The cost of direct air capture and storage: the impact of technological learning, regional diversity, and policy.

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1 ABSTRACT

Direct air capture and storage is a technological solution to removing CO_2 from our atmosphere that is deemed necessary to reach climate targets. However, huge question marks remain over the current and future costs. Here, we show the cost of DACS, for four example technologies, of plants built today before we project these costs into the future using technological learning theory. We exhibit that the costs of the first plants will be higher than many figures quoted today, but long-term, this can reduce to \$80-600 t-CO_2^{-1} at the Gt-CO_2 year^{-1} technology scale. We also show that intelligent deployment via siting and energy source selection is critical and can save a few thousand dollars per t-CO_2^{-1} for some technologies. Finally, we explore which policies can help create a market, accelerate scale-up, and reduce the long-term costs of direct air capture as a potentially vast future industry.

2 INTRODUCTION

Carbon dioxide removal (CDR) is a vital tool in the fight against climate change. The prevention of greenhouse gas (GHG) emissions should be a priority, but there is little doubt that CDR will be required to offset hard-to-abate emissions if we are to prevent the worst impacts of climate change and limit the planet's warming to 1.5℃ or even 2℃.[1,2] Also, CDR is needed to achieve net-negative emissions once carbon neutrality of our economies has been reached. Bergman and Rinberg

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approximate that "hard-to-avoid" emissions may be between 1.5-3.1 Gt-$CO_{2,eq}$* $year^{-1}$ by 2100,[3] whilst the economic-optimised integrated assessment modelling pathways that result in 1.5°C of warming suggest that net-negative CO_2 emissions are required from between 2040 and 2070.[4] Direct air capture (DAC) and storage (DACS) is a technological solution to CDR. DAC entails the extraction of CO_2 from air using (in most cases) a chemical sorbent and subsequent release of that CO_2 from the sorbent. When that released CO_2 is stored permanently, then this is DACS. As an approach to CDR, DACS facilitates comparatively easy carbon accounting and comparatively few external impacts, such as competition for land, than other approaches for CDR.[5,6] However, it may also be costly and energy-intensive.[7]

There are over a dozen DAC processes described in the academic literature and under development by commercial parties.[8] In this study, we will focus on those which have well-defined processes in literature, including a) KOH absorption paired with regeneration via lime looping,[9] b) KOH absorption paired with regeneration via bipolar membrane electrodialysis (BPMED),[10] c) solid sorbent DAC using temperature vacuum swing adsorption,[11] and d) MgO ambient weathering with regeneration via calcination,[12] presented in Figure 1. For a), b), and d), the bottom-up engineering design in literature is paired with techno-economic analysis. Meanwhile, there have been some studies that estimate the cost of solid sorbent DAC, c), based on high-level analysis.[13,14]

Overall, the cost figures of DAC that are quoted in the public domain are primarily based on information from the companies developing the technologies, and independent interpretation and corroboration are lacking. Existing academic studies and publicly presented cost figures differ in assumed boundary conditions, often omitting parts of the DACS value chain (e.g., CO_2 compression, transport, and storage) and not attempting to predict the cost of a real first-of-a-kind (FOAK) plant, leaving out costs for technology development and scale up to the first commercial plant. Therefore, the reported costs are likely too low to represent a FOAK DACS project cost and the trajectory to N^{th}-of-a-kind (NOAK) DACS cost is unknown. In general, there is high uncertainty on the current costs of DACS and where these costs may go as a result of large-scale deployment, i.e., over the course of the 21^{st} century. For example, an expert elicitation study showed that experts currently predict that the costs today lie between ~\$100-2000 t-CO_2^{-1} falling to ~\$50-1500 t-CO_2^{-1} by 2050 depending on future policy scenarios.[15] Furthermore, there is little to no information on the cost of DACS in locations outside the US (and perhaps Europe), and on how government policy may support the deployment and cost development of DACS projects.

This study aims to answer where the costs of DACS may go as a result of technological learning, and further shows the potential impact of location and policy. We believe this is critical to

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policymakers, non-governmental organisations (NGOs), and investors alike and will foster an understanding of what can plausibly be expected in DACS cost development. The four technologies chosen represent a varied technology space, thereby aiming to provide a cost trajectory more representative of DAC in general than for one or two specific technologies.[9,12,22,13,14,16–21] We also added CO_2 compression, transport, and permanent geological storage complete the chain for net-CO_2 removal.

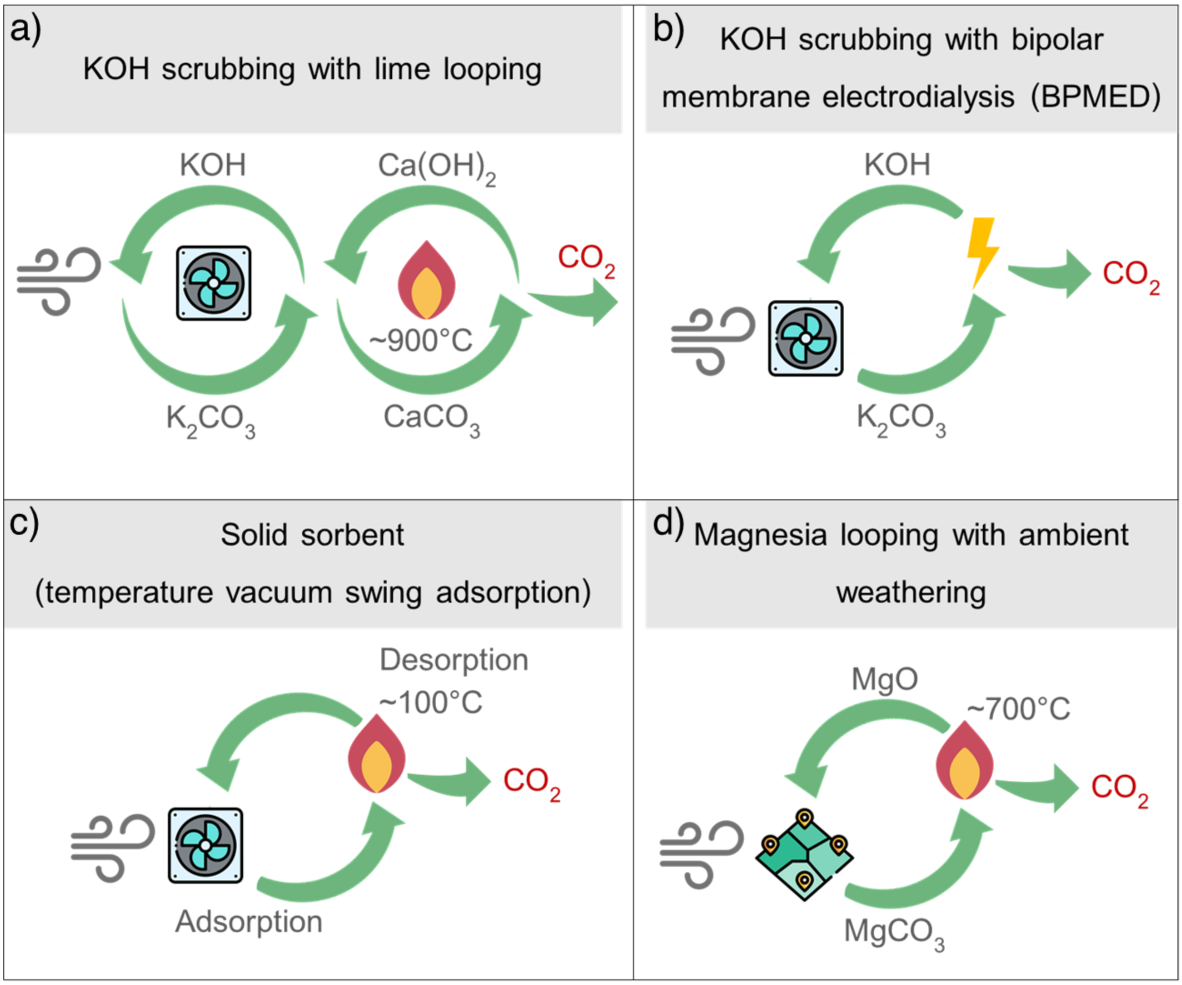

Figure 1 The four technologies assessed as part of this study. a) KOH absorption paired with regeneration via lime looping b) KOH absorption paired with regeneration via bipolar membrane electrodialysis (BPMED) c) solid sorbent DAC using temperature vacuum swing adsorption d) MgO ambient weathering with regeneration via calcination.

3 METHODOLOGY

The methodology encompassed a technical and economic performance assessment of the four selected DAC technologies for their current and future states. The techno-economic assessment model is discussed in detail in Section 3.1. The technical performance estimates are based on the existing literature for all but the solid sorbent technology, for which we used our own modelling as presented in earlier work and briefly discussed in Section 3.2.[11] Because the impact of location on net cost of

CO_2 removed is largely missing from the DACS literature, we estimated DACS costs for eight geographically and economically diverse case study countries (United States, China, the United Kingdom, Germany, Russia, Brazil, Australia, and Oman) based on a literature review assessing the variation of different cost factors across these locations, as further detailed throughout Section 3.1. As well as geographic and economic diversity, historical emissions were also considered when selecting these countries. These case studies allowed us to explore how siting decisions based on the availability of low-carbon energy sources, cost of materials and labour, among others, influence DACS cost, whilst also acknowledging that complex factors beyond costs (e.g., political and geographic) affect DACS siting decisions. Finally, we reflected on policy requirements for the scale-up of DACS and which policies could reduce the cost in both the short and long term. We suggested policies to help create the market at the scale required to enable technological learning, reduce the significant initial investments until sufficient learning-by-doing has occurred, or reduce the cost via lowering investment risk and thus the cost of capital, further detailed in Section 3.3.

3.1 TECHNO-ECONOMIC MODEL

The techno-economic framework developed in this work is based on the International Energy Agency's Greenhouse Gas Research and Development Programme's (IEAGHG's) framework[23], adapting it for consistency with recently published guidelines for the cost estimation of CO_2 capture and storage projects, as published by IEAGHG, the United States Department of Energy - National Energy Technology Laboratory (DOE/NETL), and the Electric Power Research Institute (EPRI).[24–28] Specifically, we used the so-called hybrid costing method, which uses bottom-up costing of the FOAK project costs and then implements a top-down method, using technological learning, to arrive at future, NOAK, project costs. The raw cost data of the KOH-Ca looping, KOH BPMED, and MgO ambient weathering processes was extracted from literature and entered into our harmonised framework.[9,10,12] This data included equipment and installation costs, energy usage, produced CO_2 purity, any extra CO_2 generated in addition to that captured from the air, water requirements, and chemicals and minerals requirements. Meanwhile, the solid sorbent costs were calculated entirely in this work. It should be noted that we did not consider the impact of regional variation on process configuration or technical process performance.

The bottom-up part of the framework produced the FOAK costs for the four technology archetypes. First, appropriate FOAK scales were selected for each technology. These are available in Table 1, and the reasoning behind their selection is discussed further in the table. The selection of the FOAK scale is relevant to technological learning, as it gives the starting point for cost reductions and determines how many doublings take place when deployment increases to a certain level. Then, the capital costs were built up from the installed equipment costs and are in 2019 USD. We adjusted the costs based on the Chemical Engineering Plant Cost Index (CEPCI), where values from other base years were used originally. The KOH BPMED and MgO ambient weathering installed equipment costs were scaled down as the details in literature were for plants larger than the here assumed FOAK scale.[10,12]

Table 1 FOAK scales for each technology and the corresponding justification for choosing this size.

Technology	FOAK scale [kt-CO_2 year^{-1}]	Reasoning
KOH-Ca looping	980	Used the value provided by Keith et al., as this is used to assess an "early plant" cost estimate.[9] The study considers that the minimum practical scale is 100 kt-CO_2 year^{-1}. However, there are significant cost advantages to operating at 1000 kt-CO_2 year^{-1} due to the economies of scale of the calciner and the slaker.[9,29]
KOH BPMED	46	The original study from Sabatino et al. studied a plant at a 1000 kt-CO_2 year^{-1} scale.[10] However, most of the system's components are modular, so very few economies of scale are utilised when they scale to this size. For this reason, we scaled the process down to 1 electrodialysis stack. Information on this is available in the ESI.
Solid sorbent	0.96	The scale chosen here was the two units operated in Hinwil, Switzerland, by Climeworks.[30] This technology is inherently highly modular, particularly the contactors. The maximum size of systems operating under vacuum is limited by the mechanical stress, which increases linearly with unit size. This limits the scale that one module can reach, adding to our choice for this relatively small scale as a FOAK size.
MgO ambient weathering	1100	The size was chosen to remove 1000 kt-CO_2 year^{-1} at a 90% plant capacity factor. This process uses the same type of calciner as the KOH-Ca looping process, so similar arguments can be made about the optimal scale being influenced by the calciner.[9,29]

The installed equipment cost includes the direct materials and any extra installation costs such as piping, instrumentation, valves, paint, and labour costs. These were adjusted for the location using the factors given in the electronic supplementary information (ESI) Table S3. Details of all these capital equipment costs are available in the ESI Table S2. The installed cost for the CO_2 compressor was harmonised across all technologies by using Aspen Capital Cost Estimator, inputting the required scale. Additionally, a harmonised engineering procurement and construction (EPC) factor of 15%, which is between estimates from the IEAGHG and DOE/NETL, was then applied to these costs to arrive at, what is called, the EPC cost.[23,28]

Next, the EPC costs were escalated to those of a FOAK commercial project using the process and project contingencies, and owner's, spare parts, and start-up costs to arrive at the total overnight cost, as defined by Rubin et al.[27] The project contingencies take into account site-specific costs not considered in the preliminary analysis, and we used the Association for the Advancement of Cost Engineering (AACE) guidelines for this. The project contingency is 35% of the EPC cost for all processes as they are class 4 AACE estimates, which refers to the level of detail in the design.[31] Process contingencies account for any uncertainty surrounding capital costs on account of the

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technology maturity of a process and the cost of upscaling that accompanies this. Therefore, the process contingency is higher for lower technology readiness level (TRL) technologies as they are more likely to incur extra costs whilst developing through unforeseen issues that must be addressed with process adjustments or a change of operation. The process contingencies used for each technology (as function of their TRL) can be found in Table 2. Following the addition of contingencies, the IEAGHG's assumptions were applied to estimate the owner's costs (7% of TPC) and spare parts costs (0.5% of TPC) as well as the start-up capital (2% of TPC), start-up labour (0.25 years of all labour), start-up fuel (0.02 years of fuel), and start-up chemicals (0.08 years of chemicals). The total overnight cost was then annualised using the capital recovery factor calculated from the assumed discount rate(s) and a plant life of 25 years. The discount rates and their variation by country can be found in the ESI Table S3. The capital costs were finally levelised, assuming a plant capacity factor of 90%. The accuracy of the capital cost calculation was assumed to be -30% to +50% of the calculated value, which AACE expects for a class 4 estimate.[31]

The annual fixed operating and maintenance costs included direct and indirect (30% of direct labour plus maintenance) labour, maintenance (1.5% of TPC), insurance (0.5% of TPC), and local taxes and fees (0.5% of TPC). The direct labour cost was calculated based on 278 direct employees for a 1 Mt year^{-1} plant, with the labour scaling linearly by plant size.[32] This scaling is unlikely to be entirely correct, however the direct labour costs have a relatively small impact on the overall costs as shown by the sensitivity analysis in the ESI Figures S6-S7. The number of employees was then adjusted according to productivity factors of each country. The productivity factors are located in the locational cost factors table provided in the ESI Table S3. The employees' annual salary was varied by location and is provided in the ESI Table S3.

The annual variable operating costs contain electricity, natural gas, gasoline, low-grade heat, water, chemicals, and CO_2 transport and storage costs. Natural gas is the source of heat in the KOH with Ca looping and MgO looping with ambient weathering processes. Meanwhile, the solid sorbent process requires heat at lower temperatures (100°C vs. 700-900°C). We compared low-grade heat from solar heat, dedicated geothermal heat (i.e., not waste heat from geothermal electricity), and heat via electricity from a heat pump. The energy and water requirements of each technology are detailed in the ESI Table S1, whilst the unit cost of energy is location-dependent and source-dependent. These are detailed in the ESI Table S3. Note that we assumed that a DACS plant can be paired to each electricity source all of the time, which is untrue in the case of intermittent renewables without accounting for the cost of electricity storage. Although, it may be possible to switch between these electricity sources depending on availability. The reader should consider this evaluation of electricity sources more of as a thought experiment that will require further analysis when developing a DACS project. Meanwhile, the unit cost of cooling water is assumed to be \$0.21 m^{-3} and does not vary by location as per the IEAGHG's assumption.[23,33] The electricity cost includes a harmonised contribution

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from compression, which varies slightly by the outlet purities of the process listed in the ESI Table S1. In reality, this electricity requirement will also vary slightly based on scale, but we assumed this variation to be negligible. The transport costs were also location-dependent, as detailed in the ESI Table S3, whilst the ratio of CO_2 stored to CO_2 captured from the air for each process can be found in the ESI Table S1. For example, the KOH-Ca looping process and the MgO ambient weathering process both utilise a natural gas fired calciner, meaning that fossil CO_2 is generated additionally. The transport distance was assumed to be 0-200 km with a median value of 50km. Meanwhile, the geological storage costs were taken to be \$5-27 t-CO_2^{-1} with a median value of \$11 t-CO_2^{-1}.[34]. Finally, the overall cost of chemicals was unique to each process and was calculated based on process-specific consumption rates and fixed costs of specific chemicals. These are shown in the ESI Table S1.

The sum of the levelised capital costs, fixed operating and maintenance, and the variable operating costs was then escalated to the net removed cost, as shown in Equation 1, using the calculated GHG emissions from the process.

For this calculation, only energy-related emissions are considered as it has been shown that these dominate in life cycle analysis of the greenhouse gas emissions of DAC technologies.[9,35,36] The carbon intensities of electricity sources across different locations were calculated using SimaPro® and the EcoInvent v3.8 database and are shown in the ESI Table S4.[37] Upstream natural gas emissions in different locations were calculated using a previous study on methane leakage rates across the world and the carbon intensity values calculated are shown in the ESI Table S5.[38] Across our case studies, these leakage rates vary between 0.26-2.21%. The carbon intensity of gasoline was assumed to be a constant value of 66.97 $kg_{CO2,eq}$ GJ^{-1}.[39] The carbon intensity of dedicated geothermal heat and solar thermal energy were extracted and scaled from previous studies based on different locational factors. More details can be found in in ESI Table S5.[40,41]

The costs of net CO_2 removed are:

$$C_{NR} = \frac{C_{GC}}{1 - X} \qquad 1.$$

Where C_{NR} [\$ t-CO_2^{-1}] is the net removed cost, C_{GC} [\$ t-CO_2^{-1}] is the gross capture cost, and X [t-$CO_{2,eq}$ t-CO_2^{-1}] is the GHG emissions accounted to the process per tonne of CO_2 captured.[29] As a result, we obtained the FOAK net removed costs.

The FOAK capital and variable operating costs were then extrapolated into the future using learning rates and Equations 2-3 based on analogous technologies.

$$b = -\frac{\ln(1 - L_r)}{\ln 2} \qquad 2.$$

$$y = ax^{-b} \qquad 3.$$

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Where b [-] is the learning exponent, L_r [-] is the learning rate, y [\$ t-CO_2^{-1}] is the current capital or operating cost, a [\$ t-CO_2^{-1}] is the FOAK capital or operating cost, and x [-] is the ratio of existing capacity to the initial capacity of the technology.[24]

The selected learning rates and the rationale behind their selection can be found in Table 2. Given most DAC technologies are yet to reach commercialisation and progress along the learning curves, it was needed to select the learning rates based on analogy with other technologies, and on whether a technology is more or less modular, i.e., can be mass produced to an extent. In the techno-economic model, the fixed operating and maintenance costs are highly coupled to the capital costs, hence these fixed operating and maintenance costs reduce with the reducing capital costs. The recently published guidelines on cost evaluations for carbon capture and storage, explain in detail the range of reasons why FOAK fixed operating and maintenance costs will be higher for a FOAK plant compared to a NOAK plant.[24,25] However, the variable operating costs are not linked to the capital costs, so we selected separate learning rates for these costs. Assuming an equal proportion of this learning is applied to a reduction in energy consumption, we ensured that the thermodynamic second law efficiency did not exceed 50% using the maximum learning rate. Using the same underlying assumption on the relationship between variable operating cost learning and learning on energy consumption, we also assumed the learning was reflected in a reduction of energy-based emissions of the process. The same variable operating cost learning rates were chosen for all technologies with a minimum of 0% and a maximum of 5% and a median value of 2.5%. The 5% value is consistent with our constraint on the thermodynamic minimum and is the same as the operating cost learning rate for oxygen production.[24] We then calculated the NOAK net removed cost using the same approach used for a FOAK plant with the levelised capital costs, levelised fixed operating and maintenance, levelised variable operating costs, and process emissions.

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Table 2 Process contingencies and capital cost learning rates selected for this study and the justification. This is the technology readiness level for process contingency as suggested by the AACE and EPRI.[27,31] and the analogous technologies plus level of modularity for the learning rate. The white paper by Roussanaly et al. was used as a reference to select the values given the justification.[24]

Parameter		**KOH with Ca looping**	**KOH with BPMED**	**Solid sorbent**	**MgO ambient weathering**
Process contingency	Technology readiness level	6	4	7	4
	Minimum [% of EPC]	20	30	5	30
	Middle [% of EPC]	30	50	20	50
	Maximum [% of EPC]	35	70	20	70
Capital cost learning rates	Minimum [%]	5	12	10	5
	Middle [%]	10	15	15	10
	Maximum [%]	15	19	18	15
	Analogous technologies	Flue gas desulphurisation, coal power plant, integrated gasification combined cycle power, air separation units	Electrolysis, fuel cells	Modular technologies. Fuel cells, photovoltaic solar panels	Flue gas desulphurisation, coal power plant, integrated gasification combined cycle power, air separation units

3.2 SOLID SORBENT PROCESS MODELLING

The basis for the solid sorbent temperature vacuum swing adsorption process was two units containing 18 contactors each, as is the set-up at the Climeworks plant in Hinwil, Switzerland.[42] The contactor design was based on a 2020 patent, and the sorbent used is Lewatit® VP OC 1065 due to its commercial availability.[43] It should be stressed that the heating mechanism of the contactor in this patent is indirect and not using steam stripping. We used a model and Lewatit® VP OC 1065 data from previous work to calculate the energy and productivity values of a process optimised for maximum productivity.[11] Here, we adjusted the sorbent volume based on one plate in the chosen contactor design and calculated a heat transfer coefficient using a one dimensional radial approximation around a heat transfer pipe. The parameters used can be found in the ESI Tables S6-S8. Afterwards, we built up a simple flow diagram of the process and assessed the costs based on this. This flow diagram and the cycle design can be found in the ESI Figures S1-S2. All the calculated costs and their sources can be found in the ESI Tables S1-S2.

We considered natural gas only for the two processes powered by high-grade heat, i.e., KOH-Ca looping and MgO ambient weathering, since the process configurations in literature both use natural gas in an oxy-fired calciner.[9,12] In reality, it would be possible to use other heat sources for calcination, such as solar or electricity.[12] However, this would impact the calciner design and potentially the processing downstream of the calciner, and this level of re-design is not in the scope of this study. Biogas could be an alternative that would not impact the design, but we do not investigate this here as the extra land and biomass requirements may become limiting at scale. Nevertheless, we did investigate the impact of low-grade heat choice on the solid sorbent process as this does not significantly impact other parts of the process. However, we are aware that it does affect the systems integration and siting of the plant. The three investigated low-grade heat sources are electricity with an air-source heat pump, dedicated geothermal heating, and solar heating. The ESI Figure S4 compares the effect of different heat sources on net removal cost, and we find that all of the options have the potential to be competitive, but we selected a heat pump to use in the analysis for the rest of this study, for simplicity, due to its lower median cost estimate. Here, we assumed a coefficient of performance (COP) of 2, which is consistent with an 85°C temperature rise, and we did not consider the effect of location.[44] There is also the option of using waste heat, especially for FOAK and pilot plants. This will reduce the early costs, supporting initial scale-up, but this is expected not to significantly impact cost at the scale of carbon removal we will require.[45]

3.3 SCENARIO ILLUSTRATION AND POLICY INVESTIGATION

As a thought experiment, we opted to illustrate how the learning curves translate into costs in specific years and defined two extreme technology uptake scenarios. In one scenario, we took the least aggressive DACS uptake possible from integrated assessment modelling to meet still the 2°C or 1.5°C scenarios based on analysis from the IEA, Realmonte et al., and Fuhrman et al.[2,46,47] Meanwhile, the second scenario was based on the most aggressive possible DAC uptake to meet either the 1.5°C or 2°C scenarios using the analysis from the IEA and Fuhrman et al.[46,47] The two scenarios are shown in the ESI Table S9. Within these scenarios, we allowed for a 25% technology dominance or a 100% technology dominance to understand the effect of future DAC market share. To demonstrate the scenarios, the total DACS scale in 2050 varies from 0.01-11.9 Gt-CO_2 year^{-1}, and in 2100 this increases to 1.8-31.6 Gt-CO_2 year^{-1}.

We also wanted to assess DACS policy needs and the potential impact of different policies on the DACS learning curves. As a result, we performed a comprehensive literature review on policy options. To examine the impact of different policies on DACS costs, four policies of interest that cover a wide range in the policy design space were identified and quantitatively examined. A comprehensive list of the policies investigated as part of the literature review and their relation to the four policies analysed quantitatively can be found in the ESI Table S10. The four policies selected for quantitative investigation were i) investment grants, ii) contracts for differences (CfDs), iii) a regulated asset base (RAB) model, and iv) state-owned DACS facility or a DACS facility fully backed by a state-loan. Investment grants are capital supplied to support projects without any expected return from the granter. CfDs allow a fixed price to be paid for a product for a particular

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duration. Any deviation from the market price from this fixed price is paid for by the CfD broker, which in this case is likely to be a government or consumer. We assumed the duration of the CfD is for the whole project. A RAB allows a project developer to start receiving payment for their product during the project's construction phase before operation begins. This is done through an agreement between the project developer and a regulatory body. In addition, the price charged during operation is also set by the regulator rather than an open market. Finally, a state-owned DAC facility or a DAC facility backed by state loans could take advantage of the low-interest rates available to a government through their high-risk tolerance.

The base location for the policy analysis was chosen to be the United States utilising wind-powered electricity and a heat pump for low-grade heat where required. This was chosen as an example, and it is likely that the results would vary by location, especially for the policies where the government takes on risk from the project developer, as the risk tolerance and hence bond yields of governments across the world vary significantly.[48] The analysis of investment grants was based on a scenario where a government wanted to grant \$3.5 billion of cash to scaling up DACS. This number is based on the grant size that the United States government is committing to developing “DAC hubs”.[49] In our scenario, the money was then used to pay for the capital expenditure directly with no interest until the \$3.5 billion runs out. The same learning rates are assumed as in a scenario without grants. Then, the reduction of investment risk was found to be the main impact reducing the DACS cost directly in the case of CfDs, RABs and state-owned facilities/state-backed loans. By drawing analogies with other markets and technologies, we assessed the potential decrease in the discount rate on account of each of these three policy options.[50–57] These reductions are found in the ESI Table S11. Finally, the impact of the reductions on the cost learning curves was analysed.

4 RESULTS AND DISCUSSION

4.1 LEARNING CURVES AND MODULARITY

Figure 2 shows the learning curve ranges obtained from the analysis for the United States paired with wind electricity. The conclusions drawn from this figure are generalisable, but the exact cost values vary by location and energy source. The variance in these cost values is discussed below using Figure 4 and Figure 5. Firstly, there is a large potential range in the FOAK costs of each technology, given the accuracy of the capital cost estimate, potential range of possible process contingencies, variation in energy prices, potential range of possible discount rates, and potential range of possible transport and storage costs. The capital cost accuracy, and process contingencies in particular, reflects the immaturity and perhaps more the lack of publicly available technology performance and cost data. Currently, the only commercial plants in the world are operated by Climeworks. They have quoted costs or prices of \$500-600 t-CO_2^{-1} in 2019 and €1000 t-CO_2^{-1}, specifically from the Orca plant, in 2021.[58,59] However, our costs for our FOAK estimates are \$1250-3000 t-CO_2^{-1} for a case study in the USA paired to wind electricity. These costs are perhaps not entirely comparable given the lack of information on cost breakdown, and whether the quotes would include compression, transport, and storage. For example, if we assume in our model that we have free waste heat with a 0% discount rate and no compression or storage costs, this value becomes \$570-940 t-CO_2^{-1}, which is consistent with previous quotes from Climeworks. Then if we extrapolate this using learning rates from the Hinwil to Orca scale, the range becomes \$390-770 t-CO_2^{-1}. Previously, companies have paid up to \$2050 t-CO_2^{-1} in voluntary markets, suggesting there is a potential business case currently.[60] The opportunities for these early cost reductions, such as using waste heat, will likely be exploited first leading to slightly lower costs than those predicted here for FOAK and early plants. However, when we reach large-scale deployment, these opportunities should have been fully utilised leading to the scenarios predicted in our learning curves. Papapetrou et al. estimate that 100 TWh year^{-1} of recoverable low-temperature waste heat (<200°C) is available in the European Union.[61] However, this waste heat can also be utilised for space heating or efficiency gains if it is close to urban areas or other industries. If this waste-heat could be utilised for solid sorbent DACS alone, this would only support ~37 Mt-CO_2 year^{-1} of deployment, and this is an unrealistically optimistic best-case scenario.

We should highlight that the solid sorbent FOAK scale is much smaller than for the other technologies leading to higher FOAK costs, yet similar costs at comparable scales, and we will discuss this in more detail within this section. Keith et al. explicitly state that they do not do a cost evaluation for a FOAK KOH-Ca DACS plant.[9] Instead, they compare the capital cost of an "early plant" and NOAK plant. The early plant estimates from their study are \$190-260 t-CO_2^{-1} when we escalate Keith et al's. capture cost to net removed cost using their figure of 0.1 tonnes of CO_2 emitted per tonne captured.[9] However, our FOAK cost estimate is larger and ranges from \$230-580 t-CO_2^{-1} in our harmonised framework for a case study in the USA paired to wind electricity. The main reason is that the contingencies that we apply are now reflective of the technology readiness level and detail of the engineering study. These contingencies also cascade into higher fixed operating and maintenance costs, which are a function of capital cost. Meanwhile, the literature cost estimates of the KOH BPMED and MgO ambient weathering processes are both said to be for a NOAK plant and hence are not comparable to the FOAK cost estimates here.

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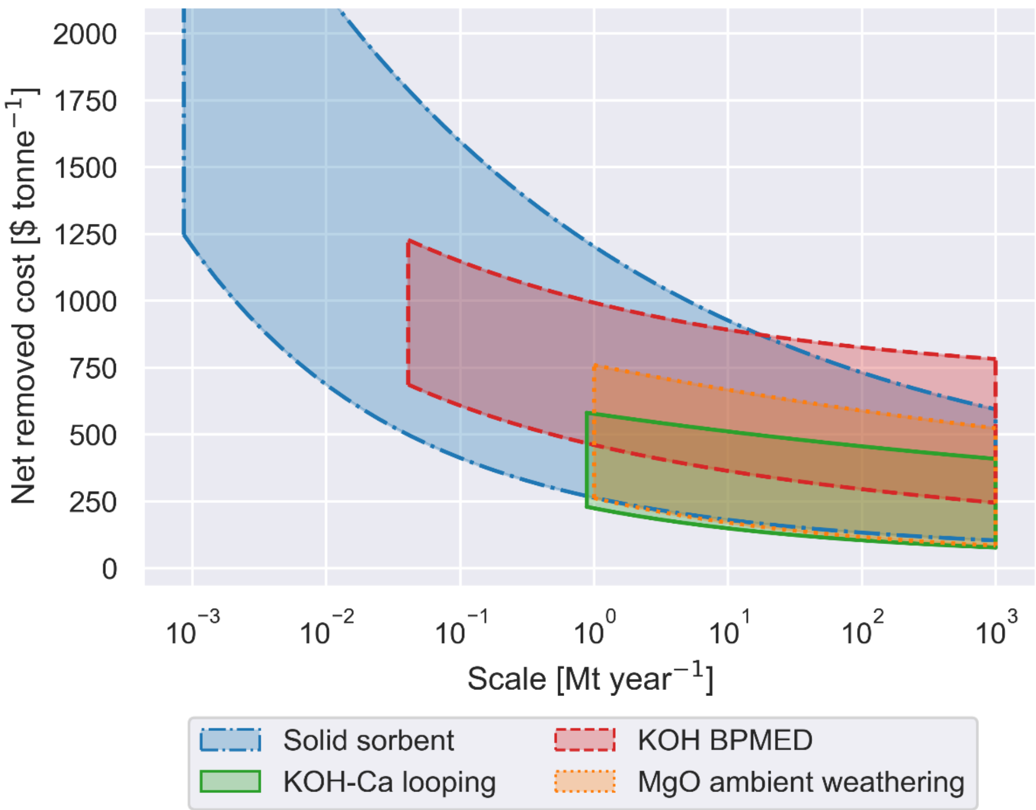

Figure 2 Cost development trajectories of the four technologies from the kilotonne to the gigatonne CO_2 net removed per annum scale. Note the log scale on the x-axis. The cases studied are in the United States paired to wind electricity and using a heat pump for low-grade heat where applicable. The figure provides ranges instead of lines, highlighting a large amount of uncertainty and variability in the estimates. Trajectories of different locations paired with wind electricity can be found in the ESI Figure S5.

Within Figure 2, we also see that the Gt-CO_2 year^{-1} scale estimates range from \$80 t-CO_2^{-1} to \$750 t-CO_2^{-1}, with all technologies in a similar range. Along the way, at the Mt-CO_2 year^{-1} scale, the costs range from \$250-1200 t-CO_2^{-1}. The lowest estimate for 3 of the 4 technologies converges onto \$80-100 t-CO_2^{-1}, indicating the lower limit to the cost of DACS under our current assumptions and the four technologies studied here. This suggests that the long-term policy goal, in the United States, of \$100 t-CO_2^{-1} may be challenging, yet not impossible, to surpass.[62,63] The technology with the highest cost at scale is the electrochemical KOH BPMED due to its high electricity requirement of 22 GJ t-CO_2^{-1}. However, alternative electrochemical technologies have the potential to reduce this requirement. For example, the recent work by the Hatton group demonstrates a technology that could use much less energy.[64,65] However, there is not enough published data and the technology readiness level is too low to perform an accurate cost assessment, and hence this technology improvement is not considered for analysis in this work.

Another observation from Figure 2 is the strong effect of the FOAK scale on the FOAK cost. The solid sorbent and KOH BPMED technologies with a smaller FOAK scale incur a higher FOAK cost as they cannot utilise economies of scale. However, these more modular technologies also exhibit higher learning rates as there are greater opportunities to improve and reduce costs when producing such modules through mass production.[66] This leads to overlapping costs at similar scales across all four technologies.

The high learning rates achieved by the modular technologies are analogous to the high learning rates achieved by wind and solar power, fuel cells, and electrolysers, which are enabled by mass production, along with the ease and speed of implementing research and development breakthroughs into the system.[24] Another reason behind the higher learning rate is their potential to gain learning from industries other than carbon removal, such as CO_2 supply to niche markets, i.e., via diversification.[67] However, this does not apply solely to more modular technologies. For example, large-scale plants may be better suited to supply CO_2 to large-scale utilisation processes, such as a sustainable aviation fuel plant. Not only are the learning rates higher for more modular technologies, but the modular technologies also gain extra doublings before reaching the larger technologies' FOAK scales, which again leads to more learning. Another important point is that the more modular technologies exhibit higher uncertainties in costs at scale. These extra doublings supply more time for the low and high cost bounds to diverge with their differing learning rates.

The downstream processing units of all the technologies, such as compression and condensation, are not inherently modular. Hence, they have a greater impact on the FOAK cost of the modular technologies, as economies of scale are not utilised. This can be observed in the ESI Figure S6, where the FOAK net removed cost for the most modular process, solid sorbent, is the most sensitive to the compressor capital cost. Co-located DAC systems could alleviate this if multiple plants share downstream processing units.

Due to the large dependence on the individual unit size, optimising this size could be an exciting problem for further investigation within each DACS technology.

4.2 SCENARIO ANALYSIS

The time for an acceptable cost of DACS to materialise depends strongly on targeted maximum global temperature increases and other socio-economic, political and technological variables. There are a few studies that project DACS deployment into the future, and we used these to provide an indicative projection of the cost development of DACS in time.[2,46,47] To do this, we assumed that the world would aim to meet the 1.5°C or 2°C temperature increase limits and identified two extreme scenarios that would require the least and most DACS. These scenarios are available in the ESI Table S9. Meanwhile, we also wanted to consider what would happen when one technology was completely dominant or when it had a 25% dominance (i.e., all four investigated technology options have an equal deployment share).

Figure 3 shows the scenario analysis results for a United States location paired with wind electricity. The conclusions drawn from this figure are general to other locations and electricity

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sources, with only the exact values varying. This variation is discussed below using Figure 4 and Figure 5. Figure 3 shows that the initial high cost of a small modular FOAK plant for solid sorbent DACS may be mitigated by higher learning rates and more doublings by 2030 at the latest (if deployment starts now). Another critical observation from Figure 3 is that the difference in cost between the two uptake scenarios is greater than the difference between a 25% or 100% market share, indicating that we could scale all technologies simultaneously and still expect to bring down the cost through learning-by-doing: we do not need to pick a winner up front. From Figure 3, we see that the long-term costs, towards the end of the century, are likely heading to around \$50-500 tonne^{-1}. When this is achieved depends on the scenario. For example, under the low uptake scenario, the costs plateau by around 2075. Meanwhile, under the high uptake scenario, this happens by 2050. The reality will likely be somewhere in between.

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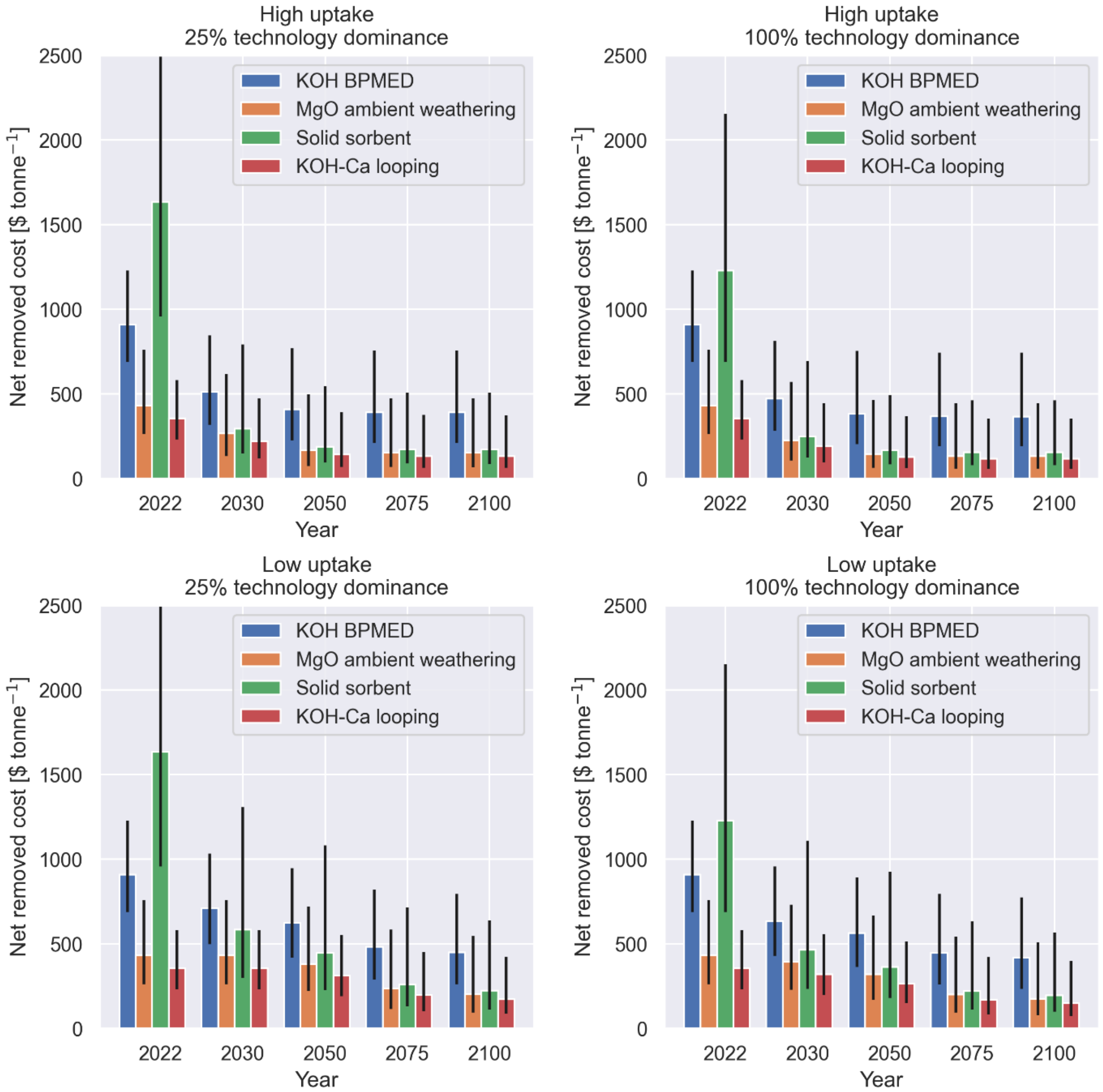

Figure 3 The net removed cost of each technology as time advances for four different scenarios. Extreme low and high uptake scenarios were identified that would still allow us to limit the planet's warming to 1.5°C or 2°C, based on integrated assessment modelling studies, whilst we also allowed for a 25% or 100% technology dominance.[2,46,47] This is for the United States paired with wind electricity and a heat pump for low-grade heat where appropriate.

4.3 COST BREAKDOWNS AND LOCATIONAL ANALYSIS

Figure 4 shows the breakdown of costs for the range of technologies across the different locations for both a FOAK plant and a plant at the Gt-CO_2 year^{-1} scale, and in this case paired to wind electricity. Two important outcomes of this figure relate to: i) the FOAK and Gt-CO_2 year^{-1} scale cost drivers and ii) options to reduce cost. First, for a FOAK plant, the capital costs are dominant for solid sorbent DACS, but they also make up a large proportion of the cost for KOH-Ca looping and MgO ambient weathering. This is supported by the sensitivity analysis in the ESI Figure S6 where the top cost drivers for all these processes affect the capital cost. Examples are capacity factor, bare erected costs, materials scaling, discount rate, and $MgCO_3$ price (in the case of the MgO ambient weathering process). The exception is KOH BPMED, which is dominated by operating costs through high energy demands. To support this, we observe in the ESI Figure S6 that the primary cost driver is the electrical energy requirement. However, as we move to a plant at the Gt-CO_2 year^{-1} scale, operating costs become more important for all technologies. To drive the cost down in the short term, we need to reduce the capital costs, which could come through process intensification or scaling-up and repetition. Whereas, to drive down the long-term costs in the future, we will need to focus on measures that can minimise the energy requirements for each process. Figure 4 also shows that, naturally, the errors become a more significant proportion of the total cost at the Gt-CO_2 year^{-1} scale, mainly due to the uncertainty of projecting costs into the future via technological learning.

Since there is a large dependence on capital cost for solid sorbent, KOH-Ca looping, and MgO ambient weathering processes, the capital cost uncertainty also has a large effect on the overall uncertainty. One way to reduce this uncertainty is through more detailed designs, which will improve the AACE class of estimate and reduce the accuracy bounds tied to this classification.[31] More importantly, after this, building pilot, demonstration, or commercial plants will provide even more accurate cost data, increase the TRL, and reduce the bounds of potential process contingencies. However, to supply accurate and independent evaluations, this data must be made public.

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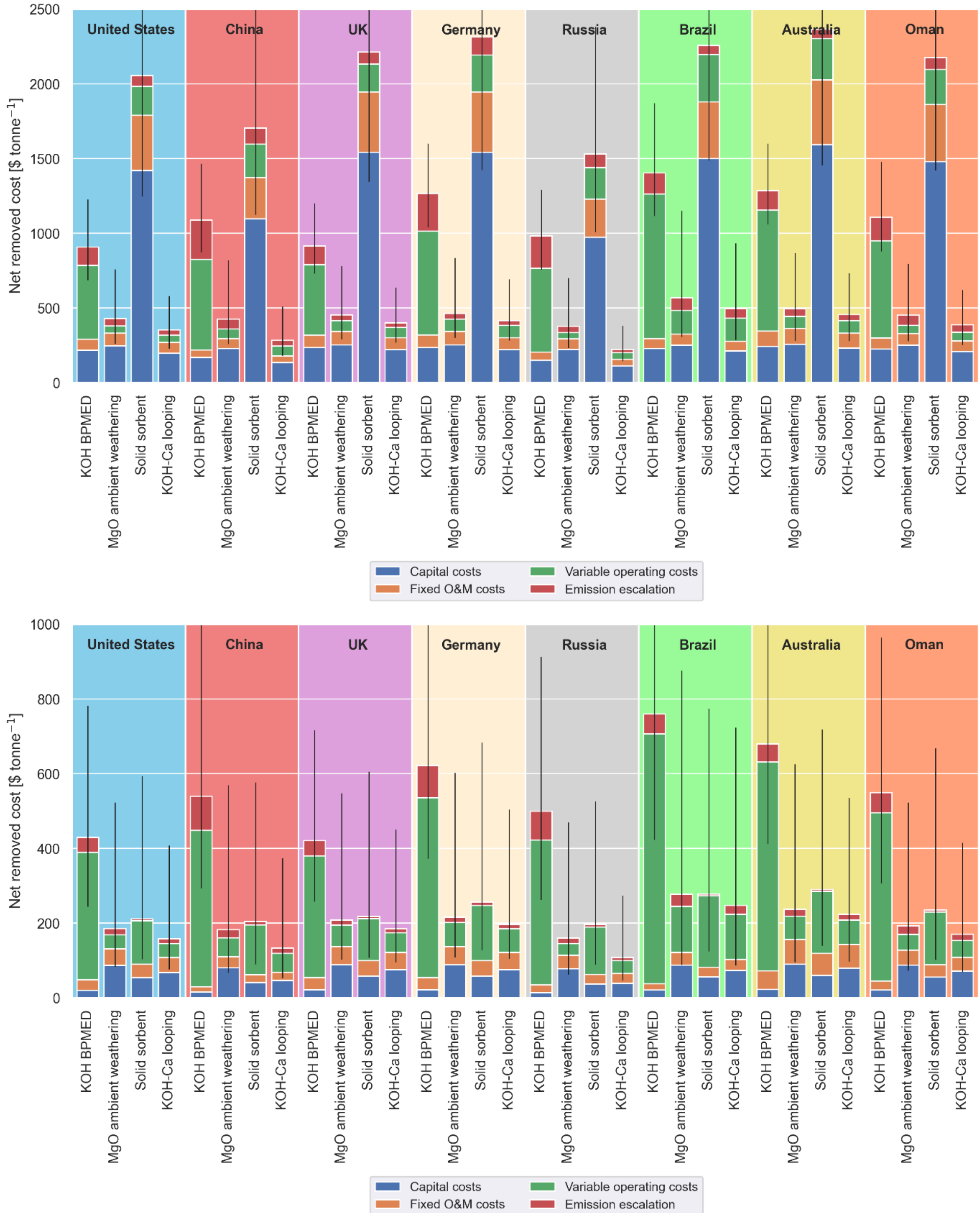

Figure 4 Top: Breakdowns of the FOAK net removed costs for every technology in each country paired with wind electricity and a heat pump for low-grade heat where applicable. Bottom: Breakdowns of the Gt-CO_2 year^{-1} scale net removed costs for every technology in each country paired with wind electricity and a heat pump for low-grade heat where applicable. The black lines are the error bars on both graphs, and the emission escalation represents the cost escalation from gross capture cost to net removed cost due to GHG emissions from energy usage. Note the difference in y-axis ranges in both figures.

Figure 4 also shows the reduced capital costs in China and Russia compared to other countries. This is particularly apparent when viewing the FOAK net removed cost for solid sorbent DACS, which is the most dominated by capital costs. This explains why China and Russia also appear as the cheapest locations for the FOAK cost in Figure 5 for three of the four technologies except for KOH BPMED DACS, where electricity costs dominate. The lower costs are primarily due to the cost of labour, which has a knock-on effect on the cost of raw materials, but also due to the more limited regulation on companies. We should stress here that these costs were calculated before the 2022 Russian invasion of Ukraine, and we would now expect the costs in Russia to be significantly higher due to economic sanctions. This highlights the potential impact geopolitics could have on cost and the limitations of a pure cost-based geographic assessment. Location seems to be a more critical factor to cost than electricity source when considering a FOAK plant apart from KOH BPMED. As the capital costs decrease with the technology scale, the source of electricity becomes more critical at the Gt-CO_2 year^{-1} scale. We see wind, hydro, and nuclear consistently being among the cheapest electricity options because of their lower price and low carbon intensity, suggesting connecting DACS to a grid which is rich in wind, hydro, or nuclear power could be critical to cost-effective DACS.

The coloured matrices in Figure 5 show how the median costs, using our middle or most likely values for all parameters, vary across locations and electricity sources. The median costs may be the most likely values in our modelling, but there are significant uncertainties. The low and high costs are also available within each matrix element as text. These ranges are often very large due to these uncertainties. However, many factors influencing these ranges will be consistent across the matrix, allowing us to focus on these medians for comparison. For example, the differences in the accuracy of capital cost, the discount rate, and process contingencies should all be consistent across each matrix. However, the energy price and transport and storage costs may not be.

Brazil has the highest natural gas price and highest natural gas carbon intensity, as shown in the ESI Table S5, which penalises the two processes using natural gas, i.e., KOH-Ca and MgO ambient weathering, as seen in Figure 5. Australia is also penalised solely due to the high natural gas price. The associated methane leakage associated with Brazil is classified as Tier 1 data, which means it is more generic, and there is a higher uncertainty associated with the carbon intensity, around 30%, compared to actual measured data available from more developed countries such as the United Kingdom where the uncertainty is estimated to be only 3%.[38] The methane leakage rate impacts the two processes that rely on natural gas, and thorough assessments of the leakage rate associated with any local supply chain to be used are required to integrate this data with techno-economic analysis. For example, in the Permian basin in the United States, where a KOH-Ca looping plant may be built,[68] the leakage rates are high, with values of around 3.7% compared to the national median of 1.5%.[38,69] Of course, in the worst-case scenario, a process could even be a net emitter, but for the KOH-Ca looping DACS, this would require a leakage rate of up to ~30%, which is unlikely. Both the KOH-Ca

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looping and MgO ambient weathering approaches would demonstrate an increased sensitivity to electricity and decreased carbon penalty if electrified calcination systems were considered.

Figure 5 and Table 3 also show that, apart from high costs in Brazil, the MgO ambient weathering process is probably the most location and electricity source agnostic, with a relatively small range on the median colour bar compared to the other processes. It uses very little electricity, which varies in price and carbon intensity more than natural gas across different locations. Meanwhile, much of the capital cost is contained within purchasing the initial batch of $MgCO_3$, and the price of minerals and chemicals is assumed to not vary by location, unlike construction materials and labour. However, it is likely that $MgCO_3$ price would vary at least a little by location, and we do see this has an impact on the cost, as shown in the sensitivity analysis in the ESI Figures S6-S7. It has been suggested that 70% of the world's $MgCO_3$ is produced in China, implying this would be where $MgCO_3$ is the cheapest as it is not subject to import tariffs or transportation costs.[70] However, the average import tariff across the world is relatively low at 2.7%, indicating that the price should have a relatively low variance across different countries since there is a strong correlation between the import tariff and the price of goods.[71,72] This justifies not varying the price by location. Practically, to minimise transporting vast quantities of mineral, local availability of $MgCO_3$ within a country could be the driving factor when siting the plant, especially since the cost of the technology does not vary substantially by location aside from this.

In contrast, KOH-BPMED DACS and solid sorbent DACS strongly depend on electricity source and location due to their high dependency on both electricity price and carbon intensity, also shown in the sensitivity analysis in the ESI Figures S6-S7. The KOH-Ca looping DACS process sits in between with a moderate dependence on electricity source and location. It is important to note that for solid sorbent DACS, the use of alternate low-grade heat sources would reduce the dependence on electricity supply, as heat would no longer be provided by electricity via a heat pump.

The impact of siting on cost can be highlighted by showing the potential cost savings between the highest and lowest median costs for each technology across the case studies. These savings for a FOAK and Gt-CO_2 year^{-1} scale plant are highlighted in Table 3. Higher savings are observed at the FOAK scale, but the difference is also significant at the Gt-CO_2 year^{-1} scale, which exemplifies that intelligent siting and electricity supply selection is crucial. This is not to say that we should not pursue DACS development in locations that seem unfavourable under free-market conditions. There may be mechanisms for incentivising DACS which are constrained nationally or regionally that still allow the cost for the project developer to be competitive. However, the provision of these incentives may be an unnecessary burden to a government and could be avoided if a transboundary CDR incentive structure was implemented.

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Table 3 Highest median cost savings for each technology at the FOAK and Gt-CO_2 year^{-1} scale via siting and energy source selection. This is defined as the highest median cost minus the lowest median cost and can also be thought of as the range of the scales in Figure 5.

Technology	FOAK highest median cost savings [$ t-CO_2^{-1}]	Gt-CO_2 year^{-1} scale highest median cost savings [$ t-CO_2^{-1}]
KOH-Ca looping	280	150
KOH BPMED	3950	1670
Solid sorbent	1240	232
MgO ambient weathering	200	120

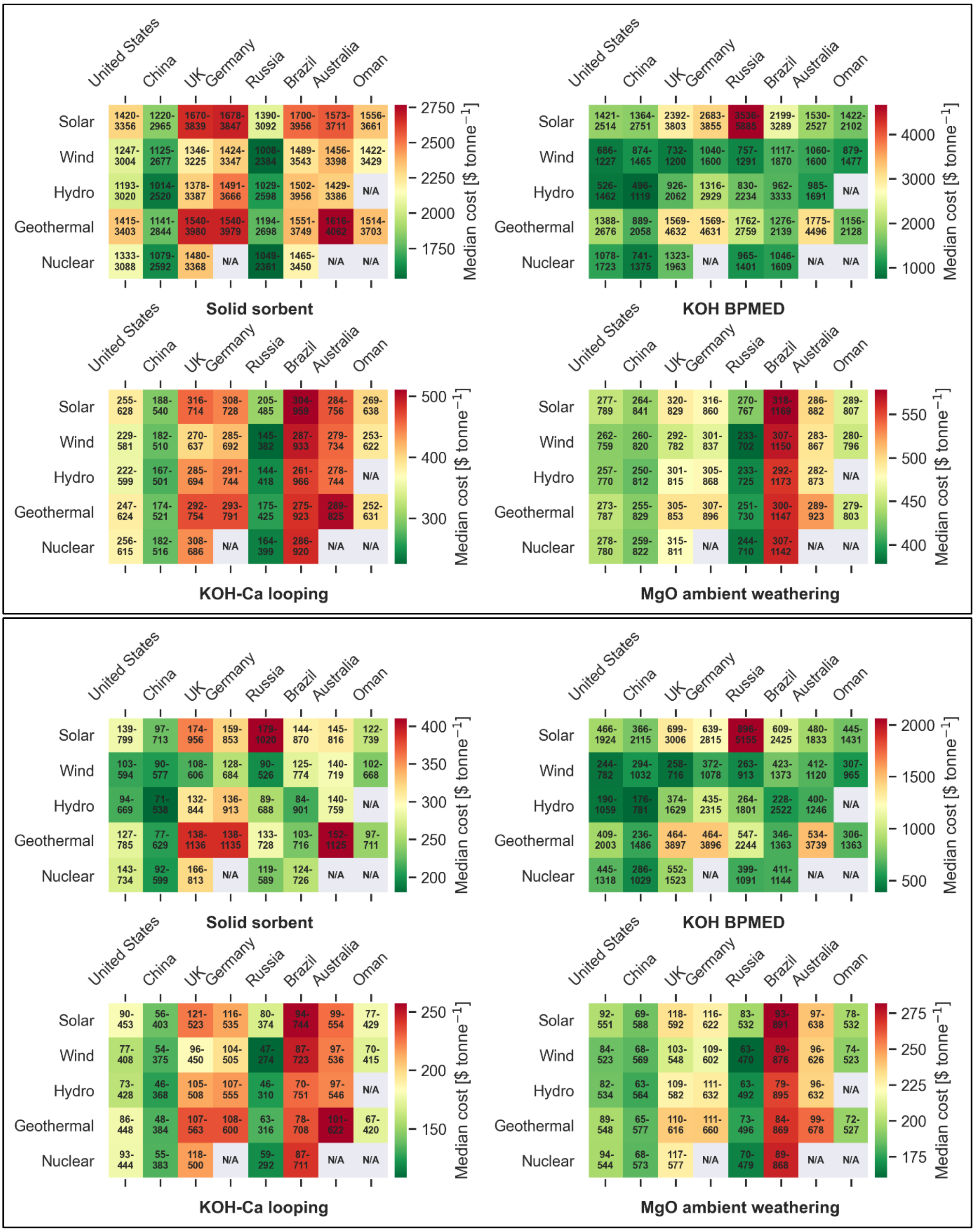

Figure 5 Matrices show different location and electricity source combinations for each technology, coloured by the median net removed cost, with the range of net removed cost in \$ t-CO_2^{-1} in text inside each square. Top: Shown for a FOAK plant paired to a heat pump for low-grade heat where appropriate. Bottom: Shown for a plant when a Gt-CO_2 year^{-1} scale has been reached paired to a heat pump for low-grade heat where appropriate.

Figure 6 presents a map showing low-carbon electricity availability and potential CO_2 storage sites. Whilst the distance from CO_2 storage does not strongly affect the net removed cost (as shown in the sensitivity analysis in the ESI Figures S6-S7), minimising the distance between DAC and the

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associated storage will reduce the number of local stakeholders and decrease the legal complexity of deploying any pipelines required.[73,74] Figure 6 shows that sweet spots exist between the availability of CO_2 storage and low-carbon electricity. We have identified that the capacity factor of the DACS plant is a critical variable in the ESI Figures S6-S7, so either a very high availability of one low-carbon electricity source or multiple electricity sources that together have high availability is required. Some examples of these sweet spots may be Texas in the United States, the North-East of the United Kingdom, East China, or Southern Oman. However, it is essential to note that Figure 6 does not highlight all the critical geographical aspects. Socio-political aspects are one, for instance. Some countries will be more likely to offer incentives to developing DACS plants than others, whilst others may incur higher costs through political instability. It also does not show variation in life cycle analysis factors, such as local natural gas leakage rates, which have already been discussed as important for some technologies. Meanwhile, the availability of land and a skilled workforce may be required for certain technologies, and this is likely to vary locally within a country.

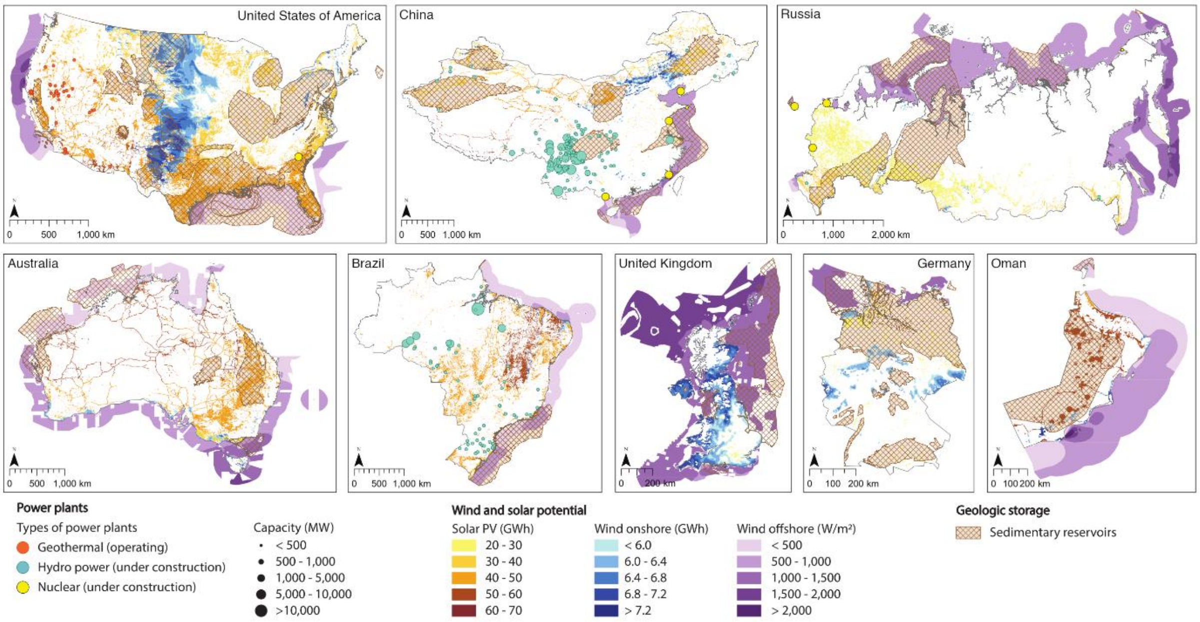

Figure 6 A map of the eight locations studied with low-carbon electricity and CO_2 storage potential highlighted. Adapted from Pilorgé et al. 2021.[73]

4.4 POLICY REQUIREMENTS AND ANALYSIS

Assessing the cost of DACS is an important step, and lower costs naturally provide a more robust business case. However, DACS requires a critical mass to reach the scale necessary to meet the cost constraints required to be self-sustaining. In this sense, DACS will need policy support. We analyse which policy mechanisms are available, what purpose they serve, and how they may affect the cost in the short and long term. A summary of all the policies investigated is shown in the ESI Table S10, whilst the ones examined quantitatively, can be found in the ESI Table S11.

Currently, the small market for removal credits generated by DACS is supported by companies pursuing voluntary offsets.[75] However, verification, including the storage and life cycle project emissions and future monitoring, is currently (to an extent) based on trust, and although it is not currently concerning the voluntary market, it should at least be standardised going forward.[76,77] Hence, a methodology needs to be established to monitor and verify the net CO_2 removal to ensure the buyer of CO_2 removal can compare products from different DACS providers fairly. Additionally, for a buyer to achieve net-zero emissions, the buyer must accurately know their GHG emissions. Complete carbon accounting across all sectors will encourage the move towards net-zero and enable any potential future compulsory offset market.

Another critical bottleneck for DACS deployment at scale is the availability of CO_2 transport and storage infrastructure. A DAC plant could be located next to a potential storage site, or the CO_2 could be transported to the storage site. Developing transport infrastructure and storage sites is capitally intensive and significant economic advantages can occur at larger scales.[78–80] Hence, it is unlikely that the infrastructure would be dedicated to a singular DAC plant. Instead, the infrastructure for the transport and storage supply chain needs to be developed independent of a specific DAC plant.[79] However, this requires existing CO_2 streams to generate a return on the capital invested.[81] Hence, government intervention is critically needed in early stage development, as has been often suggested before.[82,83]

Once the infrastructure and policy are in place for a DACS plant to generate negative emission certificates, a large market is required to sell these certificates to promote further deployment and resulting cost reductions. So, we need to consider how to create a large market. Ways of doing this could be to integrate carbon removal into a subsidy, tax or trading scheme, or regulating companies to reduce or mitigate a proportion of their emissions or, in the long-term, have net negative emissions.[84] Beyond this, advanced market commitments (AMCs) and CfDs are potential mechanisms for a DACS plant developer to receive a specific price for generating negative emissions for a particular time, providing a guaranteed market for a plant.[85–87]

In addition to market creation, it is also essential to accelerate scale-up to encourage technological learning and decrease costs. As discussed earlier and observed in Figure 4, capital costs dominate FOAK plant economics. Hence, supporting these initial investments is key to lowering early-scale deployment costs. Investment grants or grants via public competitions to pay for the capital expenditure can be used as policy instruments to help reduce the removal cost for a FOAK plant. These may pay for all of the capital costs or there may be a cost-sharing structure. There may be mechanisms to further encourage the cost reductions of such technologies, such as decreasing sizes of grants or specific cost-reduction targets that technologies must meet for the funder to fund further projects. This is analogous to the reduction in price cap enforced, e.g., by the Dutch government as

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part of their annual request for offshore wind tenders.[88,89] An alternative (and equivalent) to grants could be investment tax credits, which give companies a percentage of money back for spending capital when they have a tax equity partner.[85] The exact percentage could be progressively reduced, supplying a motive to meet cost reductions.

Another option that reduces the capital burden of early-scale deployment would be to reduce the interest rates paid on the investment. For example, Tesla, Inc. (formerly Tesla Motors, Inc.) was heavily supported by a sizeable low-interest government loan during its early years.[90] A similar loan could be provided to DACS companies. Other ways of reducing this market risk could be the implementation of feed-in tariffs, carbon subsidies, or production tax credits, which all provide a mechanism for a DACS developer to receive a specific price on top of the market price. This will reduce the discount rate and hence the net removed cost by a varying amount depending on the amount received compared to the market price. However, there is still some exposure to market risk, so the cost will likely still be higher than in the case of CfDs. A RAB model is a potential model that has been suggested for the United Kingdom's nuclear industry.[54] It would not only provide a promised price for the carbon removal, hence removing market risk, but it also provides payments during the construction phase of the project, reducing construction risk. As a result, the discount rate and net removed cost is reduced by even more than CfDs. However, the government will need a centralised market and appointed regulator to implement this policy. The regulator agrees on the market price and the advanced payments received during construction with the developer. The cost of these advanced payments is then provided by a price increase in the centralised market, effectively shifting the construction risk onto the consumer of the CO_2 removal certificates. An even larger reduction in the discount rate and net removed cost could be achieved via a state-owned enterprise since the state has a higher risk tolerance than the private sector. However, the potential implementation of these is highly subject to the socio-political environment. A compromise could be a public-private partnership (PPP) where a certain amount of risk is transferred onto the state from the private sector depending on the exact PPP model chosen. Yet, there is debate over the actual effectiveness of PPPs.[91] Finally, tax-advantaged financing structures could make investment more attractive. Examples of these are Master Limited Partnerships, Retail Estate Investment Trusts, or Private Activity Bonds.[92,93] A summary of the policies discussed and their categorisation is displayed in Figure 7. It should be noted in Figure 7, there will be overlap between accelerating scale-up and long-term cost reductions. For example, the RAB model could also prove useful during for accelerating scale-up if a regulator and centralised market can be mobilised fast enough.

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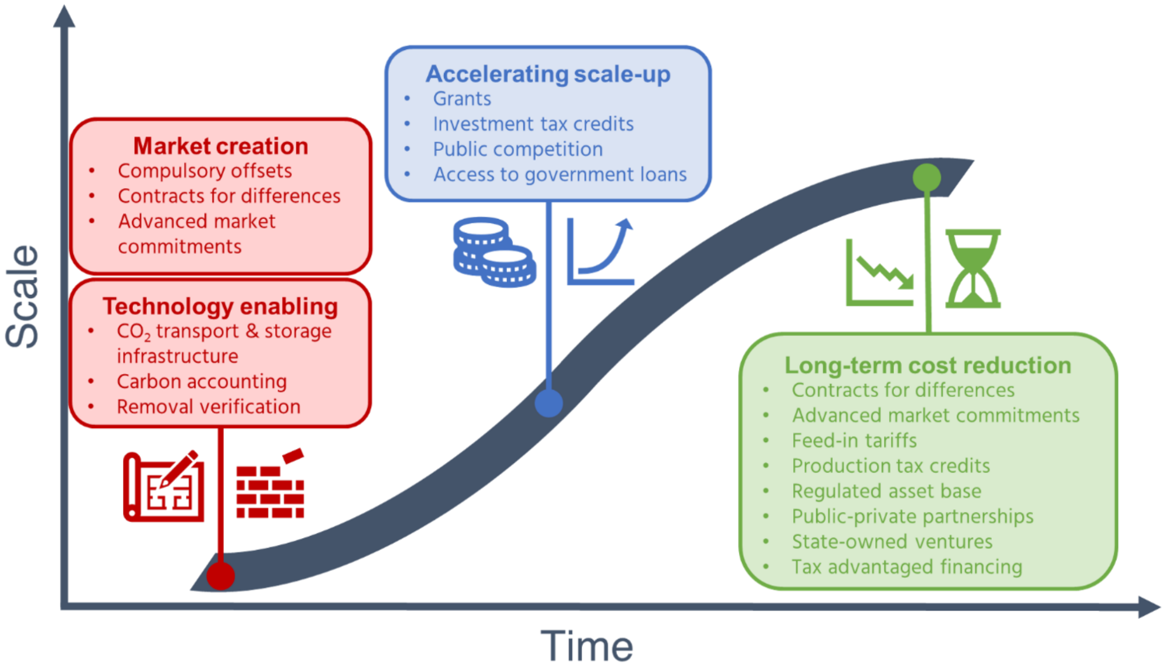

Figure 7 A selection of different policy levers available to support DACS. A complete list of policies considered and their relations to the cost reductions in Figure 8 is available in the ESI in Table S10.

Figure 8 quantifies how a selection of such policy instruments might affect the costs of net CO_2 removal via DACS. Meanwhile, Table 4 shows the percentage cost reduction at the start and end of the learning curves in Figure 8. The figure shows the median learning curves for net removed costs in the United States paired to wind electricity and a heat pump for low-grade heat where appropriate, while Figure S8 shows the full ranges for the same case.

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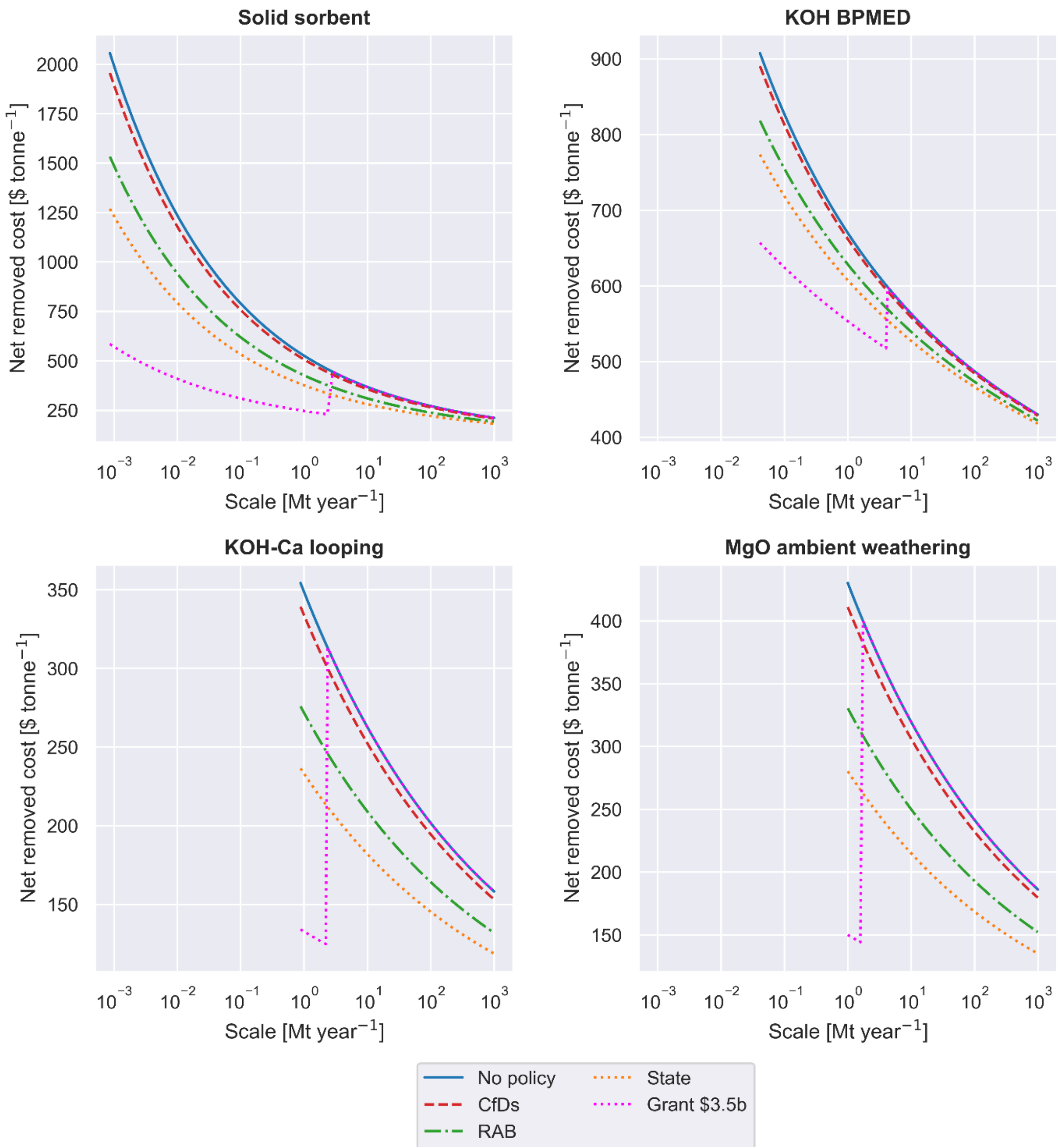

Figure 8 Median net removed costs of each DACS technology with different policies. This is for the United States paired with wind electricity and a heat pump for low-grade heat where appropriate. The full range of possible values is found in the ESI Figure S8. The variation in the discount rate by the policy is shown in the ESI Table S11.

The presented learning curve for grants in this figure represents a scenario where a government wants to spend $3.5 billion on grants (equivalent to the sum made available by the US government in their Bipartisan Infrastructure Bill of 2021) to pay for the scale-up of a technology.[49] Grants have a high potential to reduce the FOAK costs with a median reduction of 72% for the solid sorbent process and around 63% and 65% for the KOH-Ca looping and MgO ambient weathering processes, respectively. These initial cost reductions could help the technology scale until sufficient learning has happened for the technology to be viable without support. The grants pay for more iterations of the modular technologies, with a visible step-up in each graph when the grant runs out somewhere

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between 1 Mt-CO_2 year^{-1} and 10 Mt-CO_2 year^{-1} for all technologies. So, a grant of this size would allow one technology to reach the Mt-CO_2 year^{-1} scale. It would also benefit the modular technologies more than the technologies that scale with size: the median costs for the solid sorbent process will have come down from over \$2000 t-$CO_2{}^{-1}$ to below \$500 t-$CO_2{}^{-1}$ once the grant runs out, a decrease of over 75%. The median costs for the KOH-Ca looping process can be brought down from approximately \$350 t-$CO_2{}^{-1}$ to just over \$300 t-$CO_2{}^{-1}$ with the same grant size, a reduction of less than 15%.

The "State" learning curve shows the potential impact of providing state-backed loans in Figure 8. They also have a considerable potential to reduce the FOAK costs. For example, this reduction is 35% for the MgO looping ambient weathering process. These large initial reductions are another promising route to accelerating scale-up. In this case, the loan will likely be repaid in contrast to grants where the money is never repaid. This means the cost to the government will be lower and will be essentially the risk of the loan not being paid back. It is important to note that we leave this label simply as "State" as the same curve could be relevant to a state-run enterprise. The large impact on FOAK costs is through a substantial reduction in the discount rate (we here assumed a reduction from the baseline 10% to 2%, as evidenced and explained in the ESI Table S10). The impact of the lower discount rate is commensurate to the sensitivity analysis results in the ESI Figures S5-S6, where the discount rate is the fourth most influential factor on FOAK costs for all technologies apart from KOH BPMED where it is seventh.

In Table 4, we see that, at the Gt-CO_2 year^{-1} scale, the cost reductions achieved by the RAB model and CfDs for the MgO ambient weathering and KOH-Ca looping processes are more prominent than for the more modular technologies. This is because the technologies have lower learning rates and have undergone fewer doublings, so they retain a higher proportion of their costs as capital costs, which are the costs impacted by a reduction in the discount rate achieved by these policies. Nevertheless, for all technologies, these two policies have a considerable impact at the Gt-CO_2 year^{-1} scale, with median reductions of up to 4% and 18% for CfDs and a RAB model, respectively, in the case of the MgO with ambient weathering process. If we make an analogy with the electricity market, for example, a reduction of 18% in cost would have a significant and positive impact for the consumer. In the case of a RAB model, the extra cost is to organise the regulatory body to regulate a centralised market. So, the cost of this would need to be balanced against the cost reductions achieved.

Table 4 Median cost reductions from the original cost achieved for different technologies and policies at two scales, FOAK and Gt-CO_2 year^{-1} extracted from Figure 8. This is for the United States paired with wind electricity and a heat pump for low-grade heat where appropriate.

Technology	**CfDs [%]**		**RAB [%]**		**State [%]**		**Grant $3.5b [%]**	
Scale	FOAK	Gt-CO_2 year^{-1}	FOAK	Gt-CO_2 year^{-1}	FOAK	Gt-CO_2 year^{-1}	FOAK	Gt-CO_2 year^{-1}
KOH-Ca looping	4.3	3.2	22.2	16.8	33.4	25.2	62.5	N/A
KOH BPMED	1.9	0.4	9.8	1.9	14.8	2.8	27.6	N/A
Solid sorbent	4.9	1.8	25.5	9.3	38.3	13.9	71.6	N/A
MgO ambient weathering	4.5	3.5	23.2	18.2	34.9	27.4	65.1	N/A

There are promising approaches to encourage the scale-up and drive future cost reductions of DACS. State-backed loans, grants, and investment tax credits are all encouraging options to achieve this. The approach chosen will depend on the political and economic environment within the country of interest. There are also possibilities to reduce the long-term costs in the future using policies such as CfDs and a RAB model. Here, the benefits of these approaches should be weighed against their respective costs to make an informed decision on which path to pursue.

5 CONCLUSIONS

This work sought to answer the question "where are the costs of direct air capture and storage heading, and what influence does siting and policy have?" by estimating ranges for the current and future costs of four case study direct air capture technologies paired with CO_2 transport and storage. We performed this analysis across eight different countries, five sources of low-carbon electricity, and a selection of policy interventions.

The key takeaway is that the costs of the first few commercial-scale projects will likely be much higher than the values, currently, quoted in the public and academic discourse (i.e., approximately \$200 t-CO_2^{-1} for the KOH-Ca looping type process and \$600 t-CO_2^{-1} for a solid sorbent type process). For a plant in the United States paired to wind electricity and a heat-pump for low-grade heat where applicable, these first-of-a-kind (FOAK) net removed costs were estimated as i) \$230-580 t-CO_2^{-1} for KOH-Ca looping, ii) \$690-1230 t-CO_2^{-1} for KOH BPMED, iii) \$1250-3000 t-CO_2^{-1} for solid sorbent, and iv) \$260-760 t-CO_2^{-1} for MgO ambient weathering. However, technological learning will drive down the costs as a function of repetition and learning by doing, to an average of several 100's of dollars per tonne CO_2 net removed. Using technology learning curves, our study forecasted that the

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costs may reduce, at the Gt-CO_2 year^{-1} scale for a plant in the United States paired to wind electricity and a heat-pump for low-grade heat where applicable, to i) \$80-410 t-CO_2^{-1} for KOH-Ca looping, ii) \$240-780 t-CO_2^{-1} for KOH BPMED, iii) \$100-590 t-CO_2^{-1} for solid sorbent, and iv) \$80-520 t-CO_2^{-1} for MgO ambient weathering. Our analysis suggests that this plateau in costs will likely be reached between 2050 and 2075 regardless of technology and siting, depending on the targeted maximum temperature increase (1.5°C or 2°C) and CDR demand-pull and technology-push.

Modularity is a crucial driving factor for the FOAK costs, with more modular technologies exhibiting higher FOAK costs due to lack of economic benefits of scale. However, the higher learning rates, due to the modularity, means these higher costs are no longer observed as markets mature. Investment grants also favour modular technologies more than the larger unit-size technologies, as a capped subsidy pot will allow more deployment doublings for the modular technologies. The larger-unit technologies benefit much more from policy interventions which lower the weighted average cost of capital, such as CfDs or state-backed loans, because grants do not enable the same number of doublings as for modular technologies. However, these technologies do benefit from economies of scale that are not felt by more modular technologies. FOAK plants are also usually dominated by capital costs, so locations with lower construction materials and labour costs show lower overall costs. However, as the technologies mature, low energy prices and carbon intensity become more crucial. Wind, hydro, and nuclear are among the most beneficial electricity sources to pair with DACS due to their lower price and carbon intensity. We show that intelligent siting and electricity source selection can potentially save hundreds to a few thousand dollars per t-CO_2, depending on the technology and scale, demonstrating that this is critical.

Four policy aspects were found critical to support DACS deployment: i) technology enabling, ii) market creation, iii) accelerating scale-up, and iv) long-term cost reduction. To make large-scale DACS feasible, proper and widely accepted methods for carbon accounting and removal verification, and access to CO_2 transport and storage infrastructure are critical requirements. Compulsory offsets, contracts for difference and advanced market commitments can help create markets initially, whilst capital support mechanisms, such as grants, government loans, and investment tax credits, are vital to accelerating scale-up in these early stages as the FOAK plants are capital intensive. Finally, we showed that contracts for difference or a regulated asset base model could be excellent options to help minimise the costs of DACS in the long-term. Meanwhile, there is much work to be done by research and industry to develop and learn as much as possible about these technologies to enable technological learning.

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7 AUTHOR CONTRIBUTIONS

Conceptualisation was contributed to by John Young (JY), Noah McQueen (NM), Charithea Charalambous (CC), Spyros Foteinis (SF), Olivia Hawrot (OH), Manuel Ojeda (MO), Hélène Pilorgé (HP), John Andresen (JA), Peter Psarras (PP), Phil Renforth (PR), Susana Garcia (SG), and Mijndert van der Spek (MvdS). Formal analysis was contributed to by JY, NM, CC, SF, OH, MO, HP, JA, PP, PR, SG, and MvdS. Investigation was contributed to by JY, NM, CC, SF, OH, MO, HP, JA, PP, PR, SG, and MvdS. Methodology was contributed to by JY, NM, CC, SF, OH, MO, HP, JA, PP, PR, SG, and MvdS. Software was contributed to by JY, NM, SF, MO, PP and MvdS. Visualisation was contributed to by JY, HP, and MvdS. Writing – original draft was contributed to by JY. Writing – review and editing was contributed to by NM, CC, SF, OH, MO, HP, JA, PP, PR, SG and MvdS.

8 DECLARATION OF INTERESTS

Noah McQueen and Phil Renforth are named inventors on Patent Application Systems and Methods for Enhanced Weathering and Calcining for CO_2 Removal from Air, no. 62/865,708, filed on June 24, 2019, based on the MgO ambient weathering technology discussed in this work, and described in a previous paper by McQueen et al. 2020 which is referenced in this paper. Noah McQueen is also employed by Heirloom Carbon Technologies, Inc.

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