (NE), PJM Interconnection (PJM), SERC Reliability Corporation (SERC), and Southwest Power Pool (SPP) (Figure A.1). Our division of the EI into sub-regions is similar to divisions used in other macro-energy system models [16,29,32].

To capture the effects of ongoing electrification of end-use demand, we use hourly electricity demand profiles for 2050 that include moderate electrification [36,37]. To calculate hourly electricity demand for each region within the EI, we sum intra-regional hourly electricity demand profiles. Our model also endogenously captures electricity demand from optimized operation of deployed DAC systems, such that total hourly demand equals exogenous hourly demand profiles plus endogenous hourly DAC electricity consumption, which is discussed below. On the supply side, we construct our 2020 initial representative existing generator fleet by combining unit-level data on active existing units from [38] with storage units from [39], then identify the units that are located within the territory of the EI. Because the existing generation fleet in the EI is quite large with over 12,000 units, we perform fleet compression based on location, fuel-type/plant-type, heat rates, and online years. See Appendix D.2 for detailed set up of initial representative fleet.

Table 1
Transmission capacity and costs of transmission capacity upgrades between load zones within the EI. Values are in 2018$.

Transmission capacity between	Total capacity (GW)	Expansion cost ($/MW)
SERC and MISO	32.50	789,601
SERC and PJM	14.14	443,112
NYISO and ISONE	4.06	1,116,716
NYISO and PJM	3.98	1,066,926
MISO and PJM	16.44	564,650

To calculate the fixed transmission capacity between each pair of regions, we sum all existing transmission capacities [40] between them. Capital costs of new inter-regional transmission capacity are calculated as the product of the per MW-mile cost of each bi-directional aggregated transmission line between the two regions [32,40] and its distance in miles, which is assumed to be the distance between the two centroids of the two regions they connect. Table 1 depicts all possible combinations of aggregate transmission lines between our six regions in the EI and their respective fixed transmission capacities and total costs per MW.

Table 2 provides our technology parameters. To calculate variable costs, we obtain future fuel prices from the U.S. Energy Information Administration's 2020 Annual Energy Outlook [41] and heat rates and variable operation and maintenance (O&M) costs from National Renewable Energy Laboratory (NREL)' 2021 Annual Technology Baseline (ATB) [42]. We also obtain CO_2 emission rates from NREL's ATB [42]. To calculate fixed costs, we obtain overnight capital costs and fixed O&M costs from NREL's ATB [42].

To parameterize DAC, we survey engineering and system modeling studies on liquid solvent and solid sorbent systems. These technologies vary in the degree to which they require electricity and/or heat inputs for operations, with liquid solvent processes generally requiring more energy inputs than solid sorbent processes [11]. Based on work by [9], we model a liquid solvent DAC system that uses no natural gas input and instead uses electricity from the grid to substitute for all the energy input from gas steam cycle. This system uses 366 kWh of electricity per ton of CO_2 removed and costs $19.04 million/MW (Table 2). This approach is similar to other power system studies, e.g. [18], that only consider electricity inputs to DAC, as only electricity consumption couples DAC to the power sector. We choose to model electricity-input DAC for two reasons. First, a commercial scale electric calciner can potentially have advantages over a traditional one in that it provides the systems with low-carbon energy alternatives to maximize net removal of CO_2 [43]. Second, while it is environmentally and cost inefficient to run DAC systems entirely on electricity in high-carbon power systems,

Table 2
Key investment and operational parameters of new technologies that can be added to the generator fleet by the CE model. Values are in 2018$.

Plant type	Capacity (MW)	CAPEX (Million $/MW)	Heat rate (Btu/kWh)	Fixed O&M cost (Thousand $/MW-year)	Variable O&M cost ($/MWh)
Coal CCS	650	3.34	9467	94.06	11.70
NGCC	400	0.81	6363	24.46	1.56
NGCC CCS	340	1.52	6170	54.11	4.77
Nuclear	1117	5.25	10,455	129.87	2.11
Wind	500	0.68	0	29.66	0.00
Solar PV	100	0.57	0	13.42	0.00
Battery storage	100	0.53	0	13.17	0.00
Hydrogen	500	1.06	0	0.00	0.00
DAC	500	19.04	3412	0.00	120.63

as the power systems completely or nearly completely decarbonized, which is the case when DAC starts being deployed [15], electricity-input DAC yields low environmental and economic costs [9,43]. The capital cost per MW of DAC capacity we used here is estimated from detailed costs of DAC components and equipment including air contactor, pallet reactor, separation unit, calciners laker, CO_2 compressor, among others, as reported in Table 3 of [9].

To calculate wind and solar capacity factors, we apply NREL's System Advisor Model [44] to solar data from the National Solar Radiation Database [45] and wind data from the Wind Integration National Dataset [46] using a tool developed by [47]. To be consistent with our demand data which uses weather data for year 2012 [36,37], we also use wind and solar data for year 2012. The CE model incorporates these hourly wind and solar PV resources availabilities at over 2000 locations across the EI to optimize where and how much new wind and solar capacities are built at these locations on an annual basis, and how much wind and solar generation is dispatched on an hourly basis.

2.3. Emission pathway and decarbonization scenarios

To understand the robustness of our results to diverse uncertainties, we run two types of scenarios in our analysis: emissions pathway scenarios and decarbonization scenarios. We describe each type of scenario in turn below.

2.3.1. Emission pathway scenarios

To examine the value of planning for a negative emission system at different times, we run two sets of emissions pathway scenarios for the EI (Fig. 2). These emissions pathways are designed on the basis of reaching 2020-2100 cumulative CO_2 emissions that limit warming to 2 °C [1]. In the first set, we run two scenarios that each reduce CO_2 emissions by 115% below 2005 levels by 2050, which is aligned with emissions pathways that limit warming to 2 °C [1] and with a moderate emission cap scenario in [15], but that vary when planning for negative emissions begins: (1) in 2020 ("Plan Now") or (2) in 2050 from a net-zero system ("Plan After Net-Zero"). In the "Plan Now" scenario, planning for negative emissions systems begins immediately from the current (2020) power system. We run the CE model once for 2050 as a brownfield optimization with an annual CO_2 emissions cap that is 115% below 2005 levels. In the "Plan After Net-Zero" scenario, planning for negative emissions systems begins in 2050 after a net-zero system is achieved. We run the CE model twice, first for 2050 as a brownfield optimization with an annual CO_2 emissions cap of zero, then again for 2050 as a brownfield optimization initialized from the prior CE solution with an annual CO_2 emissions cap that is 115% below 2005 levels. While many other planning horizons for negative emissions exist, these two pathways bound those horizons and, in turn, bound the value of advanced planning for negative emissions.

In brownfield mode, our CE model considers existing generators and inter-regional transmission capacities in the EI in 2020. We estimate 2005 electricity sector CO_2 emissions in the EI power system by summing 2005 CO_2 emissions from states [48] within our study systems. For states located partly within the EI, we use a population-weighted CO_2 emission using the fraction of a state's 2020 population located within the EI [49]. Using this method, we estimate annual CO_2 emissions in 2005 as 4,831 million tons in the EI. As a result, our negative CO_2 emissions caps equal −725 million tons in the EI in 2050. For more details on decarbonization pathways and emission cap calculations, see Appendix D.5.3 and Appendix D.5.2, respectively.

Like other CE models [22], these pathways do not capture construction time of power infrastructure or DAC. However, an important value in advanced planning could be avoiding delays in DAC deployment. To capture the value of avoiding deployment delays, we run a second set of emission pathway scenarios (Fig. 3) that reduce CO_2 emissions by 120%, 121%, and 123% below 2005 levels, which reflect delays in DAC deployment by 5 years, 10 years, and 15 years after reaching net-zero in 2050. For this set of emission pathways, our negative CO_2 emissions caps equal −988 million tons, −1,042 million tons, and −1,102 million tons in the EI in 2055, 2060, and 2065 when DAC deployment is delayed by 5 years, 10 years, and 15 years, respectively. Here, we run the CE model twice, first for 2050 as a brownfield optimization with an annual CO_2 emissions cap of zero, then for 2055, 2060, and 2065 respectively as a brownfield optimization initialized from the prior CE solution with an annual CO_2 emissions cap that is 120%, 121%, and 123% below 2005 levels. These negative CO_2 emissions targets the reflect the same cumulative CO_2 emissions of −27,675 million tons by 2100, aligning with the amount of CO_2 removal between 2020 and 2100 needed to limit global warming to less than 2 °C [1].

2.3.2. Decarbonization scenario analyses

To quantify the robustness of our results to key decarbonization-related uncertainties, we also run five decarbonization scenarios. These scenarios capture uncertainties in technological deployment constraints and in capital costs of DAC deployment (Table 3). We run these scenarios for each of the two pathways in the first set of emission pathway scenarios, which reduce CO_2 emissions by 115% below 2005 levels by 2050. These additional scenarios analyses account for uncertain electrification rates of end-use demand, and future availability of diverse technologies as future technology availability could be constrained by societal preferences or research and development shortcomings. The sensitivities scenarios account for potential higher capital cost of DAC due to the lack of expected improvement in capital, construction costs, and build supply chain relationships during DAC plant development process [9], and potential lower capital cost of DAC due to additional improvements in these aspects. Specifically, we test the sensitivity of our results to DAC capital costs 44.5% higher and lower than the reference level [9]. See Appendix E fese scenarios.

3. Results

We first compare the deployments of generating and transmission capacities in the EI in two pathways - "Plan Now" and "Plan After Net-Zero". We then quantify the cost savings from advanced planning for a negative emissions system and discuss the economic and deployment

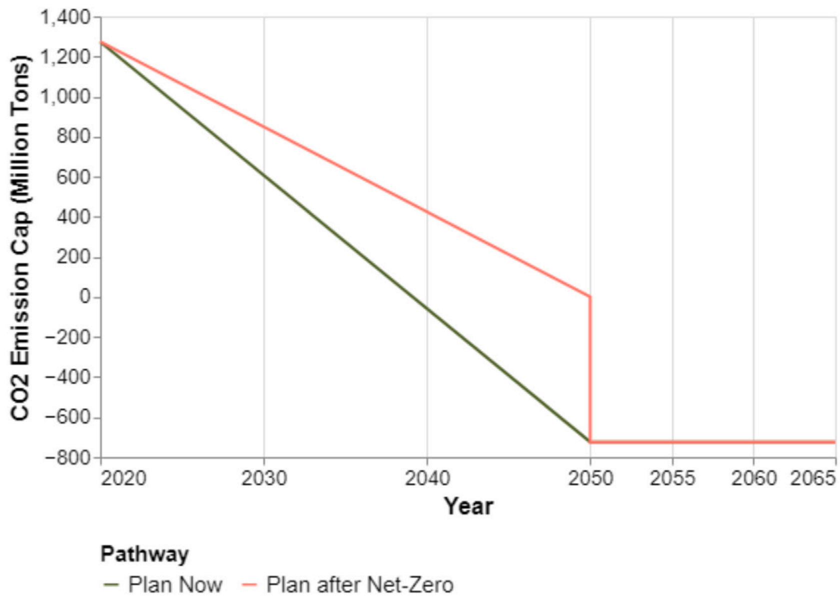


Fig. 2. Two decarbonization pathways of this study that have the same final negative CO_2 emission target of −725 million tons in 2050 (or roughly same total DAC deployment).

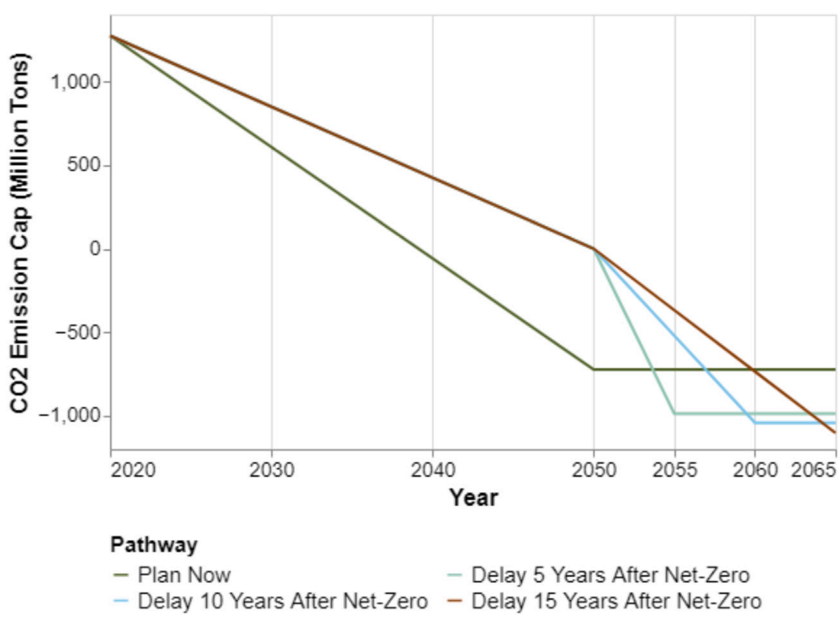


Fig. 3. Four additional decarbonization pathways of this study that have the same cumulative CO_2 emissions between 2020 and 2100, reflecting different DAC deployment delay timelines.

Table 3
Uncertainty analysis scenarios. Values are in 2012$.

Scenario	Technological limits	Electrification of end-use demand	DAC CAPEX (Million $/MW)
Reference	None	Moderate	19.04
High electrification	None	High	19.04
No CCS	No new CCS	Moderate	19.04
No hydrogen	No new H_2	Moderate	19.04
High DAC cost	None	Moderate	27.52
Low DAC cost	None	Moderate	10.17

consequences of further delayed planning for negative emissions for up to 15 years after reaching net-zero. Finally, we explore the robustness of our results across DAC cost sensitivities and limited technology deployment scenarios.

3.1. Advanced planning for a negative emissions system results in different distribution of generating capacity investments across technologies

Fig. 4 compares capacity investments in generators and storage output by our CE model for our two scenarios in the EI. Advanced planning for a negative emissions system (or planning for negative emissions systems beginning now) results in overall similar Interconnection-wide generating capacity investments in the EI (1688 GW) compared to planning for negative emission system in 2050 from a net-zero system (1685 GW). These total generating capacity investments from the two pathways have small differences in the distribution of investments across technologies, with advanced planning favoring more storage technologies investments and reducing investments in other technologies. Specifically, advanced planning for a negative emissions system reduces DAC investment by 2.1 GW (1.3%), renewable (wind and solar PV) investments by 24.6 GW (1.6%), NGCC CCS investment by 4.2 GW

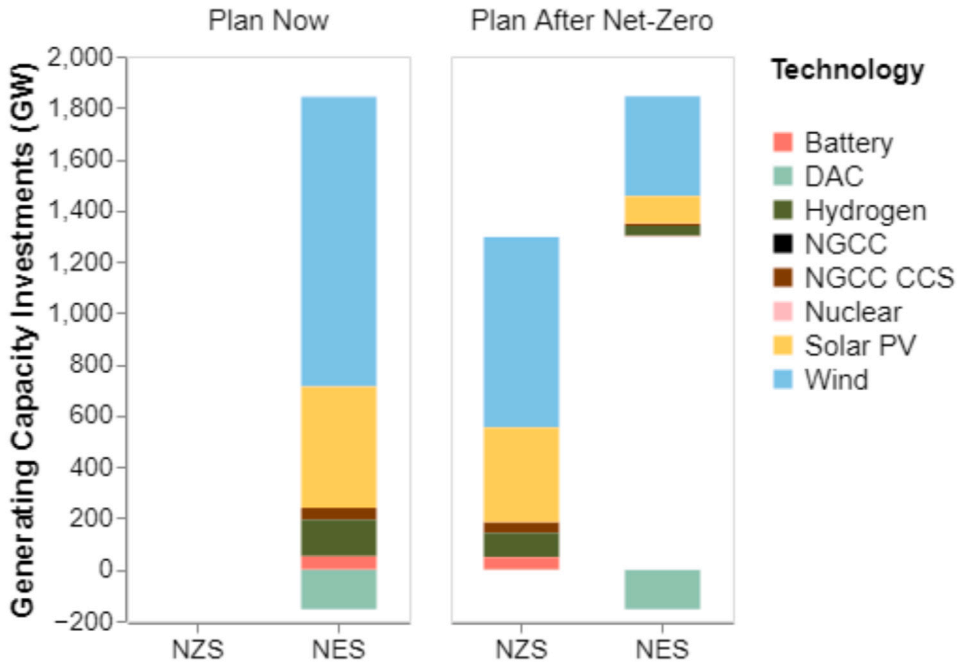


Fig. 4. Advanced planning for negative emissions systems results in different distribution of generating capacity investments across technologies. Capacity investments are divided by technology and between our two scenarios, in which negative emissions planning begins now ("Plan Now") or in 2050 with the same emission target (thus similar amount of DAC deployment) as "Plan Now" ("Plan After Net-Zero"). Plan After Net-Zero results are further divided between the net-zero system achieved in 2050 ("NZS") and additional investments needed to reach negative emissions systems ("NES"). These two scenarios share the same final negative CO_2 emission cap of −725 million tons in 2050.

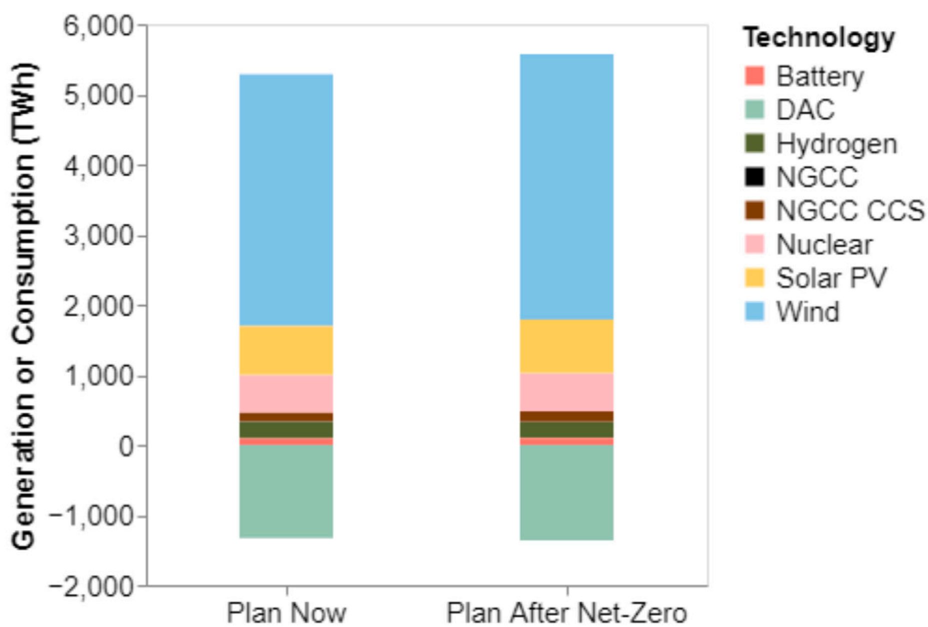
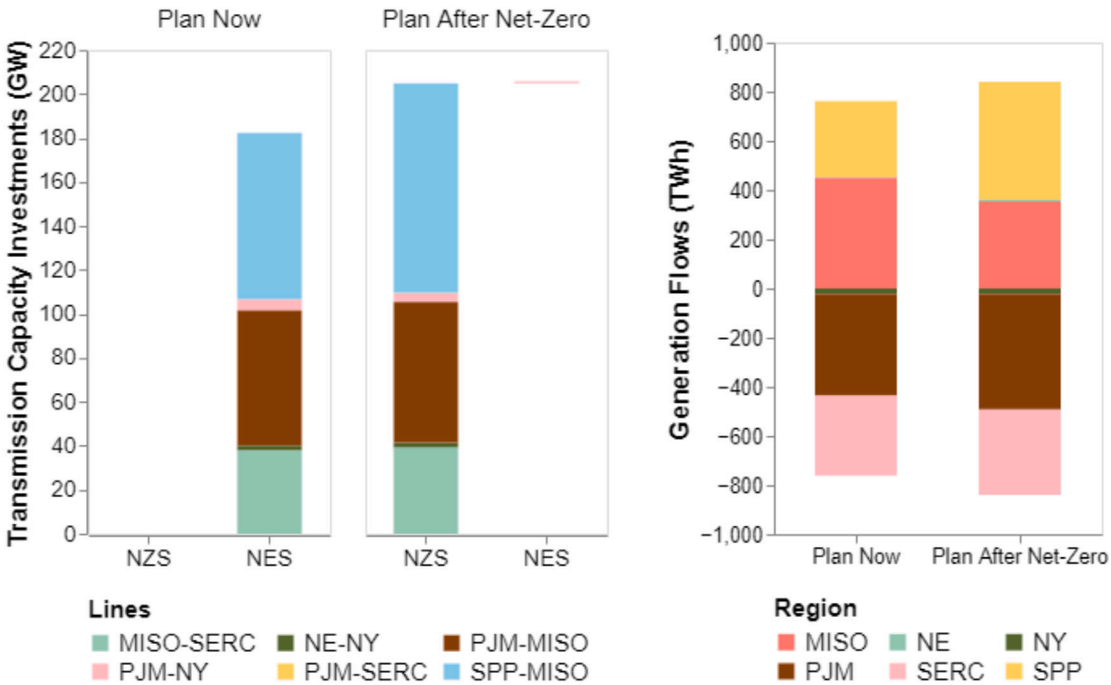


Fig. 5. Advanced planning for negative emission systems increases dispatch of long-duration storage (hydrogen) while reducing generation of other technologies in 2050. Electricity generation (positive values) or consumption (negative values) of negative emission system in the EI across two scenarios in which negative emissions planning begins now ("Plan Now") or in 2050 assuming the same amount of DAC deployment as "Plan Now" ("Plan After Net-Zero").

(8.4%), and increases battery storage investment by 2.9 GW (6.1%) and hydrogen investment by 7.4 GW (5.2%).

Changes in distribution of investments in the EI yield changes in distribution of electricity generation (Fig. 5). By 2050 after reaching the targeted negative emission system across the two planning scenarios, wind and solar generation meet around 81% of total load. Advanced planning for a negative emissions system increases total long-duration storage (hydrogen) discharge by 7 TWh (3%) annually. Additionally, DAC electricity consumption decreases in advanced planning by 30 TWh (2.3%), reducing total generation by non-storage technologies. Specifically, advanced planning causes 5% less battery discharge, 7% less renewable generation, and 11% less NGCC CCS generation. Capacity factors across technologies are similar between the two pathways. Given high DAC capital costs, DAC capacity factors are close to 1 in both scenarios, with DAC capacity factors of 98.5% under advanced planning and 99.3% when a negative emission system is planned after net-zero. Advanced planning also reduces renewable curtailment by 5.2 percentage point (to 14.5% compared to 19.7% renewable curtailment when negative emissions system is planned after net-zero). Overall, these investment and operational changes indicate that under advanced



(a) Transmission Capacity Investments (GW) **(b)** Net Generation Flows (TWh)

Fig. 6. Advance planning for negative emissions systems reduces inter-regional transmission investments due to decreased net inter-regional generation flows (a) Transmission investments are divided by lines and between two scenarios in which negative emissions planning begins now ("Plan Now") or in 2050, assuming the same DAC deployment as "Plan Now" ("Plan After Net-Zero"). (b) Net electricity flows between regions for each scenario.

planning, DAC and greater storage investments contribute to system flexibility to better take advantage of renewable generation and to avoid investment in NGCC CCS.

3.2. Advanced planning for negative emissions systems reduces inter-regional transmission investments due to decreased inter-regional flows

Within the EI, our CE model optimizes generation and DAC investments at the regional level and inter-regional transmission capacity. Advanced planning for negative emissions increases transmission capacity investments (Fig. 6(a)), but does not change the general direction of transmission flows between most regions (Fig. 6(b)). Advanced planning for a negative emissions system reduces inter-regional transmission capacity investments from 206 GW to 182 GW, or 11.4% (versus initial transmission capacity of 108 GW in 2020), and reduces net electricity flows from 839 TWh to 761 TWh, or 9.3%. Of the 24 GW reduction in transmission capacity under advanced planning, 19.6 GW or 82% occurs between SPP and MISO, 1.4 GW or 3.6% occurs between MISO and SERC, and 2.5 GW or 2.5% occurs between PJM and MISO. In other words, advanced planning decreases electricity flows from renewable-resource-rich SPP to less-rich MISO and to renewable-resource-poor PJM and SERC. Under advanced planning, DAC deployment is concentrated in SPP, so SPP exports 36% less electricity to other regions (Fig. 7). Conversely, under advanced planning, MISO increases its regional generating capacity investments (almost mostly in wind and solar) (Fig. 7) and increases its exports by 21.2% (Fig. 6(b)). Due to generally less generation flows between regions, regional capacity investments increase for most technologies in most regions except for SPP, instead these capacities are utilized more locally at higher capacity factors.

Advanced planning for a negative emissions system results in changes in regional capacity investments (Fig. 7), especially in SPP where advanced planning causes a fall in regional capacity investment by 56.1 GW or 9% and MISO where advanced planning increases regional capacity investment by 36.6 GW or 7.4%. The majority of these changes in regional capacity investments is in wind and solar PV investments. Advanced planning does not affect the distribution of DAC capacity across regions, as all of DAC investments occur in SPP across planning scenarios. DAC exploits SPP's strong wind and solar resources (Figures A.4 and A.5), lowering CO_2 removal costs.

3.3. Advanced planning for negative emissions systems lowers annual system cost

Advanced planning for a negative emissions system reduces total annualized system cost from \$576 billion to \$570 billion, or by \$6 billion (1%) (Fig. 8, left panel). Total annual system costs include annualized capital costs plus annual operating costs. Cost savings due to advanced planning come from lower annualized capital costs (by \$5.6 billion or 0.91%) and lower operating costs (by \$0.43 billion or 0.3%). The lower annualized capital cost is driven by decreased capacity investments in DAC, NGCC CCS, renewable, and transmission lines, which trumps the increased capital costs in higher deployment of long-duration and battery storage. The lower operating cost is driven by decreased generation dispatch of NGCC CCS and DAC units (Fig. 5) which have high variable operating costs (Table 2).

3.4. Longer delay in planning for negative emission systems results in higher system cost and increased interconnection-wide generating capacity investments

Our above analysis compares achieving the same CO_2 removal target via two pathways: planning now for a negative emission system versus planning for a negative emission system after achieving a net-zero system in 2050. The latter pathway provides a lower bound on what costs would actually be if planning for negative emissions waits til achieving a net-zero system, as DACS and accompanying infrastructure would not be built overnight. Here, we consider the value of advanced planning in avoiding delays in achieving negative emissions. Delays, in

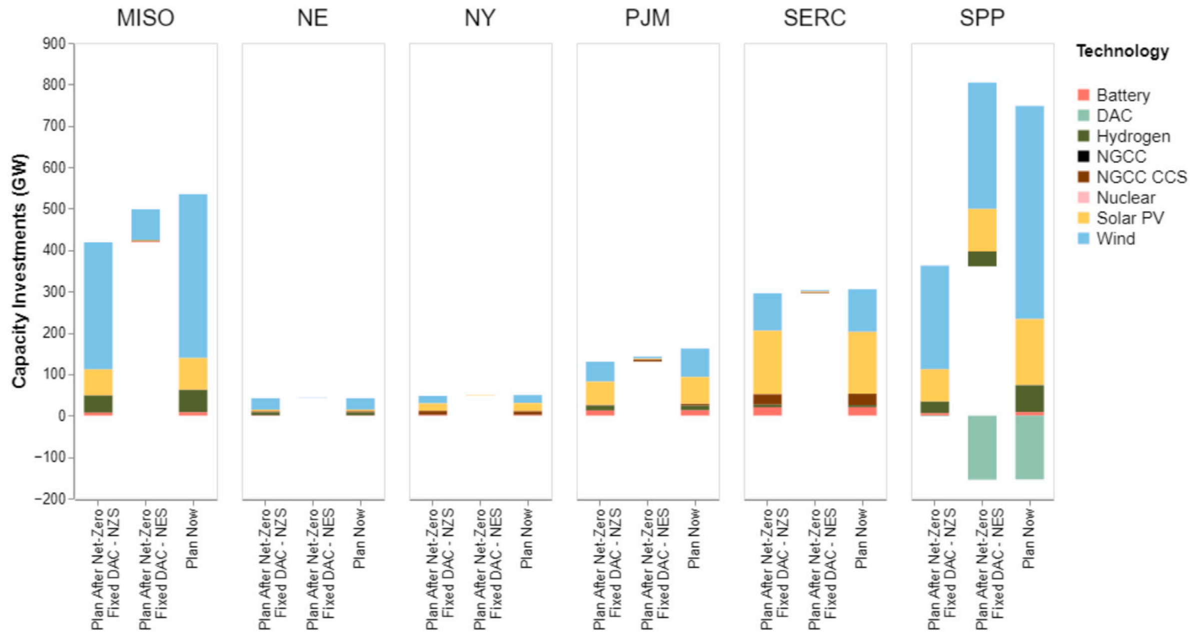


Fig. 7. Advance planning for negative emissions systems reduces regional generating capacity investments Capacity investments by technology, region, and scenario within the EI. Results for Plan After Net-Zero scenario are divided between the net-zero system achieved in 2050 ("Plan After Net-Zero Fixed DAC NZS") and additional investments needed to reach negative emissions systems ("Plan After Net-Zero Fixed DAC NES").

Fig. 8. Advanced planning for a negative emission system lowers total annyal system cost. Total annual system costs for EI divided between annualized capital (green) and annual operating (red) costs for each scenario. Results for Plan After Net-Zero scenario are divided between the net-zero system achieved in 2050 ("Plan After Net-Zero NZS") and additional investments needed to reach negative emissions systems ("Plan After Net-Zero NES").

turn, would require more annual CO_2 removal to meet the same cumulative CO_2 removal. Specifically, we consider three delay time-frames of 5, 10, and 15 years.

The longer planning for negative emissions systems is delayed, the total system cost of planning becomes higher (Fig. 9). Compared to advanced planning ("Plan Now"), delaying planning for negative emissions systems to 5, 10, and 15 years after reaching net-zero increases total annualized system cost by $165 billion (29.0%), $198 billion (34.8%), and $235 billion (41.3%), respectively. The majorities of these increases in costs are in annualized capital costs, which increase due to 5, 10, and 15 year delays in planning by $107 billion (26.6%), $128 billion (31.9%), and $152 billion (37.8%) respectively. Increases in capital costs are driven by increases in DAC capacity, which drives more generating capacity investments, mostly in wind and solar PV investments (Fig. 10). Due to higher final negative emissions targets associated with longer delayed planning compared to advanced planning, delayed planning by 5, 10, and 15 years significantly increases DAC deployment by 45 GW or 29.4%, 58 GW or 37.3%, 68 GW or 44.7%, and 82 GW or 52.9%, respectively. Because delayed planning incentivizes increases in system-wide and regional generating capacity investments, it does not result in increased transmission capacity investments (Figure A.6). Annual operational costs also significantly increase with delayed planning due to the higher cost of higher DAC operations. Specifically, annual operating costs increase by $58 billion (34.6%),

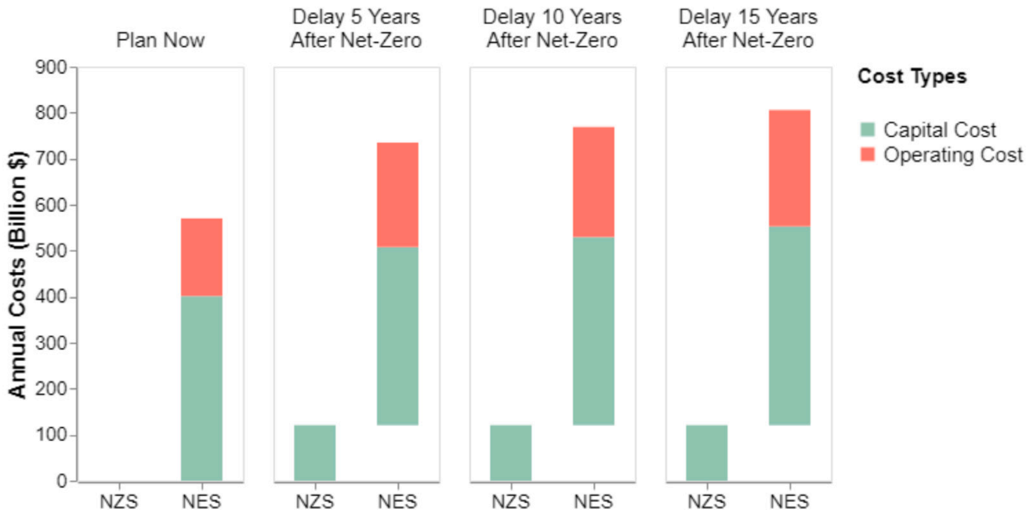


Fig. 9. The costs of planning for negative emissions systems increase the longer planning is delayed. Total annual system costs are divided between annualized capital (green) and annual operating (red) costs for each scenario.Plan After Net-Zero results are further divided between the net-zero system achieved in 2050 ("NZS") and additional investments needed to reach negative emissions systems ("NES"). These scenarios share the same cumulative CO_2 emission between 2020 and 2100.

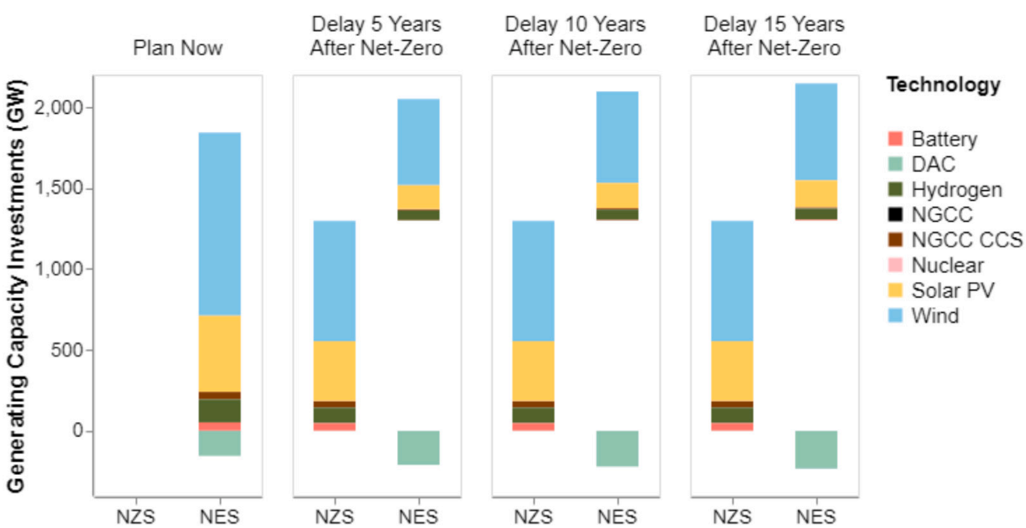


Fig. 10. Planning for negative emissions systems increases Interconnection-wide capacity investments the longer planning is delayed. Capacity investments are divided by technology and between our four scenarios in which negative emissions planning begins now ("Plan Now") or in 2050 ("Plan Immediately After Net-Zero) or later ("Plan 5 Years After Net-Zero", "Plan 10 Years After Net-Zero", "Plan 15 Years After Net-Zero"). Plan After Net-Zero results are further divided between the net-zero system achieved in 2050 ("NZS") and additional investments needed to reach negative emissions systems ("NES"). These scenarios share the same cumulative CO_2 emission between 2020 and 2100.

$70 billion (41.7%), and $84 billion (49.5%) when planning is delayed by 5 years, 10 years, and 15 years, respectively.

Advanced planning for a negative emission system via early large-scale deployment of DAC also plays an important role in reducing marginal CO_2 abatement cost. Under advanced planning, achieving the final negative emission target in 2100 from 2020 emission level in the EI requires a marginal CO_2 abatement cost of $353/t$CO_2$. Delaying planning for a negative emission system to right after reaching a net-zero emissions system results in a higher marginal CO_2 abatement cost of $436/t$CO_2$, or a 23.5% increase. Compared to advanced planning ("Plan Now"), delaying planning further by 5, 10, and 15 years raises marginal CO_2 abatement cost by $102/t$CO_2$ or 29%, $122/t$CO_2$ or 34%, and $145/t$CO_2$ or 41%, respectively.

3.5. Decarbonization scenario analyses

We run five decarbonization scenarios to capture uncertainty in DAC capital costs and availability of decarbonization technologies (Table 3). We run these scenarios for each of the two pathways in the first set of emission pathways scenarios, which reduce CO_2 emissions by 115% below 2005 levels by 2050.

Our results are largely robust to sensitivities on higher and lower DAC capital costs; unavailability of new hydrogen, NGCC with CCS; and higher end use electrification rates. Across these sensitivities, advanced planning for negative emission systems reduces total annual system cost by 0.7% to 1.2%. Specifically, advanced planning reduces total annual system cost 0.7% (when DAC capital cost is high), 1% (when DAC capital cost is low or moderate), and 1.5% (when electrification of demand is high or when deployment of new H_2 is not allowed) (Fig. 11). Similar to the reference case, these small decreases in total system costs from advanced planning in the high and low DAC cost sensitivities and technological limited scenarios are also due to increase in transmission expansion, and decreases in DAC deployment, NGCC CCS, and renewable capacity investments (Fig. 12). While not significantly impacting timelines of planning for negative emission systems, DAC capital costs significantly change total system-wide costs. A 44.5% increase in DAC capital cost from reference level results in $105 billion (18.4%) increase in total annualized system cost, while a

Fig. 11. Advanced planning for negative emissions systems yields little cost savings across different ranges of DAC capital costs and limited technology scenarios. Total annual system costs are divided between annualized capital (green) and annual operating (red) costs for each scenario.Plan After Net-Zero results are further divided between the net-zero system achieved in 2050 (“NZS”) and additional investments needed to reach negative emissions systems (“NES”). The two pathway within each scenarios share the same final negative CO_2 emission cap of −725 million tons in 2050.

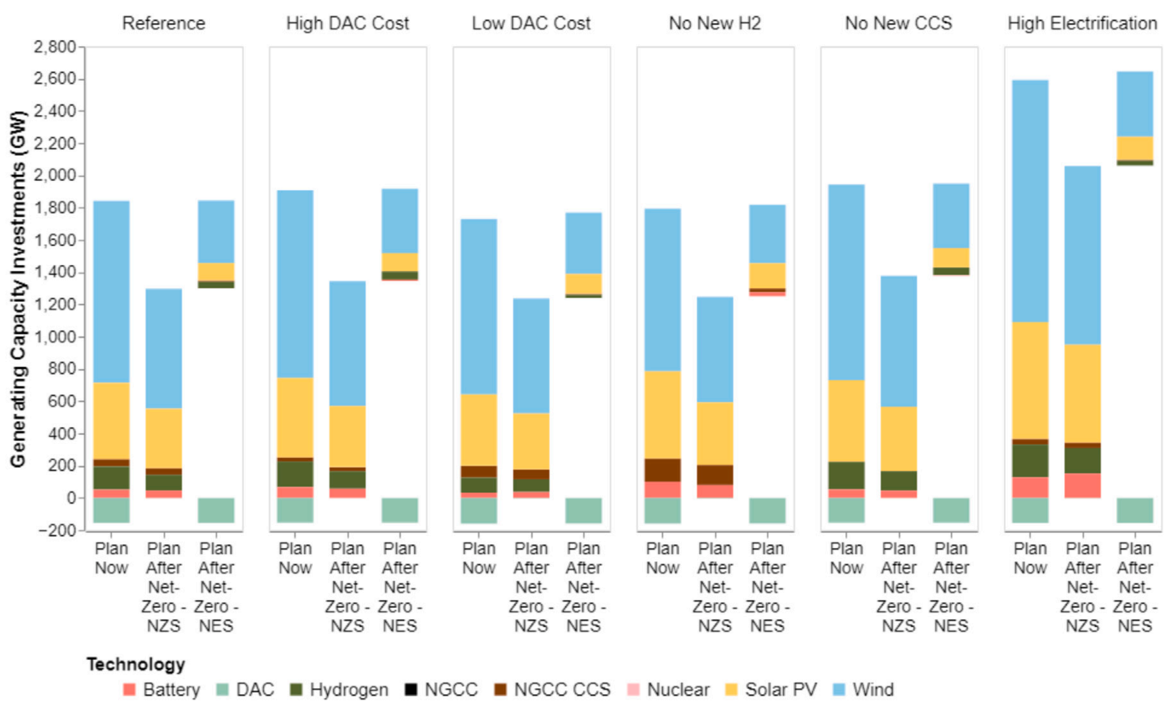


Fig. 12. Advanced planning for negative emissions systems results in more investments of storage technologies and less investments of other technologies across scenarios. The two pathway within each scenarios share the same final negative CO_2 emission cap of −725 million tons in 2050.

44.5% decrease in DAC capital cost from reference level results in $106 billion (18.7%) decrease in total annualized system cost.

4. Discussion

This paper examined the values of advanced planning for a negative emissions system starting from now versus delayed planning for negative emissions systems until after reaching net-zero. To do this, we used a macro-scale capacity expansion model applied to the EI to compare the costs and investment decisions of these two pathways. We chose to use the EI as our studied system because the EI is a large and diverse area that has shared characteristics with other U.S. and many global power systems, facilitating generalization of our results. Similar to many other systems globally, the EI has high quality renewable resources in regions that are far from load centers and diverse generation mix that includes existing and new fossil, nuclear, and renewable plants, both of which pose challenges for fully decarbonizing its power systems. Ignoring potential delay in DAC deployment after achieving a net-zero system, we found that advanced planning for negative emissions systems yielded small annual system-wide cost saving by $6 billion (1%), but increased system flexibility by increasing investments in storage technologies to take better advantage of renewable generation and thus reduce investments in renewable and other technologies, including transmission. For utilities working towards net-zero system plans, this result does not indicate an urgent need on a cost basis for those utilities to instead create and begin working towards negative emission system plans. Our analysis does not inform when it is best to achieve negative emissions systems, as we fix the year in which negative emissions are achieved to 2050 throughout our analysis.

Across planning scenarios, the dominant technologies deployed in negative emissions systems were wind and solar PV supplemented by expanded inter-regional transmission and grid-scale electricity storage. Other studies of net-zero and negative emissions systems have also demonstrated the importance of these technologies [15,16,22]. Policymakers and other stakeholders should continue to resolve hardware and non-hardware challenges to these technologies. Between planning scenarios, we found advanced planning for a negative emissions system reduces inter-regional transmission expansion requirement, incentivizing more regional generating capacity deployment and higher utilization of wind and solar resources. Given that inter-regional transmission expansion faces significant challenges in the United States due to lack of social acceptance and other factors [50], policymakers should particularly focus on enabling generating capacity expansion at regional levels to avoid long-distance transmission expansion to minimize costs of achieving negative emissions systems. Additionally, we also found delays in planning for a negative emission system significantly increase total system costs due to increased DAC deployment to reach the same cumulative negative emission target and increased system-wide generating capacity expansion required to power DAC. These delay scenarios exacerbate the importance of advanced planning when the final negative emission targets get more stringent. Given these potential cost consequences of delays, policymakers should plan for large-scale DAC deployment no later than right after reaching net-zero in 2050. Finally, our study estimates DAC cost of between $500 to $1,300 per ton of CO_2 removed, which fall within the range of early DAC cost estimates across different companies and DAC technologies around the world [51]. Although these estimates are driven by early DAC capital cost estimates, which are deeply uncertain since DAC is still a very immature technology, policymakers can use these early estimates as benchmark to develop policies that help drive down costs and support future deployment of DAC technologies.

Our work can be expanded in several ways, including by addressing methodological limitations. First, we do not model the spatial distribution of CO_2 storage capacity, which could impact our model's DAC deployment outcomes. However, significant storage capacity exists in the SPP region from which all DAC deployment occurs in our model [52–54]. Our model's 153 GW to 156 GW of DAC deployment in the SPP region across pathways is equivalent to total cumulative CO_2 removal between 2020 and 2100 in SPP region of between 40.5 $GtCO_2$ (under no delay scenario) and 47.4 $GtCO_2$ (under delay scenarios), which translates to annual removal of between 506 $MtCO_2$ and 593 $MtCO_2$. Both of these annual CO_2 removal targets are far less than total annual CO_2 storage capacity available in the Midwest plus Texas Gulf Coast (1280 $MtCO_2$) [54], which are the two CO_2 storage basins SPP can transport its CO_2 to since they are either geographically overlapped with SPP or already have existing CO_2 pipelines from SPP. Additionally, other research has shown that the cost of CO_2 storage has small effects on capacity deployment outcomes especially when there are no trade-offs between NGCC CCS and NGCC units, and NGCC CCS units are not marginally competitive [55]. Second, our CE model runs myopically, i.e. without foresight past the planning horizon, and for a single planning horizon through 2050. Without capturing intermediate investment decisions beginning with the existing generator fleet, our analysis might overestimate the value of advanced planning for negative emissions systems by overestimating flexibility in future system composition. Future work would benefit from including planning scenarios whose planning targets can be shifted at different times and integrating brownfield investments. Third, we do not model bioenergy with carbon capture and storage (BECCS) deployment, which could compete at scale with DAC in negative emissions systems [15]. Allowing BECCS deployment would likely substitute DAC deployment to achieve a net-zero system or a lenient negative emissions system. However, DAC deployment would likely become dominant as we plan for a highly negative emissions system [15]. Fourth, further research could extend our analysis to other regions in the U.S. and globe. Renewable resources and other constraints on decarbonization technologies will differ in other regions, potentially leading to different optimal generation mixes for net-zero and negative emissions power systems. As the systems reach net-zero and negative emissions, like the EI, we can expect the other regional systems to have wind and solar dominant generation mixes with some nuclear, NGCC, storage technologies, and biomass, which vary based on the regions' available renewable, storage and biomass resources. These differences in resource mixes might change total system-wide costs but might not significantly impact the timelines of negative emissions planning via electricity-powered DAC. Fifth, we examine DAC in the context of integration with the transmission-scale power system in this research, but DAC could instead be powered with distributed electricity and/or heat technologies given its modularity. In that case, DAC powered with distributed energy in modular deployment would not interact with transmission-scale investments, further undermining the small value we find of advanced planning for DAC. Finally, we only model highly aggregated transmissions across regions within the EI without consideration of AC or DC optimal power flow, which might ignore intra-regional and intra-state congestion, which might further underestimate the value of early planning for negative emission systems.

5. Conclusion

Decarbonizing the electric power sector by 2050 is crucial to limit global warming below 1.5 °C or 2 °C above the pre-industrial levels. Negative emissions power systems differ from net-zero systems in the large-scale deployment of DAC. Massive deployment of DAC would significantly increase electricity demand thus would require effective planning for significant changes in the power systems' infrastructure. However, little research has explored pathways to reach negative emissions power systems from future low-carbon or net-zero power systems. In this paper, we use a capacity expansion model to quantify the value of planning for negative emissions power systems before versus after achieving net-zero emissions systems. We apply this model to the Eastern Interconnection, which are divided into six aggregated transmission-constrained load regions. We find that for a wide range of scenarios, advanced planning for a negative emissions power system, compared to planning after reaching a net-zero emissions system, favors deployment of more storage technologies, which enhance the system's flexibility to better take advantage of renewable generation and to avoid investments in other technologies. Across load regions, advanced planning increases deployment of regional generating capacity, which allows for less investments in inter-regional transmission. We also find small cost savings from advanced planning for a negative emissions system compared to planning after net-zero. However, delaying planning for a negative emissions system further after reaching a net-zero system would significantly increase total system cost. These findings show that utilities are on the right path in planning for net-zero systems at this time, and suggest planning for negative emissions immediately after reaching net-zero. Future research in planning for negative emissions power systems should extend our analysis by modeling spatial distribution of CO_2 storage capacity and capturing the costs of CO_2 storage, modeling deployment of BECCS as another competitive CDR technology, and modeling intermediate investments.

CRediT authorship contribution statement

An T. Pham: Writing – review & editing, Writing – original draft, Visualization, Methodology, Formal analysis, Data curation, Conceptualization. **Michael T. Craig:** Writing – review & editing, Supervision, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Data curation, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data and code are available via link in manuscript.

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Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.apenergy.2023.121649.

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