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Research paper

Direct air capture integration with low-carbon heat: Process engineering and power system analysis

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ABSTRACT

Direct air capture (DAC) of carbon dioxide (CO_2) is energy intensive given the low concentration (<0.1%) of CO_2 in ambient air, but offers relatively strong verification of removals and limited land constraints to scale. Lower temperature solid sorbent based DAC could be coupled on-site with low carbon thermal generators such as nuclear power plants. Here, we undertake a unique interdisciplinary study combining process engineering with a detailed macro-energy system optimization model to evaluate the system-level impacts of such plant designs in the Texas electricity system. We contrast this with using grid power to operate a heat pump to regenerate the sorbent. Our analysis identifies net carbon removal costs accounting for power system impacts and resulting indirect CO_2 emissions from DAC energy consumption. We find that inefficient configurations of DAC at a nuclear power plant can lead to increases in power sector emissions relative to a case without DAC, at a scale that would cancel out almost 50% of the carbon removal from DAC. Net removal costs for the most efficient configurations increase by roughly 18% once indirect power system-level impacts are considered, though this is comparable to the indirect systems-level emissions from operating grid-powered heat pumps for sorbent regeneration. Our study therefore highlights the need for DAC energy procurement to be guided by consideration of indirect emission impacts on the electricity system. Finally, DAC could potentially create demand pull for zero carbon firm generation, accelerating decarbonization relative to a world without such DAC deployment. We find that DAC operators would have to be willing to pay existing or new nuclear power plants roughly \$30–80/tCO_2 or \$150–400/tCO_2 respectively, for input energy, to enable nuclear plants to be economically competitive in least cost electricity markets that do not have carbon constraints or subsidies for nuclear energy.

1. Introduction

Given the need for large scale carbon dioxide removal (CDR) to meet the temperature goals of the Paris Agreement [1,2], direct air capture (DAC) of CO_2 is gaining increasing attention and receiving growing private sector investment, advanced procurement commitments, and public policy support. DAC is energy intensive given the low concentration (< 0.1%) of CO_2 in ambient air, but offers relatively strong verification of removals (when combined with permanent geologic storage) and limited land constraints to scale.

In the United States, DAC deployment is currently being supported by tax credits for DAC established by the Inflation Reduction Act of 2022, grants to establish DAC 'hubs' funded by the Infrastructure Investment and Jobs Act of 2021, as well as increasing voluntary corporate procurement of DAC based CDR [3]. Given the potential for large scale deployment of DAC in the near future, it is important to understand the system-level implications and potential indirect emissions impacts caused by DAC deployment. DAC will interact with the electricity system in at least three ways:

- DAC plants may draw on grid power to operate equipment and generate heat for solvent/sorbent regeneration
- DAC could couple with thermal generators including natural gas with carbon capture and storage or nuclear or geothermal power for direct heat and power, competing with other demand sources for this energy
- DAC can provide CO_2 removal as a service to power generators, for e.g. enabling modest quantities of ongoing emissions from fossil fuel combustion with partial carbon capture, while still meeting net-zero emissions goals.

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Nomenclature

CapEx	Capital Expenditure
CDR	Carbon Dioxide Removal
CO_2	Carbon Dioxide
COP	Coefficient of Performance
DAC	Direct Air Capture
DOE	Department of Energy
ERCOT	Electricity Reliability Council of Texas
GJ	Gigajoule
GW	Gigawatt
HPT	High Pressure Turbine
kW	Kilowatt
LPT	Low Pressure Turbine
Mt	Million tonne
MW	Megawatt
MWh	Megawatt Hour
PWR	Pressurized Water Reactor
SMR	Small Modular Reactor

In this study, we focus on the coupling of nuclear power plants with DAC. This is the subject of considerable industry interest. For example, the Department of Energy has sponsored several Front End Engineering Design projects to evaluate the potential coupling of DAC at nuclear power plants [4]. Steam generated at nuclear power plants is of sufficiently high temperature (e.g. > 100 °C) for use in lower temperature solid sorbent based DAC [5]. A co-located DAC plant could also provide an additional stream of revenue for nuclear generators, potentially improving their economic viability.

Our research questions are specifically:

- What is the optimal configuration for coupling DAC at a pressurized water reactor (PWR) based nuclear power plant?
- What are the power system-level emission impacts from coupling DAC on-site directly with steam from nuclear power plants compared to simply drawing grid based power and using a heat pump for heat?
- What additional value can coupling with DAC provide to both existing and new nuclear power plants and system-level decarbonization goals?

To answer these questions we first build alternative plant-level process simulations of coupled nuclear plants and DAC systems. Then, we represent these configurations in an electricity system capacity expansion model with high temporal resolution (8760 h) and detailed operating decisions and constraints, to assess the impact of these configurations on the electricity system. We compare coupling DAC directly with steam from nuclear power plants versus using grid based electricity and generating heat through a heat pump. For each configuration, we assess the net cost of removal for DAC after accounting for the change in power system emissions. We then estimate the value of coupling DAC with nuclear to the economics of nuclear power plants.

The rest of the paper is structured as follows. Section 2 provides a literature review. Section 3 outlines the methods adopted in this study. Section 4 describes our results and Section 5 concludes. Section 6 highlights opportunities for future work and notes the limitations with this study.

2. Literature review

Existing literature on DAC has focused mainly on plant-level cost analyses of different DAC designs [6–9]. Such studies have primarily considered two types of DAC approaches: (1) a liquid solvent approach that requires high temperature heat (~800 °C) for solvent regeneration and CO_2 release; (2) a solid sorbent approach that requires lower temperature heat (~100 °C) for sorbent regeneration and CO_2 release.

DAC's high energy consumption requirements mean that the cost and carbon intensity of energy is a critical consideration for DAC plants to minimize the net cost of CO_2 removal. The heat/power and temperature requirements of the DAC design influence the choice of energy supply. Higher temperature heat requirements for the solvent-based approach will need natural gas combustion [9,10] or alternatively, an electric calciner [10] or high-temperature electric resistance heating. A solid sorbent approach could use lower temperature heat available from geothermal or nuclear power plants. For example, Mcqueen et al. (2020) [5] studied the option of coupling DAC with nuclear or geothermal power plants. In the case of nuclear, they considered a 5% diversion of steam at 6.0 MPa and 275 °C before the high pressure turbine at a standard PWR configuration. This was estimated to penalize the electricity generation from the nuclear plant by roughly 1.5% although the authors do not build a detailed process model. They then estimate a $3.9/GJ opportunity cost of this steam for the reactor operator, based on average electricity prices and found that this level of steam diversion could support 6 million tonnes per year of DAC based CO_2 removals assuming 5% steam diversion from all existing nuclear plants in the United States. Mcqueen et al. (2020) [5] did not endogenously model optimal levels of steam diversion given electricity market operations, the impact of DAC revenue streams on the competitiveness of nuclear power plants, or indirect impacts on power system operations and resulting emissions.

Young et al. [6] also studied various DAC processes, including solid sorbent DAC, paired to differing sources of electricity. For the solid sorbent approach, they considered drawing heat from a heat pump running on nuclear electricity. Results from this study show that running DAC based on average grid power would lead to higher costs of DAC per net ton of CO_2 removed [6], due to emissions from fossil power generation. The study incorporated a fixed exogenous carbon intensity of electricity production, rather than studying the endogenous evolution of the power system with DAC demand. In the case of meeting DAC electricity demand from nuclear power, they also did not consider how this may impact the rest of the system. Diverting nuclear electricity for DAC may increase emissions in the power sector as it reduces clean electricity available for other demands. On the other hand, a revenue stream from DAC may boost the competitiveness of nuclear power plants.

Slesinski and Litzelman (2021) [11] studied the potential coupling of prospective small modular nuclear reactors (SMRs) with DAC. They did not build a detailed process simulation for heat flows, but instead assumed that for every MWh of electricity that the SMR produces, it also produces one MWh of steam at 100 °C for a low temperature based DAC plant. They used average U.S. electricity prices as an exogenous input and found that integration with DAC allows for the SMR's capital costs to be up to 35% higher than what would be required if only selling electricity, due to a revenue stream from DAC. This is despite a 21% penalty on the plant's electricity revenues, due to steam diversions for DAC. Slesinski and Litzelman (2021) [11] only considered prospective SMRs and not existing PWR or future PWRs in the United States.

Most recently, Bertoni et al. (2024) [12] undertake a process engineering and thermodynamic analysis to also analyze coupling solid sorbent DAC with a SMR. They consider two different configurations, one that minimizes the power output loss of the SMR and the second that minimizes integration work required. They find that coupling DAC with a SMR increases the use of thermal energy produced in the reactor from 32% without DAC to 76%–85% with DAC. A 50 MWe SMR module coupled with DAC can remove roughly 0.3MtCO2/year based on their analysis. They also compare the techno-economics of such a system compared to powering DAC with geothermal, or heat pumps, and find that SMR coupled systems can be very competitive. Bertoni et al. (2024) [12] do not consider an endogenous evolution of the power system with such a configuration of SMRs competing on the electricity grid, but they do model the impact of exogenous electricity prices and grid emission factors on net removal cost of DAC.

In terms of system-level analyses which incorporate endogenous evolution of the power sector, there are limited studies. A recent exception to this includes a paper by Prado et al. (2023) [13] on the impacts of large scale CDR on power system decarbonization in the United Kingdom. They modeled power sector impacts from deployment of a diverse suite of CDR technologies including low temperature (solid sorbent) and high temperature (liquid solvent) DAC. They found that high levels of DAC deployment lead to increased generation from wind and solar plants as well as facilitate the continued operation of combined cycle natural gas power plants with carbon capture and storage (CCS) (< 100% capture rate) in a net-zero power system [13]. Nuclear power was not explicitly paired with DAC in this study and DAC deployment was found to have limited impacts on overall nuclear generation [13]. Finally, Pham and Craig (2023) modeled the impact of grid electricity demand from a liquid solvent based DAC system in capacity planning decisions for the U.S. Eastern Interconnection [14]. They found that delayed planning for a power system that supports large scale (> 100Mt) deployment of DAC incurs significant costs.

From this literature review we identify the need for a detailed study on how nuclear power plant operations can be coupled with DAC process at the plant level, how such a generator will perform in an endogenous model of the power system, and the impacts of nuclear-DAC coupled systems on *net* CO_2 removals and resulting costs of net CDR.

3. Methods

In this paper we study two approaches for providing heat for solid sorbent DAC: direct coupling with a nuclear power plant versus using heat pumps operating on grid power. We first describe our process designs for extracting steam at a nuclear power plant. This is followed by a description of the heat pump case. Finally, we describe the electricity system capacity expansion model we use in this study.

3.1. Steam flows

Solid sorbent DAC requires heat at roughly 100 °C for regeneration of the sorbent and release of captured CO_2 for further compression and storage [6,8]. PWRs generate power through a combination of low and high pressure turbines. Steam exiting the reactor core is at a temperature of 275 °C. This expands through a high pressure turbine generating electricity. Following this, the steam at lower temperature (180 °C) and pressure [15] is passed through multiple low pressure turbines responsible for roughly two-thirds of the plant's power output.

Nuclear power plants thus generate steam at sufficiently high temperatures to potentially provide heat for a solid sorbent based DAC process. We consider steam diversion for DAC at three possible points during the steam cycle, marked in the simplified process diagram, Fig. 1. The first mode of extraction occurs right after the steam generator, before the start of the steam cycle. We refer to this as the pre-cycle diversion and it is marked as 1. The second mode is to extract steam prior to entering the high pressure turbine. We refer to this as the pre-high pressure turbine (pre-HPT) diversion and it is marked as 2. Finally, the third mode is to extract steam prior to the low pressure turbines which allows for more heat to be extracted from this steam, but requires larger heat exchangers. We refer to this as the pre-low pressure turbine (pre-LPT) diversion and it is marked as 3.

The major difference between the pre-steam cycle extraction (1) and the pre-HPT extraction (2) is whether the operation of the LPT is affected. In the pre-steam cycle extraction design, the extracted steam provides heat to the DAC and returns as a condensate stream with the same characteristics as feedwater. Hence, the output from both the HPT and the LPT is reduced. In the pre-HPT extraction design, the extracted steam provides heat to the DAC and returns at the same conditions (temperature, pressure, steam fraction) as the steam leaving the HPT. Therefore, the operation of the LPT is not affected, only the output of the HPT is reduced.

As a result of this steam diversion for DAC, two types of costs are incurred. The first is a capital investment for additional equipment such as heat exchangers and inter-coolers, depending on the mode of extraction. The second is a reduction in the power generation of the nuclear plant which results in lower revenue for the plant operator. This cost depends on the heat-power ratio of the extraction, i.e. how much power generation is sacrificed for every 1 GJ of steam diversion to DAC. To estimate these costs, we built a model of the PWR steam cycle process in Aspen®. We then modified this base model to represent the three possible designs of steam extraction. We then account for the capital costs of investments in plant retrofits (e.g. heat exchangers) as well as the penalty on power generation for the nuclear power plant, for each of the configurations. For full discussion of the process simulations and associated figures please see Supplementary Information (SI) Section 1.

Our motivations for choosing these three extraction points were minimal retrofit disruptions to plant operations and building on process designs in previous literature. We expand more on these points. First, in our considered designs, no additional extraction points are required on the turbine. This significantly minimizes retrofit work at the plant. Second, the chosen extraction points do not need to be operated at high volume flows, which again reduces the complexity of integration and keeps the DAC systems at modular scale for integration with existing facilities. This is in contrast to, for example, an extraction based on using some of the waste heat post power generation, i.e. at the outlet of the low pressure turbine. While potentially more efficient, this will require significant changes to plant infrastructure including the condenser system and is unlikely to be of interest to the plant owner. Third and finally, we build on existing literature and the steam extraction points previously considered in Mcqueen et al. (2020) [5].

We provide the estimated equipment costs and impacts on nuclear power plant generation from our detailed process model (SI Section 1) as inputs to our electricity system capacity expansion model, to estimate the system-level impacts of diverting steam for DAC for each of these designs. More details on our electricity system model are provided in Section 3.3.

3.2. Heat pump

An alternative approach for providing the heat for solid sorbent based DAC is to use a heat pump. Heat pumps are powered by electricity that drives a compressor to heat up a working fluid. Industrial heat pumps can generate heat up to or above 100 °C, making them a candidate for use in solid sorbent based DAC. For example, Young et al. (2023) [6] assume a heat pump powered solid sorbent DAC process based on a coefficient of performance (COP) of 2. This means that for every 1 MWh of electricity consumed, the heat pump generates 2 MWh thermal, equivalent to more than 7 GJ of heat. We adopt this approach for heat pumps, powered by grid electricity. Input parameters for the heat pump including capital costs and electricity consumption per tCO_2 along with associated references are discussed in SI Section 2.

3.3. Electricity system capacity expansion

To study the system-level implications of DAC deployment due to modifications to nuclear plants for supporting DAC or heat pump load added to the electricity grid, we use the GenX electricity system capacity expansion model. GenX is an open-source optimization model for the electricity sector that selects the least cost suite of resources required to meet demand in a future year, subject to a number of engineering, policy, and market constraints. GenX has been used in a number of studies to evaluate emerging low-carbon technologies, power system decarbonization strategies, and policy interventions (e.g. [16–19]).

We select the electricity market in Texas, or the Electric Reliability Council of Texas (ERCOT) as our domain of interest. We focus on ERCOT for three reasons:

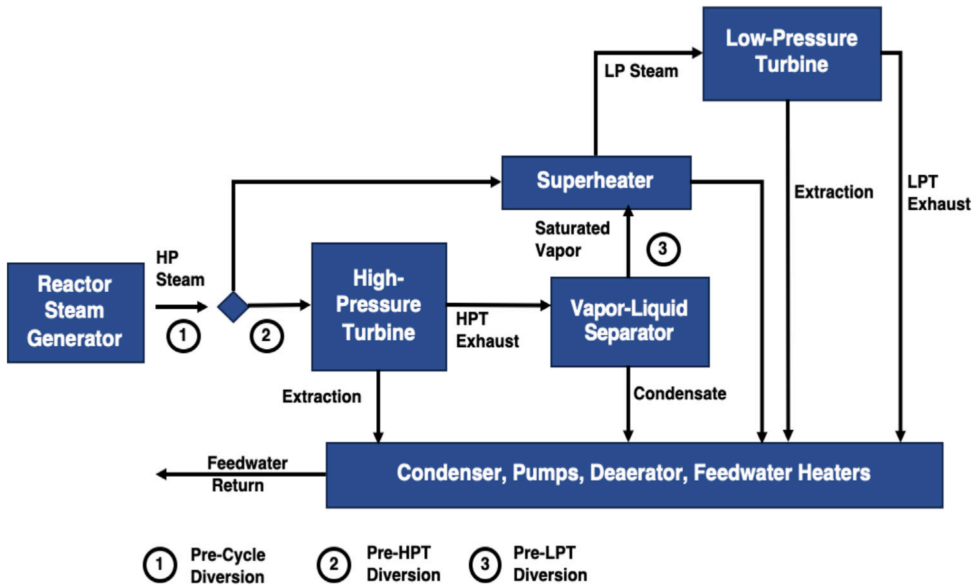

Fig. 1. Simplified process flow diagram of the steam cycle at a nuclear power plant and opportunities for steam diversion for DAC. For full Aspen® simulations and associated figures see SI Section 1.

- Texas has large potential for CO_2 sequestration and may see significant DAC deployment
- Texas has a wide variety of power generators including nuclear energy, natural gas, and abundant wind and solar energy potential, allowing us to model impacts on a diverse set of resources
- The ERCOT grid is essentially 'islanded' from the rest of the US power system allowing us to study the impacts of DAC deployment on the power grid in isolation.

We gather information on existing power plants, fuel costs, and renewable energy potential for Texas using PowerGenome [20], an open-source data compilation and scenario generation tool for electricity system planning models. We then include existing policies in electricity markets including tax credits from the Inflation Reduction Act for several clean power technologies including wind and solar power and new nuclear plants. Costs for generation technologies are based on the National Renewable Energy Laboratory Annual Technology Baseline 2022 Report [21]. A summary table on associated capital and operation and maintenance costs of key technologies and existing capacity in ERCOT, is provided in Table S4.

We approximate the Texas grid as a two-zone system, separating east and west Texas. The majority of the load is in the eastern region given the presence of major cities such as Houston, Dallas, and others. Major west–east transmission constraints from the wind- and solar-rich western portion of the state are approximated by this two-zone configuration. All DAC deployment is considered for east Texas given early announcements for DAC in the region [22], large potential for CO_2 sequestration, and the location of existing nuclear generators in this zone.

We then individually model each of the three nuclear-DAC coupling designs as well as a heat pump based approach drawing on grid power in GenX. This allows us to study the power system-level impacts of DAC deployment, i.e. how power sector operations and emissions will change due to deployment of DAC.

Input data include the operation and cost associated with DAC. The capital cost ($/t$CO_2$) of a DAC facility is highly uncertain and can vary significantly depending on the scale of the plant. We use a conservative estimate of the annualized capital cost at $800/t$CO_2$-capacity-year for a solid sorbent system [6]. In a sensitivity analysis case we halve this estimate to account for much lower cost DAC systems. Note that this estimate does not include the capital cost of the energy system required for DAC (e.g. heat pump, steam system, heat exchangers) as these are sized and costed separately in our model (see next subsection). The DAC costs therefore only represent data from Young et al. (2023) [6] on the capture costs including air contactors, blowers, condensers, valves, and vacuum pumps.

Table 1
Data assumptions for DAC coupled with a nuclear power plantb.

Parameter	Unit	Value
$C_{capex.DAC}$ (Annualized)	\$/tCO_2-capacity−year	800
$C_{opex.DAC}$	\$/tCO_2	40
E_{DAC}	GJ/tCO_2	9.8
$Power_{DAC}$	MWh/tCO_2	0.3
$Removals_{DAC}$	MtCO_2/year	1
α	–	0.4

The literature has noted that DAC plants will run as close to 24 × 7 as possible given the high capital costs [6,8,9]. The capacity factor for DAC is constrained to a maximum of 95%; we assume minimum 5% downtime would be necessary for plant maintenance. Any flexibility below that is an endogenous feature of the optimization model — for example there may be value in running DAC flexibly given high electricity prices during some periods of the year. We force a constant 1 million-ton CO_2/year of gross DAC removals designed to represent voluntary corporate or federal government procurement of DAC. This annual removals parameters is denoted by $Removals_{DAC}$. We assume 1 million-ton per year of DAC deployment as these are realistic targets for DAC in the near-medium term (2035) corresponding to DOE targets for each DAC hub [23]. This also allows us to have sufficient scale of DAC deployment to investigate system-level effects. We assume non-energy variable operation and maintenance costs of \$40/tCO_2 captured. E_{DAC} is the heat consumption from DAC per tCO_2 of 9.8 GJ/tCO_2, based on the estimates from Young et al. [6] and similarly $Power_{DAC}$ is the power consumption per tCO_2 which is primarily for the compressor and is assumed as 0.3 MWh/tCO_2 [5,6]. Finally, α is the maximum steam diversion allowed at the nuclear power plant. We cap this at a maximum 40% of diversion for DAC as grid-connected power resources are unlikely to risk turbine operation at low loads due to associated degradation in turbine performance. In practice these upper levels are not required to achieve 1MtCO_2 of removals, so this constraint is non-binding. All input assumptions are summarized in Table 1.

$$\underset{v_{CAP.DAC}, v_{DAC.CO2}, v_{Heat.DAC}, v_{HX.DAC}}{\text{minimize}} \quad C_{\text{system}} \tag{1a}$$

$$\text{subject to} \quad v_{DAC.CO2}(z,t) * E_{DAC} = v_{Heat.DAC}(z,t) \tag{1b}$$

$$v_{Heat.DAC}(z,t) \leq \sum_{y=1}^{Y} v_{HX.DAC}(y,z) \tag{1c}$$

$$\sum_{y=1}^{Y} v_{HX.DAC}(y,z) \leq E_{nuc}(z) * \alpha * \gamma \tag{1d}$$

$$Removals_{DAC} = \sum_{t=1}^{T}\sum_{z=1}^{Z} v_{DAC.CO2}(z,t) \tag{1e}$$

$$Removals_{DAC} = \sum_{y=1}^{Y}\sum_{z=1}^{Z} v_{CAP.DAC}(y,z) * CF \tag{1f}$$

$$P_{nuc}(z,t) + v_{Heat.DAC}(z,t) * \beta \leq E_{nuc}(z) \tag{1g}$$

Box I.

3.3.1. Direct air capture module

For this paper, we implement a novel module in GenX incorporating a series of equations specific to DAC into the electricity system optimization. The remainder of the existing GenX model formulation is available at https://genxproject.github.io/GenX/ and the code used in this paper is archived at Zenodo (https://doi.org/10.5281/zenodo.10120474).

Let P_{Nuc}(z, t) be the power output (MW) from nuclear plants in zone z and at time (hour) t and E_{Nuc}(z) the total electricity capacity (MW) of nuclear in zone z. Let $v_{CAP.DAC}$(y, z) be the installed DAC capacity for unit y in zone z with units (tCO_2/year). Let $v_{DAC.CO2}$(z, t) be the DAC removals of CO_2 in zone z and at time t with units tCO_2. Let the total thermal heat diverted at nuclear plants for DAC be $v_{Heat.DAC}$(z, t) in zone z at time t with units GJ. Finally, let $v_{HX.DAC}$(y, z) be the heat exchanger capacity available for DAC unit y in zone z. All of these are decision variables with P_{Nuc}(z, t) and E_{Nuc}(z) already present in the base GenX formulation.

γ is the heat available for DAC per percent steam diversion per MW nuclear capacity (GJ/MW-electric) and β is power to heat ratio (MW-electric/GJ). Both parameters are obtained from the process simulations for the nuclear-DAC coupling process described in SI Section 1.

The GenX optimization minimizes the overall power system cost C_{system} subject to engineering, market, and policy constraints. To those, we add the following DAC-specific constraints shown below in order to model a DAC system coupled to nuclear power plants: (see equation in Box I)

Eq. (1b) constrains the total energy consumption from DAC to be equal to the total thermal heat diverted for DAC. In turn, (1c) constrains the maximum heat diverted for DAC to be less than or equal to the heat exchanger capacity built. Further, (1d) caps the size of the heat exchanger by the maximum steam diversion allowed at a nuclear power-plant and the heat extraction per % of diversion. $v_{HX.DAC}$ is therefore a slack variable and is equivalent to max($v_{Heat.DAC}$). Eq. (1e) is the removal constraint, i.e. it fixes the minimum level of gross DAC removals to the annual removal parameter; this is necessary because absent this constraint no DAC is deployed given that we model ERCOT without any constraints on CO_2 emissions (as per current policy). This DAC removal constraint can be thought of as representing corporate voluntary procurement in the absence of system-wide policy constraints on emissions. Eq. (1f) is the capacity constraint that fixes the capacity required for input parameters of annual removals and operational capacity factor. Finally, Eq. (1f) reflects that the total power output from nuclear plants is a function of the total steam heat available, i.e. the steam used for power generation and the power lost from steam used for DAC, and that the sum of these is less than or equal to nuclear capacity. This is the constraint that reflects the opportunity cost in terms of power generation from nuclear power plants due to steam diversion for DAC.

Note that for the case of a grid powered heat pump, there is only power consumption and no direct heat consumption. Therefore, only Eqs. (1e) and (1f) apply. Power demands for both cases for the CO_2 compression are simply added to load in the power balance equation already present in GenX.

We also gather the capital and operating costs associated with the DAC system:

$$C_{total.DAC} = C_{capex.DAC} * \sum_{y=1}^{Y}\sum_{z=1}^{Z} * v_{CAP.DAC}(y,z) + C_{opex.DAC} * \sum_{t=1}^{T}\sum_{z=1}^{Z} v_{DAC.CO2}(z,t) + C_{energy.capex.DAC} \tag{2}$$

where $C_{energy.capex.DAC}$ is the energy related capital investments required to integrate DAC with a nuclear facility, i.e. the capital costs for heat exchangers and other equipment required for retrofitting a nuclear power plant (see SI Section 1) or the cost of the industrial heat pumps (see SI Section 2). We note for context that annualized costs for DAC (at 1 $MtCO_2$/year scale considered in this study) are small compared to the total annualized cost of the power system, which is roughly in the order of \$10–15 billion.

The energy related capital investment for DAC is calculated as:

$$C_{energy.capex.DAC} = \sum_{y=1}^{Y}\sum_{z=1}^{Z} H_1 * v_{HX.DAC}(y,z) + H_2 \tag{3}$$

where H1, H2 are constants in the linear cost formulation for heat exchangers derived from the Aspen® process simulations (see SI Section 1).

DAC costs are finally added to the total system cost that is minimized in GenX:

$$C_{system} = C_{power.system} + C_{total.DAC} \tag{4}$$

3.4. Estimating the cost of net carbon removal

To estimate the costs of *net* carbon removal, including the indirect emissions associated with changes in power system operation resulting from DAC energy demands, we adopt the following approach.

Let the facility-level levelized cost of *gross* carbon removal for case i be $C_{gross,i}$ and is equal to the sum of *annualized* costs for DAC at the facility level including capital costs for DAC, energy related capital investment (e.g. retrofits at a nuclear plant or installation of an industrial-scale heat pump), variable operating costs, and energy input costs (e.g. cost of electricity) divided by the total removals in a given year, denoted $Removal_{DAC,i}$.

To consider system-level impacts which we estimate through our capacity expansion model, let annual *power system* emissions be denoted by $E_{P,i}$ corresponding to DAC case i and $E_{P,noDAC}$ for the baseline case without DAC presented in Fig. 2. Then, the system-level levelized cost of *net* carbon removal, C_{net}, for case i is denoted by:

$$C_{net,i} = \frac{C_{gross,i} * Removal_{DAC,i}}{Removal_{DAC,i} - (E_{P,i} - E_{P,noDAC})} \tag{5}$$

i.e. we scale the gross removal costs to account for net changes in emissions after accounting for impacts on power system capacity and operational decisions.

Then, the system penalty is simply defined as the difference between net and gross removal costs:

$$SystemPenalty_i = C_{net,i} - C_{gross,i} \tag{6}$$

Note that in a case with off-grid energy resources for DAC, i.e. where power sector emissions do not change, the difference between the system-level net cost of removal and the facility-level gross cost of removal is zero and $C_{net,i} = C_{gross,i}$.

Finally, let the changes in power sector emissions as a percentage of removals be termed the leakage rate, defined as:

$$LeakageRate_i = \frac{E_{P,i} - E_{P,noDAC}}{Removal_{DAC,i}} \tag{7}$$

We present these leakage rates in our results for all three configurations at the nuclear power plant as well as with use of a grid-powered industrial heat pump.

4. Results

We begin a discussion of our results by comparing the capital costs and opportunity cost of power generation for different configurations of coupling DAC on-site with a nuclear power plant from our process model. We then discuss results from our electricity capacity expansion model without DAC to establish the baseline power system. We further show the net removal costs for DAC, including power system impacts, across different configurations supplemented with a brief sensitivity analysis of our key input assumptions. We end with results describing the economic incentives DAC would have to provide nuclear power plants in order for nuclear energy to be competitive in least-cost electricity markets without carbon constraints or subsidies for nuclear power generation.

4.1. Costs of steam extraction

Table 2 shows the results of steam extraction of 1% across the different configurations as well as the required capital investments in each case. It should be noted that both the power generation penalty and capital investments are a linear function of the level of steam extraction (the equations and graphs for both are described in SI Section 1).

The opportunity cost of power not sold to the grid per GJ of steam diversion is simply obtained by multiplying the lost power to heat ratio in Table 2 by the average wholesale electricity price in our simulation ($26/MWh). We also calculate the equivalent opportunity cost per tCO_2 based on the heat input assumption for DAC described in Table 1 of 9.8 GJ/tCO_2. We find that the lowest opportunity cost, i.e. the lowest penalty on power generation from steam diversion for DAC, is obtained through extraction prior to the low pressure turbine. Extraction prior to the steam cycle provides the most heat but incurs a higher opportunity cost than extraction pre-LPT. The highest opportunity cost is obtained with extraction pre-HPT. However, this also requires the lowest capital investment. The capital investments vary across the different extraction modes based on the required investments in additional equipment such as heat exchangers and inter-coolers, depending on the mode of extraction. SI Section 1 shows these calculations in detail. To summarize briefly here, the size of the heat exchangers for pre-LPT and pre-steam cycle heat extraction are significantly larger and therefore more expensive than the pre-HPT case, due to higher heat extraction. Finally, the capital investment for the pre-cycle case is lower than pre-LPT despite the higher heat availability, because the temperature difference between the hot fluid and the cold fluid is higher, which leads to reduced heat exchanger area required and lower capital cost.

Is a lower opportunity cost worth it despite the higher capital investment? Or is a higher heat availability worth it despite the higher opportunity cost as is the case with extraction prior to the steam cycle? We explore these trade-offs with our system-level optimization model and the results are discussed in the following sections.

It should be noted that our detailed process simulation identifies a higher cost of extraction compared to prior results in the literature. For example, Mcqueen et al. (2020) [5] estimated an opportunity cost of $3.9/GJ for steam extraction prior to the high pressure turbine. As Table 2 above demonstrates, the detailed process simulation performed for this work concludes the opportunity cost for extraction prior to the high pressure turbine incurs almost twice the cost, as the heat to power loss ratio for pre-HPT extraction is found to be higher than assumed in Mcqueen et al. (2020) [5]. This prior work also does not consider the other two opportunities for steam extraction simulated herein.

Finally, we note here the impact on net efficiency at the plant. For electricity efficiency, all extraction options for steam lead to reduced electricity efficiency compared to the base configuration without DAC, given the lowered net power production at the plant (at the same DAC capacity/same DAC heat requirement). The order from highest to least efficiency is as follows: base plant > pre-LPT > pre-Cycle > pre-HPT. For combined heat and power efficiency, all extraction options lead to higher efficiency as some of the thermal energy is used directly (for DAC) instead of conversion to electric power. The order from highest to least efficiency is as follows: pre-LPT > pre-Cycle > pre-HPT > base plant.

4.2. Capacity expansion without direct air capture

To estimate a baseline case without DAC deployment, we first model a single stage expansion of the ERCOT grid from 2022 to 2035. As discussed previously, this expansion includes the amortized value of federal clean electricity and CCS tax credits established by the Inflation Reduction Act. These credits are currently scheduled to begin phasing out for projects that commence construction after the end of 2032 for CCS and after either 2033 or the year after U.S. power-sector CO_2 emissions reach 25% of 2022 levels for carbon-free electricity projects, and thus are assumed to be available for all projects online by 2035 [24]. We consider the full suite of generation technologies shown in Table S4. The capacity mix today and in 2035 is shown below. It is important to note Texas has no additional state-level support for clean energy technologies and there is no state or federal policy mandating power sector decarbonization. However, the share of wind and solar power in Texas has grown rapidly from 10% of total generation in 2013 to roughly 30% in 2023 [25]. Texas is the leading state nationally for wind power generation and recently surpassed California to become the national leader in total installed solar capacity [26].

We find that federal subsidies for clean energy result in almost a 55% reduction in ERCOT CO_2 emissions to roughly 86 $MtCO_2$ in 2035, compared to nearly 200 $MtCO_2$ in 2022. This is facilitated by retirement of more than 6 GW of coal, 8 GW of natural gas capacity, and net increase in wind capacity by 31 GW and solar by 26 GW. Wind and

Table 2
Opportunity cost and capital investments of steam extraction for DAC at a 1000 MW PWR. All cases correspond to 1% steam extraction and an average electricity price of $26/MWh.

Extraction mode	Heat available (GJ)	Lost power to heat ratio (MW-electric/GJ)	Average opportunity cost ($/GJ)	Average opportunity cost ($/t$CO_2$)	Capital investment ($M)
Pre-Cycle	123.2	0.10	2.6	25.5	0.47
Pre-HPT	15.5	0.28	7.3	71.3	0.16
Pre-LPT	99.4	0.08	2.1	20.4	0.68

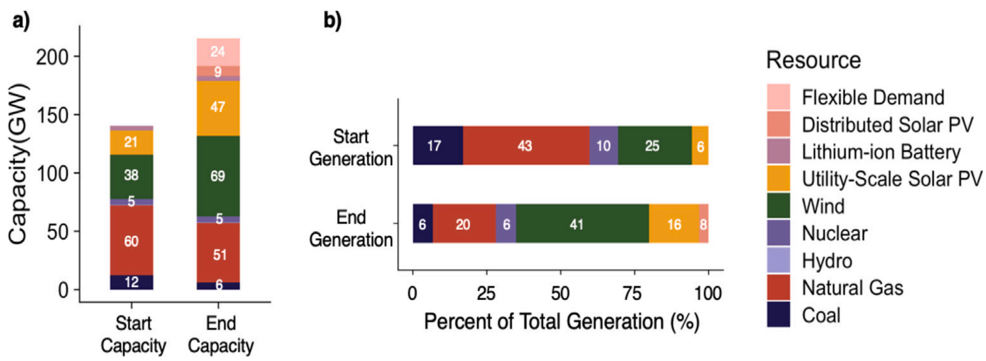

Fig. 2. Resource mix of ERCOT in 2022 and 2035. **(a)** Capacity mix. Resources below 100 MW of capacity are excluded. Text markings are only provided for resources with capacities above 5 GW. Note that 'Flexible Demand' resources in 2035 are an exogenous input and represent electric vehicle charging (54%), commercial space heating (15%), residential space heating (27%) and remainder from water heating. These are considered notionally as capacity resources as they can shift their demand. **(b)** Generation mix. Generators below 1% are excluded and numbers are rounded up so shares may not exactly sum to 100. Text markings are only provided for generation above 5% of total power generation.

Table 3
Increases in power sector emissions as a percentage of Annual DAC removal. Bracketed range shows results from modeled outcomes that fall within +/−0.01% of the cost of the optimal solution.

Energy source	Leakage rate (CO_2 %)
Heat pump	10% [7%–15%]
Pre-Cycle	19% [10%–21%]
Pre-HPT	46% [35%–46%]
Pre-LPT	15% [7%–18%]

solar together account for 57% of generation in 2035, compared to 31% in 2022. Fossil fuel based generation drops to 26% in 2035 compared to roughly 50% in 2022. Our results of changes in power sector emissions are consistent with other recent literature modeling the impact of Inflation Reduction Act incentives on power sector emissions [27].

4.3. Comparing different configurations of energy supply for direct air capture

Table 3 below shows this leakage rate, i.e. the increases in power sector emissions as a percentage of gross DAC removals across the different cases.

Note that instead of only showing point values in Table 3 corresponding to a single run of our capacity expansion model, we also show a range in square brackets that denotes variation in modeled outcomes for alternative cases that fall within +/−0.01% of the cost of the optimal solution. The result is then compared to equivalent (low and high) 0.01% perturbations in the base case capacity expansion without DAC to estimate the leakage rate. We do this to avoid a false precision with our estimates – a leakage rate of 10% for 1 Mt/year of gross removals corresponds to 100,000 tonnes of CO_2, which is small compared to the baseline ERCOT grid emissions of 86 million tonnes of CO_2 in 2035 – and to reflect the structural model uncertainty associated with small changes in outcomes of interest in a large system. For example, given this uncertainty range, we counsel the reader to view the leakage rate for heat pump and pre-LPT cases to be functionally equivalent, given the substantively overlapping uncertainty range.

Given the roughly 5 GW of existing nuclear capacity available, the maximum hourly steam diversion found necessary for achieving 1 Mt CO_2 removals per year across the fleet corresponds to diversion of 16% of available steam across the existing nuclear fleet in the case of pre-HPT extraction, 2.5% for pre-LPT extraction, and 2% for extraction prior to the steam cycle.

Fig. 3 shows the facility and system-level costs of carbon removal with DAC across the different configurations including nuclear-DAC coupling as well as a case using a heat pump powered by grid electricity. Note that all nuclear based DAC systems are retrofitted to *existing* nuclear capacity in ERCOT, as no new nuclear is built in a system without carbon constraints.

The left bars in Fig. 3 for each case correspond to the private costs, i.e. the capital costs of the DAC facility, capital investments in plant retrofits/heat pumps, energy procurement cost for DAC which is the electricity price for that hour and the equivalent opportunity cost for nuclear coupled DAC and the direct energy input cost for heat pumps, and operations and maintenance costs for DAC incurred by the DAC developer. The bars on the right then add to this the change in net carbon removal cost associated with the system-level emissions penalty, i.e. the change in power sector emissions relative to a case without DAC, explained previously in Eq. (6). As system level emissions impacts reduce net removals, this system penalty reflects the increase in DAC costs if these emissions are properly accounted for. The error bars on the system penalty reflect the bracketed uncertainty range in Table 3, i.e. outcomes within 0.01% tolerance of the optimal solution and compared to equivalent (low and high) 0.01% perturbations in the base case capacity expansion without DAC.

The system-level penalty shown here therefore identifies the impact on the power system from deployment of DAC, and reveals the *net* cost of carbon removal per tonne. We argue that given DAC deployment is currently supported by government subsidies and corporate voluntary procurement with an explicit goal of carbon removal, these costs are of importance as they capture the true or 'consequential' CO_2 impacts from such deployment. We find that inefficient configurations of DAC at a nuclear power plant (steam extraction pre-HPT) can lead to increases in power sector emissions relative to a case without DAC, at a scale that

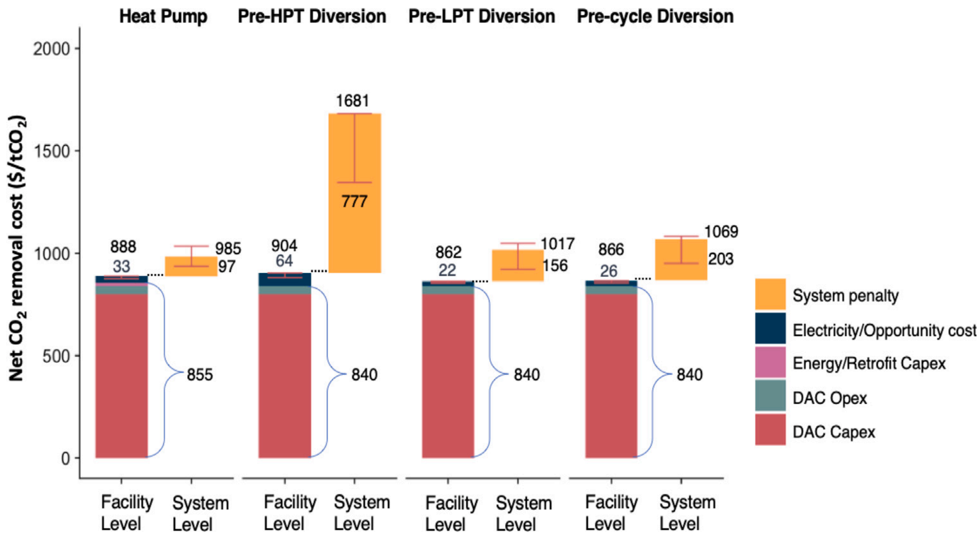

Fig. 3. Facility and system-level costs of DAC based carbon dioxide removal. The red error bars apply to results obtained from the electricity system optimization (the electricity/opportunity cost per ton and the system penalty) and correspond to results within 0.01% of the single optimal solution. For the system penalty, the error bar is estimated by comparing power sector emissions with the equivalent low and high 0.01% perturbation of the capacity expansion without DAC presented in Section 4.2.

would cancel out almost 50% of the carbon removal from DAC. Net removal costs for the most efficient configurations (pre-LPT) increase by roughly 18% once indirect power system-level impacts are considered, though this is comparable to the indirect systems-level emissions from operating heat pumps based on grid power for sorbent regeneration.

Our analysis extends previous literature which has not considered these costs and has only focused on the left bars, i.e. the cost to a DAC operator. For example, Young et al. (2023 [6] pair the electricity requirement of a heat pump with a nuclear power plant, but there is no system-level analysis of how using nuclear electricity for DAC will affect power system emissions due to diversion of this clean power from the grid. Similarly, Mcqueen et al. [5,10] pair different energy sources with DAC but do not undertake a systems-level analysis of how pairing with nuclear electricity will affect the electricity system and associated emissions.

In our results, we also find that DAC does not operate flexibly, i.e. the optimal solution chooses maximum operation of the DAC facility (95% capacity factor based on upper bound constraint as discussed in Section 3.3). Why is flexibility not valuable? This is clearly explained from the relative share of costs in Fig. 3. Given the lower share of energy-related costs for DAC compared to the capital cost invested in the DAC facility itself (contactors, valves, vacuum pumps, compressor), lowering energy related costs through more flexible operation is not found to be sufficiently valuable.

4.4. Sensitivity analysis

In the SI Section 4, we undertake a sensitivity analysis for a 50% lower capital cost of solid sorbent DAC of $400/t$CO_2$ as well as a 50% lower heat consumption per tCO_2. Results for both cases are shown in SI Figures S9 and S10.

We find that in both cases, the ordinal rankings of the different configurations does not change, and our qualitative conclusions remain the same. However, the results demonstrate some interesting features. For instance, in the case where heat required is halved (Fig. S9), we find that the emissions leakage rates drop to a range of 4%–28%, as opposed to 10%–46% shown in Table 3. This is a direct consequence of lower load on the system, both in terms of grid power and lost generation at the nuclear power plant, which results in lower emission leakages. Lower energy consumption also lowers electricity prices in the system and therefore the energy cost per ton. As such, reductions in the energy inputs required for DAC operation and sorbent regeneration can reduce (though not eliminate) the magnitude and salience of indirect system-level emissions impacts.

For the case of a lower capital cost (Fig. S10), we first explored whether a 50% lower capital cost would incentivize DAC to run flexibly, compared to the base case where we found no value in flexibility as discussed above. Once again, there was no value found in flexible operations and the optimal DAC system ran at maximum allowed capacity factor (95% assuming 5% minimum downtime would be necessary for plant maintenance). As a result of this, i.e. there were no changes in operational nature of DAC at a 50% lower annualized capital cost of $400/t$CO_2$, and therefore there were no changes found in the operational results from our electricity system optimization, namely the leakage rates and electricity/opportunity cost for this case are estimated to be exactly the same as the results presented in Table 3 and Fig. 3. To explain this further, theoretically, given variations in electricity prices over the year, the cost-optimal strategy to meet a specified gross CO_2 removal requirement could involve increasing installed DAC capacity and operating said capacity more flexibly to consume power (or incur opportunity costs from consuming nuclear plant steam) only during lower electricity price periods. However, this strategy only makes sense if savings in electricity costs justify the additional capital expenditure and lower utilization rates. Intuitively, one can see that strategy to make economic sense, capital costs must be at least the same rough magnitude as energy cost, which is not the case at $400/t$CO_2$ annualized CapEx or the base case of $800/t$CO_2$. Indeed, we find that DAC capital costs must fall below $100/t$CO_2$ to make a more flexible operating strategy with lower utilization rates and higher installed capacity per ton of annual removals financially justified. Recent literature finds no evidence to suggest this cost target can be achieved [6,28], particularly for solid sorbent approaches considered in this paper. At a capital cost higher than $100/t$CO_2$, DAC will continue to be built in the smallest capacity operated at the maximum feasible annual capacity factor.

Therefore, we note that while we treat the cost of the DAC system as simply an exogenous input parameter with no further investigation in this paper, our sensitivity analysis shows that our cost assumptions for DAC, within the range considered, do not impact the qualitative findings of our study. Finally, on a related note, results in Fig. 3 and Figures S9–10 do not show Inflation Reduction Act 45Q credits for DAC ($180 per ton CO_2 sequestered). Applying this credit would simply shift the bars downwards and again has no effect on our qualitative insights.

4.5. Value of direct air capture for economics of nuclear power plants

Nuclear power plants face a number of economic challenges in electricity markets. For existing reactors, cheap natural gas has led to recent closures of nuclear plants across the United States [29,30]. In response, state and federal policies have been implemented to help prevent retirement of nuclear units due to market forces. In the previous section, we incorporated such policies and prevented retirement of existing nuclear generation in ERCOT in our capacity expansion to 2035.[1] In the case of new nuclear plants, high capital costs (well above $5000/kW for recent projects in the U.S. and Europe) have meant that new nuclear capacity is economically unattractive. Indeed, when assuming a capital costs for new reactors of roughly $5000/kW (from [21]), our capacity expansion results in no new nuclear plants built in this case study (which lacks any binding carbon constraints; see Fig. 2).

Given that DAC deployment is being supported through voluntary procurement and government subsidies, it is possible that DAC coupled with nuclear power plants could act as a demand *pull* for nuclear generation, as DAC needs low carbon heat and power and must operate at very high utilization rates. Accordingly, here, we model how revenues from supplying heat for DAC might enable nuclear plant operators to improve their economics, and as a result, potentially get selected as part of a least cost electricity portfolio. Specifically, we model how 1 GW of nuclear capacity in ERCOT (current capacity is roughly 5 GW as shown in Fig. 2) can either be prevented from retiring due to DAC coupled energy demand in a least-cost capacity expansion of the electricity system without any system-wide carbon constraints, *or* how DAC deployment could induce 1 GW of new nuclear capacity.

To study this using GenX, we retain federal subsidies for wind and solar power but remove any supporting policies for existing nuclear plants as our goal is to see how revenues from DAC could replace that support. We model only the pre-LPT case of steam extraction, given that our results in Table 2 and Fig. 3 show this to be the superior configuration for coupling nuclear with DAC. We strip out the DAC related costs from the system and model different levels of steam diversion and associated deployment of DAC coupled with existing nuclear, and estimate the payment as the difference in power sector costs with such deployment (coupled to 1 GW of nuclear capacity) and without DAC (where all existing nuclear plants are retired). Simply put, the payment is the amount at which the power system planner is indifferent between no DAC deployment and having DAC deployment. We then repeat this process for DAC coupled with new nuclear capacity of 1 GW and compare to a no DAC capacity expansion where no new nuclear is deployed but existing nuclear capacity is retained due to policy support from the Inflation Reduction Act (this is the base case shown in Fig. 2).

Fig. 4 shows the revenues required in both $/t$CO_2$ and in equivalent $/MWh foregone electricity production as a result of steam diversion to DAC. The gross removal cost is the private-level cost that a DAC operator would have to pay the nuclear plant operator for heat, the net removal cost is the effective cost per ton CO_2 at a *system-level*, once the additional emission reductions in the power system from the nuclear plant's electricity output to the grid are taken into account and compared to a case where such nuclear capacity did not exist on the grid. This is the same concept as the results presented previously in Fig. 3, except here there is a system *benefit* and not a system *penalty*.

As the share of steam diverted for DAC increases, this allows for more CO_2 removal, and therefore the revenue required per unit decreases. Fig. 4(a) shows the revenue required for existing nuclear power plants while Fig. 4(b) shows the same for new nuclear power plants.

[1] Existing nuclear plants are subsidized through 2032 with the Inflation Reduction Act and we assume further policy support would extend this through to 2035. Minus any policy support for existing nuclear, we find that nuclear plants in ERCOT will retire in a least cost capacity expansion.

The difference between the gross and net removal reflects the fact that preventing 1 GW of nuclear retirement or inducing 1 GW of additional nuclear capacity deployment results in considerable indirect power system emission reductions, compared to the case where that capacity was not available on the grid. This is because only a portion of the nuclear plant's thermal output goes to supply DAC operations, while the majority is used to generate carbon-free electricity for grid supply. While deploying DAC at an existing nuclear plant that would *operate anyway* reduces carbon-free generation available to the grid and thus involves a system-level emissions *penalty*, deploying DAC in a manner that prevents economic retirement of a reactor or induces deployment of new reactor capacity has the opposite impact, adding carbon-free generation to the grid compared to the counterfactual and therefore *reducing* emissions at the system level. We find that this difference between the gross and net removal attenuates as steam diversion for DAC operations increases because we keep the amount of nuclear capacity fixed (1 GW), while diverting increasing levels of steam for DAC. This consumes more and more nuclear generation, leading to smaller reductions in broader power sector emissions. The effects of this attenuation are stronger for new nuclear capacity (Fig. 4(a)), because in that case we add 1 GW of new nuclear capacity to a baseline system with 5 GW of existing nuclear energy capacity. Therefore, the marginal value of zero carbon firm generation for emission reductions is less; new nuclear capacity ends up displacing some wind and natural gas generation. However, when 1 GW of existing nuclear capacity is prevented from retirement and compared to a system where all nuclear is retired (Fig. 4(a)), the difference between gross and net removal costs are stark, as remaining nuclear reduces coal generation by roughly 10% with wind/solar and natural gas generation unaffected.

Fig. 4 shows that a steam extraction rate of roughly 10% at a 1 GW nuclear plant supports gross removals of nearly 1 Mt of CO_2 per year through DAC. Assuming no credits for the power system CO_2 reductions caused by this DAC deployment due to additional nuclear capacity compared to the counterfactual, this would require nuclear plant operators to be paid roughly $60/t$CO_2$ for existing nuclear or $270/t$CO_2$ for new nuclear plants (when the opportunity cost of steam is roughly $20/t$C0_2$), equivalent to $78/MWh or $340/MWh for each MWh of nuclear electricity generation lost due to steam diversion. When emission reductions in the power sector *are* taken into account, the revenue stream required is $8/t$CO_2$ for existing nuclear and $120/t$CO_2$ for new nuclear, equivalent to roughly $10/MWh or $150/MWh for each MWh of nuclear electricity generation lost due to steam diversion. For context, the federal production tax credit for existing nuclear plants in the United States to help prevent their retirement is worth up to $15/MWh [31] and new nuclear reactors are eligible to receive a production tax credit of $27.5/MWh (in 2022 dollars) [24]. Therefore, while such a revenue stream from DAC may be a feasible strategy to keep existing nuclear plants open, in the case of inducing new nuclear capacity, this would require the DAC operator to be willing to pay a premium for energy that is >10% of the estimated levelized cost of DAC.

Finally, as previously noted in the text, existing grid-connected nuclear plants with turbines sized for maximum interconnection capacity are unlikely to operate their turbines at low loads due to reduced efficiency in turbine performance. 40% is therefore a hypothetical upper limit that is unlikely to be reached for existing plants. For new plants, reflected in Fig. 4(b), higher rates of steam extraction may be possible if the steam turbine is optimally sized. In this case, given the greenfield development, this can lead to cost savings instead of cost increases.

5. Discussion

While previous literature has focused on the plant-level costs and operations of DAC facilities, here we studied the broader impacts of DAC with a focus on the power system. Our case study of coupling

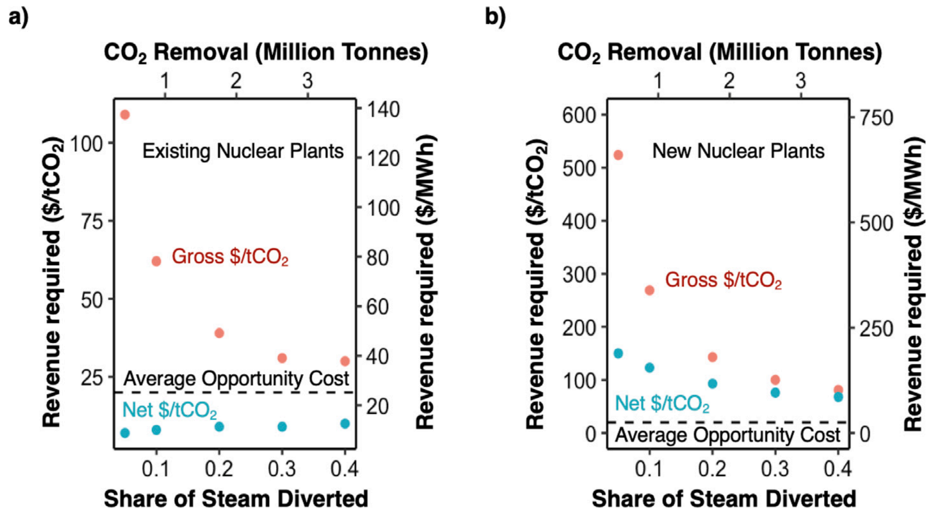

Fig. 4. Revenue required to incentivize 1 GW of nuclear generation for **(a)** existing nuclear plants and **(b)** new nuclear power plants. The red dots show the revenue required in $/t$CO_2$ when considering gross removal, i.e. removals from the DAC system alone. The turquoise dots shows the cost when also including the reduction in power system emissions (i.e. net removals). The dashed black line corresponds to $20/tCO2 and is the average opportunity cost of that steam for the power plant operator estimated previously in Table 2. The Y axis on the right shows the equivalent cost in $/MWh, i.e. the revenue required for the electricity production foregone by the nuclear plant operator due to steam diversion for DAC.

nuclear power with DAC shows that there is no free lunch — diverting steam at an existing zero carbon firm generator to supply DAC will reduce available carbon-free generation for grid supply and inevitably increase emissions in the power system (as long as there is still substantial fossil fuel based generation in the system), reducing the net removal of CO_2. Our process engineering model combined with energy system optimization reveals that the lowest cost configuration for coupling DAC with nuclear is obtained by extracting steam prior to the low pressure turbine. This involves the highest capital cost upfront for plant retrofits compared to other options considered, but its high heat availability and lower power generation penalty make up for the higher capital investment, while also reducing system-level emissions impacts.

We find that coupling DAC with nuclear can lead to increases in electricity sector emissions of 15%–46% of gross removals, with the pre-LPT configuration resulting in roughly equivalent emissions impacts as a DAC system supplied by grid-powered heat pumps. These results highlight the importance of considering system-level impacts from different DAC system configurations and operating contexts, as these indirect emissions have a significant effect on the quantity and cost of net carbon removal.

As DAC deployment begins to scale, energy procurement rules for DAC will come under increasing scrutiny. Public and private off-takers should insist on full life cycle analyses for DAC facilities including the carbon intensity of energy inputs, in order to obtain maximum *net* carbon removal through their voluntary procurement of DAC. Our results emphasize the need for such rules to go beyond the emissions from plant-level (scope 1) energy consumption and also consider broader system impacts (scope 2) as these can add materially to removal costs per net ton of CO_2.

The linkages between DAC and grid decarbonization are further explored by analyzing how DAC can act as a pull for nuclear generation that may otherwise lack competitiveness in least cost electricity markets. While consuming steam for DAC at an established nuclear plant that would be profitable to operate *without* DAC deployment results in a reduction in available carbon-free electricity for the grid, relative to the counterfactual, it is possible that revenues from DAC heat consumption could prevent retirement of an existing reactor struggling to remain profitable or prove decisive to induce investment in new nuclear capacity. In either case, since DAC consumes only a portion of the available steam generated by a reactor, this would *increase carbon-free generation on net*, beneficially reducing power system emissions. If such emission reductions can be claimed by the DAC operator, it would reduce the revenue stream required to support nuclear power plants on a per ton CO_2 basis. Therefore our findings raise an open question on who gets to claim reductions in power system CO_2 emissions due to additional nuclear capacity/generation that was specifically induced by DAC deployment.

How much DAC can nuclear energy support? With extraction prior to the low pressure turbine, roughly 10% of steam diversion is enough to support 1 million tonnes of CO_2 removal per year at a 1 GW nuclear power plant, given our input assumptions on heat requirements. The total installed capacity of PWRs in the United States is roughly 60 GW [32], meaning that absent other barriers, a 10% steam diversion at nuclear power plants in the United States could supply 60 million tonnes of DAC based removals per year, while consuming about 5 GW worth of carbon-free nuclear power generation capacity. Achieving such levels of annual CO_2 removals would need to overcome other barriers such as the high cost of DAC, availability of sequestration sites, CO_2 transport infrastructure, and more.

6. Limitations and future work

In future work we plan to extend this research to consider DAC's coupling with enhanced geothermal systems and model explicit energy procurement rules for DAC that can minimize indirect increases in power system CO_2 emissions.

We do not conduct a detailed exergy analysis in this work because it is less relevant to the input data required by the *system-level* analysis of nuclear plants coupled with DAC. Future work that analyzes this in greater detail can further inform process design.

We note that the GenX capacity expansion model we use in our analysis assumes rational decision making and perfect foresight, along with overnight build of new assets. We assume no constraints on the rate of building transmission or interconnecting new generators to the electricity grid in our runs, in reality, these may present barriers to deployment of renewable energy resources meaning that new wind and solar deployment may be more constrained than our results indicate.

Finally, although our capacity expansion model does incorporate weather variability related to generation from wind and solar power, we do not consider the impact of weather on the energy consumption from DAC units.

Code availability

GenX is an open-source optimization model and is available publicly at https://github.com/GenXProject/GenX. Code for GenX that incorporates the specific DAC module described here is also available on Zenodo (https://doi.org/10.5281/zenodo.10120474).

CRediT authorship contribution statement

Aniruddh Mohan: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Data curation, Conceptualization. **Fangwei Cheng:** Writing – review & editing, Software, Methodology, Formal analysis, Data curation, Conceptualization. **Hongxi Luo:** Writing – review & editing, Validation, Methodology, Investigation, Formal analysis, Conceptualization. **Chris Greig:** Writing – review & editing, Supervision, Methodology, Conceptualization. **Eric Larson:** Writing – review & editing, Supervision, Methodology, Funding acquisition, Conceptualization. **Jesse D. Jenkins:** Writing – review & editing, Visualization, Supervision, Software, Project administration, Methodology, Investigation, Funding acquisition, Conceptualization.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Aniruddh Mohan, Jesse D. Jenkins reports financial support was provided by Breakthrough Energy. Aniruddh Mohan, Jesse D. Jenkins reports financial support was provided by Linden Trust for Conservation. Aniruddh Mohan, Jesse D. Jenkins reports financial support was provided by Stripe Climate. Jesse D. Jenkins reports a relationship with Rondo Energy that includes: board membership and equity or stocks. Jesse D. Jenkins reports a relationship with Eavor Technologies Inc. that includes: board membership and equity or stocks. Jesse D. Jenkins reports a relationship with Energy Impact Partners that includes: consulting or advisory. Jesse D. Jenkins reports a relationship with DeSolve, LLC that includes: consulting or advisory, employment, and equity or stocks. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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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.enconman.2024.119136. Supplementary Information attached.

Data availability

All input files for the power system for our GenX simulation along with excel sheets detailing our Aspen® process simulations are provided on Zenodo (https://doi.org/10.5281/zenodo.10120474).

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